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.

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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)***	Lunch (All) ***(Symphony Ballroom)***	
Transmission		ISO Board Panel 1 ***(Handel)***		
Supplier / Short (LSE)				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)***			
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**

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.
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> 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

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

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:

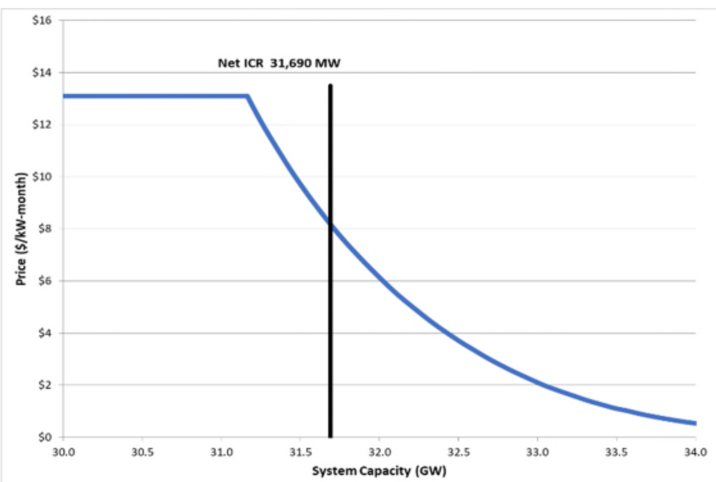


Figure 1 2023-24 CCP ARA3 System-Wide MRI Capacity Demand Curve

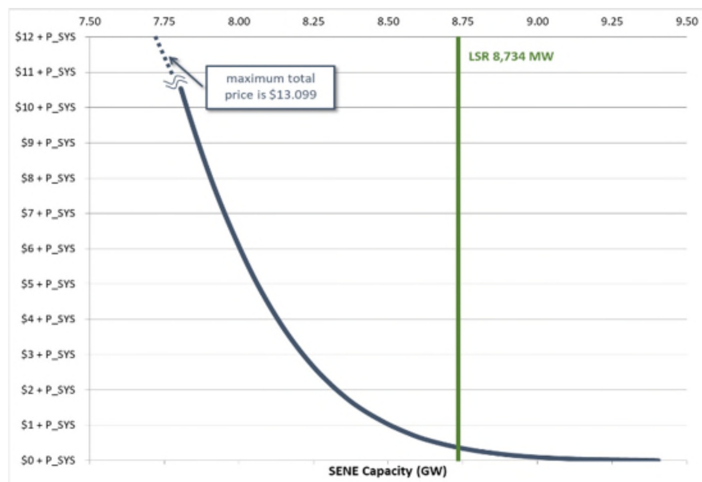


Figure 2 2023-24 CCP ARA3 SENE Import-Constrained MRI Capacity Demand Curve

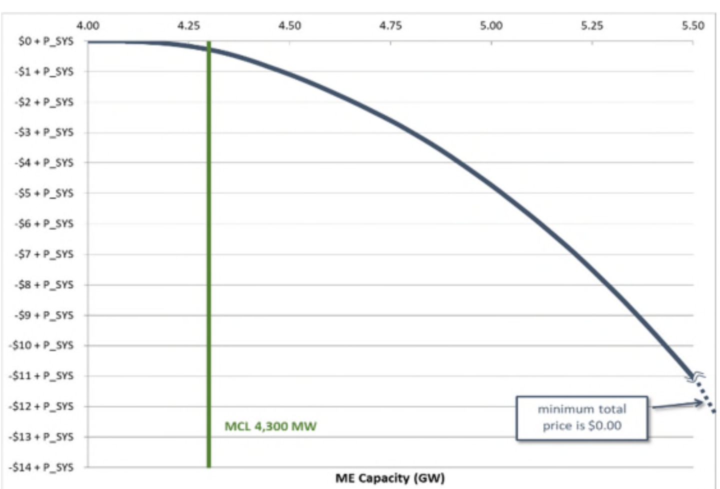


Figure 3 2023-24 CCP ARA3 ME Export-Constrained MRI Capacity Demand Curve

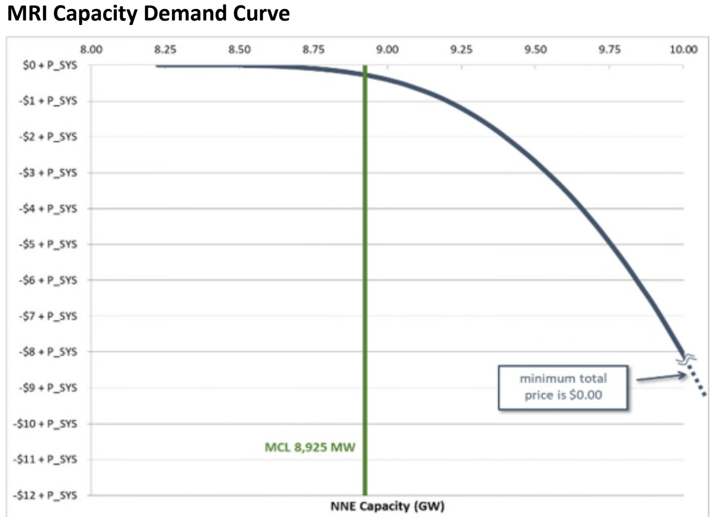


Figure 4 2023-24 CCP ARA3 NNE Export-Constrained MRI Capacity Demand Curve

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:

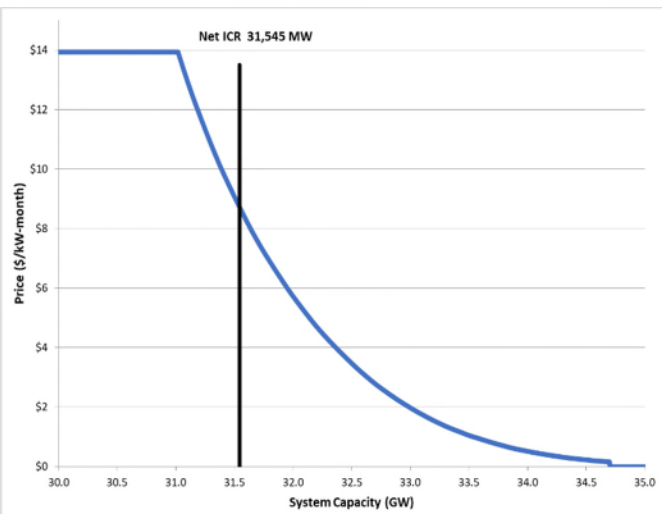


Figure 5 2024-25 CCP ARA2 System-Wide MRI Capacity Demand Curve

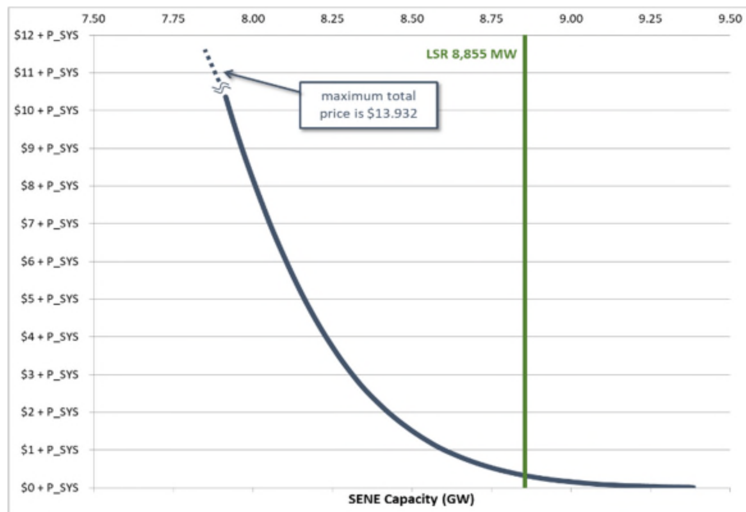


Figure 6 2024-25 CCP ARA2 SENE Import-Constrained MRI Capacity Demand Curve

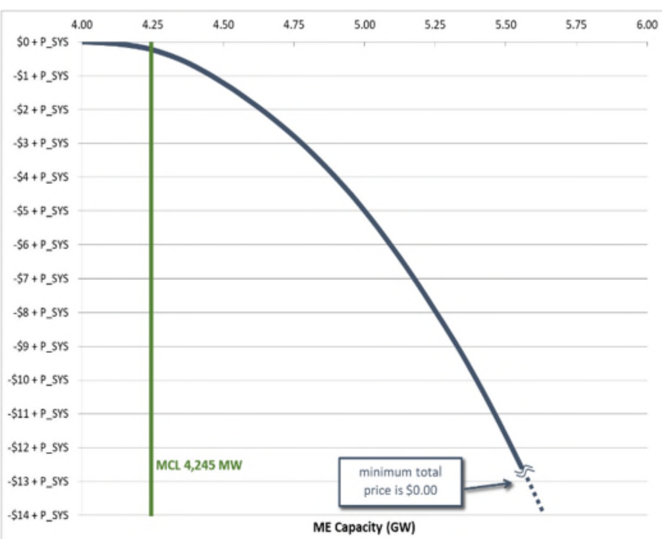


Figure 7 2024-25 CCP ARA2 Maine Export-Constrained MRI Capacity Demand Curve

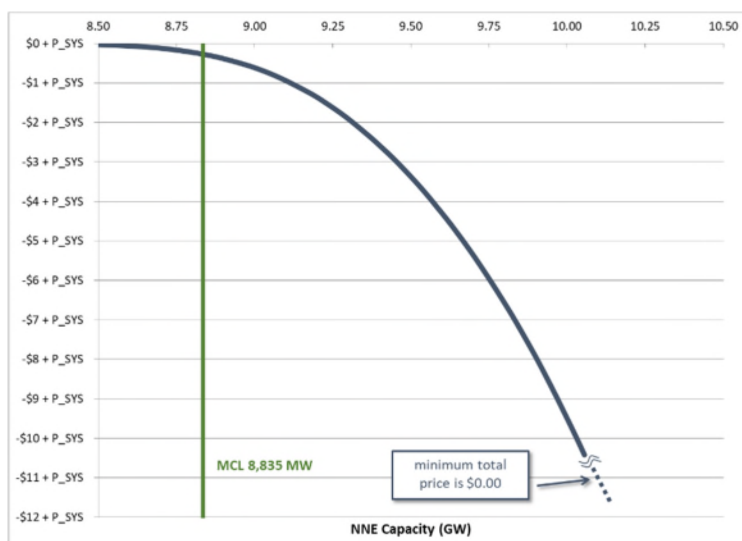


Figure 8 2024-25 CCP ARA2 NNE Export-Constrained MRI Capacity Demand Curve

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:

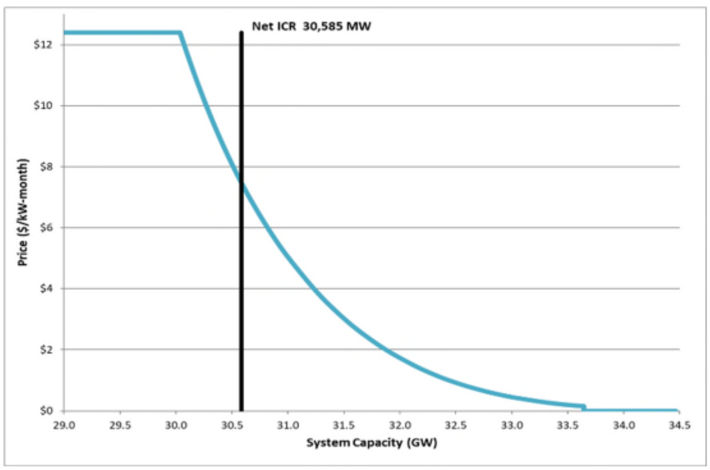


Figure 9 2025-26 CCP ARA1 System-Wide MRI Capacity Demand Curve

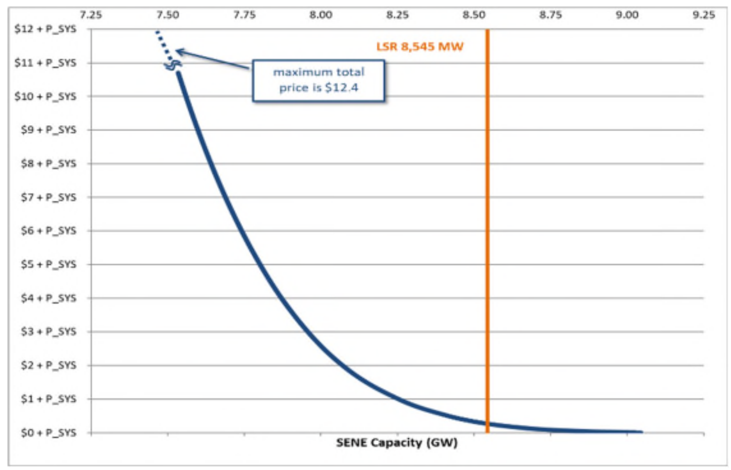


Figure 10 2025-26 CCP ARA1 SENE Import-Constrained MRI Capacity Demand Curve

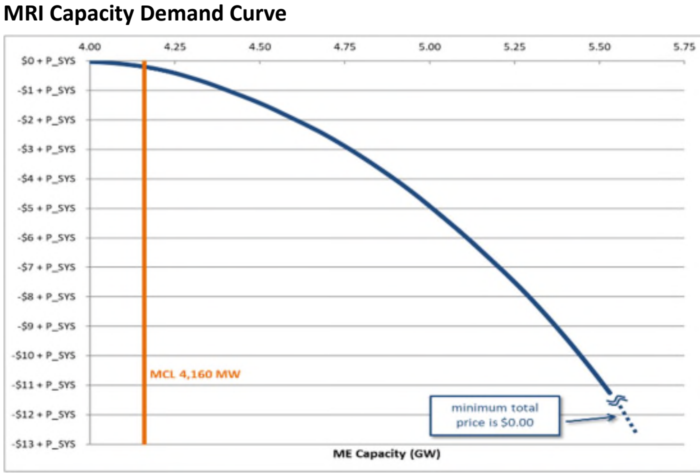


Figure 11 2025-26 CCP ARA1 Maine Export-Constrained MRI Capacity Demand Curve

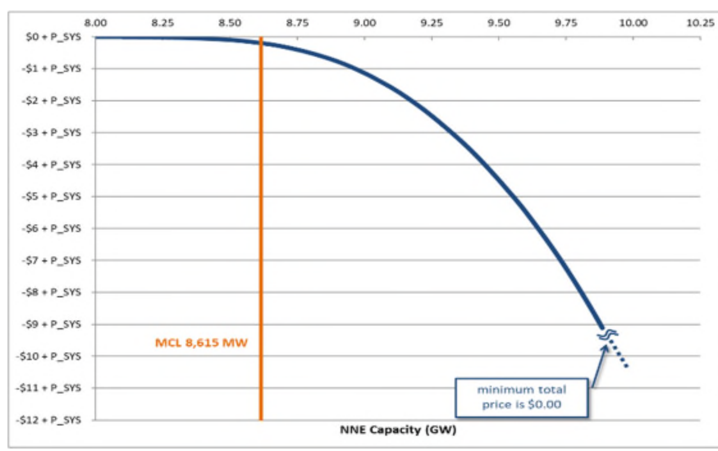


Figure 12 2025-26 CCP ARA1 NNE Export-Constrained MRI Capacity Demand Curve

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.

NEPOOL Participants Committee Report

November 2022

Vamsi Chadalavada
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through October 25th (RT NCPC through 24th)

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: September 2022 Energy Market value totaled $692M
  - October Energy market value was $419M over the period, down $273M from September 2022 and down $139M from October 2021
    - October natural gas prices over the period were 24% lower than September average values
    - Average RT Hub Locational Marginal Prices ($53.86/MWh) over the period were 12% lower than September averages
    - Average October 2022 natural gas prices and RT Hub LMPs over the period were up 8.3% and down 3.7%, respectively, from October 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.7% during October, down from 99.9% during September*
    - The minimum value for the month was 94% on Friday, October 7th

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

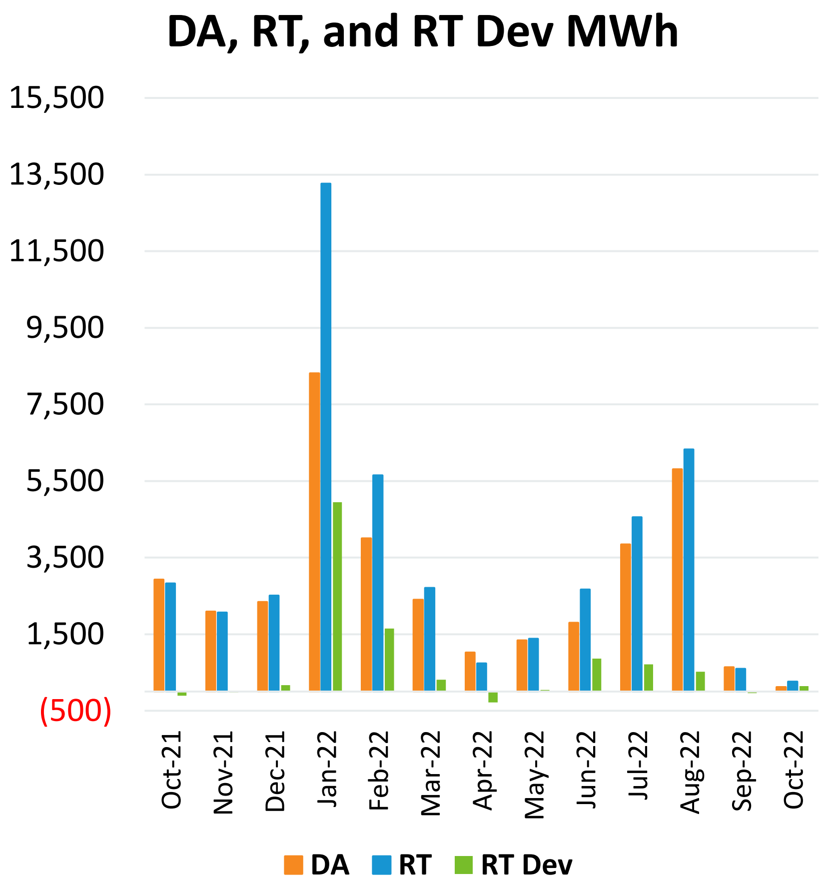
Underlying natural gas data furnished by: ICE Global markets in clear view

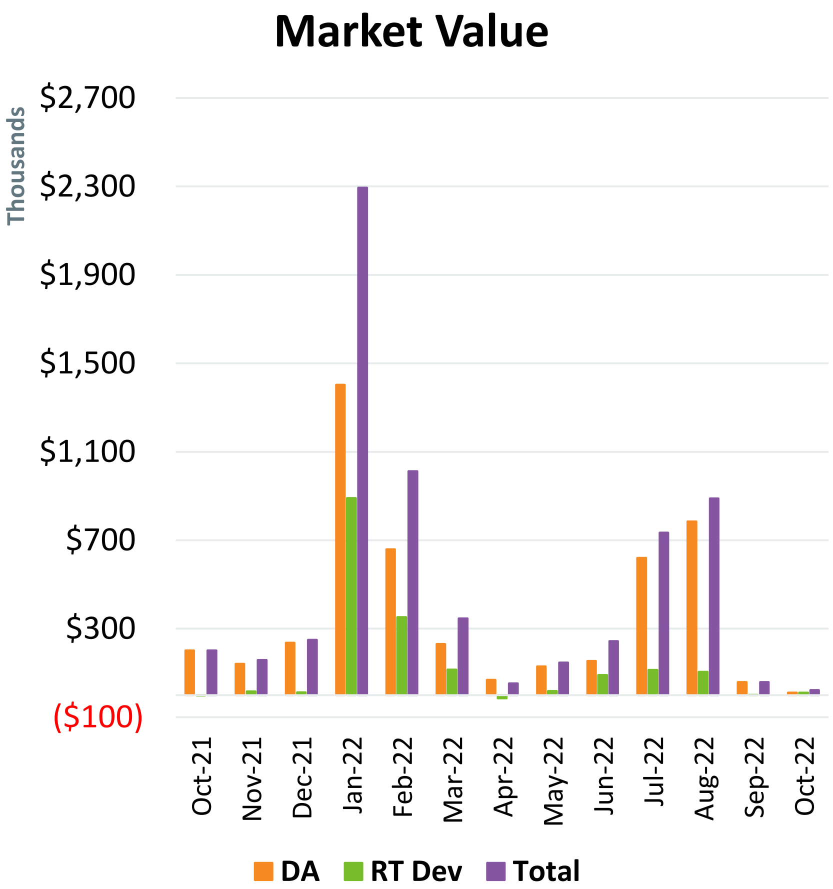
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - October NCPC payments totaled $2.2M over the period, up $143K from September and down $1.3M from October 2021
    - First Contingency payments totaled $2.1M, up $0.2M from September
      - $1.9M paid to internal resources, up $0.5M from September
        - » $275K charged to DALO, $789K to RT Deviations, $838K to RTLO*
      - $209K paid to resources at external locations, down $327K from September
        - » $9K charged to DALO at external locations, $199K to RT Deviations
    - Second Contingency payments totaled $128K, down $11K from September
  - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $261K; Rapid Response Pricing (RRP) Opportunity Cost - $304K; Posturing - $0K; Generator Performance Auditing (GPA) - $274K**

Price Responsive Demand (PRD) Energy Market Activity by Month





Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

Highlights

- ISO is working on solution development for the 2050 Transmission Study and expects to begin initial discussions with the PAC in Q4 2022
- FCA 17 Installed Capacity Requirement and related values to be filed with FERC on November 8
- The next Load Forecast Committee meeting is scheduled for November 7 and will include discussions of electrification forecast updates

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, and results were posted on August 31
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted on June 28
- CCP 16 (2025-2026)
  - Auction results were filed with FERC on March 21 and on July 18, FERC issued an order accepting the results effective July 19

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - ISO submitted the "MOPR Removal" filing to FERC on March 31, which includes a "Transition Mechanism" for FCA 17 and FCA 18
    - FERC issued an order accepting ISO's filing on May 27
  - FCA 17 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - New Capacity Qualification Package (NCQP) Submission Window closed on July 27, and review of the NCQPs is ongoing
  - FCA 17 Installed Capacity Requirement and related values to be filed with FERC on November 8

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 12, 2022.
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 7, 2023.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.0°F) Max: 78°F, Min: 42°F Precipitation: 4.28" – Above Normal Normal: 3.52"	Hartford	Temperature: Above Normal (0.9°F) Max: 80°F, Min: 30°F Precipitation: 5.03" - Above Normal Normal: 4.03"

Peak Load:	14,613 MW	10/27/2022	19:00 (ending)

Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
None for October, 2022			

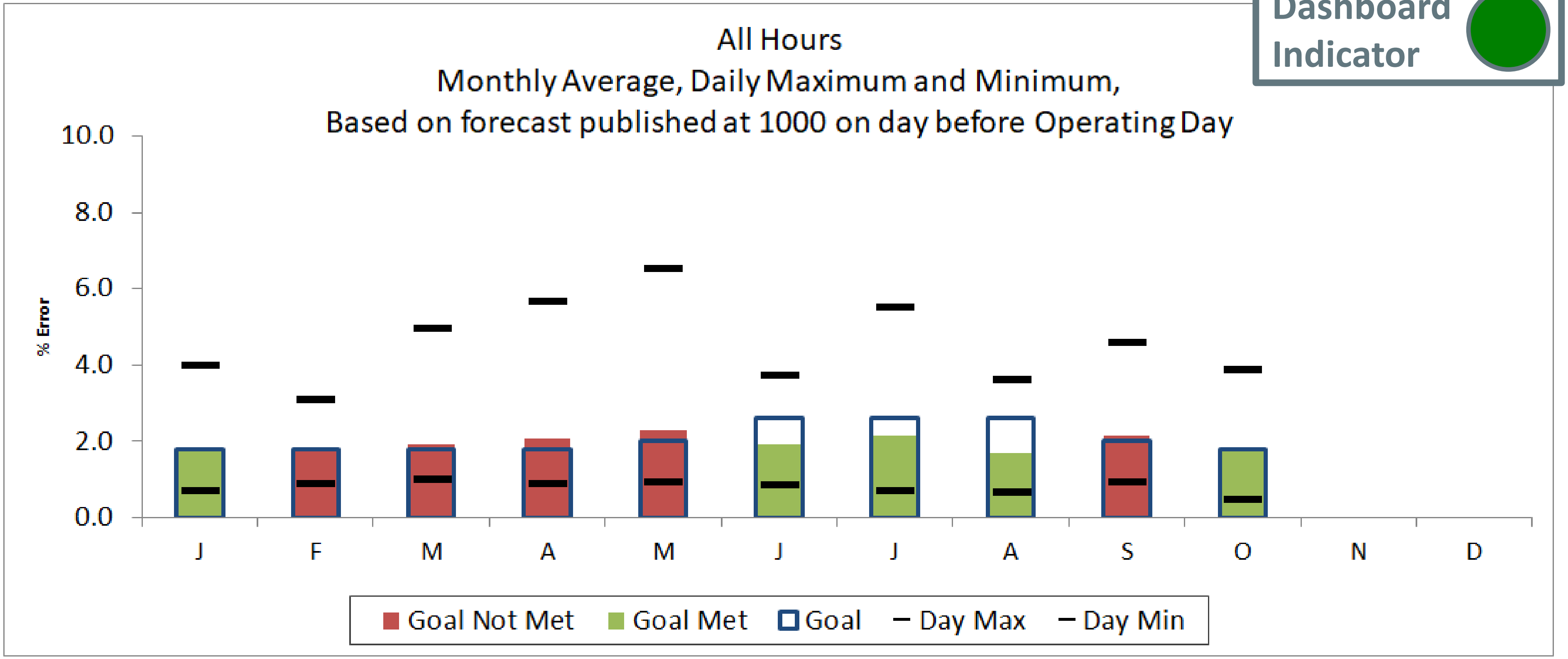
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
10/4	ISO-NE	500

2022 System Operations - Load Forecast Accuracy

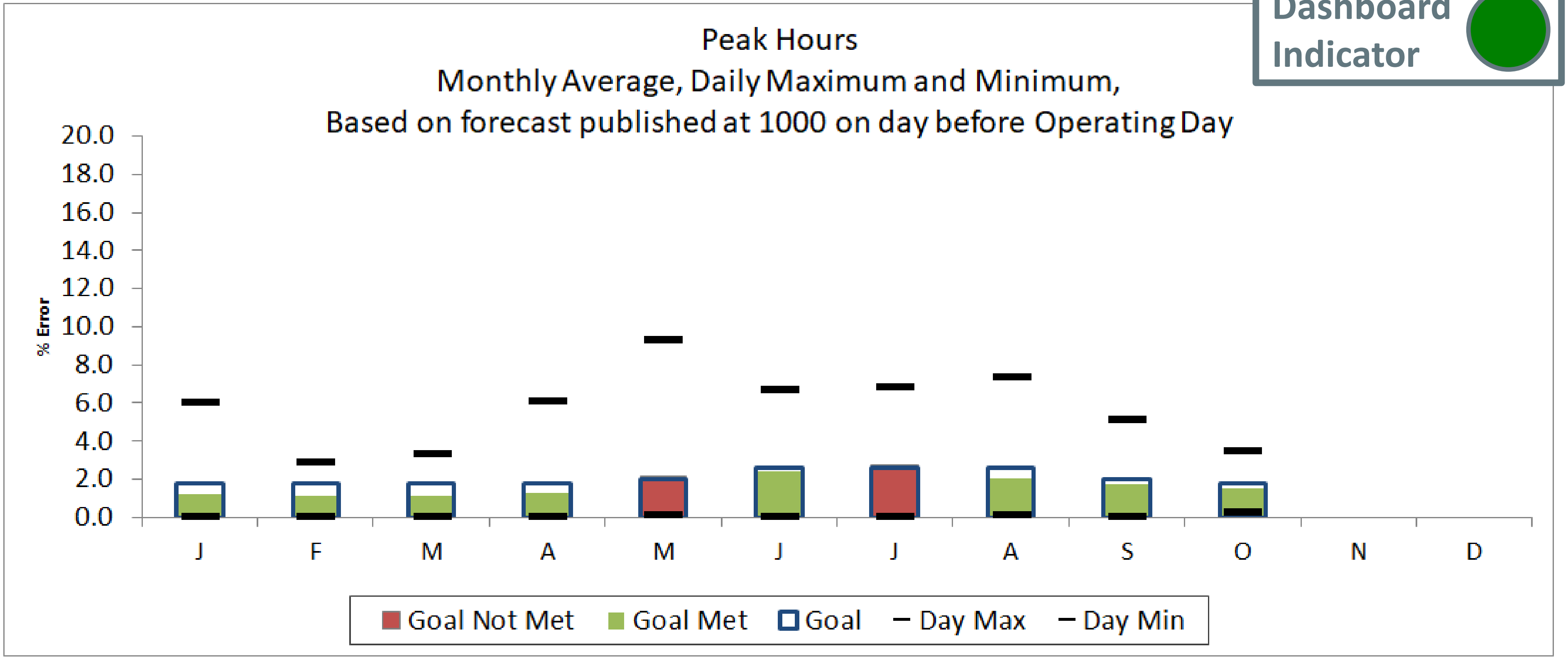
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.97	3.07	4.92	5.66	6.52	3.71	5.48	3.61	4.56	3.85			6.52
Day Min	0.69	0.87	0.97	0.85	0.91	0.83	0.69	0.66	0.90	0.46			0.46
MAPE	1.79	1.81	1.93	2.05	2.30	1.92	2.13	1.70	2.13	1.73			1.95
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

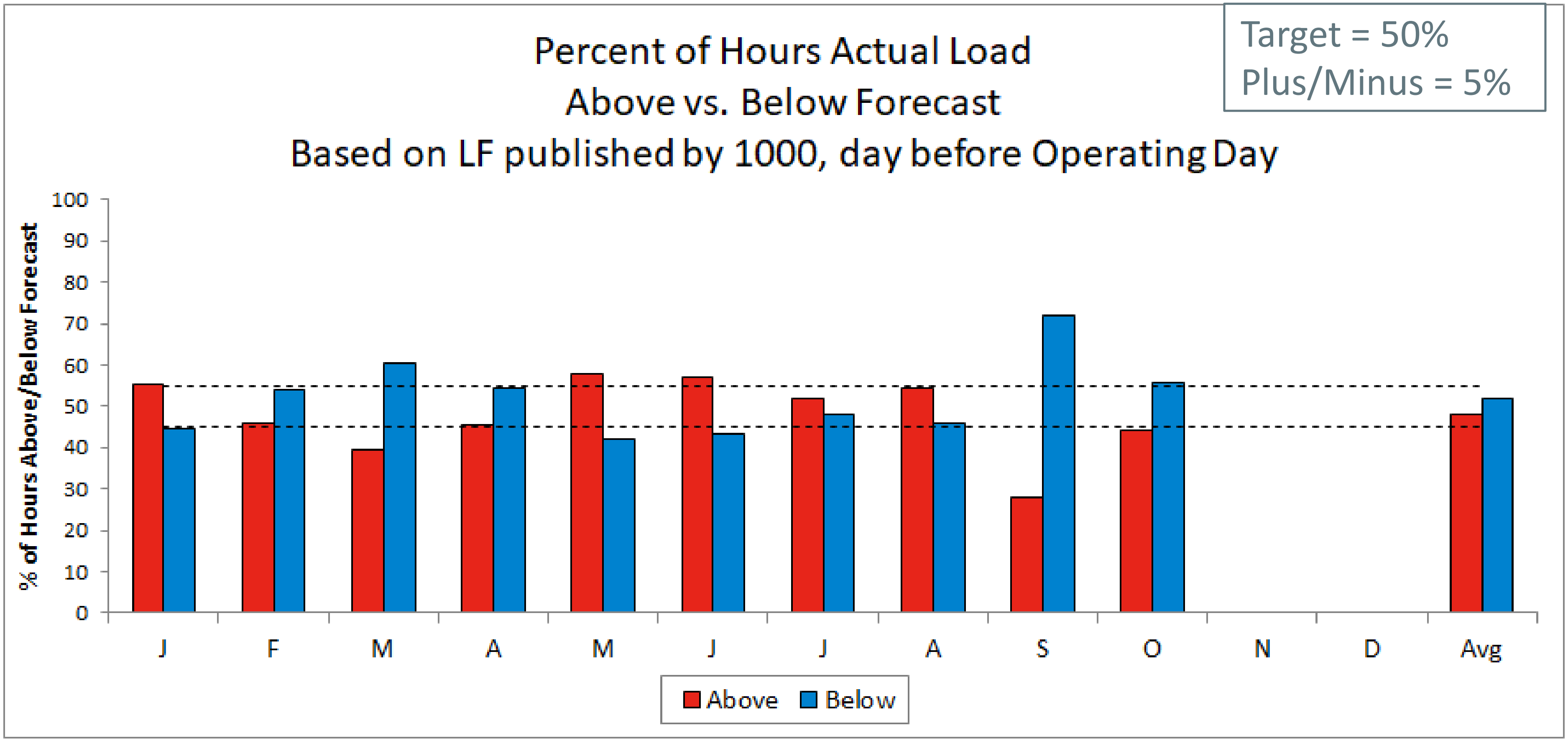
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



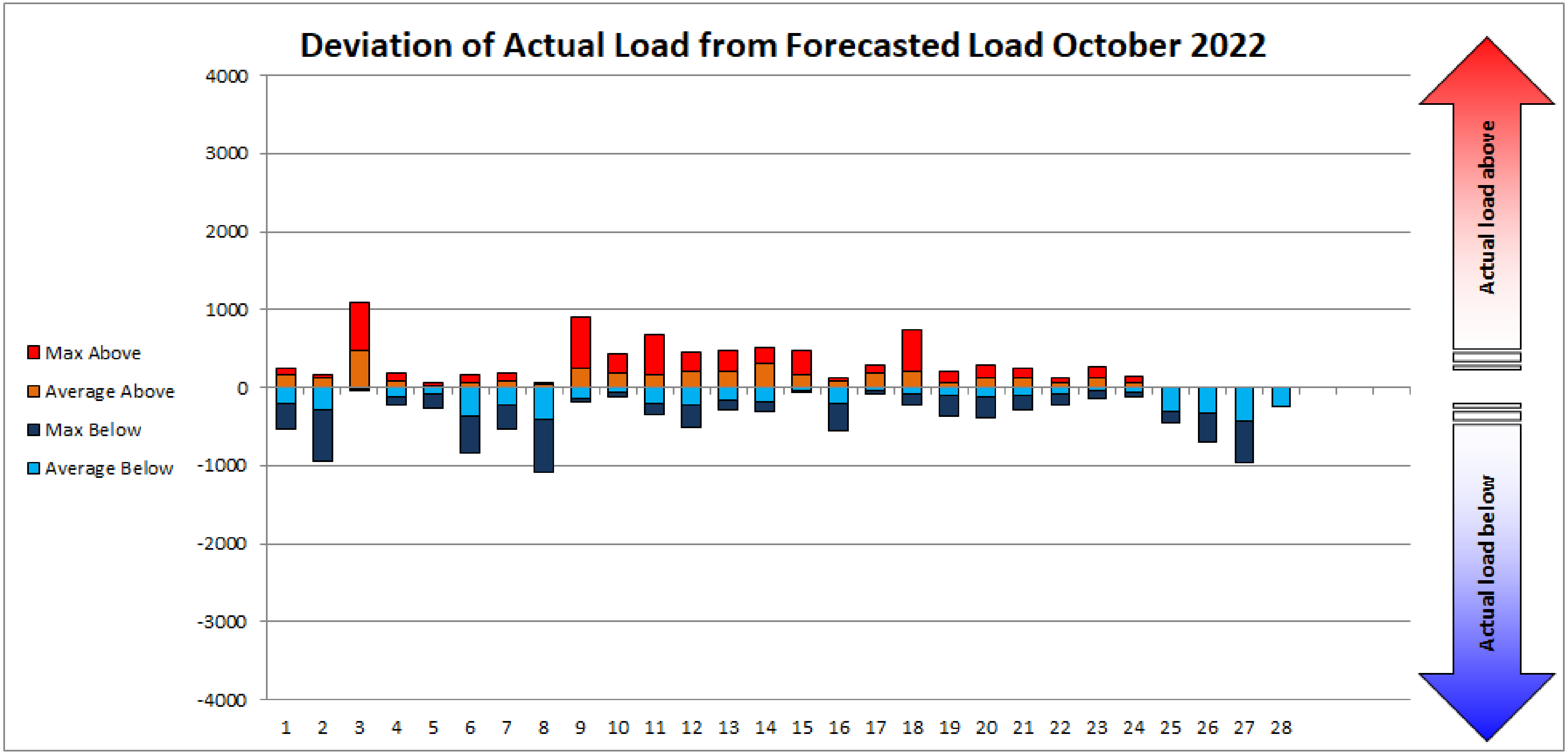
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85	3.32	6.08	9.27	6.70	6.85	7.31	5.12	3.42			9.27
Day Min	0.02	0.03	0.04	0.00	0.06	0.01	0.02	0.08	0.01	0.21			0.00
MAPE	1.25	1.11	1.13	1.29	2.14	2.43	2.73	2.06	1.71	1.49			1.74
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2022 System Operations - Load Forecast Accuracy cont.

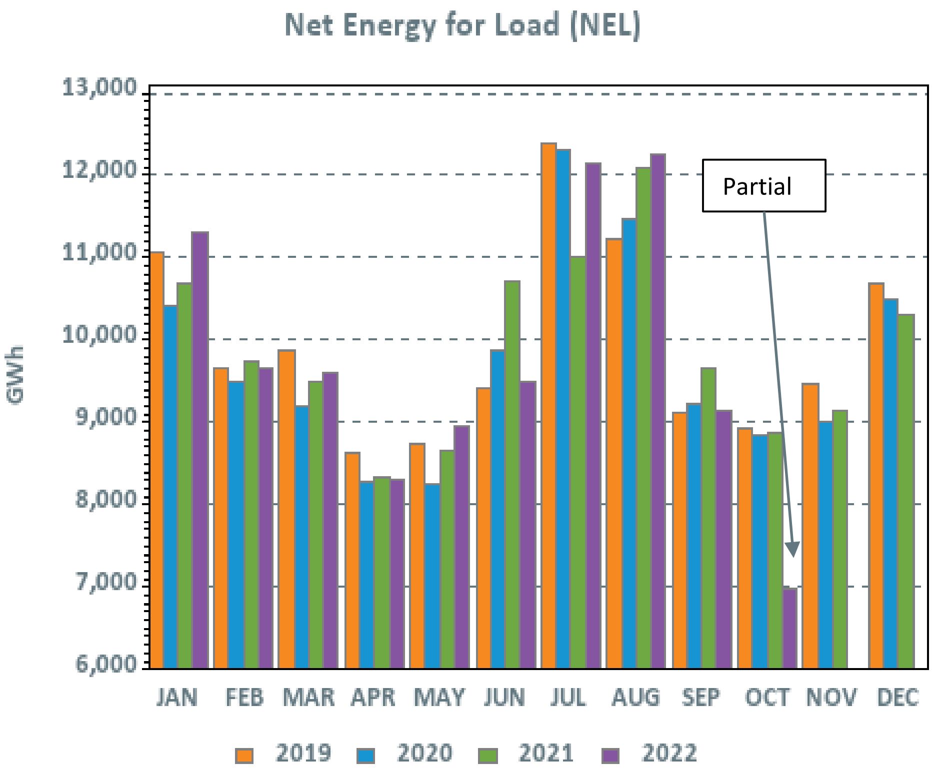


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46	39.7	45.6	57.8	56.8	51.9	54.3	27.9	44.1			48
Below %	44.8	54	60.3	54.4	42.2	43.2	48.1	45.7	72.1	55.9			52
Avg Above	219.5	245.7	175.9	180	217.2	209.6	268.3	208.5	128.1	113.7			268
Avg Below	-223.1	-207.6	-240.0	-191.5	-192.2	-215.9	-295.8	-281.9	-255.3	-157.1			-296
Avg All	22	6	-78	-18	30	23	5	-26	-134	-54			-23

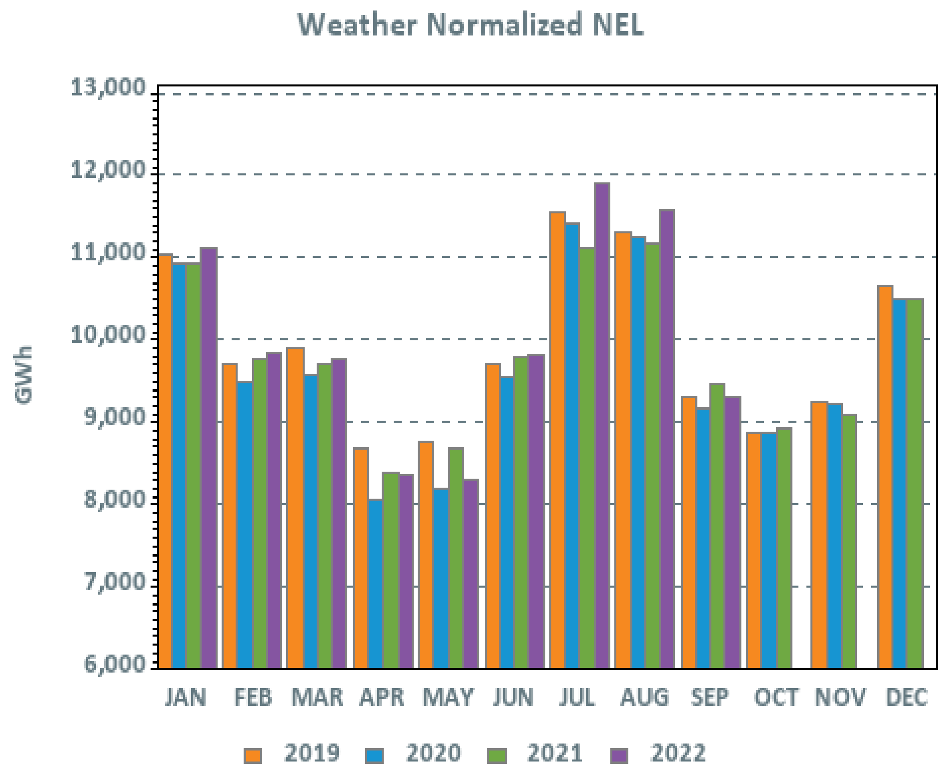
2022 System Operations - Load Forecast Accuracy cont.



Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



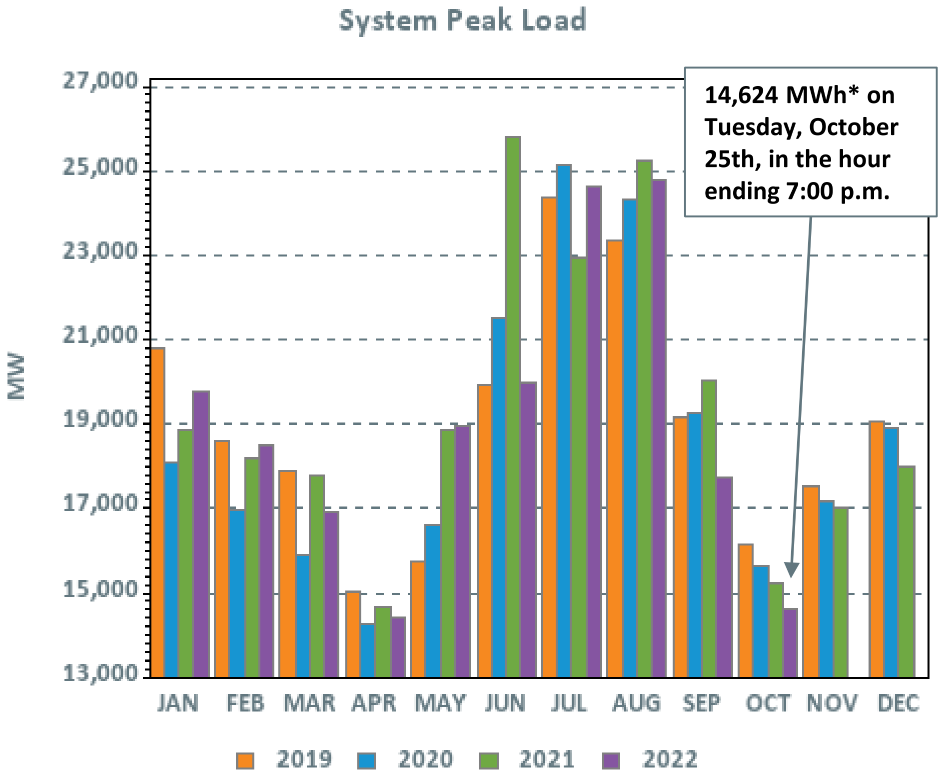
Ann Tot (TWh): 119.2 116.9 118.8 97.9



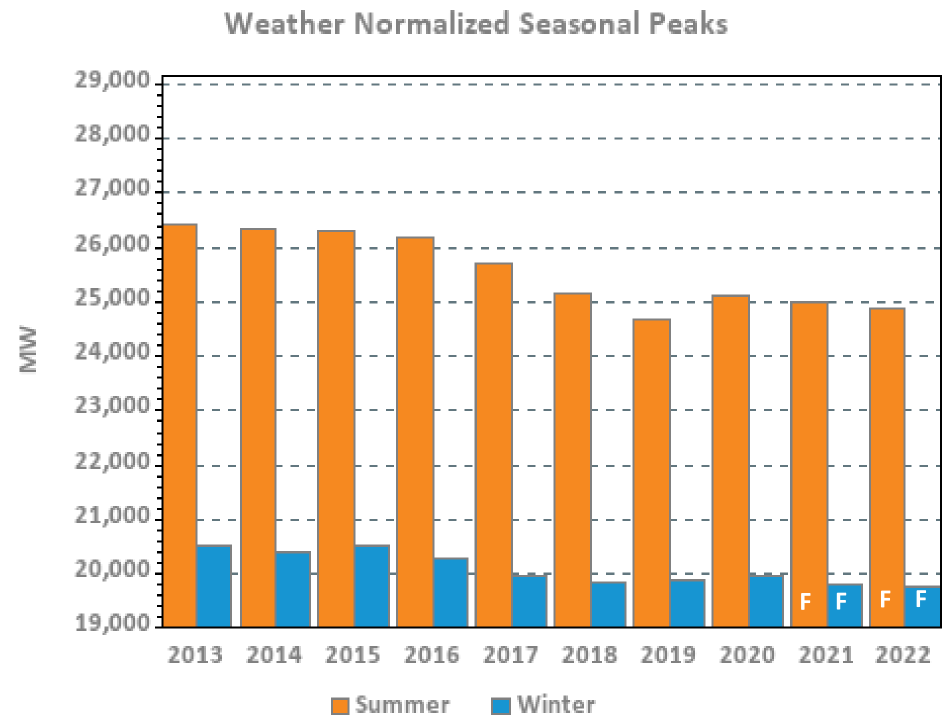
Ann Tot (TWh): 118.8 116.3 117.6 90.0

NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

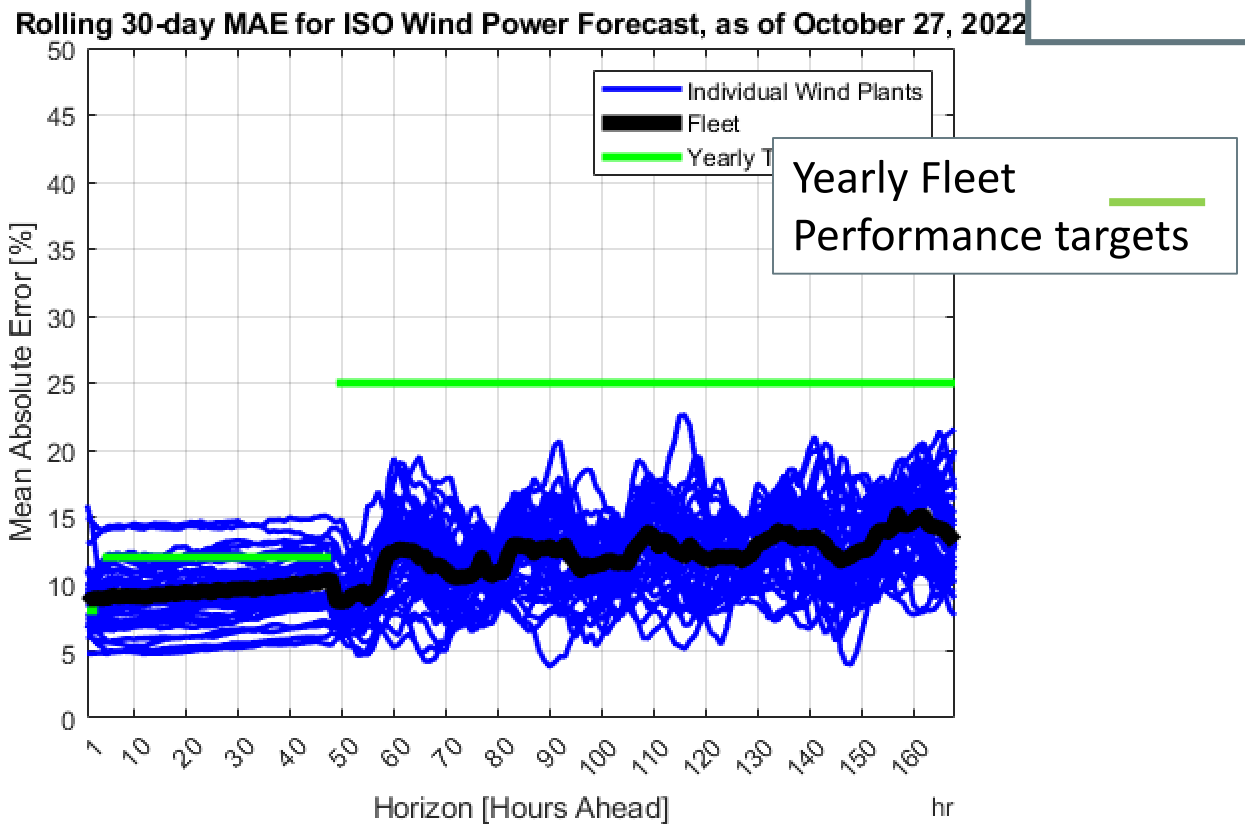


Winter beginning in year displayed

F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE

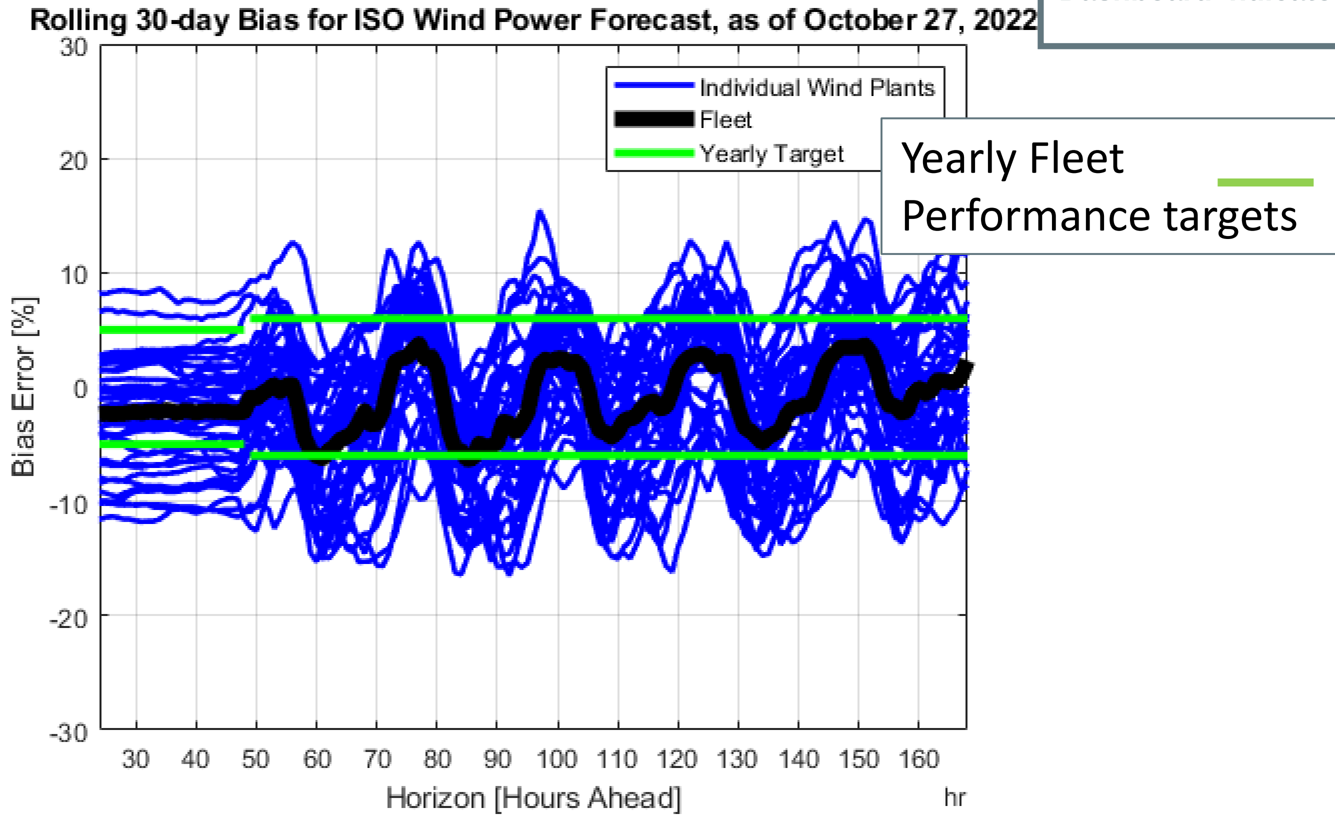
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias

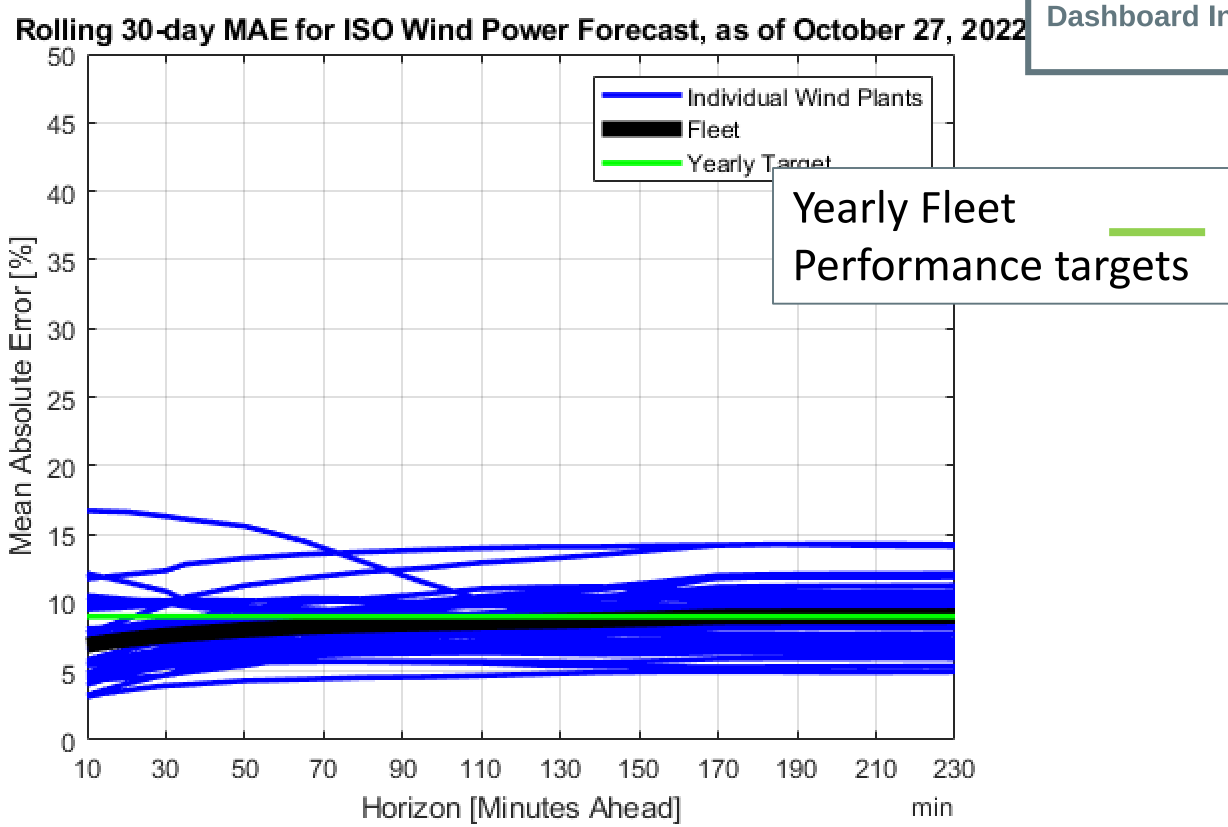
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator



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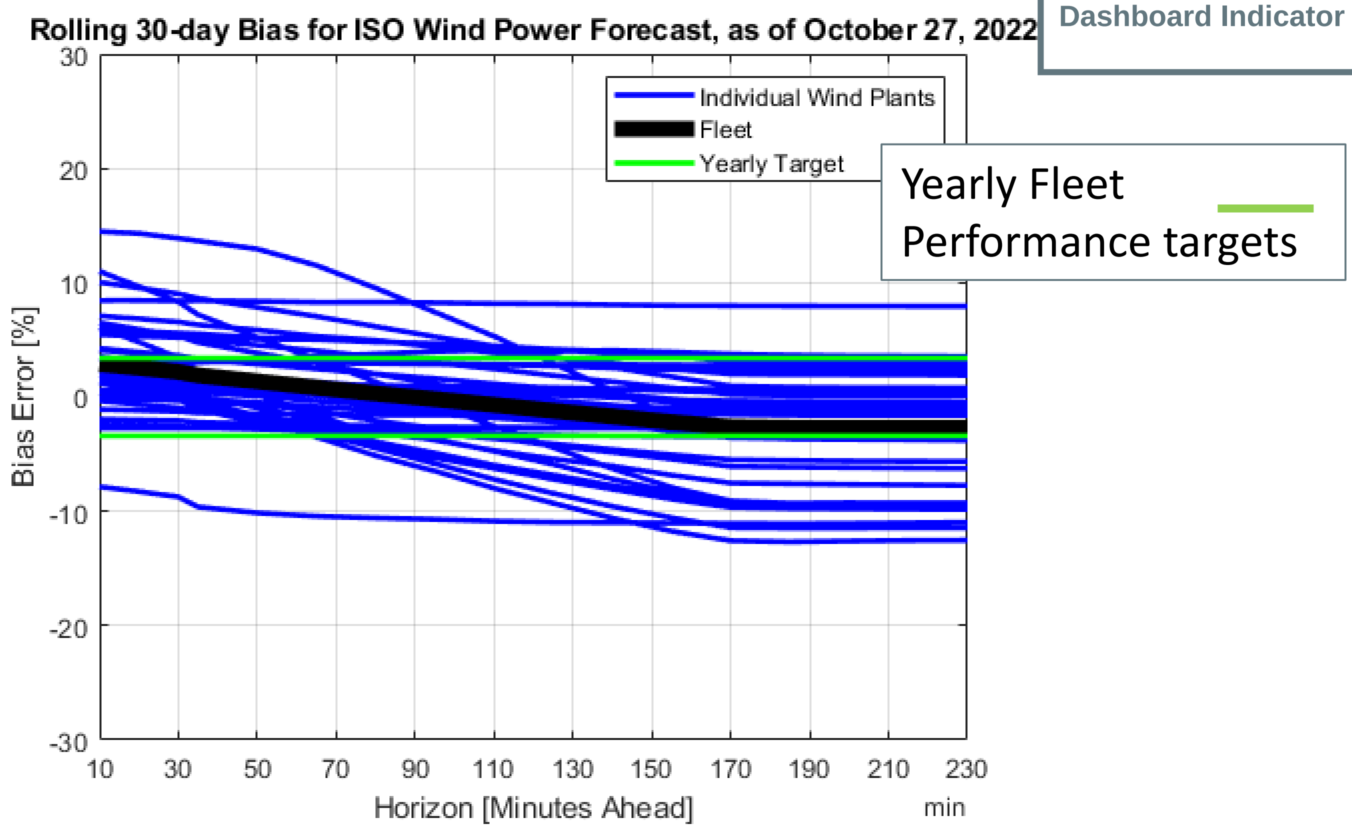
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator



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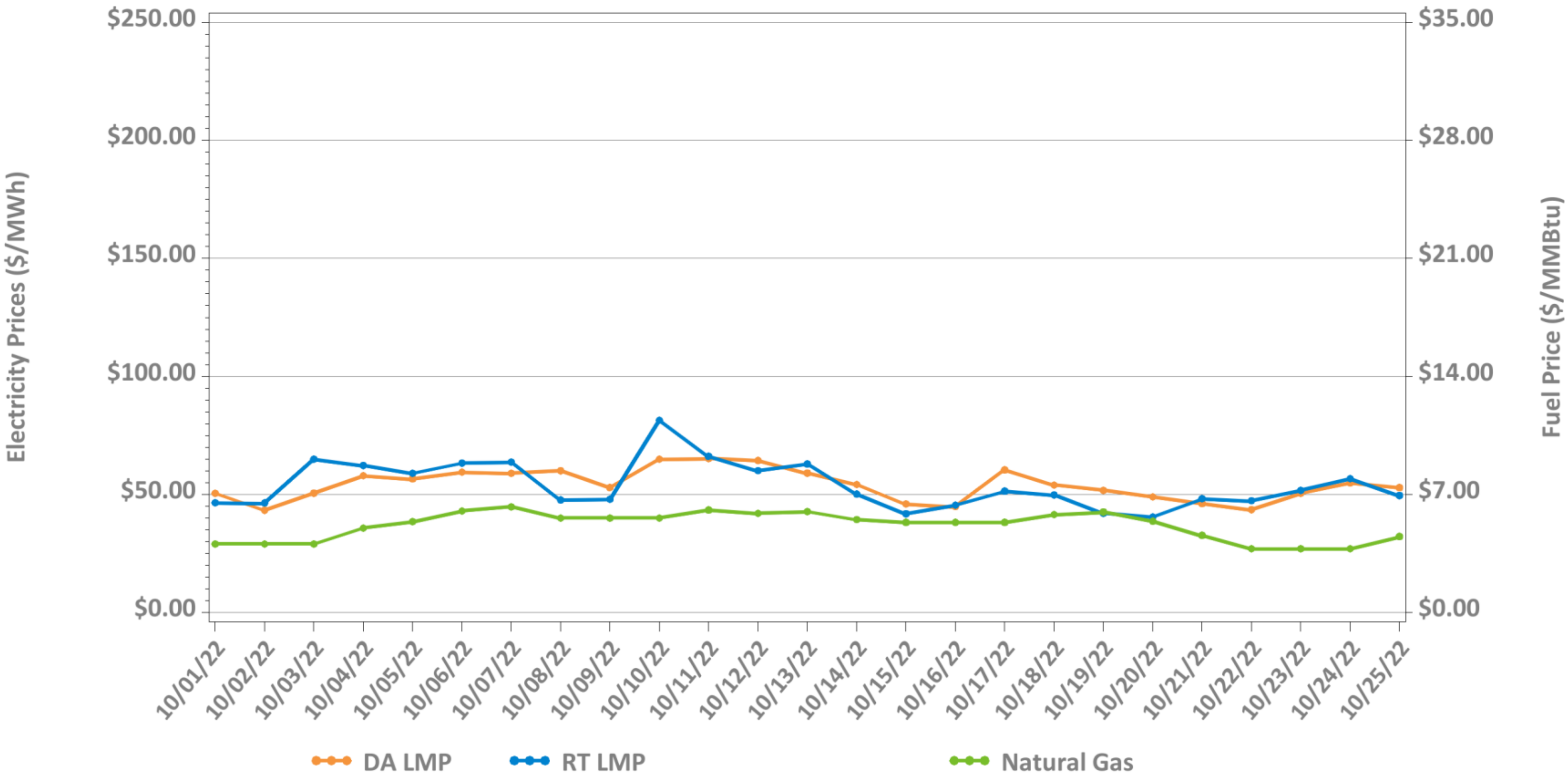
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: October 1-25, 2022



Underlying natural gas data furnished by:

ICE Global markets in clear view

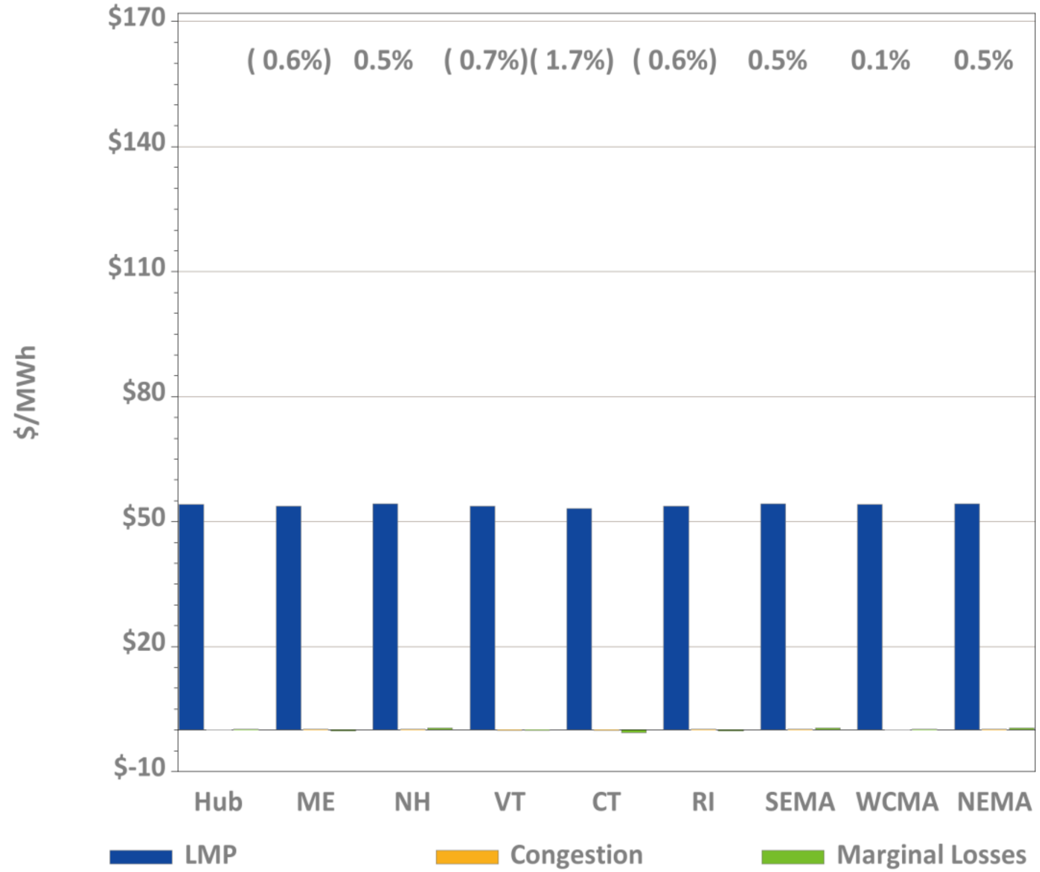
Average price difference over this period (DA-RT): $0.21

Average price difference over this period ABS(DA-RT): $5.28

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 10%

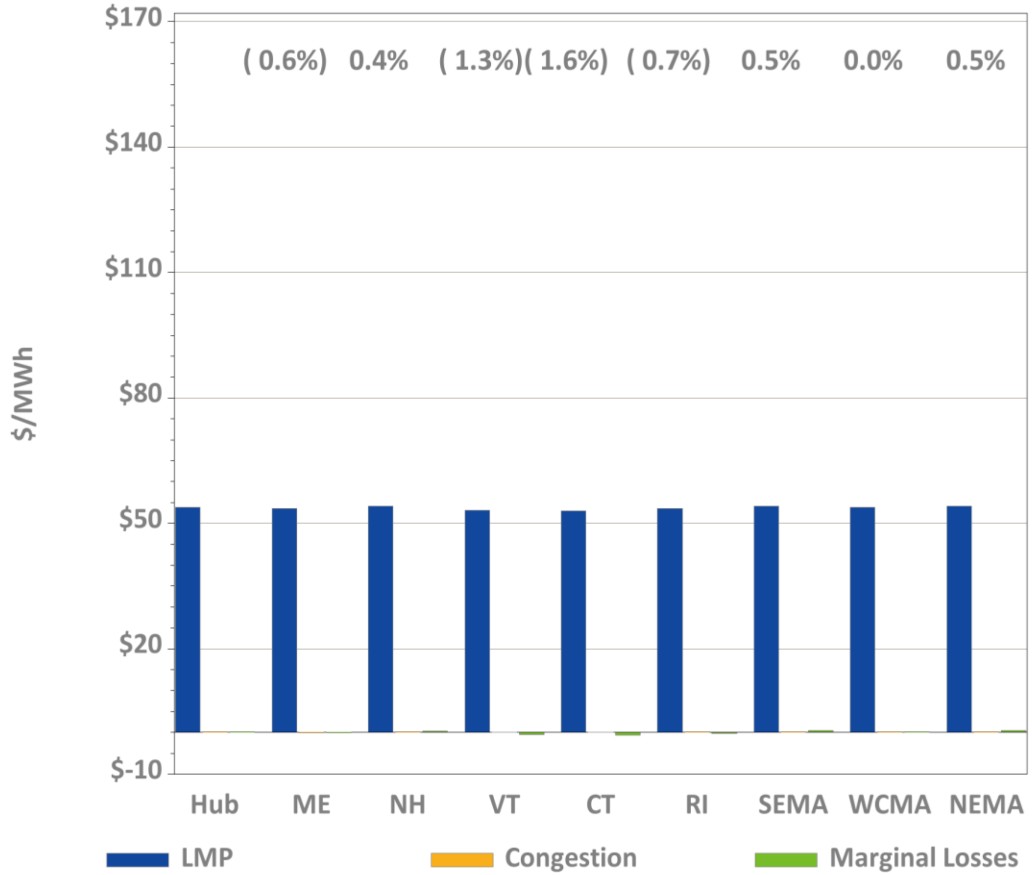
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, October 2022



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

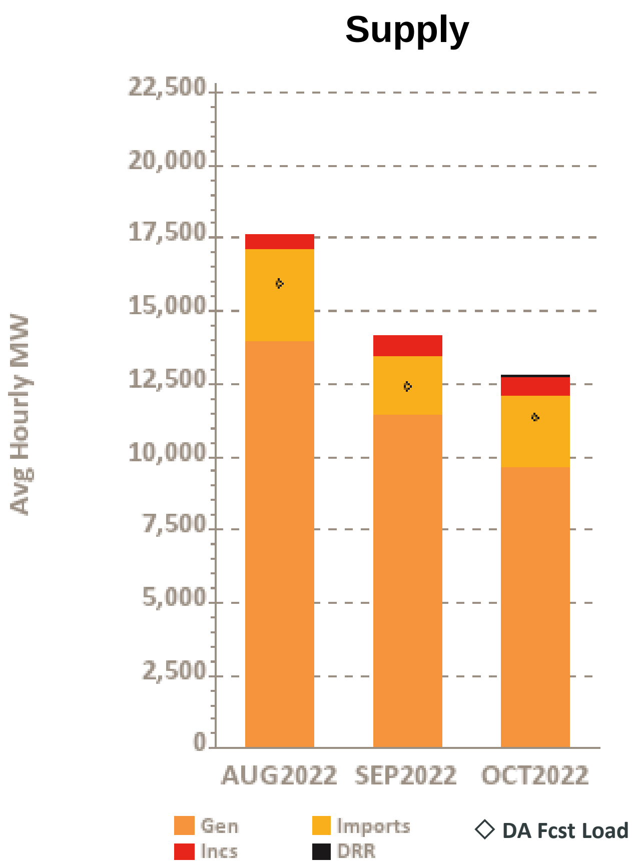
RT LMPs Average by Zone & Hub, October 2022

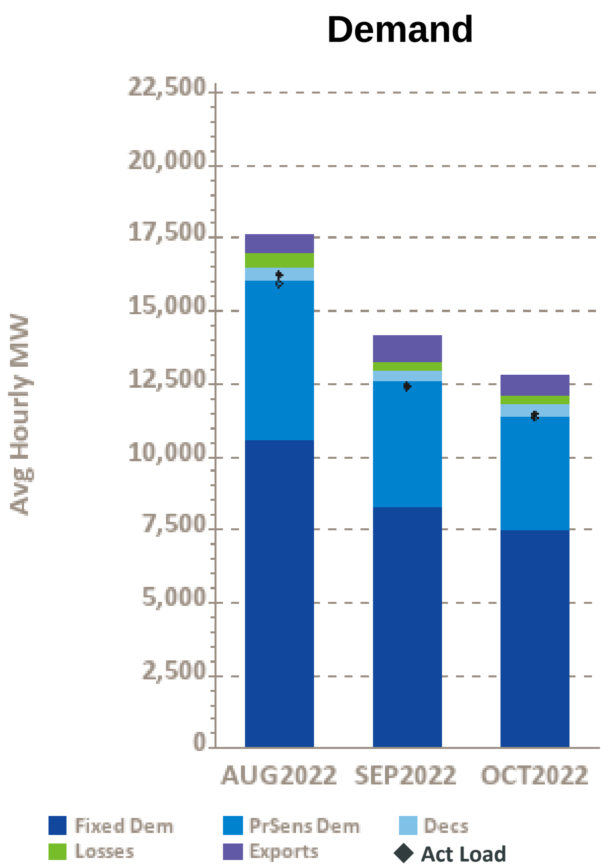


Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

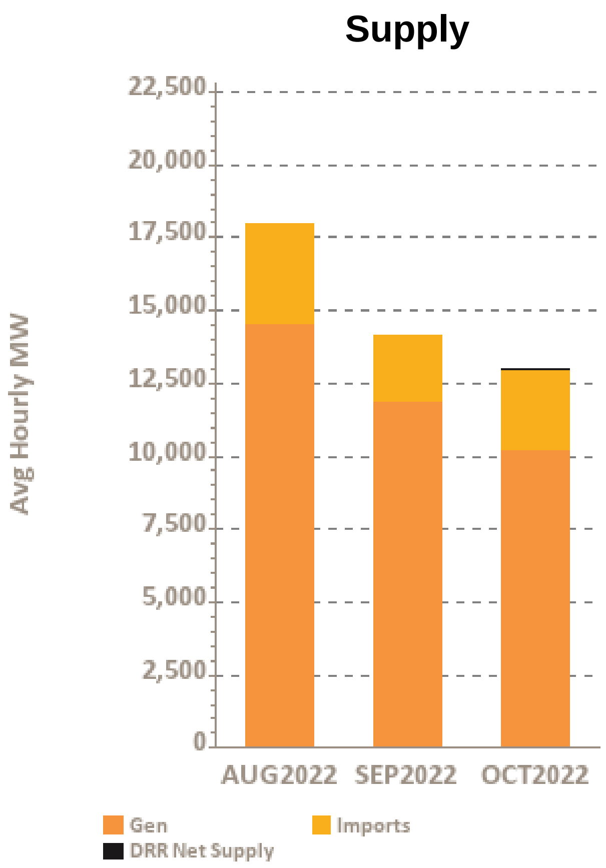


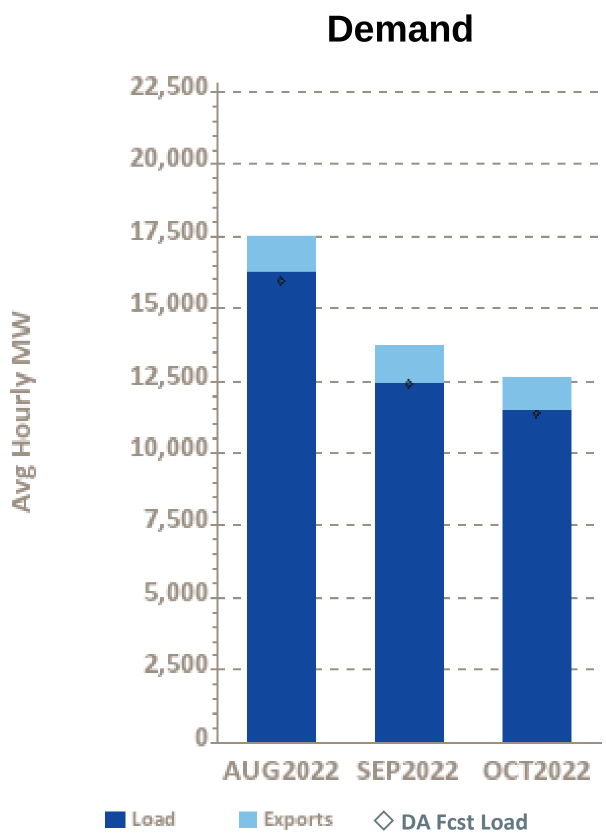


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

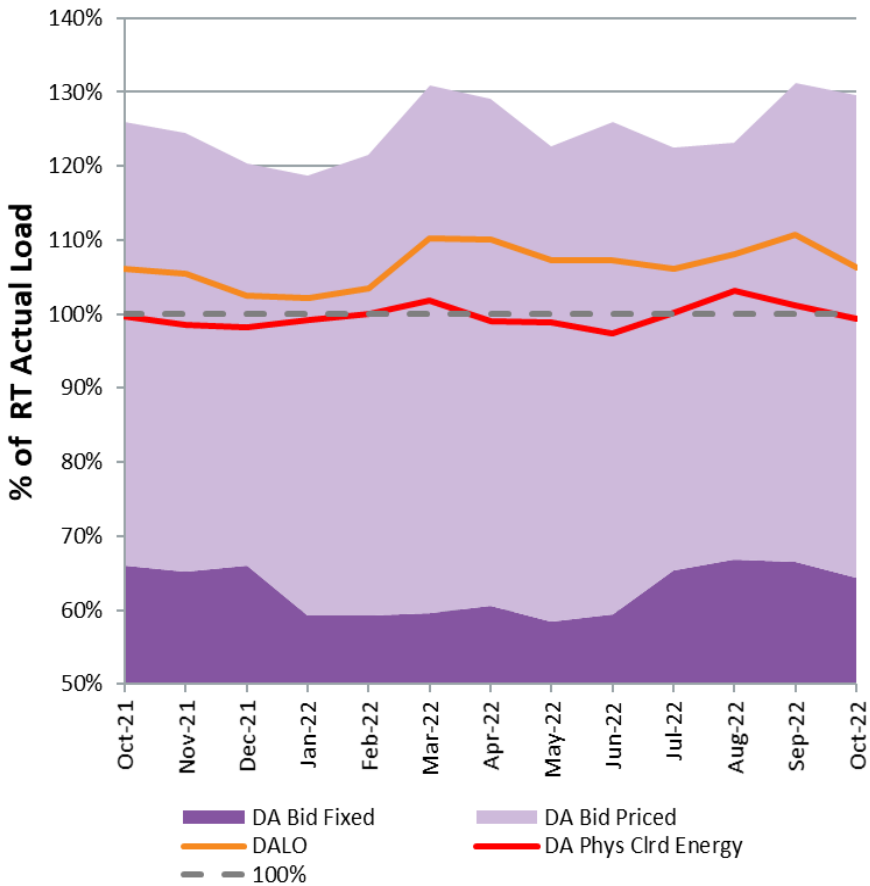
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

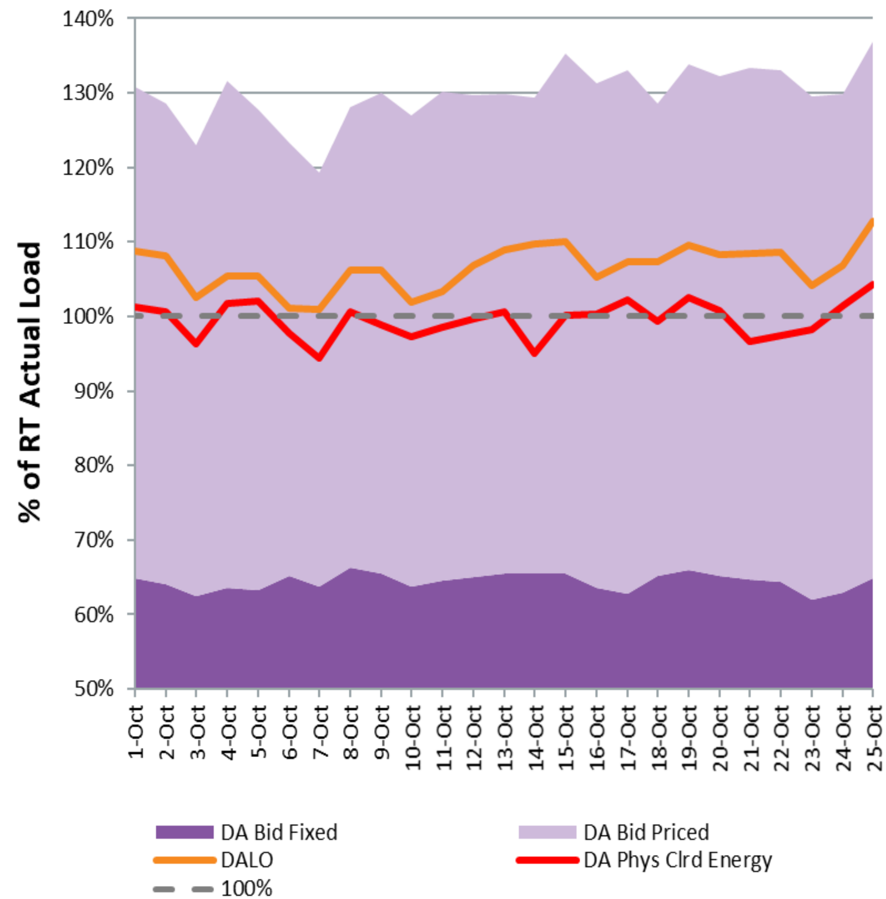
Components of RT Supply and Demand – Last Three Months





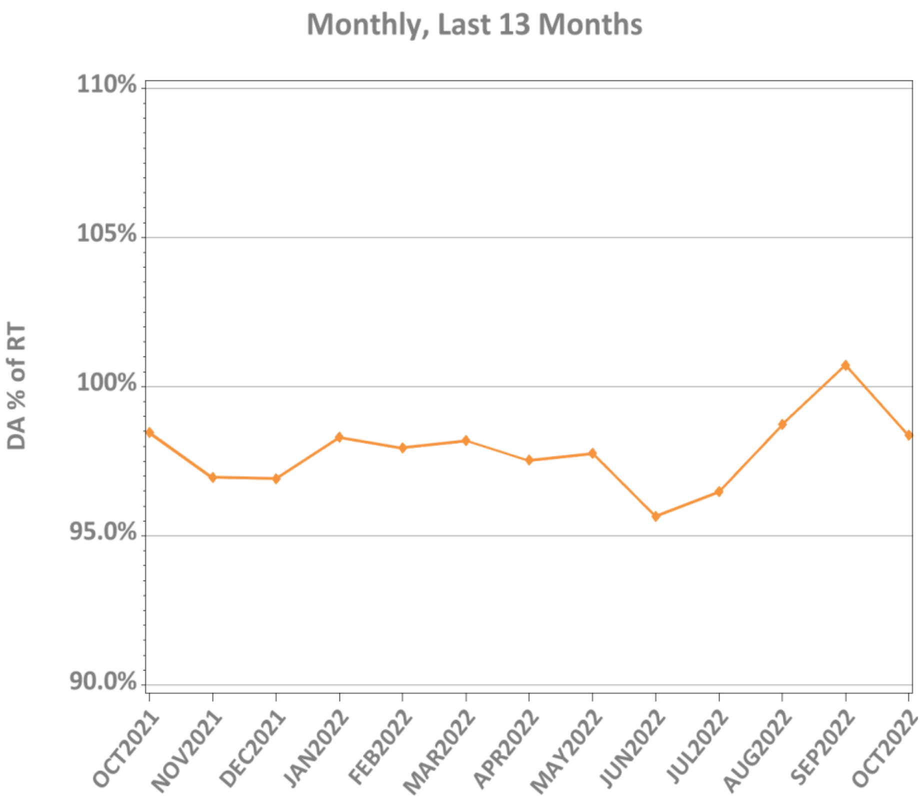
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

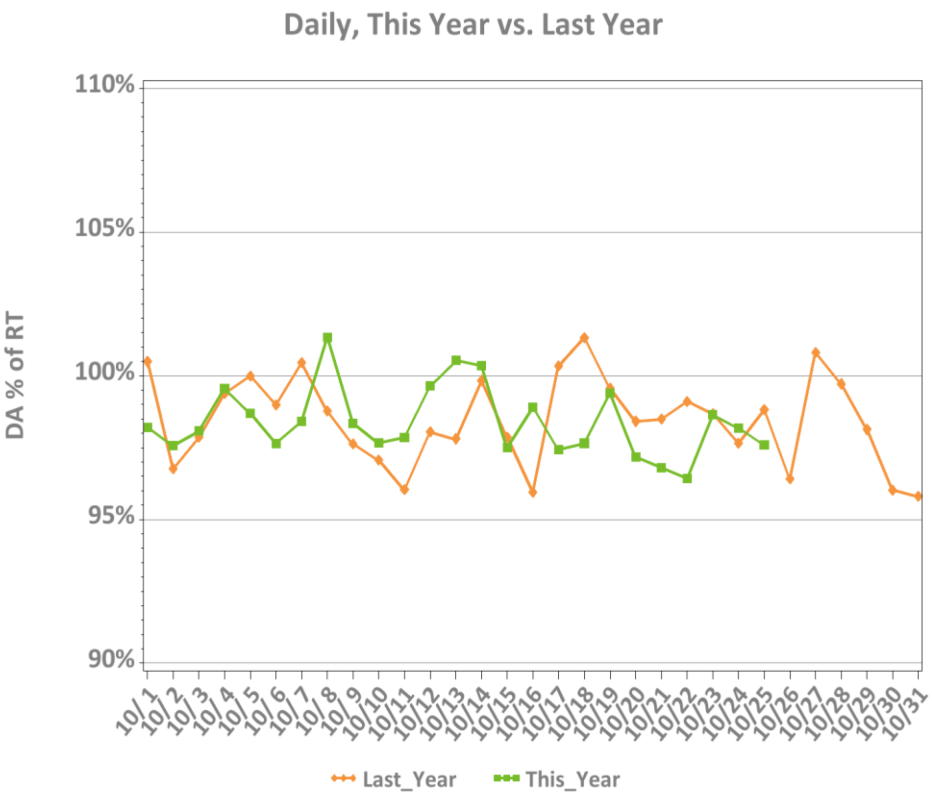




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

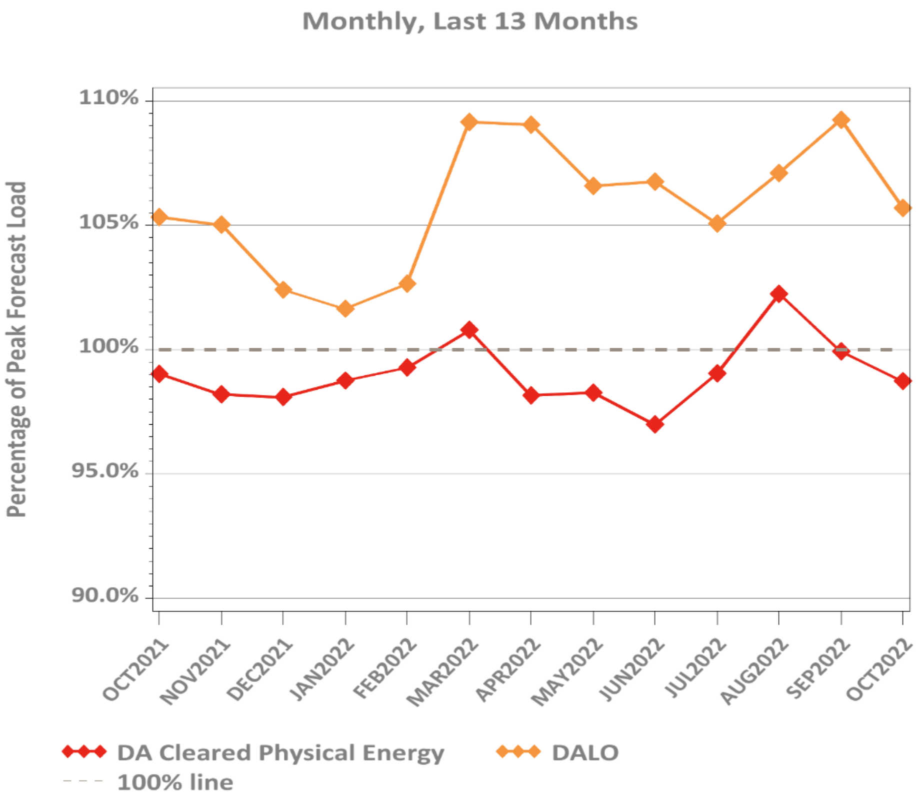
DA vs. RT Load Obligation: October, This Year vs. Last Year

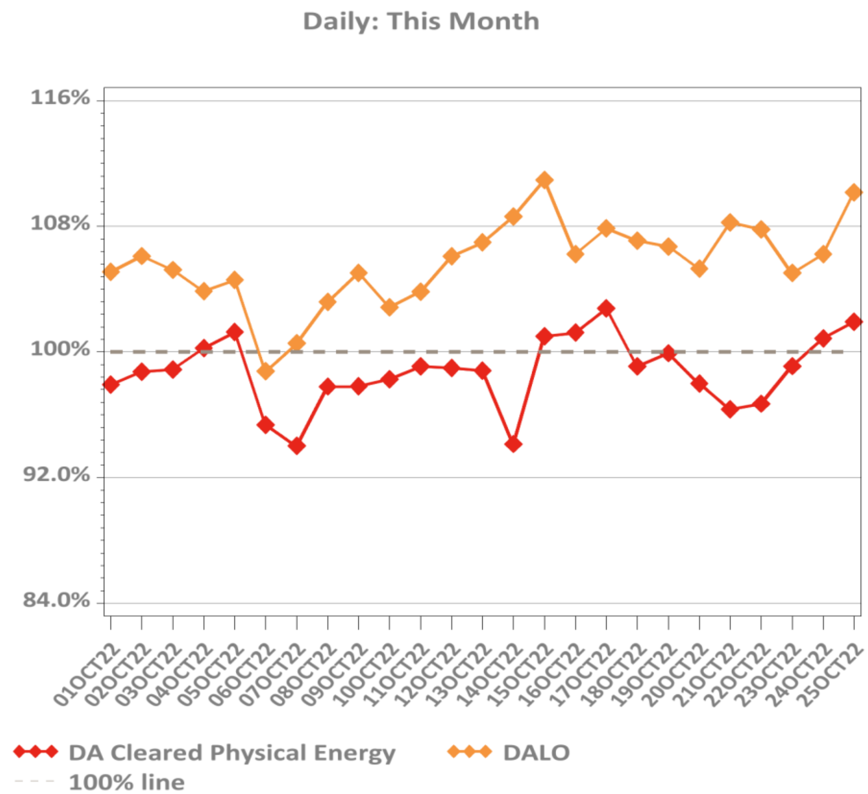




***Hourly average values**

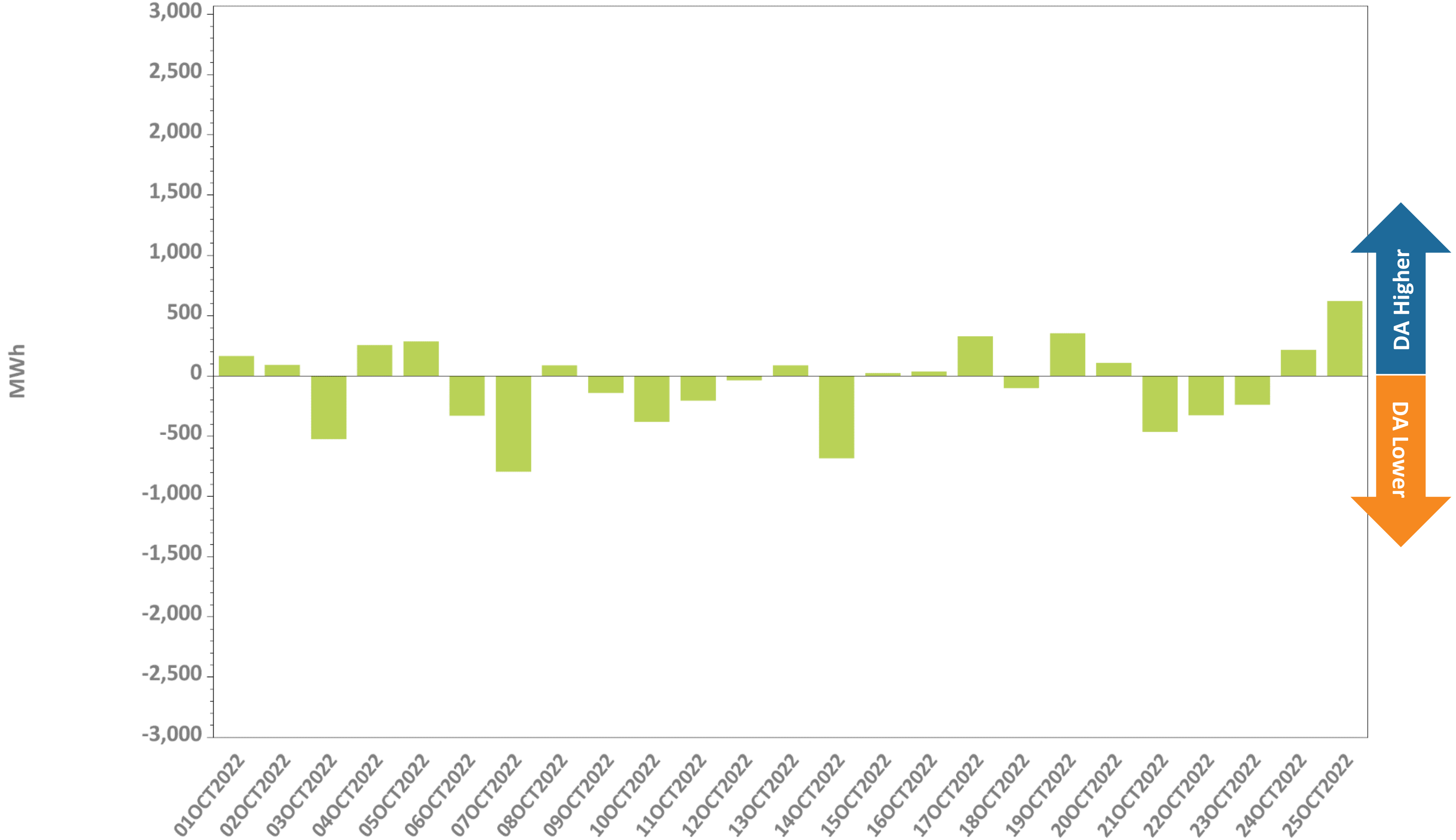
DA Volumes as % of Forecast in Peak Hour





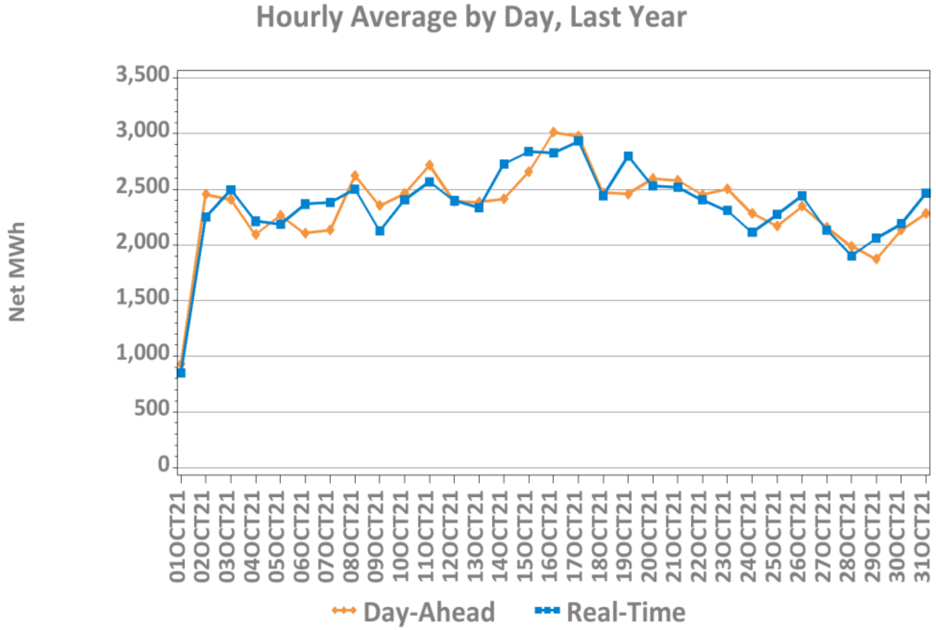
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

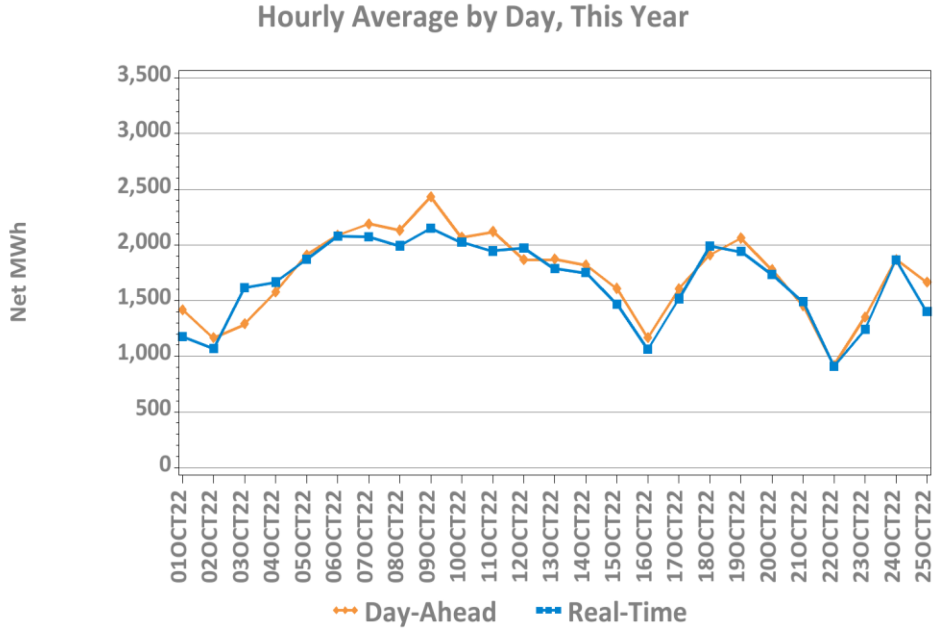
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



***Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.**

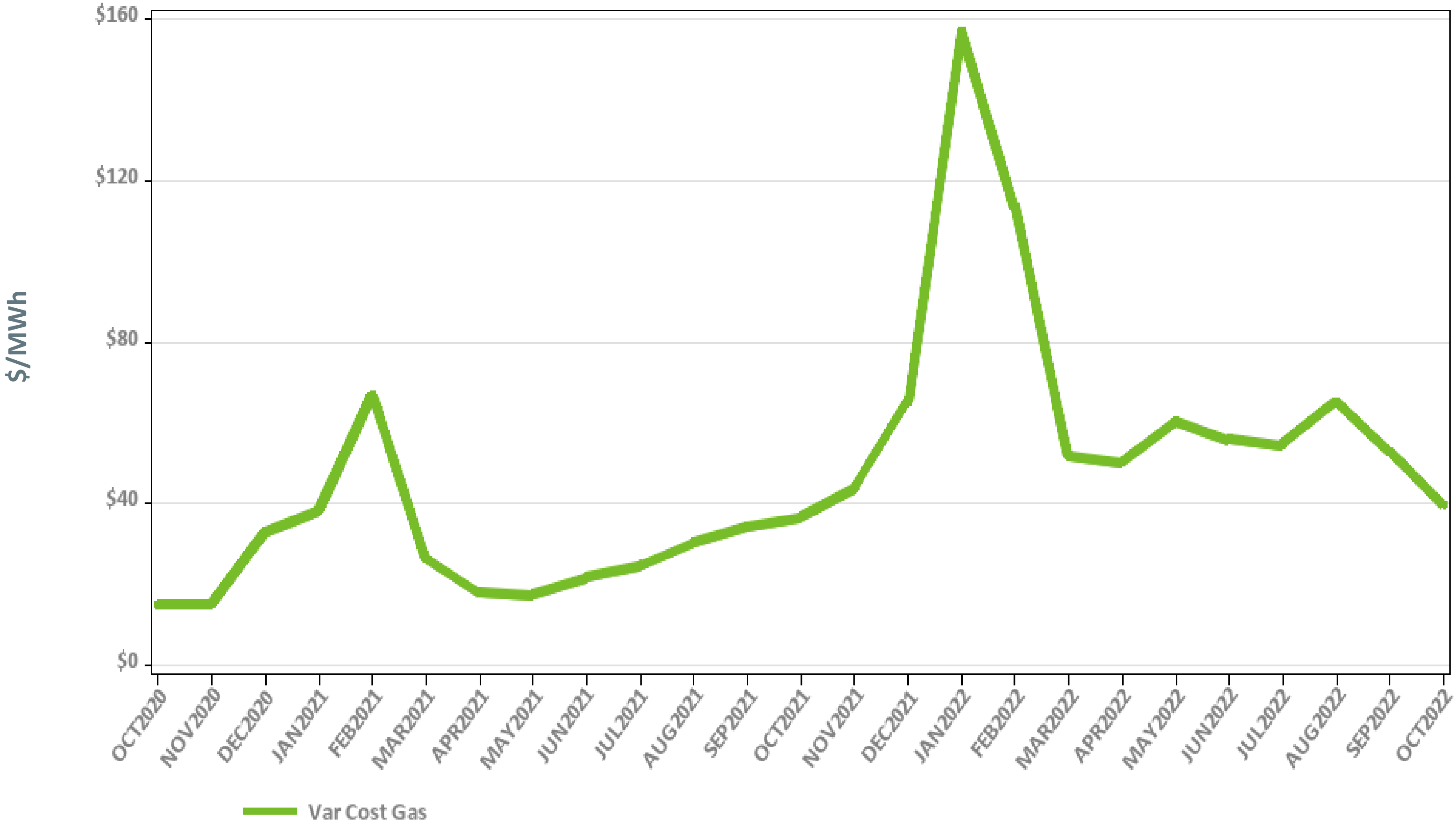
DA vs. RT Net Interchange October 2021 vs. October 2022





Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Variable Production Cost of Natural Gas: Monthly

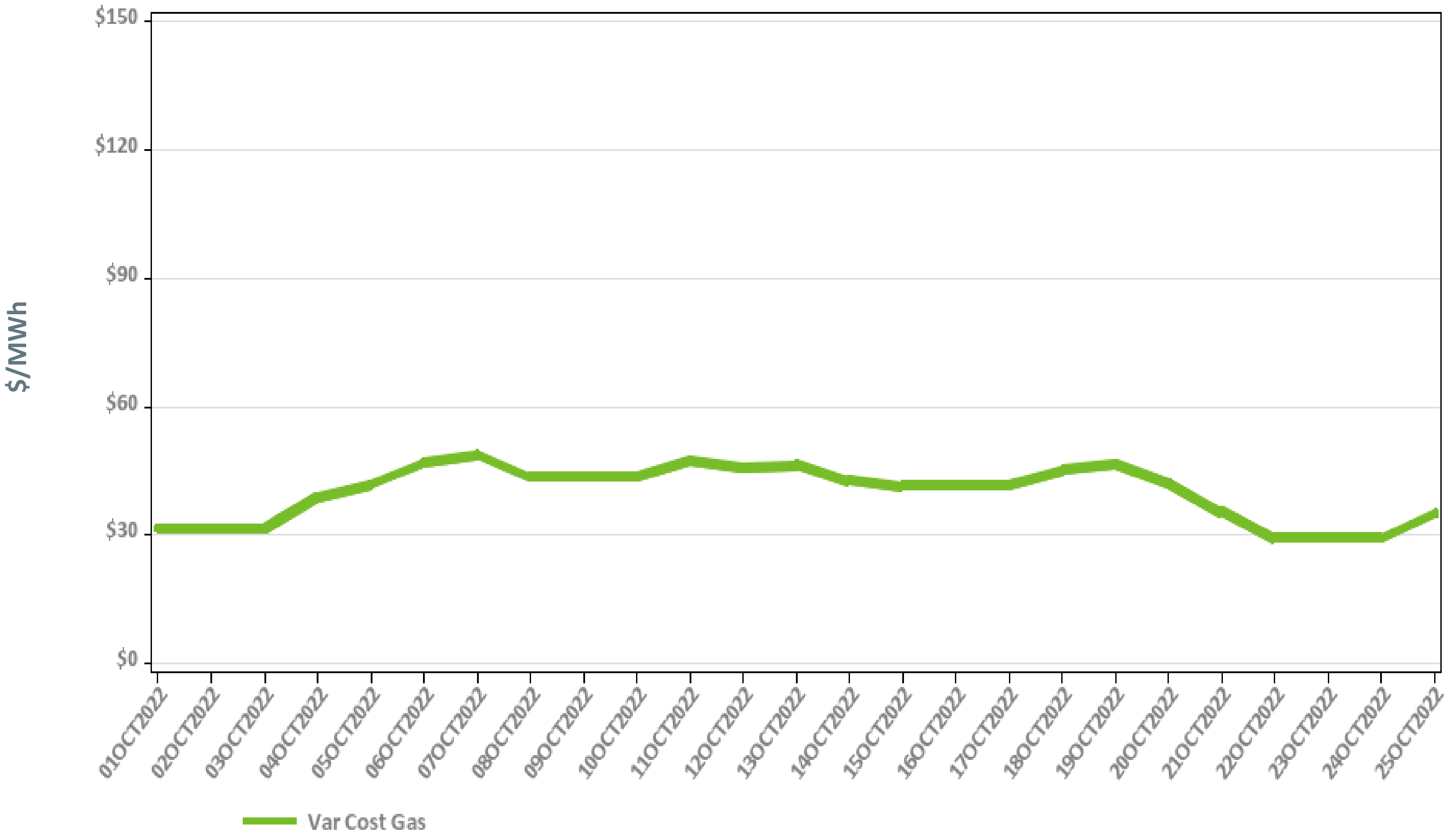


Underlying natural gas data furnished by:

ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

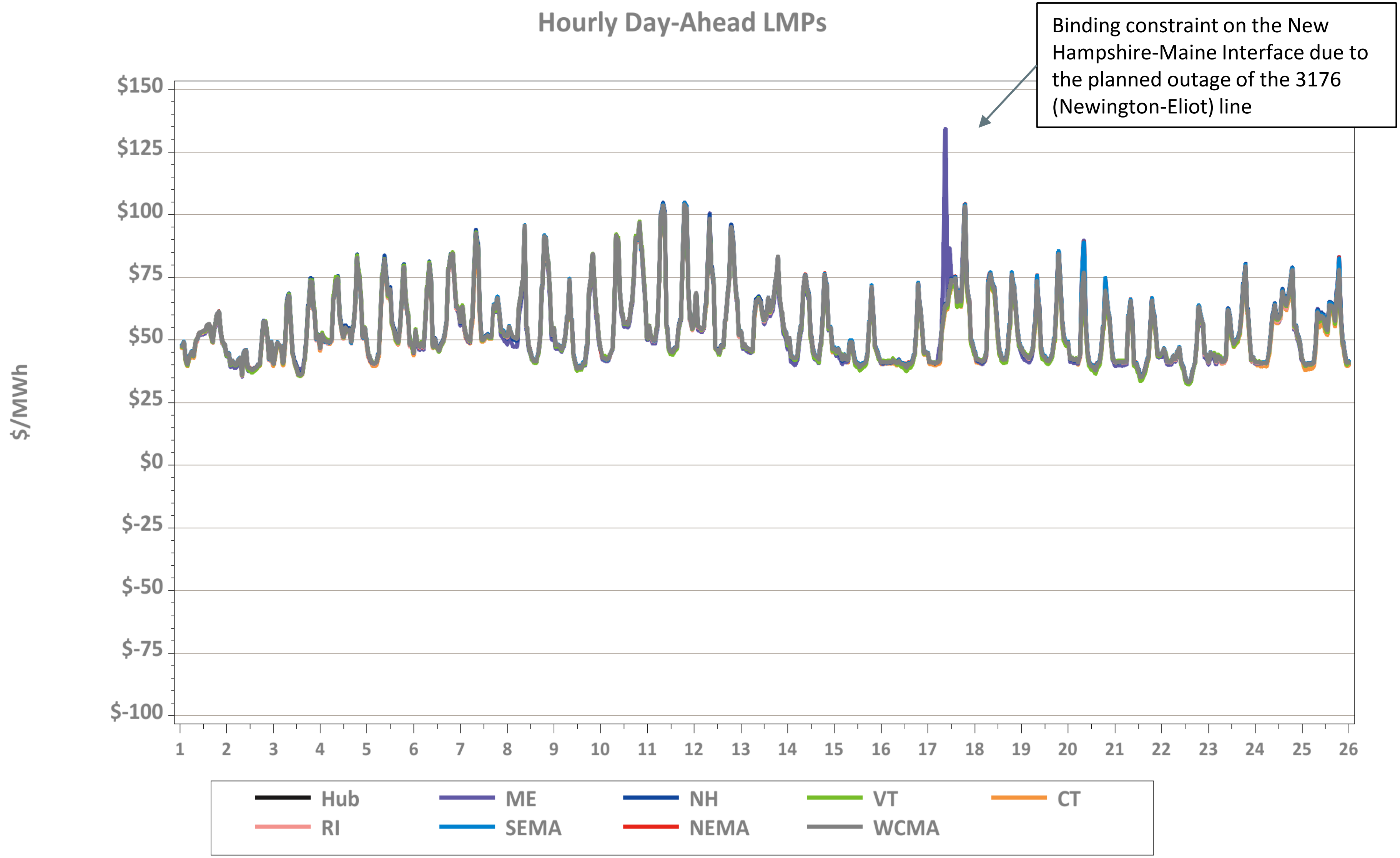
Variable Production Cost of Natural Gas: Daily



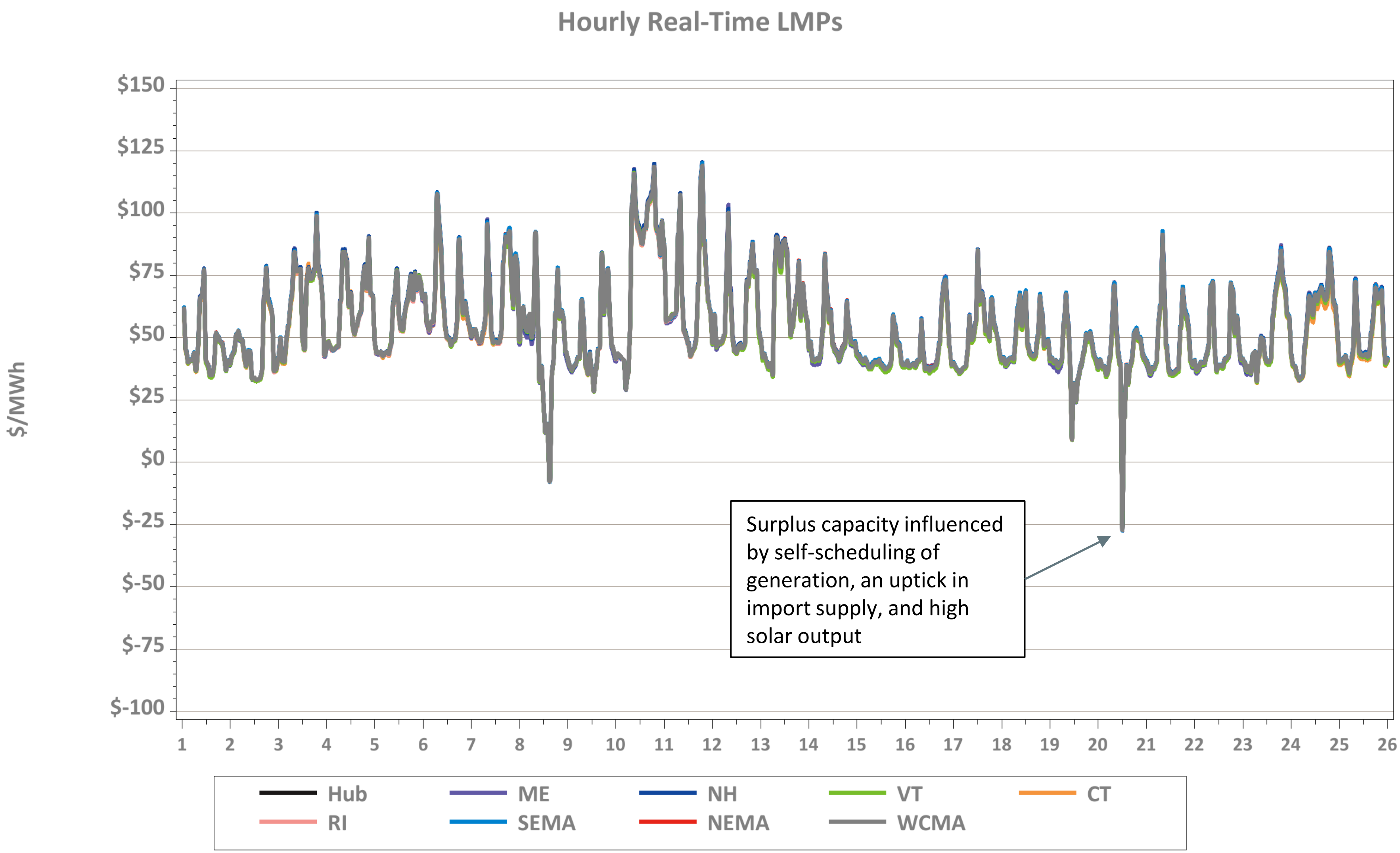
Underlying natural gas data furnished by:

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Hourly DA LMPs, October 1-25, 2022

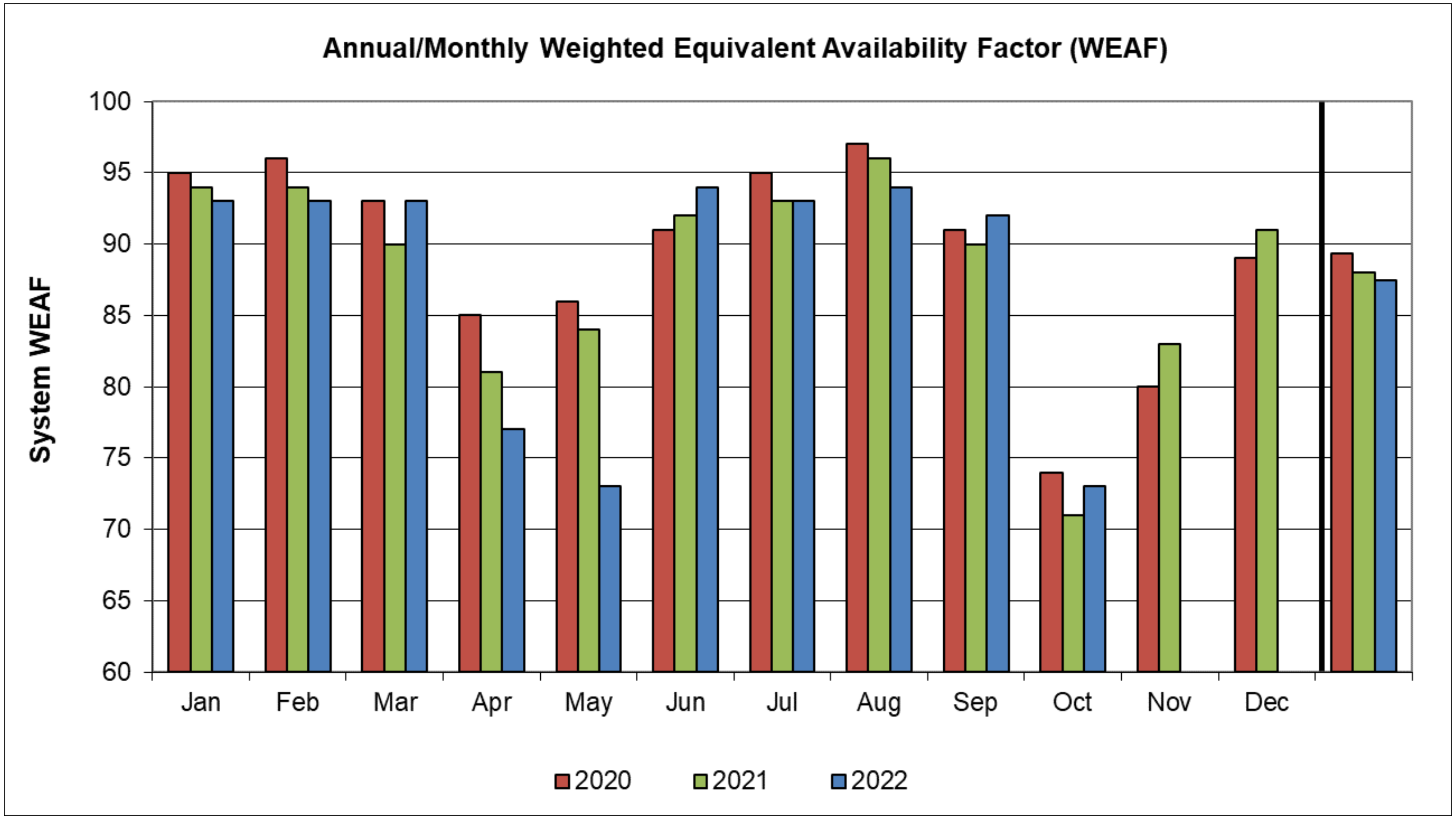


Hourly RT LMPs, October 1-25, 2022



* Telemetered load is referenced

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2022	93	93	93	77	73	94	93	94	92	73			88
2021	94	94	90	81	84	92	93	96	90	71	83	91	88
2020	95	96	93	85	86	91	95	97	91	74	80	89	89

Data as of 10/26/2022

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for November 2022

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	90.9	214.1	0.0	305.0
NH	40.5	169.4	0.0	209.9
VT	37.4	132.5	0.0	169.8
CT	147.5	227.2	614.4	989.0
RI	37.6	345.8	0.0	383.4
SEMA	41.4	531.8	0.0	573.2
WCMA	81.3	566.7	35.2	683.2
NEMA	68.6	880.2	0.0	948.8
Total	**545.2**	**3,067.7**	**649.5**	**4,262.4**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

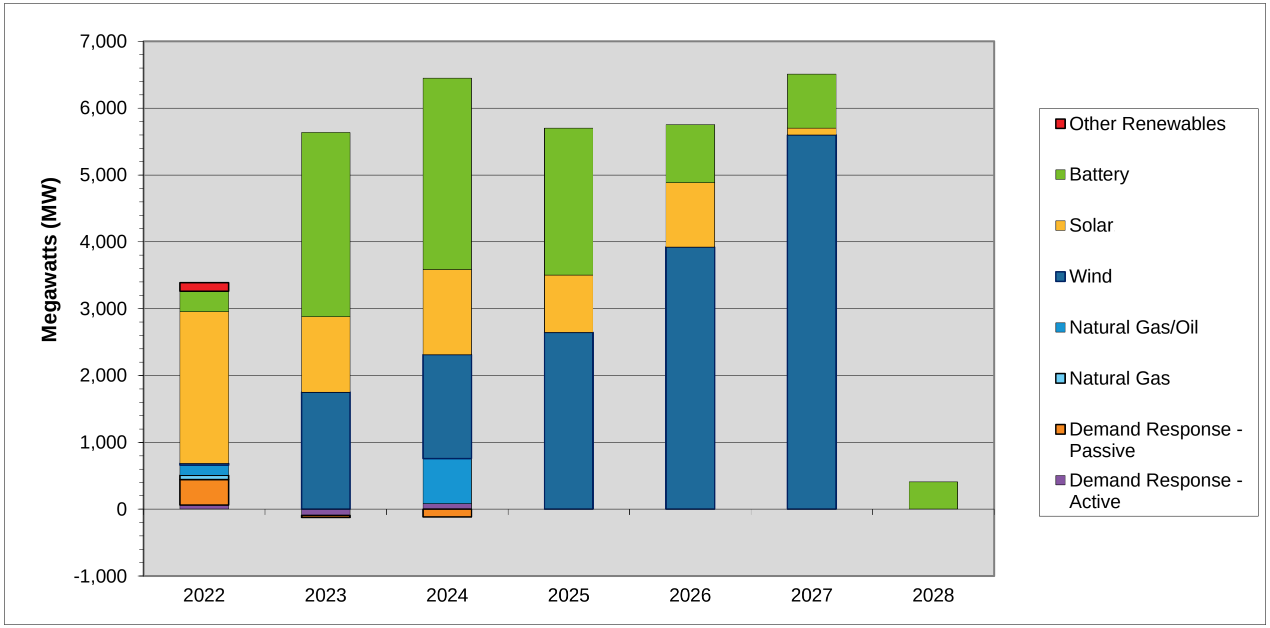
NEW GENERATION

New Generation Update

Based on Queue as of 10/28/22

- Eight projects totaling 1,125 MW were added to the interconnection queue since the last update
  - Six battery projects and two solar projects with in-service dates of 2023 to 2028
- Three projects were withdrawn and one project went commercial
- In total, 349 generation projects are currently being tracked by the ISO, totaling approximately 34,992 MW

Actual and Projected Annual Capacity Additions
By Supply Fuel Type and Demand Resource Type



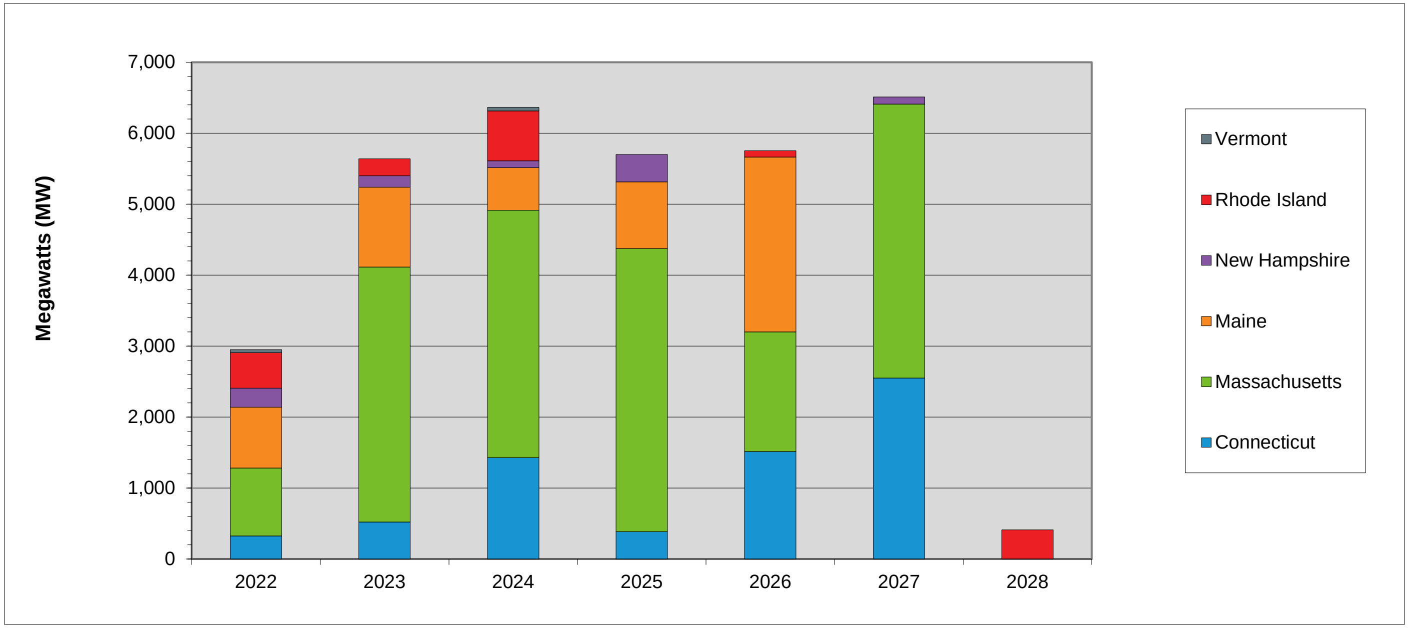
	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	129	0	0	0	0	0	0	129	0.4
Battery	305	2,756	2,863	2,196	866	810	410	10,206	30.4
Solar[2]	2,272	1,129	1,272	859	964	102	0	6,598	19.6
Wind	24	1,752	1,556	2,645	3,923	5,599	0	15,499	46.1
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.4
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	**3,390**	**5,515**	**6,335**	**5,700**	**5,753**	**6,511**	**410**	**33,614**	**100.0**

[1] Sum may not equal 100% due to rounding
[2] This category includes both solar-only, and co-located solar and battery projects
[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	40	0	50	0	0	0	0	90	0.3
Rhode Island	502	236	704	0	91	0	410	1,943	5.8
New Hampshire	266	164	97	385	0	102	0	1,014	3.0
Maine	858	1,123	597	942	2,461	0	0	5,981	17.9
Massachusetts	959	3,594	3,486	3,989	1,686	3,858	0	17,572	52.7
Connecticut	323	520	1,429	384	1,515	2,551	0	6,722	20.2
Totals	**2,948**	**5,637**	**6,363**	**5,700**	**5,753**	**6,511**	**410**	**33,322**	**100.0**

[1] **Sum may not equal 100% due to rounding**

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	72	10,206	3	32	69	10,174
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	0	0	0	0	0	0
Solar	238	6,598	18	401	220	6,197
Wind	26	17,169	1	20	25	17,149
Total	353	34,992	25	586	328	34,406

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	70	1	5	4	65
Intermediate	7	804	0	0	7	804
Peaker	315	16,949	23	561	292	16,388
Wind Turbine	26	17,169	1	20	25	17,149
Total	353	34,992	25	586	328	34,406

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	72	10,206	0	0	0	0	72	10,206	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	238	6,598	0	0	0	0	238	6,598	0	0
Wind	26	17,169	0	0	0	0	0	0	26	17,169
Total	353	34,992	5	70	7	804	315	16,949	26	17,169

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 13

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	685.554	683.116	-2.438	658.659	-24.457	609.826	-48.833
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392	3,512.604	61.705
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**	**4,122.43**	**12.872**
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07	27,426.242	-679.169
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387	778.962	-117.323
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**	**28,205.204**	**-796.492**
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**	**1,115.22**	**-177.19**
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**	**33,442.854**	**-960.81**
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**	**31,590**	**-1,175**

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

ARA – Annual Reconfiguration Auction
CSO – Capacity Supply Obligation
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	592.043	688.07	96.027	659.671	-28.399		
	Passive Demand	3,327.071	3,327.932	0.861	3,315.207	-12.725		
Demand Total		**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**		
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429		
	Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504		
Generator Total		**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**		
Import Total		**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**		
Grand Total*		**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**		
Net ICR (NICR)		**32,490**	**32,980**	**490**	**31,480**	**-1,500**		

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272				
Demand	*Passive Demand*	3,212.865	3,211.403	-1.462				
Demand Total		**3,890.538**	**3,884.804**	**-5.734**				
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425				
Generator	*Intermittent*	1,089.265	1,073.794	-15.471				
Generator Total		**29,243.468**	**28,788.572**	**-454.896**				
Import Total		**1,487.059**	**1297.132**	**-189.927**				
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**				
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**				

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35						
	Passive Demand	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
	Intermittent	1,178.933						
Generator Total		**27,983.936**						
Import Total		**1,503.842**						
Grand Total*		**32,810.384**						
Net ICR (NICR)		**31,645**						

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2,375.422**	**370.734**	**2,746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2,571.361**	**639.586**	**3,210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

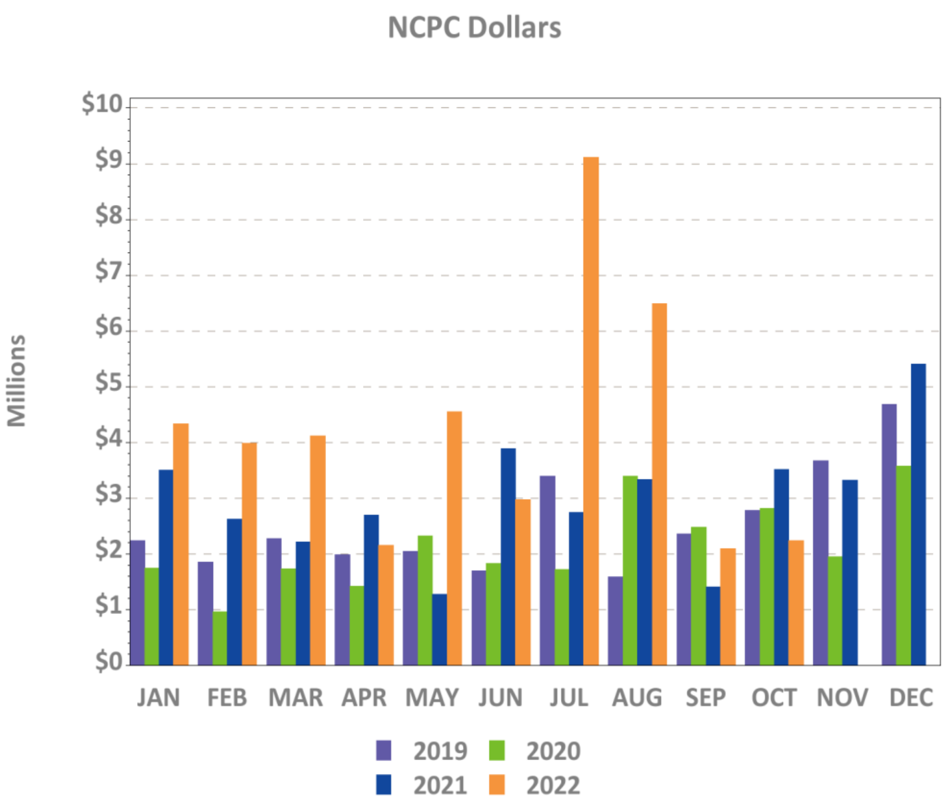
Definitions

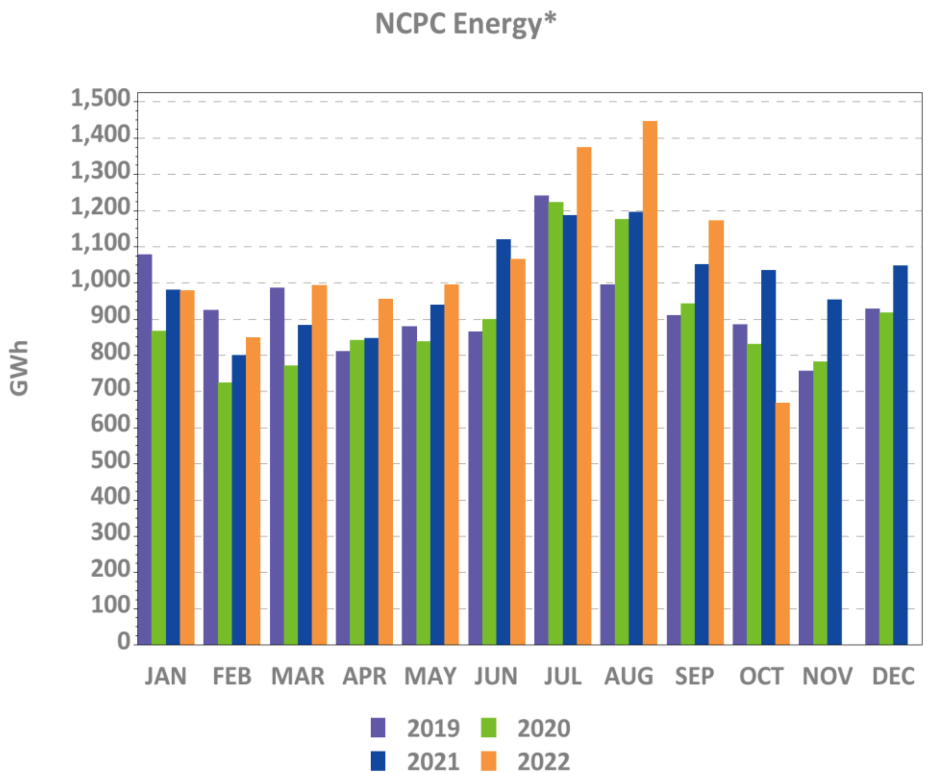
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
OATT	Open Access Transmission Tariff

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

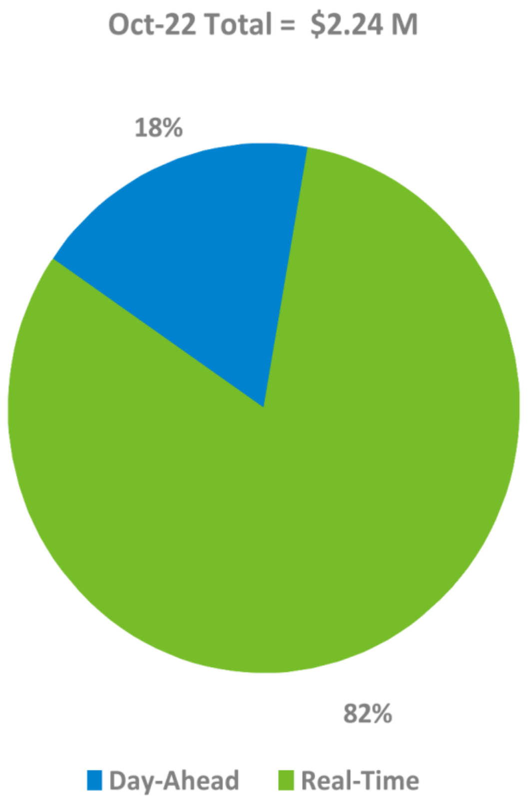
Year-Over-Year Total NCPC Dollars and Energy



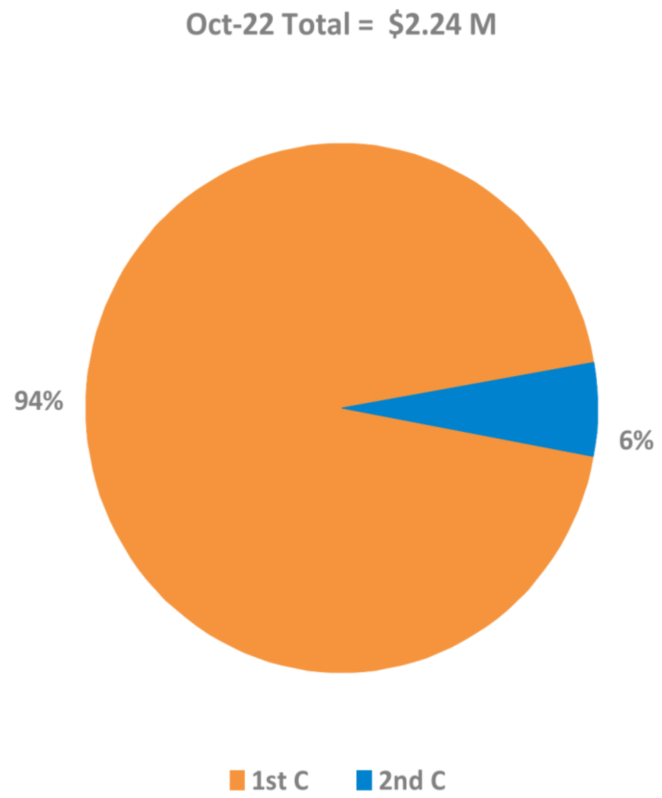


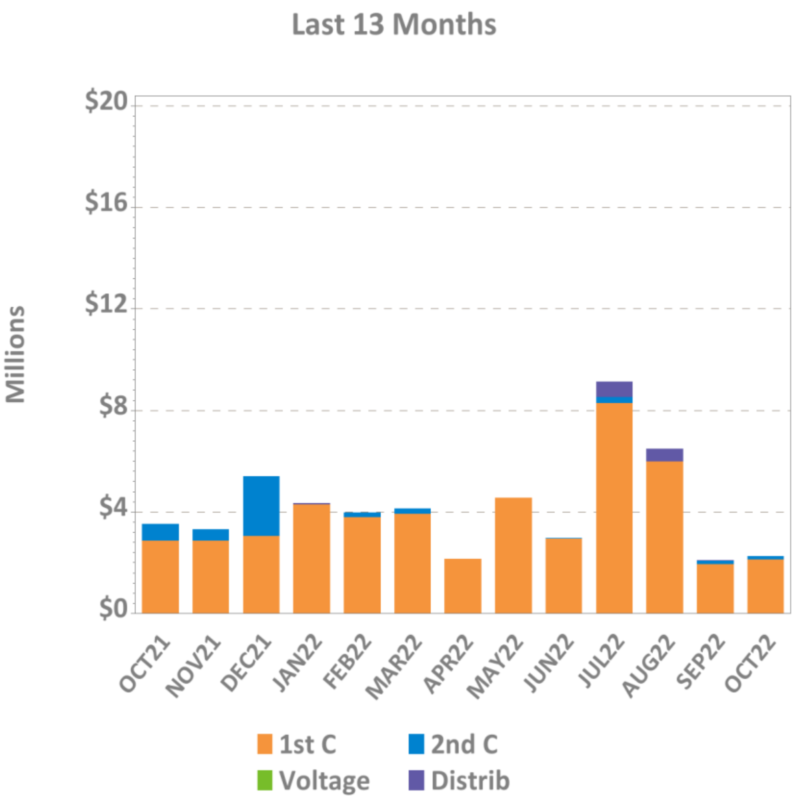
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.**

DA and RT NCPC Charges



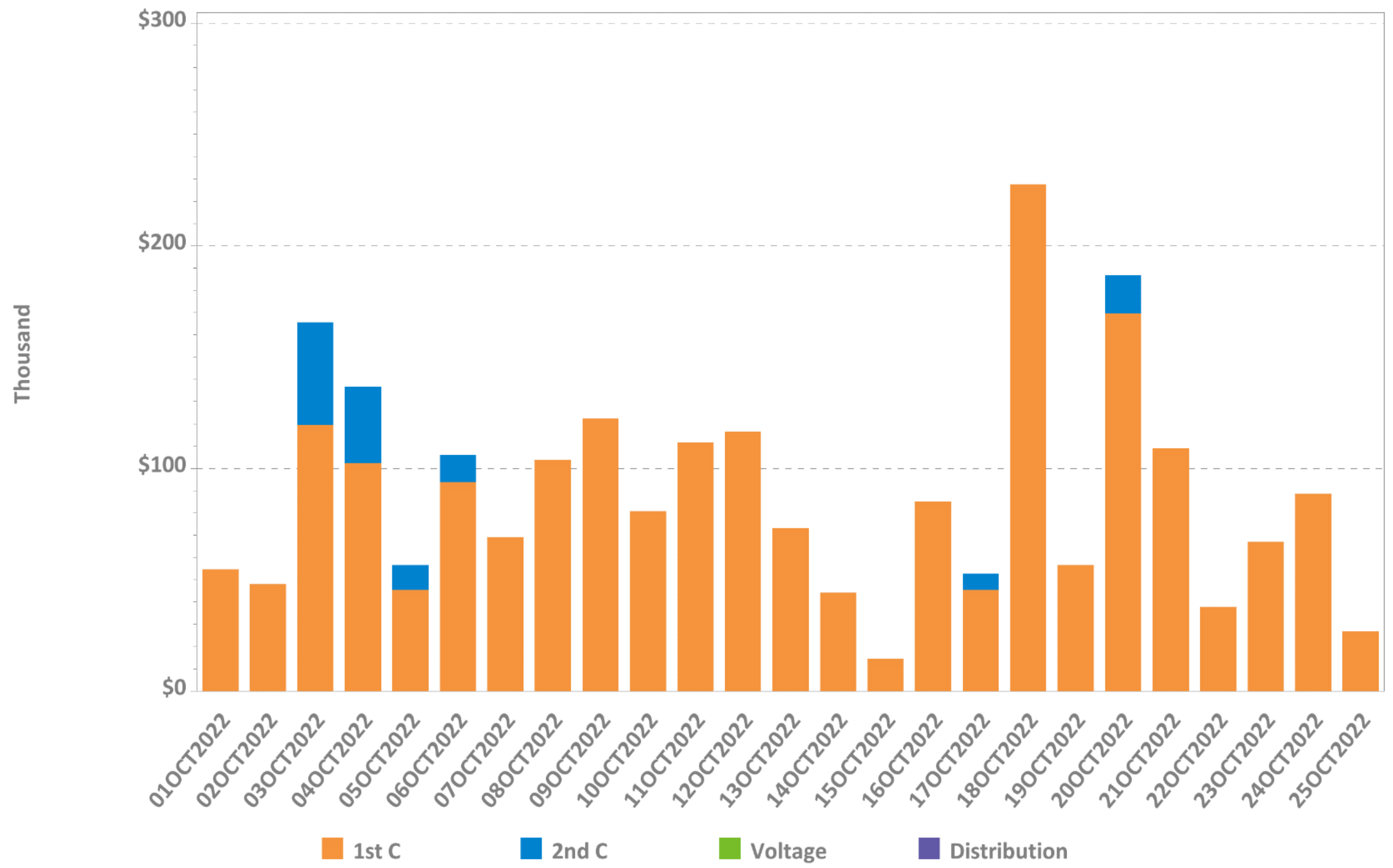
NCPC Charges by Type



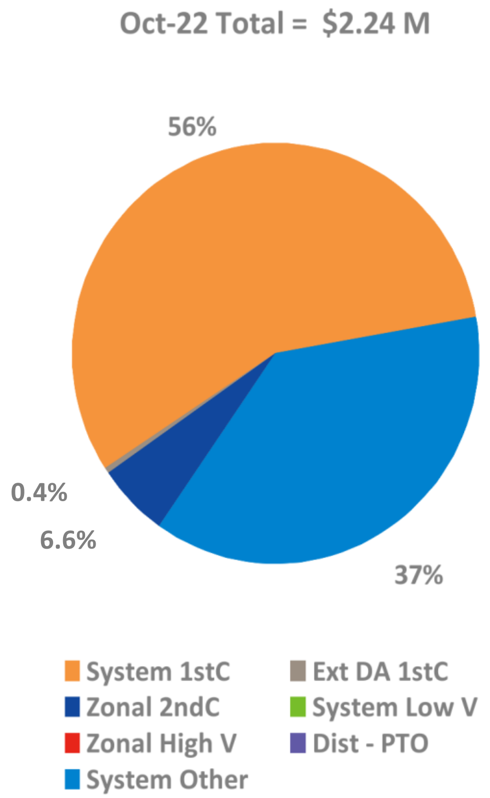


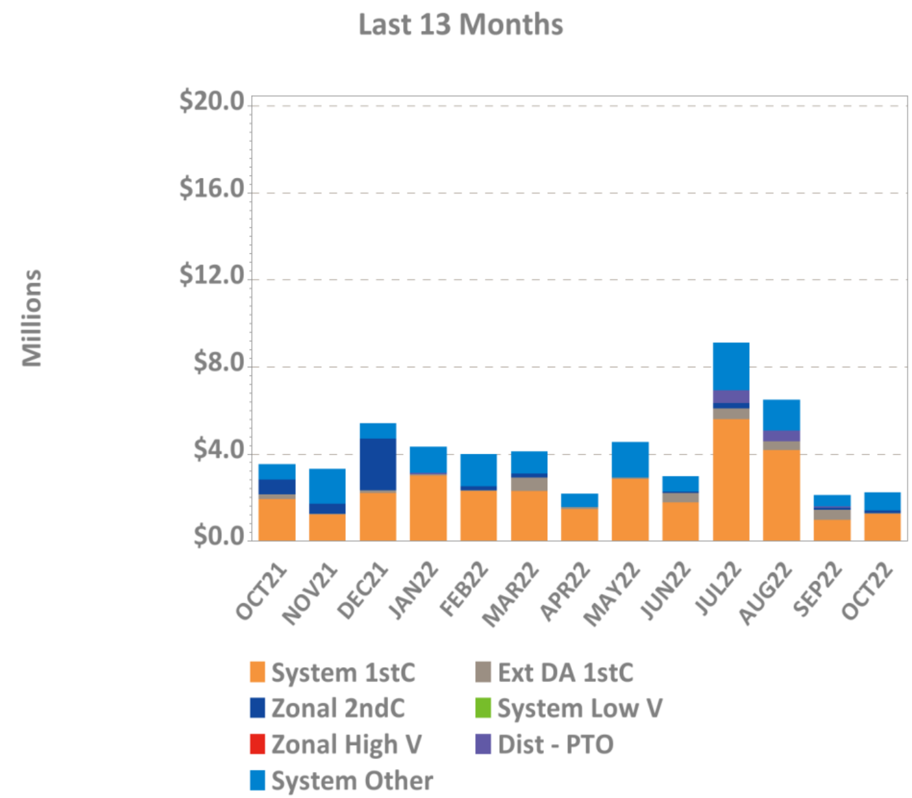
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



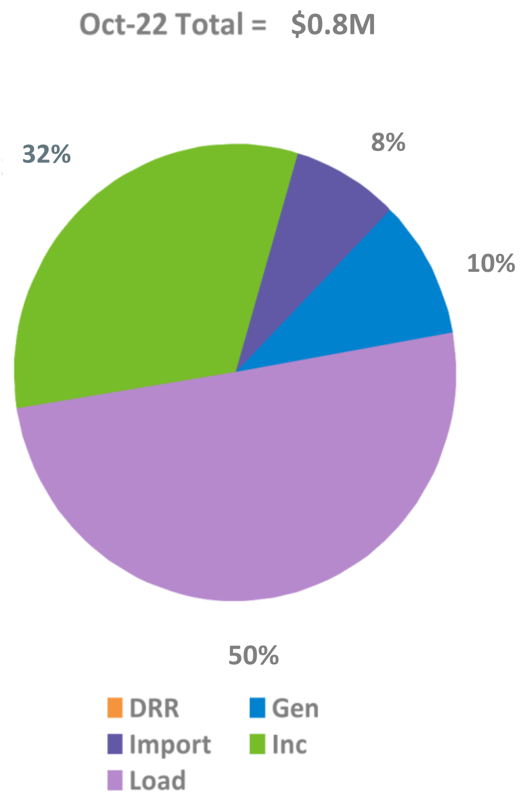
NCPC Charges by Allocation

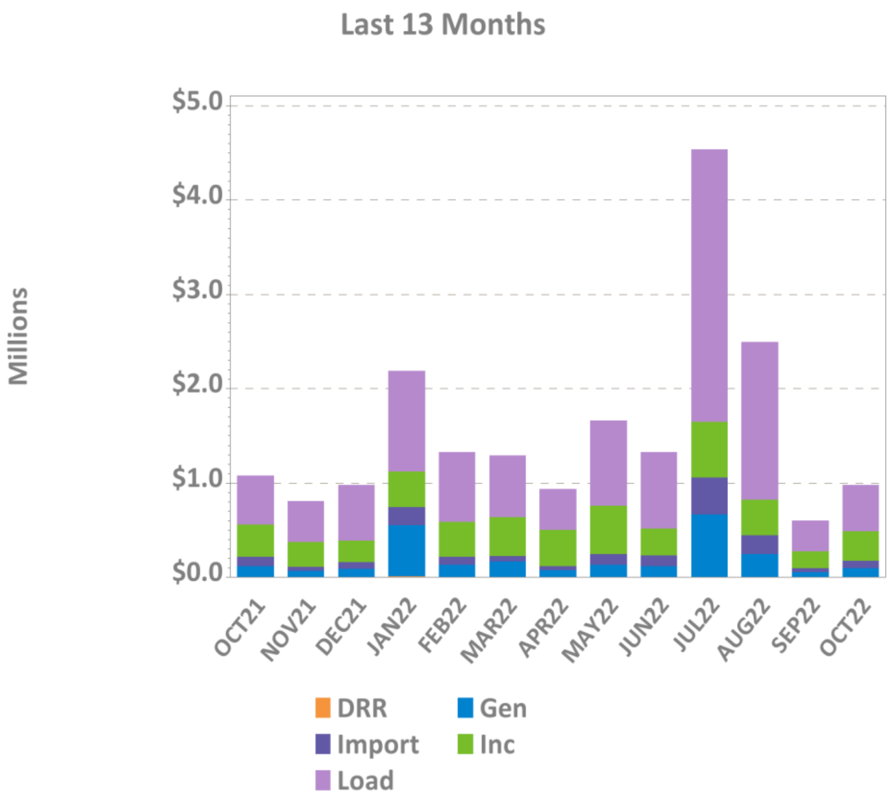




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

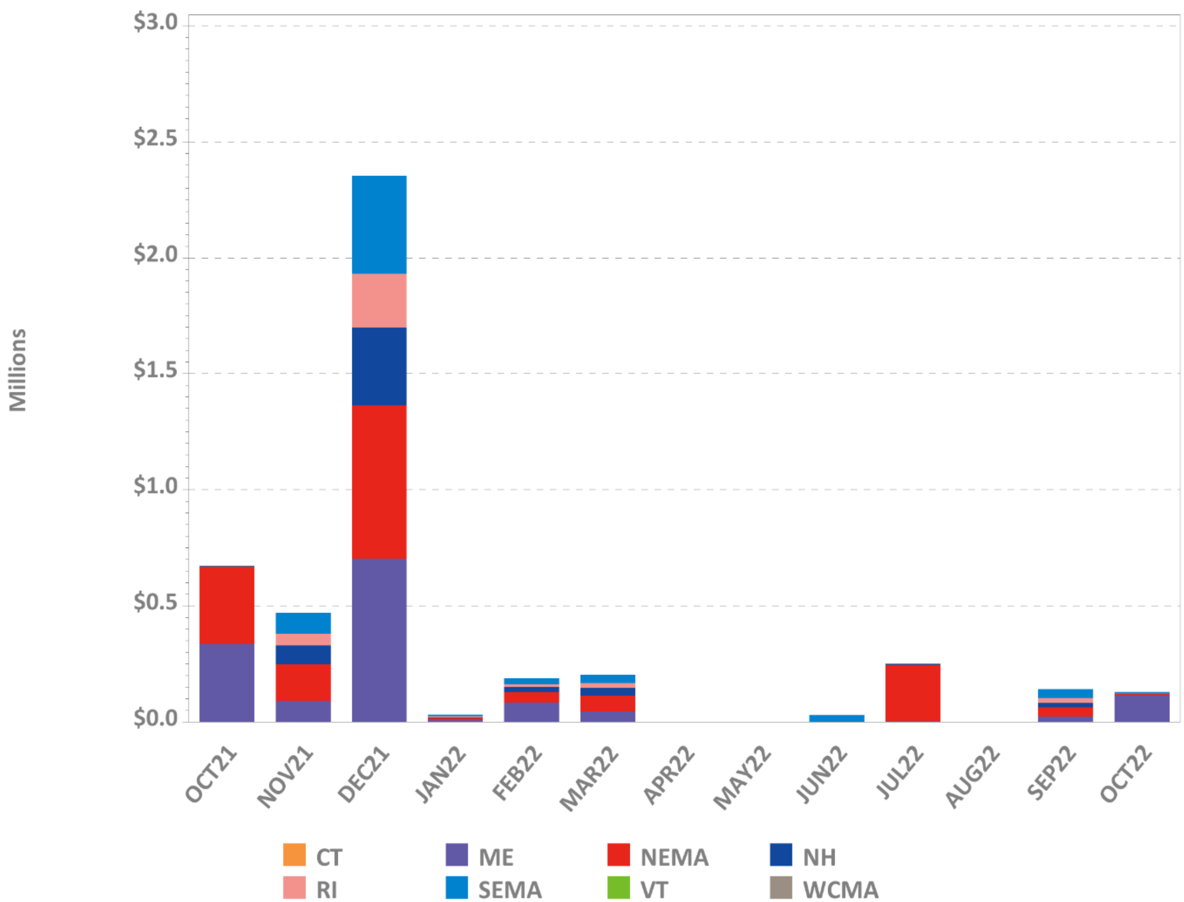
RT First Contingency Charges by Deviation Type





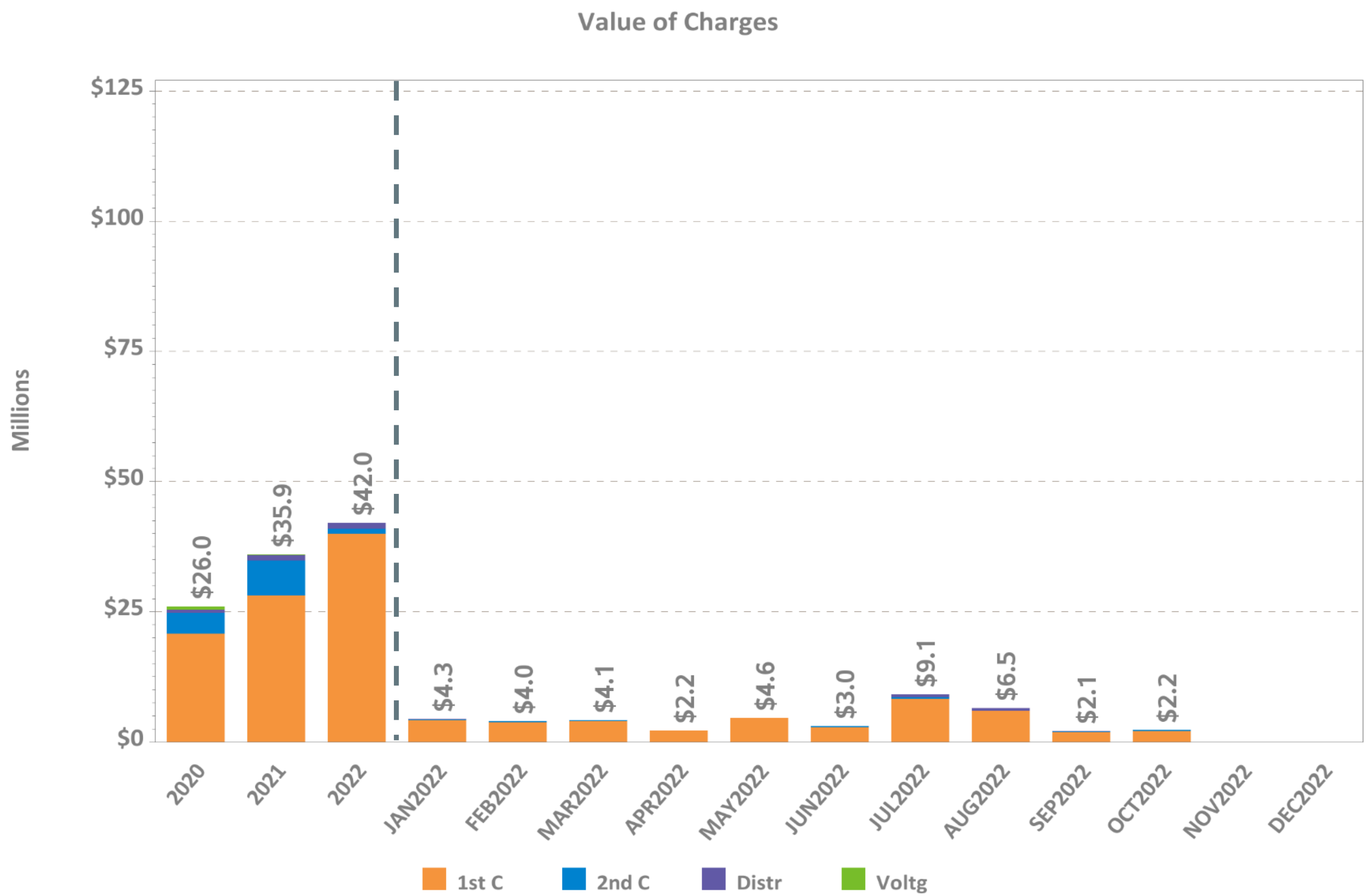
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

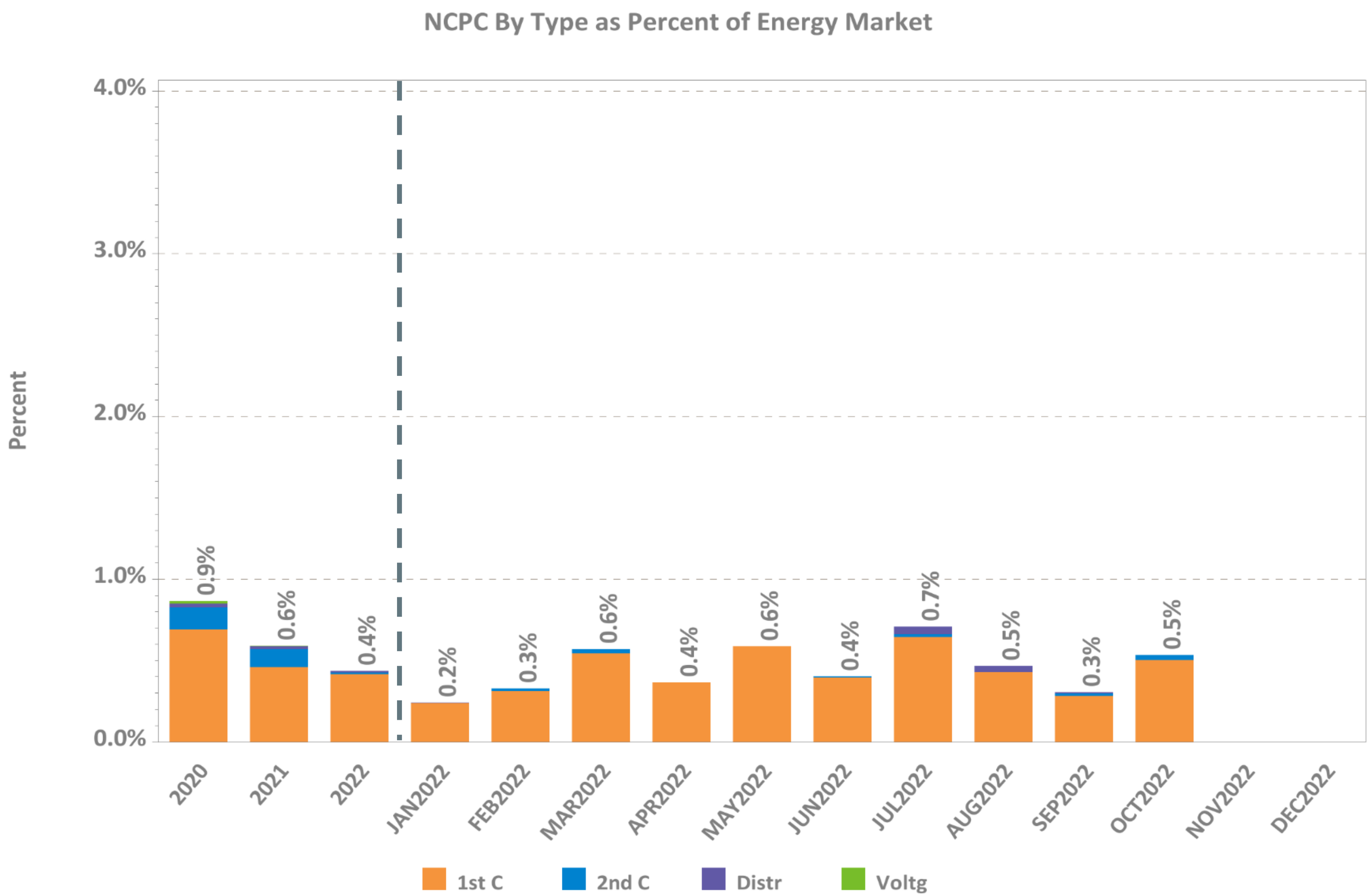


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

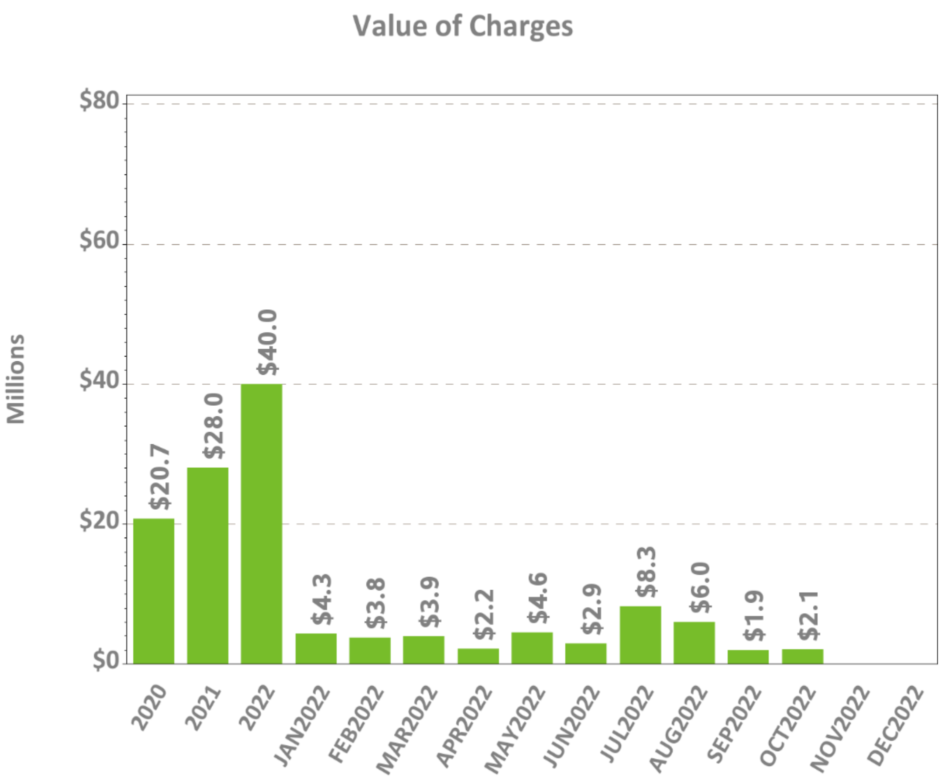
NCPC Charges by Type

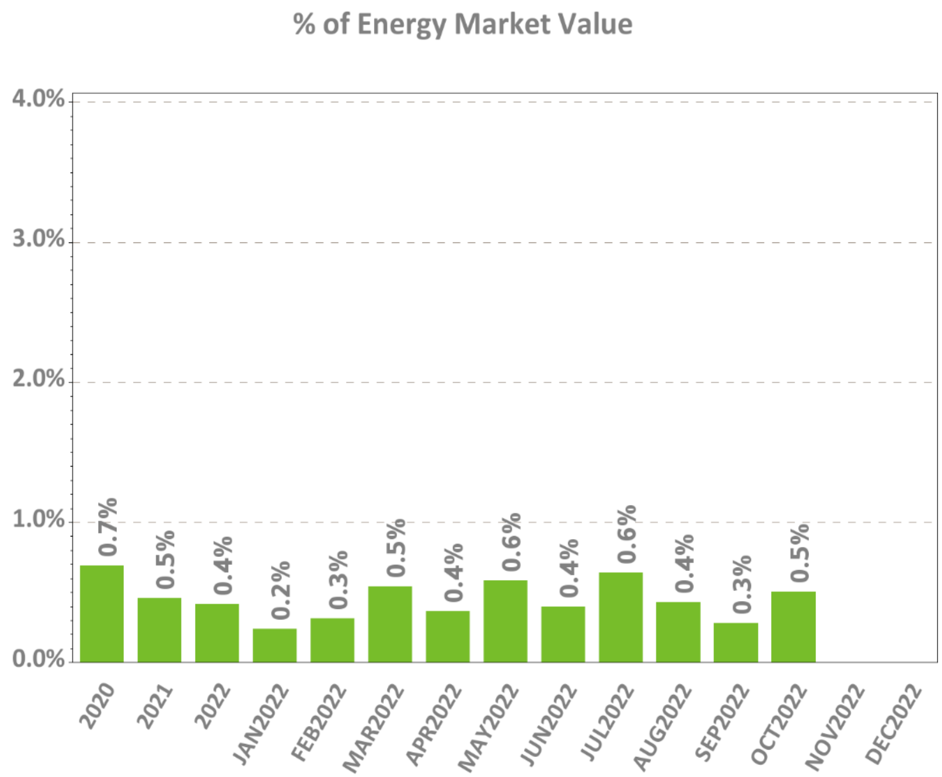


NCPC Charges as Percent of Energy Market



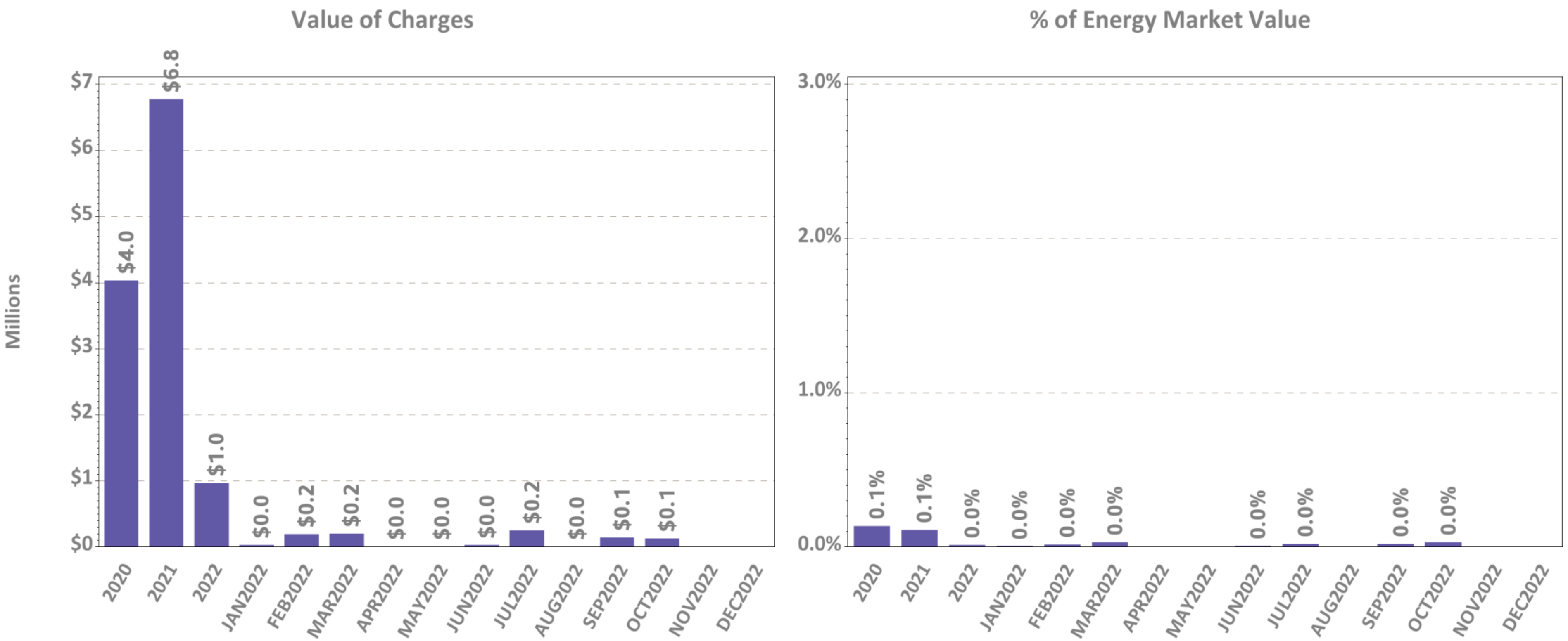
First Contingency NCPC Charges





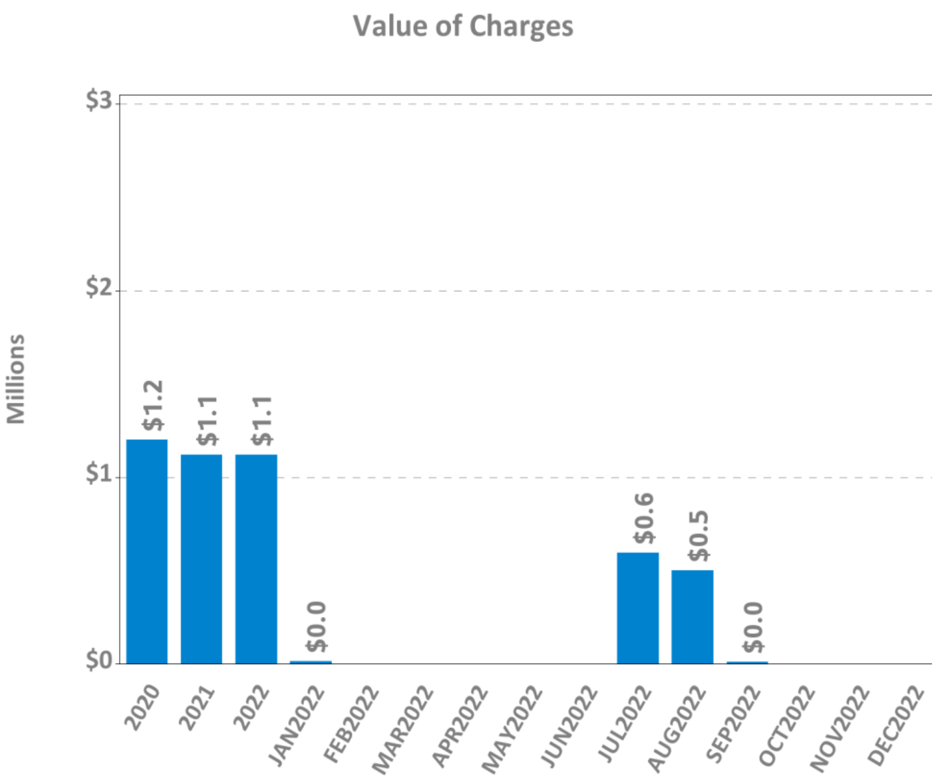
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

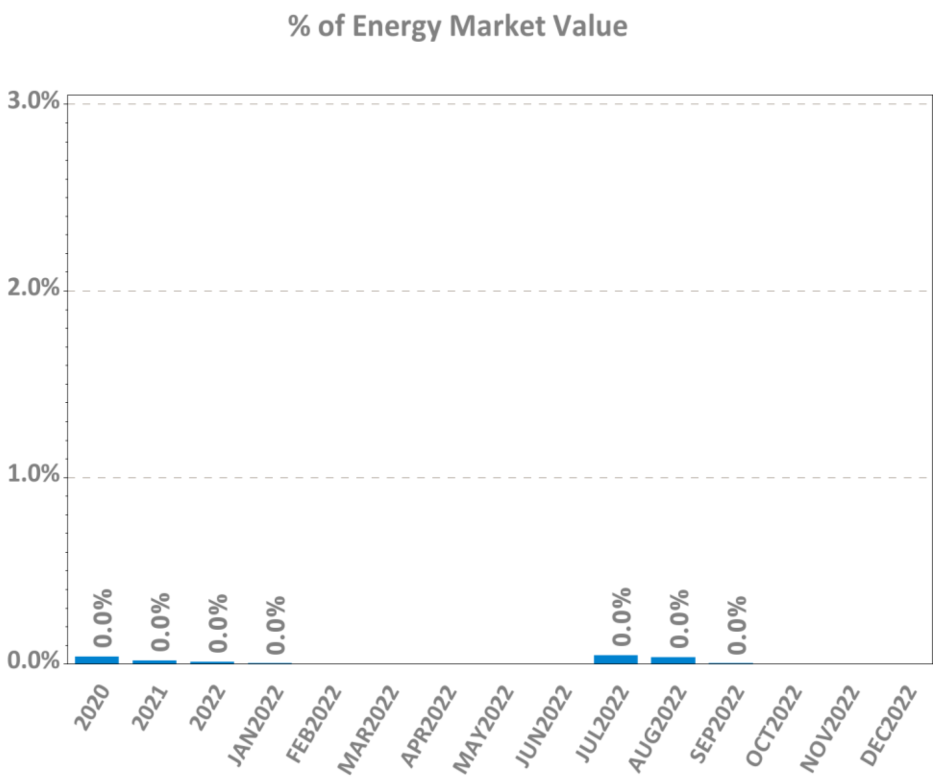
Second Contingency NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

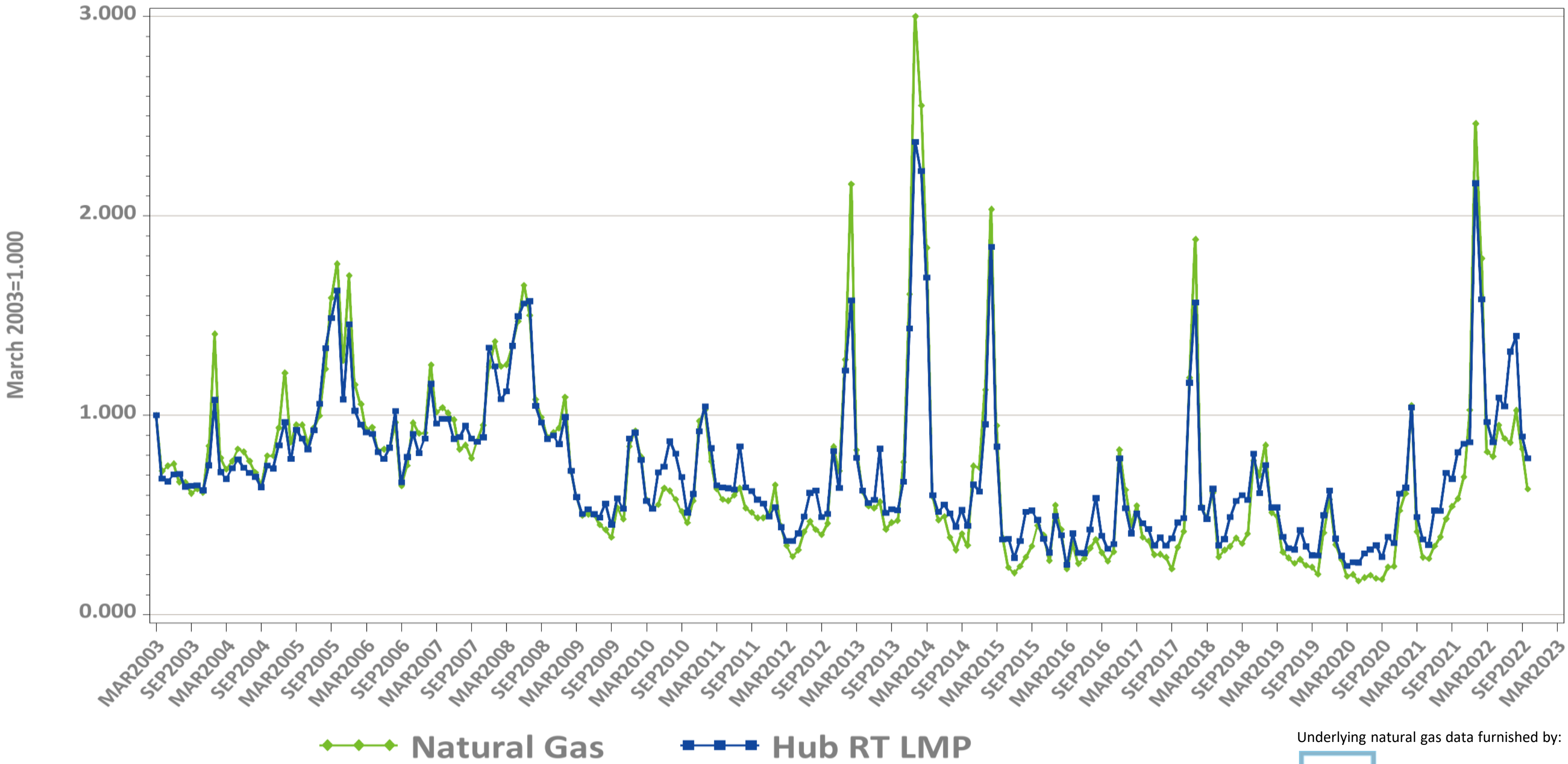
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%
Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.54	$44.60	$45.52	$46.27	$45.05	$45.88	$46.38	$45.91	$45.92
Real-Time	$45.25	$43.97	$44.28	$45.10	$44.15	$44.61	$45.09	$44.85	$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%

October-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$58.55	$56.72	$56.12	$58.26	$57.32	$56.69	$57.84	$57.77	$57.71
Real-Time	$56.49	$55.17	$53.89	$56.35	$55.41	$54.90	$55.98	$55.95	$55.93
RT Delta %	-3.5%	-2.7%	-4.0%	-3.3%	-3.3%	-3.2%	-3.2%	-3.1%	-3.1%
October-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$54.32	$53.17	$53.74	$54.32	$53.71	$53.75	$54.33	$54.12	$54.06
Real-Time	$54.13	$53.00	$53.55	$54.08	$53.15	$53.50	$54.12	$53.87	$53.86
RT Delta %	-0.3%	-0.3%	-0.4%	-0.4%	-1.0%	-0.5%	-0.4%	-0.5%	-0.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-7.2%	-6.3%	-4.2%	-6.8%	-6.3%	-5.2%	-6.1%	-6.3%	-6.3%
Yr over Yr RT	-4.2%	-3.9%	-0.6%	-4.0%	-4.1%	-2.6%	-3.3%	-3.7%	-3.7%

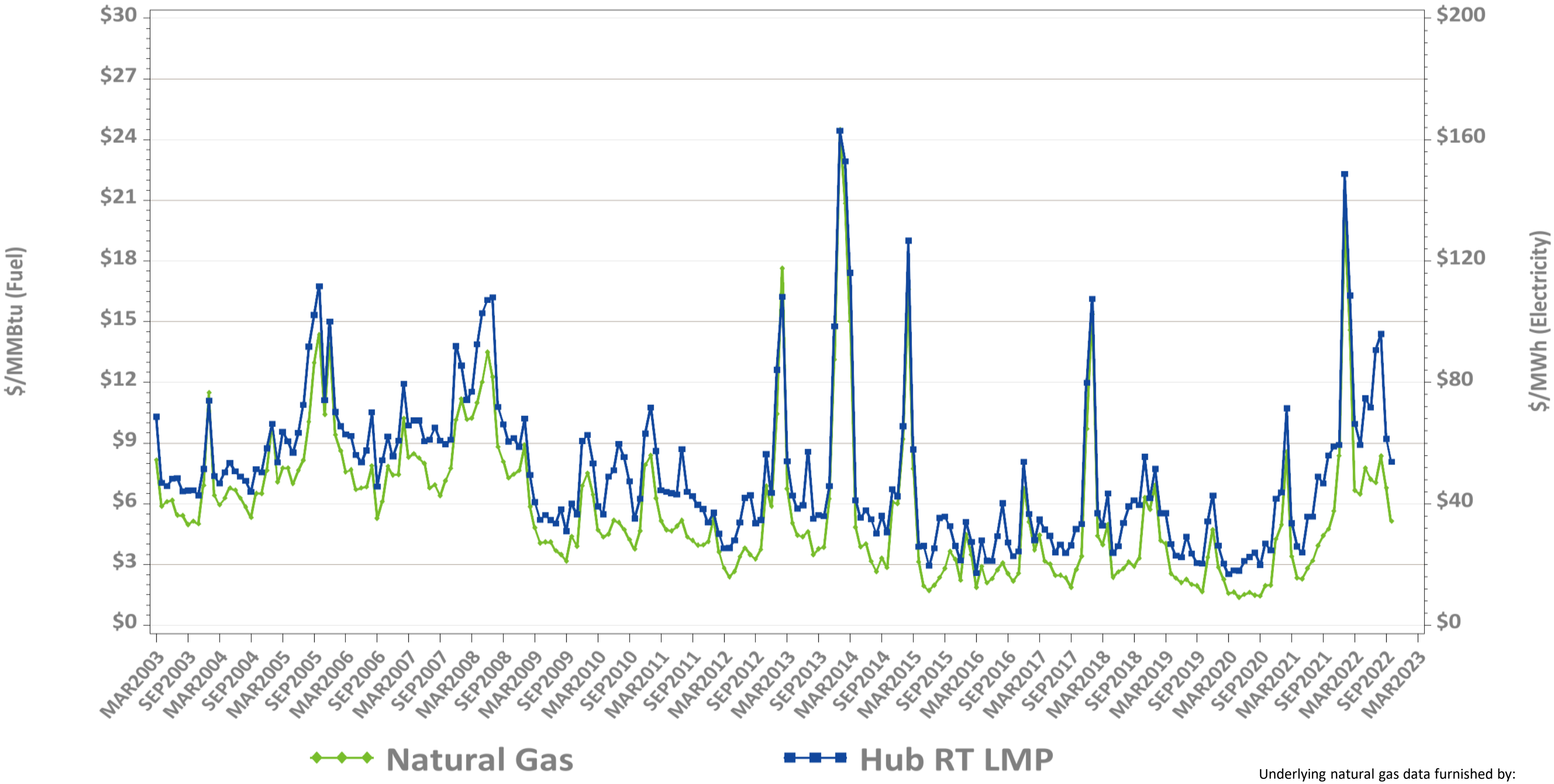
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

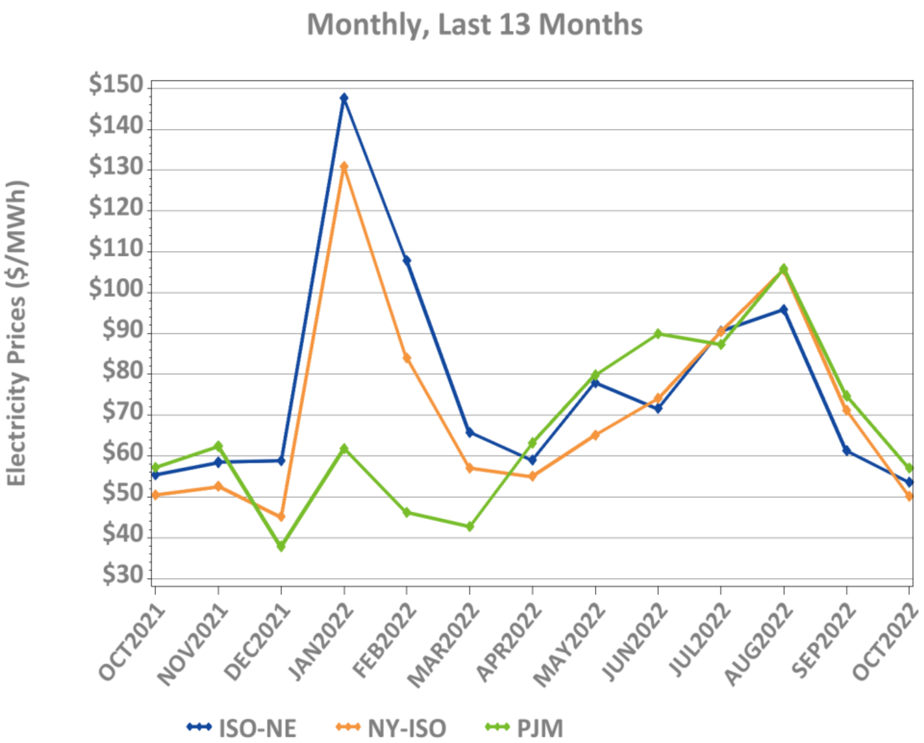
Monthly Average Fuel Price and RT Hub LMP



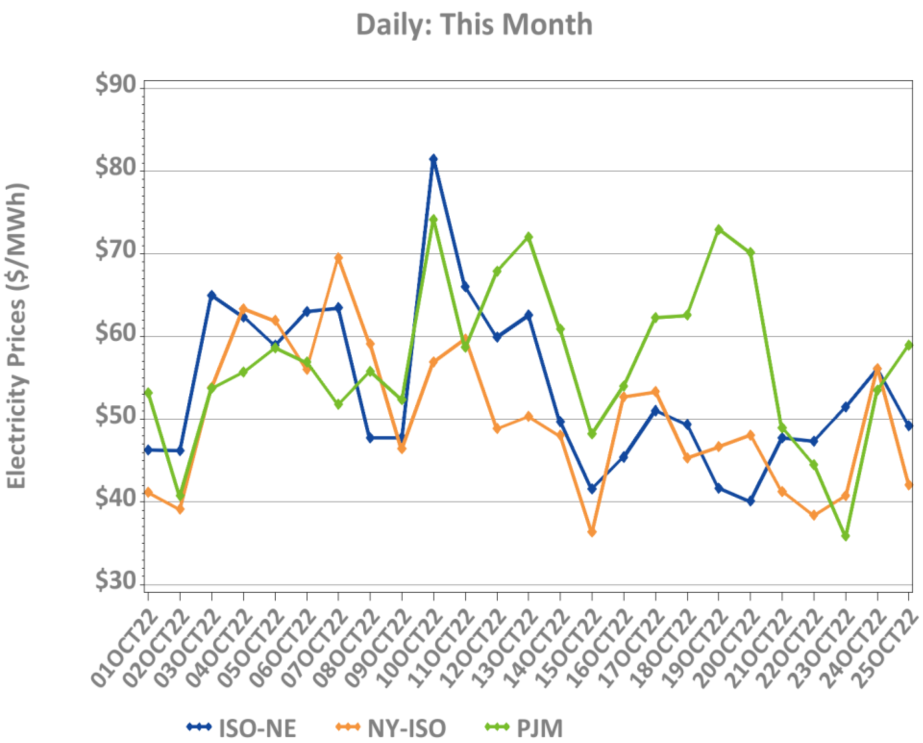
Underlying natural gas data furnished by:

ice Global markets in clear view

New England, NY, and PJM Hourly Average Real Time Prices by Month

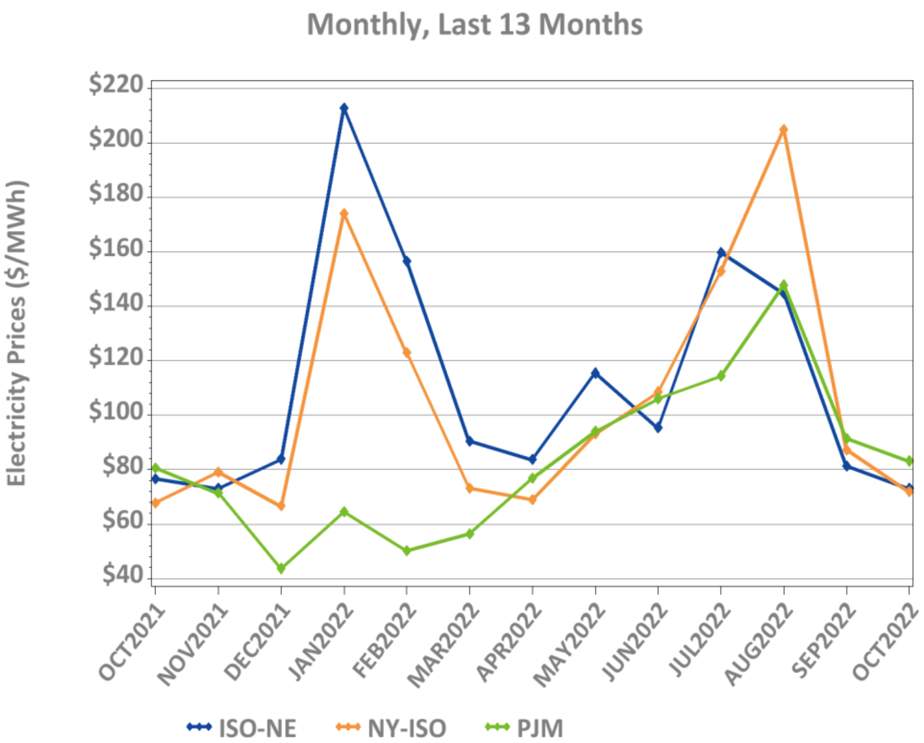


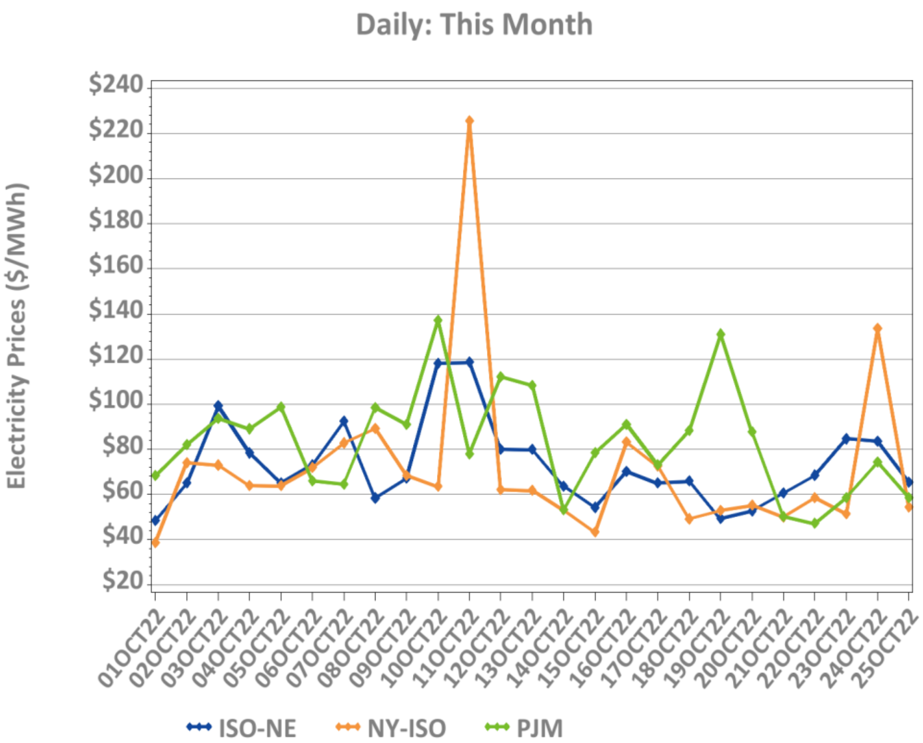
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices





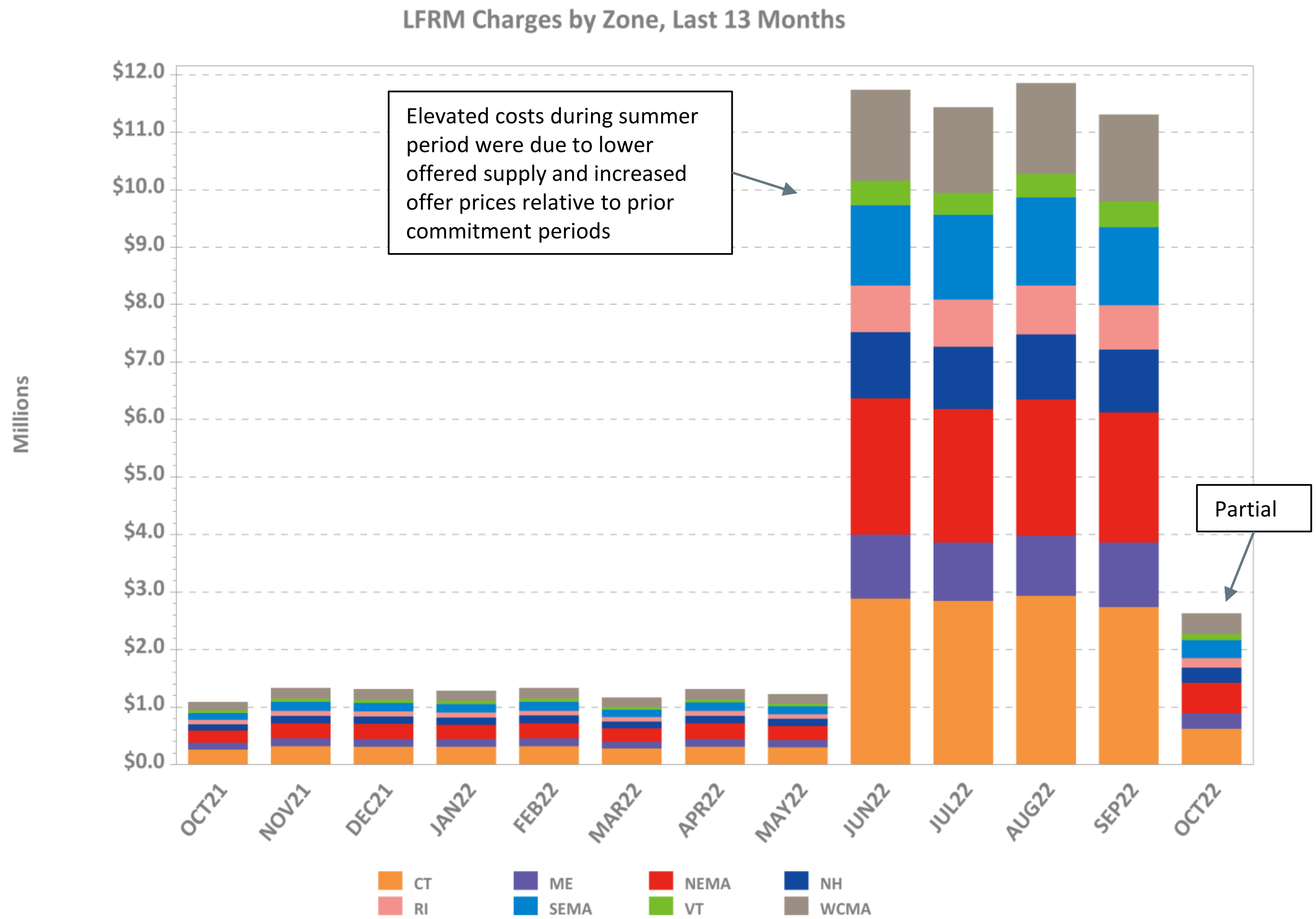
***Forecasted New England daily peak hours reflected**

Reserve Market Results – October 2022

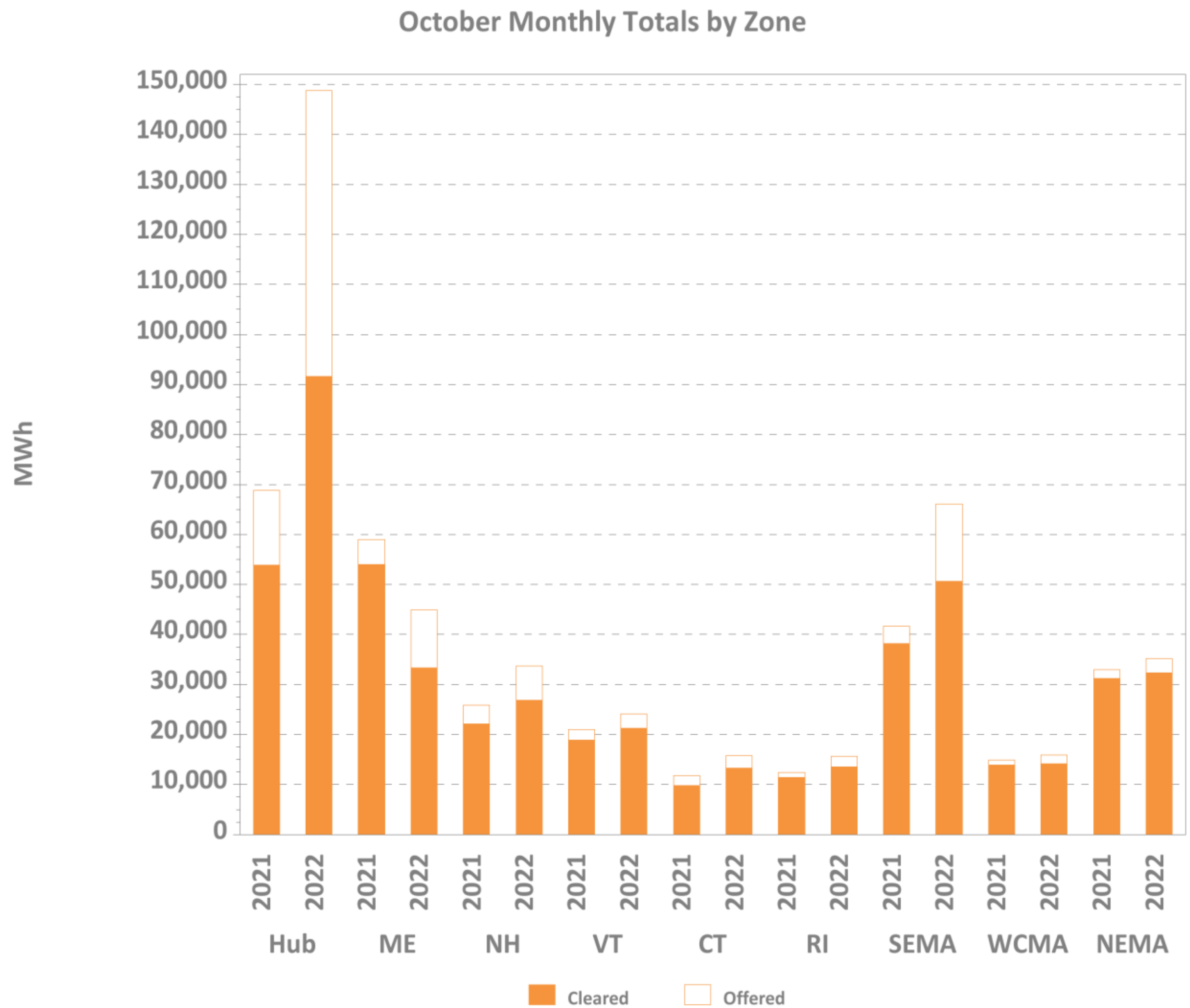
- Maximum potential Forward Reserve Market payments of \$3M were reduced by credit reductions of \$165K, failure-to-reserve penalties of \$257K and failure-to-activate penalties of \$1K, resulting in a net payout of \$2.6M or 86% of maximum
  – Rest of System: \$1.87M/2.1M (89%)
  – Southwest Connecticut: \$0.03M/0.03M (89%)
  – Connecticut: \$0.74M/0.91M (81%)
- \$338K total Real-Time credits were reduced by \$1K in Forward Reserve Energy Obligation Charges for a net of \$337K in Real-Time Reserve payments
  – Rest of System: 210 hours, \$237K
  – Southwest Connecticut: 210 hours, \$45K
  – Connecticut: 210 hours, \$36K
  – NEMA: 210 hours, \$18K

Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

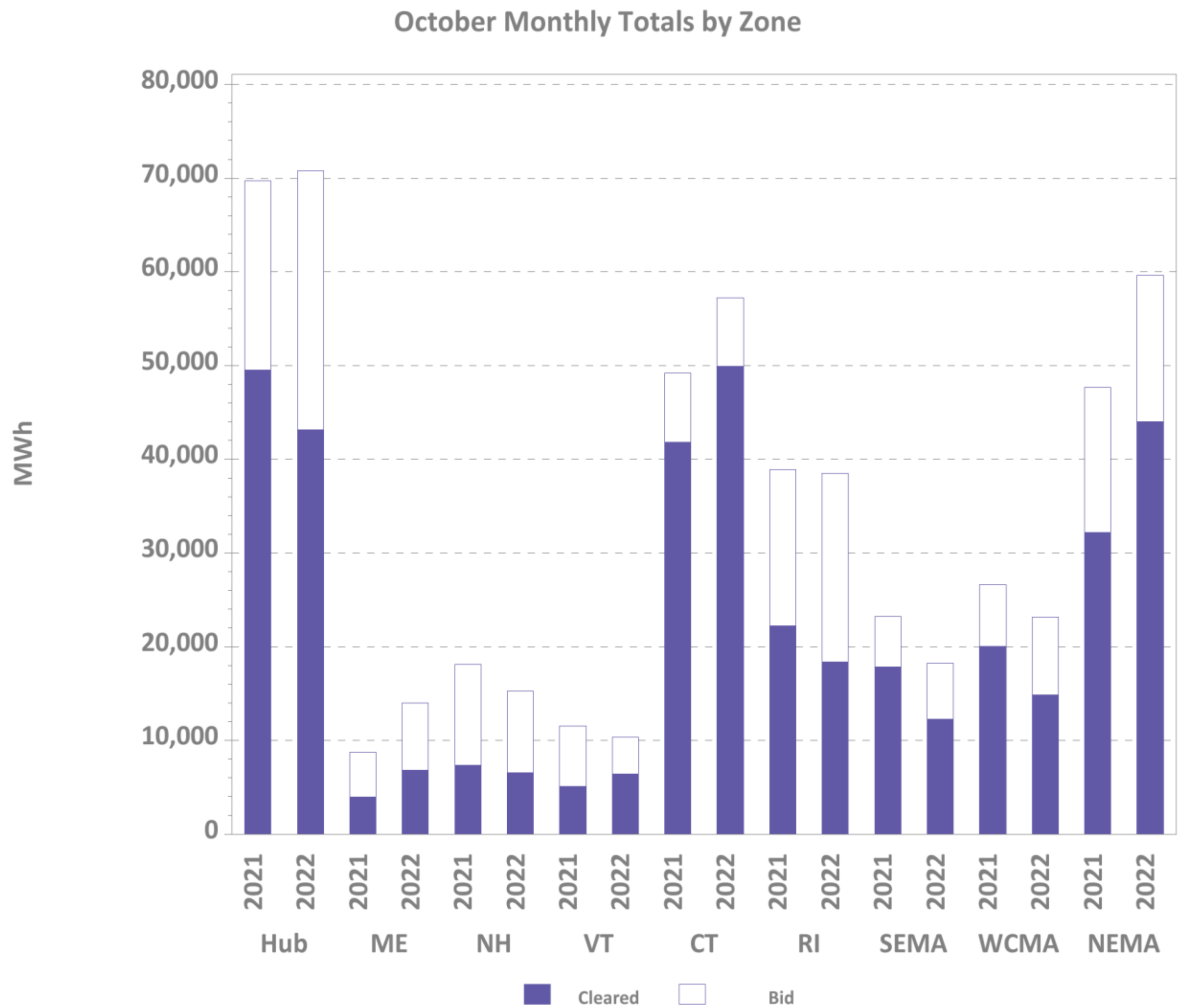
LFRM Charges to Load by Load Zone ($)



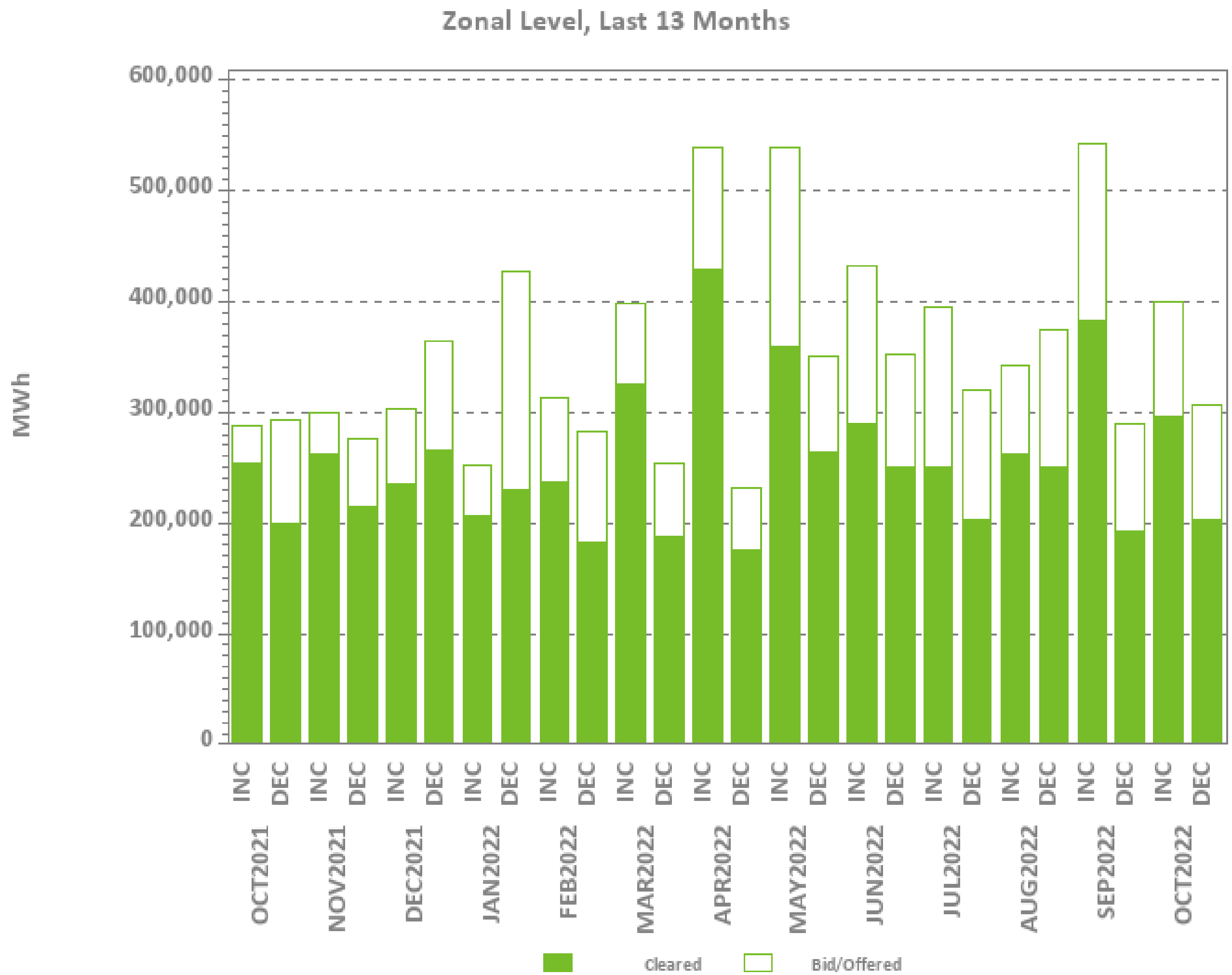
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

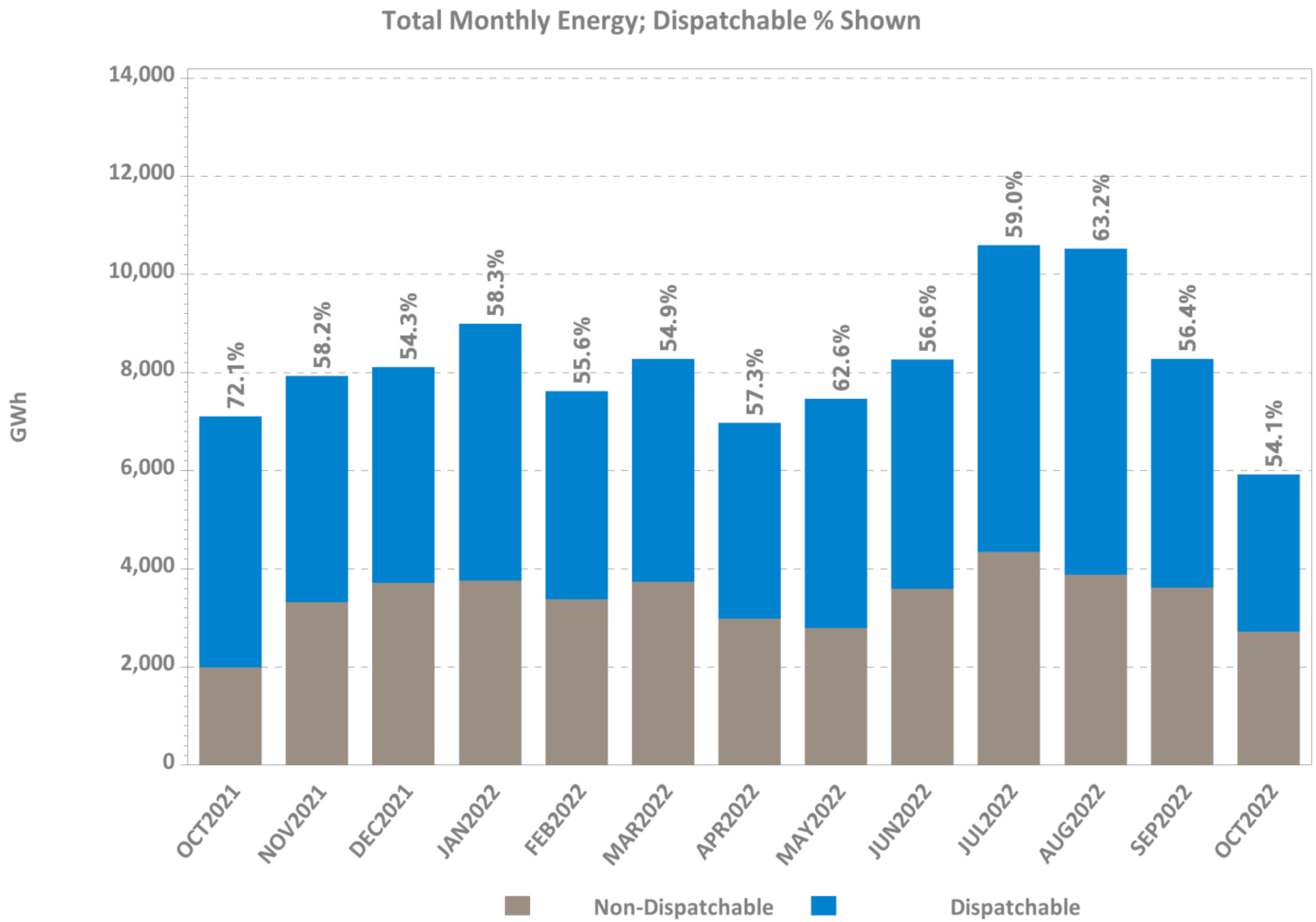


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



*** Dispatchable MWh here are defined to be all generation output that is not self-committed ('must run') by the customer.**

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- November 15 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Trumbull – Norwalk Corridor Partial 115 kV Line Rebuilds (Eversource)
    - 326 345 kV Line – Structure Replacements (National Grid)
    - Middlebury Condition Assessment & Solution (VELCO)
    - Railroad Corridor Transmission Line Asset Condition Assessment Upgrades (UI/Avangrid)
  - Transmission Planning Technical Guide: Draft v8.0 Updates

* Agenda topics are subject to change. Visit https://www.iso-ne.com/committees/planning/planning-advisory for the latest PAC agendas.

Transmission Planning for the Clean Energy Transition (TPCET)

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to transmission planning study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20, 12/16/20, and 1/21/21 PAC meetings outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21
- The final TPCET Pilot Study Report was posted to the PAC website on 1/14/22
- Status updates on ongoing transient stability modeling and performance criteria were discussed at the 4/28/22, 5/18/22, 6/15/22, and 8/24/22 PAC meetings; draft changes to the Transmission Planning Technical Guide reflecting assumption changes are expected to be brought to PAC in Q4 2022

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO is working on solution development and expects to begin initial discussions with the PAC in Q4 2022

Economic Studies

- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Final report was posted on July 29
  - Draft technical appendices are expected to be posted during Q4 2022
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - Initial scope of work was presented at the April PAC meeting; new modeling features and initial benchmark scenario results were presented at the August PAC meeting; and additional benchmark scenario results and market efficiency needs scenario assumptions were presented at the October PAC meeting

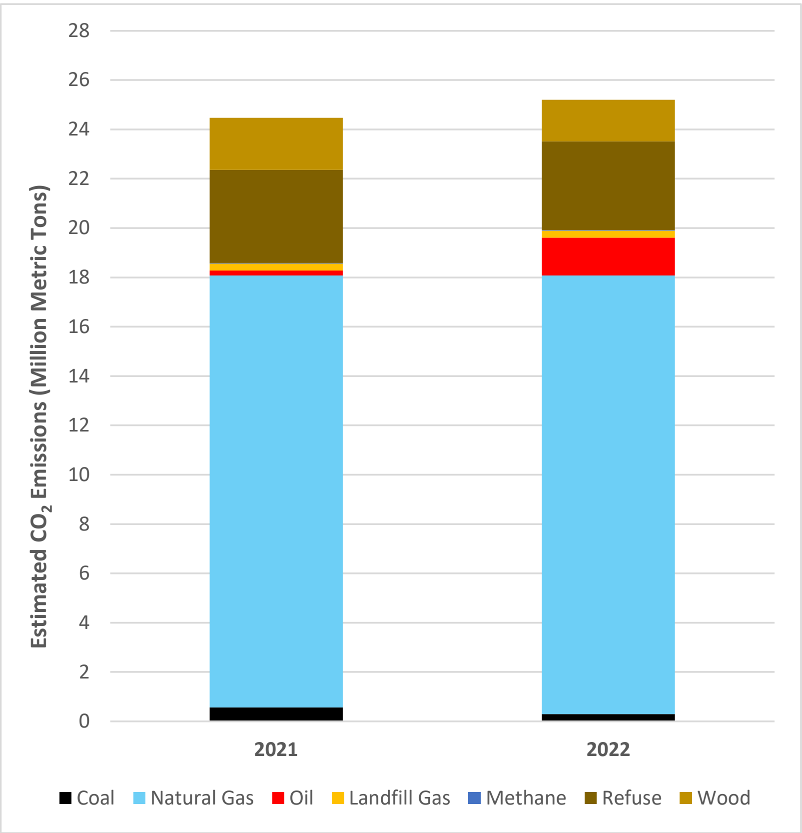
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard, including for a "preferred pathway" if established
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability "gaps" that remain will be identified
  - Scope expected to be shared with stakeholders in Q4 of 2022

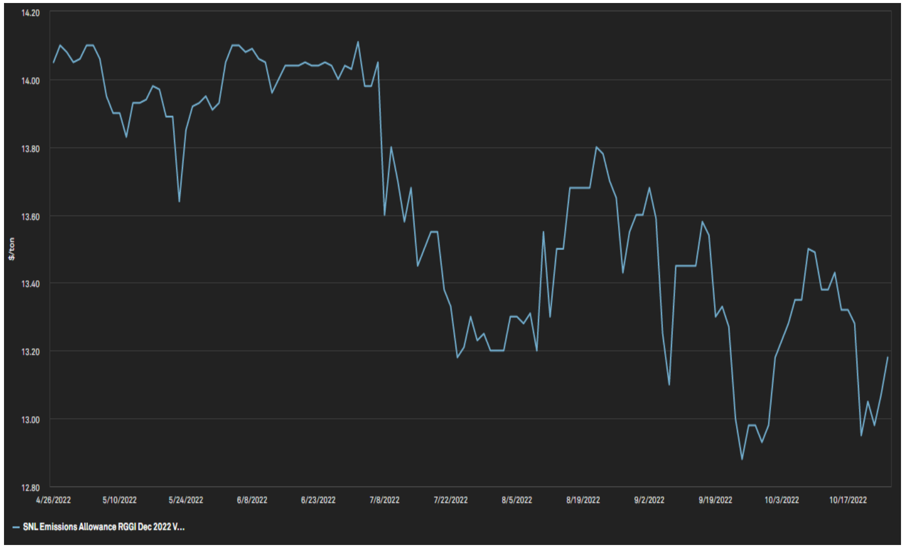
New England Power System Carbon Emissions

CO_2 emissions Up 3% year to year, reflects January oil-fired generation spike

2021 vs. 2022 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



RGGI Allowance Prices Affected by Factors External to New England



- 10/25/22: RGGI allowance spot price - $13.18 per allowance (1 allowance = 1 short ton CO_2)
- 9/7/22 57th RGGI auction cleared at $13.45
  - Slight decrease in auction price from $13.90 in previous (6/1/22) auction

Data as of 10/16/22

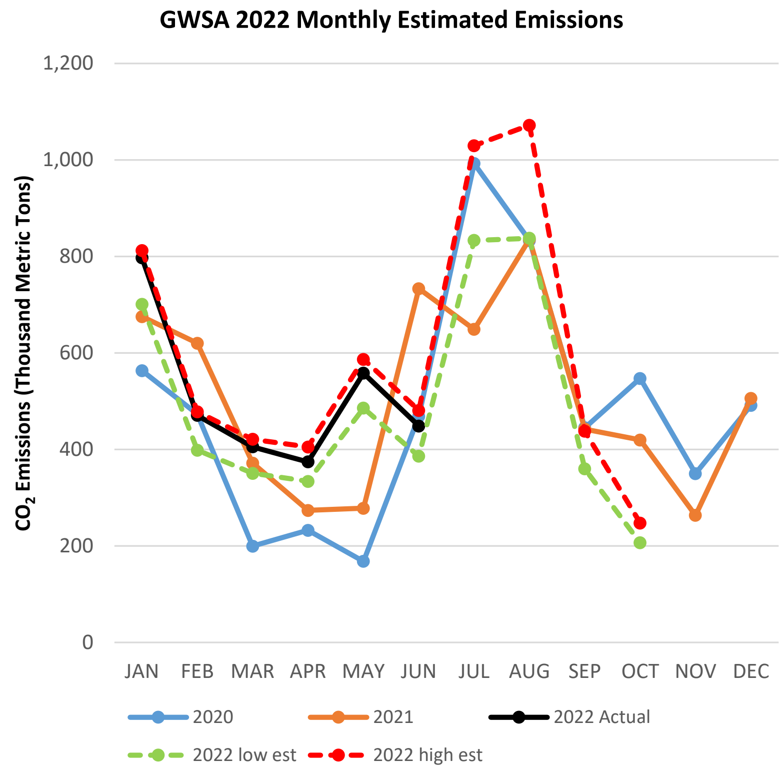
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

2022 Estimated Emissions Under CO_2 Cap

- 10/25/22: 2022 estimated GWSA CO_2 emissions range between 4.9 and 6.0 MMT
  - 61% to 74% of the 8.06 MMT 2022 cap
- 9/14/22 GWSA auction cleared at $14.73; 1.20 million 2022 vintage allowances sold
  - Clearing price was nearly $5 above the previous auction
  - 0.39 million 2023 vintage GWSA allowances were also offered, clearing at $7.51
- 2022 YTD estimated GWSA emissions range between 4% lower and 17% higher than YTD 2021 emissions

2020-2022 Estimated Monthly Emissions (Thousand Metric tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Sources: ISO-NE (estimated emissions); EPA (actual emissions)

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

Note: The listings in this section focus on major transmission line construction and rebuilding.

Greater Boston Projects

Status as of 10/25/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	Dec-23	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 10/25/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 10/25/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Mar-21	4

Greater Boston Projects, cont.

Status as of 10/25/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-23	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 10/25/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1520	Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
1643	Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
1341, 1645	Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
1646	Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
1647	Install a 115 kV breaker in series with the 5 breaker at Framingham	Mar-17	4
1554	Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	4
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	4
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Jun-23	3
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Jun-23	3
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	1

SEMA/RI Reliability Projects, cont.

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-25	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal

** Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	May 22	4
1724	Replace the Kent County 345/115 kV transformer	Mar-22	4
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	3
1851	Upgrade Card 115 kV to BPS standards	Mar-23	3
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	3
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	3

Eastern CT Reliability Projects, cont.

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	3
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	3
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	3
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-22	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	3
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	Nov-21	4
1862	Install a +55/-29 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-23	3
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Mar-22	4
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington)	Dec-23	3
1904	Convert 69 kV equipment at Buddington to 115 kV to facilitate the conversion of the 400-2 line to 115 kV	Dec-23	3

Boston Area Optimized Solution Projects

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Dec-21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Apr-22	4
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	3

New Hampshire Solution Projects

Status as of 10/25/2022

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Dec-23	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Dec-23	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	2

Upper Maine Solution Projects

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line	Dec-24	2
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Jun-24	2

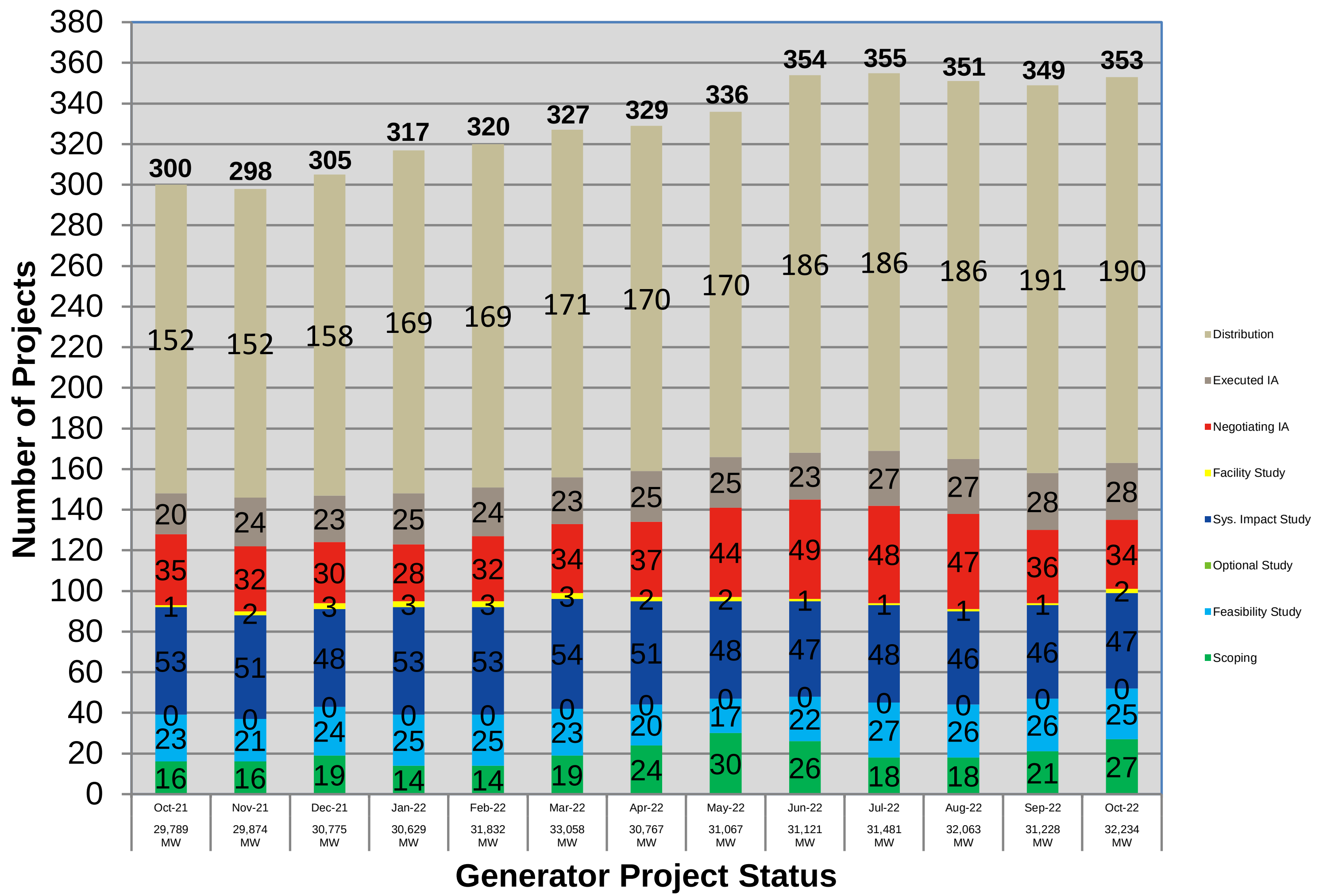
Upper Maine Solution Projects, cont.

Status as of 10/25/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	2
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	2
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	2

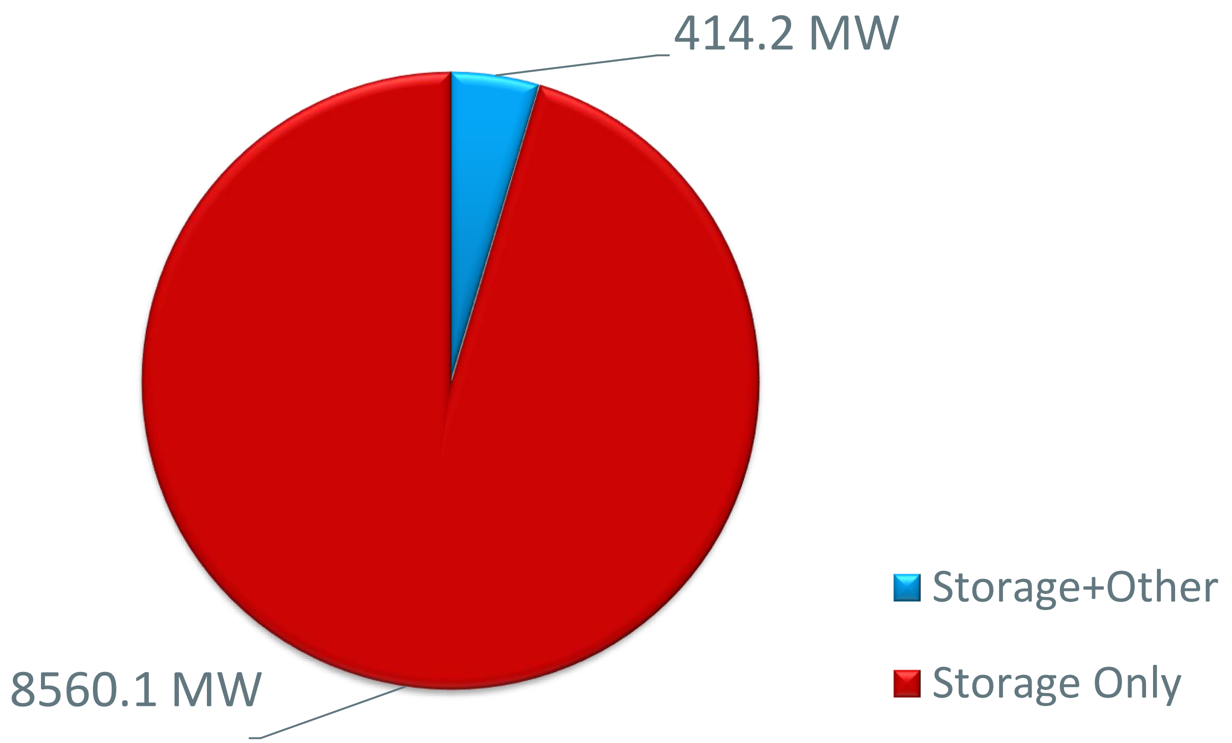
Status of Tariff Studies as of October 25, 2022



Note: October 2022 is based on partial data.
11 ETUs in Scoping, 2 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 2 Negotiating IA, and 3 with Executed IA
Transmission Service Requests needing study: 4 in Scoping and 1 in SIS
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of October 25, 2022)

Storage Projects are proposed as stand-alone storage or as co-located with wind or solar projects



OPERABLE CAPACITY ANALYSIS

Fall 2022 Analysis

Fall 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov. - 2022[2] CSO (MW)	Nov. - 2022[2] SCC (MW)
Operable Capacity MW [1]	28,062	31,976
Active Demand Capacity Resource (+) [5]	505	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,046	1,046
Non Commercial Capacity (+)	12	12
Non Gas-fired Planned Outage MW (-)	2,784	3,550
Gas Generator Outages MW (-)	1,753	2,499
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,488	23,790
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,143	17,143
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,488	19,448
Operable Capacity Margin	2,040	4,342

[1] Operable Capacity is based on data as of **October 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 25, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 12, 2022.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Fall 2022 Operable Capacity Analysis

90/10 Load Forecast	Nov. - 2022[2] CSO (MW)	Nov. - 2022[2] SCC (MW)
Operable Capacity MW [1]	28,062	31,976
Active Demand Capacity Resource (+) [5]	505	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,046	1,046
Non Commercial Capacity (+)	12	12
Non Gas-fired Planned Outage MW (-)	2,784	3,550
Gas Generator Outages MW (-)	1,753	2,499
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,488	23,790
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,744	17,744
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,049	20,049
Operable Capacity Margin	1,439	3,741

[1]Operable Capacity is based on data as of **October 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 25, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 12, 2022.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Fall 2022 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 25, 2022 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in November .

Report created: 10/25/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/12/2022	**28062**	**505**	**1046**	**12**	**2784**	**1753**	**3600**	**0**	**21488**	**17143**	**2305**	**19448**	**2040**	**Y**	**Fall 2022**
11/19/2022	28062	505	1046	12	1974	635	3600	735	22681	17875	2305	20180	2501	N	Fall 2022

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Fall 2022 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 25, 2022 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in November.

Report created: 10/25/2022

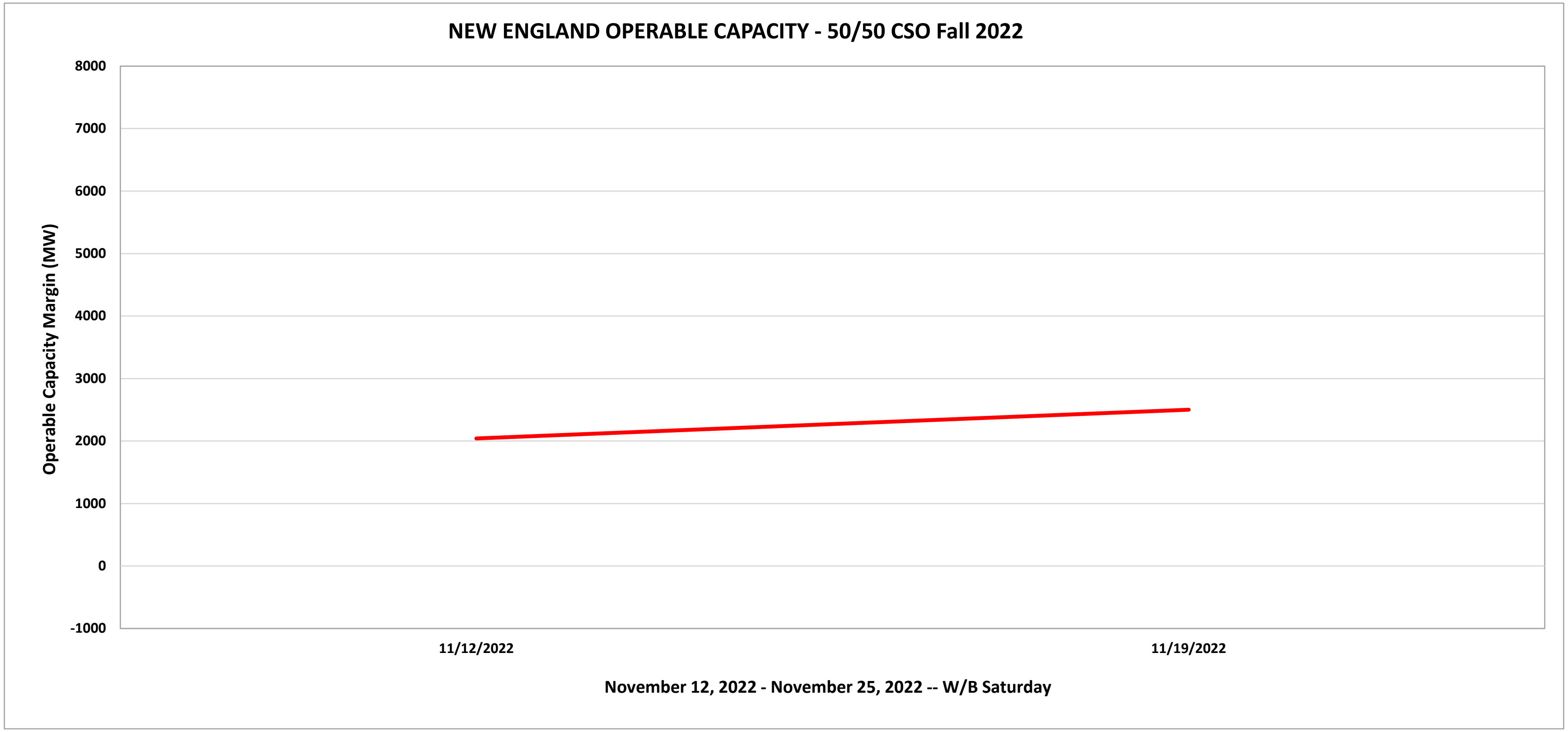
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/12/2022	**28062**	**505**	**1046**	**12**	**2784**	**1753**	**3600**	**0**	**21488**	**17744**	**2305**	**20049**	**1439**	**N**	**Fall 2022**
11/19/2022	28062	505	1046	12	1974	635	3600	1670	21746	18498	2305	20803	943	Y	Fall 2022

Column Definitions

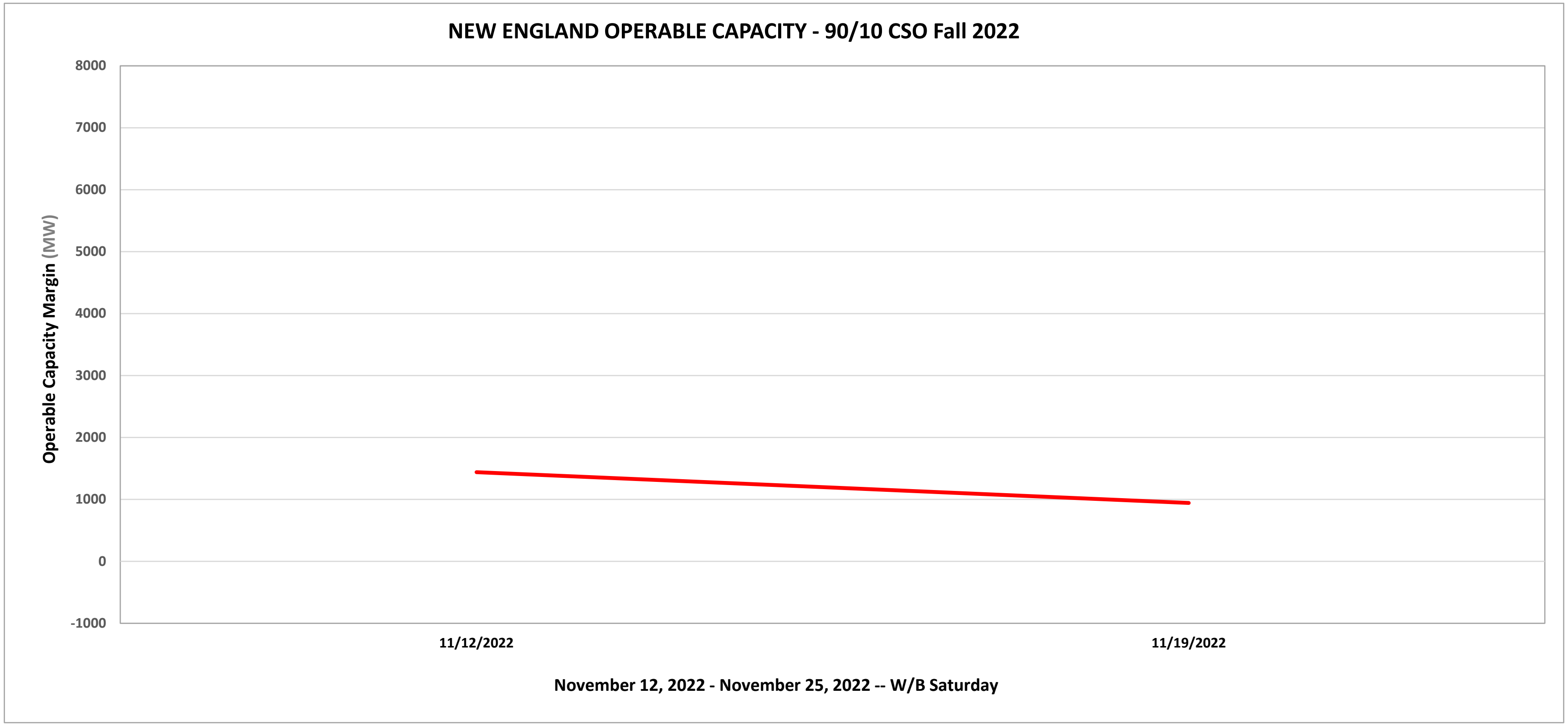
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Fall 2022 Operable Capacity Analysis
50/50 Forecast (Reference)



Fall 2022 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Winter 2022/23 Analysis

Winter 2022/23 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,251	31,976
Active Demand Capacity Resource (+) [5]	559	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	60	60
Non Gas-fired Planned Outage MW (-)	148	267
Gas Generator Outages MW (-)	7	151
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,728	4,136
Net Capacity (NET OPCAP SUPPLY MW)	23,257	26,157
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,009	20,009
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,314	22,314
Operable Capacity Margin	943	3,843

[1] Operable Capacity is based on data as of **October 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 25, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2022/23 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,251	31,976
Active Demand Capacity Resource (+) [5]	559	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	60	60
Non Gas-fired Planned Outage MW (-)	148	267
Gas Generator Outages MW (-)	7	151
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,539	5,066
Net Capacity (NET OPCAP SUPPLY MW)	22,446	25,227
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,695	20,695
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,000	23,000
Operable Capacity Margin	-554	2,227

[1]Operable Capacity is based on data as of **October 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **October 25, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2022/23 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 25, 2022 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week from November through March.

Report created: 10/25/2022

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/26/2022	28062	505	1046	12	569	607	3600	1351	23498	18588	2305	20893	2605	N	Winter 2022/2023
12/3/2022	28257	559	1070	60	481	571	3200	1811	23883	18919	2305	21224	2659	N	Winter 2022/2023
12/10/2022	28257	559	1070	60	489	206	3200	2375	23676	19205	2305	21510	2166	N	Winter 2022/2023
12/17/2022	28257	559	1070	60	472	42	3200	2752	23480	19216	2305	21521	1959	N	Winter 2022/2023
12/24/2022	28257	559	1070	60	98	0	3200	3141	23507	19278	2305	21583	1924	N	Winter 2022/2023
12/31/2022	28251	559	1070	60	145	7	2800	3733	23255	19549	2305	21854	1401	N	Winter 2022/2023
1/7/2023	**28251**	**559**	**1070**	**60**	**148**	**7**	**2800**	**3728**	**23257**	**20009**	**2305**	**22314**	**943**	**Y**	**Winter 2022/2023**
1/14/2023	28251	559	1070	60	89	7	2800	3583	23461	20009	2305	22314	1147	N	Winter 2022/2023
1/21/2023	28251	559	1070	60	89	43	2800	3098	23910	20009	2305	22314	1596	N	Winter 2022/2023
1/28/2023	28251	559	1070	60	62	43	3100	2799	23936	19789	2305	22094	1842	N	Winter 2022/2023
2/4/2023	28251	559	1070	60	62	13	3100	2530	24235	19524	2305	21829	2406	N	Winter 2022/2023
2/11/2023	28251	559	1070	60	84	13	3100	2231	24512	19496	2305	21801	2711	N	Winter 2022/2023
2/18/2023	28251	559	1070	60	15	13	3100	1782	25030	19236	2305	21541	3489	N	Winter 2022/2023
2/25/2023	28251	559	1070	60	190	13	3100	1483	25154	18258	2305	20563	4591	N	Winter 2022/2023
3/4/2023	28251	559	1070	60	199	798	2200	399	26344	17912	2305	20217	6127	N	Winter 2022/2023
3/11/2023	28251	559	1070	60	177	305	2200	293	26965	17718	2305	20023	6942	N	Winter 2022/2023
3/18/2023	28251	559	1070	60	867	1194	2200	0	25679	17357	2305	19662	6017	N	Winter 2022/2023
3/25/2023	28251	559	1070	60	826	2164	2200	0	24750	16797	2305	19102	5648	N	Winter 2022/2023

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2022/23 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 25, 2022 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week from November through March.

Report created: 10/25/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/26/2022	28062	505	1046	12	569	607	3600	2265	22584	19234	2305	21539	1045	N	Winter 2022/2023
12/3/2022	28257	559	1070	60	481	571	3200	2799	22895	19571	2305	21876	1019	N	Winter 2022/2023
12/10/2022	28257	559	1070	60	489	206	3200	3362	22689	19866	2305	22171	518	N	Winter 2022/2023
12/17/2022	28257	559	1070	60	472	42	3200	3871	22361	19877	2305	22182	179	N	Winter 2022/2023
12/24/2022	28257	559	1070	60	98	0	3200	4287	22361	19941	2305	22246	115	N	Winter 2022/2023
12/31/2022	28251	559	1070	60	145	7	2800	4408	22580	20220	2305	22525	55	N	Winter 2022/2023
1/7/2023	**28251**	**559**	**1070**	**60**	**148**	**7**	**2800**	**4539**	**22446**	**20695**	**2305**	**23000**	**-554**	**Y**	**Winter 2022/2023**
1/14/2023	28251	559	1070	60	89	7	2800	4331	22713	20695	2305	23000	-287	N	Winter 2022/2023
1/21/2023	28251	559	1070	60	89	43	2800	3996	23012	20695	2305	23000	12	N	Winter 2022/2023
1/28/2023	28251	559	1070	60	62	43	3100	3996	22739	20468	2305	22773	-34	N	Winter 2022/2023
2/4/2023	28251	559	1070	60	62	13	3100	3577	23188	20195	2305	22500	688	N	Winter 2022/2023
2/11/2023	28251	559	1070	60	84	13	3100	3278	23465	20166	2305	22471	994	N	Winter 2022/2023
2/18/2023	28251	559	1070	60	15	13	3100	2680	24132	19898	2305	22203	1929	N	Winter 2022/2023
2/25/2023	28251	559	1070	60	190	13	3100	2231	24406	18889	2305	21194	3212	N	Winter 2022/2023
3/4/2023	28251	559	1070	60	199	798	2200	1296	25447	18533	2305	20838	4609	N	Winter 2022/2023
3/11/2023	28251	559	1070	60	177	305	2200	1191	26067	18333	2305	20638	5429	N	Winter 2022/2023
3/18/2023	28251	559	1070	60	867	1194	2200	0	25679	17960	2305	20265	5414	N	Winter 2022/2023
3/25/2023	28251	559	1070	60	826	2164	2200	0	24750	17383	2305	19688	5062	N	Winter 2022/2023

Column Definitions

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2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
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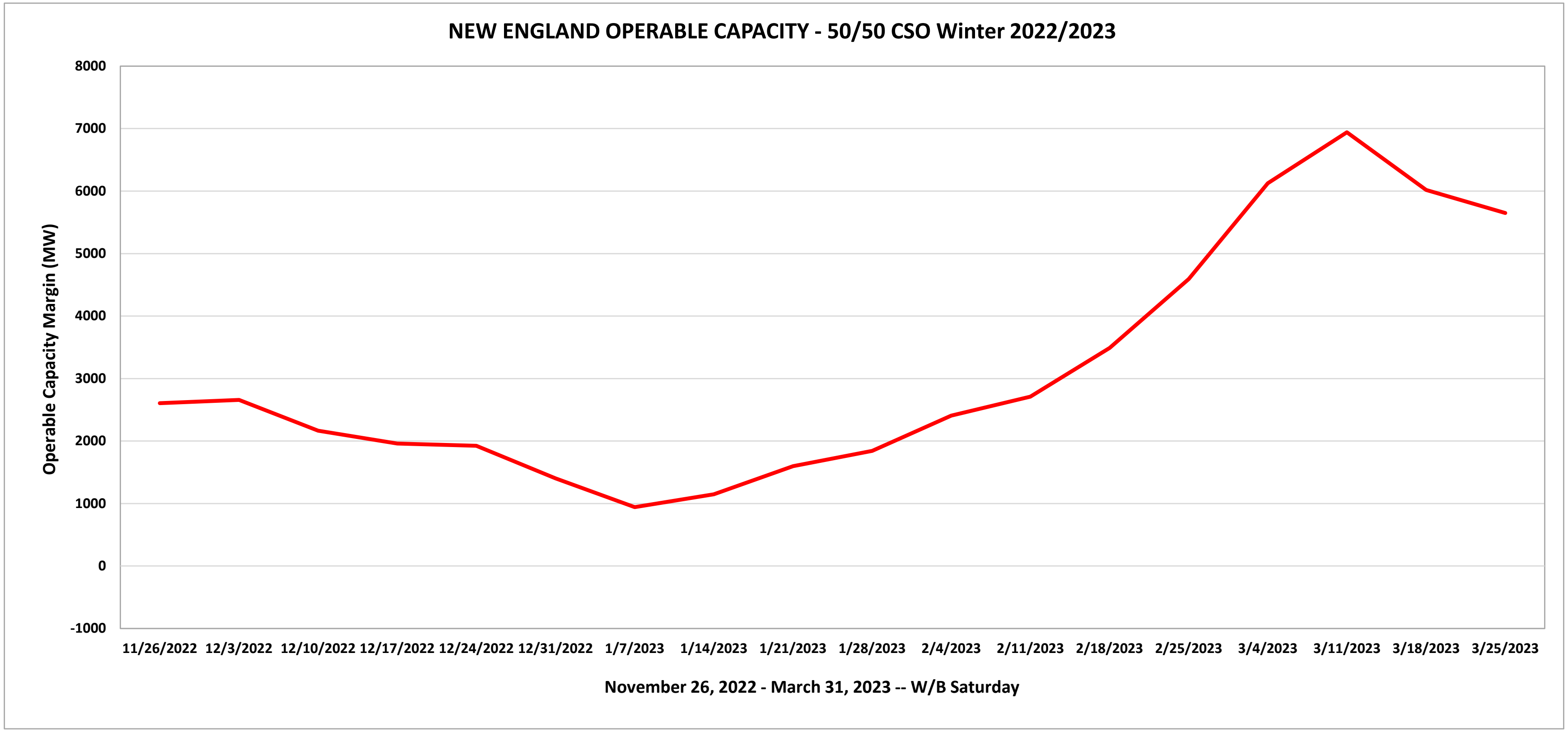
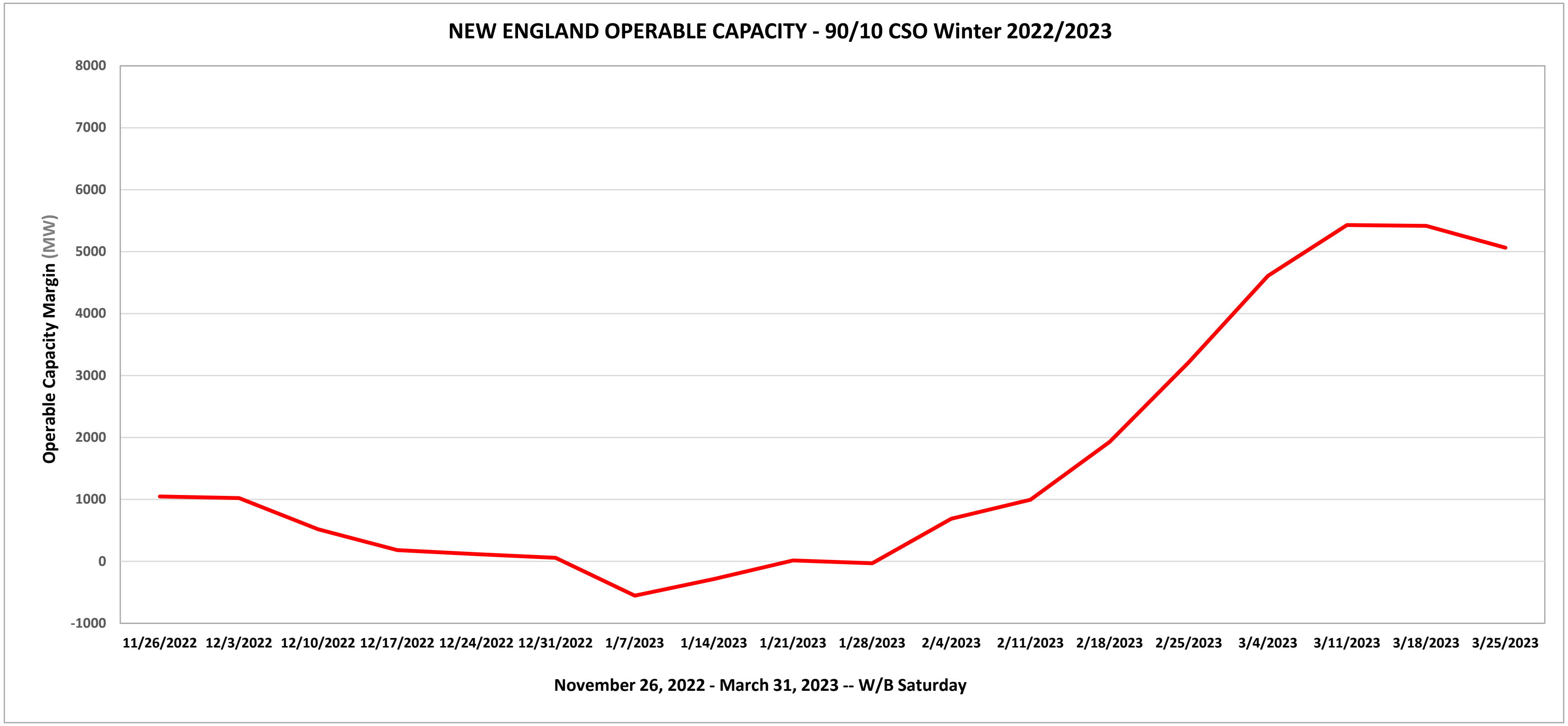
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Winter 2022/23 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2022/23 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	125 [3]

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 [3]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**2,520**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

NOVEMBER 2, 2022 | PROVIDENCE, RI

New England Winter Outlook 2022/2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER

Introduction

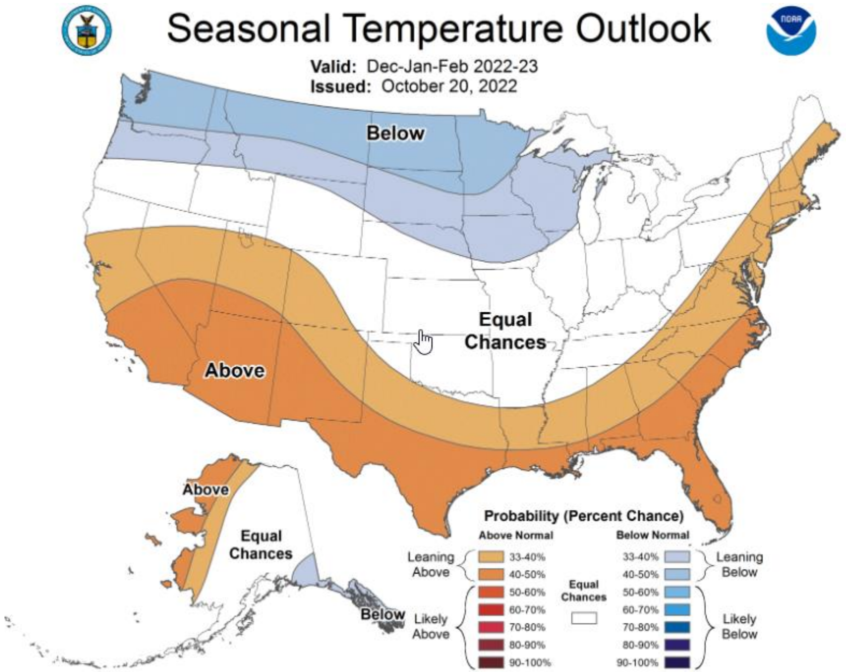
- This presentation is intended to accomplish the following:
  - Offer a current outlook of the 2022/2023 winter
  - Provide the results of a few modeled scenarios for the 2022/2023 winter
  - Present next steps

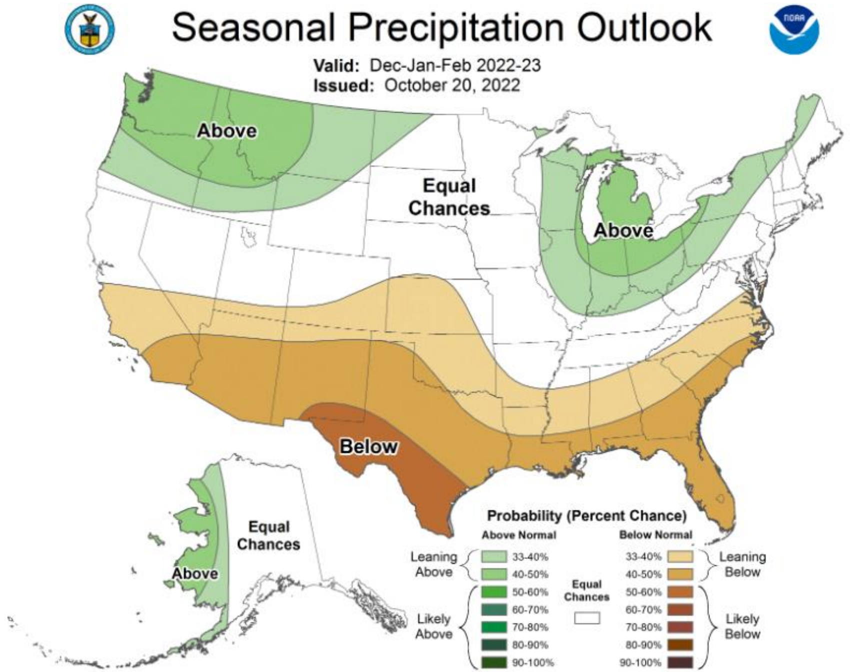
WINTER OUTLOOK 2022-2023

Highlights

- Winter Outlook
  - The seasonal temperature outlook for the winter months of December-January-February indicates a 33-40% probability of above normal temperatures for southern New England and equal chances of above average or below average temperatures for the rest of New England
  - A 33-40% probability of above normal precipitation is forecasted for extreme northern New England while equal chances for above average or below average precipitation is forecasted for the rest of New England
  - Capacity analysis for the 50/50 and the 90/10 load forecasts indicates a surplus even after accounting for generation at risk due to gas supply
    - Capacity analysis is generally limited in that it assumes all resources that are not de-rated can supply energy when called

Winter Temperature & Precipitation Probability





Winter Expectations 2022/23

- Winter Demand Forecast
  - 50/50 winter peak demand forecast of 20,009 MW, which is 299 MW (1.5%) higher than the 2021/22 forecast
  - 90/10 winter peak demand forecast of 20,695 MW, which is 346 MW (1.7%) higher than the 2021/22 forecast
- Scheduled Generation and Transmission Outages
  - All generation and transmission outages continue to be coordinated to minimize adverse transmission or capacity conditions
  - No significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Transfer capability on the New York Northern AC ties will be increased from 1,400 to 1,600 MW for the winter period (*pending final verification from NYISO*)

Winter Expectations 2022/23, cont.

LNG Replenishment

- Over the past ten winters (Dec-Feb), the region has averaged ~31.7 Bcf of LNG usage; the highest usage was ~42.9 Bcf in 2012/13, lowest usage was ~20.0 Bcf in 2021/22

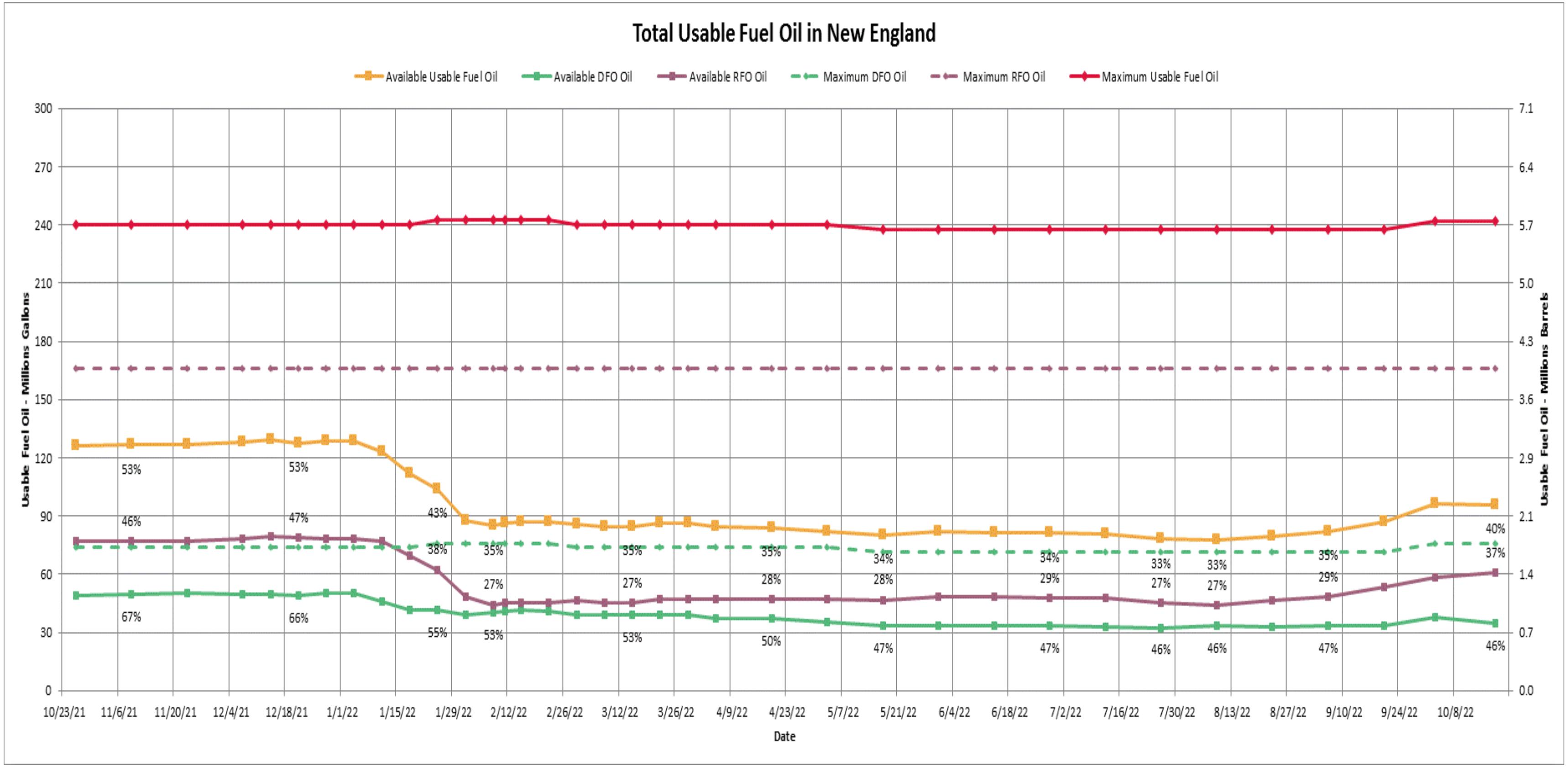
- Winter 2022/23
  - Europe met its intended LNG fuel storage target ahead of winter
  - European natural gas prices continue to remain higher than in New England
  - In early October, European prices for January delivery were ~$60/MMBtu
    - Since then, the prices have trended down
  - Cost-of-Service contract with Mystic provides greater certainty of LNG availability this winter
  - ISO's current expectation is that ~31 Bcf will be available

Winter Expectations 2022/23, cont.

Fuel Oil Replenishment

- Due in large part to declining forward prices for fuel-oil, many stations have waited until fall to procure and finalize replenishment plans
- Based on recent replenishment activities and discussions with resource owners, ISO anticipates additional replenishment prior to winter
  - Additional fuel-oil replenishment is expected to increase the region's aggregate fuel-oil inventory from ~92M gallons (~39% of max) to ~120M gallons (~50% of max) prior to winter
- Discussions with resource owners have identified some level of concern with regard to the Distillate Fuel Oil (DFO) supply chain
- No concerns have been noted with regard to the Residual Fuel Oil (RFO) supply chain and RFO stations have robust replenishment plans in place
- The potential for emissions limitations at some dual-fuel units will have to be monitored closely in the event of significant oil burn

Total Usable Fuel Oil in New England



Winter Expectations 2022/23, cont.

- Natural Gas Deliverability
  - Continue to monitor natural gas deliverability throughout the winter
  - Approximately 4,100 – 5,100 MW[1] may be at risk due to constrained natural gas pipelines
- Winter Capacity Outlook
  - Projecting the lowest 50/50 operable capacity margin of ~3,900 MW and lowest 90/10 operable capacity margin of ~2,300 MW for the week beginning January 7, 2023[1]
  - Extended periods of cold weather may rapidly deplete stored fuel inventories and capacity outlook will be adjusted accordingly

[1]-Based on resource Winter Seasonal Claimed Capabilities

Winter Preparations 2022/23

- Energy Shortfall Exercise
  - Hosted a region-wide energy shortfall tabletop exercise on October 12, 2022
- Winter Readiness Seminar
  - Will host a Generator Winter Readiness Seminar with Market Participants on November 14, 2022
- Winter Generator Readiness Survey
  - Will distribute a Winter Generator Readiness Survey to all generating resources in the region by November 1, 2022 with responses due by December 1, 2022
- Completed the annual Natural Gas Critical Infrastructure Survey process to ensure critical infrastructure is not part of automatic or manual load shed schemes
- Generator Fuel and Emissions Surveys will be of weekly or daily frequency during the winter season
- 21-day energy assessment will be performed weekly with results published to the ISO public website
  - The assessment will performed daily if necessary

21-Day Energy Assessment & Alert Thresholds

- In order to identify and communicate potential reliability issues, the ISO performs a weekly 21-day energy assessment and posts the results on the ISO public website
  - The energy assessment is based on latest responses to generator surveys, as well as planned outages, load & weather forecasts, and anticipated LNG injections
- ISO's OP-21 describes the thresholds for declaration of an Energy Alert or Energy Emergency based on the 21-day energy assessment results
  - ISO will declare an **Energy Alert** if the energy assessment indicates either the use of OP-4 Actions 6-11 (voltage reduction and conservation appeals) or OP-7 Action in at least **1 hour on 1 or more consecutive days in days 6 through 21**
  - ISO will declare an **Energy Emergency** if the energy assessment indicates the use of OP-4 Actions 6-11 (voltage reduction and conservation appeals) or OP-7 Action in at least **1 hour on 1 or more consecutive days in days 1 through 5**

Requests for Government and Cross-Sector Assistance

- ISO and resource owners may request New England State and Federal Government Assistance
- In order to minimize or alleviate need for extreme operational measures, the ISO and/or resource owners may request:
  - Jones Act waivers
  - Waivers of emissions and/or air permitting limitations (if alternate fuel is available) under 202c of the Federal Power Act or state statutes
  - Waivers of Department of Transportation restrictions on drivers for fuel deliveries
  - Activation of military staff and equipment to move fuel supplies
  - Multi-day emergency conservation measures under OP-4 and request states to assist with cross-sector energy appeals for conservation of liquid fuels and natural gas

WINTER 2022/23 SCENARIOS

Introduction – 2022/23 Winter Scenarios

- The ISO routinely performs scenario assessments to prepare for the winter
- The following slides illustrate the qualitative and quantitative aspects of three scenarios
  - Scenario 1 assumes a mild winter as represented by the 2021/22 winter
  - Scenario 2 assumes a mild winter, but with a 13 day cold spell, as represented by the 2017/18 winter
  - Scenario 3 assumes a 'colder than normal' winter as represented by the 2013/14 winter
- Unless otherwise noted, scenarios assume the following:
  - Expected starting fuel oil inventories; fuel oil replenishment assumptions range from minimal to moderate
  - No LNG injections assumed beyond current projections
  - No significant or long-duration generator or transmission contingencies
  - System demand reduced to account for distributed PV resources
- The ISO's 21-day energy forecast tool will signal any potential energy emergencies, thereby alerting the market to procure necessary fuel replenishments, both to meet their obligation and to protect against scarcity

Scenario 1 – Mild Winter, Similar to 2021/22

- Winter 2021/22 overview:
  - Milder than normal winter with very few days staying below freezing
  - Average temperature departure from normal was +1.0°F (i.e., warmer than normal)
  - Winter peak load of 19,623 MW
  - Total energy modeled is 30,591 GWh
  - During some periods, fuel oil was more economic than natural gas for power generation
  - Approximately 80M gallons of fuel oil was burned
- ISO anticipates that there would be sufficient capacity and energy available to meet the expected peak loads and energy

Scenario 2 – Moderate Winter with a Deep and Prolonged Cold Spell; Similar to 2017/18

- Winter 2017/18 characteristics:
  - Milder than normal outside of a two-week span of significantly below normal temperatures
  - Average temperature departure from normal was +0.5°F degrees
  - The region was impacted by an extended stretch of cold weather between December 25 and January 9; all major cities in the region experienced temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal
  - Winter peak load of 20,631 MW
  - Total energy modeled is 31,291 GWh
  - The cold snap was marked by reductions in natural gas availability and price inversion contributed to high fuel oil usage; several oil-fired resources were postured to maintain fuel reserves

- ISO anticipates that system reliability will be maintained, but may require the use of capacity deficiency actions under OP-4 on 5-7 days

Scenario 3 – Cold Winter with Several Cold Stretches; Similar to 2013/14

- Winter 2013/14 characteristics:
  - Colder than normal overall highlighted by a polar vortex event which resulted in significant stretches of cold weather in New England and surrounding areas
  - Average temperature departure from normal was -2.3°F degrees
  - The region experienced six cold weather stretches of four or more consecutive days, including a stretch of ten consecutive days at or below freezing
  - Winter peak load of 21,514 MW
  - Total energy modeled is 33,881 GWh
  - Significant energy usage caused high demand on both the electric and natural gas systems
- Significant usage of all available capacity deficiency actions under OP-4 (including public appeal actions) may be necessary across several weeks, including the use of OP-7 across several days
  - In-season fuel replenishment will greatly mitigate this risk

NEXT STEPS ON ENERGY ADEQUACY

Looking Ahead: Energy Adequacy Anchor Project

- NEPOOL, the New England States, FERC, and the ISO agree that energy adequacy discussions and actions are a top priority
- The ISO is currently working with EPRI on developing a probabilistic energy adequacy model to study the performance of the power system under extreme events – this project will help inform the scope of solutions
  - Upcoming work is outlined on the next slide
- To guide discussions, the following time horizons are considered:
  - **Immediate-term**: Winter 2022/23
  - **Short-term**: Winters 2023/2024 and 2024/2025
  - **Medium-term**: The subsequent seven winters–2025/2026 through 2032/2033
  - **Longer-term**: Beyond 2033 (roughly a decade from now)
- Defining timelines should offer clarity as various solutions are considered

Looking Ahead: Energy Adequacy Anchor Project

- **Q4 2022**
  - Immediate-term: Confirm protocols to work with the DOE on emissions restrictions; maintain lines of communication for potential Jones Act waivers
  - Short-term: Update the Inventoried Energy Program for Winters 2023/2024, 2024/2025
  - Short/medium-term: Continue regional dialogue with respect to the Everett LNG Facility
  - Medium/longer-term: Present and gather feedback on the EPRI energy adequacy study model
- **Q1 2023**
  - Short-term: Review 2022/23 winter and confirm readiness plans for winter 2023/2024
  - Medium/longer-term: Present preliminary results of the EPRI study
  - Medium/longer-term: Finalize problem statement
- **Q2 2023**
  - Medium/longer-term: Discuss scope and viability of energy adequacy solutions and define the list of options to pursue, which could include:
    - Market enhancements, a modernized strategic energy reserve, and infrastructure options such as transmission

Questions

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.

[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.

ISO new england

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

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

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.

Including pumped storage as eligible storage participant in the Inventoried Energy Program

NEPOOL PARTICIPANTS COMMITTEE

NOVEMBER 3 2022

Brookfield
Renewable U.S.

Background

- Inventoried Energy Program (IEP) is a voluntary program designed to compensate resources for maintaining inventoried energy during the winter months in 2023-24 and 2024-25
  - When ISO-NE filed the program in 2019 eligible asset types were coal, oil, natural gas, nuclear, biomass, and certain hydro and pumped-storage generators
- On June 2020 (after regaining quorum) FERC approved the IEP
- Several appeals were filed to the DC Circuit Court
- On June 17th 2022 the DC Circuit Court issued an order severing the IEP by making "nuclear, coal, biomass, hydroelectric generators ineligible to participate"
- On September 23rd 2022 FERC issued a compliance order asking ISO-NE to revise its tariff to remove these technology types (i.e., leave the other eligible types oil, natural gas, storage, refuse)
- Brookfield Renewable strongly disagrees with the court's reasoning to remove certain technologies that provided the same inventoried energy product on a non-discriminatory manner, but that is not the issue at hand today…

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Eligibility should be applied equally to all storage

- The DC Court and the FERC Compliance order did not impact natural gas, oil, refuse and storage resources eligible to participate in the IEP

- Brookfield's view is that when the court ruled to remove hydroelectric resources that it contemplated conventional hydro with pondage, but did not contemplate pumped storage hydro operating as storage (i.e., daily pump/charge to generate/discharge)
  - The court ruling and subsequent FERC compliance order are silent on this important distinction
  - More importantly they do not explicitly restrict pumped storage hydro

- Brookfield owns and operates both pumped storage hydro and chemical battery storage
  - The economic rationale when to charge and discharge pumped storage hydro vs chemical storage battery in the energy market is <u>identical</u>
  - **Either all storage is eligible or all storage is ineligible**
  - Just like all natural gas/oil assets are eligible for the IEP

Proposed amendment

- Brookfield Renewable's amendment is narrow and proposes that:

  Pumped storage operated as Electric Storage Facility should be eligible to participate in the IEP program given that all storage assets are operated in identical matter

- The ISO-NE tariff defines storage as "facility that is capable of receiving electricity and storing the energy for later injection of electricity into the grid."
  - The ISO-NE tariff does not make distinction whether storage is occurring via water or a chemical medium

- Further, Section III.1.10.6 of the ISO-NE tariff defines how storage facility can operate as Electric Storage Facility
  - If pumped storage meets this criteria, which it does, then it should be allowed to participate in the IEP
  - To be clear, conventional hydropower resources with pondage will remain ineligible (much to our displeasure)

- Proposed market rule amendment

  (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

- The estimated added cost to the IEP (assuming an updated rate of $120/MWh is approximately $1.5M

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Renewable U.S.

Thank you for your consideration of this amendment!

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

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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

NEXTera ENERGY

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.

NEXTera ENERGY

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 Attachment 1, and our memorandum on NuPower's prior request for adjustment of its Certificates for the Markets Committee's September 13-14 memorandum is Attachment 2.

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.

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[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 <u>Exhibit A</u>, 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 <u>Exhibit C</u>.

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

[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

MURTHA CULLINA
ATTORNEYS AT LAW

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
n	321.79	1050.00	0.02	0.00	0.01	0.00	0.00	0.00	0.02
		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

180 Marsh Hill Road, Orange, CT 06477
Telephone 203.499.2959, Fax 203.499.2414
www.avangrid.com, Daniel.Crisp@avangrid.com

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

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

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[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.

<u>EXHIBIT E</u>

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.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of November 1, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated October 4, 2022 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

*	1	ENECOS Mystic COSA Complaint (EL23-4)	Oct 17	ENECOS submit Complaint against Mystic and ISO-NE challenging the pass-through to ISO-NE customers of firm pipeline transportation costs under the Mystic COSA; comment deadline ***Nov 16, 2022***
			Oct 18; 21	ENECOS request confidential treatment for the portions of its Complaint that contain information that Mystic has provided to ENECOS pursuant to the Protective Order in ER18-1639; and submit separate protective order for use in this proceeding
			Oct 18-Nov 1	Calpine, CT OCC, MA AG, NESCOE, CT DEEP intervene
	1	206 Proceeding: FTR Collateral Show Cause Order (EL22-63)	Oct 26	ISO-NE answers *FTR Collateral Show Cause Order*, explaining how the FAP's FTR financial assurance calculations remain just and reasonable; comment deadline ***Nov 25, 2022***

II. Rate, ICR, FCA, Cost Recovery Filings

*	9	2023 NESCOE Budget (ER23-100)	Oct 14	ISO-NE files materials for funding NESCOE's 2023 operations; comment date ***Nov 4, 2022***
			Oct 17-Nov 1	NESCOE, National Grid, Calpine intervene
*	9	2023 ISO-NE Administrative Costs and Capital Budgets (ER23-94)	Oct 15	ISO-NE files its 2023 administrative costs and capital budgets; comment date ***Nov 4, 2022***
			Oct 24-31	NEPOOL, Calpine, National Grid intervene
			Oct 31	NEPOOL files comments supporting ISO-NE 2023 Budgets
	11	Mystic COS Agreement Updates to Reflect Constellation Spin Transaction (ER22-1192)	Oct 14	In light of Settlement Agreement, Acting Chief ALJ terminates settlement judge procedures
	12	Mystic 8/9 COS Agreement *Second* CapEx Info Filing (ER18-1639-000)	Oct 17-18	NESCOE and ENECOS submit formal challenges to Mystic's Second CapEx Info Filing; comments on NESCOE's and ENECOS' challenges are due on or before ***Nov 16, 2022 and Nov 17, 2022***, respectively
	12	Mystic 8/9 COS Agreement *First* CapEx Info Filing (ER18-1639-015)	Oct 13	Settlement Judge McBarnette submits status report recommending continuation of settlement judge procedures; second settlement conference scheduled for ***Nov 17, 2022***

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

*	14	FCM Parameters Recalculation Schedule Modification (ER23-74)	Oct 12	ISO-NE and NEPOOL file changes to defer and modify the FCM Parameters Recalculation Schedule; comment deadline ***Nov 2, 2022***
			Oct 13-Nov 1	Calpine, Dominion, Eversource, National Grid, NESCOE, MA DPU intervene
*	14	FCA18 Schedule Modifications (ER23-50)	Oct 11	ISO-NE and NEPOOL file changes to compress the schedule for FCA18 to ensure FCA18 is conducted, as originally scheduled, on Feb 5, 2024
			Oct 31	Dominion, Eversource, National Grid, NESCOE, MA DPU intervene

IV. OATT Amendments / TOAs / Coordination Agreements

*	15	Attachment F Revisions reflecting RIE Addition as PTO (ER23-299)	Oct 31	RIE submits revisions to Attachment F to reflect its addition as a newly independent PTO; comment date ***Nov 21, 2022***
*	15	Attachment F Depreciation Normalization Requirement Revisions (ER23-197)	Oct 26	TOs submit revisions to maintain compliance with the IRS's depreciation normalization requirements and to ensure their continued ability to use accelerated depreciation; comment date ***Nov 16, 2022***
			Nov 1	Calpine intervenes doc-lessly

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements

*	17	Schedule 21-NEP: Removal of Narragansett References; Update NGrid LCC References (ER23-165)	Oct 24	New England Power submits revisions to remove references to Narragansett as an affiliate of NEP and any Narragansett-specific rate provisions and to update references in the local service schedule to the National Grid Local Control Center; comment deadline ***Nov 14, 2022***
			Oct 28	Narragansett intervenes
	18	Schedule 21-RIE (ER23-16)	Oct 11, 25	National Grid, RI DPUC file comments
	18	Schedule 21-NEP: Narragansett/ Pawtucket Power Decomm. CRA (ER22-2732)	Oct 18	FERC accepts CRA, eff. Jul 26, 2022

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	19	Capital Projects Report - 2022 Q3 (ER23-114)	Oct 14	ISO-NE files 2022 Q3 Report; comment deadline ***Nov 4, 2022***
			Oct 31	NEPOOL files comments supporting 2022 Q3 Report
*	19	LFTR Implementation: 56th Quarterly Status Report (ER07-476)	Oct 15	ISO-NE files its 56th quarterly report

IX. Membership Filings

*	20	November 2022 Membership Filing (ER23-310)	Oct 31	***New Members***: Derby Fuel Cell, KCE CT 5, KCE CT 7, KCE CT8, KCE CT 9, RI Bioenergy, RI DPUC, Sunnova, and Triolith Energy Fund, LP; ***Withdrawal***: EIP Investment; and ***Name Change***: Stones DR, LLC (f/k/a Centrica Business Solutions Optimize, LLC); comment deadline ***Nov 21, 2022***

X. Misc. - ERO Rules, Filings; Reliability Standards

	21	NPCC Bylaws Changes (RR22-2)	Oct 5	NERCC files Bylaws changes in response to July 8, 2022 order
	22	Notice of Penalty: National Grid (NP22-33)	Oct 28	FERC determines to not review the National Grid Notice of Penalty; ***$512,000 penalty*** becomes effective

XI. Misc. - of Regional Interest

*	22	203 Application: Seneca Energy II / BP (EC23-18)	Oct 31	Seneca and BP request authorization for a transaction pursuant to which Seneca will become a Related Person to BP; comment deadline ***Nov 21, 2022***

*	22	203 Application: ConEd / RWE (EC23-17)	Oct 28	ConEd and RWE request authorization for a transaction pursuant to which RWE will acquire 100% of the equity interests in ConEd's Clean Energy Businesses; comment deadline ***Nov 28, 2022***
*	22	203 Application: Great River Hydro / HQI US (EC23-16)	Oct 28	Great River Hydro and HQI US request authorization for a transaction pursuant to which HQI US will indirectly acquire 100% of the membership interests in Great River Hydro; comment deadline ***Nov 18, 2022***
	23	203 Application: Salem Harbor / Lenders (EC22-117)	Oct 31	FERC authorizes transfer of the equity interests in Salem Harbor to Salem Harbor's lenders under a pre-petition credit facility
	23	203 Application: Centrica / CPower (EC22-90)	Oct 6 Oct 12	CPower consummates its acquisition of 100% of Centrica's equity interests CPower and Centrica submit notice of consummation of transaction
*	24	Service Agreement Cancellation: NEP/Pawtucket (ER23-144)	Oct 19	NEP files Notice of Cancellation; comment deadline, ***Nov 9, 2022***
	24	A&R E&P Agreement: Seabrook / NECEC Transmission (ER22-2807)	Oct 24	FERC accepts Seabrook's amended and restated E&P Agreement, eff. Sep 8, 2022
	25	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Oct 7, Oct 25, Oct 26	FERC accepts all but one of the remaining pending *Order 864* compliance filings

XII. Misc. - Administrative & Rulemaking Proceedings

26	Reliability Technical Conference (Nov 10) (AD22-10)	Oct 4, 28	FERC issues supplemental notices identifying conference panel compositions and speakers; conference to be held ***Nov 10, 2022***
26	New England Gas-Electric Winter Forum (AD22-9)	Oct 11 Oct 21-31	Forum transcript posted in eLibrary Comments received from 4 individuals and the NH BIA Comments due on or before ***Nov 7, 2022***
27	Transmission Planning and Cost Management Tech Conf (AD22-8)	Oct 6 Oct 5, 7 Nov 1	FERC holds Oct 6, 2022 tech conf OH PUC Commissioner, Harvard Elec. Law Initiative submit materials Tech conf transcript posted in eLibrary
28	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Oct 3-7 Oct 7, 31	ACRE and G. van Uytven file comments on agenda for 5th JFSTF mtg NARUC nominates, and FERC accepts Tricia Pridemore of GA PSC to fill a SEARUC vacancy on the JFSTF Task Force Next (5th) meeting: ***Nov 15, 2022*** in New Orleans, LA
29	NOPR: Duty of Candor (RM22-20)		comments due ***Nov 10, 2022***
29	NOPR: Advanced Cybersecurity Investment (RM22-19)	Oct 6	NOPR published in *Federal Register*; comments due ***Nov 7, 2022***; reply comments ***Nov 21, 2022***
30	NOPR: Interconnection Reforms (RM22-14)	Oct 13-14 Oct 28	Over 130 sets of initial comments filed, including by: NEPOOL, ISO-NE, NESCOE, AEE, Anbaric, Avangrid, Cypress Creek Renewables, Dominion, EDF Renewables, ENGIE, Envir. Defense Fund, Longroad, National Grid, NextEra, PPL, RWE, Shell, VELCO, Vistra, ACPA, ACRE, APPA, US DOE, EEI, ELCON, EPRI, EPSA, IRC, NARUC, NERC, NRECA, PIOs, R Street Institute, SEIA, State Agencies, and WIRES FERC extends date for reply comments by 30 days to ***Dec 14, 2022***

34	*Transmission NOPR* (RM21-17)		Nearly 100 sets of reply comments filed, including by: ISO-NE, AEE, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, SEIA

XIII. FERC Enforcement Proceedings

37	Coaltrain Energy (IN16-4)	Oct 11	FERC approves Stipulation and Consent Agreement that resolved OE's investigation into Defendants' violation of the FERC's Anti-Market Manipulation Rule and Market Behavior Rules, and a pending Federal Court lawsuit; Coaltrain must make restitution payments totaling ***$4 million***

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

45	2nd Revised Narragansett LSA Orders (22-1161, 22-1108) (consolidated)	Oct 11	Green Development files Petitioner's Brief
45	Mystic II (ROE & True-Up) (21-1198 et al.) (consol.)	Oct 7	Court grants Mystic's Sep 7, 2022 motion for voluntary dismissal of Case No. 22-1215
		Oct 25	Mystic asks Court for an order keeping these proceedings in abeyance
		Oct 26	Court grants Mystic's request, ordering that the proceedings remain in abeyance pending further order of the court and directing the parties to file motions to govern future proceedings by ***Jan 24, 2023***
46	Mystic I (Original Cost Test, Capital Structure, Everett Cost Recovery, Clawback, True-Up Mechanism) (20-1343 et al.)	Oct 17	Court issued its mandate, returning the case to the FERC
48	Northern Access Project (22-1233)	Oct 11	Sierra Club files Docketing Statement, Statement of Issues, and the underlying decision from which the appeal arise; FERC moves to hold this proceeding in abeyance
		Oct 21	Sierra Club opposes FERC's motion
49	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147 consol.)	Oct 28	Petitioners file Petitioners Brief

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: November 1, 2022

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through November 1, 2022. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **ENECOS Mystic COSA Complaint (EL23-4)**

On October 17, 2022, Eastern New England Consumer-Owned Systems ("ENECOS") filed a Complaint against Mystic and ISO-NE challenging the pass-through to ISO-NE customers of firm pipeline transportation costs under the 2nd Amended and Restated Mystic Cost-of-Service Agreement ("COSA"), which ENECOS claimed are associated with pipeline facilities that are neither used nor usable to supply fuel to Mystic 8 and 9, and therefore should not be charged to ISO-NE and its customers under the COSA. Specifically, ENECOS asked that all references to "Pipeline Transportation Agreements" be stricken from the COSA, template Line No. 7 "Fixed Pipeline Transportation" be removed from the true-up methodology, and Mystic be precluded from recovering the dollar amounts associated with that line item. ENECOS explained that the Complaint was filed as a procedural precaution as the charges that are the subject of the Complaint can be addressed by the FERC in proceedings on the DC Circuit's remand of issues relating to the FERC's allocation of Everett Marine Terminal costs under the COSA.[2] Comments on ENECOS' Complaint are due on or before ***November 16, 2023***. Thus far, Calpine, CT OCC, MA AG, NESCOE, and the CT DEEP have intervened doc-lessly. If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **206 Proceeding: FTR Collateral Show Cause Order (EL22-63)**

On July 28, 2022, the FERC instituted a Section 206 proceeding finding that the existing tariffs of certain ISO/RTOs, including the ISO-NE Tariff, appear to be unjust and unreasonable.[3] The FERC found that ISO-NE's Tariff appears to be unjust and unreasonable in the absence of volumetric minimum collateral requirements for FTR Market Participants ("volumetric FTR collateral requirements"). Accordingly, ISO-NE was directed, on or before October 26, 2022, to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1050-1052 (D.C. Cir. 2022).

[3] *CAISO, ISO-NE, NYISO, and SPP*, 180 FERC ¶ 61,049 (July 28, 2022) ("*FTR Collateral Show Cause Order*").

discriminatory or preferential.[4] As noted below, ISO-NE answered by explaining why it believes its existing Tariff provisions to be just and reasonable and changes not necessary.

By way of background, the *FTR Collateral Show Cause Order* follows PJM's *Green Hat* experience,[5] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential rulemaking to improve ISO/RTO credit practices,[6] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[7] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[8] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

The FERC issued on July 28, 2022, a notice of this proceeding and of the refund effective date, August 3, 2022.[9] Those interested in participating in this proceeding were required to intervene on or before August 18, 2022. Doc-less interventions were filed by NEPOOL, Calpine, DC Energy, NRG, the Maine Public Utilities Commission ("MPUC"), Electric Power Supply Association ("EPSA"), PJM, SPP, Public Citizen, and Financial Marketers Coalition[10] (out-of-time).

ISO-NE Response. On October 26, 2022, ISO-NE submitted its answer in response to the *FTR Collateral Show Cause Order*. In its Answer, ISO-NE explained how the FTR financial assurance calculations contained in the Financial Assurance Policy ("FAP") remain just and reasonable, adequately accounting for FTR risk in the absence of a more sophisticated risk management solution such as a clearing solution. ISO-NE asked that, should the FERC not agree and proceed to require volumetric FTR collateral requirements, that it be permitted to follow the Participants Processes to propose revisions to the FAP consistent with any such order. Comments on ISO-NE's response are due on or before November 25, 2022 (the day after Thanksgiving).

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4 *Id.* at P 31.

5 *See GreenHat Energy, LLC*, 175 FERC ¶ 61,138 (2021) (order to show cause) (GreenHat Show Cause Order); *GreenHat Energy, LLC*, 177 FERC ¶ 61,073 (2021) (order assessing civil penalties). In June 2018, GreenHat Energy LLC ("GreenHat") defaulted on its obligations to PJM after amassing one of the largest FTR portfolios in the PJM region. At the time of its default, GreenHat had only $559,447 on deposit as collateral with PJM and no other material assets. However, over the subsequent three-year period ending in May 2021, this FTR portfolio incurred approximately $179 million in losses, which were borne by non-defaulting market participants in PJM.

6 Energy Trading Institute Request for Technical Conference and Petition for Rulemaking to Update Credit and Risk Management Rules and Procedures in the Organized Markets, *Credit Reforms in Organized Wholesale Electric Markets*, Docket No. AD20-6-000 (Dec. 16, 2019).

7 *See* Supp. Notice of Tech. Conf., *RTO/ISO Credit Principles and Practices*, Docket No. AD21-6, et al. (Feb. 10, 2021).

8 The FERC explained that (i) the mark-to-auction mechanism mitigates the risk of default by updating collateral requirements to reflect the most recent valuation of the FTR position and (ii) volumetric FTR collateral requirements ensure that a market participant is required to post a minimum amount of collateral to cover potential defaults, even when the market participant has offsetting positions. With respect to volumetric FTR collateral requirements, the FERC expressed a concern that netting of FTRs with negative collateral requirements against FTRs with positive collateral requirements can lead to insufficient collateral for a portfolio's risk should future congestion be significantly different than historical congestion. Without explicit $/MWh volumetric FTR collateral requirements, the FERC is "concerned that market participants may be able to minimize their collateral requirements without a corresponding reduction in risk". The ISO-NE Financial Assurance Policy ("FAP") allows for some limited offsetting. *See* FAP § VI (allowing for netting of FTRs with the same or opposite path, same contract month and type). *FTR Collateral Show Cause Order* at PP 28-29.

9 The *Notice* was published in the *Fed. Reg.* on Aug 3, 2022 (Vol. 87, No. 148) p. 47,409.

10 "Financial Marketers Coalition" identified themselves in their doc-less intervention as "financial market participants participating in the various ISO/RTO markets, including those operated by CAISO, SPP, NYISO and ISO-NE. Many of the Coalition members participate in these ISO/RTOs' FTR markets."

If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)**

As previously reported, RENEW Northeast, Inc. ("RENEW") and the American Clean Power Association ("ACPA") filed a Complaint on March 15, 2022 under Section 206 of the Federal Power Act ("FPA") against ISO-NE seeking a FERC order directing ISO-NE to make changes to its rules for capacity accreditation and operating reserve designations, effective no later than the eighteenth Forward Capacity Auction ("FCA18") with respect to capacity accreditation and promptly with respect to operating reserve designations. RENEW/ACPA asserted that the changes are needed to address undue preferences granted under ISO-NE's rules and procedures to gas-fired generation resources that have neither dual-fuel capability nor dedicated, firm natural gas supply arrangements ("Gas-Only Resources"). Complainants asserted that the undo preferences arise in the context of capacity accreditation through an assumption of 100% fuel availability for Gas-Only Resources, and in the context of operating reserves, through the absence of any pre-dispatch requirements to confirm fuel availability. ISO-NE's response and comments, following a request for extension of time granted by the FERC, were due on or before April 14, 2022.

On April 14, 2022, ISO-NE responded to the Complaint. Protests and comments on the Complaint were filed by: NEPOOL, AEE, Calpine, EDF, FirstLight, LS Power, NEPGA, NESCOE, Public Interest Orgs ("PIOs",[11] Vistra/LSP Power, State Parties,[12] EPSA, National Hydropower Assoc., and the Solar Energy Industries Association ("SEIA"). On April 29, RENEW/ACPA answered the ISO-NE and NEPOOL motions to dismiss and answered the protests and comments filed in opposition to the Complaint. On May 17, ISO-NE answered the April 29 RENEW/ACPA answer. Interventions only were filed by AEP, Avangrid, Avangrid Renewables, Borrego, Brookfield, Constellation, CPV Towantic, Dominion, ENE, Excelerate, National Grid, NextEra, NH OCA, North East Offshore, NRG, Public Systems,[13] CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. On July 20, 2022, ISO-NE submitted a letter requested expeditious action on the Complaint (a request NEPOOL supported). RENEW/ACPA supported the request for expedited action on August 1, 2022 (adding that the FERC "should grant the Complaint and direct ISO-NE to submit a compliance filing that timely implements the proposed remedies", and could address the wish for "constructive *ex parte* communications with [FERC] Staff … with an appropriately crafted waiver of the *ex parte* limitations"). No action has yet been taken and this Complaint remains pending before the FERC. If you have any questions concerning this Complaint, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)**

On September 26, 2022, the FERC issued a notice[14] that the Northern Maine Independent System Administrator's ("NMISA") request for rehearing of the FERC's order[15] denying NMISA's complaint against ISO-NE and the Participating Transmission Owners ("PTOs") Administrative Committee ("PTO AC")[16] may be deemed

[11] "Public Interest Orgs" are the Sustainable FERC Project, Acadia Center, Conservation Law Foundation ("CLF"), Sierra Club, and Natural Resources Defense Council ("NRDC").

[12] "State Parties" are the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), the Massachusetts Attorney General ("MA AG"), and the Connecticut Attorney General ("CT AG").

[13] "Public Systems" are Connecticut Municipal Electric Energy Cooperative ("CMEEC"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), New Hampshire Electric Cooperative, Inc. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

[14] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 180 FERC ¶ 61,044 (Sep. 23, 2022) (notice that req. for reh'g of July 28 order may be deemed denied).

[15] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 180 FERC ¶ 62,168 (July 28, 2022) ("*NMISA Order*") (order denying reciprocal TOUT discount complaint).

[16] As previously reported, the FERC found in the *NMISA Order* that "NMISA has not demonstrated that the failure of the PTO AC and ISO-NE to offer NMISA reciprocal treatment is unduly discriminatory or preferential". Specifically, the FERC citied its longstanding

denied by operation of law, triggering the 60-day period during which a petition for review of the *NMISA Order* can be filed with an appropriate federal court. The notice also indicated that the FERC, as is its right, "may modify or set aside [the *NMISA Order*], in whole or in part, in such manner as it shall deem proper". If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **206 Proceeding: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)**

Still pending before the FERC is the FERC-instituted FPA Section 206 proceeding under which the FERC is considering whether Schedule 25 and Tariff § I.3.10 may be unjust and unreasonable.[17] As previously reported, this proceeding arises out of issues raised in the NECEC Transmission LLC ("NECEC")/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[18]

The FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff § I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff § I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. On September 8, 2021, the FERC issued a notice of the proceeding and of the refund effective date, which is October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021[19] and included NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), ACPA, EPSA, RENEW, and Public Citizen.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff § I.3.10 remain just and reasonable. ISO-NE called for the FERC to "assist Affected Parties and Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties had until January 7, 2022 to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate.

Comments. Comments were filed by the January 7, 2022 deadline by NEPOOL, NECEC/Avangrid, NEPGA, NextEra. On January 20, 2022, NextEra answered the NECEC/Avangrid comments. On January 28, 2022, NECEC answered NextEra's January 20 answer and ISO-NE answered NECEC's Jan 7 comments.

policy permitting such charges, found for a number of reasons NYISO and NMISA not similarly situated, and noted that NMISA's showing that the proposed approach might be superior for NMISA insufficient to meet its FPA Section 206 statutory burden. In requesting rehearing, NMISA asserted that the FERC erred by (i) failing to provide a reasoned explanation for its determination that NMISA and NYISO are not similarly situated; and (ii) failed to justify its decision not to enforce the requirement that ISO-NE engage in extensive efforts to reduce seams with neighboring control areas.

[17] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021) ("*Sep 7 Order*").

[18] *Id.* at P 20.

[19] The *Notice* was published in the *Fed. Reg.* on Sep. 14, 2021 (Vol. 86, No. 175) p. 51,140.

As noted, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)**

Still pending before the FERC is the October 13, 2020 complaint by NECEC and Avangrid Inc. (together, "Avangrid") requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the NECEC Project and seeking, among other things, an initial, expedited order that would grant certain relief[20] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage (the "Complaint"). NextEra submitted an answer to the Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid subsequently answered the supplemental answer.

Amended Complaint. On March 26, 2021, Avangrid amended the Complaint to reflect that aspects of the relief originally requested in the Complaint were no longer feasible within the timeline previously sought. Avangrid continued to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021 (which did not occur). On April 15, 2021, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. On May 6, 2021, ISO-NE submitted a letter to express importance of prompt resolution of these matters. On May 17, Avangrid submitted a letter supporting ISO-NE's May 6, 2021 letter.

Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[21] Initial briefs[22] were due on or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding). Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again pending before

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[20] Directing NextEra to comply with the ISO-NE OATT, to comply with open access requirements, and to cease and desist unlawful interference with the NECEC Project; and to have the FERC temporarily revoke NextEra's blanket waiver under Part 358 of the FERC's regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

[21] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021).

[22] The FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues: (i) whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility; (ii) if Seabrook's breaker is part of Seabrook's generating facility, under what authority, if any, Seabrook may be subject to the upgrade obligations imposed on Affected Parties under the ISO-NE Tariff; (iii) if Seabrook's breaker is part of Seabrook's generating facility, what obligations, if any, Seabrook has under its LGIA with respect to replacement of the breaker and whether or not ISO New England Operating Documents and Applicable Reliability Standards impose an obligation to replace the breaker. If Seabrook's breaker is appropriately classified as a system protection facility, what obligations Seabrook has to replace the breaker. If the Seabrook LGIA obligates Seabrook to act, a description of the scope of Seabrook's obligation under the LGIA; (iv) whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker; and (v) If replacement of Seabrook's breaker is necessary for the interconnection of the NECEC Project, whether there exists any interim solution for the interconnection of the NECEC Project that would allow energization of the NECEC Project prior to the replacement of Seabrook's breaker.

the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter, and also still pending before the FERC, is a Petition for a Declaratory Order filed by NextEra Energy Seabrook, LLC ("Seabrook") a week earlier than the Avangrid Complaint that seeks clarity on the scope of Seabrook's "FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC" (the "Seabrook Petition"). Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on the Seabrook Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission (together, "Avangrid") protested the Seabrook Petition. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. NextEra moved to lodge both an August 29, 2021 filing containing an executed Engineering and Procurement Agreement ("E&P Agreement") between Seabrook and NECEC that was filed with the FERC on August 19, 2021 and the NRC Seabrook Report. Avangrid answered that motion, asserting that the NRC Seabrook Report was outside the scope of the proceeding and the motion to lodge should be denied. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[23] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[24] However, the FERC's orders were challenged, and in *Emera Maine,*[25] the U.S. Court of

[23] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarif.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

[24] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[25] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[26] and third (EL14-86)[27] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[28] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[29] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[30] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[31] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[32] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[33] (EL14-12; EL15-45) in

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[26] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% ROE, and seeks a reduction of the Base ROE to 8.7%.

[27] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General, together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

[28] *Environment Northeast v. Bangor Hydro-Elec. Co. and Mass. Att'y Gen. v. Bangor Hydro-Elec. Co,* 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

[29] The 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders"*). *The Base ROE Complaint IV Orders*, as described in Section XVI below, have been appealed to, and are pending before, the DC Circuit.

[30] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[31] *Id.* at P 2.; Finding of Fact (B).

[32] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

[33] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[34]

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA Section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA Section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based on the results of three models: the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Expected Earnings models. Within that composite zone, a smaller, "presumptively reasonable" zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[35] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[36] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The

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on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[34] *Id.* at P 19.

[35] *Id.* at P 59.

[36] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG and EMCOS.

Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[37] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

These matters remain pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **2023 NESCOE Budget (ER23-100)**

This proceeding was initiated by ISO-NE's October 14, 2022 filing of the budget for funding NESCOE's 2023 operations. The 2023 Operating Expense Budget for NESCOE is $2,691,505. The amount to be recovered reflects true-ups from 2022 (over-collections of $1,108,802). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00701 per kilowatt ("kW") of Monthly Network Load (a $0.00035/kW decrease from 2022). The 2023 NESCOE budget was supported by the Participants Committee at its October 6, 2022 meeting. Comments and any interventions are due on or before November 4. Thus far, Calpine, NESCOE and National Grid have submitted doc-less interventions. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2023 ISO-NE Administrative Costs and Capital Budgets (ER23-94)**

Also on October 14, 2022, ISO-NE filed for recovery of its 2023 administrative costs (the "2023 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2023 ("2023 Capital Budget", and together with the 2023 Revenue Requirement, the "2023 ISO Budgets"). The 2023 ISO-NE Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 14 filing, ISO-NE reported that the 2023 Revenue Requirement is $240.2 million (a $25.1 million or 11.7% increase over 2022), which decreases to $225.6 million after the over-collection for 2021 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2023 Core Operating Budget) comprise $209.2 million; depreciation and amortization of regulatory assets, $31 million; and a $14.6 million true-up decrease for 2021 over-collections.

ISO-NE further reported that the 2023 Capital Budget is $33.5 million, a $1.5 million increase over 2022, and is comprised of the following (with 2023 projected costs and target completion dates, if available, in parentheses):

- nGem Market Clearing Engine Implementation (Mar 2023) ($1.3 million)
- FCTS Infrastructure Conversion Part III ($700,000) (Apr 2023) ($700,000)
- FCM Order 2222 (Nov 2023) ($600,000)
- IT Asset Workflow Integration and Updates (Mar 2022) ($800,000)
- PI Historian for Short-Term Phasor Measurement Units Data Repository (Sep 2023) ($500,000)
- Forecast Enhancements (Jul 2023) ($600,000)

[37] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (Nov. 21, 2019) ("*MISO ROE Order*"), *order on reh'g*, Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020).

- PI Historian for Short-Term Phasor Measurement Units Data Repository (Jul 2023) ($500,000)
- E-mail List Server Technology Refresh (Jan 2023) ($100,000)
- Day-Ahead Ancillary Services Improvements (Oct 2024) ($3.5 million)
- CIP Electronic Security Perimeter Redesign Phase II (Jan 2024) ($2 million)
- Privileged Account Management Security Enhancements 2023 (Sep 2023) ($1.3 million)
- Integrated Market Simulator Phase I (Jun 2022) ($400,000)
- Inventoried Energy Program (Sep 2023) ($1 million)
- 2023 Issue Resolution Project ($400,000)
- Microsoft 365 Service Adoption (Jun 2024) ($500,000)
- Identity and Access Management Phase III (Dec 2023) ($500,000)
- MIS Reporting by Sub Accounts (Mar 2023) ($200,000)
- Control Room Voice Recorder Upgrade (Mar 2023) ($100,000)
- LMP Monitor Replacement (Apr 2022) ($100,000)
- Physical Security Improvement Project (Sep 2023) ($400,000)
- Replace Messaging Software (Mar 2023) ($100,000)
- nGem Real-Time Market Clearing Engine Implementation (Jun 2025) ($3 million)
- nGEM Software Development Part III (Dec 2023) ($1.5 million)
- Web to Cloud Migration
  Phase I (Nov 2023) ($800,000)
  Phase I (Dec 2023) ($1.2 million)
- External Website Migration to Cloud (Oct 2022) ($400,000)
- Solar Do Not Exceed Dispatch Phase II (Dec 2023) ($1 million)
- MOPR Elimination ($650,000) (Dec 2024) ($650,000)
- Windows Server 2019R2 (Oct 2023) ($500,000)
- FERC Order 2222 (Dec 2026) ($400,000)
- Enterprise Resource Planning System Replacement (Sep 2026) ($100,000)
- Capitalized Interest ($600,000)
- Non-Project Capital Expenditures ($4.8 million)
- Other Emerging Work ($3.4 million)

The 2023 ISO-NE Budgets were supported by the Participants Committee at its October 6, 2022 meeting. Comments on this filing are due November 4, 2022. Thus far, NEPOOL filed comments supporting the 2023 Budgets and NEPOOL, Calpine and National Grid have filed doc-less interventions. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **FirstLight CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER22-2876)**

On September 16, 2022, FirstLight Power Management LLC ("FirstLight") requested FERC acceptance of a proposed rate schedule to allow FirstLight to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs ("CIP-IROL Costs") of its affiliated generation facilities under Schedule 17 of the ISO-NE Tariff. FirstLight stated that the rate schedule will provide interested parties notice of FirstLight's intent to recover CIP-IROL Costs for each affiliated facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent Section 205 filing identifying the specific costs to be recovered. A September 16, 2022 effective date was requested. Comments on this filing were due on or before October 5, 2022; none were filed. NESCOE filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NESCOE 5-year (2023-2027) *Pro Forma* Budget (ER22-2812)**

On September 6, 2022, NESCOE filed its fourth 5-year *pro forma* budget covering years 2023 - 2027 (the "5-year *Pro Forma* Budget") in accordance with the Memorandum of Understanding ("MOU") among ISO-NE, NEPOOL and NESCOE. The 5-year *Pro Forma* Budget was supported by the Participants Committee at its September meeting. Comments on this filing were due on or before September 27. NEPOOL filed comments supporting the 5-year *Pro Forma* Budget on September 27. National Grid and Eversource filed doc-less interventions. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[38] (ER22-1192)**

As previously reported, on May 2, 2022, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COS Agreement") to reflect Mystic's current upstream ownership.[39] The changes were accepted effective as of Jun 1, 2022, but subject to refund. Specifically, the FERC accepted (i) Mystic's changes throughout the COS Agreement to replace the term "Exelon Generation Company, LLC" with "Constellation Energy Generation, LLC"; and (ii) the addition of language to the true-up methodology that provides that the values included in the true-up methodology exclude costs associated with the Spin Transaction. However, noting that Mystic's contested proposal on the issue of capital structure and cost of debt raises issues of material fact that cannot be resolved based on the record, the FERC accepted and suspended this portion of the COS Agreement for a nominal period, to become effective June 1, 2022, subject to refund and to the outcome of paper hearing procedures. The FERC also directed the appointment of a settlement judge, holding its paper hearing in abeyance so as to provide the participants an opportunity for settlement discussions.[40]

Settlement Agreement (-001) and Interim Implementation of Settlement Rate (-002). On September 8, 2022, Mystic filed an offer of settlement and related materials ("Offer of Settlement") to resolve all issues set for hearing in this proceeding. Comments supporting the Offer of Settlement were filed by FERC Trial Staff on September 22, 2022. No reply comments were filed. Judge French certified the uncontested Settlement to the Commission on October 4, 2022. The Offer of Settlement is pending before the FERC.

Mystic also requested authorization to implement on an interim basis (until the Settlement Agreement is approved) the Settlement Rate agreed upon in the Settlement Agreement.[41] That request was approved by Acting Chief ALJ Satten on September 28, 2022.[42] The interim Settlement Rate, which will be reflected in ISO-NE's next invoices for Monthly Charges, will remain in effect pending the Commission's consideration of the Offer of Settlement and will be subject to refund or surcharge if and as appropriate.

Settlement Judge Procedures Terminated. Subject to final action by the Commission on the Settlement Agreement, Chief ALJ Satten ended settlement judge procedures in this proceeding on October 14, 2022.

[38] In the Spin Transaction, Constellation's and Mystic's corporate parent changed from Exelon Corporation to a newly-created holding company, Constellation Energy Corporation ("Constellation Corporation"). Mystic continues to be an indirect wholly-owned subsidiary of Constellation Energy Generation, LLC, which in turn is a direct, wholly-owned subsidiary of Constellation Corporation.

[39] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,081 (May 2, 2022) ("*May 2, 2022 Order*").

[40] *Id.* at P 24.

[41] The interim rate constitutes a reduction, achieved through a reduced proportion of equity and a lower cost of debt used in Mystic's capital structure and rate of return calculation.

[42] *Constellation Mystic Power, LLC*, 180 FERC ¶ 63,032 (Sep. 28, 2022) ("*Mystic Interim Settlement Rate Order*").

If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Mystic 8/9 Cost of Service Agreement (ER18-1639)**

As previously reported, each of the *July 17 Orders*[43] and the *Mystic ROE Orders,*[44] which addressed in part or in whole the COS Agreement[45] among Mystic, Constellation Energy Generation, LLC[46] ("Constellation") and ISO-NE, have been appealed to, and consolidated before, the DC Circuit (*see* Section XVI below).

(-000) First CapEx Info. Filing. On September 15, 2021, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols"), its informational filing to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between June 1, 2022 to December 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Mystic responded to the formal challenges on November 17, 2021 asserting that that the challenges should be rejected without further procedures. ENECOS and NESCOE replied to Mystic's November 17 reply on December 2 and December 6, 2021, respectively.

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[47] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1, 2022 and the formal challenge process begins on September 15, 202).[48] The FERC reiterated that all items except return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[49] Accordingly, the FERC set these matters for a trial-type evidentiary hearing. The FERC encouraged the parties to make every effort to settle their

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[43] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order. Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[44] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*") (setting the base ROE for the Mystic COS Agreement at 9.33%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE First Allegheny Order*") (re-setting Mystic's ROE to 9.19%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE Second Allegheny Order*", and together with the *Mystic ROE Order* and the *Mystic ROE Allegheny Order,* the *"Mystic ROE Orders"*) (modifying the discussion in, but sustaining the results of, the *Mystic ROE First Allegheny Order*).

[45] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility.

[46] On Feb. 1, 2022, Exelon Generation Company, LLC was renamed and is now known as Constellation Energy Generation, LLC.

[47] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*").

[48] *Id.* at PP 23-24.

[49] *Id.* at P 26.

disputes before hearing procedures are commenced, and to that end, will hold the hearing in abeyance pending the appointment of a settlement judge and completion of settlement judge procedures.[50]

(-000) Second CapEx Info Filing. On September 15, 2022, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "Second CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects"). Formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS. Comments on NESCOE's and ENECOS' challenges are due on or before ***November 16, 2022*** and ***November 17, 2022***, respectively.

(-014) Revised ROE (Sixth) Compliance Filing. Still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*. The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

(-015) First CapEx Info. Filing Settlement Judge Procedures. On May 4, Chief Judge Cintron designated Judge Andrea McBarnette as the Settlement Judge. A first settlement conference was convened on Wednesday June 15, 2022. A second settlement conference is scheduled for ***November 17, 2022***. On October 13, 2022, Settlement Judge McBarnette submitted a status report recommending the continuation of settlement judge procedures.

If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **Transmission Rate Annual (2022-23) Update/Informational Filing (ER09-1532; RT04-2)**

On July 29, 2022, the PTO AC submitted its 2023 annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. As prescribed in the Interim Protocols,[51] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing includes updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.75 kW-year (effective June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022. This filing was not noticed for public comment.

The July 29 filing was reviewed with the Transmission Committee at its August 16, 2022 summer meeting and at an August 22, 2022 technical session for Interested Parties. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties have until September 15, 2022 to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 days, but by no later than

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[50] *Id.* at P 27.

[51] The Interim Formula Rate Protocols ("Interim Protocols") became effective June 15, 2021, and will be replaced by permanent Formula Rate Protocols that will become effective June 15, 2023. *See* Settlement Agreement resolving all issues in Docket No. EL16-19 ("Settlement") approved by the FERC on Dec. 28, 2020, in *ISO New England et al.*, 173 FERC ¶ 61,270 (2020) ("Settlement Order").

October 15, 2022. During the Review Period, Interested Parties have until November 15, 2022 to submit Informal Challenges to the PTOs, and the PTOs are required to make a good faith effort to respond to any Informal Challenges no later than December 15, 2022. Interested Parties have until January 31, 2023 to file a Formal Challenge with the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **FCM Parameters Recalculation Schedule Modification (ER23-74)**

On October 12, 2022, ISO-NE and NEPOOL jointly filed Tariff changes to defer for two years the next recalculation of several FCM "parameters" and, going forward, to modify the schedule for such updates from no less often than once every three years to no less often than once every four years. The Participants Committee supported the changes at its August 4, 2022 meeting (Consent Agenda Item #3). ISO-NE requested an effective date of December 12, 2022 for these changes. Comments on this filing are due on or before ***November 2, 2022***. Thus far, doc-less interventions have been filed by Calpine, Dominion, Eversource, National Grid, NESCOE, and the MA DPU. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **FCA18 Schedule Modifications (ER23-50)**

On October 11, 2022, ISO-NE and NEPOOL jointly filed Tariff changes to modify the schedule for FCA18. The modifications compress the schedule for FCA18 in order that FCA18 can be conducted as originally scheduled (on February 5, 2024) notwithstanding delays in FA16 and FCA17 that otherwise would have caused the FCA18 auction date to slip. The Participants Committee supported the changes over two meetings – the September 1 and October 6, 2022 meetings (Consent Agenda Items #5 and 2, respectively). ISO-NE requested an effective date of December 11, 2022 for these changes. Comments on this filing are due on or before ***November 1, 2022***. Thus far, doc-less interventions have been filed by Dominion, Eversource, National Grid, NEPGA, NESCOE, and the MA DPU. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **New England's *Order 2222* Compliance Filing (ER22-983)**

New England's *Order 2222* Compliance Filing remains pending before the FERC. As previously reported, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted on February 2, 2022 Tariff revisions ("*Order 2222* Changes") in response to the requirements of *Order 2222*. The Filing Parties stated that the *Order 2222* Changes create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before April 1, 2022. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEE/PowerOptions/SEIA; Environmental Organizations;[52] MA AG; Voltus; AEMA and 4 New England US Senators.[53] Doc-less interventions were filed by: Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise,

[52] Environmental Organizations are Acadia Center, Conservation Law Foundation ("CLF"), Environmental Defense Fund ("EDF"), Massachusetts Climate Action Network, NRDC, Sierra Club, and the Sustainable FERC Project.

[53] Senators Markey (MA), Sanders (VT), Warren (MA), and Whitehouse (RI).

Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE (April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. Since the last Report, AEE/PowerOptions/SEIA and AEMA answered the ISO-NE and National Grid/Avangrid/ Eversource answers.

(-001) Deficiency Letter. On May 18, 2022, the FERC issued a 25-page deficiency letter directing ISO-NE to provide, on or before June 17, 2022, additional information and clarifications. ISO-NE filed its 39-page response to the deficiency letter on June 17, 2022. Comments in response to ISO-NE's deficiency letter response were due on or before July 8, 2022 and a joint protest was filed by AEE, AEMA, PowerOptions, and SEIA ("Joint Protest"). The Joint Protest, while supportive of certain responses (those regarding the exemption of DERAs from the Small Generator Interconnection Procedures ("SGIP") prior to 2026, locational requirements for DER aggregation, and the role of host utilities in identifying potential conflicts with retail program participation), protested the adequacy of ISO-NE responses regarding proposed metering and telemetering requirements for behind-the-meter ("BTM") DERs. On July 25, 2022, ISO-NE answered the July 8 Joint Protest. On August 9, 2022, AEE, AEMA, PowerOptions, and SEIA answered ISO-NE's July 25 answer.

This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com); Eric Runge (617-345-4735; ekrunge@daypitney.com); or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **IEP Remand (ER19-1428-005)**

On September 23, 2022, the FERC issued an order[54] directing ISO-NE to refile, on or before ***November 23, 2022***, Tariff provisions governing the Inventoried Energy Program ("IEP") consistent with the D.C. Circuit's decision.[55] ISO-NE's proposed Tariff changes, which must remove nuclear, biomass, coal, and hydroelectric generators from the IEP, will be reviewed at the November 2 Participants Committee meeting. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Attachment F Revisions Reflecting RIE Addition as PTO (ER23-299)**

On October 31, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy ("RIE") filed revisions to Attachment F of the OATT to reflect its addition as a newly independent Participating Transmission Owner ("PTO"). A January 1, 2023 effective date was requested. Comments on the RIE Attachment F Revisions are due on or before ***November 21, 2022***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Attachment F Depreciation Normalization Requirement Revisions (ER23-197)**

On October 26, 2022, certain Transmission Owners[56] filed revisions to Attachment F of the OATT to apply the IRS's ADIT proration formula to their actual (true-up) revenue requirements and to thereby maintain

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[54] *ISO New England Inc.*, 180 FERC ¶ 61,181 (Sep. 23, 2022) ("*2022 IEP Remand Order Directing Compliance*").

[55] *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022) (the "*IEP Decision*"). The *IEP Decision* leaves intact the FERC's *June 2020 IEP Remand Order* (*ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020)) except for the inclusion of nuclear, biomass, coal, and hydroelectric generators in ISO-NE's IEP, the inclusion of which the Court found arbitrary and capricious (because those resources were unlikely to change their behavior in response to the IEP payments). Because the Court believed "there is not substantial doubt that FERC would have adopted IEP if it had not included these resources in the first place [and] IEP can function sensibly without them", the Court found that it had the authority to sever this portion from the overall program and therefore vacated that portion of IEP from the remainder of the IEP. The Court upheld the remainder of the IEP and remanded the matter to the FERC for further proceedings consistent with its opinion.

[56] The TO filers are as follows: Central Maine Power Co. ("CMP"); Eversource Energy Service Co. ("Eversource") on behalf of The Conn. Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), NSTAR Elec. Co. ("NSTAR"); Fitchburg Gas and Elec.

compliance with the IRS's depreciation normalization requirements and to ensure their continued ability to use accelerated depreciation. Estimated revenue impacts were identified in the filing. A January 1, 2023 effective date was requested. Comments on these Attachment F Revisions are due on or before ***November 16, 2022***. Thus far, Calpine has submitted a doc-less intervention. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Phase I/II HVDC-TF Order 881*** **Compliance Filing: HVDC TOA (ER22-2467) and Sched. 20-A Common Attachment M (ER22-2468)**

On July 22, 2022, following a requested 10-day extension of time granted by the FERC, a Phase I/II HVDC-TF *Order 881* compliance filing was submitted in two parts ((i) changes to the HVDC TOA and (ii) changes to Schedule 20-Common Attachment M) by: ISO-NE, the Asset Owners,[57] and the Schedule 20A Service Providers.[58] Specifically, the Filing proposed changes to the ***HVDC TOA*** (ER22-2467) to address the Order 881 requirements related to transmission ratings and rating procedures and to ***Schedule 20A-Common*** (ER22-2468) to ensure compliance with Order 881 with respect to transmission rating transparency and transmission service (together, the "Phase I/II HVDC-TF *Order 881* Compliance Filing"). Comments on the Phase I/II HVDC-TF *Order 881* Compliance Filing were due on or before August 12, 2022; none were filed. The IRH Management Committee submitted a doc-less intervention. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 881*** **Compliance Filing: New England (ER22-2357)**

As previously reported, ISO-NE, NEPOOL, the PTO AC, and CSC (the "Filing Parties") filed, on July 12, 2022, proposed revisions to the OATT in response to the requirements of *Order 881*[59] ("*Order 881* Compliance Changes"). Specifically, the Filing Parties proposed the addition of a new Attachment Q to the OATT, and to revise OATT Schedules 18 (MTF; MTF Service) and 21 (Local Service - Common). The *Order 881* Compliance Changes (the Attachment Q and Schedule 18 changes) were supported by the Participants Committee at its June 21-23 Summer Meeting (Consent Agenda Item No. 2). An effective date of September 10, 2022 was requested, with changes to Attachment Q and Schedule 21 to become applicable by their own terms in July 2025. Comments on the *Order 881* Compliance Changes are due on or before August 2, 2022; none were filed. Eversource, Narragansett Electric Company ("Narragansett") and National Grid filed doc-less interventions. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J*** **Compliance Filing Part I (CSC-Schedule 18-Attachment Z) (ER22-1168)**

On March 2, 2022, in response to the requirements of *Order 676-J*,[60] ISO-NE and CSC filed revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in

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Light Co.; Green Mountain Power Corp.; Maine Elec. Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission, LLC; The United Illuminating Co.; Vermont Transco, LLC; and Versant Power.

[57] The "Asset Owners" are, collectively, New England Hydro-Transmission Electric Company, New England Hydro-Transmission Corporation, New England Electric Transmission Corporation, and Vermont Electric Transmission Company ("VETCO").

[58] The "Schedule 20A Service Providers" are: Central Maine Power Co. ("CMP"); The Conn. Light and Power Co. and Public Service Co. of NH ("Eversource"); Green Mountain Power Cor. ("GMP"); New England Power Co. ("NEP"); NSTAR Electric Co.; The United Illuminating Co. ("UI"); Vermont Electric Cooperative, Inc. ("VEC"); and Versant Power.

[59] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021); *Managing Transmission Line Ratings*, Order No. 881-A, 179 FERC ¶ 61,125 (May 19, 2022) (together, "*Order 881*").

[60] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*"). *Order 676-J* revised FERC regulations to incorporate by reference the latest version (Version 003.3) of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC")

the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards ("Schedule 18 Order 676-J Part I Changes").[61] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by CSC and NEPOOL. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (TOs-Schedule 20/21-Common) (ER22-1161)**

Also on March 2, 2022, in response to the requirements of *Order 676-J*, the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 20/21-Common Order 676-J Part I Changes").[61] An effective date as of the date the FERC may determine was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by NEPOOL and Eversource. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1150)**

Again on March 2, 2022, in response to the requirements of *Order 676-J*, ISO-NE filed revisions to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards) to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 24 Order 676-J Part I Changes").[61] An effective date no earlier than June 2, 2022 was requested. The Transmission Committee recommended that the Participants Committee support the Schedule 24 Order 676-J Part I Changes at its March 23 meeting, and the Participants Committee supported the changes at the April 7 meeting (Consent Agenda Item # 1). Comments on this filing were due on or before March 23, 2022; none were filed. NEPOOL, Eversource, MA DPU, and National Grid submitted doc-less interventions. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements

- **Schedule 21-NEP: Removal of References to Narragansett; Update Reference to NGrid LCC (ER23-165)**

On October 24, 2022, New England Power Company ("NEP") filed revisions to Schedule 21-NEP. The revisions remove references in Schedule 21-NEP to The Narragansett Electric Company ("Narragansett") as an affiliate of NEP and any Narragansett-specific rate provisions. NEP also proposed minor revisions to Schedule 21-NEP to update references in the local service schedule to the National Grid Local Control Center ("LCC") (f/k/a REMVEC). NEP requested a January 1, 2023 effective date for the revisions. Comments on this filing are due on or before ***November 14, 2022***. Thus far, Narragansett has filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC.

[61] Compliance filings for the rest of the WEQ Version 003.3 Standards (Schedule 24 Order 676-J Part II Changes) were due 12 months after implementation of the WEQ Version 003.2 Standards, or no earlier than Oct. 27, 2022.

- **Schedule 21-RIE (ER23-16)**

On October 4, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy ("RIE") filed revisions to Schedule 21 and Attachment E of Section II of the OATT to establish RIE's rates, terms, and conditions for the provision of Local Service and to accommodate RIE as a new Participating Transmission Owner ("PTO"). Comments on this filing were due on or before October 26, 2022 and were filed by National Grid (supporting RIE's filing) and the Rhode Island Division of Public Utilities and Carriers ("RI DPUC") (expressing concern that this proceeding's record is inadequate to demonstrate the justness and reasonableness of RIE's filing and requesting that REI (i) confirm that its filing complies with all of the commitments made by PPL in connection with approval of the Narragansett acquisition; (ii) confirm that its filing will carry forward the rate treatment of the Block Island Transmission System approved earlier in 2022;[62] and (iii) provide additional information regarding the rate impacts of the proposed changes). This matter is now pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: Narragansett/Pawtucket Power Decommissioning CRA (ER22-2732)**

On October 18, 2022, the FERC accepted, effective July 26, 2022, a Decommissioning Cost Reimbursement Agreement ("CRA") between Narragansett and Pawtucket Power Associates LP (Pawtucket").[63] As previously reported, the CRA facilitates the performance of certain work that Pawtucket requested Narragansett undertake to support the decommissioning of certain interconnection facilities and related equipment for Pawtucket's 69 MW Rhode Island generating facility that was completely retired on June 1, 2022. Unless the October 18 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: 2021 Annual Update Settlement Agreement (ER20-2119-001)**

On March 25, 2022, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2021 annual charges update filed, as previously reported, on June 15, 2021, and as amended on June 20, 2021 and July 8, 2021 (the "Versant 2021 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2021 Annual Update, all of which are resolved by the Versant 2021 Annual Update Settlement Agreement. Comments on the Versant 2021 Annual Update Settlement Agreement were due on or before April 14, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 2020 Annual Update Settlement Agreement (ER15-1434-005)**

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 10, 2021; reply comments, December 19, 2021; none were filed. There was no

[62] *See* Filing of Third Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP86 Under Schedule 21-NEP to the ISO New England Inc. Open Access Transmission Tariff, *ISO New England Inc.*, Docket No. ER22-927 (filed Jan. 31, 2022); *ISO New England Inc.*, Docket No. ER22-927 (Mar. 31, 2022) (unpublished letter order accepting changes).

[63] *The Narragansett Electric Co.,* Docket No. ER22-2732-000 (Oct. 18, 2022) (unpublished letter order).

activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

Fitchburg Gas & Electric's ("FG&E") June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Regional Refund Reports (EL11-66)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[64] *and 531-B*[65] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Capital Projects Report - 2022 Q3 (ER23-114)**

On October 14, 2022, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2022 (the "Report").[66] Report highlights included the following new projects: (i) FCM *Order 2222* ($1.15 million); and (ii) IT Asset Workflow Integration and Updates ($1.06 million). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) 2022 Issue Resolution ($120,000); (ii) Privileged Account Management Security Enhancements ($105,900); and (iii) Packet Broker Infrastructure Replacement Project ($105,500). Comments on the 2022 Q3 Report are due on or before November 4, 2022. On October 31, NEPOOL intervened doc-lessly and submitted comments supporting the Report. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **LFTR Implementation: 56th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 56th of its quarterly status reports regarding LFTR implementation on October 14, 2022. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE

64 *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

65 *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

66 *ISO New England Inc.*, Docket No. ER21-2632 (Oct. 1, 2021) (unpublished letter order).

concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

- **Reserve Market Compliance (33rd) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[67] as modified,[68] ISO-NE submitted its 33rd semi-annual reserve market compliance report on October 3, 2022. In the 33rd report, ISO-NE stated that it "will begin discussions with stakeholders in the coming months regarding development of day-ahead ancillary services, and is currently seeking to file the proposed market design changes by the end of 2023. As those discussions proceed, the ISO will update the Commission regarding the relation of the proposed day-ahead ancillary services to a forward TMSR market, through future reports in this docket." The October 3 report was not noticed for public comment. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

IX. Membership Filings

- **November 2022 Membership Filing (ER23-310)**

On October 31, 2022, NEPOOL requested that the FERC accept (i) the memberships of: Derby Fuel Cell, LLC [Related Person to Fuel Cell Energy Companies, DFC ERG CT and Bridgeport Fuel Cell (AR Sector, RG Sub-Sector)]; KCE CT 5, KCE CT 7, KCE CT8, and KCE CT 9 [Related Persons to KCE CT 1 and 2 (Provisional Group Member); Maven Energy, LLC (Supplier Sector); Rhode Island Bioenergy, LLC [Related Person to Rhode Island Bioenergy Facility, LLC (AR Sector, RG Sub-Sector, Small RG Group Member); Rhode Island Division of Public Utilities Carriers End User Sector); Sunnova Energy Corporation (AR Sector, DG Sub-Sector); and Triolith Energy Fund, LP (Supplier Sector); (ii) the termination of the Participant status of EIP Investment, LLC (Provisional Group Member); and (iii) the name change of Stones DR, LLC (f/k/a Centrica Business Solutions Optimize, LLC). Comments on the November Membership filing are due on or before November 21, 2022.

- **October 2022 Membership Filing (ER22-2982)[69]**

On September 30, 2022, NEPOOL requested that the FERC accept (i) the memberships of Danske Commodities US LLC (Supplier Sector); The Massachusetts Climate Action Network (End User Sector); MFT Energy US 1 LLC (Supplier Sector); and Spotlight Power LLC (Supplier Sector); and (ii) the termination of the Participant status of IPKeys Power Partners, Inc. (Supplier Sector). Comments on the October Membership filing were due on or before October 21, 2022; none were filed. This matter is pending before the FERC.

X. Misc. - ERO Rules, Filings; Reliability Standards

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02")) on September 15,

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[67] *See NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) ("*ASM II Order*") (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh'g denied* 117 FERC ¶ 61,106 (2006).

[68] *See NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve ("TMSR")).

[69] There was no September membership filing.

2022.[70] Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. A revised schedule for Project 2016-02, which has not changed since the last (June 2022) quarterly report, calls for final balloting of revised standards in October 2022, NERC Board of Trustees Adoption in November 2022 and filing of the revised standards with the FERC in December 2022.

- **2023 NERC/NPCC Business Plans and Budgets (RR22-4)**

On August 23, 2022, and as amended on September 12, 2022 (to correct MISO-related numbers), NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2023. FERC regulations[71] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2023 funding requirement represents an overall increase of approximately 13.7% over NERC's 2022 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $10.97 million. NPCC has requested $18.14 million in statutory funding (a U.S. assessment per kWh (2021 NEL) of $0.0000600) and $1.07 million for non-statutory functions. Comments on NERC's amended filing were due on or before ***October 7, 2022***. As previously reported, EEI submitted comments supporting NERC's budget plan and budget ("BP&B"), but suggesting that the size of the budget increase warrants subsequent analysis to ensure the effectiveness of the new expenditures. NERC answered EEI's comments, committing to public accountability for its BP&B, and requesting that the FERC allow NERC's efforts underway to "identify qualitative and quantitative ways to illustrate NERC's value relative to its budget" to continue during the 2024 BP&B planning process. There were no further comments and this matter is now pending before the FERC.

- **NPCC Bylaws Changes (RR22-2)**

As previously reported, the FERC conditionally approved, on July 8, 2022, changes to the NPCC Bylaws (the "Bylaws") designed to, among other things: (1) to improve corporate governance; (2) to ensure consistency with the Not-for-Profit Corporation Law of the State of New York ("N-PCL"), pursuant to which NPCC is organized; and (3) to remove extraneous provisions rom the Bylaws, create efficiencies, and reflect changes at NPCC since 2012 (when the last changes to the Bylaws were filed).[72] In accepting the Bylaws Changes, the FERC directed NERC/NPCC to submit in a compliance filing, due, following an extension of time requested and granted, on or before October 6, 2022, changes that (i) provide members being terminated for failure to comply with bylaw provisions related to qualifications, obligations, and conditions of membership (a) notice within a reasonable time period of the NPCC Board's membership termination decision and the reason(s) for the action and (b) the option to appeal the membership termination in accordance with the due process requirement in FPA Section 215; and (ii) specifically describe the method of providing public notice of member meetings. The FERC found Public Citizen's protest[73] beyond the scope of the proceeding. The Bylaws changes were accepted effective as of the date of the order, or July 8, 2022, as requested.

Compliance Filing. On October 5, 2022, NERC and NPCC submitted as directed their compliance filing in response to the July 8, 2022 order. The compliance filing revises the Bylaws to (i) require that prior to terminating any NPCC Member under section 4.6, the NPCC Board must provide the affected Member 21 days prior written

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[70] The other project which had been addressed in prior updates, Project 2019-02, has concluded, and the FERC approved in RD21-6 the Reliability Standards revised as part of that project (CIP-004-7 and CIP-011-3) on Dec. 7, 2021.

[71] 18 CFR § 39.4(b) (2022).

[72] *N. Am. Elec. Rel. Corp.*, 180 FERC ¶ 61,016 (July 8, 2022).

[73] In its protest, Public Citizen argued that the FERC should require a change to the composition of NPCC's Board of Directors, suggesting that NPCC be compelled to ensure that, of NPCC's eight board sectors and 15 voting members, "household consumer advocates" have two voting seats in Sector 7 (Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities), and that regulators, reliability coordinators, and end-users compose at least half of the voting seats of the board.

notice and an opportunity to cure the problem or appeal the reason for the proposed termination; (ii) to specify that the meeting notices shall be posted on NPCC's public website in a "reasonably prominent location; and (iii) to update the NPCC Bylaws' Table of Contents. Comments on the compliance filing were due on or before October 26, 2022; none were filed. The compliance filing is pending before the FERC.

- **Notice of Penalty: National Grid (NP22-33)**

On September 29, 2022, NERC filed a Notice of Penalty regarding National Grid's violation of Reliability Standards FAC-008-3 (Transmission Vegetation Management) Requirements 6 and 8, and PRC-023-4 (Transmission Relay Loadability) Requirement 1. Specifically, NPCC, NERC's Regional Entity for the Northeast, determined that National Grid (i) did not maintain accurate Facility Ratings consistent with its Facility Ratings Methodology at Facilities used for the planning and operation of the Bulk Power System ("BPS") in New York and New England, (ii) did not provide to its Reliability Coordinator accurate Facility Ratings or the accurate identity of the most limiting element of the Facility for a total of 154 Facilities (or 21% of the Entity's Facilities in scope of the Standard), and (iii) had 16 protective relay settings affecting 13 transmission lines, seven of which were 345 kV feeders and eight were part of an IROL, which did not meet various Criteria specified in PRC-023-4 R1. NERC said that the violations were caused by ineffective inter-departmental coordination or silos between departments, and contributing causes included insufficient communication, gaps in procedures, insufficient training, and failure to recognize the loadability impact of limiting transformers installed in series with applicable feeders on protection relays' settings.

To resolve all outstanding issues arising from NPCC's determinations and findings, NPCC and National Grid entered into a Settlement Agreement in which National Grid agreed to a ***$512,000 penalty***, in addition to other activities outlined in the Settlement Agreement. Pursuant to 18 CFR § 39.7(e), and because the FERC determined that it would not further review the Notice of Penalty,[74] the penalty became effective October 29, 2022. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XI. Misc. - of Regional Interest

- **203 Application: Seneca Energy II / BP (EC23-18)**

On October 31, 2022, Seneca Energy II, LLC ("Seneca") and wholly owned subsidiaries of BP Products North America Inc. ("BP") requested authorization for a transaction pursuant to which Seneca will ultimately become a Related Person of BP. Comments on the 203 application are due on or before ***November 21, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: ConEd / RWE (EC23-17)**

On October 28, 2022, RWE Renewables Americas, LLC ("RWE") and ConEd[75] requested authorization for a transaction pursuant to which RWE will acquire 100% of the equity interests in ConEd's Clean Energy Businesses (including NEPOOL members Consolidated Edison Energy, Inc.; Consolidated Edison Development, Inc.; and Consolidated Edison Solutions, Inc. (but not Consolidated Edison Company of New York)). Comments on the 203 application are due on or before ***November 28, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Great River Hydro / HQI US (EC23-16)**

Also on October 28, 2022, Great River Hydro, LLC ("Great River Hydro") and HQI US Holding LLC ("HQUI US"), an indirect and wholly-owned subsidiary of Hydro-Québec ("HQ") requested authorization for a transaction

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[74] *N. Am. Elec. Rel. Corp.*, 181 FERC ¶ 61,082 (Oct. 28, 2022).

[75] "ConEd" includes Consolidated Edison, Inc., its wholly-owned subsidiary Con Edison Clean Energy Businesses, Inc. ("CEB"), and CEB's public utility subsidiaries (together, members of the Supplier Sector). RWE's NEPOOL Related Person (Cassadaga Wind LLC) is a member of the Supplier Sector.

pursuant to which HQI US will indirectly acquire 100% of the membership interests in Great River Hydro. Comments on this 203 application are due on or before ***November 18, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: EDF Energy / BP Retail (EC22-122)**

On September 21, 2022, BP Retail Energy LLC ("BP Retail") and EDF Energy Services, LLC ("EDF Energy") requested authorization for a transaction pursuant to which BP Retail will acquire 100% of the membership interests in EDF Energy. Comments on this 203 application were due on or before October 12, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Salem Harbor / Lenders (EC22-117)**

On October 31, 2022, the FERC authorized[76] as requested a transaction pursuant to which the direct and indirect equity interests in Salem Harbor that are currently directly and indirectly held by Salem Harbor Power FinCo, LP will be transferred to a newly formed Delaware limited liability company ("New HoldCo"), and (2) the equity interests of New HoldCo will be issued to Salem Harbor's lenders (the "Lenders") under a pre-petition credit facility. Among other standard conditions, the October 31 order requires that notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Centrica / CPower (EC22-90)**

As previously reported, the FERC authorized on September 29, 2022 the sale of 100% of the equity interests in Centrica Business Solutions Optimize ("Centrica") to Enerwise Global Technologies, LLC d/b/a CPower ("CPower").[77] On October 12, 2022, Centrica and CPower filed a notice that the sale was consummated on October 6, 2022. Accordingly, CPower and Centrica (now known as Stones DR, LLC, *see* Section IX above (ER23-310)) are now Related Persons and together with Jericho Power and LS Power Grid Northeast, LLC are members of the AR Sector's RG Sub-Sector. Reporting on this proceeding is now concluded. If you have any last questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Waterside Power / KKR (EC22-79)**

As previously reported, the FERC authorized on August 19, 2022 the sale of 100% of the equity interests in Applicants, including Generation Group Seat Member Waterside Power, among others,[78] to Cretaceous Bidco Limited ("Buyer"), a special purpose vehicle indirectly owned by funds, investment vehicles and/or separately managed accounts advised and/or managed by one or more subsidiaries of KKR & Co. Inc. ("KKR & Co." and, together with its subsidiaries, ("KKR")).[79] Pursuant to the *August 19 Order*, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[76] *Salem Harbor Power Development LP*, 181 FERC ¶ 62,084 (Oct. 31, 2022).

[77] *Centrica Business Solutions Optimize, LLC and Enerwise Global Technologies, LLC*, 180 FERC ¶ 62,175 (Sep. 29, 2022).

[78] In addition to Waterside Power, "Applicants" are: Lea Power Partners, LLC; Badger Creek Limited; Chalk Cliff Limited; Double C Generation Limited Partnership; High Sierra Limited; Kern Front Limited; McKittrick Limited; Bear Mountain Limited; Live Oak Limited; and WGP Redwood Holdings, LLC.

[79] *Lea Power Partners, LLC*, 180 FERC ¶ 62,086 (Aug. 19, 2022) ("*August 19 Order*").

- **203 Application: Stonepeak / JERA Americas (EC22-71)**

On June 1, 2022, Stonepeak[80] requested authorization for the sale of 100% of the interests in Canal Power Holdings LLC to a wholly-owned affiliate of JERA Americas Inc. ("JERA Americas").[81] Comments on the 203 application were due on or before June 22, 2022 and were filed by the MA AG (which encouraged the FERC to take the time necessary to comprehensively review the Application based on potential regional and SENE Capacity Zone competition and rate impacts) and Public Citizen (which raised four issues: (i) the potential threat to competition and rates that could be caused by the concentration of power generation ownership by JERA in ISO-NE and NYISO; (ii) the need for additional information to assess impacts on competition and rates as well as potential divestiture requirements to mitigate any threats to competition and rates; (iii) a desire for public disclosure of the purchase price; and (iv) what threats to rates might result from the Related Person relationships to be created and reflected in the NEPOOL stakeholder process). On July 1, 2022, Stonepeak answered the comments and protest. On August 8, 2022, Applicants submitted an informational filing informing the FERC that the Applicants and parties to the Transaction have received all other required regulatory approvals and the FERC's authorization in this proceeding is the only remaining regulatory approval for the Transaction and requested a FERC order authorizing the transaction by August 15, 2022. Notwithstanding Applicants' request, this matter remains pending before the FERC. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Service Agreement Cancellation: NEP/Pawtucket (ER23-144)**

On October 19, 2022, New England Power submitted a Notice of Cancellation of the Firm Local Generation Deliverability Service Agreement ("Service Agreement") with Pawtucket Power Associates Limited Partnership ("Pawtucket"). Pawtucket decommissioned and retired the generating facility covered by the Service Agreement effective June 1, 2022. Therefore, the Service Agreement is no longer required. NEP requested a December 19, 2022 effective date for the Notice of Cancellation. Comments on this filing are due on or before ***November 9, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: CL&P/NY Transco (ER22-2830)**

On September 12, 2022, CL&P filed an Agreement for Engineering, Design and Procurement (the "D&E Agreement") between itself and New York Transco LLC ("NY Transco"). The D&E Agreement sets forth the terms and conditions under which CL&P will perform the necessary services to address the impacts of NY Transco's reinforcement of a major 345 kV transmission corridor in New York that will have reliability impacts on the New England System. CL&P requested that the D&E Agreement be accepted for filing as of September 13, 2022. Comments on this filing were due on or before October 3, 2022; none were filed. NY Transco filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **A&R E&P Agreement: Seabrook/NECEC Transmission (ER22-2807)**

On October 24, 2022, the FERC accepted an amended and restated Engineering and Procurement Agreement between NextEra Energy Seabrook, LLC ("Seabrook") and NECEC Transmission LLC ("NECEC") (the "A&R E&P Agreement").[82] As previously reported, the A&R Agreement covers the final engineering drawings through the procurement and delivery of the 24.5 kV generator circuit breaker and ancillary equipment to Seabrook Station in advance of the Fall 2024 outage. The parties agreed to enter into the A&R EP Agreement to provide for greater clarity, rather than amending the original E&P Agreement. This filing was not intended

[80] "Stonepeak" includes Canal Power Holdings LLC ("Seller"), and its indirect wholly-owned, public utility subsidiaries, Canal Generating LLC ("Canal Generating"), Canal 3 Generating LLC ("Canal 3"), Bucksport Generation LLC ("Bucksport"), and Stonepeak Kestrel Energy Marketing LLC ("Stonepeak Marketing").

[81] JERA Americas Related Persons include Provisional Member Cricket Valley Energy Center, LLC.

[82] *NextEra Energy Seabrook, LLC*, Docket No. ER22-2807-000 (Oct. 24, 2022) (unpublished letter order).

to affect the pending proceedings in either Docket No. EL21-3-000 or EL21-6-000 described in Section I above. The A&R E&P Agreement was accepted for filing effective as of September 8, 2022. Unless the October 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Power MPD OATT *Order 881* Compliance Filing (ER22-2358)**

On July 12, 2022, in response to the requirements of *Order 881*, Versant Power filed a proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT"). Attachment T, Versant reported, incorporates all the contents of the *pro forma* OATT's new Attachment M. An effective date of July 12, 2025 was requested in an errata filing submitted on August 1, 2022. On August 2, 2022, MPUC submitted comments asserting that Versant's Compliance Filing, without further detail, is insufficient to meet the requirements of *Order 881* and should either (i) be rejected outright, ordering Versant to re-file with sufficient detail, or (ii) subject to a deficiency letter requiring further information with respect to the Compliance Filing. MPUC withdrew those comments on August 31, 2022 in exchange for certain understandings with Versant Power (including MPUC's attendance, as a non-voting participant, at any NMISA working group discussions on *Order 881* implementation planning and Versant Power's submission of informational compliance filings to keep the FERC apprised of versant's progress in developing its AAR implementation plan). On September 6, 2022, Versant Power supplemented its compliance filing to confirm the MPUC's understandings, as delineated in its Notice of Withdrawal. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Versant Power MPD OATT *Order 676-J* Compliance Filing Part I (ER22-1142)**

As previously reported, Versant Power filed revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards in response to the requirements of *Order 676-J*, ("Versant MPD OATT *Order 676-J* Part I Changes").[61] A placeholder effective date was submitted. Comments on this filing were due on or before March 23, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): *New England Compliance Filings* (various)**

In accordance with *Order 864*[83] and *Order 864-A,*[84] and extensions of time granted, New England's transmission-owning public utilities submitted their *Order 864* compliance filings, with specific dockets and filing dates of the filings still pending or accepted since the last Report identified in the following table. The FERC has, at

[83] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess Accumulated Deferred Income Taxes ("ADIT") from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information ("ADIT Worksheet"). The ***ADIT Worksheet*** must contain the following five specific categories of information: (i) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein ("***Category 1 Information***"); (ii) is the accounting for any excess or deficient amounts in Accounts 254 (Other Regulatory Liabilities) and 182.3 (Other Regulatory Assets) ("***Category 2 Information***"); (iii) whether the excess or deficient ADIT is protected (and thus subject to the Tax Cuts and Jobs Act's normalization requirements) or unprotected ("***Category 3 Information***"); (iv) the accounts to which the excess or deficient ADIT are amortized ("***Category 4 Information***"); and (v) the amortization period of the excess or deficient ADIT being returned or recovered through the rates ("***Category 5 Information***"). In addition, the FERC stated that it expects public utilities to identify each specific source of the excess and deficient ADIT, classify the excess or deficient ADIT as protected or unprotected, and list the proposed amortization period associated with each classification or source.

[84] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 171 FERC ¶ 61,033, Order No. 864-A (Apr. 16, 2020) ("*Order 864-A*").

this point, addressed all but one of the *Order 864* compliance filings (UI's May 10 filing). The *Order 864* compliance proceeding that remains open and those filings accepted since the last Report are as follows:

Docket(s)	Transmission Provider	Date of Last Filing	Date Accepted
ER21-1130 ER20-2572	New England TOs (RNS)	Feb 18, 2022	Oct 7, 2022
ER20-2429	CMP (LNS)	May 6, 2022	Oct 26, 2022
ER21-1702	CMP (Schedule 1 Appendix A Implem. Rule)	Feb 28, 2022	Oct 26, 2022
ER20-2551	NEP (Sched. 21-NEP and TSA-NEP-22 Compliance Revs.)	Jul 18, 2022	Oct 25, 2022
ER20-2219	NEP (Tariff No. 1)	Oct 3, 2022	Oct 25, 2022
ER20-2553	NEP (MECO/Nantucket LSA)	Jul 18, 2022	Oct 25, 2022
ER22-1850	UI	May 10, 2022	Pending

XII. Misc. - Administrative & Rulemaking Proceedings[85]

- **Interregional HVDC Merchant Transmission (AD22-13)**

On July 19, 2022, Invenergy Transmission filed a petition requesting that the FERC hold a technical conference to explore ways to potentially make available and compensate certain grid reliability and resilience benefits associated with interregional high voltage direct current ("HVDC") merchant transmission. Any comments to be considered by the FERC in its determination of any action to be taken were due on or before August 26, 2022. Comments were filed by 13 parties and included, among others, CSC, ENGIE, Invenergy, Phase I/II Asset Owners and IRH, Joint Consumer Advocates, MISO, ACORE, ACPA, SEIA, and Neptune and Hudson. Invenergy answered the comments filed by MISO. This matter is pending before the FERC.

- **Reliability Technical Conference (Nov 10) (AD22-10)**

On November 10, 2022, from 12-5 pm, the FERC will convene its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the Bulk-Power System. The conference will be in person, open for the public to attend, and without fee for attendance. The FERC issued supplemental notices on October 4 and 28, 2022, which identified both the panel compositions and speakers. The conference's two panels are: (I) "Managing the Electric Grid to Advance Reliability" (to explore the current state of grid reliability and efforts that can be undertaken to improve it); and (II) "Managing Cyber Security Threats, the CIP Reliability Standards, and Best Practices for the Bulk-Power System" (to discuss how cyber security governance encompasses the CIP Reliability Standards and compliance as well as best practices; the challenges of implementing appropriate oversight; and ways in which industry can address these challenges to improve its response to evolving vulnerabilities and threats to reduce the risk to the BPS).

- **New England Gas-Electric Forum (AD22-9)**

The FERC held a New England Gas-Electric Forum on September 8, 2022 in Burlington, VT. The purpose of the Forum was to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are needed to inform the development of solutions to these challenges. On September 21, 2022, the FERC invited parties wishing to submit comments regarding the topics discussed at the Forum to do so on or before ***November***

[85] Reporting on the following Administrative & Rulemaking proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: Improving Generating Units Winter Readiness (AD22-4); NOI: Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses (RM22-5); NOI: Reactive Power Capability Compensation (RM22-2); NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14).

7, 2022. Since the last Report, a transcript of the conference was posted in the FERC's eLibrary and comments were posted from four individuals and the Business & Industry Association of New Hampshire.

- **Transmission Planning and Cost Management Technical Conference (AD22-8)**

On October 6, 2022, the FERC convened a Commissioner-led technical conference regarding transmission planning and cost management for transmission facilities developed through local or regional transmission planning processes. The 5 panels throughout the day addressed: (1) the processes by which transmission providers develop local transmission planning criteria, identify local transmission needs using those criteria, and evaluate and choose local transmission facilities to address those needs; (2) whether local transmission facility costs are adequately scrutinized; (3) the processes by which transmission providers evaluate, select, and develop regional transmission facilities for reliability; (4) whether regional transmission facilities for reliability costs are adequately scrutinized; and (5) cross-cutting themes and potential best practices for both local transmission facilities and regional reliability transmission planning and cost management, in addition to innovative approaches that could be explored further, including the possibility of establishing a role for an Independent Transmission Monitor, and mechanisms to support enhanced transparency. Advance materials were submitted by representatives on behalf of: ISO-NE, CA PUC, KY PSC, NC Utils. Comm. Public Staff, NV PUC, RI PUC, AEE, AEP, Ameren, AMP/APPA, Ari Peskoe, L. Azar, Clean Energy Buyers Assoc., Coalition of MISO Customers, Harvard Electricity Law Initiative, ITC Holdings, LPPC, IA Consumer Advocate, J. Macey, NESCOE, Northern California Power Agency, Northwest & Intermountain Power Producers Coalition, OH Consumers' Counsel, OH PUC, Old Dominion Elec. Coop., PJM, G. Poulus, SPP, Potomac Economics, Southern California Edison, Southern Environmental Law Center, and TAPS/FMPA and WIRES.

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. An additional supplemental notice identifying the opportunity for interested parties to submit post-technical conference comments has yet to be issued. On November 1, 2022, a transcript of the technical conference was posted in the FERC's eLibrary.

- **NOI: Dynamic Line Ratings (AD22-5)**

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[86] seeking comments on (i) whether and how the required use of dynamic line ratings ("DLR") is needed to ensure just and reasonable wholesale rates; (ii) whether the lack of DLR requirements renders current wholesale rates unjust and unreasonable; (iii) potential criteria for DLR requirements; (iv) the benefits, costs, and challenges of implementing DLRs; (v) the nature of potential DLR requirements; and (vi) potential timeframes for implementing DLR requirements. This NOI represents the first step in the FERC's effort to gather more information about the costs and benefits, and potentially mandating the use, of DLRs. A more detailed summary was provided to the Transmission Committee and is posted on the Transmission Committee's webpage.

Initial comments were due April 25, 2022 and filed by: ISO-NE; DC Energy; Eversource; Clean Energy Parties; Potomac Economics; CT DEEP; NERC; US DOE; CAISO; MISO; NYISO; Org of MISO States; PJM, SPP; SPP MMU; AEP; Alliant; APPA; APS; AZ PUC; Clean Energy Entities; Dayton Power; EEI; ELCON; Entergy; IN Util. Reg. Comm.; ITC; LA DPW; MISO TOs; NRECA; NYISO TOs; PPL; R Street Institute; Southern Co.; TAPS; Tri-State; Electricity Canada; Electric Grid Monitoring; Line Vision; Idaho Power.

[86] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (Feb. 17, 2022) ("*Dynamic Line Ratings NOI*").

Reply comments were due on or before May 25, 2022[87] and were filed by: AEP, Clean Energy Entities,[88] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter is pending before the FERC.

- **Joint Federal-State Task Force on Electric Transmission (AD21-15)**

The next (fifth) meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force")[89] will be held on November 15, 2022, in New Orleans, LA. All interested persons were invited to file comments in this docket suggesting agenda items by October 7, 2022. Comments were filed by ACRE and G. van Uytven. Task Force members will consider those comments in developing the agenda for the November 15, 2022 public meeting. Of note, since the last Report, NARUC nominated and the FERC accepted[90] Chair Tricia Pridemore of the Georgia Public Service Commission to represent the Southeastern Association of Regulatory Utility Commissioners ("SEARUC") region of NARUC on the Task Force for the remainder of the one-year term of Chairman Ted Thomas of the Arkansas Public Service Commission, who resigned his position.

Recent Transmission Task Force Public Meetings[91]

♦ ***July 20, 2022***. A fourth meeting was held in San Diego, CA, on July 20, 2022. Discussion addressed (i) interregional transmission planning & transmission project development; and (ii) the FERC's *Transmission NOPR*. A transcript of the meeting was posted in eLibrary on August 11, 2022. The FERC invited post-meeting comments addressing issues raised during and in the agenda for the July 20 meeting. Those comments were due on or before September 2, 2022. Comments were filed by ACRE, AEP, Invenergy, MISO, and PJM.

- **Modernizing Electricity Market Design - Resource Adequacy (AD21-10)**

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[92] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before ***October 18, 2022*** a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs.

ISO-NE Report. On October 18, 2022, ISO-NE (as well as the other ISO/RTOs) filed its report in response to the *Order Directing Reports.* Comments in response to the RTO/ISO reports are due on or before ***December 19, 2022***. The FERC will review the reports and comments to determine whether further action is appropriate.

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[87] The *Dynamic Line Ratings NOI* was published in the Fed. Reg. on Feb. 24, 2022 (Vol. 87, No. 37) pp. 10,349-10,354.

[88] The "Clean Energy Entities" are the Working for Advanced Transmission Technologies Coalition ("WATT"), ACPA, AEE, and SEIA.

[89] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021). The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective." New England is represented by Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU), each of whom will be serving a second term during the Sept. 1, 2022 – Aug. 31, 2023 term. *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

[90] *Joint Federal-State Task Force on Elec. Trans.*, 181 FERC ¶ 61,088 (Oct. 31, 2022) (order listing new member).

[91] Summaries of the first – third meetings of the Transmission Task Force can be found in previous Reports.

[92] *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029 (Apr. 21, 2022) ("*Order Directing Reports*").

2021 Technical Conferences. The *Order Directing Reports* follows a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[93] and energy and ancillary services markets.[94]

- **NOPR: Duty of Candor (RM22-20)**

On July 28, 2022, the FERC issued a NOPR[95] proposing to add a new section to its regulations to require that any entity communicating with the FERC or other specified organizations (e.g. ISO/RTOs, FERC-approved market monitors, NERC and its Regional Entities, or transmission providers) related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information, or omit material information ("Duty of Candor Requirements"). An entity would be shielded from violation of the new regulation if it has exercised due diligence to prevent such occurrences. The FERC's current regulations prohibit, in defined circumstances, inaccurate communications to the FERC and other organizations upon which the FERC relies to carry out its statutory obligations. However, because those requirements cover only certain communications and impose a patchwork of different standards of care for such communications, the FERC believes that a broadly applicable duty of candor will improve its ability to effectively oversee jurisdictional markets. It further indicated that its proposed due 'diligence standard' and other limitations are intended to minimize the additional burdens to industry that come with the new Duty of Candor Requirements.

On September 1, 2022, Joint Associations[96] requested an additional month to submit comments.[97] On September 14, 2022, the FERC granted that request. Accordingly, initial comments are now due ***November 11, 2022***.

- **NOPR: Advanced Cybersecurity Investment (RM22-19)**

On September 22, 2022, the FERC issued a NOPR[98] proposing to provide incentive-based rate treatments for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by utilities for the purpose of benefitting consumers by encouraging investments by utilities in advanced cybersecurity technology and participation by utilities in cybersecurity threat information sharing programs, as directed by the Infrastructure Investment and Jobs Act of 2021 ("Infrastructure and Jobs Act"). This

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93 The FERC held two staff-led technical conferences addressing resource adequacy, one on Mar. 23, 2021 (with post-conference comments focused on PJM-specific issues) and the other on May 25, 2021 (focused on the wholesale markets administered by ISO-NE). Following the Mar. 23 conference, more than 45 sets of initial comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA. Reply comments were filed by ACPA, AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), PJM Power Providers ("P3"), Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA"). Following the May 25 conference, comments were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

94 The FERC held two staff-led technical conferences addressing ISO/RTO EAS markets, one on Sept. 14, 2021; the second on Oct. 12, 2021. Transcripts of both technical conferences are posted in eLibrary. In advance of the EAS technical conferences, FERC staff issued on Sept. 7, 2021 a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs" summarizing recent EAS markets reforms as well as reforms then under consideration. Initial comments on the topics discussed during the EAS technical conferences were filed by: ISO-NE, Appian Way Energy Partners, Constellation, Dominion, Envir. Defense Fund, FirstLight, LS Power, CAISO, MISO, NYISO, PJM, SPP MMU, ACPA, Clean Energy Organizations, EEI, Energy Trading Institute, EPRI, EPSA, Middle River Power, National Hydropower Assoc., NYSERDA, PJM Providers Group, and Public Citizen. Reply comments were filed by EPRI, NERC and its Regional Entities and Vistra.

95 *Duty of Candor*, 180 FERC ¶ 61,052 (July 28, 2022) ("*Duty of Candor NOPR*").

96 "Joint Associations" included the following trade associations on behalf of their respective members: the American Gas Association ("AGA"), American Public Gas Association ("APGA"), Interstate Natural Gas Association of America ("INGA"), Edison Electric Institute ("EEI"), Electric Power Supply Association ("EPSA"), Energy Trading Institute ("ETI"), Natural Gas Supply Association ("NGA"), and Process Gas Consumers Group ("PGCG").

97 The *Duty of Candor NOPR* was published in the *Fed. Reg.* on Aug. 12, 2022 (Vol. 87, No. 155) pp. 49,784-49,793.

98 *Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives*, 180 FERC ¶ 61,189 (Sep. 22, 2022) ("*Advanced Cybersecurity Investment NOPR*").

NOPR also terminated the NOPR proceeding in Docket RM21-3 (*Dec 2020 Cybersecurity Incentives NOPR*)[99] described in previous Reports. Initial comments on the *Advanced Cybersecurity Investment NOPR* are due on or before ***November 7, 2022***; reply comments, ***November 21, 2022***.[100]

- **NOPR: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)**

On June 16, 2022, as corrected on July 12, 2022, the FERC issued a notice[101] proposing to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[102] (how they establish a scope for their extreme weather vulnerability assessments, develop inputs, identify vulnerabilities and determine exposure to extreme weather hazards, estimate the costs of impacts, and develop mitigation measures to address extreme weather risks). Initial comments were due August 30, 2022[103] and were filed by over 13 parties, including among others, Eversource, NRDC, NERC, MISO, PJM, and EPSA. This matter is pending before the FERC.

- **NOPR: Interconnection Reforms (RM22-14)**

On June 16, 2022, the FERC issued a notice of proposed rulemaking ("NOPR"),[104] more than 400 pages long, that proposes reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("LGIA"), and *pro forma* Small Generator Interconnection Agreement ("SGIA") to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

Initial Comments. Initial comments were due October 13, 2022[105] and over 130 sets of comments were filed, including: NEPOOL, ISO-NE, NESCOE, AEE, Anbaric, Avangrid, Cypress Creek Renewables, Dominion, EDF Renewables, ENGIE, Envir. Defense Fund, Longroad, National Grid, NextEra, PPL, RWE, Shell, VELCO, Vistra, ACPA, ACRE, APPA, US DOE, EEI, ELCON, EPRI, EPSA, IRC, NARUC, NERC, NRECA, PIOs, R Street Institute, SEIA, State Agencies, and WIRES.

Reply Comments. Following a request by EEI for a 30-day extension of time to submit reply comments, supported by AAE, ACPA, ACRE, and SEI, and granted by the FERC on October 28, 2022, reply comments are now due ***December 14, 2022***.

The proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process; (2) reforms to increase the speed of interconnection queue processing; and (3) reforms to incorporate technological advancements to the interconnection process. Within each of these categories, the FERC proposes a wide array of reforms, and requests comment.

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[99] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Dec 2022 Cybersecurity Incentives NOPR*"). As described in previous Reports, the *Dec 2022 Cybersecurity Incentives NOPR* proposed to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the Bulk Power System.

[100] The *Advanced Cybersecurity Investment NOPR* was published in the *Fed. Reg.* on Oct. 6, 2022 (Vol. 87, No. 193) pp. 60,567-60,580.

[101] *One-Time Informational Reports on Extreme Weather Vulnerability Assessments; Climate Change, Extreme Weather, and Elec. Sys. Rel.*, 179 FERC ¶ 61,196 (June 16, 2022) ("*Extreme Weather Vulnerability Assessments NOPR*").

[102] "Extreme weather vulnerability assessments" are proposed to be defined as "analyses that identify where and under what conditions jurisdictional transmission assets and operations are at risk from the impacts of extreme weather events, how those risks will manifest themselves, and what the consequences will be for system operations".

[103] The *Extreme Weather Vulnerability Assessments NOPR* was published in the *Fed. Reg.* on July 1, 2022 (Vol. 87, No. 126) pp. 39,414-39,426.

[104] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) ("*Interconnection* Reforms *NOPR*").

[105] The *Interconnection Reforms NOPR* was published in the *Fed. Reg.* on July 5, 2022 (Vol. 87, No. 127) pp. 39,934-40,032.

To implement the **first-ready, first-served cluster study process**, the FERC proposes to:

- Require transmission providers offer an alternative option for an informational interconnection study that would not require a project enter the interconnection queue;
- Make cluster studies the required interconnection study method under the *pro forma* LGIP;
- Allocate the shared costs of the cluster studies so that 90% of the applicable study costs are allocated to interconnection customers on a pro rate basis based on the requested MWs included in the applicable cluster, and 10% of the applicable study costs are allocated to interconnection customers on a per capita basis based on the number of interconnection requests in the applicable cluster;
- Require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method, in which the transmission provider will determine the degree to which each generating facility in the cluster contributes to the need for a specific network upgrade;
- Allow interconnection customers in an earlier-in-time cluster to share the costs of network upgrades with interconnection customers who will significantly benefit from those upgrades but would not share the cost of the network upgrades solely by virtue of being in a later cluster;
- Increase study deposits based on the size of the generating facility from $35,000 to $250,000;
- Require more stringent site control requirements, and proposes to require an interconnection customer to demonstrate 100% site control for a proposed generating facility when they submit the interconnection request;[106]
- Implement a commercial readiness framework whereby interconnection customers must show demonstrable milestones towards commercial readiness in order to enter the cluster, such as an executed term sheet, reasonable evidence the project was selected in a resource plan, or a provisional LGIA;[107] and
- Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.[108]

To **increase the speed of the interconnection queue process**, the FERC proposes to:

- Eliminate the “reasonable efforts” standard for transmission providers completing interconnection studies and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines. The penalty imposed would be $500 per day that the study is late and would be distributed to interconnection customers on a pro rata basis;
- Add an entirely *pro forma* affected system study process to address the current lack of uniformity in the study of affected systems, which results in late-stage withdrawals, re-studies and increased costs to remaining interconnection customers;
- Establish two new *pro forma* agreements, a *pro forma* Affected System Study Agreement (new Appendix 15) and a *pro forma* Affected Systems Facilities Construction Agreement (new Appendix 16); and

[106] The FERC proposes to limit the option to provide a financial deposit in lieu of site control and would only allow this option when regulatory limitations prohibit the interconnection customer from obtaining site control. In such instances, the interconnection customer would submit a deposit of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million.

[107] *Id.* at P 128.

[108] The proposed withdrawal penalty will increase as the interconnection customer moves through the interconnection queue and proposes a chart demonstrating the possible penalties at P 144.

- Implement an optional resource solicitation study that can be performed by entities required to conduct a resource plan or solicitation. Under this proposed study process, a resource planning agency (such as a state agency or load-serving entity implementing a state mandate) would facilitate a study to group together interconnection requests associated with the qualifying resource solicitation process, and the resources vying for selection in a qualifying state resource solicitation process would be studied together for the purposes of informational interconnection studies.

Finally, as **technological advances to the interconnection process**, the FERC proposes to:

- Require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request;
- Change the way in which transmission providers assess an addition of a generating facility to an interconnection request, requiring that transmission providers evaluate a proposed addition as long as the addition does not change the requested interconnection service level;
- Enable customers with unused interconnection capacity share that surplus capacity with other resources as long as the original interconnection customer executes an LGIA or requests filing of an unexecuted LGIA;
- Require transmission providers, at the request of the interconnection customer to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located storage resource; and
- Require transmission providers to evaluate grid-enhancing solutions and file an annual informational report on their use of grid-enhancing technologies.

The FERC proposes to require compliance within 180 days of a final rule in this proceeding. Compliance would require transmission providers to file updates to their *pro forma* LGIA, LGIP, SGIA and SGIP, as applicable. If you have any questions concerning the *Interconnection Reforms NOPR*, please contact Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NOPR: ISO/RTO Credit Information Sharing (RM22-13)**

On July 28, 2022, the FERC issued a NOPR[109] proposing to revise its regulations to permit ISO/RTOs to share among themselves[110] credit-related information regarding market participants.[111] The FERC believes that the proposed credit information sharing could improve ISO/RTOs' ability to accurately assess market participants' credit exposure and risks and enable ISO/RTOs to respond to credit events more quickly and effectively (minimizing the overall credit-related risks, including risks of unexpected defaults by market participants, in organized wholesale electric markets). The FERC proposal would not permit the information sharing to be conditioned on the specific consent of the market participant, would permit the receiving ISO/RTO to use market participant credit-related information received from another ISO/RTO to the same extent and for the same

[109] *Credit-Related Information Sharing in Organized Wholesale Electric Markets*, 180 FERC ¶ 61,048 (July 28, 2022) ("*ISO/RTO Credit-Related Info Sharing NOPR*").

[110] The *ISO/RTO Credit-Related Info Sharing NOPR* does propose credit-related information sharing with markets that are not Commission-jurisdictional (i.e. ERCOT, AESO, IESO or commodities and derivative markets that are subject to the jurisdiction of other regulators, including the Commodity Futures Trading Commission).

[111] Revisions would be to 18 CFR § 35.47(h). The changes would "[p]ermit the sharing of market participant credit-related information with, and receipt of market participant credit-related information from, other organized wholesale electric markets for the purpose of credit risk management and mitigation, provided such market participant credit-related information is treated upon receipt as confidential under the terms for the confidential treatment of market participant information set forth in the tariff or other governing document of the receiving organized wholesale electric market; and permit the receiving organized wholesale electric market to use market participant credit-related information received from another organized wholesale electric market to the same extent and for the same purposes that the receiving organized wholesale electric market may use credit-related information collected from its own market participants.

purposes that the receiving ISO/RTO may use credit-related information collected from its own market participants, and would not change the existing discretion an ISO/RTO has to act on credit-related information, regardless of the source of that information. The FERC seeks comment on whether ISO/RTOs' credit-related information sharing discretion should be limited in any specific ways or to any specific circumstances.

Initial Comments. Initial comments were due October 7, 2022[112] and were filed by, among others: NEPOOL, Dominion, EEI, Energy Trading Institute, EPSA, and the IRC.

Reply Comments. Reply comments are due ***November 7, 2022***.

- **NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)**

On June 16, 2022, the FERC issued a notice[113] proposing to require that NERC modify Reliability Standard TPL-001-5.1 (Transmission System Planning Performance Requirements) within one year of the effective date of a final rule in this proceeding to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the reliable operations of the Bulk-Power System. Specifically, the FERC proposed modifications to TPL-001-5.1 to require: (i) development of benchmark planning cases; (ii) planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios; and (iii) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Initial comments were due August 26, 2022[114] and were filed by over 37 parties, including, among others, ISO-NE, Eversource, NESCOE, NRDC, UCS, NERC, ERCOT, MISO, NYISO, PJM, ACPA, EPRI, EPSA, NARUC, and Trade Associations. This matter is pending before the FERC.

- **NOPR: Internal Network Security Monitoring for High and Medium Impact BES Cyber Systems (RM22-3)**

On January 20, 2022, the FERC issued a NOPR[115] proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[116] within a trusted Critical Infrastructure Protection networked environment for high and medium impact Bulk Electric System ("BES") Cyber Systems. The FERC stated that "including INSM requirements in the CIP Reliability Standards would ensure that responsible entities maintain visibility over communications between networked devices within a trust zone (i.e., within an ESP), not simply monitor communications at the network perimeter access point(s), i.e., at the boundary of an ESP as required by the current CIP requirements. In the event of a compromised ESP, improving visibility within a network would increase the probability of early detection of malicious activities and would allow for quicker mitigation and recovery from an attack."[117]

Comments on the *Internal Network Security Monitoring NOPR* were due on or before March 28, 2022.[118] Comments were filed by: the IRC, NERC, EEI, EPSA, TAPS, Bonneville Power Admin., Consumers Energy, Cynalytica,

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[112] The *ISO/RTO Credit-Related Info Sharing NOPR* was published in the *Fed. Reg.* on Aug. 8, 2022 (Vol. 87, No. 151) pp. 48,118-48,125.

[113] *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (June 16, 2022) ("*Extreme Weather Transmission System Planning NOPR*").

[114] The *Extreme Weather Transmission System Planning NOPR* was published in the *Fed. Reg.* on June 27, 2022 (Vol. 87, No. 122) pp. 38,021-38,044.

[115] *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, 178 FERC ¶ 61,038 (Jan. 20, 2022) ("*Internal Network Security Monitoring NOPR*").

[116] INSM is a subset of network security monitoring that is applied within a "trust zone," such as an Electronic Security Perimeter ("ESP"), and is designed to address situations where vendors or individuals with authorized access are considered secure and trustworthy but could still introduce a cybersecurity risk to a high or medium impact BES Cyber System.

[117] *Id.* at P 2.

[118] The *Internal Network Security Monitoring NOPR* was published in the *Fed. Reg.* on Jan. 27, 2022 (Vol. 87, No. 18) pp. 4,173-4,180.

CA Department of Water Resources, Electricity Canada, Entergy, Idaho Power, Juniper Networks, ITC, Microsoft, North American Generator Forum, Nozomi Networks, Operational Technology Cybersecurity Coalition, the US Bureau of Reclamation, and T. Conway. This matter is pending before the FERC.

- ***Transmission NOPR*** **(RM21-17)**

Following its ANOPR process,[119] the FERC issued on April 21, 2022 a NOPR[120] that would require public utility transmission providers to:

(i) conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;

(ii) more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes;

(iii) seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning;

(iv) adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to “right-size” replacement transmission facilities; and

(v) revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms proposed in this NOPR.

In addition, the *Transmission NOPR* would not permit public utility transmission providers to take advantage of the construction-work-in-progress (“CWIP”) incentive for regional transmission facilities selected for purposes of cost allocation through long-term regional transmission planning and would permit the exercise of federal rights of first refusal (“ROFR”) for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal ROFR for such regional transmission facilities establishing joint ownership of the transmission facilities. While the ANOPR sought comment on reforms related to cost allocation for interconnection-related network upgrades, interconnection queue processes, interregional transmission coordination and planning, and oversight of transmission planning and costs, the *Transmission NOPR* does not propose broad or comprehensive reforms directly related to these topics. The FERC indicated that it would continue to review the record developed to date and expects to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics.

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region’s transmission needs are identified, solutions are evaluated and

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119 *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) (“*Transmission Planning & Allocation/Generation Interconnection ANOPR*”). The FERC convened a tech. conf. on Nov. 15, 2021, to examine in detail the issues and potential reforms described in the *ANOPR*. Speaker materials and a transcript of the tech. conf. are posted in FERC’s eLibrary. Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEE, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute. *ANOPR* reply comments and post-technical conference comments were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, and a group of former military leaders and former Department of Defense officials, and ACPA/AEE/SEIA.

120 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (Apr. 21, 2022) (“*Transmission NOPR*”).

selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee, which will recommend whether NEPOOL should submit comments on the *Transmission NOPR*.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[121] Nearly 200 sets of comments were filed, including comments by NEPOOL , ISO-NE, Acadia/CLF, Anbaric, AEE, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

Reply Comments. Reply comments were due ***September 19, 2022***. Nearly 100 sets of reply comments were filed, including by: ISO-NE, AEE, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, and SEIA.

If you have any questions concerning the *Transmission NOPR*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **NOPR: Accounting and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)**

On July 28, 2022, the FERC issued a NOPR[122] proposing reforms to the accounting and reporting treatment of certain renewable energy assets. Specifically, the FERC proposes changes to the Uniform System of Accounts ("USofA") and relevant FERC forms to: (i) include new accounts for wind, solar, and other non-hydro renewable assets; (ii) create a new functional class for energy storage accounts; (iii) codify the accounting treatment of renewable energy credits; and (iv) create new accounts within existing functions for hardware, software, and communication equipment. The FERC also seeks comment on whether the Chief Accountant should issue guidance on the accounting for hydrogen. Comments on the *Renewable Energy Assets USofA and Reporting NOPR* are due ***November 17, 2022***.[123]

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

Supplemental NOPR. In light of comments already received in this proceeding,[124] the FERC issued on April 15, 2021 a *Supplemental NOPR*[125] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC sought comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its

[121] A July 27, 2022, request by the Georgia Public Service Commission ("GA PUC") for an additional 30 days of time to submit comments and reply comments was denied on Aug. 9, 2022.

[122] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, 180 FERC ¶ 61,050 (July 28, 2022) ("*Renewable Energy Assets USofA and Reporting NOPR*").

[123] The *Renewable Energy Assets USofA and Reporting NOPR* was published in the *Fed. Reg.* on Oct. 3, 2022 (Vol. 87, No. 190) pp. 59,870-59,963.

[124] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

[125] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[126] A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[127] Reply comments were also posted from New England State Parties,[128] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the ACPA.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[129] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments were due on or before January 14, 2022 and were filed by APPA, CAISO,

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[126] As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including the following:

- A shift from risks and challenges to a ***consumers' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period and an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.
- ***Transmission Organization Incentive***. A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

[127] "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

[128] "New England State Parties" are CT PURA, CT DEEP and the MA AG.

[129] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

Clean Energy Parties,[130] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

These matters are pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Voltus Petition for a FERC Technical Conference on Order 2222*** **(RM18-9)**

On December 22, 2021, Voltus, Inc. ("Voltus") requested that the FERC convene a technical conference regarding *Order 2222*-related issues sometime in the months of February or March, 2022. Specifically, Voltus requested the technical conference to allow for a collective discussion of key issues arising from the ISO/RTO *Order 2222* compliance proposals, including certain regional variability, roles of industry participants, narrowing perceived knowledge gaps, and subsequent FERC guidance, all of which Voltus asserts supports the request for a technical conference. On January 7, 2022, the FERC issued a notice of Voltus' request, inviting comments on Voltus' request on or before February 7, 2022. Comments supporting Voltus' request were filed by: AEE, AEMA, APPA/NRECA, EEI, ISO-RTO Council, MISO, SPP, Sunrun, Ameren, Camus Energy, Energy Web Foundation, Entegrity Energy Partners, Environmental Law and Policy Center, Fermata LLC, Google, Leapfrog Power, Nuvve Holding, Tesla, U Delaware EV Research and Development Group, and Utilidata. Voltus' request remains pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Coaltrain Energy (IN16-4)**

On October 11, 2022, the FERC approved a Stipulation and Consent Agreement with Coaltrain Energy L.P. ("Coaltrain") and individuals defendants Peter Jones, Shawn Sheehan, Robert Jones, Jeff Miller, and Jack Wells (together with Coaltrain, "Defendants")[131] that resolved OE's Part 1b investigation into Defendants' violation of the FERC's Anti-Market Manipulation Rule and the FERC's Market Behavior Rules, and a pending Federal Court lawsuit.[132] Under the Agreement, in which Defendants neither admit nor deny the alleged violations, Defendants must make restitution payments totaling ***$4 million*** and the FERC agreed to dismiss with prejudice its claims against all of the Defendants in the Federal Court lawsuit.

- **ISO-NE (Salem Harbor) (IN18-8)**

On September 30, 2022, the FERC approved a Stipulation and Consent Agreement with ISO-NE[133] that resolved OE's Part 1b investigation into ISO-NE's capacity payments to Salem Harbor before the new Salem Harbor Generating Station project ("Project") had been built or had commenced commercial operation. OE determined, among other things, that ISO-NE violated the ISO-NE Tariff by (i) failing to determine a revised COD and other CPS milestones; (ii) failing to submit a Demand Bid into the 2017 ARA3; (iii) issuing an inaccurate Qualified Capacity Value for Salem Harbor; and (iv) restricting the IMM's access to information about Salem Harbor.

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[130] The "Clean Energy Parties" are: Working for Advanced Transmission Technologies ("WATT Coalition"), ACPA, AEE, American Council on Renewable Energy ("ACORE"), NRDC, and the Sustainable FERC Project.

[131] *Coaltrain Energy, L.P. et al.*, 181 FERC ¶ 61,031 (Oct. 11, 2022) ("*Coaltrain Enforcement Order*").

[132] In a penalty order summarized in previous Reports, the FERC found that Defendants had engaged in market manipulation by placing Up To Congestion trades for the sole or primary purpose of collecting Marginal Loss Surplus Allocation payments, rather than to profit from price changes. The FERC also found that Coaltrain had violated its Market Behavior Rules by making false and misleading statements to Enforcement staff about the existence of records created by employee monitoring software. *See Coaltrain Energy, L.P.*, 155 FERC ¶ 61,204 (May 27, 2016).

[133] *ISO New England Inc.*, 180 FERC ¶ 61,223 (Sep. 30, 2022) ("*ISO-NE Salem Harbor Enforcement Order*").

Under the Agreement, in which ISO-NE neither admits nor denies the alleged violations, ISO-NE must ***pay a $500,000 civil penalty*** to the United States Treasury, make new investments in its compliance program at an estimated cost of up to ***$350,000***, and submit one annual compliance monitoring report, in accordance with the terms of the Agreement, with the requirement of a second annual report at OE's option. In setting the remedy, which was a downward departure from the FERC's penalty guidelines, OE and the Commission took into consideration the following: (a) ISO-NE was not the only Entity whose conduct contributed to the market harm resulting from the matters covered by the investigation, (b) ISO-NE is a non-profit entity funded by fee-paying entities (ISO-NE customers), and (c) that a financial penalty might be passed on to Market Participants, potentially compounding the harm from what OE concluded were ISO-NE's violations.[134] The FERC specifically noted that "each ISO/RTO and its management must adhere to the requirements of its Commission-approved tariff, which includes permitting any market monitor the ability to function in a manner consistent with that market monitor's role and obligations under that tariff".[135] Following issuance of the *ISO-NE Salem Harbor Enforcement Order*, ISO-NE posted a statement on the Settlement to its website and addressed the matter at the October 6 Participants Committee meeting.

If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Salem Harbor (IN18-8)**

On June 27, 2022, the FERC approved a Stipulation and Consent Agreement with Salem Harbor Power Development LP ("Salem Harbor")[136] that resolved OE's Part 1b investigation into Salem Harbor's receipt of capacity payments from ISO-NE for its New Salem Harbor Generating Station project ("Project") during the 2017-18 Capacity Commitment Period, a period during which the Project had neither been built nor commenced commercial operation. OE determined, among other things, that Salem Harbor failed to provide "complete updated version[s] of [its] critical path schedule ("CPS") as required by sections III.13.3.2 and III.13.3.2.1 of the ISO-NE Tariff, that narratives Salem Harbor submitted to ISO-NE made false claims regarding the Project's schedule trajectory and omitted numerous important and relevant details regarding the status of the Project and its construction-related delays, and that its CPS submission violated Salem Harbor's Duty of Candor under the FERC's Market Behavior Rules.[137] Under the Settlement, in which Salem Harbor neither admits nor denies the alleged violations, and subject to limitations of the Bankruptcy Code and in accordance with the treatment afforded to Allowed General Unsecured Claims pursuant to a plan to be approved by the Bankruptcy Court in Salem Harbor's ongoing Chapter 11 Cases, Salem Harbor must ***disgorge $26.7 million***,[138] and ***pay a $17.1 million civil penalty*** to the United States Treasury.[139] If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[140] the FERC directed PacifiCorp to show cause why it should not be found to have

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134 Id. at PP 101-103.

135 *Id.* at P 104.

136 *Salem Harbor Power Development LP*, 179 FERC ¶ 61,228 (June 27, 2022) ("*Salem Harbor Order*").

137 18 CFR § 35.41(b) (2022).

138 ISO-NE was directed to distribute the disgorgement *pro rata* to network load, subject to the limitations of the Bankruptcy Code and the order of the Bankruptcy Court.

139 In recommending the remedies, OE considered the roles that multiple individuals and entities played in ISO-NE not submitting a demand bid on Salem Harbor's behalf into ARA3. Neither the Agreement nor the *Salem Harbor Order* asserted violations by any individual or any entity other than Salem Harbor. However, the FERC reserves its right to make a determination as to the facts or issues of law that might give rise to any violation by any other individual or entity. *Salem Harbor Order* at P 58.

140 *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement filed its reply on September 14, 2021. This matter remains pending before the FERC. (Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court.) If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- **Rover Pipeline, LLC and Energy Transfer Partners, L.P. (CPCN Show Cause Order) (IN19-4)**

On January 20, 2022, the FERC issued an order establishing a hearing to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[141]

As previously reported, on March 18, 2021, the FERC issued a show cause order[142] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity ("CPCN") under NGA section 7(c).[143] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the

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141 *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*").

142 *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP CPCN Show Cause Order*").

143 Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15, 2021.

Procedural Schedule Suspended. As previously reported, ALJ Joel DeJesus will be the presiding judge for hearings in this matter. On May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, Judge DeJesus suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

- **Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)**

On December 16, 2021, the FERC issued a show cause order[144] in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[145] by: (i) intentionally including diesel fuel and other toxic substances and unapproved additives in the drilling mud during its horizontal directional drilling ("HDD") operations under the Tuscarawas River in Stark County, Ohio, in connection with the Rover Pipeline Project;[146] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[147] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[148] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[149] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[150] Opinion 549-A revised

[144] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 177 FERC ¶ 61,182 (Dec. 16, 2021) ("*Rover/ETP Tuscarawas River HDD Show Cause Order*").

[145] *Rover Pipeline LLC,* 158 FERC ¶ 61,109 (2017), *order on clarification & reh'g*, 161 FERC ¶ 61,244 (2017), *Petition for Rev*., *Rover Pipeline LLC v. FERC*, No. 18-1032 (D.C. Cir. Jan. 29, 2018) ("Certificate or Certificate Order").

[146] The Rover Pipeline Project is an approximately 711 mile long interstate natural gas pipeline designed to transport gas from the Marcellus and Utica shale supply areas through West Virginia, Pennsylvania, Ohio, and Michigan to outlets in the Midwest and elsewhere.

[147] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 179 FERC ¶ 61,090 (May 11, 2022) ("*Designation Notice Rehearing Order*"). The "Designation Notice" provided updated notice of designation of the staff of the FERC's Office of Enforcement ("OE") as non-decisional in deliberations by the FERC in this docket, with the exception of certain staff named in that notice.

[148] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*").

[149] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

[150] *BP Penalties Allegheny Order* at P 1.

Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[151]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

- **Total Gas & Power North America, Inc. et al. (IN12-17)**

On April 28, 2016, the FERC issued a show cause order[152] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[153]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[154] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[155] for the proceeding.

Discovery in this case is ongoing and is now scheduled to close on December 2, 2022. Further, pursuant to an August 30, 2022 order of the Chief Judge, hearings (estimated to last 3-4 weeks) are scheduled to begin

[151] *Id*. at P 319.

[152] *Total Gas & Power North America, Inc.,* 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[153] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated NGA section 4A and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

[154] *Total Gas & Power North America, Inc. et al.,* 176 FERC ¶ 61,026 (July 15, 2021).

[155] The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

January 23, 2023 and an initial decision is thereafter due ***July 10, 2023***. Several procedural deadlines in support of that schedule were adjusted for a third time by Judge Krolikowski in an order issued on September 9, 2022.

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

New England Pipeline Proceedings

The following New England pipeline projects are currently under construction or before the FERC:

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[156] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
  - The Project is targeted for a 4th quarter, 2023 in-service date.

Non-New England Pipeline Proceedings

The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

- **Northern Access Project (CP15-115)**
  - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[157] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).
  - As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[158] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action"

[156] *Iroquois Gas Transmission Sys., L.P.*, 178 FERC ¶ 61,200 (2022) (*Iroquois Certificate Order*).

[157] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[158] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[159] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.

- The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[160] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[161] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[162] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[163]
- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [164] finding

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[159] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[160] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[161] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[162] Summary Order, *Nat'l Fuel Gas Supply Corp. v. N.Y. State Dep't of Envtl. Conservation*, Case 17-1164 (2d. Cir., issued Feb. 5, 2019).

[163] *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir., filed May 28, 2019) (consolidated).

[164] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[165]

- On January 28, 2022, Applicants again requested an additional extension of time, this time until December 31, 2024, to complete construction of the Project and enter service. Comments on that request were due on or before February 16, 2022. Many individual comments and protests were received.
- On June 29, 2022, the FERC granted Applicants' request for an additional extension of time. Applicants now have until December 31, 2024 to construct and place the Project into service.[166]
- A request for rehearing of the *Northern Access Project Add'l Extension Order* was denied by operation of law.[167]
- On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of the *Northern Access Project Add'l Extension Order* (*see* Section XVI below).

XV. State Proceedings & Federal Legislative Proceedings

- **Maine - NECEC Transmission LLC et al. v. Bureau of Parks and Lands et al. (BCD-21-416)**

On August 30, 2022, the Maine Supreme Judicial Court concluded that the legislation enacted as a result of the passage of Maine's November 2, 2021 ballot question,[168] and that effectively halted construction of the NECEC Project,[169] was unconstitutional to the extent it required the legislation to be applied retroactively to the certificate of public convenience and necessity ("CPCN") issued for the Project if NECEC had acquired vested rights to proceed with Project construction (by undertaking substantial construction consistent with and in good-faith reliance on the CPCN before the Initiative was enacted). The Court remanded to the Business and Consumer Docket the factual question of whether NECEC performed substantial construction in good faith according to a schedule that was not created or expedited for the purpose of generating a vested rights claim (which it suggested appeared to be the case from the limited record developed in connection with the request for preliminary injunctive relief in this matter).

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which

[165] *Id.* at P 10.

[166] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

[167] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 180 FERC ¶ 62,099 (Aug. 30, 2022).

[168] The ballot question, approved by 59% of Maine voters, which summarized the citizen's initiative pursued under Maine's constitutional provision for direct initiative of legislation (ME. Const. Art. IV, pt. 3, § 18), read: "Do you want to ban the construction of high-impact electric transmission lines in the Upper Kennebec Region and to require the Legislature to approve all other such projects anywhere in Maine, both retroactively to 2020, and to require the Legislature, retroactively to 2014, to approve by a two-thirds vote such projects using public land?"

[169] The New England Clean Energy Connect ("NECEC") project (the "NECEC Project") is designed to transmit power generated in Québec through Maine and into Massachusetts. The Project includes a new 145.3-mile, high-voltage direct current ("HVDC") transmission line, proposed to run from the Maine-Québec border in Beattie Township, ME to a new converter station in Lewiston, ME and from there to an existing substation by a new 1.2-mile, high-voltage alternating current transmission line.

NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
  Underlying FERC *Proceeding*: ER22-707[170]
  Petitioner: Green Development
  Status: Briefing Underway

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[171] On June 17, 2022, the Court directed Green Development to file, and Green Development filed, a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decisions from which the appeal arises. The FERC filed the Certified Index to the Record on July 28, 2022.

Green Development filed, on August 15, 2022, a Statement of Issues and Docketing Statement. Green Development filed Petitioner's Brief on October 11, 2022. The briefing schedule calls for the following: Respondent's Brief (December 12, 2022); Intervenor for Respondent's Brief (December 19, 2022); Petitioner's Reply Brief (January 9, 2023); Deferred Appendix (January 17, 2023); and Final Briefs (January 31, 2023).

- **Mystic II (ROE & True-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026, 22-1215) (consolidated)
  Underlying FERC Proceeding: EL18-1639-010, -011,[172] **-013**[173] **-017**[174]
  Petitioners: Mystic, CT Parties,[175] **MA AG, ENECOS**
  Status: Being Held in Abeyance; Voluntary Motion to Dismiss 22-1215 Granted

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the

[170] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*"). *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration). Together, these orders referred to as the "*2nd Revised Narragansett LSA Orders*".

[171] The 2nd Revised Narragansett LSA is a Local Service Agreement ("LSA") among New England Power, Narragansett and ISO-NE. The LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island.

[172] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*")*; Constellation Mystic Power, LLC*, 176 FERC ¶ 62,127 (Sep. 13, 2021) ("*September 13 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Order).

[173] *Constellation Mystic Power, LLC,* 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*")*; Constellation Mystic Power, LLC,* 178 FERC ¶ 62,028 (Jan. 18, 2022) ("*January 18 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Second Allegheny Order).

[174] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*"); *Constellation Mystic Power, LLC*, 179 FERC ¶ 62,179 (June 27, 2022) ("*June 27 Notice*") (Notice of Denial By Operation of Law of Rehearings of *Mystic First CapEx Info. Filing Order*).

[175] In this appeal, "CT Parties" are the Connecticut Public Utilities Regulatory Authority ("CT PURA"), Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the Connecticut Office of Consumer Counsel ("CT OCC").

remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*) (*see* below). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*.

As previously reported, the Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings in MISO TOs, now on remand at the Commission. Accordingly, on October 25, 2022, Mystic, without opposition, asked the Court for an order keeping these proceedings in abeyance and directing that motions to govern future proceedings be filed within 90 days. On October 26, 2022, the Court effectively granted Mystic's request, ordering that the proceedings remain in abeyance pending further order of the court and directing the parties to file motions to govern future proceedings by ***January 24, 2023***.

On October 7, 2022, the Court granted Mystic's September 7, 2022 motion for voluntary dismissal of Case No. 22-1215, further ordering that the consolidation of Case No. 22-1215 with Case No. 21-1198, et al., be terminated and Case No. 21-1198, et al. remain in abeyance pending further order of the court.

- **Mystic I (Original Cost Test, Capital Structure, Everett Cost Recovery, Clawback, True-Up Mechanism) (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[176]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Decision Issued; Mandate Not Yet Issued

As previously reported, Mystic, NESCOE, MA AG, and CT Parties separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, Constellation and ISO-NE.[177] The cases were consolidated into Case No. 20-1343. Following briefing, oral argument was held on May 5, 2022 before Judges Srinivasan, Henderson and Rao.

On August 23, 2022, the Court issued its decision holding that:

- Mystic's petition for review be dismissed in part and denied in part;
- State Petitioners' petitions for review on the cost allocation issue be granted;
- the clawback portions excluding Everett costs and the challenged delay provision of the orders under review be vacated; and
- the cases be remanded for the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's December 2020 Rehearing Order.

On October 17, 2022, the Court issued its mandate, returning the case to the FERC.

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[176] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[177] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
Underlying FERC Proceeding: ER18-619[178]
Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
Status: Being Held in Abeyance (until March 1, 2024)

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance three times. The Court has granted each request. The most recent request was submitted on July 22, 2022 (third abeyance request) and moved the Court to hold this matter in abeyance until March 1, 2024, the date on which the elimination of MOPR is to be implemented, with motions to govern due 30 days thereafter. The Court granted the third abeyance request on July 25, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
Underlying FERC Proceeding: ER15-414[179]
Petitioners: TOs' (CMP et al.)
Status: Being Held in Abeyance

On August 28, 2020, the TOs[180] petitioned the DC Circuit Court of Appeals for review of the FERC's October 6, 2017 order rejecting the TOs' filing that sought to reinstate their transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[181] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing

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[178] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

[179] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

[180] The "TOs" are CMP; Eversource Energy Service Co., on behalf of its affiliates CL&P, NSTAR and PSNH; National Grid; New Hampshire Transmission; UI; Unitil and Fitchburg; VTransco; and Versant Power.

[181] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

and that this appeal should continue to remain in abeyance, was filed on August 11, 2022. The next status report is due on or before ***December 9, 2022***.

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[182]
  Petitioners: Sierra Club
  Status: Filing of Initial Submissions Underway

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. On October 11, 2022, Sierra Club filed a Docketing Statement, a Statement of Issues, and the underlying decision from which the appeal arises. Also on October 11, the FERC moved to hold this proceeding in abeyance. Sierra Club opposed that motion on October 21, 2022. The FERC's motion to hold this proceeding in abeyance is pending before the Court.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[183]
  Petitioners: SEIA et al.
  Status: Oral Argument Held March 8, 2022; Awaiting Decision

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[184] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[185]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Decision Issued on August 9, 2022; Mandate Issued October 4, 2022 (underlying FERC orders vacated; cases remanded to FERC to reopen proceedings)

The MISO TOs, Transource and "Dec 23 Petitioners",[186] among others, appealed *Opinion 569/569-A*. The MISO TOs' case was consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Following completion of briefing, oral argument was held on November 18, 2021 before Judges Srinivasan, Katsas and Walker.

On August 9, 2022, the Court issued its decision granting customers' petitions for review, dismissing transmission owners' petitions for review, vacating the underlying FERC orders, and remanding the cases to the

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182 *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

183 *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

184 *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

185 *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

186 "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Pub. Srvc. Comm.; MO Joint Mun. Electric Utility Comm.; Org. of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

FERC to reopen proceedings. In reaching its decision, the Court found that the "FERC failed to offer a reasoned explanation for its decision to reintroduce the risk-premium model [ ] after initially, and forcefully, rejecting it. Because FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new [ROE] produced by that model cannot stand. We therefore vacate FERC's orders." Because the Court ordered the FERC to vacate its prior rate orders, it dismissed the remaining surviving challenges (e.g. refund and authority issues), which can be resolved in and following the FERC proceedings that will ensue following this remand. Of course, this decision and those proceedings to follow are expected to impact multiple proceedings in which the FERC this now-vacated ROE methodology, including the Mystic ROE proceeding pending before the DC Circuit and the New England ROE cases that are pending before the FERC and from which the ROE issue originated. As noted in the last Report, the Court's mandate issued on October 4, 2022.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.) and (22-1146, 22-1147 consol.)**
  Underlying FERC Proceeding: CP16-9-012[187]
  Petitioners: LS Power, Algonquin, INGA
  Status: Cases 22-1146/47 Deconsolidated and Briefing Schedule Set; Remaining Cases (21-1115 et al.) Being Held in Abeyance Pending Disposition of 22-1146/47

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to file motions to govern future proceedings by May 31, 2022. On May 31, 2022, Petitioners asked the Court to continue to hold this proceeding in abeyance pending the First Circuit's disposition of Algonquin's pending motions to transfer that Court's cases 20-1458 and 22-1201 (which also challenge the FERC's authorization of the "Atlantic Bridge Project").

On June 30, the First Circuit transferred cases 20-1458 and 22-1201 to the DC Circuit. The DC Circuit docketed those cases as 22-1146 and 22-1147, consolidated them with its cases challenging the Atlantic Bridge Project orders (with 21-1115 remaining the lead case), and directed the parties to file a proposed briefing schedule. On July 19, the parties filed a proposal that cases 22-1146 and 22-1147 be severed, proposed a revised briefing format and schedule for those cases, and asked the Court to continue to hold the remaining cases in abeyance (asserting that abeyance may avoid the need for briefing and adjudication of the issues that Algonquin and INGAA would press).

On August 16, 2022, the Court deconsolidated 22-1146 and 22-1147 from 21-1115 et al., which is to remain in abeyance pending a further order of the Court. The Court consolidated Cases 22-1146 and 22-1147 together and issued a briefing schedule that calls for Joint Brief of Petitioners by October 28, 2022; Respondent Brief by January 12, 2023, Joint Brief of Intervenors by January 26, 2023, Joint Reply Brief of Petitioners by February 16, 2023, Deferred Joint Appendix by March 2, 2023, and Final Briefs by March 9, 2023. The date of oral argument and the composition of the merits panel will be provided at a later date. Since the last Report, Petitioners in the consolidated cases filed Petitioners Brief. Next up, Respondent (FERC) Brief.

[187] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law.*

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ISO new england

memo

To: NEPOOL Participants

From: Cheryl Arnold, Director, Finance and Market Risk

Date: October 28, 2022

Subject: Supplemental Information Re: Financial Assurance Calculation for Mystic COS

This memo is intended to provide the NEPOOL Participants with information regarding Market Participants' financial assurance requirements associated with charges arising from the Mystic Cost of Service (COS) agreement. We have recently received several questions from Market Participants regarding how the financial assurance is calculated and updated based on the Mystic COS settlement.

Billing Background and Summary of Financial Assurance Calculation

The Mystic COS settlement charges and payments (Mystic COS settlement) are billed as a Non-Hourly Charge[1] and included in the Monthly Statement issued on the first business day after the ninth calendar day of each month. The Mystic COS settlement is billed two months in arrears.[2]

Because the Mystic COS settlement is a Non-Hourly Charge, the financial assurance requirements for the Mystic COS settlement are calculated by taking the average of the two most recently invoiced months of settlements and then multiplying that result by 2.5.[3] The amount of required financial assurance related to the Mystic COS settlement will change monthly, upon the issuance of the Monthly Statement. Importantly, depending on the variability of the Mystic COS settlement each month, the amount of financial assurance required will fluctuate. The historical amounts of the aggregate Mystic COS settlement billed from June 2022 through August 2022, have fluctuated significantly,[4] which caused a significant change in the financial assurance requirement for this item.

Market Participants have access to the financial assurance application and can monitor the requirements for this item along with their entire financial assurance requirement for all markets. It is recommended that Market Participants review their financial assurance requirement regularly to stay abreast of any changes that may require additional collateral to be posted.

ISO-NE Tools and Reports

ISO-NE has provided a tool, the Mystic Cost of Service-Estimation Worksheet https://www.iso-ne.com/search?query=mystic, and a user guide that explains the worksheet, to assist Market Participants in estimating the Mystic COS settlement amounts.

In addition, the Market Information Server (MIS) reports with Market Participant specific Mystic COS settlement values are generally available at least two business days before the issuance of the Monthly Statements, which may be useful to Market Participants who wish to preemptively determine the expected change in the Mystic COS settlements financial assurance obligations (*i.e.*, ahead of the Monthly Statements issuance).

[1] *See* ISO New England Billing Policy, Section 1.3.

[2] *See* Presentation to NEPOOL Markets Committee, Mystic Cost of Service Agreement, Slide 9 (Oct. 13, 2022) (the "MC Presentation") available at https://www.iso-ne.com/committees/markets/markets-committee/.

[3] *See* ISO New England Financial Assurance Policy, Sections III.A.(iii) and III.A.(vi).d, available at https://www.iso-ne.com/static-assets/documents/2017/09/sect_i_ex_ia.pdf.

[4] *See* MC Presentation, Slide 17.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
413-535-4000