NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

October 26, 2022

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of November 2, 2022 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the November meeting of the Participants Committee will be held **in person on *Wednesday*, November 2, 2022, at the Renaissance - Providence Downtown Hotel, 5 Ave of the Arts, Providence, RI, in the Symphony Ballroom following individual, modified Sector meetings with the ISO Board that begin for two Sectors at 9:00 a.m. and are scheduled to continue through 1:45 p.m. (**A schedule of those planned Sector meetings is included with this notice.). We expect that the Participants Committee meeting will begin at **2:00 p.m.** following those Sector meetings for the purposes set forth on the attached agenda and that has also been posted with the meeting materials at nepool.com/meetings/.

Please note that the Participants Committee meeting schedule has been moved to Wednesday in order to occur the day after the ISO Board's first public meeting, which is to be held from 1:00 to 5:00 on Tuesday, November 1. The Board's public meeting will be at the same venue as the Participants Committee meeting--the Renaissance-Providence Downtown Hotel, 5 Ave of the Arts, Providence, RI. For your convenience, we have included with this package the ISO's Notice of its Open Board Meeting, which also can be downloaded at https://www.iso-ne.com/static-assets/documents/2022/10/iso_ne_nov_1_2022_open_board_meeting_notice.pdf. If you wish to listen to the Board meeting, you should review the notice. Note that in-person space at the venue is limited so those interested in attending the Board meeting in person will need to register early. The notice also identifies how interested persons can address the Board with written comments and, time-permitting, in oral comments presented at the meeting.

The November 2 Participants Committee meeting will be recorded. 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 in attendance or participating, either in person or by phone, are required to 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.

For those who otherwise attend NEPOOL meetings but plan to participate in the November 2 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join using WebEx, click this link and enter the event password **nepool**.

Looking forward, please make sure that your calendars reflect the upcoming NEPOOL Annual Meeting, which will be on Thursday, December 1, 2022 at the Colonnade Hotel in Boston. A holiday breakfast is planned to begin at 9:00 a.m.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the October 6, 2022 Participants Committee meeting. A copy of the draft minutes, marked to show the changes from the version circulated with the initial notice, is included with the supplemental notice and posted with the meeting materials.

2. To adopt and approve the actions recommended by the Technical Committees set forth on the Consent Agenda included with this initial notice and posted with the meeting materials. Consent Agenda Item No. 3 has been removed and will be considered as Item 4A (see below).

3. To receive an ISO Chief Executive Officer report. The November CEO report is included and posted with the supplemental notice.

4. To receive an ISO Chief Operating Officer report. The November COO report, which will include a Winter Analysis Update as previously discussed, will be circulated and posted in advance of the meeting.

4A. To consider, and take action, as appropriate, on revisions to Sections III.K.1(a)(i) and III.K.3.2.1.1(a) of Market Rule 1 to clarify that assets that run on coal, nuclear, biomass or hydropower are not eligible for participation in the Inventoried Energy Program (IEP) and may not be included in a Market Participant's list of assets for participation in the IEP. This item was removed from the Consent Agenda (Consent Agenda Item 3). Background materials and a draft resolution are included and posted with the supplemental notice.

5. To consider, and take action, as appropriate, on conforming changes to the Financial Assurance and Billing Policies to reflect the implementation of the Inventoried Energy Program (IEP), as considered by the Budget & Finance Subcommittee. Background materials and a draft resolution will be included and posted with the supplemental notice.

6. To consider, and take action, as appropriate, on a Participant proposal to amend § 9.2.3(a)(i) of the Participants Agreement (Terms of Directors) to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75. Background materials and a draft resolution(s) are included and posted with the supplemental notice.

7. To consider, and take action, as appropriate, on the request for a waiver of the NEPOOL Generation Information System (GIS) Operating Rules by NuPower Cherry Street. Background materials and a draft resolution are included and posted with the supplemental notice.

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FINAL AGENDA (cont.)

8. 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.

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

10. Administrative matters.

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

NEW ENGLAND POWER POOL

NEPOOL PARTICIPANTS COMMITTEE
NOVEMBER 2022 SECTOR/BOARD MEETING SCHEDULE**
v. 2022.10.17

SECTOR/GROUP	9:00 – 10:15 a.m.	10:35 – 11:50 a.m.	11:50 – 12:30 p.m.	12:30 – 1:45 p.m.
Generation / Long		ISO Board Panel 2 ***(Haydn)***		
Transmission		ISO Board Panel 1 ***(Handel)***		
Supplier / Short (LSE)			Lunch (All)	ISO Board Panel 1 ***(Handel)***
Publicly Owned Entity	ISO Board Panel 1 ***(Handel)***			
AR				ISO Board Panel 2 ***(Haydn)***
End User	ISO Board Panel 2 ***(Haydn)***			
			(Symphony Ballroom)	
ISO Board Panel 1	Publicly Owned Entity ***(Handel)***	Transmission ***(Handel)***		Supplier / Short (LSE) ***(Handel)***
ISO Board Panel 2	End User ***(Haydn)***	Generation / Long ***(Haydn)***		AR ***(Haydn)***

ISO Board Panel 1: Brook Colangelo, Mike Curran, Catherine Flax, Cheryl LaFleur, and Gordon van Welie.

ISO Board Panel 2: Caren Anders, Steve Corneli, Roberto Denis, Mark Vannoy, and Mel Williams.

**** Subject to change**

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PRELIMINARY

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

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

APPROVAL OF SEPTEMBER 1, 2022 MEETING MINUTES

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

CONSENT AGENDA

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

ISO CEO REPORT

ISO Board and Board Committee Meeting Summaries

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the

September 1, 2022 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

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

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

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

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

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

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

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

ISO COO REPORT

Operations Report

Dr. Chadalavada began his report first by referring the Committee to his October operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through September 28, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for September 2022 was $662 million, down $731 million from the updated August 2022 value and up $151 million from September 2021; (ii) September 2022 average natural gas prices were 17% lower than August average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for September

($62.61/MWh) were 35% lower than August averages; (iv) average September 2022 natural gas prices and Real-Time Hub LMPs over the period were up 56% and 34%, respectively, from September 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99.9% during September (down from the 102.2% reported for August), with the minimum value for the month of 90.4% on September 2; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for September totaled $2 million, which was down $4.5 million from August 2022 and up $0.6 million from September 2021. September NCPC payments, which were 0.3% of total Energy Market value, were comprised of (a) $1.9 million in first contingency payments (down $4.1 million from August); (b) $120,000 in second contingency payments (up $116,000 from August); and (c) $11,000 in distribution payments (down $491,000 from August).

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

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

Mystic Cost-of-Service Agreement

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

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

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

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

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

Draft 2022 Work Plan

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

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

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

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

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

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

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

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

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

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

Ms. Emily Laine, Reliability Committee (RC) Chair, referred the Committee to materials circulated in advance of the meeting concerning the Hydro-Québec Interconnection Capability Credits (HQICC) Values and the Installed Capacity Requirement (ICR) values and the related demand curves (collectively, the ICR Values) to be used for the 2026-27 Capacity Commitment Period associated with FCA17~~5~~. She reported that, following development by the ISO in consultation with the Power Supply Planning Committee, the ~~Reliability Committee~~ RC recommended at its September 20, 2022 meeting Participants Committee support for both the HQICC Values and the ICR Values.

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

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

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

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

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

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

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

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

There being no further discussion, the motions were then voted and passed in the single vote with a 72.17% Vote in favor (Generation Sector – 5.57%; Transmission Sector – 16.70%; Supplier Sector – 0%; AR Sector – 16.5%; Publicly Owned Entity Sector – 16.70%; End User Sector – 16.70%; and Provisional Members – 0%). (*See* Vote 1 on Attachment 2).

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

2023 ISO AND NESCOE BUDGETS

2023 ISO Budgets

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

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

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

2023 NESCOE Budget

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

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

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

STORAGE AS A TRANSMISSION-ONLY ASSET (SATOA) PROPOSAL

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

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

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

> RESOLVED, that the Participants Committee supports the SATOA Proposal as reflected in revisions to ***Sections I and II of the*** Transmission, Markets and Services ***Tariff, and to the Transmission Operating Agreement***, as recommended by the Transmission Committee and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.
>
> FURTHER RESOLVED, that the Participants Committee supports the SATOA Proposal as reflected in ***revisions to Section I.2.2 and Market Rule 1***, as recommended by the Markets Committee and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

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

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

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

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

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

NUPOWER REQUEST FOR WAIVER OF GIS OPERATING RULES AND GIS AGREEMENT

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

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

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

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

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

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

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

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

LITIGATION REPORT

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

COMMITTEE REPORTS

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

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

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

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

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

ADMINISTRATIVE MATTERS

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

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

Respectfully submitted,

____
David Doot, Secretary

ATTACHMENT 1

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

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

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

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

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

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

ATTACHMENT 2

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

TOTAL

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

GENERATION SECTOR

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

TRANSMISSION SECTOR

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

ALTERNATIVE RESOURCES SECTOR

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

SUPPLIER SECTOR

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

ATTACHMENT 2

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

END USER SECTOR

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

PUBLICLY OWNED ENTITY SECTOR

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

PUBLICLY OWNED ENTITY SECTOR (cont.)

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

PROVISIONAL MEMBERS

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

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's October 18, 2022 meeting, dated October 18, 2022.[1]

1. HQICC Values for the 2023-24 3rd ARA, 2024-25 2nd ARA, and 2025-26 1st ARA

Support the following Hydro-Québec Interconnection Capability Credit (HQICC) values for the Third Annual Reconfiguration Auction (ARA) for the 2023-24 Capacity Commitment Period (CCP), Second ARA for the 2024-25 CCP and First ARA for the 2025-26 CCP, as recommended by the RC at its October 18, 202 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve:

Month	2023-2024 HQICC Values (MW)	2024-2025 HQICC Values (MW)	2025-2026 HQICC Values (MW)
June	947	883	923
July	947	883	923
August	947	883	923
September	947	883	923
October	947	883	923
November	947	883	923
December	947	883	923
January	947	883	923
February	947	883	923
March	947	883	923
April	947	883	923
May	947	883	923

The motion to recommend Participants Committee support was approved, with two oppositions in the Supplier Sector and 11 abstentions (1 - Generation Sector; and 10 - Supplier Sector) noted.

[continued on next page]

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

2. ICR and Related Values for the 2023-24 3rd ARA, 2024-25 2nd ARA and 2025-26 1st ARA

3rd ARA for the 2022-23 CCP

Support, for the 3rd ARA for the 2022-23 CCP, the following New England Installed Capacity Requirement (ICR), Net ICR, Southeast New England (SENE) LSR, Maine (ME) Maximum Capacity Limit (MCL), and Northern New England (NNE) Maximum Capacity Limit (MCL) values:

	2023-2024 ARA 3 ICR values (MW)
Installed Capacity Requirement	32,637
Net Installed Capacity Requirement	31,690
Southeast New England Local Sourcing Requirement	8,734
Maine Maximum Capacity Limit	4,300
Northern New England Maximum Capacity Limit	8,925

and the following Marginal Reliability Impact (MRI) Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone:

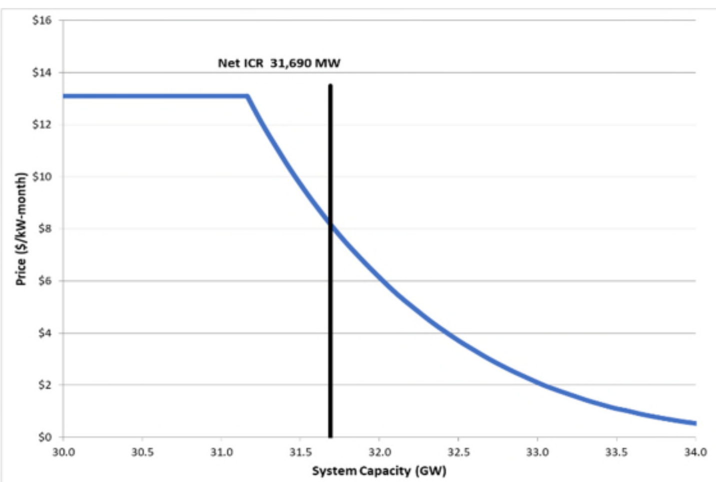

Figure 1 2023-24 CCP ARA3 System-Wide MRI Capacity Demand Curve

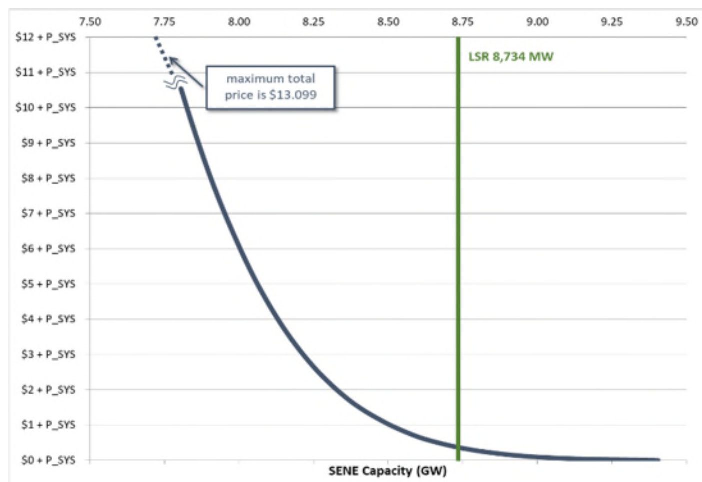

Figure 2 2023-24 CCP ARA3 SENE Import-Constrained MRI Capacity Demand Curve

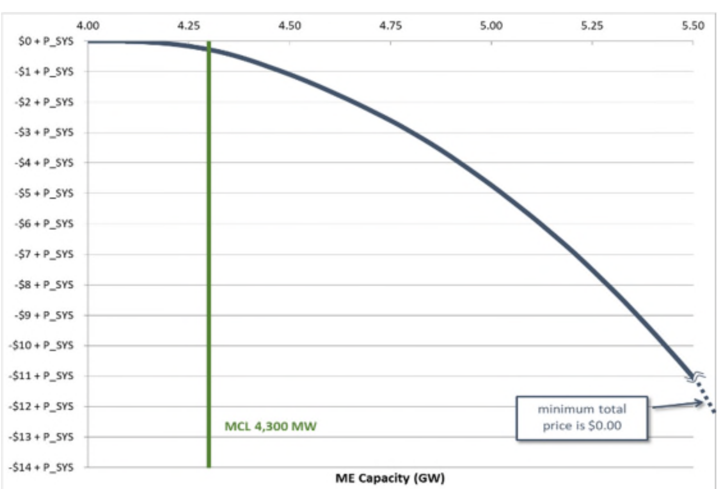

Figure 3 2023-24 CCP ARA3 ME Export-Constrained MRI Capacity Demand Curve

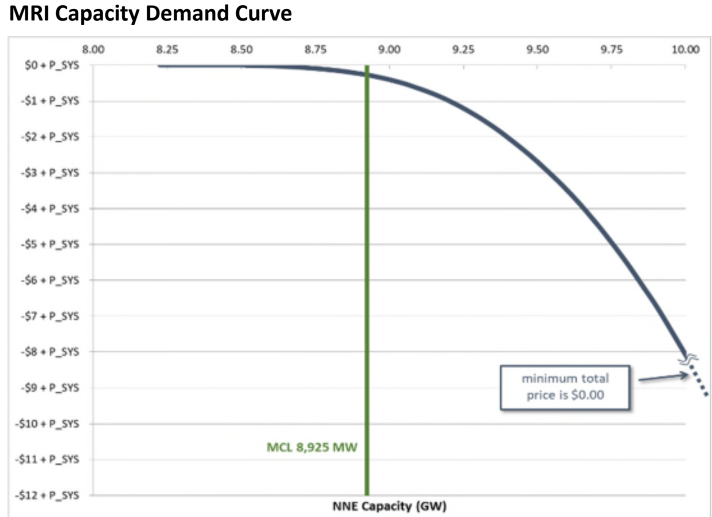

Figure 4 2023-24 CCP ARA3 NNE Export-Constrained MRI Capacity Demand Curve

2nd ARA for the 2024-25 CCP

Support, for the 2nd ARA for the 2024-25 CCP, the following New England ICR, Net ICR, SENE LSR, Maine MCL, and NNE MCL values:

	2024-2025 ARA 2 ICR values (MW)
Installed Capacity Requirement	32,428
Net Installed Capacity Requirement	31,545
Southeast New England Local Sourcing Requirement	8,855
Maine Maximum Capacity Limit	4,245
Northern New England Maximum Capacity Limit	8,835

and the following MRI Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, Maine Export-Constrained, and the NNE Export-Constrained Capacity Zone:

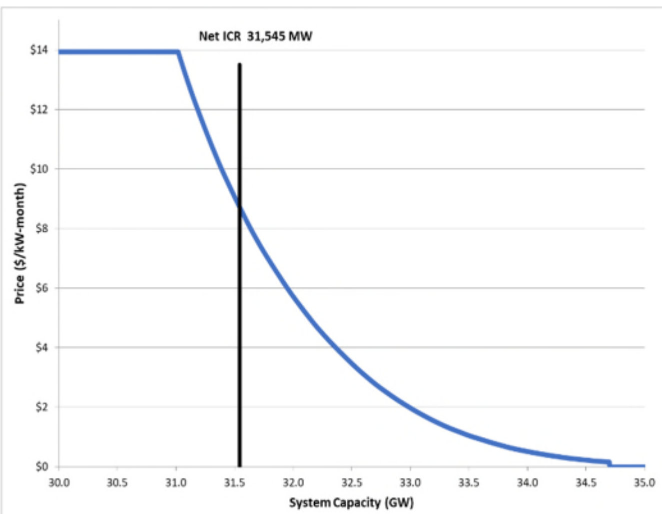

Figure 5 2024-25 CCP ARA2 System-Wide MRI Capacity Demand Curve

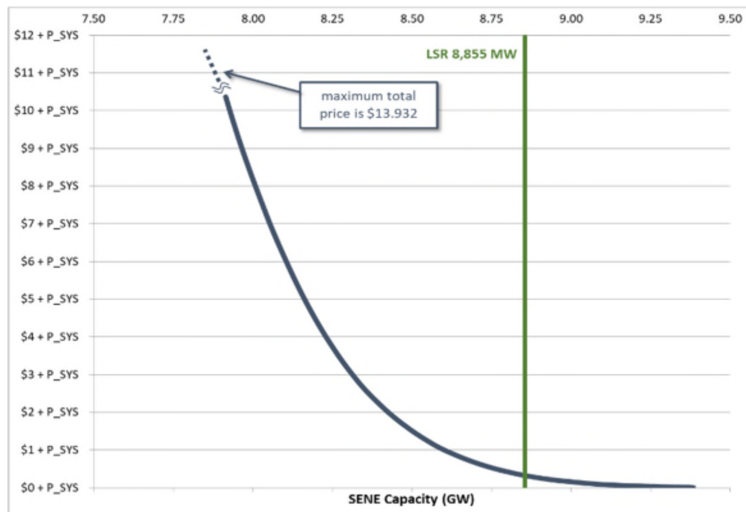

Figure 6 2024-25 CCP ARA2 SENE Import-Constrained MRI Capacity Demand Curve

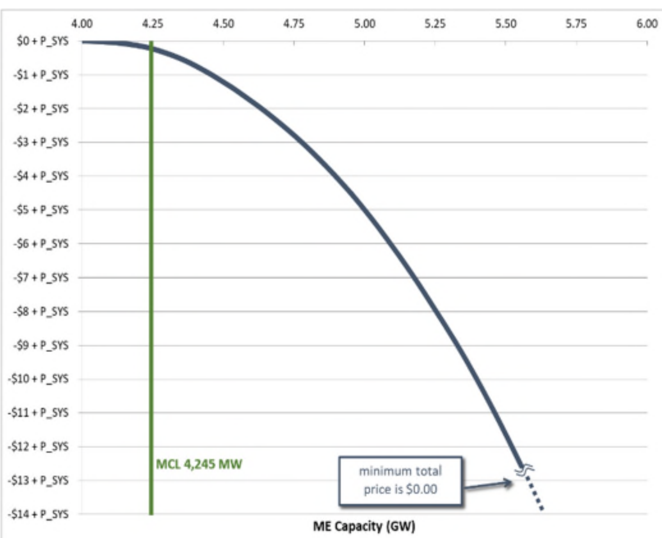

Figure 7 2024-25 CCP ARA2 Maine Export-Constrained MRI Capacity Demand Curve

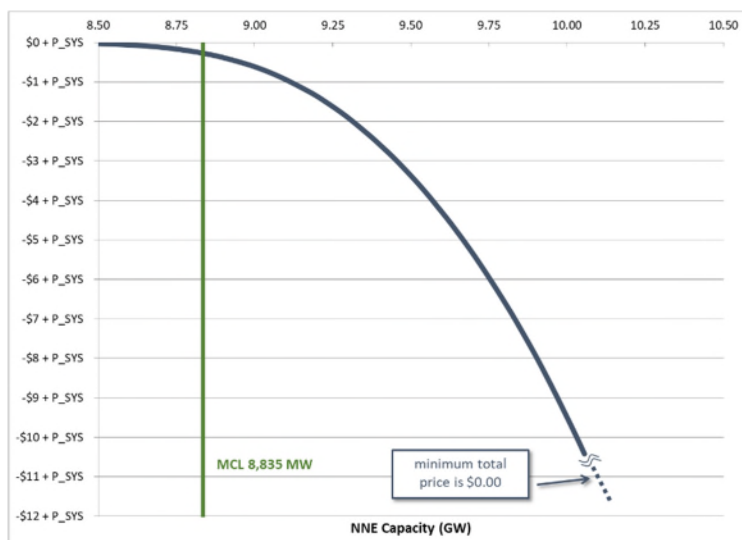

Figure 8 2024-25 CCP ARA2 NNE Export-Constrained MRI Capacity Demand Curve

1st ARA for the 2025-26 CCP

Support, for the 1st ARA for the 2025-26 CCP, the following New England ICR, Net ICR, SENE LSR, Maine MCL, and NNE MCL values:

	2025-2026 ARA 1 ICR values (MW)
Installed Capacity Requirement	31,508
Net Installed Capacity Requirement	30,585
Southeast New England Local Sourcing Requirement	8,545
Maine Maximum Capacity Limit	4,160
Northern New England Maximum Capacity Limit	8,615

and the following MRI Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, Maine Export-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone:

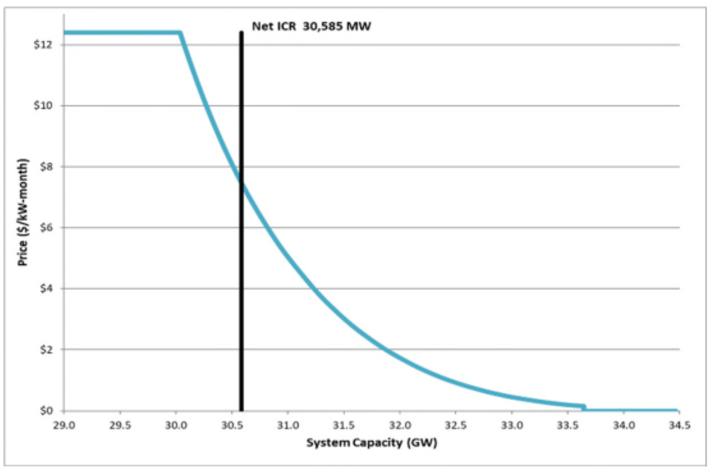

Figure 9 2025-26 CCP ARA1 System-Wide MRI Capacity Demand Curve

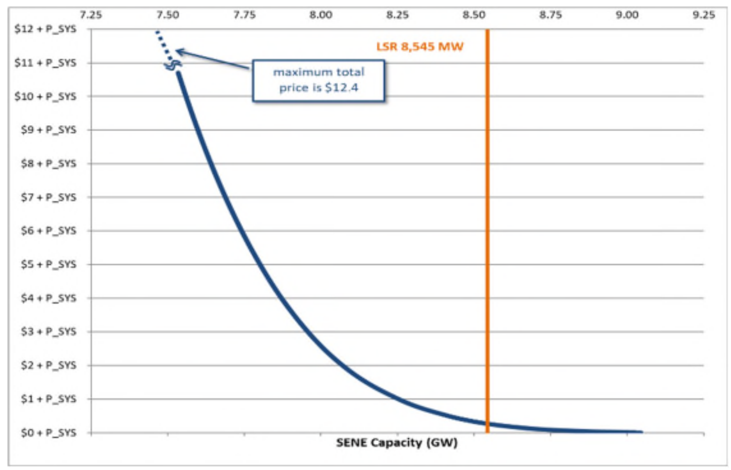

Figure 10 2025-26 CCP ARA1 SENE Import-Constrained MRI Capacity Demand Curve

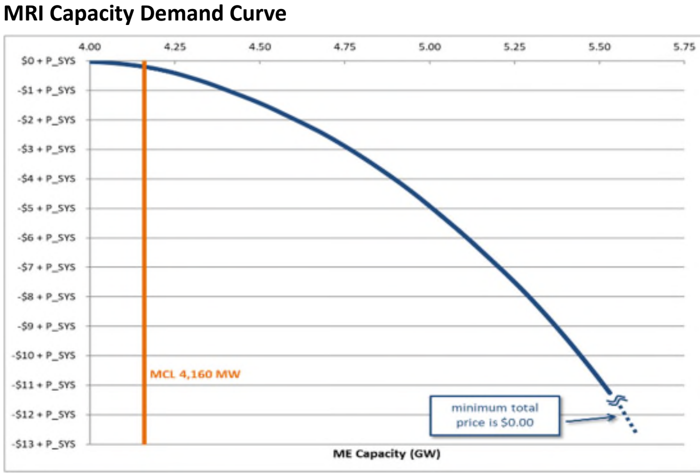

Figure 11 2025-26 CCP ARA1 Maine Export-Constrained MRI Capacity Demand Curve

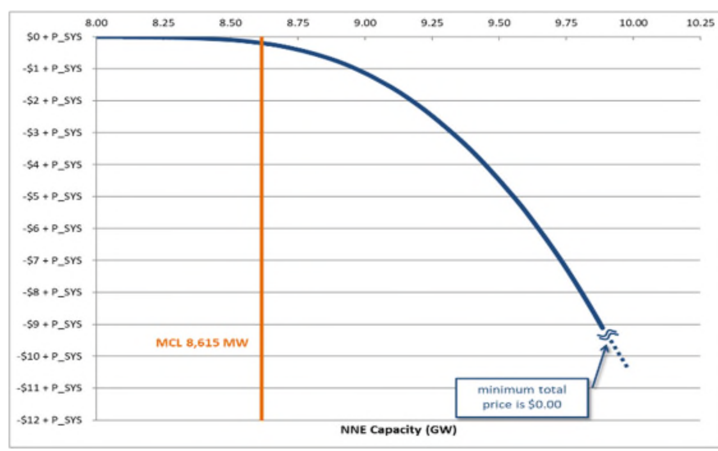

Figure 12 2025-26 CCP ARA1 NNE Export-Constrained MRI Capacity Demand Curve

each as recommended by the RC at its October 18, 2022 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved, with two oppositions in the Supplier Sector and 11 abstentions (1 - Generation Sector; and 10 - Supplier Sector) noted.

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's October 12-13, 2022 meeting, dated October 14, 2022.[2]

3. REMOVED FROM CONSENT AGENDA; TO BE DISCUSSION ITEM #4A

Inventoried Energy Program (IEP) Eligibility Compliance Revisions

Support the revisions to Sections III.K.1(a)(i) and III.K.3.2.1.1(a) of Market Rule 1 to clarify that assets that run on coal, nuclear, biomass or hydropower are not eligible for participation in the Inventoried Energy Program and may not be included in a Market Participant's list of assets for participation in the Inventoried Energy Program, as recommended by the MC at its October 12-13, 2022 meeting, with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention recorded (Generation Sector).

[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.

Summary of ISO New England Board and Committee Meetings

November 2, 2022 Participants Committee Meeting

Since the last update, the Information Technology and Cyber Security Committee met on October 14. The meeting was held by videoconference.

The Information Technology and Cyber Security Committee convened with the full Board for the Committee's annual "deep dive" on cyber security issues and received a presentation from an expert on data protection and management, and security best-practices. Following the session with the full Board, the Committee conducted its annual risk assessment of key risks within the scope of the Committee's oversight. The Committee also discussed current information technology trends and how they are monitored as part of a continuous improvement cycle. The Committee was then provided with an update on cyber security projects and current activities. Finally, during executive session, the Committee reviewed the results of its self-evaluation.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: October 26, 2022

RE: ISO-NE's Inventoried Energy Program Compliance Revisions

At the November 2, 2022 Participants Committee meeting, you will be asked to vote on revisions to Market Rule 1, Appendix K to remove certain resource types from being eligible to participate in the Inventoried Energy Program (IEP), as proposed by the ISO in response to the FERC's directive to refile provisions governing the IEP consistent with the D.C. Circuit's June 17, 2022 decision.

This item was initially placed on the Consent Agenda because the proposed set of Tariff revisions, referred to herein as the "IEP Compliance Revisions," were unanimously recommended by the Markets Committee (MC) at its October 12–13, 2022 meeting, with one abstention registered within the Generation Sector. Subsequent to the issuance of the Initial Notice for the November 2 meeting, the ISO identified a few additional, clarifying revisions to Appendix K that it would like to include in its compliance filing.[1] With the ISO's proposed set of compliance changes now differing from the Appendix K changes considered by the MC, this item has been removed from the Consent Agenda and placed on the discussion agenda for Participants Committee consideration.

Brookfield Renewable (Brookfield) has informed NEPOOL Counsel that it intends to propose a motion to amend the proposal to allow pumped hydro participating as an Electric Storage Facility to take part in the IEP. To review Brookfield's proposed Tariff changes to the ISO Compliance Revisions, see Attachment C.

If anyone else wishes to offer any other amendment for Participants Committee consideration, please provide that amendment to NEPOOL Counsel (slombardi@daypitney.com or rgarza@daypitney.com) as soon as possible so that we can circulate them in time for member review and consideration before the November 2 meeting, which we remind you will not start until 2:00 p.m. because the Sectors will be meeting with the Board earlier in that day.

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[1] Specifically, the ISO strikes out hydropower-related language in Sections III.K.1(a), (d) and III.K.3.2.1.1(c). The other modification, as shown in Section III.K.1(a)(i), adds that hydropower assets includes pumped hydro and pondage.

Background & Overview of IEP Compliance Revisions

By way of reminder, the IEP is a voluntary program that compensates certain asset types to maintain inventoried energy during the 2023–2024 and 2024–2025 winter months. On June 18, 2020, the FERC issued an order accepting the IEP tariff provisions,[2] which was subsequently appealed by certain parties to the D.C. Circuit. On June 17, 2022, the D.C. Circuit upheld the FERC's June 2020 order in part and vacated it in part.[3] With the D.C. Circuit's decision in hand, the FERC issued an order on September 23, 2022 directing the ISO "to submit a compliance filing with revised Tariff provisions governing the [IEP] (in Appendix K and/or elsewhere, as necessary) that make nuclear, coal, biomass, and hydroelectric generators ineligible to participate in the program."[4] The ISO's compliance filing is due on or before November 22, 2022.

A copy of the ISO's IEP Compliance Revisions (with post-MC meeting changes highlighted in yellow) is included with this memorandum as Attachment A. Further background information from the ISO, which was previously circulated to the MC, is included in Attachment B.

The IEP Compliance Revisions require a 60% Vote for Participants Committee approval. The following form of resolution may be used for Participants Committee action:

> RESOLVED, that the Participants Committee supports the revisions to Appendix K of Market Rule 1, as proposed by ISO New England to comply with the FERC's September 23, 2022 Order and 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 and Vice-Chair of the Markets Committee.

Please note that the form of resolution is to support the proposal as compliance with the FERC's directive. Participants that do not agree with the FERC's order (or the underlying D.C. Circuit's direction) can, nonetheless vote in favor of the resolution without that vote being considered or interpreted as vote in favor of the FERC's order.

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[2] *ISO New England Inc.*, 171 FERC ¶ 61,235 at P 2 (2020), https://www.iso-ne.com/static-assets/documents/2020/06/er19-1483-003_6-18-20_order_accept_iep.pdf.

[3] *Belmont Mun. Light Dep't v. FERC*, 38 F.4th 173, 179–78 (D.C. Cir. 2022), https://www.cadc.uscourts.gov/internet/opinions.nsf/CFEE4E3C26FDDC5285258864004E8A45/$file/19-1224-1950983.pdf.

[4] *ISO New England Inc.*, 180 FERC ¶ 61,181 at P 7 (2022), https://www.iso-ne.com/static-assets/documents/2022/09/er19-1428-005_9-23_22_order_iep.pdf.

Note: The post-MC meeting changes are highlighted in yellow.

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each winter) and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: assets that run on coal, nuclear, biomass or hydropower (including pumped hydro and pondage); Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

~~(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.~~

~~(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.~~

(~~iv~~ii) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

~~(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.~~

~~(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.~~

(~~vii~~iii) ~~Biomass/~~Refuse. The Real-Time Energy Inventory of an asset that runs on ~~biomass or~~ refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(~~viii~~iv) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as ~~water flow or~~ emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

memo

To: NEPOOL Markets Committee

From: Kathryn Boucher, Regulatory Counsel

Date: October 5, 2022

Subject: Inventoried Energy Program (IEP) Eligibility Compliance Revisions (WMPP ID: 133)

By way of background, the IEP is a voluntary program that proposed to compensate certain asset types[1] for maintaining inventoried energy during the winter months in 2023-24 and 2024-25. The ISO is requesting a vote on proposed compliance revisions to Appendix K of Market Rule 1 to revise the asset types that are eligible to participate in the IEP.

On September 23, 2022, the Federal Energy Regulatory Commission (the "Commission") issued an order requiring the ISO to make nuclear, coal, biomass, and hydroelectric generators ineligible to participate in the IEP.[2]

In compliance with the Commission's order, the proposed revisions to Appendix K of Market Rule 1 remove coal, nuclear, biomass, and hydropower as eligible asset types for participation in the IEP. In addition, the proposed revisions also clarify that these asset types may not be included in a Market Participant's submission of IEP election information to the ISO.

[1] Proposed asset types included in the IEP were oil, coal, nuclear, biomass, and refuse generators; certain hydro and pumped-storage generators; electric storage facilities, certain demand response resources; and natural gas resources that obtain contracts for firm delivery of natural gas.
[2] 180 FERC ¶ 61,181 (2022).

Inventoried Energy Program

Proposed changes to existing program structure on remand

Kathryn Boucher
REGULATORY COUNSEL
(413) 540-4559 | KBOUCHER@ISO-NE.COM

Inventoried Energy Program Eligibility Compliance Revisions

WMPP ID: 133

Proposed Effective Date: January 2023

- By way of background, the Inventoried Energy Program (IEP) is a voluntary program that proposed to compensate certain asset types for maintaining inventoried energy during the winter months in 2023-24 and 2024-25
  - These asset types included coal, nuclear, biomass, and certain hydro and pumped-storage generators among others
- On September 23, 2022, the Commission issued an order directing the ISO to make nuclear, coal, biomass, and hydroelectric generators ineligible to participate in the IEP
- To comply with the Commission's order, the ISO is proposing to remove these four types of assets that were previously eligible to participate in the Inventoried Energy Program (IEP)
  - Assets that run on oil, natural gas (both pipeline and LNG), refuse, and electric storage facilities remain eligible
- Purpose of today's presentation is to provide background and review the ISO's proposed compliance redlines

Background and Procedural History

- After extensive discussions with stakeholders, the ISO filed the IEP in March 2019
- On August 6, 2019, the IEP went into effect by operation of law due to lack of a quorum at the Commission
- FERC regained a quorum and sought an involuntary remand to address the filing on its merits. In June 2020, the Commission issued an order accepting the program
- Appeals were filed by several entities to the DC Circuit Court of Appeals

DC Circuit Court of Appeals Opinion

June 17, 2022 Order (linked here)

- Among other arguments, Petitioners argued that IEP payments to nuclear, coal, biomass, and eligible hydroelectric resources were unlikely to change these resources' behavior
- The Court found the Commission's analysis on this point contradicted its prior ruling on the Winter Reliability Program that declined to compensate generators that would not be incentivized to procure additional fuel or provide an incremental winter reliability benefit
- The Court otherwise upheld the IEP, but remanded to FERC to conform the program with its opinion

FERC Order Directing Compliance Filing

September 23, 2022 Order (linked here)

- FERC's Order directs the ISO to submit "revised Tariff provisions governing the Inventoried Energy Program (in Appendix K and/or elsewhere, as necessary) that make nuclear, coal, biomass, and hydroelectric generators ineligible to participate."
- The compliance filing must be filed within 60 days, on or before November 22, 2022
- Revisions to Appendix K remove eligible categories of asset types and clarify that assets that run on coal, nuclear, biomass or hydropower may not be included in a Market Participant's list of assets

Summary of Proposed Tariff Changes

Tariff Section	Tariff Change	Reason for Change
Section III.K.1(a)(i) - Submission of Election Information	Add the bold language: "The following asset types may not be included in a Market Participant's list of assets: **assets that run on coal, nuclear, biomass or hydropower**…"	Clarify that these asset types may not be included
Section III.K.3.2.1.1(a) - Asset-Level Real-Time Energy Inventory	Remove subsections: • (ii) [related to coal], • (iii) [related to nuclear], • (v) [related to pumped hydro], and • (vi) [related to pondage hydro]	Clarify that these asset types may not be included
Section III.K.3.2.1.1(a) - Asset-Level Real-Time Energy Inventory	Revise subsection (vii) to remove biomass	Clarify that biomass is ineligible

Conclusion

- In order to comply with FERC's directive, the ISO is removing assets that run on coal, nuclear, biomass or hydropower from eligibility for the IEP
- This filing is separate from the financial assurance and IEP program revisions efforts underway in parallel
- The ISO intends to submit this compliance filing in mid-November

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee **October 12-13, 2022**	Discussion and vote
Participants Committee **November 3, 2022**	Vote

Questions

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Note 1: The post-MC meeting changes are highlighted in yellow.

Note 2: The amendment's proposed changes are highlighted in green.

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each winter) and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: assets that run on coal, nuclear, biomass or hydropower (~~including pumped hydro and pondage~~excluding pumped hydro that participates in the New England Markets as an Electric Storage Facility); Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For

Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

~~(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.~~

~~(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.~~

(~~iv~~ii) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

~~(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.~~

~~(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.~~

(~~vii~~iii) ~~Biomass/~~Refuse. The Real-Time Energy Inventory of an asset that runs on ~~biomass or~~ refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(~~viii~~iv) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as ~~water flow or~~ emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: October 26, 2022

RE: Changes to ISO-NE Financial Assurance Policy and Billing Policy
Inventoried Energy Program

At its November 2, 2022 meeting, the Participants Committee will be asked to consider changes to the ISO New England Financial Assurance Policy ("FAP") and the ISO New England Billing Policy ("Billing Policy") to incorporate provisions related to the ISO's Inventoried Energy Program ("IEP"). Changes to the IEP are on the agenda for the November 2 meeting as well. The proposed changes to the FAP are included in Attachment 1 to this memorandum, and the proposed changes to the Billing Policy are included in Attachment 2 to this memorandum. The Participants Committee will also be asked to consider one clean-up change to the definitions in the ISO Tariff that the ISO discovered as it was preparing the filing for the changes to the FAP and Billing Policy, which is included in Attachment 3.

The proposed changes to the FAP are intended to protect Market Participants from the risk of loss from a IEP forward seller that fails to maintain adequate inventories. It does that by adding a new category of Financial Assurance Requirement, "Inventoried Energy Program Financial Assurance Requirement," to be provided by Market Participants submitting a Forward Inventoried Energy Plan Election approved by the ISO. New Section III.D of the FAP sets out a formula to determine the Inventoried Energy Program Financial Assurance Requirement, based on (1) the difference between amount of Forward Energy Inventory elected by the Market Participant and the maximum physical inventory over the prior 15 days, multiplied by (2) the 95th percentile of observed Inventoried Energy Days, which is 19 days for the 2023-24 and 2024-25 program years, multiplied by the month factor, which is 100% for December, 87% for January and 26% for February, multiplied by the spot payment rate under the ISO Tariff (currently $8.25 per MWh). The proposed changes to the Billing Policy add IEP charges and payments to the list of Hourly Charges that are billed twice weekly.

The proposed changes to the FAP and the Billing Policy with respect to the IEP were discussed by the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") at its August 23 and October 11 meetings. No Subcommittee member at those meetings objected to the proposed changes.

While preparing for filing the FAP and Billing Policy changes with the FERC, the ISO noticed a ministerial change that needed to be made to a billing-related definition in ISO Tariff Section I.2.2. In May 2020, the ISO and NEPOOL filed a joint proposal to move the issuance of monthly statements for Non-Hourly Charges from the Monday after the *tenth* of a calendar month to the Monday after the *ninth* of a calendar month. However, a conforming change to the definition of "Monthly Statement" in the terms and conditions section of the ISO Tariff was overlooked, in error. The ISO proposes to correct that error now with the IEP-related changes to the FAP and the Billing Policy.[1] The ISO plans to include that correction in the FERC filing for the IEP-related changes.

The following form of resolution may be used for Participants Committee action on the FAP, Billing Policy and ISO Tariff changes:

> RESOLVED, that the Participants Committee supports the changes to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy related to the Inventoried Energy Program and the ministerial change to the ISO Tariff to reflect the correct date for the issuance of Monthly Statements, each as proposed by the ISO and as circulated to this Committee with the October 26, 2022 supplemental notice, 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 and Finance Subcommittee.

[1] The ISO discovered this problem after the October 11 Subcommittee meeting, so the Subcommittee has not discussed this change. Tom Kaslow, the chair of the Subcommittee, agreed to include the proposed change, which is not material, with the IEP-related changes.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Table of Contents

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the "RNA"), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term "Market Participant" shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

F. Credit Limits for FTR-Only Customers

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

G. Total Credit Limit

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the “Market Participant Financial Assurance Requirement”). A Market Participant’s Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant’s membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant’s “Hourly Requirements” at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t =	The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;
n =	The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;
HC =	The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and
LMP ratio =	The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily FCM Obligation Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

FCA_Price_Ratio = (((Clearing Price_CCP_n x NDAY_P2_CCP_n) + (Clearing Price_CCP_{n+1} x NDAY_P2_CCP_{n+1}))/NDAY_P2)/(Clearing Price_CCP_n)

Where:

Clearing Price_CCP_n is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_CCP_{n+1} is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

NDAY_P2_CCP_n is number of days in the CCP_n within NDAY_P2; and

NDAY_P2_CCP_{n+1} is number of days in the CCP_{n+1} within NDAY_P2.

(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;

(v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus
b. such Market Participant's Daily FCM Requirements; plus
c. such Market Participant's Virtual Requirements; plus
d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus

g. such Market Participant's "IEP Financial Assurance Requirement" under Section III.D below; plus

~~g.~~h. the amount of any Disputed Amounts received by such -Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).

4. Serial Notice and Suspension Penalties

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

C. Additional Financial Assurance Requirements for Certain Municipal Market Participants

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation.

D. Inventoried Energy Program Financial Assurance Requirement

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, if any Market Participant has submitted a Forward Energy Inventory Election approved by the ISO under Section III.K.1.1 of the Tariff, such Market Participant shall be subject to the additional financial assurance requirements of this section. Any such Market Participant must provide additional financial assurance in one of the forms described in Section X below in an amount equal to the Inventoried Energy Program Financial Assurance Requirement on or before December 1 of each program year. The Inventoried Energy Program Financial Assurance Requirement will be calculated on a daily basis for each program year, from December 1, 2023 through February 29, 2024 and separately from December 1, 2024 through February 28, 2025, as follows:

IEP Financial Assurance Requirement = MAX(0, FE_MWh - Q_MWh) * D_95 * MF * SPR

Where:

FE_MWh = is the amount of Forward Energy Inventory elected by the Market Participant;

Q_MWh = is the maximum observed physical inventory over the prior 15 days;

D_95 = is the 95th percentile of observed Inventoried Energy Days, which for the 2023-2024 and 2024-2025 program years shall be 19;

MF = is the month factor, which shall be 100% for December, 87% for January, and 26% for February; and

SPR = spot payment rate = the $/MWh rate used in the calculation of Inventoried Energy Spot Payments as described in Section III.K.3.2 of the Tariff.

IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or a Market Participant other than an FTR-Only Customer, or a Governance Only Member whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

a) The term "Charge" refers to a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 – General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, Net Commitment Period Compensation, and daily Forward Capacity Market charges and payments ("Daily FCM Charges"), and Inventoried Energy Program charges and payments under Section III, Appendix K of the ISO Transmission, Markets and Services Tariff (all such charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the monthly Forward Capacity Market (exclusive of settlements included in the Hourly Charges) and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 – Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 – Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 - TIMING AND CONTENT OF STATEMENTS.

Section 2.1 – Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly, some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the ~~tenth~~ ninth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: October 26, 2022

RE: Participant proposal to amend § 9.2.3(a)(i) of the Participants Agreement

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At the November 2, 2022 Participants Committee meeting, you will be asked to consider, and potentially to approve the balloting of, a limited revision, proposed by a Participant, to amend § 9.2.3(a)(i) of the Participants Agreement (Terms of Directors) to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75. A presentation describing the proposed revision in additional detail is included with the materials for the November 2 meeting.

A motion to approve balloting of the Participants Agreement amendment requires a NEPOOL Vote by the Participants Committee of two-thirds, or 66.67%. The following form of resolution may be used for Participants Committee action:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of an agreement amending the Participants Agreement, to amend § 9.2.3(a)(i) of the Participants Agreement (Terms of Directors) to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75 as presented at this meeting, together with [such changes as were discussed and agreed to by the Committee and] such non-substantive changes as may be agreed to after the meeting by the Chair or any Vice-Chair of the Participants Committee, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

If approved, ballots will be circulated for signature. To be approved in balloting, changes to the Participants Agreement must be approved by a 70% Vote from enough members to satisfy the Minimum Response Requirement. Any change to the Participants Agreement also requires ISO approval.

ISO-NE Board Age Limit

Michelle Gardner, Executive Director – Northeast
NextEra Energy Resources
Vice-Chair, Generation Sector and Joint Nominating Committee Member

November 2, 2022

Executive Summary

Participant-initiated proposal to revise age limit for ISO Board members from age 70 to age 75

Conforms with best practices for the recruitment of talent for the ISO Board and aligns ISO with the rest of the RTO/ISOs in the country

Change requires one edit to the Participants Agreement

- No further changes on age or term waivers
- All other mechanisms remain the same

Vote required by the NEPOOL Participants Committee

Age Limit in the Participants Agreement

PA between the ISO and NEPOOL currently prohibits “a director from being elected or re-elected if she or he is over 70 years old at the time of election or re-election.”

The provision has been in the Participants Agreement since it was adopted in 2004.

There is also a term limit (three three-year terms) in the Participants Agreement.

Best Practices for Board Recruitment

Since 2004, best practices have changed.

The retirement ages of boards continue to rise.

Currently, 51% of boards with age limits have a mandatory retirement age of 75 or older, compared with 20% a decade ago.

- **Taken from the 2021 U.S. Spencer Stuart Board Index at page 20 us-spencer-stuart-board-index-2021.pdf (spencerstuart.com)**
- **Among boards with age limits, only 3% in 2021 have a retirement age of 70 and younger**

Age limits at the other ISOs conform to these trends. Two ISOs have age limits of 75; the others report that they have no age limits at all.

Challenges with Present Age Limit

In recent years, the age limit has contributed to difficulty in finding high-quality director candidates to serve on the ISO Board.

Heidrick & Struggles, Spencer Stuart, Egon Zehnder and most recently, Russell Reynolds (all four of the Joint Nominating Committee's director search partners), have expressed this concern to the Committee.

The concern is related to the substantial time commitment required to serve on the ISO's Board, making it challenging for actively-employed executives to serve. As many executives are working well into their 60's and not assuming Board commitments like the ISOs until retirement, the present age limit shortens their service window.

The difficulties created by the age limit are exacerbated by other restrictions on the candidate pool, including the ISO's Code of Conduct, which constrains the ability to consider candidates recently affiliated with market participants or who own investments in such companies. FERC's interlock rules create additional limitations.

Participants Agreement Revision

The proposal is for an amendment to the Participants Agreement to make a simple change to the existing language, as follows:

"The Participants Agreement between the ISO and NEPOOL prohibits "a director from being elected or re-elected if she or he is over ~~70~~ 75 years old at the time of election or re-election."

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Samantha Regan, NEPOOL Counsel

DATE: October 26, 2022

RE: Request by NuPower for Waiver of GIS Operating Rules and GIS Agreement

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At its November 2, 2022 meeting, the Participants Committee (the "PC") members will be asked to consider whether to waive certain NEPOOL Generation Information System ("GIS") requirements in order to correct renewable energy Certificates for a generator for February and March of this year. To provide the requested relief, NEPOOL would need to waive provisions of both the GIS Operating Rules ("Rules") and the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL, as amended and extended (the "GIS Agreement"). The generator, NuPower Cherry Street FC, LLC ("NuPower"),[1] requested relief stating that, if the request is accepted, the value of the Certificates at issue ($20,000 to $30,000) will be paid by third party buyers of the Certificates under NuPower's contract in the Connecticut LREC program.

The PC initially considered this matter at its October 6, 2022 PC meeting. At that time, we explained that NuPower operates the Cherry Street Facility, a fuel cell facility located in Bridgeport, Connecticut. NuPower's emissions data and Connecticut Class I eligibility for the months of February and March 2022 were not reflected on its February and March GIS Certificates when they were issued on July 15. NuPower attempted to rectify the problem via a request to the Connecticut Public Utilities Regulatory Authority that it recognize the Certificates as Connecticut Class I eligible, but its request was denied by that agency, keeping with its practice with similar requests in the recent past. The Authority noted that, in this situation, only NEPOOL can certify the Certificates as Class I and accordingly this was an issue between NuPower and NEPOOL. Based on that ruling (and after briefly pursuing another path before the Markets Committee), NuPower requested the instant waiver. As further background, our memorandum to the PC for the October 6 meeting is <u>Attachment 1</u>, and our memorandum on NuPower's prior request for adjustment of its Certificates for the Markets Committee's September 13-14 memorandum is <u>Attachment 2</u>.

At its October 6 meeting, the PC referred the waiver request to the GIS Operating Rules Working Group (the "Working Group") for consideration and for a recommendation to the PC on the specific waiver sought by NuPower, and criteria to apply in acting on future GIS waiver requests. The Working Group met on October 18, 2022 to discuss the PC's referral. The Working Group, which is non-voting, did not reach consensus on the NuPower waiver request. As part of

[1] NuPower is not a NEPOOL Participant and is a Non-Participant Account Holder under the GIS Rules.

its discussion of that request, the Working Group considered the process for entering emissions data in the GIS. When entering data for one quarter, the Account Holder will enter three separate months of data. Before submission of data for each month a "pop-up" on the screen will ask the Account Holder to confirm the information provided. After the Account Holder confirms the data for each month is correct and the data is submitted, an email is sent to the Account Holder confirming each months' entry.

With respect to criteria for GIS Rule waivers going forward, a number of Working Group members stated that, other than Connecticut, the state regulators address issues with incorrect data on GIS Certificates on a case-by-case basis, and therefore this issue does not arise in other jurisdictions. Members suggested that Account Holders should be required to go through the requisite state agencies, and not through NEPOOL, to secure any change to their Certificates. Additionally, some members expressed support for waiver requests based on human error, but Working Group members consistently agreed that waivers should not be granted for repeated errors. Finally, Working Group members suggested that independent review of generation data by a Third Party Meter Reader likely could assist in identifying errors in information in the GIS. If the PC wants to codify these or other criteria in the GIS Rules, those Rule changes would need to be reviewed by the Working Group and then approved by the Markets Committee using the regular process for modifications to the Rules. Further, any changes to the APX Agreement to authorize NEPOOL to grant future waivers and to require future applicants for waivers to pay a fee to defer costs would need to be negotiated and presented to PC for approval. NEPOOL Counsel will work with the PC Chair, the Working Group and the Markets Committee as needed to prepare such changes for PC consideration.

To be approved by the PC, NuPower's waiver request requires a 66.67% vote in favor of granting said request. In addition, as reported last month, APX must also approve the waiver, which it has agreed to do subject to NuPower withdrawing its suggestion that there was an error in the software. The following form of resolution can be used for PC action on NuPower's request:

RESOLVED, that the Participants Committee grants NuPower Cherry Street FC, LLC's request to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL ("GIS Agreement") and authorizes the Chair of the Participants Committee to execute and deliver a waiver of the GIS Agreement in a form acceptable to him and NEPOOL Counsel, as discussed in the materials circulated for this meeting.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Samantha Regan, NEPOOL Counsel

DATE: September 29, 2022

RE: Request by NuPower for Waiver of GIS Operating Rules and GIS Agreement

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At the October 6, 2022 Participants Committee (the "PC") meeting, members will be asked to consider once again whether to waive certain NEPOOL Generation Information System ("GIS") requirements, this time in order to correct renewable energy Certificates for a generator for February and March this year. To provide the requested relief NEPOOL would need to waive provisions of both the GIS Operating Rules ("Rules") and the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. ("APX") and NEPOOL, as amended and extended (the "GIS Agreement"). The generator, NuPower Cherry Street FC, LLC ("NuPower"),[1] will offer an explanation why it believes its requested relief is appropriate at the October 6 meeting. NuPower states that, if this request is accepted, the value of the Certificates ($20,000 to $30,000) will be paid by third party buyers of the Certificates under NuPower's contract in the Connecticut LREC program.

By way of context, NuPower operates the Cherry Street Facility, which is a fuel cell facility located in Bridgeport, Connecticut. NuPower's emissions data and Connecticut Class I eligibility for the months of February and March 2022 were not reflected on its GIS Certificates when they were issued on July 15. NuPower attempted to rectify the problem via a request to the Connecticut Public Utilities Regulatory Authority that it recognize the Certificates as Connecticut Class I eligible, but its request was denied by that agency, keeping with its practice with similar requests in the recent past. The Authority noted that, in this situation, only NEPOOL can certify the Certificates as Class I and accordingly this was an issue between NuPower and NEPOOL.

NuPower then sought relief from the Markets Committee ("MC") pursuant to the MC's authority under Rule 3.8 to correct Certificates, arguing that the Certificates in question were issued erroneously because of a software error in the GIS. APX, the GIS Administrator, disputes that there was an error in the GIS software and believes the problem with the NuPower Certificates was due to user error. The MC referred NuPower's request to the GIS Operating Rules Working Group (the "Working Group") to develop additional evidence of whether there was a software error in the GIS that caused the errors in the NuPower Certificates. Indicating subsequently that it did not expect further evidence to be provided with respect to a software error in the GIS, NuPower requested instead that the Rules and the GIS Agreement be waived to rectify the errors in its February and March 2022 Certificates.

[1] NuPower is not a NEPOOL Participant and is a Non-Participant Account Holder under the GIS Rules.

APX does not have the authority to correct the monthly generation data on the Certificates without both APX and NEPOOL waiving Section 4.2 of the GIS Agreement and Rule 1.4, which require APX to administer and operate the GIS in accordance with the Rules. APX, as the GIS Administrator, has under those provisions "the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the GIS Operating Rules." Since APX believes it has followed the Rules and GIS Agreement, it can correct NuPower's Certificates only if that Rule and Section of the GIS Agreement are waived.

APX indicates that it would be willing to waive the applicable requirements but only if NEPOOL, as the counterparty to the GIS Agreement, agreed to such a waiver and directed APX to correct the Certificates. In addition, APX has stated that it will not engage in discussions with NEPOOL about the requested waiver unless NuPower first retracts its previous statements regarding the claimed error in the GIS software.

When asked in August 2021 by another renewable energy generator, Stored Solar, LLC, to waive these applicable Rules and the GIS Agreement, the PC referred the matter to the MC for a recommendation first. The MC, in turn, referred the issue to the Working Group for recommendations on the request and suggestions on proposed criteria for NEPOOL to consider any future waiver requests. Before the MC acted on that direction from the PC, the producer found an alternative means of relief and withdrew its request for a waiver.

While the PC can act on NuPower's waiver request without any recommendation from the MC or the Working Group, the PC has already indicated its desire for a recommendation first from the MC in such circumstances. Similarly, while the MC can act on a waiver request without a recommendation from the Working Group, the MC has already indicated its preference for a Working Group recommendation first. Thus, for efficiency the PC can short circuit the process by directing the Working Group to recommend (1) criteria if any to apply to future requests for waiver of the Rules and GIS Agreement to correct erroneous certificates and (2) whether NEPOOL should grant the waivers here to correct NuPower's February and March Certificates (i.e. whether the criteria in item 1 are met in this instance). The PC can further direct that the MC make a recommendation here based on its consideration of any Working Group recommendation, or can have any Working Group recommendation delivered directly to the PC for action.

Whatever process is selected by the PC, NuPower has stated that it needs to have the Certificates corrected no later than the end of the year. There is time for the Working Group to consider this matter, for the MC to consider any recommendations from the Working Group on this matter, and for the PC to have a recommendation in time for a vote at its November or December meeting (depending upon when the Working Group meets and when the MC makes its recommendation). Of course, the PC could also vote on NuPower's waiver request at its October 6 meeting if it is prepared to do so.

Separately, APX requests amendments to the GIS Agreement to provide (1) NEPOOL the authority to waive the Rules to permit adjustments to Certificates without APX's consent; and (2) for APX either to charge NEPOOL for time APX must spend on waiver requests and requests for adjustments to Certificates under Rule 3.8 either at its standard rates or to charge that time against the 500 annual development hours included in the fee paid under the GIS Agreement. APX explains that it had not experienced these sorts of requests prior to the most recent extension of the GIS Agreement and had not included the considerable effort required to respond to those requests in its modified pricing structure agreed to at the time. NEPOOL may also want to consider revising the Rules to require the GIS Account Holder seeking a waiver of the Rules or an adjustment to its Certificates to pay NEPOOL for the costs associated with addressing that request. If members agree conceptually to those GIS Agreement changes, we would suggest that we work with the Participants Committee chair (or his designee(s)) and APX to prepare an amendment for the Participants Committee's consideration, not contingent on the NuPower request or its requested timeline.

The following alternative forms of resolution can be used for Participants Committee actions on NuPower's request:

> RESOLVED, that the Participants Committee refers to the NEPOOL GIS Operating Rules Working Group consideration of the request by NuPower Cherry Street FC, LLC to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL for a recommendation to [this Committee/The Markets Committee] on (1) criteria to apply in acting on this and future waiver requests and (2) the specific waivers sought by NuPower, all as discussed in the materials circulated for this meeting.
>
> OR
>
> RESOLVED, that the Participants Committee [grants] [denies] NuPower Cherry Street FC, LLC's request to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL as discussed in the materials circulated for this meeting.

M E M O R A N D U M

TO: NEPOOL Markets Committee

FROM: Paul Belval and Samantha Regan, NEPOOL Counsel

DATE: September 7, 2022

RE: NuPower Cherry Street Request for Post-Closing Account Adjustment to Q1 2022 Certificates under the GIS Operating Rules.

At its September 13-14, 2022 meeting, the NEPOOL Markets Committee will be asked to approve a request by NuPower Cherry Street FC, LLC ("NuPower")[1] for a Post-Closing Account Adjustment to Certificates issued to it for the first quarter of 2022 in accordance with Rule 3.8 of the NEPOOL Generation Information System ("GIS") Operating Rules (the "Rules"). As described in more detail below, Rule 3.8 provides for the Markets Committee to adjust Certificates after the end of a Trading Period if required to rectify an error in the GIS software or ISO's settlement software or a data entry error by APX or the ISO. NuPower claims that emissions data was not included on its Certificates for February and March, 2022 due to a GIS software error. This memorandum and the exhibits attached to this memorandum provide background for NuPower's request, as well as the response of APX, Inc., the GIS Administrator ("APX"), to that request.

In a letter to APX attached as Exhibit A, NuPower states that it entered its emissions data for each of January, February and March 2022 into the GIS. NuPower states that it entered all requisite emissions data for the first quarter into the GIS at the same time, but only the January Certificates included that emissions data. NuPower "*believes the only plausible explanation for [the failure of the emissions for February and March to be reflected in the GIS] is that there was a glitch in the GIS software*."[2] Under Rule 2.3(b), because the emissions field on the Certificates for February and March was not completed, the field for Connecticut RPS eligibility for the Certificates for those months was also left blank.[3]

On July 20, 2022 (i.e., five days after the Certificates at issue were created in the GIS) NuPower filed a letter with the Connecticut Public Utilities Regulatory Authority ("CT PURA") asking that CT PURA designate its February and March Certificates Connecticut RPS Class I

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[1] NuPower is not a NEPOOL Participant and is a Non-Participant Account Holder under the GIS Rules.

[2] NuPower acknowledges that it "overlooked an email dated July 7, 2022 confirming that the emissions information had been updated" and failed to see that the emissions data was only reflected in the GIS for January.

[3] The text of Rule 2.3(b) is included in Exhibit C.

compliant. CT PURA ultimately denied NuPower's request, stating that it was not the appropriate body to address NuPower's request. The referenced CT PURA materials are included in Exhibit B.[4]

Rule 3.8(a) of the GIS Rules provides that the Markets Committee can direct that Certificates be adjusted after the end of the Trading Period in which they were issued if the adjustment is "required solely to rectify an error in (i) the GIS software or the ISO's settlement software or (ii) data entry by either the ISO or GIS Administrator personnel." Since NuPower claims the failure of its emissions data to be reflected on its Certificates is the result of an error in the GIS software, its claim would qualify for consideration by the Markets Committee under that Rule. Rule 3.8(a) states that the Markets Committee "may approve or disapprove the Account Holder's request for a Post-Closing Account Adjustment at its sole discretion." That Rule places the burden of proving such an error in the GIS software on NuPower.[5] Finally, Rule 3.8(a) states that any adjustment to NuPower's Certificates would only happen after the close of the current Trading Period on September 15. Rule 3.8 is included in Exhibit C.

Rule 3.8(b) provides that APX may provide the Markets Committee with "any supporting or contrary information that it deems to be appropriate" for consideration in connection with a request for an adjustment to Certificates under Rule 3.8(a), and APX's response to NuPower's request is included in Exhibits D, E and F. In summary, APX asserts that the failure of NuPower's February and March 2022 emissions data to populate in the GIS was not a software glitch, but was instead the result of user error.

The Markets Committee may approve NuPower's request without confirmation by the Participants Committee. Since the request does not relate to a Market Rule, such an approval would require the affirmative vote of two-thirds of the Markets Committee. Alternatively, the Markets Committee could refer this request to the GIS Operating Rules Working Group if, for example, it determines further investigation of the facts surrounding NuPower's request would be helpful in its ultimate decision on the request.

The following resolution could be used to act on NuPower's request for an adjustment to its Certificates:

> RESOLVED, that the Markets Committee, pursuant to Rule 3.8 of the GIS Operating Rules, approves the request by NuPower Cherry Street to have its Certificates for February and March, 2022, adjusted to include its emissions data for those months, as provided by NuPower Cherry Street, and to reflect eligibility as a Class I resource under the Connecticut renewable portfolio standard.

cc: APX, Inc., GIS Administrator
NuPower Cherry Street FC, LLC

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[4] Included in the package of materials in Exhibit B is a letter filed by United Illuminating in the CT PURA docket responding to NuPower's request.

[5] "The Account Holder shall be responsible for demonstrating that the request satisfies" the criteria set forth in Rule 3.8(a).

EXHIBIT A

NuPower
103 North Park Avenue
Easton, CT, 06612

Via Email and Facsimile

APX, Inc.
2001 Gateway Place, Suite 315W
San Jose, CA 95110
Attention: NEPOOL Registry

Dear NEPOOL GIS Administrator,

NuPower Cherry Street ("NuPower" or the "Company") hereby respectfully requests a Post-Closing Account Adjustment pursuant to Rule 3.8 of the New England Power Pool Generation Information System ("NEPOOL GIS") Operating Rules for the Vintage Period February and March 2022 Certificates with the Serial Number 7364855 - Quantity: 293 and Serial Number 7370437 - Quantity: 322, respectively. Specifically, the Company requests a Post-Closing Account Adjustment designating the February and March 2022 Certificates as Class I Certificates.

On or before July 10, 2022, the Q1 2022 trading period data submission deadline, NuPower entered emissions data for the Q1 2022 period. As it is customary for the Company, NuPower entered the information for all three months at the same time. Further, because emissions for fuel cells are consistently low throughout the operating life of the units, emissions data for the reporting quarter is generally readily available and entered into the NEPOOL GIS website before the reporting deadline.[1] Unfortunately, because the NEPOOL GIS website does not immediately confirm that a submission has been successful and the Company overlooked an email dated July 7, 2022 confirming that the emissions information had been updated, NuPower failed to see that the GIS Administrator had only credited the Company for the January 2022 period, despite entering emissions data for the whole quarter. For this reason, NuPower only received Class I certification for the January 2022 Certificate. The Company filed a motion with Connecticut's Public Utilities Regulatory Authority ("PURA") in an attempt to resolve the problem and thereby, obtain Class I certification for the February and March 2022 Certificates.[2] However, PURA ultimately denied the motion explaining that the issue was predicated on a dispute between NuPower and NEPOOL, for which "[PURA] is not the proper body to adjudicate."[3] Therefore, as advised by PURA and given the fact that NuPower believes this is the result of GIS software

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[1] For the current trading period in particular, NuPower had attempted to enter the information earlier, on June 9, 2022, but the GIS Administrator informed the Company that The United Illuminating Company had not inputted the necessary information that would permit NuPower to enter the emissions data onto the NEPOOL GIS web site at that time.

[2] *See* PURA Docket No. 17-10-19, *Review of LREC/ZREC Projects*, Motion No. 146, July 21, 2022.

[3] *See* PURA Docket No. 17-10-19, *Review of LREC/ZREC Projects*, Ruling to Motion No. 146, August 2, 2022.

NuPower
103 North Park Avenue
Easton, CT, 06612

issues, the Company is submitting this letter requesting that the appropriate corrections be made in accordance with Rule 3.8(a) of the NEPOOL GIS Operating Rules.

Pursuant to Rule 3.8(a) of the NEPOOL GIS Operating Rules, an account holder may request an adjustment to the Certificates deposited or withdrawn from that account holder's account or any of its subaccounts provided the adjustment is required "solely to rectify an error in (i) the GIS software or the ISO's settlement software or (ii) data entry by either the ISO or GIS Administrator personnel." As previously stated, consistent with the Company's operating practices, NuPower had calculated and had entered into the system, emissions data for the entire Q1 2022 period before the reporting deadline. However, the NEPOOL GIS website did not capture the February and March 2022 entries. Consequently, the Company believes that the only plausible explanation for this discrepancy is that there was a glitch with the GIS software at the time NuPower entered the information resulting in the system only processing the data for January 2022. As such, the requested adjustment is not because the Company missed the deadline or entered the incorrect information, but to "rectify an error in the GIS software," which as set forth in Rule 3.8(a) of the NEPOOL GIS Operating Rules, the Markets Committee has the authority to correct.

For the foregoing reasons, NuPower respectfully requests that the emissions data for the remaining two months, February and March 2022, that the Company previously submitted be accepted and that a Post-Closing Account Adjustment designating the February and March 2022 Certificates as Class I Certificates be completed.

If you have any questions concerning this letter or need additional information, please do not hesitate to contact me at 203.395.4148.

Respectfully Submitted,

Daniel Donovan

Daniel Donovan

cc: Bruce L. McDermott, Esq., Murtha Cullina LLP
Paul N. Belval, Esq., Day Pitney LLP

EXHIBIT B

BRUCE L. MCDERMOTT
203.772.7787 DIRECT TELEPHONE
860.240.5723 DIRECT FACSIMILE
BMCDERMOTT@MURTHALAW.COM

July 20, 2022

Via Electronic Filing

Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority
Ten Franklin Square
New Britain, CT 06051

RE: Docket No. 17-10-19 – Review of LREC/ZREC Projects

Dear Mr. Gaudiosi:

NuPower Cherry Street FC, LLC ("NuPower" or the "Company") respectfully requests the Public Utilities Regulatory Authority ("PURA" or the "Authority") review and consideration of an issue surrounding the payment of Class I Renewable Energy Certificates ("RECs") for February and March, 2022 due to a failure to enter the associated emissions data into the New England Power Pool Generation Information System ("NEPOOL GIS") by individuals at NEPOOL. NuPower also respectfully requests that the Authority designate the February and March 2022 RECs as Connecticut Class I compliant.

NuPower operates the fuel cell facility located at 375 Howard Avenue in Bridgeport, Connecticut. The fuel cell facility is comprised of a Doosan PureCell® Model 400 fuel cell that were accepted into The United Illuminating Company's ("UI") 15-year Low Emissions Renewable Energy Credit ("LREC") Program. All the electricity produced at the facility is either sold to UI or used on-site. On November 18, 2020, the Authority found that pursuant to Section 16-1(a)(20) of the Connecticut General Statutes ("CGS"), the fuel fell facility qualified as a Class I renewable energy source. The fuel cell facility was assigned the Connecticut Renewable Portfolio Standard Registration No. CT20107. A copy of the Authority's decision granting Class I status is attached to this letter (Attachment A).

NuPower registered the facility into the NEPOOL GIS and the facility was assigned NEPOOL GIS Identification Number NON153454. NuPower entered emissions data for the first quarter of 2022 but was notified by NEPOOL on July 18, 2022 that emission data was not entered for February and March 2022 prior to the first quarter 2022 trading period data submission deadline. Such a determination results "in a loss of State Attribute Classification for the upcoming quarter (only for the month in which emissions were not entered)." See Attachment B. After the data submission deadlines ends, NEPOOL is unable to go back and add emissions data and assign the "RPS eligibilities for Certificates that are already issued." Id.

A screenshot of the NEPOOL website for the January filing is at Attachment C and reflects the information provided by NuPower. The website pages for the February and March filings currently are blank and do not reflect any information previously provided by NuPower and NuPower is not able to add information for those two months. It is not clear why the filing for February and March 2022 was not registered with NEPOOL in the same manner as the January RECs were registered.

NuPower respectfully requests that the February and March 2022 RECs be designated as Connecticut Class I compliant. NuPower's request is consistent with similar requests made to the Authority where a company failed to enter emissions data into the NEPOOL GIS which created RECs that are not identified as Connecticut Class I compliant yet the Authority allowed them to use these RECs for Connecticut Class I compliance.[1] Like those companies, NuPower's generating unit does not have emission limits under CGS §16-1(a)(20), consequently, NuPower respectfully requests that the Authority make the same determination.

NuPower appreciates the Authority's consideration of this request.

Very truly yours,

Bruce L. McDermott

Enclosures

[1] *See* Docket No. 99-11-14, *Application of Constellation NewEnergy f/k/a AES for an Electric Supplier License*, Letter dated 03/11/2008 re: Connecticut Class I Renewable Energy Certificates, June 4, 2008. "[The] Department believes that [Constellation NewEnergy (CNE)] should not be penalized for omitting the generators emission data. Therefore, the Department will allow CNE to use its second quarter RECs for 2007 Connecticut Class I compliance." Docket No. 12-09-02, *Annual Review of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2011*, Compliance Filings, CL&P 2011 RPS Filing / Northeast Utilities, Attachment 3, October 15, 2012. "General Statutes of Connecticut §§16-1(a)(26) and (27) do not require emission data for the particular type of generator(s) in question. As a result, the Authority believes that CL&P should not be penalized for omitting the generators' emissions data."

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 20-10-07 APPLICATION OF NUPOWER CHERRY STREET FC, LLC FOR QUALIFICATION OF 375 HOWARD AVENUE, BRIDGEPORT, CT AS A CLASS I RENEWABLE ENERGY SOURCE

November 18, 2020

DECISION

On October 5, 2020, the Public Utilities Regulatory Authority (Authority) received an application from NuPower Cherry Street FC, LLC (Company) requesting that the Authority determine that the fuel cell facility (Facility or Project) located at 375 Howard Avenue in Bridgeport, Connecticut qualifies as a Class I renewable energy source.

The Facility generates electricity using a fuel cell. The Project began commercial operation on September 8, 2020, and has an installed capacity of 0.44 MW. The Facility's New England Power Pool Generation Information System (NEPOOL GIS) Identification Number is NON153454. The Project is a behind-the-meter generation facility located in Connecticut and shall be subject to audits by the Authority.

The Facility has been accepted into The United Illuminating Company's (UI) 15-year Low Emissions Renewable Energy Credit Program and its electric generation output will be tracked by a UI Monitoring System. All of the electricity produced by the Project will be either sold to UI or used at the location of the Facility.

The Authority reviewed all of the information in the record and finds that pursuant to §16-1(a)(20) of the General Statutes of Connecticut, the Facility qualifies as a Class I renewable energy source, effective September 8, 2020. The Authority assigns the Facility Connecticut Renewable Portfolio Standard Registration No. CT201007.

The Authority's determination in this docket is based on the information submitted by the Company. The Authority may reverse its ruling or revoke the Company's registration if any material information provided proves to be false or misleading. The Company is reminded that it is obligated to notify the Authority within 10 days of any changes to any of the information it has provided.

DOCKET NO. 20-10-07 APPLICATION OF NUPOWER CHERRY STREET FC, LLC FOR QUALIFICATION OF 375 HOWARD AVENUE, BRIDGEPORT, CT AS A CLASS I RENEWABLE ENERGY SOURCE

This Decision is adopted by the following Commissioners:

John W. Betkoski, III

Marissa P. Gillett

Michael A. Caron

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Jeffrey R. Gaudiosi, Esq. Executive Secretary Public Utilities Regulatory Authority	November 18, 2020 Date

Bao Ngo (GIS)

Jul 18, 2022, 13:03 PDT

Hi Daniel,

I reviewed Q1 2022 data for NON153454 NuPower Cherry Street FC LLC - Doosan Pure Cell 400, Emission data was not entered in 02/2022 and 03/2022 prior to the Q1 2022 trading period data submission deadline. Failure to enter emissions results in a loss of State Attribute Classification for the upcoming quarter (only for the month in which emissions were not entered), as well as, an entry of the listed proxy emission rate for the registered fuel type(s) for your unit(s). I saw emissions entered for 01/2022 which is why the RECs were issued with the correct eligibility.

Per Rule 2.3 (b) of the **NEPOOL GIS Operating Rules**, after the data submission deadline ends and the trading period begins, we are unable to go back and add emissions data and assign the RPS eligibilities for Certificates that are already issued.

Please visit the NEPOOL GIS Help Center for more information.

Thank you,
Bao Ngo
GIS Registry Administrator, Environmental Registries
gis@apx.com | direct: + 1 408 899 3343

ts - | NuPower Cherr | Google Contact | My Drive - Goo | NuPower llc - C | GIS

www1.nepoolgis.com/myModule/Emissions/Emissions.asp?id1=1...

54584

	NuPower Cherry Street FC LLC - Doosan Pure Cell 400
g:	No
e and address ng actual issions):	n/a
	Month: January
it by Approved tocol:	(Active for the GIS Administrator only, please call 408-899-3343 if you would like more information on the Emission Protocol Approval process.)
	321.79 (MWh)

ns in Pounds per Month (format: 1.1234)

	Generation* (MWH)	Carbon dioxide*	Carbon monoxide*	Mercury*	Nitrogen oxides*	Particulate matter*	Particulate matter (<=10µm)	Sulfur dioxides*	Volatile or compounc
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		3.26300	0.00006	0.00000	0.00003	0.00000	0.00000	0.00000	0.0

July 26, 2022

Mr. Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051

Re: Docket No. 17-10-19, Review of LREC/ZREC Projects – **Response of The United Illuminating Company to Motion No. 146 NuPower Cherry Street FC, LLC**

Dear Mr. Gaudiosi:

On July 21, 2022, NuPower Cherry Street FC, LLC ("NuPower") submitted a motion (Motion 146) in the above-referenced proceeding (the "Request"), requesting that the Public Utilities Regulatory Authority (the "Authority") designate February and March 2022 RECs as Connecticut Class I compliant in spite of the failure to timely enter emissions data in the New England Power Pool Generation Information System ("NEPOOL GIS"). The United Illuminating Company ("UI") hereby submits its response to this Request.

UI does not oppose this Request. However, UI reminds the Authority that NuPower has submitted a similar request to the Authority, Motion No. 122, filed on May 4, 2021, when NuPower failed to enter energy emissions data into NEPOOL GIS for their fourth quarter 2020 RECs, which created RECs that were not identified as Connecticut Class I compliant. In their response, the Authority stated that they "may deny similar requests if NuPower fails to comply with all GIS requirements." In considering this second Request from NuPower, UI also believes it is important for the Authority to be informed of the practical implications of granting this Request and the added costs borne by UI customers.

NuPower itself does not have a Connecticut Class I compliance obligation. NuPower has entered into an LREC contract with UI to purchase the resulting Connecticut Class I RECs from this project at a fixed price for a fifteen-year term. Since UI meets its Connecticut Renewable Portfolio Standard ("RPS") obligations though its standard service and last resort service suppliers, UI does not use these purchased certificates to satisfy its Connecticut RPS obligations, resulting in UI selling the certificates that it purchases from long term contracts into the REC market. For this reason, these certificates could never be used to satisfy Connecticut Class I compliance obligations.

Even if the Authority allows these specific certificates to be designated as Connecticut Class I compliant, the monetary impact to customers is significant. If emissions data was uploaded per NEPOOL GIS Operating Rules by NuPower, the 928 certificates produced would be purchased by UI for the contract price described in the LREC Contract and sold for the current Connecticut

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www.avangrid.com, Daniel.Crisp@avangrid.com

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Class I market price, reducing costs for UI customers. However, since the certificates cannot be reissued as Connecticut Class I certificates in NEPOOL GIS per Attachment B of NuPower's July 21, 2022 filing, then they cannot be sold for the Connecticut Class I market price. If the "tarnished" certificates are purchased by UI at the same contract price that Connecticut Class I RECs are purchased at, the net cost to customers between the cost and resale of the "tarnished" certificates, would be a difference of around $20,000 to $30,000. Essentially, there would be less offsetting resale REC revenue for this quarter's REC purchase, with the net added costs being passed on to customers.

I hereby certify service of this filing upon all parties and intervenors of record in this proceeding.

Please contact Christie Prescott, Director, Wholesale Power Contracts, at (203) 499-2490 or christie.prescott@uinet.com if you have any questions about the contents of this response.

Very truly yours,

Daniel T. Crisp

Daniel T. Crisp
Senior Counsel
Avangrid Service Company
As Agent for The United Illuminating Company

MURTHA CULLINA
ATTORNEYS AT LAW

BRUCE L. MCDERMOTT
203.772.7787 DIRECT TELEPHONE
860.240.5723 DIRECT FACSIMILE
BMCDERMOTT@MURTHALAW.COM

July 27, 2022

Via Electronic Filing

Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority
Ten Franklin Square
New Britain, CT 06051

RE: Docket No. 17-10-19 – Review of LREC/ZREC Projects

Dear Mr. Gaudiosi:

On July 21, 2022, NuPower Cherry Street FC, LLC ("NuPower") submitted a motion (Motion 146) in the above-referenced proceeding (the "Request"), requesting that the Public Utilities Regulatory Authority (the "Authority") designate February and March 2022 RECs as Connecticut Class I compliant due to a failure to enter the associated emissions data into the New England Power Pool Generation Information System ("NEPOOL GIS") by individuals at NEPOOL. NuPower also requested that the Authority designate the February and March 2022 RECs as Connecticut Class I compliant. On July 26, 2022, The United Illuminating Company submitted its response to NuPower's July 21, 2022 letter. NuPower hereby supplements its July 21, 2022 letter as follows:

As explained in NuPower's letter, NuPower entered emissions data for the first quarter of 2022 but was notified by NEPOOL on July 18, 2022 that emission data was not entered for February and March 2022 prior to the first quarter 2022 trading period data submission deadline. NuPower's letter did not include proof that NuPower completed the February and March filings. The attached email from the NEPOOL GIS clearly shows that NuPower did in fact timely register the emissions data for three months prior to the first quarter 2022 trading period data submission deadline and therefore the Authority should determine that the February and March 2022 RECs are to be designated as Connecticut Class I compliant.

NuPower appreciates the Authority's consideration of this request.

Very truly yours,

Bruce L. McDermott

Enclosures

From: **GIS Admin** <gis@apx.com>
Date: Fri, Jul 15, 2022 at 12:16 AM
Subject: Transfer Initiated
To: <ddonovan@nupowerllc.net>

The transfer of the following certificates has been initiated:
From NuPower Cherry Street FC LLC to UI LREC/ZREC

Quantity = 928
Certificate Serial Number(s):
7397560 - 1 to 313 - Quantity: 313;
7364855 - 1 to 293 - Quantity: 293;
7370437 - 1 to 322 - Quantity: 322;

For more information please contact the Registry Administrator.

GIS Administrator
Phone: 408-899-3343
Email: gis@apx.com

STATE OF CONNECTICUT
PUBLIC UTILITIES REGULATORY AUTHORITY

August 2, 2022
In reply, please refer to:
Docket No. 17-10-19
Motion No. 146

Bruce L. McDermott, Esq.
Murtha Cullina LLP
265 Church Street
New Haven, CT 06510

Re: 17-10-19 - Review of LREC/ZREC Projects

Dear Attorney McDermott:

On July 20, 2022, the Public Utilities Regulatory Authority (Authority) received a motion (Motion No. 146) from NuPower Cherry Street FC, LLC (NuPower) requesting that the Authority designate certain Renewable Energy Certificates (RECs) created in February and March 2022 as Connecticut Class I compliant. For the reasons stated herein, Motion No. 146 is denied.

Motion No. 146 alleges that individuals at the New England Power Pool (NEPOOL) failed to enter emissions data from February and March 2022 into its NEPOOL Generation Information System (NEPOOL GIS). Motion No. 146, p. 1. As a result of the alleged omission, the RECs generated were not deemed Connecticut Class I compliant. Id., p. 2. Consequently, NuPower requests that the Authority designate the February and March 2022 RECs as Connecticut Class I compliant.

The Authority notes that NuPower made a similar request in Motion No. 122 in the above-referenced docket after it failed to enter fourth quarter 2020 emission data into NEPOOL GIS. Motion No. 122, p. 1. In the Authority's Ruling dated May 14, 2021, it granted NuPower's request for its fourth quarter RECs to be used for 2020 Connecticut Class I compliance. Motion Ruling No. 122, p. 2. However, the Authority's ruling cautioned NuPower that it may deny similar requests in the future. Id.

Unlike Motion No. 122, NuPower indicates in Motion No. 146 that NEPOOL, rather than NuPower, is responsible for failing to enter emissions data into NEPOOL GIS. Motion No. 146, p. 1. However, NuPower has not submitted any evidence to substantiate its claims. On July 27, 2022, NuPower submitted a supplemental filing to Motion No. 146 (Supplemental Filing) with an attachment it claimed "clearly shows" that emissions data in question was entered. Cover Letter to Supplemental Filing, p. 1. To the contrary, while the attachment notes that certain REC certificates were being transferred from NuPower to UI, it does not confirm that NEPOOL failed to enter the emissions data in question.[1]

Further, UI noted in a response to Motion No. 146 dated July 26, 2022 (UI Response)[2] that, if the Authority designates the RECs as Connecticut Class I Compliant, NEPOOL cannot reissue them as Connecticut Class I compliant and UI would have to sell the RECs at a loss, resulting in a ratepayer impact of $20,000 to $30,000. UI Response, pp. 1-2. Therefore, in considering the net cost to customers between the resale of the RECs in question and their contract price, it is not in the best interest of Connecticut ratepayers to grant NuPower's request.

Accordingly, the Authority denies NuPower's request to designate February and March 2022 RECs as Connecticut Class I compliant based on the analysis outlined in the preceding paragraphs.

Sincerely,

PUBLIC UTILITIES REGULATORY AUTHORITY

Jeffrey R. Gaudiosi, Esq.
Executive Secretary

cc: Service List

[1] Ultimately, this incident appears to be a dispute between NuPower and NEPOOL. A dispute which the Authority is not the proper body to adjudicate.

[2] UI stated that it does not oppose NuPower's request, but it did want to provide additional information for the Authority to consider before rendering a decision. UI Response, p. 1.

EXHIBIT C

Rule 2.3 Generation Registration

(a) GIS Generators and Account Holders owning generating units outside the New England Control Area that import Energy under Rule 2.7(c) or Account Holders that are the designees of the owners of such generating units (collectively, "Importing Account Holders") must provide the GIS Administrator with information for generation registration. To register, an agent or representative of a GIS Generator or an Importing Account Holder must manually enter data relating to its company name and generator asset identification number as recorded with the ISO, identification number, if any, assigned to the applicable generating facility by the U.S. Department of Energy, emission unit identification number, if any, assigned to the generating unit by the U.S. Environmental Protection Agency (the "EPA"), person or entity holding legal title to the generating unit and the generating unit's Lead Market Participant, status, location, fuel source, multi-fuel capability, emissions, labor characteristics, location, vintage, capability to cogenerate steam and electric power and other information, each as identified in the Certificate fields established under these GIS Operating Rules from time to time. A Non-NEPOOL Generator Representative may register multiple generating units satisfying the requirements of Rule 2.1(a)(vi) at one time. At the time a GIS Generator or Importing Account Holder registers in the GIS, the applicable Regulator(s) (defined below) listed on Appendix 5.3 shall indicate to the GIS Administrator (i) the generating Unit's status under the Regional Greenhouse Gas Initiative ("RGGI"), (ii) if the applicable generating unit is eligible under certain Attribute Laws (including, if applicable, the level of generation or imported Energy required in any year before the applicable generating unit is eligible under such Attribute Laws), and (iii) whether the applicable generating unit is required to provide the EPA with year-round continuous emissions monitoring reporting ("CEM Reporting") pursuant to the monitoring provisions of 40 C.F.R. Part 75 (an "EPA Reporting Generator"). In addition, when a Clean Peak Resource registers in the GIS, the CPS Program Administrator will indicate to the GIS Administrator that that GIS Generator satisfied the criteria as a Clean Peak Resource. Each GIS Generator, Importing Account Holder and Regulator and the CPS Program Administrator shall provide the information required by the GIS Administrator to complete all applicable Certificate fields at the time of its initial registration. Each GIS Generator Importing Account Holder and Regulator and the CPS Program Administrator shall promptly update such information to the extent that it changes after its initial registration and the GIS Administrator will notify each GIS Generator or Importing Account Holder of any update to its information that is provided by a Regulator or the CPS Program Administrator. Any update provided after the fifth calendar day preceding any Creation Date shall not apply to the Certificates created on such Creation Date.

(b) If a GIS Generator's agent or representative fails to provide the requisite information, the GIS Administrator shall obtain information regarding such GIS Generator's fuel source from the NX-12 Form most recently provided to the ISO for such GIS Generator, and the GIS Administrator may obtain such other information regarding such GIS Generator from such NX-12 Form and from the emissions data most recently provided to the EPA or the applicable Regulator(s) by such GIS Generator, although the GIS Administrator has no obligation to obtain this additional information. If a GIS Generator, the EPA, a Regulator or the CPS Program Administrator does not provide the GIS Administrator with the requisite information to complete the fields on a Certificate for any generating unit, and the GIS Administrator does not obtain such information on its own, that GIS Generator shall be deemed to have the emissions per MWh most recently provided to the GIS Administrator by one of the Environmental Regulatory Agencies listed on- Appendix 5.3 for generators using the same fuel type as the GIS Generator ("Proxy Emissions"), and all other fields for such GIS Generator shall be left blank on its Certificates. The Proxy Emissions for a GIS Generator that is (v) a NH Biodiesel Producer, (w) a MAPS Useful Thermal Resource or a MAPS CHP Resource that is not a NEPOOL Generator (a "Non-NEPOOL MAPS Resource"), (x) registered with a single Fuel Source of either Hydroelectric/Hydropower, Hydrokinetic, Geothermal, Nuclear, Ocean, Solar or Wind (including each of the subcategories listed for each such Fuel Source in Part 1 of Appendix 2.4) (a "Zero Emissions Generator"), (y) a cogeneration unit with a nameplate capacity of 5 MW or less which is located in Connecticut, eligible as a "Class III" resource under Connecticut law and not eligible for Renewable Certificates (a "Class III Cogeneration Resources") or (z) registered with a single Fuel Source of Flywheel Storage shall be zero for each emission type reported. A GIS Generator with multi-fuel capability that does not provide the GIS Administrator with the requisite information shall, for purposes of this Rule 2.3(b), be deemed to have the fuel type used by it with the greatest Proxy Emission for carbon dioxide for 100% of its output.

(c) Information for Imported System Energy (defined below) is addressed in Rule 2.7(b).

(d) Each NEPOOL Participant registering a New England Generator Asset in the MSS that is subject to net metering pursuant to the laws of one of the New England states shall register that asset such that the last thirteen characters of the name used in that registration will be, in order, the five-digit postal zip code corresponding to such generator, a two-character abbreviation to be selected by that NEPOOL Participant for the generating technology of such generator, the four-digit nameplate capacity, in kW, of such generator, and the letter "NM" (to denote that it is a net-metered Generator Asset). The System Operator will, on a monthly basis, provide a list of such net-metered New England Generator Assets to the GIS Administrator, which will in turn provide such list to the Energy Regulatory Agencies listed on Appendix 5.3, along with a list of all GIS Generators that are not NEPOOL Generators. To the extent that any Energy Regulatory Agency determines any New England Generator Asset to be the same generating unit as a GIS Generator that is accounted for in the GIS and is not a New England Generator Asset (regardless of whether New England Generator Asset is included on the list provided by the GIS Administrator) and provides that determination to the GIS Administrator, the GIS Administrator will provide that determination to the NEPOOL Participant(s) registering any New England Generator Assets included in that determination. Upon receiving that determination, such NEPOOL Participant will have ninety (90) days to notify the GIS Administrator in writing that the New England Generator Asset registered by it should be eligible to create Certificates. Unless the GIS Administrator is notified by a NEPOOL Participant that a New England Generator Asset identified under this Rule 2.3(d) should be eligible to create Certificates, the GIS Administrator will, following such ninety (90) day period, remove that New England Generator Asset from the GIS. Any determination made under this Rule 2.3(d) after the day that is five (5) days before a Creation Date will not affect Certificates created on that Creation Date.

Rule 3.8 Post-Closing Account Adjustment

(a) A request by an Account Holder for an adjustment to the Certificates deposited in or withdrawn from that Account Holder's account or any of its subaccounts (including without limitation its Banked Certificates Subaccount) in any Trading Period after the close of that Trading Period ("Post-Closing Account Adjustment") shall be considered by the NEPOOL Markets Committee provided a timely request for such consideration is made by the Account Holder (as described in paragraph (b) below) and provided the adjustment is required solely to rectify an error in (i) the GIS software or the ISO's settlement software or (ii) data entry by either the ISO or GIS Administrator personnel. No other requests for Post-Closing Account Adjustments shall be considered by the Markets Committee. The Markets Committee may approve or disapprove the Account Holder's request for a Post-Closing Account Adjustment at its sole discretion. The Account Holder shall be responsible for demonstrating that the request satisfies the above criteria.

(b) A request for a Post-Closing Account Adjustment shall be reported by the Account Holder to the GIS Administrator within thirty days of the close of the Trading Period to which such request relates. Without limiting the foregoing, a request for a Post-Closing Account Adjustment shall only be considered if the error giving rise to the request occurred during the most recently closed Trading Period. The GIS Administrator will promptly forward a request for a Post-Closing Account Adjustment, with any supporting or contrary information that it deems to be appropriate, to the Markets Committee.

(c) The GIS Administrator shall determine whether the requested Post-Closing Account Adjustment shall require a corresponding or offsetting adjustment in the account(s) of other Account Holders in order to maintain the integrity of the GIS and shall include that information in the material it forwards to the Markets Committee with respect to the request for the Post-Closing Account Adjustment. Any Account Holder(s) affected by such a request shall receive notification from the GIS Administrator and shall be permitted to appear before the Markets Committee and present its position with respect to the requested Post-Closing Account Adjustment.

(d) In addition to the foregoing provisions relating to Post-Closing Account Adjustments and notwithstanding any other provision of these Rules to the contrary, an Account Holder that has had Certificates that are eligible for inclusion in a Banked Certificate Subaccount under Rule 3.7 retired from its account or Subaccount and become Unsettled Certificates at the end of any Trading Period may, upon request to the GIS Administrator, have such Unsettled Certificates credited back to that account or Subaccount and/or subsequently transferred to another account or Subaccount if the following conditions are met:

(i) those Certificates may be credited to the Account Holder's account or Subaccount and/or transferred to another account or Subaccount not later than the date for the annual compliance filing for the state RPS, APS, CES, CES-E or CPS for which those Certificates are eligible; and

(ii) if an Energy Regulatory Agency listed on Appendix 5.3 notifies the GIS Administrator in writing that any such crediting and/or transfer of Certificates eligible for its state's RPS, APS, CES, CES-E or CPS must be approved by that Energy Regulatory Agency, then that Energy Regulatory Agency shall have approved the crediting and/or transfer of those Certificates.

In the event that any Unsettled Certificates that are to be credited to an account or Subaccount under this Rule 3.8(d) are eligible for the RPS or APS of more than one state, then those Certificates shall only be designated as being eligible for any RPS or APS for which (x) they are otherwise eligible, (y) the annual compliance filing deadline has not occurred, and (z) either no Energy Regulatory Agency approval is required or the applicable Energy Regulatory Agency has granted approval. Upon any crediting and/or transfer of Certificates under this Section 3.8(d), the GIS Administrator shall update the quarterly and annual reports produced under Rule 5.2(a) of the Account Holder(s) to which those Certificates have been credited and/or transferred.

EXHIBIT D

Statement of GIS Administrator

APX asserts that the failure of NuPower's February and March 2022 emissions data to populate in the GIS was not a software glitch, but was instead the result of user error. Indeed, APX submits as evidence of this assertion its SLA for the time frame in which NuPower was using the GIS software which is included in Exhibit E. This is the second time NuPower claims that emissions data was not included on its Certificates. The first instance occurred in Q4 2020. In both instances, the NuPower employee responsible for submission of data into the GIS was the same. In both instances, the GIS SLA was operable without an incident noted. It is APX's position that this is user error as there is no evidence that it can find that there was a 'glitch' in the GIS[1]. Exhibit F is APX Timeline of events for the Markets Committee's edification.

[1] Included in Exhibit F is detail of that operation of the GIS during the time frame(s) in question.

EXHIBIT E

NEPOOL GIS Service Level Agreement

Application Availability

Number	Metric Name	Measurement	Results
1	Non-Trading Period Intervals	99%. This equates to approximately 2.5 hours per non-Trading Period interval, where downtime is defined as the server not responding within 30 seconds for any activity	99.9%
2	Trading Period Interval	99.9%. This equates to 60 minutes per Trading Period interval, where downtime is defined as the server not responding within 30 seconds for any activity	99.9%

During 07/2022, there were 0 instances of a business continuity issue.

EmNepoolJuly.xlsx

(See Attachment E-1 for Spreadsheet)

Application Capacity

Number	Metric Name	Measurement	Results
1	Application capacity to process critical functions	Standard transaction response times for 10,000 unique Certificate records; capped at 20,000 unique records outside of standard transaction times	0
2	CPU Utilization	No more than 5 instances where server CPU utilization exceeds 80% for longer than 5 minutes in each quarter, and no more than 5 instances where database CPU utilization exceeds 80% for longer than 5 minutes	0 instances for Server CPU utilization 0 instances for db CPU utilization

During 07/2022, there were 0 instances when the database CPUC utilization exceeded 80% for longer than 5 minutes.

reportCPU-emreg-use-db02_July.xlsx ReportCPU-emreg-use-app01_July.xlsx

(See Attachments E-2 and E-3 for Spreadsheets)

EXHIBIT F

Account Holder: NuPower Cherry Street FC LLC
Project: NON153454 NuPower Cherry Street FC LLC - Doosan Pure Cell 400
Certificate Vintages Requested to be updated: 02/2022 and 03/2022

NuPower Cherry Street did not enter in their emission data for 02/2022 and 03/2022 prior to the Q1 2022 data submission deadline on 7/10/2022. As a result, their 02/2022 and 03/2022 RECs for their project NON153454 NuPower Cherry Street FC LLC - Doosan Pure Cell 400 issued on 7/15/2022 without CT Class I and CT LREC eligibility.

Here is a summary and findings of the NEPOOL GIS Administrator's investigation of the situation.

Summary of Trading Emission Data Reporting Activity Across GIS for Q1 2022

For Q1 2022, **183** account holders successfully submitted emission data for **638** NEPOOL GIS resources in NEPOOL GIS prior to the Q1 2022 data submission deadline on 7/10/2022.

NuPower Cherry Street FC LLC Emission Data Reporting History

Below is the history of emission data reported for NON153454 NuPower Cherry Street FC LLC - Doosan Pure Cell 400. GIS Administrator is listed for 10/2020, 11/2020, 12/2020, 02/2022, and 03/2022 because the Account Holder did not report emission data for those months and the GIS Administrator added proxy data for those months.

Date	fiID	AH	ahIDEnteri	CreateDate	fepCarbon	fepCarbon	fepMercur	fepNitroge	fepParticu	fepParticu	fepSulferD	fepVolatile
10/2020	NON153454	GIS Administrator	13559	4/14/2021	NULL	NULL	NULL	NULL	NULL	NULL	NULL	NULL
11/2020	NON153454	GIS Administrator	13559	4/14/2021	NULL	NULL	NULL	NULL	NULL	NULL	NULL	NULL
12/2020	NON153454	GIS Administrator	13559	4/14/2021	NULL	NULL	NULL	NULL	NULL	NULL	NULL	NULL
01/2021	NON153454	NuPower Cherry Street FC LLC	18581	7/7/2021	1050	0.02	0	0.01	0	0	0	0.02
02/2021	NON153454	NuPower Cherry Street FC LLC	18581	7/7/2021	1050	0.02	0	0.01	0	0	0	0.02
03/2021	NON153454	NuPower Cherry Street FC LLC	18581	7/7/2021	1050	0.02	0	0.01	0	0	0	0.02
04/2021	NON153454	NuPower Cherry Street FC LLC	18581	10/6/2021	1050	0.02	0	0.01	0	0	0	0.02
05/2021	NON153454	NuPower Cherry Street FC LLC	18581	10/6/2021	1050	0.02	0	0.01	0	0	0	0.02
06/2021	NON153454	NuPower Cherry Street FC LLC	18581	10/6/2021	1050	0.02	0	0.01	0	0	0	0.02
07/2021	NON153454	NuPower Cherry Street FC LLC	18581	1/5/2022	1050	0.02	0	0.01	0	0	0	0.02
08/2021	NON153454	NuPower Cherry Street FC LLC	18581	1/5/2022	1050	0.02	0	0.01	0	0	0	0.02
09/2021	NON153454	NuPower Cherry Street FC LLC	18581	1/5/2022	1050	0.02	0	0.01	0	0	0	0.02
10/2021	NON153454	NuPower Cherry Street FC LLC	18581	4/6/2022	1050	0.02	0	0.01	0	0	0	0.02
11/2021	NON153454	NuPower Cherry Street FC LLC	18581	4/6/2022	1050	0.02	0	0.01	0	0	0	0.02
12/2021	NON153454	NuPower Cherry Street FC LLC	18581	4/6/2022	1050	0.02	0	0.01	0	0	0	0.02
01/2022	NON153454	NuPower Cherry Street FC LLC	18581	7/7/2022	1050	0.02	0	0.01	0	0	0	0.02
02/2022	NON153454	GIS Administrator	13559	7/13/2022	NULL	NULL	NULL	NULL	NULL	NULL	NULL	NULL
03/2022	NON153454	GIS Administrator	13559	7/13/2022	NULL	NULL	NULL	NULL	NULL	NULL	NULL	NULL

Event Log

The Microsoft Excel link below contains the NuPower Cherry Street FC LLC My Event Log downloaded from NEPOOL GIS.

NuPower Cherry Street FC LLC My Ever **(See Attachment F-1)**

Timeline

11/20/2020 - NON153454- NuPower Cherry Street FC LLC - Doosan Pure Cell 400 approved in NEPOOL GIS with CT Class I LREC Eligibility beginning 09/2020.

04/29/2021 – United Illuminating reached out ZD 147353 asking why Q4 2020 RECs for NON153454- NuPower Cherry Street FC LLC - Doosan Pure Cell 400 did not have CT Class I and CT LREC RPS Eligibility. Below is the NEPOOL GIS Administrator's response with Daniel James Donovan CC'ed on the email

> Apr 29, 2021 10:38
>
> Hi Danielle,
>
> Looks like emission data was not reported for this project in Q4 2020. Per NEPOOL GIS rules, failure to report emission data prior to the quarterly issuance will result in a loss of State Attribute Classification for the upcoming quarter (only for the month in which emissions were not entered),* as well as, an entry of the listed proxy emission rate for the registered fuel type(s) for your unit(s). We will not be able to update the RPS eligibility flag for CT Class I at this point.
>
> You can work with the account holder to work with the state regulators directly and if you (CT PURA) want to make an exception and recognize those RECs for CT Compliance, you can transfer those RECs to the CT Compliance subaccount for CT Compliance, but those Q4 2020 RECs from this project will just not have CT Class I eligibility flagged in NEPOOL GIS.
>
> These inquiries come up every quarter from different account holders, but there's nothing we can do about it. We send out multiple courtesy email reminders for open and closing of trading periods to remind account holders to make sure that prior to data submission deadlines, to ensure emission data is entered and saved or they will not receive the RPS eligibilities.
>
> Thank you,
>
> Bao Ngo
>
> GIS Registry Administrator, Environmental Registries
>
> gis@apx.com | direct: + 1 408 899 3343

04/29/2021 – Daniel James Donovan followed up via ZD 147374. The NEPOOL GIS Administrator called Daniel via ZD 147373 to walk Daniel through the Emission Reporting process and provided Daniel with the 'Enter Generator Emissions Data' User Guide.

07/09/2021 – ZD 155400 Daniel James Donovan informed the NEPOOL GIS Administrator that Q1 2021 emissions data were entered. The NEPOOL GIS Administrator confirmed.

10/6/2021 – ZD 164510 Daniel James Donovan informed the NEPOOL GIS Administrator that Q2 2021 emissions data were entered. The NEPOOL GIS Administrator confirmed.

7/18/2022 - Daniel James Donovan initially reached out to the NEPOOL GIS Administrator via ZD 192579 to inquire about why RECs for NON153454 NuPower Cherry Street FC LLC - Doosan Pure Cell 400 were issued without CT LREC eligibility. The NEPOOL GIS Administrator reviewed and provided a response below:

> "I reviewed Q1 2022 data for NON153454 NuPower Cherry Street FC LLC - Doosan Pure Cell 400, Emission data was not entered in 02/2022 and 03/2022 prior to the Q1 2022 trading period data submission deadline. Failure to enter emissions results in a loss of State Attribute Classification for the upcoming quarter (only for the month in which emissions were not entered), as well as, an entry of the listed proxy emission rate for the registered fuel type(s) for your unit(s). I saw emissions entered for 01/2022 which is why the RECs were issued with the correct eligibility.
>
> Per Rule 2.3 (b) of the NEPOOL GIS Operating Rules, after the data submission deadline ends and the trading period begins, we are unable to go back and add emissions data and assign the RPS eligibilities for Certificates that are already issued."

8/2/2022 - Daniel James Donovan reached out to the NEPOOL GIS Administrator again via ZD 193857. The NEPOOL GIS Administrator responded to Daniel James Donovan's questions at 12:13 PM PDT on 8/3 after he seemed to imply that The NEPOOL GIS Administrator confirmed his emission data were reported successfully in NEPOOL GIS. Below is the NEPOOL GIS Administrator's response:

> Aug 03 12:13
> Hi Daniel,
>
> Please see my responses to your questions below:
>
> CT PURA rejected our request today to designate our Feb and March 2022 RECs as Class I, saying that it was a dispute between NuPower and NEPOOL. I have attached the 8.2.22 PURA letter with this email.
>
> Bao: On July 18, I reviewed your email and provided you with this response:
>
> I reviewed Q1 2022 data for NON153454 NuPower Cherry Street FC LLC - Doosan Pure Cell 400, Emission data was not entered in 02/2022 and 03/2022 prior to the Q1 2022 trading period data submission deadline. Failure to enter emissions results in a loss of State Attribute Classification for the upcoming quarter (only for the month in which emissions were not entered), as well as, an entry of the listed proxy emission rate for the registered fuel type(s) for your unit(s). I saw emissions entered for 01/2022 which is why the RECs were issued with the correct eligibility.
>
> Per Rule 2.3 (b) of the NEPOOL GIS Operating Rules, after the data submission deadline ends and the trading period begins, we are unable to go back and add emissions data and assign the RPS eligibilities for Certificates that are already issued.

Also - As you can see in my June 10 email to you in the thread below - I asked you to confirm that we had submitted the required emissions information for our LREC certificates. I did this after inputting all three months' worth of data before the June 15th deadline n the NEPOOL website.

Bao: On 6/9, you copied the Forward Certificate Transfer details you set up for UI LREC/ZREC via email and I confirmed with you on 6/10 that it looks to be set up. You did not mention anything about emissions reporting in your inquiry to me at that time.

You also sent us the following email on the 15th of June which indicated that we had successfully filed
The transfer of the following certificates has been initiated:
From NuPower Cherry Street FC LLC to UI LREC/ZREC

Quantity = 928
Certificate Serial Number(s):
7397560 - 1 to 313 - Quantity: 313;
7364855 - 1 to 293 - Quantity: 293;
7370437 - 1 to 322 - Quantity: 322;

Bao: This is an auto-generated email when Certificates are transferred from your account to another account in NEPOOL GIS. This does not indicate that you have successfully entered your emissions. Your Q1 2022 Certificates were issued, but because emission data was not entered for 02/2022 and 03/2022, those Certificates were issued without CT eligibility.

In NEPOOL GIS, if emission data was successfully entered, an email will be sent to the Account Admin of the account providing the details of the emission data entered. Please see the example that was sent for January 2022 below:

The following Vintage Period: January 2022
Fuel MWh/Emission Entries have been ADDED/UPDATED for facility "NuPower Cherry Street FC LLC - Doosan Pure Cell 400":
AepSplit : No
Fuel Type : Fuel cell
Fuel Generation (MWh) : 321.790
Carbon Dioxide : 1050
Carbon Monoxide : 0.02
Mercury : 0
Nitrogen Oxides : 0.01
Particulate Matter : 0
Particulate Matter (<=10um) : 0
Sulfur Dioxides : 0
Volatile Organic Compounds : 0.02

Thank you,
Bao Ngo
GIS Registry Administrator, Environmental Registries
gis@apx.com | direct: + 1 408 899 3343

8/3/2022 - Daniel James Donovan responded to the NEPOOL GIS Administrator's email, said he asked the NEPOOL GIS Administrator to confirm the quarterly emissions were entered in an email he sent on 6/10. The NEPOOL GIS Administrator looked back at my email exchange with Daniel James Donovan from 6/10 and on 6/13 via ZD 188789, below was the NEPOOL GIS Administrator's response:

Dan,

I do not see your emissions reporting for Q1 2021, but United Illuminating Company has not uploaded Q1 2021 data for you yet so you will not be able to enter in emissions data until they upload data.

Please visit the Enter Generator Emissions Data page for detailed instructions on how to enter emissions data for your project in GIS.