FINAL

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, October 6, 2022, at the Renaissance Providence Downtown Hotel, Providence, Rhode Island. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by telephone.

Mr. Thomas Kaslow, Acting Chair, presided, and Mr. David Doot, Secretary, recorded.

APPROVAL OF SEPTEMBER 1, 2022 MEETING MINUTES

Mr. Kaslow referred the Committee to the preliminary minutes of the September 1, 2022 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Sam Mintz noted.

CONSENT AGENDA

Mr. Kaslow referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Mintz noted.

ISO CEO REPORT

ISO Board and Board Committee Meeting Summaries

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the September 1, 2022 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

Stipulation and Consent Agreement Resolving FERC Enforcement Investigation of the ISO's Role In Certain Capacity Payments to Salem Harbor

Mr. van Welie then noted the ISO's recent settlement with the FERC Office of Enforcement (OE), which had also been circulated and posted in advance of the meeting, and asked Ms. Maria Gulluni, ISO General Counsel, to summarize the settlement and Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), to provide further information about actions undertaken by the ISO to prevent similar situations in the future.

To start, Ms. Gulluni noted that the FERC had approved the ISO's stipulation and settlement agreement with FERC OE stemming from the investigation of the ISO's capacity payments to Salem Harbor Power Development LP (Footprint) for Footprint's Salem Harbor Generating Station project before that project had commenced commercial operation, with the facts summarized in the FERC order and in a previous stipulation and settlement agreement between FERC OE and Footprint. Ms. Gulluni stated that the ISO viewed the root cause of the issue to be Footprint's failure to report accurate information to ISO staff, but also believed it was in the best interest of the ISO and stakeholders to settle the OE matter in order to avoid distractions from the already very challenging tasks facing the ISO. The ISO also acknowledged and accepted responsibility for inadequacies in the Tariff and its internal controls that permitted the failure to occur. For these reasons, Ms. Gulluni stated, the ISO agreed to the $500,000 financial penalty outlined in the settlement agreement. She noted that ISO management had proposed to the Board that the penalty be paid through a reduction in executive compensation to prevent additional financial impact on stakeholders; the Board had accepted that suggestion. Per the Stipulation and Consent Agreement, the ISO would also spend an additional $350,000 in compliance program investments over a number of years to strengthen the ISO's compliance culture.

Ms. Gulluni and Dr. Chadalavada then highlighted some of the changes that the ISO had implemented to ensure that similar issues could be avoided, or identified and addressed promptly. Specifically, the ISO had worked with stakeholders to change Capacity Market rules to include an automatic financial penalty for resources that are late to eliminate any subjective determination on the commercial readiness of a project. In addition, the ISO restructured departments, put in place mechanisms to foster increased information exchange among internal groups, and improved its internal reporting systems so ISO staff could raise issues for resolution in an effective and timely manner. They noted that the ISO would continue to fine-tune its internal processes as it learned from this experience. Dr. Chadalavada requested that members give ISO employees some time to process the recent developments and changes.

Committee members were then invited to comment and ask questions. In response to questions about the financial effects of the settlement, Mr. van Welie clarified that the $500,000 penalty will be taken out of senior management's 2023 incentive compensation and that the $350,000 in compliance investments had already been budgeted for, avoiding further incremental costs to stakeholders. Some members observed that Market Participants from time-to-time need to work with ISO staff to address ambiguous or unworkable Tariff provisions and there was fear that this event would make staff far less willing to work with the Market Participants. Mr. van Welie noted that the ISO's changed compliance procedures now encourage ISO staff to raise such issues with senior management sooner. Dr. Chadalavada added that the ISO had implemented a new case management process to log poorly-designed or unworkable Tariff provisions as well as disagreements between departments. These controls were designed to reduce Tariff problems and ambiguities in the future. Members urged the ISO to consider further process improvements to address stakeholder issues with Tariff problems or ambiguities. The

ISO noted that it was open to feedback and suggestions from stakeholders to improve the communication and feedback loop.

Noting how counterintuitive it would likely be to impose a fine on an ISO or RTO, a member asked whether anything could be done with FERC or OE to address more effectively problems with regional tariffs or their administration. The ISO responded that it was considering ways to improve the markets, such as those changes recommended by the External Market Monitor (EMM) to change the Capacity Market to a prompt market rather than a forward market, in order to reduce complexity and risk. Otherwise, the ISO noted that Tariff enforcement was within the prerogative of OE and the FERC and was beyond the ISO's control.

Finally, a member expressed appreciation for the ISO employees that had raised concerns with the ISO about its Tariff and Tariff administration. The ISO was urged to positively recognize and reward those employees in order to encourage such positive behavior in the future.

ISO COO REPORT

Operations Report

Dr. Chadalavada began his report first by referring the Committee to his October operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through September 28, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for September 2022 was $662 million, down $731 million from the updated August 2022 value and up $151 million from September 2021; (ii) September 2022 average natural gas prices were 17% lower than August average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for September ($62.61/MWh) were 35% lower than August averages; (iv) average September 2022 natural gas prices and Real-Time Hub LMPs over the period were up 56% and 34%, respectively, from September 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99.9% during September (down from the 102.2% reported for August), with the minimum value for the month of 90.4% on September 2; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for September totaled $2 million, which was down $4.5 million from August 2022 and up $0.6 million from September 2021. September NCPC payments, which were 0.3% of total Energy Market value, were comprised of (a) $1.9 million in first contingency payments (down $4.1 million from August); (b) $120,000 in second contingency payments (up $116,000 from August); and (c) $11,000 in distribution payments (down $491,000 from August).

Discussing the status of planned regional transmission outages, he highlighted one outage, on 345kV Line 347 (Killingly-Sherman Road), planned for November 16 through December 9, 2022, which had the potential to require second contingency commitments to protect the west-to-east interface. He also cautioned Market Participants to pay attention to the large number of small outages on both sides of the New York-New England interface scheduled for the fall, too numerous to permit specific identification, which would impact the interface's transfer capability on a daily basis between early October and December and could impact NCPC.

In response to questions, Dr. Chadalavada confirmed that there had been no changes to the 2022 Peak Load for Forward Capacity Market (FCM) purposes that had been identified in his e-mail update circulated following the September Participants Committee meeting.

Mystic Cost-of-Service Agreement

Dr. Chadalavada then referred to a letter from load serving entities (LSE Group) addressed to he and Mr. Van Welie, circulated and posted with the materials for the meeting, concerning the costs of the Mystic Cost-of-Service (COS) Agreement. He explained that the ISO understood the concerns raised and planned to present at the next Markets Committee (MC) meeting information about the COS Agreement and to present some scenario analysis making assumptions as to the administration of the contract during different operating scenarios. He encouraged Market Participants to follow up with remaining questions after they had received that presentation. He explained that the ISO was well aware of the potential impact this COS Agreement could have on consumers and had begun exploring cost allocation changes beyond year one given the potential impact on retail rates. The ISO planned to reach out to consumer representatives, Transmission Owners, and LSEs to explore potential changes to cost allocation for the second year of the COS Agreement. He encouraged bilateral discussions of these important issues between counterparties as well.

Members then reacted to that presentation. One member explained that the outstanding uncertainty was very adversely affecting both the competitive retail market and the willingness of suppliers to bid to supply absent very large risk premiums. The ISO was urged to provide transparency as to future costs so that future supplies could be priced based on more reliable and verifiable information. There was a very real risk, absent the ISO addressing this issue or changes in cost allocation from Real Time Load Obligation, that future requests to suppliers to provide default service would go unanswered. Dr. Chadalavada acknowledged those concerns, noted the audit provisions under the COS Agreement, and noted that the ISO had hired Levitan & Associates, Inc. to report quarterly on the actual administration of the fuel purchase provisions of the Agreement. Other members reinforced the urgency of the concerns raised by the COS Agreement’s costs, explaining that there were numerous upcoming auctions for default service across the New England states. Members suggested alternative scenarios that the ISO might present based on historic liquefied natural gas (LNG) to help bound the very significant uncertainty as to exposure for these costs and how best to handle them going forward. They suggested that the range of predicted potential outcomes under the COS Agreement run by some members suggest Agreement costs of one billion dollars or more. Other members explained that the concerns expressed in the LSE Group's letter were shared across the Supplier Sector and not just by the signatories to the letter, emphasizing the portion of the letter encouraging the ISO to explain by back-casting what happened in July and August to help Market Participants better understand the potential exposure going forward.

For the ISO, Dr. Chadalavada acknowledged the urgency of the situation and committed the ISO to share as much as it could without violating Information Policy requirements, including discussions with Mystic to permit some sharing of confidential information. He again commended the members to review the upcoming MC presentation.

Continuing with questions and feedback, a member expressed the potential adverse implications on Financial Assurance requirements, with such large sums changing hands monthly under the COS Agreement, and asked the ISO to look at whether there were escape clauses in the contract that could limit exposure to the region. Further, this member suggested that the ISO might consider planned load shed rather than paying extremely high LNG prices. The load shed suggestion was rejected by others. Members from the Publicly Owned Entity Sector and the End User Sector both urged the ISO to ensure consultation with their members. A member of the Transmission Sector urged the ISO to consider carefully the timing of any change in cost allocation in order to ensure consumers do not have to pay twice for this risk, once through higher pricing under an existing supply contract in contemplation of the supplier wearing that risk and a second time to allocate Mystic costs directly to consumers. The ISO was also encouraged to consider the possibility of creatively seeking FERC assistance in addressing these circumstances, without any particular idea to suggest.

Dr. Chadalavada responded to these various points, confirming that discussion of load shed for financial reasons was not being considered and that no change to cost allocation would happen without full input from all stakeholders in all Sectors. He urged engaged and informed participation at the Markets Committee as these issues and where concerns would be discussed more fully.

Draft 2022 Work Plan

Dr. Chadalavada then transitioned to discuss the ISO's Work Plan, which had been circulated to members in advance of the meeting and posted with the Committee materials. He noted the active participation by NEPOOL members through their officers in the priority setting process for the Work Plan. He explained that approach was different than in prior years and was helpful in the ISO's deciding on priorities for the many challenges it was facing. He noted the ISO's positive reaction to the feedback as reflected in the Work Plan.

Dr. Chadalavada then highlighted the following markets and operations anchor projects, as well as one of the notable market initiatives, summarized in the work plan presentation: Day-Ahead Ancillary Services initiative (DASI), Resource Capacity Accreditation (RCA), Energy Adequacy (EA) project, and the evaluation of alternative FCM commitment horizons.

With respect to the DASI project, Dr. Chadalavada highlighted that the project was scheduled to begin in the fourth quarter of 2022 and to continue into, and for much of, 2023. He said that the project would require an intense effort to complete ahead of the planned date for filing at the FERC at the end of 2023. He reminded Participants that the implementation of the DASI project was being de-coupled from the FCM cycle, which meant that implementation was being targeted for Winter 2024-25, rather than waiting until the Capacity Commitment Period associated with the FCA held in 2024.

Addressing the RCA project, Dr. Chadalavada noted that efforts to implement new methodologies to quantify/accredit resources' capacity contributions to regional resource adequacy were already underway and would continue through summer 2023. The ISO was planning for a filing by the fourth quarter of 2023 and implementing the identified changes for FCA19. He referred to his October 3 memo, included and posted with the materials for the meeting, that addressed the scope of what was and was not planned for inclusion in the RCA proposal planned to be filed with the FERC at the end of 2023. In response to questions, he acknowledged that all of the items, even those not specifically within the scope of the project, including the underlying framework for how tie benefits are derived, were worthy of consideration, but to the extent they would be addressed, they would be addressed in subsequent phases of RCA. He explained that the efforts underway were to establish a cornerstone for RCA and not to define a complete project.

Acknowledging concerns expressed with the underlying framework for the establishment of tie benefits, Dr. Chadalavada committed that the ISO's RCA FERC filing would make clear the ISO's willingness to discuss that framework, and to include such discussion as a project, in 2024, but said that the ISO would not be able to address or complete that effort in 2023. He went on to explain preliminary ISO plans to consider the application of seasonality to tie benefits (including HQICCs) and to explore whether outages of transmission lines that contribute to the determination of tie benefits can be factored into that calculation and methodology, roughly approximating an RCA value. Although work on the tie benefits issues would continue into subsequent RCA phases, the ISO would in the initial RCA phase solicit and incorporate as appropriate input on how best to model tie benefits as part of that phase. Dr. Chadalavada added that the initial phase would also provide the region with a substantially better starting point from which to fully address the tie benefits issue in later phases.

Some members strongly supported consideration of seasonality of tie benefits, and many expressed a desire to go further in the consideration of tie benefits, including suggesting other alternative approaches that could be considered, than those detailed in the work plan. Following further member comments, Dr. Chadalavada stated that future efforts on the tie benefits issue would include input from, and would be studied with, all perspectives in mind, including value to consumers and the value of ties with neighboring control areas during times of scarcity.

Turning to the Energy Adequacy project, Dr. Chadalavada highlighted that, in part in response to the NESCOE memo included and posted with the materials, the ISO had for clarity identified the periods represented by immediate-term (Winter 2022/23), short-term (Winters 2023/2024 and 2024/2025), medium-term (Winters 2025/2026 through 2032/2033), and longer-term (beyond 2033). He reviewed a slide setting out a schedule for the EA project over the next six to eight months. In response to questions on this project, Dr. Chadalavada confirmed that the probabilistic study undertaken by the Electric Power Research Institute (EPRI) and the ISO would be the starting point analytics-wise, and would include market-based options, but acknowledged that there may be other scenarios of interest to be studied. He was confident that the platform provided by that study would help inform any additional studies. A member asked that the ISO include in the EA project consideration of the role of the capacity market in obtaining access to energy in return for capacity payments.

Dr. Chadalavada then highlighted the 2023 initiative to assess alternative FCM commitment horizons. Consistent with the External Market Monitor's most recent report and recommendation to move towards a prompt seasonal capacity market, the ISO planned to assess in 2023 and to consult with stakeholders in 2024 on a potential construct that could replace the FCA with a prompt capacity auction. Preliminary ISO thinking had identified both benefits and trade-offs that warranted further assessment. Some members, expressing some disappointment with the timing of the emergence of this initiative, requested that the ISO minimize the impact of the initiative on ISO resources and focus on anchor projects.

In response to additional questions and comments on the work plan, Dr. Chadalavada committed to circulate and post an updated work plan reflecting the Participants Committee discussion. He confirmed that 'right-sizing' transmission was part of the work plan and would be reflected in that update. He also confirmed that FCA18 was the target for implementation of a three-year capacity time-out and more-targeted financial assurance requirements.

2026-27 (FCA17) CAPACITY COMMITMENT PERIOD HQICC AND ICR VALUES

Ms. Emily Laine, Reliability Committee (RC) Chair, referred the Committee to materials circulated in advance of the meeting concerning the Hydro-Québec Interconnection Capability Credits (HQICC) Values and the Installed Capacity Requirement (ICR) values and the related demand curves (collectively, the ICR Values) to be used for the 2026-27 Capacity Commitment Period associated with FCA17. She reported that, following development by the ISO in consultation with the Power Supply Planning Committee, the RC recommended at its September 20, 2022 meeting Participants Committee support for both the HQICC Values and the ICR Values.

The Acting Chair suggested that, based on the outcomes at the RC, and absent objection, the Committee take action on the HQICC and ICR Values together, in a single vote. Mr. Doot confirmed that the HQICC and ICR Values each required a 60% NEPOOL Vote to pass. No one raised any objections to taking action on the HQICC and ICR Values in a single vote.

Accordingly, the following motions were then together duly made and seconded:

> RESOLVED, that the Participants Committee supports the ***FCA17 HQICC Values***, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its October 6, 2022 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

> RESOLVED, that the Participants Committee supports the ***FCA17 ICR Values***, as proposed by the ISO and recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its October 6, 2022 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

With the motions before the Participants Committee, the members provided comments. A number of members expressed concerns, as more fully explained at the RC, on the issue of tie benefits. While acknowledging that the tie benefits calculations followed and were consistent with the Tariff requirements, the members averred that the results produced were nevertheless neither rational nor consistent with New England's reliability concerns. They highlighted the fact that tie benefits had reached record levels, as had assumed assistance/support from New York, notwithstanding increasing pressures on resources within their control areas related to the clean energy transition. The ISO explained that the region needed to revisit the calculation of tie benefits, as well as the determination of ICRs, more holistically in connection with the efforts to redefine resource capacity accreditation, but would not be in a position immediately to modify its calculations of ICRs and tie benefits absent considerably more work and study. Members were pleased that the ISO had agreed to take a more holistic view of the tie benefits piece, and acknowledged that the work on any changes would be challenging and would take quite some time to reflect in the Tariff. Some expressed concern with the length of time projected to address the acknowledged shortcomings with the calculation, including the potential exacerbation of current challenges with respect to retirements, particularly as the region moves toward the various clean energy reforms and a better design for energy adequacy.

A member asked whether the ISO was willing to begin discussion of tie benefits ahead of the ISO's commitment to take up the issue in 2024 as discussed earlier in the meeting. Subject to confirmation with ISO staff, and upon a better understanding of the impacts of the work underway on RCA, Dr. Chadalavada agreed that it would be reasonable to minimally begin discussions on what areas of study would be feasible to improve upon in the modeling of tie benefits. That member thanked Dr. Chadalavada for that assurance and committed to work further with the ISO on the contours of his request.

Other members echoed concerns expressed previously in the consideration of HQICC and ICR Values. The Calpine representative stated that, although Calpine would be opposed in the vote on the motions given Calpine's previously-articulated objection to the reliance by the region on non-capacity-backed tie benefits to satisfy regional capacity requirements, he was heartened that the ISO planned to look at the tie benefits issue, even if not as quickly as he would have preferred. Representatives of the Cross-Sound Cable (CSC) and LIPA stated that, as they had with prior ICR and HQICC votes, those Participants would oppose the resolutions because in their view the underlying calculations failed to take into account the reliability benefits (including emergency energy assistance) that the Cross-Sound Cable had and would continue to provide to New England.

Noting in a bit further detail the mechanics and reasoning for the inclusion of tie benefits in the calculation of ICR, a representative of numerous members that supported the motion acknowledged the timeliness and sensibility of evaluating those calculations in the future, but urged continued inclusion of benefits of reserve sharing arrangements with the region's neighbors in those calculations. Others supporting the motion similarly concurred that the application that the tie benefits calculations followed and were consistent with the Tariff requirements, but in contrast to the earlier concerns express, found the outcome appropriate and reasonable.

There being no further discussion, the motions were then voted and passed in the single vote with a 72.17% Vote in favor (Generation Sector – 5.57%; Transmission Sector – 16.70%;

Supplier Sector – 0%; AR Sector – 16.5%; Publicly Owned Entity Sector – 16.70%; End User Sector – 16.70%; and Provisional Members – 0%). (*See* Vote 1 on Attachment 2).

The Committee broke for a brief lunch recess and later reconvened to address the following:

2023 ISO AND NESCOE BUDGETS

2023 ISO Budgets

Mr. Kaslow referred the Committee to the materials circulated in advance of the meeting related to the proposed 2023 ISO Capital and Operating Budgets (ISO Budgets). He summarized the process followed to review the ISO Budgets with members and regulators, and noted that there had been no concerns raised by Participants in that process. He introduced Mr. Robert Ludlow, ISO Chief Financial and Compliance Officer, who thanked the Participants for their engagement in the process and reported that the ISO Budgets as presented at the meeting reflected and were consistent with both the discussions held since June on those Budgets, as well as with the work plan reviewed by Dr. Chadalavada earlier in the meeting.

The following motion was duly made, seconded and approved, with all members present voting in support except for an opposition noted by CSC and an abstention noted by Mr. Mintz:

> RESOLVED, that the Participants Committee supports the Year 2023 operating budget and capital budget proposed by the ISO as presented at this meeting.

2023 NESCOE Budget

Mr. Kaslow then referred the Committee to the NESCOE budget materials posted in advance of the meeting. He stated that the 2023 NESCOE Budget had been reviewed, without objection or concern, by the Budget & Finance Subcommittee at meetings in July and August and the 2023 NESCOE Budget conformed to the 5-year budget framework supported by the Participants Committee at its last meeting and pending before the FERC.

Without discussion, the following motion was duly made, seconded, and approved unanimously, with abstentions noted by CSC and Mr. Mintz:

> RESOLVED, that the Participants Committee supports the 2023 NESCOE budget, as proposed by NESCOE at this meeting, as the Year 2023 operating budget for NESCOE.

STORAGE AS A TRANSMISSION-ONLY ASSET (SATOA) PROPOSAL

Ms. Laine, Transmission Committee (TC) Chair, provided an overview of the SATOA Proposal, which the ISO developed in response to some stakeholders' requests. She reported that the TC recommended Participants Committee support for the SATOA-related revisions under the TC's purview at its August 16, 2022 meeting, as described in materials circulated in advance of the Participants Committee meeting. Ms. Laine also reported that the Markets Committee recommended Participants Committee support for the SATOA-related revisions under the MC's purview at its September 13–14, 2022 meeting, as described in materials circulated in advance of the Participants Committee meeting.

The Chair suggested that the Committee consider the SATOA revisions together in a single vote, absent objection. Mr. Doot explained that the TC-recommended changes required a 66.67% vote to pass, while the MC-recommended revisions required a 60% vote to pass. Thus, to approve the needed revisions to effectuate the SATOA Proposal, the Participants Committee vote needed to be at or above 66.67%. No one raised any objections to taking a single vote on the two sets of changes.

With that understanding, the following motions were together duly made and seconded:

> RESOLVED, that the Participants Committee supports the SATOA Proposal as reflected in revisions to ***Sections I and II of the*** Transmission, Markets and Services ***Tariff, and to the Transmission Operating Agreement***, 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.
>
> FURTHER RESOLVED, that the Participants Committee supports the SATOA Proposal as reflected in ***revisions to Section I.2.2 and Market Rule 1***, as recommended by the Markets 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 Markets Committee.

With the motions before the Participants Committee, members provided comments. Those that opposed the SATOA Proposal expressed concern that it did not sufficiently define the circumstance of when and how a SATOA would be dispatched. They also noted that a SATOA, once dispatched, could impact prices, including scarcity pricing. At the request of a member opposing the Proposal, Dr. Chadalavada committed that the ISO’s transmittal letter to the FERC would explain that a SATOA would have a narrow operating range and that a SATOA would be used solely for non-transmission purposes to mitigate load shed. Dr. Chadalavada also stated that the letter would discuss potential pricing impact. A number of members that previously opposed the SATOA Proposal indicated that they would abstain based on this commitment to make SATOA energy available in only very limited circumstances. Those members that supported the SATOA Proposal opined that it offered the least cost solution, that it was good for the region and would benefit ratepayers, and that it resulted from compromise.

One member who represented numerous Participants explained that the Entities he represented strongly supported the SATOA concept but they would abstain because they disagreed with withholding a SATOA’s energy when the ISO was taking Operating Procedure-4 actions, such as voltage reduction. He opined that Reserve-Constraint Penalty Factors would be binding and at their limit if the ISO called for voltage reduction. Thus, Energy and/or Reserve prices would not be impacted if a SATOA was dispatched when the ISO called for voltage reduction.

In response to another member's questions, the ISO confirmed that SATOAs were limited to storage approved for regional cost allocation in lieu of an alternative, more costly regionally-allocated transmission solution. Accordingly, the ISO representative opined, that SATOA treatment was not available under the SATOA Proposal for a resource that proponents would like to be treated as an Elective Transmission Upgrade. For that reason, the member later indicated when voting that the Participant he represented abstained on, rather than supported, the SATOA Proposal.

Various Committee members thanked the ISO, and the ISO's representative also thanked the Committee for its support in developing the Proposal that tried to balance transmission needs without impacting the market.

The motions were then voted and passed in the single vote with an 83.32% Vote in favor (Generation Sector – 5.57%; Transmission Sector – 16.68%; Supplier Sector – 11.13%; AR Sector – 16.5%; Publicly Owned Entity Sector – 16.68%; End User Sector – 16.68%; and Provisional Members – 0.08%). (*See* Vote 2 on Attachment 2).

NUPOWER REQUEST FOR WAIVER OF GIS OPERATING RULES AND GIS AGREEMENT

At the request of the Acting Chair, Mr. Paul Belval, NEPOOL Counsel, referring to materials circulated for Agenda Item #8, summarized NuPower Cherry Street, LLC's (NuPower) request to waive certain Generation Information System (GIS) Operating Rules and portions of the GIS Agreement between APX and NEPOOL to allow for changes to NuPower's renewable energy Certificates for February and March of this year (the Certificates). Mr. Belval explained that NuPower initially sought to correct the Certificates without a waiver, based on GIS Operating Rule 3.8. which permits Certificates to be changed based on, among other reasons, an error in the GIS software. APX disputed that there was any such error in the GIS software. In light of that disagreement and the fact that it is unlikely that there was additional evidence to demonstrate such an error, NuPower sought relief instead through the requested waiver. Mr. Belval reminded the Committee that it had previously discussed a similar GIS waiver request in 2021, and the Committee concluded that it needed a recommendation from the Markets Committee both on whether waivers should be considered by the Participants Committee and, if so, what standards should be applied for such consideration. The Markets Committee, in response to that referral, sought a recommendation from the GIS Operating Rules Working Group, and the requestor withdrew its waiver request after the Working Group met to discuss that waiver, but before further action was taken by a Principal Committee.

Based on this history, Mr. Belval explained that the Participants Committee could either act directly on NuPower's waiver request without any recommendation from the Markets Committee or GIS Operating Rules Working Group, or the Committee could refer the matter to either or both of the Markets Committee and/or the GIS Operating Rules Working Group to recommend criteria to apply to future waiver requests to correct erroneous certificates and to determine whether NEPOOL should grant the waivers requested to correct the Certificates.

Finally, Mr. Belval explained that APX would also need to agree to any waiver, and it had indicated a willingness to do so, but only if NuPower affirmatively rescinded its claim of an error in the GIS software. APX also requested that NEPOOL agree to amend the GIS Agreement to provide (1) NEPOOL the authority to waive the GIS Rules to permit adjustments to Certificates without APX's consent, and (2) for APX either to charge NEPOOL for time spent on waiver requests at its standard hourly rates or to charge that time against the 500 annual development hours included in the fee paid under the GIS Agreement (the Amendment Request). If NEPOOL were willing to grant waivers of the GIS Agreement, Mr. Belval suggested that NEPOOL Counsel work with the Chair of the NPC, Mr. Cavanaugh, to discuss and draft such an amendment, without the need for formal Participants Committee action on such an amendment prior to considering NuPower's current waiver request. Mr. Belval also noted that such an amendment to the GIS Agreement might be coupled with a revision to the GIS Operating Rules to require parties seeking waivers to pay NEPOOL's costs in considering those waiver requests, including amounts due to APX and to NEPOOL counsel.

At the request of the Acting Chair, a NuPower representative provided the Committee further context for NuPower's request. He reported that the Certificates for February and March that were the subject of the waiver request were worth about $20,000. He explained that this was a significant sum for NuPower, which was focused on providing renewable power for the benefit of low income consumers and a magnet school. He reported that NuPower had sought the requested relief from Connecticut Public Utilities Regulatory Authority (CT PURA), but CT PURA denied that request. Final action on NuPower's request was needed by years' end if NuPower were to be paid for its Certificates.

The Committee discussed the matter, with a number of members noting that CT PURA differs from other New England states in its willingness to address errors or omissions in Certificates. Other members opined that the GIS was created as a service to the New England states to help meet their RPS requirements so it should be up to each state to make such determinations on changes to Certificates.

Based on discussion, it was agreed generally that, if NuPower's waiver request was referred for further consideration, the GIS Working Group should discuss criteria to consider future similar waiver requests, which members considered to be inevitable. Some members expressed the general view that, were NEPOOL to consider future waiver requests, NEPOOL should look to the states to provide criteria for waivers that they find acceptable.

A number of NPC members expressed support for granting the requested waiver stating that mistakes and administrative errors occur and waivers should be granted for honest mistakes. Any criteria that the GIS Working Group considers should weed out reckless mistakes from those that are simple, honest errors. Conversely, some NPC members stated that no waivers should be granted, noting that NEPOOL would be overwhelmed with challenging requests.

Based on the members' varying viewpoints and perceived desire for more information before acting on NuPower's request, the Acting Chair suggested that the waiver request be referred to the GIS Working Group for consideration and for a recommendation to the NPC, prior to the end of the year, both on (1) criteria to apply in acting on the NuPower waiver request and future waiver requests; and (2) the specific waiver sought by NuPower. He explained that any voting member was entitled to seek formal action during this meeting, without such a recommendation, since this matter had been noticed for formal action. No member requested formal action at that time.

LITIGATION REPORT

Mr. Doot referred the Committee to the October 4 Litigation Report that had been circulated and posted the day before the meeting. He highlighted the FERC's September 23, 2022 order directing the ISO to refile, on or before November 23, 2022, the Tariff provisions governing the Inventoried Energy Program (IEP), consistent with the D.C. Circuit's June 17, 2022 decision. That decision left intact the FERC-accepted IEP provisions except for the inclusion in the IEP of payments to nuclear, biomass, coal, and hydroelectric generation. Mr. Doot encouraged those with questions on this or any other matter covered in the Report to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the MC had a two-day meeting in Westborough the following week and that meeting would include, in addition to continued discussion of RCA, a first look at a Day-Ahead Reserves proposal, discussion of Mystic (as previously discussed), and an update on IEP pricing. He noted that a third day was scheduled for a joint meeting with the RC on October 18, following the conclusion of the RC meeting earlier that day. Looking ahead, he noted that additional MC meeting days, beyond those already on the calendar, would be scheduled for November and December. Further, in order to get through the foreseeable business of that Committee, members should plan for at least three days of MC meetings per month in the early part of 2023.

Reliability Committee. Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting was scheduled for October 18 (to be followed by a joint RC-MC meeting as noted by Mr. Fowler). He highlighted as an item of interest the proposal to use a series reactor at Scobie Pond that would reduce the short circuit duty at Seabrook station below its rating.

Transmission Committee. Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for October 26 and would include review of changes to the economic study process provisions in Attachment K proposed in response to the Future Grid Reliability Study efforts.

Budget & Finance (B&F) Subcommittee. Mr. Kaslow reported that the next B&F Subcommittee meeting was scheduled for October 11.

Joint Nominating Committee (JNC). On a JNC-related matter, Ms. Michelle Gardner advised the Committee that she would present at the November Participants Committee meeting a limited Participant proposal to amend the Participants Agreement simply to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75. She encouraged anyone with questions before that meeting to reach out to her.

ADMINISTRATIVE MATTERS

The Acting Chair reminded members of (i) the 2023 officer election process (details of which were included in the materials circulated and posted with the meeting materials) and (ii) the Wednesday, November 2 modified Sector meetings with the ISO Board panels, materials for which were due to Ms. Gulluni at the end of the following week. He reported that the Wednesday, November 2 meetings would be held also at the Renaissance Providence Downtown Hotel. Looking ahead, he noted that the December Annual Meeting was scheduled for December 1, 2022 at the Colonnade Hotel in Boston.

There being no other business, the meeting adjourned at 2:22 p.m.

Respectfully submitted,

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David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCTOBER 6, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard		
AR Large Renewable Gen. (RG) Group Member	AR-RG	Alex Worsley (tel)		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	
Bath Iron Works Corporation	End User		Howard Plante (tel)	Bill Short; Gus Fromuth
Belmont Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Block Island Utility District	Publicly Owned Entity			Brian Forshaw (tel)
Boylston Municipal Light Department	Publicly Owned Entity	Matt Ide		
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG	Dan Allegretti		
Chester Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller (tel)
Competitive Energy Services, LLC	Supplier		Eben Perkins (tel)	
Concord Municipal Light Plant	Publicly Owned Entity			Brian Forshaw (tel)
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User	Claire Coleman (tel)		J.R. Viglione
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Steve Kirk	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity			Brian Forshaw (tel)
Dominion Energy Generation Marketing	Generation	Wes Walker (tel)	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short; Gus Fromuth
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Supplier	Brett Kruse Liz Delaney		Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User	Gus Fromuth	Howard Plante	Bill Short
Generation Group Member	Generation	Dennis Duffy	Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Granite Shore Power Companies	Generation			Bob Stein (tel)
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User	Gus Fromuth	Howard Plante	Bill Short

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCTOBER 6, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Harvard Dedicated Energy Limited	End User			Patricio Silva
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Interconnect Storage LLC		Colleen Nash (tel)		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	
Jupiter Power	Provisional Member			Ron Carrier (tel)
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity			Brian Forshaw (tel)
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny (tel)	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		José Rotger
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	
Maple Energy LLC	AR-LR			Doug Hurley
Marble River, LLC	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General's Office (MA AG)	End User		Jamie Donovan	Ashley Gagnon
Mass. Bay Transportation Authority	Publicly Owned Entity			Brian Forshaw (tel)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Middleborough Gas & Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Middleton Municipal Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Mintz, Samuel	End User	Sam Mintz (tel)		
Moore Company	End User			Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		
Natural Resources Defense Council (NRDC)	End User	Bruce Ho (tel)		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User			Patricio Silva
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin (tel)	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Norwood Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
NRG Power Marketing LLC	Supplier		Pete Fuller (tel)	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity			Brian Forshaw (tel)
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	
PowerOptions, Inc.	End User			Patricio Silva
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Rowley Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCTOBER 6, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide		
Saint Anselm College	End User	Gus Fromuth		Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User	Gus Fromuth	Howard Plante (tel)	Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	
Stowe Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Sunrun Inc.	AR-DG			Peter Fuller (tel)
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont		Brian Forshaw (tel)
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		
The Energy Consortium	End User	Bob Espindola (tel)	Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR			Patricio Silva
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission		Dave Norman (tel)	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
Wallingford DPU Electric Division	Publicly Owned Entity			Brian Forshaw (tel)
Wellesley Municipal Light Plant	Publicly Owned Entity			Brian Forshaw (tel)
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Westfield Gas & Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH LLC	End User		Gus Fromuth	Bill Short

OCTOBER 6, 2022 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON FCA17 HQICCs/ICR VALUES (VOTE 1) AND SATOA PROPOSAL (VOTE 2)

TOTAL

Sector	Vote 1	Vote 2
GENERATION	5.57	5.57
TRANSMISSION	16.70	16.68
SUPPLIER	0.00	11.13
ALTERNATIVE RESOURCES	16.50	16.50
PUBLICLY OWNED ENTITY	16.70	16.68
END USER	16.70	16.68
PROVISIONAL MEMBERS	0.00	0.08
% IN FAVOR	**72.17**	**83.32**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2
CPV Towantic, LLC	O	O
Dominion Energy Generation Mktg	A	A
FirstLight Power Management, LLC	A	A
Generation Group Member	F	F
Granite Shore Power Companies	O	O
Nautilus Power, LLC	A	A
NextEra Energy Resources, LLC	A	A
IN FAVOR (F)	1	1
OPPOSED (O)	2	2
TOTAL VOTES	3	3
ABSTENTIONS (A)	4	4

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
Avangrid (CMP/UI)	F	F
Eversource Energy	F	F
Narragansett Electric (d/b/a Rhode Island Energy)	F	F
New England Power (d/b/a National Grid)	F	A
VELCO	F	F
Versant Power	F	F
IN FAVOR (F)	6	5
OPPOSED (O)	0	0
TOTAL VOTES	6	5
ABSTENTIONS (A)	0	1

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
Central Rivers Power	A	F
ENGIE Energy Marketing NA, Inc.	A	F
Great River Hydro, LLC	A	A
Jericho Power LLC	A	F
Wheelabrator/Macquarie	A	F
Large RG Group Member	F	F
Distributed Gen. Sub-Sector		
CLEAResult Consulting, Inc.	A	--
Sunrun Inc.	A	F
Load Response Sub-Sector		
Icetec Energy Services, Inc.	F	F
Maple Energy	F	F
Vermont Energy Investment Corp.	A	F
Small LR Group Member	A	F
IN FAVOR (F)	3	10
OPPOSED (O)	0	0
TOTAL VOTES	3	10
ABSTENTIONS (A)	9	1

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2
BP Energy Company	A	F
Brookfield Renew. Trading & Mktg	A	F
Castleton Comm. Merchant Trading	O	O
Clearway Power Marketing LLC	A	F
Competitive Energy Services, LLC	A	--
Constellation Energy Generation	A	A
Cross-Sound Cable Company	O	F
DTE Energy Trading, Inc.	A	F
Dynegy Marketing and Trade, LLC	A	F
ECP Companies	Split	Split
Calpine	O	A
Accelerate	A	A
Emera Energy Services Companies	A	A
Galt Power, Inc.	A	F
H.Q. Energy Services (U.S.) Inc.	A	O
LIPA	O	A
Marble River, LLC	A	O
Mercuria Energy America, Inc.	A	F
NRG Power Marketing, LLC	A	A
Shell Energy North America (US)	A	O
IN FAVOR (F)	0	8
OPPOSED (O)	4	4
TOTAL VOTES	4	12
ABSTENTIONS (A)	15	5

ATTACHMENT 2

OCTOBER 6, 2022 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON FCA17 HQICCs/ICR VALUES (VOTE 1) AND SATOA PROPOSAL (VOTE 2)

END USER SECTOR

Participant Name	Vote 1	Vote 2
Acadia Center	A	F
Associated Industries of Mass.	A	F
Bath Iron Works Corporation	A	F
Conn. Office of Consumer Counsel	A	--
Conservation Law Foundation	A	F
Durgin and Crowell Lumber Co.	A	F
Elektrisola, Inc.	A	F
Garland Manufacturing Co.	A	F
Hammond Lumber Company	A	F
Harvard Dedicated Energy Limited	A	F
High Liner Foods (USA) Inc.	A	F
Maine Public Advocate Office	F	F
Mass. Attorney General's Office	F	F
Mass. Climate Action Network	A	--
Mass. Department of Capital Asset Management	A	F
Mintz, Samuel	A	A
Moore Company	A	F
Natural Resources Defense Council	A	F
New Hampshire OCA	A	F
Nylon Corporation of America	A	F
PowerOptions, Inc.	A	F
Shipyard Brewing Co.	A	F
St. Anselm College	A	F
The Energy Consortium	A	F
Z-TECH, LLC	A	F
IN FAVOR (F)	2	22
OPPOSED (O)	0	0
TOTAL VOTES	2	22
ABSTENTIONS (A)	23	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	F	A
Belmont Municipal Light Dept.	O	F
Block Island Utility District	F	F
Boylston Municipal Light Dept.	O	A
Braintree Electric Light Dept.	F	F
Chester Municipal Light Dept.	F	F
Chicopee Municipal Lighting Plant	O	A
Concord Municipal Light Plant	F	F
Conn. Mun. Electric Energy Coop.	F	A
Danvers Electric Division	F	F
Georgetown Municipal Light Dept.	F	F
Groton Electric Light Dept.	O	A
Groveland Electric Light Dept.	F	F
Hingham Municipal Lighting Plant	F	F
Holden Municipal Light Dept.	O	A

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2
Holyoke Gas & Electric Dept.	O	A
Hull Municipal Lighting Plant	O	A
Ipswich Municipal Light Dept.	O	A
Littleton (MA) Electric Light Dept.	F	F
Mansfield Municipal Electric Dept.	O	A
Marblehead Municipal Light Dept.	O	A
Mass. Bay Transportation Authority	F	F
Mass. Mun. Wholesale Electric Co.	O	A
Merrimac Municipal Light Dept.	F	F
Middleborough Gas and Elec. Dept.	F	F
Middleton Municipal Electric Dept.	F	F
New Hampshire Electric Cooperative	F	A
North Attleborough	F	F
Norwood Municipal Light Dept.	F	F
Pascoag Utility District	F	F
Paxton Municipal Light Dept.	O	A
Peabody Municipal Light Plant	O	A
Princeton Municipal Light Dept.	O	A
Reading Municipal Light Dept.	F	F
Rowley Municipal Lighting Plant	F	F
Russell Municipal Light Dept.	O	A
Shrewsbury's Elec. & Cable Ops.	O	A
South Hadley Electric Light Dept.	O	A
Sterling Municipal Electric Light Dept.	O	A
Stowe (VT) Electric Dept.	F	F
Taunton Municipal Lighting Plant	F	F
Templeton Municipal Lighting Plant	O	A
Village of Hyde Park (VT) Elec. Dept.	F	F
VT Public Power Supply Authority	A	A
Wakefield Mun. Gas and Light Dept.	O	A
Wallingford, Town of	F	F
Wellesley Municipal Light Plant	F	F
West Boylston Mun. Lighting Plant	O	A
Westfield Gas & Electric Light Dept.	F	F
IN FAVOR (F)	49	25
OPPOSED (O)	0	0
TOTAL VOTES	49	25
ABSTENTIONS (A)	0	24

PROVISIONAL MEMBERS

Participant Name	Vote 1	Vote 2
Jupiter Power LLC	A	F
IN FAVOR (F)	0	1
OPPOSED (O)	0	0
TOTAL VOTES	0	1
ABSTENTIONS (A)	1	0