NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

July 30, 2026

VIA E-MAIL

TO: **PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**

RE: Supplemental Notice of August 6, 2026 Participants Committee Webex Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the August 2026 meeting of the Participants Committee will be held **via Webex on Thursday, August 6, 2026, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

To join the meeting using the enhanced Webex interface, please **download the Webex app** to your desktop or to your phone (whichever device you will be using) **in advance of the meeting** and use the app to join the meeting. You may also access the meeting through the ISO's Webex meetings page by clicking https://iso-newengland.webex.com/webappng/sites/iso-newengland/meeting/home and selecting the meeting (event password = **nepool**).

Looking ahead:

- **September Participants Committee Meeting – Portland, Maine**. The September NPC meeting is scheduled for **Thursday, September 3, 2026**, and will be held in person at the ***Portland Sheraton at Sable Oaks***, 200 Sable Oaks Drive, South Portland, Maine. There are a limited number of rooms available at the Sheraton Sable Oaks for the evening before the September 3 meeting at the rate of $219.00 per night, on a first-come, first-served basis through Wednesday, August 12, 2026. Please contact Laura Clark who may be able to assist with your overnight arrangements.

- **October Participants Committee Meeting – Portsmouth, New Hampshire**. The October NPC meeting will be held on ***Friday***, ***October 2***, **2026 [NOTE THE CHANGE IN DATE]**, and will be held in person at the ***AC Hotel Portsmouth Downtown/Waterfront***, 299 Vaughan St., Portsmouth, New Hampshire. There are a limited number of rooms available at the AC Hotel for the evening before the October 2 meeting at the rate of $279.00 per night, on a first-come, first-served basis through Wednesday, September 9, 2026. Please contact Laura Clark who may be able to assist with your overnight arrangements.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

NEPOOL

FINAL AGENDA

1. To approve the draft minutes of the June 16-18, 2026 Participants Committee Summer Meeting, which are included and posted with this supplemental notice. Please provide us with any comments on these draft minutes no later than ***Tuesday, August 4, 2026***.

2. To adopt and approve the actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials.

2A. To consider, and take action, as appropriate, on revisions to Section IV.A of the Tariff (Self-Funding Tariff) to reflect implementation of the Asset Condition Reviewer process. Background materials, including a draft resolution, are included and posted with this supplemental notice.

3. To receive summaries of the ISO Board or Board Committee meetings held since the last summaries were circulated. The summaries will be circulated and posted in advance of the meeting.

4. To receive a Systems and Market Operations Report. The August Systems and Market Operations Report, reflecting July data, will be circulated and posted in advance of the meeting.

5. To receive a report on current contested matters before the FERC and the Federal Courts. The litigation report will be circulated and posted in advance of the meeting.

6. To receive reports from Committees, Subcommittees and other working groups:
   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Membership Subcommittee

7. Administrative matters.

8. To transact such other business as may properly come before the meeting.

Protocols. The NEPOOL general business portions and plenary sessions of the meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in this meeting must identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

PRELIMINARY

The 2026 Summer Meeting of the NEPOOL Participants Committee was held at Newport Harbor Island in Newport, Rhode Island, on Tuesday, June 16, and Wednesday, June 17, pursuant to notice duly given, followed on Thursday, June 18, by separate meetings between modified Sector groups and ISO Board Members, New England State officials, and FERC staff, 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 16. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting.

Ms. Sarah Bresolin, Chair, presided and Mr. Sebastian Lombardi, Secretary, recorded for the meeting.

JUNE 16, 2026 SESSION

The June 16, 2026 session began at 9:30 a.m., with Ms. Bresolin welcoming the members, alternates, federal and New England State officials, ISO colleagues, including members of the ISO Board, and guests who were present. Ms. Bresolin then invited, and those around the table each proceeded to, introduce themselves and identify on whose behalf they were participating in the meeting.

APPROVAL OF APRIL 30 AND MAY 7, 2026 MEETING MINUTES

At the conclusion of those introductions, Ms. Bresolin referred the Committee to the preliminary minutes of the April 30, 2026 special meeting and the May 7, 2026 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of those meetings were unanimously approved as circulated, with no abstentions recorded.

CONSENT AGENDA

Ms. Bresolin then 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 last circulated, except that Consent Agenda Item No. 1 (Changes to the Generation Information System (GIS) and GIS Operating Rules (MA Section 83D Certificates Changes)) was removed for separate consideration later in the meeting.

ISO CEO REPORT

In his quarterly remarks, Dr. Vamsi Chadalavada, ISO Chief Executive Officer (CEO), addressed the following four broad areas of importance: (i) the ISO's commitment to wholesale markets, the ISO's beliefs regarding (ii) consensus and (iii) agility, and (iv) the transition to Capacity Auction Reforms (CAR).

Commitment to Wholesale Markets

Noting the recent national debate over regulated and competitive wholesale market paradigms, Dr. Chadalavada emphasized the importance of reaffirming the region's confidence in wholesale markets, including a centralized capacity market, which he described as the only cost-effective vehicle for procuring needed reliability services. He said that attracting private capital requires confidence in the structural stability of markets from both regional and federal regulatory perspectives, visibility into forward prices and future demand, and confidence that the ISO will make needed course corrections to improve efficiencies and incent reliability services. He affirmed that the ISO's commitment to wholesale markets remained a core value shaping its mission and work.

Consensus

Addressing the power of consensus, Dr. Chadalavada emphasized that collaboration in the stakeholder process fills gaps in knowledge and experience and produces more durable solutions that balance market incentives with structural and regulatory stability. Consensus, he said, supports rather than compromises the ISO's core beliefs. Noting examples in other organized markets where a lack of consensus resulted in the loss of regional control, he challenged the ISO, stakeholders, and the States to sustain collaboration and engagement.

Agility

Dr. Chadalavada stressed the importance of prompt and timely action on design changes, even when faced with future, even dramatic, uncertainty. Citing several examples where the period between conception and implementation spanned several years, he suggested that the region engage in discussions on how to expedite, and more fully benefit from implementation of initiatives, without in any way shortchanging or clipping the stakeholder process.

A Transition Period for CAR Implementation

Finally, Dr. Chadalavada highlighted the advantages of transition periods for significant or complex market design reforms. He said that transitions can facilitate course corrections as impacts become better understood. He indicated that the ISO would use transitions as a fundamental approach where appropriate to maximize efficiency and retain directional control concerning our future grid system.

Several members expressed appreciation and support for Dr. Chadalavada's commitment to wholesale markets and the need to balance agility with effective stakeholder engagement and collaboration. Some encouraged greater precision regarding the areas under discussion. Dr. Chadalavada reaffirmed that stakeholder engagement and a respectful balancing of competing interests were critical to developing durable outcomes, and said that the ISO would bring its operational experience and judgment to any needed course corrections. Members also encouraged him to remind federal regulators of the region's confidence in competitive wholesale markets.

In final remarks, Dr. Chadalavada shared feedback from FERC Commissioners at a recent ISO/RTO Council (IRC) meeting identifying New England as a region where matters were being handled well. He stressed that the region's process, including how disagreements are identified and addressed, had made a favorable impression and challenged the region to maintain and build on that impression.

ISO SYSTEMS & MARKET OPERATIONS REPORT

Mr. Stephen George, ISO Vice President of System & Market Operations and Capital Projects, referred the Committee to the June System & Market Operations Report (Report), which had been circulated and posted in advance of the meeting. Mr. George began by highlighting several enhancements made to the format of the Report (summarized on slide 3 of the Report), which would be carried forward in future monthly reports, and encouraged Committee members to provide feedback on the enhancements.

Noting that data in the Report was for the full month of May 2026, Mr. George reviewed Report highlights, which included: (i) the Peak Hour for May 2026, with 19,496 MW of Revenue Quality Metered (RQM) Data, occurred on May 20, 2026 during the hour ending at 6:00 p.m. (Mr. George acknowledged that the day and hour were inadvertently omitted from the Report and would be included in future monthly reports); (ii) May averages for Day-Ahead Hub

Locational Marginal Price (LMP) ($45.80/MWh), Real-Time Hub LMP ($49.24/MWh), and natural gas prices ($2.20/MMBtu); (iii) Energy Market value for May 2026 was $466 million, up 2% from April 2026 and 40% from May 2025; (iv) Ancillary Markets value (-$10 million, largely attributable to the Day-Ahead Ancillary Services (DAAS) and Marginal Loss Revenue Fund close out results), was down 547% from April 2025 and more than four times that percentage from the -0.4 million in April 2026; (v) average Day-Ahead cleared physical energy during peak hours as a percentage of forecasted load (no longer identified as a specific percentage) was down from both April 2026 and May 2025; (vi) Net Commitment Period Compensation (NCPC) payments for May totaled $4.2 million (representing 0.9% of May's monthly Energy Market value), comprised of (a) $4.2 million in First Contingency payments (including $938,300 in Dispatch Lost Opportunity Costs, $482,600 in Rapid Response Pricing Opportunity Costs, and $37,000 paid to Real-Time Deviations) and (b) $77,700 in Second Contingency payments (there were no distribution or voltage in May); and (vii) a Forward Capacity Market (FCM) value of $89 million.

Mr. George then reviewed the May 19, 2026 Master/Local Control Center Procedure No. 2 (M/LCC 2) event. He noted that May 19 had the highest temperature and load for a May day since 2017. Temperatures and dew points came in 2–3° above forecast, producing an approximately 1,500 MW shortfall in forecasted supply; an unexpected New England Clean Energy Connect (NECEC) outage at 3:00 p.m. and stronger-than-expected thunderstorms added to the forecasting challenges. The ISO declared an M/LCC-2 Alert (projecting a *possible* capacity deficiency) at 4:00 p.m.; peak system load reached 18,707 MW; and the alert was cancelled at 10:00 p.m.

Mr. George noted two additional unplanned NECEC outages in May: one on May 20, and the other that began on May 25 (and ended June 7, 2026). In response to a question regarding the underlying causes of the outages, Mr. George clarified that each of the outages were equipment- and not weather-related, with the single day outages due to equipment-related issues in Maine and the longer-term outage that began on May 25 due to equipment issues in Quebec. He said that the ISO would continue to monitor the facility closely and maintain communications with the facility owners and operators.

With respect to upcoming planned transmission and generation outages, Mr. George referred to one of the new slides that highlighted two notable, longer-duration planned outages expected to impact transfer capability, particularly between New England and its neighboring control areas. With respect to the outage of a New Brunswick Generator (the Point Lepreau Nuclear Generation Station), scheduled to continue through July 27, 2026, transfer capability from New Brunswick to New England was expected to be reduced to 650 MW. In response to a question, Mr. George said that he did not believe that the impact of the outage on the external interface would also result in adjustments to downstream internal interfaces, such as Orrington-South or Keene Road and offered to expand in future reports the information provided on the planned outages slide to include any expected impacts on internal interfaces. He also noted that a second planned outage, of the 3001 Line (Keswick-Keene Road), planned to run from July 20 to July 30, 2026, was expected to reduce transfer capability from New Brunswick to New England to 270 MW.

In response to questions and comments, Mr. George explained that minimum load in May was affected by a combination of factors, including cloud cover and temperatures, and might have been lower had the day been sunnier. He confirmed that the ISO had on its list of to-dos to incorporate additional information related to behind-the-meter generation in its postings and reporting. He also confirmed that forecast error statistics accounted only for front-of-meter solar resources. Further, Mr. George explained that the ISO was closely monitoring the impact of minimum load on supply (including the risk of minimum load dipping below the sum of the region's nuclear supply), but offered examples of ways in which the risk of over-supply could and would be mitigated, including the growth of storage, the ability to export to neighboring control areas, market responses, and regional stakeholder discussions. He also noted ISO operational and planning initiatives under way to account for much lower loads.

Reacting to a question related to the increasing delta between cost of fuel and Day-Ahead Hub LMPs, Mr. George attributed the majority of the spread to increased CO_2 emission costs (particularly under the Regional Greenhouse Gas Initiative (RGGI) and Massachusetts Electricity Generator Emissions Limits (EGEL) programs). Mr. Matt White, ISO New England's Chief Economist and Vice President of Market Development and Settlements, confirmed that attribution, and pointed members to the annual reports of the Internal Market Monitor (IMM) and External Market Monitor (EMM) (each provided with materials for the meeting) for further information and explanation.

2027/2028 ISO PRELIMINARY BUDGETS

Ms. Kelly Reyngold, the ISO's Chief Financial Officer (CFO) and Treasurer, referred the Committee to the "top down" presentation of the ISO's 2027 and 2028 preliminary Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. She noted that the top-down presentation of the Budgets was to provide an opportunity for stakeholder review and feedback prior to presentation in August of a "bottom up" detailed budget reflecting feedback received. She reported that the preliminary budget had already been shared with New England State officials and the presentation incorporated their feedback.

Summarizing, Ms. Reyngold explained that the Budgets were designed to support the ISO's ability to operate in an environment of increasing system complexity, demand uncertainty, and rapid technology change, while maintaining a strong focus on affordability, reliability, and long-term value. The proposed 2027 Budget was $355.3 million, a 7.7% increase over the approved 2026 Budget, but a $9.4 million or 2.6% decrease from the prior year's 2027 Budget projections when excluding costs for the Asset Condition Reviewer (ACR) (2.2 million) and the second Longer-Term Transmission Planning (LTTP) study ($0.2 million).

Ms. Reyngold then highlighted the following factors, primarily structural, driving the increase from the 2026 Budget: changing resource mix and customer demand patterns; ongoing system transformation; inflationary and price escalation trends; costs to support new systems, markets, and infrastructure; the need to maintain ISO workforce capabilities; and affordability considerations (through investments prioritized to maintain reliability and avoid higher long-term system cost). Specifically, she identified and quantified the cost impacts of enterprise-wide inflationary pressures, costs to support new technology and innovation, and staff additions to support market, transmission and stakeholder initiatives/requests. She also highlighted and reviewed examples of cost efficiencies and reductions that would provide savings and reduce overall 2027 budget costs.

Turning to the preliminary 2027 Capital Budget, Ms. Reyngold noted that the 2027 Capital Budget was projected to be $45 million, a $2.5 million or 5.9% increase over the 2026 Capital Budget. She highlighted the significant projects expected for 2027 (including CAR implementation, the transition of Real-Time study modes to the nGEM platform, and the migration of ISO-NE's Energy Management System customizations to GE's Energy Management Platform version 3.5). Potential increases in future years could be anticipated, and would depend largely on regulatory direction, project timing, and the balance between internal resources and external support. She committed to provide transparency through the rolling 2-year Capital outlook.

Concluding, Ms. Reyngold identified some of the potential ways in which the Budget numbers could be increased/impacted, identifying, among others, cybersecurity, technology cost volatilities, insurance policy renewals and interest rate impacts, labor market and inflationary costs, and regulatory policy changes and requirements.

In response to questions, Ms. Reyngold clarified how the overall budget comparisons and the ACR full-time employee equivalent impacts were calculated and presented. Although she did not yet have sufficient information to summarize how the 2027 revenue requirements would affect Schedule 1, 2, and 3 rates, she emphasized that ACR costs would be recovered through, and likely increase, Schedule 1 rates. She hoped to provide an update on those rates before the Budgets were finalized and presented for Participants Committee action.

CALENDAR YEAR RATE REVISIONS

Mr. Tom Kaslow, Budget & Finance (B&F) Subcommittee Chair, introduced proposed changes to Section IV.A and Section IV.B of the Tariff to clarify how the ISO's annual rates, charges, and capital budget (together, the Calendar Year Rates) will be administered if, by January 1, those Calendar Year Rates have not been authorized by the FERC or have not otherwise become effective (due to the timing of a government shutdown or otherwise). He explained that the changes to Sections IV.A and IV.B of the Tariff would permit the ISO to continue to use the rates already in effect, until such time as the new rates could be approved and become effective. Mr. Kaslow reported that the proposed changes had been first reviewed by the B&F Subcommittee at its April meeting, with further refinements reviewed at its June meeting, and no issues or concerns had been raised with respect to the proposed Calendar Year Rate revisions.

The following motion was then duly made, seconded and approved unanimously, with an abstention by Mr. Jon Lamson noted:

> RESOLVED, that the Participants Committee supports the revisions to Tariff Sections IV.A and Section IV.B, as reflected in the materials 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.

PAY-FOR-PERFORMANCE (PFP) TREATMENT OF EXTERNAL TRANSACTIONS

Ms. Emily Laine, Markets Committee (MC) Chair, referred the Committee to the materials circulated in advance of the meeting regarding the proposed PFP treatment of external transactions during Capacity Scarcity Conditions (CSC). She noted that the changes were being proposed in response to concerns raised by the IMM, EMM, and stakeholders regarding potential inefficiencies under the existing treatment. She explained that the proposal would incorporate system-backed exports into the PFP construct, subjecting them to payments or penalties based on performance during CSCs. Ms. Laine reported that the MC reviewed the proposal at its March, April, and May meetings, and unanimously recommended Participants Committee support at its May meeting, with a number of abstentions recorded. She also reported that the B&F Subcommittee reviewed related changes to the Billing Policy and Financial Assurance Policy (FAP, and together with the Billing Policy, the Policies), with no objections raised.

Mr. Lombardi explained that action on the proposal and the Policies would be accomplished with separate resolutions and subject to different voting thresholds. However, in light of the outcome of the MC action and B&F discussions, he explained that, absent objection, action on the changes to the Market Rules and Policies could be taken by a single action. There being no objection to voting the changes by a single action, the following motions were together duly made and seconded:

> RESOLVED, that the Participants Committee supports the External Transaction Proposal revisions to Tariff Section I.2.2 and Market Rule 1, as recommended by the Markets Committee at its May 2026 meeting, together with such non-substantive changes as may be approved by the Chair of the Markets Committee.
>
> RESOLVED, that the Participants Committee supports the External Transaction Proposal revisions to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, as circulated in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

Without question or discussion, the Committee approved the motions in a single vote, with an opposition by MAG Energy Solutions and abstentions by FirstLight, BP, CSC, DTE, Galt, LIPA, Mercuria, and Mr. Lamson recorded.

BALANCING RATIO CAP COMPLIANCE CHANGES

Ms. Laine then referred the Committee to the materials related to the Balancing Ratio Compliance Proposal (BR Proposal) that were circulated and posted in advance of the meeting. She explained that, following a complaint by NEPGA, the FERC had ordered the ISO to cap the Balancing Ratio at 1, as reflected in the BR Proposal. She reported that the MC reviewed the BR Proposal at its March, April, and May meetings, and unanimously recommended Participants Committee support at its May meeting, with a couple of abstentions noted. Related FAP changes were reviewed by B&F without objection or concern.

As with the previous item, Mr. Lombardi suggested that, absent objection, the Committee could take action on the BR Proposal and FAP-related changes in a single action. There being no objection to voting the changes by a single action, the following motions were then together duly made and seconded:

> RESOLVED, that the Participants Committee supports the Tariff Section I.2.2 and Market Rule 1 revisions for the ISO's Balancing Ratio Compliance Proposal, as recommended by the Markets Committee at its May 2026 meeting and circulated 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 the ISO New England Financial Assurance Policy for the ISO's Balancing Ratio Compliance Proposal, as circulated in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

A NEPGA representative thanked the ISO for its efforts in response to the FERC order on its Complaint and noted NEPGA's support for the BR Proposal. Without further discussion, the Committee approved the motions in a single vote, with abstentions by FirstLight, HQ US and Mr. Lamson recorded.

PERFORMANCE PAYMENT RATE (PPR) PROPOSAL

Ms. Laine then introduced the Performance Payment Rate (PPR) Proposal, a proposed reduction of the PPR from $9,337/MWh to $3,500/MWh, which the ISO believed, based on prior experience, would incent performance and investment, while also addressing stakeholder concerns around financial risk at the currently effective rate. She reported that the MC reviewed the PPR Proposal at its March, April, and May meetings, with two Participant-proposed amendments considered as final MC action was taken – one by FirstLight to align the PPR reduction with the start of Capacity Commitment Period (CCP) 19 (effective June 1, 2028); the second by Canal Marketing (JERA Americas) to add a Tariff provision requiring the ISO to evaluate the PPR (assessing whether a graduated PPR structure, varying based on load levels and/or the severity of reserve shortages, would be appropriate) and issue a report on that assessment by December 15, 2027. Neither amendment was approved. The MC had recommended the unamended PPR Proposal for Participants Committee support, with an 82.23% Vote in favor.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports ISO-NE's PPR Proposal and related revisions to Section III.13.7 and Section III.15 of the Transmission, Markets, and Services Tariff, as recommended by the Markets Committee at its May 2026 meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

FirstLight PPR Effective Date Amendment

The FirstLight representative moved to amend the main motion to make the reduction in the PPR to $3,500/MWh effective at the start of the 2028/2029 CCP (June 1, 2028), and the motion was seconded. He explained FirstLight's concerns that the specific reliability need supporting an earlier effective date had not been adequately identified and that earlier implementation would disrupt the inter-relationship among the PPR, the Monthly and Annual Stop Losses, and the values used to calculate those Stop Loss triggers. Mr. Kaslow added that the PPR Proposal would reduce overperformance payment opportunities and affect the economics of original capacity sales.

A Supplier Sector representative supported the FirstLight PPR Effective Date Amendment, expressing concern that changing the PPR after certain decisions, offers, and commitments had been made for a CCP, but before the CCP concluded, could alter the applicable market rules mid-course and potentially erode confidence in the New England Markets.

The ISO responded that prompt implementation would reduce the risk that resources providing significant reliability value might leave the market because of exposure to the higher PPR. More broadly, Dr. Chadalavada emphasized that the ISO sought to preserve incentives to perform while avoiding a risk profile that could discourage market participation, thereby supporting market confidence and stability.

Following further discussion, a NESCOE representative explained that the New England States opposed the FirstLight amendment in light of the reliability benefits and broader reasons articulated by the ISO. Following a show of hands vote, the FirstLight PPR Effective Date Amendment was determined to have failed.

Unamended Main Motion

Before action on the unamended PPR Proposal, supporters cited the ISO's proactive and expedited approach and its evaluation of the PPR. Opponents expressed concern that the assessment was not sufficiently broad or well-supported and could adversely affect market design and confidence.

Without further discussion, the unamended main motion (to support the PPR Proposal) was determined by a show of hands to have been approved.

Canal Marketing (JERA Americas) Further Assessment Resolution

Mr. Lombardi, referring the Committee to materials circulated and posted in advance of the meeting, provided procedural background and an explanation of the separate resolution being proposed by JERA Americas. That resolution sought a commitment by the ISO in the filing of its PPR Proposal with the FERC (or in the absence of that commitment by the ISO, a request that the FERC direct the ISO in its order on the PPR Proposal) to conduct a further assessment of whether the Capacity PPR structure should be revised in the future to incorporate a graduated structure tied to load levels, reserve shortage severity, and/or a similar mechanism, with that assessment to be completed and provided to the NEPOOL Markets Committee no later than December 2027 (JERA Further Assessment Resolution). He confirmed that, as a procedural motion, the JERA Further Assessment Resolution would require a two-thirds vote to be approved.

Using the presentation posted with the meeting materials, the JERA Americas representative explained that the requested assessment was being sought through a filing letter commitment or FERC direction rather than through a Tariff provision, as initially proposed at the MC. He said that the assessment would evaluate potential improvements to PFP, including a graduated PPR or another mechanism, that there had not been sufficient time to consider while addressing immediate PPR concerns. He hoped that the results would be presented before the first auction following CAR implementation.

In response to clarifying questions, Mr. Lombardi explained the impact of the Further Assessment Resolution, if approved, and further confirmed that any such approval would not change the Committee's support for the PPR Proposal itself, but would inform NEPOOL's comments in the related FERC proceeding.

The JERA Americas representative clarified that the intent of the resolution was to encourage the assessment itself, without predetermining whether the assessment might suggest the continuation of a fixed PPR, a move to a graduated PPR, or establishment of another mechanism that might better tune PFP penalties and structure to the goals of the capacity market. In response to a further question, ISO Counsel, noting that the ISO would continue to evaluate changes to the PPR as the capacity market evolves, opined that comments related to the commitment and specifically-timed assessment were not likely to substantially reduce the chances that the FERC would accept the PPR Proposal itself.

The following resolution was then duly made and seconded:

> FURTHER RESOLVED, that the Participants Committee requests a commitment by ISO New England (ISO) in the filing of its PPR Proposal with the Federal Energy Regulatory Commission (FERC) (or in the absence of that commitment by the ISO, a request that the FERC direct the ISO in its order on the PPR Proposal) to conduct a further assessment of whether the Capacity Performance Payment Rate structure should be revised in the future to incorporate a graduated structure tied to load levels, reserve shortage severity, and/or a similar mechanism, with that assessment to be completed and provided to the NEPOOL Markets Committee no later than December 2027.

Commenting for the ISO, Mr. White reaffirmed the ISO's commitment to continuous market evaluation and stakeholder dialogue. He explained that the ISO's concerns with the Further Assessment Resolution were principally about timing -- the effect on broader regional priorities, interdependencies with other work unlikely to be completed in 2027, and the limited likelihood that a 2027 study would produce new empirical insights beyond those first presented in 2022 and updated since. He emphasized that the ISO was not opposed to considering a graduated PPR or other mechanisms and suggested the possibility that an assessment could occur with broader market reviews in 2028 or early 2029, including the review of Net Cost of New Entry (CONE) parameters.

Members opposing the JERA Further Assessment Resolution cited both its interaction with the 2027 Annual Work Plan process and substantive concerns about duplicating or delaying work already underway and assigning priority to a PFP assessment over other matters. Other members responded that its connection to annual priority setting process should not preclude its consideration and urged action on the merits.

Following final remarks from the JERA Americas representative and a show of hands vote, the JERA Further Assessment Resolution was determined to have failed.

DAY-AHEAD ANCILLARY SERVICES (DAAS) PROPOSAL

Following a recess for lunch, Ms. Laine introduced the Day-Ahead Ancillary Services (DAAS) Proposal. In response to the IMM's February 2026 report and recommendations, the ISO developed limited Market Rule changes addressing the Strike Price, the related mitigation threshold, and the Forecast Energy Requirement (FER) Demand Quantity (FER DQ), together with a DAAS-related Day-Ahead NCPC clean-up for import transactions. A separate recommendation to review and adjust the non-performance factor (NPF) had been considered by the Reliability Committee, and a 5% reduction was implemented on May 1, 2026).

Ms. Laine reported that, before recommending the DAAS Proposal, the MC considered an amendment proposed by FirstLight to remove the proposed Strike Price Floor and to instead commit when the DAAS refinements are filed to improve the ability of the Gaussian Mixture Model (GMM) to consistently forecast the expected Real-Time Energy LMP at the Hub (FirstLight MC Amendment). The FirstLight MC Amendment was considered but not supported by the MC, with a vote of 20.83% in favor. The ISO's unamended DAAS Proposal was recommended for Participants Committee support, by a 64.54% Vote in favor.

Accordingly, the following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports ISO-NE's DAAS Proposal and related revisions to Market Rule 1 of the Transmission, Markets, and Services Tariff, as recommended by the Markets Committee at its June 2026 meeting, together with

such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Generation Bridge Companies' Motion to Divide the Question

The Generation Bridge Companies representative moved to divide consideration of the DAAS Proposal into two parts: (i) the proposed Strike Price Floor component and (ii) the remaining components of the Proposal. He explained that separate consideration could increase support for the remaining components and provide the FERC greater transparency regarding Participants' positions on the reliability and cost impacts of the Strike Price Floor. Mr. Lombardi clarified that the procedural motion was not debatable and required a two-thirds Vote. Following a show of hands vote, the motion to divide the question was determined to have failed.

FirstLight Strike Price Amendment

The FirstLight representative identified three reasons for offering the FirstLight Strike Price Amendment to remove the proposed Strike Price Floor from the DAAS Proposal : (i) concerns with the balance between reliability incentives and cost reductions; (ii) vagueness in the proposed Tariff language; and (iii) pricing impacts associated with the resource type and the method used to establish the Strike Price Floor. The FirstLight Strike Price Amendment was then duly made and seconded.

A NESCOE representative thanked FirstLight for its work and expressed support for improving the consistency of the GMM, but explained why the States opposed the Amendment. The ISO responded that the Strike Price Floor appropriately balanced risks and incentives, was consistent with the IMM's recommendations, and could be revisited if new data supported a different conclusion; it also noted an agreement with the IMM to study the issue three years after initial implementation. Following concluding remarks and a show of hands vote, the FirstLight Strike Price Amendment was determined to have failed.

Unamended Main Motion

Opponents raised concerns with both major components of the unamended Main Motion. A NEPGA representative argued that FER DQ would depart from foundational DAAS principles and adversely affect market efficiency, pricing, revenue integrity, and reliability incentives. A Supplier Sector member opposed the Strike Price component because of its effect on non-oil resources, especially resources with Reference Prices below the Strike Price, and viewed the resulting increase as a material departure from the original design.

Supporters thanked the IMM and the ISO for promptly proposing targeted changes to address unanticipated market inefficiencies and attendant affordability impacts. They believed that the changes better aligned compensation with resource attributes and services, consistent with the original Ancillary Services Market design, and supported continued iterative refinements. A NESCOE representative explained the States' support for the ISO's unamended DAAS Proposal.

For the ISO, Mr. White emphasized the value and critical role of the DAAS Markets and committed the ISO to continued evaluation, including consideration of Participant feedback, to preserve key benefits .

Following a sector-weighted vote, the unamended main motion was approved with a 68.78% Vote in favor (Generation Sector - 0%; Transmission Sector - 16.67%; Supplier Sector - 9.52%; AR Sector - 9.25%; Publicly Owned Entity Sector – 16.67%; and End User Sector – 16.67%). (*See* Attachment 2.)

NEPOOL GIS SECTION 83D CERTIFICATE RULE CHANGES

Ms. Jamie St. Pierre, Chair of the GIS Working Group (GISWG), referred the Committee to materials circulated and posted in advance of the meeting regarding changes to the GIS and

GIS Operating Rules (the GIS Changes) related to marking of Renewable Energy Certificates (RECs) as being transferred under Section 83D of the Massachusetts Act Relative to Green Communities (Section 83D). Ms. St. Pierre reviewed the procedural history of Participant review of the GIS Changes, which she reported had been recommended unanimously for approval by the MC at its May 12 meeting, though pulled from the Consent Agenda by a Market Participant End User representative for discussion and possible amendment.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee approves the changes to the NEPOOL GIS and the GIS Operating Rules to allow the marking and designation of Certificates sold in accordance with agreements entered into in accordance with Section 83D of the Massachusetts Act Relative to Green Communities, as recommended by the Markets Committee at its May 12, 2026 meeting, together with such non-material changes thereto as may be approved after the meeting by the Chair of the Participants Committee.

Freedom Companies and Industrial Wind Action Group Amendment

Two End User Sector members, representing the Market Participant End Users represented by the Freedom Companies and the Wind Action Group then proposed to amend the Main Motion (Amendment) by adding the following proviso:

> *provided that the GISWG is directed to develop and present recommendations regarding reporting and transparency provisions for associated transmission flows and net regional deliveries related to such designated Certificates.*

The End User members explained that the proposed Amendment was in response to concerns raised by recurring simultaneous imports over the NECEC and exports over the Phase II and Highgate interconnections, as illustrated by a chart included in the materials posted and circulated with materials for the meeting. They clarified that the Amendment did not propose changes to Section 83D-marked Certificates or their treatment under the GIS.

Committee members then asked clarifying questions and provided comments. In comments, members questioned the need to identify and net out exports on the Certificates, noting the availability of that data via the ISO's dashboards and data downloads. Some were concerned about possible impacts on the contractual and regulatory frameworks approved by the Massachusetts Department of Public Utilities. A Transmission Sector representative cautioned against the use of simultaneous flows only, given contractual look-back and shortfall provisions in the NECEC arrangements that could result in later flows, and thereby muddy if not confuse the picture painted by information related solely to simultaneous flows. Others, appreciative that the data may raise questions and merit a separate review of the market dynamics and flows resulting from NECEC operations, did not believe that a closer look should be assigned to the GIS Working Group at this time, and that, so long as the renewable attribute qualifications under the PPAs were met, tracking and marking of the Certificates was appropriate under the GIS.

Following further discussion and a show of hands vote, the proposed Amendment was determined to have failed.

Unamended Main Motion

Without further discussion, the Committee then approved the Main Motion by a show of hands vote.

FERC STAFF INTRODUCTIONS & COMMENTS

Ms. Bresolin welcomed the following FERC representatives, thanked them for attending and participating in the Summer Meeting, and invited each to introduce himself: Mr. Noah Schlosser, Mr. Eric Jacobi, and Mr. Aaron Siskind.

Mr. Noah Schlosser, Supervisory Energy Industry Analyst with the Office of Energy Market Regulation (OEMR), said that he had been with the FERC for about seven years and had enjoyed opportunities to connect with Participants Committee members, particularly at prior Summer Meetings. He expressed his eagerness to discuss matters of interest with Participant representatives that were not otherwise prohibited under *ex parte* rules, whether informally during the meeting and organized activities or during the Sector meetings scheduled for the final day. He encouraged members to reach out with questions or inquiries.

Mr. Eric Jacobi shared that he had worked as part of OEMR for over 10 years and, as the regional representative for New England, regularly attended many NEPOOL Committee meetings, and enjoyed his opportunities to communicate separately with members about various matters of interest. Those meetings and communications were summarized in notes provided monthly in an RTO update from the ISO New England team. Mr. Jacobi also encouraged members to reach out to him with any questions, concerns, or comments pertaining to the region.

Mr. Aaron Siskind, Economist with the newly formed Office of Technical Reporting and Economics (OTRE), introduced himself and explained that the OTRE was the successor to the Office of Energy Policy and Innovation (OEPI). He stated that, following a reorganization, OTRE had assumed responsibility over the State of the Market Report published by FERC, the Summer and Winter Assessments, and assisting with organizing and running various technical conferences, while remaining involved in economic analysis and general monitoring. Mr. Siskind noted that, although OEMR was likely the primary point of FERC contact for members, he and his OTRE colleagues would be happy to help direct any communications on behalf of members to the FERC.

Ms. Bresolin thanked the FERC staff representatives for their introductions and willingness to work with Participant representatives and shared the Committee's interest in and anticipation for the Sector sessions scheduled for Thursday morning.

EMM 2025 ANNUAL MARKET REPORT

Overview

Dr. David Patton, President of Potomac Economics and the ISO's EMM, presented highlights from the EMM's 2025 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. In his introductory remarks, Dr. Patton noted that his report focused on key issues and market-related changes, among other topics, rather than on the prior year's outcomes, which were covered in detail in the ISO IMM's annual report.

Cross-Market Comparison

Dr. Patton began by discussing the "all-in" prices on a dollar-per-megawatt-hour basis across the various FERC-regulated markets and the Electric Reliability Council of Texas. His presentation showed that energy prices in New England remained consistently higher than those in other markets, which he explained was largely attributable to the region's higher natural gas prices, with the region's state greenhouse gas compliance costs also serving as a key driver of energy costs. His presentation showed that New England capacity prices had remained relatively stable over the prior three years.

In response to a question, Dr. Patton explained that ancillary services costs in New England were higher than in other RTOs/ISOs (excluding New York, where higher ancillary services costs are attributable to local requirements) because the region procures options on energy rather than reserves, which are more valuable and costly than reserves. He also explained that the amount of reserve quantities procured for the region's largest contingency, approximately 1 gigawatt (GW), represented a much larger share of the market in New England than it does in other markets.

Next, Dr. Patton discussed transmission congestion costs. He explained that New England experiences only a fraction (about one-tenth) of the congestion that other RTOs experience, due to the region's historically significant investment in transmission, which is in turn driven by ISO-NE's relatively conservative transmission security requirements, including its planning assessments. New England transmission rates, however, were more than double the average transmission rates in other ISO/RTOs, reaching slightly more than $29/MWh in 2025. In response to a question concerning price separation between Maine and the rest of the system, Dr. Patton explained that the price separation was driven by the NECEC contracts, which bias scheduling on that line over Phase II, a dynamic he expected to continue in 2026.

Dr. Patton then briefly discussed virtual transactions (increment bids and decrement offers) in New England, which were at a level of trading activity significantly lower than in other ISO/RTOs. He attributed the lower trading levels, in part, to the allocation of Net Commitment Period Compensation (NCPC) charges to virtual transactions, which discourage virtual trading. As a result, he opined that the Day-Ahead Energy Market was less liquid than in other regions. Although recognizing the possibility of contentious discussions, Dr. Patton reiterated his decades-long recommendation to revise NCPC cost allocation to more closely align with cost causation.

DAAS Markets Performance

Next, Dr. Patton described the DAAS markets as a significant improvement for New England that had lowered uplift costs and improved generator availability.

Referring to the IMM's estimate that the DAAS markets increased market costs by approximately **$974** million (9%), Dr. Patton suggested that the estimate likely overstated the increase because it did not fully account for lower Real-Time and Day-Ahead LMPs resulting from Day-Ahead commitments, or the higher revenue offsets used to calculate Demand Curve Net CONE. He added that higher DAAS revenues would also reduce capacity prices. Although the net consumer effect was difficult to quantify precisely, he said that those offsets could be evaluated over time.

Although the EMM strongly supported the ISO's proposal to raise the strike price and adjust the FER quantity, Dr. Patton also identified another potential improvement. Specifically, he suggested that the ISO review the mitigation structure, particularly the conduct threshold. He opined the threshold was likely too low because it did not adequately account for the legitimate range of resources' risk preferences.

Energy Affordability in New England

In light of the national discussion on energy affordability, Dr. Patton added a New England-focused section on affordability in his report. Referring to figures in his presentation, he said that New England retail rates (adjusted for inflation) increased by about 12% over the last decade, with rates in the region much higher than the national average. He explained that approximately 30% of the region's total cost of energy was associated with the ISO's wholesale markets.

Given that load-serving entities (including investor-owned utilities (IOUs) and competitive suppliers) enter into forward hedges and supply contracts, Dr. Patton explained that the primary drivers of those hedged wholesale costs are high forward fuel prices and higher emission allowance prices, including RGGI allowances. He noted that RGGI costs had reached approximately $11/MWh in 2026. Dr. Patton also observed that the spread between wholesale costs and residential retail costs was widening. He stated that the largest single driver of non-wholesale cost increases was transmission and distribution costs.

Dr. Patton made several suggestions to reduce retail rate pressure. Of the four recommendations in his report, he elaborated on the following three: (i) encouraging and permitting the conversion of gas-only resources to dual-fuel capability; (ii) increasing the opportunities and flexibility for IOU forward contracting; and (iii) assessing whether the Net CONE value should include the residual value of the incremental revenues earned by resources beyond the assumed 20-year economic life.

Resource Commitment and Pricing Issues

Next, Dr. Patton focused on system reliability issues. He began by addressing local reserve requirements. By way of background, he explained that local reserve requirements had been established about 20 years earlier and had not been revisited. Although some local reserve requirements had increased over time, others had receded. As a result, Dr. Patton opined, local reserve requirements were a poor reflection of current local needs. While this situation had not resulted in significant uplift costs, generators were not being compensated for satisfying local reserve requirements, resulting in inefficiencies and reducing incentives for generators to remain in, or invest in, those locations.

The second issue Dr. Patton raised concerned Day-Ahead imports receiving FER payments. These imports were neither obligated to be available, nor actually available in Real-Time, yet they receive FER payments. Dr. Patton noted the potential for gaming and strongly encouraged the ISO to address this issue.

Dr. Patton also provided his observations on the efficiency of Real-Time commitments. He explained that the Real-Time Unit Commitment (RTUC) model runs every 15 minutes to evaluate near-term conditions and commit fast-start resources, with results passed to the Unit Dispatch System (UDS) for execution. He noted that operators adjust load upward in RTUC, particularly during the first two intervals, resulting in price divergence between RTUC and UDS and increased Real-Time NCPC. He recommended that the ISO reassess its operator procedures and forecasting methods.

Reserve Pricing in the Fast-Start Pricing Logic

Acknowledging the challenges, Dr. Patton continued to recommend addressing what he believed was a flaw in the fast-start pricing logic for Operating Reserves that results in inefficient reserve pricing under certain conditions. He explained that when a fast-start resource operates at its Economic Minimum (EcoMin), it cannot set the marginal price. As a result, the megawatts available below the resource's EcoMin are undervalued, causing the system to appear short and artificially inflating Energy and Reserve prices.

Capacity Availability and Performance Issues

Dr. Patton then turned to the availability of qualified capacity (QC) during peak summer conditions. As detailed in his report, about 680 MW of QC was unavailable during peak conditions in the summer of 2025. One reason for that unavailability was that testing was performed under milder conditions, resulting in some thermal generators receiving favorable testing conditions that were not commensurate with observed peak summer conditions (with higher humidity, lower barometric pressure, and higher temperatures). Another reason, accounting for nearly 200 MW of unavailable QC, was underreported forced derates. Dr. Patton continued to recommend that the ISO enhance its testing procedures and strengthen its enforcement of derate reporting.

Pay-for-Performance (PFP) Assessment and Evaluation of the June 24, 2025 Capacity Scarcity Condition (CSC)

Discussing PFP, Dr. Patton noted favorably that the ISO had addressed a prior concern with paying non-Capacity Supply Obligation imports but not charging exports during PFP shortage events. He continued to recommend replacing the constant PPR with a graduated rate that would increase with the severity of a shortage event and pointed members to further detail in his report.

Turning to the June 24 event, Dr. Patton's analysis measured resources' performance, or lack thereof. His assessment concluded that between 150 MW and 270 MW (representing about 10 resources) did not perform when dispatched for energy but instead provided reserves, so as to be credited as performing during the CSC. Dr. Patton concluded that the incentives to perform in this way were problematic and should be revisited.

Further, noting that about 800 MW of reserves were not dispatched during the CSC, Dr. Patton continued to recommend that the ISO establish procedures to ensure that generators deemed to be performing are capable of providing energy and that existing requirements for generators to report derates accurately and promptly be enforced.

Recommendations

Dr. Patton concluded by reviewing a number of the recommendations included in the EMM Report, highlighting his recommendations to evaluate a look-ahead dispatch model to optimally manage fluctuations in net load and the use of storage resources, and to address shortcomings with PFP, shortage pricing and coordination between them.

RECOGNITION OF BOB STEIN

During the banquet that evening, the Committee endorsed by acclamation the following resolution of appreciation for Robert de R. Stein (Bob Stein) on the occasion of his retirement at the beginning of the month:

WHEREAS, for 55 years Bob has been involved in the New England Power Pool in a variety of roles, cutting his teeth as a transmission planning engineer for NEPOOL evaluating bulk power system performance, through a series of roles with Participants in the Publicly Owned Entity, Transmission and Supplier Sectors, and importantly as a member of this Committee since its establishment, representing many Participants in no less than three of the Pool's Sectors, serving as the Vice-Chairman for NEPOOL's Planning Committee, as a Vice-Chair of the Reliability Committee, as a Vice-Chair of the Supplier Sector, and for two years as Chairman of the Participants Committee; and

WHEREAS, Bob, throughout his time as a Participant representative and Committee member, has been a valued source of perspective, guidance and leadership for the betterment of the Pool; and

WHEREAS, throughout his time as a NEPOOL member and officer, Bob has gregariously demonstrated professionalism, integrity, dedication and understanding, unfailingly marked by a quick wit and sense of humor, in addressing the many thorny and challenging issues confronting NEPOOL and the New England region; and

WHEREAS, Bob has been a tireless advocate for efficient markets and, in many ways, the embodiment of the New England stakeholder process; and

WHEREAS, his time in the Pool has, like his time on his bike, been a memorable ride along a long and winding road.

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere gratitude to Bob for his many years of leadership and service to this Committee and to the New England region generally; and

BE IT FURTHER RESOLVED, that the Participants Committee extends to Bob our very best wishes for many more years of good health, smooth sailing, open road, and happiness, all rich with family, fulfillment and joy.

Signed and presented by the Chair of the NEPOOL Participants Committee on behalf of the NEPOOL Participants this 16th day of June, 2026, in Newport, Rhode Island.

JUNE 17 SESSION

The Summer Meeting reconvened at 9:30 a.m. on June 17, 2026.

REMARKS FROM THE HOST STATE (RI PUC CHAIRMAN RON GERWATOWSKI)

Ms. Bresolin introduced Mr. Ron Gerwatowski, Chairman of the Rhode Island Public Utilities Commission (RI PUC), who provided remarks on the occasion of the Summer Meeting being held in Newport. Acknowledging the energy policy disagreements that arise in New England, he observed that NEPOOL meetings reflected far more collegiality and collaboration than discord. He highlighted NEPOOL's demonstrated ability to work through contentious issues respectfully and, more often than not, achieve agreed-upon outcomes.

Chairman Gerwatowski also credited the ISO with helping to cement a collaborative culture and looked forward to continuation of that respectful, service-oriented approach under new ISO leadership, as reflected in the prior day's DAAS debate. He also thanked the ISO for tools developed in response to input from the New England States, particularly the Regional Energy Shortfall Threshold (REST) and Probabilistic Energy Adequacy Tool (PEAT), which he believed would help prepare the region for the future.

Chairman Gerwatowski emphasized the need to concentrate collectively on operational concerns, fuel security, and seasonal energy adequacy. He highlighted several challenges facing the region, including:

- Capacity Market redesign (ensuring, in a way that will be price sensitive to consumers, the availability of sufficient resources as the grid shifts to different sources and resources);
- Market design challenges (highlighting the relatively quick refinements to the DAAS Market as a good example of what would be needed to address future market design challenges);

- Transmission expansion and modernization;
- Creation and implementation of the ACR role (which he was confident would address concerns that had long troubled State regulators and consumer advocates, and for which he was hopeful for unanimous support); and
- Affordability (for which he acknowledged there was no simple solution, but emphasized that affordability needed to remain front-of-mind to encourage innovation, temper rising costs, and maintain an intentional focus on near and longer-term consumer impacts).

Chairman Gerwatowski then suggested that NEPOOL's track record for working through regional challenges in a collaborative and respectful way was needed more than ever. He expressed optimism for success given the region's history in achieving positive outcomes when faced with difficult challenges. He said that NEPOOL's history of collaboration, together with the ISO's current emphasis on getting major reforms across the finish line, presented a strong foundation for advancing solutions.

Before concluding, Chairman Gerwatowski recognized and celebrated Connecticut Department of Energy and Environmental Protection (DEEP) Commissioner Katie Dykes, who would soon be stepping down from that role. He highlighted that Ms. Dykes had been a designated NESCOE manager for more than a decade, during which time she had been a leader in various policy matters, and an extremely valuable asset to NESCOE. On behalf of the region, Chairman Gerwatowski thanked Ms. Dykes for her service, noted that she would be missed, and wished her well in her next chapter.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the June 12 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted (i) the expected action by the

FERC at the following day's Open Meeting regarding its Advanced Notice of Proposed Rulemaking Proceeding (ANOPR) on the interconnection of large loads to the interstate transmission system; and (ii) the July 23, 2026 technical conference regarding PJM governance and stakeholder process issues. Mr. Lombardi indicated that initial and more fulsome summaries on developments in each proceeding would be provided to supplement the Litigation Report and keep members informed during the course of the summer.

Continuing, Mr. Patrick Gerity, Assistant Secretary, described on-going activities related to the proposed merger of Vistra and Cogentrix, including reviews by both the FERC and the U.S. Department of Justice (DOJ). He noted two DOJ requests to ISO New England for data to support its analysis, the provision of which implicated the Information Policy and confidential information of NEPOOL members. He summarized and commended the ISO for the processes undertaken pursuant to the Information Policy and encouraged members to reach out with questions about those processes or the related regulatory proceedings.

Mr. Gerity also highlighted the filing of, and activity related to, the proposed new base Return on Equity (ROE), which had been the subject of the April 30 special meeting of the Participants Committee, as well as two complaints filed against certain Transmission Owners (TOs) -- a complaint against Eversource concerning its categorization of the X178 line project as an Asset Management Project, and a complaint against the Connecticut TOs asserting that the ROE adder for RTO participation should no longer apply after Connecticut law required utilities to be members of ISO New England. Mr. Gerity again encouraged members to contact NEPOOL counsel with questions and to watch for updates, including on potential large-load interconnection and PJM governance-related reforms.

COMMITTEE REPORTS

Markets Committee. Mr. Ben Griffiths, the MC Vice-Chair, reported that the next MC meeting, the MC Summer Meeting, was scheduled for July 7-9, 2026, at Lake Winnipesaukee in New Hampshire. Discussion at the MC Summer Meeting would focus primarily on CAR-related topics, but would also include discussion of Storage as a Transmission-Only Asset (SATOA)-conforming Manual changes.

Reliability Committee (RC). Mr. Frank Ettori, the RC Vice-Chair, reported that the next RC meeting was scheduled for June 25, 2026, at the DoubleTree hotel in Westborough, MA. The June RC meeting would address, among other topics, Proposed Plan Applications (PPAs) and Transmission Cost Applications (TCAs), changes to Planning Procedures (PP) PP5-1 and PP5-3 (to enhance the PPA process), SATOA-conforming changes to PP9, and a kickoff for Power Supply Planning Committee development of the 2027 Installed Capacity Requirement and related values. Looking ahead, Mr. Ettori noted that the joint RC/TC Summer Meeting was scheduled for August 18-19, 2026, at the Beauport Hotel in Gloucester, MA and encouraged those interested in attending to register.

Transmission Committee (TC). Mr. Nick Gangi, the TC Chair, reported that the next TC meeting was scheduled for June 24, 2026, at the DoubleTree hotel in Westborough, MA. The TC would review initial CAR-SA deactivation redlines, materials related to the PTO-AC's notice of 2027 Regional Network Service rates (with the traditional annual presentation to occur in July rather than at the August Summer Meeting), and a vote on the ACR Proposal.

Budget & Finance Subcommittee. Mr. Kaslow reported that the next B&F Subcommittee meeting would be July 17, 2026, with the agenda yet to be determined.

Membership Subcommittee. Mr. Brian Thompson, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held by Zoom on July 13, 2026, and encouraged all those interested to attend.

IMM 2025 ANNUAL MARKETS REPORT AND ONE-YEAR REVIEW OF DAY-AHEAD ANCILLARY SERVICES

2025 Annual Markets Report

Mr. David Naughton, IMM Executive Director, referred members to the summary of the IMM's 2025 Annual Markets Report (2025 IMM Annual Report), which had been circulated and posted with the meeting materials. He began by comparing 2025 market outcomes to outcomes from the prior four years. He expressed a positive view of overall market performance in 2025, noting that the results continued to indicate competitive market outcomes but also suggested various opportunities to enhance the markets.

Mr. Naughton reported that 2025 wholesale market costs totaled approximately $15 billion, nearly 50% higher than 2024. He identified as principal drivers of energy costs, which totaled nearly $10 billion: (i) natural gas prices, which doubled in 2025 and were the primary driver of higher energy prices; (ii) carbon pricing programs, which increased energy prices by approximately $9/MWh, contributing roughly $1.1 billion to energy costs in 2025 (RGGI allowance prices increased 6.5% year over year and MA EGEL auction clearing prices increased 290%); (iii) a decline in net imports from Québec, with Real-Time net imports averaging 932 MW (the lowest level since 2011) and (iv) new DAAS market charges, which added approximately $477 million in incremental costs.

Turning to system reliability, Mr. Naughton reported that 2025 experienced relatively few shortage conditions, although their frequency increased compared to prior years. He also reported that no posturing occurred, there were few reliability commitments, and uplift for local contingencies totaled approximately $42 million, with most of those costs attributable to resources committed and dispatched in economic order. Mr. Naughton also highlighted New England's relatively low transmission congestion costs, which totaled approximately $75 million.

Mr. Naughton next discussed generator profitability. As in prior years, the 2025 IMM Annual Report included an assessment of several metrics used to evaluate generator profitability based on the revenues hypothetical combined-cycle and combustion turbine generators could have earned in the wholesale markets. In 2025, for the second consecutive year, market revenues exceeded gross CONE. He cautioned, however, that this outcome did not demonstrably incent the construction of new gas-fired generation, noting that the interconnection queue continued to be dominated by wind and solar resources.

In response to a question, Mr. Naughton confirmed that existing combined-cycle generators experienced lower revenues as a result of the June 24, 2025 Capacity Scarcity Condition, during which the Balancing Ratio exceeded 1.0, but, on the whole, earned approximately $13/kW-month in net revenues. He continued to believe PFP provided strong incentives for resources to perform because capacity payments provide a predictable revenue stream (assuming those payments are sufficient to cover the "missing money"). He added that he did not have a strong opinion on whether scarcity pricing should reside in the capacity market, where resources can hedge, or in the energy markets, where prices would be more volatile, because performance incentives are preserved under either approach.

Turning his attention to wind and solar resources, Mr. Naughton reported that their revenues remained heavily dependent on state-level programs. With respect to battery storage profitability, he noted that battery storage resources had experienced declining net revenues, largely due to increasing saturation in the Regulation Market. At the same time, battery storage participation in the energy markets had increased. He noted that the Massachusetts Clean Peak Energy Certificates program remains a key revenue source.

Mr. Naughton next provided an overview of the section of the 2025 IMM Annual Report addressing the markets and the energy transition. Although the transition had remained gradual, he noted a significant increase in solar generation, primarily from behind-the-meter resources. Overall, he explained that increasing renewable penetration continued to re-shape load profiles and alter system load ramps. The most significant change had occurred during the evening hours, when the system relies more heavily on fast-start resources, and this trend continues to increase. Referring to a figure in his presentation comparing demand and supply during the second and third quarters of 2021 and 2025, Mr. Naughton explained that wholesale demand during those periods had declined over time, reflecting the growth of behind-the-meter solar generation. The figures also demonstrated that renewable resources had played an increasingly significant role in meeting summer energy needs and that declining imports had increased reliance on dispatchable balancing resources.

The IMM concluded his annual markets report with an overview of his assessment of wholesale market competitiveness. He explained that the Report evaluated the extent to which the ISO relies on the largest available supplier to satisfy energy and reserve requirements—otherwise known as the pivotal supplier. Based on his assessment, the frequency of pivotal suppliers remained low.

Mr. Naughton also discussed the price-cost markup metric, which estimates the difference between observed market outcomes in the Day-Ahead and Real-Time Markets and the IMM's modeled competitive benchmark. Acknowledging that the metric had an inherent margin of error because the model did not replicate the ISO's market-clearing engine, he explained that it nevertheless provided a useful indicator of how uncompetitive offer behavior affects market outcomes. In 2025, as in each of the previous five years, the price-cost markup remained well below the mitigation threshold, indicating competitive market outcomes.

In discussing mitigation thresholds, Mr. Naughton noted that he had recommended that the ISO review them. The thresholds were established more than 20 years ago and, given the pace of mergers and acquisitions in the region, increasing concentration of resource ownership might warrant recalibration. He therefore recommended that the ISO proactively recalibrate the thresholds to reflect current market conditions.

DAAS One-Year Review

Mr. Naughton then presented his June 2026 *Assessment of the Day-Ahead Ancillary Services Market* (DAAS Report). He explained that the Report addressed both competition and performance and, although thorough, was not exhaustive. The Report examined: (i) the initiative's incremental cost; (ii) the factors driving those costs; and (iii) the benefits produced. The assessment used quantitative and simulation-based analyses supplemented by survey information from Market Participants.

The IMM reviewed the purpose of the DAAS Markets: to procure and price Ancillary Services and Energy and enable the ISO to develop a more effective next-day operating plan. The markets were intended to provide transparent price signals and compensate through the market the resources needed to satisfy Reserve and Energy requirements, thereby reducing uplift and out-of-market actions.

Referring to two figures in his presentation, Mr. Naughton showed the clearing prices by product and the resource mix by technology class. When asked about price convergence, he noted that the discussion was deliberately excluded from the presentation given the complexity of the issue, but it was included in Section 9.1 of the DAAS Report. Nonetheless, he briefly noted that it was difficult to conclude definitively that price divergence occurred during the year, given the various factors discussed in his report.

Next, Mr. Naughton presented two tables providing additional background and context. One table showed DAAS settlement costs by season and product, while the other showed FER settlement costs. In total, those costs exceeded $1.25 billion, or $10.70/MWh of load served, which broke down into $2.21/MWh for Ancillary Services and $8.49/MWh for FER. Mr. Naughton added that the economic analysis focused on incremental costs by comparing DAAS Market costs against the prior market design using a simulation tool. The analysis illustrated the interplay between the FER price (FERP) and the Day-Ahead LMP, where a non-zero FERP tended to lower the Day-Ahead LMP.

Mr. Naughton summarized the principal cost findings. Actual Energy and Ancillary Services (E&AS) costs were $11.5 billion, compared with $10.577 billion under the simulated prior Energy-only design, yielding estimated incremental DAAS costs of $974 million. Twelve days accounted for approximately half of those costs.

An updated Impact Assessment (IA), using the ISO's original methodology but current market fundamentals and system conditions, estimated $733 million in incremental costs—approximately 75% of the observed $974 million. The approximately $240 million difference was attributed to lower participation and offer prices above benchmark levels. A separate simulation reflecting opportunity costs produced E&AS costs of $10.893 billion.

The IMM estimated that DAAS reduced LMP-related Energy costs by approximately $300 million but added approximately $1 billion in FER-related costs, for a net increase of $974 million, or $8.23/MWh of load served.

Five days in January 2026 accounted for approximately 40% of the annual incremental DAAS costs, and the 12 highest-cost days accounted for approximately $490 million, or about half of the total.

In response to a member's suggestion that avoided winter uplift be quantified, Mr. Naughton noted that the DAAS Report estimated approximately $35 million in avoided uplift costs for the year based on the integrated market simulator.

Mr. Naughton next provided an overview of his team's assessment of how opportunity costs may have affected the clearing prices for Flexible Response Services (FRS), which include the 10- and 30-Minute Operating Reserve products. He noted that opportunity costs play an important role in price formation by ensuring that resources were no worse off than under their next-best alternative. Simulating a scenario in which all historically offered DAAS capability was offered at $0/MWh, total E&AS costs would have resulted in approximately $316 million of incremental costs. Relatedly, Mr. Naughton's team simulated a scenario in which the FER constraint was set to $0/MWh. The results indicated that FRS accounted for 65 percent, or approximately $613 million, of the total incremental costs.

Given stakeholder interest, the DAAS Report also provided an assessment of the drivers of FER prices. Based on that analysis, he reported that both supply-side factors (e.g., outages) and demand-side factors (e.g., Load Serving Entities (LSE) under-clearing in the DAM) contributed to high FER prices. Mr. Naughton emphasized that the data indicated LSE under-clearing likely had a significant impact on FER pricing outcomes during the winter, particularly on the five highest-cost winter DAAS days.

Toward the end of the discussion, a member strongly encouraged the ISO to heed the IMM's recommendation to continue investing in modeling tools to improve the Gaussian Mixture Model.

In light of time constraints, Mr. Naughton agreed to return to a subsequent Participants Committee meeting, as requested, to complete the DAAS Report presentation. He encouraged members to contact him with any remaining questions.

There being no further business, the June 17 session and the 2026 Summer Meeting adjourned at 11:59 a.m., with the following day set for Sector meetings with the ISO Board and State and FERC representatives beginning at 8:30 a.m.

Respectfully submitted,

____
Sebastian Lombardi, Secretary

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 16-18, 2026 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (W)		
Advanced Energy United	Associate Non-Voting	Alex Lawton		
AR RG Large Group Member	AR-RG		Aidan Foley (W)	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch (W)	Jamie St. Pierre
Bath Iron Works Corporation	End User		Howard Plante (W)	Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
BP Energy Company (BP)	Supplier	Christine Hughey		José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Canal Marketing LLC	Generation	Mary Coleman (W)	Bill Fowler	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Clear River Electric and Water District	Publicly Owned Entity		Dave Cavanaugh	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (W)		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Jamie Talbert-Slagle	
Conservation Law Foundation (CLF)	End User	Nick Krakoff (W)		
Constellation Energy Generation	Supplier	Andy Gillespie	Gretchen Fuhr	Adrien Ford; Bill Fowler
CPV Towantic, LLC	Generation		Matt Lichfield (W)	
Cranberry Point Energy Storage, LLC	AR-DG	Mandy Meadors		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dartmouth Power Associates, L.P.	Generation	Carrie Hitt		Sarah Yasutake
Dominion Energy Generation Marketing	Generation	Wes Walker	Susan Adams	
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Earthjustice	End User		Ada Statler (W)	
Elektrisola, Inc.	End User			Bill Short
Emera Energy Companies	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR		Juan Diaz (W)	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	Vandan Divatia	Dave Burnham	
First Point Power, LLC	Supplier	Peter Schieffelin	Bryan Amaral	
FirstLight Power Management, LLC (FirstLight)	Generation	Tom Kaslow	Peter Rider	
Gabel Associates, Inc.	Supplier	Sarah Yasutake		
Galt Power, Inc. (Galt)	Supplier	José Rotger	Jeff Iafrati (W)	
Garland Manufacturing Company	End User		Howard Plante (W)	Bill Short
Generation Bridge Companies	Generation		Steve Kirk	Bill Fowler
Generation Group Member	Generation		Abby Krich (W)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Green Oceans	End User		Lauren Knight	Lisa Linowes
Groton Electric Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG	Louis Guibault (W)		
Hammond Lumber Company	End User		Howard Plante (W)	Bill Short

(W) = Webex

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 16-18, 2026 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Harvard Dedicated Energy Limited	End User			Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
In Commodities US LLC	Supplier	Eric Stallings		
Industrial Wind Action Corp.	End User	Lisa Linowes		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		
MAG Energy Solutions	Supplier		Ruta Skucas (W)	
Maine Power LLC	Supplier	Jeff Jones (W)		
Maine Public Advocate’s Office (Maine OPA)	End User	Drew Landry		Ariella Fuzaylov
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Mass. Attorney General’s Office (MA AG)	End User	Jacquelyn Bihrle	Jamie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Department of Capital Asset Management	End User		Paul Lopes (W)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide (W)	Dan Murphy	
MDC – The Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC (Mercuria)	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User		Howard Plante (W)	Bill Short
Natural Resources Defense Council	End User	Claire Lang-Ree		
Nautilus Power, LLC	Generation		Bill Fowler	
New Brunswick Energy Marketing Corp.	Supplier	Rob Gillies		
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
New Hampshire Office of Consumer Advocate (NHOCA)	End User	Matthew Fossum		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier	Ben Griffiths		
Nylon Corporation of America	End User			Bill Short
Onward Energy	AR-RG	Stacey Fitts		
Pawtucket Power Holding Company LLC	Generation	Dan Allegretti (W)	Kevin Telford	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
PowerOptions	End User		Zach Gray-Traverso (W)	Doug Hurley
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RENEW Northeast, Inc.	Associate Non-Voting	Francis Pullaro		Carter Scott

(W) = Webex

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 16-18, 2026 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
RI Division (DPUC)	End User	Linda George	Christy Hetherington	
RI Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette	Janell Fabiano
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Saint Anselm	End User			Bill Short
Shell Energy North America (US)	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User		Howard Plante (W)	Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Sierra Club	End User	Sara Krame (W)		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
SYSO Inc.	AR-DG			Alex Worsley
Taunton Municipal Lighting Plant	Publicly Owned Entity	Nick Parrotta	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Veolia Flexible Energy Services North America	AR-LR	Doug Hurley		
Vermont Electric Cooperative	Publicly Owned Entity		Dan Potter	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR			Doug Hurley
Vermont Public Power Supply Authority	Publicly Owned Entity		Brian Forshaw	
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vistra (Dynegy Marketing and Trade, LLC)	Generation		Andy Weinstein	Bill Fowler
Vitol Inc.	Supplier	Seth Cochran		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH LLC	End User			Bill Short

(W) = Webex

ATTACHMENT 2

JUNE 16-18, 2026 PARTICIPANTS COMMITTEE SUMMER MEETING
VOTE ON DAY-AHEAD ANCILLARY SERVICES (DAAS) PROPOSAL

TOTAL

Sector/Group	Vote
GENERATION	0.00
TRANSMISSION	16.67
SUPPLIER	9.52
ALTERNATIVE RESOURCES	9.25
PUBLICLY OWNED ENTITY	16.67
END USER	16.67
% IN FAVOR	**68.78**

GENERATION SECTOR

Participant Name	Vote
Canal Marketing LLC	O
CPV Towantic, LLC	O
Dartmouth Power Associates	A
Dominion Energy Generation Mktg	A
FirstLight Power Management, LLC	O
Generation Bridge Companies	O
Nautilus Power, LLC	O
NextEra Energy Resources, LLC	O
Pawtucket Power Holding Co.	O
Vistra (Dynegy Mktg and Trade, LLC)	O
IN FAVOR (F)	0
OPPOSED (O)	8
TOTAL VOTES	8
ABSTENTIONS (A)	2

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote
Renewable Generation Sub-Sector	
ENGIE Energy Marketing NA, Inc.	F
H.Q. Energy Services (U.S.) Inc.	O
Onward Energy	A
Wheelabrator/Macquarie	O
Large RG Group Member	F
Distributed Generation Sub-Sector	
CLEAResult Consulting, Inc.	A
Load Response Sub-Sector	
Veolia Flexible Energy Services North America	F
Vermont Energy Investment Corp.	F
IN FAVOR (F)	4
OPPOSED (O)	2
TOTAL VOTES	6
ABSTENTIONS (A)	2

TRANSMISSION SECTOR

Participant Name	Vote
Avangrid (CMP/UI)	F
Eversource	F
National Grid	F
Rhode Island Energy	F
VELCO	F
Versant Power	F
IN FAVOR (F)	6
OPPOSED (O)	0
TOTAL VOTES	6
ABSTENTIONS (A)	0

SUPPLIER SECTOR

Participant Name	Vote
BP Energy Company	F
Brookfield Renewable Trading & Mktg	O
Constellation Energy Generation	O
Cross-Sound Cable Company	A
DTE Energy Trading, Inc.	A
Emera Energy Companies	A
First Point Power LLC	F
Gabel Associates, Inc.	A
Galt Power, Inc.	A
In Commodities US LLC	A
LIPA	A
Maine Power	F
Mercuria Energy America, LLC	A
NRG Business Marketing, LLC	F
Shell Energy North America (US) LP	O
Vitol Inc.	A
IN FAVOR (F)	4
OPPOSED (O)	3
TOTAL VOTES	7
ABSTENTIONS (A)	9

JUNE 16-18, 2026 PARTICIPANTS COMMITTEE SUMMER MEETING
VOTE ON DAY-AHEAD ANCILLARY SERVICES (DAAS) PROPOSAL

END USER SECTOR

Participant Name	Vote
Acadia Center	F
Bath Iron Works	F
Conn. Office of Consumer Counsel	F
Conservation Law Foundation	F
Earthjustice	F
Elektrisola, Inc.	F
Garland Manufacturing Co.	F
Green Oceans	F
Hammond Lumber Co.	F
Harvard Dedicated Energy Limited	F
High Liner Foods	F
Industrial Wind Action Corp.	F
Lamson, Jon	A
Maine Public Advocate Office	F
Mass. Attorney General's Office	F
Moore Company	F
NH Office of Consumer Advocate	F
Nylon Corporation	F
PowerOptions, Inc.	F
RI Division of Public Utilities and Carriers	F
St. Anslem	F
Shipyard Brewing Co.	F
Z-TECH, LLC	F
IN FAVOR (F)	22
OPPOSED (O)	0
TOTAL VOTES	22
ABSTENTIONS (A)	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote
Ashburnham Municipal Light Plant	F
Belmont Municipal Light Dept.	F
Block Island Utility District	F
Boylston Municipal Light Dept.	F
Braintree Electric Light Dept.	F
Chester Municipal Light Dept.	F
Chicopee Municipal Lighting Plant	F
Clear River Electric and Water District	F
Concord Municipal Light Plant	F
Conn. Municipal Electric Energy Coop.	F
Danvers Electric Division	F
Georgetown Municipal Light Dept.	F
Groton Electric Light Dept.	F
Groveland Electric Light Dept.	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote
Hingham Municipal Lighting Plant	F
Holden Municipal Light Dept.	F
Holyoke Gas & Electric Dept.	F
Hudson Light and Power Dept.	F
Hull Municipal Lighting Plant	F
Ipswich Municipal Light Dept.	F
Littleton (MA) Electric Light Dept.	F
Mansfield Municipal Electric Dept.	F
Marblehead Municipal Light Dept.	F
Mass. Municipal Wholesale Electric Co.	F
Mass. Bay Transportation Authority	F
MDC – The (CT) Metropolitan District	F
Merrimac Municipal Light Dept.	F
Midcoast Regional Redevelopment Authority	F
Middleborough Gas and Elec. Dept.	F
Middleton Municipal Electric Dept.	F
New Hampshire Electric Cooperative	F
North Attleborough Electric Dept.	F
Norwood Municipal Light Dept.	F
Paxton Municipal Light Dept.	F
Peabody Municipal Light Plant	F
Princeton Municipal Light Dept.	F
Reading Municipal Light Dept.	F
Rowley Municipal Lighting Plant	F
Russell Municipal Light Dept.	F
Shrewsbury Electric & Cable Operations	F
South Hadley Electric Light Dept.	F
Sterling Municipal Electric Light Dept.	F
Stowe (VT) Electric Dept.	F
Taunton Municipal Lighting Plant	F
Templeton Municipal Lighting Plant	F
Vermont Electric Cooperative	F
Vermont Public Power Supply Authority	F
Village of Hyde Park (VT) Electric Dept.	F
Wakefield Municipal Gas and Light Dept.	F
Wallingford (CT), Town of	F
Wellesley Municipal Light Plant	F
West Boylston Municipal Lighting Plant	F
Westfield Gas & Electric Light Dept.	F
IN FAVOR (F)	53
OPPOSED (O)	0
TOTAL VOTES	53
ABSTENTIONS (A)	0

CONSENT AGENDA

Transmission Committee (TC)

*From the previously-circulated notice of actions of the TC's **June 24, 2026 meeting**, dated June 24, 2026.*[1]

1. **Revisions to the OATT and TOA (Asset Condition Reviewer)**

Support the addition of a proposed Attachment R (Asset Condition Review Process) to Section II of the Transmission, Markets and Services Tariff (OATT) and revisions to the Transmission Operating Agreement (TOA) to establish the ISO as the Asset Condition Reviewer and incorporate the process for ISO review of Participating Transmission Owners' asset condition practices, projects, and programs in New England, as recommended by the TC at its June 24, 2026 meeting, together with such non-material changes as may be approved by the TC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously, with 2 abstentions noted (1 Supplier Sector, 1 End User Sector).

Markets Committee (MC)

*From the previously-circulated notice of actions of the RC's **July 7-9, 2026** meeting, dated July 9 2026.*[2]

2. **Revisions to Manuals M-11, M-28 and M-RPA (Order 2222 and SATOA Conforming Changes)**

Support (i) *Order 2222* conforming changes to Manuals M-11 (Market Operations), M-28 (Market Rule 1 Accounting) and M-RPA (Registration and Performance Auditing) and (ii) Storage as a Transmission-Only Asset (SATOA) conforming changes to Manuals M-28 and M-RPA, as recommended by the MC at its July 7-9, 2026 meeting, together with such non-material changes as may be approved by the MC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously, with one abstention in the End User Sector noted.

[continued on next page]

[1] TC Notices of Actions are posted on the ISO-NE website at: https://www.iso-ne.com/committees/transmission/transmission-committee/?document-type=Committee%20Actions.

[2] MC Notices of Actions are posted on the ISO-NE website at: https://www.iso-ne.com/committees/markets/markets-committee/?document-type=Committee%20Actions.

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **July 23, 2026 meeting**, dated July 23, 2026.*[3]

3. <u>Revisions to Planning Procedure No. 9 (Storage as Transmission Only Asset (SATOA) conforming revisions)</u>

Support revisions to ISO New England Planning Procedure No. 9 (Major Substation Bus Arrangement Requirements and Guidelines) (PP-9) to include SATOAs (providing requirements on how to interconnect SATOAs to a substation), as recommended by the RC at its July 23, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

[3] RC Notices of Actions are posted on the ISO-NE website at: https://www.iso-ne.com/committees/reliability/reliability-committee/?document-type=Committee%20Actions.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: July 30, 2026

RE: Conforming Revisions to Section IV.A of the Tariff

At its August 6, 2026 meeting, the Participants Committee will be asked to vote on proposed conforming revisions to Section IV.A of the Tariff to reflect the establishment of the ISO's new Asset Condition Reviewer (ACR) function. These conforming revisions implement the cost-recovery aspects of the ACR proposal reviewed by the Budget & Finance Subcommittee (B&F). Included with this memorandum are the following materials:

- Attachment A: Redlined Section IV.A, Schedule 1 Sheets
- Attachment B: The ISO's June 5, 2026 B&F Presentation

BACKGROUND & OVERVIEW

Following stakeholder requests for an independent reviewer of Asset Condition Projects, the ISO agreed to serve in an advisory capacity as the ACR. Throughout the first half of 2026, the ISO presented its proposal to establish this new function at meetings of the Transmission Committee.[1] At its June 24, 2026 meeting, the Transmission Committee considered and recommended a package of ACR revisions to the Transmission Operating Agreement and Section II of the Transmission, Markets and Services Tariff (OATT), including a new Attachment R to the OATT establishing the process governing the ACR function. The ACR revisions are included as item no. 1 on the August 6, 2026 Consent Agenda.

Section IV of the Tariff governs how the ISO recovers the costs of administering the New England wholesale electricity markets and transmission system. As relevant here, Section IV.A (the Self-Funding Tariff) establishes the rates, charges, terms, and conditions under which the ISO recovers the revenues necessary to perform its administrative functions. As noted at the Summer Meeting, the ISO's costs to implement the ACR proposal will be recovered under Schedule 1 of the Self-Funding Tariff, which provides for the recovery of System Planning administrative costs associated with regional transmission planning and related activities.

As described in Attachment B, the ISO will establish a new group within its System Planning organization to perform the responsibilities of the ACR. Those responsibilities are set forth in proposed Attachment R to the OATT. As part of the ISO's System Planning

[1] To review documents and presentations concerning the ISO's ACR key project, click here.

administrative functions, the ISO proposes corresponding revisions to Section IV.A, Schedule 1 to clarify that the costs associated with the ACR function will be recoverable under Schedule 1.

B&F REVIEW

At the June 5, 2026 B&F meeting, the ISO presented its proposed revisions to Schedule 1. No Subcommittee member present expressed opposition to, or concerns regarding, the proposed revisions to Schedule 1.

The following form of resolution can be used for Participants Committee action:

> RESOLVED, that the Participants Committee supports the revisions to Tariff Section IV.A, Schedule 1, as reflected in the materials circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

SECTION IV.A

RECOVERY OF ISO ADMINISTRATIVE EXPENSES

Schedule 1

Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1. As part of the Scheduling Service, the ISO also serves as the Asset Condition Reviewer for the review of PTO Asset Monitoring and Evaluation Practices, Asset Condition Projects, and ACP Programs, each as defined in Attachment R of Section II of the Tariff.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service;
- Review of PTO Asset Monitoring and Evaluation Practices, Asset Condition Projects, and ACP Programs; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

BUDGET AND FINANCE SUBCOMMITTEE | JUNE 5, 2026 | VIRTUAL

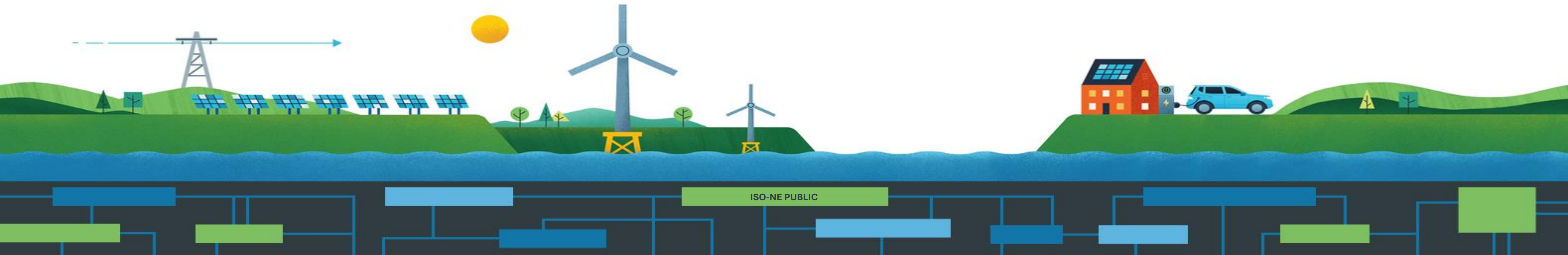
ISO new england

Asset Condition (AC) Reviewer Addition to ISO Tariff Section IV.A, Schedule 1

Update to Section IV.A – "ISO Self Funding Tariff"

John Waggoner

MANAGER, BUDGET & FINANCE REPORTING



Asset Condition (AC) Reviewer Addition to ISO Tariff Section IV.A, Schedule 1

Proposed Effective Date: January 1, 2027

- The ISO is developing a new function to provide oversight of Asset Condition Projects (ACPs) of the Participating Transmission Owners (PTOs)
  - The ISO is supportive of states' and stakeholders' request that it take on this advisory role and develop a robust process for additional, independent review of ACP proposals
- Changes to the Transmission Operating Agreement (TOA) and the ISO's Transmission, Markets, and Services Tariff (Tariff), including the Open Access Transmission Tariff (OATT), are necessary to establish this new function
  - The PTOs and ISO plan to submit a joint filing in mid-August 2026 proposing TOA and OATT revisions to incorporate the AC Reviewer and related activities, with a request for a 60-day ruling from FERC, as discussed at the April and May Transmission Committee (TC) meetings
  - Additional conforming revisions to reflect the AC Reviewer and associated responsibilities in Section IV.A, Schedule 1 (*Scheduling, System Control, and Dispatch Service*) are planned for mid-October 2026, to be filed along with the ISO's 2027 Budget and revised Tariff sheets
  - Further details on ACPs and the AC Reviewer can be found on the ISO's website - Asset Condition Reviewer Key Project

Background

- As part of the ISO's development of the AC Reviewer function, a new group will be established within ISO System Planning to perform this work
- The ISO's 2027 Budget, currently under development, contemplates the initial step in establishing the AC Reviewer, including estimated resource requirements
  - Buildout and full staffing of the AC Reviewer is expected to take up to five years to complete with incremental additions over that period
    - The ISO expects to supplement staffing with consulting support in the near-term
  - The 2027 Budget materials will include the estimated AC Reviewer resources planned for that year
  - The ISO's 2027 *Preliminary Budget* will be reviewed with the Participants Committee (PC) at the June 2026 Summer Meeting
  - The ISO's detailed 2027 *Proposed Budget* will be:
    - Reviewed with the Budget and Finance Subcommittee (BFS) on August 7, 2026
    - Reviewed with the PC on September 3, 2026
    - Voted on by the PC on October 1, 2026

Rationale for Change

- The addition of the AC Reviewer work represents a new function distinct from other existing System Planning activities
- The AC Reviewer process will be governed by the proposed draft Attachment R, *Asset Condition Review Process,* to the ISO's OATT [1]
- Both the draft Attachment R and proposed revisions to Section IV.A of the Tariff reference recovery of AC Reviewer work pursuant to Section IV.A, Schedule 1 (*Scheduling, System Control and Dispatch Service)*
  - Section IV.A, Schedule 1 covers System Planning's administrative costs related to activities, such as, implementation of regional transmission service

[1] The Draft Attachment R to the OATT can be found on the ISO's website - [Draft Attachment R Asset Condition Review Process]

Proposal

- The ISO proposes conforming revisions to Section IV.A, Schedule 1 of the Tariff to add language indicating that AC Reviewer related functions are included within this Schedule
  - The introductory paragraph to Schedule 1 includes additional language indicating that, as part of Scheduling Service, the ISO serves as the AC Reviewer for related services, with reference to Attachment R of (the OATT)
  - Under the bulleted list of functions and activities required to provide services under Schedule 1, a new line is added to indicate Schedule 1 includes the review of PTO Asset Monitoring and Evaluation Practices, and ACP programs

Summary of Proposed Tariff or Manual Changes[2]

Section	Tariff or Manual Change	Reason for Change
Addition at the end of the introductory paragraph to Section IV.A, Schedule 1 "Scheduling, System Control and Dispatch Service"	"As part of the Scheduling Service, the ISO also serves as the Asset Condition Reviewer for the review of PTO Asset Monitoring and Evaluation Practices, Asset Condition Projects, and ACP Programs, each as defined in Attachment R of Section II of the Tariff."	Addition of conforming language to indicate that, as part of Scheduling Service, the ISO serves as the Asset Condition Reviewer for related services governed by Attachment R to Section II of the Tariff
Addition to list of functions and activities required to provide services under Section IV.A, Schedule 1 "Scheduling, System Control and Dispatch Service"	"Review of PTO Asset Monitoring and Evaluation Practices, Asset Condition Projects, and ACP Programs;"	Adding conforming language to indicate that services under Section IV.A Schedule 1 include Asset Condition Reviewer-related functions and activities, as governed by Attachment R to Section II of the Tariff

[2] Section IV.A redlines are being provided with these materials

Conclusion

- The PTOs and the ISO intend to make a mid-August 2026 joint filing with changes to the TOA and Tariff to incorporate the AC Reviewer role and related activities within a new Attachment R *Asset Condition Review Process* to the OATT
- The ISO proposes conforming changes, to be made along with the ISO's 2027 Budget and revised Tariff sheets, to Section IV.A, Schedule 1 ("Scheduling, System Control and Dispatch Service") to add language reflecting the AC Reviewer role

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee January 21, 2026	Introduction to conceptual framework and incorporation of stakeholder feedback received to date
Transmission Committee February 24, 2026	Continued discussion of conceptual framework
Transmission Committee March 18, 2026	Continued discussion of conceptual framework
Transmission Committee April 21, 2026	Continued review of incremental proposal adjustments and introduction to TOA and Tariff redlines
Transmission Committee May 28, 2026	Continued review of incremental proposal adjustments and TOA and Tariff redlines; introduction of stakeholder amendments
Budget and Finance Subcommittee June 5, 2026 [3]	Introduce Section IV.A, Schedule 1 proposed changes for discussion and answer any clarifying questions
Transmission Committee June 24, 2026	Continued review and vote on incremental proposal adjustments and TOA and Tariff redlines and stakeholder amendments
Participants Committee August 6, 2026	Vote on ISO proposal and potential amendments

[3] If an additional Budget and Finance Subcommittee is necessary, the Subcommittee can continue discussions during the July 17, 2026 meeting

Questions

About the Presenter

John Waggoner

Manager, Budget & Finance Reporting

ISO New England

jwaggoner@iso-ne.com