Sebastian Lombardi
Secretary

October 26, 2023

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of November 2, 2023 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 Thursday, November 2, 2023, at the Seaport Hotel Boston, One Seaport Lane, Boston, MA following individual, modified Sector meetings with the ISO Board and with State Officials as follows:**

- 9:00 am – 10:15 am — Sector Meetings Session I
- 10:35 am – 11:50 am — Sector Meetings Session II
- 11:50 am – 12:30 pm — Lunch
- 12:30 pm – 1:45 pm — Sector Meetings Session III
- 2:00 pm – conclusion of business — NPC General Business

A schedule of the planned Sector meetings is included with this notice. The Participants Committee meeting, which is scheduled to begin at **2:00 p.m.** following those Sector meetings, will be held in the **Seaport Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. 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**.

Please also note that the ISO Board will conduct a public meeting the day before, on November 1, 2023, from 1:00 p.m. to approximately 4:30 p.m., at the same venue (the **Seaport Hotel Boston)**. 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/100003/iso_ne_nov_1_2023_open_board_meeting_rsp_public_meeting_initial_notice.pdf. If you wish to participate in or listen to the Board meeting, you should review the notice. Advanced registration is required and is available via the ISO New England Calendar at https://www.iso-ne.com/event-details?eventId=151002. While there are both in-person and virtual options to attend, please note that in-person space is limited, so those interested in attending the Board meeting in person will need to register early.

If you are in need of a room for the night before the November 2 meeting, please contact either Jaki Sloan (jsloan@daypitney.com) or Pat Gerity (pmgerity@daypitney.com) who may be able to assist getting you a room at the Seaport Hotel or an alternative venue if possible.

Looking forward, please make sure that your calendars reflect the upcoming NEPOOL Annual Meeting, which will be on Thursday, December 7, 2023 at the Colonnade Hotel in Boston. A holiday breakfast is planned to begin at 9:00 a.m.

Respectfully yours,

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the October 5, 2023 Participants Committee meeting. Copies of the draft minutes, marked to show the changes made since the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

3. To receive an ISO Chief Executive Officer report. Because there have been no ISO Board or Board Committee meetings since the report at the October meeting, there are no summaries to circulate.

4. To receive an ISO Chief Operating Officer report. The November COO report will be circulated and posted in advance of the meeting.

5. To consider and take action, as appropriate, on ICR Values for the 2024-2025 3rd Annual Reconfiguration Auction (ARA), 2025-2026 2nd ARA, and 2026-2027 1st ARA. Background materials and draft resolutions are included and posted with this supplemental notice.

6. To consider, and take action, as appropriate, on changes to Market Rule 1 to effectuate a one-year delay of FCA19 and to modify the schedules for FCAs 20-24. Background materials and a draft resolution are included and posted with this supplemental notice.

7. 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.

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

9. Administrative matters.

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

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

COVID-19 Considerations. To safeguard the well-being of yourself and others, please refrain from attending a NEPOOL meeting in person if you have confirmed that you have COVID-19. If you suspect that you might have COVID-19, or if you have been exposed to COVID-19, please take the precautions recommended by the CDC. In any case, all are encouraged to be respectful of others' personal space, and to respect individual choices with respect to wearing or not wearing masks. Should you receive a COVID-19-positive test result within 10 days of attending a NEPOOL meeting in person, we'd kindly ask that you contact NEPOOL Counsel (pmgerity@daypitney.com) to report that result.

NEW ENGLAND POWER POOL

PARTICIPANTS COMMITTEE NOVEMBER 2, 2023 MEETING
Seaport Hotel Boston, One Seaport Lane, Boston, MA
MEETING SCHEDULE**

SECTOR/GROUP	Session I 9:00 – 10:15 a.m.	Session II 10:30 – 11:45 a.m.	Lunch 11:45 – 12:30 p.m.	Session III 12:30 – 1:45 p.m.	General Business 2:00 p.m. - adjournment
Generation / Long	*Open*	ISO Board Panel 2 (Flagship A)	Lunch (*Ballroom*)	State Officials Panel 2 (Constitution)	Participants Committee General Business *(Seaport Ballroom)*
Transmission	State Officials Panel 1 (Liberty)	ISO Board Panel 1 (Flagship B)	Lunch (*Ballroom*)	*Open*	
Supplier / Short (LSE)	State Officials Panel 2 (Constitution)	*Open*	Lunch (*Ballroom*)	ISO Board Panel 1 (Flagship B)	
Publicly Owned Entity	ISO Board Panel 1 (Flagship B)	*Open*	Lunch (*Ballroom*)	State Officials Panel 1 (Liberty)	
AR	ISO Board Panel 2 (Flagship A)	State Officials Panel 1 (Liberty)	Lunch (*Ballroom*)	*Open*	
End User	*Open*	State Officials Panel 2 (Constitution)	Lunch (*Ballroom*)	ISO Board Panel 2 (Flagship A)	
ISO Board Panel 1	Publicly Owned Entity (Flagship B)	Transmission (Flagship B)	Lunch (*Ballroom*)	Supplier / Short (LSE) (Flagship B)	
ISO Board Panel 2	AR (Flagship A)	Generation / Long (Flagship A)	Lunch (*Ballroom*)	End User (Flagship A)	
State Officials Panel 1	Transmission (Liberty)	AR (Liberty)	Lunch (*Ballroom*)	Publicly Owned Entity (Liberty)	
State Officials Panel 2	Supplier / Short (LSE) (Constitution)	End User (Constitution)	Lunch (*Ballroom*)	Generation / Long (Constitution)	

ISO Board Panel 1: Mike Curran, Craig Ivey, Cheryl LaFleur, and Mel Williams.

ISO Board Panel 2: Caren Anders, Steve Corneli, Brook Colangelo, Catherine Flax, and Gordon van Welie.

State Officials Panel 1: ME Chairman Phil Bartlett, ME Commissioner Carrie Gilbert, MA Assistant Secretary Weezie Nuara; MA staff John Slocum, CT staff Josh Walters (tentative), NH staff Dan Phelan, VT staff Lou Cecere, RI staff Todd Bianco, NESCOE Exec. Dir. Heather Hunt, NESCOE staff Sheila Keane, NESCOE staff Shannon Beale **

State Officials Panel 2: ME Commissioner Pat Scully, RI Chair Ron Gerwatowski (tentative), MA Commissioner Staci Rubin, MA Deputy Secretary Jason Marshall, CT staff Eric Annes, ME staff Michael Haskell, NH staff Jared Chicoine, NH staff Tyler Sweeney, VT staff Mary Jo Krolewski, NESCOE staff Jeff Bentz, NESCOE staff Nathan Forster, NECPUC Exec. Dir George Twigg **

**** 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 5, 2023, at the Providence Marriott 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. Dave Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded.

APPROVAL OF SEPTEMBER 7, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the September 7, 2023 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. Jon Lamson noted.

CONSENT AGENDA

Mr. Cavanaugh 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 approved as circulated, with oppositions by Cross-Sound Cable (CSC) and LIPA, and with abstentions by BP, Calpine, CPV, DTE, Galt Power, the Generation Bridge Companies, HQ US, Mercuria, Nautilus Power, NextEra, Shell, Wheelabrator, and Mr. Lamson. With the exception of Mr. Lamson, all of the representatives indicated that their oppositions or abstentions related to Consent Agenda Items 1 and 2 (FCA18 HQICC Values and Installed Capacity Requirement (ICR) and Related Values (together, the FCA18 Values)). Specifically, the representatives for CSC and LIPA explained that their votes reflected their view that the FCA18 Values did not properly recognize the reliability benefits of the Cross-Sound Cable, including the emergency energy assistance that the CSC had provided and would~~ill~~ continue to provide. The Calpine representative noted Calpine's vote reflected its previously conveyed positions objecting to the use of tie benefits (or any non-firm, non-committed external capacity) in the determination of the FCA18 Values. The representative for the Generation Bridge Companies, Nautilus Power and Wheelabrator identified a concern with the tie benefits component of the FCA18 Values, which, although he believed had been calculated properly by the ISO in accordance with the Tariff, nonetheless reflected an unrealistic number in his view, a shortcoming he hoped would be addressed in reforms to be discussed in the coming months.

ISO CEO REPORT

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 7, 2023 Participants Committee meeting, which had been circulated and posted in advance of the meeting. Mr. van Welie highlighted a~~the~~ report provided to the Board, which included information on a proposed Northeast Gas Study (NE Gas Study) to be undertaken by the Northeast Power Coordinating Council (NPCC), with the assistance of the ISO, New York ISO, NERC, and the Northeast Gas Association. Mr. van Welie said that the NE Gas Study was a response, in part, to the FERC's June 20, 2023 New England Gas-Electric Forum, the recently published NERC/FERC report on Winter Storm Elliott (which he commended to Participants as an interesting read), as well as plans for a NERC/Department of Energy (DOE) study of the gas system nationally. The NE Gas Study would examine the performance of the gas system during extreme weather events under various contingencies and also the modeling of the loss of certain resource types. To stay abreast of the progress and developments related to the NE Gas Study, he encouraged NEPOOL to invite an NPCC representative to the Participants Committee to periodically provide status~~periodic~~ reports.

In response to questions, Mr. van Welie clarified that the objective of the NE Gas Study would be, minimally, to analyze (i) the expected dynamic performance of the gas system during at least the first 10-15 years of the clean energy transition (during which increased electric system volatility attributable to a changing resource mix and load growth due to increased electrification was expected), and (ii) the reliability impacts if certain resource types were lost. He encouraged members to think of the clean energy transition in terms of a transition of the energy system, rather than in terms of either of its individual components, given the interconnectedness and interdependence of the electric and gas systems. He estimated that, given the complexities involved, the NE Gas Study would take at least one year to complete. He added that, as he indicated in his recent Congressional testimony, he supported the FERC/NERC recommendation for increased oversight of the gas system, which he believed would facilitate completion of the Study and subsequent dialogue around potential solutions to any issues identified by the Study.

One member asked what would happen if study assumptions underlying the development of the Probabilistic Energy Adequacy Tool (PEAT) framework developed in conjunction with the Electric Power Research Institute (EPRI) were not to play out as expected. Mr. van Welie, emphasizing the benefits, particularly the flexibility, of the PEAT framework in adjusting and analyzing risks as the system evolves, suggested that, should circumstances so dictate, alternative approaches could possibly be developed incrementally. Another member stressed the importance of vetting and ensuring the accuracy of residual gas supply assumptions.

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 27, 2023, unless otherwise noted. The Report highlighted: (i) Energy Market value for September 2023 was $324 million, up $14 million from the updated August 2023 value and down $368 million from September 2022; (ii) September 2023 average natural gas prices were 18% higher than August average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for September ($33.69/MWh) were 17% higher than August averages; (iv) average September 2023 natural gas prices and Real-Time Hub LMPs over the period were down 76% and 45%, respectively, from September 2023 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.6% during September (up from the 99.6% reported for August), with the minimum value for the month of 94.9% on September 19; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for September totaled $3.4 million, which was up $1.2 million from August 2023 and up $1.3 million from September 2022. September NCPC payments, which were 1% of total Energy Market value, were comprised of (a) $3.3 million in first contingency payments (up $1.5 million from August); (b) ~~there was~~ no second contingency payments; and (c) $67,000 in distribution payments (down $195,000 from August).

Highlighting upcoming planned transmission outages, Dr. Chadalavada noted one outage, on Line 344 (Bridgewater-West Medway), planned for November 6 through November 22, 2023. He expected that outage to create modest exposure for second contingency uplift in the Southeast

Massachusetts (SEMA) area. In response to questions, he agreed that the expected second contingency exposure would likely have been mitigated had the Day-Ahead Ancillary Services (DASI) reforms or a recovery reserve product been in place.

A member asked Dr. Chadalavada to comment on the operational impacts of, and the ISO's readiness for, certain recent developments and trends, including warmer temperatures being experienced for longer periods of time during the later months of the year and increased solar photovoltaic (PV) penetration. Dr. Chadalavada agreed that the risk landscape was shifting and confirmed that the ISO was studying how the grid system -would perform under those conditions. He identified an emerging concern related to system performance under low load conditions. Transmission security and reliability studies at that point assumed a low load of as little as 6,500 MW, but system operations had already come close to that level the prior spring, and the ISO was concerned by the possible impacts, including on voltage support, of further shrinking low load levels as a result of further solar PV penetration. With respect to daily operations, Dr. Chadalavada was confident in the Control Room's ability to manage through the operating day. He noted the increase in M/LCC2 (Master/Local Control Center Procedure No. 2) events, but attributed the increased frequency to how the system was being operated -- a combination of increased reliance on the market, rather than on surplus commitment ahead of need, with forced outages being experienced at the most inopportune times (i.e. during the few hours leading up to the peak hour when only fast start resources would be available to be called on, as was the case during recent Tropical Storm Lee). He added that forecasts were for the New England System to be winter peaking by the end of the decade.

In response to a request, Dr. Chadalavada provided an update related to the ISO'~~it~~s efforts with Constellation to minimize the volume and cost of liquefied natural gas (LNG) deliveries under the Mystic Cost of Service Agreement (COSA). Dr. Chadalavada reported that Constellation had indicated that LNG volumes for the second year of the COSA would be reduced from the volumes initially identified. He indicated that there may be other opportunities for volume reductions through the winter period. In addition, costs were likely to be lower than the previous winter, with the Title Transfer Facility (TTF) index price at roughly $12-$14 in per MMBtu (in contrast to $40-$45 per MMBtu at the same time the year before). He also expected the spread between the Algonquin Index and the TTF to be much smaller than the previous~~last~~ winter, increasing the chance that Mystic would be called on more often to run in-merit, further reducing costs. The outlook from a cost perspective was much better than the year before.

In response to a question regarding the Inventoried Energy Program (IEP), Dr. Chadalavada confirmed that aggregate values would be shared soon, and the ISO would explore sharing additional aggregate cost data to the extent possible.

A member asked Dr. Chadalavada for additional information regarding the projection in his report for 118 projects (18,330 MWs) of new Battery Storage. Dr. Chadalavada stated that much of the Battery Storage was expected to be of short duration (2-4 hours), widely distributed across the region, and for the most part not connected with solar facilities. He expected some changes to the queue (including potential pairings) following the implementation of *Order 2023* changes, with the impact of those *Order 2023*-related changes to come into focus within six to nine months. He committed to follow-up with more specifics on the related megawatt-hours.

2024 Annual Work Plan

Turning to the ISO's 2024 Annual Work Plan, which had been circulated to members in advance of the meeting and posted with the meeting~~Committee~~ materials, Dr. Chadalavada prefaced his presentation with a caution that, particularly with respect to the 2024 Work Plan, the need for adjustments not reflected in the Work Plan was even more likely in 2024, identifying as prominent variables the potential for additional FERC directives/regulatory requirements as well as potential adjustments in response to as-yet-to-be-made decisions (likely in the second quarter of 2024) regarding alternative (prompt/seasonal) Forward Capacity Market (FCM) commitment horizons. With that caveat, he proceeded to review the following anchor projects summarized in the Work Plan presentation: FCM Resource Capacity Accreditation (RCA); Assessing Alternative FCM Commitment Horizons (Prompt/Seasonal); Energy Adequacy Threshold Determination; *Order 2023* Implementation; Extended-Term/Longer-Term Transmission Planning Phase 2; DASI Implementation; and Next Generation Markets (nGem) Real-Time Market Clearing Engine.

With respect to RCA, Dr. Chadalavada reported that, with the pause to correct the software error previously identified coming to an end, the ISO would provide Participants with a refresher in November on the work completed to that point in time, including improvements made to the natural gas accreditation and oil models during the pause, and resume the project schedule from there.

Addressing Alternative FCM Commitment Horizons, Dr. Chadalavada noted that the ISO planned to file a request to delay FCA19 by one year (referred to as Option 2A), making FCA19 a two and one-half year forward market. The ISO hoped to get swift FERC approval on the requested delay so as to provide some stability as to that timing/schedule, while work continues towards a decision on whether to proceed with a prompt capacity auction and whether to restructure capacity commitment periods from annual to seasonal periods. He expected reports from The Analysis Group on those potential alternatives to begin to be issued starting in December.

Turning to the Energy Adequacy Threshold Determination anchor project (previously referred to as the operational impacts of extreme weather study), Dr. Chadalavada explained that the PEAT framework that had been developed would be used to establish a Regional Energy Shortfall Threshold (REST), which would start with a scoping discussion at ~~by~~ the end of 2023, with Energy shortfall defined by what mitigating actions are feasible to protect against an energy shortfall and not by load shedding. He confirmed plans to run periodic assessments with PEAT, given changing conditions. He also stated that REST would not only support efforts towards a clean energy transition, but would also support market product design.

Regarding *Order 2023* Compliance and Implementation, where work was actively underway, aggressive timelines to respond to the Order, as well as the work needed to conform ~~the~~ planning and operating protocols to *Order 2023* and to ensure cluster studies are initiated and work begins in accordance with *Order 2023*, would keep folks busy through at least the end of 2024. As for Extended-Term Transmission Planning Phase 2, which would begin in November, efforts would focus on making longer-term planning studies actionable (identifying primary criteria to prioritize results, and how to solicit solutions, quantify benefits and allocate costs). The plan was to make a filing in the second quarter of 2024.

With respect to the last two anchor projects, DASI, which was expected to be filed by the end of October, had an aggressive 12 to 15-month implementation plan. Dr. Chadalavada noted that implementation in that timeframe would far exceed the speed with which past projects of similar magnitude had been implemented. He attributed DASI's rapid implementation in part to the nGEM platform, which in 2024 would also be brought into the ISO's Real-Time systems.

Members then commented and asked questions on the 2024 Work Plan. One member suggested the ISO consider, as part of the identified projects and initiatives, the establishment of a reliability requirement that would create demand that the pipeline and LNG industries might organize to supply, ensuring that the resources needed would be either retained or procured, with attendant benefits to customers and regional reliability. Dr. Chadalavada answered that, directionally, RCA would help, as could longer durational reserves. Discussion regarding REST would likewise provide an opportunity to ultimately move the needle towards establishing products and services with the necessary rents and revenues for resources to take on the needed obligations. Mr. van Welie added that the region would have to come to terms with the challenge, on both the electric and gas sides, of fixed cost recovery for very low capacity factor infrastructure needed to support the clean energy transition. Other regions were struggling with that very challenge. He agreed that, directionally, generators would be incented to find ways to firm up their fuel supply to a point, but was skeptical that gas-fired generators would ever find it rational to take long-term firm transportation on a pipeline. Mr. van Welie predicted significant policy and regulatory work ahead to address this challenge.

In response to a member's question, Dr. Chadalavada stated that the ISO would issue by the end of the year a scope of work for REST, which would identify the steps necessary to complete that project. Involvement of the NEPOOL Participants and the New England States would be crucial to the success of the project. He acknowledged and emphasized the need to better optimize opportunities for existing infrastructure/resources. In addition, referring to previous requests from that member related to nGem, Dr. Chadalavada committed to include slides in his December Operations Report (and to consider a broader ISO seminar) on nGem-related enhancements.

Dr. Chadalavada clarified the meaning of 'storage modeling market enhancements', stating that adding storage modeling into Real-Time clearing and dispatch was not part of any current scoping effort, but nonetheless something that the ISO had to do. He added that expectations were that storage's biggest impact would be in Real-Time and not in clearing Day-Ahead.

The ISO also needed also to further assess how market signals or pricing works, both Day-Ahead and in Real-Time, in times of energy shortage. Pricing had been designed to account for energy scarcity, but not shortages. Mr. Matt White, the ISO's Chief Economist and Vice President of Market Development and Settlements, added that the scope of the assessment was intended to be narrow, focused on what would or should energy market pricing or LMPs be in the case of a controlled load shedding state, particularly in the absence of explicit Tariff provisions governing that scenario in Real-Time. He explained why the assessment did not implicate Reserve-Constraint Penalty Factors (RCPF) or Pay-for-Performance (PFP) penalties, and stated that a fair amount of time-intensive testing and modeling would be required before the ISO would be in a position to propose a specific recommendation or direction on this topic.

Dr. Chadalavada described the sense of urgency motivating the ISO develop and implement some version of seasonal markets prior to the projected transition to a winter peaking system at the end of the decade. FCA18 would be run in a few months, locking in capacity arrangements through 2028. The scope of work associated with those efforts would be extensive and, should the ISO proceed down that path, the efforts would require significant planning and markets resources. He thanked members for their questions, comments, and feedback, to which he committed to respond.

Concluding the discussion, Mr. Cavanaugh acknowledged and thanked the members and the Committee Officers in particular, for their dedicated efforts in working together to establish NEPOOL's priorities over the last two years, and thanked ISO staff, including Ms. Allison

DiGrande and her Participant Relations and Services team, as well as the Markets Development team, for their willingness and efforts to evaluate and provide feedback on NEPOOL's preliminary set of priority items identified via Sector deliberations before the NEPOOL-wide list of key priorities for 2024 were finalized. He said it was rewarding to see the coordinated efforts bear fruit, particularly with the efforts integrated with the ISO's Annual Work Plan, which incorporated more than just NEPOOL's top three priorities.

2024 ISO AND NESCOE BUDGETS

2024 ISO Budgets

Mr. Tom Kaslow, Budget & Finance Subcommittee Chair, referred the Committee to the materials circulated in advance of the meeting related to the proposed 2024 ISO Capital and Operating Budgets (ISO Budgets). He summarized the process followed to review the ISO Budgets with members and state officials, and noted that there had been no concerns of note raised by Participants during the Subcommittee's review process.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the Year 2024 operating budget and capital budget proposed by the ISO as presented at this meeting.

In comments, End User representatives expressed their appreciation to the ISO for incorporating comments made on the Budgets, including the incorporation of a placeholder for an environmental and community affairs position, but also expressed concern with the steep increase in the ISO's 2024 Budgets and the sustainability of similar increases in the future.

The motion to support the ISIO's 2024 Budgets was then voted and approved, with oppositions recorded for the NH OCA, Maine OPA, and Littleton (NH) Water & Light, and abstentions for the CT OCC, CSC, IECG, Mr. Lamson, LIPA, Maine Skiing,[1] MA AG, the RI Division, and VEC.

2024 NESCOE Budget

Mr. Kaslow then referred the Committee to the NESCOE budget materials posted in advance of the meeting. He stated that the 2024 NESCOE Budget had been reviewed, without objection or concern, by the Budget & Finance Subcommittee at its August 11 meeting and the 2024 NESCOE Budget conformed to the 5-year budget framework supported by the Participants Committee and accepted by the FERC the year before.

Without discussion, the following motion was duly made, seconded, and approved unanimously, with abstentions recorded for IECG, Maine Skiing[1] and Mr. Lamson:

> RESOLVED, that the Participants Committee supports the 2024 NESCOE budget, as proposed by NESCOE at this meeting, as the Year 2024 operating budget for NESCOE.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the October 3 Litigation Report that had been circulated and posted the day before the meeting. He highlighted the following developments:

(i) *Brookfield Complaint Regarding IEP Exclusion of Pumped Storage ESFs (EL23-89).* The FERC granted Brookfield's complaint on September 21, 2023, directing the ISO to revise the Tariff to allow pumped storage resources to participate as Electric Storage Facilities (ESFs) in the Inventoried Energy Program (IEP). He reported that those Tariff revisions would be reviewed by the Markets Committee (MC) the following week and voted by the Participants Committee in November.

[1] The representative for the Industrial Energy Consumer Group (IECG) and Maine Skiing, Inc. (Maine Skiing), who was participating by phone but whose votes on the 2024 ISO and NESCOE Budgets were not communicated during the meeting, requested after the meeting that, on each those votes, each of IECG and Maine Skiing be identified as abstaining.

(ii) *Order 2023: Generation Interconnection Reforms (RM22-14).* NEPOOL requested a 45-day extension of time, to January 19, 2024, for the submission of New England's compliance filing. The extension was requested to permit time for additional Technical Committee meetings and action by the Participants Committee at its regularly-scheduled January meeting. The request was pending before the FERC.

(iii) *ACPA Petition for Resource Capacity Accreditation Technical Conference (AD23-10).* Mr. Lombardi reported that, in response to the request by the American Clean Power Association (ACPA) for a technical conference to explore ways to improve the accreditation of resources' capacity, a number of comments had been submitted, including comments by the ISO/RTO Council (IRC) that did not support the request (suggesting that the topic was not well-suited for a national forum in light of regional variation on resource adequacy-related matters).

Mr. Lombardi then raised for the Committee some of the potential impacts of a federal government shutdown, which had been temporarily averted at the end of September, but that remained a possibility when the 45-day continuing resolution that moved Congress' deadline for completing work on fiscal year 2024 appropriations was scheduled to expire on November 17. He explained that a federal government shutdown could impact the FERC and its ability to do its work. During the last shutdown (winter 2018-2019), which lasted for 35 days, the FERC was able to use surplus funds to continue its operations (including accepting and ruling on filings). He cautioned that it was not certain whether, or if so the scope of, surplus funds that may be available to the FERC to continue operations should shutdown occur after November 17. If

FERC operations were unable to continue, he speculated, the acceptance of filings and upcoming compliance deadlines may be delayed until operations re-commenced; previously submitted filings subject to statutory deadlines (e.g. Federal Power Act Section 205 filings requiring FERC action within 60 days) that would occur during any such shutdown would become effective by operation of law.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the MC had a two-day meeting in Westborough, MA the following week. Items to be considered included updates to the Net Cost of New Entry for FCA19, proposed changes to energy market upward mitigation, a number of proposed Generation Information System (GIS) changes, Tariff revisions in response to the FERC order granting the Brookfield IEP Complaint, and the RCA subject.

Transmission Committee (TC). Mr. Dave Burnham, the TC Vice-Chair, reported that the next TC meeting was scheduled for October 17, also in Westborough. The main item to be considered was *Order 2023* Compliance and there would also be a presentation by the ISO regarding the second phase of the Extended-Term Transmission Planning.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting was scheduled for October 24.

Budget & Finance (B&F) Subcommittee. Mr. Kaslow reported that the next B&F Subcommittee meeting was scheduled for October 10. The October 10 meeting would include some general reporting. Proposed changes related to financial assurance associated with PFP would be considered at an additional B&F meeting to be held on October 30.

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the next Subcommittee meeting was scheduled for October 13 at 1:00 p.m. Mr.

Cavanaugh announced that Ms. Bresolin would be stepping down as Subcommittee Chair after five years of service. On behalf of the Participants, he thanked her for her time as Subcommittee Chair. He then introduced Ms. Ashley Gagnon as the new Subcommittee Chair and wished her well in that role.

ADMINISTRATIVE MATTERS

Mr. Cavanaugh then introduced Ms. Anne George, ISO Vice President, Chief External Affairs and Communications Officer, who addressed the ISO's open Board meeting and Regional System Plan (RSP 2023) public meeting scheduled to be held at the Seaport Hotel in Boston on November 1. She stated that in-person attendance would be limited and registration for that meeting, both in person and virtual, was open and accessible via the ISO's on-line calendar.

Mr. Lombardi reminded the Committee that the next Participants Committee meeting would be held November 2, 2023 also at the Seaport Hotel in Boston, with Mr. Cavanaugh reminding Participants that materials for the modified Sector meetings with the ISO Board and State representatives to be held prior to general business on November 2 were to be submitted no later than October 13. Looking beyond November, Mr. Lombardi noted that the December Annual Meeting of the Participants Committee was scheduled for December 7, 2023 at the Colonnade Hotel in Boston.

There being no other business, the meeting adjourned at 12:24 p.m.

Respectfully submitted,

____

Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN OCTOBER 5, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy	Associate Non-Voting		Alex Lawton	
AR Small Load Response (LR) Group Member	AR-LR	Amaani Hamid (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Associated Industries of Massachusetts (AIM)	End User	Robert Ruddock		Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta (tel)	Jason Rauch	Zach Teti (tel)
Bath Iron Works Corporation	End User			Bill Short (tel)
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller (tel)
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User		J.R. Viglione (tel)	Jason Frost
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon (tel)		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Wes Walker (tel)		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short (tel)
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein (tel)		Bill Fowler
ECP Companies Calpine Energy Services, LP (Calpine) New Leaf Energy	Generation	Brett Kruse Liz Delaney (tel)	Andy Gillespie	Bill Fowler
EDF Trading North America	Supplier	Eric Osborn (tel)		
Elektrisola, Inc.	End User			Bill Short (tel)
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley (tel)		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Dave Burnham (tel)	Vandan Divatia
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc. (Galt)	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User			Bill Short (tel)
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation	Dennis Duffy	Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short (tel)
Harvard Dedicated Energy Limited	End User			Jason Frost

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN OCTOBER 5, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumer Group (IECG)	End User	Dan Collins (tel)		
Interconnect Storage LLC		Colleen Nash (tel)		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths		
Lamson, Jon	End User	Jon Lamson (tel)		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
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		
Maine Skiing, Inc.	End User	Dan Collins (tel)		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Ashley Gagnon	Jamie Donovan (tel)	Tina Belew (tel)
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide (tel)	Dan Murphy	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short (tel)
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson (tel)	Lindsay Orphanides (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		Jason Frost	
New England Power (d/b/a National Grid)	Transmission		Tim Martin (tel)	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan (tel)	
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier		Pete Fuller (tel)	
Nylon Corporation of America	End User			Bill Short (tel)
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
PowerOptions, Inc.	End User			Jason Frost
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide (tel)		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division (DPUC)	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide (tel)		
Saint Anselm College	End User			Bill Short (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCTOBER 5, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short (tel)
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller (tel)
Tangent Energy	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide (tel)		Dan Murphy
The Energy Consortium	End User		Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative (VEC)	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR			Jason Frost
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	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH LLC	End User			Bill Short (tel)

CONSENT AGENDA

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's October 11-12, 2023 meeting, dated October 13, 2023.[1]

1. Revisions to Market Rule I § III.13.2.4.2 (FCM Net CONE Updates for FCAs 19 and 20)

Support the revisions to Section III.13.2.4.2 of Market Rule 1 (Interim Year Adjustments to CONE and Net CONE) to incorporate updated parameters that will be used in the calculation of the After Tax Weighted Average Cost of Capital (ATWACC) in the annual adjustment to the Cost of New Entry (CONE) and Net CONE for Forward Capacity Auctions 19 and 20 (FCAs 19 and 20), as recommended by the MC at its October 11-12, 2023 meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the MC may approve.

> The motion to recommend Participants Committee support was approved, with 5 oppositions (Generation (1), Supplier (1), AR (1), End User (2)) and 9 abstentions (Generation (2), Supplier (1), AR (2) End User (4)) recorded.

2. Revisions to Market Rule 1 Appendix A (Energy Supply Offer Mitigation Changes in Response to FERC Show Cause Order)

Support the revisions to Appendix A to Market Rule 1 (Market Monitoring, Reporting and Market Power Mitigation) to eliminate the potential for upward mitigation of Energy Supply Offers by incorporating updates which will be used to compare each financial parameter of the Supply Offer to the Reference Level and use the lesser of the two values when performing certain automated mitigation procedures, as recommended by the MC at its October 11-12, 2023 meeting, together with such further non-substantive 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 in the End User Sector recorded.

3. Revisions to Appendix K to Market Rule 1 (IEP Inclusion of Pumped Storage ESFs)

Support the revisions to Appendix K of Market Rule 1 (Inventoried Energy Program (IEP)) to allow pumped storage facilities to participate in the Inventoried Energy Program, as recommended by the MC at its October 11-12, 2023 meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the MC may approve.

> The motion to recommend Participants Committee support was approved unanimously, with 3 abstentions in the End User Sector, and 25 abstentions in the Publicly Owned Entity Sector recorded.

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

4. <u>Market Rule 1 Revisions (Distributed Energy Capacity Resource Tariff Updates)</u>

Support revisions to Market Rule 1 to clarify and simplify several Distributed Energy Capacity Resource (DECR) Forward Capacity Market qualification provisions consistent with the ISO's *Order 2222* DECR participation design, as recommended by the MC at its October 11-12, 2023 meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the MC may approve.

> The motion to recommend Participants Committee support was approved unanimously, with 1 abstention in the End User Sector recorded.

NEPOOL PARTICIPANTS COMMITTEE | 11/2/23
Meeting Agenda item #4

NEPOOL Participants Committee Report

November 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through October 24th, unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: September 2023 Energy Market value totaled $346M
  - October Energy market value was $186M, down $160M from September 2023 and down $326M from October 2022
    - October 2023 natural gas prices over the period were 15% lower than September 2023 average values
      - Lowest average nat. gas price for any month since SMD
    - Average RT Hub Locational Marginal Prices ($23.64/MWh) over the period were 27% lower than September averages
    - Average October 2023 natural gas prices and RT Hub LMPs over the period were down 73% and 55%, respectively, from the same month a year ago
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.9% during October, up from 100.6% during September*
      - The minimum value for the month was 93.8% on Saturday, October 21st

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

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

Highlights, cont.

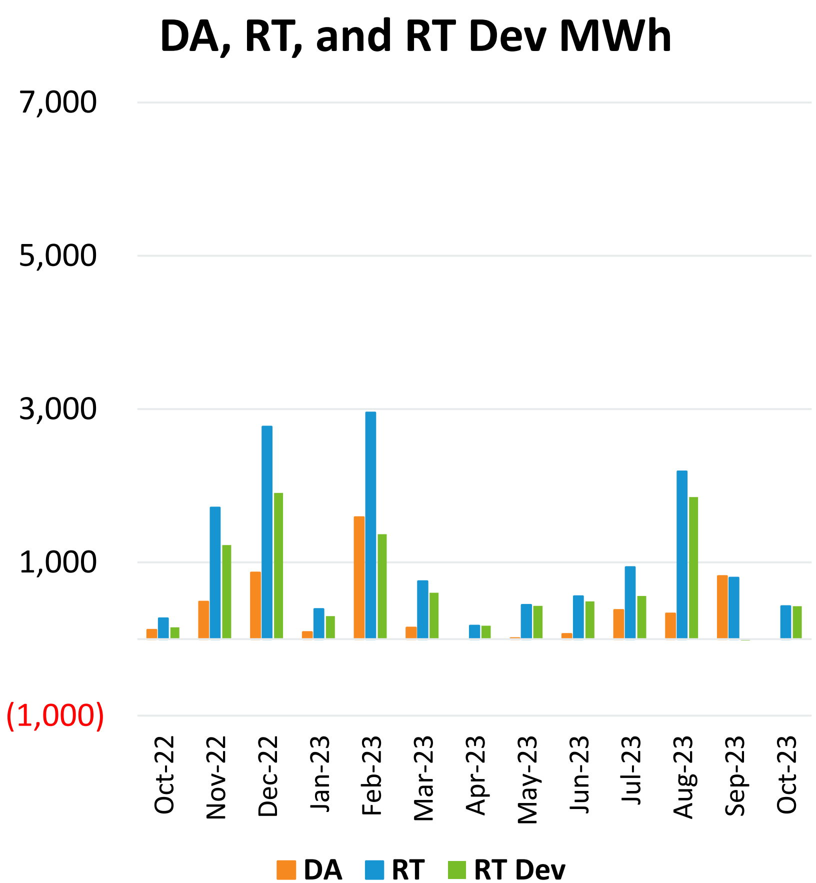
- Daily Net Commitment Period Compensation (NCPC)
  - October 2023 NCPC payments totaled $3.7M over the period, up $0.2M from September 2023 and up $0.8M from October 2022
    - First Contingency payments totaled $3.6M, up $0.2M from September
      - $3.4M paid to internal resources, comparable to September
        - » $236K charged to DALO, $2.6M to RT Deviations, $536K to RTLO*
      - $256K paid to resources at external locations, up $173K from September
        - » $3K charged to DALO at external locations, $253K to RT Deviations
    - Distribution payments totaled $42K, down $25K from September
    - Second Contingency and voltage payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 2%
    - October 4 and 23 during (M/LCC 2 days) contributed to elevated NCPC
    - Relatively low October Energy Market Value (low DA pricing and loads)

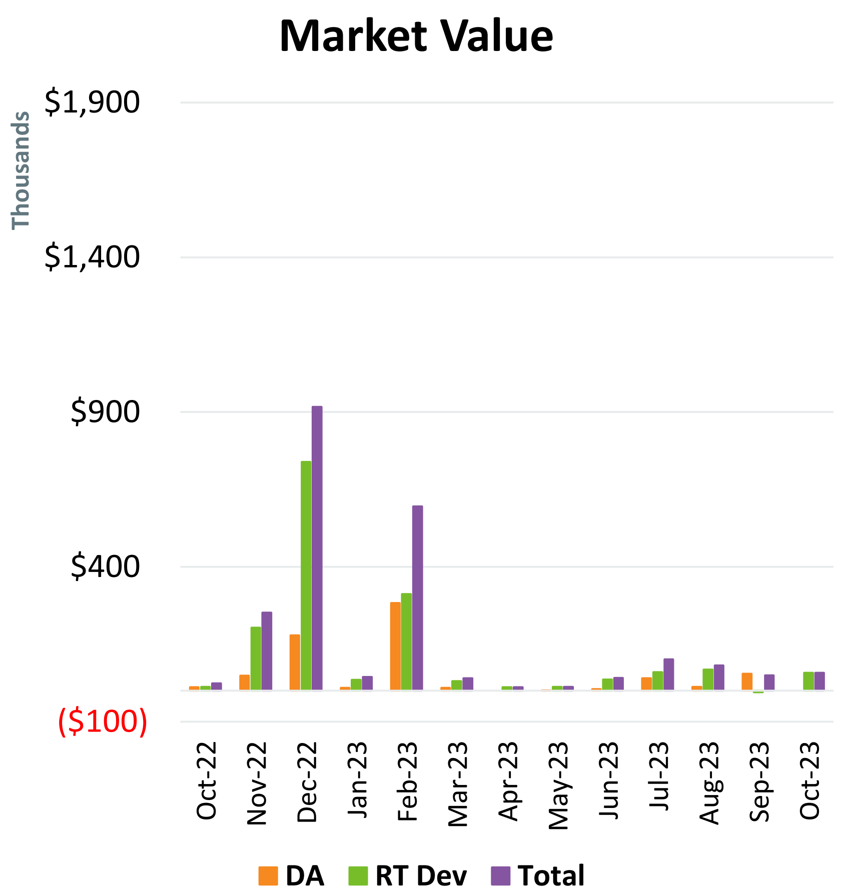
*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $181K; Rapid Response Pricing (RRP) Opportunity Cost - $355K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

Highlights (Cont'd)

- M/LCC 2 Implementation(s)
  - Effective Wednesday, October 4 between 5:30 p.m. and 10 p.m. for all of New England
    - Due to projected capacity deficiency
    - RT Hub Pricing Average: $123/MWh
  - Effective Monday, October 23 between 4:00 p.m. and 10 p.m. for all of New England
    - Due to projected capacity deficiency
    - RT Hub Pricing Average: $100/MWh

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

- FCA 18 will evaluate the same zones as evaluated in FCA 17
- ISO to kick off PSPC cycle at the May 31 meeting for ICR and related values and tie benefits study for FCA 18
- High-level outline of Future Grid Reliability Study Phase 2 was presented at the April PAC
  - FGRS Phase 2 will be run as the Stakeholder-Requested Scenario in the Economic Planning for the Clean Energy Transition study
- The 2024 forecast cycle was initiated at the September 22 Load Forecast Committee (LFC) meeting
- The next LFC meeting will be held on November 13
- Qualified Transmission Project Sponsor (QTPS)
  - 27 companies have achieved QTPS status

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 15 (2024-2025)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, and results were posted on August 24
- CCP 16 (2025-2026)
  - First annual reconfiguration auction (ARA1) was held on June 1-5, and results were posted on July 3
- CCP 17 (2026-2027)
  - Auction results were filed with FERC on March 21 and, on July 18, FERC issued an order accepting the results effective July 19
  - ICR and related values for the ARAs to be conducted in 2024 were presented and approved at the October 24 RC meeting

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - FCA 18 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - The ISO issued qualification determination notifications on October 12
  - ICR and related values were approved at the September 19 RC and October 5 PC meetings
    - FERC filing is expected to be submitted on November 7

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 11, 2023.
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 6, 2024.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (4.9°F) Max: 83°F, Min: 45°F Precipitation: 0.99” - Below Normal Normal: 3.78”	Hartford	Temperature: Above Normal (5.1°F) Max: 86°F, Min: 34°F Precipitation: 2.72” - Below Normal Normal: 4.28”

Peak Load:	16,333 MW	October 4, 2023	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	10/04/2023 17:19	10/04/2023 21:53	Capacity Deficiency
M/LCC 2	10/23/2023 15:55	10/23/2023 21:52	Capacity Deficiency

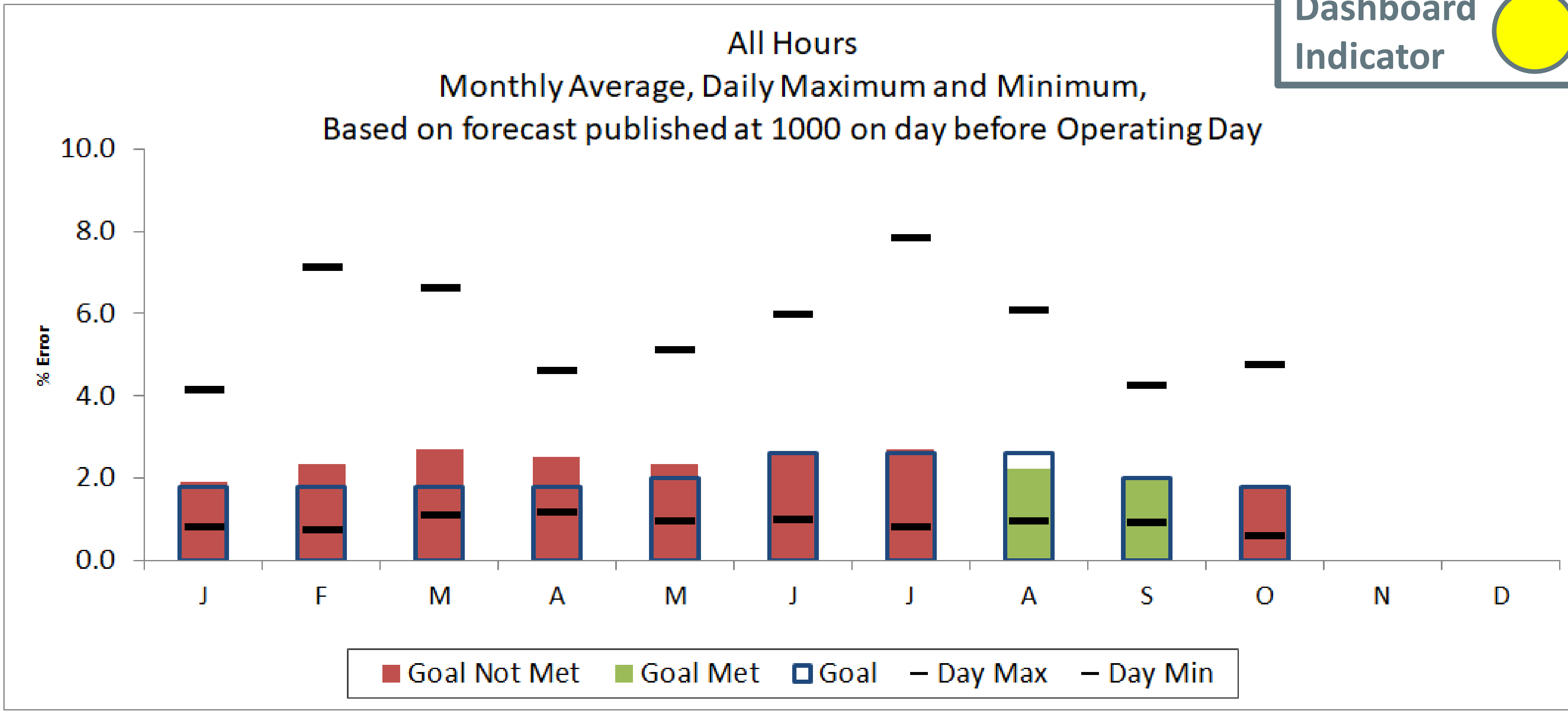
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
10/23/2023	ISO-NE	750

2023 System Operations - Load Forecast Accuracy

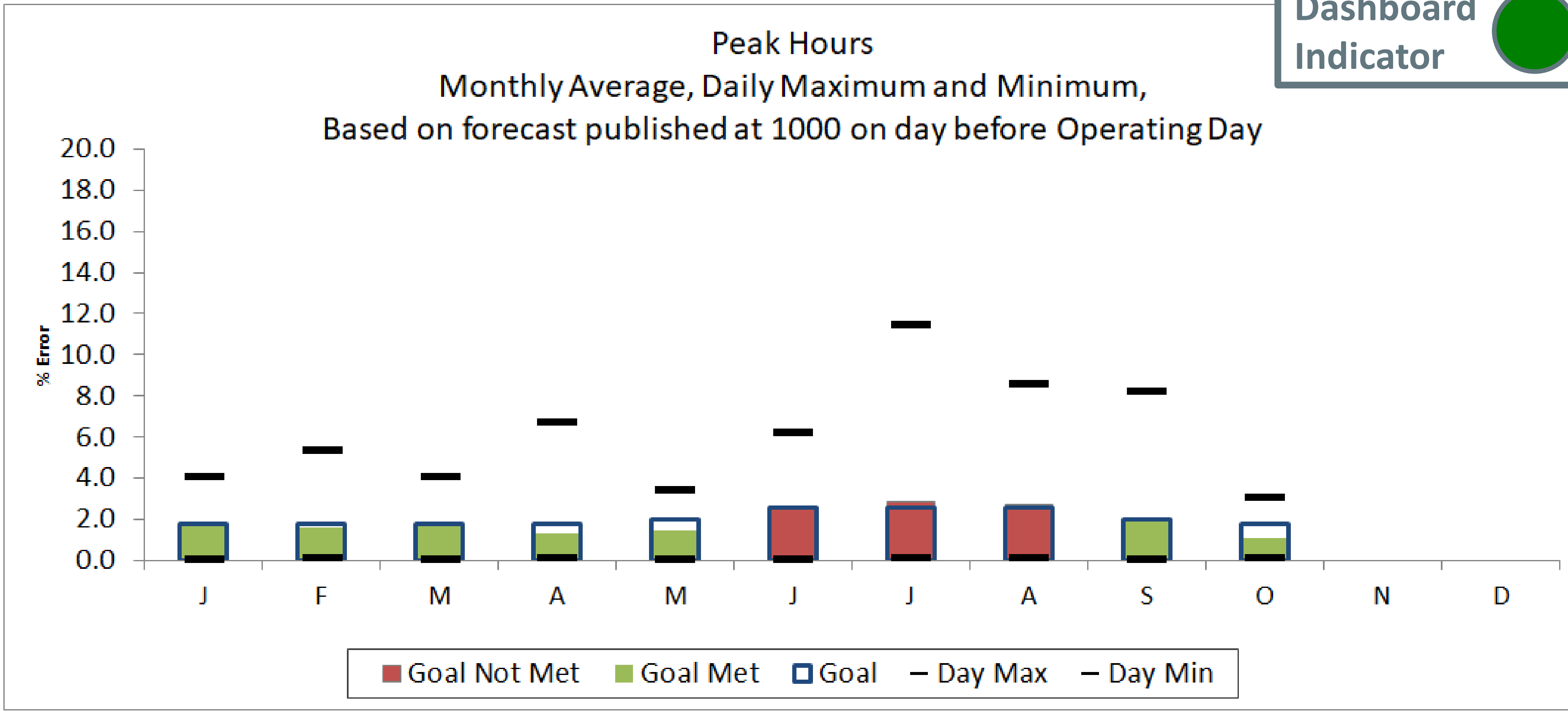
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14	7.12	6.59	4.61	5.10	5.97	7.82	6.06	4.24	4.73			7.82
Day Min	0.80	0.74	1.08	1.17	0.96	0.97	0.79	0.95	0.91	0.59			0.59
MAPE	1.91	2.34	2.70	2.52	2.36	2.63	2.70	2.23	1.94	1.81			2.31
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

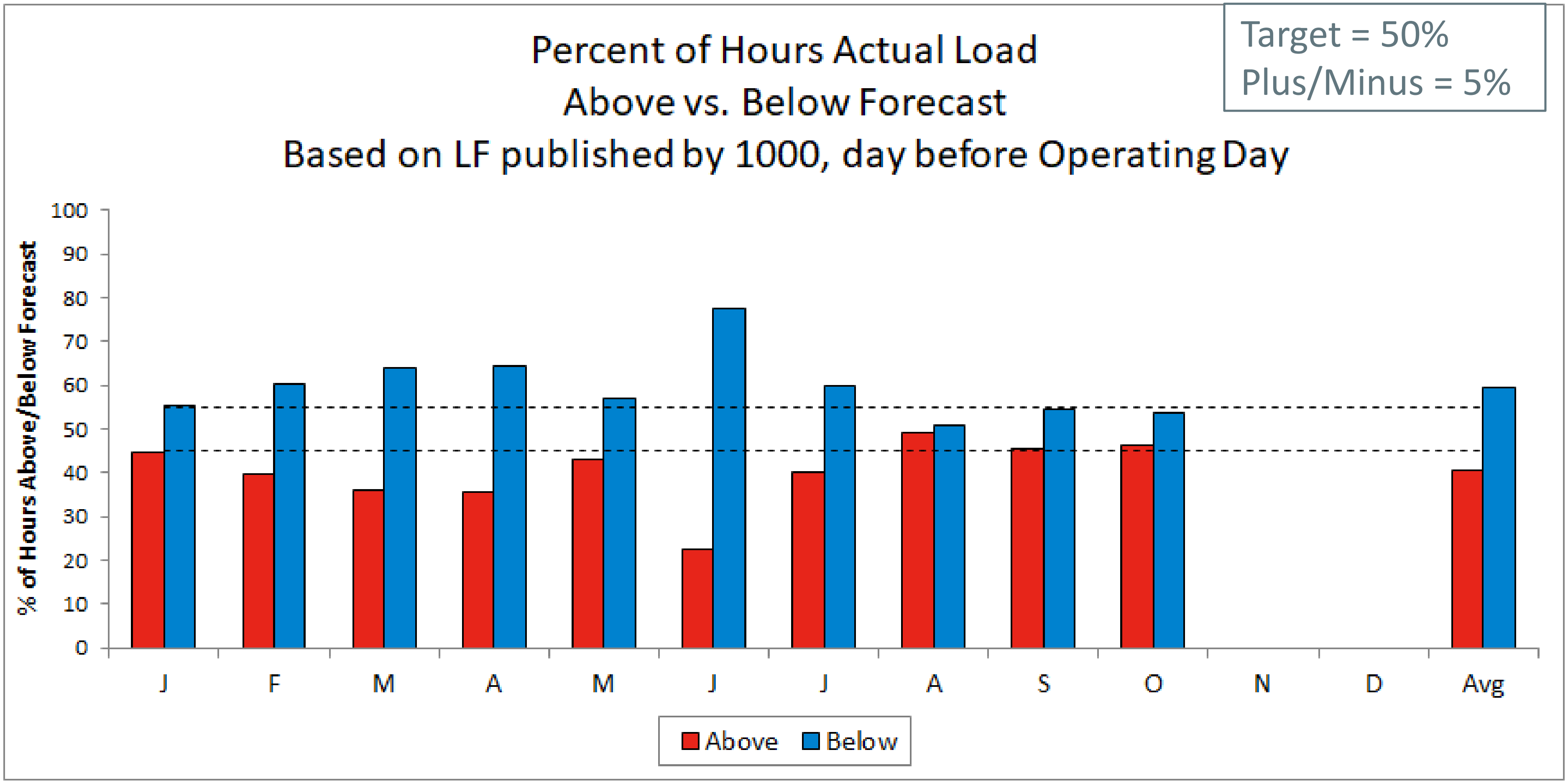
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



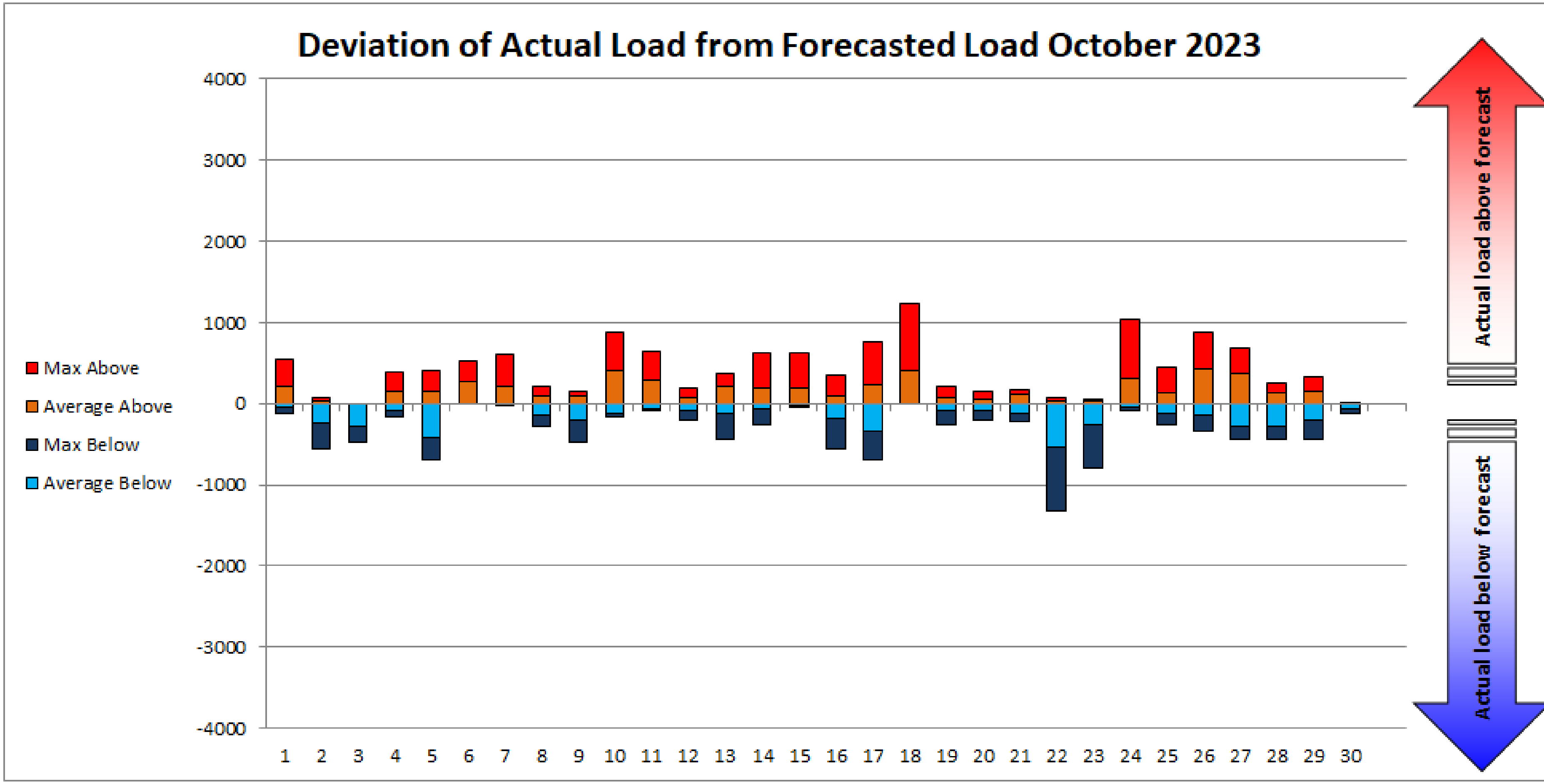
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21	11.40	8.59	8.17	3.01			11.40
Day Min	0.01	0.08	0.06	0.11	0.03	0.04	0.08	0.14	0.01	0.08			0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65	2.87	2.72	1.97	1.14			1.92
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2023 System Operations - Load Forecast Accuracy cont.

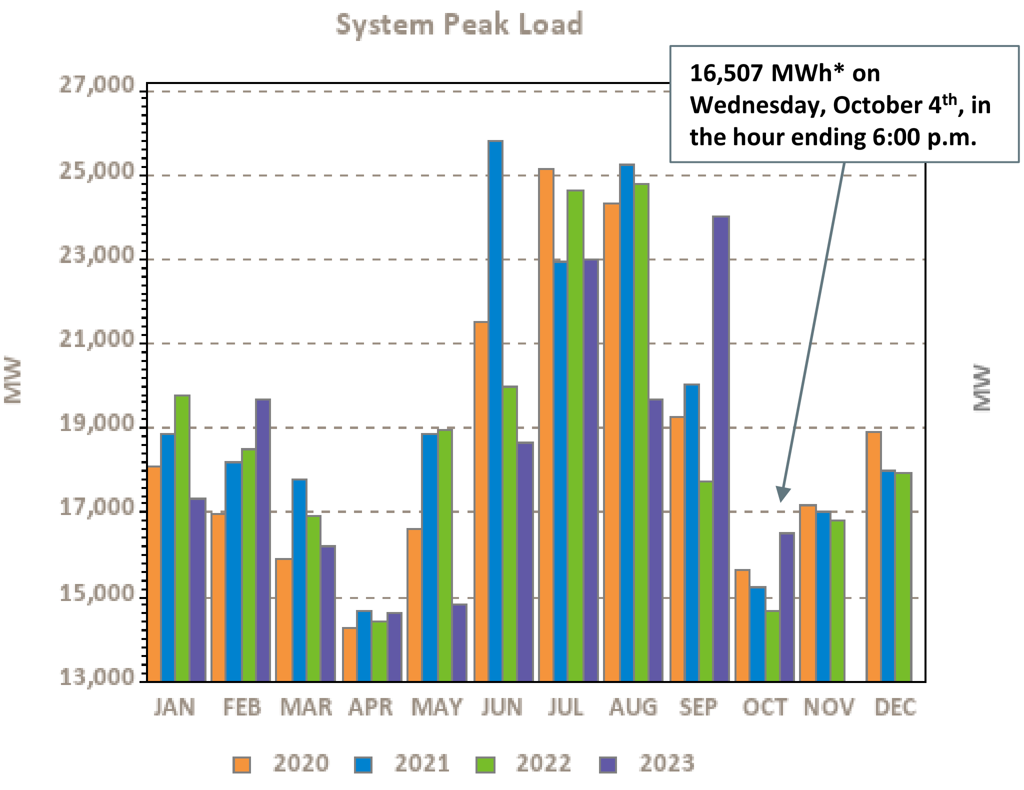


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6	40.2	49.2	45.6	46.3			40
Below %	55.4	60.3	63.8	64.3	57	77.4	59.8	50.8	54.4	53.7			60
Avg Above	235.7	228	172.9	194.5	183.5	120	194.8	228.5	226	164.7			236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3	-388.6	-215.1	-169.7	-151.9			-389
Avg All	-10	-28	-142	-74	-17	-236	-170	-6	20	-6			-67

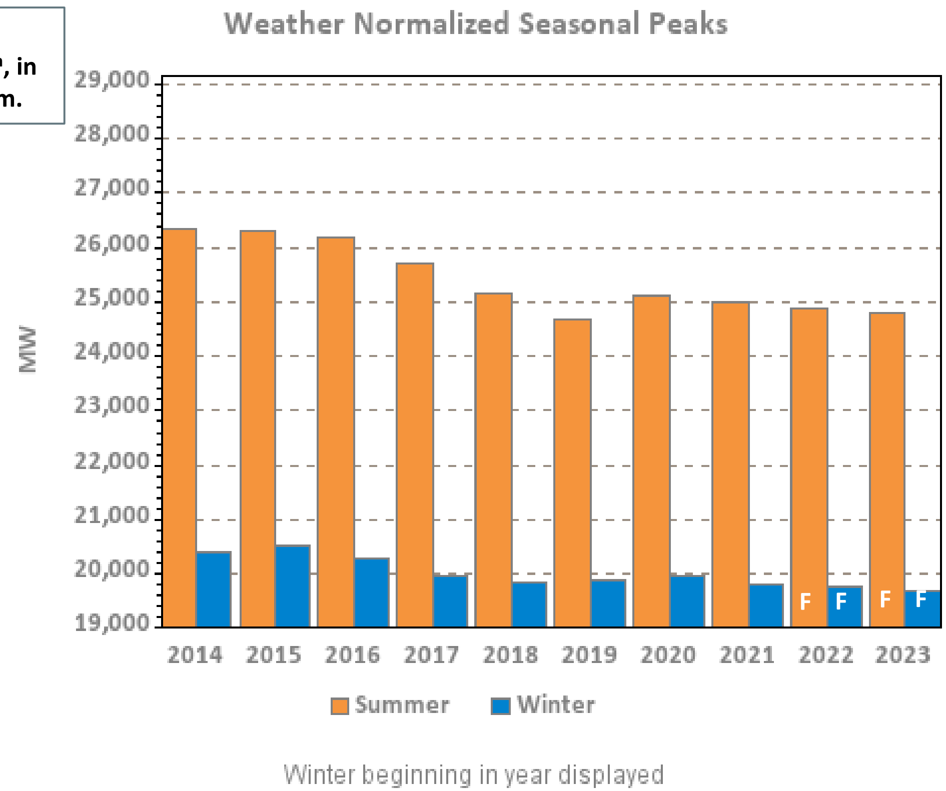
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History

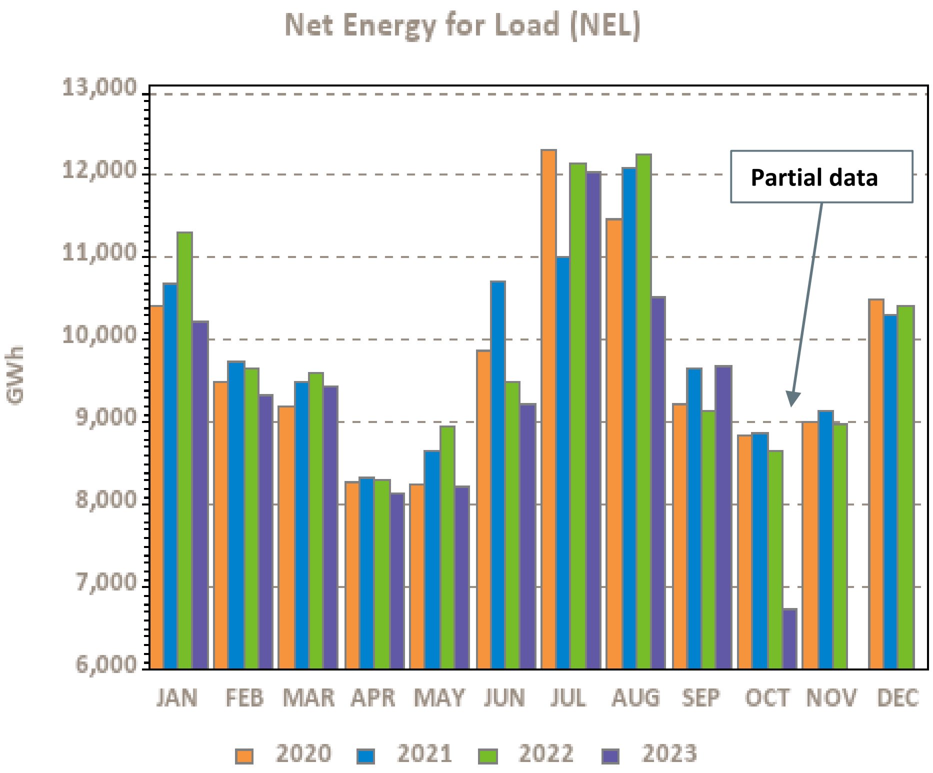


*Revenue quality metered value

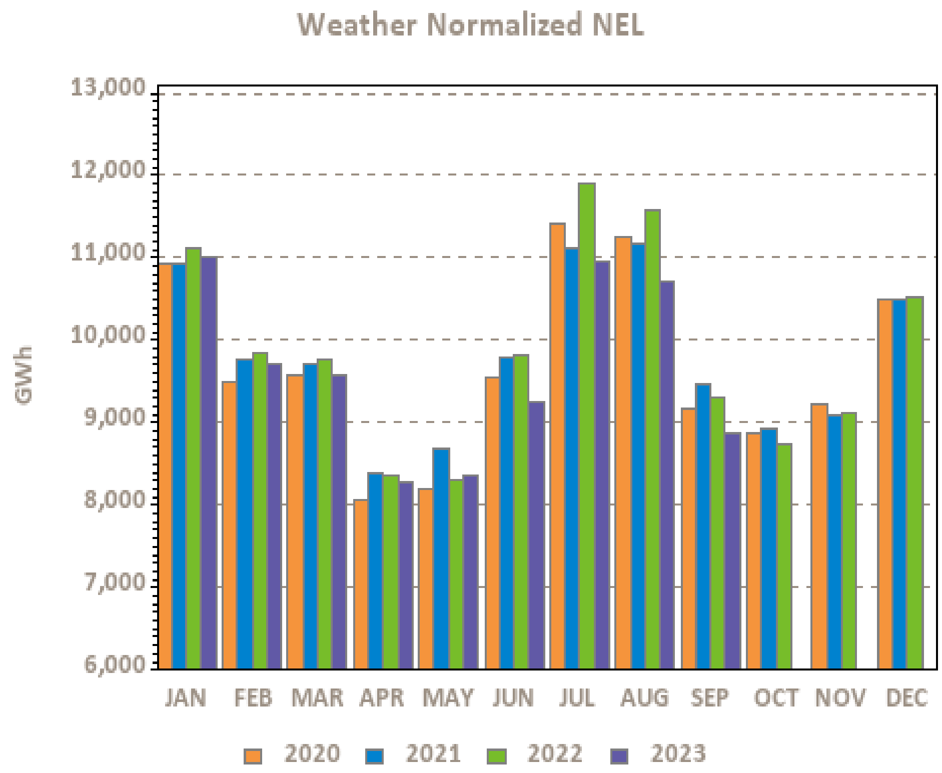


F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



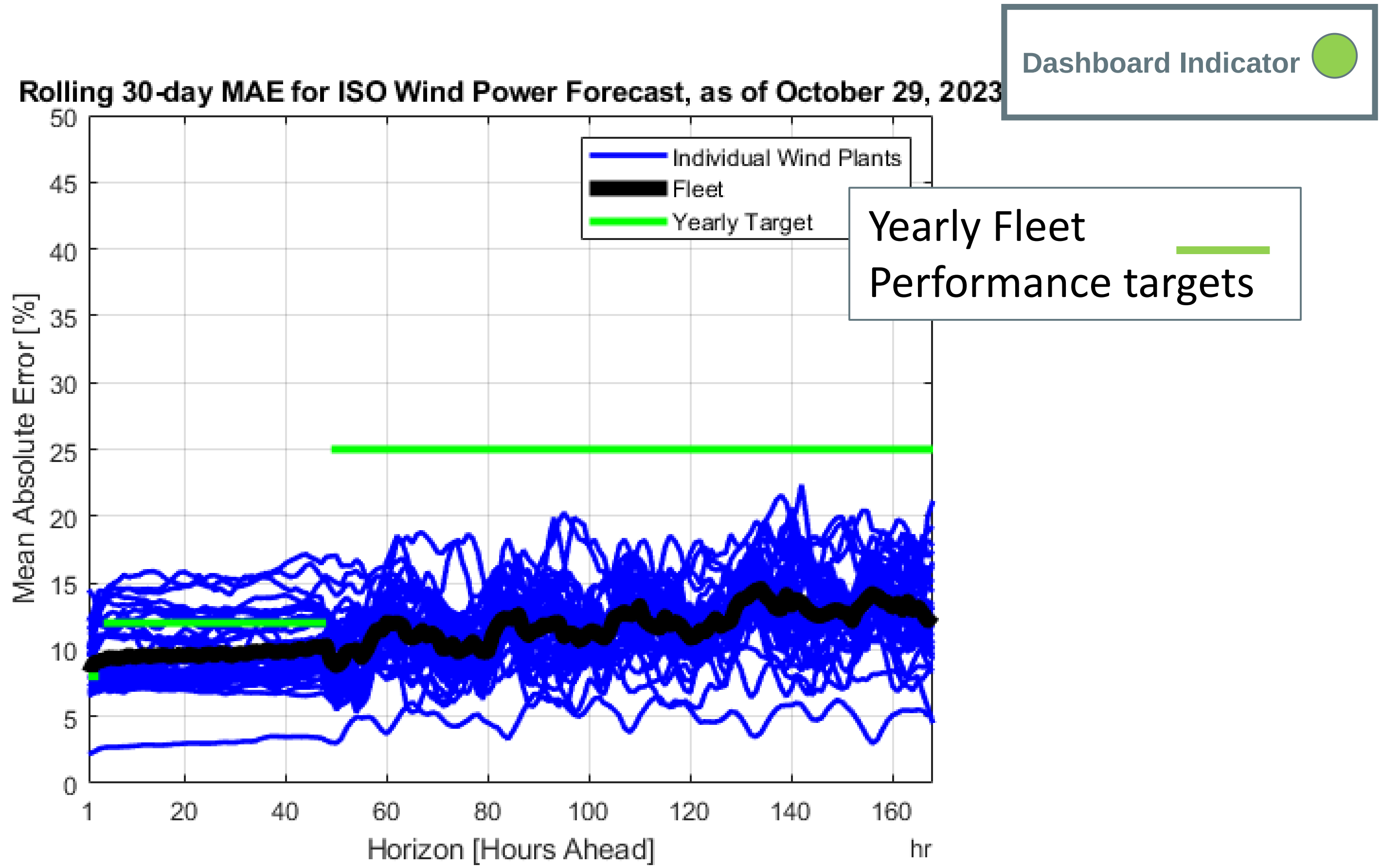
Ann Tot (TWh): 116.9 118.8 118.9 93.5



Ann Tot (TWh): 116.3 117.6 118.4 86.7

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.

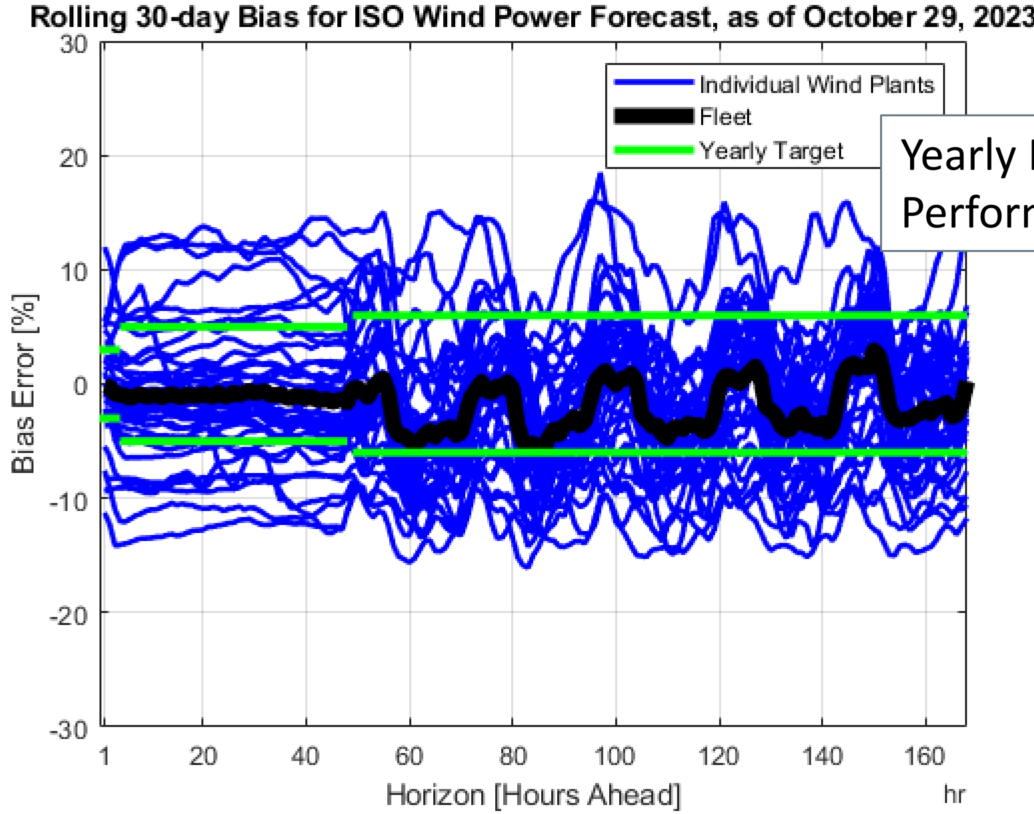
Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE



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

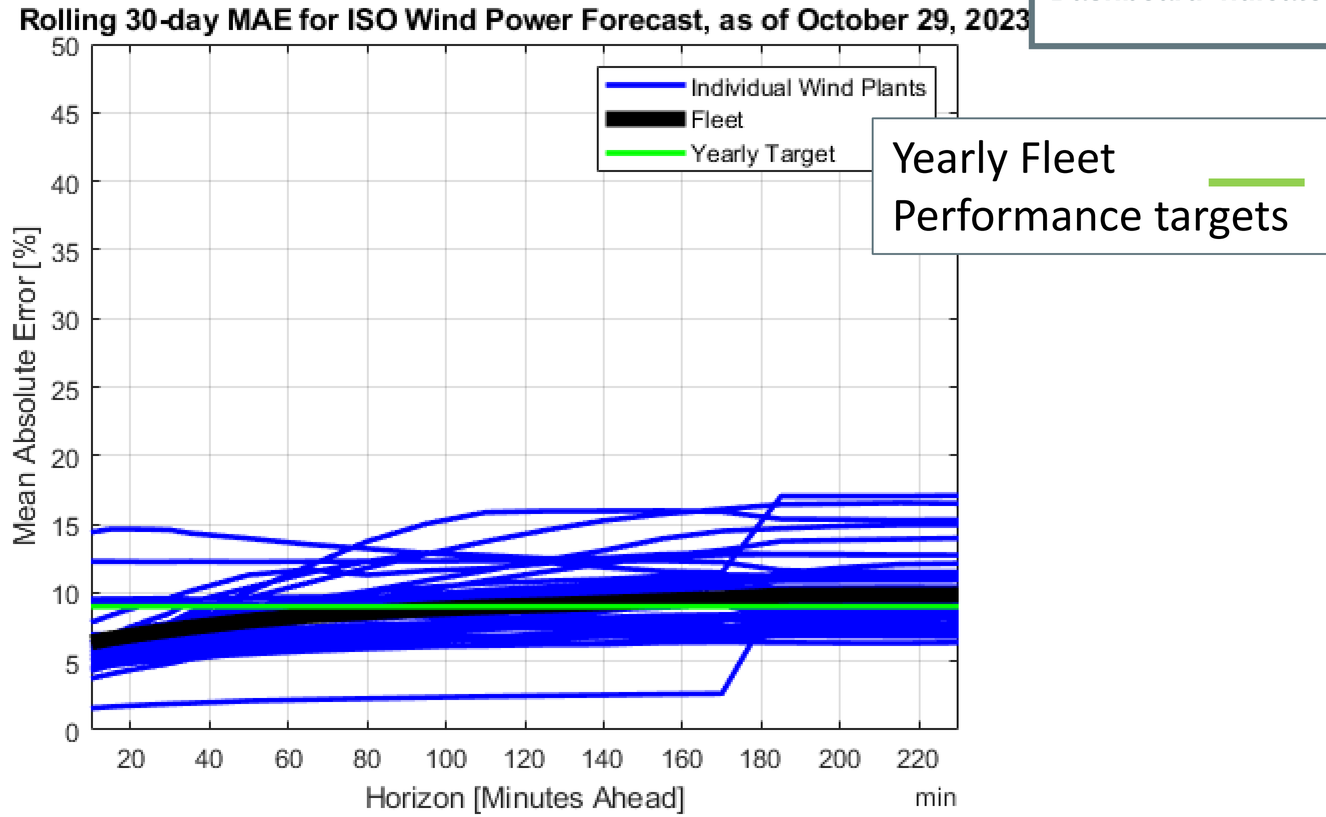


Yearly Fleet Performance targets

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

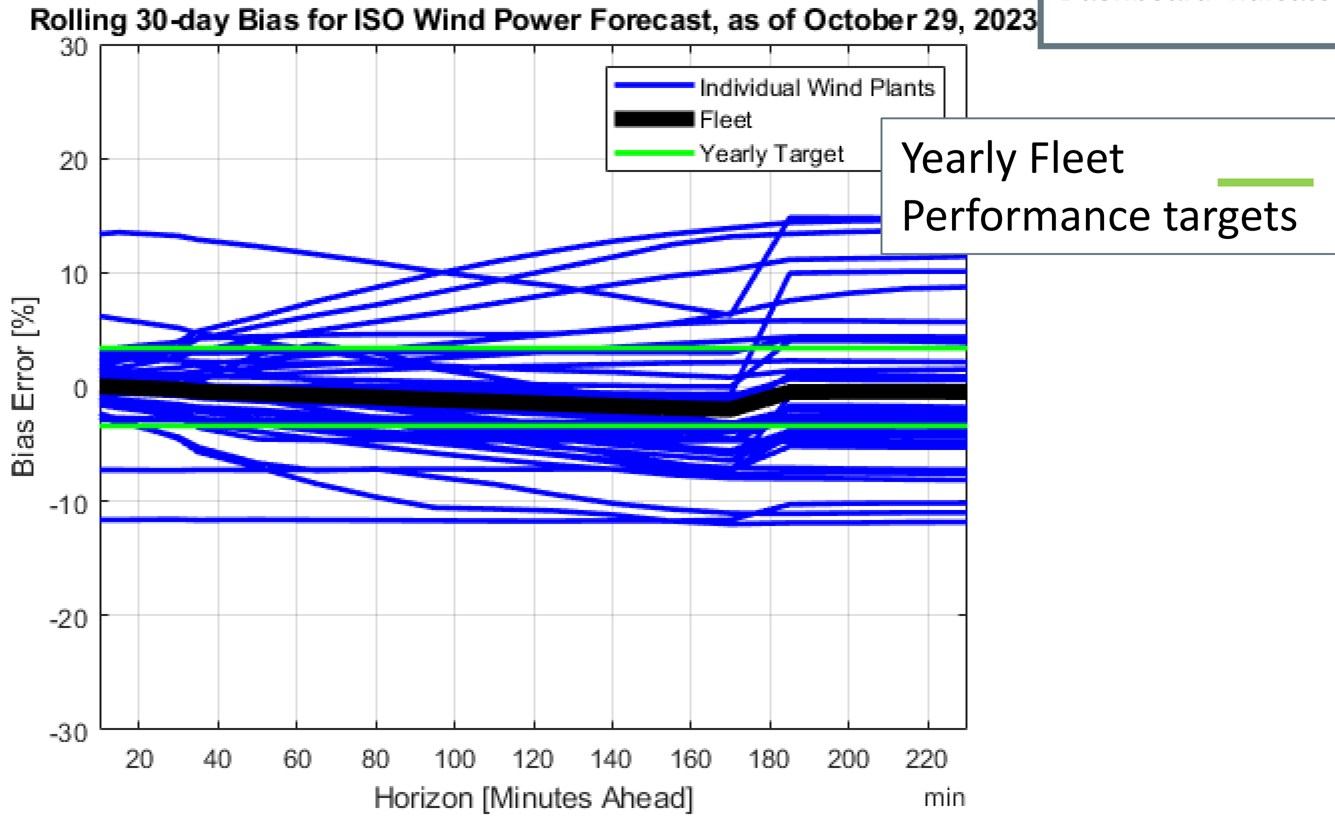
Dashboard Indicator



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 forecast compares well with industry standards, and monthly MAE is within yearly performance targets out to 180 minutes look-ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

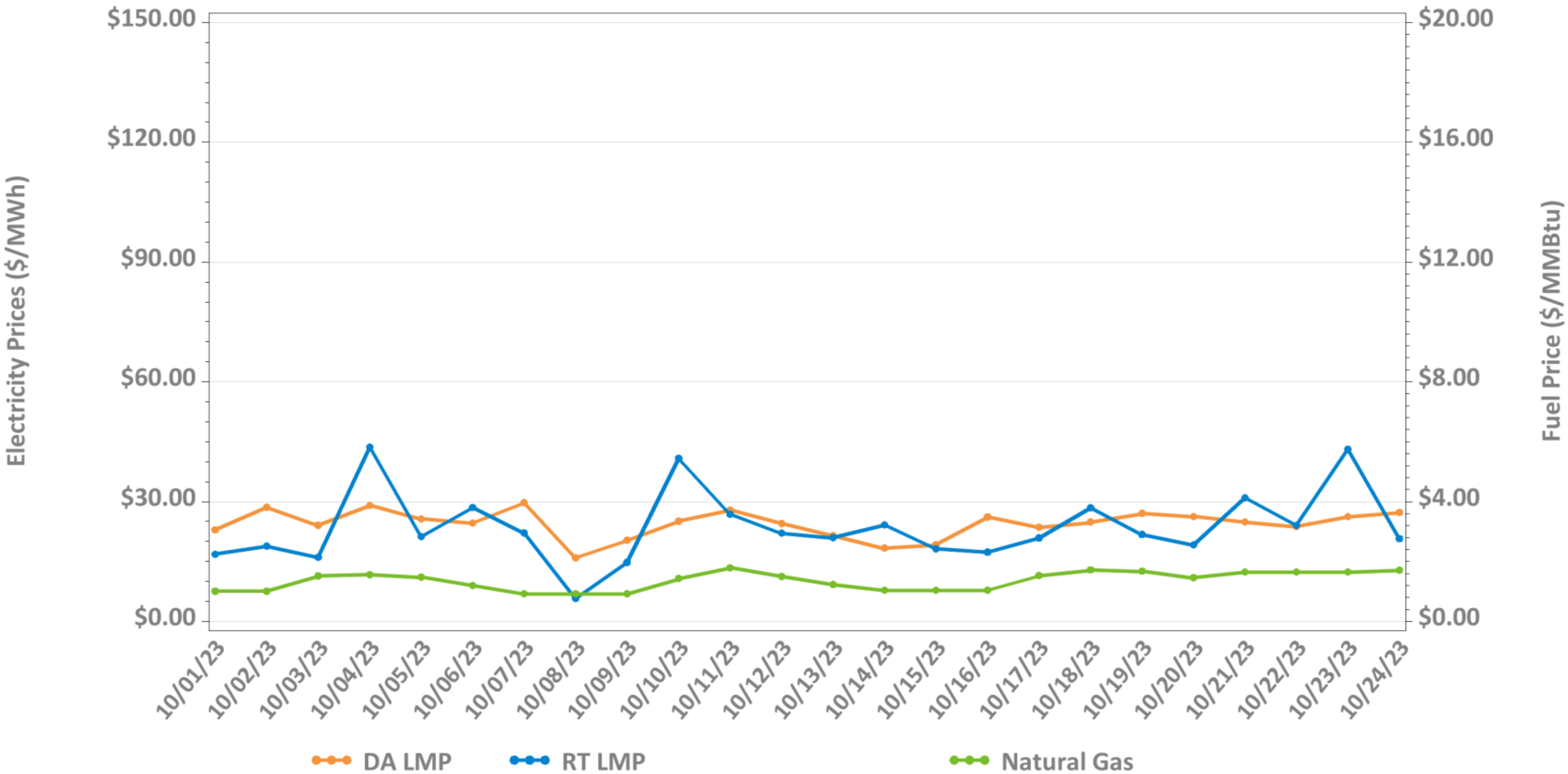
Dashboard Indicator



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.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: October 1-24, 2023



Underlying natural gas data furnished by:

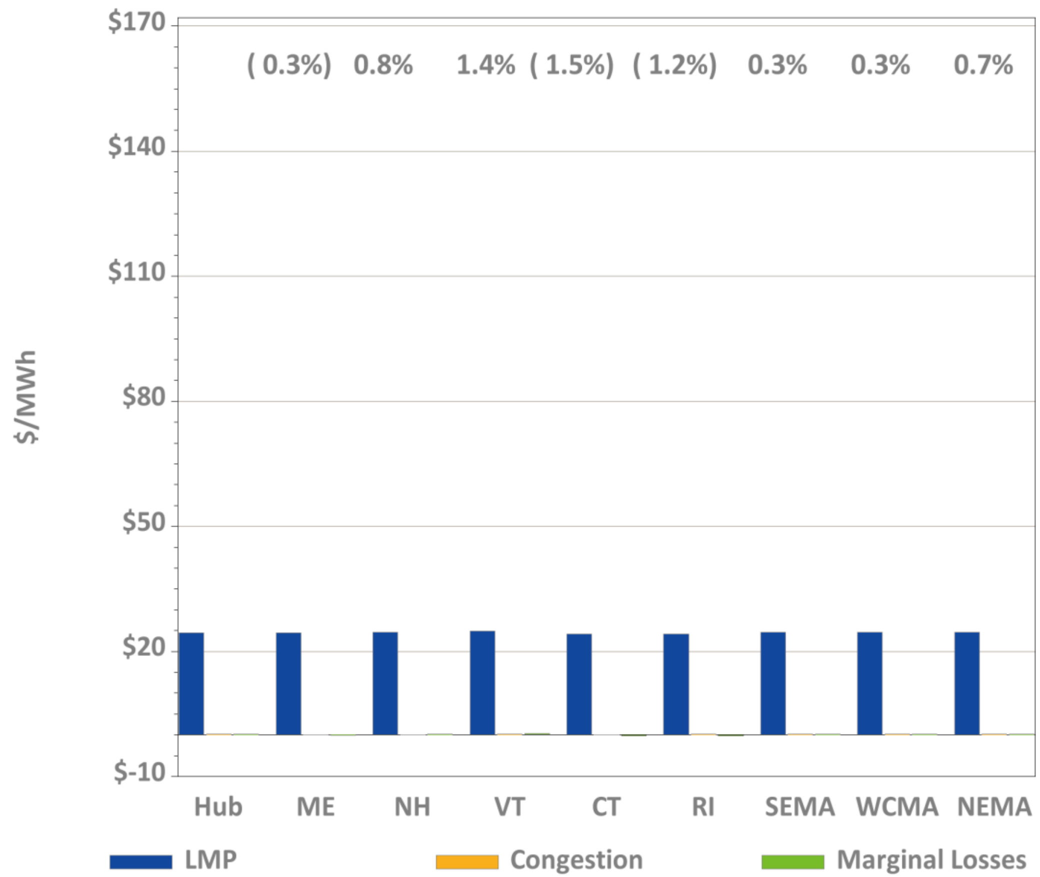
ICE Global markets in clear view

***Revenue quality metered values**

Average price difference over this period (DA-RT): $0.84
Average price difference over this period ABS(DA-RT): $6.41
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 27%
Gas price is average of Massachusetts delivery points

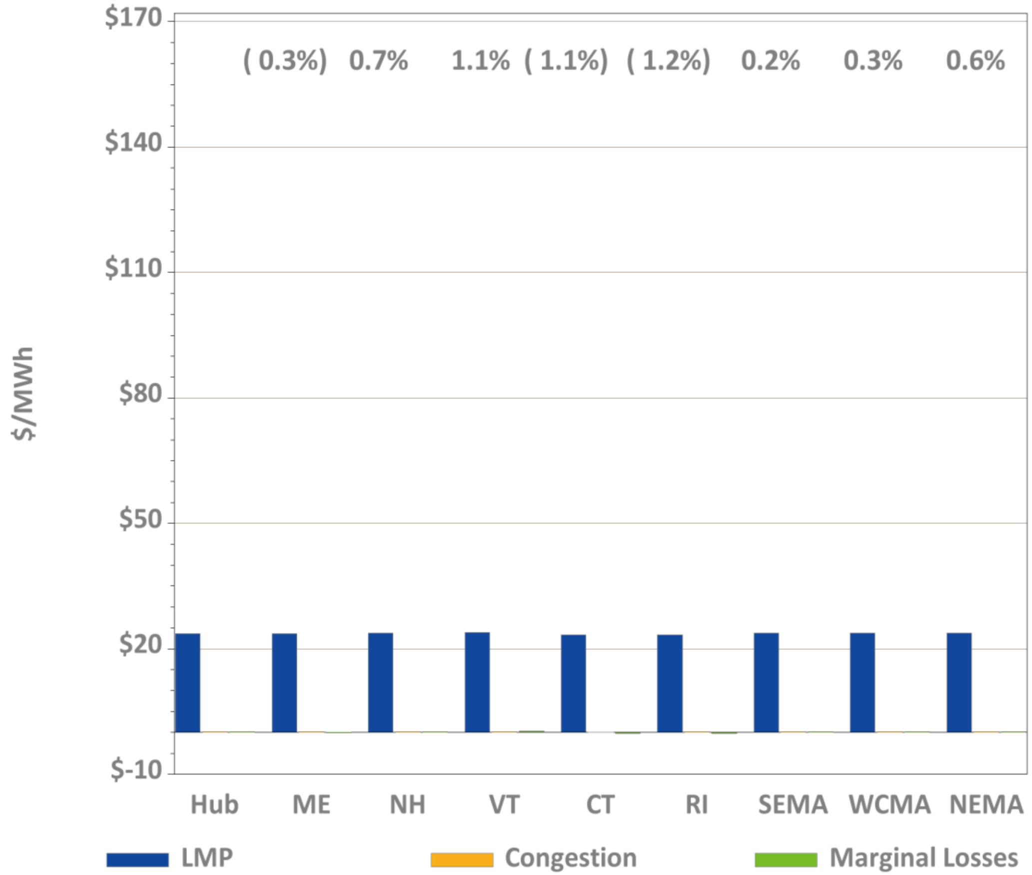
ISO-NE PUBLIC

DA LMPs Average by Zone & Hub, October 2023



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

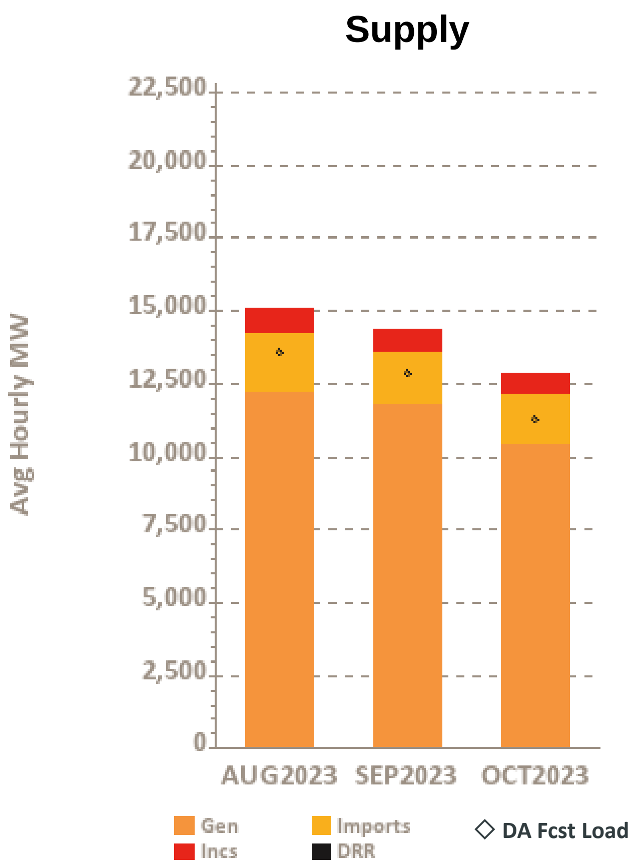
RT LMPs Average by Zone & Hub, October 2023

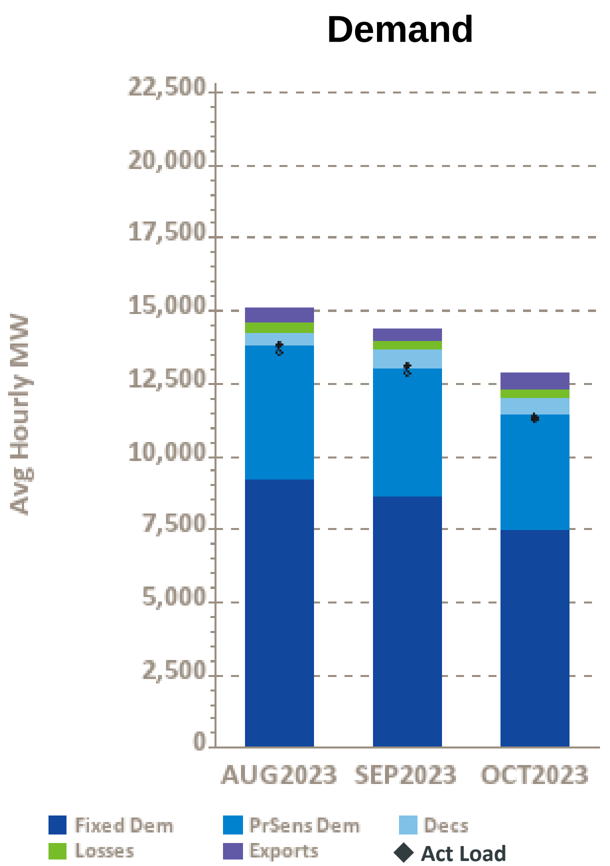


Definitions

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

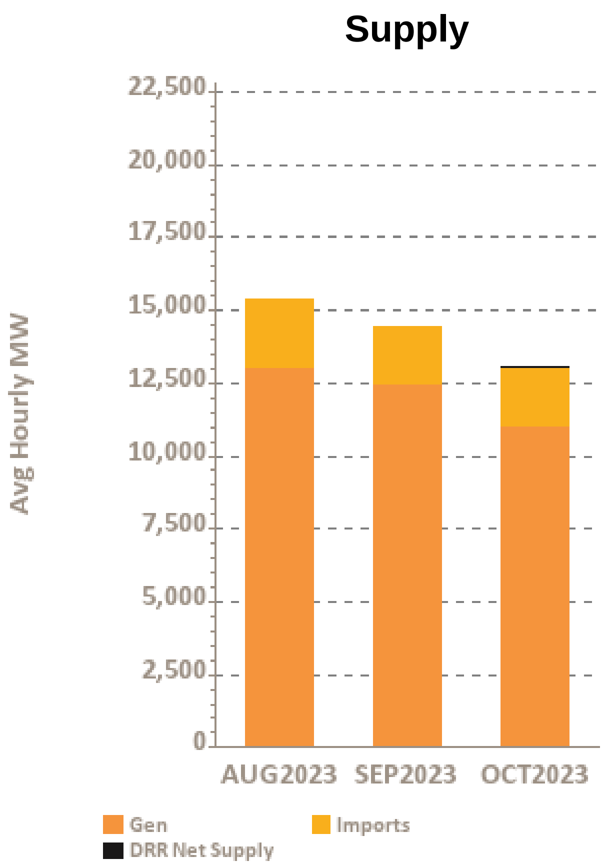


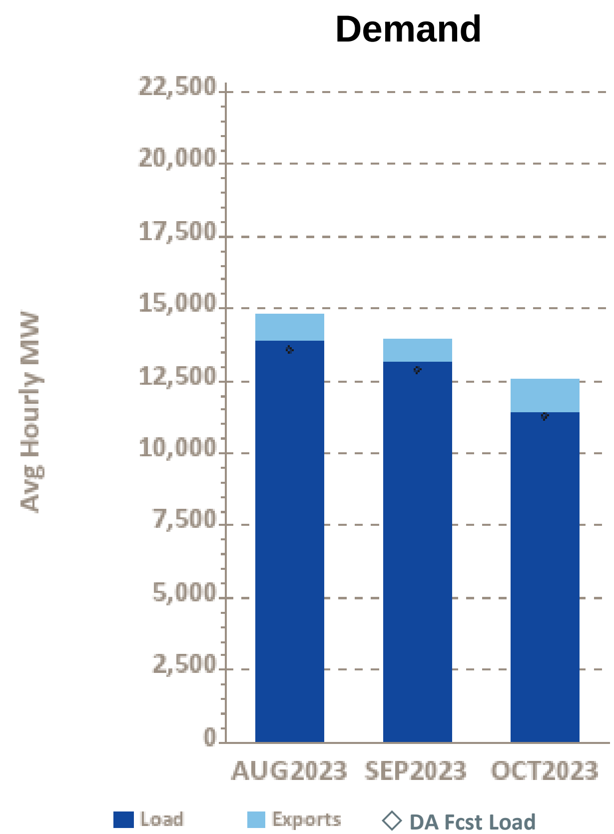


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

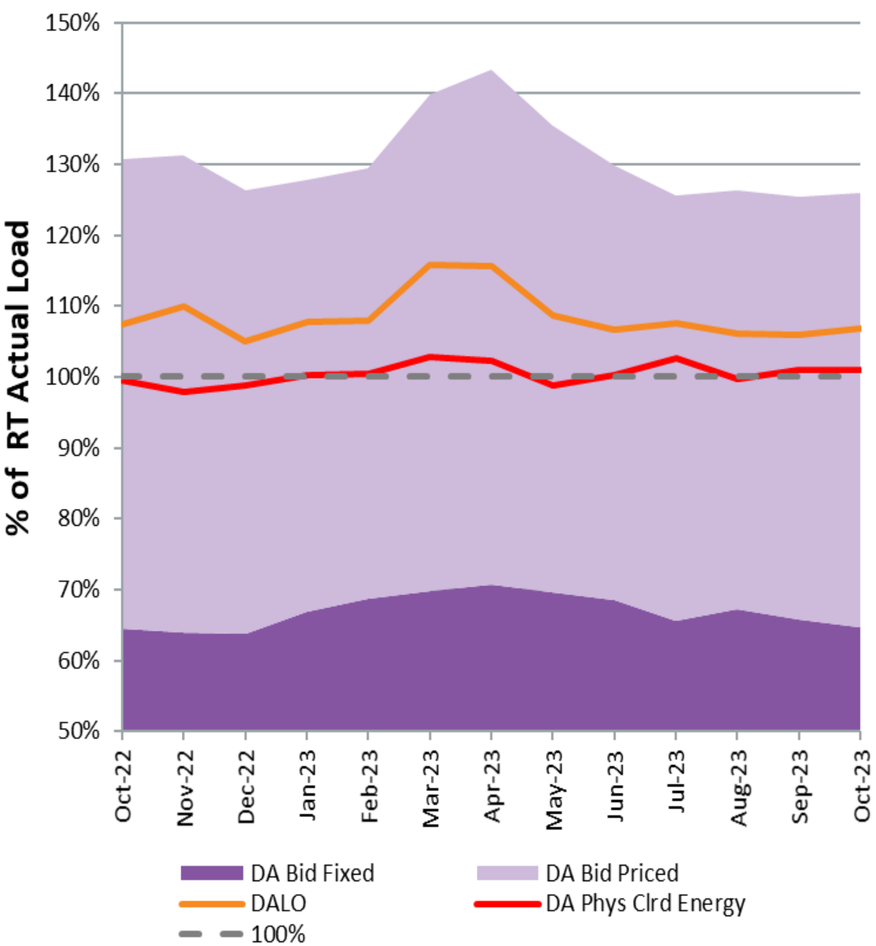
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

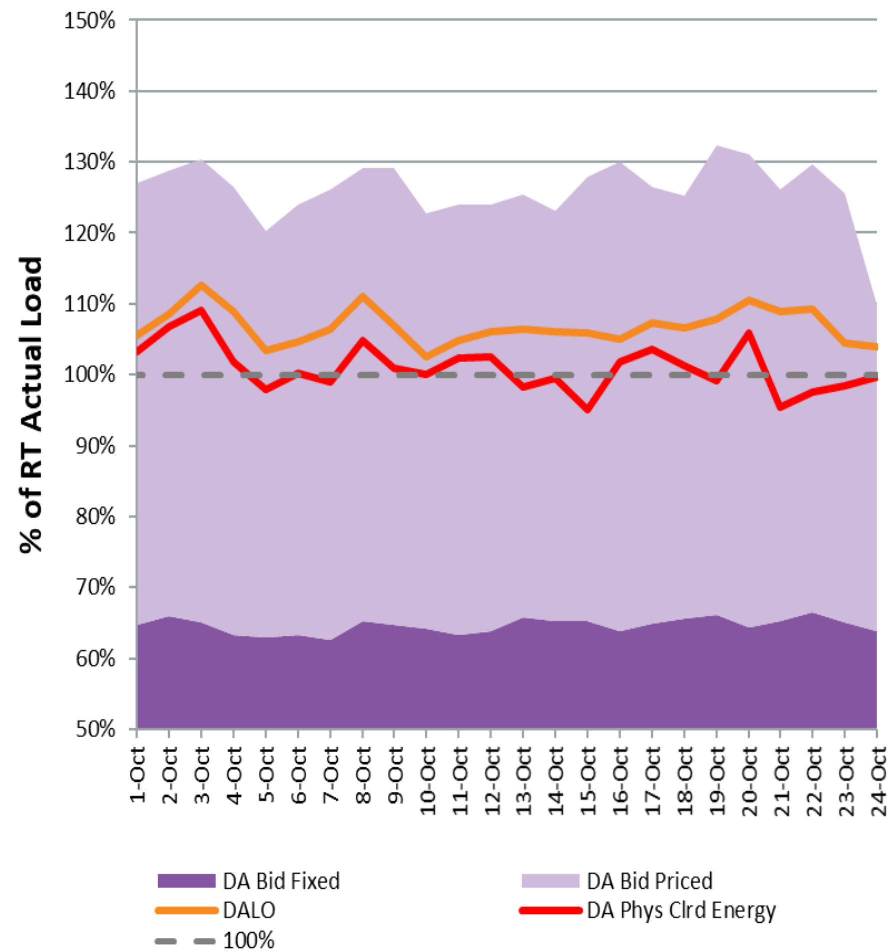
Components of RT Supply and Demand – Last Three Months





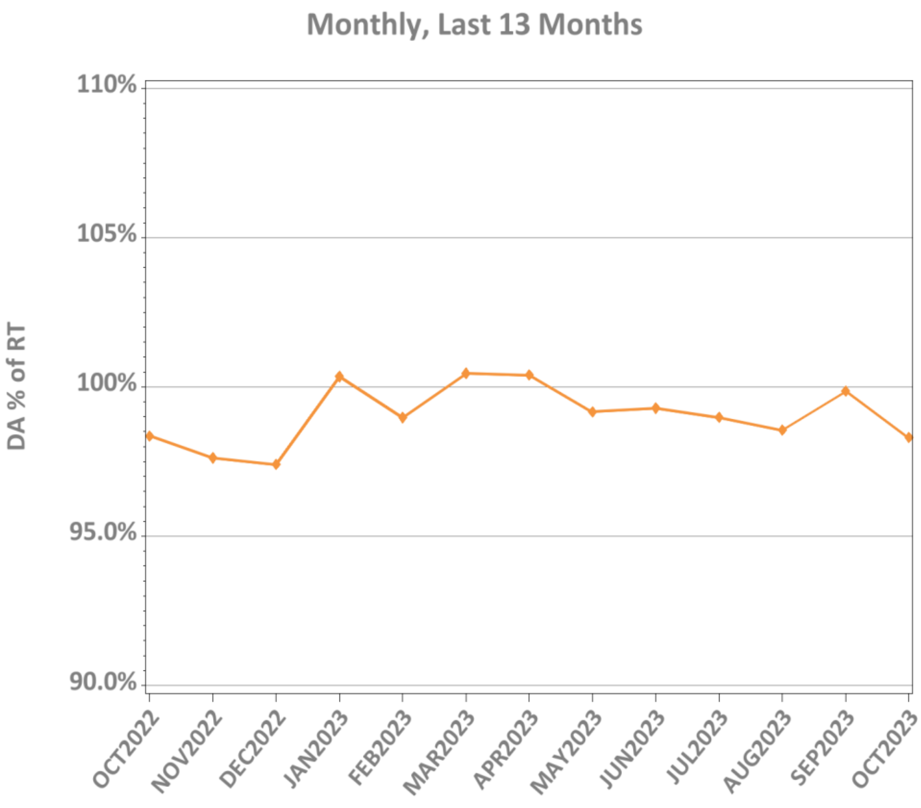
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

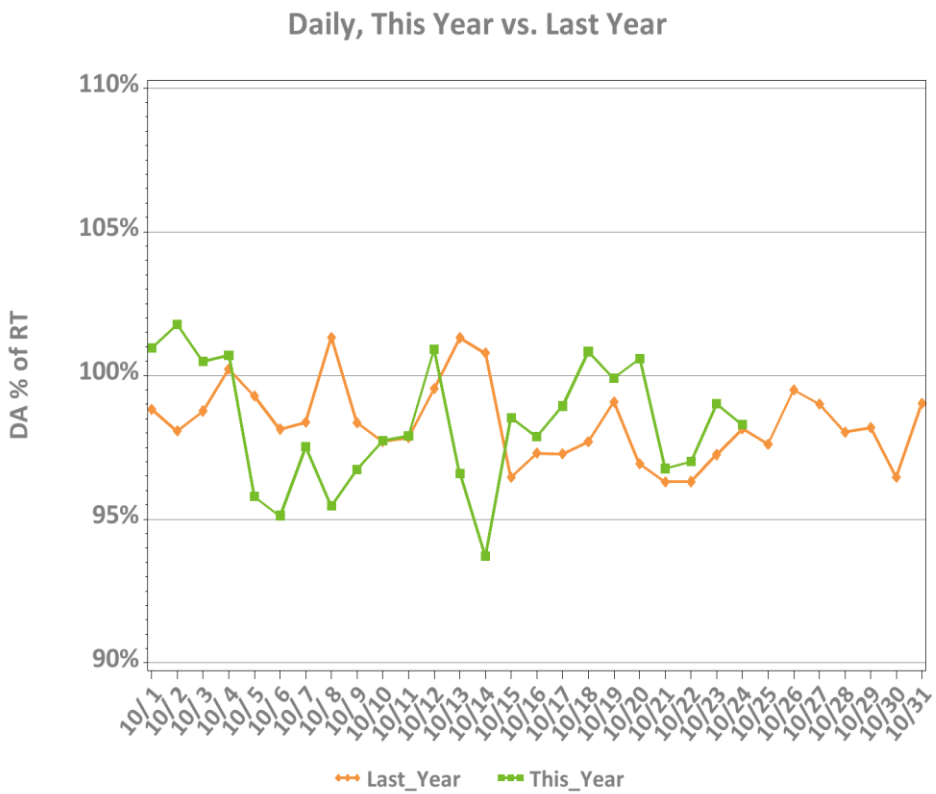




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

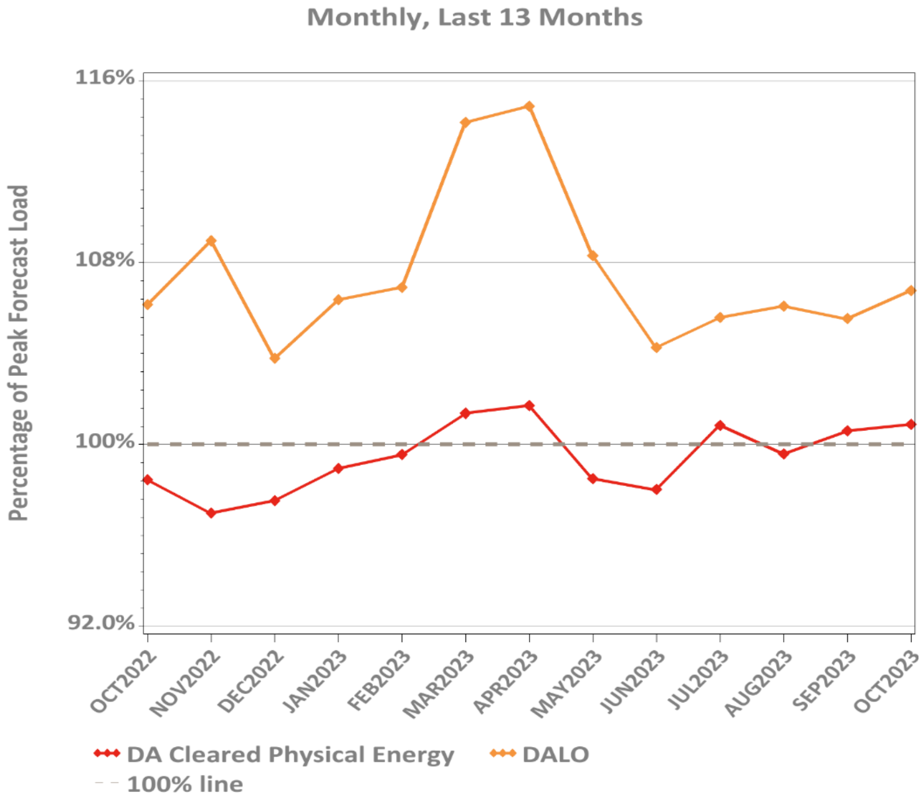
DA vs. RT Load Obligation: October, This Year vs. Last Year

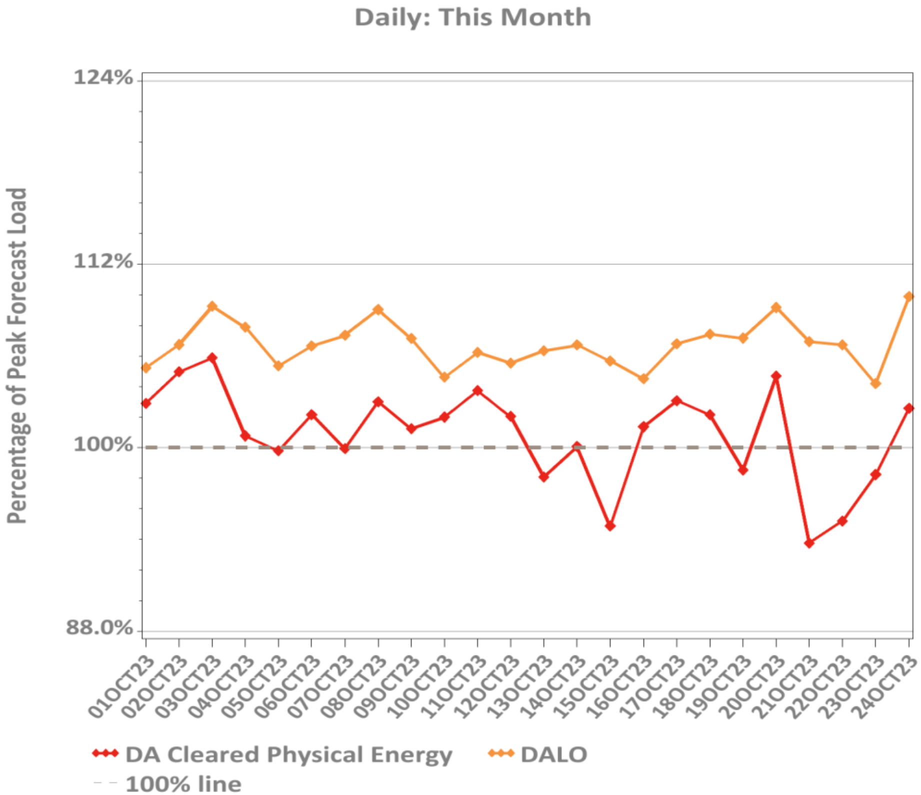




*Hourly average values

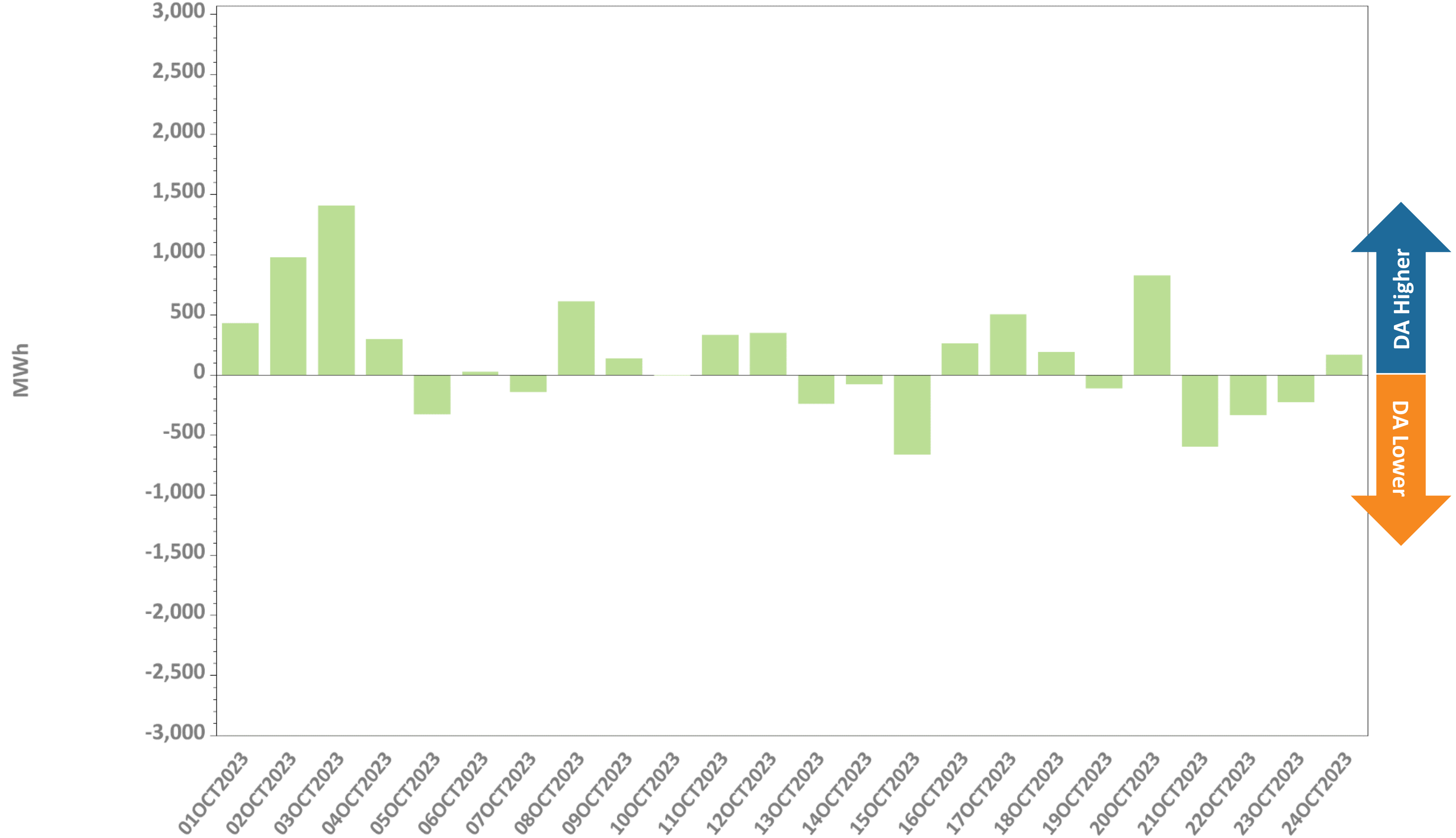
DA Volumes as % of Forecast in Peak Hour





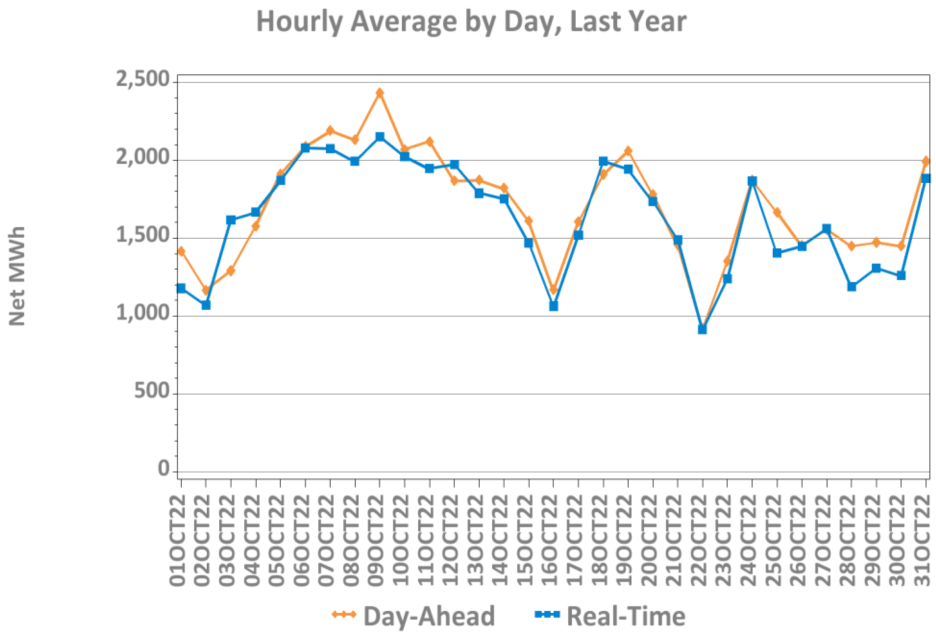
Note: The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: one (on October 21st)

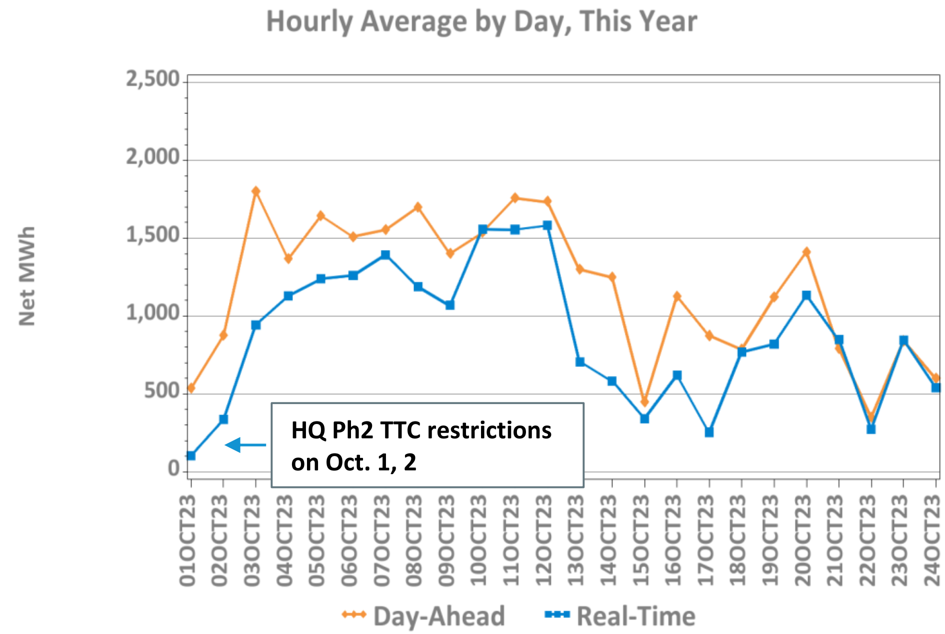
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

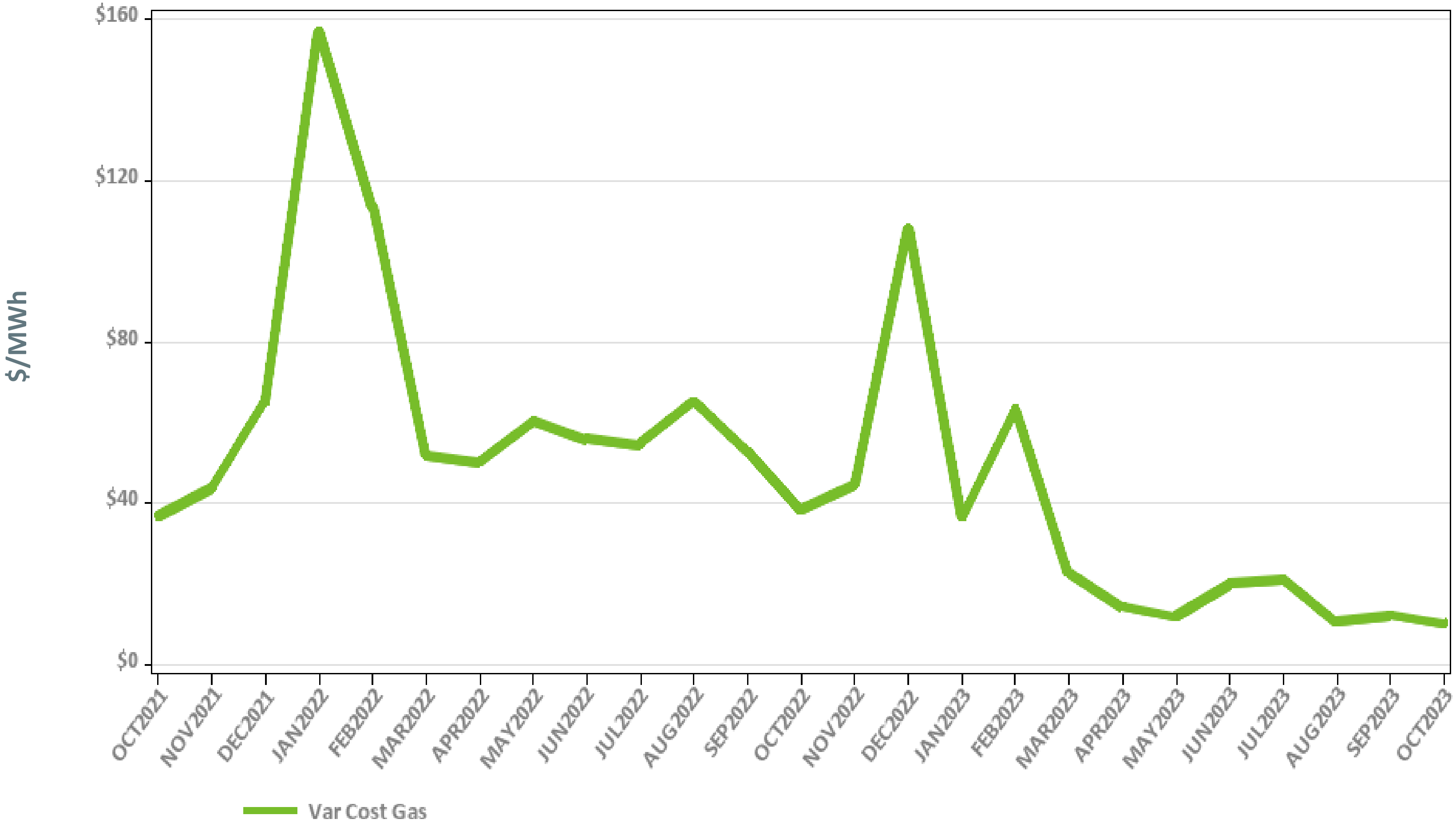
DA vs. RT Net Interchange October 2023 vs. October 2022





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

Variable Production Cost of Natural Gas: Monthly

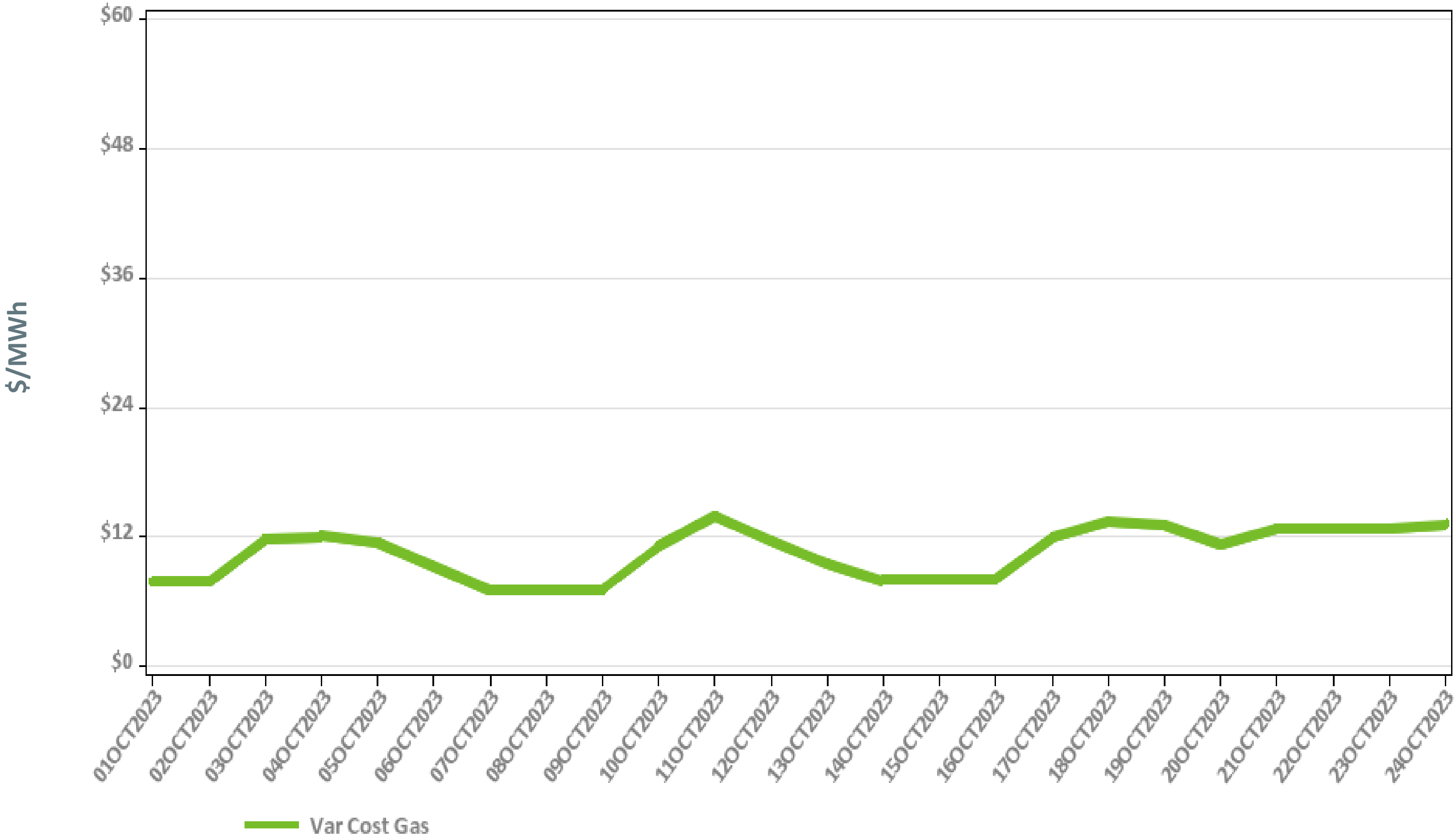


Underlying natural gas data furnished by:

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

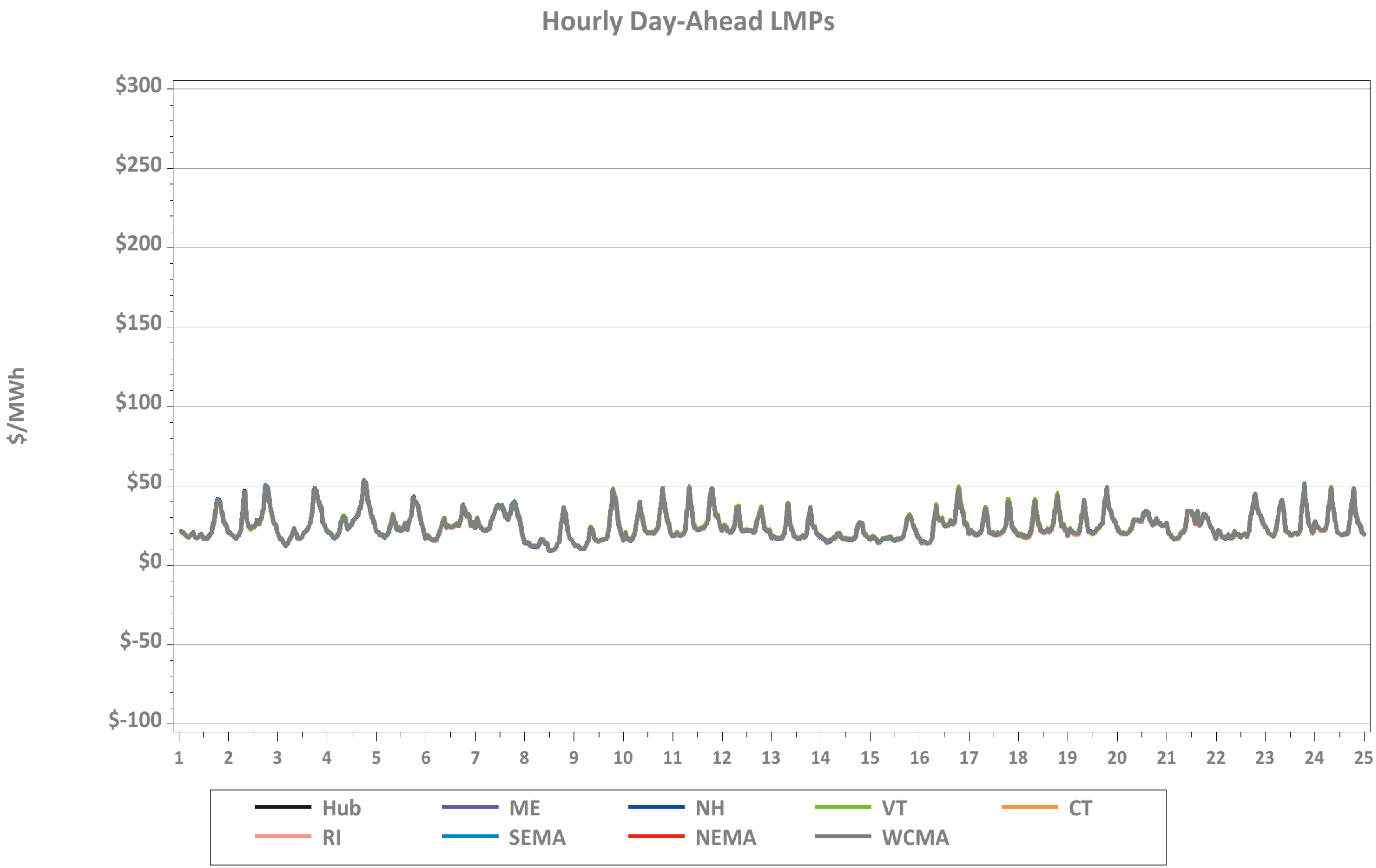


Underlying natural gas data furnished by:

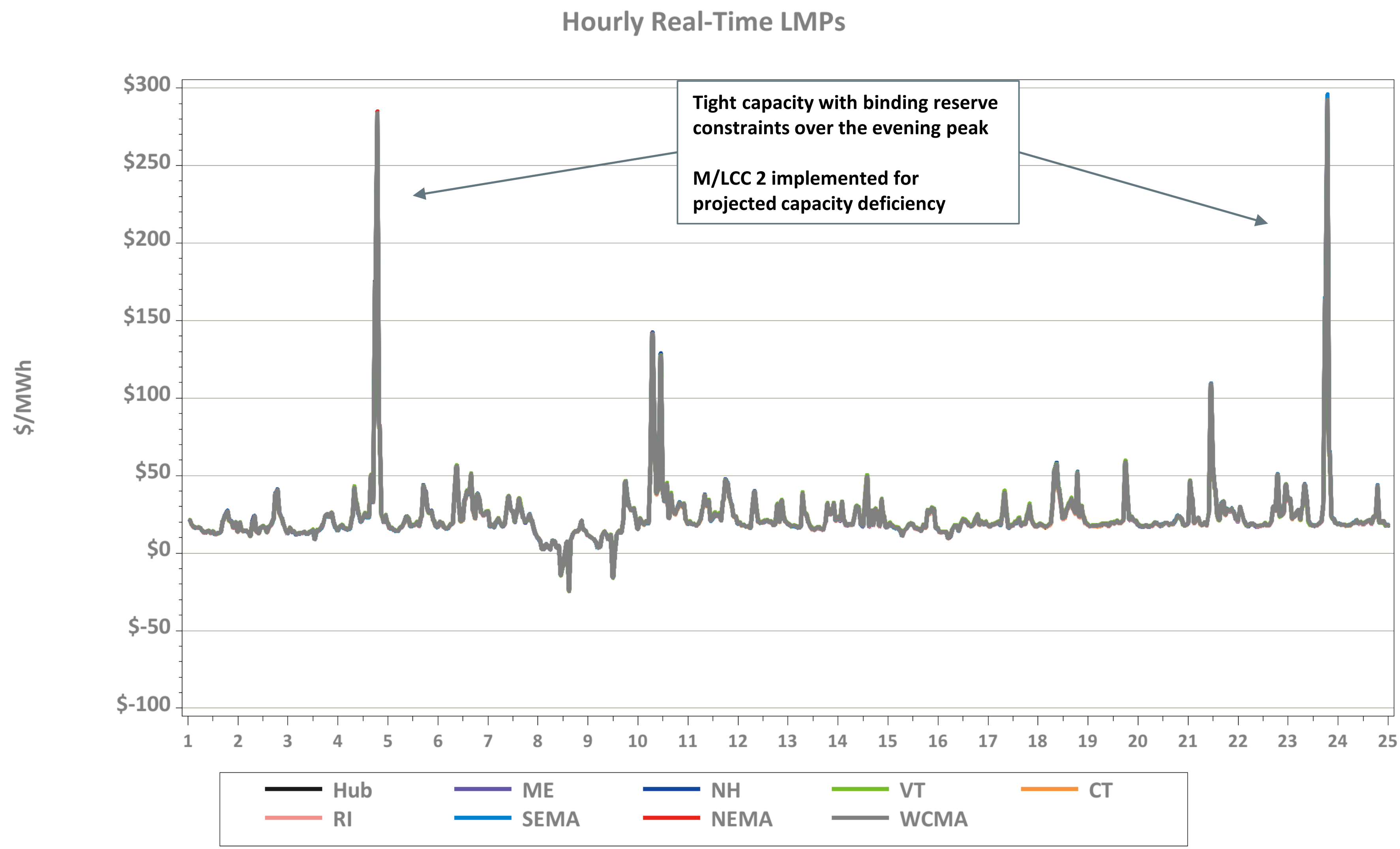
ICE Global markets in clear view

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

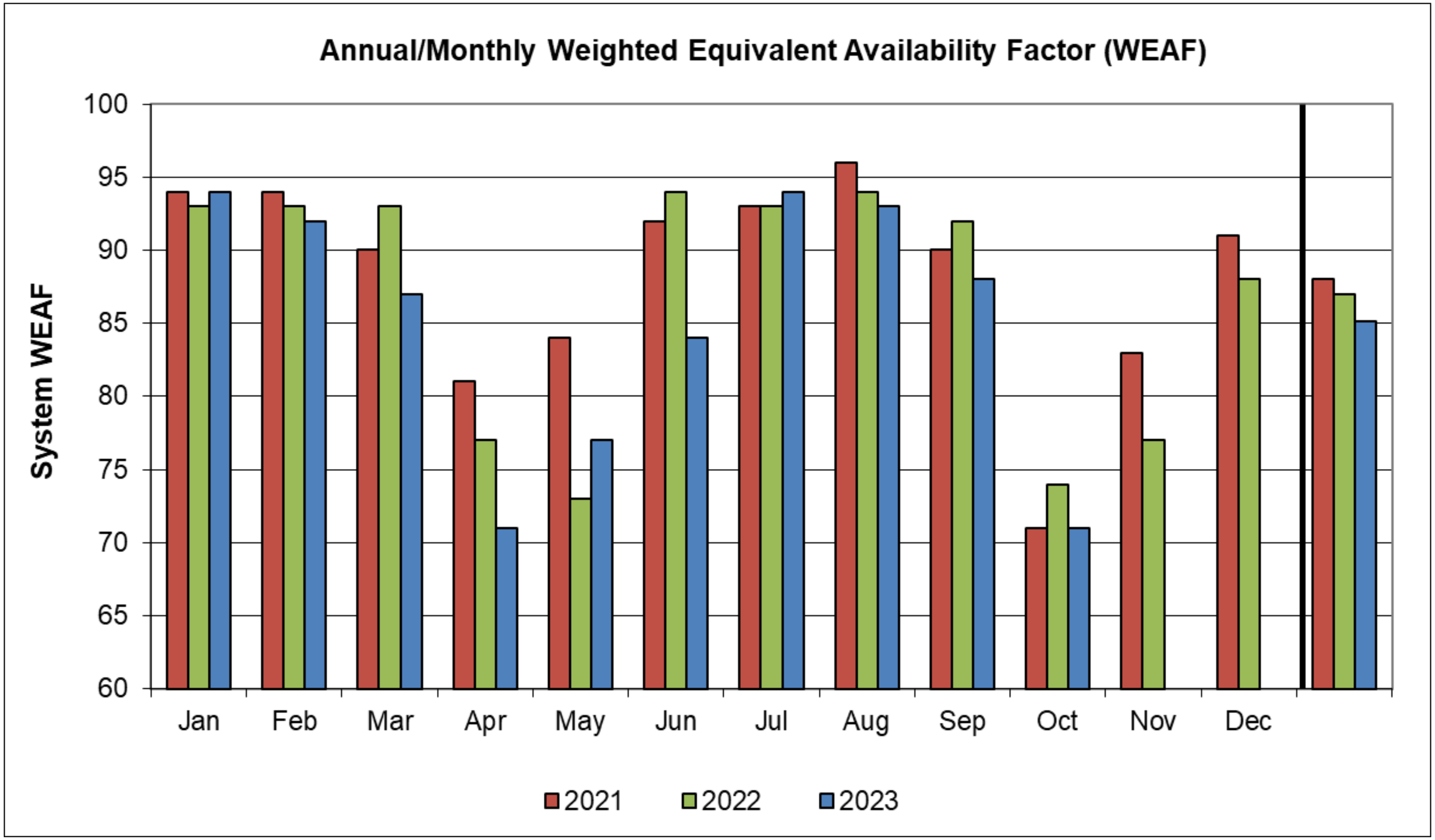
Hourly DA LMPs, October 1-24, 2023



Hourly RT LMPs, October 1-24, 2023



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92	87	71	77	84	94	93	88	71			85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87
2021	94	94	90	81	84	92	93	96	90	71	83	91	88

Data as of 10/24/2023

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for November 2023

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	48.7	201.7	0.0	250.4
NH	38.1	149.9	0.0	188.0
VT	39.9	135.6	0.0	175.6
CT	115.1	171.0	598.6	884.8
RI	22.8	322.0	0.0	344.8
SEMA	37.0	473.0	0.0	510.0
WCMA	79.2	527.0	26.6	632.8
NEMA	70.6	770.4	0.0	841.0
Total	**451.5**	**2,750.7**	**625.3**	**3,827.5**

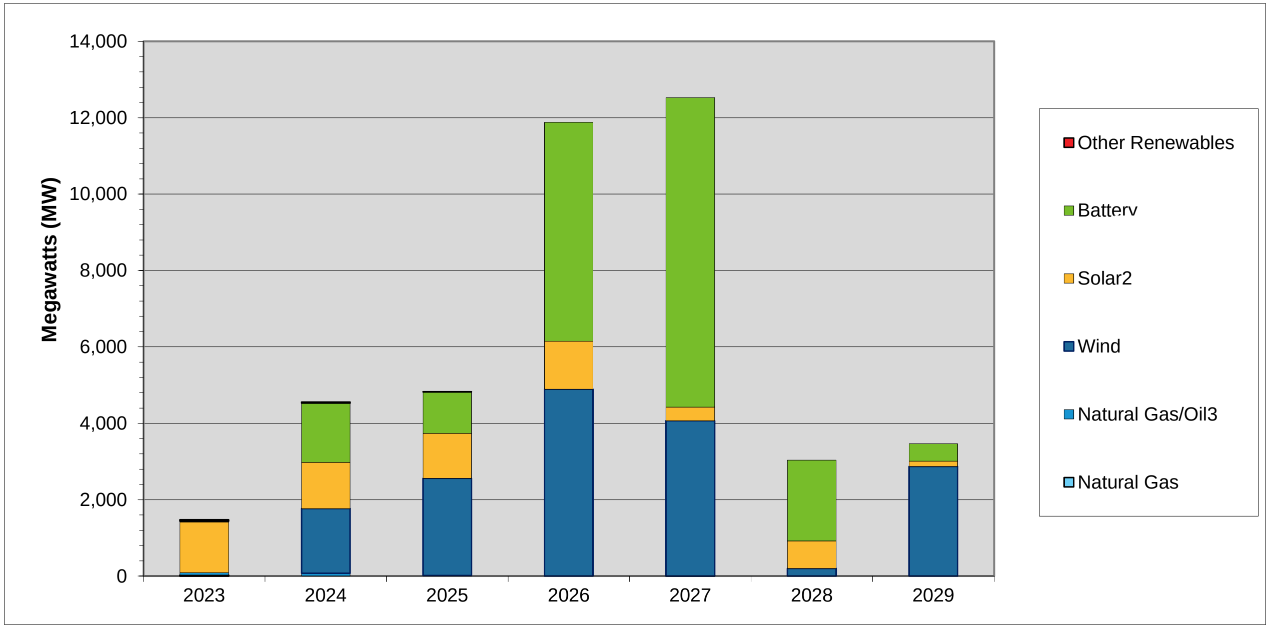
*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

New Generation Update
Based on Queue as of 10/30/23

- Eleven projects totaling 2,217 MW were added to the interconnection queue since the last update
  – Seven solar projects, three battery storage projects on offshore wind project with in-service dates of 2025 to 2030
- In total, 398 generation projects are currently being tracked by the ISO, totaling approximately 43,072 MW

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



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Other Renewables	42	30	2	0	0	0	0	74	0.2
Battery	20	1,555	1,084	5,734	8,103	2,110	454	19,060	45.6
Solar[2]	1,324	1,207	1,178	1,255	358	725	139	6,186	14.8
Wind	0	1,693	2,545	4,893	4,064	197	2,870	16,262	38.9
Natural Gas/Oil[3]	62	73	16	0	0	0	0	151	0.4
Natural Gas	26	0	0	0	4	0	0	30	0.1
Totals	**1,474**	**4,558**	**4,825**	**11,882**	**12,529**	**3,032**	**3,463**	**41,763**	**100.0**

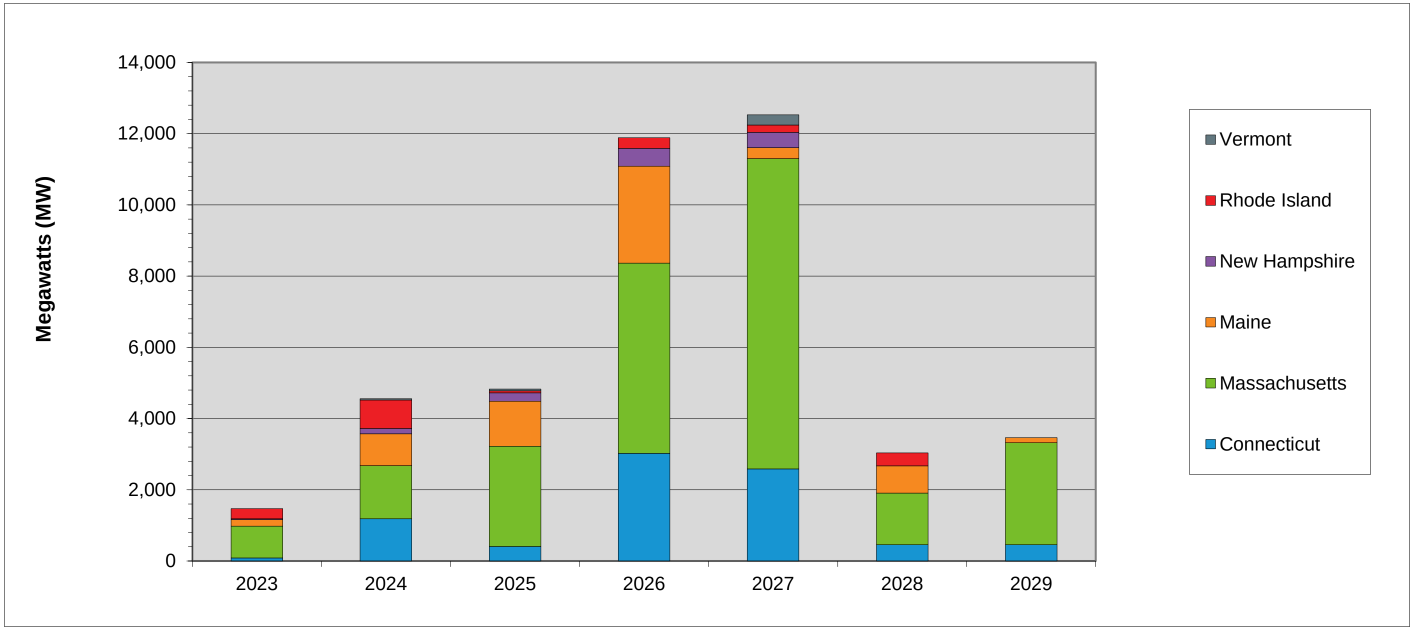
[1] Sum may not equal 100% due to rounding

[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

Actual and Projected Annual Generator Capacity Additions

By State



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Vermont	0	40	50	0	285	0	0	375	0.9
Rhode Island	291	794	54	295	211	360	0	2,005	4.8
New Hampshire	20	154	239	504	426	0	0	1,343	3.2
Maine	185	894	1,259	2,723	306	764	139	6,270	15.0
Massachusetts	896	1,488	2,815	5,336	8,713	1,453	2,870	23,571	56.4
Connecticut	82	1,188	408	3,024	2,588	455	454	8,199	19.6
Totals	**1,474**	**4,558**	**4,825**	**11,882**	**12,529**	**3,032**	**3,463**	**41,763**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	**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	119	19,060	1	15	118	19,045
Fuel Cell	4	46	0	0	4	46
Hydro	1	28	0	0	1	28
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	3	151	1	62	2	89
Nuclear	0	0	0	0	0	0
Solar	239	6,186	15	343	224	5,843
Wind	28	17,571	1	800	27	16,771
Total	398	43,072	18	1,220	380	41,852

- 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 within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	7	87	0	0	7	87
Intermediate	2	89	0	0	2	89
Peaker	361	25,325	17	420	344	24,905
Wind Turbine	28	17,571	1	800	27	16,771
Total	398	43,072	18	1,220	380	41,852

- Green denotes projects with a high probability of going into service within the next 12 months
- 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	119	19,060	0	0	0	0	119	19,060	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	3	151	0	0	2	89	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	239	6,186	0	0	0	0	239	6,186	0	0
Wind	28	17,571	0	0	0	0	0	0	28	17,571
Total	398	43,072	7	87	2	89	361	25,325	28	17,571

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

FORWARD CAPACITY MARKET

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	564.371	-95.3
	Passive Demand	3,327.071	3,327.932	0.861	3,315.207	-12.725	3,253.179	-62.028
Demand Total		**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**	**3,817.550**	**-157.328**
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429	27,684.252	-13.462
	Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504	893.444	-32.498
Generator Total		**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**	**28,577.696**	**-45.96**
Import Total		**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**	**958.380**	**-71.42**
Grand Total*		**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**	**33,353.626**	**-274.708**
Net ICR (NICR)		**32,490**	**32,980**	**490**	**31,480**	**-1,500**	**31,690**	**210**

* 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 reconfiguration auctions 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 2015-2023 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	579.692	-93.709		
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751		
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**		
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125		
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193		
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**		
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**		
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**		
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**		

* 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 and reconfiguration auctions 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 2015-2023 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	589.882	-175.468				
Demand	*Passive Demand*	2,557.256	2,579.120	21.864				
Demand Total		**3,322.606**	**3,169.002**	**-153.604**				
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624				
Generator	*Intermittent*	1,178.933	1,146.783	-32.15				
Generator Total		**27,983.936**	**27,790.162**	**-193.774**				
Import Total		**1,503.842**	**1,247.601**	**-256.241**				
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**				
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**				

* 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 reconfiguration auctions 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 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

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*	622.854						
	Passive Demand	2,316.815						
Demand Total		**2,939.669**						
Generator	*Non-Intermittent*	26,507.420						
	Intermittent	1,356.084						
Generator Total		**27,863.504**						
Import Total		**566.998**						
Grand Total*		**31,370.171**						
Net ICR (NICR)		**30,305**						

* 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 reconfiguration auctions 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 2015-2023 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

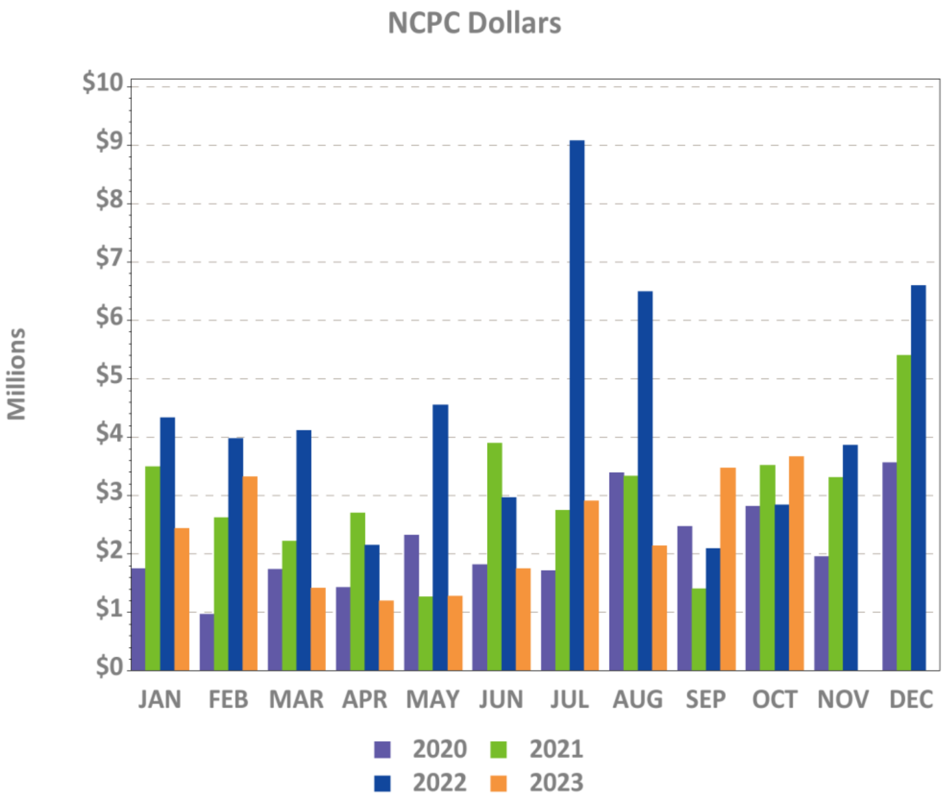
Definitions

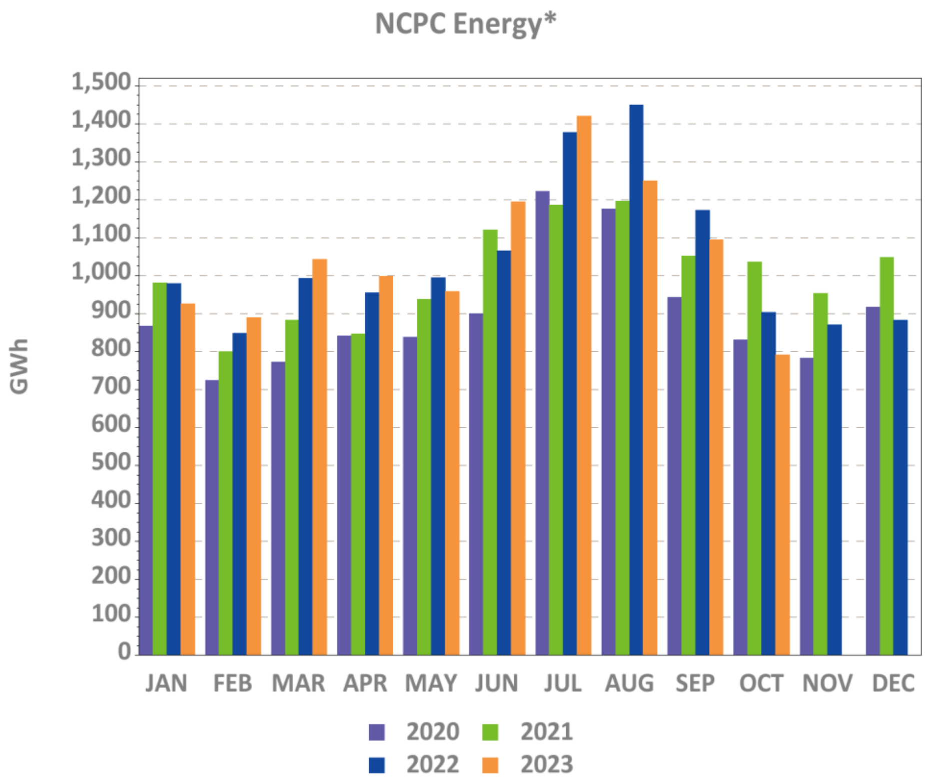
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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).

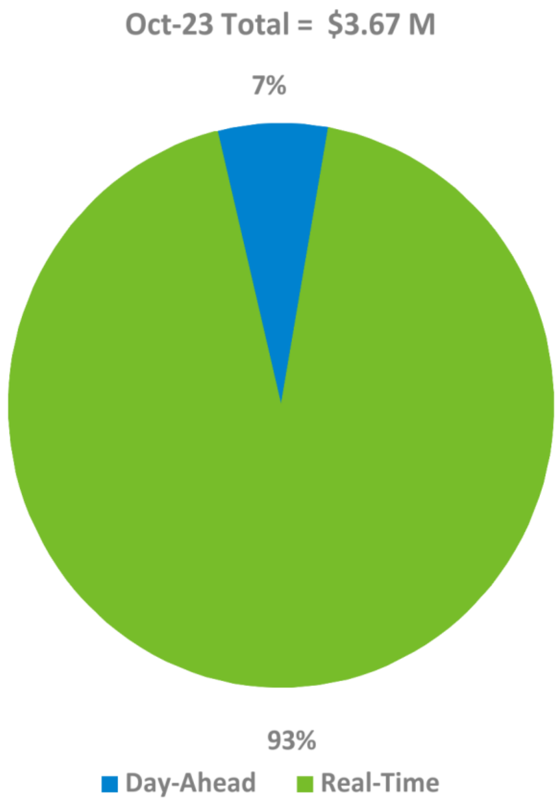
Year-Over-Year Total NCPC Dollars and Energy

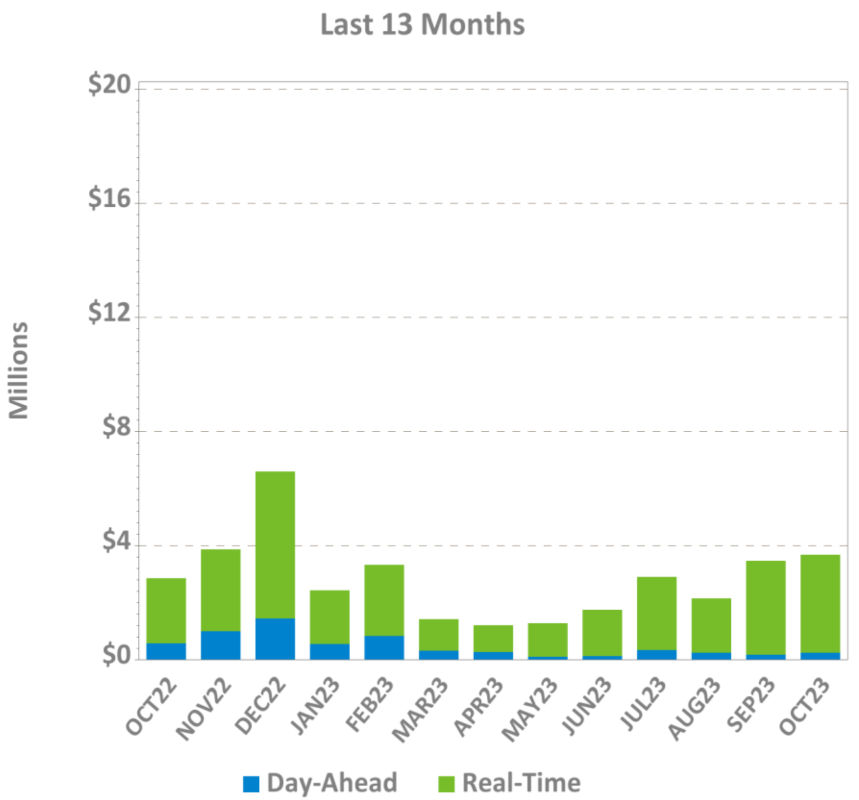




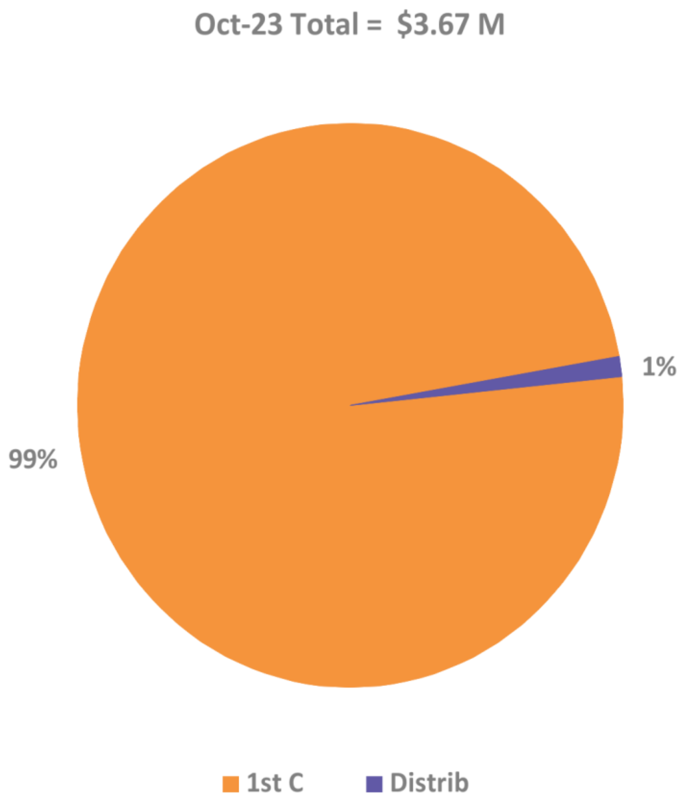
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

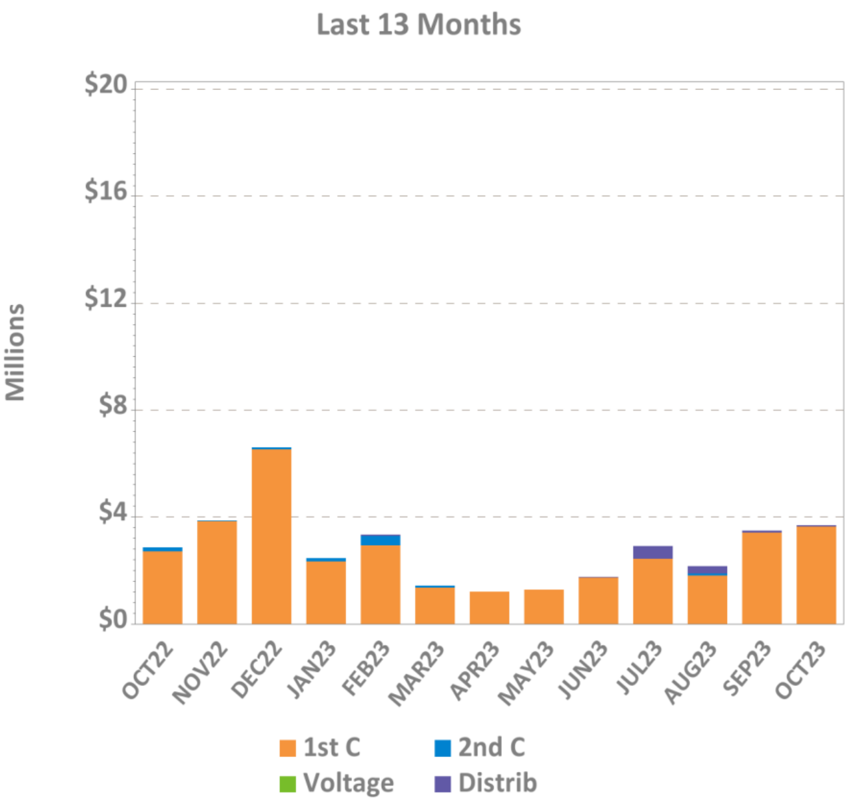
DA and RT NCPC Charges





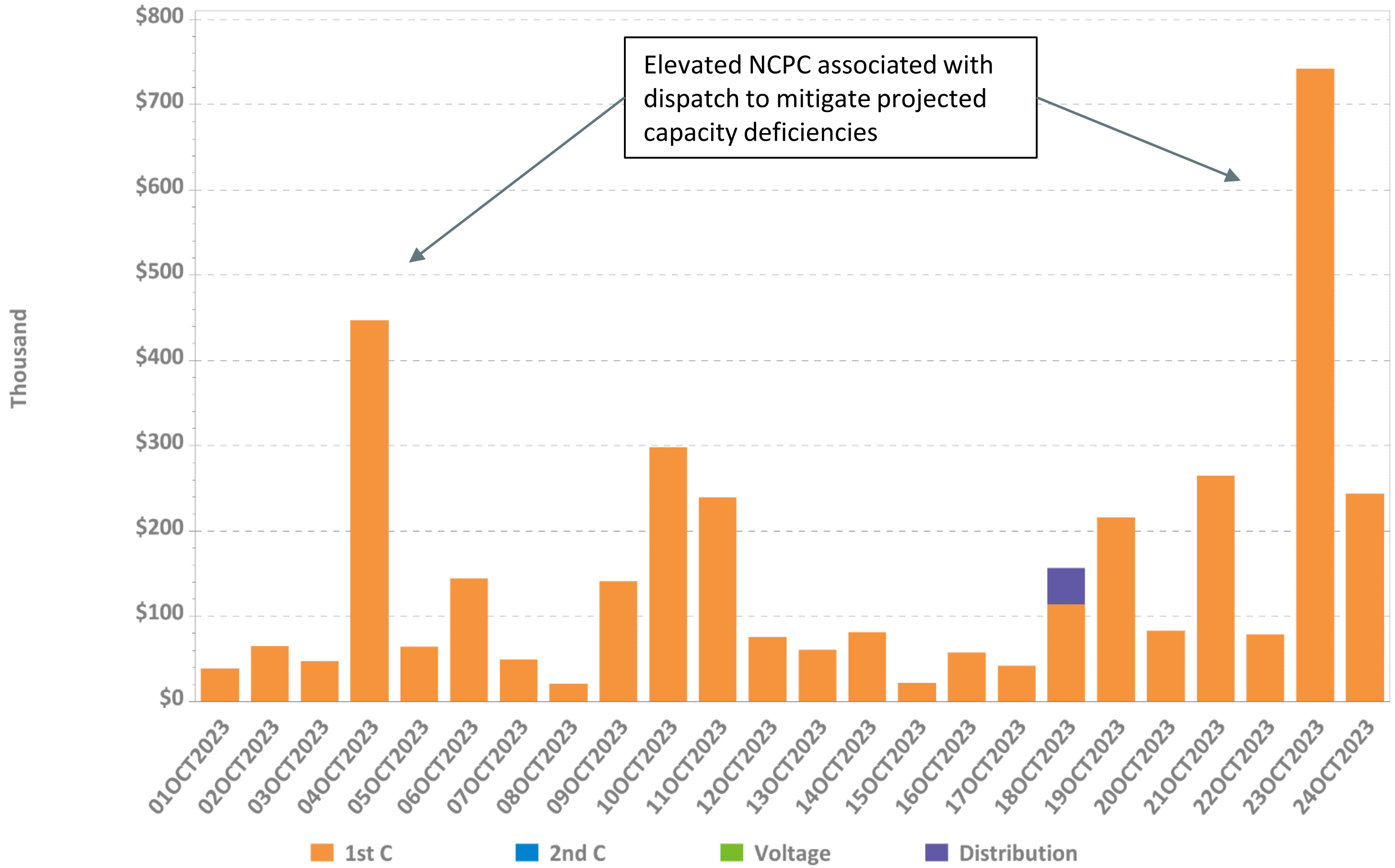
NCPC Charges by Type



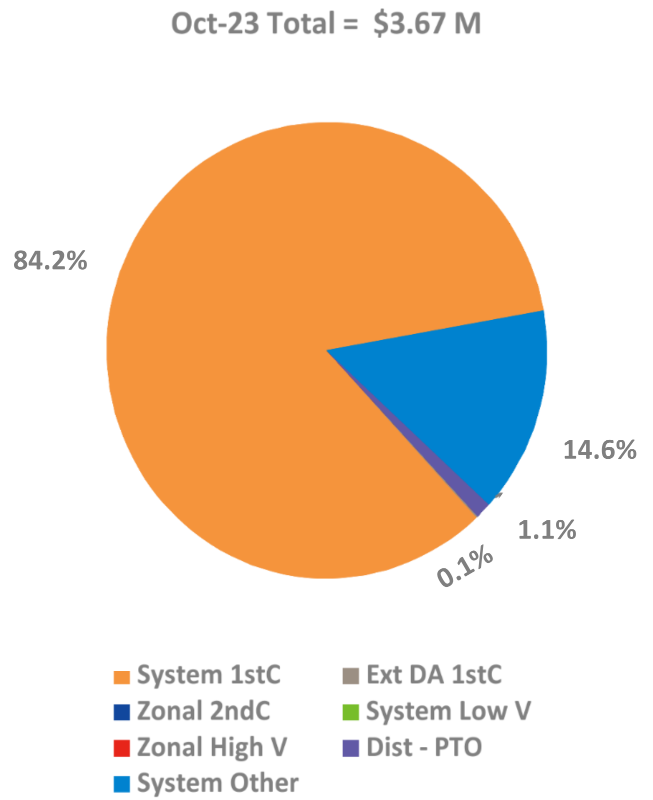


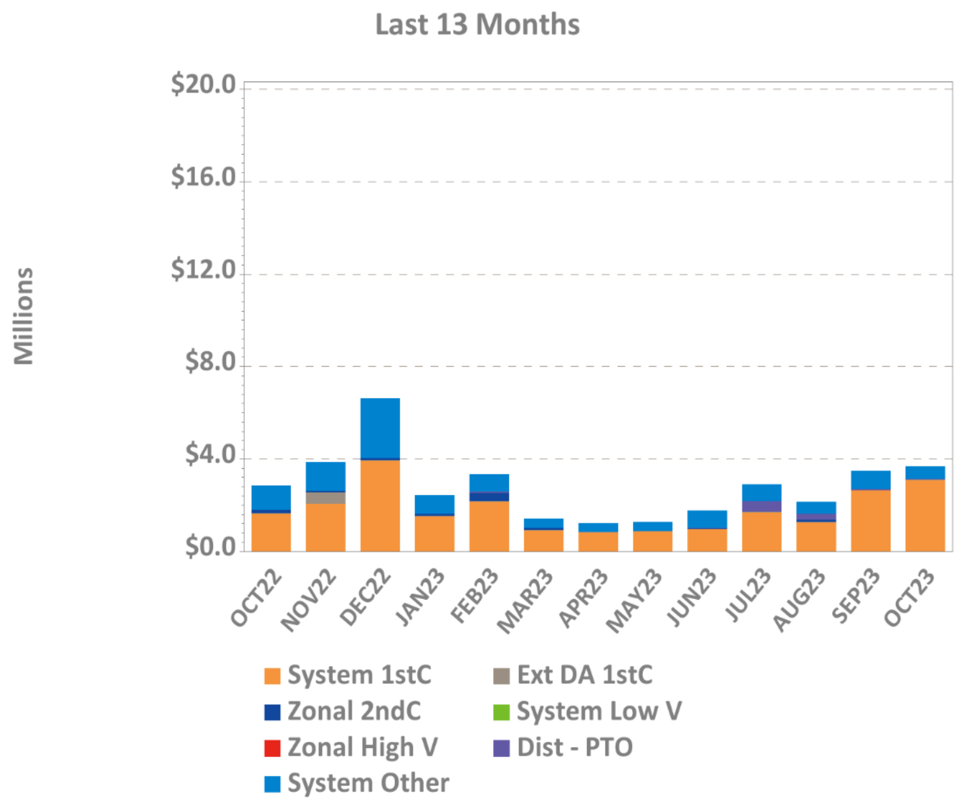
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



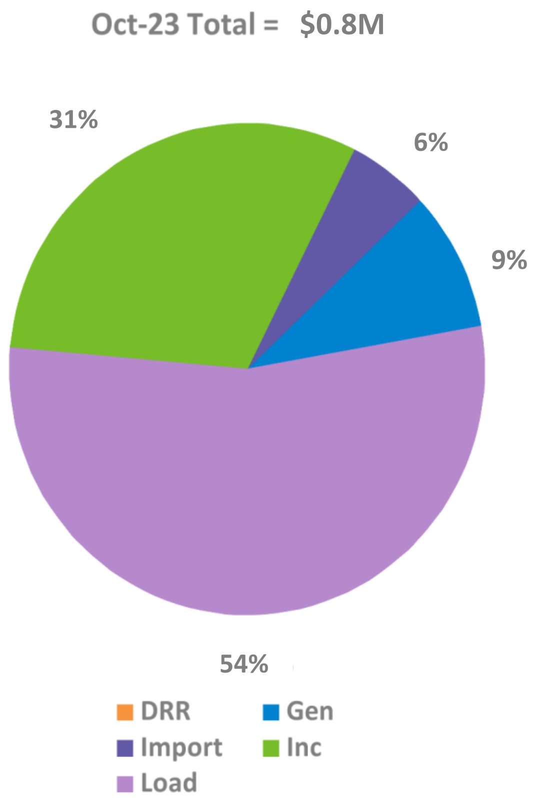
NCPC Charges by Allocation

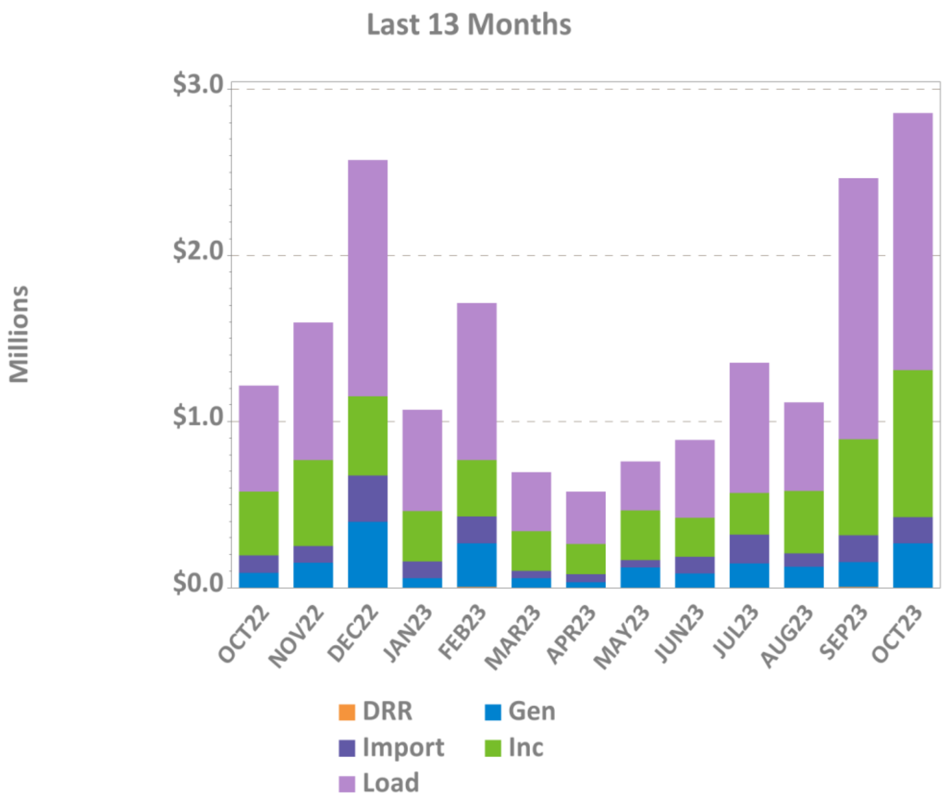




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

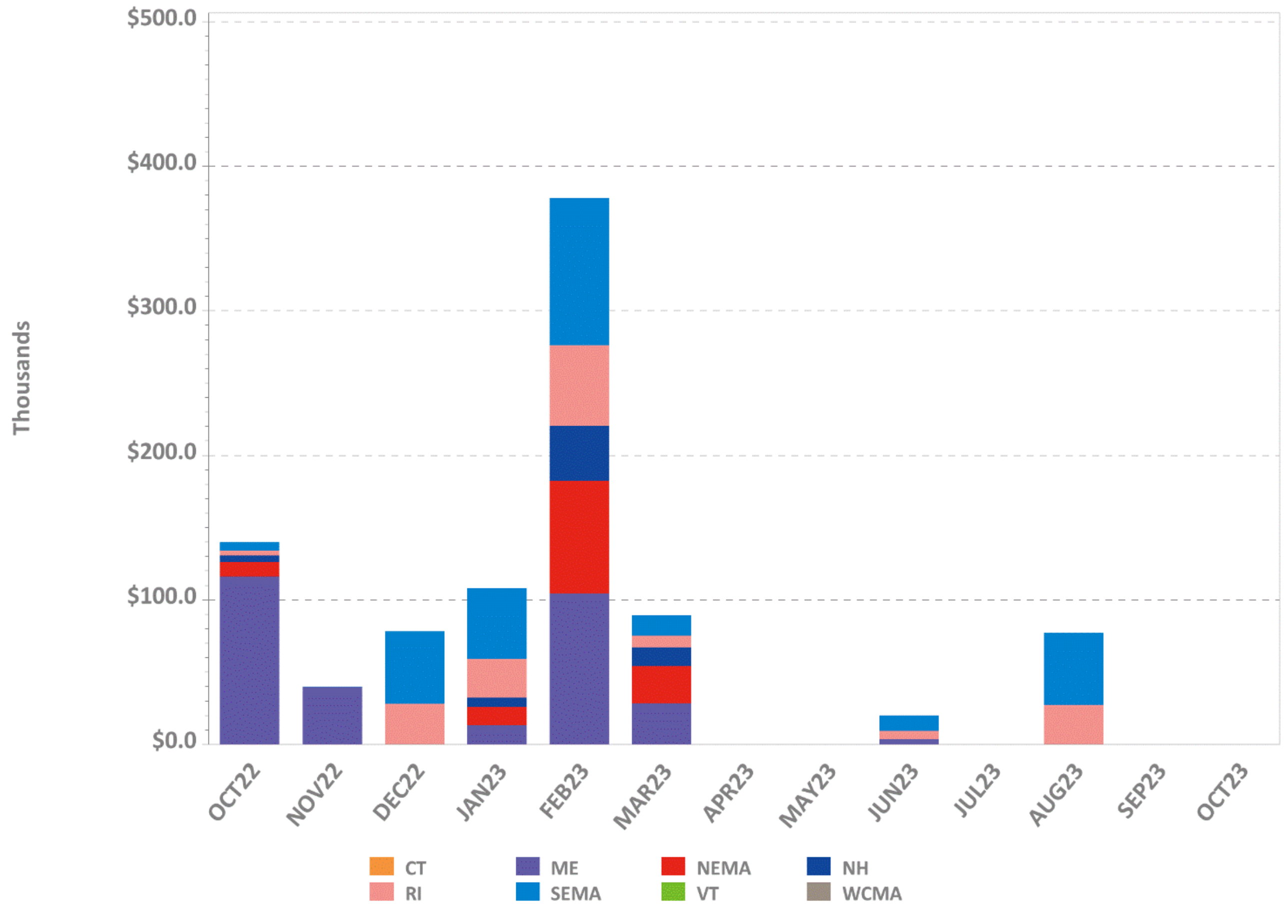
RT First Contingency Charges by Deviation Type





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

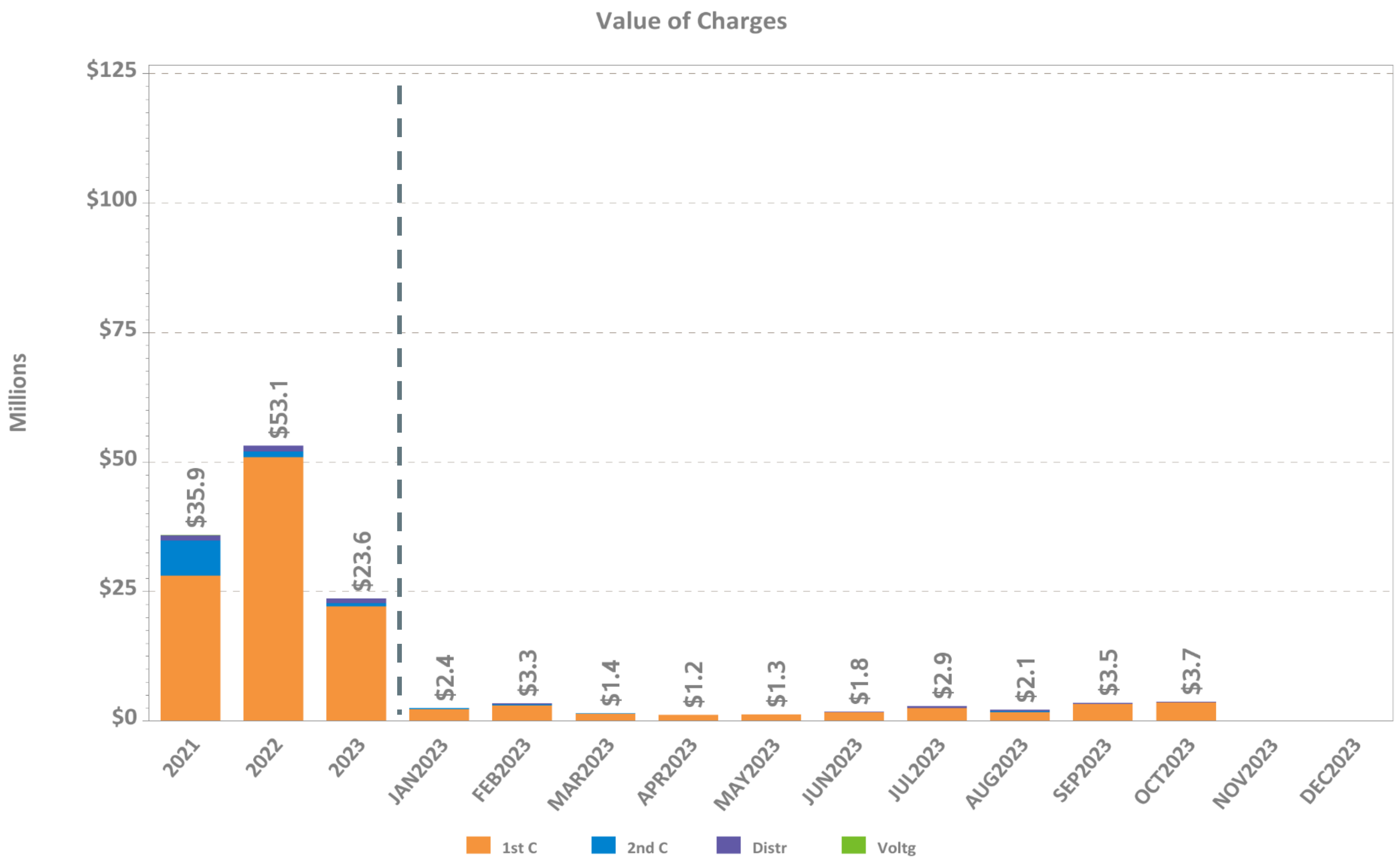
LSCPR Charges by Reliability Region



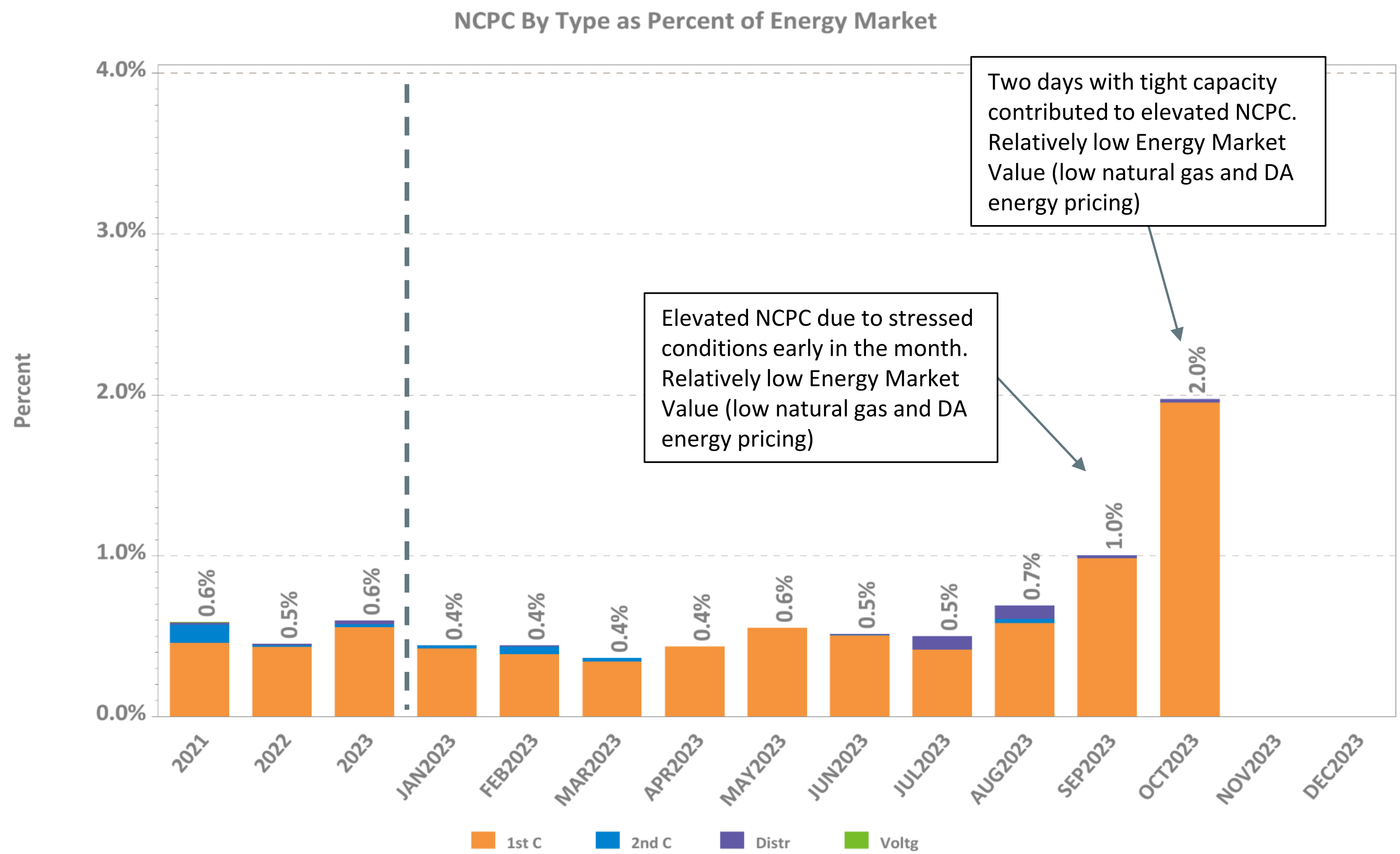
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

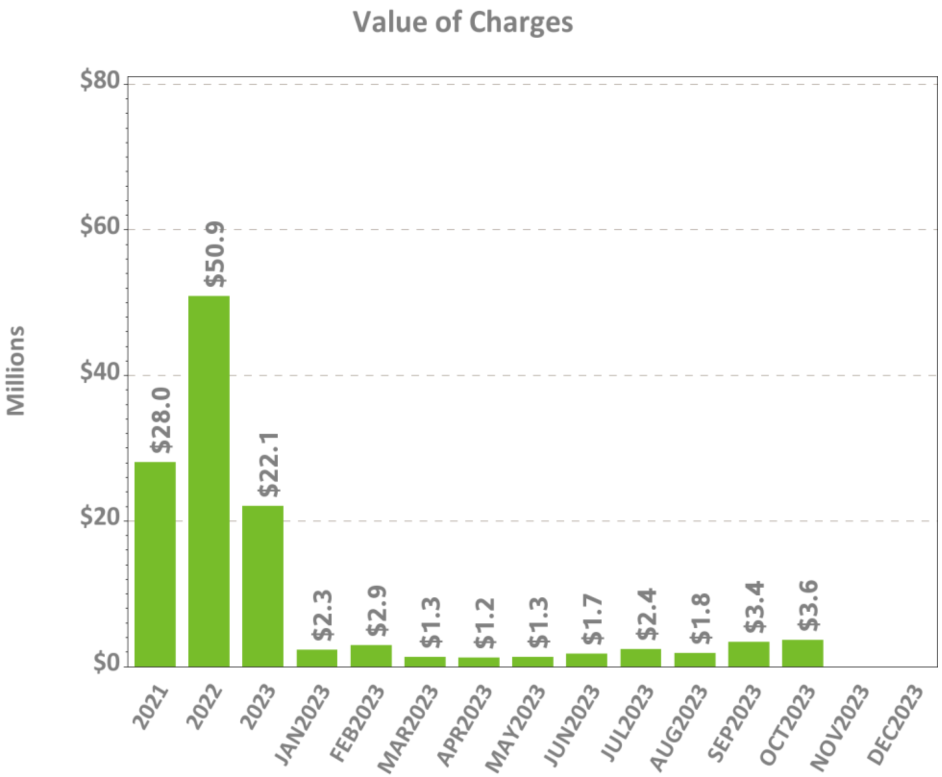
NCPC Charges by Type

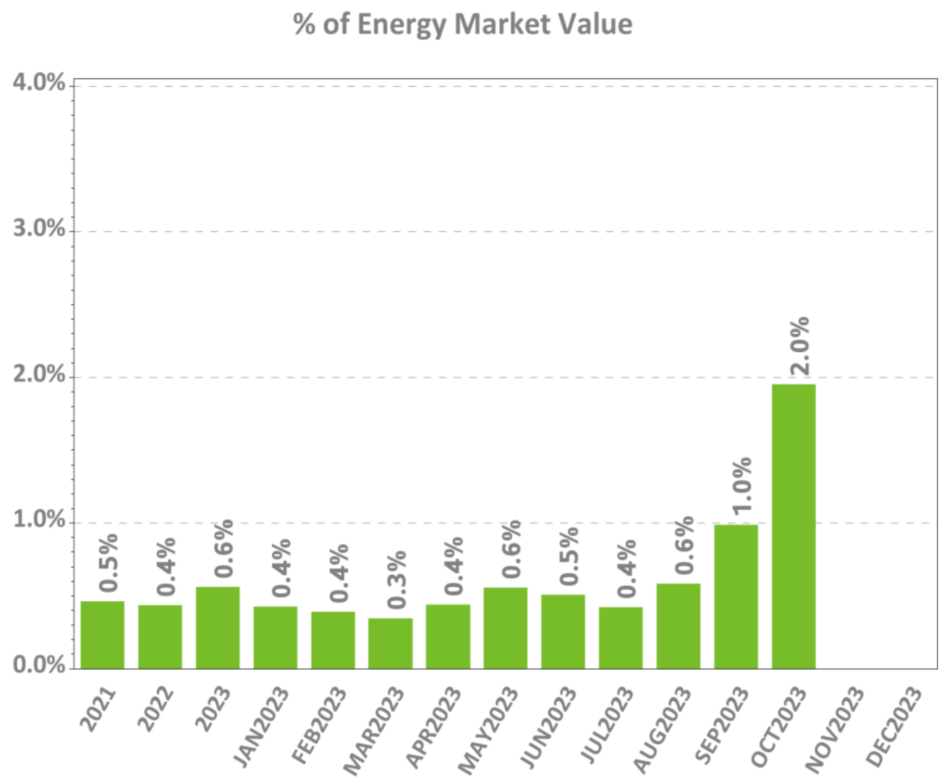


NCPC Charges as Percent of Energy Market



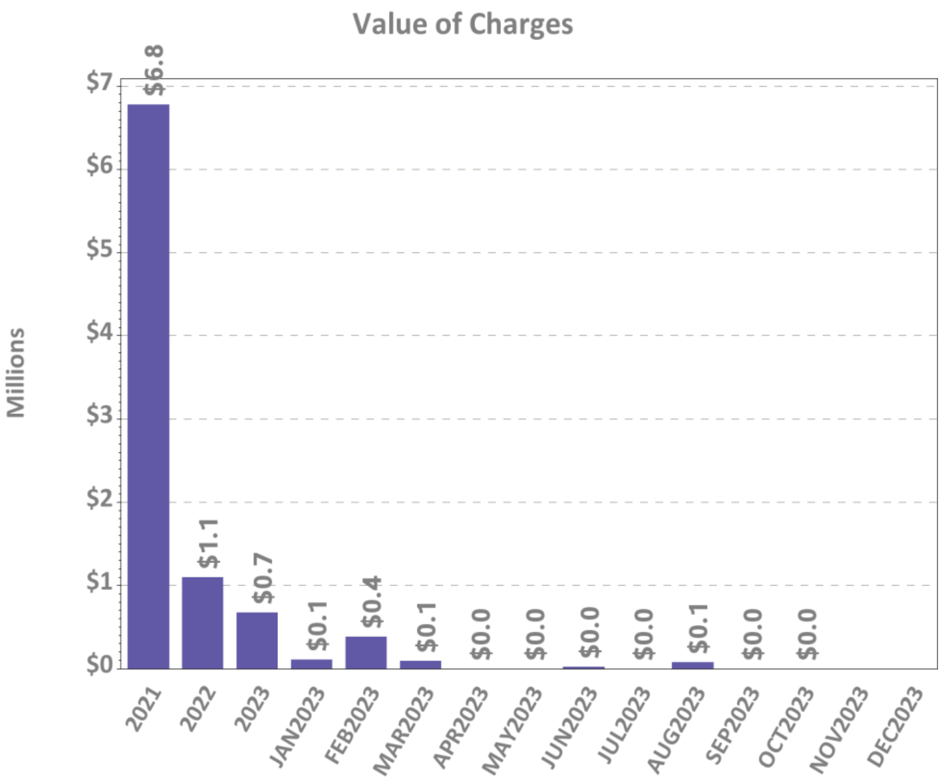
First Contingency NCPC Charges

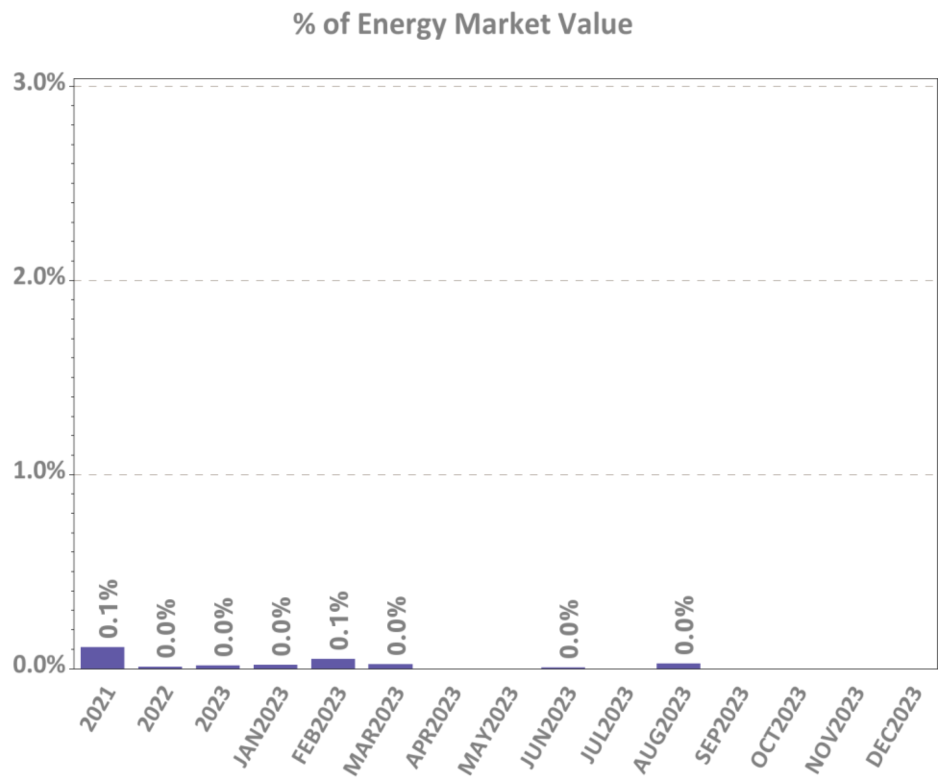




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

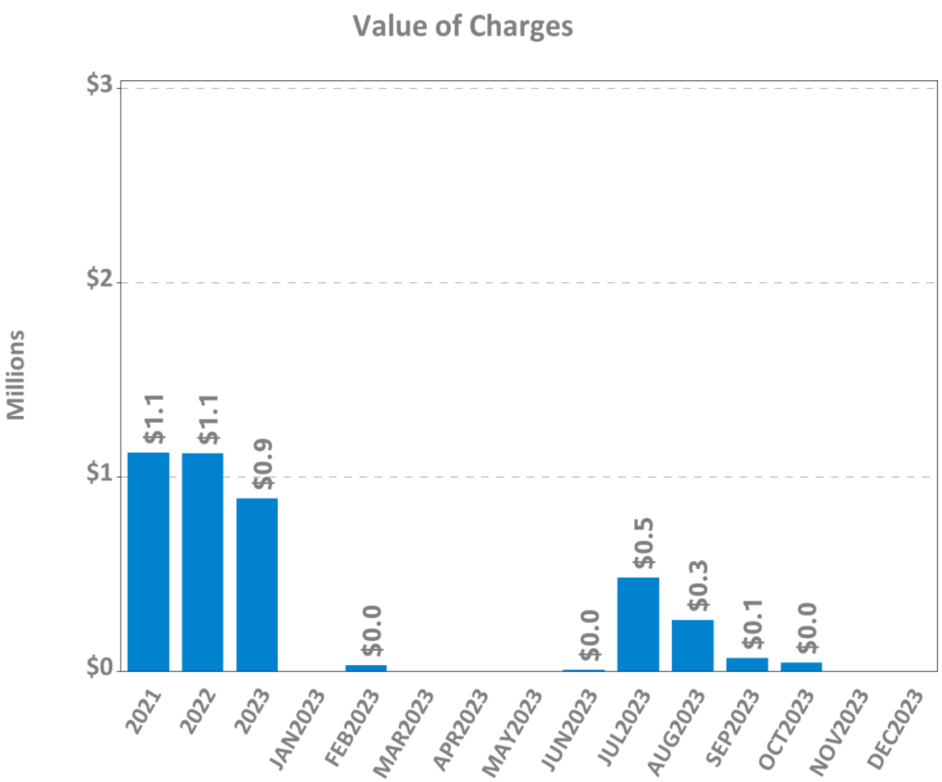
Second Contingency NCPC Charges

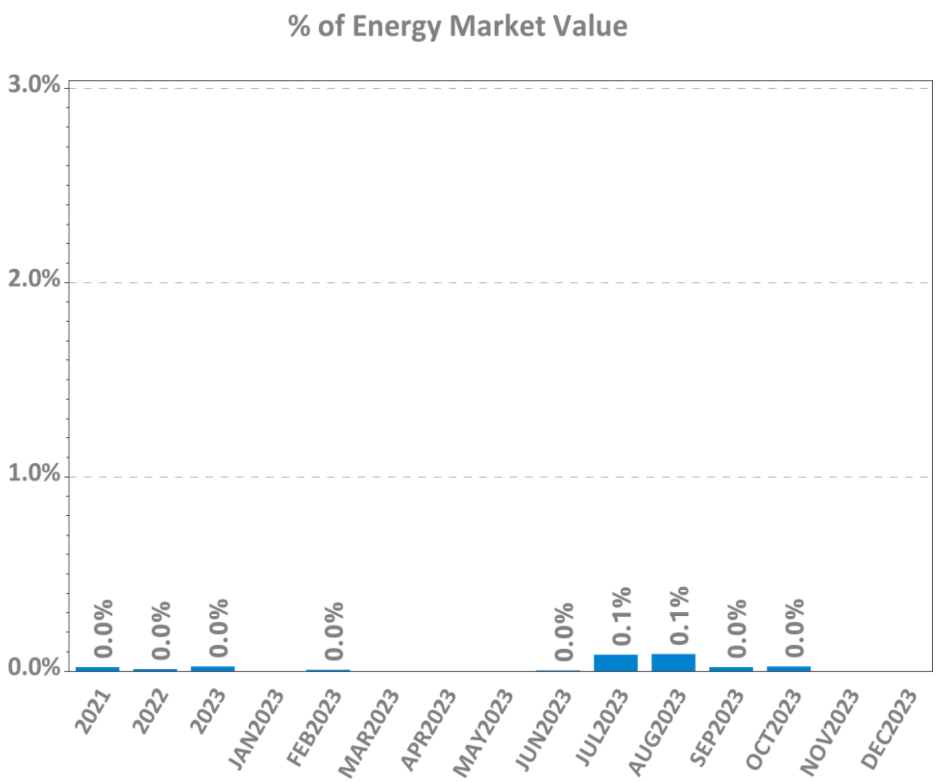




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

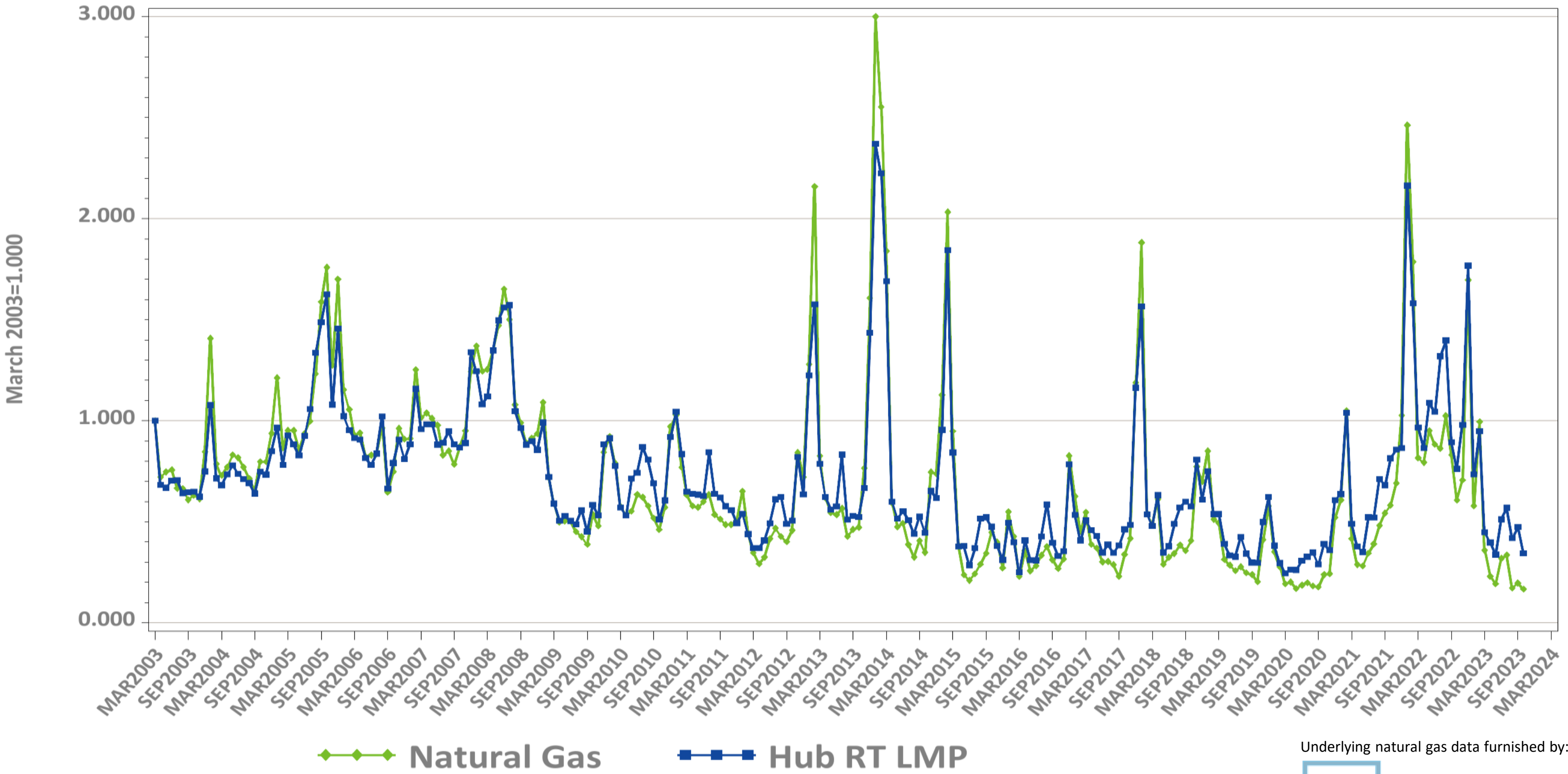
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2022	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$86.07	$84.05	$84.15	$85.73	$84.46	$85.35	$86.01	$85.66	$85.55
Real-Time	$85.42	$83.83	$83.06	$85.07	$83.67	$84.71	$85.37	$85.00	$84.92
RT Delta %	-0.8%	-0.3%	-1.3%	-0.8%	-0.9%	-0.7%	-0.7%	-0.8%	-0.7%

October-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$53.26	$52.04	$52.66	$53.27	$52.64	$52.61	$53.24	$53.03	$52.97
Real-Time	$52.63	$51.47	$52.03	$52.57	$51.64	$51.95	$52.61	$52.35	$52.34
RT Delta %	-1.2%	-1.1%	-1.2%	-1.3%	-1.9%	-1.3%	-1.2%	-1.3%	-1.2%
October-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$24.64	$24.12	$24.41	$24.67	$24.82	$24.20	$24.56	$24.56	$24.48
Real-Time	$23.78	$23.38	$23.57	$23.80	$23.91	$23.37	$23.70	$23.71	$23.64
RT Delta %	-3.5%	-3.1%	-3.4%	-3.5%	-3.7%	-3.4%	-3.5%	-3.4%	-3.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-53.7%	-53.7%	-53.7%	-53.7%	-52.8%	-54.0%	-53.9%	-53.7%	-53.8%
Yr over Yr RT	-54.8%	-54.6%	-54.7%	-54.7%	-53.7%	-55.0%	-55.0%	-54.7%	-54.8%

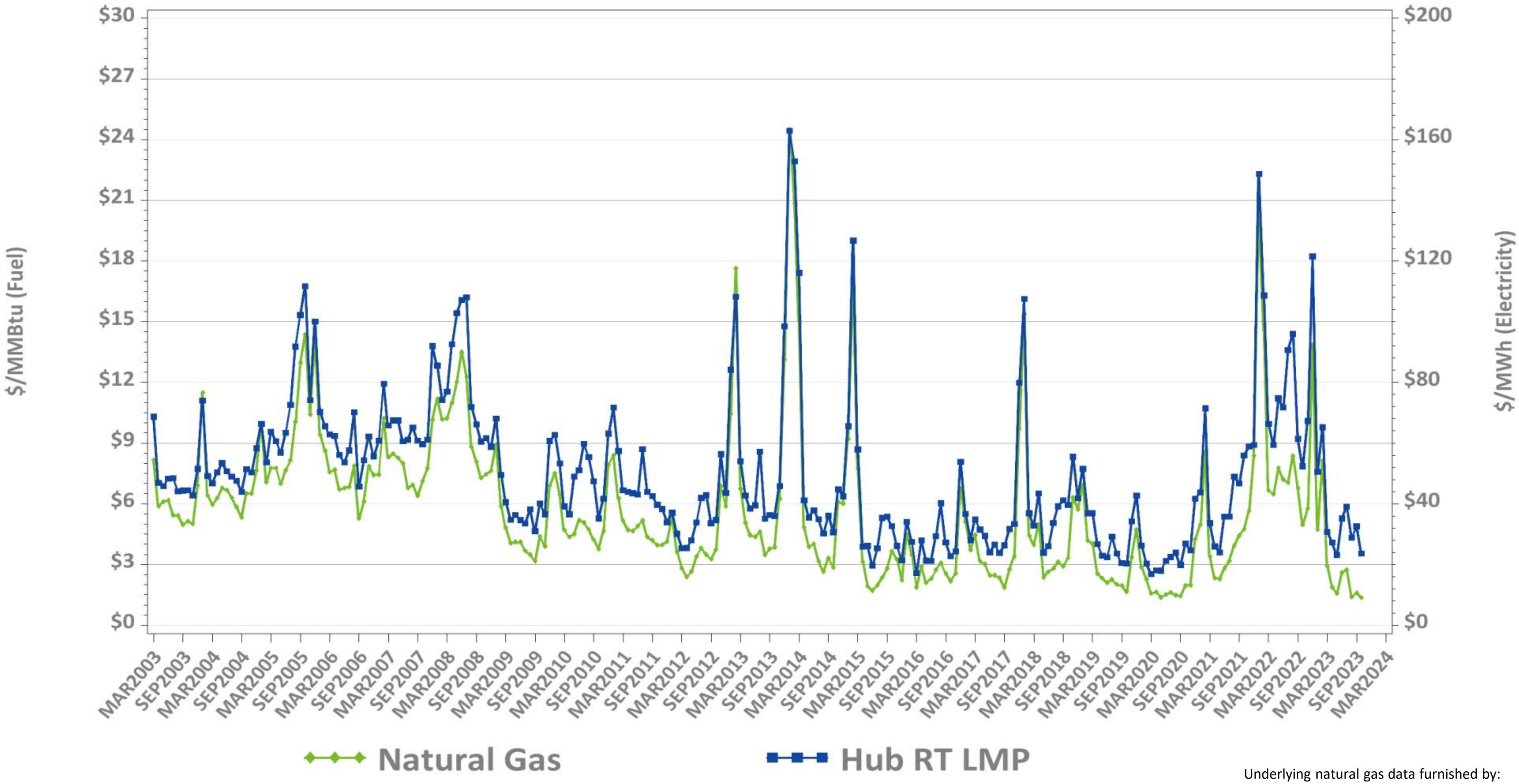
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

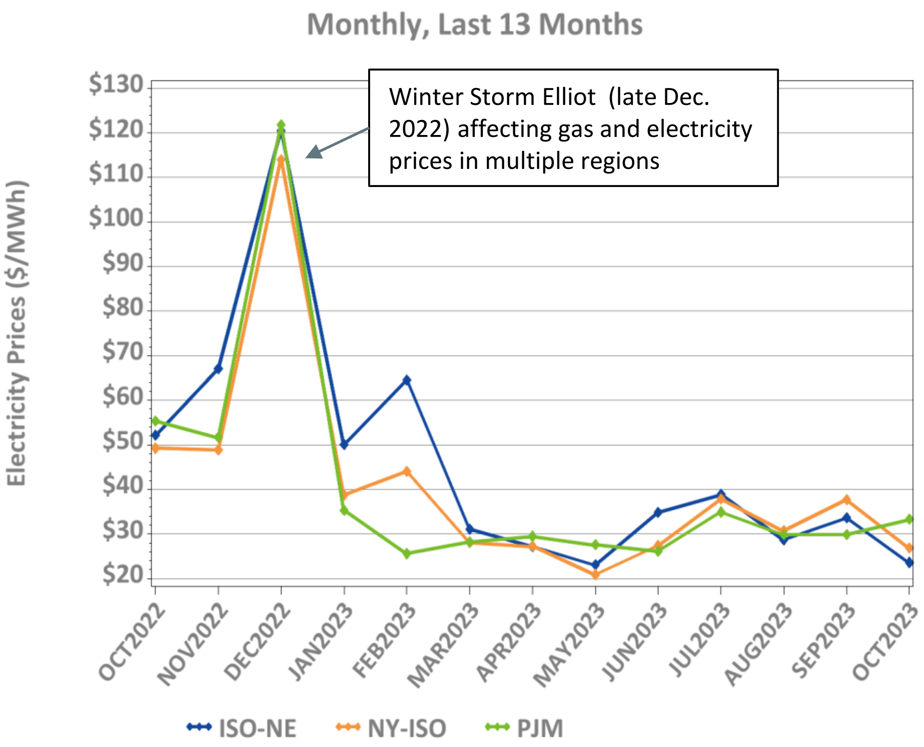
Monthly Average Fuel Price and RT Hub LMP



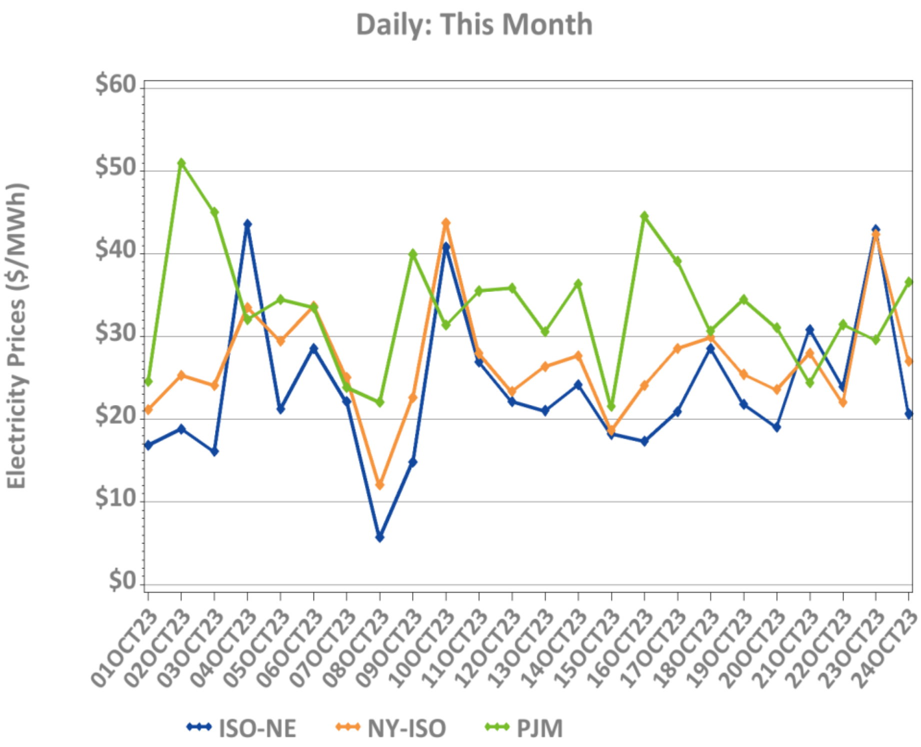
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

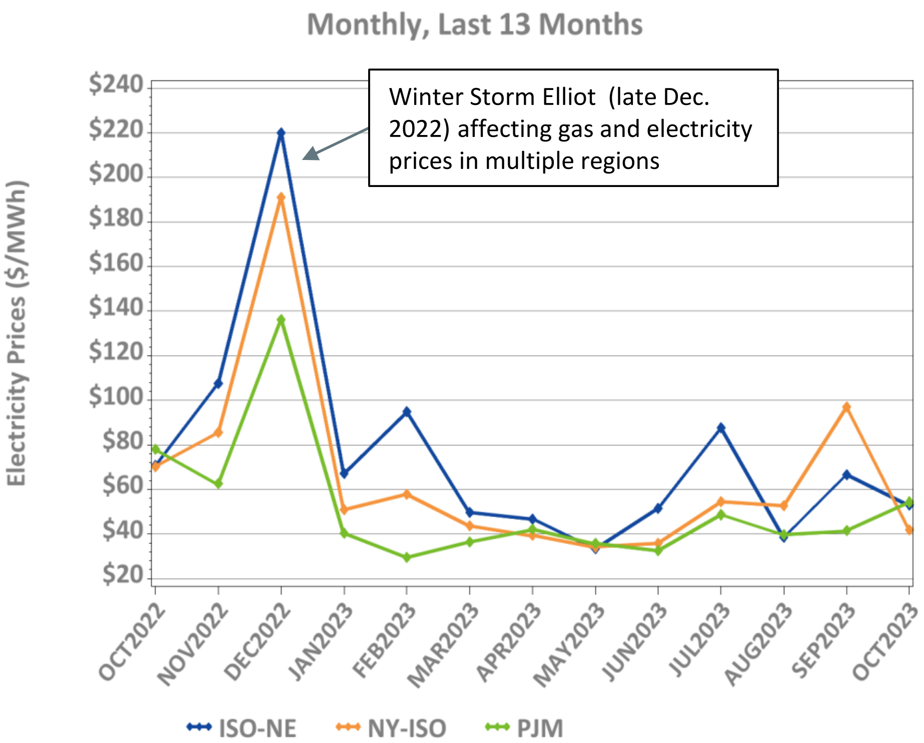


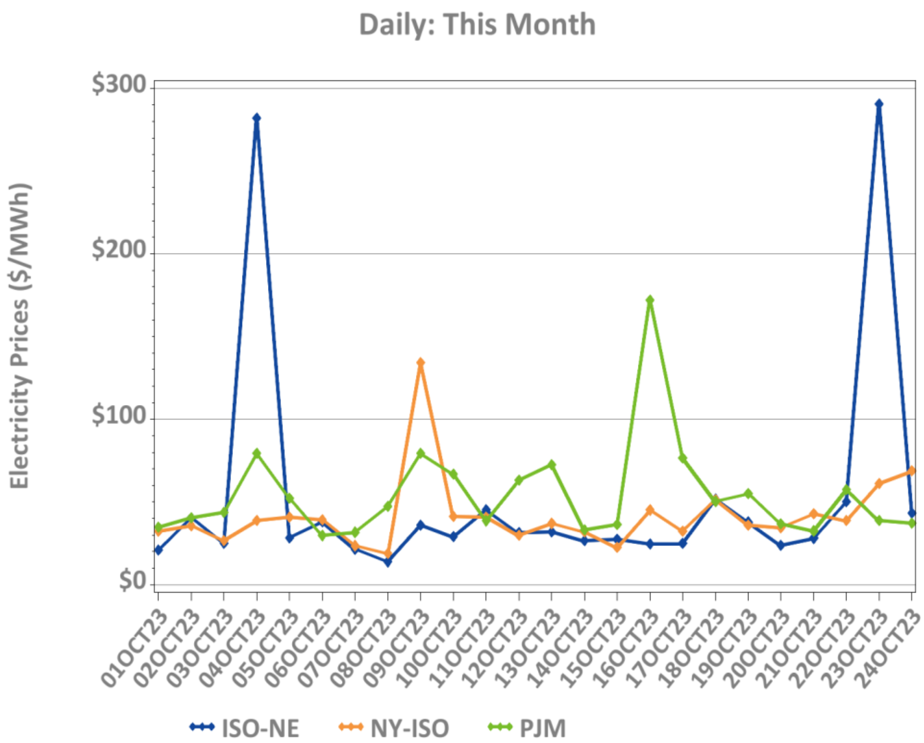
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





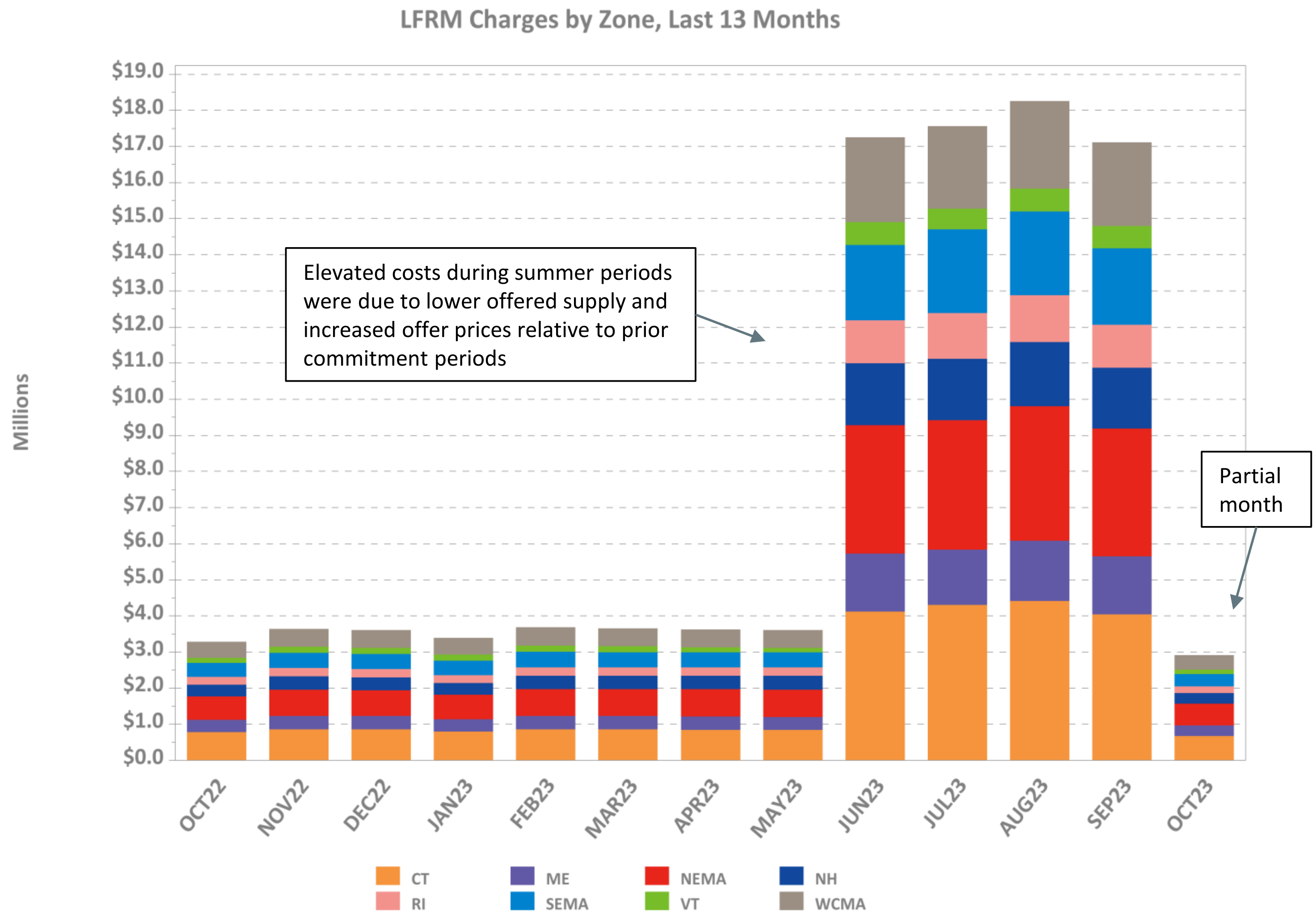
***Forecasted New England daily peak hours reflected**

Reserve Market Results – October 2023

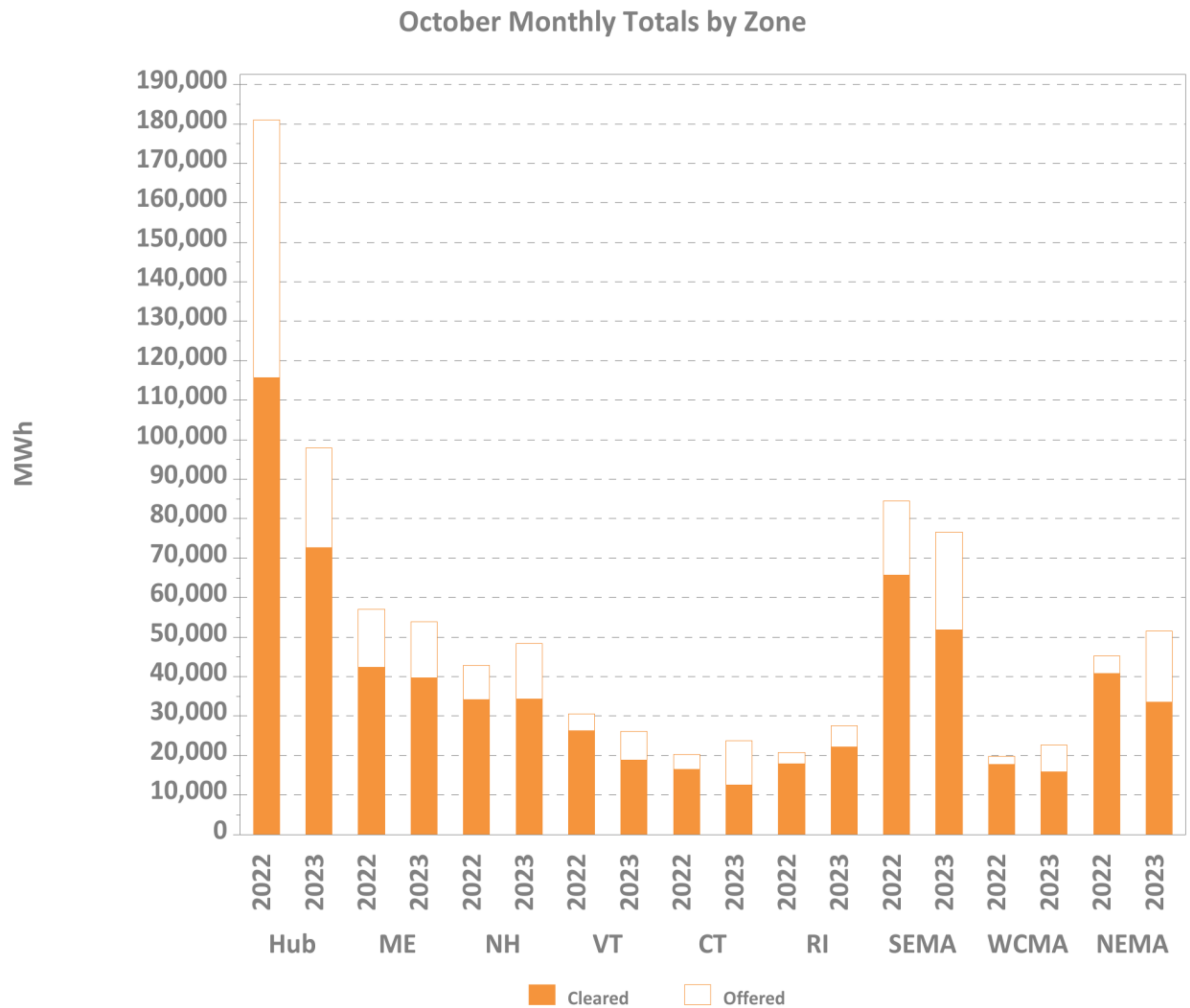
- Maximum potential Forward Reserve Market payments of $4.2M were reduced by credit reductions of $0.4M, failure-to-reserve penalties of $0.9M and negligible failure-to-activate penalties, resulting in a net payout of $2.9M or 70% of maximum
  - Rest of System: $2.39M/3.1M (77%)
  - Southwest Connecticut: $0.03M/0.03M (84%)
  - Connecticut: $0.46M/0.97M (47%)
  - NEMA: $0M/0M (99%)
- $2.9M total Real-Time credits were reduced by $1.1M in Forward Reserve Energy Obligation Charges for a net of $1.8M in Real-Time Reserve payments
  - Rest of System: 163 hours, $646K
  - Southwest Connecticut: 163 hours, $651K
  - Connecticut: 163 hours, $195K
  - NEMA: 163 hours, $326K

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.

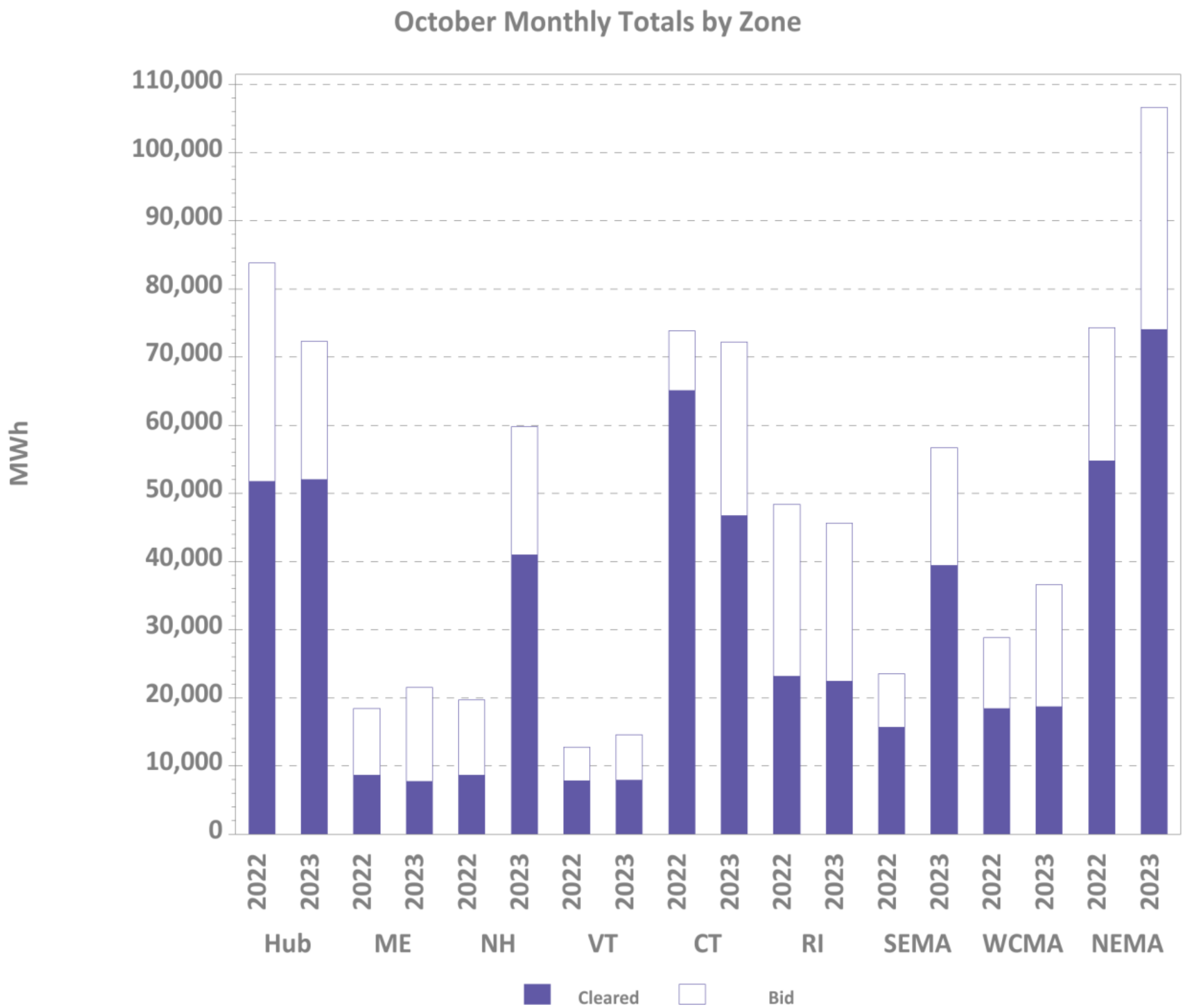
LFRM Charges to Load by Load Zone ($)



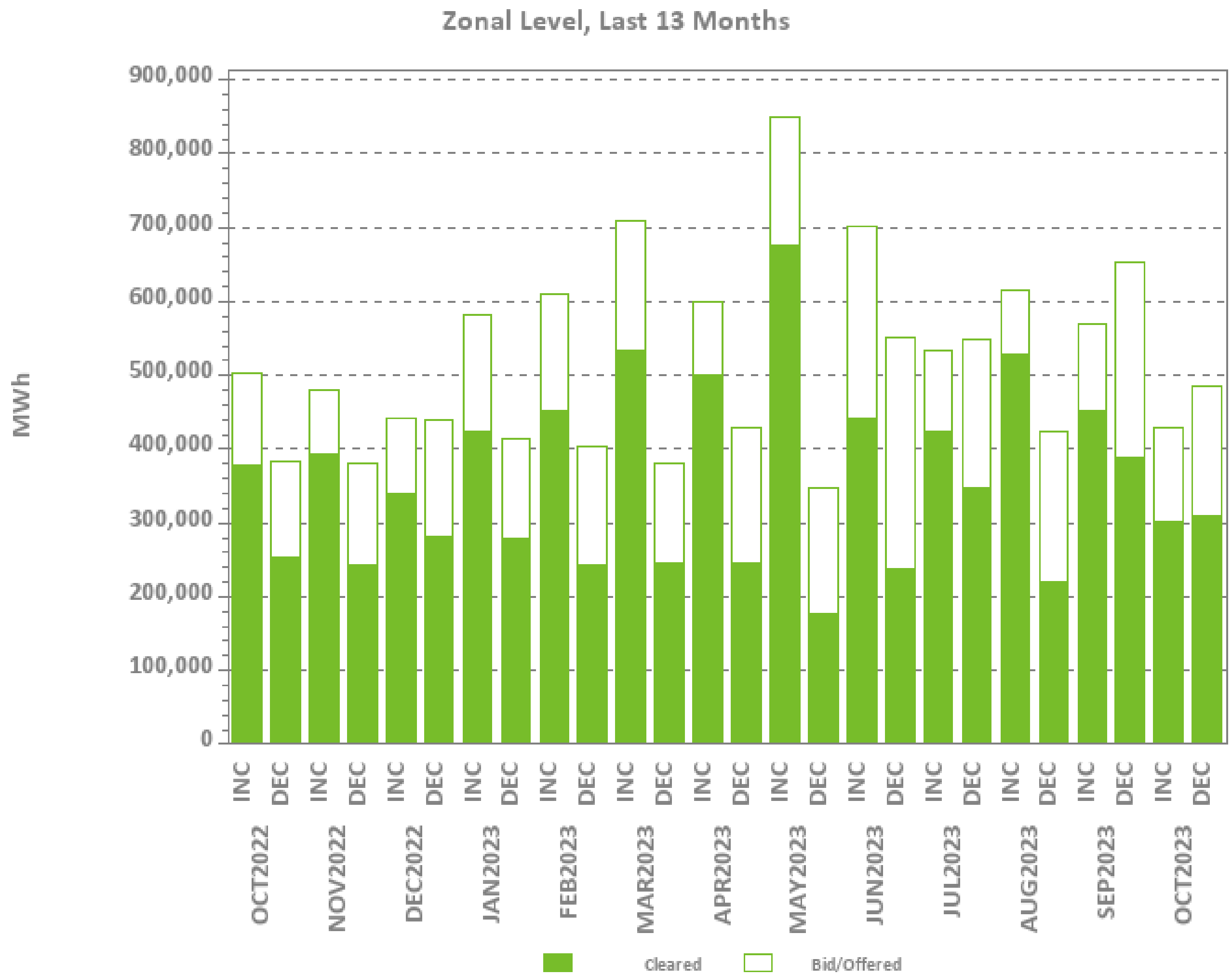
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

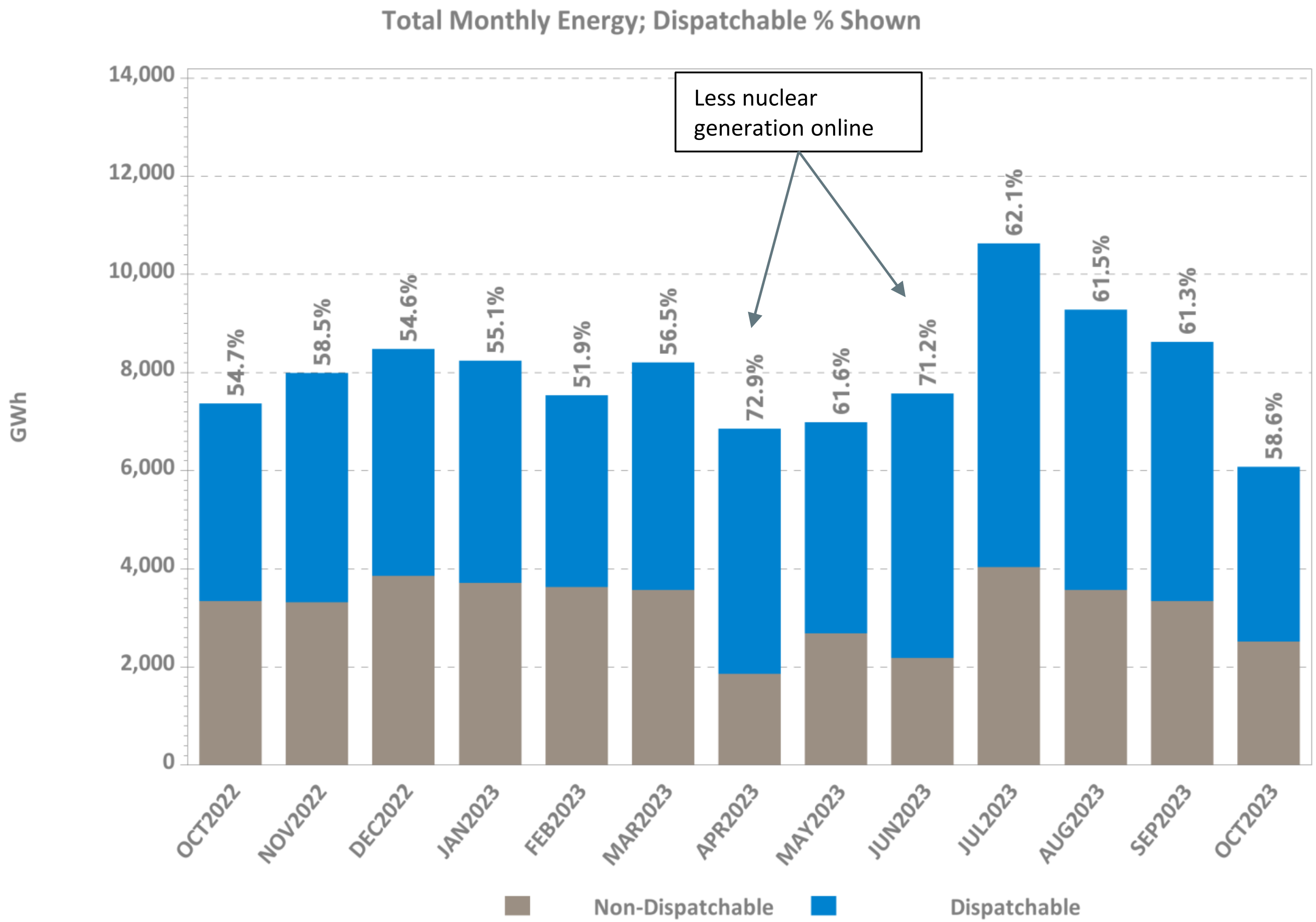


Total Increment Offers and Decrement Bids



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)

Regional System Plan (RSP)

- The development of the draft 2023 RSP is complete
  - Final review and approval of the 2023 RSP by the Board is expected by December 31

Planning Advisory Committee (PAC)

- November 15 PAC Meeting Agenda Topics*
  - Short Circuit Solutions Studies
    - Western Central MA 2028 Short Circuit Solutions Study
    - Maine 2028 Short Circuit Solutions Study
    - Rhode Island 2028 Short Circuit Solutions Study
  - Updates to DER Modeling in Transmission Planning Studies
  - Guidelines for Asset Condition PAC Presentations
  - Five-Year Forecast of Upcoming Asset Condition Projects

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

2050 Transmission Study

- 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
- 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 began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Additional discussion on solution development occurred at the 4/20/23 and 7/25/23 PAC meetings
- Development of transmission solutions and associated costs, including work by Electrical Consultants Inc. (ECI) on cost estimates, is now complete
- ISO presented solutions and associated costs at the 10/18/23 PAC meeting
- Draft report was posted on 11/1/23

Economic Studies

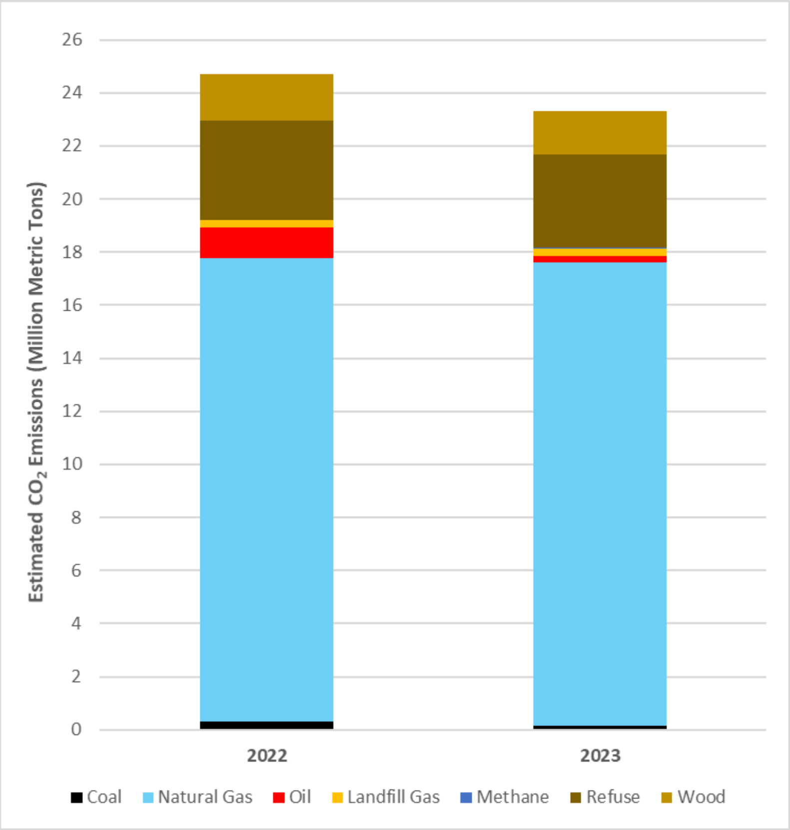
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  – New effort is to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  – PAC presentations began in April 2022. To date, the ISO has presented new modeling features, assumptions and results from the Benchmark and Market Efficiency Need scenarios, an overview of the capacity expansion model and how it will be used in the Policy scenario. The ISO presented preliminary results from the Policy scenario in June 2023. Sensitivity results were presented in July, August, and October
    - As announced at the October PAC, FGRS Phase 2 will be completed via the EPCET Policy scenario

ISO-NE Tie Benefits Evaluation

- The ISO started the tie benefits evaluation at the October 19 PSPC meeting. The first presentation reviewed general topics such as:
  - What are tie benefits?
  - What is probabilistic planning?
  - How do other ISO/RTOs factor in external emergency assistance?
- The scope of the project includes three major components
  - Historical review of external transfers
  - Future outlook for the northeast
  - Modeling assumptions review
- The evaluation will extend into Q3 of 2024
  - Additional PSPC time will be dedicated for this topic; additional meetings have been scheduled for January 15 and March 15

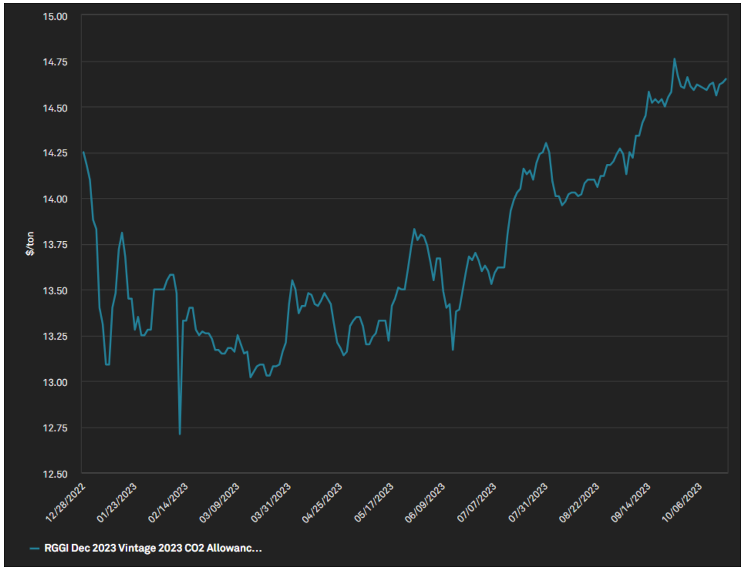
New England Power System Carbon Emissions

2022 vs. 2023 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



Data as of 10/15/2023

RGGI Allowance Prices



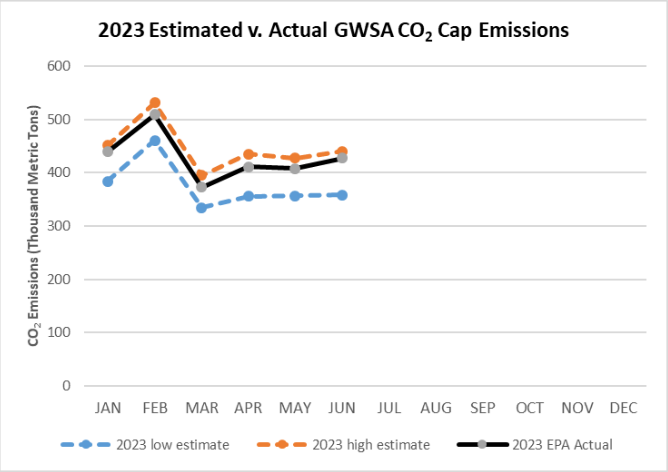
- 10/18/23: RGGI allowance spot price - $14.65
- 9/26/23: Third Program Review Public Meeting
  - RGGI states proposed to change the three-year compliance period to an annual basis
  - RGGI states released a draft RGGI Emissions Dashboard that displays CO_2 emissions from RGGI-covered facilities since the start of RGGI

RGGI – Regional Greenhouse Gas Initiative

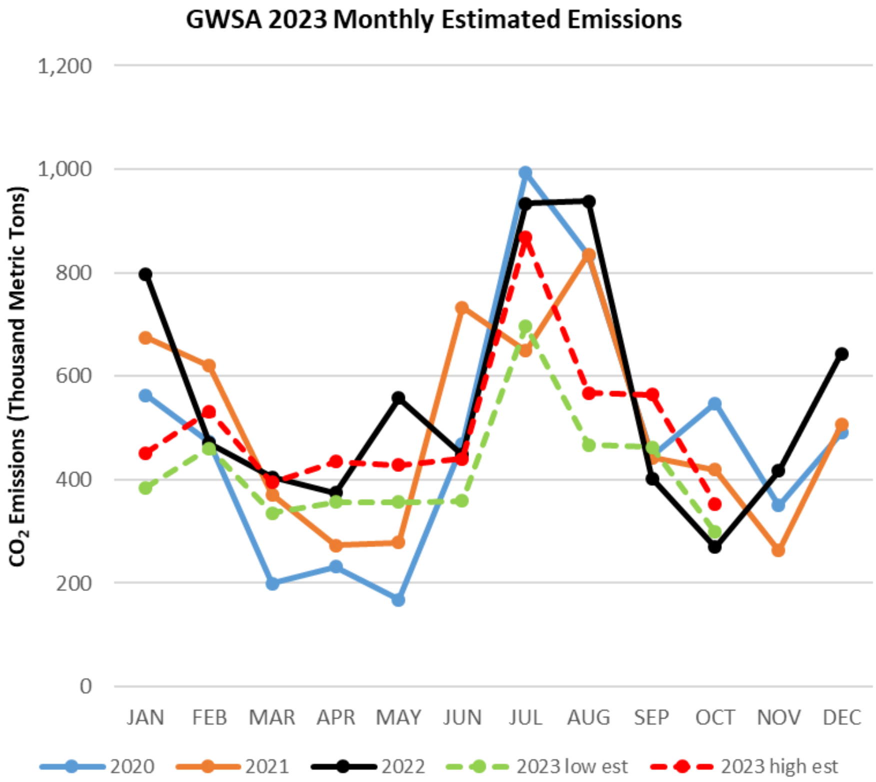
Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 10/23/23, October 2023 estimated GWSA CO_2 emissions range between **298,858** and **353,427** metric tons
  - Year-to-date 2023 estimated emissions range between **53%** and **64%** of the 2023 cap of 7.84 MMT
- According to the EPA CAMPD, the Q1 and Q2 (January-June) GWSA CO_2 emissions were **2.57** million metric tons (Q3 not finalized yet). The Q1 and Q2 emissions were **33%** of the 2023 cap of 7.84 million metric tons



2020-2023 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated 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 10/18/2023

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 10/18/2023

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	Mar-25	3

Greater Boston Projects, cont.

Status as of 10/18/2023

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 10/18/2023

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 10/18/2023

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 10/18/2023

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 10/18/2023

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	Mar-27	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	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-25	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 10/18/2023

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	3
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	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-25	1

SEMA/RI Reliability Projects, cont.

Status as of 10/18/2023

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 10/18/2023

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 10/18/2023

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	3
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Dec-22	4
1851	Upgrade Card 115 kV to BPS standards	Dec-22	4
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Feb-23	4
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	4

Eastern CT Reliability Projects, cont.

Status as of 10/18/2023

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	Jun-23	4
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Feb-23	4
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Feb-23	4
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Sept-22	4
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Feb-23	4
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 10/18/2023

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)	Feb-23	4
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

New Hampshire Solution Projects

Status as of 10/18/2023

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	Sep-24	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	Jun-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	3

Upper Maine Solution Projects

Status as of 10/18/2023

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	3
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	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	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	3

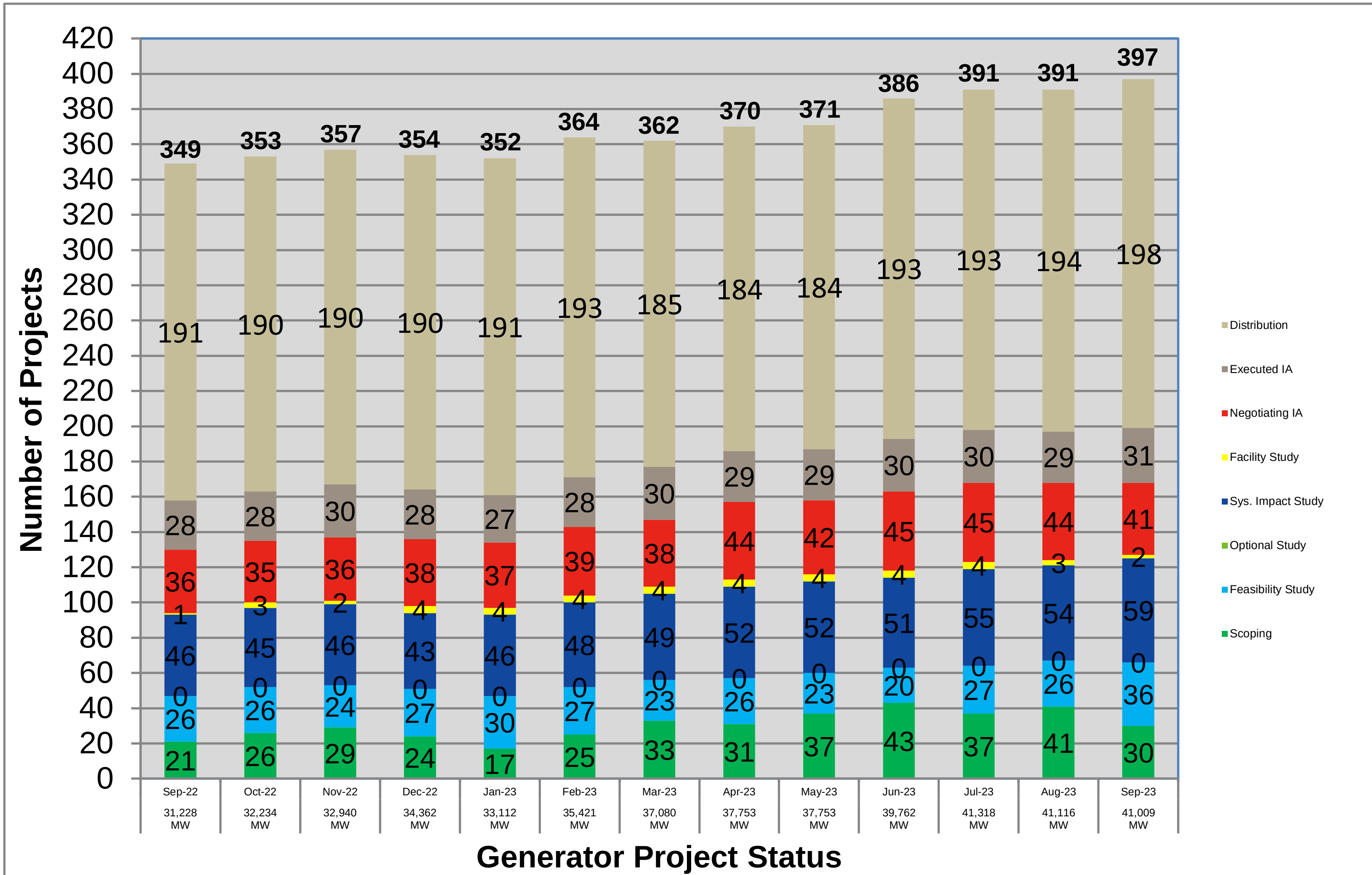
Upper Maine Solution Projects, cont.

Status as of 10/18/2023

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	3
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-24	2

Status of Tariff Studies as of October 1, 2023



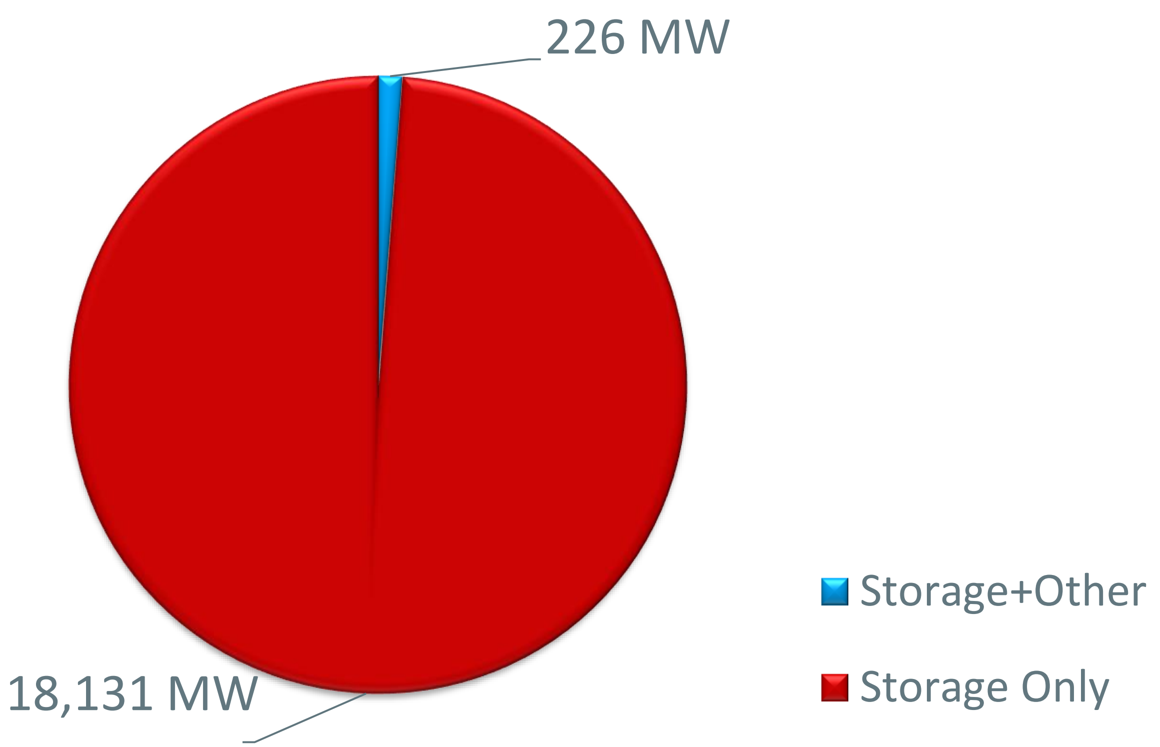
8 ETUs in Scoping, 7 in FS, 0 in SIS, 1 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 1 in SIS

https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of October 1, 2023)

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



OPERABLE CAPACITY ANALYSIS

Fall 2023 Analysis

Fall 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov. - 2023[2] CSO (MW)	Nov. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,378	31,749
Active Demand Capacity Resource (+) [5]	417	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	993	993
Non Commercial Capacity (+)	24	24
Non Gas-fired Planned Outage MW (-)	4,544	4,878
Gas Generator Outages MW (-)	1,303	2,224
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)	20,365	22,393
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,347	17,347
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,652	19,652
Operable Capacity Margin	713	2,741

[1] Operable Capacity is based on data as of **October 24, 2023** 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 24, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 11, 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.

Fall 2023 Operable Capacity Analysis

90/10 Load Forecast	Nov. - 2023[2] CSO (MW)	Nov. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,378	31,749
Active Demand Capacity Resource (+) [5]	417	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	993	993
Non Commercial Capacity (+)	24	24
Non Gas-fired Planned Outage MW (-)	4,544	4,878
Gas Generator Outages MW (-)	1,303	2,224
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)	20,365	22,393
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,015	18,015
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,320	20,320
Operable Capacity Margin	45	2,073

[1]Operable Capacity is based on data as of **October 24, 2023** 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 24, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 11, 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.

Fall 2023 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 24, 2023 - 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: 10/24/2023

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
11/11/2023	**28378**	**417**	**993**	**24**	**4544**	**1303**	**3600**	**0**	**20365**	**17347**	**2305**	**19652**	**713**	**Y**	**Fall 2023**
11/18/2023	28378	417	993	24	2584	1164	3600	206	22258	18079	2305	20384	1874	N	Fall 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 2023 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 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 24, 2023 - 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: 10/24/2023

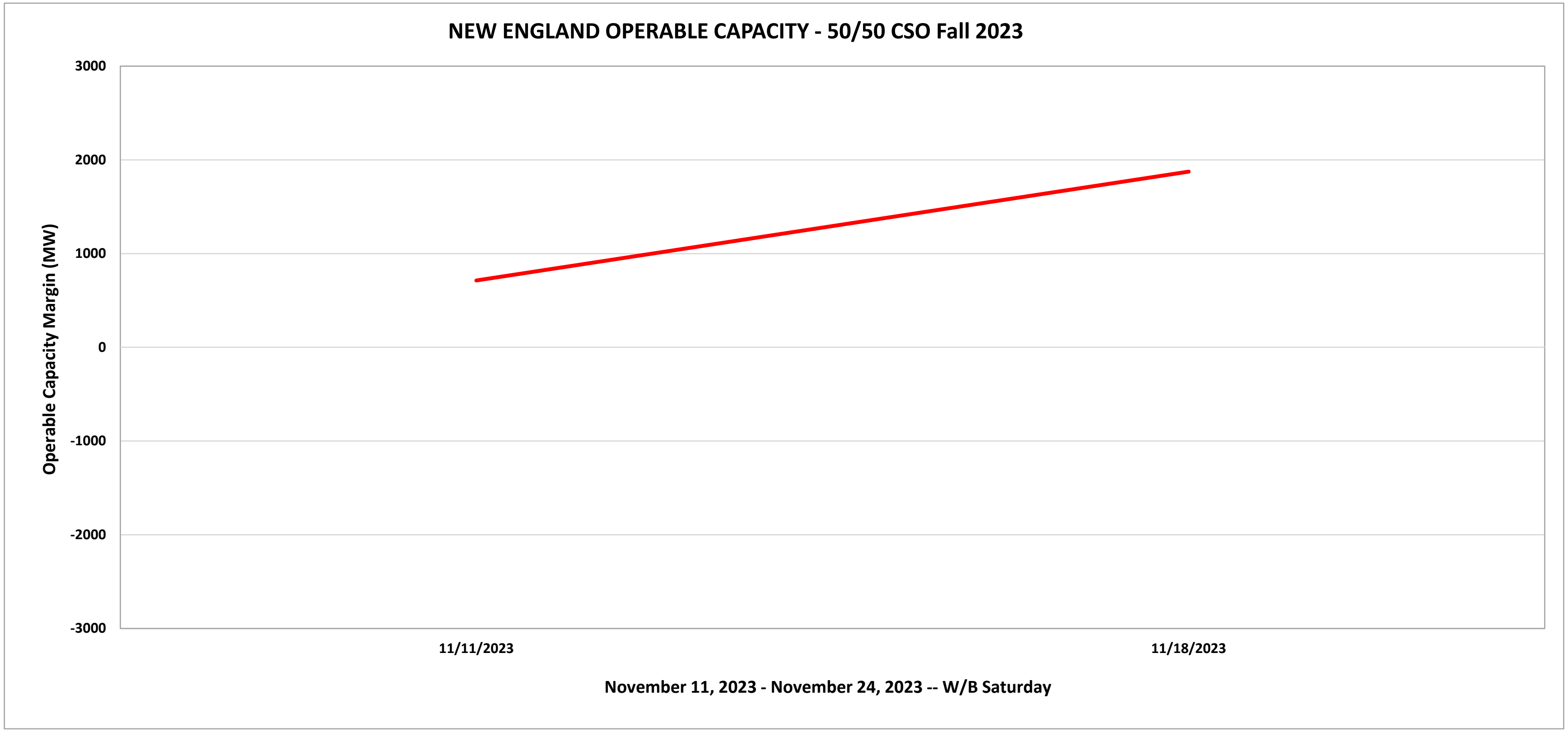
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
11/11/2023	**28378**	**417**	**993**	**24**	**4544**	**1303**	**3600**	**0**	**20365**	**18015**	**2305**	**20320**	**45**	**Y**	**Fall 2023**
11/18/2023	28378	417	993	24	2584	1164	3600	371	22093	18773	2305	21078	1015	N	Fall 2023

Column Definitions

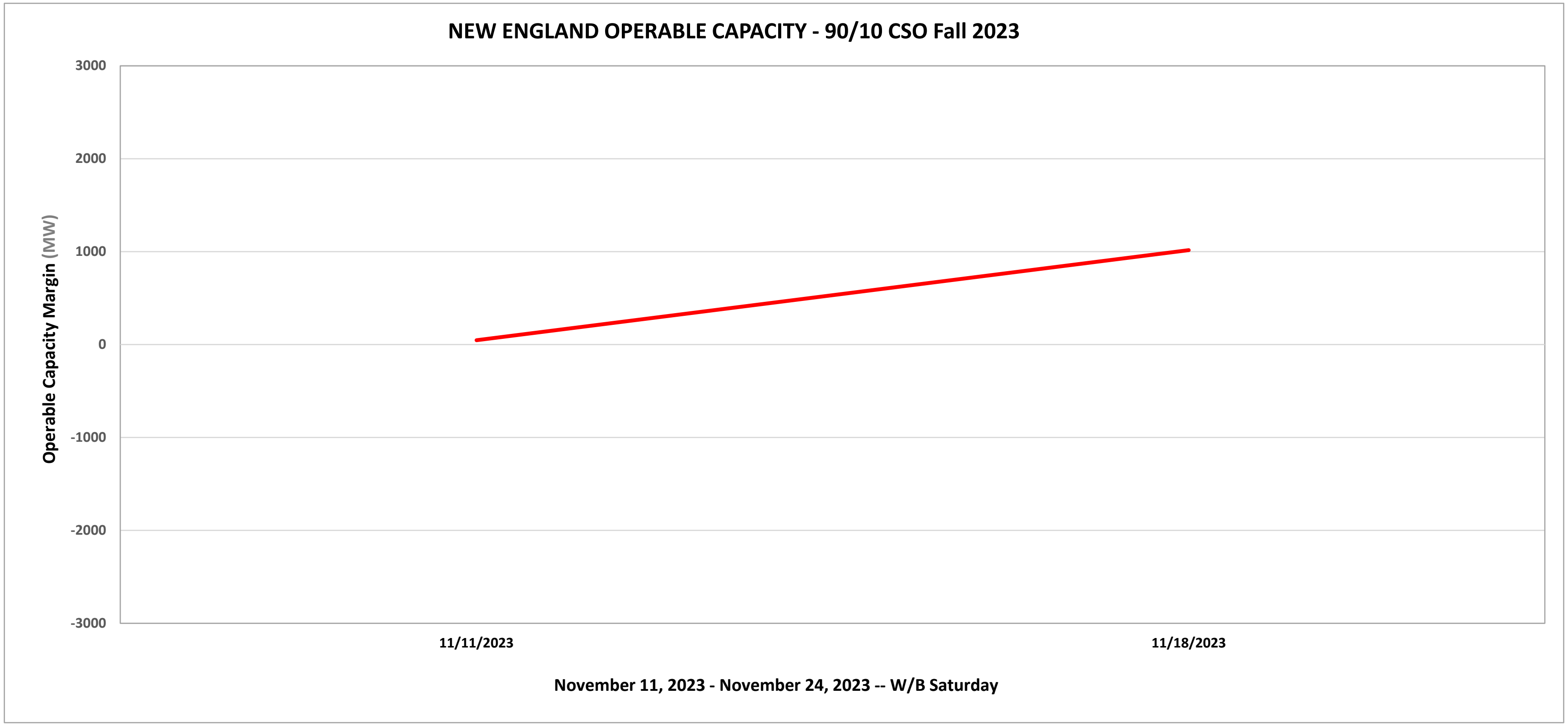
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 2023 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 2023 Operable Capacity Analysis
50/50 Forecast (Reference)



Fall 2023 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Winter 2023/24 Analysis

Winter 2023/24 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2024[2] CSO (MW)	Jan. - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,340	31,749
Active Demand Capacity Resource (+) [5]	522	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	215	215
Non Gas-fired Planned Outage MW (-)	192	350
Gas Generator Outages MW (-)	509	812
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,219	3,324
Net Capacity (NET OPCAP SUPPLY MW)	23,315	25,965
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,269	20,269
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,574	22,574
Operable Capacity Margin	741	3,391

[1]Operable Capacity is based on data as of **October 24, 2023** 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 24, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 6, 2024.**

[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 2023/24 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2024[2] CSO (MW)	Jan. - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,340	31,749
Active Demand Capacity Resource (+) [5]	522	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	215	215
Non Gas-fired Planned Outage MW (-)	192	350
Gas Generator Outages MW (-)	509	812
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,030	4,254
Net Capacity (NET OPCAP SUPPLY MW)	22,504	25,035
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,032	21,032
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,337	23,337
Operable Capacity Margin	-833	1,698

[1]Operable Capacity is based on data as of **October 24, 2023** 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 24, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 6, 2024.**

[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 2023/24 Operable Capacity Analysis

50/50 Forecast (Reference)

October 24, 2023 - 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 December, January, February and March.

Report created: 10/24/2023

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
11/25/2023	28378	417	993	24	2002	472	3600	1190	22548	18794	2305	21099	1449	N	Winter 2023/2024
12/2/2023	28345	522	958	215	1589	951	3200	853	23447	19177	2305	21482	1965	N	Winter 2023/2024
12/9/2023	28345	522	958	215	1428	951	3200	1417	23044	19464	2305	21769	1275	N	Winter 2023/2024
12/16/2023	28345	522	958	215	1304	731	3200	2014	22791	19475	2305	21780	1011	N	Winter 2023/2024
12/23/2023	28345	522	958	215	117	421	3200	2713	23589	19537	2305	21842	1747	N	Winter 2023/2024
12/30/2023	28340	522	958	215	117	366	2800	3367	23385	19808	2305	22113	1272	N	Winter 2023/2024
1/6/2024	**28340**	**522**	**958**	**215**	**192**	**509**	**2800**	**3219**	**23315**	**20269**	**2305**	**22574**	**741**	**Y**	**Winter 2023/2024**
1/13/2024	28340	522	958	215	117	400	2800	3183	23535	20269	2305	22574	961	N	Winter 2023/2024
1/20/2024	28340	522	958	215	117	400	2800	2734	23984	20269	2305	22574	1410	N	Winter 2023/2024
1/27/2024	28340	522	958	215	250	212	3100	2623	23850	20049	2305	22354	1496	N	Winter 2023/2024
2/3/2024	28340	522	958	215	176	33	3100	2503	24223	19784	2305	22089	2134	N	Winter 2023/2024
2/10/2024	28340	522	958	215	188	33	3100	2204	24510	19755	2305	22060	2450	N	Winter 2023/2024
2/17/2024	28340	522	958	215	117	33	3100	1755	25030	19495	2305	21800	3230	N	Winter 2023/2024
2/24/2024	28340	522	958	215	170	33	3100	1456	25276	18516	2305	20821	4455	N	Winter 2023/2024
3/2/2024	28340	522	958	215	223	33	2200	381	27198	18170	2305	20475	6723	N	Winter 2023/2024
3/9/2024	28340	522	958	215	1471	404	2200	0	25960	17976	2305	20281	5679	N	Winter 2023/2024
3/16/2024	28340	522	958	215	1471	376	2200	0	25988	17614	2305	19919	6069	N	Winter 2023/2024
3/23/2024	28340	522	958	215	1491	1288	2200	0	25056	17054	2305	19359	5697	N	Winter 2023/2024
3/30/2024	28238	518	958	215	996	2079	2700	0	24154	16379	2305	18684	5470	N	Winter 2023/2024

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 2023 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 2023/24 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 24, 2023 - 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 December, January, February and March.

Report created: 10/24/2023

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
11/25/2023	28378	417	993	24	2002	472	3600	2104	21634	19512	2305	21817	-183	N	Winter 2023/2024
12/2/2023	28345	522	958	215	1589	951	3200	1841	22459	19903	2305	22208	251	N	Winter 2023/2024
12/9/2023	28345	522	958	215	1428	951	3200	2404	22057	20199	2305	22504	-447	N	Winter 2023/2024
12/16/2023	28345	522	958	215	1304	731	3200	3133	21672	20211	2305	22516	-844	Y	Winter 2023/2024
12/23/2023	28345	522	958	215	117	421	3200	3859	22443	20274	2305	22579	-136	N	Winter 2023/2024
12/30/2023	28340	522	958	215	117	366	2800	4042	22710	20555	2305	22860	-150	N	Winter 2023/2024
1/6/2024	**28340**	**522**	**958**	**215**	**192**	**509**	**2800**	**4030**	**22504**	**21032**	**2305**	**23337**	**-833**	**N**	**Winter 2023/2024**
1/13/2024	28340	522	958	215	117	400	2800	3931	22787	21032	2305	23337	-550	N	Winter 2023/2024
1/20/2024	28340	522	958	215	117	400	2800	3632	23086	21032	2305	23337	-251	N	Winter 2023/2024
1/27/2024	28340	522	958	215	250	212	3100	3820	22653	20804	2305	23109	-456	N	Winter 2023/2024
2/3/2024	28340	522	958	215	176	33	3100	3550	23176	20530	2305	22835	341	N	Winter 2023/2024
2/10/2024	28340	522	958	215	188	33	3100	3251	23463	20500	2305	22805	658	N	Winter 2023/2024
2/17/2024	28340	522	958	215	117	33	3100	2653	24132	20231	2305	22536	1596	N	Winter 2023/2024
2/24/2024	28340	522	958	215	170	33	3100	2204	24528	19218	2305	21523	3005	N	Winter 2023/2024
3/2/2024	28340	522	958	215	223	33	2200	1278	26301	18860	2305	21165	5136	N	Winter 2023/2024
3/9/2024	28340	522	958	215	1471	404	2200	802	25158	18659	2305	20964	4194	N	Winter 2023/2024
3/16/2024	28340	522	958	215	1471	376	2200	0	25988	18285	2305	20590	5398	N	Winter 2023/2024
3/23/2024	28340	522	958	215	1491	1288	2200	0	25056	17705	2305	20010	5046	N	Winter 2023/2024
3/30/2024	28238	518	958	215	996	2079	2700	0	24154	17014	2305	19319	4835	N	Winter 2023/2024

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.
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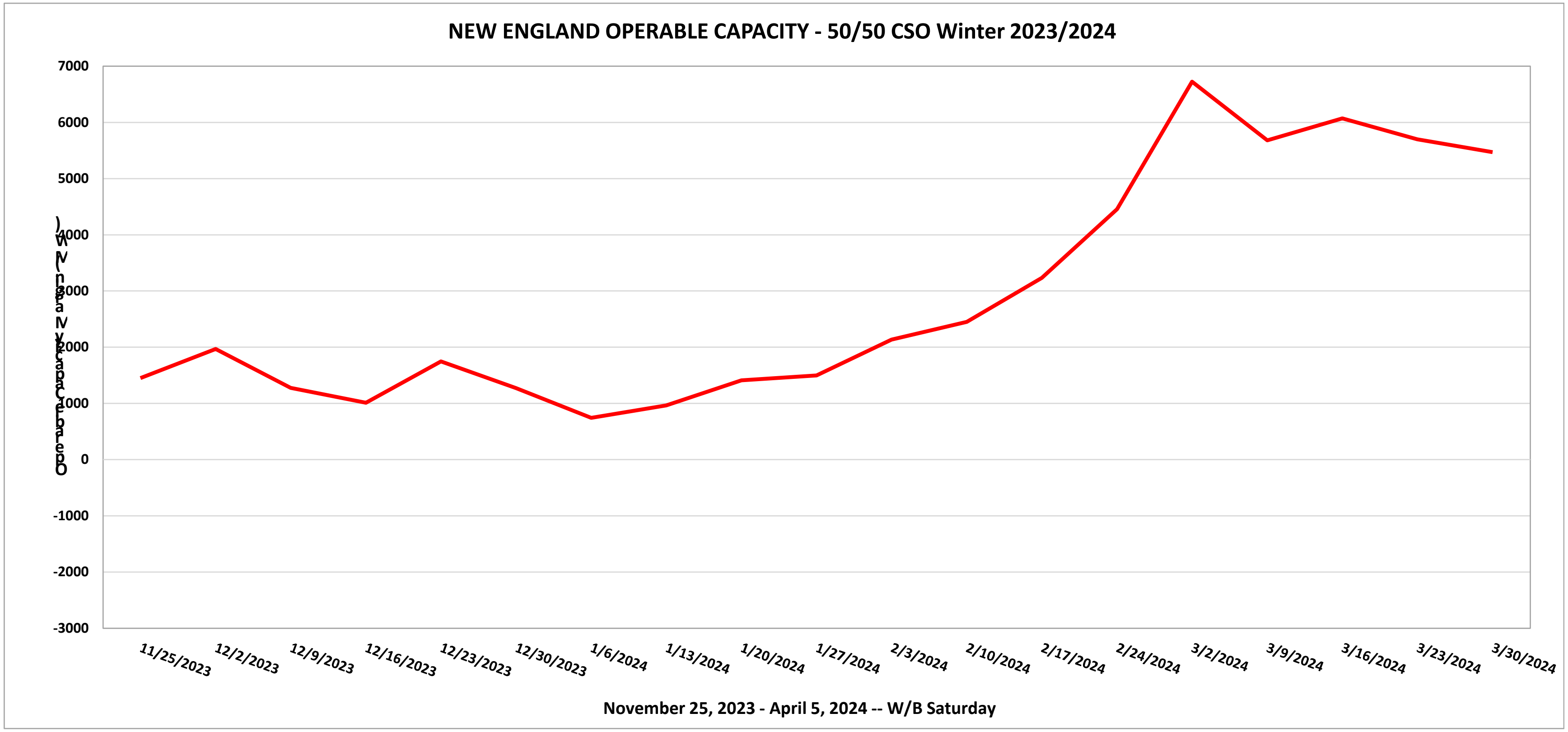
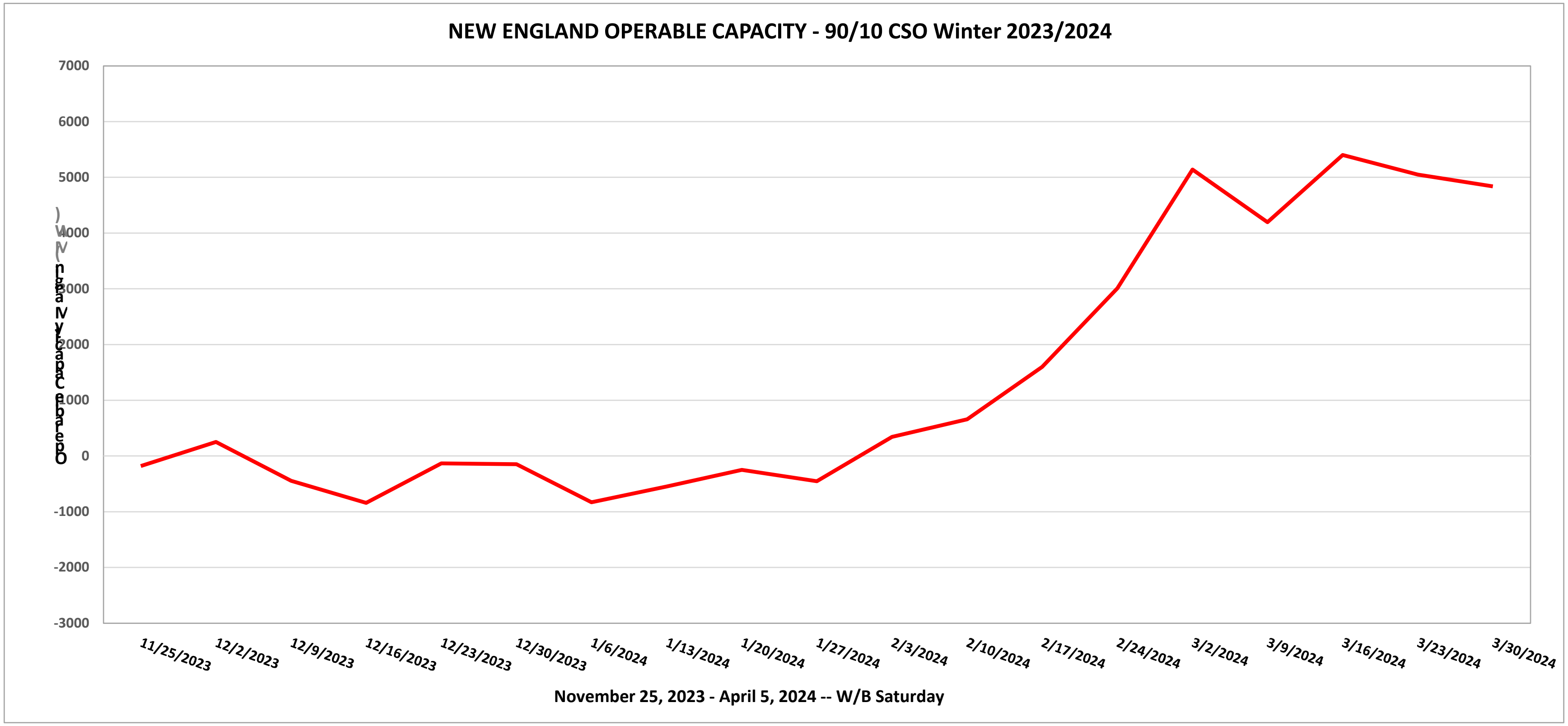
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline 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 2023 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**

Winter 2023/24 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2023/24 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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: October 26, 2023

RE: HQICC and ICR Values for Upcoming ARAs

At the November 2, 2023 Participants Committee meeting, you will be asked to vote on the values for (i) the Hydro-Quebec Interconnection Capability Credits (the HQICC Values); and (ii) proposed Installed Capacity Requirement (ICR) values, and the related demand curves (the ICR Values) to be used for the Annual Reconfiguration Auctions (ARAs) specified below.[1] At its October 23 meeting, the Reliability Committee voted in separate votes to recommend Participants Committee support for the HQICC Values and the ICR Values, with only one opposition.[2] Materials related to these votes have been included with this memo.[3] Given the vote outcome at the Reliability Committee, this item would have been on the Consent Agenda but for timing

HQICC Values for the 2024-25 3rd ARA, 2025-26 2nd ARA, and 2026-27 1st ARA

For the upcoming ARAs, ISO-NE and the Reliability Committee recommended the following **HQICC Values** for each month of the following three June 1 through May 31 Capacity Commitment Periods (CCPs):

- 2024-2025 CCP – 883 MW
- 2025-2026 CCP – 923 MW
- 2026-2027 CCP – 1,001 MW

ICR Values for the 2024-25 3rd ARA, 2025-26 2nd ARA, and 2026-27 1st ARA

ISO-NE and the Reliability Committee further recommended the following **ICR Values** for the specified ARAs:

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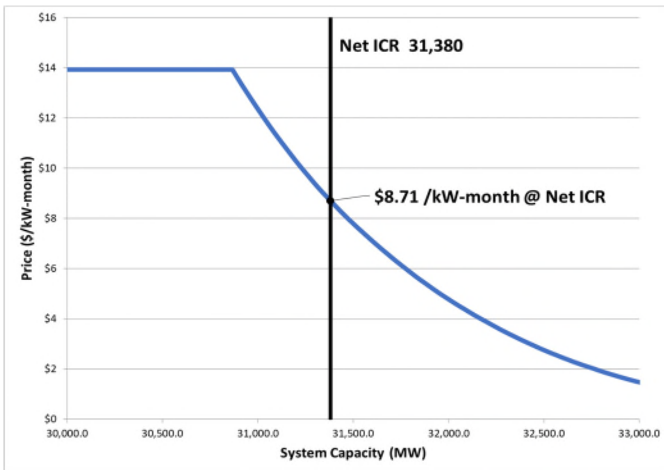
[1] The ARAs to which these ICR and HQICC values apply are, respectively: the Third ARA for the 2024-2025 Capacity Commitment Period; the Second ARA for the 2025-2026 Capacity Commitment Period; and the First ARA for the 2026-2027 Capacity Commitment Period.

[2] The HQICC Values and the ICR Values each passed on a show of hands vote at the Reliability Committee, with one opposed (Cross-Sound Cable Company opposed based on its long-standing objection to the lack of tie benefit value ascribed to Cross-Sound Cable in calculating tie benefits and the ICR) and several abstentions for each.

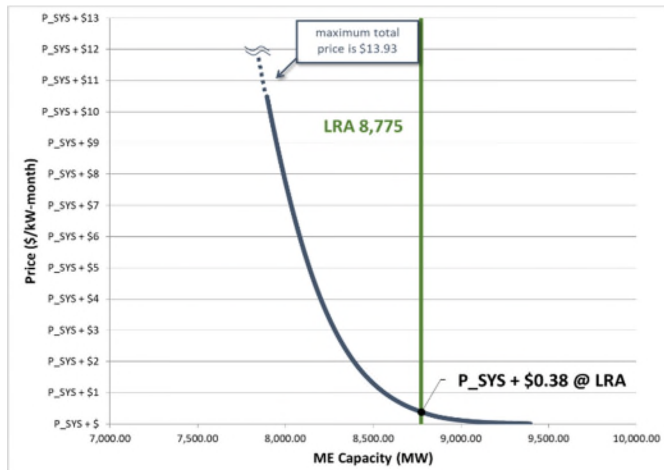
[3] The ISO-NE materials from the October 24 Reliability Committee meeting, including the ISO's presentations and spreadsheets containing values for the Marginal Reliability Impact (MRI) curves and the system and zonal demand curves to be used for the ARAs can be accessed here: https://www.iso-ne.com/static-assets/documents/100004/a06_hqiccs_icr_related_values_2024_aras.zip

3rd ARA for the 2024-25 CCP

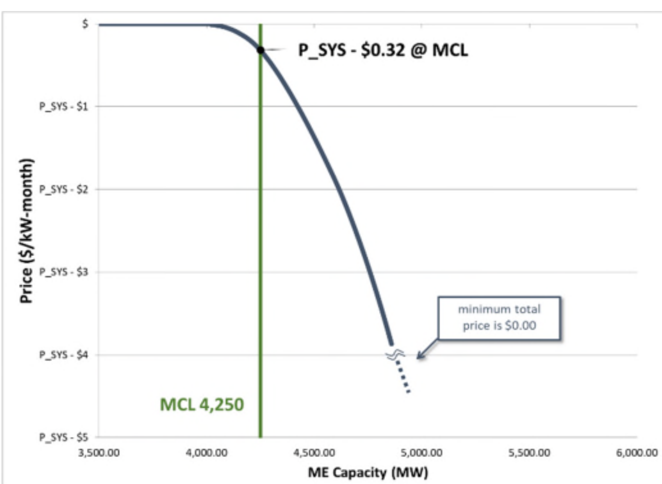
	2024-2025 ARA 3 ICR values (MW)
New England Installed Capacity Requirement (ICR)	32,263
Net ICR	31,380
Southeast New England (SENE) Local Sourcing Requirement (LSR)	8,775
Maine (ME) Maximum Capacity Limit (MCL)	4,250
Northern New England (NNE) MCL	8,900



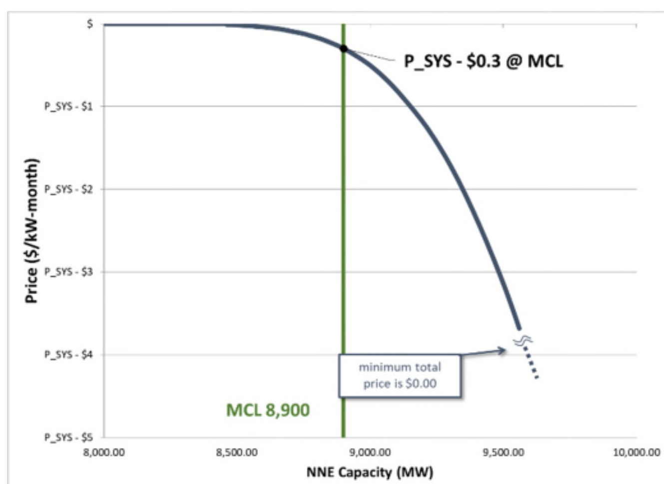
System-Wide Capacity Demand Curve
ARA 3, 2024-2025 CCP



SENE Import-Constrained Capacity Zone Demand Curve
ARA 3, 2024-2025 CCP



ME Export-Constrained Capacity Zone Demand Curve
ARA 3, 2024-2025 CCP

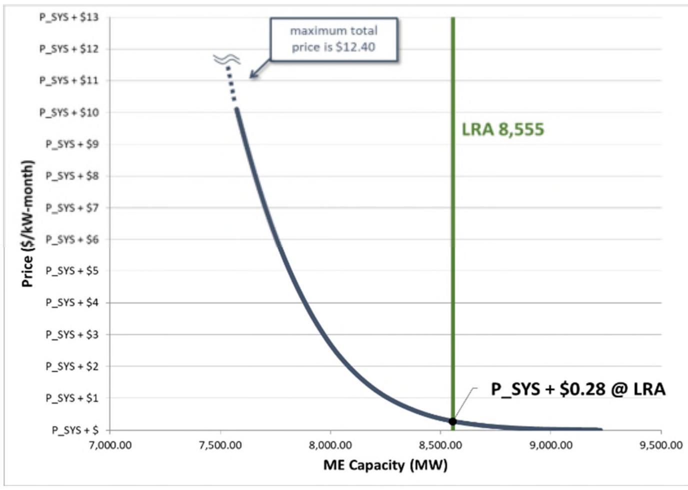


NNE Export-Constrained Capacity Zone Demand Curve
ARA 3, 2024-2025 CCP

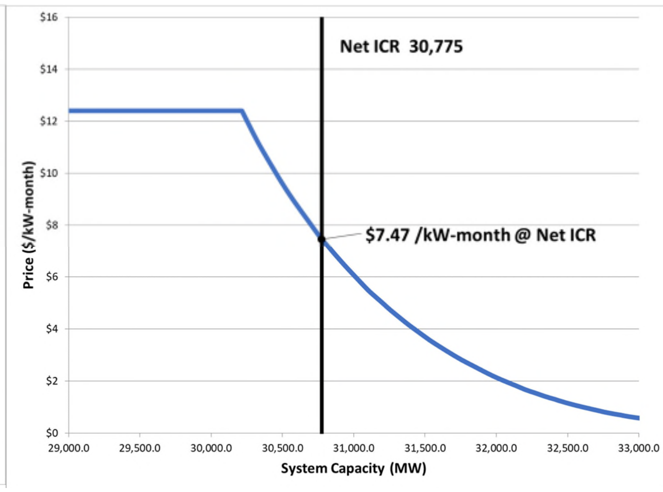
117042902.3

2nd ARA for the 2025-26 CCP

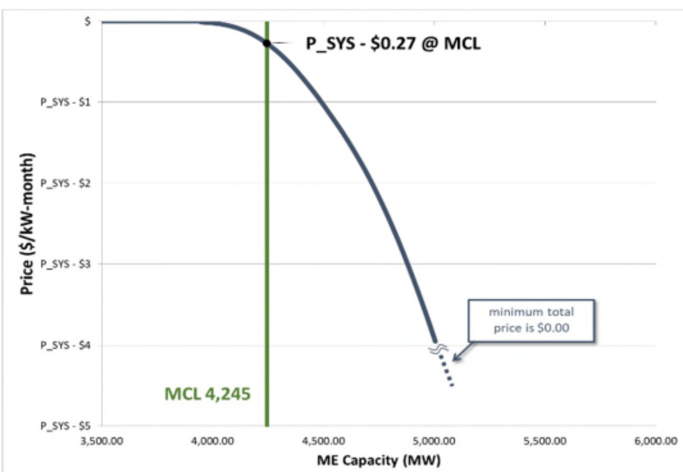
	2025-2026 ARA 2 ICR values (MW)
ICR	31,698
Net ICR	30,775
SENE LSR	8,555
ME MCL	4,245
NNE MCL	8,785



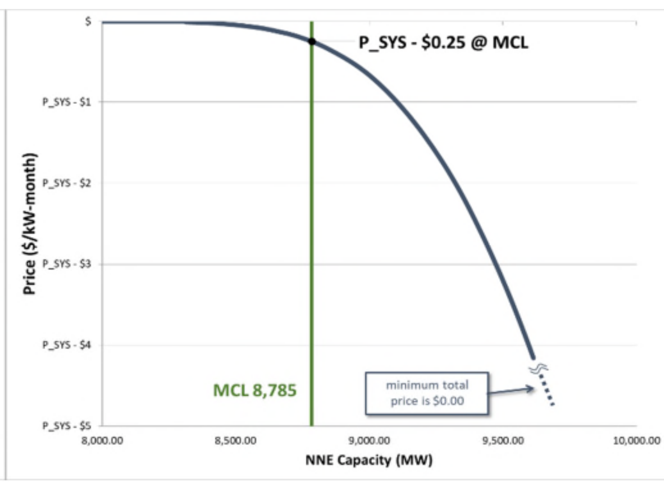
System-Wide Capacity Demand Curve
ARA 2, 2025-2026 CCP



SENE Import-Constrained Capacity Zone Demand Curve
ARA 2, 2025-2026 CCP



ME Export-Constrained Capacity Zone Demand Curve
ARA 2, 2025-2026 CCP

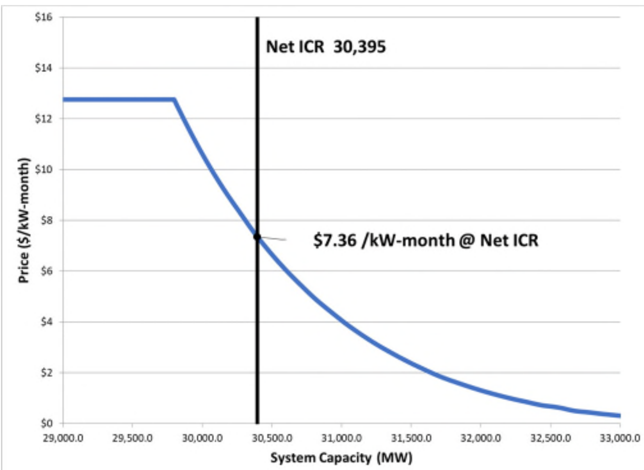


NNE Export-Constrained Capacity Zone Demand Curve
ARA 2, 2025-2026 CCP

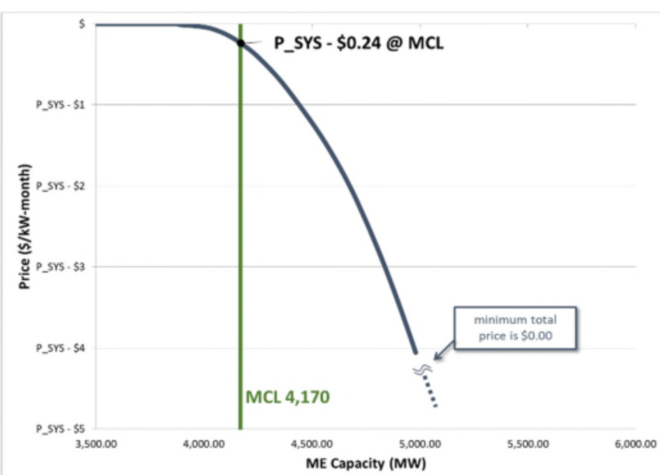
117042902.3

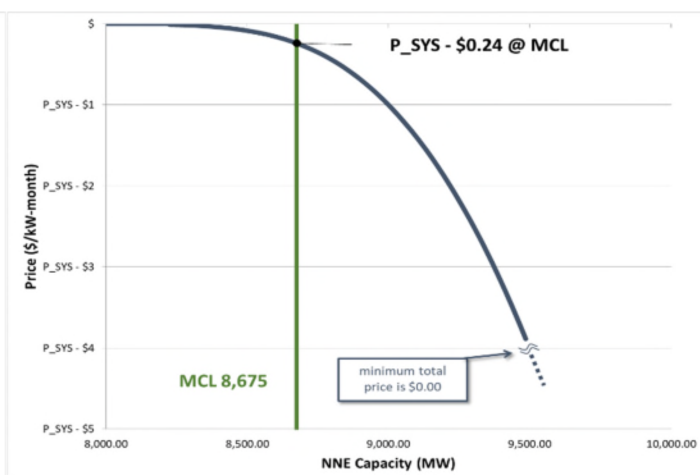
1st ARA for the 2026-27 CCP

	2026-2027 ARA 1 ICR values (MW)
ICR	31,396
Net ICR	30,395
ME MCL	4,170
NNE MCL	8,675



System-Wide Capacity Demand Curve
ARA 1, 2026-2027 CCP





ME Export-Constrained Capacity Zone Demand Curve
ARA 1, 2026-2027 CCP

NNE Export-Constrained Capacity Zone Demand Curve
ARA 1, 2026-2027 CCP

The following resolutions, which each require a minimum 60% Vote for approval, and which can be voted separately or together, can be used to act on the Reliability Committee's recommendations:

> RESOLVED, that the Participants Committee supports the proposed **HQICC Values** for the specified ARAs, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its November 2, 2023 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

> RESOLVED, that the Participants Committee supports the proposed **ICR Values** for the specified ARAs, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its November 2, 2023 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: October 26, 2023

RE: ISO-NE's Forward Capacity Auction 19 One-Year Delay Proposal

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At the November 2, 2023 Participants Committee meeting, you will be asked to vote on ISO-NE's proposed Market Rule 1 revisions to delay the nineteenth Forward Capacity Auction (FCA) by one year (FCA 19 Delay Proposal). This memorandum provides an overview of the Proposal and summarizes the stakeholder review process to date. But for timing, this item would have been placed on the Consent Agenda.

Included with this memorandum are the following materials:

- Attachment A: Markets Committee-recommended Tariff revisions
- Attachment B: ISO-NE's October 26, 2023 PowerPoint presentation
- Attachment C: ISO-NE's voting memorandum to the Markets Committee

BACKGROUND & OVERVIEW OF THE FCA 19 DELAY PROPOSAL

Regional stakeholders have spent considerable time and effort evaluating the ISO's Resource Capacity Accreditation (RCA) project. While the initial goal was to implement the new resource capacity accreditation method in time for FCA 19 (currently scheduled to be run in February 2025), due to a software error affecting the model used for the RCA project, the ISO paused the stakeholder discussions to assess the error. The ISO ultimately concluded that a sweeping modeling review was required and that a stopgap fix was unadvisable. As a result, the RCA project and associated implementation timeline has been pushed out. Given this delay, the ISO started soliciting stakeholder feedback on various options to determine the best path forward for the region. Based on feedback received from NEPOOL members and state officials, and its independent assessment, the ISO developed the FCA 19 Delay Proposal.

The FCA 19 Delay Proposal has five key components. First, the Tariff revisions delay FCA 19 qualification and auction activities by one year, i.e., FCA 19 would now be run in 2026. As ISO has explained, the additional year provides the additional time needed to develop and implement the RCA project's new accreditation methods in time for FCA 19. Second, the FCA 19 Delay Proposal incorporates a gradual transition to a forward auction construct, if necessary, over the course of FCAs 20 through 25 that would be run under a ten-month schedule. Third, the proposal eliminates the first annual reconfiguration auction (ARA) for FCAs 19 through 24 during the transition period. Fourth, the FCA 19 Delay Proposal includes Tariff provisions to permit specific resources to submit qualification materials in 2024 so those resources can qualify to participate in ARAs. Fifth, the Tariff revisions clarify when particular demand capacity resources can be considered as new capacity for FCA 19.

STAKEHOLDER PROCESS TO DATE

Over several months, the Markets Committee discussed and reviewed the FCA 19 Delay Proposal (as well as other potential options/approaches at a conceptual level). Ultimately, at its October 26 teleconference meeting, the Markets Committee considered Market Rule 1 revisions to implement ISO-NE's FCA 19 Delay Proposal, and based on a voice vote, recommended that the Participants Committee support the Proposal.[1]

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

> RESOLVED, that the Participants Committee supports the FCA 19 Delay Proposal as reflected in revisions to Section III.13 of the Tariff, as 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.

[1] Abstentions during the Markets Committee vote were recorded in the following Sectors: Generation (3); Supplier (5); Alternative Resources (1); and End User (1).

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

~~For the seventeenth Forward Capacity Auction (associated with the 2026-2027 Capacity Commitment Period), any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Inc. Transmission, Markets, and Services Tariff and all other ISO New England Operating Documents shall not apply. For the seventeenth Forward Capacity Auction, the ISO shall publish each date, date range, and/or deadline for Forward Capacity Auction activities as soon as practicable. The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities if needed and shall publish a revised date, date range and/or deadline as soon as practicable. The ISO shall establish and, as applicable, adjust, such published dates, date ranges and/or deadlines to provide reasonable advance notice of each date, date range, and/or deadline.~~

III.13.A Forward Capacity Market Interim Provisions.

III.13.A.1 Interim Forward Capacity Auction Schedules.

Notwithstanding any other any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Operating Documents, for the nineteenth, twentieth, twenty-first, twenty-second, twenty-third, twenty-fourth and twenty-fifth Forward Capacity Auctions (associated with the 2028-2029, 2029-2030, 2030-2031, 2031-2032, 2032-2033, 2033-2034, and 2034-2035 Capacity Commitment Periods, respectively), the following provisions apply.

For the nineteenth Forward Capacity Auction (associated with the 2028-2029 Capacity Commitment Period), the dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Operating Documents shall not apply and shall be delayed by one calendar year.

For the nineteenth, twentieth, twenty-first, twenty-second, twenty-third and twenty-fourth Forward Capacity Auctions (associated with the 2028-2029, 2029-2030, 2030-2031, 2031-2032, 2032-2033 and 2033-2034 Capacity Commitment Periods, respectively), the first annual reconfiguration auction as specified in Section III.13.4 that is typically held in the month of June, approximately 24 months before the start of the applicable Capacity Commitment Period, shall not be conducted.

For the twentieth, twenty-first, twenty-second, twenty-third, twenty-fourth and twenty-fifth Forward Capacity Auctions (associated with the 2029-2030, 2030-2031, 2031-2032, 2032-2033, 2033-2034, and 2034-2035 Capacity Commitment Periods, respectively), the Forward Capacity Auction, and the qualification process for each such auction, shall be conducted under a 10-month timeline in accordance with the key dates set forth in the schedule below. For each Forward Capacity Auction specified in the table below, the ISO shall publish the dates, date ranges and deadlines for activities related to the respective Forward Capacity Auction no later than six months before the applicable notification to Lead Market Participants of their Existing Capacity Resource's summer Qualified Capacity and winter Qualified Capacity values as specified in Section III.13.1.2.3(a).

Capacity Commitment Period	**Forward Capacity Auction Date**	**Revised annual reconfiguration auction Dates (as applicable)**
2029-2030	December 2026	Second annual reconfiguration auction August 2028; third annual reconfiguration auction March 2029
2030-2031	October 2027	Second annual reconfiguration auction August 2029; third annual reconfiguration auction March 2030
2031-2032	August 2028	Second annual reconfiguration auction August 2030; third annual reconfiguration auction March 2031
2032-2033	June 2029	Second annual reconfiguration auction August 2031; third annual reconfiguration auction March 2032
2033-2034	April 2030	Second annual reconfiguration auction August 2032; third annual reconfiguration auction March 2033

2034-2035	February 2031	Regular annual reconfiguration auction schedule applies.

The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities by 10 Business Days if needed, and shall publish a revised date, date range and/or deadline no later than 30 days in advance of such adjustment.

III.13.A.2. Interim Reconfiguration Auction Qualification.

Notwithstanding any other provision of the ISO New England Operating Documents, a New Capacity Resource that has not already acquired a Capacity Supply Obligation and intends to achieve Commercial Operation as defined in Section III.13.1.1.2.2.2(h) before June 1, 2026, may qualify for the annual reconfiguration auction, monthly reconfiguration auction and bilateral activities described in Section III.13.4 and Section III.13.5 under this section providing the following conditions are met:

(1) The Project Sponsor submits qualification materials as described in Section III.13.1, including a New Capacity Show of Interest Form in April 2024 and a New Capacity Qualification Package in June 2024. The ISO shall post a list of the required materials on its website and a complete schedule for their submittal at least 60 days in advance; and

(2) The Project Sponsor requests that the ISO monitor the New Capacity Resource's compliance with its critical path schedule as described in Section III.13.3.1.1 by November 1, 2024.

III.13.A.3. Interim Provisions Regarding Demand Capacity Resources.

Notwithstanding any other provision of the ISO New England Operating Documents, for the nineteenth Forward Capacity Auction (associated with the 2028-2029 Capacity Commitment Period), a New Demand Capacity Resource is an Active Demand Capacity Resource that has not cleared in a previous Forward Capacity Auction, or an On-Peak Demand Resource consisting of measures that have not been in service prior to June 1, 2024, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to June 1, 2024.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4) or a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (Section III.13.1.4A). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, Existing Distributed Energy Capacity Resource, New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, and New Distributed Energy Capacity Resource.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit. The Lead Market Participant for a resource participating in a Forward Capacity Auction may not change in the 15 Business Days prior to, or during, that Forward Capacity Auction.

Forward Capacity Auction 19 (FCA 19) One Year Delay

Proposed design and additional Tariff redlines

Al McBride

DIRECTOR, TRANSMISSION SERVICES AND RESOURCE QUALIFICATION

FCA 19 One Year Delay

WMPP ID: 176

Proposed Effective Date: January 2024

- At the June PC and July and August MC meetings, the ISO reviewed the objectives and considerations for whether the Resource Capacity Accreditation (RCA) project should be included in Capacity Commitment Period 19 (CCP 19) and sought stakeholder feedback
- At the September MC meeting, the ISO introduced its proposed approach to moving forward with RCA for CCP 19
  - Option 2A: Plan to implement RCA for FCA 19 for CCP 19, **with the auction held in 2026**; by Q1 2024 decide whether to implement prompt auctions starting with CCP 19 in early 2028; with continued discussions beginning in late 2024 on implementing as prompt/seasonal auctions starting in early 2028
- At the October 12 MC meeting, the ISO reviewed the proposed design for delaying FCA 19 by one-year (2026) as well as the proposed Tariff redlines
- The focus of this presentation is to describe two additions to the proposal in response to stakeholder feedback

Two Additional Inclusions in the Proposal

In response to stakeholder feedback, the ISO is including two additional components in the design to address qualification concerns associated with a one-year delay of FCA 19:

- In order to continue qualifying new resources with early commercial operations dates for reconfiguration auction activities for earlier Capacity Commitment Periods (e.g. ARA 3 for CCP 2025-26 and the associated monthly auctions), resources that do not yet have a Capacity Supply Obligation may submit qualification materials
  - Using the same calendar of activities that would have been used to conduct FCA 19 qualification under the current schedule
- The current rules tie the definition of new On-Peak and Seasonal-Peak Demand Resources to measures installed after the Existing Capacity Qualification Deadline
  - This deadline would shift by a year with the delay of FCA 19
    - Creating concern that a year's worth of measures will lose the ability to qualify in FCA 19
  - Therefore, the ISO is proposing that for FCA 19, a New Demand Capacity Resource will include an On-Peak Demand Resource consisting of measures that have not been in service prior to June 1, 2024, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to June 1, 2024

Summary of Proposed Tariff Changes

Tariff Section	Tariff Change	Reason for Change
III.13	Deleting language applicable to FCA 17 schedule changes	No longer needed
III.13	New language explaining FCA 19 (CCP 2028-2029) will be delayed by one year	Delay FCA 19 by 1 year
III.13	New language explaining that FCAs 20-25 (CCPs 2029-2034) will run on a 10-month schedule	Incorporate transition back to 3.5 year forward auction
III.13	New language explaining that for FCAs 19-24, the ISO will not run ARA 1 (there will only be two ARAs prior to each CCP)	Eliminate ARA 1, as needed, during transition back to 3.5 year forward auction
III.13.A.2	New language allowing for submittal of qualification materials in 2024 for resources with early in-service dates	Enable qualification for earlier reconfiguration auctions
III.13.A.3	New language adjusting the timing of measures associated with New Demand Resources	Enable continued qualification of installed measures
III.13	New language explaining that the ISO may adjust FCA activity dates by 10 business days with at least 30 days notice	Incorporate flexibility to revise FCA activity dates

Conclusion

- The ISO is preparing to implement RCA for CCP 19 with the auction delayed to 2026, while continuing to evaluate plans for developing proposals moving to prompt and then seasonal auctions for CCP 19 and beyond
- The ISO proposes to delay FCA 19 implementation by one year and compress the typical year-long FCA qualification cycle by two months for FCAs 20-24 resulting in a 10 month timeline
  - FCA 25 would be conducted according to the typical 12 month timeline
- The ISO has made two additions to the proposal to address qualification concerns associated with a one-year delay of FCA 19
- The proposed effective date for these revisions is January 2024

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee **September 12-13, 2023**	Introduction
Markets Committee **October 11-12, 2023**	Review proposed Market Rule 1 revisions
Markets Committee **October 26, 2023**	Review additional Market Rule 1 revisions and vote
Participants Committee **November 2, 2023**	Vote

Parallel Stakeholder Processes

- While the ISO continues to evaluate plans of moving to prompt and/or seasonal auctions for CCP 19 and beyond, it is preparing to implement RCA for CCP 19 with the auction delayed to 2026
- Below are the parallel stakeholder processes associated with these FCA 19-related efforts

	2023			2024											
	Q4			Q1			Q2			Q3			Q4		
	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
RCA Forward, Annual (for FCA 19 if delayed)	Refresher	Conceptual and Detail Design					Final Design, Review Tariff, and Amendments			MC/RC Vote	PC Vote File			Eff. Date	
FCA 19 One-Year Delay	Review Tariff	MC Vote PC Vote File		Eff. Date											
Alternative FCM Commitment Horizons	Analysis - Scope, Methodology, and Findings			ISO recommendation on whether to develop prompt proposal											

Questions

Al McBride
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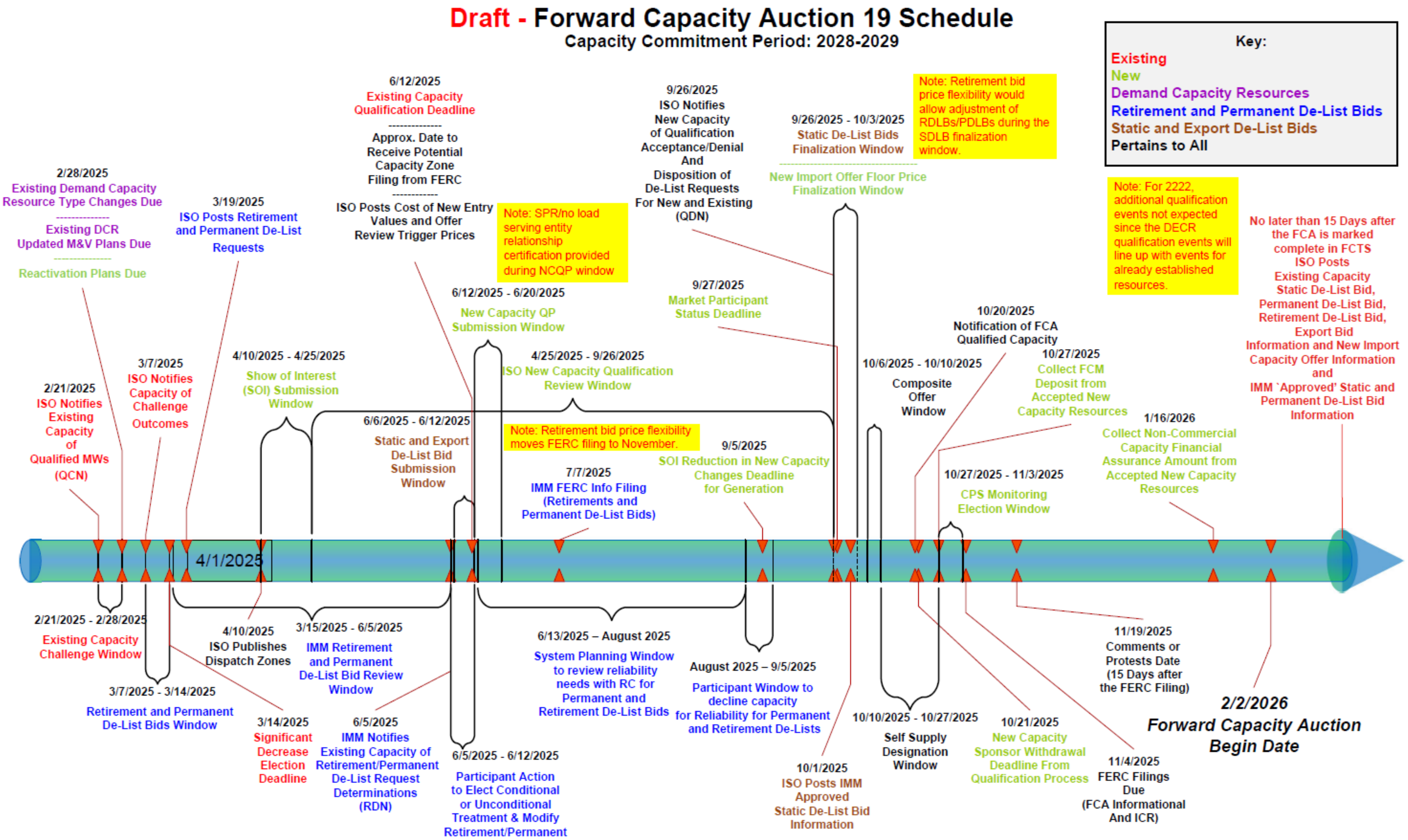
APPENDIX

ISO's Approach to Proceeding with Option 2A

- Prepare to implement RCA for CCP 19 with the auction delayed to 2026, while continuing to evaluate plans for moving to prompt and then seasonal auctions for CCP 19 and beyond
  1. Prepare proposed schedule to delay FCA 19 implementation by one year (the focus of this presentation)
  2. Continue design discussions for RCA implementation
  3. Continue assessing whether to develop a proposal for a prompt auction for CCP 19
     - Target Q1 2024 to decide whether to develop proposal for prompt auctions starting with CCP 19 in early 2028
       – Continue discussions later in 2024 on developing proposal for implementing prompt/seasonal auctions starting in early 2028

- The ISO would operationalize this by making an **initial filing** to FERC by the end of the year suspending the current timing for FCA 19, while including a backstop schedule for FCA 19 that is delayed by one year
  – The filing would indicate that the ISO would make a **second filing** in Q2/Q3 2024, after additional stakeholder discussion, either with:
    - Additional tariff changes needed to effectuate a one-year delay (this option would currently be expected to include the RCA design); or
    - A new schedule to effectuate a prompt capacity auction for CCP 19 in 2028 (detailed design would follow)

Timeline for FCA 19 Cycle with One Year Delay



memo

To: NEPOOL Markets Committee ("MC")

From: Alan McBride, Director – Transmission Services & Resource Qualification

Date: October 23, 2023

Subject: Forward Capacity Auction 19 ("FCA 19") One Year Delay (WMPP ID: 176)

The ISO is requesting a vote on proposed revisions to Section III.13 of Market Rule 1 to delay FCA 19 by one year. This proposal is part of the ISO's proposed approach to moving forward with the Resource Capacity Accreditation ("RCA") project for Capacity Commitment Period 19 ("CCP 19").

By way of background, at the June PC and July and August MC meetings, the ISO reviewed objectives and considerations regarding whether RCA should be included in CCP 19. At the September MC, the ISO introduced its proposed approach to moving forward with RCA for CCP 19, which includes delaying FCA 19 by one year. This approach emerged as a result of stakeholder discussions as a workable hybrid to provide additional time to continue developing and planning for the implementation of RCA while considering the key tradeoffs of prompt and/or seasonal auction constructs.

The proposed Market Rule 1 revisions delay the FCA 19 qualification and auction activities by one year and incorporate a gradual transition back to a 3.5 year forward auction over the course of FCAs 20-25 should that be necessary. [1] In addition, the ISO has proposed to eliminate the first Annual Reconfiguration Auction (ARA) for CCPs 19-24 during the transition period back to a 3.5 year forward auction.

Since the October 11-12 MC meeting, the ISO has incorporated Tariff revisions to address stakeholder feedback and accommodate concerns regarding the ability to qualify resources to participate in Annual Reconfiguration Auctions and clarified the associated date by which energy efficiency measures can be considered as new capacity for FCA 19 with a one year delay.

The proposal for the committee's consideration at its October 26, 2023 meeting has been presented previously to the Markets Committee at the meeting dates outlined below.

- September 12-13, 2023, agenda item #5A
- October 11-12, 2023, agenda item #10

[1] The ISO's proposed approach to moving forward with RCA for CCP 19 includes planning to implement RCA for FCA 19 for CCP 19, with the auction held in 2026; by Q1 2024 the ISO will decide whether to develop a proposal to implement prompt auctions starting with CCP 19 in early 2028; if ISO does decide to develop such a proposal, there will be continued discussions beginning later in 2024 on detailed designs for implementing prompt/seasonal auctions starting in early 2028.

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memo

To: Participants Committee

From: James Woods, Secretary, Markets Committee

Date: October 26, 2023

Subject: Actions of the Markets Committee

This memo is notification to the Participants Committee of the following actions taken by the Markets Committee (MC) at the October 26, 2023 MC meeting. A quorum was established.

Agenda Item No. 2.0 – Forward Capacity Auction 19 (FCA 19) One-Year Delay

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the proposed revisions to Section III.13 of Market Rule 1 to delay the FCA 19 qualification and auction activities by one year and incorporate a gradual transition back to a 3.5 year forward auction over the course of FCAs 20-25, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a voice vote, was approved with five abstentions in the Supplier sector, three abstentions in the Generation sector, one abstention in the End User Sector, and one abstention in the Alternative Resources sector.

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of November 1, 2023

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated October 3, 2023 ("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

No Activities to Report

II. Rate, ICR, FCA, Cost Recovery Filings

*	5	2024 NESCOE Budget (ER23-91)	Oct 13	ISO-NE files materials for funding NESCOE's 2024 operations; comment date ***Nov 3, 2023***
			Oct 13-30	NESCOE, National Grid, NEPOOL intervene
*	5	2024 ISO-NE Administrative Costs and Capital Budgets (ER24-90)	Oct 13	ISO-NE files its 2024 administrative costs and capital budgets; comment date ***Nov 3, 2022***
			Oct 24-31	NEPOOL, National Grid, NESCOE, MA DPU intervene
			Oct 31	NEPOOL files comments supporting ISO-NE 2024 Budgets
*	6	Essential Power Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER24-80)	Oct 12	Essential Power Newington requests recovery of ***$276,421*** in CIP-IROL Costs incurred between Ju1 1, 2022 and Jun 30, 2023; comment deadline ***Nov 2, 2023***
			Oct 13-24	National Grid, NESCOE file doc-less motions to intervene
	6	Stonepeak Kestrel CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-2429)	Oct 16	FERC accepts revisions allowing for recovery of ***$1,483,297*** in eligible CIP-IROL Costs, *eff. Sep 16, 2023*
	7	Bucksport Generation (Schedule 17) Section 205 Cost Recovery Filing (ER23-2428)	Oct 13	FERC accepts revisions allowing for recovery of ***$251,419*** in eligible CIP-IROL Costs, *eff. Sep 29, 2023*
	8	**Mystic 8/9 COSA (ER18-1639)**		
	8	(-025) First CapEx Settlement Agreement Tariff Sheets Filing	Oct 27	FERC accepts Tariff Sheets Filing, *eff. Jun 1, 2022*
	8	(-024) Mystic I Order on Remand Modification Order	Oct 6	FERC issues an order modifying the discussion in the *Mystic I Order on Remand* and setting aside that *Order*, in part
	9	(-000) Public Systems' Request for Disclosure of Audit Information	Oct 6	FERC denies Public Systems' request
	9	(-018) Second CapEx Info Filing	Oct 20	NESCOE provides notice of withdrawal of its Formal Challenge No. III.B to the Second CapEx Info Filing related to support for the property tax component of the AFRR

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

*	12	DASI Proposal (ER24-275)	Oct 31	ISO-NE and NEPOOL jointly file DASI changes; comment deadline ***Nov 21, 2023***
			Nov 1	HQUS, Public Citizen intervene
*	12	ISO/RTO Credit-Related Information Sharing (ER24-138)	Oct 18	ISO-NE and NEPOOL jointly file changes; comment deadline ***Nov 8, 2023***

*	12	Effective Date Deferral – Binary Storage Facility DARD Regulation (ER24-115)	Oct 16	ISO-NE requests that the effective date be deferred for the implementation of provisions permitting Battery Storage Facilities to offer Regulation when acting as a DARD; comment deadline ***Nov 6, 2023***
			Oct 18	NEPOOL, Calpine intervene
	12	IEP Parameter Updates (ER23-1588)	Oct 6	FERC issues *IEP Parameter Updates Allegheny Notice*, denying PIOs request for reh'g by operation of law
	13	SATOA Revisions (ER23-739; ER23-743)	Oct 19	FERC accepts SATOA Revisions; notice of Revisions' actual effective date to be filed no less than 30 days prior to implementation (currently projected to be *Jul 1, 2024*)
	13	New England's *Order 2222* Compliance Filing (ER22-983)	Oct 6	FERC issues an Allegheny Order on the requests for clarification and/or reh'g of its Mar 1, 2023 *Order 2222 Compliance Order*

IV. OATT Amendments / TOAs / Coordination Agreements

*	16	UI Att. F App. D Depreciation Rate Changes (ER24-272)	Oct 31	UI files changes to incorporate revised depreciation rates used to calculate UI's annual transmission revenue requirements; comment deadline ***Nov 7, 2023***
*	16	National Grid Attachment F App. A PBOP Fixed Expense Revisions (ER24-125)	Oct 17	National Grid files revisions to Appendix A to Attachment F to update NEP's fixed expense amount for transmission-related PBOP; comment deadline ***Nov 7, 2023***
	16	Attachment F Corrections & Updates (ER23-2940)	Oct 5, 10	RI Energy, National Grid intervene
			Oct 19	Public Systems file comments supporting corrections and updates
	16	Versant Power Att. F App. D Depreciation Rate Change (ER23-2483)	Oct 4	FERC accepts change, eff. *Jan 1, 2025*
	17	*Order 676-J* Compliance Filings Part II (ER23-1771; ER23-1774; ER23-1782; ER23-1785)	Oct 26	FERC accepts each of the *Order 676-J* Compliance Filings Part II, eff. *Feb 1, 2024*, directing compliance filings by ISO-NE/NEPOOL and Versant, by ***Nov 27, 2023***, to include in their tariff records the citation to their orders granting the waivers requested

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

*	18	Schedule 21-VP: Versant/Jonesboro LSA (ER24-24)	Oct 4	ISO-NE and Versant file a LSA by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro
*	18	Schedule 21-ES: PSNH /Great Lakes Hydro IA Termination (ER24-17)	Oct 4	Eversource files notice of termination of superseded IA
*	19	Schedule 21-GMP: Annual True Up Calculation Informational Filing (ER12-2304)	Oct 30	GMP submits annual info filing containing true-up calculation of its actual costs for the 2022 Service Period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

*	20	Capital Projects Report - 2023 Q3 (ER24-94)	Oct 13 Oct 24-25 Oct 31	ISO-NE files 2023 Q3 Report; comment deadline ***Nov 3, 2023*** National Grid, NEPOOL intervene NEPOOL files comments supporting 2023 Q3 Report
	20	Capital Projects Report - 2023 Q2 (ER23-2620)	Oct 4	FERC accepts Q2 Report, eff. *Jul 1, 2023*
*	20	LFTR Implementation: 60th Quarterly Status Report (ER07-476)	Oct 13	ISO-NE files its 60th quarterly report
*	20	IMM Quarterly Markets Reports - 2023 Summer (ZZ24-4)	Oct 27	IMM files Summer 2023 Report

IX. Membership Filings

*	21	Nov 2023 Membership Filing (ER24-276)	Oct 31	***New Members:*** BlueWave Public Benefit Corp.; Flatiron Energy Capital; Glenvale; New England Power and Light; Precept Power; and Wallingford Energy; ***Name Changes:*** Blueprint Power Technologies LLC and PSE US Holdings Inc. (f/k/a AMP Solar US Holdings Inc.); comment deadline ***Nov 21, 2023***
	21	Sep 2023 Membership Filing (ER23-2756)	Oct 27	FERC accepts the following NEPOOL memberships: Phoenix Energy Group (Supplier Sector); 3Degrees Group, Inc. (GIS-Only Participant); (ii) the termination of the Participant status of: Just Energy (U.S.); NRG Power Marketing, Norwalk Power and Somerset Power; and WP&G Holdings; and (iii) the name change of NRG Business Marketing, LLC (f/k/a Direct Energy Business Marketing, LLC)

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

*	22	*Order 901*: IBR Reliability Standards (RM22-12)	Oct 19	FERC issues *Order 901*; informational filing due ***Jan 19, 2024***
	22	Changes to NERC ROPs (RR23-4)	Oct 6	APPA, LPPC and TAPS submit joint comments
	23	2024 NERC/NPCC Business Plans and Budgets (RR23-3)	Oct 19	FERC accepts NERC's 2024 proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2024
	23	Report of Comparisons of 2022 Budgeted to Actual Costs for NERC and the Regional Entities (RR23-2)	Oct 26	FERC accepts NERC's annual comparisons of actual to budgeted costs for 2022 for NERC and its 6 Regional Entities

XI. Misc. - of Regional Interest

	23	203 Application: Energy Harbor / Vistra (EC23-74)	Oct 10 Oct 13 Oct 20	OH OCC, NOPEC, PJM IMM protest/comment on Deficiency Letter Response FERC tolls deadline to act on Application to ***Apr 11, 2024*** Vistra/Energy Harbor answer Oct 10 protests/comments
*	24	PURPA Enforcement Petition: Allco Finance Ltd (VT PUC) (EL23-92)	Oct 13	FERC issues a notice of its intent not to initiate an enforcement action in response to the Allco VT PUC PURPA Complaint
*	24	CL&P / WE 400 Groton Road D&E Agreement (ER24-303)	Nov 1	Eversource files D&E Agreement in connection with the interconnection of WE 400 Groton Road's 50 MW-load data; comment deadline ***Nov 22, 2023***
*	24	NSTAR-ENE Use Rights Transfer Agreement (ER24-269)	Oct 31	NSTAR files for acceptance an Agreement with ENE for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities

25	D&E Agreement Amendment: PSNH/NECEC (ER23-2645)	Oct 13	FERC accepts amendment, eff. *Aug 18, 2023*
25	MPD OATT Changes to Depreciation Rates (ER23-2085)	Oct 19	FERC accepts changes, eff. *Jun 1, 2024*
25	LSAs: RI Energy/ISO-NE/BIPCO (ER23-1003; ER23-1000)	Oct 23	RIE files amendments to the LSAs; comment deadline Nov 13, 2023

XII. Misc. - Administrative & Rulemaking Proceedings

26	ACPA Petition for Capacity Accreditation Tech Conf(AD23-10)	Oct 18-19	ACPA, PJM IMM answer Oct 2 comments
* 26	Reliability Technical Conference (AD23-9)	Oct 10 Oct 30	SPP IMM submit comments FERC issues Second Supplemental Notice of Technical Conference; ISO-NE submits pre-tech conf comments
27	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Oct 18	NARUC nominates PA PUC Vice Chair Kimberly Barrow to serve out the remainder of Joseph L. Fiordaliso's one-year term
28	*Order 897*: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)	Oct 25	ISO-NE and TOs submit 51-page Report
29	*Order 2023*: Interconnection Reforms (RM22-14)	Oct 25	FERC issues an order that extends the *Order 2023* compliance filing deadline to ***Apr 3, 2024***

XIII. FERC Enforcement Proceedings

Natural Gas-Related Enforcement Actions

* 33	AES Alamitos and AES Redondo Beach (IN23-15)	Oct 24	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into AES's submission of inaccurate data to CAISO; AES must ***disgorge $2.97 million*** to CAISO, pay a ***$1.2 million civil penalty***, and submit to OE compliance monitoring

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

37	*Order 2222* Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170)(consolidated)	Oct 10 Oct 12	FERC asks for further 90-day abeyance Court grants FERC request; motions to govern future proceedings due ***Jan 24, 2024***
38	Seabrook Dispute Order (23-1094, 23-1215) (consol.)	Oct 12 Oct 26 Oct 30	Intervenors for Respondent file Joint Brief NextEra files Reply Brief NextEra files Joint Appendix
39	Mystic II (ROE & True-Up) (21-1198 *et al.*) (consol.)	Oct 25 Oct 26	Constellation proposes continued abeyance for an additional 90 days Court orders cases to remain in abeyance; parties directed to file motions to govern future proceedings by ***Jan 24, 2024***
41	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.)	Oct 27	Petitioners ask that each of the consolidated cases be dismissed voluntarily

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, 2023

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, 2023. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **Brookfield IEP Complaint (IEP Exclusion of Pumped Storage ESFs) (EL23-89)**

On September 21, 2023, the FERC granted the complaint filed by Brookfield Renewable Trading and Marketing LP ("Brookfield") regarding the exclusion of pumped storage hydroelectric facilities that are Electric Storage Facilities ("ESFs") from the Inventoried Energy Program ("IEP").[2] In granting the Complaint, effective August 2, 2023, the FERC found "pumped storage [ESFs] are similarly situated to battery storage [ESFs] for purposes of participation in the [IEP] … [agreed] with Brookfield that the ISO-NE Tariff is unduly discriminatory because it prohibits pumped storage [ESFs] from similarly participating in the [IEP]".[3] Accordingly, the FERC ordered ISO-NE to revise its Tariff. Any challenges to the *Brookfield IEP Complaint Order* are due on or before October 23, 2023. The changes to the Tariff in response to the *Order* were supported by the Markets Committee and will be voted by the Participants Committee at the November 2, 2023 meeting (Consent Agenda Item #3). If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Proceeding: ISO Market Power Mitigation Rules (EL23-62)**

As reported below, this Section 206 proceeding, instituted by the FERC on May 5, 2023 (pursuant to its finding that the existing ISO-NE Tariff provisions related to the mechanics of its market power mitigation and the consideration of any proposed fuel price adjustment, may be unjust and unreasonable),[4] is being held in abeyance. Parties to this proceeding include: NEPOOL, Calpine, Connecticut Office of Consumer Counsel ("CT OCC"), Massachusetts ("MA") Attorney General ("MA AG"), NEPGA, New England States Committee On Electricity

[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] *Brookfield Renewable Trading and Marketing LP v. ISO New England Inc.*, 184 FERC ¶ 61,169 (Sep. 21, 2023) ("*Brookfield IEP Complaint Order*").

[3] *Id.* at P 31.

[4] *Dynegy Marketing and Trade, LLC and ISO New England, Inc.*, 183 FERC ¶ 61,091 (May 5, 2023) ("*Dynegy Mitigation Order*"). In the Dynegy Mitigation Order, ISO-NE was directed 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 discriminatory. The refund effective date for this proceeding is May 12, 2023.

(NESCOE"), Public Systems,[5] Electric Power Supply Association ("EPSA"), MA Department of Public Utilities ("MA DPU"), Maine Public Utilities Commission ("MPUC"), and Public Citizen.

Being Held In Abeyance. On July 14, 2023, the FERC granted ISO-NE's June 28, 2023 motion, supported by NEPOOL on July 5, 2023, requesting that the FERC hold this proceeding in abeyance to allow potential ISO-NE Tariff design changes to be vetted through the Participant Processes. Changes in response to the *Dynegy Mitigation Order* are to be voted by the Participants Committee at its November 2, 2023 meeting (Consent Agenda Item #2). The FERC stated that it would not take any action on this 206 proceeding before ***February 1, 2024***.

If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)**

The December 13, 2022 complaint by RENEW Northeast, Inc. ("RENEW") against ISO-NE and the Participating Transmission Owners ("PTOs"), which seeks changes to the ISO-NE Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to Interconnection Customers,[6] remains pending before the FERC. As previously reported, the proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee at its October 26, 2021 meeting, and were discussed at the Participants Committee's November 3, 2021 meeting. RENEW asked the FERC to issue an order granting the Complaint by April 14, 2023 (approximately 60 days prior to the June 15, 2023 deadline for the NE PTOs to publish a draft of the Annual Update to the data used in the transmission formula rate). Both of those dates have since passed.

Responses, comments and protests were filed in late January 2023 by ISO-NE (which alternatively moved to dismiss itself as a party ("ISO-NE Jan 19 Motion")), the PTO AC, NEPOOL, AEU/Clean Energy Council, CPV Towantic, Glenvale, MA AG, NECOS, NEPGA, and NESCOE. Doc-less interventions only were filed by Calpine, CMMEC, EMI, Eversource, Narragansett ("RI Energy"), National Grid, New Leaf Energy, NextEra, NRG, Versant, CT DEEP, MA DPU, the American Clean Power Association ("ACPA"), Solar Energy Industries Association ("SEIA"), and Public Citizen. In additional rounds of briefing, RENEW answered ISO-NE's Jan 19 Motion; RENEW, the PTO AC, and National Grid filed answers to the January 23 protests/comments; ISO-NE answered RENEW's February 7 answer; and CPV Towantic, Glenvale, and the MA AG filed answers to the February 7 answers. There was no activity since the last Report. As noted, this matter remains pending before the FERC. If you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@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,[7] set the TOs' Base ROE at 10.57%

[5] "Public Systems" for purposes of this proceeding are, collectively: the Connecticut Municipal Electric Energy Cooperative ("CMEEC"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), New Hampshire Electric Cooperative ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

[6] RENEW also requested (i) that it be considered an Interested Party or afforded adequate opportunity to participate and access transmission rate information under the PTOs' Formula Rate Protocols and (ii) the PTOs be directed to provide greater transparency regarding O&M costs in the interconnection process.

[7] 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*").

(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*).[8] However, the FERC's orders were challenged, and in *Emera Maine,*[9] the U.S. Court of 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)[10] and third (EL14-86)[11] 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.[12] 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[13] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[14] 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

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[8] *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*").

[9] *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).

[10] 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%.

[11] 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 r educe 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.

[12] *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*").

[13] 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 FER C established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on Septem ber 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held Decemb er 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.

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

FPA.[15] 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.[16] 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*[17] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[18]

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%.[19] 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

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

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

[17] *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 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*.

[18] *Id.* at P 19.

[19] *Id.* at P 59.

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[20] 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 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*[21] 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

- **2024 NESCOE Budget (ER24-91)**

This proceeding was initiated by ISO-NE's October 13, 2023 filing of the budget for funding NESCOE's 2024 operations. The 2024 Operating Expense Budget for NESCOE is $2,596,014. The amount to be recovered reflects true-ups from 2023 (over-collections of $862,664). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00807 per kilowatt ("kW") of Monthly Network Load (a $0.00106/kW increase from 2023). The 2024 NESCOE budget was supported by the Participants Committee at its October 5, 2023 meeting. Comments and any interventions are due on or before November 3. Thus far, NEPOOL, 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).

- **2024 ISO-NE Administrative Costs and Capital Budgets (ER24-90)**

Also on October 13, 2023, ISO-NE filed for recovery of its 2024 administrative costs (the "2024 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2024 ("2024 Capital Budget", and together with the 2024 Revenue Requirement, the "2024 ISO Budgets"). The 2024 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 13 filing, ISO-NE reported that the 2023 Revenue Requirement is $276.9 million (a $36.7 million or 15.3% increase over 2023), which decreases to $273.9 million after the over-collection for 2022 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2024 Core Operating Budget) comprise $244.3 million; depreciation and amortization of regulatory assets, $32.6 million; and a $3.0 million true-up decrease for 2022 over-collections.

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

[21] *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).

ISO-NE further reported that the 2024 Capital Budget is $35 million, a $1.5 million increase over 2023, and is comprised of the following (with 2024 projected costs and target completion dates, if available, in parentheses):

- Day-Ahead Ancillary Services Improvements (Mar 2025) ($3.8 million)
- nGem Software Development Part III (Mar 2025) ($2.5 million)
- Operating System Server Upgrade Phase I (Jul 2024) ($1.2 million)
- Solar DNE Dispatch Phase II (Oct 2024) ($900,000)
- IMM Data Analysis Phase IV (May 2024) ($500,000)
- Energy Management System ("EMS") Short-term Load Forecast (Jul 2024) ($400,000)
- IT Asset Workflow ("ITAW") Integration and Updates (May 2024) ($200,000)
- EMS Host Monitoring Software Replacement (Jan 2024) ($100,000)
- Settlement Technology Improvements (Mar 2024) ($100,000)
- nGem RT Mkt Clearing Engine Implementation (Jun 2025) ($6 million)
- *Order 881* Compliance (Jun 2025) ($3.3 million)
- CIP Electronic Security Perimeter Redesign Phase II (Dec 2024) ($2 million)
- Enterprise Resource Planning System Replacement (Mar 2025) ($1.6 million)
- Resource Capacity Accreditation (Dec 2025) ($1 million)
- Microsoft 365 Service Adoption (Sep 2024) ($1 million)
- 2024 Issue Resolution Project (Dec 2024) ($1 million)
- *Order 2222* (Dec 2026) ($500,000)
- Privileged Account Management Security Enhancements Phase II (Dec 2024) ($500,000)
- Capitalized Interest ($1.5 million)
- Non-Project Capital Expenditures ($5.3 million)
- Other Emerging Work ($1.6 million)

The 2024 ISO-NE Budgets were supported by the Participants Committee at its October 5, 2023 meeting. Comments on this filing are due November 3, 2023. Thus far, NEPOOL filed comments supporting the 2024 Budgets and NEPOOL, National Grid, NESCOE, and MA DPU have filed doc-less interventions. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **EP Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER24-80)**

On October 12, 2023, Essential Power Newington, LLC ("EP Newington") requested FERC acceptance of its revised rate schedule to allow recovery of eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("IROL-CIP Costs") under Schedule 17 of the ISO-NE Tariff, effective *December 11, 2023*. EP Newington seeks to recover ***$276,421*** in incremental medium impact CIP-IROL Costs incurred between July 1, 2022 and June 30, 2023. Comments on EP Newington's request are due on or before ***November 2, 2023***. Thus far, doc-less interventions have been filed by National Grid and NESCOE. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Stonepeak Kestrel CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-2429)**

On October 16, 2023, the FERC accepted Stonepeak Kestrel Energy Marketing LLC's ("Stonepeak Kestrel") revised rate schedule that will allow it to recover under Schedule 17 of the ISO-NE Tariff ***$1,483,297*** in eligible CIP-

IROL Costs incurred between March 29, 2021 and March 31, 2023.[22] The rate schedule revisions became effective September 16, 2023. Unless the *Stonepeak Kestrel CIP-IROL Costs Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Bucksport Generation (Schedule 17) Section 205 Cost Recovery Filing (ER23-2428)**

Similarly, on October 13, 2023, the FERC accepted Bucksport Generation LLC's ("Bucksport Generation") revised rate schedule to allow it to recover ***$251,419*** in eligible medium-impact CIP-IROL Costs incurred between March 29, 2021 and March 31, 2023.[23] The rate schedule revisions became effective September 29, 2023. Unless the *Bucksport CIP-IROL Costs Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **BHD Regulatory Asset - Establishment & Recovery Through Rates (ER23-1598)**

On April 7, 2023, Versant Power requested authorization to (i) establish a regulatory asset for the Bangor Hydro District ("BHD") totaling $15,622,081 in capitalized regulatory overhead costs (identified in a recent FERC audit as incorrectly allocated as construction costs) as of January 1, 2024, and amortize this asset over a period of 16 years on a straight-line basis beginning January 1, 2024, subject to FERC approval; and (ii) recover as an expense in transmission rates under the ISO-NE OATT a return of the unamortized balance of the regulatory asset effective January 1, 2026 and continuing for 16 years. Comments on Versant's request were due on or before April 28, 2023. On May 3, the MPUC moved to intervene out-of-time and protest. In its protest, the MPUC requested that Versant be required to refund retail customers for the improper collection of "Allocation of Overhead Costs to Construction Work in Progress" and to provide additional detail regarding the amounts included. On May 5, 2023, Versant answered the MPUC protest.

Deficiency Letter and Deficiency Letter Response (-001). On June 5, 2023, the FERC issued a deficiency letter directing Versant to provide additional information related to inputs to Filing Exhibits 1 and 2, which support the amount of the proposed regulatory asset. Specifically, Versant was directed to provide "all records that Versant provided to Commission audit staff in Docket No. FA20-9-000 related to the proposed regulatory asset and explain how these records support the instant filing". Versant filed its response on July 5, 2023 (which re-set the filing date and deadline for FERC action (see below)). Comments on Versant's deficiency letter response were due on or before July 26, 2023; none were filed. On July 19, the Maine Office of the Public Advocate ("MOPA") filed a motion to intervene (out-of-time).

Joint Offer of Settlement (-002). On September 22, Versant filed a joint offer of settlement ("Settlement Offer") between itself, the MPUC and MOPA. Versant stated the Settlement Offer, if accepted, would resolve all issues raised by the MPUC in this proceeding, including those described above. Comments on the Settlement Offer were due on or before October 12, 2023; none were filed. The Settlement Offer is pending before the FERC.

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

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[24] (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 ("COSA") to reflect

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[22] *Stonepeak Kestrel Energy Marketing LLC*, Docket No. ER23-2429-001 (Oct. 16, 2023) ("*Stonepeake Kestrel CIP-IROL Costs Order*").

[23] Bucksport Generation LLC, Docket No. ER23-2428-002 (Oct. 13, 2023) ("*Bucksport CIP-IROL Costs Order*").

[24] 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.

Mystic's current upstream ownership.[25] The changes were accepted effective as of June 1, 2022, but subject to refund and to the outcome of paper hearing (or settlement procedures) on the issues of capital structure and cost of debt raises issues. Mystic filed an offer of settlement on September 8, 2022 to resolve all issues set for hearing and settlement proceedings and the FERC accepted that offer of settlement on November 2, 2022,[26] directing Mystic to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action in the November 2 order. Mystic submitted that compliance filing on December 2, 2022 (ER22-1192-003). No comments were received by the December 23, 2022 comment date, and there was no activity in this proceeding since the last Report. This compliance filing remains pending before the FERC. FERC action on the compliance filing will conclude this proceeding. 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)**

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[27] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to 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*.

(-000) Third CapEx Info Filing. On September 15, 2023, 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 "Third 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, 2024 to May 31, 2024 ("2024 CapEx Projects"). This filing was not noticed for public comment by the FERC.

(-025) First CapEx Settlement Agreement Tariff Sheets Filing. As directed in the August 1, 2023 order conditionally approving the First CapEx Settlement Agreement,[28] Mystic filed, on August 30, 2023, revised tariff records in eTariff format, effective *June 1, 2022*, to reflect the FERC's action ("Tariff Sheets Filing"). Comments on the Tariff Sheets filing were due on or before September 20, 2023; none were filed. The Tariff Sheets filing was accepted on October 27, 2023 (effective June 1, 2022).[29]

(-024) Mystic Request for Rehearing of Mystic I Order on Remand. On April 27, 2023, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand*.[30] Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[31] The Notice confirmed that the 60-day period during which a

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

[26] *Constellation Mystic Power, LLC*, 181 FERC ¶ 61,099 (Nov. 2, 2022).

[27] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028 (D.C. Cir. 2022) ("*Mystic I Remand Order*").

[28] *Constellation Mystic Power, LLC*, 184 FERC ¶ 61,070 (Aug. 1, 2023) ("*Mystic First CapEx Info Settlement Order*").

[29] *Constellation Mystic Power, LLC*, Docket No. ER18-1639-025 (Oct. 27, 2023) (unpublished letter order).

[30] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,200 (Mar. 28, 2023) ("*Mystic I Order on Remand*"), *reh'g denied by operation of law,* 183 FERC ¶ 62,115 (May 30, 2023) ("*Mystic I Order on Remand Allegheny Notice*").

[31] *Mystic I Order on Remand Allegheny Notice*.

petition for review of the *Mystic I Order on Remand* can be filed with an appropriate federal court was triggered when the FERC did not act on Mystic's request for clarification and/or rehearing of the *Mystic I Order on Remand*.

Mystic I Order on Remand Modification Order. On October 6, 2023, the FERC issued an order modifying the discussion in the *Mystic I Order on Remand* and setting aside the prior order, in part.[32] Specifically, the FERC set aside its determinations in the *Mystic I Order on Remand* that: (1) interested parties may review and challenge revenues and Revenue Credits during the true-up process; (2) interested parties may review and challenge Tank Congestion Charges during the true-up process; and (3) the revenues from the sliding scale revenue sharing mechanism for third-party vapor sales should be included within the true-up. The FERC concluded that "the language of the true-up and Protocol provisions of the [COS] Agreement, Schedule 3A, does not include these three items within the scope of the true-up, nor is calculation of these items consistent with purpose for the true-up mechanism in the [COS] Agreement because none of them are projected in advance, but rather they are each settled and audited on a monthly basis. The FERC found that "existing cost review and audit processes, … facilitated by ISO-NE, its auditors, and the Internal Market Monitor, are sufficient to ensure that Mystic adheres to its filed rate with respect to these items and continues to appropriately balance customers' interest in transparency of the formula rate with Mystic's interests in protecting commercially-sensitive information, reducing security risks, and avoiding burdensome audit obligations".[33]

Public Systems' Request for Disclosure of Audit Information. The FERC's October 6 *Mystic I Order on Remand Modification Order* also denied Public Systems[34] May 19, 2023 request that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request"). As previously reported, Public Systems asserted that ISO-NE had released almost no information concerning the audits or the bases for their conclusions that Mystic's performance is consistent with its obligations under the COSA. In the *Mystic I Order on Remand Modification Order,* the FERC found that the additional audit information requested was "not supported by the Mystic Agreement and unnecessary, given the attention that ISO-NE, its auditors, and the Market Monitor give these items on a regular basis".[35] Nevertheless, the FERC accepted "ISO-NE's offer to provide additional transparency measures for the remainder of the Mystic Agreement as soon as practicable, starting no later than [December 5, 2023]."[36]

(-018) Second CapEx Info Filing. Still pending is Mystic's September 15, 2022 "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 were due on or before November 16, 2022 and November 17, 2022, respectively. Mystic responded separately to NESCOE's and ENECOS' challenges. MMWEC/NHEC filed comments supporting ENECOS' formal challenge, emphasizing its support for formal challenge to the pass through of charges incurred by Everett for pipeline transportation reservations. On December 6, 2022, ENECOS answered Mystic's November 17, 2022 answer. Later, on December 22, 2022, Mystic filed a response to ENECOS' December 6 answer, and requested that the FERC reject the Formal Challenges, and accept the Second Filing as expeditiously as possible.

On August 15, 2023, NESCOE, as it had agreed to in the FERC-approved First CapEx Settlement Agreement, submitted a notice that it was withdrawing its October 17, 2022 Formal Challenge No. III.A to the 2022

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[32] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*").

[33] *Id.* at P 12.

[34] "Public Systems" for these purposes are: MMWEC, CMEEC, NHEC, VPPSA, the Eastern New England Consumer-Owned Systems ("ENECOS"), and Energy New England, LLC ("ENE").

[35] [Order] at P 13.

[36] *Id.*

Informational Filing (its challenge that the 2023 CapEx Projects were unsupported). FERC action on the Second CapEx Info Filing remains pending.

Since the last Report, on October 20, 2023, NESCOE provided notice of withdrawal of its Formal Challenge No. III.B to the 2022 Informational Filing related to support for the property tax component of the Annual Fixed Revenue Requirement ("AFRR").

(-014) Revised ROE (Sixth) Compliance Filing. Also still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[37] 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.

30-Day Compliance Filing per Order on ENECOS Mystic COSA Complaint (ER23-1735). On April 27, 2023, Mystic filed, as directed by the FERC's March 28, 2023 *Order on ENECOS Mystic COSA Complaint*,[38] changes to the Mystic COSA to include pipeline-related crediting as an explicit provision in the COSA. Mystic also provided additional information/COSA changes to (i) describe the crediting process; (ii) differentiate, through both an explanation in its compliance filing and creation of two new line items in Schedule 3A, the credits and charges included as part of the Fixed Pipeline Costs; (iii) address how and whether the pipeline-related crediting procedure interacts or should interact with the true-up procedure already included in the COSA and revise the true-up as necessary; and (iv) differentiate in the COSA the Pipeline Transportation Costs as Fixed O&M/Return on Investment Costs from the Pipeline Transportation Agreement Costs. Comments on the 30-day compliance filing were due on or before May 18, 2023. ISO-NE and Monitoring Analytics, LLC filed doc-less motions to intervene.

On July 10, 2023, ENECOS submitted comments (out-of-time) asserting that Mystic's compliance filing did not provide information sufficient to show that Mystic's after-the-fact pipeline-related crediting ensures that Mystic customers do not pay for pipeline costs that do not benefit them ("Crediting Issue"), the Schedule 3A true-up process does not provide the opportunity for an adequate verification process, and ISO-NE's COSA-related filings to date have similarly not addressed the Crediting Issue. ENECOS requested that the FERC direct Mystic to provide a work paper to "verify its assertion that it has always applied a full credit for third-party pipeline transportation costs to Constellation LNG's billings to Mystic". On July 20, 2023, Mystic protested ENECOS' comments.

This 30-day compliance filing is pending before the FERC. If you have questions on any aspect of these proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **Transmission Rate Annual (2024) Update/Informational Filing (ER20-2054-003)**

On July 31, 2023, the PTO AC submitted its annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff for 2024. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2022 cost data, plus forecasted revenue requirements associated with projected PTF, Local

[37] An "Allegheny Order" is a merits rehearing order issued on or after the 31st day after receipt of a rehearing request, reflecting the FERC's authority to "modify or set aside, in whole or in part," its order until it files the record on appeal with a reviewing federal court. An Allegheny Order will use "modifying the discussion" if the FERC is providing a further explanation, but is not changing the outcome, of the underlying order; or "set aside" if the FERC is changing the outcome of the underlying order. Aggrieved parties have 60 days after a deemed denial to file a review petition, even if FERC has announced its intention to issue a further merits order.

[38] *Belmont Municipal Light Dept., et al. v. Constellation Mystic Power, LLC and ISO New England, Inc.*, 182 FERC ¶ 61,199 (Mar. 28, 2023) ("*Order on ENECOS Mystic COSA Complaint*", which denied in part, and accepted in part, ENECOS' Complaint against Mystic and ISO-NE challenging the pass-through of firm pipeline transportation costs under the 2nd Amended and Restated Mystic COSA).

Service and Schedule 12C capital additions for 2023 and 2024, as well as the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $154.35/kW-year effective January 1, 2024, an increase of $12.71 /kW-year from the charges that went into effect on January 1, 2023. 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 $1.95 kW-year (effective June 1, 2023 through May 31, 2024), a $0.20/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2023. Public comments on this filing were due on or before September 19, 2023; none were filed. MOPA filed a doc-less intervention.

The July 31 filing also triggered the commencement of an Information Exchange Period and a Review Period under the Protocols. Interested Parties had until September 15, 2023 to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 calendar days, but by no later than October 15, 2023. During the Review Period, Interested Parties have until ***November 15, 2023*** 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, 2023. Interested Parties have until ***January 31, 2024*** to file a Formal Challenge with the FERC.

- **Versant MPD OATT 2022 Annual Update Settlement Agreement (ER20-1977-005)**

On August 30, 2023, Versant submitted a Joint Offer of Settlement ("Versant MPD OATT 2022 Annual Update Settlement Agreement") between itself and the Maine Wholesale Customer Group, the Aroostook Energy Association, MOPA, and the Maine Public Utilities Commission (together, the "Maine Parties") which, if approved, would resolve all issues raised by the Maine Parties with regards to Versant's 2022 annual update to the transmission charges under the MPD OATT. Comments on the Versant MPD OATT 2022 Annual Update Settlement Agreement are due on or before September 20, 2023; none were filed. The Versant MPD OATT 2022 Annual Update Settlement Agreement is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

RENEW Formal Challenge. RENEW's January 31, 2023 formal challenge ("Challenge") to the 2022/23 Update/Informational Filing[39] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, Eversource answered RENEW's March 31 answer. There was no activity since the last Report. This matter is pending

[39] The 2022/23 annual 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. The formula rates in effect for 2023 included a billing true up of seven months of 2021 (June-Dec.). The Pool "postage stamp" RNS Rate, effective Jan. 1, 2023, was $140.94 /kW-year, a decrease of $1.84 /kW-year from the charges that went into effect the year prior. The updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate) resulted in a Schedule 1 charge of $1.75 kW-year (eff. 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.

before 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

- **DASI Proposal (ER24-275)**

On October 31, 2023, ISO-NE and NEPOOL jointly filed changes to the Tariff to establish a jointly optimized Day-Ahead Market for Energy and Ancillary Services ("DASI"). The Participants Committee unanimously supported DASI by way of the August 3, 2023 Consent Agenda (Item # 1). Comments on the DASI proposal are due on or before ***November 21, 2023***. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ISO/RTO Credit-Related Information Sharing (ER24-138)**

On October 18, 2023, in response to the requirements of *Order 895*, ISO-NE and NEPOOL jointly filed changes to the Information Policy to (i) permit ISO-NE to share Market Participant, Transmission Customer and Applicant (collectively, "Participants") credit-related information with other ISO/RTOs; (ii) permit ISO-NE to use credit-related information received from other ISO/RTOs to the same extent and for the same purposes as ISO-NE is permitted under the Tariff with respect to its Participants; and (iii) require ISO-NE to keep such received credit-related information confidential in accordance with the Tariff, in each case for the purpose of credit risk management and mitigation (the "Credit Info Sharing Changes"). The Credit Info Sharing Changes were supported by the Participants Committee by way of the October 5, 2023 Consent Agenda (Item # 6). Comments on the Credit Info Sharing Changes are due on or before ***November 8, 2023***. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Effective Date Deferral Request – Binary Storage Facility DARD Regulation (ER24-115)**

On October 16, 2023, ISO-NE asked that the FERC defer the effective date of *Order 841*-related changes that would permit Binary Storage Facilities to offer Regulation when acting as a Dispatchable Asset Related Demand ("DARD") in New England Markets (the "Binary Storage Facility DARD Changes"). The Binary Storage Facility DARD Changes are currently scheduled to become effective on January 1, 2024. Instead, ISO-NE asked that the effective date be deferred until such time as there is market interest in Binary Storage Facility DARD Regulation. ISO-NE stated that "Market Participants that operate the existing Binary Storage Facilities do not currently have the physical capability to provide Regulation when participating as a DARD, have not represented any immediate plans to develop that capability, and do not oppose the effective date deferral." ISO-NE further stated that the deferral would allow internal resources to be reallocated and focus on other pressing project priorities. Comments on the Deferral request are due on or before ***November 6, 2023***. Thus far, NEPOOL and Calpine have intervened doc-lessly. If you have any questions or concerns regarding this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **IEP Parameter Updates (ER23-1588)**

On August 4, 2023, the FERC accepted ISO-NE and NEPOOL's proposed revisions to Appendix K to Market Rule 1 to update certain parameters within the Inventoried Energy Program ("IEP Parameter Updates").[40] Specifically, the IEP Parameter Updates: (i) replace the IEP's fixed rate with an indexed rate that automatically adjust to account for changes in gas markets prior to each winter period, (ii) modify natural gas contracting requirements to align the IEP more closely with common industry and commercial practices and the nature of firm pipeline service available in New England; and (iii) are meant to clarify and improve the administration of the IEP. The IEP Parameter Updates were accepted effective as of *August 4, 2023*.

[40] *ISO New England Inc. and New England Power Pool Participants Comm.*, 184 FERC ¶ 61,082 (Aug. 4, 2023) ("*IEP Parameter Updates Order*").

Request for Rehearing Denied by Operation of Law; Allegheny Notice. As previously reported, Public Interest Organizations ("PIOs")[41] requested rehearing of the *IEP Parameter Updates Order*. On October 6, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[42] That Notice confirmed that the 60-day period during which a petition for review of the *IEP Parameter Updates Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of the *IEP Parameter Updates Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **SATOA Revisions (ER23-739; ER23-743)**

On October 19, 2024, the FERC accepted[43] the SATOA Revisions,[44] finding "that the proposed SATOA Revisions to establish a framework under which an electric storage resource may be considered a transmission asset are just and reasonable and not unduly discriminatory or preferential". The FERC did not direct ISO-NE to adopt any additional reporting requirements related to operation of SATOAs.[45] The FERC did, however, direct the Filing Parties (ISO-NE, NEPOOL, and the PTO AC) to make a filing notifying the FERC of the actual effective date of the proposed SATOA Revisions "no less than 30 days prior to the date ISO-NE implements the [SATOA Revisions]" (expected to be *July 1, 2024)*. Any challenges to the *SATOA Order* must be filed on or before ***November 18, 2023***. 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)**

In a lengthy compliance Order[46] issued March 1, 2023, the FERC approved in part, and rejected in part, ISO-NE, NEPOOL and the PTO AC's ("Filing Parties") *Order 2222* compliance filing[47] ("*Order 2222 Compliance Order*").[48]

In the *Order 2222 Compliance Order*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*:

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41 "PIOs" are for purposes of this proceeding: the Sierra Club and Conservation Law Foundation ("CLF").

42 *ISO New England Inc. and New England Power Pool Participants Comm.*, 185 FERC ¶ 62,009 (Oct. 6, 2023) ("*IEP Parameter Updates Allegheny Notice*").

43 *ISO New England Inc.*, 185 FERC ¶ 61,044 (Oct. 19, 2023) ("*SATOA Order*").

44 The "SATOA Revisions" enable electric storage facilities to be planned and operated as transmission-only assets ("SATOA") to address system needs identified in the OATT's regional system planning process.

45 *Id*. at P 71.

46 Commissioners Danly and Clements each provided separate concurrences with, and Commissioner Christie provided a separate dissent from, the *Compliance Order*. Commissioners Danly and Christie, despite their opposing positions on the Compliance Order, both reiterated their reasons for dissenting from *Order 2222* and concern for FERC overreach and difficulty with complying with *Order 2222*. In her separate concurrence, Commissioner Clements urged the ISO on compliance to "modify its proposal to address undue barriers and make participation more workable" and "to pursue steps that genuinely open [the New England Markets] to DERs like behind-the-meter resources."

47 As previously reported, the Filing Parties submitted on Feb. 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.

48 *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023).

- ***30-Day Compliance Requirements (-003)***. ISO-NE was directed to submit two filings by March 31, 2023. The first, a compliance filing to explain how current Tariff capacity market mitigation rules would apply to Distributed Energy Capacity Resources ("DECR") participating in FCA18. The second, an informational filing that provides an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. Those compliance filings were submitted on March 31, 2023. Comments on the DECR compliance filing (ER22-983-003) were due on or before April 21, 2023; none were filed. The March 31 informational filing was not noticed for public comment. The DECR compliance filing is pending before the FERC.

- ***60-Day Compliance Filing (-004)***. In a 60-day compliance filing, the FERC ordered ISO-NE:

  - ♦ to revise the Tariff to: (1) have RERRA make the determination of whether to allow customers of small utilities to participate in ISO-NE's markets through aggregation; (2) require that each DER Aggregator maintain and submit aggregate settlement data for the DERA; (3) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and if necessary, establish protocols for sharing meter data that minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity; (4) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; and (5) add specificity regarding existing resource non-performance penalties that would apply to a DERA when a Host Utility overrides ISO-NE dispatch instructions.

  - ♦ ISO-NE was also directed to: (1) identify the existing rules requiring a Market Participant that provides energy withdrawal service to be a load serving entity that is billed for energy withdrawal ("LSE Requirement") and explain whether the LSE Requirement is required of all resources seeking to provide wholesale energy withdrawal service in the energy market; (2) explain why its proposed metering and telemetry requirements were just and reasonable and did not pose an unnecessary and undue barrier to individual DERs joining a DERA; (3) establish protocols for sharing metering data that minimize costs and other burdens and address privacy and cybersecurity concerns; and (4) address how ISO-NE will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA.

  The 60-day compliance changes were filed on May 9, 2023, except for the requirement related to the submission of metering data, which is the subject of an ISO-NE rehearing request. Comments on the 60-day compliance filing were due on May 30, 2023 and were filed by NEPOOL (supplementing the record) and jointly by AEU/PowerOptions/SEIA ("AEU *et al*.") (who jointly protested what they asserted was a failure to make any adjustments to facilitate participation by DERs located behind a customer meter, and a failure to justify the metering and telemetry provisions as directed by the FERC). On June 14, 2023, ISO-NE answered the May 30 protest of AEU *et al*. On June 28, 2023, AEU *et al.* filed answer to ISO-NE's June 14 answer. The 60-day compliance changes are pending before the FERC.

- ***180-Day Compliance Filing (-005)***. On or before August 28, 2023, the FERC directed ISO-NE to file a further compliance filing explaining how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond.

  On August 28, 2023, ISO-NE and NEPOOL jointly filed the 180-day compliance changes ("Mitigation Compliance Revisions"). ISO-NE requested a March 1, 2024 effective date for the Mitigation Compliance Revisions. Further, ISO-NE asked that the FERC issue an order accepting the Mitigation Compliance Revisions no later than November 1, 2023 to allow sufficient time for implementation of the proposed revisions prior to the scheduled qualification process for FCA19. Also, consistent with the requests made in ISO-NE's Request for Rehearing and 30-Day Informational and Compliance Filing in this docket, ISO-NE proposed March 1, 2024 as the new effective date for the rules allowing DECRs to participate in the FCM. Comments on the Mitigation Compliance Revisions were due on or before September 18, 2023; none were filed. The Mitigation Compliance Revisions are pending before the FERC.

Requests for Rehearing and/or Clarification (-002). On March 31, 2023, ISO-NE and New England Public Utilities[49] requested rehearing and/or clarification of the *Order 2222 Compliance Order*. ***ISO-NE*** urged the FERC to reconsider allowing DECRs to participate in FCA18 and designating the DER Aggregator as the entity responsible for transmitting DERA metering data. ***New England Public Utilities*** urged the FERC to adopt the DER metering and settlement approach proposed by the Filing Parties (*Order 2222* Changes) and clarify (1) that PTOs and distribution utilities are not prohibited from requiring metering and settlement data from DERs to satisfy their obligations to perform wholesale settlement and retail customer billing and (2) that it would not be unjust and unreasonable for utilities to recover costs related to investment and expenses incurred to modify its metering, billing, settlement, cyber security and other systems, to accommodate submetering of Behind-the-Meter DER participating in the wholesale market as part of a DERA. On April 14, 2023, ***MA AG*** answered New England Public Utilities' request for rehearing and clarification and requested that the FERC address the recovery of costs necessary to implement Behind-the-Meter DER submetering and the allocation of costs to DER aggregators and program participants. On April 17, ***AEU*** answered ISO-NE's request for rehearing (urging the FERC to not reconsider its decision designating the DER Aggregator as the entity responsible for transmitting DERA metering data); ISO-NE answered the AEU answer on May 2, 2023. Answers to ISO-NE's March 31 request for rehearing were filed by May 5 by the ***MPUC*** (urging the FERC to consider ISO-NE's request to allow PTOs and distribution utilities to meter and transmit DERA data) and May 22 by NECPUC (who also supported ISO-NE's request regarding the entity responsible for transmitting DERA metering data to ISO-NE).

Order 2222 Compliance Allegheny Notice. On May 1, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[50] That Notice confirmed that the 60-day period during which a petition for review of the *Order 2222 Compliance Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of the *Order 2222 Compliance Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

Order 2222 Compliance Allegheny Order. On October 6, 2023, the FERC issued an Allegheny Order[51] on the requests for clarification and/or reh'g of its *Order 2222 Compliance Order.* In the *Order 2222 Compliance Allegheny Order*, the FERC (i) modified the discussion in the *Order 2222 Compliance Order* (*e.g.* clarifying that metering data may come from or flow through distribution utilities if ISO-NE coordinates with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing such metering data and explains how such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity);[52] (ii) set aside the *Order 2222 Compliance Order*, in part (setting aside the November 1, 2022 effective date, in favor, likely, of the effective date proposed by ISO-NE in its subsequent compliance filing);

[49] "New England Public Utilities" are: National Grid USA on behalf of Massachusetts Electric Co., Nantucket Electric Co., and New England Power Co. ("NGUSA"); Avangrid Networks, Inc. on behalf of CMP and UI ("Avangrid Networks"); and Eversource on behalf of The Connecticut Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), and NSTAR Electric Co. ("NSTAR").

[50] *ISO New England Inc. and New England Power Pool Participants Comm.*, 183 FERC ¶ 62,050 (May 1, 2023) ("*Order 2222 Compliance Allegheny Notice*").

[51] *ISO New England Inc. and New England Power Pool Participants Comm.*, 185 FERC ¶ 61,021 (Oct. 6, 2023) ("*Order 2222 Compliance Allegheny Order*").

[52] *Id.* at P 24.

and (iii) granted and denied in part the New England Public Utilities' requests for clarification (clarifying that Host Utilities are not prohibited from requiring metering and settlement data from each DER comprising a DERA to satisfy any relevant obligations (e.g. wholesale settlement and/or retail customer billing) and denying as premature the Utilities' cost concerns with the FERC's finding that ISO-NE failed to demonstrate that its proposed metering and telemetry requirements were just and reasonable).[53]

Federal Court (DC Circuit) Appeals. As previously reported, CMP and UI, National Grid, Eversource, and ISO-NE filed separate appeals of the *Order 2222 Compliance Order*. Those appeals have been consolidated (Case No. 23-1167) and are reported on in Section XVI below.

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).

IV. OATT Amendments / TOAs / Coordination Agreements

- **UI Attachment F App. D Depreciation Rate Changes (ER24-272)**

On October 31, 2023, UI filed changes to Appendix D of Attachment F to the ISO-NE OATT to incorporate the revised transmission plant depreciation and general plant depreciation rates used to calculate UI's annual transmission revenue requirements. Comments on this filing are due on or before ***November 21, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **National Grid Attachment F Appendix A PBOP Fixed Expense Revisions (ER24-125)**

On October 17, 2023, National Grid filed revisions to Appendix A to Attachment F to the ISO-NE OATT to update NEP's fixed expense amount for transmission-related post-retirement benefits other than pensions ("PBOPs") to more accurately reflect the going forward expense level and allow the existing income statement credit incurred under the current formula rate to be refunded to customers. Comments on this filing are due on or before ***November 7, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Attachment F Corrections & Updates (ER23-2940)**

On September 28, 2023, the PTO AC filed proposed revisions to Attachment F of the OATT to correct minor errors in certain worksheets of the "Formula Rate Template" contained in Appendices A and B to Attachment F. The PTO AC stated that the filing is limited to proposed Tariff revisions that fall within Moratorium Exception (i) subpart (o) of Attachment F and that the corrections and updates will not result in any additional costs being paid by New England ratepayers. An effective date of November 23, 2023 was requested. Comments on this filing were due on or before October 19, 2023. Public Systems[54] filed comments supporting the corrections and updates. National Grid filed a doc-less motion to intervene. 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 Att. F App. D Depreciation Rate Change (ER23-2483)**

On October 4, 2023, the FERC accepted updated depreciation rates for Versant Power's ("Versant") local transmission facilities in eastern and coastal Maine (the "Bangor Hydro District" or "BHD"), as set forth in Appendix D to Attachment F of the ISO-NE OATT.[55] The rate change was accepted effective *January 1, 2025*,

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[53] *Id.* at P 25.

[54] For purposes of this proceeding "Public Systems" are CMEEC, MMWEC, NHEC, and VPPSA.

[55] *ISO New England Inc. and Versant Power*, Docket No. ER23-2483-000 (Oct. 4, 2023) (unpublished letter order).

as proposed. Unless the October 4 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).

- ***Order 676-J* Compliance Filings Part II (ER23-1771; ER23-1774; ER23-1782; ER23-1785)**

On May 1, 2023, in accordance with Order 676-J,[56] the following second *Order 676-J* compliance filings to incorporate, or seek waiver of, the remainder of the WEQ Version 003.3 Standards, were submitted:

- Order 676-J Compliance Filing Part II (ISO-NE and NEPOOL-Tariff Schedule 24) (ER23-1771);
- Order 676-J Compliance Filing Part II (CSC-Schedule 18-Attachment Z) (ER23-1774);
- Order 676-J Compliance Filing Part II (Versant-MPD OATT) (ER23-1782); and
- Order 676-J Compliance Filing Part II (TOs'-Schedules 20A-Common and 21-Common) (ER23-1785).

On October 26, 2023, the FERC issued orders accepting each of *Order 676-J* Compliance Filings Part II, effective *February 1, 2024*. The FERC accepted the CSC and TOs' compliance filings without change or condition.[57] The FERC conditionally accepted the ISO-NE and NEPOOL[58] and Versant[59] compliance filings, requiring in each case ISO-NE/NEPOOL[60] and Versant[61] to revise its tariff record on or before ***November 27, 2023*** to include the citation to its order granting the waivers requested. Challenges, if any, to the ISO-NE and NEPOOL or to the Versant orders are also due on or before ***November 27, 2023***. If there are questions on any of these filings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On June 15, 2023, the FERC conditionally accepted the proposed revisions to the OATT in response to the requirements of *Order 881*[62] ("OATT *Order 881* Compliance Changes").[63] The OATT *Order 881* Compliance Changes were accepted effective as of *July 12, 2025*, subject to two compliance filings – on due on or before August 14, 2023 (60-day compliance filing); the other, ***November 12, 2024*** (the AAR explanation filing). The 60-day compliance filing must (i) revise the Tariff to specify that transmission service at ISO-NE's seams use AARs as the basis for evaluation for near-term transmission service requests (or explain why ISO-NE should not be required to do so); (ii) revise the Tariff to include the examples listed in the FERC's *pro forma* Attachment M (or explain why ISO-NE should not be required to do so); (iii) remove proposed revisions to Schedule 18 excepting the Cross-Sound Cable from the requirements of *Order 881* (or explain why such changes should not be required); and (iv) revise the Tariff to require ISO-NE in a database that it maintains (rather than dividing responsibility between ISO-NE and transmission owners) to host all transmission line ratings, ratings

[56] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

[57] ISO New England Inc. and Cross-Sound Cable Company, LLC, Docket No. ER23-1774-000 (Oct. 26, 2023) (unpublished letter order accepting CSC's compliance filing); *ISO New England Inc.*, Docket No. ER23-1785-000 (Oct. 26, 2023) (unpublished letter order accepting the TO's compliance filing).

[58] *ISO New England Inc.*, 185 FERC ¶ 61,065 (Oct. 26, 2023) ("*ISO-NE/NEPOOL Order 676-J Compliance II Order*").

[59] *Versant Power*, 185 FERC ¶ 61,065 (Oct. 26, 2023) ("*Versant Order 676-J Compliance II Order*").

[60] The FERC granted ISO-NE's request for continued waivers of the NAESB Business Practice Standards in WEQ-001 and WEQ-008 and new waivers of the new standards in WEQ-001, 001-13.2 through 13.2.4.2, 001-20.4, 001-26 through 001-26.7, 001-27 through 001-27.4.3, 001-28 through 001-28.1.3.1. *ISO-NE/NEPOOL Order 676-J Compliance II Order* at P 10.

[61] The FERC granted Versant's request for continued waivers of the NAESB Business Practice Standards in continued waivers of the NAESB Business Practice Standards in WEQ-001-101 through WEQ-001-107; WEQ-002-101 through WEQ-002-107; WEQ-013-101 through WEQ-013-106; and WEQ-001-23. *Versant Order 676-J Compliance II Order* at P 9.

[62] *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*").

[63] *ISO New England Inc.*, 183 FERC ¶ 61,180 (June 15, 2023) ("*New England Order 881 Compliance Order*").

methodologies, and exceptions or alternate ratings (or explain why they should not be required to do so). The AAR explanation filing must explain the timelines for calculating or submitting AARs.

(-001) 60-Day Compliance Changes. On August 14, 2023, ISO-NE, NEPOOL, the PTO AC, and CSC jointly filed revisions to Section II of the OATT in response to the requirements of the *New England Order 881 Compliance Order.* The further compliance changes (i) clarify that ISO-NE will use AARs at its seams; (ii) reinsert the list of exceptions in Attachment Q, and specify that the specific criteria for determining whether a transmission line is eligible for an exception will be detailed in ISO-NE's Planning and Operating Procedures; (iii) remove revisions to Schedule 18 proposed to except CSC from the requirements of *Order 881*; and (iv) modify both Attachment Q to the ISO OATT and Attachment M to Schedule 21-Common to require that ISO-NE host all ratings, ratings methodologies, and exceptions in its database. Comments on the further compliance changes were due on or before September 5, 2023; none were filed. The *Order 881* 60-Day Compliance Changes are pending before the FERC.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

- **Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804)**

On September 11, 2023, ISO-NE and New England Power ("National Grid") filed a 20-year Local Service Agreement ("LSA") by and among National Grid, ISO-NE and Green Mountain Power ("GMP").[64] The filing parties stated that the LSA conforms to the *pro forma* LSA contained in the ISO-NE Tariff and supersedes and replaces another conforming LSA among ISO-NE, NEP, and GMP that lists an expiration date of September 30, 2022 (TSA-NEP-25). The LSA was filed separately given the requested effective date (October 1, 2022). Comments on the LSA filing were due on or before October 2, 2023; none were filed. The LSA remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: Versant/Jonesboro LSA (ER24-24)**

On October 4, 2023, ISO-NE and Versant Power ("Versant") filed a LSA by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro, LLC ("Jonesboro").[65] The filing parties stated that the LSA conforms to the *pro forma* LSA contained in the ISO-NE Tariff and reflects a discounted rate. The LSA was filed separately out of an abundance of caution as it was executed more than 30 days after commencement of service. The filing parties asked that the LSA be accepted for filing effective December 2, 2022. Comments on the LSA filing are due on or before ***November 2, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-ES: Eversource/Great Lakes Hydro IA Termination (ER24-17)**

On October 4, 2023, Eversource submitted a notice of termination of the Interconnection Agreement ("IA") between PSNH and Great Lakes Hydro American LLC ("Great Lakes Hydro"). Eversource stated that the IA has been replaced by a standard LGIA, that will be reported in ISO-NE's electric quarterly reports ("EQRs"). Eversource further stated that PSNH has finalized all billing and invoices and no further work is being done or

[64] The LSA was designated as Service Agreement No. TSA-NEP-114 under the ISO-NE OATT.

[65] The LSA was designated as Service Agreement No. LSA-ISONE/VERSANT-23-01 under the ISO-NE OATT.

service being provided under the IA. Eversource requested an ***October 5, 2023*** effective date for the termination of the IA. Comments on the IA termination filing are due on or before ***November 2, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035)**

On July 28, 2023, the FERC accepted seven fully executed, non-conforming LSAs by and among Versant Power, ISO-NE and Black Bear Hydro Partners, LLC or Black Bear SO, LLC (together with Black Bear Hydro Partners, "Black Bear").[66] The service agreements are based on the Form of Local Service Agreement contained in Schedule 21-Common under the ISO-NE OATT, but were filed because they are non-conforming insofar as they reflect different rates from those set forth in Schedule 21-VP. The LSAs were accepted for filing effective August 1, 2023, rather than January 1, 2021 as requested, triggering a refund requirement.[67] On August 29, 2023, Versant Power submitted a Refund Report detailing the time value refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments on the Refund Report were due on or before September 19, 2023; none were filed. The Refund Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: 2022 Annual Update Settlement Agreement (ER20-2054-003)**

On August 29, 2023, Versant submitted a Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC. Versant stated that, if approved, the 2022 Annual Update Settlement Agreement would resolve all issues raised by the MPUC with respect to the 2022 Annual Update. Comments on the Versant 2022 Annual Update Settlement Agreement were due on or before September 19, 2023; none were filed. MPUC intervened doc-lessly on September 15, 2023. 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-GMP Annual True Up Calculation Informational Filing (ER12-2304)**

On October 30, 2023, pursuant to Section 4 of Schedule 21-GMP, Green Mountain Power ("GMP") submitted its annual informational filing containing the true-up calculation of its actual (rather than estimated) costs for the January 1, 2022 through December 31, 2022 ("2022 Service Period"). The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

[66] *ISO New England Inc.*, Docket No. ER23-2035-000 (July 28, 2023) ("*Versant Black Bear LSAs Order*").

[67] The FERC denied the requested waiver of its 60-day prior notice requirement (18 C.F.R. § 35.11), finding that the Filing Parties did not make an adequate showing of extraordinary circumstances. Accordingly, Versant was required to refund the time value of revenues collected for the time period the rate was collected without FERC authorization (with refunds limited so as not to cause Versant to operate at a loss) and file a refund report with the FERC.

VIII. Regional Reports[68]

- **Capital Projects Report - 2023 Q3 (ER24-94)**

On October 13, 2023, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2023 (the "Q3 Report").[69] Q3 Report highlights included the following new projects: (i) DASI ($9.125 million); (ii) Operating System Server Upgrade Phase I ($2.383 million); (iii) nGEM Quarterly Production Release 2-2023 Integration ($265,000); and (iv) Offer-Prioritized Mitigation Enhancement ($140,000). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) Web to Cloud Migration ($350,000); (ii) MOPR Elimination ($88,000); and (iii) Control Room Voice Recorder Upgrade ($71,600). Comments on the 2023 Q3 Report are due on or before November 3, 2023. On October 31, NEPOOL submitted comments supporting the Q3 Report. National Grid intervened doc-lessly. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Capital Projects Report - 2023 Q2 (ER23-2620)**

On October 4, 2023, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2023 (the "Q2 Report").[70] Q2 Report highlights includes the following new projects: (i) nGEM Software Development Part III ($4.5 million); (ii) IMM Data Analysis Phase IV ($1.2 million); (iii) Energy Management System Short-term Load Forecast Replacement ($1.2 million); (iv) Elimination of Minimum Offer Price Rule ($528,600); (v) Energy Management System Host Monitoring Software Replacement ($280,600); and (vi) Market Information Server Reporting by Sub-Accounts ($276,000). Projects with a significant change (amounts returned to the Emerging Work Fund) were (i) Solar Do-Not-Exceed Dispatch Phase II ($144,100); (ii) Forecast Enhancements ($173,000); and (iii) Windows Server 2019R2 Deployment Phase I ($185,500). Unless the October 4 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **LFTR Implementation: 60th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 60th of its quarterly status reports regarding LFTR implementation on October 13, 2023. 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 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.

- **IMM Quarterly Markets Reports – Summer 2023 (ZZ24-4)**

On October 27, 2023, the IMM filed with the FERC its Summer 2023 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Summer 2023 Report will be discussed with the Markets Committee at its November 7-8, 2023 meeting.

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[68] Reporting on the *Opinion 531* Refund Reports (EL11-66) has been suspended and will be continued if and when there is new activity to report.

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

[70] *ISO New England Inc.*, Docket No. ER23-2620-000 (Oct. 4, 2023) (unpublished letter order).

IX. Membership Filings

- **November 2023 Membership Filing (ER24-276)**
  On October 31, 2023, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: BlueWave Public Benefit Corp. [Related Person to Generate Colchester Fuel Cells and Generate NB Fuel Cells (AR Sector, RG Sub-Sector, Large Group Member)]; Flatiron Energy Capital [Related Person to Pawtucket Power Holding (Generation Sector); Glenvale (AR Sector, RG Sub-Sector, Large Group Member); New England Power and Light (Supplier Sector); Precept Power (Supplier Sector); and Wallingford Energy [Related Person to Jericho Power et al. (AR Sector, RG Sub-Sector)]; and (ii) the name changes of Blueprint Power Technologies LLC (f/k/a Blueprint Power Technologies Inc.) and PSE US Holdings Inc. (f/k/a AMP Solar US Holdings Inc.). Comments on this filing are due on or before ***November 21, 2023***.

- **October 2023 Membership Filing (ER23-2966)**
  On September 29, 2023, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: KCE CT 10, LLC and KCE CT 11, LLC [Provisional Members, Related Persons to KCE CT 5, LLC et al. (AR Sector, Distributed Generation Sub-Sector)]; and Sierra Club (effective *December 1, 2023*, End User Sector); and (ii) the termination of the Participant status of BP Energy Holding Company [Related Person to BP Energy Company et al. (Supplier Sector)]. Comments on this filing were due on or before October 20, 2023; none were filed. The October 2023 Membership Filing is pending before the FERC.

- **September 2023 Membership Filing (ER23-2756)**
  On October 27, 2023, the FERC accepted: (i) the following Applicant's membership in NEPOOL: Phoenix Energy Group, LLC (Supplier Sector); and 3Degrees Group, Inc. (GIS-Only Participant); (ii) the termination of the Participant status of: Just Energy (U.S.) Corp. [Related Person to Just Energy Limited and Hudson Energy Services (Supplier Sector)]; NRG Power Marketing LLC, Norwalk Power LLC and Somerset Power LLC [all Related Persons to NRG Business Marketing et al. (Supplier Sector)]; and WP&G Holdings, LLC (Supplier Sector); and (iii) the Name Change of NRG Business Marketing, LLC (f/k/a Direct Energy Business Marketing, LLC). Unless the October 27 order is challenged, this proceeding will be concluded.

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).

- **NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2)**
  As directed by the FERC's December 15, 2022 order,[71] NERC, on April 14, 2023, provided an updated evaluation of CIP-014 (its "Physical Security Reliability Standard"). NERC concluded that CIP-014 applicability criteria is meeting its objective to "appropriately focus[] limited industry resources on risks to the reliable operation of the BPS associated with physical security incidents at the most critical facilities" and the objective is broad enough to capture the subset of applicable facilities that TOs should identify as "critical" pursuant to the risks assessment mandated by Requirement R1. NERC did not find evidence that an expansion of the applicability criteria would identify additional substations that would qualify as "critical" substations under the CIP-014 Requirement R1 risk assessment, declined to recommend expansion of the CIP-014 applicability criteria, but committed to continued evaluation of the adequacy of the applicability criteria in meeting the objective of CIP-014. Comments on NERC's report were due on or before May 15, 2023 and were filed by, among others: ISO-NE, Trade Associations, and WIRES.

[71] *N. Amer. Elec. Rel. Corp.*, 181 FERC ¶ 61,230 (Dec. 15, 2022).

August 10, 2023 Joint Technical Conference. On August 10, 2023, FERC and NERC staff convened an in-person technical conference at NERC's headquarters in Atlanta, GA. The conference discussed physical security of the Bulk-Power System ("BPS"), including the adequacy of existing physical security controls, challenges, and solutions. Speaker materials are posted in the FERC's eLibrary. Those interested were invited to file post-technical conference comments to address issues raised during the technical conference. Those submitting comments included: AEP, PJM, EEI, Electricity Canada, EPSA, Foundation for resilient Societies ("FRS"), Criticality Services, Grid Coalition, ITC, North American Transmission Forum ("NATF"), Secure the Grid, L. Fitzgerald, T. Holiday, S. Naumann, and T. Holiday. On October 3, the FERC posted in eLibrary a final transcript of the August 10 joint technical conference.

- **Inverter-Based Resource Registration (RD22-4)**

As directed in the FERC's order accepting NERC's work plan to address registration of Inverter-Based Resources ("IBRs") that are connected to the BPS but not within NERC's definition of the bulk electric system ("non-BES IBRs"),[72] NERC filed on August 16, 2023, its first progress update on activities by the ERO Enterprise (NERC and the Regional Entities) to execute the Work Plan and initiate revisions to the NERC Registry Criteria to register owners and operators of non-BES IBRs that, in the aggregate, have a material impact on BPS reliability. NERC reported on its plans to post proposed Registry Criteria revisions on the NERC website for a 45-day formal comment in early September. On August 31, 2023, APPA filed comments on the IBR Work Plan Update.

- **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"))[73] on September 15, 2023. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the September 15 report, NERC reported that, because ballot body approval was again not achieved for two related Reliability Standards, the schedule for Project 2016-02 has been further revised and now calls for final balloting of revised standards in November 2023, NERC Board of Trustees Adoption in December 2023 and filing of the revised standards with the FERC in January 2024.

- ***Order 901*: IBR Reliability Standards (RM22-12)**

On October 19, 2023, the FERC issued a final rule[74] directing NERC to develop new or modified Reliability Standards that address reliability gaps related to inverter-based resources ("IBR") in the following areas: data sharing; model validation; planning and operational studies; and performance requirements. The FERC directed NERC to submit an informational filing on or before ***January 19, 2024*** that includes a detailed, comprehensive standards development plan providing that all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in *Order 901* be submitted to the FERC by ***November 4, 2026***.

- **Changes to NERC ROPs (RR23-4)**

On September 15, 2023, NERC proposed revisions to its Rules of Procedure ("RoPs") regarding Reliability Standards (specifically, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual)). The proposed revisions include new rules and authorities by which the NERC Board of Trustees may direct the development of needed Reliability Standards on its own initiative, subject to FERC approval. The

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[72] *N. Amer. Elec. Rel. Corp.*, 183 FERC ¶ 61,116 (May 18, 2023) ("*IBR Work Plan Order*") (requiring NERC to file progress reports every 90 days detailing the progress towards identifying and registering owners and operators of unregistered IBRs).

[73] 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.

[74] *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042 (Oct. 19, 2023) ("*Order 901*").

proposed revisions also include streamlined comment and ballot procedures for draft Reliability Standards, as well as revisions that would both allow NERC the flexibility to implement the streamlined comment and ballot procedures proposed in the petition and consider other streamlining enhancements that may be appropriate and consistent with a fair and open process in the future. Comments on the proposed revisions to NERC's RoPs were due on or before October 6, 2023. The one set of comments filed was submitted jointly by the American Public Power Association ('APPA"), the Large Public Power Council ("LPPC"), and the Transmission Access Policy Study Group ("TAPS") (collectively, the "Joint Commenters").

- **2024 NERC/NPCC Business Plans and Budgets (RR23-3)**

On October 19, 2023, the FERC accepted NERC's proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2024.[75] As previously reported, NERC's 2024 funding requirement represents an overall increase of approximately 12.5% over NERC's 2023 funding requirement, the NPCC U.S. allocation of NERC's net funding requirement is $12.26 million, NPCC's statutory funding is $22.01 million (a U.S. assessment per kWh (2022 NEL) of $0.000021), and NPCC's non-statutory funding is $1.15 million. Unless the October 19 order is challenged, this matter will be concluded.

- **Report of Comparisons of 2022 Budgeted to Actual Costs for NERC and the Regional Entities (RR23-2)**

On October 26, 2023, the FERC accepted[76] NERC's annual comparisons of actual to budgeted costs for 2022 for NERC and the six Regional Entities operating in 2022,[77] including NPCC. The Report included comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2020 budgets and actual results.

XI. Misc. - of Regional Interest

- **203 Application: Three Corners Solar/Three Corners Prime Tenant (EC23-90)**

On July 28, 2023, the FERC authorized[78] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). Pursuant to the July 28 order, Lessor and Lessee must file a notice 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 concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Energy Harbor / Vistra (EC23-74)**

On April 17, 2023, Energy Harbor Corp., on behalf of Energy Harbor, LLC and Energy Harbor Nuclear Generation LLC (collectively, the "Energy Harbor Public Utilities"), and Vistra Corp. ("Vistra"), requested FERC authorization for a proposed transaction pursuant to which the Energy Harbor Public Utilities and certain Vistra subsidiaries that are public utilities will become indirectly owned by a newly-formed subsidiary holding company of Vistra – Vistra Vision. Comments on this 203 application were due on or before June 23, 2023. Protests and comments were filed by Northeast Ohio Public Energy Council ("NOPEC"), Office of the Ohio Consumers' Counsel ("OH OCC"), and Monitoring Analytics, LLC (the PJM IMM). Public Citizen filed a doc-less intervention. Vistra and the Energy Harbor Public Utilities responded to the protests and comments. Answers to that answer were filed by

[75] *N. Amer. Elec. Rel. Corp.*, 185 FERC ¶ 61,047 (Oct. 19, 2023).

[76] *N. Amer. Elec. Rel. Corp.*, Docket Nos. RR23-2-000 and RR23-2-001 (Oct. 26, 2023) (unpublished letter order).

[77] Midwest Rel. Org. ("MRO"), Northeast Power Coordinating Council, Inc. ("NPCC"), ReliabilityFirst Corp. ("ReliabilityFirst"), SERC Rel. Corp. ("SERC"), Texas Rel. Entity, Inc. ("Texas RE"), and Western Elec. Coordinating Council ("WECC").

[78] *Three Corners Solar, LLC and Three Corners Prime Tenant, LLC*, 184 FERC ¶ 62,060 (Jul. 28, 2023).

PJM's IMM. Comments were filed by the Justice Department's Antitrust Division on August 22; Vistra and Energy Harbor answered those comments on September 5.

Deficiency Letter. on August 17, 2023, the FERC issued a deficiency letter identifying the additional information that it needs to process the application. Vistra and Energy Harbor responded to the deficiency letter on September 18, 2023 ("Deficiency Letter Response"). The Deficiency Letter Response constituted an amendment to the application. Comments on the Deficiency Letter Response were due on or before October 10, 2023. Comments were filed by NOPEC, OH OCC, and the PJM IMM. On October 20, Vistra and Energy Harbor answered the OH OCC and PJM IMM comments.

Tolling Order. On October 13, 2023, the FERC issued a notice that it requires additional time to "fully analyze the Application" and tolled the deadline to act on the Application until ***April 11, 2024***.[79]

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

- **PURPA Enforcement Petition: Allco Finance Limited (VT PUC) (EL23-92)**

On August 14, 2023, Allco Finance Limited ("Allco") petitioned the FERC to initiate an enforcement action against the Vermont Public Utility Commission ("VT PUC") to remedy what it asserts is the VT DPUC's improper implementation of PURPA. Allco states that the VT PUC has implemented a state law that (i) purports to redefine the size of a Qualifying Facility ("QFs") under PURPA in Vermont, (ii) bars the use of the FERC's least-cost interconnection cost responsibility for a QF's interconnection cost, and (iii) empowers the VT DPUC to exclude all non-hydroelectric QFs greater than 2.2 MW from participating in solicitations for energy and capacity for Vermont's utilities. VT PUC filed a doc-less intervention. On August 24, 2023, VT PUC requested an extension of time to answer the Allco complaint. On August 30, 2024, the FERC granted VT PUC an extension of time, to September 15, 2023, to answer the complaint. On September 14, 2023, VT PUC answered the Allco Complaint.

FERC Notice of Intent Not to Act. On October 15, 2023, the FERC issued a notice of its intent not to initiate an enforcement action in response to the Allco VT PUC Complaint.[80] The FERC's decision not to act means that Allco may itself bring an enforcement action against the VT PUC in the appropriate court.[81] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

- **CL&P / WE 400 Groton Road D&E Agreement (ER24-303)**

On November 1, 2023, Eversource Energy, on behalf of The Connecticut Light & Power Company ("CL&P"), filed a Design & Engineering ("D&E") Agreement that sets forth the terms and conditions under which CL&P will perform necessary engineering, procurement and design services in connection with the interconnection of WE 400 Groton Road's 50 MW-load data center to CL&P's North Bloomfield 2A 115 kV substation. An effective date of November 2, 2023 was requested. Comments on this filing are due on or before ***November 22, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR-ENE Use Rights Transfer Agreement (ER24-269)**

On October 31, 2023, NSTAR filed for acceptance an Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") between itself and ENE. An effective date of

[79] *Energy Harbor Corp. and Vistra Corp.*, 185 FERC ¶ 61,024 (Oct. 13, 2023).

[80] *Allco Finance Ltd. Et al.*, 185 FERC ¶ 61,006 (Oct. 13, 2023).

[81] 16 U.S.C. § 824a-3(h)(2)(B).

November 26, 2023 was requested. Comments on this filing are due on or before ***November 20, 2023.*** If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Amendment: PSNH/NECEC (ER23-2645)**

On October 13, 2023, the FERC accepted an amendment to the First Engineering, Design and Procurement Agreement ("D&E Agreement") between Public Service Company of New Hampshire ("PSNH") and NECEC Transmission LLC ("NECEC").[82] As previously reported, the revised D&E Agreement sets forth the terms and conditions under which PSNH was to undertake certain design and engineering activities for the mitigation of violations identified in the preliminary initial interconnection analysis summary for NECEC's proposed 1,200 MW high-voltage direct current ("HVDC") line from Québec to Lewiston, ME (Queue Position #979). The amendment was accepted effective as of August 18, 2023. Unless the October 13 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).

- **MPD OATT Changes to Depreciation Rates in Formula Rate (ER23-2085)**

On October 19, 2023, the FERC accepted a revised Attachment J to Versant Power's OATT for Maine Public District (the "MPD OATT") to (i) revise its Transmission Plant depreciation rates to reflect a recent depreciation study; and (ii) harmonize the General Plant depreciation rates set forth the MPD OATT with those recently approved by the MPUC for distribution ratemaking purposes.[83] The revised Attachment J was accepted effective as of June 1, 2024 (which is the first date of the next rate year under the MPD OATT formula rate), as requested. Unless the October 19 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).

- **LSAs: RI Energy/ISO-NE/BIPCO (ER23-1003; ER23-1000)**

On January 31, 2023, ISO-NE and RIE filed two Local Service Agreements ("LSAs"), as replacements to two current New England Power TSAs (TSA-NEP-83 and TSA-NEP-86), to allow RI Energy to fully recover the Block Island Transmission System ("BITS") surcharge now that it is both Transmission Owner and Customer under these arrangements. On March 31, 2023, the FERC conditionally accepted the LSA replacing TSA-NEP-86 (ER23-1003), effective January 1, 2023, [84] and directed RI Energy, on or before May 1, 2023, to add language to the LSA to make explicit that the BITS Surcharge shall be subject to the Protocols for Schedule 21-RIE. That compliance filing was submitted on May 1, 2023 as directed. Also on March 31, 2023, FERC also issued a deficiency letter asking for additional information regarding whether the LSA replacing TSA-NEP-83 (ER23-1000) is subject to the Schedule 21-RIE Protocols. The response to the deficiency letter was also filed, as directed, on May 1, 2023. Comments on both May 1 filings were due on or before May 22, 2023. On May 22, RI Division of Public Utilities and Carriers ("RI Division") filed a protest requesting that the FERC reject RIE's May 1 compliance filing and direct it to amend the TSA to incorporate the formula rate protocols contained in ISO-NE OATT Attachment F, Appendix C (ER23-1003). No comments on RIE's May 1 deficiency letter response were filed (ER23-1000-001). On June 27, ISO-NE and RIE filed a joint motion requesting the FERC hold both proceedings in abeyance to allow RIE to continue discussions with the RI Division to resolve concerns raised by the Division, the resolution of which will affect the LSAs.

Amendments. On October 23, 2023, RIE filed amendments to the LSAs to incorporate the information and challenge procedures contained in Attachment F, Appendix C to the ISO-NE OATT. Those procedures would replace the section O (Audit Provisions) from Schedule II-B of NEP Tariff No. 1 that RIE proposed to incorporate in its Deficiency Response. In filing the Amendments, ISO-NE and RI Energy asked that the FERC no longer hold these

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[82] *Public Service Co. of New Hampshire*, Docket No. ER23-2645-000 (Oct. 13, 2023) (unpublished letter order).

[83] *Versant Power*, Docket No. ER23-2085-000 (Oct. 19, 2023) (unpublished letter order).

[84] *ISO New England Inc.*, Docket No. ER23-1003-000 (Mar. 31, 2023) (unpublished letter order).

proceedings in abeyance. Comments on the Amendments are due on or before ***November 13, 2023***. If you have any questions, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **ACPA Petition for Capacity Accreditation Technical Conference (AD23-10)**

On August 22, 2023, the American Clean Power Association asked the FERC to convene a technical conference "to explore ways to improve the accreditation of resources' capacity value in ISO/RTO regions with and without capacity markets, as well as in non-ISO/RTO regions. Comments on the ACPA request were due on or before October 2, 2023. The IRC opposed the ACPA request. Comments supporting, or not opposing, a technical conference were filed by, among others: ACRE, AEU, Calpine, Colorado PUC, EPSA, NYU Law School Policy Integrity Institute, Pine Gate Renewables, SCE, SEIA, Sierra Club, UCS, and University of Chicago Law School. Both ACPA and the PJM IMM answered the October 2 comments. This matter is pending before the FERC.

- **Reliability Technical Conference (AD23-9)**

On November 9, 2023, the FERC will convene its annual Reliability Technical Conference. The purpose of the Conference is to discuss policy issues related to the reliability and security of the Bulk-Power System ("BPS"). The Conference will also discuss the impact on electric reliability of the Environmental Protection Agency's ("EPA") proposed rule under section 111 of the Clean Air Act. The conference will include the following Commissioner-led and staff-led panels: Morning Panel 1: State of Bulk Power System Reliability with a Focus on the Changing Resource Mix and Resource Adequacy (Commission Led); Morning Panel 2: CIP Reliability Standards and the Evolving Grid (Commission Led); Afternoon Panel 1: EPA Presentation of EPA Section 111 Proposed Rule (Commission Led); and Afternoon Panels 2 (Electric Industry Stakeholders Panel) and 3 (Regional, State, and Local Regulatory Entities Panel): Discussion of the Proposed Rule (Staff Led). For further information, please see the FERC's October 30, 2023 Second Supplemental Notice of Technical Conference. On October 30, 2023, ISO-NE submitted pre-technical conference comments.

- **Interregional Transfer Capability Transmission Planning & Cost Allocation Requirements (AD23-3)**

On December 5-6, 2022, the FERC held a workshop to discuss whether and how the FERC could establish a minimum requirement for Interregional Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes. Specifically, topics included: how to determine the need for and benefit of setting a minimum requirement for Interregional Transfer Capability; what to consider in establishing a potential Interregional Transfer Capability requirement, including who would be responsible for determining a minimum Interregional Transfer Capability requirement and what would be the objective and drivers of such a requirement; what process could be used in establishing a minimum Interregional Transfer Capability requirement to determine key data inputs, modeling techniques, and relevant metrics; and how costs for transmission facilities intended to increase Interregional Transfer Capability should be allocated and how to ensure a minimum amount of Interregional Transfer Capability is achieved and maintained. On February 28, 2023, the FERC invited all those interested to file post-workshop comments to address issues raised during the workshop and the questions listed in the workshop's Supplemental Notices issued on November 30 and December 2, 2022. Comments were due on or before May 15, 2023. Post-workshop comments were filed by, among others: Advanced Energy United ("AEU"), Invenergy, Vistra/NRG, ACPA, ACRE, APPA, ELCON, NRECA, Public Interest Orgs, Eastern Interconnection Planning Collaborative, and the US DOE. Reply comments were due on or before June 28, 2023 and were filed by, among others: AEP, AEU, Clean Energy Buyers Assoc., EEI, EPSA, ITC, MISO, NRDC, Vistra/NRG. Since the last Report, Commissioner Danly responded to US Senator Charles Shumer's June 20, 2023 letter addressing FERC's proposed rulemakings related to transmission planning and cost allocation. This matter is pending before the FERC.

[85] Reporting on the following Administrative proceeding has been suspended since the last Report and will be continued if and when there is new activity to report: Interregional HVDC Merchant Transmission (AD22-13); Transmission Planning and Cost Management Technical Conference (AD22-8); and Modernizing Electricity Market Design - Resource Adequacy (AD21-10).

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

The Second New England Gas-Electric Forum (June 20, 2023 in Portland, ME). As discussed and summarized at the 2023 Summer Meeting, the FERC held on June 20, 2023, in Portland Maine, a second New England Winter Gas-Electric Forum to discuss possible solutions to the electricity and natural gas challenges facing the New England region. Pre-Forum Comments and Position Statements were filed by: ISO-NE (Ltr, Opening Presentation, Extreme Weather Risks), Constellation (Allen), Eversource (Daly, Divatia), NEPGA (Dolan), NextEra (Gardner), NHOCA, Vistra, NERC/NPCC, Excelerate, Orsted (DiOrio), National Grid (Holodak), Enbridge, Kinder Morgan, Berkshire Environmental Action Team, and Repsol.

On July 10, 2023, the FERC issued a notice inviting parties to submit comments regarding the topics discussed at the Second Forum. Comments were due by August 24, 2023 and were filed by, among others: NEPOOL, NESCOE, Acadia Center, AEU, Avangrid, Calpine, CLF/UCS/Sierra Club, Constellation, Eversource, FirstLight, Generation Bridge, IECG, LS Power, CT OCC, Maine OPA, MA AG, NH OCA, National Grid, NECOS, New England LDCs, New Leaf, PowerOptions, Public Systems, Repsol, RI Energy, VEIC, Maine PUC, MA DPU, EPSA, INGAA, NGA, Berkshire Envir. Action Team, Fix the Grid Campaign, and Potomac Economics. A final transcript of the Forum was posted to eLibrary on July 21, 2023.

The First New England Gas-Electric Forum (September 8, 2022 in Burlington, VT). The purpose of the First 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 7, 2022. Post-Forum Comments were submitted by: ISO-NE, Acadia, AEU, AIM, Calpine, Constellation, Excelerate, FirstLight, LS Power, NECOS, NEPGA, NESCOE, Public Systems, Repsol, TOs, VELCO, Vistra, Potomac Economics, CT DEEP, AEMA, APGA, EPSA, INGA, NE LDCs, NGSA, New England Council, NEPPA, NH BIA, PIOs, RENEW/ACPA, Berkshire Action Team, Greater Concord Chamber of Comm., Mass. Alliance for Econ. Dev., Mass. Business Roundtable, Mass. Coalition for Sustainable Energy, Mass. United Assoc. of Journeymen, Middlesex County Chamber of Commerce, Public Citizen, Western Mass. Economic Dev. Council, and Individual Citizens (M. Axner, E. Blank, S. Botkin, D. Heimann, J. Krieger, B. Little, I. McDonald, J. Neville, W. Persons, R. Spector). On November 22, National Grid filed reply comments.

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

As previously reported, a transcript of the last (7th) meeting[86] of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF") is posted in eLibrary.[87] In addition, on August 29, 2023, the FERC issued an order listing the state commission representatives who will serve on the Task Force, each for a one-year term, commencing September 1, 2023, and expiring August 31, 2024, including Commissioner Riley Allen (VT PUC) and Chair Marissa Gillett (CT PURA) from the NECPUC region.[88] Since the last

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

[87] *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 Marissa Gillett (Chair, CT PURA). *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

[88] The 2023/24 State Commissioner Transmission Task Force members are: (1) Commissioner John Howard, NY PSC; (2) President Joseph Fiordaliso, NJ BPU; (3) Chair Andrew French, KS Corp. Comm.; (4) Chair Dan Scripps, MI PSC; (5) Commissioner Riley Allen, VT PUC;

Report, NARUC nominated PA PUC Vice Chair Kimberly Barrow to serve out the remainder of the one-year term created by the passing of NJ BPU President Joseph L. Fiordaliso.

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

On July 28, 2022, the FERC issued a NOPR[89] 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[90] requested an additional month to submit comments.[91] On September 14, 2022, the FERC granted that request. Accordingly, initial comments were due November 11, 2022 and over 30 sets of comments were filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA, APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange. The US Chamber of Commerce filed reply comments on December 12, 2022. There was no activity in the proceeding since the last Report. This matter is pending before the FERC.

- ***Order 897*: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)**

On June 15, 2023, the FERC adopted a reporting requirement[92] that directs transmission providers to file a one-time informational report describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[93] (whether and how transmission providers 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). Each transmission provider was required to file the one-time informational report required by *Order 897* on or before October 25, 2023.[94] ISO-NE and the TOs submitted their 51-page Report on October 25, 2023.

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(6) Chair Marissa Gillett, CT PURA; (7) Commissioner Kimberly Duffley, NC Utils. Comm.; (8) Chair Tricia Pridemore, GA PSC; (9) Commissioner Darcie Houck, CA PUC; and (10) Chair Thad LeVar, Utah PSC. *Joint Federal-State Task Force on Electric Transmission*, 184 FERC ¶ 61,126 (Aug. 29, 2023) (Order on Nominations).

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

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

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

[92] *One-Time Informational Reports on Extreme Weather Vulnerability Assessments; Climate Change, Extreme Weather, and Elec. Sys. Rel.*, Order No. 897, 183 FERC ¶ 61,192 (June 15, 2023) ("*Order 897*").

[93] The FERC defines an extreme weather vulnerability assessment as any analysis that identifies 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.

[94] *Order 897* was published in the *Fed. Reg.* on June 27, 2023 (Vol. 88, No. 122) pp. 41,477-41,499.

- ***Order 2023*: Interconnection Reforms (RM22-14)**

On July 28, 2023, the FERC issued Order 2023,[95] its final rule on proposed 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* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. *Order 2023* adopts reforms to: (i) implement a first-ready, first-served cluster study process;[96] (ii) increase the speed of interconnection queue processing;[97] and (iii) incorporate technological advancements into the interconnection process.[98] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of Proposed Rulemaking.[99] However, the FERC did revise aspects of the reforms.[100] *Order 2023* will become effective November 6, 2023,[101] which is 60 days from the September 6, 2023 publication of *Order 2023* in the *Federal Register* ("Publication Date").

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[95] *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*").

[96] A first-ready, first-served cluster study process improves efficiency in the interconnection study process by including the following elements: increased access to information prior to entering the queue; a mechanism to study interconnection requests in groups where all interconnection requests in the group are equally queued and of equal study priority; and increased financial commitments and readiness requirements to enter and proceed through the queue. In contrast, the existing first-come, first-served serial study process in the *pro forma* LGIA and LGIP provides limited information to interconnection customers prior to entering the queue, assigns interconnection requests an individual queue position based solely on the date of entry into the queue, and contains limited financial and readiness requirements.

In order to implement a first-ready, first-served cluster study process, *Order 2023* requires: (1) transmission providers to publicly post available information pertaining to generator interconnection; (2) transmission providers to use cluster studies as the interconnection study method; (3) transmission providers to allocate cluster study costs on a pro rata and per capita basis; (4) transmission providers to allocate network upgrade costs based on a proportional impact method; (5) interconnection customers to pay study and commercial readiness deposits as part of the cluster study process; (6) interconnection customers to demonstrate site control at the time of submission of the interconnection request; and (7) transmission providers to impose withdrawal penalties on interconnection customers for withdrawing from the interconnection queue, with certain exceptions. We also require transmission providers to adopt a transition process to move from the existing serial interconnection process to the new cluster study process.

[97] In order to increase the speed of interconnection queue processing, *Order 2023*: (1) eliminates the reasonable efforts standard for conducting interconnection studies and imposes a financial penalty on transmission providers that fail to meet interconnection study deadlines; and (2) establishes an affected system study process and associated *pro forma* affected system agreements.

[98] In order to incorporate technological advancements into the interconnection process, *Order 2023* requires transmission providers to: (1) allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request; (2) evaluate the proposed addition of a generating facility at the same point of interconnection prior to deeming such an addition a material modification if the addition does not change the originally requested interconnection service level; (3) allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA; (4) use operating assumptions in interconnection studies that reflect the proposed charging behavior of an electric storage resource; and (5) evaluate the list of alternative transmission technologies enumerated in this final rule during the generator interconnection study process.

[99] *Order 2023* also requires: (i) interconnection customers requesting to interconnect a non-synchronous generating facility to: (a) provide the transmission provider with the models needed for accurate interconnection studies; and (b) have the ability to maintain power production at pre-disturbance levels and provide dynamic reactive power to maintain system voltage during transmission system disturbances and within physical limits; (ii) all newly interconnecting large generating facilities provide ride through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis; and (iii) with respect to the *pro forma* SGIP and *pro forma* SGIA, the incorporation of enumerated alternative transmission technologies into the interconnection process, and the provision of modeling and ride through requirements for non-synchronous generating facilities.

[100] Reforms revised in *Order 2023* pertain to the cluster study process, allocation of cluster study and network upgrade costs, increased financial commitments and readiness requirements, financial penalties for delayed interconnection studies, the affected system study process, pro forma affected system agreements, the material modification process, operating assumptions for interconnection studies, incorporating the enumerated alternative transmission technologies, and ride through requirements. In addition, the FERC declined to adopt the NOPR proposals pertaining to informational interconnection studies, shared network upgrades, the optional resource solicitation study, and the alternative transmission technologies annual report.

[101] *Order 2023* was published in the Fed. Reg. on Sep. 6, 2023 (Vol. 88, No. 171) pp. 61,041-61,349.

Importantly, the FERC is requiring the submission of compliance filings within 90 calendar days of the Publication Date, or ***December 5, 2023*** (rather than the 180 days proposed in the NOPR). The FERC said it "believe[s] that it is important to implement this final rule in a timely manner, given the pressing need to reform the interconnection processes, as discussed in this final rule." The FERC went on to explain that, on the FERC-approved effective date of the transmission provider's compliance filing with this final rule, the transmission provider will commence the transition study process. After the conclusion of the transition study process, the transmission provider will begin the first standard cluster study process, and in its compliance filing, the transmission provider will indicate the number of calendar days after the conclusion of the transition study process when it will begin this first standard cluster study process (e.g., 30 calendar days after the conclusion of the transition study process).

A more detailed summary of, and a presentation on, *Order 2023* was provided to, and discussed with, the Transmission Committee. Compliance will require changes to the Tariff's *pro forma* LGIA, LGIP, SGIA and SGIP. Absent further changes to the compliance schedule, there will be much to accomplish in a relatively short amount of time.

Requests for Clarification and/or Rehearing. Requests for rehearing, clarification and/or an extension of time were filed by 35 parties. Those parties raised, among other issues, the following:

- The FERC erred in removing the Reasonable Efforts standard and imposing penalties for late studies;
- The FERC must clarify aspects of the transition process and use of Transitional Cluster Studies and Transitional Serial Studies;
- Transmission Providers need additional details on the FERC's requirement for Transmission Provider's to publish heatmaps;
- The FERC must provide insight on the process of performing cluster studies as well as the cost allocation methodology; and
- Transmission Providers require further clarity regarding the alternative transmission technologies that they are required to review.

Requests for Clarification and/or Rehearing Denied by Operation of Law. On September 28, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[102] The *Order 2023 Allegheny Notice* confirmed that the 60-day period during which a petition for review of *Order 2023* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of *Order 2023* within the required 30-day period. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." Several parties submitted petitions in Federal Court challenging *Order 2023*. Developments in those proceedings will be report on in Section XVI below.

Requests for Extension of Time. As previously reported, PJM, MISO and SPP ("***Joint RTOs***") requested an extension of time, to at least 90 days after the FERC issues a substantive order addressing the arguments on clarification and rehearing, with a request that an order on that request be issued by September 27, 2023. ***NEPOOL*** requested on October 2, 2023 a 45-day extension of time, to January 19, 2024, to permit adequate regional stakeholder consideration of, input into, and a vote on ISO-NE's proposed *Order 2023* compliance filing. ***EEI*** on September 13, 2023, while supporting Joint RTOs' approach, proposed an alternative that would: extend the compliance deadline until the later of: (i) 90 days after the FERC issues a substantive order addressing arguments on clarification and rehearing (as requested by the Joint RTOs) or (ii) 180 days after Order 2023 was

[102] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 62,163 (Sep 28, 2023) ("*Order 2023 Allegheny Notice*").

published in the *Federal Register*, or March 4, 2024. ***Joint California Utilities***[103] requested an extension of their deadline to 90 days following the FERC's approval of CAISO's compliance filing. ***SPP*** also requested an extension of the compliance deadline after the last Report.

October 25, 2023 Order Extending Compliance Deadline. On October 25, 2023, the FERC issued an order modifying the discussion in *Order 2023* and setting aside the *Order*, in part, to extend the deadline to submit compliance filings to ***April 3, 2024*** (210 days after the publication of *Order 2023* in the *Federal Register*).[104] The FERC clarified that its Order does not change or modify any other determination or other deadlines established by *Order 2023*, including the deadline for eligibility for interconnection customers to opt to proceed with a transitional serial study (for those interconnection customers tendered a facilities study agreement) or transitional cluster study (for those interconnection customers assigned a queue position) or to withdraw their interconnection requests without penalty (i.e., 30 calendar days after the transmission provider submits its initial compliance filing (or ***May 3, 2024***)).[105] A revised stakeholder schedule for consideration of New England's Order 2023 compliance filing will be discussed at the scheduled November 9, 2023 Transmission Committee meeting.

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

- ***Order 895*: ISO/RTO Credit Information Sharing (RM22-13)**

On June 15, 2023, the FERC amended its regulations to require ISO/RTOs to have tariff provisions that permit credit-related information sharing with other ISO/RTOs to ensure that credit practices in those markets result in jurisdictional rates that are just and reasonable.[106] *Order 895* will not permit 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 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 stated that the ability of ISO/RTOs to share credit-related information among themselves will improve their ability to accurately assess market participants' credit exposure and risks related to their activities across organized wholesale electric markets and should also enable ISOs/RTOs to respond to credit events more quickly and effectively, minimizing the overall credit-related risks of unexpected defaults by market participants in organized wholesale electric markets. *Order 895* became effective *August 21, 2023*.[107] ISO-NE's proposed compliance changes were supported via the October 5 Consent Agenda (Item # 6), filed, and are pending before the FERC (*see* Section III above).

- **NOPR: Transmission Siting (RM22-7)**

On December 15, 2022, the FERC issued a NOPR[108] proposing to revise its regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act. The *Transmission Siting NOPR* is intended to ensure consistency with the Infrastructure and Jobs Act's amendments to FPA section 216, to modernize certain regulatory requirements, and to incorporate other updates and clarifications to provide for the efficient and timely review of permit

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103 "Joint California Utilities" are: Pacific Gas and Electric Co.; ("PG&E"), San Diego Gas & Electric Co. ("SDG&E"), and Southern California Edison Co. ("SCE").

104 *Improvements to Generator Interconnection Procedures and Agreements*, 185 FERC ¶ 61,063 (Oct. 25, 2023).

105 *Id.* at P 11.

106 *Credit-Related Info. Sharing in Organized Wholesale Elec. Mkts*, Order No. 895, 183 FERC ¶ 61,193 (June 15, 2023) ("*Order 895*").

107 *Order 895* was published in the Fed. Reg. on June 22, 2023 (Vol. 88, No. 119) pp. 40,696-28,125.

108 *Applications for Permits to Site Interstate Electric Transmission Facilities*, 181 FERC ¶ 61,205 (Dec. 15, 2022) ("*Transmission Siting NOPR*").

applications. Following a NARUC request for an extension of time granted by the FERC, comments on the *Transmission Siting NOPR* were due on or before May 17, 2023. Comments were filed by CLF, AL PSC, National Wildlife Federation Action Fund, National Wild Life Federation and State-Affiliated Organizations, AEU, CLF (May 16), NESCOE, ACPA, ACRE, Clean Energy Buyers Assoc., EDF, EEI/WIRES, Joint Consumer Advocates, Public Interest Organizations, SEIA, and US Chamber of Commerce. Commissioner Phillips' and each of the Commissioners' responses to Senator Schumer's and Senator Barrasso's letters have been posted to eLibrary. This matter is pending before the FERC.

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

Following its ANOPR process,[109] the FERC issued on April 21, 2022 a NOPR[110] 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

[109] *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, AEU, 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, AEU, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, a group of former military leaders and former Department of Defense officials, and ACPA/AEU/SEIA.

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

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 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.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[111] Nearly 200 sets of comments were filed, including comments by NEPOOL, ISO-NE, Acadia/CLF, Anbaric, AEU, 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, AEU, 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. On November 28, 2022, the New Jersey BPU moved to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's State Agreement Approach ("SAA") for the purpose of supporting New Jersey's offshore wind ("OSW") goals, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report, which it stated demonstrates that competitive transmission solicitations can provide significant value to consumers. In December 2022, the Harvard Electricity Law Initiative, and P. Alaama submitted further comments.

LS Power and NRG filed comments in this proceeding, as well as in (Transmission Planning and Cost Management Joint Federal-State Task Force on Electric Transmission) (AD22-8) and JFSTF proceeding (AD21-15). They asserted that the FERC "cannot sufficiently address the transmission planning issues raised in its Transmission NOPR without addressing the intertwined cost management issues raised in AD22-8-000 and during the October 6, 2022 Technical Conference in AD22-8."

This matter remains pending before the FERC. 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).

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **AES Alamitos/Redondo Beach (IN23-15)**

On October 24, 2023, the FERC approved a Stipulation and Consent Agreement with AES Alamitos, LLC and AES Redondo Beach, LLC (collectively, "AES")[112] that resolved OE's investigation into whether AES, through the submission of inaccurate Physical Maximum (Pmax) values for eight of its electric generating resources located in Southern California (the "Resources") violated CAISO's Tariff and FERC statues and regulations. The Office of Enforcement determined that 12. During the Relevant Period, AES sold

[111] 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.

[112] *AES Alamitos, LLC and AES Redondo Beach, LLC*, 185 FERC ¶ 61,060 (Oct. 24, 2023).

Resource Adequacy ("RA") contracts for the Resources up to their Master File Pmax values and, in some cases, financially benefitted from RA payments for capacity the Resources could not physically provide. Under the Stipulation and Consent Agreement, in which AES neither admits nor denies the alleged violations, AES agreed to ***disgorge $2.97 million*** to CAISO, to pay a ***$1.2 million civil penalty***, and to submit compliance monitoring reports for 2 years (or 3 years at OE's discretion). 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)**

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[113] suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[114] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

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

On December 16, 2021, the FERC issued a show cause order[115] 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,[116] 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;[117] (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

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[113] See *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*"). The hearings will be 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.

[114] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 183 FERC ¶ 61,190 (June 14, 2023) ("*June 14 Order*").

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

[116] *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").

[117] 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.

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.[118] This matter is pending before the FERC.

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

On April 28, 2016, the FERC issued a show cause order[119] 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.[120]

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.[121] On July 27, 2021, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule for the proceeding.

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas ("Southern District"). In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance.[122]

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[123] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *TGPNA Presiding Officer Reassignment Order* takes effect; (ii) held that the *TGPNA Presiding Officer Reassignment Order* will take effect once the Southern District clarifies or lifts its stay for the limited purpose of allowing the *TGPNA Presiding Officer Reassignment Order* to take effect or the stay is lifted or

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[118] *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.

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

[120] 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.

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

[122] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 181 FERC ¶ 61,252 (Dec. 21, 2022).

[123] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 183 FERC ¶ 61,189 (June 14, 2023) ("*TGPNA Presiding Officer Reassignment Order*").

dissolved such that hearing procedures may resume; (iii) stated that this proceeding otherwise remains suspended until the Southern District's stay is lifted or dissolved such that hearing procedures may resume; and (iv) provided procedural guidance to the new presiding officer. On July 18, Judge Patricia M. French was substituted as Presiding Judge (relieving Judge Krolikowski of all of her duties with respect to this proceeding).

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.[124] 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.
  - In its September 8, 2023 monthly status report, Iroquois indicated that it is awaiting issuance of air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois has not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in August 2023 and no construction was planned for September.

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,[125] and that effectively halted construction

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

[125] 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?"

of the NECEC Project,[126] 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).

On April 20, 2023, after a week-long trial, a jury ruled 9-0 that developers had completed enough work in good faith before the passage of the ballot question to have a constitutional right to proceed with construction. Based on that verdict, a state judge is expected to conclude that the referendum was unconstitutional. The decision will almost certainly be appealed to the Maine Supreme Judicial Court for a final say.

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 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).

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170)(consolidated)**
  Underlying FERC Proceeding: ER22-983[127]
  Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
  Status: Being Held In Abeyance; Motions to Govern Future Proceedings Due Jan 24, 2024

On June 30, 2023, ISO-NE (23-1168), CMP/UI (23-1170), Eversource (23-1167), and National Grid (23-1169) petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the FERC's *Order 2222 Compliance Orders*.[128] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case. On July 24, 2023, the FERC moved to have the consolidated cases held in abeyance pending the issuance of the Commission's further order on rehearing. The Court granted that motion on July 27, 2023, with the case to be held in abeyance pending further order of the Court. Since the last Report, on October 10, 2023, the FERC asked that the consolidated appeals be held in abeyance for a period of 90 days to allow time for all parties to assess the FERC's recent order and to make further filings either with the FERC or with the Court. On October 12, the Court

[126] 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.

[127] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*Order 2222 Compliance Order*"); *ISO New England Inc. and New England Power Pool Participants Comm.*, 183 FERC ¶ 62,050 (May 1, 2023) ("*Order 2222 Compliance Allegheny Notice*", and together with the *Order 2222 Compliance Order*, the "*Order 2222 Compliance Orders*").

[128] In response to the region's *Order 2222 Changes*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*, as described in previous Reports. When filed, 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.

ordered that the consolidated cases remain in abeyance pending further order of the court. The parties were directed to file motions to govern future proceedings in this case by ***January 24, 2024***.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[129]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Briefing Underway

On April 4, 2023, NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC (collectively, "NextEra") petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the Seabrook Dispute.[130] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. As previously reported, initial submissions have been filed,[131] as have the Certified Index to the Record, NextEra's Petitioners' Brief, the FERC's Brief (filed on September 28, 2023), Intervenors for Respondent's Joint Brief (October 12, 2023); Petitioners' Reply Brief (October 26, 2023); and the Joint Appendix (October 30, 2023). Final Briefs are due ***November 3, 2023***. The parties will be informed later of the date of oral argument and the composition of the merits panel.

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[129] *NextEra Energy Seabrook, LLC and NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC*, 182 FERC ¶ 61,044 (Feb. 1, 2023) *("Seabrook Dispute Order*"), *reh'g denied by operation of law*, *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Notice*"); *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 61,196 (June 15, 2023) ("*Seabrook Dispute Allegheny Order*").

[130] In the Seabrook Dispute Order, the FERC (i) both denied and granted in part the Seabrook Complaint; (ii) dismissed the Seabrook Declaratory Order Petition; and (iii) directed Seabrook to replace the Seabrook Station breaker pursuant to its obligations under the Seabrook LGIA and Good Utility Practice. Specifically, the FERC denied the Seabrook Complaint in part because it found that Avangrid had "not shown that Seabrook is obligated to replace the breaker due to Seabrook failing to meet certain open access obligations or because Seabrook has failed to comply with Schedule 25 of the ISO-NE Tariff". However, the FERC found that, "under Seabrook's LGIA, Seabrook may not refuse to replace the breaker because it is needed for reliable operation of Seabrook Station and required by Good Utility Practice" and thus, given the specific facts and circumstances in the record, granted the Seabrook Complaint in part. With respect to cost issues, the FERC agreed with Avangrid that, in this case, Seabrook should not recover opportunity costs (e.g. lost profits, lost revenues, and foregone Pay for Performance ("PFP") bonuses) or legal costs. In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the Seabrook Dispute Order, that additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition. The breaker replacement is currently expected to take place during the Fall 2024 refueling outage and the commercial operation date for the NECEC Project is December 2024. Seabrook plans to file an agreement governing installation at the earlier of 30 days prior to delivery of the breaker or 120 days prior to the start of the Fall 2024 outage. The FERC noted its expectation that such an agreement would resolve whatever remaining issues exist between the parties to allow replacement of the breaker to move forward during the 2024 outage, or if not, an unexecuted agreement would be filed.

[131] Initial submissions include a Docketing Statement, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues, and the Underlying Decision from which the appeal arose (filed May 8, 2023), the Certified Index to the Record (filed July 21, 2023), and motions for leave to intervene (filed Apr. 14, 2023 by NECEC Transmission LLC and Avangrid, Inc. (collectively, "Avangrid") in support of the FERC).

- **Mystic II (ROE & *True*-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
  Underlying FERC Proceeding: EL18-1639-010, -011,[132] -013[133] -017[134]
  Petitioners: Mystic, CT Parties,[135] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Oct 25, 2023

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 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"*). 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*. The Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings related to MISO TOs, now on remand at the FERC. Most recently, on October 25, 2023, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the *MISO TOs* case. On October 26, 2023, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***January 24, 2024***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[136]
  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

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[132] *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).

[133] *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).

[134] *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*).

[135] In this appeal, "CT Parties" are the CT PURA CT PURA, Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the CT OCC.

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

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 the Court granted a few days later the request 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.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[137]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[138] 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*[139] 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 and that this appeal should continue to remain in abeyance, was filed on August 3, 2023.

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

[138] 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.

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

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[140]
  Petitioners: Sierra Club
  Status: Oral Argument Held Sep 18, 2023; Awaiting Decision

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. Briefing is complete. Oral argument before Judges Henderson, Pan and Rogers was held on September 18, 2023. This matter is pending before the Court.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[141]
  Petitioners: SEIA et al.
  Status: Decision Issued Granting in Part and Denying in Part SEIA's Petition

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[142] Briefing was completed and oral argument held March 8, 2022 before Judges Nguyen, Miller and Bumatay. On September 5, 2023, the Court issued a decision largely upholding *Order 872*. In its opinion, the 9th Circuit rejected Petitioners' objections to FERC's reforms, finding that PURPA provided the FERC discretion to construe PURPA and that FERC's interpretation of the statute in *Order 872* was reasonable and neither arbitrary nor capricious. The Court did agree, however, with the environmental organizations who joined the appeal that the FERC violated the National Environmental Policy Act ("NEPA") by failing to prepare an environmental assessment before issuing *Order 872*. Accordingly, the Court remanded the order without vacating it, directing the FERC to conduct a NEPA assessment. *Order 872* will remain in force while the FERC conducts the required NEPA assessment.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.)**
  Underlying FERC Proceeding: CP16-9-012[143]
  Petitioners: LS Power, Algonquin, INGA
  Status: Motions to Dismiss Cases Voluntarily Filed and Pending

Since the last Report, between motions filed by Algonquin and INGA, Petitioners have moved the Court to dismiss each of the consolidated cases. Reporting on this matter is now concluded.

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

[141] *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).

[142] *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.

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

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