NEW ENGLAND POWER POOL

Sebastian Lombardi
Secretary

August 28, 2024

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of September 5, 2024 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the September 2024 meeting of the Participants Committee will be held at the **Westin Portland Harborview Hotel, 157 High Street, Portland, Maine on Thursday, September 5, 2024, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. For those who are unable to attend in person but who are otherwise authorized to attend NEPOOL meetings as Participant representatives or as approved guests, the dial-in number will be **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 in Boston, MA. October's meeting is on Thursday, **October 10**, and will be at the Renaissance Boston Waterfront Hotel. The **November 7** Participants Committee meeting will be held at the Seaport Hotel and will commence following the separately scheduled modified Sector meetings with the ISO Board and state officials. The **December 5** meeting is the Participants Committee Annual Meeting and will be at the Colonnade Hotel. 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 enjoy the Labor Day Holiday. Looking forward to seeing you in Portland, Maine on September 5.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the August 1, 2024 Participants Committee meeting. A copy of the draft minutes, marked to show the changes made to the draft circulated with the initial notice, is include and posted with this supplemental notice.

2. To adopt and approve the actions 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 will be circulated and posted in advance of the meeting.

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

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

   a. 2025 ISO-NE Operating and Capital Budgets; and

   b. 2025 NESCOE Budget.

   Background materials are included and posted with this supplemental notice.

6. To consider and take action, as appropriate, on proposed Tariff changes concerning Pay-for-Performance (PFP) Financial Assurance. Background materials and draft resolution(s) are included with this supplemental notice.

7. To consider and take action, as appropriate, on a proposed enhancement to the NEPOOL Generation Information System (GIS), including changes to the GIS Operating Rules, to accommodate the transfer of hourly certificates, as requested by Constellation Energy Generation LLC. Materials regarding the proposed GIS changes and a draft resolution are included and posted with this supplemental notice.

8. To consider and take action, as appropriate, on the Governance Only End User membership application of Alan Sliski. Background materials and a draft resolution are included and posted with this supplemental notice.

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.

9. 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.

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

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

11. Administrative matters.

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

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

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference/Webex on Thursday, August 1, 2024, 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.

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

APPROVAL OF JUNE 25-26, 2024 SUMMER MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the June 25-26, 2024 Summer Meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

Ms. Bresolin then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved as circulated, with: (i) oppositions noted by Braintree, Georgetown, Groveland, Hyde Park, Littleton (MA), Middleton, Rowley, and Wallingford DPU (together, Opposing Members); and (ii) abstentions noted by Cross-Sound Cable, Jericho Power, MMWEC and each of MMWEC's Participant members (Ashburnham, Boylston, Chicopee, Groton, Holden, Holyoke, Hull, Ipswich, Mansfield, Marblehead, Paxton, Peabody, Princeton, Russell, Shrewsbury, South Hadley, Sterling, Templeton, Wakefield, and West Boylston), and Mr. Lamson. Opposing Members attributed their opposition to Consent Agenda Item # 2 (New

Planning Procedure No. 12 (Data Collection for Distributed Energy Resources)). Opposing Members' representative explained their view that, given Opposing Members' relative size (both in terms of overall staff resources and MW value impact to the processes that the ISO was enhancing), the PP-12 changes would impose an unduly burdensome and unnecessary additional reporting requirement.

UPDATES TO NON-COMMERCIAL CAPACITY FINANCIAL ASSURANCE AMOUNT MULTIPLIER

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, reported that the ISO reviewed its proposed updates to the Non-Commercial Capacity Financial Assurance (NCC FA) Amount Multiplier (the Multiplier) at the March and April B&F meetings. The changes to the Multiplier, he explained, were intended to keep the Multiplier consistent with the current level of the multiplier with respect to the length of time until the start of the Capacity Commitment Period, particularly in light of the recently-approved additional two-year delay for the nineteenth Forward Capacity Auction (FCA19). The ISO's proposal reflected feedback received at the March B&F meeting, and no concerns with the revisions were expressed when presented again to the B&F at its April meeting. Mr. Kaslow noted one further clarifying edit, which had been distributed to members with the final additional materials prior to the meeting, that reversed an unintended strikeout of the word "Day" to the term "Business Day" in the definition of Multiplier. He also noted that Participants Committee action on these updates had been deferred until after the FERC's acceptance of~~,~~ the further FCA19 delay.

In response to a member's question, Mr. Kaslow explained that, as worded, the proposed changes should work under a prompt auction design, regardless of how "prompt" might be defined. He further noted that, in its presentation to the B&F, the ISO identified that the changes were intended to become effective in the fourth quarter of 2024.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports the updates to the Financial Assurance Policy's Non-Commercial Capacity Financial Assurance Amount Multiplier as reflected in the materials circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

A member explained that he would support the changes so that there would be an incremental financial assurance posting requirement for non-commercial resources, addressing an issue raised by the FCA19 delay. Another member thanked the ISO for the changes made in response to Participant feedback at the March B&F meeting.

Without further discussion, the motion was approved unanimously with one abstention by Mr. Lamson recorded.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of the ISO Board and Board Committee meetings that had occurred since the June Participants Committee Summer Meeting, which had been circulated and posted with the materials for the meeting. There were no questions on those summaries.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his August operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through July 24, 2024, unless otherwise noted. The August report highlighted: (i) that the Peak Hour for July, with 24,816

MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on July 16, 2024 during the hour ending at 6:00 pm (Dr. Chadalavada noted that statistics for each of the three categories of Peak Load (RQM, Telemetered System and FCM) would be included in the monthly COO reports going forward); (ii) July averages for Day-Ahead Hub LMP ($49.33/MWh), Real-Time Hub LMP ($43.73/MWh), and natural gas prices ($1.86/MMBtu); (iii) Energy Market value for July 2024 was $572 million, down from $579 million in July 2023 and up from the updated June Energy Market value of $428 million; (iv) Ancillary Markets value ($13.5 million) was down from July 2023 ($22.8 million); (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 101.7% during July (up from 101.0% reported for June 2024); (vi) Daily Net Commitment Period Compensation (NCPC) payments for July totaled $6.3 million, comprised of first contingency payments, including $448,000 in Dispatch Lost Opportunity Costs, $620,000 in Rapid Response Pricing Opportunity Costs, $274,000 paid to resources at external locations, and $480,000 in Distribution (there were no second contingency or voltage NCPC payments in July); and (vii) Forward Capacity Market (FCM) value was $119.6 million.

Addressing July temperatures, Dr. Chadalavada reported that July was hotter and more humid than in the past years. The July 23-city weighted average temperature was on average 3.7°F warmer than normal, with several days being warmer than normal by 7-9°F. Dew points were also above normal, approximately 2°F higher than would be expected for the month of July.

Turning to transmission outages, Dr. Chadalavada did not have any specific outages to note, but relayed his expectation that there would likely be scheduled transmission outages occurring in the second half of September and October. He committed to report at the

September Participants Committee meeting on those outages that might impact market performance or interface limits.

Dr. Chadalavada highlighted information included in his Report on the June 18, 2024 Capacity Scarcity Condition (CSC) and implementation of Operating Procedure (OP) No. 4 (OP-4), which had also been briefly touched on at the Committee's June Summer Meeting. He welcomed questions, comments, and further discussion. In response to questions and comments, Dr. Chadalavada confirmed that aggregate information related to generation resource penalties and incentive payments could be assembled and he committed to providing that information to the Committee at or before the next Participants Committee meeting. Similarly, he committed to provide information at the next meeting on how any penalty amounts that exceed payments made would be trued-up.

Dr. Chadalavada then addressed, in response to comments, the timing of curtailment notices (both related to the June 18 event, and to subsequent notices, which were similarly timed). He confirmed that curtailment notifications were issued pursuant to a manual process, and identified some of the sensitivities and challenges that automating and accelerating the issuance of such notices could present, including inadvertent release of commercially sensitive information that could impact the market, and other administrative concerns. He agreed, however, to explore the possibility of automation further and committed to follow-up with more information, when and as available.

With respect to the Capacity Balancing Ratio (BR) that was calculated for the Capacity Scarcity Condition, Dr. Chadalavada provided a sense of the timing involved in calculating the BR. The perceived lag was due in part to the time it takes to receive full RQM data, receipt of which could take roughly five days for a larger percentage of the data, but as long as three weeks for the remainder to be submitted. He also noted provisions for certain asset classes that required continual true-up. He agreed to consider with the ISO settlement team whether some reasonably reliable estimate could be provided ahead of the final BR calculation in order to provide additional information to those that might need to prepare for impending penalties/payments. Dr. Chadalavada also reacted to comments regarding the inclusion of scheduled exports, and not just loads internal to New England, in the determination of load for BR purposes. He committed to further research that design element and follow-up with any additional insight/information.

Responding to additional questions, Dr. Chadalavada pointed a member to OP-8 for additional information on Operating Reserves, and offered to discuss available training and background materials further if OP-8 did not meet the need. He reported that progress towards the March 1, 2025 implementation of the Day-Ahead Ancillary Services Initiative (DASI) was on schedule, with a Sandbox environment to be available for testing and customer training and readiness efforts to ramp up noticeably in the October timeframe. Separately, he committed to see whether and, if so, report where, historical information on OP-4 events may be found on the ISO website and whether that information could be enhanced to include CSC information.

Addressing clarifying questions regarding the year-to-date peak load statistics included in the Report, Dr. Chadalavada confirmed that, with respect to FCM Peak Load, the sum of active load assets that are non-dispatchable included all non-dispatchable assets other than dispatchable asset-related demand assets (DARD) (or pumping load). He agreed that it would be reasonable to assume that much of the difference between RQM System and FCM Peak Load was, roughly, losses. Losses, he noted, would be more pronounced at higher load levels, and could reasonably be attributed to aggregate losses from the generation node to the Hub, though the LMP calculator was more precise in its calculation of losses as a component of LMP.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the August 1, 2024 Litigation Report that had been circulated and posted before the meeting. He highlighted the following developments:

(i) The FERC was at its full 5-member complement, with the swearing in, since the Committee's June Summer Meeting, of the remaining two of the three new Commissioners;

(ii) *New England's Order 2222 Compliance ATTR Submetering Revisions (ER22-983-009).* While the changes, supported earlier in the meeting by way of the Consent Agenda, had been filed by the ISO on July 22 in accordance with the *Order 2222 60-Day Compliance Filing Order Allegheny Order*, the comment period would remain open until August 12 and NEPOOL would submit brief comments by then noting the outcome of the Committee's action for the FERC's record;

(iii) *Longer-Term Transmission Planning (LTTP) Phase 2 Tariff Changes (ER24-1978).* The FERC accepted the LTTP Phase 2 ~~C~~changes effective July 9, 2024; and

(iv) *Chevron Doctrine (US Supreme Court Case No. 20-1329).* On June 28, 2024, the Supreme Court overturned the long-standing *Chevron Doctrine*. The *Chevron Doctrine*, which had been in place since 1984, required courts to defer to a federal agency's interpretation of the law so long as that interpretation was not unreasonable. With the Supreme Court's overturn of the *Chevron Doctrine*, instead of deferring to the expertise of the agencies, like the FERC, in their interpretation of ambiguity in a statute or law, ~~F~~federal ~~J~~judges would have the responsibility and power to decide without mandatory deference to the agency the meaning of the statute or law. Mr. Lombardi predicted that the end of the *Chevron* deference would likely increase regulatory uncertainty. While the end of *Chevron* deference was less likely to affect more routine FERC proceedings (those not typically involving statutory interpretation questions to which *Chevron* previously applied), he did suggest that it would be more likely to come into play when the FERC was pursuing new policy objectives or issuing new rule makings (those which might not be clearly addressed by its enabling statutes). He encouraged those interested to review the information summarized in a special Appendix A to the Litigation Report and to reach out to NEPOOL Counsel with any questions.

In response to a question, Mr. Lombardi confirmed that the amendments to the NEPOOL and Participants Agreements that change the allocation of any unused Provisional Member Voting Share (the Amendments) had been filed with the FERC the day before, with an August 1, 2024 effective date requested. He explained that, as of August 1, and unless or until the FERC ordered otherwise, any unused Provisional Member Voting Share in a Principal Committee vote would be allocated in accordance with the Amendments.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler, Vice-Chair, reported that the next MC meeting would be on August 7, 2024 at the DoubleTree Hotel in Westborough. He indicated that key topics would include discussion on the Capacity Auction Reforms (CAR) project, Market Rule changes proposed by NEPGA related to the ISO's PFP Financial Assurance improvements proposal, revisions to the New Brunswick Coordination Agreement, and issues related to the assignment of Real-Time Dispatch Lost Opportunity Cost Credits to Continuous Storage Facilities.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC would next meet on August 13-14, 2024 as part of the RC/TC Summer Meeting at Water's Edge in Westbrook, CT. In addition to the RC's regular business items, the RC would consider *Orders 2023/2023-A*-related revisions to Planning Procedure 5-6.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that, as part of the RC/TC Summer Meeting, the TC would review Regional Network Service (RNS) rates that became effective June 1, 2024 (Schedule 1) and would become effective January 1, 2025 (Schedule 9), as well as the five-year RNS rate forecast and planned asset condition project investments for 2024 and 2025.

Budget & Finance Subcommittee. Mr. Kaslow reported that the B&F had two meetings planned for August -- one on August 9 (to discuss the 2025 ISO and NESCOE budgets, the ISO's 2024 second quarter capital projects filing, and other periodic financial reports), and one on August 27.

Membership Subcommittee. On behalf of Mr. Brad Swalwell, Membership Subcommittee Chair, Mr. Patrick Gerity reported that the next Membership Subcommittee meeting would be by ZOOM on August 12, 2024. He said that there were two pending applications for which broader input would be appreciated and that might ultimately require subsequent Participants Committee action. Both were applications for End User membership -- one by RENEW Northeast and the other by an individual with a residential rooftop solar system which was producing more electricity than was being consumed. He encouraged all those interested in those applications, including related Sector election and eligibility issues, to participate.

NESCOE REPORT

Ms. Heather Hunt, NESCOE Executive Director, advised the Participants Committee of NESCOE's plans to host a forum on August 9, 2024, from 10:00 am to approximately 12:30 pm, to provide an opportunity for continued education and dialogue on approaches, considerations, trade-offs, etc. related to cost containment mechanisms and competitive transmission-related issues (which NESCOE had recommended during the development of the LTTP Phase 2 Tariff Changes). She indicated that an agenda would be posted on the NESCOE website. She expected the forum to include a summary by the Brattle Group and discussion of transmission project cost control approaches, a moderated Q&A session with transmission developers to get a diversity of perspectives, and an opportunity for observations of, questions for, and discussion with, ISO transmission staff. All interested were encouraged to participate.

ADMINISTRATIVE MATTERS

Mr. Lombardi informed members that the September 5 Participants Committee meeting would be held in person at the Westin Portland Harborview Hotel in Portland, ME. Further details on the meeting and room block information would be circulated in advance of the meeting. The October Participants Committee meeting would be in person, but at a location yet to determined. The November and December Participants Committee meetings would both be in person and in Boston, with the November meeting to be held at the Seaport Hotel and the December Annual Meeting to be held at the Colonnade Hotel.

There being no other business, the meeting adjourned at 11:13 a.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN AUGUST 1, 2024 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID: CMP/UI	Transmission	Alan Trotta		
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		Dan Murphy
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	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	Richard Gaudet	
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	J.R. Viglione
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Constellation Energy Generation	Supplier		Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, Inc.	Supplier	Ryan McCarthy		Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie	Alex Chaplin	Bill Fowler
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
Engie Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		Steve Conant
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	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Granite Shore Companies	Generation			Bob Stein
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG		Bob Stein	
Hammond Lumber Company	End User			Bill Short
Hanover, NH (Town of)	End User			Bill Short
High Liner Foods (USA) Incorporated	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN AUGUST 1, 2024 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Wind Action Corp.	End User	Lisa Linowes		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	AR-RG			Frank Swigonski
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 Public Advocate’s Office	End User			Stefan Koester
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Marble River	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General’s Office (MA AG)	End User	Jacquelyn Bihrle	Kelly Caiazzo	
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	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	
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Robin Lafayette	
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		
Natural Resources Defense Council	End User	Claire Lang-Ree		
New Hampshire Electric Cooperative	Publicly Owned Entity		Brian Callnan	Brian Forshaw
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
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		Matt Ide	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	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	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	Dan Murphy
Saint Anselm College	End User			Bill Short
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
Sierra Club	End User	Casey Roberts		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN AUGUST 1, 2024 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Union of Concerned Scientists	End User			Francis Pullaro
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR		Stefan Koester	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	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		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
ZTECH, LLC	End User			Bill Short

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC from its ***August 13-14, 2024 Summer Meeting****, dated August 14, 2024.*[1]

1. Revisions to OP-23 Appendix E (Updated Submission Authorization & Methodology; Notarization Requirement Eliminated) and Retirement of Appendix F

Support revisions to ISO-NE Operating Procedure ("OP") No. 23 (Resource Auditing) Appendix E (Multi-Generator Station Certification Form) and the retirement of Appendix F (No Steam Exports Certification Form),[2] as recommended by the RC at the August 13-14, 2024 joint RC/TC Summer Meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

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

2. Revisions to OP-12 (Voltage Control Options and Schedule Clarifications)

Support revisions to OP-12 (Voltage and Reactive Control),[3] as recommended by the RC at the August 13-14, 2024 joint RC/TC Summer Meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

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

3. Revisions to PP 5-6 (Orders 2023/2023-A-Related Revisions)

Support revisions to ISO New England Planning Procedure (PP) 5-6 (Interconnection Planning Procedure for Generation & Elective Transmission Upgrades),[4] as recommended by the RC at the August 13-14, 2024 joint RC/TC Summer Meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously, with three abstentions (one in each of the Supplier, AR and End User Sectors).

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

[2] The recommended revisions to OP-23 Appendix E include revisions that: (i) change who may submit the form; (ii) eliminate the notarization requirement; and (iii) update the method for submission. The retirement of OP-23 Appendix F is proposed because steam exports are no longer required to be certified in OP-23 Appendix E.

[3] The recommended revisions to OP-12 include changes to Sections II.A and II.B that: (i) revise language in Section II.A for OP-12 application; (ii) revise language and clarify Options A, B and C; (iii) add explicit voltage control requirements for Options A and B; and (iv) provide clarification for voltage schedule changes.

[4] The recommended revisions to PP 5-6 include Order 2023/2023-A conforming changes to ISO planning procedures and Model Acceptance Tests for Inverter-Based Resources.

Summary of ISO New England Board and Committee Meetings

September 5, 2024 Participants Committee Meeting

Since the last update, the Audit and Finance Committee met on August 15 by videoconference.

The Audit and Finance Committee received an update regarding the development of the 2025 operating and capital budgets, including a review of the capital structure, and a report on budget discussions with stakeholders. The Committee also reviewed the financing options that were explored in order to determine the most cost efficient way to finance short-term capital budget project needs. Next, the Committee conducted its annual review of the Company's liability insurance coverage for officers and directors, noting that the policies were recently renewed with no increase to the total premium cost. The Committee also received an update on the 2024 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 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 the internal auditors, the Committee continued in executive session to review the results of its self-evaluation.

NEPOOL Participants Committee Report

September 2024

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Data through August 27, unless otherwise noted

Highlights: August 2024

- **Peak Hour** on August 1
  - 23,758 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 P.M.
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $36.11/MWh
  - Real Time (RT) Hub LMP: $39.06/MWh
  - Natural Gas: $1.63/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $403M up from $310M in August 2023
  - Updated July Energy Market value: $674M
  - Ancillary Markets* value $14.3M down from $21.5M in August 2023
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 102.5% during August, up from 101.4% during July
- **Net Commitment Period Compensation (NCPC)** total $3M
  - First Contingency $2.5M
    - Dispatch Lost Opportunity Cost (DLOC) - $439K; Rapid Response Pricing (RRP) Opportunity Cost - $356K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $327K paid to resources at external locations, down $11K from July
      - $114K charged to Day Ahead Load Obligation (DALO) at external locations, $213K to RT Deviations
  - Second Contingency $66K (protection for South Boston/SEMA due to transmission work); Distribution $412K
- **Forward Capacity Market (FCM)** market value $120M
  - OP-4 and Capacity Scarcity Conditions (CSC) occurred on Thursday, August 1 2024, resulting in elevated LMPs and Pay for Performance (PFP) assessments

*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund
**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

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **24,310 MW**
  - hour ending 7:00 P.M. on Tuesday, July 16
- RQM System Peak Load: **24,816 MW** (initial)
  - hour ending 6:00 P.M. on Tuesday, July 16
- FCM Peak Load: **24,366 MW** (preliminary & subject to change)
  - hour ending 6:00 P.M. on Tuesday, July 16
  - At this hour, the capacity zone-level FCM peak loads were 3,296 MW in Northern New England, 1,919 MW in Maine, 9,096 MW in Rest-of-Pool, and 10,054 MW in Southeast New England.

*Telemetered loads are as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Generation (SOG). Due to the difference in calculation methodologies and the impact of SOGs, these values can occur on different days and/or hours. Both are 'net energy for load' concepts and include transmission losses. FCM load values reflect the sum of active, normal load assets that are non-dispatchable, are included in the FCM settlement and do not include transmission losses

Highlights

- The 2024/25 load forecasting cycle will begin in September and will include implementation of a new hourly forecast methodology
- EPCET Pilot Study draft report was issued on August 16, and comments are due by September 10

Forward Capacity Market (FCM) Highlights

- CCP 15 (2024-2025)
  - The ISO held the third annual reconfiguration auction (ARA3) over March 1-5 and posted the results on April 3
- CCP 16 (2025-2026)
  - The ISO held the second annual reconfiguration auction (ARA2) over August 1-5 and will post the results no later than September 3
- CCP 17 (2026-2027)
  - The ISO held the first annual reconfiguration auction (ARA1) over June 3-5 and posted the results on July 2

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - The ISO filed the auction results with FERC on February 21 and, on June 18, FERC issued an order accepting the results effective June 20
  - The ISO presented assumptions for the ICR and related values studies for the ARAs to be conducted in 2025 at the August 28 PSPC meeting
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5
    - On May 20, FERC issued an order accepting the additional delay to FCA 19
  - The Show of Interest submission window for the 2024 interim RA qualification process opened on April 17 and closed on April 30
  - The New Capacity Qualification Package submission window opened on June 13 and closed on June 21

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (0.6°F) Max: 95°F, Min: 58°F Precipitation: 3.70" – Above Normal Normal: 3.04"	Hartford	Temperature: Above Normal (1.2°F) Max: 95°F, Min: 52°F Precipitation: 4.85" - Above Normal Normal: 3.98"

Peak Load:	23,216 MW	August 1, 2024	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
OP-4	08/01/2024 16:45	08/01/2024 21:45	Capacity
M/LCC 2	08/01/2024 16:45	08/01/2024 22:00	Capacity

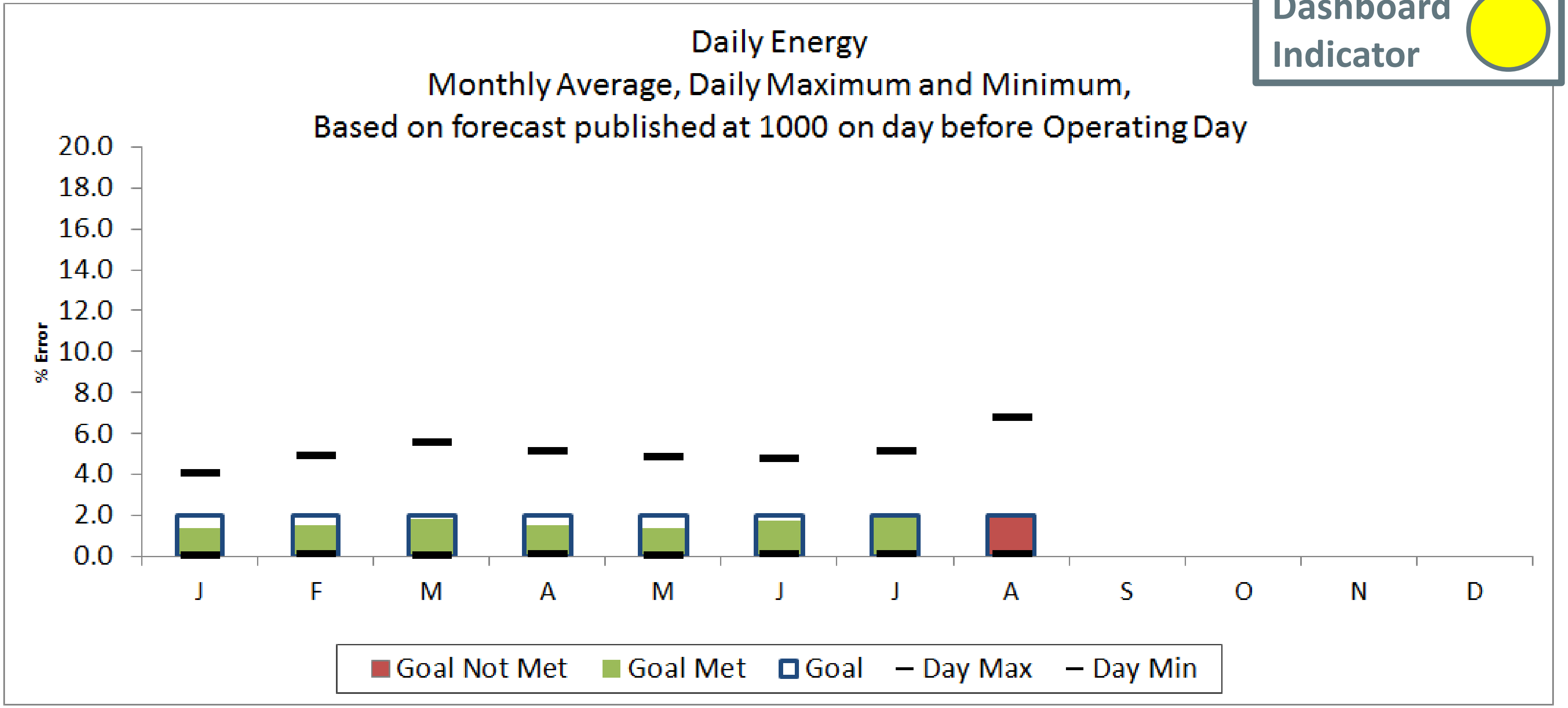
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
8/1/2024	ISO-NE	500
8/5/2024 (08:08)	NYISO	525
8/5/2024 (15:18)	NYISO	525
8/5/2024 (19:28)	NYISO	530
8/8/2024	IESO	950
8/24/2024	ISO-NE	676
8/28/2024	PJM	525

2024 System Operations - Load Forecast Accuracy cont.

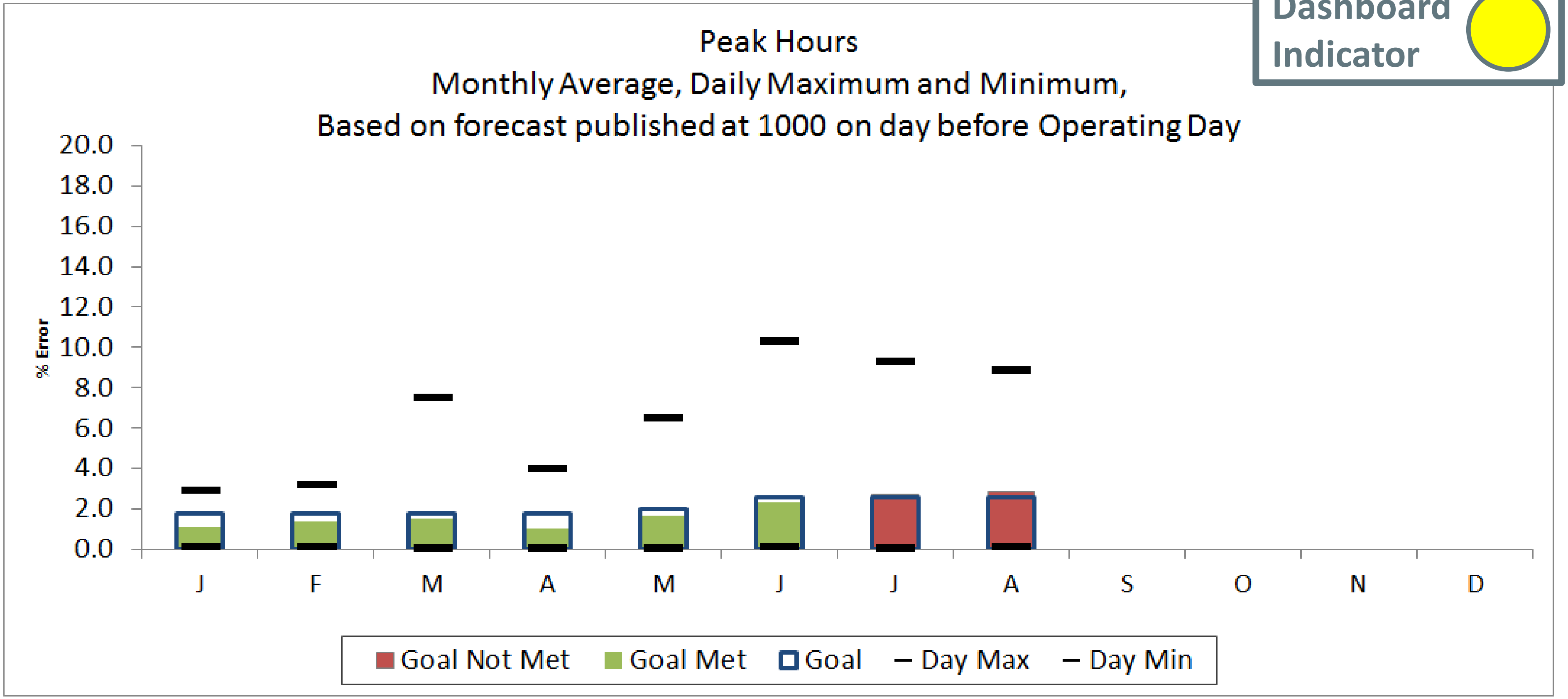
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.02	4.89	5.56	5.09	4.84	4.73	5.13	6.75					6.75
Day Min	0.00	0.12	0.02	0.09	0.07	0.11	0.10	0.12					0.00
MAPE	1.38	1.54	1.82	1.52	1.40	1.79	1.94	2.07					1.68
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00					

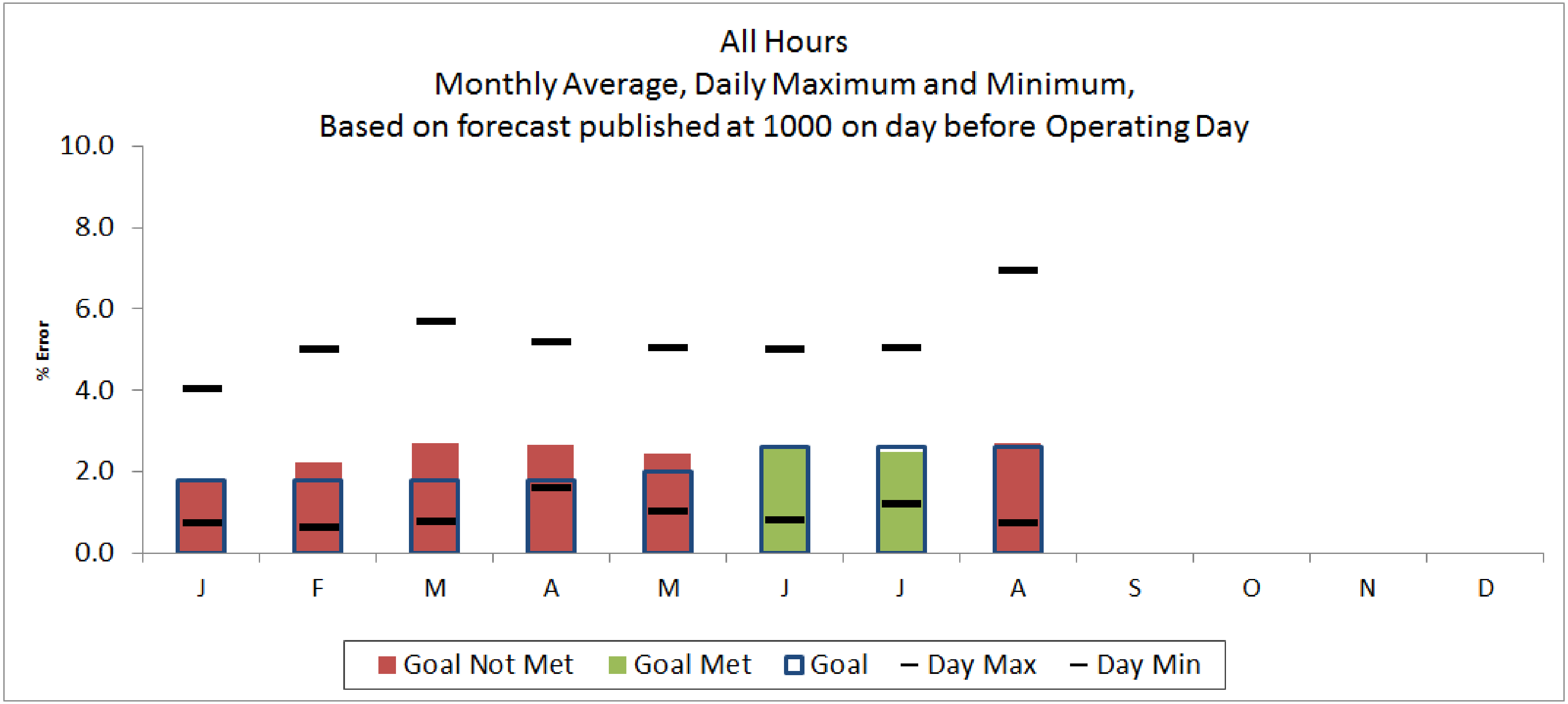
2024 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



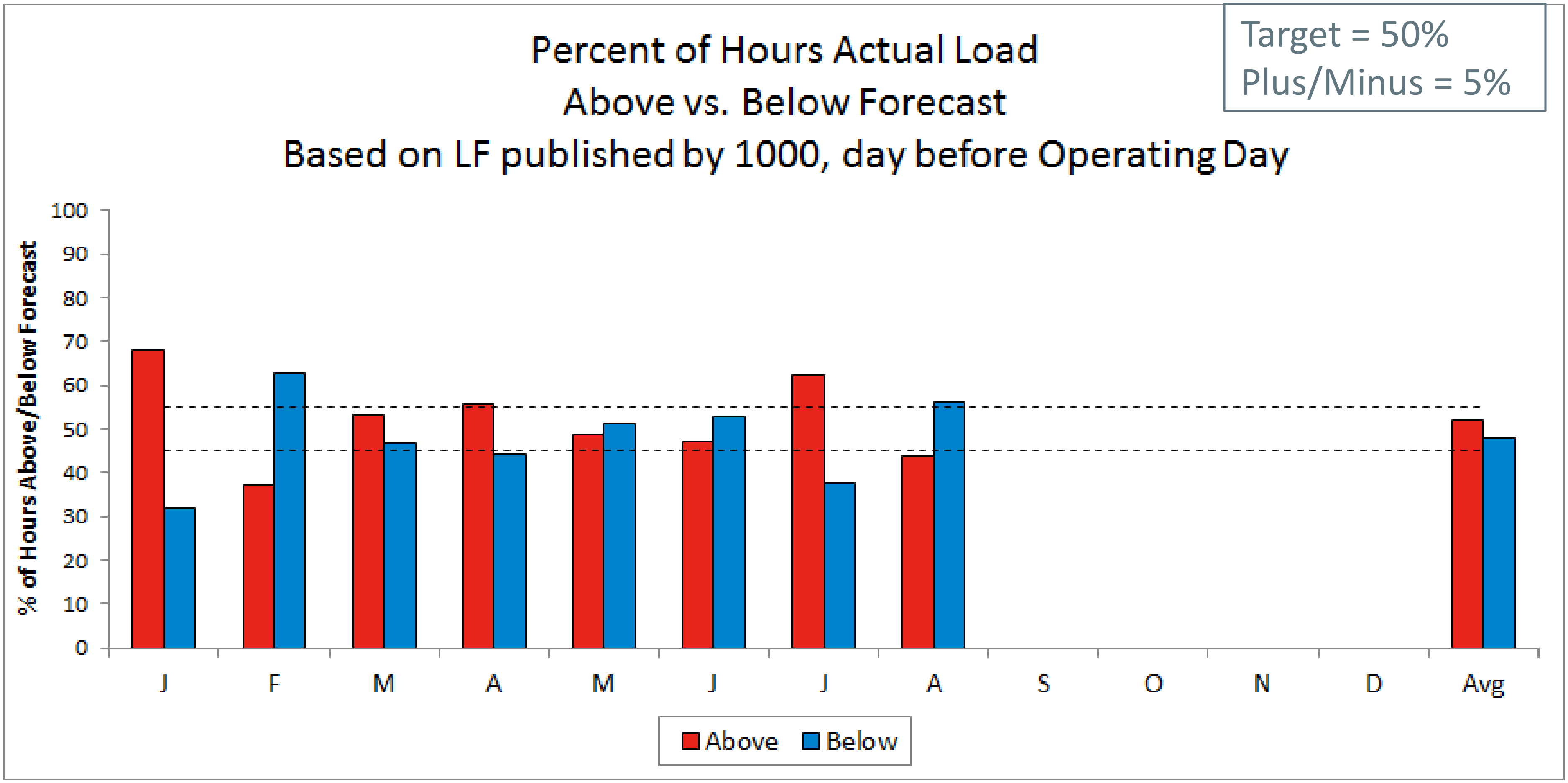
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	2.90	3.17	7.45	3.99	6.46	10.30	9.30	8.86					10.30
Day Min	0.08	0.10	0.02	0.03	0.01	0.14	0.00	0.08					0.00
MAPE	1.10	1.39	1.54	1.02	1.66	2.32	2.70	2.90					1.83
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

2024 System Operations - Load Forecast Accuracy



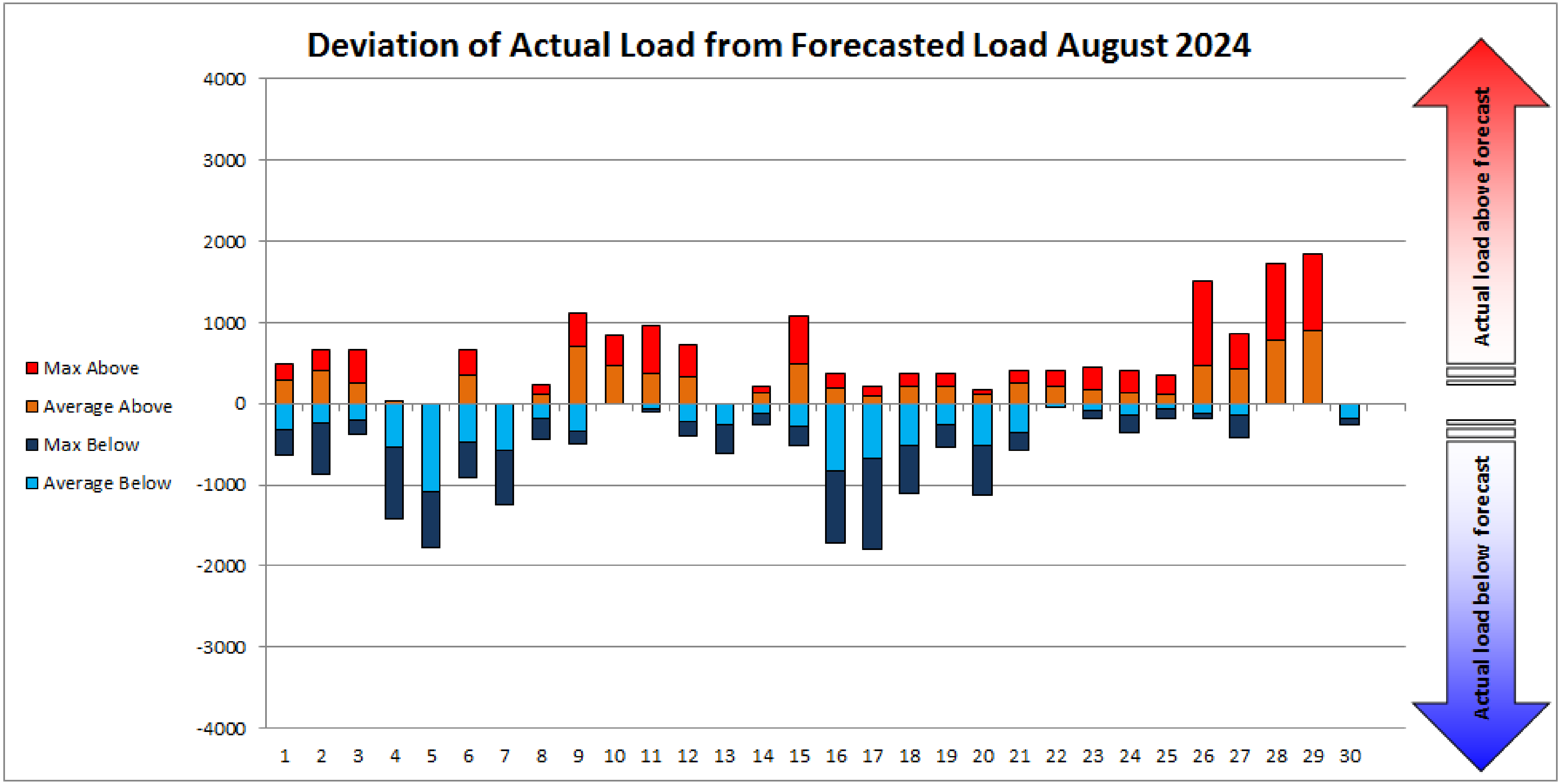
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.03	5.00	5.67	5.18	5.04	4.99	5.02	6.94					6.94
Day Min	0.73	0.64	0.76	1.59	1.00	0.81	1.20	0.74					0.64
MAPE	1.83	2.24	2.72	2.66	2.46	2.57	2.49	2.69					2.46
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

2024 System Operations - Load Forecast Accuracy cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	67.9	37.4	53.3	55.8	48.7	47.2	62.4	44					52
Below %	32.1	62.6	46.7	44.2	51.3	52.8	37.6	56					48
Avg Above	260.5	155.2	254.6	254.9	245.5	267.4	320.4	262.9					320
Avg Below	-155.5	-292.3	-253.5	-239.2	-223.2	-265.6	-270.5	-287.2					-292
Avg All	132	-130	39	38	11	-16	82	-53					14

2024 System Operations - Load Forecast Accuracy cont.



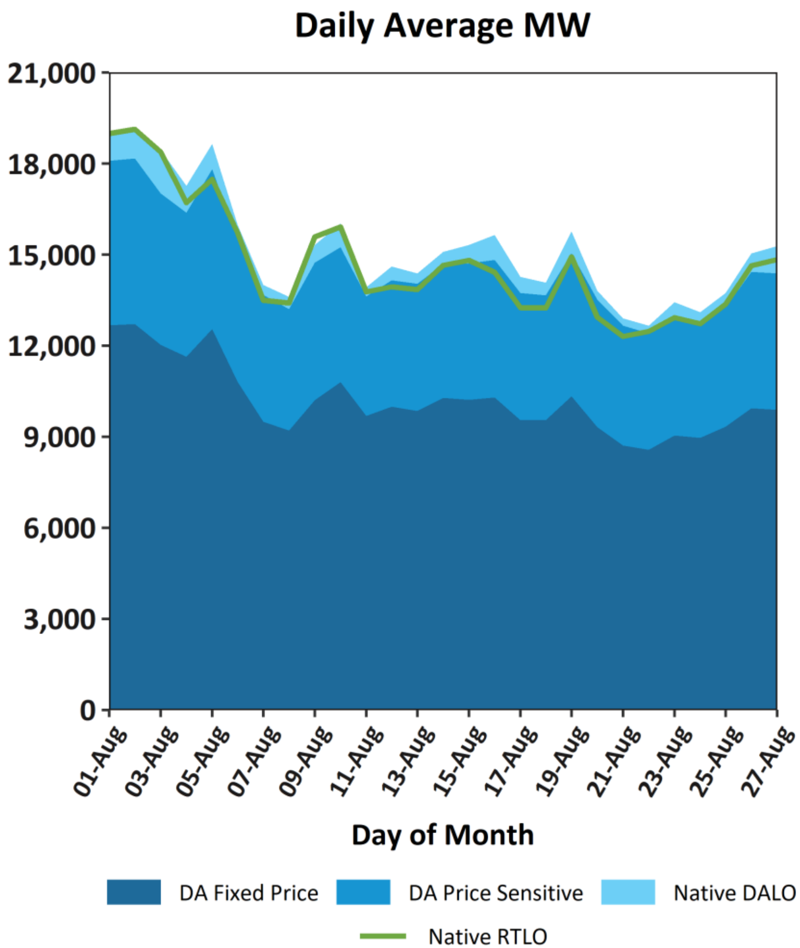
Note on Wind and Solar Forecast Error Statistics

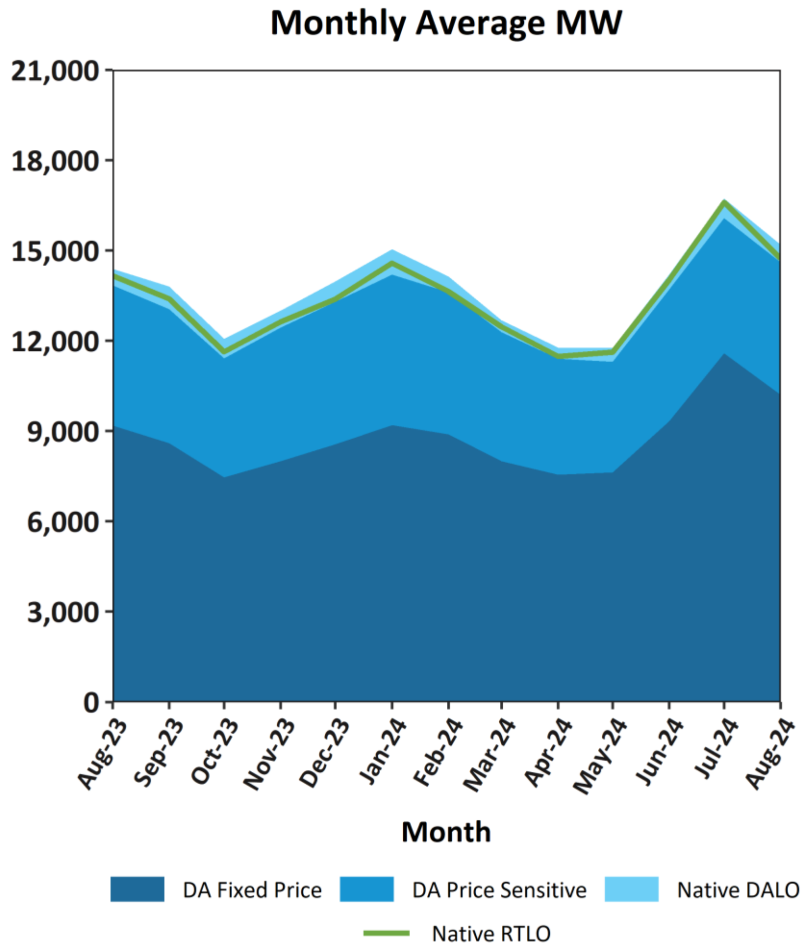
- With the launch of solar do-not-exceed dispatch in December 2023, the ISO is now able to provide the same forecast error statistics for do-not-exceed dispatchable generator (DDG) solar resources as it does for DDG wind resources
- For stakeholders' information, from now on, these monthly updates will be posted on two new pages that have been created in ISO Express:
  - ISO Express > Operations Reports > System > Wind Forecast MAE and Bias
  - ISO Express > Operations Reports > System > Solar Forecast MAE and Bias
- The ISO also provides an **annual** analysis of forecasting error statistics to the Emerging Technologies Working Group (ETWG)

MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

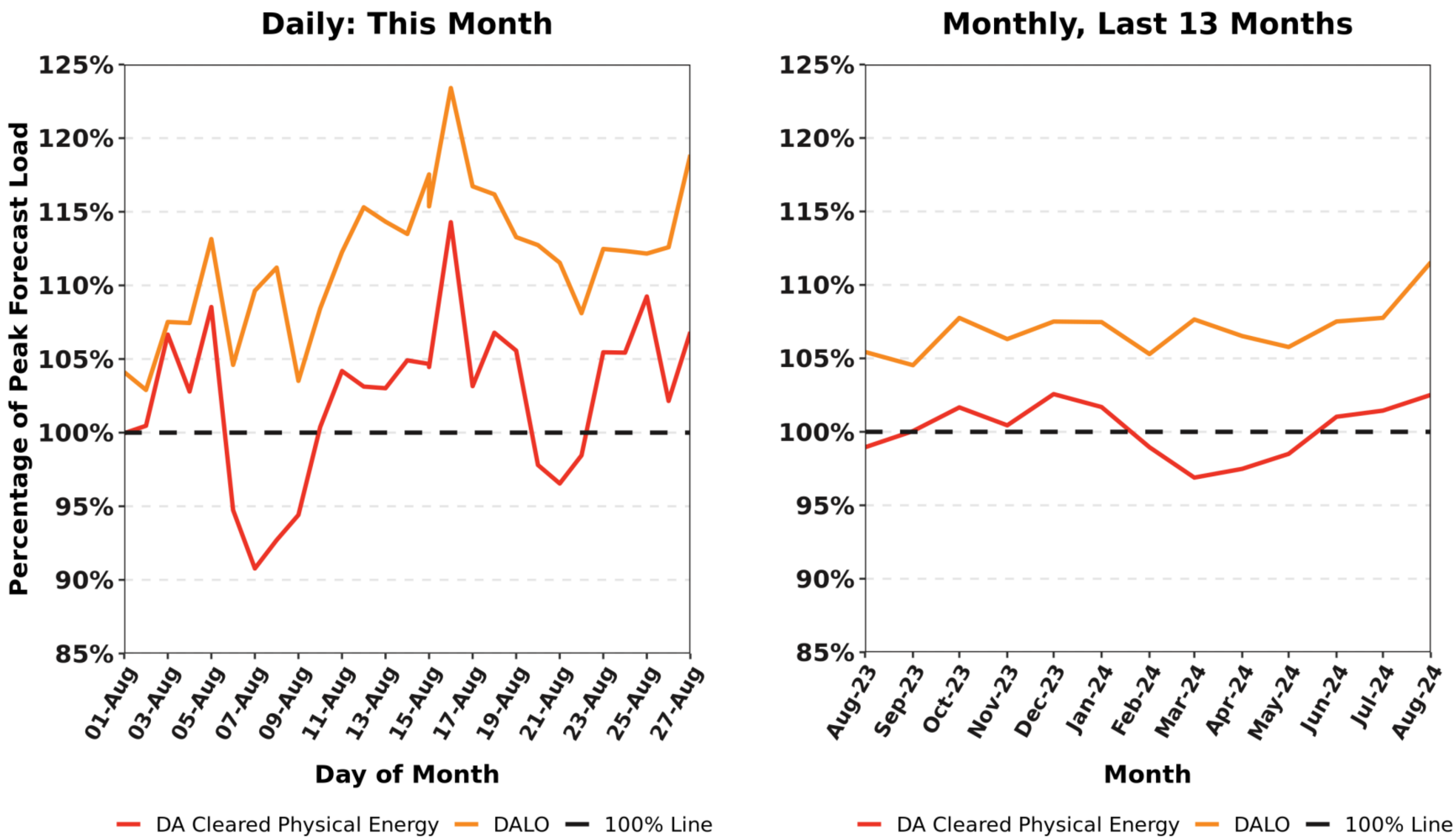
DA Cleared Native Load by Composition Compared to Native RT Load





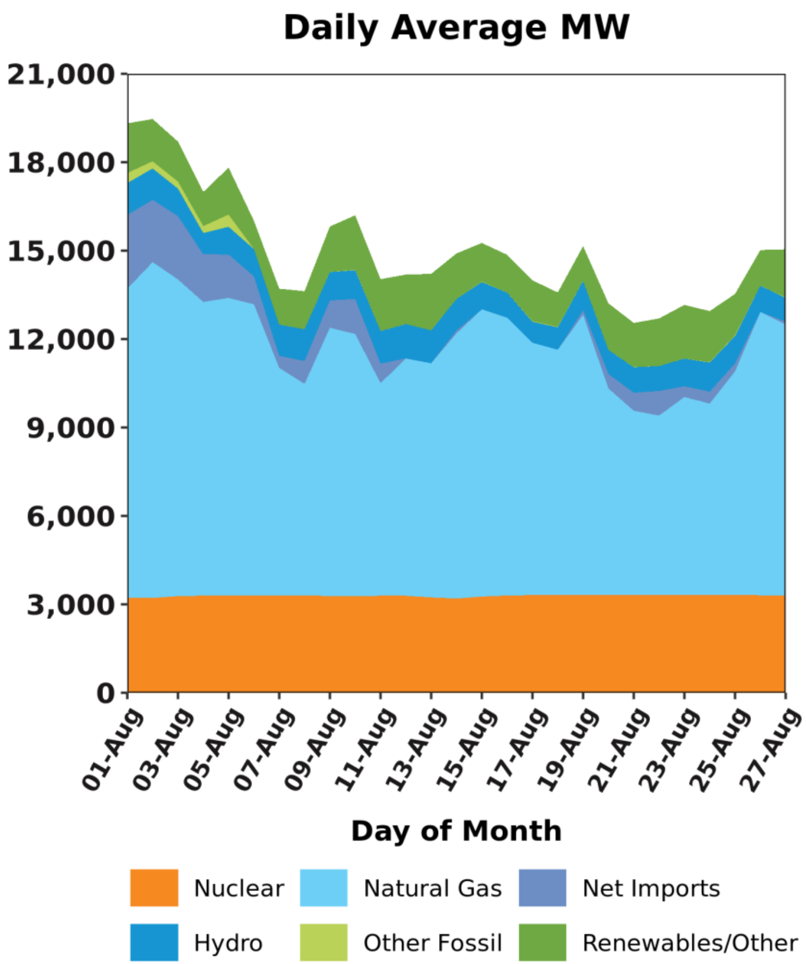
Native Day-Ahead Load Obligation (DALO) is the sum of all day-ahead cleared load, excluding modeled transmission losses and exports
Native Real-Time Load Obligation (RTLO) is the sum of all real-time load, excluding exports

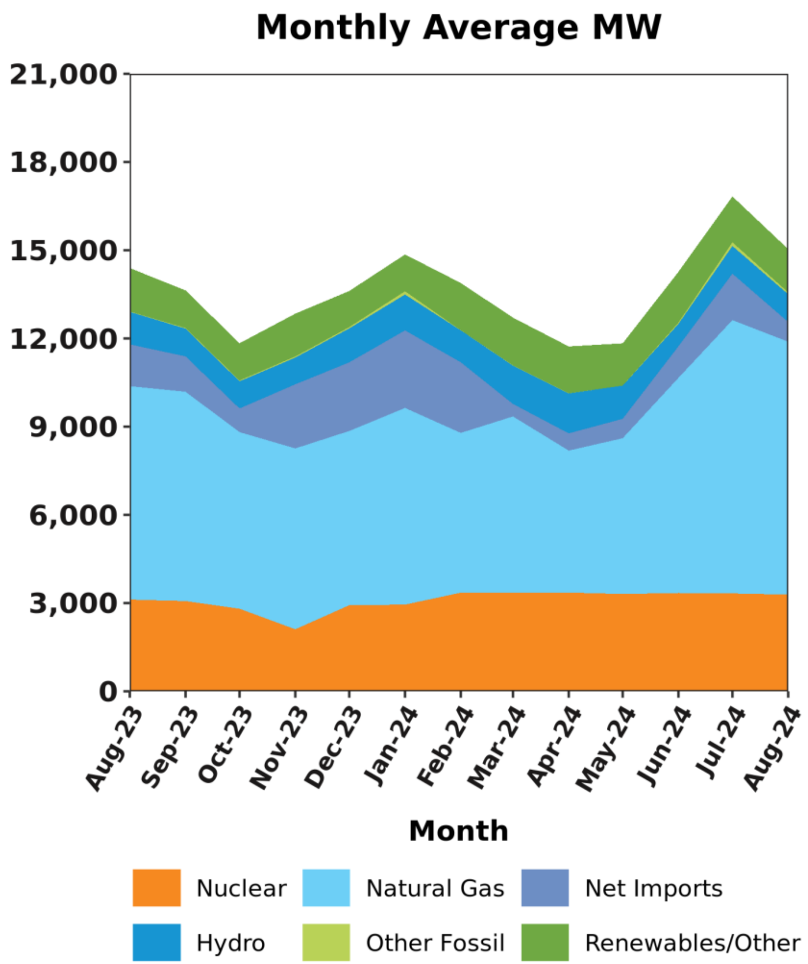
DA Volumes as % of Forecast in Peak Hour



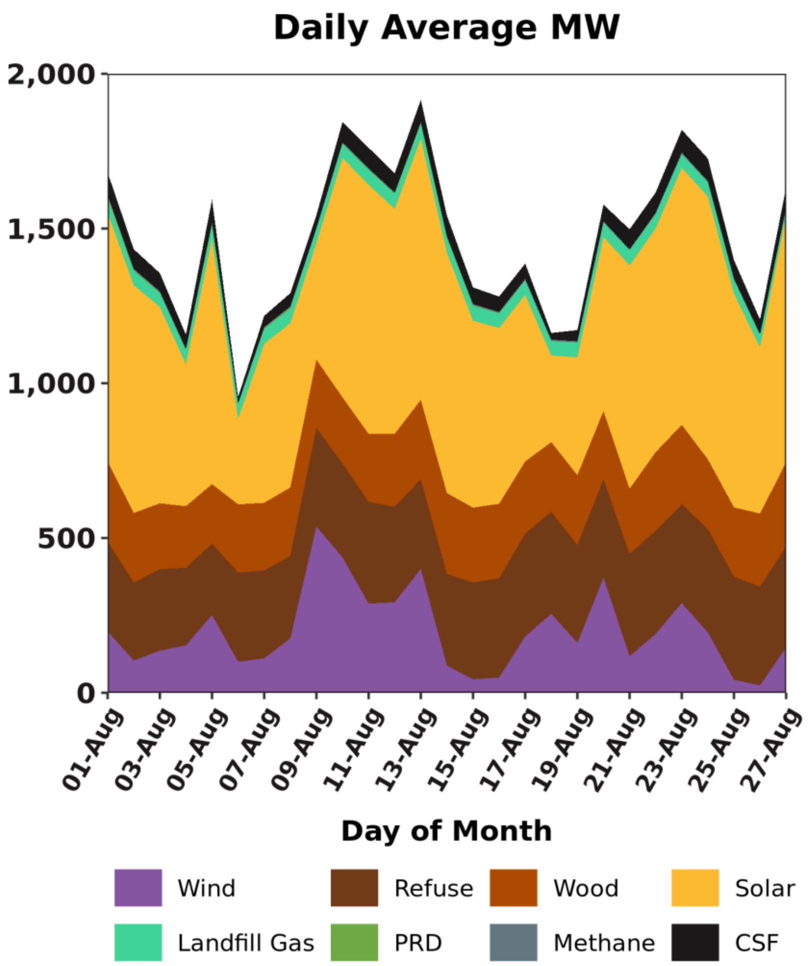
The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: one (committed for August 2nd)

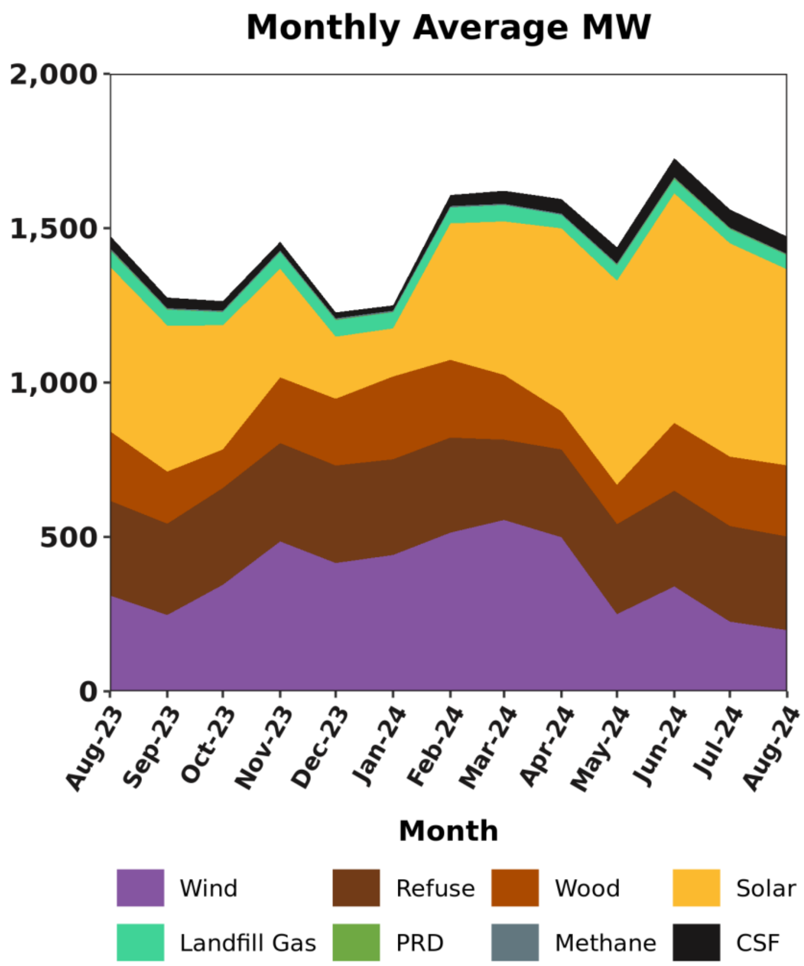
Resource Mix





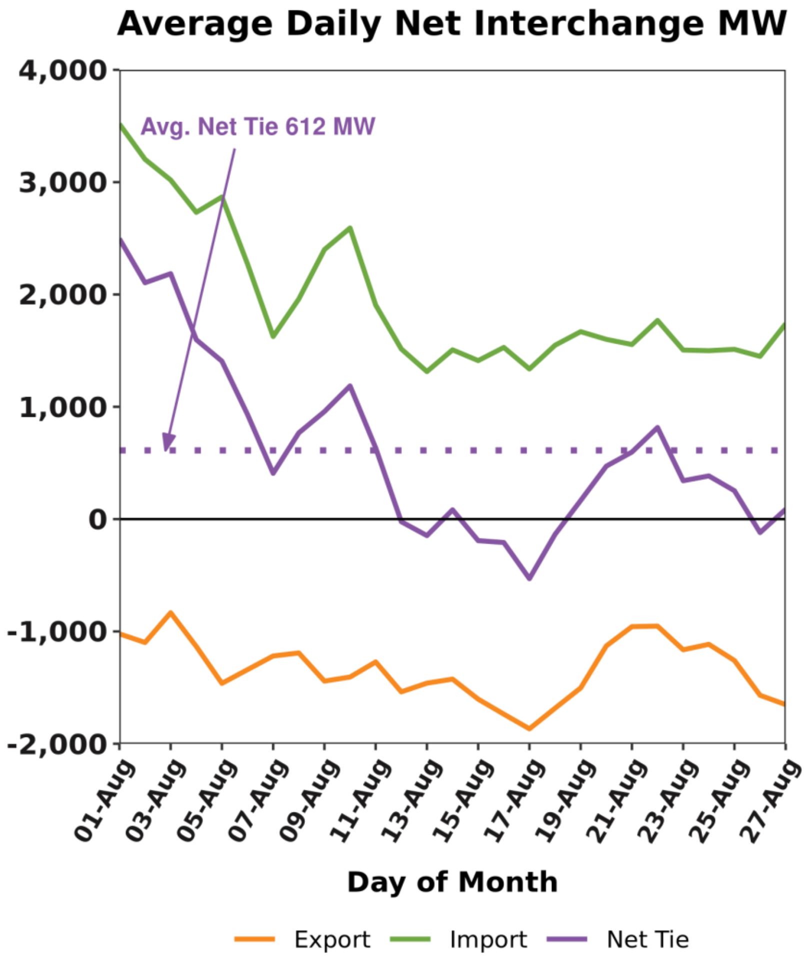
Renewable Generation by Fuel Type

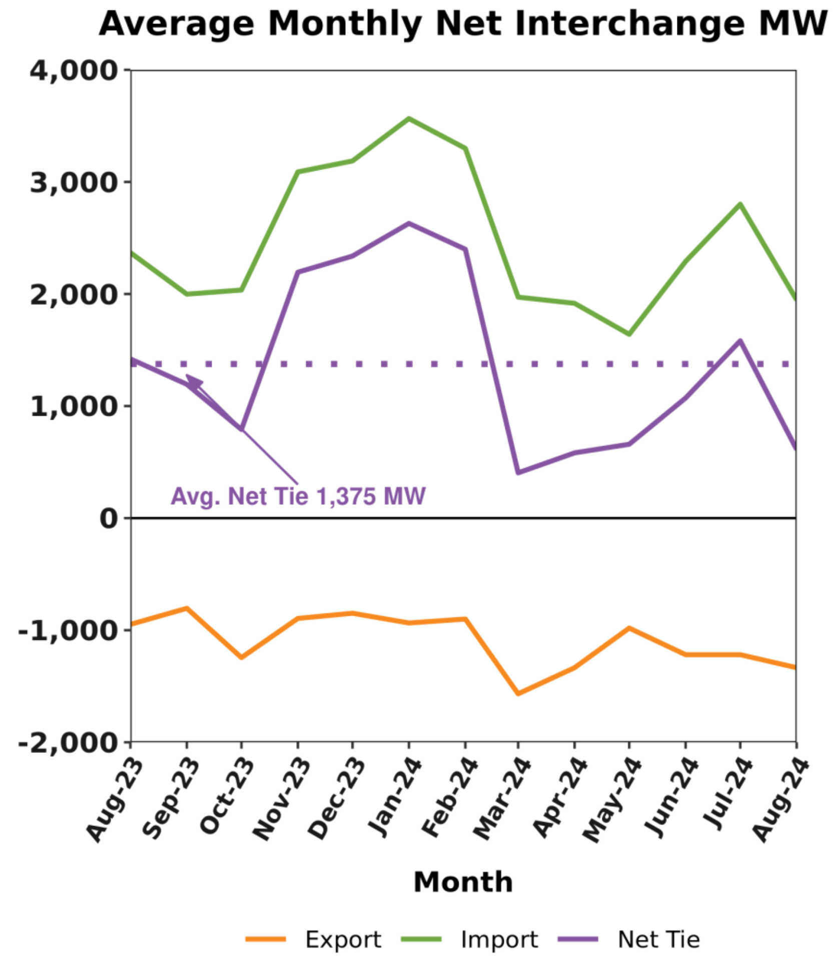




CSF = Continuous Storage Facilities (a.k.a. Batteries)

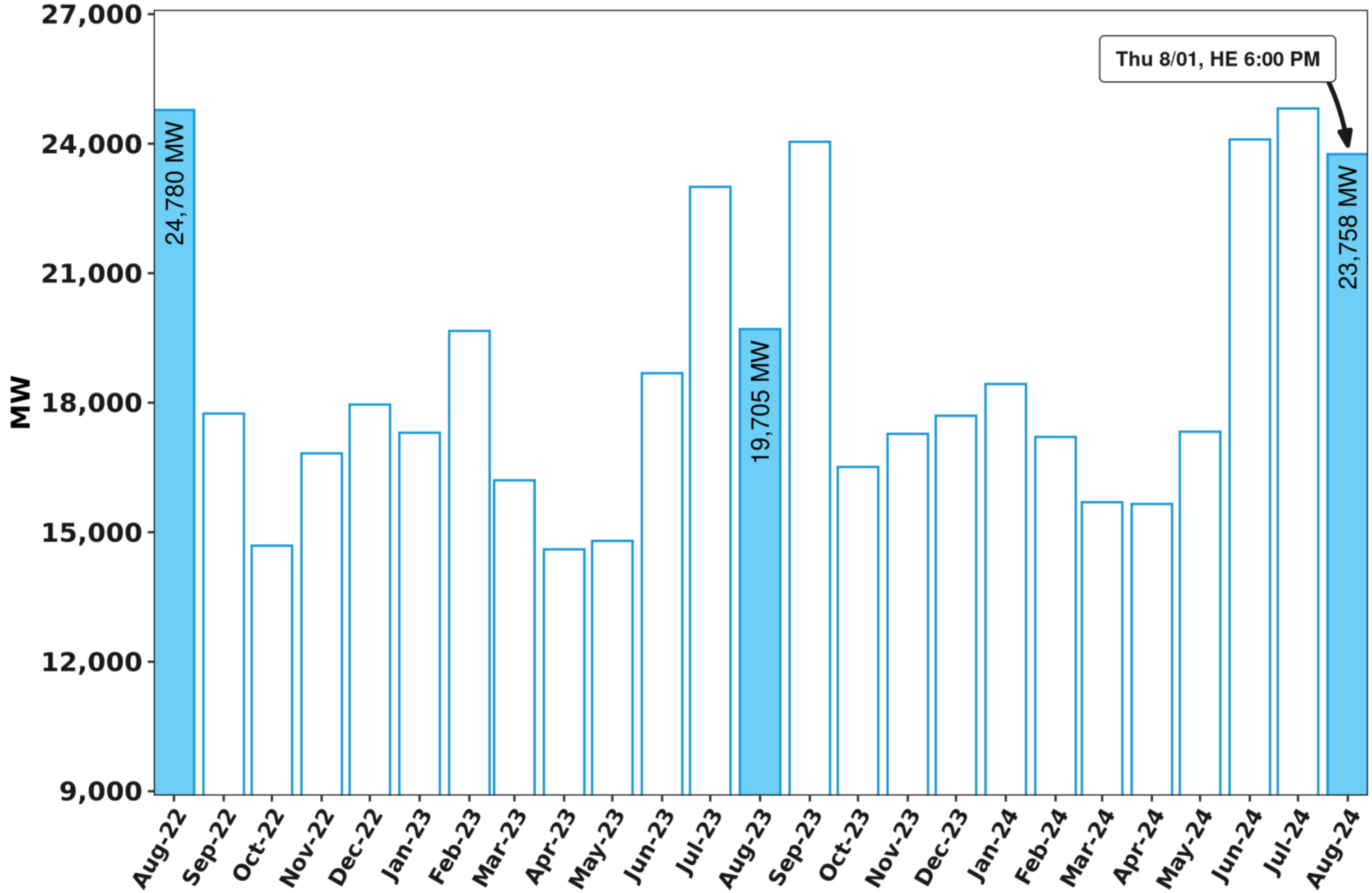
RT Net Interchange





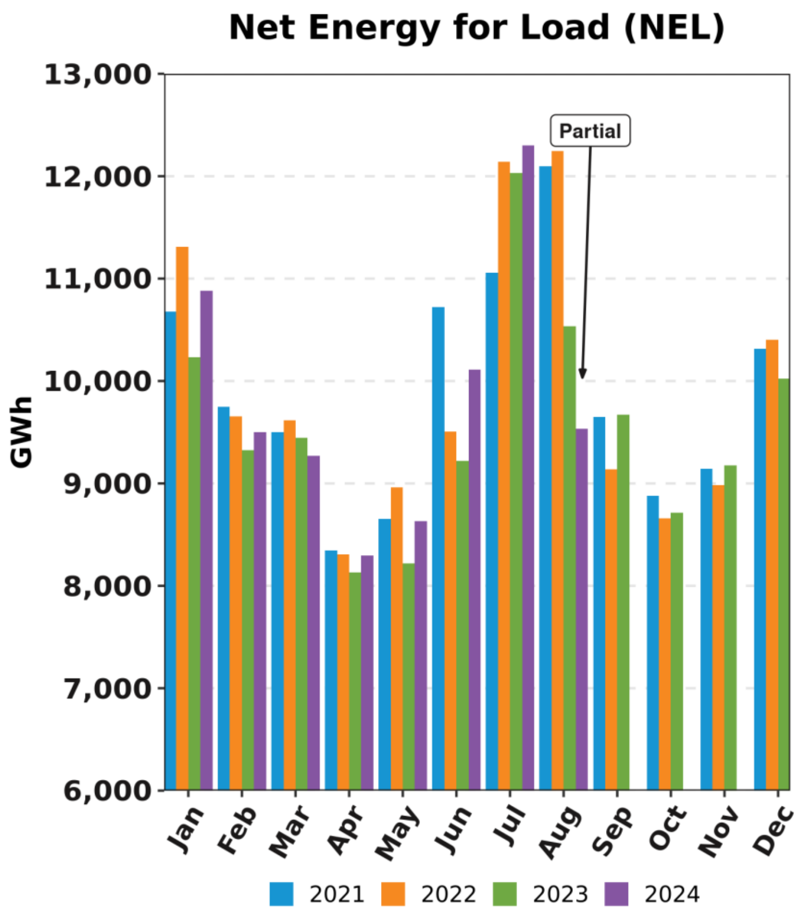
Net Interchange is the participant sum of daily imports minus the sum of daily exports; positive values are net imports

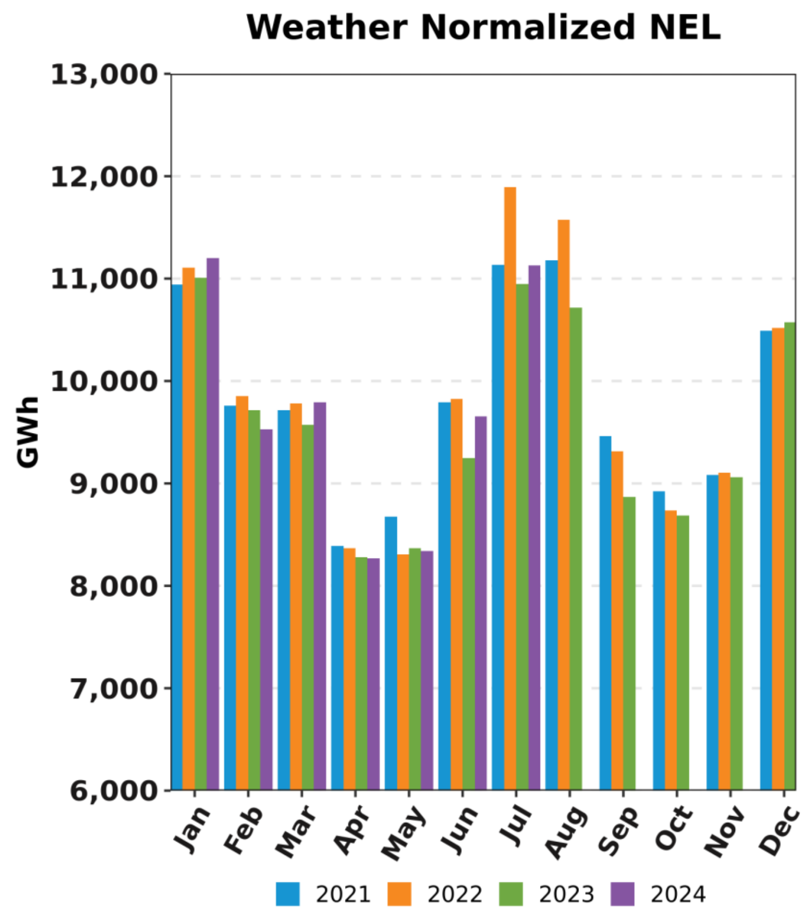
RQM System Peak Load MW by Month



Shaded columns reflect current month and the same month the last 2 years

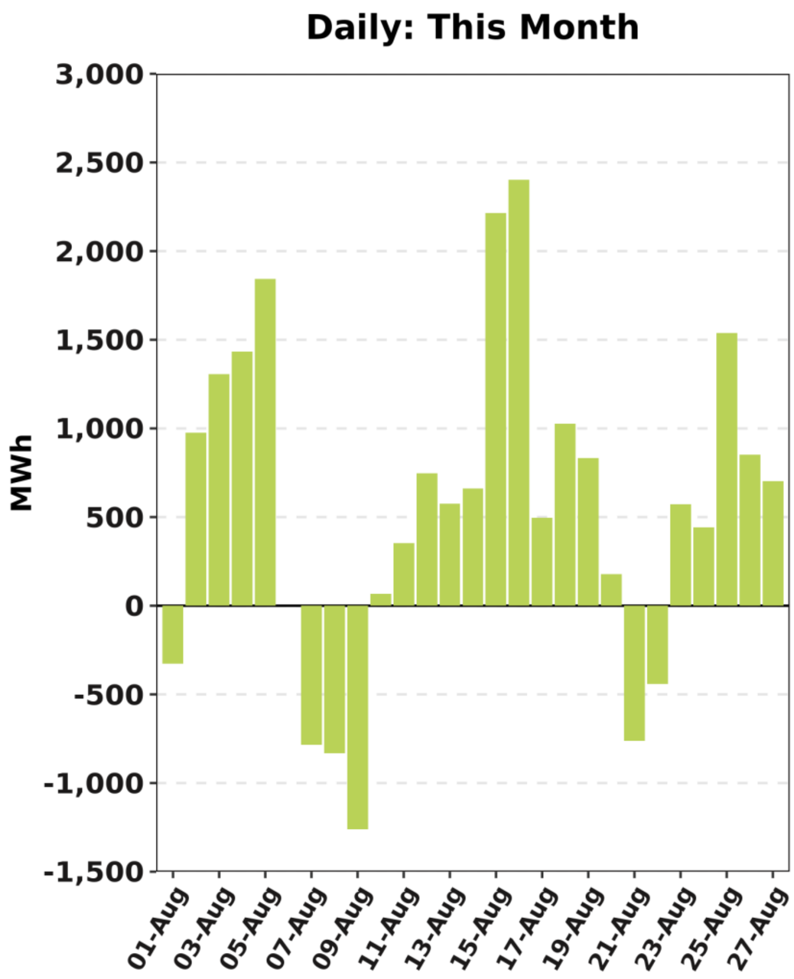
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

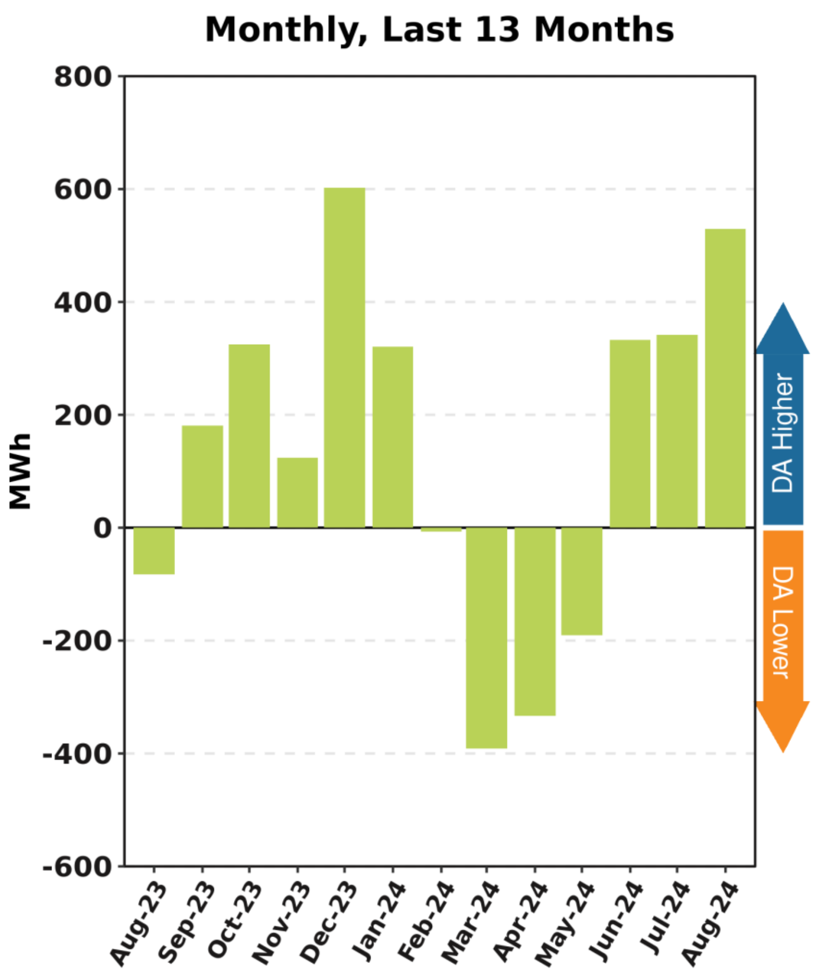




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

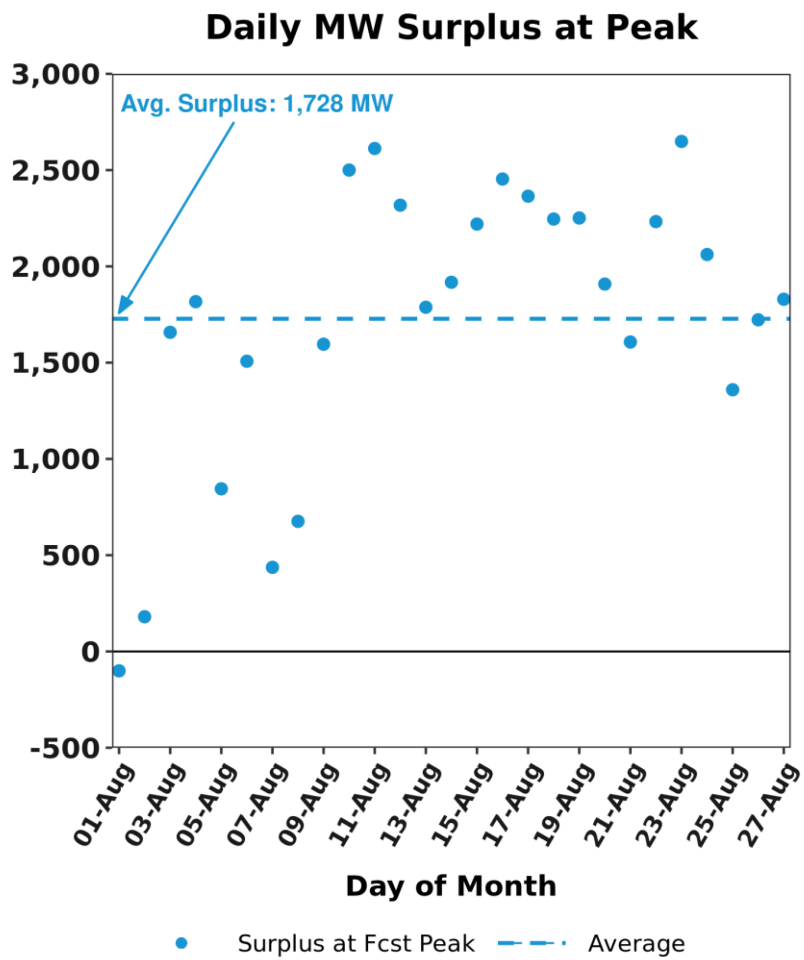
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour

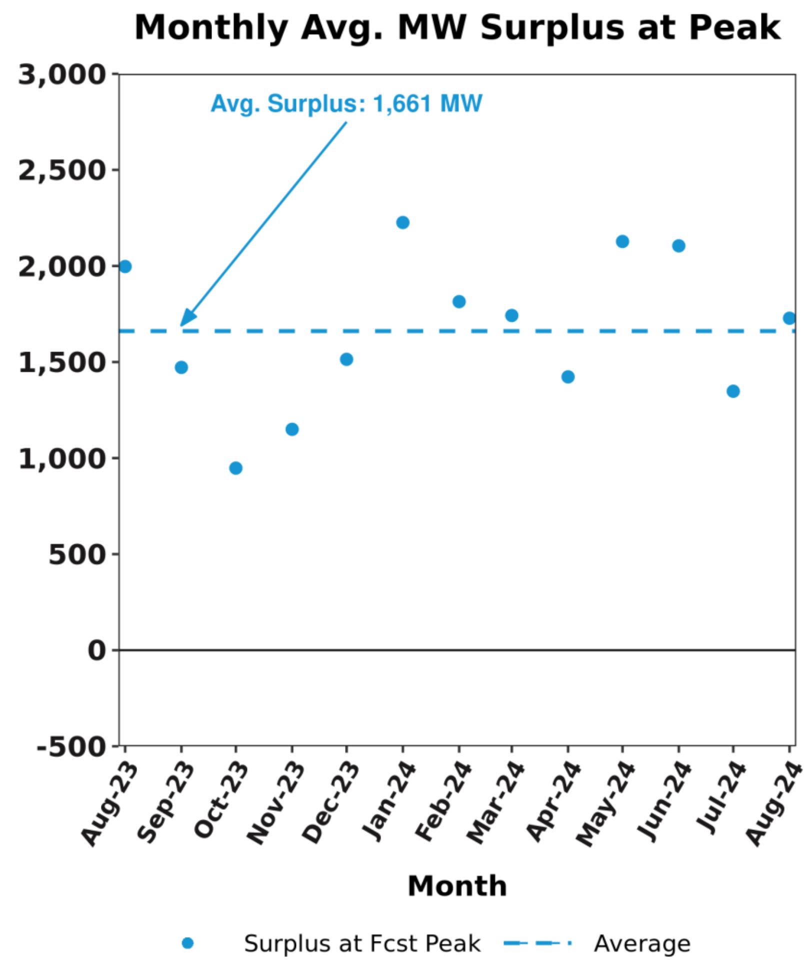




Negative values indicate DA Cleared Physical Energy value below its RT counterpart.

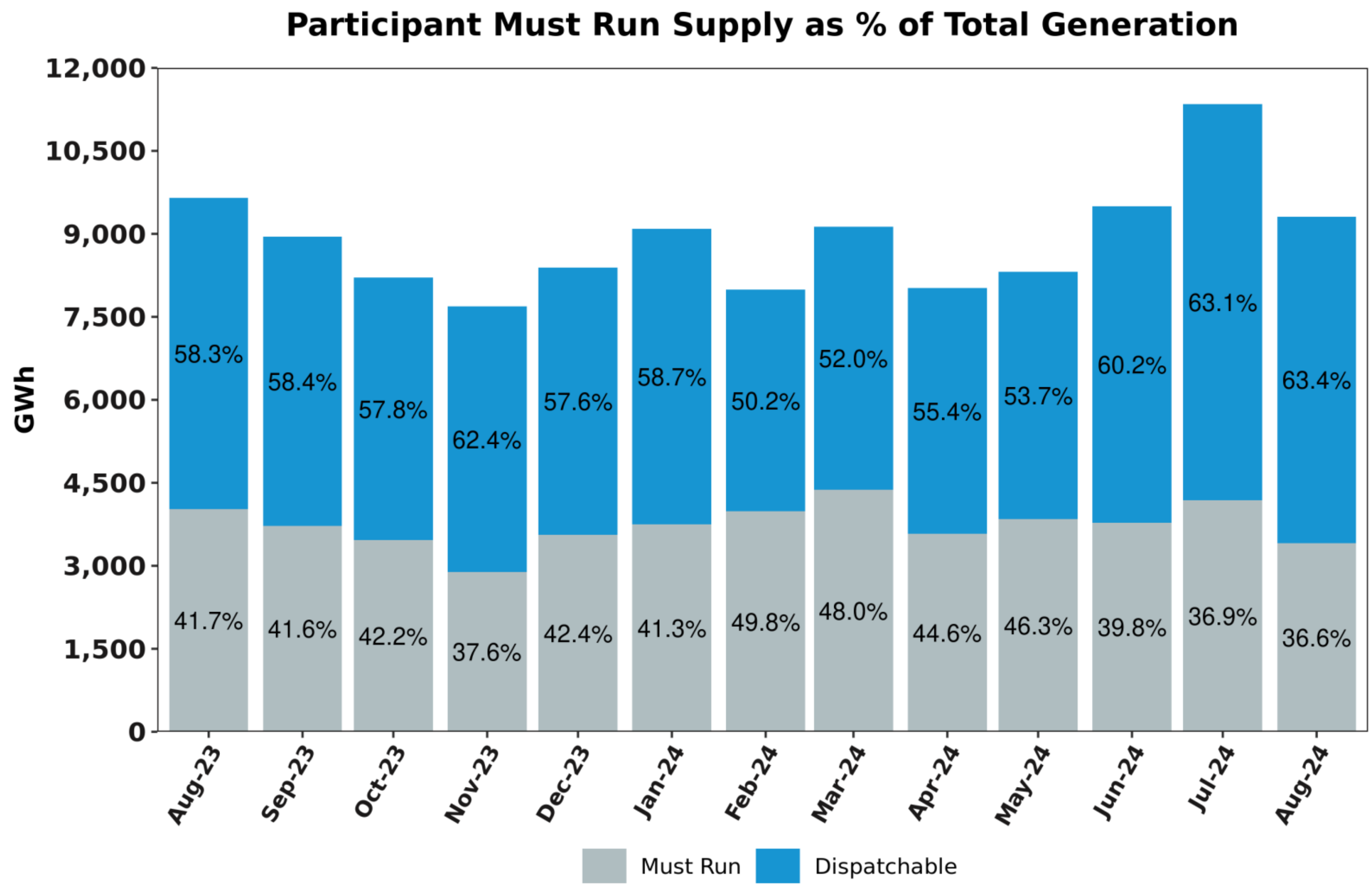
Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

RT Generation Output Offered as Must Run vs Dispatchable



Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of settlement-only generation (SOG) as well as must run offers from modeled units

MARKET PRICING

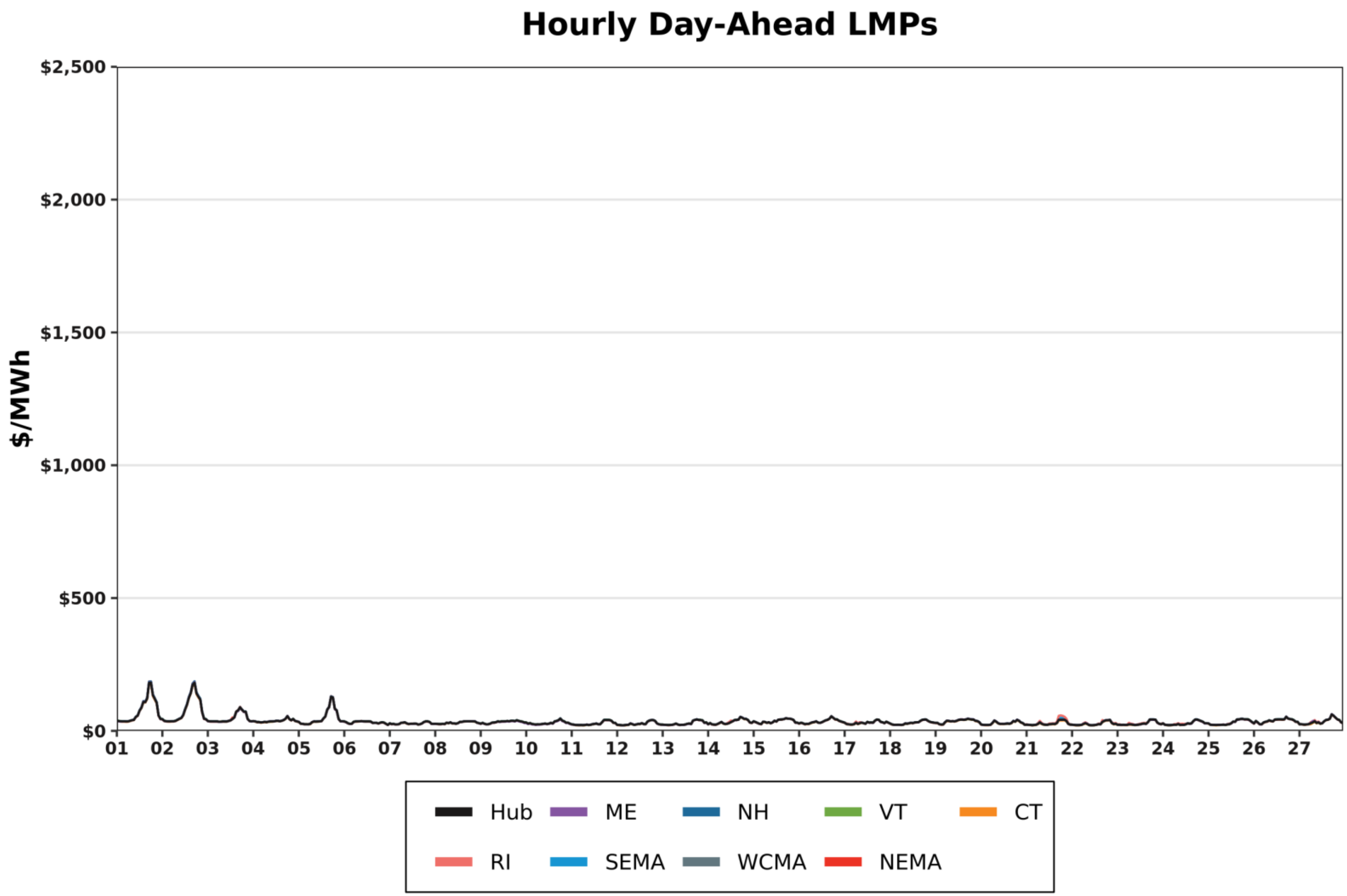
DA vs. RT LMPs ($/MWh)

Arithmetic Average

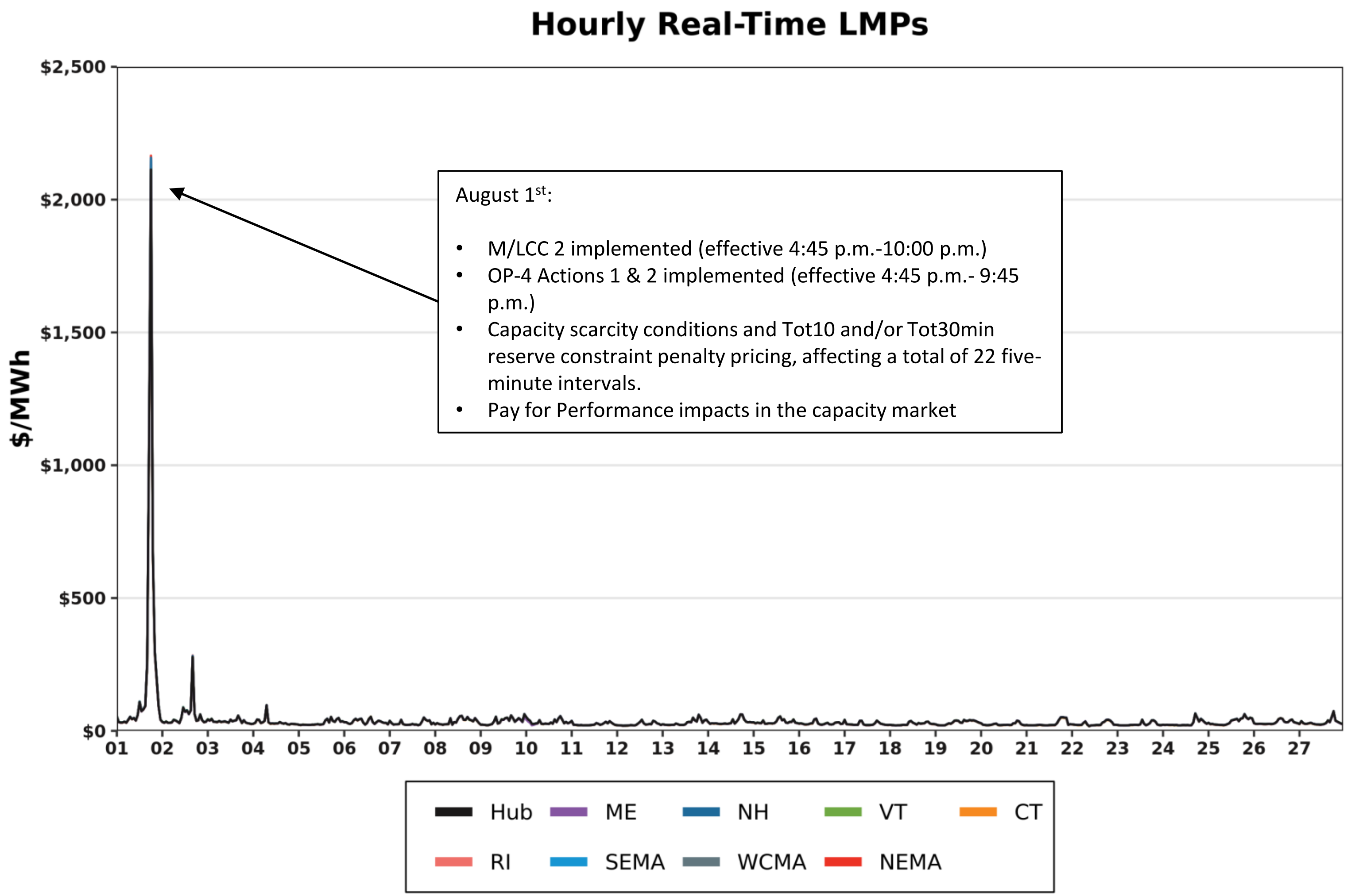
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$85.59	$84.20	$85.77	$84.48	$84.07	$85.39	$86.05	$85.69	$86.12
Real-Time	$84.89	$83.06	$85.05	$83.64	$83.80	$84.69	$85.35	$84.97	$85.40
RT Delta %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%
Year 2022	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%

August-23	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$26.94	$26.51	$27.03	$26.90	$26.50	$26.75	$27.18	$26.98	$27.22
Real-Time	$28.81	$28.29	$28.92	$28.72	$28.39	$28.59	$29.07	$28.85	$29.14
RT Delta %	6.94%	6.71%	6.99%	6.77%	7.13%	6.88%	6.95%	6.93%	7.05%
August-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$36.11	$35.80	$36.36	$36.17	$35.31	$36.19	$36.56	$36.16	$36.60
Real-Time	$39.06	$38.63	$39.40	$39.25	$38.47	$38.78	$39.36	$39.13	$39.55
RT Delta %	8.17%	7.91%	8.36%	8.52%	8.95%	7.16%	7.66%	8.21%	8.06%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	34.04%	35.04%	34.52%	34.46%	33.25%	35.29%	34.51%	34.03%	34.46%
Yr over Yr RT	35.58%	36.55%	36.24%	36.66%	35.51%	35.64%	35.40%	35.63%	35.72%

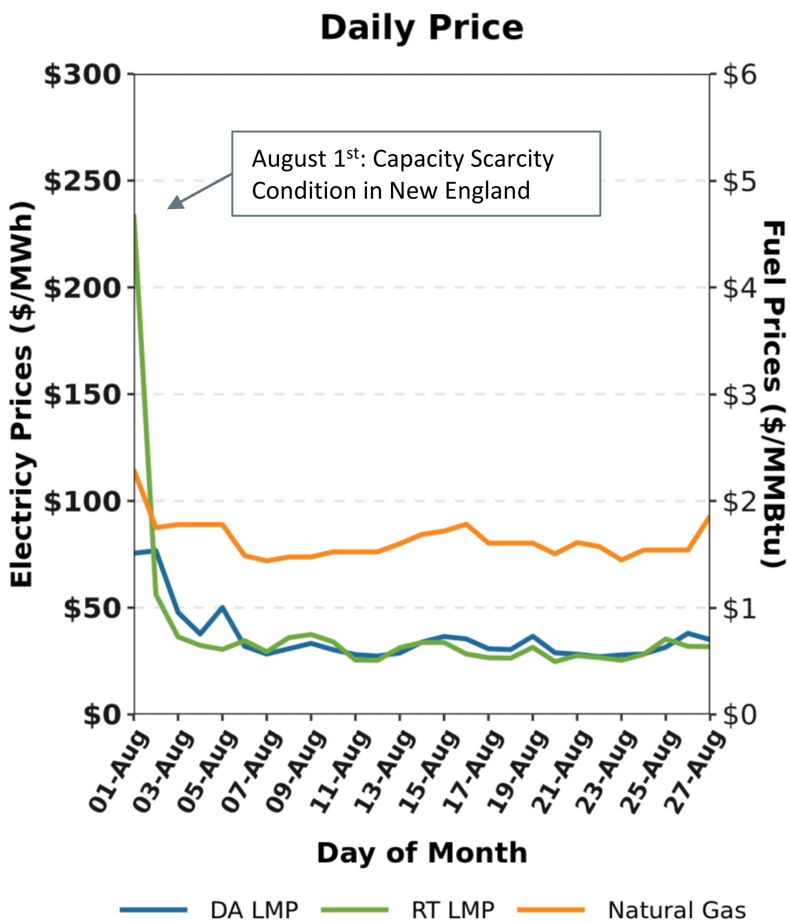
Hourly DA LMPs, August 1-27, 2024

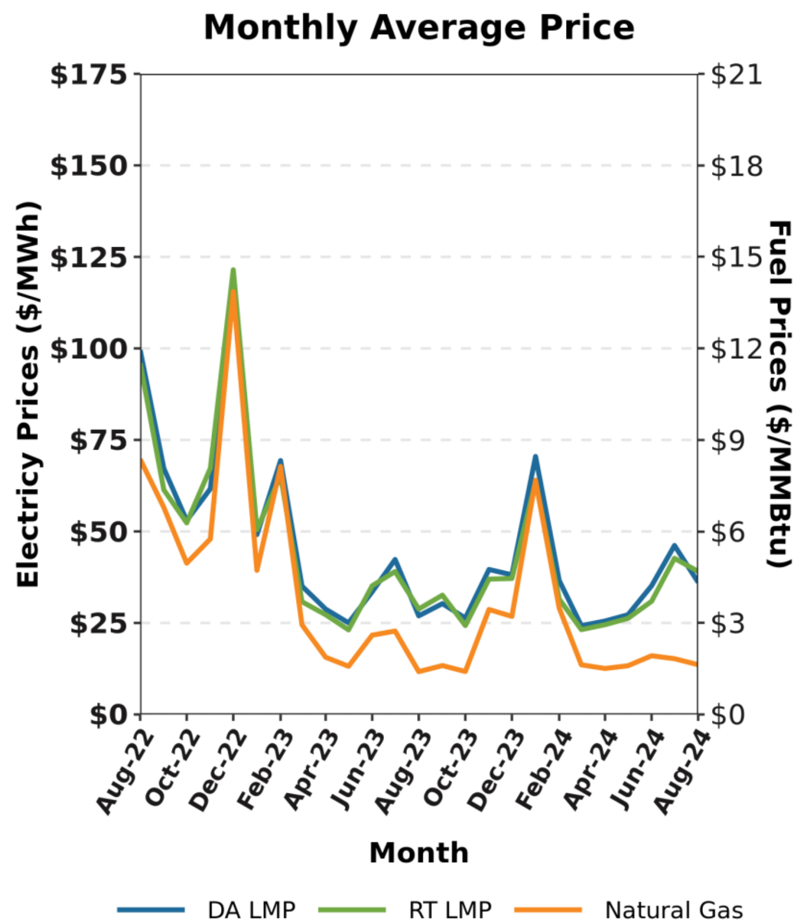


Hourly RT LMPs, August 1-27, 2024



Wholesale Electricity vs Natural Gas Prices by Month

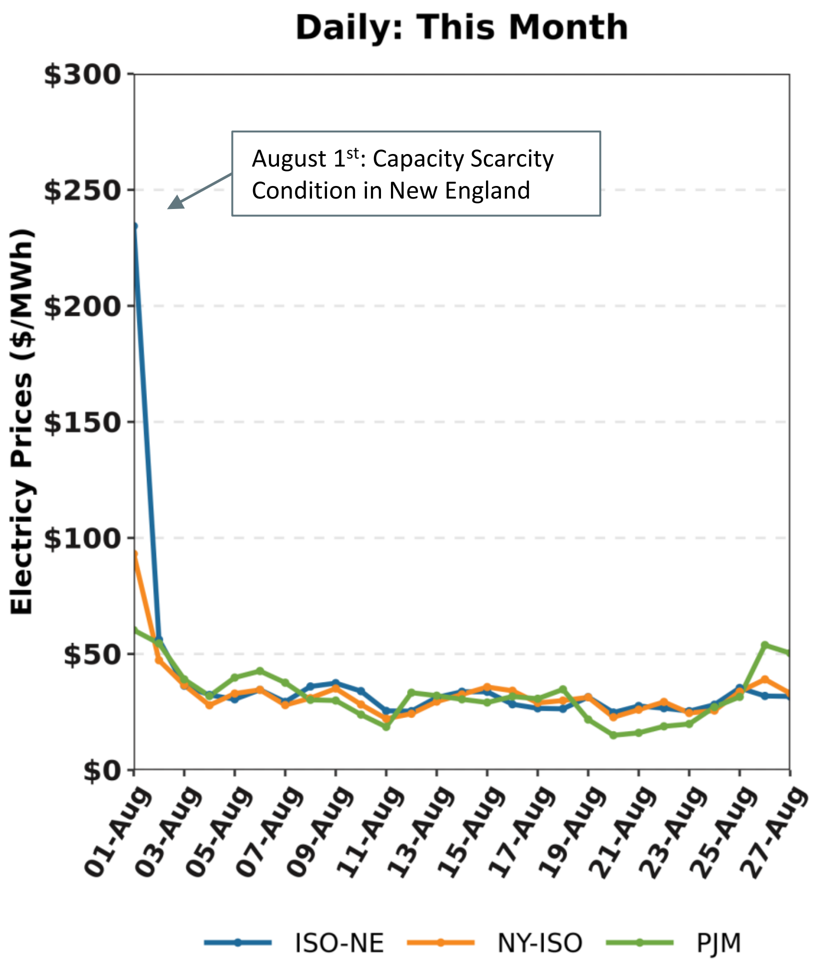


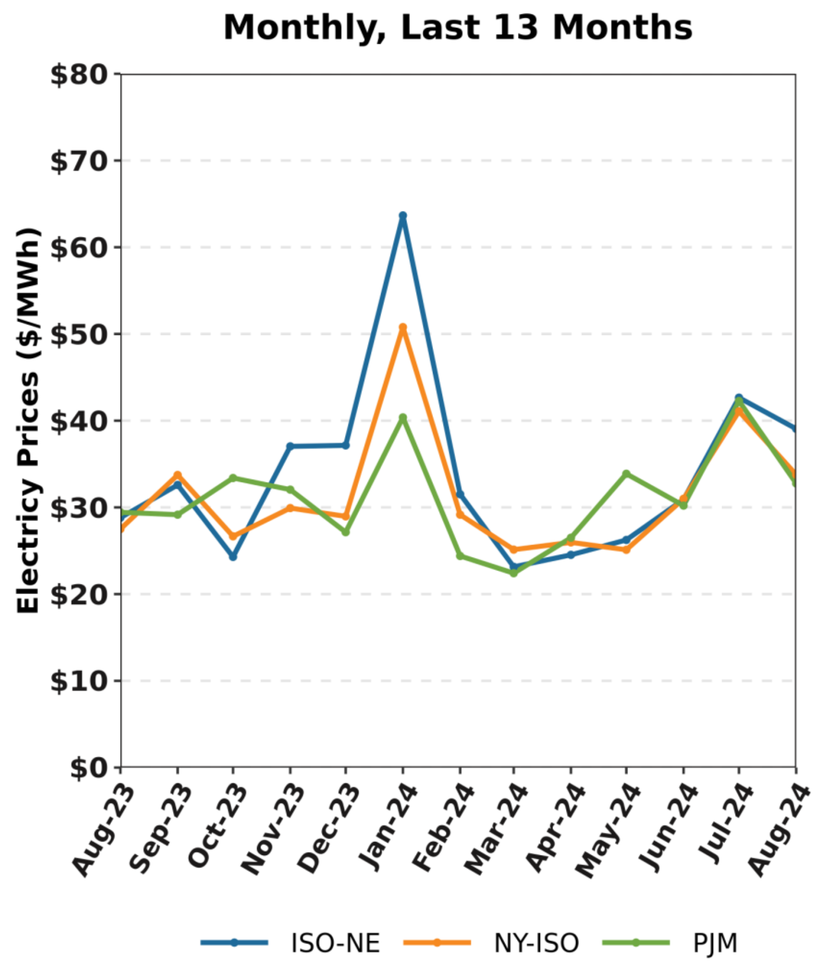


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

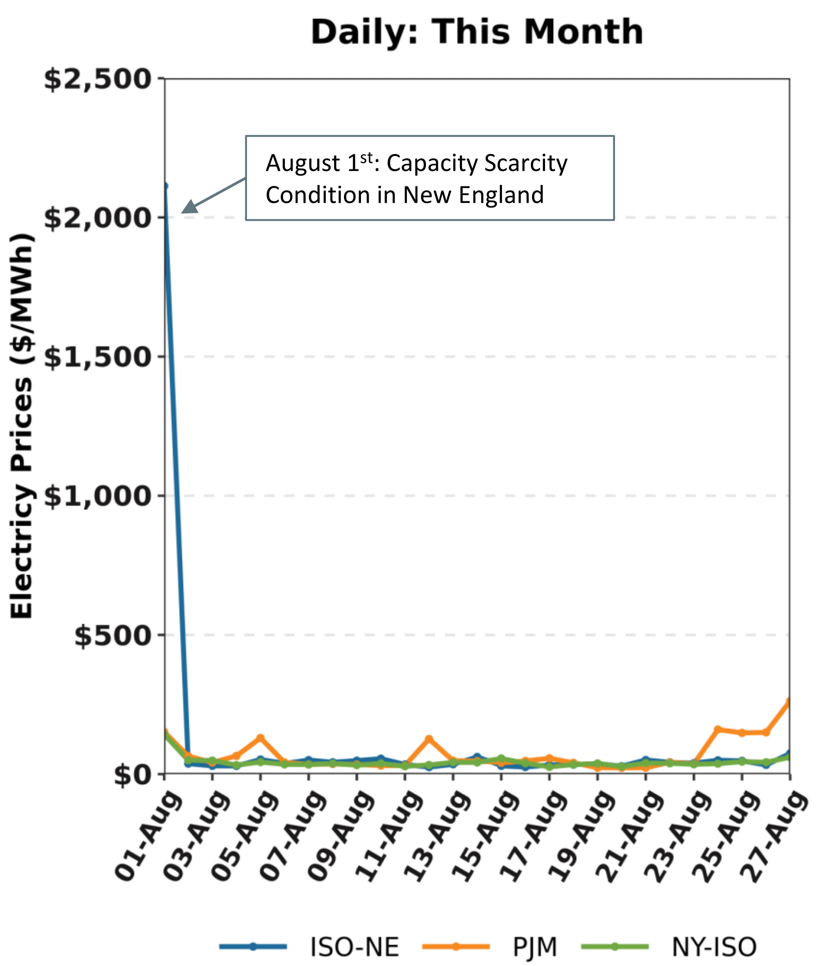
New England, NY, and PJM Hourly Average RT Prices by Month

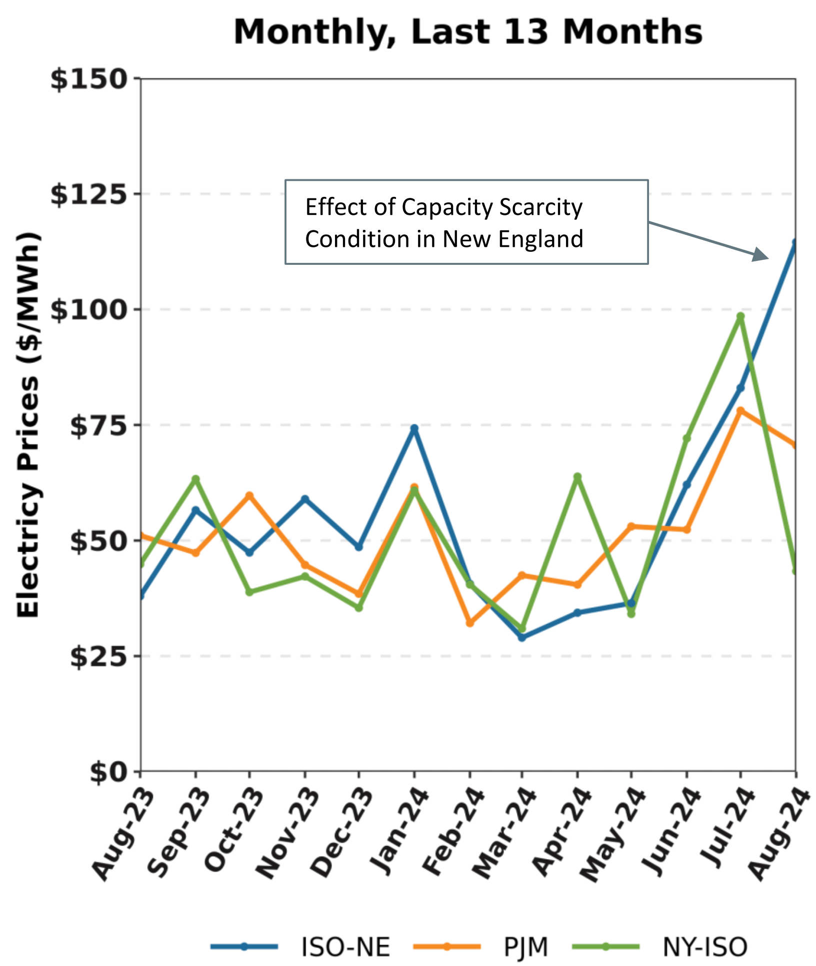




Hourly average prices are shown

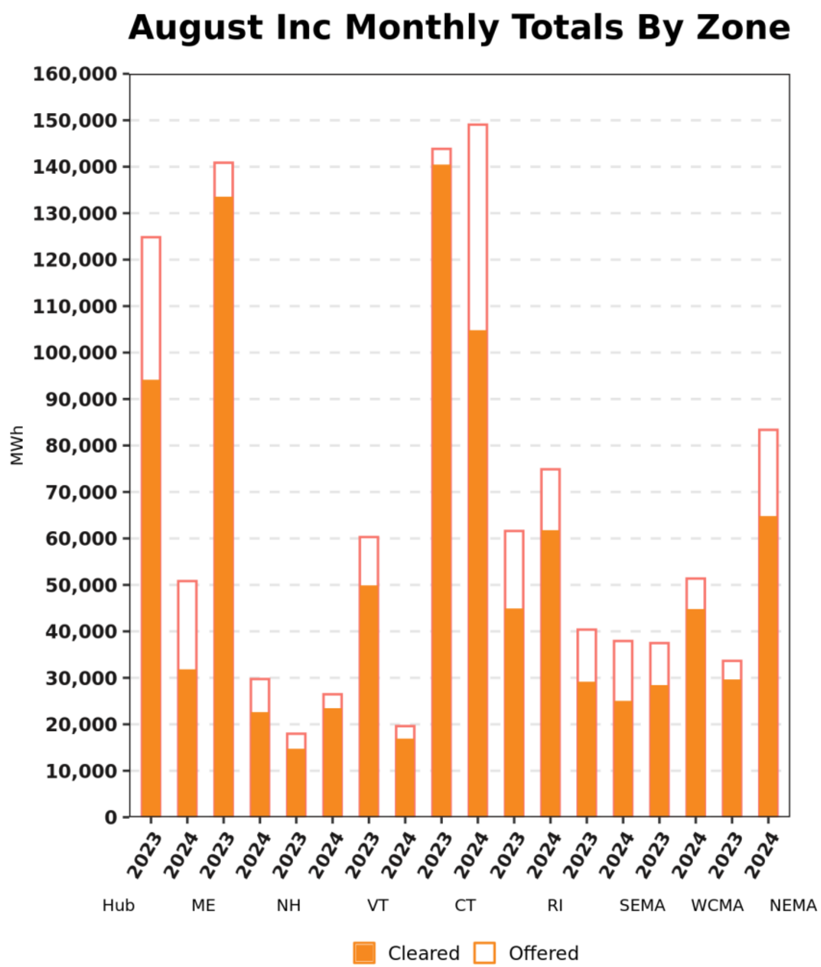
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours

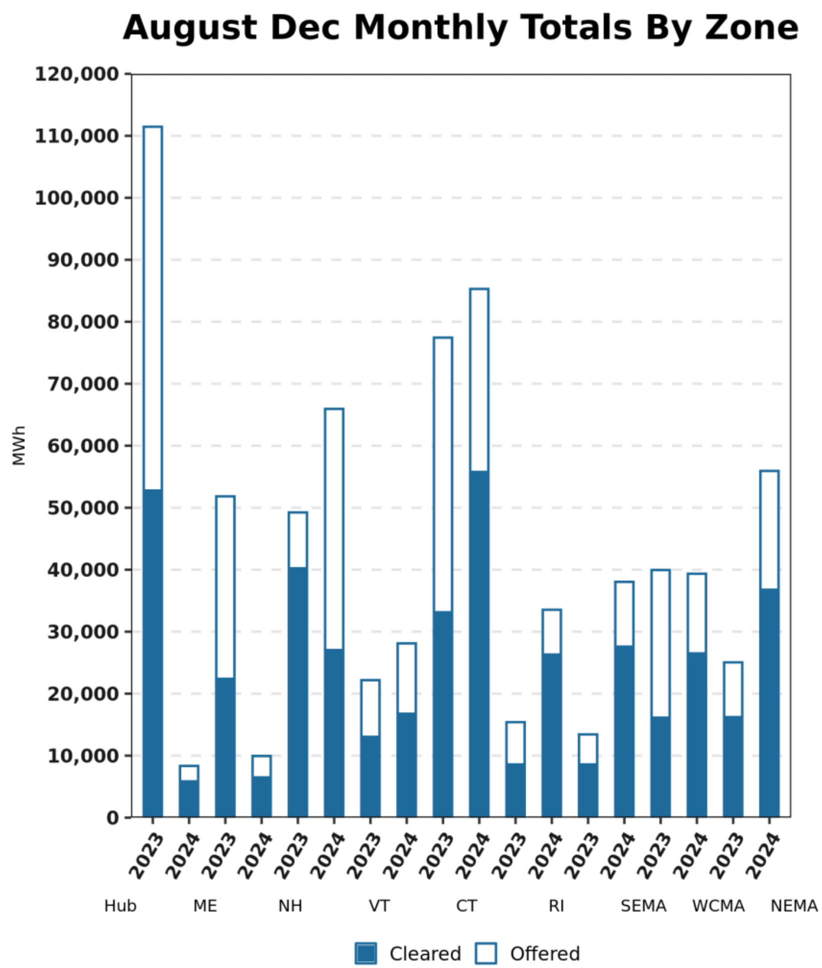




Monthly chart reflects the average of daily values

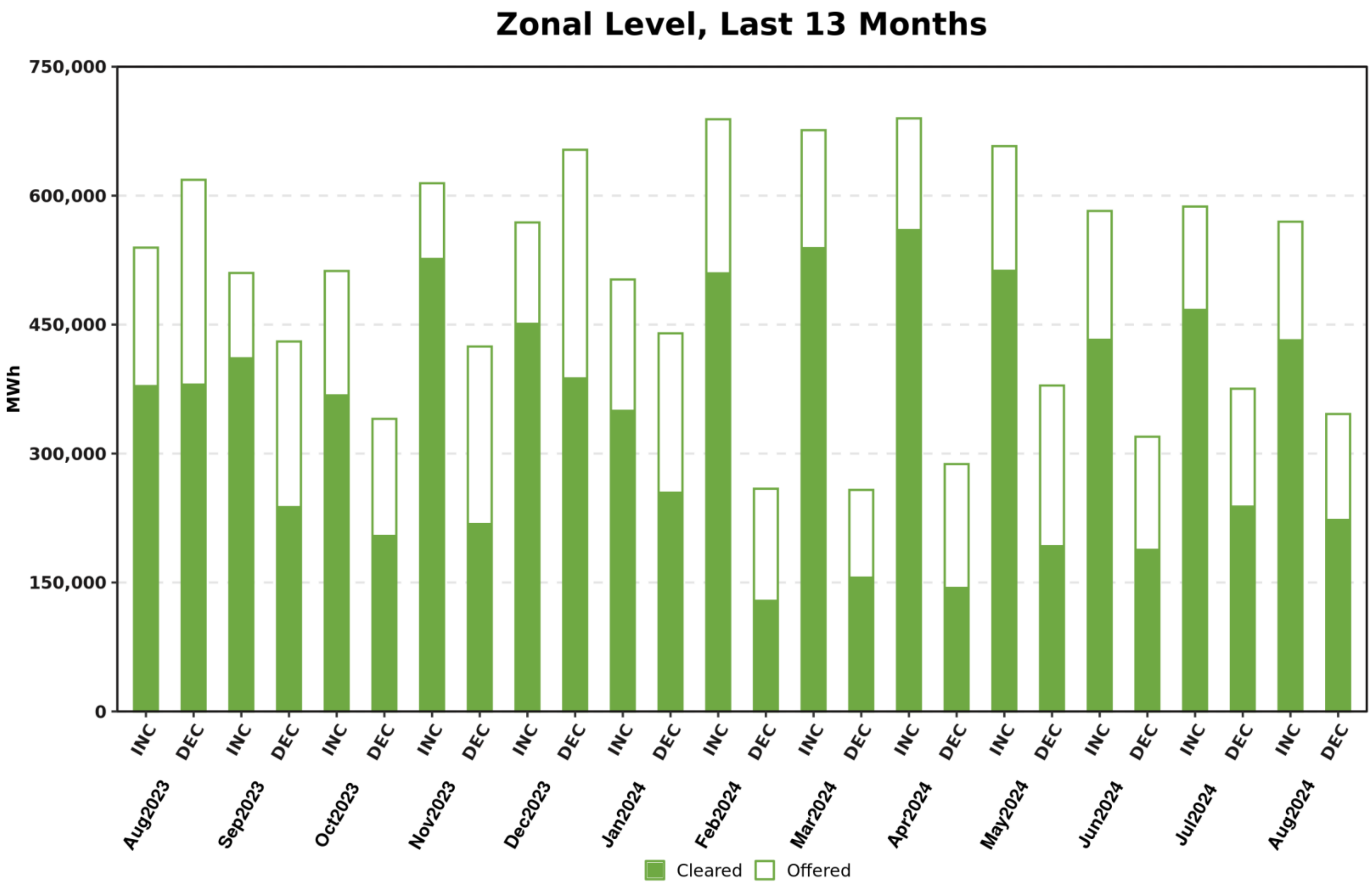
Zonal Increment Offers and Decrement Bid Amounts





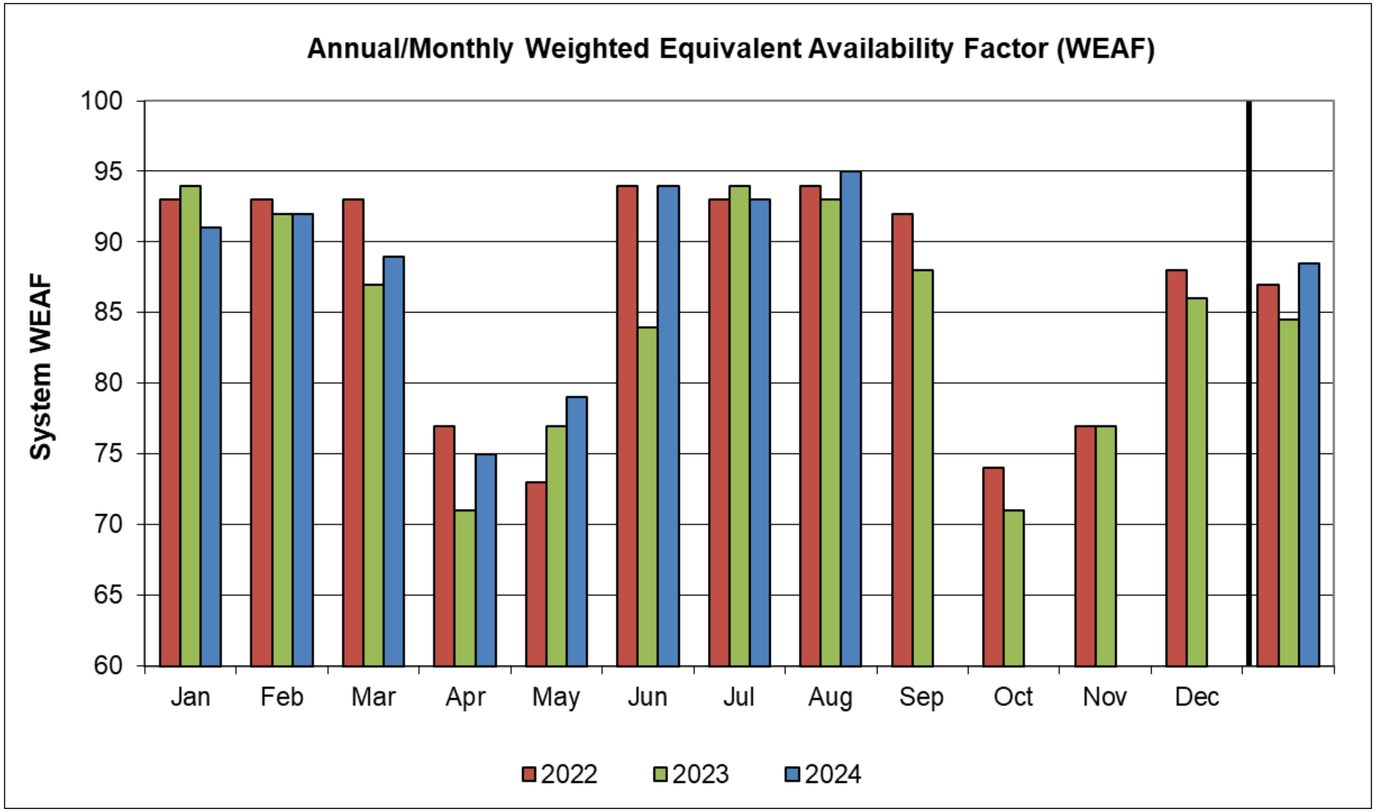
Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

System Unit Availability



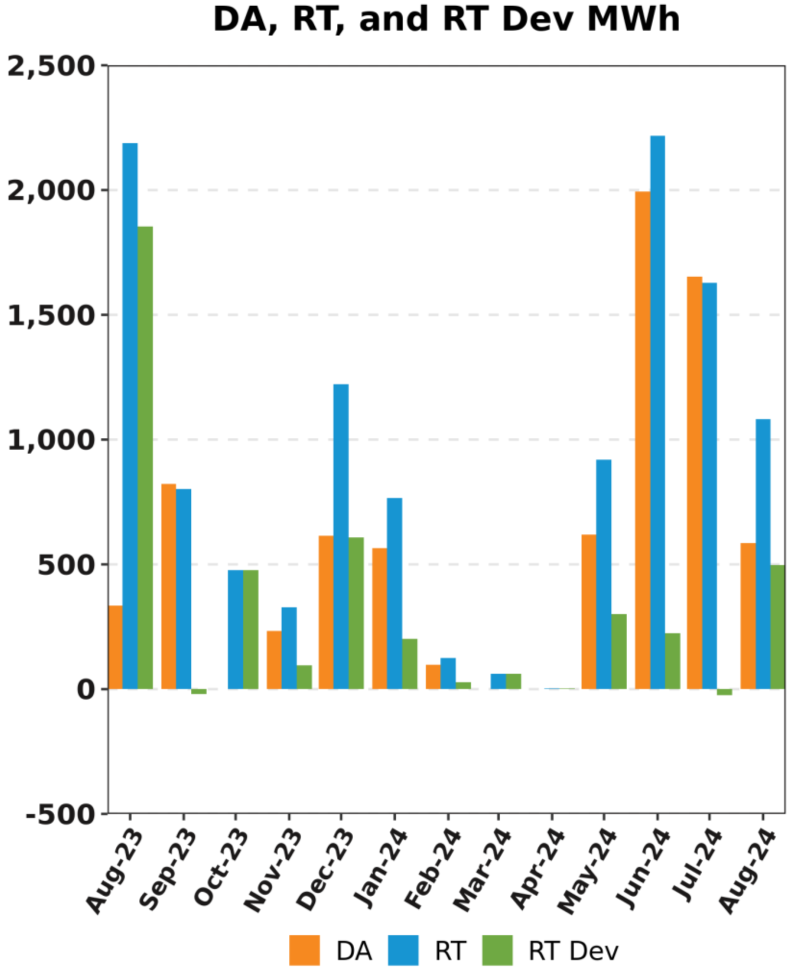
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2024	91	92	89	75	79	94	93	95					89
2023	94	92	87	71	77	84	94	93	88	71	77	86	85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87

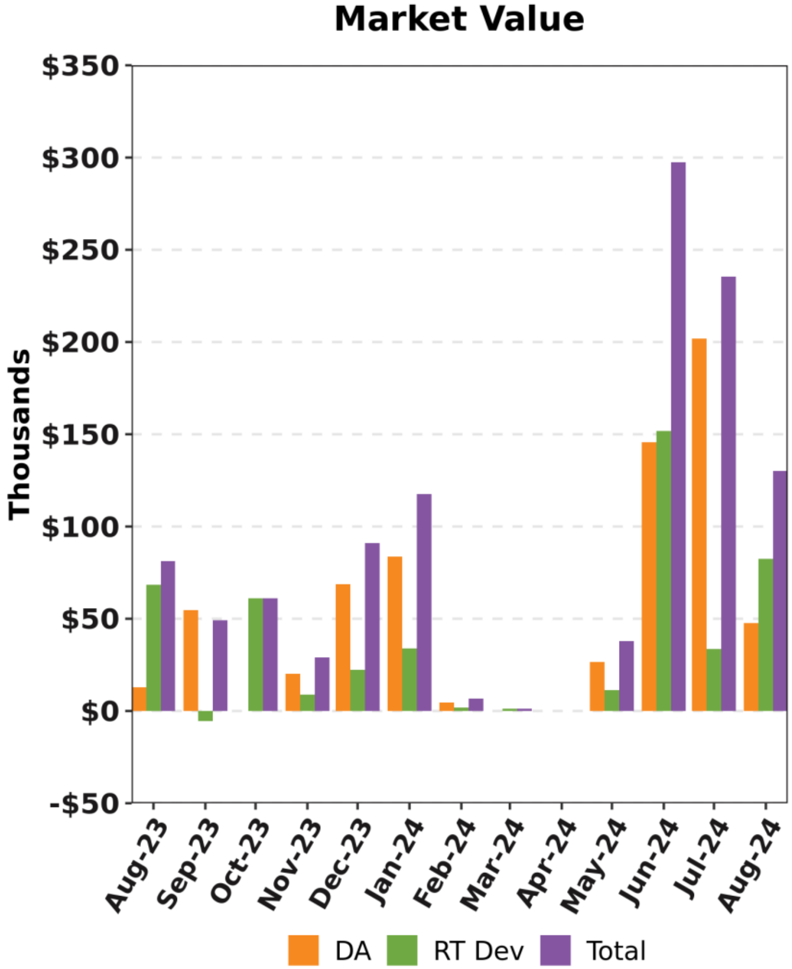
Data as of 8/26/24

BACK-UP DETAIL

DEMAND RESPONSE

Price Responsive Demand (PRD) Energy Market Activity by Month





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

NEW GENERATION

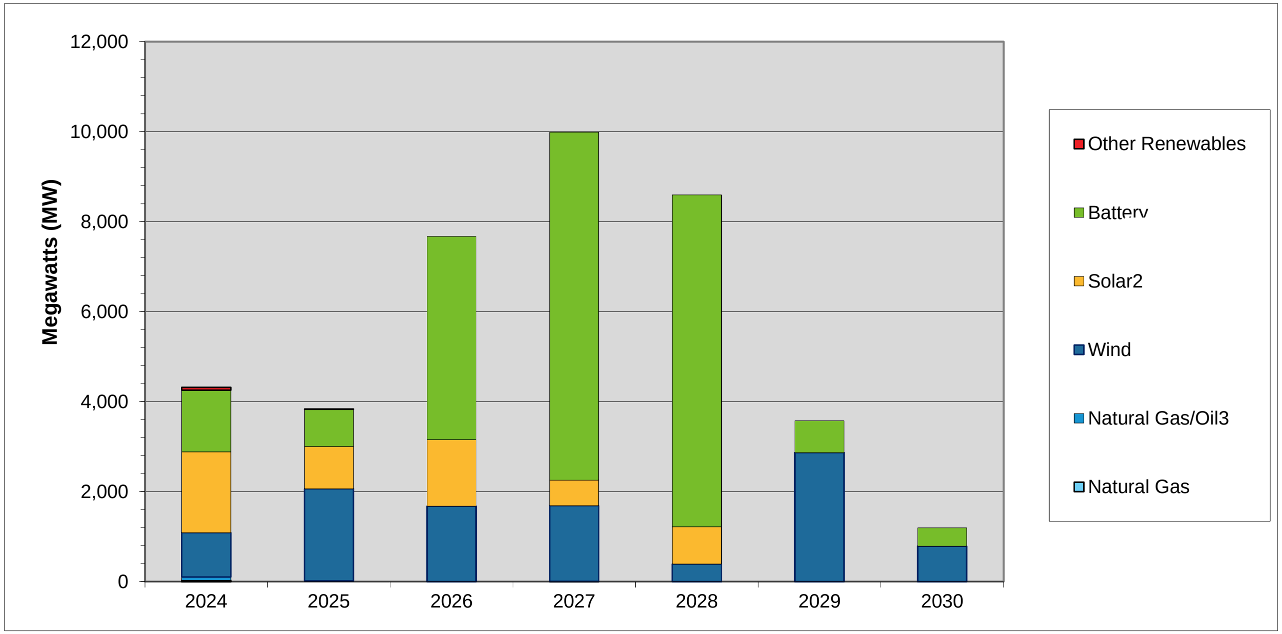
New Generation Update

Based on Queue as of 08/30/24

- No new projects were added to the interconnection queue since the last update
  - Any new ISO Interconnection Requests seeking to successfully enter the Order No. 2023 Transitional Cluster Study process were required to be submitted by June 13, 2024 at 23:59
    - Thereafter, the creation of new ISO Interconnection Requests is now suspended until the next Cluster Entry Window opens
- In total, 434 generation projects are currently being tracked by the ISO, totaling approximately 46,444 MW

Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Other Renewables	58	2	0	0	0	0	0	60	0.2
Battery	1,376	825	4,516	7,731	7,377	704	404	22,933	58.5
Solar[2]	1,792	941	1,477	565	823	0	0	5,598	14.3
Wind	989	2,049	1,679	1,687	394	2,870	791	10,459	26.7
Natural Gas/Oil[3]	73	16	0	0	0	0	0	89	0.2
Natural Gas	26	0	0	4	0	0	0	30	0.1
Totals	4,314	3,833	7,672	9,987	8,594	3,574	1,195	39,169	100.0

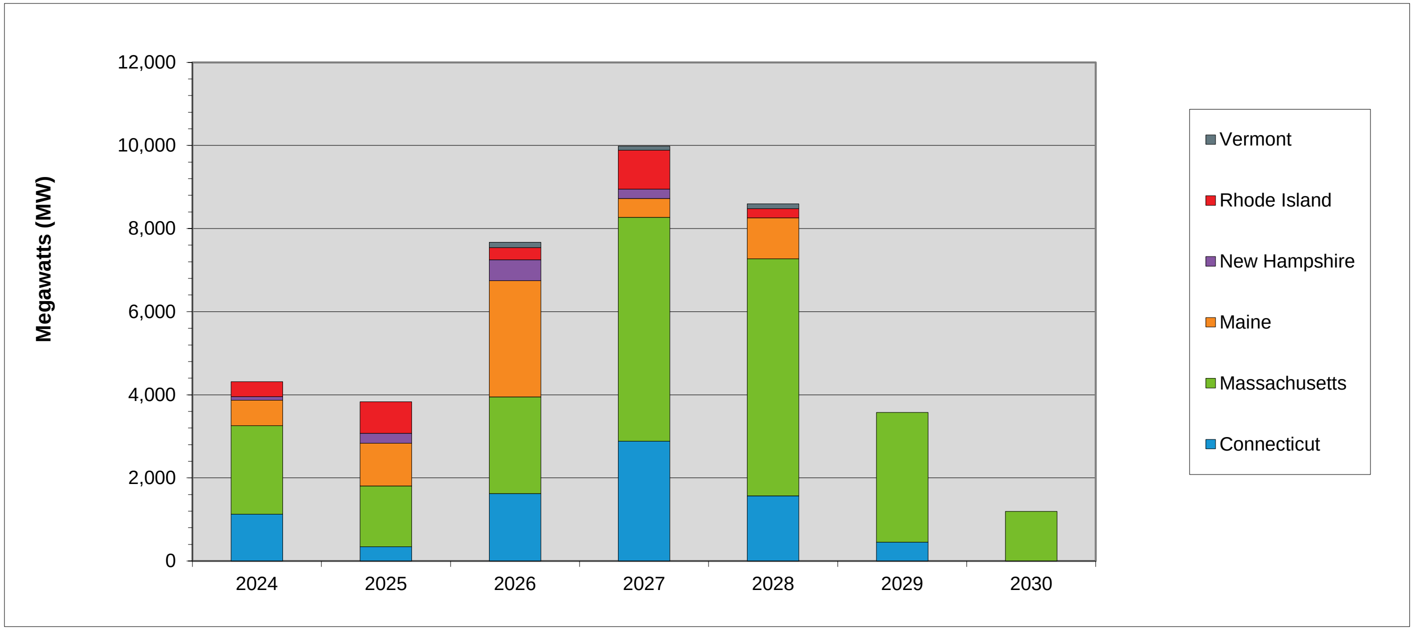
[1] Sum may not equal 100% due to rounding

[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

Projected Annual Generator Capacity Additions

By State



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Vermont	0	0	128	101	115	0	0	344	0.9
Rhode Island	360	758	295	938	221	0	0	2,572	6.6
New Hampshire	88	239	504	226	0	0	0	1,057	2.7
Maine	607	1,031	2,799	453	984	0	0	5,874	15.0
Massachusetts	2,134	1,461	2,323	5,387	5,710	3,120	1,195	21,330	54.5
Connecticut	1,125	344	1,623	2,882	1,564	454	0	7,992	20.4
Totals	**4,314**	**3,833**	**7,672**	**9,987**	**8,594**	**3,574**	**1,195**	**39,169**	**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	147	22,933	2	325	145	22,608
Fuel Cell	3	32	1	20	2	12
Hydro	1	28	1	28	0	0
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	2	89	0	0	2	89
Nuclear	0	0	0	0	0	0
Solar	249	5,598	14	310	235	5,288
Wind	28	17,734	3	985	25	16,749
Total	434	46,444	21	1,668	413	44,776

- 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	6	73	2	48	4	25
Intermediate	2	89	0	0	2	89
Peaker	398	28,548	16	635	382	27,913
Wind Turbine	28	17,734	3	985	25	16,749
Total	434	46,444	21	1,668	413	44,776

- 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

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	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	147	22,933	0	0	0	0	147	22,933	0	0
Fuel Cell	3	32	3	32	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	2	89	0	0	2	89	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	249	5,598	0	0	0	0	249	5,598	0	0
Wind	28	17,734	0	0	0	0	0	0	28	17,734
Total	434	46,444	6	73	2	89	398	28,548	28	17,734

- 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
Demand	*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
Generator	*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 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 2023-2027 CCP Month 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	461.416	-118.276
Demand	*Passive Demand*	3,212.865	3,211.403	-1.462	3,134.652	-76.751	3,113.332	-21.32
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**	**3,574.748**	**-139.596**
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125	27,132.413	50.76
Generator	*Intermittent*	1,089.265	1,073.794	-15.471	1,056.601	-17.193	865.694	-190.907
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**	**27,998.107**	**-140.147**
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**	**1,193.583**	**-55.962**
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**	**32,766.438**	**-335.705**
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**	**31,380**	**-165**

* 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 2023-2027 CCP Month 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	504.466	-85.416		
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753		
Demand Total		**3,322.606**	**3,169.002**	**-153.604**	**3,078.833**	**-90.169**		
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624	26,503.730	-139.649		
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518		
Generator Total		**27,983.936**	**27,790.162**	**-193.774**	**27,492.995**	**-297.167**		
Import Total		**1,503.842**	**1,247.601**	**-256.241**	**1,244.601**	**-3.000**		
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**	**31,816.429**	**-390.336**		
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**	**30,775**	**190.000**		

* 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 2023-2027 CCP Month 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	584.913	-37.941				
	Passive Demand	2,316.815	2,314.068	-2.747				
Demand Total		**2,939.669**	**2,898.981**	**-40.688**				
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069				
	Intermittent	1,356.084	1,286.589	-69.495				
Generator Total		**27,863.504**	**28,002.078**	**138.574**				
Import Total		**566.998**	**564.079**	**-2.919**				
Grand Total*		**31,370.171**	**31,465.138**	**94.967**				
Net ICR (NICR)		**30,305**	**30,395**	**90.000**				

* 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 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

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*	543.580						
	Passive Demand	2,070.498						
Demand Total		**2,614.078**						
Generator	*Non-Intermittent*	27,026.635						
	Intermittent	1,450.872						
Generator Total		**28,477.507**						
Import Total		**464.835**						
Grand Total*		**31,556.420**						
Net ICR (NICR)		**30,550**						

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

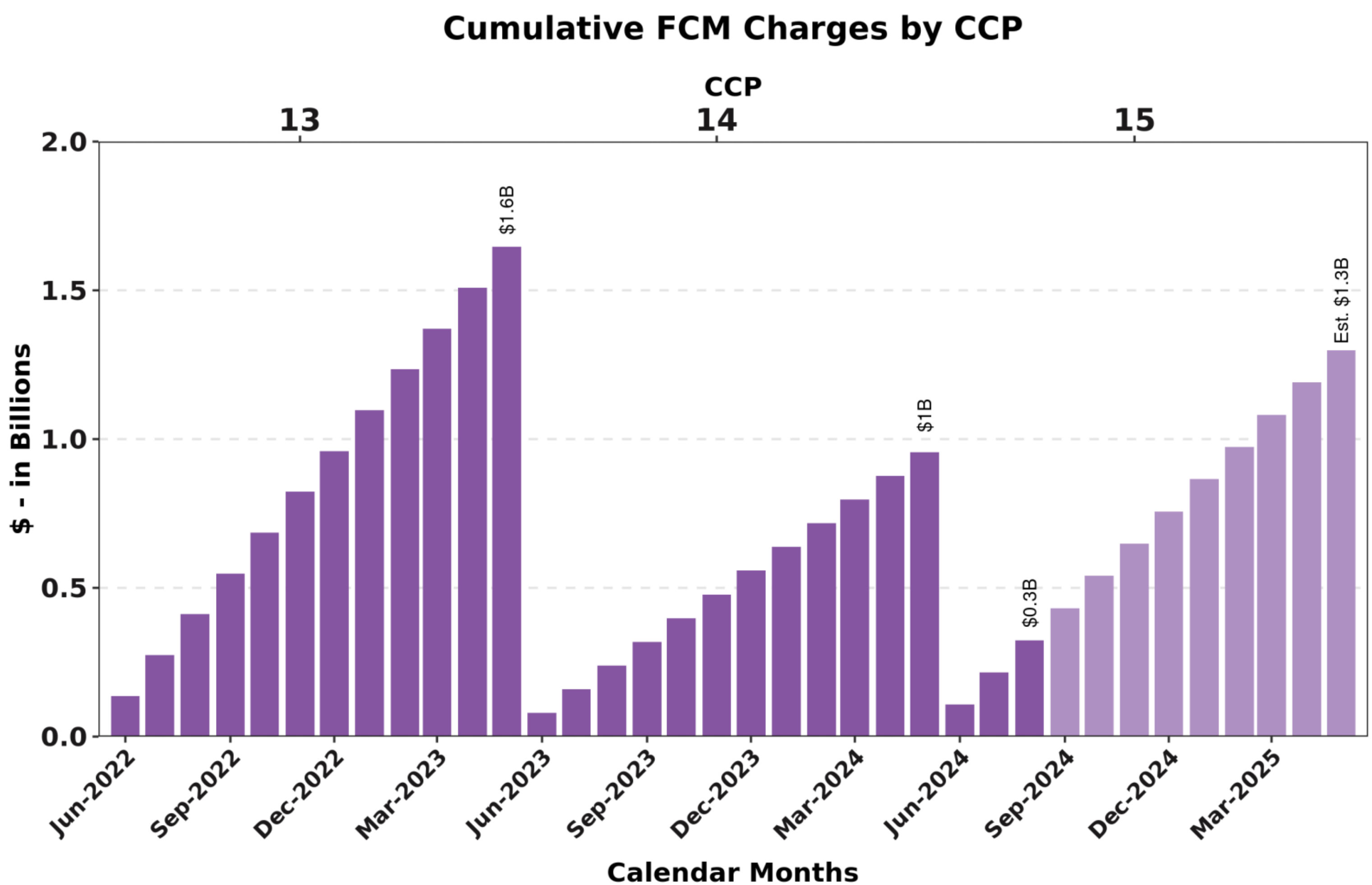
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month 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
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**
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	**2,809.541**	**130.128**	**2,939.669**
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

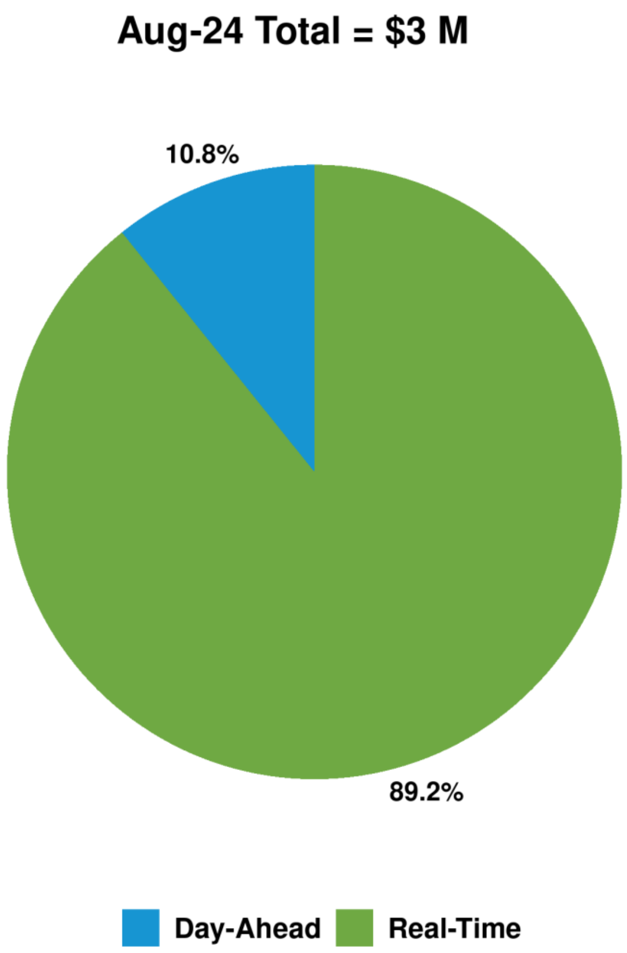
Forward Capacity Market Auctions

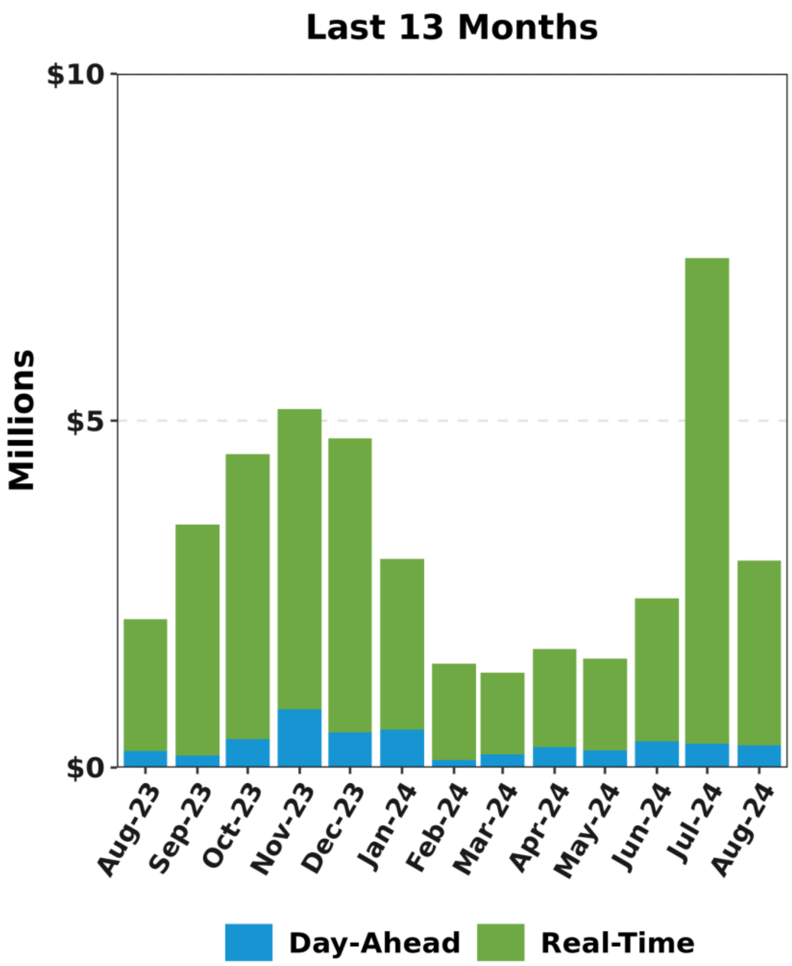


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

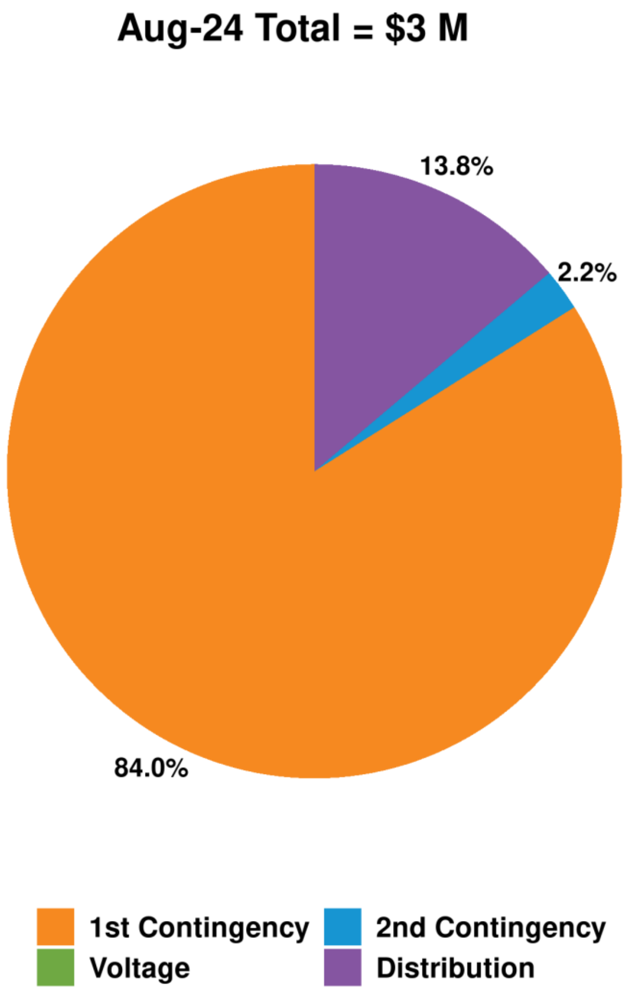
NET COMMITMENT PERIOD COMPENSATION

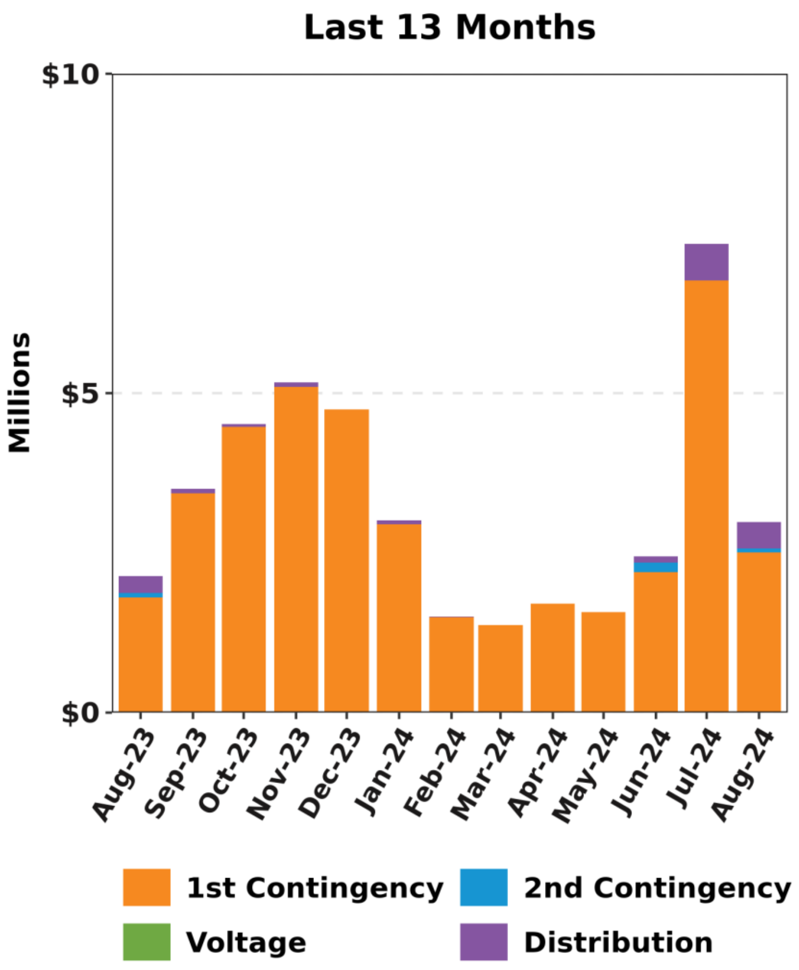
DA and RT NCPC Charges



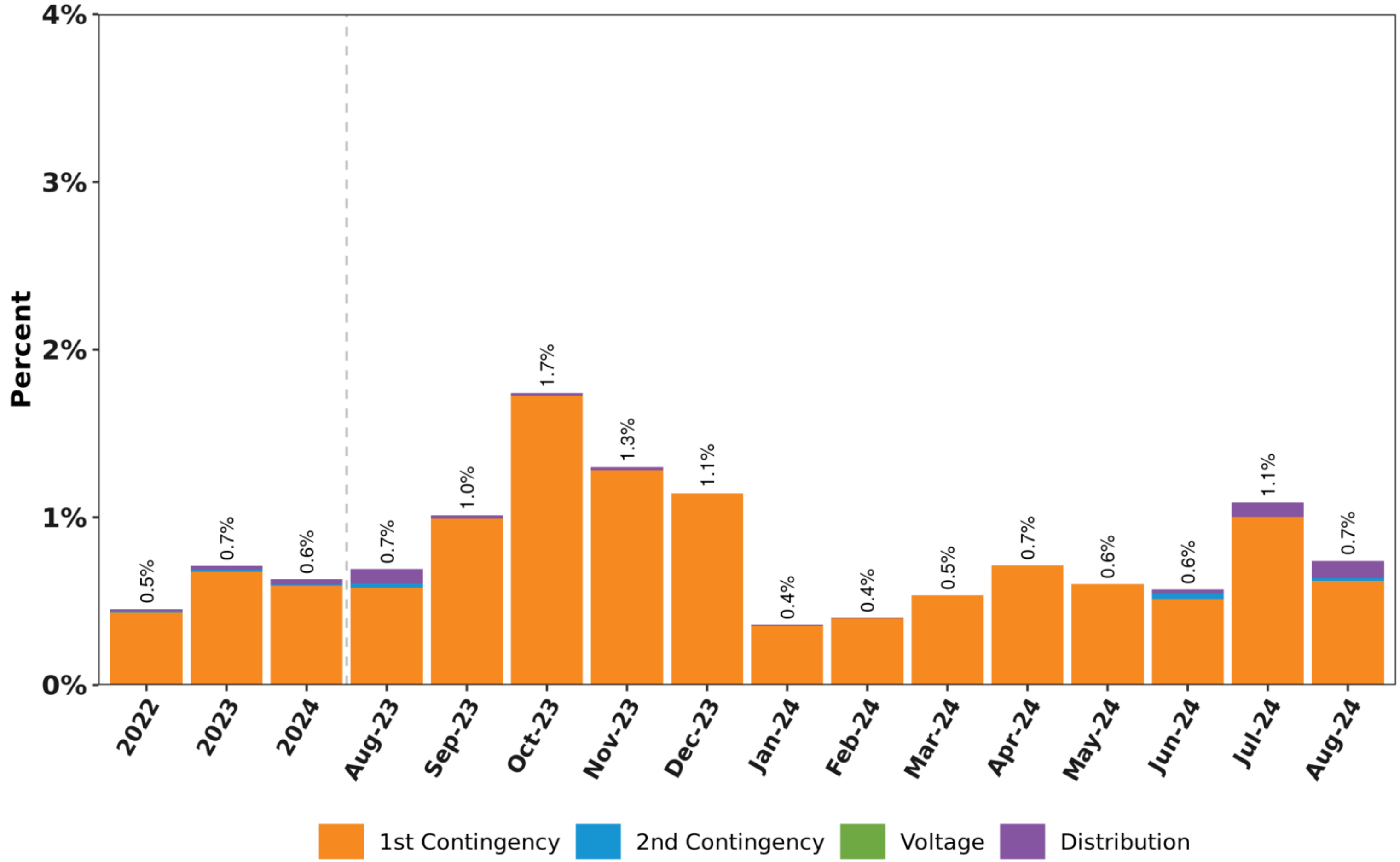


NCPC Charges by Type

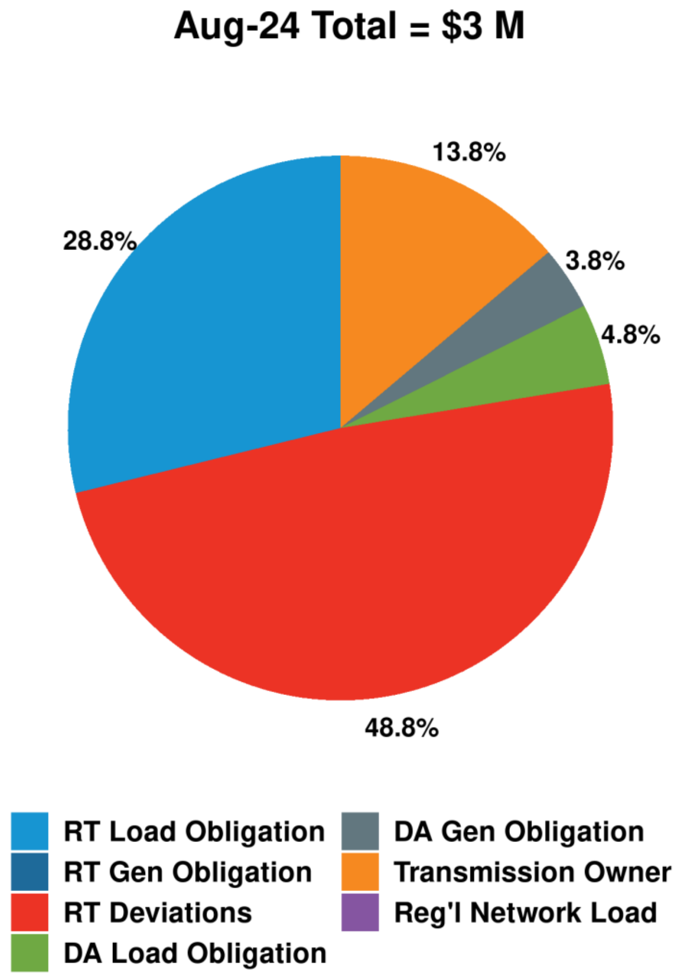


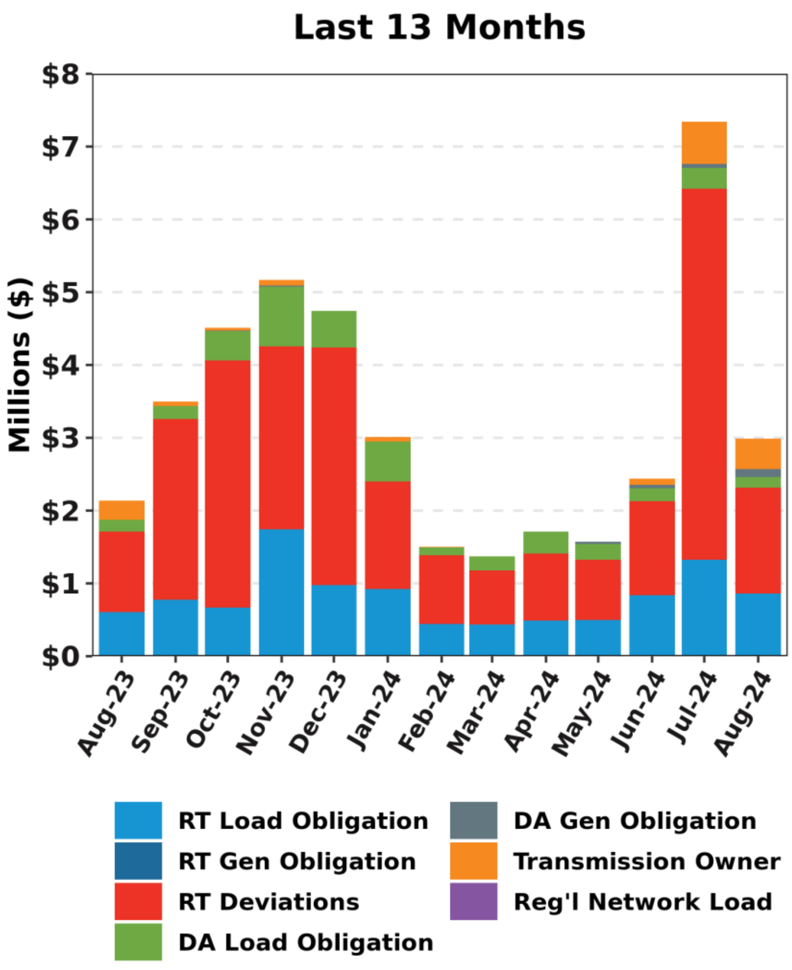


NCPC Charges by Type as Percent of Energy Market Value

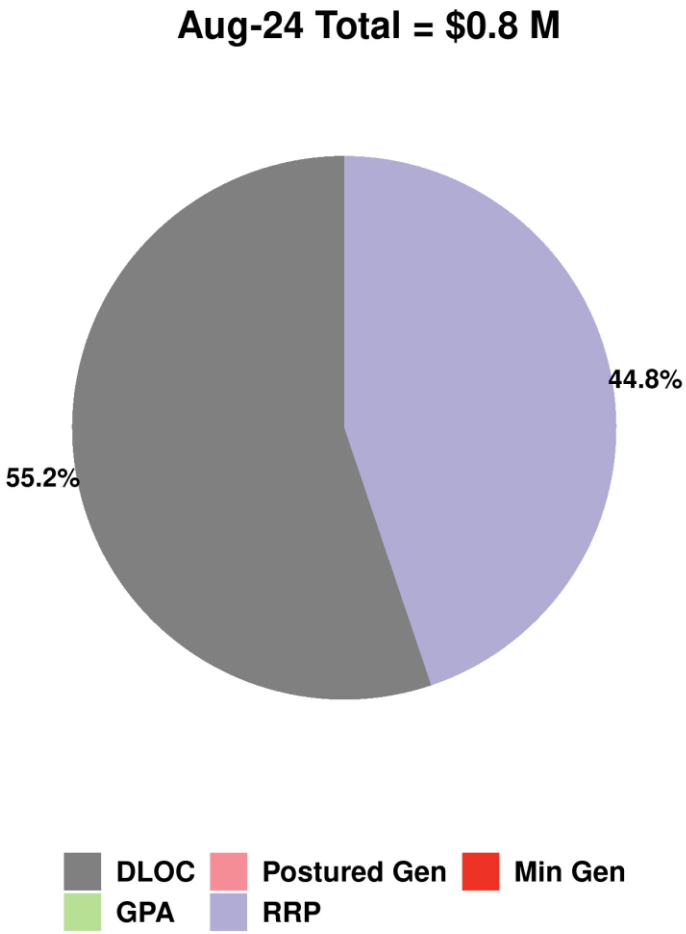


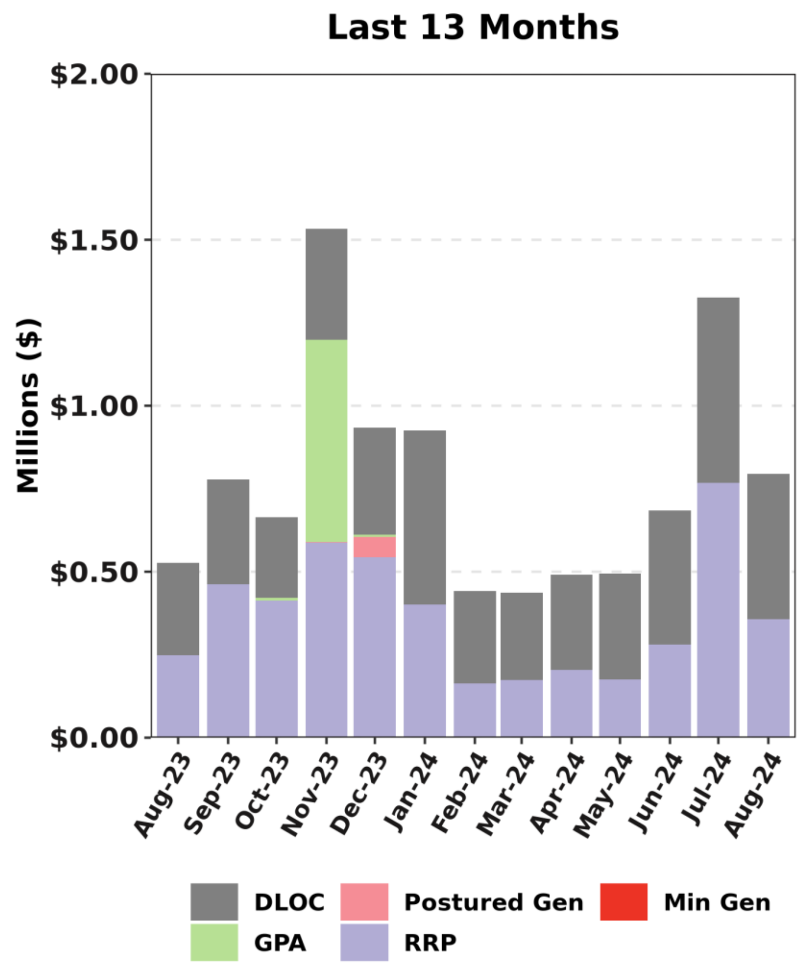
NCPC Charge Allocations





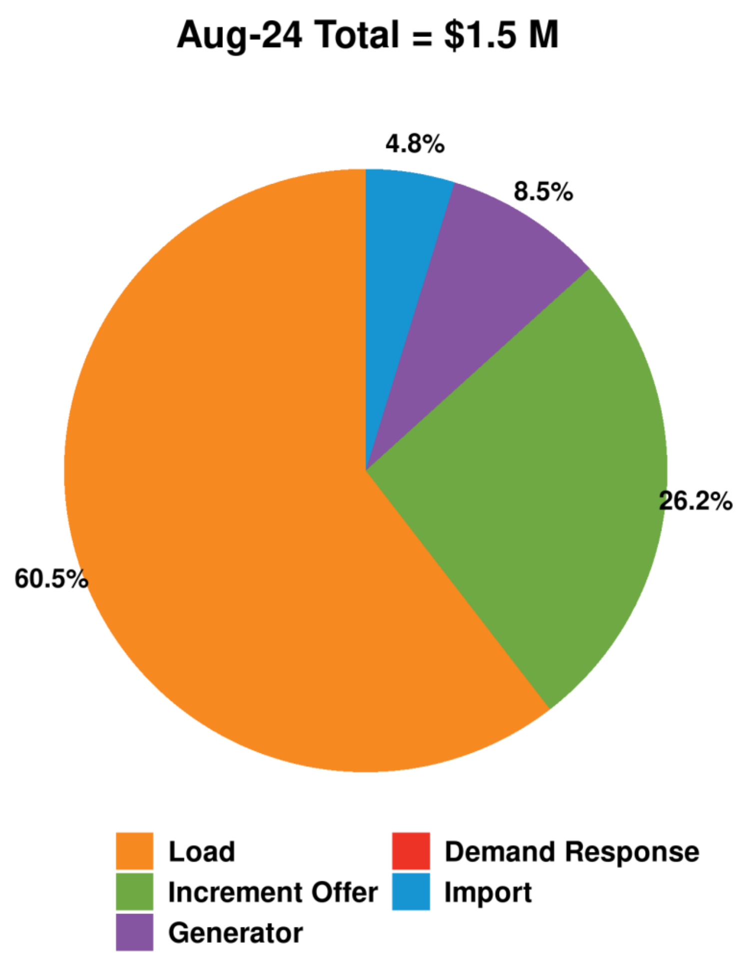
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

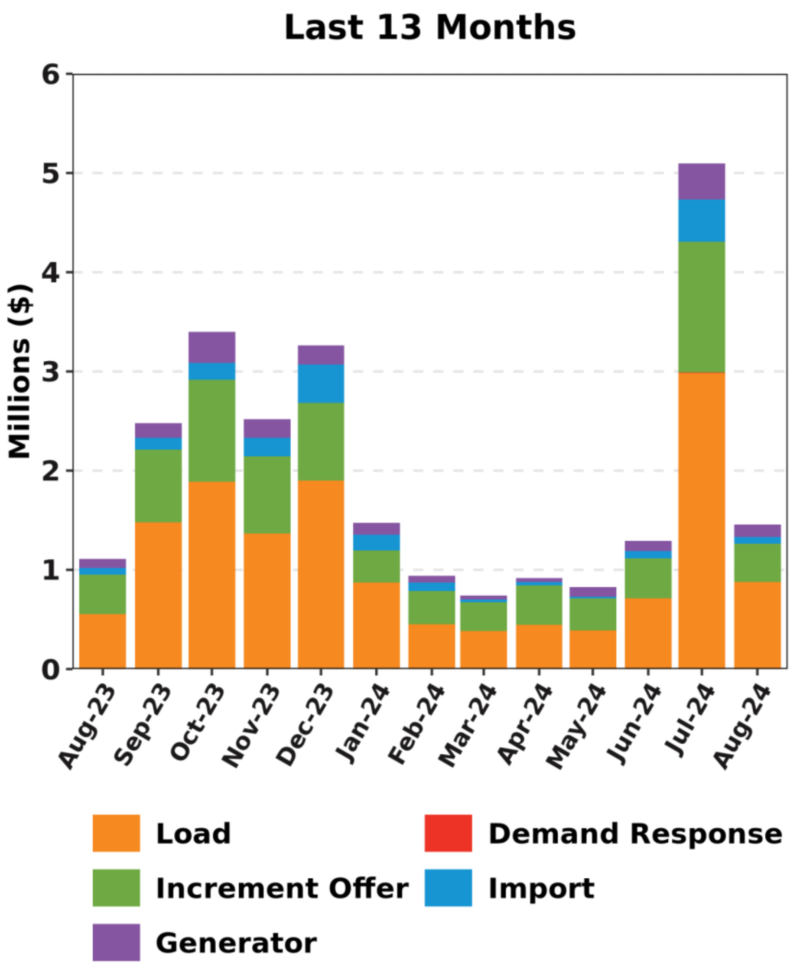




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

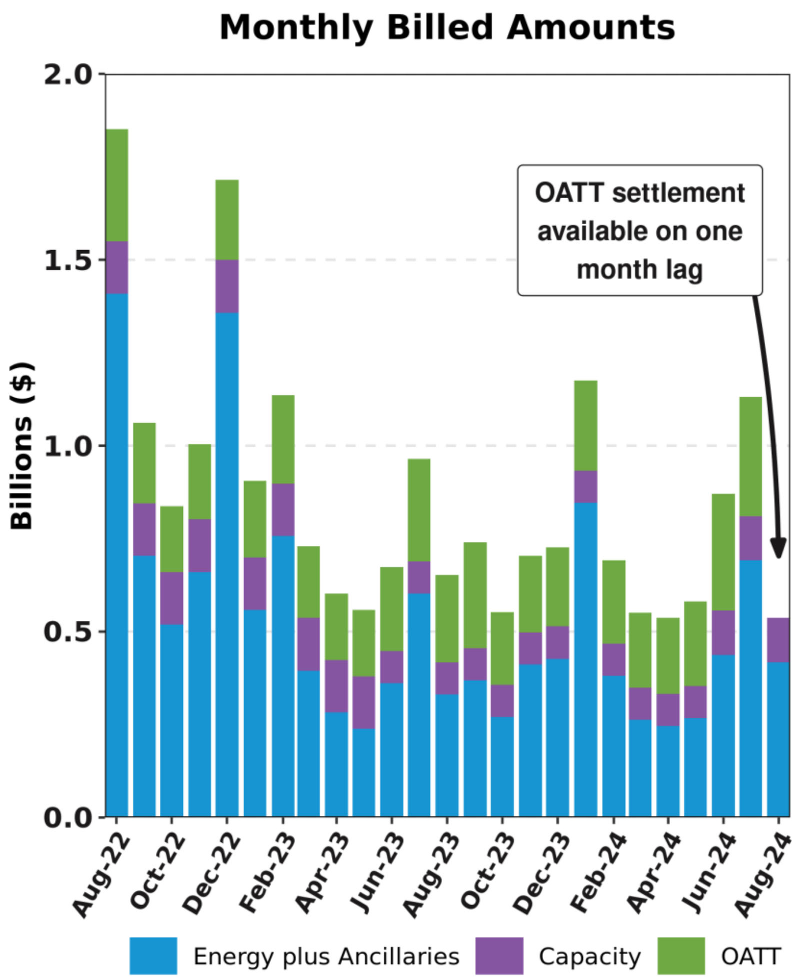
RT First Contingency Charges by Deviation Type

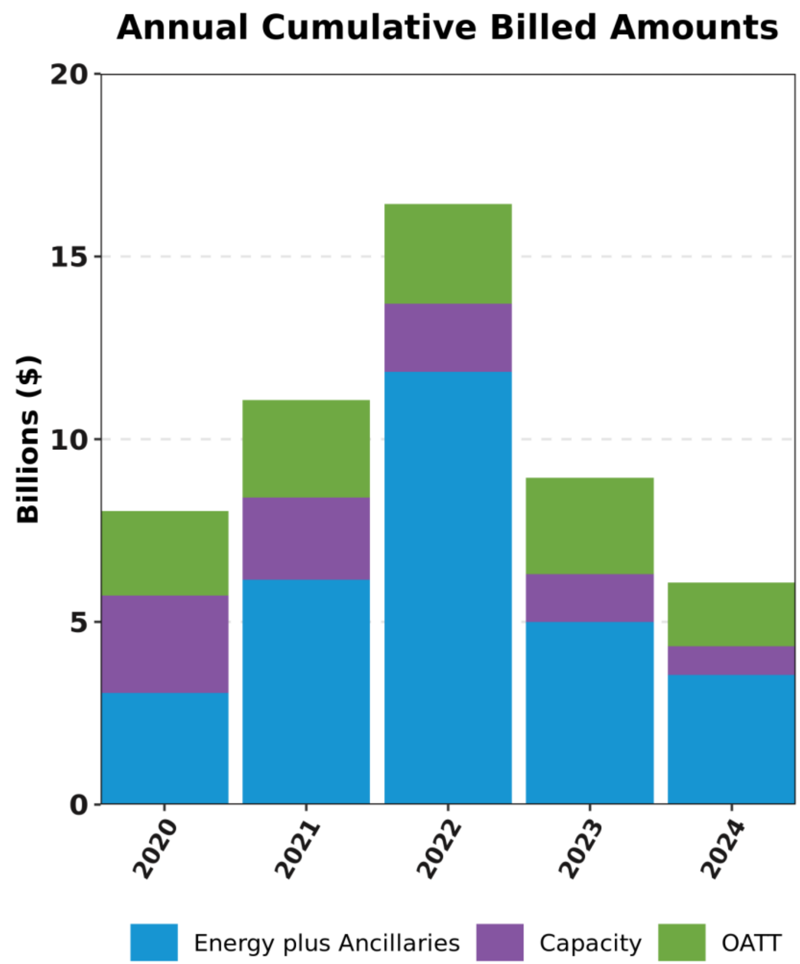




ISO BILLINGS

Total ISO Billings





Ancillaries = Reserves, Regulation, NCPC, minus Marginal Loss Revenue Fund. OATT = RNS, Through and Out, Schedule 9

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- September 18 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - 345 kV Breaker Replacements: Manchester (CT) and Amherst (MA) (Eversource)
    - VELCO Transmission Line Refurbishment - PAC Presentation K19 (VELCO)
    - 302 Asset Condition Refurbishment (National Grid)
  - NETO Presentations
    - Asset Condition Project Forecast
    - Asset Condition Process Guide, Appendix C
    - PAC Presentation Content Guidelines, Revised

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

2050 Transmission Study

- Final version of the study, technical appendix, responses to stakeholder feedback, and study fact sheet were published on 2/14/24
- Additional analysis to address stakeholder comments on offshore wind points of interconnection was presented to PAC on 3/20/24, and will continue through Q2 and Q3 2024
- Results of additional analysis on offshore wind relocation were presented at the 4/18/24 PAC meeting
- The ISO discussed the results of the offshore wind point of interconnection screening and constraint identification analysis at the 8/21/24 PAC meeting

Economic Studies: EPCET

- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - An effort to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - Final PAC presentation was made at the August meeting
  - Draft report was issued on August 16, and comments are due by September 10

Economic Studies: 2024 Study

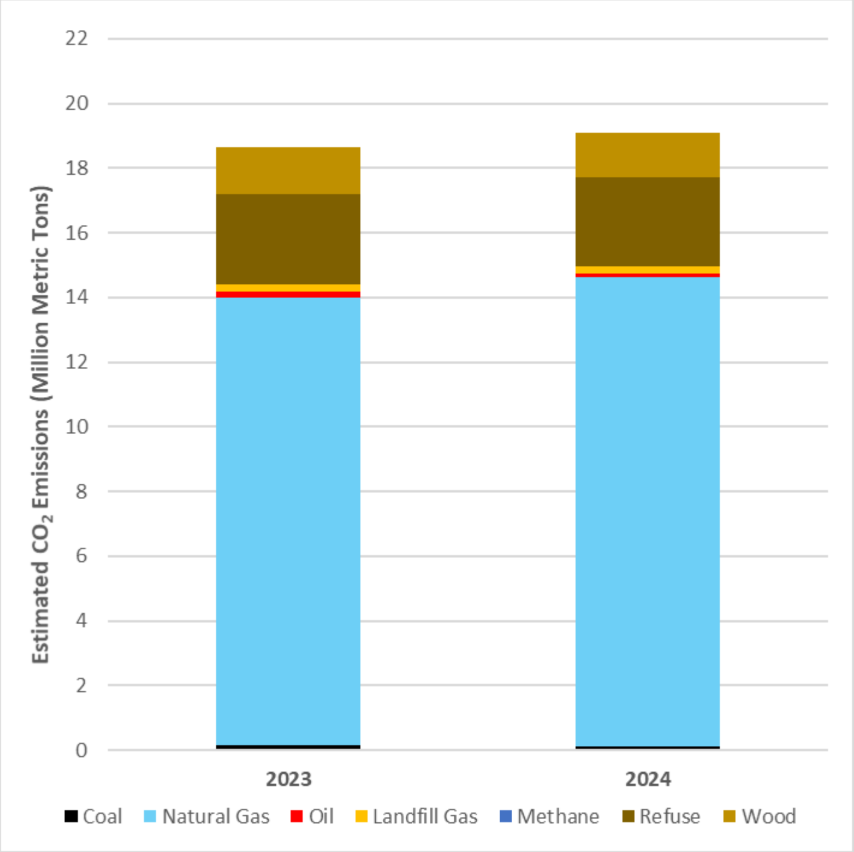
- The 2024 Economic Study
  - This study is the first use of new Economic Study Process Tariff language that was recently updated
    - The study was initiated at the January PAC meeting
  - The sequence is scenarios for the study begin with the Benchmark Scenario in Q1-Q3 2024, followed by the Policy Scenario and the Stakeholder-Requested Scenario in Q3 2024-Q1 2025
    - The stakeholder-Requested Scenario was discussed at the June PAC meeting. It focuses on the use of peaker plants in various future power system resource mixes
  - The Market Efficiency Needs Scenario will be studied in 2025

ISO-NE Tie Benefits Evaluation

- The ISO started the tie benefits evaluation at the October 19, 2023 PSPC meeting and held two additional PSPC meetings on January 25, 2024 and March 15, 2024 to review and discuss the evaluation
- The ISO issued a memo on June 26, 2024 to the RC and PSPC to summarize the evaluation and provide additional next steps
  - Continue to reach out to neighboring Balancing Areas to further modeling improvements
  - Continue efforts to adapt the current tie benefit methodology into a seasonal capacity market

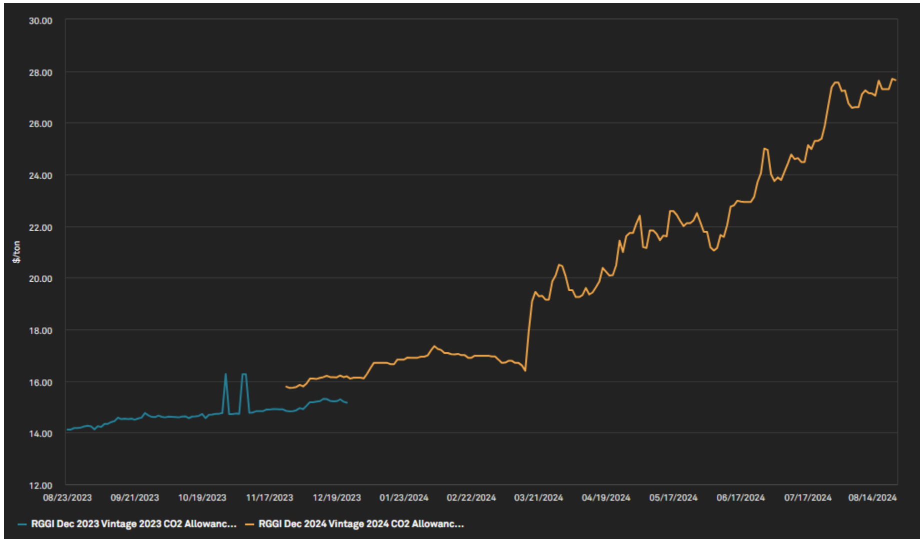
New England Power System Carbon Emissions

2023 vs. 2024 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



Data as of 8/18/24

Regional Greenhouse Gas Initiative (RGGI) Allowance Prices



- 8/22/24: RGGI allowance spot price - $27.65
- The 65th RGGI auction will be on 9/4/24
  - Cost Containment Reserve (CCR) allowances were depleted in Auction 63 and will not be available in Auction 65
  - Initial Offering for Auction 65 includes 15,943,608 CO_2 allowances

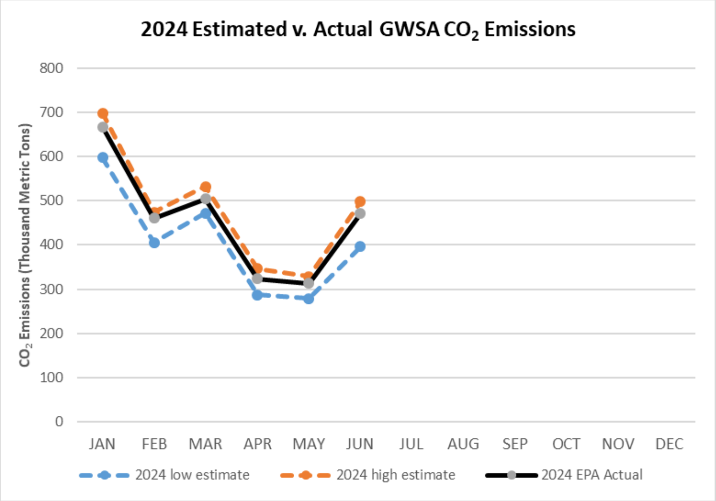
Massachusetts CO_2 Generator Emissions Cap

2024 Estimated Emissions Under CO_2 Cap

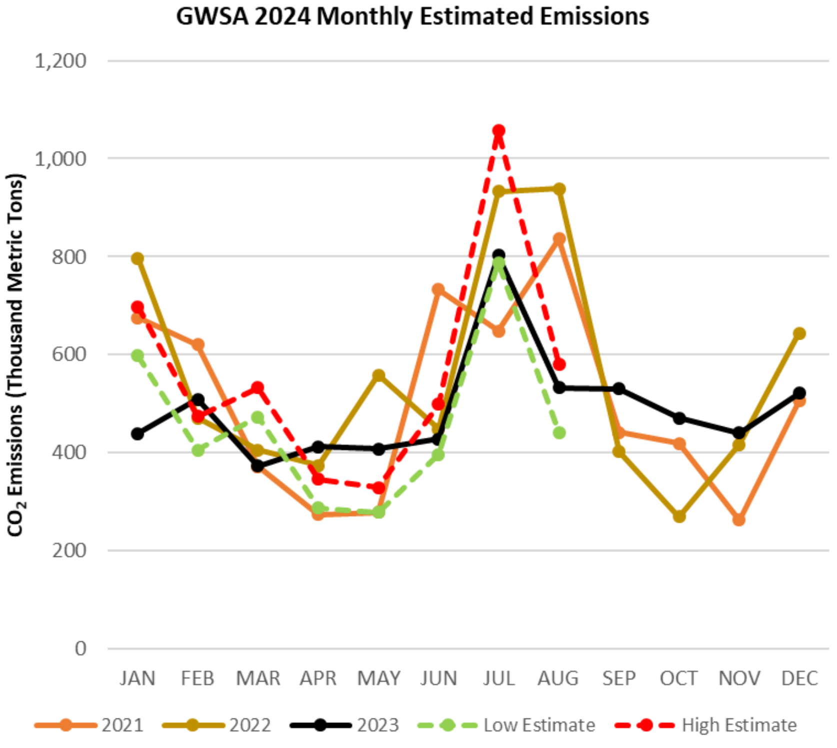
- As of 8/23/24, August estimated GWSA CO_2 emissions range between **440,988** and **581,069** metric tons
  - Year-to-date 2024 estimated emissions range between **48.2%** and **59.3%** of the 2024 cap of 7.61 MMT

2024 Q1/Q2 Actual Emissions Under CO_2 Cap

- According to the EPA CAMPD, Quarter 1 and 2 (January-June) 2024 GWSA CO_2 emissions were **2.74 MMT**, or **36.0%** of the 2024 cap of 7.61 MMT



2021-2024 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated emissions)

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 8/26/2024

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*	Mar-24	4
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

Greater Boston Projects, cont.

Status as of 8/26/2024

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 8/26/2024

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 8/26/2024

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	Mar-24	4
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 8/26/2024

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 8/26/2024

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 8/26/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Mar-27	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-25	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 8/26/2024

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	4
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-25	2

SEMA/RI Reliability Projects, cont.

Status as of 8/26/2024

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 8/26/2024

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 8/26/2024

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	Nov-23	4
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 8/26/2024

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 8/26/2024

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	4
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	4

New Hampshire Solution Projects

Status as of 8/26/2024

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	Jun-25	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Dec-24	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Sep-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	4

Upper Maine Solution Projects

Status as of 8/26/2024

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	Aug-24	4
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	Oct-24	3

Upper Maine Solution Projects, cont.

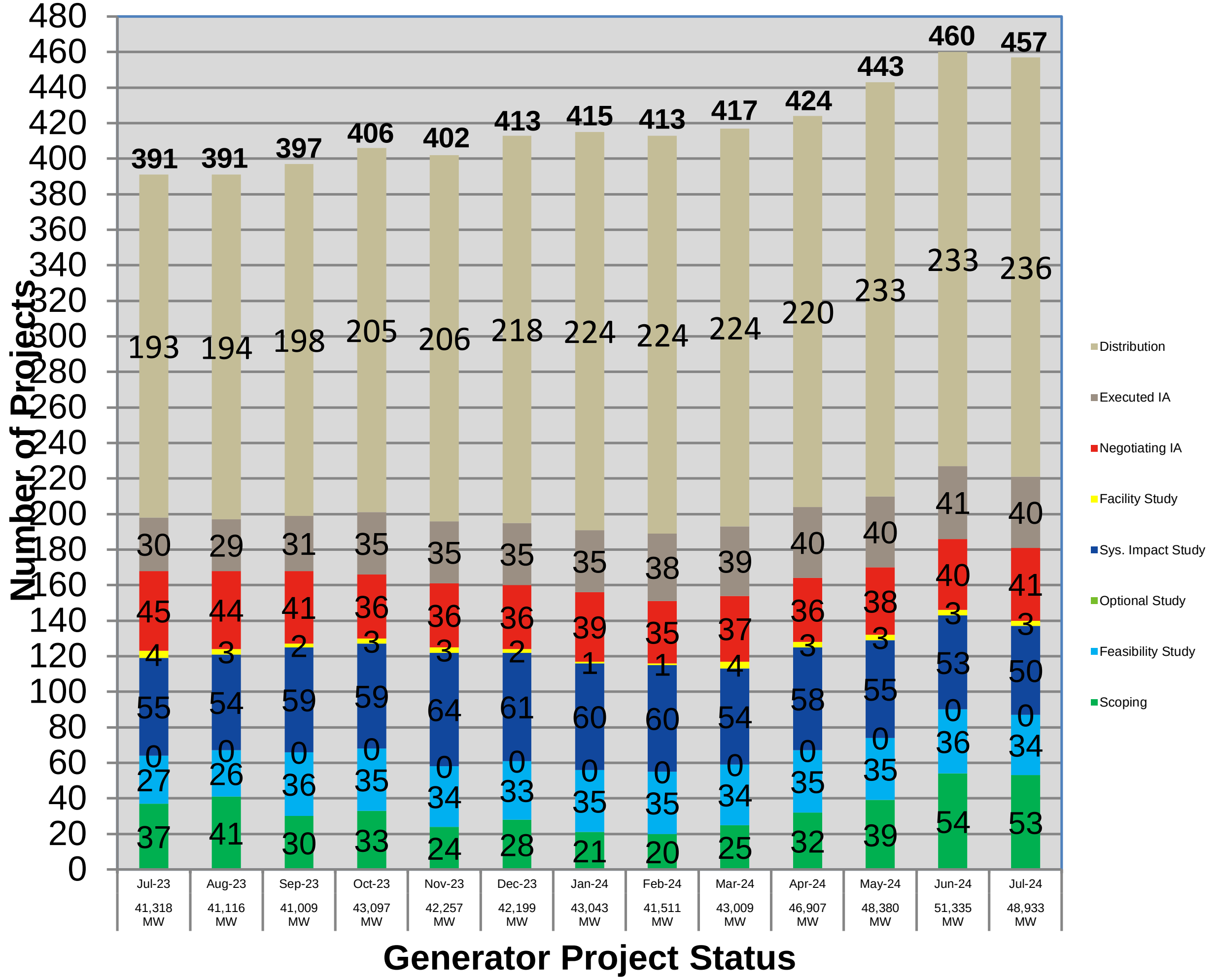
Status as of 8/26/2024

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	Oct-24	3
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Dec-25	2

* Cancelled per the Upper Maine Solutions Study Addendum that was published on January 11, 2024

Status of Tariff Studies as of August 1, 2024



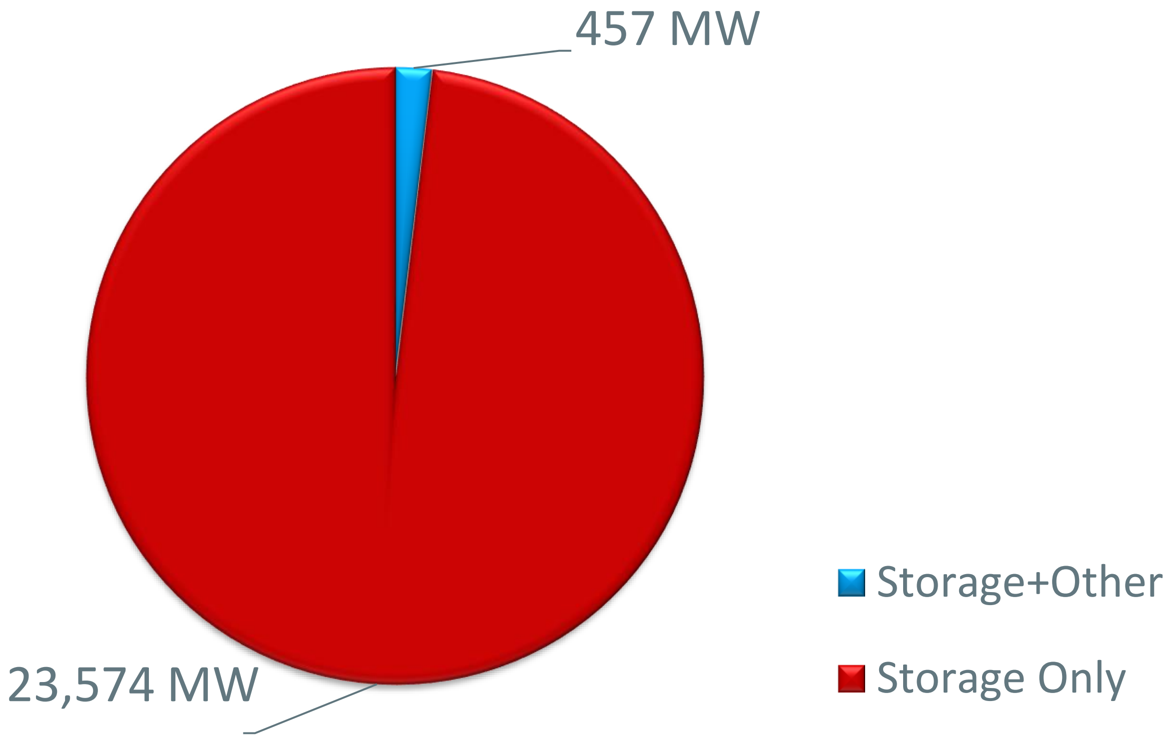
8 ETUs in Scoping, 3 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 0

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

What is in the Queue (as of August 1, 2024)

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



OPERABLE CAPACITY ANALYSIS

Fall 2024 Analysis

Fall 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Oct - 2024[2] CSO (MW)	Oct - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,097	30,029
Active Demand Capacity Resource (+) [5]	388	345
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	925	925
Non Commercial Capacity (+)	21	21
Non Gas-fired Planned Outage MW (-)	5,667	5,850
Gas Generator Outages MW (-)	2,406	3,000
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	18,558	19,670
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,821	16,821
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,946	18,946
Operable Capacity Margin	-388	724

[1]Operable Capacity is based on data as of **Aug 27, 2024** 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 **Aug 27, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Oct 19, 2024.**

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

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

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

Fall 2024 Operable Capacity Analysis

90/10 Load Forecast	Oct - 2024[2] CSO (MW)	Oct - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,097	30,029
Active Demand Capacity Resource (+) [5]	388	345
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	925	925
Non Commercial Capacity (+)	21	21
Non Gas-fired Planned Outage MW (-)	5,667	5,850
Gas Generator Outages MW (-)	2,406	3,000
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	18,558	19,670
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,482	17,482
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,607	19,607
Operable Capacity Margin	-1,049	63

[1] Operable Capacity is based on data as of **Aug 27, 2024** 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 **Aug 27, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Oct 19, 2024.**

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

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

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

Fall 2024 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2024 - 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 mid September through November.

Report created: 8/27/2024

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
9/21/2024	27285	397	803	25	1398	1784	2100	0	23228	20532	2125	22657	571	N	Fall 2024
9/28/2024	28097	388	677	21	2730	2386	2800	0	21267	15511	2125	17636	3631	N	Fall 2024
10/5/2024	28097	388	617	21	4657	3850	2800	0	17816	15546	2125	17671	145	N	Fall 2024
10/12/2024	28097	388	865	21	5270	2983	2800	0	18318	16461	2125	18586	-268	N	Fall 2024
10/19/2024	28097	388	925	21	5667	2406	2800	0	18558	16821	2125	18946	-388	Y	Fall 2024
10/26/2024	27711	426	1161	293	4478	1884	3600	0	19629	17026	2125	19151	478	N	Fall 2024
11/2/2024	27711	426	1161	293	3164	2545	3600	0	20282	17140	2125	19265	1017	N	Fall 2024
11/9/2024	27711	426	1161	293	1738	2072	3600	0	22181	17481	2125	19606	2575	N	Fall 2024
11/16/2024	27711	426	1161	293	2021	1753	3600	0	22217	18211	2125	20336	1881	N	Fall 2024
11/23/2024	27711	426	1161	293	902	299	3600	1363	23427	18923	2125	21048	2379	N	Fall 2024

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2024 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 2024 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2024 - 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 mid September through November.

Report created: 8/27/2024

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
9/21/2024	27285	397	803	25	1398	1784	2100	0	23228	22094	2125	24219	-991	N	Fall 2024
9/28/2024	28097	388	677	21	2730	2386	2800	0	21267	16125	2125	18250	3017	N	Fall 2024
10/5/2024	28097	388	617	21	4657	3850	2800	0	17816	16162	2125	18287	-471	N	Fall 2024
10/12/2024	28097	388	865	21	5270	2983	2800	0	18318	17109	2125	19234	-916	N	Fall 2024
10/19/2024	28097	388	925	21	5667	2406	2800	0	18558	17482	2125	19607	-1049	Y	Fall 2024
10/26/2024	27711	426	1161	293	4478	1884	3600	0	19629	17694	2125	19819	-190	N	Fall 2024
11/2/2024	27711	426	1161	293	3164	2545	3600	0	20282	17812	2125	19937	345	N	Fall 2024
11/9/2024	27711	426	1161	293	1738	2072	3600	0	22181	18165	2125	20290	1891	N	Fall 2024
11/16/2024	27711	426	1161	293	2021	1753	3600	0	22217	18921	2125	21046	1171	N	Fall 2024
11/23/2024	27711	426	1161	293	902	299	3600	2277	22513	19658	2125	21783	730	N	Fall 2024

Column Definitions

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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.
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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 2024 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2024/25 Analysis

Preliminary Winter 2024/25 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Dec - 2024[2] CSO (MW)	Dec - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,919	30,029
Active Demand Capacity Resource (+) [5]	427	345
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,161	1,161
Non Commercial Capacity (+)	293	293
Non Gas-fired Planned Outage MW (-)	221	243
Gas Generator Outages MW (-)	17	91
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	3,716	4,050
Net Capacity (NET OPCAP SUPPLY MW)	22,646	24,244
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,849	19,849
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,974	21,974
Operable Capacity Margin	672	2,270

[1] Operable Capacity is based on data as of **Aug 27, 2024** 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 **Aug 27, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Dec 28, 2024.**

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

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

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

Preliminary Winter 2024/25 Operable Capacity Analysis

90/10 Load Forecast	Dec - 2024[2] CSO (MW)	Dec - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,919	30,029
Active Demand Capacity Resource (+) [5]	427	345
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,161	1,161
Non Commercial Capacity (+)	293	293
Non Gas-fired Planned Outage MW (-)	221	243
Gas Generator Outages MW (-)	17	91
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	4,391	4,824
Net Capacity (NET OPCAP SUPPLY MW)	21,971	23,470
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,613	20,613
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,738	22,738
Operable Capacity Margin	-767	732

[1]Operable Capacity is based on data as of **Aug 27, 2024** 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 **Aug 27, 2024.**

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Preliminary Winter 2024/25 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2024 - 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 through March.

Report created: 8/27/2024

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
11/30/2024	27919	427	1161	293	900	554	3200	1250	23896	19220	2125	21345	2551	N	Winter 2024/2025
12/7/2024	27919	427	1161	293	411	554	3200	1814	23821	19506	2125	21631	2190	N	Winter 2024/2025
12/14/2024	27919	427	1161	293	239	17	3200	2728	23616	19517	2125	21642	1974	N	Winter 2024/2025
12/21/2024	27919	427	1161	293	221	17	3200	3117	23245	19578	2125	21703	1542	N	Winter 2024/2025
12/28/2024	27919	427	1161	293	221	17	3200	3716	22646	19849	2125	21974	672	Y	Winter 2024/2025
1/4/2025	27919	427	1161	293	12	17	2800	3711	23260	20308	2125	22433	827	N	Winter 2024/2025
1/11/2025	27919	427	1161	293	12	17	2800	3566	23405	20308	2125	22433	972	N	Winter 2024/2025
1/18/2025	27919	427	1161	293	12	17	2800	3117	23854	20308	2125	22433	1421	N	Winter 2024/2025
1/25/2025	27919	427	1161	293	12	17	2800	2818	24153	20088	2125	22213	1940	N	Winter 2024/2025
2/1/2025	27919	427	1161	293	21	17	3100	2519	24143	19824	2125	21949	2194	N	Winter 2024/2025
2/8/2025	27919	427	1161	293	11	17	3100	2220	24452	19796	2125	21921	2531	N	Winter 2024/2025
2/15/2025	27919	427	1161	293	11	17	3100	1771	24901	19536	2125	21661	3240	N	Winter 2024/2025
2/22/2025	27919	427	1161	293	11	17	3100	1472	25200	18560	2125	20685	4515	N	Winter 2024/2025
3/1/2025	27919	427	1161	293	51	174	2200	240	27135	18215	2125	20340	6795	N	Winter 2024/2025
3/8/2025	27919	427	1161	293	51	419	2200	0	27130	18022	2125	20147	6983	N	Winter 2024/2025
3/15/2025	27919	427	1161	293	51	717	2200	0	26832	17661	2125	19786	7046	N	Winter 2024/2025
3/22/2025	27919	427	1161	293	610	587	2200	0	26403	17103	2125	19228	7175	N	Winter 2024/2025
3/29/2025	27711	426	1161	293	1147	1052	2700	0	24692	16516	2125	18641	6051	N	Winter 2024/2025

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

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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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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 2024 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.

Preliminary Winter 2024/25 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2024 - 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 through March.

Report created: 8/27/2024

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
11/30/2024	27919	427	1161	293	900	554	3200	2238	22908	19962	2125	22087	821	N	Winter 2024/2025
12/7/2024	27919	427	1161	293	411	554	3200	2801	22834	20258	2125	22383	451	N	Winter 2024/2025
12/14/2024	27919	427	1161	293	239	17	3200	3847	22497	20270	2125	22395	102	N	Winter 2024/2025
12/21/2024	27919	427	1161	293	221	17	3200	4263	22099	20333	2125	22458	-359	N	Winter 2024/2025
12/28/2024	27919	427	1161	293	221	17	3200	4391	21971	20613	2125	22738	-767	Y	Winter 2024/2025
1/4/2025	27919	427	1161	293	12	17	2800	4522	22449	21089	2125	23214	-765	N	Winter 2024/2025
1/11/2025	27919	427	1161	293	12	17	2800	4314	22657	21089	2125	23214	-557	N	Winter 2024/2025
1/18/2025	27919	427	1161	293	12	17	2800	4015	22956	21089	2125	23214	-258	N	Winter 2024/2025
1/25/2025	27919	427	1161	293	12	17	2800	4015	22956	20862	2125	22987	-31	N	Winter 2024/2025
2/1/2025	27919	427	1161	293	21	17	3100	3566	23096	20588	2125	22713	383	N	Winter 2024/2025
2/8/2025	27919	427	1161	293	11	17	3100	3267	23405	20559	2125	22684	721	N	Winter 2024/2025
2/15/2025	27919	427	1161	293	11	17	3100	2669	24003	20290	2125	22415	1588	N	Winter 2024/2025
2/22/2025	27919	427	1161	293	11	17	3100	2220	24452	19279	2125	21404	3048	N	Winter 2024/2025
3/1/2025	27919	427	1161	293	51	174	2200	1137	26238	18922	2125	21047	5191	N	Winter 2024/2025
3/8/2025	27919	427	1161	293	51	419	2200	787	26343	18722	2125	20847	5496	N	Winter 2024/2025
3/15/2025	27919	427	1161	293	51	717	2200	0	26832	18348	2125	20473	6359	N	Winter 2024/2025
3/22/2025	27919	427	1161	293	610	587	2200	0	26403	17770	2125	19895	6508	N	Winter 2024/2025
3/29/2025	27711	426	1161	293	1147	1052	2700	0	24692	17166	2125	19291	5401	N	Winter 2024/2025

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

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 units <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 units <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

August 01, 2024 OP-4 Event and Capacity Scarcity Condition

Vamsi Chadalavada

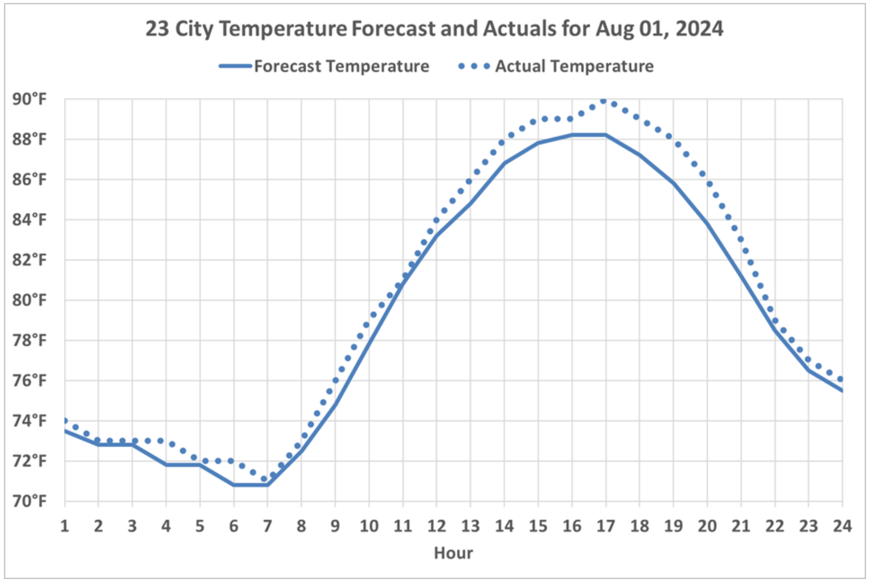
EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER

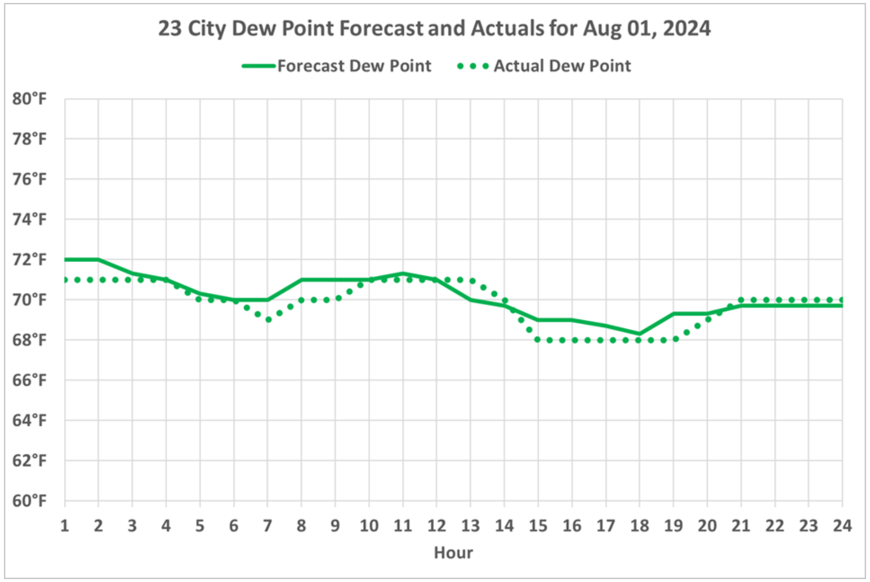
OP-4 and Capacity Scarcity Condition Thursday, August 1, 2024

- The primary factors leading to the implementation of OP-4 and the Capacity Scarcity Condition (CSC) ~750 MW of generator outages and reductions combined with higher than forecasted temperatures and loads during peak hours
- 10-minute Reserve Constraint Penalty Factor (RCPF) violated for the following 5-minute intervals: 16:55-17:00 and 17:45-18:35
  - $1,500/MWh RCPF
- 30-minute RCPF violated for the following 5-minute intervals: 17:45-19:20
  - $1,000/MWh RCPF
- System conditions required the implementation of M/LCC 2, Abnormal Conditions Alert, and OP-4, Actions During a Capacity Deficiency
  - M/LCC 2: 16:45-22:00
  - OP-4 Actions 1 and 2: 16:45-21:45

Weather Forecast – Temperatures slightly higher than Forecast

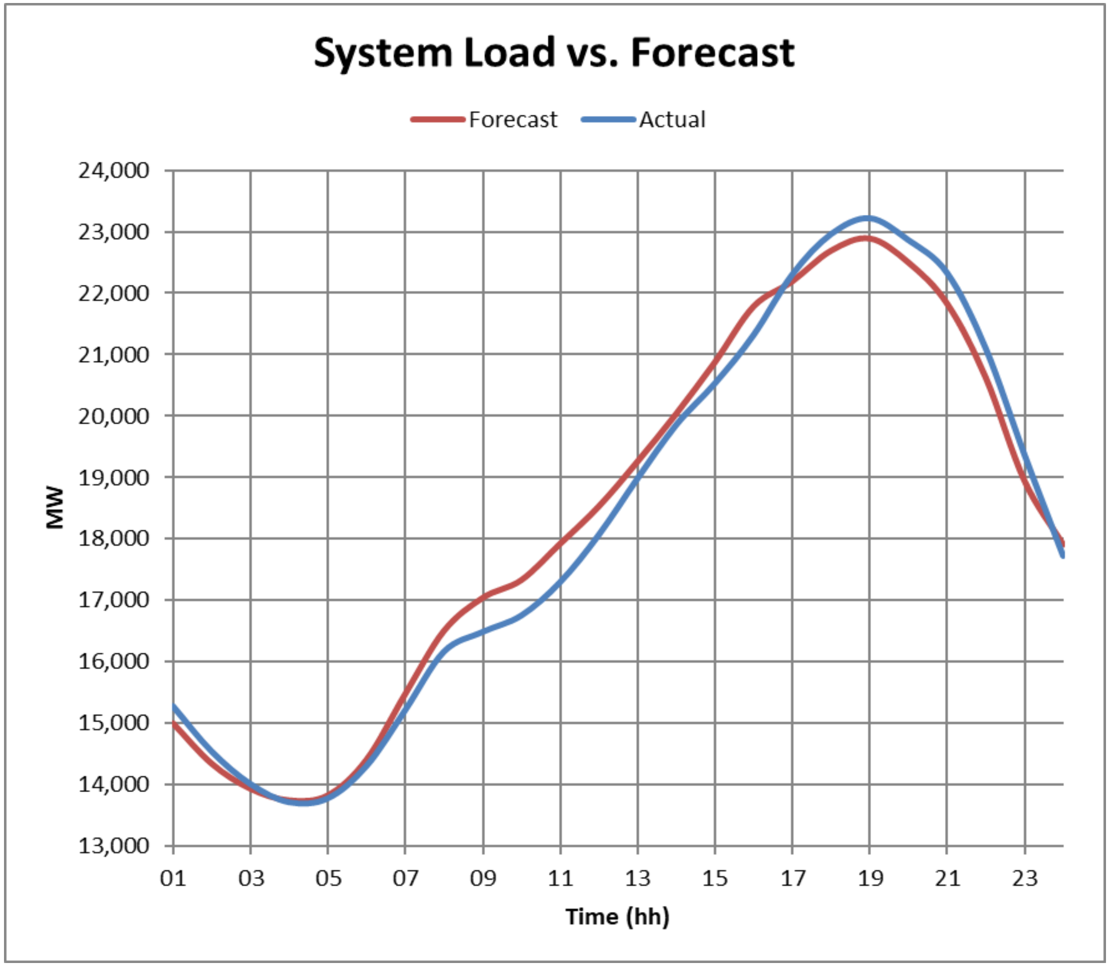
- From early afternoon through the evening peak and into the late evening hours temperatures were ~1-2°F higher than forecasted; temperatures were 2°F higher than forecasted during the peak hour (HE 19)





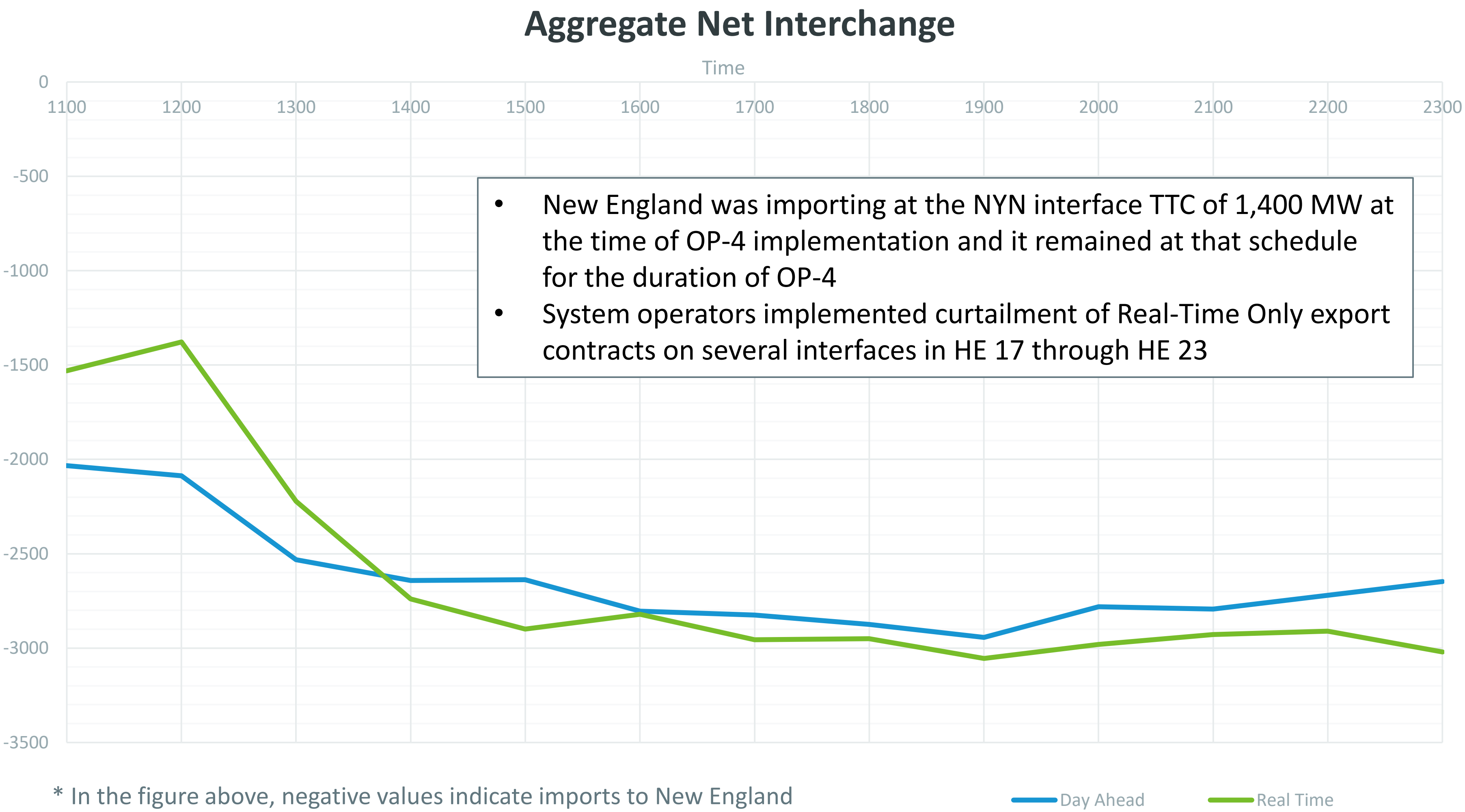
Loads Were Below Forecast Through HE 16, Then Exceeded the Peak Hour Forecast By ~1%

- ISO's load forecast for the peak hour was 22,900 MW
- Telemetered system load* for the peak hour was 23,216 MW
  - At the time of OP-4 implementation, system load was 22,583 MW
  - At 17:00 ISO observed a notable decrease in system load (~350 MW), likely due to utility conservation programs; following this reduction, loads continued to increase
- After the peak hour, loads remained 1-2% above forecast through HE 23



* Telemetered system loads are those observed in real-time by the ISO Control Room

At the Time of OP-4 Implementation, Net Interchange Was ~100 MW Above Expectations



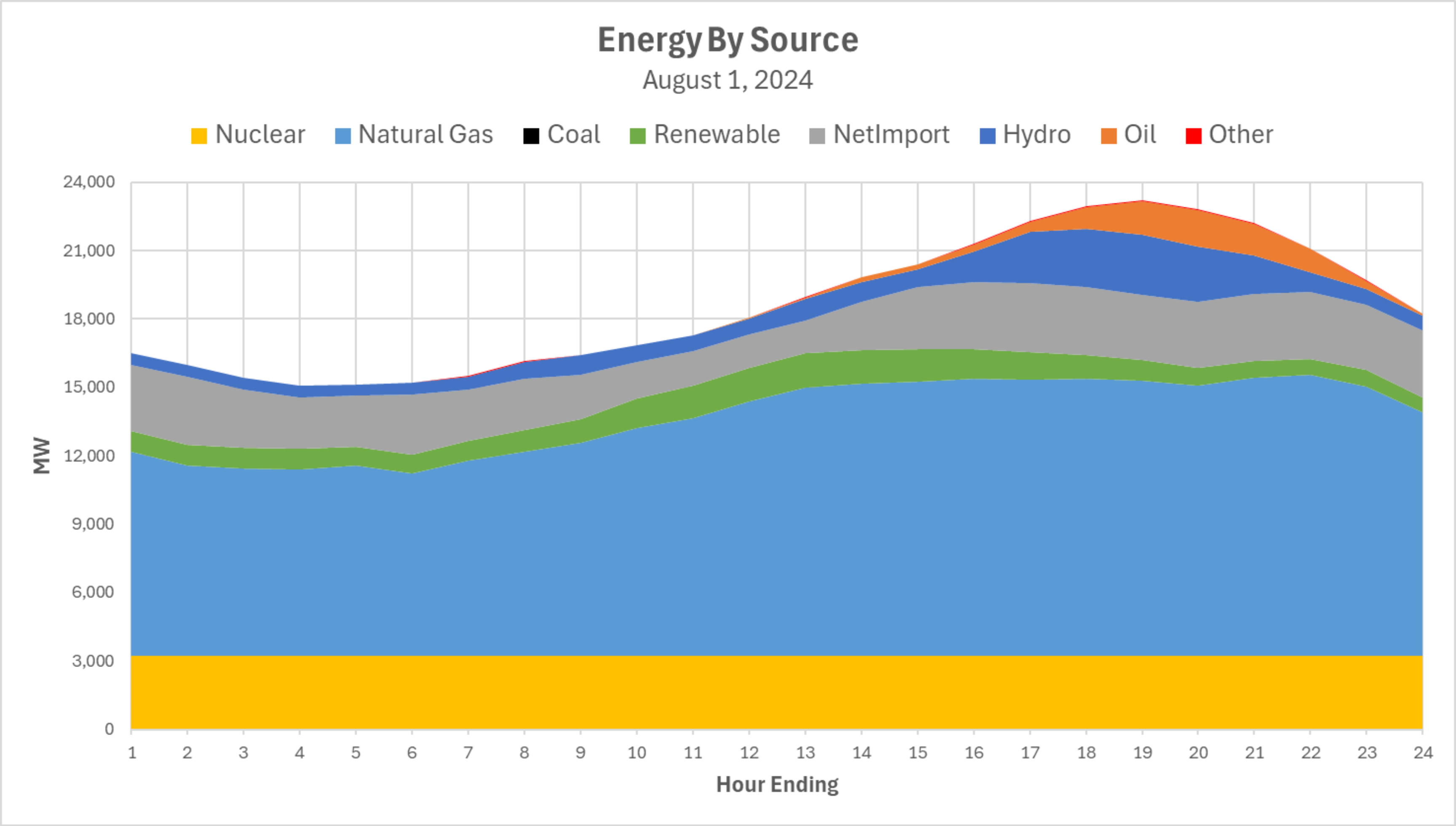
- New England was importing at the NYN interface TTC of 1,400 MW at the time of OP-4 implementation and it remained at that schedule for the duration of OP-4
- System operators implemented curtailment of Real-Time Only export contracts on several interfaces in HE 17 through HE 23

* In the figure above, negative values indicate imports to New England

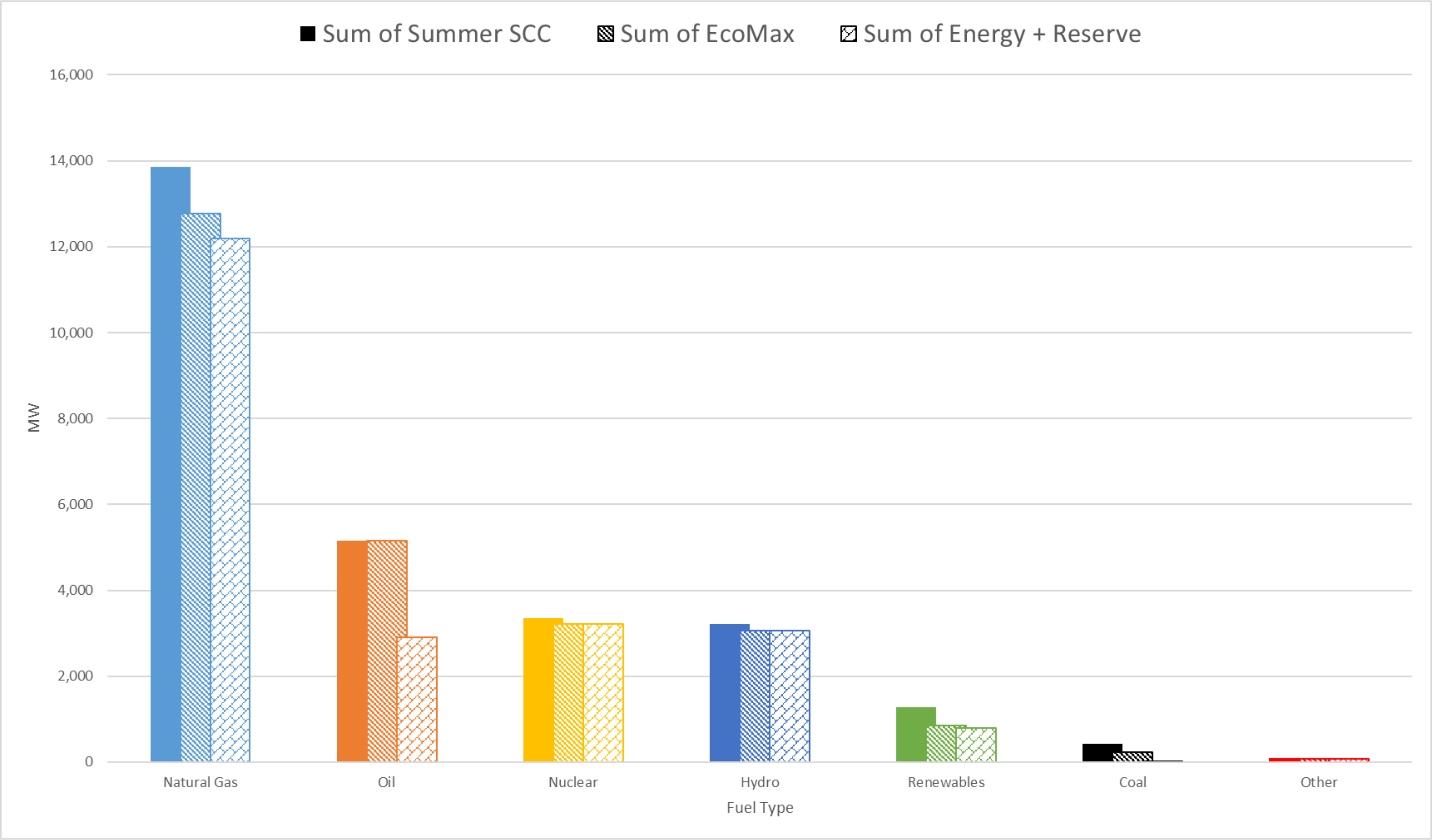
Available Generator Capacity Was Less Than Anticipated

- ISO estimated a peak hour surplus of 160 MW on the Morning Report, including the supplemental commitment of a ~600 MW oil-fired generator
- Prior to noon, a ~350 MW gas-fired combined cycle generator self-scheduled to perform testing throughout the remainder of the operating day
- In addition to the quantity accounted for in the Morning Report, another ~750 MW of outages and reductions occurred throughout the day prior to OP-4
  - Approximately 50% of these outages and reductions occurred prior to noon while the remainder occurred between noon and the time of OP-4 implementation
- At 16:44 the trip of a 335 MW gas-fired resource resulted in the initial reserve deficiency and declaration of OP-4
- At 17:20 ISO committed all available offline non-fast start resources (~125 MW) capable of being online by the peak hour
  - Almost all of the remaining available offline non-fast start generators were greater than or equal to 12 hours from being online and dispatchable
- Following the implementation of OP-4, as load continued to increase, loss of generation continued; an additional ~400 MW of outages and reductions occurred in HE19
  - In total, ~1,150 MW of additional generator outages and reductions occurred on this day

Following Implementation of OP-4, Oil-Fired Resources Ramped Up To Meet Peak Loads

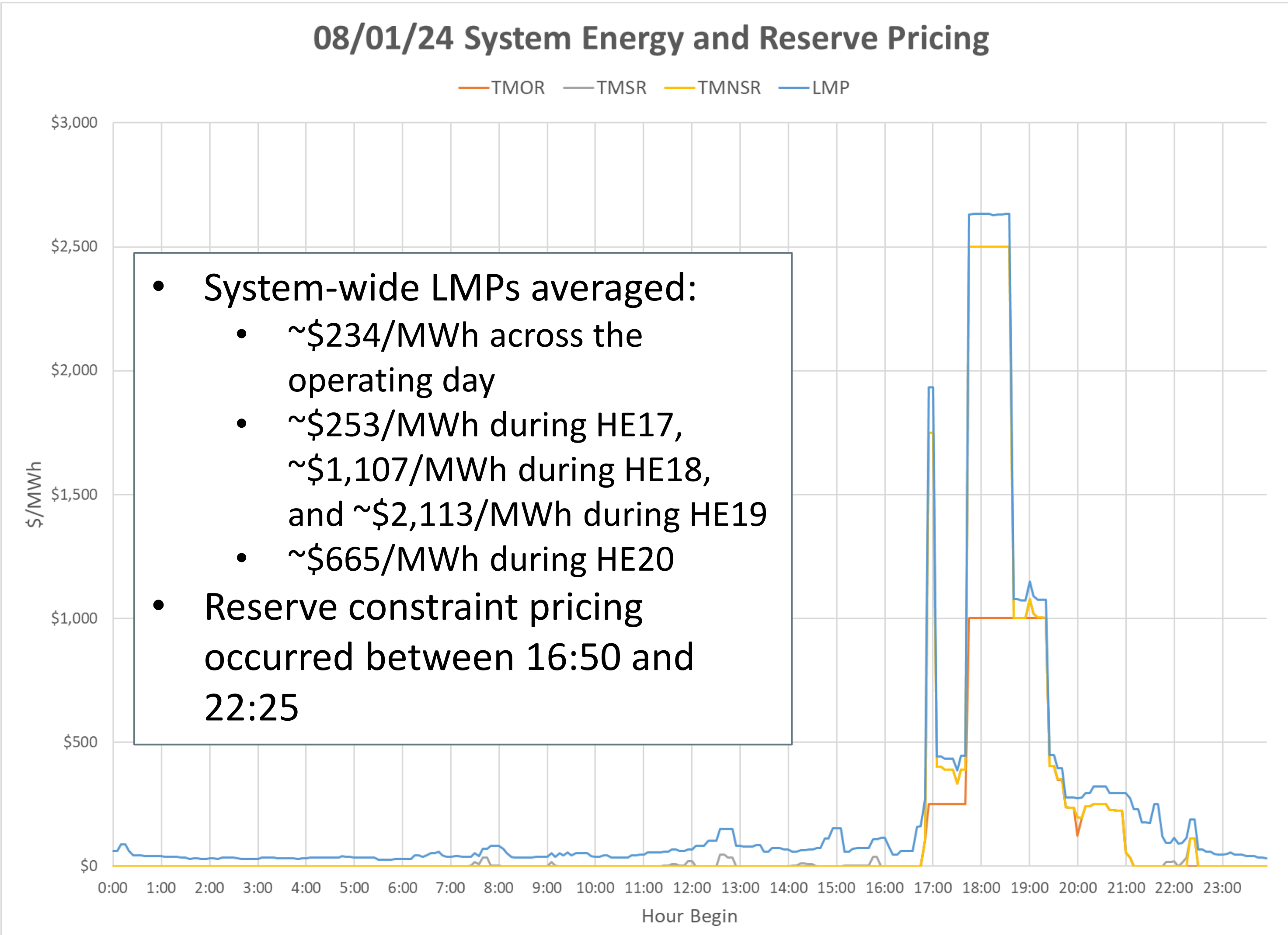


With the Exception of Oil and Coal-Fired Resources, the Available Capability To Provide Energy and Reserve on Peak Was Maximized



*Energy and reserve values utilized in the figure above are based on actual resource outputs and reserve designations

Real-Time System Energy and Reserve Pricing



- System-wide LMPs averaged:
  - ~$234/MWh across the operating day
  - ~$253/MWh during HE17, ~$1,107/MWh during HE18, and ~$2,113/MWh during HE19
  - ~$665/MWh during HE20
- Reserve constraint pricing occurred between 16:50 and 22:25

Summary of Capacity Scarcity Condition Intervals

5-Minute Intervals	System 30 Min Reserve Constraint Penalty Factor ($1,000 MW/hr)	System 10 Min Reserve Constraint Penalty Factor ($1,500 MW/hr)
16:55 – 17:00 (2 Intervals)	Binding	**Violated**
17:45 – 18:35 (11 Intervals)	**Violated**	**Violated**
18:40 – 18:45 (2 Intervals)	**Violated**	N/A
18:50 – 19:15 (6 Intervals)	**Violated**	Binding
19:20 (1 Interval)	**Violated**	N/A

- A Capacity Scarcity Condition results from the **violation** of the System 30 Minute Operating Reserve constraint or the System 10 Minute Operating Reserve constraint in any one 5-minute interval

Pay for Performance Summary

- **Pay for Performance (PFP) Event on August 1:**
  - Avg. Balancing Ratio (BR): **89.6%**
    - BR = (Load + reserve requirement) / CSO (excluding Energy Efficiency resources)
      - Avg. Load Req't :~24,337 MW
      - Avg. Reserve Req't: ~2,456 MW
      - CSO: 29,887 MW (excludes Energy Efficiency CSO)
  - Capacity Performance Payment Rate: **$5,455/MWh**
    - Effective as of June 1 for current Commitment Period
  - *Estimated* settlements*:
    - PFP charges to underperforming FCM resources: (**$49.9M)**
    - Balancing Fund: **$1.7M** (surplus collection)
      - Difference between payments and charges; allocated to CSO
  - Preliminary settlement reports were released on August 15
  - Actual settlements scheduled to be distributed by September 16, 2024 and will reflect adjustments for Capacity Performance Bilateral Contracts

*Results here are estimated. Figures subject to change in subsequent resettlements.

Changes To the Resource Mix Have Contributed to Reduced Operational Flexibility, Especially at Peak Loads

- A significant quantity of non-intermittent generation capacity* has retired or become non-operational since 2020
  - ~3,900 MW of capacity has retired or is currently non-operational pending retirement
  - ~400 MW is capacity from non-fast start resources capable of being online in < 4 hours
  - ~315 MW is capacity from fast start resources

* All capacity values listed on this slide are reflective of summer maximum output

Outages and Restrictions on Imports on August 1 Further Contributed to Reduced Operational Flexibility

- Import transfer limits across two external interfaces were reduced due to equipment outages
  - The Highgate Converter, with a normal import transfer limit of 225 MW, was out-of-service for a planned outage (7/30 - 8/2)
  - Import capability to New England from New Brunswick was reduced to 500 MW due to a planned outage of an unit in New Brunswick and an unplanned* outage of the Chester SVC (7/9 - 8/13)
- ~350 MW of fast-start resources were out of service due to an unplanned outage (7/26 – 8/12)

* An "unplanned" outage, as used on this slide, means that the outage was not planned at the time it first occurred, however the outage was expected by ISO heading into the 8/1/24 operating day

Recent OP-4/CSC Events

- Recent OP-4/CSC events have closely followed resource outages occurring within ~2 hours of peak loads (on August 1, loads were ~300 MW higher than forecast)

Date of OP-4/ CSC event	Generator/ Tie Line Outage Occurring Just Prior to Peak Load (MW)	Total Generator /Tie Line Outages and Reductions (MW)	Time of Outage	OP-4 Start Time	CSC First 5-Min Interval	Peak Load Hour
7/5/23	680	~1,300	18:15	18:30	18:25	HE 19
6/18/24	606	~1,600	17:22	17:40	17:50	HE 19
8/1/24	335	~1,150	16:44	16:45	16:55	HE 19

- Conditions at the time of these resource outages, including start-up/notification times of offline/available resources and available room to import additional energy on external interfaces, impact ISO's ability to fully mitigate the potential for short-duration capacity deficiencies

ISO is Considering Enhancements to Reports and Notifications

- ISO has received two requests to enhance its existing reporting processes
  - The first is to enhance reporting mechanisms for curtailments of Real-Time Only exports; currently, under certain conditions, these notifications may be made on the day following the relevant operating day
  - The second is to enhance reporting of daily forecasted capacity surplus values to include all hours of the day instead of only the peak hour
  - The ISO is evaluating these requests
- In order to provide earlier notice of projected capacity surplus for the upcoming operating day, ISO is considering publishing a report following the close of the day ahead market with information similar to what is contained in the Morning Report

ISO new england

memo

To: NEPOOL Participants Committee Members and Alternates

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

Date: September 5, 2024

Subject: ISO New England Inc. 2025 Operating and Capital Budgets

Budget Process

This memo provides an update to the NEPOOL Participants Committee ("NPC") on the 2025 budget process. At its August 9, 2024 meeting, the NEPOOL Budget & Finance Subcommittee ("B&F") reviewed the ISO's proposed 2025 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_2025_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:

- The ability to distinguish FTE amounts for Market Development from Settlements as presented in budget materials:
  - In today's and in future budget materials, Market Development is now broken out from Settlements FTE amounts including slides 64 and 67, in today's presentation, to reflect two 2025 FTE additions are in the Market Development area
- Clarification on capital budget costs for the nGEM Platform Replacement and Space Utilization projects:
  - For the nGEM Platform Replacement, it was indicated that to date we've spent approximately $25M with an additional $45M expected through 2028 (as noted on slide 70 of today's budget presentation) and that nGem is on track with the overall budget
  - Related to Space Utilization, we clarified that the 2025 budget includes $2.0M in addition to $0.5M planned for 2024; and that some work included in the project for our Windsor, CT campus, was planned regardless of the updates to move staff there (see page 2 of this memo for more on the capital budget and workspace changes)
- Question about distinguishing work in the Transmission Planning function being driven by NESCOE:
  - We noted that the 2025 budget includes resources for the development of a group to support states' RFP efforts for transmission planning, including economic analyses

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).

ISO New England Inc.
One Sullivan Road
Holyoke, MA
413-535-4000
rludlow@iso-ne.com

iso-ne.com
isonewswire.com
@isonewengland
iso-ne.com/isotogo
iso-ne.com/isoexpress

The Participants Committee will be asked to vote on the proposed budgets at the October 10, 2024 meeting. During the week of September 23, 2024, we will distribute a memo with the projected 2025 Revenue Requirement by ISO-NE Administrative Cost Tariff Schedule, including the draft 2025 rate components.

Proposed 2025 Budgets

The 2025 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. 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. The changes to the grid represent a step-up in system complexity that the ISO began to address in 2024 and will continue ramping-up in 2025 and throughout the remainder of the decade. This step-up in complexity represents a considerable increase to ISO workload.

The key drivers supporting the proposed 2025 operating budget increase are continuing to enhance capabilities to address the modeling, analysis, processing, and communication needs directly resulting from the clean energy transition; and addressing the effects of inflation on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation.

The 2025 operating budget year-over-year increase before depreciation is $25.1 million or 10.3%; the increase, including depreciation is $29.5 million or 10.7%. The 2025 Revenue Requirement, taking into account the 2023 true-up, is an increase of $37.4 million or 13.6% over 2024.

The net overall change from the preliminary (top-down) operating budget is an increase of approximately $0.3 million. Changes include increases of additional funding for regional study work regarding raising the minimum loss of source value for New England; Information Technology staff augmentation; higher medical renewal rates; and interest expense. These increases were largely offset by decreases in salaries due to the loss/retirement of more experienced individuals with recruiting and hiring trending to entry level staff, and the removal of capacity auction licensing fees as a result of FERC approving the two-year FCA 19 delay.

The capital budget is $42.5 million which is an increase of $7.5 million over 2024, and $2.5 million above the amount in the preliminary budget presented this past June. 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 $35.0 million in 2024. 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. The $2.5M increase over the 2025 preliminary budget is a result of incorporating the workspace changes needed to satisfy short-term office constraints for the next couple of years and consists of changes to our Windsor, CT campus to accommodate moving some staff there and reconfiguring staff at our Holyoke, MA campus. After exploring funding options management determined incorporating these costs into the capital budget was the most cost-efficient way to finance the short-term needs.

I will be available during the meeting for any questions regarding the 2025 Budgets. Please also feel free to reach out to me after today with any additional comments or questions regarding the 2025 Budgets.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-535-4000
rludlow@iso-ne.com

SEPTEMBER 5, 2024

ISO New England Proposed 2025 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:

- Appendix 1: Compensation
- Appendix 2: 2025 Operating Budget Risks
- Appendix 3: 2023 Deliverables and Select Metrics
- Appendix 4: Cyber Security and CIP Compliance History and Costs
- Appendix 5: ISO/RTO Financial Comparison

EXECUTIVE SUMMARY

Executive Summary

- The 2025 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
- 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:
  - 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 and timing of such needs
- The changes to the grid represent a step-up in system complexity that the ISO began to address in 2024 and will continue ramping-up in 2025 and throughout the remainder of the decade
  - This step-up in complexity represents a considerable increase to ISO workload

Executive Summary *(cont.)*

- In order to carry out ISO-NE'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, it is necessary to develop new capabilities 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 continue increasing headcount in order to meet the complexities of the clean energy transition; this is in line with hiring trends observed across other ISOs
- The budget reflects additional investment in information technology (IT) needed to support operations given the changing resource mix, including: new technology, transition cost related to cloud-based infrastructure, and continued improvements to cyber security
- The budget addresses the inflationary and renewal costs for current IT infrastructure and licensing, labor, and professional fees as well as the year-over-year costs of continued operation

Executive Summary *(cont.)*

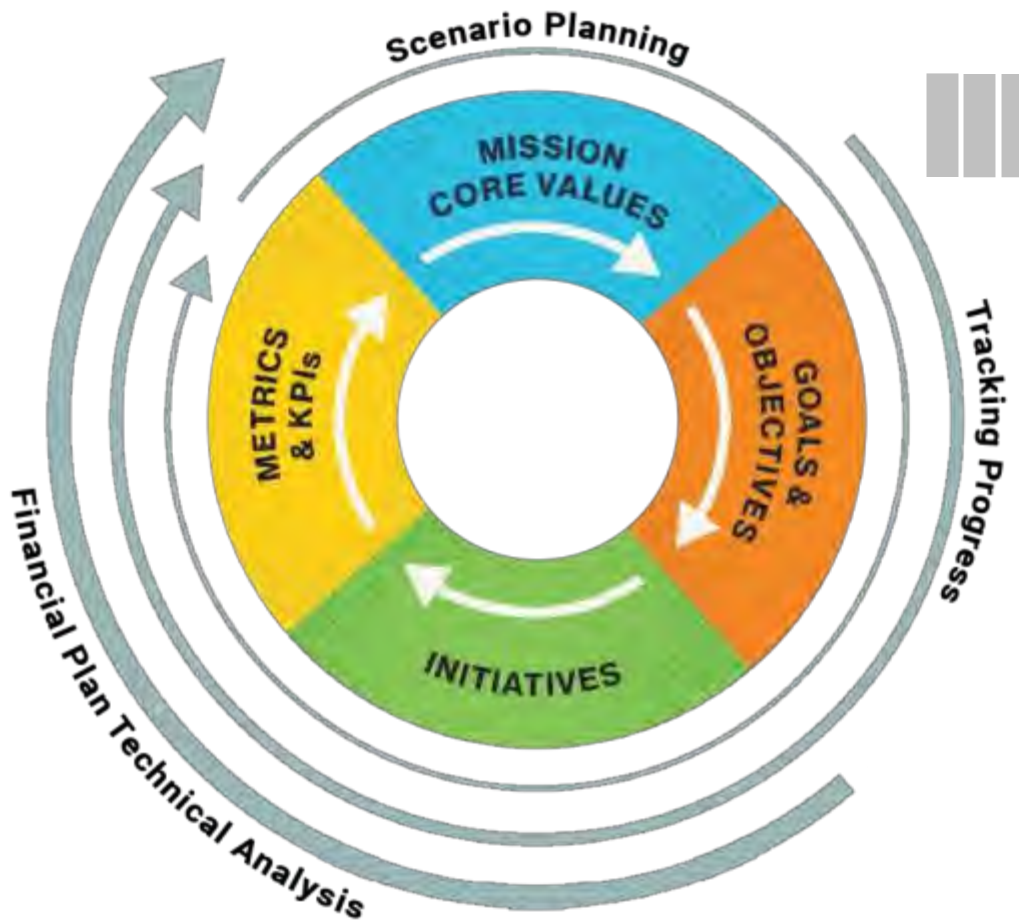
- For the 2025 budget, ISO is proposing adding 46 FTEs driven primarily by:
  - IT support to operationalize internally developed software for market simulation and situational awareness
  - Support the increasingly complex information to stakeholders and the public and to assist the growing and distributed workforce
  - Additions in System Planning for modeling, forecasting, longer-term transmission planning, and addressing current FERC orders;
    - This is the first iteration of a budget representing the need to scale up capabilities in these areas to support the Longer-Term Transmission Studies (LTTS) and necessary tariff changes, as well as the issuance of initiated transmission RFPs that require technical and economic analyses
    - There are still many unknowns, including the volume of RFPs to support and compliance with FERC transmission orders; it is our expectation that the resource requirements will be refined over time as we gain experience with the new processes

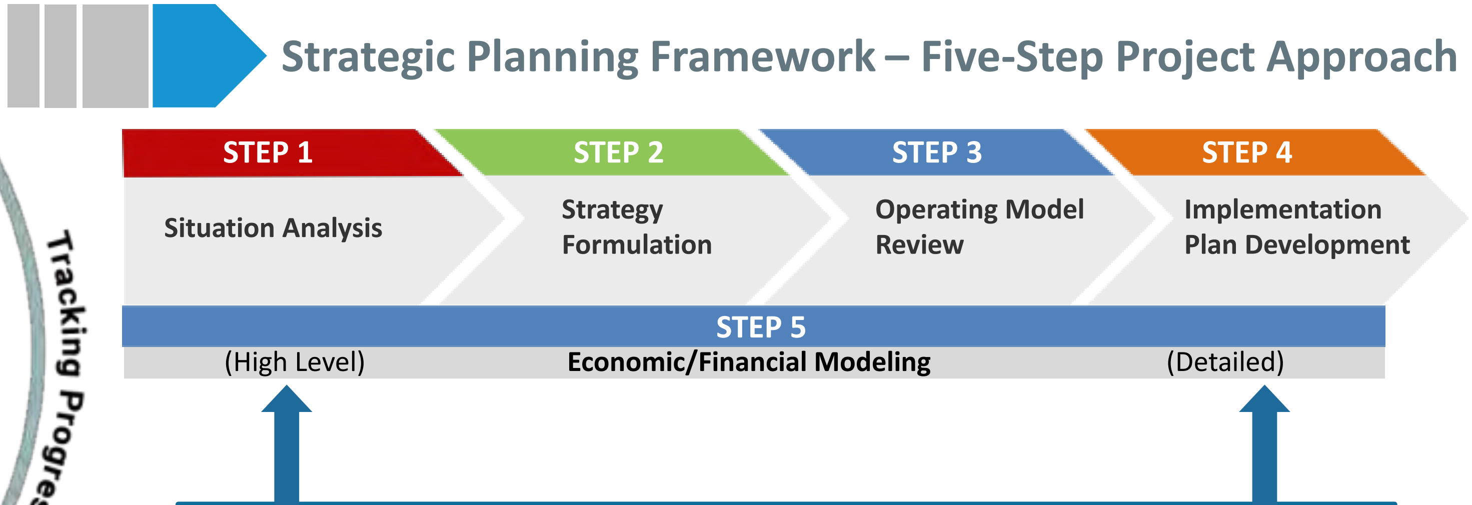
THE STRATEGIC PROCESS

ISO-NE's integrated business and strategic planning framework

Strategic Planning Framework

The 2025 ISO-NE budget represents the needs for the organization's strategy in supporting the region on its path to a decarbonized grid





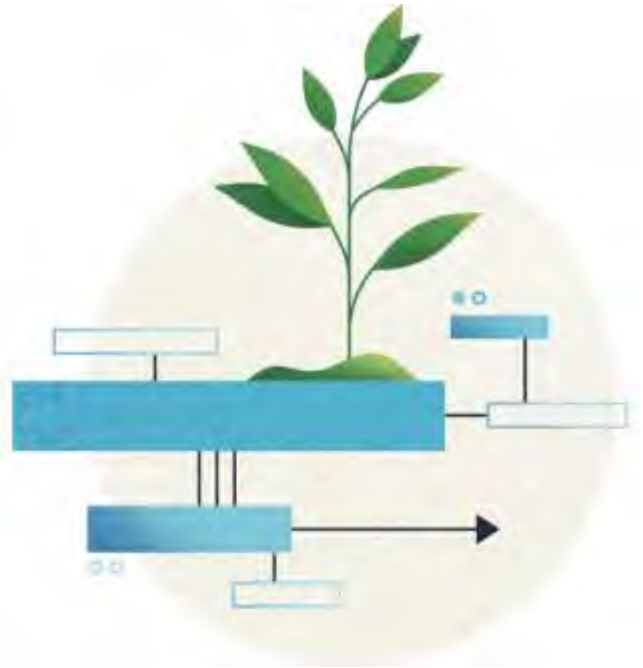
The 2025 budget responds to the emerging needs of the region in achieving their goals of decarbonizing the electric grid

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 and transmission planning



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:

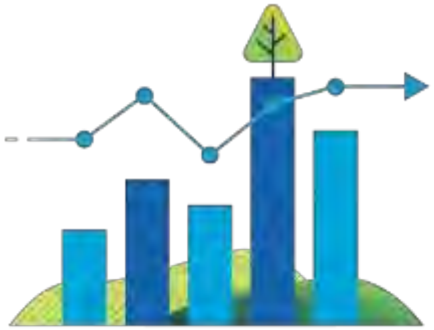
Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

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

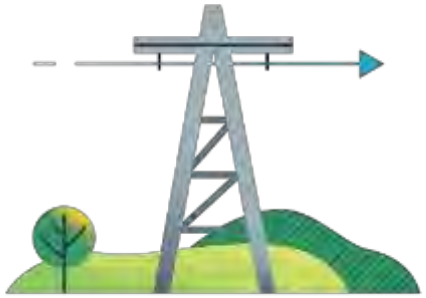


2

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

CLEAN ENERGY TRANSITION & 2040 OUTLOOK

The path to the 2040 (and beyond) decarbonized grid based on state policy goals and assumptions

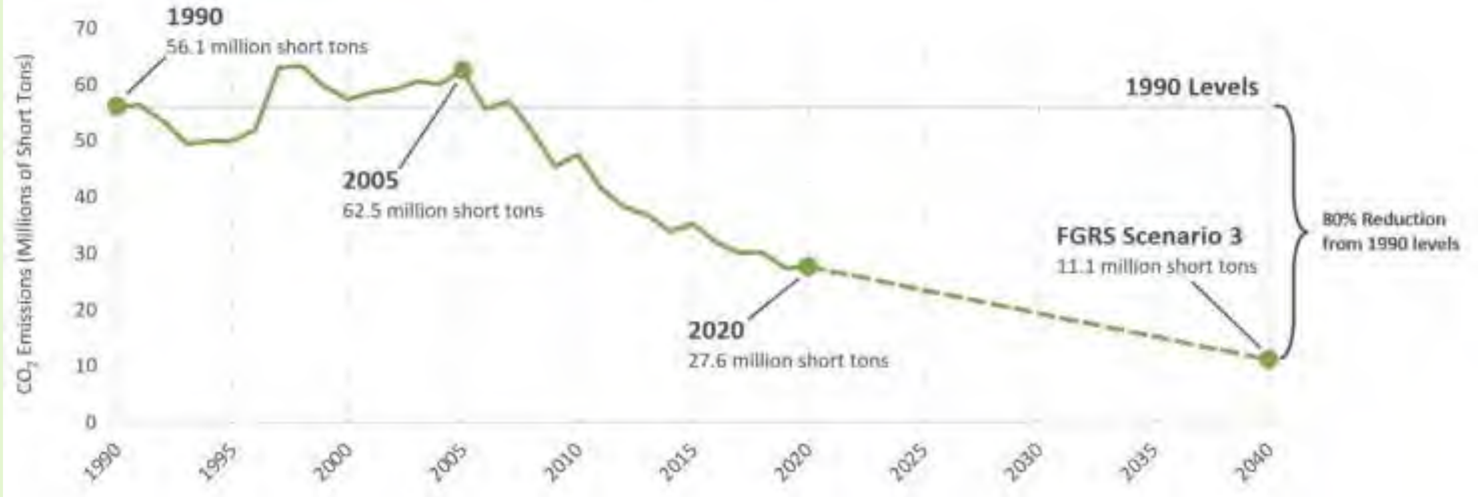
Overview of 2040 Outlook

- Renewables will continue to displace natural gas-fired resources over the next 20 years
  - A shift from centrally dispatched generation to distributed resources
  - A shift from conventional generation to weather-dependent renewable generation
  - Grid will primarily rely on a large number of non-dispatchable, weather-dependent generators, with smaller nameplate capacities
- Significant demand growth as system peak shifts to winter
  - During cold months the system will be at risk of insufficient fuel to support balancing resources (natural gas)
- Escalating variability in supply and demand
  - Most pathways to a low-carbon grid involve high variability in both supply and demand, which will result in either reliability challenges or higher costs
- By 2040, the region could experience consistent negative wholesale energy prices
- As outlined in the ISO-NE 2050 Transmission Study, of the estimated $25 billion needed for transmission upgrades by 2050, upwards of $13 billion will need to be in service by 2040; reducing peak load significantly reduces transmission costs

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

New England has seen progress in lowering emissions in 2021-2023, but 2024 emissions levels are up from the previous year, mainly due to increased demand

Historical and Extrapolated New England CO_2 Emissions

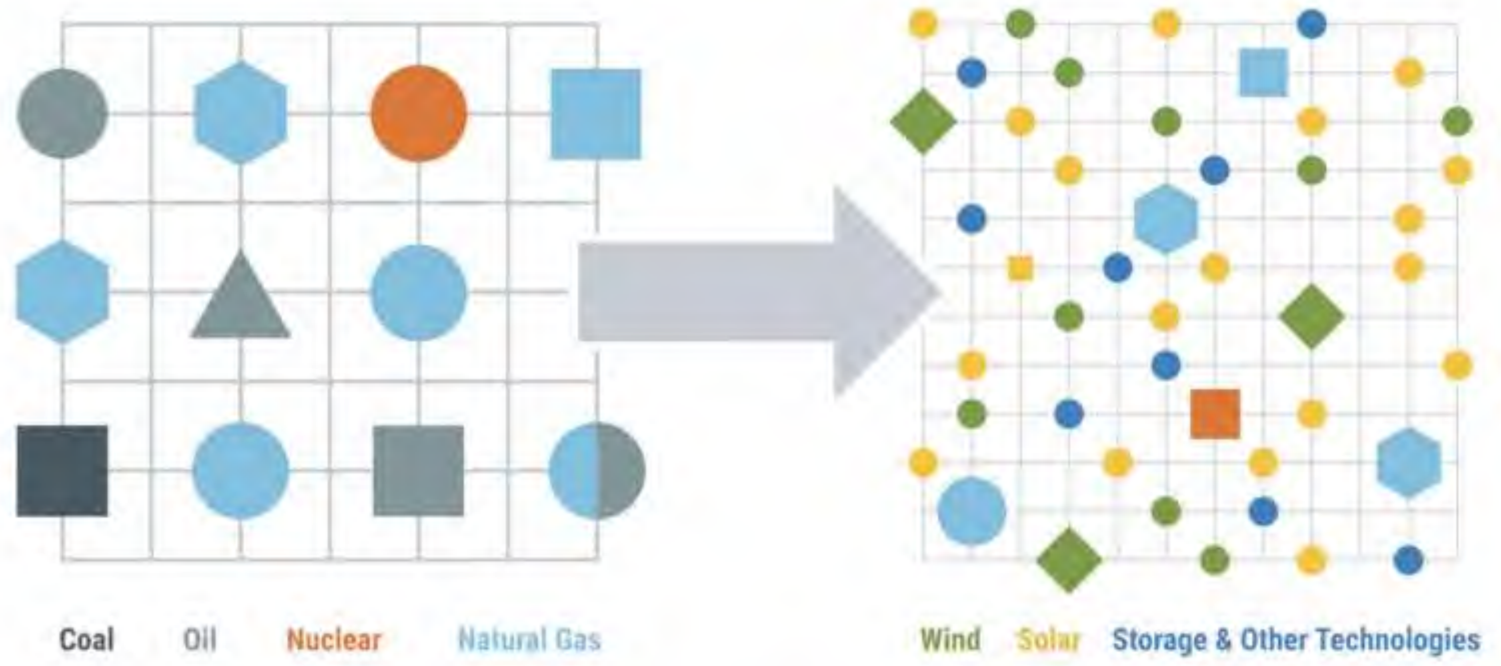


- State policies to address climate change through emissions reduction mandate an 80% reduction from 1990 levels
- These mandates will result in a drastically different generation profile for the region compared to today

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

- To illustrate the grid of 2040, we drew from the following scenario
  - **The Deep Decarbonization scenario** (Scenario 3 or S3) from the Future Grid Reliability Study – derived from the "All Options Pathway" of the Massachusetts 2050 Deep Decarbonization Roadmap Study outlining heavy renewable penetration and increased electrification loads

Two Dimensions to the Transition to Clean Energy that Contribute to Increased Grid Complexity by 2040



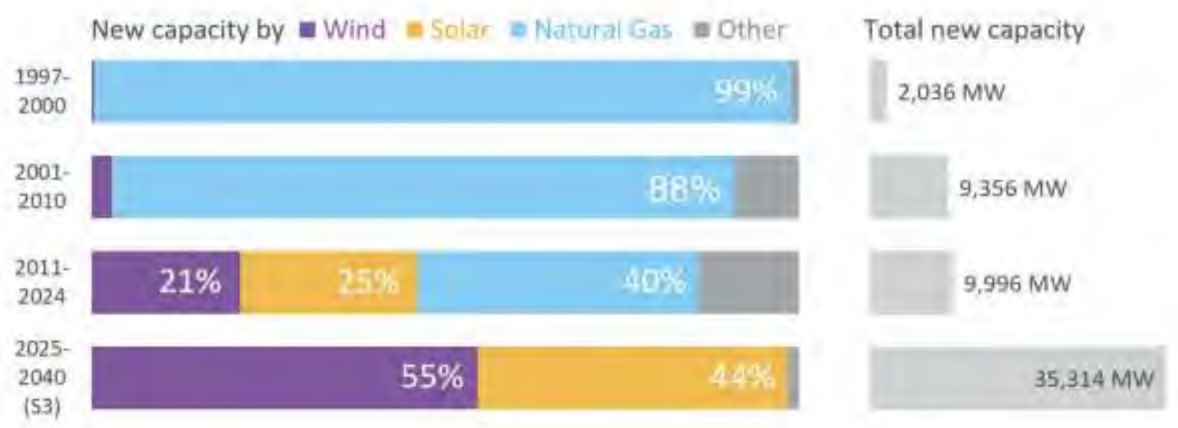
1 A shift from centrally dispatched generation to distributed resources

2 A shift from conventional generation to weather-dependent renewable generation

The 2040 Grid will Primarily Rely on a Large Number of Non-Dispatchable, Weather-Dependent Generators, With Smaller Nameplate Capacities

- **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
- **Nuclear resources clearing FCA** assumed to be staying online in 2040
- **0 GWh** of generation produced from coal, oil, or refuse burning generators
- **2 Additional Tie Lines** for imported electricity from Canada, New England Clean Energy Connect (NECEC), plus an additional new tie-line with Hydro Québec

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



Over the next 15 years, in order to meet electrification and clean energy requirements, the region will need to add almost double the amount of new generation as was added to the system in the last 25 years.

Well before the 2040 Outlook (Early 2030s), the ISO Expects to See Substantial Changes to the New England Power System

ISO needs to plan for a power system that by 2030 is projected to be very different than the grid of today:

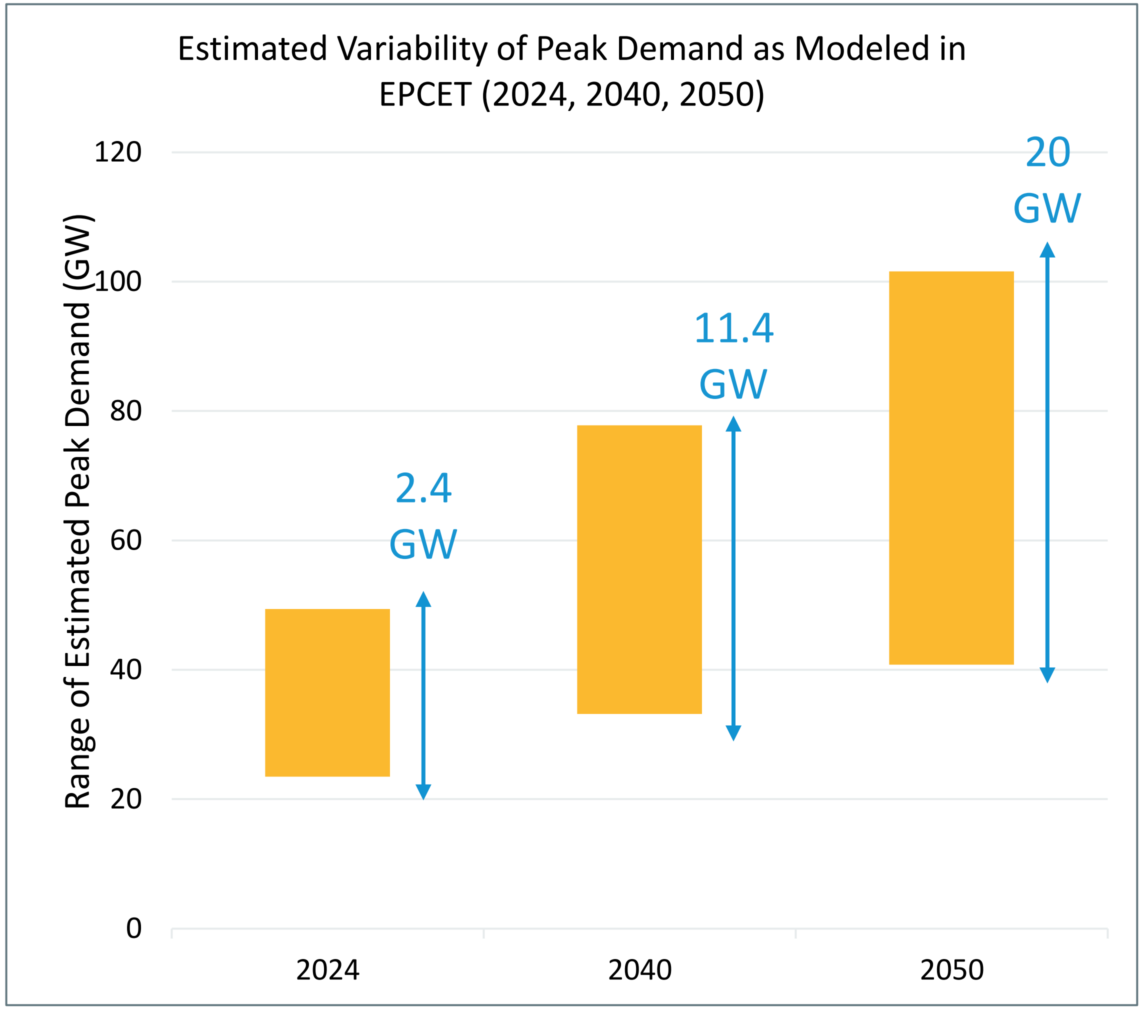
- **Double the installed capacity of solar resources**
- **Development of thousands of MW of offshore wind**
- **Substantial new transmission investment**
  - Supporting inter- and intra-regional transfers, upgrading condition of existing assets, and addressing increasing interaction between transmission and distribution system
- **Enhanced market structures** – accounting for resource mix with different operating characteristics
- **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 BTM generation
  - Increasing load-dependence on weather at a time when weather is becoming more erratic

To support these efforts, the ISO will engage in a slate of work in 2025 and beyond, that directly addresses these developments.

Escalating Variability in Supply and Demand

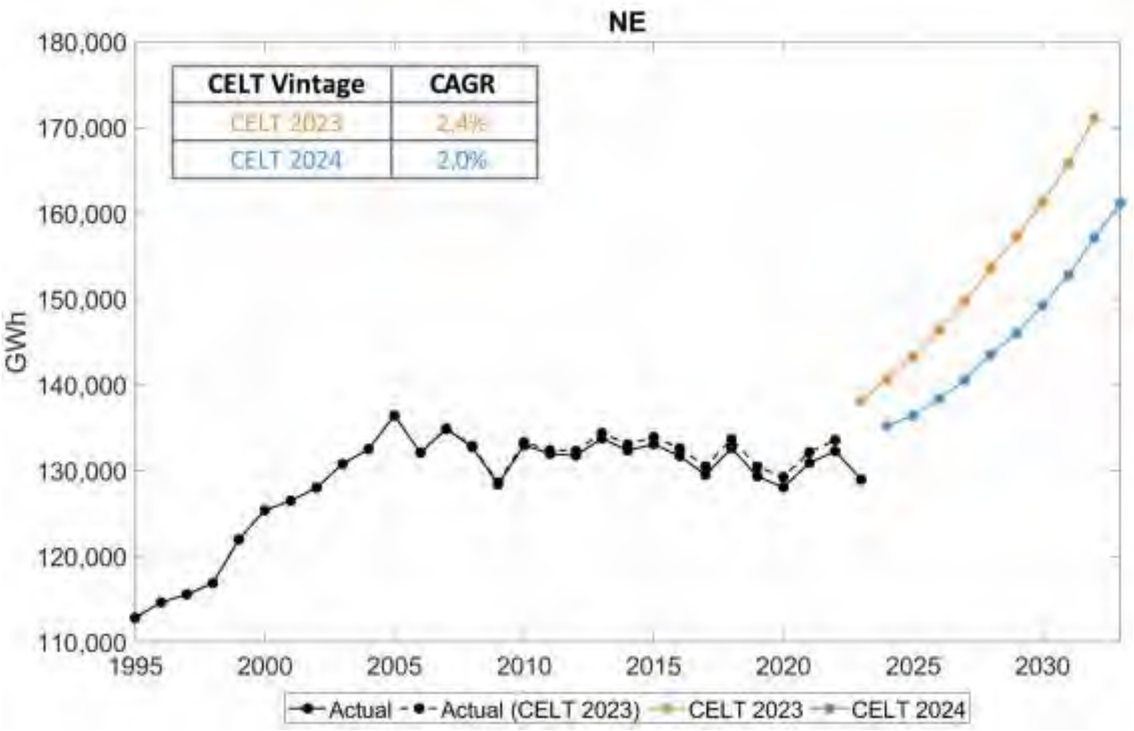
Most pathways to a low-carbon grid involve high variability in both supply and demand, which will result in either reliability challenges or higher costs

- Today's electrical grid experiences only small variations in peak annual demand between years, allowing for efficient planning for a limited number of possible outcomes
- The large variation in demand will require vastly different supply from year to year
  - Some years will require most or all resources to operate; other years, resources will run for just for a few hours of the year, or not at all



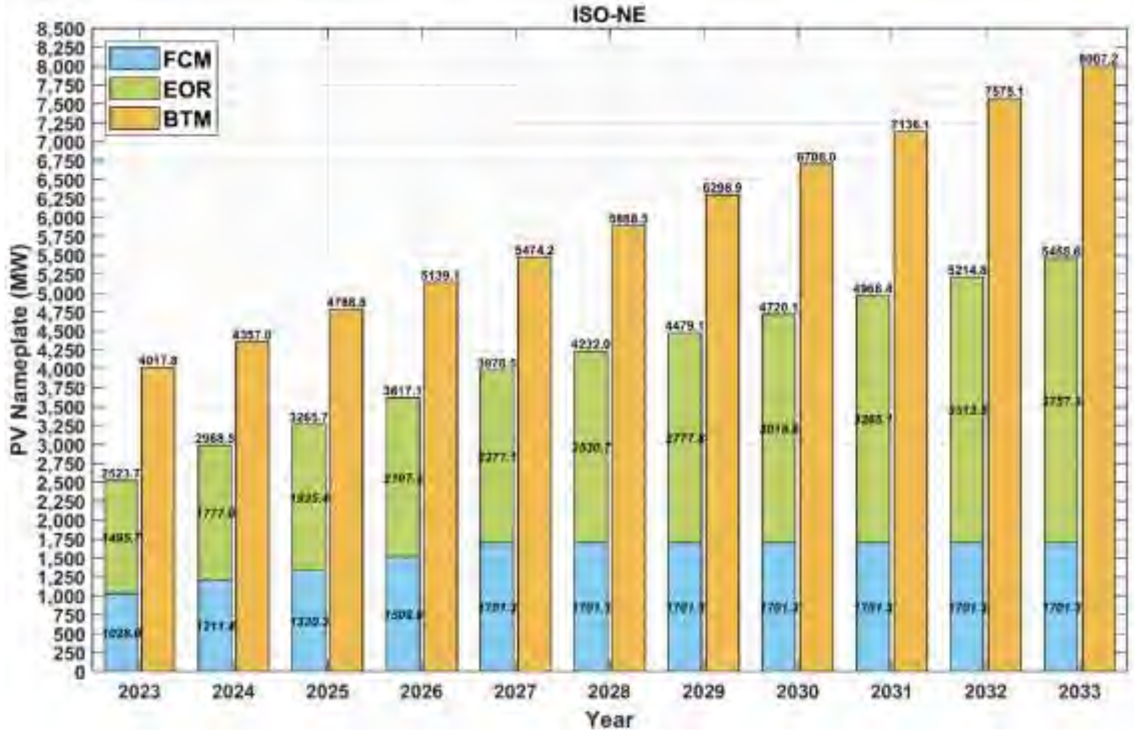
Continued Growth in PV and Peak-Load Estimates Through 2030

Peak load is projected to grow through 2030s



Source: March 2024, Load Forecast Committee: 2024 Final Draft Energy and Seasonal Peak Forecasts

ISO projects PV growth to approximately double over next 10 years

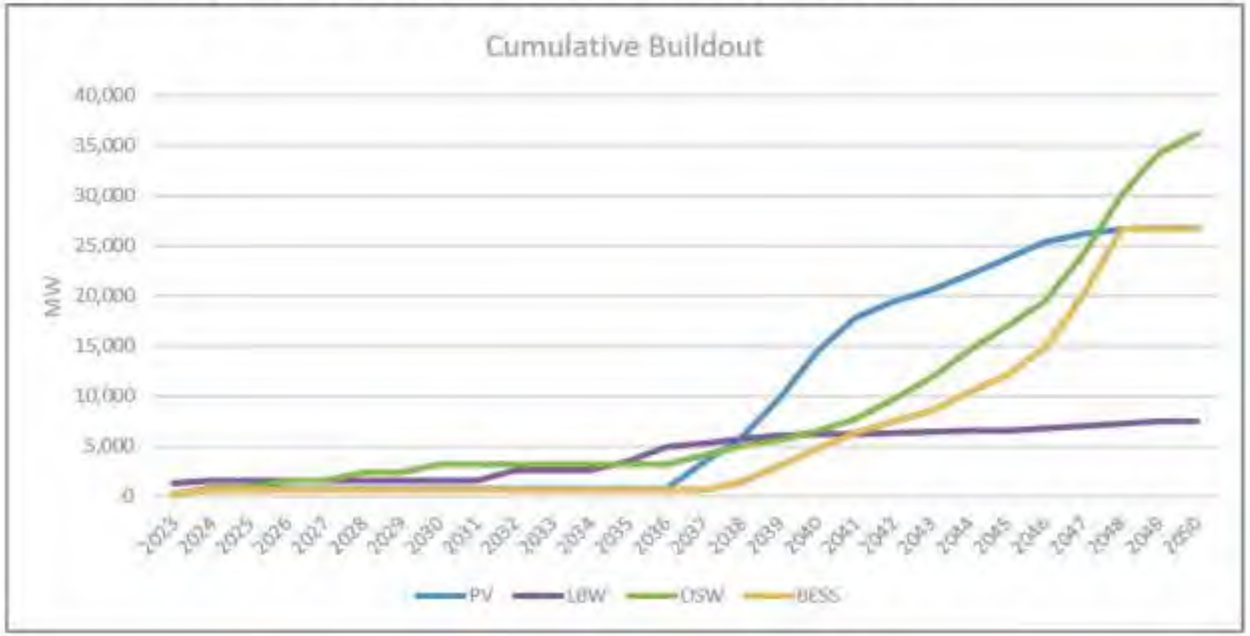


Source: March 2024, Distributed Generation Forecast Working Group: Final 2024 PV Forecast

Grid-level Renewable Capacity Will Need to Increase Substantially in the 2030s

- As load electrifies and grows, carbon constraints require increasing amounts of wind/solar/battery storage
- Despite modeled future systems with significant penetration of wind, PV, and energy storage resources, periods of high net load and depleted energy storage will drive a significant need for dispatchable resources
  - These resources will run less and less over time, but will be relied upon at crucial moments
- The quantities of energy storage needed to ride through wind and PV droughts will be immense

Carbon Constrained Buildout

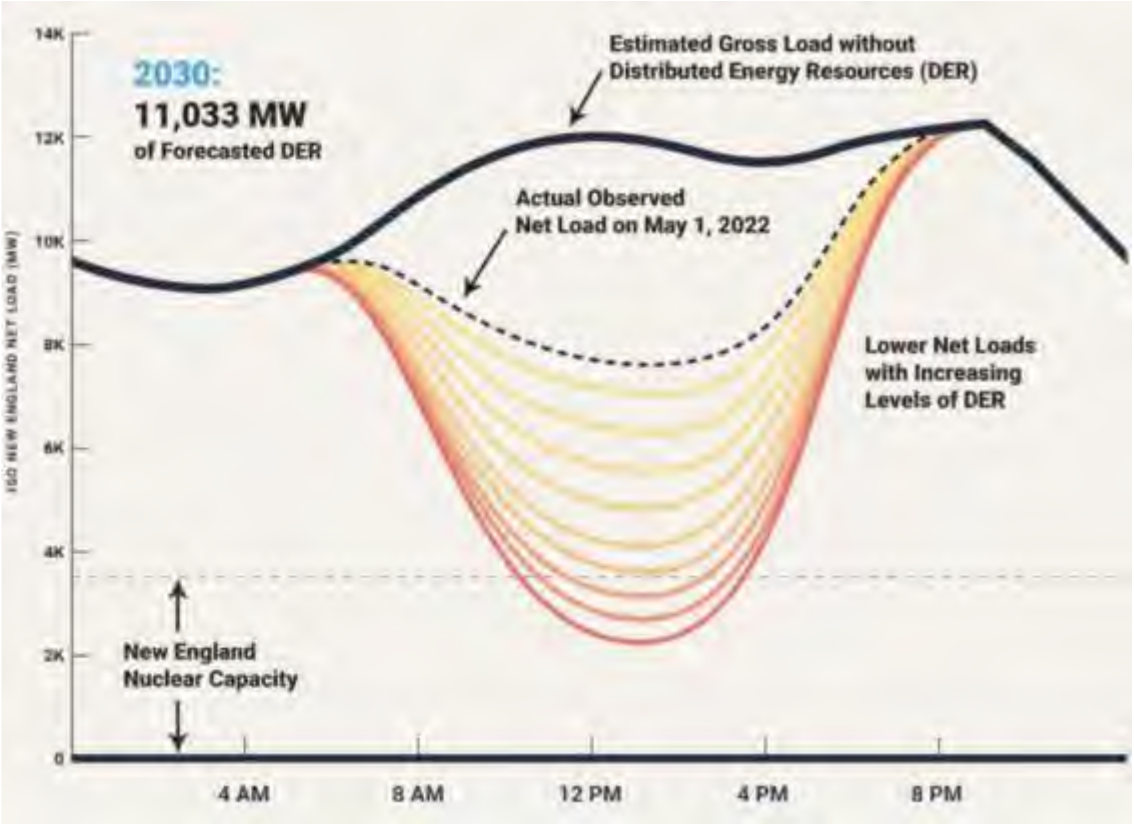


Source: [Economic Planning for the Clean Energy Transition]

By 2030s, the System May Experience Difficult Conditions with Minimum Load

- Due to increased variability in supply and demand, by the early 2030s the system may experience difficult minimum load conditions, unless demand grows during these periods (e.g., battery charging to take advantage of low/negative prices)
- Potential issues include:
  - Low loads dipping below NE nuclear capacity
  - Transmission system experiences more voltage problems
  - High ramping rates

Behind-the-Meter Solar Reduces Grid Demand



By Early-mid 2030s, Heating Electrification is Expected to Turn the Grid Into a Winter-Peaking System

- Over the next 15 years, the region needs to add almost twice as much new generation as it added in the last 25 years
  - By the early 2030s, the annual energy needed to heat buildings and charge electric vehicles is expected to grow to about 20 times the forecast for 2024
- Long duration storage helps alleviate anticipated problems
  - Higher variability in both supply and demand will increase the value of dispatchable resources
- In the medium term (2030 - 2040) when peak load begins to accelerate, there will be an urgent need for dispatchable capacity on the system
  - Anything that is retired in the short-term may have to be replaced at a larger expense in the medium- to long-term

Timing of Shift to Winter-Peaking System

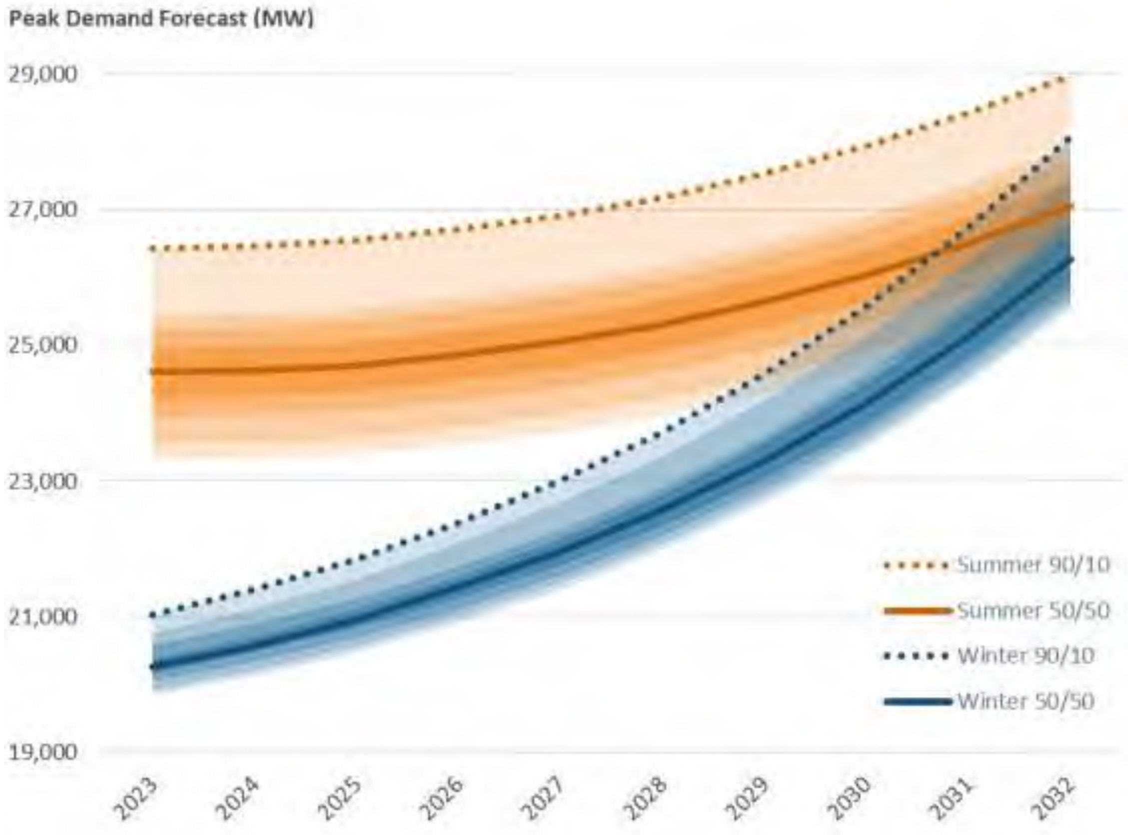


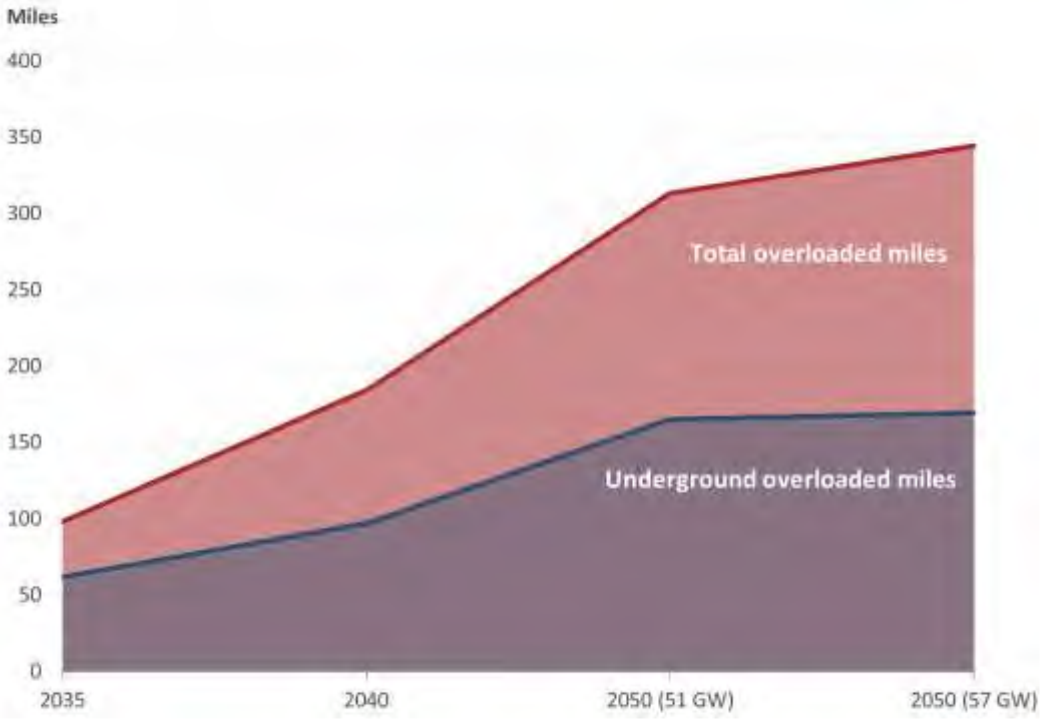
Figure source: 2023 Regional System Plan, Figure 4-9
Data Source: 2023 CELT Report

The Region's Transmission System Will Need Significant Investment

- Assuming pace of renewables continues, and electrification of heating and transportation proceeds as expected, significant upgrades to regional transmission are needed
  - As demand grows over the Clean Energy Transition, the renewable energy to serve that demand will be more geographically dispersed
- Transmission projects that address high-likelihood concerns are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates
- **Transmission projects to serve 2030s should be in planning stage now**
  - The states have recognized the need, driving the creation of the LTTS planning rules
  - The states, assisted by the ISO, have applied for DOE GRIP funding for two projects

Constraints on the distribution system may also present bottlenecks.

Line Mileage Overloaded in Boston with Generator Interconnection Locations Optimized



Source: 2050 Transmission Study, Figure 2-1

To Ensure the Four Pillars are Robust in the Long-Term, We Must Have a Focused Effort to Ramp-Up Capabilities *Now*

- New England is transitioning to a cleaner electric grid in an effort to mitigate the impacts of climate change and meet the need for a reliable, cost-effective and environmentally sustainable bulk electric system
- To ensure this successful transition, the ISO must focus on the near-term and what the organization must do to strengthen reliability today while keeping New England on the path to the clean, reliable grid of the future
- Successful management of this unprecedented transition requires us to look very carefully toward both the short and the long term
  - The short term because we must maintain reliability during the transition to a carbon-free grid, and lay the foundation for the longer term
  - The longer term because we need to make sound decisions now that will help us reach that destination in the most reliable and cost-effective way

In 2025, the ISO has identified a set of initiatives that make progress towards the goals supporting the organization’s mission and vision; the 2025 budget represents a needed step-up in preparing for the anticipated changes.

2025 BUDGET OVERVIEW

2025 Budget Overview

- Key drivers supporting the proposed increase are (see further details on the following pages):
  - Continuing to **enhance capabilities to address the modeling, analysis, processing, and communication** needs directly resulting from the clean energy transition
  - **Addressing the effects of inflation** on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation
- The 2025 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 2025 revenue requirement *before true-up* is $306.4M, an increase of 10.7% over 2024; when including the net true-up, an increase of $7.8M, the total revenue requirement increase is 13.6% year over year

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

2025 Budget Overview *(cont.)*

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

- The proposed 2025 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 $0.3 million increase compared to the preliminary top-down version:
  - Increases include: additional funding for regional study work on raising the minimum loss of source value for New England; Information Technology staff augmentation; higher medical renewal rates; and interest expense
  - Decreases, that largely offset the noted increases, include: lower salary rates due to staff turnover; and the removal of capacity auction licensing fees due to FERC approved two year FCA 19 delay

Clean Energy Transition Driving 2025 ISO-NE Budget

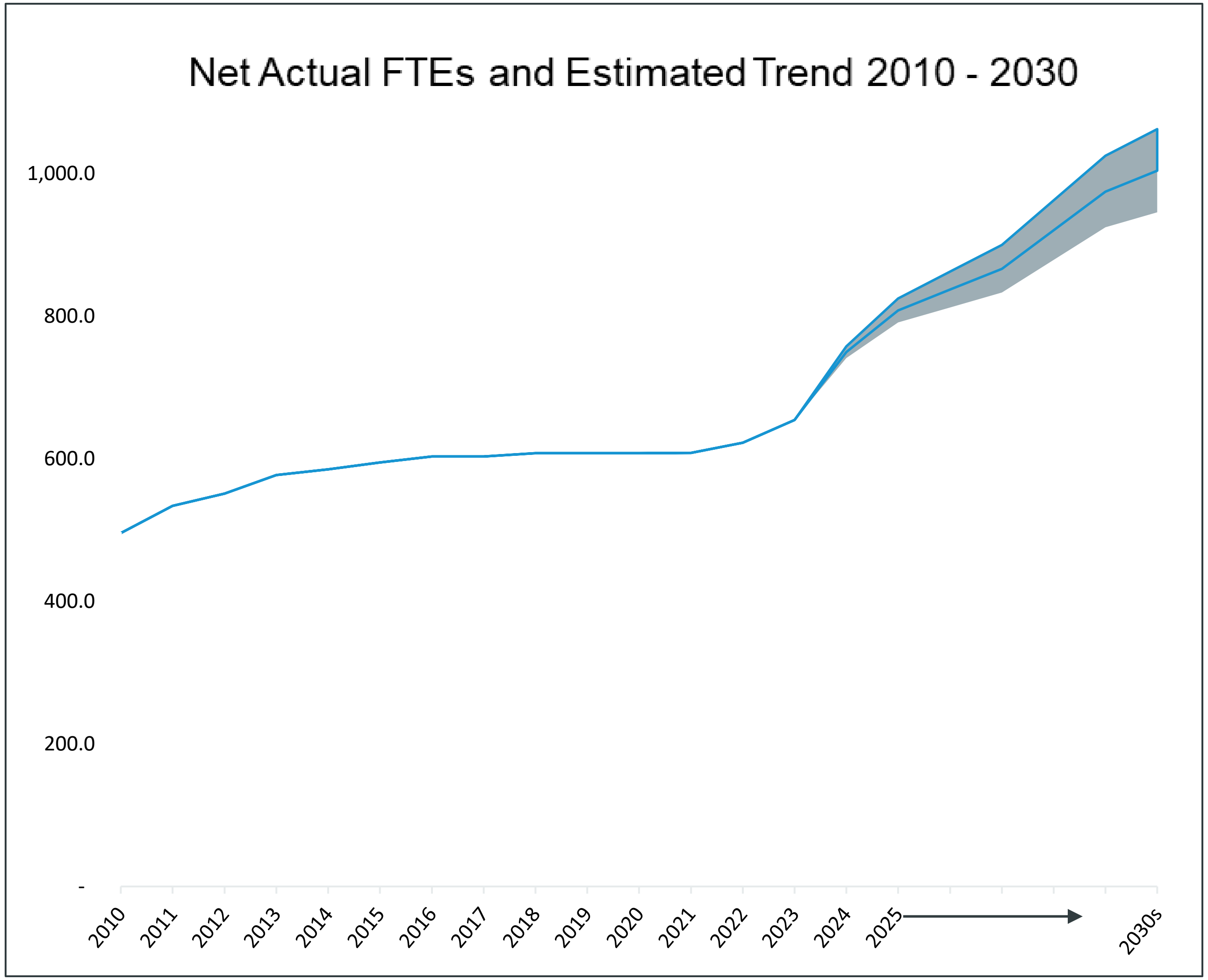
Driver: The main drivers of the 2025 budget are the need to add personnel and make technology investments for the organization to address the modeling, analysis, processing, operational and communication needs directly resulting from the clean energy transition, and includes:

- Continuing to **upgrade our IT infrastructure** to support increasing cybersecurity risk mitigation, data analysis, and rapid technology evolution (often driven by vendors)
  - Capitalize on increased computing power offered through the move to the cloud environment in order to process the volume of data and complexity of analyses that will be needed to support the changing grid
  - Maintaining the internal development and critical software developed by ISO's Advanced Technology Solutions
- **Advancements in modeling and forecasting** to account for net load characteristics and trends that have rapidly evolved in recent years and are anticipated to change even more significantly in the coming decades
- **Market design** work responding to changing system needs, public policies, and new energy technologies
- Development of a team to support **longer-term transmission planning** and administering of transmission RFPs, including analytical support for determining the Benefit to Cost Ratio (BCR) for proposed projects
- Staying compliant with and responding to increasingly **complex federal and state mandates and requests**
- **Investing in more sophisticated operational tools (including updating the EMS)** to support the control room's ability to manage rapidly increasing grid and resource complexity

After Years of Flat Headcount, in 2023, ISO-NE Began Plan to Increase Hiring to Address Clean Energy Transition

Clean energy transition driving FTE needs:

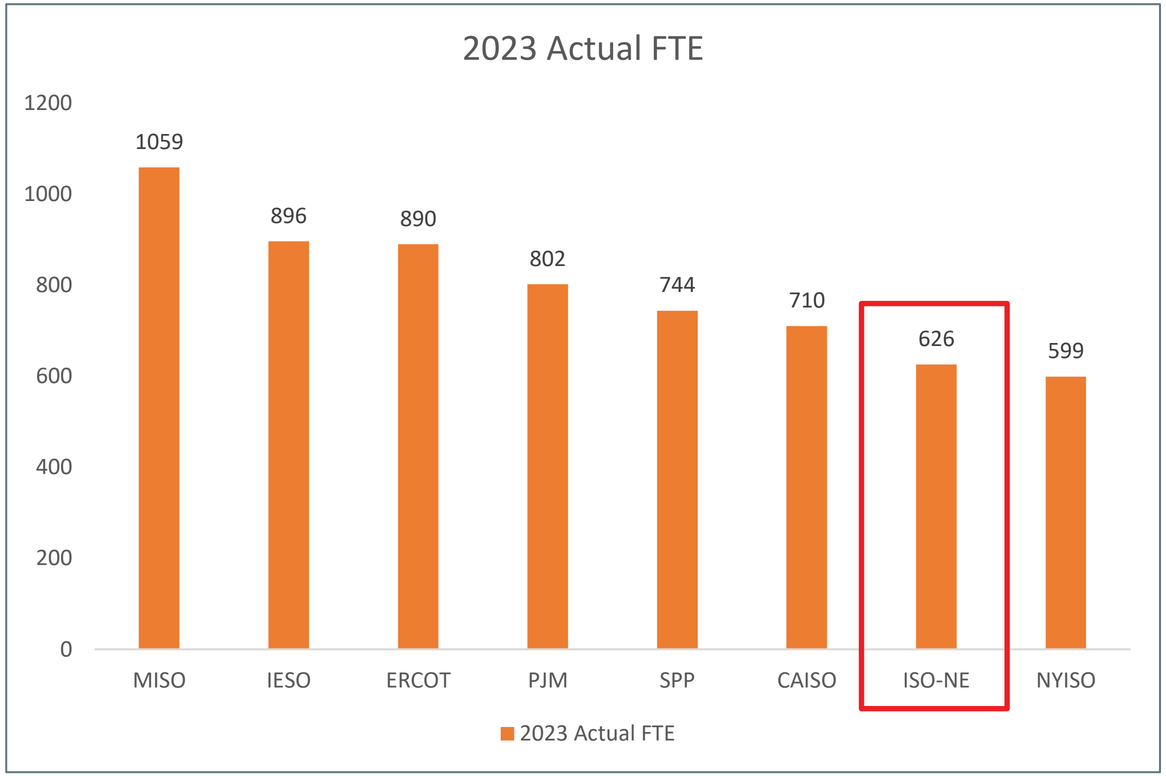
- Increasing number of resources to be interconnected, studied, and incorporated into modeling and forecasting
- New roles for the ISO including assisting states with transmission RFPs
- Increasing compliance needs to address FERC orders, and assess their impacts on operations – 2222, 841, 881, 901, 1920, and 2023
- Emergent needs to collect data for Distributed Energy Resources (DER) to address tripping and low-loads
- New and enhanced skills to work with changing technology stack, new data streams, and operationalizing new applications
- Personnel to communicate increasingly complex information to stakeholders and the public
- Increased support needs to assist the growing and distributed workforce



ISO-NE's Incremental and Actual Headcount in Comparison to other ISO/RTOs'

Other ISOs had already begun ramping up their hiring prior to ISO-NE

ISO-NE is still relatively small compared to other multi-state ISOs



Note: FTE additions and totals are based on actual FTE amounts on 12/31 of the applicable year.

Other Factors Driving Increases to the 2025 Budget

In addition to the budget increases, for added personnel and technology, to support clean energy as described in the previous slides, the other primary factor to the 2025 budget is inflationary cost increases and for continued operations

Driver: addressing the effects of inflation on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation

- This includes the need to supplement the bench strength in certain departments to compensate for turnover and retirements

The region is committing to invest tens of billions of dollars in the clean energy transition over the next three decades and much of that investment will not only drive work for the ISO, but change the way we work; in order for the region to fully realize the benefits of that investment, the ISO needs to be prepared to reliably operate in that future paradigm

- Like the region it services, the ISO is an organization that is in transition – including operational needs, inflation, and workforce composition – and because of that, our budget estimates over the ensuing years will increase and should be expected to fluctuate due to the volatility of the input assumptions
- The transition – and work flow – will be dynamic, as will other budget assumptions (e.g., various inflationary forces, turnover rates due to the competitive market, headcount needs for yet-to-be-determined market designs, and business processes); therefore long-term budget forecasts will fluctuate

For the ISO to Manage the Transition to Clean Energy, a Significant Investment is Required in The Near-Term

The main factors for the increases to the 2025 ISO budget are:

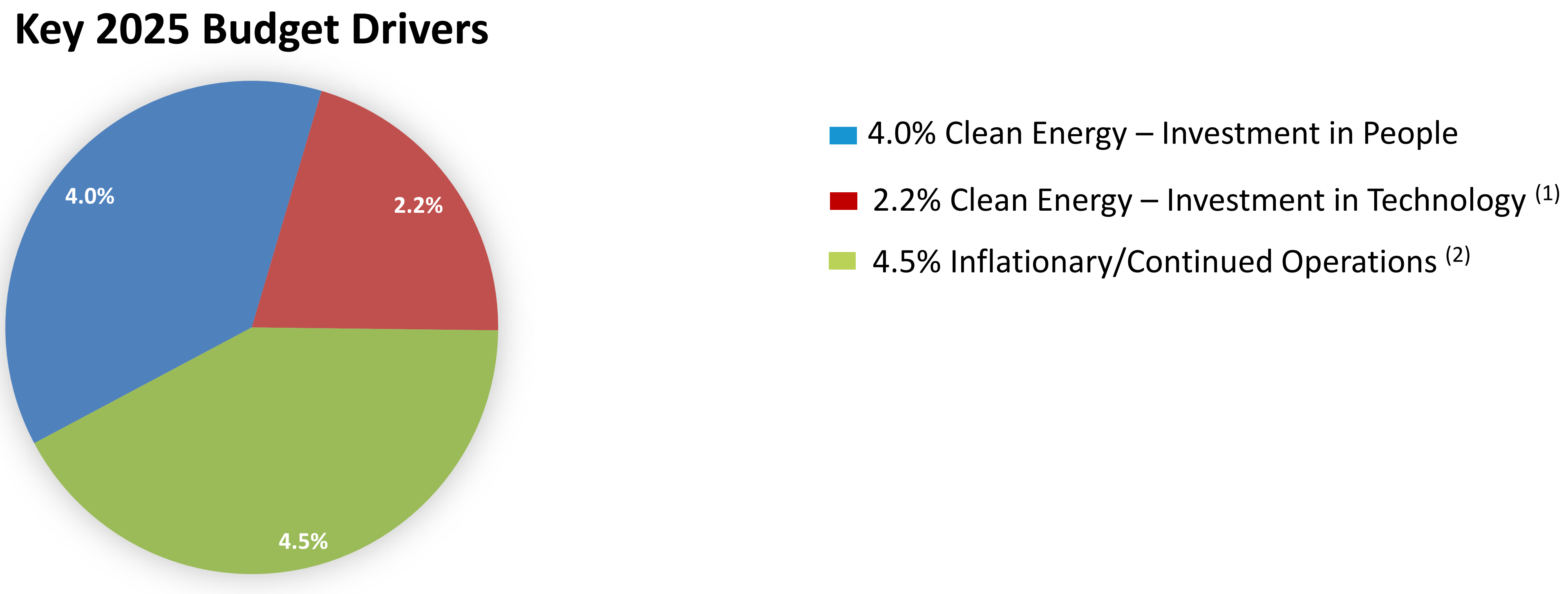
1. The transition to clean energy:
   - Adding full-time employees (FTEs) and other resources to address work directly related to the transition to clean energy
   - Additional investment in information technology (IT) for enhanced modeling, emerging technologies and forecast methods, and the transition to cloud-based infrastructure
2. Inflationary and continued operations drivers:
   - Standard salary increases to keep pace with the labor market in order to retain and attract employees, to address cybersecurity, and for other miscellaneous cost increases

Factor	% Increase	$ Amount	$KWh Rate	Average Monthly Consumer Cost Impact *
Clean Energy Transition	6.2 %	$16,898,100	$0.00012	$0.09
Inflationary/ Continued Operations	4.5 %	$12,610,100	$0.00009	$0.07
Total:	**10.7 %**	**$29,508,200**	**$0.00021**	**$0.16**

**Average Monthly Consumer Cost Impact* is based on average consumption of 750 kWh per month.

Note: See chart on the following slide with an allocation of expense by factor, including a depiction of Clean Energy between investment in people and technology

Key Factors to the 2025 ISO-NE Budget



(1) The Clean Energy Investment in Technology represents $1.7M of Computer Services increases for improved modeling, load forecasting, and moving to a cloud environment. The Clean Energy Investment in Technology also includes: increases for Depreciation Expense including that for new market features and enhancement related projects such as Day-Ahead Ancillary Services Improvements and nGEM Software Development Part III; and Network Operations increases for transition of communication lines to new technologies

(2) Inflationary/Continued Operations includes $4.3M of Computer Services increases representing $2.3M of existing product increased costs and/or licensing and $2.0M related to Cyber Security additions and enhancements

Note: See slides 36 and 37 for additional information on Computer Services and technology

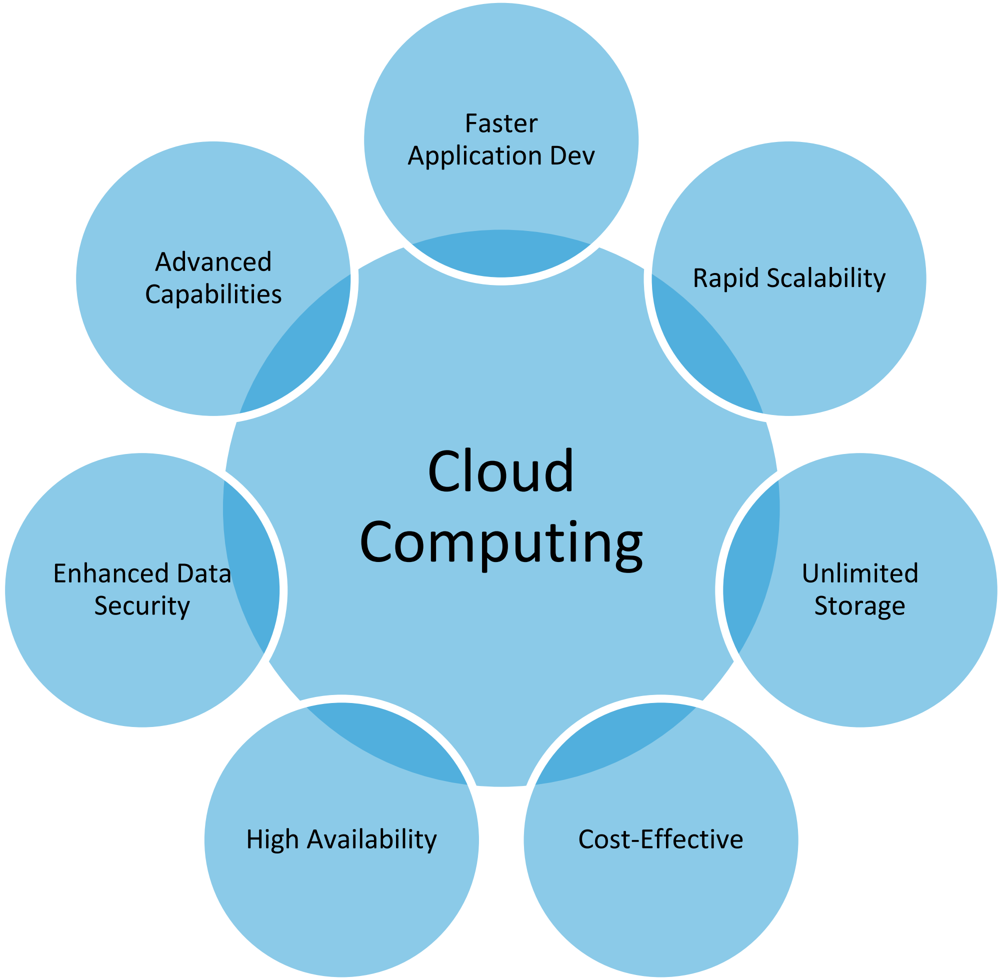
Budget Driver: The Need to Enhance Computer Services and Technology Stack

Computer services driving budget costs in 2025:

- ISO moving to cloud environment
  - Changes the organization's technology stack
  - Enhances efficiencies and capabilities
  - Necessitates new roles within IT
- New/increasing licensing and products
  - Increases in user licenses or central processing units
  - Vendor and product inflation

Existing staff will be trained to support new platforms and tools

Benefits of moving to the cloud

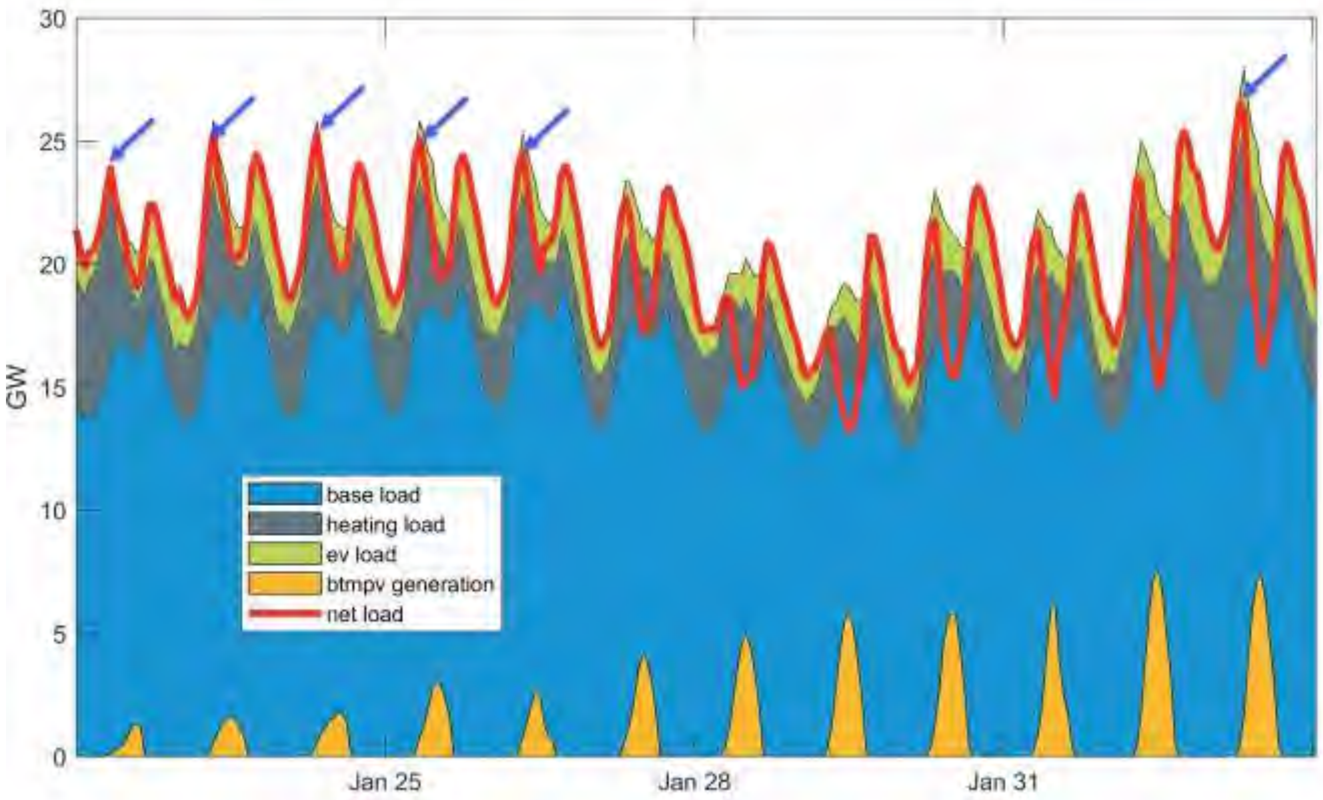


Budget Driver: Technology Improvements for Forecasting Demand and Increasing Complexity of Planning Studies

- Emerging trends require **enhanced modeling and accounting** to resolve net impacts on demand and to forecast full range of demand during all seasons and grid conditions
  - DER PV and DER storage
  - Electrified heating
  - EV managed charging
  - Retail-based active demand response
- **Keep pace with emerging technologies and forecast methods**
- Increasing need for **studying non-typical peak hour insights**
  - Midday minimum loads
  - Sub-regional, “non-coincident” load characteristics
  - Seasonal peaks occurring on weekends, holidays, or atypical months
- Growing emphasis on **load shape and short-term energy requirements in studies**

Need Explicit Accounting of Load Shape

Our current forecasting methodology does not capture the morning peaks we are observing



Source: Data from 2023 CELT Report

Budget Driver: Designing Markets and Supporting Analyses for the Clean Energy Transition

- Hiring to support the development and maintenance of new market mechanisms for the changing resource mix:
  - Capacity Auction Reforms:
    - Resource Capacity Accreditation
    - Move to a prompt/seasonal market
      - *The extent there are personnel efficiencies from the shift to a prompt/seasonal market, the ISO will redeploy existing staff to areas of need*
  - Ramping and flexible response products
  - Day-Ahead Ancillary Services Initiative
- Hiring to support the effects of evolving resource mix on market analyses
  - New and more frequent energy analyses
  - Growing number of transmission and interconnection studies
  - Need to support transmission RFPs with economic analyses

Budget Driver: Compliance with Increasingly Complex Stakeholder, State, and Federal Requests

The clean energy transition will necessitate new roles and capabilities at the ISO including supporting states' requests (including longer-term transmission planning and RFPs), staying compliant with federal mandates, and hiring new skillsets geared specifically towards engaging stakeholders

In addition to the personnel needed to address the workload associated with the modeling, forecasting, and technology needs of the changing grid, addressing the related federal, state, and stakeholder requests will drive budget needs in 2025:

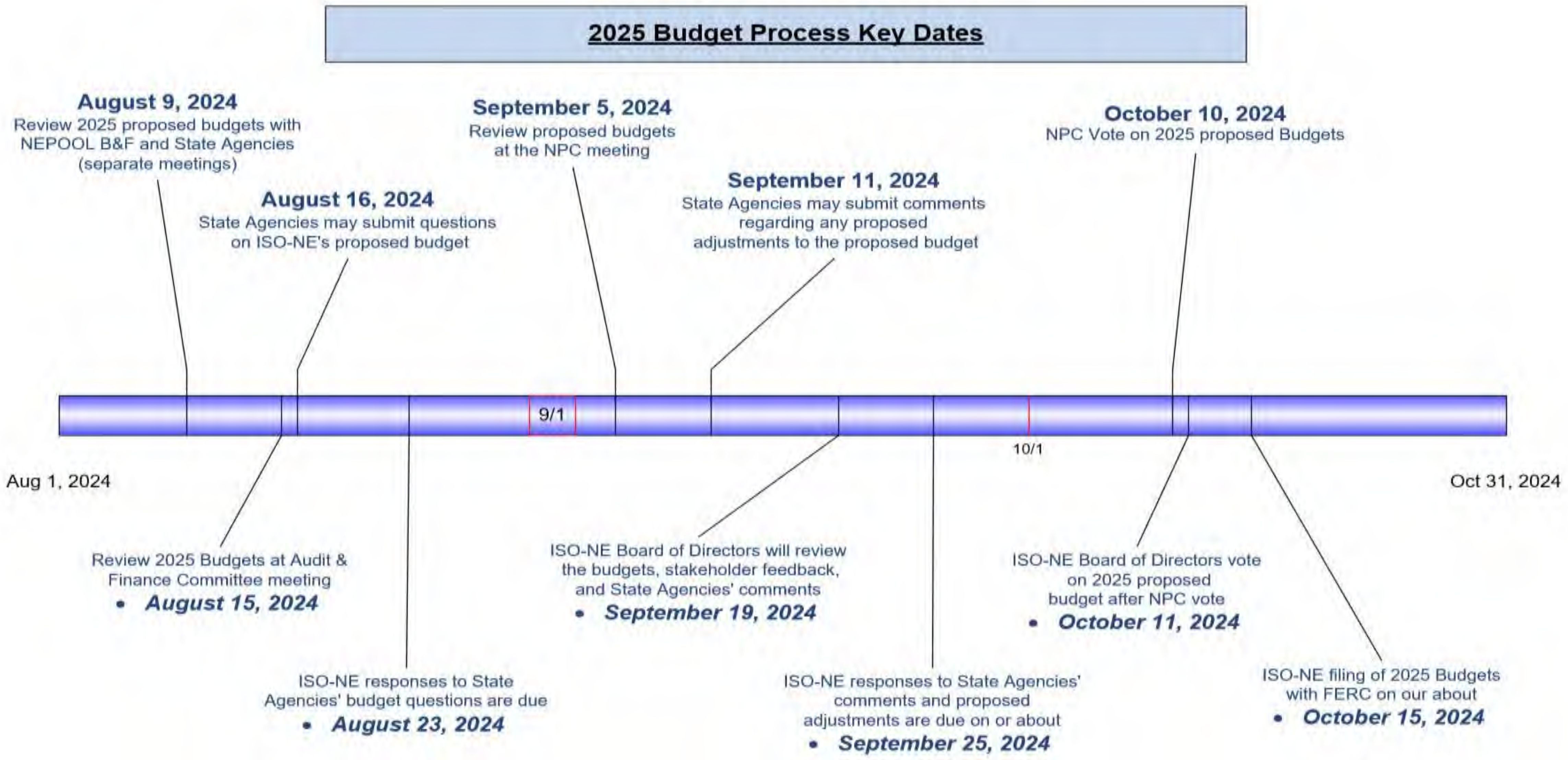
- Development of capabilities to assist states in the transmission RFP and long-term transmission planning processes, **which will necessitate the addition of a new team at the ISO**
  - **This new capability will require a buildout over the course of a few years beginning in 2025**
- Implementation and evaluation of FERC orders: FERC Orders 2222, 841, 881, 901, 1920, and 2023
  - Including elements of implementing outcomes from Regional Energy Shortfall Threshold and Day-Ahead Ancillary Services
- Hiring new skillsets to service stakeholder needs, requests, and communication of increasingly complex grid and market information

2025 Budget Overview

The 2025 Capital Budget is also presented in summary form

- The 2025 Capital Budget has increased from $35M in 2024 to $42.5M in 2025
  - The 2025 capital budget is $2.5M above the $40M presented in the preliminary 2025 budget as a result of incorporating the workspace changes needed to satisfy short-term constraints for the next couple of years; as discussed in the preliminary budget, the Holyoke campus was designed to support 560 headcount therefore creating a need to redesign the Holyoke facilities to accommodate the larger workforce; after exploring financing options with TD Bank, ISO determined this was the most cost efficient way to finance the short-term needs; the costs will be covered under the $75M private placement which will be in effect in 2024; additionally, this will allow ISO to save on closing costs
  - The increased capital budget need is being driven by four primary drivers as explained in further detail on slides 69-73
  - 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 operating budgets and rates
- The 2025 proposed capital budget of $42.5M 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)
- Detailed project descriptions are presented in Appendix 7

2025 Budget Process – Key Dates



2025 Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2025	% Change	2024	% Change	2023	% Change	2022	% Change	2021
Operating Budget Before Depreciation	$269.4	10.3%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Capital Budget	42.5	21.4%	35.0	4.5%	33.5	4.7%	32.0	14.3%	28.0
Total Cash Budget	**$311.9**	**11.7%**	**$279.3**	**15.1%**	**$242.7**	**9.8%**	**$221.1**	**7.0%**	**$206.6**
Operating Budget Before Depreciation	$269.4	10.3%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Depreciation	$37.0	13.6%	32.6	5.1%	31.0	19.1%	26.0	(1.2)%	26.3
Revenue Requirement Before True-up	306.4	10.7%	276.9	15.3%	240.2	11.7%	215.1	4.9%	205.0
True up	4.8		(3.0)		(14.6)		1.1		0.2
Revenue Requirement	**$311.2**	**13.6%**	**$273.9**	**21.4%**	**$225.6**	**4.4%**	**$216.1**	**5.4%**	**$205.1**
Forecast – TWhs (1)	**136.5**	**(3.0)%**	**140.7**	**(1.6)%**	**143.0**	**(1.0)%**	**144.4**	**(2.0)%**	**147.4**
$/KWh Rate	**$0.00228**	**17.1%**	**$0.00195**	**23.4%**	**$0.00158**	**5.4%**	**$0.00150**	**7.5%**	**$0.00139**
Average Monthly Consumer Cost (2)	**$1.71**		**$1.46**		**$1.18**		**$1.12**		**$1.04**

(1) 2025 Forecast based on May 2024 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.

2025 STRATEGIC GOAL INITIATIVES

2025 Initiatives: Responsive Market Designs

Support reliability through competitive market mechanisms

1. Capacity Auction Reforms
   - Transition to a Prompt/Seasonal Capacity Market
   - Resource Capacity Accreditation Reforms
2. Implement Day-Ahead Ancillary Services
3. Guide stakeholder discussions on specific new flexible response services
4. Finalize decision to extend or terminate IEP post 24/25 winter

Administer FERC Orders Supporting DER

1. Complete Business Requirements for all affected software and beginning development for Order No. 2222
2. Begin Implementation of Day-Ahead Market Storage Enhancements for Order 841

2025 Initiatives: Progress and Innovation

Improve modeling for emerging technology resources

1. Development of nGEM Real-Time Market Clearing Engine
2. Completion of nGEM Phase III program development
3. Integrate EMT Study Tools into Engineering Processes
4. Enhance data collection for co-located and hybrid resources to improve modeling/visibility

Continue to develop forecasting capabilities to support clean energy transition

1. Develop Probabilistic Forecast Capabilities for Wind, Solar, and Load
2. Integrate Probabilistic Energy Adequacy Tool (PEAT) analysis into seasonal forecasts
3. Improve load forecasting methodology

2025 Initiatives: Operational Excellence

Maintain Reliability and Forecasting for Operation of the Bulk Power System

- Evaluate Single Source Contingency Limit Increase
- Continue to evaluate tie benefits
- Implement ambient adjusted line ratings (FERC Order 881)
- Address trend of increasing DER/decreasing springtime load
- Enhance synchrophaser applications

Implement internal process and technology improvements to address increasing operational complexity

- Increase the usability and broaden usage of ISO-developed innovations to enhance control room situational awareness and market efficiency related to grid complexity
- Enterprise resource planning system replacement
- Evaluate the impacts of FERC Order 2023 on streamlining interconnection queue

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

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

2025 Initiatives: Stakeholder Engagement

Communicate Power System and Wholesale Markets Performance & Needs

1. Implement Extended Term/Longer Term Transmission Planning Phase 2
2. Coordinate regional discussions around Transmission Owners' asset replacement for the clean energy transition
3. Engage States/FERC to determine implementation path for Regional Energy Shortfall Threshold (REST)
4. Economic studies coming out of the Economic Planning for the Clean Energy Transition (EPCET) Study

Provide high-quality services to stakeholders and the public

1. Develop new communications materials, expand access to regional energy information and conduct outreach to new audiences
2. Survey stakeholders' satisfaction for ISO services
3. Enhance communications about clean energy transition

2025 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 programs
4. Improve employee experience- onboarding, coaching and development, flexible work (hybrid), change management
5. Deliver competitive benefit programs with a focus on emotional, physical, and financial wellness

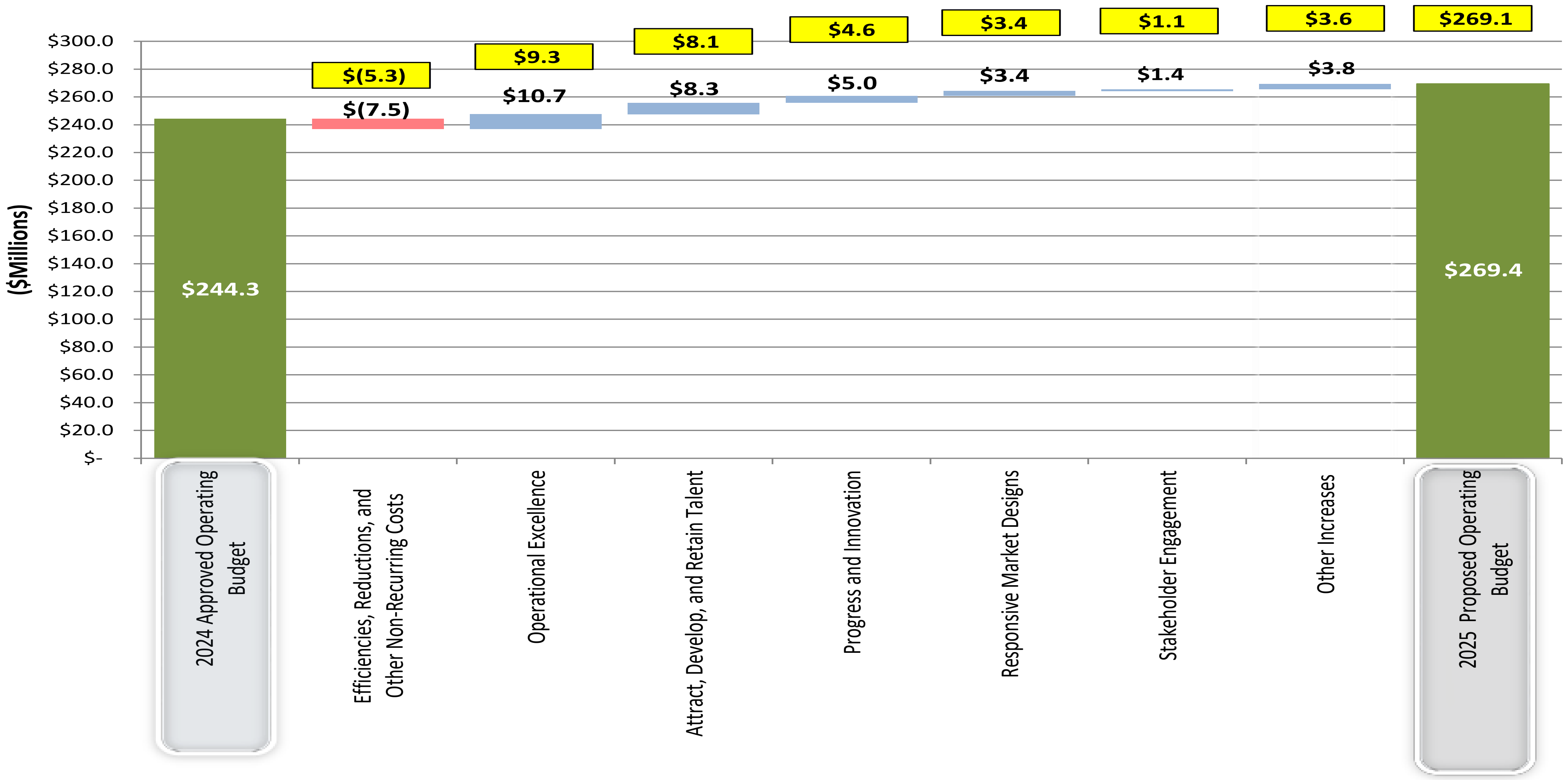
Support the Professional Development of the ISO Workforce

1. Advance Diversity and Inclusion – raising awareness, employee networks, focus on culture
2. Advance leadership capability through the design and delivery of leadership development opportunities and programs
3. Support the organization change, upskilling, and reskilling required to achieve business outcomes
4. Refresh and administer HR Policies and Programs

2025 Detailed Budget Changes by Strategic Goal

2025 Budget

Changes in budget by Strategic Goal



Note: Items in yellow above represent the estimate that was included in the 2025 preliminary budget presented in June 2024.

2025 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($7.5M)

- Reductions for consulting professional fees for 2024 studies or other non-recurring work including:
  - Utilization of external support for New England States' requests to be offset by ISO-NE internal staff
  - Funding for FCA 21 Cost of New Entry (CONE) parameter updates
  - Reduction in funding for the assessment of a conceptual framework for a Prompt Seasonal Capacity Market
  - Removal of professional fees funding in Market Administration & Auctions and Market Monitoring, and capacity auction licensing fees due to the FERC approved two year delay of FCA 19
  - For Distributed Energy Resource and minimum load studies for assistance in determining requirements on how to ensure reliability on the system under conditions where it is powered solely by inverter-based resources
  - Reductions in Market Development study and project management support
  - For Energy Resource Opportunity cost support in Market Monitoring

2025 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions: *(cont.)*

- Lower support costs, upon contract renewal, for Participant Support management software
- Lower salary rates due to employee turnover and retirements
- Increase in Interest Income due to raising of interest rates for 2025 to 2.75% compared to 1.00% in 2024 budget

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 3: Operational Excellence: $10.7M

- Computer service and leasing increases for: cyber security (security logging, firewall updates, network collaboration tool, network traffic segmentation, encryption software, and risk management); leasing of servers as part of data center refresh; photovoltaic and demand response forecast products; licensing for System Planning and Operations applications; performance monitoring software; Enterprise Resource Planning software; compliance software; and inflationary and vendor increases across our portfolio of computer service products ($6.4M)
- Funding for 11.0 FTEs* related to this goal across Information and Cyber Security Services for Cloud Computing transition including architecture, security and infrastructure support, and FinOps management, for IT modeling and software development, and support for enterprise and settlement applications; for Participant Training support; and for Finance and Market Credit Risk support to the organization ($2.5M)
- Network Operations increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases ($0.6M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

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

- Information and Cyber Security Services staff augmentation inflationary rate increases ($0.5M)
- Addition of an professional fees for an Audio Visual Engineer to support the Information Technology Service Delivery team ($0.2M)
- Internal Audit support for cloud applications and NERC Critical Infrastructure Protection (CIP) programs ($0.2M)
- Travel and training due to full renewal of in-person meetings, higher travel costs, and training of staff to support new platforms and tools ($0.2M)
- Information Technology administrative staff augmentation consulting support ($0.1M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 5: Attract, Develop, and Retain Talent: $8.3M

- Merit and Promotion increases (6.0% Total): for annual merit (3.0%-4.0%) and for standard and targeted equity/promotions (2.0%-3.0%), less timing of 2024 equity/promotion adjustments and allocation of amounts between operating and capital/reimbursable work ($4.7M)
- Increases in employee benefit costs, primarily for medical trend, increased number of employees in Defined Contribution Benefit Plan, and higher 401K match due to overall employee salaries ($1.8M)
- Increase for employee incentive target amounts including adjustments based on compensation study review ($1.4M)
- Funding for 6.0 FTEs* related to this goal across Human Resources, Legal, and Corporate Communications (in HR for talent and project management, early career associates, and learning coordinator; in Legal for corporate counsel to support employee related matters; and in Corporate Communications for a communications specialist to expand external communications to attract talent) ($1.0M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 5: Attract, Develop, and Retain Talent: *(cont.)*

- Higher recruiting and benefits administration related expenses including relocation, recruiter fees, and employee experience consulting ($0.5M)
- Leasing of land adjacent to Holyoke facility in conjunction with Space Utilization project ($0.3M)
- Human Resources support for instructional design and executive coaching ($0.2M)
- A reduction for the increase of employee vacancy from 5% to 6% (reduction of $1.6M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 2: Progress and Innovation: $5.0M

- Funding for 16.0 FTEs* including Information and Cyber Security Services and Advanced Technology Solutions for bringing ISO-NE developed advanced technologies into the operating environment to increase our situational awareness capabilities; System Operations and System Planning positions for forecasting and energy analysis across different timespans as the system's resource mix continues to evolve, and for modeling and electromagnetic transient analyses for market and reliability operating limits of Inverter Based Resources; and in Transmission Planning and Services for RFP processing and long-term studies ($3.4M)
- Funding for a transmission planning system assessment under NERC Transmission Planning Standard TPL-001 ($0.5M)
- Increased utilization of cloud computing with more products moving to the cloud including the Customer and Asset Management System (CAMS), Forward Capacity Tracking System (FCTS), and internal development software application ($0.5M)
- Funding to support transmission planning and analysis studies to establish facility out transfer capability for Northern New England and NECEC ($0.3M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 2: Progress and Innovation: *(cont.)*

- Funding for Planning Services benchmarking and validation of generator outage data ($0.1M)
- Fees for a battery storage modeling application being utilized by Internal Market Monitoring staff ($0.1M)
- For research by Advanced Technology Solutions with outside firm on impacts of Inverter Based Resources on the system based on differing scenarios including location, timing, and volumes ($0.1M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 1: Responsive Market Designs: $3.4M

- Funding for 11.0 FTEs* related to this goal including for: Market Development in design of market overhauls including Capacity Auction Reforms (prompt seasonal capacity market, and resource capacity accreditation), and flexible response services; Operations Training to design and support trainings for Operations and Market Administration and Auctions staff for new market features; Information and Cyber Security Services and Advanced Technology Solutions staffing to support and integrate new market features into applications and tools; and Planning and Transmission Services to align with new market designs, for identifying enhancements to existing reliability modeling and researching, and developing modeling techniques for emerging technologies ($2.4M)
- nGEM vendor support with the Day-Ahead Market Clearing Engine production application that is being supported at the same time as the legacy Real-Time application (forecasted to go live in 2026) ($0.6M)
- Support in Advanced Technology Solutions for Integrated Market Simulator system support and enhancements ($0.3M)
- Support for Market & Credit Risk modeling ($0.1M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 4: Stakeholder Engagement: $1.4M

- Funding for 3.5 FTEs* in Participant Relations and Services for project services (gathering, managing, and supporting the assessment of participant requests), for data analytics on key trends, for technical readiness on participants inquiries and proposals, and for technical writing and instructional design work for broader and deeper training for new market features and initiatives scheduled for 2025 and 2026 ($0.7M)
- Funding for 1.5 FTEs* in System Planning for Economic Study and Environment Outlook and Interconnection Study work; and 1.0 FTE* in External Affairs for increased support and substantive interactions with the states and facilitating engagement of ISO subject matter experts on matters related to renewable and clean energy development, transmission and interregional planning, generator interconnections, and integration of demand-side solutions and distributed resources ($0.5M)
- Increase in funding 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 ($0.2M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Other Increases: $3.8M

- The allocation of NPCC and NERC dues ($1.2M)
- An increase in Interest Expense and fees with changes to: Private Placement debt in late 2024 at higher balance and expected higher rate than previous debt; tax exempt debt due to higher rate slightly offset by decrease in principal balance; with a partial offset on the working capital borrowing ($1.1M)
- An increase in the CEO Emerging Work Allowance ($1.0M)
- Insurance policy rate increase ($0.5M)

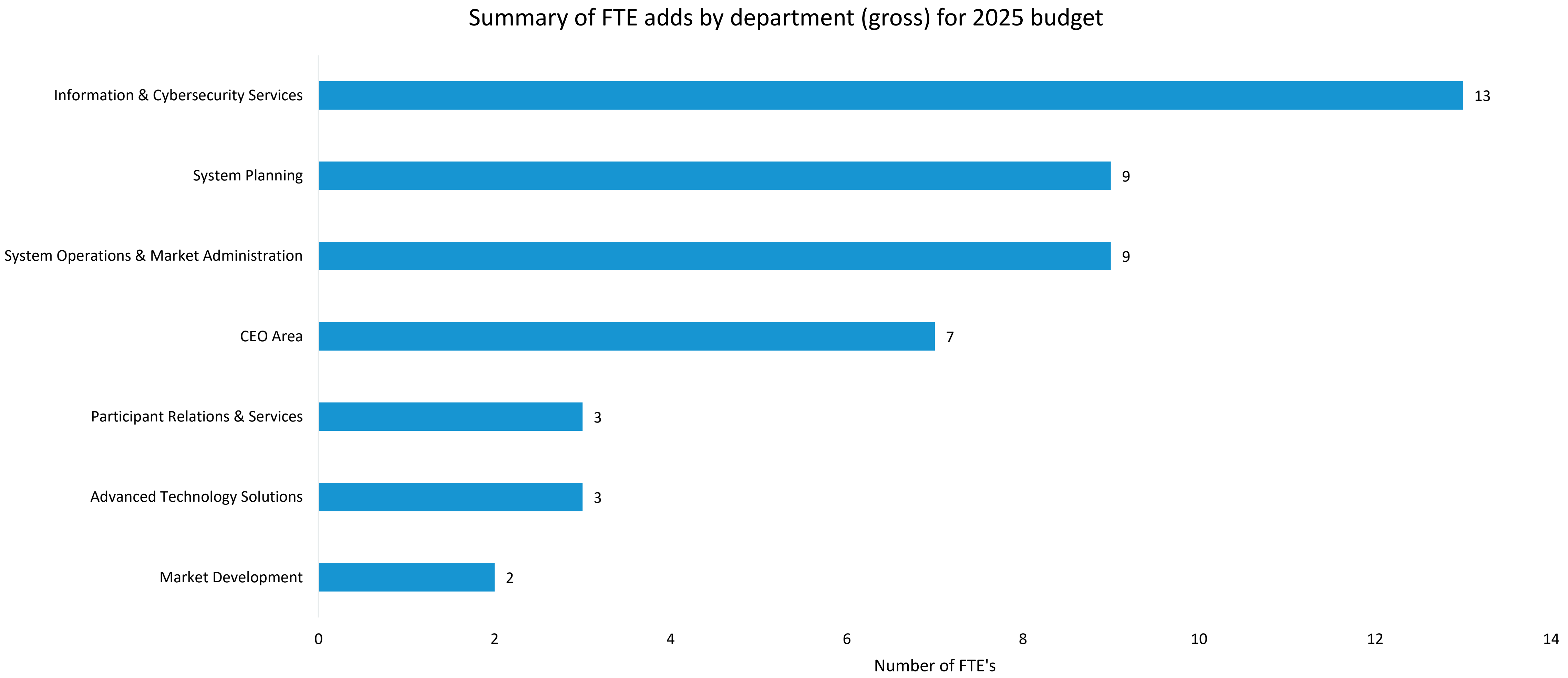
2025 BUDGET RESOURCING NEEDS

2025 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 40 positions, including 4 to-date in 2024, being repurposed for other work where a more urgent need existed
  - Positions repurposed since 2018 include: 9 for Information Technology for Software Development, Cyber Security, Power System Modeling, Application Support, Infrastructure and Digital Transformation; 7 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; 2 for Participant Support; 2 for Corporate, Media, and Digital Communications; 1 for Load Forecasting to replace a contract position; 1 for Resource Studies & Assessments; 1 for Settlements; and 1 for Corporate Strategy

Requested Additional Headcount for 2025



Note: CEO Area headcount additions include those for External Affairs, Human Resources, Finance, Market & Credit Risk, and Legal

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows:

		Clean Energy Pillar(s) (*)	Strategic Goal(s)
13.0 FTEs	**Information and Cyber Security Services**		
	Resources to support advanced technology solution tools as well as the Integrated Market Simulator, Prompt/Seasonal Markets; Development efforts including the nGEM system, and integration of Day Ahead Ancillary Services; IT Architecture to support leveraging cloud technologies; infrastructure support to alleviate understaffing pressures; and resources to break teams into smaller pods that support the growing number of IT products and services (7 FTEs Support the Clean Energy Transition)	N/A	Operational Excellence; Responsive Market Designs; Progress and Innovation
9.0 FTEs	**System Planning**		
	Resources to support continued growth and development of PSCAD modeling capability, Resource Capacity Accreditation and use of probabilistic analysis, to accommodate evolving study and forecasting needs and increased complexity associated with the clean energy transition, resources to support expected increases in transmission RFPs, support stakeholder requests for long-term transmission studies, to address FERC order on long-term transmission planning for asset condition based replacement and future-sizing of the transmission system (9 FTEs Support the Clean Energy Transition)	Energy Adequacy; Balancing Resources; Robust Transmission	Progress and Innovation; Operational Excellence; and Attract, Responsive Market Design
9.0 FTEs	**System Operations and Market Administration (SOMA)**		
	Resources to support the evolving project needs of the SOMA department, support improvements to Outage Coordination, and additional analytical requirements to perform complex and evolving Electromagnetic Transient analyses; resources for the performance of energy analysis across varying time horizons, and for Operations Training coordinate with SOMA business groups to proactively identify gaps and challenges with integrating significant amounts of clean energy and energy storage to work with Advanced Technology Solutions and IT to develop necessary tools and solutions (9 FTEs Support the Clean Energy Transition)	Clean Energy Resources; Energy Adequacy	Responsive Market Designs; Operational Excellence; Progress and Innovation

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

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows: (cont.)

3.0 FTEs Advanced Technology Solutions	**Clean Energy Pillar(s)**	**Strategic Goal(s)**
Resources to serve as the company-wide SME on synchrophasor technology, conduct research and development on emerging power system issues such as large scale renewable integration, and resources to analyze and assess market designs or operations processes to include the development of models for market design and optimization problems (3 FTEs Support the Clean Energy Transition)	Clean Energy Resources; Energy Adequacy	Progress and Innovation
3.0 FTEs Participant Relations & Services		
Resources to conduct data analysis of key trends embedded in participant inquiries to discover critical knowledge gaps, resources to provide required technical readiness and real-time support to participants on notable corporate initiatives scheduled for 2025/26 and an additional resource to address the required development of new and increasing participant training needs for new initiatives and products (3 FTEs Support the Clean Energy Transition)	Robust Transmission	Stakeholder Engagement
2.0 FTEs External Affairs		
Given the increasing expectations from the New England states to have the ISO provide support in achieving their state policy goals, the External Affairs team is being called upon increasingly to support substantive interactions with the states and facilitate engagement of ISO SMEs on matters related to renewable and clean energy development. One resource is to oversee the day-to-day responsibilities of the team's state policy advisors and one resource to enable more substantive interactions with the states and alleviate the need for involvement from SMEs. (2 FTEs Support the Clean Energy Transition)	Clean Energy Resources	Stakeholder Engagement

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows: (cont.)

	Clean Energy Pillar(s)	Strategic Goal(s)
2.0 FTE Market Development		
Resources for increasing data analytics capacity and capability, focused on Prompt/Seasonal Capacity Market, Resource Capacity Accreditation Reforms, and future Flexible Response Services, as well as ongoing data-intensive priority work on Storage Modeling Enhancements, Multi-Interval Optimization, and other projects (2 FTEs Support the Clean Energy Transition)	Support	Responsive Market Designs
2.0 FTE Human Resources		
Resources to support department and organizational change and effectiveness efforts, foster a diverse, inclusive and engaging work environment, as well as centralizing coordination of learning activities and administration into a single role (1 FTE Supports the Clean Energy Transition)	Support	Attract, Develop, and Retain Talent
1.0 FTE Finance		
For a FinOps Manager to provide financial and analytical support, assist in the development of department budgets as well as act as a liaison between IT departments and the finance and budget departments	Support	Operational Excellence
1.0 FTE Market & Credit Risk		
For an experienced credit analyst to assess and monitor the creditworthiness of banks and market participants due to changes to the Financial Assurance Program (FAP) made in 2023 as well as planned changes to the FAP regarding parental/affiliate guarantees in the Forward Capacity Market (pending FERC approval)	Robust Transmission	Operational Excellence
1.0 FTE Legal		
Support for growing legal needs in Human Resources including employee relations and benefit plan changes	Support	Attract, Develop and Retain Talent

46.0 FTE's Total 2025 Proposed FTE Additions

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 and to accommodate the expanded workspace, ISO has increased the capital spending over the last few years with spending of $35M in 2024, and increasing to $42.5M in 2025, and at a $40M level in 2026 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, ever 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 shouldered by each ISO individually
- With the completion of the infrastructure and the day-ahead version of the new market clearing engine (MCE) in 2023, the ISO is continuing work on the complex processes for customizing and implementing the next phases, which include the infrastructure and real-time version of the MCE; this work is expected to continue until 2026 with an estimated cost of $15M
- Additional phases for nGem are expected in 2025 thru 2028 with an estimated cost of $45M

(*) nGEM Platform Replacement is a multi-year initiative that will advance multiple strategic goals, including Responsive Market Designs, Progress and Innovation, and Operational Excellence. The initiative will require significant investment (over $15M) and, as such, is being flagged consistent with the enhanced process for Board overview of significant and multi-year capital projects.

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts

- The capital budget will support ISO's market design objectives for 2024 and beyond of moving toward clean energy, balancing resources, energy adequacy, and robust transmission
- Many of these 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 2025 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

Forward Looking Capital Budget Spending *(cont.)*

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

- Significant Capacity Market Reforms: The ISO is currently recommending the move 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
- Managing Transmission Line Ratings: 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 $40M - $60M over the next five plus years

Forward Looking Capital Budget Spending *(cont.)*

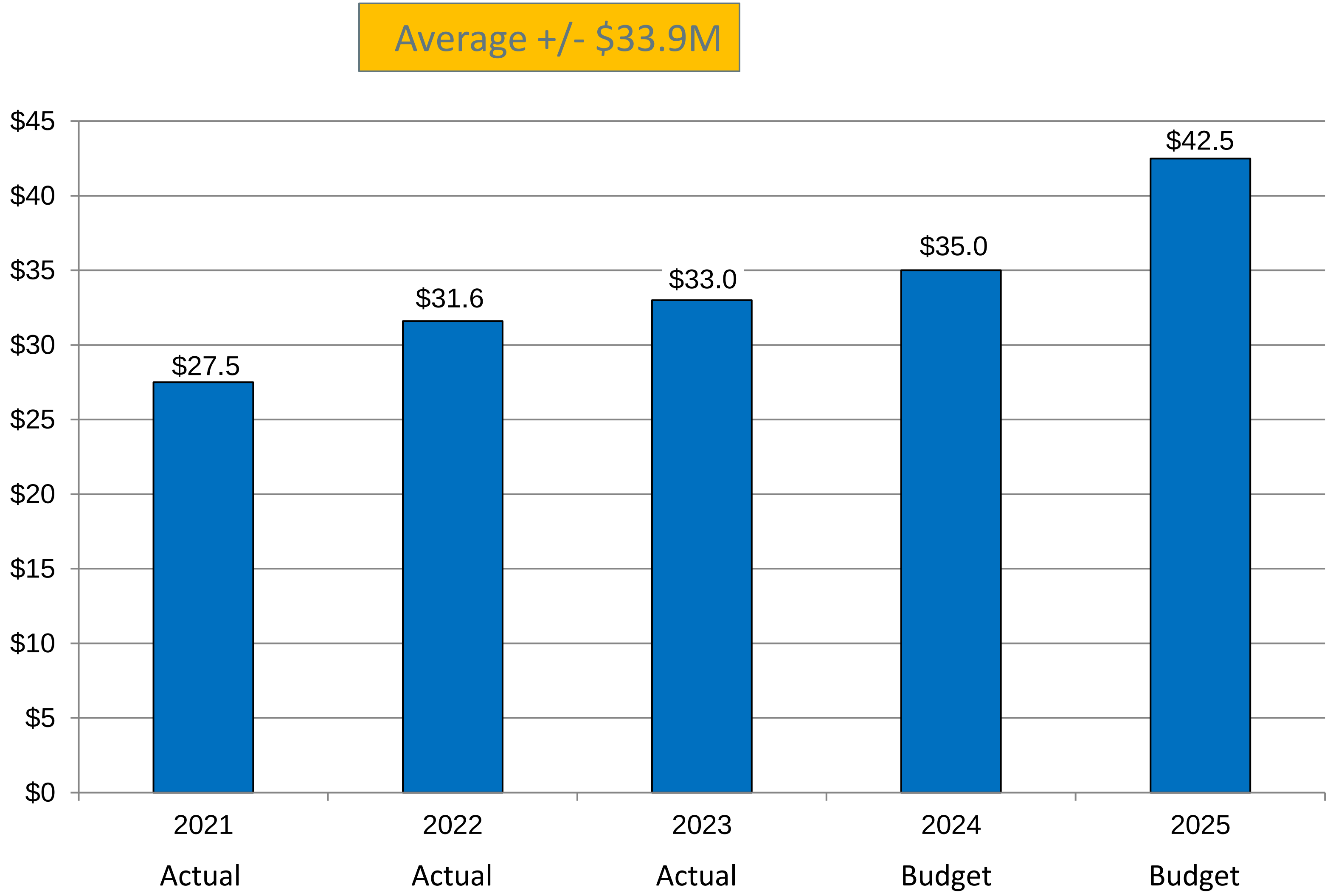
Cyber Security & IT Asset and Infrastructure Replacement

- 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
- ISO's cyber security maturity level has been an ongoing major investment and will continue over the next 3 - 5 years; ISO has greatly benefited from earlier investments in this area and is now able to layer improved defense, network segmentation, email and web filtering to improve 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



Capital Budget
2025 Expenditures

Goal: Responsive Market Designs

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. FERC Order 841	$2.0 M	$2.2 M	10/25	Conceptual Design
. Day-ahead Ancillary Services Improvements	$1.5 M	$9.1 M	03/25	In Development
. FERC Order 2222	$1.0 M	$6.0 M	11/26	Conceptual Design
. Solar Do Not Exceed Dispatch Phase III	$0.3 M	$0.3 M	11/25	Conceptual Design
. Storage as Transmission Only Asset	$0.4 M	$1.4 M	03/27	Conceptual Design
Total:	**$5.2 M**			

Goal: Progress and Innovation

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. nGEM Real-Time MCE Implementation	$4.7 M	$14.7 M	05/26	In Development
. nGEM Software Development Part III	$2.6 M	$4.5 M	03/25	In Development
. Integrated Market Simulator Enhancement	$1.5 M	$1.5 M	12/25	Conceptual Design
. nGEM Software Development Part IV	$1.0 M	$2.0 M	06/26	Conceptual Design
. EMS Short-term Load Forecast Replacement	$0.1 M	$1.4 M	01/25	In Development
Total:	**$9.8 M**			

Capital Budget
2025 Expenditures *(cont.)*

Goal:Operational Excellence

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Space Utilization Project Phase I	$2.0 M	$3.0 M	08/25	Conceptual Design
. Microsoft 365 Service Adoption	$2.0 M	$3.0 M	12/25	Conceptual Design
. Enterprise Core Network Refresh	$2.0 M	$2.0 M	12/25	Conceptual Design
. Enterprise Resource Planning System Replacement	$1.9 M	$4.1 M	12/25	Conceptual Design
. Managing Transmission Line Ratings	$1.7 M	$7.7 M	06/25	In Development
. EMP 3.5 Upgrade	$1.5 M	$5.5 M	12/26	Conceptual Design
. Windows Server Replacement Phase II	$1.5 M	$1.7 M	12/25	Conceptual Design
. CAMS Application Software Technology Upgrade	$1.4 M	$1.7 M	12/25	Conceptual Design
. MW Dependent Fuel Price Adjustment	$1.0 M	$1.1 M	11/25	Conceptual Design
. 2025 Issue Resolution Project	$0.8 M	$0.8 M	09/25	Conceptual Design
. Control Room Tie Line Telemetry and PCEC Upgrades Phase II	$0.5 M	$0.5 M	09/25	Conceptual Design
. Network Modeling Tool Enhancements	$0.4 M	$1.3 M	06/25	In Development
. Circuit Inventory Management Platform	$0.4 M	$0.6 M	10/25	Conceptual Design

Continue to the next page

Capital Budget
2025 Expenditures *(cont.)*

Goal:Operational Excellence

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. CIP Electronic Security Perimeter Redesign Phase II	$0.4 M	$5.2 M	05/25	In Development
. Replace Employee & Pager Application	$0.3 M	$0.4 M	10/25	Conceptual Design
. Adoption of NERC CIP Compliance of Synchrophasor Systems	$0.3 M	$1.0 M	10/26	Conceptual Design
. Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements	$0.2 M	$0.9 M	08/25	In Development
. New England Clean Energy Connect	$0.1 M	$0.2 M	10/25	Conceptual Design
. Non-Project Capital Expenditures	$5.0 M			
Total:	**$23.4 M**			

Capital Budget
2025 Expenditures Summary

- 2025 Capital Budget Expenditure Summary

Allocation Category	2025 Budget
Goal: Responsive Market Designs	$5.2 M
Goal: Progress and Innovation	$9.8 M
Goal:Operational Excellence	$23.4 M
Other Emerging Work	$3.1 M
Capital Interest	$1.0 M
Total:	**$42.5 M**

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 $35M in 2024 to $42.5M in 2025, and at $40M in 2026 and beyond
  - 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; consequently, ISO worked through the stakeholder and Board process to get approval for $75M Private Placement Note and is working to complete the offering in Q3 of 2024

Capital Structure and Cash Flow *(cont.)*

The ISO received FERC approval on July 19, 2024 to enter into $75M Private Placement Note. The ISO is current in the process of going out to market to secure funding that will be issued and available by the time the $50M balloon payment on the current note is due in November.

ISO New England
2024 - 2028 Debt Service Cash Flow

	2024 Forecast	2025 Budget	2026 Forecast	2027 Forecast	2028 Forecast
Cash flows from operating activities:					
Operating Cost Recovery *	$ 228,956	$ 268,509	$ -	$ -	$ -
Non Cash Items:					
Depreciation, Amortization & G/L on Disposals	32,659	36,975	42,132	40,296	39,786
Amortization Term Loan Fees	61	96	96	96	96
Chg in Deferred Revenue-Depreciation	(100)	-	-	-	-
Chg in Accrued Expenses	120	-	-	-	-
Interest Expense	(3,570)	(4,475)	-	-	-
Operating Expenses, net of CEO Emerging Work & Allowance & Board Contingency *	(233,487)	(264,859)	-	-	-
Net cash provided by operating activities	24,639	36,247	42,228	40,392	39,882
Cash flows from investing activities:					
Capital expenditures	(35,000)	(42,500)	(40,000)	(40,000)	(40,000)
Net cash used in investing activities	(35,000)	(42,500)	(40,000)	(40,000)	(40,000)
Cash flows from financing activities:					
Net Proceeds/(Repayment) - Revolving Credit Line	-			-	
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)
Net cash provided by (used by) financing activities	21,820	(3,180)	(3,180)	(3,180)	(3,180)
Net increase/(decrease) in cash	11,459	(9,433)	(952)	(2,788)	(3,298)
Cash & Cash Equivalents on Hand - Beginning of Period	16,207	27,666	18,233	17,281	14,493
Change in Cash & Cash Equivalents Available	11,459	(9,433)	(952)	(2,788)	(3,298)
Cash & Cash Equivalents on Hand - End of Period	$ 27,666	$ 18,233	$ 17,281	$ 14,493	$ 11,195
Debt Maturity Schedule					
Tax Exempt Bond - BCC	1,360	1,360	1,360	1,360	1,360
Tax Exempt Bond - MCC	1,820	1,820	1,820	1,820	1,820
Total Year Repayment	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180

*= Operating Cost Recovery for 2024 has decreased by an overcollection in 2022 of $3,006 which was not amortized in 2023 but included in the 2024 tariff. The undercollection of $4,844 for 2023 will be filed with the 2025 tariff and will be reflected in the Operating Cost Recovery for 2025. The Operating Cost Recovery for 2026-2028 is projected to offset Operating Expenses for 2026-2028. The Operating Cost Recovery amount for 2026-2028 has not yet been established at this point.

Capital Structure and Cash Flow *(cont.)*

- The ISO currently has two revolving credit lines with TD Bank that are set to expire July 1, 2028; the first is a $40 million working capital line to support the ISO's short-term operational needs and cash flow risks, which may include draws to support lower than projected load driving decreased Tariff collections, a continued increase in budgetary needs over the next 3 - 4 years, and more recently the issuance of FERC Order 2023 which may increase withdrawals of system impact studies (i.e., reducing cash available to the ISO); the second is a $4 million line to support the short-fall funding arrangements necessary to support twice- weekly billing of the ISO New England markets
- For the six months ended June 30, 2024, the ISO's total weighted average cost of capital was 4.04%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

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 used for 2025 are Mercer, WorldatWork, WillisTowersWatson, and Payscale
  - 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, 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 Slide 90, ISO engaged a compensation consulting firm 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 assessed another 1/3 of the organization, with continued focus on IT and other roles requiring significant technical expertise
  - In 2024 and 2025, 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 regarding budgeted merit and promotional/equity increases (if any) 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	
2025	Not yet available	Not yet available	**3.0 – 4.0%**	Not yet available	Not yet available	**2.0 – 3.0%**
2024	3.7% - 4.0%	3.5% - 3.7%	**4.0%**	0.0% - 0.5%	0.5% - 1.0%	**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%**

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
- The clean energy transition has increased the demand for highly specialized personnel required to address the modeling, analysis, processing, and operational needs of the transition
  - Hiring and retaining highly specialized technical talent has become more challenging and costly
- 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, will require the requisite staff to complete this work

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
- 2025 Budget for Executive Salaries $5.2M
  - Executive Salaries comprise the base salaries of the officers on the IRS Form 990

Pension and Defined Contribution Benefit Plans in 2025

- 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 2025 *(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. ISO is in process of having this analysis refreshed and preliminary results show $10,000,000 continues to be an appropriate level of funding to cover the service cost of the plan and the fluctuating interest rate environment
  - The Pension Plan expense that is included in the 2025 budget is $10,000,000 compared to the projected FAS expense of $5,480,000

Postretirement Medical Benefit Plan in 2025

- 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 2025 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, 2024 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 5.33%
  - Salary Scale assumption (weighted Avg.) 3.00%
  - Projected 2025 annual earnings rate 6.25% (approximately)
- The calculated FAS expense amount for the Postretirement Benefit Plan of $880,000 is included in the 2025 budget

APPENDIX 2: 2025 OPERATING BUDGET RISKS

2025 Operating Budget Risks

- Additional funding may be required to enhance new models to study extreme weather and contingencies; to conduct new studies related to the integration of variable resources and emerging technologies; and for long-range transmission planning studies including request for proposals (RFP) process for finding competitive solutions to identified transmission needs in the region
- Resources may be needed as operations evolve (e.g., energy forecasting, load management) due to the changing resource mix occurring
- Information Technology software licensing and maintenance costs, and cloud migration costs 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

APPENDIX 3: 2023 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

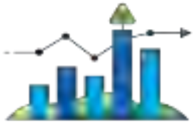
In 2023 the ISO Delivered on a Large Number of Complex and Novel Initiatives Addressing the Clean Energy Transition

ISO initiatives illustrate our commitment to advancing our vision to support the region's clean energy transition

Clean Energy Pillar

- Supported the changing grid and adapted to increasing system complexity through:
  - Acquiring new and more granular data about weather and end-use customer behavior
  - New modeling techniques to assimilate increasingly complex data sets
- Supported policy-makers considerations about how to achieve the goals of the clean energy transition
  - 2050 Transmission Study
  - Economic Planning for the Clean Energy Transition (EPCET)

Balancing Resources Pillar



- Filed Day-Ahead Ancillary Services Initiative (DASI)
- Completed an internal assessment of moving to a prompt and/or seasonal capacity market construct
- Took significant steps to reform how ISO accredits resource capacity with its Resource Capacity Accreditation work

In 2023 the ISO Delivered on a Large Number of Complex and Novel Initiatives Addressing the Clean Energy Transition

ISO initiatives illustrate our commitment to advancing our vision to support the region's clean energy transition

Energy Adequacy Pillar

- Developed advanced forecasting and modeling processes to drive actionable decision-making around power system needs
  - Quantified region's energy adequacy vulnerabilities
  - Developed Probability Energy Adequacy Tool (PEAT)
  - Established Regional Energy Shortfall Threshold (REST)
- ISO recognized for its leading-edge actions developing a systematic approach to determine risk of extreme weather conditions on energy adequacy
  - ISO employees awarded by EPRI for their work to develop metrics and methods for maintaining grid stability with inverter based resources
  - ISO employees participating in NERC energy adequacy standard drafting effort

Transmission Pillar

- The 2050 Transmission Study highlighted for stakeholders the high value of taking steps in the nearer term to mitigate long-term transmission needs:
  - Encouraged state regulators to further enable demand reductions to reduce peak loads
  - Gave greater consideration to the location and size of new generation
  - Identifies the important incremental upgrades and priorities to address high-likelihood concerns
- Filing on Extended/Longer-Term Transmission Planning Phase 2 accepted by FERC in Q3 2024
  - Enables development of transmission infrastructure to address the findings of a Longer-Term Transmission Study
    - Codifies NESCOE and the ISO's respective roles throughout the process
    - Establishes the cost recovery methodology for resulting transmission
    - Provides for ISO supporting States' RFPs

Responsive Market Designs

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 2023, 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, and the regulation market structurally competitive.

In 2024, ISO filed and obtained approval from FERC to implement changes for the 2024 Forward Reserve Auction to address previous years' findings that the Forward Reserve Market (FRM) was structurally uncompetitive.

Note: *See IMM 2023 Annual Markets Report for detail*

2025 continue to focus 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*
- Implemented Day-Ahead nGEM Platform in 2023

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 2024, ISO filed and obtained approval from FERC to enhance longer-term transmission planning program

Interconnect and register new resources to meet FERC established timeframes
- Order 2023 Reporting metrics (to be implemented)
- Analyzing the impacts of FERC Order 2023 on the interconnection process
- Streamlined DER process through transferring all distribution system interconnection to state processes

2025 focus is on integrating recent studies and analyses into 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)

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 SOC 1 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.

2025 focus is on improving business operations across organization

- Implement internal process and technology improvements to address increasing grid complexity, including:
  - Broadening usage of ISO-developed innovations to enhance control room situational awareness and market efficiency
  - Addressing the trend of increasing DER/decreasing springtime load
  - Examining the single-source contingency limit
- Continue to modernize IT assets, technologies, and tools to mitigate cybersecurity threats
- Migrate ISO systems to the cloud

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
  - Hired for position to focus on environmental policies and community outreach in 2024
- 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 New England States' 2020 Vision and policy initiatives:
  - Request to evaluate clean energy pricing (Pathways report)
  - Request to conduct longer-term transmission planning (Future Grid Reliability Study; 2050 transmission study)
  - Enhancement to longer-term transmission planning process
  - Technical support on States' RFP efforts

- Focus in 2025 includes:
  - Building on novel analyses performed in 2023-24 to update assessments of regional energy adequacy vulnerabilities
    - Regional Energy Shortfall Threshold (REST)
    - Economic Planning for the Clean Energy Transition (EPCET) Study
  - Continue to work with States and stakeholders to improve asset condition process, and establish a criteria for right-sizing transmission investments to support integration of renewables and higher load levels
  - Continue to provide technical support to States, as requested, on clean energy and transmission RFP

APPENDIX 4: CYBER SECURITY AND CIP COMPLIANCE HISTORY AND COSTS

Cyber Security and CIP Compliance

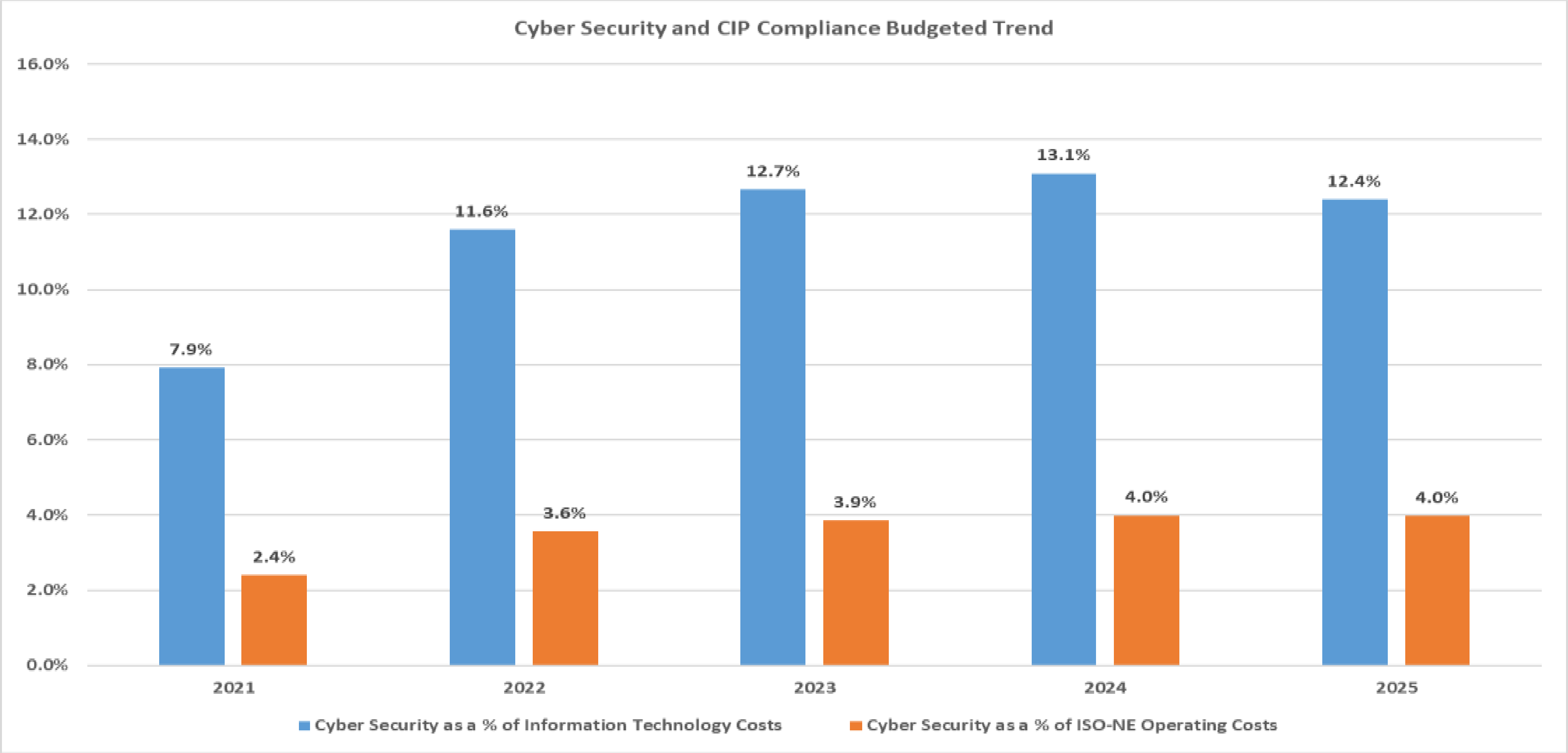
- Background
  - Information technology has become an indispensable tool for efficiently and reliably operating the increasingly complex regional power system, administering the billion-dollar markets where wholesale electricity is bought and sold in New England, and engaging and collaborating with our 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; ISO-NE has tightened security controls for cyber assets and visitors to ISO facilities in compliance with revised NERC CIP cyber security standards
  - ISO-NE developed and implemented a third-party cyber security risk management program that includes compliance with CIP-013 related to Supply Chain Cyber Security Risk

Cyber Security and CIP Compliance *(cont.)*

- 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
- 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; additional alerts and automations to increase the reach and productivity of Security Operations Center staff were developed in 2023 and will continue in 2024
- In 2023, additional security awareness training capabilities were added to address the human element of cyber security regularly
- During 2023 ISO-NE began to incorporate "immutable" technology that prevents modifications to data written to disk for both enterprise storage applications and system backups providing greater resiliency and protection for ransomware-style attacks; in the same year, ISO-NE deployed a technology framework to identify and fix known vulnerabilities more rapidly and to protect applications from emerging threats
- In June 2024, ISO-NE completed its periodic NERC CIP compliance audit with NPCC resulting in zero potential non-compliance (PNC) items, zero areas of concern (AOC), and four positive observations shared jointly with the Operations review

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 - 2023 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2023, and Outstanding Debt as of December 31, 2023 (1)

(Amounts in Millions)

	ISO-NE (2)	PJM	NYISO	CAISO	IESO (3)	MISO	SPP	ERCOT
Operating Expense - 2023	$ 235.6	$ 437.9	$ 231.6	$ 273.4	$ 280.4	$ 449.4	$ 254.9	$ 286.2
Less: Amortization & Depreciation	(30.0)	(37.7)	(17.7)	(28.7)	(24.1)	(30.4)	(16.8)	(34.7)
Regulatory Fees	(7.3)	(81.3)	(17.6)	-	-	(67.4)	(31.3)	-
Grant Expenses	-	-	-	-	-	-	-	-
Net Operating Expense - 2023	$ 198.3	$ 318.9	$ 196.3	$ 244.7	$ 256.3	$ 351.6	$ 206.8	$ 251.5
Other Financial Data								
Capital Expenditures for 2023	$ 35.4	$ 43.2	$ 16.3	$ 20.9	$ 72.6	$ 34.6	$ 14.3	$ 32.4
Outstanding Debt as of 12/31/23	$ 86.6	$ 5.0	$ 73.9	$ 156.7	$ 203.0	$ 274.4	$ 130.7	$ 2,514.0
Actual full-time equivalent headcount as of 12/31/23	625.5	802.0	599.0	710.0	896.0	1059.0	744.0	890.0

(1) Applicable amounts were taken from each entity's 2023 audited financial statements.

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

(3) Amounts are in Canadian dollars

SEPTEMBER 5, 2024

ISO New England Proposed 2025 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 2025 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
- 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:
  - 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 and timing of such needs
- The changes to the grid represent a step-up in system complexity that the ISO began to address in 2024 and will continue ramping-up in 2025 and throughout the remainder of the decade
  - This step-up in complexity represents a considerable increase to ISO workload

Executive Summary *(cont.)*

- In order to carry out ISO-NE'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, it is necessary to develop new capabilities 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 continue increasing headcount in order to meet the complexities of the clean energy transition; this is in line with hiring trends observed across other ISOs
- The budget reflects additional investment in information technology (IT) needed to support operations given the changing resource mix, including: new technology, transition cost related to cloud-based infrastructure, and continued improvements to cyber security
- The budget addresses the inflationary and renewal costs for current IT infrastructure and licensing, labor, and professional fees as well as the year-over-year costs of continued operation

Executive Summary *(cont.)*

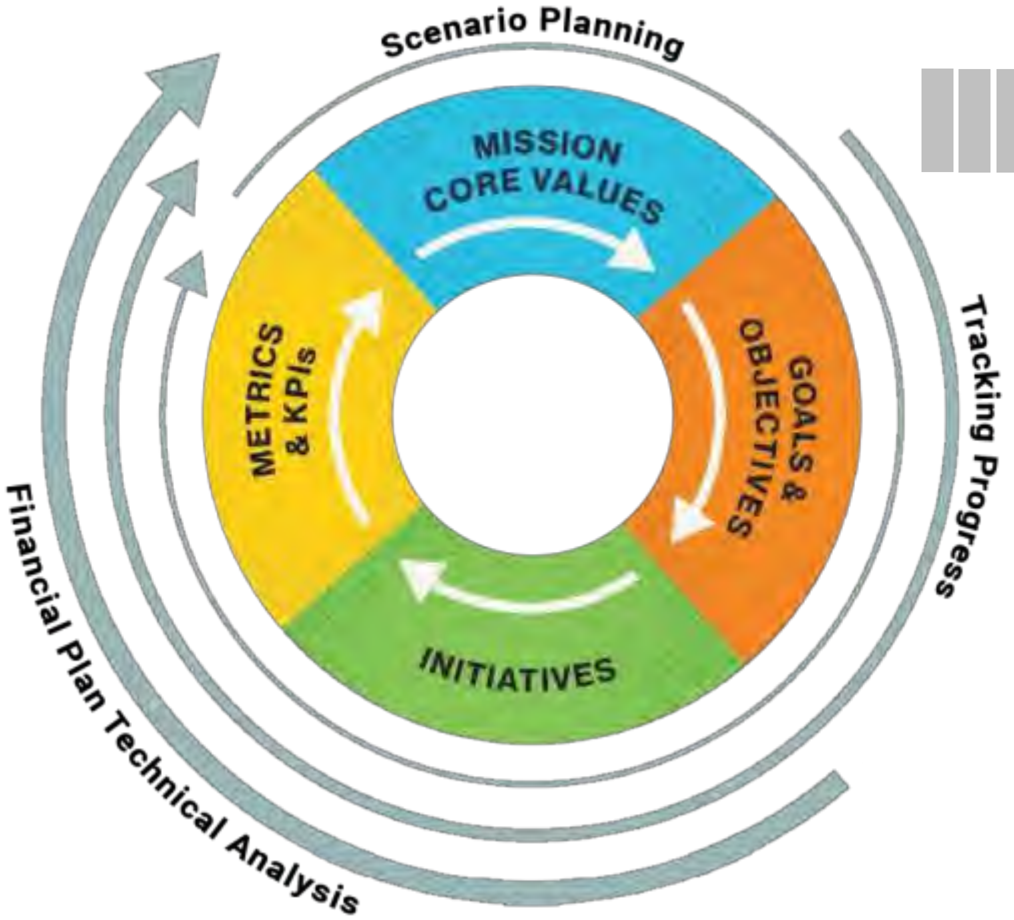
- For the 2025 budget, ISO is proposing adding 46 FTEs driven primarily by:
  - IT support to operationalize internally developed software for market simulation and situational awareness
  - Support the increasingly complex information to stakeholders and the public and to assist the growing and distributed workforce
  - Additions in System Planning for modeling, forecasting, longer-term transmission planning, and addressing current FERC orders;
    - This is the first iteration of a budget representing the need to scale up capabilities in these areas to support the Longer-Term Transmission Studies (LTTS) and necessary tariff changes, as well as the issuance of initiated transmission RFPs that require technical and economic analyses
    - There are still many unknowns, including the volume of RFPs to support and compliance with FERC transmission orders; it is our expectation that the resource requirements will be refined over time as we gain experience with the new processes

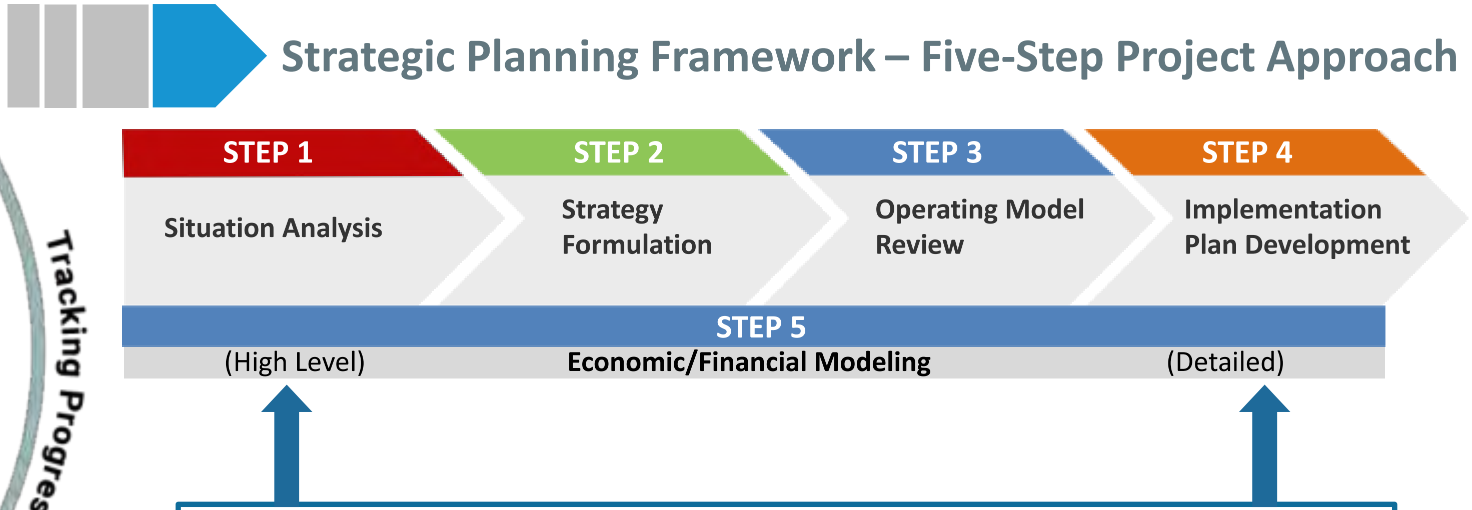
THE STRATEGIC PROCESS

ISO-NE's integrated business and strategic planning framework

Strategic Planning Framework

The 2025 ISO-NE budget represents the needs for the organization's strategy in supporting the region on its path to a decarbonized grid





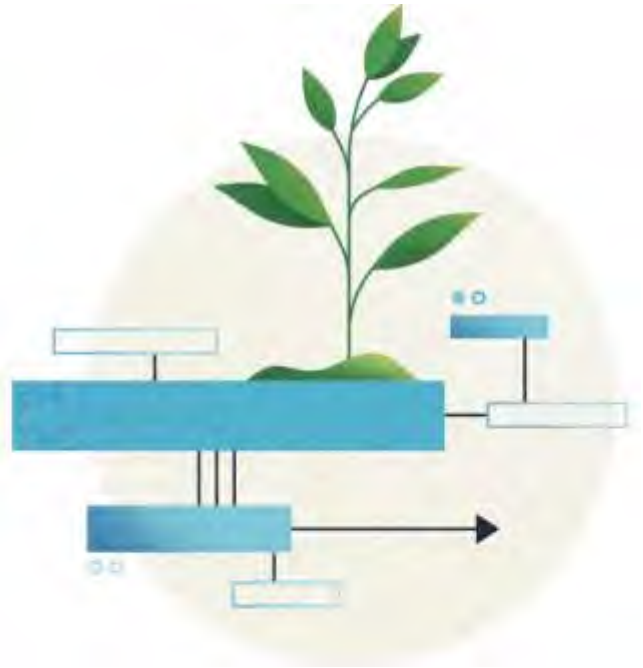
The 2025 budget responds to the emerging needs of the region in achieving their goals of decarbonizing the electric grid

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 and transmission planning



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:

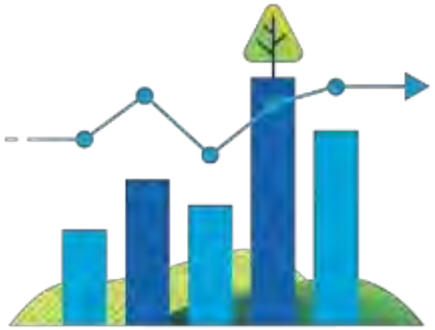
Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

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

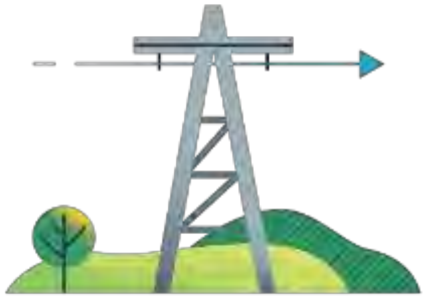


2

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

CLEAN ENERGY TRANSITION & 2040 OUTLOOK

The path to the 2040 (and beyond) decarbonized grid based on state policy goals and assumptions

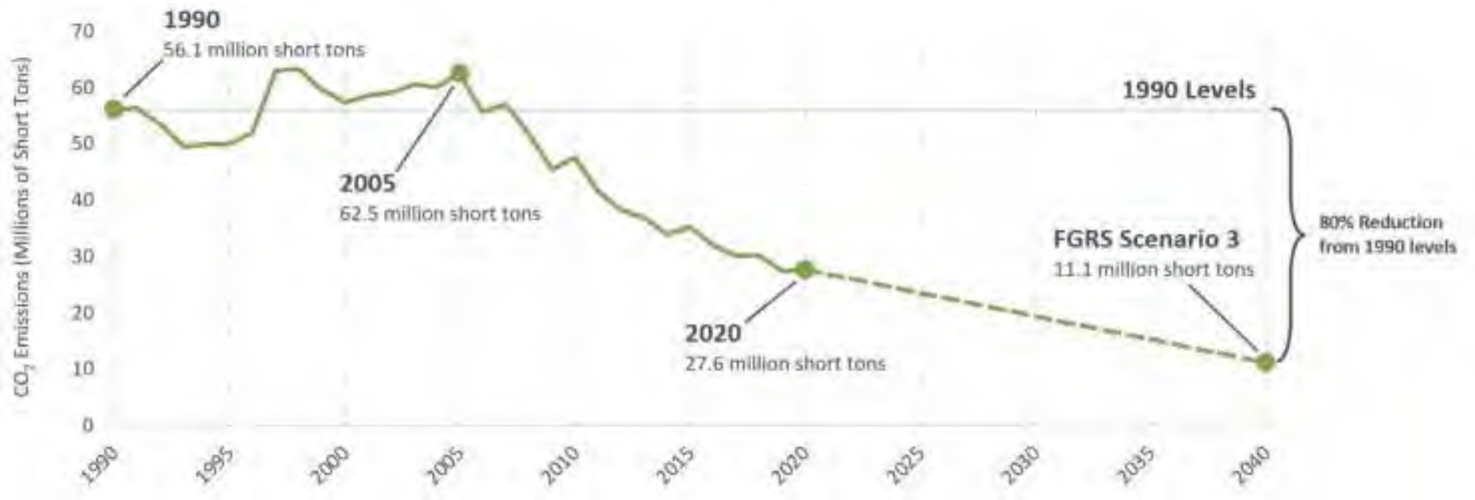
Overview of 2040 Outlook

- Renewables will continue to displace natural gas-fired resources over the next 20 years
  - A shift from centrally dispatched generation to distributed resources
  - A shift from conventional generation to weather-dependent renewable generation
  - Grid will primarily rely on a large number of non-dispatchable, weather-dependent generators, with smaller nameplate capacities
- Significant demand growth as system peak shifts to winter
  - During cold months the system will be at risk of insufficient fuel to support balancing resources (natural gas)
- Escalating variability in supply and demand
  - Most pathways to a low-carbon grid involve high variability in both supply and demand, which will result in either reliability challenges or higher costs
- By 2040, the region could experience consistent negative wholesale energy prices
- As outlined in the ISO-NE 2050 Transmission Study, of the estimated $25 billion needed for transmission upgrades by 2050, upwards of $13 billion will need to be in service by 2040; reducing peak load significantly reduces transmission costs

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

New England has seen progress in lowering emissions in 2021-2023, but 2024 emissions levels are up from the previous year, mainly due to increased demand

Historical and Extrapolated New England CO_2 Emissions

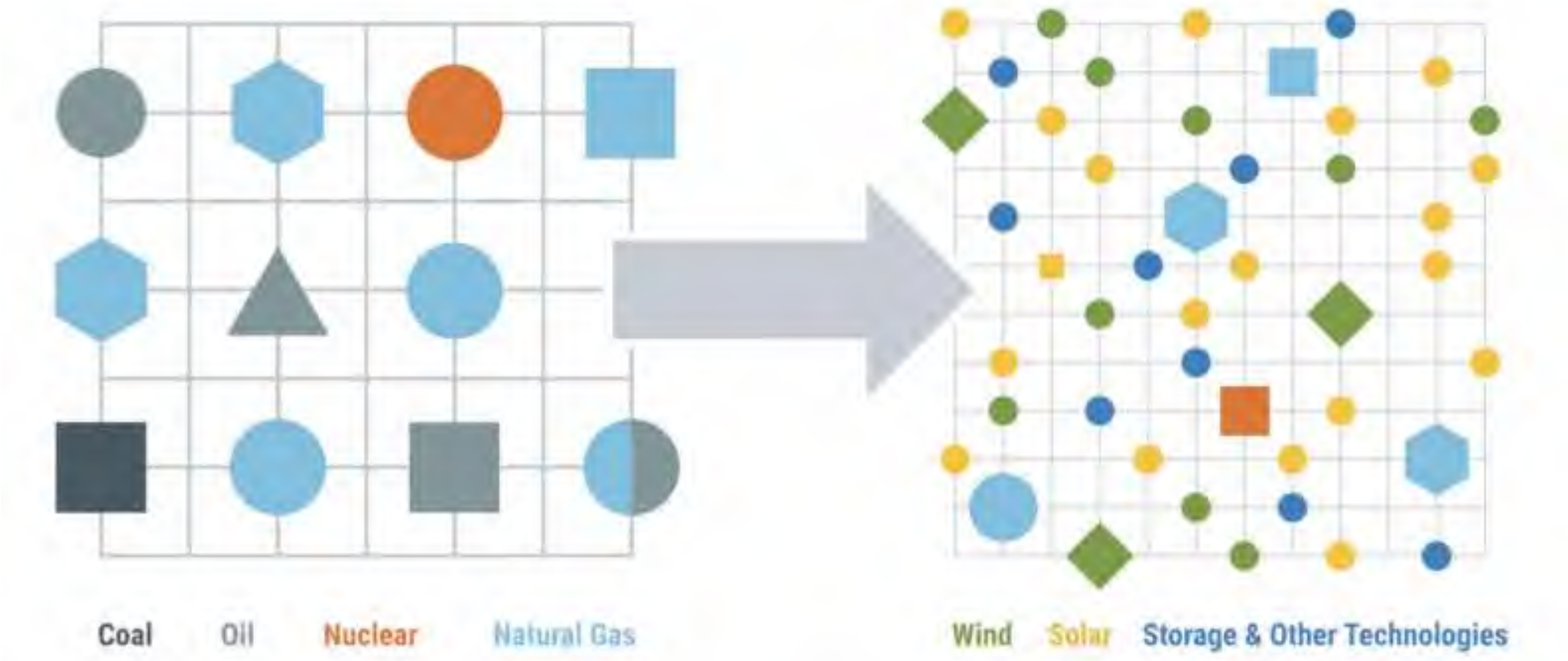


- State policies to address climate change through emissions reduction mandate an 80% reduction from 1990 levels
- These mandates will result in a drastically different generation profile for the region compared to today

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

- To illustrate the grid of 2040, we drew from the following scenario
  - **The Deep Decarbonization scenario** (Scenario 3 or S3) from the Future Grid Reliability Study – derived from the "All Options Pathway" of the Massachusetts 2050 Deep Decarbonization Roadmap Study outlining heavy renewable penetration and increased electrification loads

Two Dimensions to the Transition to Clean Energy that Contribute to Increased Grid Complexity by 2040



1 A shift from centrally dispatched generation to distributed resources

2 A shift from conventional generation to weather-dependent renewable generation

The 2040 Grid will Primarily Rely on a Large Number of Non-Dispatchable, Weather-Dependent Generators, With Smaller Nameplate Capacities

- **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
- **Nuclear resources clearing FCA** assumed to be staying online in 2040
- **0 GWh** of generation produced from coal, oil, or refuse burning generators
- **2 Additional Tie Lines** for imported electricity from Canada, New England Clean Energy Connect (NECEC), plus an additional new tie-line with Hydro Québec

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

Over the next 15 years, in order to meet electrification and clean energy requirements, the region will need to add almost double the amount of new generation as was added to the system in the last 25 years.

Well before the 2040 Outlook (Early 2030s), the ISO Expects to See Substantial Changes to the New England Power System

ISO needs to plan for a power system that by 2030 is projected to be very different than the grid of today:

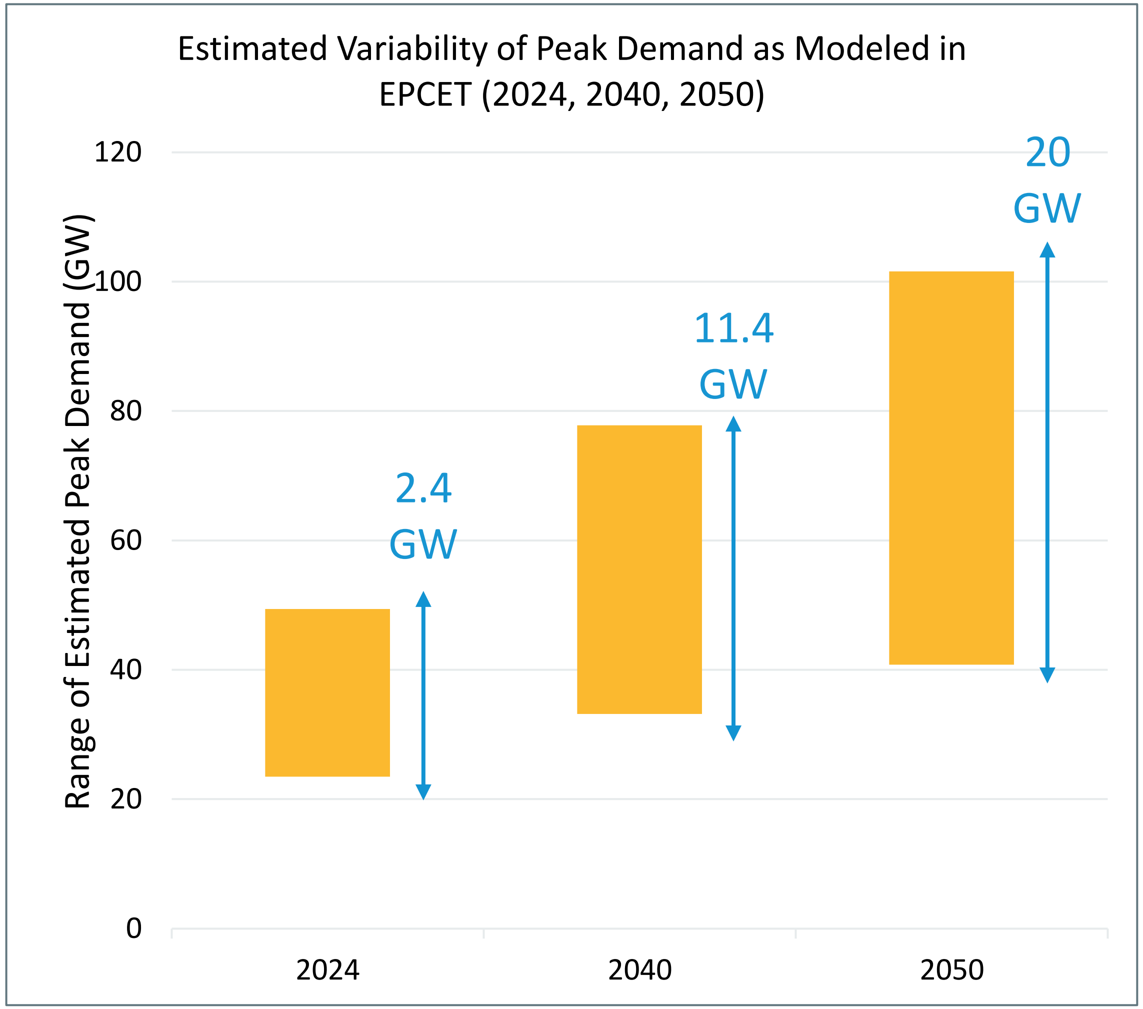
- **Double the installed capacity of solar resources**
- **Development of thousands of MW of offshore wind**
- **Substantial new transmission investment**
  - Supporting inter- and intra-regional transfers, upgrading condition of existing assets, and addressing increasing interaction between transmission and distribution system
- **Enhanced market structures** – accounting for resource mix with different operating characteristics
- **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 BTM generation
  - Increasing load-dependence on weather at a time when weather is becoming more erratic

To support these efforts, the ISO will engage in a slate of work in 2025 and beyond, that directly addresses these developments.

Escalating Variability in Supply and Demand

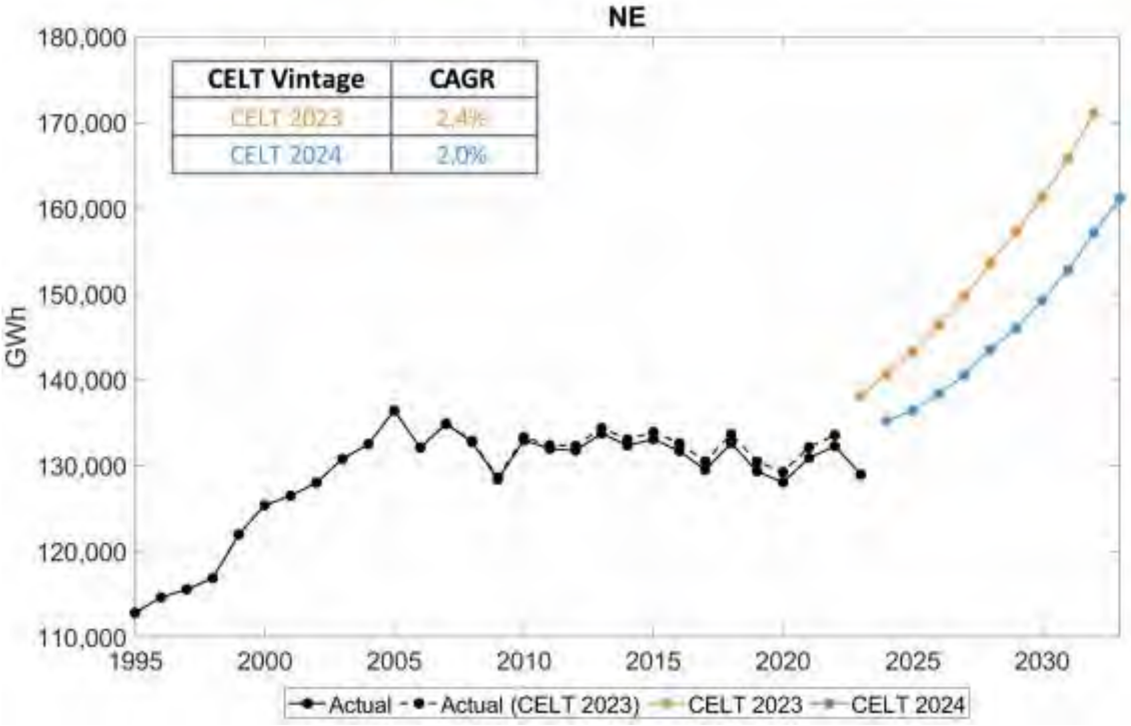
Most pathways to a low-carbon grid involve high variability in both supply and demand, which will result in either reliability challenges or higher costs

- Today's electrical grid experiences only small variations in peak annual demand between years, allowing for efficient planning for a limited number of possible outcomes
- The large variation in demand will require vastly different supply from year to year
  - Some years will require most or all resources to operate; other years, resources will run for just for a few hours of the year, or not at all



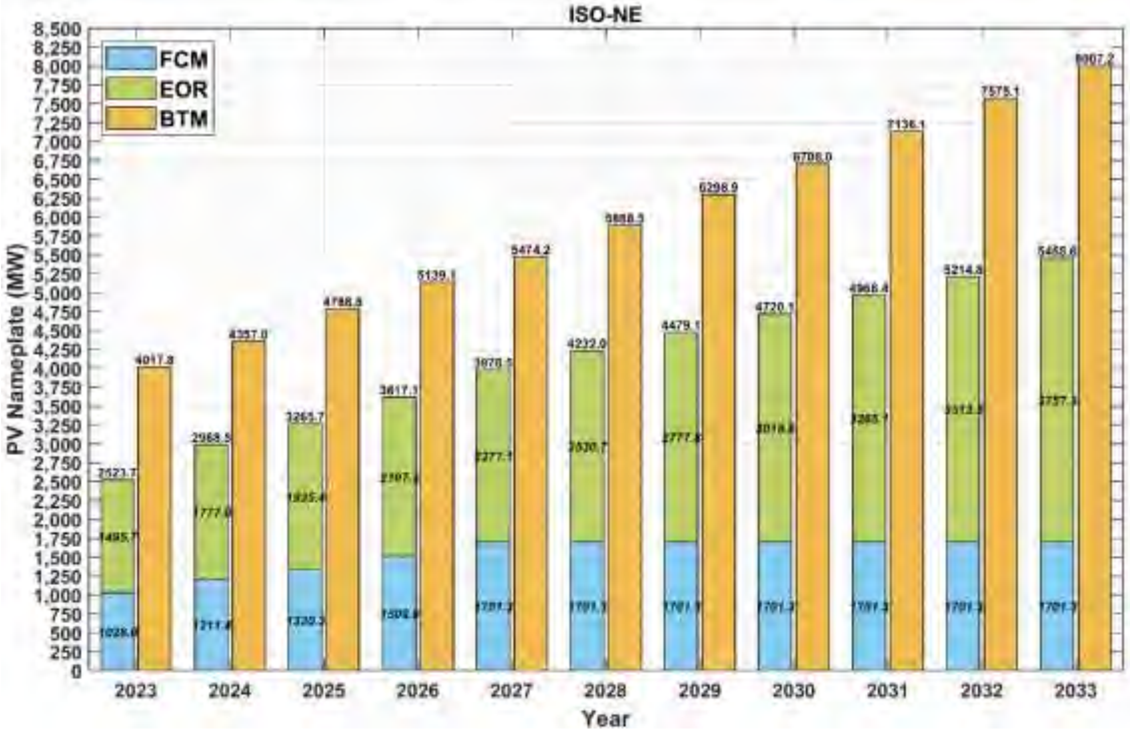
Continued Growth in PV and Peak-Load Estimates Through 2030

Peak load is projected to grow through 2030s



Source: March 2024, Load Forecast Committee: 2024 Final Draft Energy and Seasonal Peak Forecasts

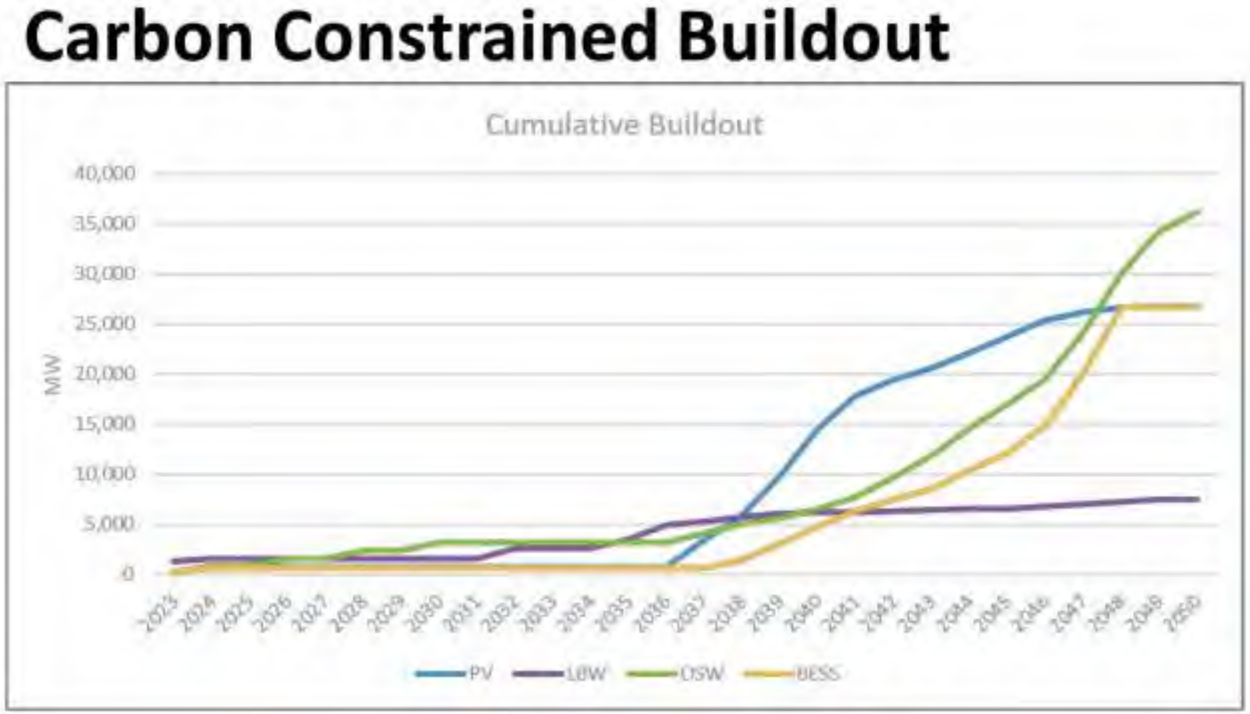
ISO projects PV growth to approximately double over next 10 years



Source: March 2024, Distributed Generation Forecast Working Group: Final 2024 PV Forecast

Grid-level Renewable Capacity Will Need to Increase Substantially in the 2030s

- As load electrifies and grows, carbon constraints require increasing amounts of wind/solar/battery storage
- Despite modeled future systems with significant penetration of wind, PV, and energy storage resources, periods of high net load and depleted energy storage will drive a significant need for dispatchable resources
  - These resources will run less and less over time, but will be relied upon at crucial moments
- The quantities of energy storage needed to ride through wind and PV droughts will be immense

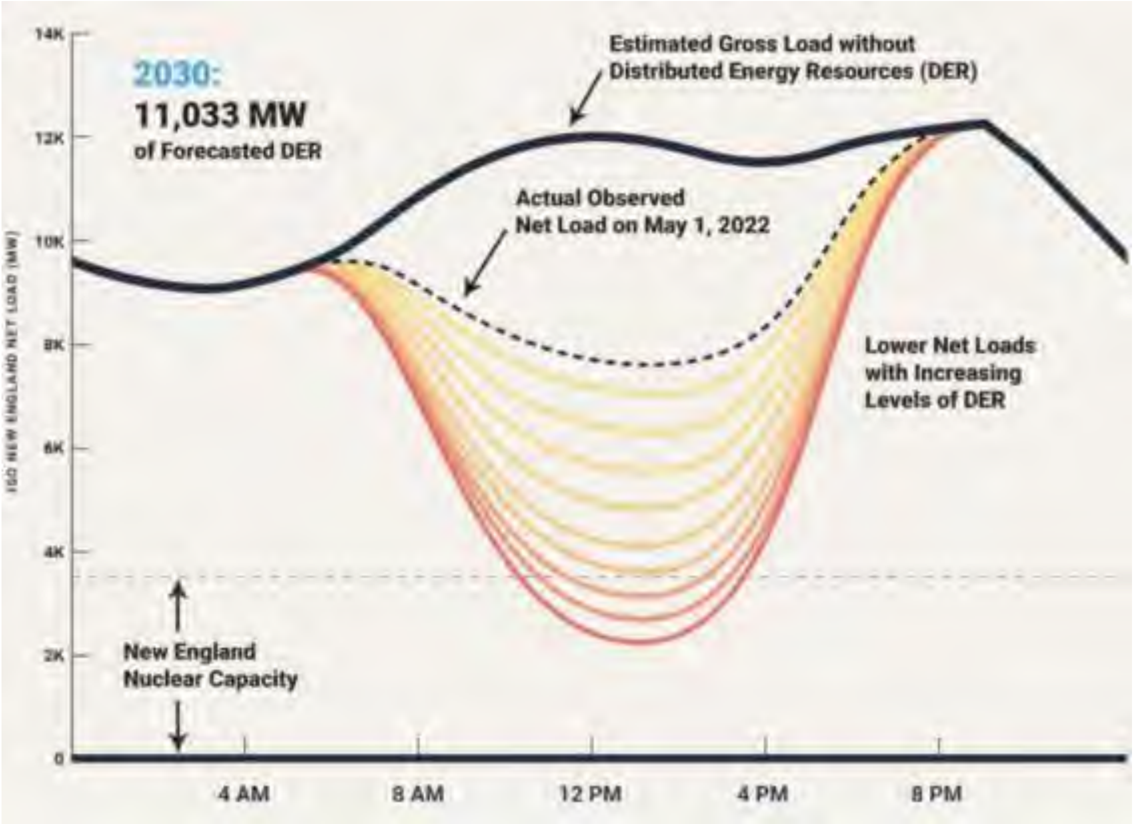


Source: Economic Planning for the Clean Energy Transition

By 2030s, the System May Experience Difficult Conditions with Minimum Load

- Due to increased variability in supply and demand, by the early 2030s the system may experience difficult minimum load conditions, unless demand grows during these periods (e.g., battery charging to take advantage of low/negative prices)
- Potential issues include:
  - Low loads dipping below NE nuclear capacity
  - Transmission system experiences more voltage problems
  - High ramping rates

Behind-the-Meter Solar Reduces Grid Demand



By Early-mid 2030s, Heating Electrification is Expected to Turn the Grid Into a Winter-Peaking System

- Over the next 15 years, the region needs to add almost twice as much new generation as it added in the last 25 years
  - By the early 2030s, the annual energy needed to heat buildings and charge electric vehicles is expected to grow to about 20 times the forecast for 2024
- Long duration storage helps alleviate anticipated problems
  - Higher variability in both supply and demand will increase the value of dispatchable resources
- In the medium term (2030 - 2040) when peak load begins to accelerate, there will be an urgent need for dispatchable capacity on the system
  - Anything that is retired in the short-term may have to be replaced at a larger expense in the medium- to long-term

Timing of Shift to Winter-Peaking System

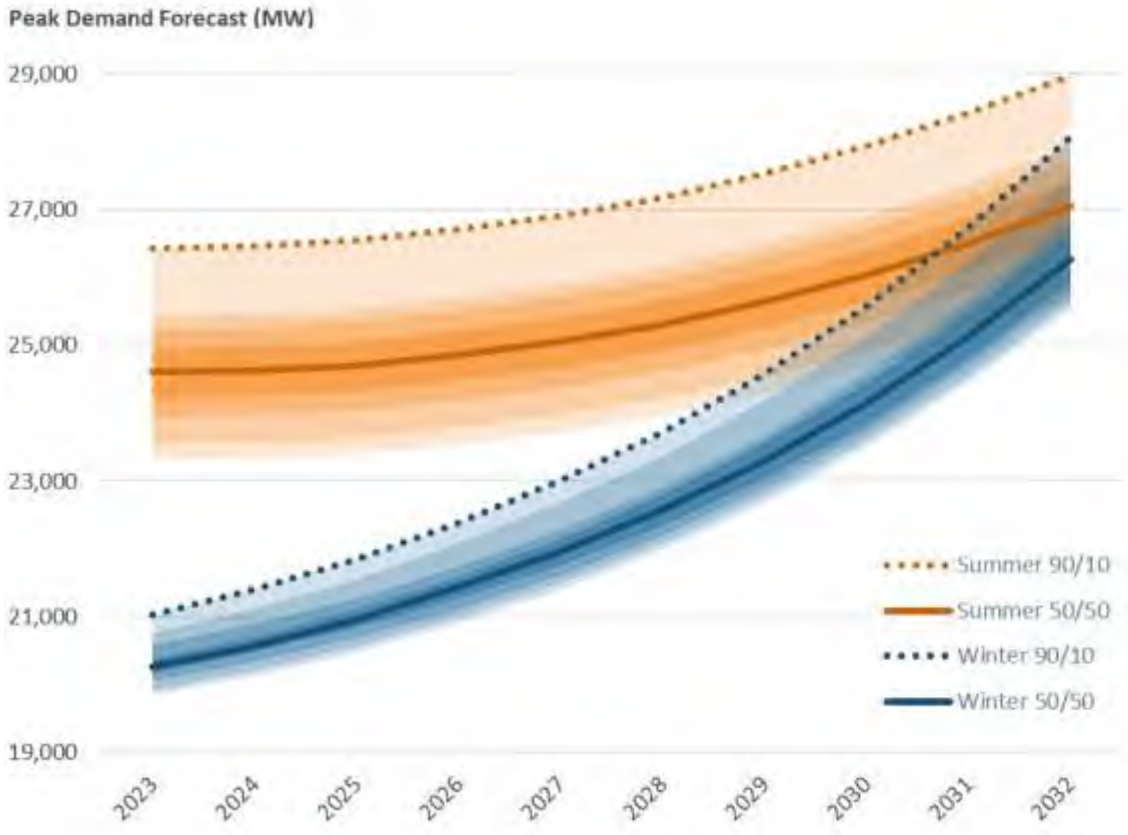


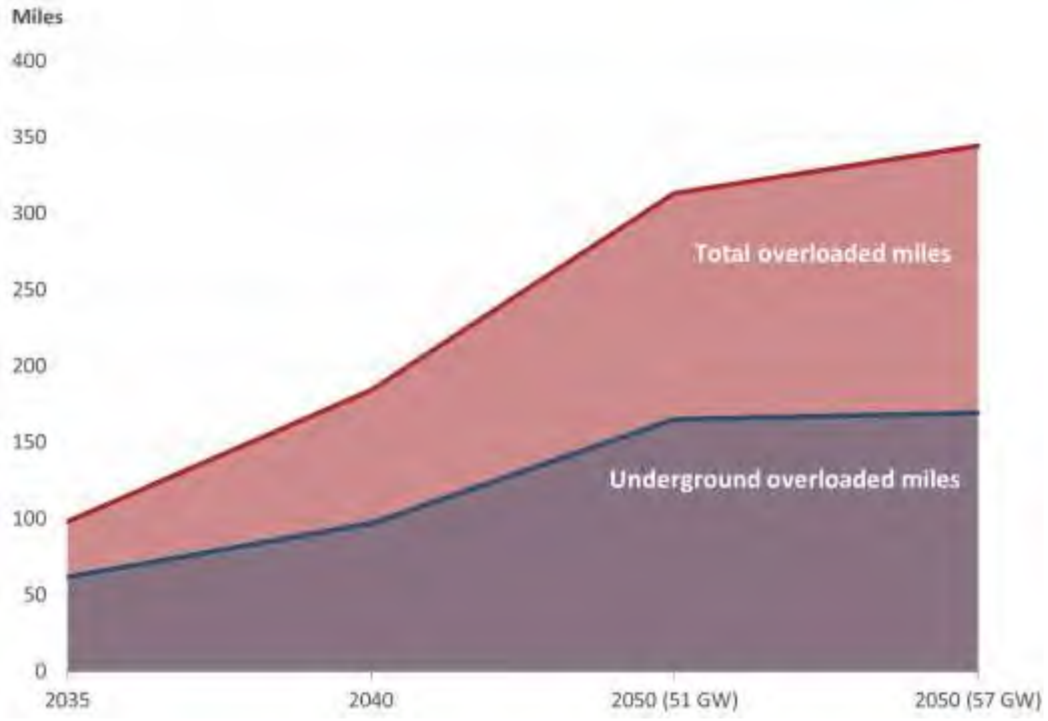
Figure source: 2023 Regional System Plan, Figure 4-9
Data Source: 2023 CELT Report

The Region's Transmission System Will Need Significant Investment

- Assuming pace of renewables continues, and electrification of heating and transportation proceeds as expected, significant upgrades to regional transmission are needed
  - As demand grows over the Clean Energy Transition, the renewable energy to serve that demand will be more geographically dispersed
- Transmission projects that address high-likelihood concerns are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates
- **Transmission projects to serve 2030s should be in planning stage now**
  - The states have recognized the need, driving the creation of the LTTS planning rules
  - The states, assisted by the ISO, have applied for DOE GRIP funding for two projects

Constraints on the distribution system may also present bottlenecks.

Line Mileage Overloaded in Boston with Generator Interconnection Locations Optimized



Source: 2050 Transmission Study, Figure 2-1

To Ensure the Four Pillars are Robust in the Long-Term, We Must Have a Focused Effort to Ramp-Up Capabilities *Now*

- New England is transitioning to a cleaner electric grid in an effort to mitigate the impacts of climate change and meet the need for a reliable, cost-effective and environmentally sustainable bulk electric system
- To ensure this successful transition, the ISO must focus on the near-term and what the organization must do to strengthen reliability today while keeping New England on the path to the clean, reliable grid of the future
- Successful management of this unprecedented transition requires us to look very carefully toward both the short and the long term
  - The short term because we must maintain reliability during the transition to a carbon-free grid, and lay the foundation for the longer term
  - The longer term because we need to make sound decisions now that will help us reach that destination in the most reliable and cost-effective way

In 2025, the ISO has identified a set of initiatives that make progress towards the goals supporting the organization's mission and vision; the 2025 budget represents a needed step-up in preparing for the anticipated changes.

2025 BUDGET OVERVIEW

2025 Budget Overview

- Key drivers supporting the proposed increase are (see further details on the following pages):
  - Continuing to **enhance capabilities to address the modeling, analysis, processing, and communication** needs directly resulting from the clean energy transition
  - **Addressing the effects of inflation** on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation
- The 2025 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 2025 revenue requirement *before true-up* is $306.4M, an increase of 10.7% over 2024; when including the net true-up, an increase of $7.8M, the total revenue requirement increase is 13.6% year over year

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

2025 Budget Overview *(cont.)*

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

- The proposed 2025 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 $0.3 million increase compared to the preliminary top-down version:
  - Increases include: additional funding for regional study work on raising the minimum loss of source value for New England; Information Technology staff augmentation; higher medical renewal rates; and interest expense
  - Decreases, that largely offset the noted increases, include: lower salary rates due to staff turnover; and the removal of capacity auction licensing fees due to FERC approved two year FCA 19 delay

Clean Energy Transition Driving 2025 ISO-NE Budget

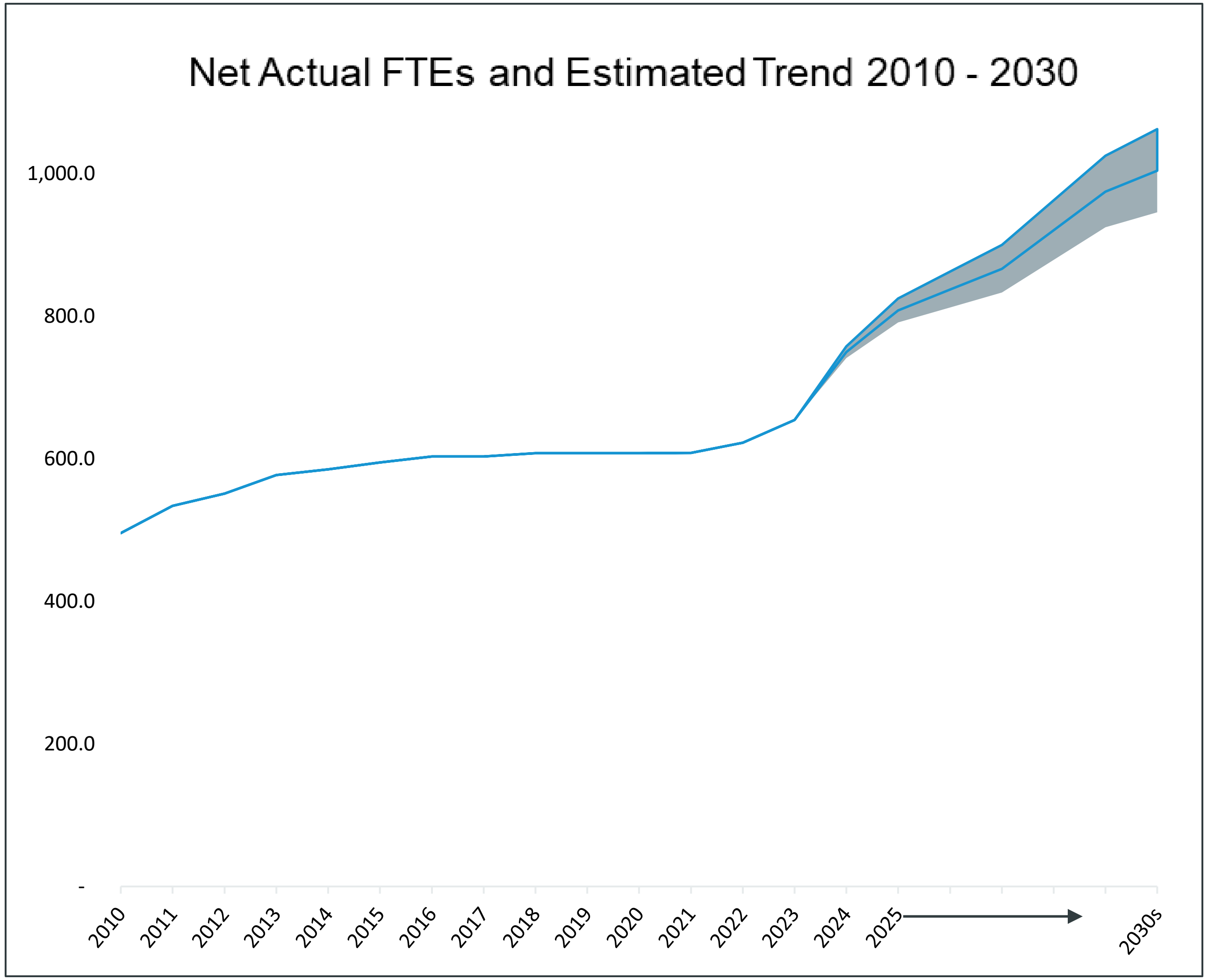
Driver: The main drivers of the 2025 budget are the need to add personnel and make technology investments for the organization to address the modeling, analysis, processing, operational and communication needs directly resulting from the clean energy transition, and includes:

- Continuing to **upgrade our IT infrastructure** to support increasing cybersecurity risk mitigation, data analysis, and rapid technology evolution (often driven by vendors)
  - Capitalize on increased computing power offered through the move to the cloud environment in order to process the volume of data and complexity of analyses that will be needed to support the changing grid
  - Maintaining the internal development and critical software developed by ISO's Advanced Technology Solutions
- **Advancements in modeling and forecasting** to account for net load characteristics and trends that have rapidly evolved in recent years and are anticipated to change even more significantly in the coming decades
- **Market design** work responding to changing system needs, public policies, and new energy technologies
- Development of a team to support **longer-term transmission planning** and administering of transmission RFPs, including analytical support for determining the Benefit to Cost Ratio (BCR) for proposed projects
- Staying compliant with and responding to increasingly **complex federal and state mandates and requests**
- **Investing in more sophisticated operational tools (including updating the EMS)** to support the control room's ability to manage rapidly increasing grid and resource complexity

After Years of Flat Headcount, in 2023, ISO-NE Began Plan to Increase Hiring to Address Clean Energy Transition

Clean energy transition driving FTE needs:

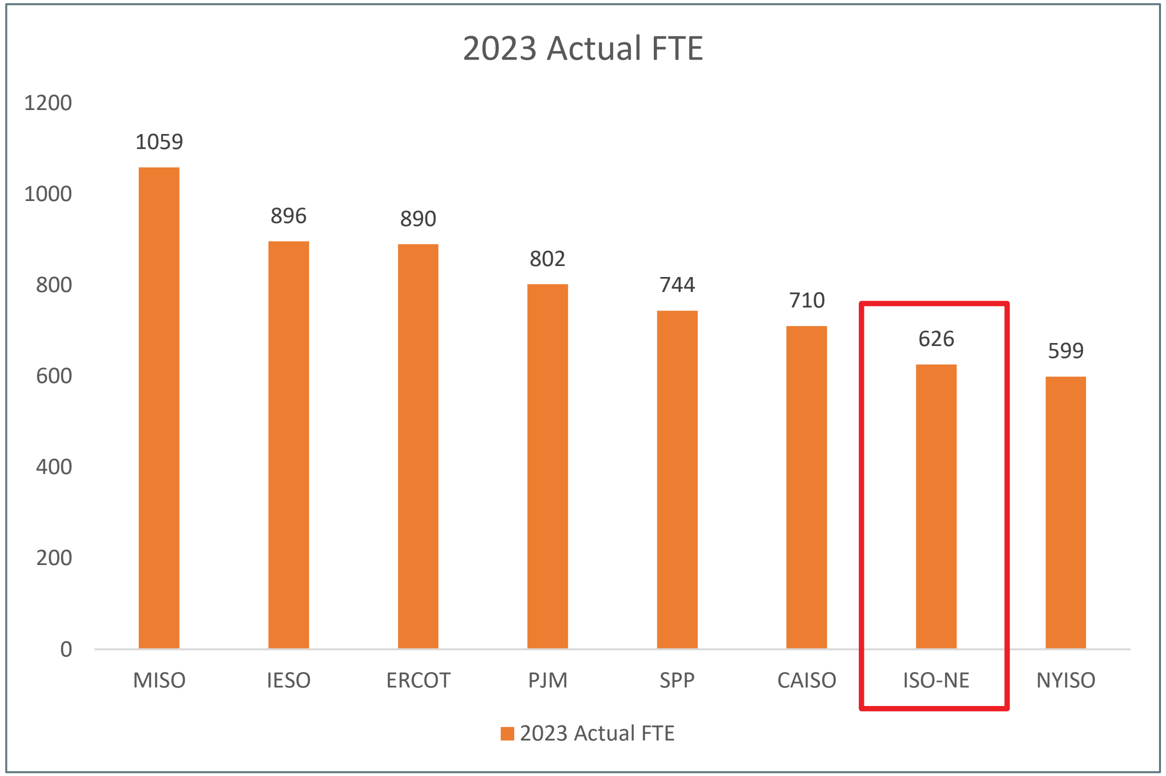
- Increasing number of resources to be interconnected, studied, and incorporated into modeling and forecasting
- New roles for the ISO including assisting states with transmission RFPs
- Increasing compliance needs to address FERC orders, and assess their impacts on operations – 2222, 841, 881, 901, 1920, and 2023
- Emergent needs to collect data for Distributed Energy Resources (DER) to address tripping and low-loads
- New and enhanced skills to work with changing technology stack, new data streams, and operationalizing new applications
- Personnel to communicate increasingly complex information to stakeholders and the public
- Increased support needs to assist the growing and distributed workforce



ISO-NE's Incremental and Actual Headcount in Comparison to other ISO/RTOs'

Other ISOs had already begun ramping up their hiring prior to ISO-NE

ISO-NE is still relatively small compared to other multi-state ISOs



Note: FTE additions and totals are based on actual FTE amounts on 12/31 of the applicable year.

Other Factors Driving Increases to the 2025 Budget

In addition to the budget increases, for added personnel and technology, to support clean energy as described in the previous slides, the other primary factor to the 2025 budget is inflationary cost increases and for continued operations

Driver: addressing the effects of inflation on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation

- This includes the need to supplement the bench strength in certain departments to compensate for turnover and retirements

The region is committing to invest tens of billions of dollars in the clean energy transition over the next three decades and much of that investment will not only drive work for the ISO, but change the way we work; in order for the region to fully realize the benefits of that investment, the ISO needs to be prepared to reliably operate in that future paradigm

- Like the region it services, the ISO is an organization that is in transition – including operational needs, inflation, and workforce composition – and because of that, our budget estimates over the ensuing years will increase and should be expected to fluctuate due to the volatility of the input assumptions
- The transition – and work flow – will be dynamic, as will other budget assumptions (e.g., various inflationary forces, turnover rates due to the competitive market, headcount needs for yet-to-be-determined market designs, and business processes); therefore long-term budget forecasts will fluctuate

For the ISO to Manage the Transition to Clean Energy, a Significant Investment is Required in The Near-Term

The main factors for the increases to the 2025 ISO budget are:

1. The transition to clean energy:
   - Adding full-time employees (FTEs) and other resources to address work directly related to the transition to clean energy
   - Additional investment in information technology (IT) for enhanced modeling, emerging technologies and forecast methods, and the transition to cloud-based infrastructure
2. Inflationary and continued operations drivers:
   - Standard salary increases to keep pace with the labor market in order to retain and attract employees, to address cybersecurity, and for other miscellaneous cost increases

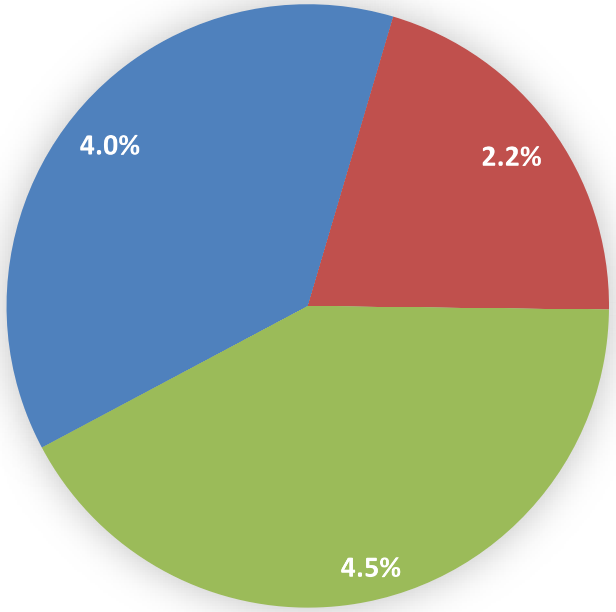
Factor	% Increase	$ Amount	$KWh Rate	Average Monthly Consumer Cost Impact *
Clean Energy Transition	6.2 %	$16,898,100	$0.00012	$0.09
Inflationary/ Continued Operations	4.5 %	$12,610,100	$0.00009	$0.07
Total:	**10.7 %**	**$29,508,200**	**$0.00021**	**$0.16**

**Average Monthly Consumer Cost Impact* is based on average consumption of 750 kWh per month.

Note: See chart on the following slide with an allocation of expense by factor, including a depiction of Clean Energy between investment in people and technology

Key Factors to the 2025 ISO-NE Budget

Key 2025 Budget Drivers



- 4.0% Clean Energy – Investment in People
- 2.2% Clean Energy – Investment in Technology (1)
- 4.5% Inflationary/Continued Operations (2)

(1) The Clean Energy Investment in Technology represents $1.7M of Computer Services increases for improved modeling, load forecasting, and moving to a cloud environment. The Clean Energy Investment in Technology also includes: increases for Depreciation Expense including that for new market features and enhancement related projects such as Day-Ahead Ancillary Services Improvements and nGEM Software Development Part III; and Network Operations increases for transition of communication lines to new technologies

(2) Inflationary/Continued Operations includes $4.3M of Computer Services increases representing $2.3M of existing product increased costs and/or licensing and $2.0M related to Cyber Security additions and enhancements

Note: See slides 36 and 37 for additional information on Computer Services and technology

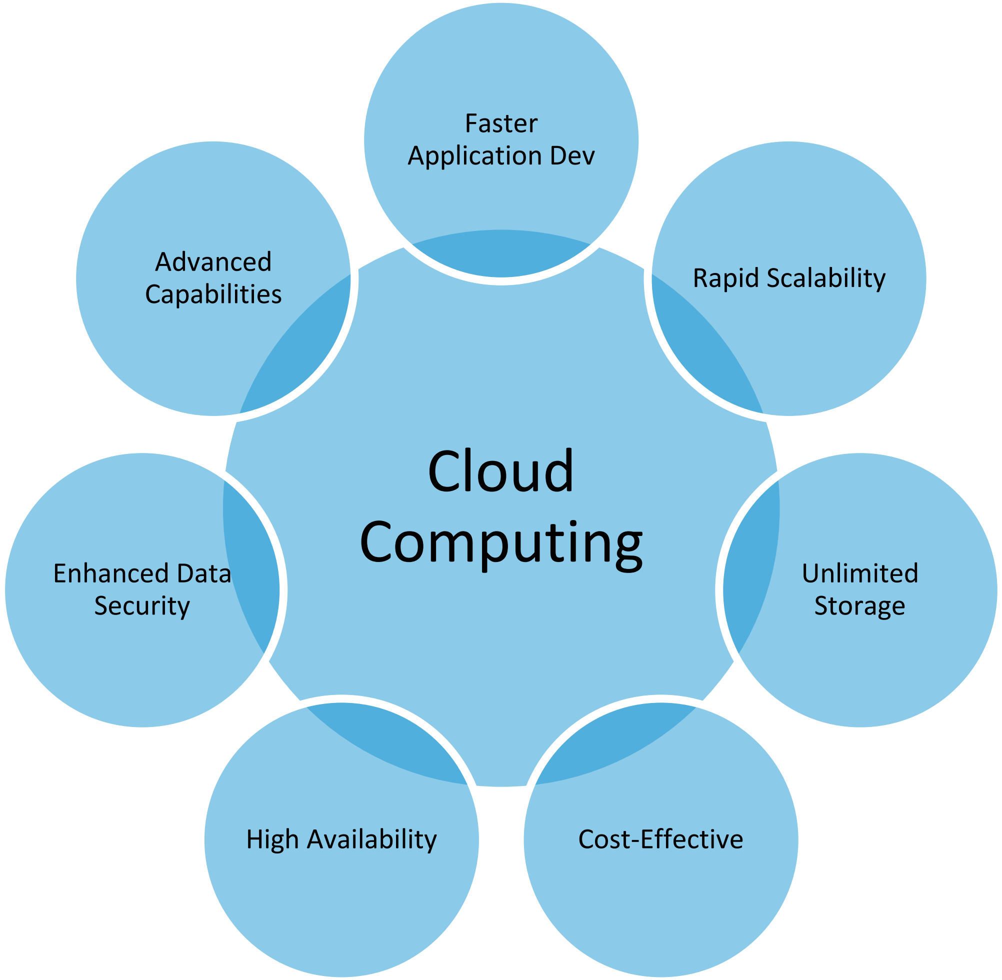
Budget Driver: The Need to Enhance Computer Services and Technology Stack

Computer services driving budget costs in 2025:

- ISO moving to cloud environment
  - Changes the organization's technology stack
  - Enhances efficiencies and capabilities
  - Necessitates new roles within IT
- New/increasing licensing and products
  - Increases in user licenses or central processing units
  - Vendor and product inflation

Existing staff will be trained to support new platforms and tools

Benefits of moving to the cloud

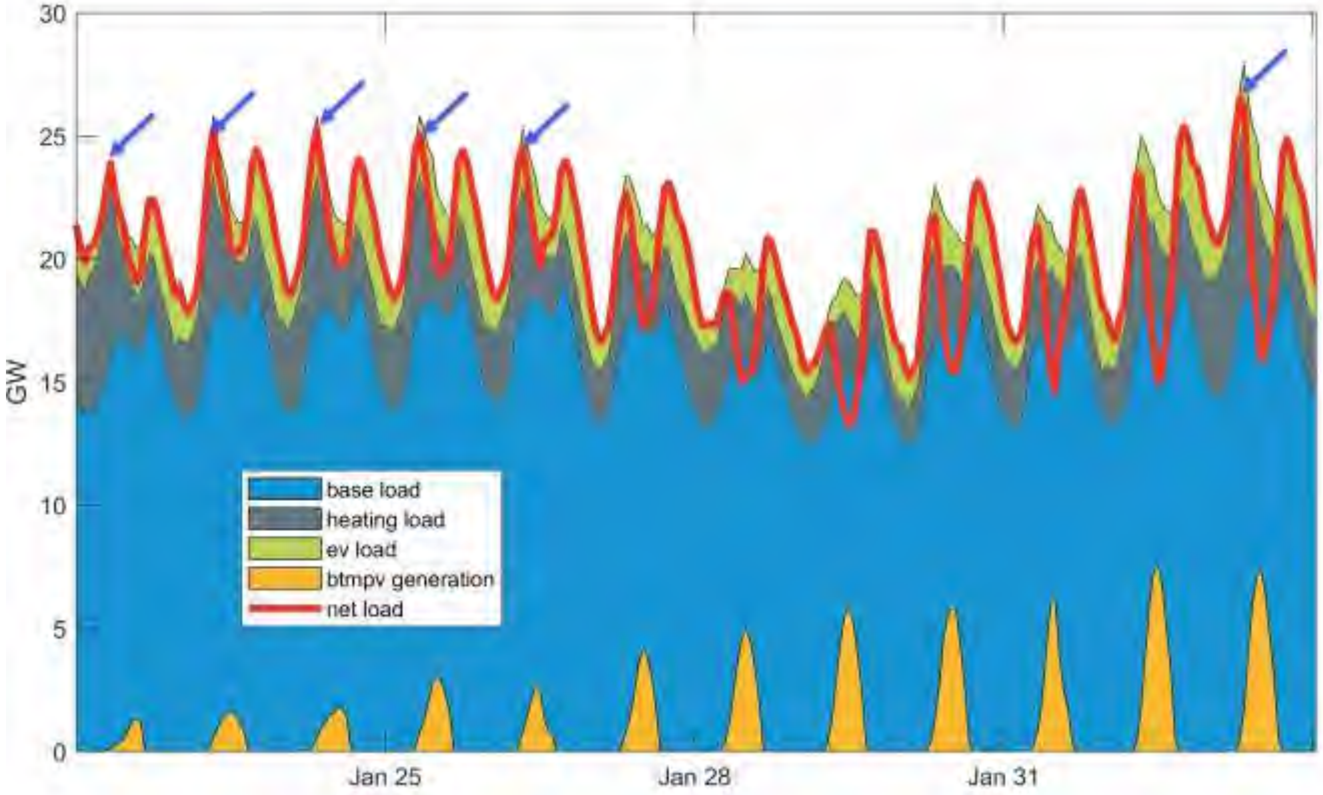


Budget Driver: Technology Improvements for Forecasting Demand and Increasing Complexity of Planning Studies

- Emerging trends require **enhanced modeling and accounting** to resolve net impacts on demand and to forecast full range of demand during all seasons and grid conditions
  - DER PV and DER storage
  - Electrified heating
  - EV managed charging
  - Retail-based active demand response
- **Keep pace with emerging technologies and forecast methods**
- Increasing need for **studying non-typical peak hour insights**
  - Midday minimum loads
  - Sub-regional, "non-coincident" load characteristics
  - Seasonal peaks occurring on weekends, holidays, or atypical months
- Growing emphasis on **load shape and short-term energy requirements in studies**

Need Explicit Accounting of Load Shape

Our current forecasting methodology does not capture the morning peaks we are observing



Source: Data from 2023 CELT Report

Budget Driver: Designing Markets and Supporting Analyses for the Clean Energy Transition

- Hiring to support the development and maintenance of new market mechanisms for the changing resource mix:
  - Capacity Auction Reforms:
    - Resource Capacity Accreditation
    - Move to a prompt/seasonal market
      - *The extent there are personnel efficiencies from the shift to a prompt/seasonal market, the ISO will redeploy existing staff to areas of need*
  - Ramping and flexible response products
  - Day-Ahead Ancillary Services Initiative
- Hiring to support the effects of evolving resource mix on market analyses
  - New and more frequent energy analyses
  - Growing number of transmission and interconnection studies
  - Need to support transmission RFPs with economic analyses

Budget Driver: Compliance with Increasingly Complex Stakeholder, State, and Federal Requests

The clean energy transition will necessitate new roles and capabilities at the ISO including supporting states' requests (including longer-term transmission planning and RFPs), staying compliant with federal mandates, and hiring new skillsets geared specifically towards engaging stakeholders

In addition to the personnel needed to address the workload associated with the modeling, forecasting, and technology needs of the changing grid, addressing the related federal, state, and stakeholder requests will drive budget needs in 2025:

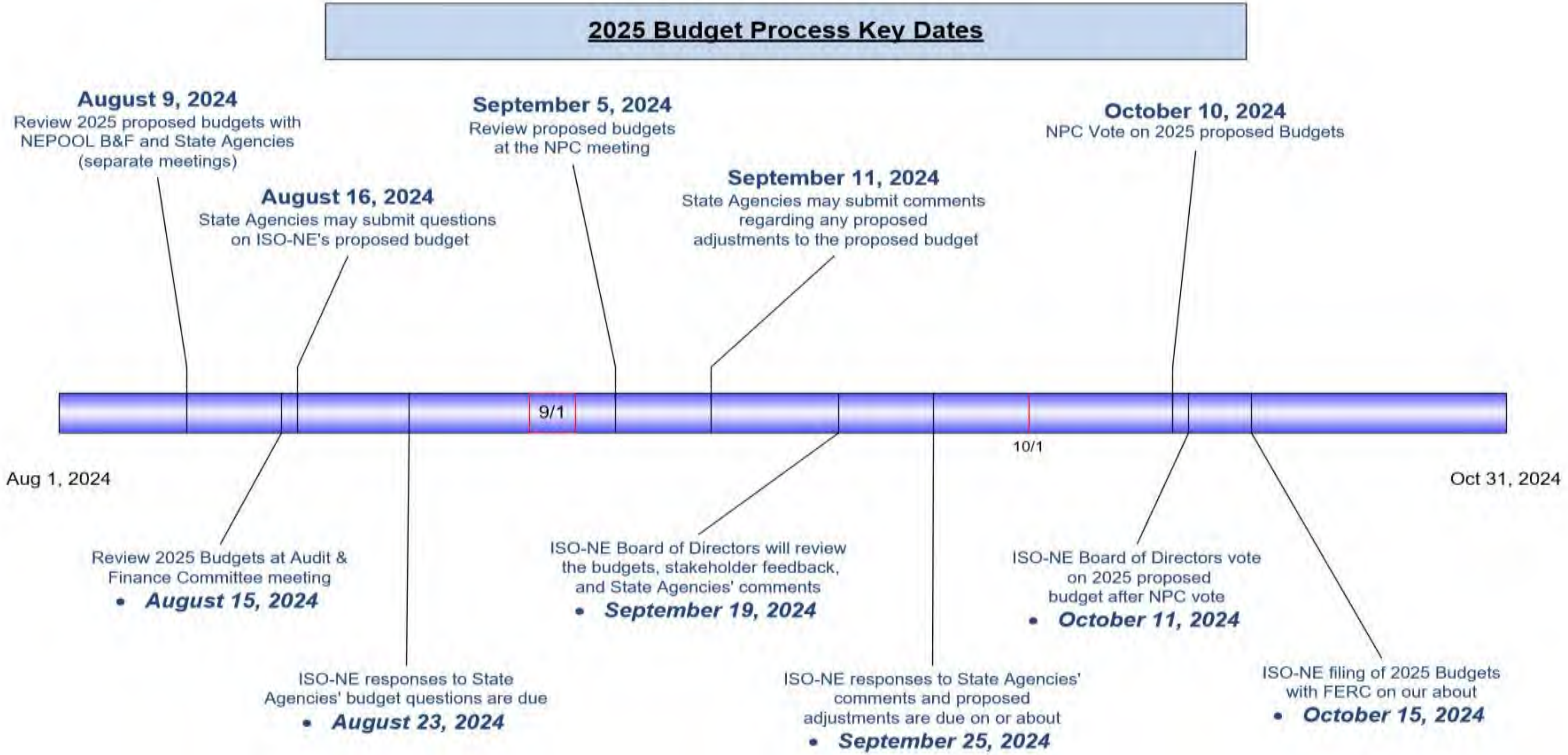
- Development of capabilities to assist states in the transmission RFP and long-term transmission planning processes, **which will necessitate the addition of a new team at the ISO**
  - **This new capability will require a buildout over the course of a few years beginning in 2025**
- Implementation and evaluation of FERC orders: FERC Orders 2222, 841, 881, 901, 1920, and 2023
  - Including elements of implementing outcomes from Regional Energy Shortfall Threshold and Day-Ahead Ancillary Services
- Hiring new skillsets to service stakeholder needs, requests, and communication of increasingly complex grid and market information

2025 Budget Overview

The 2025 Capital Budget is also presented in summary form

- The 2025 Capital Budget has increased from $35M in 2024 to $42.5M in 2025
  - The 2025 capital budget is $2.5M above the $40M presented in the preliminary 2025 budget as a result of incorporating the workspace changes needed to satisfy short-term constraints for the next couple of years; as discussed in the preliminary budget, the Holyoke campus was designed to support 560 headcount therefore creating a need to redesign the Holyoke facilities to accommodate the larger workforce; after exploring financing options with TD Bank, ISO determined this was the most cost efficient way to finance the short-term needs; the costs will be covered under the $75M private placement which will be in effect in 2024; additionally, this will allow ISO to save on closing costs
  - The increased capital budget need is being driven by four primary drivers as explained in further detail on slides 69-73
  - 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 operating budgets and rates
- The 2025 proposed capital budget of $42.5M 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)
- Detailed project descriptions are presented in Appendix 7

2025 Budget Process – Key Dates



2025 Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2025	% Change	2024	% Change	2023	% Change	2022	% Change	2021
Operating Budget Before Depreciation	$269.4	10.3%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Capital Budget	42.5	21.4%	35.0	4.5%	33.5	4.7%	32.0	14.3%	28.0
Total Cash Budget	**$311.9**	**11.7%**	**$279.3**	**15.1%**	**$242.7**	**9.8%**	**$221.1**	**7.0%**	**$206.6**
Operating Budget Before Depreciation	$269.4	10.3%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Depreciation	$37.0	13.6%	32.6	5.1%	31.0	19.1%	26.0	(1.2)%	26.3
Revenue Requirement Before True-up	306.4	10.7%	276.9	15.3%	240.2	11.7%	215.1	4.9%	205.0
True up	4.8		(3.0)		(14.6)		1.1		0.2
Revenue Requirement	**$311.2**	**13.6%**	**$273.9**	**21.4%**	**$225.6**	**4.4%**	**$216.1**	**5.4%**	**$205.1**
Forecast – TWhs (1)	**136.5**	**(3.0)%**	**140.7**	**(1.6)%**	**143.0**	**(1.0)%**	**144.4**	**(2.0)%**	**147.4**
$/KWh Rate	**$0.00228**	**17.1%**	**$0.00195**	**23.4%**	**$0.00158**	**5.4%**	**$0.00150**	**7.5%**	**$0.00139**
Average Monthly Consumer Cost (2)	**$1.71**		**$1.46**		**$1.18**		**$1.12**		**$1.04**

(1) 2025 Forecast based on May 2024 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.

2025 STRATEGIC GOAL INITIATIVES

2025 Initiatives: Responsive Market Designs

Support reliability through competitive market mechanisms

1. Capacity Auction Reforms
   – Transition to a Prompt/Seasonal Capacity Market
   – Resource Capacity Accreditation Reforms
2. Implement Day-Ahead Ancillary Services
3. Guide stakeholder discussions on specific new flexible response services
4. Finalize decision to extend or terminate IEP post 24/25 winter

Administer FERC Orders Supporting DER

1. Complete Business Requirements for all affected software and beginning development for Order No. 2222
2. Begin Implementation of Day-Ahead Market Storage Enhancements for Order 841

2025 Initiatives: Progress and Innovation

Improve modeling for emerging technology resources

1. Development of nGEM Real-Time Market Clearing Engine
2. Completion of nGEM Phase III program development
3. Integrate EMT Study Tools into Engineering Processes
4. Enhance data collection for co-located and hybrid resources to improve modeling/visibility

Continue to develop forecasting capabilities to support clean energy transition

1. Develop Probabilistic Forecast Capabilities for Wind, Solar, and Load
2. Integrate Probabilistic Energy Adequacy Tool (PEAT) analysis into seasonal forecasts
3. Improve load forecasting methodology

2025 Initiatives: Operational Excellence

Maintain Reliability and Forecasting for Operation of the Bulk Power System

- Evaluate Single Source Contingency Limit Increase
- Continue to evaluate tie benefits
- Implement ambient adjusted line ratings (FERC Order 881)
- Address trend of increasing DER/decreasing springtime load
- Enhance synchrophaser applications

Implement internal process and technology improvements to address increasing operational complexity

- Increase the usability and broaden usage of ISO-developed innovations to enhance control room situational awareness and market efficiency related to grid complexity
- Enterprise resource planning system replacement
- Evaluate the impacts of FERC Order 2023 on streamlining interconnection queue

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

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

2025 Initiatives: Stakeholder Engagement

Communicate Power System and Wholesale Markets Performance & Needs

1. Implement Extended Term/Longer Term Transmission Planning Phase 2
2. Coordinate regional discussions around Transmission Owners' asset replacement for the clean energy transition
3. Engage States/FERC to determine implementation path for Regional Energy Shortfall Threshold (REST)
4. Economic studies coming out of the Economic Planning for the Clean Energy Transition (EPCET) Study

Provide high-quality services to stakeholders and the public

1. Develop new communications materials, expand access to regional energy information and conduct outreach to new audiences
2. Survey stakeholders' satisfaction for ISO services
3. Enhance communications about clean energy transition

2025 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 programs
4. Improve employee experience- onboarding, coaching and development, flexible work (hybrid), change management
5. Deliver competitive benefit programs with a focus on emotional, physical, and financial wellness

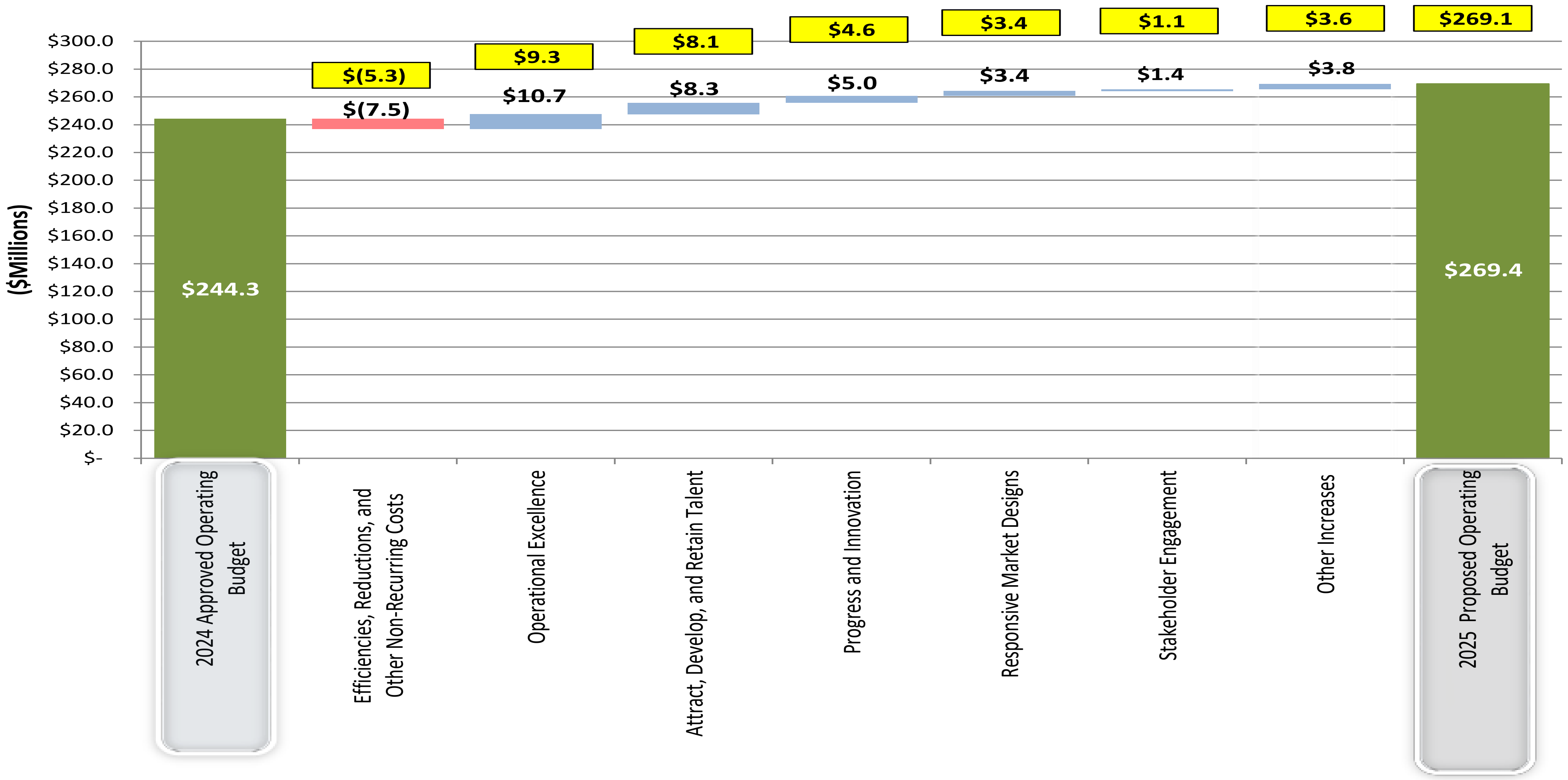
Support the Professional Development of the ISO Workforce

1. Advance Diversity and Inclusion – raising awareness, employee networks, focus on culture
2. Advance leadership capability through the design and delivery of leadership development opportunities and programs
3. Support the organization change, upskilling, and reskilling required to achieve business outcomes
4. Refresh and administer HR Policies and Programs

2025 Detailed Budget Changes by Strategic Goal

2025 Budget

Changes in budget by Strategic Goal



Note: Items in yellow above represent the estimate that was included in the 2025 preliminary budget presented in June 2024.

2025 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($7.5M)

- Reductions for consulting professional fees for 2024 studies or other non-recurring work including:
  - Utilization of external support for New England States' requests to be offset by ISO-NE internal staff
  - Funding for FCA 21 Cost of New Entry (CONE) parameter updates
  - Reduction in funding for the assessment of a conceptual framework for a Prompt Seasonal Capacity Market
  - Removal of professional fees funding in Market Administration & Auctions and Market Monitoring, and capacity auction licensing fees due to the FERC approved two year delay of FCA 19
  - For Distributed Energy Resource and minimum load studies for assistance in determining requirements on how to ensure reliability on the system under conditions where it is powered solely by inverter-based resources
  - Reductions in Market Development study and project management support
  - For Energy Resource Opportunity cost support in Market Monitoring

2025 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions: *(cont.)*

- Lower support costs, upon contract renewal, for Participant Support management software
- Lower salary rates due to employee turnover and retirements
- Increase in Interest Income due to raising of interest rates for 2025 to 2.75% compared to 1.00% in 2024 budget

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 3: Operational Excellence: $10.7M

- Computer service and leasing increases for: cyber security (security logging, firewall updates, network collaboration tool, network traffic segmentation, encryption software, and risk management); leasing of servers as part of data center refresh; photovoltaic and demand response forecast products; licensing for System Planning and Operations applications; performance monitoring software; Enterprise Resource Planning software; compliance software; and inflationary and vendor increases across our portfolio of computer service products ($6.4M)
- Funding for 11.0 FTEs* related to this goal across Information and Cyber Security Services for Cloud Computing transition including architecture, security and infrastructure support, and FinOps management, for IT modeling and software development, and support for enterprise and settlement applications; for Participant Training support; and for Finance and Market Credit Risk support to the organization ($2.5M)
- Network Operations increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases ($0.6M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

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

- Information and Cyber Security Services staff augmentation inflationary rate increases ($0.5M)
- Addition of an professional fees for an Audio Visual Engineer to support the Information Technology Service Delivery team ($0.2M)
- Internal Audit support for cloud applications and NERC Critical Infrastructure Protection (CIP) programs ($0.2M)
- Travel and training due to full renewal of in-person meetings, higher travel costs, and training of staff to support new platforms and tools ($0.2M)
- Information Technology administrative staff augmentation consulting support ($0.1M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 5: Attract, Develop, and Retain Talent: $8.3M

- Merit and Promotion increases (6.0% Total): for annual merit (3.0%-4.0%) and for standard and targeted equity/promotions (2.0%-3.0%), less timing of 2024 equity/promotion adjustments and allocation of amounts between operating and capital/reimbursable work ($4.7M)
- Increases in employee benefit costs, primarily for medical trend, increased number of employees in Defined Contribution Benefit Plan, and higher 401K match due to overall employee salaries ($1.8M)
- Increase for employee incentive target amounts including adjustments based on compensation study review ($1.4M)
- Funding for 6.0 FTEs* related to this goal across Human Resources, Legal, and Corporate Communications (in HR for talent and project management, early career associates, and learning coordinator; in Legal for corporate counsel to support employee related matters; and in Corporate Communications for a communications specialist to expand external communications to attract talent) ($1.0M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 5: Attract, Develop, and Retain Talent: *(cont.)*

- Higher recruiting and benefits administration related expenses including relocation, recruiter fees, and employee experience consulting ($0.5M)
- Leasing of land adjacent to Holyoke facility in conjunction with Space Utilization project ($0.3M)
- Human Resources support for instructional design and executive coaching ($0.2M)
- A reduction for the increase of employee vacancy from 5% to 6% (reduction of $1.6M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 2: Progress and Innovation: $5.0M

- Funding for 16.0 FTEs* including Information and Cyber Security Services and Advanced Technology Solutions for bringing ISO-NE developed advanced technologies into the operating environment to increase our situational awareness capabilities; System Operations and System Planning positions for forecasting and energy analysis across different timespans as the system's resource mix continues to evolve, and for modeling and electromagnetic transient analyses for market and reliability operating limits of Inverter Based Resources; and in Transmission Planning and Services for RFP processing and long-term studies ($3.4M)
- Funding for a transmission planning system assessment under NERC Transmission Planning Standard TPL-001 ($0.5M)
- Increased utilization of cloud computing with more products moving to the cloud including the Customer and Asset Management System (CAMS), Forward Capacity Tracking System (FCTS), and internal development software application ($0.5M)
- Funding to support transmission planning and analysis studies to establish facility out transfer capability for Northern New England and NECEC ($0.3M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 2: Progress and Innovation: *(cont.)*

- Funding for Planning Services benchmarking and validation of generator outage data ($0.1M)
- Fees for a battery storage modeling application being utilized by Internal Market Monitoring staff ($0.1M)
- For research by Advanced Technology Solutions with outside firm on impacts of Inverter Based Resources on the system based on differing scenarios including location, timing, and volumes ($0.1M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 1: Responsive Market Designs: $3.4M

- Funding for 11.0 FTEs* related to this goal including for: Market Development in design of market overhauls including Capacity Auction Reforms (prompt seasonal capacity market, and resource capacity accreditation), and flexible response services; Operations Training to design and support trainings for Operations and Market Administration and Auctions staff for new market features; Information and Cyber Security Services and Advanced Technology Solutions staffing to support and integrate new market features into applications and tools; and Planning and Transmission Services to align with new market designs, for identifying enhancements to existing reliability modeling and researching, and developing modeling techniques for emerging technologies ($2.4M)
- nGEM vendor support with the Day-Ahead Market Clearing Engine production application that is being supported at the same time as the legacy Real-Time application (forecasted to go live in 2026) ($0.6M)
- Support in Advanced Technology Solutions for Integrated Market Simulator system support and enhancements ($0.3M)
- Support for Market & Credit Risk modeling ($0.1M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 4: Stakeholder Engagement: $1.4M

- Funding for 3.5 FTEs* in Participant Relations and Services for project services (gathering, managing, and supporting the assessment of participant requests), for data analytics on key trends, for technical readiness on participants inquiries and proposals, and for technical writing and instructional design work for broader and deeper training for new market features and initiatives scheduled for 2025 and 2026 ($0.7M)
- Funding for 1.5 FTEs* in System Planning for Economic Study and Environment Outlook and Interconnection Study work; and 1.0 FTE* in External Affairs for increased support and substantive interactions with the states and facilitating engagement of ISO subject matter experts on matters related to renewable and clean energy development, transmission and interregional planning, generator interconnections, and integration of demand-side solutions and distributed resources ($0.5M)
- Increase in funding 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 ($0.2M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Other Increases: $3.8M

- The allocation of NPCC and NERC dues ($1.2M)
- An increase in Interest Expense and fees with changes to: Private Placement debt in late 2024 at higher balance and expected higher rate than previous debt; tax exempt debt due to higher rate slightly offset by decrease in principal balance; with a partial offset on the working capital borrowing ($1.1M)
- An increase in the CEO Emerging Work Allowance ($1.0M)
- Insurance policy rate increase ($0.5M)

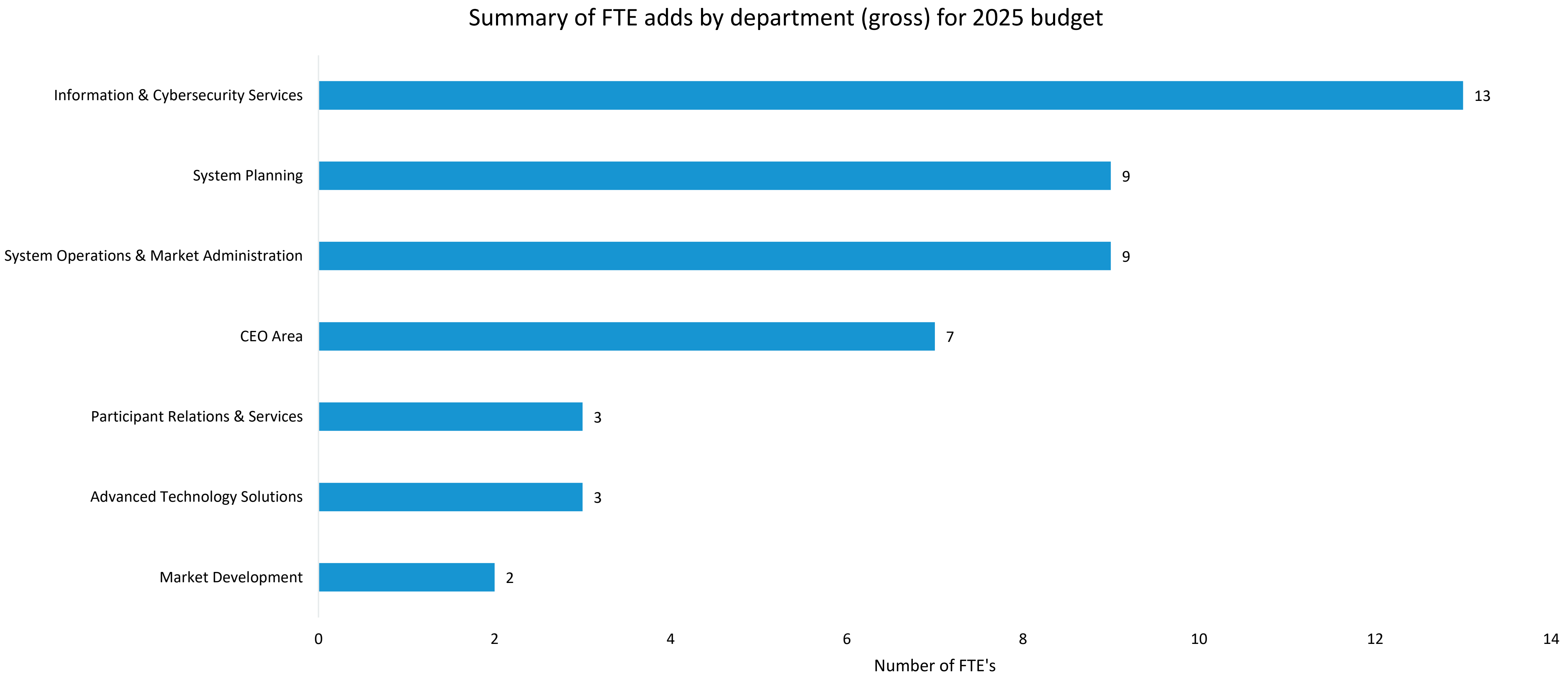
2025 BUDGET RESOURCING NEEDS

2025 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 40 positions, including 4 to-date in 2024, being repurposed for other work where a more urgent need existed
  - Positions repurposed since 2018 include: 9 for Information Technology for Software Development, Cyber Security, Power System Modeling, Application Support, Infrastructure and Digital Transformation; 7 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; 2 for Participant Support; 2 for Corporate, Media, and Digital Communications; 1 for Load Forecasting to replace a contract position; 1 for Resource Studies & Assessments; 1 for Settlements; and 1 for Corporate Strategy

Requested Additional Headcount for 2025



Note: CEO Area headcount additions include those for External Affairs, Human Resources, Finance, Market & Credit Risk, and Legal

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows:

FTEs	Description	Clean Energy Pillar(s) (*)	Strategic Goal(s)
13.0 FTEs	**Information and Cyber Security Services**		
	Resources to support advanced technology solution tools as well as the Integrated Market Simulator, Prompt/Seasonal Markets; Development efforts including the nGEM system, and integration of Day Ahead Ancillary Services; IT Architecture to support leveraging cloud technologies; infrastructure support to alleviate understaffing pressures; and resources to break teams into smaller pods that support the growing number of IT products and services (7 FTEs Support the Clean Energy Transition)	N/A	Operational Excellence; Responsive Market Designs; Progress and Innovation
9.0 FTEs	**System Planning**		
	Resources to support continued growth and development of PSCAD modeling capability, Resource Capacity Accreditation and use of probabilistic analysis, to accommodate evolving study and forecasting needs and increased complexity associated with the clean energy transition, resources to support expected increases in transmission RFPs, support stakeholder requests for long-term transmission studies, to address FERC order on long-term transmission planning for asset condition based replacement and future-sizing of the transmission system (9 FTEs Support the Clean Energy Transition)	Energy Adequacy; Balancing Resources; Robust Transmission	Progress and Innovation; Operational Excellence; and Attract, Responsive Market Design
9.0 FTEs	**System Operations and Market Administration (SOMA)**		
	Resources to support the evolving project needs of the SOMA department, support improvements to Outage Coordination, and additional analytical requirements to perform complex and evolving Electromagnetic Transient analyses; resources for the performance of energy analysis across varying time horizons, and for Operations Training coordinate with SOMA business groups to proactively identify gaps and challenges with integrating significant amounts of clean energy and energy storage to work with Advanced Technology Solutions and IT to develop necessary tools and solutions (9 FTEs Support the Clean Energy Transition)	Clean Energy Resources; Energy Adequacy	Responsive Market Designs; Operational Excellence; Progress and Innovation

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

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows: (cont.)

FTEs	Area / Description	Clean Energy Pillar(s)	Strategic Goal(s)
3.0 FTEs	**Advanced Technology Solutions**		
	Resources to serve as the company-wide SME on synchrophasor technology, conduct research and development on emerging power system issues such as large scale renewable integration, and resources to analyze and assess market designs or operations processes to include the development of models for market design and optimization problems (3 FTEs Support the Clean Energy Transition)	Clean Energy Resources; Energy Adequacy	Progress and Innovation
3.0 FTEs	**Participant Relations & Services**		
	Resources to conduct data analysis of key trends embedded in participant inquiries to discover critical knowledge gaps, resources to provide required technical readiness and real-time support to participants on notable corporate initiatives scheduled for 2025/26 and an additional resource to address the required development of new and increasing participant training needs for new initiatives and products (3 FTEs Support the Clean Energy Transition)	Robust Transmission	Stakeholder Engagement
2.0 FTEs	**External Affairs**		
	Given the increasing expectations from the New England states to have the ISO provide support in achieving their state policy goals, the External Affairs team is being called upon increasingly to support substantive interactions with the states and facilitate engagement of ISO SMEs on matters related to renewable and clean energy development. One resource is to oversee the day-to-day responsibilities of the team's state policy advisors and one resource to enable more substantive interactions with the states and alleviate the need for involvement from SMEs. (2 FTEs Support the Clean Energy Transition)	Clean Energy Resources	Stakeholder Engagement

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows: (cont.)

		Clean Energy Pillar(s)	Strategic Goal(s)
2.0 FTE	**Market Development**		
	Resources for increasing data analytics capacity and capability, focused on Prompt/Seasonal Capacity Market, Resource Capacity Accreditation Reforms, and future Flexible Response Services, as well as ongoing data-intensive priority work on Storage Modeling Enhancements, Multi-Interval Optimization, and other projects (2 FTEs Support the Clean Energy Transition)	Support	Responsive Market Designs
2.0 FTE	**Human Resources**		
	Resources to support department and organizational change and effectiveness efforts, foster a diverse, inclusive and engaging work environment, as well as centralizing coordination of learning activities and administration into a single role (1 FTE Supports the Clean Energy Transition)	Support	Attract, Develop, and Retain Talent
1.0 FTE	**Finance**		
	For a FinOps Manager to provide financial and analytical support, assist in the development of department budgets as well as act as a liaison between IT departments and the finance and budget departments	Support	Operational Excellence
1.0 FTE	**Market & Credit Risk**		
	For an experienced credit analyst to assess and monitor the creditworthiness of banks and market participants due to changes to the Financial Assurance Program (FAP) made in 2023 as well as planned changes to the FAP regarding parental/affiliate guarantees in the Forward Capacity Market (pending FERC approval)	Robust Transmission	Operational Excellence
1.0 FTE	**Legal**		
	Support for growing legal needs in Human Resources including employee relations and benefit plan changes	Support	Attract, Develop and Retain Talent
46.0 FTE's	**Total 2025 Proposed FTE Additions**		

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 and to accommodate the expanded workspace, ISO has increased the capital spending over the last few years with spending of $35M in 2024, and increasing to $42.5M in 2025, and at a $40M level in 2026 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, ever 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 shouldered by each ISO individually
- With the completion of the infrastructure and the day-ahead version of the new market clearing engine (MCE) in 2023, the ISO is continuing work on the complex processes for customizing and implementing the next phases, which include the infrastructure and real-time version of the MCE; this work is expected to continue until 2026 with an estimated cost of $15M
- Additional phases for nGem are expected in 2025 thru 2028 with an estimated cost of $45M

(*) nGEM Platform Replacement is a multi-year initiative that will advance multiple strategic goals, including Responsive Market Designs, Progress and Innovation, and Operational Excellence. The initiative will require significant investment (over $15M) and, as such, is being flagged consistent with the enhanced process for Board overview of significant and multi-year capital projects.

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts

- The capital budget will support ISO's market design objectives for 2024 and beyond of moving toward clean energy, balancing resources, energy adequacy, and robust transmission
- Many of these 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 2025 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

Forward Looking Capital Budget Spending *(cont.)*

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

- Significant Capacity Market Reforms: The ISO is currently recommending the move 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
- Managing Transmission Line Ratings: 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 $40M - $60M over the next five plus years

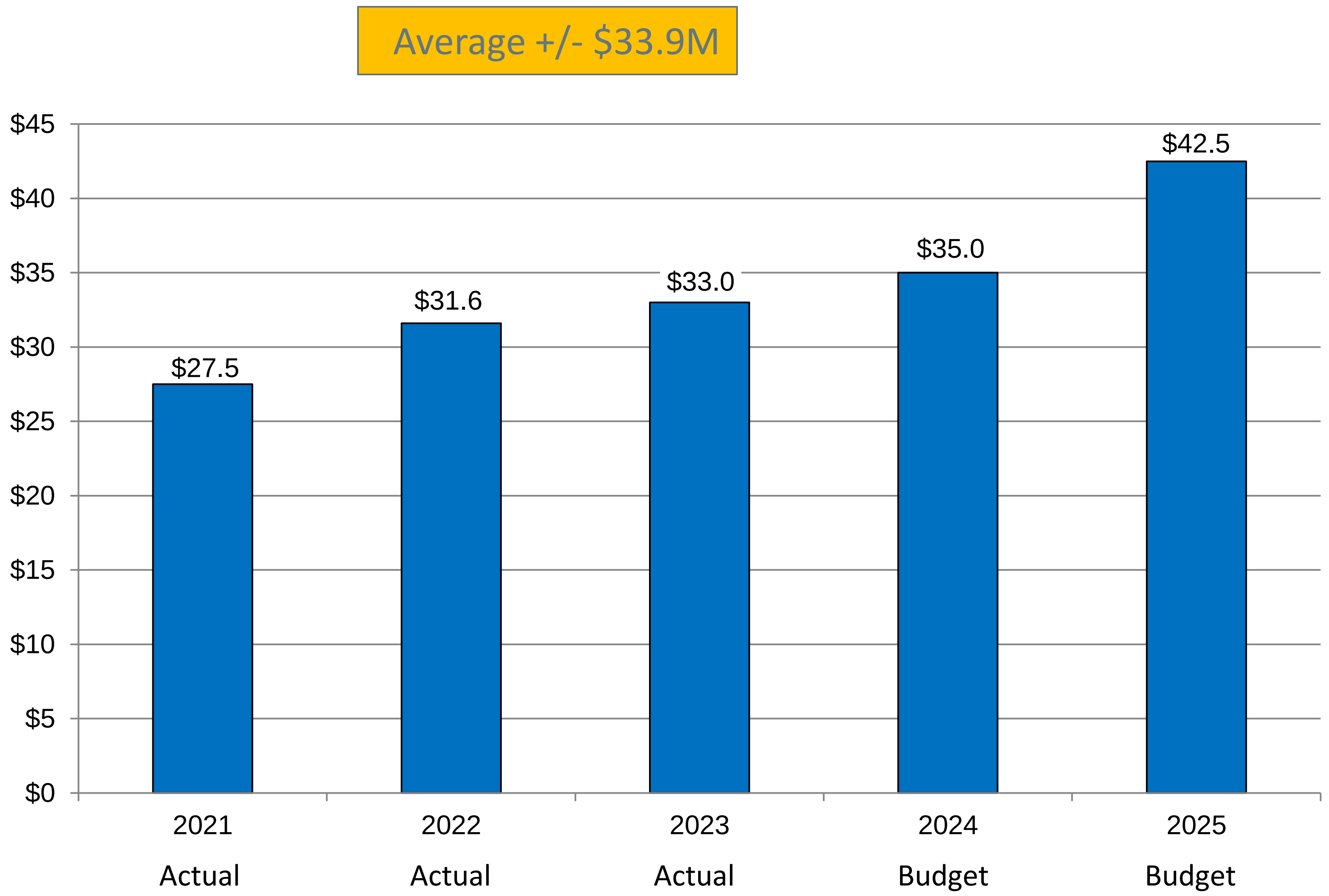
Forward Looking Capital Budget Spending *(cont.)*
Cyber Security & IT Asset and Infrastructure Replacement

- 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
- ISO's cyber security maturity level has been an ongoing major investment and will continue over the next 3 - 5 years; ISO has greatly benefited from earlier investments in this area and is now able to layer improved defense, network segmentation, email and web filtering to improve 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



Capital Budget
2025 Expenditures

Goal: Responsive Market Designs

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. FERC Order 841	$2.0 M	$2.2 M	10/25	Conceptual Design
. Day-ahead Ancillary Services Improvements	$1.5 M	$9.1 M	03/25	In Development
. FERC Order 2222	$1.0 M	$6.0 M	11/26	Conceptual Design
. Solar Do Not Exceed Dispatch Phase III	$0.3 M	$0.3 M	11/25	Conceptual Design
. Storage as Transmission Only Asset	$0.4 M	$1.4 M	03/27	Conceptual Design
Total:	**$5.2 M**			

Goal: Progress and Innovation

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. nGEM Real-Time MCE Implementation	$4.7 M	$14.7 M	05/26	In Development
. nGEM Software Development Part III	$2.6 M	$4.5 M	03/25	In Development
. Integrated Market Simulator Enhancement	$1.5 M	$1.5 M	12/25	Conceptual Design
. nGEM Software Development Part IV	$1.0 M	$2.0 M	06/26	Conceptual Design
. EMS Short-term Load Forecast Replacement	$0.1 M	$1.4 M	01/25	In Development
Total:	**$9.8 M**			

Capital Budget
2025 Expenditures *(cont.)*

Goal:Operational Excellence

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Space Utilization Project Phase I	$2.0 M	$3.0 M	08/25	Conceptual Design
. Microsoft 365 Service Adoption	$2.0 M	$3.0 M	12/25	Conceptual Design
. Enterprise Core Network Refresh	$2.0 M	$2.0 M	12/25	Conceptual Design
. Enterprise Resource Planning System Replacement	$1.9 M	$4.1 M	12/25	Conceptual Design
. Managing Transmission Line Ratings	$1.7 M	$7.7 M	06/25	In Development
. EMP 3.5 Upgrade	$1.5 M	$5.5 M	12/26	Conceptual Design
. Windows Server Replacement Phase II	$1.5 M	$1.7 M	12/25	Conceptual Design
. CAMS Application Software Technology Upgrade	$1.4 M	$1.7 M	12/25	Conceptual Design
. MW Dependent Fuel Price Adjustment	$1.0 M	$1.1 M	11/25	Conceptual Design
. 2025 Issue Resolution Project	$0.8 M	$0.8 M	09/25	Conceptual Design
. Control Room Tie Line Telemetry and PCEC Upgrades Phase II	$0.5 M	$0.5 M	09/25	Conceptual Design
. Network Modeling Tool Enhancements	$0.4 M	$1.3 M	06/25	In Development
. Circuit Inventory Management Platform	$0.4 M	$0.6 M	10/25	Conceptual Design

Continue to the next page

Capital Budget
2025 Expenditures *(cont.)*

Goal:Operational Excellence

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. CIP Electronic Security Perimeter Redesign Phase II	$0.4 M	$5.2 M	05/25	In Development
. Replace Employee & Pager Application	$0.3 M	$0.4 M	10/25	Conceptual Design
. Adoption of NERC CIP Compliance of Synchrophasor Systems	$0.3 M	$1.0 M	10/26	Conceptual Design
. Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements	$0.2 M	$0.9 M	08/25	In Development
. New England Clean Energy Connect	$0.1 M	$0.2 M	10/25	Conceptual Design
. Non-Project Capital Expenditures	$5.0 M			
Total:	**$23.4 M**			

Capital Budget
2025 Expenditures Summary

2025 Capital Budget Expenditure Summary

Allocation Category	2025 Budget
Goal: Responsive Market Designs	$5.2 M
Goal: Progress and Innovation	$9.8 M
Goal:Operational Excellence	$23.4 M
Other Emerging Work	$3.1 M
Capital Interest	$1.0 M
Total:	**$42.5 M**

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 $35M in 2024 to $42.5M in 2025, and at $40M in 2026 and beyond
  - 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; consequently, ISO worked through the stakeholder and Board process to get approval for $75M Private Placement Note and is working to complete the offering in Q3 of 2024

Capital Structure and Cash Flow *(cont.)*

The ISO received FERC approval on July 19, 2024 to enter into $75M Private Placement Note. The ISO is current in the process of going out to market to secure funding that will be issued and available by the time the $50M balloon payment on the current note is due in November.

ISO New England
2024 - 2028 Debt Service Cash Flow

	2024 Forecast	2025 Budget	2026 Forecast	2027 Forecast	2028 Forecast
Cash flows from operating activities:					
Operating Cost Recovery *	$ 228,956	$ 268,509	$ -	$ -	$ -
Non Cash Items:					
Depreciation, Amortization & G/L on Disposals	32,659	36,975	42,132	40,296	39,786
Amortization Term Loan Fees	61	96	96	96	96
Chg in Deferred Revenue-Depreciation	(100)	-	-	-	-
Chg in Accrued Expenses	120	-	-	-	-
Interest Expense	(3,570)	(4,475)	-	-	-
Operating Expenses, net of CEO Emerging Work & Allowance & Board Contingency *	(233,487)	(264,859)	-	-	-
Net cash provided by operating activities	24,639	36,247	42,228	40,392	39,882
Cash flows from investing activities:					
Capital expenditures	(35,000)	(42,500)	(40,000)	(40,000)	(40,000)
Net cash used in investing activities	(35,000)	(42,500)	(40,000)	(40,000)	(40,000)
Cash flows from financing activities:					
Net Proceeds/(Repayment) - Revolving Credit Line	-			-	
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)
Net cash provided by (used by) financing activities	21,820	(3,180)	(3,180)	(3,180)	(3,180)
Net increase/(decrease) in cash	11,459	(9,433)	(952)	(2,788)	(3,298)
Cash & Cash Equivalents on Hand - Beginning of Period	16,207	27,666	18,233	17,281	14,493
Change in Cash & Cash Equivalents Available	11,459	(9,433)	(952)	(2,788)	(3,298)
Cash & Cash Equivalents on Hand - End of Period	$ 27,666	$ 18,233	$ 17,281	$ 14,493	$ 11,195
Debt Maturity Schedule					
Tax Exempt Bond - BCC	1,360	1,360	1,360	1,360	1,360
Tax Exempt Bond - MCC	1,820	1,820	1,820	1,820	1,820
Total Year Repayment	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180

*= Operating Cost Recovery for 2024 has decreased by an overcollection in 2022 of $3,006 which was not amortized in 2023 but included in the 2024 tariff. The undercollection of $4,844 for 2023 will be filed with the 2025 tariff and will be reflected in the Operating Cost Recovery for 2025. The Operating Cost Recovery for 2026-2028 is projected to offset Operating Expenses for 2026-2028. The Operating Cost Recovery amount for 2026-2028 has not yet been established at this point.

Capital Structure and Cash Flow *(cont.)*

- The ISO currently has two revolving credit lines with TD Bank that are set to expire July 1, 2028; the first is a $40 million working capital line to support the ISO's short-term operational needs and cash flow risks, which may include draws to support lower than projected load driving decreased Tariff collections, a continued increase in budgetary needs over the next 3 - 4 years, and more recently the issuance of FERC Order 2023 which may increase withdrawals of system impact studies (i.e., reducing cash available to the ISO); the second is a $4 million line to support the short-fall funding arrangements necessary to support twice- weekly billing of the ISO New England markets
- For the six months ended June 30, 2024, the ISO's total weighted average cost of capital was 4.04%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

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 used for 2025 are Mercer, WorldatWork, WillisTowersWatson, and Payscale
  - 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, 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 Slide 90, ISO engaged a compensation consulting firm 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 assessed another 1/3 of the organization, with continued focus on IT and other roles requiring significant technical expertise
  - In 2024 and 2025, 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 regarding budgeted merit and promotional/equity increases (if any) 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	
2025	Not yet available	Not yet available	**3.0 – 4.0%**	Not yet available	Not yet available	**2.0 – 3.0%**
2024	3.7% - 4.0%	3.5% - 3.7%	**4.0%**	0.0% - 0.5%	0.5% - 1.0%	**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%**

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
- The clean energy transition has increased the demand for highly specialized personnel required to address the modeling, analysis, processing, and operational needs of the transition
  - Hiring and retaining highly specialized technical talent has become more challenging and costly
- 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, will require the requisite staff to complete this work

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
- 2025 Budget for Executive Salaries $5.2M
  - Executive Salaries comprise the base salaries of the officers on the IRS Form 990

Pension and Defined Contribution Benefit Plans in 2025

- 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 2025 *(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. ISO is in process of having this analysis refreshed and preliminary results show $10,000,000 continues to be an appropriate level of funding to cover the service cost of the plan and the fluctuating interest rate environment
  - The Pension Plan expense that is included in the 2025 budget is $10,000,000 compared to the projected FAS expense of $5,480,000

Postretirement Medical Benefit Plan in 2025

- 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 2025 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, 2024 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 5.33%
  - Salary Scale assumption (weighted Avg.) 3.00%
  - Projected 2025 annual earnings rate 6.25% (approximately)
- The calculated FAS expense amount for the Postretirement Benefit Plan of $880,000 is included in the 2025 budget

APPENDIX 2: 2025 OPERATING BUDGET RISKS

2025 Operating Budget Risks

- Additional funding may be required to enhance new models to study extreme weather and contingencies; to conduct new studies related to the integration of variable resources and emerging technologies; and for long-range transmission planning studies including request for proposals (RFP) process for finding competitive solutions to identified transmission needs in the region
- Resources may be needed as operations evolve (e.g., energy forecasting, load management) due to the changing resource mix occurring
- Information Technology software licensing and maintenance costs, and cloud migration costs 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

APPENDIX 3: 2023 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

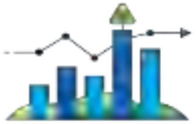
In 2023 the ISO Delivered on a Large Number of Complex and Novel Initiatives Addressing the Clean Energy Transition

ISO initiatives illustrate our commitment to advancing our vision to support the region's clean energy transition

Clean Energy Pillar

- Supported the changing grid and adapted to increasing system complexity through:
  - Acquiring new and more granular data about weather and end-use customer behavior
  - New modeling techniques to assimilate increasingly complex data sets
- Supported policy-makers considerations about how to achieve the goals of the clean energy transition
  - 2050 Transmission Study
  - Economic Planning for the Clean Energy Transition (EPCET)

Balancing Resources Pillar



- Filed Day-Ahead Ancillary Services Initiative (DASI)
- Completed an internal assessment of moving to a prompt and/or seasonal capacity market construct
- Took significant steps to reform how ISO accredits resource capacity with its Resource Capacity Accreditation work

In 2023 the ISO Delivered on a Large Number of Complex and Novel Initiatives Addressing the Clean Energy Transition

ISO initiatives illustrate our commitment to advancing our vision to support the region's clean energy transition

Energy Adequacy Pillar

- Developed advanced forecasting and modeling processes to drive actionable decision-making around power system needs
  - Quantified region's energy adequacy vulnerabilities
  - Developed Probability Energy Adequacy Tool (PEAT)
  - Established Regional Energy Shortfall Threshold (REST)
- ISO recognized for its leading-edge actions developing a systematic approach to determine risk of extreme weather conditions on energy adequacy
  - ISO employees awarded by EPRI for their work to develop metrics and methods for maintaining grid stability with inverter based resources
  - ISO employees participating in NERC energy adequacy standard drafting effort

Transmission Pillar

- The 2050 Transmission Study highlighted for stakeholders the high value of taking steps in the nearer term to mitigate long-term transmission needs:
  - Encouraged state regulators to further enable demand reductions to reduce peak loads
  - Gave greater consideration to the location and size of new generation
  - Identifies the important incremental upgrades and priorities to address high-likelihood concerns
- Filing on Extended/Longer-Term Transmission Planning Phase 2 accepted by FERC in Q3 2024
  - Enables development of transmission infrastructure to address the findings of a Longer-Term Transmission Study
    - Codifies NESCOE and the ISO's respective roles throughout the process
    - Establishes the cost recovery methodology for resulting transmission
    - Provides for ISO supporting States' RFPs

Responsive Market Designs

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 2023, 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, and the regulation market structurally competitive.

In 2024, ISO filed and obtained approval from FERC to implement changes for the 2024 Forward Reserve Auction to address previous years' findings that the Forward Reserve Market (FRM) was structurally uncompetitive.

Note: *See IMM 2023 Annual Markets Report for detail*

2025 continue to focus 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*
- Implemented Day-Ahead nGEM Platform in 2023

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 2024, ISO filed and obtained approval from FERC to enhance longer-term transmission planning program

Interconnect and register new resources to meet FERC established timeframes

- Order 2023 Reporting metrics (to be implemented)
- Analyzing the impacts of FERC Order 2023 on the interconnection process
- Streamlined DER process through transferring all distribution system interconnection to state processes

2025 focus is on integrating recent studies and analyses into 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)

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 SOC 1 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.

2025 focus is on improving business operations across organization

- Implement internal process and technology improvements to address increasing grid complexity, including:
  - Broadening usage of ISO-developed innovations to enhance control room situational awareness and market efficiency
  - Addressing the trend of increasing DER/decreasing springtime load
  - Examining the single-source contingency limit
- Continue to modernize IT assets, technologies, and tools to mitigate cybersecurity threats
- Migrate ISO systems to the cloud

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
  - Hired for position to focus on environmental policies and community outreach in 2024
- 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 New England States' 2020 Vision and policy initiatives:
  - Request to evaluate clean energy pricing (Pathways report)
  - Request to conduct longer-term transmission planning (Future Grid Reliability Study; 2050 transmission study)
  - Enhancement to longer-term transmission planning process
  - Technical support on States' RFP efforts

- Focus in 2025 includes:
  - Building on novel analyses performed in 2023-24 to update assessments of regional energy adequacy vulnerabilities
    - Regional Energy Shortfall Threshold (REST)
    - Economic Planning for the Clean Energy Transition (EPCET) Study
  - Continue to work with States and stakeholders to improve asset condition process, and establish a criteria for right-sizing transmission investments to support integration of renewables and higher load levels
  - Continue to provide technical support to States, as requested, on clean energy and transmission RFP

APPENDIX 4: CYBER SECURITY AND CIP COMPLIANCE HISTORY AND COSTS

Cyber Security and CIP Compliance

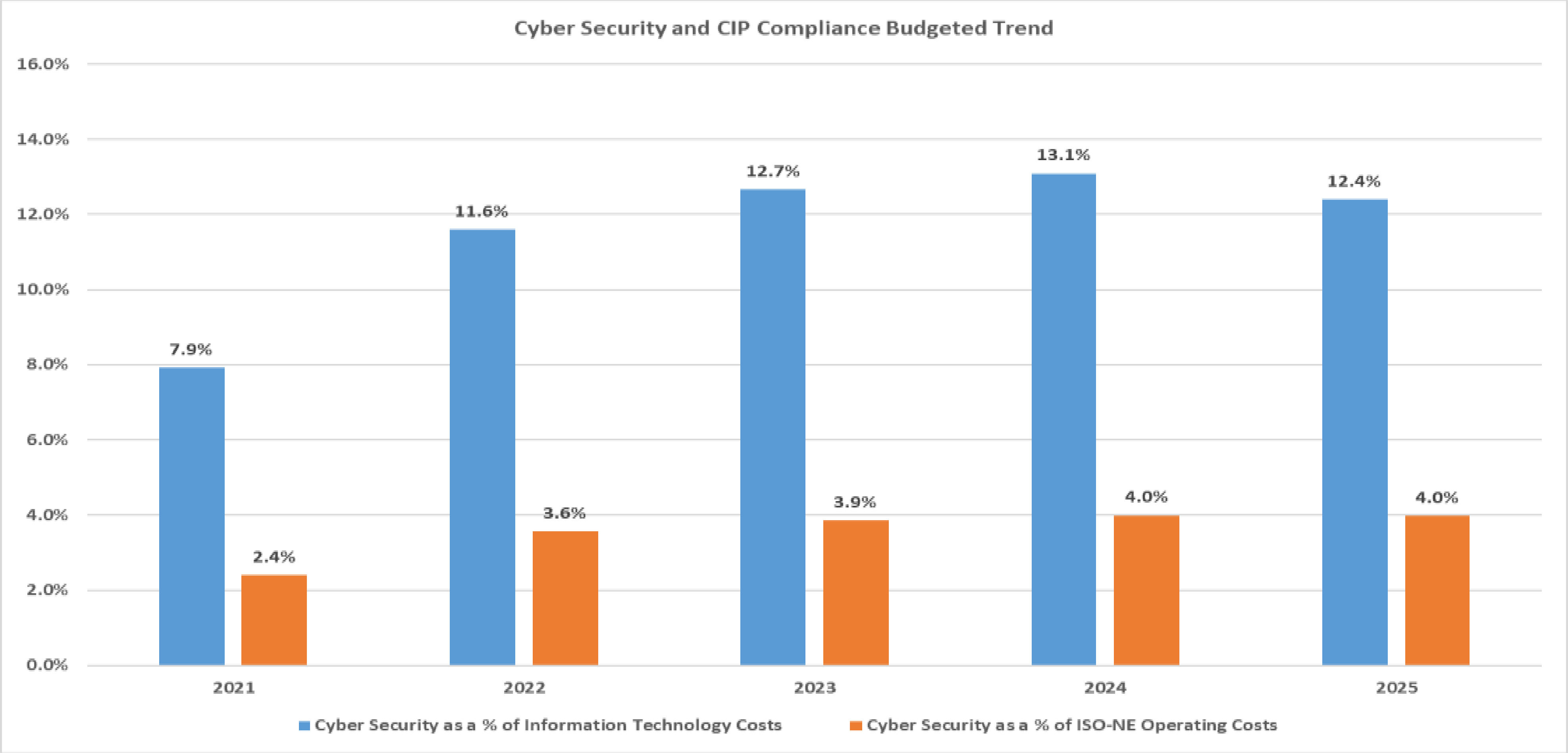
- Background
  - Information technology has become an indispensable tool for efficiently and reliably operating the increasingly complex regional power system, administering the billion-dollar markets where wholesale electricity is bought and sold in New England, and engaging and collaborating with our 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; ISO-NE has tightened security controls for cyber assets and visitors to ISO facilities in compliance with revised NERC CIP cyber security standards
  - ISO-NE developed and implemented a third-party cyber security risk management program that includes compliance with CIP-013 related to Supply Chain Cyber Security Risk

Cyber Security and CIP Compliance *(cont.)*

- 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
- 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; additional alerts and automations to increase the reach and productivity of Security Operations Center staff were developed in 2023 and will continue in 2024
- In 2023, additional security awareness training capabilities were added to address the human element of cyber security regularly
- During 2023 ISO-NE began to incorporate "immutable" technology that prevents modifications to data written to disk for both enterprise storage applications and system backups providing greater resiliency and protection for ransomware-style attacks; in the same year, ISO-NE deployed a technology framework to identify and fix known vulnerabilities more rapidly and to protect applications from emerging threats
- In June 2024, ISO-NE completed its periodic NERC CIP compliance audit with NPCC resulting in zero potential non-compliance (PNC) items, zero areas of concern (AOC), and four positive observations shared jointly with the Operations review

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 - 2023 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2023, and Outstanding Debt as of December 31, 2023 (1)

(Amounts in Millions)

	ISO-NE (2)	PJM	NYISO	CAISO	IESO (3)	MISO	SPP	ERCOT
Operating Expense - 2023	$ 235.6	$ 437.9	$ 231.6	$ 273.4	$ 280.4	$ 449.4	$ 254.9	$ 286.2
Less: Amortization & Depreciation	(30.0)	(37.7)	(17.7)	(28.7)	(24.1)	(30.4)	(16.8)	(34.7)
Regulatory Fees	(7.3)	(81.3)	(17.6)	-	-	(67.4)	(31.3)	-
Grant Expenses	-	-	-	-	-	-	-	-
Net Operating Expense - 2023	$ 198.3	$ 318.9	$ 196.3	$ 244.7	$ 256.3	$ 351.6	$ 206.8	$ 251.5
Other Financial Data								
Capital Expenditures for 2023	$ 35.4	$ 43.2	$ 16.3	$ 20.9	$ 72.6	$ 34.6	$ 14.3	$ 32.4
Outstanding Debt as of 12/31/23	$ 86.6	$ 5.0	$ 73.9	$ 156.7	$ 203.0	$ 274.4	$ 130.7	$ 2,514.0
Actual full-time equivalent headcount as of 12/31/23	625.5	802.0	599.0	710.0	896.0	1059.0	744.0	890.0

(1) Applicable amounts were taken from each entity's 2023 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 23, 2024

State Agencies' Questions to ISO-NE regarding 2025 Budget

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

   A copy of ISO-NE's 2023 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) Budget Flexibility. Given that future ISO-NE workflows are dynamic and budgets likely to fluctuate, how has ISO-NE built flexibility into its budget proposals? What protects ISO-NE's customers/ratepayers in the event ISO-NE budgeted amounts turn out to be overstated relative to actual amounts?

   Each year's annual operating budget is integrated with the ISO's business planning and organizational strategy. This connects our broader strategy to annual resource commitment and day-to-day execution. The annual work plan published in the fall and updated in the spring, identifies the objectives and initiatives supporting the ISO's strategic goals. The states and stakeholders have input into the work plan and during the operating year, we regularly provide updates on budgeted versus actual spending to FERC, the states and our stakeholders.

   To manage the flexibility in workload and potential needed resources, ISO-NE includes contingency amounts in the annual budget. The 2025 budget includes $3.0 million for the CEO Emerging Work Allowance contingency. The use of these contingency funds requires CFO and CEO approval as described in Appendix 8 (slides 196 and 197) of the 2025 budget presentation[1]. As a funding of last resort there is also $700,000 of Board contingency funding that requires approval of the Board of Directors to use.

   Any underspending of budgeted amounts is returned through ISO-NE billing rates via the *True-up* mechanism that is included and governed as stated in Section IV.A.2.2 of the Federal Energy Regulatory Commission (FERC) approved Transmission, Markets, and Services Tariff[2]. The True-up is comprised of any variation of the FERC approved Revenue Requirement compared to actual collections, and the actual spending compared to budget for the most recently completed year. The True-up mechanism is explained on slide 95 of the budget presentation and slides 95 and 96 include the components of the 2023 Revenue Requirement True-Up included in the 2025 budget and revenue requirement. In sum, underspending in one year reduces the collections a year after the underspending occurs, thereby protecting ratepayers.

[1] The presentation was presented to the NEPOOL Budget and Finance Subcommittee and can be found at 6_isone_2025_proposed_op_cap_budget.pdf (iso-ne.com)

[2] ISO-NE Transmission, Markets, and Services Tariff can be found at Transmission, Markets, and Services Tariff (iso-ne.com)

4) Capital Budget. Describe the process by which capital projects are identified and priced. In particular, detail the steps taken to determine the appropriate design, cost, and schedule for the resizing the Holyoke facilities to accommodate a larger work force.

   Capital projects are identified primarily by (1) Orders by ISO-NE's regulator (FERC) (2) Requests from ISO-NE Participants and (3) ISO-NE internal business owner needs. As a first step, a detailed work request must be prepared which is reviewed by our Subject Matter Experts (SMEs). The work request is subsequently reviewed, given appropriate priority, and approved/rejected/deferred by management. The result of this process informs capital project budgeting and Annual Work Plan priorities.

   If a project is approved, a project manager is assigned to plan the project and create a project charter. The essential parts of the project charter include: 1. Scope of work 2. Schedule 3. Budget. The charter is then approved or rejected by senior staff at the monthly Project and Risk Management (P&RM) meeting.

   Once approved, the project is executed per the charter. Implementation of capital projects in most cases use internal employees, contractors augmenting our internal staff, as well as vendors. The selection of vendors and contractors follows our purchasing policy. Additional information on our purchasing process can be found on slide 198. Senior management is given a monthly update on the progress of each project at the P&RM meeting.

   The 2025 Capital Budget includes $500,000 to develop a conceptual design and estimated project costs for the resizing of the Holyoke facilities to accommodate a larger expected workforce and refresh the facilities, which were built and/or last refreshed in 2007. These funds are included in the Space Utilization Phase 1 Project, which also includes $1.5M for upgrades needed at the Windsor Campus to house the System Planning Department. Our last investment in that facility occurred when it was built in 2013. To support these efforts, ISO-NE plans to engage two outside firms; a Project and Real Estate Services firm and an Architect and Design firm for both of these projects.

   The consultants will work closely with management to provide options that meet the objectives for the resizing of the Holyoke space, including providing seating for the expected increase in headcount over the next 7-10 years and ultimately for most employees to be based at one campus to foster collaboration; while focusing on the most cost effective design to achieve these objectives. ISO-NE will continue to utilize the established stakeholder process to provide updates on this project.

5) Computer System. Is the future computer system expected to be a completely new system or a patch of the old one? Explain.

   Rapid technology advances dictate that the future computer system will have to evolve from its current platform to a new platform. The ISO will be judicious about the transition, focusing initially on mission critical technology systems. To the extent that vendors continue to support older versions of their software and hardware, and such versions support the needs of the grid, the ISO will seek to maximize their use. Further, it is critical that all ISO systems have improved cyber security defenses embedded. Currently a major upgrade of our Market software (nGEM Platform Replacement) is underway. We have partnered with two other ISOs (PJM Interconnection & Midcontinent ISO) and our Market and EMS vendor (GE) to accomplish this task and share costs. This is a new system, which is needed to handle the complexity of a growing number and type of grid assets, new and more complex market features, ever multiplying security threats, and advancing IT technologies.

6) FTEs. Is the labor market as competitive currently as it was several months ago? If not, does that change ISO-NE expected employee costs? Explain.

   Although we have seen a recent positive trend in the number of applications for our analyst, data analyst, and computer science roles; the labor market continues to remain highly competitive for a majority of the roles required to address the increase in volume and complexity of work required to support the clean energy transition. These difficult-to-fill roles include Lead and Principal level analysts, engineers and technologists as well as economists. These positions have the greatest impact on employee costs due to higher salaries and higher acquisition and retention costs. They require greater investment in relocation assistance, immigration sponsorship, and signing and retention bonuses. Given that many of our growth roles fall into these categories, we are still projecting an increase in employee costs.

7) FTEs. What is the process by which ISO-NE decides the number of FTEs needed for each task?

   ISO-NE managers and supervisors prepare workplans and tasks for their areas of responsibility based on on-going work, and planned initiatives and projects consistent with the strategic plan. Where possible, emerging and shifting priorities and requirements for each business unit are reviewed to determine the availability to cover with existing staff and resources.

   Where business units determine additional resources are needed, they make a request for an additional FTE. Position justification documentation must be prepared by managers that includes a description of the need and the position responsibilities.

   The ISO determines the number of FTEs through the two stages of the annual budget process. In the first stage, ISO-NE prepares a "Top-Down" preliminary resource plan and requested budget that is presented in June of the preceding year to NEPOOL and NECPUC/State Agencies to obtain feedback on ISO-NE's planned work and needed resource requirements. In the second stage, after obtaining feedback during the preliminary budget period ISO-NE prepares a "Bottom-Up" detailed budget that forms the basis for the budgets presented during August and September preceding the budget year.

8) FTEs. What is the nexus between complexity and ISO-NE employee levels? Is the increased complexity expected to result in a need for: more employees; more highly skilled employees; and/or employees with different skill sets? Explain.

This response addresses both questions 8 and 12.

Complexity in the ISO's environment is manifest in many different dimensions and results in all of the stated outcomes: additional new tasks, more difficult existing tasks, revising existing tasks, and maintaining a workforce that can handle the challenges. All of the ISO's business functions have to process an increasing volume of change on the power system, while maintaining reliability and adherence to an expanding body of regional and national standards. Change is simultaneously happening on the supply, demand, transmission, distribution, wholesale markets, and technology dimensions. A brief description and examples follow.

One of the biggest technical challenges is building the capability to operate a power system dominated by inverter-based resources (such as solar, wind, and battery-storage technologies). This requires the ISO to build new, more sophisticated, power system models for its planning and operations functions, and building new applications to study, monitor, and control an inverter-based power system. The large number of individually smaller-scale inverter-based resources (relative to the size of traditional generating plants) involves developing a technology platform to achieve these requirements that is high performance, scalable, and secure. These complex engineering and IT-intensive tasks require the ISO to upskill its existing workforce, add new teams and analytic capabilities, and to implement an extensive set of new technical studies that will impact everything from interconnection evaluations, to long-term planning assumptions, to real-time operations software systems. The ISO expects that real-time operations in the future will include a significant level of coordination with the distribution system. Importantly, a central challenge is performing all of this work and systems development for the new system while simultaneously maintaining effective and reliable day-to-day operations for the current system.

As a practical matter, there are several other areas where the system's clean energy transition requires significant overhauls of the ISO's existing platforms – work that lies at the intersection of new tasks, revising existing processes and systems, and evermore complexity to manage. As an example, it is no longer sufficient to accurately forecast only hourly loads the next day and throughout the current day, but instead the ISO has to implement multi-hour forecasts on highly granular frequencies (minute-level intervals) and update them nearly continuously. The granularity and accuracy of these forecasts now impacts the efficiency of dispatch, and ultimately the system's cost to consumers. Similarly, managing operations under more frequent extreme weather conditions as the system's long-standing capacity surplus continues to tighten (both within New England and its neighboring regions) is significantly more challenging.

From a power system planning perspective, the volume and pace of interconnection requests, associated transmission system upgrades, as well as the longer-term transmission studies to address the reliability and policy goals of the states creates a high-volume of specialized work – as do the complete overhaul of the interconnection process pursuant to FERC Order No. 2023 and the development of a long-term public policy planning process pursuant to FERC Order No. 1920. Moreover, many of these changes require resource-intensive discussion and development in concert with stakeholders, development of corresponding tariff revisions and processes, and coordination with the states to best align the ISO's activities with the states' longer-term policy goals.

Regarding the wholesale market, the power system's transition requires the ISO to continuously assess the existing market structure against the projected needs of the future. Markets must incent and reward flexibility and create/maintain incentives for resources to operate reliably. Components of ongoing work include enhancements to the energy and ancillary service markets to better reward flexibility, including implementation of the significant Day Ahead Ancillary Services Initiative. The ISO has articulated the pressing need to develop the prompt and seasonal capacity market, marginal accreditation of capacity resources, and related reforms to the capacity market's design to support a future power system very different then when the Forward Capacity Market was developed twenty years ago. To develop such market-based products and innovations requires a significant investment in teams that can conduct the necessary analyses, build the requisite models, simulate the designs to prospectively evaluate their impacts, present these ideas to stakeholders, implement related software, and thereby continue to ensure the overall efficacy and cost-effectiveness of the wholesale markets.

All of the changes noted above have a material effect on the underlying technology platforms. They create the need for additional services and capabilities which must be developed and integrated into existing reliability and markets platforms. The rapid pace of change on the technology front requires the ISO to continually evolve legacy systems and databases. The ISO is leveraging cloud technologies to the extent possible to take advantage of its greater agility and scalability and reduce the amount of rework due to hardware obsolescence, but this also requires the upskilling and redeployment of our workforce. Cyber security (particularly from nation states) may be growing as the biggest threat to reliability, and it requires the ISO to invest heavily in its ability to detect, prevent, and recover from such threats. Equally importantly, the ISO needs to continue to be mindful of fast emerging technology like artificial intelligence. The ISO technical teams need to develop the requisite proficiency to understand the costs, benefits, and risks of AI based tools and applications prior to integrating them into its platform.

In sum, the complexity of the power system's evolution to support the clean energy transition and integrate new technologies is creating new tasks, increasing the volume and difficulty of existing tasks, and requiring significant upgrades to the existing systems, tools, and procedures we employ to perform our core responsibilities. Accordingly, we need a workforce of sufficient strength and skill to manage these new challenges.

9) <u>FTEs.</u> With an expected influx of employees, how has ISO-NE geared up its ability

repurpose/redeploy its existing employees as needed? Describe the process ISO-NE uses to identify and prepare employees for repurposing/redeployment.

Assessing our talent needs is a standard practice aligned with our strategic, operating, and budget planning processes. Each business group assesses their needs over a two-to-three-year time horizon and updates those projections each year as operating objectives become clearer. When requesting a new FTE, the manager must consider whether there is a repurposed position that s/he could use. The business unit must work with Human Resources to determine if a repurposed or other vacant position is available, or an internal staff member could be utilized to meet the business needs. Individual and/or group development plans are created and priorities for our Enterprise Learning Organization are updated accordingly.

10) <u>Future Budget Levels.</u> Once the transitory process is complete, does ISO-NE expect its workload and employee level needs to diminish? Explain. If so, how does ISO-NE expect to downsize accordingly?

ISO expects the clean energy transition to take us well into the mid 2030's and beyond. The ISO expects that its workload and associated complexity will continue to grow. Maximizing the performance of the new power system will depend on successfully optimizing the integration of supply and demand resources, transmission, and distribution systems. As such, the ISO expects the increase in FTEs to continue for the foreseeable future (at least through 2030) as indicated in the budget presentation. When the power system and expected changes are more stable and/or predictable, the ISO expects that attrition and retirements will lead to a rebalancing of the workforce.

11) <u>Interest Income.</u> What is the basis for the projected interest income rate for 2025 of 2.75%?

Interest is earned from an overnight sweep of the settlement cash collected and held for two days before being remitted back to market participants. The overnight sweep currently yields an interest rate of 2.75%. We expect that rate to continue into 2025 and therefore reflected in 2025 budget. Given the short period for which the settlement money is held, ISO is unable to utilize a higher yielding investment vehicle such as a money market account.

12) <u>ISO-NE Workload.</u> What is the nexus between complexity and ISO-NE workload? Is the increased complexity expected to result in: new, additional tasks; more difficult existing tasks; and/or having to redo past tasks? Explain.

See response for question 8 that addresses questions 8 and 12.

13) <u>Job Benchmarking Study</u>. Detail how the job benchmarking study impacted the proposed budget for 2025 and for 2026. What impacts from the study linger beyond 2026? Explain.

After a spike in employee departures, we engaged with Mercer, our compensation consultants, to conduct a comprehensive study of the competitiveness of our compensation.

More generally, our compensation practices are designed to attract, retain, and motivate our highly skilled workforce, and we use benchmark data to ensure we remain competitive and cost-effective in an ever-changing talent market. Mercer provides us with relevant benchmarking data to inform our annual merit, promotion, and adjustment budget. Additional benchmarking data includes consultation with other ISO/RTO's and participation in several other national merit, promotion, and adjustment salary surveys. Benchmarking has and will continue to inform our budget requests each year.

14) Market Design. What is it about the current market design that is inadequate for the future?

New England's markets have two overarching goals: to provide electricity and reliability services at competitive prices; and to guide investment in new resources to ensure the electricity system across the region is continuously reliable. The ISO has designed the wholesale markets in a technology-neutral manner that provides opportunities for any resource that can deliver the needed services. The existing suite of market products and compensation structures has served New England well and has enabled thousands of megawatts of renewable resources, batteries, and distributed energy resources (including energy efficiency and demand response) to participate in the wholesale markets.

Yet, the power grid and the industry face challenges that are dynamic and complex. The market structure is increasingly under pressure to deliver outcomes that support both the states' decarbonization objectives and the region's reliability objectives. This presents a challenge to the ISO: how to incentivize the resources needed to balance the system and ensure reliability in the future.

As the region's resource mix transitions to more renewable energy, the ISO must ensure that market prices and products continue to adequately compensate the resources possessing the capabilities necessary to meet future system needs. In recent years, the ISO has developed market enhancements in response to these changes and continues to assess the needs of the future system.

A recent market enhancement that will be implemented in 2025 is the Day-Ahead Ancillary Services Initiative (DASI), which will procure and transparently price the ancillary service capabilities needed for a reliable, next-day operating plan with an evolving generation fleet. One component of DASI involves procuring a new day-ahead ancillary service to cover the "gap" when the day-ahead market's physical energy supply awards are below the ISO's forecast real-time load. The second component of DASI is to procure day-ahead flexible response services to ensure the system is prepared to recover from sudden source-loss contingencies and can respond quickly to fluctuations in net load during the operating day.

In addition to DASI, the ISO is assessing changes to the Forward Capacity Market (FCM) to better ensure power system reliability and cost-efficiency as New England's resource mix evolves. The Capacity Auction Reforms (CAR) project would transition the capacity market from a forward/annual market to a prompt/seasonal market with resource accreditation reforms. The existing FCM design does not adequately reflect the needs of the current or future system. The forward nature of the market is inefficient as it does not capture the faster timelines of smaller distributed resources. The annual cycle does not capture the different seasonal needs and the current resource qualification process does not reflect the various energy constraints on the system.

Other market enhancements to address future needs are:

- Order No. 2222 - Participation of DER Aggregations in Wholesale Markets Key Project: enabling distributed energy resources to participate in wholesale electricity markets as aggregations, in compliance with the Federal Energy Regulatory Commission's landmark Order.
- Storage Modeling Market Enhancements Assessment: the ISO continues to evaluate opportunities to more efficiently integrate energy storage resources into the energy and ancillary service markets.

The ISO continues to conduct analysis of the potential future system to understand how changes on the system will affect reliability, economic efficiency and carbon intensity. In the recently released draft report, Economic Planning for the Clean Energy Transition (EPCET), the ISO explains how variability in both supply and demand increases significantly between years in the future. The expected increase in variability and the critical, but sporadic, need for dispatchable resources to ensure reliability will change the grid dramatically, which will likely affect the performance of some elements of the current "grid economy".

The increased use of intermittent resources, combined with shifting energy use patterns and a drive toward electrification, will create an energy landscape that is increasingly weather dependent at a time when more severe weather events are expected for the future. Given the growing variability in both energy production and demand, the New England power system will require a greater ability to respond to operational uncertainties during the operating day.

The ISO continually assesses the system, both current operations and future scenarios, to determine if additional market enhancements are needed.

15) <u>Operations.</u> What operational tools is ISO-NE seeking to acquire and what are the functions of the tools? How does ISO-NE become aware of the available tools?

In general, the ISO's expectation for continued investment in new and/or enhanced operational tools is driven largely by the changing resource mix, the increased complexity of the region's demand profile, and the increased impacts of weather on operation of the system. For example, the expected shift toward a resource mix comprised of large quantities of intermittent and energy limited resources requires that ISO to enhance its existing capacity and energy analysis tools in order to better account for the variability associated with these types of resources across a variety of time horizons. Some of these tools requiring enhancement reside within ISO's energy management system (EMS), which is scheduled for another major upgrade by the end of 2026, and some are developed and supported in-house (e.g., 21-day energy simulator/Probabilistic Energy Assessment Tool). The incorporation of large quantities of inverter-based resources requires that ISO continue investing in capabilities (tools and training) supporting the performance of electromagnetic transient (EMT) studies; more specifically, the buildout of an EMT study database and training of staff in the performance of EMT analysis. Also related to the changing resource mix, ISO's implementation of FERC Order No. 2222 is expected to require significant enhancements to the EMS and market clearing engines ahead of the planned Nov. 2026 implementation date. The increased complexity (e.g., higher, more variable) of demand is also driving ISO's expectation for new and/or enhanced operational tools. While ISO has made significant enhancements to its demand forecasting capabilities over the past few years (e.g., integration of 23-city weather forecast), continued investment in this area is expected. For example, the incorporation of probabilistic load forecasting techniques is expected in the next several years though exploration and definition of specific tool requirements remain in their early stages. Lastly, and closely linked with both the changes on the supply and demand sides, is the increased impact of weather on operation of the system. One notable example impacting operational tools is the implementation effort associated with FERC Order No. 881, Managing Transmission Line Ratings. This multi-year implementation effort is driving the development of various systems in order to meet the requirements to account for ambient-adjusted line ratings.

Notably, many of the examples listed above are largely focused on enhancement of existing software and tools, but ISO remains cognizant of the need to stay alert to the need for new operational tools should the need arise. ISO often becomes aware of new tools through a variety of mechanisms including participation in industry committees, working groups, and other outreach efforts. ISO staff has leadership roles on a number of North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) working groups. Many of which are engaged in efforts related to the energy transition that is occurring across North America. These forums provide significant exposure to what others are doing across the industry as well as best practices. Along the same lines, participation in groups such as the ISO/RTO Council (IRC) enables ISO to gain insights from other ISOs/RTOs that are experiencing many of the same challenges that ISO-NE expects to face in the coming years. Lastly, on-going engagement with industry leaders such as the Electric Power Research Institute (EPRI), the North American Transmission Forum (NATF), and the Institute of Electrical and Electronics Engineers (IEEE), among others, allows ISO staff to identify and bring back best practices and relevant lessons learned from across the industry.

16) Stakeholder Engagement. What is the objective of the new skillsets to engage stakeholders? Who are the new audiences that ISO-NE wants to reach?

The complexities of the changing resource mix and changing load patterns continually require new initiatives to reliably manage the ISO systems. These changes range from updated ancillary services and capacity market designs to notable transmission interconnection and modeling requirements mandated by the ISO's regulator (FERC) and thus to participants. Accordingly, a portion of our budget for stakeholder engagement in

2025 focuses on additional education for participants doing business with the ISO to help them understand their evolving tariff requirements. Newer companies and companies outside of New England who are engaging in transactions in New England as a result of state, federal, and other incentives, have limited background on New England's physical electricity system or FERC-regulated competitive markets. The questions and information they seek are detailed and take considerable time and resources to respond. Thus, the ISO is focusing additional training and programing to direct them to the information and resources they need to better learn and understand their requirements so they can function properly in our systems. In addition, public interest and engagement in the regional energy system continues to grow as well as the need for additional interactions with the media, community groups and public officials. A portion of our budget focuses on increasing outreach to these groups and developing additional educational materials regarding the ISO and the clean energy transition.

17) System Transition. Are there other ISOs/RTOs that are ahead on the system transition curve relative to ISO-NE? If so, what has ISO-NE learned from them?

All ISOs/RTOs are undergoing significant changes to their systems. ISO New England has been a leader in developing changes to market rules and system operations and planning processes in order to facilitate the integration of advanced technologies and renewable resources and operating the power grid under cold weather conditions.[3] The nature of the region's power system, public policy initiatives, the need (or lack thereof) for new supply and the ability to site and develop certain infrastructure are just some of the factors that can affect the pace of the clean energy transition. When other regions have faced particular issues earlier than New England, we have learned from them and when New England has surfaced issues earlier, such as gas-electric coordination, we have shared our lessons. However, the many differences in each of the regions' power systems (including resource mix), regulatory and market structures, applicable reliability standards and other factors often calls for flexibility in how each ISO/RTO will address various issues. That said, ISO New England regularly engages with the other ISO/RTOs in several forums. The ISO/RTO Council (IRC) comprises members from nine North American ISO/RTOs, with eight individual committees focused on areas like operations, markets, and planning. Each ISO/RTO brings to the table varying perspectives and strategies on the collective challenges faced by our industry. Through this collaboration, ISO/RTOs are able to share ideas and industry best practices on topics, including transmission, to help create a better, more efficient electric power system.

ISO New England, NYISO and PJM have in place a Northeastern ISO/RTO Planning Coordination Protocol, ensuring that the electric system is planned on a wider interregional basis and is proactive and well-coordinated. ISO-NE, along with NYISO and PJM, are also members of the Eastern Interconnection Planning Collaborative (EIPC). EIPC is a collaborative made up of the major transmission planning coordinators responsible for the planning of the bulk power grid throughout the Eastern Interconnection, which represents about two-thirds of the United States and Canada.

ISO New England exchanges knowledge and best practices with other ISOs and RTOs on

[3] ISO New England: Where We are Going, https://www.iso-ne.com/about/where-we-are-going.

a variety of subjects, from analytical modeling to regional collaboration. Some areas where we have benefited from these exchanges are:

- In January 2024, as part of ISO New England's work on Longer-Term Transmission Planning processes, staff from our System Planning team and other departments met with counterparts from the Midcontinent Independent System Operator (MISO) engaged in similar work to learn from each other's experiences;
- We are incorporating lessons-learned from large-scale deployments of inverter-based resources in other areas, especially ERCOT and California. This has informed our adoption of various practices in planning and operations, such as the use of Electromagnetic Transient analysis;
- We are learning from CAISO's experience with integrating high-levels of battery-electric storage, which has highlighted the importance of forward-looking dispatch and pricing methods to support batteries' efficient and cost-effective real-time optimization; in recent years this has helped CAISO to successfully manage the steep PV-related net load ramps that New England is beginning to experience, and to reflect the costs of doing so in real-time prices so storage and other resources are appropriately compensated for their flexibility;
- SPP's experience managing large unanticipated fluctuations in wind power (at times exceeding several GW per hour), and their reserve market enhancements to address it, have been instructive on the benefits of improving reserve market designs to reliably address increasing operational uncertainties through the markets in higher-renewables systems.

18) Transmission Expansion. Describe transmission team that ISO-NE is planning to build. What is the time frame? What are the tasks? In your response, please specifically describe the transmission team that ISO-NE is planning to build to support the new LTTP Phase 2 process.

ISO-NE is expecting to grow the Planning team over the next several years. This growth will support a range of new and growing activities. The incorporation of additional inverter-based resources and the emerging associated new NERC standards will require additional staff to review the performance of these resources and their network model representations. FERC's Order No. 2023 will require additional staff to administer and study new requests for interconnection. The updated approach to resource capacity accreditation will require additional resource adequacy modeling and qualification staff.

The new LTTP Phase 2 process will also require additional staffing and skills. We will require personnel to administer the issuance of requests for proposals and the processing of submittals. While the ISO is currently resource constrained in its transmission engineering capability, it plans to ramp up and expand its capabilities to be able to issue multiple RFPs in future cycles. Additionally, the ISO will need to add staff to evaluate and compare different proposed solutions. Resources will be needed to perform the multi-value evaluation of the various submittals.

In addition, ISO is still waiting on a number of FERC orders on compliance to finalize structures, including those related to Order Nos. 2023 and 1920.

19) Transmission Expansion. Given the expected need for significant transmission expansion:

a) How does ISO-NE view its Mission to plan the transmission system? I.e., is ISO-NE responsible for planning the transmission system? If not, who is? Explain.
b) Does ISO-NE expect to use market driven outcomes or planned outcomes to determine how the system expands? Explain.
c) How will ISO-NE ensure that the transmission system expands appropriately and efficiently?

Under the Regional Transmission Operator construct, ISO is responsible for the regional planning process in New England. Along with that, ISO is the Planning Coordinator under the NERC functional model and is therefore responsible for ensuring that the region meets the mandatory planning reliability standards.

The ISO expects to continue to rely on wholesale markets to provide the necessary incentives to existing and new resources to meet the operating needs of the system. Market-driven outcomes, such as the addition of new generation or demand-side resources, including state-contracted resources, or the retirements of resources are reflected in the planning models.

The regional planning process, laid out in Attachment K of our Open Access Transmission Tariff, contains the mechanisms to ensure the system expands appropriately and efficiently. This process is developed through discussion with our stakeholders at NEPOOL, and with input from the New England states. The Federal Energy Regulatory Commission reviews and approves these rules. The approach provides for the sharing of inputs, scopes of work and results with our open stakeholder Planning Advisory Committee. With the newly-approved LTTP process, the ISO, working in coordination with the states, will determine transmission expansion to facilitate state policies. The states will play a key role in determining transmission expansion through this process.

20) Transmission Expansion. In addition to identifying transmission needs sooner and assisting states with transmission related studies and RFPs:

a) What other improvements to transmission planning and expansion does ISO-NE expect to implement going forward? Explain.
b) Is ISO-NE satisfied with the way specific transmission projects are determined, assigned, and/or priced? Explain.

ISO-NE recently published the 2050 Transmission Study identifying future needs and highlighting the transmission upgrades that will be needed to meet the region's needs as it seeks to decarbonize its economy. In addition, this study recently included a high-level assessment of the ability to interconnect offshore wind at various points along the coastline. ISO-NE expects to continue to provide information of this nature to assist the market and policy makers going forward.

In the context of a transmission RFP, qualified transmission providers will determine the types and pricing of projects that they wish to submit. The selection process includes a methodology for how winning bids are selected.

We believe that the Planning Advisory Committee process provides transparent and robust information about the transmission planning projects for which the ISO is responsible. The regional transmission planning process that is governed by the ISO's Tariff is robust and has resulted in a reliable and efficient system. However, we acknowledge that there are questions about the adequacy of the review and approval process for certain projects that are outside of the ISO's jurisdiction, such as asset condition projects.

21) Transmission System Operations. Describe the expected changes to transmission and distribution system operations and interactions going forward.

As more intermittent and inverter-based resources are connected to the transmission and distribution circuits, system operations are expected to continue to become increasingly complex. Fewer dispatchable resources and more variable resources will require increased preparation and oversight. Operators will have to manage a wider range of system conditions, such as periods of extremely low net system loads during spring periods of high solar production as well as winter periods of constrained energy conditions. The volumes of new resources that are connecting to the distribution systems are changing the flows and conditions at the transmission-distribution interfaces, requiring increased operator preparation and action. All of these changes will require more coordination with distribution companies. Moreover, should the states take action to improve the price-responsiveness of demand, we will have to make further adaptions to our markets and systems.

ISO-NE Responses August 23, 2024

Questions from the Connecticut Office of Consumer Counsel (CTOCC)

Please refer to the slide deck from the August 9, 2024 presentation to state representatives on the ISO New England Proposed 2025 Operating and Capital Budgets

CTOCC 1 In last year's (2024) budget presentation, ISO proposed nine (2023) new FTEs and twenty new (2024) FTE hires. How many of these positions did ISO-NE fill? Please provide hiring dates for each new position authorized and filled under last year's budget.

For additional FTEs requested during the annual budget, ISO-NE budgets an estimated portion of the FTEs based on the assumption that all positions will not be filled or need funding during the initial year due to the time to recruit and onboard, and defers a portion of the funding to the following year. The 2024 budget included funding for 9 FTEs that was deferred from 2023 and estimated funding for 20 FTE positions from the 2024 requested positions (with the rest deferred to 2025).

CTOCC 2 For 2023 and 2024 to date, please provide the number of new hires that joined ISO-NE and the number of employees that left the organization.

For 2023, there were 73 new hires and 37 departures for the organization, and through June 30, 2024, there have been 43 new hires and 21 departures. New hires include positions added in the budget process and those due to normal turnover for the organization.

CTOCC 3 On an annual basis for the period 2019 through the present, please provide the authorized level of employee positions (in FTEs), the average level of filled positions (in FTEs) and the average vacant level of employees (in FTEs).

The requested information from 2015 to the present is included on slide 119 of the 2025 Budget presentation.

CTOCC 4 What vacancy factor was utilized in determining the proposed 2025 Budget? How does that factor compare to actual vacancy rates during the period 2019-2014?

For existing headcount, a vacancy factor of 6.0% was utilized for funding in the 2025 Budget to account for the recent experience in 2023 and 2024. Actual vacancy rates from 2015 to the present are included on slide 119 of the 2025 Budget presentation.

CTOCC 5 While ISO is requesting 46 new FTEs in this year's budget, please discuss any future potential staff organizations and restructuring that may result in reassignments within the ISO organization.

While no significant reorganization or restructuring is currently planned, this has occurred in the past where management has determined efficiencies can be gained or groups within the organization would be better aligned working together or under a common business unit.

For example, in early 2024 the Information and Cyber Security Services area did a restructuring to combine their software development and support teams. The changes were made in an effort to benefit customer business units having a single team with which to collaborate and giving the new teams a greater sense of ownership and the ability to develop deeper expertise for reliability.

CTOCC 6 Please identify cost containment initiatives performed by ISO over the last two years. Discuss the cost savings realized. Will any projected cost savings continue to be realized during the 2025 budget cycle? Are any cost-savings initiatives expected to continue in 2025? If so, please identify which cost-savings initiatives are expected to continue and the expected cost savings that ISO expects to realize from those initiatives.

The 2025 Budget materials include Efficiencies, Reductions, and Other Non-Recurring Costs (slide 51), as well as positions that have been repurposed since 2018 (slide 63).

On an ongoing basis, ISO-NE uses an issues management process to identify and track needed enhancements to existing systems and processes to more efficiently administer the market rules and procedures. Identified enhancement activities are tracked via an internal application to administer the change action through to completion. ISO-NE doesn't typically quantify the cost savings realized for these activities although employees are encouraged to identify areas of improvements in systems and processes. Additionally, each year a capital project is initiated to package together identified system enhancements that can be completed by Information Technology staff within the timeframe and budget under the capital project.

CTOCC 7 Please provide detailed workpapers showing the calculation of the 2023 actual depreciation expense, as well as the depreciation expense stemming from the approved 2024 budget and proposed 2025 budgeted year.

Please refer to slides 72-73 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 on page 49 of ISO-NE's Annual Financial Report (see 2023_financial_statements.pdf (iso-ne.com)) contains additional information regarding the method of calculating depreciation expense for ISO-NE.

CTOCC 8 Does ISO remove fully depreciated plant from the calculation of annual depreciation expense in the proposed budget? If so, please specify that calculation in the budget documents.

Once an asset is fully amortized it is no longer included in depreciation expense. It will remain on the statement of financial position until the asset is no longer in use.

CTOCC 9 **Slide 91**. Please provide a detailed breakdown of computer services expenses comparing 2023 actual ($20,469,000) to the proposed 2025 budget ($31,336,000).

Please see the table below with a breakdown of Computer Service costs by Information and Cyber Security Services area.

	2025 Budget	2023 Actual	Change
Infrastructure & Service Delivery	$ 14,482,988	$ 9,546,754	$ 4,936,234
Architecture & Enterprise Applications	$ 7,669,254	$ 5,027,566	$ 2,641,688
Energy & Markets Applications	$ 6,035,565	$ 3,976,921	$ 2,058,644
Cyber Security	$ 2,951,565	$ 1,751,533	$ 1,200,032
Change & License Management	$ 197,004	$ 166,475	$ 30,529
Total	$ 31,336,376	$ 20,469,249	$ 10,867,127

In addition to continued investment and upgrades for Cyber Security monitoring and protection, significant computer service increases include: Inflationary and product renewal costs ($2.22M); Advanced firewall tools ($0.83M); Operating System Increases and Enhancements ($0.74M); Cloud Storage Usage and Tools ($0.67M); nGEM Market System Maintenance ($0.6M); PV/Wind/Weather Forecasting Service additions ($0.57M); Application Performance Monitoring Software ($0.5M); Power System Simulation and Modeling Software needs ($0.48M); Collaboration Tool Enhancements ($0.48M); Additional On-Premises Storage needs ($0.43M); Virtualization Software ($0.37M); Computer Network Routers and Switches ($0.33M); Data Delivery Protection ($0.33M); ERP System Licensing ($0.27M); Interchange Distribution Calculation Tools ($0.16M); Incident Management Platform ($0.13M); and Battery Storage Modeling Tool ($0.12M).

CTOCC 10 **Slide 92** states "... Salaries ($12.7M or 10.4%) – Increases include salary related to annual merit and promotional increases to align compensation according to compensation study results, funding for the addition of 50 full-time equivalent positions including funding for 30 in 2025 and carryover of 20 FTE's from 2024." Does this mean that the 2025 proposed budget includes 20 positions that were included in the 2024 budget but have not yet been filled? If so, please identify the positions that have yet to be filled and the commensurate salary.

The assumption is that 2024 positions, included in that year's budget, would take a period of time to recruit and onboard and therefore, only partial funding was included in the 2024 budget. The remaining funding for 20 FTEs was deferred to the 2025 budget. The assumption is that 2024 positions will be filled (except for normal vacancy) by the end the current budget year and the deferred portion will need funding in the subsequent year's budget (in this case 2025).

CTOCC 11 Please provide ISO's incentive compensation plan, including general information on the range of payouts (amounts of payouts and percentages of salary that those payouts represent) within the organization.

ISO-NE's incentive compensation plan provides for non-fixed payments. The Annual Performance Incentive (API) plan is intended to reward employees for their annual contribution to ISO-NE's business results and, as such, is based on both corporate and individual performance. API bonus eligibility levels are determined by an employee's salary grade, and for non-officer employees range from 6.5% to 25% of base salary. Actual API bonus payments can range from 0-120% of an individual's eligibility level.

ISO-NE Officer compensation, including bonus amounts, are included in ISO-NE's IRS Form 990.

CTOCC 12 Please identify the performance metrics that ISO-NE relies upon when awarding payouts under the incentive compensation plan, including performance goals that are measured to determine incentive plan payouts.

As noted in the response to CTOCC 11, API awards are based on both corporate and individual performance. Corporate performance includes metrics tied to ISO-NE's Strategic Goals with a number of weighted factors that are objectively measured. The ISO Board of Directors approves the metrics and conducts a final review process prior to payouts. Individual performance includes an annual formal review by an employee's manager with measurements for an employee's major responsibilities and other performance factors based on the employee's position.

NESCOE Pro Forma Budget
Proposed 2025 Budget

	2025
Salaries and Wages	
Salaries	1,219,758
Payroll Taxes	121,976
Health and Other Benefits	140,000
Retirement §401(k)	48,790
Total, Salaries and Wages	**1,530,524**
Direct Expenses - Consulting	
Technical Analysis	527,634
Legal (FERC)	200,000
Total, Direct Expenses, Consulting	**727,634**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	51,938
Professional Services	48,925
Travel/Lodging/Meetings	92,700
Total General and Administrative	**193,563**
Capital Expend. & Contingencies	
Computer Equipment	10,000
Contingencies	246,172
Capital Expend. & Contingencies	**256,172**
TOTAL EXPENSES	**2,707,893**

New England States
Committee on Electricity

2025 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 9, 2024

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 2025 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: 2025 proposed budget is less than 2025 5-year pro forma budget
- ✓ Following calendar year 2023, 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, 2023 *Report to the New England Governors*:

- ✓ Reviewed work in 2023
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

- ✓ NESCOE provided to the Governors the ***2023 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

Projected Policy Priorities

- ✓ **Transmission has a strong presence in forward-looking priorities.** This includes, but is not limited to:
  - ✓ Asset Condition Project process changes
  - ✓ Operationalizing long-term transmission analysis; moving as expeditiously as possible toward ISO-NE's first competitive solicitation under FERC-approved procedures
  - ✓ Continued engagement in FERC's efforts to reform transmission planning, generator interconnection, and cost allocation processes
  - ✓ Continued work to improve transmission cost oversight, estimation, and controls
- ✓ **Wholesale Market Reforms**. Continued engagement on means to modernize wholesale electricity markets to support achievement of clean energy laws and other state law objectives while maintaining system reliability, and participate in the design of associated market rules and governance, including for example:
  - ✓ resource capacity accreditation
  - ✓ retirement reforms
  - ✓ capacity market timing changes, as well as those to support energy storage and distributed generation.

NESCOE Organization & Misc.

Employees

- ✓ Retain and attract diversity in academic training, skills; blend of private & public sector experience
- ✓ Assume return to NESCOE's prior steady state employee level of six
  - ✓ Seeking transmission technical expertise/engineer

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
- ✓ Oxford Power
- ✓ Apex Analytics
- ✓ 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 2024, 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 2025 budget conforms to 2025 budget in 5-year Pro Forma Framework

✓ 2025 Projected Budget in 5-Year Pro Forma:	$2,942,090
✓ 2025 Proposed Budget:	$2,707,893
✓ 2024 Budget, for reference:	$2,596,015

The 2025 Proposed Budget reflects:

- ✓ Assumed return to prior steady state of six employees
- ✓ Continued inflationary pressures
- ✓ No office rent or utilities
- ✓ More travel for meetings

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.

2025 Proposed Budget

	2025
Salaries and Wages	
Salaries	1,219,758
Payroll Taxes	121,976
Health and Other Benefits	140,000
Retirement §401(k)	48,790
Total, Salaries and Wages	**1,530,524**
Direct Expenses - Consulting	
Technical Analysis	527,634
Legal (FERC)	200,000
Total, Direct Expenses, Consulting	**727,634**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	51,938
Professional Services	48,925
Travel/Lodging/Meetings	92,700
Total General and Administrative	**193,563**
Capital Expend. & Contingencies	
Computer Equipment	10,000
Contingencies	246,172
Capital Expend. & Contingencies	**256,172**
TOTAL EXPENSES	**2,707,893**

2023 & 2024 Spending & Implications for 2025

Unspent funds in any year credited toward future year

2023 Total Spending:	$1,490,069*
2024 Spending to end of June:	$760,663
2024 Projected Year End:	$2,158,180*

Second half of 2024 spending projected to exceed first half due to work on transmission matters and interest in returning to prior staff size with addition of transmission technical expertise/engineer.

*Cumulative prior years' true up, including 2022, was reflected in the 2024 revenue requirement and rates. The 2023 true up will be reflected in the 2025 revenue requirement and rates (see next slide). Any 2024 true up will be reflected in the 2026 revenue requirements and rates.

2025 Projected Billing Rate

With thanks to ISO-NE for calculations -

2025 Budget:	$2,707,893
Less 2023 True Up:	($1,115, 346)
Total Revenue Recovery:	$1,592,547
Divided by Total Network Load:	214,795,375

(total network load from 2024 ISO-NE tariff; no escalation or reduction used in calculation)

2025 Schedule 5 Estimated **Rate $0.00741 per kW-month**

Thank you.

Questions?

NESCOE

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: August 28, 2024

RE: Proposed Revisions to the ISO-NE Financial Assurance Policy

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At its September 5, 2024 meeting, the Participants Committee will consider a package of revisions to the ISO New England Financial Assurance Policy (FAP) modifying the Pay-for-Performance (PFP) financial assurance provisions, i.e., the FCM Delivery Financial Assurance. As detailed below, the ISO proposes introducing a corporate liquidity assessment to evaluate PFP penalty default risk that could result in additional financial assurance requirements for higher risk Market Participants (Corporate Liquidity Revisions). The ISO also proposes to modify the intra-month collateral (IMC) variable in the FCM Delivery Financial Assurance formula to prevent unnecessary collateral spikes (IMC Revisions). Together, these changes are referred to herein as the "FAP Proposal."

The following documents are included in this memorandum:

- Attachment A: ISO-NE's August 21, 2024 Memo (circulated with the Initial Notice)
- Attachment B: Proposed Redlines for the ISO's FAP Proposal[1]
- Attachment C: ISO-NE's July Presentation to the Budget & Finance Subcommittee
- Attachment D: NEPGA's July Presentation to the Budget and Finance Subcommittee
- Attachment E: NEPGA's Proposed FAP Revisions
- Attachment F: NEPGA's August Presentation to the Markets Committee
- Attachment G: NEPGA's Proposed Market Rule 1 Revisions

BACKGROUND

In the wake of Winter Storm Elliott and after observing some of the defaults in PJM, the ISO determined that it should enhance the FCM Delivery Financial Assurance methodology to account for the risk of nonpayment of potential PFP penalty payment obligations.[2] To reach its

[1] A minor scrivener's error is corrected and highlighted in yellow.

[2] In September 2023, the ISO recommended four updates to improve the PFP collateral methodology. Given the complexity of the Corporate Liquidity Revisions, the ISO moved forward with the other three, i.e., revisions concerning the scaling factor, the capacity weighted average performance,

conclusion, the ISO evaluated the corporate liquidity of entities that acquired a Capacity Supply Obligation (CSO) in FCA 16. The assessment aimed to determine whether those Market Participants had sufficient liquidity to pay their potential PFP penalties. The ISO's evaluation revealed that on a standalone basis (i.e., without parental or affiliate support) less than one-quarter of all FCA 16 Market Participants had sufficient corporate liquidity to pay their total potential PFP penalty payments. The ISO has concluded that capacity sellers unable to show an ability to satisfy the financial obligations associated with their CSO, as limited by the monthly and annual stop-losses, poses a significant risk of default and the default risk creates an unacceptably high credit risk to the rest of the pool.[3]

OVERVIEW OF THE ISO'S FAP PROPOSAL

The ISO's proposal to modify the financial assurance requirements evolved in response to stakeholder feedback, resulting in the Corporate Liquidity Revisions presented for Participants Committee action. These FAP revisions amend the financial assurance requirements for capacity sellers that do not have adequate corporate liquidity relative to potential PFP obligations. Under the proposed corporate liquidity assessment, the ISO would evaluate a capacity seller's liquidity relative to the three largest monthly stop-losses over a rolling six-month period. Based on the results of this assessment, a Market Participant would be assessed in one of the following risk categories: (1) low; (2) medium; and (3) high.[4] As more fully explained in the ISO-sponsored materials included with this memorandum, a Market Participant's FCM Delivery Financial Assurance requirement would be calculated via a formula associated with the category in which that Market Participant would be placed.[5]

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and the intra-month collateral. At its December 7, 2023 meeting, the Participants Committee supported those FAP revisions. A week later, ISO-NE, joined by NEPOOL, filed the proposal, and on February 9, 2024, the FERC approved that jointly filed proposal in Docket No. ER24-661.

[3] For context, if a resource with a CSO underperforms during a scarcity event, the monthly stop-loss sets a limit on the amount a Market Participant might have to pay in PFP penalties for the delivery month. Tariff § III.13.7.3.1. Moreover, a Market Participant's potential PFP penalty obligations are limited by the annual stop-loss provision. Tariff § III.13.7.3.2. As it concerns the FAP Proposal, the ISO examined a Market Participant's corporate liquidity as compared to the applicable stop-loss amounts to ensure that each Market Participant with a CSO had enough liquidity to meet its PFP financial obligations.

[4] The low risk category applies to those Market Participants whose corporate liquidity is greater than or equal to the sum of the three largest monthly stop-losses, while the medium risk category is for those whose corporate liquidity is greater than or equal to the sum of the two largest monthly stop-losses and the high risk is reserved for those whose corporate liquidity is less than the sum of the two largest monthly stop-losses.

[5] Market Participants assessed as low risk would be subject to the current FCM Delivery Financial Assurance requirements, albeit with an updated IMC variable due to the IMC Revisions. The applicable FCM Delivery Financial Assurance formula would include a risk adder for those assessed as medium and high risk. Consequently, medium and high risk Market Participants would likely be required to post additional financial assurance. To review the proposed FCM Delivery Financial Assurance formulas, see slide 21 in Attachment C.

Under its proposal, Market Participants would be required to submit quarterly financial statements showing their liquidity.[6] If a Market Participant does not have enough standalone corporate liquidity, it could provide an unconditional, irrevocable guaranty from its parent/affiliate guarantying the payment of all Capacity Performance Payments. In that case, the corporate liquidity assessment would be based on the financial statements of the guarantor.

As the final component of the Corporate Liquidity Revisions, the ISO proposes to exclude the FCM Delivery Financial Assurance from the capitalization deduction for medium and high risk assessed Market Participants. Specifically, if a Market Participant is subject to the 25 percent additional financial assurance requirement under the existing capitalization provisions, the FCM Delivery Financial Assurance amount will be subtracted before the calculation of the 25 percent in recognition of the fact that medium and high risk entities are providing additional financial assurance through the risk adders.

Concerning the IMC Revisions, the ISO proposes to update the IMC variable.[7] The ISO's proposal seeks to limit the IMC value to the maximum penalty amount less the difference between the current month's financial assurance requirement and the next month's financial assurance requirement.[8]

The ISO requests an effective date of January 1, 2025 for its FAP Proposal, making the IMC Revisions operative as of that date. However, the Corporate Liquidity Revisions introducing the new corporate liquidity assessment would apply to the Capacity Commitment Period (CCP) associated with the sixteenth Forward Capacity Auction (FCA), i.e., June 1, 2025.

STAKEHOLDER PROCESS TO DATE

As detailed further below, the ISO's FAP Proposal (as well as the New England Power Generators Association (NEPGA)-sponsored changes) were discussed at the Budget and Finance Subcommittee and the Markets Committee.

Budget and Finance Subcommittee Consideration of the ISO's FAP Proposal and NEPGA's Proposed FAP Revisions

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[6] Additionally, a capacity seller classified as medium or high risk may opt to provide monthly financial statements until the capacity seller is assessed as low risk (for a minimum of six continuous months of being assessed as lower risk). If a capacity seller chooses not to submit financial statements or submits non-compliant ones, the ISO would use $0 for the value derived from financial statements when calculating available liquidity.

[7] This variable is part of the existing FCM Delivery Financial Assurance Formula and estimates the amount of PFP penalties a Market Participant incurs during the current month. See note 2 (discussing the FAP changes FERC approved in February 2024, which introduced the IMC variable).

[8] The ISO has explained that the IMC Revisions would avoid unnecessary collateral swings without introducing any additional risk to the market by limiting the IMC value. For an example of how these proposed revisions would work, see slide 24 in Attachment C.

Discussions at the Budget and Finance Subcommittee regarding the FAP Proposal started in January and continued through July. Although some members supported the ISO's proposal, various stakeholders were concerned with the increased costs to satisfy the additional financial assurance, some of the ISO's assumptions that went into certain aspects of the analysis, and the proposed date the ISO would begin instituting the corporate liquidity assessment, among other things. Some members, including NEPGA, encouraged pursuing market-based solutions to reduce the risk of defaulting rather than requiring additional financial assurance.

To address certain of its concerns, NEPGA presented conceptual amendments to the ISO's proposal that fell within the Budget and Finance Subcommittee's purview. Relevant here, NEPGA proposed to amend the date when the corporate liquidity assessment is implemented (NEPGA FAP Revisions). Specifically, NEPGA's revisions would align the implementation of the new assessment with the CCP coinciding with FCA 19, i.e., changing the proposed date of June 1, 2025 to June 1, 2028. NEPGA stated that its amendment would allow capacity sellers the opportunity to reflect the incremental financial assurance costs, which some NEPGA members have stated were significant, in capacity market offers.[9]

At the July 29 Budget and Finance Subcommittee meeting, some members expressed support for the ISO's overall FAP Proposal. However, the majority of those who spoke at that July Subcommittee meeting voiced a preference for NEPGA's proposed alternative implementation timing. In its August 21 memorandum (Attachment A), the ISO explains why it does not support a delayed effective date for the FAP Proposal.[10]

Markets Committee Consideration of NEPGA's Proposed Market Rule 1 Revisions

NEPGA also proposed revisions to the Tariff, which fall under the Markets Committee's ambit, seeking to improve the ISO's proposal. As detailed in Attachment F and Attachment G, NEPGA's Market Rule 1 changes would allow a Market Participant to submit a CSO Bilateral up to five business days before the Obligation Month and require the ISO to complete its Tariff-mandated review within five business days of receiving the CSO Bilateral. NEPGA stated that these Market Rule revisions would allow Markets Participants to manage their CSO positions better, which ultimately affects the amount of financial assurance required. At its August 6, 2024 meeting, the Markets Committee, with a 50% Vote in favor, did not recommend that the Participants Committee support these NEPGA-sponsored revisions.[11] The ISO also did not support NEPGA's Market Rule 1 changes, with further explanation provided by the ISO in its August 21 memorandum (see Attachment A).

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[9] For more information, see Attachment D and Attachment E.

[10] *See* page 4 of Attachment A.

[11] The individual Sector votes on the NEPGA-proposed Market Rule revisions were as follows: Generation – 16.67% in favor, 0% opposed, two abstentions; Transmission – 0% in favor, 16.67% not in favor, five abstentions; Supplier – 16.67% in favor, 0% opposed, six abstentions; Publicly Owned Entity – 0% in favor, 16.67% opposed, zero abstentions; Alternative Resources – 16.67% in favor, 0% opposed, two abstentions; and End User – 0% in favor, 16.67% not in favor, seven abstentions.

PARTICIPANTS COMMITTEE ACTION

In addition to requested action on the ISO's FAP Proposal, NEPGA has indicated that it intends to offer the two motions to amend, as described above, for Participants Committee consideration.

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

> RESOLVED, that the Participants Committee supports the revisions to the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

memo

To: NEPOOL Participants Committee (PC)

From: Robert Ludlow, Vice President, Chief Financial & Compliance Officer; and Christopher Nolan, Director, Market and Credit Risk

Date: August 21, 2024

Subject: ISO's updates Financial Assurance Policy to mitigate risk of Pay-for-Performance penalty payment defaults

Executive Summary

At the September 5, 2024 PC meeting, the ISO will be requesting a vote on its proposed revisions to the Financial Assurance Policy (FAP) to mitigate the impact of a large-scale default by Forward Capacity Market (FCM) capacity sellers who have inadequate corporate liquidity to pay potential pay-for-performance (PFP) penalties.[1]

The ISO is taking this action after studying the events in PJM following Winter Storm Elliott (December 2022). After significant performance penalties were assessed, multiple companies with generating assets in the PJM market filed for bankruptcy while others required a negotiated settlement to meet their obligations. As part of this settlement, penalties were reduced by nearly one-third – as were the bonus payments to well-performing resources. To avoid similar detrimental outcomes, the ISO is proposing changes to address the risks posed by capacity sellers with inadequate corporate liquidity (i.e., cash or short-term liquid assets available on their balance sheet) to pay potential PFP penalty payments.

The ISO's FAP Revisions mitigate the increased risk posed by FCM capacity suppliers who have insufficient corporate liquidity to pay the total potential PFP penalty payments associated with their Capacity Supply Obligation (CSO). This risk is material and needs to be addressed for the upcoming Capacity Commitment Period (CCP 16) when the PFP performance payment rate increases. Our proposal is to perform a corporate liquidity assessment on each FCM participant to determine their ability to pay potential peak penalty payment obligations associated with their CSO over a forward-looking, rolling six months. Based on the results of this liquidity assessment, low-risk participants will continue to be subject to the current financial assurance requirements (i.e., they are not subject to higher collateral requirements) while medium- and high-risk market participants will be subject to higher collateral requirements (risk adders), commensurate with the higher non-payment risk they pose to the market. If a participant is high- or

[1] *See* ISO's presentation at the July 29, 2024 Budget and Finance Subcommittee meeting, located here. ISO's proposal is referred to as the "FAP Revisions" throughout this memorandum.

medium-risk, but has a parent/affiliate with adequate liquidity, the parent/affiliate may provide a guaranty guaranteeing the payment of the participant's potential PFP penalties, and the liquidity assessment will then utilize the liquidity of the parent/affiliate entity.[2]

The ISO's proposal is the product of extensive discussion with stakeholders and incorporates a number of stakeholder-suggested revisions, including a modification of the risk adders to account for the expected performance of portfolios based on historical performance. The ISO has also considered stakeholder feedback regarding alternative proposals (such as longer payoff periods, increased trading opportunities, or a later effective date) and, as discussed in more detail below, has concluded that such proposals do not address the underlying fundamental risk introduced to the markets by entities that do not have enough corporate liquidity to support their contractual CSO financial obligations.

ISO's Rationale for the FAP Revisions

The FAP Revisions protect the market from risks posed by capacity sellers with weak corporate liquidity.

Capacity sellers that have weak corporate liquidity pose a significant risk to the market because they cannot pay their potential PFP penalty payments following Capacity Scarcity Conditions. The ISO is concerned that capacity sellers that have not accounted for the full amount of penalties may need to seek bankruptcy protection causing further market disruptions.

Several disruptions to the PJM market occurred following Winter Storm Elliott. Specifically, multiple companies with generating assets in the PJM market filed for bankruptcy, as they were unable to pay the penalty payments that arose when they failed to operate during the PJM scarcity events. Other market participants asserted they were unable to pay absent a negotiated settlement regarding the penalty amounts and the time period to pay off such penalties.

Through a negotiated settlement, PJM agreed to a significant haircut of 31.7% on the ~$1.8 billion of penalty payments and agreed to extend the time allowed for payment of such penalties by several months.[3] Despite some key differences between ISO-NE and PJM (such as the payoff period for penalty payments and the way any shortfalls are socialized),[4] the key lesson learned is that to avoid the financial repercussions of the PJM scenario the ISO must have a credit risk management strategy in place to address the risks posed by capacity sellers with inadequate corporate liquidity. The ISO's proposal is to address this risk upfront rather than wait for a significant event to cause disruptions to the New England

[2] The FAP Revisions also contain one improvement to the existing formula for all participants, by updating the intra-month collateral (IMC) variable.

[3] The settlement was driven by several factors, including the arguments that some capacity sellers were asked to provide capacity when it was not needed; the concern that more generators would be forced to file for bankruptcy protection if required to pay the full contractual share of the ~$1.8 billion in total penalties; and reliability concerns for the region if, as a result of the penalties, generators chose to decommission earlier than expected.

[4] Within the ISO-NE markets, socialized defaults may occur in scenarios where capacity sellers have insufficient corporate liquidity (i.e., cash available on their balance sheet) to settle the total amount of penalty payments, and the posted collateral (i.e., financial assurance) is insufficient to cover the realized penalties. In other words, unlike the PJM markets, the risk of nonpayment of PFP penalties is not limited to other capacity sellers.

markets. The proposal does this by periodically reviewing the liquidity of capacity sellers and requiring more collateral on an ongoing basis from the riskiest entities.

The risk of multiple capacity sellers potentially defaulting on penalty payments is material and must be addressed for the upcoming Capacity Commitment Period (i.e., CCP 16) due to the scale of the underlying problem.

The risk of incurring penalty payments is borne by individual capacity sellers upon acquiring a CSO for a specific Capacity Commitment Period. Based on the ISO's review of corporate liquidity of capacity sellers in CCP 16, the ISO was able to identify that some capacity sellers have planned, from a corporate treasury perspective, to keep enough liquidity on their balance sheets to be able to make the required potential penalty payments per the CSO's contractual terms. Unfortunately, many other capacity sellers are taking the risk that Capacity Scarcity Conditions will not occur (or that they will always operate per the ISO's dispatch instructions) as they have not accounted for potential PFP penalty payments on their balance sheets. These actions shift such risk to the market and allow the market participant to avoid bearing the associated costs of maintaining adequate corporate liquidity to mitigate their default risk.

The ISO's assessment revealed that less than one-quarter of all CCP 16 capacity sellers on a standalone basis (i.e., without parental/affiliate support) have sufficient corporate liquidity to pay their total potential PFP penalty payments, which could result in significant market disruptions (including clearing and socialized defaults).

The ISO also assessed the corporate liquidity of the parent entities of CCP 16 capacity sellers and found that, conversely, approximately 86% of parent companies (by CSO volume) can demonstrate adequate corporate liquidity to support the settlement of the total potential penalty payments incurred by their subsidiaries. However, corporate parent entities are not obligated to cover the penalty payments of subsidiary capacity sellers because the ISO has no contractual relationship or agreements with such entities (i.e., no parent/affiliate guarantee) to mitigate the PFP penalty payment risk posed by their subsidiaries.

The ISO's recommended FAP Revisions require *only* those market participants that are assessed as presenting a higher payment risk to make a choice: they can raise more corporate liquidity to demonstrate their ability to pay the potential penalties without any support from their parent/affiliate; they can provide a guarantee from a parent/affiliate (with adequate liquidity) guaranteeing the payment of PFP penalties; or, per the revised methodology, they can post more collateral (letter of credit or cash) to the ISO on an ongoing basis to mitigate the risk they pose to the market.

Short duration scarcity events can result in the realization of the maximum potential monthly penalty payment. The PFP performance payment rate increases from $5,455/kWh in CCP 15 to $9,377/kWh in CCP 16, which nearly doubles the size of the penalty payment per Capacity Scarcity Condition interval. Under such conditions, it will take less than two hours for a resource to reach its monthly stop loss.

The specific performance payment rates effective in each CCP determines both the size of the penalty for poor performers and the size of the bonus payment for over-performers. As the rate increases, it reduces the number of Capacity Scarcity Condition intervals (an interval is a five-minute period) that are needed for market participants to incur their maximum potential penalty payments during a month (or year).

Consequently, market participants have even less time to resolve operational issues that are impeding their performance in real time because the number of hours needed to reach the maximum penalty obligation has decreased. For example, for the ninth Capacity Commitment Period, it would have taken approximately 40 hours of Capacity Scarcity Conditions (over several months since each month is limited by a monthly stop loss) before a market participant reached its annual stop loss. For the sixteenth Capacity Commitment Period, this will reduce to just nine hours (over several months because each month is limited by a monthly stop loss). The underlying event causing a Capacity Scarcity Condition does not need to be an extreme, days' long event for a participant's maximum monthly penalty to be triggered. Although it would take more hours for a resource to reach its monthly stop loss at a lower penalty rate, the underlying event still does not need to be extreme to trigger the maximum penalty.

Stakeholder amendments to increase trading opportunities, incorporate longer payoff periods, or delay implementation do not address the need for ISO's FAP Revisions.

At the August NEPOOL Markets Committee meeting, the ISO explained its concerns with the proposed amendment to increase trading opportunities by eliminating the existing CSO bilateral submission windows and replacing them with CSO bilateral submission deadlines. In short, this amendment would not address the need for and approach of the ISO's FAP Revisions and would necessitate a substantial overhaul of many ISO processes that cannot be supported at this time given the current calendar and competing priorities, including planned reforms in the capacity market.[5]

Stakeholders have also suggested that the ISO consider changing the way PFP penalties are billed and allocated to allow market participants a longer time to pay off PFP penalties. While such an approach may ease short-term liquidity concerns directly after a PFP event, it ultimately does not account for the fact that if an entity is illiquid and unable to satisfy its contractual CSO obligations, extending the payment period may only exacerbate the financial loss incurred by the pool. For example, the ISO would lose valuable set-off rights related to any remittances to the participants and/or the problem could grow if additional Capacity Scarcity Conditions occur during the payoff period. Additionally, a longer payment period would require the ISO to short pay others in the market until the full PFP penalties are collected, effectively requiring participants that have performed consistent with their obligations to act as an interest-free lender to those participants that have fallen short on their obligations.

Furthermore, some stakeholders have requested that NEPOOL support a proposal to delay the implementation of the FAP Revisions until CCP 19. Delaying implementation of the FAP Revisions beyond CCP 16 is only prudent if the marketplace can rely on market participants to take the necessary steps to reduce their default risk. Some market participants have already internalized the cost of ensuring they have sufficient liquidity to satisfy their contractual obligations. Those that have not and instead prefer to take the risk that Capacity Scarcity Conditions do not occur (or assume they will operate as dispatched by the ISO) are forcing the market to bear the financial cost should they face PFP penalties that they are unable to cover. Therefore, the ISO does not support delaying the implementation of the FAP Revisions as some stakeholders have proposed.

[5] *See* the ISO's memo for the August 6, 2024 Markets Committee meeting, located here.

Conclusion

The ISO has identified a fundamental gap in its credit risk management approach regarding the mitigation of PFP penalty payment defaults. The ISO's proposal to assess capacity sellers' liquidity and require more collateral from higher-risk entities on an ongoing basis addresses this risk. The ISO is proactively addressing these concerns before experiencing major clearing issues (and/or socialized defaults) after significant operating reserve deficiency events. To the extent that a capacity seller has not accounted for potential PFP penalties on its balance sheet it can raise the appropriate corporate liquidity, provide an appropriate guarantee or collateral, or decide to trade out of some or all of the CSO position in the next annual reconfiguration auction in March 2025 (prior to the start of the sixteenth Capacity Commitment Period).

ISO-NE's Proposed Redlines for the FAP Proposal

Note: The yellow highlighted revision in proposed Section VII.A.3 corrects a scrivener's error.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement, ~~(~~excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity

Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the sixteenth Forward Capacity Auction (i.e., June 1, 2025) or any Capacity Commitment Period thereafter~~)~~.

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);

(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately

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C. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1] – Second Largest Monthly Stop-loss x max [(ABR – CWAP), 0.1]

Where:
MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM

Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. ~~and,~~ Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server ~~and shall be limited by the monthly stop loss as described in Section III.13.7.3.1 of Market Rule 1~~.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all ABR values reflect actual data.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all average performance values reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June and December	2.000;
July and January	1.732;
August and February	1.414;
All other months	1.000.

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

2. Corporate Liquidity Assessment Methodology

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk, medium risk, or high risk) that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter.

(a) For each Designated FCM Participant, the Corporate Liquidity Assessment shall be performed as follows:

- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest but greater than or equal to the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered high risk.

(b) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from the same Affiliate, or for Designated FCM Participants that are also providing a guaranty (in accordance with this Section VII.A) for an Affiliate:

- The respective Designated FCM Participants will be assessed as a whole and will be collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk);
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest aggregated Applicable Monthly Stop-losses but is greater than or equal to the sum of two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered high risk.

(c) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from multiple Affiliates:

- The guarantors' financial statements will be considered on an aggregate basis for purposes of the Available Corporate Liquidity calculation taking into account other guaranties provided by any such guarantor under this Section VII.A.

Where:

Calculation Period is the current delivery month through the following five consecutive months.

The Applicable Monthly Stop-loss equals the sum of the monthly stop-losses for each resource in a Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1 for the corresponding months within the Calculation Period.

Available Corporate Liquidity is the sum of unrestricted cash and cash equivalents; marketable securities and money market instruments; undrawn committed credit facilities not expiring within three months of the date of the applicable financial statements; and excess financial assurance. Other than with respect to excess financial assurance, such values shall be (a) as reflected on the most recent financial statements provided by the Designated FCM Participant, provided that such financial statements were timely provided and compliant with the requirements of this Section VII.A, and (b) calculated in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied. Excess financial assurance shall be calculated as any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant covering its FCM Delivery Financial Assurance obligations plus any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant in excess of its total Financial Assurance Obligations, each as reflected in the ISO's Financial Assurance Management (FAM) or equivalent system.

For the avoidance of doubt, the components of the Available Corporate Liquidity calculation that are derived from financial statements shall be based on the financial statements of the Designated FCM Participant unless it provides an Affiliate guaranty in compliance with this Section VII.A, in which case the values shall be based on the financial statements of the entity(ies) providing the guaranty. If an acceptable Affiliate guaranty is provided, stop-loss and excess financial assurance values will still be based on the Designated FCM Participant.

Each Designated FCM Participant shall submit to the ISO, on a quarterly basis, its (or its guarantor's, as applicable) audited or unaudited balance sheet or equivalent financial statements, which shall show sufficient detail for the ISO to assess the Designated FCM Participant's (or guarantor's, as applicable) Available Corporate Liquidity. Such financial information shall be accompanied by a certificate from a Senior Officer of the Designated FCM Participant (or guarantor as applicable) that provides the relevant financial information and certifies the accuracy of the attached financial statements. If an attestation was made by an independent accounting firm, then the certificate shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required. The ISO shall post a generally acceptable "clean" form of certificate on its website. Financial statements provided on a quarterly basis shall be submitted within 10 days of such statements becoming available and within 65 days after the end of the applicable fiscal quarter.

Designated FCM Participants that are assessed as medium risk or high risk may elect to provide financial statements on a monthly basis until such a time as they are subsequently assessed as a lower risk category (e.g., from high risk to medium risk, medium risk to low risk, or high risk to low risk); provided that such election shall be for a minimum period of six continuous months during which they are continuously assessed at a lower risk category. Financial statements submitted on a monthly basis are required to be provided to the ISO within 20 days after the end of the prior month and otherwise be provided in accordance with this Section VII.A.

A Designated FCM Participant may choose not to submit financial statements as described in this Section VII.A. If a Designated FCM Participant chooses not to submit financial statements as described in this Section VII.A or if such financial statements are not compliant with the requirements described in this Section VII.A, the ISO shall use a value of $0.00 for Available Corporate Liquidity values derived from financial statements until such time as compliant financial statements are provided.

The ISO shall review the information provided pursuant to this Section VII.A on a rolling basis and will calculate the Available Corporate Liquidity within a reasonable time period which shall not exceed 30 Business Days from the date of receipt.

3. FCM Affiliate Guaranties

For the purposes of the Corporate Liquidity Assessment, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from an Affiliate to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant. Upon the ISO's acceptance of an Affiliate guaranty, the guarantor(s) must provide financial statements in accordance with this Section VII.A, and the Corporate Liquidity Assessment will be performed based on the financial information of the guarantor(s). The ISO website will provide a generally acceptable sample "clean" guaranty, and all guaranties provided pursuant to this Section VII.A shall be in such form with only non-material changes (as determined by the ISO in its sole discretion). The ISO in its sole discretion may update the form guaranty from time to time. The ISO has the right to draw upon the guaranty in the event of a default under the ISO New England Billing Policy up to any amount owed for unpaid Capacity Performance Payments. At any time, the ISO may in its sole discretion provide notice to a Designated FCM Participant that it is choosing to reject or terminate its Affiliate guaranty because such guaranty presents unreasonable risk to the ISO or the New England Markets. In the case of a termination (or planned termination), upon the ISO providing such notice the guaranty shall not be considered for purposes of such Designated FCM Participant's Corporate Liquidity Assessment beginning at 8:30 a.m. on the next Business Day, provided that the ISO may, in its sole discretion, extend this period by up to twenty (20) Business Days. For the avoidance of doubt, notice from the ISO to the Designated FCM Participant that the guaranty its Affiliate provided is being terminated (or will be terminated), does not constitute a termination notice under such guaranty and the ISO, in its sole discretion, may choose when to send the applicable termination notice under the terms of such guaranty.

In the ISO's sole discretion, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from multiple Affiliates to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant, so long as guaranty is otherwise in accordance with this Section VII.A and the guarantors have joint and several liability under such guaranty.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the “FCM Deposit”).

2. Non-Commercial Capacity in Forward Capacity Auctions

a. Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction

For Non-Commercial Capacity participating in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction, a Designated FCM Participant that had its supply offer of Non-Commercial Capacity accepted in a Forward Capacity Auction must include in the calculation of its Financial Assurance Requirement under the ISO New England Financial Assurance Policy the following amounts at the following times:

(i) beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day following announcement of the awarded supply offers in that Forward Capacity Auction, an amount equal to $5.737(on a $/kW-month basis) multiplied by the number of kW of capacity awarded to that Designated FCM Participant in that Forward Capacity Auction (such amount being referred to herein as the “Non-Commercial Capacity FA Amount”);

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JULY 29, 2024

Updated 07/22/2024

Pay-for-Performance Financial Assurance

Discussion of Financial Assurance Policy regarding Pay-for-Performance Penalties and further Redlines to the FAP

NEPOOL Budget & Finance Subcommittee Meeting

Christopher Nolan
DIRECTOR MARKET AND CREDIT RISK

Joshua LaRoche
MANAGER – CREDIT AND MARKET ANALYTICS

Zachary Shell
LEAD RISK ANALYST

Contents of Presentation

The ISO has developed a recommendation to address the higher credit risk posed by participants in the FCM that may be unable to pay PFP penalties when they arise due to capacity scarcity conditions occurring

Executive Summary

- The ISO performed a credit risk assessment of all capacity sellers in FCA 16 and determined that more than three quarters of them do not have sufficient corporate liquidity to cover their potential penalty payment obligations associated with the CSOs that were awarded to them
- The ISO, therefore, developed a recommendation to update the FCM Delivery FA methodology (i.e., Pay-for-Performance collateral requirements) in the FAP with input from stakeholders over the last year
- The updated FCM Delivery FA will require capacity sellers that are assessed as medium / high risk per a new Corporate Liquidity Assessment to post additional collateral in order to ensure the PFP market design operates as intended, the ISO can clear the market on a timely basis and socialized defaults are adequately mitigated
- The ISO plans to file the recommendation with FERC during Q4-2024 with an effective date of January 1, 2025 so MPs may reconfigure their CSOs in the final ARA before the effective CCP
- The expected cost to consumers is immaterial and ranges from $0.00003 to $0.00007/kWh using very conservative financing assumptions for the cost of the incremental collateral incurred by medium / high risk capacity sellers

The ISO's recommendation to address the risk posed by uncreditworthy capacity sellers in the FCM was indicated to stakeholders back in 2023

Background

- In September 2023, the ISO initially presented four recommended updates to the FAP regarding FCM Delivery FA following its analysis of the adequacy of the PFP collateral methodology in the wake of Winter Storm Elliot and events in PJM
- The ISO subsequently filed three of those updates to the methodology (i.e., Scaling Factor, CWAP and IMC) with FERC which addressed the risk of collateral shortfalls with capacity sellers that incur net payment obligations, but doesn't address the higher non-payment risk posed by capacity sellers with inadequate corporate liquidity risk profiles in the FCM; these FAP updates became effective on March 1, 2024
- In September 2023, the ISO indicated that the fourth recommended FAP update was significantly more complex to develop because, even accounting for the updated PFP collateral methodology that became effective as of March 1, 2024, the FAP does not have a nuanced approach to evaluate capacity sellers and collateralize based on their financial ability to settle their contractually obligated PFP penalty payment obligations that exceed collateral already posted to the ISO

The ISO's credit risk management of capacity sellers that are not creditworthy needs to evolve to ensure the PFP market design operates as intended, the ISO can clear the market on a timely basis and socialized defaults are adequately mitigated

Rationale for Making Recommendation

- Per the ISO's analysis of the corporate liquidity of all capacity sellers awarded CSOs in FCA 16, the ISO is concerned about the following credit risks and issues that it sees in the FCM
  a) Many capacity sellers cannot demonstrate access to adequate corporate liquidity to ensure that they are able to pay PFP penalty charges resulting from a capacity scarcity condition. This affects the ISO's ability to settle the market efficiently.
  b) The current PFP collateral methodology doesn't increase the collateralization of the potential credit exposure (i.e., the monthly and annual stop-loss) posed by capacity sellers that may be unable to make those penalty payments on a timely basis to the ISO
  c) Capacity sellers are unlikely to be able to resolve operational performance issues during capacity scarcity conditions before triggering their maximum potential financial loss for the given month
  d) Although there have been no socialized defaults to date, some capacity sellers may be risking bankruptcy absent appropriate corporate liquidity risk management practices (similar to recent events in PJM) which would result in socialized defaults impacting consumers and the rest of the market

ISO is recommending the application of a new Corporate Liquidity Risk Assessment methodology to determine the appropriate PFP collateral requirements for all capacity sellers from CCP 25-26 onwards

Options Considered to Address Credit Risk Issue

- The ISO considered the following potential options to address the risks and issues introduced by capacity sellers with inadequate liquidity to meet their contractual obligations
  a) Do nothing given that historically the ISO has only experienced five periods of capacity scarcity conditions in the last 10 years and just socialize defaults to the market when the risk materializes and illiquid capacity sellers cannot pay the bill; or
  b) Apply a periodic corporate liquidity risk assessment to determine the ability of capacity sellers on a standalone basis to honor their contractual financial obligations under their CSOs and mitigate those posing higher credit risk by increasing cash and LC collateral requirements which would be the most costly impact for the overall market; or
  c) Apply a periodic corporate liquidity assessment to determine the ability of capacity sellers and potential guarantors on a collective basis to satisfy the contractual financial obligations of the MP and mitigate those remaining that pose higher credit risk by increasing cash and LC collateral requirements which has lower cost implications for the market; or
  d) Develop other market based (non-collateral approaches) that could potentially mitigate risk such as those proposed by NEPGA and CPV at the joint meeting last month of the Markets Committee and Budget and Finance Subcommittee meeting

The ISO recommendation focuses on addressing the higher credit risk presented by capacity sellers that are unable to demonstrate their ability to satisfy the financial obligations associated with their CSOs (as limited by the stop-losses)

ISO's Recommendation

- The ISO determined that Option C is the most optimal solution for the following reasons
  - a) It periodically monitors and assesses the ability of capacity sellers to satisfy their financial contractual obligations under a CSO (i.e., the monthly and annual stop-loss) and adjusts collateral accordingly which pro-actively mitigates default risk
  - b) Additional collateral is required to be posted only by those capacity sellers assessed as posing a higher default risk which mitigates socialized defaults to the market
  - c) Capacity sellers that pose a higher default risk are therefore required to internalize their own collateral financing costs to reduce their risk to the pool rather than using other mechanisms such as longer-pay back periods which disadvantages capacity sellers that over-performed during capacity scarcity conditions and expect timely payment of their bonus revenues (i.e., the capacity performance payment)
  - d) Higher risk capacity sellers have incremental financial assurance requirements which ensures the ISO can clear the market on a timely basis
- As requested by stakeholders, the ISO has also provided a range of expected costs incurred by capacity sellers using more conservative financing assumptions for the incremental PFP collateral associated with this recommendation
- The expected cost to consumers is immaterial and ranges from $0.00003 to $0.00007/kWh despite applying more conservative financing assumptions potentially incurred by capacity sellers while the integrity of the consumer's capacity hedge is significantly improved as potential socialized defaults are mitigated by this recommendation

Per feedback from stakeholders, the ISO has reflected the operational diversification benefits of multi-resource portfolios into the recommended incremental collateral requirements for capacity sellers that are assessed as high and medium risk

Modification of ISO's Recommendation Per Stakeholder Feedback

- The ISO has decided to incorporate the diversification benefits of multi-resource MPs into the "risk adders" applied to the PFP collateral methodology for medium and high risk capacity sellers; the risk adders now take into account the historical performance of a capacity sellers portfolio relative to its slice of system obligation and continues to assume the largest resource is offline during scarcity conditions
- Additionally, based on feedback from Stakeholders during prior Budget and Finance Subcommittee meetings, the ISO modified the Corporate Liquidity Risk Assessment Methodology recommendation in several instances to include the following
  a) Additional corporate liquidity risk assessment categories and resulting collateralization levels so that there's more differentiation in the risk assessment versus just a binary pass or fail result
  b) Delaying the effective date in terms of when the corporate liquidity assessment methodology would start (i.e., from June 1, 2024 to June 1, 2025) so capacity sellers have adequate time to reconfigure their CSOs during an ARA prior to the commencement of the CCP
  c) The inclusion of excess collateral in the corporate liquidity assessment calculation to reflect all sources of corporate liquidity available to cover PFP net payment obligations and other modifications to the corporate liquidity assessment (such as the exclusion of debt maturing in 12 months)

Several amendments recently proposed by the stakeholders do not meaningfully address the fundamental credit risk issue facing the ISO in the FCM by uncreditworthy capacity sellers

NEPGA / CPV Proposed Amendments

- The ISO analyzed each of the proposed amendments and conceptual ideas put forward by NEPGA and CPV and has several concerns
- The ISO doesn't consider them a replacement for the current recommendation nor do they address the underlying credit risk issue
- Conceptually, the most meaningful way to mitigate credit risk to the pool is by collecting higher amounts of collateral from capacity sellers upfront based on their assessed ability to pay the PFP penalties that they are contractually obliged to per the size of their CSO throughout the CCP
- Capacity sellers are encouraged to proactively manage their exposure to PFP penalty payments by shedding CSO in ARAs / MRAs or executing capacity performance bilaterals, but this in no way allows the ISO to prudently reduce collateral requirements for a CSO
- Additionally, the ISO considers it a moral hazard to put longer-pay mechanisms in place to force the pool to effectively lend to uncreditworthy capacity sellers that fail to pay the PFP penalties on a timely basis should they arise

The ISO plans to request a vote from the Participants Committee in September and subsequently file its proposal with FERC in Q4 2024

Next Steps and Stakeholder Process

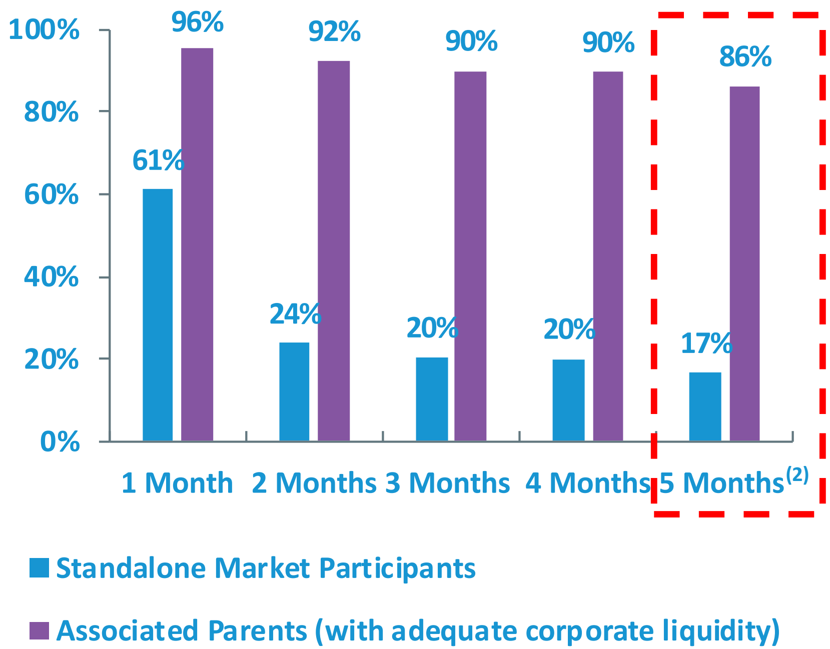
- The ISO is planning to request a vote at the Participants Committee on September 5, 2024 regarding this modified recommendation
- The ISO will request a January 1, 2025 effective date, however the new PFP risk management framework would apply to capacity commitment period 2025-26 (FCA 16) starting on June 1, 2025 and each CCP thereafter
- Capacity sellers would be able to participate in ARA3 occurring in March 2025 which is after the effective date should they decide to reconfigure their CSOs going into the next CCP (i.e., June 1, 2025)

Contents of Presentation

There is significant risk that many MPs default on their PFP contractual obligations (i.e., max penalties associated with the stop-loss) after multiple months of capacity scarcity conditions without adequate corporate liquidity

Probability of Default due to Inadequate Corporate Liquidity

% of MPs / Parents by CSO Volume with Corporate Liquidity Exceeding Monthly Stop-Loss Obligation[1]



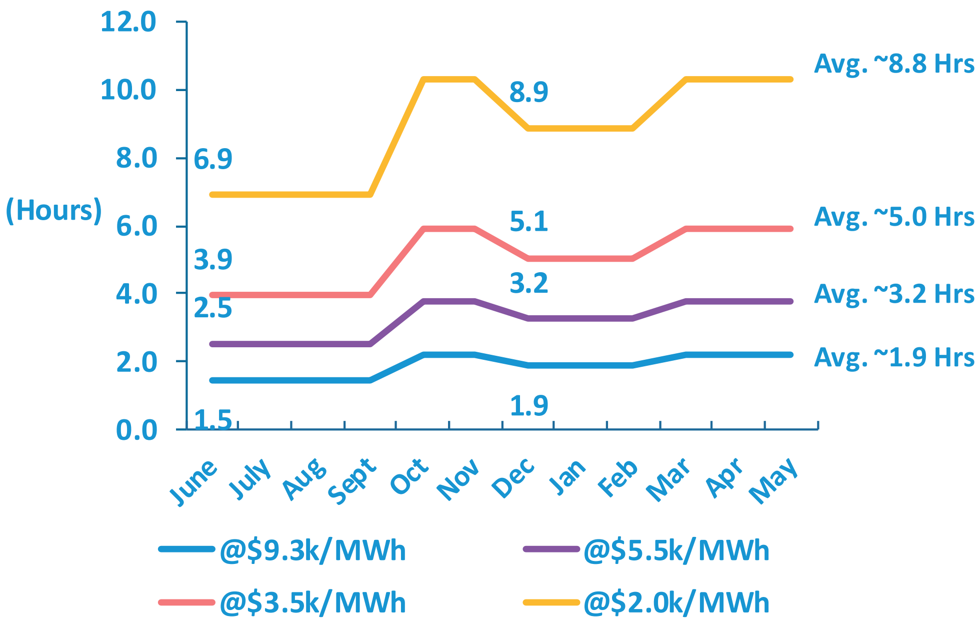
1) Based on review of the financial statements of MPs in FCA 16 as of Q4-23.
2) 5 Months stop-loss is approximately equal to the Annual stop-loss

- The maximum potential net settled obligations (i.e., penalties) can be calculated ahead of time in the FCM and prudently managed from a corporate liquidity perspective but only ~17% of MPs (i.e., capacity sellers) reported enough corporate liquidity to cover the maximum potential contractual obligations associated with their CSO position
- The ISO has noted that the majority of the parent entities of these capacity sellers maintain much stronger levels of liquidity to cover these potential payment obligations as the cash flows generated by the capacity sellers are regularly swept up to equity owners and debt providers
- Market participants that face a liquidity-crunch after repeated capacity scarcity conditions pose higher default risk to the pool as they may need to seek bankruptcy protection without firm parental support
- During stressed market conditions, there is correlated risk that multiple market participants with inadequate liquidity will be unable to meet their contractual CSO obligations; the ISO's proposal is focused on analyzing the risk at an individual market participant level based on such market participant's corporate liquidity as compared to its obligations

Capacity sellers have limited opportunities in real time to address operational performance issues before incurring the maximum potential financial loss during a month

Ability to Address Operational Performance Issues in Real Time

# of Capacity Scarcity Condition (CSC) Hours Required to Reach Monthly Stop-Loss[1]



- Capacity sellers may not be able to resolve operational performance issues in real time before incurring their monthly stop-loss obligation during capacity scarcity conditions
- Short duration capacity scarcity condition (CSC) events can result in capacity sellers owing the ISO their maximum monthly financial contractual obligation due to non-performance
- Even at the lower PFP payment rates, the risk of capacity sellers with inadequate corporate liquidity defaulting still exists

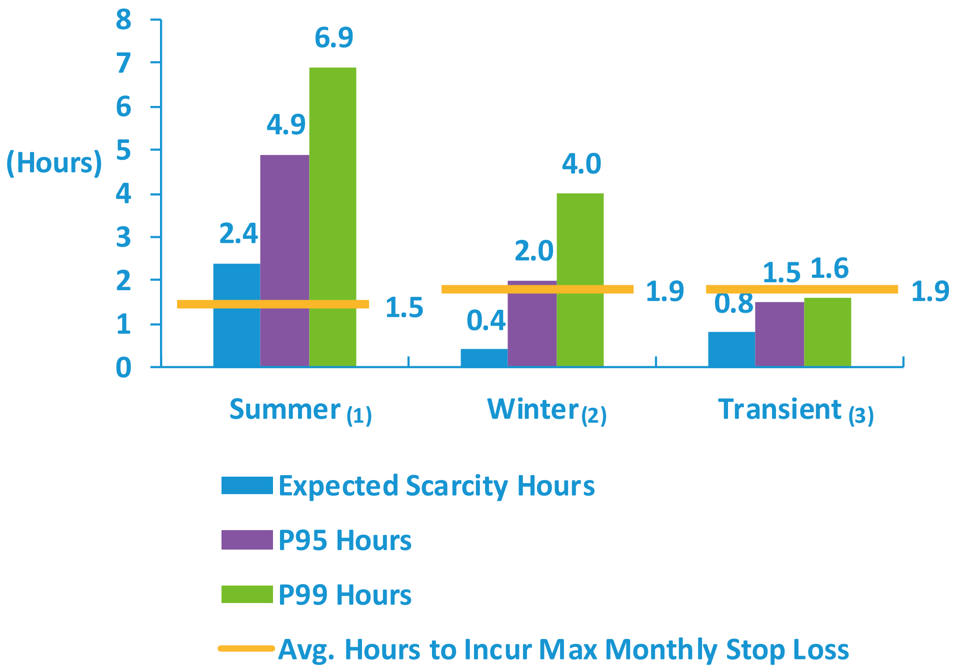
In all PFP payment rate scenarios, capacity sellers may able unable to resolve operational performance issues in time before realizing their maximum potential loss during capacity scarcity conditions

1) FCA 16 (CCP 2025-26)

Capacity sellers are expected to honor their contractual financial obligations to the ISO following stressed market conditions

Capacity Scarcity Conditions Hours

FCA 16 CSC in Hours at Current Capacity Levels[4]



- Stressed market conditions can place significant pressure on corporate liquidity constrained capacity sellers in scenarios where non-performance leads to the stop-loss being reached during a month (i.e., the monthly stop-loss) or series of months (i.e., the annual stop-loss)
- The ISO expects that all capacity sellers are able to satisfy their financial contractual obligations during stressed market conditions
- As indicated by several ISO studies regarding the summer, winter, and transient periods such events (or series of events) could place significant pressure on capacity sellers available corporate liquidity

1) Per the memo "Operating Reserve Deficiency Information – Capacity Commitment Period 2025-2026" https://www.iso-ne.com/static-assets/documents/2021/12/a00_pspc_2021_12_iso_memo_or_def_fca_16.pdf
2) Per the "FCA16 Net CONE Parameters - Expected Capacity Scarcity Hours and Balancing Ratio" https://www.iso-ne.com/static-assets/documents/2020/07/a5_a_iso_memo_scarcity_hours_balancing_ratio.pdf
3) Per the "Summary of Analysis for Calculating an Updated Forward Reserve Offer Cap" https://www.iso-ne.com/static-assets/documents/100006/a07_mc_2023_12_12_14_frm_offer_cap_iso_memo.pdf
4) Current Capacity Levels for FCA 16 are ~ICR + 2,000 MW

NEPGA's proposed amendments regarding trading out of CSOs do not fundamentally mitigate the credit risk posed by uncreditworthy capacity sellers

NEPGA "Shedding / Termination" Proposed Amendments

- A capacity seller's collateral requirements during the capacity commitment period (CCP) are determined by the FCM Delivery FA methodology which is designed to ensure sufficient collateral is posted to the ISO to cover the potential financial settlement of the CSO
- Increasing the ability of capacity sellers to shed a CSO more frequently during a CCP doesn't change the payment risk associated with the financial settlement of a CSO (i.e., PFP penalties) although it can help them to more proactively risk manage their CSO position with more frequent trading opportunities
- Likewise, the proposed termination of a CSO following a FA default still results in potential uncollateralized exposure for the ISO
- Capacity performance bilaterals (CPBs) already offer capacity sellers the ability to prospectively manage the financial risk associated with their CSO
  - CPBs are processed by the ISO only after a capacity scarcity condition (CSC) occurs
  - In concept, participants could make arrangements before CSCs occur to manage their risk, but the ISO is not involved until after the CSC occurs and acts only as a settlement agent
- The ISO has provided links in the appendix of this presentation to existing training materials regarding capacity performance bilaterals

The ability to shed a CSO more frequently doesn't have any bearing on the collateral requirements designed to mitigate the default risk of capacity sellers related to penalty payments

CSO Collateral Requirements

- The potential credit exposure begins on the day the position is created where capacity sellers acquire a CSO which has an embedded financial obligation to pay penalty payments up to the value of the annual stop-loss associated with the CSO position (~$6.1 MM for a 100 MW CSO position in FCA 16)
- CSO bilateral trades will reduce the potential credit exposure only after the trade is completed (i.e., the CSO is shed) and financially settled with the ISO
- Consequently, the capacity sellers maximum potential financial obligation remains ~$6.1 MM until the settlement process (i.e., shedding or acquisition of CSO) is fully completed
- The FCM Delivery FA methodology is already designed to increase / decrease the collateralization of a CSO position if a capacity seller acquires / sheds a CSO as a result of trading activity in ARAs, MRAs and bilaterals
- The ISO doesn't see any merit in reducing the collateral requirements of capacity sellers even if they were able to shed / acquire CSO on a daily basis as the credit risk of a position is always determined by the size of the exposure (e.g., ~$6.1 MM for a 100 MW CSO position in FCA 16) and the ability of the counterparty to the trade to financially settle from existing funds

Contents of Presentation

ISO recommends updating the PFP collateral requirements to curtail socialized defaults impacting consumers and capacity sellers (that over-perform) due to the non-payment of PFP penalties by illiquid capacity sellers

PFP Collateral Recommendation Overview

Current Risk Framework

- All MPs with CSOs are required to post PFP collateral based on the current FCM Delivery FA methodology
- The PFP collateral requirements are the same for all MPs despite material differences in their ability to satisfy the potential penalty payments that they are contractually obligated to per their CSO positions
- Cash and LCs are the only acceptable forms of financial assurance

Recommended Risk Framework

- All MPs are subject to the same corporate liquidity assessment to determine their ability to pay potential peak penalty payment obligations associated with their CSO over a forward looking rolling 6 months
- Low risk MPs are subject to the current FCM Delivery FA methodology
- Medium and high risk MPs are subject to higher collateral requirements (risk adders) as they pose higher non-payment risk to the market
- Operational diversification benefits of multi-resource portfolios are reflected in risk adders
- MPs may provide Parent / Affiliate guarantees to satisfy the new corporate liquidity assessment
- MPs have a quarterly / monthly corporate liquidity reporting requirement
- Cash and LCs are the only acceptable forms of financial assurance
- ISO can draw upon Parent / Affiliate guarantees up to the amount of unpaid PFP penalties in the event of a payment default

A corporate liquidity assessment determines if MPs pose a higher default risk to the ISO regarding potential PFP penalty payment obligations and increases collateral requirements accordingly

Recommended PFP Risk Management Framework

All MPs are assessed by the ISO using the same corporate liquidity assessment method		Corporate Liquidity Assessment	
Assessment places MPs into a low, medium or high risk category	Low Risk	Medium Risk	High Risk
Updated PFP collateral requirements only increase for MPs that fall into the medium / high risk assessment categories	Current FCM Delivery FA Requirements	Current FCM Delivery FA methodology plus a risk adder	Current FCM Delivery FA methodology plus a larger risk adder
New capitalization deduction treatment only applies to medium and high risk categories	Cap. deduction applies to PFP collateral	Cap. deduction does not apply to PFP Collateral	Cap. deduction does not apply to PFP Collateral

ISO modified its recommendation and now reflects the diversification benefit of multi-resource portfolios in collateral requirements; as a result, the liquidity test thresholds are set equivalent for all capacity sellers

Corporate Liquidity Assessment

Available Corporate Liquidity Assessment

Single & Multi-Resource MPs (i.e., All Capacity Sellers)
≥ 3 Largest Monthly Stop-Losses = Low Risk
≥ 2 Largest Monthly Stop-Losses = Medium Risk
< 2 Largest Monthly Stop-Losses = High Risk

- Liquidity testing thresholds are the same for all MPs and the ISO intends to calculate the assessment daily for all MPs with a CSO position from June 1, 2025
- Available corporate liquidity is based off financial statements provided to the ISO for the most recently reported period and applicable financial assurance in FAM
- The monthly stop-losses are based on the profile of a MP's CSO position over the next 6 months from the start of the current delivery month
  a) The test will find the 3 largest monthly stop-losses over the current month and next 5 months
    - If corporate liquidity is greater than or equal to the sum of the 3 largest monthly stop-losses, the MP will be assessed as Low Risk
    - If corporate liquidity is greater than or equal to the sum of the largest 2 monthly stop-losses, the MP will be assessed as Medium Risk
    - If corporate liquidity is less than the sum of the largest 2 monthly stop-losses, the MP will be assessed as High Risk

Higher risk MPs are required to post incremental PFP collateral based on a risk adder component which accounts for their non-performance risk in future months (i.e., CWAP) as well as their slice of system obligation (i.e., ABR)

FCM Delivery FA Methodology Per Liquidity Risk Category

Liquidity Risk Assessment Category	Applicable FCM Delivery FA Methodology	Applicable Risk Adders
Low Risk	DFAMW*PE*max[(ABR-CWAP), 0.1]*SF – IMC – MCC(1)	None
Medium Risk	DFAMW*PE*max[(ABR-CWAP), 0.1]*SF – IMC – MCC – Applicable Risk Adder	Peak Monthly Stop-Loss(2)*max[(ABR-CWAP), 0.1]
High Risk	DFAMW*PE*max[(ABR-CWAP), 0.1]*SF – IMC – MCC – Applicable Risk Adder	Peak Monthly Stop-Loss(2)*max[(ABR-CWAP), 0.1] + 2nd Largest Monthly Stop-Loss*max[(ABR-CWAP), 0.1]

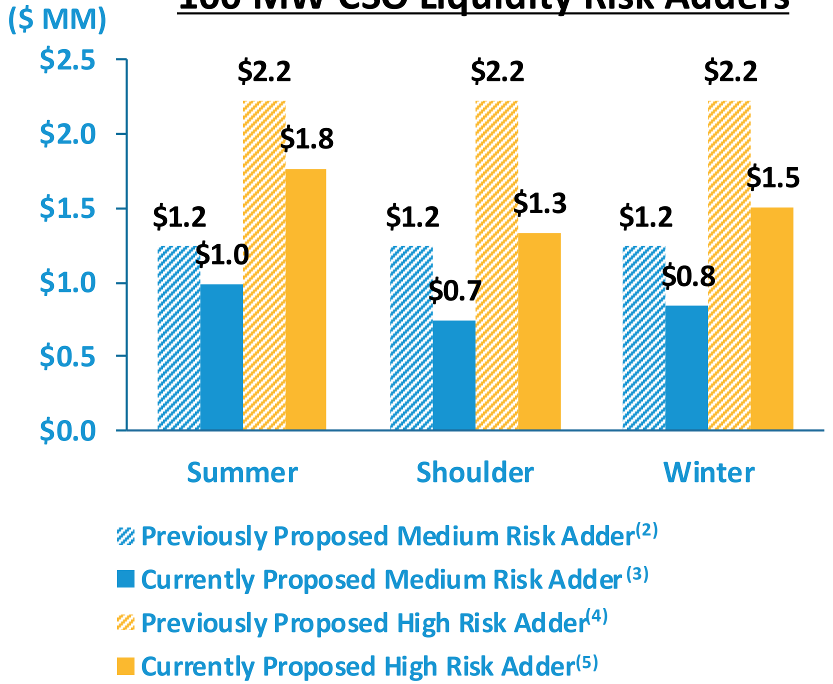
- ISO has reflected the operational diversification benefits of multi-resource portfolios of medium and high risk MPs into the applicable risk adders for such MPs and IMC (intra-month collateral) is now also included in the applicable FCM Delivery FA methodology; this diversification benefit is reflected in the "max[(ABR-CWAP),0.1]" portion of the risk adder

(1) ISO filed updates to the FCM Delivery FA methodology which were approved by FERC with an effective date of March 1, 2024 (Docket No. ER24-661-000). The formula above reflects those updates.
(2) Peak month stop-loss = CSO MW from peak month over a 6 month window * FCA Starting Price; see market rule 1 section III.13.7.3.1 for the formal definition.

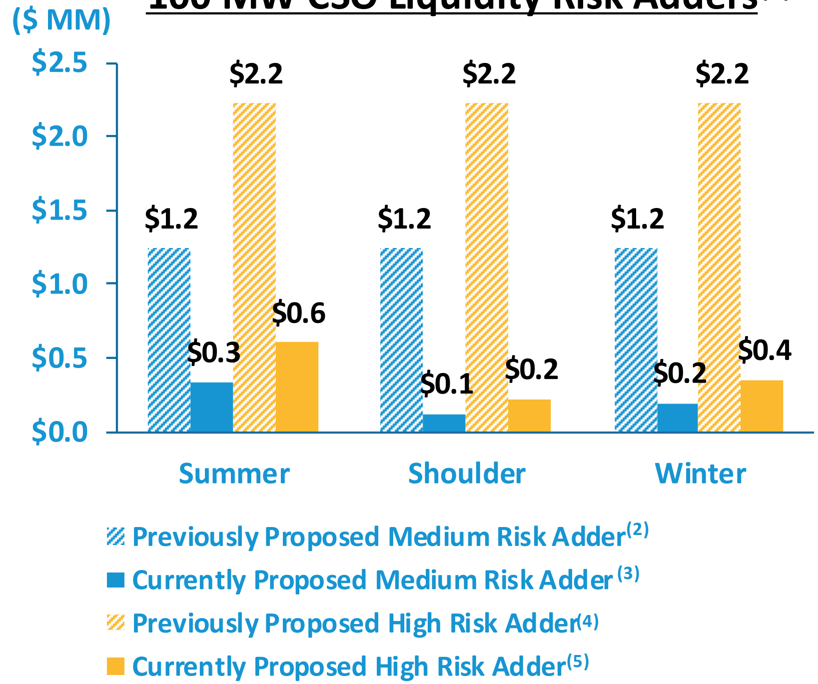
ISO has reduced the proposed applicable risk adders by considering expected operational performance (CWAP) relative to the slice of system obligation (ABR)

Applicable Risk Adders

Single Resource Example
100 MW CSO Liquidity Risk Adders



Multi-Resource Example
100 MW CSO Liquidity Risk Adders[1]



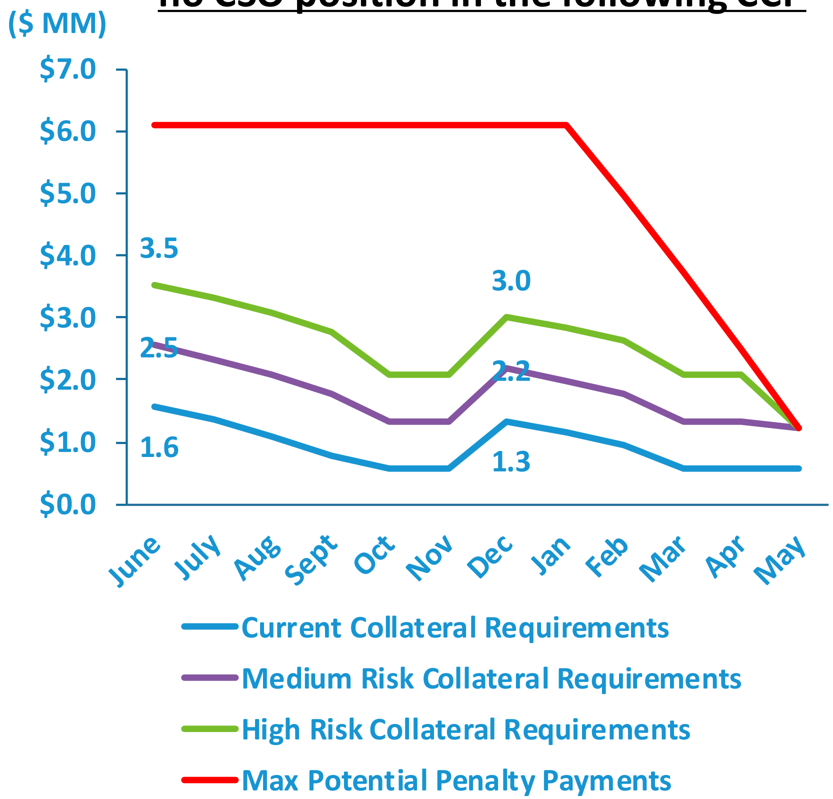
The high risk adder has been reduced by 73% - 90% for multi-resource portfolios[1] and 20% - 40% for single resources on average across the CCP

(1) Based on weighted average CWAP (Capacity Weighted Average Performance) of all multi-resource MPs awarded CSOs in FCA 16.
(2) Current Month Stop-Loss
(3) Peak Monthly Stop-Loss * max(ABR-CWAP,0.1)
(4) Current Month Stop-Loss + Next Month Net Loss
(5) Peak Monthly Stop-Loss * max(ABR-CWAP,0.1) + Second Largest Monthly Stop-Loss * max(ABR-CWAP,0.1)

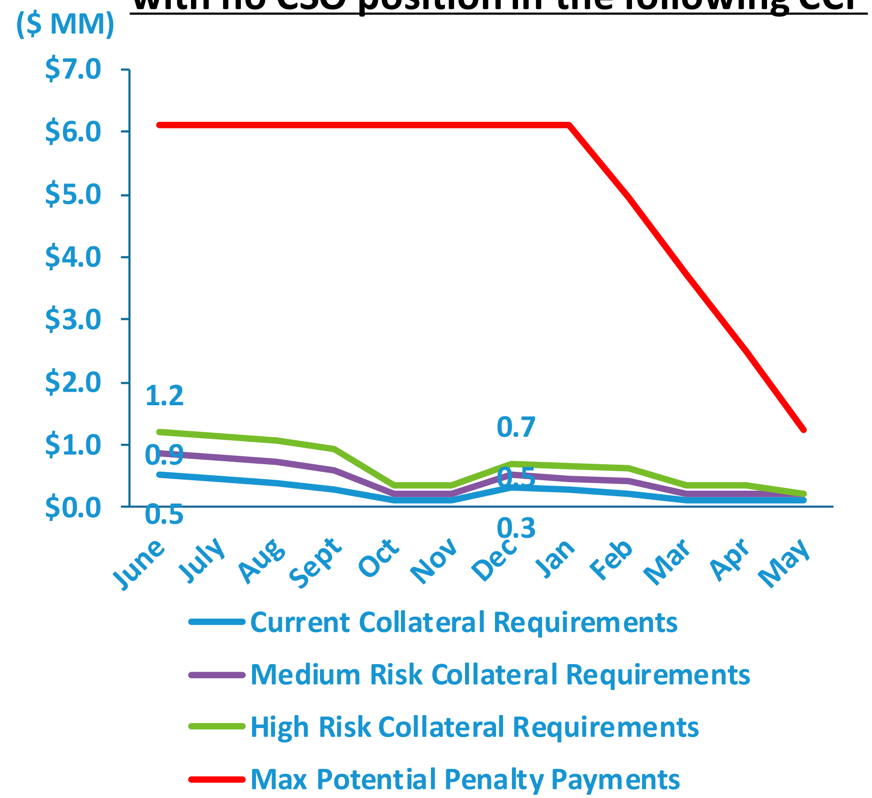
ISO's recommendation increases collateral requirements for MPs that are assessed as posing a higher risk of defaulting and reflects the operational performance benefits of multi-resource portfolios

Incremental PFP Collateral Requirements Examples

Single Resource Example
100 MW CSO Collateral Requirements with no CSO position in the following CCP



Multi-Resource Example
100 MW CSO Collateral Requirements(1) with no CSO position in the following CCP



(1) Based on weighted average CWAP (Capacity Weighted Average Performance) of all multi-resource MPs awarded CSOs in FCA 16.

The ISO is also recommending an update to the Intra-Month Collateral (IMC) calculation so that the overall collateralization of the delivery month PFP penalty payment risk is commensurately sized

Maximum IMC Calculation Example

Month	DFAMW (MW)	Remaining Annual Stop-Loss ($ MM)	Monthly Stop-Loss ($ MM)	Max PFP Penalty ($ MM) A	PE ($/MW)	ABR	CWAP	SF	Current Month Collateralization ($ MM) B	Next Month Collateralization ($ MM) C	Max IMC ($ MM) A - (B – C)
Jun	100	$6.1	$1.2	$1.2	$9,810	0.9	0	2.000	$1.8	$1.5	$0.9
Jul	100	$4.9	$1.2	$1.2	$9,810	0.9	0	1.732	$1.5	$1.2	$0.9
Aug	100	$3.7	$1.2	$1.2	$9,810	0.9	0	1.414	$1.2		

- The Intra-Month Collateral (IMC) variable was introduced as part of the updates to the FCM Delivery FA methodology which were approved by FERC with an effective date of March 1, 2024 (Docket No. ER24-661-000) and the ISO has identified a further beneficial refinement
- IMC, which estimates the amount of PFP penalties incurred during the current month, will be limited to the maximum Pay-for-Performance penalty less the difference between current month collateralization and next month collateralization
- Limiting the amount of IMC is appropriate to avoid situations where the ISO collects collateral that will ultimately be returned to the MP on the first of the following month regardless of the result of future CSC events and resulting PFP penalties
  a) Maximum IMC = Maximum PFP Penalty – Max[(Current Month Collateralization – Next Month Collateralization), 0]
  b) Maximum PFP Penalty = MIN[Current Month Stop-Loss, Remaining Annual Stop-Loss]
  c) Current Month Collateralization = DFAMW * PE * Max[(ABR-CWAP), 0.1] * SF
     - All values are taken from the current delivery month
  d) Next Month Collateralization = DFAMW * PE * Max[(ABR-CWAP), 0.1] * SF
     - All values are taken from the delivery month immediately following the current delivery month

The available corporate liquidity calculation assesses the ability of MPs to satisfy the PFP penalty payment obligations should they arise during the CCP

Available Corporate Liquidity Calculation

Data Source	Corporate Liquidity Values	Values	Amount
Financial Statements of MP or Guarantor	Unrestricted Cash	(a)	$1 MM
	Marketable Securities / Money Market Instruments	(b)	$5 MM
	Undrawn Committed Credit Facilities expiring $\geq$ 3 Months from Reporting Date	(c)	$20 MM
ISO FAM System	Cash / LCs Posted by MP to ISO covering FCM Delivery FA plus any excess collateral(1)	(d)	$1 MM
Available Corporate Liquidity = (a + b + c + d)			$27 MM

- ISO's calculation of available corporate liquidity will be based on the financial statements of the MP or a guarantor (in cases where an affiliate guarantee has been provided)
- Collateral data is taken directly from the FAM system

(1) Excess collateral is defined as excess remaining cash / LCs posted to the ISO which exceed the MP's total financial assurance obligations.

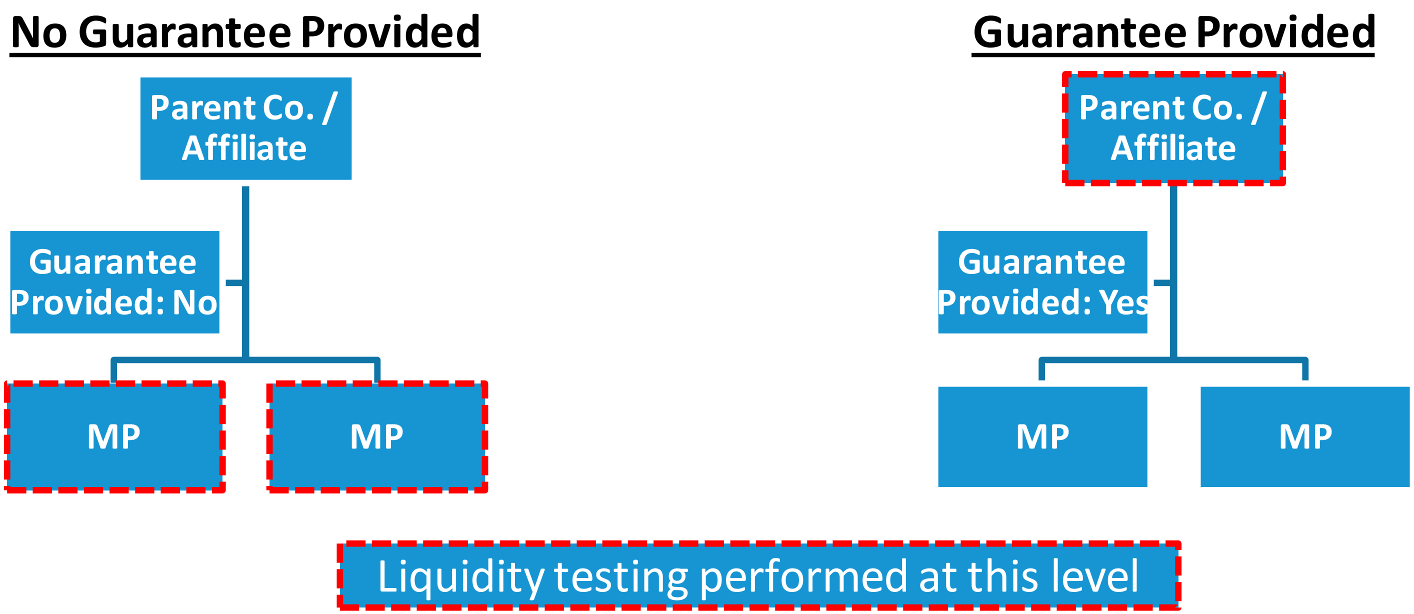
The financial information reporting requirements for the new corporate liquidity test assessment will remain generally consistent with the requirements in the FAP regarding establishing credit limits

Financial Information Reporting Requirements

- The ISO will accept both audited and unaudited financial statements (including officer certified financial statements) to conduct the corporate liquidity assessment which is consistent with the information reporting requirements applied to the establishment of credit limits currently in the FAP
- Quarterly (and annual) financial statements are required to be provided within 10 days of them becoming available and within 65 days after the end of the applicable fiscal quarter
- Monthly financial statements such as officer certified financial statements are required (for MPs who opt in to monthly liquidity testing) to be provided within 20 days of the applicable monthly reporting period
- For MPs that have chosen not to submit financial statements or who have failed to provide them per the respective deadlines above, the ISO will assume available corporate liquidity is equal to their current FCM Delivery FA plus excess financial assurance (i.e., $0 values will be assigned to components of the corporate liquidity assessment derived from financial statements)

ISO will look through to the liquidity profile of a parent / affiliate entity of a MP that posts an acceptable unconditional guarantee when conducting the corporate liquidity assessment

Liquidity Demonstration Options



- In cases where a parent / affiliate is providing a guarantee covering multiple MPs, the respective Designated FCM Participants will be assessed as a whole and are collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk)
- In cases where more than one parent / affiliate provides a guarantee (e.g., for a joint venture entity), the ISO will assess the guarantors collectively

The guarantee accepted by the ISO is intended to exclusively cover the PFP penalty payments in the forward capacity markets

ISO Guarantee Form

- ISO has developed a new guarantee template which it will post on the ISO website, a draft of the guarantee template has been posted for discussion
- Upon acceptance of a parent / affiliate guarantee and associated financial statements, the ISO will perform certain components of the corporate liquidity assessment based on the financial statements of the guarantor
- The guarantee will cover all capacity performance payment obligations in any amount owed at any time
- The ISO has rights to draw upon the guarantee up to the amount of unpaid PFP penalties in the event of a payment default
- The guarantee terminates at the earlier of (a) termination by the ISO, (b) ISO providing written consent to terminate (not to be unreasonably withheld) so long as MP has provided adequate financial assurance, or (c) when the market participant no longer has obligations under the FAP
- The ISO in its sole discretion can reject a guarantor at any time if it presents unreasonable risk to the pool
- A MP can provide a guaranty from multiple guarantors (e.g., in the case of a joint venture) if the guaranty is joint and several

The additional FA requirements for MPs that fail to satisfy the minimum capitalization requirements are revised for those that fall into the medium and high risk liquidity assessment categories

FAP Capitalization Deduction Approach

Liquidity Test Result	Minimum Capitalization Requirements	Applicable FCM Delivery FA Methodology	Capitalization Deduction Treatment
Low	Fail	DFAMW*PE*max[(ABR-CWAP), 0.1]*SF – IMC – MCC (1)	No change from current policy approach
Medium	Fail	DFAMW*PE*max[(ABR-CWAP), 0.1]*SF – IMC – MCC – Applicable Risk Adder	Excluded from additional 25% financial assurance requirement against total FCM Delivery FA obligations
High	Fail	DFAMW*PE*max[(ABR-CWAP), 0.1]*SF – IMC – MCC – Applicable Risk Adder	Excluded from additional 25% financial assurance requirement against total FCM Delivery FA obligations

- If a MP falls into the medium / high risk liquidity test assessment category and is required to post additional FCM Delivery FA (under the new collateral methodology), such MP will be excluded from additional FCM Delivery FA requirements for failing to meet the capitalization requirements in FAP Section II.A.4
- ISO considers this a reasonable approach given the higher collateralization

(1) ISO filed updates to the FCM Delivery FA methodology which were approved by FERC with an effective date of March 1, 2024 (Docket No. ER24-661-000). The formula above reflects those updates.

Contents of Presentation

The updated PFP penalty risk management framework commences from FCA 16 onwards (i.e., June 1, 2025)

FAP Redlines – FCM Delivery FA

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

The liquidity risk adders now reflect the operational diversification benefits offered by multi-resource portfolios by introducing (ABR-CWAP) into the formula

FAP Redlines – FCM Delivery FA Calculation

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1] – Second Largest Monthly Stop-loss x max[(ABR – CWAP), 0.1]

The basis for medium and high risk additional collateral requirements are the peak monthly stop losses over a forward looking 6 month window

FAP Redlines - FCM Delivery FA Calculation (cont.)

Where:

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. ~~and,~~ Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server ~~and shall be limited by the monthly stop loss as described in Section III.13.7.3.1 of Market Rule 1~~.

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Multi-resource portfolios are evaluated on the same basis as single resources in terms of corporate liquidity

FAP Redlines – Corporate Liquidity Assessment

2. Corporate Liquidity Assessment Methodology

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk, medium risk, or high risk) that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter.

(a) For each Designated FCM Participant, the Corporate Liquidity Assessment shall be performed as follows:

- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest but greater than or equal to the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered high risk.

MPs guaranteed by the same parent / affiliate are assessed on a consolidated basis for the purposes of the liquidity assessment while multiple guarantors will be considered on an aggregate basis

FAP Redlines – Corporate Liquidity Assessment (cont.)

(b) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from the same Affiliate, or for Designated FCM Participants that are also providing a guaranty (in accordance with this Section VII.A) for an Affiliate:

- The respective Designated FCM Participants will be assessed as a whole and will be collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk);
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest aggregated Applicable Monthly Stop-losses but is greater than or equal to the sum of two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered high risk.

(c) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from multiple Affiliates:

- The guarantors' financial statements will be considered on an aggregate basis for purposes of the Available Corporate Liquidity calculation taking into account other guaranties provided by any such guarantor under this Section VII.A.

The corporate liquidity assessment takes into account collateral posted to the ISO by a market participant and corporate liquidity as reported in financial statements

FAP Redlines – Corporate Liquidity Assessment (cont.)

Where:

Calculation Period is the current delivery month through the following five consecutive months.

The Applicable Monthly Stop-loss equals the sum of the monthly stop-losses for each resource in a Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1 for the corresponding months within the Calculation Period.

Available Corporate Liquidity is the sum of unrestricted cash and cash equivalents; marketable securities and money market instruments; undrawn committed credit facilities not expiring within three months of the date of the applicable financial statements; and excess financial assurance. Other than with respect to excess financial assurance, such values shall be (a) as reflected on the most recent financial statements provided by the Designated FCM Participant, provided that such financial statements were provided for the most recently completed financial reporting period and compliant with the requirements of this Section VII.A, and (b) calculated in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied. Excess financial assurance shall be calculated as any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant covering its FCM Delivery Financial Assurance obligations plus any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant in excess of its total Financial Assurance Obligations, each as reflected in the ISO's Financial Assurance Management (FAM) or equivalent system.

Financial statements provided to the ISO are typically reviewed at least quarterly

FAP Redlines – Corporate Liquidity Assessment (cont.)

For the avoidance of doubt, the components of the Available Corporate Liquidity calculation that are derived from financial statements shall be based on the financial statements of the Designated FCM Participant unless it provides an Affiliate guaranty in compliance with this Section VII.A, in which case the values shall be based on the financial statements of the entity(ies) providing the guaranty. If an acceptable Affiliate guaranty is provided, stop-loss and excess financial assurance values will still be based on the Designated FCM Participant.

Each Designated FCM Participant shall submit to the ISO, on a quarterly basis, its (or its guarantor's, as applicable) audited or unaudited balance sheet or equivalent financial statements, which shall show sufficient detail for the ISO to assess the Designated FCM Participant's (or guarantor's, as applicable) Available Corporate Liquidity. Such financial information shall be accompanied by a certificate from a Senior Officer of the Designated FCM Participant (or guarantor as applicable) that provides the relevant financial information and certifies the accuracy of the attached financial statements. If an attestation was made by an independent accounting firm, then the certificate shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required. The ISO shall post a generally acceptable "clean" form of certificate on its website. Financial statements provided on a quarterly basis shall be submitted within 10 days of such statements becoming available and within 65 days after the end of the applicable fiscal quarter.

Medium and high risk market participants may elect to submit financial statements monthly

FAP Redlines – Corporate Liquidity Assessment (cont.)

Designated FCM Participants that are assessed as medium risk or high risk may elect to provide financial statements on a monthly basis until such a time as they are subsequently assessed as a lower risk category (e.g., from high risk to medium risk, medium risk to low risk, or high risk to low risk); provided that such election shall be for a minimum period of six continuous months during which they are continuously assessed at a lower risk category. Financial statements submitted on a monthly basis are required to be provided to the ISO within 20 days after the end of the prior month and otherwise be provided in accordance with this Section VII.A.

A Designated FCM Participant may choose not to submit financial statements as described in this Section VII.A. If a Designated FCM Participant chooses not to submit financial statements as described in this Section VII.A or if such financial statements are not compliant with the requirements described in this Section VII.A, the ISO shall use a value of $0.00 for Available Corporate Liquidity values derived from financial statements until such time as compliant financial statements are provided.

The ISO shall review the information provided pursuant to this Section VII.A on a rolling basis and will calculate the Available Corporate Liquidity within a reasonable time period which shall not exceed 30 Business Days from the date of receipt.

The ISO may at its sole discretion, reject or terminate any guaranty that poses unreasonable risk to the New England Markets and, may accept a guaranty from multiple affiliates

FAP Redlines – Affiliate Guarantees

3. FCM Affiliate Guaranties

For the purposes of the Corporate Liquidity Assessment, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from an Affiliate to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant. Upon the ISO's acceptance of an Affiliate guaranty, the guarantor(s) must provide financial statements in accordance with this Section VII.A, and the Corporate Liquidity Assessment will be performed based on the financial information of the guarantor(s). The ISO will post a generally acceptable sample "clean" guaranty on its website, and all guaranties provided pursuant to this Section VII.A shall be in such form with only non-material changes (as determined by the ISO in its sole discretion). The ISO in its sole discretion may update the form guaranty from time to time. The ISO has the right to draw upon the guaranty in the event of a default under the ISO New England Billing Policy up to any amount owed for unpaid Capacity Performance Payments. At any time, the ISO may in its sole discretion provide notice to a Designated FCM Participant that it is choosing to reject or terminate its Affiliate guaranty because such guaranty presents unreasonable risk to the ISO or the New England Markets. In the case of a termination (or planned termination), upon the ISO providing such notice the guaranty shall not be considered for purposes of such Designated FCM Participant's Corporate Liquidity Assessment beginning at 8:30 on the next Business Day, provided that the ISO may, in its sole discretion, extend this period by up to twenty (20) Business Days. For the avoidance of doubt, notice from the ISO to the Designated FCM Participant that the guaranty its Affiliate provided is being terminated (or will be terminated), does not constitute a termination notice under such guaranty and the ISO, in its sole discretion, may choose when to send the applicable termination notice under the terms of such guaranty.

In the ISO's sole discretion, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from multiple Affiliates to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant, so long as such guaranty is otherwise in accordance with this Section VII.A and the guarantors have joint and several liability under such guaranty.

FCM Delivery FA for medium and high risk MPs are excluded from the capitalization deduction requirements

FAP Redlines – Capitalization Deduction Requirements

For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement~~, (~~excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the sixteenth Forward Capacity Auction (i.e., June 1, 2025) or any Capacity Commitment Period thereafter~~)~~.

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

Contents of Presentation

The incremental PFP collateral costs incurred by higher risk capacity sellers may be passed through to consumers so the ISO has provided an estimated potential range for informational purposes

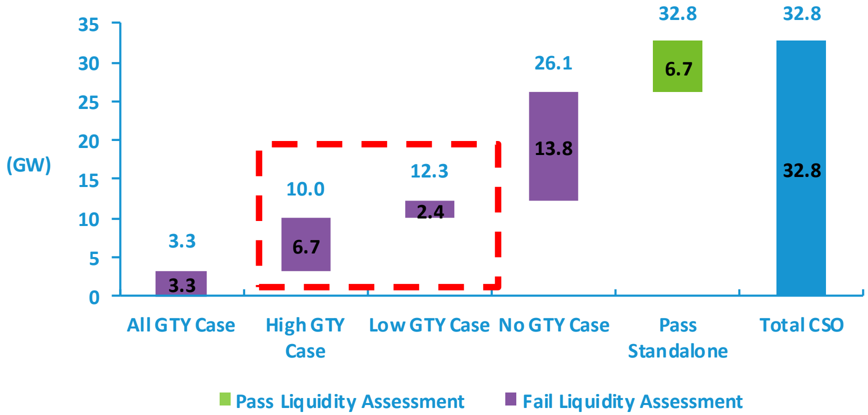
Potential Cost Impact to Consumers

- It is important to note that the potential cost impact to consumers may fall within an estimated range depending on the total amount of additional collateral in the form of cash or letters of credit that are posted to the ISO and the respective financing costs thereof
  - The analysis doesn't reflect the offsetting benefit of the returns generated by investments in the Blackrock accounts of capacity sellers (currently, ~5% annually)
- Capacity sellers that are operating on adequate corporate liquidity levels will not incur any incremental collateral costs as they have already internalized the cost of such liquidity requirements on their balance sheets
- Capacity sellers that fall into the medium / high risk categories may be faced with financing costs that range from the cost of capital associated with a debt (liquidity facilities or term debt) or an equity style issuance
  - ISO has provided more conservative cost ranges using the after-tax weighted average cost of capital (ATWACC) assumptions used in the Net CONE for FCA 19
- The ISO has assessed the potential impact on consumers if capacity sellers successfully passed through their incremental financing costs
  - Capacity sellers are assumed to incur financing costs of 5.01% (after-tax cost of debt) at the low-end to 8.96% (after-tax weighted average cost of capital) at the higher end

PFP collateral requirements are expected to increase by $72 to $90 MM out of a maximum of $154 MM depending on the number of affiliate guarantees received by the ISO

Estimated Incremental PFP Collateral (FCA 16) Requirements

Corporate Liquidity Assessment by CSO (GW)



Incremental PFP Collateral ($ MM)

- If the ISO receives the maximum number of guarantees from eligible affiliates, the total increase in collateral requirements would be $35 MM as 3.3 GW of CSO would fall into the higher risk categories from a corporate liquidity perspective (i.e., 3.3 GW of CSO are from single entity MPs in the medium/high risk categories)
- ISO expects the number of guarantees(1) offered by eligible affiliates to fall within the low and high case guarantee posting scenarios which would result in the total increase in PFP collateral falling within a range of $72 MM (~10.0 GW of high liquidity risk CSOs) to $90 MM (~12.3 GW of high liquidity risk CSOs) which is assumed in our cost analysis for consumers
- If the ISO receives no guarantees, then total collateral requirements would increase by a maximum of $154 MM (currently, total collateral requirements stands at $114 MM on average based on the current methodology) when aggregated across all capacity sellers reflecting the total additional PFP collaterals posted by medium and high liquidity risk capacity sellers

1) See slides 51-52 for further details.

The expected cost to consumers if the cost of the additional collateral was fully passed through by capacity sellers ranges from $0.00003 to $0.00007/KWh using a 5% and 9% financing assumption, respectively

FCA 16 Estimated Incremental Cost to Consumers Analysis

GTY Case	CSO Failing Liquidity Assessment (GW) A	Real Time Load (GW) B	Incremental FA ($ MM) C	After Tax Cost of Debt (%) D	After Tax WACC (%) E	Low End Generator Cost(1) (@5.01%) ($/kW-Month) (C/A*D/12)	High End Generator Cost(1) (@8.96%) ($/kW-Month) (C/A*E/12)	Low End Cost (@ 5.01%) to Consumer ($/kWh) (C/B*D/12/30/24)	High End Cost (@ 8.96%) to Consumer ($/kWh) (C/B*E/12/30/24)
High	10	13	$72	5.01%	8.96%	$0.030	$0.054	$0.00003	$0.00006
Low	12	13	$90	5.01%	8.96%	$0.031	$0.055	$0.00004	$0.00007

- Under the high case guarantee posting scenario, ~10 GW of CSOs fall into the higher risk corporate liquidity assessment category resulting in on average ~$72 MM of additional PFP collateral posting requirements costing between $0.030/KW-M and $0.054/KW-M for capacity sellers
  - Assuming all these additional costs for capacity sellers are passed through to consumers, the additional cost to the consumer ranges from $0.00003 and $0.00006/KWh
- Under the low case guarantee scenario, ~12 GW of CSOs fall into the higher risk corporate liquidity assessment category resulting in on average ~$90 MM of additional PFP collateral posting requirements costing between $0.031/KW-M and $0.055/KW-M for capacity sellers
  - Assuming all these costs are passed through to consumers by the affected capacity sellers, the additional cost to the consumer ranges from $0.00004 to $0.00007/KWh

The expected costs to consumers is immaterial in all cases versus the benefit of mitigating socialized defaults by non-performing illiquid capacity sellers

1) Generator cost assumptions were adjusted from 0.2% (20 BPS) - 5.0% (500 BPS) in previous materials to 5.01% - 8.96%

Contents of Presentation

The ISO is recommending an effective date on January 1, 2025 however the new FA methodology would go-live as of June 1, 2025 (FCA 16) and apply to each Capacity Commitment Period thereafter. The revised IMC calculation will be effective January 1, 2025

Recommended Effective Date

FCA	Capacity Commitment Period	FCM Delivery FA Methodology
15	2024-25	Current Methodology
16	2025-26	Recommended Methodology
17	2026-27	Recommended Methodology
18	2027-28	Recommended Methodology
19	2028-29	Recommended Methodology
Beyond		Recommended Methodology

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee January 24, 2024	Introduce Pay-for-Performance Financial Assurance Update to the Financial Assurance Policy (FAP)
Budget and Finance Subcommittee February 9, 2024	Continue discussion on Pay-for-Performance Financial Assurance Updates including detail on corporate liquidity testing assessment
Budget and Finance Subcommittee March 26, 2024	Continue discussion on Pay-for-Performance Financial Assurance Updates including FCM Delivery FA methodology and assessment
Budget and Finance Subcommittee April 24, 2024	Continued discussion on Pay-for-Performance Financial Assurance Update to the FAP, including redlines
Budget and Finance Subcommittee May 10, 2024	Continued discussion on stakeholder presentation and stakeholder memo on Pay-for-Performance Financial Assurance Update to the FAP
Joint Markets Committee and Budget and Finance Subcommittee June 11, 2024	Introduce stakeholder amendment concepts to MR1 and FAP or Billing Policy

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee July 9-10, 2024	Discuss stakeholder amendment detail including Market Rule 1 Redlines
Budget and Finance Subcommittee July 29, 2024	Discuss any updates to the ISO's Financial Assurance Proposal and final redlines Discuss stakeholder amendments in detail, including redline review of stakeholder amendments to the Financial Assurance Policy (FAP) or billing policy
Markets Committee August 6-7, 2024	Discuss and vote on stakeholder amendments to MR1 related to the ISO's financial assurance update proposal
Participants Committee September 5, 2024	Vote

- **The NPC vote is targeted for September to ensure adequate time for filing and to receive an order by January 1, 2025. This will provide an opportunity for participants to utilize ARA3 to adjust their position ahead of the upcoming CCP**

Contents of Presentation

The updated FCM Delivery FA methodology accepted by FERC recently(1) will remain the PFP collateral requirement for low risk MPs but an updated definition of IMC is proposed

Low Risk PFP Collateral Methodology

DFAMW*PE*max[(ABR-CWAP), 0.1]*SF – IMC – MCC	
DFAMW (Delivery Financial Assurance MW)	The sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1
PE (Potential Exposure)	PE is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss
ABR (Average Balancing Ratio)	The duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. It generally reflects a participant's slice of system obligation
CWAP (Capacity Weighted Average Performance)	The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period
SF (Scaling Factor)	A month specific multiplier: June / December 2.00; July and January 1.732; August and February 1.414; and all other months 1.00
***(Proposed)* IMC (Intra-month Collateral)**	IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server.
MCC (Monthly Capacity Charge)	MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

(1) ISO filed updates to the FCM Delivery FA methodology which were approved by FERC with an effective date of March 1, 2024 (Docket No. ER24-661-000). The formula above reflects those updates, IMC changes will be part of the upcoming filing.

In a scenario where the ISO receives no affiliate guarantees, the average increase in PFP collateral requirements is ~$154 MM for the entire market while this reduces to $35 MM on average if it received guarantees from every affiliate that is creditworthy

Guarantee Posting Scenarios

CCP 2025-26 (Total CSOs ~32.8 GW)								
	No GTY Scenario				All GTY Scenario			
Market Participant Category	CSO (GW)	MPs (#)	Current Average Monthly PFP Collateral ($ MM)	Average Incremental PFP Collateral ($ MM)	CSO (GW)	MPs (#)	Current Average Monthly PFP Collateral ($ MM)	Incremental PFP Collateral ($ MM)
Pass on Standalone Basis[1]	6.7	75	$26	NA	6.7	75	$26	NA
Pass Utilizing Affiliate GTY[1]	0.0	0	$0	NA	22.8	40	$68	NA
Medium & High Risk[1]	26.1	82	$88	$154	3.3	42	$20	$35
Total	32.8	157	$114	$154	32.8	157	$114	$35

(1) Based on a review of financial statements reporting as of Dec 31, 2023.

The ISO expects that the total incremental collateral requirements for the entire market increases to between $72 MM and $90 MM depending on the number of guarantees it receives which is reflected in the low and high guaranty case scenarios below

Guarantee Posting Scenarios

CCP 2025-26 (Total CSOs ~32.8 GW)								
	Low GTY Scenario				High GTY Scenario			
Market Participant Category	CSO (GW)	MPs (#)	Current Average Monthly PFP Collateral ($ MM)	Average Incremental PFP Collateral ($ MM)	CSO (GW)	MPs (#)	Current Average Monthly PFP Collateral ($ MM)	Incremental PFP Collateral ($ MM)
Pass on Standalone Basis(1)	6.7	75	$26	NA	6.7	75	$26	NA
Pass Utilizing Affiliate GTY(1)	13.8	14	$37	NA	16.1	27	$47	NA
Medium & High Risk(1)	12.3	68	$51	$90	10.0	55	$41	$72
Total	32.8	157	$114	$90	32.8	157	$114	$72

(1) Based on a review of financial statements reporting as of Dec 31, 2023.

The ISO made a conservative assumption regarding non-energy industry parents/ affiliates and their willingness to provide guarantees

Parent / Affiliate Guarantee Assumptions Revision

	Revised Assumption	
Market Participant (Parent) Sector	**Low GTY Case CSO Coverage (GW)**	**High GTY Case CSO Coverage (GW)**
Energy Industry	13.8	14.1
Asset Management, Private Equity or Pension Fund Firms	0.0	2.0
Total	13.8	16.1

- ISO has revised the High and Low Guaranty scenarios by grouping ~16 GWs of CSO that is expected to require liquidity support from a guarantor into two categories
  - The remaining ~17 GWs either pass on a standalone basis (6.7 GW) or is not assumed to have an affiliate with adequate liquidity willing to provide a guaranty (10.3 GW)
- CSOs from MPs with a guarantor showing adequate liquidity that is also in the energy industry were largely placed in the Low GTY Case while CSOs from MPs with an affiliate not in the energy industry fall into the High GTY Case
  - ISO anticipates that affiliate companies with significant balance sheets that are in the energy industry are highly likely to provide a guaranty on behalf of their MP
  - Affiliate companies outside of the energy industry may provide a guaranty as well, but ISO is less confident in receiving a guaranty from this sector and assumed zero would be received in the low case

These are the links to capacity performance bilateral ISO materials and trainings

Capacity Performance Bilateral ISO Training Materials

- https://www.iso-ne.com/static-assets/documents/support/user_guides/submitting_ibts_using_sms.pdf (page 78)
- Settlements Forum: 2018 Q1 (presentation) (slides 11-14)
- Pay-for-Performance (video)
- See Section 6 of the User Guide for Submitting Internal Bilateral Transactions using SMS for additional details

NEPGA
NEW ENGLAND POWER GENERATORS ASSOCIATION, INC.

Mitigation of Default Risk as Alternatives to Incremental Financial Assurance Requirements

Bruce Anderson, SVP & General Counsel
NEPOOL Budget and Finance Subcommittee Meeting
July 29, 2024

Conceptual Amendment #1: Longer Pay Off Period on Negative Monthly Capacity Payment Balances

- **NEPGA offers a conceptual amendment the ISO-NE Billing Policy to allow a Designated FCM Participant to pay off any Pay for Performance charges beyond a defined threshold over a period of up to nine months.**
  - Associated changes to Market Rule 1 are needed to fully execute the proposal. NEPGA intends to introduce its proposed Market Rule 1 changes at the August 6-7, 2024, NEPOOL Markets Committee meeting.
- **PJM Interconnection recently adopted Tariff changes allowing for longer pay off periods of up to nine months following its experience with a tail-risk event (Winter Storm Elliot).**
  - Prior to Winter Storm Elliot, the PJM tariff provided that for any Non-Performance Charges (under its version of Pay for Performance), the amount charged to the resource each month = Non-Performance Charges/months remaining in Delivery Year for which invoices have yet to be issued (e.g., $1.2M in Non-Performance Charges with 6 months remaining in the Delivery Period = $200,000/month).
  - Following Winter Storm Elliot, PJM amended its tariff to provide that If the number of months remaining in the Delivery Year for which invoices have yet to be issued is ***less than six months***, then the PJM Office of Interconnection may extend the monthly payment period to up nine months.
- **In accepting PJM's billing proposal, the Commission concluded that to allow more time to pay "when the charges are large" should reduce the risk of defaults and maximize the total bonus pool (those payments issued to "over-performers" during an Emergency Condition). 183 FERC P 61,001, at P 21 (2023)**
  - PJM as well opined that this change would "reduce the risk of PJM members defaulting due to non-payment of Non-Performance Charges." *Id*. at P 7.
  - In practice this played out – PJM collected on approximately 95% of total charges.

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Conceptual Amendment #1 (Continued): Longer Pay Off Period on Negative Monthly Capacity Payment Balances

- **A resource's Monthly Capacity Payment for an Obligation Month is equal to the sum of the Capacity Base Payment for the month and either (positive) payments or (negative) charges for all Capacity Scarcity Conditions during the month (i.e., Capacity Performance Payments). Tariff s. III.13.7.3.**

- **If the sum of Capacity Performance Payments for the month is negative, the amount of charges subtracted from the Capacity Base Payment is capped by the Monthly Stop-Loss (and the Annual Stop Loss).** ***See*** **Tariff s. III.13.7.3.1 and III.13.7.3.2.**
  - Under the ISO-NE Billing Policy, monthly statements (including Invoices, i.e., amounts due to ISO-NE) are issued on the *first Monday after the 9th of each month*. Payments on the monthly Invoices are *due two business days later*.
  - Monthly statements include *"nonhourly services"* defined to include capacity payments/charges.

- **This conceptual amendment would allow for a longer period to pay off large Pay for Performance charges under conditions similar to the terms and conditions adopted by PJM (i.e., upon ISO-NE discretion following an extreme Capacity Scarcity Condition(s)).**
  - The conceptual amendment would necessarily dictate that suppliers due Pay for Performance payments would receive such payments over a longer period of time than under the current rules (pursuant to which Remittance Advice amounts (i.e., net payments due to the supplier) must be paid within four business days following issuance of the Remittance Advice).

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Amendment #2:
Incremental Financial Assurance Obligations Should Be Prospective Only

- **NEPGA has repeatedly raised concerns with making the ISO proposal effective beginning with the FCA 16 Capacity Commitment Period (*i.e.*, June 1, 2025).**
- **Imposing new costs on capacity suppliers without *any* opportunity to reflect those costs in capacity market offer prices undermines the price signals the capacity market is designed to send.**
  - The Internal Market Monitor has opined in prior BFS meetings that it would expect Market Participants to reflect these incremental financial assurance costs in capacity market offer prices.
- **For some Market Participants, the ISO-NE proposal will impose a material increase in the cost of assuming the energy market offer requirements and other obligations inherent in a CSO (e.g., financial assurance requirement costs).**
  - According to ISO-NE, a single resource Market Participant deemed at high risk is expected to be obligated to post from $1.3M - $1.8M in incremental financial assurance for every 100 MW of CSO. *See* ISO-NE Presentation, July 29 BFS Meeting, at p. 22.
  - NEPGA Members have reported higher incremental cost impacts than estimated by ISO-NE.
- **Increasing the cost of assuming a Capacity Supply Obligation after a supplier agrees to take on the obligation at a certain price creates bad precedent (for supply and load alike) and uncertainty in the finality of market rules.**
- **Accordingly, NEPGA proposes to amend ISO-NE's proposal to make it effective as of the first Capacity Commitment Period for which a supplier has an opportunity to reflect these incremental financial assurance costs, i.e., on June 1, 2028 (coinciding with the FCA 19 Capacity Commitment Period).**

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Check out our blog, *Power Lines*

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NEPGA's Proposed Revisions to ISO-NE's FAP Proposal

Note 1: The yellow highlighted revision in proposed Section VII.A.3 corrects a scrivener's error and is part of NEPGA's revisions.

Note 2: The green highlighted revisions are NEPGA's proposed amendment to the ISO's FAP Proposal.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement, ~~(~~excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity

Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the ~~sixteenth~~nineteenth Forward Capacity Auction (i.e., June 1, 202~~5~~8) or any Capacity Commitment Period thereafter~~)~~.

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);

(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately

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C. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the ~~sixteenth~~nineteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the ~~fifteenth~~eighteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the ~~sixteenth~~nineteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1] – Second Largest Monthly Stop-loss x max [(ABR – CWAP), 0.1]

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM

Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. ~~and,~~ Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server ~~and shall be limited by the monthly stop loss as described in Section III.13.7.3.1 of Market Rule 1~~.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all ABR values reflect actual data.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all average performance values reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June and December	2.000;
July and January	1.732;
August and February	1.414;
All other months	1.000.

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

2. Corporate Liquidity Assessment Methodology

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk, medium risk, or high risk) that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the ~~sixteenth~~nineteenth Forward Capacity Auction or any Capacity Commitment Period thereafter.

(a) For each Designated FCM Participant, the Corporate Liquidity Assessment shall be performed as follows:

- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest but greater than or equal to the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered high risk.

(b) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from the same Affiliate, or for Designated FCM Participants that are also providing a guaranty (in accordance with this Section VII.A) for an Affiliate:

- The respective Designated FCM Participants will be assessed as a whole and will be collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk);
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest aggregated Applicable Monthly Stop-losses but is greater than or equal to the sum of two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered high risk.

(c) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from multiple Affiliates:

- The guarantors' financial statements will be considered on an aggregate basis for purposes of the Available Corporate Liquidity calculation taking into account other guaranties provided by any such guarantor under this Section VII.A.

Where:

Calculation Period is the current delivery month through the following five consecutive months.

The Applicable Monthly Stop-loss equals the sum of the monthly stop-losses for each resource in a Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1 for the corresponding months within the Calculation Period.

Available Corporate Liquidity is the sum of unrestricted cash and cash equivalents; marketable securities and money market instruments; undrawn committed credit facilities not expiring within three months of the date of the applicable financial statements; and excess financial assurance. Other than with respect to excess financial assurance, such values shall be (a) as reflected on the most recent financial statements provided by the Designated FCM Participant, provided that such financial statements were timely provided and compliant with the requirements of this Section VII.A, and (b) calculated in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied. Excess financial assurance shall be calculated as any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant covering its FCM Delivery Financial Assurance obligations plus any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant in excess of its total Financial Assurance Obligations, each as reflected in the ISO's Financial Assurance Management (FAM) or equivalent system.

For the avoidance of doubt, the components of the Available Corporate Liquidity calculation that are derived from financial statements shall be based on the financial statements of the Designated FCM Participant unless it provides an Affiliate guaranty in compliance with this Section VII.A, in which case the values shall be based on the financial statements of the entity(ies) providing the guaranty. If an acceptable Affiliate guaranty is provided, stop-loss and excess financial assurance values will still be based on the Designated FCM Participant.

Each Designated FCM Participant shall submit to the ISO, on a quarterly basis, its (or its guarantor's, as applicable) audited or unaudited balance sheet or equivalent financial statements, which shall show sufficient detail for the ISO to assess the Designated FCM Participant's (or guarantor's, as applicable) Available Corporate Liquidity. Such financial information shall be accompanied by a certificate from a Senior Officer of the Designated FCM Participant (or guarantor as applicable) that provides the relevant financial information and certifies the accuracy of the attached financial statements. If an attestation was made by an independent accounting firm, then the certificate shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required. The ISO shall post a generally acceptable "clean" form of certificate on its website. Financial statements provided on a quarterly basis shall be submitted within 10 days of such statements becoming available and within 65 days after the end of the applicable fiscal quarter.

Designated FCM Participants that are assessed as medium risk or high risk may elect to provide financial statements on a monthly basis until such a time as they are subsequently assessed as a lower risk category (e.g., from high risk to medium risk, medium risk to low risk, or high risk to low risk); provided that such election shall be for a minimum period of six continuous months during which they are continuously assessed at a lower risk category. Financial statements submitted on a monthly basis are required to be provided to the ISO within 20 days after the end of the prior month and otherwise be provided in accordance with this Section VII.A.

A Designated FCM Participant may choose not to submit financial statements as described in this Section VII.A. If a Designated FCM Participant chooses not to submit financial statements as described in this Section VII.A or if such financial statements are not compliant with the requirements described in this Section VII.A, the ISO shall use a value of $0.00 for Available Corporate Liquidity values derived from financial statements until such time as compliant financial statements are provided.

The ISO shall review the information provided pursuant to this Section VII.A on a rolling basis and will calculate the Available Corporate Liquidity within a reasonable time period which shall not exceed 30 Business Days from the date of receipt.

3. FCM Affiliate Guaranties

For the purposes of the Corporate Liquidity Assessment, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from an Affiliate to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant. Upon the ISO's acceptance of an Affiliate guaranty, the guarantor(s) must provide financial statements in accordance with this Section VII.A, and the Corporate Liquidity Assessment will be performed based on the financial information of the guarantor(s). The ISO website will provide a generally acceptable sample "clean" guaranty, and all guaranties provided pursuant to this Section VII.A shall be in such form with only non-material changes (as determined by the ISO in its sole discretion). The ISO in its sole discretion may update the form guaranty from time to time. The ISO has the right to draw upon the guaranty in the event of a default under the ISO New England Billing Policy up to any amount owed for unpaid Capacity Performance Payments. At any time, the ISO may in its sole discretion provide notice to a Designated FCM Participant that it is choosing to reject or terminate its Affiliate guaranty because such guaranty presents unreasonable risk to the ISO or the New England Markets. In the case of a termination (or planned termination), upon the ISO providing such notice the guaranty shall not be considered for purposes of such Designated FCM Participant's Corporate Liquidity Assessment beginning at 8:30 a.m. on the next Business Day, provided that the ISO may, in its sole discretion, extend this period by up to twenty (20) Business Days. For the avoidance of doubt, notice from the ISO to the Designated FCM Participant that the guaranty its Affiliate provided is being terminated (or will be terminated), does not constitute a termination notice under such guaranty and the ISO, in its sole discretion, may choose when to send the applicable termination notice under the terms of such guaranty.

In the ISO's sole discretion, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from multiple Affiliates to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant, so long as guaranty is otherwise in accordance with this Section VII.A and the guarantors have joint and several liability under such guaranty.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the “FCM Deposit”).

2. Non-Commercial Capacity in Forward Capacity Auctions

a. Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction

For Non-Commercial Capacity participating in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction, a Designated FCM Participant that had its supply offer of Non-Commercial Capacity accepted in a Forward Capacity Auction must include in the calculation of its Financial Assurance Requirement under the ISO New England Financial Assurance Policy the following amounts at the following times:

(i) beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day following announcement of the awarded supply offers in that Forward Capacity Auction, an amount equal to $5.737(on a $/kW-month basis) multiplied by the number of kW of capacity awarded to that Designated FCM Participant in that Forward Capacity Auction (such amount being referred to herein as the “Non-Commercial Capacity FA Amount”);

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NEPGA
NEW ENGLAND POWER GENERATORS ASSOCIATION, INC.

Management of Incremental Financial Assurance Requirements Under ISO-NE's Financial Assurance Proposal – *Revision 1*

Bruce Anderson, SVP & General Counsel
NEPOOL Markets Committee Meeting
August 6, 2024

Allow For More Timely Trading Out and Recognition of a Monthly CSO Position

- **A Market Participant may sell all or part of the monthly Capacity Supply Obligation for a resource in one of two ways, through either: (1) a demand bid in a monthly reconfiguration auction (MRA) (Tariff s. III.13.4.2.2); or (2) a monthly Capacity Supply Obligation bilateral agreement. (Tariff s. III.13.5.1).**

- **Whether through a MRA or bilateral agreement, the Market Participant(s) must transact months in advance of the month for which the parties look to transfer a CSO. For example, to transfer a CSO held for July 2024, the Market Participant must trade out through either the MRA, running from May 22-23, 2024, or bilaterally by May 13-14, 2024.**

- **Thus, e.g., if a resource suffers an equipment failure in June 2024 that will render it unable to respond to a Capacity Scarcity Condition that may occur in July 2024, the MRA and bilateral windows will have already closed.**

- **These deadlines unduly limit the ability of a Market Participant to manage the incremental financial assurance requirements required under ISO-NE's proposal. Changes to those deadlines would relieve these undue limits and improve upon ISO-NE's financial assurance proposal.**

Allow For More Timely Trading Out and Recognition of a Monthly CSO Position

- **NEPGA proposes to eliminate the open window-based Capacity Supply Obligation Bilateral submission deadlines, and instead:**
  - **Allow a Market Participant to submit a Capacity Obligation Bilateral to ISO-NE up to 5 Business Days before ~~the monthly reconfiguration auction for~~ the Obligation Month and require that ISO-NE conduct its reliability, financial assurance, and other reviews of the Capacity Supply Obligation Bilateral (and either accept or reject the bilateral) within 5 Business Days of the submission of a Capacity Supply Obligation Bilateral to ISO-NE.**
- **NEPGA's amendment is directly related to ISO-NE's financial assurance proposal.**
  - **ISO-NE's proposal dictates incremental financial assurance requirements based in part on the monthly CSO positions held by Market Participants in the present and following six months. The amendment proposed by NEPGA allows Market Participants to better manage their CSO positions (financial assurance requirements) over that six-month look-ahead period and recognize changed CSO positions sooner in time to more accurately calculate financial assurance due under ISO-NE's proposal. Further, NEPGA's amendments directly effect the inputs to the incremental financial assurance calculations ISO-NE proposes.**
- **NEPGA's amendment creates market-wide benefits:**
  - **The current rules create incremental risk and increase the cost of assuming a CSO (e.g., the risk of not being able to timely trade out of a monthly CSO position). NEPGA's amendment reduces that risk/cost and allows for more efficient capacity market outcomes.**
  - **Further, the ability to trade closer in time to the Obligation Month improves reliability, in that it allows for timely substitution of anticipated Capacity Scarcity Condition performance.**

NEPGA
NEW ENGLAND POWER GENERATORS ASSOCIATION, INC.

Require More Timely Recognition of CSO Bilaterals in Financial Assurance Calculations

- **A Designated FCM Participant can execute a CSO transfer directly with a counter-party, with the negotiating parties determining the transferred price and quantity of the capacity obligation.**
  - **These arrangements can be made for future delivery periods, not just for the prompt month. When submitted for future periods these trades remain in a '*parking lot*' until that month's bilateral window opens.**
  - **The seller reduces its capacity obligation and in turn the amount of PFP exposure (in terms of nominal collateral $'s needed to be posted, as the CSO quantity is lower after the bilateral transfer).**

- **The current construct provides the opportunity to submit risk reducing trades in future periods (in that month's 'parking lot'), but the proposed PFP FA rules do not account for the lower CSO quantity in the future month (at the time a CSO Bilateral is submitted, prior to the open window). This approach unnecessarily ignores the submitted bilateral transaction.**

- **NEPGA proposes the following amendments (see redlined Sections III.13.5.1.1.1 and III.13.5.1.1.3):**
  1. **A Capacity Supply Obligation Bilateral may be submitted to ISO-NE up to 5 Business Days before ~~the monthly reconfiguration auction for~~ the Obligation Month;**
  2. **The counter-party to the bilateral must confirm the bilateral within 1 Business Day thereafter; and**
  3. **ISO-NE must review the Capacity Supply Obligation Bilateral within 5 Business Days of its submittal.**

Check out our blog, *Power Lines*

www.NEPGA.org

@NEPowerGen

NEPGA's Proposed Tariff Revisions Related to ISO-NE's FAP Proposal

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III.13.5.1.1.1. Timing of Submission and Prior Notification to the ISO.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the ~~submittal windows for~~ Capacity Supply Obligation Bilaterals submission deadlines as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral submission deadline shall be no more than 5 Business Days prior to the Obligation Month. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than 1 Business Day following the submission of the Capacity Supply Obligation Bilateral~~the end of the relevant submittal window~~.

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III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. The ISO shall complete its review no more than 5 Business Days following the submission of the Capacity Supply Obligation Bilateral.~~For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.~~

(b) ~~After the close of the relevant submittal window~~Once submitted to ISO-NE, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity

Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset or Demand Response Resource outage information, and will include transmission security studies. The ISO will review a~~ll~~ confirmed Capacity Supply Obligation Bilateral~~s for each upcoming Obligation Month~~ for reliability needs within 5 Business Days of its submission to ISO-NE. ~~immediately preceding the monthly reconfiguration auction.~~ The ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource.

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M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Samantha Regan and Paul Belval, NEPOOL Counsel

DATE: August 28, 2024

RE: NEPOOL Generation Information System Hourly Certificates Rule Changes

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At the September 5, 2024 Participants Committee Meeting, members will be asked to consider an enhancement to the NEPOOL Generation Information System ("GIS") to accommodate the transfer of hourly certificates (the "Enhancement"). The proposed Enhancement would involve changes to the GIS and the GIS Operating Rules (the "Rules") requested by Constellation Energy Generation LLC ("Constellation").

I. The Enhancement

Currently, the GIS creates Certificates with generation data for generators in the ISO-NE Market Settlement System ("MSS") (including certain imports) on a monthly basis. Generators that are not in the MSS (behind-the-meter generators, for example) either self-report their generation data to the GIS or engage a Third Party Meter Reader to report that data. The GIS uses the generation data (and other data provided by generators and regulators on fuel source, eligibility under state clean energy laws and other categories) to create Certificates in the GIS on a quarterly basis, roughly three to six months after the generation occurs. Those Certificates denote the month in which the generation occurred, but are no more specific than that. Similarly, ISO-NE provides load information to the GIS on a monthly basis, based on each load asset in the MSS, and the GIS uses that information to create Certificate Obligations in the GIS. Certificates are retired on a quarterly basis by applying the Certificates to the Certificate Obligations in each account or subaccount in the GIS. Both Certificates and Certificate Obligations are generally in full MWh denominations.

The Enhancement would involve changes to the GIS and the Rules to accommodate the transfer of Certificates tracking energy generation on an hourly basis through a separate register maintained by the GIS Administrator, APX, Inc. ("APX"). All Certificates would continue to be issued on a monthly basis, and APX would separately obtain hourly generation data from the ISO for generators opting in to hourly treatment. An Account Holder seeking to transfer generation attributes for a specific hour would provide APX with the amount of generation for that transaction and the specific hour(s) in which the generation occurred. APX would keep a separate record of those hourly transactions, and the amount of the claimed attributes for a specific generator in any hour could not exceed the generator's generation in that hour. Once the transaction is complete, the "monthly" Certificates representing the aggregate amount of the attributes in the transaction would be transferred from the seller to the buyer, and those Certificates would include a notation that they are subject to an hourly transaction that has been tracked separately by APX. Only generators in the ISO-NE MSS or generators importing generation into ISO-NE that, in each case, are "Zero Emission Generators" would be eligible for these hourly Certificate transfers. The Rule changes required to effectuate the Enhancement are attached as Attachment 1.

II. Voting Requirement and Cost

Under Rule 1.3, changes to the GIS that require 50 hours or more of labor or have an estimated cost to NEPOOL of more than $30,000 and that in either case are not required to address a change in law or a change in the ISO Tariff must be approved by the Participants Committee. All other changes to the GIS may be approved by the Markets Committee. As described below, because the Enhancement exceeds the hour and dollar thresholds and is not required to address a change in law or the ISO Tariff, Participants Committee approval is required to adopt the Enhancement.

The Amended and Restated Generation Information System Agreement between NEPOOL and APX (the "GIS Agreement") provides that APX will perform up to 500 hours of development work for improvements to the GIS each year without additional cost to NEPOOL. Proposed GIS changes requiring more than 500 of the annual development hours included under the GIS Agreement would be charged to NEPOOL at the rate of $180/hour. APX estimated that 1,245 hours would be required to implement the Enhancement with the scope broken down below:

Scope Breakdown	***Hours***
Hourly Clean Energy tracking for wholesale ISO-NE generators	935 hours
Hourly Clean Energy tracking for Import Projects	210 hours
Total	**1,245 hours**

Currently, there are 328 annual development hours remaining for 2024.[1] If NEPOOL were to use the remaining 328 development hours from 2024 and the 500 development hours for 2025, the remaining 417 hours required to effectuate the Enhancement would be paid at a rate of $180/hour and would have a total cost to NEPOOL of $75,060.

[1] At the May 8, 2024 Markets Committee meeting, the Markets Committee approved a change to the GIS related to the password reset reminder in the application program interface, which will require 10 development hours to implement. The Markets Committee also recommended that the Participants Committee approve a GIS change that would provide for the bulk upload of Clean Peak Resources data, which would require 424 development hours to implement, and that change was approved by the Participants Committee on June 25, 2024. APX had agreed that NEPOOL could use the 262 development hours that were not used in 2023 for those changes, meaning only 172 hours of the 500 development hours for 2024 are needed for those changes.

III. Procedural History

The Markets Committee first referred the Enhancement to the GIS Operating Rules Working Group (the "Working Group") on August 10, 2022. The Working Group originally met to discuss the proposed Enhancement on August 22, 2022. Subsequently, APX and Constellation worked to refine the proposed Enhancement, which was then brought before the Working Group again in March 2023, and then back to the Markets Committee on May 8, 2024.

At the May 2024 Markets Committee meeting, members asked whether APX could stage the Enhancement work over 2024 and 2025 so that NEPOOL could apply the 500 development hours for 2025 to that work, thereby reducing the out-of-pocket costs to NEPOOL for the Enhancement. APX later confirmed that it could do so. Markets Committee members also expressed concern that demand for Certificates that are registered in the hourly tracking register would decrease the total number of Certificates available for state clean energy law compliance, driving up the cost of those Certificates. Constellation noted that PJM GATS has already implemented an hourly tracking approach and offered to look into whether there has been an increase in REC costs in that region as a result.

At the July 2024 Markets Committee Summer Meeting, the Markets Committee again considered whether to recommend the Participants Committee's approval of the Enhancement. The motion recommending approval of the Enhancement failed at the Markets Committee with a vote of 65.10% in favor (a vote of 66.67% was required). The Enhancement is now being presented to the Participants Committee for its consideration.

IV. Participants Committee Approval

The following resolution can be used for Participants Committee action on Constellation's requested Enhancement:

> RESOLVED, that the Participants Committee approves the changes to the NEPOOL Generation Information System (GIS) and the NEPOOL GIS Operating Rules proposed and discussed at this meeting related to transferring Certificates on an hourly basis, with such non-material changes thereto as the Chair of the Participants Committee may approve.

APPENDIX A

HOURLY TRACKING CHANGE RULE CHANGES

[Attached]

Rule 2.2 Account Holder Registration

* * * *

(l) A NEPOOL Generator that is also a Zero Emissions Generator, or an Importing Account Holder importing Imported Unit Energy from a Zero Emissions Generator, may opt to have the Certificates for its generation in any calendar month denoted as being tracked in the Hourly Generation Ledger, as described in Rule 2.9. Such Certificates are referred to as "Hourly Claim Certificates," and the NEPOOL Generator or Importing Account Holder receiving Hourly Claim Certificates shall be referred to as an "Hourly Claim Generator". Hourly Claim Certificates shall be denoted in full MWh, as with other Certificates. Hourly Claim Certificates will be issued, in accordance with Rule 2.9 and transferred in accordance with Rule 3.1(b).

* * * *

Rule 2.9 Hourly Claim Certificates

(a) Each Account Holder opting to claim the hourly output of its eligible NEPOOL Generator or Imported Unit Energy and have Hourly Claim Certificates issued for that eligible NEPOOL Generator or Imported Unit Energy for a specific calendar month shall notify the GIS Administrator at least five (5) days prior to the start of that month, which notice shall apply to all subsequent calendar months unless and until that Account Holder notifies the GIS Administrator that it no longer wishes to receive Hourly Claim Certificates for that GIS Generator or Imported Unit Energy, which notice shall also be given at least five (5) days prior to the start of the month for which Hourly Claim Certificates are not to be issued.

(b) Monthly generation data for an Hourly Claim Generator must meet all requirements of these Rules. The hourly breakdown of that monthly generation data must be provided directly to the GIS Administrator via a secure internet portal by either (1) the regional transmission organization or independent system operator (as recognized by the Federal Energy Regulatory Commission) that covers the area in which such generating unit is located (including ISO-NE for NEPOOL Generators), or (2) an electric utility metering the generation of such generating unit, or (3) a nationally recognized renewable energy credit tracking system, or (4) a Third Party Meter Reader meeting the requirements of Rule 2.5(j). The GIS Administrator will keep a separate ledger of the generation data for each such Hourly Claim Generator for each month in which it is an Hourly Claim Generator (the "Hourly Generation Ledger"). Generation data shall be recorded in the Hourly Generation Ledger in thousandths of a MWh. The GIS Administrator shall not create Hourly Claim Certificates or record generation in the Hourly Generation Ledger for any hour for which is has not received hourly generation data as provided above.

(c) Each Hourly Claim Certificate shall include a notation that it is an Hourly Claim Certificate and the generation represented by that Certificate is registered in the Hourly Generation Ledger maintained by the GIS Administrator, as provided in Part 12 of Appendix 2.1. Except for such notation on each Hourly Claim Certificate, Hourly Claim Certificates shall be created and issued in the same manner as all other Certificates.

Rule 3.1 Transfers Among Account Holders

(a) Except as otherwise provided in these Rules, Account Holders may transfer Certificates to other Account Holders pursuant to a Forward Certificate Transfer (defined below) or at any time during a Trading Period (defined below). Account Holders transferring such Certificates shall reflect such transfer in the GIS by indicating in a designated screen in the GIS that such Certificate has been transferred and selecting the transferee. The designated transfer screen shall include a field for price information and a free-form text field for the transferor to use in identifying the transfer transaction, which fields shall also only be visible to the GIS Administrator and the transferee and which fields may be left blank in any transfer. In turn and in a similar fashion, the Certificate transferee shall confirm the transfer in a designated screen in the GIS. If the transfer includes Hourly Claim Certificates as described in Rule 3.1(b), the date and hour of the generation represented by those Hourly Claim Certificates shall also be included in the designated transfer screens. Subject to any restrictions for Forward Certificate Transfers described in Rule 3.3, the transferring Account Holder may cancel any Certificate transfer before such transfer has been confirmed by the transferee by withdrawing the transfer in a designated screen in the GIS. The transfer of any Certificate shall only be registered in the GIS upon the electronic notification by both the transferor and the transferee. Account Holders may designate one or more agents for purposes of transfers and acceptances of transfers of Certificates by creating logins for them.

(b) In any transfer of Hourly Claim Certificates, the transferring Account Holder shall include in the transfer request the date(s) and hour(s) of the generation associated with such Hourly Claim Certificates. Prior to the transfer screen becoming available to the transferee for confirmation, the GIS Administrator will confirm in the Hourly Generation Ledger that such generation does not exceed the uncommitted generation (i.e., generation that actually occurred and is not associated with Hourly Claim Certificates subject to another pending or accepted transfer request) of the applicable Hourly Claim Generator for the specified date(s) and hour(s). Upon confirmation of the transfer by the transferee, the GIS Administrator shall record the transfer in the Hourly Generation Ledger. In the event that the sum of the generation included in a single transfer request for Hourly Claim Certificates does not result in whole MWhs being transferred, the number of Hourly Claim Certificates transferred in response to such transfer request will in each case be rounded down to the next lower number of whole MWhs.

* * * *

Rule 3.3 Forward Certificate Transfers

* * * *

(b) In the registration of a Forward Certificate Transfer, the GIS Generator or Importing Account Holder registering that transfer shall indicate (in addition to the requirements in Rule 3.1) (1) the GIS Generator or Importing Account Holder that will create such Forward Certificates, (2) the months or Trading Period(s) to which the Forward Certificate Transfer relates (which may be a single month or Trading Period or a specific number of Trading Periods, as designated in the registration), (3) the maximum number of Forward Certificates to be transferred, or the percentage of total Certificates actually created that will be transferred, during each such month or Trading Period, (4) whether, as a result of Massachusetts vintage requirements, a certain number of Certificates must be created in any calendar year before the Forward Certificates to be transferred will be created, and, if so, the number of such Certificates in each indicated calendar year, and (5) whether the transferor has the ability to rescind the Forward Certificate Transfer prior to the creation of the Forward Certificates. For a Forward Certificate Transfer of Hourly Claim Certificates, the GIS Generator or Importing Account Holder registering the transfer may only indicate a percentage of total Hourly Claim Certificates to be transferred in that Forward Certificate Transfer, and that percentage will be applied to the generation in every hour of the month or Trading Period to which the Forward Certificate Transfer relates. For Reserved Certificate and export transactions, the transferor shall transfer the number or percentage of Forward Certificates to the specially designated accounts for Reserved Certificate transfers and exports in the same fashion as those transfers are effected presently under Rules 3.5 and 3.6, respectively. Neither NEPOOL nor the GIS Administrator, nor the ISO shall have any liability if some or all of the Forward Certificates to be transferred are not created during any applicable Trading Period because of an outage of the GIS Generator or importing generating unit, failure to dispatch the GIS Generator or importing generating unit, failure of an Importing Account Holder to satisfy the requirements of Rule 2.7, or any other reason beyond the reasonable control of NEPOOL, the GIS Administrator or the ISO. Once the Forward Certificate Transfer is registered in the GIS, such Forward Certificates, when converted into Certificates on their Creation Date, will be deposited directly into the account of the transferee, and the transferor will not at any point have possession of those Forward Certificates. The GIS Administrator will notify each transferor when its Forward Certificate Transfer has been registered in the GIS. Any exercise of a contractual right of rescission of a Forward Certificate Transfer by a transferor shall be effected upon notice to the GIS Administrator from the transferor (without confirmation by the transferee), and in no event will the GIS Administrator be required to determine whether conditions to that rescission, other than receipt of the rescission notice, have been satisfied before effecting the rescission.

* * * *

Rule 3.5 Reserved Certificates

(a) Account Holders may sell Certificates directly to third parties in good faith, arm's length transactions for reasonable value, independent of transactions involving Energy between those purchasers and their Retail LSEs (Certificates sold in such transactions are referred to herein as "Reserved Certificates.") To avoid the possibility of double counting Certificates, each Account Holder that sells a Reserved Certificate shall, at the time of such transfer, transfer such Reserved Certificate in the GIS to a specially designated Reserved Certificate account using the procedure described in Rule 3.1 and, for a Forward Certificate Transfer of Reserved Certificates, the procedure described in Rule 3.3 (but without confirmation by the transferee). Each Account Holder may designate one or more subaccounts within the Reserved Certificate account. Transactions involving Reserved Certificates are limited to Certificates (other than Clean Peak Energy Certificates) representing MWhs (A) generated or to be generated by a Zero Emissions Generator or (B) generated or to be generated using a fuel source that is designated as being eligible for such transactions on Appendix 2.4 hereto (except as otherwise provided in these Rules) ("Renewable Certificates"), it being the intent of this Rule that Fuel Sources identified in Part 1 of Appendix 2.4 that are defined as "renewable" (i) by any Attribute Law or (ii) by any statute, regulation or order or decision of a governmental agency of a New England state with respect to eligibility for monies from a state renewable energy fund would be considered Renewable Certificates. A Reserved Certificate may be returned from the Reserved Certificates account to the Account Holder transferring it at any time during the Trading Period for that Certificate if the underlying sale of such Certificate to a third party has not been effectuated. At the end of such Trading Period, all Reserved Certificates in the Reserved Certificate account shall be retired and shall no longer be available for further transfer, and their attributes shall not be included in any Residual Mix Certificates.

* * * *

Rule 4.1 Retail LSE Obligations, Accounts and Subaccounts

* * * *

(e) Retail LSEs may hold Certificates in their Default Subaccounts without assigning them to any other Retail Subaccount. APS Certificates may be held in a Retail LSE's Retail Subaccount without being matched to that Retail LSE's Certificates Obligation. Clean Peak Energy Certificates shall be held solely in a

Retail LSE's subaccount specifically designated for those Clean Peak Energy Certificates, and no Certificates that are not Clean Peak Energy Certificates will be held in such a subaccount. Hourly Claim Certificates may not be transferred into or held in a Retail Subaccount.

* * * *

Rule 5.2 Reports for Account Holders

(a) The GIS Administrator will furnish electronically to each registered Account Holder quarterly and annual reports that aggregate by MWh the various Certificate fields listed on the Certificates owned by such Account Holder for such reporting period. Information regarding Hourly Claim Certificates may be provided in a separate report. Quarterly reports shall be provided by the 5th day after the close of a Trading Period, and annual reports shall be produced by June 20 of the year following the year to which the report applies. Annual reports shall include amounts for the generation occurring and Certificates Obligations arising during the applicable calendar year and shall include Certificates transactions that occurred during the portions of the Trading Periods that occurred following the end of such calendar year. Account Holders may view only data for their individual accounts and subaccounts.

* * * *

Rule 5.3 Reports for Regulatory Agencies and ISO

* * * *

(b) Each report provided to the Regulators and the ISO shall include the following information:

(i) List of GIS Generators identified by name, date commercial operations were commenced, and date of any repowering and/or capacity addition, categorized by fuel source, with Hourly Claim Generators during the applicable period specifically designated;

* * * *

(vi) Total number of Certificates created during the reporting period (with APS Certificates, NH Class I Thermal Certificates, NH Biodiesel Producer Certificates, Maine Thermal Certificates ~~and~~, Conservation Certificates and Hourly Claim Certificates accounted for separately);

* * * *

* * * *

(xxv) Subject to Rule 5.3(d) below, list of GIS Generators identified by (A) name, (B) location, (C) date commercial operations were commenced, (D) date of any repowering and/or capacity addition, (E) fuel source, (F) eligibility under state renewable portfolio standards, alternative energy portfolio standards, clean energy standards or clean peak standards (as reflected in Part 2 of Appendix 2.4), (G) asset identification number, (H) total generation or conservation, in MWh, for the reporting period, ~~and~~ (I) whether generation or conservation data included in that report was provided to the GIS Administrator by a Third Party Meter Reader and the identity of any Third Party Meter Reader providing such data; and (J) whether each GIS Generator was an Hourly Claim Generator during the applicable reporting period (the information described in items (G), (H) and (I) of this Section 5.3(b)(xxv) is referred to as "Protected Generator Information");

* * * *

(xxviii) Total number of SREC-II Ineligible Certificates created during the reporting period; ~~and~~

(xxix) Total number of Clean Peak Energy Certificates created during the reporting period~~.~~; and

(xxx) Total number of Hourly Claim Certificates created during the Reporting Period, reported separately for NEPOOL Generators and Importing Account Holders.

* * * *

Rule 5.4 Publicly Available Reports

* * * *

(e) The publicly available reports posted on the GIS Administrator's website shall include an aggregation and/or average, as appropriate, of the Certificate fields for all Certificates created during the quarterly or annual reporting period. Such reports shall aggregate data separately for NEPOOL Generators, Importing Account Holders, Non-NEPOOL Generators, Included Generators, C&LM Resources, BMG Resources, Class III Cogeneration Resources, DR Resources, MAPS CHP Resources, MAPS Useful Thermal Resources, NH Useful Thermal Resources, NH Biodiesel Producers, Maine Thermal Resources, Clean Peak Resources ~~and~~, Non-NEPOOL Generator Representatives and Hourly Claim Generators, and shall also include data aggregated for all GIS Generators and Importing Account Holders and data aggregated by originating control area (if other than ISO New England) and RPS or APS eligibility for all Imported Unit Energy. Those reports shall include the aggregate and/or average, as appropriate, of the Certificate fields for all Residual Mix Certificates, all Reserved Certificates, all Certificates assigned to state-specific subaccounts and all

Certificates associated with Energy exported from the New England for the quarterly or annual reporting period as well. Those reports shall also include a listing of all Third Party Meter Readers for the time period covered by each such report and the number of Certificates issued using the RSIP Estimation Methodology during the time period covered by each such report. In addition, those reports shall be capable of being sorted by the state of origination and settlement, by eligibility for RPS and APS programs, and by fuel type for all such Certificates for the time period covered by each such report.

* * * *

(h) In addition to the other reports provided for under this Rule 5.4, at the start of each Trading Period, the GIS Administrator will post in a publicly available portion of the GIS website the following information for the three-month period applicable to such Trading Period:

(i) GIS Generators names and locations;
(ii) Total number of Certificates created in such Trading Period;
(iii) Total Energy imported into the New England Control Area by state or control area, aggregated by RPS or APS eligibility;
(iv) Total Energy exported from the New England Control Area: ~~and~~
(iii) Total Certificate Obligations for such Trading Period~~.~~;
(iv) Total Hourly Claim Certificates created in such Trading Period, reported separately for NEPOOL Generators and Importing Account Holders; and
(v) Total Hourly Claim Certificates transferred in such Trading Period, reported separately for NEPOOL Generators and Importing Account Holders.

* * * *

Appendix 2.4

GIS Certificate Fields[1]

* * * *

Part 12 –Hourly Claim Certificate with the generation represented by that Certificate registered in the Hourly Generation Ledger maintained by the GIS Administrator (yes/no)

[1] Fields identified with an asterisk (*) will not change.

MEMORANDUM

TO: Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: August 28, 2024

RE: Governance Only End User Membership Application of Alan Sliski

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You will be asked at the September 5, 2024 meeting to take action on the Governance Only End User membership application of Alan Sliski (Applicant or Application), a Massachusetts residential customer of Eversource who has solar panels on the roof of his home (Rooftop System). We have summarized below why the Application requires Participants Committee action and the facts underlying the Application. Additional background materials and a form of resolution are also included with this memorandum.

A. Participants Committee Action Required

The Membership Subcommittee has prior, NPC-delegated authority to approve membership applications that are subject to the Standard Membership Conditions, Waivers and Reminders. The Subcommittee, a self-selected group of Participant representatives which meets monthly, acts by consensus (i.e., no member objecting). The Subcommittee was unable to approve the Application by consensus because two End User Sector representatives opposed Subcommittee approval of the Application (Opposing Members), Opposing Members raised concerns with Applicant's End User Sector election, given the data provided on the production of Applicant's Rooftop System (which, on an annual basis, exceeds Applicant's consumption).

B. End User Definition and Sector Establishment.

1. ***End User Definition***. The Second Restated NEPOOL Agreement (RNA) defines End User Participant as

   > a Participant which is (a) a consumer of electricity in the New England Control Area that generates or purchases electricity primarily for its own consumption, (b) a non-profit group representing such consumers, ….

2. ***Establishment of End User Sector***. It is our understanding that the intent of the Participants in establishing the potential for an End User Sector was the creation of a Sector whose members were not engaged principally in the business of providing transmission service, generation, or supply of electricity, but instead would be comprised of members who, as related to the electricity sector, are principally consumers of electricity in the NEPOOL Control Area, or organizations representing such consumers. The Participants crafted the definition to make it broad enough to incorporate all Participants that purchase [and/]or generate electricity primarily for their own consumption, in recognition of the fact that certain customers may also have generation which is intended primarily for their own consumption and not for sale to third parties.

C. End User Sector Election

During the Membership Subcommittee's consideration, the one substantive disagreement regarding the Application centered around the interpretation of whether Applicant generates and/or purchases "primarily for its own consumption." At the August 12 Subcommittee meeting, all that were present, but for the two Objecting Members, were of the view that, in Applicant's circumstances, the "primarily" requirement was satisfied and the End User Sector election appropriate at this time. Those factual circumstances of the Application include:

- ***Applicant's Rate Class***. Applicant's Eversource rate class is "A1 R1 Residential".

- ***In 2023, Applicant consumed more than 80% of the electricity that the Rooftop System produced.*** In 2023, using a combination of actual and approximate consumption numbers, Applicant consumed more than 80% of the electricity produced by the Rooftop System. Net consumption (-3,821 kWh), or the amount provided to Eversource, represented less than 20% of the electricity produced; the numbers for 2022 were similar (see Attachment 1). Data for 2024 is incomplete and not provided.[1]

- ***Credits/Payments for Excess Production.*** Applicant began 2023 with a credit in his residential account. Each month, his account was debited or credited based on his net usage. Applicant stated that his residential account balance is a continuously running balance (now reflecting nearly 6 years of credits), and has not been re-set to zero by way of direct compensation/check or other administrative action. Other than as a credit to his account, Applicant has never been paid for the excess production of his Rooftop System.

- ***GIS Participation.*** Applicant is registered with the GIS. On an annual basis, through the GIS Bulletin Board, Applicant sells his SRECs.

- ***Governance Only Election***. Applicant has requested to be a Governance Only Member, with no access to New England's wholesale electric markets.

- ***Sector Eligibility Verification Process.*** As with all Participants, Applicant's Sector eligibility and Membership Fee level will be revisited in connection with the Annual Fee billing process or other change in circumstances. Applicant's Sector eligibility would be re-visited if and as future circumstances dictate.

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[1] ***Projected Increase in Applicant's Consumption***. Applicant informed the Subcommittee of his plans, given the Rooftop System's annual (currently excess) production, to install three heat pumps, which will increase his annual consumption and reduce his annual excess. He plans to install those heat pumps as replacements to his current oil-based heating system. Installation of the heat pumps is in process, but has not yet been completed.

D. Form of Resolution for Participants Committee Action

The following form of resolution could be used for Participants Committee action on this matter:

RESOLVED, that the Participants Committee approves the application of Alan Sliski to be a Governance Only End User subject to the following conditions: (1) that NEPOOL Counsel and the ISO find the Applications complete; (2) that the Applicant sign and return the Standard Membership Conditions, Waivers and Reminders letter; (3) that Applicant execute an Indemnification Agreement to permit an expedited membership effective date [and (4) {specify any additional conditions or understandings}].

If there are questions on any of the above, please feel free to contact me.

	A	B	E	F	L	M	N
1			**Net**		**Measured Production**	**Consumption Actual (if E>0, (L+E)) Approx (if E=0, (H))**	**% Production Consumed (M/L)**
2	**2022**						
3		Jan	868		435	1,303	299.74%
4		Mar	783		447	1,230	275.23%
5		Mar	0		1,365	1,357	99.45%
6		Apr	0		1,845	1,357	73.57%
7		May	0		1,845	1,357	73.57%
8		Jun	0		2,210	1,357	61.39%
9		Jun	0		2,054	1,357	66.08%
10		Aug	0		2,261	1,357	60.01%
11		Aug	0		1,918	1,357	70.76%
12		Sep	0		1,880	1,357	72.19%
13		Nov	0		1,449	1,357	93.62%
14		Dec	458		963	1,421	147.54%
15					18,671	16,167	86.59%
16			2,109				
17							
18	**2023**						
19		Jan	938		511	1,449	283.66%
20		Feb	1,063		1,073	2,136	199.04%
21		Mar	332		1,892	2,224	117.55%
22		Apr	0		2,344	1,357	57.88%
23		May	0		3,209	1,357	42.29%
24		Jun	0		2,398	1,357	56.60%
25		Jul	0		2,472	1,357	54.90%
26		Aug	0		2,375	1,357	57.14%
27		Sep	0		1,864	1,357	72.79%
28		Oct	0		1,586	1,357	85.58%
29		Nov	0		1,052	1,357	128.96%
30		Dec	289		624	913	146.32%
31					21,399	17,578	82.14%
32			2,622				

	A	B	E	F	L	M	N
33							
34							
35							
36	**2018**						
37		**Indicative Annual Consumption Pre-Solar Panel Installation**					
38		Mar	1,295				
39		May	1,485				
40		Jun	1,322				
41		Jun	1,339				
42		Aug	1,643				
43		Aug	952				
44		Oct	1,242				
45		Nov	1,108				
46		Dec	1,243				
47		Jan	1,740				
48		Feb	1,484				
49		Mar	1,352				
50		Apr	1,431				
51							
52			17,636	1,357			
53							
54	***Except as noted, all numbers expressed in monthly kWhs**						

LINOWES-SHORT COMMENTS
AUG 30, 2024
Sliski Application

M E M O R A N D U M

TO: Membership Subcommittee

FROM: Lisa Linowes and William P. Short III

DATE: August 30, 2024

RE: Application of Alan Sliski (Sliski)

At the August 12 meeting, the Membership Subcommittee evaluated the application of Sliski to join the End User sector of NEPOOL, specifically for governance purposes.

To provide some background, in 2018, Sliski installed a 15-kilowatt solar system on his rooftop. This system operates with a 15% capacity factor and has a peak capacity of 15 kilowatts. From August 2023 to July 2024, the system generated more electricity than was consumed during eight consecutive months (April to November), resulting in a net-metering credit of 6,224 kWh, valued at the retail electricity rate.

According to Provision 1.22(a) of the NEPOOL agreement,[1] an end user participant is defined as a "consumer of electricity in the New England Control Area that generates or purchases electricity primarily for its own consumption." Historically, this definition was intended to apply to entities like paper mills, where on-site generation primarily meets the facility's load, with any excess power sold to the grid during low demand periods and at the real time wholesale rate. Typically, most of the power generated is consumed on-site with the grid acting as a balancing resource.

We are questioning whether Sliski's application fits the intent of this definition. His situation differs from the traditional example of a paper mill in two significant ways:

1. **Generation vs. Consumption**: Sliski's solar system is not expected to consistently meet his energy demand. Instead, it offsets his consumption when the sun is shining. On a daily basis, Sliski buys electricity from the grid about two-thirds of the time (4:30 pm to 7:30 am the next day) and sells excess power to the grid about one-third of the time (7:30 am to 4:30 pm). Annually, this pattern reverses, with Sliski selling power to the grid two-thirds of the time (April to November) and buying power one-third of the time (December to March).[2] These patterns are driven by his solar production rather than his energy needs. These patterns differ radically from those of an end user with behind-the-meter generation.

2. **Pricing Impact**: The energy sold to the grid by Sliski is priced at the full retail rate, which may incentivize him or other similar solar operators to support higher electricity rates. This contrasts with the

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[1] New England Power Pool Second Restated NEPOOL Agreement, https://www.iso-ne.com/static-assets/documents/2015/01/op_2d_rna.pdf

[2] NEPOOL Membership Subcommittee memo (Sliski Additional Materials). August 8. 2024.

typical end users in NEPOOL, those who only consume from the grid or generally sell back at the wholesale rate, and whose interests align with keeping electricity rates low.

The purpose of this memo is not to debate net-metering policy or to question Sliski's interest in joining NEPOOL. Instead, we are raising a valid concern about how operators of behind-the-meter solar systems should be classified under NEPOOL's rules. In our view, these participants align more closely with the definition of a generator rather than an end user.

Recommendation: Sliski's membership application should be approved for the A/R Sector, small generator. The Membership Subcommittee should be tasked with drafting language to clarify that applications, like Sliski's, are only eligible for NEPOOL membership in the A/R Sector.

We appreciate your attention to this matter and are open to further discussion.

Respectfully,

/s/ Lisa Linowes

/s/ William P. Short III

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of September 3, 2024

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated July 31, 2024 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

FERC I. Complaints/Section 206 Proceedings

	1	206 Proceeding: *TO Initial Funding Show Cause Order* (EL24-83)	Aug 15	FERC issues Allegheny Notice noting that Indicated Utilities' request for reh'g may be deemed to have been denied by operation of law, but noting that Indicated Utilities' request will be addressed in a future order
			Aug 30	Parties appeal FERC orders in 8th Circuit
	3	RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)	Aug 9	RENEW replies to PTO AC's protest to July 16 supplemental submissions

II. Rate, ICR, FCA, Cost Recovery Filings

	6	Bear Swamp Power Co. CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER24-2260)	Aug 2	FERC accepts Bear Swamp Power Co.'s CIP-IROL Rate Schedule, eff. *Jun 12, 2024*
	6	MOPA Formal Challenge to TO's Annual (2023-24) Transmission Rate Update/Info Filing (ER20-2054-000)	Aug 23-29	Indicated TOs submit all responses to MOPA Formal Challenge (both public and confidential)
	7	**Mystic 8/9 COSA (ER18-1639)**		
	9	(-027) Second CapEx Info Filing Settlement Proceedings	Aug 7	Judge French issues 4th status report recommending that settlement proceedings continue
			Aug 29	7th formal settlement conference held
	11	Mystic COSA Protocols Waiver Request (ER24-2528)	Aug 12	FERC grants waiver of the deadlines in Sections II.6.A and II.4.F of the Protocols to allow for a delay to the filing of the 2024 Informational Filing while settlement negotiations that may impact the 2024 Informational Filing are ongoing
*	11	Mystic COSA ROE Settlement Agreement (ER24-2804)	Aug 14	Mystic files ROE Settlement (lowering the ROE to 9.0%) to resolve pending DC Circuit ROE litigation
			Aug 29-30	ISO-NE, CT PURA, MMWEC, National Grid, NHEC intervene

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

*	12	Waiver Request: Late Stage SIS Process (GDQ ESS) (ER24-2926)	Aug 29	GDQ ESS requests waiver of pending Tariff provisions so as to allow its acceptance after Aug 30, 2024 of the SIS results for its facility to enable its LGIA to benefit from the proposed Late-Stage SIS Process and for it to be refunded its deposits associated with participation in the Transitional Cluster Study; comment deadline ***Sep 19, 2024***
*	12	DASI Conforming Changes (ER24-2883)	Aug 27	ISO-NE and NEPOOL file DASI Conforming Tariff Changes; comment deadline ***Sep 17, 2024***
			Aug 28-Sep 3	Calpine, Public Citizen intervene

	13	MW-Dependent Fuel Price Adjustments (ER24-2584)	Aug 1-13 Aug 14	EPSA, MA DPU, National Grid intervene ISO-NE IMM, NEPGA, Vistra submit comments supporting the Fuel Price Adjustments
	13	eTariff § I.2 Corrections (ER24-2270)	Aug 5	FERC accepts eTariff changes, eff. *Apr 15, 2024*
	13	Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received (Canal Marketing/ Canal 3) (ER24-1407)	Aug 12 Aug 21 Aug 27	FERC issues order establishing settlement judge procedures to address the issue of whether and how CM should return revenues or net revenues, with applicable interest, to ISO-NE Chief ALJ designates ALJ Patricia E. Hurt as the settlement judge Judge Hurt schedules first settlement conference for ***Sep 23, 2024***
	16	New England's *Order 2222* Compliance Filings: ATTR Submetering Revisions (ER22-983-009)	Aug 1 Aug 12	NEPOOL supports ATTR Submetering Revisions NEPOOL files comments supporting Revisions

IV. OATT Amendments / TOAs / Coordination Agreements

*	16	Fitchburg Att. F App. D Depreciation Rate Changes (ER24-2766)	Aug 13	Fitchburg files changes to reflect updated depreciation rates as approved by the MPUC
	16	*Order 2023* Compliance Changes (ER24-2009)	Aug 5 Aug 7	Longroad Energy answers ISO-NE's Jul 19 Answer ISO-NE answers Longroad's Aug 5 Additional Answer
	17	*Order 2023* Related Changes (ER24-2007)	Aug 5 Aug 7	Longroad Energy answers ISO-NE's Jul 19 Answer ISO-NE answers Longroad's Aug 5 Additional Answer

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

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

No Activity to Report

VII. NEPOOL Agreement/Participants Agreement Amendments

	20	135th Agreement; PA13 (Unused Provisional Member Voting Share Allocation Changes) (ER24-2636)	Aug 5-13	Calpine, National Grid intervene

VIII. Regional Reports

*	20	Capital Projects Report – 2024/Q2 (ER24-2769)	Aug 9 Aug 15 Aug 30	ISO-NE files Q2 2024 Capital Projects Report NEPOOL files comments supporting ISO-NE 2024 Q2 Report National Grid intervenes
*	21	Interconnection Study Metrics Processing Time Exceedance Report 2024/Q2 (ER19-1951)	Aug 14	ISO-NE files required quarterly report
*	22	ISO-NE FERC Form 3Q (2024/Q2) (not docketed)	Aug 23	ISO-NE submits its 2024 Q2 FERC Form 3Q

IX. Membership Filings

	22	Sep 2024 Membership Filing (ER24-2925)	Aug 30	***New Members:*** Elyctra LLC and Halia Energy LLC; and ***Termination of Participant status:*** Town on Hanover, NH; comment deadline ***Sep 20, 2024***
	22	July 2024 Membership Filing (ER24-2430)	Aug 22	FERC accepts (i) the Data-Only memberships of Aurora Energy Research and Enverus; and (ii) the termination of the Participant status of KCE CT 10, LLC

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

*	23	2025 NERC/NPCC Business Plans and Budgets (RR24-5)	Aug 23	NERC submits proposed 2025 Business Plan and Budget for itself and its Regional Entities, including NPCC; comment deadline ***Sep 13, 2024***

XI. Misc. - of Regional Interest

*	24	203 Application: Carlyle Group (Nautilus)/Q-Generation (Trafigura) (EC24-114)	Aug 23	Applicants request authorization for Q-Generation's acquisition of 100% of the interests of a company indirectly owned by investment fund vehicles managed/advised by The Carlyle Group (owner of Nautilus Power and its Related Persons); comment deadline ***Sep 13, 2024***
			Aug 28	PJM IMM intervenes
	24	203 Application: Trailstone/ Engelhart (EC24-87)	Aug 23	Transaction consummated, making Trailstone Companies and Engelhart US Related Persons
			Aug 28	Trailstone Companies file notice of consummation of transaction
*	25	Wholesale Distribution Tariff – UI (ER24-2939)	Aug 30	UI files new Wholesale Distribution Tariff to facilitate BESS resources' participation in the ISO-NE markets via distribution facilities owned by UI; comment deadline ***Sep 20, 2024***
*	25	CRA Cancellation: NEP/Holden (ER24-2852)	Aug 23	NEP files notice of cancellation of its Cost Reimbursement Agreement with Holden; comment deadline ***Sep 13, 2024***
*	25	Wholesale Distribution Tariffs – National Grid (ER24-2796 (MECO); ER24-2795 (Nantucket))	Aug 16	National Grid files two new Wholesale Distribution Tariffs to enable National Grid to provide the services necessary to facilitate ESS resources' participation in the ISO-NE markets via distribution facilities owned by National Grid, consistent with FERC Order 841 and the Massachusetts Clean Energy Act; comment deadline ***Sep 6, 2024***
			Aug 19-30	MDPU, MA AG, New Leaf, MA DOER intervene
*	26	LGIA: ISO-NE/CL&P/Brookfield Husky Solar (ER24-2740)	Aug 9	ISO-NE files non-conforming LGIA covering the interconnection of Brookfield's ~50 MW solar facility located in Sterling, CT
			Aug 14	Brookfield Husky Solar intervenes
*	26	D&E Agreement Cancellation: NSTAR/Hingham (ER24-2695)	Aug 2	NSTAR submits notice of cancellation of Hingham D&E Agreement
	26	E&P Agreement, 3d Amendment: Seabrook / NECEC Transmission (ER24-2588)	Aug 13	National Grid intervenes
	26	Interconnection Study Agreement: PSNH / Wok, LLC (ER24-2522)	Aug 30	FERC accepts ISA, eff. *Jul 16, 2024*
	26	Versant Order 1920 MPD Waiver Request (ER24-2462)	Sep 3	FERC grants Versant Power's waiver request of the regional transmission planning, interregional transmission coordination, and cost allocation requirements of *Order 1920* for the MPD

27	LCCSA: RIE/BIPCO/Pascoag (ER24-2390)	Aug 21	FERC accepts Local Control Center Services Agreement among RIE, BIPCO and Pascoag, eff. *May 30, 2024*
27	D&E Agreement Cancellation: NSTAR/Medway Grid (ER24-2356)	Aug 16	FERC accepts termination of D&E Agreement, eff. *Jun 26, 2024*
27	D&E Agreement: CL&P/BPUS (ER24-2233)	Aug 8	FERC accepts D&E Agreement, eff. *Aug 11, 2024*
28	CMP ESF Service Rate (ER24-1177)	Aug 5	Judge Hessler issues 2nd status report recommending continuation of settlement judge procedures; 3rd settlement conference scheduled for ***Sep 19, 2024***

XII. Misc. - Administrative & Rulemaking Proceedings

* 29	Large Loads Co-Located at Generating Facilities (AD24-11)	Aug 16	FERC issues supplemental notice of ***Nov 1, 2024*** tech. conf.
29	Innovations & Efficiencies in Generator Interconnection (AD24-9)	Aug 14 Aug 23-Sep 3 Sep 3	FERC issues 2nd supplemental notice of workshop Panelists provide written answers to the questions presented for their respective panel and further information for the record FERC issues 3rd supplemental notice of workshop
29	Joint Federal-State Current Issues Collaborative (AD24-7)	Aug 12	FERC issues order listing Collaborative members, including, from NECPUC, MPUC Chairman Phil Bartlett and NHPUC Commissioner Pradip Chattopadhyay

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

33	VES Stipulation and Consent Agreement (IN24-11)	Aug 6	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into whether VES violated the CAISO Tariff and FERC regulations by submitting bids for a battery storage system that was not reasonably expected to be available and capable of performing at the levels specified in the bids; VES agrees to ***disgorge $1.67 million***, pay a ***$1 million civil penalty***, and be subject to compliance monitoring
34	NextEra CAISO Affiliates Stipulation and Consent Agreement (IN24-10)	Aug 8	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into whether NextEra CAISO Affiliates violated the CAISO Tariff and FERC regulations when providing ancillary services to CAISO; NextEra CAISO Affiliates agree to ***disgorge $381,724***, pay a ***$105,000 civil penalty***, and be subject to compliance monitoring

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

38	*Order 1920*: Transmission Planning Reforms (24-1254 et al.) (consolidated)	Aug 9	Judicial Panel on Multidistrict Litigation randomly selects Fourth Circuit in which to consolidate the petitions for review of *Order 1920*; DC Circuit orders its cases be transferred to the Fourth Circuit
38	Mystic Second CapEx Info Filing (24-1077)	Aug 6	Court grants Mystic's unopposed Jul 16 motion, ordering that the case continue to be held in abeyance, with parties directed to file motions to govern future proceedings by ***Dec 4, 2024***

39	*Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)	Aug 5 Aug 21	Court issues briefing and format schedule Parties file Initial Submissions and Certified Index to the Record
39	*Order 2222* Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)	Jul 31	Court issues order that these consolidated cases remain in abeyance pending further order of the court; FERC directed to file status reports at 60-day intervals beginning ***Sep 30, 2024***
40	Mystic II (ROE & True-Up)	Aug 14	Mystic files unopposed Settlement Agreement to set the ROE at 9.0% and moot these appeals (*see* Section II, ER24-2804)

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 4, 2024

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 3, 2024. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **206 Proceeding: TO Initial Funding Show Cause Order (EL24-83)**

As previously reported, On June 13, 2024, the FERC instituted a Section 206 proceeding finding that the ISO-NE Tariff appears to be unjust, unreasonable, and unduly discriminatory or preferential because it includes provisions for transmission owners to unilaterally elect transmission owner ("TO") Initial Funding (the funding of network upgrade capital costs that the TO incurs to provide interconnection service to an interconnection customer, with the network upgrade capital costs subsequently recovered from the interconnection customer through charges that provide a return on and of those network upgrade capital costs).[2] TO Initial Funding, the FERC found, may increase the costs of interconnection service without corresponding improvements to that service, may unjustifiably increase costs such that it results in barriers to interconnection, and may result in undue discrimination among interconnection customers.[3] The FERC also found that there may be no risks associated with owning, operating, and maintaining network upgrades for which transmission owners are not already otherwise compensated.[4] Accordingly, ISO-NE was directed, on or before ***September 11, 2024***, 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.[5] The refund effective date for this proceeding will be June 24, 2024.[6] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

[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] *ISO New England Inc. et al.,* 187 FERC ¶ 61,170 (June 13, 2024) ("*TO Initial Funding Show Cause Order*").

[3] *Id.* at P 1.

[4] *Id.*

[5] *Id.* at P 2.

[6] Notice of this 206 proceeding was published in the *Fed. Reg.* on June 24, 2024 (Vol. 89, No. 121) pp. 52,454-52,455.

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:[7] NEPOOL, AEU, Avangrid, Calpine, CMEEC (out-of-time), EDP Renewables, Eversource, Invenergy, MA AG, National Grid, NESCOE, NextEra, NRDC, PPL, Maine Public Utilities Commission ("MPUC"), Massachusetts Department of Public Utilities ("MA DPU"), American Clean Power Association ("ACPA"), American Council on Renewable Energy ("ACRE"), Edison Electric Institute ("EEI"), Electric Power Supply Association ("EPSA"), RENEW Northeast ("RENEW"), Solar Energy Industries Association ("SEIA"), WIRES, Cordelio Services, and Public Citizen.

Deemed Denied by Operation of Law – Indicated Utilities[8] (-001). On July 15, 2024, Indicated Utilities requested rehearing, if and as appropriate, and requested that the FERC rescind its *TO Initial Funding Show Cause Order*. On August 15, 2024, the FERC issued an "Allegheny Notice",[9] noting that Indicated Utilities request for rehearing may be deemed to have been denied by operation of law, but noting that Indicated Utilities' request will be addressed in a future order.[10]

Federal Court Appeals. On August 30, 2024, certain parties[11] filed a petition for review of the FERC's orders in this proceeding in the 8th Circuit. Further developments on the federal court appeals will be reported in Section XVI below. In the meantime, 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: ISO Market Power Mitigation Rules (EL23-62)**

This Section 206 proceeding is being held in abeyance. As previously reported, this proceeding was 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.[12] Changes in response to some of the requirements of the *Dynegy Mitigation Order* ("Upward Mitigation Revisions") were supported by the Participants Committee, jointly filed with ISO-NE,

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[7] The notice instituting this 206 proceeding was issued in the following four unconsolidated dockets (which resulted in some parties intervening in all four proceedings): EL24-80 (MISO); EL24-81 (PJM); EL24-82 (SPP); and EL24-83 (ISO-NE).

[8] "Indicated Utilities" are: Ameren Srvcs. Co. ("Ameren"), on behalf of Ameren Illinois Co. ("Ameren Illinois"), Union Elec. Co. d/b/a Ameren Missouri, and Ameren Trans. Co. of Illinois ("ATXI")); American Trans. Co. LLC ("ATC"); Duke Energy Corp., on behalf of Duke Energy Business Services, LLC and its franchised public utility affiliates, Duke Energy Ohio, Inc. ("Duke Ohio"), Duke Energy Kentucky, Inc. ("Duke Kentucky"), Duke Energy Indiana, LLC ("Duke Indiana") (collectively "Duke Energy"); Exelon Corp. on behalf of its affiliates Atlantic City Elec. Co., Baltimore Gas and Elec. Co., Commonwealth Edison Co., Delmarva Power & Light Co., PECO Energy Company, and Potomac Elec. Power Co.; Northern Indiana Pub. Srvc. Co. LLC ("NIPSCO"); and Xcel Energy Services, Inc. ("XES"), on behalf of Northern States Power Co., a Minnesota Corp. ("NSPM"), Northern States Power Co., a Wisconsin Corp. ("NSPW"), and Southwestern Public Service Co. ("SPS").

[9] The FERC issues an "Allegheny Notice" when it does not act within 30 days after receiving a challenge (a request for clarification and/or rehearing) to a FERC order. An Allegheny Notice confirms that the request is deemed denied by operation of law (see Allegheny Def. Project v. FERC, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020)) and the FERC order is final and ripe for appeal. The FERC has the right, up to the point when the record in a proceeding is filed with the court of appeals, to modify or set aside, in whole or in part, any finding or order made or issued by it. The FERC's intention to avail itself of its right and to issue a further order addressing the issues raised in the request (a "merits order") is signaled by the phrase "and providing for Further Consideration"; the absence of that phrase signals that the FERC does not intend to issue a merits order in response to the rehearing request.

[10] *Midcontinent Independent System Operator, Inc. et al*., 188 FERC ¶ 62,084 (Aug. 15, 2024) ("*TO Initial Funding Show Cause Allegheny Notice*").

[11] The parties to the 8th Circuit Appeal are: Ameren Services Co., Ameren Illinois Co., Union Elec. Co. d/b/a Ameren Missouri, Ameren Trans. Co. of IL, American Trans. Co. LLC, Duke Energy Corp., Duke Energy Business Services, LLC, Duke Energy Ohio, Inc., Duke Energy KY, Inc., Duke Energy IN, LLC, Exelon Corp., Atlantic City Elec. Co., Baltimore Gas and Elec. Co., Commonwealth Edison Co., Delmarva Power & Light Co., PECO Energy Co., Potomac Elec. Power Co., Northern Indiana Pub. Srvc. Co. LLC, Xcel Energy Services Inc., Northern States Power Co., a MN Corp., Northern States Power Co., a WI Corp., and Southwestern Pub. Srvc. Co. ("8th Circuit Parties").

[12] *Dynegy Marketing and Trade, LLC and ISO New England, Inc.*, 183 FERC ¶ 61,091 (May 5, 2023) ("*Dynegy Mitigation Order*"). In the Dynegy Mitigation Order, ISO-NE was directed to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory. The refund effective date for this proceeding is May 12, 2023.

accepted by the FERC,[13] and became effective as of *December 12, 2023*. On January 29, 2024, ISO-NE requested that this proceeding continue to be held in abeyance,[14] through August 30, 2024, "pending completion of the stakeholder process through which further revisions to [the Tariff] are being proposed and vetted.[15] The FERC granted ISO-NE's motion on February 7, 2024, stating that it would not take any action on this 206 proceeding before August 30, 2024.

Further changes to address issues raised by the FERC in the *Dynegy Mitigation Order* were filed on July 24, 2024 (*see* Section III, MW-Dependent Fuel Price Adjustments (ER24-2584), below). Those changes are 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).

- **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,[16] 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 long 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, CMEEC, 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.

On July 16, 2024, RENEW submitted supplemental affidavits as further evidence in support of its Complaint and requested that the FERC issue an order on an expedited basis. On July 31, 2024, the PTO AC protested RENEW's July 16 supplemental submission. On August 9, 2024, RENEW replied to the PTO AC's July 31 protest. 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).

[13] *ISO New England Inc.*, Docket No. ER24-324-000 (Dec. 12, 2023) (unpublished letter order).

[14] 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 Feb. 1, 2024.

[15] ISO-NE identified as additional topics not fully addressed by the Upward Mitigation Revisions the following: (1) whether the duration of general threshold energy mitigation is appropriate; and (2) whether a Resource should be permitted to submit multiple fuel price adjustments that reflect the cost of fuel for segments of its Supply Offer that exceed a Resource's Day-Ahead Energy Market awards.

[16] 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.

- **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,[17] 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*).[18] However, the FERC's orders were challenged, and in *Emera Maine,*[19] 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)[20] and third (EL14-86)[21] 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.[22] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[23] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March

[17] 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*")).

[18] *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*").

[19] *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).

[20] 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%.

[21] 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.

[22] *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*").

[23] 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 ¶

27, 2017.[24] 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.[25] 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.[26] 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*[27] (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.[28]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-

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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.

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

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

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

[27] *Ass'n of Bus. 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*.

[28] *Id.* at P 19.

based total ROE at 13.08%.[29] 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[30] 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*[31] 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

- **Bear Swamp Power Co. CIP-IROL (Schedule 17) Cost Recovery Schedule Filing (ER24-2260)**

On August 2, 2024, the FERC accepted Bear Swamp Power Company's ("Bear Swamp") rate schedule that will allow Bear Swamp to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff.[32] The Bear Swamp CIP-IROL Rate Schedule was accepted effective *June 13, 2024*, as requested. The August 2, 2024 order was not challenged and is final and unappealable. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Transmission Rate Annual (2023-24) Update/Informational Filing (ER20-2054-000)**

Formal Challenge by MOPA. As previously reported, the Maine Office of the Public Advocate ("MOPA") filed a formal challenge ("MOPA Formal Challenge") to the 2023-24 Annual Update on January 31,

[29] *Id.* at P 59.

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

[31] *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).

[32] *Bear Swamp Power Co. LLC*, Docket No. ER24-2260-000 (Aug. 2, 2024) (unpublished letter order).

2024.[33] MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, Identified TOs[34] have refused to answer questions regarding investment policies and practices related to prudence of these investments and (ii) that the Identified TOs' decision not to respond to these questions violates their obligation under the OATT's Protocols. Comments on the MOPA Formal Challenge were due on or before February 21, 2024 and were filed by Consumer Advocates[35] (who supported MOPA's attempt to discover the information requested in its September 15, 2023 requests and agreed that policies, processes, and procedures related to ACP costs are discoverable pursuant to the Protocols) and Identified TOs (who urged the FERC to reject the MOPA Formal Challenge as baseless and misguided). On March 4, 2024, MOPA answered Identified TOs' comments. Identified TOs answered MOPA's March 4 answer on March 15 (as corrected on March 18, 2024).

On July 26, 2024, the FERC directed Identified TOs to provide to the FERC its responses (both public and confidential) to MOPA's questions related to general processes and procedures for asset condition project planning. The FERC stated that it needs the full information to evaluate whether the Identified TOs made "a good faith effort to respond to [the] information request[] pertaining to the Annual Update." Identified TOs' responses were due on or before August 26, 2024 and were filed by CMP, Eversource (CL&P, NSTAR East, NSTAR Wes, and PSNH), MEPCO, and National Grid (Narragansett and New England Power). The MOPA Formal Challenge is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[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*.

(-000) Third CapEx Info Filing. On September 15, 2023, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "Third CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2024 to May 31, 2024 ("2024 CapEx Projects"). This filing was not noticed for public comment by the FERC.

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[33] 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 "2023-24 Annual Update"). 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 stated that the annual updates result in a Pool "postage stamp" RNS Rate of $154.35/kW-year effective Jan. 1, 2024, an increase of $12.71 /kW-year from the charges that went into effect on Jan. 1, 2023. 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 $1.95 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.

[34] "Identified TOs" are the New England Transmission Owners with asset condition projects that are the focus of the MOPA Formal Challenge: CL&P, Maine Electric Power Company ("MEPCO"), NSTAR (East & West), National Grid, Public Service Company of New Hampshire ("PSNH"), Rhode Island Energy ("RI Energy"), and Vermont Transco LLC ("VTransco").

[35] For purposes of this proceeding, "Consumer Advocates" are the MA AG, CT OCC, NH OCA and RI Division.

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

(-018) Second CapEx Info Filing. On December 5, 2023, the FERC issued an order[37] on the formal challenges to Mystic's September 15, 2022 "Second CapEx Info Filing".[38] As previously reported, formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS[39] (with ENECOS challenges supported separately by MMWEC/NHEC). Several rounds of answers, described in previous reports, followed. In February 2023, Mystic asked that the Formal Challenges to the Second CapEx Info Filing be held in abeyance pending submission of a settlement agreement to resolve challenges to the First CapEx Info Filing. ENECOS protested that request, identifying issues in their challenges to the Second CapEx Info Filing that would not be resolved by a First CapEx Settlement Agreement. The First CapEx Settlement Agreement was filed and approved, leaving for resolution certain of ENECOS' challenges.

In the *Second CapEx Info Filing Order*, the FERC granted in part, subject to hearing and settlement judge procedures, and dismissed in part, ENECOS' Formal Challenges. Specifically, the FERC found that, issues of material fact, that could not be resolved on the record before it, continued with respect to a number of ENECOS' Formal Challenges. Accordingly, the FERC set for hearing and settlement judge procedures issues raised, in whole or in part, in ENECOS Formal Challenges 1, 2, 6, and 7. The FERC summarily dismissed ENECOS' Formal Challenges 3-5 and 8 (as outside the scope of the proceeding).

(-026) Allegheny Order Addressing ENECOS' Request for Rehearing of Order on Remand Modification Order. On November 6, 2023, ENECOS requested rehearing of the *Mystic I Order on Remand Modification Order*.[40] Specifically, ENECOS requested that the FERC both (i) reinstate its conclusions as to the scope of customer scrutiny of formula rate inputs under the COSA set forth in its March 28, 2023 *Mystic I Order on Remand*[41] and (ii) grant Public Systems' motion for additional disclosure to facilitate customer review of the extraordinary costs incurred during the first 18 months of the COSA's operation. On December 7, 2023, the FERC issued an "Allegheny Notice", noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but noting

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[37] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*").

[38] The "Second CapEx Info Filing" provides 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").

[39] ENECOS Formal Challenges included failures by Mystic: (1) to adequately support its July 1, 2004 – Dec. 31, 2017 Rate Base on Attachment B to Mystic 8&9 Schedule D (with the majority of the cost appearing to O&M expenses that should have been expensed prior to the term); (2) to adequately support its Jan. 1, 2018 – May 31, 2022 Rate Base in line with the requirements of Schedule 3A and the Methodology of the Mystic COSA; (3-5) to prove that certain costs under Mystic's 2022 CapEx Projects - specifically, its Campus Segregation Project and comprehensive rotor inspections - are necessary to meet the reliability need of the Mystic COSA and the least-cost commercially reasonable option consistent with Good Utility Practice; (6) to sufficiently support Everett's Nov. 1, 2018 – May 31, 2022 Rate Base in Attachment B; (7) to properly classify certain of Everett's 2022 and 2023 CapEx Projects costs (some of which should have been characterized as maintenance expenses charged before the term of the Mystic COSA); and (8) to include costs of firm interstate and intrastate pipeline transportation reservations in Everett Schedule B of the populated template.

[40] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*"). The *Mystic I Order on Remand Modification Order* set aside the FERC determinations in the *Mystic I Order on Remand* that: (i) interested parties may review and challenge revenues and Revenue Credits during the true-up process; (ii) interested parties may review and challenge Tank Congestion Charges during the true-up process; and (iii) the revenues from the sliding scale revenue sharing mechanism for third-party vapor sales should be included within the true-up. As previously reported, the FERC concluded in the *Mystic I Order on Remand* that "the language of the true-up and Protocol provisions of the [COS] Agreement, Schedule 3A, does not include these three items within the scope of the true-up, nor is calculation of these items consistent with purpose for the true-up mechanism in the [COS] Agreement because none of them are projected in advance, but rather they are each settled and audited on a monthly basis. The FERC found that "existing cost review and audit processes, … facilitated by ISO-NE, its auditors, and the Internal Market Monitor, are sufficient to ensure that Mystic adheres to its filed rate with respect to these items and continues to appropriately balance customers' interest in transparency of the formula rate with Mystic's interests in protecting commercially-sensitive information, reducing security risks, and avoiding burdensome audit obligations".

[41] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,200 (Mar. 28, 2023) ("*Mystic I Order on Remand*"), *reh'g denied by operation of law,* 183 FERC ¶ 62,115 (May 30, 2023) ("*Mystic I Order on Remand Allegheny Notice*"); *Mystic I Order on Remand Modification Order* (addressing arguments raised on reh'g and setting aside the *Mystic I Order on Remand*, in part, granting Constellation motion to lodge and denying Public Systems' Request for Disclosure of Audit Information).

that ENECOS' request will be addressed in a future order.[42] On February 15, 2024, the FERC issued that order, modifying the discussion in the *Mystic I Order on Remand Modification Order* but reaching the same result.[43] On February 29, 2024, ENECOS amended their petition for review before the DC Circuit (Case No. 24-1018) to include the *Mystic I Order on Remand Modification Order Allegheny Order* (*see* Section XVI below),

Recall that, as previously reported with respect to this aspect of the Mystic proceeding, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand (*-024*)*. Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[44] The FERC then issued the *Mystic I Order on Remand Modification Order* which modified the discussion in the *Mystic I Order on Remand* and set aside that *Order* in part.[45] In addition, the *Order* also denied Public Systems[46] May 19, 2023 request that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request").[47]

(-027) Second CapEx Info Filing Settlement Proceedings. While the FERC set several aspects of ENECOS Formal Challenges for a trial-type evidentiary hearing, the FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures. As directed, the Chief ALJ appointed a settlement judge, Judge Patricia M. French, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action. Judge French has since convened seven settlement conferences.[48] Judge French submitted her 4th status report on August 7, 2024, recommending that the settlement process continue. A seventh Settlement Conference was held on August 29, 2024. The settlement process continues.

(-028) Second CapEx Info Filing Order - Mystic's Request for Rehearing Deemed Denied by Operation of Law. On January 4, 2024, Mystic requested clarification, and in the alternative rehearing, of the *Second CapEx Info Filing Order*.[49] Specifically, Mystic requested clarification and/or rehearing of (i) the FERC's ruling on ENECOS's Formal Challenge No. 7 related to Everett's projected 2023 capital expenditures, (ii) that the FERC denied the accounting argument that ENECOS included in their Formal Challenge No. 1; and (iii) the FERC's rulings related to

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[42] *Constellation Mystic Power, LLC*, 185 FERC ¶ 62,120 (Dec. 7, 2023) ("*Mystic I Order on Remand Modification Order Allegheny Notice*").

[43] *Constellation Mystic Power, LLC*, 186 FERC ¶ 61,103 (Feb. 15, 2024) ("*Mystic I Order on Remand Modification Order Allegheny Order*").

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

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

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

[47] In the *Mystic I Order on Remand Modification Order*, the FERC found that the additional audit information requested was "not supported by the Mystic [COSA] and unnecessary, given the attention that ISO-NE, its auditors, and the Market Monitor give these items on a regular basis". Nevertheless, the FERC accepted "ISO-NE's offer to provide additional transparency measures for the remainder of the Mystic Agreement as soon as practicable, starting no later than [Dec. 5, 2023]." (P 13).

[48] The first settlement conference was convened on Jan. 4, 2024; the second, Mar. 20, 2024; the third, Apr. 19, 2024; the fourth, May 17, 2024; the fifth, June 14, 2024; the sixth, June 18, 2024; and the most recent and seventh settlement conference, Aug. 29, 2024.

[49] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*").

capital costs incurred prior to the start of the term of the COS Agreement (its grant in part of ENECOS's Formal Challenge No. 1 on the basis that Mystic did not adequately "support" Mystic 8&9 capital costs between July 2004 and December 31, 2017 ("Pre-2018 Rate Base"), and its grant of ENECOS's Formal Challenges Nos. 2 and 6). On January 19, 2024, ENECOS answered Mystic's request. On February 5, 2024, the FERC issued an "Allegheny Notice",[50] noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but noting that ENECOS' request will be addressed in a future order.[51] On April 3, 2024, Mystic appealed to the DC Circuit the *Second CapEx Info Filing Order Allegheny Notice* (Case No. 24-1077) (*See* Section XVI below).

***Second CapEx Info Filing Order Allegheny Order*.** On May 23, 2024, the FERC issued an order (i) modifying the discussion in the *Second CapEx Info Filing Order*; (ii) granting in part and denying in part, the clarifications requested by Mystic (granting Mystic's requested clarification of Formal Challenge Issue 7; denying Mystic's requested clarification regarding Formal Challenge Issue 1; confirming that Formal Challenge Issues 1, 2 and 6 were appropriately set for hearing and settlement judge procedures); and setting aside that order, in part (setting aside, in part, the determination regarding Challenge Issue 7)); and (iii) dismissing Mystic's alternative request for reh'g.[52] As noted immediately above, this matter has been appealed to, and is pending before, the DC Circuit.

***(-014) Revised ROE (Sixth) Compliance Filing*.** Still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[53] The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

***30-Day Compliance Filing per Order on ENECOS Mystic COSA Complaint (ER23-1735)*.** On April 27, 2023, Mystic filed, as directed by the FERC's March 28, 2023 *Order on ENECOS Mystic COSA Complaint*,[54] 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.

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[50] The FERC issues an "Allegheny Notice" when it does not act within 30 days after receiving a challenge (a request for clarification and/or rehearing) to a FERC order. An Allegheny Notice confirms that the request is deemed denied by operation of law (*see Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020)) and the FERC order is final and ripe for appeal. The FERC has the right, up to the point when the record in a proceeding is filed with the court of appeals, to modify or set aside, in whole or in part, any finding or order made or issued by it. The FERC's intention to avail itself of its right and to issue a further order addressing the issues raised in the request (a "merits order" or an "Allegheny Order") is signaled by the phrase "and providing for Further Consideration"; the absence of that phrase signals that the FERC does not intend to issue a merits order in response to the rehearing request.

[51] *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[52] *Constellation Mystic Power, LLC*, 187 FERC ¶ 61,099 (May 23, 2024) ("*Second CapEx Info Filing Order Allegheny Order*").

[53] 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.

[54] *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).

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 remains pending before the FERC.

Mystic COSA Protocols Waiver Request (ER24-2528). As previously reported, Mystic requested on July 12, 2024 waiver of the deadlines in Sections II.6.A and II.4.F of the COSA Protocols so that the deadline to make the 2024 Informational Filing (and subsequent related deadlines, including billings and re-billings) can be delayed to allow Mystic and active intervenors in ER18-1639-027, who have agreed to a settlement in principle in that proceeding, to determine whether a settlement can be reached that may impact or obviate the need for the filing or challenges that might be filed subsequent thereto. Comments on Mystic's waiver request were due on or before August 2, 2024; none were filed. On August 12, 2024, the FERC granted the requested waiver.[55]

Mystic COSA ROE Settlement Agreement (ER24-2804). On August 14, 2024, Mystic filed an unopposed Settlement Agreement to establish a settled ROE of 9.0%[56] for the Mystic COSA ("*Mystic ROE Settlement Agreement*") that would, if approved, moot all of the ROE appeals currently pending before the DC Circuit related to that ROE.[57] Mystic requested a November 1, 2024 effective date for the Settlement Agreement. Comments on the Settlement Agreement were due on or before September 4, 2024. The Mystic ROE Settlement Agreement is pending before the FERC.

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

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

RENEW Formal Challenge. RENEW's January 31, 2023 formal challenge ("Challenge") to the 2022/23 Update/Informational Filing[58] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show

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55 *Constellation Mystic Power, LLC*, 188 FERC ¶ 61,121 (Aug. 12, 2024) ("*Mystic Protocols Waiver Oder*").

56 The ROE to be used in the Methodology for both Everett and Mystic would be 9.0% for the entirety of the Term (or June 1, 2022 – May 31, 2024) ("Settled Mystic ROE"), a reduction from the currently-on-file ROE of 9.19%. Recall that, on July 15, 2021, the FERC set the base ROE for the Mystic COSA at 9.33%. (*Constellation Mystic Power, LLC*, 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*")) Subsequently, in response to challenges, the FERC on rehearing lowered the base ROE to 9.19%. (*Constellation Mystic Power*, LLC, 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*")).

57 The *Mystic ROE Order* and the *Mystic ROE Second Allegheny Order* were appealed to the DC Circuit and are being held in abeyance. *See* Section XVI of this Report, Mystic II (ROE & True-Up) (21-1198 *et al.*)

58 The 2022/23 annual filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. The formula rates in effect for 2023 included a billing true up of seven months of 2021 (June-Dec.). The Pool "postage stamp" RNS Rate, effective Jan. 1, 2023, was $140.94 /kW-year, a decrease of $1.84 /kW-year from the charges that went into effect the year prior. The updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate) resulted in a Schedule 1 charge of $1.75 kW-year (eff. June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022.

how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, 2023, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, 2023, Eversource answered RENEW's March 31 answer. There has been no activity in this proceeding since Eversource's answer. This matter remains 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: Late Stage SIS Process (GDQ ESS) (ER24-2926)**

On August 29, 2024, GDQ ESS LLC ("GDQ ESS") requested a limited waiver of pending *Order 2023* compliance Tariff revisions[59] to allow it to accept, after August 30, 2024, the SIS results for its facility[60] and thus to enable its LGIA to benefit from the proposed Late-Stage SIS Process and for it to be refunded its deposits associated with participation in the Transitional Cluster Study.[61] Comments on GDQ ESS' waiver request must be filed on or before ***September 19, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **DASI Conforming Tariff Changes (ER24-2883)**

On July 24, 2024, ISO-NE and NEPOOL jointly filed Tariff changes necessary to fully implement the Day-Ahead Ancillary Services Initiative ("DASI") in the spring of 2025 ("DASI Conforming Changes"). Specifically, the DASI Conforming Changes: (i) revise the Day-Ahead Net Commitment Period Compensation ("NCPC") framework to incorporate the new DASI costs and revenues introduced by the DASI Rules; (ii) revise certain "special case" NCPC rules to include the Forecast Energy Requirement ("FER") Price, which was also introduced by the DASI Rules and incorporated into Day-Ahead Prices; (iii) update the Day-Ahead excess energy condition rules to account for the new co-optimized Day-Ahead Market created as part of DASI; (iv) incorporate average avoided peak distribution losses into Day-Ahead Ancillary Services obligations for Demand Response Resources; and (v) propose a methodology to capture and allocate administrative costs related to DASI in Section IV.A of the Tariff. In addition to the DASI Conforming Changes, the filing also proposes Tariff clarifications related to Day-Ahead Self-Scheduled External Transactions ("Self-Scheduled External Transactions Changes"). Two effective dates were requested -- October 27, 2024 for the Self-Scheduled External Transactions Changes and March 1, 2025 for the DASI Conforming Changes. The Participants Committee supported the DASI Conforming Changes, including the Self-Scheduled External Transactions Changes, by way of the Summer Meeting Consent Agenda (Consent Agenda Items 1-3). Comments on the Tariff Changes are due on or before ***September 17, 2024***. Thus far, Calpine and Public Citizen have intervened doc-lessly. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

[59] Revisions to Section 5.1.1.2 of the LGIP, pending in the *Order 2023* Compliance Changes proceeding (ER24-2009), provide that "if the Interconnection Customer accepts the results of its system impact study on or before August 30, 2024, the System Operator shall not include the Interconnection Request in the Transitional Cluster Study and instead tender a Large Generator Interconnection Agreement pursuant to Section 11 of this LGIP, and refund any deposits associated with participation in the Transitional Cluster Study" (the "Late-Stage SIS Process").

[60] GDQ is the project company for a 203 MW battery energy storage project located in North Kingstown, Rhode Island (Queue Position "QP1163") (the "ESS Facility"). The ESS Facility will interconnect to the RI Energy transmission system.

[61] GDQ states that it is in potential jeopardy of missing the August 30, 2024 deadline under Section 5.1.1.2 to enter into a LGIA because a previously queued project upon which its queue position is dependent was unlikely to complete its System Impact Study ahead of GDQ's.

- **MW-Dependent Fuel Price Adjustments (ER24-2584)**

On August 27, 2024, ISO-NE and NEPOOL jointly filed changes to allow Market Participants to submit up to two different MW-dependent fuel prices in their cost-based Reference Levels ("Fuel Price Adjustments"). In addition, ISO-NE provided its explanation for why the current market power mitigation provisions addressing the duration of mitigation are just and reasonable and not unduly discriminatory or preferential. Comments on this filing were due on or before August 14, 2024. The ISO-NE IMM, NEPGA and Vistra filed comments generally supporting the Fuel Price Adjustments. Calpine, National Grid, MA DPU, EPSA, and Public Citizen filed doc-less interventions. 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).

- **eTariff § I.2 Corrections (ER24-2270)**

On August 5, 2024, the FERC accepted corrections to ISO-NE's eTariff to remove from Section I.2.2 changes (from the DASI (ER24-275) and SATOA (ER23-739) filings) that were inadvertently included in the FRM Offer Cap eTariff changes that became effective on April 15, 2024.[62] Other than to pull out the yet-to-effective changes from the effective eTariff text, no other changes were made to the definitions. The corrections were accepted *April 15, 2024*, as requested. Unless the August 5 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).

- **Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received (Canal Marketing/ Canal 3) (ER24-1407)**

As previously reported, on March 4, 2024 (as amended and supplemented on March 8 and March 22, 2024), Canal Marketing LLC (f/k/a Stonepeak Kestrel Energy Marketing LLC) ("CM") requested a one-time waiver of the provisions of Appendix K to Market Rule 1 (Inventoried Energy Program (the "IEP")) so as to permit CM to (i) withdraw CM's participation in the IEP on behalf of Canal 3 Generating LLC ("Canal 3")[63] for Winter 2023-24 and (ii) to return to ISO-NE the net revenues, with applicable interest, that CM received on behalf of Canal 3 for Canal 3's participation in the IEP for Winter 2023-2024 because Canal 3's return from a forced outage was delayed beyond the end of the IEP's Winter 2023-24 period.[64] CM explained that, when it elected to participate in the IEP on behalf of Canal 3 on September 21, 2023, CM anticipated that the Canal 3 Facility would be back in service by December 18, 2023, and would be available for the remainder of the IEP's Winter 2023-24 period. However, the actual return-to-service date for the Canal 3 Facility was delayed beyond the end of the IEP's Winter 2023-24 period and Canal 3 was not able to perform during the Winter 2023-24 period. CM seeks the requested waiver because no provision in Appendix K nor any other provision of the Tariff was identified as providing a mechanism for a Participant to withdraw from the IEP or to return IEP revenues to ISO-NE. Comments on the CM Waiver Request were due on or before March 25, 2024. The IMM submitted comments supporting the CM Waiver Request insofar as CM requests the prompt repayment of the revenues received on behalf of Canal 3 under the IEP and, if determined to be warranted by the FERC, net of Program charges. NEPOOL (out-of-time) and National Grid intervened doc-lessly.

Settlement Judge Proceedings. On August 12, 2024, the FERC issued an order establishing settlement judge procedures to address the issue of whether and how CM should return revenues or net revenues, with applicable interest, to ISO-NE.[65] On August 21, 2024, the Chief ALJ designated ALJ Patricia E. Hurt as the

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[62] *ISO New England Inc.*, Docket No. ER24-2270-000 (Aug. 5, 2024) (unpublished letter order).

[63] Canal 3 is an approximately 333 MW (summer rating) gas- and oil-fired generation facility. Canal 3 has been on forced outage since Feb. 3, 2023, when a blade on the turbine wheel broke off and caused catastrophic damage to the gas turbine, which significantly impacted the compressor blades and bearings. As a result, the full train was disassembled and shipped to General Electric ("GE"), its manufacturer, for repair. GE initially provided a repair schedule that contemplated Canal 3's return to service by Dec. 15, 2023.

[64] At the time CM made its IEP election submission, CM anticipated that, based on information provided by GE, Canal 3 would be back on line by Dec. 18, 2023. CM informed ISO-NE in mid-December that forced outage of Canal 3 would continue until near the end of the IEP's Winter 2023-24 period, but no mechanism for a withdrawal from the IEP or the return of IEP payments received was identified.

[65] *Canal Marketing LLC*, 188 FERC ¶ 61,122 (Aug. 12, 2024).

settlement judge in this proceeding. Judge Hurt scheduled a first formal settlement conference for ***September 23, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

In a lengthy compliance Order[66] issued March 1, 2023, the FERC approved in part, and rejected in part, the *Order 2222* compliance filing[67] ("*Order 2222 Compliance Order*") filed jointly by ISO-NE, NEPOOL and the PTO AC ("Filing Parties").[68] 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.* As previously reported, the FERC accepted the 30-, 60- and 180-day compliance filings.[69] In the order conditionally accepting the 60-day compliance filing,[70] the FERC directed ISO-NE to submit a further compliance filing, on or before January 31, 2024, to comply with the directives of the *First Compliance Order* regarding the submission of DERA meter data.[71] The FERC also granted in part ISO-NE's request for an extension of time to address directives

[66] 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."

[67] 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.

[68] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*First Order 2222 Compliance Order*").

[69] *ISO New England Inc.*, Docket Nos. ER22-983-003 and ER22-983-005 (Oct. 25, 2023) (unpublished letter order) ("*30/180-Day Order 2222 Compliance Order*"). The 30-Day compliance filings explained how current Tariff capacity market mitigation rules would apply to DECRs participating in FCA18 and provided an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. The 180-Day compliance filing explained how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond and the Mar. 1, 2024 effective date for the rules allowing DECRs to participate in the FCM).

[70] *ISO New England Inc.*, 185 FERC ¶ 61,095 (Nov. 2, 2023) ("*Order 2222 60-Day Compliance Filing Order*").

[71] Specifically, the FERC directed ISO-NE to revise the Tariff to designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and to require that each DER Aggregator maintain and submit aggregate settlement data for the DERA, so that ISO-NE can regularly settle with the DER Aggregator for its market participation. To the extent that ISO-NE proposes in that further compliance filing that metering data come from or flow through distribution utilities, the FERC directed ISO-NE to coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing such metering data, and explain how such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity. *Id.* at P 34.

in the *First Order 2222 Compliance Order*.[72] On December 4, 2023, AEU requested rehearing of the *Order 2222 60-Day Compliance Filing Order*, which was deemed to have been denied by operation of law.[73]

(-006) Order 2222 60-Day Compliance Filing Order Allegheny Order. On May 23, 2024, in response to AEU's December 4, 2023 request for rehearing of the *Order 2222 60-Day Compliance Filing Order*, the FERC issued an *Allegheny* order,[74] sustaining three of the four findings challenged by AEU. However, the FERC set aside, in part, its prior finding that ISO-NE partially complies with the requirement to revise its Tariff to establish market rules that address metering requirements necessary for distributed energy resource aggregations ("DERAs").[75] The FERC found that, under its rule of reason,[76] ISO-NE's basic description of its metering practices for DERAs was incomplete because the Tariff did not include submetering requirements for DERAs participating as submetered Alternative Technology Regulation Resources ("ATRRs").[77] Accordingly, the FERC directed ISO-NE to file, on or before ***July 22, 2024***, a further compliance filing to revise ISO-NE's Tariff to specify its submetering requirements for DER Aggregations' participation as submetered ATRRs.

(-007) Further Compliance Changes. On April 11, 2024, the FERC conditionally accepted ISO-NE's January 31 Further Compliance Filing, subject to a further 60-day compliance filing.[78] In the *Further Order 2222 Compliance Filing Order*, the FERC found that ISO-NE complied with *Order 2222 60-Day Compliance Filing Order*'s directive to (i) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; (ii) require that each DER Aggregator maintain and submit aggregate settlement data for DERAs; and (iii) establish protocols for sharing metering data. However, the FERC disagreed with ISO-NE's assertion that meter data submission responsibilities and deadlines at issue are technical and timing details to implement the Tariff's settlement requirements, and, therefore, properly included in ISO-NE's manuals rather than its Tariff. Rather, the FERC found that "the meter data submission deadline is a key component of metering practices for DER Aggregators that should be included in the basic description of metering practices in the Tariff".[79]

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[72] The FERC ordered ISO-NE in its 60-day compliance filing 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.

[73] *ISO New England Inc.*, 186 FERC ¶ 62,002 (Jan. 4, 2023) ("*Order 2222 60-Day Compliance Filing Order Allegheny Notice*").

[74] *ISO New England Inc.*, 187 FERC ¶ 61,100 (May 23, 2024) ("*Order 2222 60-Day Compliance Filing Order Allegheny Order*").

[75] *See id.* P 78 ("we find that ISO-NE partially complies with the requirement to revise its Tariff to establish market rules that address metering requirements necessary for DERAs").

[76] "[d]ecisions as to whether an item should be placed in a tariff or in a business practice manual are guided by the [FERC]'s rule of reason policy, under which provisions that 'significantly affect rates, terms, and conditions' of service, are readily susceptible of specification, and are not generally understood in a contractual agreement must be included in the tariff, while items better classified as implementation details may be included only in the business practice manual." *Order 2222 60-Day Compliance Filing Order Allegheny Order* at P 36 citing *Order 2222*, 172 FERC ¶ 61,247 at P 271.

[77] *Order 2222 60-Day Compliance Filing Order Allegheny Order at P 6.*

[78] *ISO New England Inc*., 187 FERC ¶ 61,017 (Apr. 11, 2024) ("*Further Order 2222 Compliance Filing Order*").

[79] *Id.* at P 13.

Accordingly, the FERC directed ISO-NE, on or before June 10, 2024, "to submit … Tariff revisions that include the meter data submission deadline in its Tariff."[80]

(-008) Metering Data Submission Revisions. The Metering Data Submission Revisions required by the April 11, 2024 *Further Order 2222 Compliance Filing Order* were recommended for Participants Committee support by the Markets Committee at its May 7-8, 2024 meeting and, because of the compliance deadline, filed by ISO-NE on June 10, 2024. The changes were supported by the Participants Committee at the June 25-26 Summer Meeting (Consent Agenda Item No. 6). Comments on ISO-NE's June 10 compliance filing were due on or before July 1, 2024; NEPOOL filed comments supporting the Revisions. The June 10 compliance filing is remains pending before the FERC.

(-009) ATTR Submetering Tariff Revisions. The ATTR Submetering Revisions required by the *Order 2222 60-Day Compliance Filing Order Allegheny Order*[81] were recommended for Participants Committee support by the Markets Committee at its July 9-10, 2024 Summer Meeting and, because of the compliance deadline, filed by ISO-NE on July 22, 2024. The Participants Committee supported the ATTR Submetering Revisions at its August 1, 2024 meeting (Consent Agenda Item No. 1). Comments on ISO-NE's July 22 compliance filing were due on or before *August 12, 2024*. NEPOOL filed comments reporting on the Participants Committee's August 1 action and supporting the revisions. No other comments or interventions were filed. The July 22 compliance filing is pending before the FERC.

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

If you have any questions concerning these matters, 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

- **FG&E Attachment F App. D Depreciation Rate Changes (ER24-2766)**

On August 13, 2024, Fitchburg Gas & Electric Company ("FG&E") and ISO-NE filed changes to FG&E Appendix D to Attachment F of the ISO-NE OATT to reflect updated depreciation rates in FG&E's Regional and Local Service formula rate calculations, as recommended in a depreciation study based on 2022 data and approved by the MPUC as part of FG&E's retail rate filing. The proposed updates to depreciation rates submitted will result in an estimated annual decrease of $28,067 to depreciation expense. FG&E said that the revised depreciation rates will have a *de minimus* effect on the transmission rates of Regional and Local Service customers. Comments on this filing were due on or before September 3, 2024; 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).

- ***Order 2023*** **Compliance Changes (ER24-2009)**

On May 14, 2024 (as corrected May 31, 2024), ISO-NE, NEPOOL and the PTO AC filed proposed Tariff revisions tin response to the requirements of *Orders 2023* and *2023-A* ("*Order 2023* Revisions"). The Order 2023 Revisions adopt most of the required *pro forma* OATT changes, with some regional variations to recognize certain existing features of the ISO-NE interconnection process, including an existing cluster process to address cases where cluster enabling transmission is required, integration of the interconnection process with FCM

[80] *Id.*

[81] *See Order 2222 60-Day Compliance Filing Order Allegheny Order (-006) infra*.

participation, and a unified treatment of all ISO interconnection requests, including those for small generators and Elective Transmission Upgrades ("ETU") (such revisions were filed in a separate concurrent filing (ER24-2007)). Concurrently, the Filing Parties proposed changes to aspects of the Tariff impacted by the *Order 2023* Revisions, but that may be considered to be beyond the scope of the compliance obligations (*see* ER24-2007 immediately below). The filing parties requested an effective date of August 12, 2024 for the *Order 2023* Revisions. Comments on this filing were due on or before June 4, 2024, and were filed by BlueWave, Glenvale, New Leaf, RENEW, Clean Energy Associations,[82] and Longroad Energy Holdings. Calpine, Clearway, Constellation, National Grid, NESCOE, RIE, Shell Energy/Savion, MA DPU, and Cordelio Services intervened doc-lessly. On June 20, 2024, ISO-NE answered the June 4 comments. On July 5, Glenvale and Longroad Energy answered ISO-NE's Jun 20 Answer. On July 19, ISO-NE answered Glenvale's and Longroad Energy's further July 5 answers. Since the last Report, on August 5, Longroad Energy answered ISO-NE's July 19 answer (again advocating for why ISO-NE should be required to accept surety bonds for CETU Participation Deposits, as it asserts is required for all commercial readiness deposits per *Order 2023*) ("Additional Answer"). ISO-NE answered Longroad's August 5 Additional Answer on August 7. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

- ***Order 2023* Related Changes (ER24-2007)**

Also on May 14, 2024, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") filed proposed Tariff revisions to harmonize the SGIP, ETU Interconnection Procedures ("ETUIP"), and Regional Transmission Service rules with the contemporaneously-filed Order 2023 Revisions ("*Order 2023* Related Changes"). The *Order 2023* Related Changes, which propose changes to aspects of the Tariff impacted by the *Order 2023* Revisions, but that may be considered to be beyond the scope of the *Order 2023* compliance requirements, include: (i) revisions to the *pro forma* SGIP beyond those explicitly required in *Order 2023/2023-A* to align the Small Generator Interconnection Procedures ("SGIP") with the Large Generator Interconnection Procedures ("LGIP") and include Small Generating Facilities in the new Cluster Study Process; (ii) revisions to the ETUIP to ensure it remains aligned with the LGIP and include ETUs in the Cluster Study Process; and (iii) revisions to Study Procedures for Regional Network Service Requests and Through or Out Service Requests to require that System Impact Studies related to Regional Transmission Service requests take place in the Cluster Study incorporated as part of the Cluster Study Process. The Filing Parties requested, contingently, that the *Order 2023 Related Changes* become effective on the same date as the *Order 2023 Revisions* (i.e. August 12, 2024) and that the FERC issue an order for the *Order 2023 Related Changes* concurrently with its order on the *Order 2023 Revisions*. Comments on the *Order 2023* Related Changes were due on or before June 4, 2024, and were filed by Glenvale, Longroad, New Leaf Energy, RENEW and Clean Energy Associations. BlueWave, Calpine, Clearway (out-of-time), National Grid, NESCOE, RIE, Shell Energy/Savion, Cordelio Services, and the MA DPU intervened doc-lessly. On June 20, 2024, ISO-NE answered the June 4 comments. On July 5, Glenvale and Longroad Energy answered ISO-NE's June 20 Answer. On July 19, ISO-NE answered Glenvale's and Longroad Energy's further answers. On August 5, Longroad Energy answered ISO-NE's July 19 answer (again advocating for why ISO-NE should be required to accept surety bonds for CETU Participation Deposits, as it asserts is required for all commercial readiness deposits per *Order 2023*) ("Additional Answer"). ISO-NE answered Longroad's August 5 Additional Answer on August 7. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

- **LTTP Phase 2 Tariff Changes (ER24-1978)**

On July 8, 2024, the FERC accepted proposed revisions to Section 16 of Attachment K of the OATT to establish, as part of the optional, longer-term transmission planning process, the mechanisms that enable the New England states to develop policy-based transmission facilities in connection with Longer-Term Transmission Studies ("LTTS"), and the associated cost allocation methods for these upgrades (the "LTTP

[82] "Clean Energy Associations" are, collectively, Advanced Energy United ("AEU"), the American Clean Power Association ("ACPA"), Natural Resources Defense Council ("NRDC"), and the Solar Energy Industries Association ("SEIA").

Phase 2 Changes").[83] As previously reported, the LTTP Phase 2 Changes incorporate the following processes: (i) a comprehensive core process (which allows the New England states to advance the development of transmission when at least one Longer-Term Proposal submitted in response to a request for proposal meets the identified needs and has financial benefits that exceed the project's costs as calculated over the first 20 years of the project's life has a benefit-to-cost ratio ("BCR") that is greater than one) and (ii) an add-on supplemental process (which enables the New England states to agree to move forward with a transmission project where none of the proposals that meet the identified needs satisfy the greater-than-one BCR requirement). The FERC addressed, but ultimately found misplaced, arguments made regarding the right of first refusal, and found that even if aspects of the LTTP Phase 2 Changes "make it more difficult for nonincumbent transmission developers to submit comprehensive proposals than it would be for incumbent transmission owners, such potential difficulty does not render the proposed LTTP Phase 2 Changes unjust and unreasonable or unduly discriminatory or preferential."[84] The LTTP Phase 2 Changes were accepted effective *July 9, 2024*, as requested. The *LTTP Phase 2 Changes Order* was not challenged as is final and unappealable.

In addition, the FERC accepted ISO-NE's proposal to correct Tariff Section I.1.2, to remove the revisions to the definition of the term "Regulation Resources" and the addition of the terms "Storage as Transmission-Only Asset (SATOA)" and "Real-Time SATOA Obligation" that are not yet intended to be in effect and were included with the LTTP Phase 2 Changes in error. Those corrections were submitted on July 27, 2024. Comments on the compliance filing were due on or before August 16, 2024; none were filed. The compliance filing is pending before the FERC. Subject to action on the July 27 compliance filing, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

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

As previously reported, the FERC accepted for filing a Local Service Agreement ("LSA") by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro, LLC ("Jonesboro"), effective *December 4, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[85] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties (i) to refund the time value of revenues collected for the time period the rate was collected without FERC authorization, with refunds limited so as not to cause Filing Parties to operate at a loss ("Time Value Refunds"); and (ii) to file a refund report, including information supporting calculation of the Time Value Refunds.

Time Value Refunds Report. On December 18, 2023, Versant Power filed a refund report ("Report") detailing the Time Value Refunds it paid to NE Renewable Power and Jonesboro on December 15, 2023. Comments on the Report were due on or before January 8, 2024; none were filed. The Report remains 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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[83] *ISO New England Inc. and New England Power Pool*, 188 FERC ¶ 61,010 (July 8, 2024) ("*LTTP Phase 2 Changes Order*").

[84] *Id.* at P 40.

[85] *ISO New England Inc.*, Docket No. ER24-24-000 (Nov. 30, 2023) (unpublished letter order).

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

As previously reported, ISO-NE and New England Power ("National Grid", and together with ISO-NE, the "Filing Parties") filed on September 11, 2023, a 20-year LSA by and among National Grid, ISO-NE and Green Mountain Power ("GMP").[86] The Filing Parties stated that the LSA conformed to the *pro forma* LSA contained in the ISO-NE Tariff and superseded and replaced another conforming LSA among ISO-NE, National Grid, and GMP that listed an expiration date of September 30, 2022 (TSA-NEP-25). The Parties requested that the FERC grant waiver of its notice requirement[87] to the extent necessary to permit a requested October 21, 2022 effective date. The LSA was filed separately given that requested effective date.

LSA Accepted; Waiver of Prior Filing Requirement Denied; Time Value Refunds Ordered. Similar to the Versant/Jonesboro proceeding (*see* ER24-24 above), the FERC accepted the National Grid/GMP LSA for filing, effective *November 11, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[88] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties to make Time Value Refunds. On December 4, 2023, Filing Parties requested, and on December 6, 2023 the FERC granted, a 45-day extension of time (to January 22, 2024) to make the Time Value Refunds, with the corresponding refund report to be filed no later than February 21, 2024.

Time Value Refunds Report. On February 21, 2024, National Grid filed a refund report ("Report") detailing the Time Value Refunds National Grid paid to GMP on January 22, 2024. Comments on the Report were due on or before March 13, 2024; none were filed. The Report remains pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 28, 2023, the FERC accepted seven fully executed, non-conforming LSAs by and among Versant Power, ISO-NE and Black Bear Hydro Partners, LLC or Black Bear SO, LLC (together with Black Bear Hydro Partners, "Black Bear").[89] 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 Time Value Refund requirement.[90] On August 29, 2023, Versant Power submitted a Refund Report detailing the Time Value Refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments on the Refund Report were due on or before September 19, 2023; none were filed. The Refund Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

[87] 18 CFR § 35.11 (which permits, upon application and for good cause shown, the FERC to allow a rate schedule, tariff, service agreement, or a part thereof, to become effective as of a date prior to the date of filing or the date such change would otherwise become effective in accordance with the FERC's rules (e.g. 60 days after filing)). FERC policy is to deny waiver of the prior notice requirement when an agreement for new service is filed on or after the date that services commence, absent a showing of extraordinary circumstances.

[88] *ISO New England Inc.*, Docket No. ER23-2804-000 (Nov. 7, 2023) (unpublished letter order).

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

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

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

On August 29, 2023, Versant submitted a Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC. Versant stated that, if approved, the 2022 Annual Update Settlement Agreement would resolve all issues raised by the MPUC with respect to the 2022 Annual Update. Comments on the Versant 2022 Annual Update Settlement Agreement were due on or before September 19, 2023; none were filed. MPUC intervened doc-lessly on September 15, 2023. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **135th Agreement; PA13 (Unused Provisional Member Voting Share Allocation Changes) (ER24-2636)**

On July 31, 2024, NEPOOL and ISO-NE jointly filed the 135th Agreement Amending New England Power Pool Agreement ("135th Agreement") and Amendment No. 13 to the PA (together, the "Unused Provisional Member Voting Share Allocation Changes" or "Changes"). The Changes modify the allocation of any unused Provisional Member Group Seat voting share to all six Sectors. As previously reported, the Changes were approved unanimously by the Participants Committee pursuant to balloting under Section 6.10 of the NEPOOL Agreement and Section 17.2.3 of the Participants Agreement in which the Minimum Response Requirement was satisfied. An August 1, 2024 effective date was requested. Comments on the Changes were due on or before August 21, 2024; none were filed]. Calpine and National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning the Changes, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports[91]

- **Capital Projects Report – 2024/Q2 (ER24-2769)**

On August 9, 2024, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2024 (the "Report"). Report highlights include:

  - One new project -- Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements ($897,200).
  - Two projects with significant changes: (i) Energy Management System Short-Term Load Forecast Replacement (increased in 2024 by $327,300); and (ii) IT Asset Workflow Integration and Updates (2024 budget increased by $116,400); and
  - Three projects completed in Q2: (i) Settlement Technology Improvements; (ii) Control Room Voice Recorder Update; and (iii) On Call Notification Systems. Each cost less than planned.

Comments on the Report were due on or before August 30, 2024. NEPOOL filed comments supporting the Report. National Grid intervened doc-lessly. 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).

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

- **Interconnection Study Metrics Processing Time Exceedance Report 2024 Q2 (ER19-1951)**

On August 14, 2024, ISO-NE filed, as required,[92] public and confidential[93] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Second Quarter of 2024 ("2024 Q2"). ISO-NE reported that with respect to:

- **Interconnection Feasibility Study ("IFS") Reports**
  - One IFS Report was delivered to an Interconnection Customer in 2024 Q2 and was delivered later than the best efforts completion timeline of 90 days.
  - 32 IFSs that are not yet completed have already exceeded the 90-day completion expectation.
  - The average time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS Report to the Interconnection Customer was 307 days (which is approximately 134 days longer than the previous quarter).

- System Impact Study ("SIS") Reports
  - 4 SIS Reports were delivered to Interconnection Customers in 2024 Q2. 3 of those 4 SIS Reports were delivered later than the best efforts completion timeline of 270 days.
  - 31 SISs that are not yet completed have already exceeded the 270-day completion expectation.
  - The average time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 416 days (a decrease of approximately 120 days from 2024 Q1's average).

- Facility Study Reports
  - No Facility Study Reports were delivered to Interconnection Customers in 2024 Q2.
  - 3 Facility Studies in process have exceeded the 90-day completion expectations for a 20% level of cost estimate.

Section 4 of the Exceedance 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. The Exceedance Report was not noticed for public comment.

- **IMM Quarterly Markets Reports: Spring 2024 (ZZ24-4)**

On July 22, 2024, the IMM filed with the FERC its Spring 2024 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. The Spring 2024 Report will be reviewed with the Markets Committee at the Markets Committee's September 10, 2024 meeting. These filings are not noticed for public comment by the FERC.

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[92] Under section 3.5.4 of ISO-NE's 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.

[93] 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.

- **ISO-NE FERC Form 3Q (2024/Q2) (not docketed)**

On August 23, 2024, ISO-NE submitted its 2024/Q2 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. Form 3-Q filings are not noticed for public comment.

IX. Membership Filings

- **September 2024 Membership Filing (ER24-2925)**

On July 30, 2024, NEPOOL requested that the FERC accept: (i) the following Applicant's membership in NEPOOL as of August 1, 2024: Elyctra LLC (Supplier Sector) and Halia Energy LLC (Supplier Sector); and (ii) the termination of the Participant status of the Town on Hanover, New Hampshire. Comments on this filing are due on or before ***September 20, 2024***.

- **August 2024 Membership Filing (ER24-2623)**

On July 30, 2024, NEPOOL requested that the FERC accept: (i) the following Applicant's membership in NEPOOL as of August 1, 2024: Twig Redwood Inc.; and (ii) the termination of the Participant status of MFT Energy US 1 LLC. Comments on this filing were due on or before August 20, 2024; none were filed. This matter is pending before the FERC.

- **July 2024 Membership Filing (ER24-2430)**

On August 22, 2024, the FERC accepted (i) the Data-Only Participant memberships Aurora Energy Research LLC and Enverus, Inc.; and (ii) the termination of the Participant status of KCE CT 10, LLC.[94] Unless the August 22, 2024 order is challenged, this proceeding will be concluded.

X. Misc. - ERO Rules, Filings; Reliability Standards[95]

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).

- **Revised Reliability Standard: EOP-012-2 (RD24-5)**

On June 27, 2024, the FERC approved Reliability Standard EOP-012-2 (Extreme Cold Weather Preparedness and Operations) ("Freeze Protection Standards"),[96] subject to further modification.[97] As previously reported, EOP-012-2 clarifies the applicability of standard's requirements for generator cold weather

[94] *New England Power Pool Participants Comm.*, Docket No. ER24-2430-000 (Aug. 22, 2024) (unpublished letter order).

[95] Reporting on the following ERO Reliability Standards or related rule-making proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2); *Order 901*: IBR Reliability Standards (RM22-12); and 2024 Reliability Standards Development Plan (RM05-17 *et al.*).

[96] *N. Am. Elec. Rel. Corp.*, 187 FERC ¶ 61,204 (June 27, 2024).

[97] On or before Mar. 25, 2025, NERC was directed to develop and submit modifications to EOP-012-2: (1) to address concerns related to the ambiguity of the newly defined term Generator Cold Weather Constraint to ensure that the Generator Cold Weather Constraint declaration criteria included within EOP-012-2 are objective and sufficiently detailed so that applicable entities understand what is required of them and to remove all references to "reasonable cost," "unreasonable cost," "cost," and "good business practices" and replace them with objective, unambiguous, and auditable terms; (2) to require NERC to receive, review, evaluate, and confirm the validity of each Generator Cold Weather Constraint invoked by a generator owner, in a timely fashion, to ensure that such declaration cannot be used to avoid mandatory compliance with EOP-012-2 or obligations in a corrective action plan; (3) to shorten and clarify the corrective action plan implementation timelines and deadlines in Requirement R7; (4) to ensure that any extension of a corrective action plan implementation deadline beyond the maximum implementation timeframe required by EOP-012-2 is pre-approved by NERC and to ensure that the generator owner informs relevant registered entities of operating limitations in extreme cold weather during the period of the extension; and (5) to implement more frequent reviews of Generator Cold Weather Constraint declarations to verify that the constraint declaration remains valid.

preparedness, further defining the circumstances under which a Generator Owner may declare that constraints preclude them from implementing one or more corrective actions to address freezing issues. EOP-012-2 also reflects additional improvements that would address the recommendations of the FERC, NERC, and Regional Entity Staff Joint Inquiry into the causes of the February 2021 cold weather event affecting Texas and the south-central United States. EOP-012-2 will become effective on *October 1, 2024*.[98]

- **Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization) (RM24-8)**

On July 10, 2024, NERC filed for approval 11 revised Critical Infrastructure Protection ("CIP") Reliability Standards,[99] as well as 18 new or revised definitions for inclusion in NERC's Glossary,[100] to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments. The proposed CIP Reliability Standards would permit Responsible Entities with more "traditional" architecture to continue with their current configurations. As of the date of this Report, the FERC still has not notice a proposed rulemaking proceeding or otherwise invited public comment.

- **2025 NERC/NPCC Business Plans and Budgets (RR24-5)**

On August 23, 2024, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2025. FERC regulations[101] 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 2025 funding requirement represents an overall increase of approximately 8.2% over NERC's 2024 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $13.12 million. NPCC has requested $25.69 million in statutory funding (a U.S. assessment per kWh (2023 NEL) of $0.000023) and $1.22 million for non-statutory functions. Comments on this filing are due on or before ***September 13, 2024***.

- **Report of Comparisons of 2023 Budgeted to Actual Costs for NERC and the Regional Entities (RR24-3)**

On May 30, 2024, NERC filed its annual comparisons of actual to budgeted costs for 2023 for NERC and the six Regional Entities operating in 2023,[102] including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2023 budgets and actual results. Comments on this filing were due on or before June 20, 2024; none were filed. This matter remains pending before the FERC.

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[98] Nearly all of EOP-012-2 Requirements will also become enforceable on *October 1, 2024*, with the exception of Requirement R3 which will become mandatory and enforceable on *October 1, 2025*.

[99] The revised Cyber Security Standards are: CIP-002-7 (BES Cyber System Categorization); CIP-003-10 (Security Management Controls); CIP-004-8 (Personnel & Training); CIP-005-8 (Electronic Security Perimeter(s)); CIP-006-7 (Physical Security of BES Cyber Systems); • CIP-007-7 (Systems Security Management); CIP-008-7 (Incident Reporting and Response Planning); CIP-009-7 (Recovery Plans for BES Cyber Systems); CIP-010-5 (Configuration Change Management and Vulnerability Assessments); CIP-011-4 (Information Protection); and CIP-013-3 (Supply Chain Risk Management).

[100] The new and/or revised Glossary Terms are: BES Cyber Asset ("BCA"), BES Cyber System ("BCS"), BES Cyber System Information ("BCSI"), CIP Senior Manager, Cyber Assets, Cyber Security Incident, Cyber System, Electronic Access Point ("EAP"); External Routable Connectivity ("ERC"), Electronic Security Perimeter ("ESP"), Interactive Remote Access ("IRA"), Intermediate System, Management Interface, Physical Access Control Systems ("PACS"), Physical Security Perimeter ("PSP"), Protected Cyber Asset ("PCA"), Removable Media, Reportable Cyber Security Incident, Shared Cyber Infrastructure ("SCI"), Transient Cyber Asset ("TCA"), and Virtual Cyber Asset ("VCA").

[101] 18 CFR § 39.4(b) (2014).

[102] 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").

XI. Misc. - of Regional Interest

- **203 Application: Carlyle Group (Nautilus)/Q-Generation (Trafigura) (EC24-114)**

On August 23, 2024, Applicants, including Nautilus Power, Bridgeport Energy LLC; Essential Power Massachusetts, LLC; Essential Power Newington, LLC; Rumford Power LLC; and Tiverton Power LLC (collectively, the "ISO-NE Companies") requested authorization for Q-Generation Partner's acquisition of 100% of the interests of CPP II Master Holdco, LLC ("CPP II"), a company indirectly owned by investment fund vehicles managed/advised by The Carlyle Group. Following consummation of the proposed transaction, the ISO-NE Companies will no longer be Related Persons to The Carlyle Group and will become Related Persons to Trafigura Trading LLC (whose upstream parent will own or control more than 10% of the equity interests in Q-Generation Partners). Comments on this application are due on or before ***September 13, 2024***. Thus far, the PJM IMM has intervened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Berkshire Power/Gate City Power (EC24-104)**

On July 19, 2024, Berkshire Power Company, LLC ("Berkshire Power") requested authorization for a proposed transaction whereby Gate City Power – NE Generation LLC ("Gate City Power") will acquire all of the membership interests of Berkshire Power's parent, Tenaska Hampden Partners, LLC ("Tenaska Hampden"), from Tenaska Energy, Inc. ("Tenaska Energy") and Tenaska Energy Holdings, LLC ("Tenaska Holdings"). Following consummation of the proposed transaction, Berkshire Power will no longer be a Related Person to Tenaska Power Services *et al*. Comments on this application are due on or before August 9, 2024; none were filed. Public Citizen filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Trailstone/Engelhart US (EC24-87)**

On July 25, 2024, the FERC authorized the acquisition by Engelhart CTP (US) LLC ("Engelhart US") of 100% of the interests in the Trailstone Companies[103] from Riverstone V Trailstone Holdings.[104] Pursuant to the *Trailstone Order*, Engelhart US and the Trailstone Companies filed a notice of consummation that the transaction was completed on August 23, 2024 (making the Trailstone Companies and Engelhart US Related Persons). This concludes reporting on this proceeding. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Eversource/GIP IV (EC24-59)**

On June 7, 2024, the FERC issued an order authorizing the proposed transaction pursuant to which GIP IV Whale Fund Holdings, L.P. ("GIP Whale") and/or one more of its affiliates will acquire Eversource Investment, LLC's interests in North East Offshore, LLC, Revolution Wind, LLC, South Fork Wind, LLC (together with North East Offshore, Revolution Wind and GIP Whale, the "Applicants").[105] Upon consummation, GIP Whale will hold: (i) Eversource Investment's 50 percent interest in North East Offshore and will thereby also indirectly hold a 50 percent interest in Revolution Wind; and (ii) Eversource Investment's 50 percent Class B interest in South Fork Class B and will thereby also indirectly hold an interest in South Fork Wind. The Applicants must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not happened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: GIP/BlackRock (EC24-58)**

Still pending is the March 12, 2024 request by Global Infrastructure Management, LLC ("GIM") d/b/a Global Infrastructure Partners, on behalf of investment funds sponsored by GIM that own public utility

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[103] The "Trailstone Companies" are Trailstone Energy Marketing, LLC and Trailstone Renewables, LLC.

[104] *TrailStone Energy Marketing, LLC, Trailstone Renewables, LLC, and Engelhart CTP (US) LLC*, 188 FERC ¶ 62,046 (July 25, 2024) ("*Trailstone Order*").

[105] *North East Offshore, LLC, et al.*, 187 FERC ¶ 62,151 (June 7, 2024).

subsidiaries, and BlackRock, Inc., for authorization for a transaction pursuant to which BlackRock Funding Inc. will acquire 100% of the LLC interests in GIM and thereby an indirect controlling interest in the GIM public utility subsidiaries, including, among others, Clearway Power Marketing and GenConn Energy. Following an errata notice, comments on this 203 application were due on or before May 13, 2024. As previously reported the FERC issued a deficiency letter, to which GIM responded on June 18, 2024.[106] Public Citizen and Private Equity Stakeholder Project[107] have filed three joint protests (the first related to upstream ownership/affiliate issues; the second, addressing Applicants' proposed purchase of Allete; the third, with GIM's deficiency letter response, particularly the transaction would impact the blanket authorization granted to BlackRock and certain of its investment management subsidiaries); Sierra Club also filed a protest. On June 5, 2024, Applicants answered the Protests. On June 18, 2024, Applicants answered the FERC's deficiency letter. As noted, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariff – UI (ER24-2939)**

On August 30, 2024, UI filed a new Wholesale Distribution Tariff to provide for UI's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own front-of-the-meter ("FTM"), distribution-connected battery energy storage systems ("BESS") connected to UI's distribution systems and participate in the ISO-NE markets. The proposed Wholesale Distribution Tariff will enable UI to provide the WDS necessary to facilitate BESS resources' participation in the ISO-NE markets via distribution facilities owned by UI, consistent with FERC *Orders 841* and *2222* and Connecticut's ESS Program.[108] An October 30, 2024 effective date was requested. Comments on the UI Wholesale Distribution Tariff are due on or before ***September 20, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement Cancellation: NEP/Holden (ER24-2852)**

On August 23, 2024, NEP filed a notice of cancellation of its Cost Reimbursement Agreement ("CRA") with Holden Municipal Light Department ("Holden") pursuant to which NEP performed work to support Holden's plan to rebuild its Chaffins Substation. The CRA is no longer required because all work pursuant to the CRA is complete and all invoices for that work paid. An October 23, 2024 effective date was requested. Comments on the CRA cancellation are due on or before ***September 13, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariffs – National Grid (ER24-2796; ER24-2795)**

On August 16, 2024, National Grid filed two new Wholesale Distribution Tariffs (one for Massachusetts Electric Company (ER24-2796); the other for Nantucket Electric Company (ER24-2795)) to provide for National Grid's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own qualifying standalone electric energy storage systems ("ESS") connected to National Grid's distribution system and who charge those resources via deliveries over National Grid's distribution system for purposes of making wholesale sales through the ISO-NE markets. The proposed Wholesale Distribution Tariffs will enable

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[106] The FERC issued a deficiency letter on June 5, 2024 directing Applicants to address issues related to the data and methods used for the submitted Delivered Price Test ("DPT") and how the Proposed Transaction is consistent with, or would have any impact on the terms of, the blanket authorization granted to BlackRock and certain of its investment management subsidiaries. GIM responded to the deficiency letter on June 18, 2024. Comments on the deficiency letter were due on or before July 9, 2024. As noted herein, Public Citizen and Private Equity Stakeholder Project protested a piece of the deficiency letter response.

[107] The Private Equity Stakeholder Project states that it supports stakeholders impacted by private equity firms and similar private asset managers. *See* https://pestakeholder.org/.

[108] The ESS Program provides incentives for residential and commercial customers to install energy storage systems at their homes or businesses. *See* State of Conn. Pub. Utils. Regul. Auth., PURA Investigation into Distrib. Sys. Plan. of the Elec. Distrib. Cos. – Elec. Storage, Decision, CT PURA Docket No. 17-12-03RE03 at 5, 50 (July 28, 2021), https://portal.ct.gov/-/media/pura/electric/final-decision-17-12-03re03.pdf.

National Grid to provide the WDS necessary to facilitate ESS resources' participation in the ISO-NE markets via distribution facilities owned by National Grid, consistent with FERC *Order 841* and the Massachusetts Clean Energy Act. A March 1, 2025 effective date was requested. Comments on these Tariffs are due on or before ***September 6, 2024***. Thus far, the MA AG, MA DPU, MA DOER, and New Leaf have intervened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Hingham (ER24-2695)**

On August 2, 2024, NSTAR filed to terminate the Design & Engineering Agreement ("D&E Agreement") between NSTAR and Hingham Municipal Lighting Plant ("Hingham"). NSTAR stated that it has completed all work pursuant to the Agreement and reconciliation of billings is complete. An effective termination date of July 1, 2024 was requested. Comments on this filing were due on or before August 23, 2024; 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).

- **LGIA: ISO-NE/CL&P/Brookfield Husky Solar (ER247-2740)**

On August 9, 2024, ISO-NE filed for acceptance a non-conforming LGIA covering the interconnection of Brookfield's ~50 MW solar facility located in Sterling, CT (non-conforming only in that it is unexecuted). ISO-NE stated that FERC acceptance of the LGIA will eliminate any uncertainty remaining regarding the issue of whether Sterling Property, LLC retains any right to use the 87 MW of capacity on the CL&P Tie Line pursuant to the IA between Sterling and CL&P. Comments on this filing were due on or before August 30, 2024; none were filed. Brookfield Husky Solar LLC intervened doc-lessly. 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).

- **E&P Agreement 3d Amendment: Seabrook/NECEC Transmission (ER24-2588)**

On July 25, 2024, NextEra Energy Seabrook, LLC ("Seabrook") filed a third amendment to the Engineering and Procurement ("E&P") Agreement between Seabrook and NECEC Transmission LLC ("NECEC") (the "A&R E&P Agreement"). The A&R E&P Agreement covers the final engineering drawings through the procurement and delivery of the 24.5 kV generator circuit breaker and ancillary equipment to Seabrook Station in advance of the Fall 2024 outage. The third amendment seeks approximately $3 million in additional funding to cover "higher costs driven by increased engineering scope, outage planning, and higher internal project support". Comments on this filing were due on or before August 15, 2024; none were filed. Avangrid and National Grid filed doc-less interventions. 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).

- **Interconnection Study Agreement: PSNH / Wok, LLC (ER24-2522)**

On August 30, 2024, the FERC accepted an Interconnection Study Agreement ("ISA") between PSNH and Wok, LLC (which is proposing to potentially construct a facility and establish a load interconnection to PSNH's transmission system) to cover the costs of assessing the viability of a potential interconnection and providing high-level, non-binding cost estimates for the portion of such infrastructure that would be paid for by Wok.[109] The ISA was accepted effective as of *July 16, 2024*, as requested. Unless the August 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant *Order 1920* MPD Waiver Request (ER24-2462)**

On September 3, 2024, the FERC issued an order granting Versant Power's request a waiver of *Order 1920*'s requirements for the Maine Public District ("MPD") related to regional transmission planning, interregional transmission coordination, and cost allocation methods.[110] Finding that the MPD's unique

[109] *Public Service Co. of New Hampshire*, Docket No. ER24-2522-000 (Aug. 30, 2024) (unpublished letter order).

[110] *Versant Power*, 188 FERC ¶ 61,150 (Sep. 3, 2024)

geographic and electrical situation makes it impossible for it to meet the requirements of *Order 1920* with respect to regional transmission planning, interregional transmission coordination, and cost allocation, the FERC granted Versant Power's waiver request for the MPD. Unless the September 3 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).

- **LCCSA: RIE/BIPCO/PUD (ER24-2390)**

On August 21, 2024, the FERC accepted a Local Control Center Services Agreement ("LCCSA") among Rhode Island Energy ("RIE"), Block Island Power Company ("BIPCO) and Pascoag Utility District that sets forth the terms of certain local control services provided at or through a dispatching center by RIE and operated under the direction or authorization of ISO-NE.[111] The LCCSA was accepted effective as of *May 30, 2024*, as requested. Unless the August 21 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 (ER24-2356)**

On August 16, 2024, the FERC accepted the termination of the Engineering, Design and Procurement Agreement ("D&E Agreement") between NSTAR and Medway Grid, LLC.[112] As previously reported, NSTAR stated that it had completed all work pursuant to the Agreement. The termination was accepted effective as of *June 26, 2024*, as requested. Unless the August 16 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: CL&P/BPUS (ER24-2233)**

On August 8, 2024, the FERC accepted a Design & Engineering ("D&E") Agreement between CL&P and BPUS Generation Development LLC ("BPUS").[113] As previously reported, the D&E Agreement sets forth the terms and conditions under which CL&P will perform necessary engineering, procurement and design services in connection with the interconnection of BPUS' 50 MW solar facility in Windham, Connecticut. The D&E Agreement was accepted effective as of *August 11, 2024*, as requested. Unless the August 8 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 2023* Compliance Filing: Versant MPD OATT (ER24-2035)**

Versant Power's MPD OATT Order 2023 Compliance filing remains pending. As previously reported, Versant Power proposed revisions to its *pro forma* LGIP, Large Generator Interconnection Agreement ("LGIA"), SGIP and Small Generator Interconnection Agreement ("SGIA") in the MPD OATT in compliance with *Orders 2023* and *2023-A* in a May 16, 2024 filing. The revised LGIP contains two deviations from *Order 2023-A.* Versant proposes (i) to eliminate the reference to when the transition process will commence and, instead, only reference when it plans to hold its first Cluster Study process on January 1, 2025 langauge that was previously approved by the FERC in Versant Power's Order No. 845 compliance filing and (ii) to limit the use of surety bonds to those where the surety bond is "issued by an insurer reasonably acceptable to the Transmission Provider" and that "specify a reasonable expiration date." An effective date of January 1, 2025 was requested. Comments were due on or before June 6, 2024; none were filed. As noted, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA – ISO-NE/CMP/Andro Hydro (ER24-1477)**

Also still pending is the non-conforming LGIA, filed March 13, 2024 by ISO-NE and CMP, to govern the interconnection of Andro Hydro, LLC's 27.57 MW hydro facility, which interconnects to the Jay Substation. The

[111] *The Narragansett Electric Co.*, Docket No. ER24-2390-000 (Aug. 21, 2024) (unpublished letter order).

[112] *NSTAR Electric Co.*, Docket No. ER24-2356-000 (Aug. 16, 2024) (unpublished letter order).

[113] *The Connecticut Light & Power Co.*, Docket No. ER24-2233-000 (Aug. 8, 2024) (unpublished letter order).

LGIA is non-conforming in that it contains limited deviations from the Schedule 22 *pro forma* LGIA that are necessary to reflect unique characteristics of Andro Hydro's proposed interconnection, including the interconnection of its facility through shared facilities co-owned, and used by, JGT2 Redevelopment LLC to serve its own load. A February 12, 2024 effective date was requested. Comments on the LGIA filing were due on or before April 3, 2024; none were filed. Andro Hydro intervened doc-lessly. On May 7, 2024, the Filing Parties filed a replacement LGIA to allow the FERC additional time to consider the filing, as well as a related filing made by Andro Hydro (ER24-1629), and further consultation among the Filing Parties. Comments on the May 7 filing were due on May 28, 2024; none were filed. As noted, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CMP ESF Rate (ER24-1177)**

As previously reported, the FERC accepted, subject to refund and settlement judge procedures, CMP's rate schedule for distribution services for electric storage facilities ("ESFs") seeking to participate in the ISO-NE Market ("ESF Rate").[114] CMP filed the ESF Rate following re-consideration by the MPUC of the jurisdictional applicability of the ESF rate (which, while it recovers costs associated with the use of local the distribution network, the MPUC found upon re-consideration to include charges related to a FERC-jurisdictional wholesale transaction per *Order 841*). CMP sought in this proceeding to obtain FERC approval of a modified version of the MPUC Rate, with the primary difference between the MPUC Rate and the ESF Rate being the removal of state benefit charges. In the *CMP ESF Rate Order*, the FERC found that CMP's filing had not been shown to be just and reasonable, and raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed in hearing and settlement judge procedures.[115] Accordingly, the FERC accepted the filing, subject to refund, and established hearing and settlement judge procedures. The FERC denied CMP's request for waiver of the FERC's 60-day prior notice requirement, and accepted the ESF Rate effective April 2, 2024, though, as noted, subject to refund and hearing and settlement judge procedures.[116] The FERC encouraged efforts to reach settlement before hearing procedures commence and will hold the hearing in abeyance pending the outcome of settlement judge procedures.

Settlement Judge Proceedings. As directed, the Chief ALJ appointed a settlement judge, Judge Jeremy Hessler, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action.[117] There have been two settlement conferences (May 3 and July 17, 2024); a third settlement conference is scheduled for ***September 19, 2024.*** Settlement Judge proceedings are on-going. On August 5, 2024, Judge Hessler submitted his latest status report, noting the scheduled settlement conference and the exchange of settlement proposals underway, and recommending that settlement judge procedures continue. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Cancellation Versant / PERC (ER24-965)**

At Versant's request, action on this matter has not yet been taken. As previously reported, on January 22, 2024, Versant filed a notice of cancellation of an Interconnection Agreement ("IA") between itself and Penobscot Energy Recovery Company ("PERC"). Versant reported that PERC discontinued operations of an approximately 25 MW solid waste-fired generating facility that interconnected to its Orrington Substation. The facility was later sold to C&M Faith Holdings LLC, and is no longer connected or operating. Comments on the notice of cancellation are due on or before February 12, 2024; none were filed. On February 12, PERC intervened doc-lessly. On February 29, 2024, Versant Power asked that the FERC take no action on the filed notice of cancellation prior to May 1, 2024, in order to allow Versant and the new owner of the PERC facility, which may wish to reenergize the facility

[114] *Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate Order*").

[115] *Id.* at P 29.

[116] *Id.*

[117] *Central Maine Power Co.*, Docket No. ER24-1177-000 (Apr. 5, 2024) (unpublished letter order).

and assume the IA, to agree to a course of action. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[118]

- **Innovations and Efficiencies in Generator Interconnection (AD24-9)**

On ***September 10-11, 2024***, The FERC will hold a workshop to provide a public forum for the presentation and discussion of opportunities for further innovation and increased efficiency in the generator interconnection process. The three September 10 panels will address: Integrated Transmission Planning and Generator Interconnection, Exploring Different Approaches to Processing and Studying Generator Interconnection Requests, and Prioritizing Certain Generator Interconnection Requests. The three September 11 panels will address: Further Efficiencies in the Generator Interconnection Process, Automation and Advanced Computing Technologies, and Post-Generator Interconnection Agreement Construction Phase. In a second supplemental notice issued on August 14, 2024, the FERC asked panelists to submit advance materials to provide written answers to the questions presented for their respective panel and any further information (e.g., summary statements, reports, whitepapers, studies, or testimonies) that panelists believe should be included in the record of the proceeding. Panelists materials were filed in this proceeding between August 23 and September 3. In a third supplemental notice issued on September 3, 2024, the FERC attached a revised agenda for the workshop, which included a final workshop program and expected speakers. The third notice noted that the Commissioners may attend and participate in the workshop. An additional supplemental notice will be issued following the technical conference identifying the opportunity for interested parties to submit post-technical conference comments. The technical conference will be held at FERC headquarters in Washington, DC. There is no fee for attendance, and those unable to attend in person will be able to watch via a free webcast or the recording thereof.

- **Large Loads Co-Located at Generating Facilities (AD24-11)**

On ***November 1, 2024***, the FERC will hold a Commissioner-led technical conference to explore whether co-located loads require the provision of wholesale transmission or ancillary services, related cost allocation issues, and potential resource adequacy, reliability, affordability, market, and customer impacts. The FERC said that its next supplemental notice will include details on panels and a self-nomination process. The technical conference will be open to the public. Advance registration will not be required, and there will be no fee for attendance. Information will also be posted on the Calendar of Events on the FERC's website prior to the event.

- **Joint Federal- State Current Issues Collaborative (AD24-7)**

On August 12, 2024, the FERC issued an order[119] listing the members of the Federal and State Current Issues Collaborative ("Collaborative"), the successor to the Joint Federal-State Task Force on Electric Transmission:[120] From NECPUC: MPUC Chairman Phil Bartlett and NHPUC Commissioner Pradip Chattopadhyay;

[118] Reporting on the following Administrative proceedings have been suspended since the last Report and will be continued if and when there is new activity to report: ACPA Petition for Capacity Accreditation Technical Conference (AD23-10); and Reliability Technical Conference (AD23-9).

[119] *Federal and State Current Issues Collaborative*, 188 FERC ¶ 61,120 (Aug. 12, 2024).

[120] *Joint Federal-State Task Force on Elec. Transmission and Federal and State Current Issues Collaborative*, 186 FERC ¶ 61,189 (Mar. 21, 2024) ("*Order Establishing Collaborative*"). The Collaborative will provide a venue for federal and state regulators to share perspectives, increase understanding, and, where appropriate, identify potential challenges and coordination on matters that impact specific state and federal regulatory jurisdiction, including (but not limited to) the following: electric reliability and resource adequacy; natural gas-electric coordination; wholesale and retail markets; new technologies and innovations; and infrastructure. The Collaborative will be comprised of all FERC Commissioners as well as representatives from 10 state commissions, who will be nominated for and serve one-year terms from the date of appointment by the FERC. The FERC will issue notices announcing the time, place and agenda for each meeting of the Collaborative, after consulting with members of the Collaborative and considering suggestions from state commissions. Collaborative meetings will be on the record, and open to the public for listening and observing. The FERC expects that the first public meeting of the Collaborative will be held in the Fall of 2024. The Collaborative will expire 3 years after its first public meeting, but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

from MACRUC: PA PUC Vice Chair Kimberly M. Barrow and PH PUC Commissioner Dennis P. Deters; from the Mid-America Regulatory Conference ("MARC") IN Utility Regulatory Commission Chairman Jim Huston and MI PUC Commissioner Katherine Peretick; from SEARUC: NC Utilities Commissioner Kimberly W. Duffley and FL PSC Commissioner Art Graham; and from WESTERN: ID PUC Commissioner Eric Anderson and NM Public Regulation Commission Chair Patrick O'Connell. Each state commissioner will each serve a one-year term. The FERC Chairman will serve as the Chair of the Collaborative, with one state commission member of the Collaborative, selected by the 10 state commission members, to as the Co-Chair of the Collaborative. The FERC said that it expects the initial public meeting of the Collaborative to be held during the Fall of 2024, and will issue a notice announcing the time and place and agenda for the first meeting of the Collaborative, after consulting with members of the Collaborative.

- **ANOPR: Implementation of Dynamic Line Ratings (RM24-6)**

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[121] seeking comments on both the need for a dynamic line ratings ("DLRs")[122] requirement and proposed framework of DLR reforms to improve the accuracy of transmission line ratings. Proposed reforms would require transmission providers to implement, on all transmission lines, DLRs that reflect solar heating, based on the sun's position and forecastable cloud cover, and on certain transmission lines, DLRs that reflect forecasts of wind speed and wind direction. The FERC seeks comments about whether to reflect hourly solar conditions and wind conditions in all transmission line ratings, how transmission congestion levels and environmental factors could identify locations of transmission lines that would most benefit from DLR, and what other technical details of transmission line ratings reflect wind conditions. Comments in response to the ANOPR are due ***October 15, 2024***.[123] Reply comments are due ***November 12, 2024***. A more detailed summary of the ANOPR was provided to and reviewed with the Transmission Committee. On July 26, 2024, Electric Grid Monitoring filed comments in support of FERC moving forward with a NOPR and Final Rule.

- **NOPR: EQR Filing Process and Data Collection (RM23-9)**

On October 19, 2023, the FERC issued a NOPR[124] proposing various changes to current Electric Quarterly Report ("EQR") filing requirements, including both the method of collection and the data being collected. The proposed changes are designed to update the data collection, improve data quality, increase market transparency, decrease costs, over time, of preparing the necessary data for submission, and streamline compliance with any future filing requirements. Among other things, the FERC proposes to implement a new collection method for EQR reporting based on the eXtensible Business Reporting Language ("XBRL")-Comma-Separated Values standard; amend its regulations to require ISO/RTOs to produce reports containing market participant transaction data; and modify or clarify EQR reporting requirements. Requests for additional time to comment on the *EQR NOPR* were filed by EEI/EPSA, the IRC and the Bonneville Power Administration ("BPA"). On December 7, 2023, the FERC extended the deadline for submitting comments to and including February 26, 2024. Comments on the NOPR were filed by ISO-NE, CAISO, MISO, NYISO, PJM, BPA, EEI, Energy Compliance Consulting, EPSA, Interstate Gas Supply, Macquarie, PG&E, Systrends, Tri-State, XBRL US. This matter remains pending before the FERC.

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[121] *Implementation of Dynamic Line Ratings*, 187 FERC ¶ 61,201 (Jun. 27, 2024) ("*DLR ANOPR*"). The ANOPR reflects public comments in response to the FERC's February 17, 2022, Notice of Inquiry ("NOI") on DLRs. The NOI, in turn, found its roots in *Order 881*, which required transmission line ratings to reflect ambient air temperatures to improve efficiency in operating transmission lines.

[122] DLRs, are transmission line ratings that reflect up-to-date forecasts of weather conditions, such as ambient air temperature, wind, cloud cover, solar heating, and precipitation, in addition to transmission line conditions such as tension or sag.

[123] The *ANOPR* was published in the *Fed. Reg.* on July 15, 2024 (Vol. 89, No. 135) pp. 57,690-57,716.

[124] *Revisions to the Filing Process and Data Collection for the Electric Quarterly Report*, 185 FERC ¶ 61,043 (Oct. 19, 2023) ("*EQR NOPR*").

- ***Order 1977*: Transmission Siting (RM22-7)**

On May 16, 2024, the FERC issued *Order 1977*[125] updating the regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act, and particularly to reflect FERC's jurisdiction over projects located in National Interest Electric Transmission Corridors that have been denied state siting authority. There is no compliance filing requirement associated with *Order 1977*, but applicants seeking to develop transmission under federal authority in a National Interest Corridor must comply with the revised and new regulations effective ***July 29, 2024***.[126] NEPOOL Counsel prepared a summary of *Order 1977* which was distributed to the Transmission Committee.

Requests for rehearing of *Order 1977* were filed by the LA PSC, NY PSC, PA PUC, and Public Interest Organizations.[127] On July 15, 2024, the FERC issued an "Allegheny Notice", noting that the requests for rehearing may be deemed to have been denied by operation of law, but noting that the requests will be addressed in a future order.[128] If you have any questions concerning *Order 1977*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **NOPR: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)**

On March 21, 2024, the FERC issued a NOPR[129] proposing revisions to Schedule 2 of the *pro forma* OATT, § 9.6.3 of the *pro form* LGIA, and § 1.8.2 of the *pro forma* SGIA to prohibit separate compensation to generators for the provision of reactive power within the standard power factor range or "deadband."[130] The proposed change may affect revenues received by reactive power resources in New England.[131] The NOPR seeks comments on, among other issues, the following:

(i) The reliability impact of prohibiting transmission providers from including in their transmission rates any charges associated with the supply of reactive power within the standard power factor range from a generating facility in regions where generating facilities currently receive such compensation;

(ii) Whether, and if so how, the elimination of separate reactive power payments will affect generating facilities' ability to recover their costs in the markets that currently provide reactive power compensation within the standard power factor range;

(iii) Whether, and if so how, eliminating separate reactive power compensation within the standard power factor range may affect investment decisions to build, or finish building, generation facilities, and whether, and if so how, the elimination could otherwise affect generators' business decisions in those markets; and

(iv) If the FERC allows existing generation resources that have previously received compensation for reactive power supply to continue to receive compensation for a limited period while prohibiting new generation resources from receiving reactive power compensation, how should it determine

[125] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, 187 FERC ¶ 61,069 (May 13, 2024) ("*Order 1977*").

[126] *Order 1977* was published in the *Fed. Reg.* on May 29, 2024 (Vol. 89, No. 104) pp. 46,682-46,740.

[127] "Public Interest Organizations" are Earthjustice, Environmental Defense Fund, NRDC, Sierra Club, Sustainable FERC Project, UCS, WE ACT for Environmental Justice, and the Yurok Tribe.

[128] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, 188 FERC ¶ 61,027 (July 15, 2024).

[129] *Compensation for Reactive Power Within the Standard Power Factor Range*, 186 FERC ¶ 61,203 (Mar. 21, 2024) ("*Reactive Power NOPR*").

[130] *Reactive Power NOPR* PP 51-53.

[131] Generating facilities in New England are compensated for reactive power under a flat, inflation-adjusted rate design.

eligibility for continued compensation in a manner that is just and reasonable and not unduly discriminatory or preferential.[132]

Initial comments on the *Reactive Power NOPR* were due May 28, 2024; reply comments were due ***June 26, 2024***.[133] NEPOOL Counsel prepared a summary of the NOPR which was distributed to, and was reviewed with, the Transmission Committee at the March 27, 2024 TC Meeting.

Comments. Initial comments were filed on May 28, 2024 by over 30 parties, including by: ISO-NE, Calpine, CT OCC, EDP Renewables, Glenvale, National Grid, New England Consumer Advocates, ACPA/SEI, ACORE, EPSA, National Hydropower Assoc., NEI, and Reactive Service Providers. Reply comments were due by June 26, 2024 and filed by: NEPOOL in response to ISO-NE's initial comments, NEPGA, NESCOE, Elevate Renewables F7, EPSA, IPPNY, MISO TOs, Old Dominion Electric Coop, PJM IMM, and Dr. C. Gaunt. Onward Energy filed supplemental comments on July 23, 2024.

The Reactive Power NOPR is pending before the FERC.

- ***Order 1920*: Transmission Planning Reforms (RM21-17)**

On May 13, 2023, the FERC issued *Order 1920*,[134] its final rule on proposed reforms to existing the transmission planning and cost allocation requirements. In *Order 1920*, the FERC explained that under existing processes, transmission providers are not required to: (i) perform a sufficiently long-term assessment of transmission needs identifying Long-Term Transmission Needs; (ii) adequately account for known determinants of Long-Term Transmission Needs prospectively; and (iii) consider the broader benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. The existing processes result in less efficient and cost-effective investment in transmission infrastructure and higher costs to customers and, therefore, unjust and unreasonable rates and need for reforms. *Order 1920* requires all transmission providers, *inter alia*, to

(i) conduct Long-Term Regional Transmission Planning to identify, evaluate and select Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs;

(ii) to evaluate for selection regional transmission facilities that will address identified interconnection-related transmission needs through the existing Order No. 1000 processes;

(iii) to include in their compliance filings one or more default ex ante Long Term-Regional Transmission Cost Allocation Methods to allocate costs for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected for regional cost allocation; and

(iv) revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms adopted in *Order 1920*.

Order 1920 adopts a number of reforms from the *Transmission NOPR,*[135] but also declines to adopt several reforms, including the NOPR proposal to restrict the availability of the construction-work-in-progress ("CWIP") incentive for Long-Term Regional Transmission Facilities and to establish a federal rights of first refusal ("ROFR") for incumbent transmission providers, conditioned on the incumbent transmission provider establishing joint ownership of the transmission facilities. Although the FERC did not adopt a federal ROFR, it did adopt a limited ROFR applicable only to certain "right-sized" replacement transmission facilities. In addition, the FERC noted a willingness to consider the CWIP and ROFR issues in future proceedings.

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[132] *Id.* at PP 47, 49, 56.

[133] The *Reactive Power NOPR* was published in the Fed. Reg. on Mar. 28, 2024 (Vol. 89, No. 61) pp. 21,454-21,468.

[134] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 187 FERC ¶ 61,068 (May 13, 2024) ("*Order 1920*").

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

Order 1920 took effect on *August 12, 2024.*[136] Transmission providers must submit compliance filings by ***June 12, 2025*** with respect to most of the Order's requirements, while filings to comply with the interregional transmission coordination requirements are due by ***August 12, 2025***.

A detailed high-level summary of *Order 1920* was distributed to, and was reviewed with, the Transmission Committee. NEPOOL counsel will coordinate with ISO-NE counsel on stakeholder engagement to develop a compliance filing in response to *Order 1920*.

Requests for Clarification and/or Rehearing. Over 50 parties file requests for clarification and/or rehearing, including requests by: AEU, Dominion, Invenergy, NESCOE (with VT PUC supporting), Versant, APPA, EEI, Large Public Power Council, NARUC, NRECA, TAPS, WIRES, Consumer Advocates, and Harvard Electricity Institute. On July 15, 2024, the FERC issued an "Allegheny Notice", noting that the requests for rehearing may be deemed to have been denied by operation of law, but noting that the requests will be addressed in a future order.[137]

Petitions for Federal Court Review. *Order 1920* has been challenged in several federal circuits, including the DC, First, Fourth, Fifth, Sixth, Ninth, and Eleventh Circuits. Further developments on the federal court appeals will be reported in Section XVI below.

If you have any questions concerning *Order 1920*, 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

- **VES Stipulation and Consent Agreement (IN24-11)**

On August 6, 2024, the FERC approved a Stipulation and Consent Agreement with Vista Energy Storage, LLC ("VES")[138] to resolve OE's investigation of whether VES violated FERC regulations and/or the CAISO Tariff by submitting bids to CAISO when its battery storage system ("Vista Battery") was not reasonably expected to be available and capable of performing at the levels specified in the bids.[139] The investigation arose out of a referral from the CAISO Department of Market Monitoring. Under the Stipulation and Consent Agreement, VES agreed to ***disgorge $1.67 million*** to CAISO, to pay a ***civil penalty of $1 million*** to the United States Treasury, and to be subject to compliance monitoring. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[136] *Order 1920* was published in the Fed. Reg. on Jun. 11, 2024 (Vol. 89, No. 113) pp. 49,280-49,586.

[137] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 188 FERC ¶ 62,025 (July 15, 2024).

[138] VES is a subsidiary of REV, a renewable power company with approximately 2.8 GW in generation assets, including the Vista Battery in CAISO, and an indirect subsidiary of LS Power, whose affiliates own approximately 87% of REV. VES owns and operates the Vista Battery, which has a maximum storage capacity of 40 MWh, and can fully charge or discharge at a rate of 40 MW within one hour.

[139] *Vista Energy Storage, LLC*, 188 FERC ¶ 61,112 (Aug. 6, 2024). On 33 days during Summer 2022 ("Relevant Period"), Vista submitted inaccurate/low expected Initial State of Charge values as part of its Regulation Down bids when the Vista Battery actual State of Charge was otherwise much higher based on Regulation Up awards in the final hour of the day before. Because VES submitted low Initial State of Charge values, VES obtained Bid Cost Recovery payments and Regulation Down awards it would not have otherwise obtained.

- **NextEra CAISO Affiliates Stipulation and Consent Agreement (IN24-10)**

On August 8, 2024, the FERC approved a Stipulation and Consent Agreement with NextEra CAISO Affiliates[140] to resolve OE's investigation into whether NextEra CAISO Affiliates violated FERC regulations and/or the CAISO Tariff when providing ancillary services to CAISO during the relevant period (January 1, 2022 through September 1, 2023).[141] The NextEra CAISO Affiliates each operate a co-located battery energy storage system and solar generation facility (which taken together are considered a "Plant") that function as separate resources but share the same point of interconnection. Under the CAISO LGIA for each Plant, the resources cannot exceed the POI limit, which is significantly below the combined maximum potential output of each Plant's battery and solar facilities. During the relevant period, there were many five-minute intervals during which the Plants' battery facilities deviated from dispatch instructions while holding ancillary services awards because, on these occasions, as the combined output of the Plants approached or met the shared POI limit, NextEra's software automatically curtailed the battery facilities instead of curtailing the solar facilities, thereby allowing the solar facilities to receive energy revenues when they should have otherwise been curtailed. This investigation also arose out of a referral from the CAISO Department of Market Monitoring. Under the Stipulation and Consent Agreement, NextEra CAISO Affiliates agreed to ***disgorge $381,724*** to CAISO, to pay a ***civil penalty of $105,000*** to the United States Treasury, and to be subject to compliance monitoring. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Ketchup Caddy / Phillip Mango (MISO DR Program Violations) (IN23-14)**

On February 21, 2024, the FERC directed Ketchup Caddy, LLC ("Ketchup Caddy") and Phillip Mango, Ketchup Caddy's CEO and co-owner (together, "Respondents"), to show cause why they should not be found to have violated FPA section 222, along with section 1c.2 of the FERC's regulations, Sections 69A.3.5 and 69A.7.1 of the MISO Tariff by offering uncontracted resources into the annual Planning Resource Auctions ("PRAs") that MISO uses to procure capacity necessary to maintain the reliability of the MISO grid.[142] The FERC directed Ketchup Caddy and Mango to show cause why they should not be assessed ***civil penalties of $25 million*** and ***$1.5 million***, respectively, and why ***Mango*** should not ***disgorge $506,502, plus interest***, in unjust profits. Enforcement alleges that "Ketchup Caddy operated as a fraudulent enterprise with no legitimate market activity, registering and clearing demand response resources without their knowledge or consent and collecting capacity payments in turn, without making payments to the registered resources. Mango … made no attempt to contract with—or even to contact—legitimate customers, and the purported customers Ketchup Caddy registered with MISO would not have responded if dispatched. Collectively, Mango and his co-owner received $1,013,004 in capacity payments paid to Ketchup Caddy by MISO during the Relevant Period. Staff's recommended penalties are predicated on its finding that Respondents caused $17,639,142.07 in losses to other suppliers because Ketchup Caddy's fraudulent offers lowered capacity prices in the 2019/20, 2020/21, and 2021/22 MISO PRAs."[143]

As reported in last Report, finding that the Order to Show Cause was not served on Respondents, as required by Rule 2010 of the FERC's Rules of Practice and Procedure, the FERC directed the FERC Secretary to serve the Order to Show Cause on Respondents and to issue a notice in this proceeding indicating the date on

140 *Arlington Energy Center III, LLC et al.*, 188 FERC ¶ 61,117 (Aug. 8, 2024). "NextEra CAISO Affiliates" are for purposes of this proceeding collectively: Arlington Energy Center III, LLC; Blythe Solar 110, LLC; Blythe Solar III, LLC; Blythe Solar IV, LLC; Desert Sunlight 250, LLC; Sunlight Storage, LLC; and McCoy Solar, LLC.

141 NextEra CAISO Affiliates' software had not been updated to comply with a December 2021 CAISO Tariff change that prohibits co-located battery facilities from deviating from dispatch instructions when providing ancillary services. NextEra Affiliates' battery facilities deviated from dispatch instructions while holding ancillary services awards at times when the combined output of the facilities approached or met their shared Point of Interconnection ("POI") limit and NextEra's software automatically curtailed the battery facilities instead of curtailing the solar facilities.

142 *Ketchup Caddy, LLC and Philip Mango*, 186 FERC ¶ 61,132 (Feb. 21, 2024).

143 *Id.* at P 3.

which service was made.[144] The FERC amended the answer deadline in the Order to Show Cause to require Respondents to respond to the Order to Show Cause by no later thain19-4

n 30 days after the date on which the Office of the Secretary serves the Order to Show Cause on Respondents. 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,[145] 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 FERC issued an Order on Presiding Officer Reassignment,[146] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

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

On December 16, 2021, the FERC issued a show cause order[147] 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,[148] 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;[149] (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

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[144] *Ketchup Caddy, LLC and Philip Mango*, 188 FERC ¶ 61,081 (July 26, 2024) at P 4.

[145] 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.

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

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

[148] *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*").

[149] 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.

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.[150] 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[151] 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.[152]

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

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[153] 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.[154]

On June 14, 2023, the FERC issued an Order on Presiding Officer Reassignment,[155] 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

[150] *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.

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

[152] 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.

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

[154] *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).

[155] *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*").

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, 2023, 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.[156] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
    - In its March 8, 2024 monthly status report, Iroquois indicated that it is still awaiting issuance of air permits from the New York State Department of Environmental Conservation ("NYDEC") and the CT DEEP. Iroquois noted that the public comment period on the NY DPS reliability and needs determination, noticed by NYDEC was open until March 29, 2024. Iroquois has still not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in February 2024 and no construction was planned for March 2024.

XV. State Proceedings & Federal Legislative Proceedings

No activities to report.

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

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Order 1920*: Transmission Planning Reforms (24-1254 et al. transferred to 4th Circuit)**
  Underlying FERC Proceeding: RM21-17[157]
  Petitioners: among others, AEU/ACPA/SEIA, Invenergy
  Status: Petitions for Review Consolidated in Fourth Circuit Court of Appeals (lead case 24-1650)

As previously reported, on July 18, 2024, AEU/ACPA/SEIA and Invenergy petitioned the DC Circuit Court of Appeals for review of the FERC's *Order 1920*.[158] Petitions were also filed in the First, Second, Fourth, Fifth, Sixth, Seventh, Ninth, and Eleventh Circuits. The Judicial Panel on Multidistrict Litigation randomly selected the Fourth Circuit in which to consolidate the petitions for review. The DC Circuit ordered that its cases be transferred to the Fourth Circuit. The 4th Circuit lead case no. is 24-1650. On August 22, 2024, the FERC moved, without opposition, to hold the petitions for review in abeyance, with motions to govern due ***January 6, 2025***. The FERC's requested relief would defer all filing deadlines— including filing of the agency record—until after the abeyance period expires. The FERC suggested that abeyance will afford the FERC time to respond to the approximately 50 applications for rehearing of *Order 1920*. The FERC's motion is pending before the 4th Circuit.

- **Mystic Second CapEx Info Filing (24-1077)**
  Underlying FERC Proceeding: ER18-1639-028[159]
  Petitioner: Mystic
  Status: Being Held In Abeyance

On April 3, 2024, Constellation Mystic Power, LLC petitioned the DC Circuit Court of Appeals for review of the FERC's orders. Mystic filed, on May 6, 2024, a Certificate as to Parties, Rulings, and Related Cases, 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. Appearances and other procedural motions, if any, were also due on or before May 6. Interventions were filed by ISO-NE, NESCOE, and a collective of Massachusetts municipal utilities.[160]

In response to a motion by the FERC, the Court ordered that this case be held in abeyance pending further order of the court. Subsequently, in response to a July 16, 2024 unopposed motion by Mystic, the court ordered that the case remain in abeyance pending further order of the Court, with the parties directed to file motions to govern future proceedings in this case by ***December 4, 2024***.

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[157] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*"); *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[158] Petitioners for review of *Order 1920* have also been filed in the 1st, 4th, 5th, and 9th Circuits

[159] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*"); *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[160] Braintree Electric Light Department, Concord Municipal Light Plant, Georgetown Municipal Light Department, Hingham Municipal Lighting Plant, Littleton Electric Light & Water Department, Middleborough Gas & Electric Department, Middleton Electric Light Department, Norwood Light & Broadband Department, Pascoag Utility District, Reading Municipal Light Department, Taunton Municipal Lighting Plant, Wellesley Municipal Light Plant, and Westfield Gas & Electric Department (collectively, the "Eastern New England Consumer-Owned Systems").

- **Orders 2023 and 2023-A (23-1282 et al.) (consolidated)**
  Underlying FERC Proceeding: RM22-14[161]
  Petitioners: AEU et al.
  Status: Being Held In Abeyance; Unopposed Proposed Schedule to Govern Future Proceedings Pending

Several Petitioners have challenged *Orders 2023 and 2023-A*. Those challenges have now been consolidated, with the AEU docket (23-1282) as the lead docket. On August 5, 2024, the Court ordered the following briefing schedule: Initial Submissions and Certified Index to the Record (August 21, 2024); Joint Petitioners' Briefs (October 30, 2024); Petitioner-Intervenor Brief(s) (November 13, 2024); Respondent's Brief (February 5, 2025); Intervenors for Respondent's Brief (February 19, 2025); Petitioners' Reply Briefs (March 19, 2025); Petitioner-Intervenor Reply Brief(s) (March 19, 2025), Deferred Joint Appendix (April 2, 2025); and Final Briefs (April 16, 2025). The parties will be informed later of the date of oral argument and the composition of the merits panel. The next expected submission will be Joint Petitioners' Briefs.

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)**
  Underlying FERC Proceeding: ER22-983[162]
  Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
  Status: Being Held In Abeyance

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*.[163] 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. On June 6, 2024, the FERC filed a status report reporting that, on May 23, 2024, the Commission issued its order on rehearing of its November 2023 order in the ER22-983 docket and that, under the Court's February 6 order, the parties therefore have until ***August 5, 2024***, to file motions to govern future proceedings in these consolidated appeals. However, since the last Report, the FERC asked that the Court continue to hold these consolidated petitions for review in abeyance until 90 days after the Commission's issuance of a final order in ER22-983, with parties to file motions to govern future proceedings at the end of the abeyance period. The FERC asked for the additional period of abeyance "because compliance filings in the ER22-983 proceeding remain pending before the Commission, and Commission action on those filings may ultimately result in further petitions for review of ER22-983 orders, or otherwise expand or reduce the issues presented for review". On July 31, 2024, the Court issued an order that these consolidated cases remain in abeyance pending further order of the court. The FERC was directed to file status reports at 60-day intervals beginning ***September 30, 2024***. The parties were directed to file motions to govern future proceedings within 90 days of the FERC's issuance of a final order in the ER22-983 proceeding.

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[161] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*"); 184 FERC ¶ 62,163 (Sep. 28, 2023) (Notice of Denial of Rehearing by Operation of Law).

[162] *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*").

[163] 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[164]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Oral Argument Held Feb 6, 2024; Case Pending Before the Court

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.[165] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. Briefing is completed. Oral argument was heard on February 6, 2024 by Judges Millett, Katsas and Rao. This matter remains pending before the Court.

- **Mystic II (ROE & *True*-Up) (21-1198 *et al.*) (consolidated)**
  Underlying FERC Proceeding: ER18-1639-010, -011,[166] **-013**[167] **-017**[168]
  Petitioners: Mystic (21-1198 (lead), 22-1008, 22-1026), CT Parties,[169] **(21-1222, 22-1001) MA AG (21-1223), ENECOS (21-1224)**
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Nov 27, 2024

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 Decisions 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

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[164] *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*").

[165] 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.

[166] *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).

[167] *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).

[168] *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*).

[169] In this appeal, "CT Parties" are the CT PURA CT PURA, CT DEEP, and the CT OCC.

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.

Abeyance. As previously reported, these proceedings have been held in abeyance pending disposition of *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*), now on remand at the FERC. Most recently, on July 22, 2024, 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 30, 2024, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***Nov 27, 2024***. Since the last Report, Mystic filed an opposed Settlement Agreement that would set the ROE at 9.0% and moot these appeals; Mystic asked for a November 1, 2024 effective date for that Agreement. (*see* Section II, Mystic COSA ROE Settlement Agreement (ER24-2804). On August 14, 2024, Mystic filed an unopposed Settlement Agreement to establish a settled ROE of 9.0% for the Mystic COSA ("Mystic ROE Settlement Agreement") that would, if approved, moot all of the ROE appeals currently pending before the DC Circuit related to that ROE. Mystic requested a November 1, 2024 effective date for the Settlement Agreement).

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[170]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Mar 2, 2026

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

Petitioners have moved to hold this matter in abeyance now four times. In the most recent request (filed March 1, 2024) (fourth abeyance request), Petitioners asked the Court to hold this matter in abeyance until March 1, 2026 "in light of the continued delay of the revisions to its capacity market that ISO New England previously asserted were a predicate to eliminating the market impediment that is the subject of the underlying claims before the Court". The Court granted the request on May 12, 2024, ordering the parties to file motions to govern future proceedings by ***March 2, 2026***.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[171]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[172] 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*[173] 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

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

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

[172] 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.

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

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 FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on July 23, 2024.

- ***Chevron Doctrine* (US Supreme Ct 20-1329)**[174]
  Status: Overturned

On June 28, 2024, the Supreme Court overturned the *Chevron* deference doctrine in its decisions in *Loper Bright v. Raimondo* and *Relentless, Inc. v. Dep't of Commerce*.[175] *Chevron*, a landmark and often-cited 1984 decision, required courts to defer to a federal agency's reasonable interpretation of ambiguity in a statute.[176] A more fulsome summary of the *Loper Bright* and *Relentless* Decisions and some of their projected impacts are included as Appendix A to this Report.

[174] *Loper Bright Enterprises v. Raimondo*, No. 22-451 at 1–2 (U.S. June 28, 2024) (citing *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U. S. 837, 842 (1984)).

[175] *Loper Bright Enterprises v. Raimondo*, No. 22-451 at 1–2 (U.S. June 28, 2024) (citing *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U. S. 837, 842 (1984)).

[176] Chevron had established a two-step framework for courts to address ambiguity and gaps in statutes. In step one, a court was required to determine whether Congress had "directly spoken to the precise question at issue" using "traditional tools of statutory construction." If the courts could not determine a clear congressional intent, in step two, the court was required to assess whether the agency's interpretation was a "permissible construction of the statute."

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