Sebastian Lombardi
Secretary

August 30, 2023

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of September 7, 2023 Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the September 2023 meeting of the Participants Committee will be held **via teleconference/Webex on Thursday, September 7, 2023, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and approved guests, is **866-803-2146; Passcode: 7169224.** To join Webex, click this link and enter the event password **nepool**.

Looking ahead, please mark your calendars for the remaining Participants Committee meetings this year, each of which are planned to be held in person. October's meeting is on Thursday, **October 5** and will be at the Renaissance Providence Downtown Hotel, 5 Avenue of the Arts, **Providence**, RI, 02903. The Thursday, **November 2** meeting, which will be the day after the ISO Board's open meeting, will include modified Sector meetings with the ISO Board and regulators, and will be held at the Seaport Hotel, 1 Seaport Lane, **Boston**, MA, 02210. The **December 7** meeting is the Participants Committee annual meeting and will be at the Colonnade Hotel, 120 Huntington Ave, **Boston**, MA, 02116. If you are interested in taking advantage of the advanced arrangements to stay at these venues the night before the meetings, we urge you to let Jaki Sloan (jsloan@daypitney.com) and Pat Gerity (pmgerity@daypitney.com) know soon, since room availability will be limited.

We hope all of you have a wonderful Labor Day weekend. Looking forward to touching base virtually on September 7.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the June 27-29, 2023 and the August 3, 2023 Participants Committee meetings. A copy of the draft minutes for the June 27-29, 2023 and the August 3, 2023 meetings, marked to show changes from the drafts last circulated, are included with this supplemental notice.

2. To adopt and approve the action recommended by the Reliability 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. The September CEO report is included and posted with this supplemental notice.

4. To receive a report from the ISO Chief Operating Officer. The monthly Operations Report will be circulated and posted in advance of the meeting.

5. To receive a report on the following proposed budgets:

   a. 2024 ISO-NE Operating and Capital Budgets; and

   b. 2024 NESCOE Budget.

   Background materials are included and posted with this supplemental notice.

6. 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.

7. To receive reports from Committees, Subcommittees and other working groups:

   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Membership Subcommittee
   - Others

8. Administrative matters.

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

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

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.

PRELIMINARY

The 2023 Summer Meeting of the NEPOOL Participants Committee was held at The Equinox, Manchester Village, Vermont, on Tuesday, June 27, and Wednesday, June 28, pursuant to notice duly given, followed on Thursday, June 29, by meetings between modified Sector groups and ISO Board Members, state officials, and FERC staff, respectively. 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 attending the meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Secretary, recorded for the meeting.

JUNE 27, 2023 SESSION

The June 27, 2023 session began at 10:00 a.m., with Mr. Cavanaugh welcoming the members, alternates, federal and state officials, ISO colleagues, including members of the ISO Board, and guests who were present.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting, which included four items unanimously recommended for Participants Committee support by the respective Technical Committees. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Jon Lamson noted.

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, which had been circulated and posted in advance of the meeting, and invited questions. There were no questions or comments on those summaries.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, noting that his June 2023 report (with May data) had been circulated and posted earlier in the month and his July 2023 report (with June data) would be circulated early the following month, highlighted a few operations-related items. First, he stated that, although seasonal forecasts had called for above-average temperatures, June had been mild; July and August, however, were expected to be warmer. The ISO had assessed the impact of ~~the~~ an upcoming scheduled pipeline outage and had concluded that the outage would not have an adverse impact on reliability. He confirmed that, as reported, there had been and continued to be an outage at Seabrook Station, with no indication as to when the unit would come back on line.

Turning to the impact of the wildfires in Québec, he reported that the resulting smoke had caused the Phase II HVDC-TF Intertie with Hydro-Québec (Phase II) to trip three times, on June 22, 24 and 26, but some relief was expected given the rain forecasted for the remainder of the week. In response to questions, he said that ~~the~~ Phase II had not been operating at full capacity on any of those days. Looking ahead, and based on discussions with the Hydro-Québec control room, the ISO did not expect there to be any specific adverse reliability impacts from the drought conditions being experienced in Canada, with the 12-month supply from Hydro-Québec appearing to be secure and no drought-related reductions or curtailments impacting power delivery over Phase II expected during the winter.

Concluding his report, Dr. Chadalavada referred to his June 14 memorandum circulated to the Committee that outlined potential approaches for proceeding with the Resource Capacity Accreditation (RCA) project (RCA Memo). He explained that the options identified were not exhaustive nor was the final course set. He looked forward to discussing the potential options and receiving feedback during the Wednesday session.

ISO CFO REPORT: 2024/2025 ISO PRELIMINARY BUDGETS

Mr. Robert Ludlow, the ISO's Chief Financial Officer and Compliance Officer (CFO), referred the Committee to the presentation of the ISO's 2024 and 2025 preliminary "top down" Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. He stated that the preliminary budget presentation provided an opportunity for stakeholder review and feedback prior to presentation in August of the proposed detailed budget reflecting that feedback. He reported that he had also shared the preliminary budget information with New England state officials earlier in the month.

Mr. Ludlow discussed the following key drivers causing the proposed increase over the 2023 budget: (i) the net change in Revenue Requirement true-up; (ii) inflationary and continued operational increases, including inflationary increases to salaries and benefits; and (iii) additional investments in information technology (IT) infrastructure and licensing, cybersecurity, and the transition to cloud-based infrastructure. He projected that the proposed 2024 Operating Budget would reflect an overall increase, before true-up, of 15.4% over 2023.

Mr. Ludlow explained further that the 2024 proposed Capital Budget was $35 million, a $1.5 million increase over the 2023 Capital Budget. Areas driving capital costs included spending to replace the current market system (nGem platform), major reliability-related efforts, cyber security, and IT asset and infrastructure replacement. He noted further that, to support the future capital program, the ISO would have to secure roughly $75 - $90 million in private placement notes, and may have to secure short-term financing to fund the increases in the 2023 and 2024 programs(at least until the private placement notes are in place).

In response to questions, Mr. Ludlow provided additional explanation as to how the change in the application of the Revenue Requirement true-up operated to increase the overall budget amount by roughly 5.1%. He committed to provide in mid- to late-September, once the ISO's proposed budget numbers were closer to final, the increases in rates that would take effect under Schedules 1, 2 and 3 of the Tariff. He also provided additional context regarding employee turnover experienced by the ISO, with much of the turnover related directly to compensation, which was driving the reevaluation of the ISO's compensation program.

FAP CHANGES - ELIGIBLE LETTER OF CREDIT ISSUERS

Mr. Thomas Kaslow, Chairman of the Budget & Finance Subcommittee (Subcommittee), referred members to the materials circulated in advance of the meeting. He reviewed the changes to the Financial Assurance Policy (FAP) proposed by the ISO in response to the recent deterioration in financial condition of some of the banks on the ISO's List of Eligible Credit Issuers (List) (the Eligible LOC Issuer Changes). The Eligible LOC Issuer Changes would permit the ISO to disqualify a letter of credit (LOC) bank if the ISO determined in its sole discretion that accepting a LOC from that bank would present an unacceptable risk that the bank will fail to honor the LOC. Further, the Eligible LOC Issuer Changes expanded the circumstances in which the ISO could extend the period to replace a LOC to 20 Business Days, established requirements for notice to the Subcommittee when a bank is removed from its List, and established how a disqualified LOC bank could be reinstated to the List. He reported that the Proposal was reviewed at the Subcommittee's May 12 meeting, without any objections to the Proposal expressed by any Subcommittee member in attendance.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to the letter of credit bank eligibility standards in the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee with the June 20, 2023 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

The Committee then asked questions regarding the Eligible LOC Issuer Changes. In response, Mr. Chris Nolan, ISO Director, Market and Credit Risk, reported that there were no banks currently in a position to be dropped from the List if the Changes were implemented, though there had been at least one bank (since acquired by another bank) that would have met the criteria for being dropped from the List during the time in which the Proposal was being developed and vetted. Mr. Ludlow confirmed that there was no specific linkage between the Eligible LOC Issuer Changes and the proposed increase in employees for market and credit risk functions in the ISO's proposed 2024 Operating Budget. In addition, while Mr. Ludlow opined that the Eligible LOC Issuer Changes provided the ISO adequate flexibility to remove from, and reinstate banks to, the List, he acknowledged the potential burden and concerns for Market Participants that, in accordance with the deadlines identified in the FAP, would be required to replace their LOC provided by a bank removed from the List.

Without further discussion, the motion to support the Eligible LOC Issuer Changes was voted and approved unanimously, with abstentions noted by CPV, Jericho Power, Nautilus, Wheelabrator, and Mr. Lamson.

GIS OPERATING RULES AND GIS AGREEMENT WAIVER REQUEST – 777 MAIN STREET

Mr. Paul Belval, NEPOOL Counsel, introduced the request of 777 Residential LLC (Account Holder) for Committee action to waive certain Generation Information System (GIS) Operating Rules and portions of the GIS Agreement between APX and NEPOOL to allow for changes to the renewable energy certificates for Account Holder's Hartford, Connecticut fuel cell facility (777 Main Street). He explained that Account Holder was seeking the waiver so that its 2022 fourth quarter (Q4) certificates for 777 Main Street could be changed to be GIS eligible. Account Holder asserted that it was unable to have emissions data for 777 Main Street inputted before the requisite deadline due to IT/password complications accessing the GIS System on the day of the Q4 deadline. Efforts by Account Holder to separately have the Connecticut Public Utilities Regulatory Authority (CT PURA) recognize 777 Main Street's GIS Certificates as Connecticut Class I eligible had not, to date, been successful.

Members asked clarifying questions. In response, representatives for Account Holder and APX, Inc. (GIS Administrator) provided additional information from their perspectives regarding the circumstances surrounding the password complications and the pending request by Account Holder for access to any APX records regarding the password reset, which required NEPOOL authorization. Mr. Belval described the experience with the two most recent GIS waiver requests and the response by CT PURA to treat certificates differently than as registered in the GIS.

In discussion, members expressed both willingness and reluctance to support the requested waiver. Those supporting the waiver suggested that a softening of the hard line historically taken by the Participants Committee with respect to GIS waiver requests, given the ubiquitous nature of administrative snafus and human mistake, was warranted and encouraged others to support the waiver. Those inclined not to support the waiver focused on the role of the GIS as a tool to support state renewable energy requirements and were hesitant to participate in or unduly influence the ultimate determination by a state of the qualification of a renewable energy certificate.

Mr. Cavanaugh, informed the Committee that, on behalf of NEPOOL, he had directed APX to share with Account Holder, to the extent possible, the requested information related to the password re-set. Under these circumstances, he then suggested to the Committee that the matter move to the GIS Operating Rules Working Group (GIS WG) for a discussion and potential recommendation on the requested waiver once all the requested information had been provided to Account Holder. Consideration of, and action by, the Participants Committee on the 777 Main Waiver Request could be scheduled thereafter. He added that any changes or enhancements to the GIS system/processes identified as part of the consideration of the 777 Main Street request could be taken up separately in follow-up by the GIS WG using the established GIS rule change processes. Mr. Cavanaugh asked whether there was any objection or opposition to moving the matter to the GIS WG. No objection or opposition to that course of action was ultimately expressed.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the June 24 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following developments:

(i) *ISO Deficiency Letter Responses - Storage As Transmission-Only Assets (SATOA) (ER23-739/743) and IEP Parameters Updates (ER23-1588)*. Responses to the deficiency letters issued in the SATOA and IEP Parameters Updates proceedings, respectively, had been submitted by the ISO, each restarting the FERC's 60-day clock for action. The comment periods on those responses were about to end, with FERC actions anticipated thereafter;

(ii) *FERC-Initiated Section 206 Proceeding re Market Power Mitigation Rules (EL23-62)*. The FERC instituted a Section 206 proceeding on May 5, 2023, finding that some of the mechanics of the ISO's current market power mitigation rules, including consideration of any proposed fuel price adjustment(s), may be unjust and unreasonable. FERC had directed the ISO to show cause as to why the Tariff provisions remain just and reasonable or to identify changes to remedy the concerns identified in FERC's order; and

(iii) *FERC Order 895 (ISO/RTO Credit-Related Information Sharing)*. Closely adhering to its earlier Notice of Proposed Rulemaking, the FERC issued a final order requiring ISO/RTOs to amend their tariffs to permit the sharing of credit-related market participant information with other ISO/RTOs.

Mr. Lombardi encouraged anyone with questions on these highlights or on the full Report to reach out to him or any of NEPOOL counsel.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the MC would hold its next meeting on July 11. It had been rescheduled as a single day meeting, rather than the three-day meeting as originally noticed. A full meeting day agenda was projected, with votes to be taken on the Day-Ahead Ancillary Services Initiative (DASI) project, and a discussion on the RCA.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC would meet jointly with the Transmission Committee (TC) for a Summer Meeting in Newport, RI on July 18-19.

Transmission Committee. Mr. David Burnham, the TC Vice-Chair, reported that the TC would also meet next at the joint RC/TC Summer Meeting, with topics for consideration to include presentations on the ISO's response to the FERC's order conditionally accepting the region's Order 881 compliance filing and on the Participating Transmission Owners' annual update to the Regional Network Service rates. The TC was also schedule to take action on its pieces of the DASI project.

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the Subcommittee was next scheduled to meet on July 10.

Budget & Finance (B&F) Subcommittee. Mr. Thomas Kaslow reported that the B&F Subcommittee had no meeting scheduled in July, but two in August.

HOST STATE WELCOME REMARKS (TONY ROISMAN)

After a recess for lunch, Mr. Cavanaugh introduced Vermont Public Utility Commission Chairman Anthony Roisman for welcoming remarks on behalf of the host state. Chairman

Roisman reflected on the remarkable time of transition facing the region generally, and NEPOOL particularly. He noted the opportunity for NEPOOL, in its role as the region's stakeholder body, to bring together, as it had so successfully done in the past, diverging views to work together towards a common goal. He poignantly suggested that the region, at that particular moment in time (Point A), knew where it wanted to go, and knew when it wanted to get there (Point B) – it just had to work through the demanding task of getting from Point A to Point B. He suggested that the transition would require navigating the journey with considerations of equity, affordability and reliability. He thanked all those in attendance for their commitment to making the transition a successful one. He looked forward not only to the remainder of the meeting, but to a future of increased electrification, reduced climate change impacts and bountiful days for New England.

EMM 2022 ANNUAL MARKETS REPORT

Overview

Dr. David Patton, President of Potomac Economics and the ISO's External Market Monitor (EMM), presented highlights from the EMM's 2022 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. Dr. Patton introduced his presentation by noting that the EMM Annual Report complimented the report published by the ISO's Internal Market Monitor (IMM). He opined that the ISO's markets performed competitively in 2022 and that the EMM Annual Report included recommendations to improve the markets' performance.

Cross-Market Comparison

Referring to his presentation, Dr. Patton started by comparing the "all-in" energy prices across various organized markets (RTOs), noting the consistently highest energy prices for New England, mainly driven by higher natural gas prices. He also noted that New England's capacity costs were much higher than those in other RTOs.

In contrast, Dr. Patton explained that New England's transmission congestion costs were much lower than other RTOs, even after accounting for the difference in the size of the RTO markets, due to prior transmission investments in New England. Although costs were low, New England's 2022 transmission rates were the country's highest at $22/MWh. Dr. Patton also noted that, in the future, it would be essential for New England to conduct transmission planning that is compatible with market incentives in order to facilitate the addition of technology, such as storage devices, that lower transmission congestion costs.

Dr. Patton then addressed virtual transactions. He observed that, in New England as compared to other markets, virtual transactions (Increment Offers (INCs) and/or Decrement Bids (DECs) in the Day-Ahead Energy Market) had historically been lower, and profit volatility higher, each an indication of lower liquidity in the Day-Ahead Market. Day-Ahead and Real-Time price convergence in New England was also more volatile than that experienced in MISO or NYISO. Dr. Patton opined that New England's uplift cost allocation methodology, particularly the quantity of costs allocated, contributed to higher costs for virtual transactions, discouraging market participation. He believed that DASI could help address this issue.

In response to further comments and questions, Dr. Patton answered additional DASI-related questions. Among other points, he noted that he was not too concerned with the ISO's forecasting of Day-Ahead prices. He suggested that higher strike prices tended, from his perspective, to be better than lower strike prices, and could help mitigate both risk for generators that might otherwise be passed along in offer prices as well as ISO price forecast errors.

Although not part of his presentation, but included in the EMM Annual Report, Dr. Patton observed that Coordinated Transaction Scheduling (CTS) would perform much better if the CTS process operated every five minutes based on the most recent Real-Time prices rather than forecasted prices.

Competitive Assessment of the Energy Market

Dr. Patton opined that the Energy M~~m~~arket performed very competitively. His analysis found no significant issues. He highlighted, as the sole example of concern in the competitive performance area, a mitigation event from December 24, 2022, which had illustrated several deficiencies in the market power mitigation process and had led to the 206 proceeding described earlier in the meeting. After providing a brief background, Dr. Patton presented three recommendations to address, in as surgical a way as possible, the mitigation issues highlighted by the December 24 event. In response to a question, Dr. Patton explained that the mitigation had raised costs to others in the market by reducing the dispatch from the mitigated generator, but opined that the mitigation did not create a reliability problem.

Out-of-Market (OOM) Commitments and Operating Reserve Prices

Dr. Patton began by discussing Day-Ahead commitments for Ten-Minute Spinning Reserve (TMSR). He explained why he characterized the commitments as out-of-market (due to the requirement to fulfill physical reserve constraints, but with no corresponding product procurement). With no product procurement, no price was being set to reflect the reserve requirement, needed commitments would not be covered by prices, and uplift in the Day-Ahead market would be generated as a result. He noted that 2022 OOM commitments occurred in nearly 2,450 hours to satisfy New England's TMSR requirement. He pointed out that the nearly $2/MWh average reserve value, as shown in his presentation, illustrated the magnitude of energy price depression and that pricing TMSR could raise revenues by up to $15/kW-year for resources providing energy and/or spinning reserves. Dr. Patton opined that these results underscored the value of DASI.

Dr. Patton then turned his attention to Day-Ahead commitments for Local Second Contingency Protection. Although the reserve needs for local areas in 2022 were quite a bit less than in previous years, he highlighted that the NH-ME and NE West-to-East interfaces had seen the most significant number of OOM commitments for local needs. He explained that those areas were not defined in the Real-Time markets and that the Reserve requirements were not priced in the Day-Ahead markets. Dr. Patton noted that pricing the local needs in the Day-Ahead market from 2020 to 2022 would have raised between $4/kW-year and $10/kW-year of additional revenue for resources in the local areas. Ultimately, the EMM recommended the adoption of a more dynamic regime for defining local reserve zones.

Dr. Patton concluded this section by presenting an issue identified through the annual assessment process concerning the fast-start pricing logic to price Operating Reserves, an essential aspect of the New England M~~m~~arket. After providing a high-level explanation of the fast-start pricing logic (explained further in the EMM Annual Report), he illustrated how the identified issues result in raising Reserve and Energy prices inefficiently under tight conditions. Although the inefficient result did not occur frequently in 2022, Dr. Patton noted that, as the region moves towards less surplus and additional intermittent resource integration and, thus, increased reliance on peaking resources, the fast-start pricing logic issue was likely to be magnified. Accordingly, he recommended that the ISO address this issue by modifying the fast-start pricing logic.

Assessment of the December 24 OP-4 and Capacity Scarcity Condition Event

In the next section, Dr. Patton discussed the December 24 shortage event that triggered the Pay-For-Performance (PFP) Reserve Constraint Penalty Factors (the "December PFP Event"). He began by reviewing external transactions during the December PFP Event. He noted that in hour 16, New England cut exports to New York. In turn, New York cut more than 700 MW of exports to New England. Dr. Patton noted that this type of curtailment, i.e., cutting exports to a neighboring Balancing Area in an emergency, occurs in every RTO. Thus, based on his experience, Dr. Patton expressed astonishment that New York and New England did not have amongst themselves an agreement to promote coordinated reliability-maximizing interchanges when one or both of the regions were in an emergency.

The EMM turned to a broader discussion on PFP incentives. One of his concerns was the increased PFP rate for 2025, i.e., approximately $9,300/MWh. In his opinion, that high rate would distort incentives for some resources to remain in the market. Dr. Patton concluded that over-penalizing certain resources could result in premature retirements. He also discussed the PFP incentives for importers. As he explained, PFP creates a significant incentive to transfer power into New England, even when it is demonstrably non-economic, as shown during the December PFP Event. Dr. Patton expressed concern that the current PFP incentives could create undesirable opportunities to schedule equal imports and exports at the New England/New York interchange.

Assessment of the Forward Capacity Market

Before presenting his assessment of winter reliability, Dr. Patton provided that he viewed energy adequacy and resource adequacy as sharing the same goal, i.e., to produce enough energy to keep the lights on when needed. Turning to a chart in his presentation showing several critical points regarding New England's generation supply during prolonged cold weather periods between December 2017 and January 2018, Dr. Patton pointed out that some units obtained natural gas through liquefied natural gas (LNG) injections and that oil-fired resources continuously produced large amounts of energy. The key takeaways from the chart were that generators with only pipeline gas supply had limited value, especially on the margins, and New England relies on oil and LNG during conditions presented during the studied winter period. Thus, Dr. Patton added that the accreditation method becomes very important, particularly for oil resources.

Next, Dr. Patton presented a chart showing the total Seasonal Claimed Capacity of resources with Capacity Supply Obligations for January 2027 and the capacity of dual-fuel and oil resources based on the maximum days of output in MW. He pointed out that a fair number of oil units could run for 14 days or more. Dr. Patton also noted that about half of the units would run out of oil in less than seven days, with a good number of units running out in about two days. With this in mind, oil replenishment becomes a key modeling assumption when accrediting resources. Dr. Patton stated that he disagreed with the ISO's modeling assumption that oil units with 40 hours of fuel are assumed with unlimited availability.

Dr. Patton reviewed several slides detailed in the EMM Annual Report to support his conclusions. He concluded this section by addressing several members' questions/comments concerning accreditation (including the ISO's ongoing approach) and offering three points: (1)

the oil replenishment assumption was critical in resource accreditation; (2) expressing a concern with the ISO's current average accreditation approach as opposed to the marginal approach; and (3) based on technological capabilities and the ability to procure fuel, noting that appropriate accreditation is one mechanism to send the appropriate entry and exit signals to the market.

The EMM turned its attention to the Forward Capacity Market (FCM). Dr. Patton expressed two concerns with the FCM. First, he opined that the FCM did not have a good record of facilitating the entry of new resources. Second, Dr. Patton stated that the FCM created financial risks for existing older retirements, which could result in premature retirements. Thus, he recommended that the region move to a prompt seasonal market. Anticipating a question concerning the four options the ISO laid out in the RCA Memo, Dr. Patton stated that he preferred Option C. Under this option, the ISO would delay the nineteenth Forward Capacity Auction (FCA19). With the additional time, the ISO could implement a new RCA construct and transition to a prompt and seasonal market for FCA19 running in 2028 rather than 2025. In responding to a member's question, Dr. Patton stated that moving to a prompt market was more critical than a seasonal market.

JUNE 28 SESSION

The Summer Meeting reconvened at 9:00 a.m. on June 28, 2023.

FERC STAFF INTRODUCTIONS & COMMENTS

Mr. Cavanaugh welcomed members and guests back to the meeting. He also welcomed, introduced and thanked the following representatives from the Federal Energy Regulatory Commission for their attendance and participation: Ms. Nicole Businelli, Mr. Zach Harris, Mr.

Noah Schlosser, and Mr. Eric Jacobi. Ms. Businelli, who had since the last Summer Meeting joined Chairman Phillips' staff, spoke briefly about her focus on New England matters for the Chairman's office and her wish to stay engaged with NEPOOL. She looked forward to discussions with members during Thursday's Sector meetings. Messrs. Schlosser and Harris, each members of the FERC's Office of Energy Market Regulation (OEMR) ISO New England virtual team, provided similar overviews of their roles and experiences related to New England. They encouraged members, subject to the Commission's rules regarding *ex parte* communications, to share their perspectives on regional issues with any of them during the meeting's activities or in the Sector meetings to be held the following day.

DEBRIEF & DISCUSSION ON JUNE 20 FERC NEW ENGLAND WINTER GAS-ELECTRIC FORUM

Mr. Lombardi recapped highlights from the June 20, 2023 New England Winter Gas-Electric Forum (June Forum). He summarized the June Forum's presentations, panels, and round table discussions. He noted the keen interest expressed in the completion of the 2032 portion of the study effort being jointly undertaken by the ISO and the Electric Power Research Institute (EPRI) to conduct a probabilistic assessment of the operational energy adequacy risks in New England under extreme weather events (ISO/EPRI Study). He concluded by sharing his overall sense that, compared to and since the FERC's first forum in September 2022, some foundational progress had been made, and there appeared to be, at least at the highest-level, broader consensus among those participating and in the room. Mr. Cavanaugh then invited those participating in the Summer Meeting to share their reactions and feedback on, and any takeaways from, the June Forum.

A number of Participants commended the ISO on both the analysis and framework presented by way of the Study, including the review of the history preceding the ISO/EPRI Study, which many found to be informative and understandable. Some stressed the importance of prompt completion of the 2023 Study results, which they believed would be key to informing critical decisions and continued progress in addressing the long-term challenges facing the region as it endeavors to ensure electric system reliability at a reasonable cost to customers. Other Participants thought it helpful that the FERC heard regional commitment to market-based solutions, and proposed various concepts for further consideration, including new and different reserve products (beyond the DASI proposal to be voted the following month), other market-rule-based enhancements, as well as the value and potential use of resource types not traditionally noted or used for their winter reliability benefits. With respect to consideration of potential longer-term reserve products, a member suggested that a short thought piece, incorporating the efforts from the previous Energy Security Initiative (ESI), could be used to better frame and facilitate concrete discussion on that topic. There were conflicting views on whether any such solutions should be exclusively market-based or should also include potential out-of-market mechanisms/elements. Some cautioned that solutions centered just in the capacity market may not be sufficient to ensure that the necessary resources are procured. More generally, and looking ahead, some, expressing a desire to build on the progress being made, asked for additional clarity as soon as practicable on proposed next steps in the consideration of solutions that ensure that region benefits from appropriate long-term market signals, including possible capacity, energy and reserve market changes.

On the topic of Everett as it related~~s~~ to the reliable operation of New England's electric and/or natural gas systems, some stakeholders noted the nuances of the ISO's positions regarding

Everett's contribution to electric system and broader regional winter reliability, and the challenges communicating those nuances effectively to the public. Some viewed the June Forum as a success because of the additional clarity provided with respect to roles and responsibilities in addressing Everett and its attendant issues, and urged that, whether or not Everett is retained, that new products or market rule changes be considered to ensure the availability of the levels of LNG assumed in the ISO/EPRI Study. The ISO was complimented for its continued commitment and efforts to better understand the natural gas system, which would be increasingly important going forward.

Officials from multiple New England States expressed their appreciation for the FERC's outreach ahead of the Forum, and the recognition of the importance of the States' collective and distinct role in identifying paths forward. They also highlighted their appreciation for the opportunity for the dialogue at the Participants Committee table, described as both essential and timely. They noted the caution expressed by those charged with maintaining bulk power system reliability of winter risks going forward and emphasized the need for robust, rigorous analysis. Consistent with their mandate, they urged that the welfare of the citizens of New England be a central component of all constructs considered, such that ratepayers would neither be cold nor sitting in the dark during a New England winter. They implored the ISO and NEPOOL to approach the consideration of solutions with a sense of urgency, and to commit early in the process to market-type solutions, rather than be left with a round of out-of-market solutions. One suggested that any solutions be presented in way that every day citizens could understand, in order to enhance support for those solutions and to inspire confidence.

More specifically, some of the State Officials suggested that, when considering solutions to tightening winter conditions, additional uses or roles for Demand Response (DR) and other technologies be explored, and that any such consideration not be limited to fuel-related solutions. They urged the ISO to continue its commitment to better understanding the natural gas system, and to comprehensively consider and assess how that system will hold up from a reliability stand-point under the assumptions and solutions to be proposed on the electric side.

On behalf of the ISO, Dr. Chadalavada thanked everyone for the additional and helpful feedback as well as the support provided by many. He highlighted the achievement of developing a platform that would provide advanced notice and signals regarding future contingencies, which he believed distinguished New England from the rest of the county's organized markets, and would serve the region well into the future.

In response to questions regarding next steps, he stated that the ISO planned to publish the 2032 Study results in August, which would provide the region an opportunity to discuss those results in September. From there, in late 2023 and into 2024, he expected discussion on the "Regional Energy Shortfall Metric" described at the June Forum. He explained that the Metric would provide a necessary and predicate baseline to the development of potential market and/or infrastructure solutions and the evaluation of their feasibility and cost effectiveness. He noted the ISO's preference to design market-based solutions, but next steps would be informed and determined by evaluation using that Metric.

For his part, Mr. van Welie identified a couple of takeaways from the Forum. The first was his sense that the oft-used 1-in-10 resource adequacy standard (that presumed the probability or risk of demand exceeding generation capacity was less than one day in 10 years) was, on its own, likely obsolete, particularly given the rapidly evolving circumstances facing the region. He noted his satisfaction with the work that had already been completed to address this changing situation, which he believed positioned the region to move from the conceptual to the tangible in quantifying the energy adequacy risks that it faced. He stated that, among the next steps to be taken by the region, would be to supplement the 1-in-10 standard with an energy shortfall metric that would, in turn, inform the development of solutions to hedge against resource adequacy risk.

The other high-level takeaway Mr. van Welie identified was the importance of the role that DR could and should play going forward. He agreed with the view expressed that DR was not being fully reflected in proposed solutions, and explained why, at least to him, managing increasing demand for electricity without the participation of a large quantity of responsive demand in the marketplace didn't make much sense. He explained how anticipated system build-out and ramp up in demand was likely to present constraints on the wires (both transmission and distribution), as demonstrated in the 2050 transmission-related study. He viewed increased integration of DR as a potential tool to mitigate that risk, noting the positive impact/reduction in costs to consumers if DR is able to reduce the amount of energy that the system is required to solve for. He opined that the increased use of DR would require action by the States, noting that, while DR had been incorporated into the wholesale arrangements, there remained much to do to unleash the benefits of DR at the retail level, including deployment of automation into people's homes and electric charging facilities.

Mr. Cavanaugh concluded this discussion by thanking all for their feedback, takeaways and views on possible actions to be taken, noting that there was much work ahead for the region. Echoing sentiments expressed by a State Official, he expressed confidence that the regional stakeholders best suited to accomplish the critical tasks were around the NEPOOL table, that NEPOOL could and should provide a forum for future discussions, and that discussion and efforts would continue.

RESOURCE CAPACITY ACCREDITATION UPDATE & OPTIONS

Dr. Chadalavada referred the Committee to the memo that had been circulated in advance of the meeting providing an update on and potential options for proceeding with the Resource Capacity Accreditation (RCA) project (Memo). He emphasized that the Memo was intended to facilitate conversation at this meeting regarding the RCA project, which had been delayed as a result of a GE Multi-Area Reliability Simulation (GE MARS) software error identified by the ISO. He reviewed both the broad objectives that the ISO sought to balance and potential options for proceeding with the project, noting that the list of options was neither exhaustive nor final. He asked for Participant feedback as to (i) whether the ISO had gotten the objectives right; (ii) what should be the scope of work (including capacity accreditation reforms and/or prompt/seasonal capacity market designs) and timing in connection with the Forward Capacity Auction for Capacity Commitment Period 19 (FCA19); and (iii) what should be the scope of the end state.

Turning to process, he reported that the ISO was planning for a discussion at the July Markets Committee meeting on its thoughts on the trade-offs between a prompt and forward capacity market design and looking forward to further feedback at that time.

Participants proceeded to provide their views, both in response to the three~~3~~ topics that Dr. Chadalavada had identified, as well as on several additional but related topics. Participants were appreciative of the opportunity to provide feedback on the Memo and urged the ISO to minimize, to the maximum extent possible, regulatory uncertainty and implementation risk.

Addressing the need for additional time to improve and rerun the winter risk model, members sought additional clarity on the modeling error identified, as well as its impact on the RCA schedule. Dr. Chadalavada confirmed that the current pause was attributable to modeling errors identified, primarily related to LNG resources, but also to deficiencies revealed with respect to the modeling of other resources (e.g. gas-fired units), rather than any fundamental flaws with the RCA methodology itself. He was unequivocal that the modeling error had to be corrected and, while not prejudging the outcomes that would follow after those corrections were completed, was certain that there would be some level of winter risk identified, though the scope of that risk was yet to be determined and addressed.

A number of members offered their preliminary thoughts on what might be incorporated into FCA19 and/or the RCA efforts as a result of the pause, and whether, and if so, how, the pause or further additional time could or should impact the schedule and conduct of FCA19. Some explained why they would entertain proposals to delay, or would support, even insist, that the conduct of FCA19 be delayed, so that the RCA project, at least in some form, could be incorporated into FCA19 (rather than in a future auction). Many opined that there were likely to be efficiencies to be had by coupling FCA19 with RCA reforms, and wished to maximize those efficiencies and avoid incremental implementation. The opportunity to discuss the feasibility of, and trade-offs associated with, that approach, with the benefit of as much information and analysis as possible, would be appreciated.

Others expressed concerns with delaying, and/or incorporating RCA reforms into, FCA19. Those actively developing new resources explained the impacts and challenges that would follow from a delay. Some were hesitant, if at all able, to commit to a delay prior to a full discussion on the pros and cons of proposed changes to the market. Still others suggested that, absent impact analysis showing that there was heightened winter risk to be accounted for in the FCA19 Capacity Commitment Period, they could support conducting FCA19 under the existing rules, with or without RCA. Notwithstanding some suggestion that an auction delay would not be viewed as undesirably as it might have been in the past, there were members who favored proceeding with FCA19 as planned in the interest of certainty and optics, at least until any changes to the market structure going forward had been decided upon.

An End User Sector representative, noting the importance of assumptions made in the modeling, questioned whether the additional time might permit consideration of alternatives or further changes to GE MARS, which was being contorted beyond its intended uses to support the winter risk modeling. A Generation Sector member hoped that the pause would allow for concerns with gas resource accreditation to also be addressed.

More broadly, members offered feedback on suggestions that the region should consider a move from a forward to a prompt and seasonal capacity market construct. Some members from the supply side cautioned that any change in approach would have to ensure that market revenues would~~ill~~ be sufficient for them to cover their total costs (thereby ensuring appropriate financial incentives for capacity investment), and requested further analysis illustrating how those principles would be satisfied.

Seasonality, Dr. Chadalavada suggested, was less about resource adequacy and more about New England's overall needs going into the future, e.g. how winter and summer demand may shape future annual load curves. Designing a seasonal market would, given the challenges and timing involved, likely be a multi-year effort and, in a forward construct, implementation would take the region into the early to mid years of the next decade. For that reason, focus had turned to the prospect of a prompt capacity market construct, which might offer better options to more nimbly and quickly incorporate seasonality into the region's market structure.

Various perspectives on seasonality were expressed. There was an acknowledgement of the momentum around seasonal capacity market design efforts, and the need for much work ahead to determine its feasibility, periodic basis, and resolution to its many perceived challenges. Many favored undertaking the required efforts sooner rather than later (and before it was too late) to fully consider the design and facilitate implementation if that design was ultimately supported or adopted. In any such efforts, members were urged to also view the direction to be pursued holistically, carefully considering whether and how State objectives for a clean energy resource mix and visions for the future system could be incorporated in the design.

Members expressed some interest in further exploring how changes in the capacity market might impact basic service procurements and retail customers. A Transmission Owner representative expressed confidence that, given planning assumptions and processes, the transmission system could absorb any impacts from market changes (e.g., generation retirements) without perceivable disruption. Raising the determination of tie benefits, a couple of members encouraged, with the benefit of the extra time contemplated, a full analysis of tie benefits, includinge HQICCs.

Dr. Chadalavada acknowledged the breadth and complexity of the work to be completed, as well as the need for discussion and feedback on each of the components to be pursued. He looked forward to the collaborative efforts and shared commitment to resolving the challenges ahead. There being no other business, the June 28 session ended at 11:35 a.m., with the following day set for modified Sector meetings beginning at 8:00 a.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 27-29, 2023 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting	Caitlin Marquis		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	
Associated Industries of Massachusetts (AIM)	End User	Robert Ruddock		Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Alex Noviki Zach Teti
Bath Iron Works Corporation	End User			Gus Fromuth; Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity	Matt Ide		
BP Energy Company	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	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier	John Miller		Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw	Dave Meisenger	
Connecticut Office of Consumer Counsel	End User	Claire Coleman	J.R. Viglione	
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis (tel)		
Deepwater Wind Block Island, LLC	Generation	Eric Wilkerson		
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (tel)		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, Inc.	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	 Brett Kruse Liz Delaney		 Bill Fowler Alex Chaplin (tel)
EDF Trading North America, LLC	Supplier	Eric Osborn		
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
Engie Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission		Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow	Peter Rider	
First Point Power, LLC	Supplier	Peter Schieffelin (tel)	Bryan Amaral	
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User	Gus Fromuth		Bill Short
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 27-29, 2023 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault	Bob Stein	
Hammond Lumber Company	End User	Gus Fromuth		Bill Short
Hanover, NH (Town of)	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User	Dan Collins		
Industrial Wind Action Corp.	End User		Annette Smith	
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
Jericho Power LLC (Jericho Power)	AR-RG	Ben Griffiths		
Jupiter Power	AR-RG			Ron Carrier (tel)
KCE Companies	AR-DG		Paul Williamson	
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		José Rotger
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Skiing, Inc.	End User	Dan Collins		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General's Office (MA AG)	End User	Ashley Gagnon	Jaimie Donovan	Tina Belew (tel)
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network				
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		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			Gus Fromuth; Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Amanda Rumsey	Lindsay Orphanides
Nautilus Power, LLC (Nautilus)	Generation		Bill Fowler	
New Brunswick Energy Marketing Corp.	Supplier	Rob Gillies		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
New Hampshire Office of Consumer Advocate	End User		Jason Frost	
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	

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 27-29, 2023 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
NRG Power Marketing LLC	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Onward Energy (Blue Sky West LLC)	AR-RG	Emily Chapin	Katie Belleza	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company	Generation	Dan Allegretti	Kevin Telford	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Repsol Energy North America	Associate Non-Voting		Karen Iampen	
RI Division of Public Utilities Carriers	End User	Paul Roberti	Linda George	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	
Saint Anselm College	End User	Gus Fromuth		Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User	Gus Fromuth		Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Tangent Energy	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Tenaska Power Services Co.	Supplier		Eric Stallings	
The Energy Consortium	End User		Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity		Dan Potter	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR	David Westman	Jason Frost	
Vermont Public Power Supply Authority	Publicly Owned Entity	Ken Nolan		Brian Forshaw
Versant Power	Transmission	Lisa Martin (tel)	Dave Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
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	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc. (Wheelabrator)	AR-RG		Bill Fowler	
ZTECH, LLC	End User		Gus Fromuth	Bill Short

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference on Thursday, August 3, 2023, at 10:00 a.m. 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.

Mr. David Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and guests who were in attendance.

APPROVAL OF MAY 4, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the May 4, 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 recorded.

CONSENT AGENDA

Mr. Cavanaugh then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Mr. Cavanaugh noted the achievement represented by the Consent Agenda's inclusion of a substantial market design reform proposal (the Day-Ahead Ancillary Services Initiative (DASI)). On behalf of the Participants, he thanked the ISO, in particular, for its resource commitment, engagement and responsiveness to stakeholder input and feedback received during the process. Following motion duly made and seconded, the Consent Agenda was approved unanimously, with abstentions recorded for Calpine, the Granite Shore companies, Icetec, Maple Energy, Jericho Power, and Mr. Lamson.

Explaining further their abstentions, the Calpine, Granite Shore companies and Jericho Power representatives attributed their votes to Consent Agenda Item 1 (DASI Proposal). The Calpine representative explained that, although Calpine supported the Day-Ahead procurement of Ancillary Services and the co-optimization with Energy in the Day-Ahead Market, it was nevertheless concerned with certain other aspects of the DASI design, including as they viewed it, the ~~p~~Proposal's effective transformation of what is or should be a physical, reliability-mandated product instead into a financial (options format) product.~~-~~ For its part, noting Jericho Power's appreciation for several aspects of the DASI Proposal, the Jericho Power representative described concerns with the Proposal's mitigation scheme, which it worried, particularly in light of the coincident implementation of the elimination of the Forward Reserve Market, would impact revenue streams and potentially precipitate the retirement of flexible resources essential to the energy transition. A Generation Sector member noted for the record and referred to the many different views and perspectives regarding the DASI Proposal, beyond those expressed by those abstaining at this meeting, that were offered during Technical Committee consideration of this matter, as captured in the records of those meetings.

The representative for Icetec and Maple Energy attributed their abstentions to Consent Agenda Item 2 (*Order 2222* 180-Day Compliance Filing Proposal), based on a continuing belief that the region's overall *Order 2222* strategy (and related reforms) didn't go far enough to allow Distributed Energy Resource Aggregations to participate in the Markets, though not attributable to any particular concern with the specific Proposal encompassed by the Consent Agenda item.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), added his thanks for the support of the DASI Proposal, and that he looked forward to its implementation. He also referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since his last report circulated for the Participants Committee June 27-29 Summer Meeting, which had been circulated and posted with the materials for the meeting. There were no questions on the summaries.

ISO COO REPORT

Operations Highlights

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his August operations report (Report), which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the ~~report~~ Report was through July 26, 2023, unless otherwise noted. The R~~r~~eport highlighted: (i) Energy Market value for July 2023 was $425 million, up $110 million from the updated June 2023 value and down $835 million from July 2022; (ii) July 2023 average natural gas prices were 62% lower than July 2022 average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for June ($39.45/MWh) were 12% higher than June averages; (iv) average July 2023 natural gas prices and Real-Time Hub LMPs over the period were down 62% and 56%, respectively, from July 2022 average prices; (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 100.6% during July (up from 98% reported for June), with the minimum value for the month of 94.6% on Friday, July 21; (vi) Daily Net Commitment Period Compensation (NCPC) payments for July totaled $2.4 million, which was up $0.6 million from

June 2023 and down $6.7 million from July 2022. July NCPC payments, which were 0.5% of total Energy Market value, were compromised of (a) $2 million in first contingency payments (up $0.3 million from June); (b) and there were no Second Contingency or voltage payments in June; and (c) not listed on the ~~report~~Report, $400,000 in distribution payments made to the diesel-fired units committed by the distribution company on Martha's Vineyard.

Regarding system planning highlights, he reported that a draft of the 2023-2024 Regional System Plan (RSP) would be shared later in August. He said that the ISO would continue to explore improvements to the long-term forecast methodology to support the evolving grid, and noted that 26 companies had to that point achieved Qualified Transmission Project Sponsor (QTPS) status. He also reported that the second phase of the longer-term transmission planning effort to have the ISO regularly perform extended long-term planning would begin at the Transmission Committee in October.

July 5, 2023 Capacity Scarcity Condition (July 5 Event)

Addressing the July 5 Event, Dr. Chadalavada explained that the ISO implemented Operating Procedure No. 4 (Action During a Capacity Deficiency) (OP-4) due to higher-than-forecasted temperatures, higher-than-expected demand (approximately 300 MW) during the peak hour, and fewer available imports during the peak hour (during the peak hour, Phase II tripped, unable to deliver an expected 1,300 MW). There were violations for both 30-Minute and 10-Minute Operating Reserves for the intervals identified in the Report. He noted that system operators took the necessary and prescribed actions to curtail Real-Time Only export transactions and highlighted the temporal lag between the receipt of information by operators and the incorporation of that information into the dispatch software.

Comparing the July 5 Event to a similar event on December 24, 2022 (discussed in more detail at prior meetings), he noted that communications with Hydro-Québec (HQ) during the July 5 Event were significantly improved. Ultimately, the ISO had roughly one hour's notice that Real-Time imports were likely to fall short of Day-Ahead-scheduled levels. He explained that, with the shortfall expected to be relatively fleeting and moderate, ISO intervention, beyond applicable operating protocols, was not warranted; instead, the ISO relied primarily on existing market mechanisms.

In response to further questions, Dr. Chadalavada provided additional insight and detail into the Control Room actions taken, particularly the steps taken to recover from Area Control Error (ACE) as required under NERC reliability standards. Those steps included mutual assistance (Energy) from neighboring Control Areas (New York, PJM, New Brunswick, and Ontario), under protocols that had been in place for several~~at least two or three~~ decades. The distribution of that assistance amongst the other four Control Areas varied and was based on the system conditions in those Areas at the time required. In light of the July 5 Event experience, there had been preliminary discussions within the ISO about whether, and if so how best, to capture that inadvertent energy in the Pay-for-Performance (PFP) rules, but no final determinations had been made, and the ISO planned to report back with any proposed stakeholder process to effectuate that inclusion within the following few months.

Dr. Chadalavada addressed a question whether the trip on the Phase II line and the reduction of imports from HQ ~~Quebec~~ had caused or contributed to a capacity deficiency. A discussion regarding HQ's Day-Ahead commitment and scheduled net interchange, as well as Phase II reductions and trips in general, followed. As to whether the 90-minute and/or 4-hour reserve products, previously proposed as part of the Energy Security Improvements (ESI) project, but ultimately not implemented, would have prevented or mitigated the July 5 Event, Dr. Chadalavada opined that those ESI products would have been helpful, but given the specific circumstances, unlikely to have prevented on their own the July 5 Event.

Dr. Chadalavada acknowledged the delay in publication of LMP and preliminary settlement information related to the July 5 Event, which was largely due to the need to confirm that the inadvertent energy component was captured accurately and in conformance with the Tariff. With that confirmation work completed this time around, he did not expect similar delays following future events, and thanked Participants for their patience following the July 5 Event.

Responding to additional questions, Dr. Chadalavada reported on a three-day outage, from August 6-9, expected for West Medway station, which could result in relatively modest second contingency protection costs. He also confirmed that the July 28 peak load fell just short of the July 6 peak, which remained the peak for Summer 2023 (subject to August developments).

Dr. Chadalavada concluded his Report by providing answers to certain questions received ahead of the meeting with respect to the Mystic 8/9 Cost of Service Agreement (Mystic COSA). He confirmed that the Mystic COSA would be in effect only through May 31, 2024, with no renewal anticipated following its expiration. He explained how Mystic 8/9 was obligated to offer into the Day-Ahead Market and could be called on to perform during the Operating Day if the economics dictated. He confirmed that Mystic 8/9 would generally not be called on out-of-market, absent extreme (weather) circumstances where Mystic 8/9 might otherwise be required for the protection of the New England System.

ORDER 881 60-DAY FURTHER COMPLIANCE REVISIONS

Ms. Emily Laine, Transmission Committee Chair, referred the Committee to the materials circulated in advance of the meeting that revised Attachment Q to the Open Access Transmission Tariff (OATT, Section II of the Tariff) in response to the FERC's June 15, 2023 order conditionally accepting the region's *Order 881* compliance changes (related broadly to the incorporation of ambient air adjusted transmission line ratings) (the Further *Order 881* Compliance Changes). She reported that the Further *Order 881* Compliance Changes were presented without objection or concern at the July 18-19 joint Summer Meeting of the Reliability (RC) and Transmission Committees (TC), but were not voted because one aspect of the Compliance Changes (related to how the ISO would maintain local transmission line ratings and exceptions in its database of Transmission Line Ratings and Transmission Line Rating methodologies) had not at that point been finalized. Following that meeting, and in consultation with the Transmission Owners, the ISO had finalized the Further *Order 881* Compliance Changes (with the post-RC/TC Summer Meeting changes highlighted in the circulated materials) so that they could be voted by the Participants Committee before the August 14 FERC compliance filing deadline. The Transmission Owners thanked the ISO for the additional time and effort to finalize the Changes.

Without discussion, the Committee approved unanimously the following motion, with an abstention recorded for Mr. Lamson:

> RESOLVED, that the Participants Committee supports the Further *Order 881* Compliance Changes, as proposed by the ISO in response to the FERC's June 15, 2023 order in Docket No. ER22-2357, and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the August 2, 2023 Litigation Report that had been circulated and posted before the meeting. He highlighted the following developments:

(i) *FCA17 Results Filing (ER23-1435).* The FERC had accepted on July 18 the FCA17 Results filing, effective July 19, 2023;

(ii) *June 20, 2023 Second New England Winter Gas-Electric Forum (AD22-9).* The FERC had invited post-forum comments to be filed on or before August 24, 2023 on the topics discussed in the notices for or at the June 20 Forum;

(iii) *ISO-NE Market Power Mitigation Rules (EL23-62).* The FERC had accepted the ISO's request that the proceeding be held in abeyance to allow for a fulsome stakeholder process, with no FERC action to be taken until after February 1, 2024;

(iv) *SATOA Revisions (ER23-739; ER23-743) and IEP Parameter Updates (ER23-1588).* Both proceedings remained pending before FERC following ISO responses to deficiency letters issued in both proceedings. With respect to the IEP Parameter Updates, action by August 4 had been requested and would be noticed by e-mail and posting on the NEPOOL website following FERC action;

(v) *Brookfield Complaint Regarding IEP Exclusion of Pumped Storage ESFs (EL23-89).* The day before this meeting, Brookfield had, in a complaint filed pursuant to Section 206 of the Federal Power Act, requested a FERC order directing the ISO to revise the Tariff to allow Pumped Storage Electric Storage Facilities (ESFs) to participate in the IEP. Comments on the Brookfield Complaint were due on or before August 22, 2023; and

(vi) *Order 2023: Interconnection Reforms (RM22-14).* FERC had issued its final rule on proposed interconnection reforms, with compliance filings due 90 days following *Order*

2023's publication in the *Federal Register*. NEPOOL counsel was preparing and would present a summary of *Order 2023* at the August Transmission Committee meeting.

Ms. Maria Gulluni, ISO General Counsel, in response to questions received ahead of the meeting, addressed the prospects for an ISO request for additional time beyond the 90-day deadline to submit its compliance filing. Noting the FERC's discussion of the pressing need for reform and its decision to direct a quicker 90-day deadline (versus the 180-day compliance timeframe that was proposed during the NOPR stage), she thought it unlikely that any of the ISO/RTOs, individually or collectively, would ask for an extension of time to comply. However, while ISO New England was not then planning to ask for any such extension on its own, the ISO would consider joining other ISO/RTOs in a request for an extension of time.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler, MC Chair, reminded the Committee of the MC's three-day Summer Meeting, August 8-10, 2023, in Stowe, VT. He reported that the first day would be focused on Resource Capacity Accreditation (RCA) and eliciting Participant preferences for proceeding with FCA19 (e.g., including RCA, a prompt or seasonal market, or some other combination). The third day of the meeting would address amendments to the Net Cost of New Capital (Net CONE), in light of the removal of the Minimum Offer Price Rule (MOPR).

Reliability Committee. Mr. Robert Stein, the RC Vice-Chair, reported that the RC would next meet on August 15, 2023, and would be looking at the 2032 Extreme Weather Winter Results.

Transmission Committee. Mr. David Burnham, TC Vice-Chair, reported that the TC would next meet on August 22, 2023 by teleconference only. The primary agenda item would be review of NEPOOL counsel's summary of *Order 2023*. A formal ISO presentation on *Order 2023* was not expected until September, and would be followed by concentrated efforts to meet the FERC's compliance deadline.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Chair, reported that B&F was scheduled to hold two meetings in August. The first, on August 11, 2023, to address primarily the 2024 NESCOE and ISO budgets. The second meeting, on August 24, 2023, to address any changes to the Financial Assurance Policy in response to *Order 895* (FERC's final rule on credit-related information sharing among organized markets).

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for August 14, 2023.

ADMINISTRATIVE MATTERS

Mr. Lombardi informed members that the next Participants Committee meeting was scheduled for September 7, 2023 and would most likely be held by teleconference. Looking further ahead, the October, November, and December meetings would be held in person, with venues and details to be provided in subsequent notices.

Ms. Heather Hunt, NESCOE Executive Director, highlighted upcoming transmission-related matters – discussions addressing asset condition projects to be held both at the Technical Committees and at the Planning Advisory Committee, as well as the start of the second phase of the longer-term transmission planning effort that Dr. Chadalavada had mentioned earlier in the meeting would begin in October at the Transmission Committee.

There being no other business, the meeting adjourned at 11:20 a.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN AUGUST 3, 2023 TELECONFERENCE MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United (AEU)	Associate Non-Voting		Alex Lawton	
AR Large RG Group Member	AR-RG	Anton Kaeslin		
Ashburnham Municipal Light Plant	Publicly Owned Entity			Dan Murphy
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI	Transmission	Alan Trotta		Zach Teti
Bath Iron Works Corporation	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity			Dan Murphy
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		J.R. Viglione	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danske Commodities US LLC	Supplier			Norman Mah
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, Inc.	Supplier			Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Brett Kruse Liz Delaney		John Flumerfelt, Bill Fowler
EDF Trading North America, LLC	Supplier	Eric Osborn		
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services Companies	Supplier			Bill Fowler
Engie Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity			Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault	Bob Stein	
Hammond Lumber Company	End User			Bill Short

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN AUGUST 3, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hanover, NH (Town of)	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity			Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity			Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Icetec Energy Services, Inc. (Icetec)	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity			Dan Murphy
Jericho Power LLC (Jericho Power)	AR-RG	Ben Griffiths		
Jupiter Power	AR-RG			Ron Carrier
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		José Rotger
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate’s Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity			Dan Murphy
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity			Dan Murphy
Mass. Attorney General’s Office (MA AG)	End User	Ashley Gagnon	Jaimie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Dept. Capital Asset Management	End User		Paul Lopes	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity			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
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		Lindsay Orphanides
New England Power (d/b/a National Grid)	Transmission		Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
New Hampshire Office of Consumer Advocate	End User		Jason Frost	
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	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity			Dan Murphy
Princeton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN AUGUST 3, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Russell Municipal Light Dept.	Publicly Owned Entity			Dan Murphy
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity			Dan Murphy
South Hadley Electric Light Department	Publicly Owned Entity			Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity			Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Tangent Energy	AR-LR	Brad Swalwell		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
The Energy Consortium	End User		Mary Smith	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR	Jason Frost		
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity			Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich
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			Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's August 15, 2023 meeting, dated August 15, 2023.[1]

1. Revisions to PP-4 (Updates to Reflect Current Processes)

Support revisions to ISO New England Planning Procedure 4 (PP-4) (Procedure for Pool-Supported PTF Cost Review), including revisions to Attachments B-E and G-H,[2] as recommended by the RC at its August 15, 2023 meeting, together with such further non-material changes as may be approved by the Chair and Vice-Chair of the RC.

The motion to recommend Participants Committee support was approved unanimously.

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

[2] The recommended revisions to PP-4 and its Attachments include: (i) clarifications to the Transmission Cost Allocation (TCA) submission and review processes; (ii) the removal of duplicative or outdated information; (iii) the relocation of content to other documents; (iv) updates to inland and costal area flood level guidance; and (v) other clarifications and grammatical updates.

Summary of ISO New England Board and Committee Meetings

September 7, 2023 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Information Technology and Cyber Security Committee, and the Markets Committee each met on August 17. All of the meetings were held by videoconference.

The Audit and Finance Committee received an update regarding the development of the 2024 operating and capital budgets, including a review of the capital structure, and a report on budget discussions with stakeholders. Next, the Committee conducted its annual review of the Company's liability insurance coverage for officers and directors. The Committee also received an update on the 2023 budget and approved the second quarter unaudited financial statements after management confirmed that all relevant disclosures from managers were included in the financial statements. The Committee then undertook its biennial review of its charter and considered proposed changes to transfer the Committee's responsibility for oversight of the Code of Conduct to the Compensation and Human Resources Committee. The Committee received an update on internal audit activities, as well as highlights of recent external audits, and held an executive session with the Company's internal auditors. Following the session with internal auditors, the Committee was updated on a proposal to purchase an annuity to cover the obligation to pension plan beneficiaries, at an overall cost savings to the Company.

The Information Technology and Cyber Security Committee reviewed progress related to the Company's three-year cyber security work plan. The Committee conducted its annual review of critical vendors, and considered the Company's mitigation plan in the event of an interruption of service from a critical vendor. The Committee reviewed the status of major IT projects, and received an update on the nGEM project, noting that the Company had recently placed in-service the day-ahead market clearing engine nGEM product. The Committee also discussed the plans for the annual cyber security "deep dive" for the full Board in September which is to include a guest speaker providing a cyber threat intelligence briefing specific to the energy sector, and a second guest speaker delivering a presentation regarding ransomware with an event case study analysis. Finally, the Committee requested a summary of new recently issued Security and Exchange Commission cyber security rules, along with related Company processes, policies and procedures, and any changes recommended by management.

The Markets Committee received reports from the Market Monitors on market operations in Spring 2023, and discussed management's responses to the recommendations included in the Market Monitors' annual reports. In addition, the Committee considered its biennial review of its charter to confirm compliance. Lastly, the Committee received an update on the Day-Ahead Ancillary Services Initiative.

NEPOOL Participants Committee Report

September 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through August 30th (NCPC through 29th) unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: July 2023 Energy Market value totaled $580M
  - August 2023 Energy market value was $301M, down $279M from July 2023 and down $1.1B from August 2022
    - August 2023 natural gas prices over the period were 49% lower than July average values
    - Average RT Hub Locational Marginal Prices ($29.09/MWh) over the period were 26% lower than July averages; Avg. DA Hub: $27.01/MWh
    - Average August 2023 natural gas prices and RT Hub LMPs over the period were down 83% and 70 %, respectively, from August 2022 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.6% during August, down from 100.8% during July
    - The minimum value for the month was 93.5% on Sunday, August 20th
  - M/LCC declared on August 21 (18:00-22:00)

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

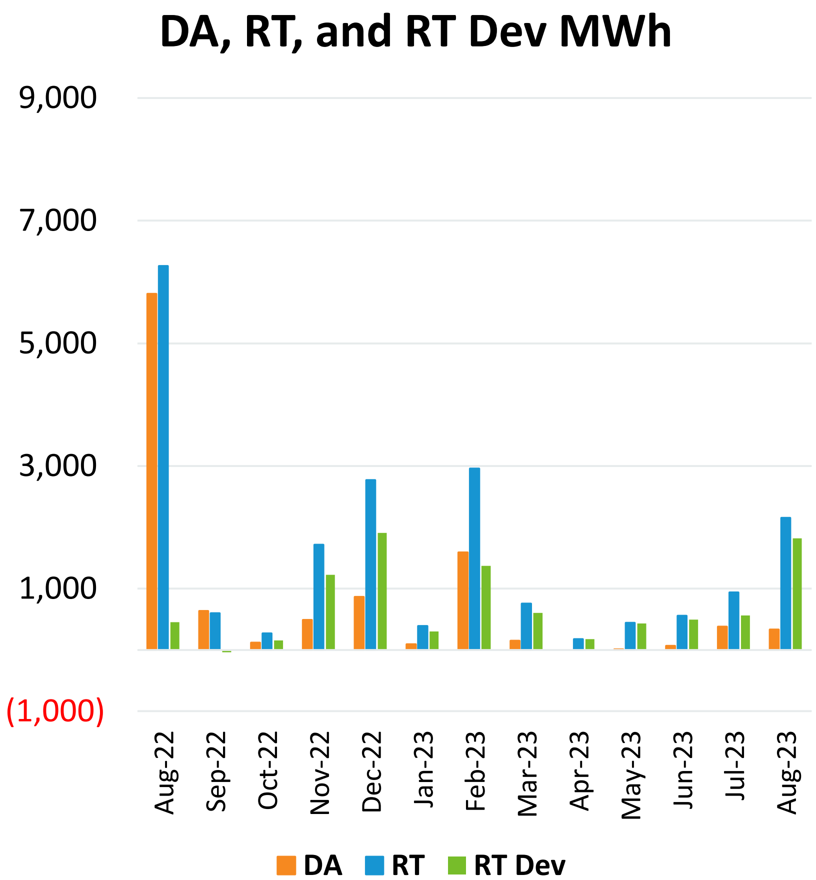
Underlying natural gas data furnished by: ICE Global markets in clear view

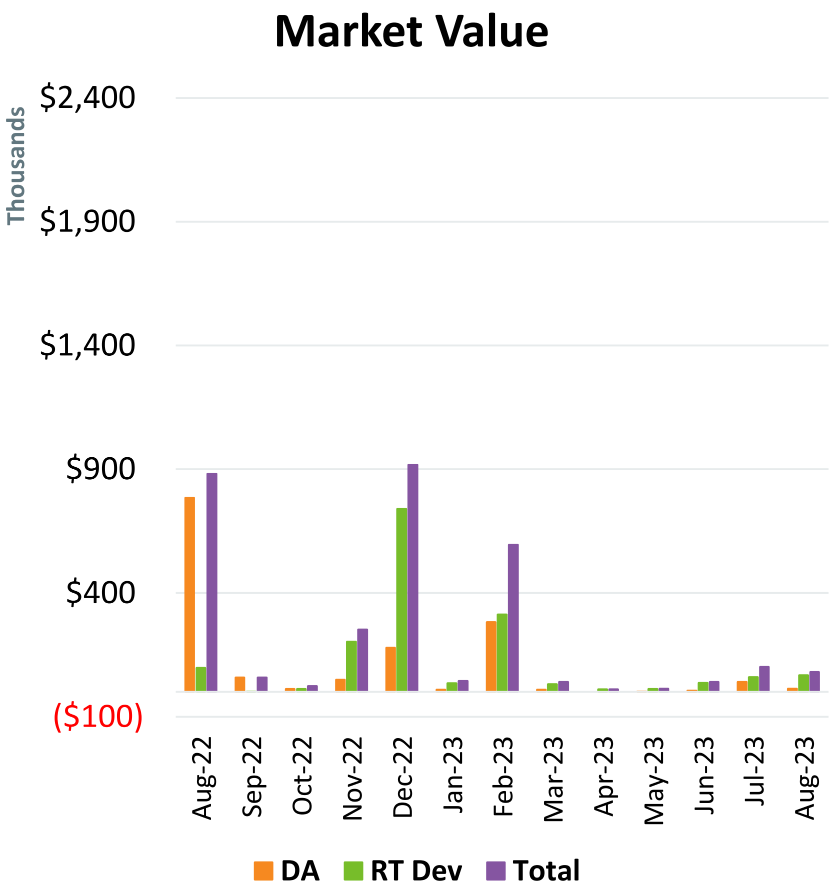
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - August NCPC payments totaled $2.1M over the period, down $0.8M from July 2023 and down $4.4M from August 2022
    - First Contingency payments totaled $1.8M, down $0.7M from July 2023
      - $1.6M paid to internal resources, down $0.7M from July
        - » $157K charged to DALO, $967K to RT Deviations, $520K to RTLO*
      - $109K paid to resources at external locations, up $31K from July
        - » $1K charged to DALO at external locations, $107K to RT Deviations
    - Second Contingency payments totaled $77K, up $77K from July
      - Protection for SEMA/RI area
    - Distribution payments totaled $262K, down $219K from July
    - Voltage payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.7%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $273K; Rapid Response Pricing (RRP) Opportunity Cost - $247K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

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.

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
  - At the August 23 PSPC meeting, ISO presented assumptions for the CCP 15 ARA 3 tie benefits study and assumptions for the ICR studies for the 2024 ARAs for CCP 15, 16, and 17
- 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

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - ISO posted existing capacity values on March 30
  - ISO posted the Retirement and Permanent Delist Bid summary on April 12
  - Show of Interest Submission Window closed on May 8
  - At the May 31 PSPC meeting, the ISO confirmed FCA 18 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - New Capacity Qualification Package Submission Window closed on June 28
  - ISO held a PSPC meeting on August 23 and discussed the preliminary results of the ICR and related values study
    - The ICR and related values were also discussed at the August 31 RC meeting with a planned vote at the September 19 RC meeting

Highlights

- The draft 2023-24 RSP was shared with stakeholders on August 16 and comments were received by August 30
- The draft FCA 18 ICR and related values were presented to stakeholders at the August 31 RC meeting
- The 2024 forecast cycle will begin in Q4 2023
- Qualified Transmission Project Sponsor (QTPS)
  - 26 companies have achieved QTPS status
- Discussions on the second phase of Extended-Term/Longer-Term Transmission Planning will begin in October 2023

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (1.0°F) Max: 88°F, Min: 59°F Precipitation: 6.46" – Above Normal Normal: 3.23"	Hartford	Temperature: Below Normal (1.0°F) Max: 88°F, Min: 52°F Precipitation: 3.88" - Below Normal Normal: 4.21"

Peak Load:	19,335 MW	August 21, 2023	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	August 21, 2023 18:00:00	August 21, 2023 22:00:00	All of New England - Capacity

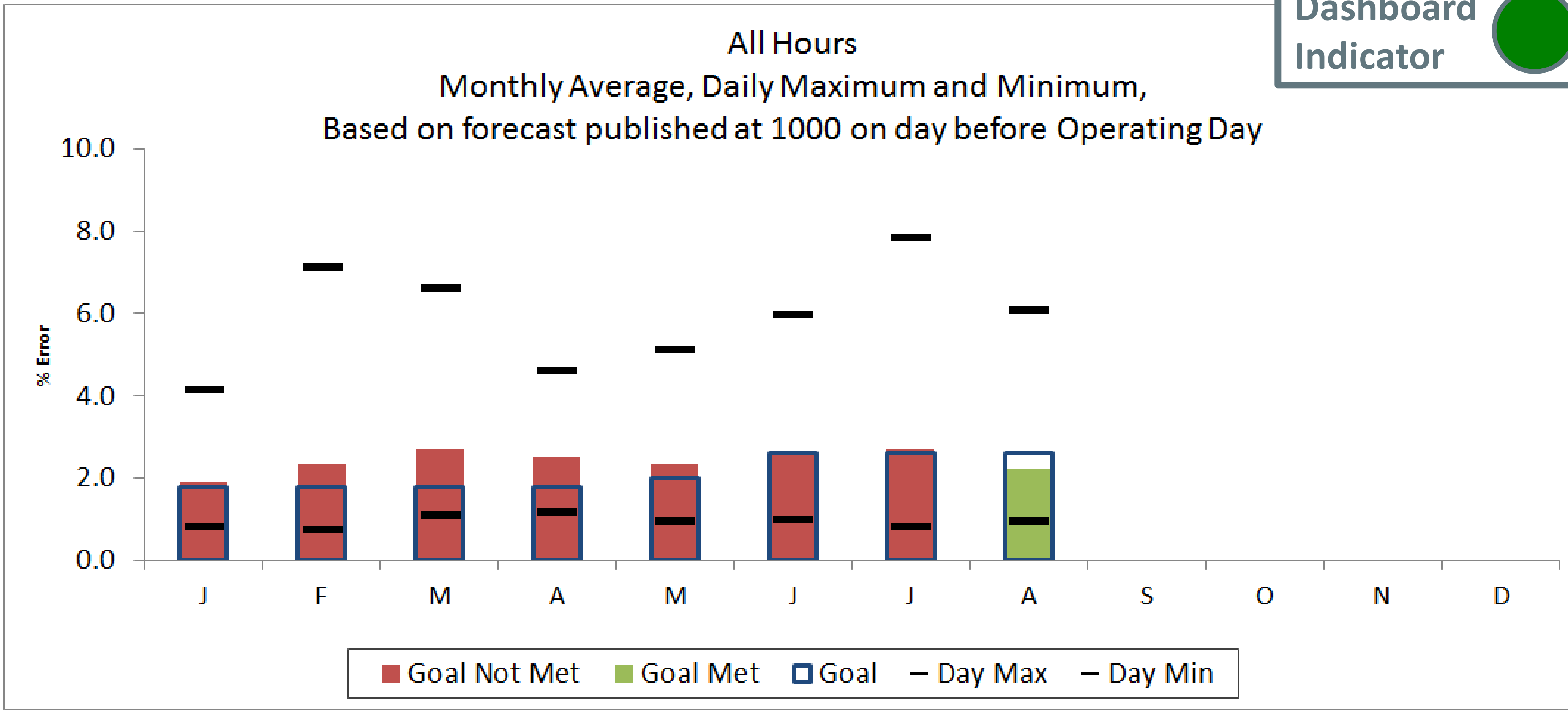
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
08/07/2023	IESO	600
08/08/2023	ISO-NE	950
08/09/2023	NYISO	950
08/17/2023	ISO-NE	650
08/17/2023	ISO-NE	600
08/18/2023	ISO-NE	600
08/28/2023	ISO-NE	650

2023 System Operations - Load Forecast Accuracy

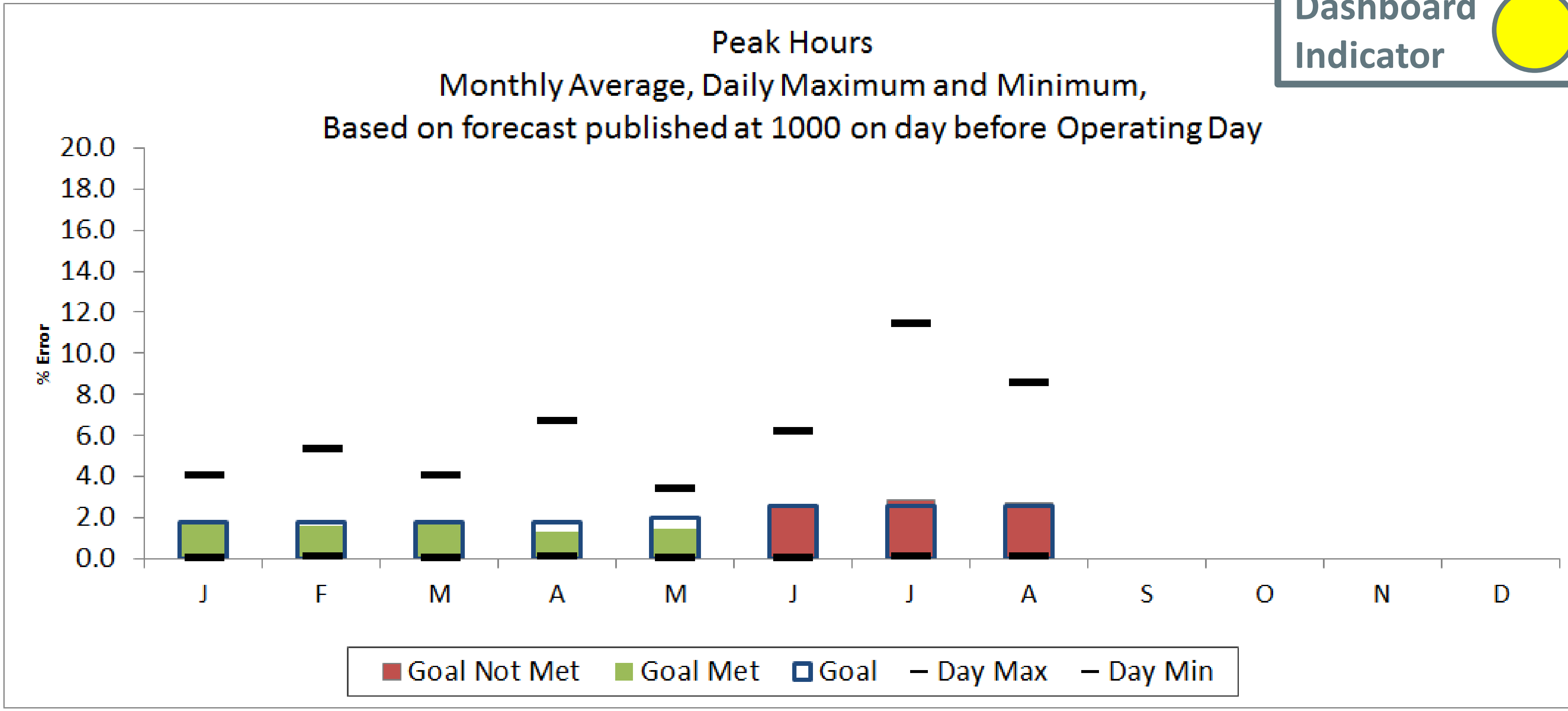
Dashboard Indicator



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					7.82
Day Min	0.80	0.74	1.08	1.17	0.96	0.97	0.79	0.95					0.74
MAPE	1.91	2.34	2.70	2.52	2.36	2.63	2.70	2.23					2.42
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

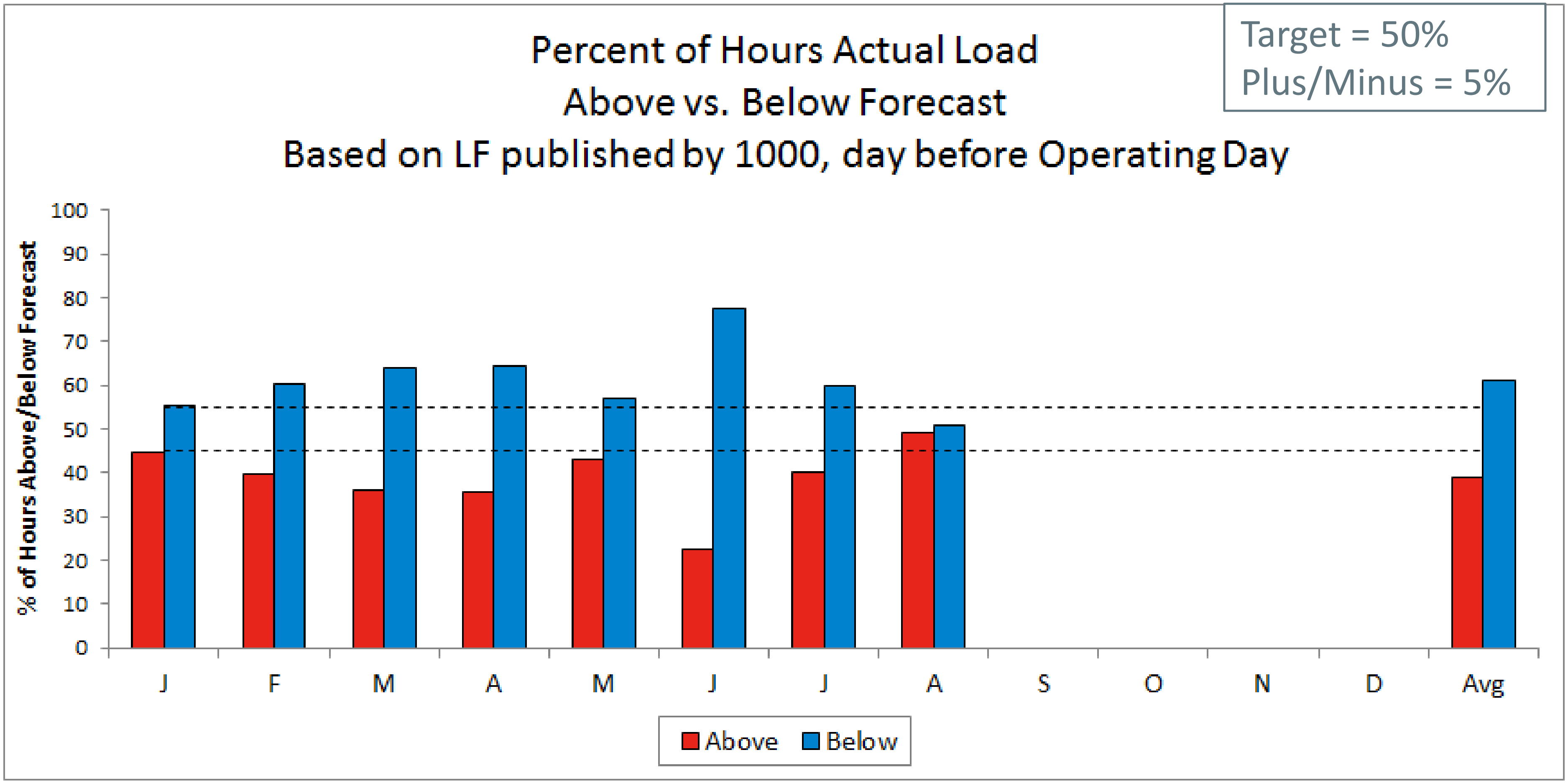
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



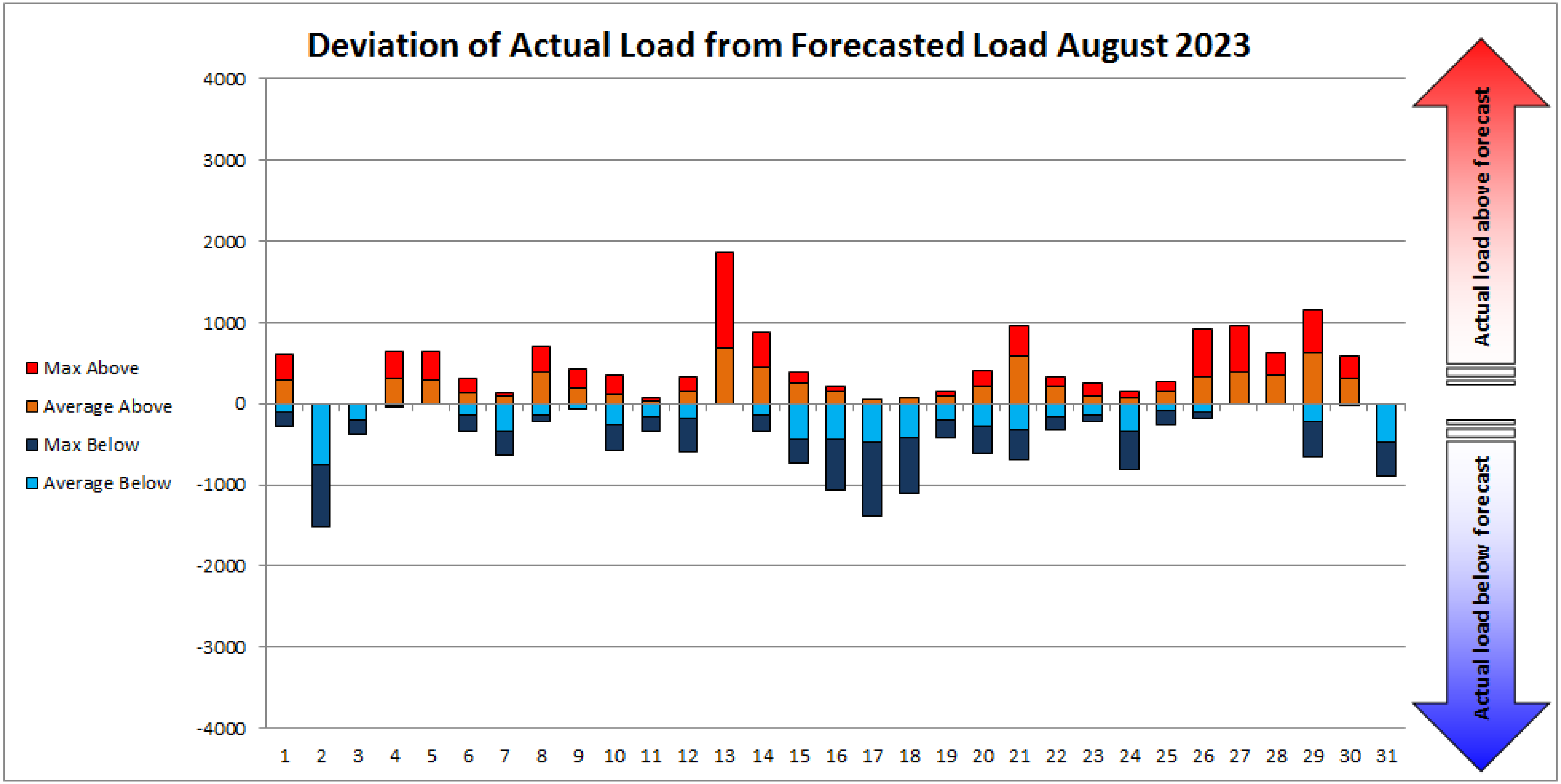
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21	11.40	8.59					11.40
Day Min	0.01	0.08	0.06	0.11	0.03	0.04	0.08	0.14					0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65	2.87	2.72					2.02
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

2023 System Operations - Load Forecast Accuracy cont.

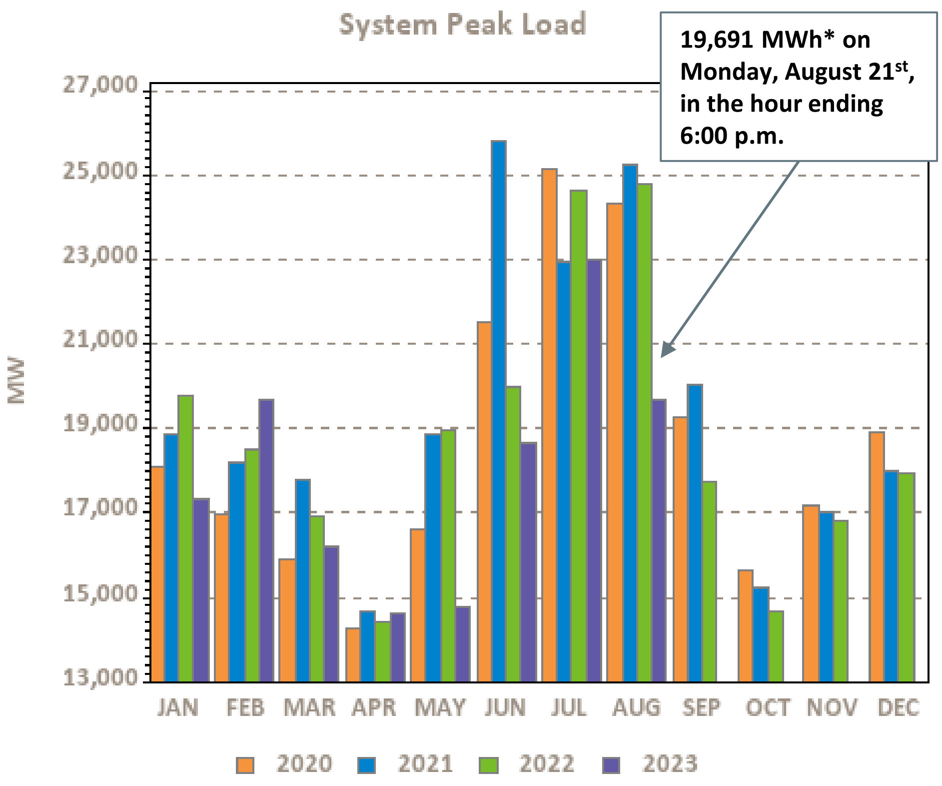


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6	40.2	49.2					39
Below %	55.4	60.3	63.8	64.3	57	77.4	59.8	50.8					61
Avg Above	235.7	228	172.9	194.5	183.5	120	194.8	228.5					236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3	-388.6	-215.1					-389
Avg All	-10	-28	-142	-74	-17	-236	-170	-6					-86

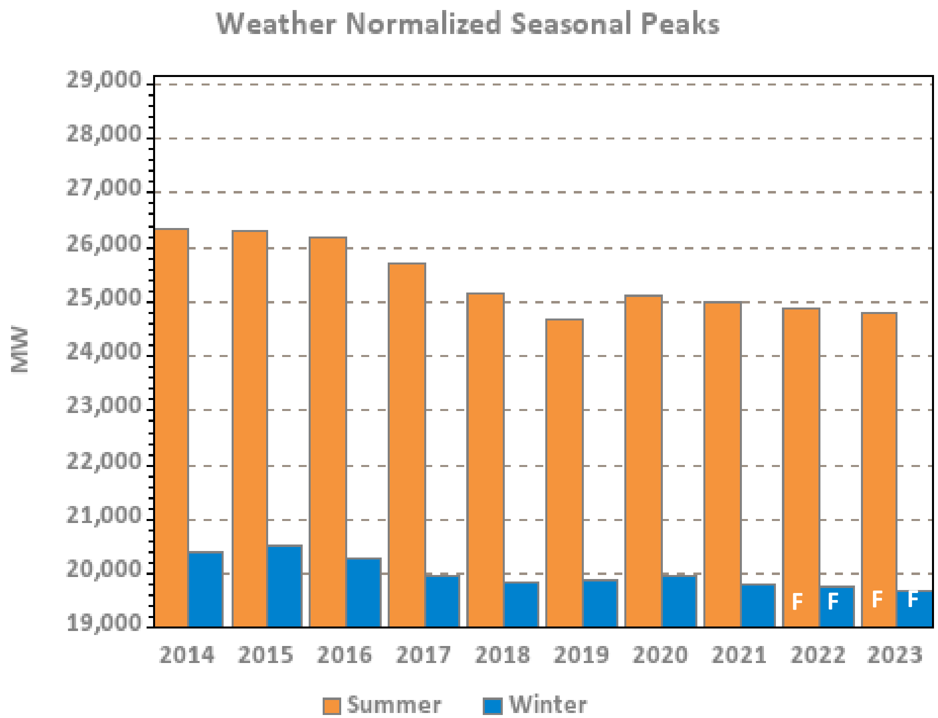
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History



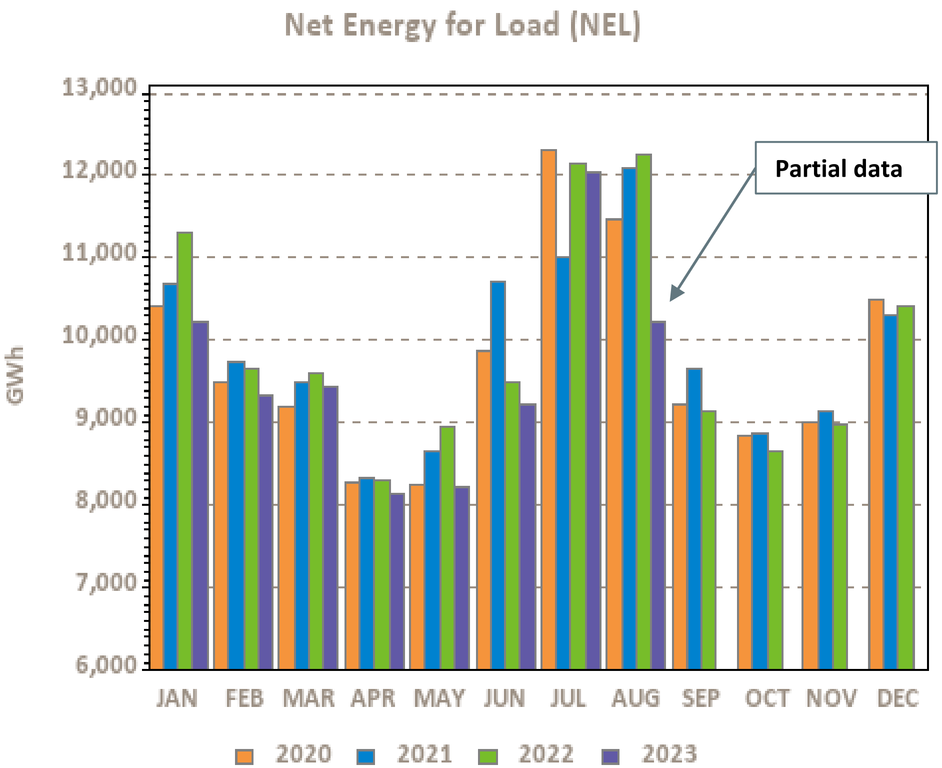
*Revenue quality metered value



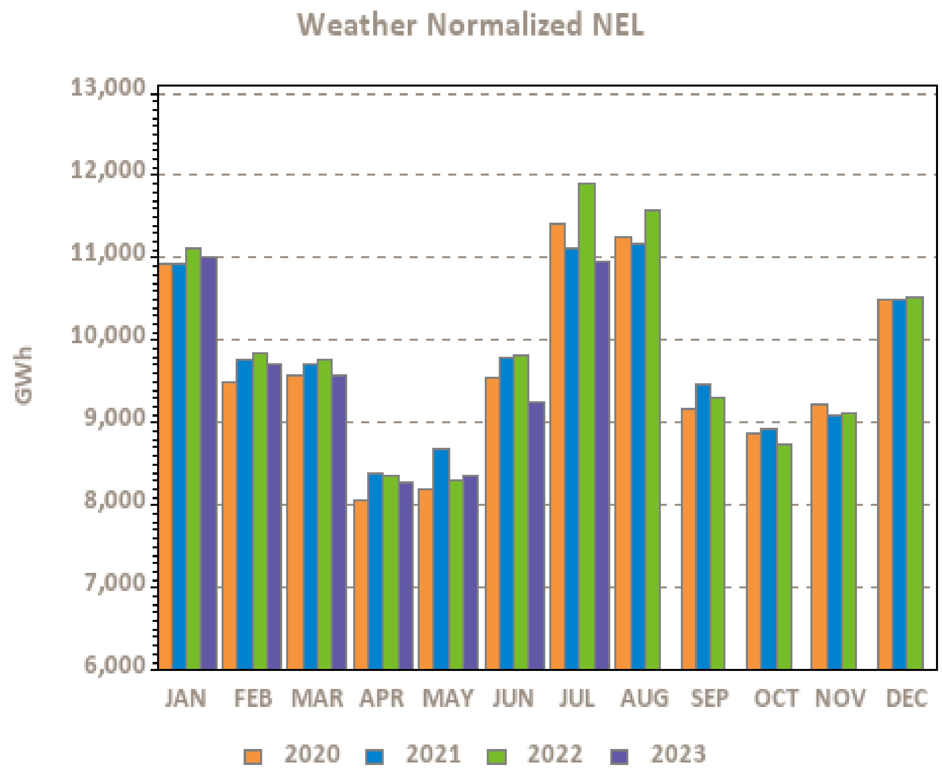
Winter beginning in year displayed

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

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



Ann Tot (TWh): 116.9 118.8 118.9 76.8

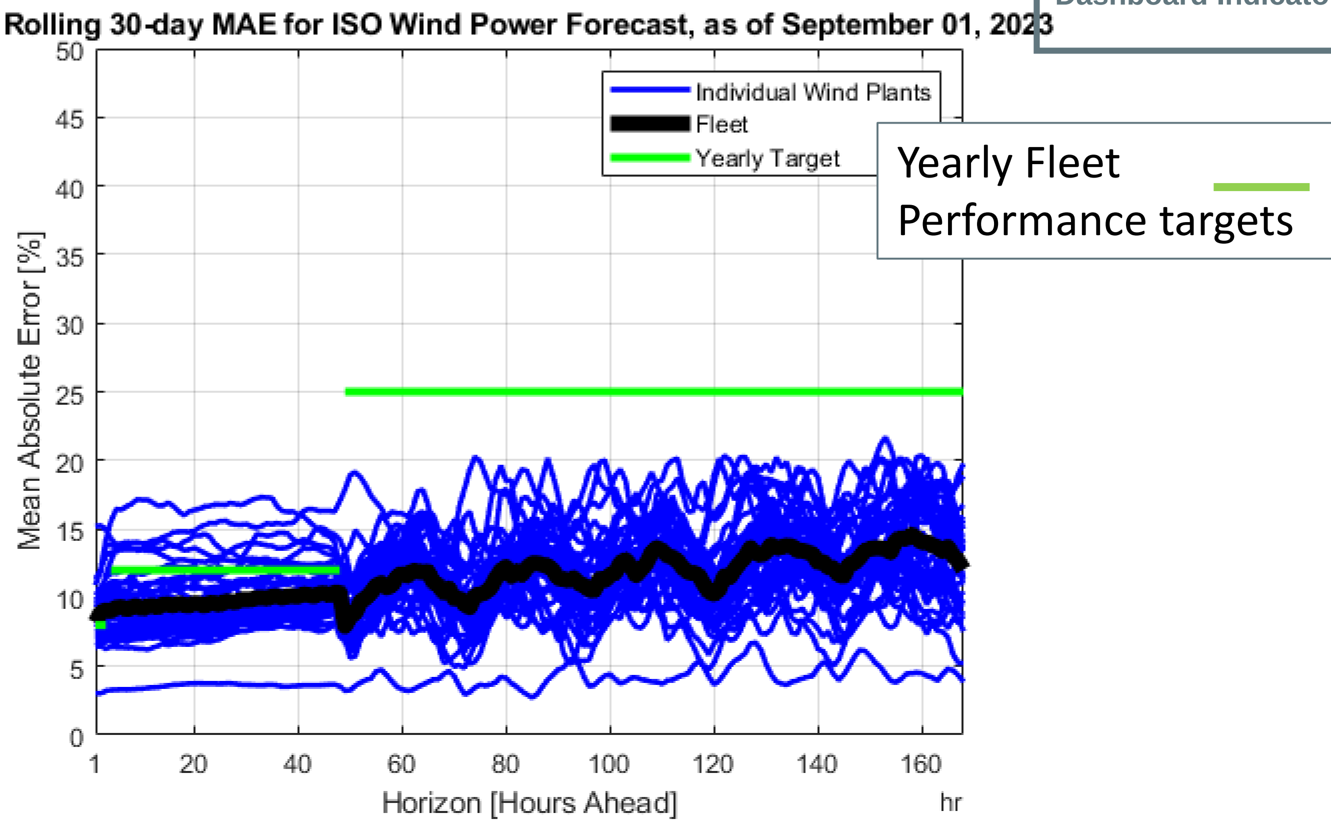


Ann Tot (TWh): 116.3 117.6 118.4 67.1

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

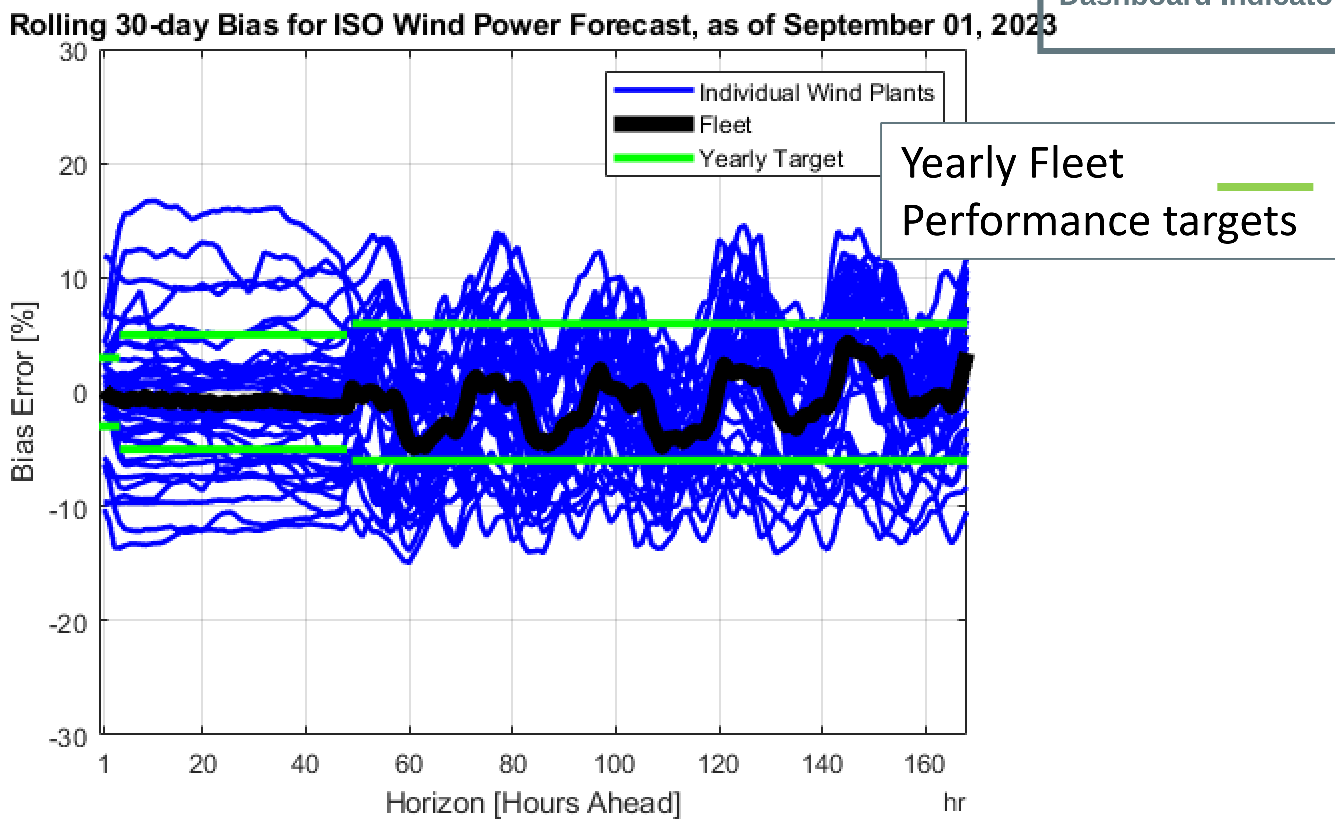
Dashboard Indicator



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

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

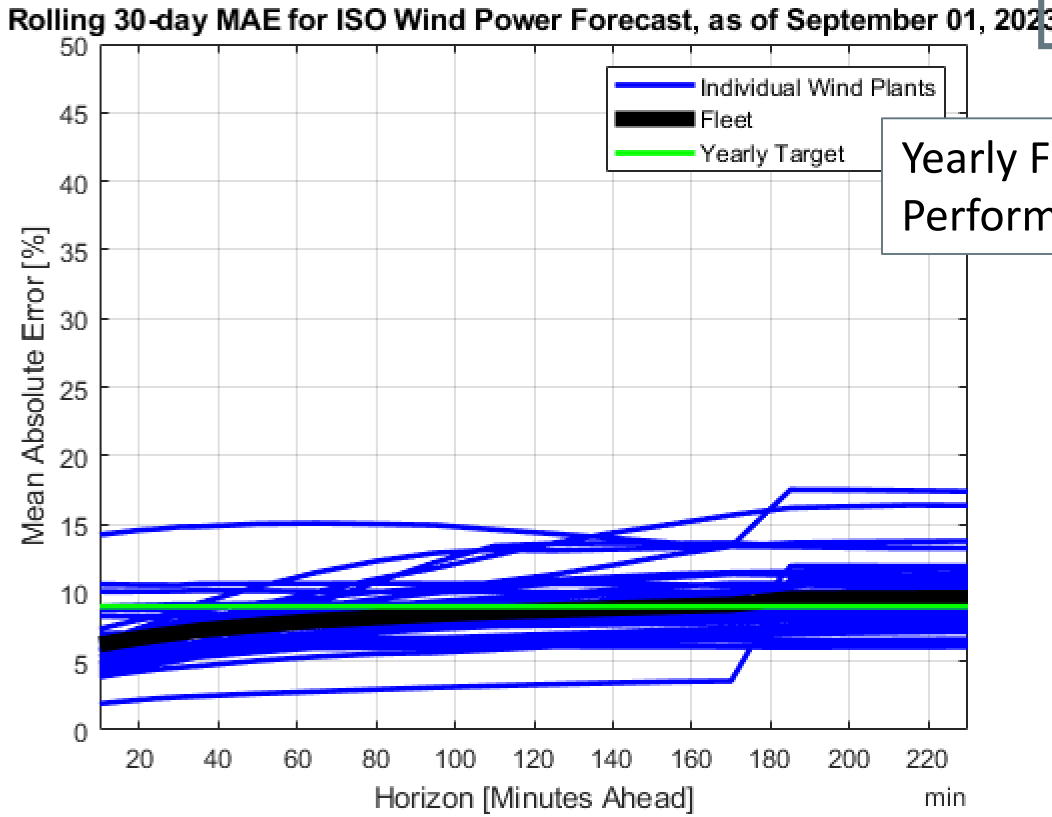
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

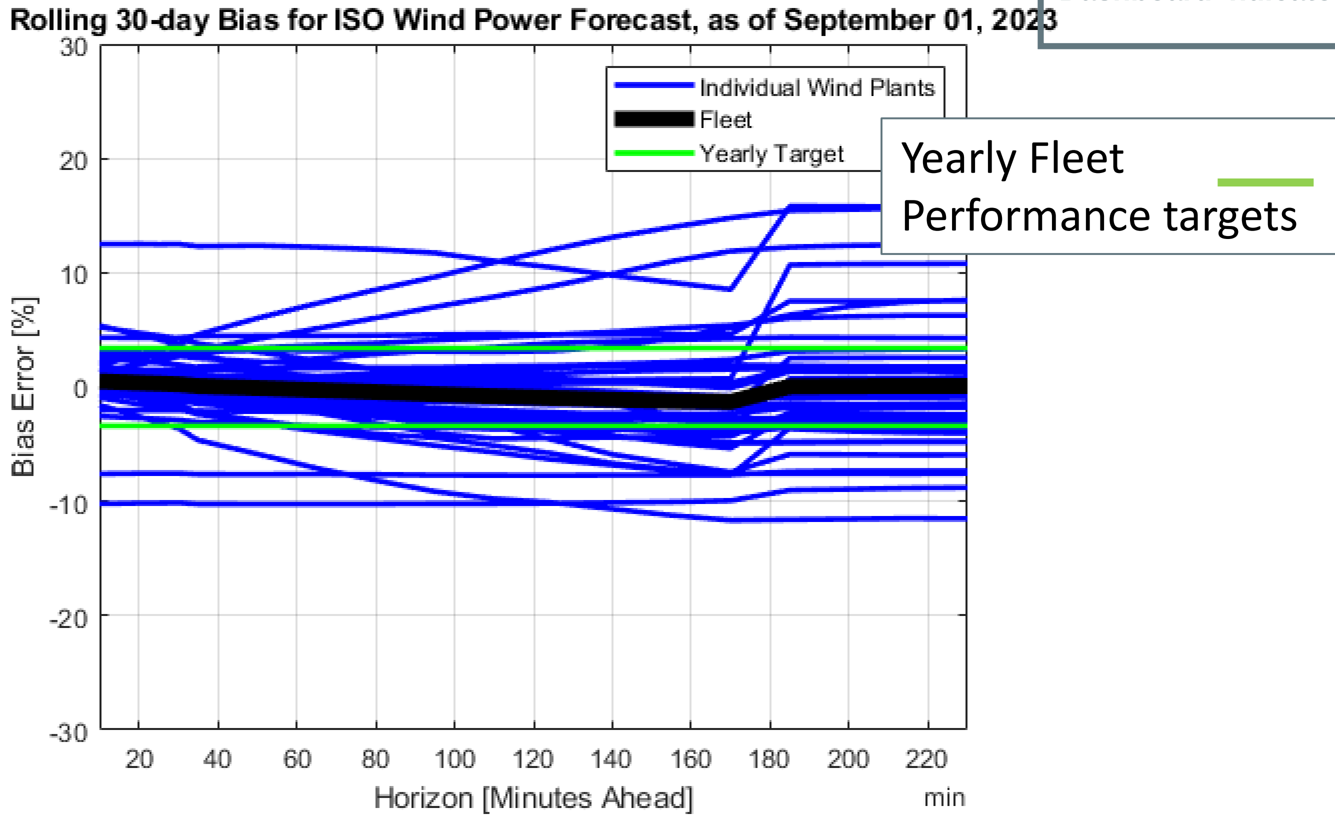


Yearly Fleet Performance targets

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.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

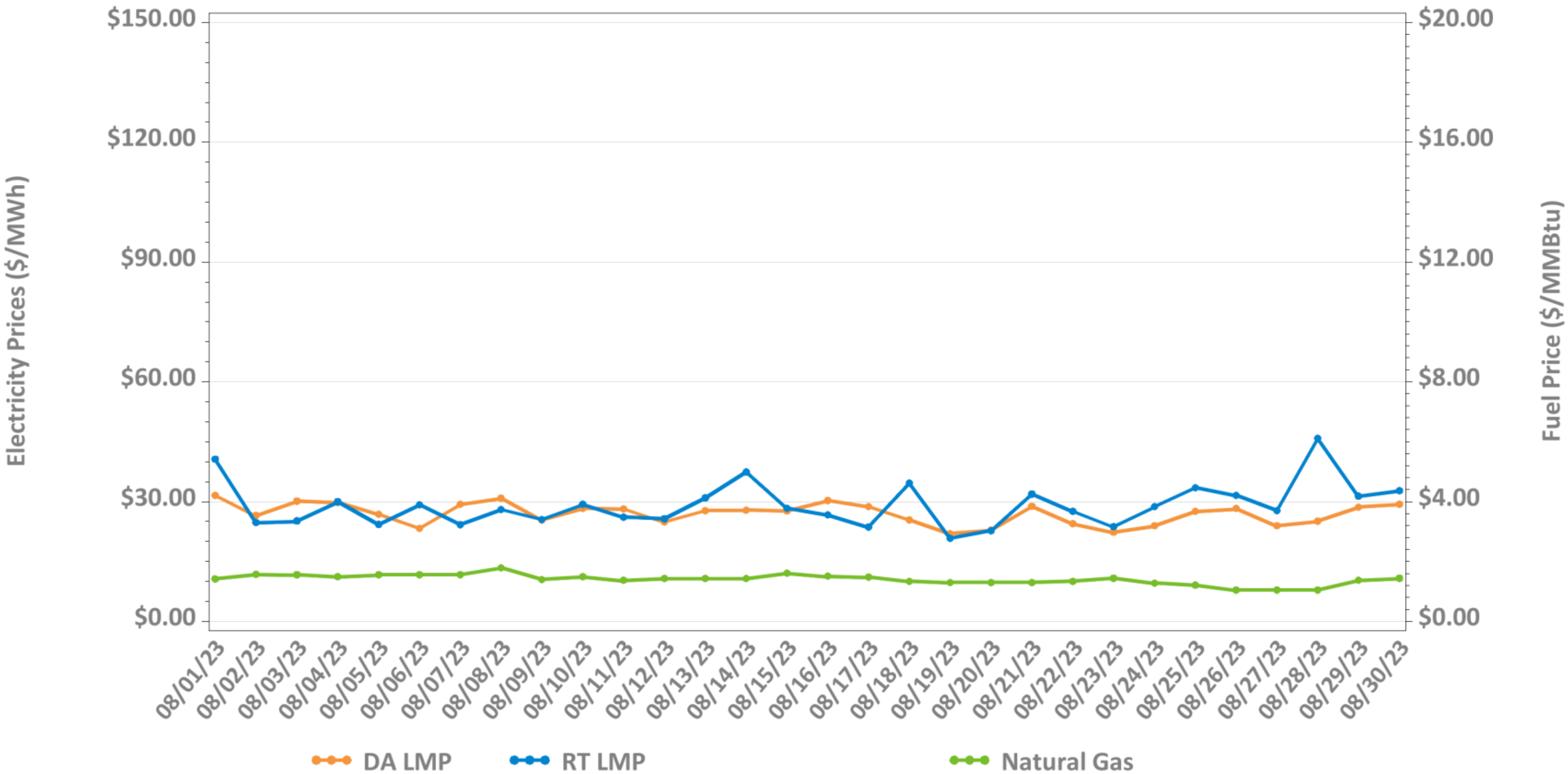
Dashboard Indicator



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: August 1-30, 2023



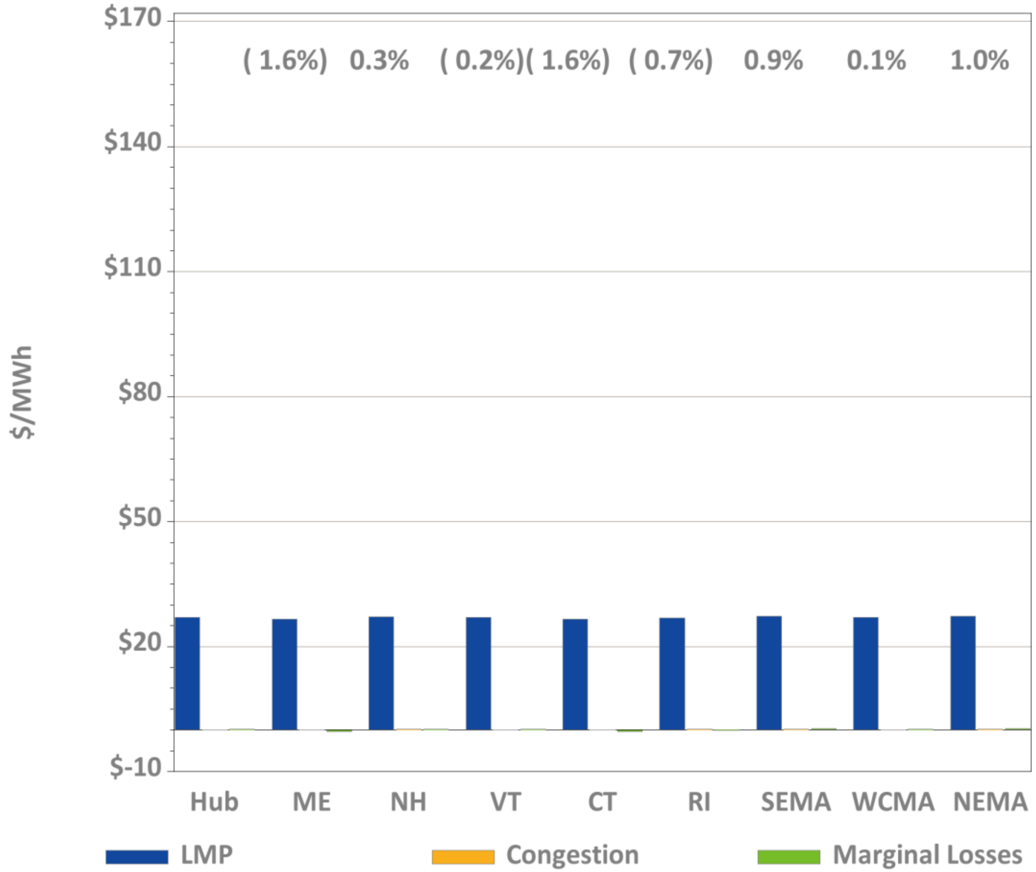
Underlying natural gas data furnished by:

ICE Global markets in clear view

*Revenue quality metered values

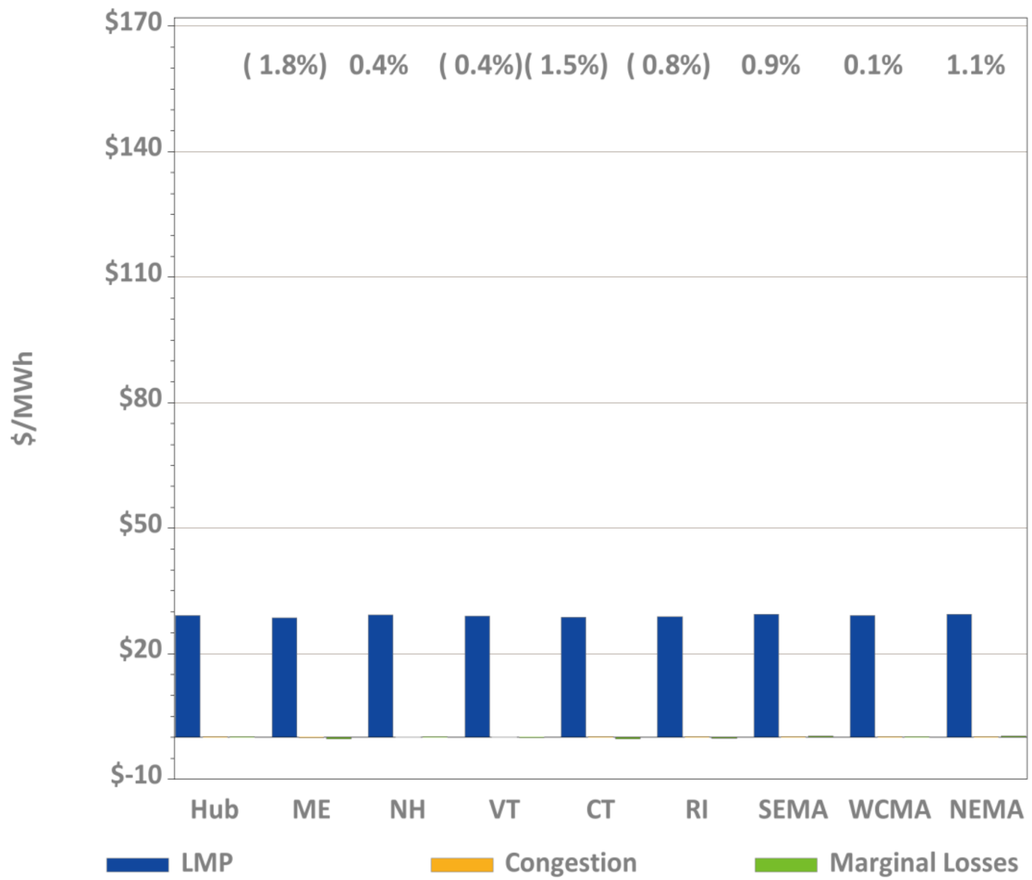
Average price difference over this period (DA-RT): $-2.08
Average price difference over this period ABS(DA-RT): $4.04
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 14%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, August 2023



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

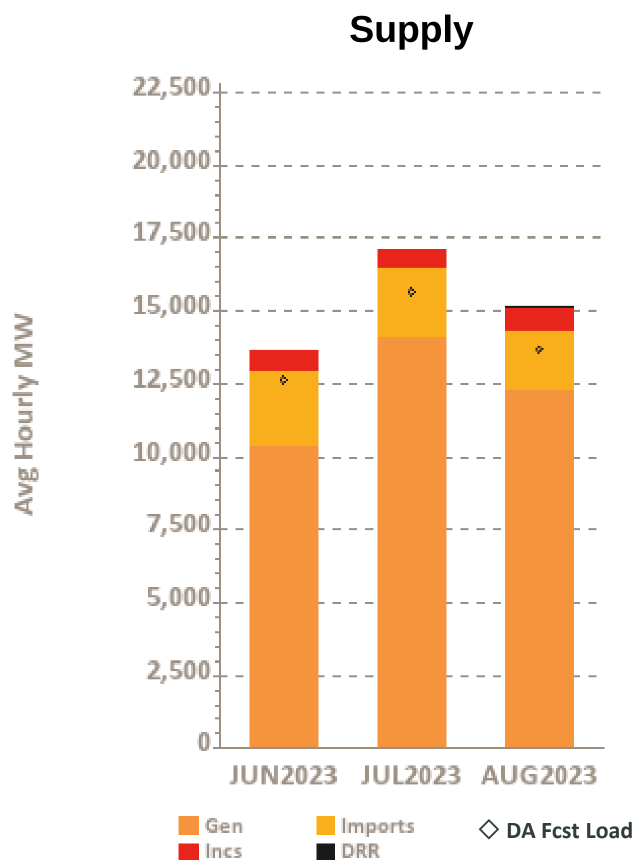
RT LMPs Average by Zone & Hub, August 2023

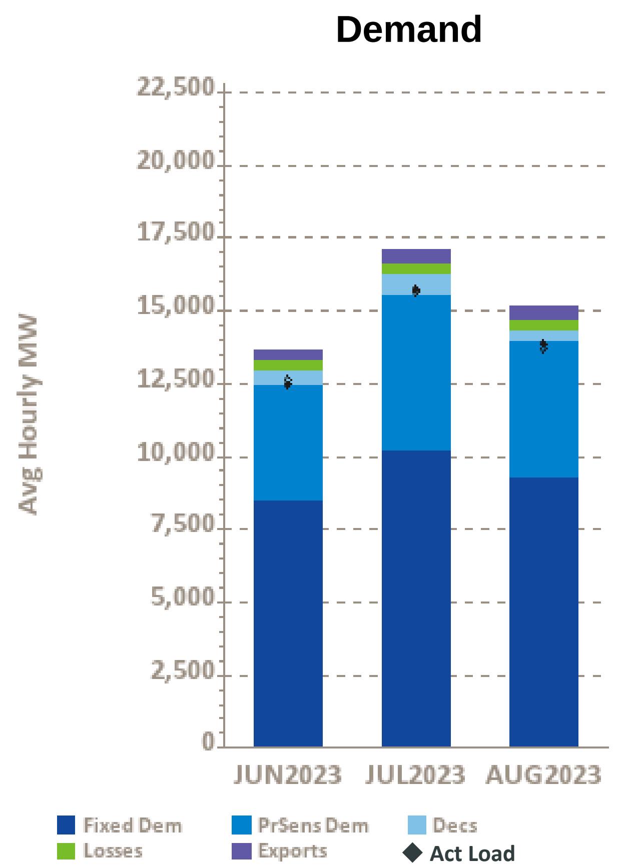


Definitions

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

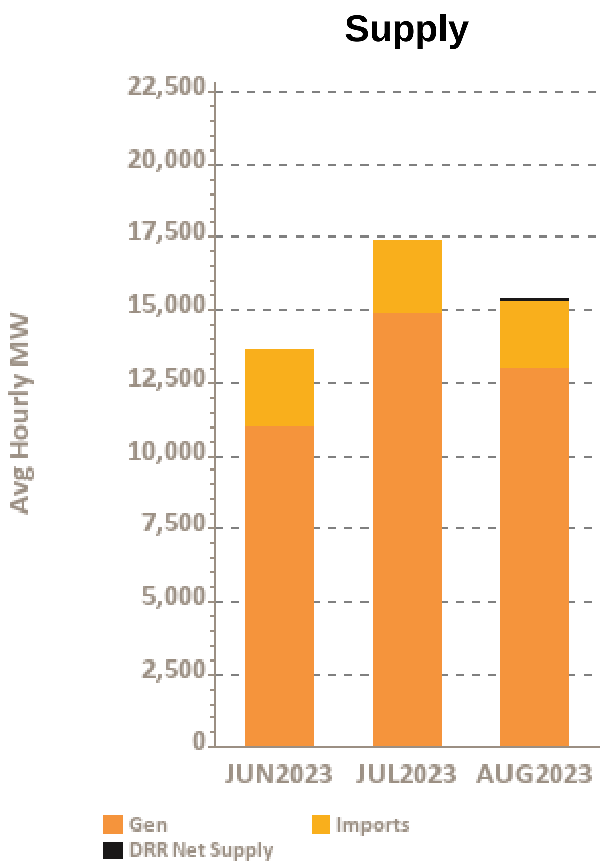


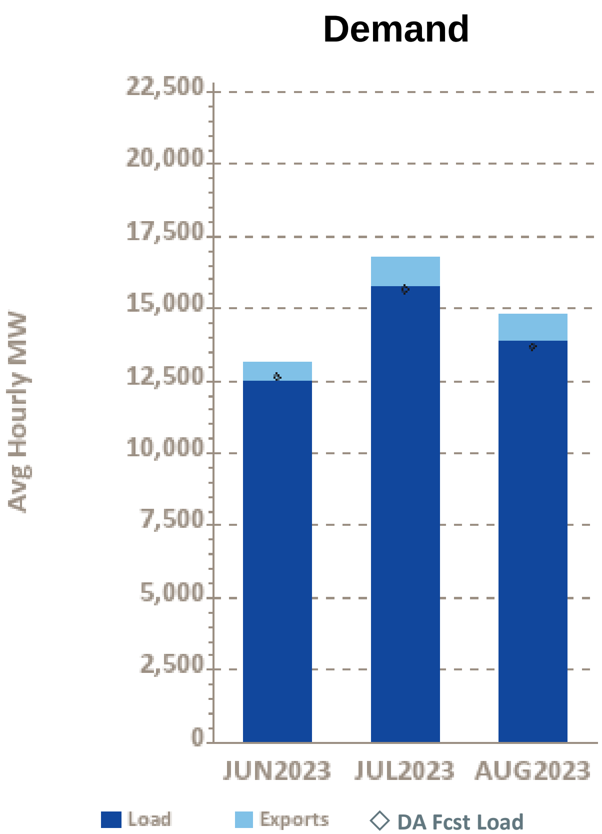


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

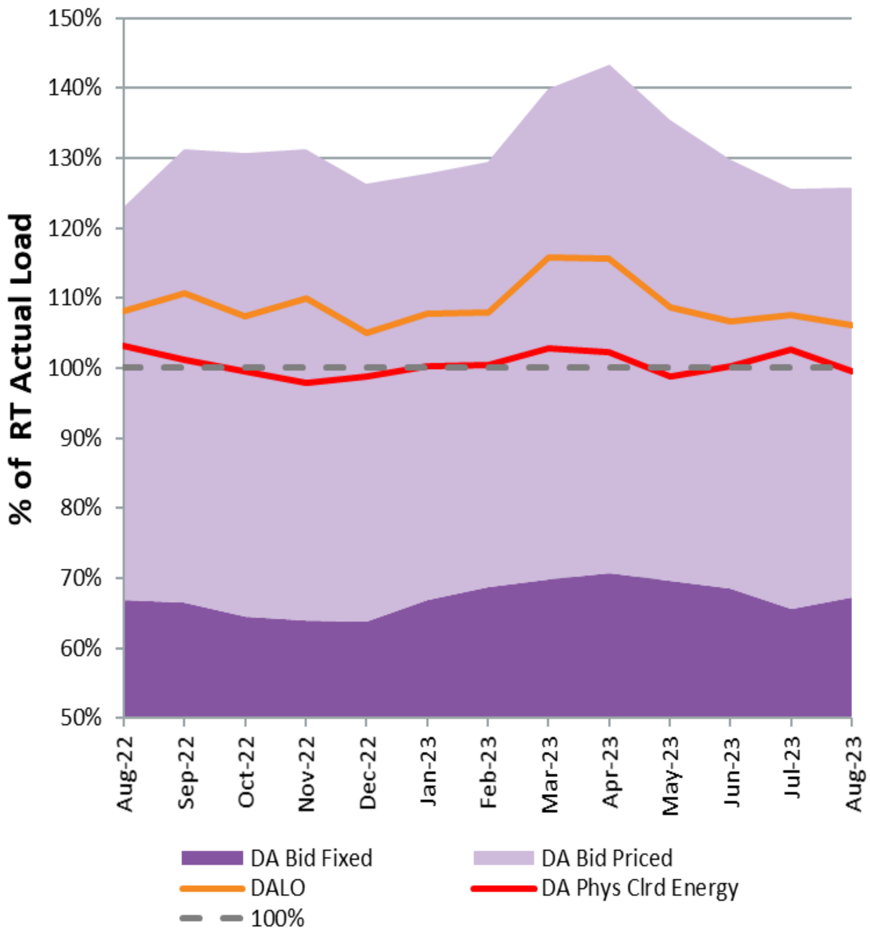
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

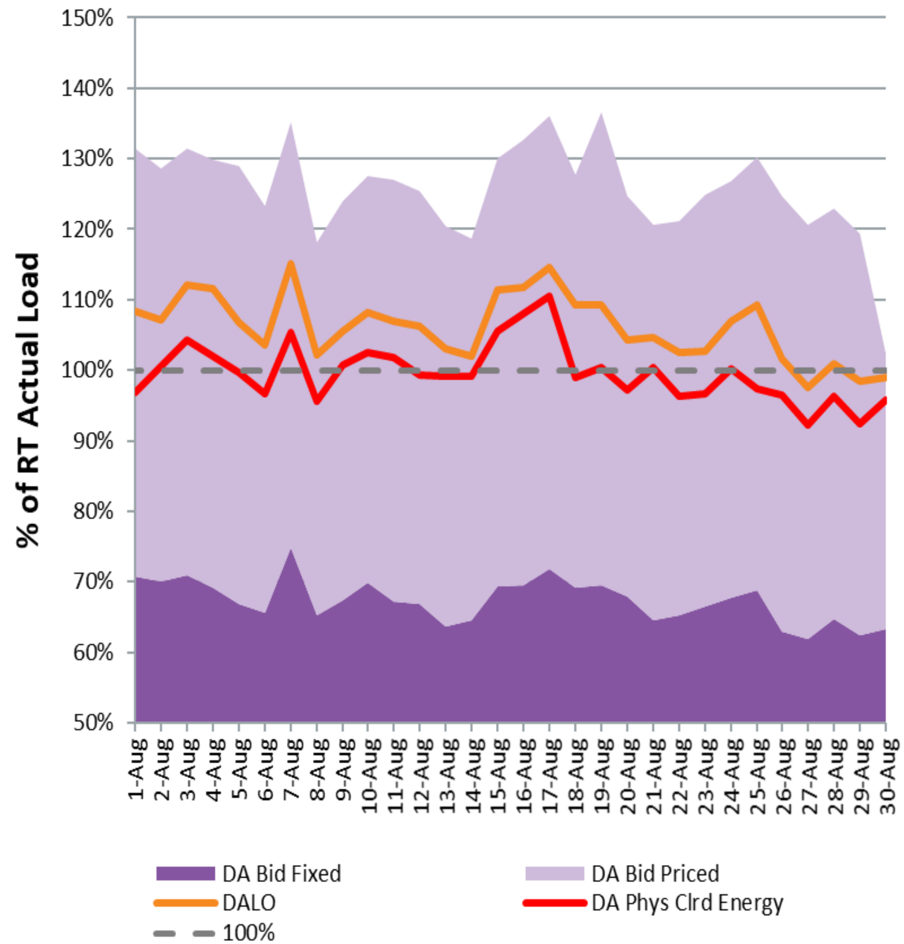
Components of RT Supply and Demand – Last Three Months





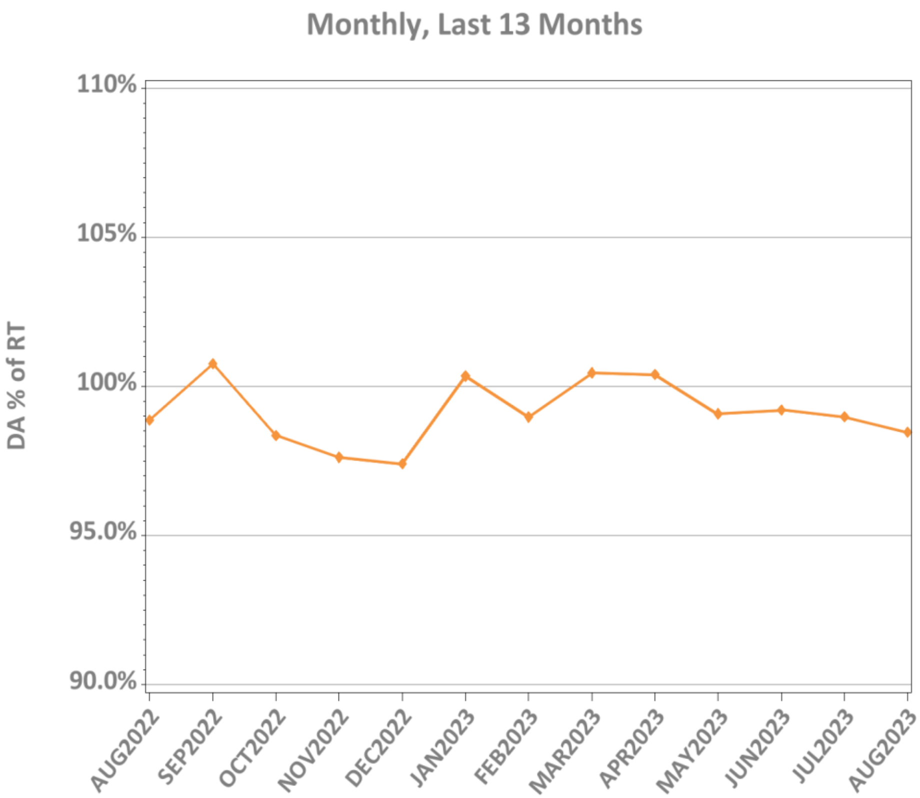
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

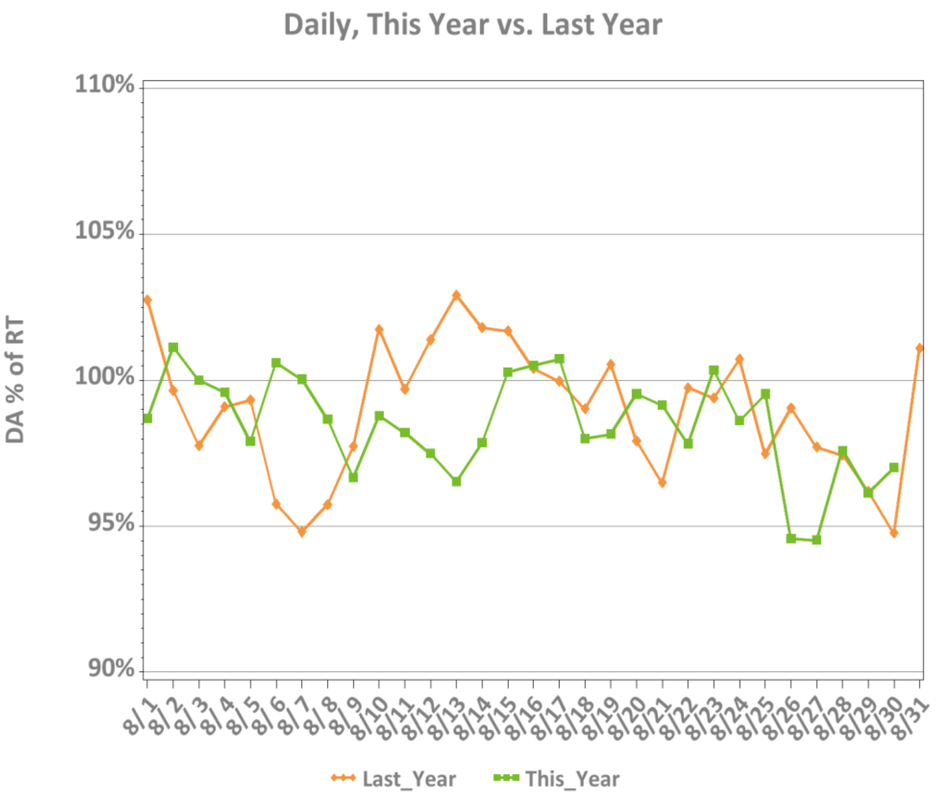




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

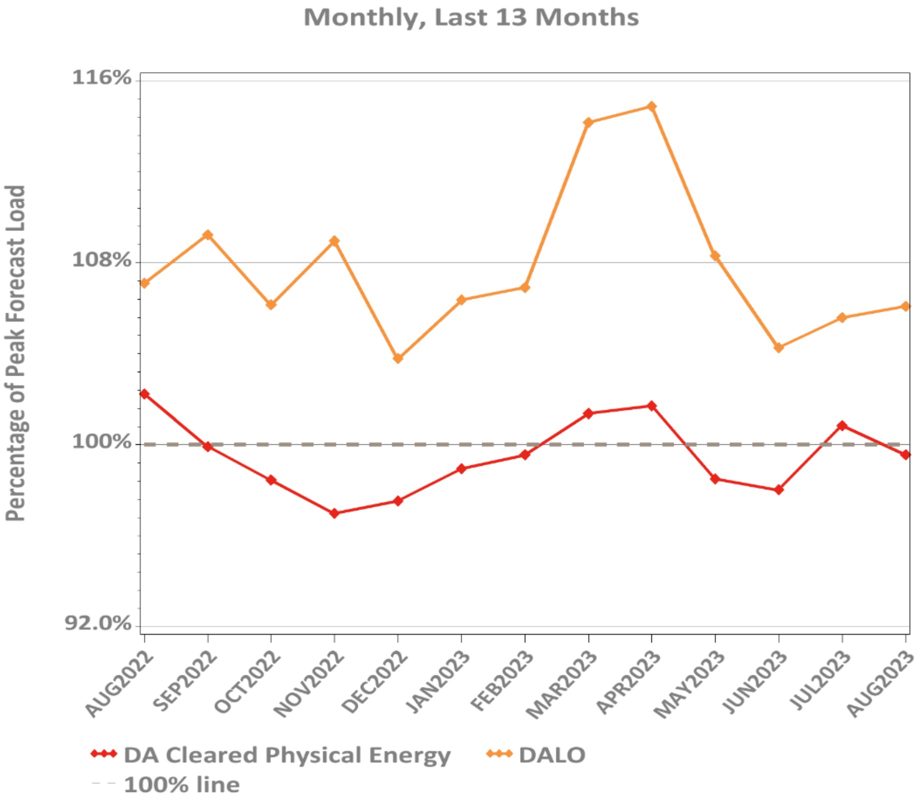
DA vs. RT Load Obligation: August, This Year vs. Last Year

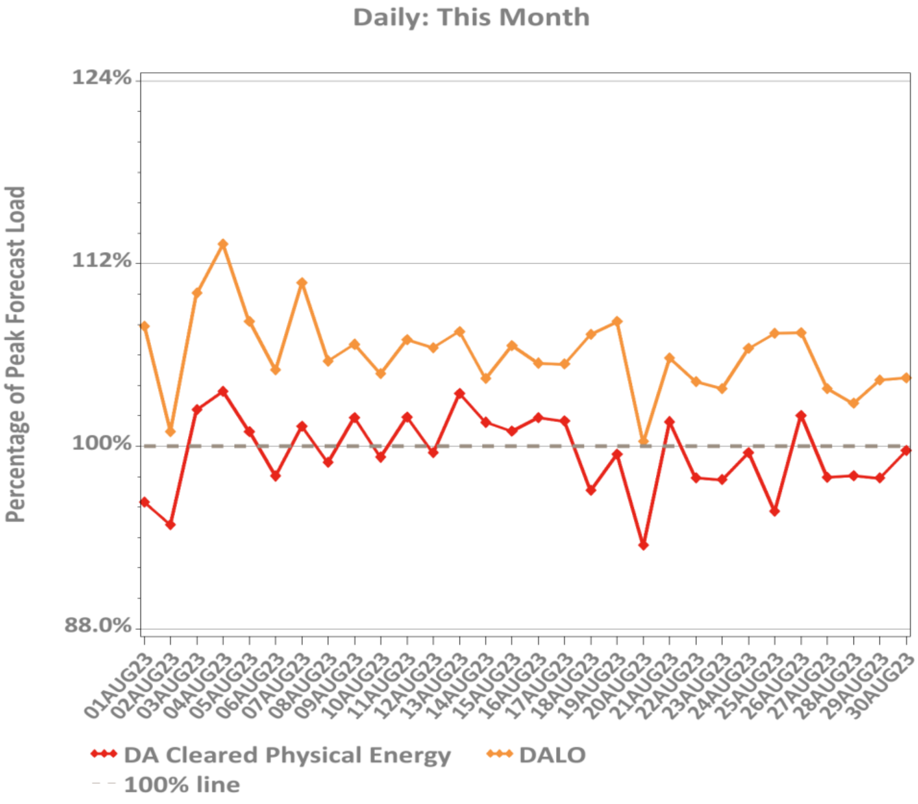




*Hourly average values

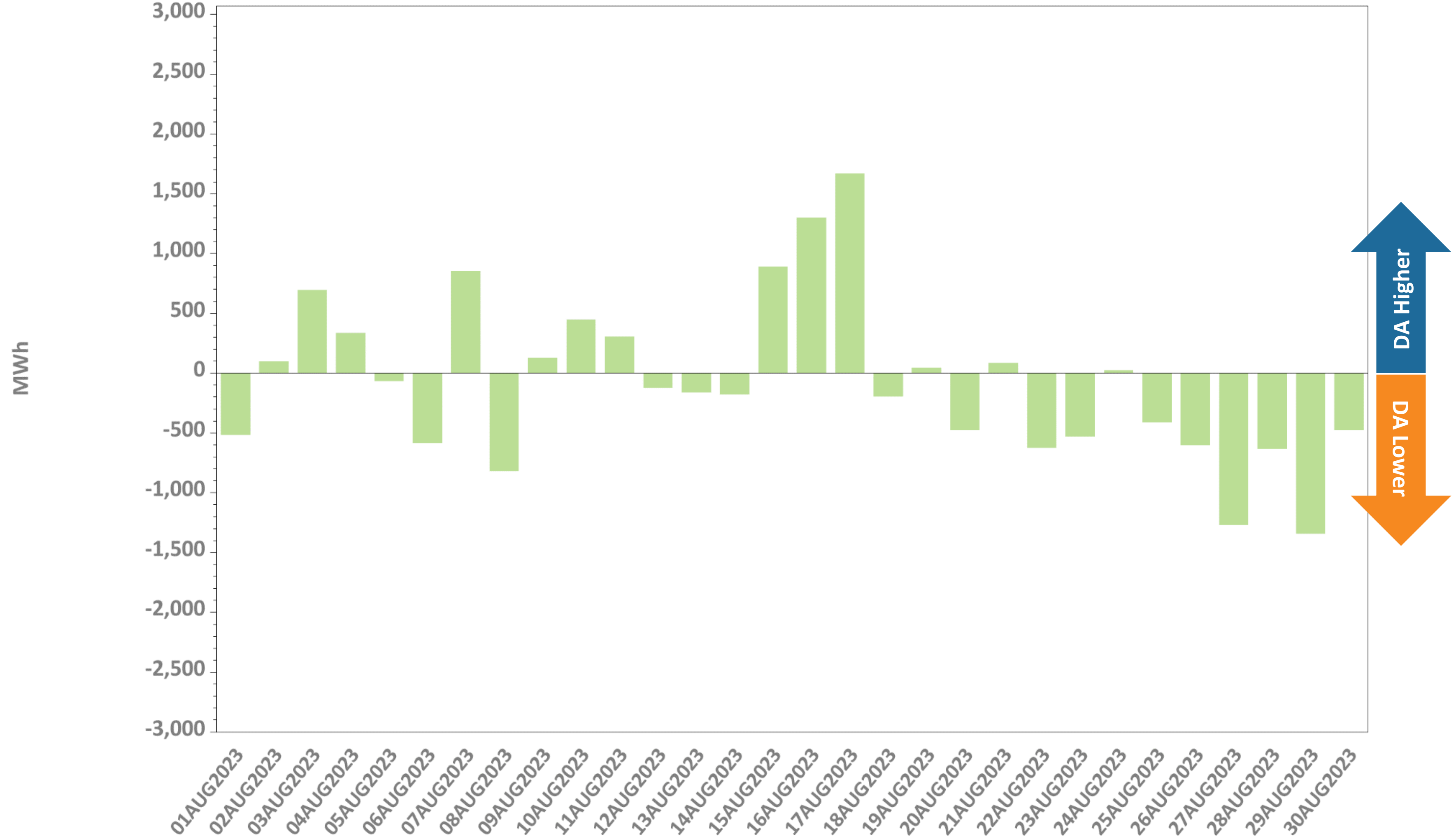
DA Volumes as % of Forecast in Peak Hour





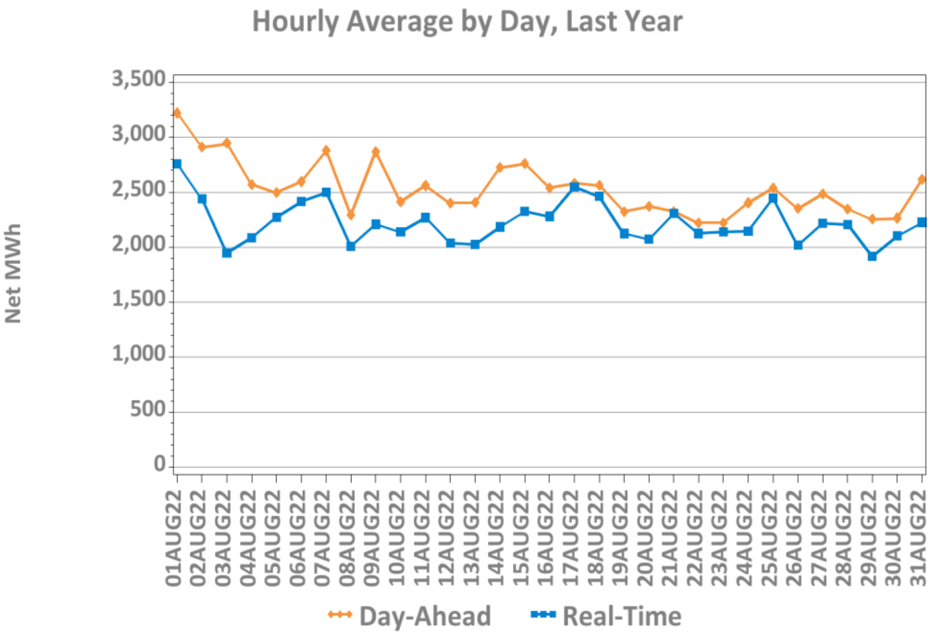
Note: The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

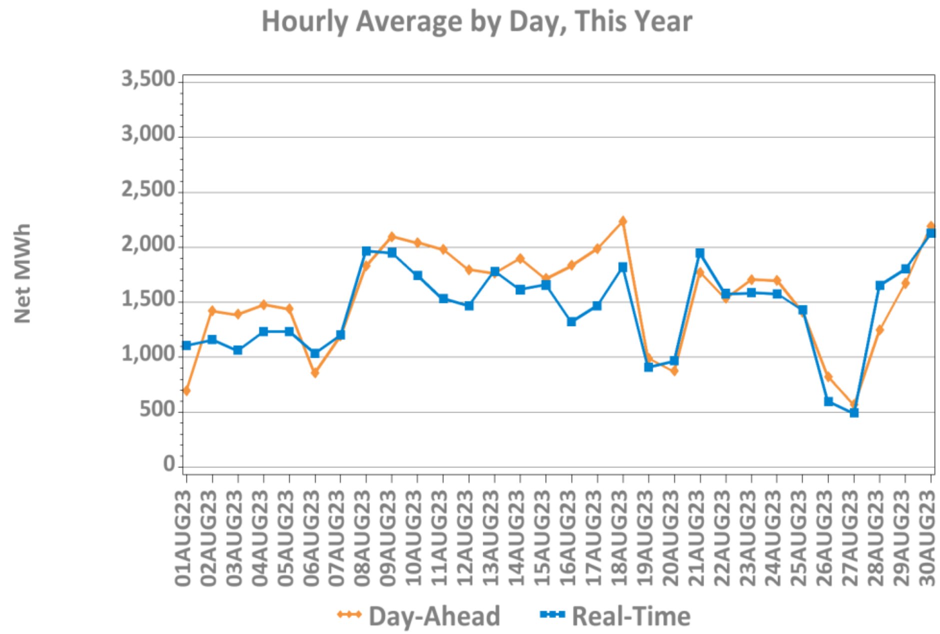
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

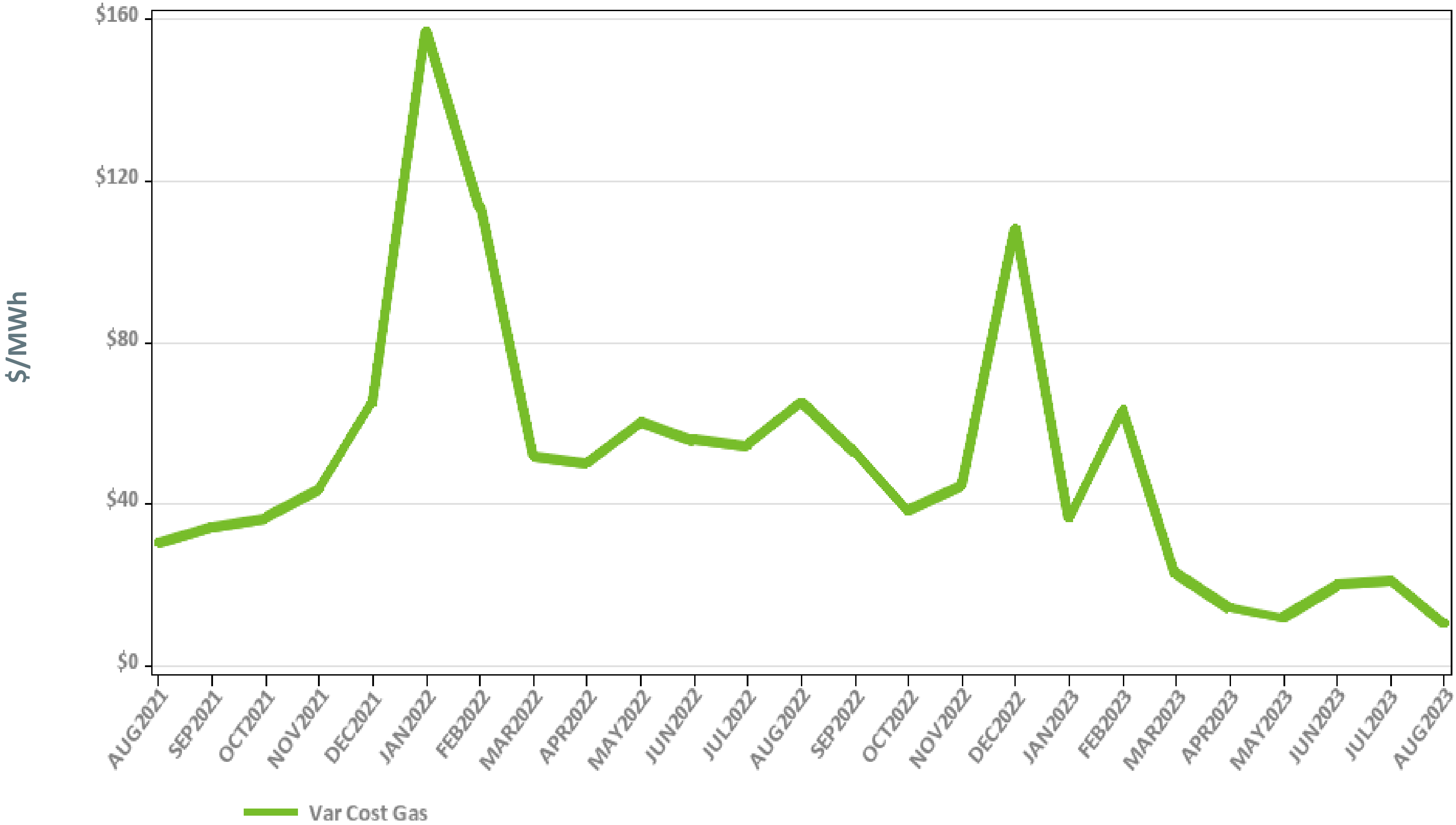
DA vs. RT Net Interchange August 2023 vs. August 2022





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

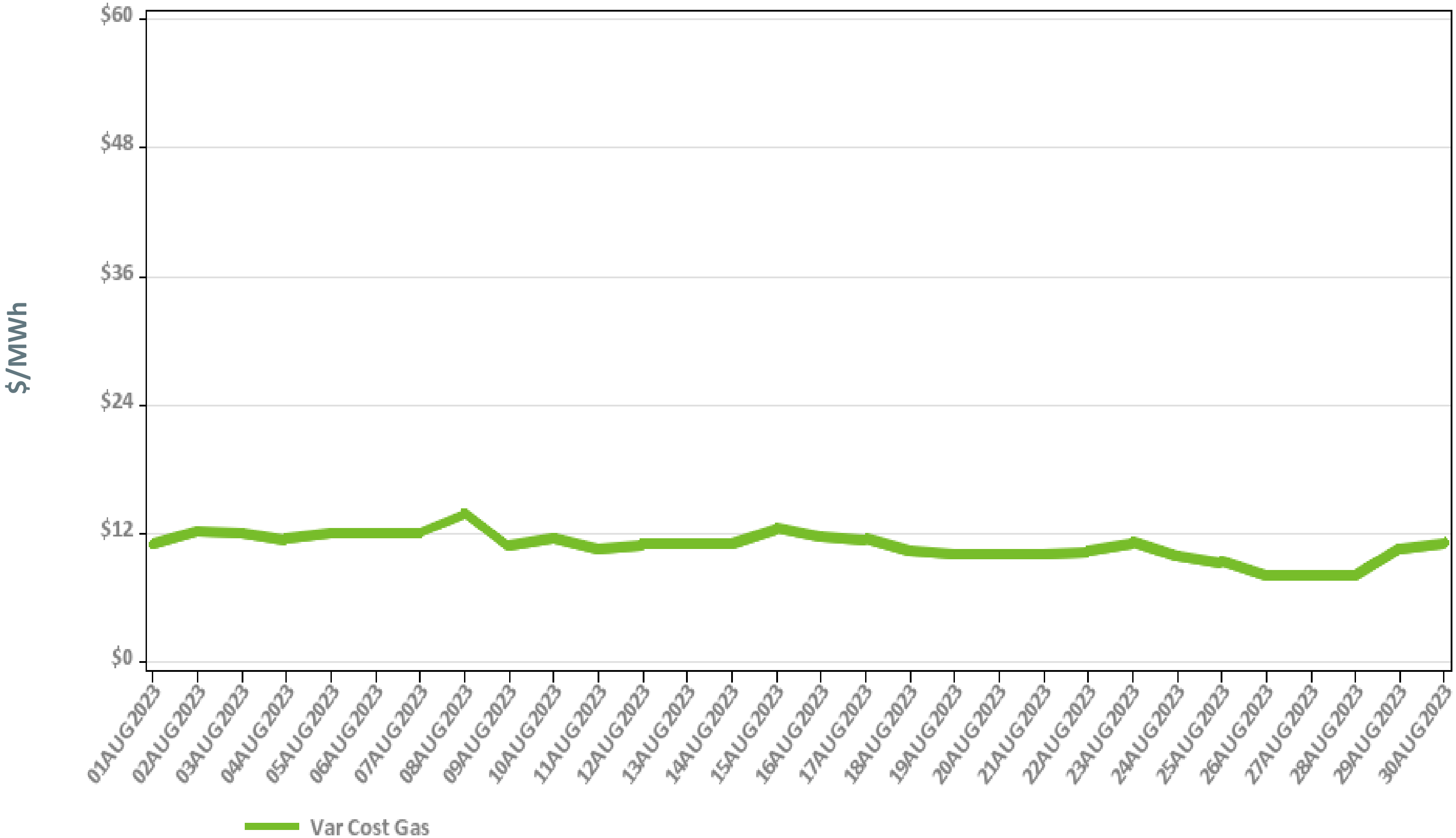


Underlying natural gas data furnished by:

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

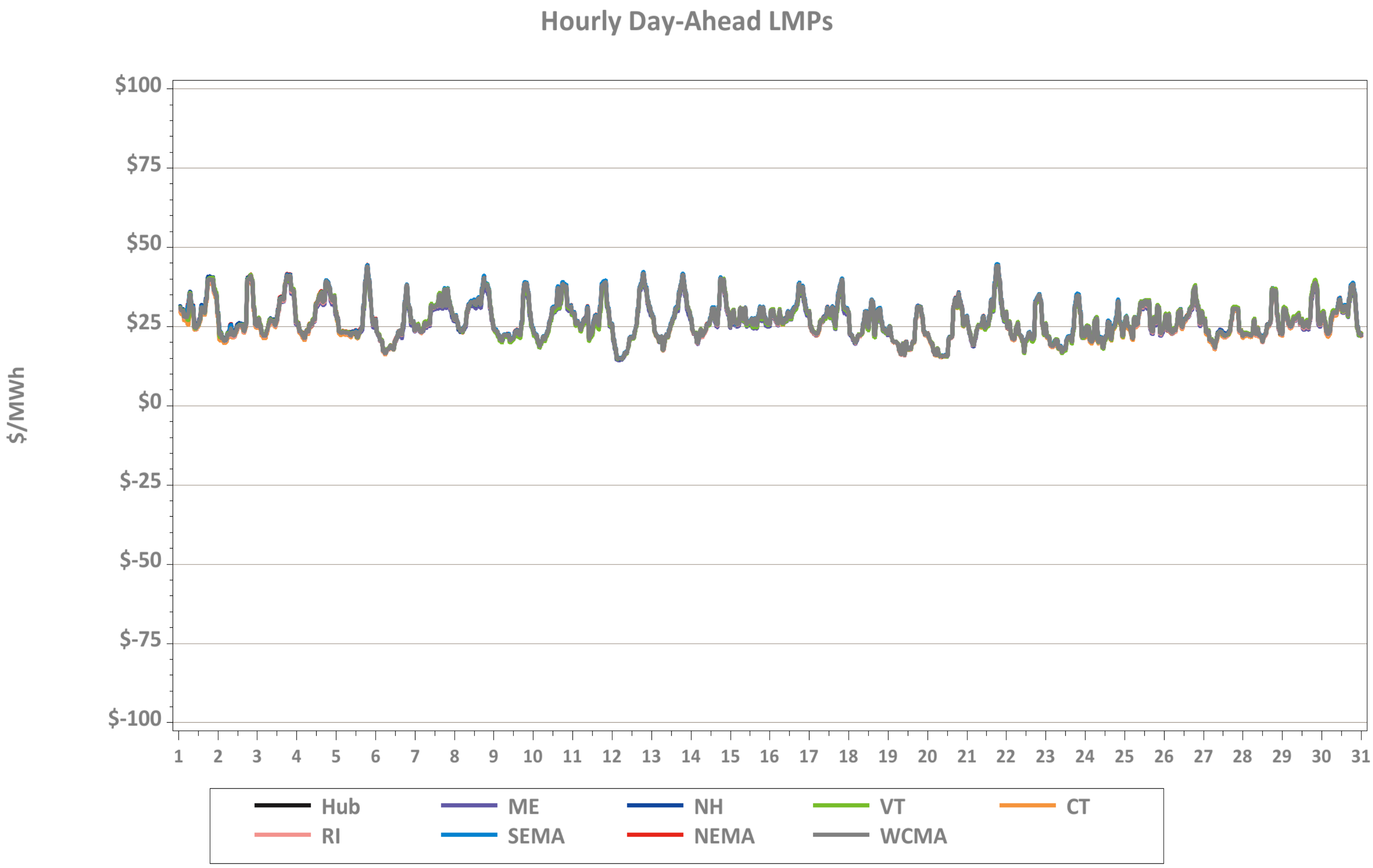


Underlying natural gas data furnished by:

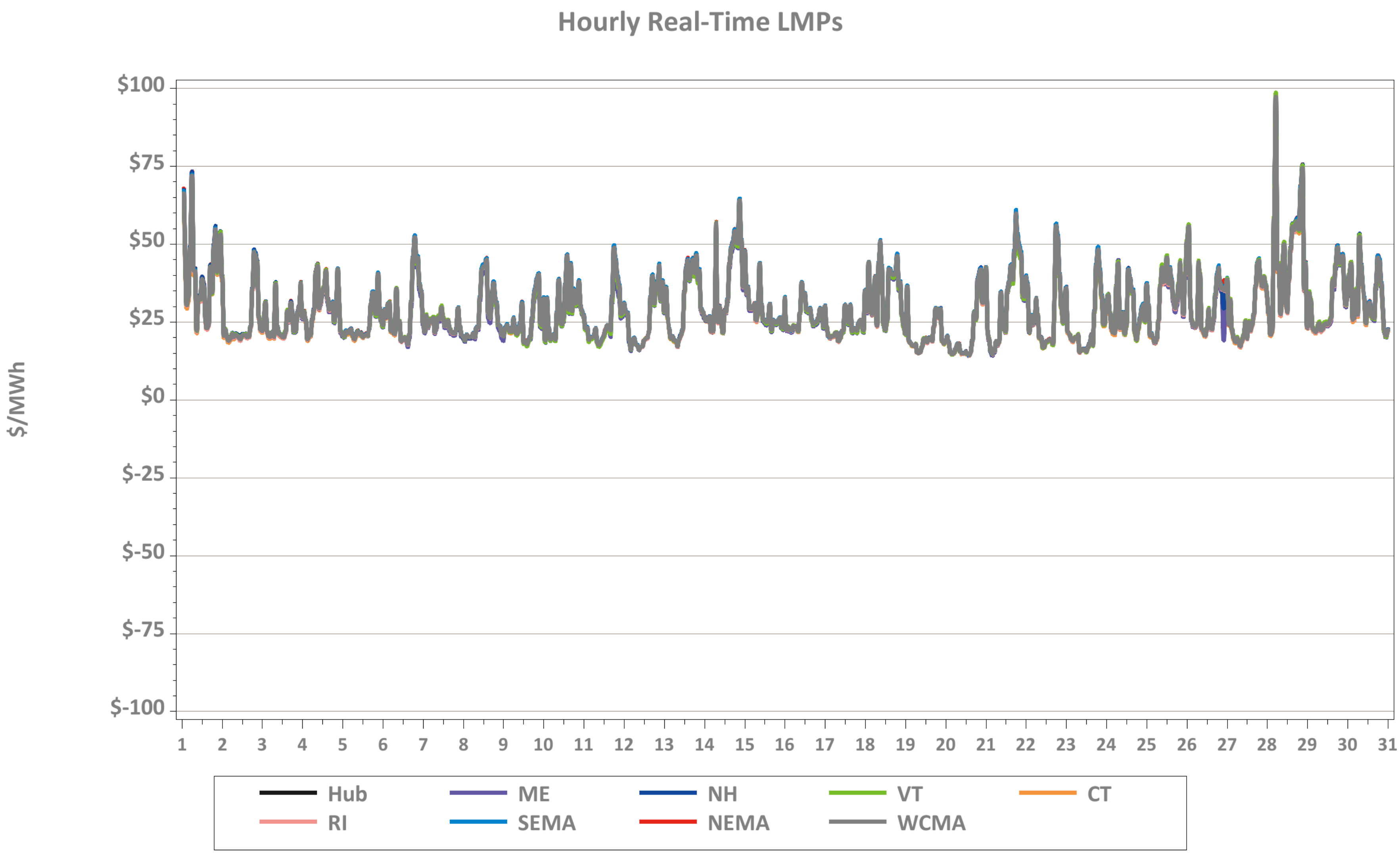
ICE Global markets in clear view

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

Hourly DA LMPs, August 1-30, 2023

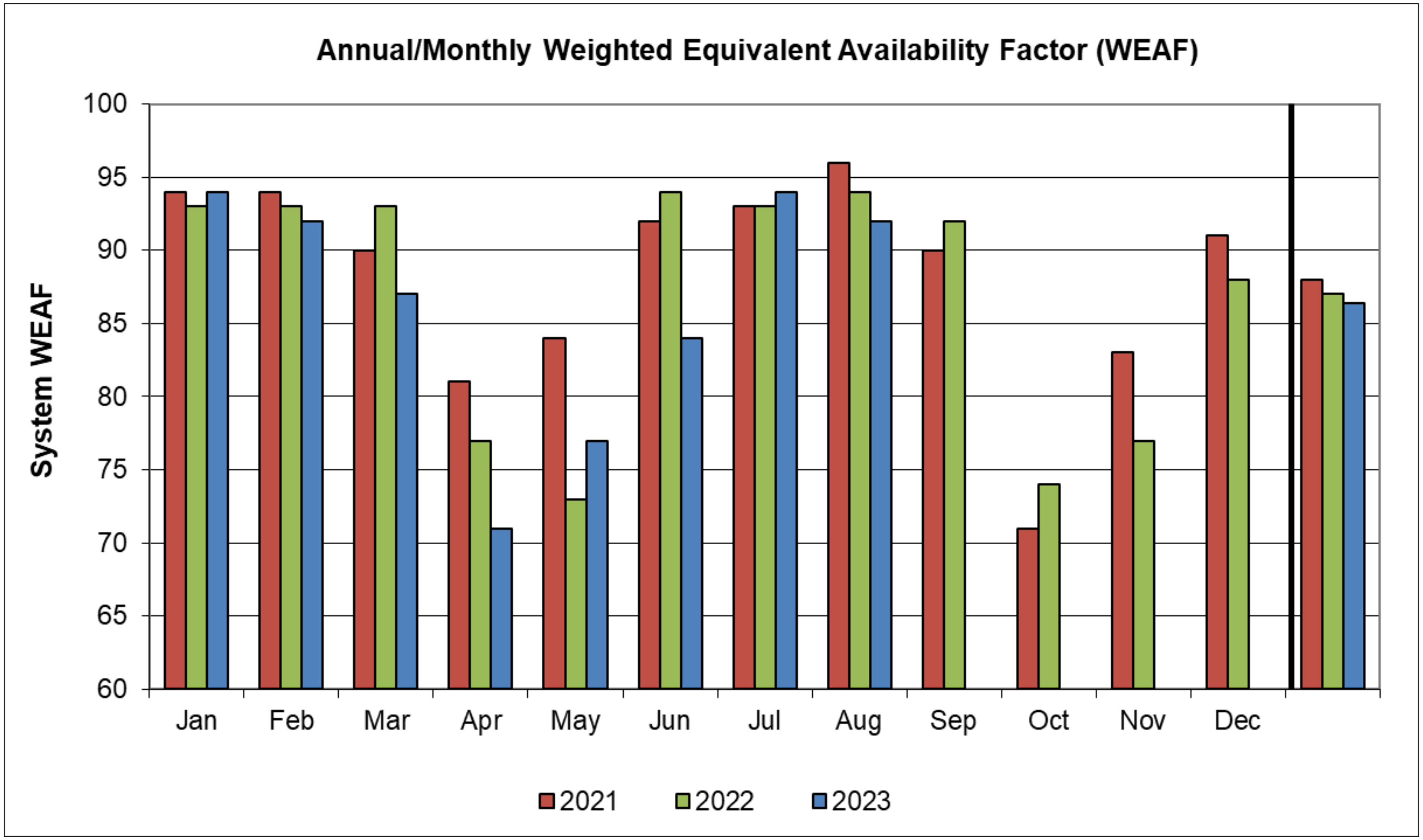


Hourly RT LMPs, August 1-30, 2023



* BTM (Behind the meter)

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92	87	71	77	84	94	92					86
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 8/24/2023

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	48.7	201.7	0.0	250.4
NH	39.6	156.7	0.0	196.3
VT	39.6	136.0	0.0	175.6
CT	118.9	166.0	598.6	883.6
RI	24.5	320.8	0.0	345.3
SEMA	38.3	472.0	0.0	510.3
WCMA	76.6	521.9	26.6	625.1
NEMA	71.8	774.3	0.0	846.1
Total	**458.1**	**2,749.4**	**625.3**	**3,832.7**

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

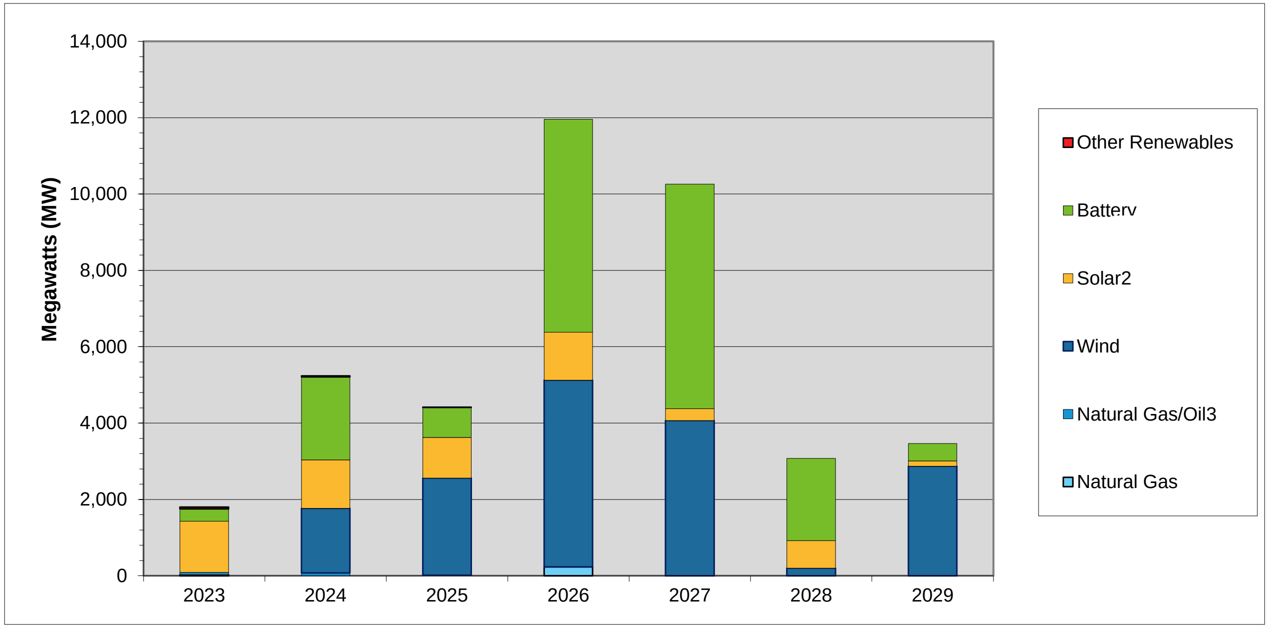
NEW GENERATION

New Generation Update
Based on Queue as of 9/04/23

- Eight projects totaling 1,362 MW were added to the interconnection queue since the last update
  - Seven battery projects and one wind project with in-service dates of 2025 to 2029
- In total, 383 generation projects are currently being tracked by the ISO, totaling approximately 41,086 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	47	30	2	0	0	0	0	79	0.2
Battery	320	2,171	788	5,580	5,889	2,150	454	17,352	43.2
Solar[2]	1,342	1,270	1,060	1,255	306	725	139	6,097	15.2
Wind	0	1,693	2,545	4,893	4,064	197	2,870	16,262	40.4
Natural Gas/Oil[3]	62	73	16	0	0	0	0	151	0.4
Natural Gas	26	0	0	233	4	0	0	263	0.7
Totals	1,797	5,237	4,411	11,961	10,263	3,072	3,463	40,204	100.0

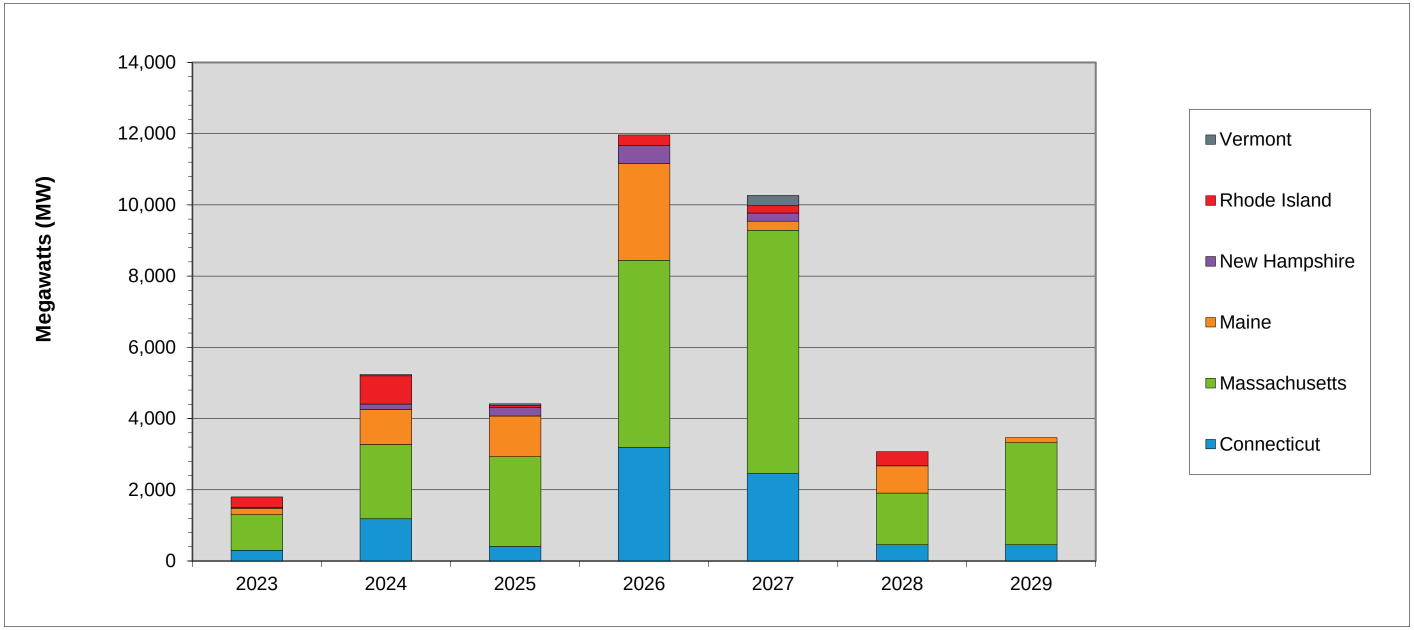
[1] Sum may not equal 100% due to rounding

[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	400	0	2,045	5.1
New Hampshire	25	154	238	504	226	0	0	1,147	2.9
Maine	185	977	1,141	2,723	254	764	139	6,183	15.4
Massachusetts	996	2,084	2,520	5,257	6,824	1,453	2,870	22,004	54.7
Connecticut	300	1,188	408	3,182	2,463	455	454	8,450	21.0
Totals	**1,797**	**5,237**	**4,411**	**11,961**	**10,263**	**3,072**	**3,463**	**40,204**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	114	17,352	1	15	113	17,337
Fuel Cell	4	46	0	0	4	46
Hydro	2	33	1	5	1	28
Natural Gas	5	263	0	0	5	263
Natural Gas/Oil	3	151	1	62	2	89
Nuclear	0	0	0	0	0	0
Solar	227	6,097	16	361	211	5,736
Wind	28	17,144	1	800	27	16,344
Total	383	41,086	20	1,243	363	39,843

- 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

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	92	1	5	7	87
Intermediate	2	89	0	0	2	89
Peaker	345	23,761	18	438	327	23,323
Wind Turbine	28	17,144	1	800	27	16,344
Total	383	41,086	20	1,243	363	39,843

- 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	114	17,352	0	0	0	0	114	17,352	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	2	33	2	33	0	0	0	0	0	0
Natural Gas	5	263	2	13	0	0	3	250	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	227	6,097	0	0	0	0	227	6,097	0	0
Wind	28	17,144	0	0	0	0	0	0	28	17,144
Total	383	41,086	8	92	2	89	345	23,761	28	17,144

- 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				
	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				
	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

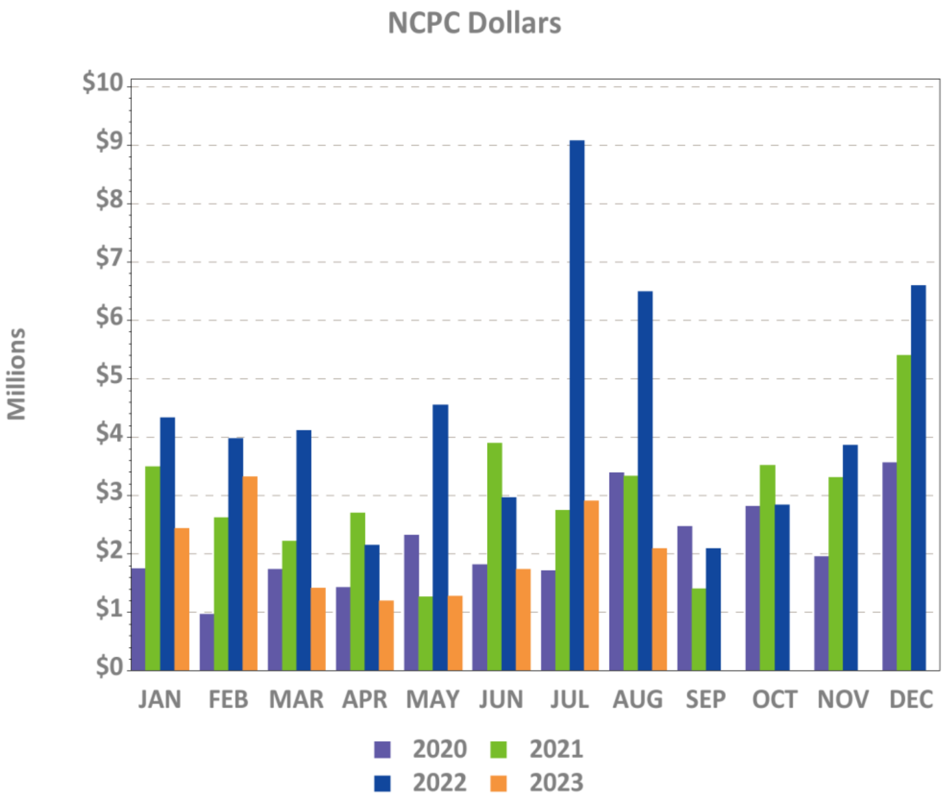
Definitions

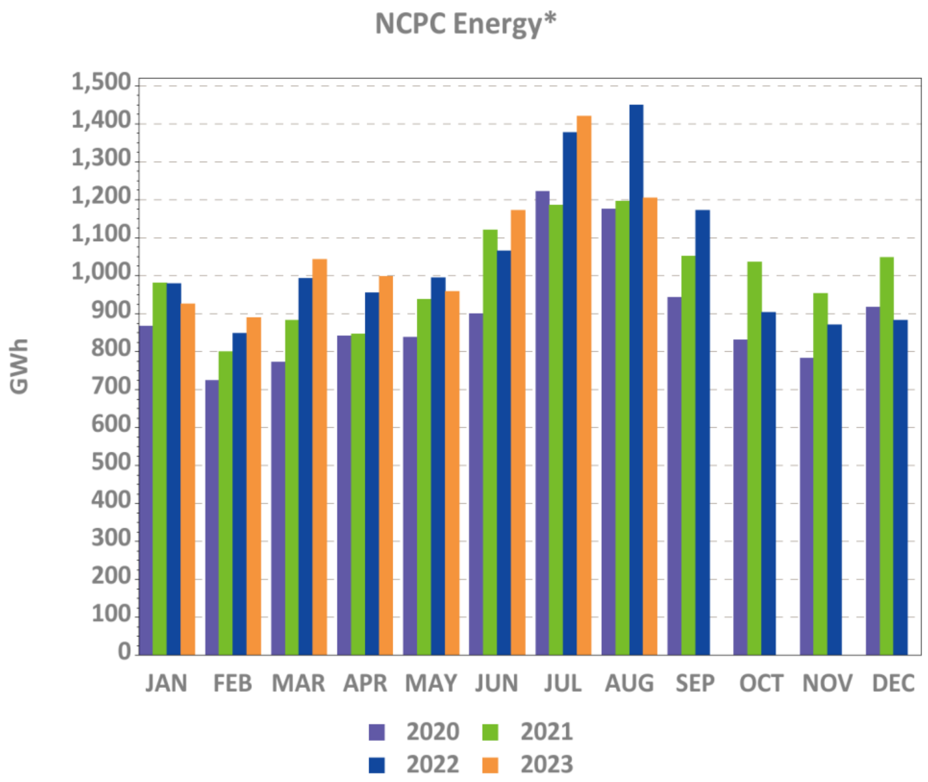
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

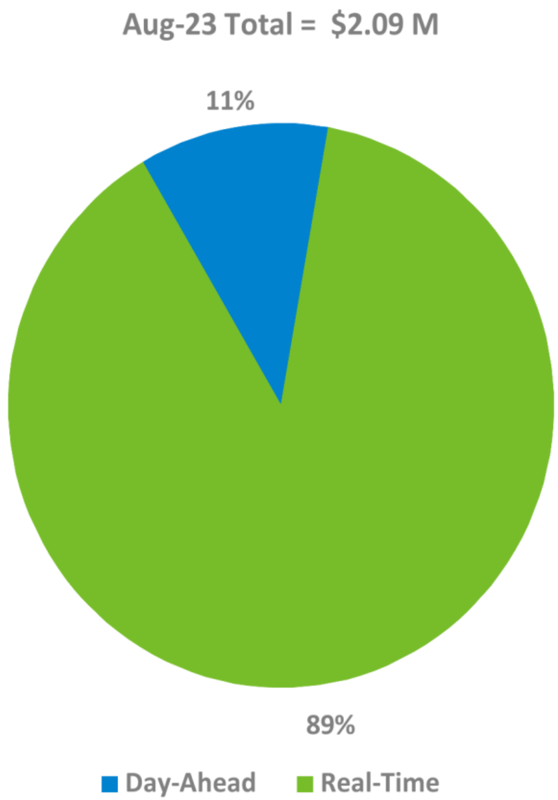
Year-Over-Year Total NCPC Dollars and Energy

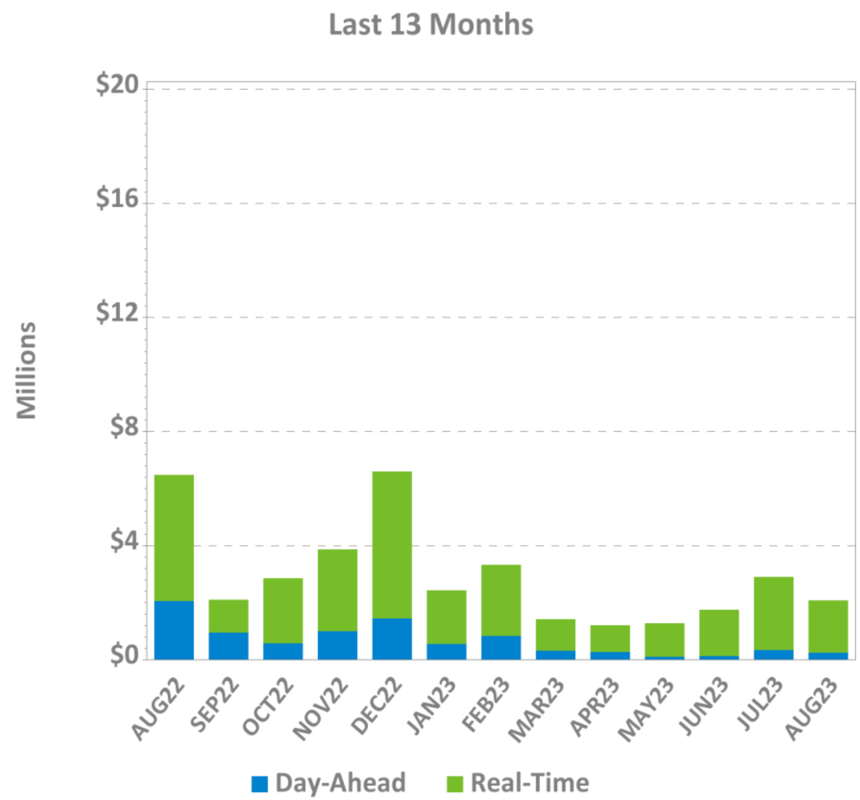




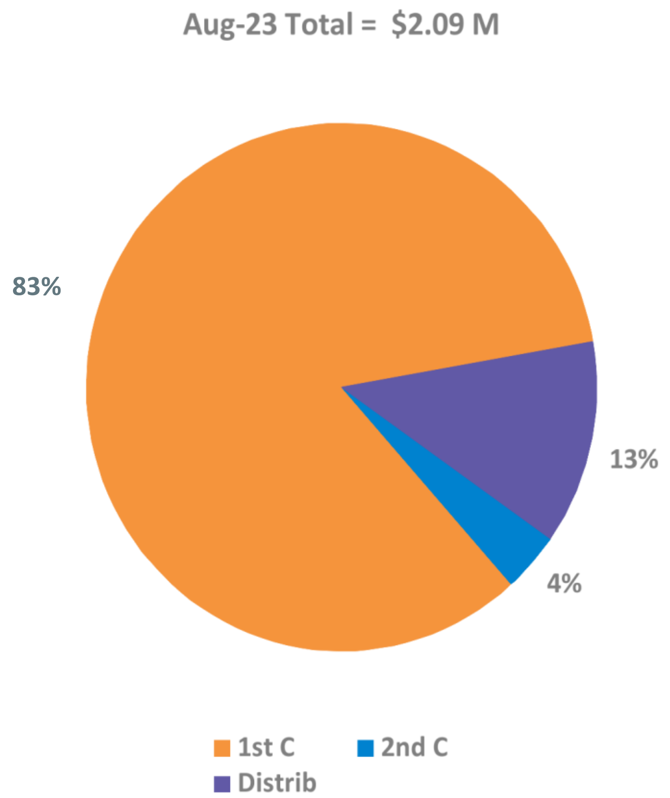
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

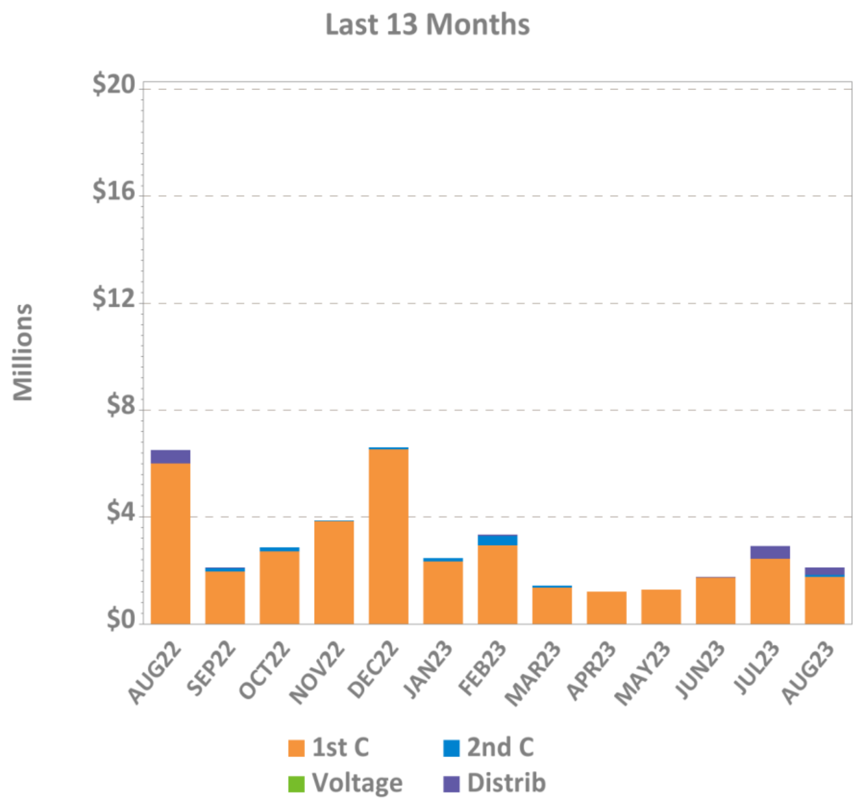
DA and RT NCPC Charges





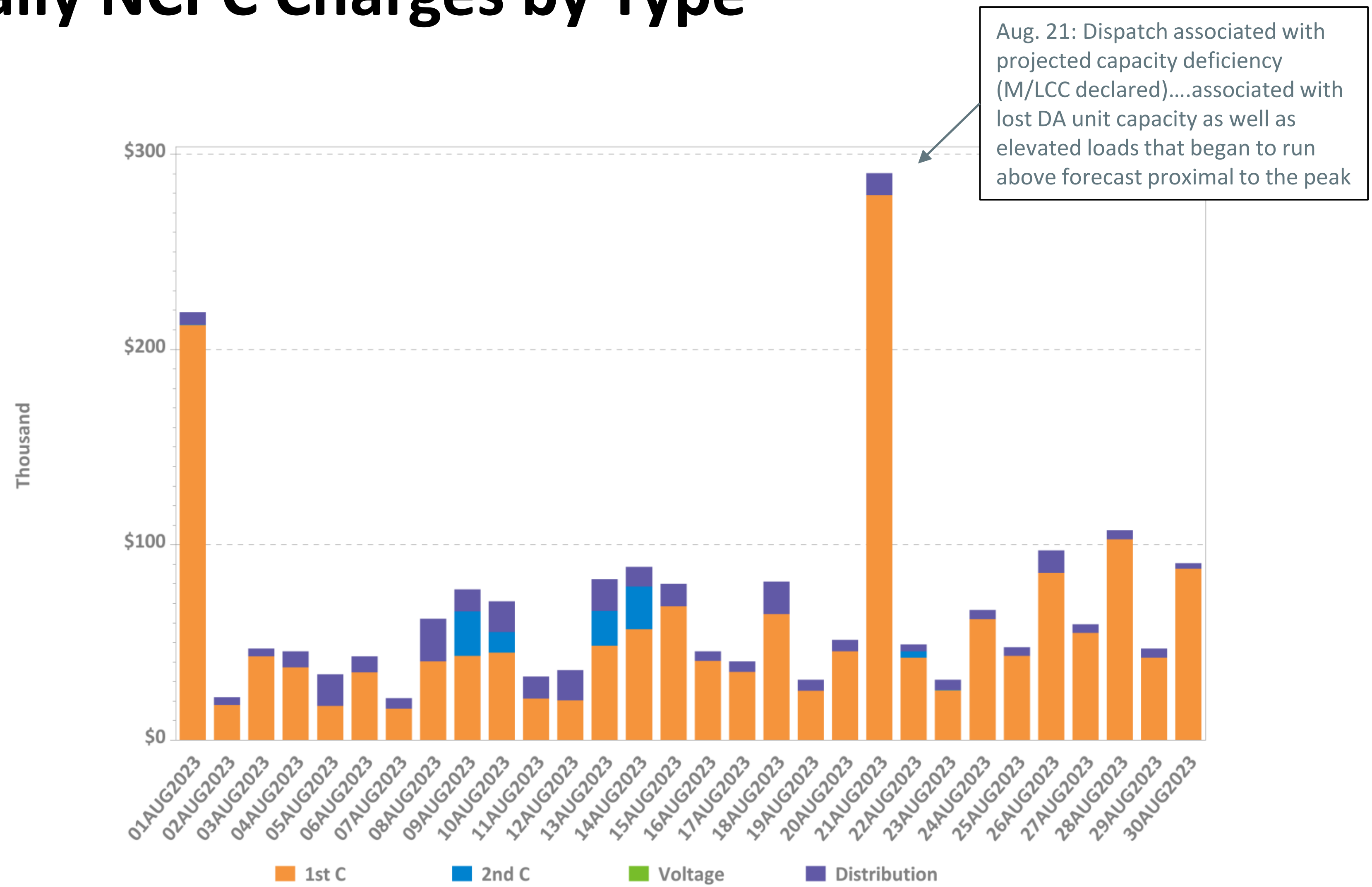
NCPC Charges by Type



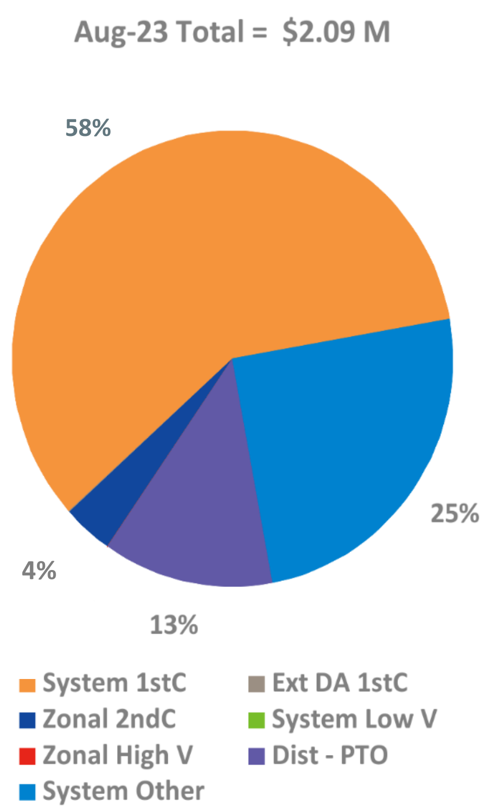


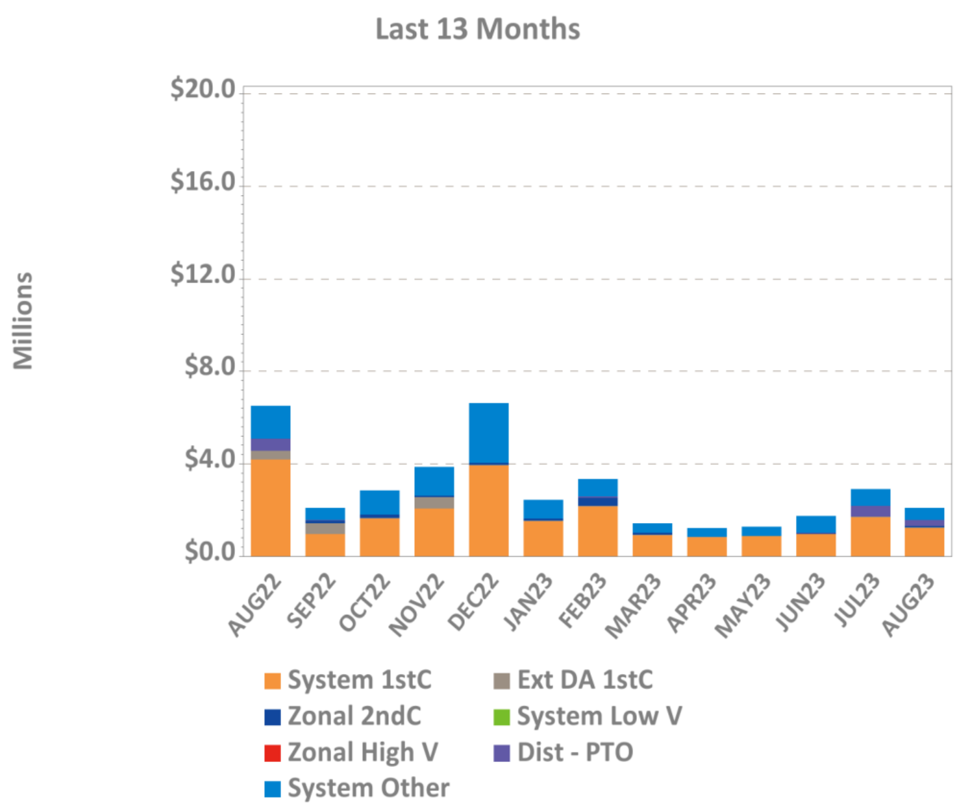
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



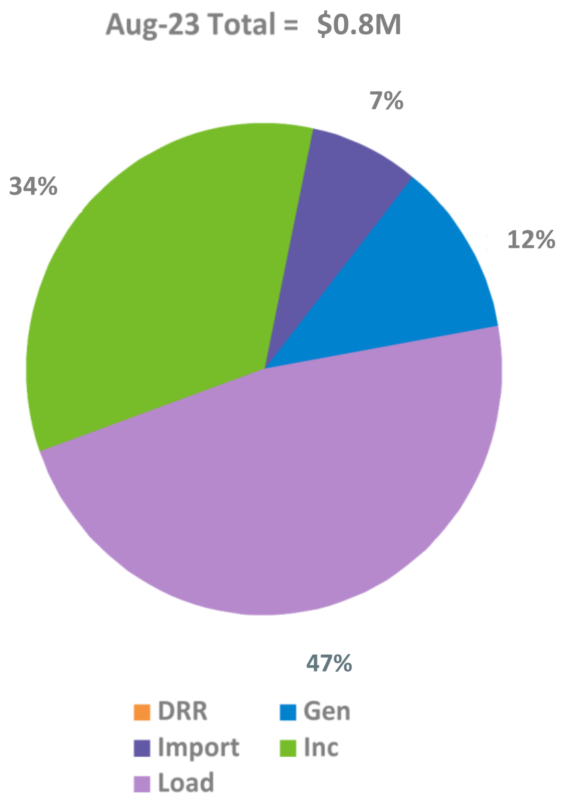
NCPC Charges by Allocation

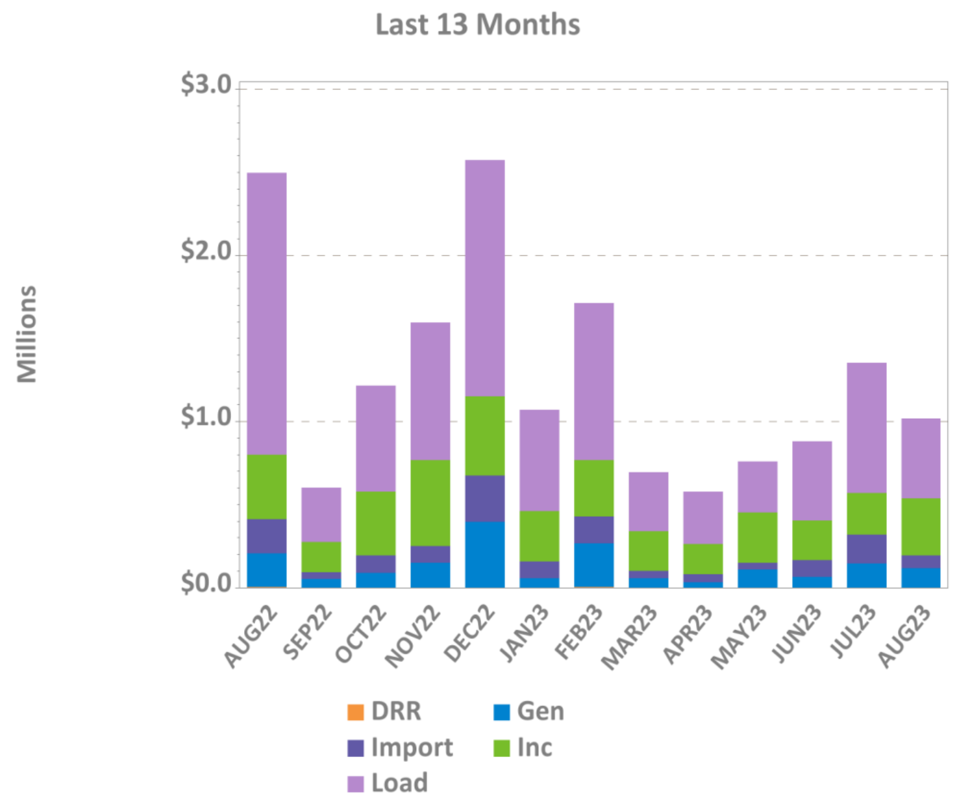




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

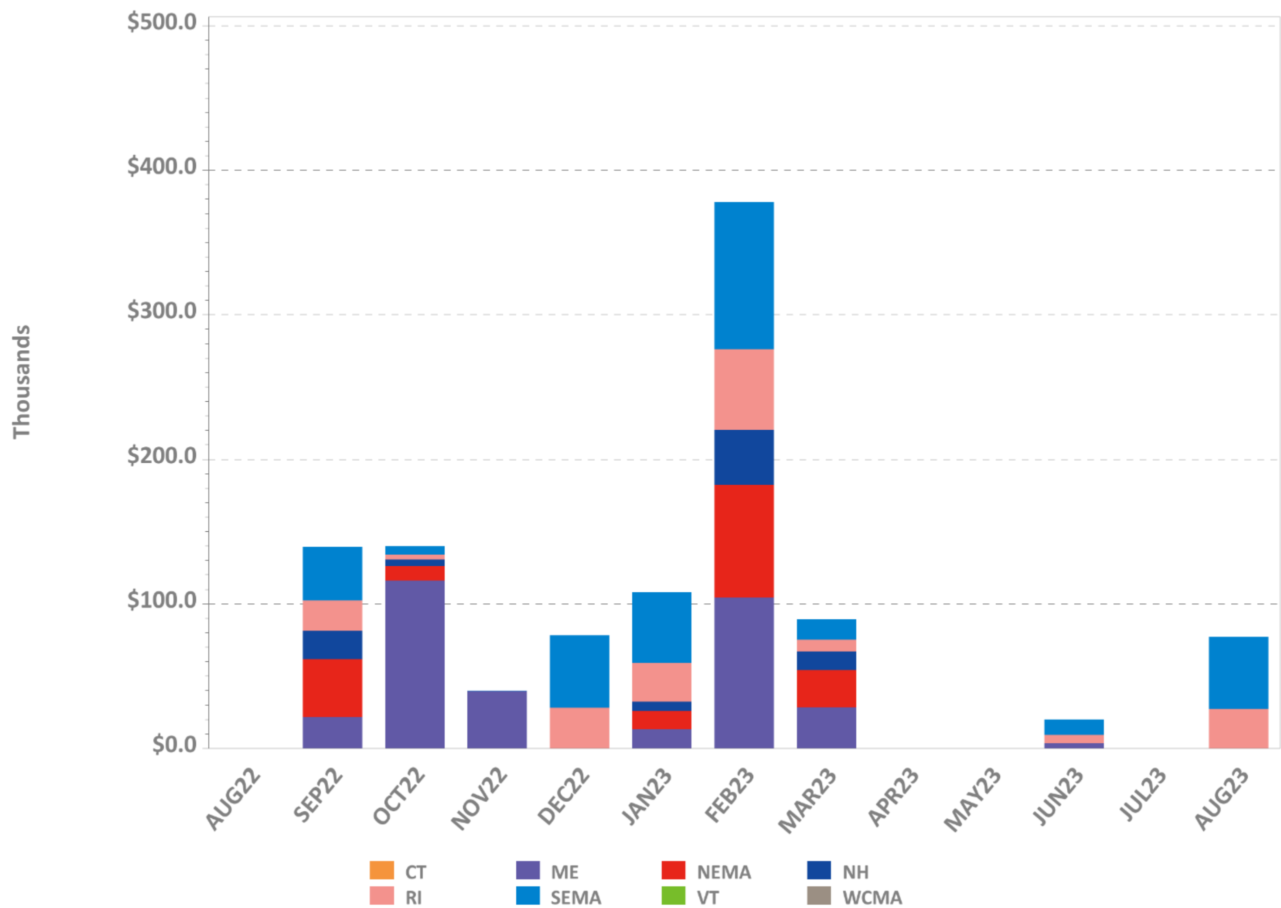
RT First Contingency Charges by Deviation Type





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

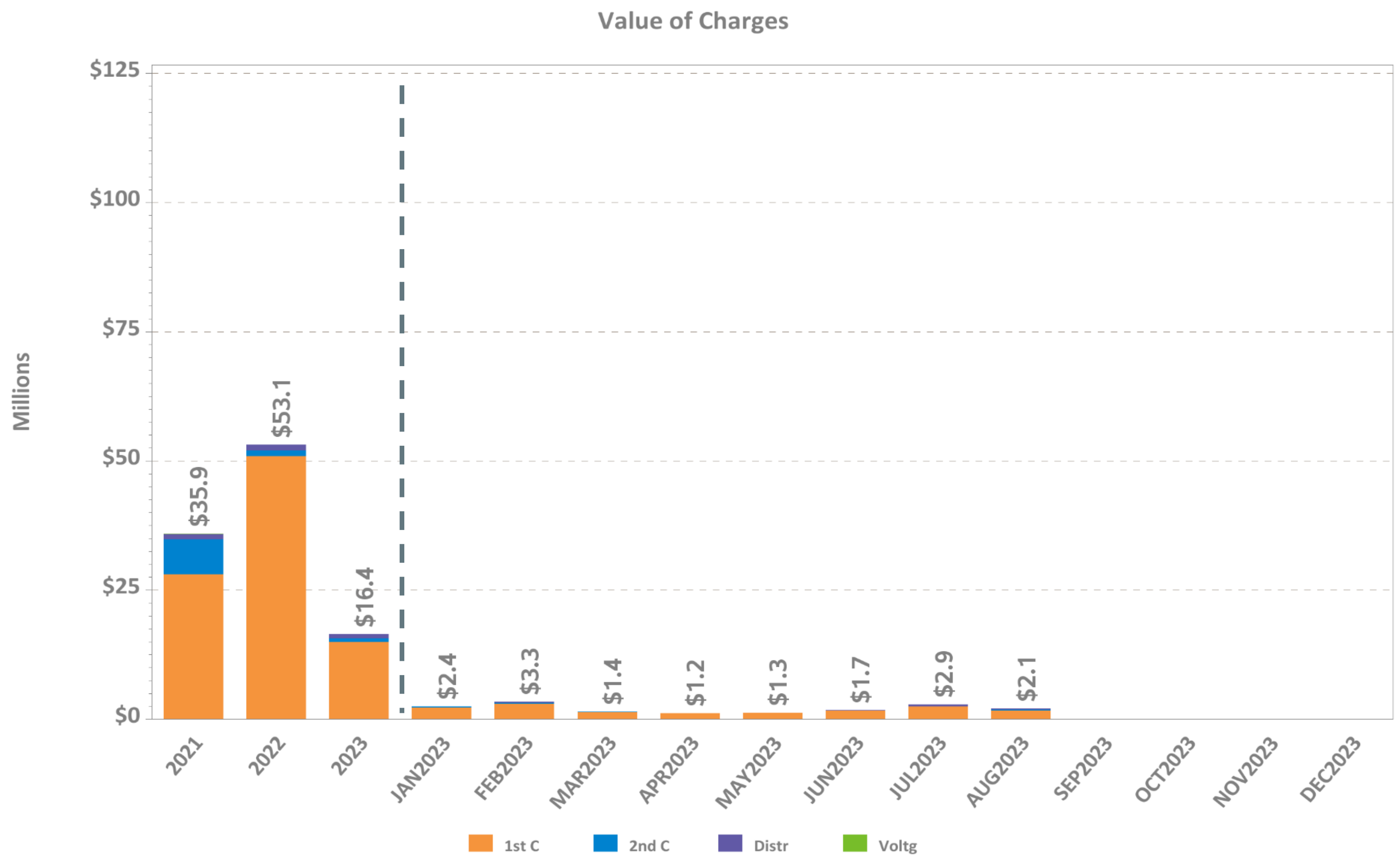
LSCPR Charges by Reliability Region



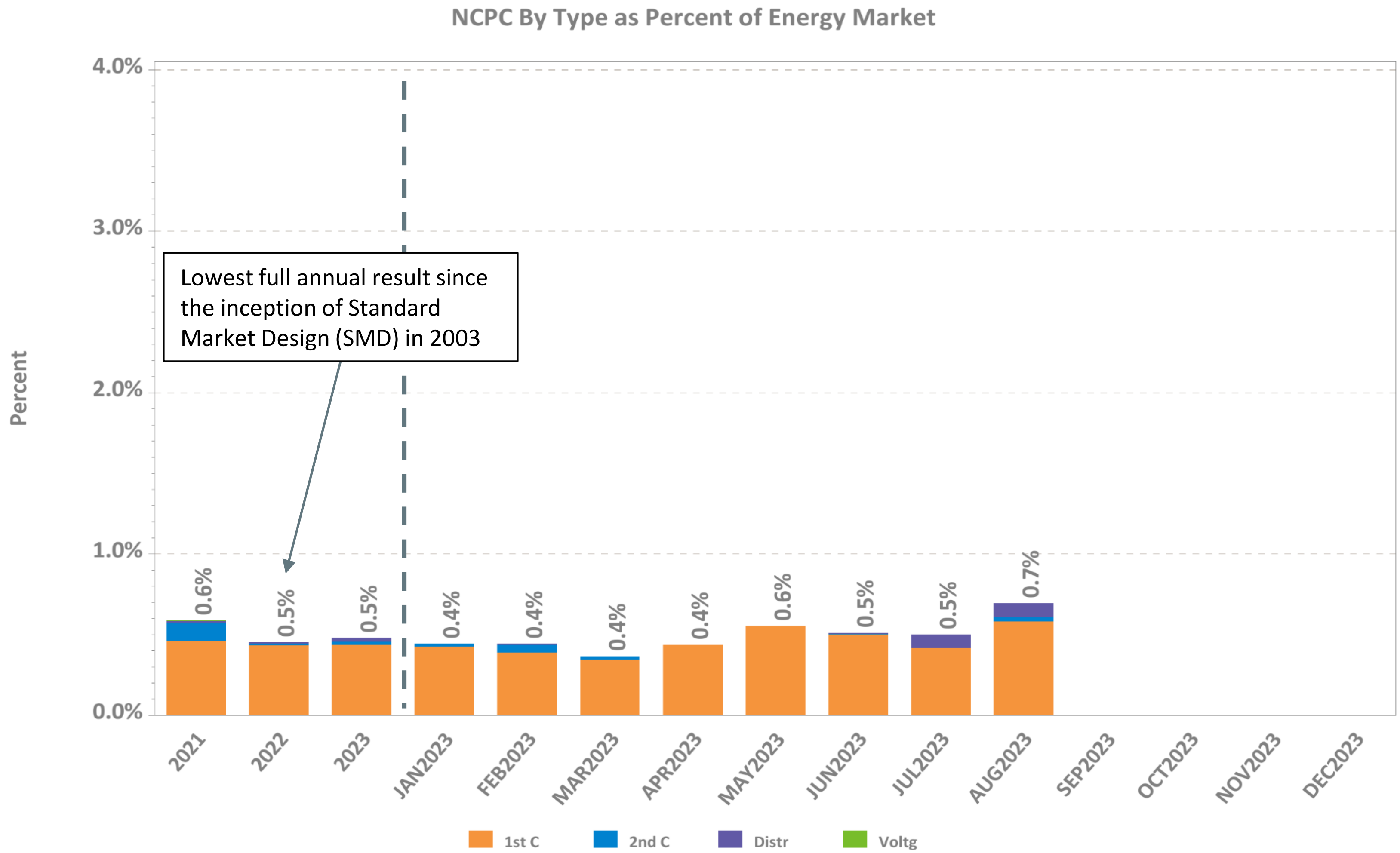
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

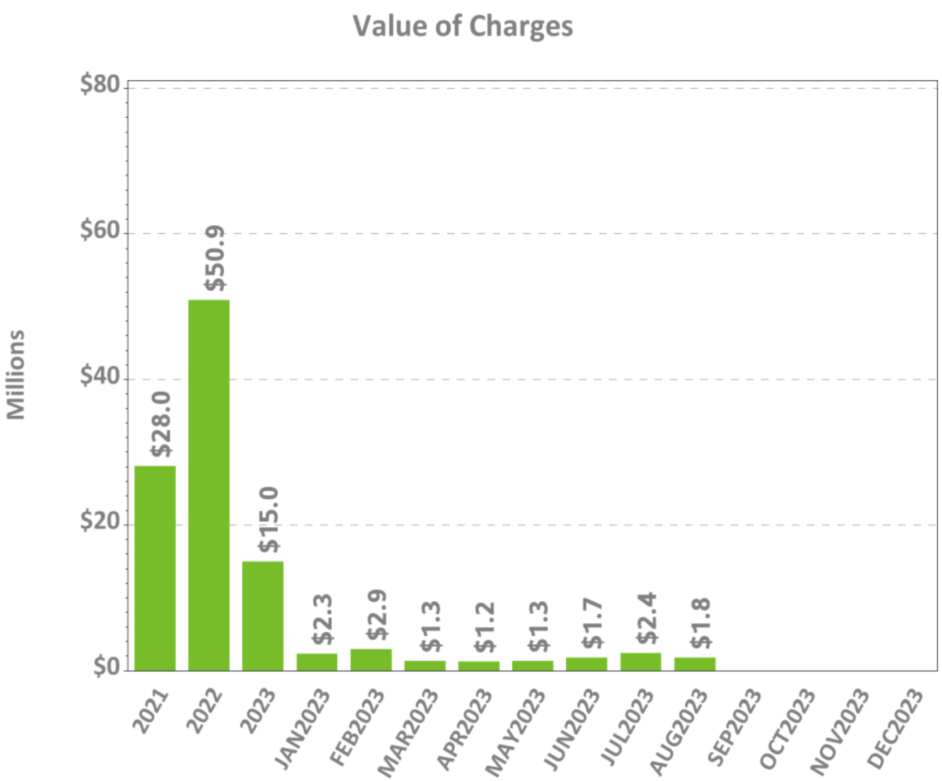
NCPC Charges by Type

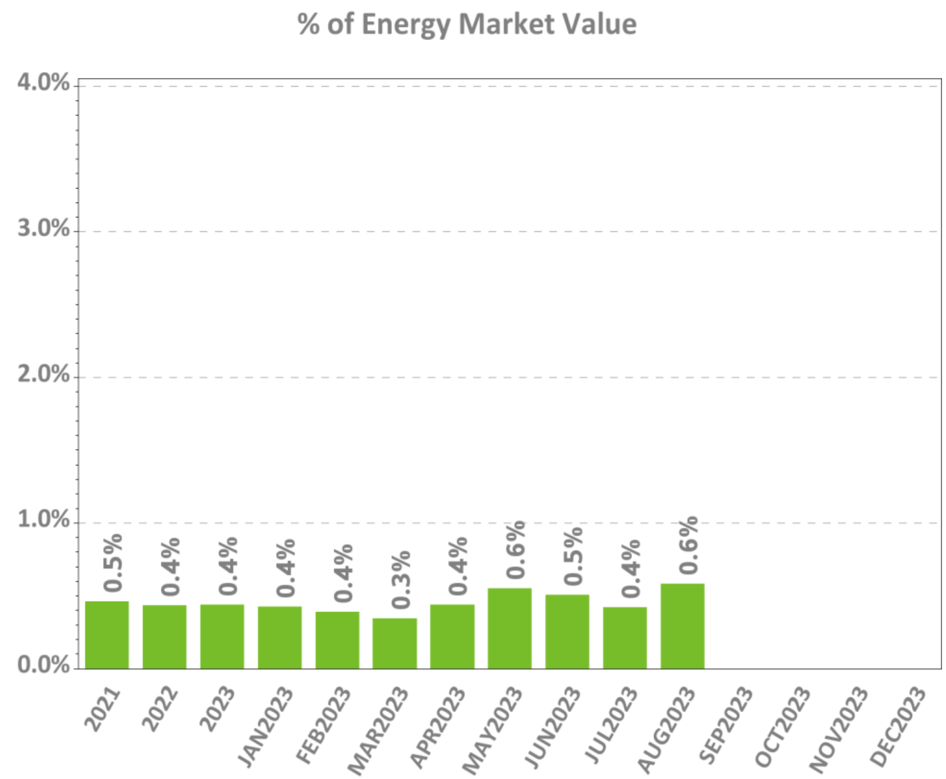


NCPC Charges as Percent of Energy Market



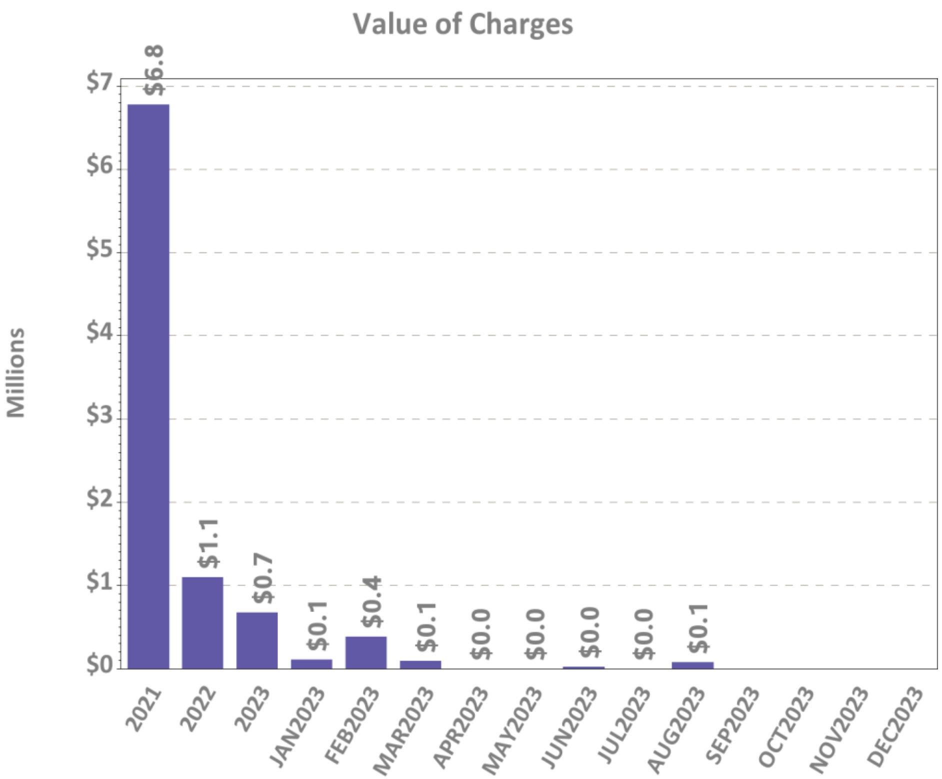
First Contingency NCPC Charges

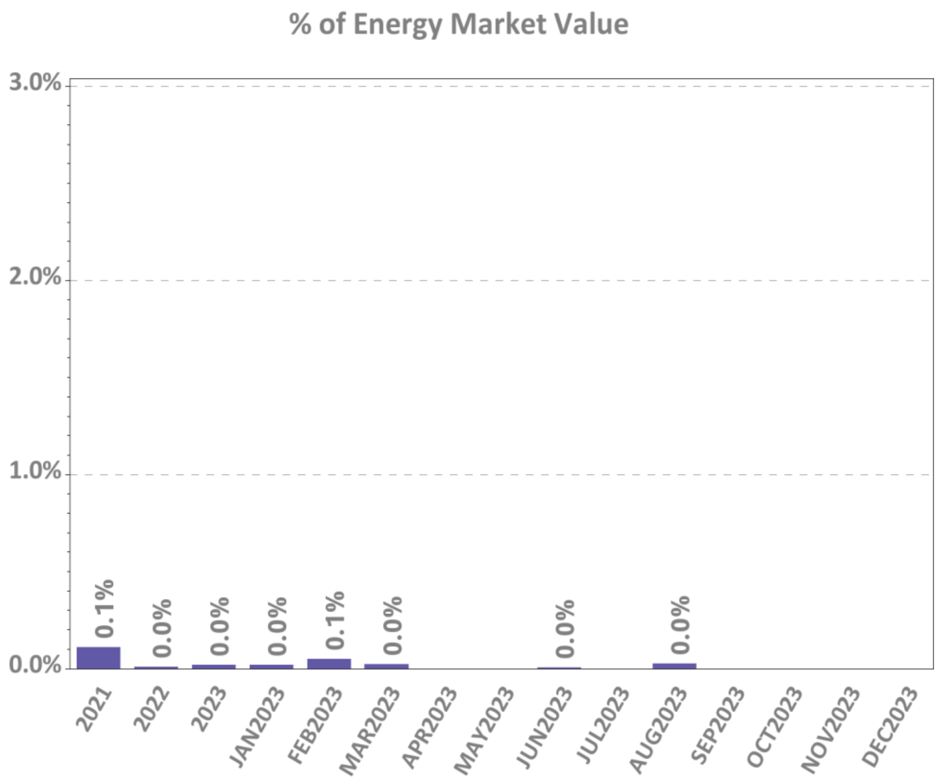




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

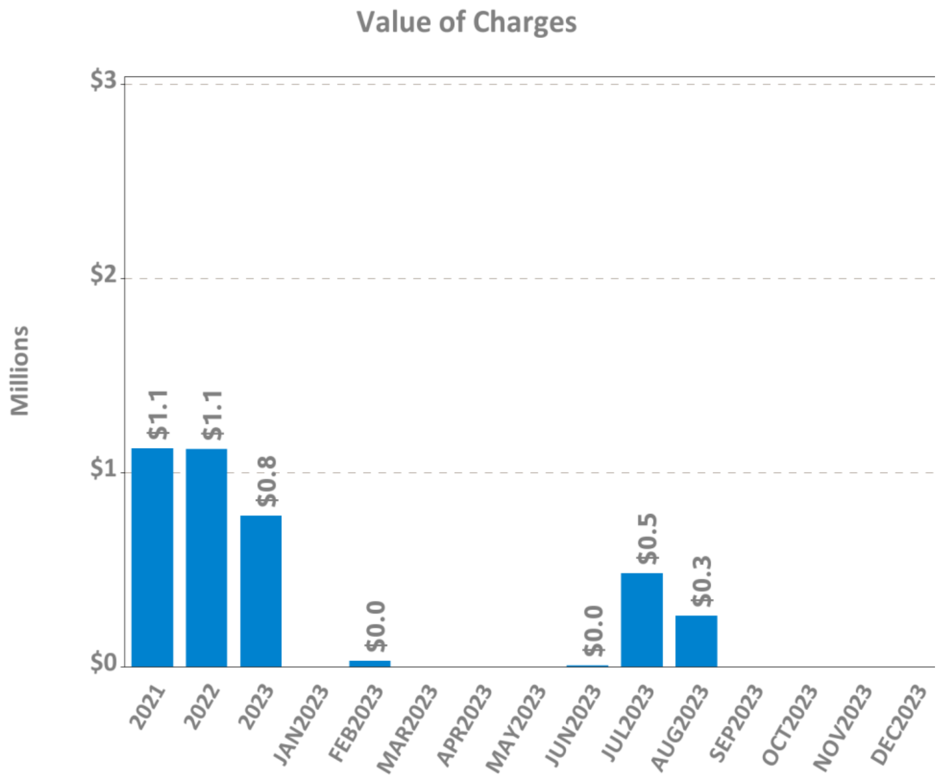
Second Contingency NCPC Charges

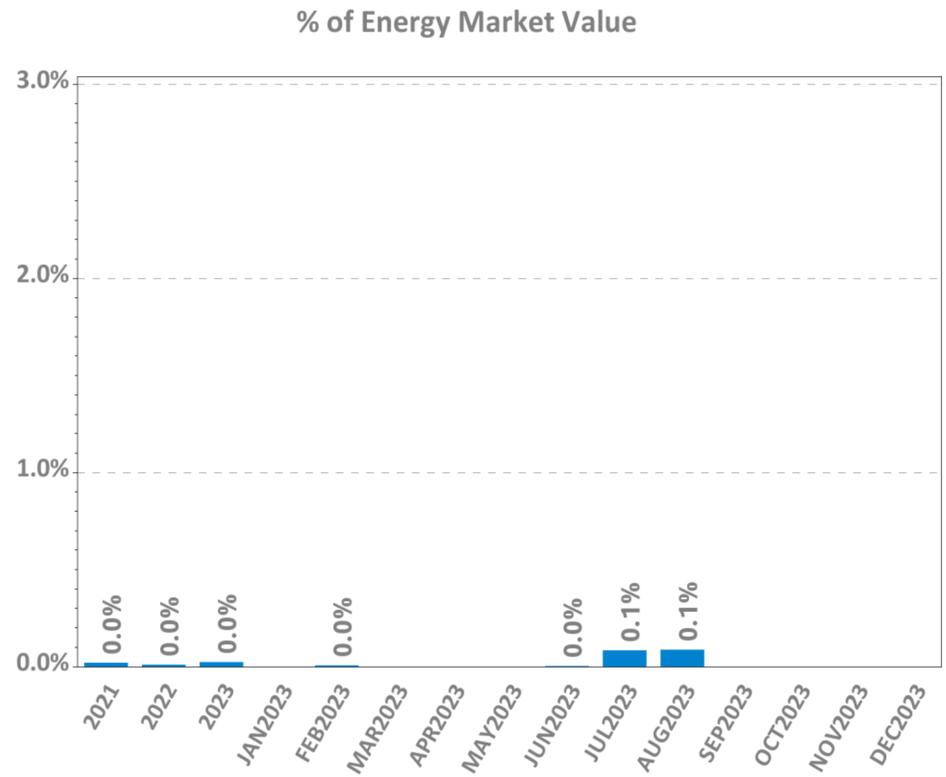




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

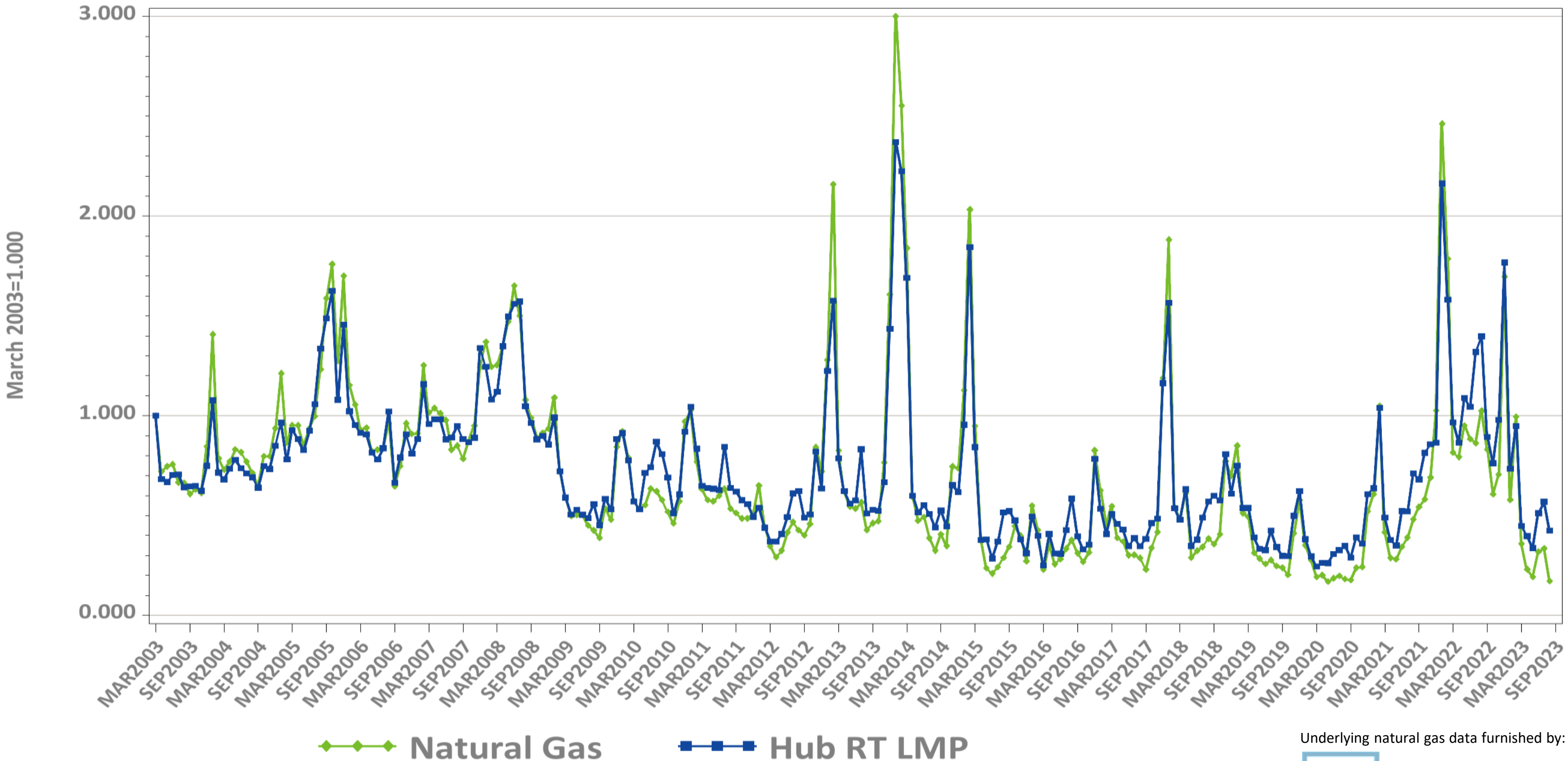
DA vs. RT LMPs ($/MWh)

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%

August-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$100.25	$97.95	$97.47	$100.07	$99.12	$99.14	$100.40	$99.70	$99.55
Real-Time	$96.79	$95.12	$94.27	$96.78	$95.83	$95.53	$96.68	$96.20	$95.99
RT Delta %	-3.5%	-2.9%	-3.3%	-3.3%	-3.3%	-3.6%	-3.7%	-3.5%	-3.6%
August-23	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$27.29	$26.56	$26.58	$27.09	$26.95	$26.82	$27.25	$27.04	$27.01
Real-Time	$29.42	$28.66	$28.57	$29.20	$28.99	$28.86	$29.35	$29.13	$29.09
RT Delta %	7.8%	7.9%	7.5%	7.8%	7.6%	7.6%	7.7%	7.7%	7.7%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-72.8%	-72.9%	-72.7%	-72.9%	-72.8%	-72.9%	-72.9%	-72.9%	-72.9%
Yr over Yr RT	-69.6%	-69.9%	-69.7%	-69.8%	-69.7%	-69.8%	-69.6%	-69.7%	-69.7%

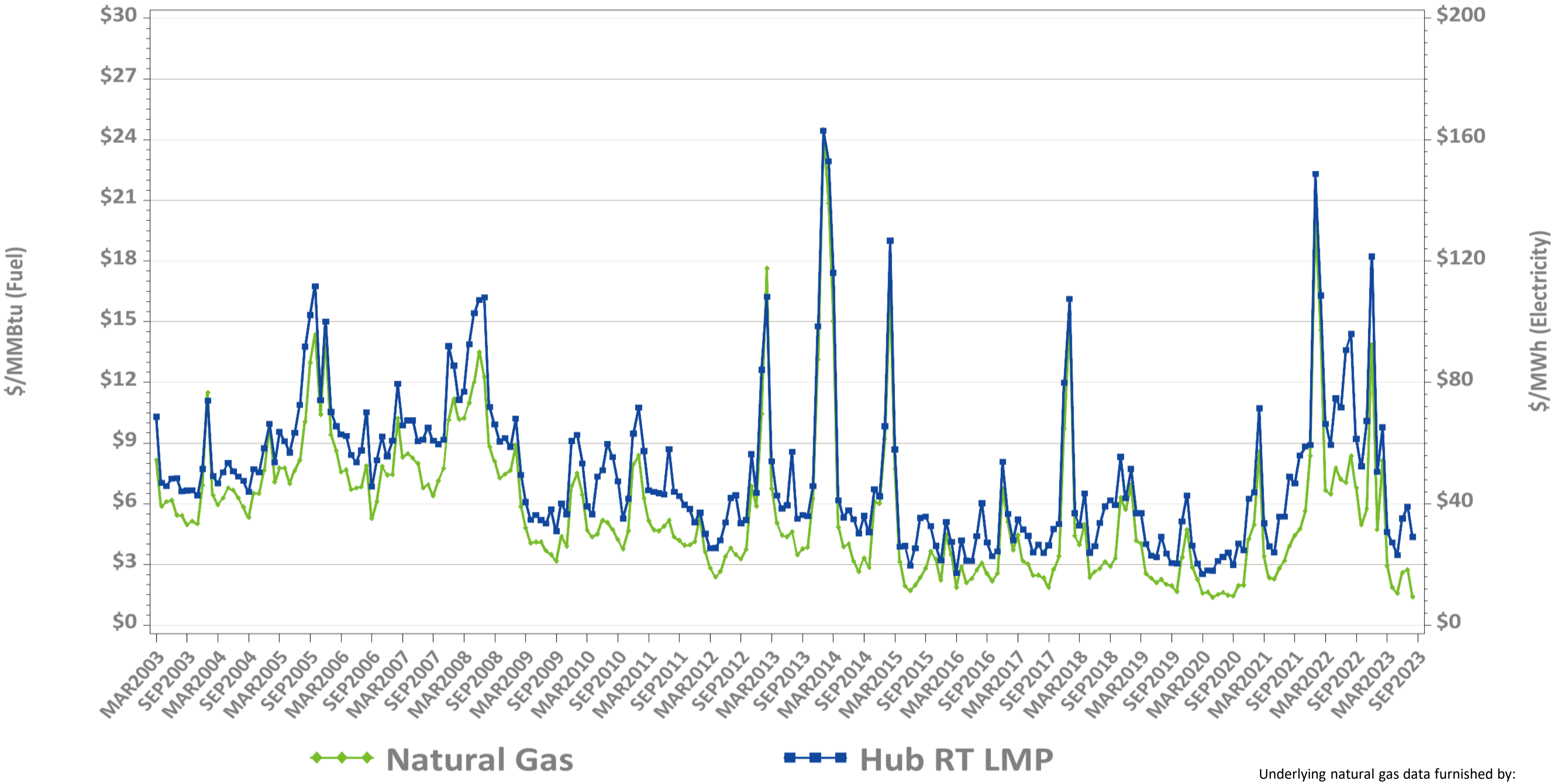
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

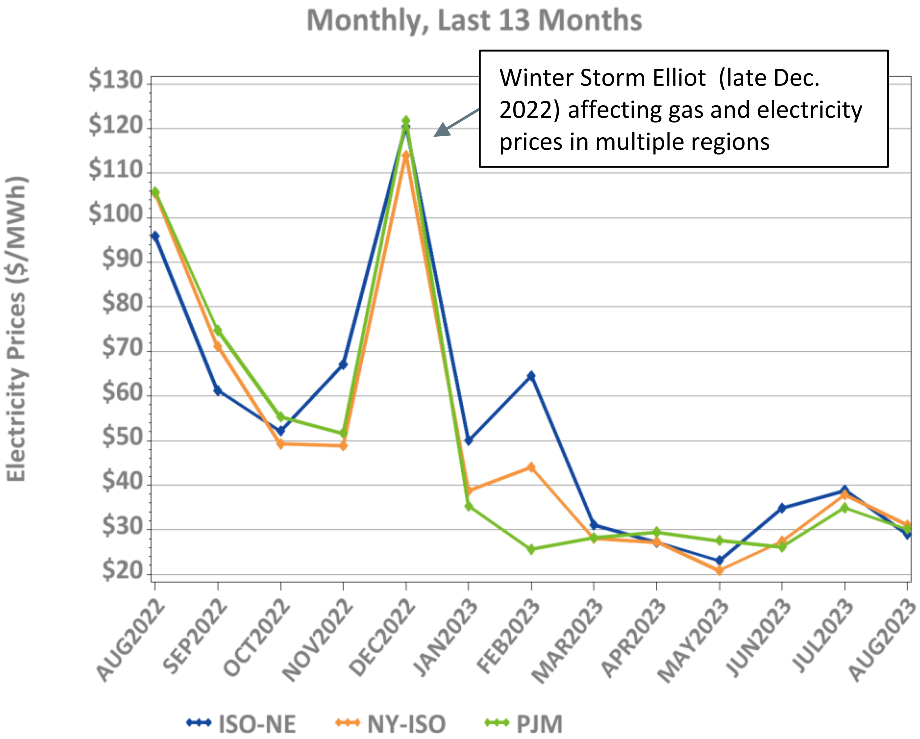
Monthly Average Fuel Price and RT Hub LMP



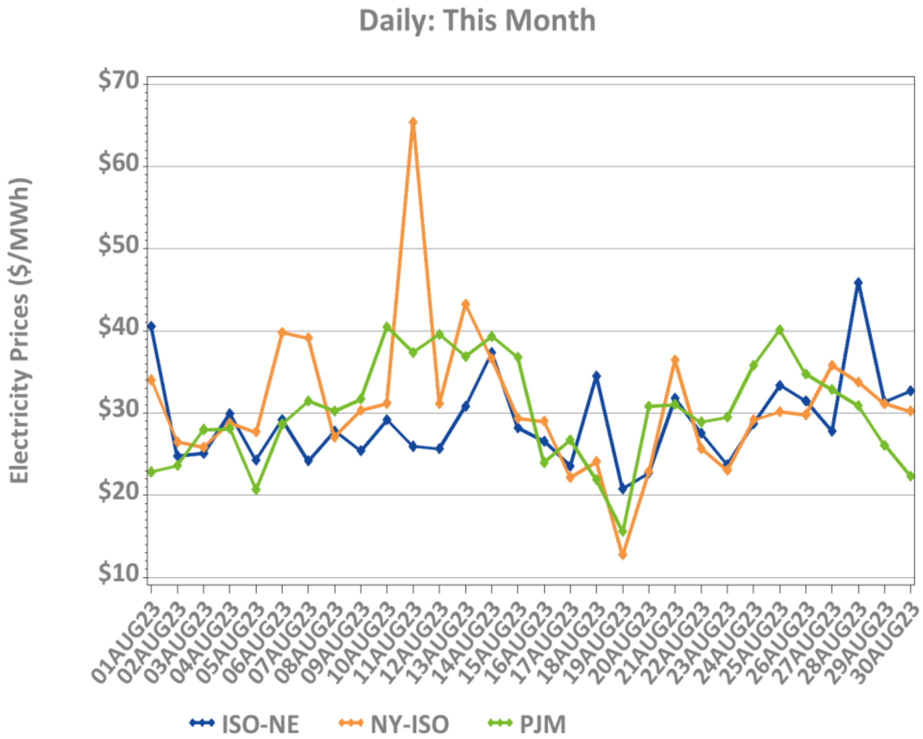
Underlying natural gas data furnished by:

ice Global markets in clear view

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

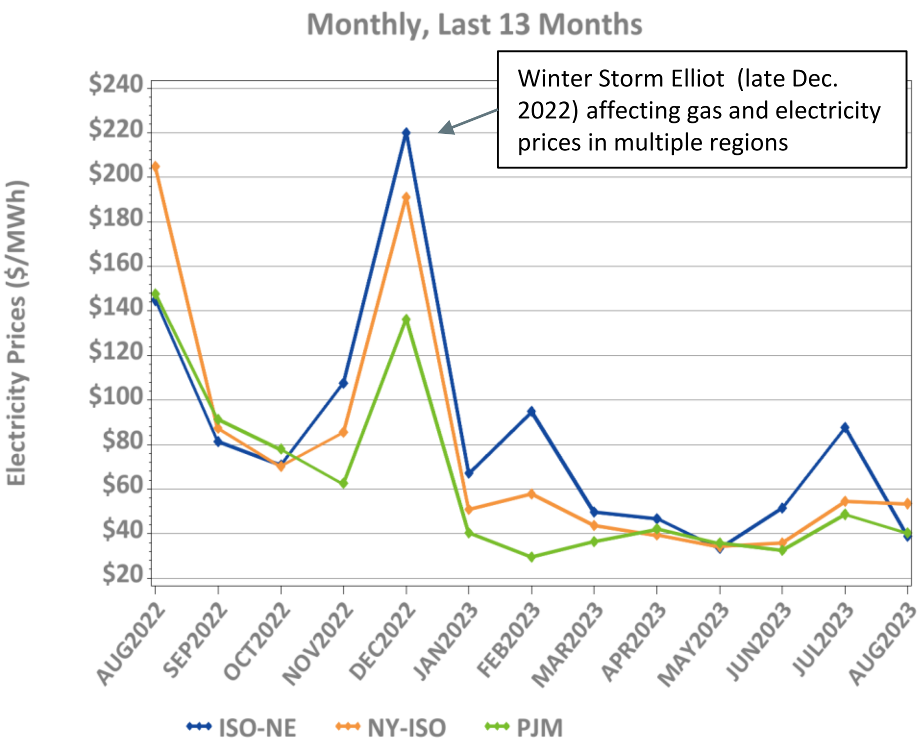


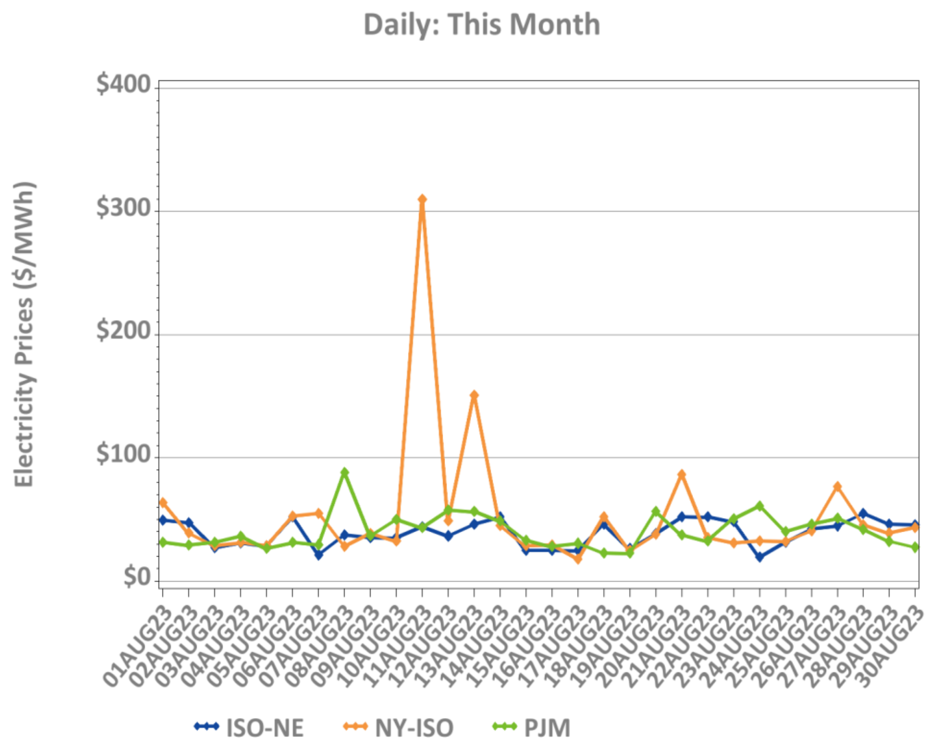
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





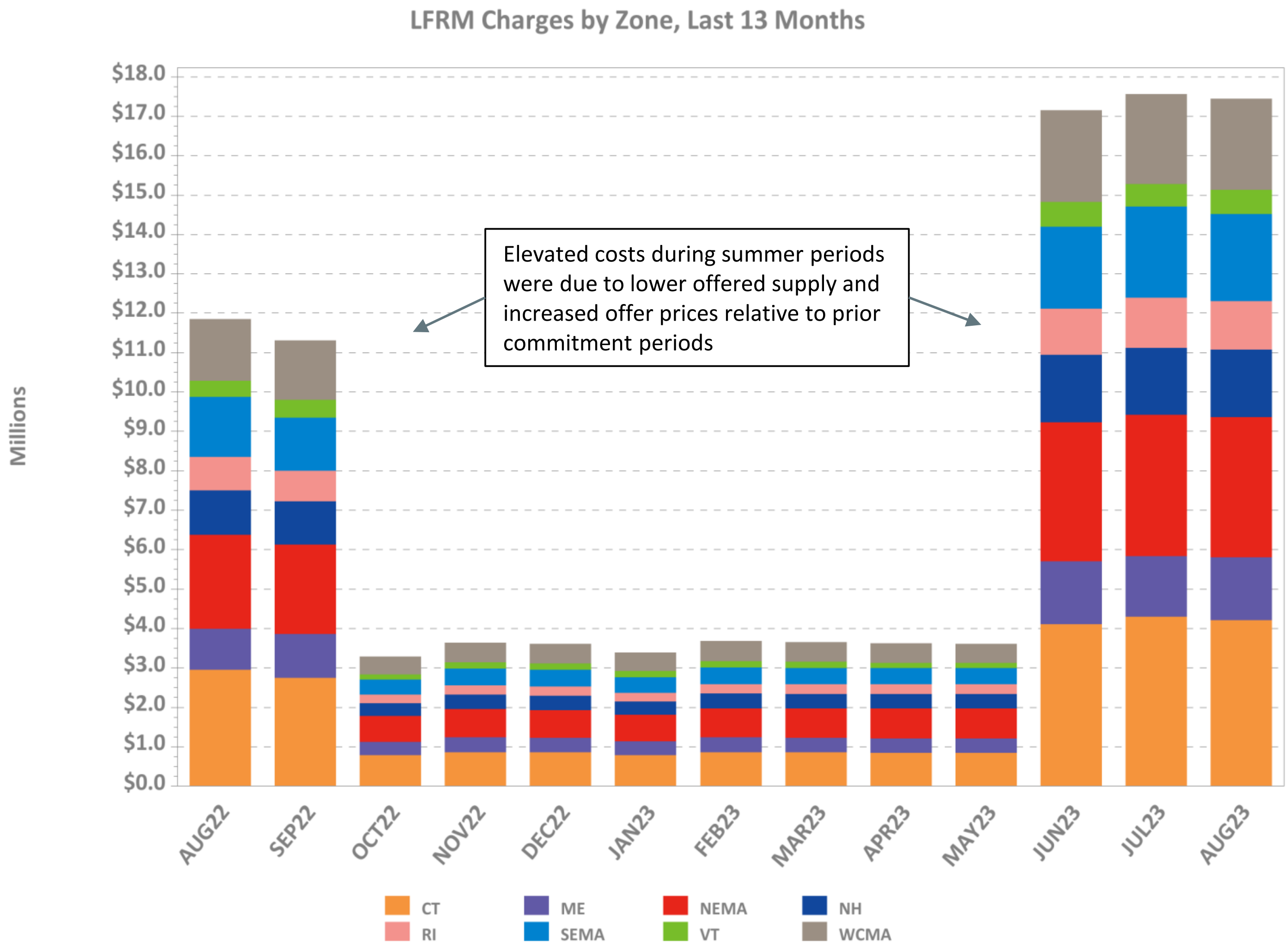
***Forecasted New England daily peak hours reflected**

Reserve Market Results – August 2023

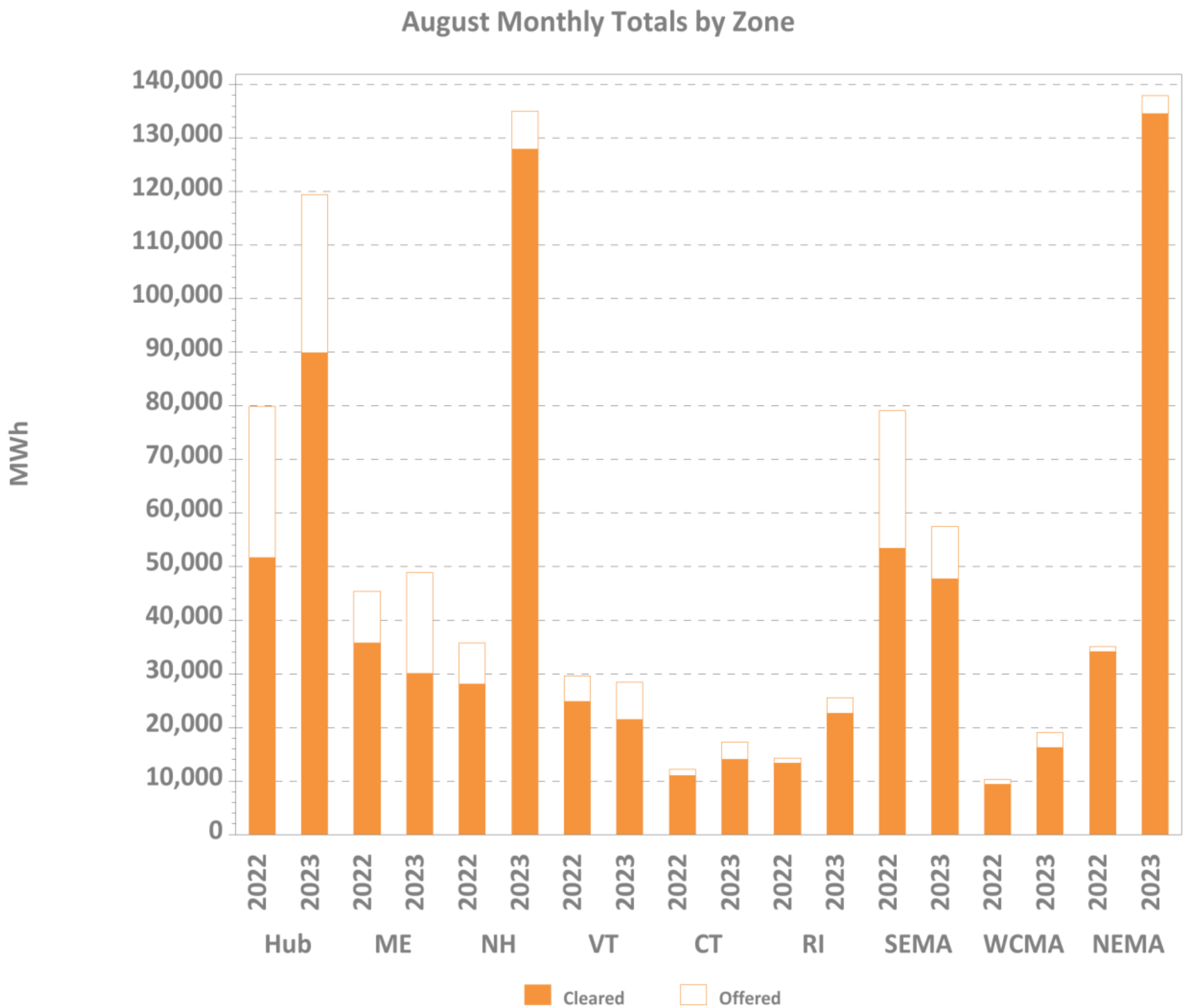
- Maximum potential Forward Reserve Market payments of $18.1M were reduced by credit reductions of $257K, failure-to-reserve penalties of $385K and failure-to-activate penalties of $7K, resulting in a net payout of $17.4M or 96% of maximum
  - Rest of System: $14.33M/14.84M (97%)
  - Southwest Connecticut: $0.47M/0.47M (98%)
  - Connecticut: $2.54M/2.67M (95%)
  - NEMA: $0.1M/0.1M (100%)
- $176K total Real-Time credits were reduced by $9K in Forward Reserve Energy Obligation Charges for a net of $166K in Real-Time Reserve payments
  - Rest of System: 239 hours, $116K
  - Southwest Connecticut: 239 hours, $26K
  - Connecticut: 239 hours, $15K
  - NEMA: 239 hours, $10K

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.

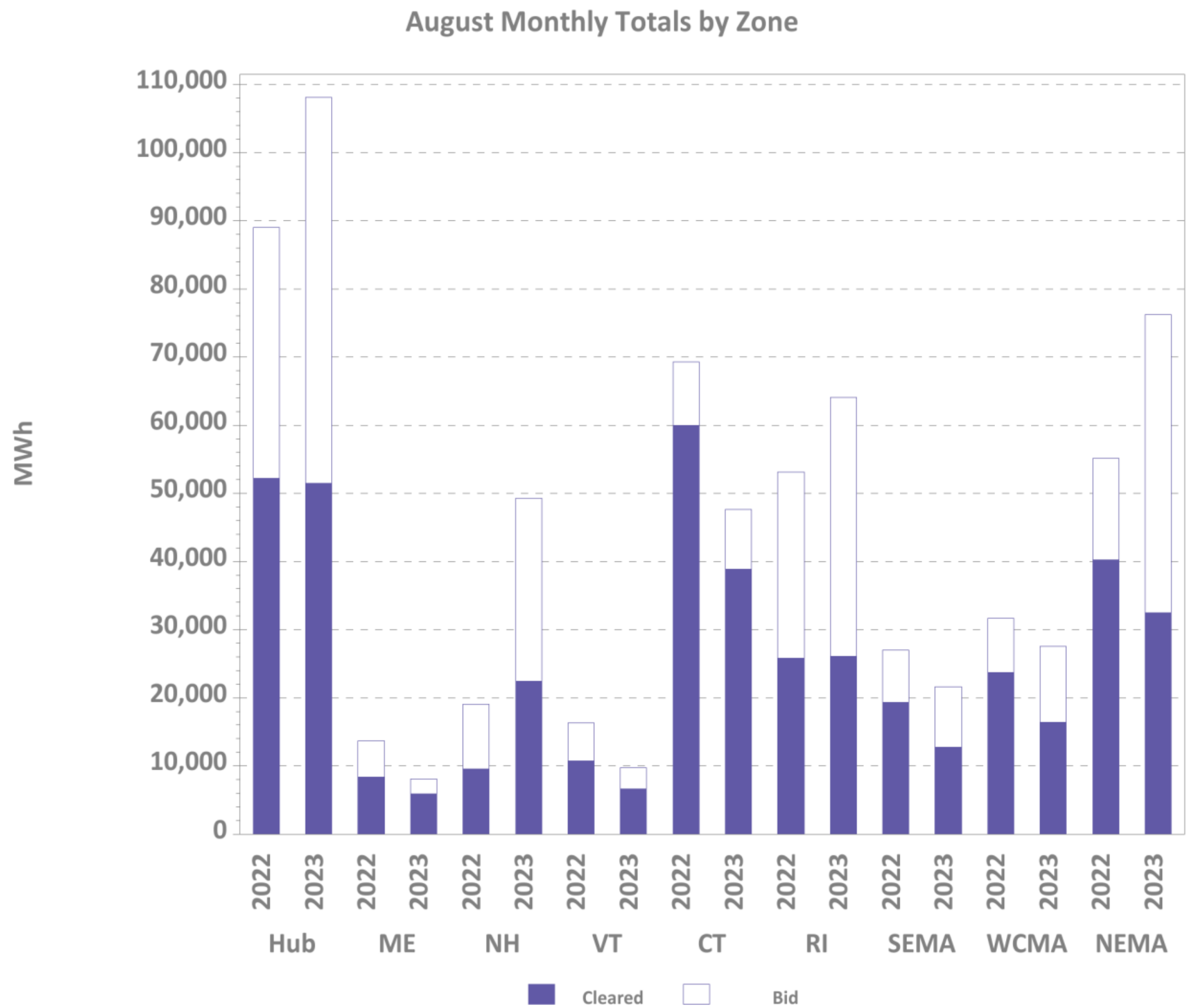
LFRM Charges to Load by Load Zone ($)



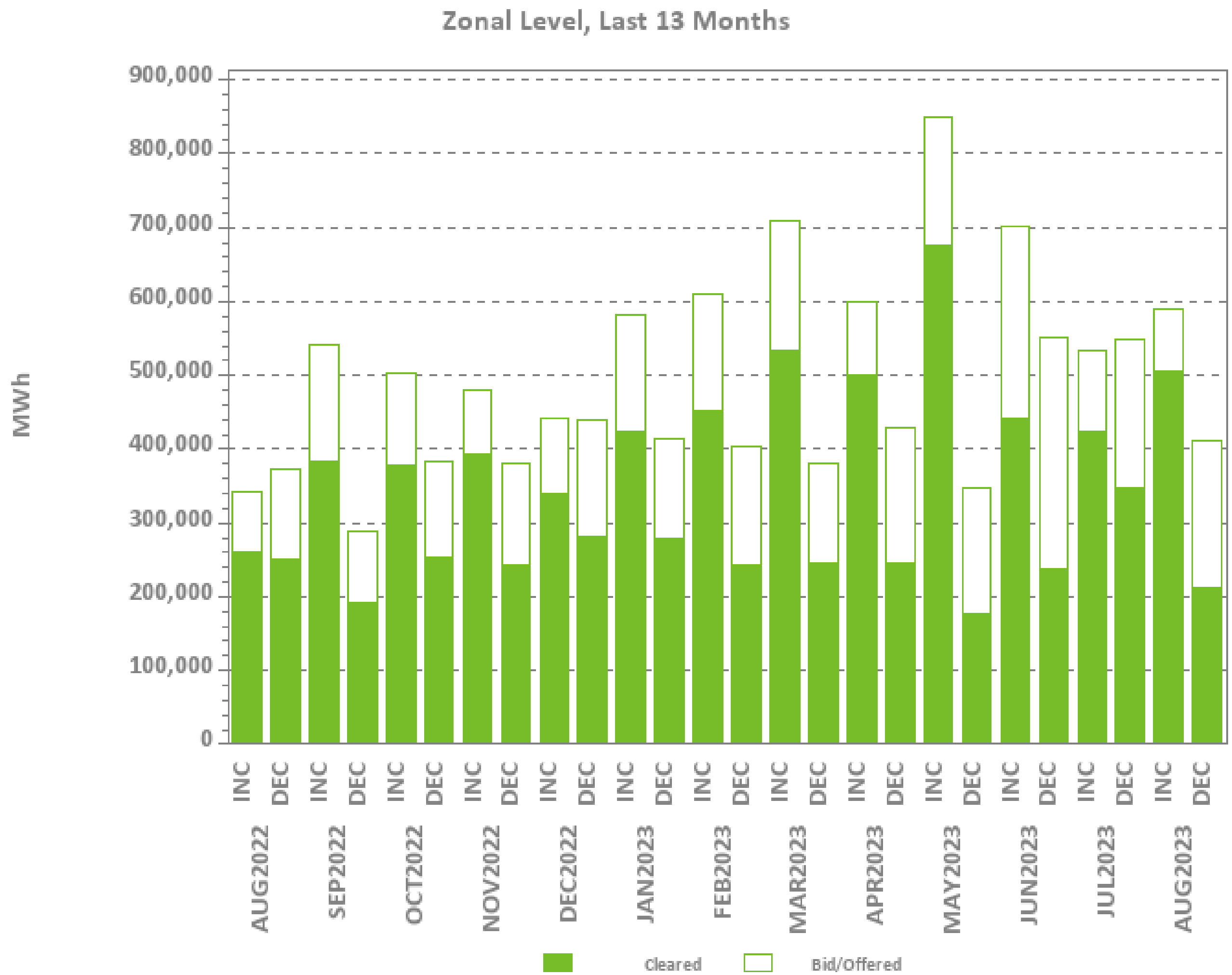
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

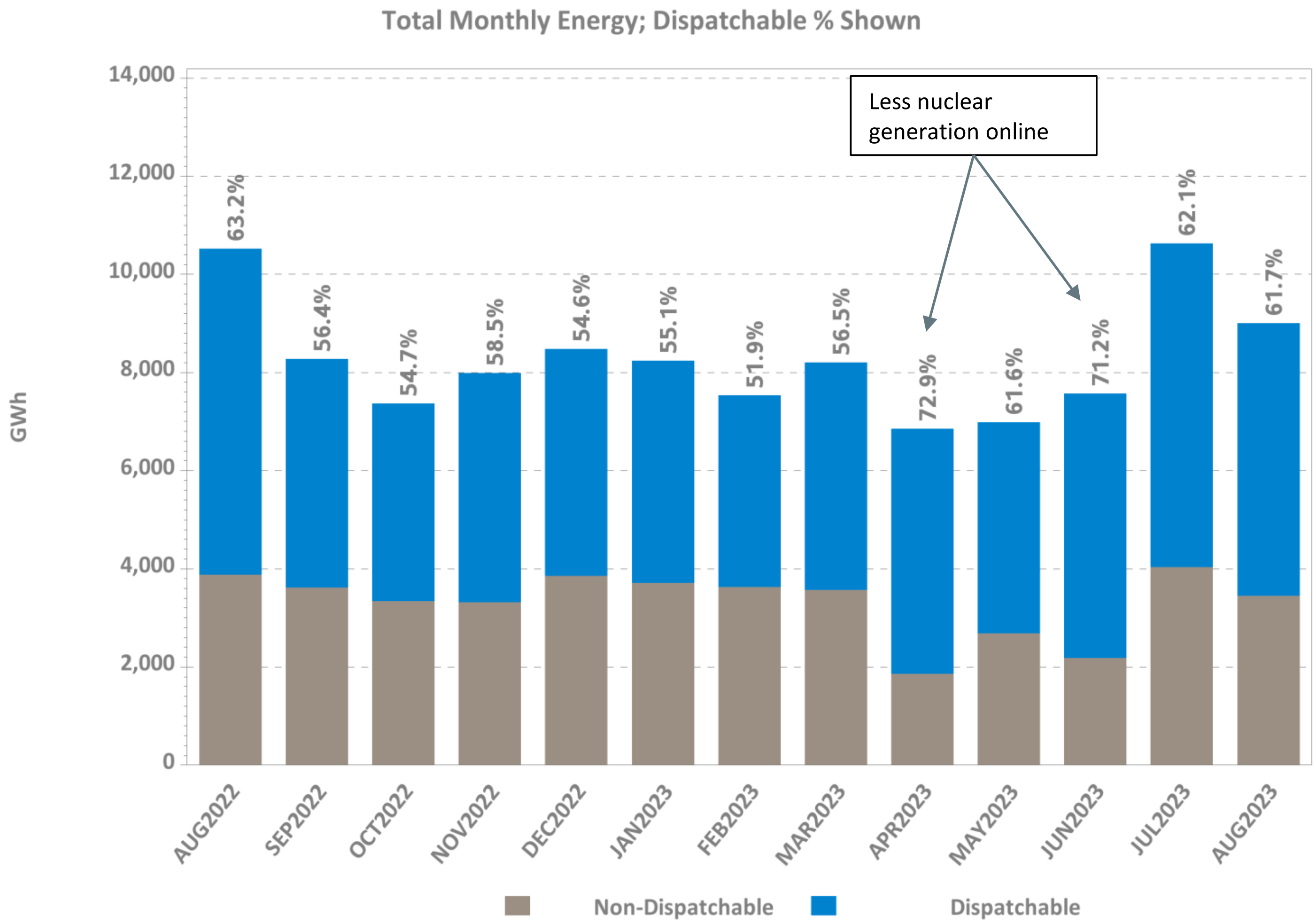


Total Increment Offers and Decrement Bids



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)

- 2023 is an RSP publication year
- 2023-24 RSP will continue the streamlining efforts started with the 2021 RSP
- 2023-24 RSP will focus on being an overview narrative about ISO's system planning and the outlook for the New England grid
- 2023-24 RSP Public Meeting date is set for November 1 and will be held concurrently with the ISO Open Board Meeting
- The draft 2023-24 RSP was shared with stakeholders on August 16 and comments were received by August 30

Planning Advisory Committee (PAC)

- September 20 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - E183W 115 kV Line Rebuild (Rhode Island Energy)
    - M13 & L14 115 kV Line Rebuild (Rhode Island Energy)
    - S171N & T172N 115 kV Line Rebuild (Rhode Island Energy)
  - Proposed PTF Asset Condition Database (New England Transmission Owners "NETO")
  - New England TO's LSP Public Policy (NETO)

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

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- 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
- Consultant to perform cost estimates has been selected – Electrical Consultants Inc. (ECI)
- ECI is working on developing cost estimates for potential transmission additions
- Development of transmission solutions will continue throughout the first half of 2023
- Additional discussion on solution development occurred at the 4/20/23 and 7/25/23 PAC meetings
- Draft report is scheduled for release by 11/1/23

Economic Studies

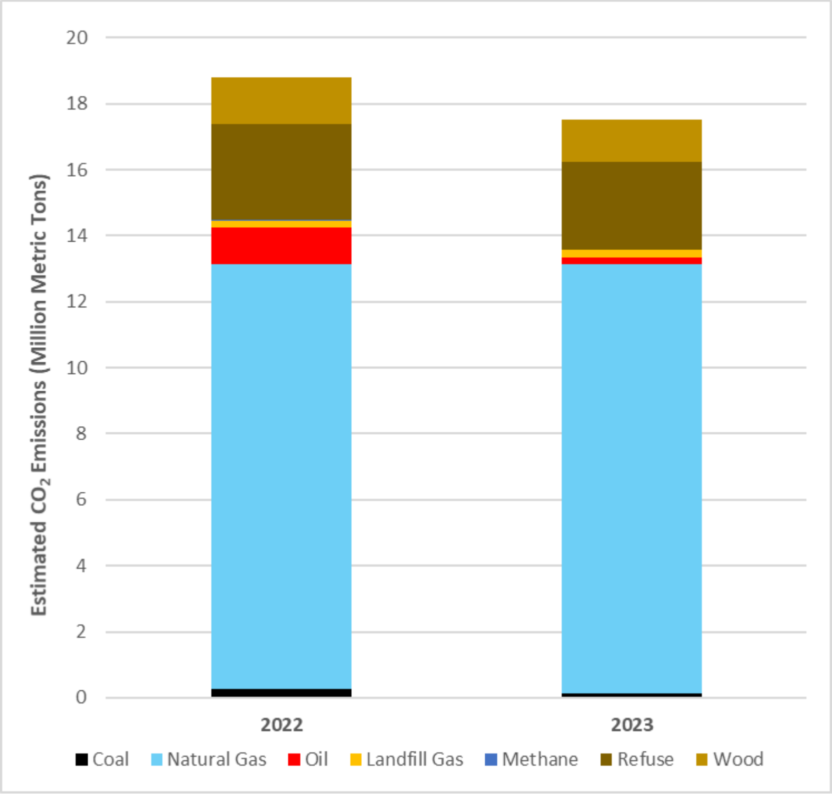
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, 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 and August.
    - FGRS Phase 2 is now the Stakeholder-Requested Scenario in EPCET

Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability "gaps" that remain will be identified
  - High-level outline was presented at the April PAC

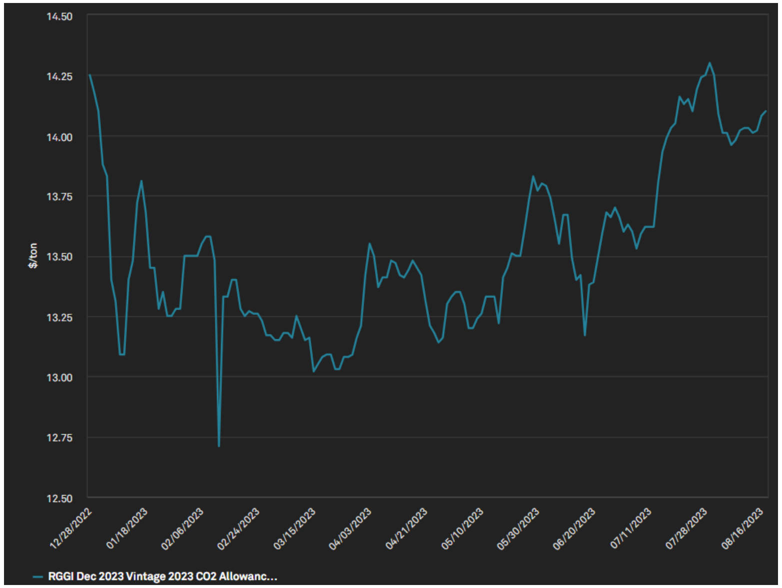
New England Power System Carbon Emissions

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



Data as of 08/06/2023

RGGI Allowance Prices



- 08/17/23: RGGI allowance spot price - $14.10
- 06/07/23: Virginia's State Air Pollution Control Board voted 4 to 3 to repeal the CO_2 Budget Trading Program.
  - This would end the state's participation in RGGI.

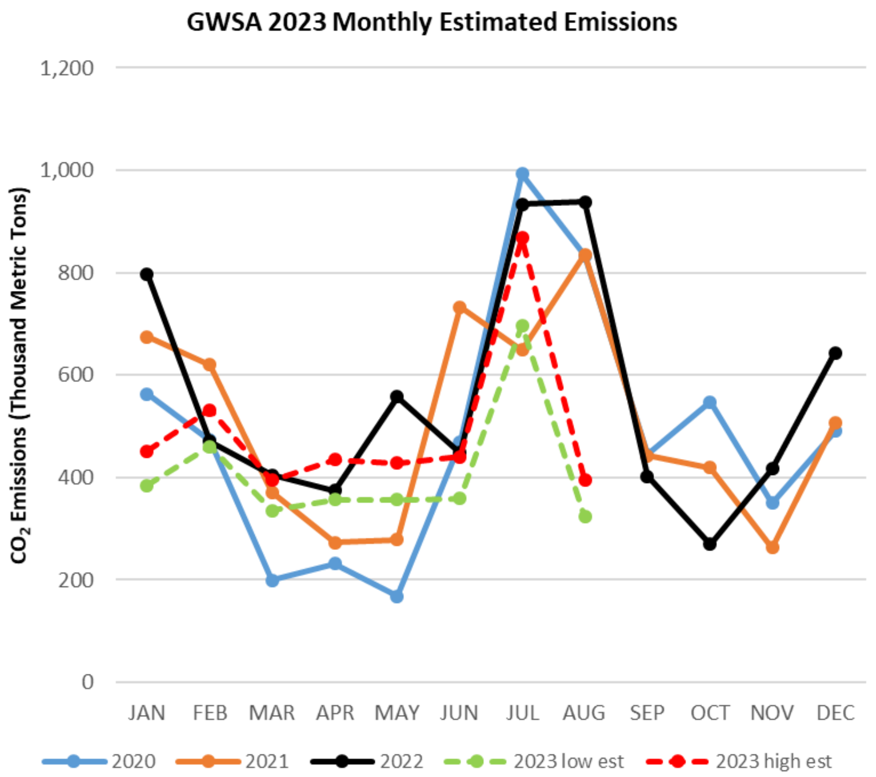
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 08/21/23, August 2023 estimated GWSA CO_2 emissions range between **322,842** and **394,266** metric tons
  - Year-to-date 2023 estimated emissions range between **42%** and **50%** of the 2023 cap of 7.84 MMT

2020-2023 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

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

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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-26	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 8/24/2023

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	Dec-23	3
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-23	3
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 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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 8/24/2023

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

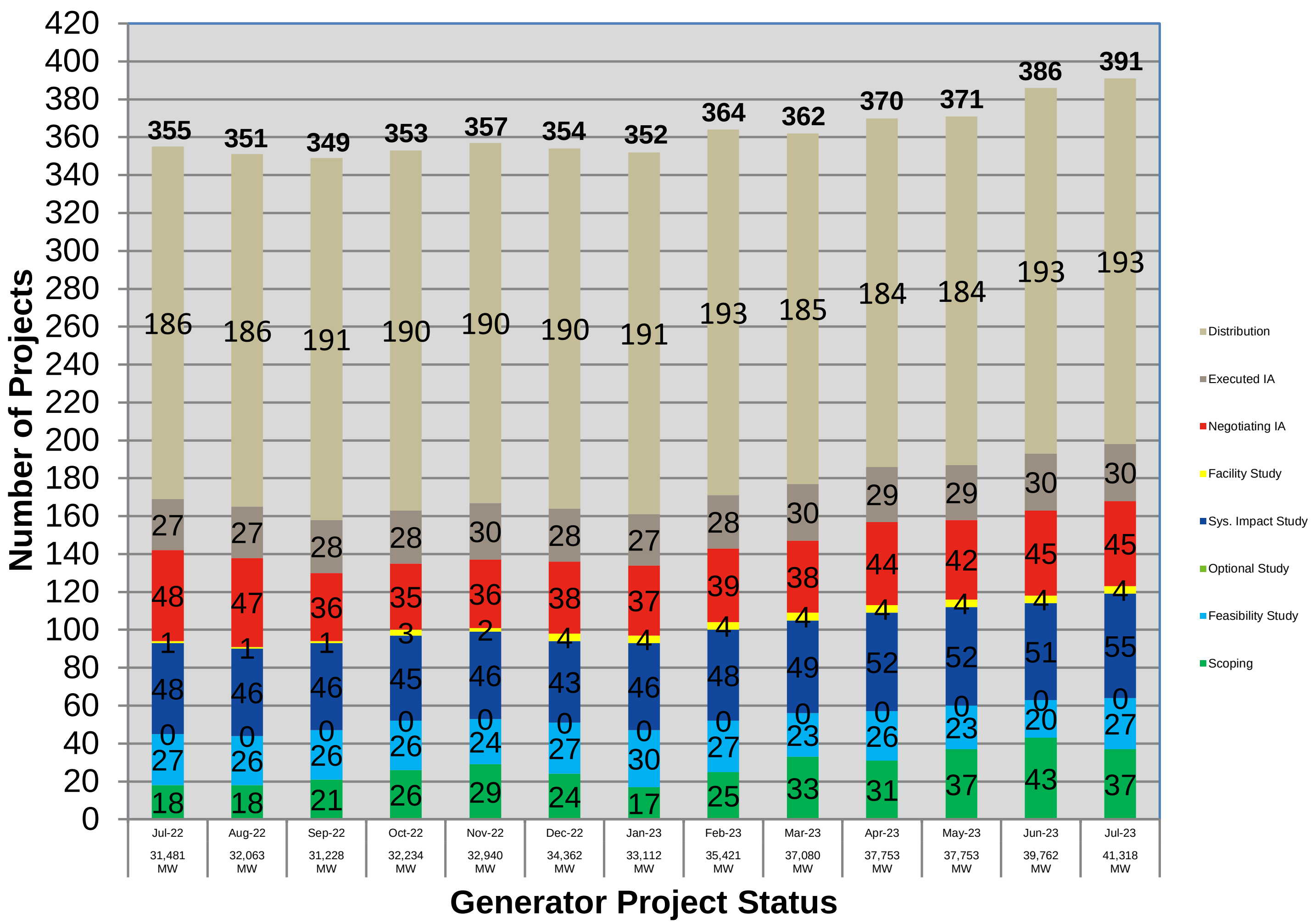
Upper Maine Solution Projects, cont.

Status as of 8/24/2023

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-23	2

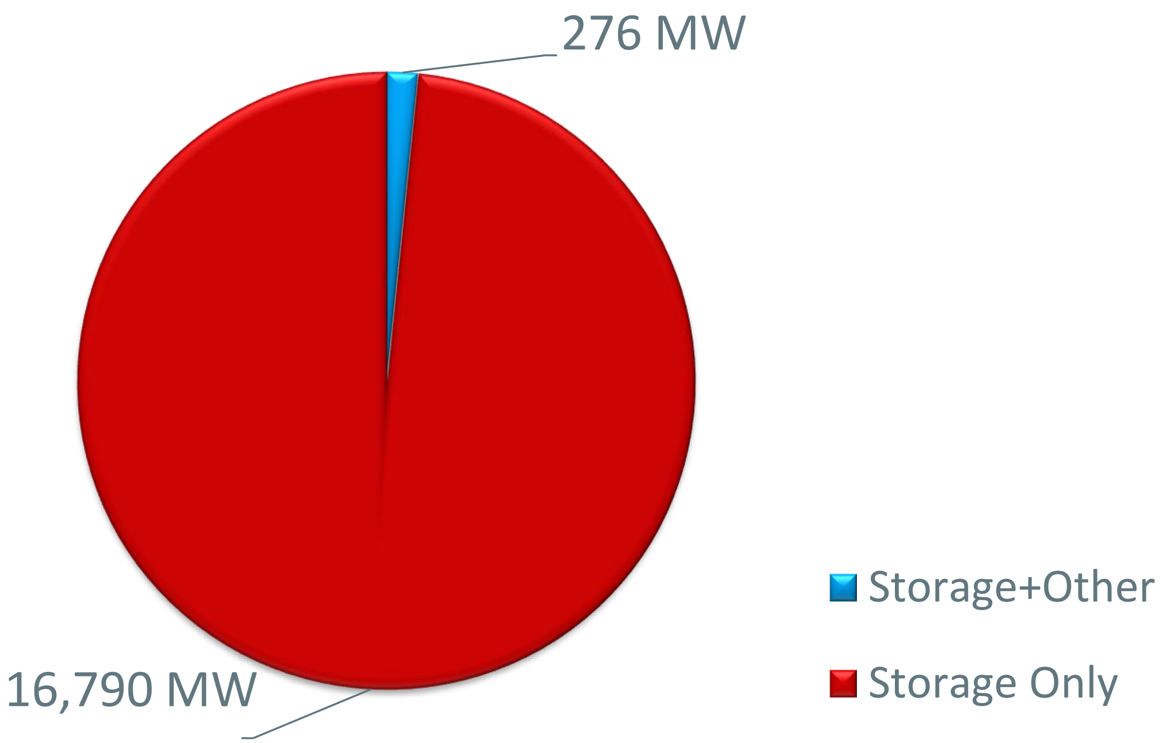
Status of Tariff Studies as of August 1, 2023



10 ETUs in Scoping, 7 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA
Transmission Service Requests needing study: 3 in SIS
https://irtt.iso-ne.com/external.aspx

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

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



OPERABLE CAPACITY ANALYSIS

Fall 2023 and Preliminary Winter 2023/24 Analysis

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning September 23, 2023.
- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning December 16, 2023.

OPERABLE CAPACITY ANALYSIS

Fall 2023 Analysis

Fall 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Sep. - 2023[2] CSO (MW)	Sep. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,072	29,349
Active Demand Capacity Resource (+) [5]	421	414
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	525	525
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	4,607	4,757
Gas Generator Outages MW (-)	380	510
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,946	22,936
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,566	20,566
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,871	22,871
Operable Capacity Margin	-925	65

[1] Operable Capacity is based on data as of **August 28, 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 **August 28, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 23, 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	Sep. - 2023[2] CSO (MW)	Sep. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,072	29,349
Active Demand Capacity Resource (+) [5]	421	414
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	525	525
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	4,607	4,757
Gas Generator Outages MW (-)	380	510
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,946	22,936
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,115	22,115
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,420	24,420
Operable Capacity Margin	-2,474	-1,484

[1]Operable Capacity is based on data as of **August 28, 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 **August 28, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 23, 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

August 28, 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 September, October & November.

Report created: 8/28/2023

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
9/16/2023	28072	421	525	15	3938	495	2100	0	22500	20657	2305	22962	-462	N	Fall 2023
9/23/2023	**28072**	**421**	**525**	**15**	**4607**	**380**	**2100**	**0**	**21946**	**20566**	**2305**	**22871**	**-925**	**Y**	**Fall 2023**
9/30/2023	28364	418	529	66	4173	2021	2800	0	20383	15371	2305	17676	2707	N	Fall 2023
10/7/2023	28364	418	941	66	3418	4315	2800	0	19256	15406	2305	17711	1545	N	Fall 2023
10/14/2023	28364	418	941	66	5195	2102	2800	0	19692	16324	2305	18629	1063	N	Fall 2023
10/21/2023	28364	418	941	66	4573	2696	2800	0	19720	16685	2305	18990	730	N	Fall 2023
10/28/2023	28232	518	958	223	4502	2340	3600	0	19489	16890	2305	19195	294	N	Fall 2023
11/4/2023	28232	518	958	223	4269	2548	3600	0	19514	17005	2305	19310	204	N	Fall 2023
11/11/2023	28232	518	958	223	4966	876	3600	0	20489	17347	2305	19652	837	N	Fall 2023
11/18/2023	28232	518	958	223	3139	14	3600	1356	21822	18079	2305	20384	1438	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

August 28, 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 September, October & November.

Report created: 8/28/2023

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
9/16/2023	28072	421	525	15	3938	495	2100	0	22500	22212	2305	24517	-2017	N	Fall 2023
9/23/2023	**28072**	**421**	**525**	**15**	**4607**	**380**	**2100**	**0**	**21946**	**22115**	**2305**	**24420**	**-2474**	**Y**	**Fall 2023**
9/30/2023	28364	418	529	66	4173	2021	2800	0	20383	15971	2305	18276	2107	N	Fall 2023
10/7/2023	28364	418	941	66	3418	4315	2800	0	19256	16007	2305	18312	944	N	Fall 2023
11/18/2023	28232	518	958	223	3139	14	3600	1521	21657	18773	2305	21078	579	N	Fall 2023
11/25/2023	28232	518	958	223	3143	361	3600	2215	20612	19512	2305	21817	-1205	N	Winter 2023/2024
12/2/2023	28334	523	958	223	2360	618	3200	2174	21686	19903	2305	22208	-522	N	Winter 2023/2024
12/9/2023	28334	523	958	223	2533	343	3200	3012	20950	20199	2305	22504	-1554	N	Winter 2023/2024
12/16/2023	28334	523	958	223	2531	343	3200	3521	20443	20211	2305	22516	-2073	Y	Winter 2023/2024
12/23/2023	28334	523	958	223	333	33	3200	4247	22225	20274	2305	22579	-354	N	Winter 2023/2024
12/30/2023	28334	523	958	223	333	33	2800	4375	22497	20555	2305	22860	-363	N	Winter 2023/2024
1/6/2024	28334	523	958	223	333	33	2800	4506	22366	21032	2305	23337	-971	N	Winter 2023/2024
1/13/2024	28334	523	958	223	333	33	2800	4298	22574	21032	2305	23337	-763	N	Winter 2023/2024
1/20/2024	28334	523	958	223	333	33	2800	3999	22873	21032	2305	23337	-464	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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11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
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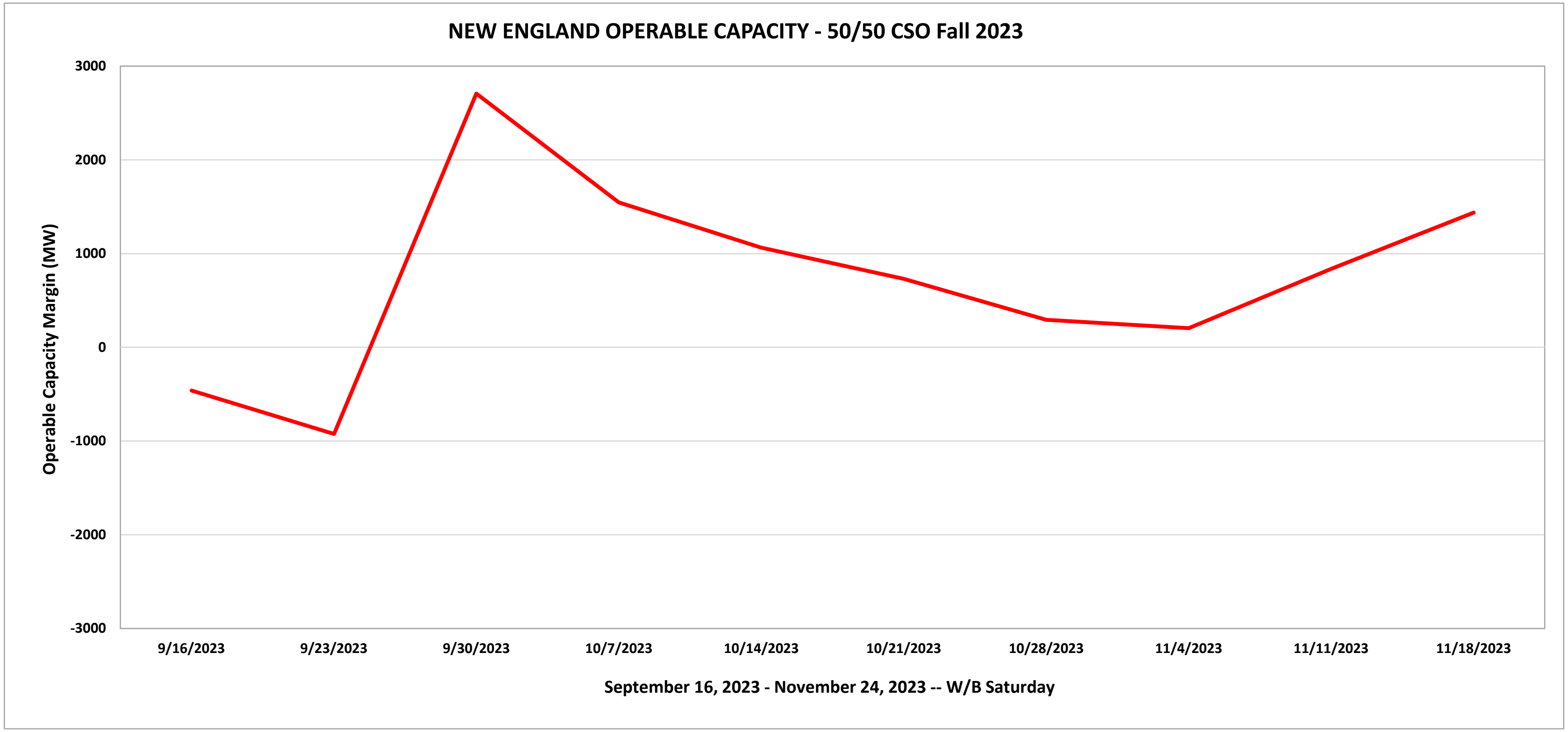
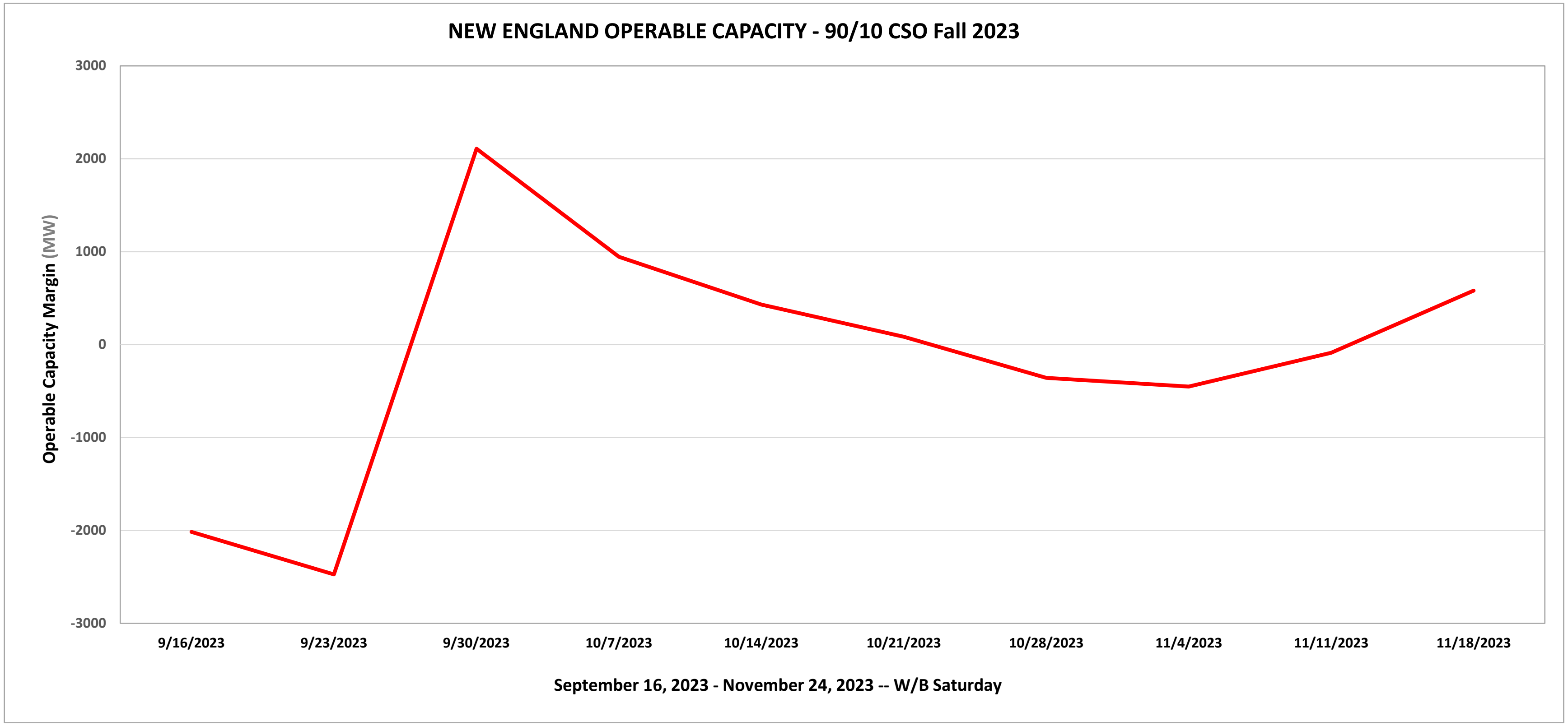
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its 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

Preliminary Winter 2023/24 Analysis

Preliminary Winter 2023/24 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Dec. - 2023[2] CSO (MW)	Dec. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,334	31,846
Active Demand Capacity Resource (+) [5]	523	368
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	2,531	2,734
Gas Generator Outages MW (-)	343	559
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	2,402	2,451
Net Capacity (NET OPCAP SUPPLY MW)	21,562	24,451
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,475	19,475
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,780	21,780
Operable Capacity Margin	-218	2,671

[1]Operable Capacity is based on data as of **August 28, 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 **August 28, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **December 16, 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.

Preliminary Winter 2023/24 Operable Capacity Analysis

90/10 Load Forecast	Dec. - 2023[2] CSO (MW)	Dec. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,334	31,846
Active Demand Capacity Resource (+) [5]	523	368
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	2,531	2,734
Gas Generator Outages MW (-)	343	559
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	3,521	3,735
Net Capacity (NET OPCAP SUPPLY MW)	20,443	23,167
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,211	20,211
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,516	22,516
Operable Capacity Margin	-2,073	651

[1]Operable Capacity is based on data as of **August 28, 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 **August 28, 2023.**

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

ISO-NE OPERABLE CAPACITY ANALYSIS

August 28, 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 and February.

Report created: 8/28/2023

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	28232	518	958	223	3143	361	3600	1301	21526	18794	2305	21099	427	N	Winter 2023/2024
12/2/2023	28334	523	958	223	2360	618	3200	1186	22674	19177	2305	21482	1192	N	Winter 2023/2024
12/9/2023	28334	523	958	223	2533	343	3200	2025	21937	19464	2305	21769	168	N	Winter 2023/2024
12/16/2023	**28334**	**523**	**958**	**223**	**2531**	**343**	**3200**	**2402**	**21562**	**19475**	**2305**	**21780**	**-218**	**Y**	**Winter 2023/2024**
12/23/2023	28334	523	958	223	333	33	3200	3101	23371	19537	2305	21842	1529	N	Winter 2023/2024
12/30/2023	28334	523	958	223	333	33	2800	3700	23172	19808	2305	22113	1059	N	Winter 2023/2024
1/6/2024	28334	523	958	223	333	33	2800	3695	23177	20269	2305	22574	603	N	Winter 2023/2024
1/13/2024	28334	523	958	223	333	33	2800	3550	23322	20269	2305	22574	748	N	Winter 2023/2024
1/20/2024	28334	523	958	223	333	33	2800	3101	23771	20269	2305	22574	1197	N	Winter 2023/2024
1/27/2024	28334	523	958	223	353	33	2800	2802	24050	20049	2305	22354	1696	N	Winter 2023/2024
2/3/2024	28334	523	958	223	20	33	3100	2503	24382	19784	2305	22089	2293	N	Winter 2023/2024
2/10/2024	28334	523	958	223	0	33	3100	2204	24701	19755	2305	22060	2641	N	Winter 2023/2024
2/17/2024	28334	523	958	223	0	33	3100	1755	25150	19495	2305	21800	3350	N	Winter 2023/2024
2/24/2024	28334	523	958	223	52	33	3100	1456	25397	18516	2305	20821	4576	N	Winter 2023/2024
3/2/2024	28334	523	958	223	105	33	2200	381	27319	18170	2305	20475	6844	N	Winter 2023/2024
3/9/2024	28334	523	958	223	1354	404	2200	0	26080	17976	2305	20281	5799	N	Winter 2023/2024
3/16/2024	28334	523	958	223	1354	501	2200	0	25983	17614	2305	19919	6064	N	Winter 2023/2024
3/23/2024	28334	523	958	223	1354	778	2200	0	25706	17054	2305	19359	6347	N	Winter 2023/2024
3/30/2024	28232	518	958	223	759	1796	2700	0	24676	16379	2305	18684	5992	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).
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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.
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Preliminary Winter 2023/24 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 28, 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 and February.

Report created: 8/28/2023

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	28232	518	958	223	3143	361	3600	2215	20612	19512	2305	21817	-1205	N	Winter 2023/2024
12/2/2023	28334	523	958	223	2360	618	3200	2174	21686	19903	2305	22208	-522	N	Winter 2023/2024
12/9/2023	28334	523	958	223	2533	343	3200	3012	20950	20199	2305	22504	-1554	N	Winter 2023/2024
12/16/2023	28334	523	958	223	2531	343	3200	3521	20443	20211	2305	22516	-2073	Y	Winter 2023/2024
12/23/2023	28334	523	958	223	333	33	3200	4247	22225	20274	2305	22579	-354	N	Winter 2023/2024
12/30/2023	28334	523	958	223	333	33	2800	4375	22497	20555	2305	22860	-363	N	Winter 2023/2024
1/6/2024	28334	523	958	223	333	33	2800	4506	22366	21032	2305	23337	-971	N	Winter 2023/2024
1/13/2024	28334	523	958	223	333	33	2800	4298	22574	21032	2305	23337	-763	N	Winter 2023/2024
1/20/2024	28334	523	958	223	333	33	2800	3999	22873	21032	2305	23337	-464	N	Winter 2023/2024
1/27/2024	28334	523	958	223	353	33	2800	3999	22853	20804	2305	23109	-256	N	Winter 2023/2024
2/3/2024	28334	523	958	223	20	33	3100	3550	23335	20530	2305	22835	500	N	Winter 2023/2024
2/10/2024	28334	523	958	223	0	33	3100	3251	23654	20500	2305	22805	849	N	Winter 2023/2024
2/17/2024	28334	523	958	223	0	33	3100	2653	24252	20231	2305	22536	1716	N	Winter 2023/2024
2/24/2024	28334	523	958	223	52	33	3100	2204	24649	19218	2305	21523	3126	N	Winter 2023/2024
3/2/2024	28334	523	958	223	105	33	2200	1278	26422	18860	2305	21165	5257	N	Winter 2023/2024
3/9/2024	28334	523	958	223	1354	404	2200	802	25278	18659	2305	20964	4314	N	Winter 2023/2024
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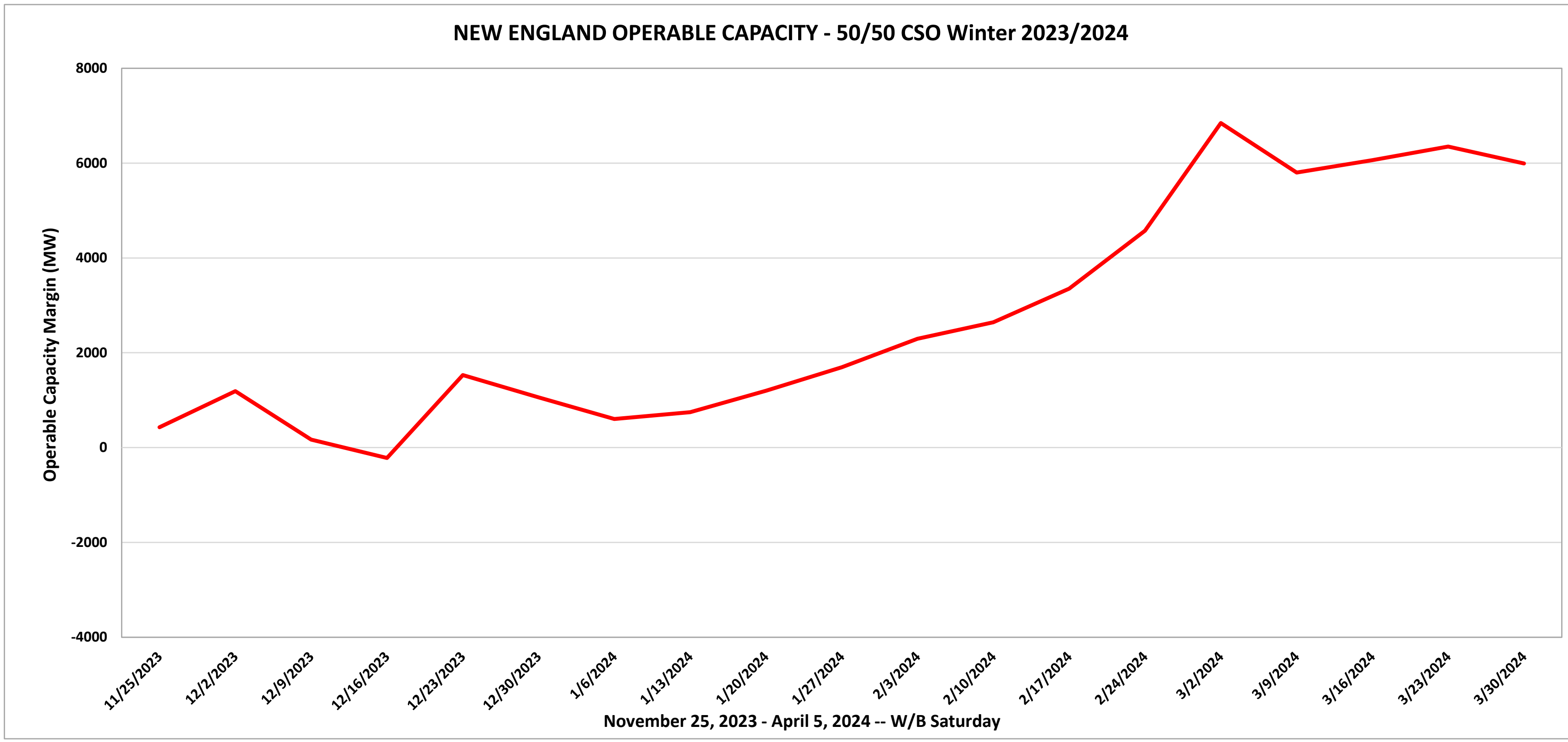
Preliminary Winter 2023/24 Operable Capacity Analysis
50/50 Forecast (Reference)



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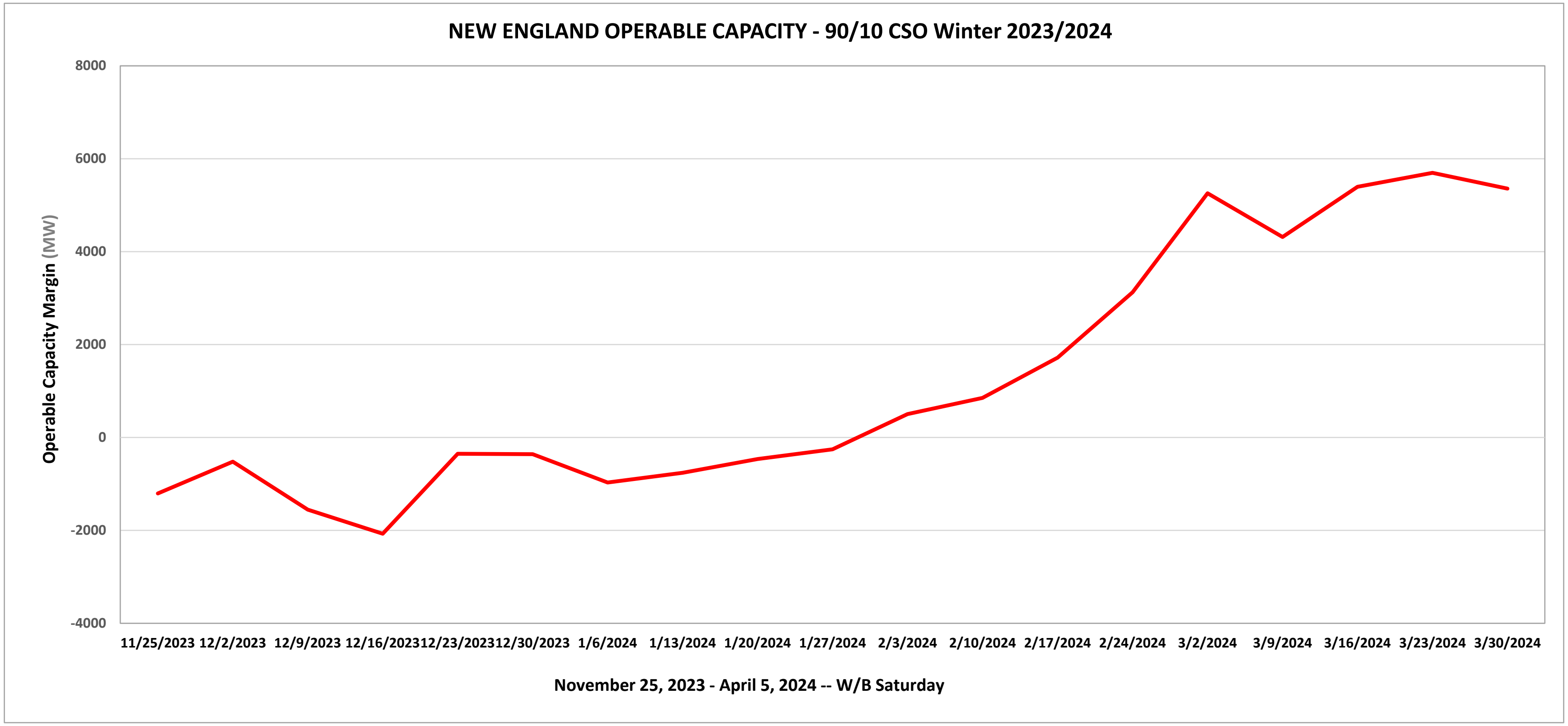

OPERABLE CAPACITY ANALYSIS

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

ISO new england

memo

To: NEPOOL Participants Committee Members and Alternates

From: Robert C. Ludlow, VP & CF/CO

Date: September 7, 2023

Subject: ISO New England Inc. 2024 Operating and Capital Budgets

Budget Process

This memo provides an update to the NEPOOL Participants Committee ("NPC") on the 2024 budget process. At its August 11, 2023 meeting, the NEPOOL Budget & Finance Subcommittee ("B&F") reviewed the ISO's proposed 2024 operating and capital budgets (collectively, the "Budgets"). Included with this memorandum is a presentation of the Budgets. The more detailed presentation provided to B&F can be found on the ISO's website at 6_isone_2024_proposed_op_cap_budget.pdf (iso-ne.com).

At the August B&F meeting, participants asked questions, and we responded as noted, on the following:

- Whether the ISO could share further compensation study information
  - We explained that supporting details would be included in the testimony accompanying the Budgets filing and that we would follow-up if we could provide any additional information. In our responses to New England state agencies we responded to their similar requests for compensation study information (see link below to the questions and ISO-NE response (NECPUC question 5 and CTOCC questions 1 and 2)).
- The rationale for partial funding of the forty-one positions proposed in the 2024 operating budget
  - We explained that due to the timing to recruit and hire for the sizable number of positions we only budgeted for a portion of these in 2024 with expected onboard dates spread across 2024
- The timing of work related to a Maine Interconnection Cluster Study
  - We responded that this is expected to commence in 2023 with carryover costs included in the 2024 operating budget

Of note, the proposed 2024 operating budget includes a headcount (in the ISO's External Affairs and Corporate Communications department) related to environmental policy and consumer affairs. This position will allow the ISO to enhance and expand our existing policy assessment, analysis, and outreach efforts regarding environmental policy. This headcount addition is consistent with the ISO's current mission and does not require updates to the ISO's governing documents.

The ISO has also presented the Budgets to the New England state agencies; following that presentation we received questions from multiple state agencies. The ISO responded to state agencies' questions and those responses are posted under the budget section on the ISO's website at Budget (iso-ne.com).

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The Participants Committee will be asked to vote on the proposed budgets at the October 5, 2023 meeting. During the week of September 25, 2023, we will distribute a memo with the projected 2024 Revenue Requirement by ISO-NE Administrative Cost Tariff Schedule, including the draft 2024 rate components.

Proposed 2024 Budgets

The 2024 Budgets represent the organization's commitment to supporting the region as it transitions to clean energy and to ensuring that its continued operations are efficient and reliable. The clean energy transition is creating increased grid complexity and competition for in-demand talent and the 2024 Budgets represent the needed ramping-up of organizational capacity to carry out the organization's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively priced wholesale electricity; as well as developing new capabilities that will be necessary for supporting the grid of the future.

The key drivers supporting the proposed 2024 operating budget increase are the continued preparation for the clean energy transition, inflationary and continued operations increases, and a net change in the Revenue Requirement true-up.

The 2024 operating budget year-over-year increase before depreciation is $35.3 million or 16.9%; the increase, including depreciation is $36.9 million or 15.4%. The 2024 Revenue Requirement, taking into account the 2022 true-up, is an increase of $48.5 million or 21.5% over 2023.

The net overall change from the preliminary (top-down) operating budget, that was presented at the June 27, 2023 NPC meeting, is a decrease of approximately $58,000. Changes in two primary areas resulted in this variance: an increase of approximately $1 million in Computer Services, primarily related to cyber security licenses and maintenance costs; and a decrease of about $800,000 in depreciation expense based on an updated capital projects schedule. A number of other small adjustments across several lines occurred.

The capital budget is $35.0 million which is an increase of $1.5 million over 2023. The ISO has increased the capital budget over the last few years with budget amounts of $32.0 million in 2022, $33.5 million in 2023, and proposed $35.0 million in 2024. The capital budget is projected to increase to $40 million in 2025 and beyond. The increased capital budget need is being driven by four primary drivers: the nGEM platform; major market and reliability related efforts; cyber security work; and information technology asset and infrastructure replacement.

I will be available during the meeting for any questions regarding the 2024 Budgets. Please also feel free to reach out to me after today with any additional comments or questions regarding the 2024 Budgets.

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SEPTEMBER 7, 2023

ISO New England Proposed 2024 Operating and Capital Budgets

NEPOOL Participants Committee Meeting

Robert Ludlow
VP, CHIEF FINANCIAL & COMPLIANCE OFFICER

Contents of Presentation

The Presentation Includes:

Contents of Presentation *(cont.)*

The following appendices are also included for reference:

EXECUTIVE SUMMARY

Executive Summary

- The 2024 budget represents the organization's commitment to supporting the region as it transitions to clean energy and ensuring that its continued operations are efficient and reliable
- The clean energy transition is creating increased grid complexity and competition for in-demand talent
  - The 2024 budget represents the continued investments needed to address these challenges
  - ISO management believes these increases are measured and in-line with the trends seen across the industry and at other ISOs
- The 2024 budget represents the needed ramping-up of organizational capacity to carry out the organization's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively priced wholesale electricity; as well as developing new capabilities that will be necessary for supporting the grid of the future
  - As indicated during last year's budgeting process, after years of keeping headcount flat or with minimal additions, the organization has seen the need to begin increasing headcount more substantially in order to support the clean energy transition

Executive Summary

- Public impetus around addressing climate change through clean energy investments and electrifying transportation and heating sectors is driving substantial changes to the New England power system:
  - Substantial increases to the number of interconnected and behind-the-meter (BTM) generating assets are changing how the transmission and distribution system operate and interact with each other
  - A shift from larger, dispatchable resources to smaller non-dispatchable, weather-dependent ones is changing the complexity involved in dispatching resources to meet demand
  - New daily and seasonal demand patterns are changing the types of resources are needed and the timing of such needs
- The changes to the grid represent a step-up in system complexity that the ISO needs to be prepared to address beginning in 2024 and throughout the remainder of the decade
  - This step-up in complexity represents a considerable increase to ISO workload

Executive Summary

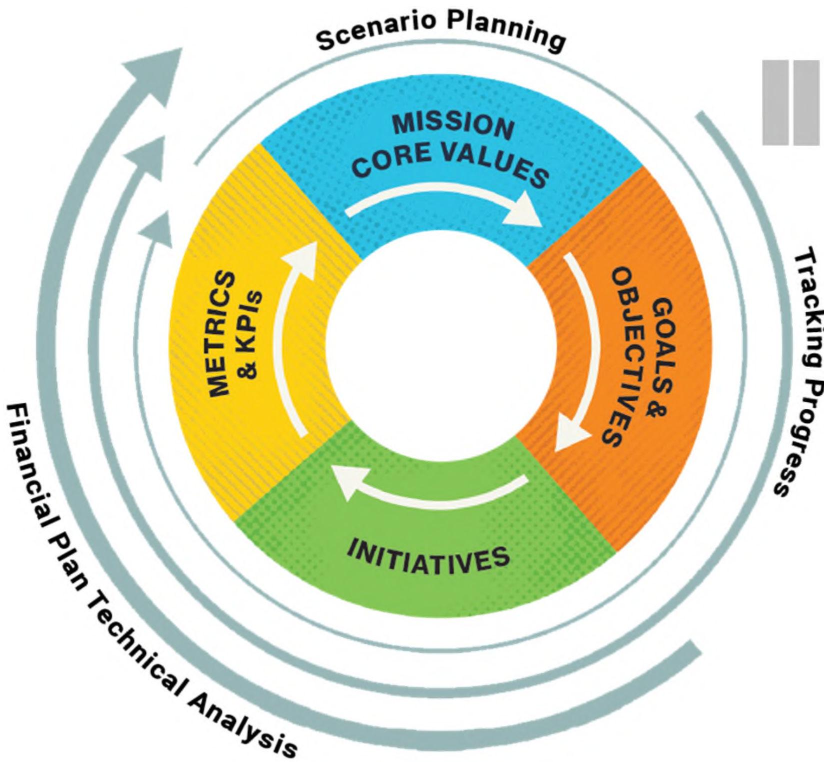
- The proposed budget represents what is needed for the ISO to address increased workload, remain competitive in the labor market, and keep pace with inflationary effects on employee compensation in order to attract and retain experienced personnel necessary to support the clean energy transition
- The ISO conducted a job-specific market competitiveness analysis that outlined the need for the ISO to "catch-up" on salary commitments to both attract new talent and retain existing employees
  - Turnover rate has increased since the pandemic, and remains high
  - In 2022, the ISO engaged a compensation consulting film to conduct 1-for-1 job-specific benchmarking to establish competitive rates of pay for our highly skilled and in-demand workforce
- Lastly, the budget reflects additional investment in information technology (IT) to address inflationary and renewal costs for IT infrastructure and licensing, cybersecurity, and the transition to cloud-based infrastructure

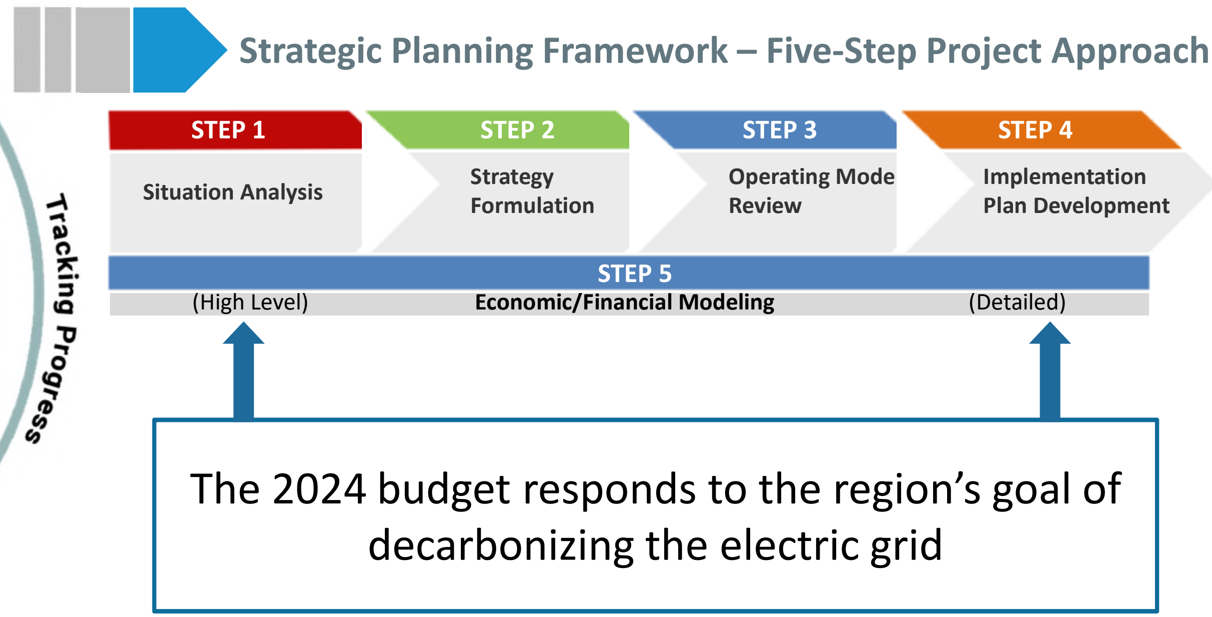
THE STRATEGIC PROCESS

ISO-NE's integrated business and strategic planning framework

Strategic Planning Framework

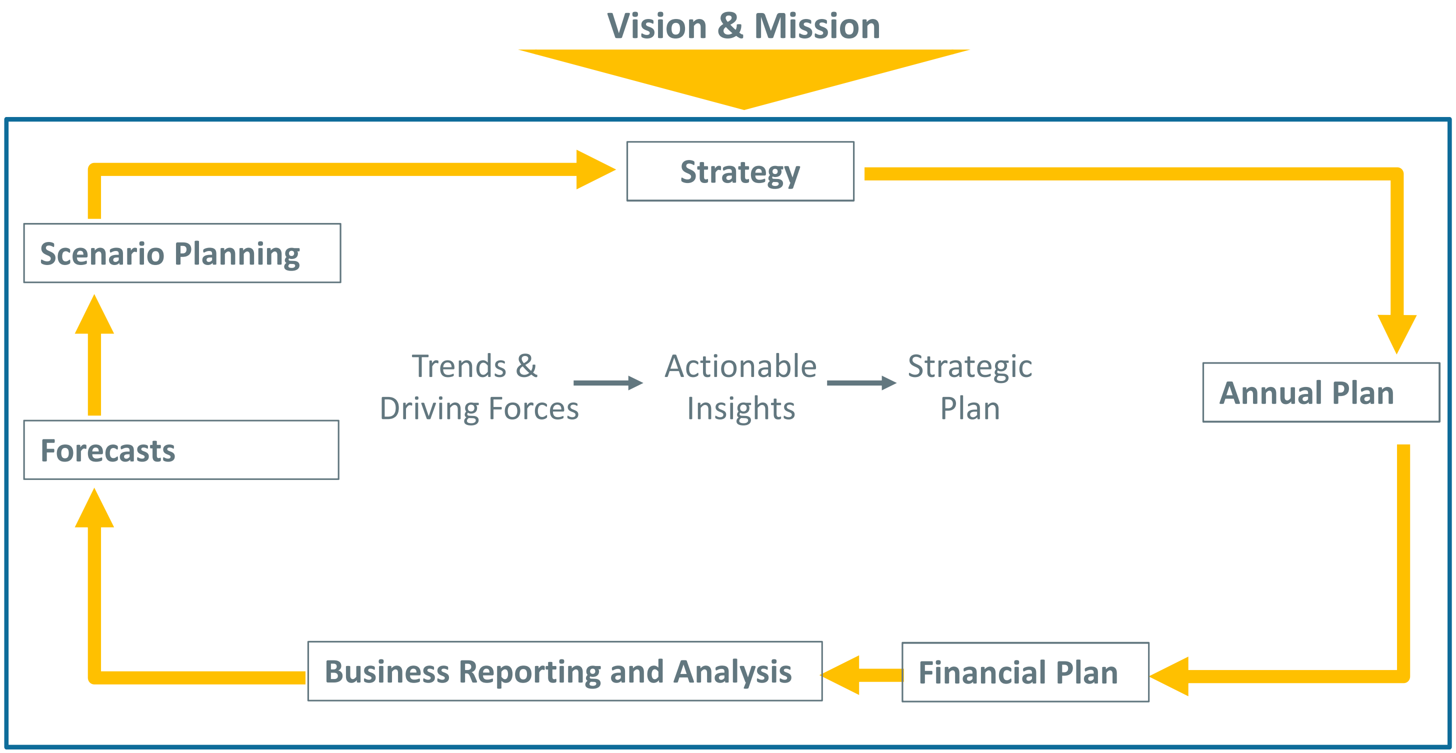
The 2024 ISO-NE budget represents the needs for the organization's strategy in supporting the region on its path to a decarbonized grid





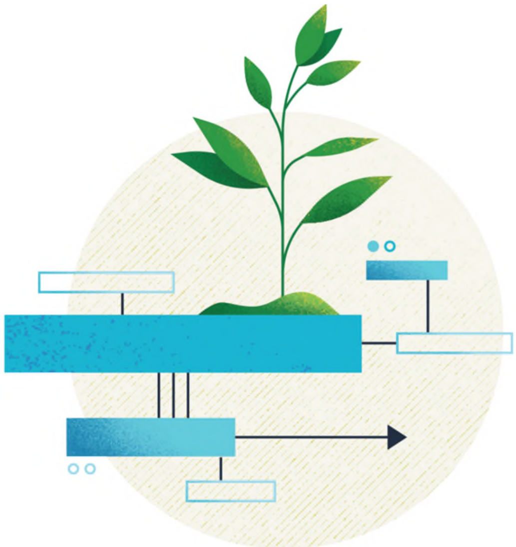
Annual Process – Business and Strategic Planning

ISO-NE is guided by a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can get behind, with the aim of creating value for ISO stakeholders



Our Guidepost: The ISO New England Vision Statement

The ISO-NE Vision Statement is an explicit statement about our intent to achieve a reliable transition to clean energy utilizing competitive markets



Vision Statement:

To harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy

The ISO's Vision represents the company's commitment to work with FERC, the states, and market participants to support the clean energy transition (within the limits of our jurisdiction)

Our Responsibility to the Region: ISO's Mission

The ISO-NE Mission Statement outlines the core role and responsibilities of the ISO's daily operations

Mission Statement:

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

Four Pillars of Supporting a Successful Energy Transition

When the ISO looks toward the future, these are the objectives the ISO, states, market participants, and regulators need to advance in order to support the clean energy transition

1

Significant amounts of clean energy to power the economy with a greener grid

2

Balancing resources that keep electricity supply and demand in equilibrium

3

Energy adequacy—a dependable energy supply chain and/or a robust energy reserve to manage through extended periods of severe weather or energy supply constraints

4

Robust transmission to integrate renewable resources and move clean electricity to consumers across New England

TRENDS AND DRIVERS IMPACTING THE 2024 ISO-NE BUDGET

Supporting Decarbonization of the New England Power System Will be the Primary Driver of ISO Work Over the Next Decade

- Decarbonization will change the composition of the power system
  – Increasing numbers of inverter-based resources looking to connect to the New England grid
  – Additional resources are connecting to the distribution system, outside of the ISO's current visibility, that contribute to load variability and forecasting challenges
- Changing load characteristics will exacerbate operational complexity
  – Increased load anticipated through electrification of heating and transportation
  – Increased variability through proliferation of behind-the-meter (BTM) generation
  – Increasing load-dependence on weather at a time when weather is becoming more erratic

ISO Planning New Investments to Support Clean Energy Transition

The region has embarked on a major grid transformation that the ISO is well-positioned to support

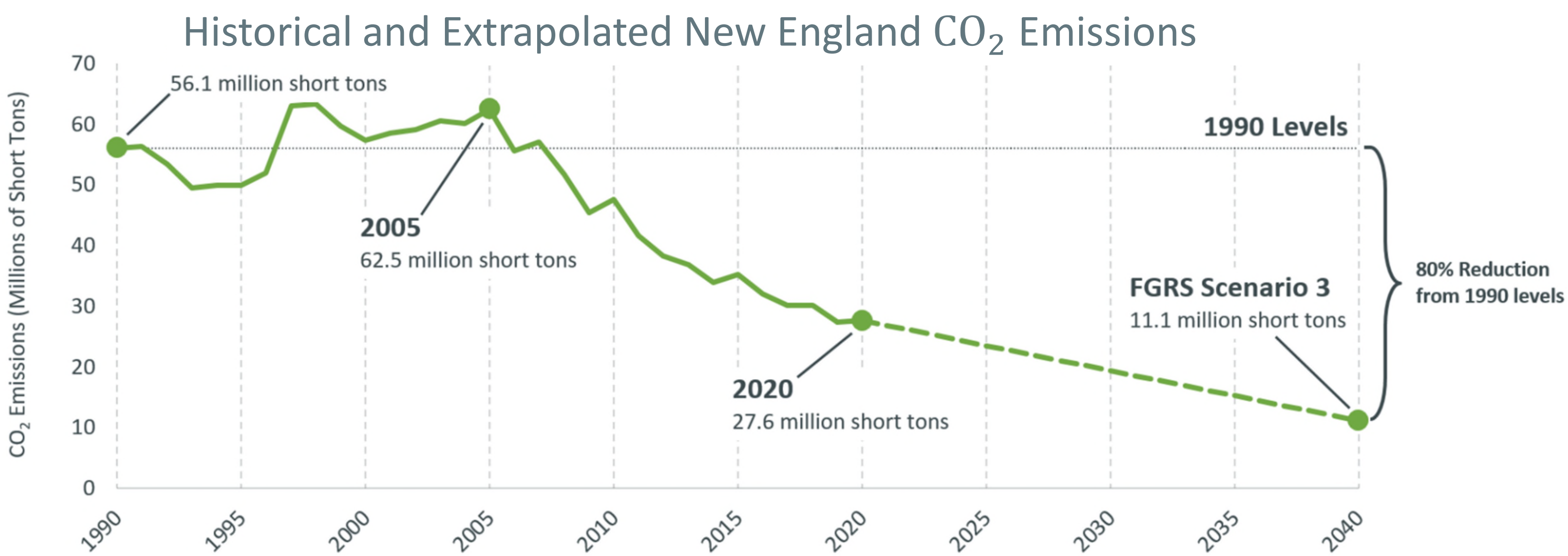
Public policies driving decarbonization represent the largest catalyst for change to the New England power system

Decarbonization goals will lead to a 2040 grid with much higher loads, load-variability, and a much greater number of variable supply resources

More employees, with different skillsets will be needed to address the volume of market design changes and operational/planning complexities

Major investments in new technologies to create and support the core business applications and processes, including increased computational capacity to deal with increased grid complexity

Emissions Reduction of the New England Grid through Decarbonization of the Resource Fleet is the Catalyst for Change to the New England Grid

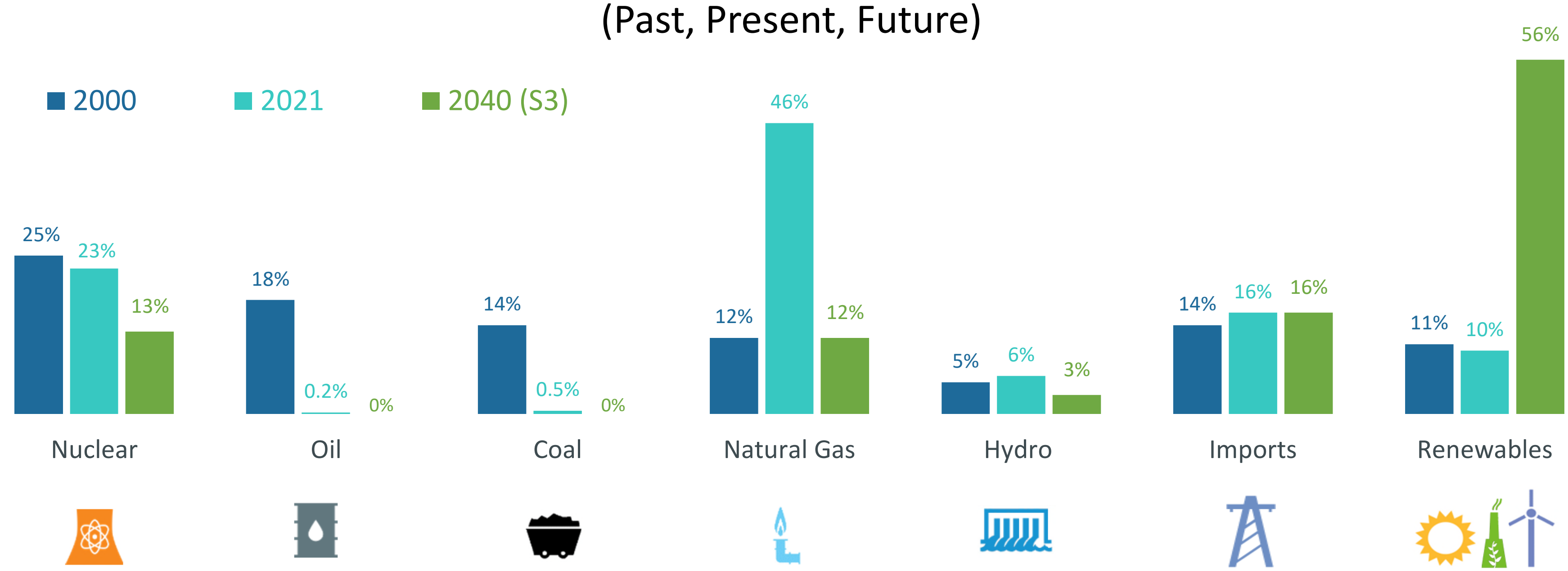


Note: The dashed line between 2020 and 2040 illustrates the difference between the known emissions in 2020 and the simulated emissions in 2040 from FGRS Scenario 3. We are not predicting what the annual emissions levels or rate of reduction will be between those two years

- State policies to address climate change through emissions reduction outline, for the most part, an **80% reduction from 1990 levels by 2040**
- These policies will result in a drastically different generation profile for the region

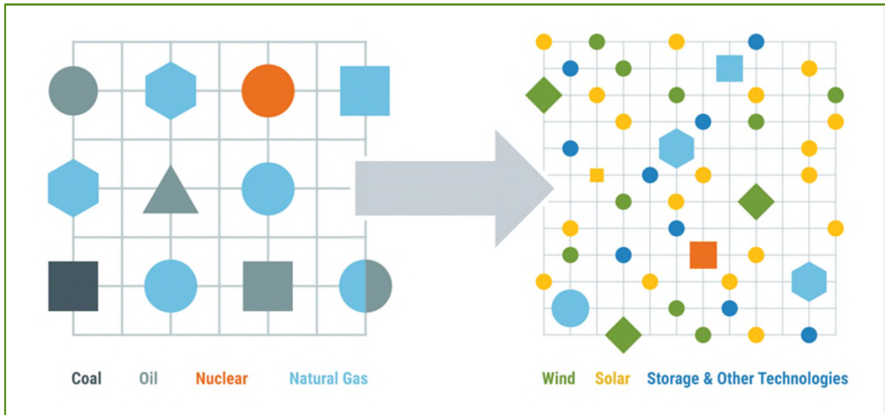
Just as Natural Gas Displaced Oil/Coal-Fueled Resources Over the Last 20 Years, Renewables will Displace Natural Gas-Fired Resources Over the Next 20

Percent of Total **Electric Energy** Production by Source
(Past, Present, Future)



Source: ISO New England Net Energy and Peak Load by Source; data for 2021 is preliminary and subject to resettlement; data for 2040 is based on Scenario 3 of the ISO New England 2021 Economic Study: Future Grid Reliability Study Phase 1. Renewables include landfill gas, biomass, other biomass gas, wind, grid-scale solar, behind-the-meter solar, municipal solid waste, and miscellaneous fuels.

Two Dimensions to the Transition to Clean Energy that Contribute to Increased Grid Complexity



1. A shift from centrally dispatched generation to distributed resources
2. A shift from conventional generation to weather-dependent renewable generation

The changing resource mix **will increase ISO workload** in both the long- and short-term

- The number of assets in New England will grow into hundreds of thousands/one-million-plus in number, leading to increased administrative burden and computational capacity requirements
- Growing generation and fuel uncertainty will lead to increased focus on energy adequacy efforts
- The resource mix will likely require different market designs
- Urgency around the transition to clean energy will increase, leading to greater focus on ISO actions and the need for more and different types of public and regulatory engagement
- **Additional ISO staff and new capabilities will be needed to support these efforts**

By 2030 the ISO Expects to See Substantial Changes to the New England Power System

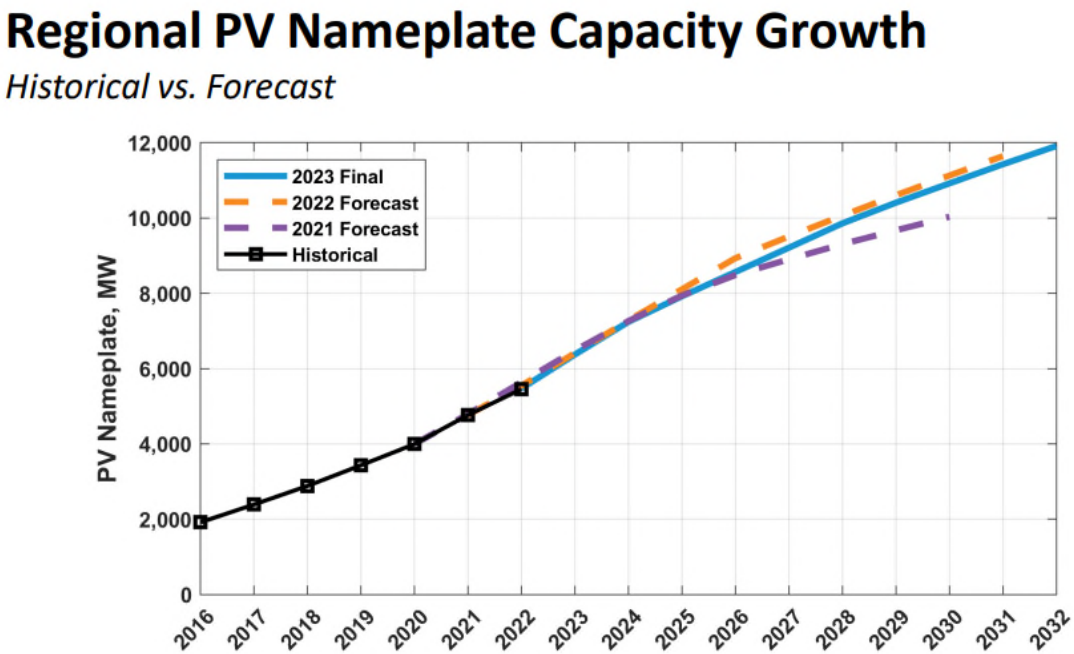
The ISO needs to plan to administer, operate, and make market design changes for a power system that, by 2030, is projected to be very different than the grid today

- **Doubled installed capacity of solar resources** (both on the grid and on the distribution system)
- **Thousands of MW of planned offshore wind**
- **Substantial new transmission investment**
  - Supporting inter- and intra-regional transfers, upgrading condition of existing assets, and addressing increasing interaction between transmission and distribution system
- **Substantial increase in number of energy resources** integrated into ISO markets – pursuant to FERC Order 2222
- **Enhanced market structures** – accounting for resource mix with different operating characteristics

To support these efforts, the ISO will engage in a slate of work in 2024 and beyond that directly addresses these developments, including but not limited to:

- Market design focused on forward market overhauls for Resource Capacity Accreditation and assessments for auction format (prompt-seasonal), planning for Order 2222, FCA reforms, initiatives to improve forecasting and modeling, continued work on the 2050 Transmission Study, and extended/longer-term transmission planning

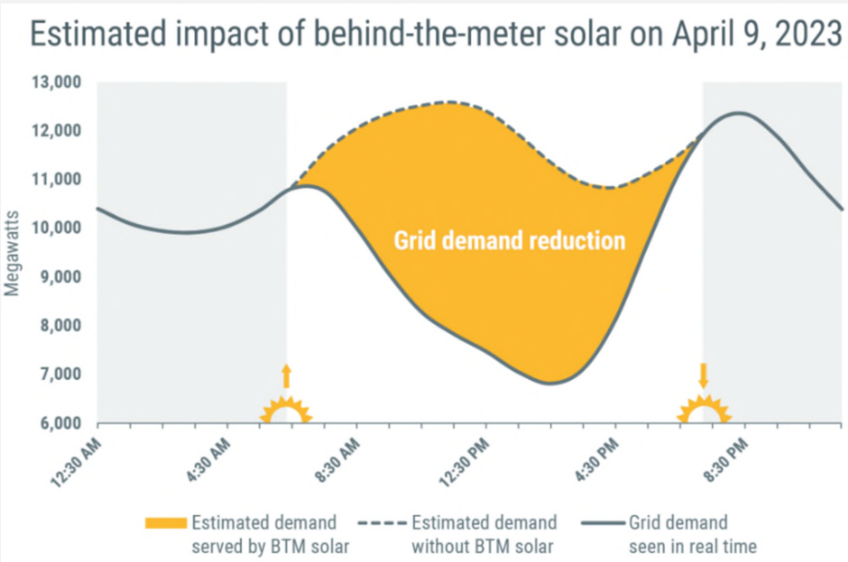
ISO Forecasts Strong Growth in Solar Photovoltaic (PV) Resources



Source: 2023 Final PV Forecast, NEPOOL Distributed Generation Forecast Working Group (Apr. 2023)

- Investments in ISO forecasting capabilities have improved our ability to forecast PV capacity growth, and further investments will be needed
  - ISO started forecasting electrification (both heating and transportation) as part of CELT 2020 and has since devoted increased attention to each forecast in terms of inputs and methodological enhancements
  - Each year, additional sub-trends and data emerge, and are expected to warrant continuous refinements/enhancements over time

The Region Increasingly Relies on Variable, Weather-Dependent Resources Outside of ISO's Visibility

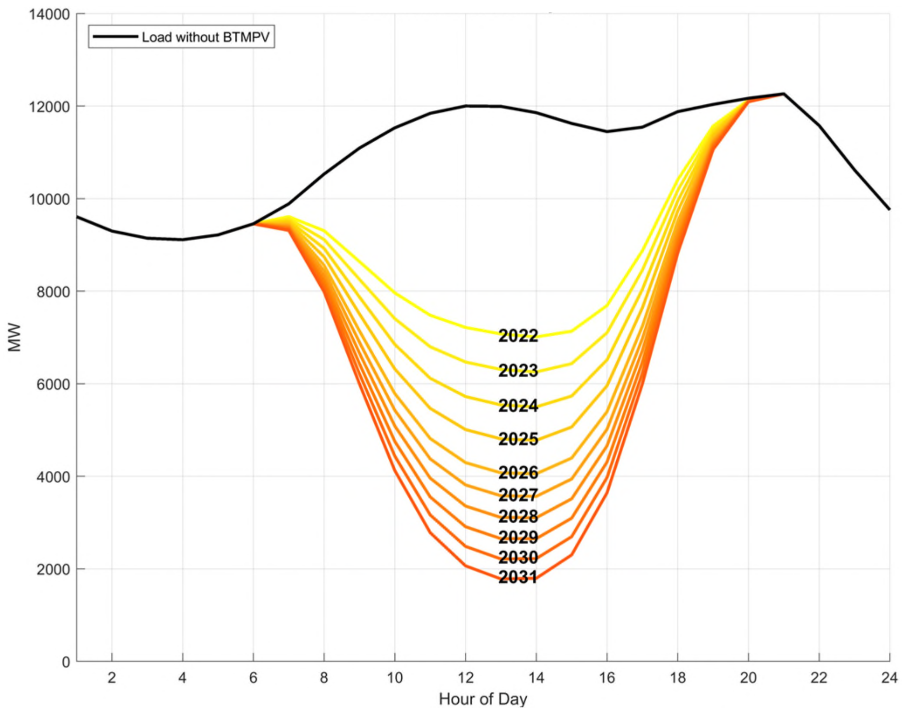


The 2024 budget increases represent initiatives and personnel to help address the changing system dynamics illustrated above

- Midday loads are driven by non-dispatchable, weather-dependent resources, outside of ISO's purview, whose output changes on a **second-to-second basis**
- This changing load profile, and impact on transmission system operations and generation dispatch, drive 2024 initiatives and work in the latter part of decade
  - Work with transmission owners and distribution companies to manage transmission system voltage/stability and develop new operating protocols
  - Allocate internal resources for deriving and implementing EMS solutions
  - Study implications for generator dispatch as load reaches minimum generation levels
  - Study a bulk electric system that can work at very low load levels (e.g., sunny, spring days) and at very high levels (as electrification increases)
  - Enhance market rules to compensate balancing resources needed to address steep load changes

Moving Towards 2030, Operational Impacts Will Become More Pressing as BTM Proliferation Continues

Projected NE Load Profile with Increasing BTM PV (“Duck Curve” transitions to “Canyon”)



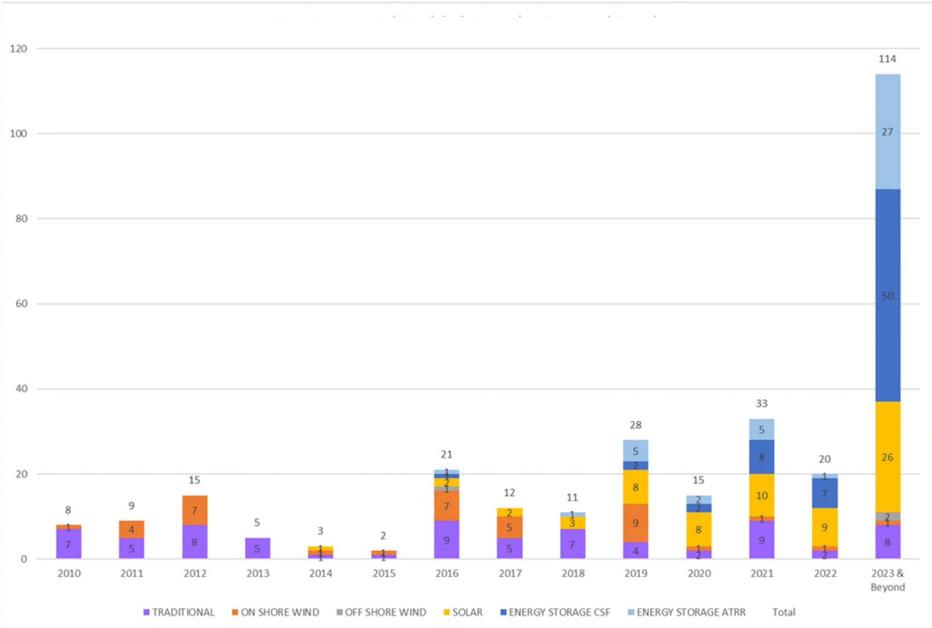
Source: ISO Load Forecasting, May 2023

- Trends in electrification and Distributed Energy Resources also warrant continuous methodological enhancements to both long- and short-term load forecasting processes to prepare for future changes in grid operation:
  - Acquisition of new or improved data sources and the use of increasing volumes of data needed as model inputs
  - Improved modeling capabilities and related data analytics
  - Need to move to increasing levels of granularity in our processes and overall accounting
  - Greater emphasis on probabilistic forecasting to quantify and provide situational awareness regarding the time-varying amounts of uncertainty in planning and operating our system

Commercial Modeled Assets Have Grown Substantially, Requiring a Substantial Increase in Asset Registration Workload

- The number of projects being coordinated per year has increased, while both the average and median size of Modeled Assets (MW) has decreased
- These new assets (greater than 1MW) consist of primarily solar and energy storage connecting to 115 kV lines that are visible and controllable by the ISO
  - ISO expects to administer registration for an increasing number of new modeled assets
- The registration effort is mostly the same regardless of size of the project
- The change in market asset mix shows a shift from large controllable generation to smaller, weather-dependent generation

New Commercial Modeled Assets by Category (Count)

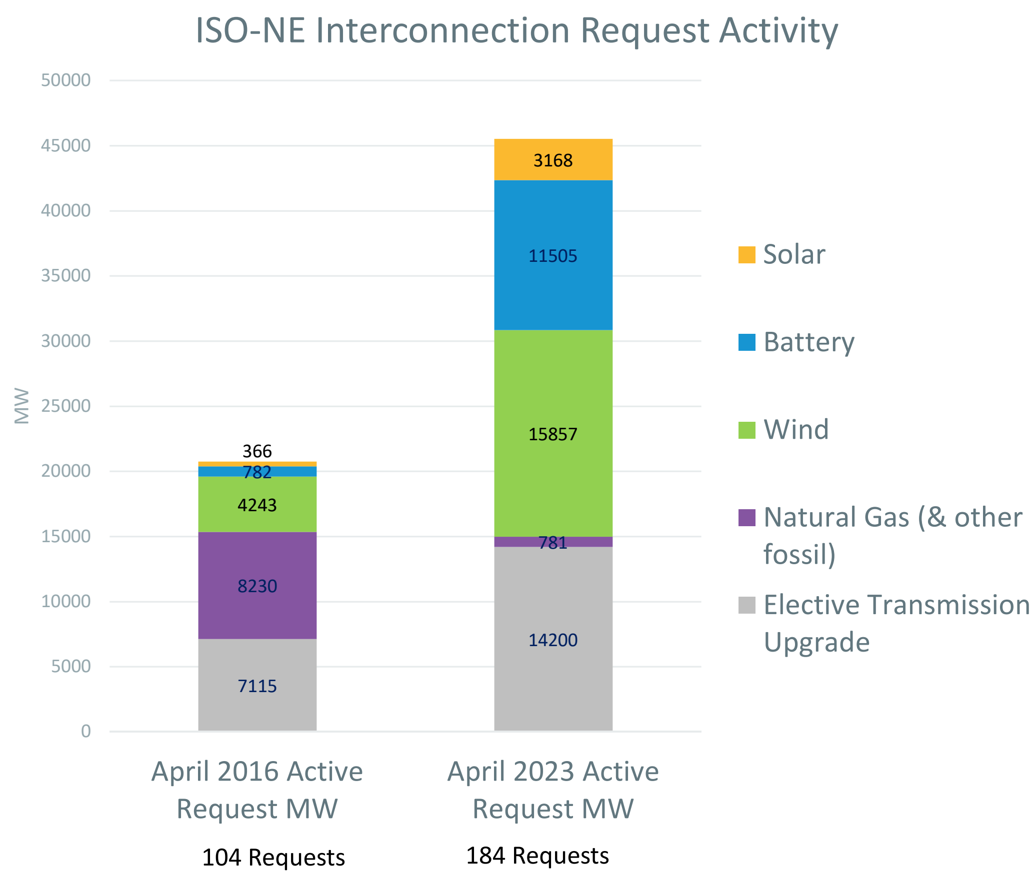


The numbers from 2023-2025 include any projects that are being coordinated with the ISO-NE Asset Registration team and working towards Commercial Operation in the market.

Source: ISO Asset Registration, June 2023

Administering More Resources Connecting to Transmission System

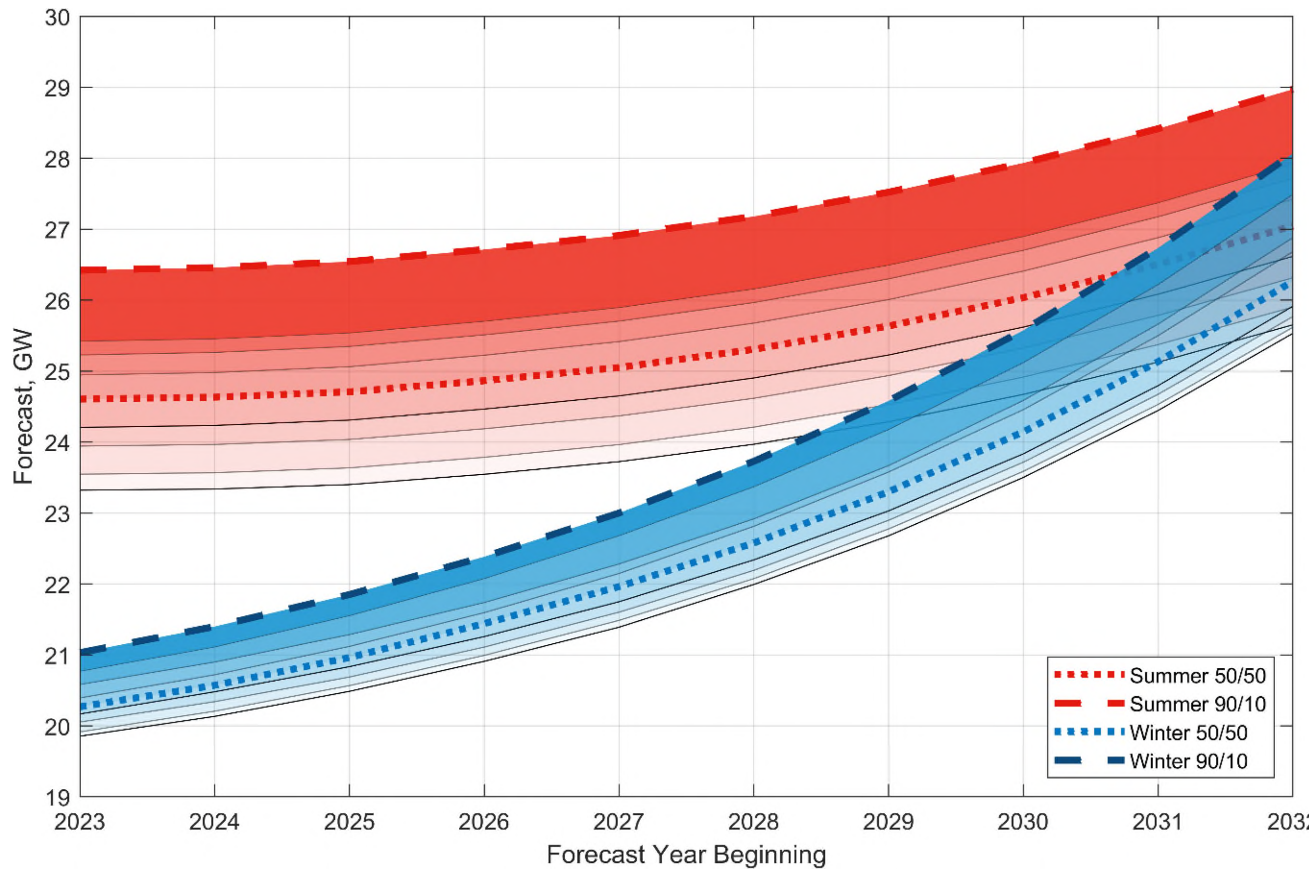
- Significant increase in applications to be studied (mainly solar, wind, & battery)
  - Number of requests in the ISO Queue is approx. 80% higher now than seven years ago
- Substantial increase in capacity being proposed to interconnect to grid requires analysis addressing a material revamping of supply & grid operations
- ISO is allocating resources while also taking into account policy changes (i.e., FERC Interconnection rulemaking – "first ready, first served") that will ameliorate some of the queue backlog



Source: ISO Transmission Services & Resource Qualification, May 2023

Electrification of Heating and Transportation Cause Winter and Summer Peak Convergence, Expected in the Early-Mid 2030s

- Plot shows "peak" portion of probabilistic net load forecast distribution for both winter and summer
- By 2031, the 90/10 net winter demand forecast exceeds the 50/50 net summer demand forecast
- Beyond the forecast horizon, by the mid-2030s, electrification will cause winter demand to become the typical, prevailing peak season



Source: ISO Load Forecasting, May 2023

The Grid is Increasingly Reliant on Non-Dispatchable, Weather-Dependent Generators that Have Already Begun to Stress ISO Forecasting and Interconnection Capabilities

Over the next 15 years, the region needs to add almost double the amount of new generation as was added to the system in the last 25 years

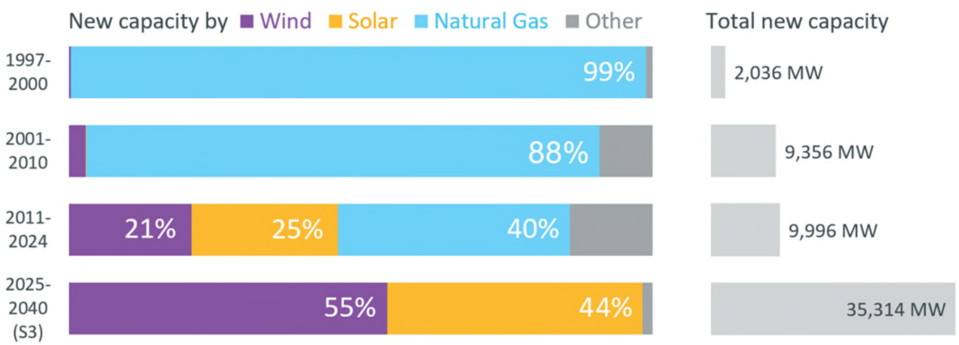
2040 grid projection:

- **Potential for 1 Million+** non-dispatchable/weather-dependent generators
- **Addition of 17,000 MW** of offshore wind
- **Addition of 28,000 MW** of solar power

Compared to the grid of today:

- **Approx. 350 dispatchable generators** with **approx. 32,600 MW** of generating capability
- **About 270,000** solar power installations totaling about **5,500 MW** (nameplate), with most connected "behind the meter"

Historical and Anticipated New Resource Capacity by Fuel Type, 1997 Baseline



Source: Future Grid Reliability Study

ISO Planning New Investments to Support Clean Energy Transition

The region has embarked on a major grid transformation that the ISO is well-positioned to support

Public policies driving decarbonization represent the largest catalyst for change to the New England power system

Decarbonization goals will lead to a 2040 grid with much higher loads, load-variability, and a much greater number of variable supply resources

More employees, with different skillsets will be needed to address the volume of market design changes and operational/planning complexities

Major investments in new technologies to create and support the core business applications and processes, including increased computational capacity to deal with increased grid complexity

Successfully Achieving the Goals Outlined by the Region Will Require Substantial Investment in ISO Workforce, Systems, and Processes

- In order to keep pace with the needs of the transition to cleaner generating resources, the ISO **must begin ramping-up its capabilities and operational capacity now**
- **The 2024 budget increases represent increases that explicitly support the clean energy transition** through:
  - Addressing the expanding interconnection queue and related FERC interconnection order
  - Investments in cloud capabilities to support data requirements for increased number of resources
  - Incorporating hybrid, storage, renewable, and smaller generating assets into ISO markets
  - Assessment of a conceptual framework for a prompt/seasonal capacity market
  - Assessment and implementation of tools for improving ISO capabilities for modeling and maintaining situational awareness of distributed and limited energy resources and changing load behavior
  - Increasing granularity of weather forecasting for weather-dependent resources
  - Supporting states' policy/project preferences & NEPOOL prioritization process
  - Addressing forthcoming FERC order on long-term transmission planning for asset condition-based replacement and future-sizing of the transmission system
  - Developing and retaining in-demand skillsets for IT advancements and for clean energy transition
  - Commensurate increases to ISO support staff to ensure continued efficient operations

Clean Energy Transition and Adjustment to Salaries

Addressing the clean energy transition is impacting all aspects of industry nationwide, leading to a **tight labor market; inflation is also impacting new and existing employees' compensation expectations**

- **Addressing inflationary effects and increased competition in labor market:**
  - For many years, the ISO's annual budgets have focused on creating efficiency through keeping expenses and headcount flat, which has caused the organization to fall behind in offering competitive salaries
  - The ISO engaged the consulting firm, Mercer, to conduct a 1-for-1 job-specific market competitiveness analysis in addition to our historical national compensation surveys to ensure we have the data needed to budget and offer competitive wages for staff
  - The ISO expects continued upward pressure on compensation with remote flexibility creating additional opportunities for highly-valued talent

2024 FTE Additions to Address the Clean Energy Transition

- As the clean energy transition is taking hold, **ISO is experiencing a step-change in work** to enable/support the changing resource mix:
  - Associated operational/market design complexity; FERC directives; and related state and participant work requests
- In 2024, the ISO needs to continue ramping up headcount to address the increased system complexity presented by the changing resource mix
  - To support the objectives of the Four Pillars of the clean energy transition and to continue making progress on the ISO's strategic goals, there are 41 proposed FTE additions in 2024
  - 35 of the 2024 FTE additions, or 85%, are related to the clean energy transition, spread across departments
- Budget increases for 2024 are in-line with the observed trends of other ISOs and ISO-NE management believes it is taking a measured, gradual approach to a major shift in the energy industry

2024 BUDGET OVERVIEW

2024 Budget Overview

- There are **three key drivers supporting the proposed 2024 budget increase** (see further details on the following slides):
  - Continued preparation for the clean energy transition
  - Inflationary and continued operations increases
  - Net change in revenue requirement true-up
- The 2024 Proposed Budget reflects the resources needed to support the clean energy transition and to continue carrying out the work to fulfill ISO's mission and continuing operations
- The proposed 2024 revenue requirement *before true-up* is $277.1M, an increase of 15.4% over 2023, including the net true-up of $11.6M, the total revenue requirement increase is 21.5% year over year

Note: Throughout the presentation some schedules may appear inconsistent due to rounding.

2024 Budget Overview *(cont.)*

Changes Compared to Preliminary (Top-Down) Budget presented in June

- The proposed 2024 budget presented today is the bottom-up detailed budget (prepared with input from each ISO business unit and refinements to preliminary estimates), compared to the top-down budget presented in June (that included preliminary estimates); the detailed bottom-up budget resulted in a $(0.1) million decrease compared to the preliminary top-down version; key changes consist of:
  - A $(0.9) million reduction in Depreciation Expense due to adjustments to capital project spending for which project in-service dates impacted this line item
  - $0.8 million added for Computer Services upon refinement of details in the bottom-up budget
    - Increases include maintenance costs on capital project additions (primarily related to Cyber Security), a tool for Transmission System congestion management, and for various additional licensing needs
  - Other changes that net with each other include:
    - Professional Fees increases to address ISO-NE's decreased spending power from the combined effects of inflation and scarcity of in-demand skillsets, these were offset by partial estimated reductions in funding for the assessment of a Prompt Seasonal Capacity Market and Transmission Planning study work
    - Small dollar adjustments across several other line items

For the ISO to Meet Region's Objectives for Transitioning to Clean Energy, a Significant Investment is Required in the Near-Term

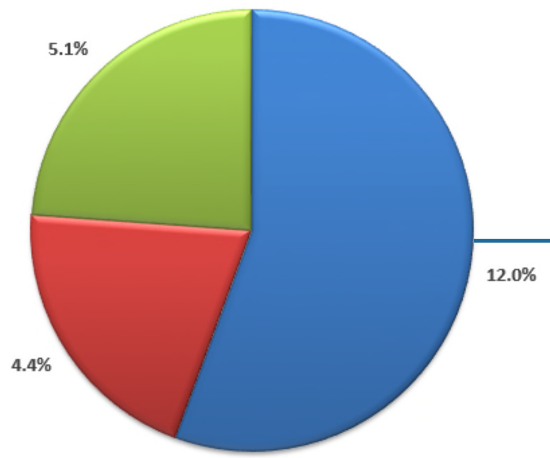
There are three main drivers for the increases to the 2024 ISO budget.

1. Adding full-time employees (FTEs) and other resources to address work directly related to the transition to clean energy and related indirect support
2. Inflationary and continued operations drivers:
   - "Catch-up" on salary increases to retain and attract employees by keeping pace with labor market
   - Additional investment in information technology (IT) to address inflationary and renewal costs for IT infrastructure and licensing, cybersecurity, and the transition to cloud-based infrastructure
3. Net change in the annual revenue true-up

Driver	Increase as a % of Total Revenue Requirement	$ Amount
Clean Energy Transition	4.4 %	$ 9,952,500
Inflationary/ Continued Operations	12.0 %	$26,941,400
Net Change in Rev Req True-Up	5.1 %	$11,582,500
Total:	**21.5 %**	**$48,476,400**

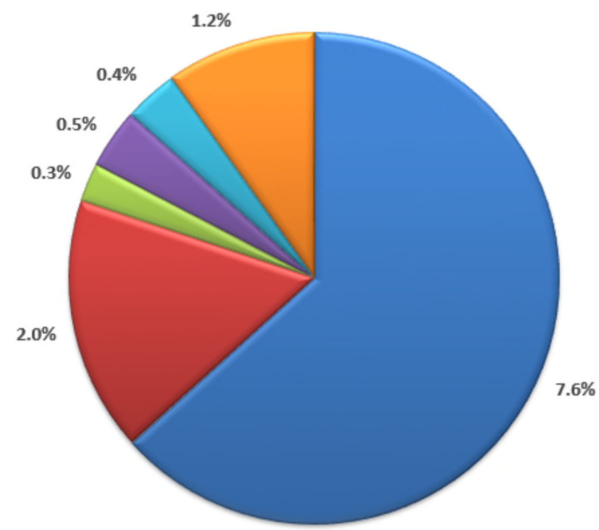
Key Drivers to the 2024 ISO-NE Budget

Key 2024 Budget Drivers



- 12.0% Inflationary/Continued Operations
- 5.1% Net Change in Rev Req True-Up
- 4.4% Clean Energy Transition

Inflationary/Continued Operation Budget Impact Components



- 7.6% Adjustments to Current Employee Salaries
- 2.0% Computer Services
- 0.3% FTEs for Continuing Operation Support
- 0.5% Professional Fees
- 0.4% NPCC/NERC Dues
- 1.2% Other

Continued Preparation for the Clean Energy Transition

- Continued preparation for the clean energy transition requires the ISO to maintain current operations (markets, grid, and systems) while incorporating new models, redesigning and implementing new systems, and planning the transmission systems for the new mix of clean energy resources
  - Resources for market design focused on forward market overhauls for Resource Capacity Accreditation and assessments for auction format (prompt-seasonal); Day-Ahead Ancillary Services; Forward Capacity Market evolution and parameter updates; and Inverter-Based Resources
  - Will require utilization of the nGEM system for the next generation of the markets
  - Market & Credit Risk must design collateral requirements for the evolving markets and continually perform risk assessments for sufficiency
  - Funding will also include professional fees and computer services to support the continuing efforts towards the region's transition to high levels of renewable and distributed resources while maintaining a robust fleet of balancing resources
  - Improving power system modeling capabilities for both reliability and planning
  - Integrating new and enhanced systems for the Clean Energy Transition, reflecting the increasing levels of Distributed Energy Resources and Inverter-Based Resources
  - Depreciation Expense is also budgeted to increase in 2024 due primarily to the 2023 mid-year go-live of the nGEM Market Clearing Engine Implementation project resulting in a full year of depreciation expense in 2024
- 35 of 41 FTEs proposed for 2024 (with funding allocated throughout the year*) are to address the Clean Energy Transition

***See slide 67 for details on FTE funding impacts with allocating FTE additions throughout the year.**

Inflation and Ensuring Continued Operations

- Address Employee Salaries and Recruiting Efforts:
  - Increased funding to align employee compensation in a tight labor market and to reduce turnover rates, particularly employees with mid-range experience (5-10 years) fulfilling critical roles, funding to reflect the impact of job specific benchmarking to level set the base salaries commensurate with the market, for incentive compensation to align with market, and for increases to expand recruiting efforts (within the industry and the broader market)
    - 8.0% increase (in 2024) for the annual merit and equity/promotion budgets (4.0% targeted for annual merit and 4.0% for standard and targeted equity/promotions); and the full-year impact of additional targeted equity increases given in 2023 (2.0%), that were funded primarily by the CEO emerging work allowance during 2023
      - The past several years have been challenging in hiring and retention requiring the ISO to offer higher salaries to attract and retain employees
      - The ISO has been conducting compensation studies in phases to determine the appropriateness of compensation in roles across the organization; phase I was completed in 2023 with compensation increases funded by the emerging work allowance as noted above; compensation increases resulting from the results of the future study phases will be funded, as needed, in the 2024 budget
    - Increases for employee incentive compensation target amounts including adjustments based on compensation study review
  - Funding for recruiting related costs including relocation and recruiter fees

Inflation and Ensuring Continued Operations *(cont.)*

- Computer Services and Cyber Security Technology:
  - Providing additional resources to continue efforts to combat cyber security threats that have become more complex and frequent
  - Moving forward with technology shifts to utilize increased levels of cloud infrastructure and virtualization technology in a coordinated manner to improve performance while maintaining IT system reliability
  - Impacts of supply chain pressures and inflationary increases in procuring IT assets, renewal costs for IT licensing, and maintenance support
- A net increase of three consultant FTEs to augment staff in the area of Cyber Security; and various other increases including inflationary and rate increases across our consulting structure
- NPCC and NERC Dues which are increasing by 14.3% and 11.6%, respectively, due to many similar reasons as ISO-NE budgetary increases, including reliance on technology professionals and tools, decarbonization initiatives, cyber risks, criteria evaluation activity, and recruiting and retention of technically skilled employees
- Inflationary increases (in 2024) for other line items including Insurance Expense, Utilities, Network Operations, Data Services, Meetings and Related expenses, and Employee Training

2024 Budget Overview *(cont.)*

- The 2024 Capital Budget is also presented in summary form
  - Beginning in 2022 the capital budget has increased by $7M over the $28M budget that had been in place for several years through 2021
    - The increased capital budget need is being driven by four primary drivers as explained in further detail Slides 68 through 73
    - The increased capital spending will result in higher interest expense costs and depreciation expense in future years as capital projects go into service and are included in budgets and rates
  - The 2024 Capital Budget is an increase of $1.5 million from the 2023 Capital Budget
  - The 2024 proposed capital budget of $35.0 million is provided with a list of projects by strategic goal that are currently chartered and on-going or in planning/conceptual design (See Slides 76-79)

2024 Budget Process – Key Dates

- The ISO reviewed the 2024 proposed Operating and Capital Budgets:
  - With the NEPOOL Budget & Finance Subcommittee on August 11; for further detail on ISO-NE's 2024 budget, please see the presentation provided to the NEPOOL Budget & Finance Subcommittee at the August 11, 2023 meeting; the presentation can be found at: 6_isone_2024_proposed_op_cap_budget.pdf (iso-ne.com)
- With State Agencies on August 11
  - State Agencies submitted questions on ISO-NE's proposed budget on August 18
  - ISO-NE responded to State Agencies' questions on August 25; ISO-NE's responses to the State Agencies' questions can be found under the budget section on ISO-NE's website at: Budget (iso-ne.com)
  - State Agencies may submit comments regarding any proposed adjustments to the proposed budget by September 5
  - The ISO-NE Board of Directors will review the budgets, stakeholder feedback, and State Agencies' comments on September 14
  - ISO-NE responses to State Agencies' comments and proposed adjustments are due on or about September 21
- Review 2024 proposed Budgets at the September 14 Board of Directors Meeting, as noted above, with submitted State Agencies' comments
- NPC vote on the ISO-NE 2024 proposed Budgets at the October 5 meeting
- ISO New England Board of Directors vote on the 2024 proposed Budgets after the NPC vote
- ISO New England filing of 2024 Budgets with FERC on or about October 13

2024 Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2024	% Change	2023	% Change	2022	% Change	2021	% Change	2020
Operating Budget Before Depreciation	$244.5	16.9%	$209.2	10.7%	$189.1	5.8%	$178.6	1.8%	$175.4
Capital Budget	35.0	4.5%	33.5	4.7%	32.0	14.3%	28.0	0.0%	28.0
Total Cash Budget	**$279.5**	**15.2%**	**$242.7**	**9.8%**	**$221.1**	**7.0%**	**$206.6**	**1.6%**	**$203.4**
Operating Budget Before Depreciation	$244.5	16.9%	$209.2	10.7%	$189.1	5.8%	$178.6	1.8%	$175.4
Depreciation	$32.6	5.1%	31.0	19.1%	26.0	(1.2)%	26.3	0.2%	26.3
Revenue Requirement Before True-up	277.1	15.4%	240.2	11.7%	215.1	4.9%	205.0	1.6%	201.7
True up	(3.0)		(14.6)		1.1		0.2		(2.9)
Revenue Requirement	**$274.1**	**21.5%**	**$225.6**	**4.4%**	**$216.1**	**5.4%**	**$205.1**	**3.2%**	**$198.8**
Forecast – TWhs (1)	**140.7**	**(1.6)%**	**143.0**	**(1.0)%**	**144.4**	**(2.0)%**	**147.4**	**1.0%**	**145.9**
$/KWh Rate	**$0.00195**	**23.5%**	**$0.00158**	**5.4%**	**$0.00150**	**7.5%**	**$0.00139**	**2.1%**	**$0.00136**
Average Monthly Consumer Cost (2)	**$1.46**		**$1.18**		**$1.12**		**$1.04**		**$1.02**

(1) 2024 Forecast based on May 2023 CELT Report (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

(2) Based on average consumption of 750 kWh per month.

Note: Throughout the presentation some schedules may appear inconsistent due to rounding of amounts.

2024 STRATEGIC GOAL INITIATIVES

2024 Initiatives: Responsive Market Designs

Ensure sufficient balancing resources to support reliability

1. Assess options for Alternative FCM Commitment Horizons (Prompt/Seasonal)
2. Continued work on Resource Capacity Accreditation
3. Implement Day-Ahead Ancillary Services
4. Implement FCM Reforms in advance of FCA 19 (Bid Flexibility & Return to Service; File FCM Parameters updates supporting MOPR Reforms)

Integrate distributed and storage assets into ISO markets

1. Develop business requirements and software design for Order No. 2222

Other Initiatives:

1. Implement Inventoried Energy Program (winters of 23/24 & 24/25)
2. Design storage modeling market enhancements

2024 Initiatives: Progress and Innovation

Improve modeling for emerging technology resources

1. Implement nGEM Real-Time Market Clearing Engine
2. Enhance data collection for co-located and hybrid resources to improve modeling/visibility
3. Improve modeling and validation to integrate inverter-based resource models

Develop forecasting and load-management solutions for weather-dependent resources

1. Load, Solar, Wind Forecast Improvements – Seeks to improve the wind, solar, and load forecasts through a continuous improvement method including more sophisticated forecast models, increasing the number of weather stations
2. Distribution congestion management
   - Develop a plan for aggregators that will be critical for Order 2222 implementation and settlement-only resource (SOR) enhancements or elimination

2024 Initiatives: Operational Excellence

Continue to modernize IT assets, technologies, and tools to mitigate cybersecurity threats

1. Modernizing tools for escalating cybersecurity threats
2. IT Asset Workflow (ITAW) Integration and Updates
3. IT Support for specific projects (e.g., market design evolution; enhancements to system operator situational awareness/modeling tools)
4. Cloud Computing

Assess near-term impacts of BTM and DER resources on the distribution system

1. Assess voltage issues related to minimum loads
2. Assessing solutions for legacy distributed energy resources tripping on the distribution system

Implement internal process and technology improvements to address increasing grid complexity

1. Enhance reliability assessment software and processes to reflect uncertainty of intermittent resources, energy storage, and hybrid resources
2. Coordinate with PJM and NYISO to initiate study on 1,200 MW single source limit
3. Report on evaluation of tie-benefits to Power Supply Planning Committee
4. Develop and test software for planned 2025 implementation of ambient adjusted line ratings (per FERC Order 881)

2024 Initiatives: Stakeholder Engagement

Working with stakeholders on power system needs for the Clean Energy Transition

1. Extended Term/Longer Term Transmission Planning Phase 2
2. Assist States with RFPs for transmission proposals
3. Coordinate asset replacement for the clean energy transition

Provide high-quality services to stakeholders

1. Finalize Communication Plan in support of ISO Initiatives
2. Survey stakeholders' satisfaction for ISO services

Assessing energy adequacy solutions for the clean energy transition

1. Support the ongoing development of initiatives that promote and ensure energy adequacy in the region (EPRI follow-up)
2. Implementation of Economic Planning for Clean Energy Transition (EPCET)

2024 Initiatives: Attract, Develop, and Retain Talent

Maintain Competitiveness in Labor Market

1. Advance competitive pay benchmarking and associated salary adjustments and structure
2. Continue critical talent retention strategies inclusive of pay, development, and succession planning
3. Additional investment in early career talent - intern, rotation, and network programs
4. Improve employee experience- onboarding, coaching and development, flexible work (hybrid)
5. Deliver competitive benefit programs with a focus on emotional, physical, and financial wellness

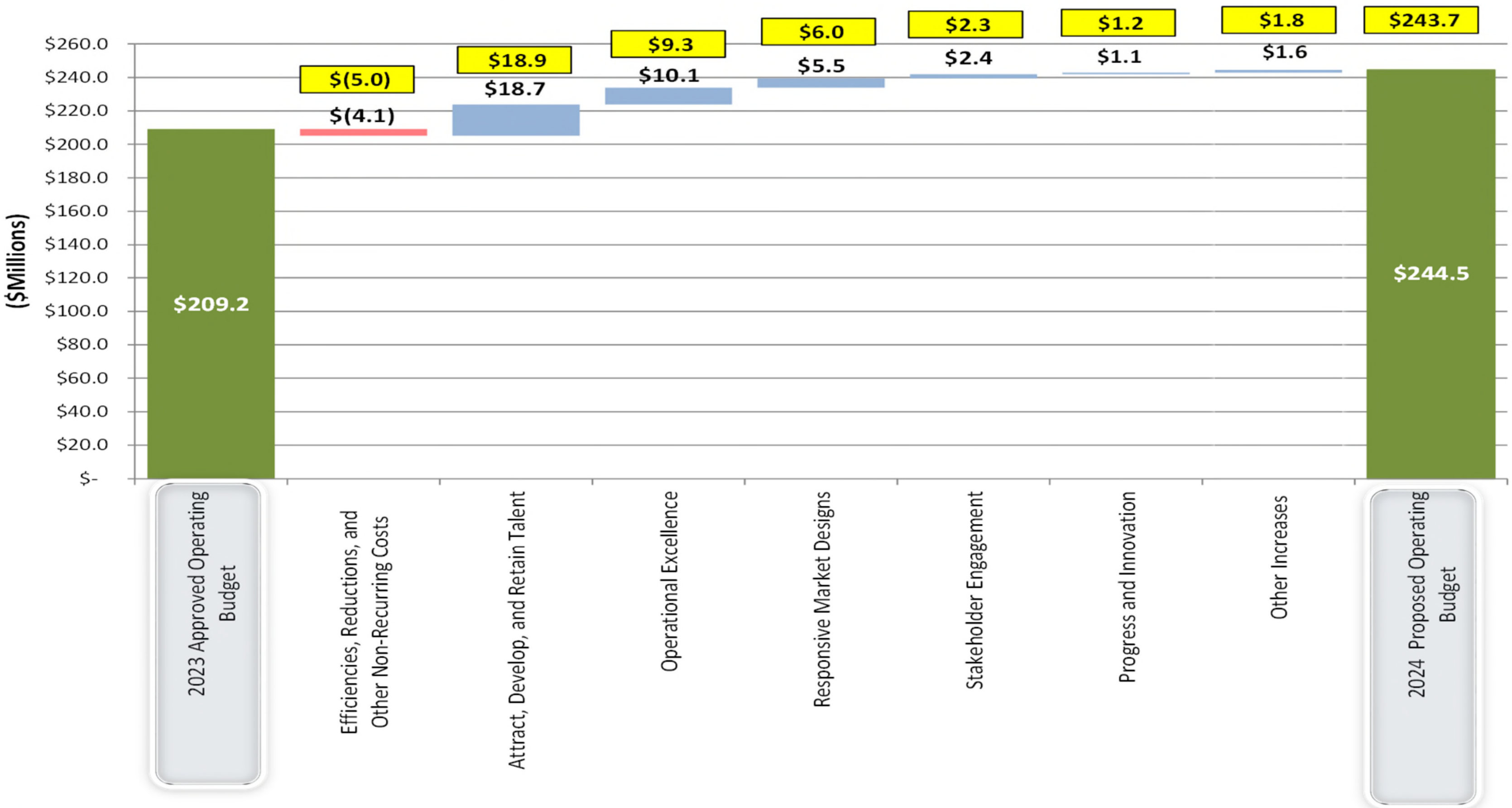
Support the Professional Development of the ISO Workforce

1. Advance Diversity and Inclusion- raising awareness, employee networks, reducing bias
2. Meet identified training needs through design and delivery of all mandatory and requested training
3. Effectively administer all HR core processes to achieve required results- annual/interim performance review process, development plans, etc.
4. Refresh and administer HR policies and programs
5. Operations training for departments beyond control room

2024 Detailed Budget Changes by Strategic Goal

2024 Budget

Changes in budget by Strategic Goal



Note: Items in yellow above represent the estimate that was included in the 2024 preliminary budget presented in June 2023.

2024 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($4.1M)

- Reduction from non-recurring markets study work, including Future Grid Phase II study; Inventoried Energy Program; and Day-Ahead Ancillary and FCA 19 Parameter update reviews
- Reductions for Resource Capacity Accreditation Parameters and Design, and Pathways Study Phase II work (Pathways Study Phase II work will be included in EPCET effort)
- Reduction for Mystic Cost of Service agreement fuel supply management work with agreement ending in mid-2024
- 2050 Transmission Study Work to be completed in 2023
- A forecasted increase in Interest Income due to rates and settlement account balances
- Reduction for participant proposal support work to largely be covered by internal staff
- Reduction in board of director related expenses: No board search required in 2024 based on current turnover dates and non-recurring board evaluations in 2024
- Information Technology patching staff augmentation to be covered by internal staff
- Transmission Planning and Analysis tool maintenance absorbed by internal staff
- Reduction in communications campaign work in 2024, with funding only included for periodic updates

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 5: Attract, Develop, and Retain Talent: $18.7M

- Merit and Promotion increases: for annual merit (4.0%) and for standard and targeted equity/promotions (4.0%); 2.0% impact for additional targeted equity increases in 2023 that were funded primarily by contingency funding during that year that will have an impact on 2024 budget ($14.1M)
- Increase for employee incentive target amounts including adjustments based on compensation study review ($2.6M)
- Increases in employee benefit costs, primarily for increased number of employees in Defined Contribution Benefit Plan and payroll taxes ($0.8M)
- Higher recruiting related expenses including relocation, recruiter fees, and background checks ($0.4M)
- 2.5 FTEs for early career technical talent FTE's to meet future talent needs with continued investment in attracting, developing, and retaining talent ($0.3M)
- Increase of intern program funding for both number of interns and higher pay rates ($0.3M)
- 0.75 FTE in Human Resources for talent program manager to lead and support the design and improvement of HR programs ($0.1M)
- Increase in board member retainers based on compensation firm recommendation ($0.1M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 3: Operational Excellence: $10.1M

- Computer Services infrastructure increases for operating system support including extended coverage for unsupported versions while completing the version upgrades; additional backup storage needs; for backup recovery software; and for additional virtualization licensing ($1.2M)
- Professional Fees to support Information Technology reliability and cyber defenses including the development of a cyber security framework, an engineer to support cyber security network monitoring and detection software, increases for cyber related social engineering assessment work, and a network reliability engineer ($1.0M)
- Support for a regional study with PJM and NYISO for 1,200MW single source contingency limit appropriateness and determine upgrades required to support 2,000MW single source limit ($0.9M)
- Increases for application maintenance on new products including those for Cyber Security, Information Technology Infrastructure, and Information Technology Architecture and Development ($0.8M)
- Professional Fees for Distributed Energy Resource and minimum load studies for assistance in determining requirements on how to ensure reliability on the system under conditions where the system is powered solely by inverter-based resources ($0.5M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 3: Operational Excellence: *(cont.)*

- Computer Services cyber security costs for cloud enterprise software to provide visibility and management of the growing portfolio of SaaS applications and for impacts of increased cyber security tool enhancements ($0.5M)
- Increases for various other Computer Service costs across multiple areas including Enterprise Application Support and Architecture & Data Governance ($0.4M)
- 1.25 FTE in IT Cyber Security support to address threats quickly and the addition of identity and access management functions, ransomware concerns, and additional monitoring for cloud technologies ($0.2M)
- 1.0 FTE in IT Enterprise Application Support for settlements support due to Day-Ahead Ancillary Services and Resource Capacity Accreditation projects and for continued integration and delivery of new software products ($0.2M)
- Increases in various software products due to licensing needs to accommodate the ISO’s larger workforce ($0.1M)
- Building Services increases for facility updates and cyclical maintenance ($0.1M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 3: Operational Excellence: *(cont.)*

- Power System Modeling license increase due to software vendor no longer providing product discount ($0.1M)
- 1.0 FTE in Strategy, Risk, and Operations Compliance to support ISO-NE resiliency program ($0.1M)
- 1.0 FTE in Internal Audit primarily to support Information Technology, Cyber Security, and CIP related audits ($0.1M)
- 0.75 FTE in Information Technology Infrastructure to alleviate understaffing pressures that impact the whole organization as new technologies are implemented ($0.1M)
- 0.75 FTE in Participant Relations & Services to continue effort to convert in-person training and webinar modules to self-paced micro-learning modules that provide time and cost savings to the ISO and participant companies ($0.1M)
- 0.5 FTE in Advanced Technology Solutions for re-architecting and deployment of Integrated Market Simulator in cloud environment ($0.1M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 3: Operational Excellence: *(cont.)*

- 0.5 FTE in Resource Qualification for increased workload of RCA requirements starting with FCA 19 (increased qualification steps and activities, fuel contracting reviews, and customer interactions and training) ($0.1M)
- 0.5 FTE in IT Energy Management Systems to support development as multiple markets related projects progress ($0.1M)
- 0.5 FTE in IT Architecture to support critical Market Monitoring analytics data management platforms ($0.1M)
- Professional Fees to support the enhancement and utilization of Human Resource systems including employee benefit program applications ($0.1M)
- Funding for market software algorithm certifications to provide parallel testing as the ISO transitions to a new vendor performing this work ($0.1M)
- Reallocation of 0.5 FTE to support Transmission Planning and Analysis tool maintenance ($0.1M)
- Inflationary increases for Computer Services and Network Operations costs for which the ISO has seen a steep increase across our portfolio of products ($1.8M)
- Other increases primarily inflationary, and rate increases for staff augmentation consulting, utilities and building maintenance, meetings and related expenses and training, and data services ($1.2M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 1: Responsive Market Designs: $5.5M

- Consulting support for assessment of Prompt Seasonal Capacity Market and Resource Capacity Accreditation market mechanisms ($2.5M)
- Funding for FCA 21 Cost of New Entry (CONE) parameter updates ($0.8M)
- 3.0 FTEs in Market Development to support continued market design and development of RCA, Day-Ahead Ancillary Services, Forward Capacity Market (FCM) evolution and parameters, and the integration of renewable resources in market designs ($0.7M)
- 2.0 FTEs in Market Development for integration of distributed energy resources, and large scale storage resources including batteries ($0.4M)
- 1.0 FTE in Energy Management Systems for integration and utilization of nGEM as market mechanisms get built into the system and to ensure a market structure that will support clean energy and reliability throughout the green energy transition ($0.3M)
- Consulting support for build out of new margin model for Real-Time, Day-Ahead, and Prompt Seasonal Capacity Markets ($0.2M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 1: Responsive Market Designs: *(cont.)*

- 1.0 FTE in Market & Credit Risk for developing, designing, and testing the risk-based adequacy of market participant collateral obligations and supporting implementation of new Market Development projects ($0.2M)
- 0.5 FTE each in Advanced Technology Solutions related to the development of market design and in Planning Services due to workload related to RCA and increased use of probabilistic analysis in projects ($0.2M)
- 0.5 FTE in IT Application Software Development to add software development staff to contribute to the Day Ahead Ancillary Services and Resource Capacity Accreditation projects ($0.1M)
- 0.25 FTE in Resource Adequacy to support work including: Order 2222 and requirements related to a new resource category; additional qualification reviews regarding Sponsored Policy Resources as a result of the MOPR removal; and qualification changes related to Resource Capacity Accreditation ($0.1M)

Note: FTE counts in this section and in blue font are net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 4: Stakeholder Engagement: $2.4M

- To provide support for New England States' requests ($0.9M)
- Funding for a medium term energy adequacy assessment ($0.5M)
- Funding for a Maine Interconnection Cluster Study ($0.2M)
- 1.0 FTE in Participant Relations & Services to assist in the gathering, managing, and supporting the assessment of participant proposals/requests for the ISO's Annual Work Plan ($0.2M)
- 1.25 FTE in Transmission Planning resources to support expected increases in transmission RFPs, to move project work forward (document RAS limitations, load interruption thresholds), and support stakeholder requests for long-term transmission studies ($0.2M)
- 1.0 FTE in Corporate Communications for communications on initiatives, projects, issue positions, emergency communications, and other related regional efforts ($0.1M)
- 0.5 FTE in Market Development for efforts on energy adequacy that may require significant assessment and novel market initiatives ($0.1M)
- 0.5 FTE in Transmission Services to support volume increases in the interconnection queue ($0.1M)
- 0.25 FTE in Planning Services to accommodate evolving economic study needs and environmental outlook efforts ($0.1M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Goal 2: Progress and Innovation: $1.1M

- 1.5 FTE in Power System Modeling - the increase of renewables, storage, and DERs in the region has resulted in a significant increase in the demand for power system modeling – both for reliability and planning purposes ($0.3M)
- 1.0 FTE in Planning Services for evolving forecast needs and increased complexity/risk associated with the industry's clean energy transition ($0.2M)
- 0.75 FTE in IT Architecture for leveraging cloud technology benefits, including greater agility and reduced time to deploy infrastructure, infinitely scalable computing performance, and reduced hardware maintenance ($0.2M)
- 0.75 FTE in Advanced Technology Solutions for research and development needs in advanced modeling and simulation of inverter-based resources, probabilistic planning and operations, impact of climate change and extreme weather on power system reliability, and the development of a more efficient market clearing algorithm ($0.1M)
- 0.5 FTE in Market Development for continuing work on integration of DERs and large scale storage integration ($0.1M)
- 0.25 FTE in Transmission Services to support increased requirements to review, validate, and integrate inverter-based resource models ($0.1M)
- Increase in Computer Services for higher utilization and related fees for cloud storage through Amazon Web Services ($0.1M)

Note: FTE counts in this section and in blue font are the net funded amount for the 2024 budget which is 29. FTE counts on Slides 64 through 66 (equaling 41 FTEs) are proposed gross additions.

2024 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2024 Initiatives

Other Increases: $1.6M

- The allocation of NPCC and NERC dues ($1.0M)
- An increase in Interest Expense and fees due primarily to an increase in borrowings on the working capital line resulting from increases in the operating and capital budgets ($0.3M)
- Corporate insurance policy premium increases ($0.3M)

2024 BUDGET RESOURCING NEEDS

2024 Budget Resourcing Needs

Repurposed Positions

- The ISO evaluates each position that becomes vacant to determine the continued need in that area and for possible repurposing for use in other areas of the organization
  - Since 2018 this has resulted in 34 positions, including 5 to-date in 2023, being repurposed for other work where a more urgent need existed
  - Positions repurposed since 2018 include: 8 for Information Technology for Software Development, Cyber Security, Power System Modeling, Application Support, Infrastructure and Digital Transformation; 6 for System Operations & Market Administration for Energy Security, Asset Registration & Auditing, Control Room Operations, and Operations Training; 6 for Market Development analysis and market design work; 4 for Human Resources for recruiting support and to replace contract positions; 2 for Advanced Technology Solutions; 2 for Market Monitoring; 2 for Market & Credit Risk; 1 for Load Forecasting to replace a contract position; 1 for Resource Studies & Assessments; 1 for Participant Support; and 1 for Corporate Strategy

2024 Budget Resourcing Needs *(cont.)*

In 2024 there are 41 FTE additions as follows:

	Clean Energy Pillar(s) (*)	Strategic Goal(s)
13.0 FTE's Information and Cyber Security Services		
Resources for Energy Management System; Power System Modeling; and Development for efforts including the nGEM system, the integration of increasing renewables, storage and distributed energy resources modeling and integration, and integration of Day Ahead Ancillary Services and Resource Capacity Accreditation projects. Resources for Cyber Security; IT Architecture to support leveraging cloud technologies; support for critical Market Monitoring analytics data management platforms; infrastructure support to alleviate understaffing pressures; and retaining the best early career technical talent to meet our future needs. (12 FTE's Support the Clean Energy Transition)	Clean Energy Resources; Balancing Resources	Operational Excellence; Responsive Market Designs; Progress and Innovation; and Attract, Develop and Retain Talent
12.0 FTE's System Planning		
Resources to support Resource Capacity Accreditation and use of probabilistic analysis, to accommodate evolving study and forecasting needs and increased complexity associated with the clean energy transition, a resource to support interconnection study requests, a resource for modeling and validation to integrate inverter-based resource models, resources to support expected increases in transmission RFPs, to address deferred projects due to a lack of staff (document RAS limitations, load interruption thresholds, etc.), support stakeholder requests for long-term transmission studies, to address forthcoming FERC order on long-term transmission planning for asset condition based replacement and future-sizing of the transmission system, and retaining the best early career technical talent to meet our future needs. (12 FTE's Support the Clean Energy Transition)	Clean Energy Resources; Balancing Resources; Robust Transmission	Stakeholder Engagement; Progress and Innovation; Operational Excellence; and Attract, Develop and Retain Talent

(*) See the Four Pillars of the Clean Energy Transition on Slide 13

2024 Budget Resourcing Needs *(cont.)*

In 2024 there are 41 FTE additions as follows: (cont.)

		Clean Energy Pillar(s)	Strategic Goal(s)
4.0 FTE's	**Market Development**		
	Resources for market design focused on forward market overhauls for RCA and assessments for auction format (prompt-seasonal); efforts regarding energy adequacy will likely require significant assessment and novel market initiatives; continued progress on integrating large-scale storage, intermittent, and distributed resources for the future grid transition. (4 FTE's Support the Clean Energy Transition)	Clean Energy Resources; Balancing Resources; Energy Adequacy	Responsive Market Designs; Stakeholder Engagement; Progress and Innovation
3.0 FTE's	**Participant Relations and Services**		
	Resources to continue effort to convert in-person training and webinar modules to self-paced micro-learning modules that provide time and cost savings to the ISO and participant companies; continue effort for the gathering, managing, and supporting the assessment of participant proposals/requests that the ISO will consider incorporating into our Annual Work Plans; and an additional resource to support NEPOOL committee meetings including expanded work for RCA in Power Supply Planning Committee. (2 FTE's Support the Clean Energy Transition)	Support	Stakeholder Engagement; Operational Excellence
3.0 FTE's	**Advanced Technology Solutions**		
	Resources for R&D needs in advanced modeling and simulation of inverter-based resources, probabilistic planning and operations, and impact of climate change and extreme weather on power system reliability; Re-architecting and deployment of Integrated Market Simulator in cloud environment; new market design to deal with increasing risk of operational uncertainty, investigation of energy adequacy definition/metrics, the development of a more efficient market clearing algorithm, and integration of new technologies. (3 FTE's Support the Clean Energy Transition)	Clean Energy Resources; Balancing Resources; Energy Adequacy	Progress and Innovation; Responsive Market Designs; Operational Excellence

2024 Budget Resourcing Needs *(cont.)*

In 2024 there are 41 FTE additions as follows: (cont.)

FTE	Description	Clean Energy Pillar(s)	Strategic Goal(s)
2.0 FTE	**External Affairs and Corporate Communications**		
	One resource to focus on marketing communications/graphics/employee communications (including support for Human Resources internal employee communications (diversity and inclusion)) and recruiting communications; and one resource to focus on environment policies and community affairs (See Note *) (1 FTE Supports the Clean Energy Transition)	Support	Stakeholder Engagement; Operational Excellence
1.0 FTE	**Market & Credit Risk**		
	Resource for developing, designing, and testing the risk-based adequacy of market participant collateral obligations and support the design, IT implementation, and risk reporting required for all new market development projects (IEP, Day-Ahead Ancillary Services, Distributed Energy Resources, Prompt Seasonal Capacity Market). (1 FTE Supports the Clean Energy Transition)	Clean Energy Resources; Support	Responsive Market Designs
1.0 FTE	**Strategy, Risk, and Operations Compliance**		
	Support ISO-NE resiliency program. Primary responsibilities will include the collection of data, analysis of information, and enhancements of plans related to Disaster Recovery for IT applications and related technology supporting essential company functions.	Support	Operational Excellence
1.0 FTE	**Human Resources**		
	For a Talent Program Manager to lead and support the design and improvement of HR programs including diversification of talent, employee advancement, succession planning, and business knowledge transfer.	Support	Attract, Develop, and Retain Talent
1.0 FTE	**Internal Audit**		
	Audit plan includes higher focus on IT and Cyber area including the nGEM implementations, Cloud Technology adoption, and data/cyber security testing; and the onboarding of Pennsylvania Power and Light to the ISO grid network requires additional IT and operations audit field work which will utilize audit resources and CIP readiness audits.	Support	Operational Excellence
41.0 FTE's	**Total 2024 Proposed FTE Additions**		

* Environmental policy and community affairs FTE is a placeholder as ISO-NE management evaluates the 8/1/2023 request from New England State Agencies and the responsibilities and role of this position

2024 Budget Resourcing Needs *(cont.)*

2024 Gross and Net FTE Funding

In budgeting for FTE additions the ISO has only partially funded new FTEs in the year they are authorized in the budget while deferring a portion due to length of time to recruit and onboard these additional positions. In the 2023 budget 9 FTE positions were deferred that are largely expected to be onboarded in 2024. For 2024 the gross FTE proposed additions are 41, and of those, funding of only 20 are included in the 2024 budget with the remainder deferred to the following year. See the table below to illustrate the deferment "layering" effect.

	FTE Impacts					$ Impacts			
	A	B	= A and B	C	= A and C	D $ Impact of A	E $ Impact of B	= D and E	$ Impact of C
Year	Net Current Year FTEs Budget	Previous Year FTEs Deferrals Included in Current Year Budget	Total Funded FTEs Included in Current Year Budget	Current Year FTEs Deferred to Following Year	Gross FTEs Authorized for Recruiting - Current Budget Year	Net Current Year FTE $'s	Previous Year FTEs Deferrals $ Impacts to Current Year Budget	Gross $ Impact to Budget	FTE Costs Deferred to Following Year
2023	23	5	28	9	32	3,885,600	867,000	4,752,600	1,733,700
2024	20	9	29	21	41	3,582,878	1,733,700	5,316,578	4,006,798
2025	TBD	21	TBD	TBD	TBD	TBD	4,006,798	TBD	TBD

Forward Looking Capital Budget Spending

Forward Looking Capital Budget Spending

- The capital budget over the next five years and beyond will continue to support the Company's strategic goals with specific focus on four primary drivers:
  – nGem platform (replacing the current market system)
  – Major market and reliability related efforts
  – Cyber security
  – IT asset and infrastructure replacement
- In order to achieve these goals, ISO has increased the capital spending over the last few years with spending of $33.5M in 2023, $35M in 2024 and projected increase to $40M in 2025 and beyond; the capital costs are dependent on various factors, including regulatory orders and approvals and the use of professional services or internal staff
  – The ISO will continue with its current practice of providing a rolling two-year look-ahead window

Forward Looking Capital Budget Spending *(cont.)*

nGEM Platform Replacement

- The nGEM program (next Generation Markets Management) will upgrade the core market software by supporting a system with a growing number and type of grid assets, new and more complex market features, multiplying security threats, and advancing IT technologies
  - GE Solutions is developing nGEM in collaboration with ISO-NE, MISO, and PJM; the portion of the software upgrade unique to each ISO will be funded by each ISO individually
- The ISO has been working, for the last few years, on the complex processes for customizing and implementing the day-ahead version of the new market clearing engine (MCE) software and infrastructure, which went into service in the middle of 2023
- The ISO expects to continue work on the next phases, which include a real-time version of the MCE; this work is expected to continue over the next few years with an estimated cost of up to $54M

Forward Looking Capital Budget Spending *(cont.)*
Major Market and Reliability Related Efforts

- The capital budget will support ISO's market design objective for 2024 and beyond of moving toward clean energy, balancing resources, energy adequacy, and robust transmission
- Many of these market and reliability projects are complex efforts that will have long lead times to complete and have dependencies of stakeholder and regulatory approval; the following projects have been identified for 2024 and beyond but may fluctuate depending on stakeholder/FERC priorities:
  - Day-Ahead Ancillary Services Improvements Design: This project seeks to develop market constructs for procuring and transparently pricing ancillary service capabilities needed for a reliable, next-day operating plan with an evolving resource mix; the ISO plans to develop day-ahead flexible response services to enable the system to recover from sudden source-loss contingencies and respond quickly to fluctuations in net load during the operating day
  - FERC Order 2222: The ISO will be building software systems to integrate distributed energy resources into the wholesale markets
  - Energy Storage Modeling: The ISO filed a set of enhancements with FERC to improve the modeling of energy storage in wholesale markets; the ISO plans to make substantial improvements to the modeling of storage over the next few years

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts *(cont.)*

- Significant Capacity Market Reforms: The ISO is currently assessing the feasibility of moving from a forward capacity auction construct to a prompt and seasonal capacity auction construct; this is a substantial scope of work that will better position the ISO to mitigate energy adequacy risks as the power system evolves
- Resource Capacity Accreditation (RCA): This is a major project that accredits resources on their marginal reliability contributions during reliability hours; this project is currently being discussed with stakeholders
- Transmission Line Ratings Enhancements: This project is in response to recent FERC orders and will require substantial IT and database work to collect and appropriately use data in planning and operations
- Market Simulator, 21 Day Energy Simulator, Inverter-Based Resource Modeling: There are various research and development efforts at the ISO that are expected to result in significant improvements to ISO modeling capabilities and situational awareness
- Stakeholder Priorities: The ISO has embarked on an improved prioritization process with stakeholders; each year, the ISO expects stakeholders to highlight three key priorities; some of these priorities will require the development of new software and associated applications
- Other Market Design Projects Identified in the ISO's Multi-Year Work Plan: The ISO plans to continue to make improvements to existing ancillary services and design new ancillary services products; new ancillary products may include replacement reserves and ramping products

• Based on the complexity of the projects, the ISO expects the cost for market and reliability efforts will range from approximately $45M - $65M over the next five plus years

Forward Looking Capital Budget Spending *(cont.)*

Cyber Security & IT Asset and Infrastructure Replacement

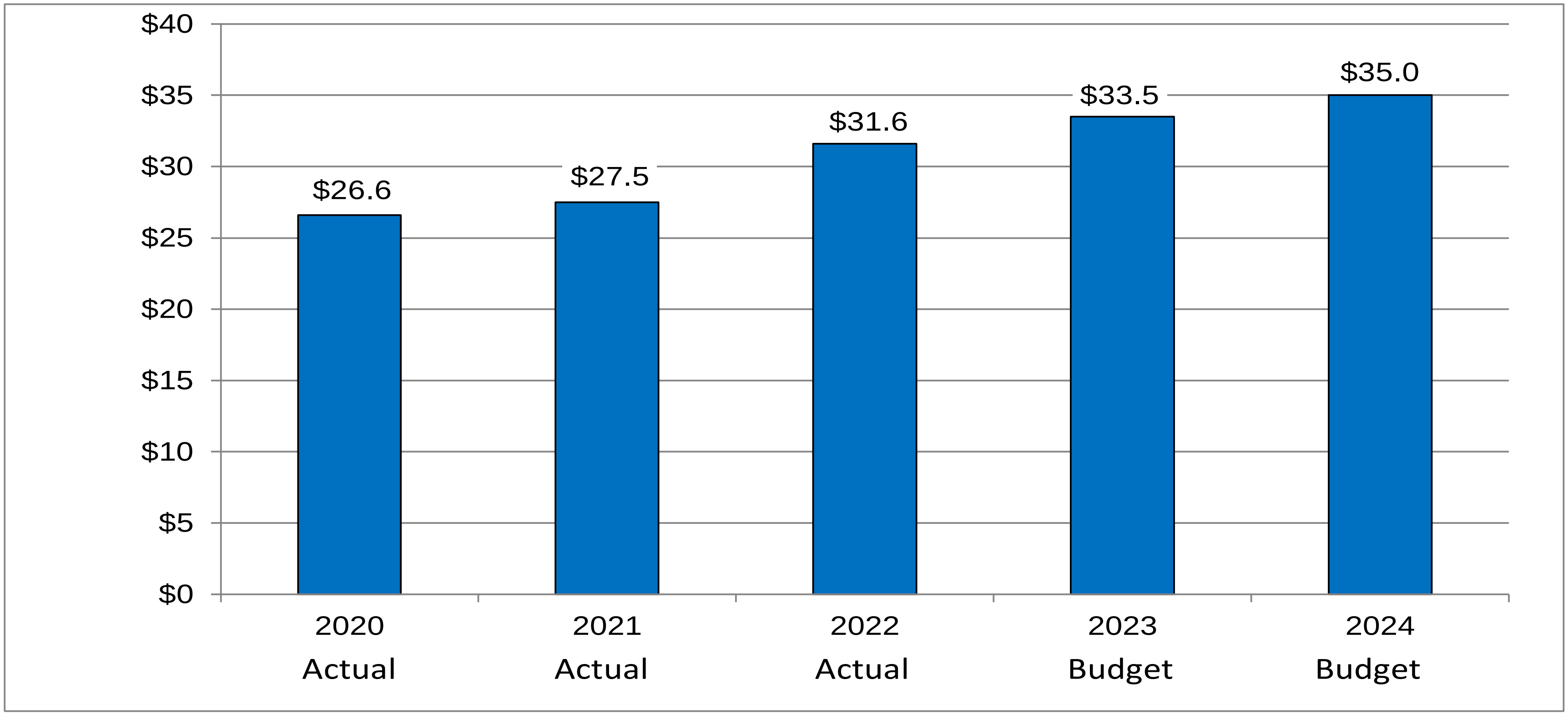
- Capital spending on improvements to cyber security and IT assets and infrastructure will support the ISO's strategic goals of Operational Excellence and Progress and Innovation
- The ISO expects that it will continue to invest capital funding in cyber security over the next 3-5 years by improved monitoring, detection, and recovery tools to keep pace with increasingly sophisticated attack threats
- The ISO's transition to a cloud environment began in 2022 and is expected to be a major capital effort over the next several years
  - Reliability of operating a modern system comprised of renewable and storage resources requires the processing, transfer, and storing of vast amounts of data; in multiple phases, the ISO will be implementing cloud-computing infrastructure and virtualization technology to reduce reliance on energy-heavy data centers and enable more dynamic expansion of computing capability, while maintaining reliability
- The cost for IT and cyber security initiatives will vary depending on the use of professional services or internal staff; the cost will range from approximately $20M - $40M over the next several years

CAPITAL BUDGET SUMMARY

Capital Budget

Historical Comparison Capital Expenditures

Average +/- $30.8M



Capital Budget
2024 Expenditures

Goal: Responsive Market Designs

Project	2024 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Day-Ahead Ancillary Services Improvements	$4.0M	$8.6M	3/25	Planning/Conceptual Design
FERC Order 2222	$0.5M	$7.4M	12/26	Planning/Conceptual Design
Resource Capacity Accreditation	$1.3M	$1.5M	12/24	Planning/Conceptual Design
Solar Do Not Exceed Dispatch Phase II	$0.9M	$1.8M	10/24	In Development
Total:	**$6.7M**			

Goal: Progress and Innovation

Project	2024 Budget	Total Project Cost	Estimated Completion Date	Project Stage
nGEM Real-Time Market Clearing Engine Implem. (see Note 1)	$7.0M	$16.9M	01/26	Planning/Conceptual Design
nGEM Software Development Part III (see Note 1)	$2.5M	$4.5M	03/25	In Development
Internal Market Monitoring Data Analysis Phase IV	$0.5M	$1.2M	05/24	In Development
Energy Management System Short-term Load Forecast Replacement	$0.4M	$1.2M	07/24	In Development
Total:	**$10.4M**			

Note 1: nGEM related projects will advance multiple goals including Responsive Market Designs, Progress and Innovation, and Operational Excellence. For purposes of this presentation, nGEM projects have been grouped under the Progress and Innovation strategic goal.

Capital Budget

2024 Expenditures *(cont.)*

- Goal: Operational Excellence

Project	2024 Budget	Total Project Cost	Estimated Completion Date	Project Stage
CIP Electronic Security Perimeter Redesign Phase II	$2.5M	$5.0M	12/24	Planning/Conceptual Design
Eterra Source Project	$2.2M	$2.7M	10/24	Planning/Conceptual Design
Enterprise Resource Planning System Replacement	$2.0M	$2.5M	03/25	Planning/Conceptual Design
Microsoft 365 Service Adoption	$1.3M	$1.4M	09/24	Planning/Conceptual Design
IT Asset Workflow Integration and Updates	$0.2M	$1.1M	05/24	In Development
2024 Issue Resolution Project	$1.0M	$1.0M	12/24	Planning/Conceptual Design
Replace Employee & Pager Application	$0.5M	$0.6M	08/24	Planning/Conceptual Design
Settlement Technology Improvements Project	$0.1M	$0.5M	03/24	In Development

Continued on Next Slide

Capital Budget
2024 Expenditures *(cont.)*

- Goal: Operational Excellence (*cont.*)

Project	2024 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Privileged Account Management Security Enhancements Phase II	$0.5M	$0.5M	12/24	Planning/Conceptual Design
Energy Management System Host Monitoring Software Replacement	$0.1M	$0.3M	01/24	In Development
Non-Project Capital Expenditures	$5.3M			
Total:	**$15.7M**			

Capital Budget
2024 Expenditures Summary

- 2024 Capital Budget Expenditure Summary

Allocation Category		2024 Budget
Goal: Responsive Market Designs		$ 6.7M
Goal: Progress and Innovation		$10.4M
Goal: Operational Excellence		$15.7M
Other Emerging Work		$ 0.7M
Capital Interest		$ 1.5M
	Total:	**$35.0M**

CAPITAL STRUCTURE AND CASH FLOW

Capital Structure and Cash Flow

- In order to support the markets and reliability efforts, ISO will increase the capital spending from $33.5M in 2023 to $35M in 2024 and $40M in 2025 and beyond
  - As noted last year and on slide 69 regarding Capital Budget Spending, the areas driving the increase in spending are dependent on various factors such as regulatory approvals, use of professional services versus internal staff, estimated range of spending, inflationary cost and longer lead times to complete
  - Longer lead time to complete capital projects results in a greater period of time from when the ISO spends capital funds to tariff recovery through depreciation expense of these projects
- Capital project costs are largely funded by $50M in Private Placement Notes set to expire in November 2024; in order to support the future capital program, we have determined that another $25M in available capital project funding is needed to support a higher sustained level of capital spend at $40M shown on the ten-year cash flow on the next slide

Capital Structure and Cash Flow *(cont.)*

The ISO will be going out to market in 2024 for $75M 10 year Private Placement Note to be issued and available by the time the $50M balloon payment on the current note is due in November. The Company has been advised that entering into a one time note at the higher dollar value will generate more interest within the market and will result in lower closing costs.

ISO New England
2023 - 2032 Debt Service Cash Flow

	2023 Forecast	2024 Budget	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
Cash flows from operating activities:										
Operating Cost Recovery *	$ 191,123	$ 233,004	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non Cash Items:										
Depreciation & Loss on Disposals	30,236	32,520	38,502	39,600	42,828	43,432	46,224	42,786	42,061	41,073
Amortization Land	39	39	39	39	39	39	39	39	39	39
Amortization Term Loan Fees	128	78	106	106	106	106	106	106	106	106
Chg in Accrued Expenses & Deferred Revenue-Depreciation	700	-	-							
Interest Expense	(2,838)	(3,382)	-	-	-	-	-	-	-	-
Operating Expenses *	(205,513)	(241,080)	-	-	-	-	-	-	-	-
Net cash provided by operating activities	13,875	21,179	38,647	39,745	42,973	43,577	46,369	42,931	42,206	41,218
Cash flows from investing activities:										
Capital expenditures	(33,500)	(35,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)
Net cash used in investing activities	(33,500)	(35,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)
Cash flows from financing activities:										
Net Proceeds/(Repayment) - Revolving Credit Line	-	-		2,000	-	(2,000)	-	-	-	-
Repayment of Principal - Private Placement	-	(50,000)	-	-	-	-	-	-	-	-
Proceeds - Private Placement	-	75,000		-	-	-	-	-	-	-
Repayment of Principal - Tax Exempt Bonds	(3,180)	(3,180)	(3,180)	(3,180)	(3,180)	(3,180)	(3,180)	(3,180)	(3,180)	(1,815)
Net cash provided by (used by) financing activities	(3,180)	21,820	(3,180)	(1,180)	(3,180)	(5,180)	(3,180)	(3,180)	(3,180)	(1,815)
Net increase/(decrease) in cash	(22,805)	7,999	(4,533)	(1,435)	(207)	(1,603)	3,189	(249)	(974)	(597)
Cash & Cash Equivalents on Hand - Beginning of Period	23,098	293	8,292	3,759	2,324	2,117	514	3,703	3,454	2,480
Change in Cash & Cash Equivalents Available	(22,805)	7,999	(4,533)	(1,435)	(207)	(1,603)	3,189	(249)	(974)	(597)
Cash & Cash Equivalents on Hand - End of Period	$ 293	$ 8,292	$ 3,759	$ 2,324	$ 2,117	$ 514	$ 3,703	$ 3,454	$ 2,480	$ 1,883
Debt Maturity Schedule										
Tax Exempt Bond - BCC	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360
Tax Exempt Bond - MCC	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	455
Total Year Repayment	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 1,815

*= Operating Cost Recovery for 2023 has decreased by an overcollection in 2021 of $14,589 which was not amortized in 2022 but included in the 2023 tariff. The overcollection from 2022 of $3,006 will be filed in the 2024 tariff and reflected in the Operating Cost for 2024. The Operating Cost Recovery for 2025-2032 is projected to offset Operating Expenses for 2025-2032. The Operating Cost Recovery amount for 2025-2032 has not yet been established at this point.

Capital Structure and Cash Flow *(cont.)*

- The ISO currently has a $20M working capital line which is set to expire on July 1, 2024; based on the projected 2024 cash flow on the next slide and increase spending in capital projects not covered by the $50M Private Placement Notes, the ISO has determined that additional working capital is required to meet its needs; the ISO will look to obtain a working capital line up to $40M which can be dropped back to $20M once the $75M private placement note is in place
  - Projected SOFR (Secured Overnight Financing Rate) plus negotiated basis points on our working capital line along with the unused fees will remain the same for the new working capital line
  - Projected rates for private placement note if obtained in 2023 would be higher than the projected SOFR rates for 2024
  - ISO will be filing 204 application with FERC in 2023 for the working capital line to be in effect March 2024
- For the six months ended June 30, 2023, the ISO's total weighted average cost of capital was 3.67%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

Capital Structure and Cash Flow *(cont.)*

2024 Budget
Cash Flow (000's)

	Jan Budget	Feb Budget	Mar Budget	Apr Budget	May Budget	June Budget	July Budget	Aug Budget	Sept Budget	Oct Budget	Nov Budget	Dec Budget	2024 Budget
Operating Cost Recovery (1)	14,166	15,652	20,617	18,729	18,571	16,157	18,509	22,426	25,404	25,691	19,894	17,189	233,004
Non-Cash Items:													
Depreciation	2,977	2,764	2,741	2,729	2,581	2,603	2,611	2,622	2,608	2,672	2,821	2,790	32,520
Amortization Land	3	3	3	4	3	3	4	3	3	4	3	3	39
Amortization Term Loan Fees	6	6	6	6	6	6	6	6	7	7	8	8	78
Chg in Deferred Revenue - Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
Chg in Accrued Expenses (2)			(14,143)	5,000	3,500							5,643	-
Interest Expense	(286)	(369)	(166)	(366)	(373)	(132)	(370)	(371)	(78)	(341)	(378)	(150)	(3,382)
Operating Expenses	(19,740)	(15,328)	(31,282)	(18,013)	(21,008)	(16,597)	(16,030)	(22,973)	(18,281)	(17,475)	(17,026)	(27,327)	(241,080)
Net cash provided by (used in) operating activities	(2,874)	2,728	(22,224)	8,089	3,280	2,040	4,730	1,713	9,663	10,558	5,322	(1,844)	21,179
Cash flows from investing activities:													
Capital expenditures	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(35,000)
Net cash used in investing activities	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(2,917)	(35,000)
Cash flows from financing activities:													
Net Proceeds/(Repayment) - Revolving Credit Line	6,500	-	26,000	(5,000)	-	1,000	(2,000)	2,000	(6,500)	(8,000)	(14,000)	-	-
Net Proceeds/(Repayment - Private Placement	-	-	-	-	-	-	-	-	-	-	25,000	-	25,000
Repayment of Principal (3)	-	(795)	-	-	(795)	-	-	(795)	-	-	(795)	-	(3,180)
Net cash provided by (used in) financing activities	6,500	(795)	26,000	(5,000)	(795)	1,000	(2,000)	1,205	(6,500)	(8,000)	10,205	-	21,820
Net increase (decrease) in cash	709	(984)	859	172	(432)	123	(187)	1	246	(359)	12,610	(4,761)	7,999
Cash & Cash Equivalents on Hand - Beginning of Period	293	1,002	18	877	1,049	617	741	554	555	801	443	13,053	293
Change in Cash & Cash Equivalents Available	709	(984)	859	172	(432)	123	(187)	1	246	(359)	12,610	(4,761)	7,999
Cash & Cash Equivalents on Hand - End of Period	1,002	18	877	1,049	617	741	554	555	801	443	13,053	8,292	8,292

(1) Monthly revenue recovery is based on the average of 2 years of historical data
(2) Assumed Balance Sheet items such as Accrued Expenses, Prepaids, Accounts Receivable & Accounts Payable would remain constant year to year.

(3) Debt Maturity Schedule	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	2024
Tax-Exempt Bonds for MCC ($45.5M)		455			455			455			455		1,820
Tax-Exempt Bonds for BCC ($36.0M)		340			340			340			340		1,360
Total Year Repayment	-	795	-	-	795	-	-	795	-	-	795	-	3,180

APPENDIX 1: COMPENSATION

Process for Establishing Salary Budget Increases

- Each year, ISO-NE reviews comprehensive salary budget planning data compiled by nationally-recognized compensation consulting firms
  - The firms we expect to use for 2024 are Mercer, WorldatWork, WillisTowersWatson, and the Conference Board
  - These surveys are typically published later in the summer and reflect planned salary budget increases of over 2,300 employers, including more than 100 utility companies
    - The data is presented by region, industry, and by employee group (executive, management, exempt, and non-exempt employees)
    - Salary budget data is further classified into two categories: merit increases and promotional/equity increases
- ISO-NE will also review expected salary increases of other ISOs/RTOs

Process for Establishing Salary Budget Increases *(cont.)*

- Merit Increases
  - Merit pools are the percentage of total employee salaries that companies intend to use for broad-based salary increases in the coming year
    - At ISO-NE, this pool funds the annual performance-based increases for eligible non-bargaining unit employees
    - Individual percentage increases vary based on employees' performance, with some receiving less than and some receiving more than the budget percentage
- Promotional/Equity Increases
  - Historically, a separate, much smaller pool of monies used in select circumstances to fund promotions and base salary adjustments for critical positions
    - At ISO-NE, this pool more recently has been increased to fund any required salary adjustments based on our benchmarking initiative and to allow for targeted compensation adjustments to enable us to retain key talent

Process for Establishing Salary Budget Increases *(cont.)*

- In 2022, to address competitive challenges related to the clean energy transition, particularly those specified on Slides 91 and 92, ISO engaged a compensation consulting film to conduct more discrete, 1-for-1 job-specific benchmarking to establish competitive rates of pay for our highly skilled and in-demand workforce
- Supplementing the salary budget survey data with job-specific benchmarking allows us to better ensure that we are providing competitive rates of pay to our current employees, as well as attracting the necessary talent to be successful in the future
  - In 2022, we assessed compensation levels for our most technical engineering and IT roles, approximately 1/3 of our organization
  - In 2023, we are assessing another 1/3 of the organization, with continued focus on IT and other roles requiring significant technical expertise
  - Later in 2023 or in early 2024, we plan to assess the remainder of the roles in the organization

Process for Establishing Salary Budget Increases *(cont.)*

- A summary of the survey results and management's recommendation is presented to the Compensation and Human Resources Committee of the Board of Directors
  - The Committee reviews the data at its September meeting and establishes the annual merit and promotional/equity adjustment increase percentages
- The table on the next slide compares annual survey data to ISO-NE's budgeted increases for the past ten years

ISO New England Salary History

Comparison: Survey Data to ISO New England Salary Increase Budgets						
Year	*Merit Increase Budgets* *(survey results represent averages of all participating companies)*			*Promotion/Equity Increase Budgets* *(survey results represent averages of all participating companies)*		
	Survey Results		ISO-NE Budget	Survey Results		ISO-NE Budget
	Utility Industry	General Industry		Utility Industry	General Industry	
2024	Not yet available	Not yet available	**4.0%**	Not yet available	Not yet available	**4.0%**
2023	3.5% - 4.0%	3.1% - 4.0%	**4.0%**	0.5% - 1.0%	1.0% - 1.2%	**1.75%**
2022	3.0% - 3.0%	3.0% - 3.0%	**3.0%**	0.5% - 1.0%	0.0% - 1.0%	**0.5%**
2021	2.9% - 3.1%	2.8% - 3.0%	**2.5%**	0.0% - 1.5%	0.15% - 1.1%	**0.5%**
2020	3.0% - 3.1%	2.9% - 3.2%	**3.0%**	0.5% - 1.0%	0.5% - 1.0%	**0.5%**
2019	2.8% - 3.1%	2.9% - 3.0%	**2.75%**	0.0% - 1.0%	0.0% - 1.0%	**0.75%**
2018	2.8% - 3.2%	2.9% - 3.0%	**2.75%**	0.5% - 0.8%	0.5% - 1.0%	**0.75%**
2017	2.8% – 3.1%	3.0% - 3.0%	**2.75%**	0% - .05%	0.5% - 0.5%	**0.75%**
2016	2.8% - 3.0%	3.0% - 3.0%	**2.75%**	0% - 0.8%	0.5% - 1.0%	**0.75%**
2015	2.9% - 3.0%	2.9% -3.1%	**2.75%**	0.5% - 1.0%	0.5% - 1.0%	**0.75%**
2014	3.0% - 3.0%	3.0% - 3.0%	**3.0%**	0.6% - 1.4%	0.5% - 1.0%	**0.5%**

Note: Because of the competitive challenges explained on the next two slides, the proposed merit and promotion/equity budgets are in line with the salary adjustments that we believe will be required based on the consultant's competitive benchmarking project and as a result, the promotion/equity proposed increase is likely higher than the national survey results.

Competitive Challenges

- As described in industry literature and shared with NEPOOL in the past, ISO-NE and utility employers face significant challenges associated with the retirement of a seasoned, technical workforce
  - Approximately 19% of the ISO-NE workforce is retirement-eligible
- One third of ISO-NE's workforce is comprised of IT professionals who are in increasingly high demand
  - Near full employment of these professionals has made the sourcing of replacements for open positions more challenging often resulting in longer times-to-fill
  - Software development and cyber security skills are the most sought after as organizations invest in newer, faster technology and mobile networks; compensation for these professionals is escalating
- This competition will only intensify as the region becomes increasingly involved with new and emerging technologies
  - More employees, with different skillsets will be needed to address the volume of market design changes and operational/planning complexities
  - Major investments in new technologies to create and support the core business applications and processes, including increased computational capacity to deal with increased grid complexity, which will require the requisite staff to complete this work

Competitive Challenges *(cont.)*

- Prior to 2021 our voluntary turnover rate (including retirements) had been approximately 7%. In 2021 the turnover rate spiked to 10.5%, and remained high at 9% in 2022. We expect the rate to remain at +/- 9% for 2023; the make-up of those departing is skewed towards staff possessing in-demand and unique skills who are often offered higher compensation, with some not needing to relocate due to fully remote work opportunities
  - Most of the individuals who have departed over the past few years were in positions within System Operations, Advanced Technology Solutions, System Planning, IT, and Market Operations, all areas that are critical to operating the grid and running our markets
    - The unemployment rate for these skills nationwide is under 3%; our salaries in these areas tend to be equal to or, in many cases, lower than the going market rate, making it particularly challenging to fill these roles
    - The local market does not typically have the required experience and relocation is sometimes challenging due to the company's location
- Addressing the clean energy transition is impacting all aspects of industry nationwide, leading to a tight labor market and inflation on new and existing employees' compensation expectations
- For all of these reasons, it is essential that we maintain competitive compensation; doing so is a cost-effective measure that will help prevent additional turnover and ensure the Company does not experience vacancies that will hinder implementation of major initiatives or impact efficient operation of its systems and markets

Executive Compensation

- As a tax-exempt organization, ISO-NE's Board of Directors is required by the Internal Revenue Code Section 4958 to ensure that executive compensation falls within a reasonable range of compensation practices among functionally comparable positions at similarly-situated organizations, both taxable and tax-exempt
- ISO-NE's Board of Directors contracts with Mercer, an independent compensation consulting firm, to study each executive's total compensation for "reasonableness"
  - The analysis includes examining data from other ISOs, utilities, and as appropriate, the general industry
  - Considerations such as the complexities of the markets, the significance of maintaining the grid, and the multi-billion dollars in settlements handled by ISO-NE are also factored into the review
  - Following its analysis, Mercer issues a Reasonableness Opinion
- The Mercer Reasonableness Opinion has consistently concluded that ISO-NE's executive compensation is within the appropriate competitive range

Executive Compensation *(cont.)*

- The Compensation and Human Resources Committee of the Board of Directors and the full Board of Directors review the Mercer Reasonableness Opinion and use it to finalize their decisions regarding each executive's compensation
- Executive compensation is reported in ISO-NE's annually filed IRS Form 990
  - This public filing is required for all tax-exempt companies and depicts officer compensation in detail
  - In addition to annual compensation, the data includes incremental increases in accrued pension benefits and other potential future compensation not yet received by the executive
- 2024 Budget for Executive Salaries $5.0M
  - Executive Salaries comprise the base salaries of the 11 officers on the IRS Form 990

Pension and Defined Contribution Benefit Plans in 2024

- Defined Contribution Pension Plan: In 2014, ISO-NE changed its retirement plan offering from a Defined Benefit Pension Plan (Pension Plan) to a Defined Contribution Pension Plan (DC Plan) for employees hired after 12/31/13 and closed its Pension Plan to new participants; the DC Plan provides predictable cost and reduced balance sheet liability, with no investment risk and minimal cost volatility for ISO-NE

Pension and Defined Contribution Benefit Plans in 2024 *(cont.)*

- Defined Benefit Pension Plan: In 2016, for the Pension Plan, ISO-NE modified the funding approach that it had consistently employed since 1997
  – ISO-NE previously calculated the budgeted Pension Plan expense amount in accordance with the Financial Accounting Standards (FAS)
  – This amount was included in the filed rates and contributed to the Pension Plan
  – In 2014 ISO-NE began looking into a level funding approach for the Pension Plan; ISO-NE engaged its actuaries and its investment consulting firm to perform analyses on implementing a change to the current funding approach
  – In 2016, ISO-NE implemented the level funding approach for making contributions and for inclusion in the filed rates
  – ISO-NE's actuaries refreshed the analysis in 2019 and the conclusion was to continue to fund the Pension Plan at the originally established level funding amount of $10,000,000 per year
  – The Pension Plan expense that is included in the 2024 budget is $10,000,000 compared to the projected FAS expense of $5,950,000
  – ISO-NE will request an update to the level funding approach in 2024

Postretirement Medical Benefit Plan in 2024

- In 2014 ISO-NE looked at making changes to its benefit plan offerings; to better align with the industry, the decision was made to close the Postretirement Benefit Plan to new hires, effective January 2016; in addition, a modification was made to the criteria for when this benefit could start for those employees in the plan prior to January 1, 2016; the age and years of service requirements were increased, thereby reducing future benefits that could be paid
- Consistent with previous years' budgets, ISO-NE's actuaries prepared estimated 2024 Financial Accounting Standards (FAS) Expense for the Postretirement Benefit Plan
- Actuaries utilized the FTSE Pension Discount curve, and reflected the change in discount rates as of May 31, 2023 to estimate the discount rate used in the calculation of the Postretirement Benefit Plan; current rates approximate the forward curve rates
  - Discount Rates Selected:
    - Postretirement Benefit Plan 4.85%
  - Salary Scale assumption (weighted Avg.) 4.25%
  - Projected 2024 annual earnings rate 6.00% (approximately)
- The calculated FAS expense amount for the Postretirement Benefit Plan of $1,020,000 is included in the 2024 budget

APPENDIX 2: 2024 OPERATING BUDGET RISKS

2024 Operating Budget Risks

- Additional funding may be required to construct new models to study extreme weather and contingencies; and to conduct new studies related to the integration of variable resources and emerging technologies, including long-range transmission planning studies
- Resources may be needed as operations evolve (e.g., energy forecasting, load management) due to the changing resource mix occurring
- Information Technology costs including software licensing and maintenance, cloud migration, backup and storage, and desktop peripherals, may each require additional funding
- Insurance policy renewals may be higher than increases estimated in the budgets
- Interest Rates may impact the ISO floating rates on tax-exempt debt, pension and post-retirement benefit plans liability costs, and interest income on settlement float balance
- Legal costs from material litigation that may arise during the course of the year would pose a risk to the ISO’s ability to operate within the approved budget
- Federal and state policy directives/changing policies could result in additional cost associated with new requirements
- Workforce sourcing and related pay rates and supply chain disruption may each have budgetary impacts
- Increases across multiple expense lines due to inflationary pressures in the current economic environment

APPENDIX 3: 2022 DELIVERABLES AND SELECT METRICS

ISO Tracks Metrics to Monitor Progress and Efficiency in Upholding its Regional Responsibilities

- To carry out the ISO's mission and keep track on its strategic goals, the organization tracks a number of metrics to gauge progress; those metrics are listed in the subsequent slides
- ISO-NE Five strategic goals:
  - Responsive Market Designs
  - Progress and Innovation
  - Operational Excellence
  - Stakeholder Engagement
  - Attract, Develop, and Retain Talent

Mission Statement:

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

The ISO in 2022 took on a large number of complex and novel initiatives addressing the clean energy transition

A subset of 2022 initiatives illustrates the effort the ISO has dedicated to supporting the region in their efforts to decarbonize the New England grid:

- Support NE States' policy initiatives
  - Completed the Pathways Study: Evaluation of Pathways to a Future Grid
  - Obtained FERC approval to administer capacity markets without a Minimum Offer Price Rule (MOPR)
  - Completed the Future Grid Reliability Study Phase 1
  - Initiated the 2050 Transmission Study
  - Respond to inquiries about 2022/23 Winter Reliability Program
  - Provided technical support to the states for their procurements of renewable and clean energy resources
- Enhance market design to improve pricing and resource accreditation to promote reliability and manage resource uncertainty
  - Delivered a detailed design proposal for Resource Capacity Accreditation (RCA, also known as effective load carrying capability) to stakeholders and held numerous discussions with them regarding design elements
  - Developed and proposed to stakeholders the Day-Ahead Ancillary Services Initiative (DASI) for reserve markets and to support fuel security
- Enhance ISO modeling and situational awareness to address changing resource mix
  - Improved system software and analytic methods for inverter-based resources (through developing a unique simulation scheme that will enable time-efficient electromagnetic transient simulation of multiple inverter based resources projects in the Eastern Interconnection system)
  - Completed a prototype of a scenario engine tool to support the modeling and assessment of operational impacts of extreme weather events
  - Developed a sub-hourly simulation model for the integrated market simulator (IMS)

Responsive Market Design

Improve the current market structure and continue to evolve and reposition the market design to support the states' objectives and transition to high levels of renewables and distributed resources. Maintain a robust fleet of balancing resources and preserve the ability of the market to guide the orderly entry and exit of resources.

Wholesale energy market is structurally competitive

- Operating reserve margins remain relatively high
- Residual Supply Index (RSI) scores meet expectations
- Energy market mitigation is relatively infrequent
- Markups in RT and DA markets were close to zero or negative
- In 2022, withheld economic capacity relatively low

Wholesale capacity market structurally competitive

- RSI and Pivotal Supplier Test scores: no pivotal suppliers
- Overall competitiveness increased with decrease in SENE zonal load forecast & increase in import capability limit

Wholesale Ancillary Services generally performing well. Regulation market structurally competitive. Forward Reserve Market (FRM) structurally uncompetitive.

- Recent FRM auctions show low Residual Supply Index scores at system-level for TMNSR; and for total thirty reserves

Note: *See IMM 2022 Annual Markets Report for detail*

2024 focus in on enhancing market design for capacity, energy and ancillary services markets to send more accurate price signals – addressing changing resource mix, associated operating complexity, and the region's winter security risks

Note: *See Annual Work Plan & Wholesale Markets Plan for detail*

Progress & Innovation

Evolve capabilities to support the grid as the region transitions to clean energy, including improved power system and market modeling. Support investments in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources. Provide data and information-based services.

Improve day-ahead load forecasting accuracy

- Average accuracy for peak hours of the month meets ISO's standards, *but* average accuracy across all hours of month does not. *See Monthly COO report to NEPOOL for detail*

Enhance programs to incorporate state policy objectives

- Reflect state energy efficiency goals; PV and electrification growth in long-term forecasting methodology. *See NEPOOL Load Forecast Committee & Planning Committee working groups*
- In consultation with states, conduct longer-term transmission planning program

Interconnect and register new resources to meet FERC established timeframes

- *See Order 845 Quarterly Performance metric filings*
- Streamline DER process through transferring all distribution system interconnection to state processes

2024 focus is on enhancing existing tools and programs to improve modeling of emerging technology resources and develop forecasting solutions and load management solutions for weather dependent resources:

- collect more detailed information about resources' operating characteristics, reflecting increased complexity and limited energy of resources
- methods for tracking and forecasting amount and impact of electrification of heating (space & water) and transportation (vehicle classes)
- Process interconnection requests more quickly and advocate/plan for federal interconnection queue policy changes

Operational Excellence:

Continuously improve operations and processes, with a focus on prioritizing project scope and implementation, business results, and continuity of reliable operations

Maintain NERC Standards compliance

- Operate bulk electric system reliability, e.g., within frequency limits; to avoid instability, cascading outages or uncontrolled separation;
- Maintain accurate planning models and update planning studies
- Oversee facility interconnection studies

Accurately settle markets with no errors

- Satisfactorily complete annual SSAE 18 audit
- Administer hourly market operations with minimal LMP corrections and zero provisional DAM results adjustments

Maintain IT uptime and ensure business continuity

- Continuous assessments of cyber security threats and risks against CIP Standards; NIST Framework; DHS Known Exploited Vulnerabilities; phishing attempts

Maintain accurate quarterly budget forecasts, comparing projected costs/revenues against actual financial results

2024 focus is on improving business operations across organization

- Implement internal process and technology improvements to address increasing grid complexity
- Maintain resources for providing participants with settlements finality and allocate resources to administer unique provisions of the Mystic Cost of Service Agreement
- Continue to modernize IT assets, technologies, and tools to mitigate cybersecurity threats

Stakeholder Engagement:

Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with FERC, the states and market participants in supporting the four pillars of the clean energy transition

- Address public policy concerns
  - Assess regional policy requests
  - Administer stakeholder prioritization process
- Annually survey stakeholder satisfaction with ISO services
  - Overall service quality
  - Market Participant training course satisfaction
- Over past several years, ISO has delivered products responsive to:
  - NE States 2020 Vision
  - Request to evaluate clean energy pricing (Pathways report)
  - Request to conduct longer-term transmission planning (Future Grid Reliability Study; 2050 transmission study)
  - Requests for mid-year winter energy adequacy assessments
  - Technical support on states' RFP efforts
- Focus in 2024 is addressing:
  - Building on novel analyses performed in 2022-23 to update assessments of regional energy adequacy vulnerabilities
  - Mature longer-term transmission planning program
  - Provide technical support to States, as requested, on RFP programs

APPENDIX 4: CYBER SECURITY AND CIP COMPLIANCE HISTORY AND COSTS

Cyber Security and CIP Compliance

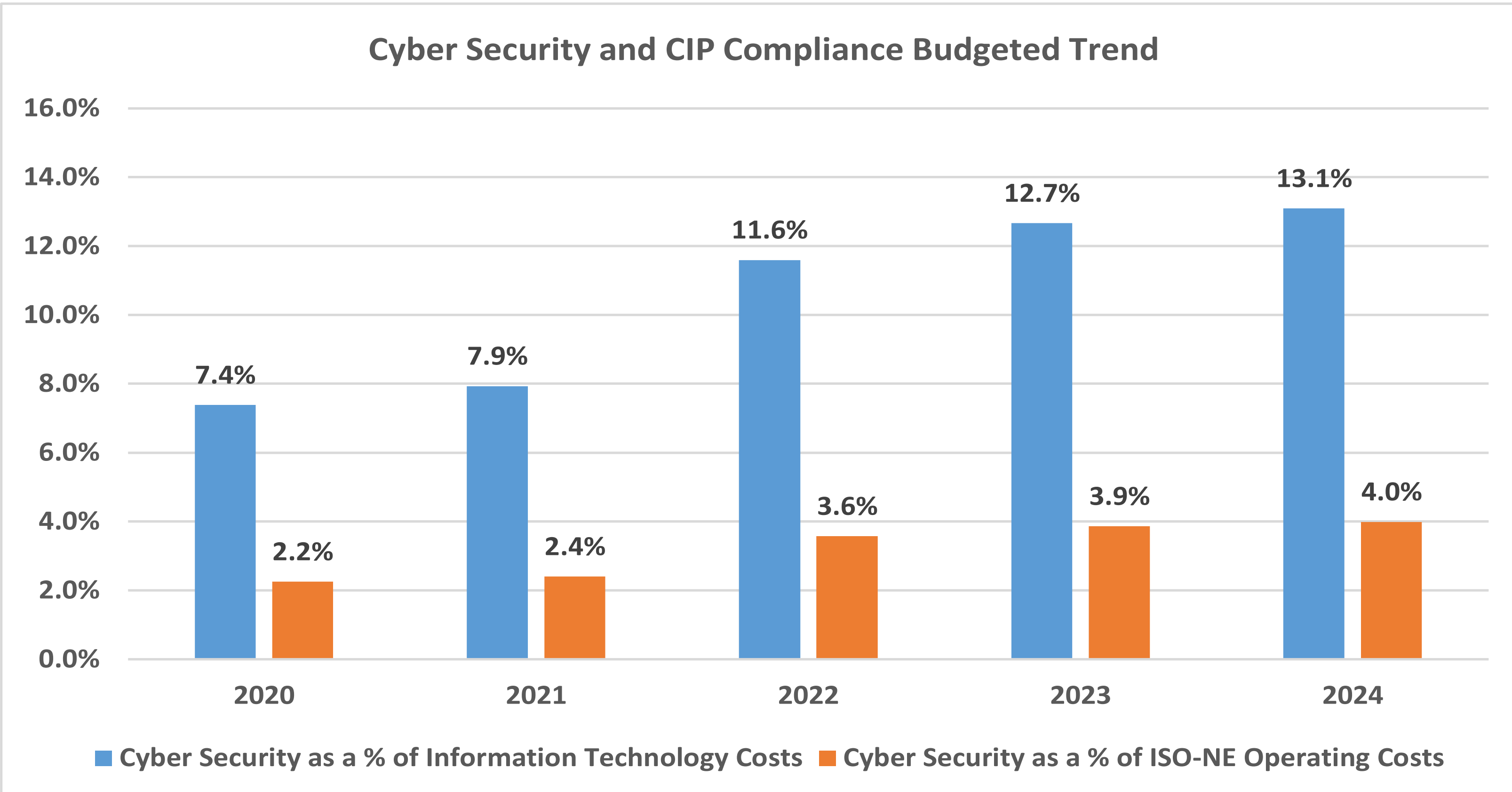
- Background
  - Information technology has become an indispensable tool for efficiently and reliably operating the increasingly complex regional power system, administering the billion-dollar markets where wholesale electricity is bought and sold in New England, and engaging and collaborating with our stakeholders
  - The energy sector faces significant risk of attempted cyber intrusion. ISO-NE is committed to making sure power grid and market operations remain secure and will continue to build on our already extensive process controls, advanced detection and response systems, and redundancy in systems and control centers
  - Our Security Operations Center monitors the ISO-NE environment and multiple new state-of-the-art cyber security capabilities were deployed in 2022, including best in class endpoint detection and response, network detection and response, software vulnerability detection, and cyber threat hunting
  - A prominent corporate objective requires all ISO-NE employees to participate in annual cyber security training
  - A CIP and Systems Compliance Operations Group provide day-to-day support of highly complex infrastructure and cybersecurity compliance functions required by North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards - Version 5

Cyber Security and CIP Compliance *(cont.)*

- ISO-NE has tightened security controls for cyber assets and visitors to ISO facilities in compliance with revised NERC CIP cybersecurity standards
- ISO-NE developed and implemented a third-party cyber security risk management program that includes compliance with the new CIP standard (CIP-013) related to Supply Chain Cyber Security Risk
- During 2021 ISO-NE replaced our old system for modeling and tracking physical and electronic access to systems and applications; the new Identity and Access Management system added cloud-service access tracking, privileged access management, automated implementation of accounts, and enhanced reporting to address NERC CIP compliance
- In 2022 ISO-NE replaced an outdated existing tool that served as a foundation for all network security with a new modern platform for ISO-NE's network traffic capture and visibility infrastructure, which is a critical component to cyber security and IT infrastructure operations. This infrastructure tool serves as a foundation for all network security throughout ISO-NE; the new tool (Packet Broker) was needed to maintain compliance with North American Electric Reliability Corporation Critical Infrastructure Protection standards; in addition, the new tool added an optimized design to accommodate the expansion of network traffic monitoring capabilities, enhanced filtering capabilities and integrates into other cyber security monitoring tools
- During 2022 ISO-NE also procured additional software to enhance our capability to visualize, detect and respond to threats and vulnerabilities from industrial control systems and technology that interfaces with the physical world (e.g., distributed control systems, SCADA); and software to improve ISO-NE's ability to recognize and block phishing attempts, as these attempts have increased exponentially and become more sophisticated in the past several years

Cyber Security and CIP Compliance *(cont.)*

To ensure robust cyber security defenses against ongoing sophisticated threats and to ensure compliance with CIP standards, ISO-NE has increasingly invested in these areas which have trended higher of our Information Technology and Overall Operating Expense Budgets



APPENDIX 5: ISO/RTO FINANCIAL COMPARISON

Financial Results Summary

ISO/RTO Financial Summary - 2022 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2022, and Outstanding Debt as of December 31, 2022 (1)

(Amounts in Millions)

	ISO-NE (2)	NYISO	CAISO	IESO (3)	PJM	MISO	SPP	ERCOT
Operating Expense - 2022	$ 210.8	$ 206.8	$ 246.1	$ 239.8	$ 401.9	$ 424.6	$ 220.7	$ 247.5
Less: Amortization & Depreciation	(25.0)	(25.6)	(36.7)	(21.4)	(36.4)	(31.8)	(17.5)	(26.3)
Regulatory Fees	(6.4)	(15.3)	-	-	(71.8)	(68.2)	(27.3)	-
Grant Expenses	-	-	-	-	-	-	-	-
Net Operating Expense - 2022	$ 179.4	$ 165.9	$ 209.4	$ 218.4	$ 293.7	$ 324.6	$ 175.9	$ 221.2
Other Financial Data								
Capital Expenditures for 2022	$ 29.1	$ 19.3	$ 19.2	$ 62.2	$ 30.9	$ 34.2	$ 11.5	$ 63.9
Outstanding Debt as of 12/31/22	$ 89.7	$ 82.4	$ 165.4	$ 120.0	$ 7.9	$ 274.4	$ 161.7	$ 2,950.5
Actual full-time equivalent headcount as of 12/31/22	589.5	568.8	665.0	806.0	760.0	1019.0	662.0	790.0

(1) Applicable amounts were taken from each entity's 2022 audited financial statements.

(2) ISO-NE Amortization & Depreciation and Capital Expenditures are presented on a cash-flow basis

(3) Amounts are in Canadian dollars

ISO-NE Responses August 25, 2023

NECPUC State Agencies' Questions to ISO-NE regarding 2024 Budget

1) Please provide the latest copy of ISO-NE's FERC Form 1.

   A copy of ISO-NE's 2022 FERC Form 1 is attached.

2) Please provide the most recent copy of ISO-NE's Form 990.

   A copy of ISO-NE's 2022 IRS Form 990 is attached.

3) Metrics. Given the transition of the system and expected changes ISO-NE operations, will ISO-NE be changing/modifying its metrics, best practices and/or KPIs? Explain.

   Yes. ISO-NE's metrics either: (1) measure performance against achieving our strategic goals; (2) measure risk tolerance for identified risks in light of available resources; or (3) measure compliance with various regulatory requirements. For example, as described in Appendix 3 of the August 11, 2023 presentation titled "ISO New England Proposed 2024 Operating and Capital Budgets" (the "Budget Presentation")[1], the ISO lists the strategic goals that are measured by various metrics. As new goals are added, the metrics are updated. Similarly, as risks change (e.g., cyber risks grow) and regulatory requirements are added (e.g., FERC's new Order No. 2023), the ISO's metrics change.

4) Complexity. Detail how complexity:

   a) Drives ISO-NE work load; and
   b) Changes ISO-NE operations.

   ISO-NE's operating environment will become increasingly complex as:
   - The number of assets in New England will grow to hundreds of thousands/one-million-plus in number
   - Many of these assets are behind-the-meter (BTM), changing how the transmission and distribution system operate and interact with each other
   - More non-dispatchable weather-dependent resources interconnect
   - Load and load patterns change with increasing amounts of solar PV and the region transitions to electric transportation and home heating

   This complexity will increase the workload in ways that are straightforward (e.g., higher volume of asset registrations and transmission interconnections to study and manage), and less straightforward (e.g., changes to adapt the markets and operating procedures, including forecasting, to the aforementioned growth in complexity). New employees and new skills will be needed to meet the challenges.

   For more detail on the effects of system complexity on the ISO-NE workload, please reference slides 15-29

[1] The presentation was presented to the NEPOOL Budget and Finance Subcommittee and can be found at 6_isone_2024_proposed_op_cap_budget.pdf (iso-ne.com)

from the Budget Presentation.

5) Job Benchmarking Study. Detail the results of the job benchmarking study. Provide a description and an example of how the results were used to modify ISO-NE salaries.

In 2022, in response to necessary growth, increased turnover, and greater difficulty attracting critical talent required to achieve our strategic objectives, ISO-NE Human Resources initiated a multi-year competitive compensation benchmarking project with our independent compensation consulting firm Mercer. The first roles studied in 2022 included many of our most technical Engineering, Analyst, and IT roles.

We discovered that our base salaries were below market, and requested a higher salary adjustment budget for 2023 than in prior years so that we could begin to address deficits. We will continue to measure the market competitiveness of the salaries of this first group of employees to ensure we can attract and retain the talent required to achieve our strategic objectives.

We are currently in the process of conducting Phase 2 of the analysis, covering an additional 200+ employees. Based on the Phase 1 results, our understanding of the talent market, and our growth objectives, we have projected a need for additional salary adjustment funding in the 2024 budget.

In 2024, we will conduct Phase 3 of the analysis, covering all remaining employees, and plan to make any necessary compensation changes in 2024, which will affect both the 2024 and 2025 salary budgets.

6) Inverter-Based Resources. Describe inverter-based resources, including how they differ from other resources and why they impact ISO-NE operations.

Most traditional resources, or synchronous generators, produce Alternating Current (AC) power. This is accomplished by mechanically spinning a rotating assembly at a constant speed in a magnetic field, which naturally creates AC power. Many clean resource technologies, such as solar and wind, produce Direct Current (DC) power. Batteries also charge and discharge DC power. These resources require an electronic power converter known as an "inverter" to convert DC power to AC power, and are broadly referred to as Inverter-Based Resources (IBRs) because of this.

IBRs lack many of the intrinsic behaviors of synchronous generators. Their behavior is almost entirely defined by control algorithms. These behavioral differences can present novel challenges to power system stability and reliability, given their lower fault current capability that can result in larger voltage fluctuations on the grid, the need for higher fidelity simulation practices, and the lack of an inherent inertial response. As IBR development continues to increase, ISO Operations must understand these evolving challenges and optimally solve them to ensure both a reliable and efficient power system for New England.

7) Transition to Clean Resources. Does ISO-NE see itself as accommodating the transition to clean resources or also helping drive it? Explain.

ISO-NE is fully committed to working with the New England states and NEPOOL to achieve the region's goals for a clean energy system that is reliable and efficient. As ISO-NE's vision states, we are working "to harness the power of competition and advance technologies to reliably plan and operate the grid as the region transitions to clean energy." The work we do in fulfilling our three critical responsibilities is helping enable the reliable interconnection and operation of renewable energy in the region. ISO New England has been a leader in facilitating the growth of demand resources and clean technologies through enhancements to long-term and short-term forecasting and modeling tools, system studies and implementation of rule changes to allow for greater participation in the wholesale markets. For more information on how our work is enabling a clean and reliable transition, please see our strategic plan.[2]

8) Future Budget Levels. Are the proposed budget levels reflective of a transitory process that will diminish once the transition is complete? Explain.

The budget reflects increases necessary to successfully transition to the clean energy future as well as catch up on inflation costs that were higher than previously budgeted. While the inflationary pressures will subside, there will still be a need to increase resources in the foreseeable future. At this point we are still assessing what may be needed for a post-transition paradigm.

9) Standards. Does ISO-NE have standards that it strives to meet? For instance, what made ISO-NE decide the transmission que system needed to be changed? If so, provide those standards and explain their rationale.

ISO-NE meets the standards of the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Northeast Power Coordinating Council, all of which are mandatory. In addition, the ISO has adopted a number of standards in its operating and planning procedures. The ISO is taking steps to modify its interconnection queue in compliance with the rulemaking issued by the Federal Energy Regulatory Commission.

10) Transmission Expansion. What mechanisms/processes does ISO-NE have in place to ensure that transmission expansion is accomplished efficiently? Is ISO-NE satisfied with these mechanisms/processes? Explain.

As the Regional Transmission Organization for New England, ISO-NE is the independent entity responsible for regional system planning, and for coordinating with transmission owners within the region and with neighboring systems. Since 2002, ISO-NE's regional system planning process has facilitated approximately $12 billion in regional investments across all six New England states, providing a robust, reliable, and resilient transmission system. The benefits of this investment in the region go beyond reliability and include market efficiency, reduced out-of-market reliability costs, and facilitation of the transition to clean energy.

ISO-NE carries out its regional planning responsibility in accordance with a comprehensive, open and transparent regional system planning process. Through this process, ISO-NE develops plans for the region's networked transmission facilities to address future system needs. The transmission planning study process begins with the development of a study scope and the identification of key inputs for conducting a needs assessment to determine the adequacy of the power system to maintain reliability while promoting the operation of efficient wholesale electric markets in New England. After the results of a needs assessment are made available for stakeholder input, the potential transmission system solutions are evaluated thoroughly to identify the solutions that offer the best combination of electrical performance, cost, future system expandability, and feasibility to meet the needs identified. These study efforts may be in the form of a solutions study or a competitive solicitation, depending on the timing of reliability needs. The development of transmission to address market-efficiency and public policy needs also is subject to the competitive solution process. The identification of the preferred transmission solution, whether developed through a solutions study or competitive solution process, is subject to stakeholder review and input before

[2] Strategic Plan (iso-ne.com).

the ISO finalizes its determination.

This robust process provides for increased sharing of information on identified needs and evaluation of solutions, leading to informed, efficient and cost-effective decisions on transmission expansion. Among the information shared is the identification of the location and nature of potential problems on the system so that generation, merchant transmission, or load can potentially develop and implement market-based solutions to the identified needs. Market responses, such as new generation pending in the interconnection queue, are included in the planning studies to assess their effects on identified needs. If a market response addresses an identified need, the transmission solution is set aside, thereby reducing the need for, and costs associated with, more transmission.

Beyond assessing reliability, market-efficiency and public policy transmission needs, the ISO has been working closely with the New England states to conduct longer-term scenario-based studies to identify potential future needs, e.g., the 2050 transmission study. The first phase of this effort focused on the development and implementation of rules to authorize the ISO to conduct state-led scenario-based transmission planning studies that rely on the states to determine the range of scenarios, drivers, inputs, assumptions and timeframes for use in the studies. The second phase entails the development of rules to enable the states to select and fund transmission upgrades identified in the longer-term studies. In addition to the longer-term studies, the ISO has had discussions with the New England states, transmission owners and regional stakeholders on potential enhancements to the planning process to optimize projects to meet future needs.

While the regional planning process has resulted in substantial benefits for New England, significant additional transmission will be needed for a reliable and clean energy future. ISO-NE will continue to identify enhancements to planning processes to ensure that any new infrastructure is aligned with the region’s goals and that such infrastructure is developed efficiently and economically.

ISO-NE Responses August 25, 2023

Questions from the Connecticut Office of Consumer Counsel (CTOCC)

CTOCC-1 Slide 38. Provide the employee incentive compensation target amounts since 2021.

ISO New England currently administers two incentive compensation plans that both provide for non-fixed payments: an annual performance incentive plan and a long-term incentive plan. We assume you are asking for the amounts that are budgeted by the ISO for employee incentive compensation. In 2021 through 2023, the ISO budgeted for incentive compensation in amounts that began at 5.6% of non-exempt employees' salaries. For 2024, the ISO has budgeted amounts beginning at 6.5% of non-exempt employees' salaries.

CTOCC-2 Slide 38. Provide the results of the compensation study review and what adjustments to the incentive compensation target is recommended in the current budget.

See the response to NECPUC Question no. 5 and CTOCC-1. The ISO has proposed an increase in the incentive payment pool for 2024 of $2.561 million.

CTOCC-3 Provide the document distributed to new employees detailing the incentive compensation plan.

Employees are eligible for a discretionary bonus based on corporate and personal performance. The policy is not a public document.

CTOCC-4 Slide 67. Based on the method shown, is it effectively assumed that the target date for the nine 2023 positions and twenty 2024 positions to be hired is January 1, 2024? When will the recruitment and hiring process begin for these additional positions?

For the thirty-two positions included in the 2023 budget, it is expected the majority of those positions, including the nine noted on slide 67, will be filled by January 1, 2024 with openings expected for normal vacancy.

We expect to recruit for the forty-one positions included in the 2024 budget over the course of that year, with funding included for an average of twenty positions. Due to the time required to recruit and hire for these openings, many of which are technical positions, we did not include full funding for all forty-one positions in the 2024 budget.

CTOCC-5 Slide 71. Provide detailed workpapers showing the calculation of actual and projected depreciation expenses for the periods presented.

Please refer to pages 71-73 of the Budget Presentation, which detail the depreciable lives and other capital asset accounting guidelines for the calculation of depreciation expense.

In addition, Footnote 1, page 52, of the ISO's Annual Financial Report (see https://www.iso-ne.com/static-assets/documents/2023/03/2022_financial_statements.pdf) contains additional information regarding the method of calculating depreciation expense for ISO-NE.

CTOCC-5 Slide 75. Provide detailed capital budgets for 2023-2025.

See Appendix 8 starting on Slide 150 of the 2023 budget presentation for the detailed 2023 capital budget at 7_isone_2023_proposed_op_cap_budget_update_09_29_2022.pdf (iso-ne.com).

See Appendix 7 starting on Slide 164 of the 2024 budget presentation for the detailed 2024 capital budget at 6_isone_2024_proposed_op_cap_budget.pdf (iso-ne.com).

A detailed 2025 capital budget has not yet been developed.

CTOCC-6 Slide 75. Provide variance reports comparing actual to budgeted capital expenditures for the period 2020-2023 to date.

On a quarterly basis, ISO-NE prepares capital budget reports that are reviewed with the NEPOOL Budget & Finance Subcommittee and filed with the Federal Energy Regulatory Commission. These quarterly reports explain changes in capital budget amounts in addition to information on each capital project that has been chartered for that quarter. Below are the links to each of these quarterly filings back to 2020:

- Q1 2020 - capital_budget_q1_2020.pdf (iso-ne.com)
- Q2 2020 - capital_budget_filing_q2_2020.pdf (iso-ne.com)
- Q3 2020 - capital_budget_filing_q3_2020.pdf (iso-ne.com)
- Q4 2020 - capital_budget_q4_2020.pdf (iso-ne.com)
- Q1 2021 - capital_budget_q1_2021.pdf (iso-ne.com)
- Q2 2021 - cap_budget_q2_2021.pdf (iso-ne.com)
- Q3 2021 – Microsoft Word - Capital Budget Filing Letter Q3 2021.doc (iso-ne.com)
- Q4 2021 - q4_2021_qtrly_budget.pdf (iso-ne.com)
- Q1 2022 - Capital Budget Filing Letter Q1 2022 (iso-ne.com)
- Q2 2022 - cap_budget_qtrly_filing_q2_2022.pdf (iso-ne.com)
- Q3 2022 - cap_budget_qtrly_filing_q3_2022.pdf (iso-ne.com)
- Q4 2022 - capita_budget_qtrly_filing_q4_2022.pdf (iso-ne.com)
- Q1 2023 - q1_2023_qtrly_budget_filing.pdf (iso-ne.com)
- Q2 2023 - q2_2023_capital_budget_filing.pdf (iso-ne.com)

CTOCC-7 Slide 92. Indicate the level of contingency funds previously included in past annual budgets. If this is a new line item, please provide rationale for including it in the budget at this time. If not included as a separate line item in prior year budgets, explain how any contingency factors were applied in setting past budgets.

Contingency funds have always been reported as a separate line item in ISO-NE's budget. Below is the five-year history of the contingency fund budget amount:

2020: $1.8 million
2021: $1.8 million
2022: $2.7 million
2023: $2.7 million
2024: $2.7 million

CTOCC-8 Slide 111. Is the 4.0% Promotional/Equity Increase Budget for 2024 considered a "catch-up" increase? Was the 1.75% Promotional/Equity Increase a "catch-up" increase?

As described on slide 38 of the Budget Presentation, the 2024 budget includes three components to base compensation amounts:

- 4.0% for annual merit increases targeted for the entire ISO-NE employee population (this is reflected in the chart on slide 111)
- 4.0% for targeted promotional/equity increases to cover employees in the 2nd and 3rd phases of the job-specific benchmarking survey described on slide 109 (this is reflected in the chart on slide 111)
- 2.0% for targeted equity/promotion increases given in 2023, primarily funded from contingency funds (in 2023), that covered employees in the 1st phase of the job-specific benchmarking survey as described on slide 109

The targeted equity/promotion increases described in the second and third bullets above would be considered “catch-up” increases to level set base salaries with market amounts.

CTOCC-9 Slide 29. What are the projected costs associated with compliance with FERC’s interconnection order?

We are still reviewing the order.

CTOCC-10 Regarding the “expanding interconnection queue,” does ISO-NE also account for any potential downward impacts in queue volume as a result of the FERC interconnection order?

See response to CTOCC-9.

CTOCC-11 Does ISO-NE anticipate needing an extension for compliance with FERC’s interconnection order and, if so, are there any costs associated with that?

We are still discussing the need for an extension internally and with the other U.S. ISOs/RTOs. The work would be done internally and therefore would be absorbed by the 2023 operating budget.

CTOCC-12 What are the additional effects on staffing, if any, associated with the addition of the Environmental Justice position that is under consideration?

No additional effects.

CT-OCC-13 Provide an estimated projection of the level of increase in energy resources (DERAs) integrated into ISO markets due to FERC order 2222.

We do not have a projection for DERA participation in ISO markets due to Order 2222. The rules for DERAs do not become effective until November 1, 2026, and aspects of our compliance proposal are still subject to FERC review.

New England States Committee on Electricity

2024 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 11, 2023

Background: Budget Review

Term Sheet Provision: "… the annual review of its [NESCOE's] proposed budgets by at least the NEPOOL Participants Committee will be limited to considerations of accounting and reconciliation, so long as spending remains within the boundaries established by those frameworks….. NESCOE will develop an operating budget recommendation for each year in consultation with NEPOOL, the PTO Administrative Committee and ISO-NE within the boundaries of the then-approved five year budget framework …"

- ✓ Proposed 2024 budget conforms to:
  - Boundaries of 5-year pro forma (2023-2027) reviewed by Budget & Finance
  - NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year: 2024 proposed budget is less than 2024 5-year pro forma budget
- ✓ Following calendar year 2022, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

"Each year NESCOE will produce a ***Report to the New England Governors*** that will document its accomplishments from the preceding year and its projected policy priorities for the coming two years. This report will include a full accounting of spending by NESCOE during the preceding year and proposed budgets for each of the upcoming two years."

Consistent with Term Sheet, 2022 *Report to the New England Governors*:

✓ Reviewed work in 2022
✓ Projected policy priorities
✓ Provided spending from prior year
✓ Projected budget information for upcoming two years

Projected Policy Priorities

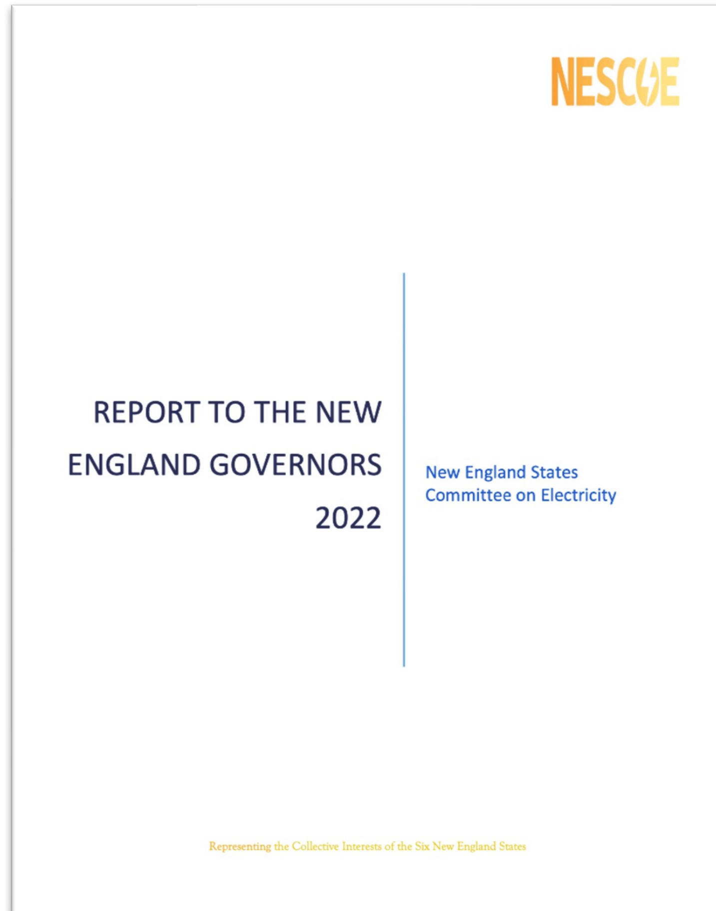
✓ NESCOE provided to the Governors the ***2022 Annual Report to New England Governors***

✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the Participants Committee

✓ NESCOE identified forward looking policy priorities at Section V, pages 13

Report in "Resource Center"

www.nescoe.com


NESCOE

REPORT TO THE NEW ENGLAND GOVERNORS 2022

New England States Committee on Electricity

Representing the Collective Interests of the Six New England States

Projected Policy Priorities

- ✓ **Transmission**. Work with ISO-NE and stakeholders on tariff changes (Phase II) to enable states to consider options to address issues identified in the longer-term public policy-related transmission analysis; work with ISO-NE and Transmission Owners on reforms to bring visibility and more consistent approaches to asset condition projects and thoughtful, cost-effective approaches to right-sizing; assess the results of the 2050 Transmission Study, including the estimated costs for different potential infrastructure development pathways
- ✓ **Future Grid-Related Studies and Reforms**. Collaborate with ISO-NE and stakeholders in connection with the contemplated Phase 2 analysis to assess revenue sufficiency and system security in a gap analysis.
- ✓ **Winter**. Assess ISO-NE's analysis of the risk and implications of extreme weather events and contingencies as well as whether, and to what extent, any such risk requires market adjustments or other near-term mitigation and the effects from changes in both gas and electric infrastructure.
- ✓ **FCM Reforms.** Work with ISO-NE and stakeholders to determine the benefits and disadvantages of changes to the current FCM construct. This includes further considerations related to capacity accreditation and major design changes such as moving to a prompt, seasonal, or prompt seasonal capacity auctions.

NESCOE Organization & Misc.

Employees

- ✓ Retain and attract diversity in academic training, skills; blend of private & public sector experience
- ✓ Return to NESCOE's prior steady state employee level of six
  - ✓ New General Counsel in mid-2023
  - ✓ System planning staff in 2024

Office Space

- ✓ No office leases at this time, instead renting meeting space as needed

Other Organization Matters

Technical Consultants

Technical consultants assist NESCOE in the regular course of business in analyzing ISO-NE studies and data.

Continue work with technical consultants to conduct independent analysis to inform state officials' decisions on key issues, including, for example:

- ✓ Wilson Energy Economics
- ✓ PeterGFlynn, LLC
- ✓ Oxford Power
- ✓ Supplement with other expertise as needed, such as Daymark

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2023, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

- ✓ Primary FERC Counsel: Phyllis G. Kimmel Law Office PLLC

5-Year Pro Forma

Proposed 2024 budget conforms to 2024 budget in 5-year Pro Forma Framework

✓ 2024 Projected Budget in 5-Year Pro Forma:	$2,823,665
✓ 2024 Proposed Budget:	$2,596,014
✓ 2023 Budget, for reference:	$2,691,505

The 2024 Proposed Budget

- ✓ Assumes steady state of six employees
- ✓ Reflects reduction in anticipated inflationary pressures
- ✓ Increased travel post pandemic and in lieu of office space

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2023-2027*

Expense Category	Year 16 (2023)	Year 17 (2024)	Year 18 (2025)	Year 19 (2026)	Year 20 (2027)
Salaries and Wages					
Salaries	1,311,718	1,377,304	1,446,169	1,518,478	1,594,401
Payroll Taxes	131,172	137,731	144,617	151,848	159,440
Health and Other Benefits	110,098	115,603	121,383	127,452	133,825
Retirement §401(k)	52,469	55,092	57,847	60,739	63,776
Total, Salaries and Wages	**1,605,457**	**1,685,730**	**1,770,016**	**1,858,517**	**1,951,443**
Direct Expenses - Consulting					
Technical Analysis	342,933	353,221	363,818	374,732	385,974
Legal (FERC)	342,933	353,221	363,818	374,732	385,974
Total, Direct Expenses, Consulting	**685,866**	**706,442**	**727,635**	**749,464**	**771,948**
General and Administrative					
Rent		12,000	12,360	12,731	13,113
Utilities		2,500	2,575	2,652	2,732
Office and Administrative Expenses	50,000	51,500	53,045	54,636	56,275
Professional Services	41,500	42,745	44,027	45,348	46,709
Travel/Lodging/Meetings	60,000	61,800	63,654	65,564	67,531
Total General and Administrative	**151,500**	**170,545**	**175,661**	**180,931**	**186,359**
Capital Expendiures & Contingencies					
Computer Equipment	8,666	8,926	9,194	9,470	9,754
Contingencies	244,682	252,022	259,583	267,371	275,392
Capital Expenditures & Contingencies	**253,348**	**260,948**	**268,777**	**276,840**	**285,145**
TOTAL EXPENSES**	**2,696,171**	**2,823,665**	**2,942,090**	**3,065,753**	**3,194,896**

*Projected 5% salaries and wages annual adjustment, and projected 3% annual adjustment on all other items. Line items and categories subject to increase greater than, or decrease from, amounts projected. Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).

**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year of more than 30% on a cumulative basis.

2024 Proposed Budget

NESCOE Pro Forma Budget
Proposed 2024 Budget

	2024
Salaries and Wages	
Salaries	1,154,954
Payroll Taxes	115,495
Health and Other Benefits	140,000
Retirement §401(k)	46,198
Total, Salaries and Wages	**1,456,648**
Direct Expenses - Consulting	
Technical Analysis	353,220
Legal (FERC)	353,221
Total, Direct Expenses, Consulting	**706,441**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	50,425
Professional Services	47,500
Travel/Lodging/Meetings	90,000
Total General and Administrative	**187,925**
Capital Expend. & Contingencies	
Computer Equipment	9,000
Contingencies	236,001
Capital Expend. & Contingencies	**245,001**
TOTAL EXPENSES	**2,596,014**

2022 & 2023 Spending & Implications for 2024

Unspent funds in any year credited toward future year

2022 Total Spending:	$1,548,186*
2023 Spending to end of June:	$784,144**
2023 Projected Year End:	$1,875,373 *

*Cumulative prior years' true up, including 2021, was reflected in the 2023 revenue requirement and rates. The 2022 true up will be reflected in the 2024 revenue requirement and rates (see next slide). Any 2023 true up will be reflected in the 2025 revenue requirements and rates.

** 2023 Spending through June reflects General Counsel on-boarding in June, vacant staff position (system transmission consultant began service in June 2023.)

2024 Projected Billing Rate

With thanks to ISO-NE for calculations -

2024 Budget:	$2,596,014.
Less 2022 True Up:	($862,664.)
Total Revenue Recovery:	$1,733,350.
Divided by Total Network Load:	225,688,515

(total network load from 2023 ISO-NE tariff; no escalation or reduction used in calculation)

2024 Schedule 5 Estimated **Rate $0.00768 per kW-month**

Thank you.

Questions?

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of September 6, 2023

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated August 2, 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

	Page	Matter	Date	Activity
	1	206 Proceeding: Brookfield IEP Complaint (IEP Exclusion of Pumped Storage ESFs) (EL23-89)	Aug 22	ISO-NE, FirstLight, NECOS, NEPGA file comments and protests to Brookfield's Complaint
			Sep 5	Brookfield answers ISO-NE and NECOS comments and protest

II. Rate, ICR, FCA, Cost Recovery Filings

	Page	Matter	Date	Activity
	6	Stonepeake Kestrel CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-2429)	Aug 22	Stonepeake Kestrel amends its filing and reduces the amount of IROL-CIP Costs that it's seeking to recover from $1.6 million to ***$ 1.48 million***; comment deadline on amended filing ***Sep 12, 2023***
	7	Bucksport Generation (Schedule 17) Section 205 Cost Recovery Filing (ER23-2428)	Aug 22	Bucksport Generation amends its filing and reduces the amount of IROL-CIP Costs that it's seeking to recover from $277,874 to ***$251,419***; comment deadline on amended filing ***Sep 14, 2023***
	7	FCA18 De-List Bids Filing (ER23-2379)	Aug 22	FERC accepts ISO-NE's filing, eff. *Sept 11, 2023*
	7	CSC CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-1826)	Aug 28	FERC accepts amended filing for recovery of ***$650,244*** in CIP-IROL costs, eff. *Jul 4, 2023*
	8	BHD Regulatory Asset-Establishment & Recovery Through Rates (ER23-1598)	Aug 7	Versant requests delay in FERC action, to ***Oct 7, 2023***, to allow for possible resolution of MPUC's questions and concerns
	9	**Mystic 8/9 COSA (ER18-1639)**		
	9	(-025) First CapEx Settlement Agreement Tariff Sheets Filing	Aug 30	Mystic files revised tariff records in eTariff format, effective *Jun 1, 2022*, to reflect the FERC's approval of the First CapEx Settlement Agreement; comment deadline ***Sep 20, 2023***
*	12	Versant MPD OATT 2022 Annual Update Settlement Agreement (ER20-1977-005)	Aug 30	Versant submits 2022 Annual Update Offer of Settlement between itself and the Maine Wholesale Customer Group, the Aroostook Energy Assoc., the Maine OPA, and the MPUC; comment deadline ***Sep 20, 2023***

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

	Page	Matter	Date	Activity
	13	IEP Parameter Updates (ER23-1588)	Aug 4	FERC accepts IEP Parameter Updates, eff. *Aug 4, 2023*
			Sep 5	Public Interest Organizations request reh'g of *IEP Parameter Updates Order*
	14	New England's *Order 2222* Compliance Filing (ER22-983)	Aug 28	ISO-NE and NEPOOL joint file 180-day Mitigation Compliance Revisions (Mitigation Compliance Revisions); comment deadline ***Sep 18, 2023***

IV. OATT Amendments / TOAs / Coordination Agreements

	16	Versant Power Att. F App. D Depreciation Rate Change (ER23-2483)	Aug 8	Versant Power supplements its filing with additional exhibits
	17	CMP Att. F App. D Depreciation Rate Change (ER23-2477)	Aug 28	FERC accepts change, eff. *Jul 1, 2023*
	17	*Order 881* Compliance Filing: New England (ER22-2357)	Aug 14	ISO-NE, NEPOOL, the PTO AC, CSC jointly file revisions to Section II of the OATT in response to the requirements of the *New England Order 881 Compliance Order*

V. Financial Assurance/Billing Policy Amendments

	18	FAP Eligible LOC Issuer Changes (ER23-2277)	Aug 11	FERC accepts Eligible LOC Issuer Changes, eff. *Aug 27,2023*

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

	18	Schedule 21-VP: Real Power Loss Factor Charge (ER23-2142)	Aug 11	FERC accepts change, eff. *Sep 1, 2023*
	18	Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035)	Aug 29	Versant submits refund report; comment deadline ***Sep 19, 2023***
*	19	Schedule 21-VP: 2022 Annual Update Settlement Agreement (ER20-2054-003)	Aug 29	Versant submits 2022 Annual Update Offer of Settlement between itself and the MPUC; comment deadline ***Sep 19, 2023***

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

*	19	Capital Projects Report -2023 Q2 (ER23-2620)	Aug 11 Aug 16 Aug 28, 31	ISO-NE files 2023 Q2 Report NEPOOL submits comments supporting Report National Grid, Eversource intervene doc-lessly
	19	Interconnection Study Metrics Processing Time Exceedance Report 2023 Q2 (ER19-1951)	Aug 14	ISO-NE files 2023 Q2 Report
*	20	ISO-NE 2023 Q2 FERC Form 3Q (not docketed)	Aug 21	ISO-NE submits its 2023 Q2 FERC Form 3Q

IX. Membership Filings

*	20	Sep 2023 Membership Filing (ER23-2756)	Aug 31	***New Members:*** Phoenix Energy Group and 3Degrees Group; ***Terminations:*** Just Energy (U.S.) Corp., NRG Power Marketing, Norwalk Power, Somerset Power, and WP&G Holdings; and the ***Name Change*** of NRG Business Marketing, LLC; comments deadline ***Sep 21, 2023***
	21	Membership – Manchester Methane Involuntary Termination (ER23-2390)	Sep 1	FERC accepts the involuntary termination of the Participant status of Manchester Methane, eff. *Sep 11, 2023*

21	Jul 2023 Membership Filing (ER23-2319)	Aug 28	***New Members:*** Hecate Energy Albany 2; Erie Wind, LLC; and SCEF1 FUEL CELL, LLC ***Terminations:*** Concurrent LLC; and Brookfield Energy Marketing LP ***Name Change:*** CPV Spruce Mountain Wind, LLC

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

21	NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2)	Aug 10 Aug 21	FERC/NERC staff convene tech. conf. to discuss BPS physical security FERC issues post-tech. conf. notice inviting comments; comment deadline ***Sep 21, 2023***
21	Inverter-Based Resource Registration (RD22-4)	Aug 16 Aug 31	NERC files first 90-Day Progress Report APPA comments on Aug 16 Report
* 22	2024 NERC/NPCC Business Plans and Budgets (RR23-3)	Aug 23	NERC submits proposed 2024 Business Plan and Budget for itself and its Regional Entities, including NPCC; comment deadline ***Sep 14, 2023***

XI. Misc. - of Regional Interest

23	203 Application: Energy Harbor / Vistra (EC23-74)	Aug 4 Aug 15 Aug 17 Aug 22 Sep 1 Sep 5	Vistra/Energy Harbor answer NOPEC PJM IMM answers Energy Harbor/Vistra's Jul 10 answer FERC issues deficiency letter; response due ***Sep 18, 2023*** US DOJ Antitrust Division submits comments OHIO PUC's office of Fed. Energy Advocate support Ohio Consumer Counsel's protest Vistra/Energy Harbor answer US DOJ Antitrust Division comments
23	203 Application: Weaver Wind / Greenbacker (EC23-68)	Aug 2	Weaver Wind notifies the FERC that the authorized transaction was consummated on Jul 25, 2023
24	PURPA Enforcement Petition: Allco Finance Limited (EL23-84)	Aug 14 Aug 21 Aug 24	NECEC Transmission, MOPA file protests; MA State Agencies request an extension of time to file comments FERC grants extension of time to file comments only to Aug 24, 2023 MA State Agencies protest Allco Petition
* 24	D&E Agreement Amendment: PSNH/NECEC (ER23-2645)	Aug 17 Aug 28	PSNH files an amendment to D&E Agreement with NECEC; comment deadline ***Sep 7, 2023*** National Grid intervenes
24	LGIAs: RIE/ISO-NE/RISEC & Tiverton (ER23-2494 and ER23-2491)	Aug 8	RI Energy intervenes
24	LGIA Termination: CL&P/ISO-NE/NTE CT (ER23-2378)	Aug 31	FERC accepts notice of termination of LGIA, eff. *Jul 12, 2023*
25	Engineering & Test Agreement: CL&P/BPUS (ER23-2335)	Aug 15	FERC accepts Engineering and Test Agreement, eff. *Jul 6, 2023*
25	IA Cancellation: NEP/TransCanada (ER23-2182)	Aug 10	FERC accepts notice of cancellation, eff. *Aug 14, 2023*
25	D&E Agreement Cancellation: NSTAR/Medway Grid (ER23-2117)	Aug 10	FERC accepts notice of cancellation, eff. *Jun 13, 2023*

XII. Misc. - Administrative & Rulemaking Proceedings

27	Second New England Winter Gas-Electric Forum (AD22-9)	Aug 24-28	Post Forum Comments filed by 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 Eniv. Action Team, and the Fix the Grid Campaign, and Potomac Economics
29	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Aug 8	FERC posts transcript of Jul 16, 2023 meeting
		Aug 29	FERC issues Order on Nominations identifying state commissioners who will serve on the Task Force for the Sep 2023 – Aug 2024 term, including Commissioner Riley Allen (VT PUC) and Chair Marissa Gillett (CT PURA)
31	*Order 2023*: Interconnection Reforms (RM22-14)	Aug 24-31	35 Parties requests clarification and/or reh'g of *Order 2023*
		Aug 28	Joint RTOs request extension of time, to at least 90 days after the FERC issues a substantive order on the issues raised on clarification and/or reh'g
		Sep 6	*Order 2023* published in *Federal Register*; absent further action, compliance filings due ***Dec 5, 2023***
33	NOPR: Transmission Siting (RM22-7)	Aug 9	Chairman Phillips' response to Senator Schumer's Jun 20, 2023 letter posted to eLibrary
		Aug 21	Each Commissioner's response to Senator Barrasso's Apr 26, 2023 letter posted to eLibrary

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

*	35	Big River Steel (BRS) and Entergy Arkansas (EA) (IN23-11)	Aug 21	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into BRS's participation in a MISO demand response program between Sep 2016 and Apr 2022; BRS must ***disgorge $15,940,399***, pay a ***$6 million civil penalty***, and EA must ***disgorge $5,033,780***, and ensure return of ***$8,181,899*** to its customers

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

40	Seabrook Dispute Order (23-1094, 23-1215) (consol.)	Aug 17	Court consolidates 23-1215 with 23-1094
42	Opinion 531-A Compliance Filing Undo (20-1329)	Aug 3	FERC files abeyance status report
43	Northern Access Project (22-1233)		Oral argument scheduled for ***Sep 18, 2023***
43	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.)	Aug 14	Court orders remaining consolidated cases remain in abeyance and directs the parties to file motions to govern future proceedings by ***Sep 11, 2023***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: September 6, 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 September 6, 2023. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

As previously reported, on August 2, 2023, Brookfield Renewable Trading and Marketing LP ("Brookfield") filed a complaint pursuant to Section 206 of the FPA regarding the exclusion of pumped storage hydroelectric facilities that are Electric Storage Facilities ("ESFs") from the Inventoried Energy Program ("IEP"). Consistent with its proposed amendment to the IEP that was supported by the Participants Committee at the November 2, 2022 meeting, but ultimately rejected by the FERC in its April 24, 2023 order in the IEP Remand Proceeding,[2] Brookfield asked the FERC to direct ISO-NE to revise the Tariff, effective August 2, 2023, to allow Pumped Storage ESFs to participate in the IEP. Brookfield asked that the FERC act on its Complaint expeditiously, noting that ISO-NE has informed Brookfield that any order from the FERC directing ISO-NE to include Pumped Storage ESFs in the IEP cannot be implemented for Winter 2023/24 unless it is received on or before September 22, 2023. Comments on the Brookfield IEP Complaint were due on or before August 22, 2023 and were filed by ISO-NE, FirstLight, NECOS,[3] and the New England Power Generators Association ("NEPGA"). On September 5, Brookfield answered ISO-NE's comments and NECOS' protest. This matter is pending before the FERC. 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.

[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] *See ISO New England Inc.*, 183 FERC ¶ 61,059 (Apr. 24, 2022) ("*IEP Remand Compliance Filing Order*").

[3] "NECOS" are Belmont Municipal Light Dept., Block Island Utility District, Braintree Electric Light Dept., Chicopee Municipal Light Dept., Energy New England, LLC, Georgetown Municipal Light Dept., Hingham Municipal Lighting Plant, Littleton Electric Light & Water Dept., Merrimac Municipal Light Dept., Middleborough Gas & Electric Dept., Middleton Electric Light Dept., North Attleborough Electric Dept., Norwood Municipal Light Dept., Pascoag Utility District, Reading Municipal Light Dept., Rowley Municipal Lighting Plant, Stowe Electric Dept., Taunton Municipal Lighting Plant, Wallingford Electric Division, and Westfield Gas & Electric Light Dept.

[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

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 (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. 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).

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

Also still pending before the FERC is the Section 206 proceeding, instituted on July 28, 2022, in which the FERC found that the existing tariffs of certain ISO/RTOs, including the ISO-NE Tariff, appear to be unjust and unreasonable.[7] In the case of ISO-NE's tariff, the FERC found that the absence of volumetric minimum collateral requirements for FTR Market Participants ("volumetric FTR collateral requirements") appeared to render the ISO-

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.

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

NE Tariff unjust and unreasonable. Accordingly, ISO-NE was directed, on or before October 26, 2022, to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential.[8] As noted below, ISO-NE answered by explaining why it believes its existing Tariff provisions to be just and reasonable and changes not necessary.

By way of background, the *FTR Collateral Show Cause Order* follows PJM's *Green Hat* experience,[9] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential rulemaking to improve ISO/RTO credit practices,[10] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[11] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[12] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

The FERC issued on July 28, 2022, a notice of this proceeding and of the refund effective date, August 3, 2022.[13] Those interested in participating in this proceeding were required to intervene on or before August 18, 2022. Doc-less interventions were filed by NEPOOL, Calpine, DC Energy, NRG, MPUC, EPSA, PJM, SPP, Public Citizen, and Financial Marketers Coalition[14] (out-of-time).

ISO-NE October 26, 2022 Response. In its Answer in response to the *FTR Collateral Show Cause Order*, ISO-NE explained how the FTR financial assurance calculations contained in the Financial Assurance Policy ("FAP") remain just and reasonable, adequately accounting for FTR risk in the absence of a more sophisticated risk management solution such as a clearing solution. ISO-NE asked that, should the FERC not agree and proceed to require volumetric FTR collateral requirements, that it be permitted to follow the Participant Processes to propose

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[8] *Id.* at P 31.

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

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

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

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

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

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

revisions to the FAP consistent with any such order. Comments on ISO-NE's response were due on or before November 25, 2022; none were filed. As noted, this matter remains pending before the FERC.

If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@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,[15] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE _plus_ transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[16] However, the FERC's orders were challenged, and in *Emera Maine,*[17] 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)[18] and third (EL14-86)[19] 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.[20] 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*.

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[15] 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*")).

[16] *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*").

[17] *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).

[18] 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%.

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

[20] *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*").

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[21] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[22] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[23] 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.[24] 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*[25] (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.[26]

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

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

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

23 *Id.* at P 2.; Finding of Fact (B).

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

25 *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*.

26 *Id.* at P 19.

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%.[27] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[28] 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*[29] 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

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

Stonepeake Kestrel Energy Marketing LLC ("Stonepeake Kestrel") initiated this proceeding on July 18, 2023, by requesting that the FERC accept 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 September 16, 2023. Stonepeake Kestrel initially sought recovery of $1,605,854 in incremental medium impact CIP-IROL Costs incurred between March 29, 2021 and March 31, 2023. Since the last Report, on August 22, Stonepeake Kestrel amended its July 18 filing to remove

[27] *Id.* at P 59.

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

[29] *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).

certain capital and interest on operations and maintenance costs from its revised rate schedule.[30] Accordingly, Stonepeake Kestrel is now seeking recovery of ***$1,483,297*** in IROL-CIP Costs. Comments on Stonepeake Kestrel's amended filing are due on or before ***September 12, 2023***. Thus far, doc-less interventions have been filed by NEPOOL and NESCOE. 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, Bucksport Generation LLC ("Bucksport Generation") has requested that the FERC accept its revised rate schedule to allow recovery of its eligible medium-impact IROL-CIP Costs. For the same reasons articulated by Stonepeake Kestrel, Bucksport Generation also amended its initial filing (removing certain capital and interest on operations and maintenance costs from its revised rate schedule) and now seeks to recover ***$251,419*** in incremental medium impact CIP-IROL Costs incurred between March 29, 2021 and March 31, 2023. Comments on Bucksport Generation's amended filing are due on or before ***September 14, 2023***. Thus far, doc-less interventions have been filed by NEPOOL and NESCOE. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA18 De-List Bids Filing (ER23-2379)**

On August 21, 2023, the FERC accepted ISO-NE's filing describing the Permanent De-List Bids and Retirement De-List Bids that were submitted on or prior to the April 6, 2023 FCA18 Existing Capacity Retirement Deadline.[31] As previously reported, ISO-NE reported that it received 14 Retirement De-List Bids. The bids were for resources located in the Connecticut, Northeastern Massachusetts, RI, Southeastern Massachusetts, and Western/ Central MA Load Zones, with 870.718 MWs of aggregate capacity. 10 of the Bids (totaling 15.916 MWs) were for resources under 20 MW or that did not meet the affiliation requirements that would have required Internal Market Monitor ("IMM") review. Unless the *FCA18 De-List Bids 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).

- **CSC CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-1826)**

On May 4, 2023, Cross-Sound Cable ("CSC") requested that the FERC accept its revised rate schedule to allow recovery of eligible medium-impact IROL-CIP Costs under Schedule 17 of the ISO-NE Tariff, effective July 4, 2023. CSC sought recovery of $723,601 in CIP-IROL Costs incurred between June 1, 2021 and December 31, 2022. Comments on CSC's request were due on May 25; none were filed. Doc-less interventions were filed by NEPOOL, National Grid and NESCOE.

Deficiency Letter and Deficiency Letter Response. On June 29, 2023, the FERC issued a deficiency letter requesting additional information/clarification from CSC. CSC filed its response on July 28, 2023. In its response, among other things, CSC removed the interest on operations and maintenance expenses, as well as IROL-CIP Accumulated Deferred Income Taxes and Working Capital, from its calculations, reducing the amount of the costs sought to be recovered to ***$650,244***. Comments on CSC's deficiency letter response were due on or before August 18, 2023; none were filed.

Amended CSC Filing Accepted. On August 28, 2023, the FERC accepted CSC's CIP-IROL Cost Recovery filing, effective *July 4, 2023*.[32] Unless the August 28, 2023 order is challenged, this proceeding will be concluded.

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[30] Stonepeake Kestrel explained that it removed working capital and interest on operations and maintenance costs for the purposes of this filing in order to avoid a deficiency letter similar to the one received by CSC in Docket No. ER23-1826 (*see* below), and to obtain an affirmative order in this proceeding as expeditiously as possible.

[31] *ISO New England Inc.*, Docket No. ER23-2379-000 (Aug. 21, 2023) (unpublished letter order) ("*FCA18 De-List Bids Order*").

[32] *Cross-Sound Cable Co., LLC*, Docket No. ER23-1826-001 (Aug. 28, 2023) (unpublished letter order).

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. 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).

Request to Delay FERC Action Until October 7, 2023. On August 7, 2023, Versant requested without opposition that the FERC delay its action on this matter in order to allow for Versant Power and the MPUC, which are exchanging information, to resolve the MPUC's questions and concerns described above.

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[33] (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 Mystic's current upstream ownership.[34] 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,[35] 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).

[33] 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.

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

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

- **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[36] 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*.

Public Systems' Request for Disclosure of Audit Information. On May 19, 2023, Public Systems[37] requested that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request"). Public Systems asserted that ISO-NE has 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. Answers to Public Systems' Audit Information Request were filed by Constellation ***Mystic*** Power LLC ("Mystic") (opposing the Audit Information Request), ***ISO-NE*** (which proposed, in addition to the summary of COSA-related audits that ISO-NE posted shortly after Public Systems filed the Request, to make available redacted versions of the FSA audit reports, prepare a narrative of its meetings with Mystic and CLNG regarding the fuel supply plan, and make a member of Levitan & Associates' audit team available to answer questions on three occasions over the remainder of the COSA's term) and ***CT Parties*** (urging the FERC to grant the Audit Information Request). Public Systems answered the Mystic and ISO-NE answers on July 5, 2023. Mystic answered Publicly Systems'' July 5 answer on July 14, 2023. The Audit Information Request is pending before 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,[38] Mystic filed, on August 31, 2023, revised tariff records in eTariff format, effective *June 1, 2022*, to reflect the FERC's action. Comments, if any, on the Tariff Sheets filing are due on or before ***September 20, 2023***.

(-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*.[39] 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 12, ENECOS answered Mystic and urged the FERC to require that Mystic submit full data on its Revenue Credit and sliding-scale revenue sharing calculations in the Information Exchange and Challenge procedure under Schedule 3A to the COSA. On May 15, ISO-NE filed limited comments to provide the FERC with further information and to note that should the Commission allow interested parties to review Mystic's revenue credits during the true-up process, the review should be facilitated by Mystic. ISO-NE stated that the data involved in the calculation of Mystic's revenue credits are confidential under ISO-NE's Information Policy

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

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

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

[39] *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). In the *Mystic I Order on Remand*, the FERC (1) found the initial allocation of 91% of Everett's fixed operating costs to Mystic remains just and reasonable and required that the revenue sharing mechanism be reinstated in the COSA; (2) held its ruling on the clawback issue in abeyance pending resolution in the settlement proceeding; (3) found that the existing language of the COSA mitigates the incentive to unduly delay capital projects; and (4) clarified that all interested parties can review and challenge Mystic's revenue credits and tank congestion charges during a subsequent true-up process. The FERC directed Mystic to submit a 30-day compliance filing, on or before April 27, 2023, revising the COSA to reinstate the revenue sharing mechanism (*see* -023).

but Mystic is provided with the necessary data to calculate the revenue credits. On May 25, 2023, Mystic moved to lodge ISO-NE's May 25, 2023 Audit Controls Memorandum to provide the FERC with a more complete description of the various controls and audits that apply to the Mystic COSA.

Request for Rehearing Denied by Operation of Law. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[40] The Notice confirmed that the 60-day period during which a 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*. The Notice also indicated that the FERC may address, as is its right, the 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."

(-023) 30-Day Compliance Filing (Revised COSA). As directed in the *Mystic I Order on Remand*, Mystic filed, on April 27, 2023, an amended COSA to reinstate the previous revenue sharing mechanism. An effective date of June 1, 2022 was requested. Comments on the 30-Day Compliance Filing were due on or before May 18, 2023; none were filed. The 30-Day Compliance Filing remains pending before the FERC.

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

(-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*.[41] 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.

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[40] *Constellation Mystic Power, LLC*, 183 FERC ¶ 62,115 (May 30, 2023) ("*Mystic I Order on Remand Allegheny Notice*").

[41] 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.

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*,[42] 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)**

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 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.

While this filing will not be noticed for public comment, this filing triggers the commencement of an Information Exchange Period and a Review Period under the Protocols. Interested Parties have 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.

[42] *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).

- **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, the Maine Office of the Public Advocate ("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***. 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)**

About this time last year, the PTO AC submitted its 2023 annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. As prescribed in the Interim Protocols,[43] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC stated that the annual updates result in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing included updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.75 kW-year (effective June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022. This filing was not noticed for public comment.

The July 29 filing was reviewed with the Transmission Committee at its August 16, 2022 summer meeting and at an August 22, 2022 technical session for Interested Parties. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties had until September 15, 2022 to submit information and document requests, and the PTOs were required to make a good faith effort to respond to all requests within 15 days, but by no later than October 15, 2022. During the Review Period, Interested Parties had until November 15, 2022 to submit Informal Challenges to the PTOs, and the PTOs were required to make a good faith effort to respond to any Informal Challenges by no later than December 15, 2022. Interested Parties had until January 31, 2023 to file a Formal Challenge with the FERC.

RENEW Formal Challenge. On January 31, 2023, RENEW filed a formal challenge ("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:

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

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 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

- **Waiver Request: FCA18 Summer Qualified Capacity (Yarmouth 4) (ER23-2356)**

On July 6, 2023, FPL Energy Wyman IV LLC ("Wyman IV") requested a one-time waiver of the Tariff to allow an incremental increase in the summer Qualified Capacity at W.F. Wyman Station Unit 4 ("Yarmouth 4"). In its Waiver Request, Wyman IV explained how, as a result of the failure by Yarmouth 4's Lead Market Participant (NextEra Energy Marketing, LLC ("NextEra EM")) to re-submit by the applicable April 6, 2023 FCA18 deadline a restoration plan related to a forced outage during Yarmouth 4's summer claimed capability audit,[44] Yarmouth 4's FCA18 Summer Qualified Capacity (for the 2027-2028 Capacity Commitment Period ("CCP 2027-2028")) was reduced to approximately 432 MW, rather than 595 MW, under the Tariff rules. Wyman IV seeks a one-time waiver of the Tariff to allow ISO-NE to revise Yarmouth 4's Summer Qualified Capacity to reflect its higher capability consistent with the Tariff. ISO-NE, Wyman IV stated, does not oppose the waiver request. Comments on Wyman IV's waiver request were due on or before July 27, 2023; none were filed. NEPOOL and National Grid each filed a doc-less motion to intervene. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@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").[45] 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.

Request for Rehearing. On September 5, 2023, Public Interest Organizations ("PIOs")[46] requested rehearing of the *IEP Parameter Updates Order*. The PIOs' request for rehearing is pending, with FERC action required on or before October 5, 2023, or the request will be deemed denied by operation of law. 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 December 29, 2022, ISO-NE, NEPOOL and the PTO AC filed revisions to the Tariff and the TOA, in two parts, to 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 ("SATOA Revisions"). The SATOA

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[44] Section III.13.4.2.1.3 of the Tariff allows adjustments for significant decreases to be made if the Lead Market Participant submits to ISO-NE a FCM Restoration Plan describing the measures taken to demonstrate "that the resource will be able to provide an amount of capacity consistent with its total CSO for the CCP by the start of all months in that CCP in which the resource has a CSO." ISO-NE must receive the Plan by no later than 10 Business Days after the Lead Market Participant is notified of the resource's Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for ARA3.

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

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

Revisions were supported by the Participants Committee at its October 6, 2022 meeting (Agenda Item #7). ISO-NE requested a FERC order by March 29, 2023 and indicated that it intends to implement the SATOA Revisions effective July 1, 2024. ISO-NE committed to submit a filing specifying the precise effective date prior to implementation. For eTariff reasons, Part I included the ISO-NE Tariff revisions (ER23-739); Part II, the TOA revisions (ER23-743). Comments on the SATOA Revisions were due on or before January 19, 2023.

On January 19, 2023, comments and protests were filed by: Advanced Energy United ("AEU"), FirstLight, National Grid, NEPGA, NESCOE, UCS, and VELCO. Doc-less interventions only were filed by Avangrid, Vistra, MA DPU, LSP Transmission Holdings, RENEW, RI Energy, ACPA, and EPSA. On February 3, 2023, NEPOOL answered VELCO's comments and ISO-NE answered VELCO's comments and National Grid's limited protest. NEPGA answered VELCO's comments and National Grid's limited protest on February 7. In turn, on February 16, National Grid answered NEPGA's and ISO-NE's answers. ISO-NE answered National Grid's February 16 answer.

Deficiency Letter; ***Response (-001)***. On May 15, 2023, FERC staff issued a deficiency letter requiring additional information to be submitted on or before June 14, 2023. ISO-NE filed its response to the Deficiency Letter in this proceeding on June 14, 2023, re-setting the filing date and deadline for FERC action. Comments on the Deficiency Letter response were due on or before ***July 5, 2023*** and were filed by Elevate Renewables F7, LLC ("Elevate Renewables"). Elevate Renewables urged the FERC to accept ISO-NE's filing as submitted, without condition or modification. On July 12, National Grid requested that the FERC reject Elevate Renewables' July 5 comments (as an impermissible, untimely answer to National Grid's January 19, 2023 pleading filing in this proceeding and as beyond the scope of the questions in or responses to the Deficiency Letter). Elevate Renewables answered National Grid's motion to reject on July 27, urging the FERC to reject that motion.

The SATO Revisions, including the Deficiency Letter and all of the pleadings filed in this proceeding are again pending before the FERC. 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[47] 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[48] ("*Order 2222 Compliance Order*").[49]

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*:

- ***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

[47] 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."

[48] 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.

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

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***. 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 180-Day Compliance Filing are due on or before ***September 18, 2023***.

Requests for Rehearing and/or Clarification (-002). On March 31, 2023, ISO-NE and New England Public Utilities[50] 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".[51] 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."

Federal Court (DC Circuit) Appeals. 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 will be 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

- **Versant Power Att. F App. D Depreciation Rate Change (ER23-2483)**

On July 26, 2023, Versant Power ("Versant") proposed updated depreciation rates for its local transmission facilities in eastern and coastal Maine (the "Bangor Hydro District" or "BHD") set forth in Appendix D to Attachment F of the ISO-NE OATT. A January 1, 2025 effective was proposed. On August 8,

[50] "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").

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

Versant supplemented its filing with exhibits that were inadvertently excluded from its initial filing. Comments on this filing were due on or before August 16, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CMP Att. F App. D Depreciation Rate Change (ER23-2477)**

On August 28, 2023, the FERC accepted updated depreciation rates for CMP's transmission facilities that are set forth in Appendix D to Attachment F of the ISO-NE OATT.[52] The updated depreciation rates were accepted effective as of *July 1, 2023*, as requested. Unless the August 28 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,[53] 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).

Comments on the compliance filings were due on or before May 22, 2023; none were filed. These compliance filings remain pending before the FERC. 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*[54] ("OATT *Order 881* Compliance Changes").[55] 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 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)

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[52] *ISO New England Inc. and Central Maine Power Co.*, Docket No. ER23-2477-000 (Aug. 28, 2023) (unpublished letter order).

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

[54] *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*").

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

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 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

- **FAP Eligible LOC Issuer Changes (ER23-2277)**

On August 11, 2023, the FERC accepted ISO-NE and NEPOOL's jointly-filed revisions to the ISO-NE Financial Assurance Policy ("FAP") to allow ISO-NE to remove banks from the List of Eligible Letter of Credit ("LOC") Issuers (the "Eligible LOC List") ("Eligible LOC Issuer Changes").[56] As previously reported, the Eligible LOC Issuer Changes (i) allow ISO-NE to remove a bank from the Eligible LOC List if ISO-NE determines that despite satisfying the eligibility criteria, accepting a LOC from a bank on the list presents an unreasonable risk that the bank may fail to honor the terms of such letter of credit; (ii) provides Market Participants five Business Days from the date of notice by ISO-NE that a bank is removed from the Eligible LOC List to replace the LOC (and ISO-NE has discretion to extend this cure period to 20 Business Days); and (iii) add language to clarify that when a bank is removed from the Eligible LOC List, ISO-NE will provide a notice to the Budget & Finance Subcommittee. The Eligible LOC Issuer Changes were accepted effective as of August 27, 2023. Unless the August 11, 2023 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).

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

- **Schedule 21-VP: Real Power Loss Factor Charge (ER23-2142)**

On August 11, 2023, the FERC accepted Versant Power's proposed revision to Schedule 21-VP of the ISO-NE OATT to reflect a change in the Real Power Loss factor for Local Point-to-Point Service from 1.99 % to 1.764 %, effective September 1, 2023.[57] Unless the August 11 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 28, 2023, the FERC accepted seven fully executed, non-conforming Local Service Agreements ("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").[58] 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.[59] On August 29, 2023, Versant Power submitted a Refund Report detailing the time value

[56] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER23-2277-000 (unpublished letter order).

[57] *ISO New England Inc.*, Docket No. ER23-2142-000 (Aug. 11, 2023) (unpublished letter order).

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

[59] 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

refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments, if any, on the Refund Report are due on or before ***September 19, 2023***. 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 are due on or before ***September 19, 2023***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports[60]

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

On August 11, 2023, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2023 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include 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). Comments on this filing were due on or before September 1, 2023. NEPOOL filed comments supporting the 2023 Q2 Report. Eversource and National Grid filed doc-less interventions only. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report 2023 Q2 (ER19-1951)**

On August 14, 2023, ISO-NE filed, as required,[61] public and confidential[62] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Second Quarter of 2023 ("2023 Q2"). ISO-NE reported that, with respect to:

  - ***Interconnection Feasibility Study ("IFS") Reports***

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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.

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

[61] Under section 3.5.4 of ISO-NE's Large Generator Interconnection Procedures ("LGIP"), ISO-NE must submit an informational report to the FERC describing each study that exceeds its Interconnection Study deadline, the basis for the delay, and any steps taken to remedy the issue and prevent such delays in the future. The Exceedance Report must be filed within 45 days of the end of the calendar quarter, and ISO-NE must continue to report the information until it reports four consecutive quarters where the delayed amounts do not exceed 25 percent of all the studies conducted for any study type in two consecutive quarters.

[62] ISO-NE requested that the information contained in Section 3 of the un-redacted version of the Exceedance Report, which contains detailed information regarding ongoing Interconnection Studies and if released could harm or prejudice the competitive position of the Interconnection Customer, be treated as confidential under FERC regulations.

- 6 out of 7 2023 Q2 IFS Reports delivered to Interconnection Customers were delivered later than the best efforts completion timeline (90 days from the Interconnection Customer's execution of the study agreement).
- 13 IFS Reports not yet completed have exceeded the 90-day completion expectation.
- The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 186 days (roughly 60 days longer than in 2023 Q1).

♦ ***System Impact Study ("SIS") Reports***

- Both of the SIS Reports delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days.
- 19 SIS Studies that are not yet completed have exceeded the 270-day completion expectation.
- The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 394.5 days (a decrease of roughly 390 days from 2023 Q1).

♦ ***Facility Study Reports***

- 1 Facility Study Report delivered to an Interconnection Customer was delivered later than the best efforts completion timeline of 90 days.
- 1 Facility Study that is not yet completed have exceeded the 290-day completion expectation for a 20% level of cost estimate.
- The average mean time from ISO-NE's receipt of the executed Facility Study Agreement to delivery of the completed Facility Study report to the Interconnection Customer was 181 days.

Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- **ISO-NE FERC Form 3Q (2023/Q2) (not docketed)**

On August 21, 2023, ISO-NE submitted its 2023/Q1 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). Submission of a FERC Form 3-Q is a quarterly requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for public comment.

IX. Membership Filings

- **September 2023 Membership Filing (ER23-2756)**

On August 31, 2023, NEPOOL requested that the FERC accept: (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). Comments on this filing are due on or before ***September 21, 2023***.

- **Aug 2023 Membership Filing (ER23-2514)**

On July 31, 2023, NEPOOL requested that the FERC accept the membership of Clover Energy LLC (Supplier Sector). Comments on the August membership filing were due on or before August 21, 2023; none were filed. This matter is pending before the FERC.

- **Involuntary Termination of Membership of Manchester Methane, LLC (ER23-2390)**

On September 1, 2023, the FERC accepted the termination of Manchester Methane, LLC's ("Manchester Methane") status as a NEPOOL and ISO-NE Market Participant.[63] The involuntary termination of Manchester Methane's NEPOOL and Market Participant status will become effective as of September 11, 2023. Unless the September 1, 2023 order is challenged, this proceeding will be concluded.

- **July 2023 Membership Filing (ER23-2319)**

On August 28, 2023, the FERC accepted: (i) the memberships of Hecate Energy Albany 2 LLC [Related Person to Howard Wind and RoxWind (Supplier Sector)]; Erie Wind, LLC [Related Person to Brookfield Renewable Trading and Marketing (Supplier Sector)]; and SCEF1 FUEL CELL, LLC [Related Person to Bridgeport Fuel Cell and Derby Fuel Cell (AR Sector, RG Sub-Sector)]; (ii) termination of Concurrent LLC (Supplier Sector); and Brookfield Energy Marketing LP [Related Person to Brookfield (Supplier Sector)]; and (iii) the name change of: CPV Spruce Mountain Wind, LLC (f/k/a Spruce Mountain Wind, LLC).[64]

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,[65] 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.

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 are invited to file post-technical conference comments to address issues raised during the technical conference, as identified in the August 3, 2023 Final Notice of Joint Technical Conference. Those comments are due on or before ***September 20, 2023***.

- **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"),[66] 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

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[63] *ISO New England Inc. and New England Power Pool*, Docket No. ER23-2390-000 (Sept. 1, 2023) (unpublished letter order).

[64] *New England Power Pool Participants Comm.*, Docket No. ER23-2319-000 (Aug. 28, 2023) (unpublished letter order).

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

[66] *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).

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"))[67] on June 15, 2023. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the June 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 October 2023, NERC Board of Trustees Adoption in December 2023 and filing of the revised standards with the FERC in January 2024.

- **NOPR: IBR Reliability Standards (RM22-12)**

On November 17, 2022, the FERC issued a notice[68] proposing to direct NERC (i) to develop new or modified Reliability Standards that address the following reliability gaps related to IBRs: data sharing; model validation; planning and operational studies; and performance requirements; and (ii) to submit a 90-day compliance filing that includes a detailed, comprehensive standards development and implementation plan to ensure all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in the final rule are submitted to the FERC within 36 months of FERC approval of the plan. Initial comments were due February 6, 2023[69] and were filed by nearly 20 parties, including, among others, ISO-NE, the IRC, SPP, CAISO, Advanced Energy United, ACPA/SEIA, EEI, and EPRI. Reply comments were due on March 6, 2023 and were filed by ISO-NE, APPA, and CA DWP. This matter is pending before the FERC.

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

On August 24, 2023, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2024. FERC regulations[70] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 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 has requested $22.01 million in statutory funding (a U.S. assessment per kWh (2022 NEL) of $0.000021) and $1.15 million for non-statutory functions. Comments on this filing are due on or before ***September 14, 2023***.

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

On May 31, 2023, NERC filed its annual comparisons of actual to budgeted costs for 2022 for NERC and the six Regional Entities operating in 2022,[71] including NPCC. The Report includes comparisons of actual funding

[67] 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.

[68] *Reliability Standards to Address Inverter-Based Resources*, 181 FERC ¶ 61,125 (Nov. 17, 2022) ("*IBR NOPR*").

[69] The *IBR NOPR* was published in the *Fed. Reg.* on Dec. 6, 2022 (Vol. 87, No. 233) pp. 74,541-74,563.

[70] 18 CFR § 39.4(b) (2014).

[71] 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").

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. Comments on this filing were due on or before June 21, 2023; none were filed. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

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

On July 28, 2023, the FERC authorized[72] 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, and Monitoring Analytics, LLC (the PJM IMM). Public Citizen filed a doc-less intervention.

Since the last Report, Vistra and the Energy Harbor Public Utilities responded to the protests and comments. Answers to that answer were filed by 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. In addition, on August 17, 2023, the FERC issued a deficiency letter identifying the additional information that it needs to process the application. The Response to the deficiency letter is due on or before September 18, 2023 and will constitute an amendment to the application. The FERC noted that the application will not be a completed application for purposes of FERC regulations[73] until the information requested is submitted. A notice of amendment will be issued upon receipt of the response.

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

- **203 Application: Weaver Wind / Greenbacker (EC23-68)**

On August 2, 2023, Weaver Wind, LLC and Weaver Wind Maine Master Tenant, LLC ("Weaver Wind") filed a notice that the FERC-authorized transaction,[74] pursuant to which Jade Energy LLC, a wholly-owned subsidiary of Greenbacker Renewable Energy Company, acquired all the membership interests in Weaver Wind, was consummated on July 25, 2023 (making Weaver Wind a Related Person to Howard Wind and Hecate Energy Albany 2). Reporting on this proceeding is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

[73] 18 C.F.R. § 33.11(a) (2023).

[74] *Weaver Wind, LLC and Weaver Wind Maine Master Tenant, LLC*, 183 FERC ¶ 62,077 (May 12,2023).

- **PURPA Enforcement Petition: Allco Finance Limited (EL23-84)**

On July 24, 2023, Allco Finance Limited ("Allco") petitioned the FERC to initiate an enforcement action against the Massachusetts DPU and DOER (collectively, the "MA State Agencies") to remedy what it asserts if the MA State Agencies' improper implementation of PURPA. Allco states that the MA State Agencies have implemented a state law that empowers the MA State Agencies to compel wholesale energy transactions outside the confines of PURPA, and that empowers those Agencies to exclude all Qualifying Facilities from participating in solicitations for energy and capacity for Massachusetts utilities. Doc-less interventions have been filed by MA DOER, MA DPU, HQUS, MOPA, NEPGA, Public Citizen, MA AG, National Grid, and NECEC Transmission LLC.

On August 14, 2023, MA State Agencies filed a Joint Motion for Extension of Time to file comments, from August 14, 2023 to October 23, 2023 (stating that additional time was needed to consult with the MA AG). On August 21, the FERC issued a notice extending the comment deadline only to August 24, 2023. NECEC Transmission, Maine Office of Public Advocate and MA State Agencies protested Allco's complaint. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On August 17, 2023, Public Service Company of New Hampshire ("PSNH") filed an amendment to the First Engineering, Design and Procurement Agreement ("D&E Agreement") with NECEC Transmission LLC ("NECEC") that was accepted by the FERC as Service Agreement No. IA-PSNH-13. 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-megawatt high-voltage direct current line from Québec to Lewiston, ME (Queue Position #979). PSNH requested an August 18, 2023 effective date. Comments on this filing are due on or before ***September 7, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: RIE/ISO-NE/RISEC & Tiverton (ER23-2494, ER23-2491)**

On July 26, 2023, ISO-NE and Rhode Island Energy ("RIE") filed two revised LGIAs to reflect RIE as the new Interconnecting Transmission Owner. A January 1, 2023 effective date was requested for each of the following LGIAs:

  - **ER23-2494**: Second Revised LGIA that governs the interconnection of Rhode Island State Energy Center, LP's ("RISEC") 209 MW facility located in Johnston, RI.
  - **ER23-2491:** First Revised LGIA that governs the interconnection of Tiverton's 305 MW generating facility located in Newport County in Tiverton, RI.

Comments on these filings were due on or before August 16, 2023; none were filed. RI Energy filed doc-less interventions in both proceedings. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA Termination: CL&P/ISO-NE/NTE CT (ER23-2378)**

On August 31, 2023, the FERC accepted a Notice of Termination of a 3-party LGIA between CL&P, ISO-NE and NTE Connecticut LLC ("NTE CT").[75] The LGIA covered the interconnection of NTE CT's 714 MW combined cycle generating facility located in Killingly, Connecticut. The notice was accepted effective as of *July 12, 2023*, as requested. Unless the August 31 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).

[75] *ISO New England Inc. and The Conn. Light and Power Co.*, Docket No. ER23-2378-000 (Aug. 31, 2023) (unpublished letter order).

- **Engineering & Test Agreement: CL&P / BPUS (ER23-2335)**

On August 15, 2023, the FERC accepted an Engineering and Test Agreement ("Agreement") between CL&P and BPUS Generation Development LLC ("Interconnection Customer" or "BPUS").[76] As previously reported, the Agreement sets forth the terms and conditions under which CL&P will perform necessary engineering and testing services in connection with the development of BPUS's large generating facility, and prior to the execution of 3-party IA with ISO-NE. CL&P designated the Agreement IA-ESCLP-011. The Agreement was accepted effective as of July 6, 2023, as requested. Unless the August 15 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).

- **IA Cancellation: NEP/TransCanada (ER23-2182)**

On August 10, 2023, the FERC accepted the New England Power Company ("NEP")'s Notice of Cancellation of the Interconnection Agreement ("IA") between NEP and TransCanada Hydro Northeast Inc. ("TransCanada") that has been superseded by a new SGIA between NEP and Great River Hydro, TransCanada's successor in interest.[77] The Notice of Cancellation was accepted, effective *August 14, 2023*, as requested. Unless the August 10 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).

- **D&E Agreement Cancellation: NSTAR/Medway Grid (ER23-2117)**

On August 10, 2023, the FERC accepted NSTAR's notice of cancellation of the Engineering, Design and Procurement Agreement ("D&E Agreement") with Medway Grid, LLC ("Medway Grid").[78] The D&E Agreement set forth the terms and conditions under which NSTAR was to undertake certain design and engineering activities on the Interconnection Facilities for Medway Grid's proposed Large Generation Facility prior to the execution of an LGIA. Specifically, the Agreement addressed Qualified Transmission Upgrades ("QTUs") identified by ISO-NE in its FCA15 Post-Auction Overlapping Impact Restudy ("Restudy") for QP844. However, ISO-NE has subsequently performed a review of the Restudy results and has determined that the QTUs are not required for the interconnection of Medway Grid's facility. NSTAR, accordingly, filed a Notice of Termination to reflect the termination of the Agreement. All billing, refunds, and invoices have been finalized and no further work is being done under the Agreement. The notice of cancellation was accepted effective as of June 13, 2023, as requested. Unless the August 10 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).

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

On June 7, 2023, Versant Power filed a revised Attachment J to its 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. Versant requested a June 1, 2024 effective date (which is the first date of the next rate year under the MPD OATT formula rate), but action on the filing by August 7, 2023. Comments on this filing were due on or before June 28, 2023 and were filed by the Maine PUC. Versant answered the June 28 comments of the Maine PUC on July 13, 2023, and the Maine PUC answered Versant's July 13, 2023 comments on July 18, 2013. On July 31, 2023, Versant Power asked the FER to delay action on this filing until ***October 9, 2023*** to allow for a possible resolution of the MPUC's questions and concerns. Accordingly, this matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[76] *The Conn. Light and Power Co.*, Docket No. ER23-2335-000 (Aug. 15, 2023) (unpublished letter order).

[77] *New England Power Co.*, Docket No. ER23-2182-000 (Aug. 10, 2023) (unpublished letter order).

[78] *NSTAR Electric Co.*, Docket No. ER23-2117-000 (Aug. 10, 2023) (unpublished letter order).

- **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, [79] 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. RIE continues to seek January 1, 2023 as the effective date for the LSAs. There has been no activity in this proceeding since ISO-NE and RIE asked that the proceedings be held in abeyance. If you have any questions, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On July 27, 2023, the FERC conditionally accepted Versant Power's proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT") filed in response to the requirements of *Order 881*.[80] The FERC found that Versant Power had complied with most of the requirements of *Order 881*.[81] However, Versant Power was directed to file, no later than ***November 12, 2024*** (8 months prior to Versant Power's July 12, 2025 Attachment T implementation date), a further compliance filing that provides an explanation of its timelines for calculating or submitting AARs. The *MPD OATT Order 881 Compliance Order* was not challenged as is final and unappealable. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **VEC-HQUS Use Rights Transfer Agreement (NJ23-12)**

On June 7, 2023, as amended on June 30, 2023, VEC filed for acceptance an Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") between itself and HQUS. An effective date of May 27, 2023 was requested. No comments on the filings were filed and the Transfer Agreement remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings

- **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;

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

[80] *Versant Power*, 184 FERC ¶ 61,047 (July 27, 2023) ("*MPD OATT Order 881 Compliance Order*").

[81] *Id.* at P 9.

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, 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. This matter is pending before the FERC.

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

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

On November 10, 2022, Invenergy again urged the FERC to "hold a technical conference to examine and to improve the policy and processes relating to the interconnection of interregional MHVDC systems". In December, ENGIE, Grid United and SEIA filed comments supporting Invenergy's November 10 request. On February 6, 2023, the FERC issued a notice of Invenergy's November 10, 2022 request, providing any person interested in commenting a March 8, 2023 comment deadline. Comments were filed by the following parties: Advanced Energy United, NRDC, IRC, SPP, NARUC, Amer. Council on Renewable Energy, Assoc. Industries of MO, Clean Energy Buyers Assoc., Converge Strategies, ELCON, Grid United, IL Manufac. Assoc., MN PSC, Natl. Elec. Manufac. Assoc., ND PSC, Public Citizen, Niskanen Center, Prysmian Group, P. Stockton, R Street Institute, Rail Electrification Council, Renew Missouri Advocates, SOO Green HVDC Link ProjectCo, and World Resources Institute. This matter is pending before the FERC.

- **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 Eniv. 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 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.

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

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

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. On November 1, 2022, a transcript of the technical conference was posted in the FERC's eLibrary. On December 23, 2022, the FERC issued a notice inviting post-technical conference comments on questions listed in that notice. Those comments were due by March 23, 2023 and were filed by: ISO-NE, AEU, Avangrid, Cypress Creek Renewables, Eversource, LS Power, MA AG, NE Public Systems, NESCOE, NextEra, NRDC, NRG, Maine PUC, American Council on Renewable Energy ("ACRE"), APPA, EEI, Harvard Elec. Law Inst., LPPC, NASUCA, NRECA, and R Street Institute. Since the last Report, WIRES, AEP, and EEI filed reply comments. On June 8, 2023, CA Utilities[82] moved to lodge CA PUC Final Resolution E-5252 (which proposed a new CA PUC jurisdictional transmission review program called the Transmission Project Review Process). In comments filed on July 19, 2023, the CA PUC supported the Motion to Lodge, but emphasized that California's establishment of the TPR Process does not obviate the need for the FERC to adopt critical transmission policy reforms applicable to the CAISO (and the rest of the country). This matter is pending before the FERC.

[82] "CA Utilities" are Pacific Gas and Electric Co. ("PG&E"), Southern California Edison Co. ("SCE"), and San Diego Gas & Elec. Co. ("SDG&E").

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

Since the last Report, the FERC posted to eLibrary a transcript of the seventh meeting[83] of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF").[84] 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.[85]

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[86] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before October 18, 2022 a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. The *Order Directing Reports* followed a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[87] and energy and ancillary services markets.[88]

ISO-NE Report. On October 18, 2022, ISO-NE (as well as the other ISO/RTOs) filed its report in response to the *Order Directing Reports.* Comments in response to the RTO/ISO reports were due, following an EEI request, on or before January 18, 2023. Comments were filed by, among others: AEU, API, Constellation, New England Public

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

[84] *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).

[85] 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; (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).

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

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

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

Systems,[89] Shell, Clean Energy Assocs, Clean Energy Buyers Association, EEI, EPSA, Public Interest Orgs, and R Street Institute.

The FERC is reviewing the RTO/ISO reports and comments related thereto to determine whether further action is appropriate.

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

On July 28, 2022, the FERC issued a NOPR[90] 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[91] requested an additional month to submit comments.[92] 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[93] 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[94] (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 must file the one-time informational report required by *Order 897* on or before ***October 25, 2023***.[95]

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[89] "New England Public Systems" are CMMEC, MMWEC, NHEC, and VPPSA.

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

[91] "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").

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

[93] *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*").

[94] 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.

[95] *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,[96] 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;[97] (ii) increase the speed of interconnection queue processing;[98] and (iii) incorporate technological advancements into the interconnection process.[99] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of Proposed Rulemaking.[100] However, the FERC did revise aspects of the reforms.[101] *Order 2023* will become effective November 6, 2023,[102] which is 60 days from the September 6, 2023 publication of *Order 2023* in the *Federal Register* ("Publication Date").

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

[97] 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.

[98] 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.

[99] 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.

[100] *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.

[101] 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.

[102] *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 and A Request for an Extension of Time. Since the last Report, 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.

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. A summary of the request for extension of time, as well as of the prominent issues raised in the requests for rehearing, is provided in a separate memo included as Appendix A to this Report.

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.[103] *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

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

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*.[104] Since the last Report, SPP asked for a 14-day extension of time for the submission of its compliance filing. The SPP request is pending before the FERC. No other ISO/RTO has requested an extension of time.

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

On December 15, 2022, the FERC issued a NOPR[105] 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 applications. Following a NARUC request for an extension of time, granted by the FERC on March 3, 2023, 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. Since the last Report, Chairman Phillips' response to Senator Schumer's June 20, 2023 letter and each of the Commissioner's responses to Senator Barrasso's April 26, 2023 letter were posted to eLibrary. This matter is pending before the FERC.

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

Following its ANOPR process,[106] the FERC issued on April 21, 2022 a NOPR[107] 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

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

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

[106] *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.

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

regional transmission plan for purposes of cost allocation through long-term regional transmission planning;

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

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

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

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and 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.[108] 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

[108] 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.

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

- **Big River Steel (BRS) and Entergy Arkansas (EA) (IN23-11)**

On August 21, 2023, the FERC approved a Stipulation and Consent Agreement with Big River Steel LLC ("BRS") and Entergy Arkansas, LLC ("Entergy AK")[109] that resolved OE's investigation into whether BRS' participation in a MISO demand response program between September 2016 and April 2022 (the "Relevant Period") violated MISO's Tariff or FERC regulations. Entergy AK was (as the Market Participant for BRS) selling Energy, in the form of reduced energy usage, in MISO's Day Ahead and Real Time markets. BRS did not (with the exception of seven days in February 2021) reduce energy consumption levels in response to MISO accepting its demand response offers. Instead, BRS operated at the load levels at which it would have operated if it were not a DRR-1 unit. OE concluded that this conduct violated § 38.2.5(d)(ii)(e) of the MISO Tariff because BRS did not "respond to [MISO] directives to . . . change output levels" by reducing its load below what it would otherwise have been. Because Entergy AK was the Market Participant for BRS's participation as a DRR-1, OE concluded that Entergy AK is responsible for BRS's conduct that violated the MISO Tariff. Under the Settlement, in which neither BRS nor Entergy AK admits nor denies the alleged violations, BRS agreed to ***disgorge $15,940,399*** it received through its participation as a DRR-1 unit in MISO during the Relevant Period, to pay a ***$6 million civil penalty***, and to provide compliance training to its traders if it intends to participate again as a DRR-1 unit in MISO. Entergy AK agreed to ***disgorge $5,033,780*** in connection with BRS's participation as a DRR-1 unit in MISO, and to ***ensure that customers are credited the net amount ($8,181,899)***, with interest from the date that MISO transmits funds to EAL under the Agreement, that the customers were charged in connection with BRS's participation as a DRR-1 unit in MISO. 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,[110] 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,[111] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a

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[109] *Big River Steel LLC and Entergy Arkansas, LLC*, 184 FERC ¶ 61,111 (Aug. 21, 2023).

[110] 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.

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

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[112] 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,[113] 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;[114] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[115] 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[116] 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.[117]

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

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

[113] *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").

[114] 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.

[115] *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.

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

[117] 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.

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.[118] 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.[119]

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[120] 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 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.[121] 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;

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

[119] *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).

[120] *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*").

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

(ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- The Project is targeted for a 4th quarter 2023 in-service date.

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,[122] and that effectively halted construction of the NECEC Project,[123] 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).

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[122] 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?"

[123] 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.

- **Order 2222 Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170)(consolidated)**
  Underlying FERC Proceeding: ER22-983[124]
  Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
  Status: Being Held In Abeyance Pending Further FERC Order on Rehearing in ER22-983

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*.[125] 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. The parties were directed to file motions to govern future proceedings in this case by ***October 10, 2023***. Motions to intervene by non-appealing parties have been filed by Versant Power.

[124] *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*").

[125] 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.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[126]
  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.[127] 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,[128] as have the Certified Index to the Record and NextEra filed Petitioners' Brief. Remaining submissions include: Respondent's Brief (***September 28, 2023***); Intervenors for Respondent's Joint Brief (October 12, 2023); Petitioners' Reply Brief (October 26, 2023); Joint Appendix (October 30, 2023); and Final Briefs (November 3, 2023). The parties will be informed later of the date of oral argument and the composition of the merits panel.

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
  Underlying FERC Proceeding: ER22-707[129]
  Petitioner: Green Development
  Status: Petitions for Review Denied; Issuance of Mandate Withheld

On July 28, 2023, the DC Circuit issued an order denying Green Development's petitions for review. The Court held that each of Green Development's four grounds for vacatur lacked merit. The Court directed the Clerk to withhold issuance of the mandate until seven days after disposition of any timely petition for rehearing or petition for rehearing *en banc*.

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[126] *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*").

[127] 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.

[128] 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).

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

- **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,[130] -013[131] -017[132]
Petitioners: Mystic, CT Parties,[133] 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 July 24, 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 July 27, 2023, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***October 25, 2023***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
Underlying FERC Proceeding: ER18-619[134]
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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[130] *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).

[131] *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).

[132] *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*).

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

[134] *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[135]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[136] 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*[137] 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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[135] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

[136] 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.

[137] *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*[138]
Petitioners: Sierra Club
Status: Briefing Complete; Oral Argument Scheduled for Sep 18, 2023

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. Briefing is complete. On June 23, 2023, the Court scheduled oral argument for ***September 18, 2023***. The merits panel will be comprised of Judges Henderson, Pan and Rogers.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
Underlying FERC Proceeding: RM19-15[139]
Petitioners: SEIA et al.
Status: Oral Argument Held March 8, 2022; Awaiting Decision

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[140] Briefing was completed and oral argument held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.)**
Underlying FERC Proceeding: CP16-9-012[141]
Petitioners: LS Power, Algonquin, INGA
Status: Being Held in Abeyance Pending Further Order of the Court

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

On June 30, 2022, the First Circuit transferred cases 20-1458 and 22-1201 to the DC Circuit. The DC Circuit docketed those cases as 22-1146 and 22-1147, consolidated them with its cases challenging the Atlantic Bridge Project orders (with 21-1115 remaining the lead case), and directed the parties to file a proposed briefing schedule. On July 19, 2022, the parties filed a proposal that cases 22-1146 and 22-1147 be severed, proposed a revised briefing format and schedule for those cases, and asked the Court to continue to hold the remaining cases

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

[139] *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).

[140] *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.

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

in abeyance (asserting that abeyance may avoid the need for briefing and adjudication of the issues that Algonquin and INGAA would press).

As previously reported, briefing was completed in Cases 22-1146 and 22-1147 and oral argument held on April 20, 2023. Since the last Report, the DC Circuit issued an order dismissing both petitions for lack of jurisdiction. The remaining matters will be returned to active consideration.

Since the last Report, the Court ordered that the remaining consolidated cases remain in abeyance pending further order of the Court and directed the parties to file motions to govern future proceedings by ***September 11, 2023***.

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MEMORANDUM

TO: NEPOOL Officers

FROM: NEPOOL Counsel

DATE: September 6, 2023

RE: Order No. 2023 Update: Requests for Rehearing, Clarification and/or Additional Time

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On July 28, 2023, the Federal Energy Regulatory Commission ("FERC" or "the Commission") issued Order No. 2023, a final rule reforming its *pro forma* Large and Small Generator Interconnection Procedures and Agreements to ensure that "interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner" ("Order No. 2023" or the "Final Rule").[1] Pursuant to Section 313 of the Federal Power Act ("FPA"), requests for rehearing of Order No. 2023 were due thirty days after the issuance of the Final Rule – on Monday, August 28. On or by that date, thirty-five parties submitted requests for rehearing, clarification and/or an extension of time with the Commission.[2] This document summarizes the prominent issues raised in the requests for rehearing and also summarizes the requests for extension of time.

Compliance filings in accordance with Order No. 2023 are currently due within 90 days after the Final Rule is published in the *Federal Register*, which occurred September 6, 2023, making the compliance filing due date December 5, 2023.[3] To date, the Joint RTOs[4] are the only entities to file a motion requesting an extension of time. The Joint RTOs requested to extend the compliance filing deadline **until at least 90 days after the Commission issues a substantive order addressing arguments on clarification and rehearing.**

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[1] *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,051 (2023) ("Order No. 2023" or "Order"). The Final Rule is available here: https://www.ferc.gov/media/e-1-order-2023-rm22-14-000. The Day Pitney summary of the Final Rule is available here: https://www.iso-ne.com/static-assets/documents/2023/08/a03_2023_08_22_tc_nepool_counsel_memo_order_2023_summary.pdf.

[2] Attachment 1 contains the list of all parties that submitted requests for rehearing or clarification and/or requests for extension of time.

[3] The published Final Rule can be found here: https://www.federalregister.gov/documents/2023/09/06/2023-16628/improvements-to-generator-interconnection-procedures-and-agreements.

[4] The Joint RTOs are PJM Interconnection, LLC ("PJM"), Midcontinent Independent System Operator, Inc. ("MISO"), and Southwest Power Pool, Inc. ("SPP").

The following are prominent themes/issues raised in the requests for rehearing:

- The Commission erred in removing the Reasonable Efforts standard and imposing penalties for late studies;
- The Commission must clarify aspects of the transition process and use of Transitional Cluster Studies and Transitional Serial Studies;
- Transmission Providers need additional details on the Commission's requirement for Transmission Provider's to publish heatmaps;
- The Commission 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.[5]

I. <u>REQUESTS FOR ADDITIONAL TIME TO COMPLY</u>

While the Joint RTOs are the only entities that explicitly filed a motion requesting additional time to comply with Order No. 2023, several other entities argued on rehearing that the Commission erred when it shortened the compliance deadline from 180 days (as was proposed in the Notice of Proposed Rulemaking) to 90 days in the Final Rule.[6] The majority of these entities simply requested that the Commission re-establish the proposed 180-day compliance deadline.[7]

Joint RTOs requested that the Commission extend the compliance filing deadline until at least 90 days after the Commission issues a substantive order addressing arguments raised on rehearing. The Joint RTOs stated that they wanted the Commission to address the open issues raised in requests for rehearing and/or clarification and provide upfront answers on Order No. 2023's directives before requiring a compliance filing. They argued that requiring compliance filings prior to a ruling on rehearing could require Transmission Providers to make substantial changes to their filings and implementation, and ultimately cause work to be redone. The Joint RTOs also requested an order from the Commission on the extension of time within 30 days – on or by September 27. The potential practical outcome of such an extension request (if granted) would mean that Transmission Providers/RTOs may have several months, if not a year, to prepare compliance filings as the Commission can tend to take that amount of time to consider the issues raised on rehearing and issue an order addressing those arguments.

[5] We have also provided a category herein for "other" requests for rehearing that we viewed as important to raise. However, please note that this memo does not provide an exhaustive list of all issues raised on rehearing and/or clarification.

[6] Dominion Energy Services Request for Rehearing, Pacificorp Request for Rehearing and the Edison Electric Institute ("EEI") Request for Rehearing.

[7] *See e.g.*, Pacificorp Rehearing Request at 20.

II. REQUESTS FOR REHEARING AND/OR CLARIFICATION: MAIN THEMES/ISSUES RAISED

A. Removal of the Reasonable Efforts Standard and Imposition of Study Delay Penalties

Likely the most prevalent topic raised in requests for rehearing is that the Commission erred in removing the Reasonable Efforts standard and imposing penalties for study delays. The entities that raised this point made arguments such as:

- The Commission's decision to eliminate the reasonable efforts standard and impose study delay penalties is not supported by substantial evidence and is arbitrary and capricious under the federal Administrative Procedure Act;[8]
- The Commission failed to consider evidence of unintended consequences of imposing penalties for study delays including additional costs that Transmission Providers will bear in complying with this requirement;[9]
- The penalty scheme violates constitutional protections on due process by assessing penalties with no development of a factual record about whether the Transmission Provider did anything wrong;[10]
- Elimination of the Reasonable Efforts standard is not reasoned decision-making because it will be counterproductive to the Commission's goal of expediting interconnection queue processing;[11]
- FERC lacks statutory authority to impose late-study penalties without a determination of fault and to absolve interconnection customers from bearing any form of late-study penalty when such customers have caused the penalties to become applicable;[12]
- Late study penalties result in a regulatory taking by failing to provide recovery for prudently incurred study costs and are unduly discriminatory and preferential rendering only Transmission Providers and RTO/ISOs as potentially culpable for such penalties;[13]

[8] Dominion Energy Services Request for Rehearing, Pacificorp Request for Rehearing, WIRES Request for Rehearing, MISO TOs Request for Rehearing, EEI Request for Rehearing, Avangrid Request for Rehearing, NYTOs Request for Rehearing, AEP Request for Rehearing, PJM TOs Request for Rehearing, PJM Request for Rehearing, SPP Request for Rehearing.

[9] Pacificorp Request for Rehearing, MISO TOs Request for Rehearing, PJM Request for Rehearing.

[10] Pacificorp Request for Rehearing, PJM TOs Request for Rehearing.

[11] WIRES Request for Rehearing.

[12] NYTOs Request for Rehearing, PJM TOs Request for Rehearing.

[13] NYTOs Request for Rehearing.

- The Final Rule's rigid penalty structure for study delays and the imposition of deadlines that are not tailored to the unique circumstances presented in each RTO/ISO, are arbitrary and capricious, unduly discriminatory and preferential;[14]
- Commission departed from well-established policy (reasonable efforts standard) without offering a reason;[15]
- Penalty appeal process is ill-conceived, ill-defined and adopts unreasonable regime depriving utilities of due process;[16]
- Penalty scheme is unduly discriminatory because it does not assign study delay penalties to Interconnection Customers regardless of their own role in causing the delay, imposes the same study delay penalty framework on each Transmission Provider without regard to the number of Interconnection Requests it is responsible for, and awards study delay penalties to Interconnection Customers on a pro rata basis;[17]
- Objections to the suggestion that RTO/ISOs may pass through study delay penalties imposed on it to market participants (which will ultimately be borne by consumers).[18]

B. Clarity Sought Regarding Transition Process and Applicability to Transmission Providers That Already Use Clustering

Several entities raised questions with the Commission about the proposed transition process to move to the first-ready, first-served cluster study process.[19] These requests generally fall into two categories: (1) questions about the general logistics of the transition process; and (2) requests for clarification for entities who already have some form of clustering in their Large Generator Interconnection Procedures.

With regards to the first, entities raised the concern that the scope of the Transition Cluster Group established by the Commission unjustly and unreasonably groups customers that submit interconnection requests on the eve of transmission providers' Order No. 2023

[14] NYTOs Request for Rehearing.

[15] MISO TOs Request for Rehearing.

[16] MISO TOs Request for Rehearing, PJM TOs Request for Rehearing.

[17] PJM TOs Request for Rehearing.

[18] NYPSC Request for Rehearing.

[19] As described in the NEPOOL Counsel Memo on Order No. 2023, the Commission has proposed a transition process whereby entities who have been tendered a Facilities Study Agreement as of 30 Calendar Days after the date of the Transmission Provider's initial compliance filing, may opt to proceed in the serial process with a Transitional Serial Interconnection Facilities Study (and pay a deposit/demonstrate 100% site control) or withdraw without penalty. Entities who have been assigned a queue position as of 30 Calendar Days after the filing date of the initial compliance filing may opt to proceed with the Transitional Cluster Study (and pay a deposit/demonstration 100% site control) or withdraw without penalty.

compliance filing and customers that have been pending in the queue for substantially longer periods of time.[20] These entities argue that it is unfair for developers who have been in the queue for months or years to be put in the same transitional cluster as a developer who submits an Interconnection Request right after the compliance filing date. Instead, these entities ask the Commission to revise the Transitional Cluster Study process to set the July 28, 2023 issuance date of Order No. 2023 as the date for eligibility for Transitional Cluster Study participation.

For Transmission Providers who already have a form of clustering, there were several questions and requests for rehearing/clarification on the transition process. A few Transmission Providers argued that it was generally an error for the Commission to issue a generic rulemaking determining that *all* interconnection processes are unjust and unreasonable, even those that the Commission recently approved and which utilize clustering.[21] The requests for rehearing and/or clarification raised the following:

- The Commission should clarify that "early adopters" i.e., entities that already use clustering approved by the Commission may conclude their pending/existing studies before transitioning to the new Order No. 2023 process;
- Clarify that if interconnection customers part of currently-existing clusters will be required to update their respective study deposits, commercial readiness deposits correlating to the amounts required at the various stages of the process should be provided, and their site control documentation should be updated in order to remain in the queue;[22]
- Clarify how recently-approved queue reforms will be reviewed in the independent entity variation process.[23]

C. Heatmaps

Several entities requested rehearing and/or clarification on specifics of the Commission's heatmaps proposal,[24] such as:

- The Commission should clarify when heatmaps are due for Transmission Providers that do not conduct a new transition period;[25]

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[20] Shell Request for Rehearing, IPP Request for Rehearing.

[21] Dominion Request for Rehearing, PJM Request for Rehearing, PJM TOs Request for Rehearing.

[22] NV Energy Request for Rehearing

[23] PJM Request for Rehearing.

[24] As described in the NEPOOL Counsel Memo on Order No. 2023, the Commission required that Transmission Providers publicly post available information pertaining to generator interconnection in the form of a heatmap within 30 calendar days after the completion of each cluster study and cluster restudy.

[25] Pacificorp Request for Rehearing.

- The individual heatmap mandate for non-RTO Transmission Providers is arbitrary and capricious and contrary to reasoned decision-making. Heatmap websites only make sense financially when done at a scale for several utilities; [26]
- Does the heatmap have to include proposed network upgrades with capacity amounts to reflect the available transfer capacity or only the existing facilities?[27]
- Final Rule's overly prescriptive approach to a heatmap will provide information to Interconnection Customers and its requirement that load pay for this tool rather than permitting other arrangements that would charge the costs to the Interconnection Customers that benefit from it is arbitrary and capricious.[28]

D. Cluster and Cost Allocation Issues

In addition to the transition issues, discussed above, several entities raised general concerns about the switch to a first-ready, first-served system and the cost allocation provisions that the Commission proposed. Included among the arguments/requests made are the following:

- The 150 day timeframe for cluster studies is arbitrary and capricious as this study period is an unreasonable limitation on the time required for performing the system impact study evaluations, including necessary reliability analyses;[29]
- Whether the Commission acted arbitrarily and capriciously and failed to engage in reasoned decision-making when it declined to require transmission owners to attend scoping meetings as part of the cluster study process;[30]
- The Commission committed reversible error by requiring, in section 4.4.1 of the pro forma LGIP that the opportunity to reduce generation project size can be exercised only prior to the initial Cluster Study result. The opportunity to reduce generation project size should be able to be exercised after the initial Cluster Study result and prior to the start of subsequent Cluster Re-Study;[31]
- The Commission should clarify that the obligation to reimburse generator interconnection customers for affected system upgrades extends to both traditional affected system analyses and to "seams" analyses that integrate generator interconnection and regional (and inter-regional) transmission planning and cost allocation;[32]
- Order No. 2023 should not result in transmission providers removing existing inter-cluster cost sharing provisions from their tariffs or prevent transmission providers from

[26] Non-RTO Providers Request for Rehearing.

[27] NV Energy Request for Rehearing.

[28] PJM Request for Rehearing.

[29] NYISO Request for Rehearing.

[30] Orsted Request for Rehearing.

[31] Shell Request for Rehearing.

[32] *Id.*

proposing new inter-cluster cost sharing mechanisms in the future. Example provided of ISO-NE Late Comer provision in Schedule 11 of ISO-NE OATT;[33]

- FERC erred and should implement minimum impact thresholds for use within the proportional impact method when evaluating the cost allocation of network upgrades to generator interconnection customers requesting ERIS and NRIS;[34]
- How does the 150-day restudy deadline apply to cascading restudies?[35]
- Concern that aspects of the Commission's reasoning could be misinterpreted as constituting a blanket determination that any thresholds or metrics used by a Transmission Provider to allocate costs among customers within a study cluster do not significantly affect rates and need not be filed with FERC;[36]

E. Technology Issues

Order No. 2023 mandated Transmission Providers incorporate alternative transmission technologies ("ATTs") and use operating assumptions for storage if presented by the Interconnection Customer. There were several requests for rehearing on these points, including:

- The Final Rule unlawfully excluded Dynamic Line Ratings from the final list of enumerated alternative transmission technologies;[37]
- The Final Rule unlawfully gave Transmission Providers unfettered discretion to disregard and disadvantage advanced transmission technologies as network upgrades;[38]
- Whether the Commission acted arbitrarily and capriciously by requiring the interconnection customer to provide a validated electromagnetic transient model at the time of queue applications despite evidence in the record that it is more useful and less burdensome when provided later in the interconnection process;[39]
- Use of customer-provided operating assumptions is not consistent with how planning studies are performed and will add additional administrative burdens for transmission providers;[40]
- The requirement that Grid Enhancing Technologies ("GETs") be evaluated with no limits on how many such technologies Interconnection Customers may present for study and

[33] *Id.*

[34] Longroad Request for Rehearing.

[35] EEI Request for Rehearing.

[36] Generation Developers Request for Rehearing.

[37] WATT Coalition Request for Rehearing, Public Interest Organizations Request for Rehearing.

[38] WATT Coalition Request for Rehearing.

[39] Orsted Request for Rehearing.

[40] PJM Request for Rehearing, NYISO Request for Rehearing, SPP Request for Rehearing, Joint RTOs Request for Rehearing.

when they can present them undermines orderly process and is overly burdensome, particularly given requirement to report separately on the evaluation of GETs.

F. Other

Finally, there were additional requests for rehearing that do not explicitly fall into one of the categories enumerated above, but that raise important issues with respect to the Final Rule. These include issues such as:

- Whether the Commission erred by not allowing TPs additional time to submit compliance filings for their Wholesale Distribution Access Tariffs. Order 2023 states that the changes apply to a request to interconnect to a public utility's distribution facilities used to transmit electric energy in interstate commerce on behalf of a wholesale purchaser pursuant to a Commission-filed Open Access Transmission Tariff;[41]

- Clarification that Order No. 2023 does not require transmission providers to re-file and seek approval for portions of their existing LGIA and LGIP that have previously been approved by the Commission and are not directly impacted by Order 2023;[42]

- FERC erred and should provide a broader range of financial security available under the LGIP/LGIA for the purposes of protecting the transmission provider from the risk of non-payment, including surety bonds or other form of security reasonably acceptable.[43]

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[41] EEI Request for Rehearing.

[42] EEI Request for Rehearing.

[43] Longroad Request for Rehearing.

Attachment 1 – List of Entities that Filed Requests for Rehearing, Clarification and/or an Extension of Time

VEIR Inc.	MISO Transmission Owners
Dominion Energy Services, Inc.	American Electric Power Service Corporation
Dominion Energy South Carolina, Inc., Pacificorp and Tri-State Generation and Transmission Association, Inc. (as the "Revised Early Adopters Coalition")	Indicated PJM Transmission Owners
Pacificorp	National Grid Renewables Development, LLC, Clearway Energy Group LLC and Pine Gate Renewables (together, "Generation Developers")
Dominion Energy South Carolina, Inc., Florida Power & Light Company and Public Service Company of Colorado (as the "non-RTO Providers")	PJM Interconnection, LLC
Shell Energy North America (US) L.P., Shell New Energies US, LLC and Savion, LLC	Southwest Power Pool, Inc.
Longroad Energy Holdings, LLC	Invenergy
Working for Advanced Transmission Technologies ("WATT") Coalition	Duke Southeast Utilities
Nevada Power Company and Sierra Pacific Power Company (together, "NV Energy")	ITC Holdings Corp.
Orsted North America, LLC	New York Independent System Operator, Inc.
WIRES	Duke Southeast Utilities, Louisville Gas and Electric, Kentucky Utilities Company, PowerSouth Energy Cooperative, Southern Company Services Inc. (together, "Southeastern Utilities")
The Edison Electric Institute ("EEI")	Advanced Energy United, American Clean Power Association and the Solar Energy Industries Association (collectively, "Clean Energy Associations")

Energy Alabama, Environmental Defense Fund, National Audubon Society, Natural Resources Defense Council, NW Energy Coalition, Sierra Club, Southern Environmental Law Center, Sustainable FERC Project (together, "Public Interest Organizations" or "PIOs")	Cypress Creek Renewables, LLC, New Leaf Energy, Inc. and Enel Green Power (collectively, "Independent Power Producers Coalition" or "IPP Coalition")
New York State Public Service Commission	Midcontinent Independent System Operator, Inc.
New York Transmission Owners	NewSun Energy LLC
PJM, MISO and SPP (as the "Joint RTOs")	
Avangrid, Inc.	