NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

January 2, 2025

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of January 9, 2025 Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the January 2025 meeting of the Participants Committee will be held **via teleconference on Thursday, January 9, 2025, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, is **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

FOR PARTICIPANTS, PARTICULARLY THOSE WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE THAT 2025 ANNUAL FEES WILL BE INCLUDED ON THE MONTHLY STATEMENTS TO BE ISSUED ON FEBRUARY 10, 2025. Participants that are members effective as of January 1, 2025 will be assessed that Annual Fee, which must be paid, if the annual fee billing results in an invoice, on or before the close of business on **February 12, 2025** in order to avoid penalties and interest. Please plan accordingly. If there are questions, you can reach out to Pat Gerity (860-275-0533; pmgerity@daypitney.com) or to ISO New England's Participant Support and Solutions (413-540-4220; askISO@iso-ne.com).

Looking ahead, the February Participants Committee meeting is scheduled for Thursday, February 6, 2025 and will be held in person at the Colonnade Hotel in Boston. We will in future notices provide more detailed information regarding arrangements for those seeking accommodations the evening before that meeting.

Happy New Year to all of you.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the December 5, 2024 Participants Committee Annual Meeting. A copy of the draft minutes, marked to show the changes since the minutes were circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

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

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

5. 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.

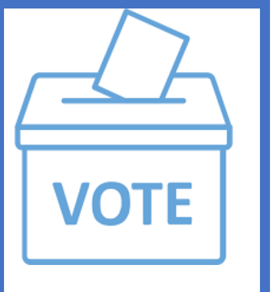
6. To receive reports from Committees, Subcommittees and other working groups:
   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Membership Subcommittee
   - Joint Nominating Committee
   - Others

7. Administrative matters.

8. 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.

1 December 5, 2024 Minutes



66.67%

RESOLVED, that the Participants Committee approves the preliminary minutes of the December 5, 2024 meeting, as circulated in advance of this meeting[, together with any changes agreed to by the Participants Committee at this meeting,] as the final minutes of the December 5, 2024 meeting.

PRELIMINARY

Pursuant to notice duly given, the 2024 annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, December 5, 2024, at the Colonnade Hotel, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting, either in person or electronically.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates and guests who were present, including ISO and State colleagues. She also welcomed FERC Commissioner Judy W. Chang and her Technical Advisor, Ms. Pearl Donohoo-Vallett.

Ms. Heather Hunt, Executive Director of NESCOE, introduced the NESCOE Managers in attendance -- Chairman Phil Bartlett from Maine, Deputy Secretary Jason Marshall from Massachusetts, and Dan Phalen, the newly-appointed NESCOE Manager for New Hampshire. She also noted that TJ Pore was the newly-appointed Manager for Vermont. Mr. Frank Ettori then introduced his invited guest, David Mullett, who was welcomed back after a long absence since his prior time as a Committee representative for the Vermont Public Power Supply Authority.

APPROVAL OF NOVEMBER 7, 2024 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the November 7, 2024 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 abstentions by the Rhode Island Division of Public Utilities and Carriers and 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 unanimously approved, with an abstention by Mr. Lamson noted.

REMARKS BY FERC COMMISSIONER JUDY W. CHANG

Ms. Bresolin introduced FERC Commissioner Judy W. Chang, providing a brief summary of her experience, including her service as former Undersecretary of Energy and Climate Solutions for Massachusetts, and her founding role and efforts supporting the New England Women in Energy and the Environment (NEWIEE).

Recalling her previous time and experiences in New England and her past interactions with NEPOOL, Commissioner Chang expressed her appreciation for the opportunity to speak in person to the Committee as a FERC Commissioner, subject to the standard disclaimer that her comments would be her own and not those of the FERC. She began with a brief overview of her early time as a Commissioner, coming up to speed on the procedural interworkings of, and substantive issues facing, the FERC.

Commissioner Chang then identified and provided insights on many of the matters of importance facing her as a Commissioner, identifying some of her more immediate priorities, including (i) transmission planning and development (with a focus on regional as well as individual consumer benefits and participation), as recently exemplified in *Order 1920-A*, (ii) enhanced reliability through continued incremental and regional improvements to gas-electric coordination, (iii) collectively and equitably addressing the co-location of large loads at generating facilities (and thereby supporting U.S. global leadership in artificial intelligence and data analytics); and (iv) unlocking the full potential of demand-side resources, particularly in light of resource adequacy and pricing challenges. She noted each of those priorities would require significant collaboration with and among the States, FERC, ISOs/RTOs, and regional stakeholders.

Commissioner Chang further explored th~~e~~ose priority areas in response to members' questions, highlighting where she hoped incremental improvements could be achieved in New England. She emphasized that, in all of its actions, the FERC was focused on, and sought to balance, among other issues, system reliability and the reasonableness of costs to consumers. She looked forward to efforts to further facilitate generation interconnection and cost allocation, including identifying ways to minimize policy or other barriers impeding the addition of much needed resources to a more robust, more flexible, and more adaptive electric system.

On behalf of the Committee, Ms. Bresolin warmly thanked Commissioner Chang for her thoughtful comments, the generosity of her time, and looked forward to working with her in the future.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of ISO New England Board and Board Committee meetings that had occurred since the November 7 meeting, which had been circulated and posted in advance of this meeting. There were no questions or comments on the summaries.

After wishing everyone a very happy holiday season and predicting a busy 2025, Mr. van Welie commented on the Board of Director's November 6 public meeting. He thanked everyone for their attendance, participation, and feedback on the meeting's format. He reminded the Committee that a recording of that meeting, the meeting materials, and the Board report for that meeting were posted on the ISO's website. He looked forward to further improving the format for the public meeting and to working with Participants in the coming years to fulfill the agenda that had been layed out. Ms. Hunt, remarking on the good discussions at that meeting and general feedback that the format for the November 7 Board meeting reflected an improvement, thanked the ISO Board for its efforts and expressed appreciation for the evolving open meeting process.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his December operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through November 25, 2024, unless otherwise noted. The December report highlighted: (i) that the Peak Hour for November, with 15,714 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on November 13, 2024 during the hour ending at 6:00 p.m.; (ii) November averages for Day-Ahead Hub LMP ($37.28/MWh), Real-Time Hub LMP ($38.48/MWh), and natural gas prices ($1.86/MMBtu); (iii) Energy Market value for November 2024 was $320 million, down from $398 million in November 2023 and up from the updated October 2024 Energy Market value of $350 million; (iv) Ancillary Markets value ($5.3 million) was down from November 2023 ($13.8 million); (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 96.0% during November (down from 98.9% reported for October 2024); (vi) Daily Net Commitment Period Compensation (NCPC) payments for October totaled $2.3 million, comprised of (a) $2.2 million in first contingency payments, including $352,000 in Dispatch Lost Opportunity Costs, $240,000 in Rapid Response Pricing Opportunity Costs, and $442,000 paid to resources at external locations, (b) Second Contingency payments totaling $29,200, and (c) no Distribution, or Voltage payments; and (vii) a Forward Capacity Market (FCM) value of $119.7 million.

Providing additional detail, Dr. Chadalavada stated that much of November was mild weather-wise, averaging 46°F, which was 5°F warmer than November 2023. Because of the mild weather, together with significant behind-the-meter photo-voltaic (PV) production, the region continued to experience record low loads, approximately 12,000 MWh on average. He added that there were no new transmission outages to note heading into the winter season.

In response to a member's questions, Dr. Chadalavada explained that the continuing outage of a large nuclear unit in New Brunswick, which had been affecting the New Brunswick/New England interface, was forecasted to end and the resource was expected to be back online by mid-December. Dr. Chadalavada addressed concerns over supply/demand balances in Quebec and projected import/export trends between the regions. Following members' suggestions, he committed to provide additional information related to monthly flows in future reports.

A member asked about the status of the ISO's study, being conducted jointly with the New York ISO (NYISO) and PJM Interconnection (PJM), of (i) the maximum level of source loss in New England that leads to reliability concerns in NYISO's or PJM's systems under planned system conditions and (ii) the determination of reliability upgrades that might be necessary to raise the loss of source limit. Dr. Chadalavada said that progress had been slower than hoped for, but ISO-NE, NYISO, and PJM continued to make progress on the study and expected to identify by the second quarter of 2025 the maximum loss of source limit in New

England without any transmission upgrades and the scope of work necessary to ascertain the high-level transmission upgrades in PJM and NYISO's systems needed to raise the loss of source limit in New England.

Finally, in response to a question he had received by e-mail related to uplift experienced on November 19-20, he explained that the uplift, which accounted for 20-30 percent of November's $2.3 million in uplift, was attributable to the loss of a large unit in eastern New England. The ISO had to make out-of-merit second contingency protection commitments in the eastern zone to respond to the increased west-to-east flows and transmission constraints that follow such a loss of a large source in eastern New England.

2024 NEPOOL ANNUAL REPORT

Ms. Bresolin referred the Committee to the 2024 NEPOOL Annual Report distributed at the meeting, posted on the NEPOOL website, and accessible through use of the QR code also distributed with the Annual Report. She thanked the NEPOOL Counsel team for all its efforts on the Report. She also thanked the Vice-Chairs of each Sector and the Technical Committees for their assistance in assembling and completing the Annual Report as well as those Participants at-large who submitted photos for use in the Report.

Ms. Bresolin called attention to some of the region's achievements highlighted in the Report, including consideration of major changes to the ISO's interconnection procedures and agreements that were proposed in response to FERC Order No. 2023 and support for the Longer-Term Transmission Planning Revisions that were proposed by the ISO in collaboration with the New England States. She noted how these achievements underscored the continuing importance of the stakeholder process and regional cooperation. Ms. Bresolin also highlighted that NEPOOL members had~~ve~~ put in a significant effort into preparing for the comprehensive capacity auction reforms (CAR) project coming in 2025. She stressed that NEPOOL, the Participant Processes, and relationships that have been built would all be essential to a successful 2025, and she looked forward to working with everyone to that end.

ELECTION OF 2025 PARTICIPANTS COMMITTEE OFFICERS

Ms. Bresolin then referred the Committee to the proposed slate of 2025 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting. The following motion was duly made, seconded and unanimously approved, with an abstention noted by Mr. Lamson.

WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and

WHEREAS, pursuant to those procedures the individuals identified in the following resolution were nominated and elected for 2025 to the offices of Chair and Vice-Chair, as set forth opposite their names; and

WHEREAS, Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the annual meeting of the Participants Committee.

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2025 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Sarah Bresolin
Vice-Chair	Jackie Bihrle
Vice-Chair	Dave Cavanaugh
Vice-Chair	Michelle Gardner
Vice-Chair	Aleks Mitreski
Vice-Chair	Dave Norman
Secretary	Sebastian Lombardi
Assistant Secretary	Pat Gerity

ACKNOWLEDGEMENT OF MR. ALAN TROTTA

Ms. Bresolin, noting that Mr. Trotta was completing a two-year tenure as Transmission Sector Vice-Chair, expressed appreciation on behalf of the Participants Committee, and on her behalf, for Mr. Trotta's thoughtful and measured engagement during his time as a Committee Vice-Chair. She said Mr. Trotta was an asset to NEPOOL leadership and his contributions and presence would be sorely missed. Mr. Trotta thanked the Committee for the opportunity to serve as a Vice-Chair, which he found educational and rewarding. He looked forward to continued engagement with the Committee.

Ms. Bresolin further conveyed her appreciation to each of the NEPOOL Officers for their service to NEPOOL, leadership, good counsel, and support during 2024. She thanked the Committee for the opportunity to serve as its Chair in 2024 and looked forward to serving as the Chair for 2025 and the important collective work ahead.

ESTIMATED BUDGET FOR 2025 NEPOOL EXPENSES

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, reported that B&F reviewed at its November 22, 2024 meeting the estimated budget for 2025 Participant Expenses, a copy of which had been circulated and posted in advance of the meeting and is included as Attachment 2 to these minutes. He reported that, while there were a few questions asked at that meeting, no objections or concerns with the 2025 NEPOOL Budget were identified by B&F members. Without further discussion, the following motion was duly made, seconded and unanimously approved, with an abstention by Mr. Lamson noted:

> RESOLVED, that the Participants Committee adopts the estimated budget for NEPOOL expenses for 2025 as presented at this meeting.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the December 4, 2024 Litigation Report that had been circulated and posted before the meeting. He highlighted the following three developments: (i) the November 21, 2024 issuance of FERC *Order 1920-A,* the FERC's order on clarification and rehearing of its final rule on Long-Term Regional Transmission Planning Reforms (a more detailed summary from NEPOOL Counsel was circulated to the Transmission Committee (TC), and would be presented at the TC's December 19, 2024 meeting); (ii) the global settlement filed in the Mystic 8/9 Cost of Service Agreement (COSA) proceeding, which if accepted would resolve all remaining/outstanding issues related to the COSA; and (iii) the December 9, 2024 deadline for comments following the FERC's technical conference on large loads co-located at generating facilities.

In addition, Mr. Gerity advised the Committee of renewed activity in the pending litigation over the Transmission Owners' return on equity (ROE) for regional transmission service. Reminding the Committee that the litigation had been to the Court of Appeals for the DC Circuit and remanded to the FERC (in 2017), and had since been held in abeyance, generally pending resolution of a MISO-related ROE proceeding, the TOs had, since the November Participants Committee meeting, submitted legal and procedural arguments why the New England cases being held in abeyance should proceed. Responses to those arguments, and further activity in the proceedings, could be expected and would return to active reporting in subsequent Litigation Reports.

Mr. Lombardi encouraged anyone with questions on any matter in the Litigation Report to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler, MC Vice-Chair, reported that the next MC meeting would be on December 10, 2024 at the DoubleTree Hotel in Westborough. Meeting topics would include the CAR project, a vote on revisions to Market Rule 1 to clarify the calculation of Metered Quantity For Settlement for Load Assets and Storage as Transmission-Only Assets (SATOAs), and the Internal Market Monitor's latest (Summer 2024) quarterly markets report. Mr. Gerity encouraged those who had not already done so to cast their ballot for 2025 MC Vice-Chair (the successor to Mr. Fowler following his nine years' of distinguished service as the MC Vice-Chair).

Reliability Committee (RC). Mr. Bob Stein, RC Vice-Chair, reported that the next RC meeting would be on December 17, 2024 at the DoubleTree Hotel in Westborough. Among the items to be discussed would be revisions to Planning Procedure 7 to conform to *Order 881*. He also noted that RC members and alternates had been invited to attend the TC meeting to be held virtually a few days thereafter.

Transmission Committee. Mr. Dave Burnham, TC Vice-Chair, confirmed that the next TC meeting would be held virtually on December 19, 2024. For the first part of that meeting, the RC and TC would meet jointly to discuss the New England Clean Energy Connect (NECEC) Transmission Operating Agreement (TOA) and Interconnection Operating Agreement (IOA). There would also be a presentation by NEPOOL counsel on, and a brief update from ISO and NEPOOL Counsel on the compliance plans in response to, *Order 1920-A*. The main agenda item would be an initial discussion on the changes to the Reactive Power Compensation Rules in response to FERC *Order 904*. There would also be a presentation from Advanced Energy United on proposed further reforms to the interconnection process.

Budget & Finance Subcommittee. Mr. Tom Kaslow reported that the January B&F meeting had been cancelled, so that the next B&F meeting would be on February 7, 2025.

Membership Subcommittee. On behalf of Mr. Brad Swalwell, Membership Subcommittee Chair, Mr. Pat Gerity reported that the next Membership Subcommittee meeting would be held by Zoom on Monday, December 16, 2025 and encouraged all those interested to participate and reach out to him for the Zoom information.

ADMINISTRATIVE MATTERS

NECPUC

Mr. George Twigg, NECPUC Executive Director, reported on some upcoming changes in NECPUC membership. He reported that Connecticut Commissioner Jack Betkoski and Vermont Commissioner June Tierney were completing their terms of service at the end of 2024. Looking ahead, he reported that Mark Dell'Orfano would be stepping into the seat vacated by New Hampshire Commissioner Carlton Simpson, who had resigned earlier in the Fall.

Other Administrative Matters

Mr. Lombardi reported that the January 2025 Participants Committee meeting would be held virtually given the agenda and time of year. The February NPC meeting would be in person at the Colonnade Hotel in Boston. At the February meeting, the three incumbent ISO Board Members ~~who are~~ up for re-appointment/re-election in 2025 were expected to attend and address their ISO Board experiences and answer Participant questions.

Ms. Bresolin reminded the Committee of the New Member Orientation which would begin after lunch.

There being no other business, and having wished members very happy holidays, the meeting adjourned at 11:42 a.m.

Respectfully submitted,

____
Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE DECEMBER 5, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Assoc. Non-Voting		Alex Lawton	
AR Renewable Generation (RG) Large Group Seat	AR-RG		Aidan Foley	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	
Bath Iron Works	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BlueWave Public Benefit Corp.	AR-DG	Mike Berlinski		
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	
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Clearway Power Marketing				Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	JR Viglione (tel)
Conservation Law Foundation	End User	Phelps Turner (tel)		
Constellation Energy Generation (Constellation)	Supplier	Gretchen Fuhr	Bill Fowler (tel)	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co.	End User			Bill Short
Dominion Energy Generation Mktg	Generation	Wes Walker (tel)		
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie	Alex Chaplin	Bill Fowler (tel)
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler (tel)
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	Steve Conant (tel)
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Bill Fowler (tel)	
Generation Group Member	Generation	Dennis Duffy (tel)	Abby Krich (tel)	
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	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE DECEMBER 5, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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
Icetec Energy Services, Inc.	AR-LR	Doug Hurley (tel)		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	Marji Philips
Jupiter Power	AR-RG			Frank Swigonski
Lamson, Jon	End User	Jon Lamson (tel)		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny (tel)	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		Chelsea Mattioda Stefan Koester
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Marble River		John Brodbeck (tel)		
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User		Kelly Caiazzo	Jamie Donovan
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	Nancy Chafetz (tel)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short
Nautilus Power, LLC	Generation		Bill Fowler (tel)	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors (tel)
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum	Don Kries	Stefan Koester
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 Business Marketing	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
PowerOptions	End User			Chelsea Mattioda (tel)
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rhode Island Division of Public Utilities and Carriers	End User	Linda George		
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson		Janelle Fabiano
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
Shell Energy North America (US) LP	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE DECEMBER 5, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Sliski, Alan	End User	Alan Sliski		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Tangent Energy	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Union of Concerned Scientists	End User			Francis Pullaro (tel)
Vermont Electric Company	Transmission	Frank Ettori		
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Energy Investment Corporation	AR-LR		Stefan Koester	Chelsea Mattioda
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vineyard Offshore	Generation			Sarah Herbert
Vistra (Dynegy Marketing and Trade, Inc.)	Supplier	Ryan McCarthy		Bill Fowler (tel)
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler (tel)	
ZTECH, LLC	End User			Bill Short

ESTIMATED 2025 NEPOOL BUDGET COMPARED TO
2024 NEPOOL BUDGET AND 2024 PROJECTED ACTUAL EXPENSES

Line Items	2024 Approved Budget	2025 Proposed Budget	2024 Current Forecast
NEPOOL Counsel Fees (1)	$ 4,350,000	$ 4,500,000	$ 4,350,000
NEPOOL Counsel Disbursements (1)	$ 30,000	$ 30,000	$ 30,000
Independent Financial Advisor Fees and Disbursements (2)	$ 48,000	$ 48,000	$ 48,000
Committee Meeting Expenses (1)	$ 920,000	$ 960,000	$ 920,000
Generation Information System (4)	$ 1,086,700	$ 1,183,624	$ 1,139,100
Credit Insurance Premium (3)	$ 578,800	$ 604,500	$ 561,700
NEPOOL Audit Management Subcommittee (“NAMS”) Consultant (5)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$ 7,013,500	$ 7,326,124	$ 7,048,800
Revenue			
NEPOOL Membership Fees (3)	($ 2,300,000)	($ 2,500,000)	($ 2,419,200)
Generation Information System (4) (6)	($ 1,086,700)	($ 1,183,624)	($ 1,139,100)
Credit Insurance Premium (3) (7)	($ 578,800)	($ 604,500)	($ 561,700)
TOTAL REVENUE	($ 3,965,500)	($ 4,288,124)	($ 4,120,000)
TOTAL NEPOOL EXPENSES	$ 3,048,000	$ 3,038,000	$ 2,928,800

Notes

(1) 2025 proposed estimate provided by Day Pitney LLP, NEPOOL counsel, reflecting a challenging work plan in 2025 and a modest increase in billing rates.

(2) 2025 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor, and reflects responsibility for reviewing meeting and travel expenses.

(3) 2025 proposed estimate provided by ISO New England Inc.

(4) Based on fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the annualized fixed fee for 2025 is projected to be $1,183,624, which includes $24,000 for ISO-NE's administrative GIS-related costs. Estimate assumes NEPOOL will remain at the 120,000-129,999 tier of sum Account Holders and Generators for half the year and then increase to the 130,000-139,999 tier of sum Account Holders and Generators for the second half of the year, increasing the annual fee.

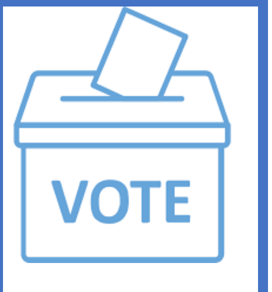
The 500 development hours included in the annual fees NEPOOL paid for 2025 are committed to the hourly tracking changes to the GIS that the NEPOOL Participants Committee approved in September 2024. Thus, based on the fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement any additional approved changes to the GIS in 2025 requiring use of development hours will be billed to NEPOOL at a cost of $180 per hour.

(5) If NEPOOL determines that an audit should be performed in 2025, funding for that audit will be addressed separately.

(6) GIS costs are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2001 and amended by the NEPOOL Participants Committee on May 6, 2016.

(7) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO New England Financial Assurance Policy.

2 Consent Agenda



66.67%

1. Revisions to Market Rule 1, § III.3.2.1.1 (Clarifications to Metered Quantity For Settlement Calculations for Load Assets and SATOAs)

RESOLVED, that the Participants Committee approves the Consent Agenda as circulated in advance of this meeting.

CONSENT AGENDA

Markets Committee (MC)

*From the previously-circulated notice of actions of the MC's **December 10, 2024 meeting:**[1]*

1. Revisions to Market Rule 1, § III.3.2.1.1 (Clarifications to Metered Quantity For Settlement Calculations for Load Assets and SATOAs)

Support the proposed revisions to Market Rule 1 § III.3.2.1.1 to clarify the calculation of Metered Quantity For Settlement for Load Assets and Storage as Transmission-Only Assets (SATOAs), as recommended by the MC at its December 10, 2024 meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

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

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

3 CEO Report

January 9, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

Summary of ISO New England Board and Committee Meetings

January 9, 2025 Participants Committee Meeting

Since the last update, the Information Technology and Cyber Security Committee met virtually on December 12.

The Information Technology and Cyber Security Committee conducted its annual review of the IT-related portions of the Internal Audit Department's work plan. The Committee then reviewed the annual vendor report, which illustrated the year over year change in vendor spending and highlighted key vendors and risks associated. The Committee also received an update on the Company's three-year cyber security plan and discussed the status of major IT projects, which are currently on schedule and budget. The Committee considered its compliance with the Committee's charter, and reviewed its calendar for 2025. Finally, the Committee held an executive session to discuss the achievement of corporate goals for 2024, and the proposed corporate goals for 2025.

4 COO Report – Operations Report Highlights

January 9, 2025
Meeting

NEPOOL Participants Committee Report

January 2025

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights: December 2024

- **Peak Hour** on December 22
  - 19,030 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 P.M.
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $87.56/MWh
  - Real Time (RT) Hub LMP: $84.03/MWh
  - Natural Gas: $9.13/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $1B up from $415M in December 2023
  - Ancillary Markets* value $4.2M down from $12.4M in December 2023
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 97.3% during December, up from 96.0% during November
  - Updated November Energy Market value: $411M
- **Net Commitment Period Compensation (NCPC)** total $3.9M
  - Represents 0.4% of monthly Energy Market value
  - First Contingency $3.2M
    - Dispatch Lost Opportunity Cost (DLOC) - $520K; Rapid Response Pricing (RRP) Opportunity Cost - $401K; Posturing - $0; Generator Performance Auditing (GPA) - $213K
    - $41.9K paid to resources at external locations, down $462K from November
      - $9K charged to Day Ahead Load Obligation (DALO) at external locations, $33K to RT Deviations
  - Second Contingency $626K
  - Distribution $127K
- **Forward Capacity Market (FCM)** market value $119.7M
  - FCM peak for 2024 is currently 24,461 MWh
- **Inventoried Energy Program (IEP)**
  - Inventoried Energy Days (IED) were triggered on December 22 and 23, resulting in program spot settlement

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

*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

Highlights

- 2050 Transmission Study draft report on additional analysis to address stakeholder comments is expected to be issued in January
- 2024 Economic Study Benchmark Scenario has been completed and the Policy and Stakeholder-Requested Scenarios are being analyzed between now and Q2 2025

Forward Capacity Market (FCM) Highlights

- CCP 16 (2025-2026)
  - The third annual reconfiguration auction (ARA3) will be held March 3-5 and results will be posted by April 2
- CCP 17 (2026-2027)
  - The second annual reconfiguration auction (ARA2) will be held August 1-5 and results will be posted by September 3
- CCP 18 (2027-2028)
  - Auction results were filed with FERC on February 21, 2024 and, on June 18, 2024, FERC issued an order accepting the results effective June 20, 2024
  - ICR and related values for the ARAs to be conducted in 2025 were filed with FERC on November 22, 2024 with a requested effective date of January 21
  - The first annual reconfiguration auction (ARA1) will be held June 2-4 and results will be posted by July 3

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
    - On May 20, 2024 FERC issued an order accepting the additional delay to FCA 19
  - 2024 interim RA qualification process completed on November 1, 2024
    - A total of 1,389 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

Load Forecast

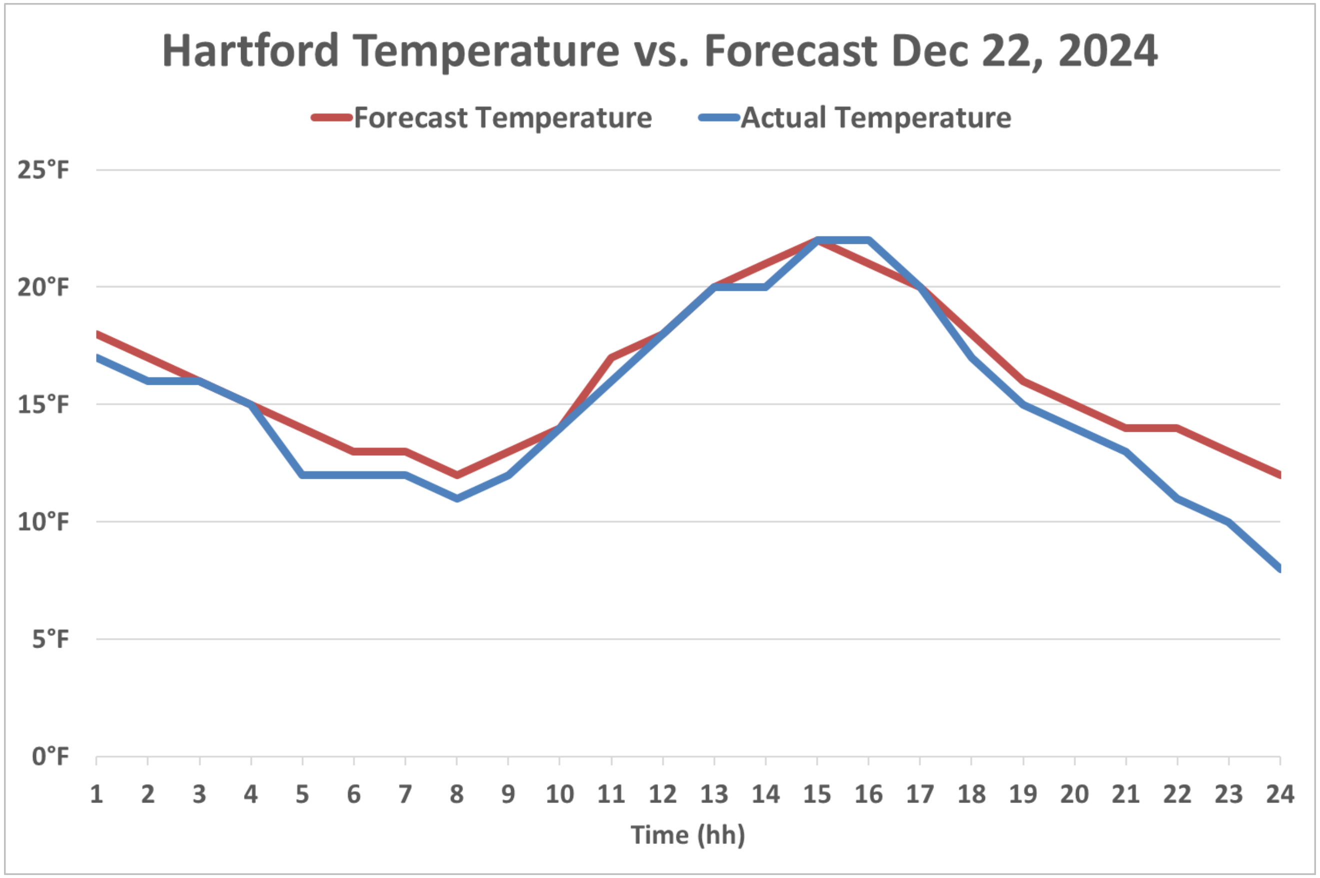
- A new hourly forecast methodology is being implemented as part of the 2024/25 load forecasting cycle, and is being discussed at the Load Forecast Committee (LFC)
- The next LFC meeting will be held on February 21

Inventoried Energy Program

Occurred on December 22nd and 23rd, 2024

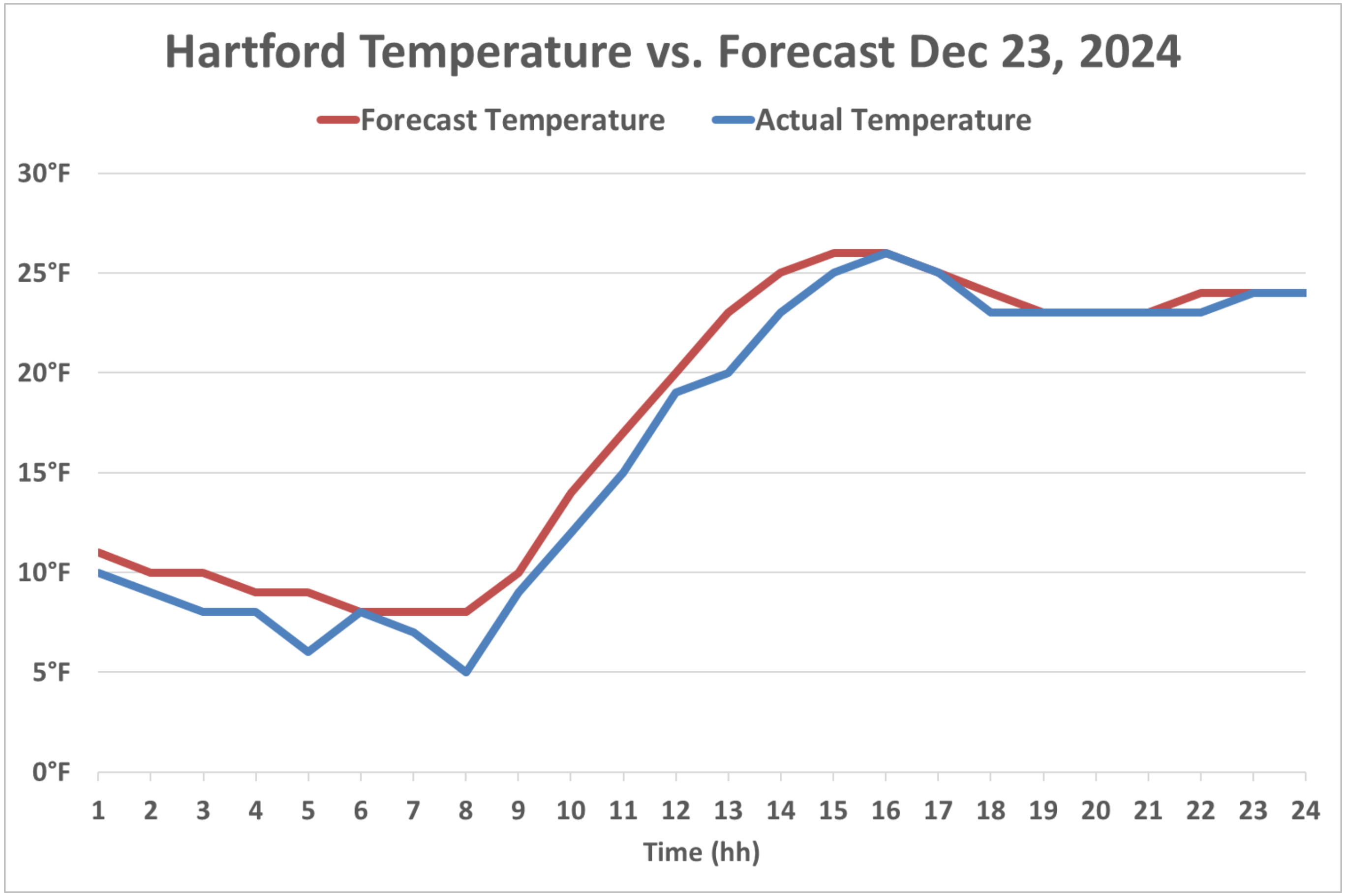
Forecast vs Actual Temperature – 12/22/2024

- The Day Ahead temperature forecast for Hartford (BDL) on the 22nd, was an average temperature of 16°F, with an actual average temperature of 15°F.



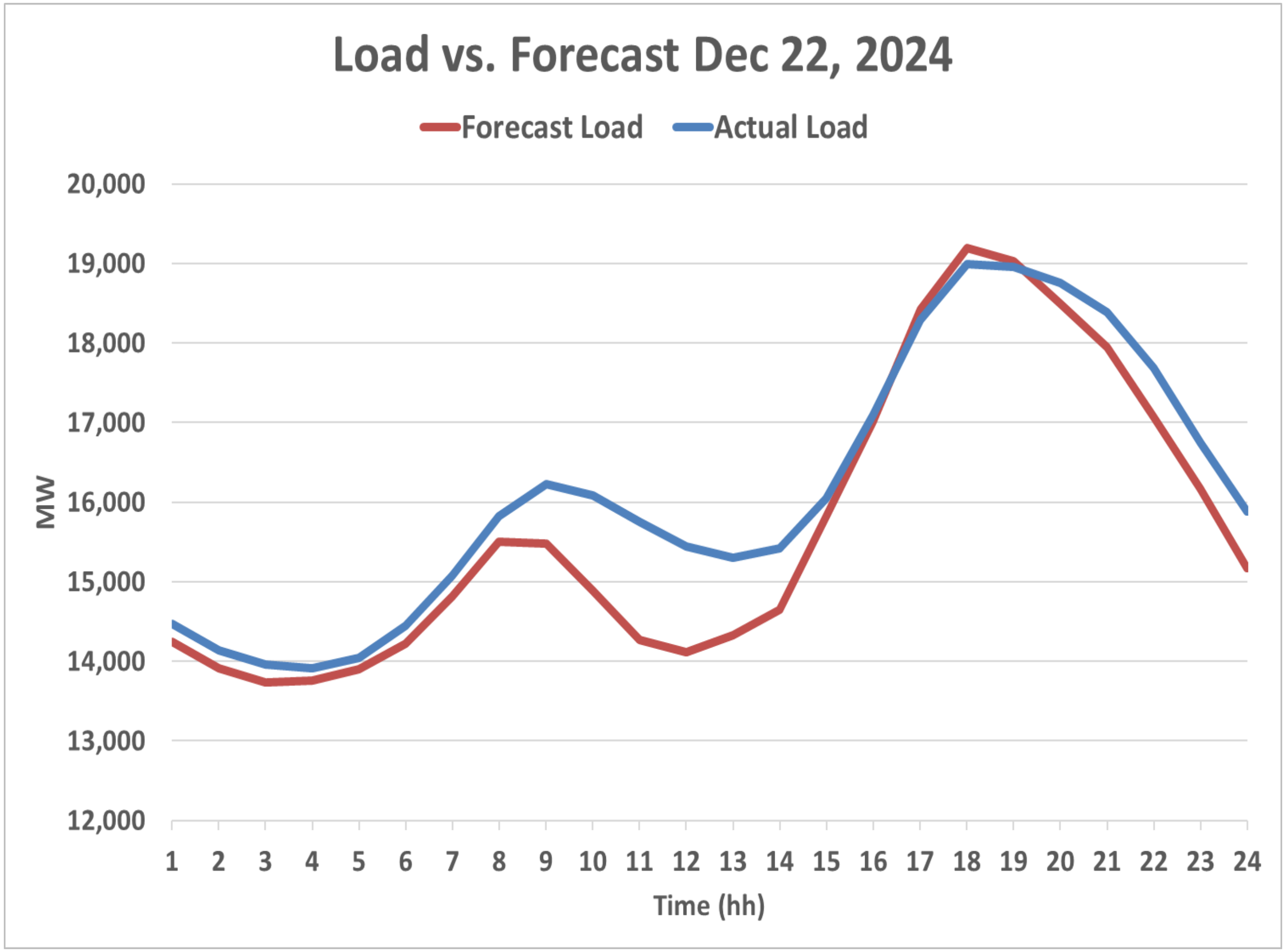
Forecast vs Actual Temperature – 12/23/2024

- The Day Ahead temperature forecast for Hartford (BDL) on the 23rd, was an average temperature of 18°F, with an actual average temperature of 16°F.



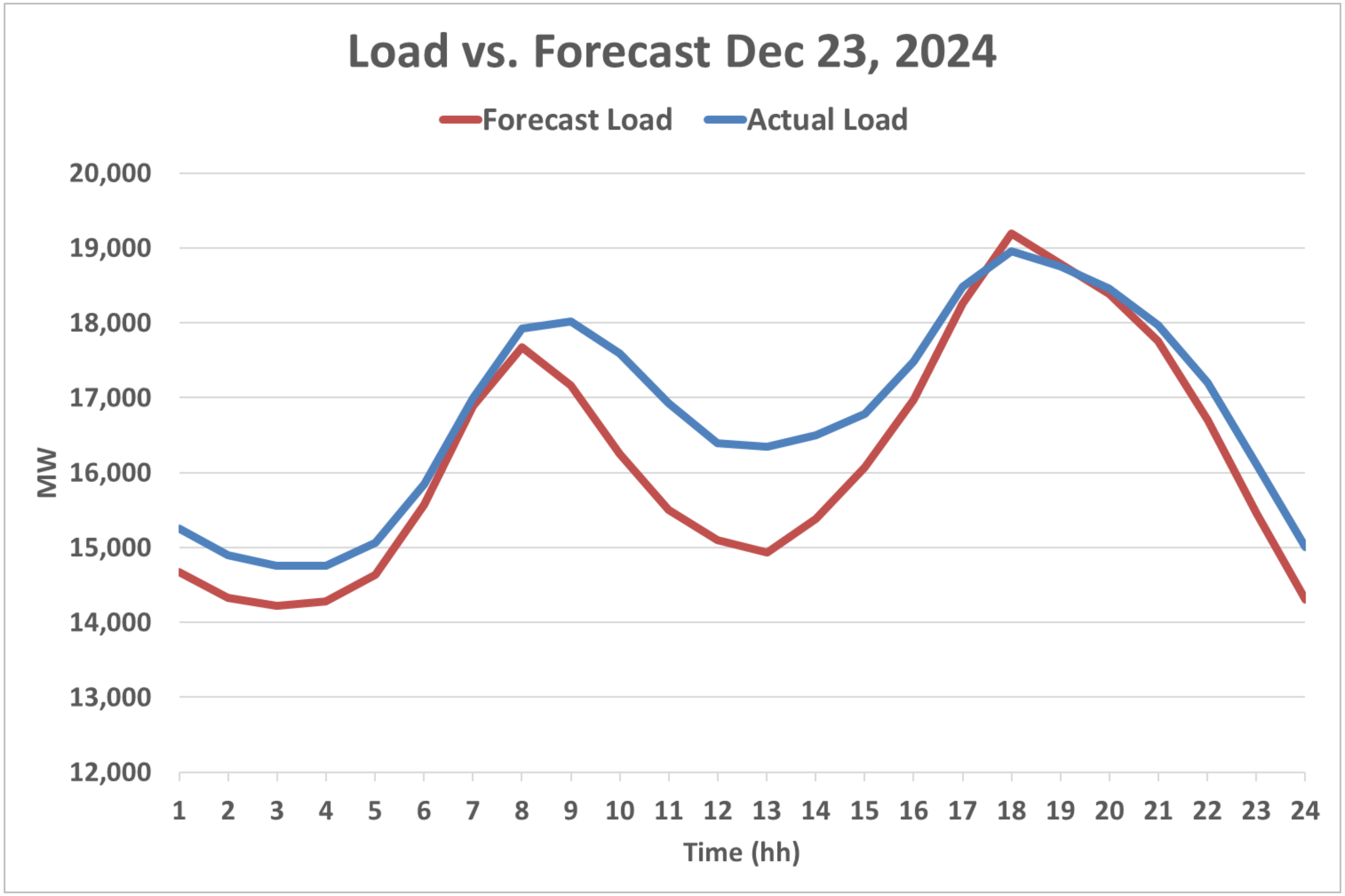
Forecast Load vs Actual Load – 12/22/2024

- The Peak load forecast error at HE 18 was 1.10%.



Forecast Load vs Actual Load – 12/23/2024

- The Peak Load forecast error at HE 18 was 1.30%.



Inventoried Energy Program Costs

- Inventoried Energy Day's (IED) were triggered from December 22nd through the 23rd due to cold weather[1]
- IEP Net Payments/Charges for December 22 and 23 combined: **$2.13M**
  - Forward Component Daily Base Payments: $1.75M
  - Spot Net Payments[2]: $383K
- Updated Projected Program Cost[3]: **$78.9M**

[1] **An IED is declared when the average of the high and low temperature is less than or equal to 17 degrees Fahrenheit as reported by the National Weather Service at Bradley International Airport**
[2] **Includes charges to underperforming inventory from forward component units, spot payments to spot-only component units, and spot payments to forward components units for inventory in excess of their forward election**
[3] **Reflects total projected Forward Base Payments plus any actual Spot settlement payments that have transpired during the period**

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (0.4°F) Max: 62°F, Min: 10°F Precipitation: 5.65" – Above Normal Normal: 4.30" Snow: 5.7"	Hartford	Temperature: Above Normal (1.2°F) Max: 64°F, Min: 5°F Precipitation: 4.22" - Above Normal Normal: 4.08" Snow: 4.8"

Peak Load:	18,991 MW	December 22, 2024	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
NONE			

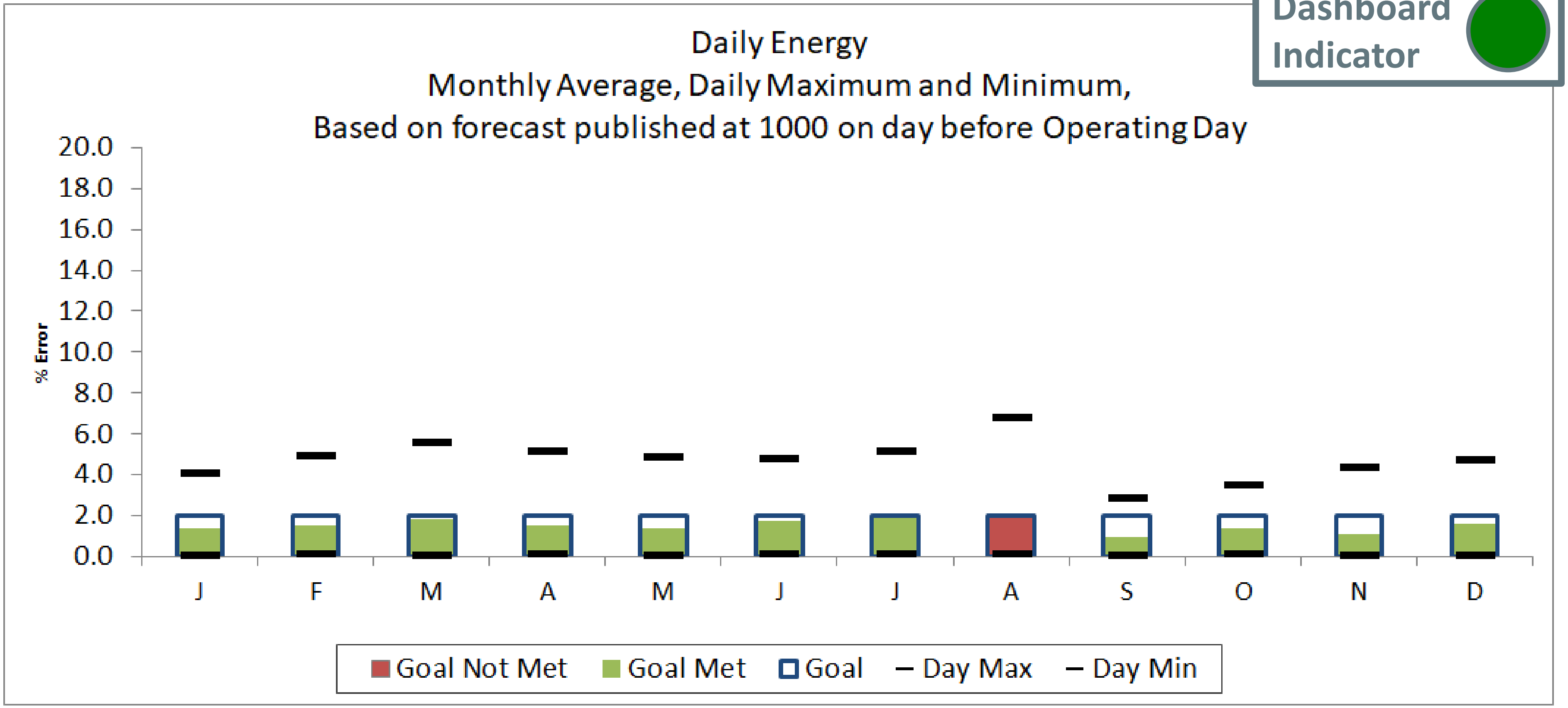
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
12/02/2024	NYISO	1050
12/03/2024	NYISO	550
12/13/2024	IESO	700
12/26/2024	NYISO	1050

2024 System Operations - Load Forecast Accuracy cont.

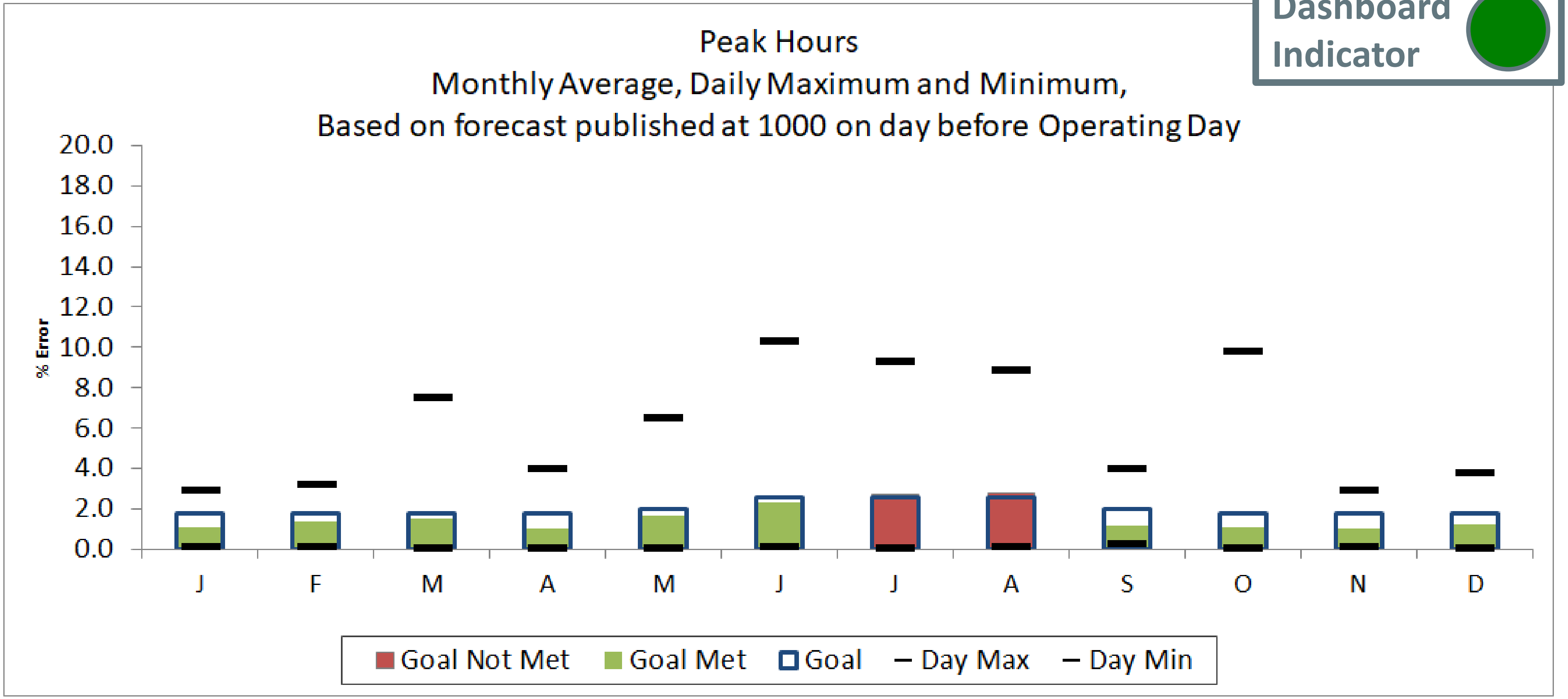
Dashboard Indicator



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	2.82	3.46	4.32	4.72	6.75
Day Min	0.00	0.12	0.02	0.09	0.07	0.11	0.10	0.12	0.03	0.08	0.02	0.00	0.00
MAPE	1.38	1.54	1.83	1.52	1.40	1.79	1.94	2.06	0.94	1.37	1.08	1.61	1.54
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	

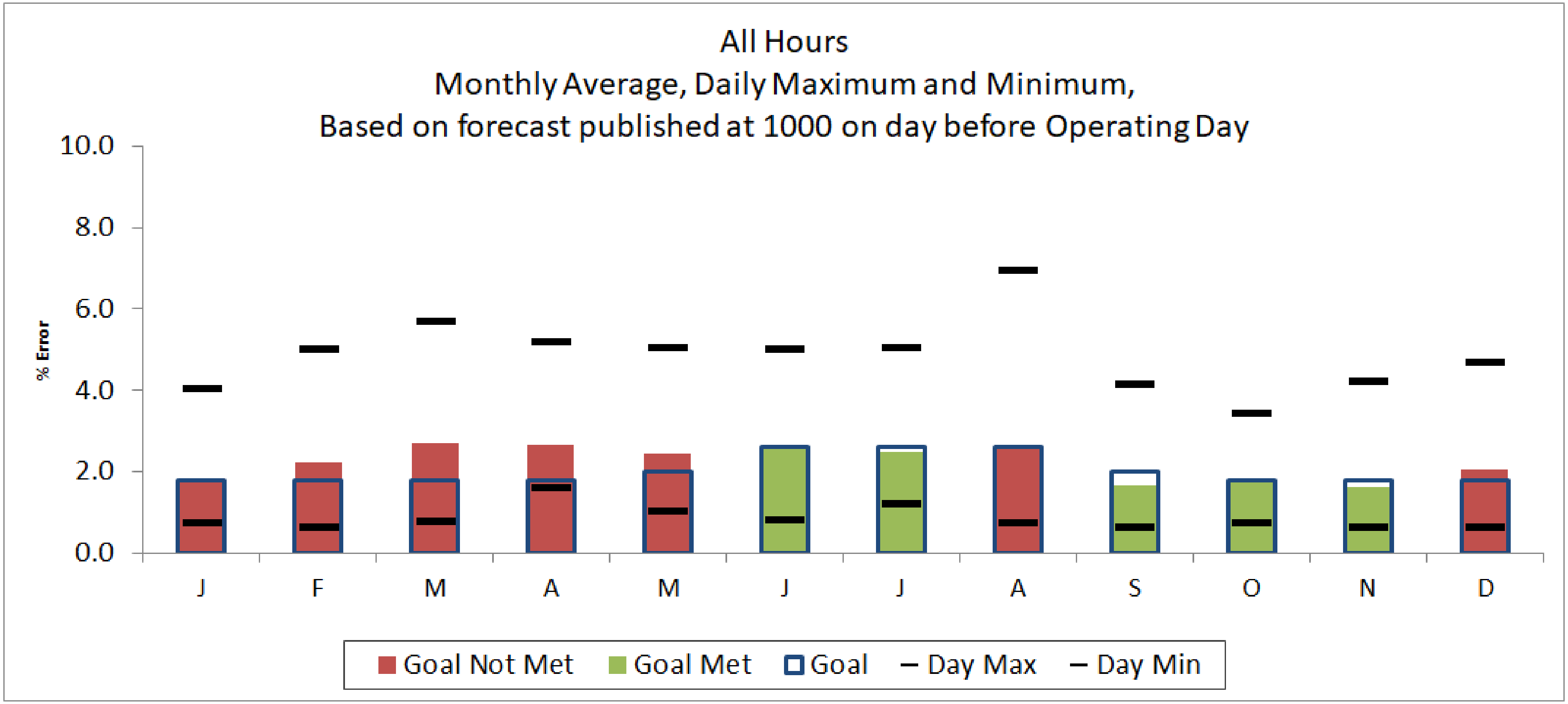
2024 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



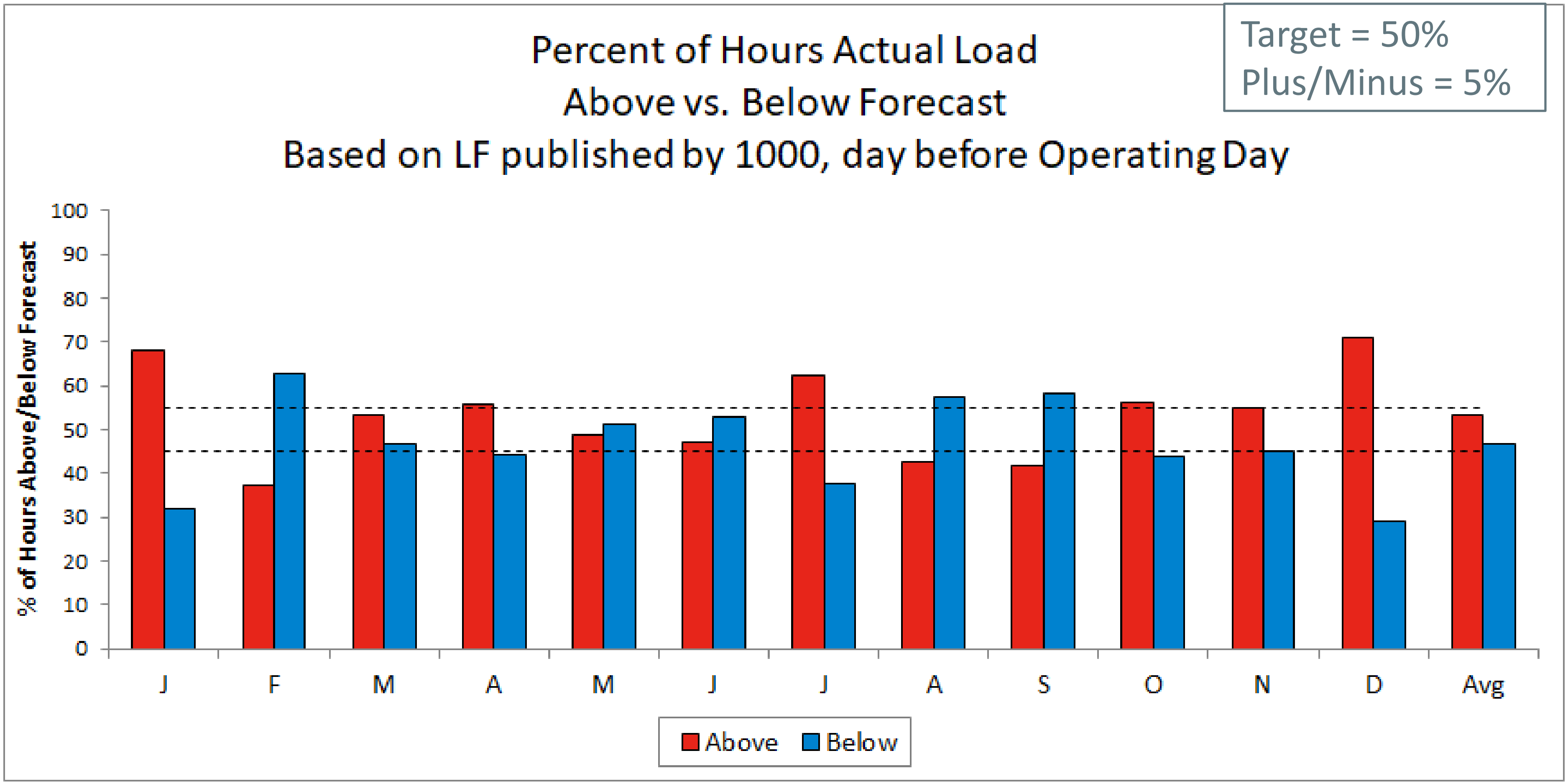
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	2.90	3.17	7.45	3.99	6.46	10.30	9.30	8.86	3.96	9.78	2.91	3.78	10.30
Day Min	0.08	0.10	0.02	0.03	0.01	0.14	0.00	0.08	0.28	0.01	0.11	0.00	0.00
MAPE	1.10	1.39	1.54	1.02	1.66	2.32	2.70	2.76	1.16	1.08	1.02	1.28	1.59
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

2024 System Operations - Load Forecast Accuracy



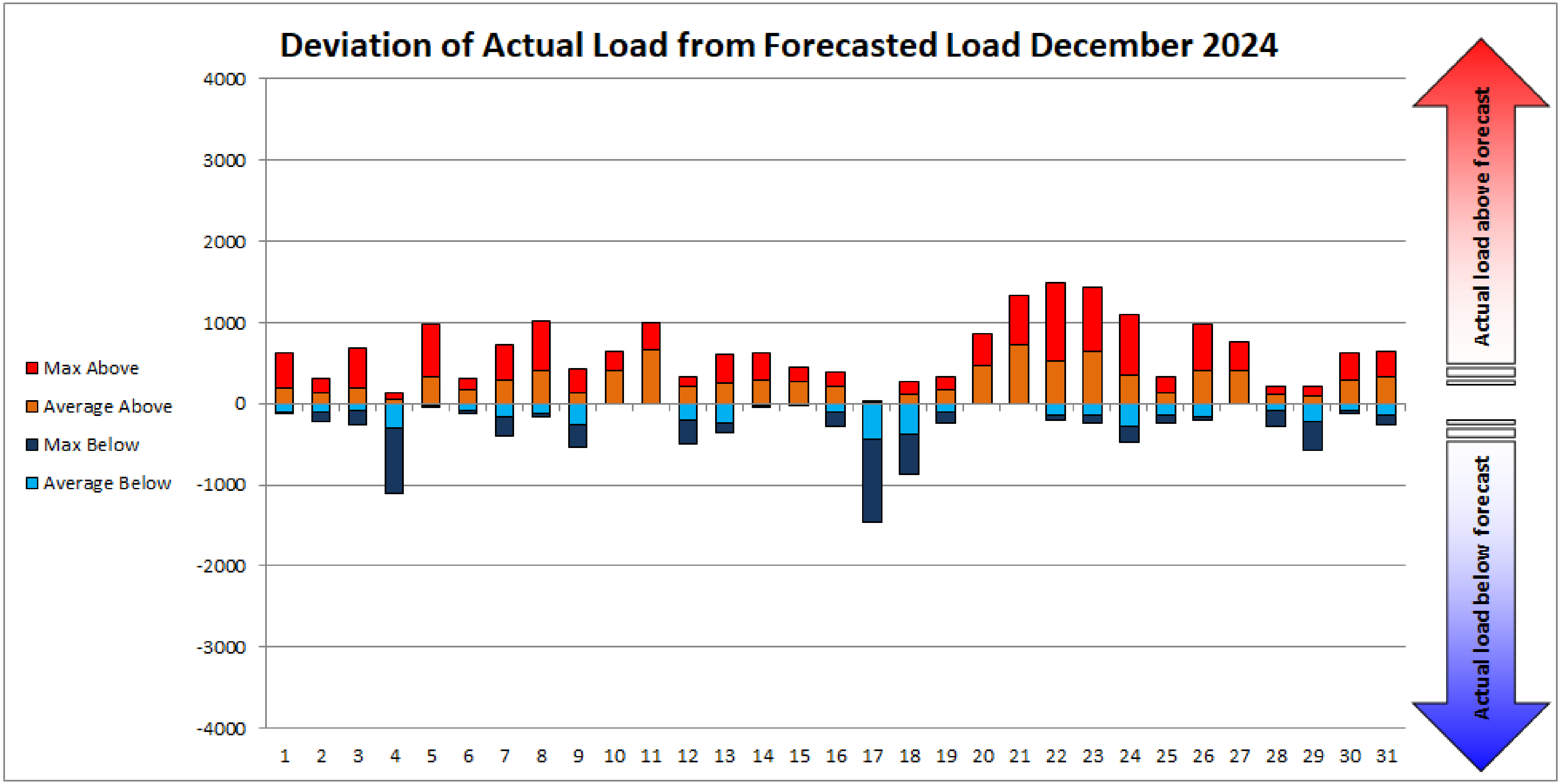
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.03	5.00	5.67	5.18	5.04	4.99	5.02	6.94	4.15	3.41	4.20	4.69	6.94
Day Min	0.73	0.64	0.76	1.59	1.00	0.81	1.20	0.74	0.62	0.73	0.62	0.64	0.62
MAPE	1.83	2.24	2.72	2.66	2.46	2.57	2.49	2.68	1.65	1.74	1.63	2.05	2.23
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

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	53.4	55.8	48.7	47.2	62.4	42.5	41.9	56.2	55	70.8	53
Below %	32.1	62.6	46.6	44.2	51.3	52.8	37.6	57.5	58.1	43.8	45	29.2	47
Avg Above	260.5	155.2	255.1	254.9	245.5	267.4	320.4	267.8	150.6	196.7	175.2	288.7	320
Avg Below	-155.5	-292.3	-253.5	-239.2	-223.2	-265.6	-270.5	-298.2	-181.5	-97.0	-139.5	-134.4	-298
Avg All	132	-130	39	38	11	-16	82	-58	-29	76	29	178	30

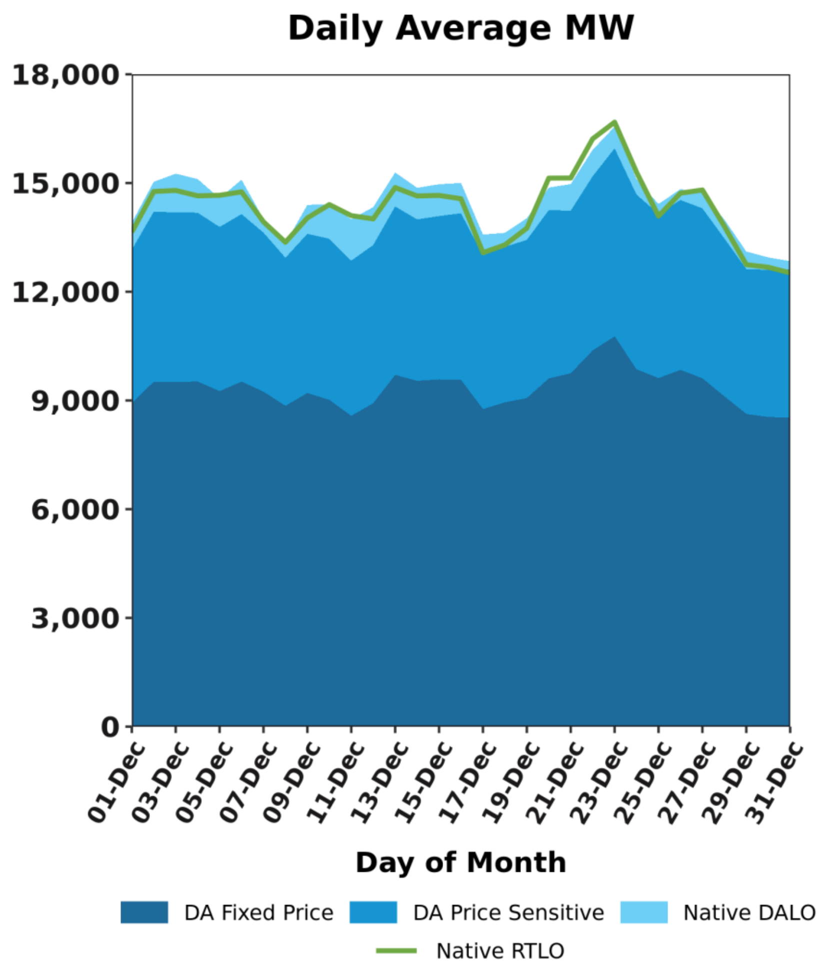
2024 System Operations - Load Forecast Accuracy cont.

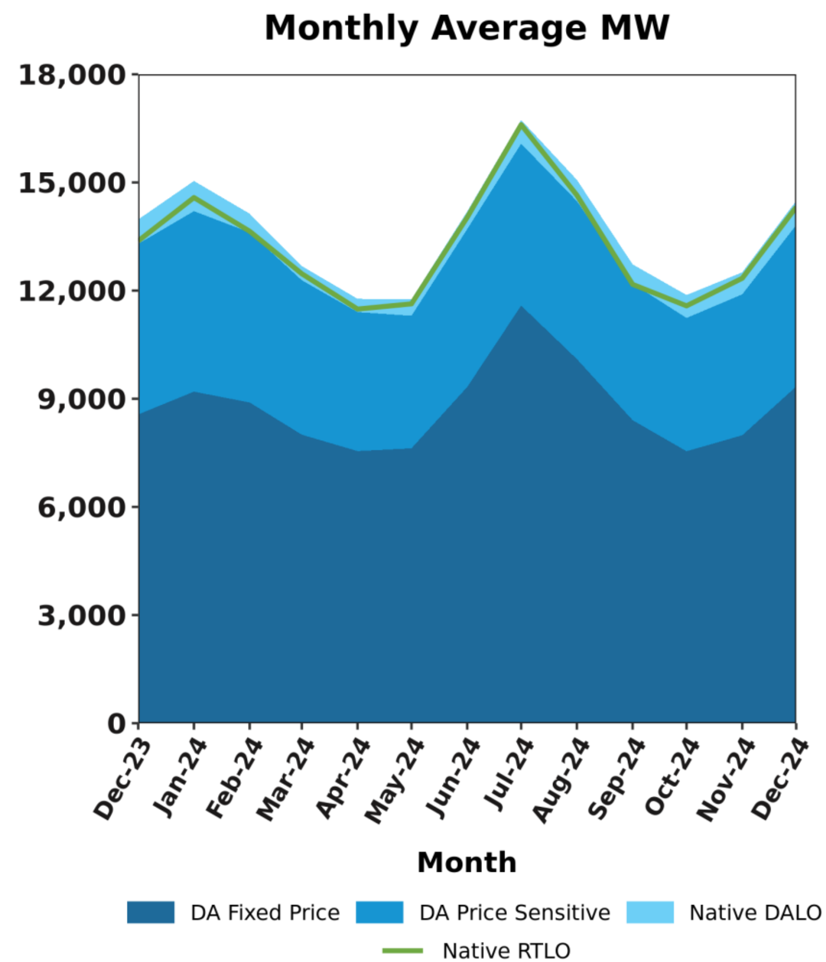


MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

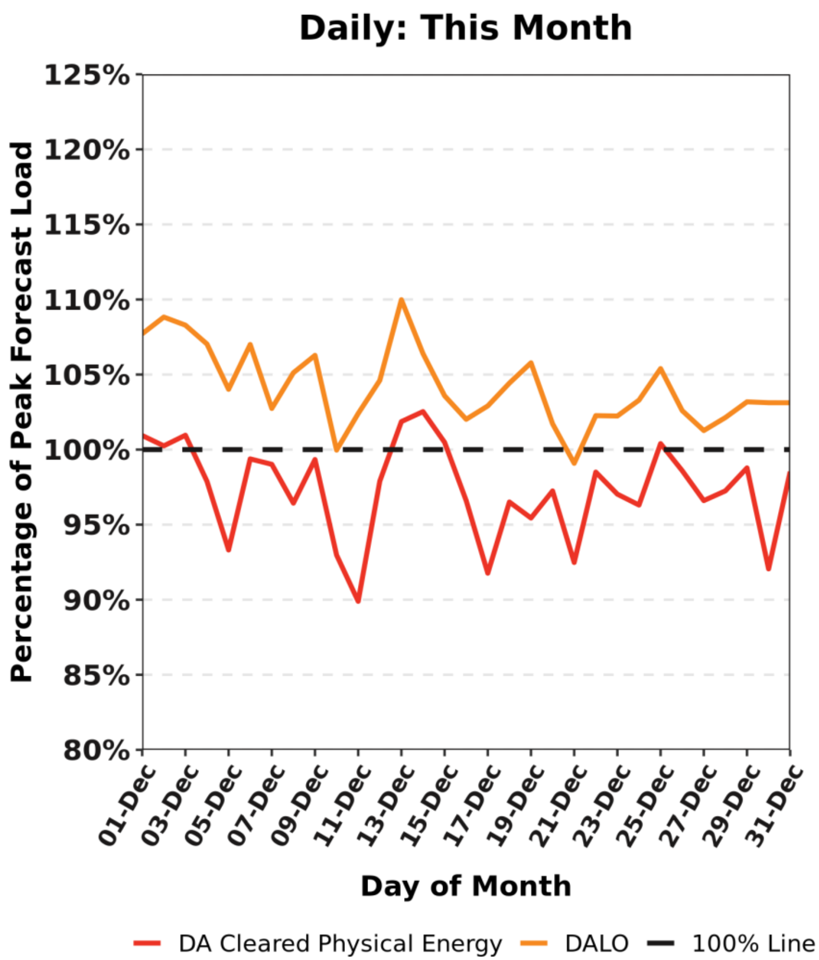
DA Cleared Native Load by Composition Compared to Native RT Load

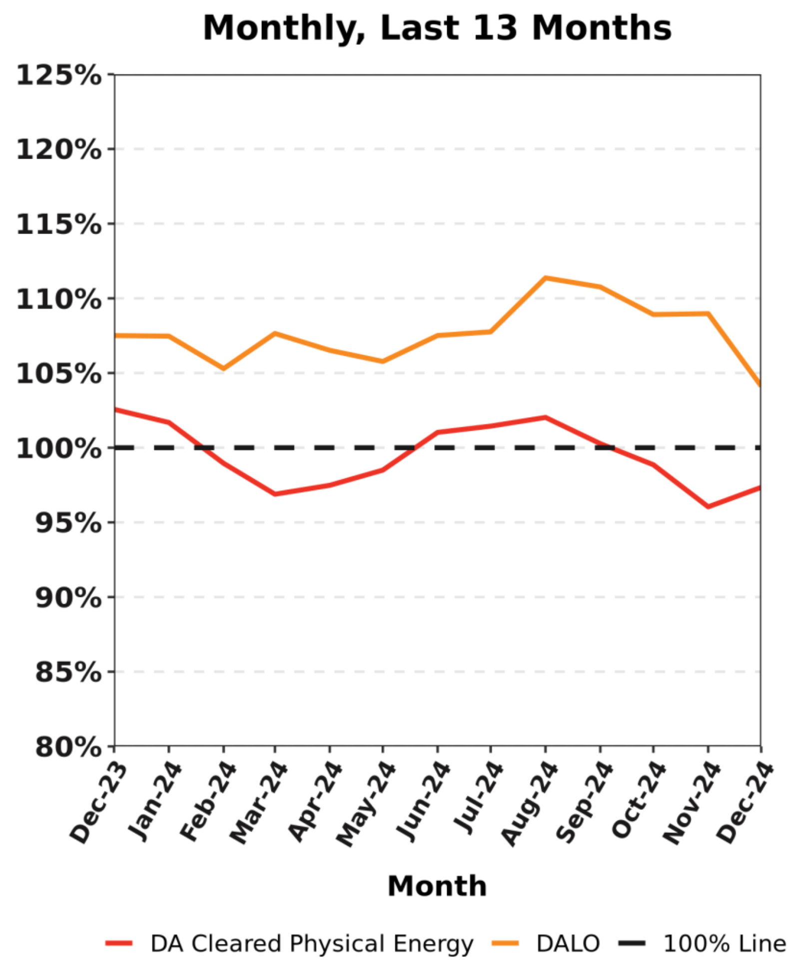




Native Day-Ahead Load Obligation (DALO) is the sum of all day-ahead cleared load, excluding modeled transmission losses and exports
Native Real-Time Load Obligation (RTLO) is the sum of all real-time load, excluding exports

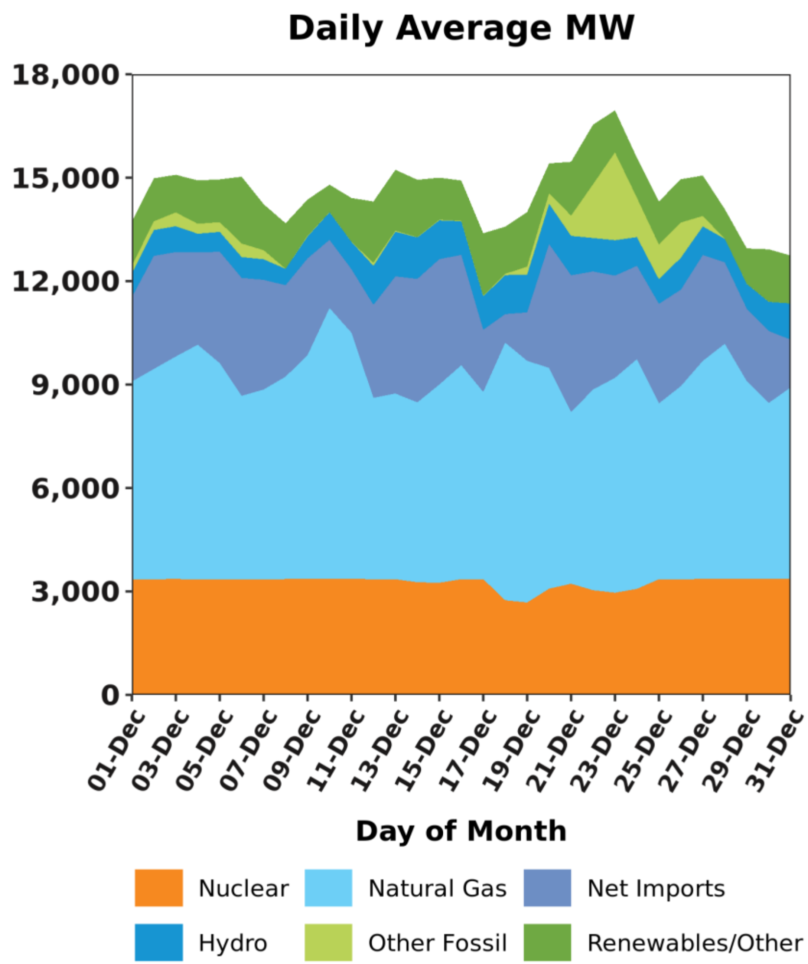
DA Volumes as % of Forecast in Peak Hour

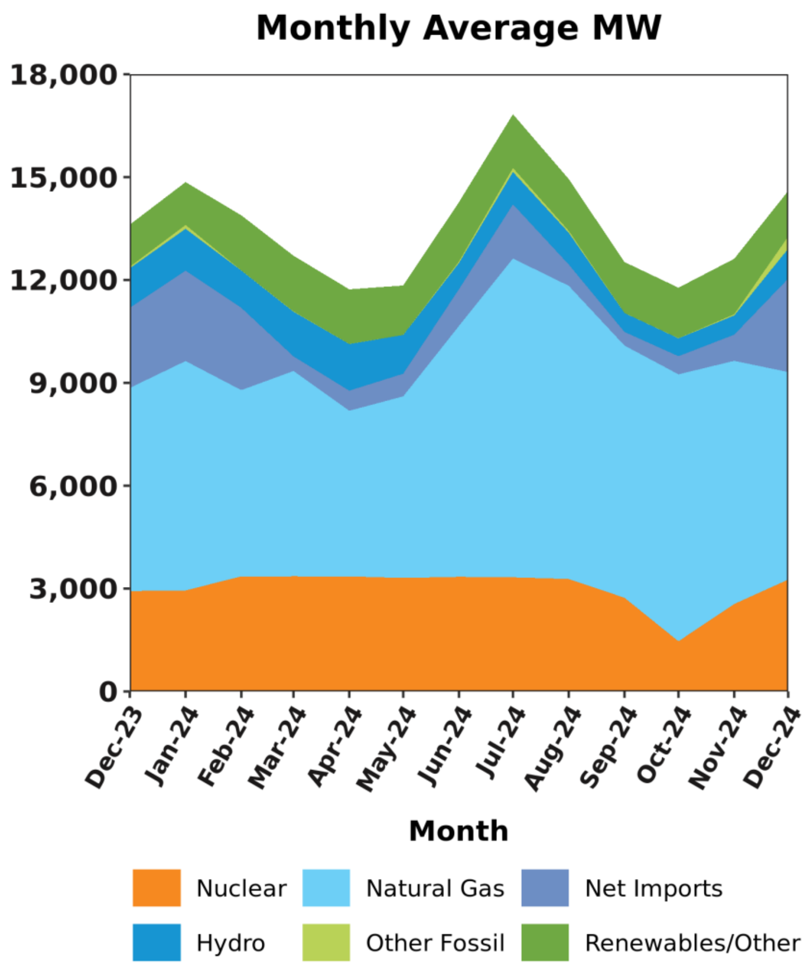




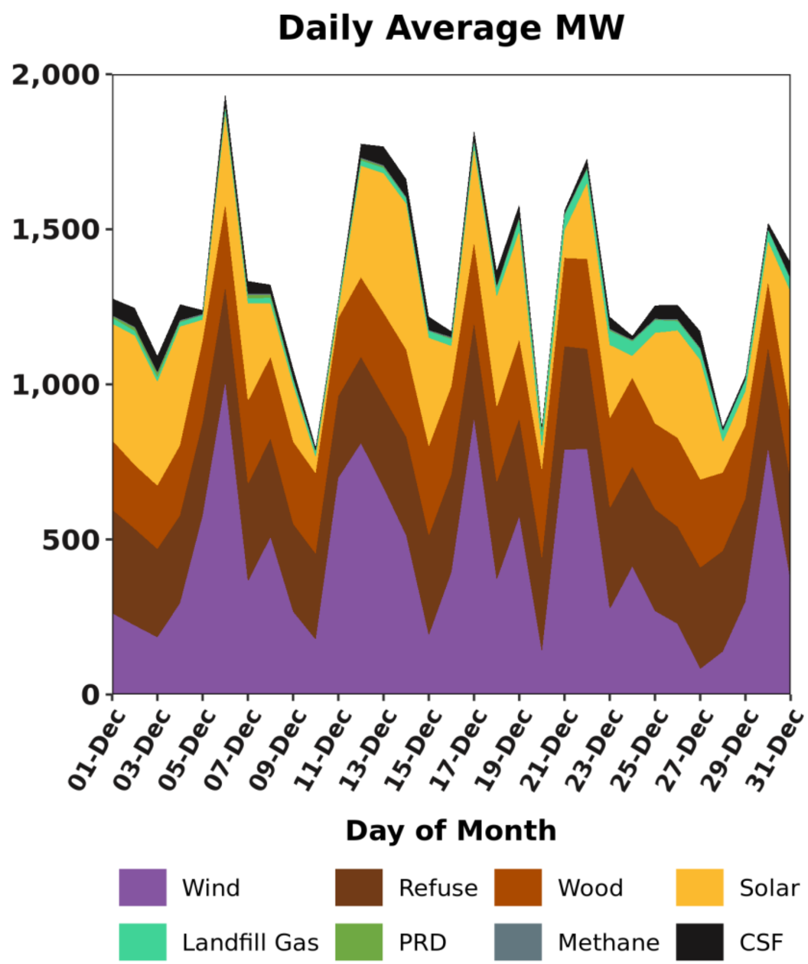
The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

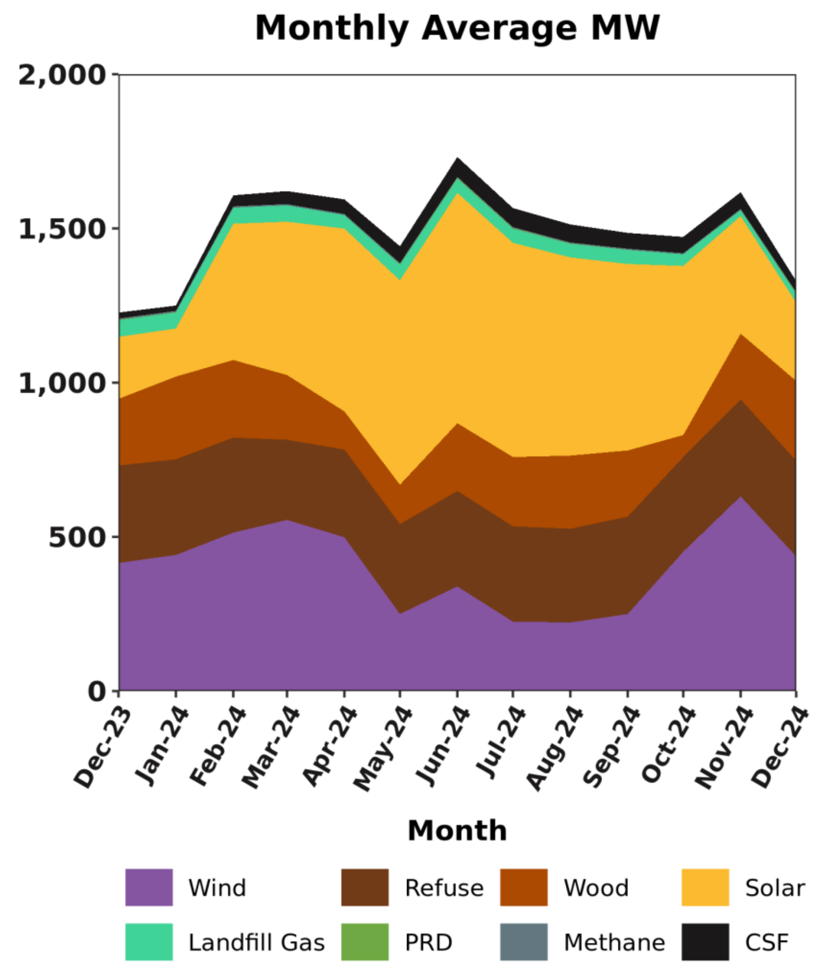
Resource Mix





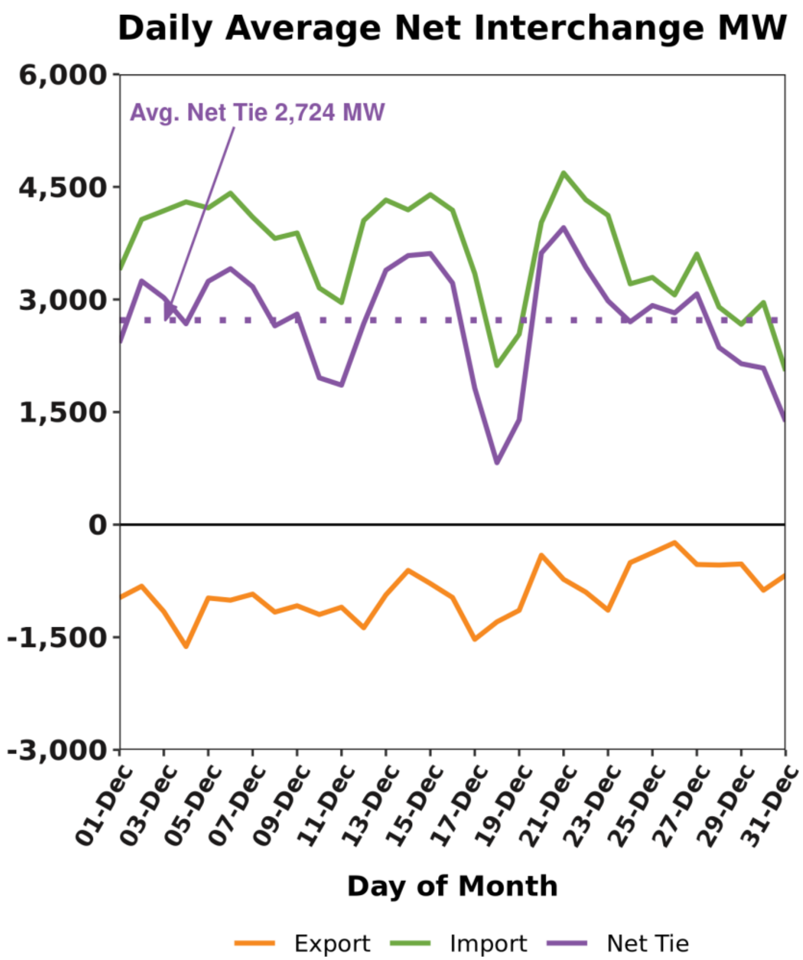
Renewable Generation by Fuel Type

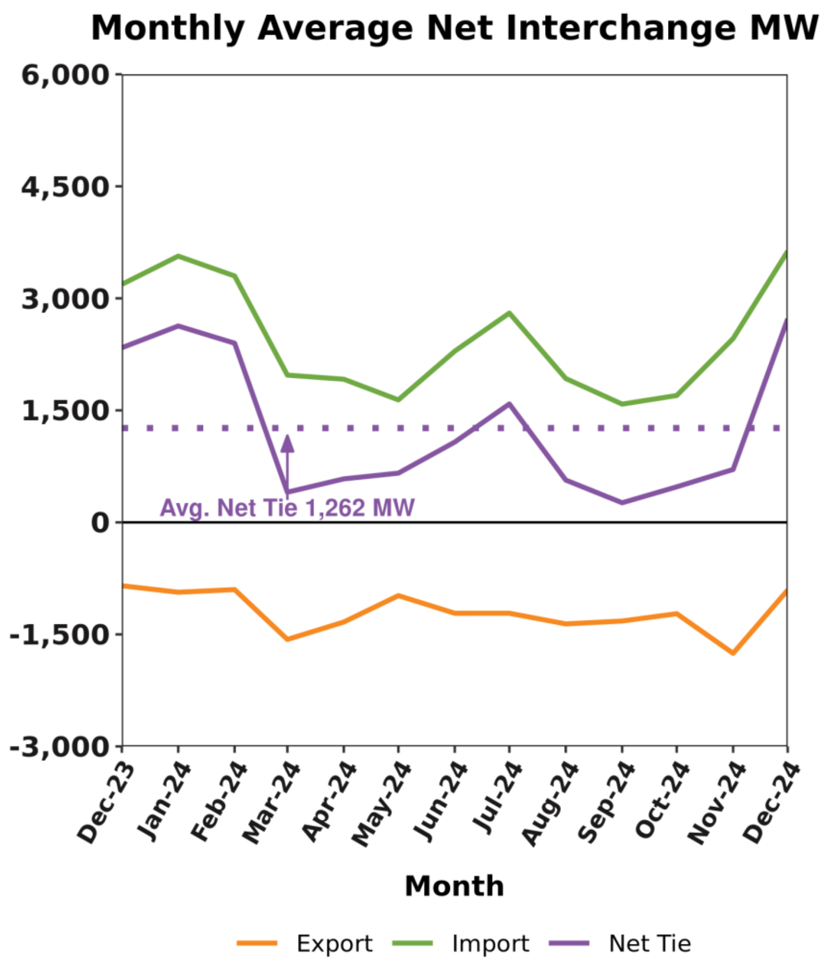




CSF = Continuous Storage Facilities (a.k.a. Batteries)

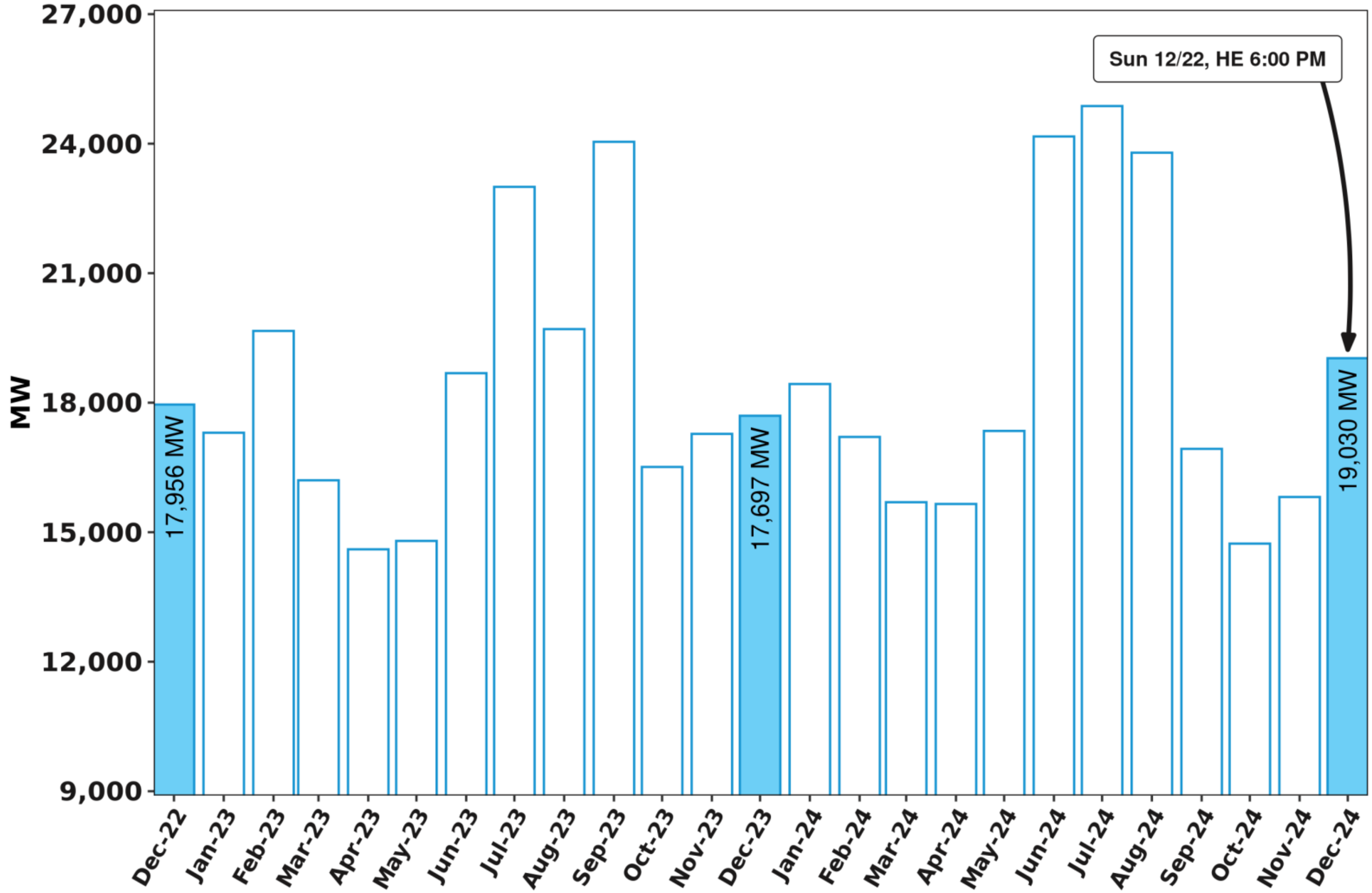
RT Net Interchange





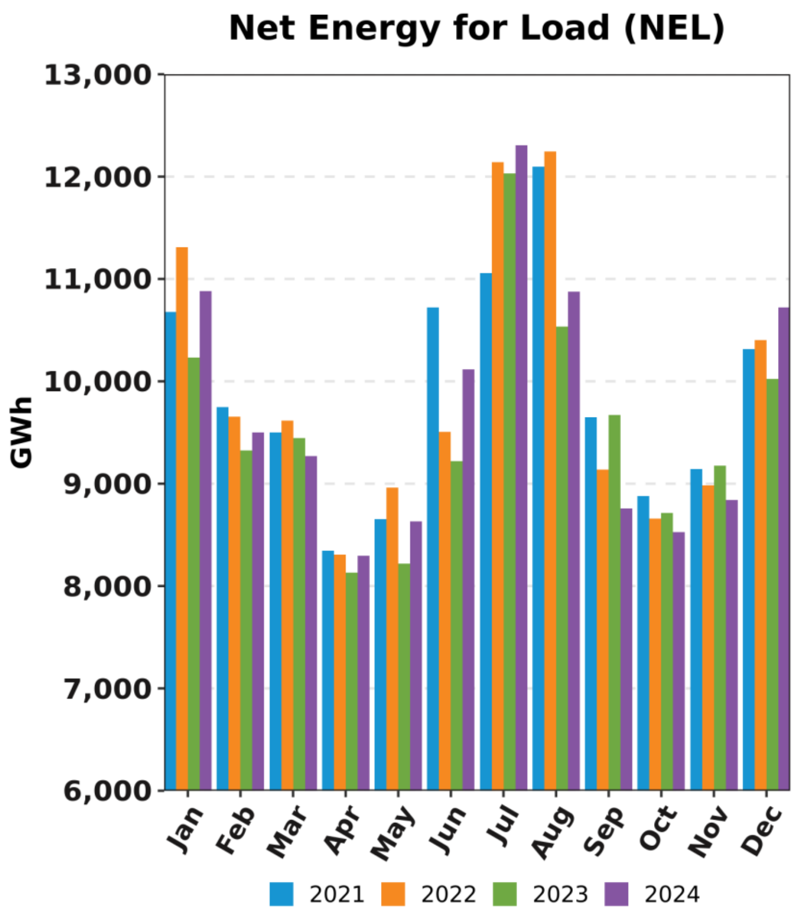
Net Interchange is the participant sum of daily imports minus the sum of daily exports; positive values are net imports

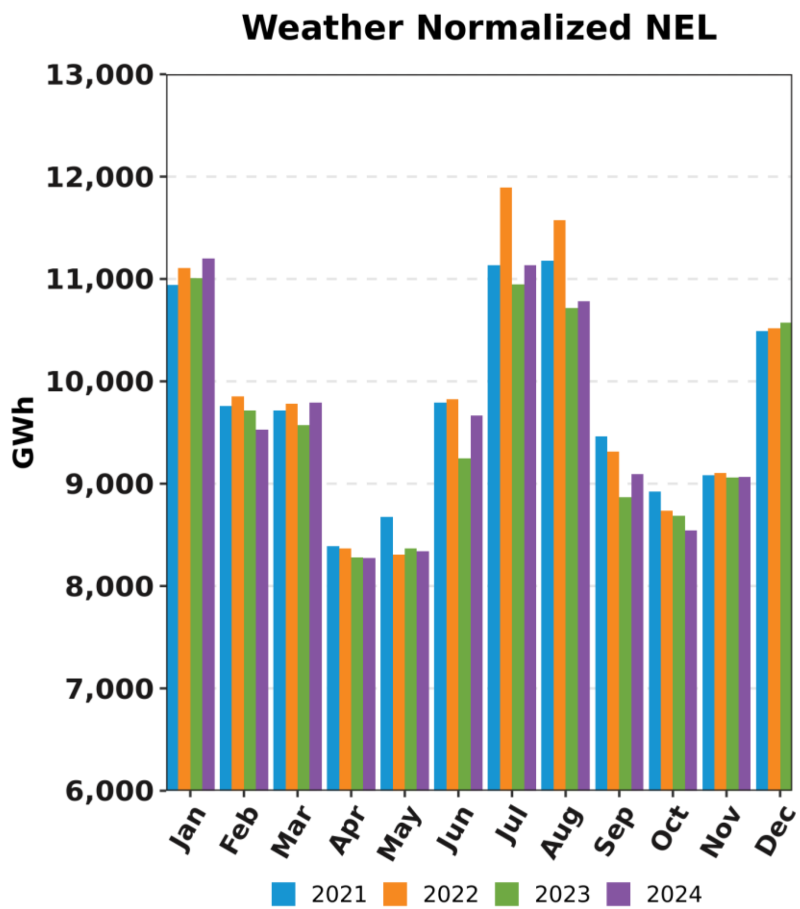
RQM System Peak Load MW by Month



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

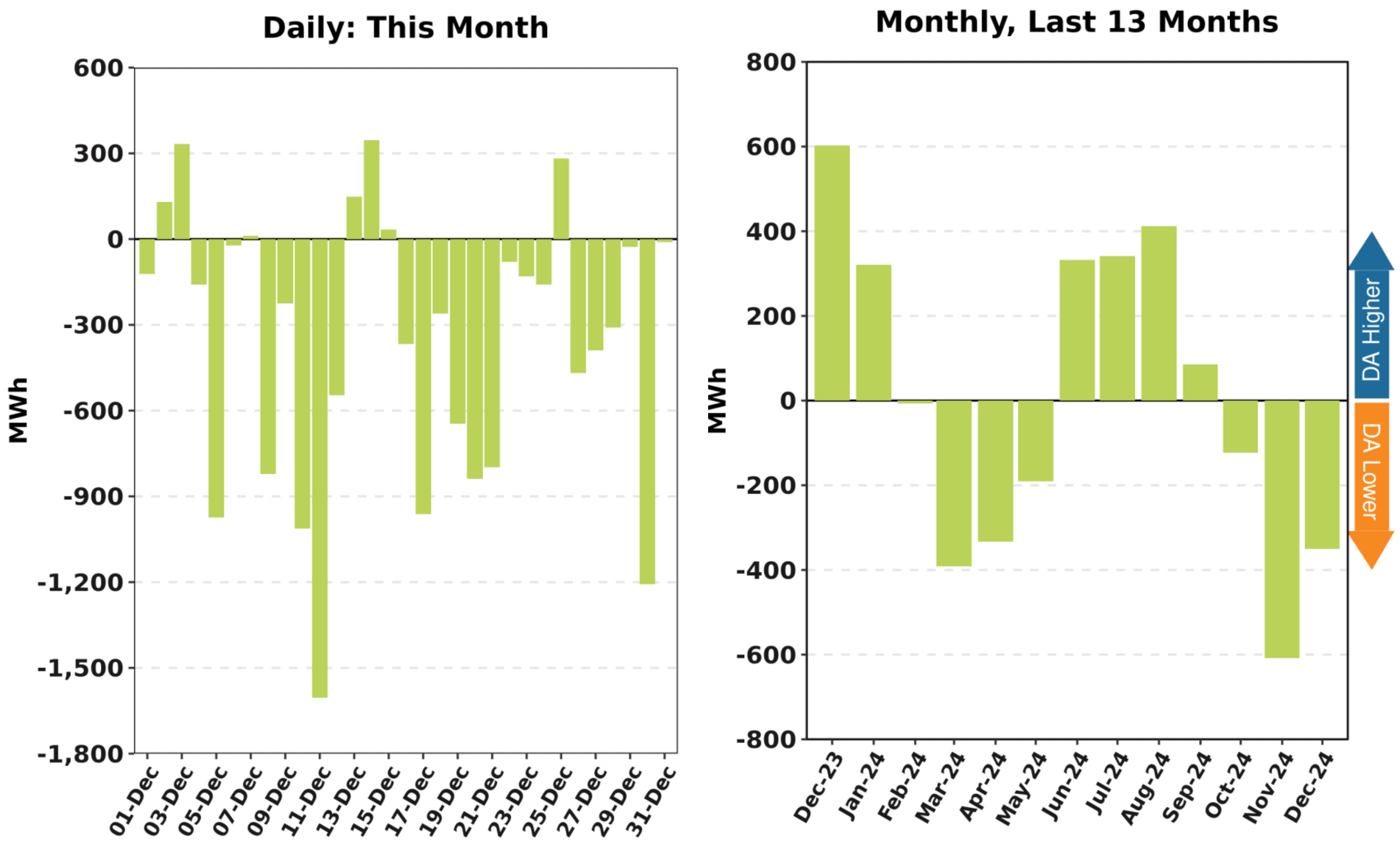
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL





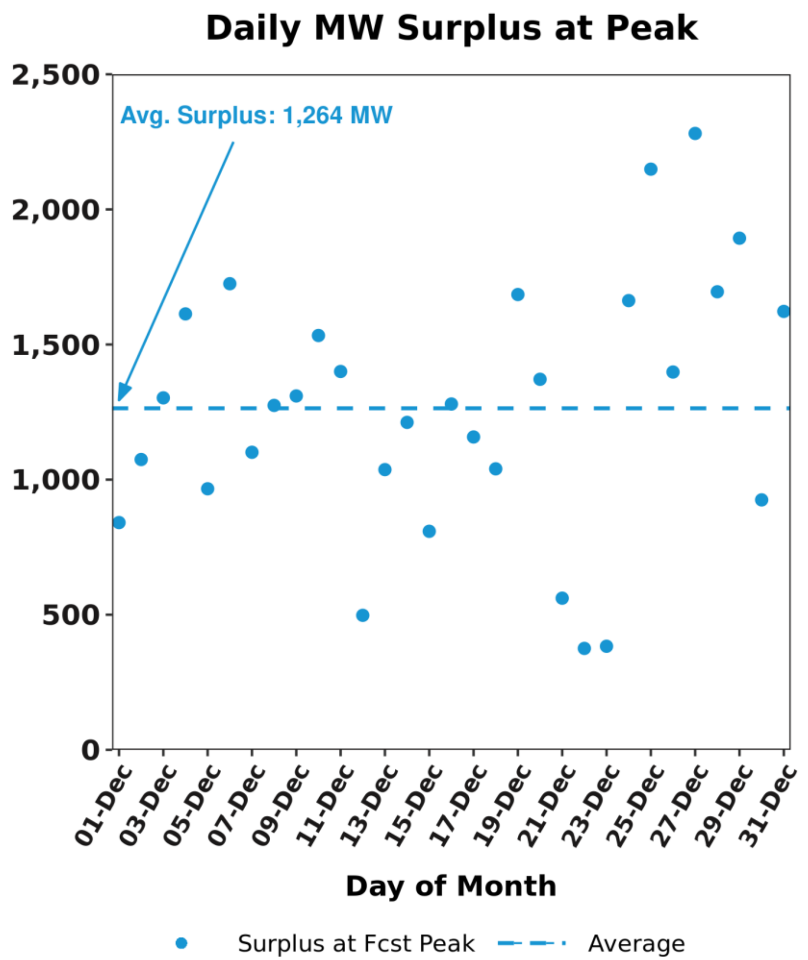
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

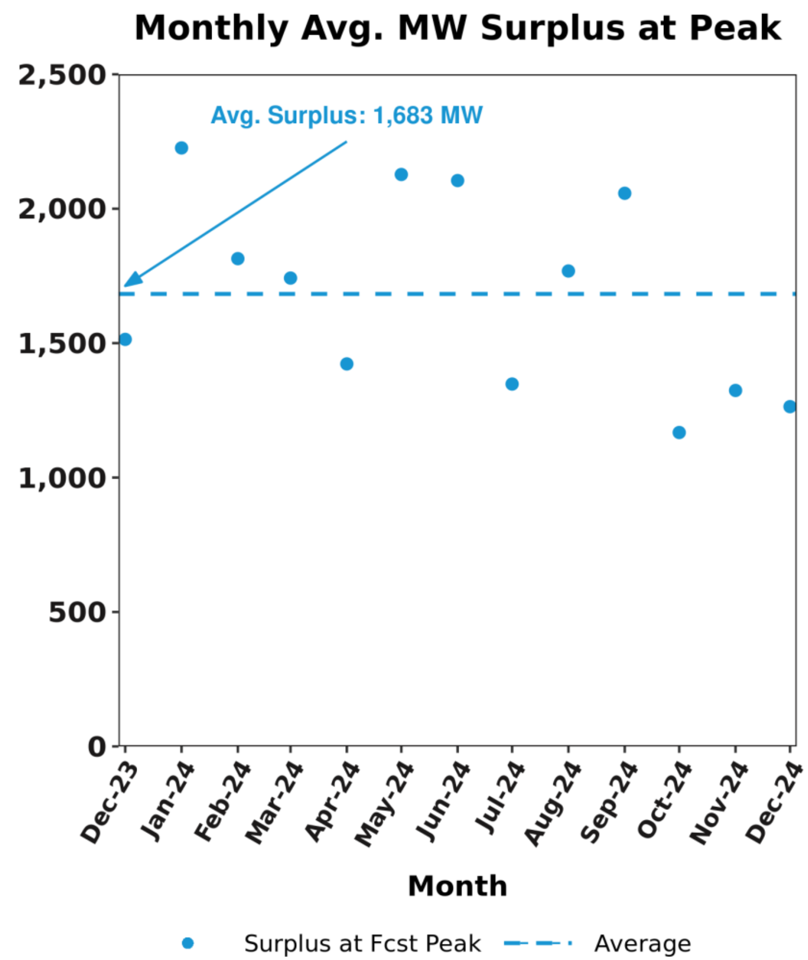
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour



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

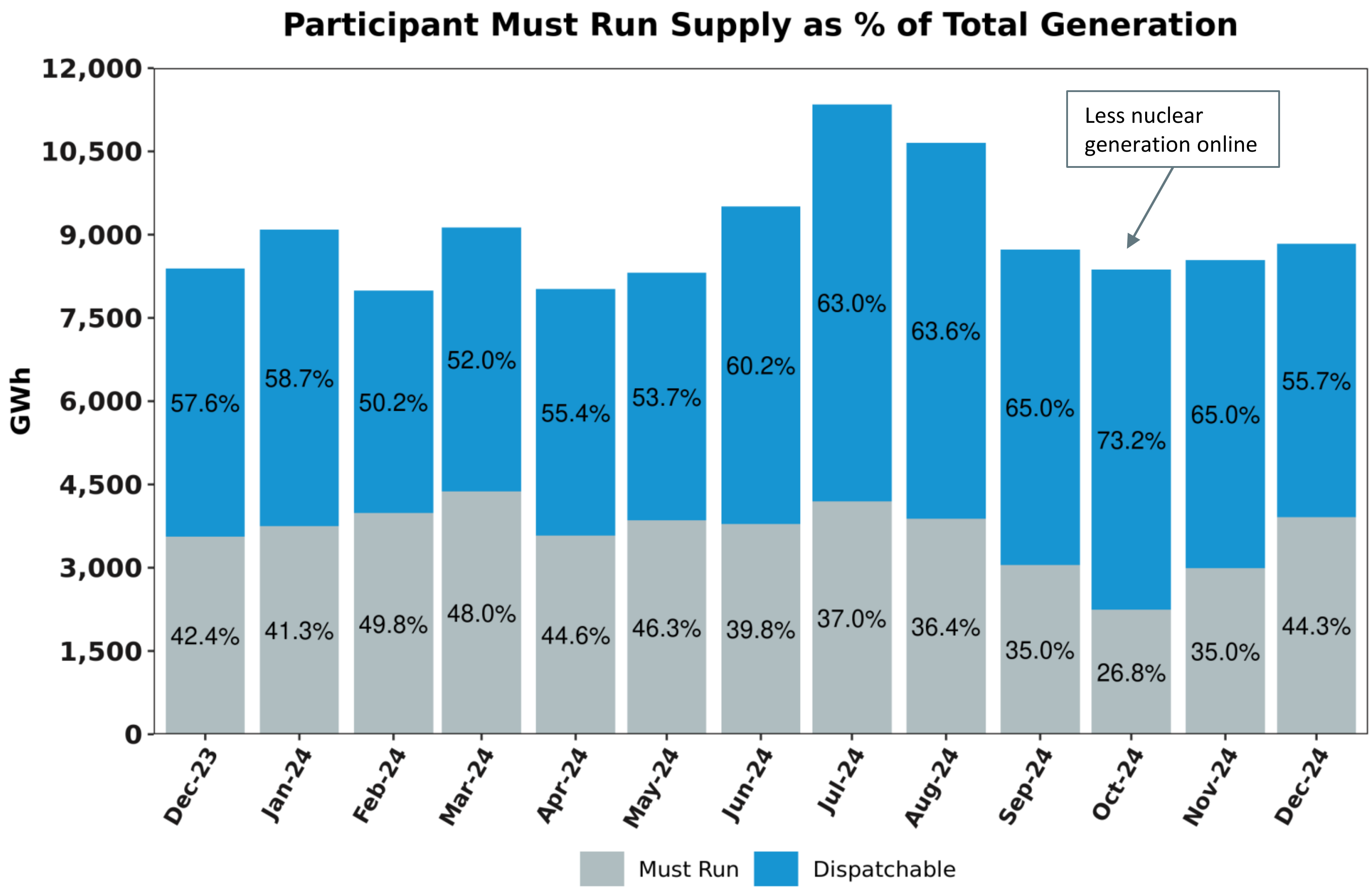
Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





*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

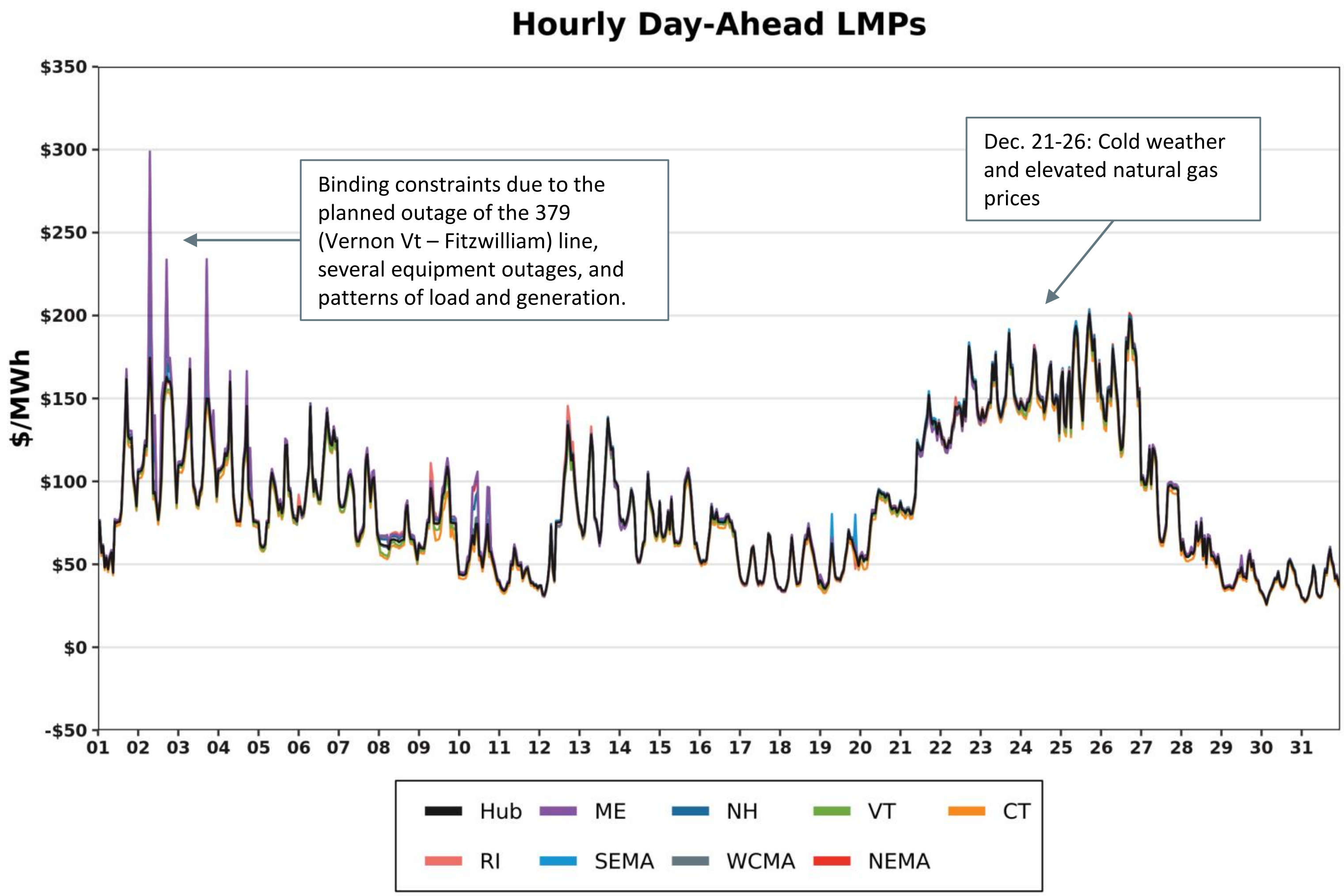
DA vs. RT LMPs ($/MWh)

Arithmetic Average

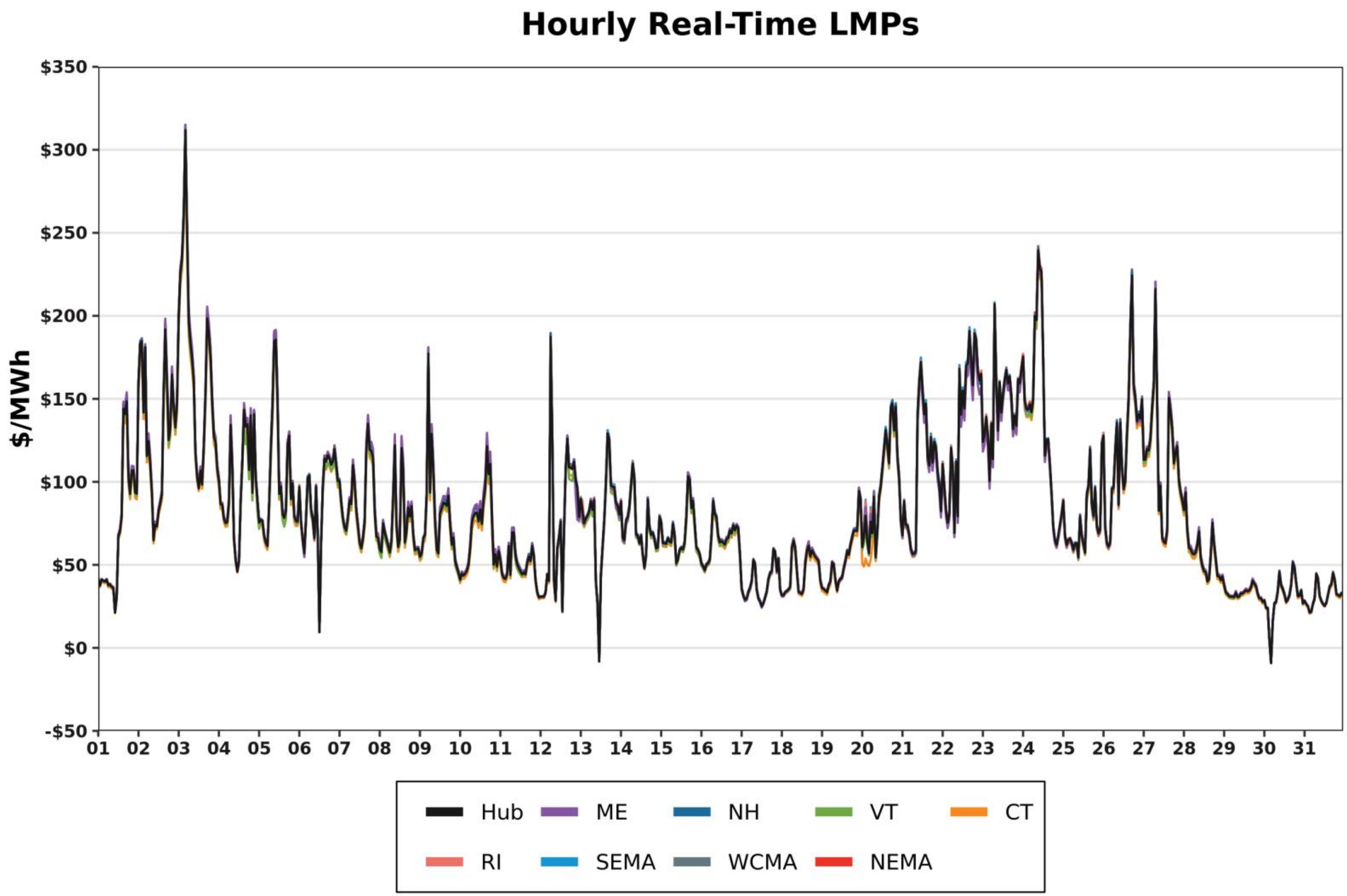
Year 2022	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$85.59	$84.20	$85.77	$84.48	$84.07	$85.39	$86.05	$85.69	$86.12
Real-Time	$84.89	$83.06	$85.05	$83.64	$83.80	$84.69	$85.35	$84.97	$85.40
RT Delta %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	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%

December-23	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$38.14	$37.59	$38.23	$37.73	$37.07	$38.27	$38.44	$38.17	$38.37
Real-Time	$37.15	$36.65	$37.28	$36.80	$36.18	$37.13	$37.38	$37.17	$37.37
RT Delta %	-2.60%	-2.50%	-2.48%	-2.46%	-2.40%	-2.98%	-2.76%	-2.62%	-2.61%
December-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$87.56	$89.33	$89.11	$86.07	$84.10	$87.60	$88.58	$87.58	$89.75
Real-Time	$84.03	$84.30	$85.01	$82.46	$81.13	$84.10	$84.83	$83.91	$85.29
RT Delta %	-4.03%	-5.63%	-4.60%	-4.19%	-3.53%	-4.00%	-4.23%	-4.19%	-4.97%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	129.58%	137.64%	133.09%	128.12%	126.87%	128.90%	130.44%	129.45%	133.91%
Yr over Yr RT	126.19%	130.01%	128.03%	124.08%	124.24%	126.50%	126.94%	125.75%	128.23%

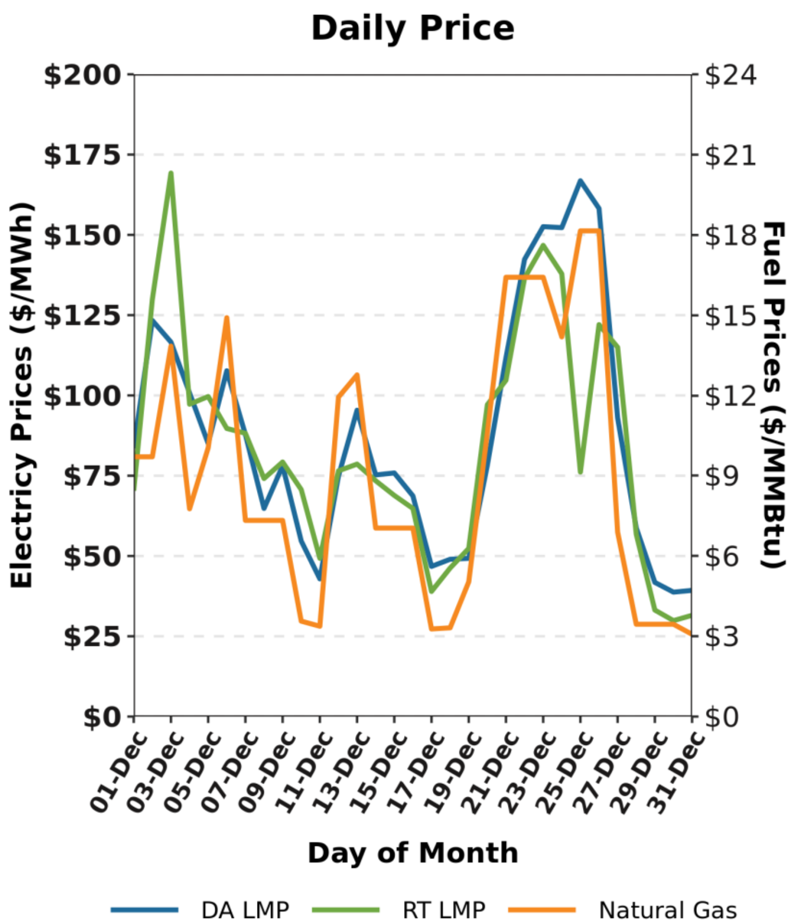
Hourly DA LMPs, December 1-31, 2024

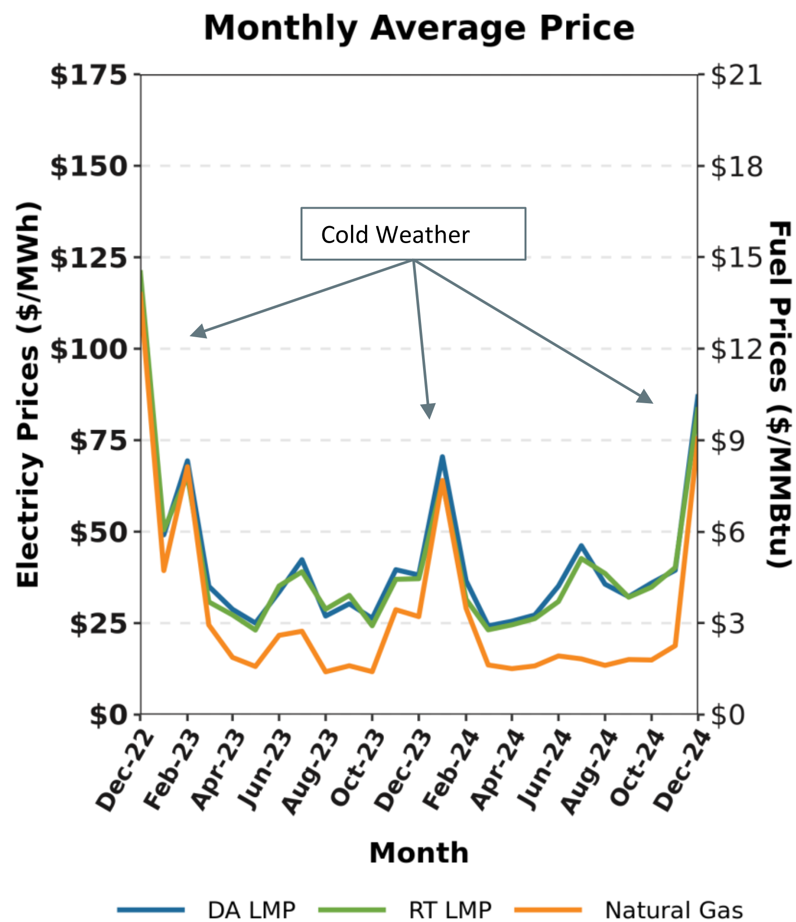


Hourly RT LMPs, December 1-31, 2024



Wholesale Electricity vs Natural Gas Prices by Month

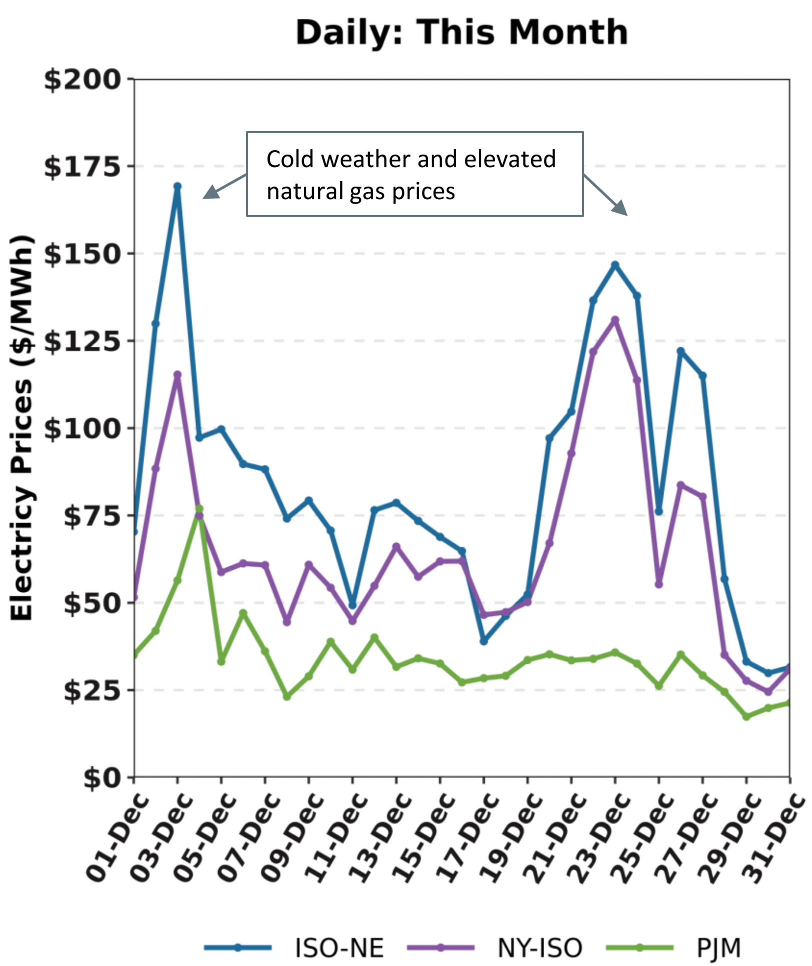


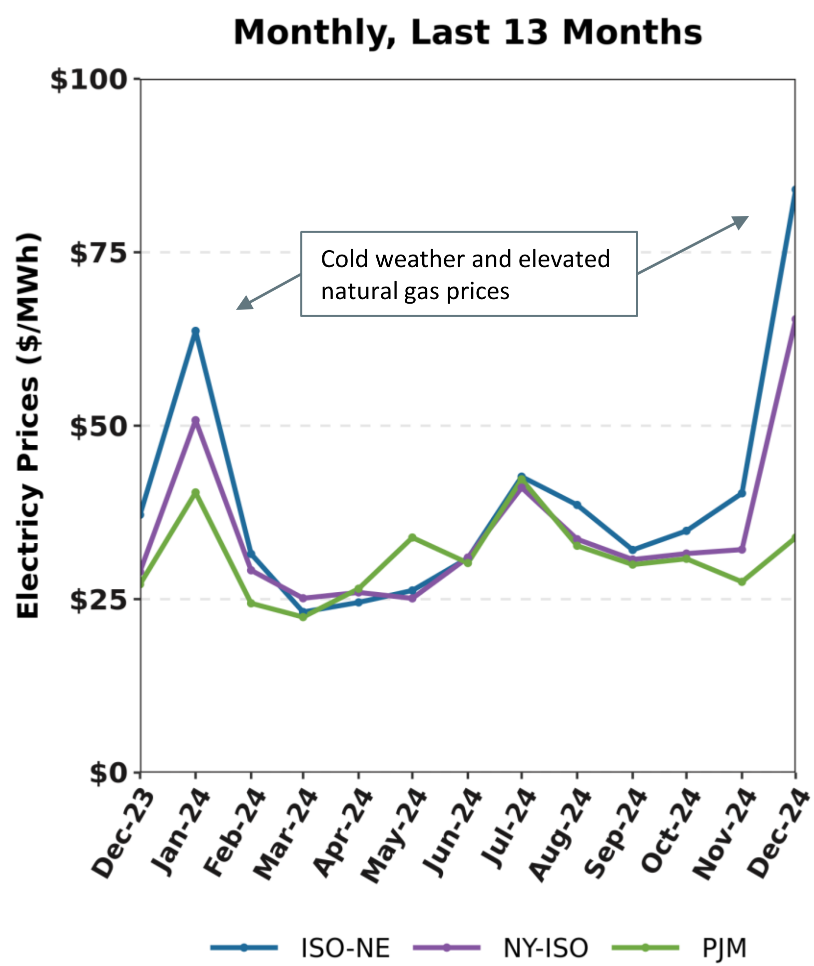


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

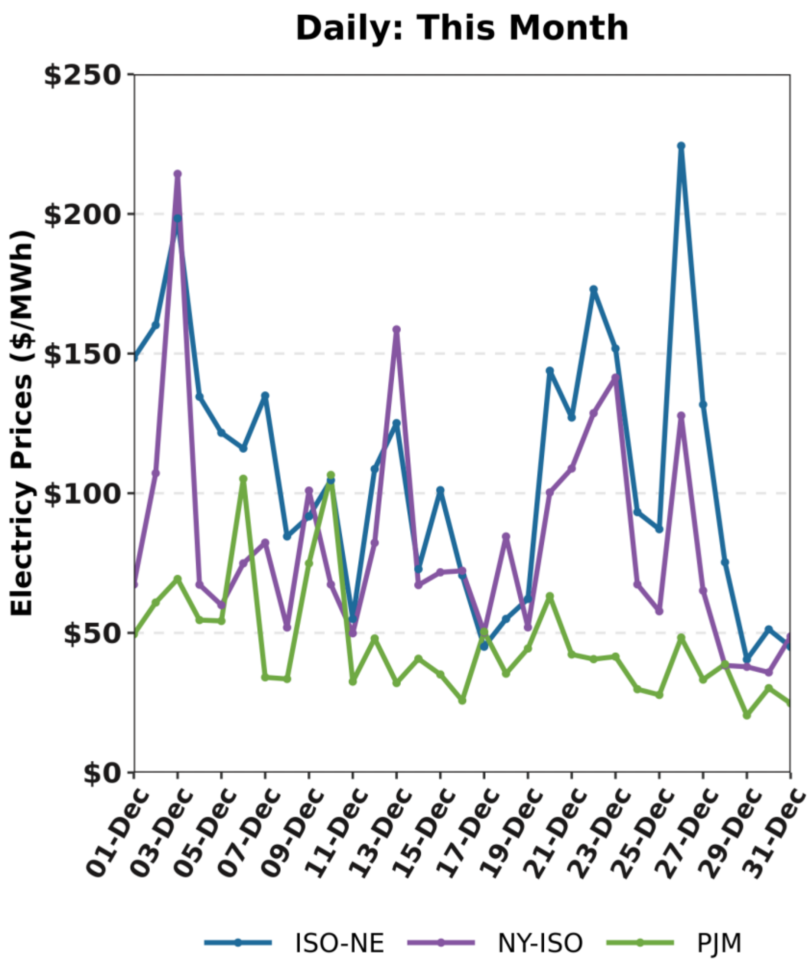
New England, NY, and PJM Hourly Average RT Prices by Month

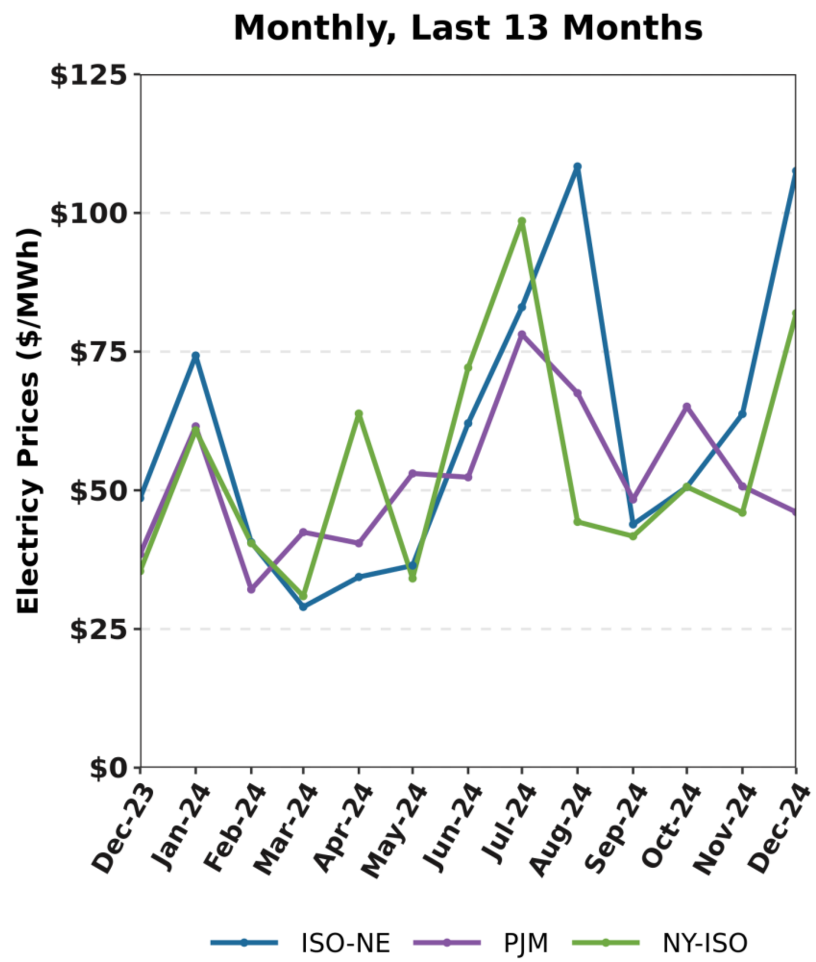




Hourly average prices are shown

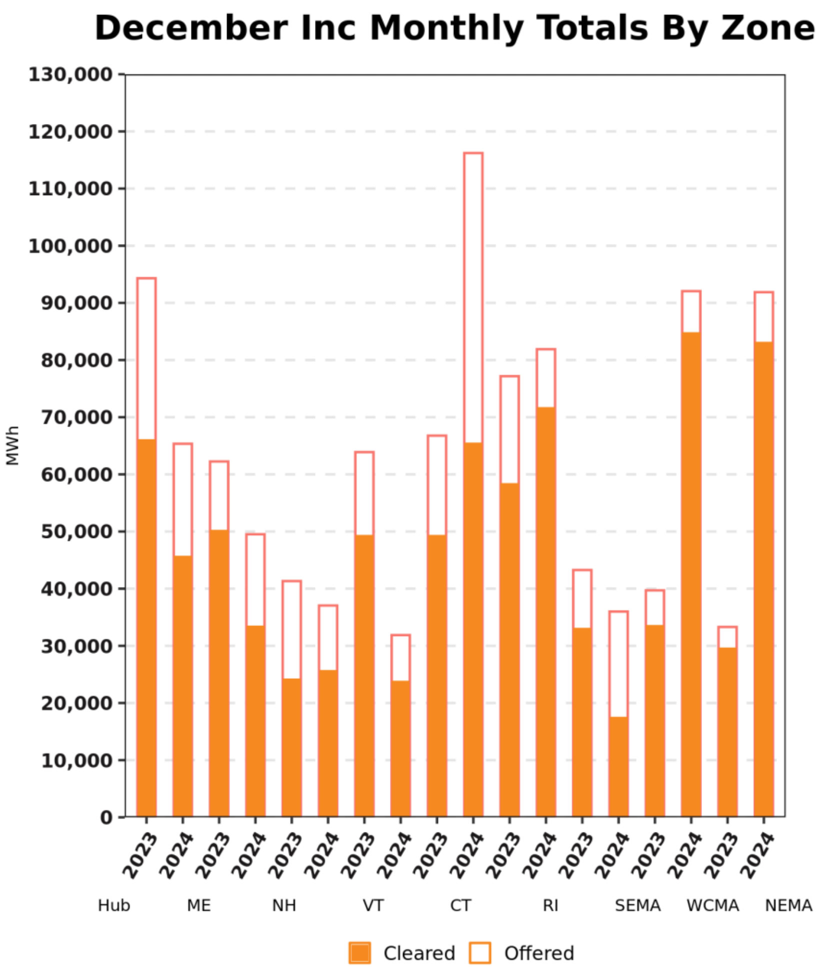
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours

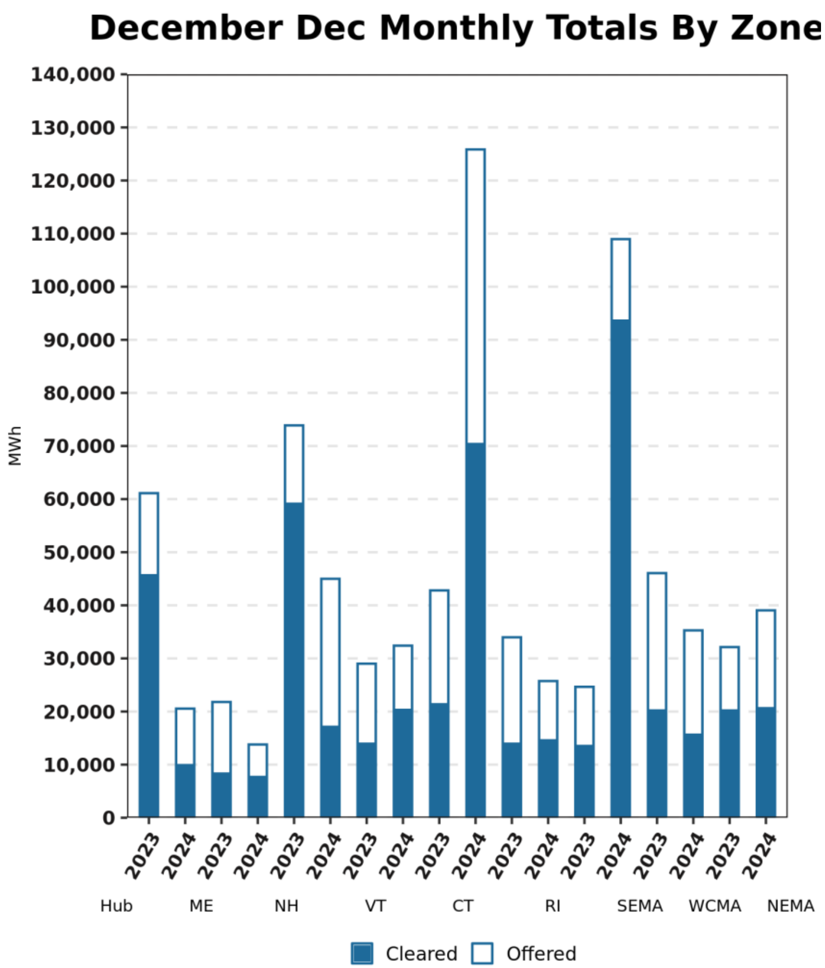




Monthly chart reflects the average of daily values

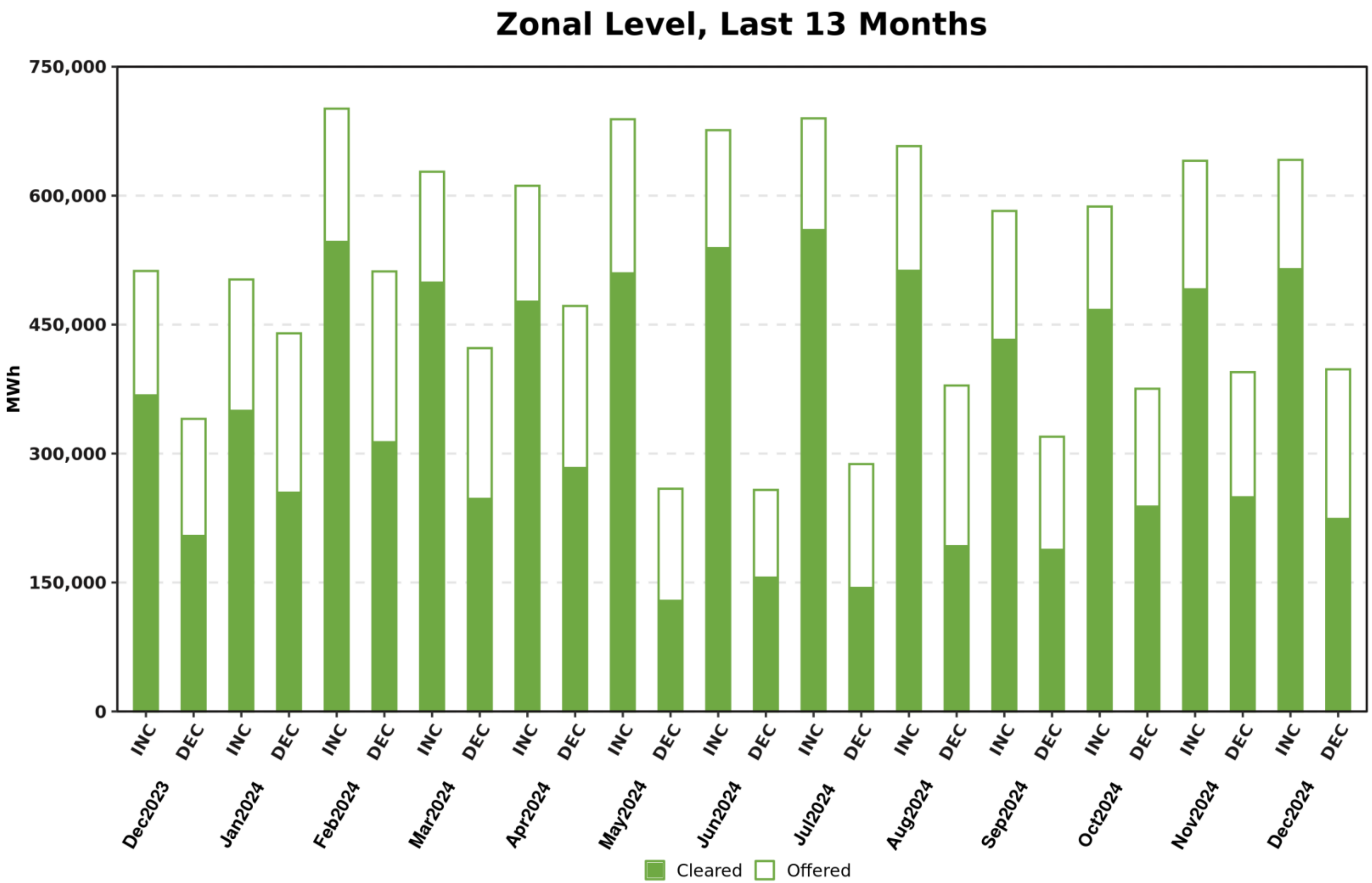
Zonal Increment Offers and Decrement Bid Amounts





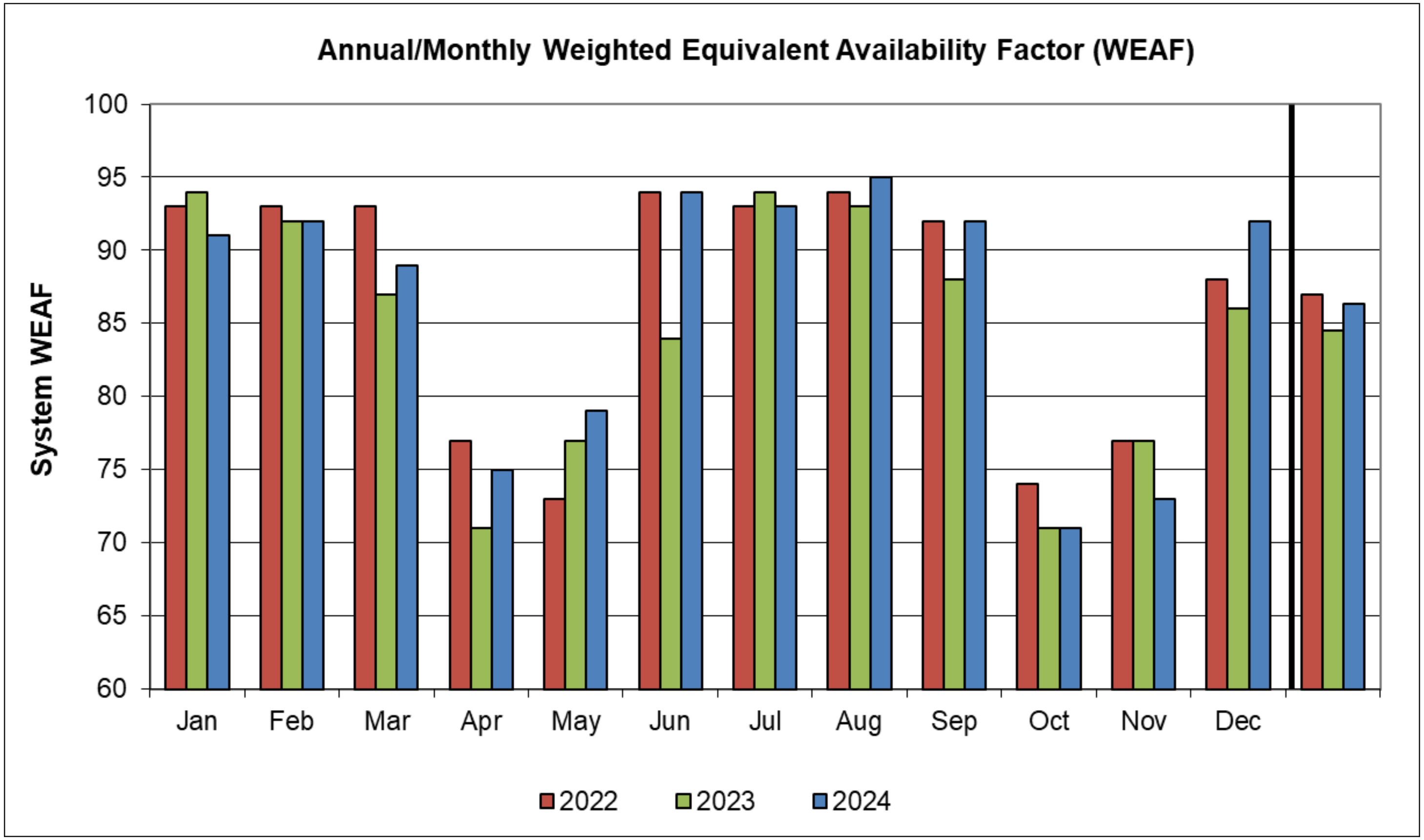
Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

System Unit Availability



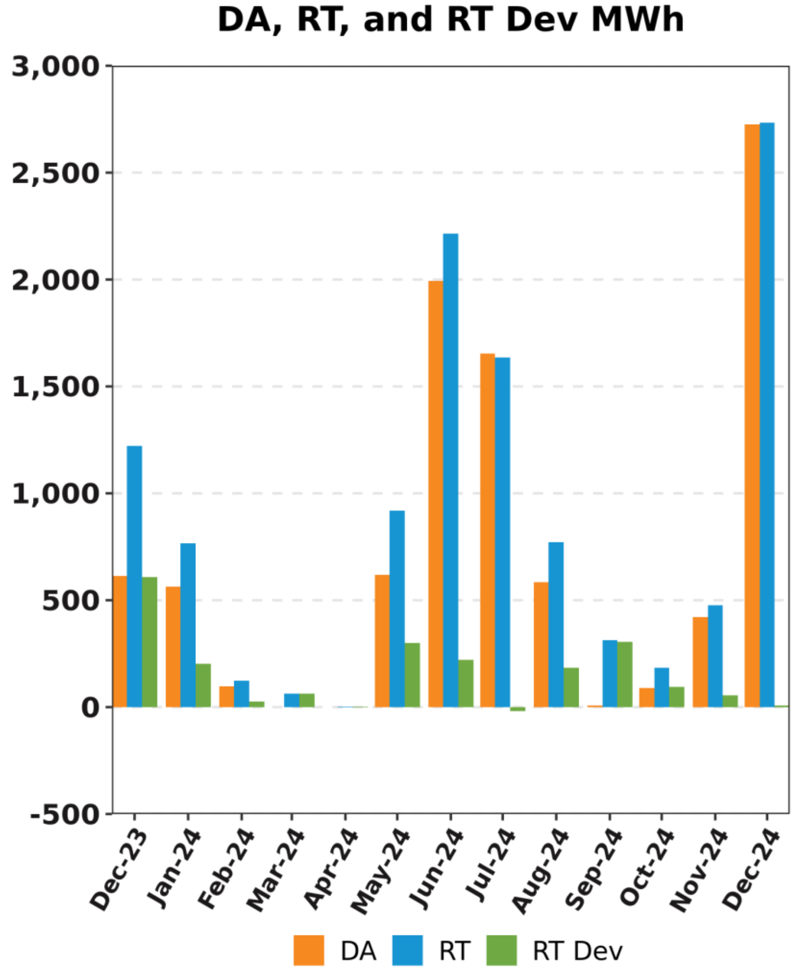
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2024	91	92	89	75	79	94	93	95	92	71	73	92	86
2023	94	92	87	71	77	84	94	93	88	71	77	86	85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87

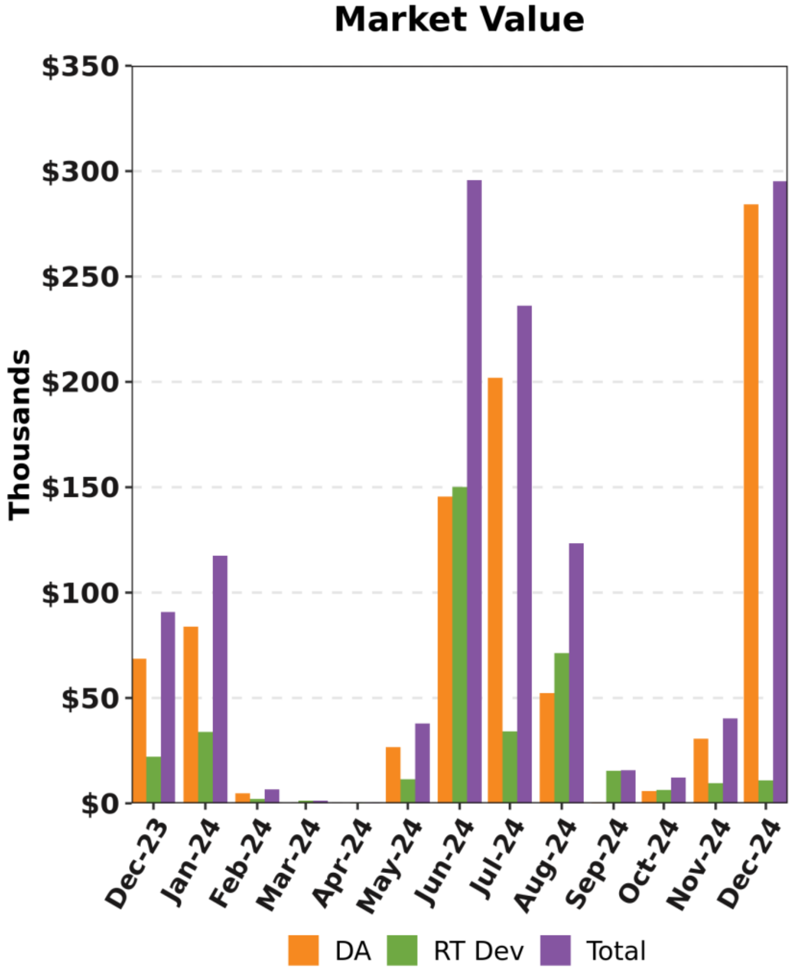
Data as of 1/2/25

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.

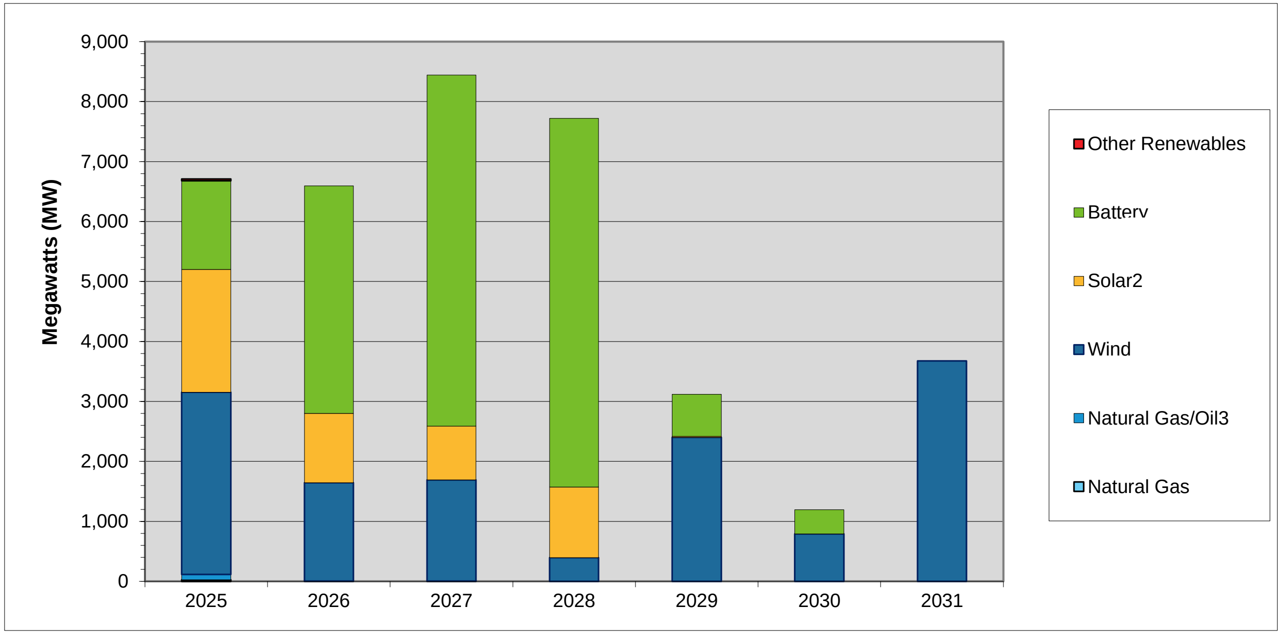
NEW GENERATION

New Generation Update
Based on Queue as of 12/31/24

- 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, 406 generation projects are currently being tracked by the ISO, totaling approximately 41,058 MW

Projected Annual Capacity Additions

By Supply Fuel Type



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total[1]
Other Renewables	32	0	0	0	0	0	0	32	0.1
Battery	1,477	3,793	5,857	6,145	704	404	0	18,380	49.1
Solar[2]	2,047	1,157	896	1,181	17	0	0	5,298	14.1
Wind	3,038	1,640	1,687	394	2,400	791	3,675	13,625	36.4
Natural Gas/Oil[3]	89	0	0	0	0	0	0	89	0.2
Natural Gas	26	4	4	0	0	0	0	34	0.1
Totals	6,709	6,594	8,444	7,720	3,121	1,195	3,675	37,458	100.0

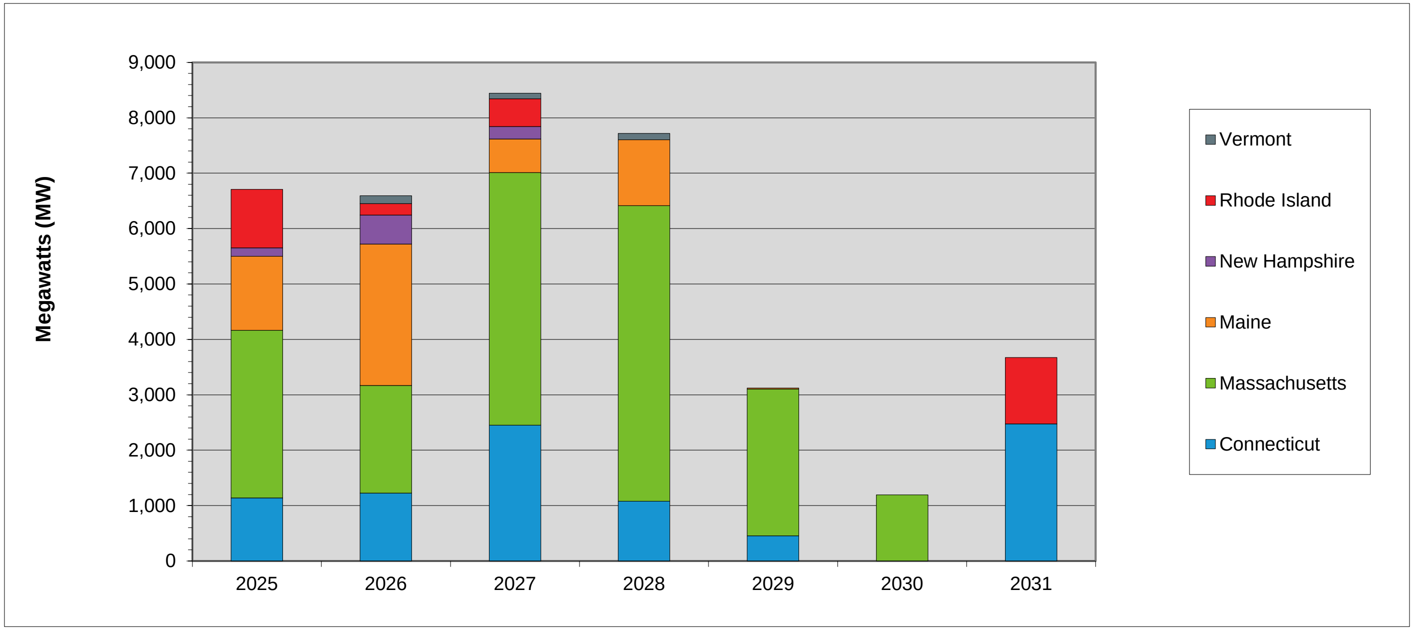
[1] Sum may not equal 100% due to rounding

[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



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total[1]
Vermont	0	144	101	115	0	0	0	360	1.0
Rhode Island	1,059	205	499	0	0	0	1,200	2,963	7.9
New Hampshire	150	524	226	0	0	0	0	900	2.4
Maine	1,337	2,555	607	1,192	17	0	0	5,708	15.2
Massachusetts	3,025	1,942	4,558	5,336	2,650	1,195	0	18,706	49.9
Connecticut	1,138	1,224	2,453	1,077	454	0	2,475	8,821	23.5
Totals	**6,709**	**6,594**	**8,444**	**7,720**	**3,121**	**1,195**	**3,675**	**37,458**	**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	130	18,380	3	575	127	17,805
Fuel Cell	3	32	1	20	2	12
Hydro	0	0	0	0	0	0
Natural Gas	5	34	0	0	5	34
Natural Gas/Oil	2	89	0	0	2	89
Nuclear	0	0	0	0	0	0
Solar	240	5,298	18	381	222	4,917
Wind	26	17,225	3	985	23	16,240
Total	406	41,058	25	1,961	381	39,097

- 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	5	45	1	20	4	25
Intermediate	2	89	0	0	2	89
Peaker	373	23,699	21	956	352	22,743
Wind Turbine	26	17,225	3	985	23	16,240
Total	406	41,058	25	1,961	381	39,097

- 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	130	18,380	0	0	0	0	130	18,380	0	0
Fuel Cell	3	32	3	32	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	5	34	2	13	0	0	3	21	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	240	5,298	0	0	0	0	240	5,298	0	0
Wind	26	17,225	0	0	0	0	0	0	26	17,225
Total	406	41,058	5	45	2	89	373	23,699	26	17,225

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	592.043	688.07	96.027	659.671	-28.399	564.371	-95.3
	Passive Demand	3,327.071	3,327.932	0.861	3,315.207	-12.725	3,253.179	-62.028
Demand Total		**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**	**3,817.550**	**-157.328**
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429	27,684.252	-13.462
	Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504	893.444	-32.498
Generator Total		**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**	**28,577.696**	**-45.96**
Import Total		**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**	**958.380**	**-71.42**
Grand Total*		**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**	**33,353.626**	**-274.708**
Net ICR (NICR)		**32,490**	**32,980**	**490**	**31,480**	**-1,500**	**31,690**	**210**

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes 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 2024-2028 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
	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
	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 2024-2028 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 2024-2028 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				
Demand	*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				
Generator	*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 2024-2028 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

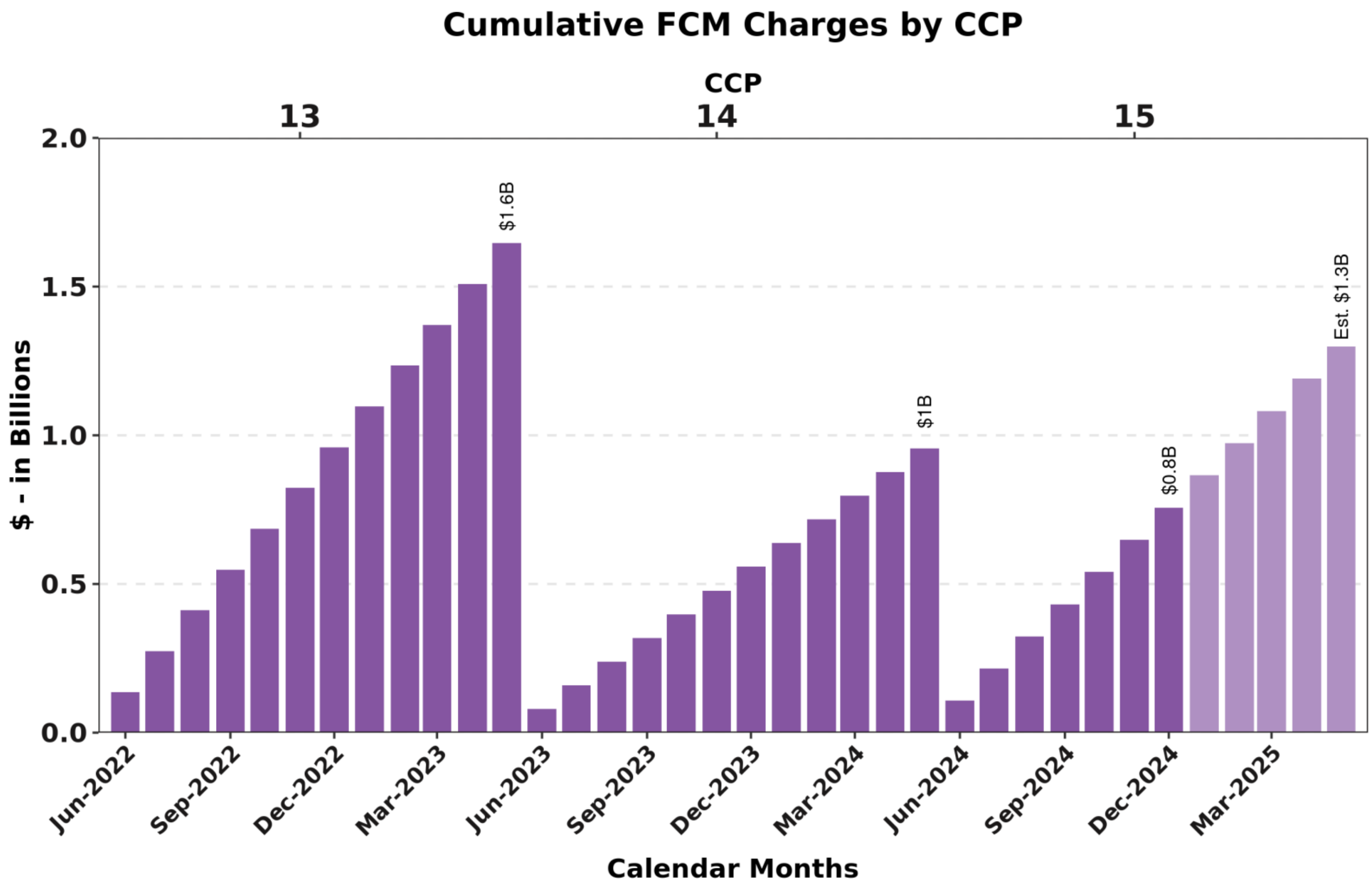
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 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**

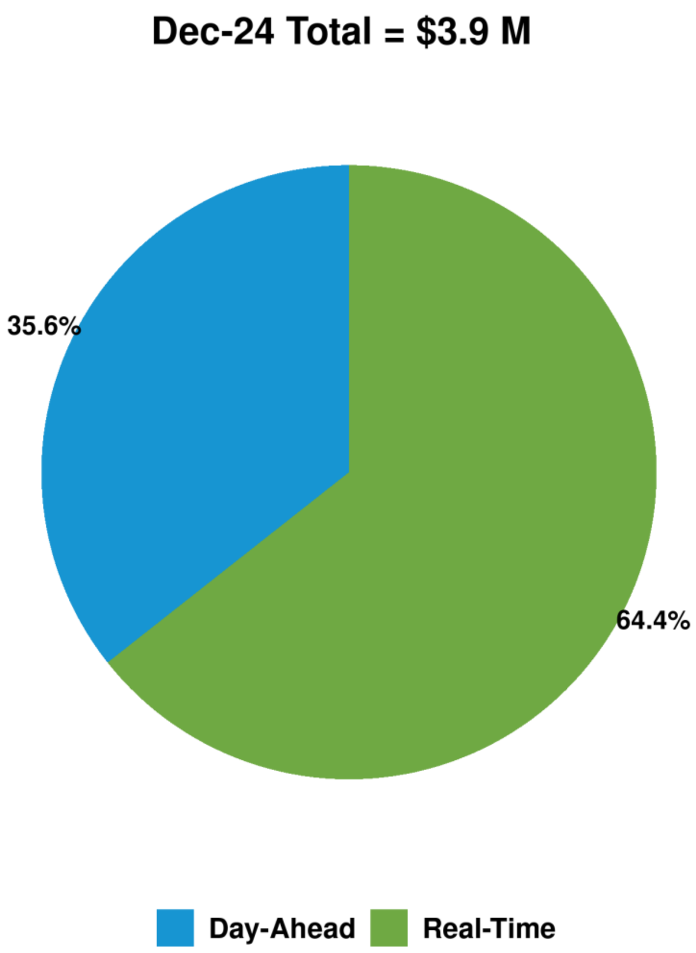
Forward Capacity Market Auctions

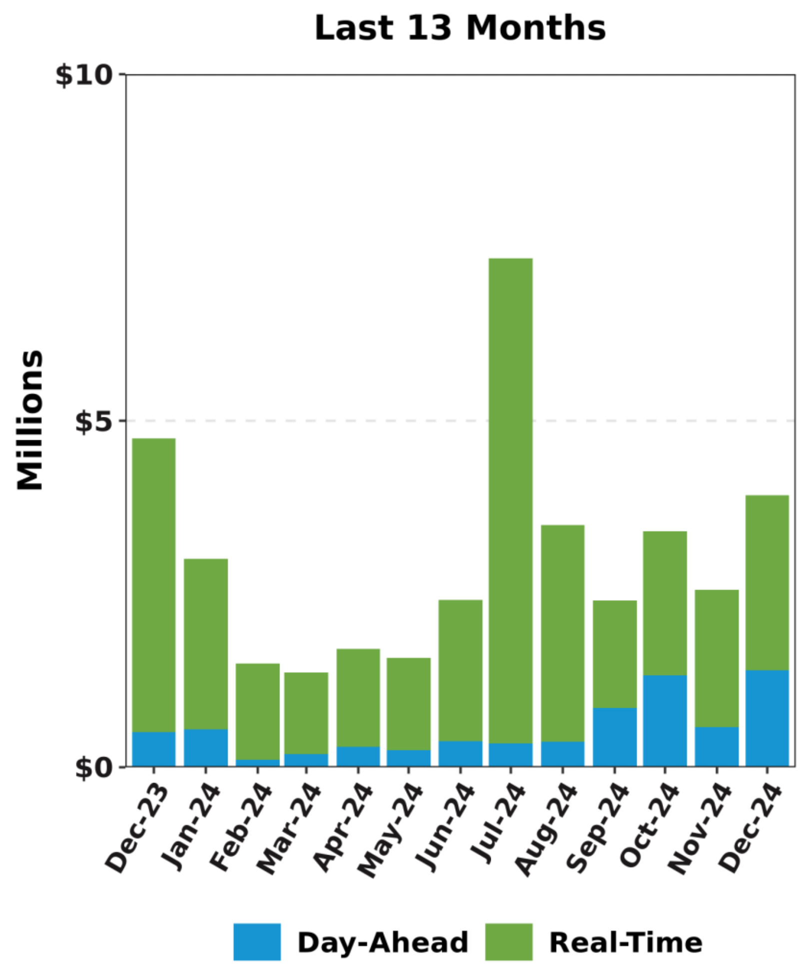


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

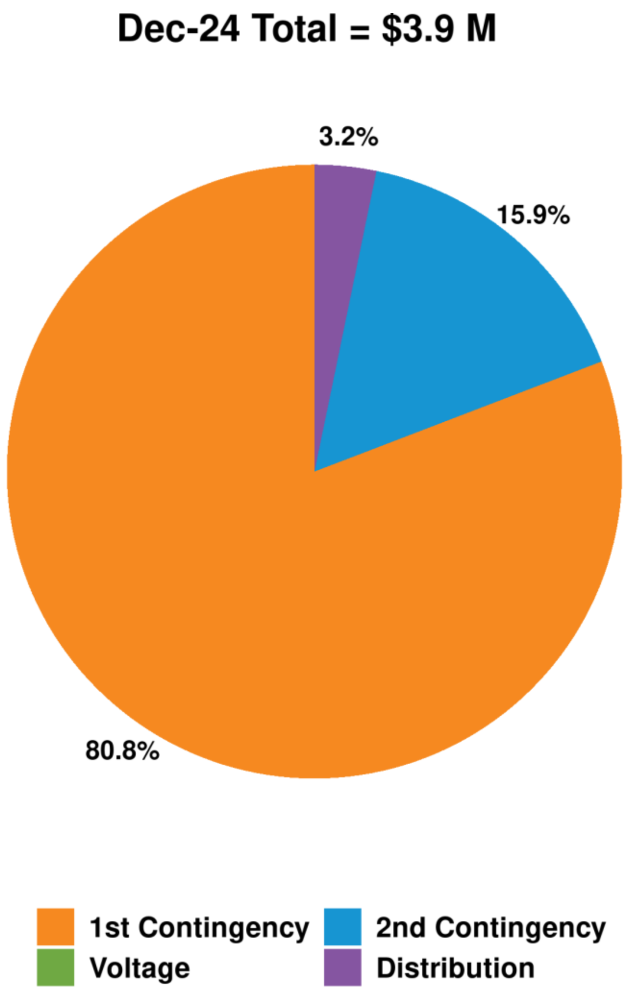
NET COMMITMENT PERIOD COMPENSATION

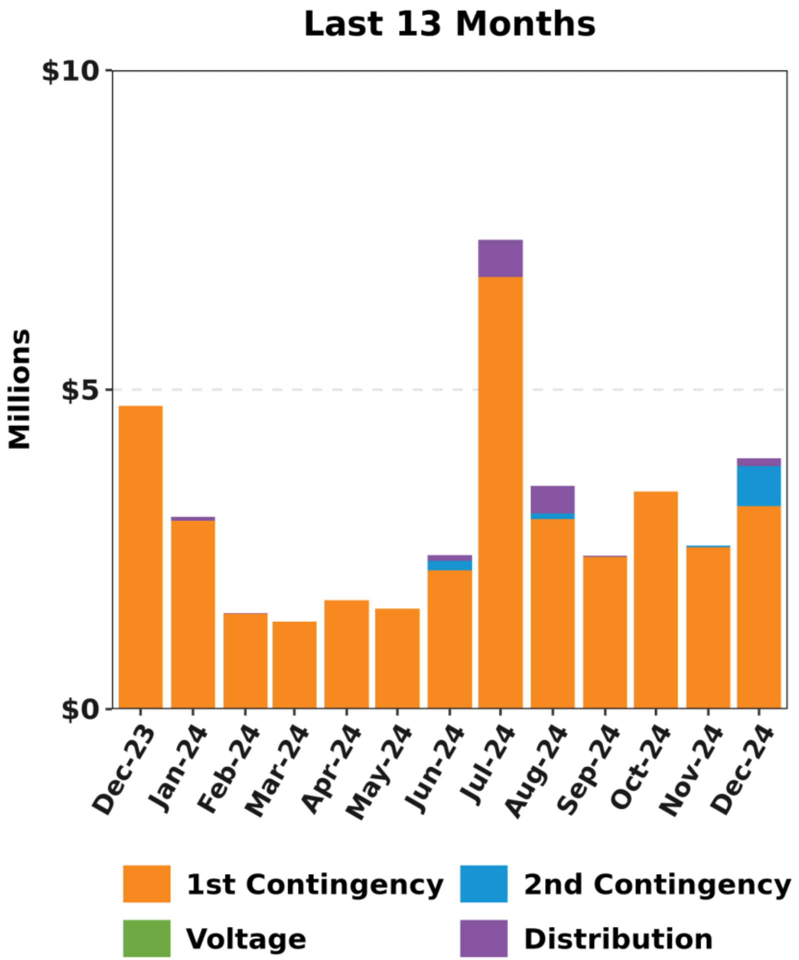
DA and RT NCPC Charges



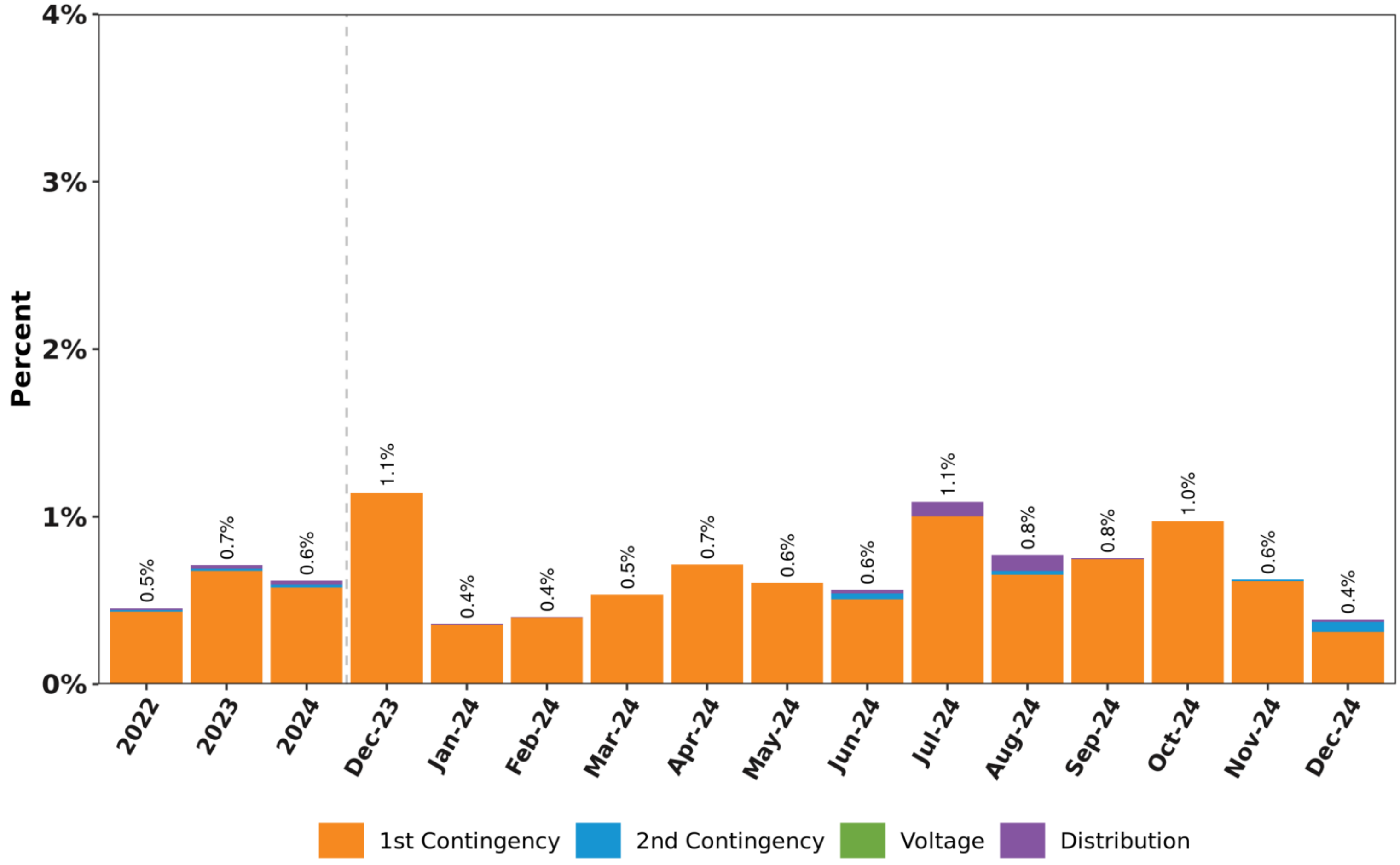


NCPC Charges by Type

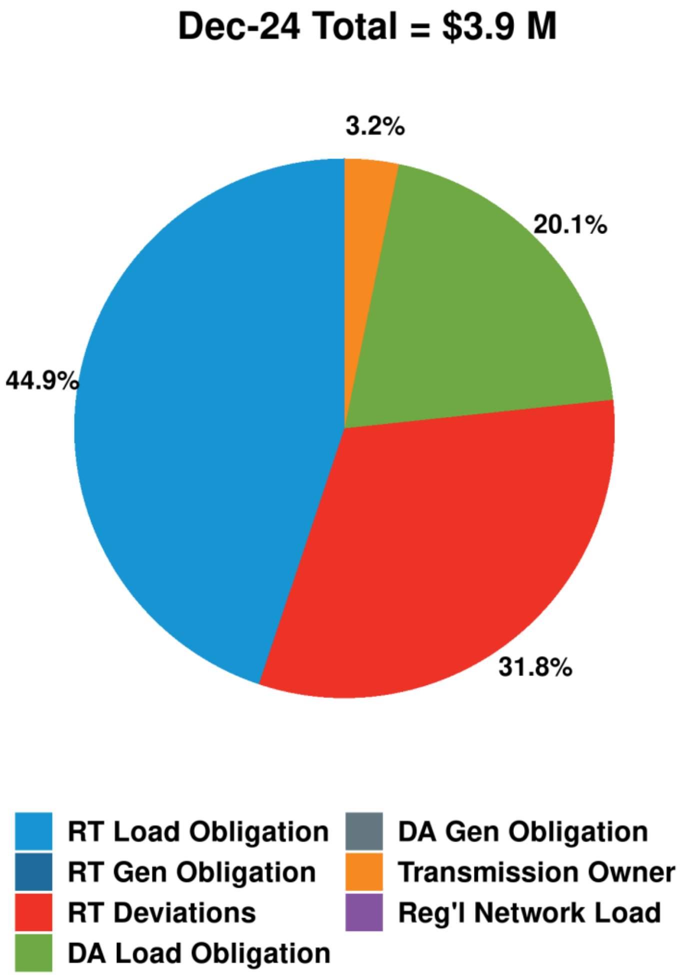


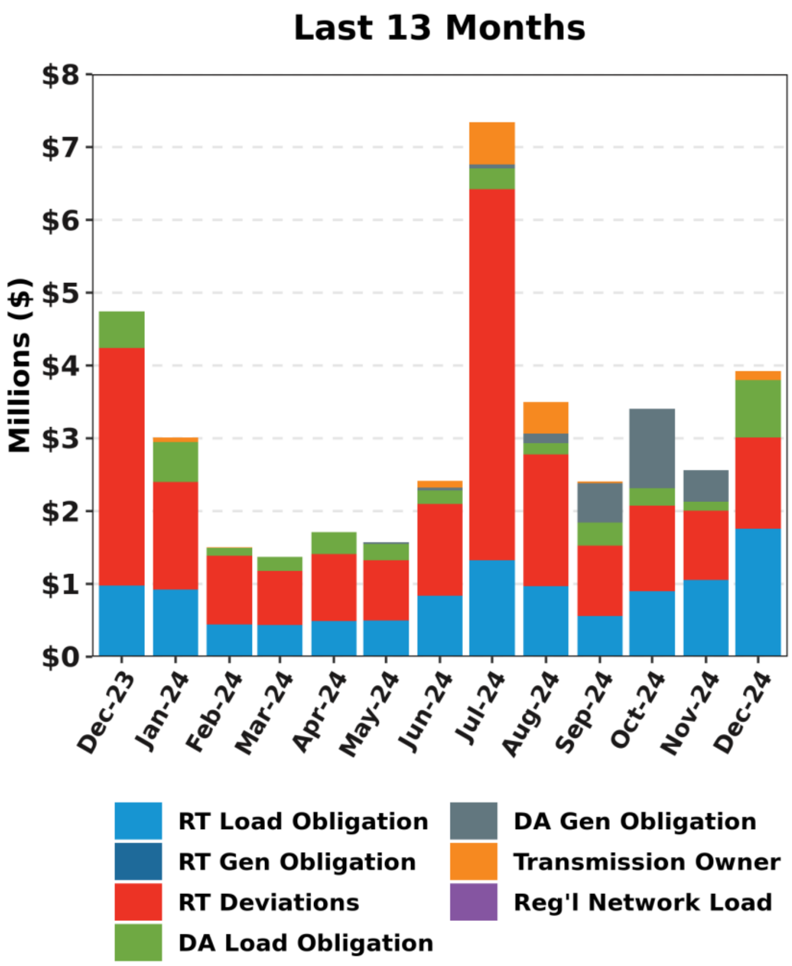


NCPC Charges by Type as Percent of Energy Market Value

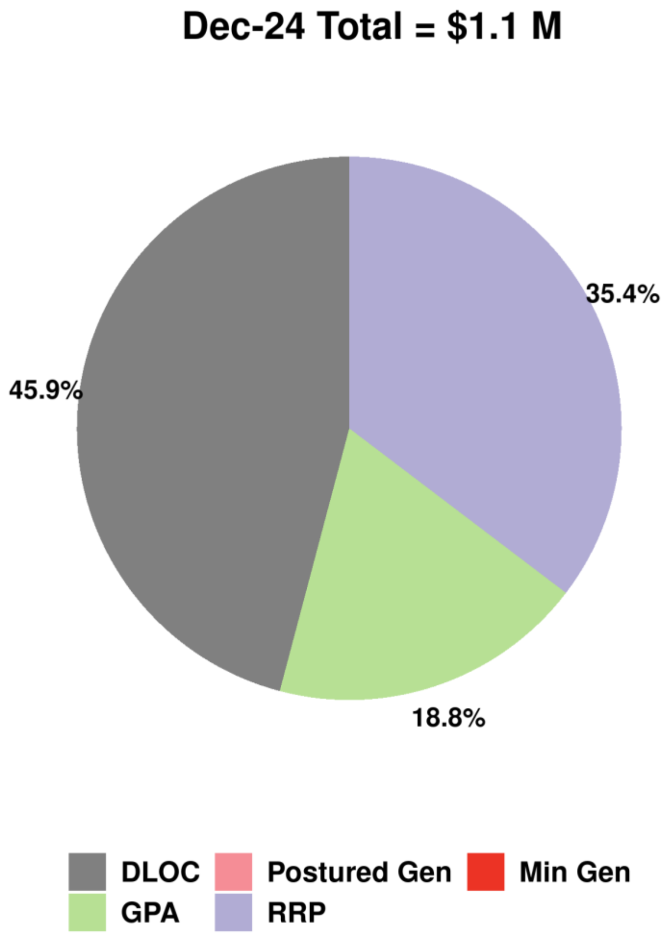


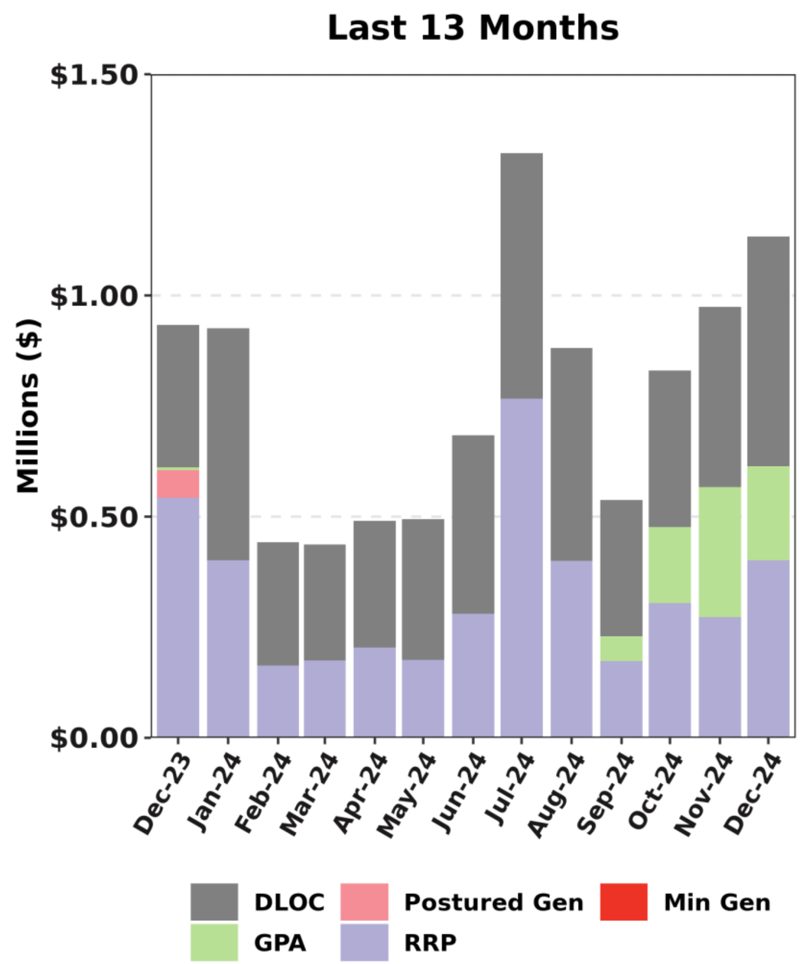
NCPC Charge Allocations





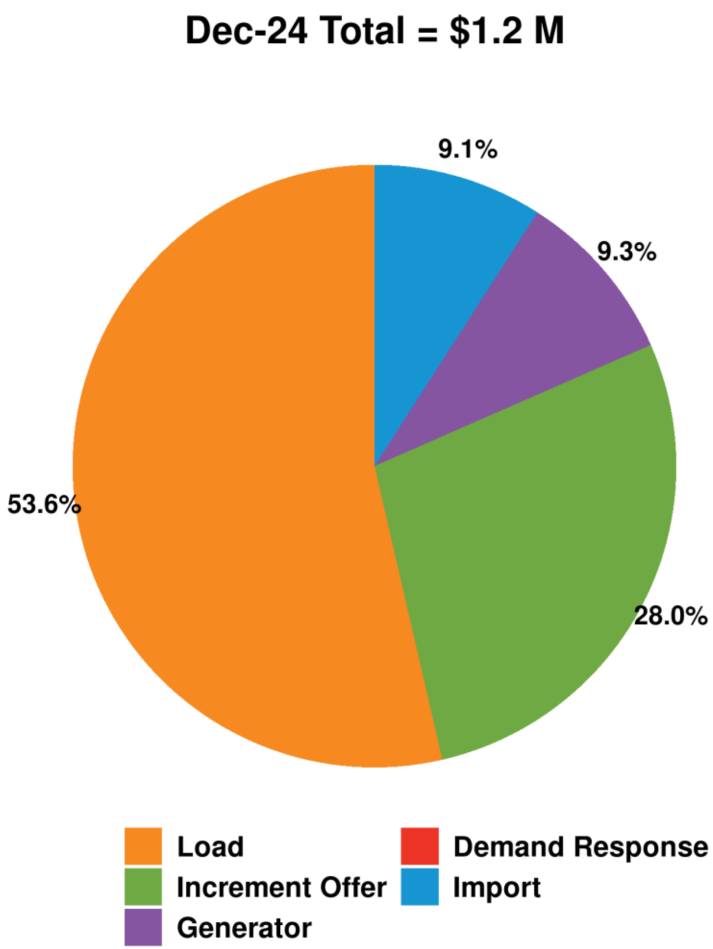
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

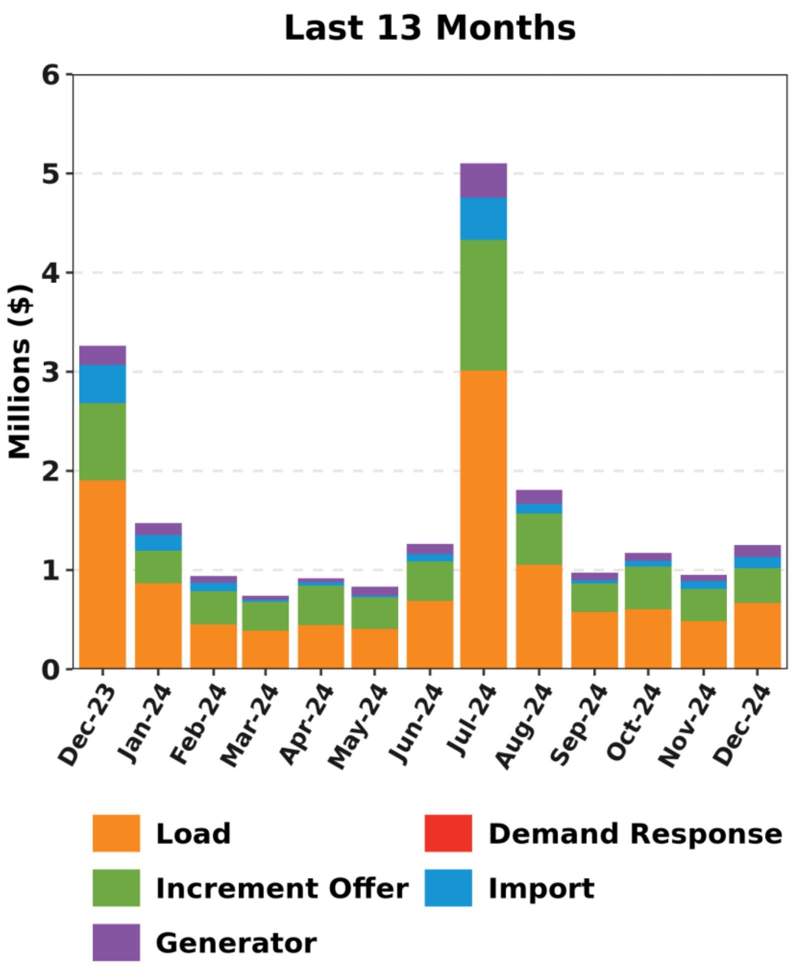




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

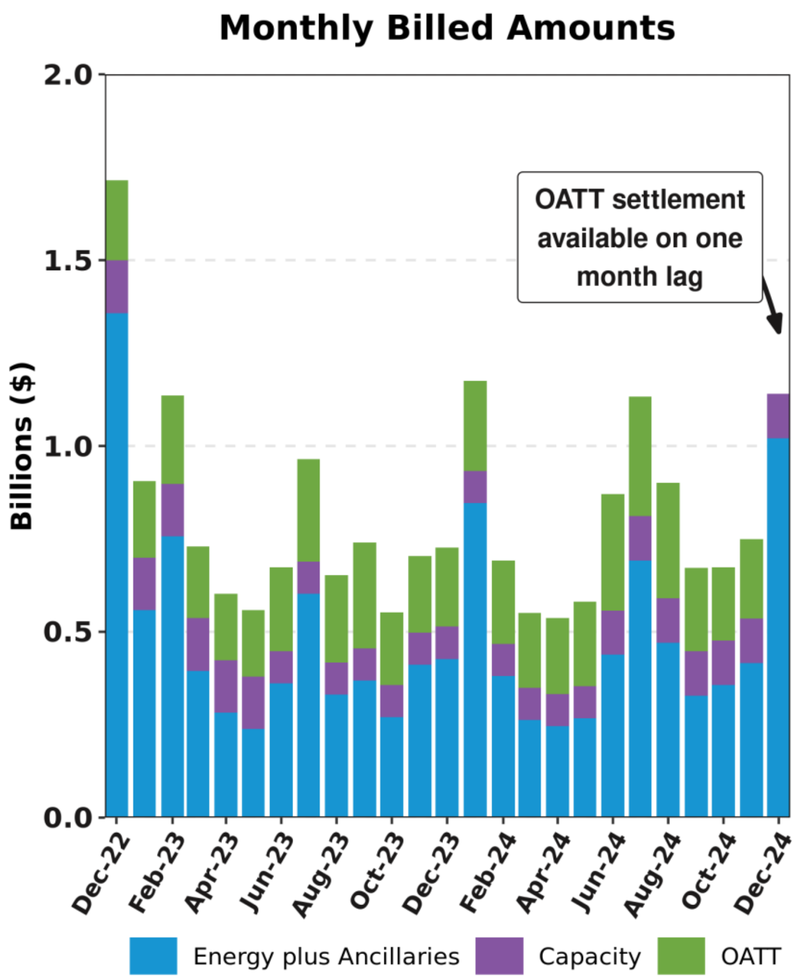
RT First Contingency Charges by Deviation Type

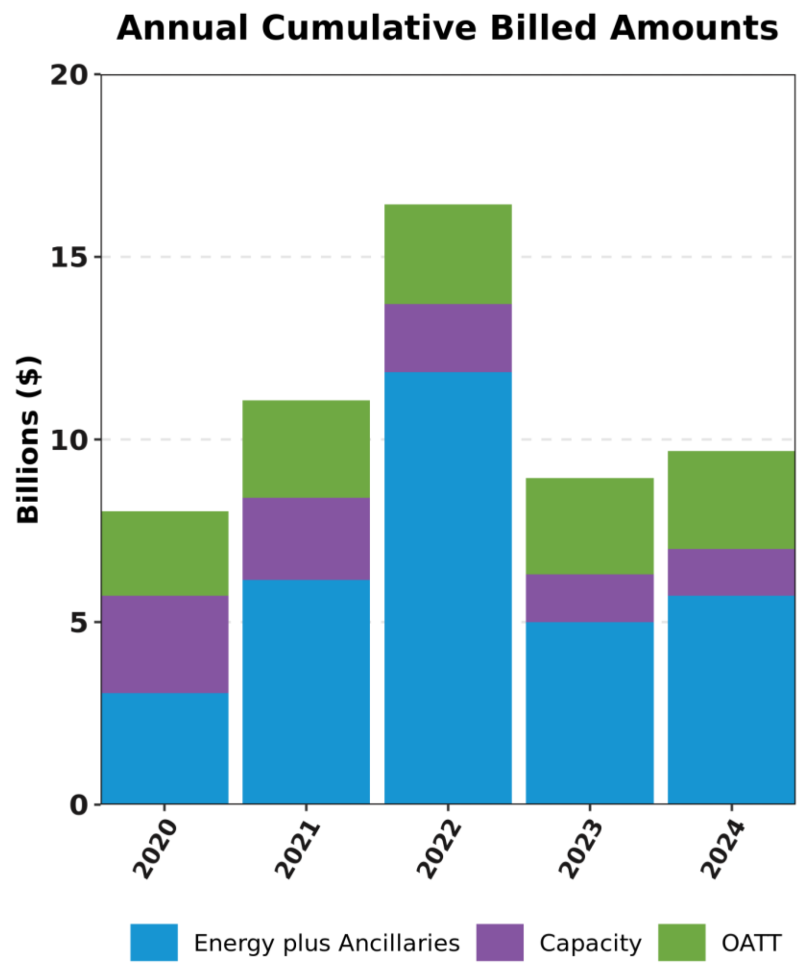




ISO BILLINGS

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)

- January 23 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Eastern Massachusetts Underground Cable Modernization Program (UCMP)
    - E-183W 115 kV Line Rebuild (Updated Scope Presentation) (RIE)
  - Longer-Term Transmission Planning RFP Plans and Schedule
  - 2024 Economic Study: Final Policy Results & Preliminary Stakeholder Results
  - Updates to the Economic Study Technical Guide

* 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
- Draft report on additional analysis to address stakeholder comments is expected to be issued in January

Economic Studies: EPCET

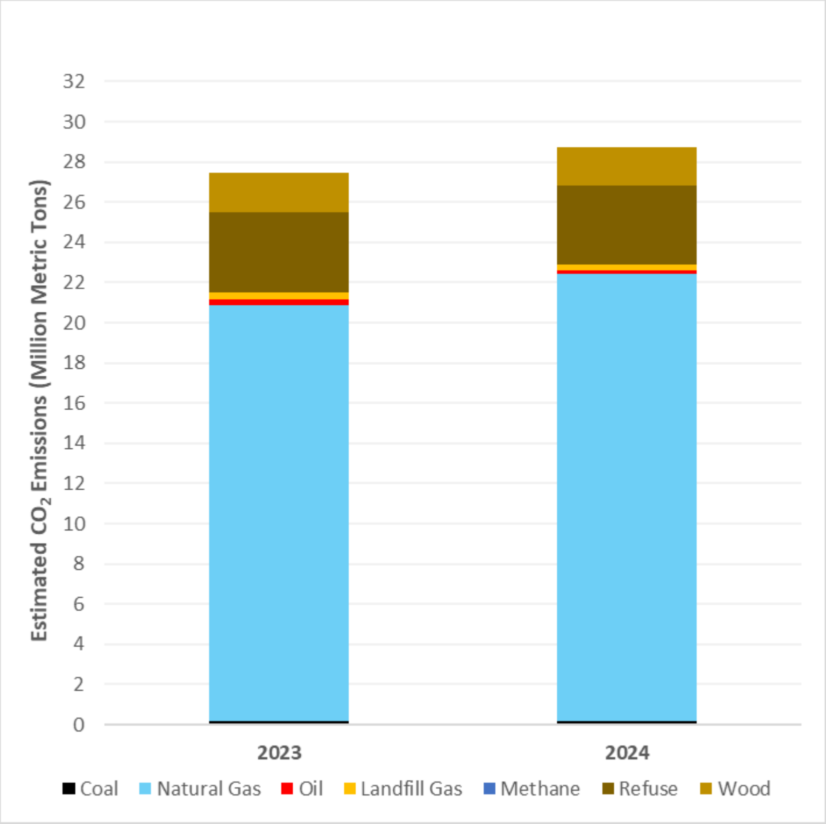
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - An effort to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - This study is now complete with the issuance of the final report and two-pager on October 24
  - A webinar occurred in December and the rollout of the study is now complete

Economic Studies: 2024 Study

- The 2024 Economic Study
  - This study is the first use of new Economic Study Process Tariff language
    - The study was initiated at the January PAC meeting
  - The Benchmark Scenario has been completed and the Policy and Stakeholder-Requested Scenarios are being analyzed between now and Q2 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 System Efficiency Needs Scenario will be studied in 2025
    - As part of the Economic Study Process Phase 2 Tariff changes, “Market Efficiency” is being renamed to “System Efficiency”

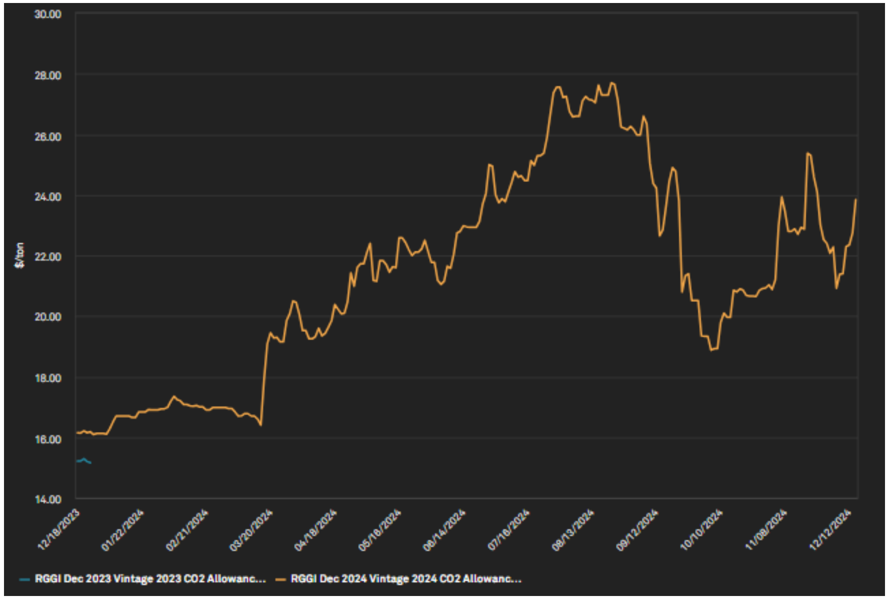
New England Power System Carbon Emissions

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



Data as of 12/08/24

Regional Greenhouse Gas Initiative (RGGI) Allowance Prices



- 12/16/24: RGGI allowance spot price - $23.85
- 12/04/24: RGGI released the results of the 66th auction
  - Initial offering includes 15,943,608 CO_2 allowances
  - 15,943,608 CO_2 allowances were sold at clearing price of $20.05

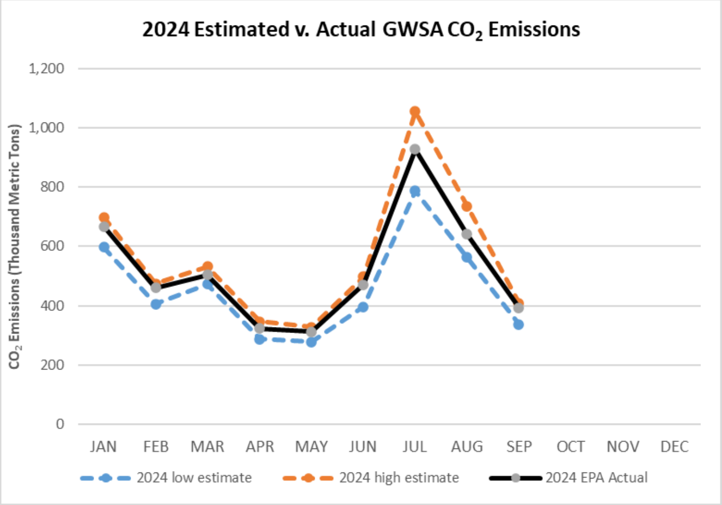
Massachusetts CO_2 Generator Emissions Cap

2024 Estimated Emissions Under CO_2 Cap

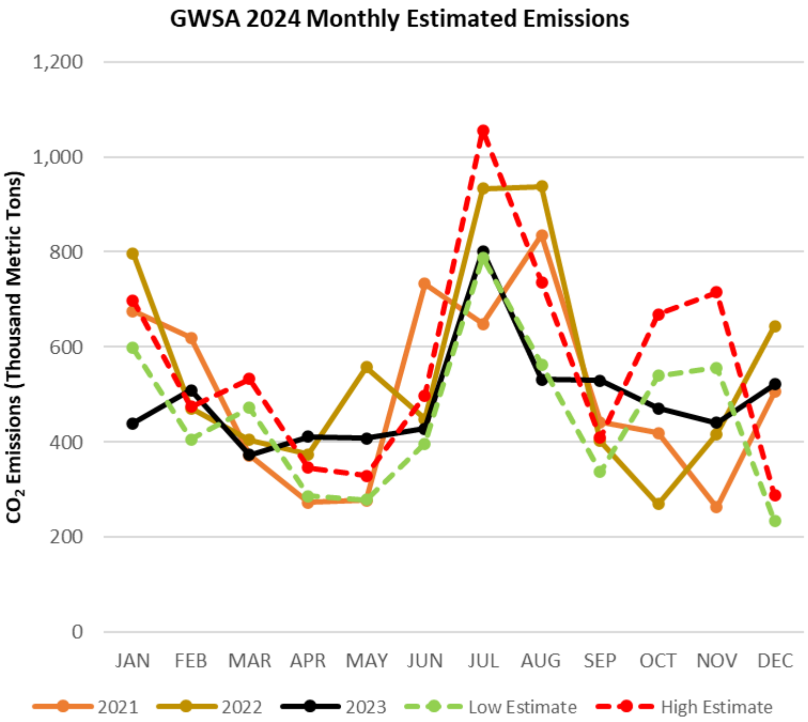
- As of 12/16/24, December estimated GWSA CO_2 emissions range between **234,276** and **287,713** metric tons
  - Year-to-date 2024 estimated emissions range between **71.7%** and **88.7%** of the 2024 cap of 7.61 MMT

2024 Q1-Q3 Actual Emissions Under CO_2 Cap

- According to the EPA CAMPD, Quarters 1-3 (January-September) 2024 GWSA CO_2 emissions were **4.7 MMT**, or **61.8%** of the 2024 cap of 7.61



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 12/20/2024

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 12/20/2024

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, 1672*	Install a new 115 kV line from Sudbury to Hudson	Dec-24, Sep-25*	4, 3

* The new 115 KV line from Sudbury to Hudson is currently in-service with some station work remaining at Hudson.

Greater Boston Projects, cont.

Status as of 12/20/2024

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 12/20/2024

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 12/20/2024

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 12/20/2024

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 12/20/2024

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 12/20/2024

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 12/20/2024

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 12/20/2024

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 12/20/2024

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	Jan-25	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 12/20/2024

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 12/20/2024

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 12/20/2024

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	Oct-24	4
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec 24	4
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 12/20/2024

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	Feb-25	3

Upper Maine Solution Projects, cont.

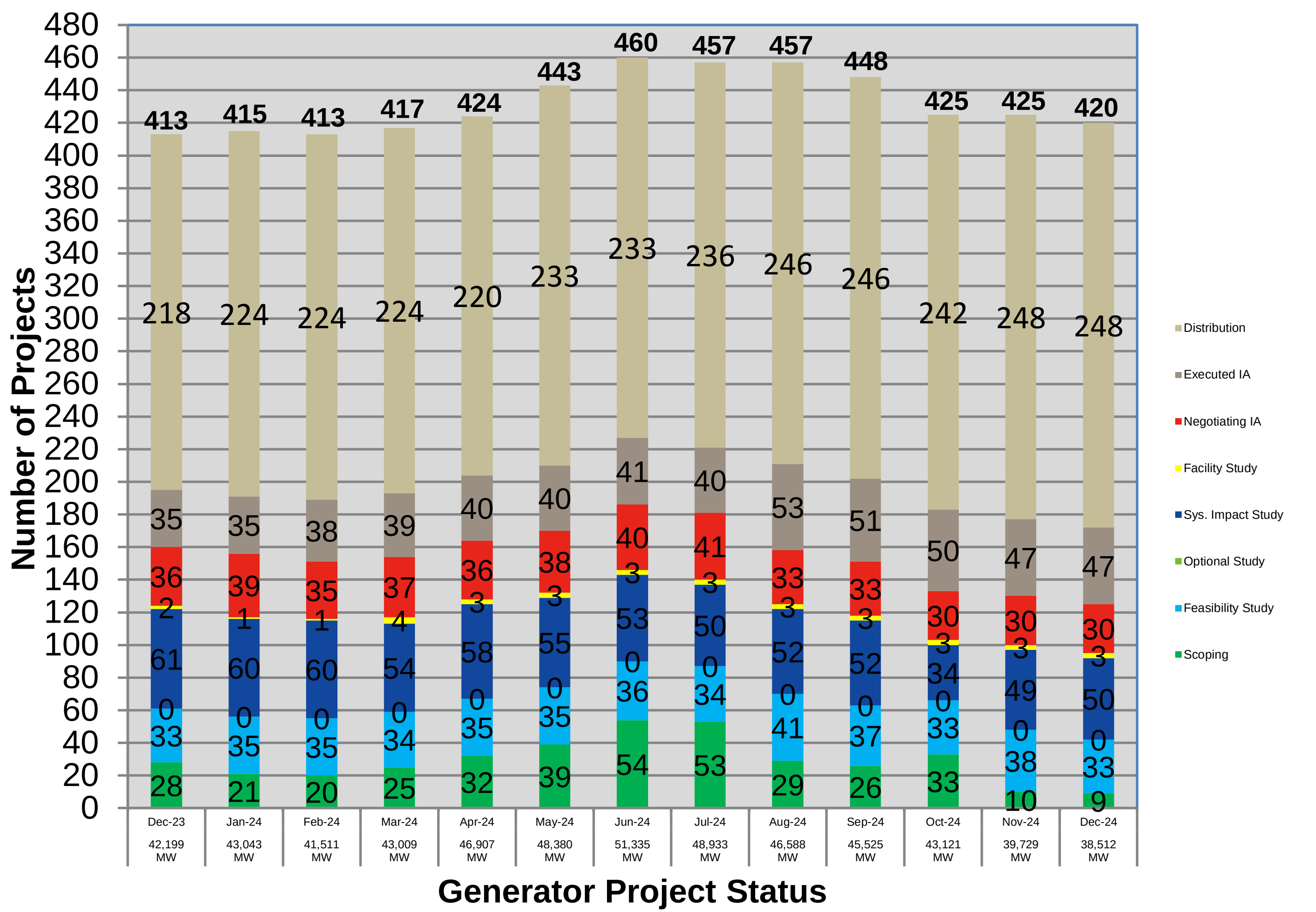
Status as of 12/20/2024

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	Nov-24	4
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	Jun-26	2

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

Status of Tariff Studies as of January 1, 2025



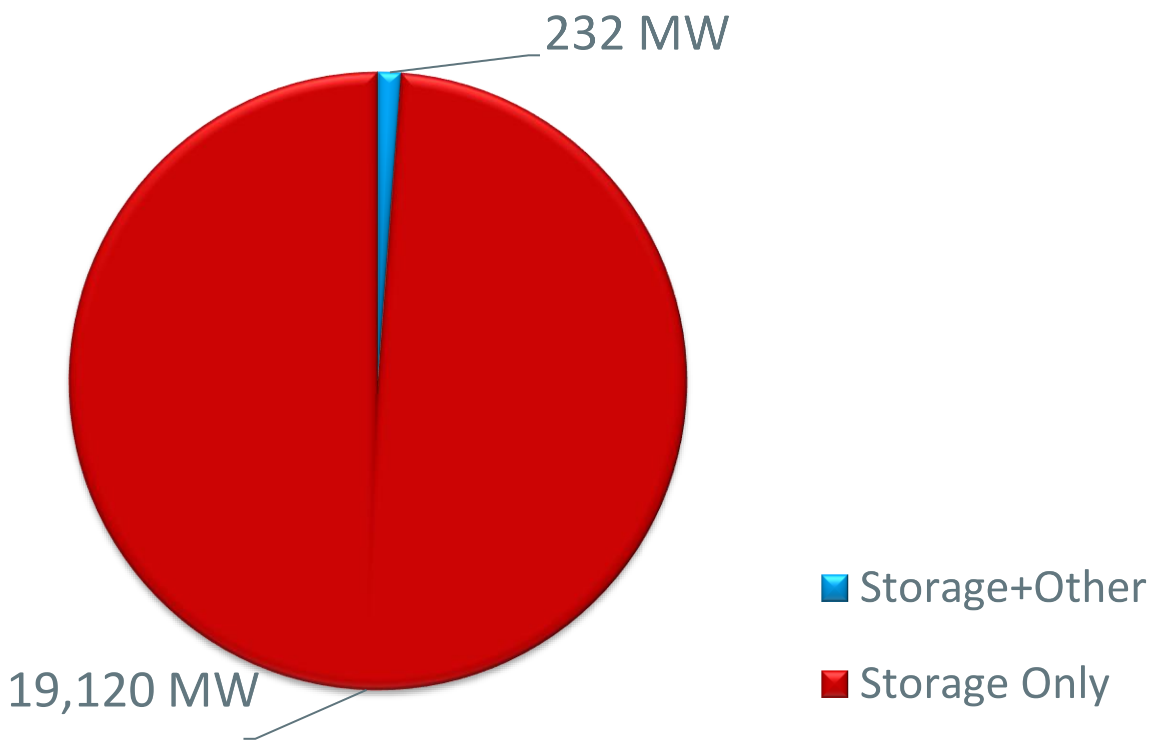
5 ETUs in Scoping, 3 in FS, 1 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 0

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

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

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



OPERABLE CAPACITY ANALYSIS

Winter 2025 Analysis

Winter 2025 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2025[2] CSO (MW)	Jan - 2025[2] SCC (MW)
Operable Capacity MW [1]	27,830	29,974
Active Demand Capacity Resource (+) [5]	312	317
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,475	1,475
Non Commercial Capacity (+)	20	20
Non Gas-fired Planned Outage MW (-)	710	1,128
Gas Generator Outages MW (-)	30	123
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,553	3,846
Net Capacity (NET OPCAP SUPPLY MW)	22,544	23,889
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,308	20,308
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,433	22,433
Operable Capacity Margin	111	1,456

[1]Operable Capacity is based on data as of **Dec 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 **Dec 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 **Jan 11, 2025.**

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

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

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

Winter 2025 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2025[2] CSO (MW)	Jan - 2025[2] SCC (MW)
Operable Capacity MW [1]	27,830	29,974
Active Demand Capacity Resource (+) [5]	312	317
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,475	1,475
Non Commercial Capacity (+)	20	20
Non Gas-fired Planned Outage MW (-)	710	1,128
Gas Generator Outages MW (-)	30	123
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,301	4,705
Net Capacity (NET OPCAP SUPPLY MW)	21,796	23,030
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,089	21,089
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,214	23,214
Operable Capacity Margin	-1,418	-184

[1]Operable Capacity is based on data as of **Dec 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 **Dec 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 **Jan 11, 2025.**

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

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

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

Winter 2025 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 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 from January through March.

Report created: 12/27/2024

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
1/11/2025	**27830**	**312**	**1475**	**20**	**710**	**30**	**2800**	**3553**	**22544**	**20308**	**2125**	**22433**	**111**	**Y**	**Winter 2024/2025**
1/18/2025	27830	312	1475	20	692	30	2800	3104	23011	20308	2125	22433	578	N	Winter 2024/2025
1/25/2025	27830	312	1475	20	672	30	2800	2805	23330	20088	2125	22213	1117	N	Winter 2024/2025
2/1/2025	28041	304	1254	25	303	30	3100	2506	23685	19824	2125	21949	1736	N	Winter 2024/2025
2/8/2025	28041	304	1254	25	297	30	3100	2207	23990	19796	2125	21921	2069	N	Winter 2024/2025
2/15/2025	28041	304	1254	25	282	30	3100	1758	24454	19536	2125	21661	2793	N	Winter 2024/2025
2/22/2025	28041	304	1254	25	338	30	3100	1459	24697	18560	2125	20685	4012	N	Winter 2024/2025
3/1/2025	27919	427	1161	293	715	545	2200	0	26340	18215	2125	20340	6000	N	Winter 2024/2025
3/8/2025	27919	427	1161	293	714	790	2200	0	26096	18022	2125	20147	5949	N	Winter 2024/2025
3/15/2025	27919	427	1161	293	694	790	2200	0	26116	17661	2125	19786	6330	N	Winter 2024/2025
3/22/2025	27919	427	1161	293	1322	908	2200	0	25370	17103	2125	19228	6142	N	Winter 2024/2025
3/29/2025	27711	426	1161	293	2267	1387	2700	0	23237	16516	2125	18641	4596	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).
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.

Winter 2025 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

December 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 from January through March.

Report created: 12/27/2024

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
1/11/2025	**27830**	**312**	**1475**	**20**	**710**	**30**	**2800**	**4301**	**21796**	**21089**	**2125**	**23214**	**-1418**	**Y**	**Winter 2024/2025**
1/18/2025	27830	312	1475	20	692	30	2800	4002	22113	21089	2125	23214	-1101	N	Winter 2024/2025
1/25/2025	27830	312	1475	20	672	30	2800	4002	22133	20862	2125	22987	-854	N	Winter 2024/2025
2/1/2025	28041	304	1254	25	303	30	3100	3553	22638	20588	2125	22713	-75	N	Winter 2024/2025
2/8/2025	28041	304	1254	25	297	30	3100	3254	22943	20559	2125	22684	259	N	Winter 2024/2025
2/15/2025	28041	304	1254	25	282	30	3100	2656	23556	20290	2125	22415	1141	N	Winter 2024/2025
2/22/2025	28041	304	1254	25	338	30	3100	2207	23949	19279	2125	21404	2545	N	Winter 2024/2025
3/1/2025	27919	427	1161	293	715	212	2200	1099	25574	18922	2125	21047	4527	N	Winter 2024/2025
3/8/2025	27919	427	1161	293	714	790	2200	416	25680	18722	2125	20847	4833	N	Winter 2024/2025
3/15/2025	27919	427	1161	293	694	790	2200	0	26116	18348	2125	20473	5643	N	Winter 2024/2025
3/22/2025	27919	427	1161	293	1322	908	2200	0	25370	17770	2125	19895	5475	N	Winter 2024/2025
3/29/2025	27711	426	1161	293	2267	1387	2700	0	23237	17166	2125	19291	3946	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).
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.

***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

5 Litigation Report

January 9, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of January 8, 2025

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated December 4, 2024 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

*	1	Consumers RTP Complaint (EL25-44)	Dec 19 Dec 20-Jan 8 Jan 7	Consumer Complainants file Complaint Over 50 parties intervene FERC extends comment deadline to ***Mar 20, 2025***
*	1	Allco PP5 Complaint (EL25-43)	Dec 19 Dec 23-Jan 8 Dec 31	Allco files Complaint requesting FERC direct ISO-NE to abolish its PP5 procedures NEPOOL, Calpine, National Grid, Public Citizen intervene FERC grants extension of time for reply period; comment deadline ***Jan 15, 2025***
	3	RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)	Dec 19	FERC grants the RENEW Complaint in part and dismisses it in part; Tariff Changes in response to the *RENEW O&M Complaint Order* due ***Feb 17, 2025***
	4	Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)	Dec 9 Dec 13 Dec 20	WIRES intervenes out-of-time WIRES/EEI file comments supporting TOs' Nov 13 Motion; CAPs oppose TOs' Nov 13 Motion TOs answer CAPs' Dec 13 reply

II. Rate, ICR, FCA, Cost Recovery Filings

7	EP Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER25-588)	Dec 13	NEPOOL intervenes
7	Canal Marketing CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER25-168)	Dec 18	FERC accepts Canal Marketing's revised rate schedule, to recover $642,189 in eligible medium-impact IROL CIP Costs incurred between Apr 1, 2023 and Mar 31, 2024; eff. *Dec 21, 2024*
8	2025 NESCOE Budget (ER25-134)	Dec 17	FERC accepts 2025 NESCOE Budget, eff. *Jan 1, 2025*
8	2025 ISO-NE Administrative Costs and Capital Budgets (ER25-110)	Dec 23	FERC accepts 2025 ISO-NE Budgets, eff. *Jan 1, 2025*
10	**Mystic 8/9 COSA (ER18-1639)**		
10	Mystic Global Settlement (ER18-1639-029)	Dec 5	Chief Judge terminates Settlement Judge procedures; Global Settlement pending before the FERC
10	Mystic COSA ROE Settlement Agreement Tariff Records (ER25-584; ER24-2804)	Dec 17-18	National Grid, ISO-NE intervene

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

*	11	Waiver Request: Withdrawal from 2024-25 IEP (Cleary Unit 9) (ER25-707)	Dec 2	Cleary 9 Participants request one-time waiver of Market Rule 1 Appendix K (IEP) to withdraw forward component participation of Cleary Unit 9 in the Winter 2024-25 IEP
			Dec 20-27	NEPOOL, ENE intervene
			Dec 23	ISO-NE submits comments supporting removing Clearly 9's participation in, and the return of payments received for, the Winter 2024-25 IEP, as requested
	12	DASI Tariff Sheet Effective Date Change (to Feb 28, 2025) (ER25-456)	Jan 2	FERC accepts change to effective date of DASI Tariff sheets from Mar 1, 2025 to Feb 28, 2025, ensuring certainty that the first Operating Day covered by Day-Ahead Ancillary Services awards will be ***Mar 1, 2025***, eff. *Feb 28, 2025*

IV. OATT Amendments / TOAs / Coordination Agreements

14	Attachment C and Q Revisions (ER25-410)	Dec 10	ISO-NE supplements the record to confirm that notwithstanding an error in the eTariff submission, the requested effective date for the Revisions is *Jul 12, 2025*
14	PBOP Collections Report (RI Energy) (ER25-343)	Dec 10	FERC accepts collections report, eff. *Jan 1, 2025*
14	NE/NB Coordination Agreement Updates (ER25-328)	Dec 17	FERC accepts Coordination Agreement updates, eff. *Jan 1, 2025*
15	PBOP Collections Report (CL&P) (ER25-306)	Dec 10	FERC accepts collections report, eff. *Jan 1, 2025*

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

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

17	Schedule 21-ES: Essential Power MA/NSTAR/ISO-NE LSA (ER25-429)	Dec 5	Essential Power MA submits comments supporting the LSA
		Jan 6	FERC accepts non-conforming Local Service Agreement, eff. *Oct. 15, 2024*
17	Schedule 21-RIE: Revisions (ER25-347)	Dec 23	RI Energy amends its filing to include in Attachment RR, Exhibit 2.3 note 3 language that was inadvertently omitted from the clean version of note that was filed; comment deadline ***Jan 13, 2025***
18	Schedule 22: ISO-NE/CMP/Andro Hydro LGIA (ER24-2970)	Dec 27	FERC issues deficiency letter; response to deficiency letter due on or before ***Jan 27, 2025***

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

20	Capital Projects Report – 2024 Q3 (ER25-125)	Dec 5	FERC accepts 2024 Q3 Report, eff. *Oct 1, 2024*
20	IMM Quarterly Markets Reports (ZZ24-4)	Dec 18	IMM corrects Summer 2024 Report

IX. Membership Filings

*	21	Jan 2025 Membership Filing (ER25-841)	Dec 31	***New Members:*** All Choice Energy NE LLC (Supplier Sector); Karbone Energy LLC (Supplier Sector); and The Metropolitan District (Publicly Owned Entity Sector); and ***Termination of Participant status:*** TrueLight Commodities; Blueprint Power Technologies; and Sunrun
	21	Nov 2024 Membership Filing (ER25-296)	Dec 30	FERC accepts termination of Participant status of ProGrid Ventures and Palm Energy

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

*	21	Reliability Standards: BAL-007-1 and TOP-003-7 (RD25-5)	Jan 6	NERC files Reliability Standards for approval; comment deadline ***Feb 5, 2025***
*	22	Reliability Standard: TPL-008-1 (RD25-4)	Dec 17	NERC files Reliability Standard for approval; comment deadline ***Jan 17, 2025***
	23	Revised Reliability Standards: PRC-029-1 and PRC-024-4 (RM25-3)	Dec 19	FERC issues NOPR; comment deadline [60 days from the date of publication in the *Federal Register*]
			Dec 19	UnFrack FERC Coalition files comments
			Dec 19-Dec 31	KY AG, PJM IMM, IN URC, Sunflower Electric intervene
	23	NOPR: Supply Chain Risk Reliability Standards (RM24-4)	Dec 16	TAPS filed comments supporting the comments of APPA/LPPC

XI. Misc. - of Regional Interest

*	24	203 Application: Plus Power/TWG Global (EC25-28)	Dec 10	Plus Power MBR Applicants request FERC approval for transfer of managerial control over Plus Power MBR Entities to TWG Global
			Dec 12	Public Citizen intervenes
	24	203 Application: RISEC/Shell (EC25-14)	Jan 7	FERC authorizes Shell's indirect acquisition of 100% of the ownership interests in Rhode Island State Energy Center, LP
*	24	CL&P/BPUS Agreements Cancellation Notices (ER25-870 and ER25-869)	Jan 7	CL&P submits notices of cancellation of an Engineering and Design and an Engineering and Test Agreement with BPUS; comment deadline ***Jan 28, 2025***
*	25	National Grid Incentives for NGPUP Project (ER25-866)	Jan 6	National Grid requests transmission rate incentives for its portion of the Power Up Project
			Jan 8	MA DOER intervenes
*	25	CL&P Rate Incentives for Huntsbrook Junction Project (ER25-747)	Dec 18	CL&P requests transmission rate incentives for its portion of the Power Up Project – the Huntsbrook Project
			Jan 7	MA AG intervenes
			Jan 8	NESCOE, MA DOER submit comments
	25	TSAs: Fourth Amendments to NECEC Transmission TSAs (ER25-261 et al.)	Dec 23	FERC accepts fourth amendments to NECEC Transmission TSAs, eff. *Oct 30, 2024*
	25	UI Rate Incentives Request for Fairfield to Congress 115kV Railroad Project (ER25-167)	Dec 20	FERC grants UI's requested Rate Incentives, eff. *Dec 21, 2024*
	26	LCCSA Amendment: National Grid (Termination of RIE/BIPCO/PUD Participation) (ER25-88)	Dec 9	FERC accepts LCCSA Amendment, eff. *May 30, 2024*

27	PJM/PPL/Susquehanna ISA Amendments Related to Increased Co-Located Load (ER24-2172)	Dec 16 Dec 23	Exelon/AEP answer Susquehanna's Req. for Reh'g FERC issues "Allegheny Notice", noting that the requests for reh'g may be deemed to have been denied by operation of law, but noting that the requests will be addressed in a future order

XII. Misc. - Administrative & Rulemaking Proceedings

29	Large Loads Co-Located at Generating Facilities (AD24-11)	Dec 9-17	Post-tech conf. comments filed by, among others: AEU, Calpine, Constellation, Dominion, Vistra, Potomac Economics, ACORE, ACPA, Clean Energy Buyers Association, Data Center Coalition, EPSA, LS Power, NY State Reliability Council, Organization of PJM States, PJM IMM, Industrial Energy Consumers of America, Joint Public Service Parties, NRECA, SEIA
30	Joint Federal-State Current Issues Collaborative (AD24-7)	Jan 3	AGA, ConEd, National Grid, NRG file comments
31	*Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)	Dec 19	FERC issues "Allegheny Notice", noting that the requests for reh'g may be deemed to have been denied by operation of law, but noting that the requests will be addressed in a future order
32	*Orders 1920* and *1920-A*: Transmission Planning Reforms (RM21-17)	Dec 10 Dec 13-23 Dec 20 Jan 2-3	FERC grants MISO 1-year extension of time to comply with *Order 1920* West Connect Coordinating TOs, MISO TOs, PJM TOs, EEI, NRECA, SWEPCO, WIRES request reh'g of *Order 1920-A* PJM requests 6-month extension of time to comply with *Order 1920* PJM TOs, OPSI support PJM request

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

* 34	Montpelier Generating Stipulation and Consent Agreement (IN24-15)	Dec 6	FERC approves Agreement that resolves OE's investigation into whether Montpelier and Rockland violated the PJM Tariff and FERC regulations by classifying a Forced Outage as a Maintenance Outage in submissions to PJM, causing Montpelier to avoid Performance Assessment Interval penalties during Winter Storm Elliott; Montpelier and Rockland agree to ***disgorge $674,064 plus $84,690 in interest***, pay a ***$105,000 civil penalty***, and provide compliance monitoring
* 34	Sonoran West Solar Stipulation and Consent Agreement (CAISO Tariff Violations) (IN24-13)	Dec 5	FERC approves Agreement that resolves OE's investigation into whether Sonoran violated the CAISO Tariff (and thereby 18 C.F.R. § 35.41(a)) by submitting biddable Initial State of Charge parameters that reflected a value that was other than the actual state of charge the batteries were forecasted to hold at the start of the real time market; Sonoran agrees to ***disgorge $2,473,265***, pay a ***$1 million civil penalty***, and provide compliance training & monitoring
* 35	EWP Renewable Corp. (Springfield Power/Hemp Hill) Stipulation and Consent Agreement (IN24-12)	Dec 23	FERC approves Agreement that resolves OE's investigation into whether Springfield Power violated the ISO-NE Tariff (and thereby 18 C.F.R. § 35.41(a)) by failing to offer, operate and schedule the Hemp Hill plant consistent with the Tariff and FERC regulations; BREC agrees to ***disgorge $259,669***, pay a ***$722,000 civil penalty***, and provide compliance training & monitoring

*	35	American Efficient Show Cause Order (IN24-2)	Dec 16	FERC directs American Efficient to show cause why they should not be found to have violated the FPA, FERC regulations and PJM and MISO Tariffs by (i) extracting millions of dollars in capacity payments for a purported energy efficiency project that did not actually cause reductions in energy use and (ii) failing to satisfy Tariff requirements for participation as an Energy Efficiency Resource; American Efficient was also directed to show cause why they should not (i) ***disgorge $2,116,057*** and ***$250,937,821*** back to MISO and PJM, respectively; (ii) disgorge back to PJM additional unjust profits received between April 2024 and the date of any future FERC order directing disgorgement; and (iii) pay a ***$722 million civil penalty***. American Efficient must file an answer with the FERC on or before ***Mar 17, 2025***
	36	Ketchup Caddy / Phillip Mango (MISO DR Program Violations) (IN23-14)	Dec 5	FERC issues order assessing penalties; Ketchup Caddy and Mango assessed ***civil penalties of $25 million and $1.5 million***, respectively, and Mango directed to ***disgorge $506,502, plus interest***
*	36	PSEG Stipulation and Consent Agreement (PJM RTEP violations) (IN21-5)	Dec 5	FERC approves Agreement that resolves OE's investigation into whether PSEG violated FERC regulations by failing to fully and accurately provide information to PJM regarding its $546 million RPV line transmission project; PSEG agrees to pay a ***$6.6 million civil penalty***
		Gas-Related Enforcement Actions		
	38	Total Gas & Power North America, Inc. et al. Stipulation and Consent Agreement (IN12-17)	Jan 8	FERC approves Agreement that resolves claims and allegations that TGPNA engaged in manipulation in violation of NGA § 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest US between Jun 2009 and Jun 2012; TGPNA agreed to pay ***$5 million*** in restitution to certain agreed-upon non-governmental organizations

XIV. Natural Gas Proceedings

38	Iroquois ExC Project (CP20-48-001)		Protests to and comments on Iroquois' request for an extension of time associated with its ExC Project filed by Sierra Club CT, Save the Sound, and nearly 20 individual citizens Iroquois answers protests and comments

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

39	*Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)	Dec 12	Court directs parties to file a status report regarding the status of the statutorily-mandated FERC rehearing process by Dec 23, 2024
		Dec 23	FERC files status report
		Jan 6	FERC moves to extend abeyance, including deferral of all filing deadlines, until the earlier of the date it issues a substantive response to pending rehearing requests, or ***Apr 30, 2025***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Joan Bosma, NEPOOL Counsel

DATE: January 8, 2025

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 January 8, 2025. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **Consumers RTP Complaint (EL25-44)**

On December 19, 2024, a group of "Consumer Complainants"[2] filed a complaint against all FERC-jurisdictional public utility transmission providers with local planning tariffs (including ISO-NE and the remaining ISO/RTOs) asserting that their tariffs, which authorize individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above ("Local Planning") without regard to whether such Local Planning approach is the more efficient or cost-effective transmission project for the interconnected transmission grid and cost-effective for electric consumers, coupled with the absence of an independent transmission system planner, "are unjust and unreasonable, having produced inefficient planning and projects that are not cost-effective, resulting in unjust and unreasonable rates for both individual projects and cumulative regional transmission plans and portfolios." Specifically, the Consumer Complainants assert that the FERC must mandate (i) revision of local and regional planning tariffs to (a) prohibit individual transmission owner planning of FERC-jurisdictional transmission facilities 100 kV and above; and (b) require exclusive regional planning of all transmission facilities 100 kV and above, utilizing existing *Order 1000* regions; and (ii) that all regional planning must be conducted through an Independent Transmission Planner as described in their Complaint. Answers, interventions, comments, and protests to the Consumers RTP Complaint are due on or before ***March 20, 2025***.[3] Thus far, interventions have been filed by over 50 parties, including NEPOOL. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Allco PP5 Complaint (EL25-43)**

Also on December 19, 2024, Allco Finance Limited ("Allco") filed a complaint asking the FERC to (i) direct ISO-NE to abolish its Planning Procedure No. 5 ("PP5") procedures by (ii) finding that PP5's procedures

[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] "Consumer Complainants" are Industrial Energy Consumers of America, American Forest & Paper Assoc., R Street Institute, Glass Packaging Institute, Public Citizen, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Assoc. of Businesses Advocating for Tariff Equity, Carolina Utility Customers Assoc., PA Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Elec. Energy Consumers, Inc., Public Power Assoc. of NJ, OK Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of PA, MD Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Div. of the Public Service Commission of WV, and Missouri Industrial Energy Consumers.

[3] EEI and WIRES asked that the period for answers to, interventions in, comments on, and protests of the Complaint be extended an additional 45 days -- to March 20, 2025. The EEI/WIRES request was supported by the ISO/RTO Council ("IRC"), MISO TOs, and Americans for a Clean Energy Grid ("ACEG"). Complainants opposed the EEI/WIRES request.

are unjust and unreasonable and unduly discriminatory and/or preferential in violation of section 206 of the FPA; and (iii) find that ISO-NE has violated the FPA by forcing on State jurisdictional interconnections, such as Allco's, the requirement to pay for transmission level interconnection studies, to pay for Power Systems Computer Aided Design ("PSCAD") models in connection with such studies, and by causing delays to the execution by distribution utilities of State jurisdictional generator interconnection agreements (particularly for Allco's 2 MW Winsted solar energy project). Allco's arguments are very similar to those Allco raised in the *Order 2023* Compliance Revisions and Related Changes proceeding (*see* Section IV below). Comments on the Allco PP5 Complaint, following an ISO-requested and FERC-granted extension of time, are due on or before ***January 15, 2025***. Thus far, interventions have been filed by NEPOOL, Calpine, National Grid, and Public Citizen. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **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).[4] 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.[5] 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.[6] 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.[7] The refund effective date for this proceeding is June 24, 2024.[8] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:[9] NEPOOL, Advanced Energy United ("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.

NE Response to Show Cause Order (Attaching Substantive Response by NETOs). On September 11, 2024, ISO-NE submitted a response ("NE Response") explaining that, because the rules identified in the *TO Initial*

[4] *ISO New England Inc. et al.,* 187 FERC ¶ 61,170 (June 13, 2024) ("*TO Initial Funding Show Cause Order*").

[5] *Id.* at P 1.

[6] *Id.*

[7] *Id.* at P 2.

[8] Notice of this 206 proceeding was published in the *Fed. Reg.* on June 24, 2024 (Vol. 89, No. 121) pp. 52,454-52,455.

[9] 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).

Funding Show Cause Order[10] fall within the exclusive purview of, and are implemented by, the Participating Transmission Owners ("PTOs") under the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs, it had requested that the PTOs respond to the *TO Initial Funding Show Cause Order* and attached the response of Indicated New England Transmission Owners ("NETOS")[11] to the NE Response. NETOs' response identified several reasons why the FERC's proposal is in their view beyond the FERC's authority and power.

Responses to the September NE Response were due on or before October 25, 2024. Responses from ISO-NE-related parties to this joint proceeding were filed by, among others: NE TOs, Invenergy, Public Interest Organizations, Public Systems, Clean Energy Associations, EEI, WIRES, and the Harvard Law Initiative. This matter is pending before the FERC.

Federal Court Appeals. On August 30, 2024, certain parties[12] filed a petition for review of the FERC's orders in this proceeding in the 8th Circuit, since challenged by the FERC. 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).

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

On December 19, 2024, the FERC granted in part and dismissed in part[13] the December 13, 2022 complaint by RENEW Northeast, Inc. ("RENEW") against ISO-NE and the Participating Transmission Owners ("PTOs") that sought changes to the ISO-NE Tariff (Schedules 11 and 21) to eliminate the direct assignment of Network Upgrade Operations and Maintenance costs ("O&M Costs") to Interconnection Customers.[14] In the *RENEW O&M Complaint Order*, the FERC (i) denied ISO-NE's motion for dismissal as a party; (ii) found the Tariff's assignment of O&M Costs unjust and unreasonable; (iii) found the definition of Interested Party from the Formula Rate Protocols does not comply with FERC precedent and is unjust and unreasonable; and (iv) given its findings, dismissed as moot the complaint as to the *transparency* of O&M Costs.[15] Accordingly, the FERC directed ISO-NE and the PTOs to submit a compliance filing, on or before ***February 17, 2025***, "to remove from the Tariff any provisions allowing the assignment of Network Upgrade O&M costs to Interconnection Customers" and directed the PTOs "to revise the Formula Rate Protocols in accordance with [FERC] precedent, including … the definition of Interested Party in the Formula Rate Protocols as including but not limited to customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general." The FERC stated that the revisions will take effect prospectively, from December 19, 2024.[16] A memo from NEPOOL Counsel summarizing in more detail

---

[10] The rules identified in the *Order to Show Cause* were those that establish the methodology to recover costs associated with interconnection-related upgrades, and the related financial obligations of the PTO or the interconnecting party – in New England, set forth in Article 11.3 of the LGIA, Article 5.2 of the SGIA, and Article 11.3 of the ETU IA, as well as Schedule 11 of the OATT.

[11] The NETOs, for purposes of this proceeding, are: Eversource; Central Maine Power Company ("CMP"); The United Illuminating Company ("UI"); New England Power Company ("National Grid"); The Narragansett Electric Company ("RI Energy"); Fitchburg Gas and Electric Light Co. ("Unitil"); and Versant Power ("Versant").

[12] 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").

[13] RENEW Northeast, Inc. v. ISO New England Inc. and New England Participating Transmission Owners, 189 FERC ¶ 61,216 (dec. 19, 2024) ("*RENEW O&M Complaint Order*").

[14] 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.

[15] *Id.* at P 2.

[16] *Id.* at P 3.

the *RENEW O&M Complaint Order* was circulated to and is posted the webpage for the Transmission Committee. Tariff revisions required in response to the Order will be considered at the TC's January 29, 2025 meeting. Challenges, if any, to the *RENEW O&M Complaint Order* are due on or before ***January 21, 2025***. If you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**
  There are four proceedings, long pending before the FERC, in which the TOs' return on equity ("Base ROE") for regional transmission service has been challenged.

  - ***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*.

---

[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*").

➢ ***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 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

---

[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 ¶ 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 Maine 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.

model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[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 Complainant-Aligned Parties ("CAPs") opposed the TOs' request and brief. No action was ever taken in response to this activity.

They're Back …. As reported at the December 5, 2024 Annual Meeting, the TOs filed, on November 13, 2024, a "Motion to File Supplemental Brief Addressing the Inability of the [FERC]'s MISO Methodology to Satisfy the Mandate of the *Emera Maine* Court in these Cases, the Requirements of Section 206, and the Need to Promote Transmission Investment in New England". On December 13, 2024, WIRES/EEI supported the TOs Motion,[32] and CAPs[33] replied in opposition to the Motion. On December 20, 2024, the TOs filed an answer to

---

[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] Agreeing with the TOs, the WIRES/EEI comments asserted: (i) that the FERC lacks the statutory authority to order refunds outside the 15-month refund period; (ii) the FERC's claim of remedial authority to correct legal error does not justify retroactive ROE refunds; and (iii) the FERC should accept and give consideration to the NETOs' supplemental brief and supporting affidavits.

[33] "CAPs" are: the Conn. Pub. Utils. Regulatory Authority ("CT PURA"); the Conn. Office of Consumer Counsel ("CT OCC"); Mass. Mun. Wholesale Elec. Co. ("MMWEC"); NH Elec. Coop. ("NHEC"); the RI Div. of Pub. Utils. and Carriers ("RI Div"); and Eastern Mass. Consumer-Owned Systems ("EMCOS"), who consist of the Belmont Mun. Light Dept. ("Belmont"); Braintree Elec. Light Dept. ("Braintree"); Concord Mun. Light Plant ("Concord"); Georgetown Mun. Light Dept. ("Georgetown"); Groveland Elec. Light Dept. ("Groveland"); Hingham Mun. Lighting Plant ("Hingham"); Littleton Elec. Light & Water Dept. ("Littleton"); Merrimac Mun. Light Dept. ("Merrimac"); Middleton Elec.

the CAPs' statements concerning the FERC's authority to order refunds for the period from when the FERC issues its order on remand back to October 16, 2014.

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

- **Essential Power Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER25-588)**

On November 27, 2024, Essential Power Newington, LLC ("EP Newington") requested FERC acceptance of its revised rate schedule to allow recovery of eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("IROL-CIP Costs") under Schedule 17 of the ISO-NE Tariff, effective 60 days from the date of filing. EP Newington seeks to recover ***$356,401*** in incremental medium impact CIP-IROL Costs incurred between July 1, 2023 and June 30, 2024. Comments on EP Newington's request were due on or before December 18, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER25-519)**

On November 22, 2024 (as corrected on November 25, 2024), ISO-NE and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2025-26 Capability Year, the second ARA for the 2026-27 Capability Year, and the first ARA for the 2027-28 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 7, 2024 meeting (Agenda Item 5). A January 21, 2025 effective date was requested. Comments on this filing were due on or before December 21, 2024; none were filed. Calpine, Eversource, and National Grid intervened doc-lessly. 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).

- **FirstLight CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER25-509)**

On November 21, 2024, FirstLight Power Management ("FirstLight") requested FERC acceptance of its revised rate schedule to allow recovery of eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("IROL-CIP Costs") under Schedule 17 of the ISO-NE Tariff, effective January 20, 2025. FirstLight seeks to recover ***$87,186*** in incremental medium impact CIP-IROL Costs incurred between September 16, 2022 and December 31, 2023. Comments on FirstLight's request were due on or before December 12, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Canal Marketing CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER25-168)**

On December 18, 2024, The FERC accepted Canal Marketing's revised rate schedule to allow recovery of eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("IROL-CIP Costs") under Schedule 17 of the ISO-NE Tariff.[34] Canal Marketing seeks to recover ***$642,189*** in incremental medium impact CIP-IROL Costs incurred between April 1, 2023 and March 31,

Light Dept. ("Middleton"); Reading Mun. Light Dept. ("Reading"); Rowley Mun. Lighting Plant ("Rowley"); Taunton Mun. Lighting Plant ("Taunton"); and Wellesley Mun. Light Plant ("Wellesley").

[34] *Canal Marketing LLC*, Docket No. ER25-168-000 (Dec. 18, 2024) (unpublished letter order).

2024. Canal's revised rate schedule was accepted effective as of December 21, 2024. Unless the December 18 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).

- **2025 NESCOE Budget (ER25-134)**

On December 17, 2024, the FERC accepted ISO-NE's Tariff changes to fund NESCOE's 2025 operations.[35] As previously reported, the 2025 Operating Expense Budget for NESCOE is $2,707,893, and the amount to be recovered, reflecting true-ups from 2023 (over-collections of $1,115,346), will result in a charge of $0.00716 per kilowatt ("kW") of Monthly Network Load (a $0.00091/kW decrease from 2024). The 2025 NESCOE budget changes were accepted effective as of *January 1, 2025*. Unless the December 17 order is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2025 ISO-NE Administrative Costs and Capital Budgets (ER25-110)**

On December 23, 2024, the FERC accepted ISO-NE's filing for recovery of its 2025 administrative costs (the "2025 Revenue Requirement") and its capital budget and supporting materials for calendar year 2025 ("2025 Capital Budget", and together with the 2025 Revenue Requirement, the "2025 ISO Budgets").[36] The 2025 ISO-NE Budgets were accepted effective as of January 1, 2025, as requested. As previously reported, ISO-NE reported in its October 17 filing that the 2025 Revenue Requirement is $306.4 million (a $29.5 million or 10.7% increase over 2024), increased to $311.2 million after the over-collection for 2023 was subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2025 Core Operating Budget) comprise $269.4 million; depreciation and amortization of regulatory assets, $37 million; and a $4.8 million true-up increase for 2023 under-collections.

ISO-NE further reported that the 2025 Capital Budget is $42.5 million, a $7.5 million increase over 2024, and is comprised of the following (with 2025 projected costs and target completion dates, if available, in parentheses):

- nGem Clearing Engine Implementation (Jun 2026) ($4 million)
- Managing Transmission Line Ratings (Nov 2025) ($1.7 million)
- CAMS Software Technology Upgrade (Jun 2025) ($700,000)
- New England Clean Energy Connect ("NECEC") (Dec 2025) ($300,000)
- CIP Electronic Security Perimeter Redesign Phase II ($300,000)
- EMS Short-term Load Forecast Replacement (Jul 2025) ($100,000)
- *Order 841* (Oct 2025) ($2 million)
- Enterprise Core Network Refresh (Dec 2025) ($2 million)
- nGem Software Development Part III (Apr 2025) ($2.9 million)
- DASI Improvements (Mar 2025) ($1.5 million)
- Network Modeling Tool Enhancements (Jul 2025) ($500,000)
- Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements (Aug 2025) ($300,000)
- Tie Line Telemetry and PCEC Upgrade Phase I (Jun 2025) ($100,000)
- Microsoft 365 Service Adoption (Nov 2024) ($100,000)
- Space Utilization Project Phase I (Aug 2025) ($2 million)
- Enterprise Resource Planning System Replacement (Dec 2025) ($1.9 million)

---

[35] *ISO New England Inc.*, Docket No. ER25-134-000 (Dec. 17, 2024) (unpublished letter order).

[36] *ISO New England Inc.*, Docket No. ER25-110-000 (Dec. 23, 2024) (unpublished letter order) ("*2025 ISO-NE Budgets Order*").

- EMS Energy Management Platform ("EMP") 3.5 Upgrade (Dec 2026) ($1.5 million)
- Integrated Market Simulator Enhancement (Dec 2025) ($1.5 million)
- nGEM Software Development Part IV (Jun 2026) ($1 million)
- Tie Line Telemetry and PCEC Upgrade Phase II (Jul 2025) ($500,000)
- Circuit Inventory Management Platform (Oct 2025) ($400,000)
- Adoption of NERC CIP Compliance of Synchrophasor Systems (Oct 2026) ($300,000)
- Non-Project Capital Expenditures ($5 million)
- Capitalized Interest ($1 million)
- Windows Server Replacement Phase II (Dec 2025) ($1.5 million)
- *Order 2222* (Nov 2026) ($1 million)
- MW Dependent Fuel Price Adjustment (Nov 2025) ($1 million)
- Storage as Transmission Only Asset (Mar 2027) ($400,000)
- Replace Employee & Pager Application (Oct 2025) ($300,000)
- Solar DNE Dispatch Phase III (Nov 2025) ($300,000)
- Other Emerging Work ($5.7 million)

Unless the *2025 ISO-NE Budgets Order* is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Rosendo Garza (860-275-0660; rgarza@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, 2024.[37] MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, Identified TOs[38] 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[39] (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).

[37] 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.

[38] "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").

[39] For purposes of this proceeding, "Consumer Advocates" are the MA AG, CT OCC, NH OCA, and RI Division.

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 filed by CMP, Eversource (CL&P, NSTAR East, NSTAR West, and PSNH), MEPCO, National Grid (Narragansett and New England Power), and VTransco (on September 6). On September 5, 2024, MOPA challenged National Grid's claim that, because it had provided copies of what it sent to MOPA originally, MOPA's Formal Challenge could be rejected without further procedures. MOPA continues to assert that the materials provided by National Grid do not constitute a "good faith response" and renewed its request for the FERC to direct the Identified TOs to answer its questions concerning the investment policies and practices used to evaluate the need for a particular asset condition project, a necessary predicate to a prudence review.

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 ("COSA") (ER18-1639)**

***(-029) Global Settlement*.** On November 8, 2024, Constellation Mystic Power, LLC ("Mystic") submitted an unopposed Settlement Agreement and related materials (collectively, the "Global Settlement") to resolve all remaining/outstanding issues related to the COSA between Mystic, Constellation Energy, and ISO-NE.[40] The following parties joined the Global Settlement in its entirety: Mystic; Constellation Energy; Eastern New England Consumer Owned Systems ("ENECOS"); ISO-NE; and the New England States Committee on Electricity ("NESCOE") (collectively, the "Settling Parties").[41] The Settling Parties requested that the FERC act upon the Global Settlement as soon as possible, but no later than February 3, 2025. Comments on the Global Settlement were due on or before November 29, 2024. FERC Trial Staff filed comments in support of the Global Settlement Agreement. No reply comments were filed. The Global Settlement is pending before the FERC. On December 5, 2024, the Chief Judge terminated Settlement Judge procedures.

Mystic COSA ROE Settlement Agreement (ER25-584; ER24-2804). As previously reported, the FERC approved on November 1, 2024 the unopposed Settlement Agreement that establishes a settled ROE of 9.0%[42] for the Mystic COSA ("*Mystic ROE Settlement Agreement*").[43] The *Mystic ROE Settlement Order* will moot the ROE appeals currently pending before the DC Circuit[44] and a pending Revised ROE (Sixth) Compliance Filing pending in

[40] The unresolved issues include, among others, certain formal challenges to Mystic's Sep. 15, 2022 "Second CapEx Info Filing" (which addressed the capital expenditures and related costs that Mystic projected would be collected as an expense between Jan. 1, 2023 to Dec. 31, 2023 ("2023 CapEx Projects"), as well as certain challenges to Mystic's 30-Day Compliance Filing in response to the requirements of *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).

[41] In addition to NEPOOL, the following parties, while not Settling Parties, did not oppose the Global Settlement: MA AG, CT DEEP, CT PRA, CT OCC, MMWEC, National Grid, and NHEC.

[42] 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*")).

[43] *Constellation Mystic Power, LLC*, 189 FERC ¶ 61,091 (Nov. 1, 2024) ("*Mystic ROE Settlement Order*").

[44] 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.*)

ER18-1639-014.[45] As directed, Mystic submitted on November 27, 2024 a compliance filing with revised tariff records in eTariff format to reflect the FERC's action in the *Mystic ROE Settlement Order* (ER25-584).

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[46] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, 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: Withdrawal from Forward Component of the Winter 2024-25 IEP (Cleary Unit 9) (EL25-36)**

On December 2, 2024, Taunton Municipal Lighting Plant ("TMLP"), Hudson Light & Power Department ("Hudson"), and North Attleboro Electric Light Department ("North Attleboro") (collectively, the "Cleary 9 Participants")[47] requested a one-time of the November 1 deadline for rejection by ISO-NE under Market Rule 1 Section III.K.1.1 of the proposed participation by TMLP's Cleary Unit 9 generating unit in the forward component of the Winter 2024-25 Inventoried Energy Program ("IEP"). The Cleary 9 Participants explained that TMLP discovered, during routine maintenance work undertaken in November 2024, that the distillate fuel pump for its Cleary Unit 9A combustion turbine was inoperative and could not be repaired. The time frame for procurement of a replacement distillate fuel pump could take up to 14 months. Given the combination of Cleary 9's interruptible natural gas supply and inability to operate on distillate fuel oil without the Unit 9A fuel pump, it is unlikely that

[45] As long reported, Mystic filed a revised ROE (Sixth) compliance filing (docketed as ER18-1639-014) in response to the requirements of the *Mystic ROE Allegheny Order*. The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods.

[46] 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.

[47] TMLP is the owner and operator of the Cleary Unit 9 electric generating resource (which is composed of generating units 9A and 9S). Hudson and North Attleboro have entitlements to the capacity of Cleary Unit 9 of 4.55% and 9.09%, respectively.

Cleary Unit 9 will be able to provide Inventoried Energy during the Winter 2024-25 IEP program. Accordingly, Cleary 9 Participants asked for a waiver that would enable ISO-NE to reject the participation of TMLP's Cleary Unit 9 in the forward component of the Winter 2024-25 IEP (and thereby not receive the associated base payments). The Cleary 9 Participants also asked that the FERC grant the waiver without impacting the ability of Cleary 9 to participate in the spot component of the Winter 2024-25 IEP (should TMLP be able to replace the Unit 9 fuel pump prior to February 28, 2025). Comments on the Cleary 9 Waiver Request were due on or before December 23, 2024. On December 23, ISO-NE submitted comments supporting the removal of Clearly 9 from the IEP for the 2024-2025 period and refunding the IEP payments received by Cleary 9,[48] as requested by the Cleary 9 Participants. NEPOOL and ENE intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **DASI Effective Date Change (to Feb 28, 2025) (ER25-456)**

On January 2, 2025, the FERC accepted the change filed by ISO-NE to make the effective date for the Day-Ahead Ancillary Services Initiative ("DASI")-related Tariff revisions February 28, 2025 (rather than the previously-accepted date of March 1, 2025).[49] As previously reported, by making the DASI changes effective February 28, 2025, ISO-NE intends to eliminate any confusion about when ISO-NE will first begin accepting Day-Ahead Ancillary Services Offers and clearing Day-Ahead Ancillary Services awards given the termination of the Forward Reserve Market ("FRM") -- the first Operating Day covered by Day-Ahead Ancillary Services awards will be ***March 1, 2025***. The Tariff changes were accepted effective February 28, 2025, as requested. Unless the January 2 letter order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received (Canal Marketing/ Canal 3) (ER25-56; 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 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")[50] 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.[51] 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.

---

[48] If the FERC grants Cleary 9 Participants' request by May 2025, ISO-NE stated that it will use the data reconciliation process set forth in Manual 28 § 6 for the Clearly 9 Participants to refund and repay the ISO-NE IEP revenues received for Clearly 9's participation in the IEP and for ISO-NE to distribute the repayments to the average Real-Time Load Obligation for the IEP winter 2024-2025 period. A resettlement bill for IEP payments would be issued in May 2025 and prospective months. If the FERC does not grant Cleary 9 Participants' request by May 2025, instead of using the Manual 28 data reconciliation process, ISO-NE will utilize the same process as used in the Canal Marketing LLC proceeding (Docket No. ER14-1407-000).

[49] *ISO New England Inc.*, Docket No. ER25-456-000 (Jan. 2, 2025) (unpublished letter order.

[50] 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.

[51] 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.

The IMM submitted comments supporting the CM Waiver Request in so far 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.[52] On August 21, 2024, the Chief ALJ designated ALJ Patricia E. Hurt as the settlement judge in this proceeding. Judge Hurt submitted her 1st status report on September 20, 2024, recommending that the settlement process continue. A formal settlement conference was held on September 23, 2024, at which time the parties reported that a settlement in principle between Canal and ISO-NE had already been reached. On November 19, 2024, Judge Hurt issued a second status report, followed one week later by a third and final status report that reported that she had certified the Canal IEP Settlement Agreement to the Commission and recommended that settlement procedures be terminated. On December 2, 2024, Deputy Chief ALJ Renee Terry, subject to final action by the Commission, terminated the settlement judge procedures in this proceeding.

Settlement Agreement (ER25-56). An *unopposed* settlement agreement, which will resolve all of the issues raised in this proceeding ("Canal IEP Settlement Agreement"), was submitted on October 8, 2024 (ER25-56). The Settlement Agreement provides that CM will refund and repay to ISO-NE the net revenues that it received on behalf of Canal 3 for participating in the IEP for the Winter 2023-2024 period, plus interest. The settlement amount ("Settlement Amount") will consist of a lump sum of $1,968,156.08 and an amount of interest to be calculated in accordance with FERC regulations. The time period for calculating that interest will be from January 15, 2024, the midpoint of the IEP 2023-2024 Winter period, until the day that the parties receive notice of approval of the Canal IEP Settlement Agreement by the FERC. Canal Marketing will have 10 Business Days from the date that the FERC approves the Settlement Agreement to pay the Settlement Amount to ISO-NE. ISO-NE will have 60 days to distribute the Settlement Amount as appropriate to the average Real-Time Load Obligation for the IEP Winter 2023-2024 period. Details regarding the distribution to IEP Participants will be provided by ISO-NE in a notice and included in the applicable monthly settlement's job aid. On October 28, 2024, FERC Trial Staff filed initial comments in support of the Canal IEP Settlement Agreement. No reply comments were filed. Settlement Judge Hurt certified the uncontested Canal IEP Settlement Agreement to the Commission on November 26, 2024. The Canal IEP Settlement Agreement is pending before the Commission. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **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[53] to allow it to accept, after August 30, 2024, the SIS results for its facility[54] 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.[55] On September 6, ISO-NE protested the waiver request asserting that GDQ ESS does not meet the FERC's standard for granting waivers. NEPOOL and Calpine

[52] *Canal Marketing LLC*, 188 FERC ¶ 61,122 (Aug. 12, 2024).

[53] 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").

[54] 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.

[55] 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.

intervened. There has been no activity in this proceeding since the last Report. The GDQ ESS waiver request remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **PBOP Collections Report (New England Power) (ER25-510)**

On November 22, 2024, New England Power ("NEP") filed a report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT. The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F.[56] No changes to the filed rate were sought. The report shows an over-recovery, after interest, of ***$2,852,101***. If accepted, the PBOP figures will be used in NEP's 2025 Annual Updates. Comments on this filing were due on or before December 13, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Attachments C and Q Revisions (ER25-410)**

On November 12, 2024, ISO-NE and NEPOOL jointly filed proposed revisions to Attachments C and Q of the OATT. The revisions to Attachment C are to conform to the requirements established by Order 881.[57] The revisions to Attachment Q address the use of Ambient Adjusted Ratings at ISO-NE's seams. An effective date of July 12, 2025 was requested. Comments on this filing were due on or before December 3, 2024; none were filed. Calpine and National Grid intervened doc-lessly. On December 10, 2024, ISO-NE supplemented the record by identifying an error in the eTariff effective date requested as part of the November 12 filing. The supplement confirmed that the effective date requested is July 12, 2025. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PBOP Collections Report (RI Energy) (ER25-343)**

On December 10, 2024, the FERC accepted RI Energy's report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions under Appendix A to Attachment F to the ISO-NE OATT.[58] The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F.[59] No changes to the filed rate were sought. The report showed an over-recovery, after interest, of $974,272. The revised PBOP figures will be used in RI Energy's 2025 Annual Updates. The report was accepted effective *January 1, 2025*. Unless the December 10 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NE/NB Coordination Agreement Updates (ER25-328)**

On December 17, 2024, the FERC accepted updates to the Coordination Agreement Between ISO-NE and the New Brunswick System Operator ("NE/NB Coordination Agreement") jointly filed by ISO-NE and NEPOOL.[60] As previously reported, the updates: (i) reflect the amalgamation of the New Brunswick Power

[56] A Report is required when "the absolute value of [(Cumulative Under/(Over) Recovery, including Current Year interest)] is greater than $100,000 and the absolute value of [(Cumulative Under/(Over) recovery, including Current Year interest, as a percent of transmission-related PBOP expense)] is greater than 20%. See ISO-NE OATT, Attachment F, Appendix A, Worksheet 9, Note (j).

[57] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021) ("*Order 881*").

[58] *ISO New England Inc.*, Docket No. ER25-343-000 (Dec. 10, 2024) (unpublished letter order).

[59] A Report is required when "the absolute value of [(Cumulative Under/(Over) Recovery, including Current Year interest)] is greater than $100,000 and the absolute value of [(Cumulative Under/(Over) recovery, including Current Year interest, as a percent of transmission-related PBOP expense)] is greater than 20%. See ISO-NE OATT, Attachment F, Appendix A, Worksheet 9, Note (j).

[60] *ISO New England Inc.*, Docket No. ER25-328-000 (Dec. 17, 2024) (unpublished letter order).

Group of Companies and align the agreement with the structure of the ISO-NE/NYISO Coordination Agreement; (ii) recognize the NERC Registered Reserve Sharing Group; and (iii) update pricing-related provisions for Security Energy and Emergency Energy. The updates were accepted effective as of *January 1, 2025*, as requested. Unless the December 17 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PBOP Collections Report (CL&P) (ER25-306)**

On December, 2024, the FERC accepted CL&P's report identifying planned collection activity related to the over recovery of PBOP under Appendix A to Attachment F to the ISO-NE OATT.[61] The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F. No changes to the filed rate were sought. The report showed an over-recovery, after interest, of $173,347. The PBOP figures will be used in CL&P's 2025 Annual Updates. The filing was accepted effective *January 1, 2025*, as requested. Unless the December 10 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 2023* Compliance Revisions (ER24-2009) and Related Changes (ER24-2007)**

On May 14, 2024 (as corrected May 31, 2024), ISO-NE, NEPOOL and the PTO AC filed (i) proposed Tariff revisions in response to the requirements of *Orders 2023* and *2023-A* ("*Order 2023 Compliance Revisions*") and Tariff revisions to harmonize the SGIP, ETU Interconnection Procedures ("ETUIP"), and Regional Transmission Service rules with the contemporaneously-filed *Order 2023 Compliance Revisions* ("*Order 2023 Related Changes*"). The *Order 2023 Compliance 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 Forward Capacity Market ("FCM") participation, and a unified treatment of all ISO interconnection requests, including those for small generators and Elective Transmission Upgrades ("ETU") (filed in ER24-2007).[62] The *Order 2023 Related Changes* were filed concurrently as they may be considered to be beyond the scope of the compliance obligations.[63] The filing parties requested an effective date of August 12, 2024 for the *Order 2023 Compliance Revisions* and that the FERC issue an order for the *Order 2023 Related Changes* concurrently with its order on the *Order 2023 Compliance Revisions* and that the *Order 2023 Related Changes* become effective on the same date as the *Order 2023 Compliance Revisions*.

Comments on these filings were due on or before June 4, 2024, and were filed by BlueWave, Glenvale, New Leaf, RENEW, Clean Energy Associations,[64] and Longroad Energy Holdings. Calpine, Clearway, Constellation, National Grid, NESCOE, RIE, Shell Energy/Savion, MA DPU, and Cordelio Services intervened doc-lessly. On June

[61] *ISO New England Inc.*, Docket No. ER25-306-000 (Dec. 10, 2024) (unpublished letter order).

[62] The *Order 2023 Related Changes*, which propose changes to aspects of the Tariff impacted by the *Order 2023 Compliance 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.

[63] The *Order 2023 Related Changes* 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.

[64] "Clean Energy Associations" are, collectively, AEU, ACPA, Natural Resources Defense Council ("NRDC"), and SEIA.

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. On September 30, 2024, Allco intervened out-of-time and protested this filing (asserting that the new proposed ISO-NE practices "will strike a crushing blow to small distributed solar between 1 MW and 5 MW" by "imposing knee-buckling interconnection fees and costs and a crushing interconnection process"). On October 18, 2024, ISO-NE answered the Allco protest, and Allco answered ISO-NE's October 18 answer on October 24, 2024. Allco supplemented its October 24 answer on November 12, ISO-NE answer Allco's November 12 supplement on November 13, and Allco answered ISO-NE November 18 answer. In addition, on November 25, 2024, NESCOE urged the FERC to act swiftly on the region's *Order 2023* compliance proposal. In a related matter, Allco filed a separate complaint (*see* EL25-43 above) making many of the same points as laid out in its out-of-time protest and comments.

The Order 2023 Compliance Revisions and Related Changes remain pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 881* Compliance Filing (Transmission Line Rating Calculation and Submittal Timeframe Implementation Details) (Phase I/II HVDC-TF) (ER22-2468-001; ER22-2467-001)**

Following a requested 14-day extension of time granted by the FERC,[65] ISO-NE, the Asset Owners,[66] and the Schedule 20A Service Providers[67] jointly submitted their compliance filing to address the sole directive in the June 15, 2023 *Phase I/II HVDC-TF Order 881 Compliance Order*[68] to provide implementation details regarding the calculation and submittal timeframes for the ambient-adjusted ratings ("AARs") required by *Order 881*. Comments on this filing were due on or before December 13, 2024; none were filed. This *Order 881* compliance filing is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 881* Compliance Filing (Transmission Line Rating Calculation and Submittal Timeframe Implementation Details) (New England) (ER22-2357-002)**

On November 12, 2024, ISO-NE and the PTO AC jointly submitted implementation details regarding the calculation and submittal timeframes for the Transmission Line Ratings as required by *Order 881*. Comments on this filing were due on or before December 3, 2024; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FAP Revisions to Mitigate Risk of PFP Penalty Payment Defaults (ER24-3071)**

On September 18, 2024, ISO-NE proposed Financial Assurance Policy ("FAP") revisions for Participants that are determined not to have adequate corporate liquidity relative to potential obligations that may be incurred

[65] *See* Notice of Extension of Time, *ISO New England Inc.*, Docket Nos. ER22-2467-000 and ER22-2468-000 (Nov. 19, 2024) (extending by 14 days, to Nov. 26, 2024, the compliance deadline set forth in the *Phase I/II HVDC-TF Order 881 Compliance Order*).

[66] The "Asset Owners" are, collectively: New England Hydro-Transmission Elec. Co., Inc.; New England Hydro-Transmission Corp.; New England Elec. Transmission Corp.; and Vermont Elec. Transmission Co.

[67] The "Schedule 20A Service Providers" are the public utilities that provide transmission service under Schedule 20A to the ISO-NE OATT.

[68] *ISO New England Inc.*, 183 FERC ¶ 61,179 (June 15, 2023) ("*Phase I/II HVDC-TF Order 881 Compliance Order*").

under the pay for performance ("PFP") construct of the FCM (the "FAP Revisions"). Beginning with the 2025 – 2026 Capacity Commitment Period ("CCP"), ISO-NE will perform a corporate liquidity assessment on each FCM participant holding a Capacity Supply Obligation ("CSO") (or its guarantor, if such guarantor is guaranteeing the payment of PFP penalties), to determine its ability to pay potential penalty payment obligations associated with its CSO within the applicable Capacity CCP, over a forward-looking rolling six months. "Low risk" participants will continue to be subject to the current FCM Delivery Financial Assurance methodology; "medium and high risk" participants will be subject to higher collateral requirements (risk adders). ISO-NE proposed a February 1, 2025, effective date for these changes. The changes were considered, but were not supported, by the Participants Committee at its September 5, 2024 meeting (Agenda Item #5). Comments on these changes were due on or before October 9, 2024. NEPGA filed a protest (protesting the proposed effective date, though not the substance of, the FAP Revisions)[69] and NEPOOL filed comments (summarizing consideration of the changes in the stakeholder process). Interventions only were filed by: Calpine, Dominnion, ENE, HQ US, National Grid, MA DPU, and Public Citizen. On October 24, as corrected on November 1, 2024, ISO-NE answered NEPGA's protest. NEPGA answered ISO-NE's answer on November 5, 2024. On November 15, ISO-NE answered NEPGA's November 5 answer. This matter ***remains pending*** before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

- **Schedule 21-ES: Essential Power MA/NSTAR/ISO-NE LSA (ER25-429)**

On January 6, 2025, the FERC accepted a non-conforming[70] Local Service Agreement ("LSA") between NSTAR and Essential Power Massachusetts, Inc. for firm Local Point-to-Point Service to Essential Power's 45 MW BESS Large Generating Facility located in West Springfield, MA ("West Springfield Project").[71] The LSA was accepted effective as of *October 15, 2024*, as requested. Unless the January 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-RIE: Revisions (ER25-347)**

On November 1, 2024, RI Energy submitted revisions to Schedule 21-RIE ("RIE Revisions") to, among other things: (i) clarify the function of the meter surcharge calculation contained in Attachment OCC, Exhibit 3; (ii) align the exhibit numbers with the corresponding excel spreadsheet titles in Attachment OCC, Exhibits 4 and 5; (iii) add a definition for "Primary Revenue Credit" to Attachment RR, Exhibit 1; (iv) amend the definition for "Primary Related Accumulated Deferred Income Taxes" contained in Attachment RR, Exhibit 1; (v) revise Attachment OCC Exhibit 4 to include ISO-NE expenses in Line 6; and (vi) amending Attachment RR, Exhibit 2, to clarify the function of the (Excess)/Deficient Accumulated Deferred Income Tax ("ADIT") calculation. RI Energy requested a January 1, 2025 effective date for the RIE Revisions. Comments on this filing were due on or before November 22, 2024; none were filed. On December 23, 2024, RI Energy amended its filing to include in Attachment RR, Exhibit 2.3 note 3 language that was inadvertently omitted from the clean version of note that was filed. Comments on that amendment are due ***January 13, 2025***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

---

[69] NEPGA asserted that the FAP Revisions, if applied as requested beginning on June 1, 2025, would alter the legal requirements associated with CSOs in violation of the filed rate doctrine, and would decrease confidence in the stability and predictability of the wholesale markets, undermining reliability in New England. Accordingly, NEPGA asked that the FAP Revisions be made effective June 1, 2028 (i.e., the first day of the FCA19 CCP).

[70] The LSA is non-conforming in that it contains provisions reflecting a long-standing agreement between NSTAR and Essential Power, including a discounted rate. Although NSTAR believes that the discounted rate provisions may not trigger a Section 205 filing requirement, NSTAR nevertheless requested that the LSA be accepted for filing without any determination whether the LSA needed to be submitted in the first instance.

[71] *ISO New England Inc.*, Docket No. ER25-429-000 (Jan. 6, 2025) (unpublished letter order).

- **Schedule 21-GMP: GMP-Hardwick NITSA Notice of Cancellation (ER25-298)**

On October 30, 2024, GMP submitted a notice of cancellation of the Network Integration Transmission Service Agreement and Local Operating Agreement ("NITSA") with the Village of Hardwick Electric Department ("Hardwick") filed under Schedule 21-GMP. GMP reported that, as of June 30, 2024, Hardwick is no longer taking service pursuant to the NITSA. GMP requested that the FERC grant waiver of its notice requirement[72] to the extent necessary to permit a requested June 30, 2024 effective date. Comments on this filing were due on or before November 20, 2024; none were filed. As of the date of this Report, the FERC has not acted on this filing. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 22: ISO-NE/CMP/Andro Hydro LGIA (ER24-2970)**

On September 4, 2024, as corrected on October 28, 2024,[73] ISO-NE and CMP filed a revised LGIA with Andro Hydro to clarify the relationship between Andro Hydro (Interconnection Customer) and JGT2 Redevelopment LLC ("JGT2"), the owner of a closed paper mill located on Andro Hydro's side of the interconnection, and the status of the Interconnection Facilities governed by the LGIA. While the LGIA is based on the Schedule 22 *pro forma* LGIA, it contains limited revisions that are necessary given the Large Generating Facility's unique interconnection to the system, , including the interconnection of its facility through shared facilities co-owned, and used by, JGT2 Redevelopment LLC to serve its own load,[74] thus making it non-conforming and requiring it to be filed with the FERC. The Parties requested an August 8, 2024 effective date (the date on which all of the parties to the LGIA executed the agreement). Initial comments on the LGIA filing were due on or before September 25, 2024; none were filed. With the correction filed on October 28, a second comment period was established, with any comments due on or before November 18, 2024; no comments were submitted by the second comment deadline.

Deficiency Letter. On December 27, 2024, the FERC issued a deficiency letter requesting additional information required to process the filing. Specifically, ISO-NE was directed to explain in detail why the proposed revisions to the *pro forma* LGIA are necessary deviations, identifying any specific reliability concerns, novel legal issues, or other unique factors that make the non-conforming language necessary.[75] The response to the Deficiency Letter is due on or before ***January 27, 2025*** and, as an amendment to the amended September 4 filing, will again re-set the statutory deadline for FERC action.

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

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

As previously reported, the FERC accepted for filing a LSA by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro, LLC ("Jonesboro"), effective *December 4, 2023*, but denied waiver of the

[72] 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.

[73] The October 28 filing corrects an administrative error that resulted in the redlined and clean versions of the LGIA being inconsistent with one another. A corrected version of the LGIA was being submitted and noticed for public comment.

[74] The original non-conforming LGIA was filed in Docket No. ER24-1477. Reporting on that docket has concluded as the Filing Parties indicated that filing will be withdrawn upon action on this instant filing. Details concerning Docket No. ER24-1477 can be found in the last Report.

[75] A transmission provider seeking a case-by-case specific deviation from a *pro forma* interconnection agreement bears a high burden, and it must explain what makes the interconnection unique and what operational concerns or other reasons necessitate each non-conforming provision. *See Order 2023* at P 15 (citing *PJM Interconnection, L.L.C.*, 111 FERC ¶ 61,098, at P 9 (2005)); *Order 2003-B* at P 140 ("each Transmission Provider submitting a non-conforming agreement for Commission approval must explain its justification for each nonconforming provision").

FERC's 60-day prior notice requirement for the filing.[76] 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).

- **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").[77] 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[78] to the extent necessary to permit a requested October 21, 2022 effective date. The LSA was filed separately given that requested effective date. 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.[79] 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.

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").[80] 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

[76] *ISO New England Inc.*, Docket No. ER24-24-000 (Nov. 30, 2023) (unpublished letter order).

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

[78] 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.

[79] *ISO New England Inc.*, Docket No. ER23-2804-000 (Nov. 7, 2023) (unpublished letter order).

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

requirement.[81] On August 29, 2023, Versant submitted a Refund Report detailing the Time Value Refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments on the Refund Report were due on or before September 19, 2023; none were filed. The Refund Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On August 29, 2023, Versant submitted a Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC. Versant stated that, if approved, the 2022 Annual Update Settlement Agreement would resolve all issues raised by the MPUC with respect to the 2022 Annual Update. Comments on the Versant 2022 Annual Update Settlement Agreement were due on or before September 19, 2023; none were filed. MPUC intervened doc-lessly on September 15, 2023. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports[82]

- **Capital Projects Report – 2024 Q3 (ER25-125)**

On December 5, 2024, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2024 (the "Q3 Report").[83] As previously reported, 2024 Q3 Report highlights included:

- One new project -- Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements ($300,000);
- 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.

The Report was accepted, effective as of *October 1, 2024*, as requested. The December 5 order was not challenged and is final and unappealable. Reporting on this matter has concluded. If you have any final questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **IMM Quarterly Markets Reports: Summer 2024 (ZZ24-4)**

On November 25, 2024, the IMM filed with the FERC its Summer 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. These filings are not noticed for public comment by the FERC. The Summer Report was discussed with the Markets Committee at

[81] 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.

[82] 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.

[83] *ISO New England Inc.*, Docket No. ER25-125-000 (Dec. 5, 2024) (unpublished letter order).

the Markets Committee's December annual meeting. Following that meeting, on December 18, 2024, the IMM filed a revised report to correct (i) the calculation of total PFP payments for the June 18 and August 1 scarcity events (total PFP payments for June 18 were $13.9 million, not $10.1 million as originally stated; and $48.8 million August 1, not $36.9 million as originally stated); and (ii) footnote 44 to state that no local reserve constraints bound (and not for two intervals as previously stated).

IX. Membership Filings

Questions concerning any of the Membership Filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Jan 2025 Membership Filing (ER25-841)**

On December 31, 2024, NEPOOL requested that the FERC accept: (i) the following Applicants' memberships in NEPOOL as of January 1, 2025: All Choice Energy NE LLC (Supplier Sector); Karbone Energy LLC (Supplier Sector); and The Metropolitan District (Publicly Owned Entity Sector); and (ii) the termination of the Participant status of: TrueLight Commodities, LLC (Supplier Sector) (Dec 1, 2024); Blueprint Power Technologies LLC [Related Person to BP Energy (Supplier Sector)] (Jan 1, 2025); and Sunrun Inc. (AR Sector, DG Sub-Sector) (Jan 1, 2025). Comments on this filing are due on or before January 21, 2025.

- **November 2024 Membership Filing (ER25-296)**

On December 30, 2024, the FERC accepted the termination of the Participant status of ProGrid Ventures and Palm Energy.[84] Unless the December 30 order is challenged, this proceeding will be concluded.

X. Misc. - ERO Rules, Filings; Reliability Standards[85]

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).

- **Reliability Standards: BAL-007-1 and TOP-003-7 (RD25-5)**

On January 6, 2025, NERC filed for approval a proposed new Reliability Standard BAL-007-1 (Near-Term Energy Reliability Assessments), revisions to TOP-003-7 (Transmission Operator and Balancing Authority Data and Information Specification and Collection) and proposed definitions of "Energy Reliability Assessment" ("ERA") and "Near-Term Energy Reliability Assessment" ("Near-Term ERA") for inclusion in the *Glossary of Terms* used in NERC Reliability Standards. NERC also requested approval of the associated Implementation Plan, Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and the retirement of currently-effective Reliability Standard TOP-003-6.1. NERC states that these changes are to help address the reliability risks associated with inconsistent output from various energy resources, which, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk-Power System ("BPS") needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS.[86] Comments on this filing are due on or before ***February 5, 2025***.

---

[84] *New England Power Pool Participants Comm.*, Docket No. ER25-296-000 (Dec. 30, 2024) (unpublished letter order).

[85] 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.*).

[86] To address the risks, proposed BAL-007-1 would require Balancing Authorities to (1) perform ERAs in the operations planning time horizon to identify possible Energy Emergencies, and (2) develop and implement Operating Plans to minimize the risks of any forecasted Energy Emergency identified in the ERA. The TOP-003 modifications are designed to provide Balancing Authorities with the ability to collect the data necessary to perform such assessments.

- **Reliability Standard: TPL-008-1 (RD25-4)**

On December 17, 2024, NERC filed for approval, in response to the requirements of *Order 896*,[87] a proposed new Reliability Standard TPL-008-1 (Transmission System Planning Performance Requirements for Extreme Temperature Events) and a proposed definition of "Extreme Temperature Assessment" for inclusion in the *Glossary of Terms*. NERC also requested approval of the associated Implementation Plan, VRFs and VSLs. NERC states that the new Reliability Standard is intended to improve how the entities responsible for planning for the reliable operation of the North American interconnected transmission systems plan for the wide-area impacts of extreme heat and cold temperature events, particularly when their systems are facing unexpectedly high demand. Comments on this filing are due on or before ***January 17, 2025***.

- **Revised Reliability Standard: PRC-030-1 (RD25-3)**

On November 4, 2024, NERC filed for approval, in response to the requirements of *Order 901*,[88] revisions to Reliability Standard PRC-030-1 (Unexpected Inverter-Based Resource Event Mitigation) to require Generator Owners to identify, analyze, and mitigate Inverter-Based Resources ("IBR") performance issues. NERC stated that "PRC-030-1 addresses the need for Corrective Action Plans to reduce poor IBR ride-through performance from exacerbating system disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop and implement new processes to meet the new requirements." Comments on this filing were due on or before December 4, 2024; none were filed. Calpine, Dominion, Eversource, ACPA, North Carolina Electric Membership Corporation ("NCEMC"), Orsted Wind, and the Solar Energy Industries Association intervened doc-lessly. This matter is pending before the FERC.

- **Revised Reliability Standards: PRC-028-1 and PRC-002-5 (Disturbance Monitoring) (RD25-2)**

On November 4, 2024, NERC filed for approval, also in response to the requirements of *Order 901*, revisions to Reliability Standards PRC-028-1 and PRC-002-5 to ensure that adequate data from both synchronous generating resources and IBRs is available to facilitate the analysis of disturbances on the Bulk-Power System, and that adequate data is available from IBRs to evaluate ride-through performance during disturbances. Comments on this filing were due on or before December 4, 2024; none were filed. Calpine, Dominion, Eversource, Invenergy Renewables, ACPA, NCEMC, Orsted Wind, and SEIA intervened doc-lessly. This matter is pending before the FERC.

- **Addition of "Inverter-Based Resource" to NERC Glossary of Terms (RD25-1)**

On November 4, 2024, NERC filed for approval a new definition of the term "Inverter-Based Resource" ("IBR") for inclusion in the Glossary of Terms used in NERC Reliability Standards. The proposed definition is as follows:

> Inverter-Based Resource: A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as an inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. Examples include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

NERC asked that the definition of IBR become effective on the first day of the first calendar quarter following FERC approval. Comments on this filing were due on or before December 4, 2024; none were filed. Calpine, Dominion, Eversource, Invenergy Renewables, ACPA, NCEMC, Orsted Wind, RENEW Northeast, and SEIA intervened doc-lessly. This matter is pending before the FERC.

---

[87] *Transmission System Planning Performance Requirements for Extreme Weather*, Order No. 896, 183 FERC ¶ 61,191 (2023) ("*Order 896*").

Reliability Standards to Address Inverter-Based Resources, Order No. 901, 185 FERC ¶ 61,042 at P 229 (2023) ("*Order 901*").

[88] *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042 at P 229 (2023) ("*Order 901*").

- **Revised Reliability Standards: PRC-029-1 and PRC-024-4 (RM25-3)**

On November 4, 2024, NERC filed for approval, in response to the requirements of *Order 901*, revisions to Reliability Standards PRC-029-1 and PRC-029-4, as well as a proposed change to the Glossary definition of "Ride-through" to establish voltage and frequency ride-through criteria for Generator Owners of IBRs to continue to inject current and perform voltage support during a BPS disturbance and prohibit momentary cessation in the no-trip zone during disturbances. On December 19, 2024, the FERC issued a NOPR proposing to approve the Reliability Standards.[89] Comments on the IBR Frequency and Ride-Through Reliability Standards NOPR will be due [60 days after the date of publication in the *Federal Register*, which as of the date of this Report has not yet happened.] Since the last Report, the UnFrack FERC Coalition submitted comments, and interventions were filed by The KY AG, PJM IMM, Indiana Utility Regulatory Commission, and Sunflower Electric Power Corporation. Eversource, ACPA, NCEMC, Orsted Wind, and SEIA intervened have also intervened.

- **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,[90] as well as 18 new or revised definitions for inclusion in NERC's Glossary,[91] 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 yet noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **NOPR: CIP-015-1 (Cyber Security – Internal Network Security Monitoring) (RM24-7)**

On September 19, 2024, the FERC issued a NOPR[92] proposing to approve Reliability Standard CIP-015-1 (Cyber Security – Internal Network Security Monitoring) and to direct that NERC develop certain modifications to CIP-015-1 to extend internal network security monitoring ("INSM") to include electronic access control or monitoring systems and physical access control systems outside of the electronic security perimeter. Comments on the NOPR were filed by NERC, NESCOE, the IRC, APPA, and Open Policy. This matter is pending before the FERC.

- **NOPR: Supply Chain Risk Reliability Standards (RM24-4)**

Also on September 19, 2024, the FERC issued a NOPR proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that address the sufficiency of responsible entities' supply chain risk management plans related to the identification of, assessment of, and response to supply chain risks, and applicability of Reliability Standards' supply chain protections to protected cyber assets.[93] Comments on the

[89] *Reliability Standards for Frequency and Voltage Protection Settings and Ride-Through for Inverter-Based Resources*, 189 FERC ¶ 61,212 (Dec. 19, 2024) ("IBR Frequency and Ride-Through Reliability Standards NOPR").

[90] 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).

[91] 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").

[92] *Critical Infrastructure Protection Reliability Standard CIP-015-1 – Cyber Security – Internal Network Security Monitoring*, 188 FERC ¶ 61,175 (Sep. 19, 2024) ("*CIP-015 INSM NOPR*").

[93] *Supply Chain Risk Management Reliability Standards Revisions*, 188 FERC ¶ 61,174 (Sep. 19, 2024) ("*Supply Chain Risk Standards NOPR*").

NOPR were due on or before December 2, 2024[94] and were filed by, among others: NERC and its Regional Entities, NESCOE, BPA, APPA/LPPC, EEI, North American Transmission Forum, National Electrical Manufacturers Association, and Secure the Grid. On December 16, 2024, TAPS filed comments supporting the APPA/LPPC comments. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Plus Power/TWG Global (EC25-28)**

On December 10, 2024, Plus Power MBR Applicants[95] requested FERC approval for the transfer of managerial control over the Plus Power MBR Entities to TWG Global Holdings, LLC ("TWG Global"). Comments on this application were due on or before December 31, 2024; none were filed. Public Citizen intervened doc-lessly. This application 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: RISEC/Shell (EC25-14)**

On January 7, 2025, the FERC authorized Shell's indirect acquisition of 100% of the ownership interests in Rhode Island State Energy Center, LP ("RISEC") from investment fund vehicles managed/advised by The Carlyle Group.[96] Following consummation of the proposed transaction, RISEC will become a Related Person to Shell and its Related Persons. A notice of consummation must be filed within 10 days of the date of consummation (which as of the date of this Report has not been filed). If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Carlyle Group (Nautilus)/Q-Generation (Trafigura) (EC24-114)**

On November 21, 2024, the FERC authorized 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.[97] As previously reported, following consummation of the proposed transaction, the ISO-NE Companies[98] 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). 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). A notice of consummation must be filed within 10 days of the date of consummation (which as of the date of this Report has not been filed). If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CL&P/BPUS Agreements Cancellation Notices (ER25-870 and ER25-869)**

On January 7, 2025, CL&P submitted notice of cancellation for two agreements with BPUS Generation Development LLC ("BPUS") – an Engineering and Design Agreement (ER25-870) and an Engineering and Test Agreement (ER25-869). CL&P stated that it has completed all work pursuant to each of the Agreements and reconciliation of billings is complete. A January 8, 2025 effective date was requested for each notice. Comments

---

[94] The *Supply Chain Risk Standards NOPR* was published in the *Fed. Reg.* on Oct. 1, 2024 (Vol. 89, No. 190) pp. 79,794-79,804.

[95] "Plus Power MBR Applicants" include Energy Storage Resources, a voting member in the AR Sector's Distributed Generation Sub-Sector, and two Entities whose applications have been conditionally approved for membership -- Cranberry Point Energy Storage and Cross Town Energy Storage.

[96] *Rhode Island State Energy Center, LP and Shell Energy North America (US), L.P.*, 190 FERC ¶ 62,010 (Jan. 7, 2025).

[97] *Bridgeport Energy LLC et al.*, 189 FERC 61,129 (Nov. 21, 2024).

[98] "ISO-NE Companies" include: Nautilus Power, Bridgeport Energy LLC; Essential Power Massachusetts, LLC; Essential Power Newington, LLC; Rumford Power LLC; and Tiverton Power LLC.

on these filings are due on or before ***January 28, 2025***. If you have any questions concerning either of these notices, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Rate Incentive: National Grid portion of Power Up Project (NGPUP) (ER25-866)**

On January 6, 2025, National Grid requested approval of an Abandoned Plant Incentive in connection with transmission upgrades that it plans to construct as part of the Power Up New England Project ("Power Up Project").[99] National Grid's portion of the Power Up Project (or "NGPUP") is designed to provide congestion relief enabling 2,400 MW of simultaneous power injection capacity at Brayton Point in coastal Massachusetts. NGPUP is being constructed as an Elective Transmission Upgrade ("ETU") under the Tariff. National Grid requested a March 7, 2025 effective date for the Abandoned Plant Incentive. Comments on the NGPUP Abandoned Plant Incentive request are due on or before ***January 27, 2025***. Thus far, a doc-less intervention only was filed by the MA DOER. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Rate Incentives: CL&P portion of Power Up Project (Huntsbrook Junction Project) (ER25-747)**

On December 18, 2024, CL&P requested approval of an Abandoned Plant Incentive and, "out of an abundance of caution and to the extent necessary" an RTO Participation Incentive (together, the "Huntsbrook Junction Incentives") in connection with its portion of the Power Up Project – CL&P's Huntsbrook Junction project (the "Huntsbrook Project"). The Huntsbrook Project is a new 345 kV switching station at the Huntsbrook Junction in eastern Connecticut that will enable the interconnection of up to 2,400 MW of offshore wind. The Huntsbrook Project has a projected in-service date of December 2031. Comments on the Huntsbrook Project were due on or before January 8, 2025, and were filed by NESCOE and the MA DOER. A doc-less intervention only was filed by the MA AG. 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).

- **TSAs: Fourth Amendments to NECEC Transmission TSAs (ER25-261 et al.)**

On December 23, the FERC accepted fourth amendments to 7 of NECEC Transmission's previously-filed and accepted, cost-based transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of the New England Clean Energy Connect Project ("NECEC").[100] As previously reported, the amendments (i) extend critical milestone dates set forth in the TSAs and (ii) amend the changes to applicable law provisions set forth in the TSAs. An October 30, 2024 effective date was requested. Comments on the fourth amendments were due on or before November 19, 2024; none were filed. Eversource, National Grid, and the MA DPU 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).

- **UI Rate Incentives for Fairfield to Congress 115kV Railroad Project (ER25-167)**

On December 20, 2024, the FERC granted UI's requests for approval of a Construction Work in Progress ("CWIP") Incentive and an Abandoned Plant Incentive (together, the "Incentives") in connection with its Fairfield to Congress 115kV Railroad Project (the "Project").[101] As previously reported, the Project is a transmission line rebuild project in Fairfield, CT and Bridgeport, CT that includes the relocation of transmission lines from 7.3 miles of the existing Connecticut Department of Transportation's Metro-North Railroad corridor and a rebuild of a 115-kV transmission line along 0.23 miles of existing UI right-of-way to allow interconnection of the rebuilt facilities with UI's existing Ash Creek, Resco, Pequonnock, and Congress Street substations. The Project was identified in the March 2023 RSP Asset Condition List as PTF that must be rebuilt or modified due to its condition, age, or

[99] The total estimated cost of the transmission portion of the Power Up Project is approximately $898 million, of which $389 million will be funded through a DOE grant under DOE's Grid Resilience and Innovation Partnership ("GRIP") program.

[100] *NECEC Transmission LLC*, Docket Nos. ER25-254 *et al.* (Dec. 23, 2024) (unpublished letter order).

[101] *United Illuminating Co. and ISO New England Inc.*, 189 FERC ¶ 61,221 (Dec. 20, 2024) ("*UI Railroad Project Incentives Order*").

physical deterioration to comply with National Electrical Safety Code standards. The Project revenue requirement will be charged to RNS pursuant to Schedule 9 of the ISO-NE Tariff. The Incentives were granted effective *December 21, 2024*. Unless the *UI Railroad Project Incentives Order* is challenged, with any challenges due on or before ***January 20, 2025***, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LCCSA Amendment: National Grid (Termination of RIE/BIPCO/PUD Participation) (ER25-88)**

On December 9, 2024, the FERC accepted an amended Local Control Center Services Agreement ("LCCSA") filed by New England Power ("National Grid") reflecting the termination of the participation of RI Energy, Block Island Power Company ("BIPCO") and Pascoag Utility District ("Pascoag") (the three parties to a successor LCCSA recently accepted by the FERC in ER24-2390).[102] The amended LCCSA was accepted with an effective date of *May 30, 2024*, as requested. Unless the December 9 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: NSTAR / Vicinity Energy Boston (ER25-49)**

On December 3, 2024, the FERC accepted a Design and Engineering Agreement ("D&E Agreement") between NSTAR and Vicinity Energy Boston, Inc. ("Vicinity") to initiate the D&E process required to develop a non-binding cost estimate for the development of Kneeland Substation, which will incorporate Vicinity's proposed 100 MW electrode boiler load into the overall design, at Vicinity's expense.[103] The December 3 order was not challenged and is final and unappealable. Reporting on this matter has concluded. If you have any remaining 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 Access Tariff ("WDAT") 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.[104] An October 30, 2024 effective date was requested. Comments on the UI WDAT were due on or before September 20, 2024. Supportive comments and were filed by ACT (but requesting clarifications, supporting data, and additional information as to how UI proposes to measure and bill for demand-related charges when a BESS is providing ancillary services in response to ISO-NE dispatch instructions) and Elevate Renewable F7, LLC (but offering proposed clarifications to improve customer understanding). Interventions were filed by Agilitas, Eversource, and New Leaf. On October 7, 2024, UI answered the comments submitted by ACT and Elevate.

Deficiency Letter. On October 29, 2024, the FERC issued a deficiency letter, seeking additional information required to process this filing, including information regarding the workpapers provided and an explanation as to how UI intends to apply the WDAT's terms and conditions to distribution customers that take service thereunder. UI filed its responses to the deficiency letter on November 27, 2024. Comments on UI's deficiency letter responses were due on or before December 18, 2024; none were filed. This matter is again pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

---

102 *New England Power Co.*, Docket No. ER25-88-000 (Dec. 9, 2024) (unpublished letter order).

103 *NSTAR Electric Co.*, Docket No. ER25-49-000 (Dec. 3, 2024) (unpublished letter order).

104 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.

- **PJM/PPL/Susquehanna ISA Amendments Related to Increased Co-Located Load (ER24-2172)**

Many have found interesting an order issued by the FERC rejecting, in a 2-1 decision,[105] an amended Interconnection Service Agreement ("ISA") among PJM, PPL (the interconnected TO) and Susquehanna Nuclear (the interconnection customer).[106] The amended ISA, covering the interconnection of Sesquehana's 2,520 MW nuclear facility, proposed modifications to increase the amount of co-located load from 300 MW to 480 MW and to make revisions related to the treatment of the co-located load.[107]

Opponents of the proposed ISA changes (Exelon and AEP, among others) argued that the proposed changes would raise unresolved questions, could have resulted in unfair cost burdens on ratepayers, and could have negatively impacted market operations and reliability. Notably, Exelon and AEP argued the AWS data center could derive benefits from the transmission system without paying for them (the co-located data center would not be classified as "network load" and therefore would not have been be required to pay PJM transmission fees). They also cited previous unplanned outages at the Susquehanna station that led to unintended power withdrawals from the PJM system, such as one from November 2023, questioning how such a withdrawal of power would be properly metered and accurately billed if or when it does occur.

FERC largely agreed with the concerns raised, and rejected PJM's filing without prejudice, ruling that PJM had not provided sufficient justification for the proposed changes to the ISA (i.e. that the proposed non-conforming provisions in the Amended ISA were necessary deviations from the *pro forma* ISA due to specific reliability concerns, novel legal issues, or other unique factors.)[108] It is notable that on the same day the *Susquehanna Co-Located Load Order* was issued, the FERC convened its technical conference on Large Loads Co-Located at Generating Facilities (AD24-11). Challenges to the *Susquehanna Co-Located Load Order* were due on or before December 2, 2024. Susquehanna Nuclear requested rehearing and Vistra requested clarification of the *Susquehanna Co-Located Load Order.* On December 16, 2024, Exelon and AEP answered Susquehanna's request for rehearing. On December 23, 2024, the FERC issued an "Allegheny Notice", noting that the requests for rehearing and/or clarification may be deemed to have been denied by operation of law, but noting that the requests will be addressed in a future order.[109] If you have any questions concerning this matter, please contact or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or 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), together the "WDTs")) to provide for National Grid's recovery of costs associated with the provision of Wholesale Distribution Service to customers who own qualifying standalone electric energy storage systems 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 WDTs will 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. A March 1, 2025 effective date was requested. Comments on these Tariffs were due on or before September 6, 2024. Protests and comments were filed by the MA AG and the Alliance for Climate Transition ("ACT") (formerly

---

[105] Commissioners Christie and See in favor, Chairman Phillips dissenting, and Commissioners Chang and Rosner not participating.

[106] PJM Interconnection, L.L.C., 189 FERC ¶ 61,078 (Nov. 1, 2024) ("*Susquehanna Co-Located Load Order*").

[107] Co-located load refers to end-use customer load that is physically connected to the facilities of an existing or planned customer facility at the point of interconnection to the PJM transmission system. In March, Talen announced the sale of its 960 MW Cumulus data center campus in northeast Pennsylvania to Amazon Web Services ("AWS"), with a long-term agreement to provide power from its Susquehanna plant. The Cumulus campus is directly connected to the two-unit nuclear power plant.

[108] *Id.* at P 85.

[109] *PJM Interconnection L.L.C.*, 189 FERC ¶ 62,132 (Dec. 23, 2024) ("*Susquehanna Co-Located Load Order Allegheny Notice*").

known as the Northeast Clean Energy Council). Agilitas, BlueWave, Engie, Eversource, New Leaf, MA DPU, and MA DOER intervened. On September 23, 2024, National Grid answered the ACT and MA AG comments. On October 4, 2024, ACT answered National Grid's September 23 answer.

WDT Amendments. On November 13, 2024, National Grid filed amendments to each of the WDTs ("WDT Amendments"). The WDAT Amendments include clarifications and update the proposed WDS rates to reflect the retail revenue requirement and Allocated Cost of Service Study approved by the MA DPU in the Companies' retail rate proceeding and subsequent revenue requirement recalculations approved by the MA. Comments on the WDT Amendments were due on or before December 4, 2024; none were filed. This matter is again 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 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).

- **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").[110] 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.[111] 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.[112] 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.[113] There have been four settlement conferences (May 3, July 17, September 19,

[110] *Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate Order*").

[111] *Id.* at P 29.

[112] *Id*.

[113] *Central Maine Power Co.*, Docket No. ER24-1177-000 (Apr. 5, 2024) (unpublished letter order).

and December 10-11, 2024). Judge Hessler's fourth status report, issued on November 26, 2024, recommended that settlement judge procedures continue. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[114]

- **Large Loads Co-Located at Generating Facilities (AD24-11)**

On November 1, 2024, the FERC held 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 agenda consisted of 3 panels: Overview of Large Co-Located Load Issues (Panel 1); Exploration of Issues Presented by Large Co-Located Loads (Panel 2); and Roundtable with State Representatives (Panel 3). The list of panelists was included in the third and fourth supplemental notices of the technical conference, issued October 10 and 22, respectively. Speaker statements have been posted to eLibrary. A recording of the technical conference is available from the FERC's Calendar of Events. The FERC invited post-technical conference comments to be submitted on or before December 9, 2024. Comments were filed by, among others, AEU, Calpine, Constellation, Dominion, Vistra, Potomac Economics, ACORE, ACPA, Clean Energy Buyers Association, Data Center Coalition, EPSA, LS Power, NY State Reliability Council, Organization of PJM States, PJM IMM, Industrial Energy Consumers of America, Joint Public Service Parties, NRECA, SEIA. A final transcript of the conference was posted to eLibrary on December 3, 2024.

- **Annual Reliability Technical Conference (AD24-10)**

On October 16, 2024, the FERC convened its annual Commissioner-led Reliability Technical Conference to discuss policy issues related to the reliability and security of the Bulk-Power System. The agenda consisted of panels on two topics: Managing Reliability Risks and Challenges (Panel 1); and Resource Adequacy and Expected Load Growth (Panel 2). The technical conference will be open to the public. Advance registration is not required, and there is no fee for attendance. Information will also be posted on the Calendar of Events on the FERC's website prior to the event. In a notice issued on October 28, 2024, the FERC invited those interested to submit post-technical conference comments, on or before November 27, 2024, on the questions presented in the technical conference agenda or on issues raised during the technical conference. Comments were filed by EPSA and Tri-State Generation and Transmission Association. A final transcript of the October 16 conference was posted to eLibrary on November 19, 2024.

- **Innovations and Efficiencies in Generator Interconnection (AD24-9)**

On September 10-11, 2024, the FERC held a workshop for the presentation and discussion of opportunities for further innovation and increased efficiency in the generator interconnection process. The three September 10 panels addressed: 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 addressed: Further Efficiencies in the Generator Interconnection Process, Automation and Advanced Computing Technologies, and Post-Generator Interconnection Agreement Construction Phase. Panelists materials are posted in the FERC's eLibrary. The FERC invited post-workshop comments and comments were filed by 23 Entities, including by: ISO-NE, AEU, Constellation, Dominion, EEI, Elevate Renewables F7, ENGIE, Environmental Law and Policy Center, Invenergy Transmission, National Grid, New Leaf Energy, Public Interest Organizations, Vistra Corp, RWE Clean Energy, Shell, and SEIA.

[114] Reporting on the following administrative proceedings have been suspended 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).

- **Joint Federal- State Current Issues Collaborative (AD24-7)**

On November 12, 2024, the Federal and State Current Issues Collaborative ("Collaborative")[115] held its first public meeting in Anaheim, California. The agenda for the first public meeting included a presentation on NARUC's Gas-Electric Alignment for Reliability ("GEAR") Taskforce. On December 4, 2024, the FERC issued a notice inviting all interested persons to file, on or before January 3, 2025, post-meeting comments to address issues raised during the meeting. Comments were filed by AGA, ConEd, National Grid, and NRG. A final transcript of the meeting was also posted on December 4, 2024.

- **ANOPR: Implementation of Dynamic Line Ratings (RM24-6)**

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[116] seeking comments on both the need for a dynamic line ratings ("DLRs")[117] 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. A more detailed summary of the ANOPR was provided to and reviewed with the Transmission Committee. Comments in response to the ANOPR were due October 15, 2024[118] and were filed by nearly 70 parties, including by the following New England parties: ISO-NE, AEU, Avangrid, Dominion, Eversource, MA AG, National Grid, NESCOE, NextEra (on October 22), EEI, EPSA, NASUCA, NERC, PIOs, Public Power,[119] TAPS, and R Street Institute. Nine sets of reply comments were filed, including from: ISO-NE, DC Energy, and the US DOE.

- **NOPR: EQR Filing Process and Data Collection (RM23-9)**

On October 19, 2023, the FERC issued a NOPR[120] 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;

---

[115] *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 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.

[116] *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.

[117] 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.

[118] The *ANOPR* was published in the *Fed. Reg.* on July 15, 2024 (Vol. 89, No. 135) pp. 57,690-57,716.

[119] "Public Power" is: The National Rural Elec. Coop. Assoc. ("NRECA"), the American Public Power Assoc. ("APPA"), and the Large Public Power Council ("LPPC").

[120] *Revisions to the Filing Process and Data Collection for the Electric Quarterly Report*, 185 FERC ¶ 61,043 (Oct. 19, 2023) ("*EQR NOPR*").

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.

- ***Order 1977*: Transmission Siting (RM22-7)**

On May 16, 2024, the FERC issued *Order 1977*[121] 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*.[122] For example, applicants must demonstrate good faith efforts to engage with landowners in the permitting process, and develop engagement plans for outreach to environmental justice communities and Tribes. NEPOOL Counsel prepared a summary of *Order 1977* which was distributed to the Transmission Committee.

Requests for rehearing of *Order 1977 and Order 1977-A.* were filed by the LA PSC, NY PSC, PA PUC, and Public Interest Organizations.[123] 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.[124] On October 17, 2024, the FERC issued *Order 1977-A*,[125] its order addressing arguments raised on rehearing, modifying the discussion in, and setting aside in part, *Order 1977*. In *Order 1977-A*, the FERC added a new requirement for applicants' engagement plans for outreach to Tribes (if a project requires a right of way on Tribal land, the applicant must describe in its Tribal engagement plan how it will work with Tribal landowners on right-of-way issues). *Order 1977-A* became effective on *November 22, 2024*.[126] If you have any questions concerning *Orders 1977* or *1977-A*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- ***Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)**

On October 17, 2024, the FERC issued *Order 904,*[127] which revises 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."[128] The proposed change will affect revenues received by reactive power resources in New England.[129] Although compliance filings are due

---

[121] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, 187 FERC ¶ 61,069 (May 13, 2024) ("*Order 1977*").

[122] *Order 1977* was published in the *Fed. Reg.* on May 29, 2024 (Vol. 89, No. 104) pp. 46,682-46,740.

[123] "Public Interest Organizations" are Earthjustice, Environmental Defense Fund, NRDC, Sierra Club, Sustainable FERC Project, UCS, WE ACT for Environmental Justice, and the Yurok Tribe.

[124] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, 188 FERC ¶ 61,027 (July 15, 2024).

[125] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, Order No. 1977-A, 189 FERC ¶ 61,033 (Oct. 17, 2024) ("*Order 1977-A*").

[126] *Order 1977-A* was published in the Fed. Reg. on Oct. 23, 2024 (Vol. 89, No. 205) pp. 84,465-84,472.

[127] *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (Oct. 17, 2024) ("*Order 904*").

[128] *Reactive Power NOPR* PP 51-53.

[129] Generating facilities in New England are currently compensated for reactive power under a flat, inflation-adjusted rate design. In *Order 904*, the FERC rejected the requests by ISO-NE and NEPOOL for the flexibility to retain the current Schedule 2.

on or before ***March 28, 2025***,[130] and must generally include a proposed effective date within 90 days from the date of the compliance filing, *Order 904* expressly states that ISO-NE may request a later effective date for the FERC's consideration, in order to allow any necessary market rule changes that accommodate *Order 904*'s elimination of compensation for the provision of reactive power within the standard power factor range to be developed and proposed.[131] A summary of *Order 904* was provided to the Transmission Committee. Challenges to *Order 904* were filed by: D. E. Shaw Renewable Investments, Invenergy Nelson, NYISO, the PSEG Companies,[132] and Vistra. On December 19, 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.[133] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Orders 1920 and 1920-A*: 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

[130] *Order 904* will become effective on *Jan. 27, 2025*. *Order 904* was published in Fed. Reg. on Nov. 26, 2024 (Vol. 89, No. 228) pp. 93,410-93,456.

[131] *Order 904* at P 224. "With any such request, [ISO-NE] must affirmatively demonstrate why such a requested effective date is necessary, given, for example, its existing market rules, and what market rule changes [ISO-NE] believes may be needed to accommodate [*Order 904*]."

[132] The "PSEG Companies" are: Public Service Electric and Gas Co., PSEG Power LLC, and PSEG Energy Resources & Trade LLC, each wholly-owned, direct or indirect subsidiaries of Public Service Enterprise Group Inc.

[133] *Compensation for Reactive Power Within the Standard Power Factor Range*, 189 FERC ¶ 62,127 (Dec. 19, 2024) ("*Order 904 Allegheny Notice*").

[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*").

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.

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.

Order 1920-A. In response to requests for clarification and/or rehearing of *Order 1920*, the FERC issued its order on rehearing and clarification (*Order 1920-A*) on November 21, 2024.[137] In *Order 1920-A*, the FERC stated that it was refining and improving Long-Term Regional Transmission Planning ("LTRTP") "by building on the reforms adopted in Order No. 1920, with a particular focus on ensuring that states have a robust role" in LTRTP and cost allocation processes established in *Order 1920*. *Order 1920-A* largely sustained and further justified the findings and reforms of *Order 1920*, but granted several requests for rehearing and clarification. A significant focus of the modifications to *Order 1920* pertained to the role of the states in LTRTP and the related cost allocation requirements. *Order 1920-A* maintained the ***June 12, 2025*** compliance filing deadline for regional requirements[138] and the ***August 12, 2025*** deadline for interregional requirements. Any deviations from the final rule proposed on compliance must be justified under the "consistent with or superior to" standard. A memorandum providing a brief summary of the more important features of *Order 1920-A*, including a list and more detailed summary of the key modifications and clarifications made by the FERC in *Order 1920-A* was provided by NEPOOL Counsel to the Transmission Committee (and can be found here).

Order 1920-A Requests for Rehearing. Requests for clarification and/or rehearing of *Order 1920-A* were filed by West Connect TOs,[139] MISO TOs,[140] PJM TOs,[141] EEI, NRECA, SWEPCO, and WIRES. Those requests are

---

[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*, Order on Reh'g, Order No. 1920-A, 189 FERC ¶ 61,126 (Nov. 21, 2024) ("*Order 1920-A*"). Over 50 parties filed 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.

[138] MISO requested and was granted a one-year extension of time (to June 12, 2026) to submit its compliance filing (except for those related to interregional transmission coordination). Notice of Extension of Time, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Docket No. ER21-17-000 (Dec. 10, 2024).

[139] "West Connect Coordinating TOs" are non-jurisdictional members of the WestConnect regional planning organization and include: Colorado Springs Utils., Imperial Irrigation District, Los Angeles Department of Water and Power, Platte River Power Authority, Sacramento Mun. Util. District, Salt River Project Agr. Improvement and Power District, and the Transmission Agency of N. California.

[140] "MISO TOs" are AEP Indiana Michigan Trans. Co., Ameren Srvcs. Co., as agent for Union Elec. Co. d/b/a Ameren Missouri, Ameren Illinois Co. d/b/a Ameren Illinois and Ameren Trans. Co. of Illinois; American Trans. Co.; Big Rivers Elec. Corp.; Central Minnesota Mun. Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Dairyland Power Coop.; Duke Energy Business Srvcs for Duke Energy Indiana; Great River Energy; Hoosier Energy Rural Elec. Coop.; Indiana Municipal Power Agency; Indianapolis Power & Light Co. d/b/a AES Indiana; Lafayette Utils. Sys.; MidAmerican Energy Co.; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Srvcs; Montana-Dakota Utils. Co.; Northern Indiana Pub. Srvc Co.; Northern States Power Co., a Minnesota corp., and Northern States Power Co., a Wisconsin corp., subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Elec. Co.; Otter Tail Power Co.; Prairie Power; Southern Illinois Power Coop.; Southern Indiana Gas & Elec. Co. (d/b/a CenterPoint Energy Indiana South); Southern Minnesota Mun. Power Agency; Wabash Valley Power Assoc.; and Wolverine Power Supply Coop.

[141] "PJM TOs" include: include: American Elec. Power Srvc. Corp. on behalf of its affiliates, Appalachian Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., Wheeling Power Co., AEP Appalachian Trans. Co., AEP Indiana Michigan Trans. Co., AEP Kentucky Trans. Co., AEP Ohio Trans. Co., and AEP West Virginia Trans. Co.; Dayton Power and Light Co. d/b/a AES Ohio; Dominion Energy Srvcs. on behalf of Virginia Elec. and Power Co. d/b/a Dominion Energy Virginia; Duke Energy Corp. on behalf of its affiliates Duke Energy Ohio, Duke Energy Kentucky, and Duke Energy Bus. Srvcs.; Duquesne Light Co.; East Kentucky Power Coop.; 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 Co., and Potomac Elec. Power Co.; FirstEnergy Srvc. Co., on behalf of its affiliates American Trans. Systems, Jersey Central Power & Light Co., Mid-Atlantic Interstate Trans., West Penn Power Co., The Potomac Edison Co., Monongahela Power Co.,

pending, with FERC action required by ***January 12, 2025*** or the requests will be deemed denied by operation of law.

Petitions for Federal Court Review. *Order 1920* has been challenged in several federal circuits, including the DC, First, Fourth, Fifth, Sixth, Ninth, Tenth, and Eleventh Circuits. Further developments on the federal court appeals will be reported in Section XVI below.

Motions for Extension of Time. Since the last Report, PJM (supported by PJM TOs and OPSI) requested a six-month extension of time—to December 12, 2025—to submit its compliance filing. On December 10, 2024, the FERC granted MISO's request for a 12-month extension of time – to June 12, 2026, to makes its compliance filing (except those requirements related to interregional transmission coordination). ISO-NE is also contemplating requesting an extension of time.

If you have any questions concerning *Orders 1920* or *1920-A*, 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

- **Montpelier Generating Station Stipulation and Consent Agreement (PJM Tariff Violations) (IN24-15)**

On December 6, 2024, the FERC approved a Stipulation and Consent Agreement[142] with Montpelier Generating Station, LLC ("Montpelier") and Rockland Capital, LP ("Rockland") (together, the "Companies") to resolve OE's investigation into whether the Companies violated the PJM Tariff and the FERC's Market Behavior Rules by classifying a Forced Outage as a Maintenance Outage in submissions to PJM during the October 25, 2022 through January 11, 2023 period ("Relevant Period"), causing Montpelier to avoid Performance Assessment Interval penalties during Winter Storm Elliott in December 2022. Under the Stipulation and Consent Agreement, the Companies agreed to ***disgorge $674,064 in avoided penalties to PJM, plus $84,690 in interest***; to pay a ***$105,000 penalty*** 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).

- **Sonoran West Solar Stipulation and Consent Agreement (CAISO Tariff Violations) (IN24-13)**

On December 5, 2024, the FERC approved a Stipulation and Consent Agreement[143] with Sonoran Solar Holdings, LLC ("Sonoran 1") and Sonoran West Solar Holdings 2, LLC ("Sonoran 2") (together, "Sonoran") to resolve OE's investigation, following a CAISO IMM referral, of whether Sonoran violated CAISO Tariff provisions (and thereby FERC regulations) by submitting biddable Initial State of Charge parameters that reflected a value that was other than a "forecasted starting physical position" – i.e., other than the actual state of charge the batteries were forecasted to hold at the start of the real time market. Under the Stipulation and Consent Agreement, Sonoran agreed to ***disgorge $2,473,265*** to CAISO and to pay a ***$1 million civil penalty*** to the United States Treasury, and to provide compliance monitoring reports to Enforcement. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Keystone Appalachian Trans. Co., and Trans-Allegheny Interstate Line Co.; PPL Elec. Utils. Corp.; Public Service Elec. and Gas Co.; Rockland Elec. Co.; and UGI Utilities.

[142] *Montpelier Generating Station, LLC and Rockland Capital, LP*, 189 FERC ¶ 61,185 (Dec. 6, 2024).

[143] *Sonoran West Solar Holdings, LLC et al.*, 189 FERC ¶ 61,174 (Dec. 5, 2024).

- **EWP Renewable Corp. (Springfield Power/Hemp Hill) Stipulation and Consent Agreement (IN24-12)**

On December 23, 2024, the FERC approved a Stipulation and Consent Agreement[144] with EWP Renewable Corp. ("EWP")[145] to resolve OE's investigation, following an ISO-NE IMM referral, of whether Springfield Power violated ISO-NE Tariff provisions (and thereby FERC regulations) by failing to offer, operate and schedule the Hemp Hill plant consistent with the ISO-NE Tariff. Under the Stipulation and Consent Agreement, EWP agreed to ***disgorge $259,669*** to ISO-NE (which represents the capacity payments to Springfield for the 66 days of the relevant period that Hemp Hill was unable to operate in accordance with certain ISO-NE Tariff requirements), to pay a ***civil penalty of $722,000*** to the United States Treasury, and to submit an annual compliance monitoring report to Enforcement one year after the Effective Date of the Agreement (with a second annual report at OE's option). If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **American Efficient Show Cause Order (IN24-2)**

On December 16, 2024, the FERC issued a show cause order[146] in which it directed American Efficient, LLC, its various subsidiary companies,[147] and its corporate parents[148] (collectively, "American Efficient") to show cause why they should not be found to have violated (i) Section 222 of the FPA and § 1c.2 of the FERC's regulations through a manipulative scheme and course of business in PJM and MISO that extracted millions of dollars in capacity payments for a purported energy efficiency project that did not actually cause reductions in energy use;[149] and (ii) provisions of MISO's and PJM's Tariffs for failure to satisfy the tariff requirements for participation as an Energy Efficiency Resource ("EER").[150] American Efficient was also directed to show cause why they should not (i) ***disgorge $2,116,057 and $250,937,821***, back to MISO and PJM, respectively (in each case plus interest); (ii) ***disgorge additional unjust profits*** received between April 2024 and the date of any future FERC order directing disgorgement back to PJM; and (iii) pay a ***$722 million*** civil penalty (yes, these numbers are breath taking). American Efficient may seek a modification of these amounts consistent with FPA § 31(d)(4).[151] American Efficient must file an answer with the FERC on or before ***March 17, 2025***; OE staff may reply to American Efficient's answer within 30 days thereafter. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

---

144 *EWP Renewable Corp.*, 189 FERC ¶ 61,233 (Dec. 23, 2024).

145 Until Dec. 2020 (and for the entirety of the relevant period at issue), EWP owned and operated the 17.5 MW Hemp Hill biomass generator ("Hemp Hill"), located in Springfield NH, through its wholly owned subsidiary, Springfield Power, LLC ("Springfield"). Springfield was Hemp Hill's Lead Market Participant since 2012.

146 *American Efficient, LLC et al.,* 189 FERC ¶ 61,196 (Dec. 16, 2024) ("*American Efficient Show Cause Order*").

147 Affirmed Energy LLC, Wylan Energy L.L.C., Midcontinent Energy LLC, and Maple Energy LLC.

148 Modern Energy Group LLC and MIH LLC.

149 OE concludes that "[w]hat American Efficient passes off as energy efficiency in its capacity supply offers really is just market research. It buys sales data of energy efficient products from large retailers like The Home Depot, Lowes, and Costco and then figures out how many MWs of electricity would be saved if end-use customers installed those products and used them in accordance with predictive models. It then bids those energy savings into the capacity markets as if it caused the savings. But American Efficient does not cause the energy savings."

150 OE's Report notes that American Efficient initially cleared 10.6 MWs (worth $518,000) in an ISO-NE Forward Capacity Auction. When American Efficient sought to expand its Program in ISO-NE from 10.6 MWs to 189 MWs, "ISO-NE and its IMM sent a series of emails and letters critiquing the Program and then disqualified the Company from expanded participation in the FCA. In one of those letters, ISO-NE explained that it never would have qualified any of American Efficient's capacity if it had understood the true nature of the Program from the beginning." Similar disqualification occurred in MISO. American Efficient expressly kept information about those disqualifications from PJM and expanded the Program in PJM. No disgorgement with respect to American Efficient's New England activity is contemplated.

151 Under Section 31(d)(4) of the FPA, 16 U.S.C. § 823b(d)(4), the Commission may "compromise, modify, or remit, with or without conditions, any civil penalty which may be imposed . . . at any time prior to a final decision by the court of appeals . . . or by the district court."

- **Ketchup Caddy / Phillip Mango (MISO DR Program Violations) (IN23-14)**

On December 5, 2024, the FERC found that Ketchup Caddy, LLC ("Ketchup Caddy") and Phillip Mango, Ketchup Caddy's CEO and co-owner (together, "Respondents") violated FPA § 222, § 1c.2 of the FERC's regulations, and §§ 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.[152] The FERC assessed ***civil penalties of $25 million*** and ***$1.5 million*** to Ketchup Caddy and Mango, respectively, and directed ***Mango*** to ***disgorge $506,502, plus interest***, in unjust profits. As previously reported, Enforcement alleged 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."[153] Mango was directed to disgorge the $506,502, plus interest within 60 days of the Order. With respect to the civil penalties, both Ketchup Caddy and Mango were directed to make payment within 60 days of the Order, or to submit a proposed payment plan for approval within 30 days of the Order. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Voltus/Greg Dixon Stipulation and Consent Agreement (IN21-10)**

On January 6, 2025, the FERC approved a Stipulation and Consent Agreement[154] with Voltus, Inc. ("Voltus") and its former CEO, Greg Dixon, to resolve OE's investigation into whether Voltus violated the MISO Tariff), by registering demand response resources without those resources' knowledge or consent and clearing Load-Modifying Resource ("LMR") capacity that would not have performed if the resources were dispatched, during the period from October 1, 2016, and continuing through June 1, 2020. Under the Stipulation and Consent Agreement: (a) Voltus agreed to ***disgorge $7,080,543***, pay a ***$10,919,457 civil penalty*** to the US Treasury and provide compliance monitoring reports to OE; and (b) Dixon agreed to pay a ***$1 million civil penalty*** and to step down from Voltus' Board of Directors. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PSEG Stipulation and Consent Agreement (IN21-5)**

On December 5, 2025, the FERC approved a Stipulation and Consent Agreement[155] with Public Service Electric and Gas Company ("PSEG") to resolve OE's investigation into whether PSEG violated FERC regulations by failing to fully and accurately provide information to PJM (in its power point presentations and otherwise) related to its Roseland-to-Pleasant Valley corridor ("RPV line"). Under the Stipulation and Consent Agreement, PSEG agreed to pay a ***$6.6 million civil penalty*** to the US Treasury and provide on annual compliance monitoring report to OE, with a second at OE's option. 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

[152] *Ketchup Caddy, LLC and Philip Mango*, 189 FERC ¶ 61,176 (Dec. 5, 2024) ("*Ketchup Caddy Penalties Order*").

[153] *Ketchup Caddy, LLC and Philip Mango*, 186 FERC ¶ 61,132 at P 3 (Feb. 21, 2024) ("*Ketchup Caddy Show Cause Order*").

[154] *Voltus, Inc. and Gregg Dixon*, 190 FERC ¶ 61,008 (Jan. 6, 2025).

[155] *Public Service Elec. and Gas Co.*, 189 FERC ¶ 61,175 (Dec. 5, 2025).

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,[156] 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,[157] 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[158] 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,[159] 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;[160] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[161] This matter is pending before the FERC.

---

[156] 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.

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

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

[159] *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*").

[160] 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.

[161] *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.

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

Resolving an investigation that has been open for more than 12 years and a case that has been ongoing for nearly 9 years,[162] the FERC approved, on January 8, 2025,[163] a Stipulation and Consent Agreement between the Enforcement and TotalEnergies Gas & Power North America, Inc. ("TGPNA") that fully resolves the claims and allegations that TGPNA engaged in manipulation in violation of Natural Gas Act ("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. Under the approved Stipulation and Consent Agreement, TGNPA agreed to pay ***$5 million*** in restitution to certain agreed-upon non-governmental organizations. The FERC agreed to dismiss with prejudice its claims and allegations in the FERC Enforcement Matter in accordance with the terms set forth in the Agreement. If you have any remaining questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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 Proceeding

The following New England pipeline project is 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 now requested for March 25, 2027.
  - 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.[164] 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.

---

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

[163] *Total Gas & Power North America, Inc., et al.*, 190 FERC ¶ 61,011 (Jan. 8, 2025) ("*TGPNA Stip. and Consent Agreement Order*").

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

- On October 28, 2024, Iroquois requested an extension of time, until ***March 25, 2027***, to construct and place into service its Enhancement by Compression Project (Project) located in Greene and Dutchess Counties, New York and Fairfield and New Haven Counties, Connecticut as authorized in the *Iroquois Certificate Order*. (The *Iroquois Certificate Order* required Iroquois to complete construction of the Project and make it available for service within three years of the date of the Order or by March 25, 2025.) Iroquois stated that construction of the Project has been delayed due to pending state permit approvals, specifically air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois asserts that it has been working in good faith with these agencies and expects to receive approvals for the Project in the near future.
- Comments on Iroquois' request were due on or before November 15, 2024. Protests and comments were filed by the Sierra Club of Connecticut, Save the Sound, and nearly 20 individual citizens. A number of others requested an extension of time to comment, but those requests have not been (nor should be expected to be) acted on by the FERC.[165]

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

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 (4th Circuit – 24-1650)**
  Case Title: *Appalachian Voices v. FERC*
  Underlying FERC Proceeding: RM21-17[166]
  Status: Being Held in Abeyance

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*.[167] 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 as the Circuit in which to consolidate the petitions for review. The DC Circuit ordered that its cases be transferred to the 4th Circuit. The 4th Circuit lead case no. is 24-1650. On August 26, 2024, the 4th Circuit granted the FERC's motion to hold the petitions for review in abeyance, with motions to govern due January 6, 2025. On January 6, 2025, the FERC moved to extend abeyance, including deferral of all filing deadlines, until the earlier of the date it issues a substantive response to pending rehearing requests, or ***April 30, 2025***. The parties would file

[165] The FERC will aim to issue an order acting on the request within 45 days. The FERC will address all arguments relating to whether the applicant has demonstrated there is good cause to grant the extension. The FERC will not consider arguments that re-litigate the issuance of the certificate order, including whether the Commission properly found the project to be in the public convenience and necessity and whether the Commission's environmental analysis for the certificate complied with the National Environmental Policy Act ("NEPA").

[166] *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*").

[167] Petitioners for review of *Order 1920* have also been filed in the 1st, 4th, 5th, and 9th Circuits.

motion(s) to govern further proceedings by 21 days thereafter. On January 7, 2025, Indicated Petitioners[168] provided a response which, while not opposing the FERC's further abeyance request, highlighted their concerns with any further delay beyond the requested abeyance. The FERC's motion is pending before the Court.

- **Mystic Second CapEx Info Filing (24-1077)**
  Case Title: *Constellation Mystic Power, LLC v. FERC*
  Underlying FERC Proceeding: ER18-1639-028[169]
  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 on Mystic's Second CapEx Info Filing. 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.[170] On December 4, 2024, the Court granted Mystic's November 22, 2024 motion for continued abeyance of this case (to allow for FERC action on the Mystic Global Settlement, which, if approved, will lead to voluntary dismissal of this proceeding), directing the parties to file motions to govern future proceedings by ***March 10, 2025***.

- ***Orders 2023 and 2023-A*** **(23-1282 et al.) (consolidated)**
  Case Title: *Advanced Energy United, et al. v. FERC*
  Underlying FERC Proceeding: RM22-14[171]
  Status: Briefing Underway

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. Initial Submissions and a Certified Index to the Record were filed on August 21, 2024. Joint Petitioners' Briefs were filed on October 30, 2024. The following deadlines remain: 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 Respondent's Brief.

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335) (consolidated)**
  Case Title: *Eversource Energy Service Company v. FERC*
  Underlying FERC Proceeding: ER22-983[172]
  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*.[173] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case.

---

168 "Indicated Petitioners" were Appalachian Voices, Environmental Defense Fund, NRDC, North Carolina Sustainable Energy Assoc., Sierra Club, Southern Alliance for Clean Energy, and South Carolina Coastal Conservation League.

169 *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*").

170 Braintree, Concord, Georgetown, Hingham, Littleton (NH), Middleborough, Middleton, Norwood, Pascoag, Reading, Taunton, Wellesley, and Westfield (collectively, the "Eastern New England Consumer-Owned Systems").

171 *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).

172 *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*").

173 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,

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 had until August 5, 2024 to file motions to govern future proceedings in these consolidated appeals. However, 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 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. The FERC was also directed to file status reports at 60-day intervals beginning September 30, 2024. The FERC filed its latest status report on December 3, 2024 stating that its most recent order in ER22-983 (November 19, 2024) is still subject to rehearing and that, until that rehearing period expires, these consolidated appeals should remain in abeyance.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Case Title: *Sierra Club, et al. v. FERC*
  Underlying FERC Proceeding: ER18-619[174]
  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***.

---

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.

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

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Case Title: *Central Maine Power Company, et al. v. FERC*
  Underlying FERC Proceeding: ER15-414[175]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[176] 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*[177] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged *Order Rejecting Compliance Filing*, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on November 20, 2024.

- ***Chevron Doctrine* (US Supreme Ct 20-1329)**[178]
  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*.[179] *Chevron*, a landmark and often-cited 1984 decision, required courts to defer to a federal agency's reasonable interpretation of ambiguity in a statute.[180] 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.

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

176 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.

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

178 *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)).

179 *Id.*

180 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."

INDEX
Status Report of Current Regulatory and Legal Proceedings
as of January 8, 2025

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

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

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. FERC Enforcement Proceedings

XIV. Natural Gas Proceedings

XV. State Proceedings & Federal Legislative Proceedings

No Activities to Report

XVI. Federal Courts

6 Committee Reports

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

7 Administrative Matters

Admin Matters

January 9, 2025 Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee