Sebastian Lombardi
Secretary

November 30, 2023

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of December 7, 2023 NEPOOL Participants Committee Annual Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the 2023 Annual Meeting of the Participants Committee will be held **in person on Thursday, December 7, 2023 at 10:00 a.m., at the Colonnade Hotel, 120 Huntington Avenue, Boston, MA in the Huntington Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. Please note the following:

- **FERC Chairman Willie L. Phillips**: We are honored to be joined by FERC Chairman Phillips, who is planning to join in person on December 7 and will address the Committee toward the beginning of the meeting.
- **Holiday Breakfast**: A holiday breakfast, providing attendees with an opportunity to share a few moments of the holiday season, will begin at **9:00 a.m.**, one hour before the meeting begins.
- **Sector Changes**: Participants wishing to change its Sector for the next year ***must provide us with written notice of that request before the Annual Meeting***. Under Section 6.3 of the NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective *at the first annual meeting following that request*.

For those who otherwise attend NEPOOL meetings but plan to participate in the December 7 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join using WebEx, click this link and enter the event password **nepool**.

Post-Meeting New Member Orientation: As previously noticed, we will hold a New Member Orientation following the meeting for anyone wishing to learn more about, or dive deeper into, the aspects of the NEPOOL stakeholder process. There are now more than 30 Entities that became NEPOOL members in 2023. Representatives of these new members and anyone else wanting to learn more about the NEPOOL process are welcome and encouraged to attend. Please let Pat Gerity (pmgerity@daypitney.com) know if you plan to attend the New Member Orientation so we can ensure sufficient space and copies of materials.

Respectfully yours,

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the November 2, 2023 Participants Committee meeting. A copy of the draft minutes, marked to show changes made to the draft circulated with the initial notice, is included with this supplemental notice and posted with the meeting materials.

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

3. To receive remarks from the Honorable Willie L. Phillips, Chairman, Federal Energy Regulatory Commission.

4. To receive an ISO Chief Executive Officer (CEO) report. The December CEO report will be circulated and posted in advance of the meeting.

5. To receive an ISO Chief Operating Officer (COO) report on the following:

   a. *November 2023 Operations Highlights.* The monthly Operations Report will be circulated and posted in advance of the meeting.

   b. *Winter 2023-24 Outlook Report.* Materials for this report will be circulated and posted in advance of the meeting.

   c. *nGem Overview*. To receive a high-level introduction to, and overview of, the planned system enhancements associated with the ISO's next Generation Electricity Management (nGem) platform. Separate materials for this report will be circulated and posted in advance of the meeting.

6. To receive the 2023 NEPOOL Annual Report, which will be distributed at the Participants Committee meeting and posted with the meeting materials.

7. To elect NEPOOL Participants Committee Officers for 2024. A draft resolution reflecting the outcome of the balloting for Participants Committee Chair and candidates for Secretary and Assistant Secretary are included with this supplemental notice and posted with the meeting materials.

8. To adopt a NEPOOL Budget for 2024. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

8A. To consider and take action, as appropriate, on proposed changes to the Financial Assurance Policy that update provisions related to the FCM Delivery Financial Assurance requirements. Background materials and a draft resolution are included with this supplemental notice.

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

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

FINAL AGENDA
(cont.)

9. To receive an ISO Internal Market Monitor Report by David Naughton, Executive Director, Internal Market Monitor. The IMM's 2022 Annual Markets Report is available on-line at https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf. IMM Quarterly Markets Reports are available on the ISO website at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

10. 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.

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

12. Administrative matters.

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

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

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

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 2:00 p.m. on Thursday, November 2, 2023, at the Seaport Hotel, One Seaport Lane, 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 by telephone.

Mr. Dave Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded.

APPROVAL OF OCTOBER 5, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the October 5, 2023 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved as circulated, with opposition by the Maine Office of the Public Advocate (MOPA) and with abstentions by the Connecticut Office of Consumer Counsel (CT OCC), Conservation Law Foundation (CLF), Environmental Defense Fund, New Hampshire Office of the Consumer Advocate (NH OCA), Power Options, Massachusetts Office of the Attorney General (MA AG), the Rhode Island Division, and Mr. Lamson. Representatives of MOPA, CT

OCC, MA AG, NH OCA, and Power Options attributed their votes on the Consent Agenda to concerns related to some of the cost of equity updates underlying the annual adjustment to the Net Cost of New Entry for FCAs 19 and 20 (Consent Agenda Item 1).

ISO CEO REPORT

There having been no ISO Board or Board Committee meeting summaries issued since the October 5 meeting, Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), simply invited any comments or questions members might have. One member, referring to the ISO Board's open meeting the day before, commended to Committee members the written and recorded presentation by Dr. Debra Lew, Associate Director, Energy Systems Integration Group, entitled "What Does a Decarbonized Future Look Like: The Last 10%". Mr. van Welie seconded that suggestion, encouraging those interested to review Dr. Lew's presentation in both mediums.

ISO COO REPORT

Dr. Chadalavada began his report first by referring the Committee to his November Operations Report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the Report was through October 24, 2023, unless otherwise noted. The Report highlighted: (i) Energy Market value for October 2023 was $186 million, down $160 million from the updated September 2023 value of $346 million and down $326 million from October 2022; (ii) October 2023 average natural gas prices were 15% lower than September 2023 average prices, reflecting the lowest October average natural gas prices since the advent of Standard Market Design; (iii) average Real-Time Hub Locational Marginal Prices

(LMPs) for October ($23.64/MWh) were 27% lower than the September averages; (iv) average October 2023 natural gas prices and Real-Time Hub LMPs over the period were down 73% and 55%, respectively, from October 2022 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.9% during October (up from the 100.6% reported for September), with the minimum value for the month of 93.8% on October 21; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for October totaled $3.7 million, which was up $0.8 million from September 2023 and up $0.8 million from October 2022. October NCPC payments, which were 2% of total Energy Market value, were comprised of (a) $3.7 million in first contingency payments (up $0.2 million from September); (b) no second contingency payments; and (c) $42,000 in distribution payments (down $25,000 from September).

Dr. Chadalavada then provided an update on the status of the Inventoried Energy Program (IEP). He reported that approximately 845,000 ~~/~~MWh were participating in the IEP's "forward component" (at a cost of approximately $78 million); roughly 100,000 ~~/~~MWh, in the "spot-only component" or projected 10 inventoried energy days (IEDs) (at a cost of approximately $9.2 million). IEP costs for the upcoming winter period were thus expected to total approximately a little less than $88 million. He noted that spot-only program costs were not capped, so that number could increase based on winter season activity or an increase in the number of IEDs experienced.

In response to further questions, Dr. Chadalavada stated that of the resources participating in the IEP, 68% are oil-fired resources and 30% are natural gas-fired resources (one-half fueled by liquefied natural gas (LNG); the other half fueled by pipeline gas). IEP participation consists of 115 resources totaling 17 gigawatts. Dr. Chadalavada noted that most of the resources participating in the forward component were signed up for less than the full 72 hour complement, further indicating a fairly robust level of participation. He explained that there was over two days of energy supply participating in the forward program, providing some comfort that the ISO would be well-positioned for Winter 2023/24.

Addressing Master/Local Control Center Procedure No. 2 (M/LCC 2) events during the month of October, Dr. Chadalavada identified two declarations – one on October 4; the other on October 23. He explained that both of those declarations were for projected capacity deficiency events during peak hours. Each were transitory, as expected, largely driven by unit outages occurring just prior to the peak hours when there was limited opportunity for the ISO to timely commit other resources in response. In neither case did an actual capacity deficiency materialize. In response to questions, he explained that the supply side, rather than load forecasts, was the principal factor in the M/LCC 2 declarations. He noted that, of the two events, the supply-side shortfall was more pronounced on October 4. That resulted in some additional commitments (between 200 and 400 MW) during the 2-3 hour window, including commitments of Demand Response resources that were at the time the lowest-cost resource in the supply stack. He estimated uplift attributable to those two events to be approximately $1-1.5 million. In response to a question, he further differentiated the M/LCC 2 events from the Real-Time curtailments experienced in October. He described the Real-Time curtailments as short-term reserve product deficiencies (driven by outage season and a lack of Black Start capability), and not as capacity deficiencies requiring M/LCC 2 declarations.

In response to another member’s question regarding planned outages, Dr. Chadalavada answered that, for the rest of 2023, the only outage of note, as reported in October, was a 10-day outage scheduled for Line 344 (West Medway to Bridgewater), which could impact the lower

Southeastern Massachusetts/Rhode Island (SEMA/RI) interface, but only for a few hours on a few days during that stretch of time.

An End User Sector representative asked for additional color or clarification related to off-shore wind included in the November Operations Report's new generation back-up detail. Dr. Chadalavada committed to provide, on a roughly semi-annual basis, additional information related to those projects that either clear in the market or are used in ISO projections, models or planning tools. In response to a second question, Dr. Chadalavada speculated that there were two primary factors driving decreased load numbers – the first was 2023's wetter, milder summer; the second, and a more important factor, was the remarkable growth in New England's photovoltaic (PV) resources, contrasting 4,650 MW of PV generation available on a peak day in 2022 against approximately 5,300 MW of PV generation in 2023. He expected similar growth in PV installations, and the attendant reduction in load, to continue for at least the next couple of years.

HQICC/ICR VALUES FOR UPCOMING ARAS

Ms. Emily Laine, Reliability Committee (RC) Chair, referred the Committee to, and summarized the materials circulated and posted in advance of the meeting related to, the Hydro Quebec Interconnection Capability Credits (HQICC Values) and the Installed Capability Requirement (ICR) and related demand curves (collectively, the ICR Values) for the 3rd Annual Reconfiguration Auction (ARA) for the 2024–25 Capacity Commitment Period (CCP), 2nd ARA for the 2025–26 CCP and 1st ARA for the 2026–27 CCP. She explained that the proposed HQICC and ICR Values for the ARAs to be conducted in 2024 were first reviewed by the Power Supply Planning Committee and then by the RC. At its October 24, 2023 meeting, the RC recommended that the Participants Committee support both the HQICC Values (with one opposed and 14 abstentions) and the ICR Values (with one opposed and 7 abstentions). She confirmed that, but for the timing of the RC actions, the HQICC and ICR Values could have been on the Consent Agenda. Ms. Laine also noted that the materials circulated to the Participants Committee could permit, absent objection, action on the motions to support the HQICC and ICR Values through one vote.

Without objection to action by a single vote, the following resolutions were then duly made together in one motion, seconded and approved, with oppositions by Cross-Sound Cable (CSC) and LIPA, and abstentions by BP, Calpine, CLF, DTE, Galt Power, HQ US, Mercuria, Shell, and Mr. Lamson:

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

Explaining their votes, the representatives for CSC and LIPA attributed their opposition, and the Shell representative its abstention, to the view that the proposed set of Values did not properly recognize the reliability benefits of the Cross-Sound Cable, including the emergency energy assistance that the CSC had provided and would continue to provide.

FCA19 DELAY PROPOSAL

Ms. Mariah Winkler, Markets Committee (MC) Chair, referred the Committee to the materials that were circulated and posted with the meeting materials. She explained that the proposed Market Rule revisions would delay FCA 19 qualification and auction activities by one year, incorporate a gradual transition back to a three and one-half year forward auction construct, eliminate the first ARA for FCAs 19 through 24 during the transition period, permit specific resources to submit qualification materials in 2024 so those resources can qualify to participate in ARAs, and clarify when particular demand capacity resources can be considered as new capacity for FCA 19. She noted that the FCA 19 Delay Proposal was part of the ISO's proposed approach to moving forward with the Resource Capacity Accreditation (RCA) project. The MC recommended Participants Committee support for the Proposal, with limited abstentions noted. But for the timing of the MC action, she added, this matter could have been considered by way of the Consent Agenda.

Following Ms. Winkler's overview, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the FCA 19 Delay Proposal as reflected in revisions to Section III.13 of the Tariff, as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Members and State representatives expressed their appreciation for the ISO's responsiveness to stakeholder feedback provided during Markets Committee consideration, which many felt improved the overall Proposal. Some, following further consideration, identified the possibility for additional refinements and improvements, and looked forward to working through those as part of future Market Rule discussions, but would not oppose the MC-recommended revisions to implement the Proposal. Others, noting some concerns that might follow from a delay, and an overall preference not to delay FCA19, nevertheless stated their plans not to oppose the Proposal.

Following further discussion, the Proposal was voted and approved unanimously, with abstentions noted by BlueWave Public Benefit Corp., BP, Brookfield, CSC, DTE, FirstLight, Galt Power, the Generation Group Member, Mercuria, New Leaf Energy, NextEra, SYSO, Tenaska, and Mr. Lamson.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the November 2 Litigation Report that had been circulated and posted the morning of the meeting. He highlighted the following developments:

(i) *SATOA Revisions (ER23-739, ER23-743).* The FERC accepted the revisions to enable electric storage facilities to be planned and operated as transmission-only assets (SATOA Revisions); notice of the Revisions' actual effective date must be filed no less than 30 days prior to implementation (currently projected to be July 1, 2024).

(ii) *Order 2023: Interconnection Reforms (RM22-14).* FERC issued an order that extended the *Order 2023* compliance filing deadline to April 3, 2024.

Ms. Maria Gulluni, ISO General Counsel, then reported on the proposed timelines for compliance with *Order 2023*. She explained that the ISO's plan was to ask the Participants Committee to consider/vote on its compliance proposal at the March 7, 2024 meeting and to file its proposal with the FERC on or about April 1, 2024. Regarding questions related to the *Order 2023* transition period, the ISO planned to ask for an effective date of May 31, 2024, which would make the eligibility date May 1, 2024. At that point, Participants could decide whether they wanted to be a part of the transition period or withdraw. With a proposed effective date of May 31, 2024, the ISO planned to issue contracts and have those returned along with related requirements by July 30, 2024. She encouraged those seeking more detail or with questions to attend the November 9 Transmission Committee meeting at which the plan for the process to review ISO's *Order 2023* compliance proposal would be discussed in more detail.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting would take place the following week, November 7-8, at the Doubletree in Westborough, MA. He further noted that the December MC would be a full three-day meeting.

Transmission Committee (TC). Mr. Dave Burnham, the TC Vice-Chair, reported that the next TC meeting, as mentioned previously, was scheduled for November 9, also in Westborough. The main items for consideration would be action on proposed Tariff revisions in response to *Order 676-J*, as well as discussion on the proposed schedule for reviewing and finalizing the region's *Order 2023* compliance filing, including a stakeholder presentation on proposed aspects of compliance with *Order 2023*. A second, virtual meeting of the TC was scheduled for November 21 and would focus on Longer-Term Transmission Planning issues. The main focus of the December TC meeting would be *Order 2023* compliance.

Reliability Committee. Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting was scheduled for November 4, at which the results of the extreme weather and stakeholder-requested scenarios would be discussed. Looking further ahead, he reported that the RC planned to meet for two days in December (18-19), January (16-17), and February (13-14).

Budget & Finance Subcommittee (B&F). Mr. Kaslow reported that the next B&F meeting was scheduled for November 28, and would include a review of the proposed 2024 NEPOOL budget.

Membership Subcommittee. Ms. Ashley Gagnon, Membership Subcommittee Chair, reported that the next Subcommittee meeting was scheduled for Monday, November 13 at 10:00 a.m.

ADMINISTRATIVE MATTERS

Mr. Lombardi reminded the Committee that the December Annual Meeting of the Participants Committee was scheduled for December 7, 2023 at the Colonnade Hotel in Boston. He reported that the FERC Chairman, Willie Phillips, was scheduled to provide remarks at that meeting. He encouraged all members to attend the holiday breakfast scheduled to precede the Annual Meeting.

There being no other business, the meeting adjourned at 2:56 p.m.

Respectfully submitted,

____

Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 2, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting		Alex Lawton	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID: CMP/UI	Transmission	Alan Trotta (tel)	Jason Rauch	
Bath Iron Works Corporation	End User			Bill Short (tel)
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BlueWave Public Benefit Corp.	AR-DG	Mike Berlinski		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User	Claire Coleman		Jason Frost
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)	Priya Gandbnir	
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short (tel)
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP (Calpine) New Leaf Energy	Generation	Brett Kruse Liz Delaney	Andy Gillespie	Bill Fowler Alex Chaplin
Elektrisola, Inc.	End User			Bill Short (tel)
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	Vandan Divatia
Environmental Defense Fund (EDF)	End User	Jolette Westbrook (tel)		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc. (Galt)	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short (tel)
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation		Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG		Bob Stein	
Hammond Lumber Company	End User			Bill Short (tel)
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 2, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	AR-RG		Ron Carrier	
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		José Rotger
Maine Public Advocate’s Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General’s Office (MA AG)	End User	Ashley Gagnon	Jamie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Department of Capital Asset Management	End User			Nancy Chafetz
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 (tel)
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		Preston Walker
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
New Hampshire Office of Consumer Advocate	End User	Donald Kreis	Jason Frost	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		
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	
Nylon Corporation of America	End User			Bill Short (tel)
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company LLC	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, Inc.	End User			Jason Frost
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division (DPUC)	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide		
Saint Anselm College	End User			Bill Short (tel)
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short (tel)
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
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	
SYS Inc.	AR-DG	Doug Matheson (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 2, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		Dan Murphy
Tenaska Power Services Co. (Tenaska)	Supplier		Eric Stallings (tel)	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR			Jason Frost
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich (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	
Z-TECH LLC	End User			Bill Short (tel)

CONSENT AGENDA

Transmission Committee (TC)

*From the previously-circulated notice of actions of the TC's **November 9, 2023 meeting**, dated November 9, 2023.*[1]

1. **Changes to OATT Schedule 24 (Additional Order 676-J Compliance)**

   Support the revisions to Schedule 24 (Incorporation by Reference of NAESB Standards) of the ISO-NE England Open Access Transmission Tariff (OATT), which adds a citation reference to FERC's Order on Compliance and Request for Waivers (Docket No. ER23-1771-000) issued on October 26, 2023, and updates the North American Electric Standard Board's (NAESB) Wholesale Electric Quadrant (WEQ) versions, as recommended by the RC at its November 9, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was unanimously approved.

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **November 14, 2023 meeting**, dated November 14, 2023.*

2. **Changes to OP-3 (Biennial Review)**

   Support revisions to ISO New England Operating Procedure (OP) No. 3 (Transmission Outage Scheduling) (OP-3),[2] as recommended by the RC at its November 14, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was unanimously approved.

3. **Changes to OP-5 Appendix A (Biennial Review)**

   Support revisions to Appendix A to OP-5 (Operable Capacity Definitions),[3] as recommended by the RC at its November 14, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was unanimously approved.

---

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

[2] The recommended revisions to OP-3 include: replacement of the term "disapprove" with "deny"; an update to a note on p. 11 to reflect that outages that will isolate a Resource will not be posted; the addition of a note for repositioning or recall of outages based on potential risk to reliability of the system; the addition of a bullet to clarify that LCCs shall notify Resources of potential restrictions; and clarifications and minor administrative changes.

[3] The recommended revisions to Appendix A to OP-5 include: revisions to the end of the summer Peak Load Exposure (PLE) period (to the end of the second full week of September); and clarifications to PLE starting time in the definitions section.

4. Changes to OP-23 Appendix G (Biennial Review)

Support revisions to Appendix G to OP-23 (Reactive Resources Required to Perform Reactive Capability Auditing),[4] as recommended by the RC at its November 14, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

5. Changes to Planning Procedures 5-3 and 5-1 (Addition of Level of Analysis Guideline Table to PP5-3; Conforming Changes to PP5-3 and 5-1)

Support revisions to ISO New England Planning Procedure (PP) No. 5-3 (Guidelines for Conducting and Evaluating Proposed Plan Application Analysis) and PP5-1 (Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans),[5] as recommended by the RC at its November 14, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **October 24, 2023 meeting**, dated October 24, 2023.* [6]

6. Changes to Appendix A to OP-14 (Biennial Review; Clarification for Auto Start Capable Generators)

Support revisions to Appendix A (Explanation of Terms and Instructions for Data Preparation of ISO New England Form NX-12, Generator Technical Data)[7] to ISO New England Operating Procedure No. 14 (OP-14) (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources), as recommended by the RC at its October 24, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

---

[4] The recommended revisions to Appendix G to OP-23 include: updates to resource audit testing dates and the addition/deletion of specific resources.

[5] The recommended revisions include: the addition to PP5-3 of a new table called the "Level of Analysis Guideline Table" in place of Table and Figure 1, together with conforming changes to the remainder of PP5-3 and PP5-1.

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

[7] The recommended revisions to Appendix A to OP-14 update the Auto Start Capable Flag for Intermittent Power Resources and Continuous Storage Facilities.

7. Changes to Appendix B to OP-14 (Periodic Review; Add Synchronous Condenser and FACT Device Requirements)

Support revisions to Appendix B to OP-14 (Resource Reactive Capability Data Explanation of Terms and Instructions for Data Preparation for ISO Form NX-12D),[8] as recommended by the RC at its October 24, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

[8] The recommended revisions to Appendix B to OP-14 include: a change to Appendix B's title, the addition of NX-12D requirements for shunt-connected dynamic reactive power devices, the addition of a note regarding unavailable Manufacturer Nameplate Reactive Capability curves; a clarification that Synchronous Machines and Non-Synchronous Machines include those that pump real power and include DARDs; the addition of definitions for Synchronous Machines and Non-Synchronous Machines; a clarification of the non-applicability of break-point value if there are no break-points in lagging and leading load MW curves; the addition of Data Determination for Submittal for Shunt-Connected Dynamic Reactive Power Devices; and a clarification that Clarified Summer Seasonal Claimed and Economic Minimum Data applies to All Reactive Resources.

Chairman Phillips

Willie L. Phillips was named by President Biden to be Acting Chairman of the Federal Energy Regulatory Commission on January 3, 2023 and is serving a Commission term that ends June 30, 2026.

He most recently served as the Chairman of the Public Service Commission of the District of Columbia, named to that role in 2018. He served on the Commission since 2014. He is an experienced regulatory attorney combining nearly 20 years of legal expertise in public and private practice. He has an extensive background in the areas of public utility regulation, bulk power system reliability, and corporate governance.

Prior to being appointed to the DCPSC, Mr. Phillips served as Assistant General Counsel for the North American Electric Reliability Corporation (NERC), in Washington, D.C. Before joining NERC, he also worked for two law firms, where he advised clients on energy regulatory compliance and policy matters.

Mr. Phillips has also served on the boards of several organizations, including the board of directors for the National Association of Regulatory Utility Commissioners (NARUC) and the Organization of PJM States (OPSI). He also has served as president of the Mid-Atlantic Conference of Regulatory Utility Commissioners (MACRUC), and he has held leadership roles on several advisory councils, including the Electric Power Research Institute (EPRI) Advisory Council.

Mr. Phillips has a *Juris Doctor* from Howard University School of Law, and a Bachelor of Science from the University of Montevallo. He lives in Washington, D.C., with his wife and two children.

Sworn In

December 3, 2021

Term Expires

June 30, 2026

Contact

Request a Meeting →

Staff

RONAN GULSTONE
Chief of Staff

KAL AYOUB
Critical Infrastructure and Resilience Advisor

RICHARD LEHFELDT
Senior Legal Advisor

GRACE HU
Technical Advisor

MICHELLE BROWN
Confidential Assistant

KARIN HERZFELD
Senior Transmission Counsel

THOMAS CHANDLER
Legal Advisor

JAMOND D. PERRY
Legal Advisor

NICOLE BUSINELLI
Technical Advisor

TRENICE JETT
Confidential Assistant

This page was last updated on September 14, 2023

HEADLINES

Joint Statement of FERC, NERC on Reliability

November 06, 2023

Comments of Chairman Willie L. Phillips and NERC CEO James B. Robb

We remain concerned about the potential loss of the Everett Marine Terminal (Everett) in New England and the consequences that it might have for the reliability and affordability of the region's energy supplies.

At the September 2023 Open Meeting, Federal Energy Regulatory Commission (Commission) and North American Electric Reliability Corporation (NERC) staff presented preliminary findings and recommendations regarding Winter Storm Elliott. During the storm, both electric and natural gas systems throughout much of the eastern half of the United States were subjected to significant stress, resulting in significant unplanned generating unit losses, with nearly 90,000 megawatts out at the same time. Indeed, the Winter Storm Elliott findings demonstrate the importance energy infrastructure plays in ensuring that we have reliable, affordable supplies of all types of energy.

While the New England Winter Gas-Electric Forum (Forum) largely focused on the Commission-jurisdictional bulk power system and interstate natural gas system, the Winter Storm Elliott report illustrates the extent to which such winter events can also have significant consequences for infrastructure subject to state jurisdiction, such as the local gas distribution system.

For example, although much of the attention has focused on the electric outages, the storm's effects on the natural gas system, and the local gas distribution system in particular, cannot be overlooked. During the storm, flows of natural gas into the pipelines were reduced, while at the same time, shippers requested increased volumes of natural gas, which dramatically lowered line pressures. That dynamic put significant stress on the natural gas system, which only narrowly avoided significant outages. By way of illustration, Consolidated Edison, Inc. (ConEd) faced reliability-threatening low pipeline pressures during the storm, forcing it to declare an emergency and use its own liquid natural gas facility to maintain necessary pressure. Without those emergency efforts, ConEd potentially faced system collapse, and it would have taken "many months" to restore service, leaving hundreds of thousands of natural gas customers without heat in the middle of winter.

This point is especially relevant considering the evidence presented at the Forum regarding Everett. With respect to the natural gas system, the evidence raised what we view as serious concerns about certain local gas distribution systems' ability to ensure reliability and affordability in the region without Everett. And, although there was evidence that the retirement of Everett would be "manageable" for the electric system, at least in the near-term, given anticipated new resource deployments and transmission development, minimal load growth, limited resource retirements, and increased reliance on non-natural gas generators, the evidence indicates that, should those expectations not materialize as anticipated, ensuring reliability and affordability could become challenging in the face of a significant winter event.

As discussions regarding the future of Everett continue, we encourage all parties to keep reliability and affordability at the center of those negotiations. With respect to electric reliability, we encourage ISO-New England and its stakeholders to pursue reforms aimed at ensuring that the electric system remains reliable by incentivizing resources to obtain the energy supplies, e.g., fuel, necessary to perform during extreme weather conditions. To the extent that Everett or other infrastructure plays a role in supporting electric reliability by making needed energy supplies available, in the near-term or the future, such reforms should consider how to ensure that any needed reliability contributions are appropriately valued.

With respect to the natural gas system, we recognize that the reliability needs turn, at least for the foreseeable future, largely on facilities subject to the New England states' jurisdiction. If our organizations can be any help to state regulators and other stakeholders as they address those needs, we are, of course, available to assist in any way we can.

Chairman Willie L. Phillips

and NERC CEO James B. Robb

Documents & Docket Numbers

- AD23-9-000
- AD22-9-000

Contact Information

News Media
Email: MediaDL@ferc.gov

This page was last updated on November 06, 2023

FOR IMMEDIATE RELEASE
Contact: Jacqulyn Priestly 202-251-9703

NPCC Announces Northeast Gas/Electric System Study

New York, NY – 11/27/2023 – Today, the Northeast Power Coordinating Council (NPCC) announced the launch of a northeastern regional gas infrastructure study to evaluate fuel supply to the region's electric generation. The study will consider the gas supply and pipeline constraints that may occur during extreme and protracted winter weather events during the winter peak heating season (December through February 2024-2025, 2027-28 and 2032-33).

The study will also reflect insight related to recent concerns presented at the June 20 New England Winter Gas-Electric FERC Forum regarding future reliability and affordability of the local gas distribution systems. In addition, FERC's recently released Winter Storm Elliott report underscores the consequences that significant winter weather events may have on the reliability of both the electric and the local gas distribution systems.

"This study will be vital to the region's energy infrastructure decisions and will inform both regulatory and legislative policy and decision makers about the capacity, capabilities and resilience of the region's gas infrastructure," said Charles Dickerson, President and Chief Executive Officer of NPCC, Inc. "This study also serves as an example of how NPCC continues to work with NERC and other stakeholders to facilitate reliability in the region."

A Steering Committee consisting of the New York ISO, ISO New England, NERC and the Northeast Gas Association will support evaluation of the gas pipeline and storage infrastructure to serve the NPCC gas-fired generation during the winter peak heating season.

"Hydraulic system modeling along with system data from various entities that use the region's gas infrastructure will be used to illustrate the ability of the natural gas system to serve gas-fired generation for the winter peak heating season for a variety of gas-side or electric-side scenarios," explained Phil Fedora, NPCC's Chief Engineer and Vice President of Reliability Services.

"As has been demonstrated in recent events across the country, the electric and gas systems are interdependent and a failure in one system can impact the other. The independent system operators have no jurisdiction over the natural gas system and do not have the expertise to determine whether it will remain reliable as the energy industry evolves. This study will provide important insight into the gas system and its ability to support both electric generation needs and customer gas use as the demands from both change in the future." added Gordon van Welie, President and CEO of ISO New England, Inc.

NPCC selected Levitan & Associates, Inc. to conduct the analysis. The group expects to complete the study by December, 2024. NPCC will post periodic status reports on its website at www.npcc.org.

###

About NPCC

NPCC is one of six Regional Entities located throughout the United States, Canada and portions of Mexico. NPCC's geographic area includes the state of New York, the six New England states, Ontario, Québec, and the Canadian Maritime Provinces of New Brunswick and Nova Scotia. Overall, NPCC covers an area of nearly 1.2 million square miles, populated by more than 56 million people.

NPCC is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. NPCC carries out its mission through: (i) the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, (ii) coordination of system planning, design and operations, and assessment of reliability, and (iii) the establishment of regionally-specific criteria and monitoring and enforcement of compliance with such criteria.

Summary of ISO New England Board and Committee Meetings

December 7, 2023 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on October 31. The Board of Directors met on October 31 and November 1. All of the meetings were held in person in Boston, Massachusetts.

The Audit and Finance Committee received an annual report on employee and Board compliance with the Code of Conduct following the annual collection of certificates, and an update on the availability of an internet- and telephone-based tool for anonymously reporting compliance issues. The Committee was provided with a report on current budget performance, along with an update on interest rates. The Committee then reviewed and approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. Next, the Committee met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2023 System and Organization Controls Report and resulting unqualified audit opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee then met with KPMG in executive session to ensure that the auditors had the opportunity to make any necessary reports without management present. The Committee also met with Meyers Brothers Kalicka, the Company's external benefit plan auditors, to discuss the results of employee benefit plan audits. The Committee also received a report on internal audit activities. The Committee discussed management's proposal to increase the Company's working capital line, and inquired about the process to ensure the cost-effectiveness of the terms. Finally, in executive session, the Committee reviewed the proposed corporate goals for 2024.

The Compensation and Human Resources Committee discussed key dates and deliverables for 2024 goal setting and conducting the corporate performance review for 2023. Next, the Committee reviewed its calendar for the upcoming year after considering the risks and strategic objectives that the Committee sought to address. The Committee was then provided with updated survey data for salary increase budgets to ensure that the salary increase budget included in the Company's 2024 budget remained reasonable and necessary to ensure the competitiveness of the Company's salaries, given the data and the Company's needs. During an executive session, the Committee reviewed management succession plans and current practices regarding director compensation.

The Markets Committee was provided with a summary of market performance for the 2023 summer season from the internal and external market monitors, and discussed the lower wholesale market costs compared to the previous summer, which were partly driven by lower natural gas prices. Next, the Committee reviewed its charter and incorporated edits to reflect the Committee's obligation to ensure that the Internal Market Monitoring unit conducts its work consistent with FERC's guidance, including overseeing the Internal Market Monitor's communications with management. The Committee also requested that management evaluate the Company's current monitoring of the market for Financial Transmission Rights (FTRs), and provide the Committee with an update including any recommended changes or enhancements to aid in the monitoring of the FTR markets. The Committee then reviewed its calendar for the upcoming year. Following that discussion, the Committee held an executive session to review proposed corporate goals for 2024.

The Nominating and Governance Committee considered the 2024 Joint Nominating Committee process and topics for discussion at the meetings. The Committee then reviewed the Company's reporting on environmental, social, and governance (ESG) topics in its annual financial statements and on its website. Next, the Committee discussed possible site visits and potential guest speakers to meet with the Board in 2024 as part of the Board's continuing education program. The Committee also received an update on the corporate communications campaign, and reviewed its calendar for the upcoming year.

The System Planning and Reliability Committee reviewed summer operations for 2023 and the outlook for the upcoming winter. The Committee received updates on various operations and planning activities, including qualification results for Forward Capacity Auction #18, efforts to codify long-term transmission planning, integration of Distributed Energy Resources, and winter preparedness. In addition, the Committee reviewed key operations and planning metrics, as well as reliability standards compliance, and was informed of updates to Regional System Plan project costs and timelines. Next, the Committee received a report on the 2050 Transmission Study, a description of the current interconnection queue backlog, and an explanation of the GE MARS software error related to winter risk modeling in the Resource Capacity Accreditation project, which error has subsequently been corrected. The Committee also reviewed its calendar for the upcoming year and held an executive session to discuss the proposed corporate goals for 2024.

The Board of Directors convened to prepare for its meetings with NEPOOL and NECPUC, as well as the annual open meeting of the Board. The Board discussed board operations and governance in executive session. The Board then received the report of the CEO, including an update on achievement of corporate goals. During the CEO report, the Board discussed stakeholder requests for additional sensitivities to be run using the Probabilistic Energy Adequacy Tool. The Board also heard reports from the standing committees. During the Audit and Finance Committee report, the Board approved the proposed increase in the Company's working capital line. During the Compensation and Human Resources Committee report, the Board approved modifications to the Committee's charter, and that of the Audit and Finance Committee, to reflect a shift in the responsibility for oversight of the Company's Code of Conduct from the Audit and Finance Committee to the Compensation and Human Resources Committee. The revised charters and Code of Conduct have been posted to the Company's website. Last, the Board held an executive session.

NEPOOL PARTICIPANTS COMMITTEE | 12/7/23
Meeting Agenda item #5

NEPOOL Participants Committee Report

December 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Data is through November 29th, unless otherwise noted.

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: October 2023 Energy Market value totaled $259M
  - November 2023 Energy market value was $378M, up $118M from October and down $275M from November 2022
    - November natural gas prices over the period were 144% higher than October average values
    - Average RT Hub Locational Marginal Prices ($35.96/MWh) over the period were 48% higher than October averages
      - DA Hub: $38.95/MWh (8% premium)
    - Average November 2023 natural gas prices and RT Hub LMPs over the period were down 40% and 47%, respectively, from the prior November
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.6% during November, down from 101.6% during October*
    - The minimum value for the month was 95.2% on Saturday, November 18th

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

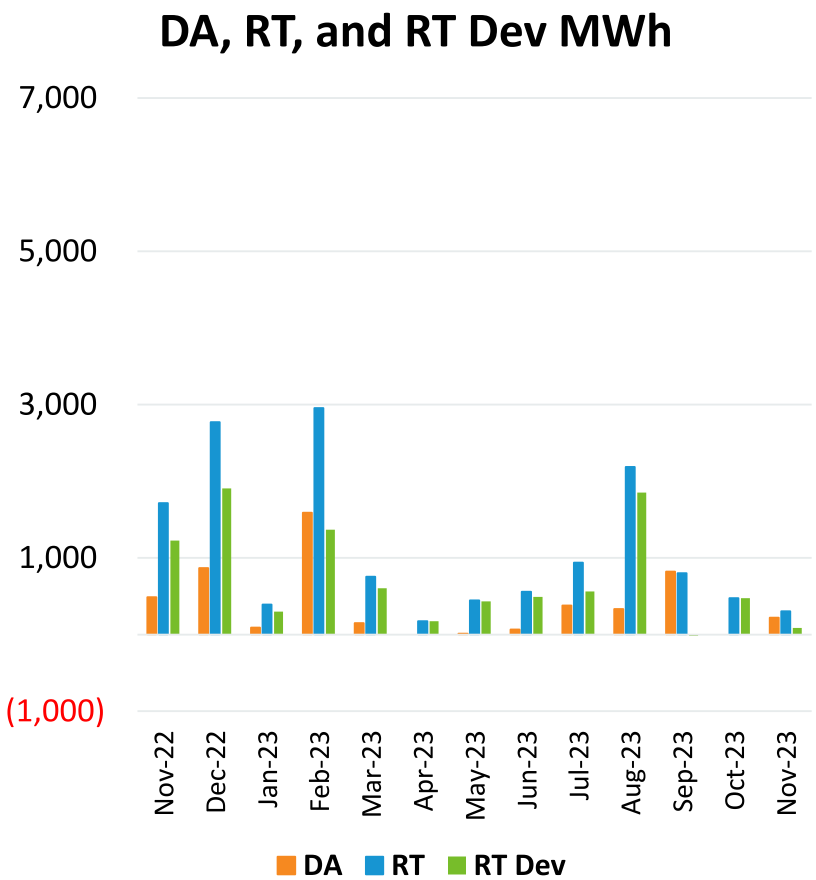
Underlying natural gas data furnished by: ICE Global markets in clear view

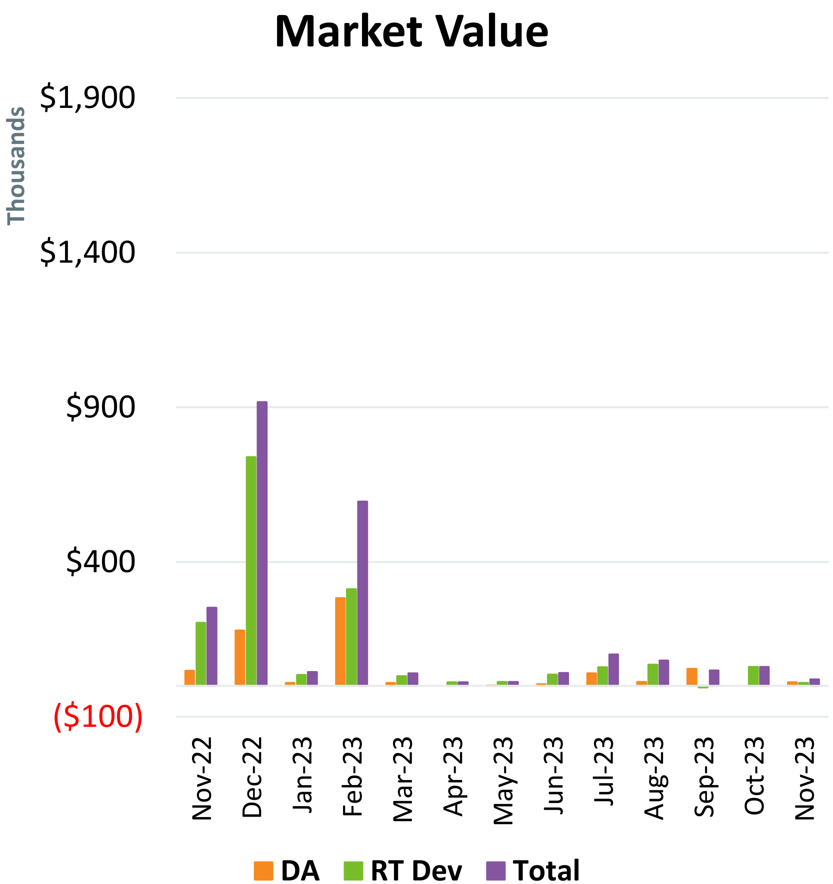
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November NCPC payments totaled \$4.9M over the period, up \$0.4M from October and up \$1.1M from November 2022
    - First Contingency payments totaled \$4.9M, up \$0.4M from October
      - \$4.7M paid to internal resources, up \$0.5M from October
        - » \$0.8M charged to DALO, \$2.3M to RT Deviations, \$1.6M to RTLO*
      - \$143K paid to resources at external locations, down \$165K from October
        - » \$23K charged to DALO at external locations, \$121K to RT Deviations
    - Distribution payments were \$73K, up \$31K
    - Second Contingency and Voltage NCPC payments were all zero
  - NCPC payments over the period as percent of Energy Market value were 1.3%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - \$306K; Rapid Response Pricing (RRP) Opportunity Cost - \$528K; Posturing - \$8K; Generator Performance Auditing (GPA) - \$784K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- 2023 RSP is complete and was approved by the Board on November 16
- FCA 18 informational filing was submitted to FERC on November 22
- ICR and related values for the ARAs to be conducted in 2024 were filed with FERC on November 30
- The 2024 forecast cycle was initiated at the September 22 Load Forecast Committee (LFC) meeting
- The next LFC meeting will be held on December 8
- Qualified Transmission Project Sponsor (QTPS)
  - 27 companies have achieved QTPS status

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 15 (2024-2025)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, and results were posted on August 24
- CCP 16 (2025-2026)
  - First annual reconfiguration auction (ARA1) was held on June 1-5, and results were posted on July 3
- CCP 17 (2026-2027)
  - Auction results were filed with FERC on March 21 and, on July 18, FERC issued an order accepting the results effective July 19
  - ICR and related values for the ARAs to be conducted in 2024 were presented and approved at the October 24 RC and November 2 PC meetings and were filed with FERC on November 30

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - FCA 18 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - The ISO issued qualification determination notifications on October 12
  - ICR and related values were approved at the September 19 RC and October 5 PC meetings and filed with FERC on November 7
  - The ISO submitted the FCA 18 informational filing to FERC on November 22

Highlights

- The lowest 50/50 Winter Operable Capacity Margin is projected for week beginning January 6, 2024.
- The lowest 90/10 Winter Operable Capacity Margin is projected for week beginning December 23, 2023.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (1.7°F) Max: 66°F, Min: 27°F Precipitation: 1.93" – Below Normal Normal: 3.66"	Hartford	Temperature: Below Normal (2.0°F) Max: 67°F, Min: 21°F Precipitation: 1.83" - Below Normal Normal: 3.51"

Peak Load:	17,144 MW	November 29, 2023	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

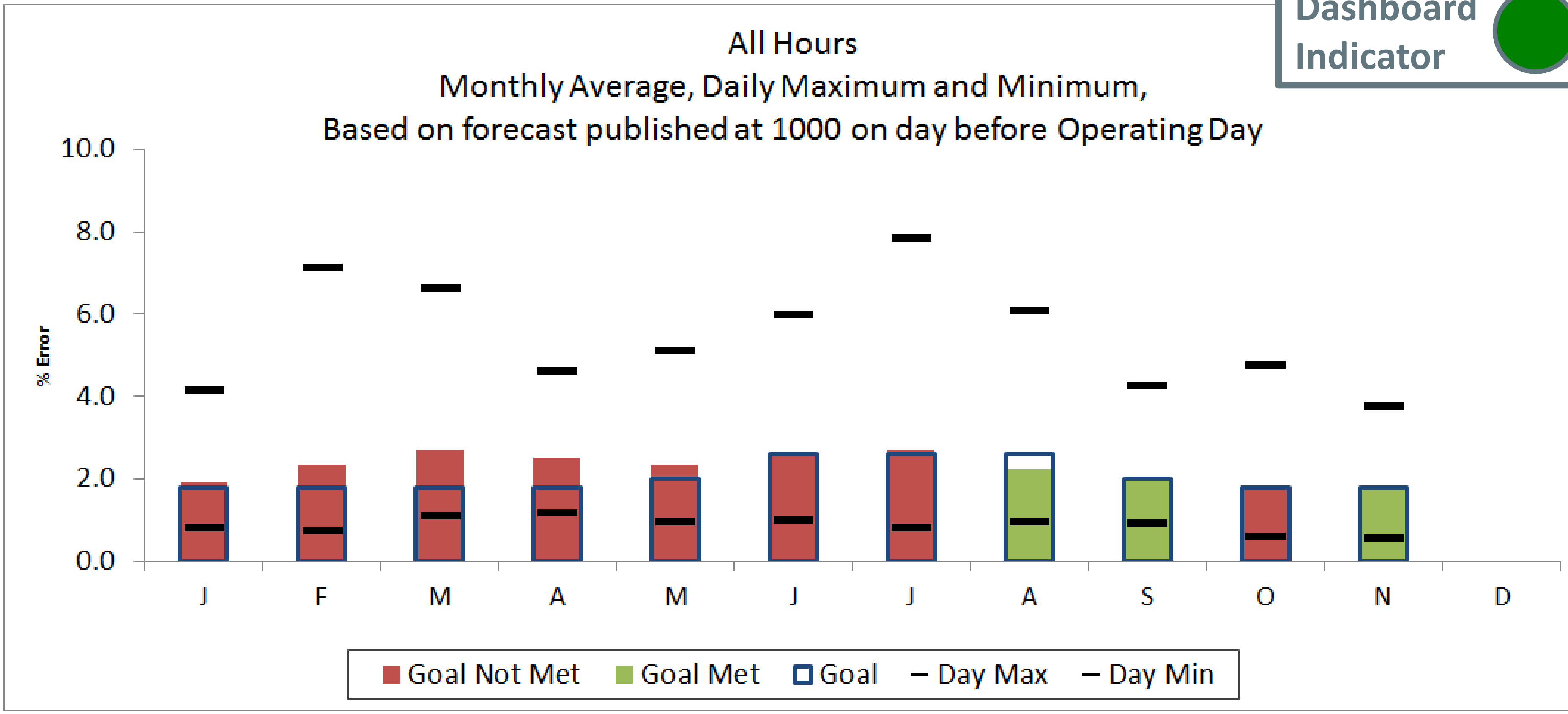
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
11/21/2023	ISO-NE	750

2023 System Operations - Load Forecast Accuracy

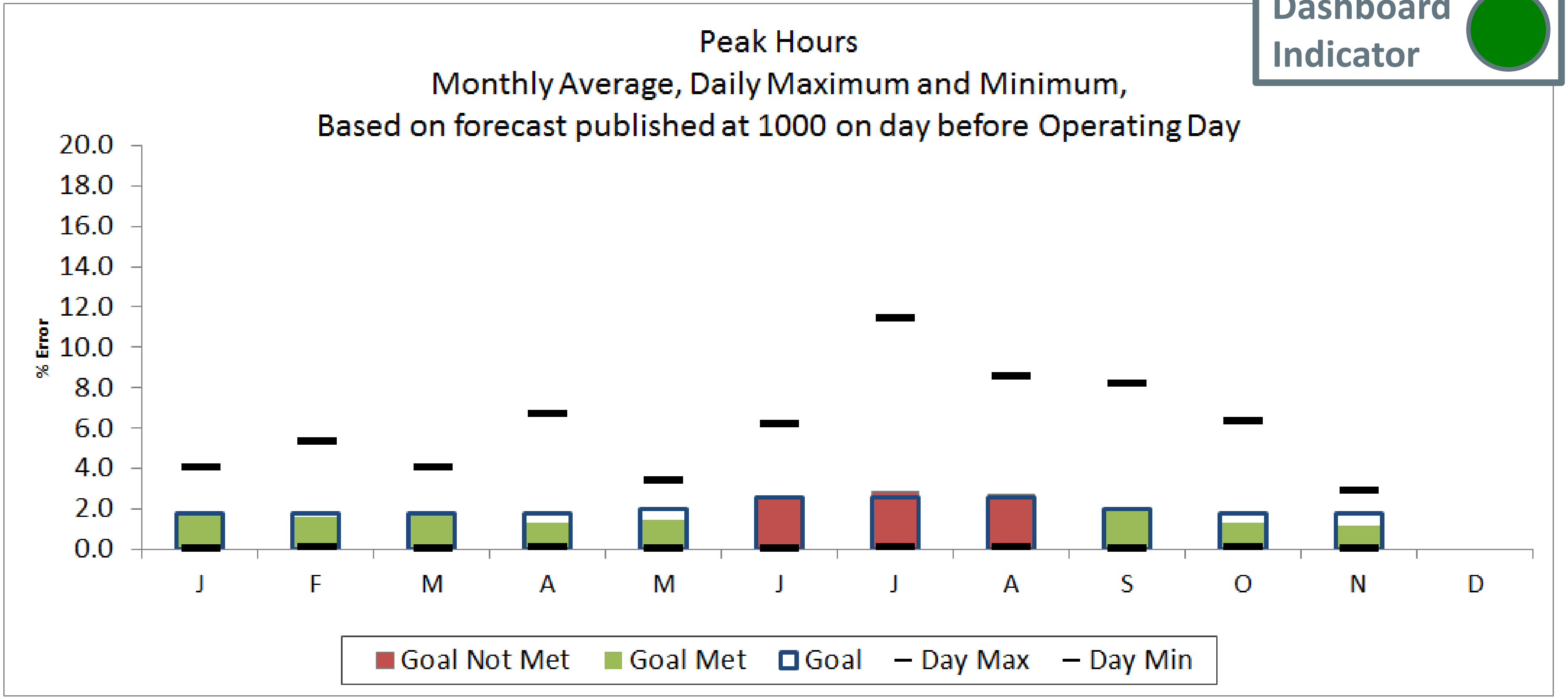
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14	7.12	6.59	4.61	5.10	5.97	7.82	6.06	4.24	4.73	3.73		7.82
Day Min	0.80	0.74	1.08	1.17	0.96	0.97	0.79	0.95	0.91	0.59	0.54		0.54
MAPE	1.91	2.34	2.70	2.52	2.36	2.63	2.70	2.23	1.94	1.84	1.79		2.27
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

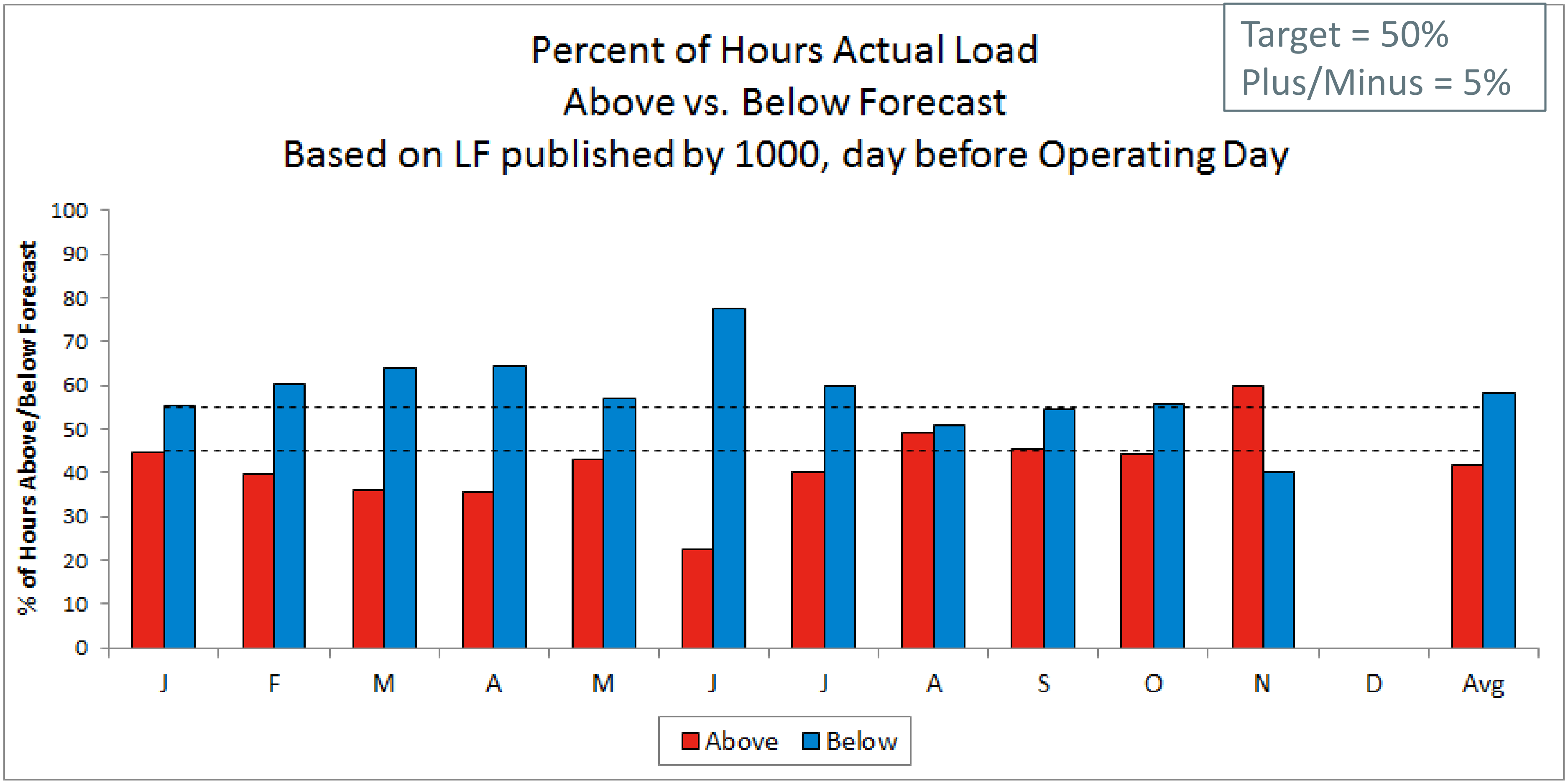
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



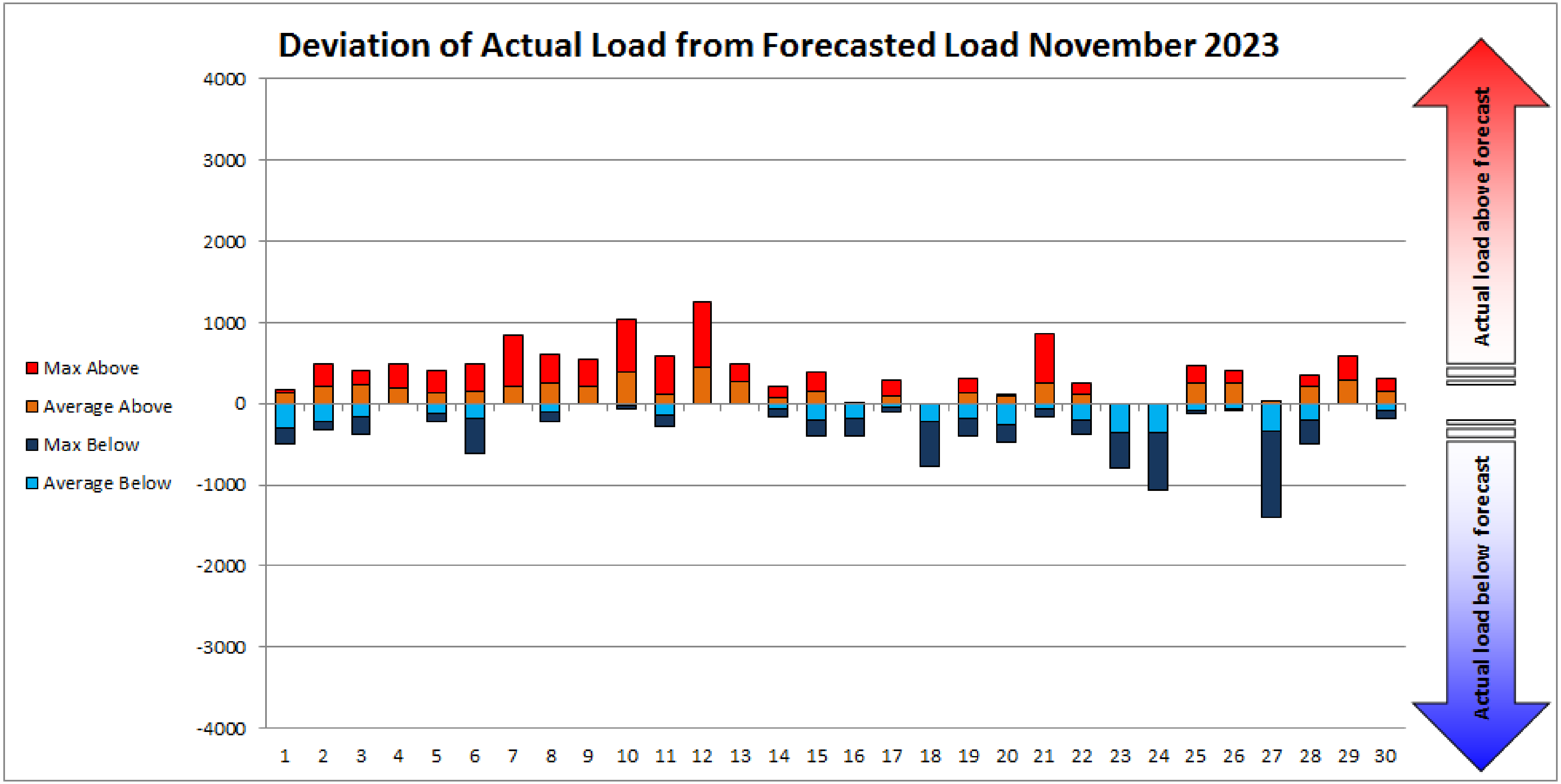
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21	11.40	8.59	8.17	6.31	2.88		11.40
Day Min	0.01	0.08	0.06	0.11	0.03	0.04	0.08	0.14	0.01	0.10	0.02		0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65	2.87	2.72	1.97	1.34	1.18		1.87
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

2023 System Operations - Load Forecast Accuracy cont.

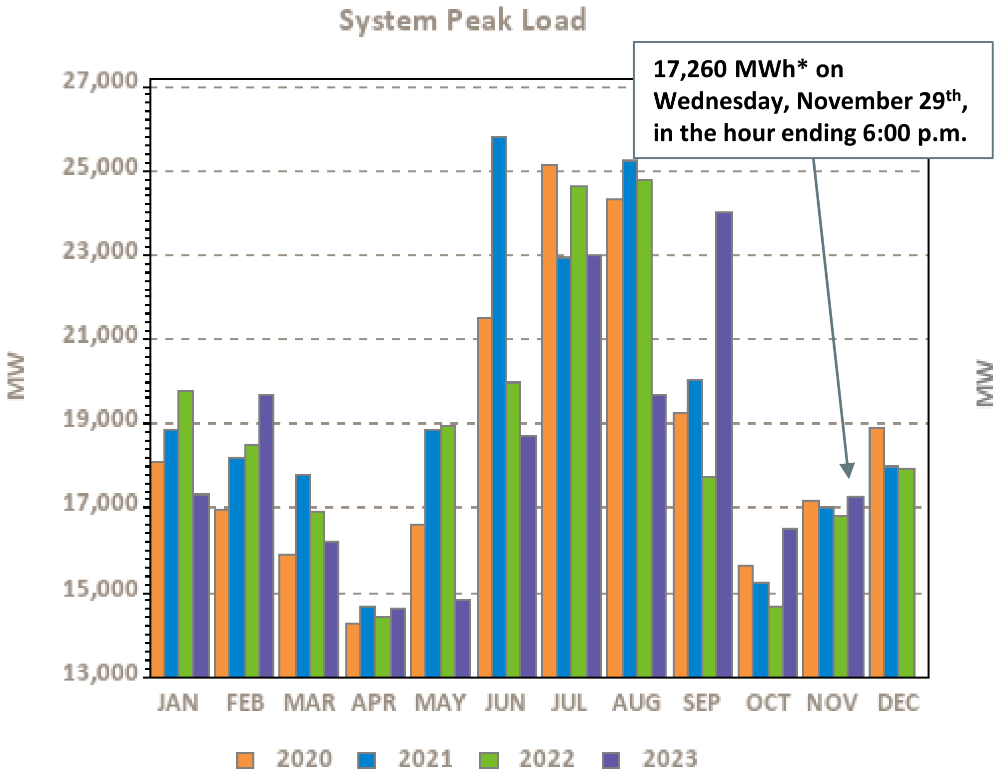


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6	40.2	49.2	45.6	44.4	59.7		42
Below %	55.4	60.3	63.8	64.3	57	77.4	59.8	50.8	54.4	55.6	40.3		58
Avg Above	235.7	228	172.9	194.5	183.5	120	194.8	228.5	226	171.4	166.8		236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3	-388.6	-215.1	-169.7	-163.7	-139.1		-389
Avg All	-10	-28	-142	-74	-17	-236	-170	-6	20	-16	39		-58

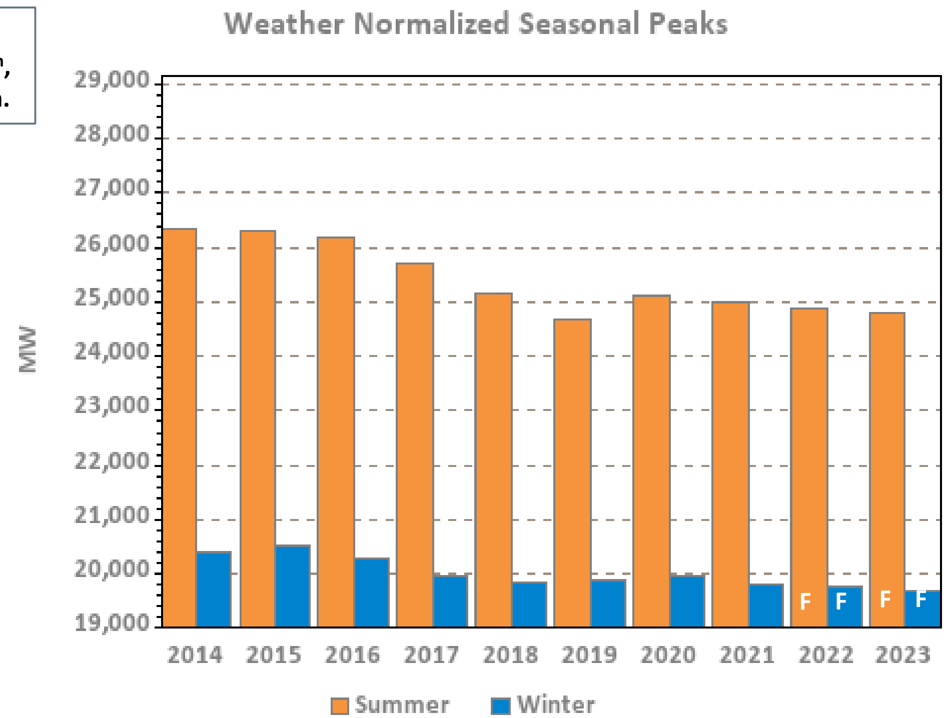
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History



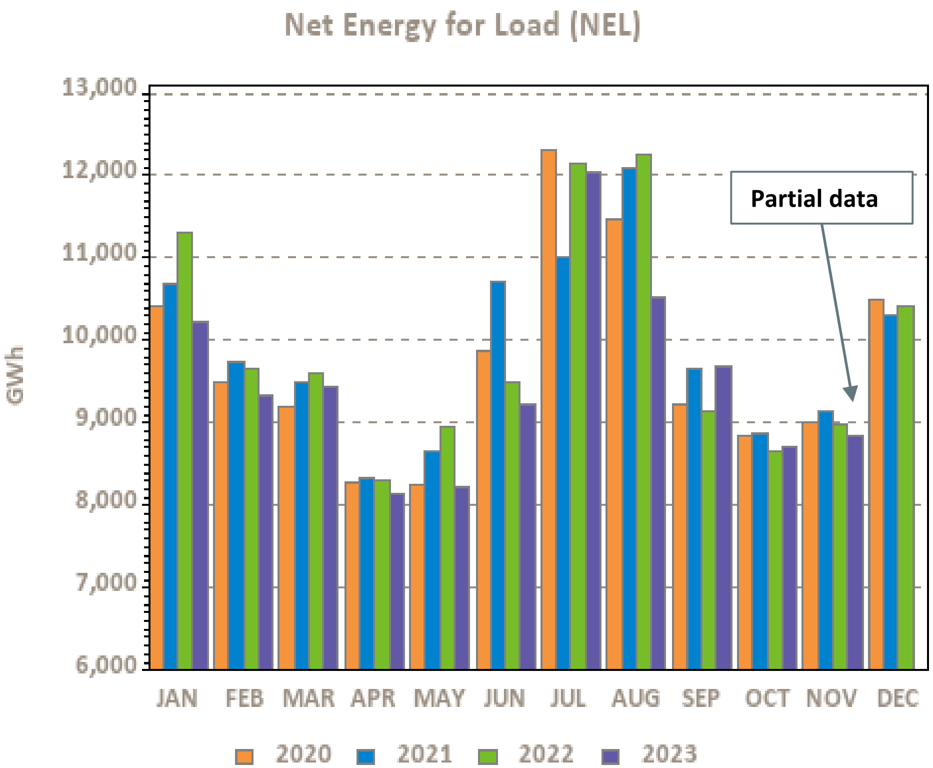
*Revenue quality metered value



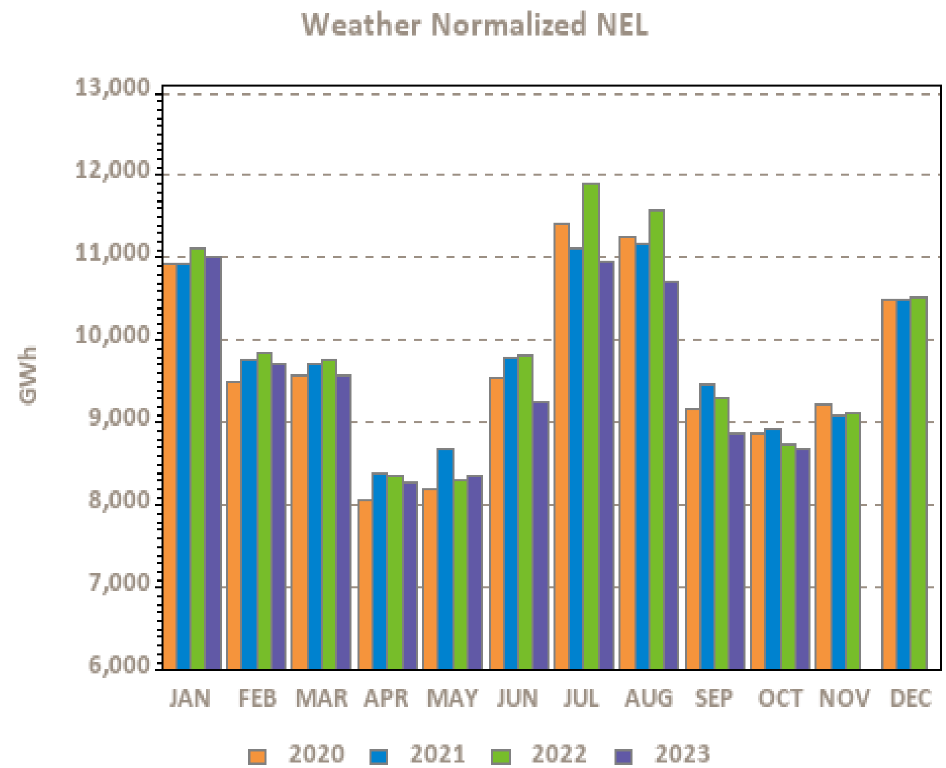
Winter beginning in year displayed

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

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



Ann Tot (TWh): 116.9 118.8 118.9 104.4

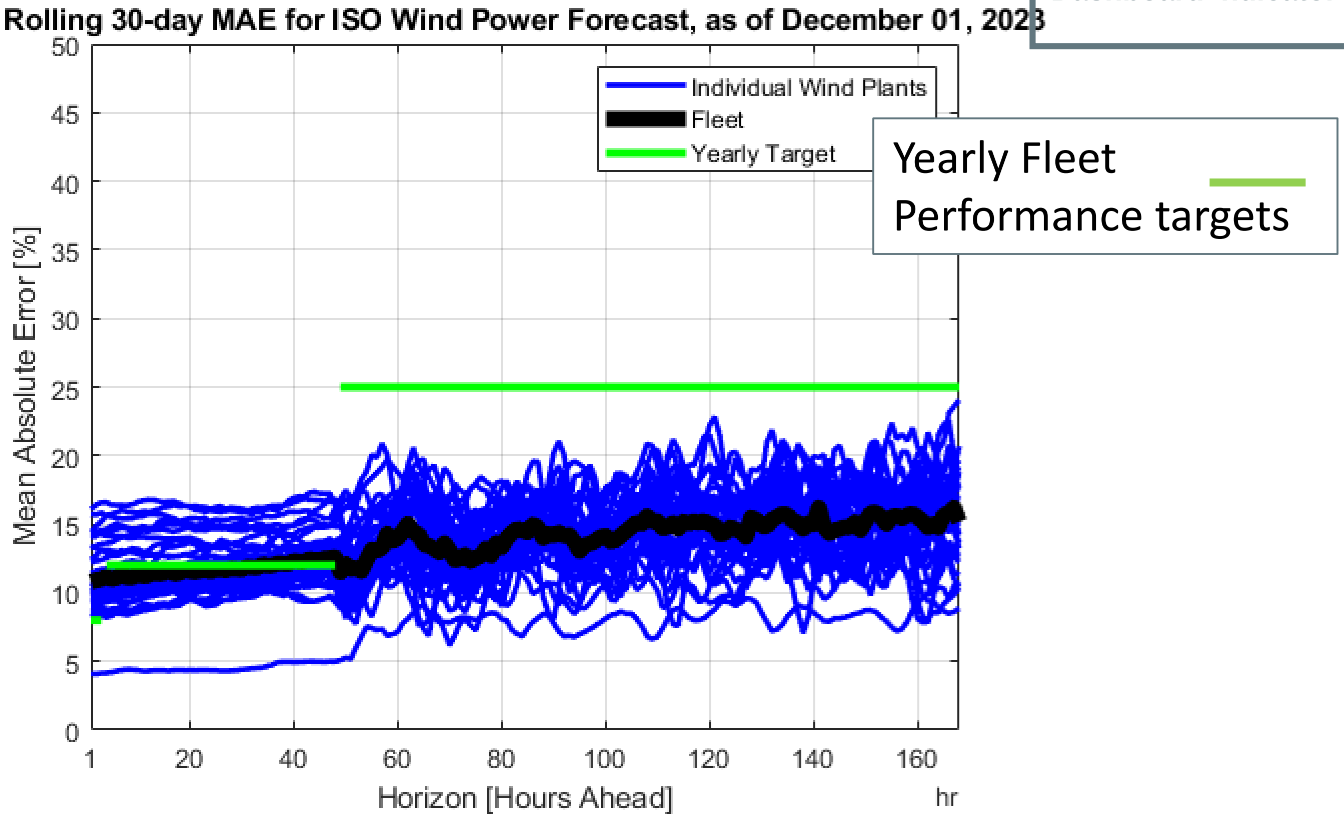


Ann Tot (TWh): 116.3 117.6 118.4 95.4

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

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

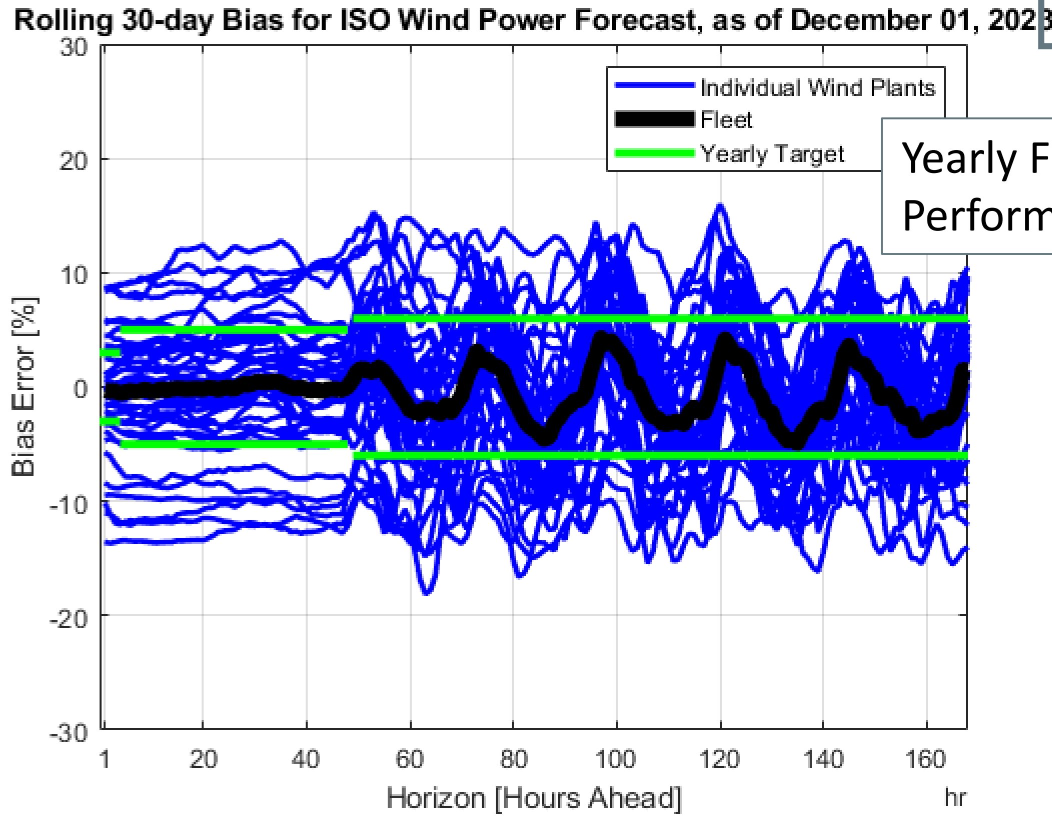
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards. Monthly MAE is outside of yearly performance targets for 1 hour ahead and hours ahead 34 through 48 .

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

Dashboard Indicator

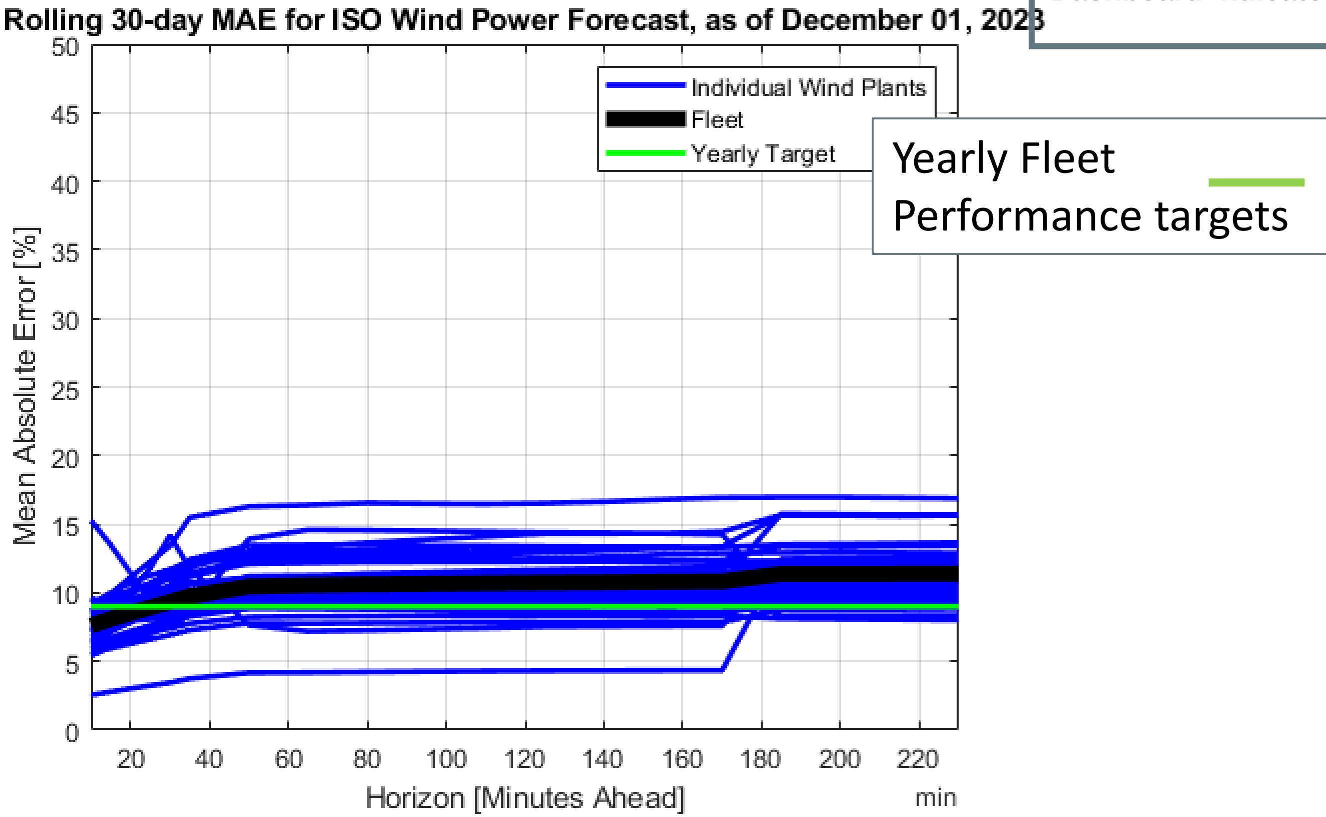


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

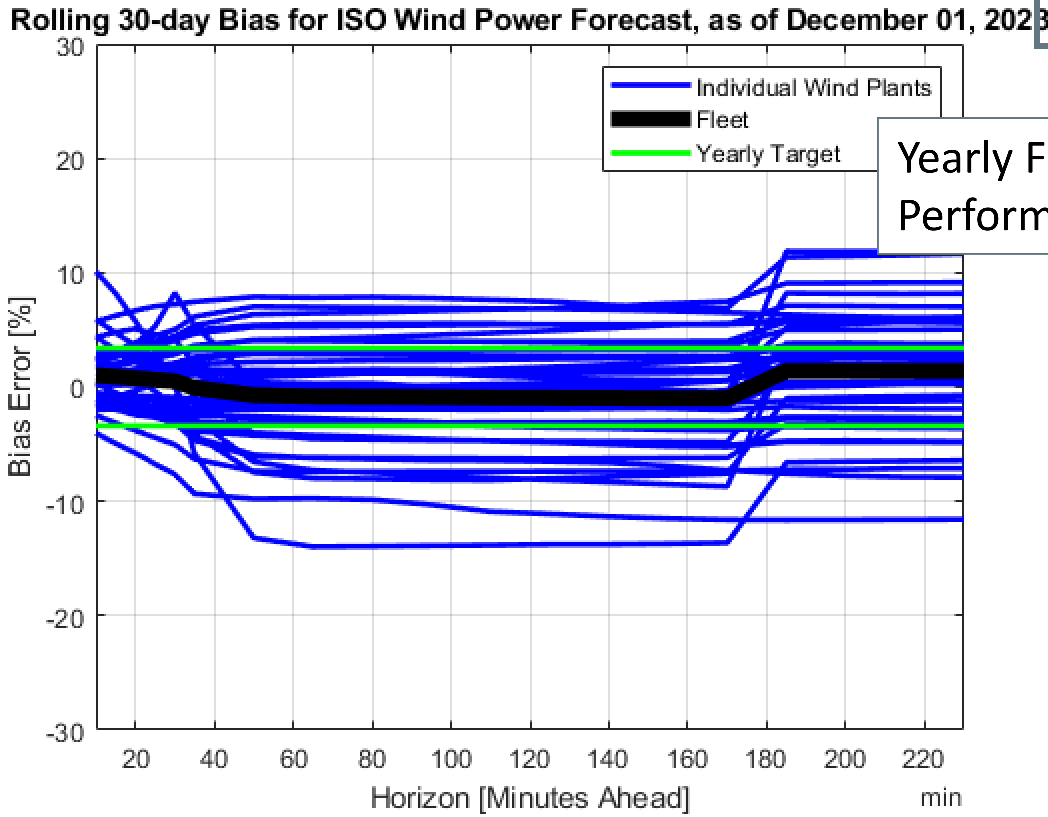
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the forecast compares well with industry standards, but monthly MAE is mostly outside of yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

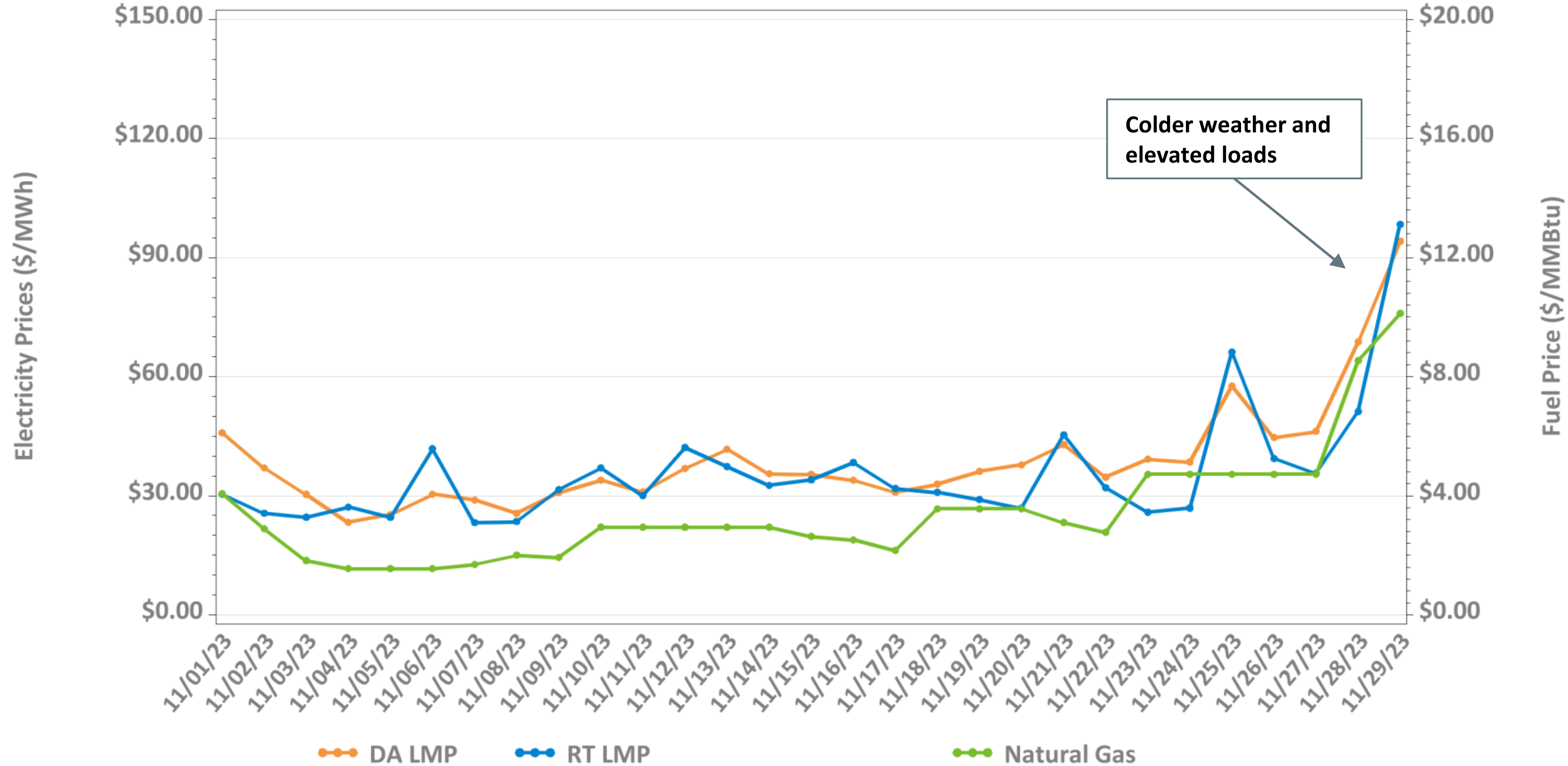


Yearly Fleet Performance targets

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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: November 1-29, 2023

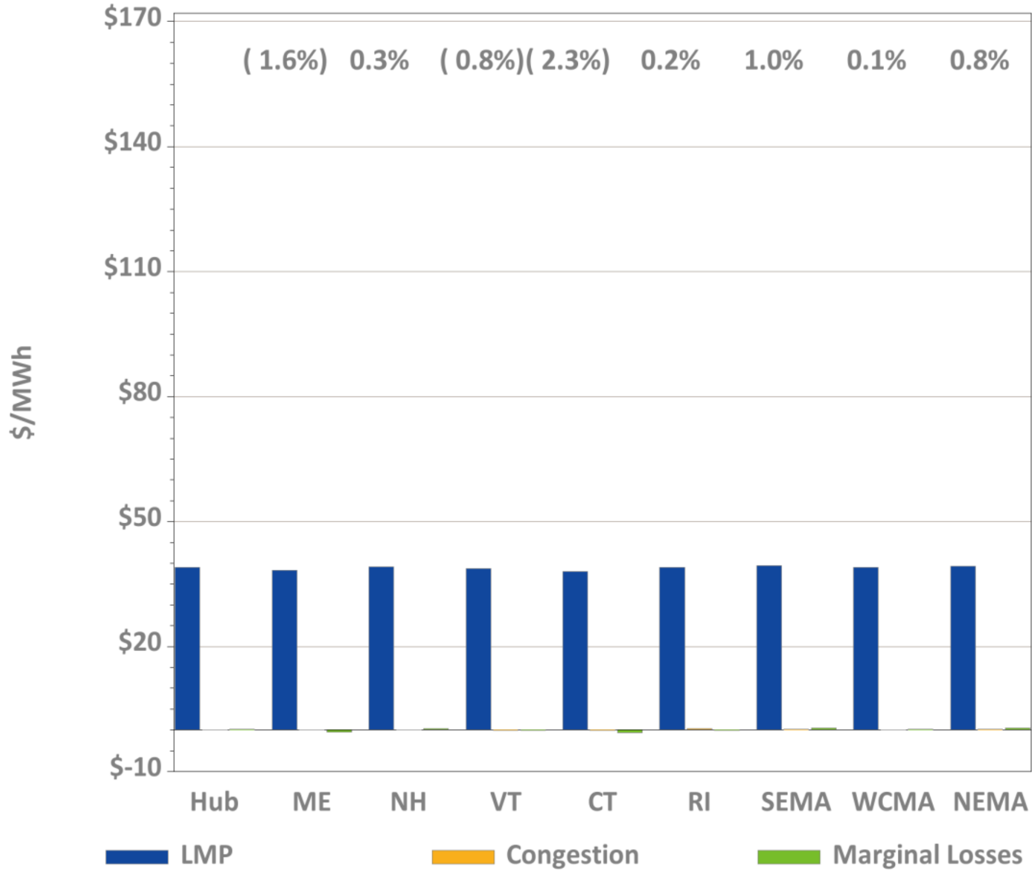


Underlying natural gas data furnished by: ICE Global markets in clear view

*Revenue quality metered values

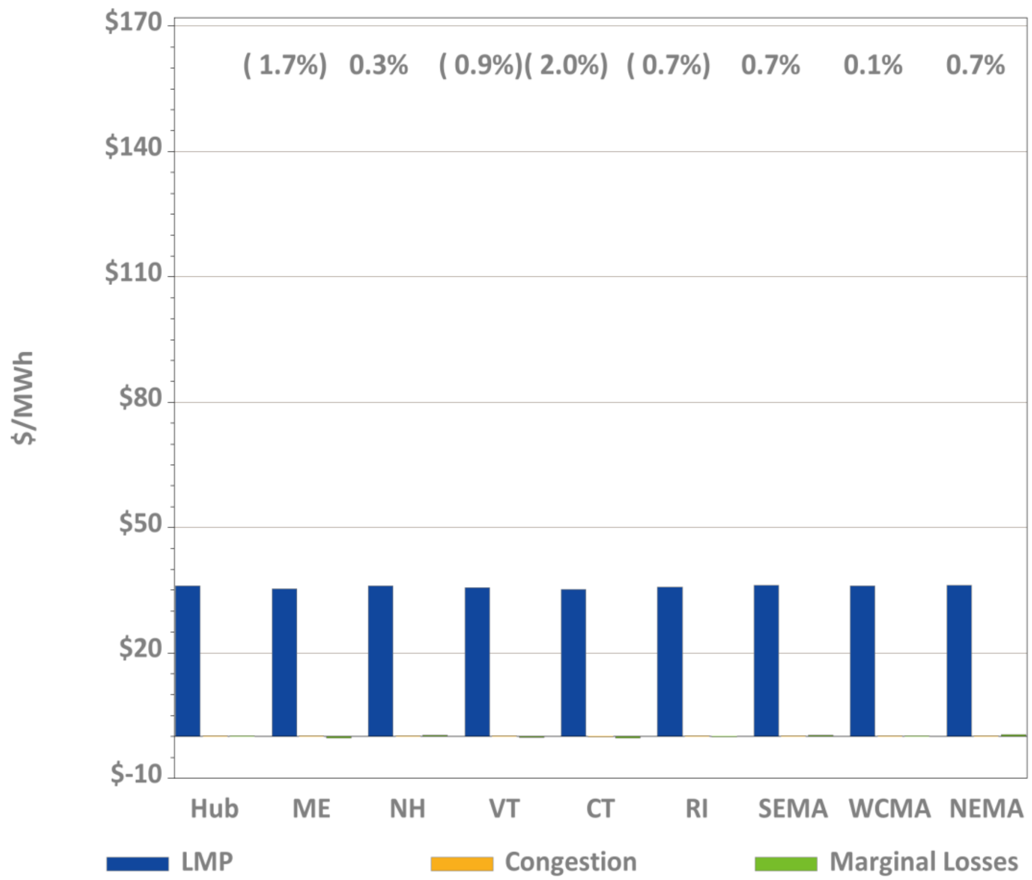
Average price difference over this period (DA-RT): $2.99
Average price difference over this period ABS(DA-RT): $6.09
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 17%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2023



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

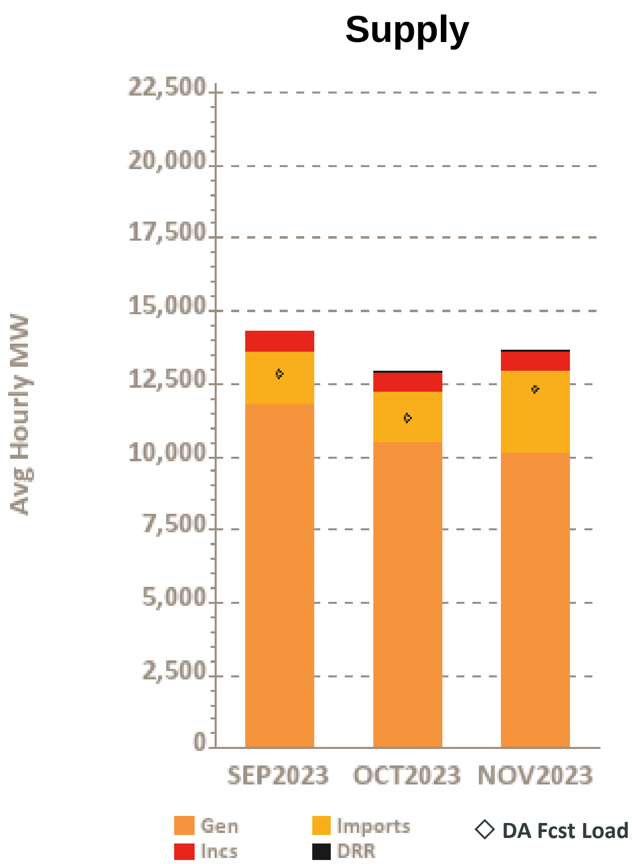
RT LMPs Average by Zone & Hub, November 2023

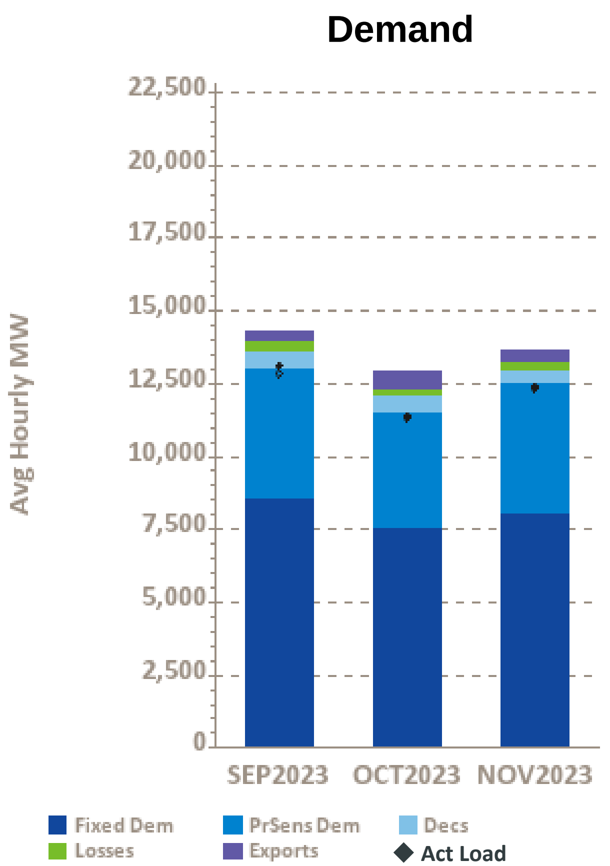


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

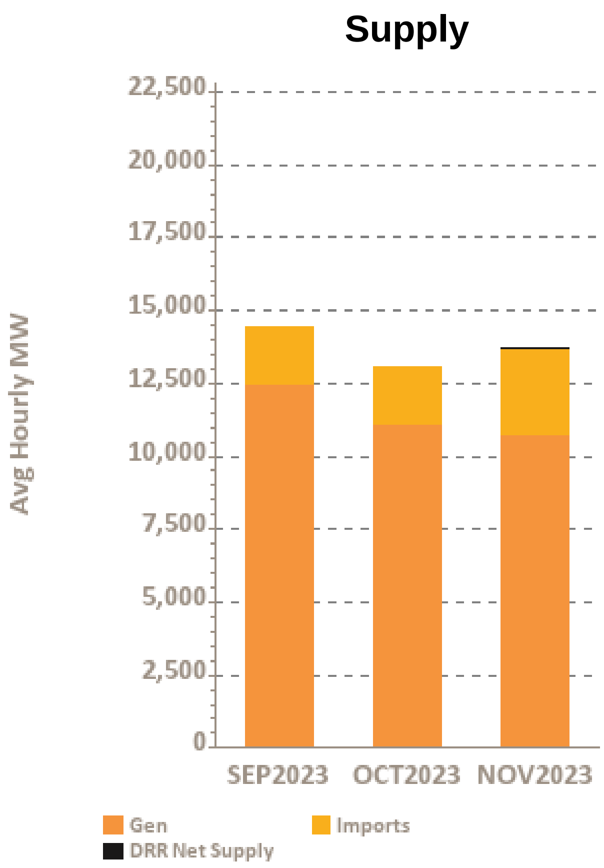


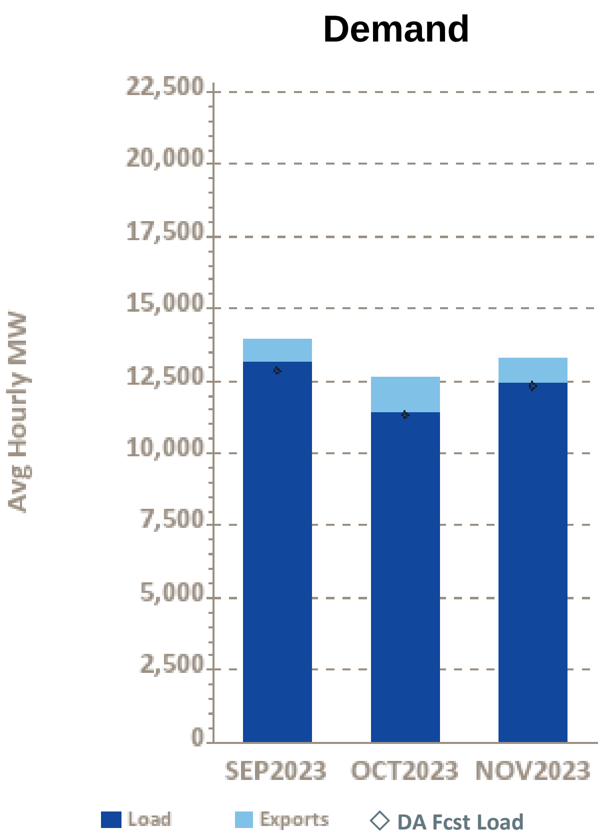


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

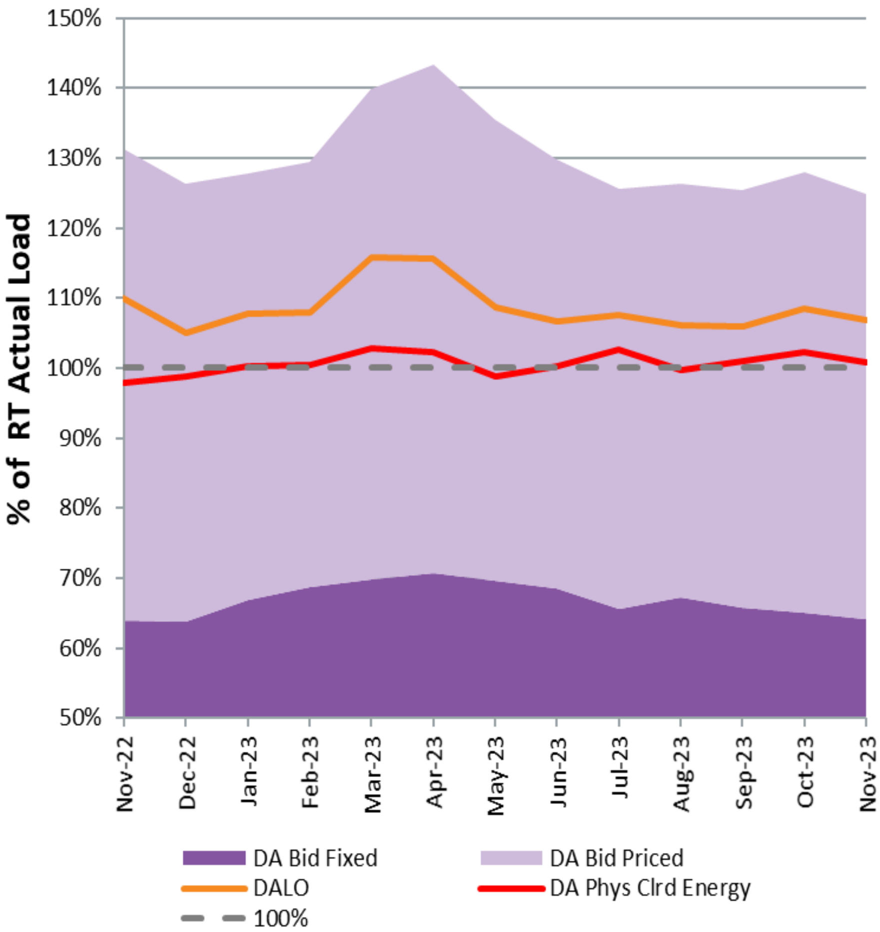
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

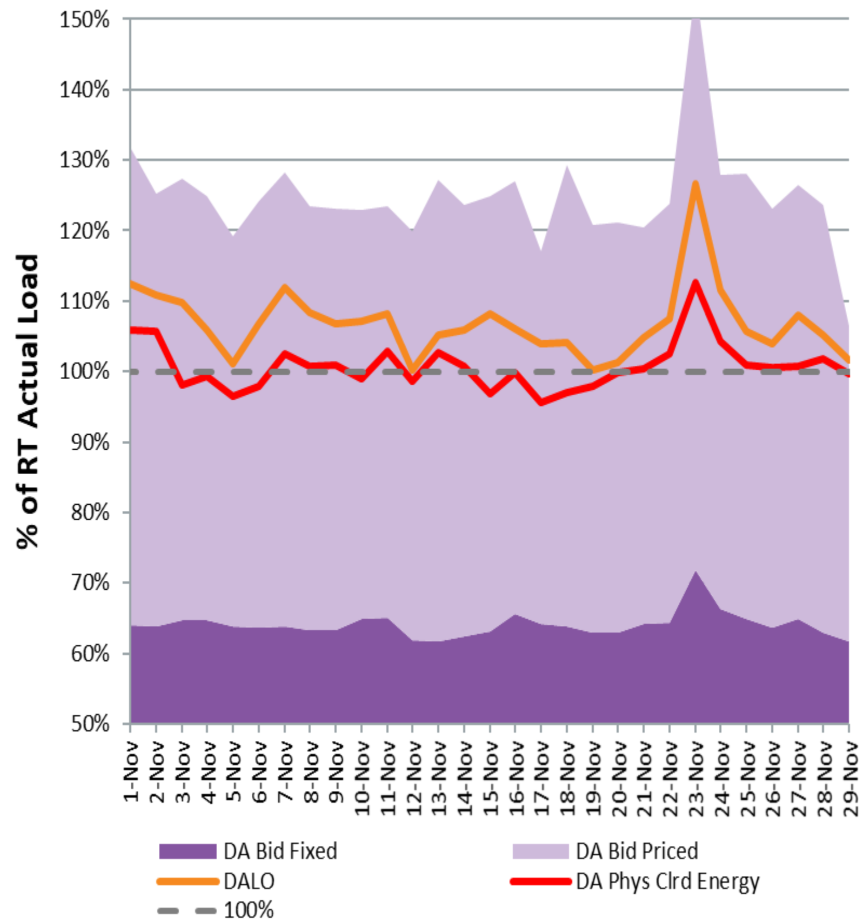
Components of RT Supply and Demand – Last Three Months





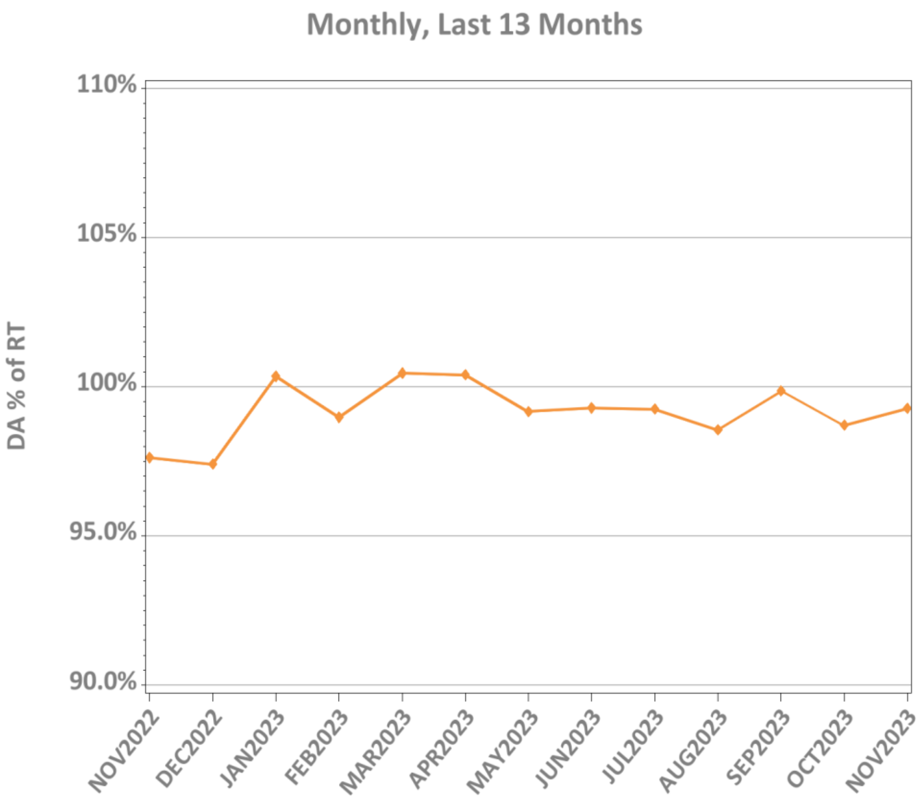
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

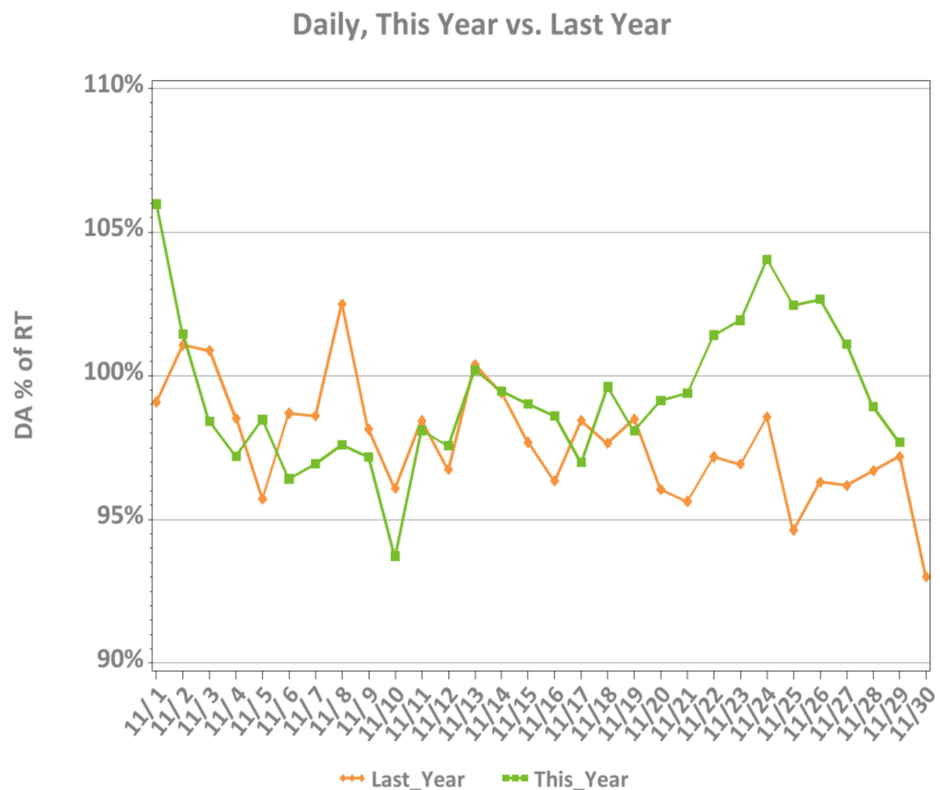




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

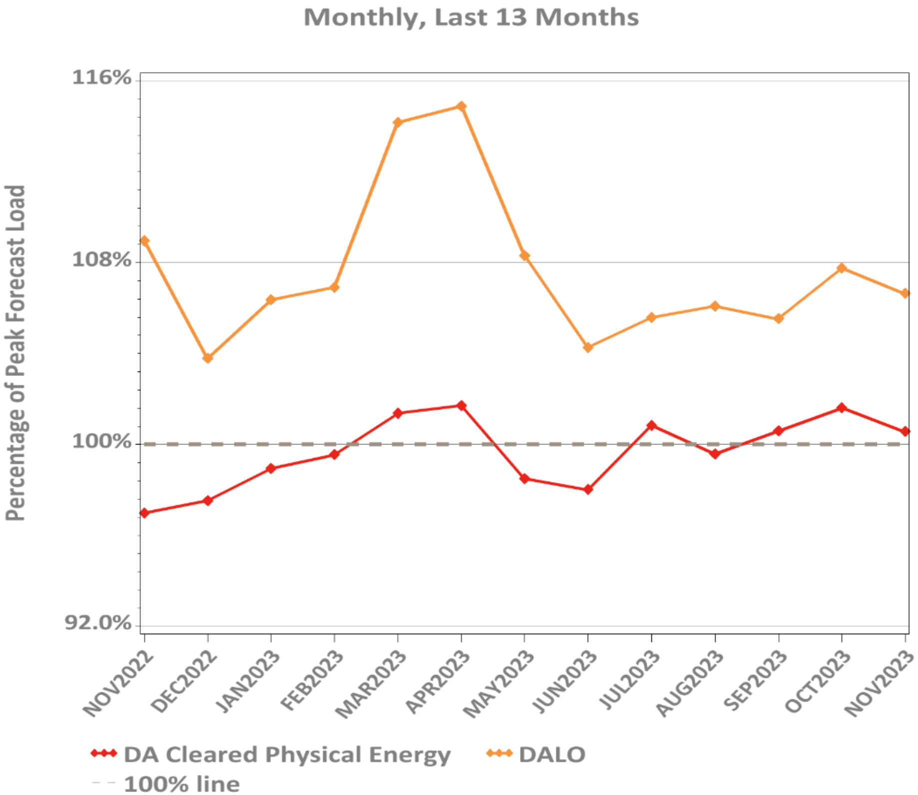
DA vs. RT Load Obligation: November, This Year vs. Last Year

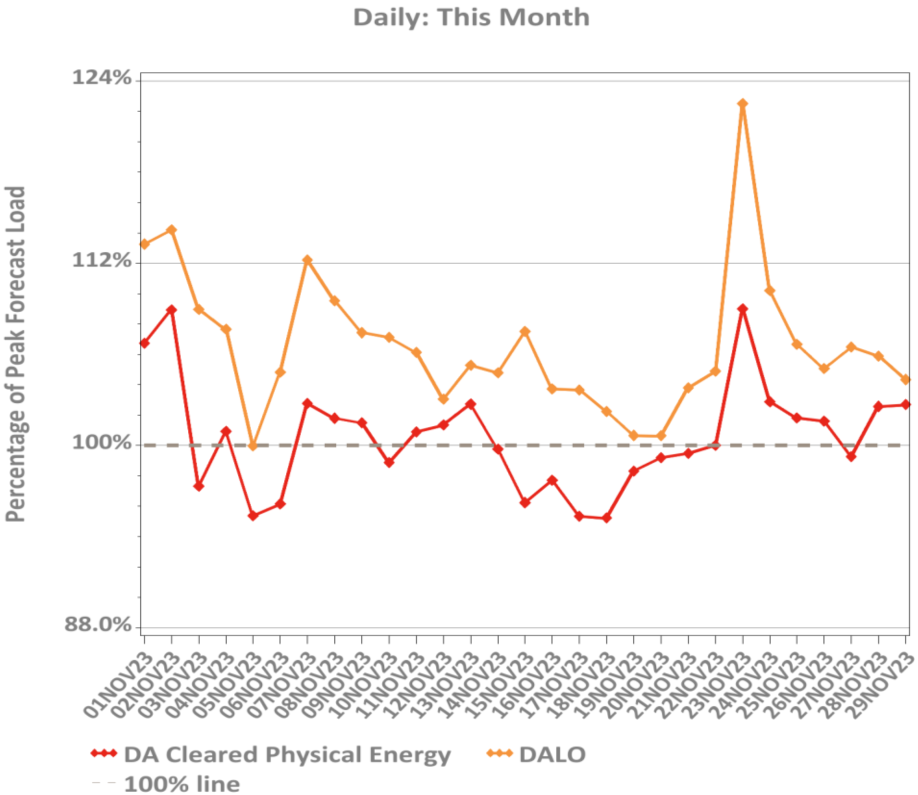




*Hourly average values

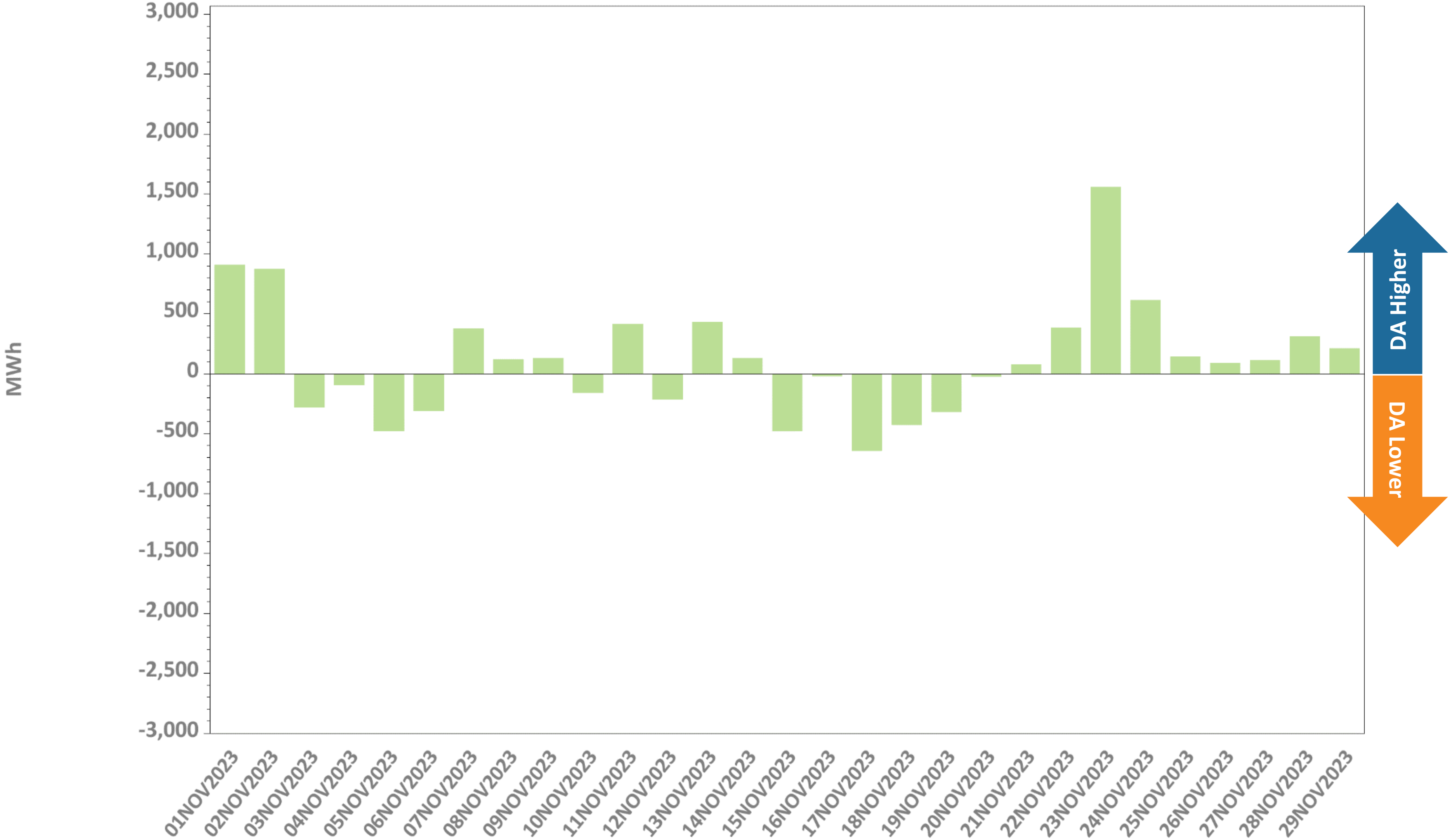
DA Volumes as % of Forecast in Peak Hour





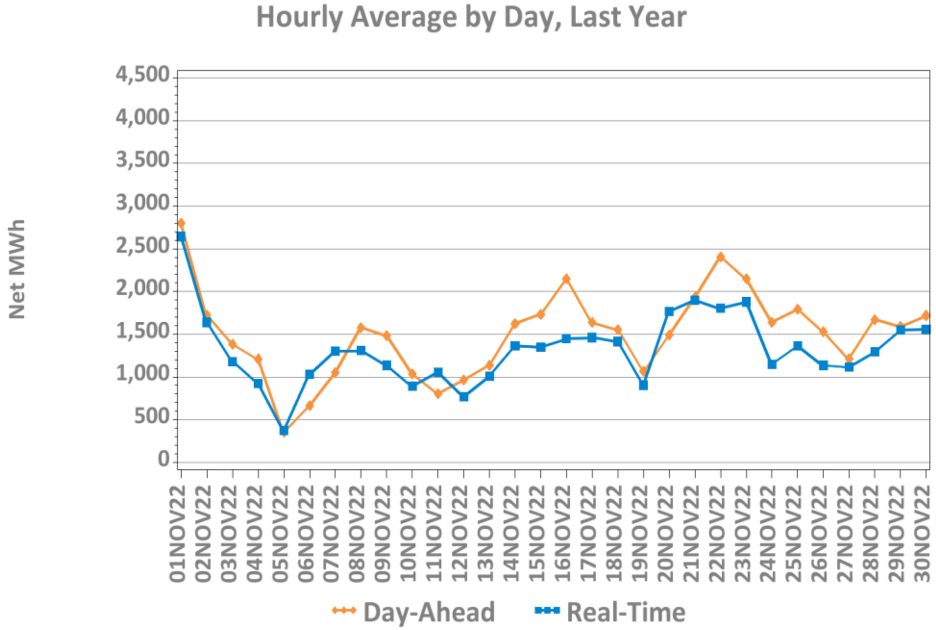
Note: The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: three (for the days of November 6 and 18)

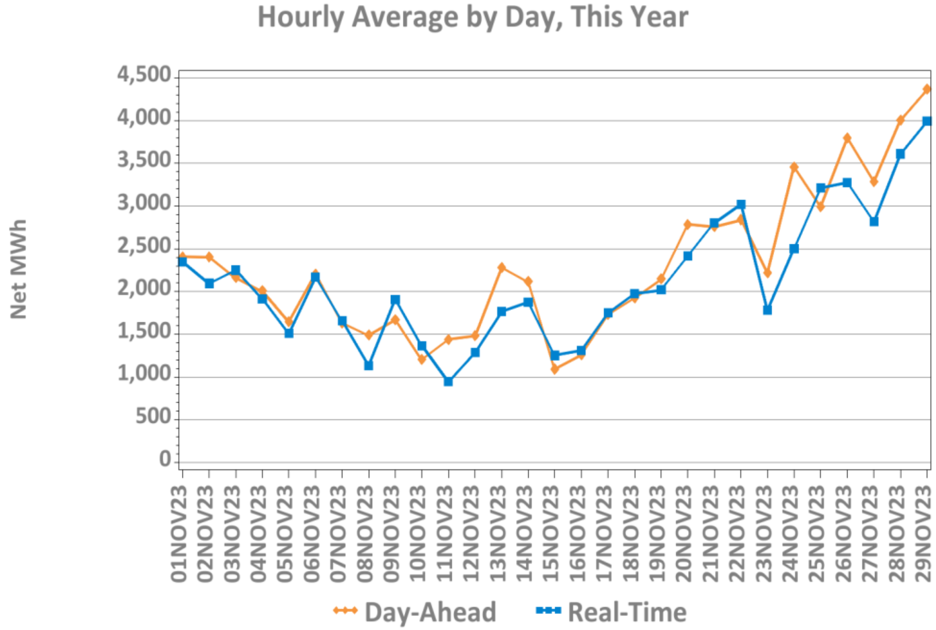
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

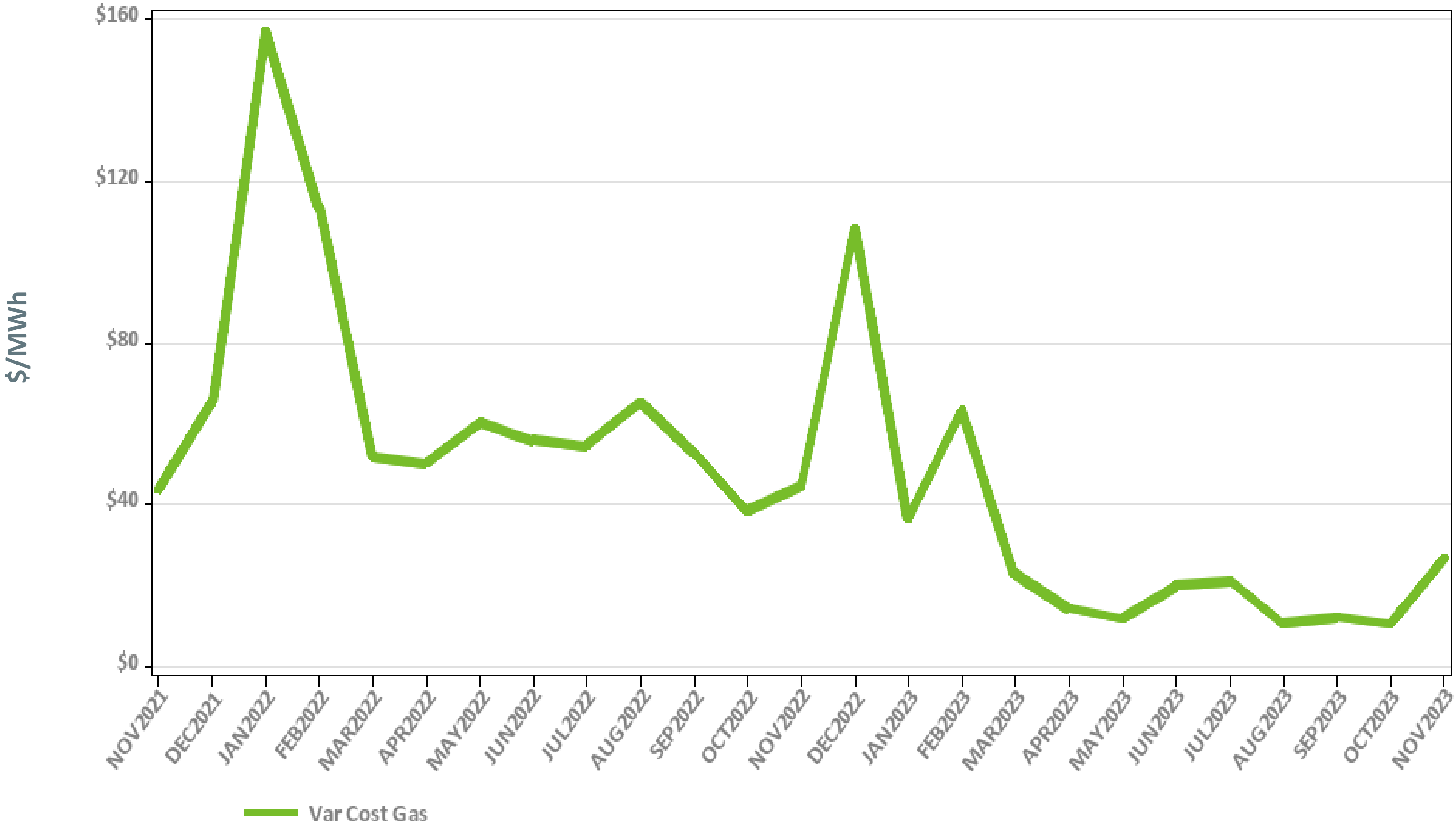
DA vs. RT Net Interchange November 2023 vs. November 2022





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

Variable Production Cost of Natural Gas: Monthly

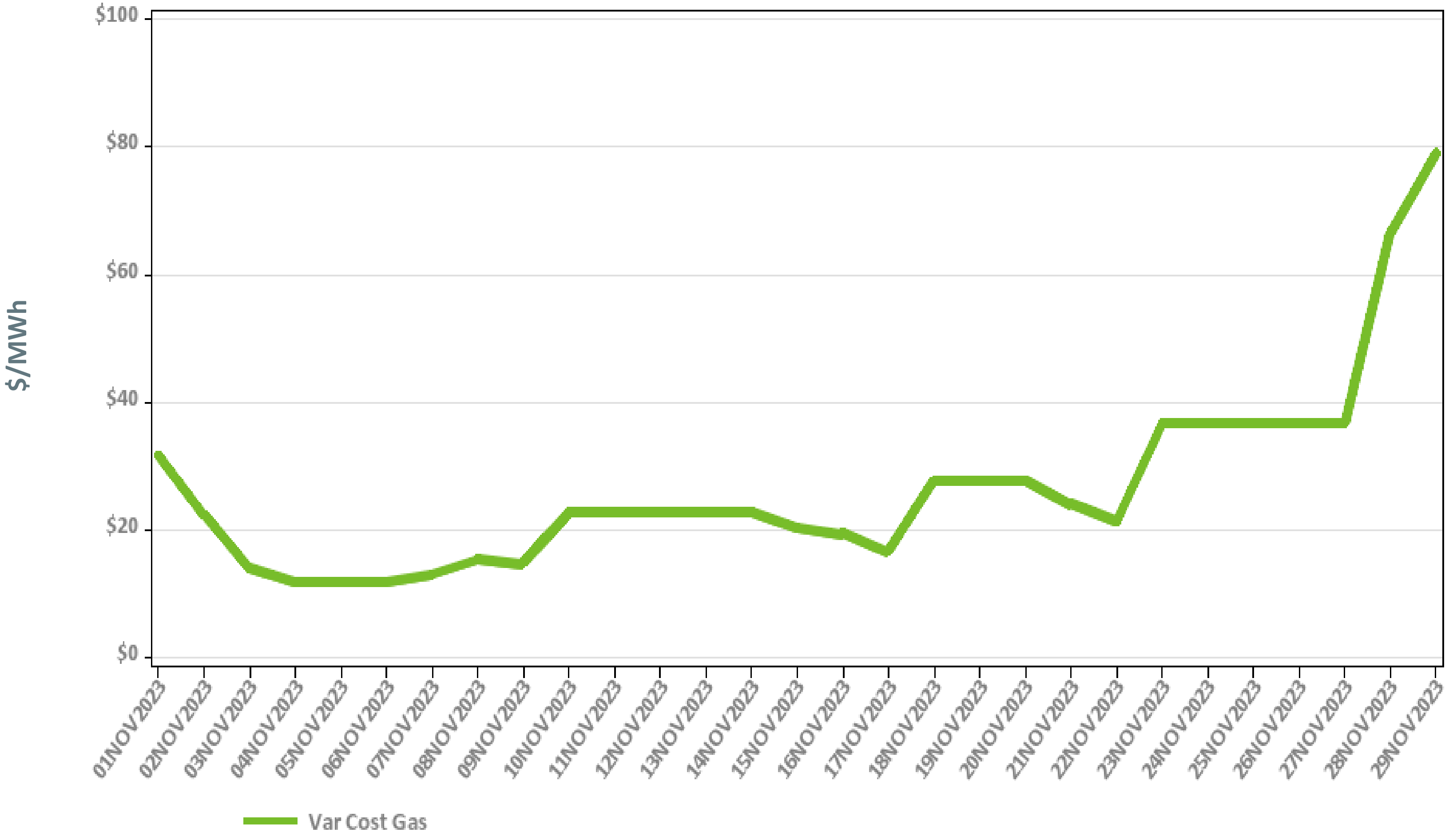


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

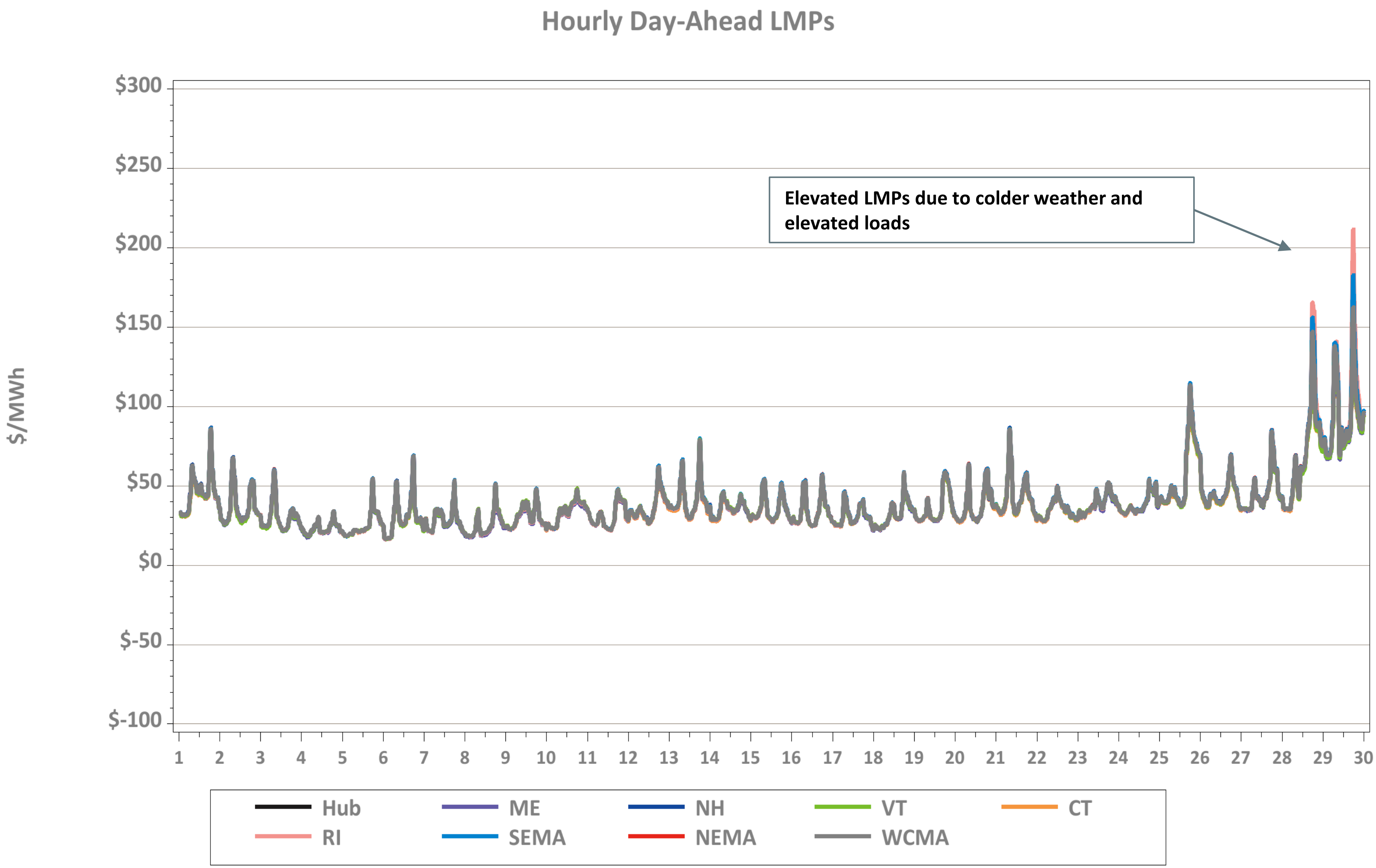


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

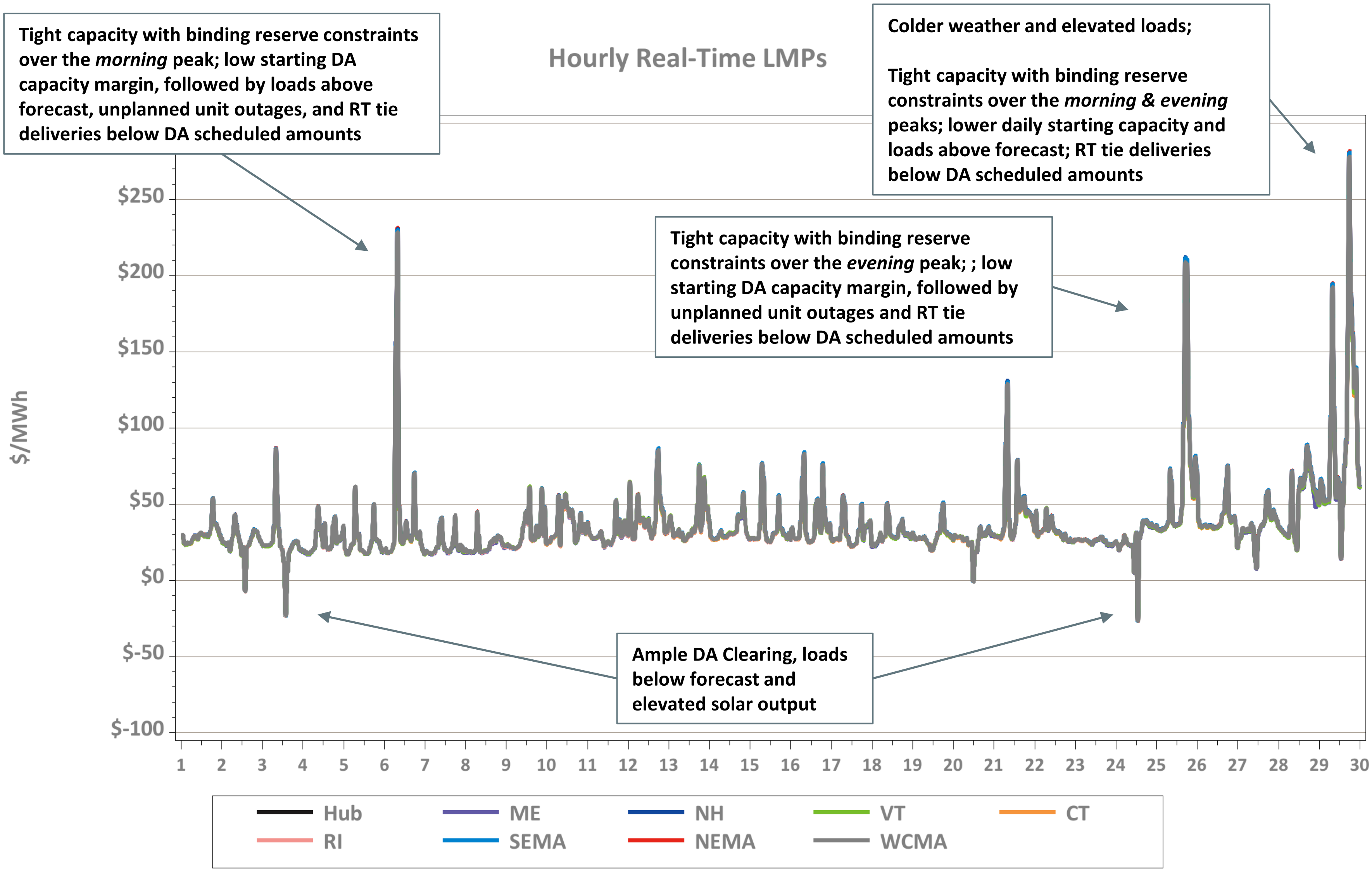
Underlying natural gas data furnished by:

ice Global markets in clear view

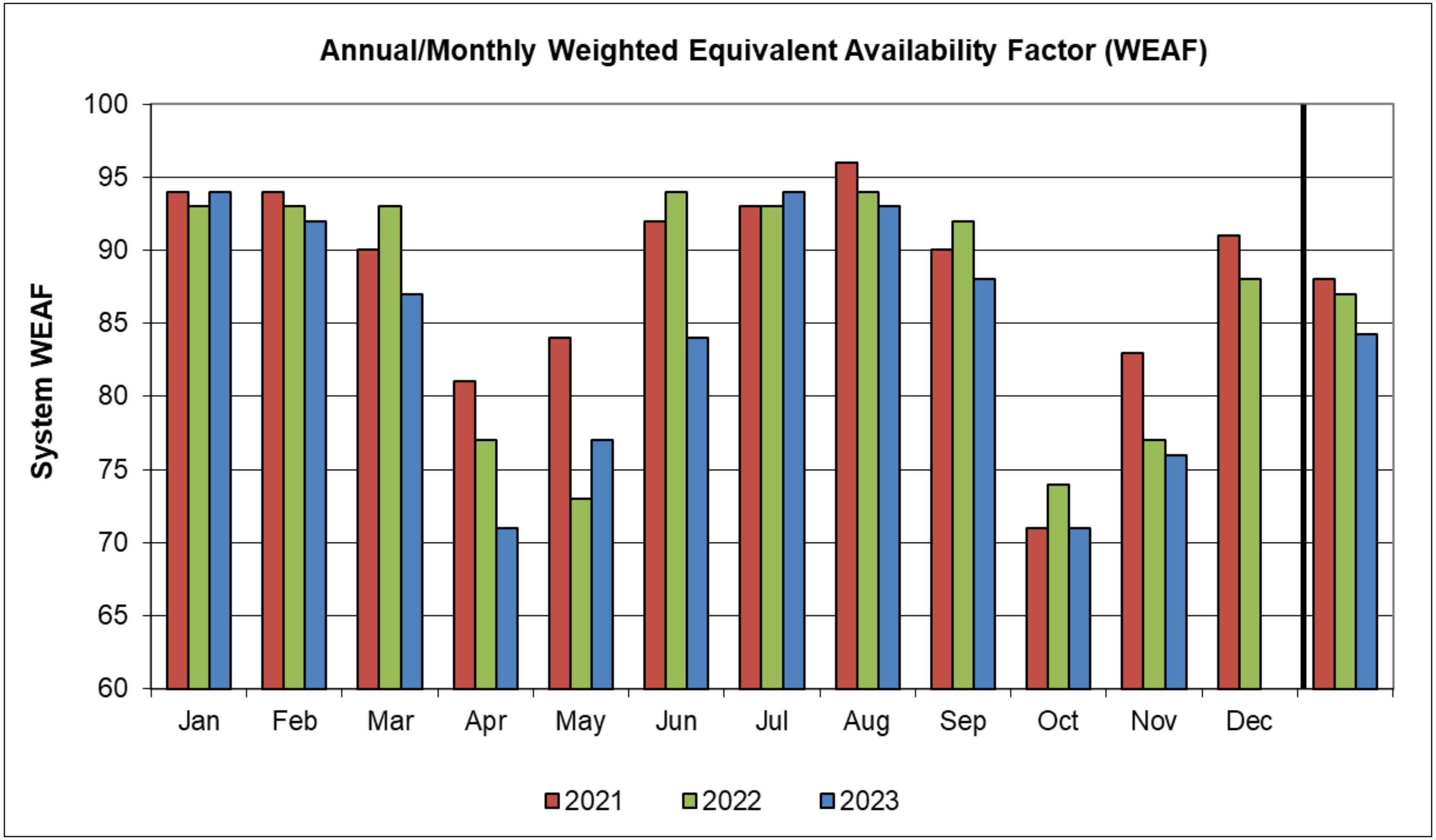
Hourly DA LMPs, November 1-29 2023



Hourly RT LMPs, November 1-29, 2023



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92	87	71	77	84	94	93	88	71	76		84
2022	93	93	93	77	73	94	93	94	92	74	77	88	87
2021	94	94	90	81	84	92	93	96	90	71	83	91	88

Data as of 11/27/2023

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	55.0	174.1	0.0	229.2
NH	31.7	147.2	0.0	178.9
VT	37.8	169.4	0.0	207.1
CT	90.6	72.5	664.8	827.9
RI	21.8	319.3	0.0	341.0
SEMA	33.5	466.6	0.0	500.0
WCMA	60.4	517.8	8.4	586.6
NEMA	62.0	758.0	0.0	820.0
Total	**392.8**	**2,624.8**	**673.2**	**3,690.8**

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

NEW GENERATION

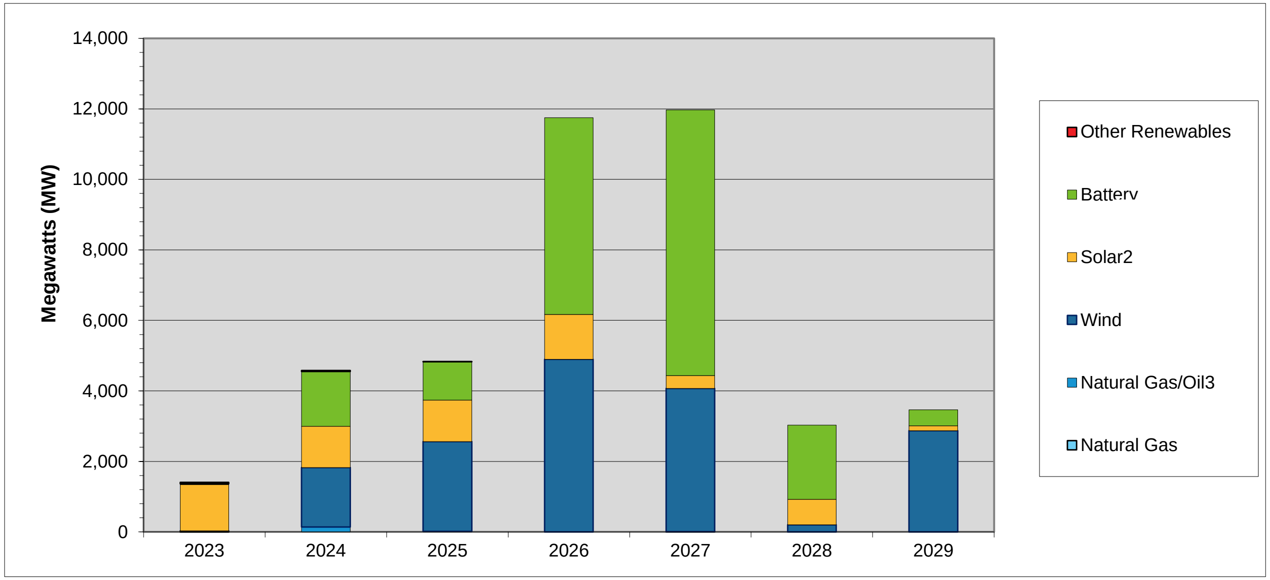
New Generation Update

Based on Queue as of 12/01/23

- Two projects totaling 123 MW were added to the interconnection queue since the last update
  - One solar project and one battery storage project with in-service dates of 2027
- In total, 394 generation projects are currently being tracked by the ISO, totaling approximately 42,332 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Other Renewables	42	30	2	0	0	0	0	74	0.2
Battery	20	1,555	1,084	5,584	7,535	2,110	454	18,342	44.7
Solar[2]	1,314	1,167	1,178	1,275	366	725	139	6,164	15.0
Wind	0	1,693	2,545	4,893	4,064	197	2,870	16,262	39.6
Natural Gas/Oil[3]	0	135	16	0	0	0	0	151	0.4
Natural Gas	26	0	0	0	4	0	0	30	0.1
Totals	**1,402**	**4,580**	**4,825**	**11,752**	**11,969**	**3,032**	**3,463**	**41,023**	**100.0**

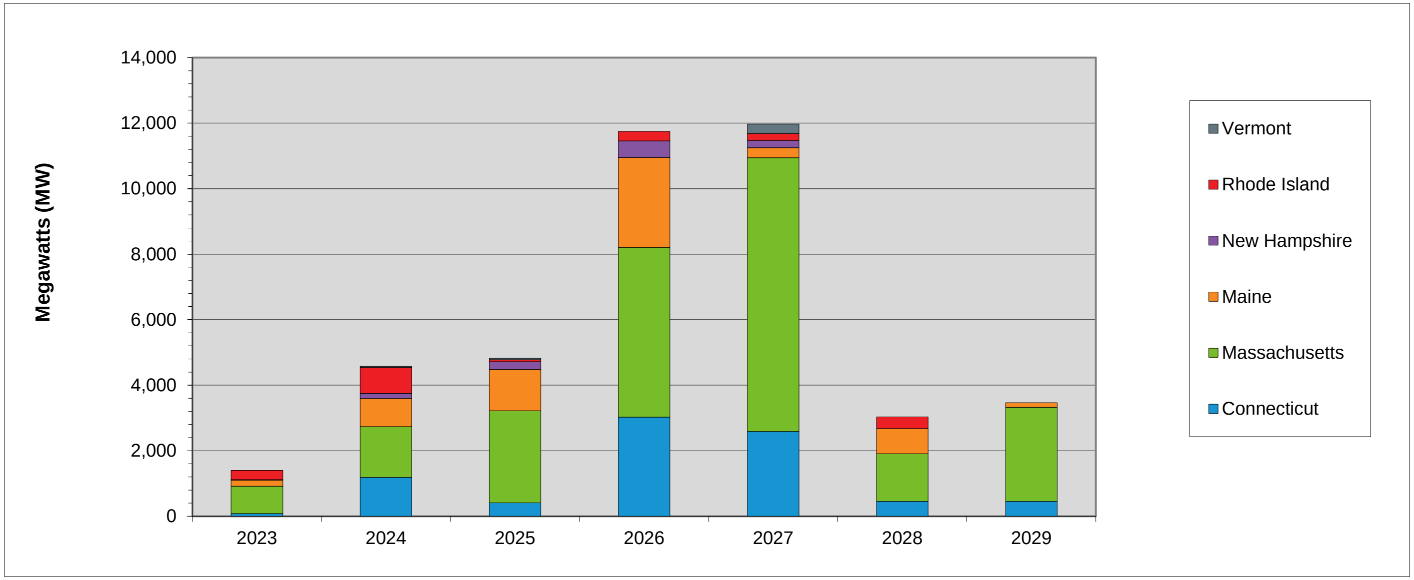
[1] **Sum may not equal 100% due to rounding**

[2] **This category includes both solar-only, and co-located solar and battery projects**

[3] **The projects in this category are dual fuel, with either gas or oil as the primary fuel**

Actual and Projected Annual Generator Capacity Additions

By State



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Vermont	0	40	50	0	285	0	0	375	0.9
Rhode Island	281	794	54	295	211	360	0	1,995	4.9
New Hampshire	20	154	239	504	226	0	0	1,143	2.8
Maine	185	854	1,259	2,743	306	764	139	6,250	15.2
Massachusetts	834	1,550	2,815	5,186	8,353	1,453	2,870	23,061	56.2
Connecticut	82	1,188	408	3,024	2,588	455	454	8,199	20.0
Totals	**1,402**	**4,580**	**4,825**	**11,752**	**11,969**	**3,032**	**3,463**	**41,023**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	115	18,342	1	15	114	18,327
Fuel Cell	4	46	0	0	4	46
Hydro	1	28	0	0	1	28
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	3	151	1	62	2	89
Nuclear	0	0	0	0	0	0
Solar	239	6,164	15	343	224	5,821
Wind	28	17,571	1	800	27	16,771
Total	394	42,332	18	1,220	376	41,112

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	7	87	0	0	7	87
Intermediate	2	89	0	0	2	89
Peaker	357	24,585	17	420	340	24,165
Wind Turbine	28	17,571	1	800	27	16,771
Total	394	42,332	18	1,220	376	41,112

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	115	18,342	0	0	0	0	115	18,342	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	3	151	0	0	2	89	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	239	6,164	0	0	0	0	239	6,164	0	0
Wind	28	17,571	0	0	0	0	0	0	28	17,571
Total	394	42,332	7	87	2	89	357	24,585	28	17,571

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272	579.692	-93.709		
Demand	*Passive Demand*	3,212.865	3,211.403	-1.462	3,134.652	-76.751		
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**		
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125		
Generator	*Intermittent*	1,089.265	1,073.794	-15.471	1,056.601	-17.193		
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**		
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**		
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**		
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**		

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond and reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35	589.882	-175.468				
	Passive Demand	2,557.256	2,579.120	21.864				
Demand Total		**3,322.606**	**3,169.002**	**-153.604**				
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624				
	Intermittent	1,178.933	1,146.783	-32.15				
Generator Total		**27,983.936**	**27,790.162**	**-193.774**				
Import Total		**1,503.842**	**1,247.601**	**-256.241**				
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**				
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**				

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	622.854						
	Passive Demand	2,316.815						
Demand Total		**2,939.669**						
Generator	*Non-Intermittent*	26,507.420						
	Intermittent	1,356.084						
Generator Total		**27,863.504**						
Import Total		**566.998**						
Grand Total*		**31,370.171**						
Net ICR (NICR)		**30,305**						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

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

What are Daily NCPC Payments?

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

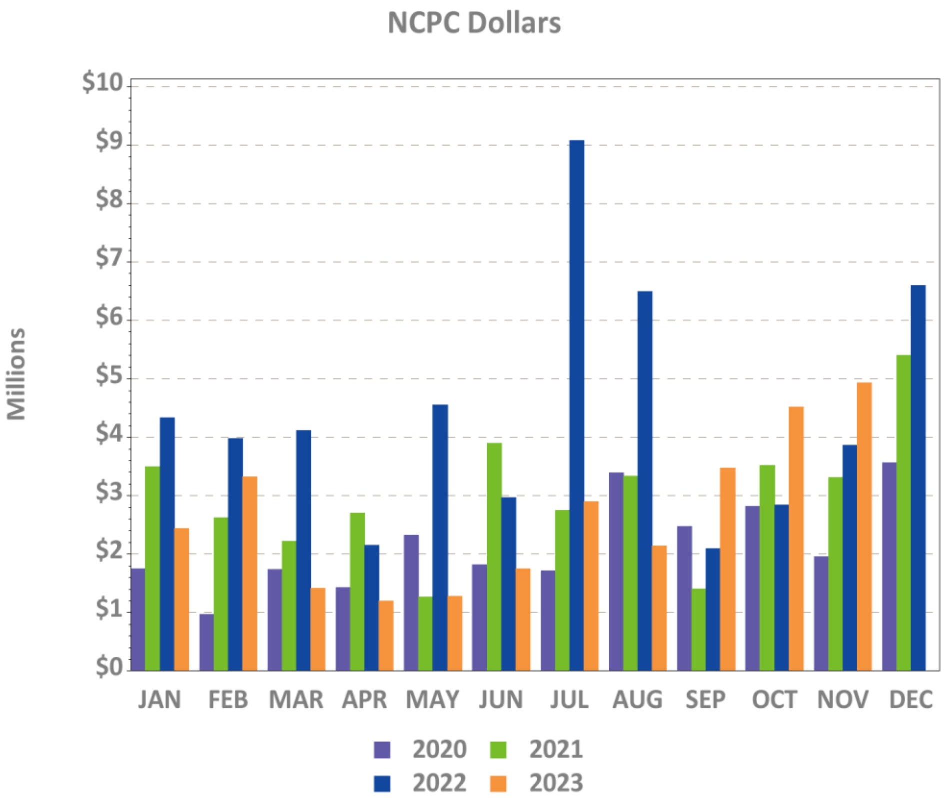
Definitions

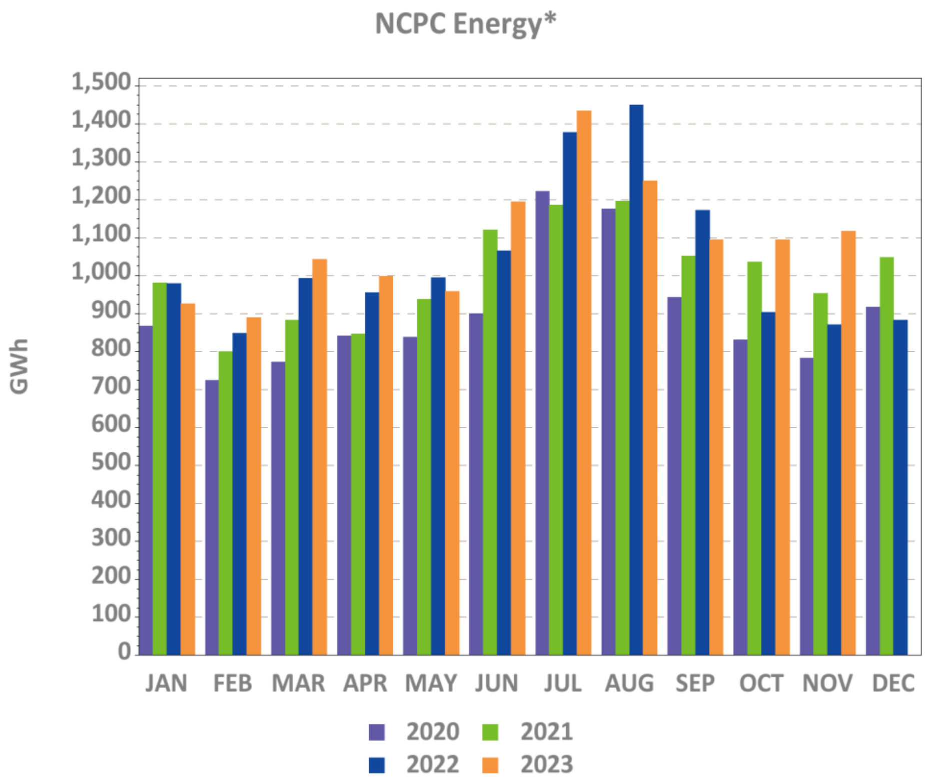
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

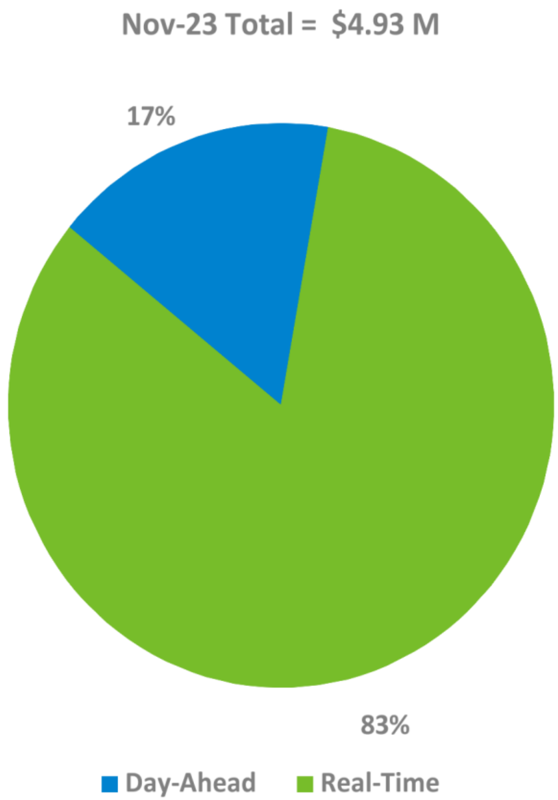
Year-Over-Year Total NCPC Dollars and Energy

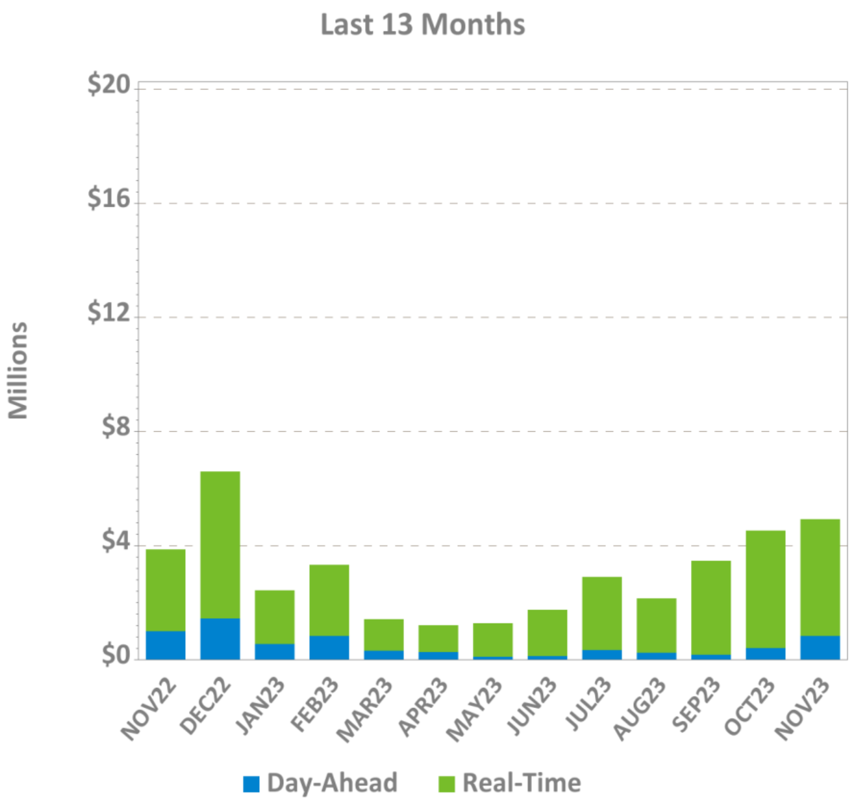




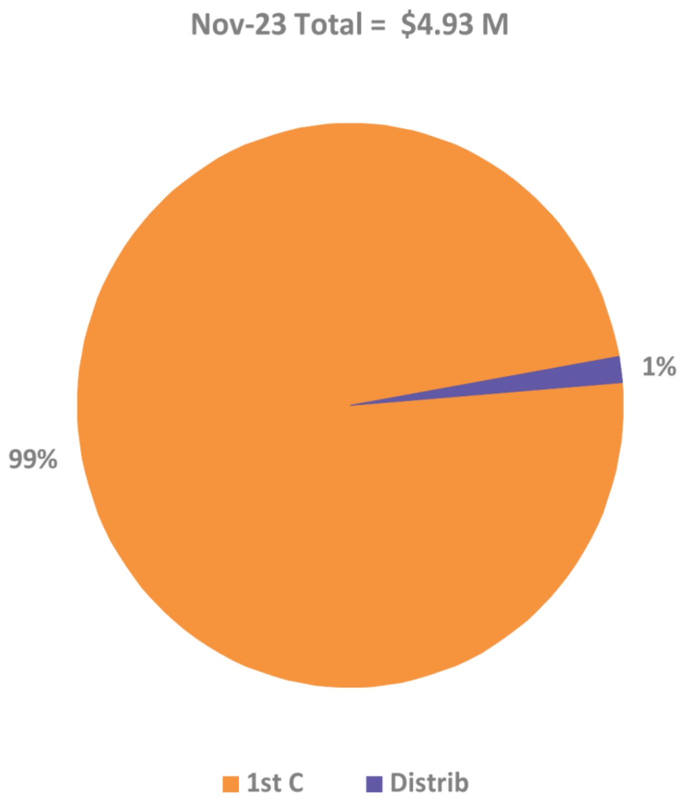
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

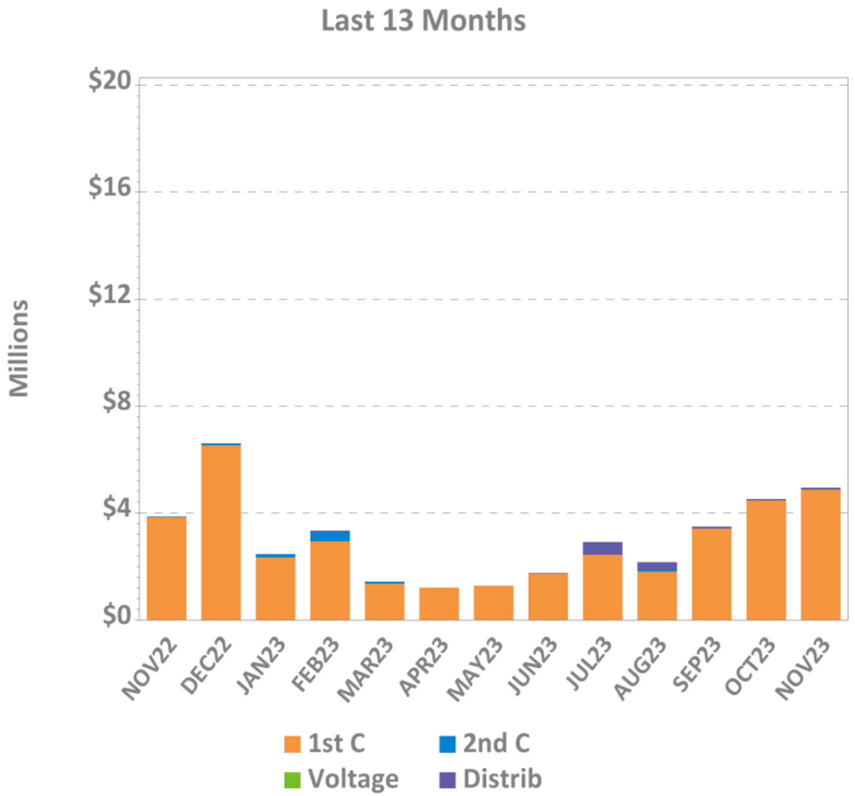
DA and RT NCPC Charges





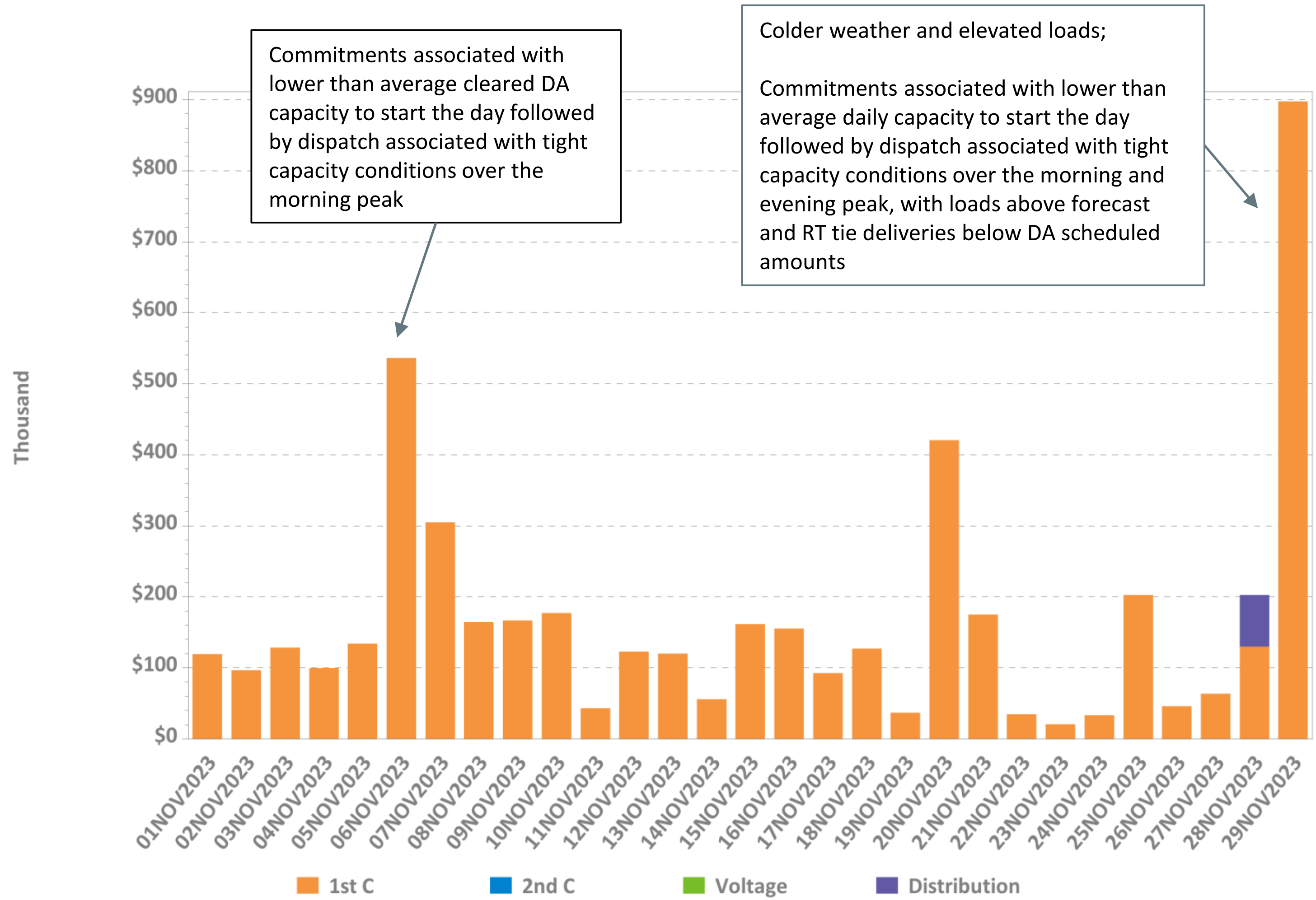
NCPC Charges by Type



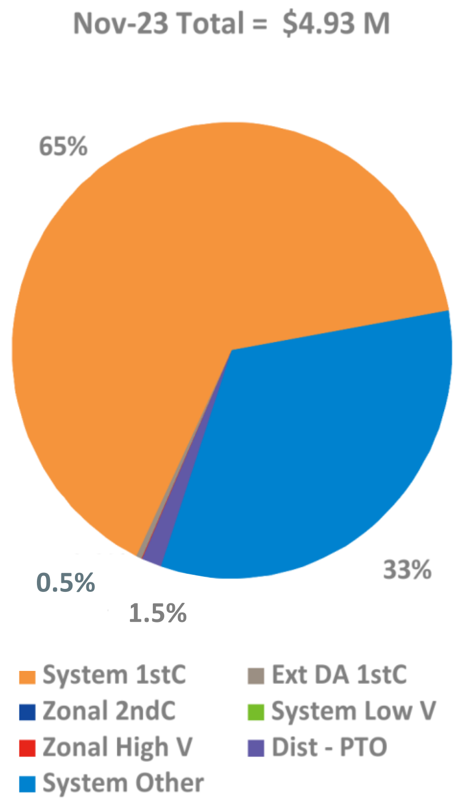


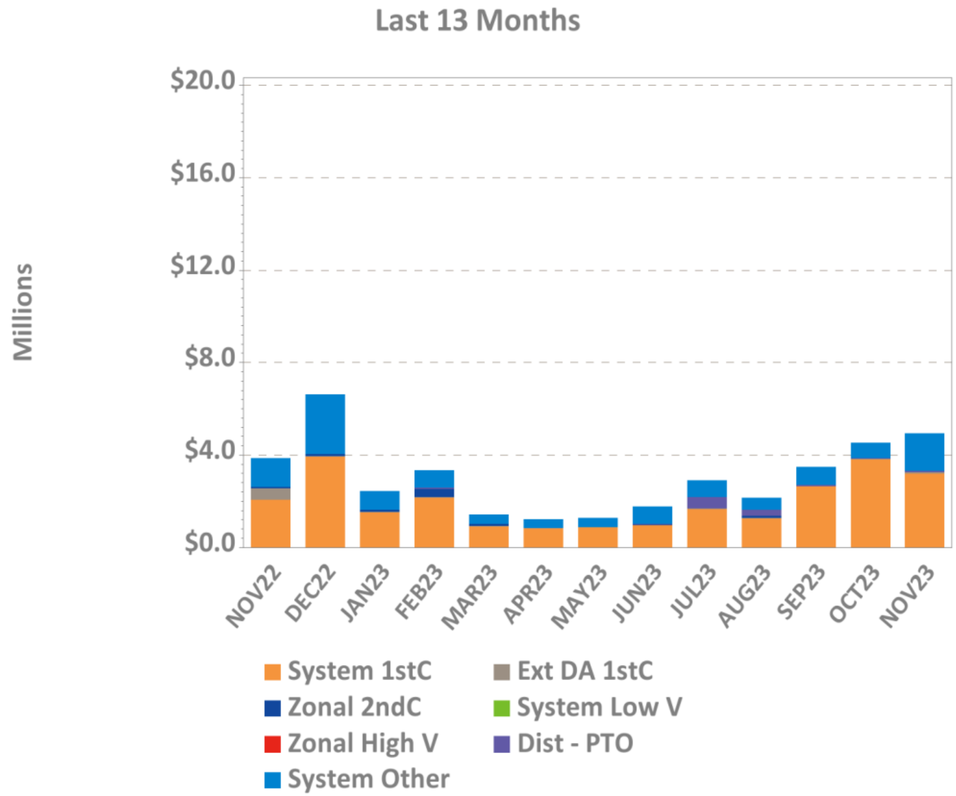
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



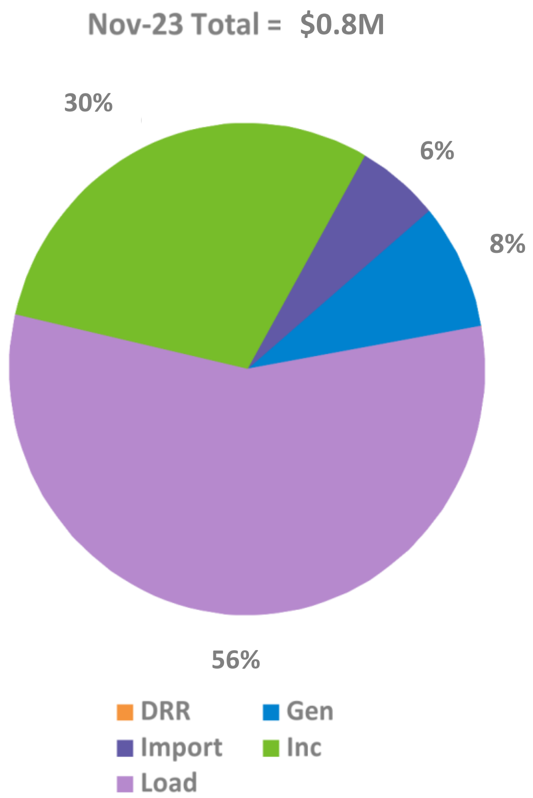
NCPC Charges by Allocation

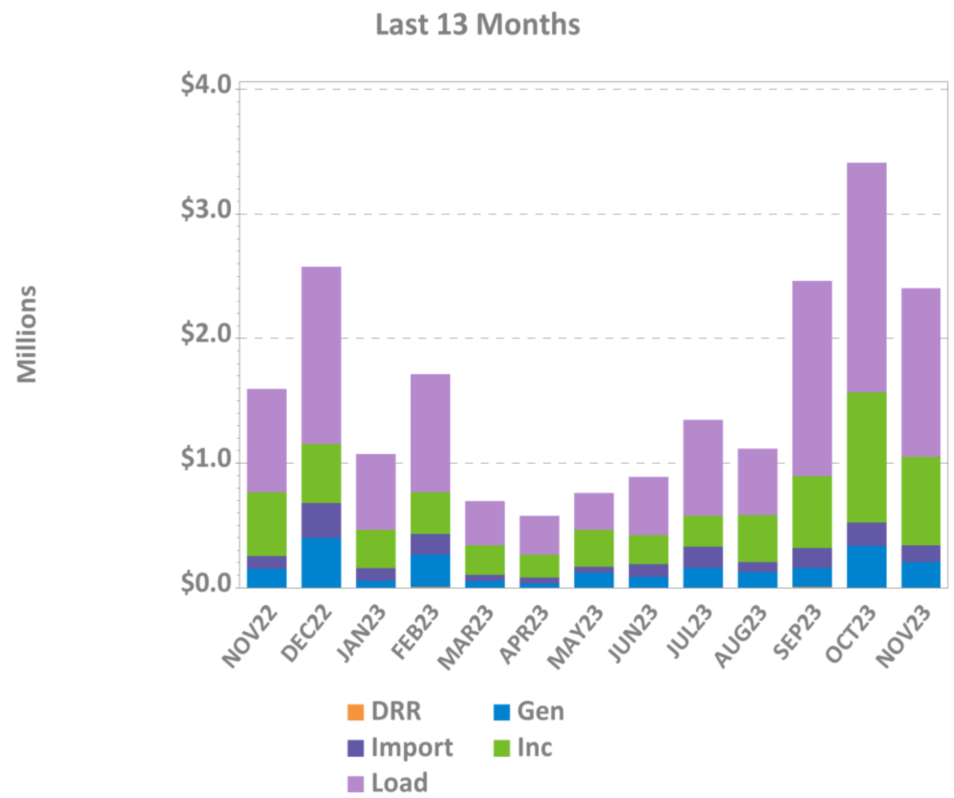




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

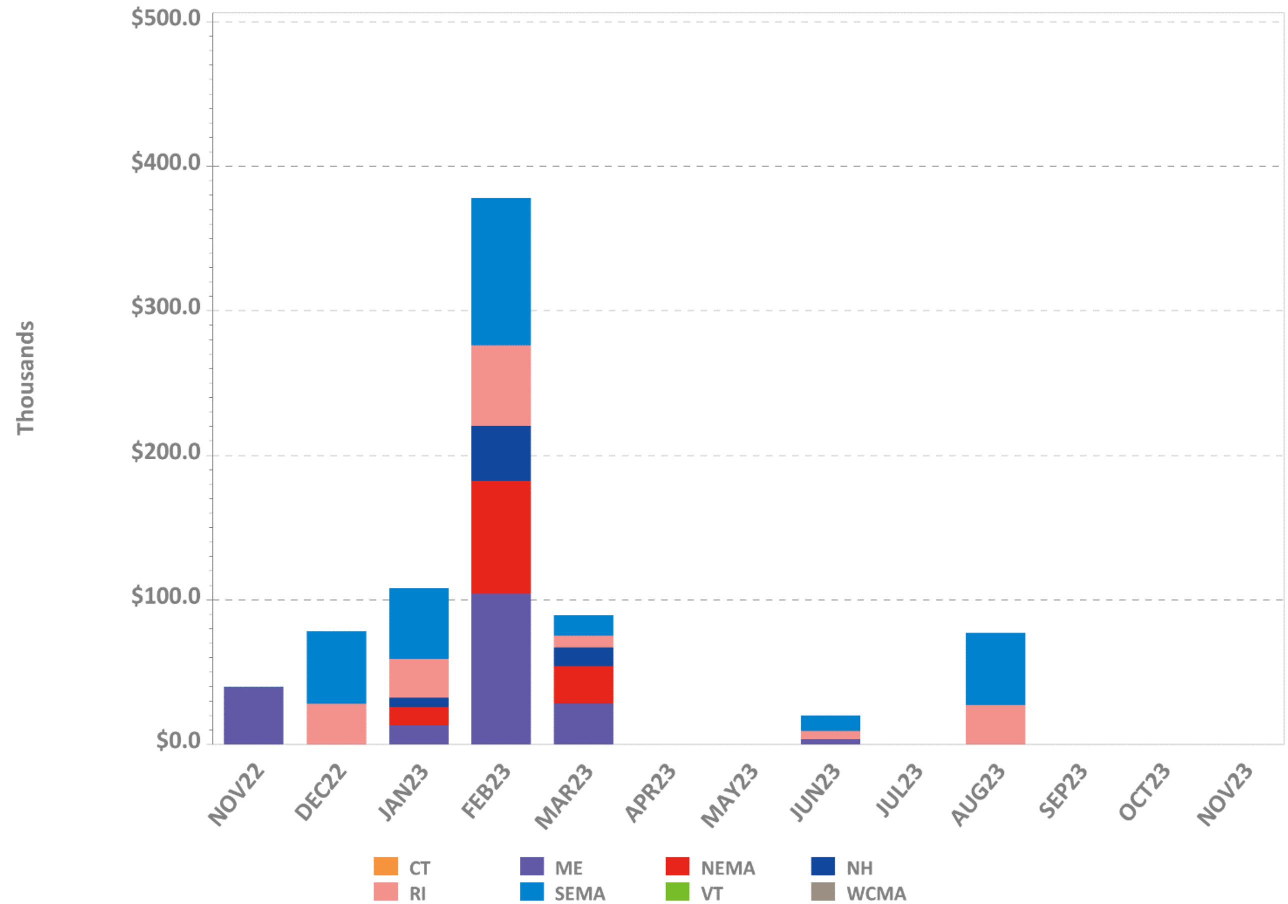
RT First Contingency Charges by Deviation Type





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

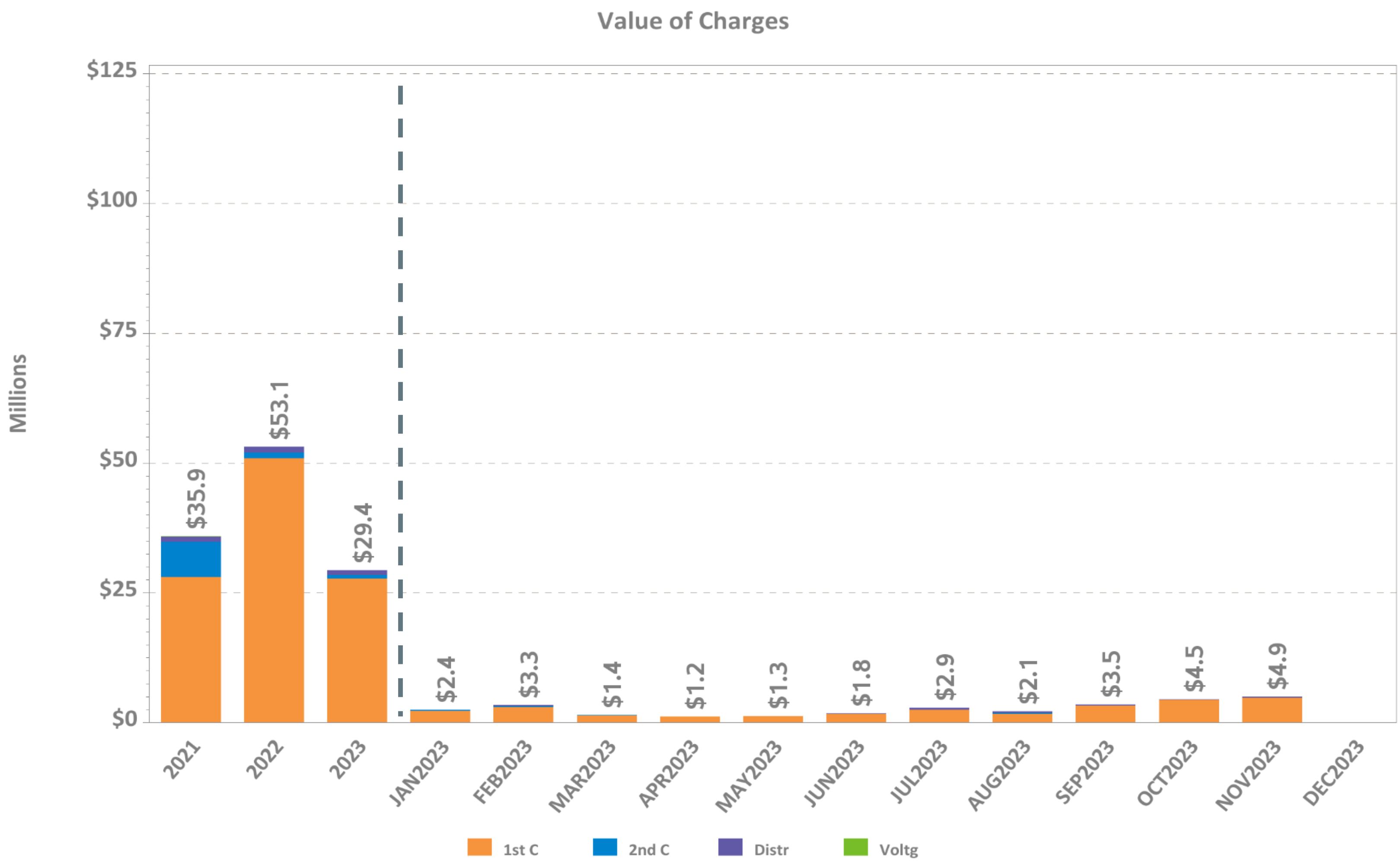
LSCPR Charges by Reliability Region



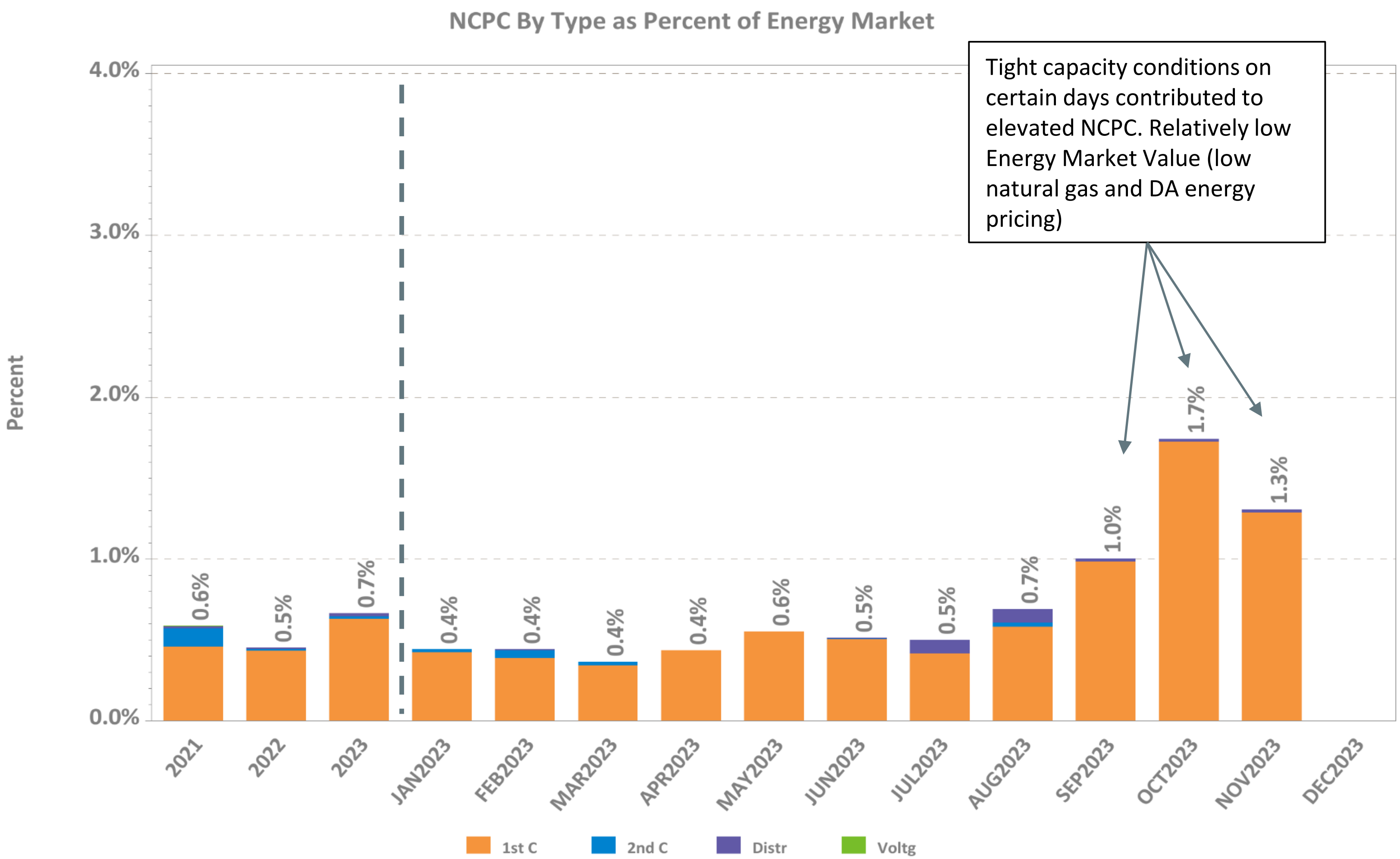
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

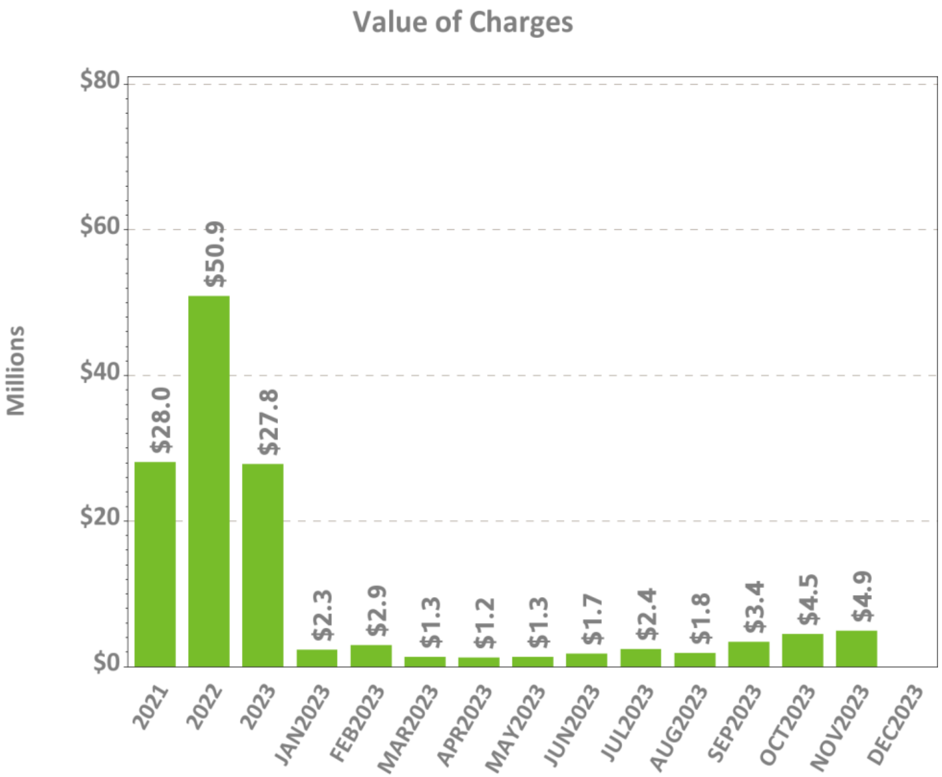
NCPC Charges by Type

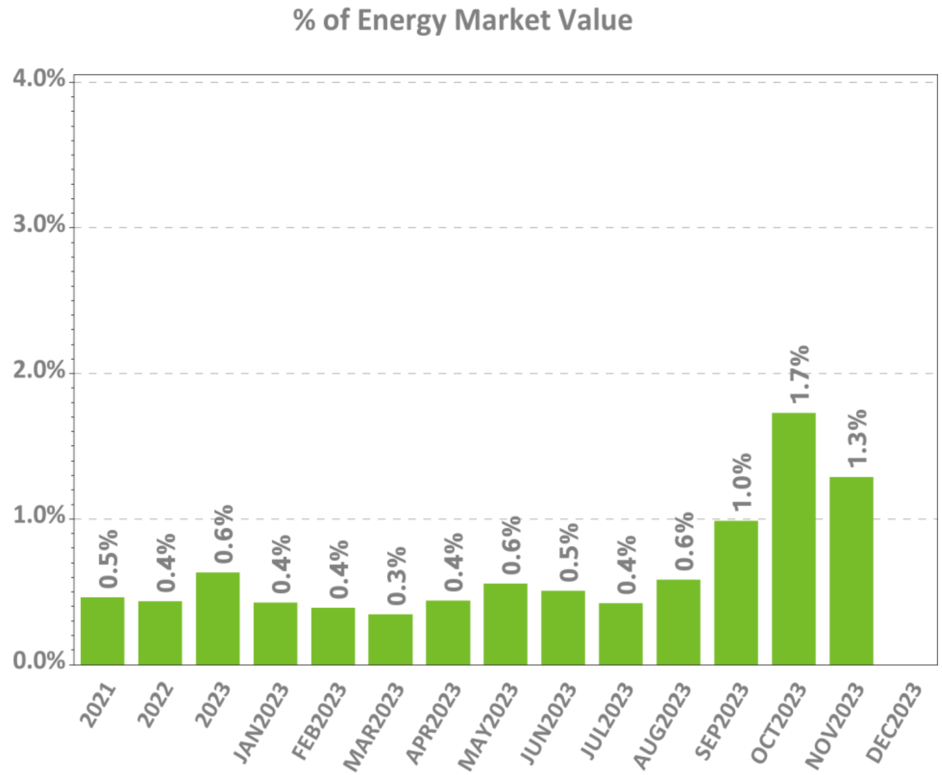


NCPC Charges as Percent of Energy Market



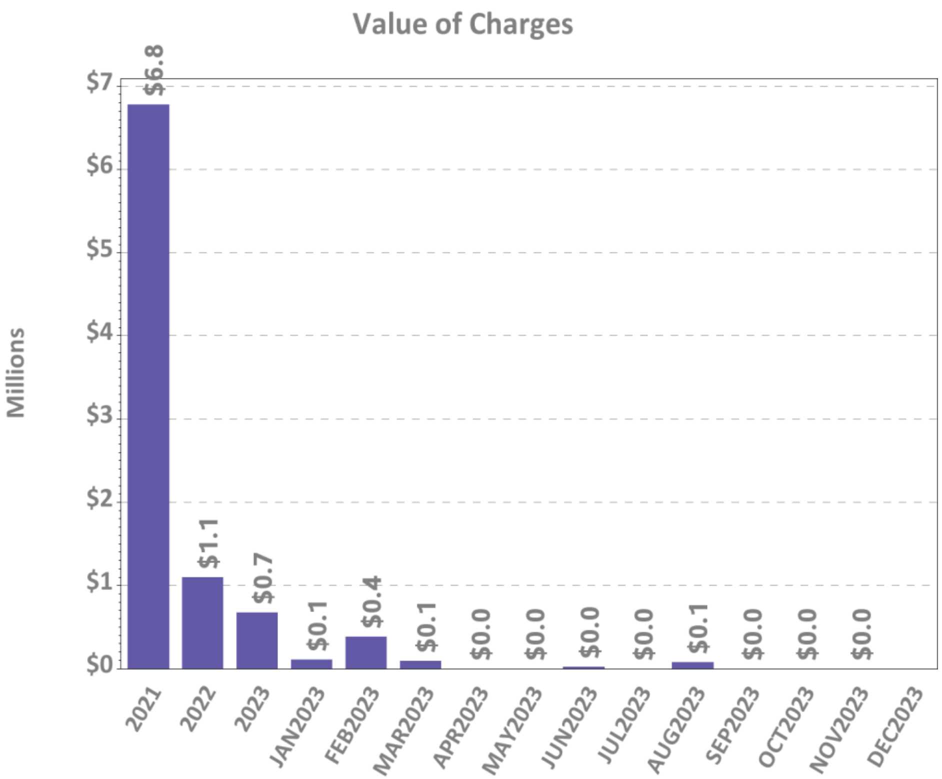
First Contingency NCPC Charges

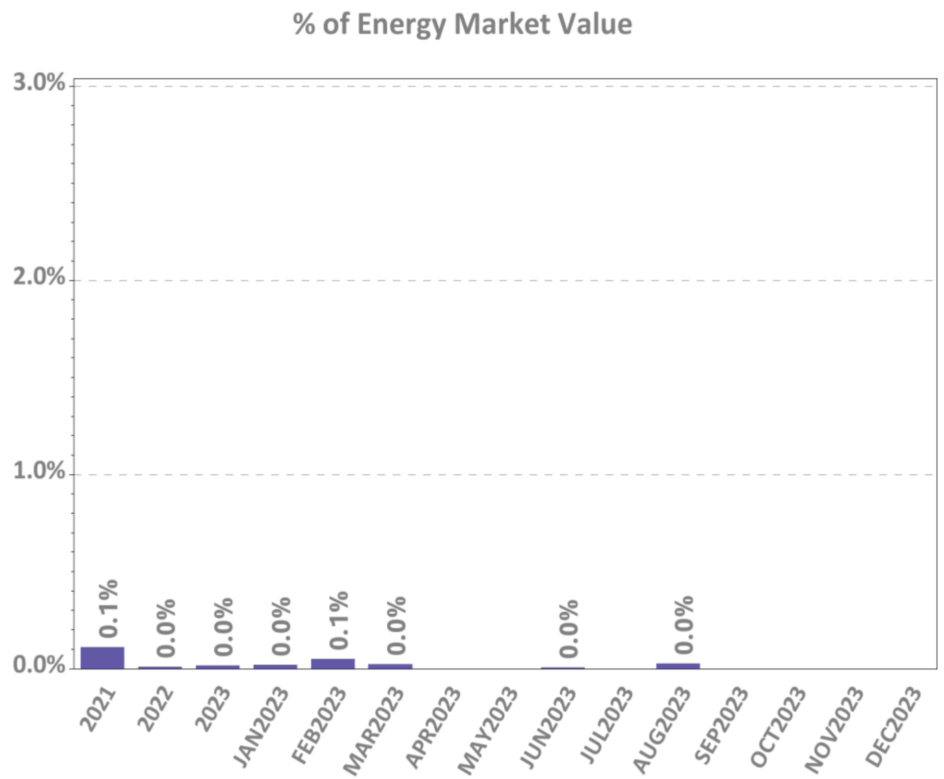




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

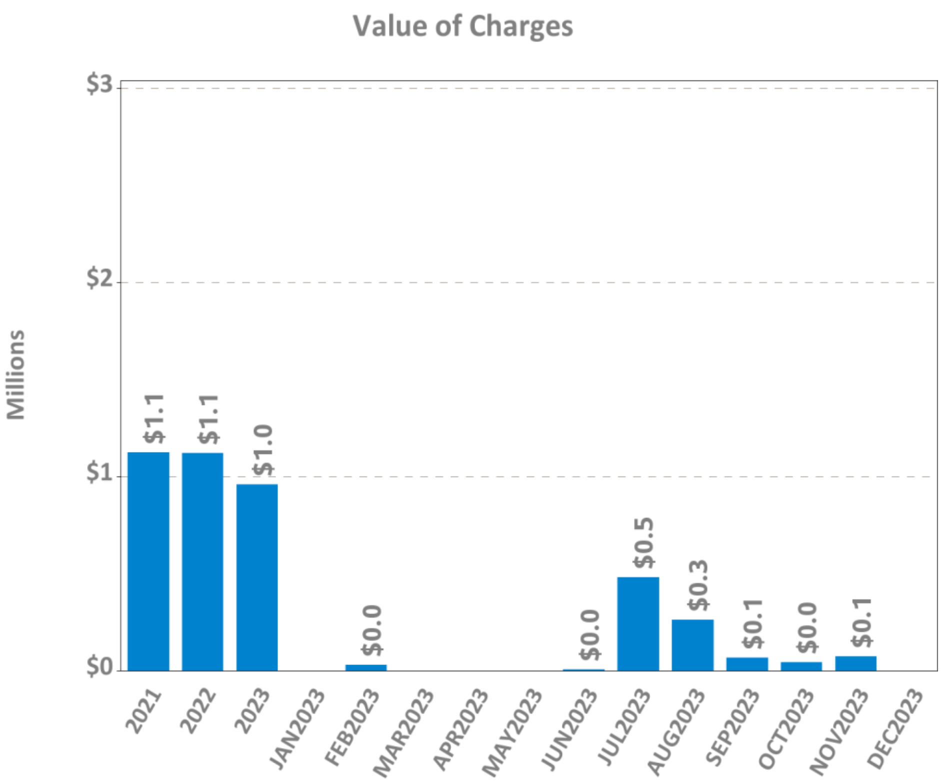
Second Contingency NCPC Charges

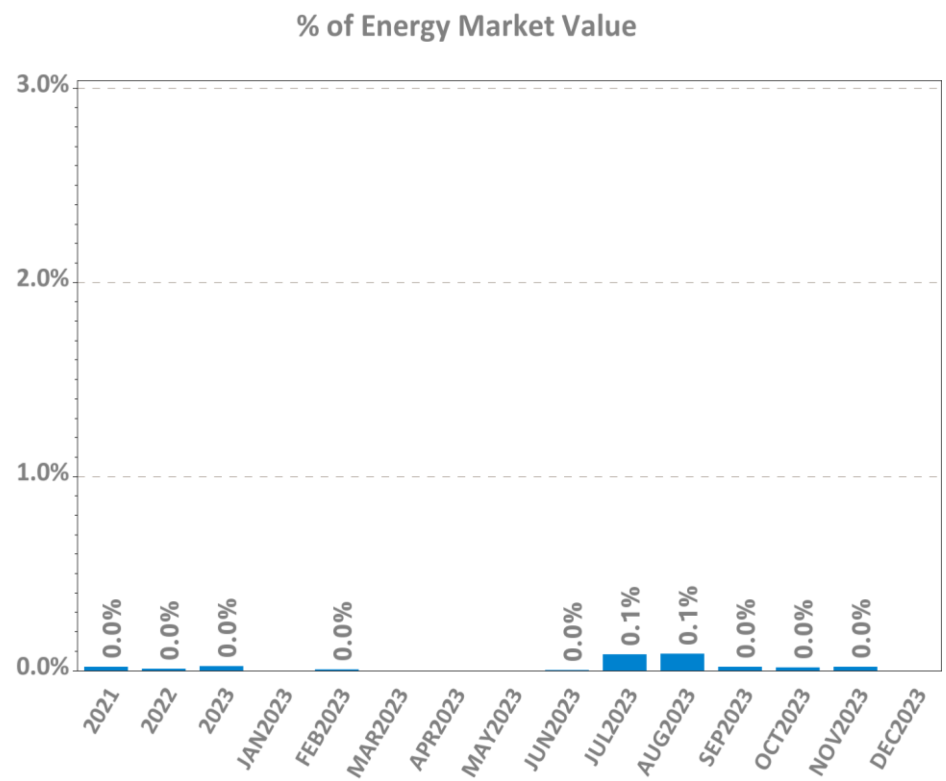




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

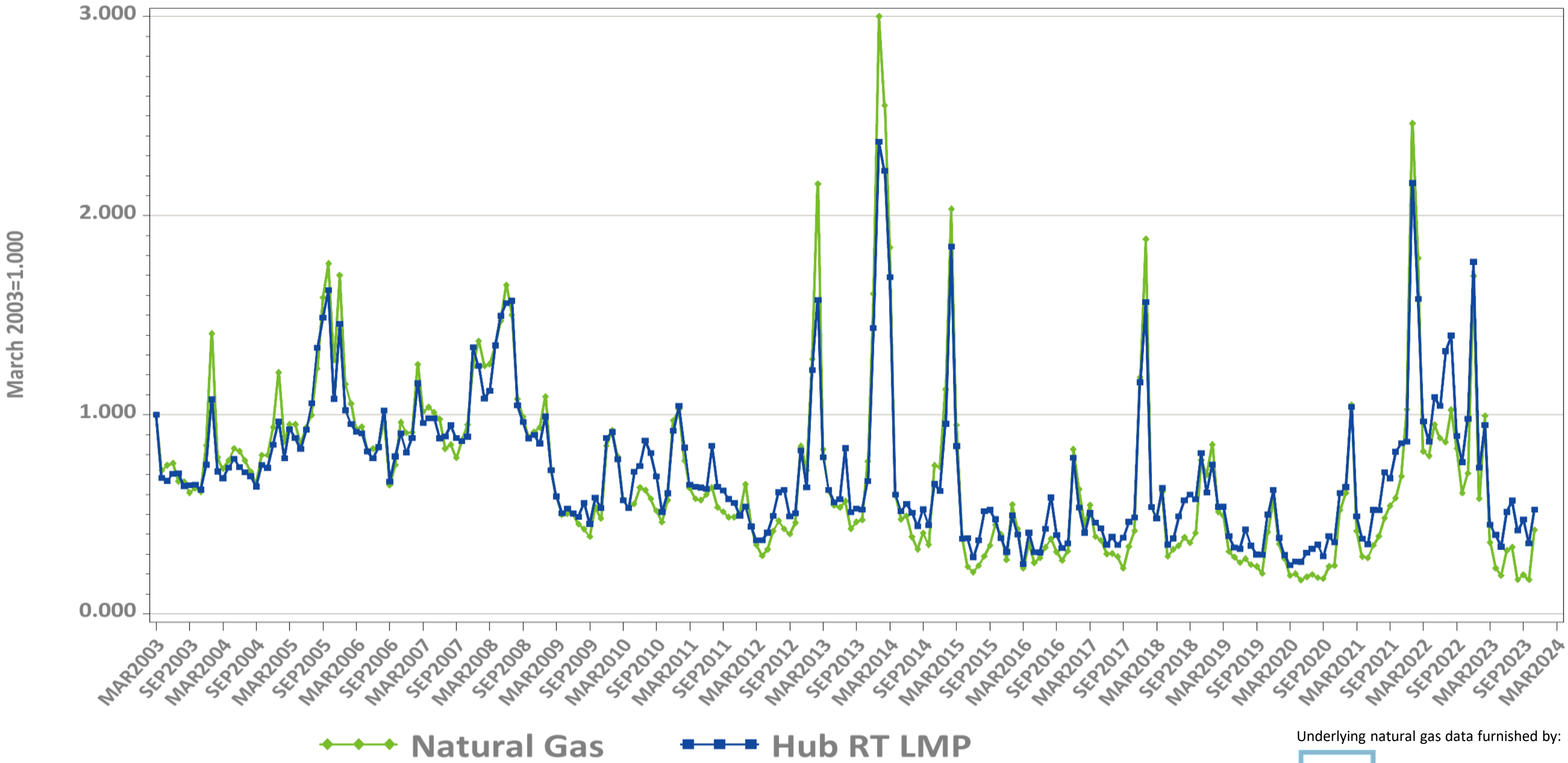
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.54	$44.60	$45.52	$46.27	$45.05	$45.88	$46.38	$45.91	$45.92
Real-Time	$45.25	$43.97	$44.28	$45.10	$44.15	$44.61	$45.09	$44.85	$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%
Year 2022	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$86.07	$84.05	$84.15	$85.73	$84.46	$85.35	$86.01	$85.66	$85.55
Real-Time	$85.42	$83.83	$83.06	$85.07	$83.67	$84.71	$85.37	$85.00	$84.92
RT Delta %	-0.8%	-0.3%	-1.3%	-0.8%	-0.9%	-0.7%	-0.7%	-0.8%	-0.7%

November-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$62.07	$60.61	$61.02	$62.16	$61.19	$61.17	$61.92	$61.90	$61.72
Real-Time	$67.77	$65.84	$66.32	$67.81	$66.84	$66.76	$67.60	$67.46	$67.32
RT Delta %	9.2%	8.6%	8.7%	9.1%	9.2%	9.1%	9.2%	9.0%	9.1%
November-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$39.28	$38.06	$38.32	$39.08	$38.65	$39.02	$39.35	$39.00	$38.95
Real-Time	$36.21	$35.23	$35.37	$36.08	$35.62	$35.71	$36.20	$35.98	$35.96
RT Delta %	-7.8%	-7.4%	-7.7%	-7.7%	-7.8%	-8.5%	-8.0%	-7.7%	-7.7%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-36.7%	-37.2%	-37.2%	-37.1%	-36.8%	-36.2%	-36.4%	-37.0%	-36.9%
Yr over Yr RT	-46.6%	-46.5%	-46.7%	-46.8%	-46.7%	-46.5%	-46.5%	-46.7%	-46.6%

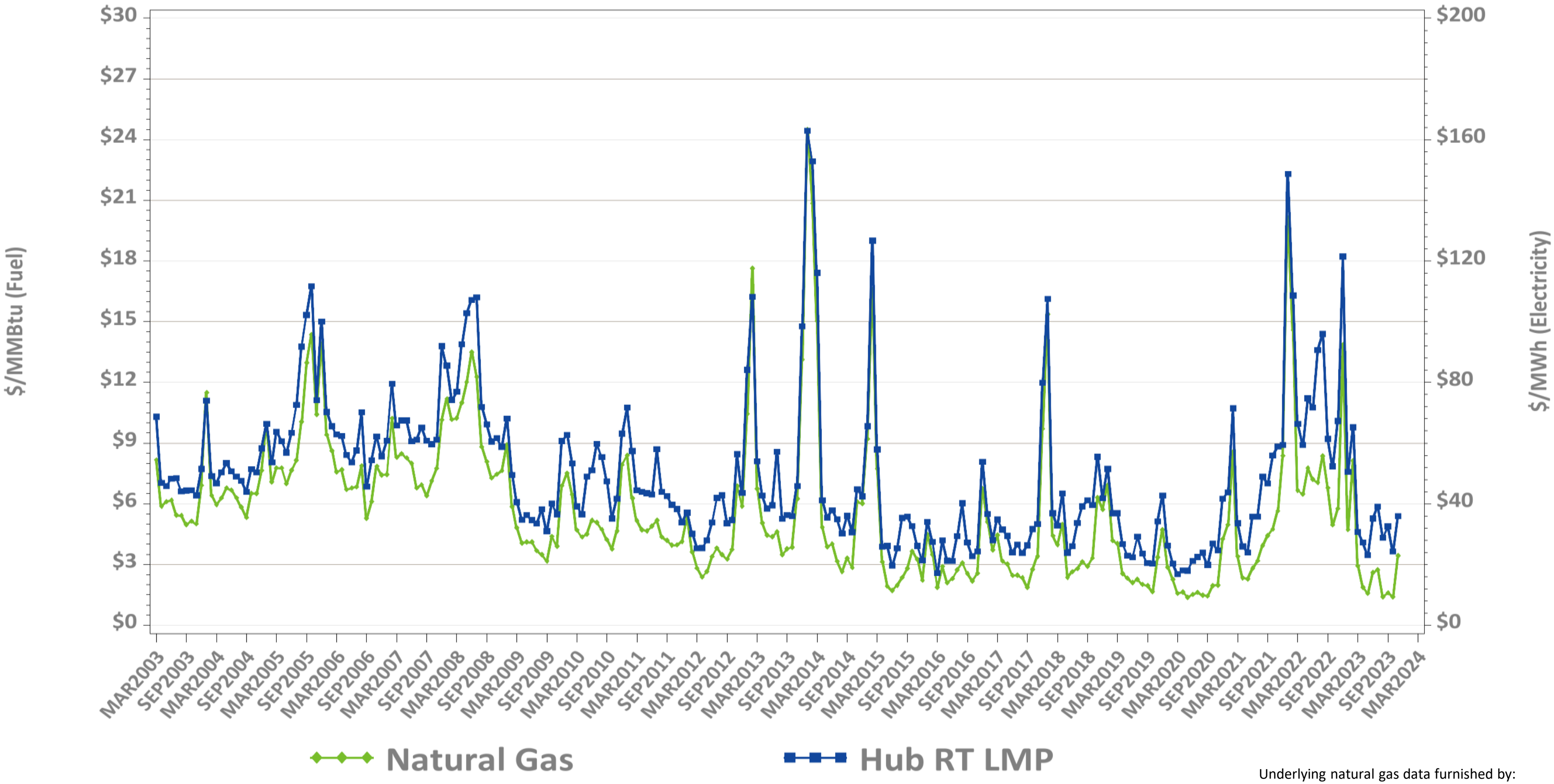
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

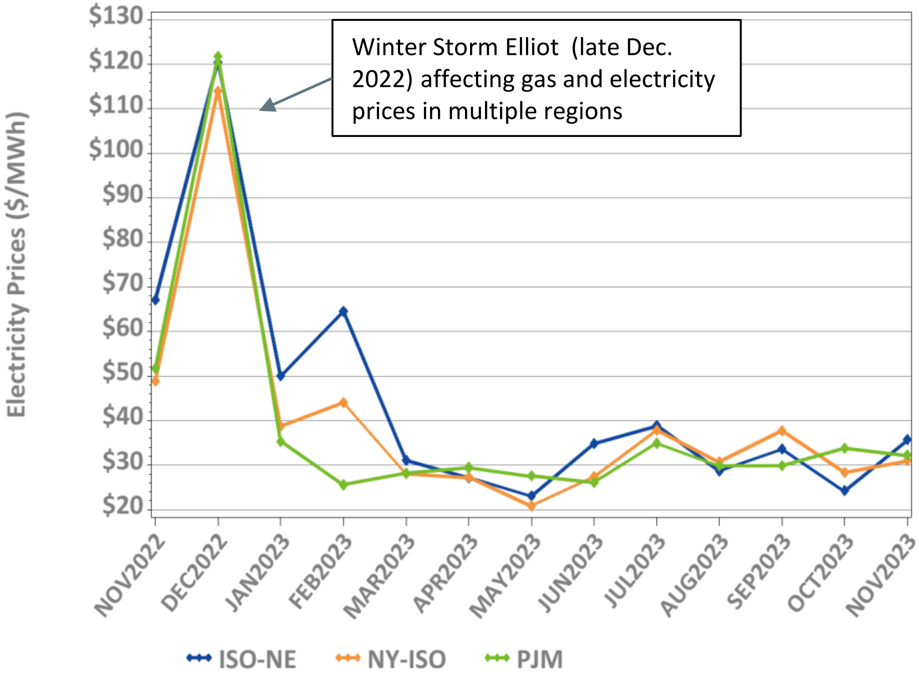
Monthly Average Fuel Price and RT Hub LMP



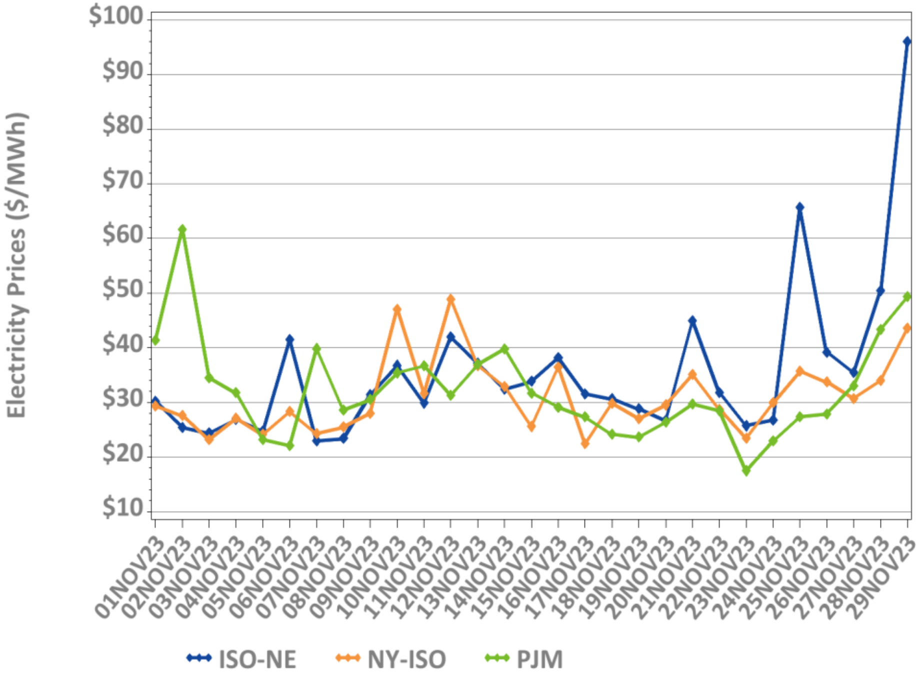
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

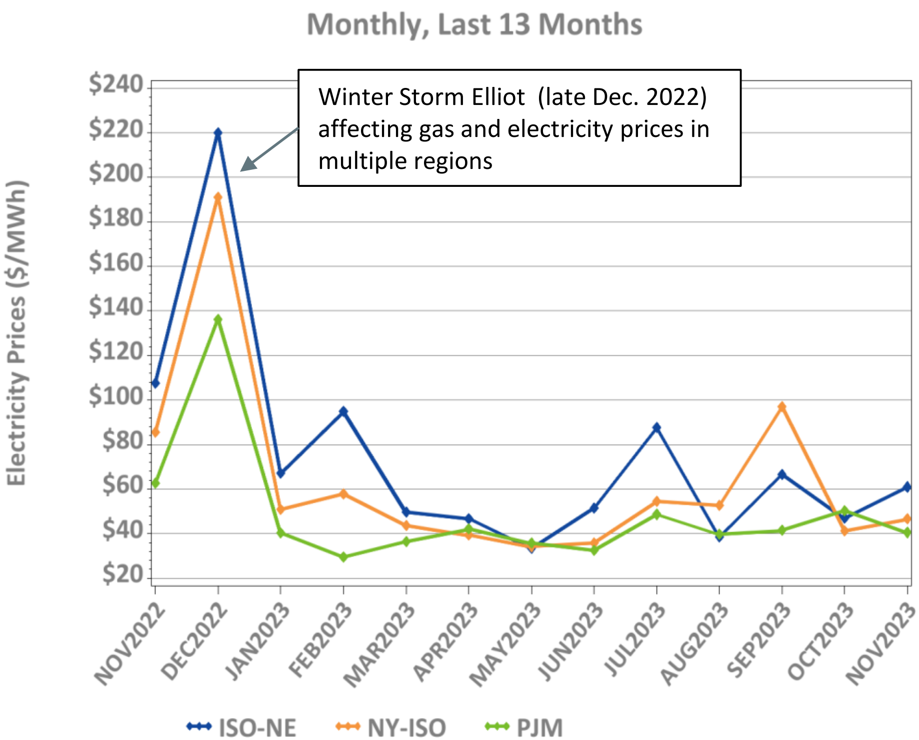


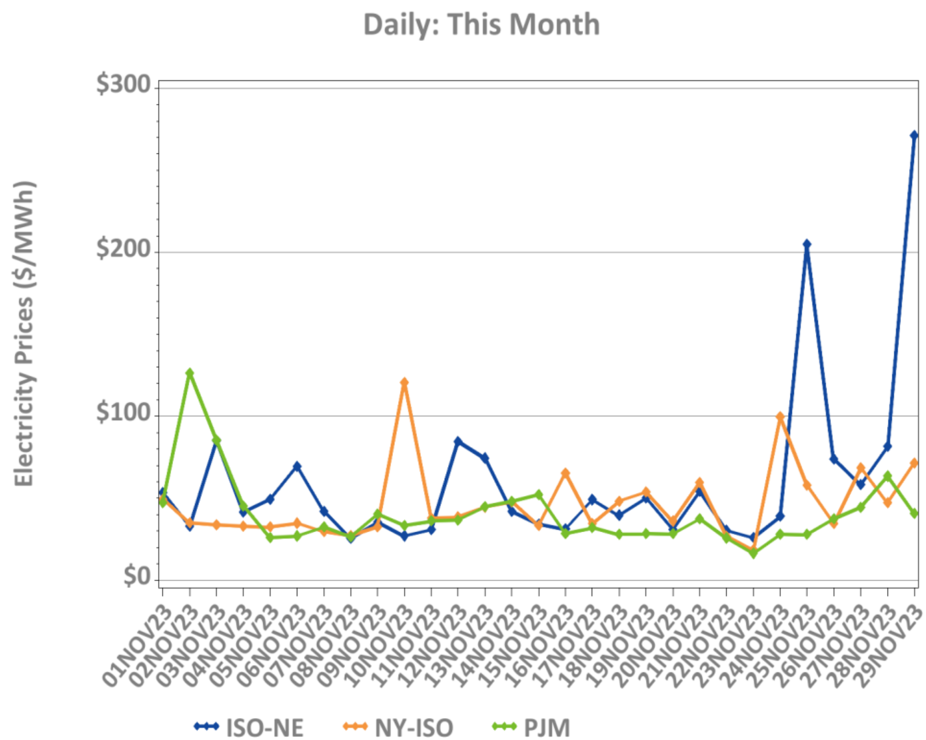
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





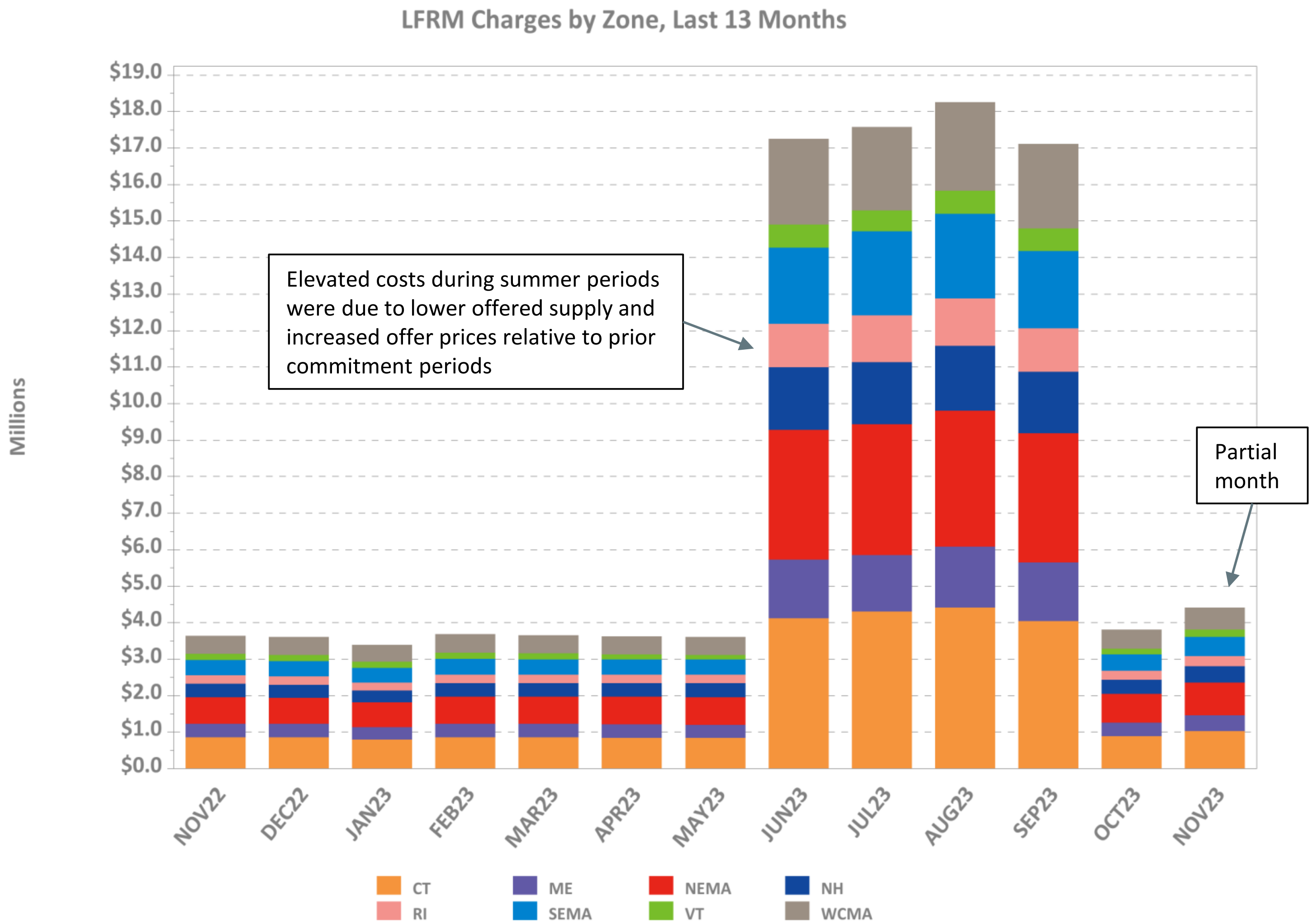
***Forecasted New England daily peak hours reflected**

Reserve Market Results – November 2023

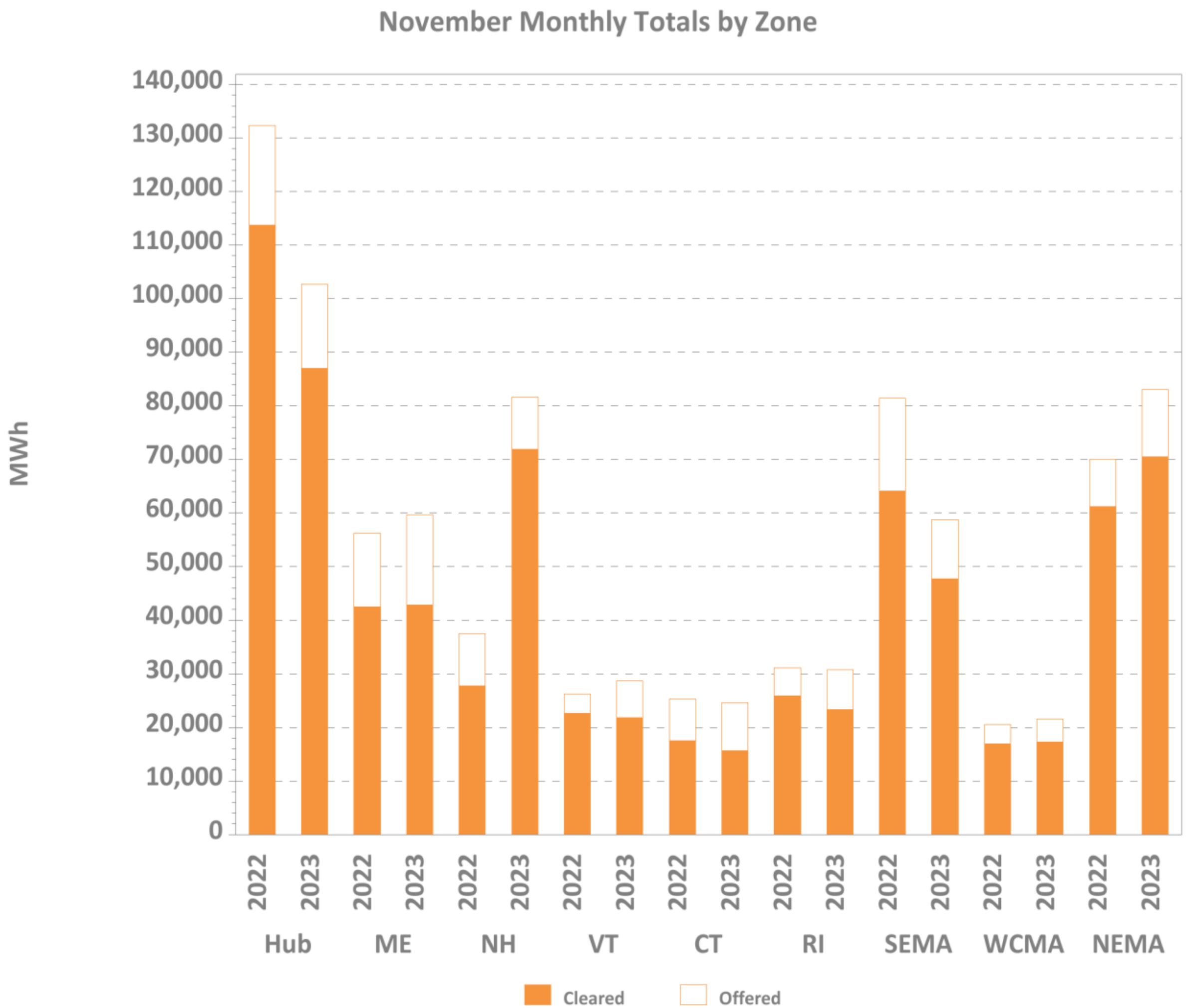
- Maximum potential Forward Reserve Market payments of $5.1M were reduced by credit reductions of $0.3M, failure-to-reserve penalties of $0.4M and failure-to-activate penalties of $8K, resulting in a net payout of $4.4M or 86% of maximum
  - Rest of System: $3.35M/3.83M (88%)
  - Southwest Connecticut: $0.04M/0.04M (85%)
  - Connecticut: $0.98M/1.2M (81%)
  - NEMA: $42K/49K (89%)
- $2.4MK total Real-Time credits were reduced by $0.7M in Forward Reserve Energy Obligation Charges for a net of $1.7M in Real-Time Reserve payments
  - Rest of System: 131 hours, $865K
  - Southwest Connecticut: 131 hours, $549K
  - Connecticut: 131 hours, $195K
  - NEMA: 131 hours, $91K

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

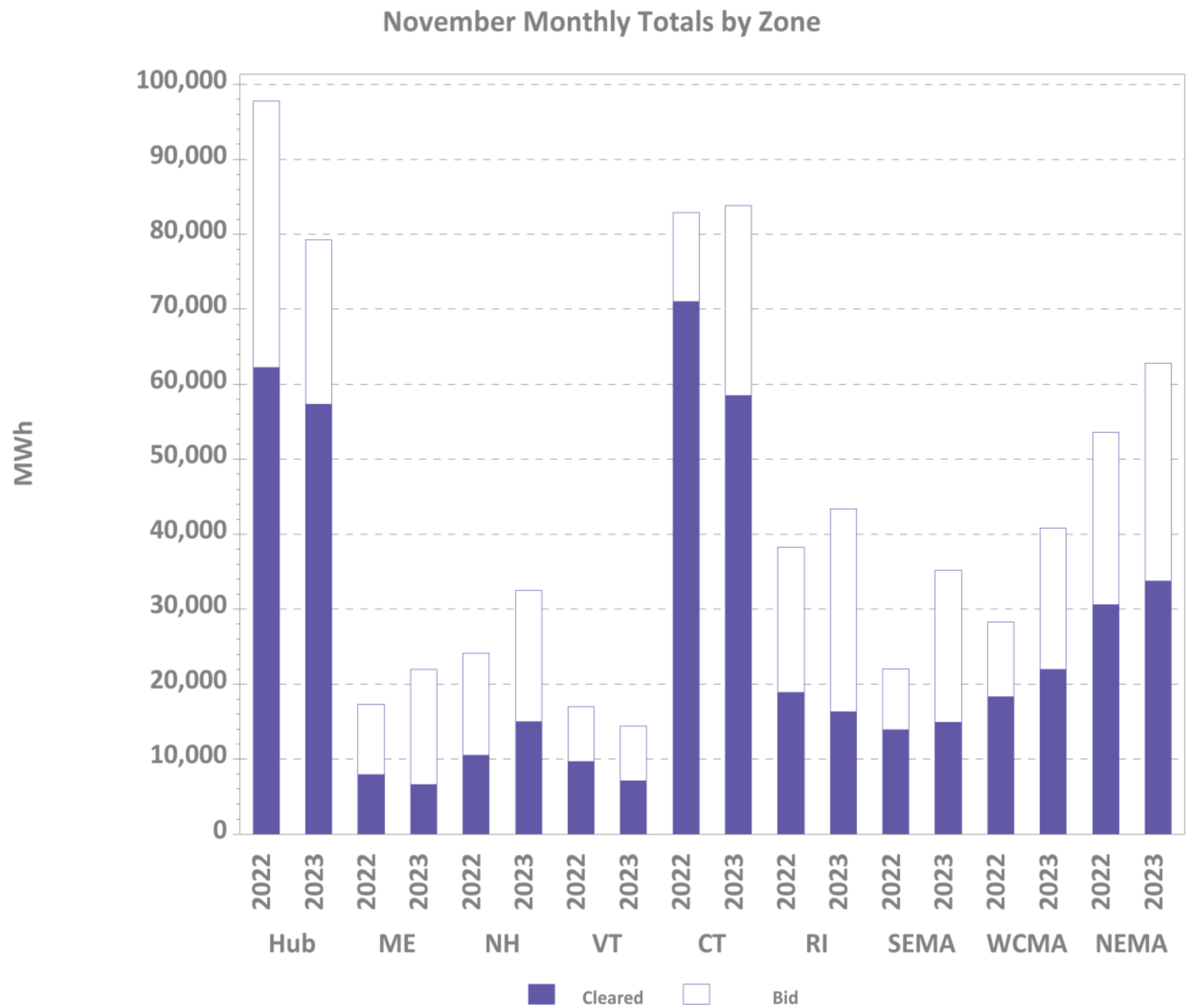
LFRM Charges to Load by Load Zone ($)



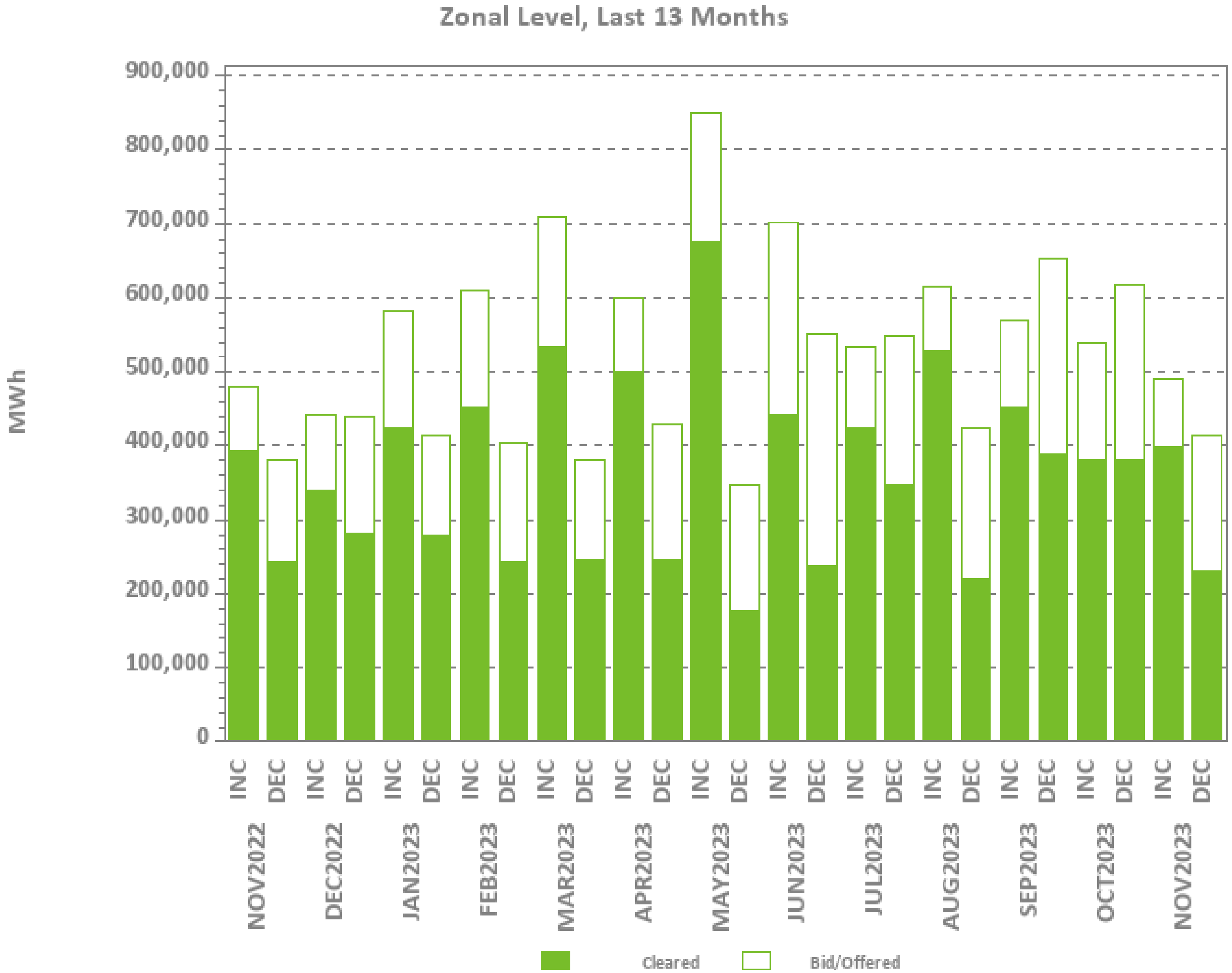
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

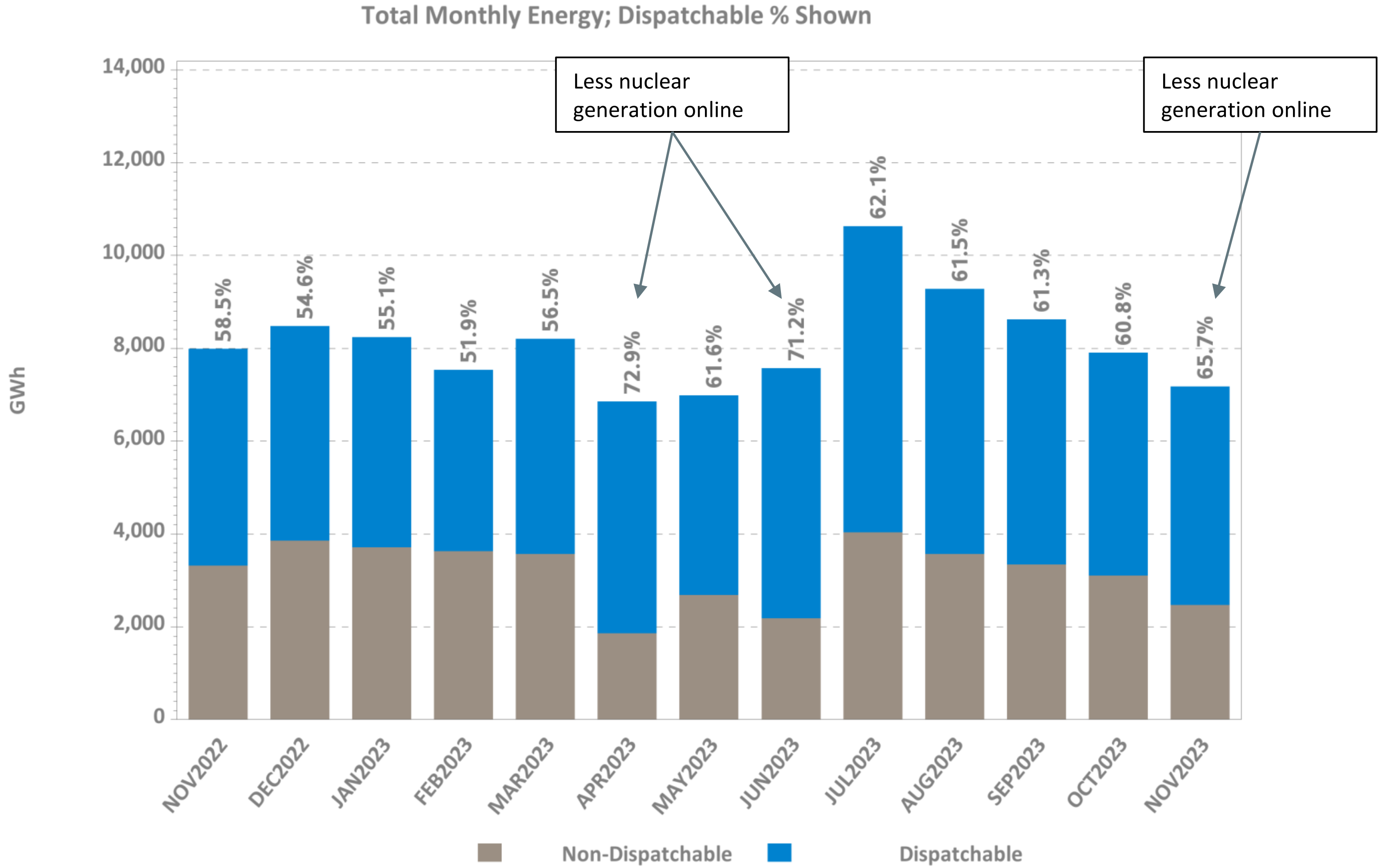


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- The 2023 RSP was approved by the Board on November 16

Planning Advisory Committee (PAC)

- December 20 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - NH Line A152 & M127 Structure Replacement Projects - Eversource
    - Overview of Pipe-Type Cable (PTC) Replacement Projects - Eversource
    - A201/B202 230 kV Line Asset Condition Project - National Grid
  - Moody's Analytics Update
  - Vermont 2033 Needs Assessment
  - NETO Update on Asset Condition Project Process Enhancements
  - Economic Planning Clean Energy Transition (EPCET) - Additional Market Efficiency Need Scenario (MENS) Sensitivity and Policy Scenario Revenue Adequacy Sensitivity

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

2050 Transmission Study

- Meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Additional discussion on solution development occurred at the 4/20/23 and 7/25/23 PAC meetings
- Development of transmission solutions and associated costs, including work by Electrical Consultants Inc. (ECI) on cost estimates, is now complete
- ISO presented solutions and associated costs at the 10/18/23 PAC meeting
- Draft report was posted on 11/1/23
- Draft technical appendix is expected to be posted by early December

Economic Studies

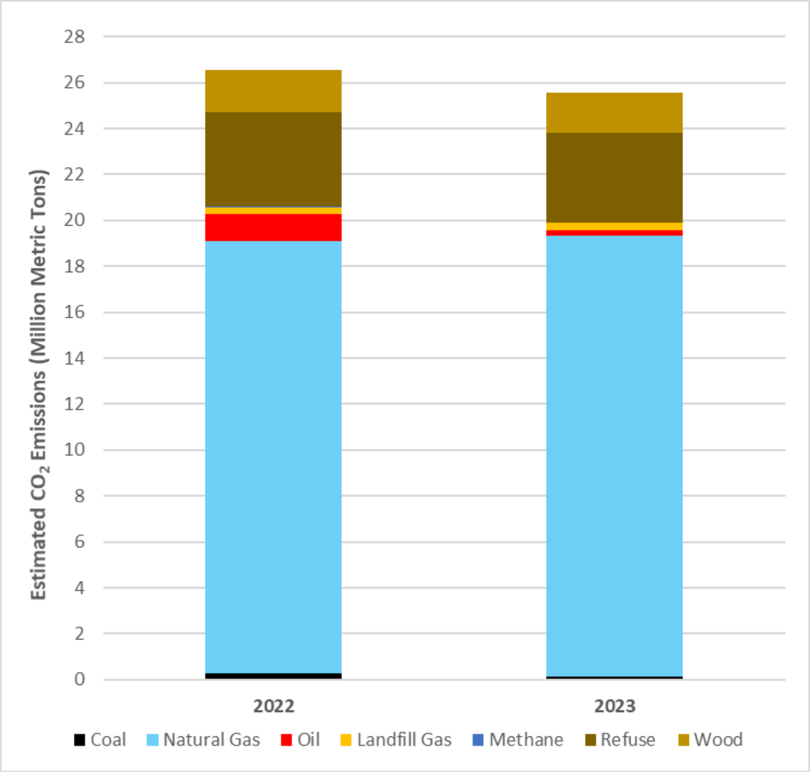
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - An effort to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented results from the Benchmark, Market Efficiency Need, and Policy scenarios.
    - As announced at the October PAC, FGRS Phase 2 will be completed via the EPCET Policy scenario
    - Further sensitivity results will be presented through Q1 2024
    - A report will be issued in Q2 2024

ISO-NE Tie Benefits Evaluation

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

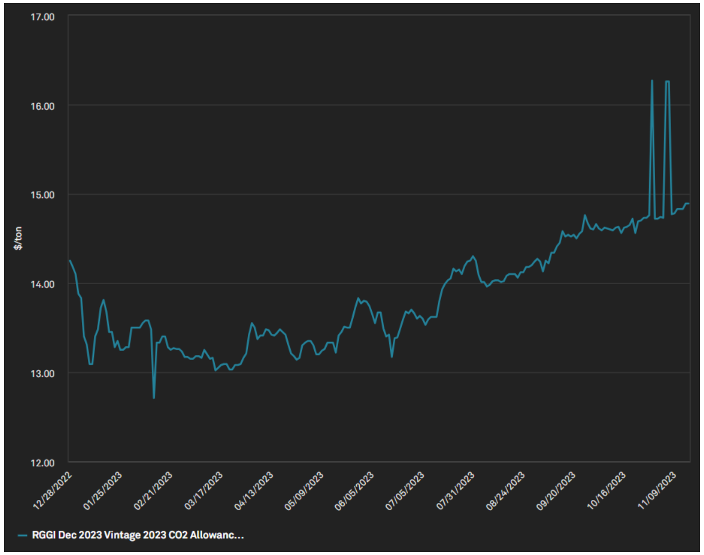
New England Power System Carbon Emissions

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



Data as of 11/12/2023

RGGI Allowance Prices



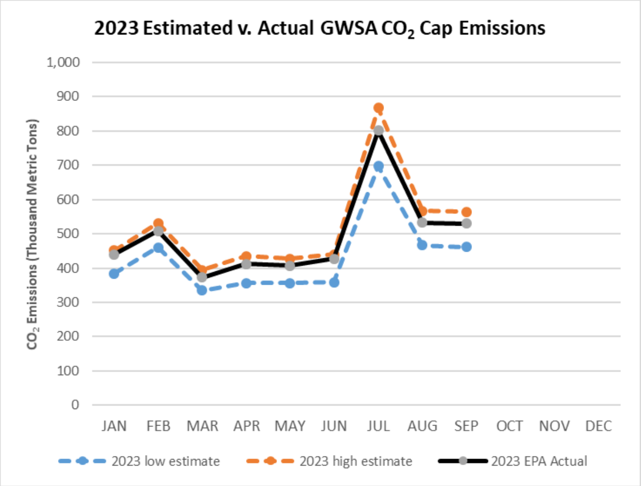
- 11/17/23: RGGI allowance spot price - \$14.89
- 9/26/23: Third Program Review Public Meeting
  - RGGI states proposed to change the three-year compliance period to an annual basis
  - RGGI states released a draft RGGI Emissions Dashboard that displays CO_2 emissions from RGGI-covered facilities since the start of RGGI

RGGI – Regional Greenhouse Gas Initiative

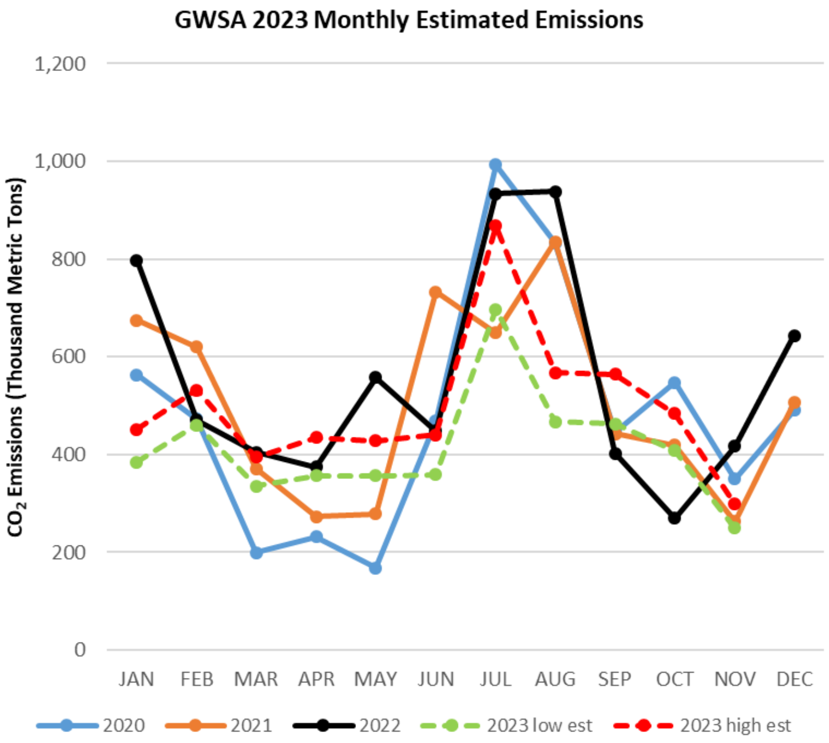
Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 11/20/23, November 2023 estimated GWSA CO_2 emissions range between **249,221** and **299,165** metric tons
  - Year-to-date 2023 estimated emissions range between **58%** and **70%** of the 2023 cap of 7.84 MMT
- According to the EPA CAMPD, the Q1-Q3 (January-September) GWSA CO_2 emissions were **4.43** million metric tons. The Q1-Q3 emissions were **57%** of the 2023 cap of 7.84 million metric tons



2020-2023 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated emissions)

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 11/27/2023

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

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

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

Greater Boston Projects, cont.

Status as of 11/27/2023

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Mar-25	3

Greater Boston Projects, cont.

Status as of 11/27/2023

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

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

Greater Boston Projects, cont.

Status as of 11/27/2023

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

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

Greater Boston Projects, cont.

Status as of 11/27/2023

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

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

SEMA/RI Reliability Projects

Status as of 11/27/2023

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

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

SEMA/RI Reliability Projects, cont.

Status as of 11/27/2023

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 11/27/2023

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	3
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-25	2

SEMA/RI Reliability Projects, cont.

Status as of 11/27/2023

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 11/27/2023

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

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

Eastern CT Reliability Projects

Status as of 11/27/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	3
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Dec-22	4
1851	Upgrade Card 115 kV to BPS standards	Dec-22	4
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Feb-23	4
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	4

Eastern CT Reliability Projects, cont.

Status as of 11/27/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 11/27/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

New Hampshire Solution Projects

Status as of 11/27/2023

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Sep-24	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Dec-23	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Jun-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	4

Upper Maine Solution Projects

Status as of 11/27/2023

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line	Dec-24	3
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Jun-24	3

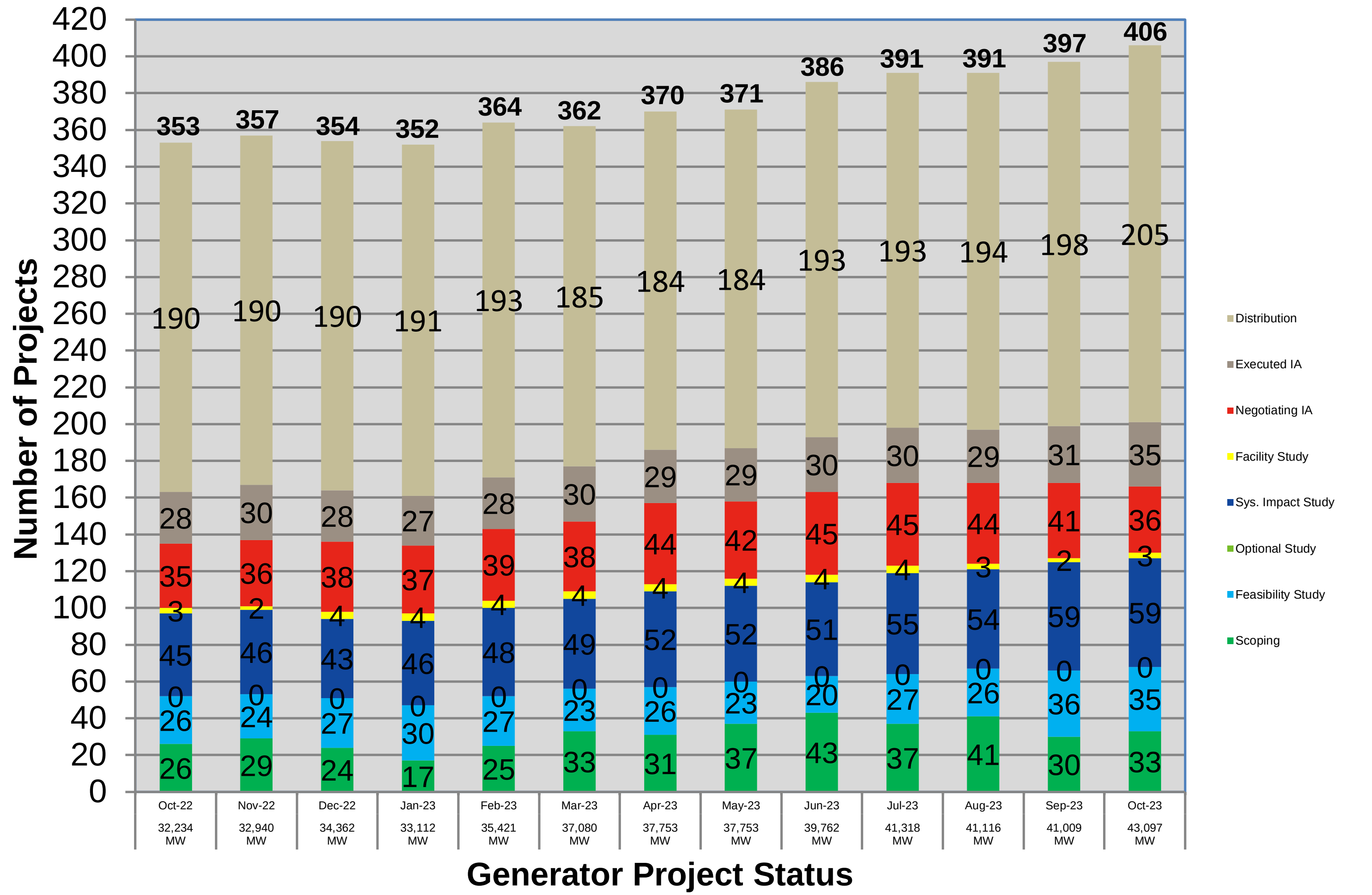
Upper Maine Solution Projects, cont.

Status as of 11/27/2023

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	3
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	2
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-24	2

Status of Tariff Studies as of November 1, 2023



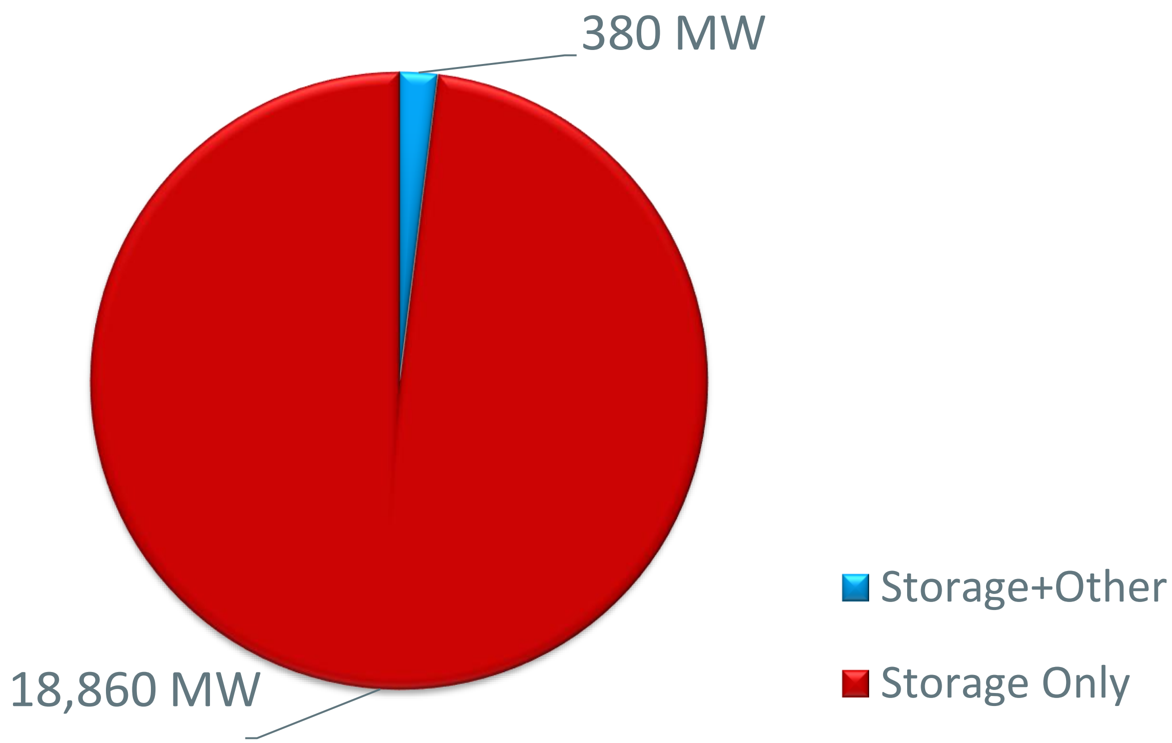
8 ETUs in Scoping, 7 in FS, 0 in SIS, 1 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 1 in SIS

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

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

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



OPERABLE CAPACITY ANALYSIS

Winter 2023/24 Analysis

Winter 2023/24 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2024[2] CSO (MW)	Jan. - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,343	31,733
Active Demand Capacity Resource (+) [5]	522	328
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	213	213
Non Gas-fired Planned Outage MW (-)	834	979
Gas Generator Outages MW (-)	192	495
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,536	3,641
Net Capacity (NET OPCAP SUPPLY MW)	22,674	25,317
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,269	20,269
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,574	22,574
Operable Capacity Margin	100	2,743

[1]Operable Capacity is based on data as of **November 28, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **November 28, 2023.**

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

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

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

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

Winter 2023/24 Operable Capacity Analysis

90/10 Load Forecast	Dec. - 2023[2] CSO (MW)	Dec. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,578	31,733
Active Demand Capacity Resource (+) [5]	362	328
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	951	951
Non Commercial Capacity (+)	16	16
Non Gas-fired Planned Outage MW (-)	1,404	1,870
Gas Generator Outages MW (-)	533	1,030
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	3,747	3,739
Net Capacity (NET OPCAP SUPPLY MW)	21,023	23,189
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,274	20,274
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,579	22,579
Operable Capacity Margin	-1,556	610

[1]Operable Capacity is based on data as of **November 28, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **November 28, 2023.**

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

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

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

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

Winter 2023/24 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

November 28, 2023 - 50-50 FORECAST using CSO MW

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

Report created: 11/28/2023

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
12/16/2023	28578	362	951	16	1442	707	3200	2038	22520	19475	2305	21780	740	N	Winter 2023/2024
12/23/2023	28578	362	951	16	1404	533	3200	2601	22169	19537	2305	21842	327	N	Winter 2023/2024
12/30/2023	28343	522	958	213	758	49	2800	3684	22745	19808	2305	22113	632	N	Winter 2023/2024
1/6/2024	**28343**	**522**	**958**	**213**	**834**	**192**	**2800**	**3536**	**22674**	**20269**	**2305**	**22574**	**100**	**Y**	**Winter 2023/2024**
1/13/2024	28343	522	958	213	747	83	2800	3500	22906	20269	2305	22574	332	N	Winter 2023/2024
1/20/2024	28343	522	958	213	455	83	2800	3051	23647	20269	2305	22574	1073	N	Winter 2023/2024
1/27/2024	28337	522	958	213	334	228	3100	2607	23761	20049	2305	22354	1407	N	Winter 2023/2024
2/3/2024	28337	522	958	213	178	94	3100	2442	24216	19784	2305	22089	2127	N	Winter 2023/2024
2/10/2024	28337	522	958	213	191	94	3100	2143	24502	19755	2305	22060	2442	N	Winter 2023/2024
2/17/2024	28337	522	958	213	137	94	3100	1694	25005	19495	2305	21800	3205	N	Winter 2023/2024
2/24/2024	28337	522	958	213	210	49	3100	1440	25231	18516	2305	20821	4410	N	Winter 2023/2024
3/2/2024	28337	522	958	213	1730	98	2200	316	25686	18170	2305	20475	5211	N	Winter 2023/2024
3/9/2024	28337	522	958	213	1566	420	2200	0	25844	17976	2305	20281	5563	N	Winter 2023/2024
3/16/2024	28337	522	958	213	1566	392	2200	0	25872	17614	2305	19919	5953	N	Winter 2023/2024
3/23/2024	28337	522	958	213	2151	1304	2200	0	24375	17054	2305	19359	5016	N	Winter 2023/2024
3/30/2024	28235	518	958	213	1105	2079	2700	0	24040	16379	2305	18684	5356	N	Winter 2023/2024

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2023/24 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

November 28, 2023 - 90/10 FORECAST using CSO MW

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

Report created: 11/28/2023

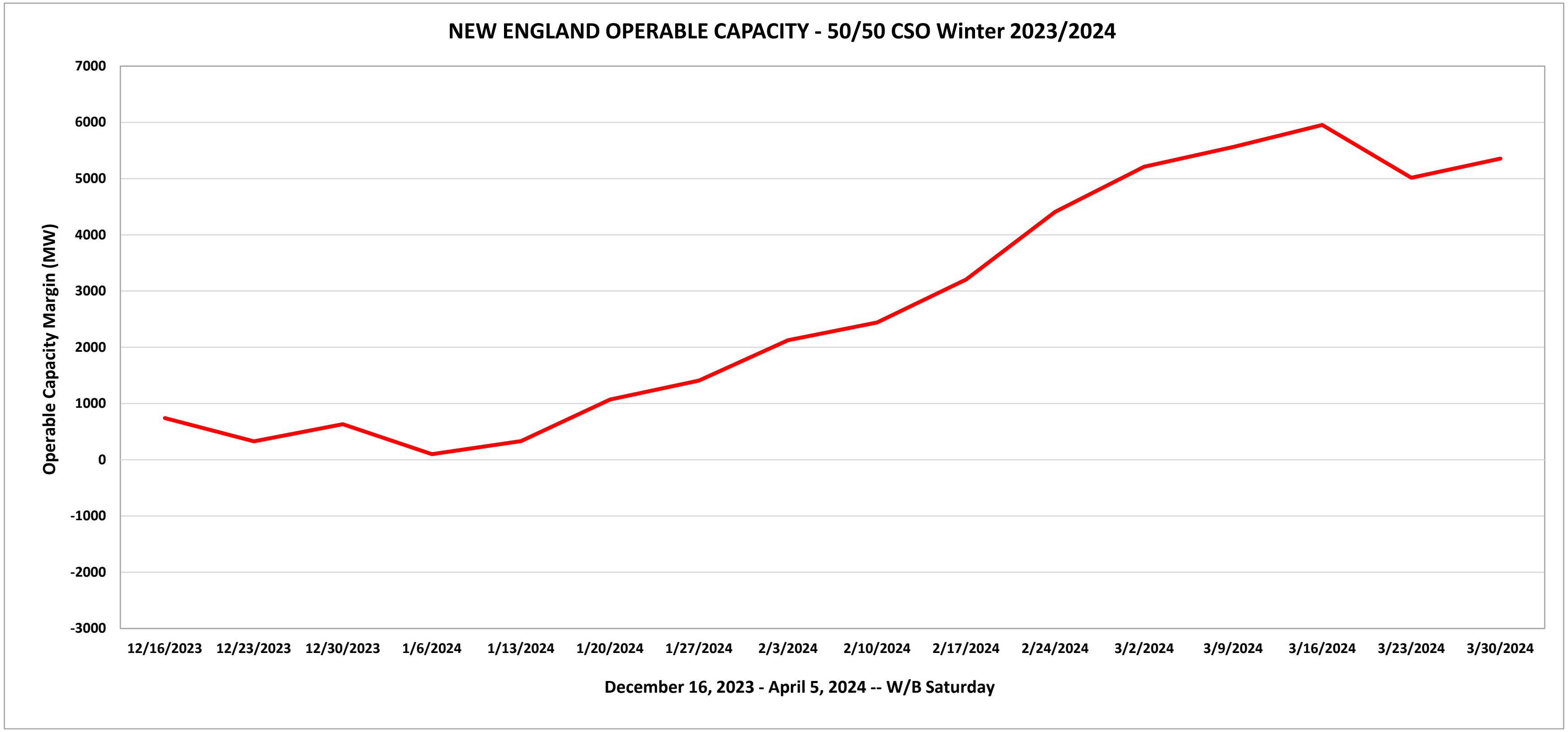
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
12/16/2023	28578	362	951	16	1442	707	3200	3157	21401	20211	2305	22516	-1115	N	Winter 2023/2024
12/23/2023	**28578**	**362**	**951**	**16**	**1404**	**533**	**3200**	**3747**	**21023**	**20274**	**2305**	**22579**	**-1556**	**Y**	**Winter 2023/2024**
12/30/2023	28343	522	958	213	758	49	2800	4359	22070	20555	2305	22860	-790	N	Winter 2023/2024
1/6/2024	28343	522	958	213	834	192	2800	4347	21863	21032	2305	23337	-1474	N	Winter 2023/2024
1/13/2024	28343	522	958	213	747	83	2800	4248	22158	21032	2305	23337	-1179	N	Winter 2023/2024
2/24/2024	28337	522	958	213	210	49	3100	2188	24483	19218	2305	21523	2960	N	Winter 2023/2024
3/2/2024	28337	522	958	213	1730	98	2200	1213	24789	18860	2305	21165	3624	N	Winter 2023/2024
3/9/2024	28337	522	958	213	1566	420	2200	786	25058	18659	2305	20964	4094	N	Winter 2023/2024
3/16/2024	28337	522	958	213	1566	392	2200	0	25872	18285	2305	20590	5282	N	Winter 2023/2024
3/23/2024	28337	522	958	213	2151	1304	2200	0	24375	17705	2305	20010	4365	N	Winter 2023/2024
3/30/2024	28235	518	958	213	1105	2079	2700	0	24040	17014	2305	19319	4721	N	Winter 2023/2024

Column Definitions

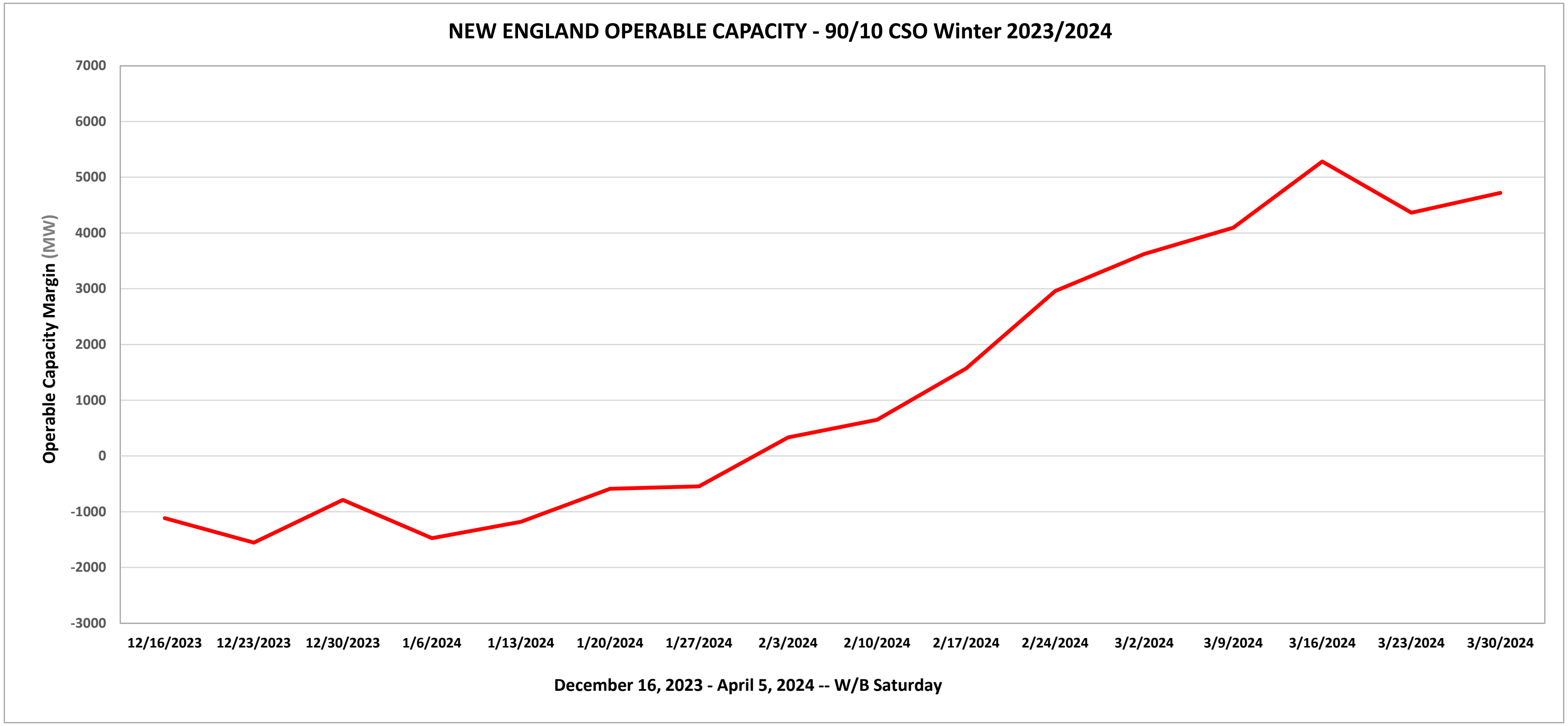
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2023/24 Operable Capacity Analysis

50/50 Forecast (Reference)



Winter 2023/24 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

NOTES:

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

DECEMBER 7, 2023

New England Winter Outlook 2023/2024

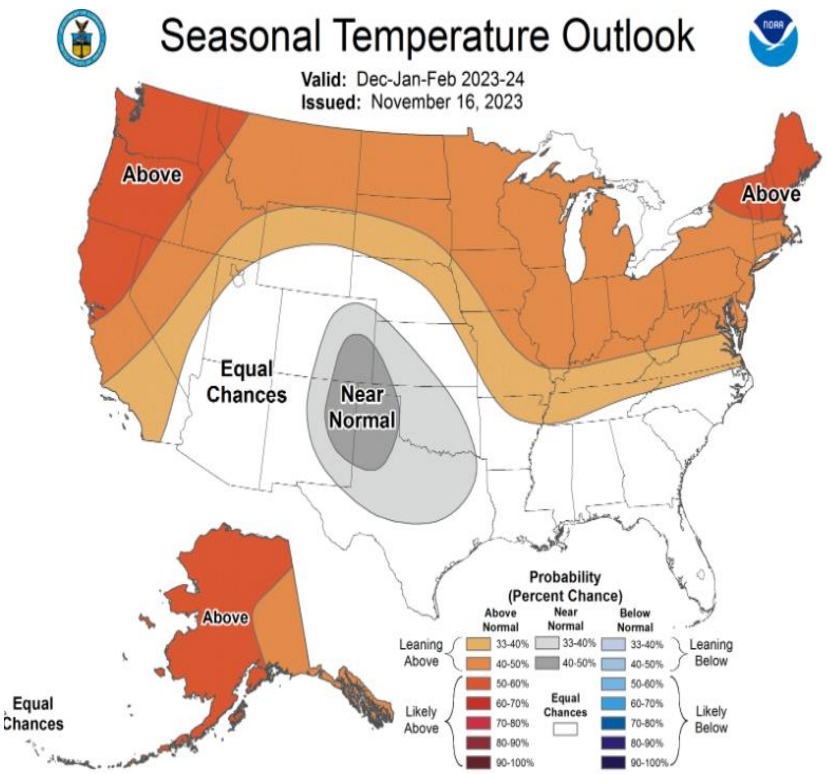
Vamsi Chadalavada

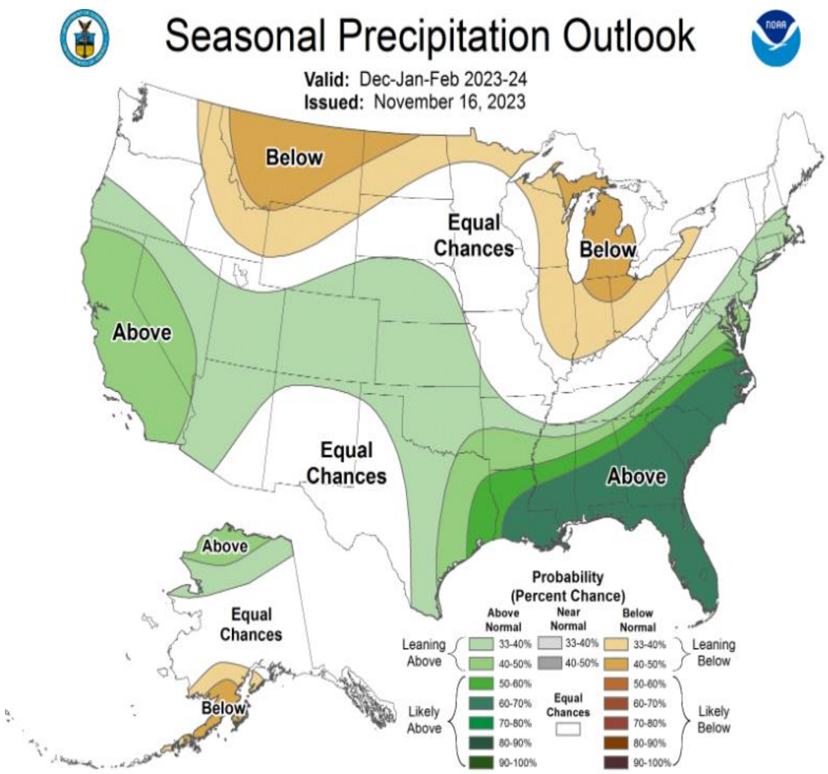
EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER

Highlights

- Winter Outlook
  - The seasonal temperature outlook for the winter months of December - February indicates a 40-60% probability of above normal temperatures for most of New England
  - A 33-40% chance of above normal precipitation is forecasted for southern New England while equal chances for above average or below average precipitation is forecasted for northern New England
  - Based on generator capabilities expected during the winter season, capacity analysis for the 50/50 and the 90/10 load forecast indicates a surplus even after accounting for generation at risk due to gas supply
  - Cost-of-service for Mystic 8 & 9 continues through winter 2023/2024
  - Inventoried Energy Program (IEP) is in effect for two winters, starting this winter

Winter Temperatures and Precipitation Outlook





Winter Expectations 2023/2024

- Winter Demand Forecast
  - 50/50 winter peak demand forecast of 20,269 MW, which is ~250 MW (~1.3%) higher than the 2022/2023 forecast
  - 90/10 winter peak demand forecast of 21,032 MW, which is ~350 MW (~1.6%) higher than the 2022/2023 forecast
- Scheduled Generation and Transmission Outages
  - All generation and transmission outages continue to be coordinated to minimize adverse transmission or capacity conditions
- Transfer Capability
  - Transfer capability on the New York Northern AC ties has been increased from 1,400 to 1,600 MW for the winter period

Winter Expectations 2023/2024, cont.

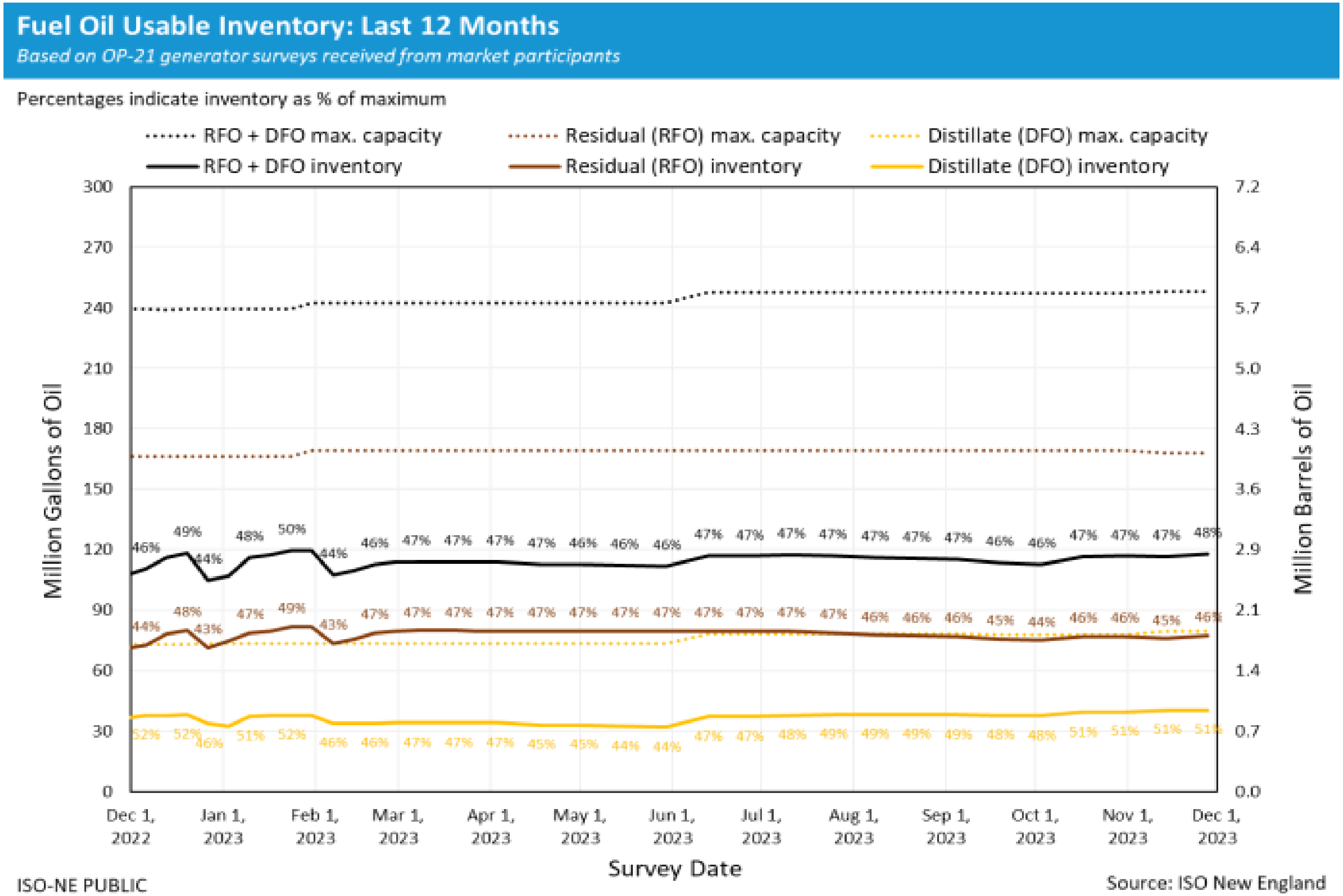
- Natural Gas Deliverability
  - ISO will continue to monitor natural gas deliverability and maintain close communication with regional interstate gas pipelines throughout the winter
  - Consistent with past winter seasons, the ISO assumes that approximately 3,500 – 4,300 MW[1] may be at risk due to constrained natural gas pipelines
- Winter Capacity Outlook
  - Projecting the lowest 50/50 operable capacity margin of ~2,700 MW and the lowest 90/10 operable capacity margin of ~1,050 MW for the week beginning January 6, 2024[1]
  - Extended periods of cold weather may rapidly deplete stored fuel inventories and capacity outlook will be adjusted accordingly

[1] - Based on resource Winter Seasonal Claimed Capabilities

LNG and Fuel Oil Expectations

- Over the past ten winters, the region has averaged ~28.5 Bcf of liquefied natural gas (LNG) usage; the highest usage was ~36 Bcf in 2018/2019, lowest usage was ~11.5 Bcf in 2022/2023
- Cost-of-service contract with Mystic provides some certainty of LNG availability this winter; ISO's current expectation is that ~31 Bcf will be available
- Aggregate fuel-oil inventories ended winter 2022/2023 at ~114M gallons (~47% of max); current inventory is ~118M gallons (~48% of max)
  - Discussions with owners of resources with significant fuel-oil storage capability this fall indicates that robust replenishment plans are in place and highlighted no significant concerns related to fuel oil supply chains this winter
- For winter 2023/2024, an additional ~500 MW of dual-fuel generating capability is available following completion of commissioning efforts earlier this year
- The potential for emissions limitations at some dual-fuel units will monitored closely in the event of significant oil burn

Total Usable Fuel Oil in New England



Inventoried Energy Program Update

Dec. 18, 2023 revision indicated in red

- The first year of the IEP runs from Dec. 1, 2023 through Feb. 29, 2024
  - Program consists of Forward and Spot components
  - Forward component elections were submitted to the ISO between Sept. 1 and Oct. 1, 2023; Spot-only component elections may be submitted between Sept. 1 and through the end of the winter period
- Forward Energy inventory elections for this winter total ~844,201 MWh, including ~104,492 MWh of Forward LNG Inventory Elections
  - Forward energy includes ~68% from oil-fired resources and ~30% from natural gas- fired resources; remainder is from pumped storage hydro and refuse-burning resources
  - Forward cost is ~$78 million
- As of Dec. 1, Spot Energy inventory elections for this winter total ~287,022 MWh; this includes ~104,271 MWh of Spot-only component participation and ~182,751 MWh of Spot component participation estimated from resources participating in the forward component of the program (in excess of Forward Inventory elections)
  - Spot participation is compensated at $9.25/MWh on days meeting the IEP day threshold; therefore each IEP day adds ~$2.65 million to total program costs

ISO New England Winter Preparations

- Hosted the annual Generator Winter Readiness Seminar with Market Participants on October 31, 2023
- Distributed the annual Winter Generator Readiness Survey on October 26, 2023; responses were due on December 1
  - Several survey questions were enhanced in light of recently adopted NERC cold weather reliability standards; responses are currently under review by ISO
- Completed the annual Natural Gas Critical Infrastructure Survey process to ensure critical infrastructure is not part of automatic or manual load shed schemes
- Dual fuel audits of ~30 generators totaling ~6,500 MW of capacity are expected to be completed soon
- Generator Fuel and Emissions Surveys and 21-Day Energy Assessments will be performed weekly (or daily, if required) during the winter season
  - 21-day Energy Assessment results and summaries of generator fuel surveys will be posted weekly to the ISO public website

Winter 2023/2024 Energy Analysis (no changes since last published in June)

Scenario Descriptions & Results

Scenario:	Moderate	Severe
Similar Winter	Winter 2017/2018	Winter 2013/2014
Observed Weather Conditions	Milder than normal; two-week span of significantly below normal temps	Colder than normal; six cold snaps of four or more days; one stretch of ten consecutive days below freezing
Peak Load Modeled	19,600 MW	20,300 MW
Total Winter Energy Demand Modeled	29,200 GWh	31,100 GWh
Results:	**Sufficient capacity and energy to meet peak loads and energy demands**	**Capacity deficiency actions across a few days; energy shortfall unlikely**

Assumptions

Imports	Vary between 3,000 – 4,000 MW/hr when ≥ 20°F; 1,500 MW/hr when < 20°F
Behind-the-Meter PV Capacity	6,400 MW nameplate
No significant or long-duration generator or transmission contingencies	

DECEMBER 7, 2023| BOSTON, MA

nGEM Program Overview

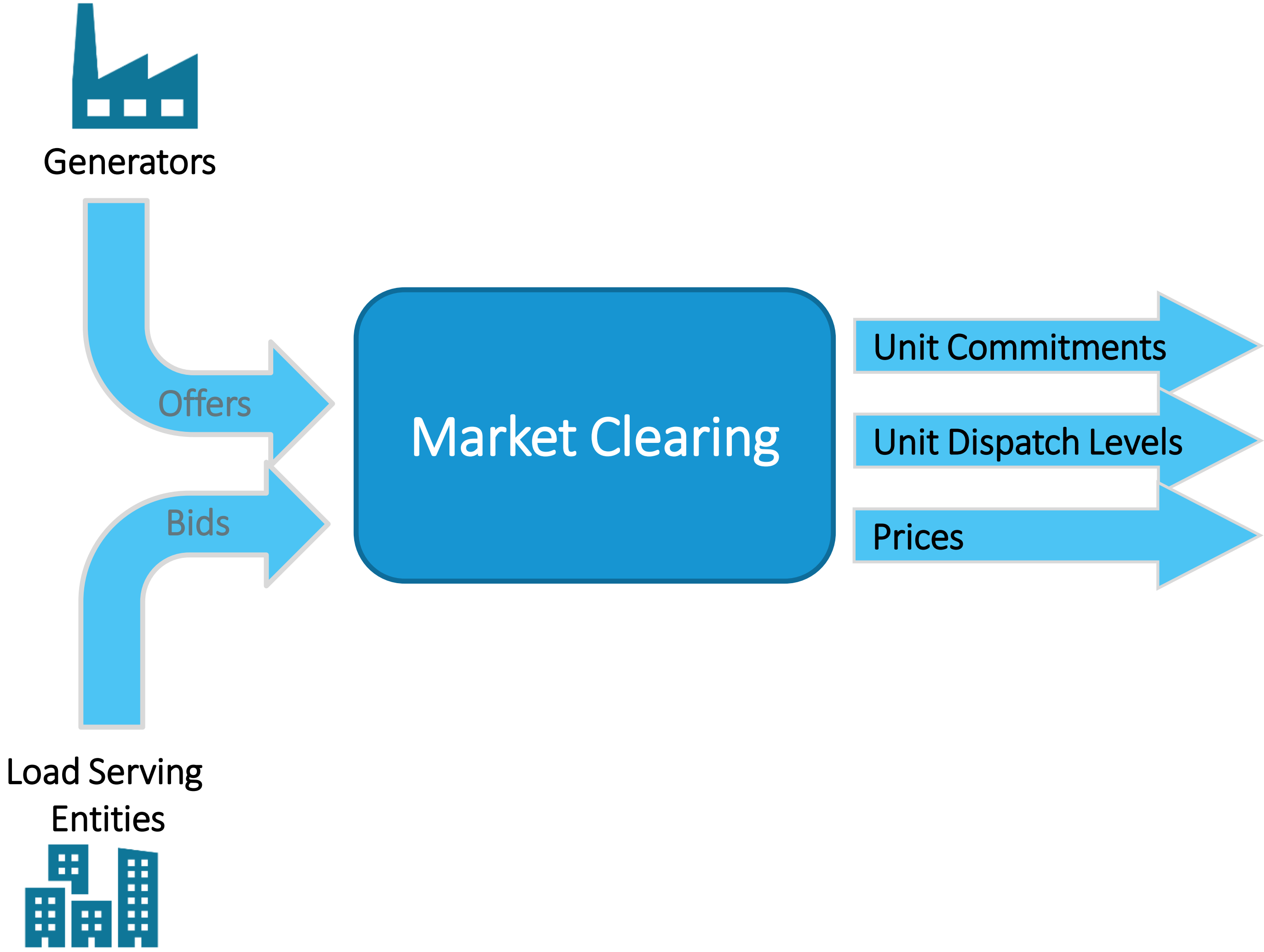
Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER

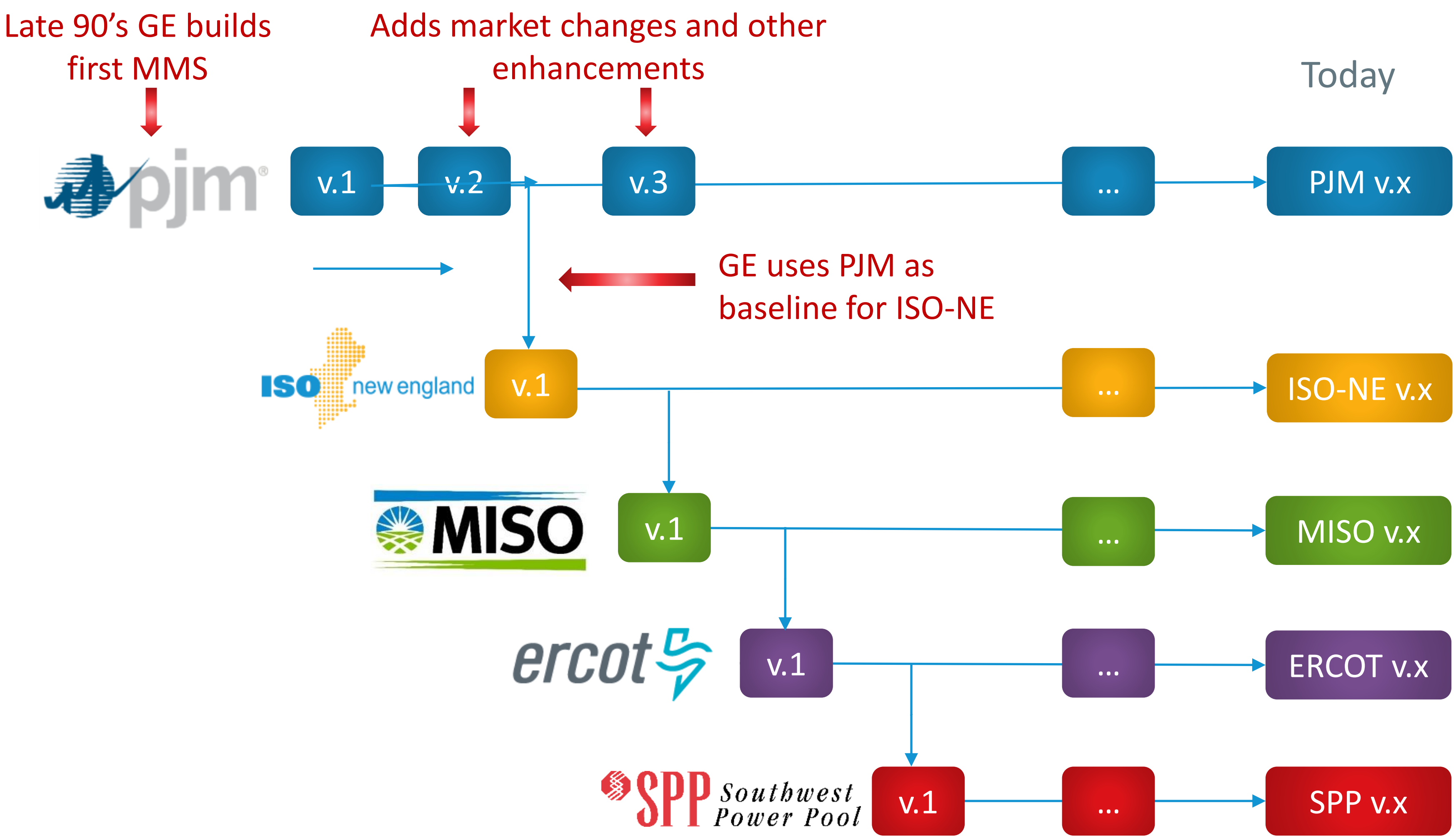
nGEM Program – Introduction

- This presentation is intended to provide an overview of the next Generation Electricity Market (nGEM) program that GE is developing
- nGEM will replace the current GE platform that is installed at multiple ISO's, including PJM, MISO, and ISO-NE
- GE's nGEM program development, and subsequently the ISO-NE implementation roadmap, will continue through 2028
  - GE's nGEM program development is on a separate track and, by design, ahead of the ISO's implementation roadmap

At ISO-NE, the GE Market Management System comprises the Day-Ahead and Real-Time Markets



Evolution of GE's Market Management System



Current System Limitations

Technology limitations: Because of the limited number of clients, there have been infrequent upgrades by GE and the system has not kept up with technology changes

- Monolithic centralized database
- AIMMS optimization platform with CPLEX commercial solver
- GE's Habitat-based network applications

Cost of changes are higher because each upgrade is custom for each ISO

Cybersecurity challenges have increased exponentially and the original system was not designed for today's security needs

Performance is acceptable now, but will eventually be challenged by the increasing number of renewable resources

next Generation Electricity Market

2015

GE visited several ISOs and generated high-level collaborative plan

2016

GE's initial R&D investment to explore architecture

- Developed a vision and roadmap
- Executed several pilots
- Discussed co-funding with PJM, ISO-NE, MISO and SPP

2017

GE proposed the **nGEM** program (**n**ext **G**eneration **E**lectricity **M**arket) to develop core product market software sharing the cost with three ISOs:

nGEM Program Goals

Incremental Upgrade	Incrementally replace current market system to reduce risk to Operations
Security	Design for industry standard Cyber Security requirements (NERC, IRC/ITC). Proactive approach to CIP compliance
Standardization	Standardize various ISO's features into the nGEM product where possible
High Performance	High performance with flexibility to choose different solvers; **Kubernetes/Containers based technology** (*see* next slide)
Maintainability	Ensure system stays current and remains a product. **Support faster market rule implementations**
Test Automation	Allow each new release to be regression-tested against existing system

What are containers?

- Containers are a way to isolate applications running on the same machine from one another
  - This allows multiple applications to run on the same resources without problems due to shared dependencies

  - The biggest benefit of containers is agility. It breaks down larger applications or code sets into smaller chunks that can be maintained on their own lifecycle without dependencies on the Operating System and other Hardware items
  - Kubernetes is a container orchestrator, managing their workloads and services

nGEM Program – Maintenance and Upgrades

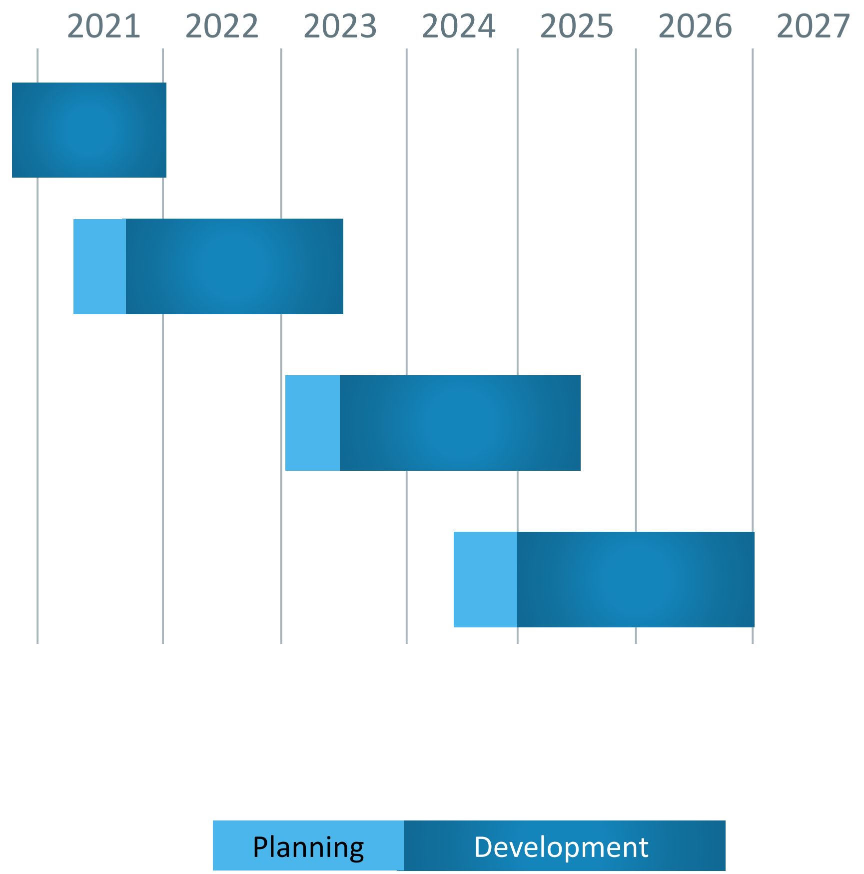
- Periodic releases of core nGEM product
  - Extensive regression test library
- Permanent Product Development Team
  - Proactively pushes out fixes for product bugs and 3rd party security patches
  - Reviews new work requests from the ISO's to determine what should be added to the base Product
  - Improves centralized product support for all ISOs
- Cloud enabled - starting with private cloud deployment

nGEM Consortium – GE, PJM, MISO, ISO-NE

- nGEM Consortium will to continue to provide direct guidance on architecture, functionality, security and features
  - Establish product standardization
  - Share core development across program participants

nGEM Program Development – ISO-NE Share

	ISO-NE Share
nGEM Phase 1	$3.25M
nGEM Phase 2	$4.75M
nGEM Phase 3	$4.0M
nGEM Phase 4	$3.0M
	$15.0M*



***Best estimate based on current scope**

nGEM Program Dashboard Status – As of December 1, 2023

nGEM Program Development				
	Phase 1	Phase 2	Phase 3*	Phase 4*
Schedule	●	●	●	
Budget	●	●	●	
Scope	●	●	●	

nGEM Implementation Projects				
	Phase 1	Phase 2**	Phase 3	Phase 4
Schedule	●	●		
Budget	●	●		
Scope	●	●		

*nGEM Phase 3 Program Development underway, Phase 4 scope to be defined in Q4, 2024
**nGEM Implementation for Phase 2 (Real-Time Market Clearing Engine) underway

nGEM Program – Phase 1 Details – Completed

Scope

1. New Data Transfer Infrastructure
2. Habitat-Free Power System Network Functions
3. Day Ahead Market Clearing Platform
4. New Market User Interface

Schedule

Completed in Q4 2021

Budget

ISO-NE share was ~$3.25M

nGEM Program – Phase 2 Details – Completed

Scope

1. Real Time Market Clearing Platform
2. Unit Commitment/ Contingency Analysis Interaction
3. Replace Oracle-based Case Workflow Manager
4. Enhance Long Term Case Storage
5. Generalized EMS Interfaces
6. Market Clearing Engine User Interface
7. Distributed Model Manager

Schedule

Completed in Q4 2022

Budget

ISO-NE share was ~$4.75M

nGEM Program – Phase 3 Details – In Progress

Scope

1. Storage Model
2. Current Operating Plan
3. Training and Testing Simulator
4. Ramping & Aggregated Distributed Energy Resources
5. Transmission Constraint Management

Schedule

Q3 2023 – Q1 2025

Budget

ISO distributions have not been finalized; Expect ISO-NE share to be ~$4M

nGEM Program – Phase 4 Details – Conceptual

Scope

1. Schedule Service
2. Day-Ahead Market Operator Interface
3. Real-Time Market Operator Interface
4. Others TBD

Schedule

Q2 2025 – Q4 2026

Status

Planning has not started

Budget

ISO distributions have not been determined; Expect ISO-NE share to be ~$3M

ISO-NE Project Implementation

- While GE's nGEM product program continues on a parallel path, ISO-NE has a roadmap for deployment
- At key intervals, ISO-NE will take specific releases from each completed phase of the nGEM program for implementation
- The ISO implemented the nGEM Day-Ahead Market Clearing Platform earlier this year
  - This has allowed the ISO to expedite the planned implementation of the Day-Ahead Ancillary Services Initiative (subject to FERC approval)
- The ISO initiated the nGEM Real-Time Market Clearing Platform in November 2023 and this project is expected to be in-service by Q2 2026

Primary Areas of Risk

- Vendor delivery risk
  - GE is experiencing significant change and while several new hires have been made, loss of experience translates to schedule delays
  - GE is supporting multiple ISO's on different timelines and with different priorities
- ISO-NE and regional priorities
  - While the core platform is essential, the ISO also has several market and operational priorities that could divert project resources
- New technology
  - nGEM uses Kubernetes which is an open-source platform for automating computer application deployment, scaling, and management of containerized applications

Primary Risk Mitigation Steps

- Program split into multiple phases spanning several years
- Early phases focus on the highest value functions to minimize overall risk and boost confidence in the entire program
  - For example, the ISO prioritized data models and Day-Ahead and Real-Time clearing engine functionality in the first phase
  - Phase one has already delivered key data model improvements and the Day-Ahead clearing engine
- Frequent checkpoints with the other ISO’s and regular management briefings (bi-weekly, monthly, and quarterly)
- Proof of Concept requirements for new technologies
- Training employees; hiring additional information technology resources to deliver high-quality projects and maintain them

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

December 7, 2023

RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2024

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 indentified in the following resolution were nominated and elected for 2024 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 2024 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Sarah Bresolin
Vice-Chair	Dave Cavanaugh
Vice-Chair	Michelle Gardner
Vice-Chair	Aleks Mitreski
Vice-Chair	Paul Roberti
Vice-Chair	Alan Trotta
Secretary	Sebastian Lombardi
Assistant Secretary	Pat Gerity

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Tom Kaslow, Chair, NEPOOL Budget & Finance Subcommittee
Paul Belval, NEPOOL Counsel

DATE: November 30, 2023

RE: Estimated Budget for 2024 Participant Expenses

The Participants Committee will be asked at its December 7 meeting to approve the estimated NEPOOL expense budget for 2024, which is attached to this memorandum (the "2024 Budget"). As in prior years, the proposed 2024 Budget estimates are compared to both the current-year estimated expenses approved by the Participants Committee at its last annual meeting and the current forecast of actual expenses for this year (Attachment A). Also, an estimated calculation of the per-Participant share of the 2024 Budget expenses are compared to 2023 per-Participant shares of expenses (Attachment B). Impacted by the number of members over which expenses are allocated, 2024 per-Participant expenses are projected, when compared to 2023 numbers, to generally increase by 2.2% for most Participants (those in the Generation or Supplier Sectors or those with an individual vote in the AR Sector's Renewable Generation Sub-Sector) and by 0.3% for those Participants in the Transmission and Publicly Owned Entity Sectors.

Consistent with the practice employed in previous years, NEPOOL Counsel, the GIS Administrator, the ISO and NEPOOL's Independent Financial Advisor worked together to develop the recommended 2024 Budget. The NEPOOL Budget & Finance Subcommittee discussed the proposed 2024 Budget at its November 28 meeting, and no objections were raised at that meeting.

The following form of resolution may be used in acting on the 2024 Budget:

> RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2024 as presented at this meeting.

ESTIMATED 2024 NEPOOL BUDGET COMPARED TO 2023 NEPOOL BUDGET AND 2023 PROJECTED ACTUAL EXPENSES

Line Items	2023 Approved Budget	2024 Proposed Budget	2023 Current Forecast
NEPOOL Counsel Fees (1)	$4,350,000	$4,350,000	$4,350,000
NEPOOL Counsel Disbursements (1)	$ 30,000	$ 30,000	$ 30,000
Independent Financial Advisor Fees and Disbursements (2)	$ 48,000	$ 48,000	$ 47,000
Committee Meeting Expenses (1)	$ 900,000	$ 920,000	$ 720,000
Generation Information System (4)	$1,022,400	$1,086,700	$1,022,000
Credit Insurance Premium (3)	$ 799,000	$ 578,800	$ 484,700
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (5)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$7,149,400	$7,013,500	$6,653,700
Revenue			
NEPOOL Membership Fees (3)	($2,300,000)	($2,300,000)	($2,300,000)
Generation Information System (4) (6)	($1,022,400)	($1,086,700)	($1,022,000)
Credit Insurance Premium (3) (7)	($ 799,000)	($ 578,800)	($ 484,700)
TOTAL REVENUE	($4,121,400)	($3,965,500)	($3,806,700)
TOTAL NEPOOL EXPENSES	**$3,028,000**	**$3,048,000**	**$2,847,000**

Notes

(1) 2024 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2024 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor, and reflects responsibility for reviewing meeting and travel expenses.

(3) 2024 proposed estimate provided by ISO New England Inc. ("ISO").

(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 2024 is projected to be $1,047,400 for three months and $1,099,700 for nine months. Estimate assumes NEPOOL will not exceed 520 development hours for changes to GIS, and any additional development hours would impose additional charges on NEPOOL.

(5) If NEPOOL determines that an audit should be performed in 2024, 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 Financial Assurance Policy. The 2023 sales figure that was estimated using future pricing turned out to be higher than the actual pricing for the 2023 policy period, resulting in a lower actual premium than projected in the 2023 NEPOOL Budget.

ESTIMATED BREAKDOWN OF PROJECTED 2024 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2024 figures assume no change in current NEPOOL membership)
(2023 figures as projected and budgeted at 2022 Annual Meeting)

CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS			
		2024	**2023**
A.	Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)	**5,348,000**	**5,000,000**
B.	Projected NEPOOL Membership Fees	**2,300,000**	**2,140,000**
C.	Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)	**3,048,000**	**2,860,000**
D.	Projected Amount to be paid by all Market Participant End Users (based on highest hourly load in any month in preceding calendar year) (figure used here for 2024 is based on 2023 peak loads of MPEU members)	**34,785**	**35,625**
E.	Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2024 is estimated amount based on 2023 membership data)	**84,526**	**72,834**
F.	[Reserved]	**0**	**0**
G.	Large Renewable Generation Sub-Sector Share (C-(D+E)) x RG%	**292,869**	**291,954**
H.	Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors ("Remaining Sectors") (C – (D+E+G))	**2,635,820**	**2,627,587**

CALCULATION OF SECTOR ALLOCATIONS			
		2024	**2023**
I.	Amount to be allocated to each of the Remaining Sectors (H ÷ 4)	**658,955**	**556,897**
J.	Total Amount paid by Related Person Suppliers (3 voting members) $(I \div s_y) \times rps_y$	**14,643**	**13,977**
K.	Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ((I x 2) + G – J)	**1,596,135**	**1,591,771**
L.	[Reserved]	**0**	**0**
M.	Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector, Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers $(K \div (g_y + (s_y - rps_y) + lrg_y))$	**10,102**	**9,887**
N.	Transmission Sector Share per full voting member $(I \div t_y)$	**109,826**	**109,483**
O.	[Reserved]	**0**	**0**
P.	Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)[i] $(I \div poe_y)$	**11,169**	**11,134**

ANNUAL VARIABLES			
		2024	**2023**
s_y	# Supplier Sector voting members	**135**	**141**
rps_y	# Supplier Sector Related Person Suppliers	**3**	**3**
g_y	# Generation Sector voting members	**15**	**12**
lrg_y	# AR Sector Large Renewable Generation Resource Providers	**11**	**11**
RG%	Lesser of (lrg_y*2%) or 10%	**10%**	**10%**
t_y	# Transmission Sector voting members	**6**	**6**
poe_y	# Publicly Owned Entity voting members	**59**	**59**

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: November 30, 2023

RE: Changes to ISO-NE Financial Assurance Policy: FCM Delivery Financial Assurance

At its December 7, 2023 meeting, the Participants Committee will be asked to consider changes to the ISO New England Financial Assurance Policy ("FAP") to update the provisions related to the FCM Delivery Financial Assurance requirements. The FAP changes are intended to better align the financial assurance required with respect to pay-for-performance penalties with the potential risk of non-payment of those penalties. The proposed changes to the FAP are included in Attachment 1 to this memorandum.

BACKGROUND

In response to the pay-for-performance defaults experienced in PJM in connection with Winter Storm Elliot and observations from the recent one-time extreme weather study on the operational impacts of extreme weather conducted by the ISO and EPRI, the ISO ran several stress tests to assess whether the pay-for-performance financial assurance requirements in the FAP would perform as expected in a longer duration Capacity Scarcity Condition and at higher pay-for-performance payment rates. The results indicated that moderate levels of financial assurance shortfalls could occur in those scenarios. As a result, the ISO determined that several changes should be made to the FAP to address those potential shortfalls.[1]

OVERVIEW OF FAP CHANGES

Currently, the FAP calculates a Market Participant's FCM Delivery Financial Assurance (which accounts for that Market Participant's risk of non-payment with respect to its Capacity Supply Obligations, including its pay-for-performance obligations) based on several factors, including a scaling factor that increases the financial assurance requirements in high risk summer and winter months to reflect the risk that losses may continue to accrue until a Market Participant closes out its Capacity Supply Obligation position. The attached changes would adjust those scaling factors to apply a higher scaling factor to the months of December, January and February, making each winter monthly scaling factor the same as a corresponding summer month's scaling factor. This change recognizes the increasing risk of capacity scarcity events in winter months.

Second, the FAP changes would shorten the time lag in calculating the Capacity Weighted Average Performance, or "CWAP" factor in the FCM Delivery Financial Assurance

[1] In addition to the FAP changes to be considered at the December 7 meeting, the ISO expects to propose credit scoring for generators in the Forward Capacity Market in the first quarter of 2024.

formula. CWAP reflects the assumed operating performance of a Market Participant during Capacity Scarcity Conditions and is based on the assumption that (1) the Market Participant's largest (or only) resource would be unavailable during those conditions and (2) all of its other resources would perform based on average historical data from the prior three Capacity Commitment Periods. The attached changes would also include performance of those resources in previous months of the current Capacity Commitment Period in the CWAP calculation.

Third, the FAP changes would add an "IMC," or intra-month collateral, factor to the FCM Delivery Financial Assurance formula to reflect estimated monthly capacity payments incurred during the current month. Currently, the formula does not include unsettled charges that occur within a month until the formula picks up those charges in the following month (within the "MCC" factor), creating unsecured exposure for those amounts. The attached changes correct that. At the November 28 meeting of the Budget and Finance Subcommittee ("B&F"), the ISO clarified that those estimated charges would be updated into the formula three days after publication of the most recent FCM Preliminary Capacity Score report on the Market Information Server, which is reflected in Attachment 1.

Finally, the FAP changes in Attachment 1 make conforming and clean-up changes, including deleting the reference to the discount factor that only applied to Capacity Commitment Periods ending prior to June 1, 2021. The ISO will update the instructional memo on its website regarding how Market Participants can calculate their FCM Delivery Financial Assurance after the FERC accepts the FAP changes.

The proposed changes to the FAP with respect to FCM Delivery Financial Assurance were discussed by the B&F Subcommittee at its September 26, October 30, and November 28 meetings. No Subcommittee member at those meetings objected to the proposed changes.

The following form of resolution may be used for Participants Committee action on the FAP changes:

> RESOLVED, that the Participants Committee supports the changes to the ISO New England Financial Assurance Policy related to the calculation of FCM Delivery Financial Assurance, as proposed by the ISO and as circulated to this Committee with the November 30, 2023 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

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

A. FCM Delivery Financial Assurance

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

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

Where:

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

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month and, for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server and shall be limited by the monthly stop loss as described in Section III.13.7.3.1 of Market Rule 1.

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

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

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

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

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

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

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

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

~~DF(discount factor) is a multiplier that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF shall equal 0.75; and thereafter, DF shall equal 1.00.~~

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not

OCTOBER 30, 2023

NEPOOL BUDGET & FINANCE COMMITTEE MEETING

Pay for Performance Financial Assurance

Updates to the Financial Assurance Policy (including redlines) regarding Pay-for-Performance penalties

Christopher Nolan

DIRECTOR MARKET AND CREDIT RISK

Joshua LaRoche

MARKET & CREDIT RISK ANALYTICS MANAGER

Contents of Presentation

The ISO plans to move forward with the filing of several updates to the financial assurance policy (FAP) regarding FCM Delivery FA

Executive Summary

- The ISO presented and discussed several recommended updates to the financial assurance policy with the Budget and Finance Committee last month regarding FCM Delivery FA (i.e., Pay-for-Performance Collateral)
- Currently, there are three recommended updates (Scaling Factor, Capacity Weighted Average Performance (CWAP) and Realized PFP Collateral Timing) which are planned to be filed during Q4 of 2023
- An additional update regarding Credit Scoring will be further discussed and developed during Q1 to Q2 of 2024
- This presentation focuses on discussing the detailed design of the first three updates (Scaling Factor, CWAP and Realized PFP Collateral Timing) including a review of the redlines to the FAP
- ISO-NE's goal is to request an effective date in Q1 of 2024 for the FAP rule changes in the ISO's FERC filing to revise the FAP
- FCM Delivery FA Instructional Memo on ISO website will reflect these new changes when effective

Contents of Presentation

The scaling factor takes into account the liquidation risk of a capacity supply obligation (CSO)

Scaling Factor Overview

- The scaling factor reflects the risk that losses may accrue against a CSO post default (up to the annual stop-loss) before a Market Participant is able to close-out the position
- The risk is not uniform across all months of the capacity commitment period as the risk of severe scarcity conditions is different in each month
- There are consecutive high-risk months during summer and winter
- If a resource defaults early in the summer / winter season, there is a risk it will accrue additional losses in subsequent months of that season due to the higher potential for additional capacity scarcity conditions
- Summer was considered the riskiest season followed by winter and then the shoulder months based on a review of historical data (2010-2013) at the time of filing the PFP collateral design

The scaling factors vary by month as the risk of capacity scarcity events occurring is uneven throughout the capacity commitment period

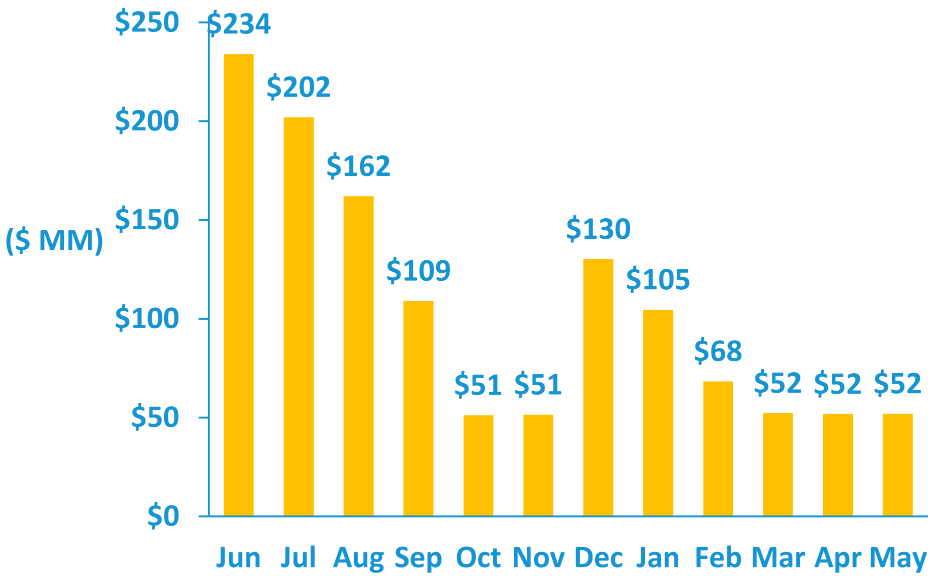
Scaling Factor versus FCM Delivery FA Methodology

DFAMW*PE*max[(ABR-CWAP), 0.1]*SF*DF - MCC	
Scaling Factor	Liquidation risk the risk that losses may continue to accrue against a Capacity Supply Obligation (CSO) position post default up to the annual stop-loss limit in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss Liquidation risk is addressed in the "SF," or "scaling factor," term included in the FCM Delivery FA formula. The scaling factor is a month-specific multiplier, as follows: • June: 2.000 • December and July: 1.732 • January and August: 1.414 • all other months: 1.000 The risk that losses may continue to accrue against a CSO position post default (up to the annual stop-loss limit) before a Market Participant is able to close the position is not uniform across all months of the Capacity Commitment Period. This risk exists because a defaulted CSO position is not terminated from the market. Rather, the Market Participant must close the position through a bilateral contract or continue to be exposed to charges up to the annual stop-loss limit

The scaling factors need to be updated to reflect the increasing risk of capacity scarcity events occurring during the winter

Rationale for Updating Scaling Factors

Average FCM Delivery FA Collateral 2018-2023



Current Scaling Factors	2	1.7	1.4	1	1	1	1.7	1.4	1	1	1	1

- Currently more collateral is held during the summer versus the winter due to the shape of the scaling factors which reflects the risk of capacity scarcity conditions occurring due to peak load risks

- The ISO's recent study on the operational impacts of extreme weather in New England indicates that the risk of capacity scarcity conditions during the winter linked to extreme weather is increasing

Increasing the scaling factors reduces the risk of collateral shortfalls during the winter season due to extreme weather

The ISO proposes the following language changes to the Financial Assurance Policy regarding the Scaling Factor (SF)

Proposed FAP Redlines (Scaling Factor)

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

June and December 2.000;

~~December and~~ July and January 1.732;

~~January and~~ August and February 1.414;

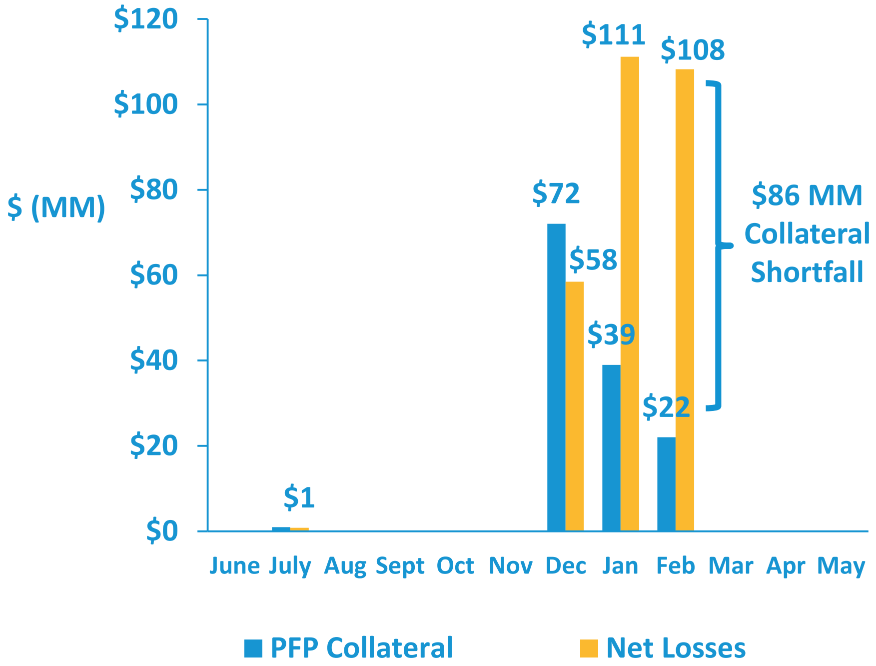
All other months 1.000.

Month	Current SF	Updated SF
June	2.000	2.000
July	1.732	1.732
August	1.414	1.414
September	1	1
October	1	1
November	1	1
December	1.732	2.000
January	1.414	1.732
February	1	1.414
March	1	1
April	1	1
May	1	1

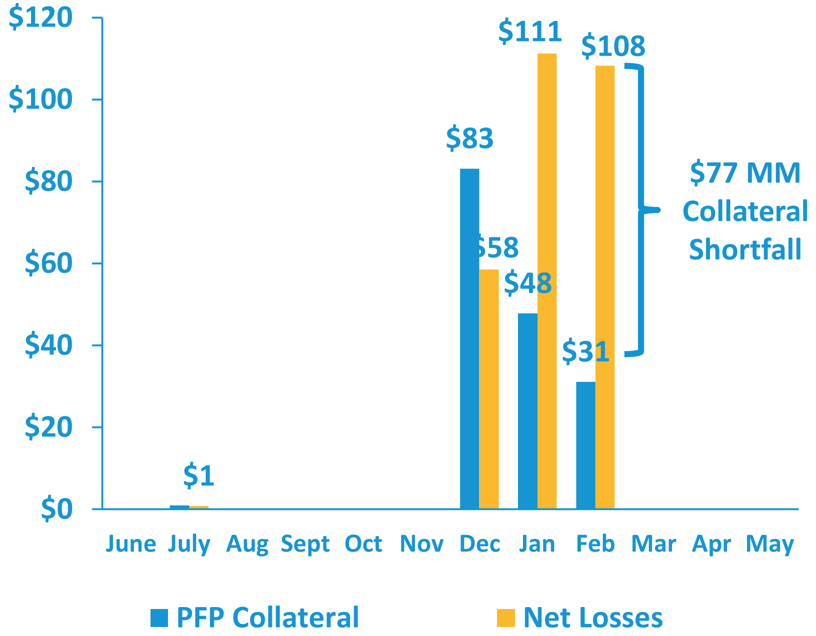
The collateral shortfall in February drops by $9 MM from $86 MM to $77 MM after adjusting the scaling factors under the base case scenario

Impact Analysis of Scaling Factor Update

Base Case Stress Scenario[(1)]



Scaling Factor Updated[(1)]



1) CCP 2025-26 CSO Portfolio

The SF update reduces collateral shortfalls to $63 MM and $77 MM during January and February, respectively

Impact Analysis of Methodology Updates

	Collateral Shortfall Scenarios ($ MM)			
	Base Case Stress Scenario	Scaling Factor Updated	CWAP Updated	SF & CWAP Updated
July	$0	$0	$0	$0
December	$0	$0	$0	$0
January	$72	$63	$44	$29
February	$86	$77	$50	$26

Contents of Presentation

The methodology relies heavily upon assumptions regarding a resource's historical performance (CWAP) addressing operating risk

Capacity Weighted Average Performance Overview

- CWAP looks at the operating performance of Market Participants during capacity scarcity conditions (CSCs) occurring in the prior three capacity commitment periods on a weighted average basis
- Single plant resources are assumed to be fully off-line during CSCs
- A Market Participant with multiple resources is assumed to perform based on its weighted average performance during the prior three capacity commitment period
- A Market Participant with multiple resources generally posts relatively less collateral if its historical operating performance is higher than its assumed slice of system obligations
- Conversely, a Market Participant with multiple resources is required to post relatively more collateral if its historical operating performance is lower than its assumed slice of system obligations

CWAP reflects the assumed operating performance of a Market Participant during capacity scarcity conditions in the methodology

CWAP versus FCM Delivery FA Methodology

DFAMW*PE*max[(ABR-CWAP), 0.1]*SF*DF - MCC	
CWAP	It is addressed in this part of the formula “DFAMW × PE × max[(ABR – CWAP), 0.1)]” The “DFAMW” term represents the MW amount on which a Market Participant must submit FCM Delivery FA “PE” is the dollar per MW value that will apply in calculating the Market Participant’s FCM Delivery FA; “Max[(ABR – CWAP), 0.1]” is a ratio reflecting the performance of the Market Participant’s capacity resources

The ISO is under-collateralized in scenarios when actual operating performance is lower than its expected “CWAP” versus its slice of system obligation

Collateral is posted based on the assumption that each participant's largest (or only) resource is unavailable during scarcity conditions; remaining resources assumed to perform per average historical data

CWAP versus FCM Delivery FA Methodology (Continued)

CWAP Assumptions

Resource Type	Default Performance Assumption (CWAP)
Single / Largest Plant Resource in Portfolio	0.00
Gas	0.90
Coal	0.85
Oil	0.65
Other (Solar, Wind etc.)	1.00

CSO Volumes CCP 25-26

Resource Diversification	MW	% of Total
Single Plant Resource	4,875	15%
Multi-Plant Largest Resource	11,147	35%
Multi-Plant 2nd Largest Resource	6,717	21%
Multi-Plant Rest (3rd, 4th)	9,458	29%
	32,197	100%

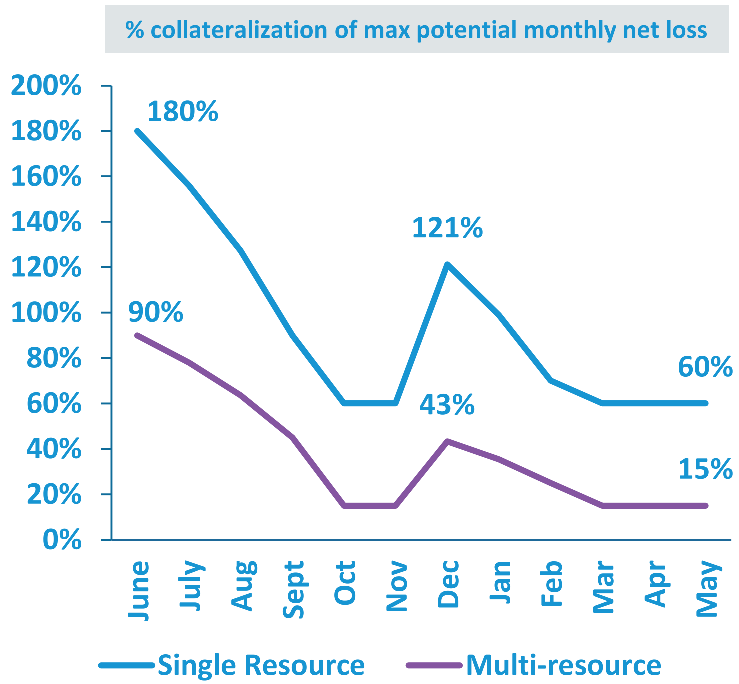
- 50% of CSO volume is from participants largest/only resource and collateral is collected assuming this volume is unavailable
- For the remaining volumes, collateral is collected assuming these resources perform in line with weighted average historical performance data looking back the three prior seasons (e.g. the last three winters)

Assuming further resources (e.g. 2nd largest in portfolio) fail would overestimate the degree to which a Market Participant is exposed to potential penalties

Collateral shortfalls occur if the actual operating performance during capacity scarcity conditions of multi-resource portfolios is lower than the historical performance data used in the collateral calculations

Collateralization of Maximum Monthly Potential Net Losses

100 MW CSO CCP 2025-26[1,2]



- Per the collateralization methodology, ISO-NE holds the highest amount of collateral against Market Participants that have just one resource due to concerns about operational risk during capacity scarcity conditions
- As operational risk is diversified with Market Participants that have multiple plants in their portfolios, the methodology calls for relatively less collateral as it assumes some plants in the portfolio operate per recent historical operating performance data

1) For single resources, the collateral requirement is based on the entire resource being unavailable during the scarcity event
2) Multi-resource Market Participant based on 2 gas plants with 50 MW CSO per plant and assumes 50 MW is experiencing an outage and the other 50 MW operates per its weight average performance

It is prudent to shorten the current time-lag between demonstrating weak operating performance and using that fresh performance data in collateral calculations for multi-resource portfolios

Rationale for Updating CWAP

- CWAP assumptions for multi-resource Market Participants are currently updated at the start of a new CCP with actual performance data demonstrated during scarcity conditions (if any) during the applicable seasons of the three prior CCPs
- For example actual performance data applied in the CWAP metric demonstrated during the summers of CCP 22-23, 23-24 & 24-25 are used in summer collateral calculations for CCP 25-26
- Performance scores are typically available ~4-5 business days after capacity scarcity conditions occur which therefore can be incorporated (on a weighted basis) sooner into the CWAP metric calculations in order to increase collateral requirements against underperforming generators during the current season

The additional application of operating performance data from the current CCP season mitigates the risk of collateral shortfalls with poorly performing generators

The ISO proposes the following language change to Financial Assurance Policy regarding Capacity Weighted Average Performance

FAP Redlines (CWAP)

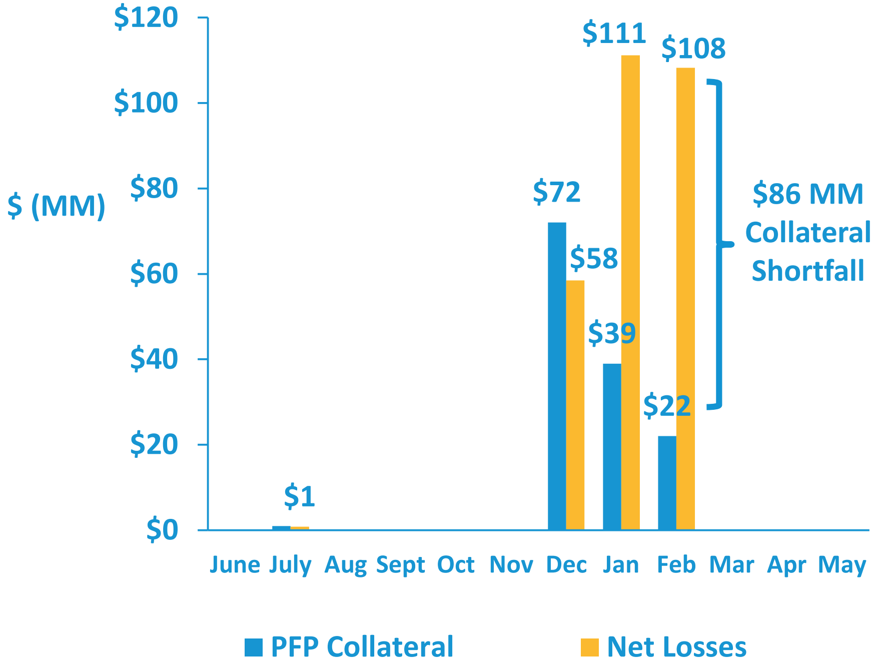
CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of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

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

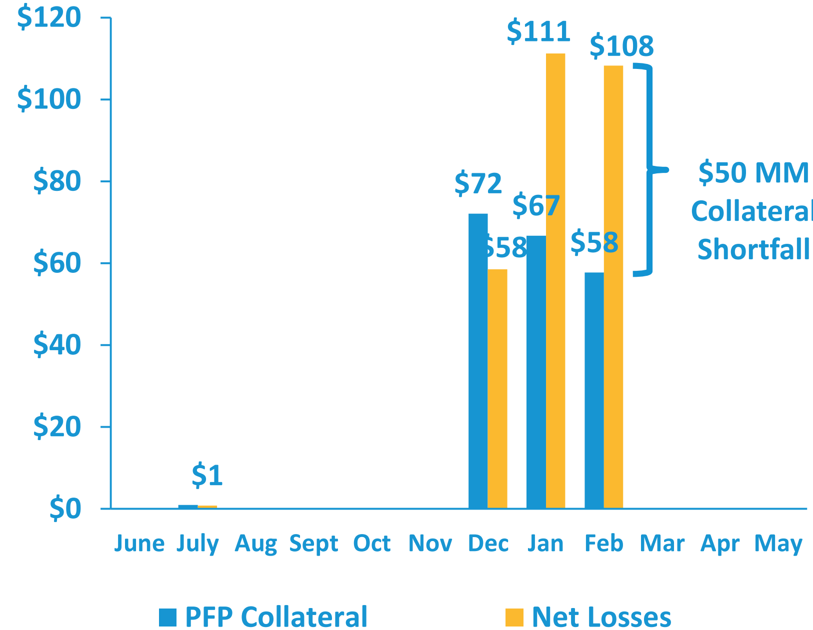
The collateral shortfall in February drops by $36 MM from $86 MM to $50 MM due to the updated CWAP methodology

Impact Analysis of CWAP Update

Base Case Stress Scenario(1)



CWAP Updated(1)



1) CCP 2025-26 CSO Portfolio

The updated CWAP methodology reduces collateral shortfalls to $44 MM and $50 MM for January and February under the base case scenario

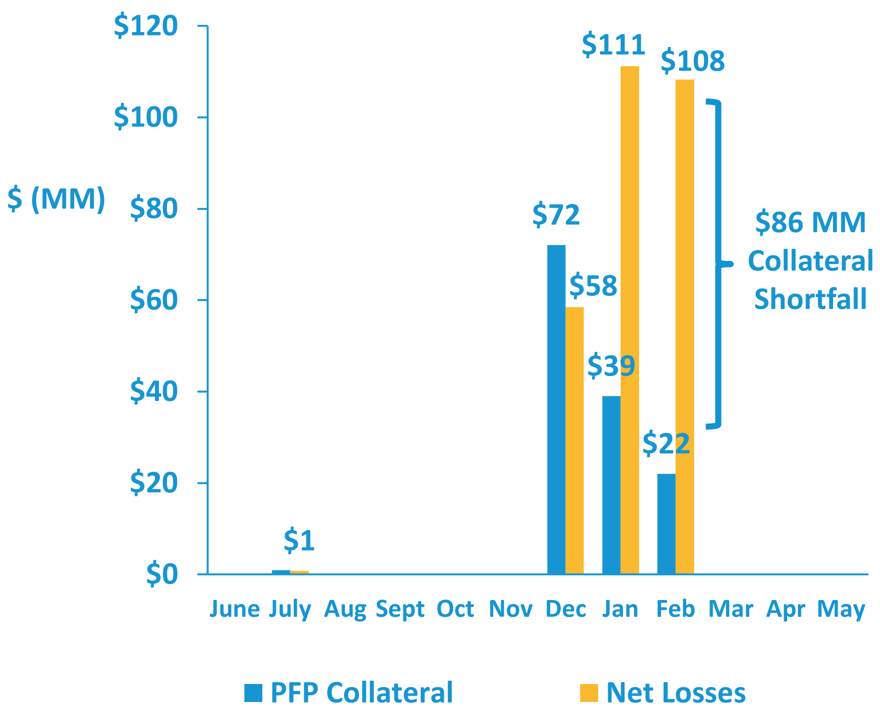
Impact Analysis of Methodology Updates

	Collateral Shortfall Scenarios ($ MM)			
	Base Case Stress Scenario	Scaling Factor Updated	CWAP Updated	SF & CWAP Updated
July	$0	$0	$0	$0
December	$0	$0	$0	$0
January	$72	$63	$44	$29
February	$86	$77	$50	$26

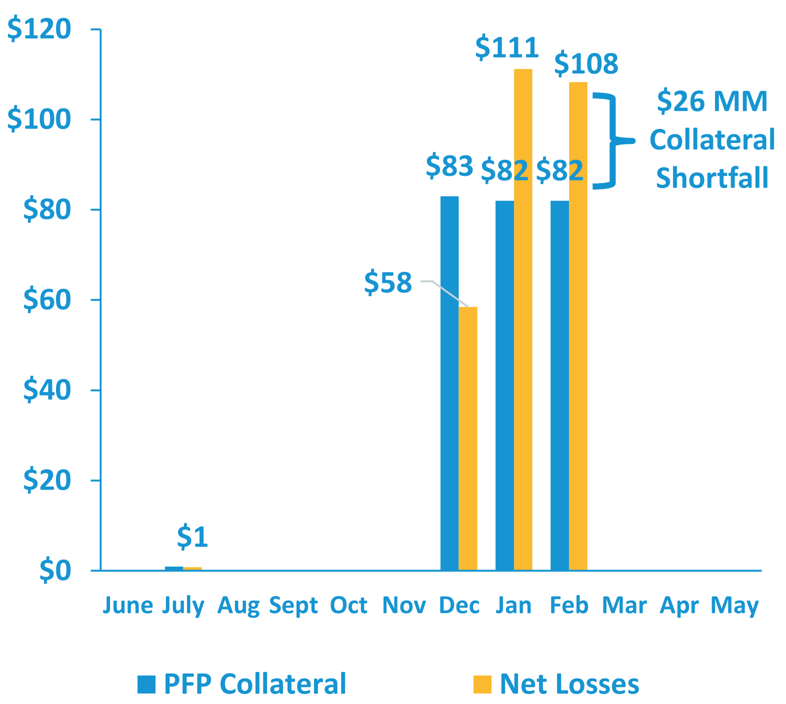
Overall the collateral shortfall drops from ~$86 MM to ~$26 MM in February by applying both the new CWAP and SF updates

Impact Analysis of Combined SF & CWAP Updates

Base Case Stress Scenario[1]



SF & CWAP Updated[1]



1) CCP 2025-26 CSO Portfolio

The SF and CWAP updates when combined reduce collateral shortfalls to a reasonable level (as they are multiplicative)

Impact Analysis of Methodology Updates

	Collateral Shortfall Scenarios ($ MM)			
	Base Case Stress Scenario	Scaling Factor Updated	CWAP Updated	SF & CWAP Updated
July	$0	$0	$0	$0
December	$0	$0	$0	$0
January	$72	$63	$44	$29
February	$86	$77	$50	$26

Contents of Presentation

Monthly capacity charges (MCC) are included in the FCM delivery FA methodology to address clearing risk

Monthly Capacity Charge Overview

- Provisional operating performance scores are available in the Market Participant MIS reports usually 5-6 business days after capacity scarcity conditions have occurred
- The performance scores are used to calculate the provisional capacity performance bonus / penalty payments which are then included in the monthly capacity charge
- The provisional capacity performance bonus / penalty payments are included in MCC as of the 1st of the following month after which they occur
- MCC goes to zero upon settlement of the invoice (the 10th business day of the month)
- MCC temporarily reduces / increases collateral requirements reflecting bonus / penalty payments, respectively
- Overall, there can be a time-lag of up to approximately 22 days between when provisional capacity performance bonus / penalty payments can be calculated and when collateral increases / decreases to reflect that credit exposure

The monthly capacity charges (MCC) can temporarily increase or decrease collateral requirements until the payments are settled

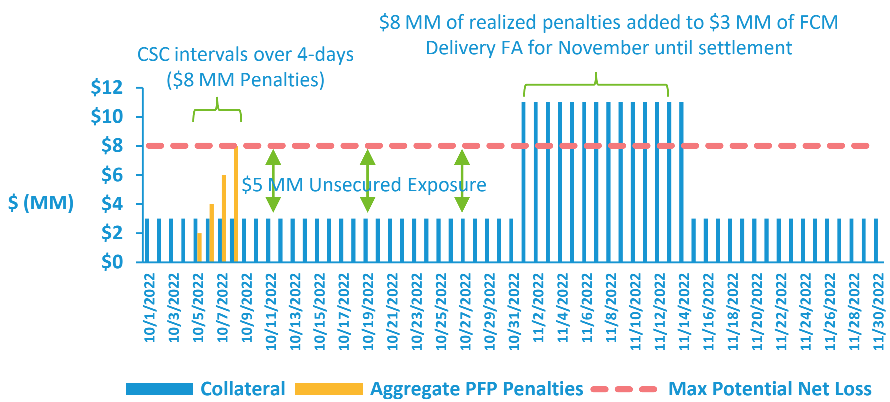
MCC versus FCM Delivery FA Methodology

DFAMW*PE*max[(ABR-CWAP), 0.1]*SF*DF - MCC	
MCC	Clearing risk is where a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month “MCC” - The monthly capacity charge (“MCC”) factor addresses clearing risk. It includes the performance payments (bonus / penalty) after a capacity scarcity event occurs

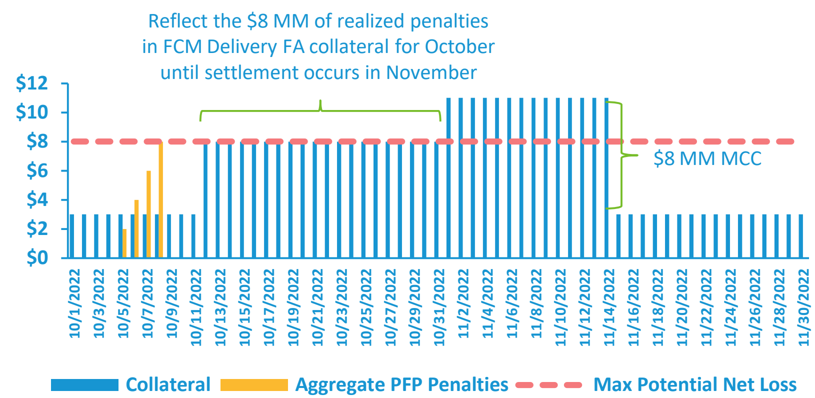
ISO considers it sensible to reduce the time-period during which it has unsecured exposure to realized penalty payment obligations of Market Participants during the current delivery month

Rationale for Updating Collateral Posting Timing

Current Methodology Example



Revised Methodology Example[1]



- Under the current methodology, the ISO has unsecured credit exposure of $5 MM to realized payment penalties incurred during October (i.e. total incurred penalties of $8 MM versus collateral of $3 MM) in the example above until 1st of following month (November) when they're reflected in the MCC (monthly capacity charge) value

- In the revised methodology, the ISO requires additional collateral of $5 MM during October to cover the unsecured exposure. The $8 MM in penalties are subsequently collateralized via the MCC value in November until they're settled

1) Assumes no capacity scarcity conditions occurred during prior month (Sept) and scaling factor is 1 as it's a shoulder month

The ISO proposes the following language change to Financial Assurance Policy to address clearing risks using a new financial assurance value called Intra-Month Collateral (IMC)

FAP Redlines (IMC)

A. FCM Delivery Financial Assurance

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

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

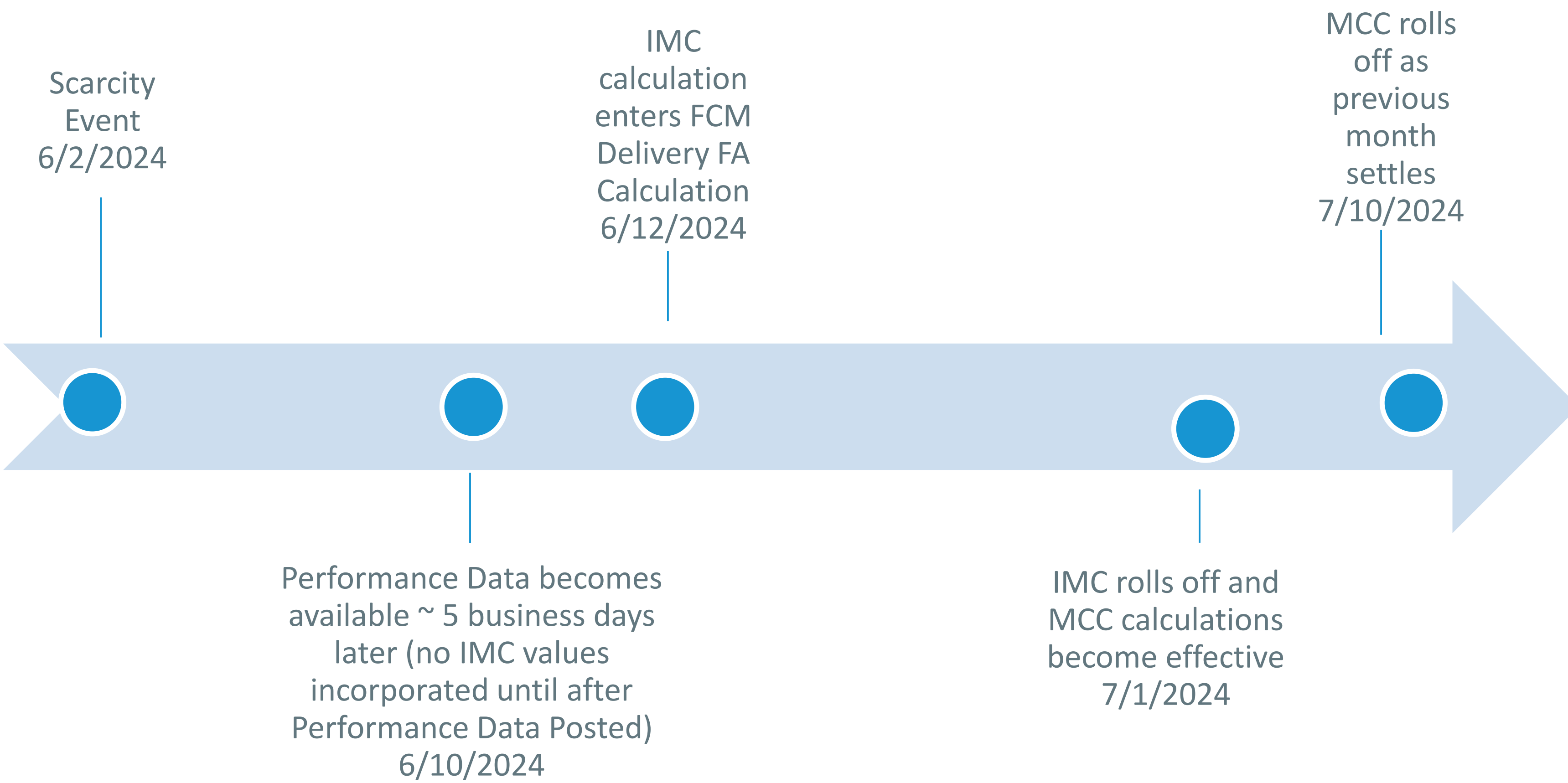
Where:

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

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month. The IMC shall be estimated from the first day of the current delivery month until the end of the current delivery month and limited by the monthly stop loss as described in Section III.13.7.3.1 of Market Rule 1.

Intra-month collateral (IMC) posting requirements reduces the time period during which the ISO has potential exposure to unsecured realized payment penalties during the current delivery month

Realized Penalties Collateralization Timeline



Contents of Presentation

There are several conforming and clean-up changes which are also included in the revision to FAP

Conforming and Clean-up Changes to FAP

Discount Factor	Explanation
• Deletion of "DF – Discount Factor" in FCM Delivery FA formula ~~DF(discount factor) is a multiplier that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF shall equal 0.75; and thereafter, DF shall equal 1.00.~~	Deleted as it is set to 1 from May 31, 2021 onwards and therefore has no impact on collateral requirements

Conforming and Clean-up Changes to FAP (continued)

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

Conforming and Clean-up Changes to FAP (continued)

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

Contents of Presentation

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
B&F Committee October 30, 2023	Present and discuss proposed FAP revisions - Scaling Factor, CWAP, and Realized PFP Collateral Timing - Completed
Participants Committee December 7, 2023	Vote on Scaling Factor, CWAP, and Realized PFP Collateral Timing
Effective Date	Expected March, 2024

Contents of Presentation

ISO's PFP collateral methodology is formally called FCM Delivery FA in the FAP

PFP Collateral Methodology

DFAMW*PE*max[(ABR-CWAP), 0.1]*SF*DF – MCC	
DFAMW (Delivery Financial Assurance MW)	The sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss
PE (Potential Exposure)	PE is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss
ABR (Average Balancing Ratio)	The duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period. Generally reflects participant's slice of system obligation
CWAP (Capacity Weighted Average Performance)	Historical performance assumption for various resource types (assumes largest / only resource is offline during CSC events) applied on a weighted average basis per season; excludes resources that have reached the annual stop loss
SF (Scaling Factor)	Square root of remaining months in season reflecting seasonality risk
DF (Discount Factor)	1
MCC (Monthly Capacity Charge)	Reflects monthly revenues generated or payments that have been incurred but not yet billed. MCC is estimated from the first day of the current delivery month until it is replaced by the settled value (bonus / penalty payments)

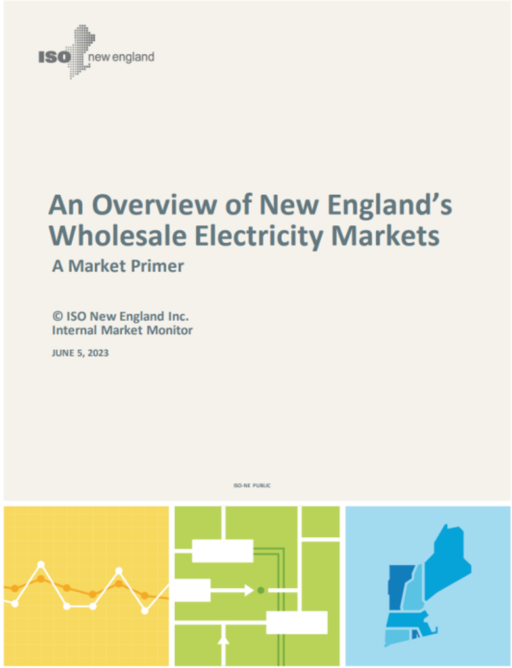
Annual Markets Report on 2022

Report Highlights

Dave Naughton

EXECUTIVE DIRECTOR, INTERNAL MARKET MONITOR

Two annual publications: Annual Markets Report and accompanying Market Primer



Feedback welcome and appreciated!

Email: dnaughton@iso-ne.com

Key Takeaways

1. Capacity, energy, and ancillary service markets generally performed well and exhibited competitive outcomes
   - Energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix

2. Energy costs ($11.7 bn) drove an overall increase in wholesale costs ($16.7 bn) due to high natural gas prices [slide 6]
   - Highest natural gas prices ($9.32/MMBtu) since 2008, driven by a combination of international events and a higher New England winter basis [slide 7]
   - Energy prices ($86/MWh) were the highest since 2003, energy costs highest since 2008

3. Moderate increase in load; the long-term trend of decreasing load may have reached an inflection point [slide 10]

4. Net interchange continued to decrease [slide 13]; imports also down in the most recent annual capacity auction [slide 27]

Key Takeaways (Cont.)

6. Energy market price formation is generally robust; relatively low uplift (NCPC) and low amount of out-of-market commitments in 2022 [slides 16 -19]
   – However, we recommend a review of reserve pricing mechanics under the fast start pricing rules [slide 19]

7. Stable levels of structural market power and low energy offer mitigation
   – Economic withholding metrics indicate small price and quantity impacts of withholding
   – However, it is appropriate to review certain aspects of the mitigation rules; multiple recommendations contained in the report [slide 23-24]
   – Upward mitigation event on December 24, 2022 highlighted a number of further areas for potential improvement

8. Structural market power is a concern in the Forward Reserve Auction (FRA) [slide 25]
   – Recently recommended a review of the FRA offer/price cap (see spring 2023 quarterly report)

9. Low capacity prices reflect surplus supply conditions; older fossil-fuel generator exits with renewable and battery resource entry [slides 26 to 28]

Highlights Data

	2018	2019	2020	2021	2022	% Change '22 to '21	Sparkline
Demand (MW)							
Load (avg. hourly)	14,095	13,614	13,309	13,566	13,576	0%	
Weather-normalized load (avg. hourly)[a]	13,725	13,558	13,279	13,419	13,472	0%	
Peak load (MW)	26,024	24,361	25,121	25,801	24,780	-4%	
Generation Fuel Costs ($/MWh) [b]							
Natural Gas	38.72	25.48	16.34	36.07	72.57	101%	
Coal	54.52	40.58	37.82	67.77	144.87	114%	
No.6 Oil	127.73	130.89	89.42	138.21	221.17	60%	
Diesel	187.55	173.55	112.07	184.50	331.99	80%	
Hub Electricity Prices: LMPs ($/MWh)							
Day-ahead (simple avg.)	44.14	31.22	23.31	45.92	85.56	86%	
Real-time (simple avg.)	43.54	30.67	23.37	44.84	84.92	89%	
Day-ahead (load-weighted avg.)	46.88	32.82	24.57	48.30	91.36	89%	
Real-time (load-weighted avg.)	46.85	32.32	24.79	47.34	91.07	92%	
Estimated Wholesale Costs ($ billions)							
Energy	6.0	4.1	3.0	6.1	11.7	92%	
Capacity	3.6	3.4	2.7	2.3	2.0	-11%	
Uplift (NCPC)	0.07	0.03	0.03	0.04	0.05	49%	
Ancillary Services	0.1	0.1	0.1	0.1	0.1	127%	
Regional Network Load Costs	2.3	2.2	2.4	2.7	2.8	2%	
Total Wholesale Costs	**12.1**	**9.8**	**8.1**	**11.2**	**16.7**	**49%**	
Supply Mix [c]							
Natural Gas	40%	39%	42%	45%	45%	0%	
Nuclear	25%	25%	22%	22%	23%	0%	
Imports	17%	19%	20%	16%	14%	-2%	
Hydro	7%	7%	7%	6%	6%	0%	
Other[d]	5%	5%	5%	5%	4%	-1%	
Wind	3%	3%	3%	3%	3%	0%	
Solar	1%	1%	2%	2%	3%	0.8%	
Coal	1%	0%	0%	0%	0.3%	-0.20%	
Oil	1%	0%	0%	0%	1.5%	1.34%	

Average energy demand comparable to 2021 due to similar average weather conditions.

Prices of all major fuels increased.

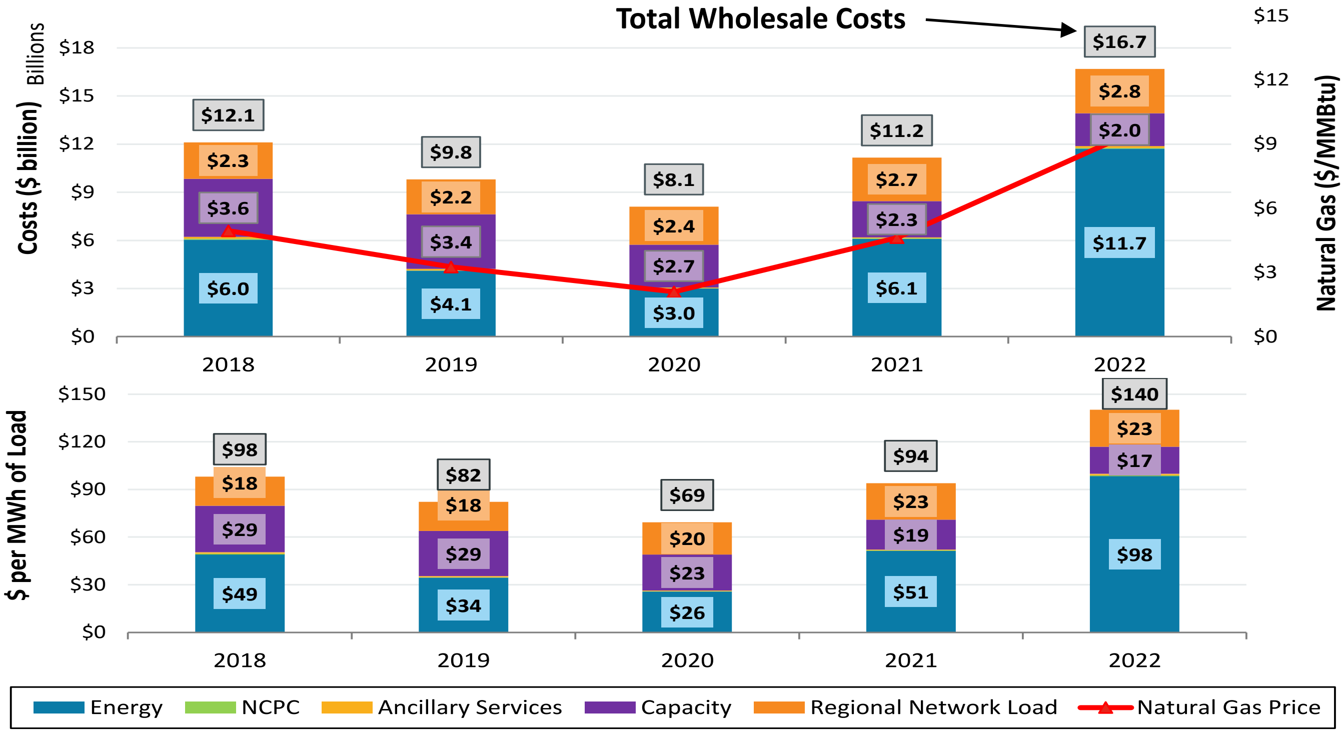
Simple- and load-weighted avg. LMPs up significantly, but not as much as the increase in gas prices. Upward pressure of natural gas on energy costs was partially offset by relatively cheaper oil prices during winter cold spells.

Energy comprised 70% of wholesale costs. Increases in all wholesale cost categories, with the exception of capacity costs.

Reduction in avg. net imports (by 231 MW per hour), mostly over the NY North interface. Increase in oil generation (by 185 MW per hour) due to oil generators being in-merit in the winter.

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] Capacity cost in 2022 includes the Mystic cost-of-service costs of $0.17 billion.
[d] Provides a breakdown of total supply, which includes net imports. Note that section 2 provides a breakdown of native supply only.
[e] The "Other" fuel category includes landfill gas, methane, refuse and steam

Increase in wholesale costs driven by high energy and natural gas prices

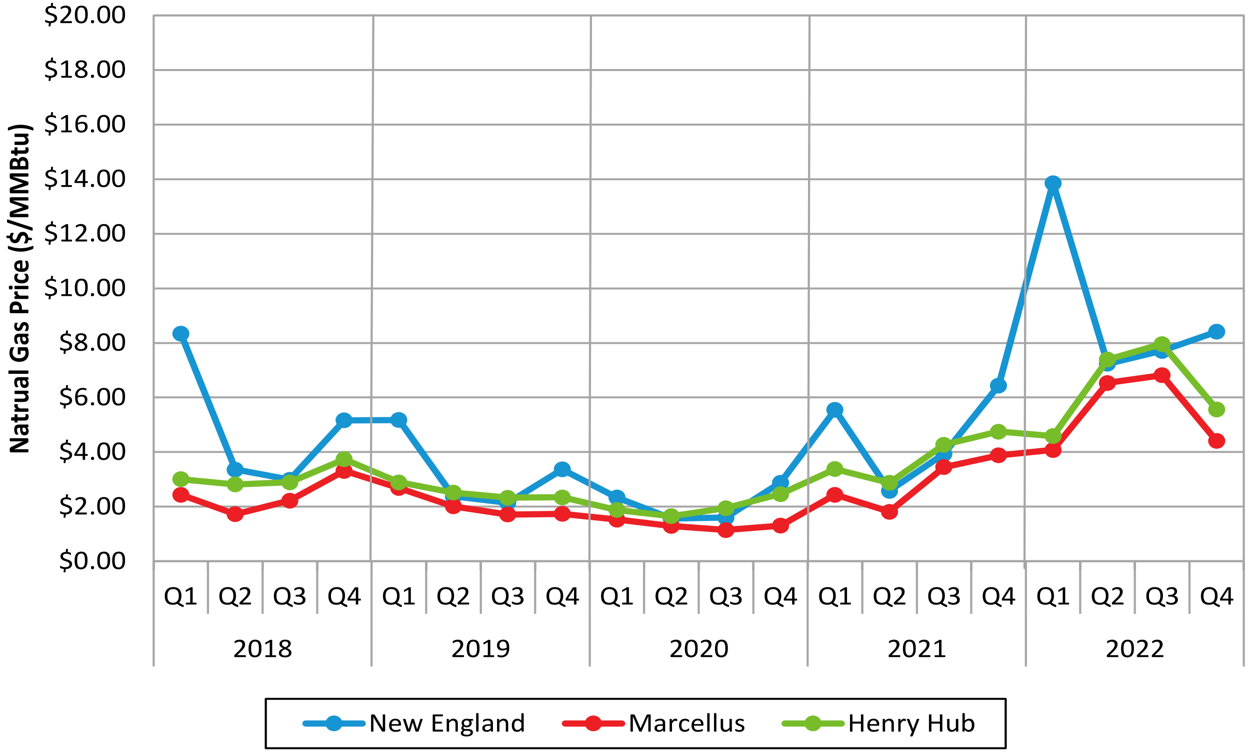


Energy costs at highest dollar level since 2008, making up over 70% of total wholesale costs. 98% of energy costs arose in the day-ahead energy market.

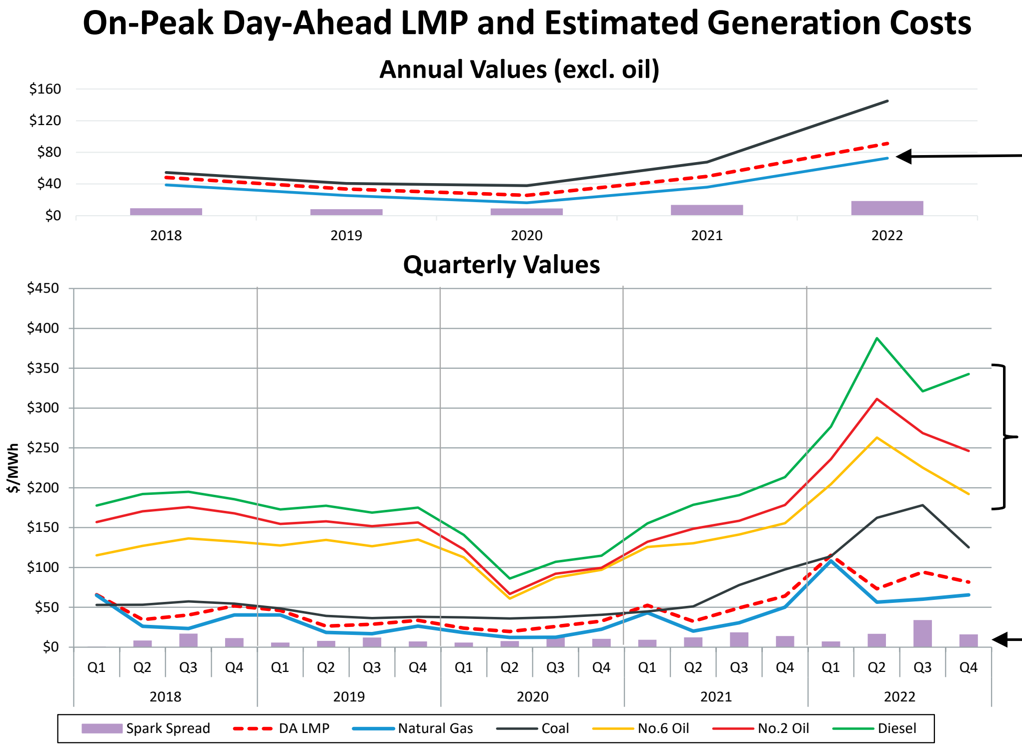
Capacity costs reflect auction prices from FCAs 12 & 13, comprising 12% of total costs. Costs will continue to decline over the next 4 years, down to ~$1 billion [slide 21].

Note: 2022 capacity cost total includes supplemental payments of $166 million under the Mystic Cost of Service agreement.

High natural gas prices driven by international events, national and New England market conditions



Highest annual average energy price since 2003, driven by high natural gas prices

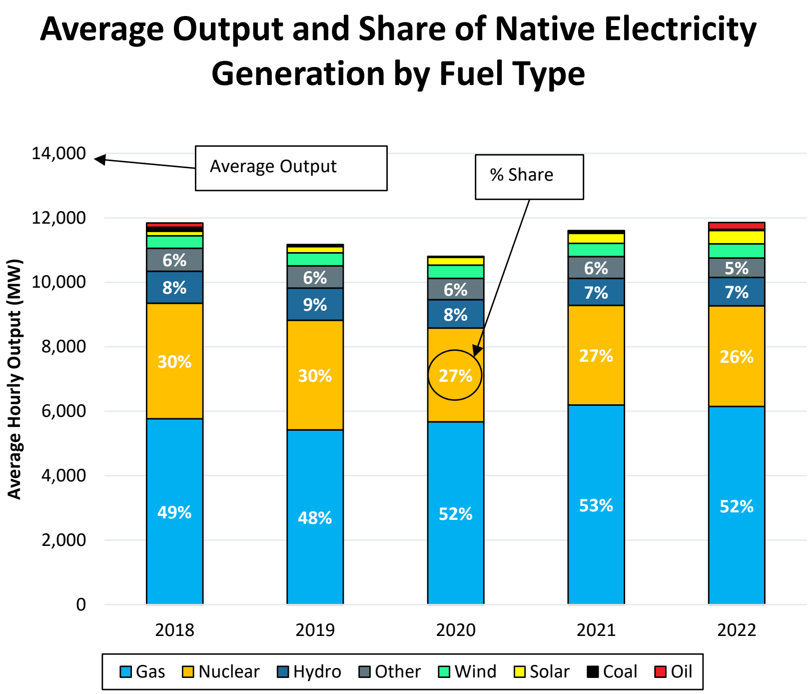


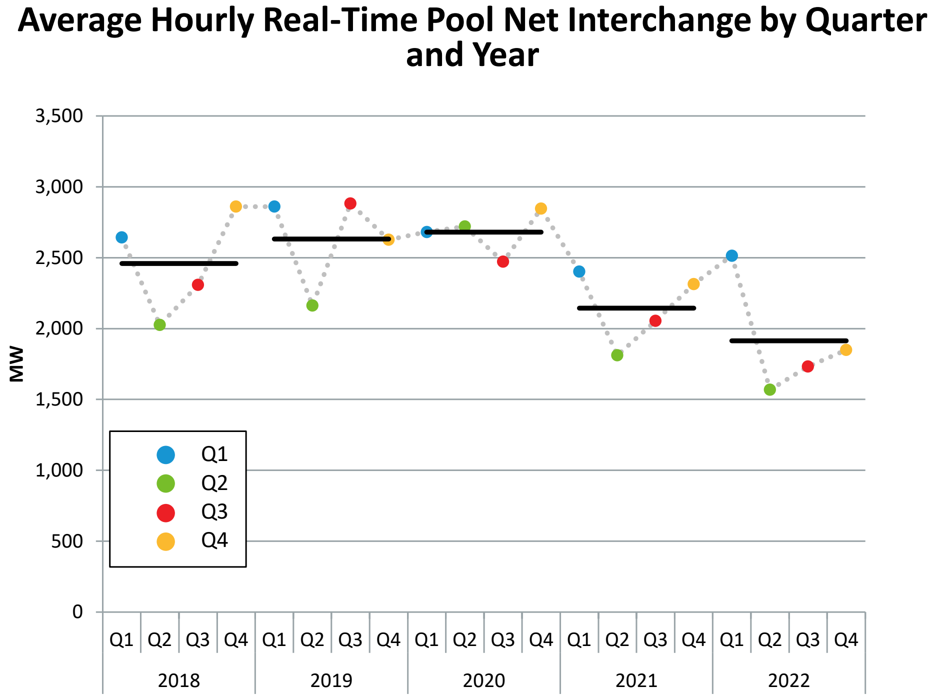
Highest annual natural gas price since 2008.

Oil prices up but lower than natural gas frequently during Q1, increasing oil generation and attenuating upward pressure of extremely high gas prices on energy prices.

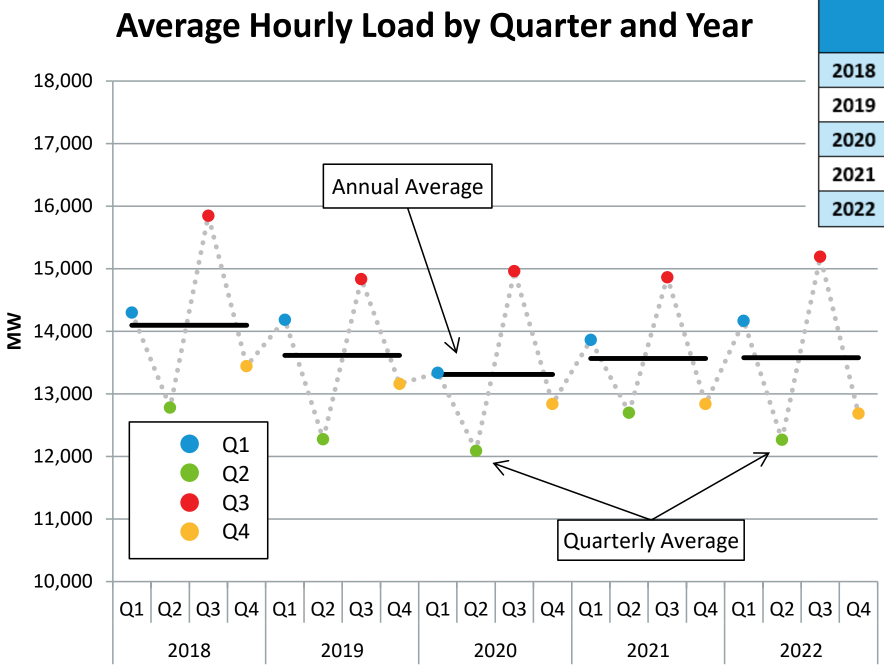
Profitability indices/metrics up on higher gas prices [see Slide 12]

Increase in native generation balanced out a reduction in net imports



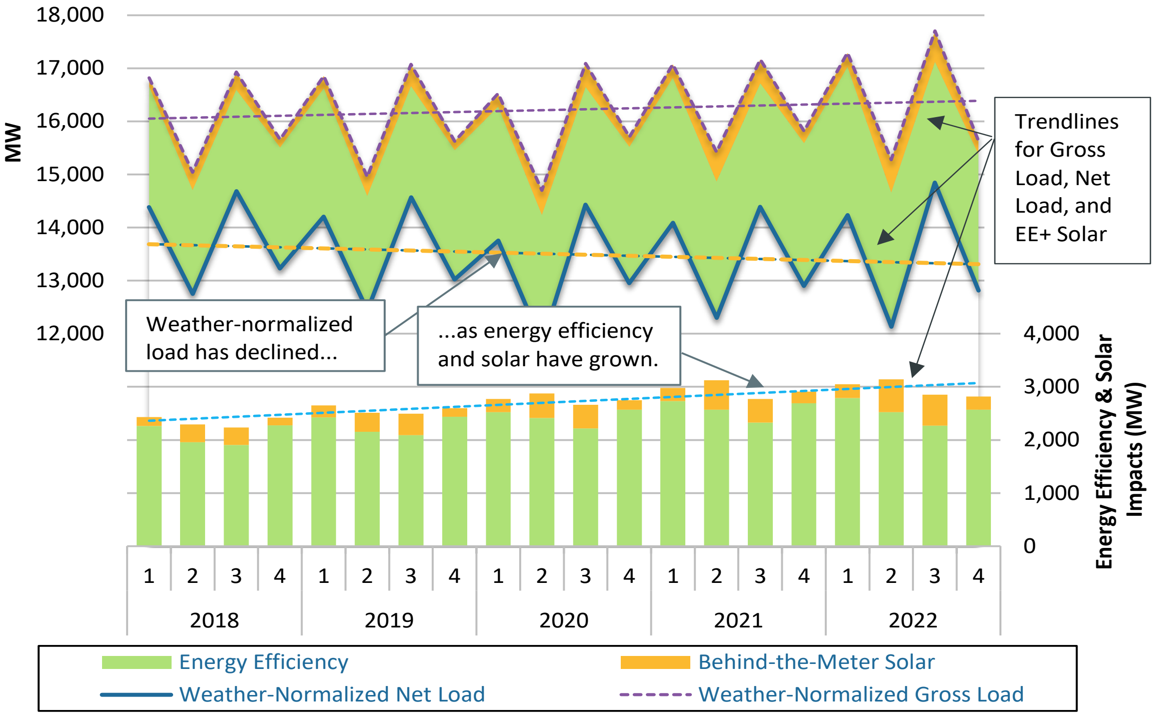


Similar average weather conditions resulted in comparable average wholesale energy demand to 2021



Year	Load (GWh)	Average Hourly Load (MW)	Peak Load (MW)	Weather Normalized Load (GWh)	Average Hourly Weather Normalized Load (MW)
2018	123,472	14,095	26,024	120,560	13,762
2019	119,235	13,614	24,361	118,772	13,558
2020	116,874	13,309	25,121	116,322	13,242
2021	118,758	13,565	25,801	117,551	13,419
2022	118,874	13,576	24,780	118,337	13,508

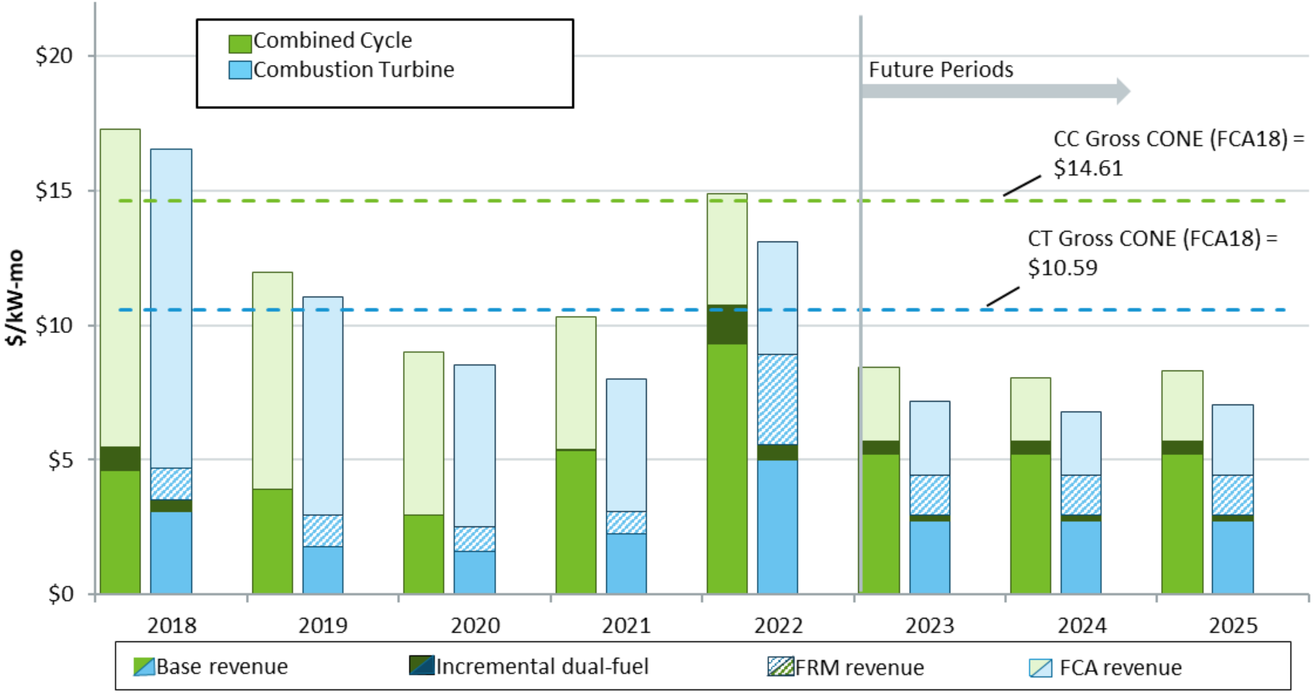
Energy efficiency and behind-the-meter solar have significant impacts on reducing wholesale demand



Behind-the-meter solar generation reduced (weather-normalized) load by 426 MW (by ~3%) or nearly 14% of estimated installed capacity (3,170 MW), a 15% increase (57 MW) compared to 2021.

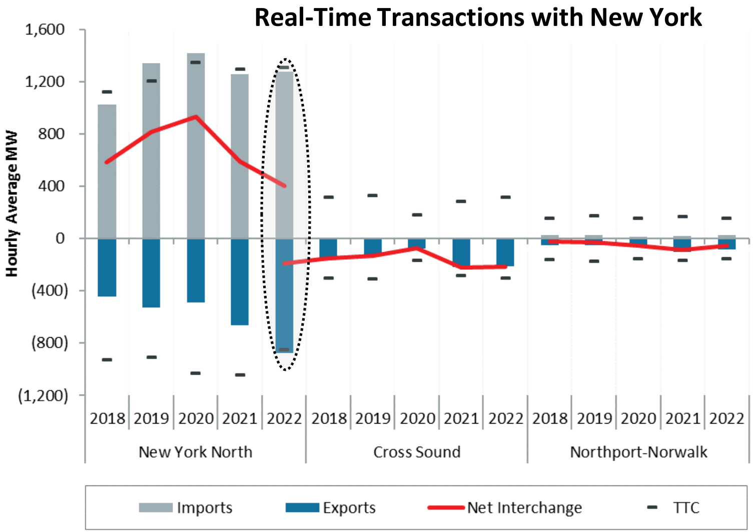
Energy efficiency reduced annual average load by an estimated 2,538 MW, a 2% decrease (40 MW) compared to 2021.

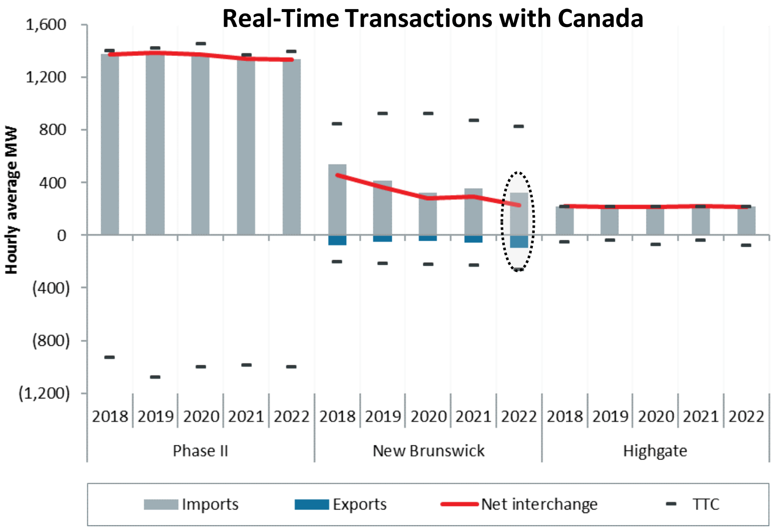
Natural gas generator profitability metrics up on higher gas prices



Lower net imports at the New York North (down 189 MW) and New Brunswick (down 68 MW) interfaces

New England was a net importer of 1,914 MW per hour in 2022, meeting 14% of load. Canadian net imports totaled 1,781 MW (similar to 2021), while New York net imports totaled 133 MW (down by 152 MW).



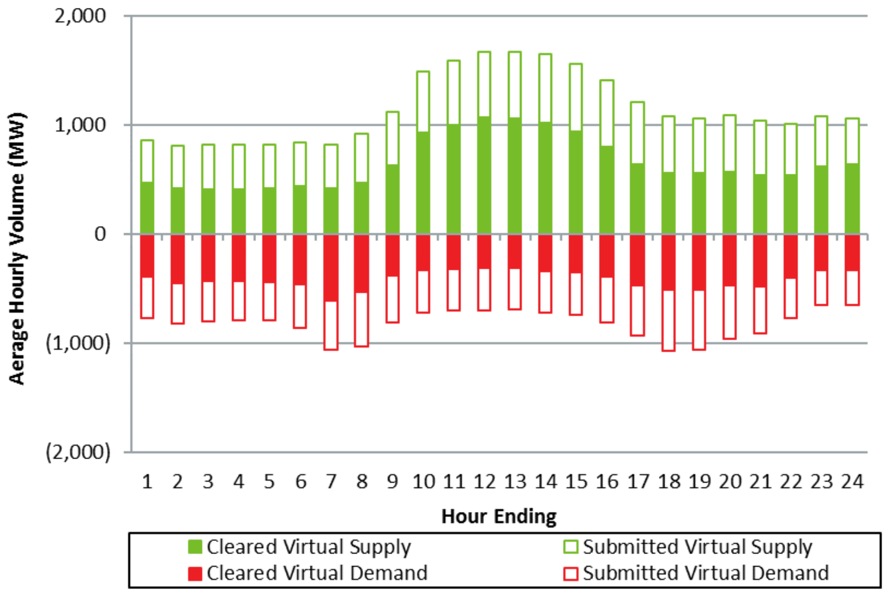


Cleared import transactions with New York were comparable to 2021, but real-time exports increased by 31% (or 209 MW). The increase in exports was due to increased congestion and higher prices in Eastern New York.

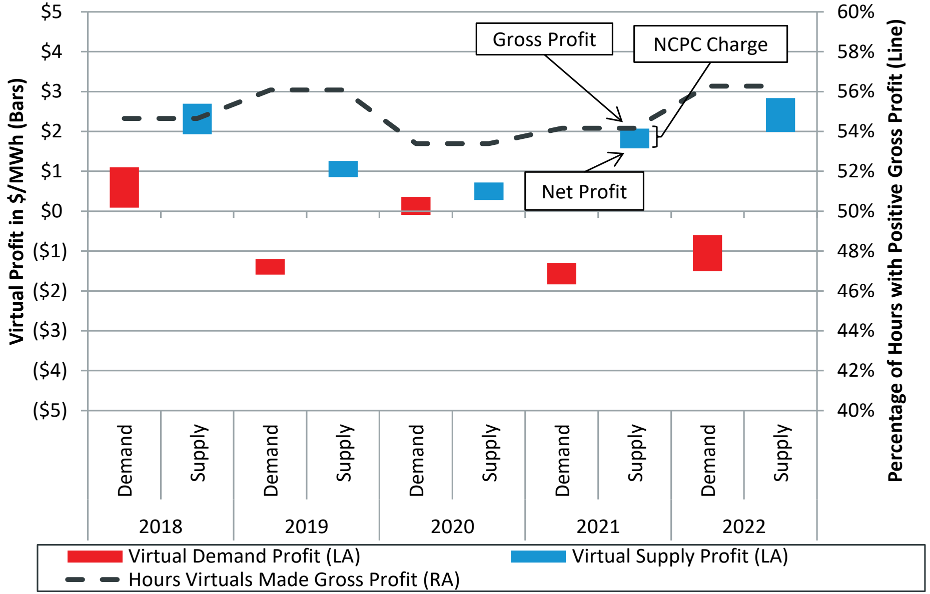
New England continues to import significantly more power from Canada than it does from New York. In 2022, a 660-MW New Brunswick nuclear generator had an extended outage, resulting in decreased imports and increased exports over the interface.

More virtual supply cleared during middle part of the day, coincident with higher solar output; profitable overall

Volume



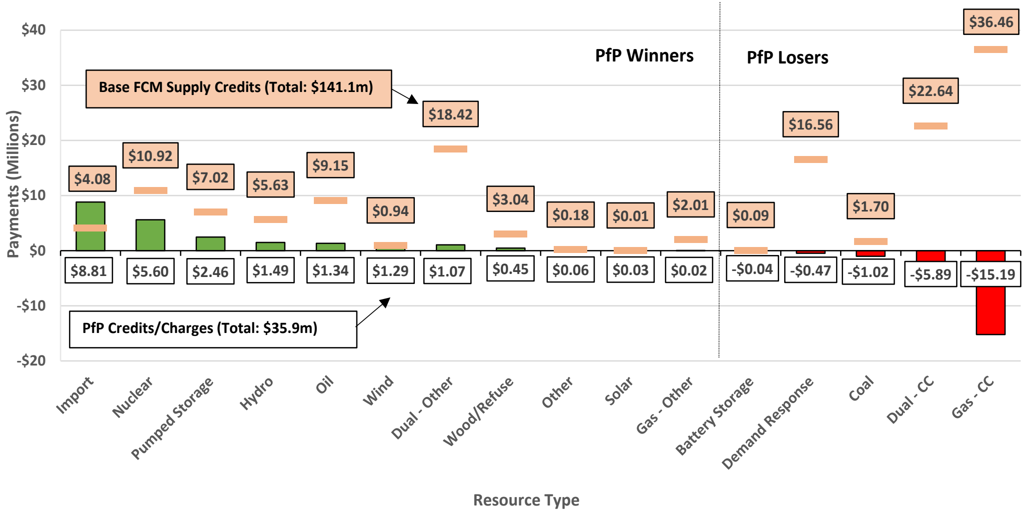
Profitability



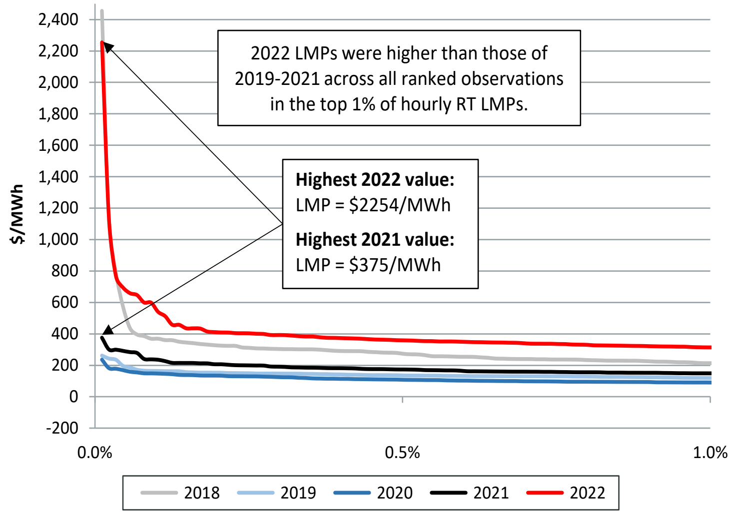
We continue to recommend a review of NCPC allocation rules to virtual transactions (recommendation 2010-1)

No major reliability issues in 2022; Dec. 24 saw first capacity scarcity condition for approx. 1½ hours

Total PfP Payments by Resource Type (December 2022)

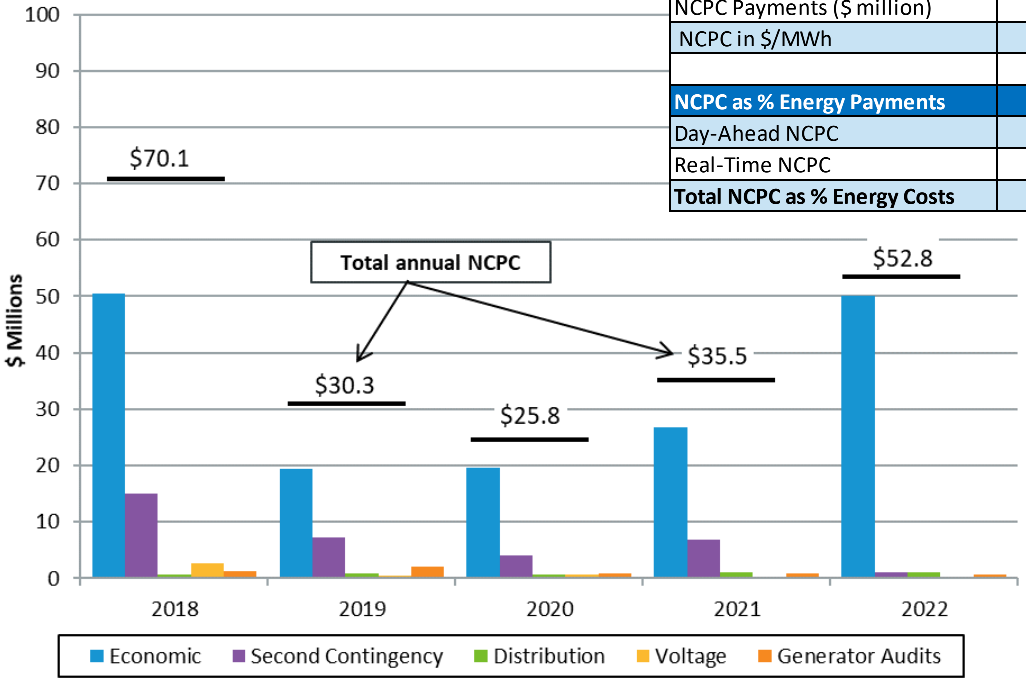


LMP Duration Curves for Top 1% of Real-Time Pricing Hours



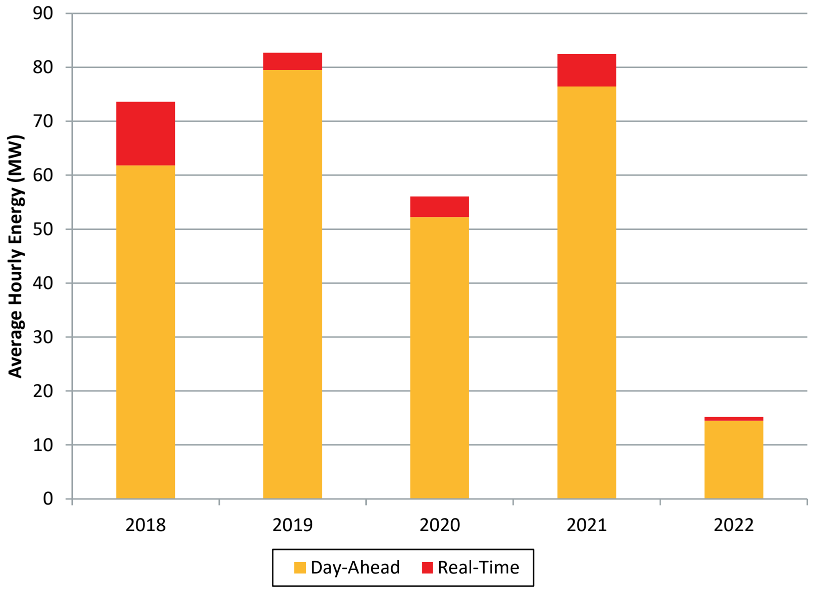
Majority of uplift costs for resources committed and dispatched in economic merit order

	2018	2019	2020	2021	2022
Energy Payments ($ millions)	$6,041	$4,105	$2,996	$6,099	$11,698
NCPC Payments ($ million)	$70.12	$30.29	$25.78	$35.49	$52.83
NCPC in $/MWh	$0.57	$0.25	$0.22	$0.30	$0.44
NCPC as % Energy Payments					
Day-Ahead NCPC	0.4%	0.3%	0.3%	0.3%	0.1%
Real-Time NCPC	0.7%	0.4%	0.5%	0.3%	0.3%
Total NCPC as % Energy Costs	**1.2%**	**0.7%**	**0.9%**	**0.6%**	**0.5%**

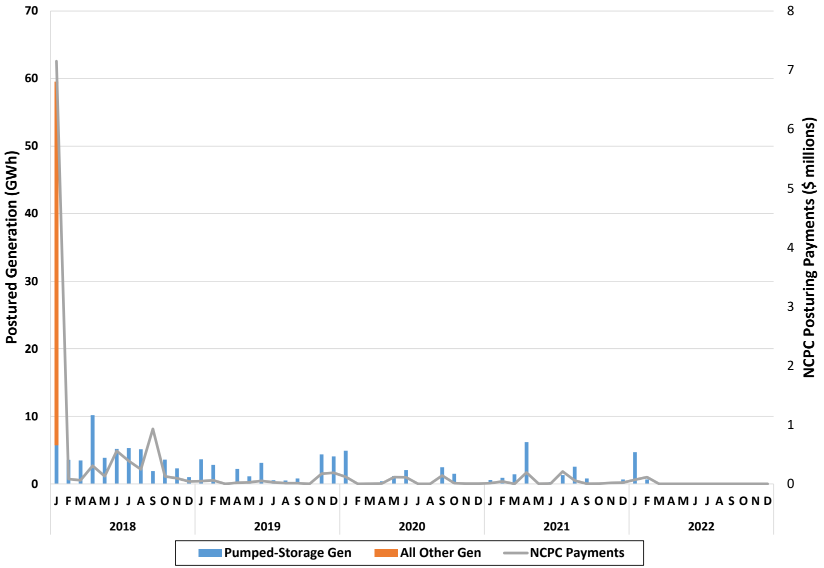


Out-of-merit commitments and posturing actions down significantly in 2022

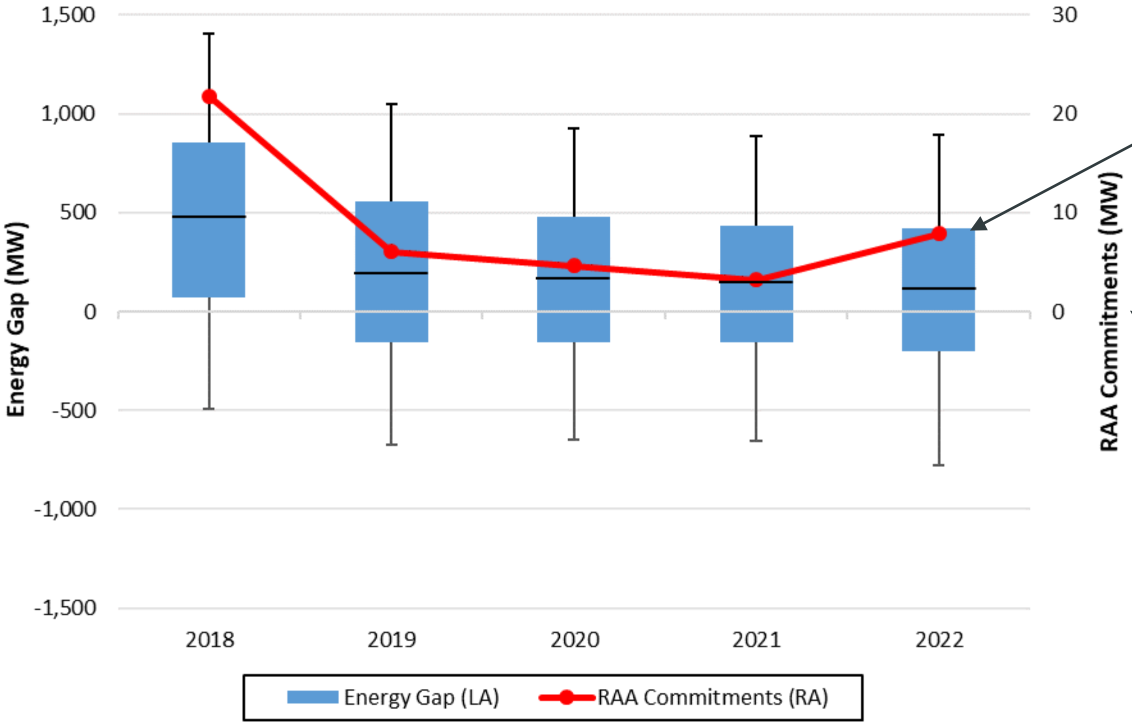
Average Hourly Energy Output from Reliability Commitments, Peak Load Hours



Monthly Postured Energy and NCPC Payments



Day-Ahead energy market continues to clear a significant share of generation to meet expected real-time energy needs



Day-ahead Ancillary Services Initiative (DASI) will procure and price physical generation to satisfy the energy gap.

Supplemental commitments of long-lead time generation in the Reserve Adequacy Analysis (RAA) were infrequent and generally small in 2022.

Recommendation to review reserve pricing logic under the fast start pricing rules

- Fast-Start Pricing is generally meeting its key design objective of improving real-time price formation
- However, we observe frequent non-zero reserve pricing when the reserve constraint is not physically binding
- Function of the tradeoff in separating dispatch and pricing and relaxing EcoMin for energy but not for reserves.
- In 2022, $13.7 million in reserve payments were made when there was a reserve surplus (over half of the $26.9 million in total reserve payments during the year).

Reserve Prices in the Pricing vs. Dispatch Software on December 12, 2022

Energy and capacity markets outcomes competitive, while market power in forward reserve market is a concern

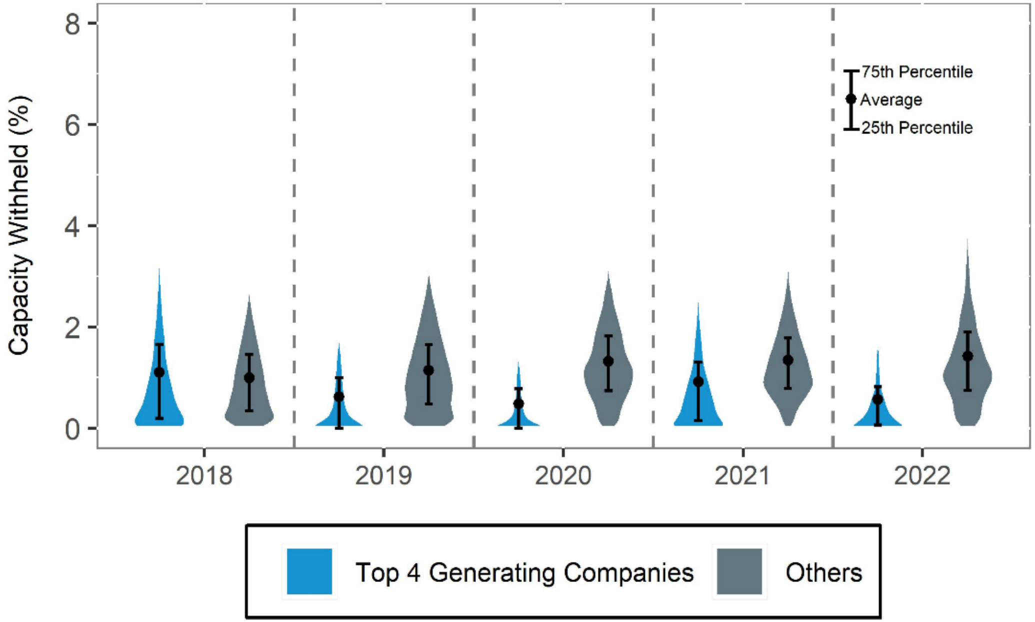
- Energy supply concentration in line with prior years; at least one pivotal supplier in about 25% of hours
- Withholding metrics indicate low price and quantity impact of energy supply offers above competitive levels; mitigation of energy offers was infrequent
  - However, a review of several aspects of the energy market mitigation rules is recommended, particularly conduct and impact thresholds
- Capacity market structurally competitive with enough existing supply to meet the capacity requirement at system and zonal levels
- Forward reserve auction prices have increased significantly in recent auctions; summer auctions are not structurally competitive

Energy market economic withholding metrics indicate competitive outcomes

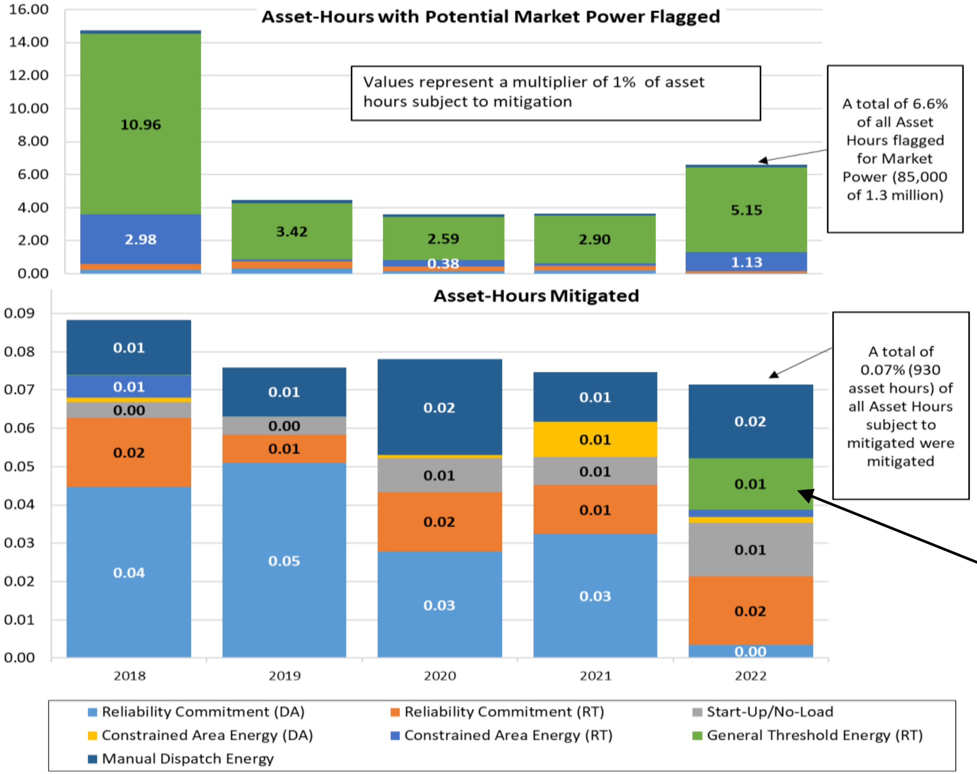
Day-Ahead Price-Cost Markup

Year	Price-Cost Markup
2018	-4.0%
2019	-2.4%
2020	0.9%
2021	-0.6%
2022	-1.8%

Real-time Economic Withholding During On-Peak Hours



Energy market mitigations remained low; but appropriate to review rules under a range of supply/demand scenarios



Potential design enhancements also revealed by systemwide mitigation and cost recovery issues on December 24, 2022.

Recommendation to review aspects of the energy market mitigation design

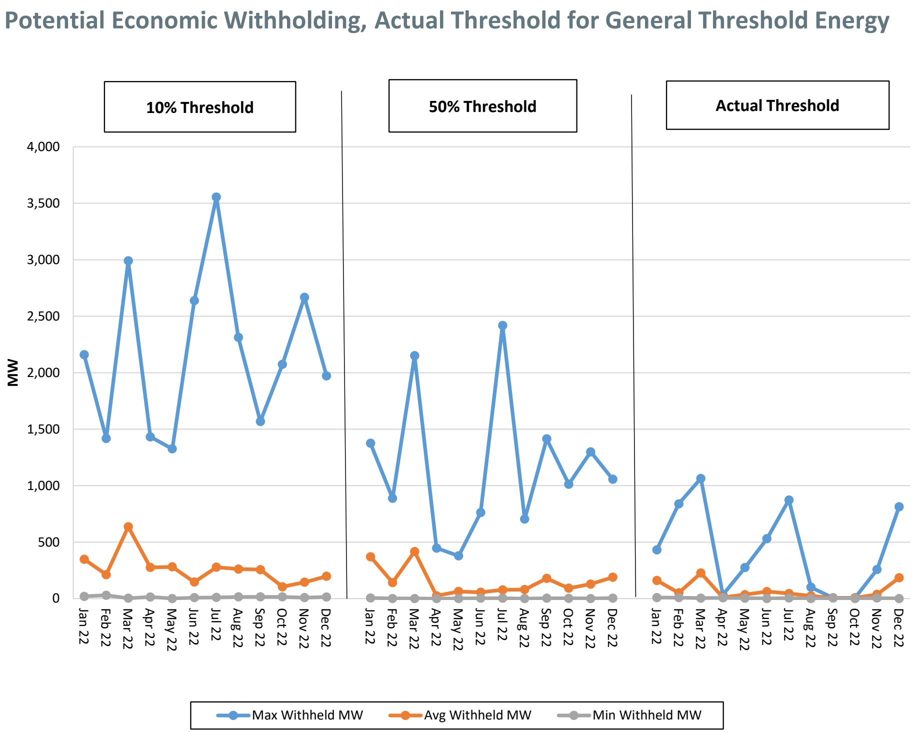
1. Review mitigation thresholds for system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support

2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market

3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas

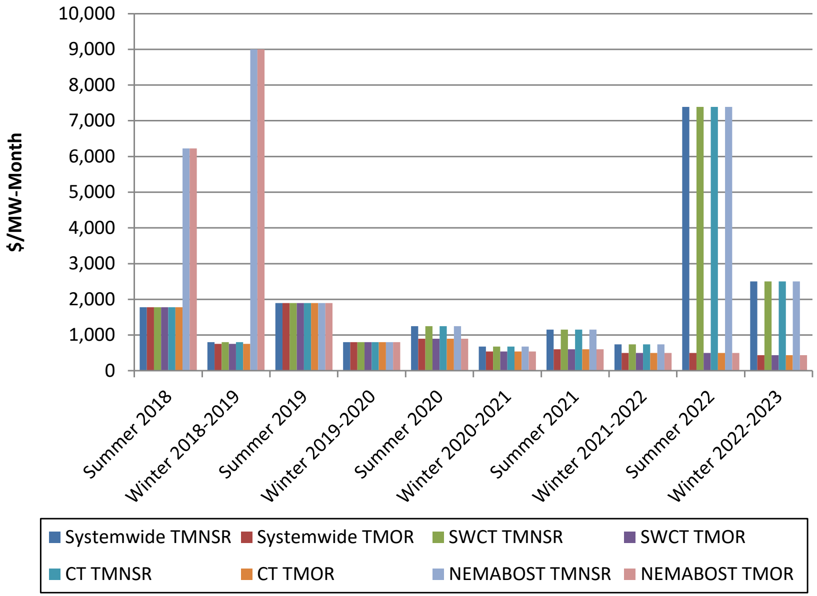
4. Review the methodologies for determining reference levels, which are used to evaluate if an offer is competitive (the “conduct test”). We recommend that only marginal cost-based reference levels be relied on for generators that have robust cost estimates with the IMM. Reference levels based on historical fuel-adjusted accepted supply offers or LMPs can produce unreasonably high reference levels

Potential economic withholding at various conduct threshold levels



Structural market power in forward reserve market persists, with an offer cap the only mitigation mechanism

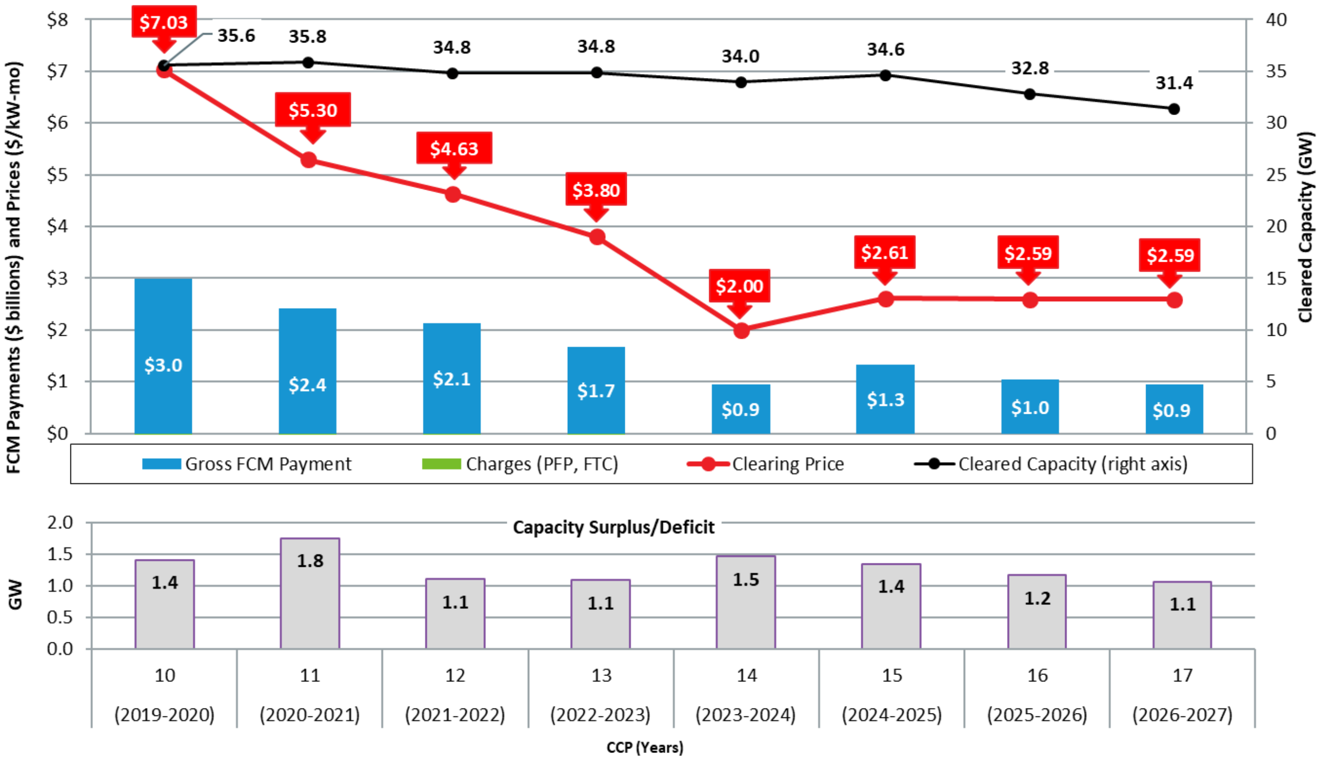
Forward Reserve Prices by FRM Procurement Period



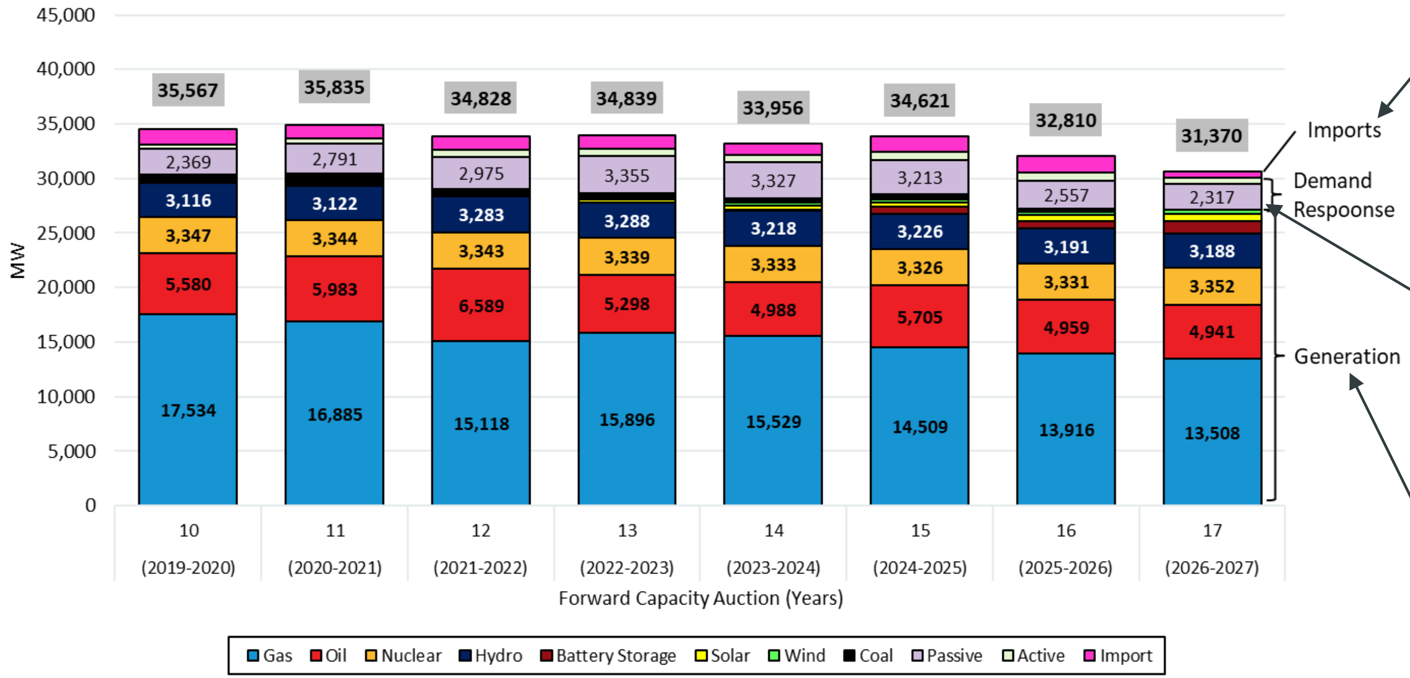
Offer RSI in the FRM for TMNSR and TMOR (system-wide)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI Total Thirty (System-Wide))
Summer 2018	112	108
Winter 2018-19	127	127
Summer 2019	90	97
Winter 2019-20	120	118
Summer 2020	84	97
Winter 2020-21	102	115
Summer 2021	92	108
Winter 2021-22	110	116
Summer 2022	78	90
Winter 2022-23	109	112

Low capacity costs continue under surplus capacity market conditions



Contracted capacity falling with lower capacity requirement and low prices



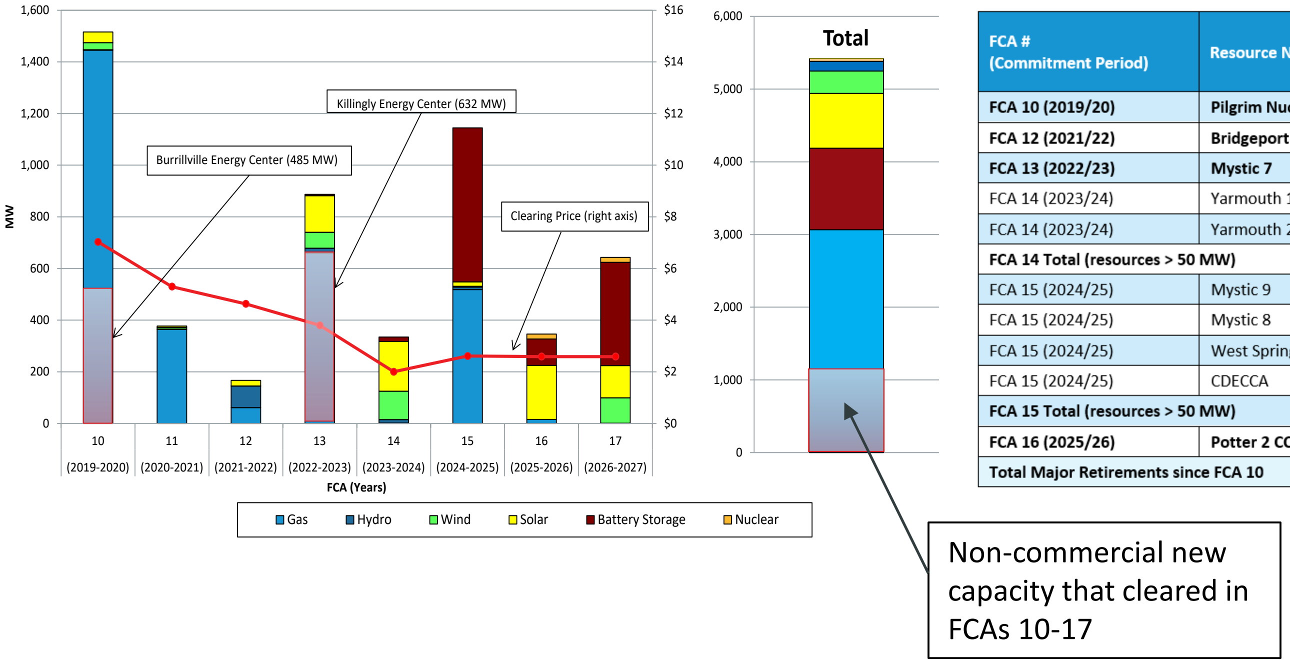
Reduction in import resources in most recent auction.

Energy Efficiency capacity declining due to rising costs of eligible EE measures and associated baselines.

Gas and oil capacity declining due to combination of retirements and single-year exits; in FCA 17 over 2,000 MW of existing oil, gas and coal capacity de-listed for one year.

Battery, solar and wind resources comprise most recent new entry, with no significant retirements in past two auctions

New Generation Capacity by Fuel Type



Generating Resource Retirements over 50 MW

FCA # (Commitment Period)	Resource Name	Fuel Type	Capacity Zone	FCA MW
FCA 10 (2019/20)	**Pilgrim Nuclear**	**Nuclear**	**SEMA**	**677**
FCA 12 (2021/22)	**Bridgeport Harbor 3**	**Oil**	**Connecticut**	**383**
FCA 13 (2022/23)	**Mystic 7**	**Oil**	**NEMA/Boston**	**575**
FCA 14 (2023/24)	Yarmouth 1	Oil	Maine	50
FCA 14 (2023/24)	Yarmouth 2	Oil	Maine	51
FCA 14 Total (resources > 50 MW)				**101 MW**
FCA 15 (2024/25)	Mystic 9	Gas	NEMA/Boston	710
FCA 15 (2024/25)	Mystic 8	Gas	NEMA/Boston	703
FCA 15 (2024/25)	West Springfield 3	Gas	WCMA	95
FCA 15 (2024/25)	CDECCA	Gas	Connecticut	52
FCA 15 Total (resources > 50 MW)				**1,560 MW**
FCA 16 (2025/26)	**Potter 2 CC**	**Gas**	**SEMA**	**72**
Total Major Retirements since FCA 10				**3,368 MW**

Questions

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

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated November 1, 2023 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	Page	Matter	Date	Activity
	1	Brookfield IEP Complaint (IEP Exclusion of Pumped Storage ESFs) (EL23-89)	Nov 29	Tariff changes in response to the *Brookfield IEP Complaint Order* jointly filed by ISO-NE and NEPOOL (see Section III, Docket No. ER24-492 below)
	1	206 Proceeding: ISO Market Power Mitigation Rules (EL23-62)	Nov 2	ISO-NE and NEPOOL file changes to address at least one of the FERC's concerns in the *Dynegy Mitigation Order* (see Section III, Docket No. ER24-324 below)

II. Rate, ICR, FCA, Cost Recovery Filings

	Page	Matter	Date	Activity
*	5	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER24-528)	Nov 30	ISO-NE and NEPOOL jointly file ICR-Related Values and HQICCs for 2024/25 ARA3, 2025/26 ARA2; and 2026/27 ARA1; comment deadline ***Dec 21, 2023***
*	5	FCA18 Qualification Informational Filing (ER24-476)	Nov 22	ISO-NE submits required FCA18 informational filing; comment deadline ***Dec 7, 2023***
			Nov 24-Dec 4	NEPOOL, Calpine, National Grid, Public Citizen intervene
*	6	ICR-Related Values and HQICCs – FCA18 (2027-28) Capacity Commitment Period (ER24-362)	Nov 7	ISO-NE and NEPOOL file ICR-Related Values for the 2027-28 Capacity Comm. Period
			Nov 8-15	Calpine, NESCOE, Public Citizen intervene
	6	2024 NESCOE Budget (ER24-91)	Nov 3	NEPOOL files comments supporting 2024 NESCOE Budget
	7	Essential Power Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER24-80)	Nov 2	NEPOOL files doc-less motion to intervene
			Dec 5	FERC accepts revised rate schedule permitting recovery of ***$276,421*** in incremental medium impact CIP-IROL Costs, eff. *Dec 11, 2023*
	8	**Mystic 8/9 COSA (ER18-1639)**		
	10	(-018) Second CapEx Info Filing	Dec 5	First issues order on the remaining (ENECOS' Formal) challenges to the Second CapEx Info Filing, granting in part, subject to hearing and settlement judge procedures, and dismissing in part, those formal challenges
	9	(-026) ENECOS Request for Reh'g of *Mystic I Order on Remand Modification Order*	Nov 6	FERC accepts Tariff Sheets Filing, *eff. Jun 1, 2022*
*	12	ISO-NE Securities: Authorization for Future Drawdowns (ES24-18)	Nov 13	ISO-NE requests continued authorization for drawdowns under new Revolving Credit Line and Payment Default Shortfall Fund
			Dec 4	National Grid intervenes

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

	Page	Matter	Date	Activity
*	13	IEP Compliance Filing (ER24-492)	Nov 29	ISO-NE and NEPOOL jointly file changes that make eligible to participate in the IEP pumped storage resources participating as ESFs in the New England Markets; comment deadline ***Dec 20, 2023***
			Nov 30	Brookfield intervenes

*	13	DECR FCM Qualification Revisions (ER24-484)	Nov 27	ISO-NE and NEPOOL jointly file revisions to the FCM qualification rules for DECRs; comment deadline ***Dec 18, 2023***
			Nov 28-Dec 1	NESCOE, MA DPU, Calpine intervene
*	13	Waiver Request: OP-14 Solar Dispatch Point Requirements (Galt Power) (ER24-478)	Nov 22	Galt Power requests for its FR/SR Facilities a waiver of the requirements for solar resources to receive and respond to DNE Dispatch Points; comment deadline ***Dec 13, 2023***
			Nov 24	ISO-NE opposes shortened comment period request and indicates it will oppose requested waiver; NEPOOL intervenes
*	13	Downward De-List Bid Price Flexibility (ER24-420)	Nov 17	ISO-NE and NEPOOL jointly file changes to allow Lead Market Participants greater flexibility for submitting Permanent and Retirement De-List Bids in a FCA; comment deadline ***Dec 8, 2023***
			Nov 17-Dec 4	NESCOE, Calpine, Constellation, National Grid intervene
*	14	FCM CONE and Net CONE Updates for FCAs 19 and 20 (ER24-401)	Nov 15	ISO-NE and NEPOOL jointly file updates to reflect for FCAs 19 and 20 the elimination of MOPR (through revisions to the ATWACC);
			Nov 15-Dec 6	NESCOE, Calpine, Constellation, National Grid intervene
			Dec 6	NEPGA submits comments supporting updates
*	14	FCA19 Delay Proposal (ER24-339)	Nov 3	ISO-NE and NEPOOL jointly file FCA 19 Schedule Changes
			Nov 6-22	Brookfield, Calpine, Dominion, Eversource, MA AG, National Grid, NESCOE, NRG, Orsted, RENEW, MA DPU, Public Citizen intervene doc-lessly
			Nov 22-24	FirstLight, NEPGA, and Public Systems file comments supporting FCA 19 Schedule Changes
*	14	Energy Supply Offer Mitigation Changes (ER24-324)	Nov 2	ISO-NE and NEPOOL jointly file changes to eliminate the potential for upward mitigation of Energy Supply Offers
			Nov 6-15	Calpine, Constellation, MA AG, National Grid, NESCOE intervene
			Nov 16	Dynegy/Vistra, NEPGA file comments supporting Changes
	15	DASI Proposal (ER24-275)	Nov 2-30	LS Power, NEPGA, NESCOE, EPSA, the National Hydropower Association, and the ISO-NE IMM and EMM file comments generally supporting the DASI proposal
			Nov 21	Brookfield, Calpine, Constellation, CPV Towantic, Dominion, ENE, Eversource, FirstLight, LS Power, MA AG, National Grid, NRG, Public Systems, Shell, MA DPU intervene doc-lessly only
			Dec 6	ISO-NE files an answer to certain comments filed
	15	ISO/RTO Credit-Related Information Sharing (ER24-138)	Nov 6	National Grid intervenes
	15	Effective Date Deferral – Binary Storage Facility DARD Regulation (ER24-115)	Nov 6	National Grid intervenes
	15	IEP Parameter Updates (ER23-1588)	Nov 30	FERC issues *IEP Parameter Updates Allegheny Order*, modifying the discussion in, but reaching the same result as, the *IEP Parameter Updates Order*
	16	New England's *Order 2222* Compliance Filings (ER22-983)	Nov 2	FERC conditionally accepts 60-Day compliance filing; directs further compliance due on or before ***Jan 31, 2024***
			Dec 4	AEU requests reh'g of Nov 2 *Order 2222 60-Day Compliance Filing Order*

IV. OATT Amendments / TOAs / Coordination Agreements

19	UI Att. F App. D Depreciation Rate Changes (ER24-272)	Nov 21	Bridgeport Energy intervenes

	19	National Grid Attachment F App. A PBOP Fixed Expense Revisions (ER24-125)	Nov 7 Dec 5	Eversource, MA AG intervene FERC accepts revisions, *eff. Jan 1, 2024*
	19	Attachment F Corrections & Updates (ER23-2940)	Nov 22	FERC accepts corrections and updates, *eff. Nov 28, 2023*
	19	*Order 676-J* Compliance Filings Part II (ER23-1771; ER23-1782)	Nov 13, 17	Versant and ISO-NE submit revisions to MPD OATT Section 4 and Schedule 24, respectively, to include the citation to the order granting the requested waivers of certain v. 003.3 NAESB WEQ Standards; comment deadline for Schedule 24 changes ***Dec 8, 2023***
	20	*Order 881* Compliance Filing: New England (ER22-2357)	Dec 4	FERC accepts *Order 881* 60-Day Compliance Changes, *eff. Jun 1, 2025*

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

	20	Schedule 21-VP: Versant/Jonesboro LSA (ER24-24)	Nov 30	FERC accepts LSA, eff. *Dec 4, 2023*, denies waiver of prior filing requirement, orders Time Value Refunds
	21	Schedule 21-ES: PSNH /Great Lakes Hydro IA Termination (ER24-17)	Nov 30	FERC accepts notice of termination of superseded IA, eff. *Oct 5, 2023*
	21	Sched. 21-GMP: National Grid/ISO-NE/GMP LSA (ER23-2804)	Nov 7 Dec 4 Dec 6	FERC accepts LSA, eff. *Nov 11, 2023*, denies waiver of prior filing requirement, orders Time Value Refunds Filing Parties request extension of time to make Time Value Refunds and to file Refund Report FERC grants Filing Parties' request for an extension of time to make Time Value Refunds (to ***Jan 22, 2024***) and file to a Refund Report (to ***Feb 21, 2024***)

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

	22	Capital Projects Report - 2023 Q3 (ER24-94)	Dec 5	FERC accepts 2023 Q3 Report, eff. *Oct 1, 2023*
	23	Interconnection Study Metrics Processing Time Exceedance Report 2023 Q3 (ER19-1951)	Nov 14	ISO-NE files 2023 Q3 Report
*	24	ISO-NE FERC Form 3Q (2023/Q3) (not docketed)	Nov 21	ISO-NE submits its 2023 Q3 FERC Form 3Q

IX. Membership Filings

	24	Dec 2023 Membership Filing (ER24-512)	Nov 30	***New Members:*** Citadel Energy Marketing; Downeast Wind; JGT2 Energy; and Qnti.fyi Inc.; ***Termination of Participant status:*** Sam Mintz; comment deadline ***Dec 21, 2023***
	24	Oct 2023 Membership Filing (ER23-2966)	Nov 22	FERC accepts (i) the membership in NEPOOL of: KCE CT 10, KCE CT 11, and the Sierra Club; and (ii) the termination of the Participant status of BP Energy Holding Company

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

*	24	Report on 2022 Winter Storm Elliott (AD23-8)	Nov 7	FERC posts FERC/NERC/RE report entitled "Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott"
*	25	Revised Reliability Standard: PRC-023-6 (RD23-5)	Nov 3	FERC files revised Reliability Standard
	25	Inverter-Based Resource Registration (RD22-4)	Nov 14	NERC files second 90-Day Progress Report
	26	Changes to NERC ROPs (RR23-4)	Nov 28	FERC approves changes to ROPs

XI. Misc. - of Regional Interest

*	27	E&P Agreement, 2d Amendment: Seabrook / NECEC Transmission (ER24-508)	Nov 30	Seabrook files a second amendment to the E&P Agreement with NECEC Transmission; comment deadline ***Dec 21, 2023***
*	27	IA Cancellation MECo / Dichotomy Collins Hydro (ER24-353)	Nov 3	MECo files notice of cancellation of IA with Dichotomy Collins Hydro that was superseded by new SGIA with NEP

XII. Misc. - Administrative & Rulemaking Proceedings

	29	Reliability Technical Conference (AD23-9)	Nov 3-14	Comments, including pre-tech conf and speaker statements/materials and comments, posted to eLibrary
			Nov 14	FERC invites post-tech conf comments; comment deadline ***Dec 14, 2023***
			Nov 30-Dec 1	EEI, supported by NRDC, requests extension of time, to Dec 20, 2023, to file comments
			Nov 27-Dec 5	Reliable Energy Analytics, US EPA Office of Air and Radiation, Sue Tierney file post-tech conf comments
	29	New England Gas-Electric Forums (AD22-9)	Nov 6	FERC Chairman and NERC CEO issue a joint statement regarding the potential loss of the Everett Marine Terminal
	30	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Nov 6	FERC issues order listing PA PUC Vice Chair Kimberly Barrow to serve out the remainder of Joseph L. Fiordaliso's one-year term
	30	NOPR: EQR Filing Process and Data Collection (RM23-9)	Nov 17, 27 Dec 5	EEI/EPSA request additional time to comment on *EQR NOPR* BPA requests additional time to comment on *EQR NOPR*
	31	*Order 2023*: Interconnection Reforms (RM22-14)	Nov 7-27	Parties petition DC Circuit for review of *Order 2023* (*see* Section XVI below)

XIII. FERC Enforcement Proceedings

*	36	2023 FERC Enforcement Staff Report (AD07-13-017)	Nov 16	OE issues 2023 annual report
		Natural Gas-Related Enforcement Actions		
	36	Black Hills Corp., et al. (IN23-10)	Dec 5	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into Black Hills' failure, on more than 100 occasions, to file before jurisdictional service commenced associated jurisdictional agreements; Black Hills must pay a ***$150,000 civil penalty***, and submit to OE compliance monitoring for two years

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

40	*Order 2023* (23-1282 et al.) (consolidated)	Dec 1-4	Parties file Statements of Issue; Docketing Statements; motions to govern future proceedings due ***Dec 12, 2024***
40	*Order 2222* Compliance Orders (23-1167 et al.)(consolidated)	Dec 6	23-1335 consolidated with 23-1167 et al.; motions to govern future proceedings due by ***Jan 24, 2024***
40	Seabrook Dispute Order (23-1094, 23-1215) (consol.)	Nov 3	FERC files Final Reply Brief and Final Brief; NECEC Transmission and Avangrid (Intervenors for Respondent) file Final Brief
42	Opinion 531-A Compliance Filing Undo (20-1329)	Nov 28	FERC files status report, suggests continued abeyance

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: December 6, 2023

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through December 6, 2023. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

On September 21, 2023, the FERC granted the complaint filed by Brookfield Renewable Trading and Marketing LP ("Brookfield") regarding the exclusion of pumped storage hydroelectric facilities that are Electric Storage Facilities ("ESFs") from the Inventoried Energy Program ("IEP").[2] In granting the Complaint, effective August 2, 2023, the FERC found "pumped storage [ESFs] are similarly situated to battery storage [ESFs] for purposes of participation in the [IEP] … [agreed] with Brookfield that the ISO-NE Tariff is unduly discriminatory because it prohibits pumped storage [ESFs] from similarly participating in the [IEP]".[3] Accordingly, the FERC ordered ISO-NE to revise its Tariff. Any challenges to the *Brookfield IEP Complaint Order* were due on or before October 23, 2023; none were filed. Tariff changes in response to the *Order* were supported by the Participants Committee at its November 2, 2023 meeting (Consent Agenda Item #3) and were jointly filed with ISO-NE on November 29, 2023 in Docket No. ER24-492 (*see* Section III below). Reporting on the complaint proceeding is now concluded, with any further developments related to the Tariff changes to be reported in Section III (ER24-492) below. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

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

---

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

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

[3] *Id.* at P 31.

[4] *Dynegy Marketing and Trade, LLC and ISO New England, Inc.*, 183 FERC ¶ 61,091 (May 5, 2023) ("*Dynegy Mitigation Order*"). In the Dynegy Mitigation Order, ISO-NE was directed to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory. The refund effective date for this proceeding is May 12, 2023.

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

Being Held In Abeyance. On July 14, 2023, the FERC granted ISO-NE's June 28, 2023 motion, supported by NEPOOL on July 5, 2023, requesting that the FERC hold this proceeding in abeyance to allow potential ISO-NE Tariff design changes to be vetted through the Participant Processes. The FERC stated that it would not take any action on this 206 proceeding before ***February 1, 2024***. Changes in response to the *Dynegy Mitigation Order* were supported by the Participants Committee at its November 2, 2023 meeting (Consent Agenda Item #2) and jointly filed with ISO-NE in Docket No. ER24-324 (*see* Section III below.)

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

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

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

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

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

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

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

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

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[7] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[8] However, the FERC's orders were challenged, and in *Emera Maine,*[9] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[10] and third (EL14-86)[11] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[12] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[13] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[14] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%,

---

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

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

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

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

[11] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General, together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to 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.

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

[13] The 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The 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.

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

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.[15] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[16] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[17] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[18]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[19] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the

---

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

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

[17] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[18] *Id.* at P 19.

[19] *Id.* at P 59.

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[20] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

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

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER24-528)**

On November 30, 2023, 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 2024-25 Capability Year, the second ARA for the 2025-26 Capability Year, and the first ARA for the 2026-27 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 2, 2023 meeting (Agenda Item 5). A January 29, 2024 effective date was requested. Comments on this filing are due on or before ***December 21, 2023***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA18 Qualification Informational Filing (ER24-476)**

On November 22, 2024, ISO-NE submitted its informational filing for qualification in FCA18 (the "FCA18 Informational Filing"). ISO-NE is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by ISO-NE for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA18 is scheduled to begin February 5, 2024. The Informational Filing contained ISO-NE's determinations that three Capacity Zones will be modelled for FCA18 -- Northern New England ("NNE"), Maine, and Rest of Pool. NNE and Maine will be modeled as export-constrained. The Informational Filing reported that there will be 29,855 MW of existing capacity in FCA18

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

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

competing with 4,108 MW of new capacity under a Net ICR of 30,550 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 1,391 MW of De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 8 demand bids, totaling 858 MW, and 47 supply offers, totaling 341 MW, to participate in the substitution auction. Comments on the FCA18 Informational Filing are due on or before ***December 7, 2023***. Thus far, NEPOOL, Calpine, National Grid, and Public Citizen have filed doc-less interventions. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ICR-Related Values and HQICCs – FCA18 (2027-28) Capacity Commitment Period (ER24-362)**

  On November 7, 2023, ISO-NE and NEPOOL jointly filed the ICR, MCL for the Maine and NNE Capacity Zones, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2026-27 ICR-Related Values") for the 2026-27 Capacity Commitment Period ("CCP"). The 2027-28 ICR will be 31,591 MW (reflecting tie benefits of 1,041 MW) and HQICCs of 1,041 MW/mo., the net amount of capacity to be purchased in FCA18 to meet the ICR will be 30,550 MW. The MCL for the Maine Capacity Zone is 4,150 MW. The MCL for the NNE Capacity Zone is 8,760 MW. (For FCA18, there are no import-constrained Capacity Zones; Accordingly, ISO-NE did not have to calculate a LSR for any Capacity Zone.) The Participants Committee supported the FAC18 ICR-Related Values at its October 5, 2023 meeting. Comments on this filing were due November 28, 2023; none were filed. Calpine, NESCOE and Public Citizen 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).

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

  This proceeding was initiated by ISO-NE's October 13, 2023 filing of the budget for funding NESCOE's 2024 operations. The 2024 Operating Expense Budget for NESCOE is $2,596,014. The amount to be recovered reflects true-ups from 2023 (over-collections of $862,664). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00807 per kilowatt ("kW") of Monthly Network Load (a $0.00106/kW increase from 2023). The 2024 NESCOE budget was supported by the Participants Committee at its October 5, 2023 meeting. Comments and any interventions were due on or before November 3, 2023. NEPOOL filed comments on November 3 supporting the 2024 NESCOE Budget. NESCOE and National Grid filed doc-less interventions only. This matter is pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

  Also on October 13, 2023, ISO-NE filed for recovery of its 2024 administrative costs (the "2024 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2024 ("2024 Capital Budget", and together with the 2024 Revenue Requirement, the "2024 ISO Budgets"). The 2024 ISO-NE Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 13 filing, ISO-NE reported that the 2023 Revenue Requirement is $276.9 million (a $36.7 million or 15.3% increase over 2023), which decreases to $273.9 million after the over-collection for 2022 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2024 Core Operating Budget) comprise $244.3 million; depreciation and amortization of regulatory assets, $32.6 million; and a $3.0 million true-up decrease for 2022 over-collections.

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

- Day-Ahead Ancillary Services Improvements (Mar 2025) ($3.8 million)
- nGem Software Development Part III (Mar 2025) ($2.5 million)
- CIP Electronic Security Perimeter Redesign Phase II (Dec 2024) ($2 million)
- Enterprise Resource Planning System Replacement (Mar 2025) ($1.6 million)

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

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

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

On December 5, 2023, the FERC accepted a revised rate schedule filed by Essential Power Newington, LLC (“EP Newington”) to allow EP Newington 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.[22] As previously reported, EP Newington will recover ***$276,421*** in incremental medium impact CIP-IROL Costs incurred between July 1, 2022 and June 30, 2023. The revised rate schedule was accepted effective as of *December 11, 2023*. Unless the December 5 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

[22] *Essential Power Newington, LLC*, Docket No. ER24-80-000 (Dec. 5, 2023).

Overhead Costs to Construction Work in Progress" and to provide additional detail regarding the amounts included. On May 5, 2023, Versant answered the MPUC protest.

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

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

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

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[23] (ER22-1192)**

As previously reported, on May 2, 2022, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COSA") to reflect Mystic's current upstream ownership.[24] The changes were accepted effective as of June 1, 2022, but subject to refund and to the outcome of paper hearing (or settlement procedures) on the issues of capital structure and cost of debt raises issues. Mystic filed an offer of settlement on September 8, 2022 to resolve all issues set for hearing and settlement proceedings and the FERC accepted that offer of settlement on November 2, 2022,[25] directing Mystic to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action in the November 2 order. Mystic submitted that compliance filing on December 2, 2022 (ER22-1192-003). No comments were received by the December 23, 2022 comment date, and there was no activity in this proceeding since the last Report. This compliance filing remains pending before the FERC. FERC action on the compliance filing will conclude this proceeding. If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[26] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's *December 2020 Rehearing Order*.

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

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

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

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

(-000) Third CapEx Info Filing. On September 15, 2023, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "Third CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2024 to May 31, 2024 ("2024 CapEx Projects"). This filing was not noticed for public comment by the FERC.

(-026) ENECOS Request for Rehearing of Mystic I Order on Remand Modification Order. On November 6, 2023, ENECOS requested rehearing of the *Mystic I Order on Remand Modification Order*.[27] Specifically, ENECOS requested that the FERC both (i) reinstate the its conclusions as to the scope of customer scrutiny of formula rate inputs under the COSA set forth in its March 28, 2023 *Mystic I Order on Remand*[28] and (ii) grant Public Systems' motion for additional disclosure to facilitate customer review of the extraordinary costs incurred during the first 18 months of the COSA's operation. The FERC must take action on ENECOS' request for rehearing by ***December 6, 2023***, or the request will be deemed denied by operation of law.

As previously reported, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand (*-024*)*. Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[29]

The FERC then issued the *Mystic I Order on Remand Modification Order* which modified the discussion in the *Mystic I Order on Remand* and set aside that *Order* in part.[30] In addition, the *Order* also denied Public Systems[31] May 19, 2023 request that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request").[32]

---

[27] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*"). The *Mystic I Order on Remand Modification Order* set aside the FERC determinations in the *Mystic I Order on Remand* that: (i) interested parties may review and challenge revenues and Revenue Credits during the true-up process; (ii) interested parties may review and challenge Tank Congestion Charges during the true-up process; and (iii) the revenues from the sliding scale revenue sharing mechanism for third-party vapor sales should be included within the true-up. As previously reported, the FERC concluded in the *Mystic I Order on Remand* that "the language of the true-up and Protocol provisions of the [COS] Agreement, Schedule 3A, does not include these three items within the scope of the true-up, nor is calculation of these items consistent with purpose for the true-up mechanism in the [COS] Agreement because none of them are projected in advance, but rather they are each settled and audited on a monthly basis. The FERC found that "existing cost review and audit processes, … facilitated by ISO-NE, its auditors, and the Internal Market Monitor, are sufficient to ensure that Mystic adheres to its filed rate with respect to these items and continues to appropriately balance customers' interest in transparency of the formula rate with Mystic's interests in protecting commercially-sensitive information, reducing security risks, and avoiding burdensome audit obligations".

[28] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,200 (Mar. 28, 2023) ("*Mystic I Order on Remand*"), *reh'g denied by operation of law,* 183 FERC ¶ 62,115 (May 30, 2023) ("*Mystic I Order on Remand Allegheny Notice*"); *Mystic I Order on Remand Modification Order* (addressing arguments raised on reh'g and setting aside the *Mystic I Order on Remand*, in part, granting Constellation motion to lodge and denying Public Systems' Request for Disclosure of Audit Information).

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

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

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

[32] In the *Mystic I Order on Remand Modification Order*, the FERC found that the additional audit information requested was "not supported by the Mystic [COSA] and unnecessary, given the attention that ISO-NE, its auditors, and the Market Monitor give these items on a regular basis". Nevertheless, the FERC accepted "ISO-NE's offer to provide additional transparency measures for the remainder of the Mystic Agreement as soon as practicable, starting no later than [December 5, 2023]." (P 13).

(-018) Second CapEx Info Filing. On December 5, 2023, the FERC issued an order[33] on the formal challenges to Mystic's September 15, 2022 "Second CapEx Info Filing".[34] As previously reported, formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS[35] (with ENECOS challenges supported separately by MMWEC/NHEC). Several rounds of answers, described in previous reports, followed. In February 2023, Mystic asked that the Formal Challenges to the Second CapEx Info Filing be held in abeyance pending submission of a settlement agreement to resolve challenges to the First CapEx Info Filing. ENECOS protested that request, identifying issues in their challenges to the Second CapEx Info Filing that would not be resolved by a First CapEx Settlement Agreement. The First CapEx Settlement Agreement was filed and approved, leaving for resolution certain of ENECOS' challenges.

In the *Second CapEx Info Filing Order*, the FERC granted in part, subject to hearing and settlement judge procedures, and dismissed in part, ENECOS' Formal Challenges. Specifically, the FERC found that, issues of material fact, that could not be resolved on the record before it, continued with respect to a number of ENECOS' Formal Challenges. Accordingly, the FERC set for hearing and settlement judge procedures issues raised, in whole or in part, in ENECOS Formal Challenges 1, 2, 6, and 7. The FERC summarily dismissed ENECOS' Formal Challenges 3-5 and 8 (as outside the scope of the proceeding).

While the FERC set several aspects of ENECOS Formal Challenges for a trial-type evidentiary hearing, the FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures. The Chief ALJ was directed to appoint a settlement judge on or before ***January 19, 2024***; the appointed Settlement Judge was directed to convene a settlement conference as soon as practicable and to file a report within 60 days of her/his appointment on the status of settlement discussions.

(-014) Revised ROE (Sixth) Compliance Filing. Also still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[36] The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

---

[33] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*").

[34] The "Second CapEx Info Filing" provides support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects").

[35] ENECOS Formal Challenges included failures by Mystic: (1) to adequately support its July 1, 2004 – Dec. 31, 2017 Rate Base on Attachment B to Mystic 8&9 Schedule D (with the majority of the cost appearing to O&M expenses that should have been expensed prior to the term); (2) to adequately support its Jan. 1, 2018 – May 31, 2022 Rate Base in line with the requirements of Schedule 3A and the Methodology of the Mystic COSA; (3-5) to prove that certain costs under Mystic's 2022 CapEx Projects - specifically, its Campus Segregation Project and comprehensive rotor inspections - are necessary to meet the reliability need of the Mystic COSA and the least-cost commercially reasonable option consistent with Good Utility Practice; (6) to sufficiently support Everett's Nov. 1, 2018 – May 31, 2022 Rate Base in Attachment B; (7) to properly classify certain of Everett's 2022 and 2023 CapEx Projects costs (some of which should have been characterized as maintenance expenses charged before the term of the Mystic COSA); and (8) to include costs of firm interstate and intrastate pipeline transportation reservations in Everett Schedule B of the populated template.

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

30-Day Compliance Filing per Order on ENECOS Mystic COSA Complaint (ER23-1735). On April 27, 2023, Mystic filed, as directed by the FERC's March 28, 2023 *Order on ENECOS Mystic COSA Complaint*,[37] changes to the Mystic COSA to include pipeline-related crediting as an explicit provision in the COSA. Mystic also provided additional information/COSA changes to (i) describe the crediting process; (ii) differentiate, through both an explanation in its compliance filing and creation of two new line items in Schedule 3A, the credits and charges included as part of the Fixed Pipeline Costs; (iii) address how and whether the pipeline-related crediting procedure interacts or should interact with the true-up procedure already included in the COSA and revise the true-up as necessary; and (iv) differentiate in the COSA the Pipeline Transportation Costs as Fixed O&M/Return on Investment Costs from the Pipeline Transportation Agreement Costs. Comments on the 30-day compliance filing were due on or before May 18, 2023. ISO-NE and Monitoring Analytics, LLC filed doc-less motions to intervene.

On July 10, 2023, ENECOS submitted comments (out-of-time) asserting that Mystic's compliance filing did not provide information sufficient to show that Mystic's after-the-fact pipeline-related crediting ensures that Mystic customers do not pay for pipeline costs that do not benefit them ("Crediting Issue"), the Schedule 3A true-up process does not provide the opportunity for an adequate verification process, and ISO-NE's COSA-related filings to date have similarly not addressed the Crediting Issue. ENECOS requested that the FERC direct Mystic to provide a work paper to "verify its assertion that it has always applied a full credit for third-party pipeline transportation costs to Constellation LNG's billings to Mystic". On July 20, 2023, Mystic protested ENECOS' comments. This 30-day compliance filing is pending before the FERC.

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

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

On July 31, 2023, the PTO AC submitted its annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff for 2024. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2022 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2023 and 2024, as well as the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $154.35/kW-year effective January 1, 2024, an increase of $12.71 /kW-year from the charges that went into effect on January 1, 2023. In addition, the filing includes updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.95 kW-year (effective June 1, 2023 through May 31, 2024), a $0.20/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2023. Public comments on this filing were due on or before September 19, 2023; none were filed. MOPA filed a doc-less intervention.

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

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

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

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

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

RENEW Formal Challenge. RENEW's January 31, 2023 formal challenge ("Challenge") to the 2022/23 Update/Informational Filing[38] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, Eversource answered RENEW's March 31 answer. There 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).

- **ISO Securities: Authorization for Future Drawdowns (ES21-34)**

On November 13, 2023, ISO-NE requested the necessary FERC authorization for drawdowns under a $40 million (up from $20 million) Revolving Credit Line and a $4 million line of credit supporting the Payment Default Shortfall Fund, each of which are with TD Bank, are for a term of three years ending June 30, 2027, and replace similar arrangements that will expire June 30, 2024.[39] Comments on this filing were due on or before December 4, 2023; none were filed. National Grid filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

---

[38] 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.

[39] *See ISO New England Inc.*, 139 FERC ¶ 62,248 (June 22, 2012) (initially authorizing borrowings). The arrangements that expire at the end of June 2024 were first authorized in 2021. *ISO New England Inc., 175 FERC ¶ 62,084 (May 12, 2021) (granting authorization through May 31, 2023, the maximum 2-year period allowable under FERC regulations*); *ISO New England Inc.*, 183 FERC ¶ 62,112 (May 26, 2023) (continuing authorization through May 29, 2025, despite expiration of arrangements at the end of June 2024).

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

- **IEP Compliance Filing (ER24-492)**

On November 29, 2023, ISO-NE and NEPOOL jointly filed changes, as directed by the FERC,[40] that make eligible to participate in the IEP pumped storage resources participating as Electric Storage Facilities in the New England Markets. The Participants Committee unanimously supported the IEP changes by way of the November 2, 2023 Consent Agenda (Item # 3). Comments, if any, on the IEP changes and interventions are due on or before ***December 20, 2023***. Thus far, Brookfield submitted a doc-less intervention on November 30, 2023. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **DECR FCM Qualification Revisions (ER24-484)**

On November 27, 2023, ISO-NE and NEPOOL jointly filed changes to the Forward Capacity Market ("FCM") qualification rules for Distributed Energy Capacity Resources ("DECRs") ("DECR Qualification Revisions") to allow for a more streamlined qualification process for DECRs as early as Forward Capacity Auction 19 ("FCA19"), and to correct inadvertent errors in the DECR qualification rules. The Participants Committee unanimously supported the DECR Qualification Revisions by way of the November 2, 2023 Consent Agenda (Item # 4). Comments, if any, on the DECR Qualification Revisions and interventions are due on or before ***December 18, 2023***. Thus far, Calpine, NESCOE and the MA DPU have intervened doc-lessly only. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: OP-14 Solar Dispatch Point Requirements (Galt Power) (ER24-478)**

On November 22, 2023, Galt Power, Inc. and GSRP Pipeline Acquisition I LLC (together, "Galt Power") requested for certain resources (the "FR/SR Facilities")[41] a waiver of the requirements for solar resources to receive and respond to Do Not Exceed ("DNE") Dispatch Points.[42] Galt Power asserted that, due to the size and characteristics of the FR/SR Facilities, "full compliance with the DNE Requirements would be technically challenging and would impose significant costs that are not necessary to ensure reliability, which is the underlying purpose of the DNE Requirements." Galt Power went on to demonstrate how it believes the waiver request is consistent with the FERC's standards for granting waiver requests. Without the Waiver Request being granted in an expedited manner, Galt Power asserted that the FR/SR Facilities "will be required to expend unnecessary resources on costly and unnecessary compliance with the DNE Requirements".

Galt Power asked that the FERC set an abbreviated comment period and act on and approve the Waiver Request by December 4, 2023. Neither of those requests were granted. Comments on the Waiver Request are due on or before ***December 13, 2023***. In initial comments opposing the request for an expedited comment period, ISO-NE indicated that it will oppose the Waiver Request. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Downward De-List Bid Price Flexibility (ER24-420)**

On November 17, 2023, ISO-NE and NEPOOL jointly filed changes to allow Lead Market Participants greater flexibility for submitting Permanent De-List Bids and Retirement De-List Bids in a Forward Capacity Auction ("FCA"). A March 1, 2024 effective date was requested. The Participants Committee supported the Downward De-List Bid Price Flexibility changes by way of the Consent Agenda (Item # 1) at the 2023 Summer Meeting. Comments, if any, on the Downward De-List Bid Price Flexibility changes and interventions are due on or before

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

[41] as those requirements apply to nine sub-transmission solar projects, roughly 12 MW total nameplate capacity, that have been in operation since 2017

[42] The extension of DNE Requirements to solar resources larger than 5 MW, with certain exceptions, takes effect Dec. 5, 2023. *ISO New England Inc.*, Docket No. ER23-517-000 (Jan. 19, 2023) (unpublished letter order); *See* Revisions to ISO New England Transmission, Markets and Services Tariff to Incorporate Solar Resources into DNE Dispatch Rules, Docket No. ER23-517-000 (Nov. 30, 2022).

December 8, 2023. Thus far, Calpine, Constellation, NESCOE and National Grid have intervened doc-lessly only. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **FCM CONE and Net CONE Updates for FCAs 19 and 20 (ER24-401)**

On November 15, 2023, ISO-NE and NEPOOL jointly filed updates to the cost of new entry ("CONE") and net cost of new entry ("Net CONE") for FCAs 19 and 20, reflecting the elimination of the Minimum Offer Price Rule ("MOPR") through revisions to the after tax weighted average cost of capital ("ATWACC"). The Participants Committee supported the CONE/Net CONE Updates by way of the November 2, 2023 Consent Agenda (Item # 1). Comments, if any, on the CONE/Net CONE Updates and interventions were due on or before December 6, 2023. On December 6, NEPGA filed comments supporting the updates. Calpine, Constellation, NESCOE, and National Grid intervened doc-lessly only. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **FCA19 Delay Proposal (ER24-339)**

On November 3, 2023, ISO-NE and NEPOOL jointly filed Tariff revisions (i) to delay FCA19, including all pre-auction and post-auction activities related thereto, for one calendar year; (ii) to also address the timeline for conducting subsequent auctions, as well as impacts to the schedule for running the three ARAs that are held between the time of the FCA and the commencement of the capacity delivery year; and (iii) to make adjustments to the FCA qualification rules for certain resources, to prevent the delay from adversely impacting their participation in the FCM (collectively, the "FCA 19 Schedule Changes"). The Participants Committee unanimously supported the FCA 19 Schedule Changes at the November 2, 2023 meeting (Item # 6). Comments on the FCA 19 Schedule Changes and interventions were due on or before November 24, 2023. Comments supporting the FCA 19 Schedule Changes were filed by: FirstLight,[43] NEPGA, and Public Systems.[44] Brookfield, Calpine, Dominion, Eversource, MA AG, National Grid, NESCOE, NRG Business Marketing ("NRG"), Orsted Wind Power North America ("Orsted"), RENEW, the MA DPU, and Public Citizen intervened doc-lessly only. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Energy Supply Offer Mitigation Changes (ER24-324)**

On November 2, 2023, ISO-NE and NEPOOL jointly filed Tariff revisions to eliminate the potential for upward mitigation of Energy Supply Offers by incorporating updates which will be used to compare each financial parameter of the Supply Offer to the Reference Level and use the lesser of the two values when performing certain automated mitigation procedures (the "Energy Supply Offer Mitigation Changes"). The Energy Supply Offer Mitigation Changes address the primary issue raised by the FERC in the *Dynegy Mitigation Order* (*see* Section I, EL23-62 (206 Proceeding: ISO Market Power Mitigation Rules) above). The Participants Committee unanimously supported the Energy Supply Offer Mitigation Changes at the November 2, 2023 meeting (Consent Agenda Item # 2). ISO-NE requested a *December 12, 2023* effective date for the Energy Supply Offer Mitigation Changes. Comments on the Energy Supply Offer Mitigation Changes were due on or before November 16, 2023. Comments supporting the Energy Supply Offer Mitigation Changes were filed by: Dynegy/Vistra and NEPGA. Calpine, Constellation, MA AG, National Grid, and NESCOE intervened doc-lessly only. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

[43] FirstLight noted that, "whether the region succeeds in completing a well-designed RCA in time for FCA19 implementation will be proven (or not) by the extent of progress made in the stakeholder discussions in coming months".

[44] "Public Systems" for purposes of this proceeding are: Conn. Mun. Elec. Energy Coop. ("CMEEC"), Mass. Mun. Wholesale Elec. Co. ("MMWEC"), New Hampshire Elec. Coop. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

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

As previously reported, ISO-NE and NEPOOL jointly filed changes to the Tariff to establish a jointly optimized Day-Ahead Market for Energy and Ancillary Services ("DASI") on October 31, 2023. The Participants Committee unanimously supported DASI by way of the August 3, 2023 Consent Agenda (Item # 1). Comments were due on or before November 21, 2023, with generally supporting the DASI proposal filed by LS Power, NEPGA, NESCOE, EPSA, the National Hydropower Association, and the ISO-NE IMM and EMM. Doc-less interventions only were filed by: Brookfield, Calpine, Constellation, CPV Towantic, Dominion, ENE, Eversource, FirstLight, HQ US, LS Power, MA AG, National Grid, NRG, Public Systems,[45] Shell, MA DPU, and Public Citizen. On December 6, 2023, ISO-NE filed an answer to certain comments made regarding compensation in light of the Forward Reserve Market's elimination and the mitigation framework, as well as the specific request by commenters for ISO-NE to develop additional types of operating reserve products. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

As previously reported, in response to the requirements of *Order 895*, ISO-NE and NEPOOL jointly filed, on October 18, 2023, changes to the Information Policy to (i) permit ISO-NE to share Market Participant, Transmission Customer and Applicant (collectively, "Participants") credit-related information with other ISO/RTOs; (ii) permit ISO-NE to use credit-related information received from other ISO/RTOs to the same extent and for the same purposes as ISO-NE is permitted under the Tariff with respect to its Participants; and (iii) require ISO-NE to keep such received credit-related information confidential in accordance with the Tariff, in each case for the purpose of credit risk management and mitigation (the "Credit Info Sharing Changes"). The Credit Info Sharing Changes were supported by the Participants Committee by way of the October 5, 2023 Consent Agenda (Item # 6). Comments on the Credit Info Sharing Changes were due on or before November 8, 2023; none were filed. National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On October 16, 2023, ISO-NE asked that the FERC defer the effective date of *Order 841*-related changes that would permit Binary Storage Facilities to offer Regulation when acting as a Dispatchable Asset Related Demand ("DARD") in New England Markets (the "Binary Storage Facility DARD Changes"). The Binary Storage Facility DARD Changes are currently scheduled to become effective on January 1, 2024. Instead, ISO-NE asked that the effective date be deferred until such time as there is market interest in Binary Storage Facility DARD Regulation. ISO-NE stated that "Market Participants that operate the existing Binary Storage Facilities do not currently have the physical capability to provide Regulation when participating as a DARD, have not represented any immediate plans to develop that capability, and do not oppose the effective date deferral." ISO-NE further stated that the deferral would allow internal resources to be reallocated and focus on other pressing project priorities. Comments on the Deferral request were due on or before November 6, 2023; none were filed. NEPOOL, Calpine and National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions or concerns regarding this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On August 4, 2023, the FERC accepted ISO-NE and NEPOOL's proposed revisions to Appendix K to Market Rule 1 to update certain parameters within the Inventoried Energy Program ("IEP Parameter Updates").[46] Specifically, the IEP Parameter Updates: (i) replace the IEP's fixed rate with an indexed rate that automatically adjust to account for changes in gas markets prior to each winter period, (ii) modify natural gas contracting

[45] "Public Systems" for purposes of this proceeding are, again, CMEEC, MMWEC, NHEC, and VPPSA.

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

requirements to align the IEP more closely with common industry and commercial practices and the nature of firm pipeline service available in New England; and (iii) are meant to clarify and improve the administration of the IEP. The IEP Parameter Updates were accepted effective as of *August 4, 2023*.

Request for Rehearing Denied by Operation of Law; Allegheny Notice. As previously reported, Public Interest Organizations ("PIOs")[47] requested rehearing of the *IEP Parameter Updates Order*. On October 6, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[48] That Notice confirmed that the 60-day period during which a petition for review of the *IEP Parameter Updates Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of the *IEP Parameter Updates Order*. As of the date of this Report, there is no evidence that any party has petitioned a federal court for review of the *IEP Parameters Update Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

Oder Addressing Arguments on Rehearing; IEP Parameter Updates Allegheny Order. On November 30, 2023, the FERC issued an order addressing the PIO's arguments raised on rehearing.[49] The FERC modified the discussion in, but reached the same result as, the *IEP Parameter Updates Order*. In the *IEP Parameter Updates Allegheny Order*, the FERC continued to find that (i) "ISO-NE met its burden to show that the proposed Tariff revisions represent a just and reasonable means of updating the program payment rates to ensure that the [IEP] provides appropriate incentives and compensation for market participants to participate in the program"; and (ii) "ISO-NE's proposed indexed rates are expected to change market participants' behavior in the manner intended by the [IEP] and are a just and reasonable means of addressing the "misaligned incentives" problem that persists in New England. The FERC further explained why it was not persuaded by PIOs' arguments on rehearing.

If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

In a lengthy compliance Order[50] issued March 1, 2023, the FERC approved in part, and rejected in part, ISO-NE, NEPOOL and the PTO AC's ("Filing Parties") *Order 2222* compliance filing[51] ("*Order 2222 Compliance*

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

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

[49] *ISO New England Inc. and New England Power Pool Participants Comm.*, 185 FERC ¶ 61,151 (Nov. 30, 2023) ("*IEP Parameter Updates Allegheny Order*").

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

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

Order").[52] In the *Order 2222 Compliance Order*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*:

- ***30-Day Compliance Requirements (-003)***. The FERC accepted ISO-NE's 30-Day compliance filings (the first, a compliance filing to explain how current Tariff capacity market mitigation rules would apply to Distributed Energy Capacity Resources ("DECR") participating in FCA18; the second, an informational filing that provided an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets) on October 25, 2023.[53]

- ***60-Day Compliance Filing (-004)***. On November 2, 2023, the FERC conditionally accepted[54] ISO-NE's 60-day compliance filing,[55] subject to a further 90-day compliance filing, and granted in part ISO-NE's request for an extension of time to address directives in the *First Order 2222 Compliance Order*. In the *Order 2222 60-Day Compliance Filing Order*, the FERC, unpersuaded by Protestors' concerns,[56] found that ISO-NE complied with the *First Order 2222 Compliance Order*'s directives (i) to explain why its proposal to require measurement of behind-the-meter DERs not participating solely as demand response at the Retail Delivery Point, unless the Assigned Meter Reader can accommodate submetering or parallel metering of the DER, is just and reasonable and does not pose an unnecessary and undue barrier to individual DERs joining an aggregation; and (ii) to discuss the steps contemplated and the less burdensome alternative approaches considered. Although the FERC found that ISO-NE satisfied these aspects of its compliance requirements, it nevertheless encouraged ISO-NE to continue to work with stakeholders to consider additional metering options in the future, including for DERAs to utilize alternative submetering configurations.[57]

  However, the FERC found that ISO-NE only partially complied with the requirement to revise the Tariff to establish Market Rules that address metering requirements necessary for DERAs. Specifically, the FERC found that the Tariff appears to lack a deadline for meter data submission for settlements. Accordingly, the FERC directed ISO-NE to revise its Tariff to include the meter

---

[52] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*First Order 2222 Compliance Order*").

[53] *ISO New England Inc.*, Docket Nos. ER22-983-003 and ER22-983-005 (Oct. 25, 2023) (unpublished letter order) ("*October Order 2222 Compliance Order*").

[54] *ISO New England Inc.*, 185 FERC ¶ 61,095 (Nov. 2, 2023) ("*Order 2222 60-Day Compliance Filing Order*").

[55] The FERC ordered ISO-NE in its 60-day compliance filing to revise the Tariff to: (1) have RERRA make the determination of whether to allow customers of small utilities to participate in ISO-NE's markets through aggregation; (2) require that each DER Aggregator maintain and submit aggregate settlement data for the DERA; (3) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and if necessary, establish protocols for sharing meter data that minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity; (4) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; and (5) add specificity regarding existing resource non-performance penalties that would apply to a DERA when a Host Utility overrides ISO-NE dispatch instructions. ISO-NE was also directed to: (1) identify the existing rules requiring a Market Participant that provides energy withdrawal service to be a load serving entity that is billed for energy withdrawal ("LSE Requirement") and explain whether the LSE Requirement is required of all resources seeking to provide wholesale energy withdrawal service in the energy market; (2) explain why its proposed metering and telemetry requirements were just and reasonable and did not pose an unnecessary and undue barrier to individual DERs joining a DERA; (3) establish protocols for sharing metering data that minimize costs and other burdens and address privacy and cybersecurity concerns; and (4) address how ISO-NE will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA.

[56] Protestors (AEU/PowerOptions/SEIA) asserted that ISO-NE failed to make any adjustments to facilitate participation by DERs located behind a customer meter, and failed to justify the metering and telemetry provisions as directed by the FERC.

[57] *Order 2222 60-Day Compliance Filing Order* at P 77.

data submission deadline for settlement or explain why such Tariff revisions are not necessary. That further compliance filing is due on or before ***January 31, 2024***.[58]

ISO-NE's request for an extension of time to address directives in the First Order 2222 Compliance Order regarding submission of DERA meter data. In the *Order 2222 60-Day Compliance Filing Order*, the FERC directed ISO-NE to submit a further compliance filing, on or before ***January 31, 2024***, to comply with the directives of the First Compliance Order regarding the submission of DERA meter data. Specifically, the FERC directed ISO-NE to revise the Tariff to designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and to require that each DER Aggregator maintain and submit aggregate settlement data for the DERA, so that ISO-NE can regularly settle with the DER Aggregator for its market participation. To the extent that ISO-NE proposes in that further compliance filing that metering data come from or flow through distribution utilities, the FERC directed ISO-NE to coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing such metering data, and explain how such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity.[59]

- ***180-Day Compliance Filing (-005)***. The FERC accepted the Mitigation Compliance Revisions (an explanation of how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond and proposal that March 1, 2024 be the effective date for the rules allowing DECRs to participate in the FCM) in the *October Order 2222 Compliance Order*.

Request for Rehearing of Order 2222 60-Day Compliance Filing Order (-006). On December 4, 2023, AEU requested rehearing of the *Order 2222 60-Day Compliance Filing Order*. AEU asserted that the *Order 2222 60-Day Compliance Filing Order* is arbitrary and capricious because (i) it concludes, contrary to substantial record evidence, that ISO-NE's metering configurations do not pose an undue barrier to participation for most behind-the-meter DERs, and as such, are consistent with Order No. 2222; (ii) it fails to respond meaningfully to the arguments and record evidence submitted by AEU; (iii) it concludes that "ISO-NE satisfactorily discusses the steps that it contemplated and the less burdensome alternative approaches it considered" in connection with its metering proposal; (iv) it concludes that ISO-NE's description of submetering requirements for DERAs participating as Alternative Technology Regulation Resources ("ATRR") conforms to the FERC's orders; and (v) it concludes that ISO-NE's proposal to extend its existing requirements for Binary Storage Facilities ("BSF") and Continuous Storage Facilities ("CSF") to DERAs seeking to provide withdrawal service are consistent with *Order 2222*. The FERC must take action on AEU's request for rehearing by ***January 3, 2024***, or the AEU request will be deemed denied by operation of law.

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

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

[58] *Id.* at P 79.

[59] *Id.* at P 34.

IV. OATT Amendments / TOAs / Coordination Agreements

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

On October 31, 2023, UI filed changes to Appendix D of Attachment F to the ISO-NE OATT to incorporate the revised transmission plant depreciation and general plant depreciation rates used to calculate UI's annual transmission revenue requirements. Comments on this filing were due on or before November 21, 2023; none were filed. Bridgeport Energy filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On December 5, 2023, the FERC accepted revisions filed by National Grid to Appendix A to Attachment F to the ISO-NE OATT.[60] The revisions update NEP's fixed expense amount for transmission-related post-retirement benefits other than pensions ("PBOPs") to more accurately reflect the going forward expense level and allow the existing income statement credit incurred under the current formula rate to be refunded to customers. The revisions were accepted effective *January 1, 2024*. Unless the December 5 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).

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

On November 22, 2023, the FERC accepted revisions to Attachment F of the OATT filed by the PTO AC to correct minor errors in certain worksheets of the "Formula Rate Template" contained in Appendices A and B to Attachment F.[61] As previously reported, the PTO AC stated that the filing was limited to proposed Tariff revisions that fall within Moratorium Exception (i) subpart (o) of Attachment F and that the corrections and updates would not result in any additional costs being paid by New England ratepayers. The revisions were accepted effective as of *November 28, 2023*. Unless the November 22 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC issued orders conditionally accepting the Schedule 24[62] and Versant's MPD-OATT[63] *Order 676-J* Compliance Filings Part II, effective *February 1, 2024*, requiring in each case ISO-NE/NEPOOL[64] and Versant[65] to revise its tariff record to include the citation to its order granting the waivers requested. Versant submitted its changes to the MPD OATT on November 13, 2023; ISO-NE submitted the Schedule 24 changes on November 17, 2023. Comments on the compliance filings were due December 4, 2023 in the MPD OATT proceeding (none were filed) and are due ***December 8, 2023*** in the Schedule 24 proceeding. If there are questions on any of these filings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

---

[60] *ISO New England Inc. and New England Power Co.*, Docket No. ER24-125-000 (Dec. 5, 2023) (unpublished letter order).

[61] *ISO New England Inc.*, Docket No. ER23-2940-000 (Nov. 22, 2023) (unpublished letter order).

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

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

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

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

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

As previously reported, the FERC conditionally accepted the proposed revisions to the OATT in response to the requirements of *Order 881*[66] ("OATT *Order 881* Compliance Changes") on June 15, 2023.[67] The OATT *Order 881* Compliance Changes were accepted effective as of *July 12, 2025*, subject to two compliance filings – on due on or before August 14, 2023 (60-day compliance filing); the other, ***November 12, 2024*** (the AAR explanation filing). The 60-day compliance filing must (i) revise the Tariff to specify that transmission service at ISO-NE's seams use AARs as the basis for evaluation for near-term transmission service requests (or explain why ISO-NE should not be required to do so); (ii) revise the Tariff to include the examples listed in the FERC's *pro forma* Attachment M (or explain why ISO-NE should not be required to do so); (iii) remove proposed revisions to Schedule 18 excepting the Cross-Sound Cable from the requirements of *Order 881* (or explain why such changes should not be required); and (iv) revise the Tariff to require ISO-NE in a database that it maintains (rather than dividing responsibility between ISO-NE and transmission owners) to host all transmission line ratings, ratings methodologies, and exceptions or alternate ratings (or explain why they should not be required to do so). The AAR explanation filing must explain the timelines for calculating or submitting AARs.

(-001) 60-Day Compliance Changes. On August 14, 2023, ISO-NE, NEPOOL, the PTO AC, and CSC jointly filed revisions to Section II of the OATT in response to the requirements of the *New England Order 881 Compliance Order*. The further compliance changes (i) clarify that ISO-NE will use AARs at its seams; (ii) reinsert the list of exceptions in Attachment Q, and specify that the specific criteria for determining whether a transmission line is eligible for an exception will be detailed in ISO-NE's Planning and Operating Procedures; (iii) remove revisions to Schedule 18 proposed to except CSC from the requirements of *Order 881*; and (iv) modify both Attachment Q to the ISO OATT and Attachment M to Schedule 21-Common to require that ISO-NE host all ratings, ratings methodologies, and exceptions in its database. On December 4, 2023, the FERC accepted the *Order 881* 60-Day Compliance Changes, effective *July 12, 2025*, as requested.[68]

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

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

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

As previously reported, ISO-NE and Versant Power ("Versant") filed, on October 4, 2023, a Local Service Agreement ("LSA") by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro, LLC ("Jonesboro").[69] The filing parties stated that the LSA conforms to the *pro forma* LSA contained in the ISO-NE Tariff and reflects a discounted rate. The LSA was filed separately out of an abundance of caution as it was executed more than 30 days after commencement of service. The filing parties asked that the LSA be

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

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

[68] *ISO New England Inc.,* Docket No. ER22-2357-001 (Dec. 4, 2023) (unpublished letter order).

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

accepted for filing effective December 2, 2022.[70] Comments on the LSA filing were due on or before November 2, 2023; none were filed.

LSA Accepted; Waiver of Prior Filing Requirement Denied; Time Value Refunds Ordered. On November 30, 2023, the FERC accepted the LSA for filing, effective *December 4, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[71] 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") on or before ***January 2, 2024***; and (ii) to file a refund report, including information supporting calculation of the Time Value Refunds, on or before ***February 1, 2024***.

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

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

On November 30, 2023, the FERC accepted Eversource's notice of termination of the Interconnection Agreement ("IA") between PSNH and Great Lakes Hydro American LLC ("Great Lakes Hydro").[72] Eversource stated that the IA has been replaced by a standard LGIA that will be reported in ISO-NE's electric quarterly reports ("EQRs"). Eversource further stated that PSNH had finalized all billing and invoices and no further work was being done or service being provided under the IA. The notice of termination was accepted effective as of *October 5, 2023*, as requested. Unless the November 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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").[73] 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[74] to the extent necessary to permit a requested October 21, 2022 effective date. The LSA was filed separately given that requested effective date.

LSA Accepted; Waiver of Prior Filing Requirement Denied; Time Value Refunds Ordered. Similar to the Versant/Jonesboro proceeding (*see* ER24-24 above), the FERC accepted the National Grid/GMP LSA for filing, effective *November 11, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the

---

[70] *See* 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.

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

[72] *Public Service Co. of New Hampshire*, Docket No. ER24-17-000 (Nov. 30, 2023) (unpublished letter order).

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

[74] 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.

filing.[75] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties to make Time Value Refunds. On December 4, 2023, Filing Parties requested, and on December 6, 2023 the FERC granted, a 45-day extension of time (to ***January 22, 2024***) to make the Time Value Refunds, with the corresponding refund report to be filed no later than ***February 21, 2024***.

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

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

On July 28, 2023, the FERC accepted seven fully executed, non-conforming LSAs by and among Versant Power, ISO-NE and Black Bear Hydro Partners, LLC or Black Bear SO, LLC (together with Black Bear Hydro Partners, "Black Bear").[76] The service agreements are based on the Form of Local Service Agreement contained in Schedule 21-Common under the ISO-NE OATT, but were filed because they are non-conforming insofar as they reflect different rates from those set forth in Schedule 21-VP. The LSAs were accepted for filing effective August 1, 2023, rather than January 1, 2021 as requested, triggering a Time Value Refund requirement.[77] On August 29, 2023, Versant Power submitted a Refund Report detailing the Time Value Refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments on the Refund Report were due on or before September 19, 2023; none were filed. The Refund Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

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

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports[78]

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

On December 5, 2023, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2023 (the "Q3 Report").[79] As previously reported,

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

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

[77] 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 Versan t to operate at a loss) and file a refund report with the FERC.

[78] 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.

[79] *ISO New England Inc.*, Docket No. ER24-94 (Dec. 5, 2023) (unpublished letter order).

Q3 Report highlights included the following new projects: (i) DASI ($9.125 million); (ii) Operating System Server Upgrade Phase I ($2.383 million); (iii) nGEM Quarterly Production Release 2-2023 Integration ($265,000); and (iv) Offer-Prioritized Mitigation Enhancement ($140,000). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) Web to Cloud Migration ($350,000); (ii) MOPR Elimination ($88,000); and (iii) Control Room Voice Recorder Upgrade ($71,600). The Q3 Report was accepted effective *October 1, 2023*, as requested. Unless the December 5 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

On November 14, 2023, ISO-NE filed, as required,[80] public and confidential[81] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Third Quarter of 2023 ("2023 Q3"). ISO-NE reported that, with respect to:

- ***Interconnection Feasibility Study ("IFS") Reports***
  - All 7 2023 Q3 IFS Reports delivered to Interconnection Customers were delivered later than the best efforts completion timeline (90 days from the Interconnection Customer's execution of the study agreement).
  - 17 IFS Reports not yet completed have exceeded the 90-day completion expectation.
  - The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 383 days (roughly 200 days longer than in 2023 Q2).
- ***System Impact Study ("SIS") Reports***
  - All 3 of the SIS Reports delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days.
  - 24 SIS Studies that are not yet completed have exceeded the 270-day completion expectation.
  - The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 631 days (an increase of roughly 250 days from 2023 Q2).
- ***Facility Study Reports***
  - The 1 Facility Study Report delivered to an Interconnection Customer was delivered later than the best efforts completion timeline of 90 days.
  - 1 Facility Study that is not yet completed have exceeded the 290-day completion expectation for a 20% level of cost estimate.
  - The average mean time from ISO-NE's receipt of the executed Facility Study Agreement to delivery of the completed Facility Study report to the Interconnection Customer was 205 days (up 24 days from 2023 Q2 mean).

Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process

---

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

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

certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- **ISO-NE FERC Form 3Q (2023/Q3) (not docketed)**

On November 21, 2023, ISO-NE submitted its 2023/Q3 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **December 2023 Membership Filing (ER24-512)**

On November 30, 2023, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: Citadel Energy Marketing LLC (Supplier Sector); Downeast Wind, LLC [Related Person to Kleen Energy (Generation Sector)]; JGT2 Energy LLC (Generation Sector); and Qnti.fyi Inc. (Supplier Sector); and (ii) the termination of the Participant status of Sam Mintz (End User Sector). Comments on this filing, if any, are due on or before ***December 21, 2023***.

- **November 2023 Membership Filing (ER24-276)**

On October 31, 2023, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: BlueWave Public Benefit Corp. (AR Sector, DG Sub-Sector); Flatiron Energy Capital [Related Person to Pawtucket Power Holding (Generation Sector); Glenvale (AR Sector, RG Sub-Sector, Large Group Member); New England Power and Light (Supplier Sector); Precept Power (Supplier Sector); and Wallingford Energy [Related Person to Jericho Power et al. (AR Sector, RG Sub-Sector)]; and (ii) the name changes of Blueprint Power Technologies LLC (f/k/a Blueprint Power Technologies Inc.) and PSE US Holdings Inc. (f/k/a AMP Solar US Holdings Inc.). Comments on this filing were due on or before November 21, 2023; none were filed. This matter is pending before the FERC.

- **October 2023 Membership Filing (ER23-2966)**

On November 22, 2023, the FERC accepted: (i) the following Applicants' membership in NEPOOL: KCE CT 10, LLC and KCE CT 11, LLC [Provisional Members, Related Persons to KCE CT 5, LLC et al. (AR Sector, Distributed Generation Sub-Sector)]; and Sierra Club (effective *December 1, 2023*, End User Sector); and (ii) the termination of the Participant status of BP Energy Holding Company [Related Person to BP Energy Company et al. (Supplier Sector)].[82]

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

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

- **Report on 2022 Winter Storm Elliott (AD23-8)**

On November 7, 2023, the FERC posted a report on the "Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott" undertaken by FERC, NERC and Regional Entity ("RE") Staff. The report describes how the December 21-26, 2022 extreme cold weather event ("Winter Storm Elliott")[83] impacted the reliability of the Bulk Electric System ("BES"), the supporting natural gas infrastructure in the U.S. Eastern

[82] *New England Power Pool Participants Comm.*, Docket No. ER23-2966-000 (Nov. 22, 2023) (unpublished letter order).

[83] Winter Storm Elliott was the fifth event in the past 11 years in which unplanned cold weather-related generation outages jeopardized grid reliability, and had the largest controlled firm load shed recorded in the history of the Eastern Interconnection (more than 5,400 MW).

Interconnection, and service to consumers. This report makes recommendations designed to address matters identified in the report that call for improvement.

- **Revised Reliability Standard: PRC-023-6 (RD23-5)**

On November 3, 2023, NERC filed for FERC approval an amended petition for the approval of PRC-023-6 (Transmission Relay Loadability). NERC stated that PRC-023-6 would retire "redundant and unnecessary language that has contributed to confusion regarding the proper application of the PRC-023 standard to out-of-step blocking relays." Comments on the amended petition were due on or before November 27, 2023; none were filed. PRC-023-6 is pending before the FERC.

- **NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2)**

As directed by the FERC's December 15, 2022 order,[84] NERC, on April 14, 2023, provided an updated evaluation of CIP-014 (its "Physical Security Reliability Standard"). NERC concluded that CIP-014 applicability criteria is meeting its objective to "appropriately focus[] limited industry resources on risks to the reliable operation of the BPS associated with physical security incidents at the most critical facilities" and the objective is broad enough to capture the subset of applicable facilities that TOs should identify as "critical" pursuant to the risks assessment mandated by Requirement R1. NERC did not find evidence that an expansion of the applicability criteria would identify additional substations that would qualify as "critical" substations under the CIP-014 Requirement R1 risk assessment, declined to recommend expansion of the CIP-014 applicability criteria, but committed to continued evaluation of the adequacy of the applicability criteria in meeting the objective of CIP-014. Comments on NERC's report were due on or before May 15, 2023 and were filed by, among others: ISO-NE, Trade Associations, and WIRES.

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

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

As directed in the FERC's order accepting NERC's work plan to address registration of Inverter-Based Resources ("IBRs") that are connected to the BPS but not within NERC's definition of the bulk electric system ("non-BES IBRs"),[85] NERC filed on November 14, 2023, its second progress update on activities by the ERO Enterprise (NERC and the Regional Entities) to execute the Work Plan and initiate revisions to the NERC Registry Criteria to register owners and operators of non-BES IBRs that, in the aggregate, have a material impact on BPS reliability.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard

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

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

development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[86] on September 15, 2023. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the September 15 report, NERC reported that, because ballot body approval was again not achieved for two related Reliability Standards, the schedule for Project 2016-02 has been further revised and now calls for final balloting of revised standards in November 2023, NERC Board of Trustees Adoption in December 2023 and filing of the revised standards with the FERC in January 2024.

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

On October 19, 2023, the FERC issued a final rule[87] directing NERC to develop new or modified Reliability Standards that address reliability gaps related to inverter-based resources ("IBR") in the following areas: data sharing; model validation; planning and operational studies; and performance requirements. The FERC directed NERC to submit an informational filing on or before ***January 19, 2024*** that includes a detailed, comprehensive standards development plan providing that all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in *Order 901* be submitted to the FERC by ***November 4, 2026***.

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

On November 28, 2023, the FERC approved revisions to NERC's Rules of Procedure ("RoPs") regarding Reliability Standards (specifically, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual)).[88] As previously reported, the proposed revisions include new rules and authorities by which the NERC Board of Trustees may direct the development of needed Reliability Standards on its own initiative, subject to FERC approval. The proposed revisions also include streamlined comment and ballot procedures for draft Reliability Standards, as well as revisions that would both allow NERC the flexibility to implement the streamlined comment and ballot procedures proposed in the petition and consider other streamlining enhancements that may be appropriate and consistent with a fair and open process in the future. In approving the revisions, the FERC also directed NERC "to submit an informational filing no later than 18 months after the date of this order that discusses the effectiveness of the revised standards development process".[89]

XI. Misc. - of Regional Interest

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

On July 28, 2023, the FERC authorized[90] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). Pursuant to the July 28 order, Lessor and Lessee must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On April 17, 2023, Energy Harbor Corp., on behalf of Energy Harbor, LLC and Energy Harbor Nuclear Generation LLC (collectively, the "Energy Harbor Public Utilities"), and Vistra Corp. ("Vistra"), requested FERC

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

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

[88] *N. Amer. Elec. Rel. Corp.*, 185 FERC ¶ 61,146 (Nov. 28, 2023).

[89] *Id.* at PP 1, 28.

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

authorization for a proposed transaction pursuant to which the Energy Harbor Public Utilities and certain Vistra subsidiaries that are public utilities will become indirectly owned by a newly-formed subsidiary holding company of Vistra – Vistra Vision. Comments on this 203 application were due on or before June 23, 2023. Protests and comments were filed by Northeast Ohio Public Energy Council ("NOPEC"), Office of the Ohio Consumers' Counsel ("OH OCC"), and Monitoring Analytics, LLC (the PJM IMM). Public Citizen filed a doc-less intervention. Vistra and the Energy Harbor Public Utilities responded to the protests and comments. Answers to that answer were filed by PJM's IMM. Comments were filed by the Justice Department's Antitrust Division on August 22; Vistra and Energy Harbor answered those comments on September 5.

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

Tolling Order. On October 13, 2023, the FERC issued a notice that it requires additional time to "fully analyze the Application" and tolled the deadline to act on the Application until ***April 11, 2024***.[91]

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

- **E&P Agreement 2d Amendment: Seabrook/NECEC Transmission (ER24-508)**

On November 30, 2023, NextEra Energy Seabrook, LLC ("Seabrook") filed a second amendment to the Engineering and Procurement ("E&P") Agreement between Seabrook and NECEC Transmission LLC ("NECEC") (the "A&R E&P Agreement"). The A&R E&P Agreement covers the final engineering drawings through the procurement and delivery of the 24.5 kV generator circuit breaker and ancillary equipment to Seabrook Station in advance of the Fall 2024 outage. The second amendment seeks approximately $2 million in additional funding to cover higher engineering costs as well as changes to the scope of work related to a hydraulic controller, the generator breaker monitoring system, and other items. Comments on this filing are due on or before ***December 21, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Cancellation MECo / Dichotomy Collins Hydro (ER24-353)**

On November 3, 2023, Massachusetts Electric Company ("MECo") filed a notice of cancellation of an Interconnection Agreement ("IA") with Dichotomy Collins Hydro LLC ("DCH"), successor in interest to Swift River Company. The IA was superseded by a new SGIA between NEP and DCH filed with and accepted by the FERC.[92] MECo requested an effective date of *January 3, 2024* for the notice of cancellation. Comments on this filing were due on or before November 24, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On November 1, 2023, Eversource Energy, on behalf of The Connecticut Light & Power Company ("CL&P"), filed a Design & Engineering ("D&E") Agreement that sets forth the terms and conditions under which CL&P will perform necessary engineering, procurement and design services in connection with the interconnection of WE 400 Groton Road's 50 MW-load data center to CL&P's North Bloomfield 2A 115 kV substation. An effective date of November 2, 2023 was requested. Comments on this filing were due on or before November 22, 2023; none were

---

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

[92] *See New Eng. Power Co.*, Docket No. ER23-888-001 (June 12, 2023) (unpublished letter order).

filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On October 31, 2023, NSTAR filed for acceptance an Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") between itself and ENE. An effective date of November 26, 2023 was requested. Comments on this filing were due on or before November 20, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On January 31, 2023, ISO-NE and RIE filed two Local Service Agreements ("LSAs"), as replacements to two current New England Power TSAs (TSA-NEP-83 and TSA-NEP-86), to allow RI Energy to fully recover the Block Island Transmission System ("BITS") surcharge now that it is both Transmission Owner and Customer under these arrangements. On March 31, 2023, the FERC conditionally accepted the LSA replacing TSA-NEP-86 (ER23-1003), effective January 1, 2023,[93] and directed RI Energy, on or before May 1, 2023, to add language to the LSA to make explicit that the BITS Surcharge shall be subject to the Protocols for Schedule 21-RIE. That compliance filing was submitted on May 1, 2023 as directed. Also on March 31, 2023, FERC also issued a deficiency letter asking for additional information regarding whether the LSA replacing TSA-NEP-83 (ER23-1000) is subject to the Schedule 21-RIE Protocols. The response to the deficiency letter was also filed, as directed, on May 1, 2023. Comments on both May 1 filings were due on or before May 22, 2023. On May 22, RI Division of Public Utilities and Carriers ("RI Division") filed a protest requesting that the FERC reject RIE's May 1 compliance filing and direct it to amend the TSA to incorporate the formula rate protocols contained in ISO-NE OATT Attachment F, Appendix C (ER23-1003). No comments on RIE's May 1 deficiency letter response were filed (ER23-1000-001). On June 27, ISO-NE and RIE filed a joint motion requesting the FERC hold both proceedings in abeyance to allow RIE to continue discussions with the RI Division to resolve concerns raised by the Division, the resolution of which will affect the LSAs.

Amendments. On October 23, 2023, RIE filed amendments to the LSAs to incorporate the information and challenge procedures contained in Attachment F, Appendix C to the ISO-NE OATT. Those procedures would replace the section O (Audit Provisions) from Schedule II-B of NEP Tariff No. 1 that RIE proposed to incorporate in its Deficiency Response. In filing the Amendments, ISO-NE and RI Energy asked that the FERC no longer hold these proceedings in abeyance. Comments on the Amendments were due on or before November 13, 2023; none were filed. This matter is pending before the FERC. If you have any questions, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

XII. Misc. - Administrative & Rulemaking Proceedings[94]

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

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

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

94 Reporting on the following Administrative proceeding has been suspended since the last Report and will be continued if and when there is new activity to report: Interregional Transfer Capability Transmission Planning & Cost Allocation Requirements (AD23-3).

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

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

On November 14, 2023, the FERC invited all interested persons to file post-technical conference comments addressing issues raised during the Reliability Technical Conference and identified in the Second Supplemental Notice. Those comments are currently due on or before ***December 14, 2023***.[95] Thus far, comments have been submitted by Reliable Energy Analytics, US EPA Office of Air and Radiation, and Sue Tierney (who attached her prepared statement from the technical conference and her recently-prepared report on the same issues).

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

Joint statement of FERC Chairman Willie Phillips and NERC CEO James Robb. On November 6, 2023, FERC Chairman Phillips and NERC CEO Robb issued a joint statement regarding the potential loss of the Everett Marine Terminal and the consequences that it might have for the reliability and affordability of New England's energy supplies.

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

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

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

[95] EEI, supported by NRDC and the Clean Air Task Force ("CATF"), requested an extension of time, to ***Dec. 20, 2023***, to submit their comments.

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

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

As previously reported, a transcript of the last (7th) meeting[96] of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF") is posted in eLibrary.[97] In addition, on August 29, 2023, the FERC issued an order listing the state commission representatives who will serve on the Task Force, each for a one-year term, commencing September 1, 2023, and expiring August 31, 2024, including Commissioner Riley Allen (VT PUC) and Chair Marissa Gillett (CT PURA) from the NECPUC region.[98] Since the last Report, the FERC confirmed[99] that PA PUC Vice Chair Kimberly Barrow will serve out the remainder of the one-year term created by the passing of NJ BPU President Joseph L. Fiordaliso.

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

On October 19, 2023, the FERC issued a NOPR[100] 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-Comma-Separated Values standard; amend its regulations to require ISO/RTOs to produce reports containing market participant transaction data; and modify or clarify EQR reporting requirements. Requests for additional time to comment on the *EQR NOPR* were filed by EEI/EPSA, the IRC, and the Bonneville Power Administration ("BPA"). Those requests are pending before the FERC.

---

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

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

[98] The 2023/24 State Commissioner Transmission Task Force members are: (1) Commissioner John Howard, NY PSC; (2) President Joseph Fiordaliso, NJ BPU; (3) Chair Andrew French, KS Corp. Comm.; (4) Chair Dan Scripps, MI PSC; (5) Commissioner Riley Allen, VT PUC; (6) Chair Marissa Gillett, CT PURA; (7) Commissioner Kimberly Duffley, NC Utils. Comm.; (8) Chair Tricia Pridemore, GA PSC; (9) Commissioner Darcie Houck, CA PUC; and (10) Chair Thad LeVar, Utah PSC. *Joint Federal-State Task Force on Electric Transmission*, 184 FERC ¶ 61,126 (Aug. 29, 2023) (Order on Nominations).

[99] *Joint Federal-State Task Force on Electric Transmission*, 185 FERC ¶ 61,104 (Nov. 6, 2023).

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

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

On July 28, 2022, the FERC issued a NOPR[101] proposing to add a new section to its regulations to require that any entity communicating with the FERC or other specified organizations (e.g. ISO/RTOs, FERC-approved market monitors, NERC and its Regional Entities, or transmission providers) related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information, or omit material information ("Duty of Candor Requirements"). An entity would be shielded from violation of the new regulation if it has exercised due diligence to prevent such occurrences. The FERC's current regulations prohibit, in defined circumstances, inaccurate communications to the FERC and other organizations upon which the FERC relies to carry out its statutory obligations. However, because those requirements cover only certain communications and impose a patchwork of different standards of care for such communications, the FERC believes that a broadly applicable duty of candor will improve its ability to effectively oversee jurisdictional markets. It further indicated that its proposed due 'diligence standard' and other limitations are intended to minimize the additional burdens to industry that come with the new Duty of Candor Requirements.

On September 1, 2022, Joint Associations[102] requested an additional month to submit comments.[103] On September 14, 2022, the FERC granted that request. Accordingly, initial comments were due November 11, 2022 and over 30 sets of comments were filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA, APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange. The US Chamber of Commerce filed reply comments on December 12, 2022. There was no activity in the proceeding since the last Report. This matter is pending before the FERC.

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

On June 15, 2023, the FERC adopted a reporting requirement[104] that directs transmission providers to file a one-time informational report describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[105] (whether and how transmission providers establish a scope for their extreme weather vulnerability assessments, develop inputs, identify vulnerabilities and determine exposure to extreme weather hazards, estimate the costs of impacts, and develop mitigation measures to address extreme weather risks). Each transmission provider was required to file the one-time informational report required by *Order 897* on or before October 25, 2023.[106] ISO-NE and the TOs submitted their 51-page Report on October 25, 2023.

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

On July 28, 2023, the FERC issued *Order 2023*,[107] its final rule on proposed reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("LGIA"), and *pro forma* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. *Order 2023* adopts

---

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

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

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

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

[105] The FERC defines an extreme weather vulnerability assessment as any analysis that identifies where and under what conditions jurisdictional transmission assets and operations are at risk from the impacts of extreme weather events, how thos e risks will manifest themselves, and what the consequences will be for system operations.

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

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

reforms to: (i) implement a first-ready, first-served cluster study process;[108] (ii) increase the speed of interconnection queue processing;[109] and (iii) incorporate technological advancements into the interconnection process.[110] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of Proposed Rulemaking.[111] However, the FERC did revise aspects of the reforms.[112] *Order 2023* will become effective November 6, 2023,[113] which is 60 days from the September 6, 2023 publication of *Order 2023* in the *Federal Register* ("Publication Date").

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

---

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

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

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

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

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

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

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

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

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

Requests for Clarification and/or Rehearing Denied by Operation of Law. On September 28, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[114] The *Order 2023 Allegheny Notice* confirmed that the 60-day period during which a petition for review of *Order 2023* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of *Order 2023* within the required 30-day period. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." Several parties submitted petitions in Federal Court challenging *Order 2023*. Developments in those federal court proceedings will be summarized in Section XVI below.

October 25, 2023 Order Extending Compliance Deadline. On October 25, 2023, the FERC issued an order modifying the discussion in *Order 2023* and setting aside the *Order*, in part, to extend the deadline to submit compliance filings to ***April 3, 2024*** (210 days after the publication of *Order 2023* in the *Federal Register*).[115] The FERC clarified that its Order does not change or modify any other determination or other deadlines established by *Order 2023*, including the deadline for eligibility for interconnection customers to opt to proceed with a transitional serial study (for those interconnection customers tendered a facilities study agreement) or transitional cluster study (for those interconnection customers assigned a queue position) or to withdraw their interconnection requests without penalty (i.e., 30 calendar days after the transmission provider submits its initial compliance filing (or ***May 3, 2024***)).[116] A revised stakeholder schedule for consideration of New England's Order 2023 compliance filing was discussed at the November 9, 2023 Transmission Committee meeting.

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

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

On June 15, 2023, the FERC amended its regulations to require ISO/RTOs to have tariff provisions that permit credit-related information sharing with other ISO/RTOs to ensure that credit practices in those markets result in jurisdictional rates that are just and reasonable.[117] *Order 895* will not permit information sharing to be

---

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

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

[116] *Id.* at P 11.

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

conditioned on the specific consent of the market participant, would permit the receiving ISO/RTO to use market participant credit-related information received from another ISO/RTO to the same extent and for the same purposes that the receiving ISO/RTO may use credit-related information collected from its own market participants, and would not change the existing discretion an ISO/RTO has to act on credit-related information, regardless of the source of that information. The FERC stated that the ability of ISO/RTOs to share credit-related information among themselves will improve their ability to accurately assess market participants' credit exposure and risks related to their activities across organized wholesale electric markets and should also enable ISOs/RTOs to respond to credit events more quickly and effectively, minimizing the overall credit-related risks of unexpected defaults by market participants in organized wholesale electric markets. *Order 895* became effective *August 21, 2023*.[118] ISO-NE's proposed compliance changes were supported via the October 5 Consent Agenda (Item # 6), filed, and are pending before the FERC (*see* Section III above).

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

On December 15, 2022, the FERC issued a NOPR[119] proposing to revise its regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act. The *Transmission Siting NOPR* is intended to ensure consistency with the Infrastructure and Jobs Act's amendments to FPA section 216, to modernize certain regulatory requirements, and to incorporate other updates and clarifications to provide for the efficient and timely review of permit applications. Following a NARUC request for an extension of time granted by the FERC, comments on the *Transmission Siting NOPR* were due on or before May 17, 2023. Comments were filed by CLF, AL PSC, National Wildlife Federation Action Fund, National Wild Life Federation and State-Affiliated Organizations, AEU, CLF (May 16), NESCOE, ACPA, ACRE, Clean Energy Buyers Assoc., EDF, EEI/WIRES, Joint Consumer Advocates, Public Interest Organizations, SEIA, and US Chamber of Commerce. Commissioner Phillips' and each of the Commissioners' responses to Senator Schumer's and Senator Barrasso's letters have been posted to eLibrary. This matter is pending before the FERC.

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

Following its ANOPR process,[120] the FERC issued on April 21, 2022 a NOPR[121] that would require public utility transmission providers to:

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

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

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

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

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

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

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

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

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

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

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[122] Nearly 200 sets of comments were filed, including comments by NEPOOL, ISO-NE, Acadia/CLF, Anbaric, AEU, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

Reply Comments. Reply comments were due September 19, 2022. Nearly 100 sets of reply comments were filed, including by: ISO-NE, AEU, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, and SEIA. On November 28, 2022, the New Jersey BPU moved to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's State Agreement Approach ("SAA") for the purpose of supporting New Jersey's offshore wind ("OSW") goals, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report, which it stated demonstrates that competitive transmission solicitations can provide significant value to consumers. In December 2022, the Harvard Electricity Law Initiative, and P. Alaama submitted further comments.

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

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

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

XIII. FERC Enforcement Proceedings

- **2023 FERC Enforcement Staff Report (AD07-13-017)**

On November 16, 2023, staff of FERC's Office of Enforcement ("OE") issued its annual report summarizing the 2023 activities of OE and its three divisions (Investigations, Audits and Accounting, and Analytics and Surveillance). The report provides information regarding the nature of non-public OE activities, the administration of the audit, accounting and OE surveillance programs, and pointers to help companies enhance compliance programs.

Electric-Related Enforcement Actions

- **Black Hills Corp., et al. (IN23-10)**

On December 5, 2023, the FERC approved a Stipulation and Consent Agreement with Black Hills Corporation ("BHC"), as the corporate parent of, and on behalf of its three electric public utility subsidiaries, Black Hills Power, Inc. ("BHP"), Cheyenne Light, Fuel and Power Company ("Cheyenne Light"), Black Hills Colorado Electric, LLC ("Black Hills Colorado Electric") (together, "Black Hills"). Following a self-report, OE determined that Black Hills violated FPA section 205 and Part 35 of the FERC's regulations by commencing jurisdictional service, and entering into associated agreements, without providing the requisite notice or filing of the agreements. Under the Stipulation and Consent Agreement, Black Hills agreed to pay a ***$150,000 civil penalty***, and to submit compliance monitoring reports for 2 years. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

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

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[123] suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[124] 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

[123] 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.

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

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[125] 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,[126] 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;[127] (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.[128] This matter is pending before the FERC.

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

On April 28, 2016, the FERC issued a show cause order[129] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[130]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based

---

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

[126] *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").

[127] 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.

[128] *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.

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

[130] 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.

on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[131] On July 27, 2021, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule for the proceeding.

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas ("Southern District"). In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance.[132]

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[133] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *TGPNA Presiding Officer Reassignment Order* takes effect; (ii) held that the *TGPNA Presiding Officer Reassignment Order* will take effect once the Southern District clarifies or lifts its stay for the limited purpose of allowing the *TGPNA Presiding Officer Reassignment Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; (iii) stated that this proceeding otherwise remains suspended until the Southern District's stay is lifted or dissolved such that hearing procedures may resume; and (iv) provided procedural guidance to the new presiding officer. On July 18, Judge Patricia M. French was substituted as Presiding Judge (relieving Judge Krolikowski of all of her duties with respect to this proceeding).

XIV. Natural Gas Proceedings

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

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

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[134] 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

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

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

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

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

equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- In its September 8, 2023 monthly status report, Iroquois indicated that it is awaiting issuance of air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois has not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in August 2023 and no construction was planned for September.

XV. State Proceedings & Federal Legislative Proceedings

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

On August 30, 2022, the Maine Supreme Judicial Court concluded that the legislation enacted as a result of the passage of Maine's November 2, 2021 ballot question,[135] and that effectively halted construction of the NECEC Project,[136] was unconstitutional to the extent it required the legislation to be applied retroactively to the certificate of public convenience and necessity ("CPCN") issued for the Project if NECEC had acquired vested rights to proceed with Project construction (by undertaking substantial construction consistent with and in good-faith reliance on the CPCN before the Initiative was enacted). The Court remanded to the Business and Consumer Docket the factual question of whether NECEC performed substantial construction in good faith according to a schedule that was not created or expedited for the purpose of generating a vested rights claim (which it suggested appeared to be the case from the limited record developed in connection with the request for preliminary injunctive relief in this matter).

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

XVI. Federal Courts

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

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

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

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

- **Order 2023 (23-1282 (AEU); 23-1284 (MISO); 23-1289 (PacificCorp); 23-1293 (FPL); 23-1297 (SPP); 23-1299 (PJM); 23-1305 (FirstEnergy); 23-1310 (NYISO); 23-1312 (Dominion); 23-1313 (Exelon); 23-1320 (MISO TOs); 23-1327 (Avangrid) (consolidated)**
Underlying FERC Proceeding: RM22-14[137]
Petitioners: AEU et al.
Status: Initial Submissions Underway

Several Petitioners have challenged *Order 2023*. Those challenges have now been consolidated, with the AEU docket (23-1282) as the lead docket. Submissions of Statements of Issues and Docketing Statements are underway. The Parties were directed to file motions to govern future proceedings in these consolidated cases by ***December 12, 2023***.

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)**
Underlying FERC Proceeding: ER22-983[138]
Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
Status: Being Held In Abeyance; Motions to Govern Future Proceedings Due Jan 24, 2024

On June 30, 2023, ISO-NE (23-1168), CMP/UI (23-1170), Eversource (23-1167), and National Grid (23-1169) petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the FERC's *Order 2222 Compliance Orders*.[139] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case. On July 24, 2023, the FERC moved to have the consolidated cases held in abeyance pending the issuance of the Commission's further order on rehearing. The Court granted that motion on July 27, 2023, with the case to be held in abeyance pending further order of the Court. Since the last Report, on October 10, 2023, the FERC asked that the consolidated appeals be held in abeyance for a period of 90 days to allow time for all parties to assess the FERC's recent order and to make further filings either with the FERC or with the Court. On October 12, the Court ordered that the consolidated cases remain in abeyance pending further order of the court. The parties were directed to file motions to govern future proceedings in this case by ***January 24, 2024***.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
Underlying FERC Proceeding: EL21-6, EL 23-3[140]
Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
Status: Briefing Completed; Oral Argument Not Yet Scheduled

On April 4, 2023, NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC (collectively, "NextEra") petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the Seabrook

[137] *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).

[138] *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*").

[139] In response to the region's *Order 2222 Changes*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*, as described in previous Reports. When filed, the Filing Parties stated that the *Order 2222 Changes* create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

[140] *NextEra Energy Seabrook, LLC and NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC*, 182 FERC ¶ 61,044 (Feb. 1, 2023) *("Seabrook Dispute Order*"), *reh'g denied by operation of law*, *NextEra Energy*

Dispute.[141] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. Initial submissions have been filed,[142] as have the Certified Index to the Record, NextEra's Petitioners' Brief, the FERC's Brief (filed on September 28, 2023), Intervenors for Respondent's Joint Brief (October 12, 2023); Petitioners' Reply Brief (October 26, 2023); the Joint Appendix (October 30, 2023) and Final Briefs (November 3, 2023). With Briefing completed, the parties will next be informed of the date of oral argument and the composition of the merits panel.

- **Mystic II (ROE & *True*-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
  Underlying FERC Proceeding: EL18-1639-010, -011,[143] -013[144] -017[145]
  Petitioners: Mystic, CT Parties,[146] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Jan 24, 2024

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

---

Seabrook, LLC et al., 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Notice*"); *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 61,196 (June 15, 2023) ("*Seabrook Dispute Allegheny Order*").

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

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

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

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

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

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

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

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs*"). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*. The Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings related to MISO TOs, now on remand at the FERC. Most recently, on October 25, 2023, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the *MISO TOs* case. On October 26, 2023, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***January 24, 2024***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[147]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until March 1, 2024)

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

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

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[148]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[149] 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*[150] 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

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

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

[149] 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.

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

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

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on November 28, 2023.

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[151]
  Petitioners: Sierra Club
  Status: Oral Argument Held Sep 18, 2023; Awaiting Decision

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

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

INDEX
Status Report of Current Regulatory and Legal Proceedings as of December 6, 2023

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

No Activities to Report

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

XVI. Federal Courts