NEW ENGLAND POWER POOL
Sebastian M. Lombardi
Secretary

December 28, 2022

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of January 5, 2023 Participants Committee Teleconference Meeting

Pursant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is herby given that the January meeting of the Participants Committee will be held **via teleconference on Thursday, January 5, 2023, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, is **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

For your information, the January 5 meeting will be recorded. 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 the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

FOR PARTICIPANTS WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE THAT INVOICES FOR 2023 NEPOOL ANNUAL FEES WILL BE ISSUED IN FEBRUARY. If you are a member of the Pool on January 1, 2023, you will be assessed the NEPOOL Annual Fee in the February Monthly Statements that will be issued on Monday, February 13, 2023. To avoid a Payment Default and possible financial penalties, that invoice must be paid in full by Wednesday, February 15, 2023, so please plan accordingly. If there are questions, you can call ISO New England or Pat Gerity (860-275-0533).

Happy New Year.

Respectfully yours,

/s/
Sebastian M. Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the December 1, 2022 Participants Committee annual meeting. A copy of the draft minutes, marked to show the changes made since the minutes were 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 an ISO Chief Executive Officer report. The January CEO report is included with this supplemental notice and posted with the meeting materials.

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

5. To consider and take action, as appropriate, on changes to ISO New England Planning Procedure 5-1 (Procedure for Review of Market Participant's or Transmission Owner's Proposed Plan Application submittals), as recommended by the Reliability Committee. This item has been placed on this agenda for discussion at the request of Eversource. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

6. To receive a report on current contested matters before the FERC and the Federal Courts. The litigation report will be circulated and posted in advance of the meeting.

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

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

8. Administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, the 2022 annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, December 1, 2022, at the Colonnade Hotel, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by telephone.

Mr. David Cavanaugh, Chair, presided, and Mr. David Doot, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and guests who were present, including Connecticut Public Utilities Regulatory Authority Commissioner Michael Caron, the newly-elected president of the National Association of Regulatory Utility Commissioners.

PROPOSAL TO RAISE AGE LIMITATION ON ISO BOARD MEMBER ELECTION

Mr. Cavanaugh recognized Ms. Michelle Gardner, the Committee member for NextEra, the elected Generation Sector Vice-Chair and Joint Nominating Committee (JNC) member, to discuss changes she was proposing to the Participants Agreement to revise the age limit for ISO Board members from age 70 to age 75. She reminded members that the proposal was previously presented at the November 2 meeting and referred all to the materials circulated and posted in advance of the meeting. Ms. Gardner then introduced Ms. Jennifer Rockwood of Russell Reynolds Associates (RRA), who joined the meeting virtually, to provide additional insight on the challenges the 70 years' old age limit placed on recruitment efforts. Ms. Rockwood described how RRA identifies the potential candidate pool for outreach in ISO Board member searches. She noted that, after RRA identifies the candidate pool through significant vetting, 20% of those candidates were eliminated from the remaining candidates due to the age limit, which she explained was usually because they were discovered to be too old to stand for election or only able without waiver to serve for one term. She noted that there were other constraints, particularly financial and business conflicts, that also materially narrow the candidate pool for the region.

She clarified, in response to questions, that the 20% elimination rate was after RRA already removed from the pool candidates that they already recognized through their sources would be age-limited. It was clarified further in discussion that, while there was no express requirement that ISO Board members when first considered be of an age that they could be able to serve 3 terms (9 years) without a waiver of the age limitation, previous JNCs expressed a strong preference for candidates that could serve at least two terms due to the level of expertise and steep learning curve required of Board members. She then stated that RRA had previously presented candidates that were only eligible for one term but only when the candidate was an extremely strong fit. She explained that age was only one factor in determining the size of the potential candidate pool. The pool size could be highly affected by factors such as years of experience and level of technical expertise being sought by the JNC. She indicated that the age constraints made the candidate pool for ISO New England smaller that the candidate pools for other RTOs that utilize RRA services. Ms. Rockwood concluded by confirming that Participants could ease the difficulty in finding high-quality director candidates to serve on the ISO Board by raising the age limit from 70 to 75 years old.

Executive Session

At members' requests, and without objection, the Committee went into executive session at approximately 10:20 a.m. and Ms. Rockwood and those not Participant representatives left the meeting. Those present in executive session discussed the various reasons for raising the age limit to 75 as proposed and for maintaining the requirement that NEPOOL vote to grant a specific waiver for a nominee older than 70 to serve for a full term as a Board member. Following discussion, the Committee duly made, voted and approved the following motion that had been circulated and posted in advance of the meeting:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of an agreement amending the Participants Agreement, to amend § 9.2.3(a)(i) of the Participants Agreement (Terms of Directors) to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75 as presented at this meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair or any Vice-Chair of the Participants Committee, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

Following that vote, the Committee came out of executive session.

GENERAL SESSION

The Committee resumed the general session at approximately 11:00 a.m. Mr. Cavanaugh welcomed federal and state officials and guests who joined the meeting following the executive session. He then introduced FERC Commissioner James Danly.

REMARKS BY FERC COMMISSIONER JAMES DANLY

Commissioner Danly expressed his appreciation for the opportunity to speak in person and began with a discussion on the reliability challenges faced by New England. He noted that, although a vocal critic of the New England wholesale power markets, he was not anti-markets. Rather, Commissioner Danly opposed poorly designed markets with illegal tariffs. He explained his view that markets, if designed correctly, could provide positive outcomes, but this was not presently the case in New England. Commissioner Danly noted that the region's reliability problems were also a result of a failure of the region to build needed transmission facilities. Returning to the issue of market design, he said that, in his view, no market tariff could be just and reasonable under the Federal Power Act (FPA) without a minimum offer price rule or similar mechanism to retain the integrity of and purpose in forming the current markets. He acknowledged that other Commissioners had reached a different conclusion and said he looked forward to the federal courts' views on this matter.

Transitioning to a discussion of state public policies and their effects on the New England markets, Commissioner Danly acknowledged the unambiguous rights of states to enact energy policies to influence their resource mix as those states saw fit. However, the FERC was obligated to ensure that jurisdictional rates affected by state public policies remain just and reasonable. He reviewed the history of rate regulation and the evolution to market-based rates. Commissioner Danly explained that, in theory, fully competitive markets could produce just and reasonable rates but emphasized that the FERC's obligations to ensure just and reasonable rates had remained constant throughout the evolution of markets. He identified what he saw as a tension between states' policy goals and the desire for a market-based mechanism to produce just and reasonable rates and incentivize investments. Re-emphasizing the states' authority to incentivize and subsidize certain types of resources, Commissioner Danly questioned whether such actions could ever not impede the competition necessary for markets to produce just and reasonable rates. He suggested that, if states were not willing to allow markets to operate as designed, the markets should be reexamined. Commissioner Danly concluded his remarks by stating that he was perplexed by the lack of discussion on the dysfunctionality of the market caused by public policy and the impact on rates and reliability in the region.

In response to comments concerning the fuel supply challenges in New England and the suggestion to require generators to procure sufficient fuel to meet severe winter conditions, Commissioner Danly stated that a long-term solution could be to build more gas pipelines. Recognizing that building more pipelines may not be feasible, he opined that the Commission and a reviewing court could accept as just and reasonable a scheme to compensate generators for procuring fuel as a short-term solution. Notwithstanding this point, Commissioner Danly acknowledged that such an out-of-market solution could undermine proper price formation and noted that his acknowledgement that such a solution could be just and reasonable was indicative that the markets might be failing.

When asked for his opinion on the role of the North American Electric Reliability Corporation (NERC) on reliability and the FERC's role in overseeing the NERC's reliability standards, Commissioner Danly explained that the FERC could not use its oversight authority under Section 215 of the FPA to resolve reliability issues caused by fuel security issues. He also noted that the FERC's power rested with its authority to oversee tariffs.

A member noted that market-based mechanisms had been designed to provide energy adequacy and fuel security in New England and that other efforts, such as capacity accreditation, were underway to improve the market. In light of those comments, the member opined that a complaint proceeding under Section 206 of the FPA would not be ideal given the FERC's *ex parte* rules. After acknowledging ISO-NE's efforts in coming up with market solutions, Commissioner Danly noted that, despite the reality of the FPA's off-the-record communication strictures in a contested proceeding, there were ways to allow parties to speak with Commission staff to receive input and perspective. For example, members of FERC staff could be designated non-decisional. He also expressed his dislike for reliability-must-run agreements and clarified that he wa~~i~~s reluctant to encourage an energy-only market, despite his criticism of the capacity market.

In response to a request to share his thoughts on a letter from Eversource detailing the region's concerns entering into the winter and potential Jones Act waiver, Commission Danly noted that, as a general matter, the FERC neither actively participates in, nor is privy to, such policy discussions.

Finally, he was asked to comment on whether he thought the ISO and the region should continue to explore ways to harmonize decarbonization policies and clean energy objectives with competitive markets to produce just and reasonable rates. Commissioner Danly encouraged continued efforts to find a market-based solution but expressed skepticism on whether such a solution was possible, in a region with similar yet different state policies and goals, without running afoul of the FPA's just, reasonable, and not unduly discriminatory standard.

On behalf of the Committee, Mr. Cavanaugh thanked the Commissioner for his time and thoughtful comments.

ACKNOWLEDGEMENT – DOROTHY CAPRA AND DENIS BERGERON

After a short break for lunch, Mr. Cavanaugh welcomed members back and, before returning to the business at hand, acknowledged and expressed appreciation, on behalf of NEPOOL and the Participants Committee, to two longstanding colleagues, Ms. Dorothy Capra, NESCOE's Director of Regulatory Services, and Mr. Denis Bergeron, Senior Utility Analyst for the Maine Public Utilities Commission (MPUC), on their impending retirements and for their collegial collaboration with NEPOOL. Mr. Cavanaugh highlighted Ms. Capra's multifaceted roles in the NEPOOL process, including as a Vice-Chair of both the Transmission and

Reliability Committees, as a Generation and Transmission Sector representative, and most recently her more than 10 years as a NESCOE representative. Mr. Bergeron, he noted, had just received the NECPUC lifetime achievement award, and had been much appreciated for his work on behalf of the MPUC and NECPUC. The Committee congratulated Ms. Capra and Mr. Bergeron with a round of applause.

APPROVAL OF NOVEMBER 2, 2022 MEETING MINUTES

Mr. Cavanaugh then referred the Committee to the preliminary minutes of the November 2, 2022 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. Sam Mintz.

REVISIONS TO OP-24 AND APPENDIX D TO OP-24

Ms. Amy Crowley, the acting Chair of the Reliability Committee (RC), was introduced to present proposed revisions to the ISO's Operating Procedure 24 (Protection Outages, Settings and Coordination) (OP-24) and its Appendix D (Required Protection Outage Request Form and Examples) (together, the OP-24 Revisions). Before doing so, she reported that Ms. Emily Laine, the current RC Chair, had her baby two days earlier and both were doing fine. She then noted that, at its November 16 meeting, the RC considered and unanimously supported the OP-24 Revisions as reflected in the materials circulated in advance of the meeting and posted on the website, and the OP-24 Revisions would have been on the Consent Agenda but for the timing of the RC meeting. Without further discussion, the following motion was duly made, seconded and approved unanimously, with an abstention by Mr. Mintz:

RESOLVED, that the Participants Committee supports the OP-24 ~~and 24-D~~ Revisions, as recommended by the Reliability Committee at its November 16, 2022 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.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of ISO New England Board and Board Committee meetings, which had been circulated and posted in advance of the meeting. The only question on the summary was whether the materials shared with the Board concerning retail rates in the region were publicly available. In response, Ms. Anne George, the ISO's Vice President of External Affairs, noted that the specific documents provided to the Board were not public but the retail rates contained in those documents were pulled from publicly-available U.S. Energy Information Administration (EIA) information.

ISO COO REPORT

Operations Highlights Report

Dr. Chadalavada referred 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 November 21, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for November 2022 was $412 million, down $99 million from the updated October 2022 value and down $159 million from November 2021; (ii) October 2022 average natural gas prices were 2.34% lower than October average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for October ($64.69/MWh) were 24% higher than October averages; (iv) average October 2022 natural gas prices and Real-Time Hub LMPs over the period were up 10% and down 10%, respectively, from October 2021 average prices; (v) average Day-

Ahead cleared physical energy during peak hours as percent of forecasted load was 97% during November (down from 98.4% reported for October), with the minimum value for the month of 92.3% on November 8; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for November totaled $3.0 million, which was up $0.1 million~~M~~ from October 2022 and down $0.4 milllion~~M~~ million from November 2021. October NCPC payments, which were 0.5% of total Energy Market value, were comprised of $2.9 million in first contingency payments (up $0.2 million from October) and $40k in second contingency payments (down $100,000~~K~~ from October).

Turning to operational highlights from November, Dr. Chadalavada noted that the weather during the month was relatively moderate, with the exception of a single weekend where temperatures dropped to the high 20s° Fahrenheit (F) and low 30s° F. He said that t~~T~~he average temperature for November was 48° F. He further noted that November average load was the lowest average load recorded since 2003 (the implementation of Standard Market Design), which he attributed to the mild temperatures. Dr. Chadalavada then reminded Participants of the regional transmission outage on 345 kV Line 315 (West Farnum–Brayton Point) planned for December 5 through December 23, 2022, with some possibility of second contingency payments, depending on load levels, by those in lower Southeastern Massachusetts.

New England Winter Outlook 2022/2023 Update

Dr. Chadalavada then updated the Committee on the winter analysis. He reported that fuel stock had increased from 40% reported in the previous month to 46%, and the ISO anticipated that inventory to increase to 50% during December. Responding to questions from members, Dr. Chadalavada noted that the latest oil inventories survey would be posted shortly.

In response to questions concerning the reliability of weather forecast and trends from the National Oceanic and Atmospheric Administration (NOAA), he indicated that those forecasts and trends were averages, and were generally accurate, but were not indicative of how the ISO would position or posture the system.

2022 NEPOOL ANNUAL REPORT

Mr. Cavanaugh referred the Committee to the 2022 NEPOOL Annual Report distributed at the meeting and posted on the NEPOOL website. Mr. Cavanaugh thanked the Day Pitney team and the Vice-Chairs of each Sector and the Technical Committees for their efforts assembling and completing the Annual Report. He encouraged members to review the Annual Report.

ELECTION OF 2023 PARTICIPANTS COMMITTEE OFFICERS

Mr. Cavanaugh referred the Committee to the proposed slate of 2023 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting. The following motion was duly made, seconded and unanimously approved, with an abstention noted by Mr. Mintz:

> WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and
>
> WHEREAS, pursuant to those procedures the individuals identified in the following resolution were nominated and elected for 2023 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 2023 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	David A. Cavanaugh
Vice-Chair	Sarah Bresolin
Vice-Chair	Michelle C. Gardner
Vice-Chair	Aleksander Mitreski
Vice-Chair	Paul J. Roberti
Vice-Chair	Alan Trotta
Secretary	Sebastian M. Lombardi
Assistant Secretary	Patrick M. Gerity

ESTIMATED BUDGET FOR 2023 NEPOOL EXPENSES

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, reported that the B&F Subcommittee reviewed, at its November 20, 2022 meeting, the estimated budget for 2023 Participant Expenses, a copy of which was circulated and posted in advance of the meeting and is included as Attachment 2 to these minutes. He reported that there were no concerns or objections identified by Subcommittee members. He noted that an updated budget, distributed just prior to this meeting, had been updated to reflect adjustments to the 2022 Credit Insurance Premium, but made no change in the estimated Participant Expenses for 2023. Without further discussion, the following motion was duly made, seconded and approved unanimously, with an abstention noted by Mr. Mintz:

RESOLVED, that the Participants Committee adopts the estimated budget for NEPOOL expenses for 2023 as presented at this meeting.

LITIGATION REPORT

Mr. Lombardi, the newly-elected Secretary, referred the Committee to the December 1 Litigation Report that had been circulated and posted before the meeting. He highlighted the following:

(i) *New England Gas-Electric Winter Forum*. Over 50~~fifty~~ sets of post-Forum comments were filed;

(ii) *IEP Remand*. The ISO filed Tariff provisions governing the Inventoried Energy Program (IEP) in response to FERC directives following the D.C. Circuit decision requiring the elimination of nuclear, biomass, coal, and hydroelectric generators from the IEP. He reminded the Committee that the ISO's Tariff changes were supported by the Participants Committee at its November 2 meeting, as were alternative Tariff changes proposed by Brookfield that would expressly allow pumped hydro resources to participate in the IEP as Electric Storage Facilities. He said that NEPOOL would submit comments explaining the history and process leading up to the approval of both sets of proposed compliance changes; and

(iii) *Mystic Related Proceedings*. He reviewed v~~V~~arious developments in the Mystic~~-~~-related proceedings, including in the Complaint proceeding initiated by the Eastern New England Consumer Owned Entities, the approval of the offer of settlement related to the updates to the Cost of Service Agreement (COSA) reflecting Constellation's spin transaction, motions requesting expedited action on the cost allocation and clawback issues remanded to the FERC, and activity related to Mystic's first and second capital expenditure informational filings.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting was scheduled from December 6–8 in Westborough, MA. He note that, if FERC acted on the previous *Order 2222* changes jointly filed by ISO and NEPOOL, the MC would consider further changes to implement those *Order 2222* changes for FCA18. He said that the tentative December 21, 2022 MC had been canceled and would be rescheduled.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for December 20, also to vote on the ISO proposed Tariff changes to allow the participation of Distributed Energy Resource Aggregations in FCA18, but that meeting would be canceled should the FERC not issue an order on the ISO's *Order 2222* compliance filing by then.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting was scheduled for December 14 and would continue discussion on the Resource Capacity Accreditation program, as well as the initial extreme weather modeling results.

Budget & Finance Subcommittee. Mr. Kaslow reported that the next B&F Subcommittee meeting was scheduled for January 17, 2023.

Membership Subcommittee. Ms. Sarah Bresolin reported that the next Membership Subcommittee meeting was scheduled for December 12.

ADMINISTRATIVE MATTERS

Mr. Lombardi reminded members that the next Participants Committee meeting was scheduled for Thursday, January 5, 2023, and would likely be a virtual meeting. Mr. Cavanaugh stated that with new officers now elected for 2023, the Joint Nominating Committee (JNC) would meet to identify the next slate of nominees for the ISO Board of Directors. He noted that Mr. Roberto Denis was finishing his final term on the Board and would serve as the JNC Chair with support from Ms. Kathleen DeCastro, the ISO's new Vice President of Human Resources and Chief People Diversity Officer. He reported that the second term of Board member Mr. Brook Colangelo and the first term of Mr. Mark Vannoy were expiring in 2023 and both were eligible for re-election. He indicated that each of them would be coming to the Committee to review their experiences on the Board ahead of confidential Committee discussions concerning their potential re-election. Mr. Doot reminded members that they would be receiving early the following week ballots on the age limit proposal and encouraged members to vote and return those ballots.

There being no other business, the meeting adjourned at 1:00 p.m., followed by a celebration of my retirement with members and guests sharing memories, observations, comments, and perceptions that I will long remember and most appreciate. Thank you all for the honor and pleasure of serving you.

Respectfully submitted and signing off,

____
David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 1, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
Advanced Energy Economy	Associate Non-Voting	Caitlin Marquis		
AR Large Renewable Gen. (RG) Group Member	AR-RG	Abby Krich		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity			Brian Forshaw (tel)
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti (tel)
Bath Iron Works Corporation	End User			Bill Short; Gus Fromuth
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Pawtucket Power Holding Company	Generation	Kevin Telford	Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
Clearway Power Marketing LLC	Supplier			Pete Fuller
Competitive Energy Services	Supplier		Eben Perkins (tel)	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User			J.R. Viglione (tel)
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Constellation Energy Generation	Supplier	Steve Kirk	Bill Fowler (tel)	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Deepwater Wind Block Island, LLC	Generation	Eric Wilkerson (tel)		
DFC-ERG CT, LLC	AR-RG	Lauren Mix		
Dominion Energy Generation Marketing	Generation	Wes Walker	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short; Gus Fromuth
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Brett Kruse Liz Delaney		Bill Fowler (tel)
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Services	Supplier			Bill Fowler (tel)
Enel X North America, Inc.	AR-LR	Alex Worsley	Sarah Griffiths	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia (tel)
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User	Gus Fromuth		Bill Short
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler (tel)
Groton Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 1, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User	Gus Fromuth		Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Holyoke Gas & Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Hull Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
Icetec Energy Services, Inc.	AR-LR	Doug Hurley (tel)		
IDT Energy, LLC	Supplier		Glen Biren (tel)	
Ipswich Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	
Jupiter Power	Provisional Member			Ron Carrier (tel)
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			Jason Frost
Mansfield Municipal Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Maple Energy LLC	AR-LR			Doug Hurley (tel)
Marblehead Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Mass. Attorney General's Office (MA AG)	End User	Tina Belew (tel)	Jaimie Donovan	Ashley Gagnon
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	Nancy Chafetz (tel)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity			Brian Forshaw (tel)
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	
Mintz, Sam	End User	Sam Mintz (tel)		
Moore Company	End User			Bill Short; Gus Fromuth
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		Lindsay Orphanides (tel)
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin (tel)	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson (tel)	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User	Jason Frost		
NextEra Energy Resources, LLC	Generation	Michelle Gardner (tel)		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier	Neal Fitch	Pete Fuller	
Nylon Corporation of America	End User			Bill Short; Gus Fromuth
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Peabody Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
PowerOptions, Inc.	End User			Jason Frost
Princeton Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti (tel)		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity			Brian Forshaw (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 1, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Saint Anselm College	End User	Gus Fromuth		Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User	Gus Fromuth		Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity			Brian Forshaw (tel)
South Hadley Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Sterling Municipal Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunnova Energy Corporation	AR-DG			David Skillman (tel)
Sunrun Inc.	AR-DG			Peter Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
The Energy Consortium	End User	Bob Espindola (tel)	Mary Smith (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 (tel)
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity			Brian Forshaw (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			Brian Forshaw (tel)
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler (tel)	
Z-TECH LLC	End User		Gus Fromuth	Bill Short

ESTIMATED 2023 NEPOOL BUDGET COMPARED TO
2022 NEPOOL BUDGET AND 2022 PROJECTED ACTUAL EXPENSES

Line Items	2022 Approved Budget	2023 Proposed Budget	2022 Current Forecast
NEPOOL Counsel Fees (1)	$4,200,000	$4,350,000	$4,200,000
NEPOOL Counsel Disbursements (1)	$ 30,000	$ 30,000	$ 30,000
Independent Financial Advisor Fees and Disbursements (2)	$ 45,000	$ 48,000	$ 48,000
Committee Meeting Expenses (3)(4)	$ 725,000	$ 900,000	$ 550,000
Generation Information System (5)	$ 950,000	$1,022,438	$ 976,000
Credit Insurance Premium (3) (9)	$ 637,000	$ 799,000	$ 757,400
NEPOOL Audit Management Subcommittee (NAMS) Consultant (6)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$6,587,000	$7,149,438	$6,561,400
Revenue			
NEPOOL Membership Fees (3)	($2,140,000)	($2,300,000)	($2,301,700)
Generation Information System (5) (7)	($ 950,000)	($1,022,438)	($ 976,000)
Credit Insurance Premium (3) (8) (9)	($ 637,000)	($ 799,000)	($ 757,400)
TOTAL REVENUE	($3,727,000)	($4,121,438)	($4,035,100)
TOTAL NEPOOL EXPENSES	**$2,860,000**	**$3,028,000**	**$2,526,300**

Notes

(1) 2023 proposed estimate provided by Day Pitney LLP, NEPOOL counsel, reflecting modest increase in billing rates and challenging work plan in 2023.

(2) 2023 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor, and reflects increased responsibility for reviewing meeting and travel expenses.

(3) 2023 proposed estimate provided by ISO New England Inc. (ISO).

(4) 2023 proposed estimate is based on continuation of in-person meetings for NPC and Technical Committees and reflects increased charges imposed by venues when compared to pre-pandemic charges.

(5) 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 2023 is projected to be $997,500 for six months and $1,047,375 for six months. Estimate assumes NEPOOL will not exceed 500 development hours for changes to GIS, and any additional development hours would impose additional charges on NEPOOL. Estimate also assumes that costs incurred in connection with requested waivers of GIS Rules will be paid by the party seeking that waiver.

(6) If NEPOOL determines that an audit should be performed in 2023, funding for that audit will be addressed separately.

(7) GIS costs, other than those associated with accessing the GIS through the application programming interface (API) 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. GIS costs associated with accessing the GIS through the API are paid by the GIS account holders using that API.

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

(9) Due to increased costs in the New England Markets, the credit insurance premiums for the renewal period of December 1, 2022 - November 30, 2023 have increased. The final true-up of the premium for the period of December 1, 2021 to November 30, 2022 has not yet been determined, and the ISO was able to negotiate the premium for the 2022- 2023 period to be $688,500 (which is based on 2022 annual policy sales, escalated by a factor based on future expected fuel cost increases). The amounts shown for the 2022 forecast includes the 2022-2023 premium of $688,500 along with a true-up of $68,900 for the period of 2020-2021.

CONSENT AGENDA

Transmission Committee (TC)

From the previously-circulated notice of actions of the TC's November 22, 2022 meeting dated November 22, 2022.[1]

1. **OATT Attachment K and Tariff § 1.2.2 Changes - Economic Study Process Improvements**

   Support the revisions to Open Access Transmission Tariff Attachment K and Section I.2.2 (Definitions) of the Transmission, Markets, and Services Tariff to enable a repeatable economic study based on defined scenarios and stakeholder-requested sensitivities, as recommended by the TC at its November 22, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the TC may approve.

   The motion to recommend Participants Committee support was unanimously approved, with 2 abstentions in the Supplier Sector and 1 abstention in the Generation Sector.

Reliability Committee (RC)

From the previously-circulated, revised notice of actions of the RC's December 14, 2022 meeting dated December 14, 2022.[2]

2. **OP-5 Revisions – Periodic Review Changes**

   Support the revisions to ISO Operating Procedure No. 5 (Resource Maintenance and Outage Scheduling) (OP-5), which include (i) updates to the definitions of Maintenance Outage and Overrun Planned Outage; (ii) removal of transmission outage information revision applicability; (iii) updates to the Response Time Table; (iv) updates to Market Participant Responsibilities Information Requirements; (v) minor grammatical edits; (vi) the replacement of Generator with Resource when that term is utilized as a general identification; and (vii) the removal of Generator from Qualified Reactive Resource to align with OP-23, all as recommended by the RC at its December 14, 2022 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 Notice of Actions are posted on the ISO-NE website at https://www.iso-ne.com/committees/transmission/transmission-committee/?document-type=Committee%20Actions.

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

Summary of ISO New England Board and Committee Meetings

January 5, 2023 Participants Committee Meeting

Since the last update, the Information Technology and Cyber Security Committee met virtually on December 15.

The Information Technology and Cyber Security Committee received a presentation from Dr. Tommy Gardner, Chief Technology Officer for HP Federal. Next, the Committee was provided with an update on the Company's three-year cyber security plan, and discussed completed projects and the plan's major areas of emphasis going forward. The Committee reviewed the Company's business continuity and disaster recovery plans, and discussed the current initiatives underway to update business processes, further develop and refine disaster recovery plans, and to perform periodic testing. The Committee also conducted its annual review of the IT-related portions of the Internal Audit Department's work plan. Next, the Committee received a report on the May 18 information technology outage, in which reliability operations were unaffected, and discussed a root cause analysis and how causal factors are being addressed. The Committee then held an executive session to discuss the achievement of corporate goals for 2022, and the proposed corporate goals for 2023.

NEPOOL Participants Committee Report

January 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through December 27th

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: November 2022 Energy Market value totaled $649M
  - December 2022 Energy market value was $1.2B, up $530M from November 2022 and up $459M from December 2021
    - December 2022 natural gas prices over the period were 157% higher than November average values
    - Average RT Hub Locational Marginal Prices ($126.19/MWh) over the period were 87% higher than November averages
      - Avg. DA Hub: $117.21/MWh
    - Average December 2022 natural gas prices and RT Hub LMPs over the period were up 77% and 112%, respectively, from December 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 97.4% during December, up from 97% during November*
    - The minimum value for the month was 91% on Friday, December 23rd

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

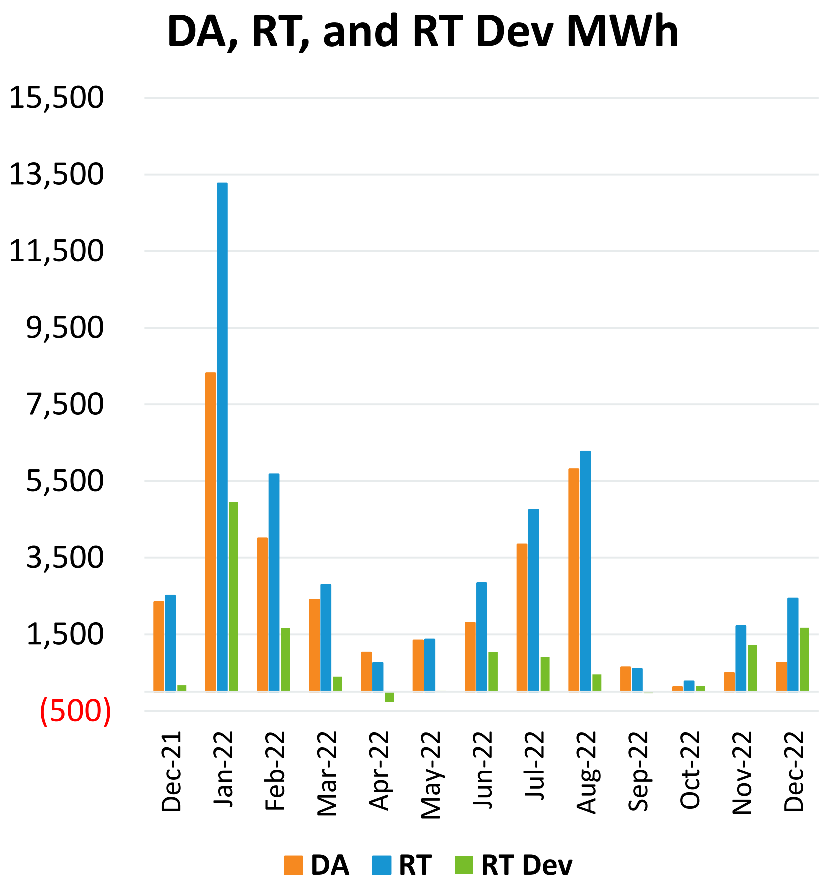
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

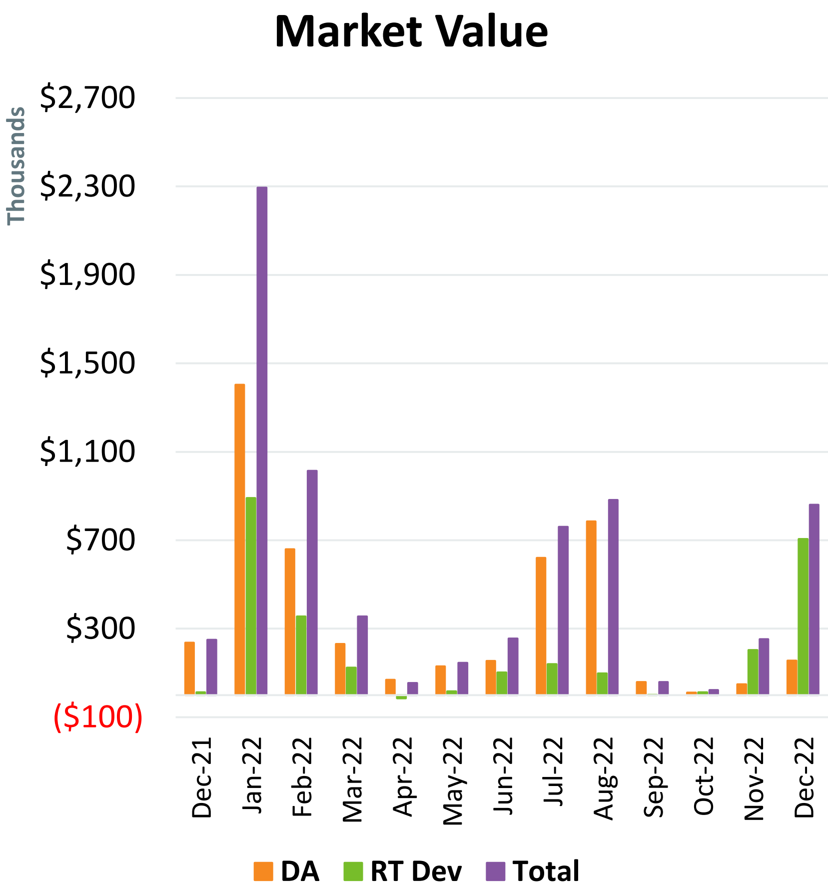
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - December 2022 NCPC payments totaled $6.2M over the period, up $2.5M from November 2022 and up $0.8M from December 2021
    - First Contingency payments totaled $6.1M, up $2.5M from November
      - $6.1M paid to internal resources, up $3M from November
        - » $1.3M charged to DALO, $2.4M to RT Deviations, $2.5M to RTLO*
      - $25K paid to resources at external locations, down $531K from November
        - » $1K charged to DALO at external locations, $24K to RT Deviations
    - Second Contingency payments totaled $78K, up $38K from November
    - Voltage and Distribution payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $951K; Rapid Response Pricing (RRP) Opportunity Cost - $1.4M; Posturing - $0K; Generator Performance Auditing (GPA) - $85K**

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

- ISO began initial discussions on the 2050 Transmission Study solution development and lessons learned at the 12/13/22 PAC meeting
- Storage as a Transmission-Only Asset (SATOA) was filed with FERC on 12/29/22
- The Economic Study Process Improvement project to update Attachment K of the OATT will be up for a vote at the 1/5/23 PC meeting and expected to be filed with FERC in January
- The next Load Forecast Committee meeting is scheduled for February 24 and will include discussions of final electrification forecasts and draft energy and demand forecasts
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 7, 2023.

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, 2022 and results were posted on August 31, 2022
  - ARA3 will be held in March 2023
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, 2022 and results were posted on June 28, 2022
  - ARA2 will be held in August 2023
- CCP 16 (2025-2026)
  - Auction results were filed with FERC on March 21, 2022 and on July 18, 2022 FERC issued an order accepting the results effective July 19, 2022
  - ARA1 will be held in June 2023

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - FCA 17 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - Qualification determination notifications were issued on November 10, 2022
  - FCA 17 Installed Capacity Requirement and related values were filed with FERC on November 8, 2022
  - ISO submitted the FCA 17 informational filing to FERC on December 21, 2022

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 11, 2022
    - TOs to identify in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects to be shared with the RC at their January 2023 meeting
  - Capacity zone development discussions began at the December 13, 2022 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (0.1°F) Max: 59°F, Min: 11°F Precipitation: 3.40" – Below Normal Normal: 3.93" Snow: 1.0"	Hartford	Temperature: Below Normal (0.1°F) Max: 59°F, Min: 7°F Precipitation: 4.18" - Above Normal Normal: 3.71" Snow: 0.7"

Peak Load:	17,802 MW	Dec 12, 2022	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	12/24/2022 16:00	12/24/2022 21:00	Capacity
OP-4	12/24/2022 16:30	12/24/2022 19:00	All of New England - Capacity

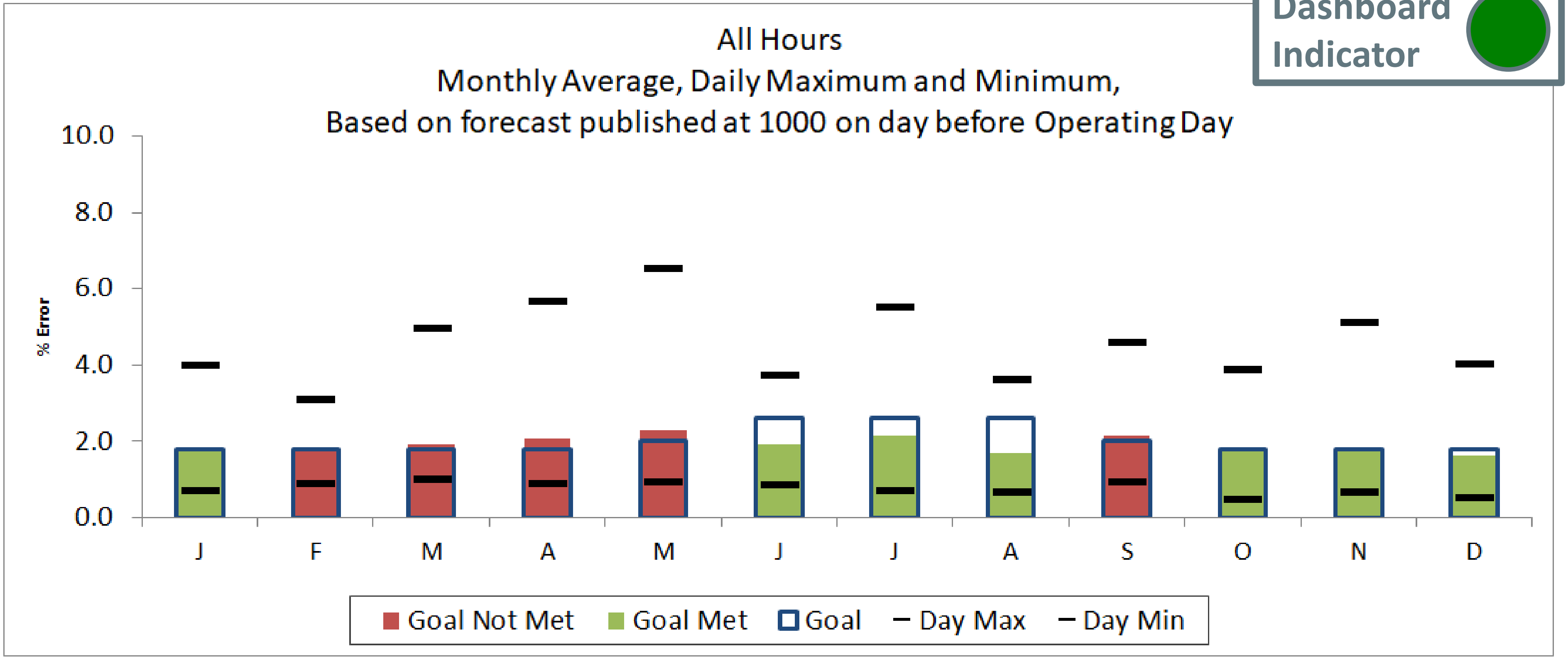
System Operations

NPCC Simultaneous Activation of Reserve Events

Date / Time	Area	MW Lost
12/14 23:57	NBPSO	710
12/23 16:57	PJM	3000
12/23 17:35	PJM	2000
12/23 23:05	ISO-NE	515
12/24 02:23	PJM	1209
12/24 04:26	PJM	2000
12/24 13:59	NYISO	540
12/26 00:10	NYISO	610

2022 System Operations - Load Forecast Accuracy

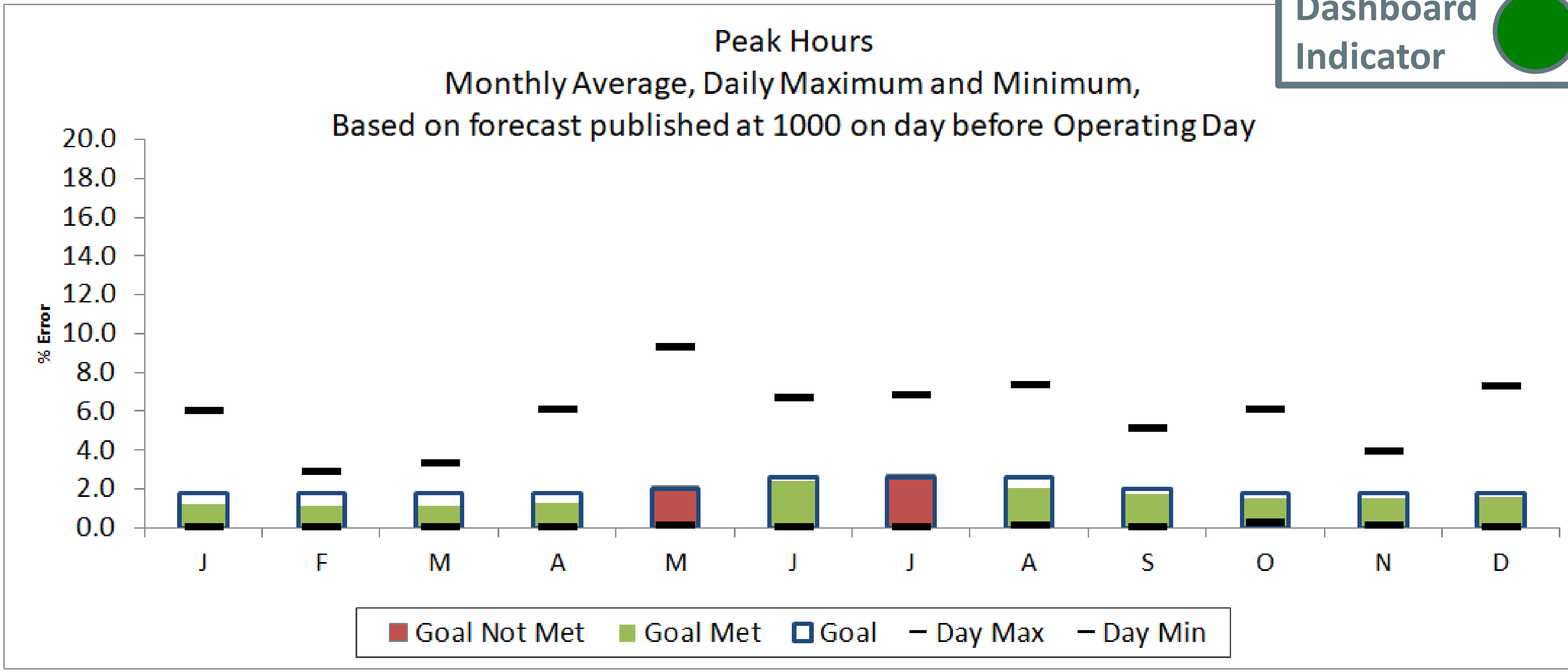
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.97	3.07	4.92	5.66	6.52	3.71	5.48	3.61	4.56	3.85	5.09	4.02	6.52
Day Min	0.69	0.87	0.97	0.85	0.91	0.83	0.69	0.66	0.90	0.46	0.64	0.48	0.46
MAPE	1.79	1.81	1.93	2.05	2.30	1.92	2.13	1.70	2.13	1.74	1.80	1.60	1.91
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

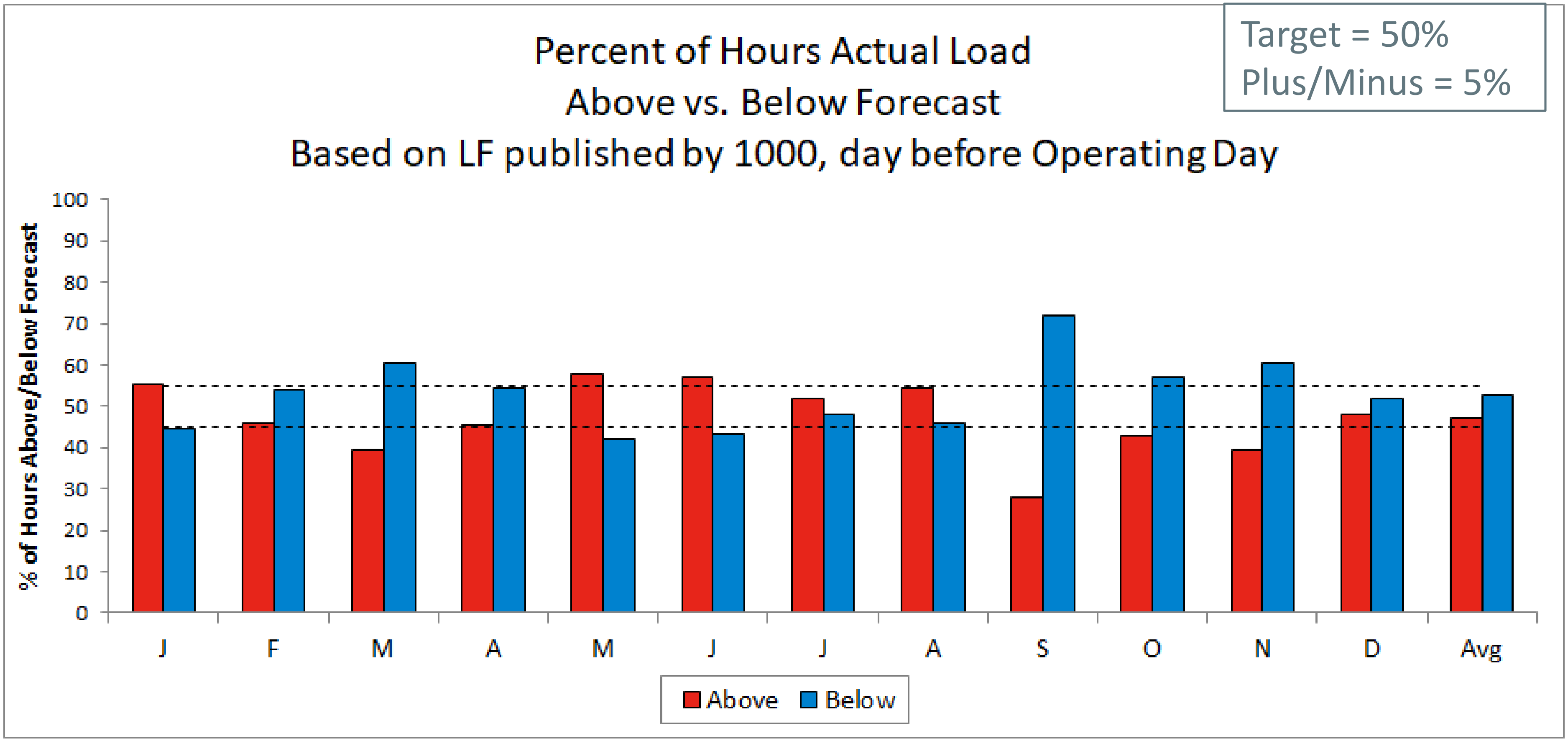
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



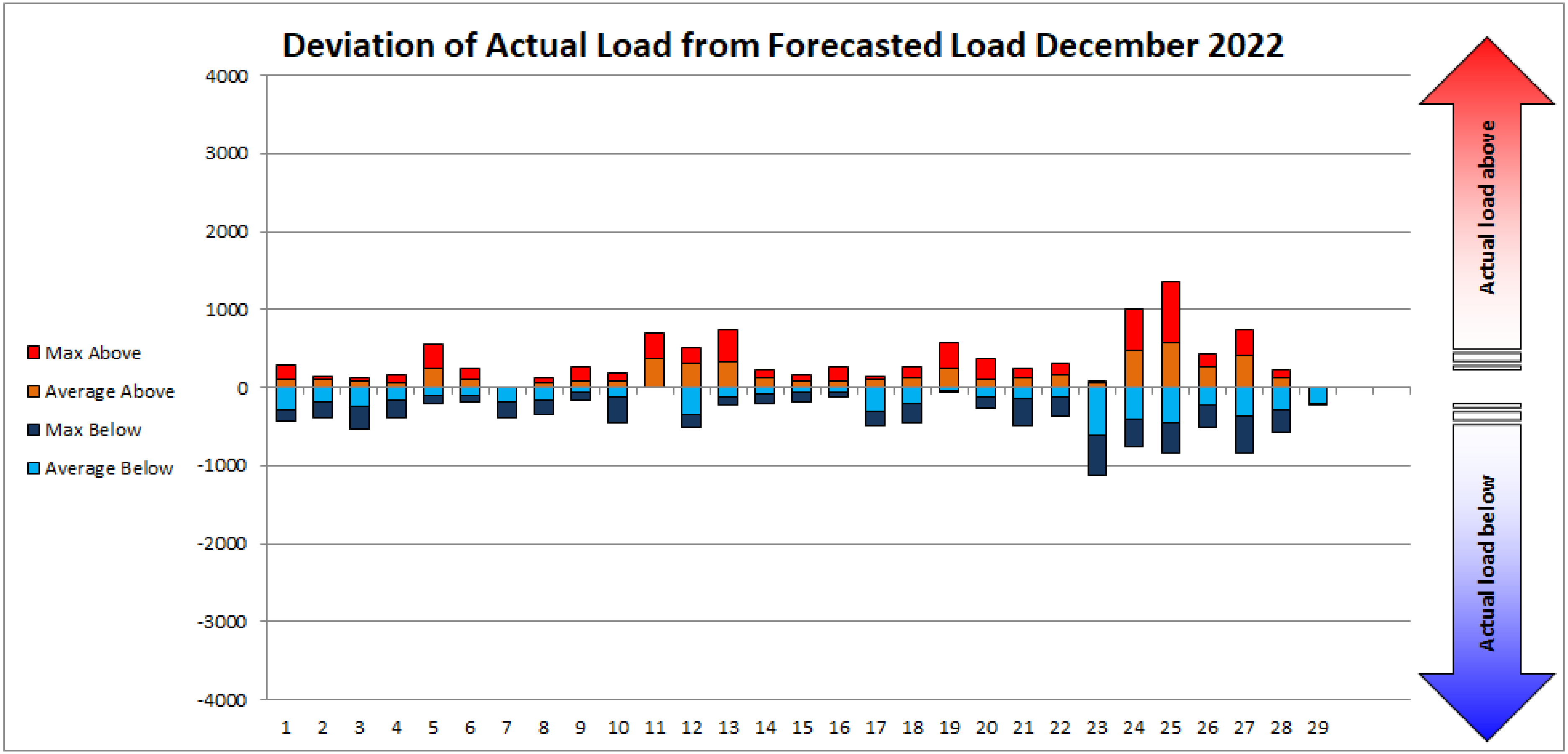
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85	3.32	6.08	9.27	6.70	6.85	7.31	5.12	6.04	3.92	7.30	9.27
Day Min	0.02	0.03	0.04	0.00	0.06	0.01	0.02	0.08	0.01	0.21	0.06	0.05	0.00
MAPE	1.25	1.11	1.13	1.29	2.14	2.43	2.73	2.06	1.71	1.55	1.51	1.58	1.71
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

2022 System Operations - Load Forecast Accuracy cont.

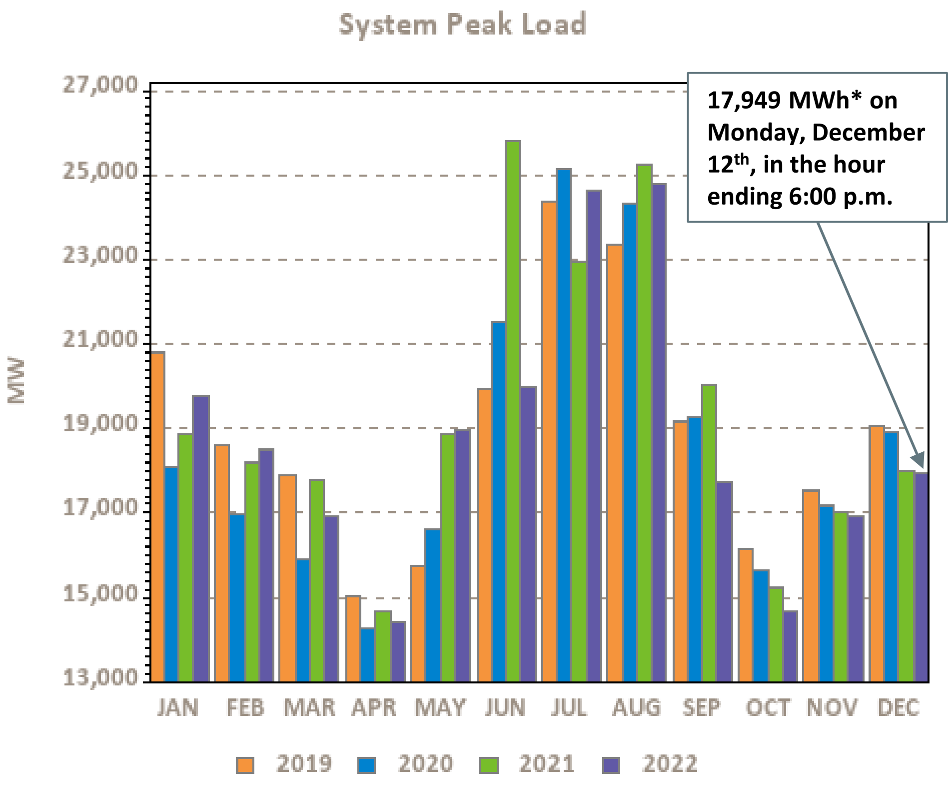


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46	39.7	45.6	57.8	56.8	51.9	54.3	27.9	43.1	39.6	48.2	47
Below %	44.8	54	60.3	54.4	42.2	43.2	48.1	45.7	72.1	56.9	60.4	51.8	53
Avg Above	219.5	245.7	175.9	180	217.2	209.6	268.3	208.5	128.1	122.8	133.3	161.8	268
Avg Below	-223.1	-207.6	-240.0	-191.5	-192.2	-215.9	-295.8	-281.9	-255.3	-177.2	-201.0	-186.7	-296
Avg All	22	6	-78	-18	30	23	5	-26	-134	-57	-78	-15	-27

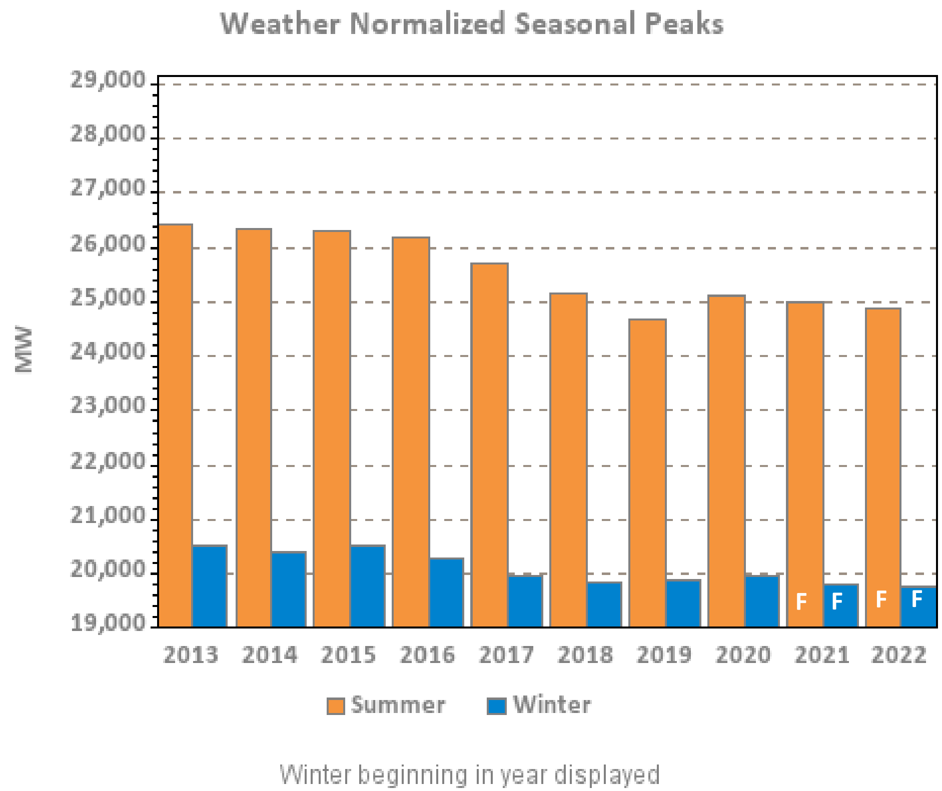
2022 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History



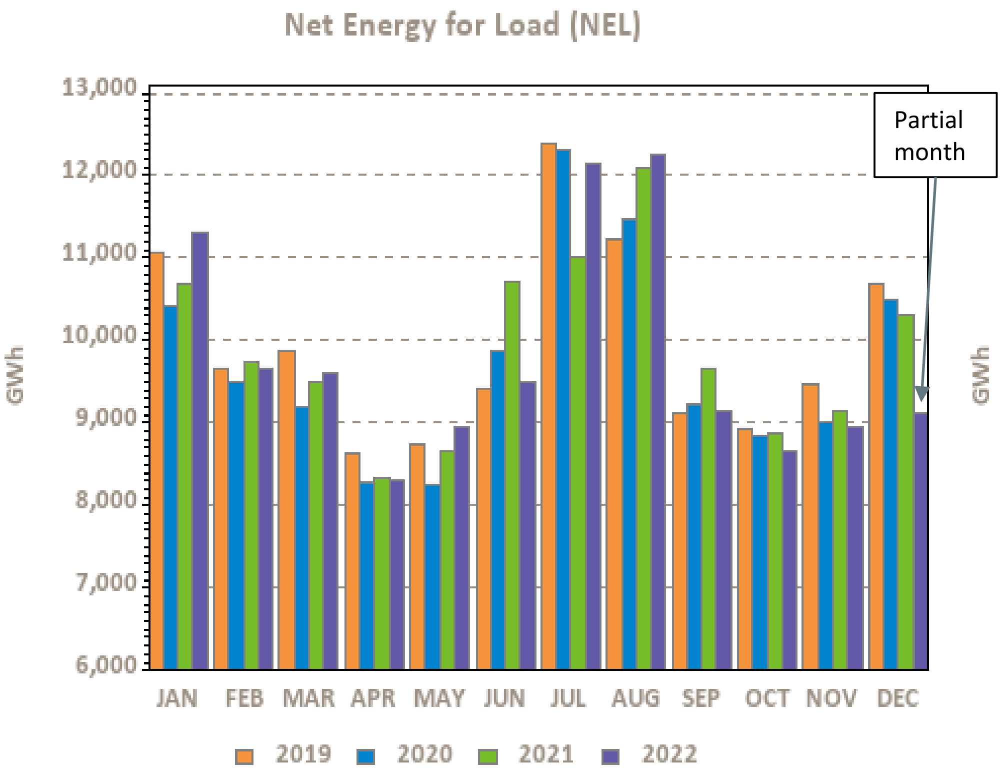
*Revenue quality metered value



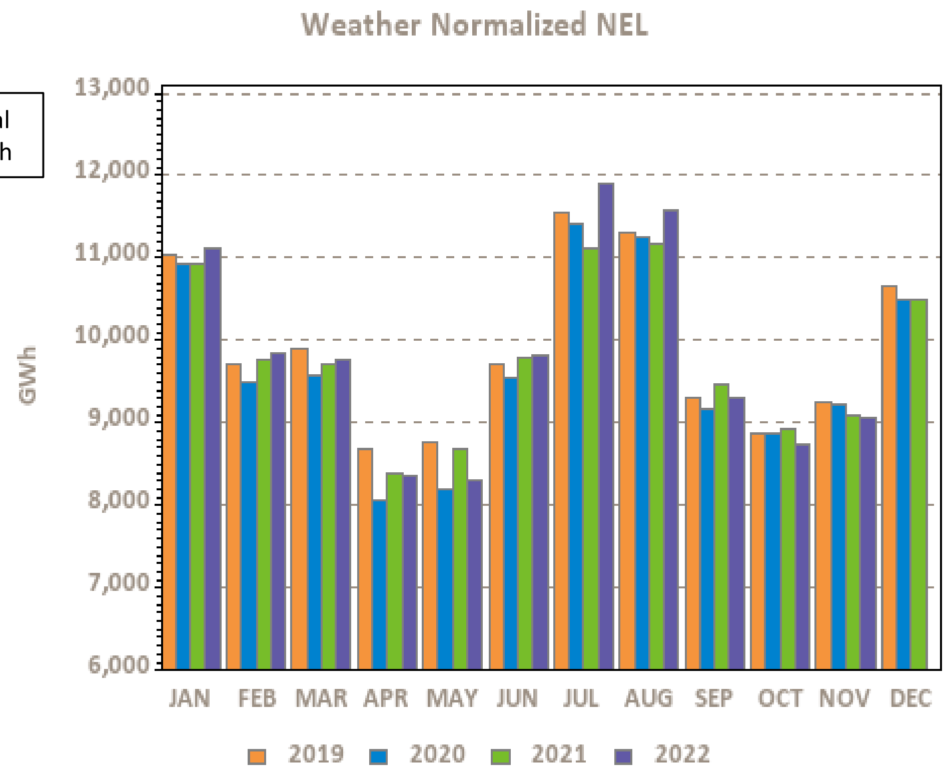
Winter beginning in year displayed

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): 119.2 116.9 118.8 117.6

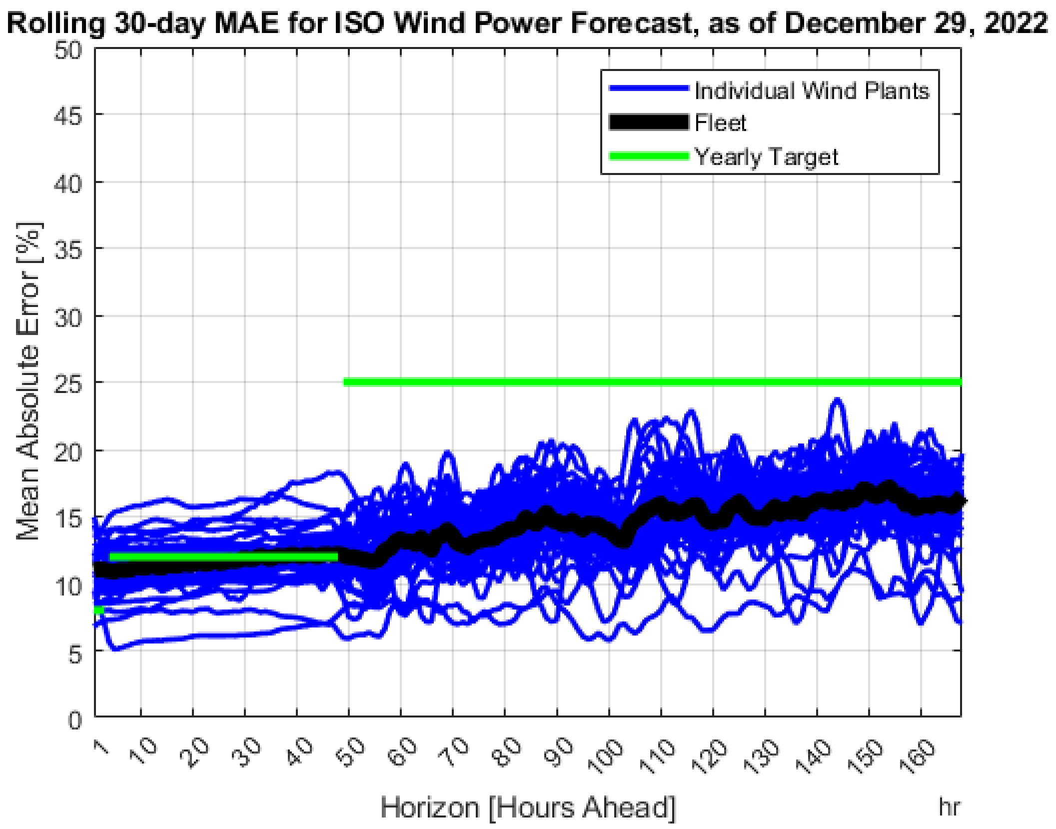


Ann Tot (TWh): 118.8 116.3 117.6 107.8

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

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

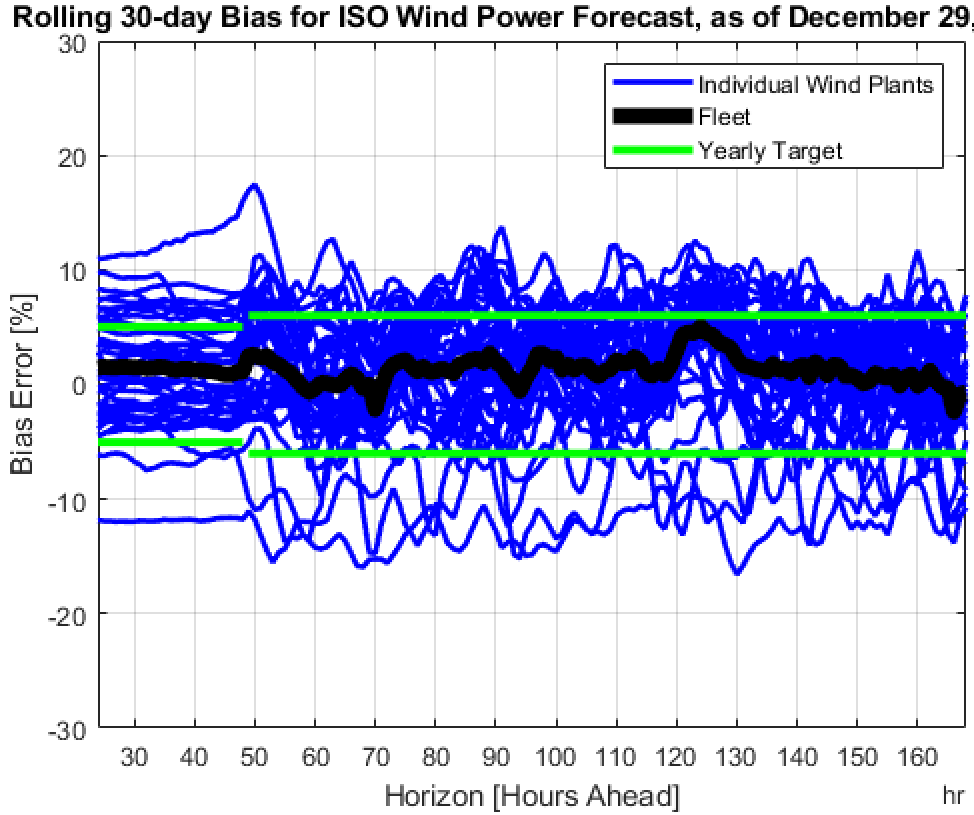
Dashboard Indicator



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

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

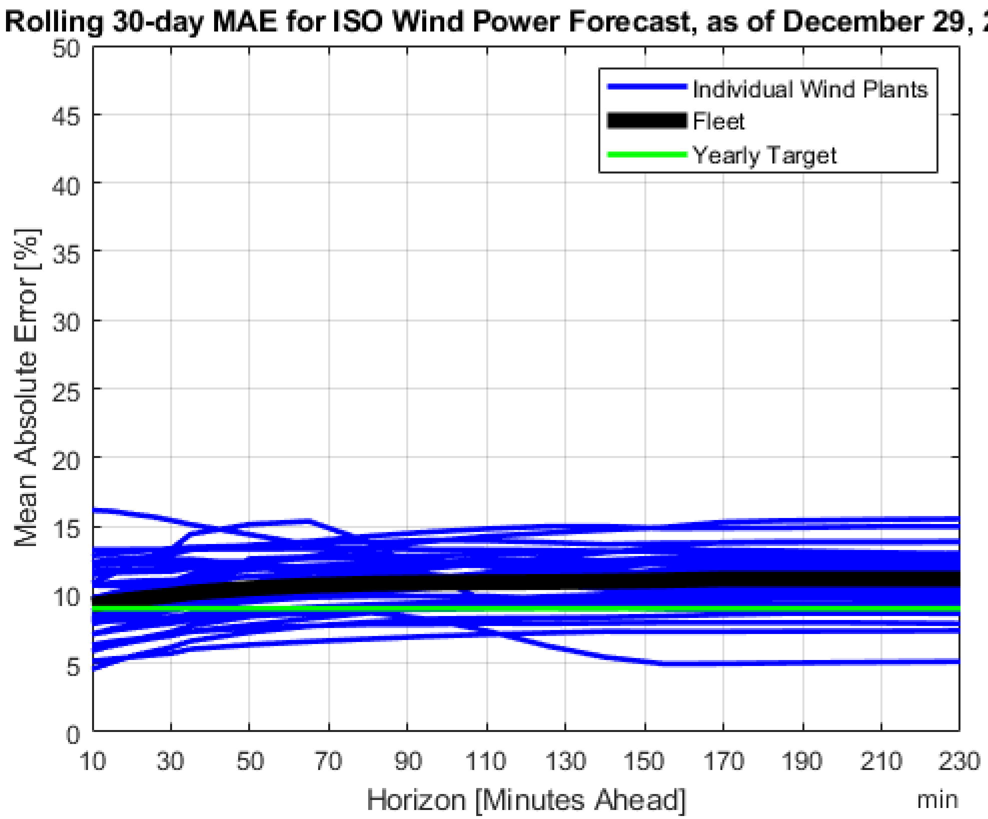
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

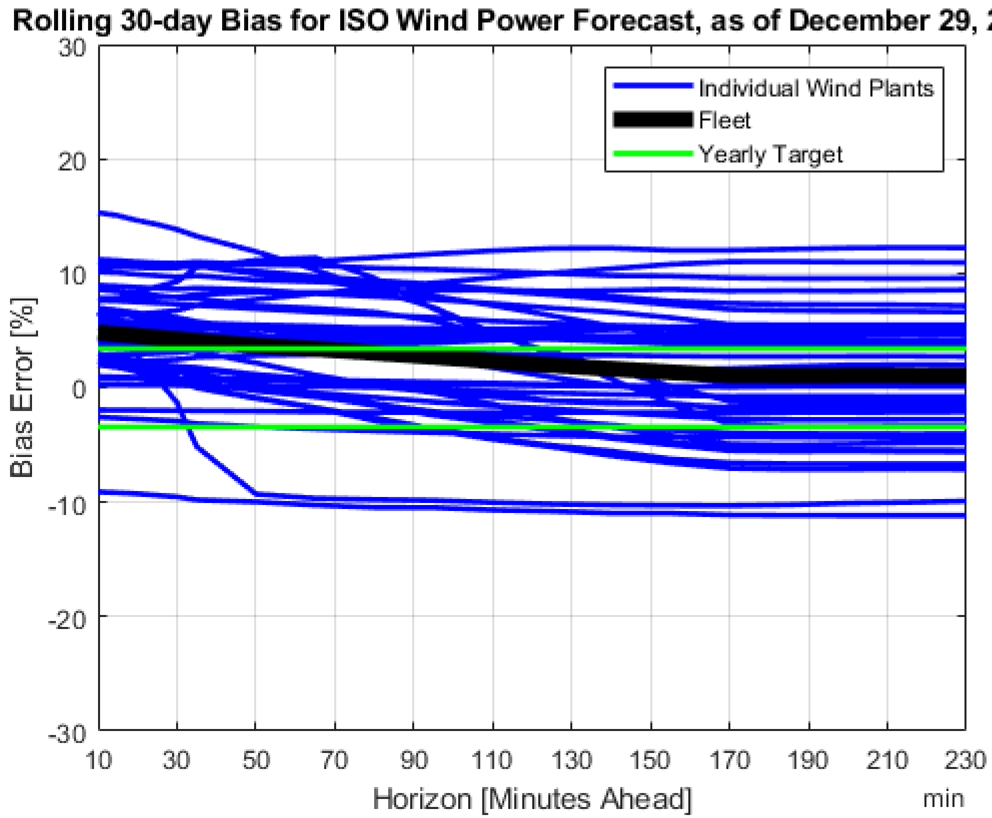
Dashboard Indicator



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. While the ISO-NE/DNV forecast compares with industry standards, monthly MAE is outside yearly performance targets. Recently implemented corrective changes have not had time to effect monthly statistics.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

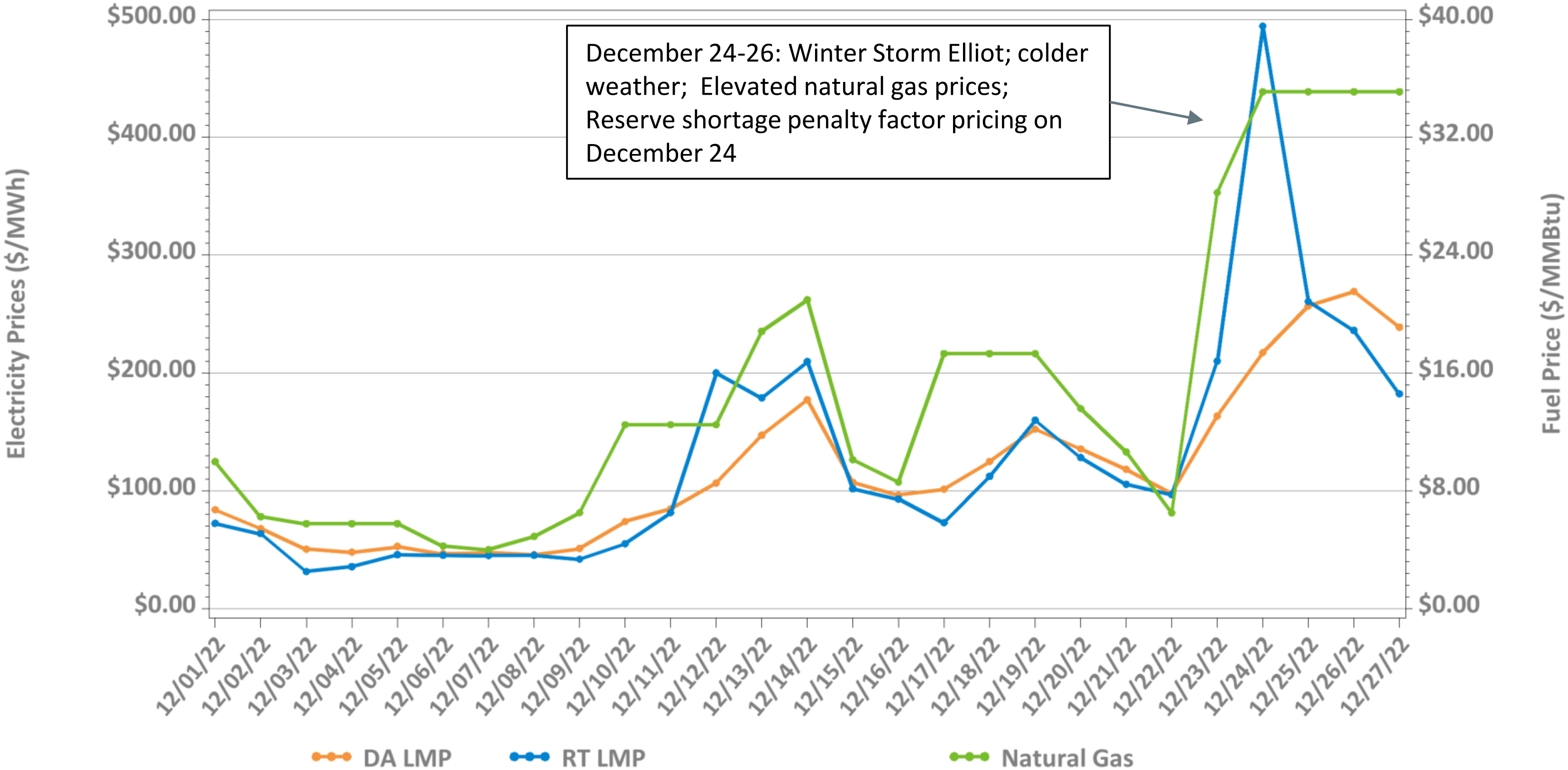
Dashboard Indicator



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: December 1-27, 2022

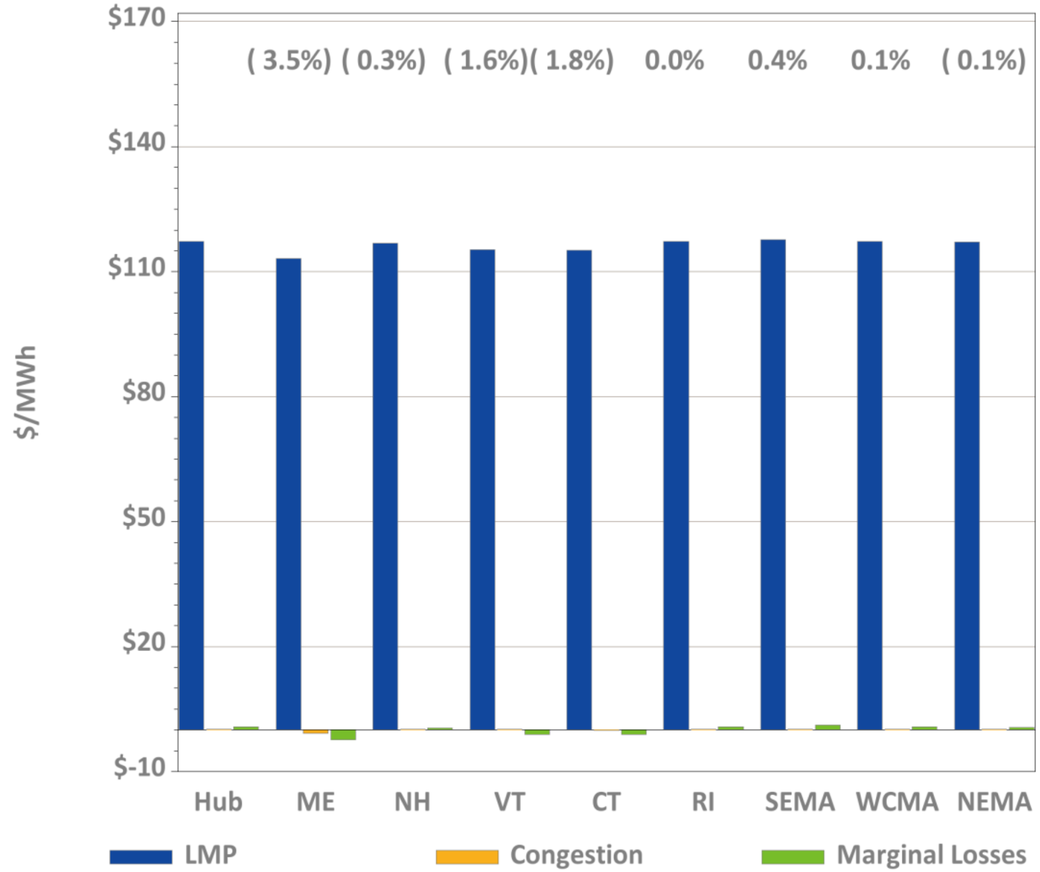


Underlying natural gas data furnished by:

ICE Global markets in clear view

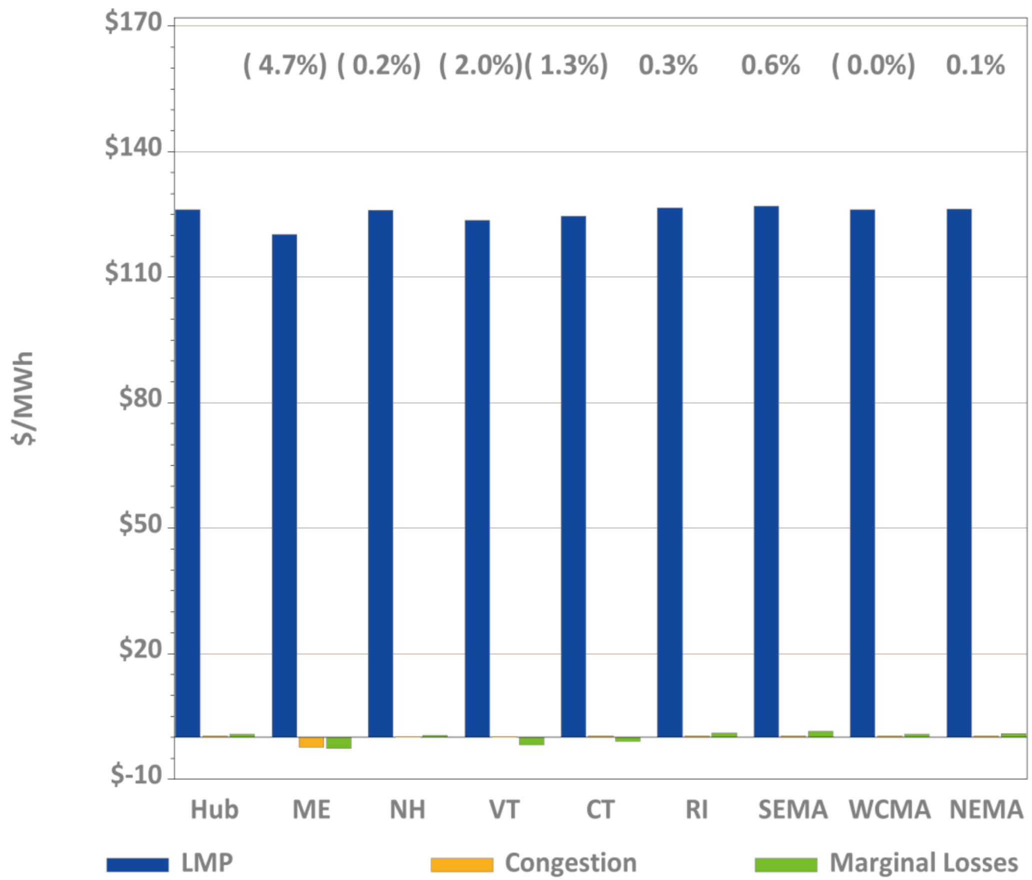
Average price difference over this period (DA-RT): $-8.98
Average price difference over this period ABS(DA-RT): $27.56
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 22%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, December 2022



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

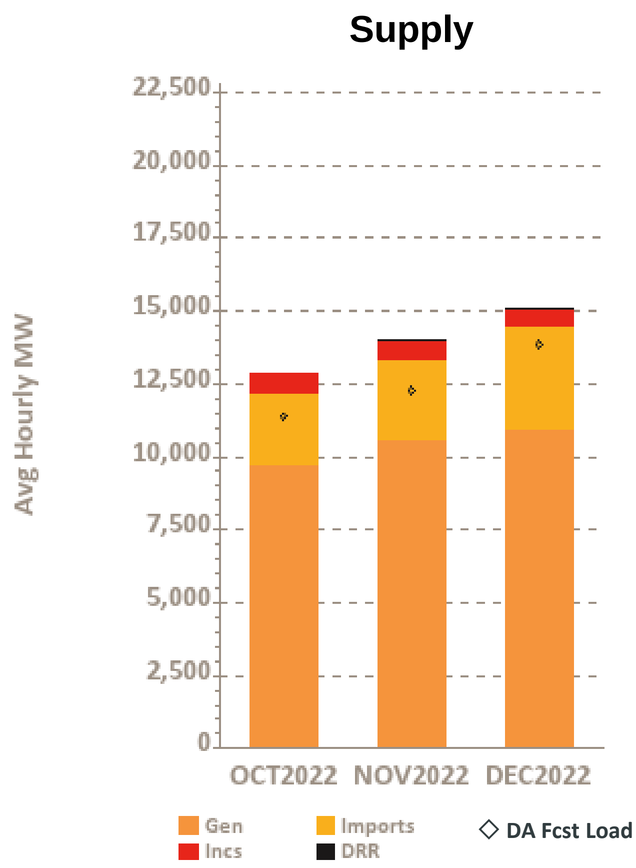
RT LMPs Average by Zone & Hub, December 2022

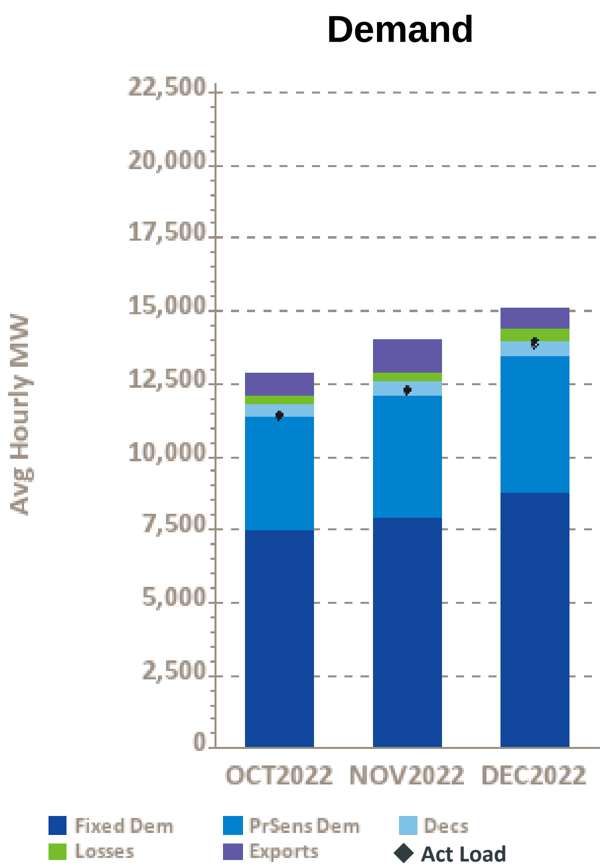


Definitions

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

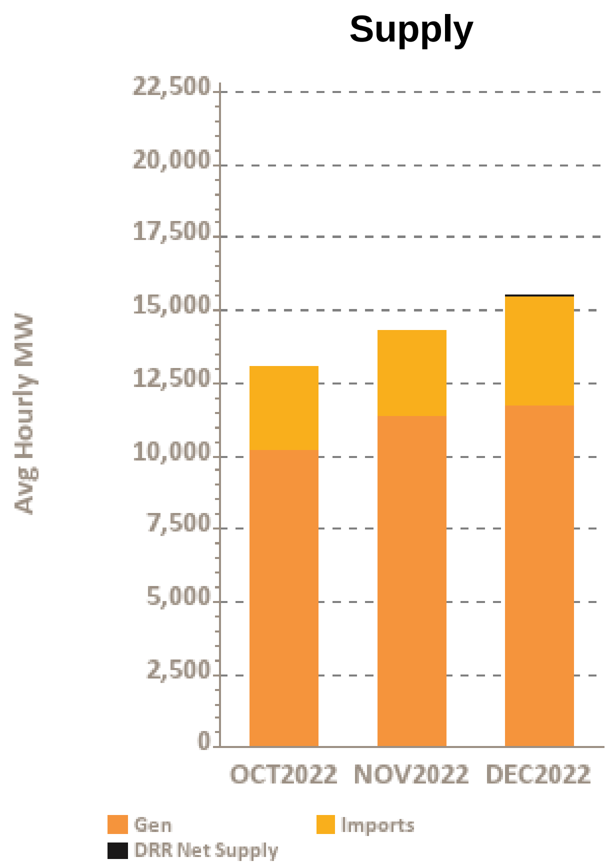


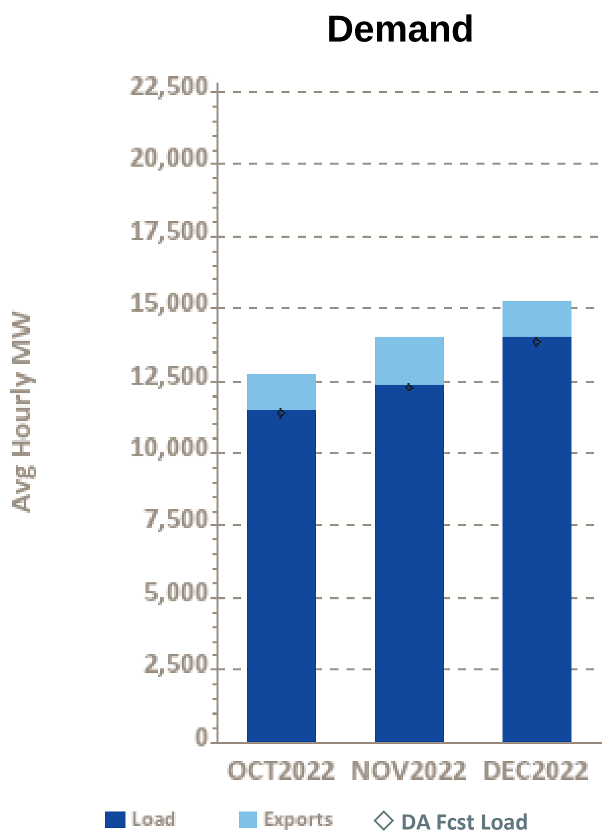


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

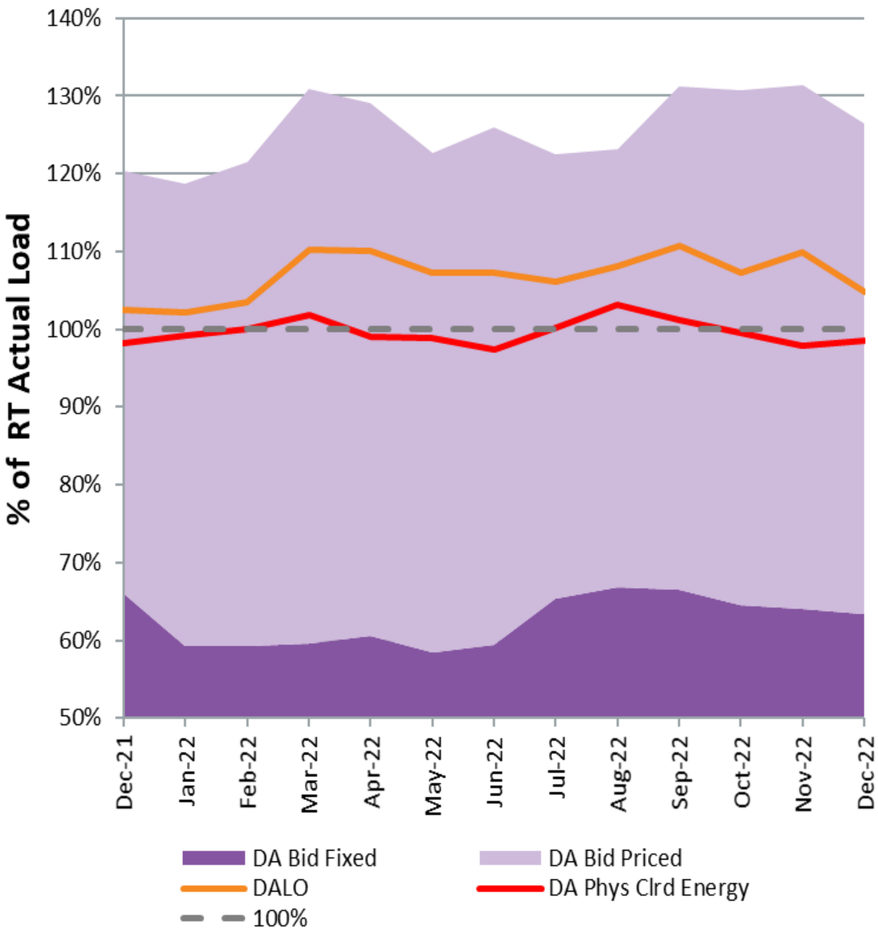
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

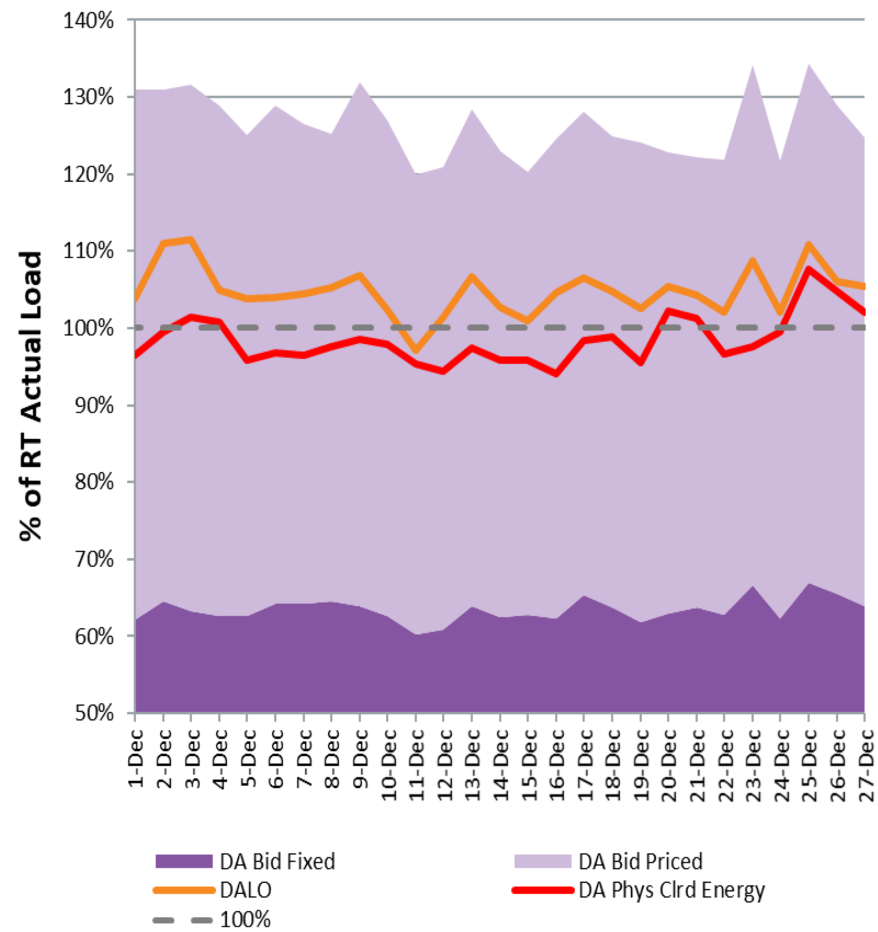
Components of RT Supply and Demand – Last Three Months





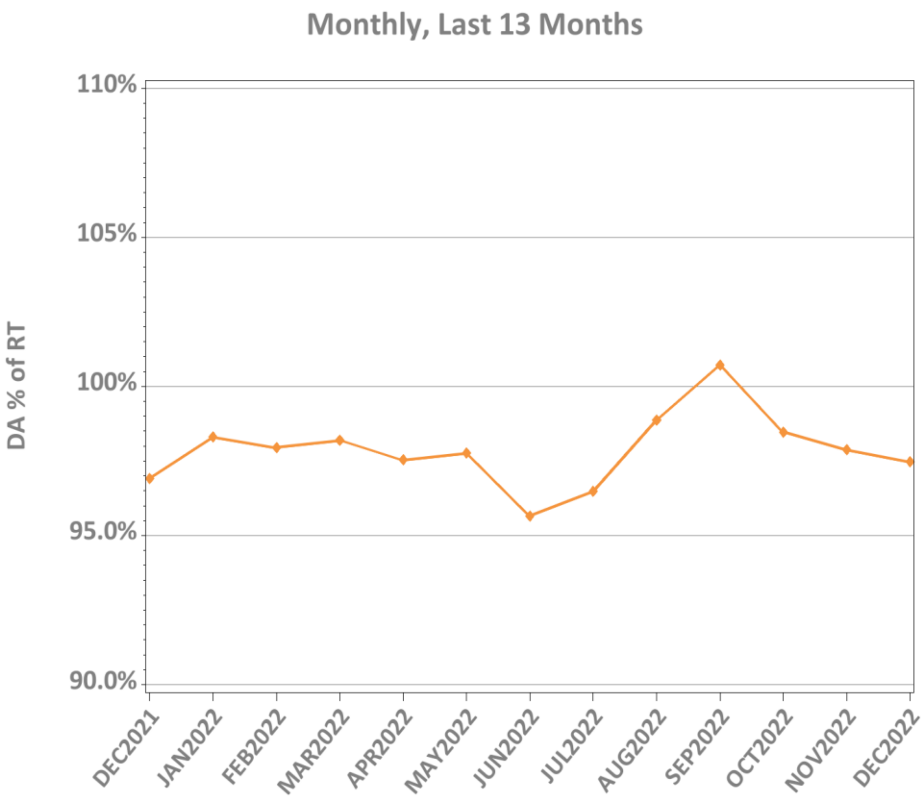
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

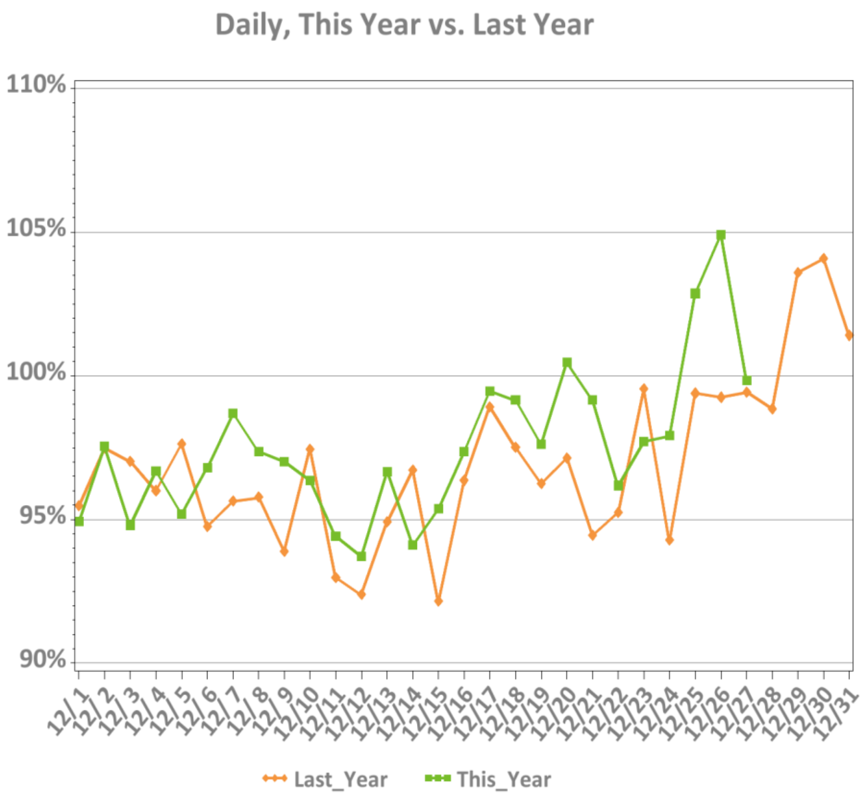




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

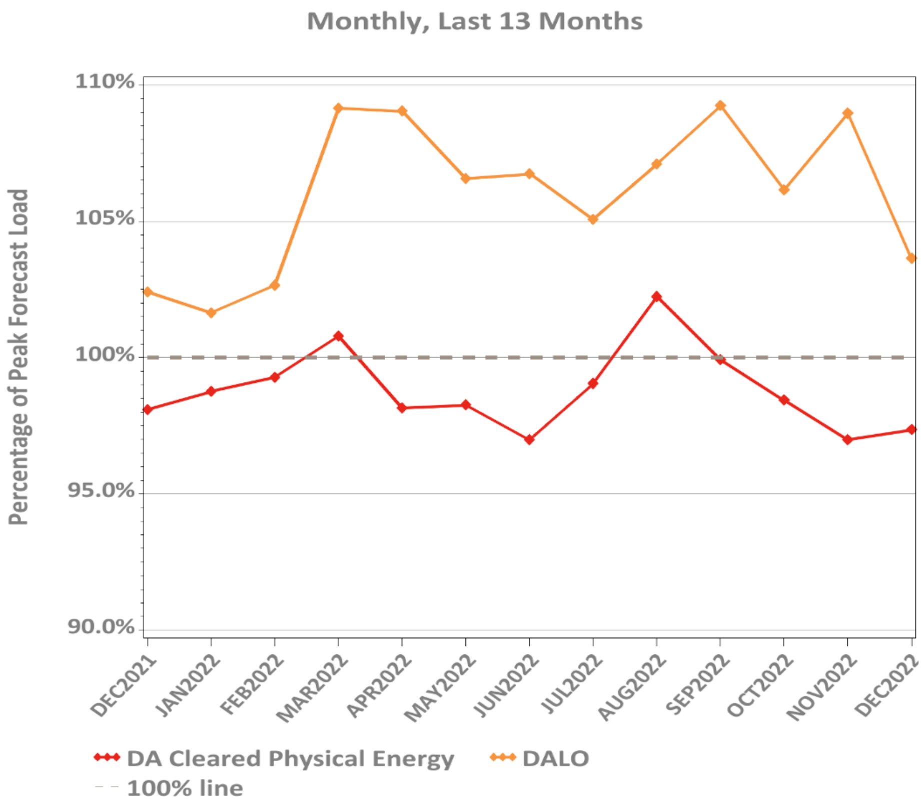
DA vs. RT Load Obligation: December, This Year vs. Last Year

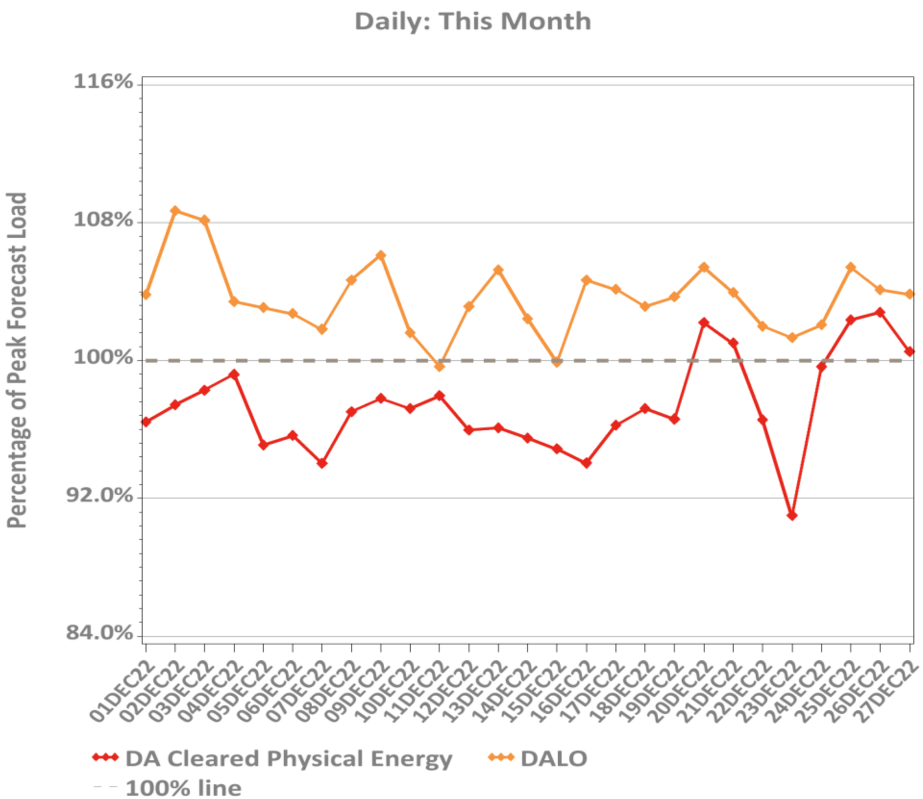




*Hourly average values

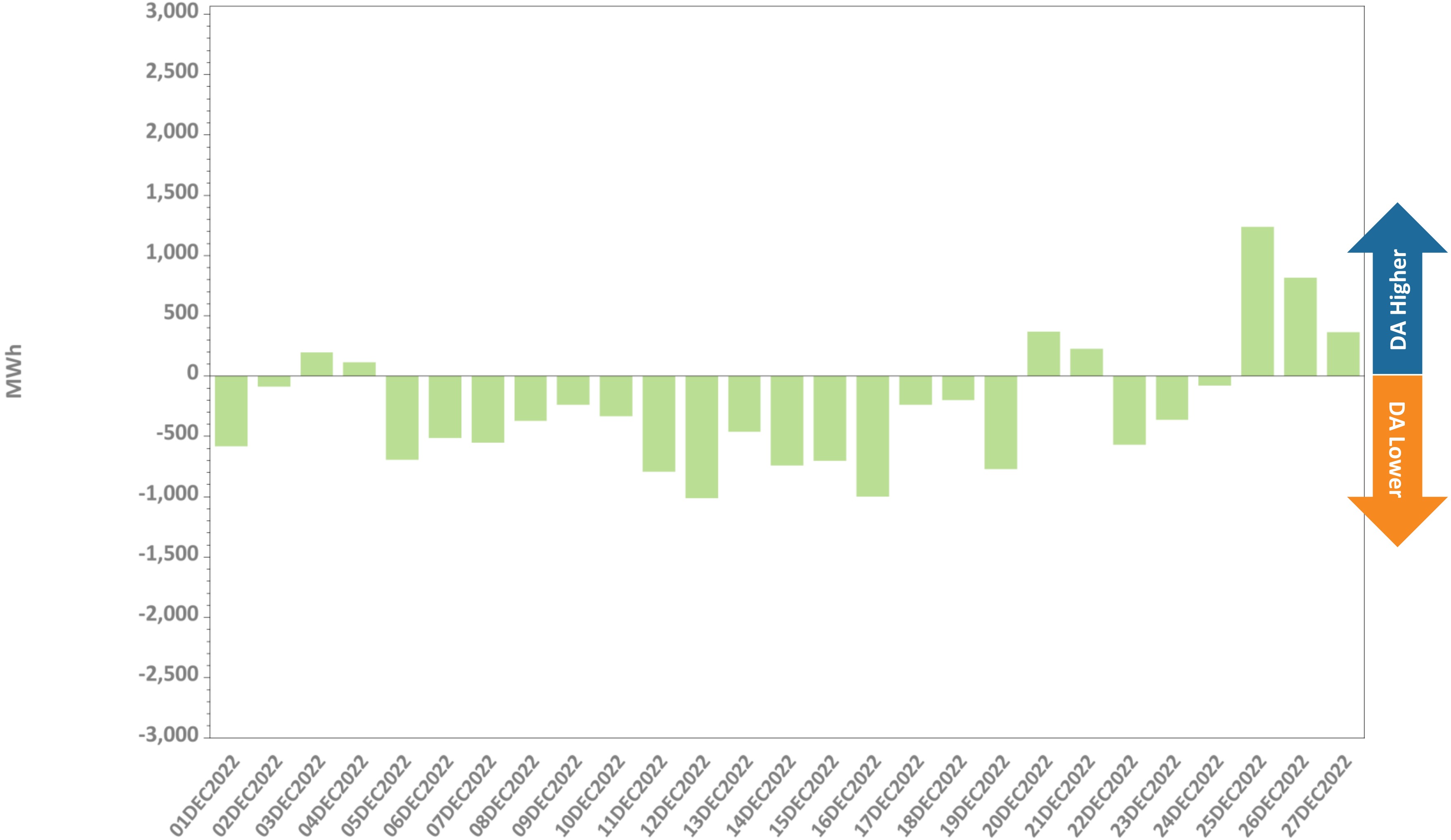
DA Volumes as % of Forecast in Peak Hour





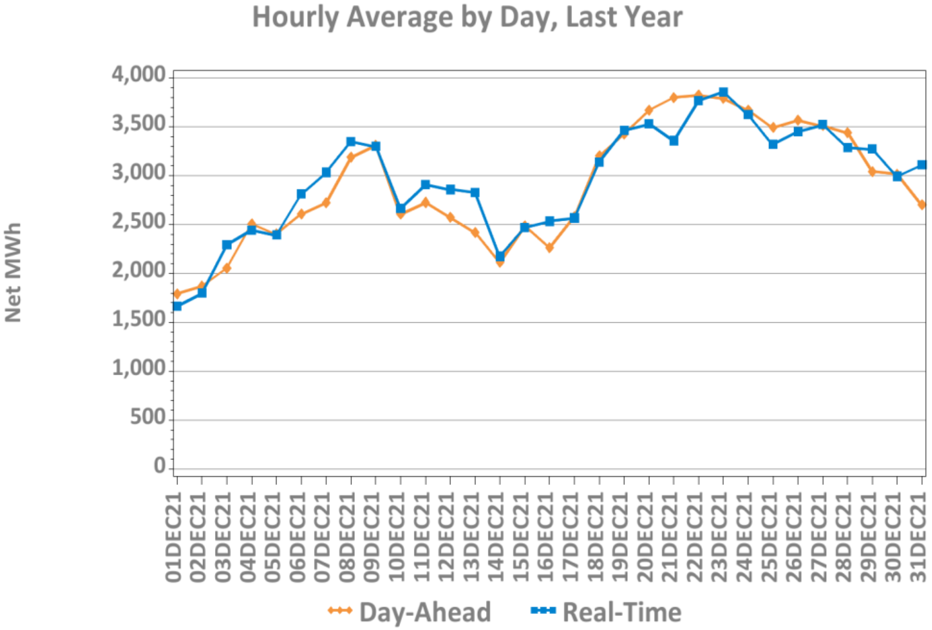
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

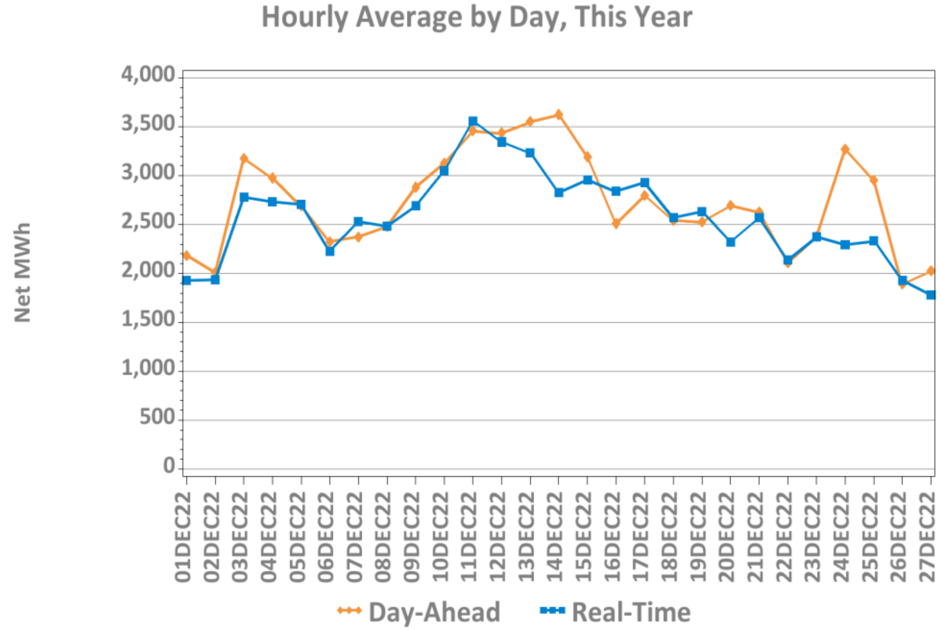
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

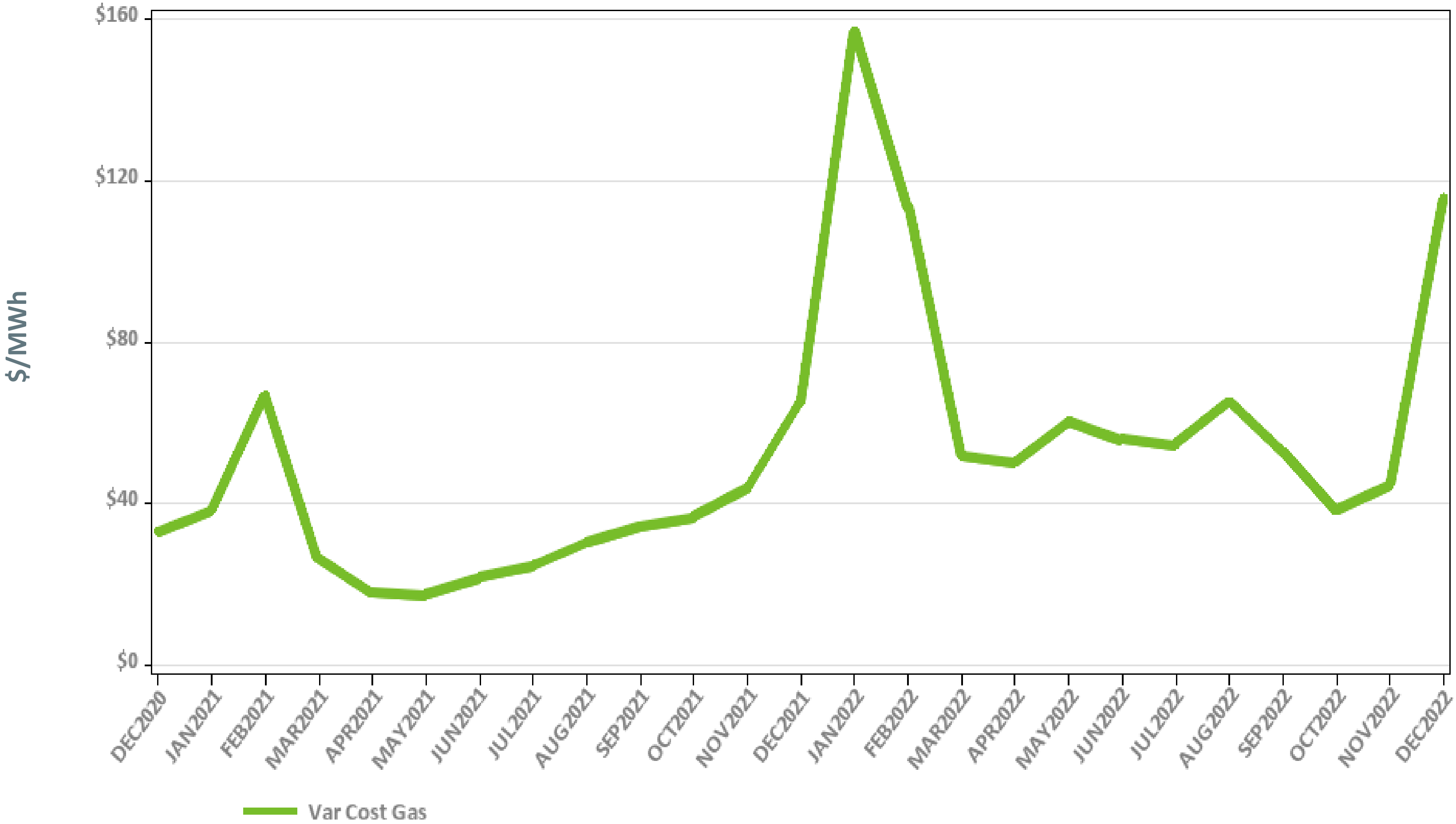
DA vs. RT Net Interchange December 2021 vs. December 2022





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

Variable Production Cost of Natural Gas: Monthly

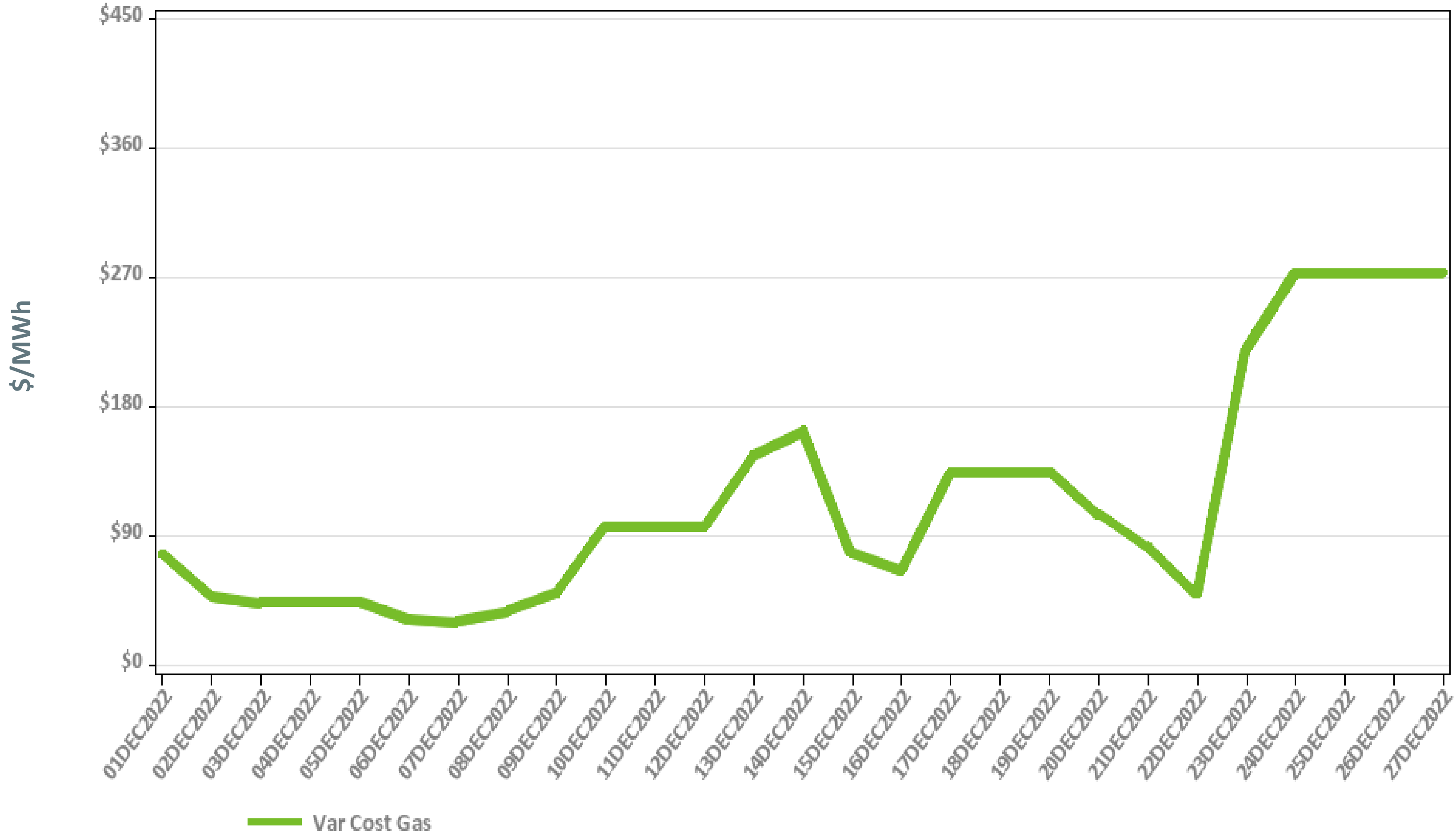


Underlying natural gas data furnished by:

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

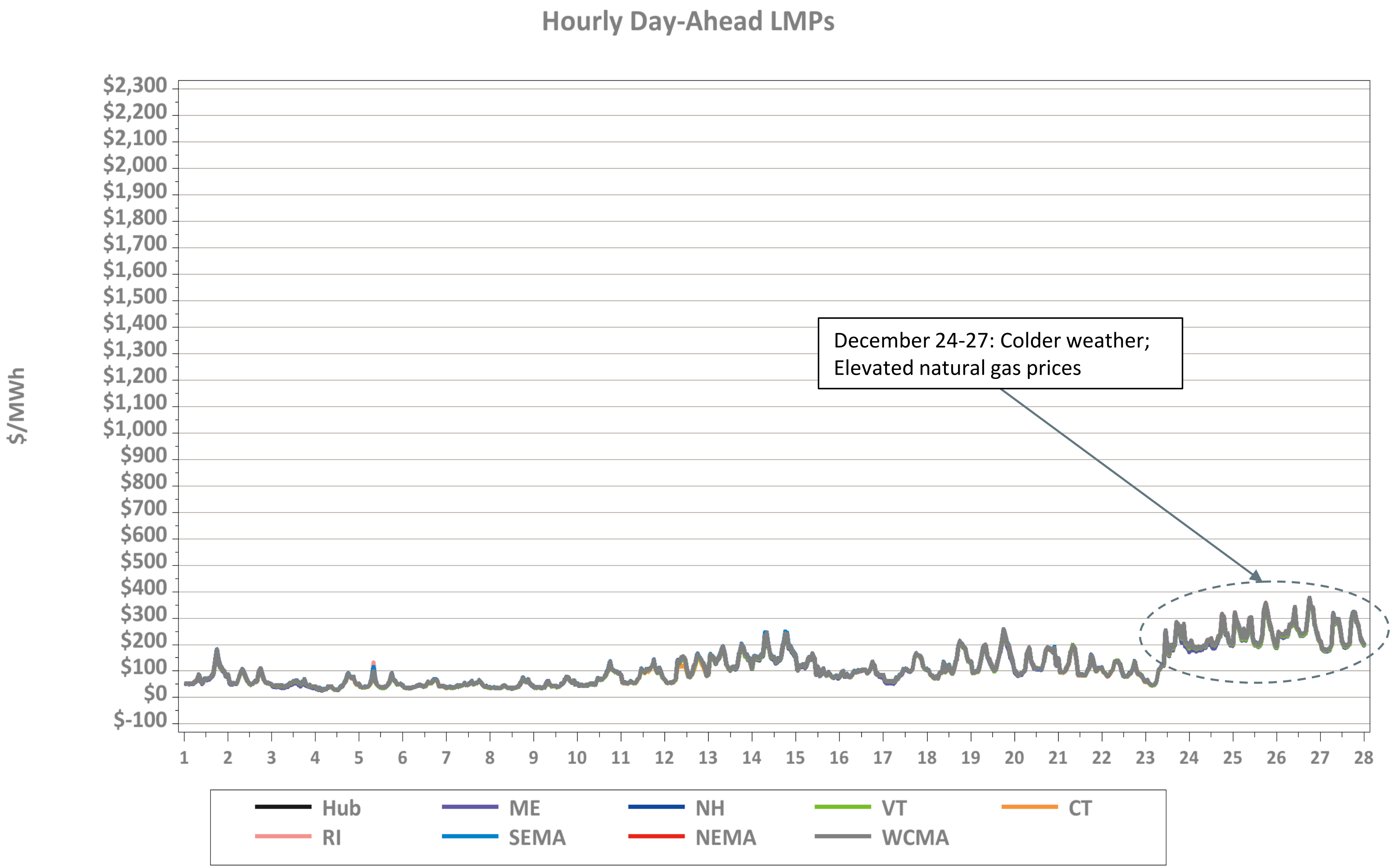


Note: **Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.**

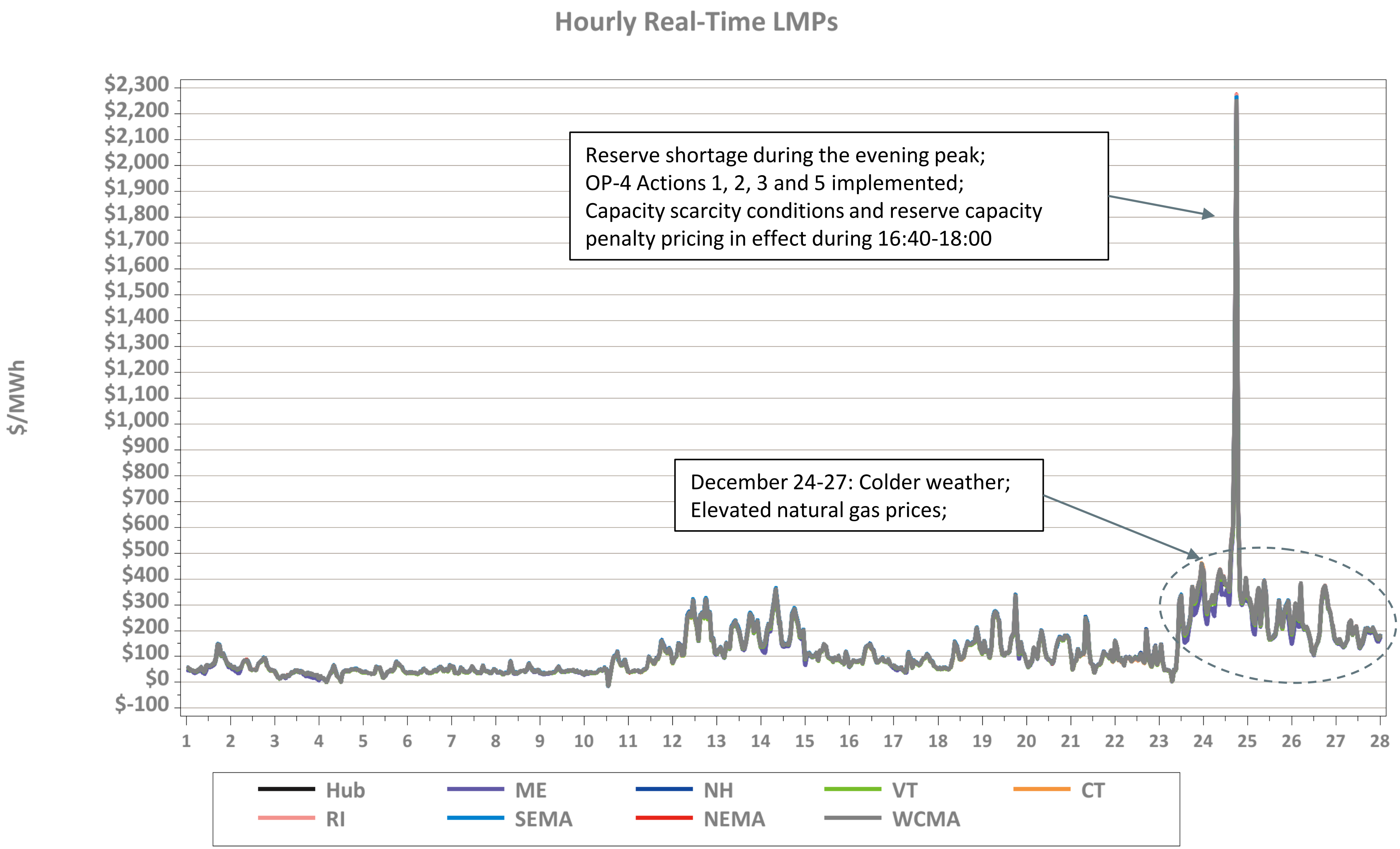
Underlying natural gas data furnished by:

ICE Global markets in clear view

Hourly DA LMPs, December 1-27, 2022

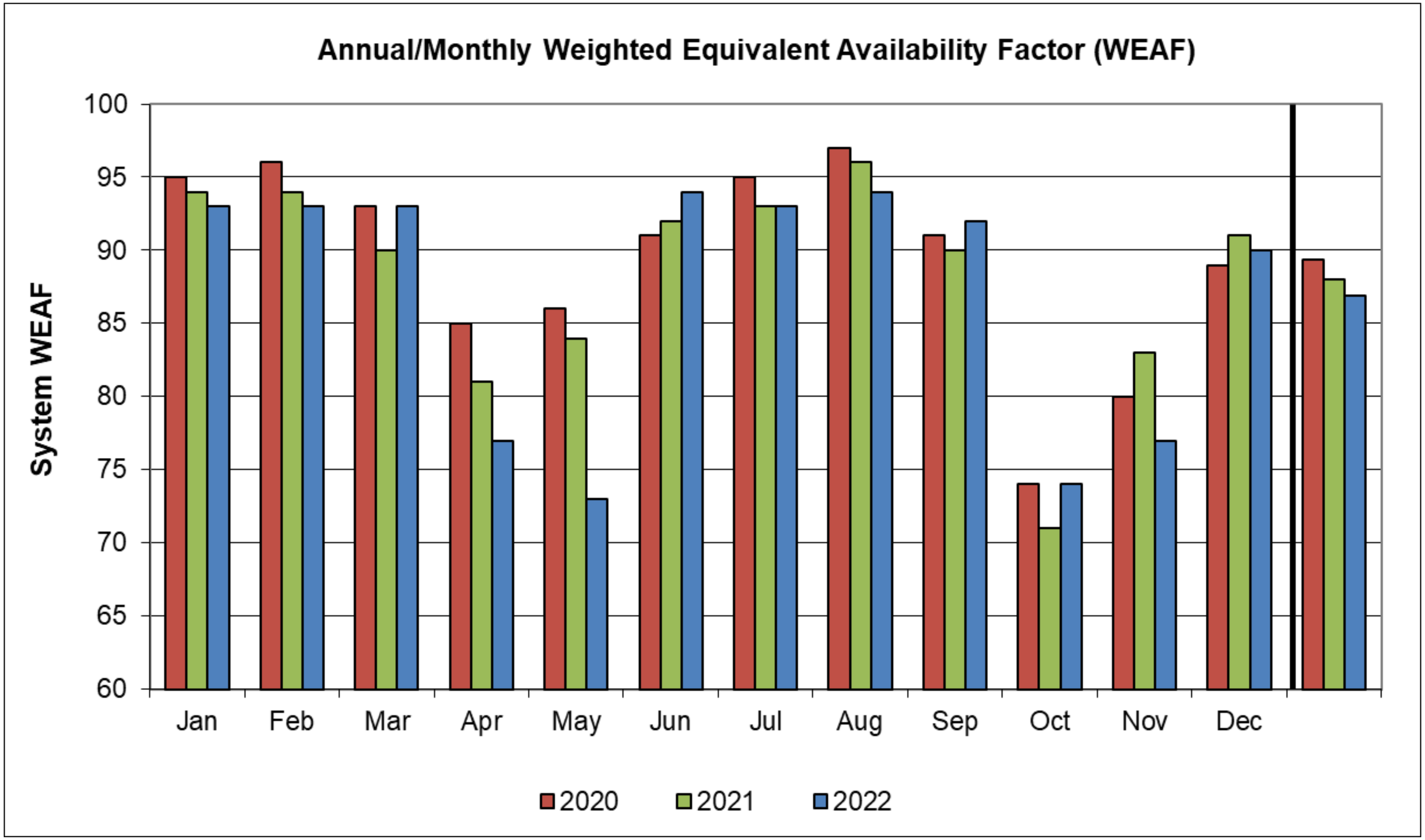


Hourly RT LMPs, December 1-27, 2022



* Telemetered load is referenced

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2022	93	93	93	77	73	94	93	94	92	74	77	90	87
2021	94	94	90	81	84	92	93	96	90	71	83	91	88
2020	95	96	93	85	86	91	95	97	91	74	80	89	89

Data as of 12/22/2022

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for January 2022

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	99.1	180.2	0.0	279.3
NH	30.5	180.0	0.0	210.4
VT	41.8	164.4	0.0	206.2
CT	78.4	110.9	687.4	876.7
RI	18.6	342.9	0.0	361.5
SEMA	33.7	503.5	0.0	537.2
WCMA	60.6	544.2	14.4	619.2
NEMA	50.6	852.4	0.0	903.0
Total	**413.2**	**2,878.6**	**701.8**	**3,993.6**

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

NEW GENERATION

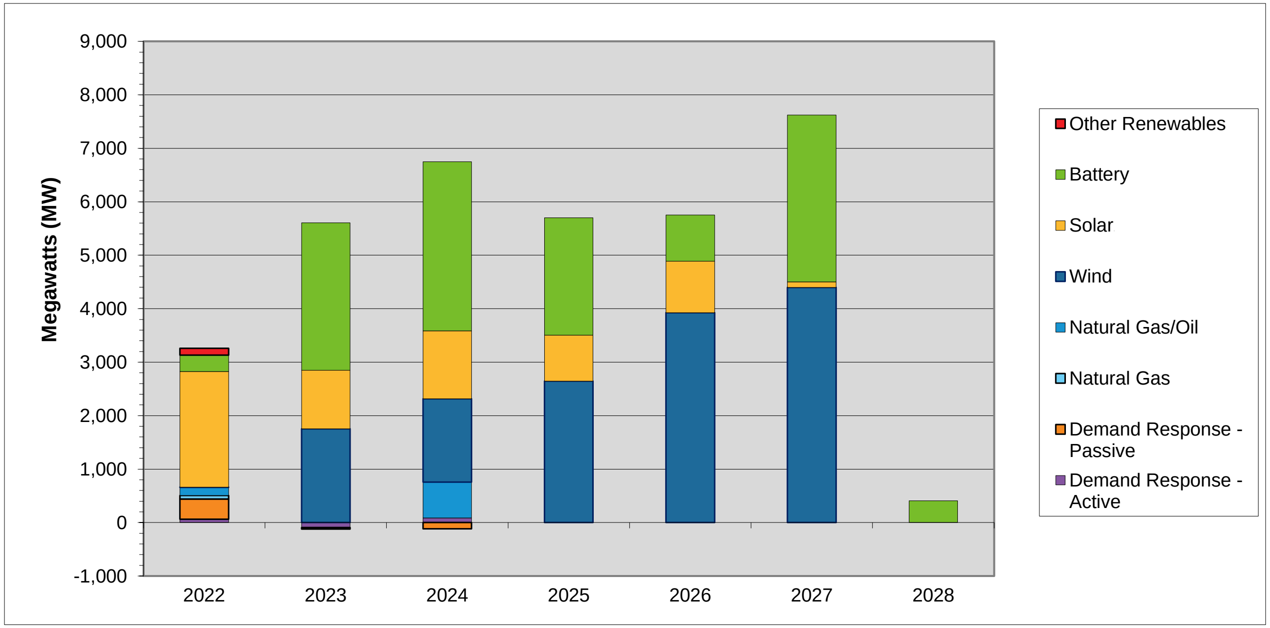
New Generation Update

Based on Queue as of 12/30/22

- Six projects totaling 2,949 MW were added to the interconnection queue since the last update
  - Four battery projects and two wind projects with in-service dates of 2024 to 2029
- Four projects were withdrawn and one project went commercial
- In total, 360 generation projects are currently being tracked by the ISO, totaling approximately 37,443 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



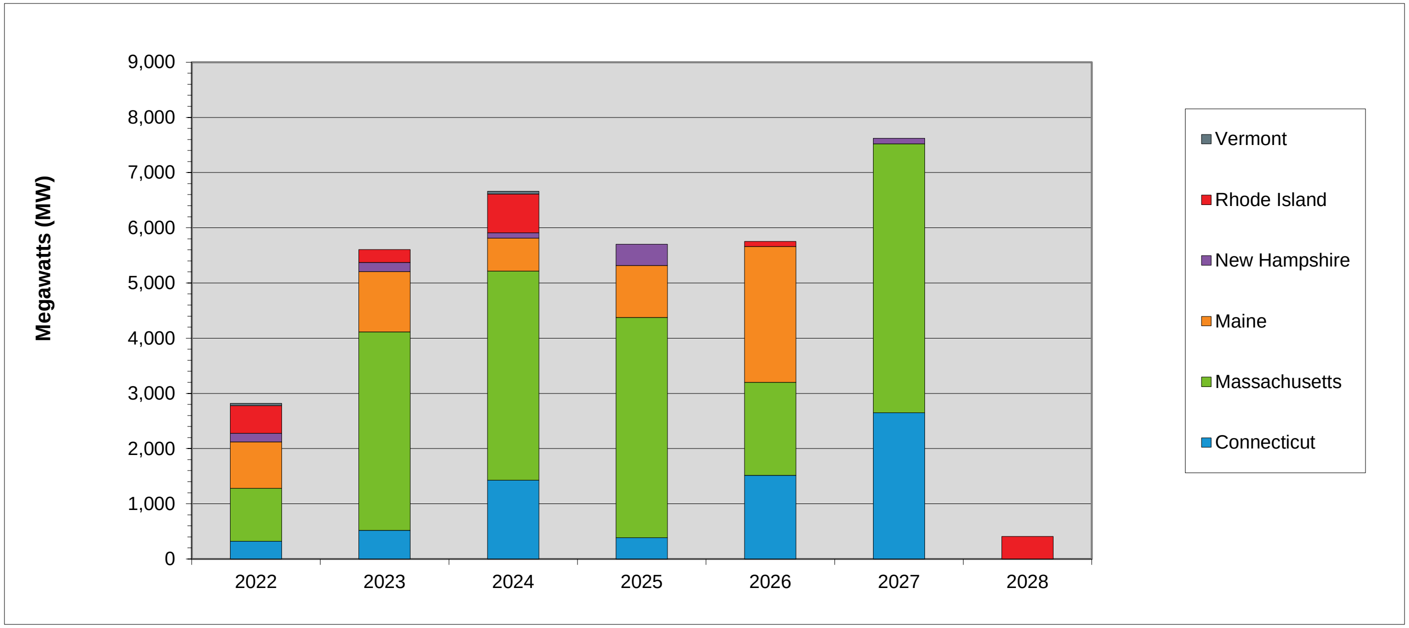
	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	129	0	0	0	0	0	0	129	0.4
Battery	305	2,756	3,163	2,196	866	3,122	410	12,818	36.8
Solar[2]	2,162	1,098	1,272	859	964	102	0	6,457	18.5
Wind	4	1,752	1,556	2,645	3,923	4,399	0	14,279	41.0
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.4
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	3,260	5,484	6,635	5,700	5,753	7,623	410	34,865	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

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	40	0	50	0	0	0	0	90	0.3
Rhode Island	502	236	704	0	91	0	410	1,943	5.6
New Hampshire	156	164	97	385	0	102	0	904	2.6
Maine	838	1,092	597	942	2,461	0	0	5,930	17.2
Massachusetts	959	3,594	3,786	3,989	1,686	4,873	0	18,887	54.6
Connecticut	323	520	1,429	384	1,515	2,648	0	6,819	19.7
Totals	**2,818**	**5,606**	**6,663**	**5,700**	**5,753**	**7,623**	**410**	**34,573**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	81	12,818	3	32	78	12,786
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	0	0	0	0	0	0
Solar	236	6,457	18	401	218	6,056
Wind	26	17,149	0	0	26	17,149
Total	360	37,443	24	566	336	36,877

- 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
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	70	1	5	4	65
Intermediate	7	804	0	0	7	804
Peaker	322	19,420	23	561	299	18,859
Wind Turbine	26	17,149	0	0	26	17,149
Total	360	37,443	24	566	336	36,877

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	81	12,818	0	0	0	0	81	12,818	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	236	6,457	0	0	0	0	236	6,457	0	0
Wind	26	17,149	0	0	0	0	0	0	26	17,149
Total	360	37,443	5	70	7	804	322	19,420	26	17,149

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 13

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*	685.554	683.116	-2.438	658.659	-24.457	609.826	-48.833
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392	3,512.604	61.705
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**	**4,122.43**	**12.872**
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07	27,426.242	-679.169
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387	778.962	-117.323
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**	**28,205.204**	**-796.492**
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**	**1,115.22**	**-177.19**
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**	**33,442.854**	**-960.81**
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**	**31,590**	**-1,175**

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

ARA – Annual Reconfiguration Auction
CSO – Capacity Supply Obligation
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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		
Demand	*Passive Demand*	3,327.071	3,327.932	0.861	3,315.207	-12.725		
Demand Total		**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**		
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429		
Generator	*Intermittent*	1,160.916	1,128.446	-32.47	925.942	-202.504		
Generator Total		**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**		
Import Total		**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**		
Grand Total*		**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**		
Net ICR (NICR)		**32,490**	**32,980**	**490**	**31,480**	**-1,500**		

* 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 bilaterals and reconfiguration auction 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 2015-2022 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				
	Passive Demand	3,212.865	3,211.403	-1.462				
Demand Total		**3,890.538**	**3,884.804**	**-5.734**				
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425				
	Intermittent	1,089.265	1,073.794	-15.471				
Generator Total		**29,243.468**	**28,788.572**	**-454.896**				
Import Total		**1,487.059**	**1297.132**	**-189.927**				
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**				
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**				

* 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 bilaterals and reconfiguration auction 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 2015-2022 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						
	Passive Demand	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
	Intermittent	1,178.933						
Generator Total		**27,983.936**						
Import Total		**1,503.842**						
Grand Total*		**32,810.384**						
Net ICR (NICR)		**31,645**						

* 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 bilaterals and reconfiguration auction 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 2015-2022 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

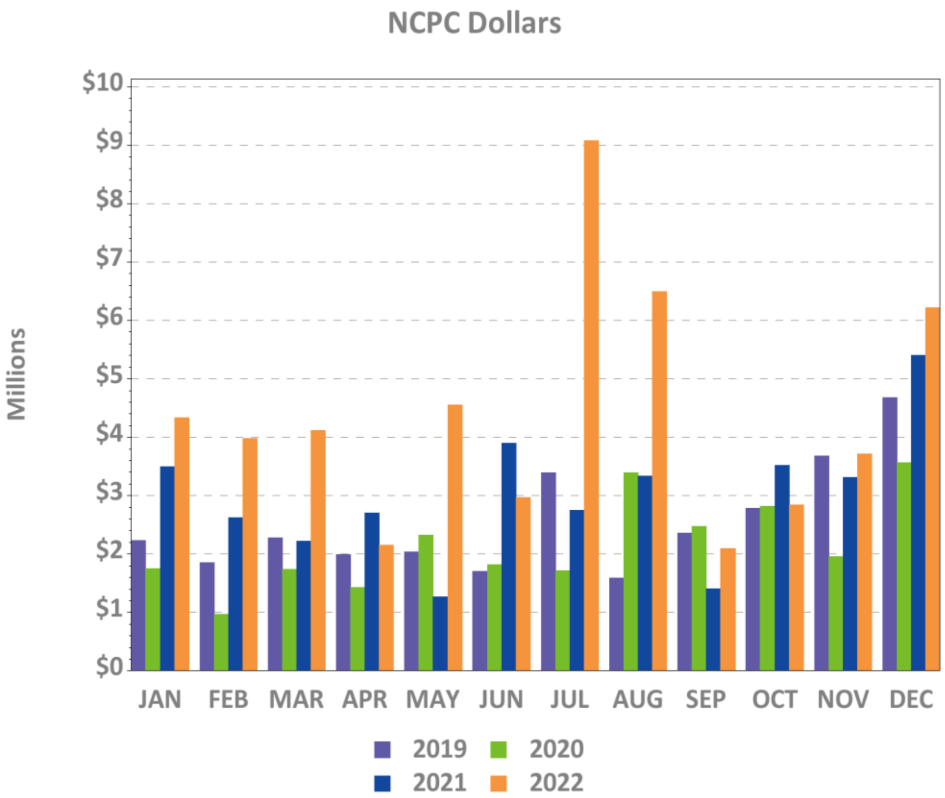
Definitions

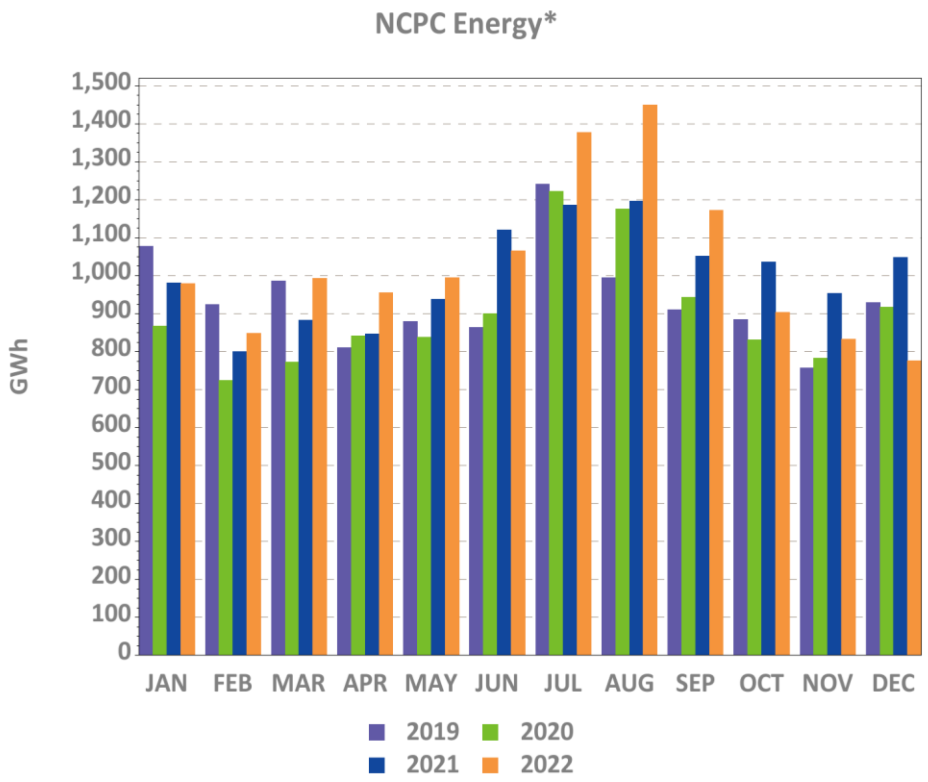
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

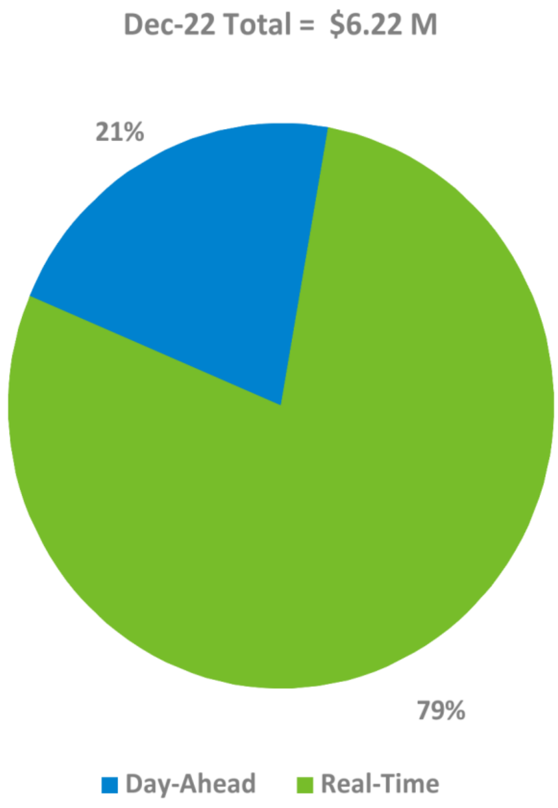
Year-Over-Year Total NCPC Dollars and Energy

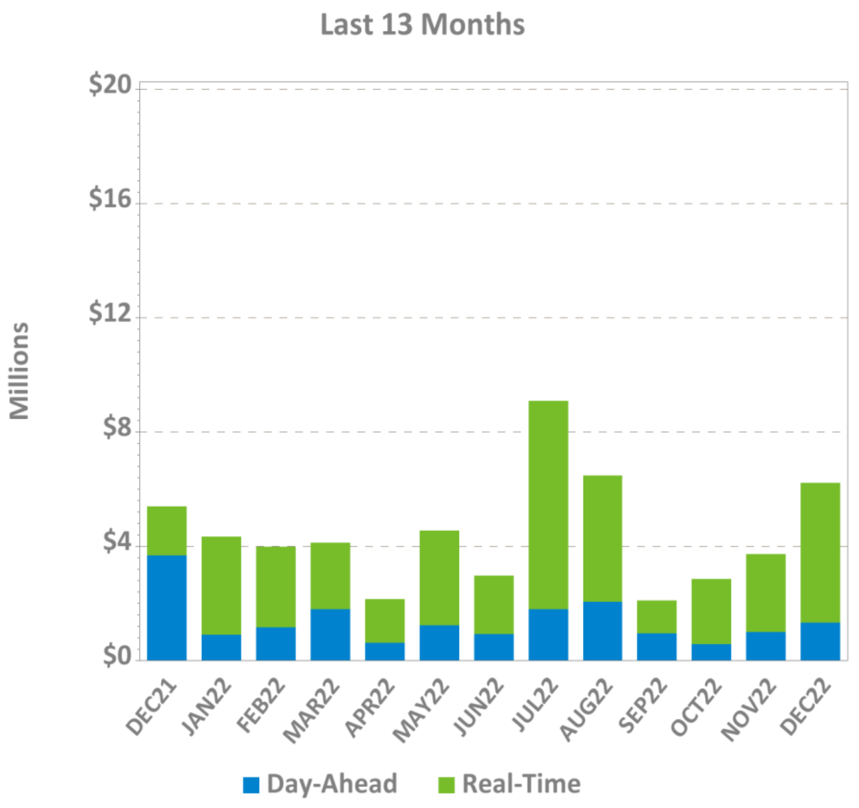




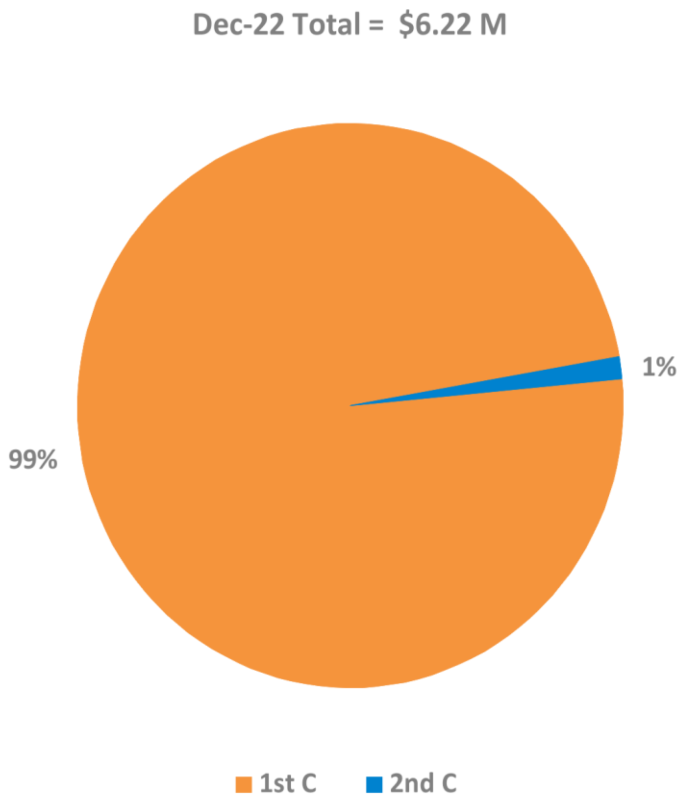
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

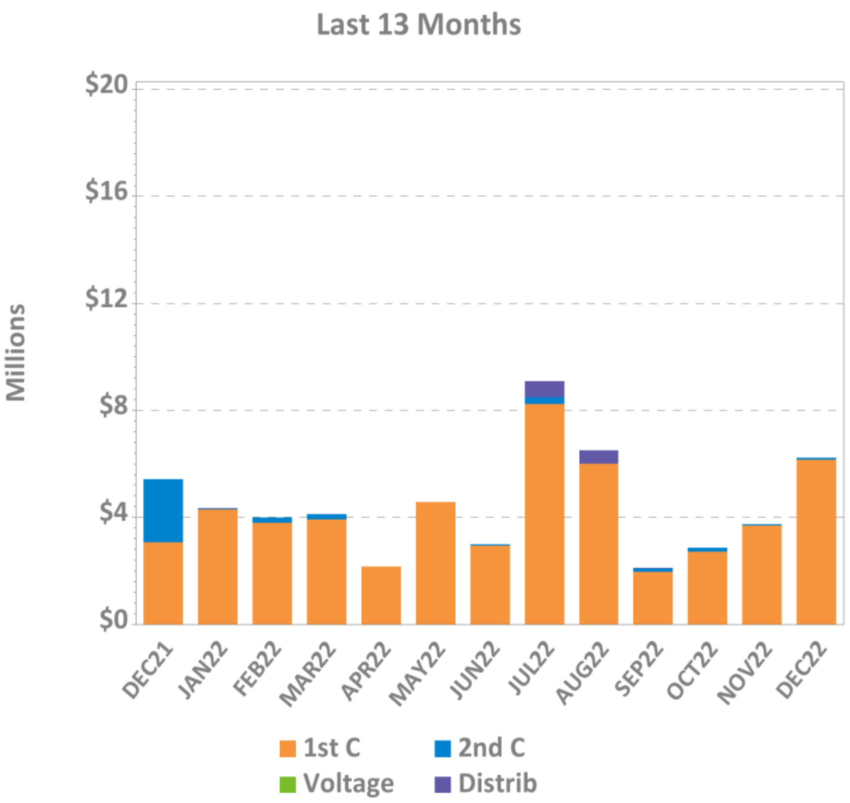
DA and RT NCPC Charges





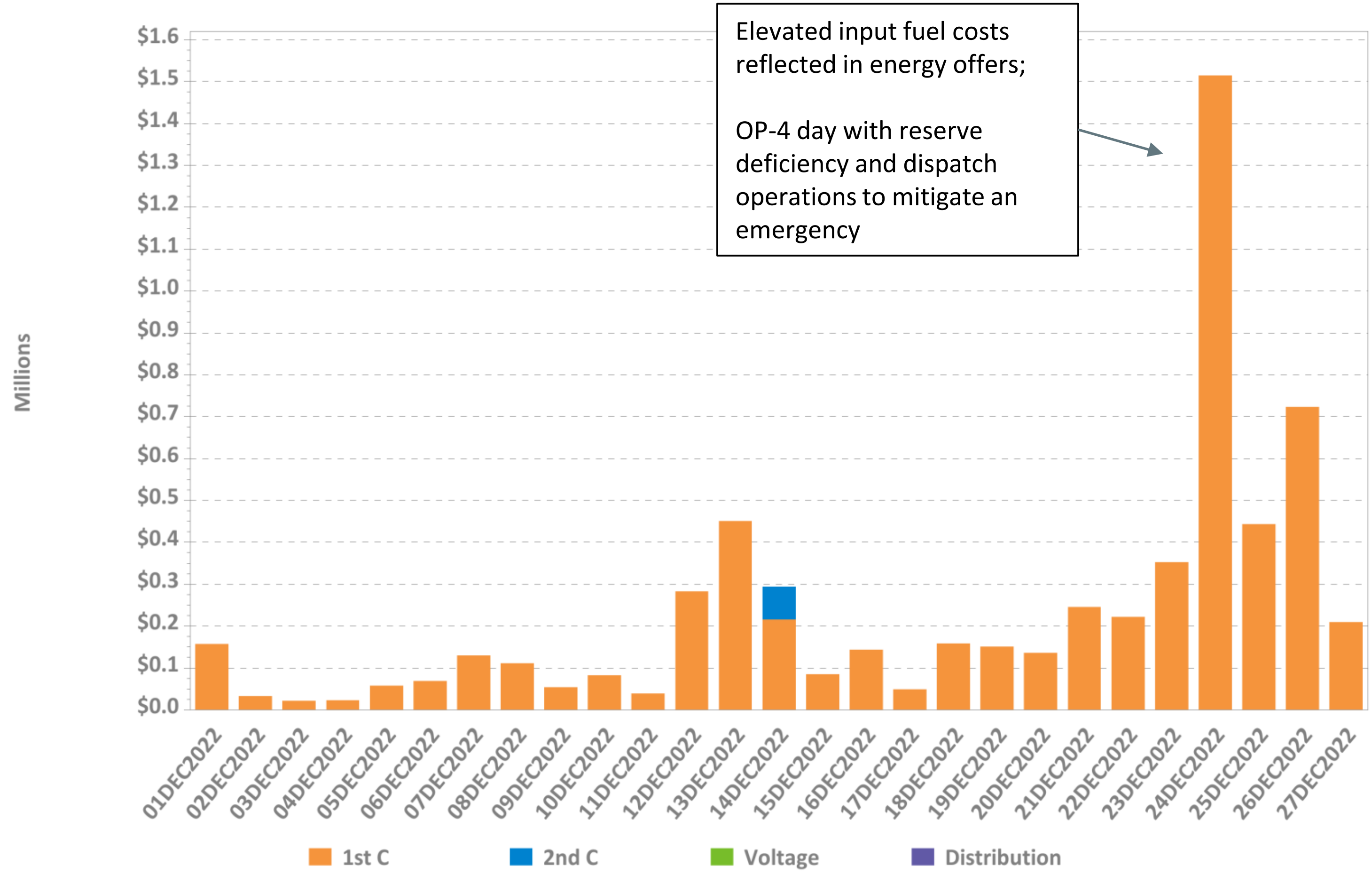
NCPC Charges by Type



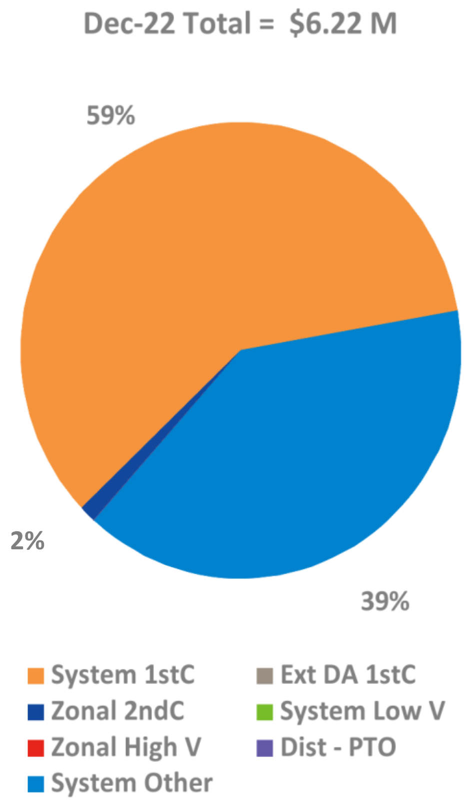


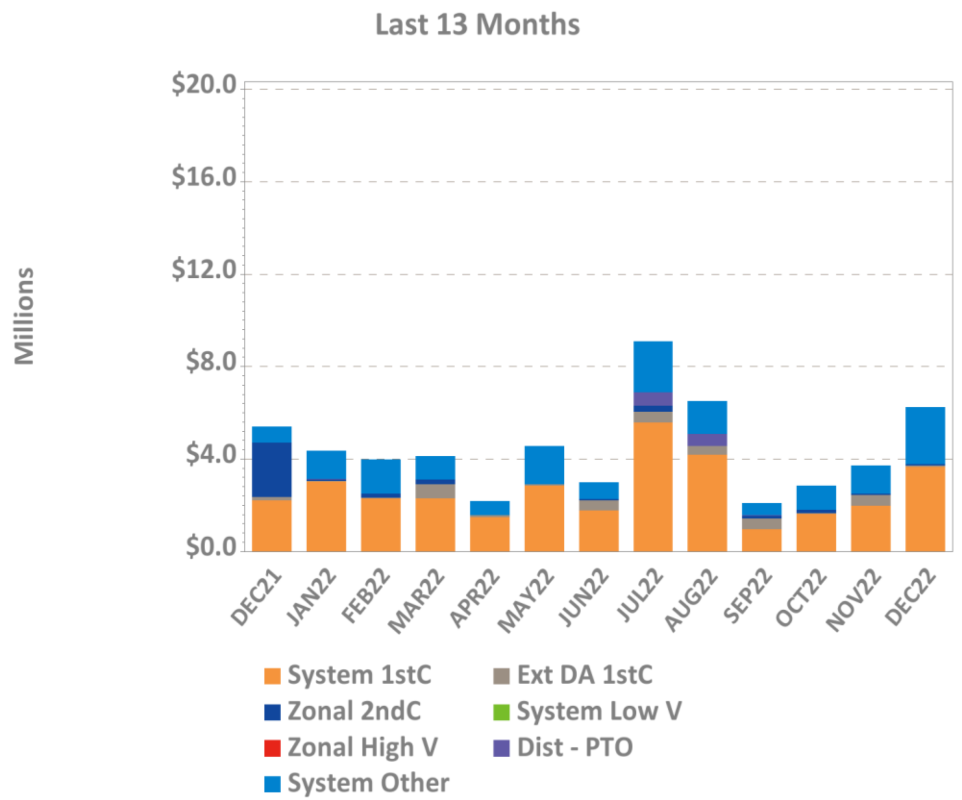
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



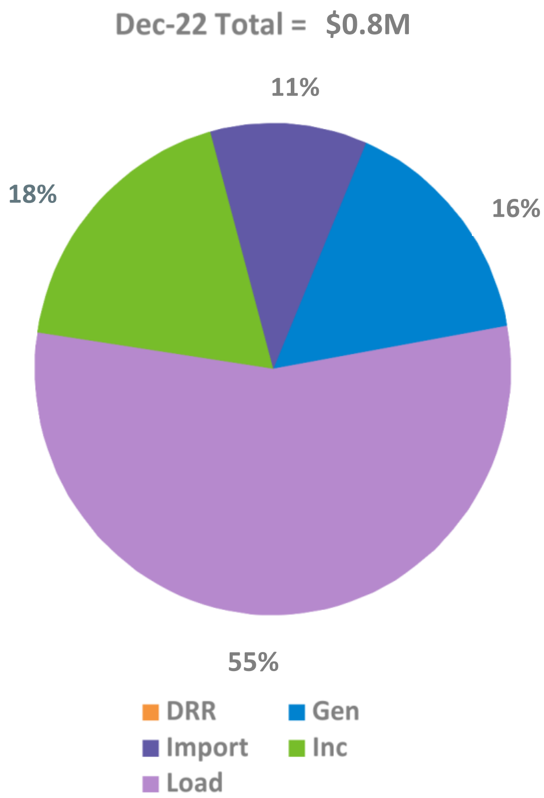
NCPC Charges by Allocation

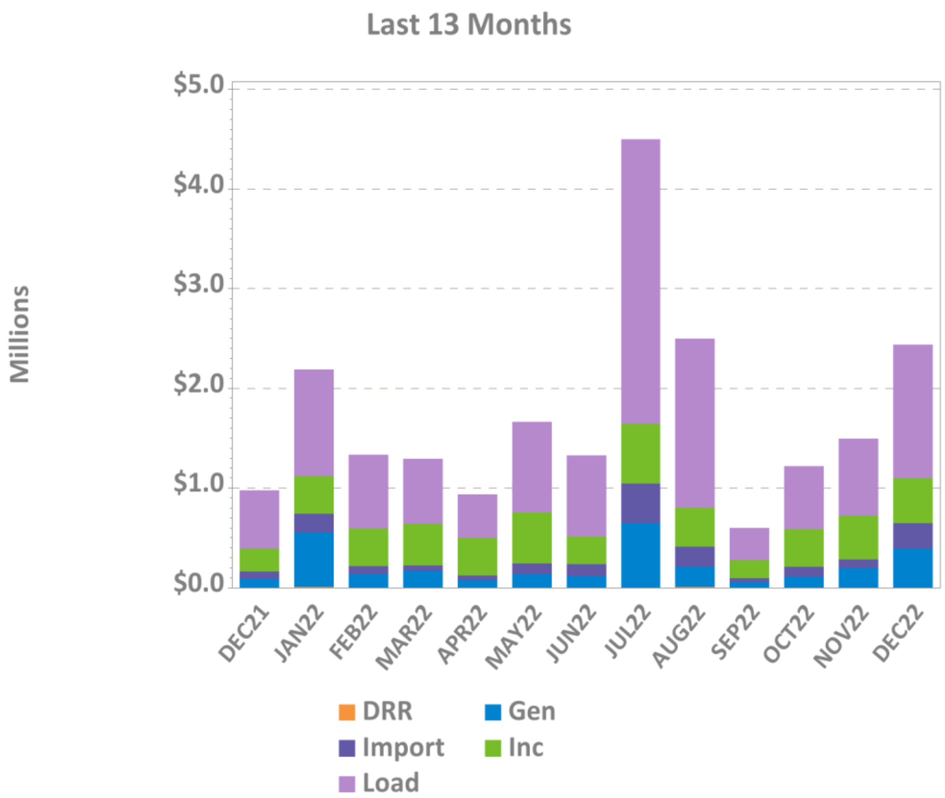




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

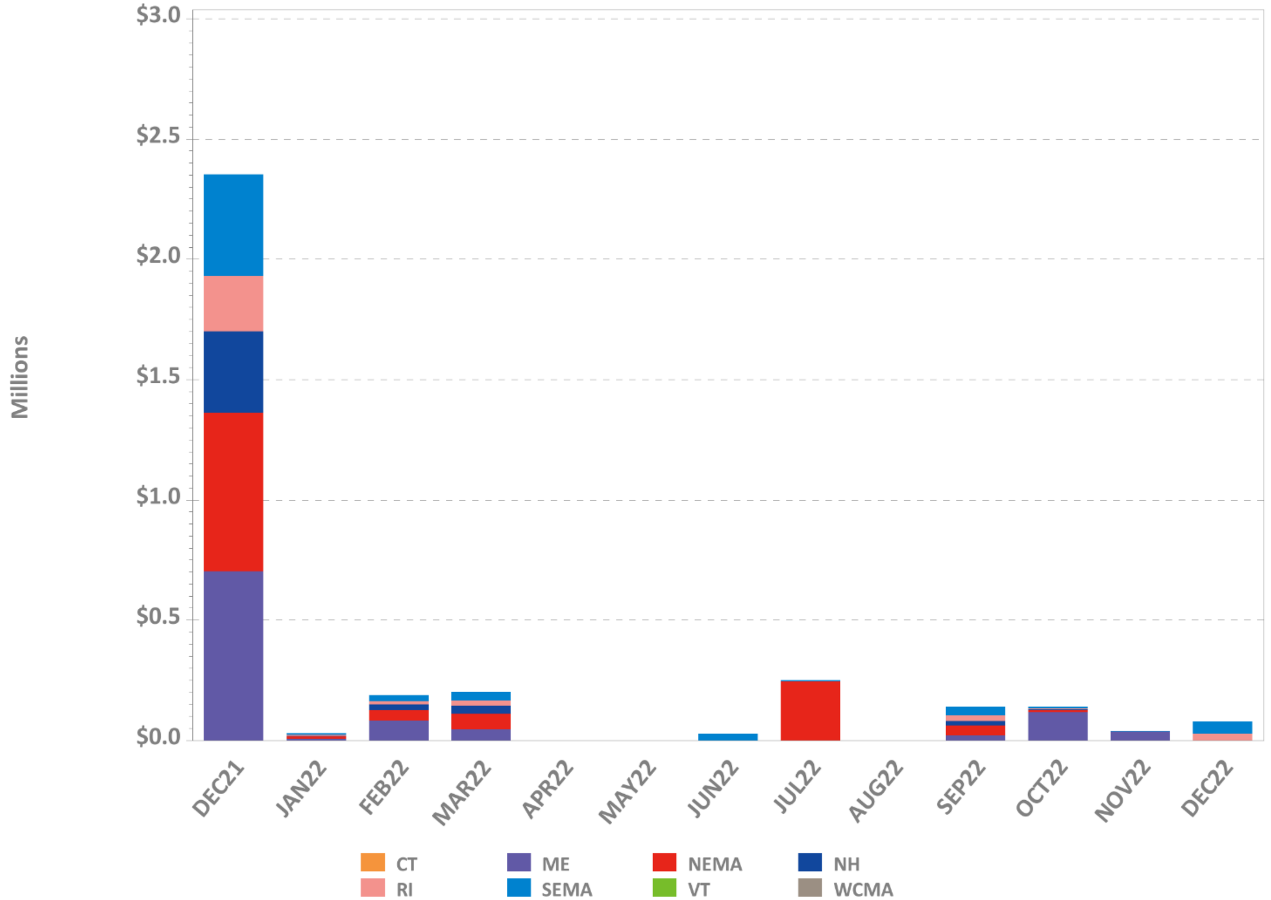
RT First Contingency Charges by Deviation Type





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

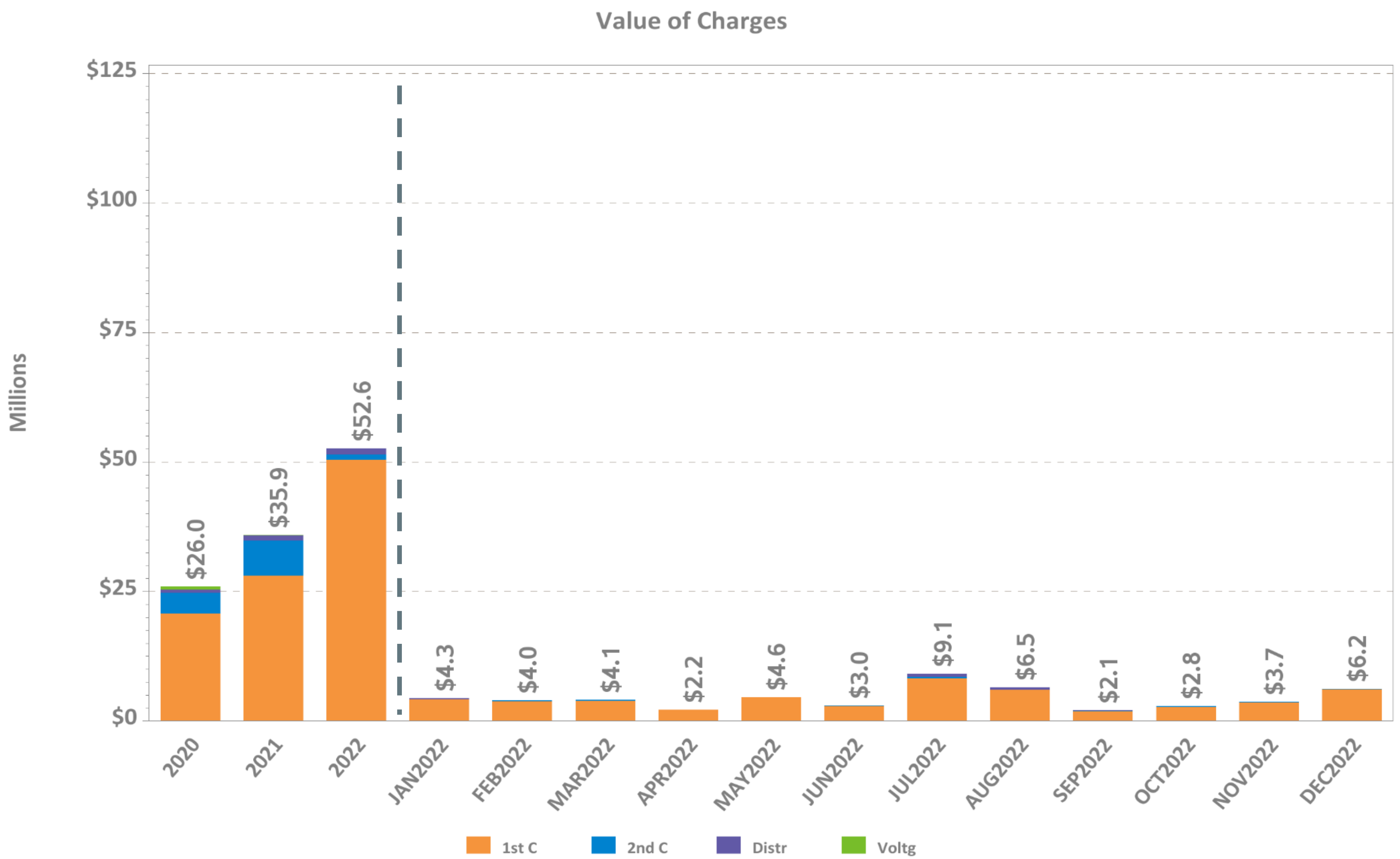
LSCPR Charges by Reliability Region



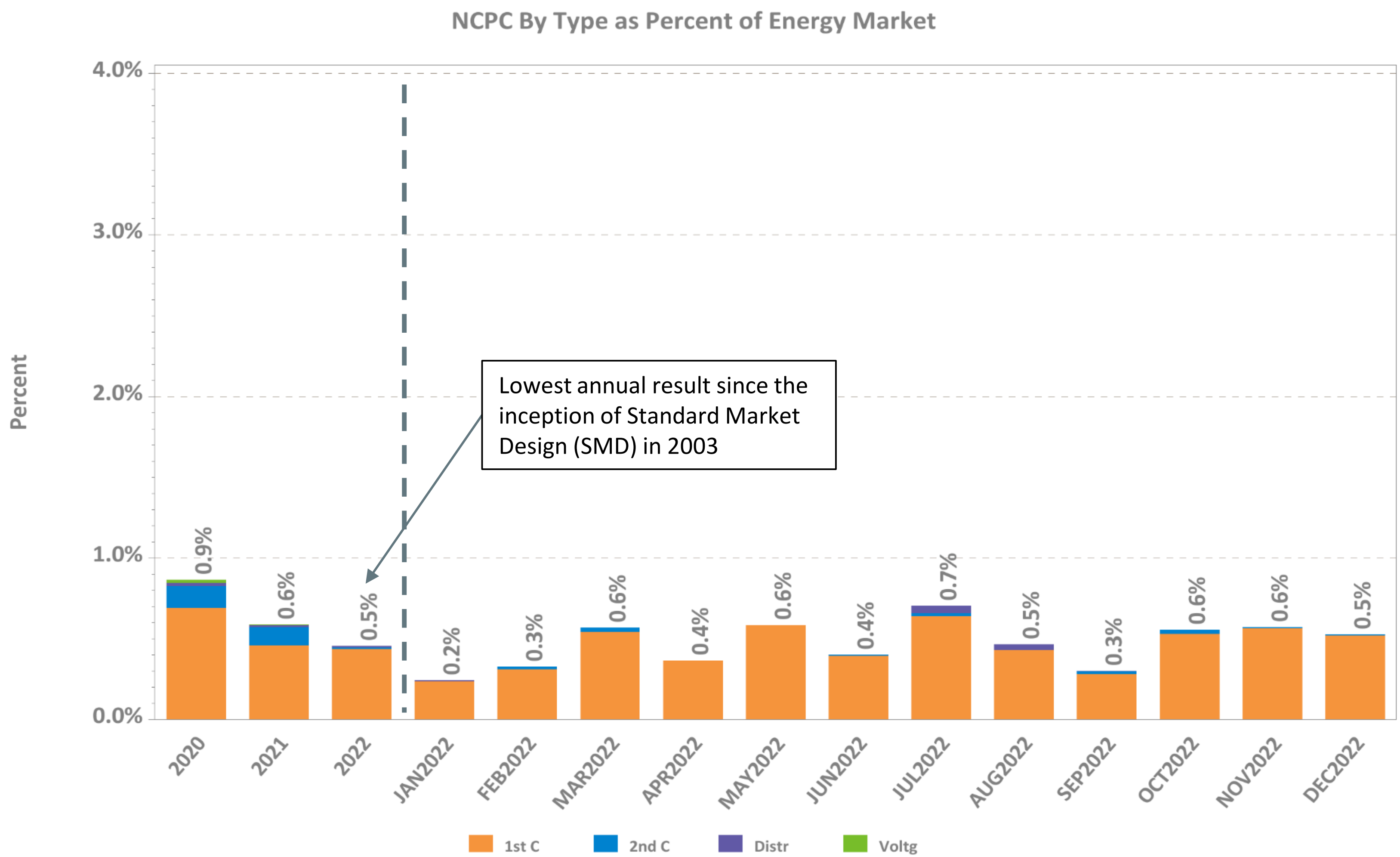
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

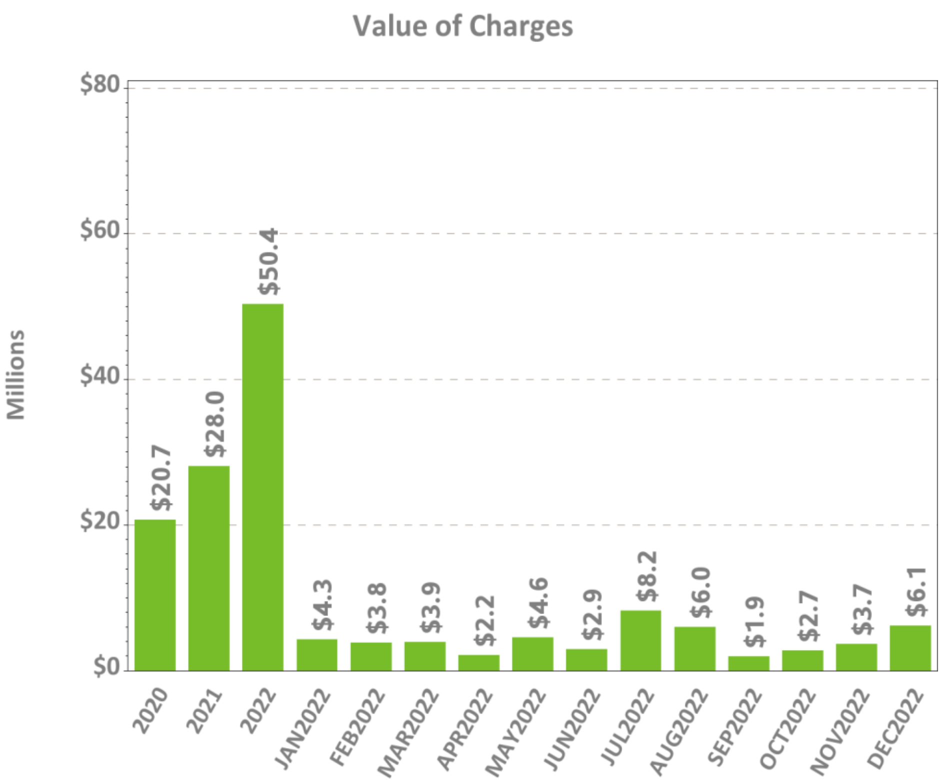
NCPC Charges by Type

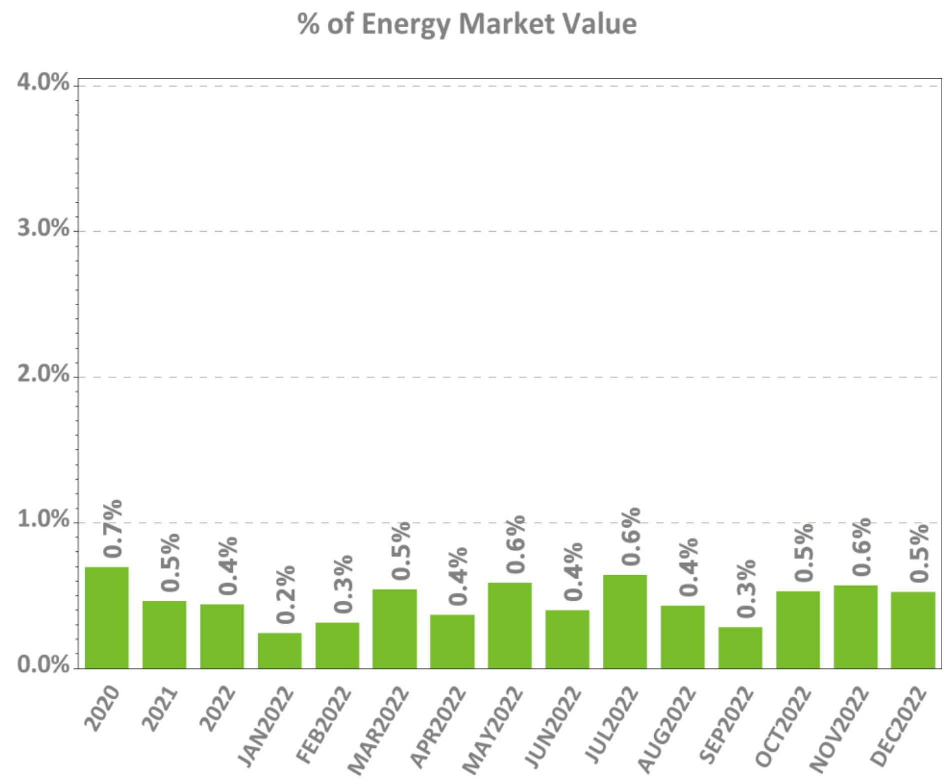


NCPC Charges as Percent of Energy Market



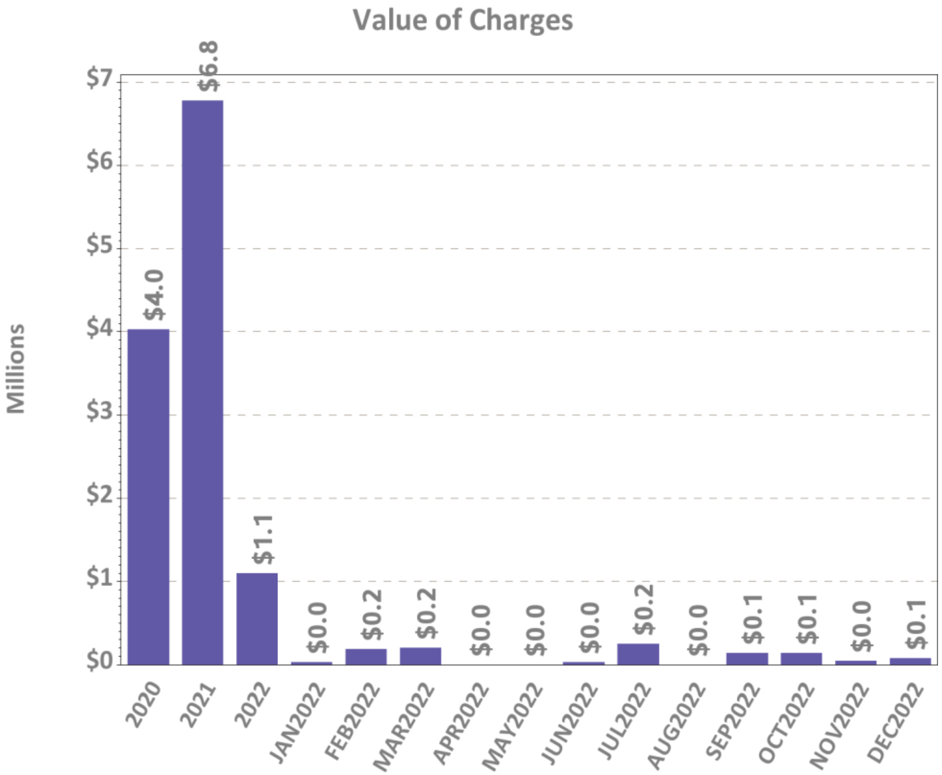
First Contingency NCPC Charges

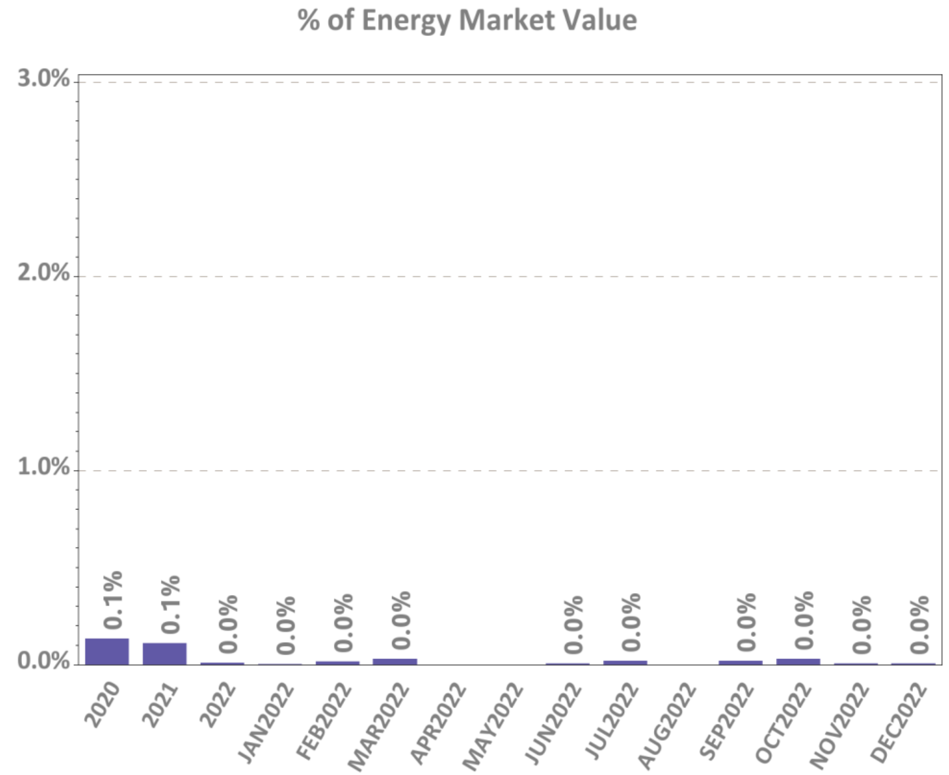




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

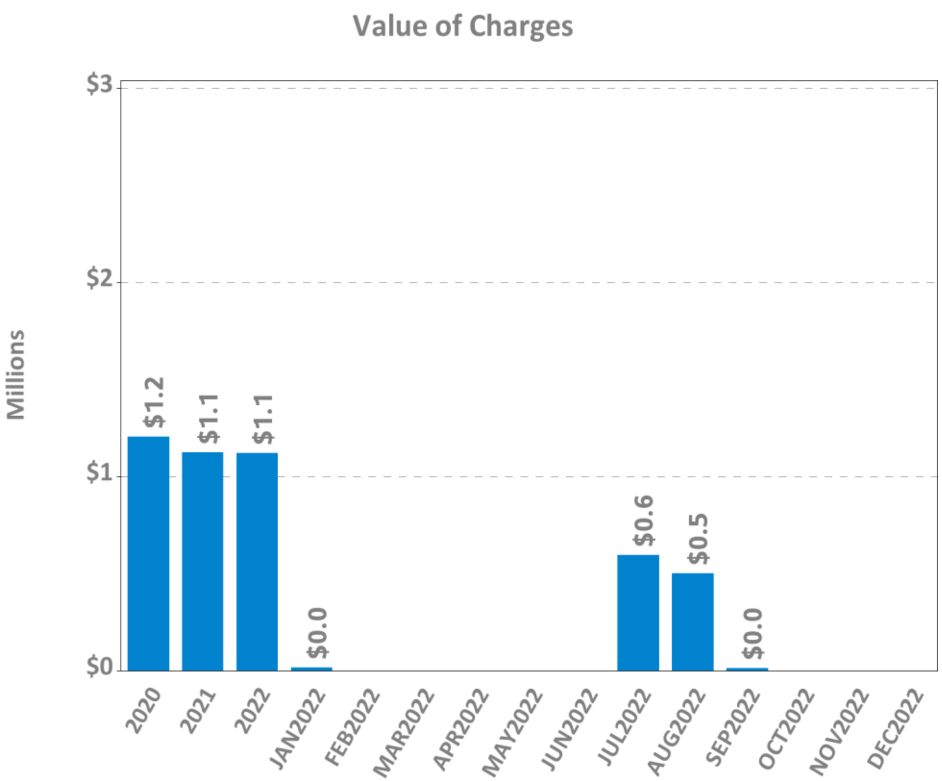
Second Contingency NCPC Charges

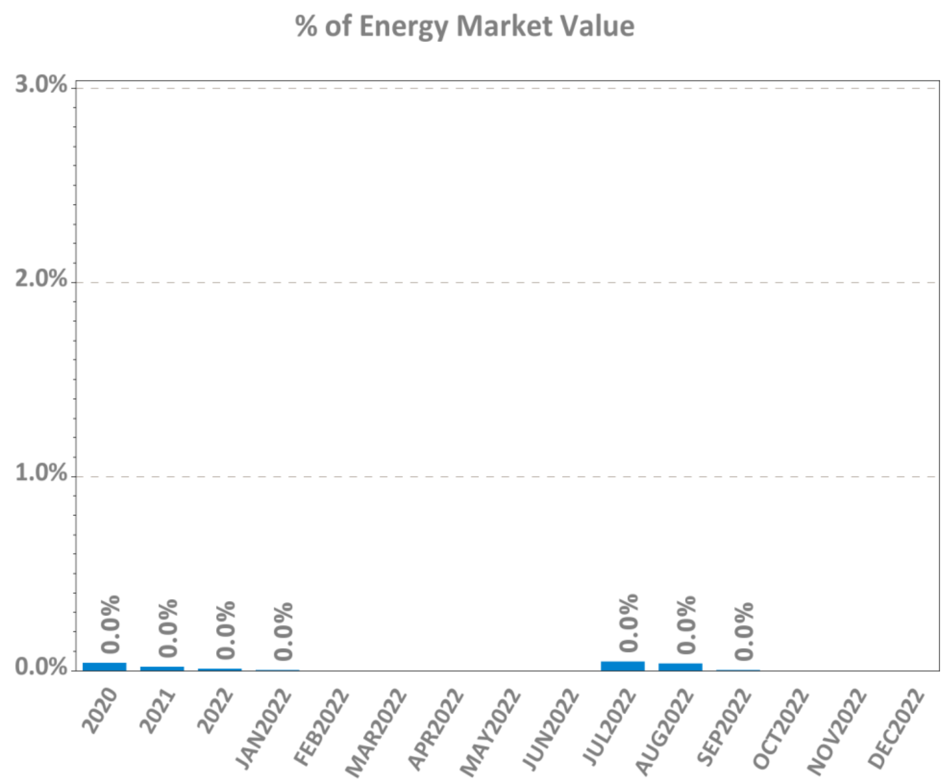




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

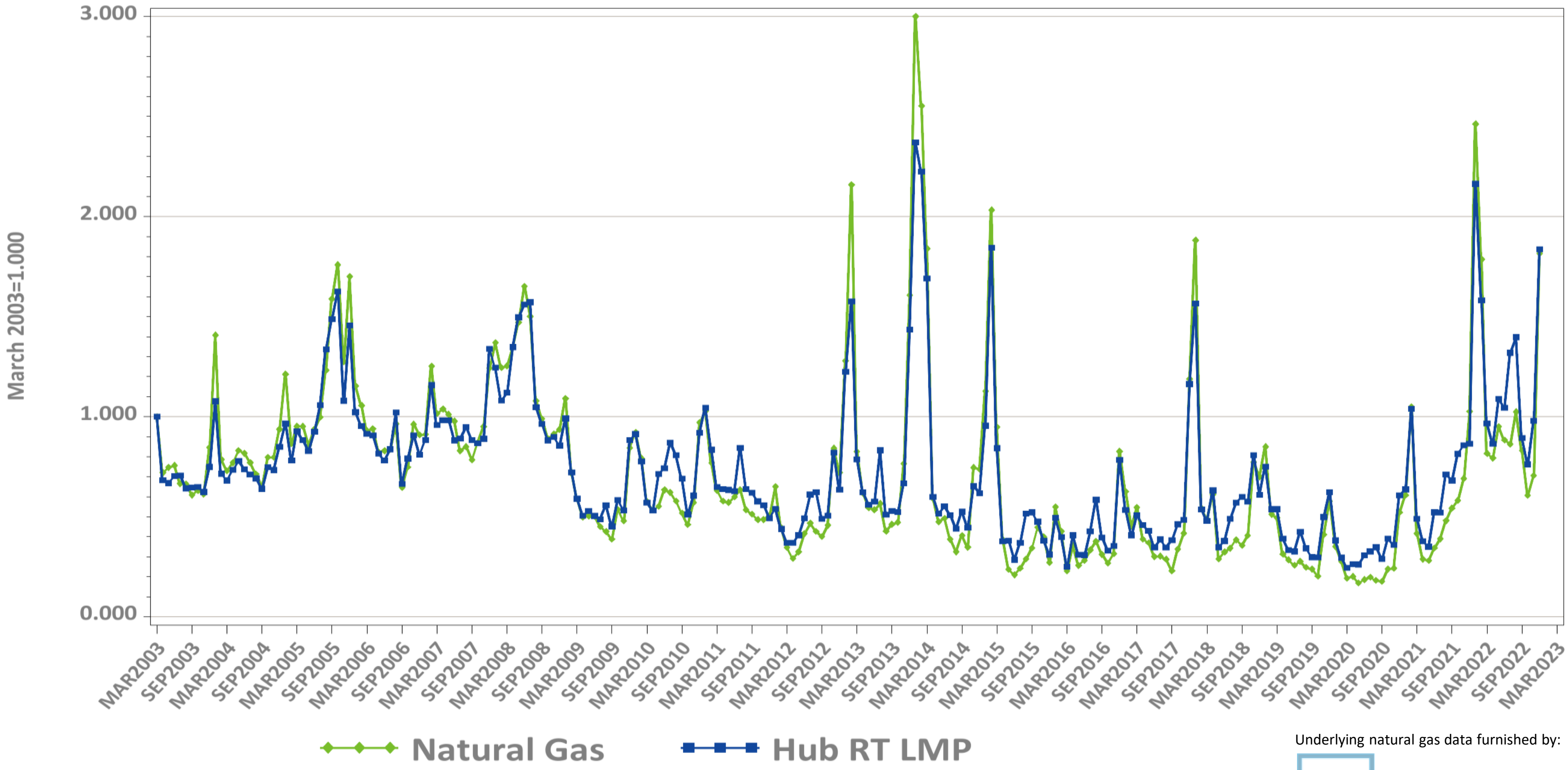
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%
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%

December-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$67.34	$60.93	$66.78	$66.68	$62.03	$66.54	$67.26	$64.82	$65.14
Real-Time	$60.04	$57.60	$59.57	$59.96	$57.91	$59.31	$59.97	$59.27	$59.42
RT Delta %	-10.8%	-5.5%	-10.8%	-10.1%	-6.6%	-10.9%	-10.8%	-8.6%	-8.8%
December-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$117.06	$115.15	$113.11	$116.88	$115.34	$117.26	$117.63	$117.29	$117.21
Real-Time	$126.32	$124.59	$120.24	$125.97	$123.67	$126.55	$126.92	$126.19	$126.19
RT Delta %	7.9%	8.2%	6.3%	7.8%	7.2%	7.9%	7.9%	7.6%	7.7%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	73.8%	89.0%	69.4%	75.3%	85.9%	76.2%	74.9%	80.9%	79.9%
Yr over Yr RT	110.4%	116.3%	101.9%	110.1%	113.6%	113.4%	111.6%	112.9%	112.4%

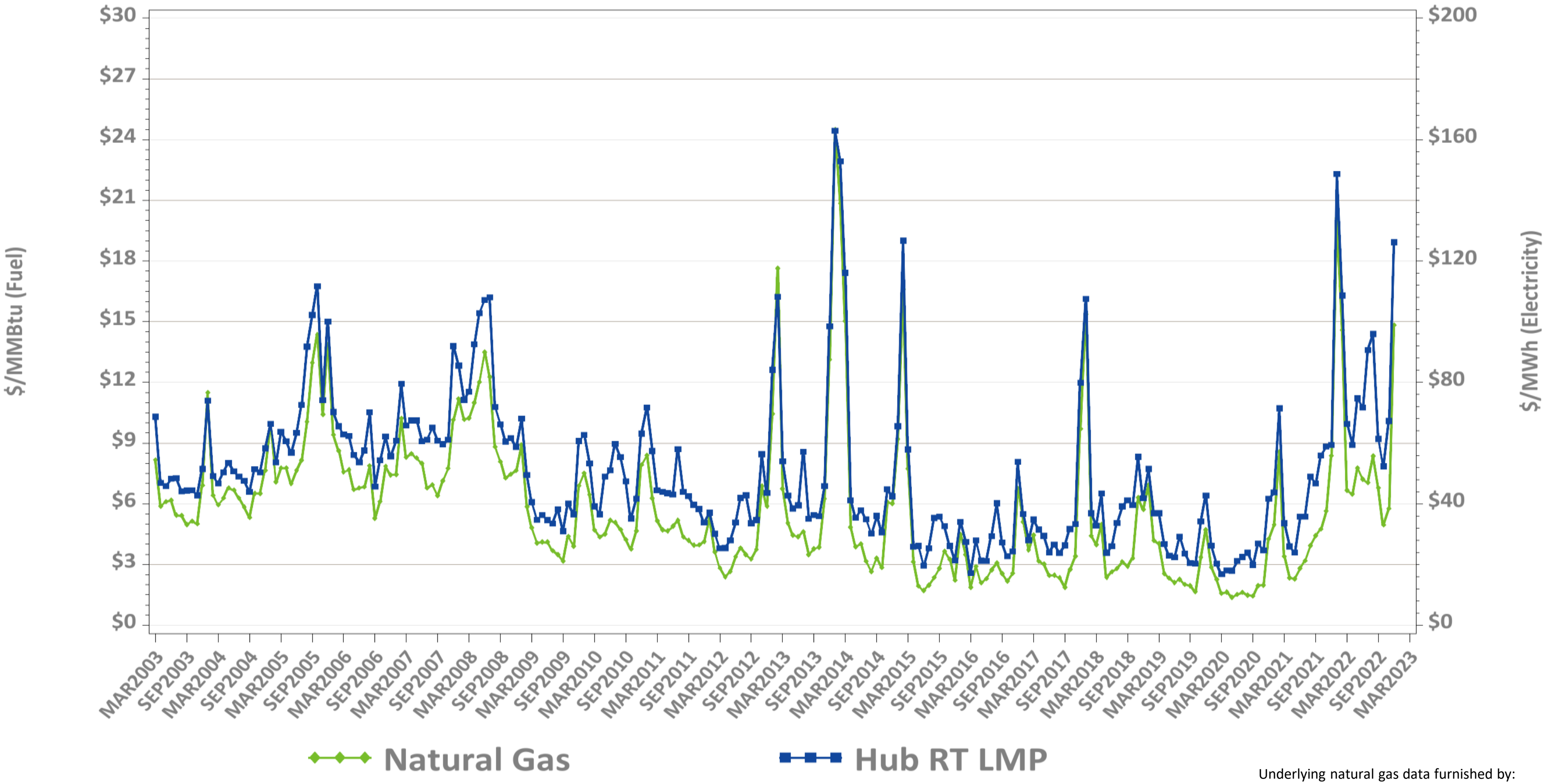
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

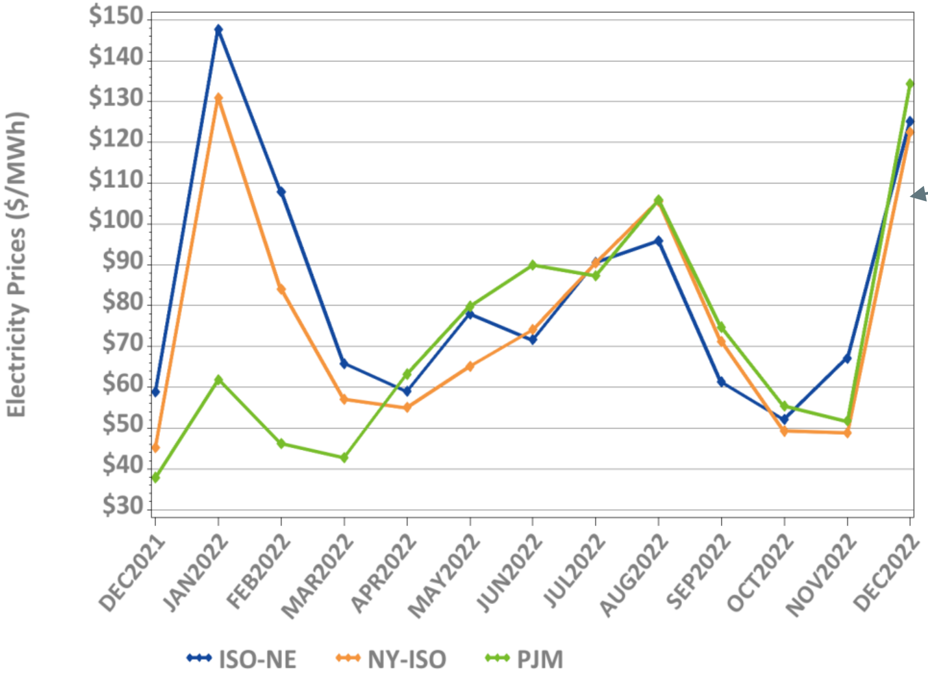
Monthly Average Fuel Price and RT Hub LMP



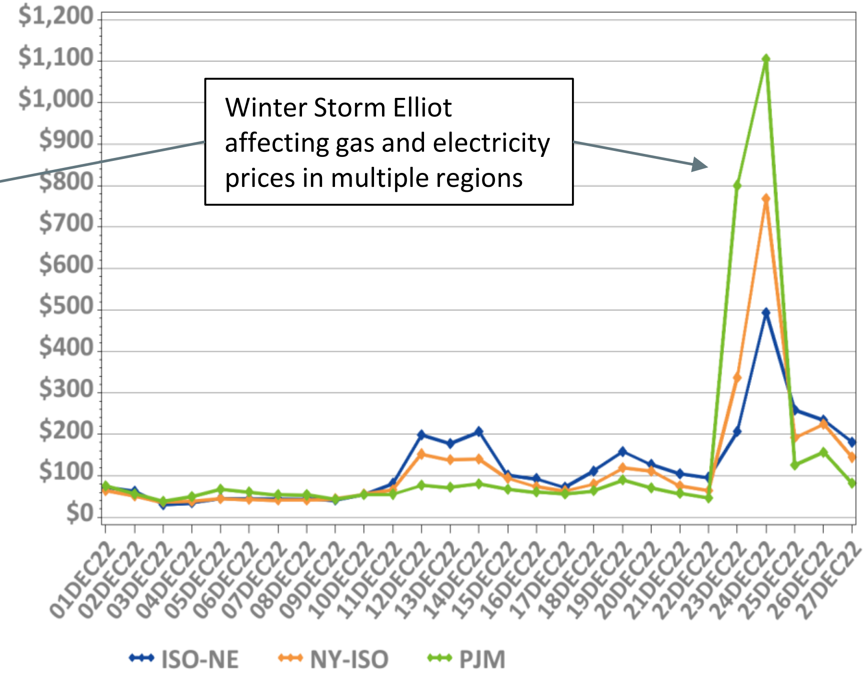
Underlying natural gas data furnished by:

ice Global markets in clear view

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



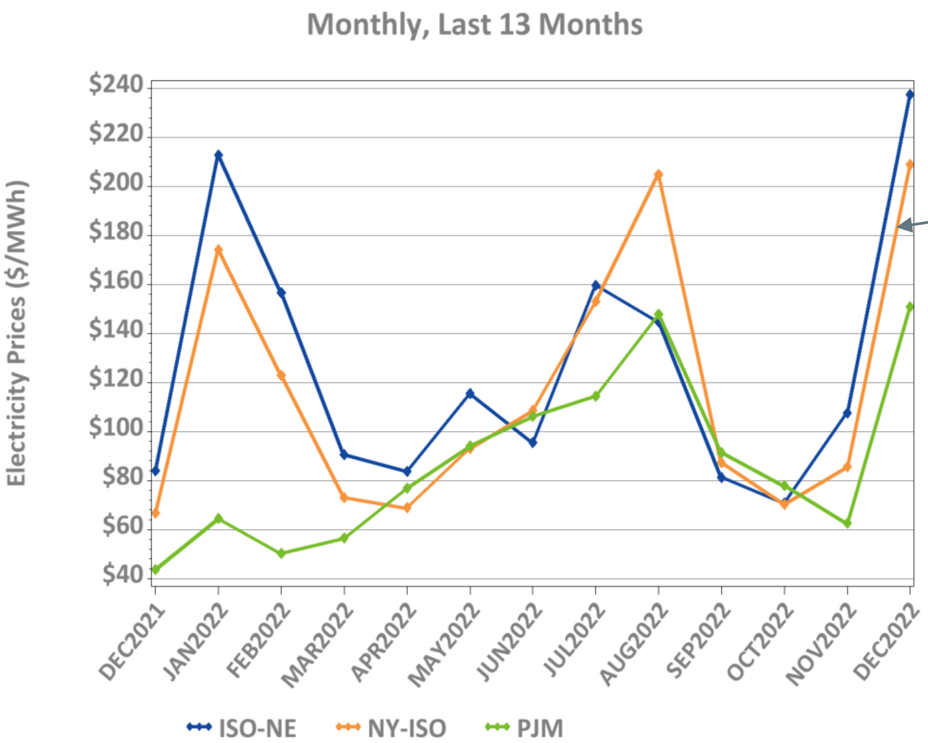
*Note: Hourly average prices are shown.

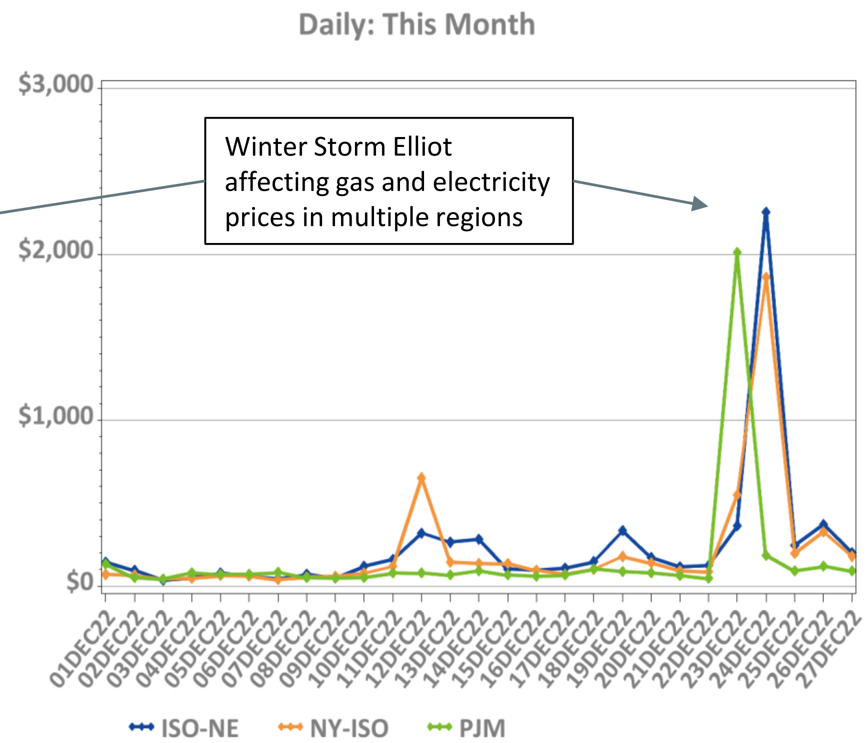


*Note: Hourly average prices are shown.

ISO-NE PUBLIC

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





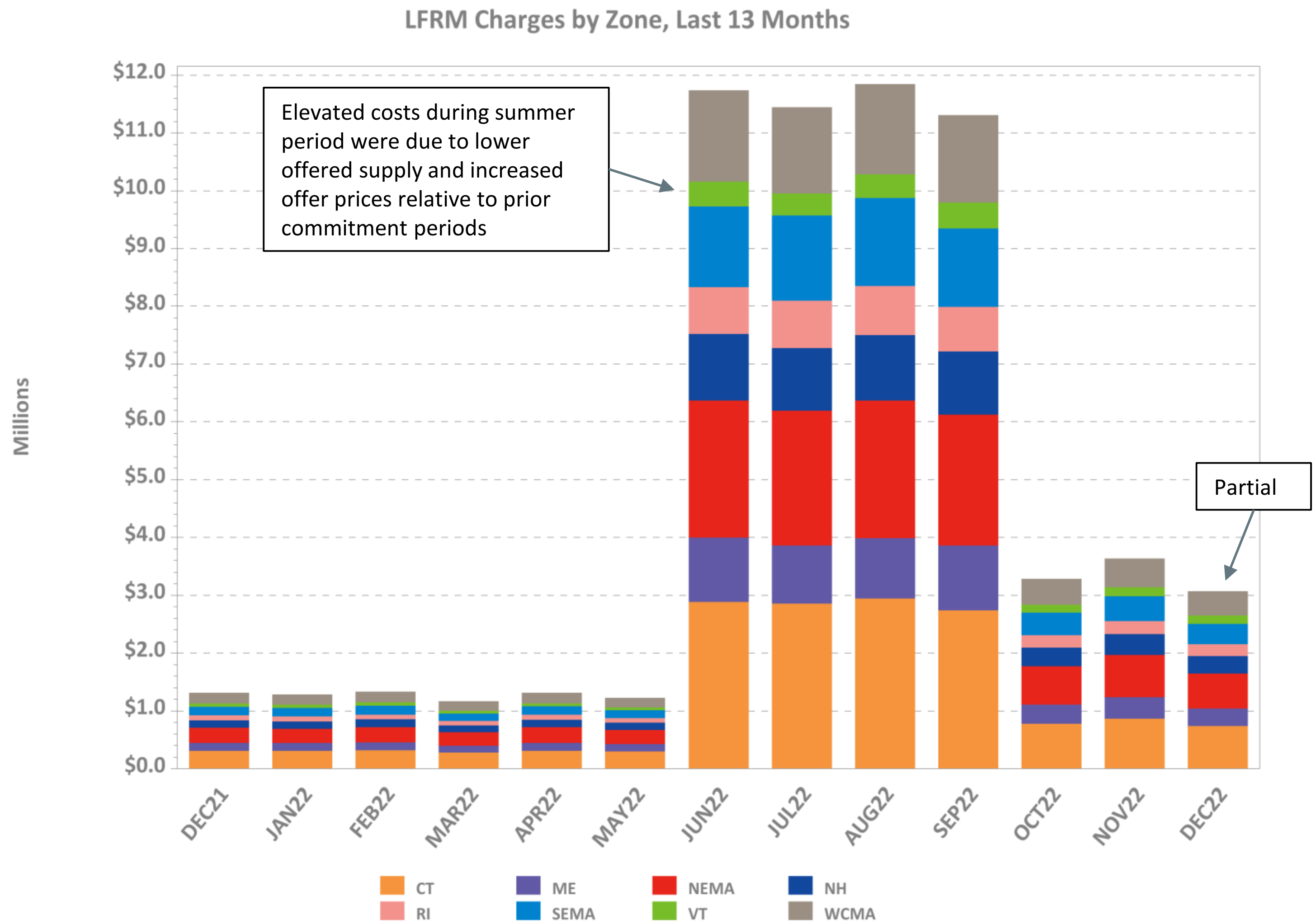
***Forecasted New England daily peak hours reflected**

Reserve Market Results – December 2022

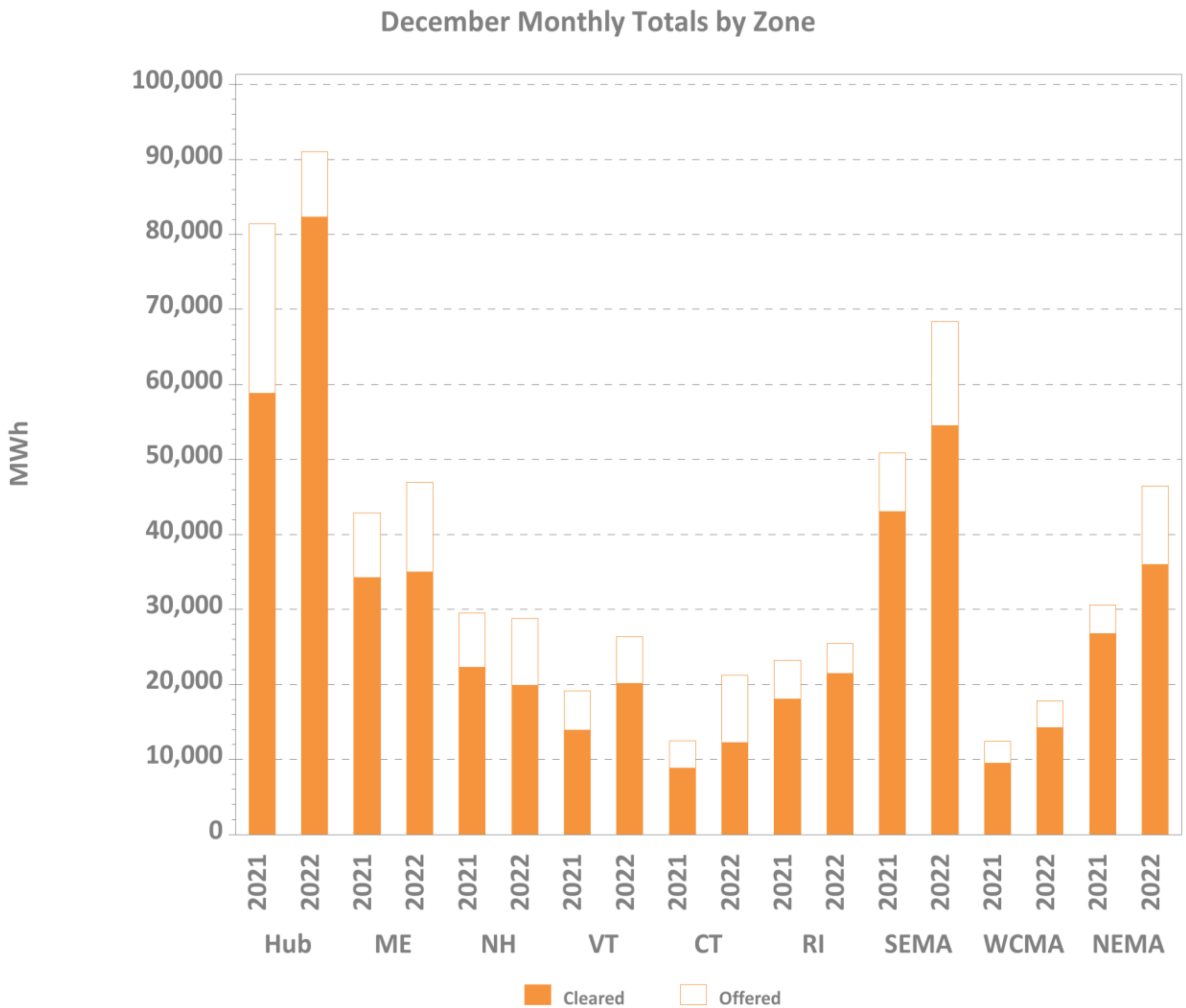
- Maximum potential Forward Reserve Market payments of \$3.2M were reduced by credit reductions of \$62K, failure-to-reserve penalties of \$93K and failure-to-activate penalties of \$114, resulting in a net payout of \$2.9M or 97% of maximum
  - Rest of System: \$2.08M/2.23M (94%)
  - Southwest Connecticut: \$0.03M/0.03M (95%)
  - Connecticut: \$0.95M/0.96M (99%)
- \$5.7M total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of \$5.7M in Real-Time Reserve payments
  - Rest of System: 152 hours, \$3.7M
  - Southwest Connecticut: 152 hours, \$976K
  - Connecticut: 152 hours, \$734K
  - NEMA: 152 hours, \$266K

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.

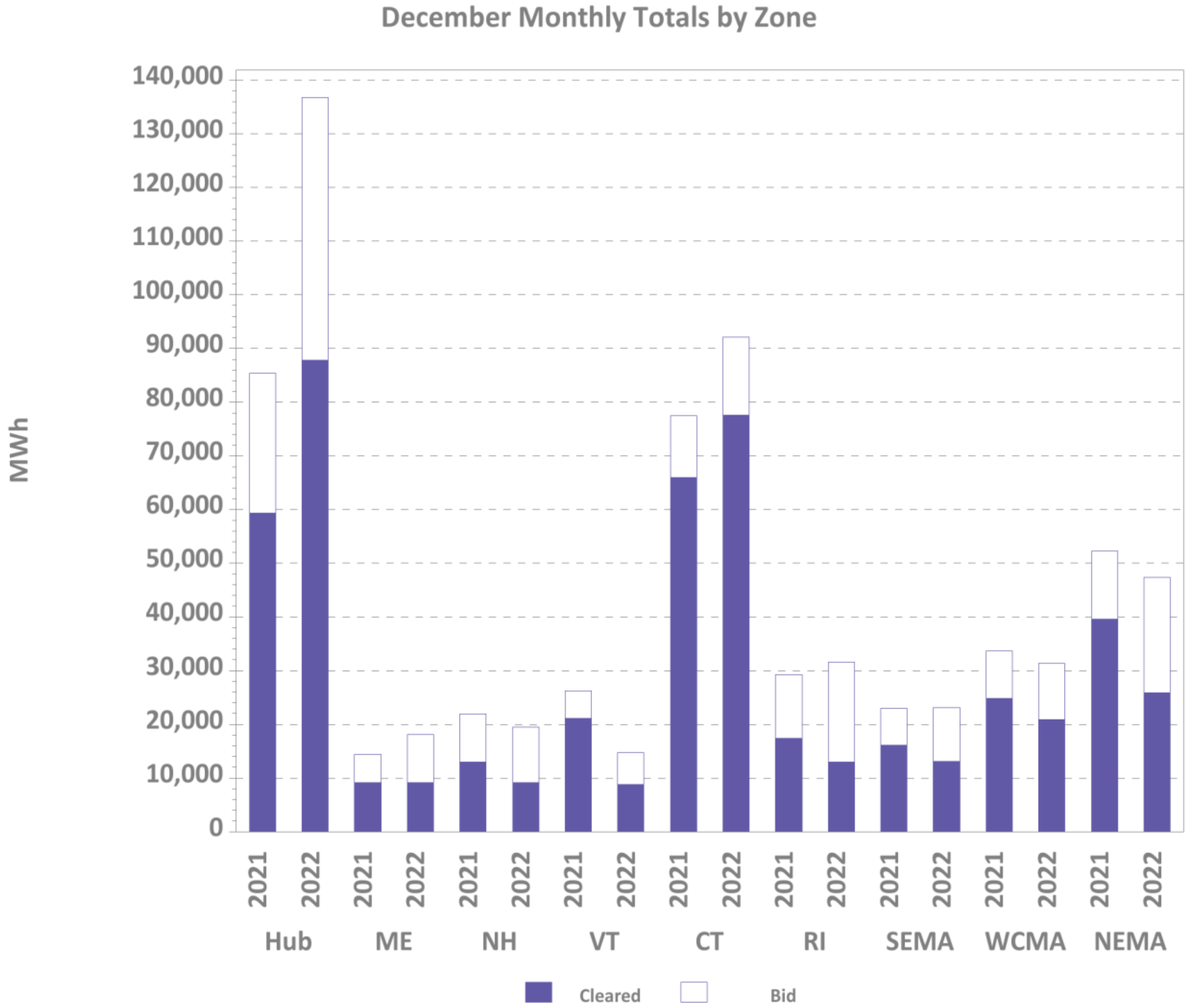
LFRM Charges to Load by Load Zone ($)



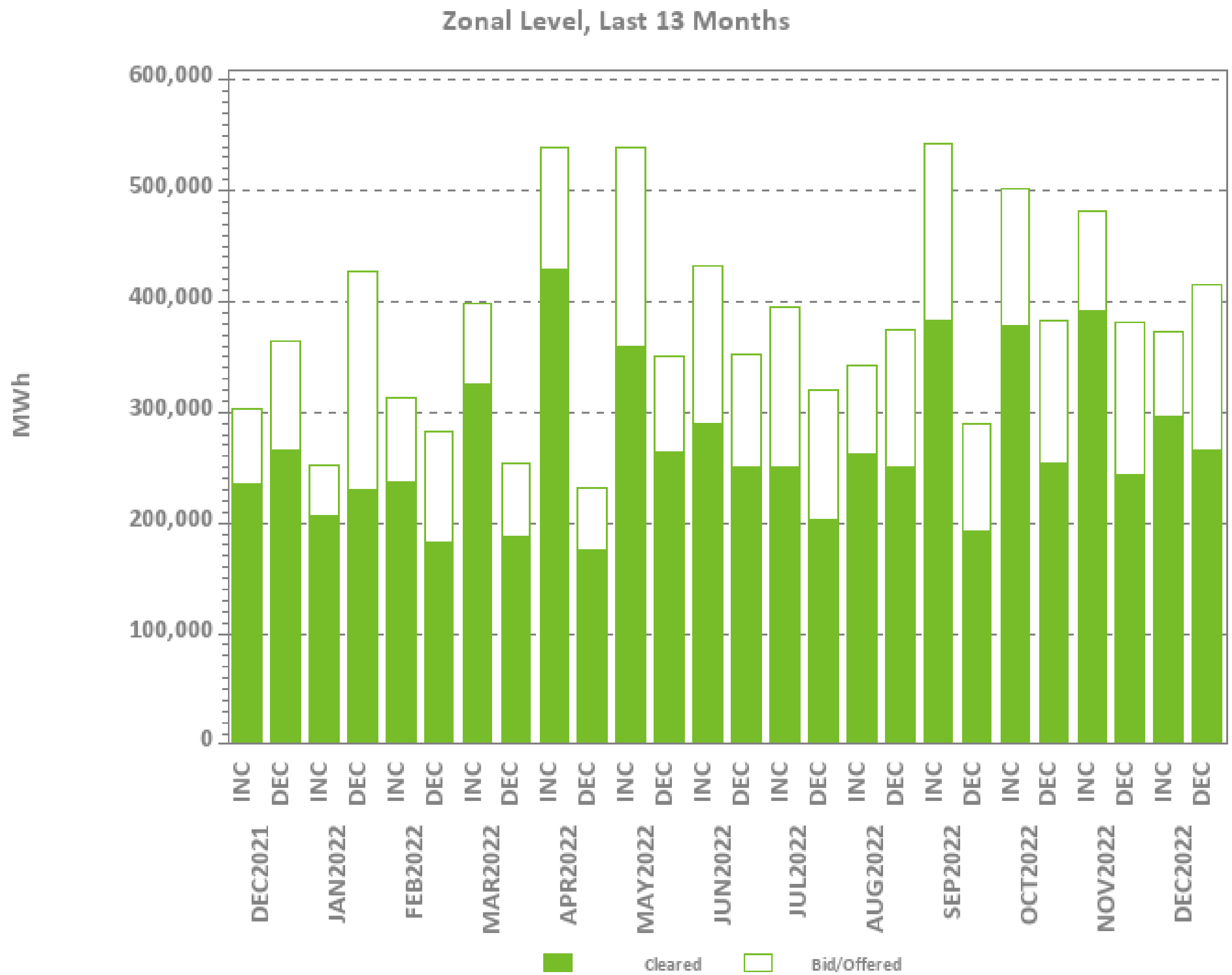
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

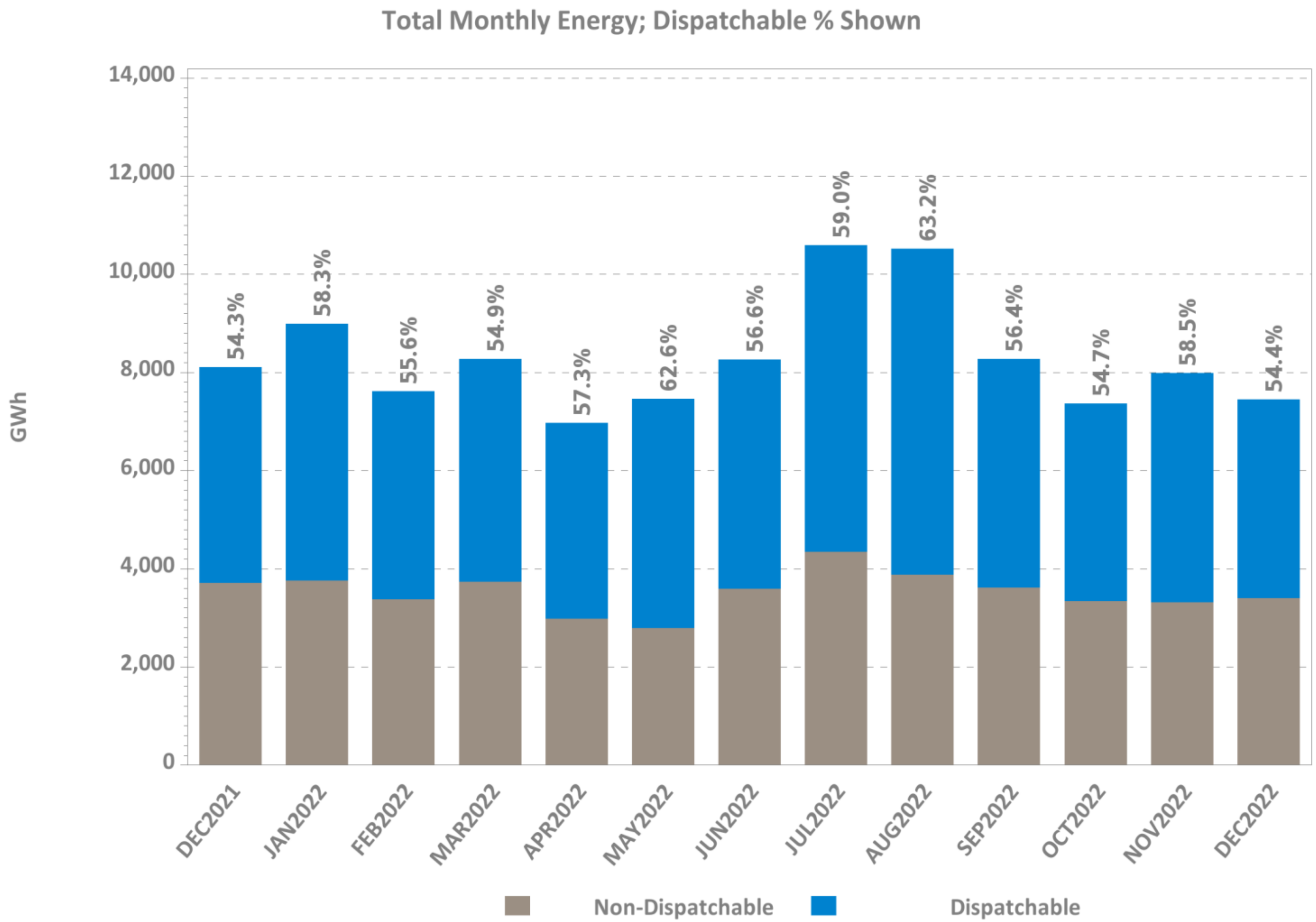


Total Increment Offers and Decrement Bids



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)

Planning Advisory Committee (PAC)

- January 19 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - 1163/1550 & 1268/1485/1887 Reconductor and Shield Wire Replacement Projects Update (Eversource)
    - Asset Condition Wood Structure Replacements (Eversource)
    - Line 381/379 Optical Ground Wire Upgrade (Eversource)
    - Maplewood #16 - Substation Asset Replacements (National Grid)
  - 2023 Public Policy Process

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

Transmission Planning for the Clean Energy Transition (TPCET)

- On 9/24/20, the ISO initiated discussions with the PAC about proposed refinements to transmission planning study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20, 12/16/20, and 1/21/21 PAC meetings outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21
- The final TPCET Pilot Study Report was posted to the PAC website on 1/14/22
- Status updates on ongoing transient stability modeling and performance criteria were discussed at the 4/28/22, 5/18/22, 6/15/22, and 8/24/22 PAC meetings; draft changes to the Transmission Planning Technical Guide (TPTG) reflecting assumption changes were discussed at the 11/15/22 PAC meeting; draft revisions to the TPTG were posted on 12/7/22, with feedback requested by 1/10/23

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Consultant to perform cost estimates has been selected – Electrical Consultants Inc. (ECI)

Economic Studies

- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Final report was posted on 7/29/22
  - Final production cost technical appendix and draft ancillary services technical appendix were posted on 12/5/22
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - Initial scope of work was presented at the April 2022 PAC meeting; new modeling features, initial benchmark and market efficiency scenario assumptions and results were presented at the August, October, and December 2022 PAC meetings

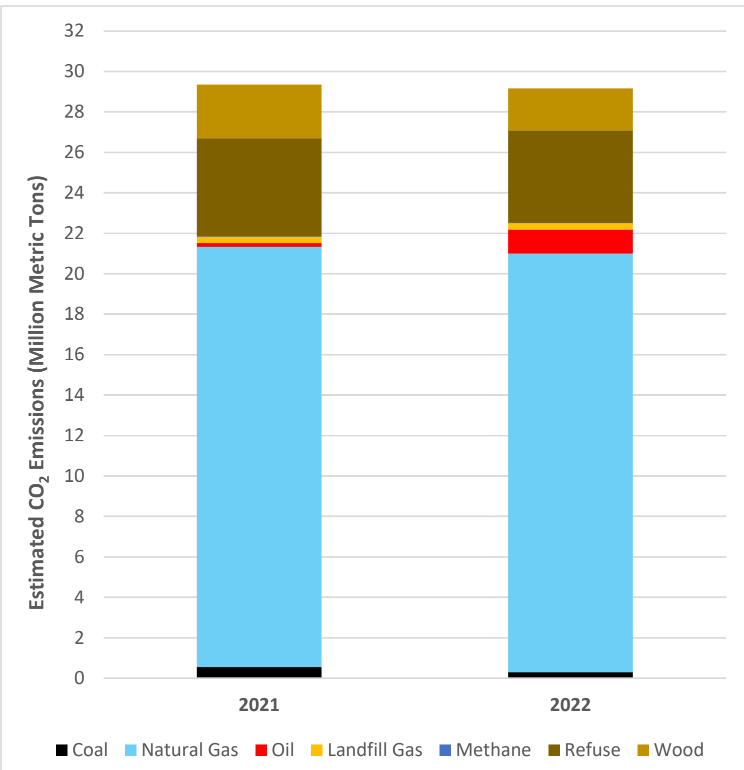
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability "gaps" that remain will be identified
  - High-level outline expected to be shared with stakeholders in early 2023

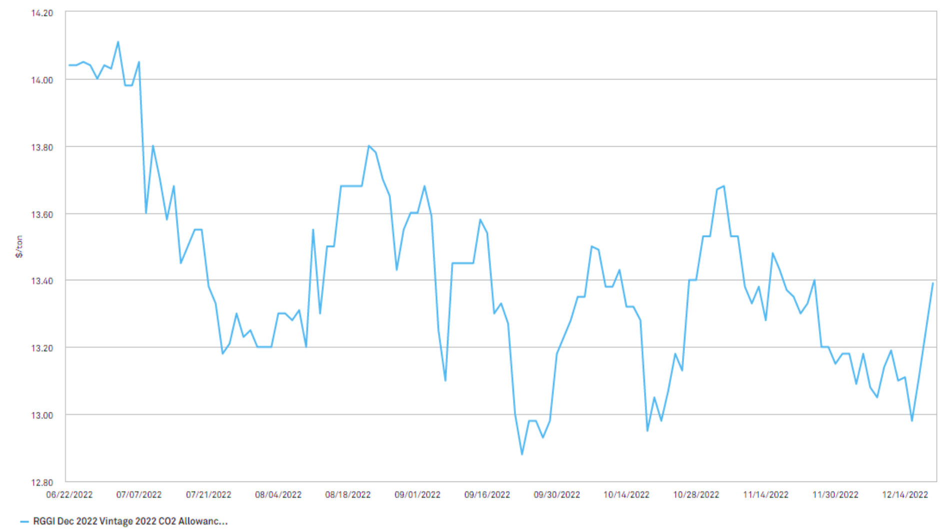
New England Power System Carbon Emissions

- ***2022 CO_2 emissions slightly below 2021***
- ***January oil-fired generation spike***

2021 vs. 2022 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



RGGI Allowance Prices



- 12/20/22: RGGI allowance spot price - \$13.39 per allowance (1 allowance = 1 short ton CO_2)

RGGI Annual Compliance Costs by Fuel Type (\$/MWh)

	2019	2020	2021	2022
Natural Gas	\$2.51	\$2.88	\$4.85	\$6.16
No. 2 Oil	\$5.19	\$5.95	\$12.24	\$12.71
No. 6 Oil	\$5.03	\$5.77	\$11.88	\$12.33
Coal	\$5.67	\$6.50	\$13.39	\$13.90

Data as of 12/18/22

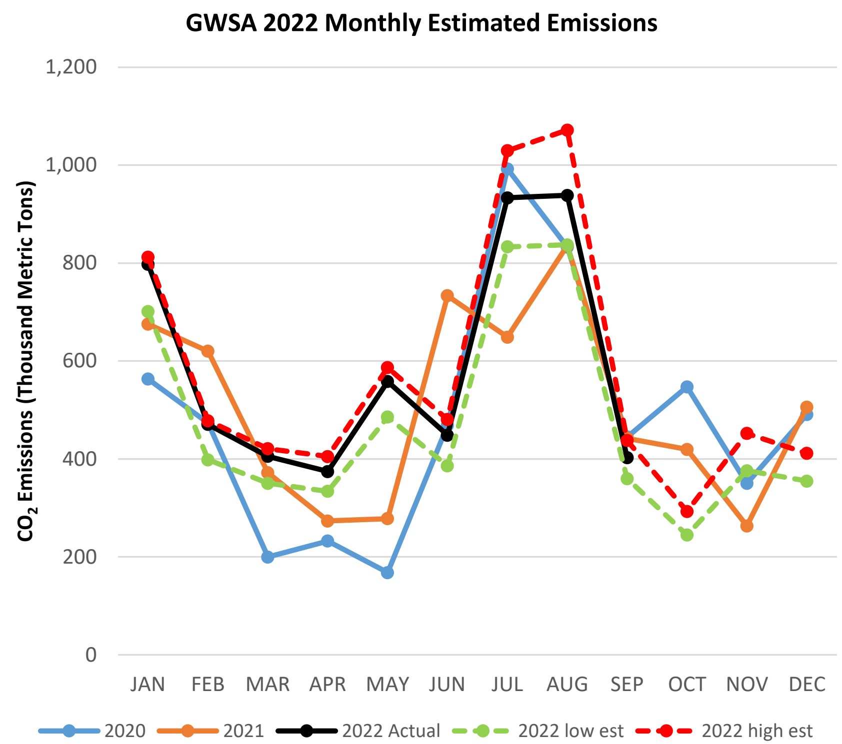
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

2022 Estimated Emissions Under CO_2 Cap

- 12/21/22: 2022 estimated GWSA CO_2 emissions range between 5.7 and 6.9 MMT
  - 70% to 85% of the 8.06 MMT 2022 cap
- 9/14/22 GWSA auction cleared at \$14.73; 1.20 million 2022 vintage allowances sold
  - Clearing price was nearly \$5 above the previous auction
  - 0.39 million 2023 vintage GWSA allowances were also offered, clearing at \$7.51
- Year-to-date ISO-NE IMM estimated compliance costs by fuel type):
  - Natural gas - \$3.20/MWh
  - No. 2 fuel oil - \$8.07/MWh
  - No. 6 fuel oil - \$7.83/MWh

2020-2022 Estimated Monthly Emissions (Thousand Metric tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

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

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 12/15/2022

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 12/15/2022

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	Dec-23	2

Greater Boston Projects, cont.

Status as of 12/15/2022

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

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

Greater Boston Projects, cont.

Status as of 12/15/2022

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 12/15/2022

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

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

SEMA/RI Reliability Projects

Status as of 12/15/2022

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/15/2022

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	May-25	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	Dec-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 12/15/2022

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	1
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	Jun-23	3
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Jun-23	3
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	1

SEMA/RI Reliability Projects, cont.

Status as of 12/15/2022

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/15/2022

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

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

Eastern CT Reliability Projects

Status as of 12/15/2022

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	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	3
1851	Upgrade Card 115 kV to BPS standards	Mar-23	3
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	3
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	3

Eastern CT Reliability Projects, cont.

Status as of 12/15/2022

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	Dec-23	3
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Apr-23	3
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	3
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.)	Apr-23	3
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 12/15/2022

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)	Dec-23	3
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

Boston Area Optimized Solution Projects

Status as of 12/15/2022

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Dec-21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Apr-22	4
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	3

New Hampshire Solution Projects

Status as of 12/15/2022

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	Dec-23	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	Dec-23	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	2

Upper Maine Solution Projects

Status as of 12/15/2022

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	2
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	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	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	2

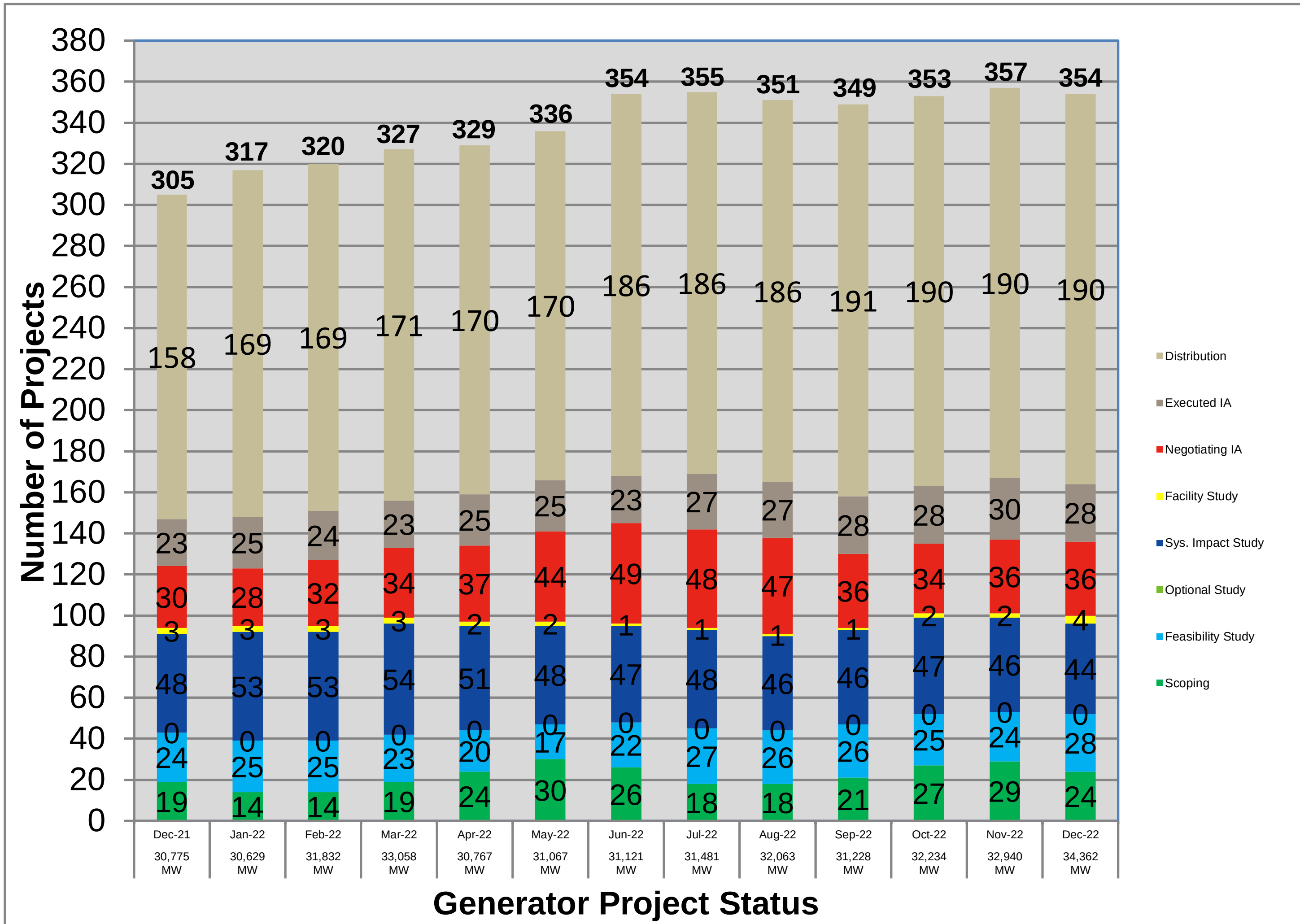
Upper Maine Solution Projects, cont.

Status as of 12/15/2022

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	2
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	2
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	2

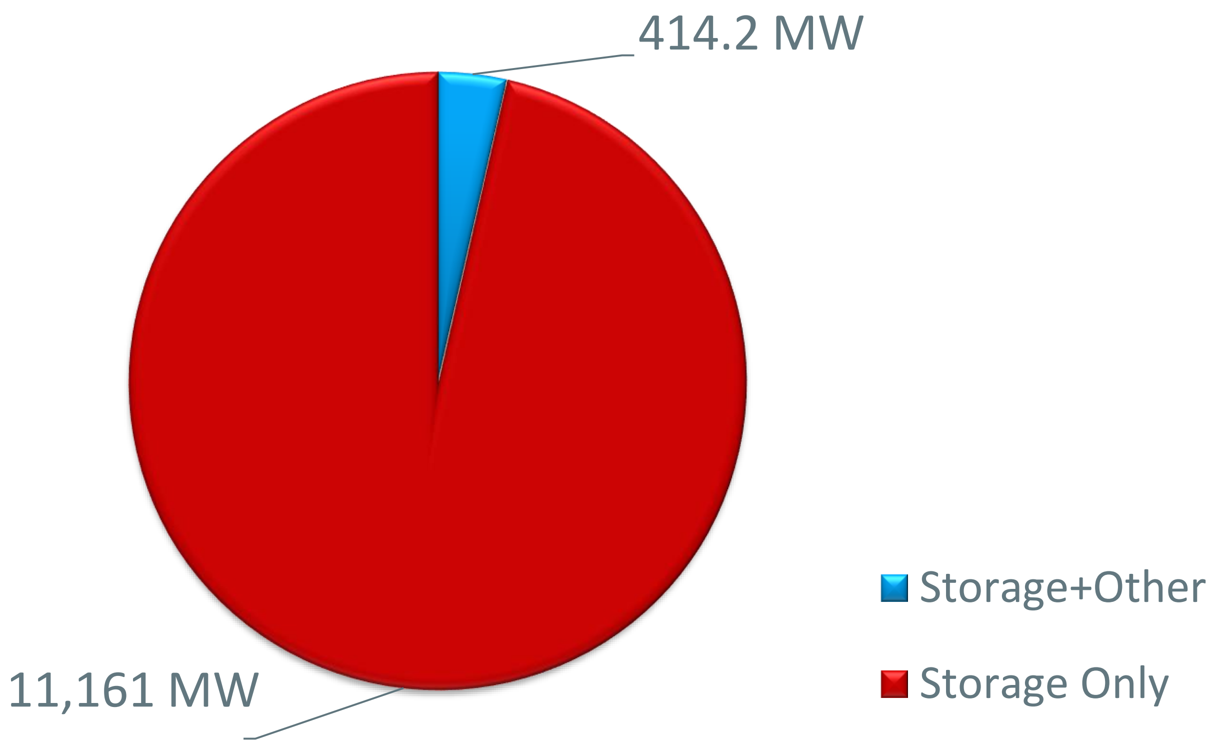
Status of Tariff Studies as of December 20, 2022



Note: December 2022 is based on partial data.
10 ETUs in Scoping, 1 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 2 Negotiating IA, and 3 with Executed IA
Transmission Service Requests needing study: 1 in Scoping and 3 in SIS
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of December 20, 2022)

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



OPERABLE CAPACITY ANALYSIS

Winter 2023 Analysis

Winter 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,262	31,974
Active Demand Capacity Resource (+) [5]	383	389
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,100	1,100
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	265	403
Gas Generator Outages MW (-)	311	436
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,424	3,851
Net Capacity (NET OPCAP SUPPLY MW)	22,960	25,988
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,009	20,009
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,314	22,314
Operable Capacity Margin	646	3,674

[1]Operable Capacity is based on data as of **December 22, 2022** 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 **December 22, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 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 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,262	31,974
Active Demand Capacity Resource (+) [5]	383	389
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,100	1,100
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	265	403
Gas Generator Outages MW (-)	311	436
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,235	4,781
Net Capacity (NET OPCAP SUPPLY MW)	22,149	25,058
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,695	20,695
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,000	23,000
Operable Capacity Margin	-851	2,058

[1]Operable Capacity is based on data as of **December 22, 2022** 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 **December 22, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 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 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 22, 2022 - 50-50 FORECAST using CSO MW

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

Report created: 12/22/2022

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1/7/2023	**28262**	**383**	**1100**	**15**	**265**	**311**	**2800**	**3424**	**22960**	**20009**	**2305**	**22314**	**646**	**Y**	**Winter 2022/2023**
1/14/2023	28262	383	1100	15	211	311	2800	3279	23159	20009	2305	22314	845	N	Winter 2022/2023
1/21/2023	28262	383	1100	15	176	344	2800	2797	23643	20009	2305	22314	1329	N	Winter 2022/2023
1/28/2023	28257	559	1070	60	161	344	3100	2498	23843	19789	2305	22094	1749	N	Winter 2022/2023
2/4/2023	28257	559	1070	60	1289	317	3100	2226	23014	19524	2305	21829	1185	N	Winter 2022/2023
2/11/2023	28257	559	1070	60	64	317	3100	1927	24538	19496	2305	21801	2737	N	Winter 2022/2023
2/18/2023	28257	559	1070	60	16	317	3100	1478	25035	19236	2305	21541	3494	N	Winter 2022/2023
2/25/2023	28257	559	1070	60	191	317	3100	1179	25159	18258	2305	20563	4596	N	Winter 2022/2023
3/4/2023	28251	559	1070	60	250	862	2200	335	26293	17912	2305	20217	6076	N	Winter 2022/2023
3/11/2023	28251	559	1070	60	179	616	2200	0	26945	17718	2305	20023	6922	N	Winter 2022/2023
3/18/2023	28251	559	1070	60	1445	1540	2200	0	24755	17357	2305	19662	5093	N	Winter 2022/2023
3/25/2023	28251	559	1070	60	1404	2704	2200	0	23632	16797	2305	19102	4530	N	Winter 2022/2023

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also partcipate 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 2022 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 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

December 22, 2022 - 90/10 FORECAST using CSO MW

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

Report created: 12/22/2022

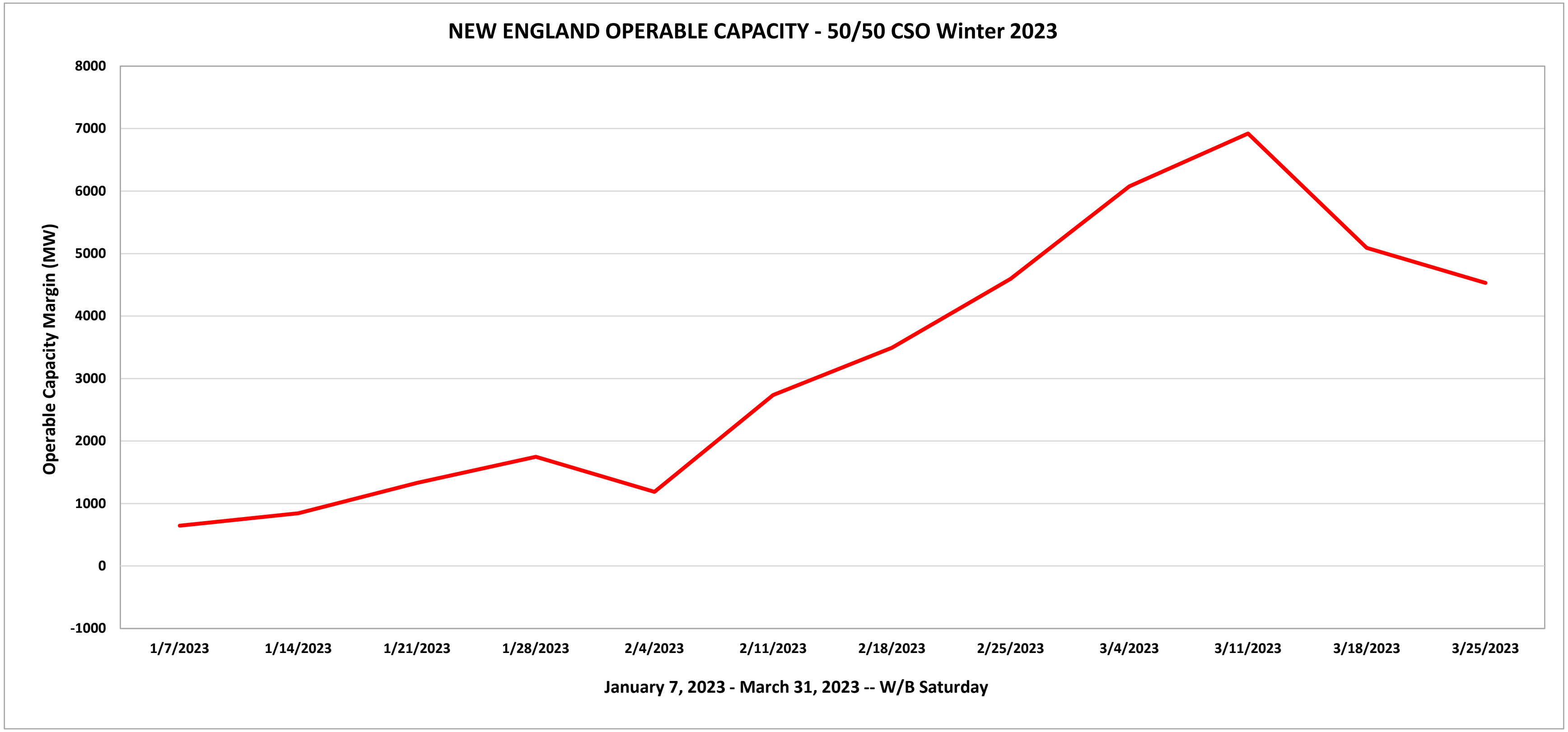
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1/7/2023	**28262**	**383**	**1100**	**15**	**265**	**311**	**2800**	**4235**	**22149**	**20695**	**2305**	**23000**	**-851**	**Y**	**Winter 2022/2023**
1/14/2023	28262	383	1100	15	211	311	2800	4027	22411	20695	2305	23000	-589	N	Winter 2022/2023
1/21/2023	28262	383	1100	15	176	344	2800	3695	22745	20695	2305	23000	-255	N	Winter 2022/2023
1/28/2023	28257	559	1070	60	161	344	3100	3695	22646	20468	2305	22773	-127	N	Winter 2022/2023
2/4/2023	28257	559	1070	60	1289	317	3100	3273	21967	20195	2305	22500	-533	N	Winter 2022/2023
2/11/2023	28257	559	1070	60	64	317	3100	2974	23491	20166	2305	22471	1020	N	Winter 2022/2023
2/18/2023	28257	559	1070	60	16	317	3100	2376	24137	19898	2305	22203	1934	N	Winter 2022/2023
2/25/2023	28257	559	1070	60	191	317	3100	1927	24411	18889	2305	21194	3217	N	Winter 2022/2023
3/4/2023	28251	559	1070	60	250	862	2200	1232	25396	18533	2305	20838	4558	N	Winter 2022/2023
3/11/2023	28251	559	1070	60	179	616	2200	880	26065	18333	2305	20638	5427	N	Winter 2022/2023
3/18/2023	28251	559	1070	60	1445	1540	2200	0	24755	17960	2305	20265	4490	N	Winter 2022/2023
3/25/2023	28251	559	1070	60	1404	2704	2200	0	23632	17383	2305	19688	3944	N	Winter 2022/2023

Column Definitions

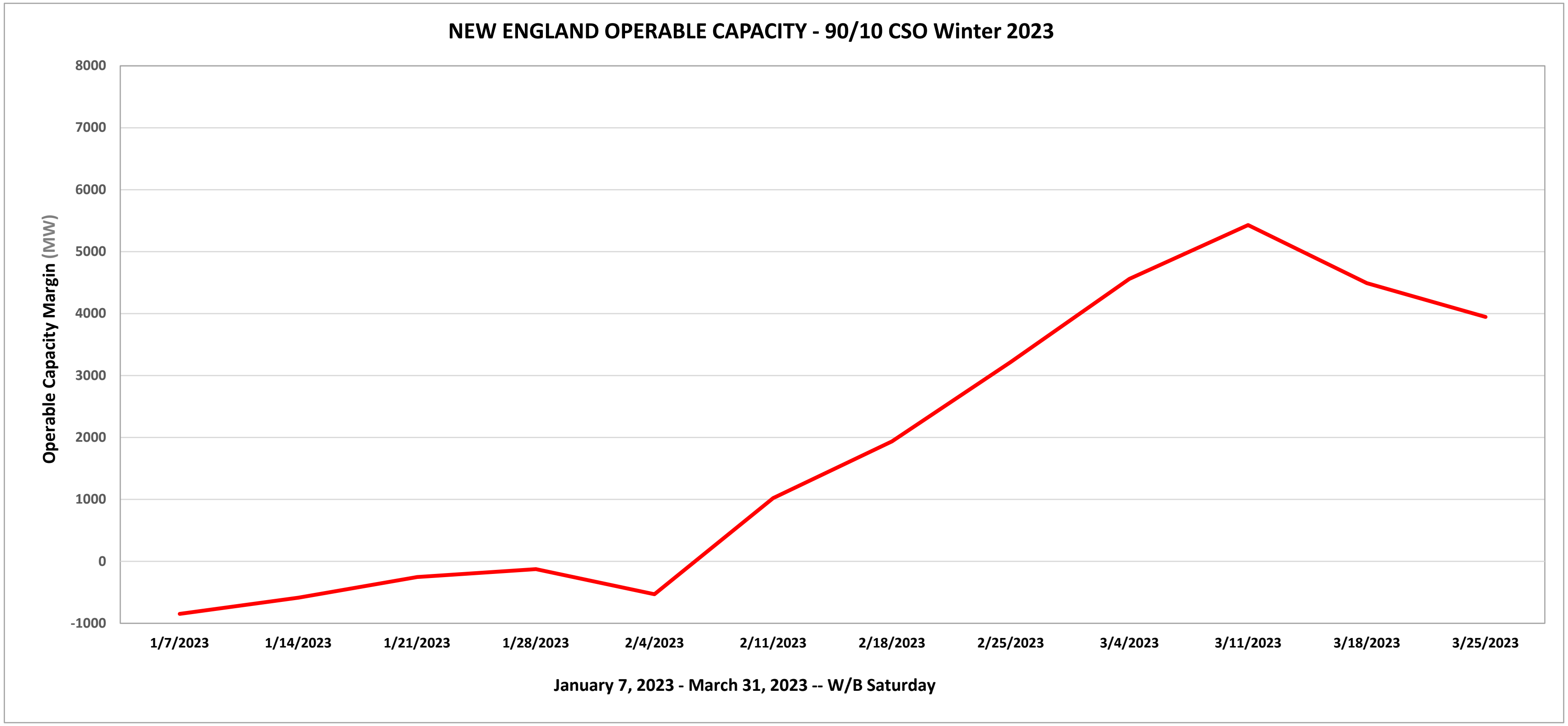
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



Winter 2023 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

JANUARY 5, 2023| NEPOOL PARTICIPANTS COMMITTEE

December 24, 2022 OP-4 Event and Capacity Scarcity Condition

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER

OP-4 and Capacity Scarcity Condition Saturday, December 24, 2022

- Two primary factors led to the implementation of OP-4 and the Capacity Scarcity Condition
  - Generator outages and reductions totaling ~2,150 MW occurred across the operating day
  - Net imports were less than the quantity that cleared the Day-Ahead Energy Market (~1,100 MW less at the time OP-4 actions were implemented)
- 30-minute Reserve Constraint Penalty Factor violated for the following 5-minute intervals: 16:40 – 18:00
  - $1,000/MWh Reserve Constraint Penalty Factor
- 10-minute Reserve Constraint Penalty Factor violated for the following 5-minute interval: 17:10
  - $1,500/MWh Reserve Constraint Penalty Factor
- System conditions required the implementation of M/LCC 2 and OP-4
  - M/LCC 2, Abnormal Conditions Alert: 16:00 – 21:00
  - OP-4, Actions 1, 2: 16:30 – 19:00
  - OP-4, Action 3: 16:45 – 19:00
  - OP-4, Action 5: 17:30 – 18:30

December 24th LMP Finalization and Preliminary Settlement Information

- Finalized Real-Time LMPs for December 24th and the Capacity Scarcity Condition report were published to the ISO website on Wednesday, December 28th at 12:45 p.m.
- Preliminary settlement reports released on Friday, December 30th
  - Balancing Ratios and Performance Scores published
  - The balancing ratio over each 5-min interval ranged from 0.652 – 0.681
  - The average balancing ratio over the period is 0.67
  - Final Settlement will adjust for Capacity Performance Bilateral Contracts
- Estimated Pay-for-Performance penalties*: $39M
  - Pay-for-Performance penalties during the last event on September 3, 2018: $36M

**Estimates based on available data*

Weather Forecast and Preparations for the Operating Day

- Following a winter storm and unseasonably mild weather on December 23rd, below normal temperatures were forecasted across the region on December 24th; forecasted peak hour temperatures for Boston and Hartford were 20°F and 17°F, respectively
- Severe cold weather conditions were impacting neighboring areas;
  - PJM issued a request for conservation throughout its footprint between the hours of 4 a.m. on December 24th and 10 a.m. on December 25th, and in order to obtain relief from potential emissions limitations at some generating stations, filed a request for an Emergency Order Under Section 202(c) of the Federal Power Act with the U.S. Department of Energy
- ISO System Operations staff was in close communication with neighboring Reliability Coordinators, Balancing Areas, and Local Control Centers ahead of and throughout the severe cold weather
- On the morning of December 24th, based on a peak load forecast of 17,510 MW (in HE18), ISO projected a capacity surplus of ~950 MW above load and operating reserve requirements

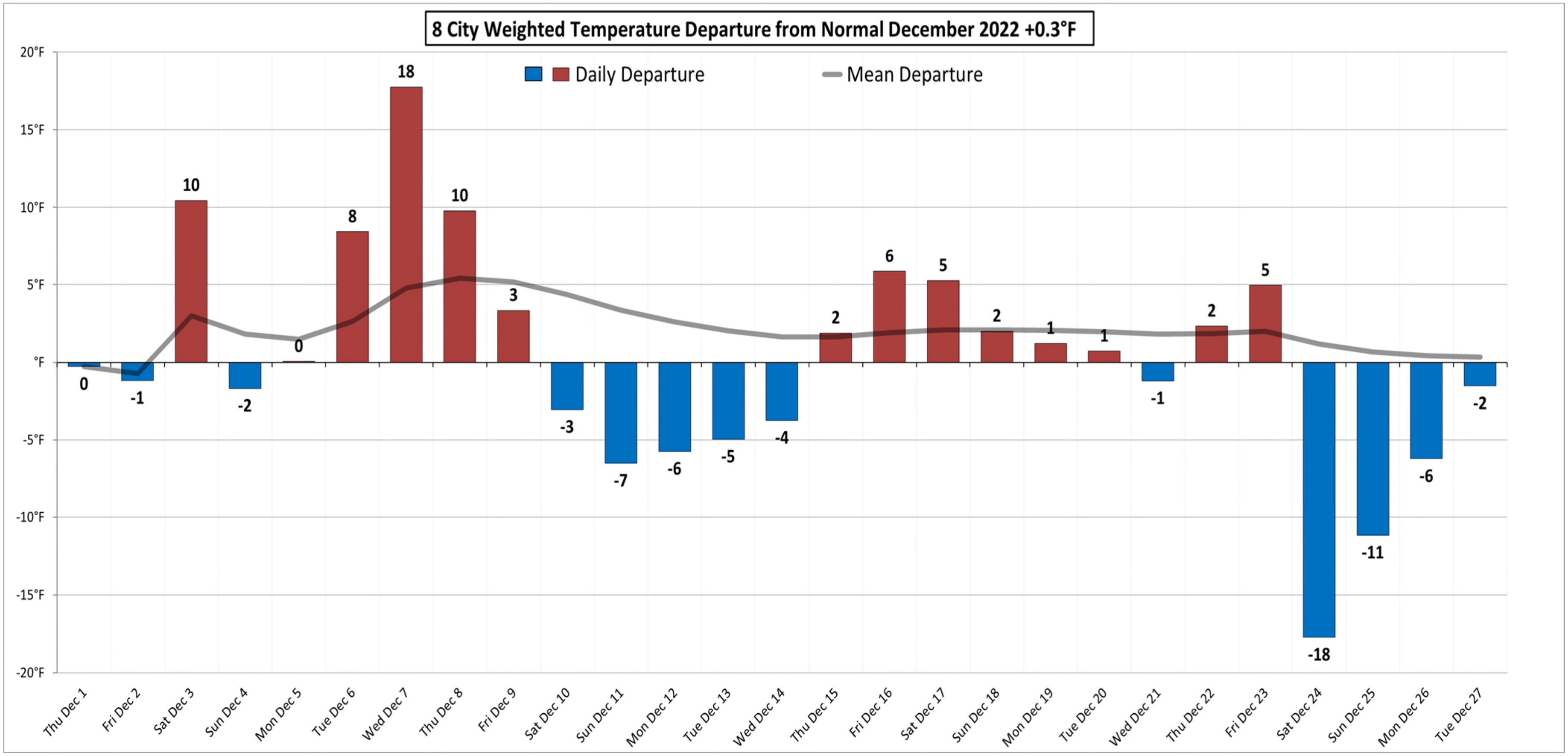
Coordination with Natural Gas Pipelines Was Critical

- Due to the severe cold weather across the region, Operational Flow Orders (OFOs) were in effect on the Algonquin, Iroquois, M&N, and Tennessee Pipelines
- ISO Operations staff closely monitored pipeline conditions and remained in close contact with pipeline operators throughout the day

Regional Weather Was Colder than Forecast

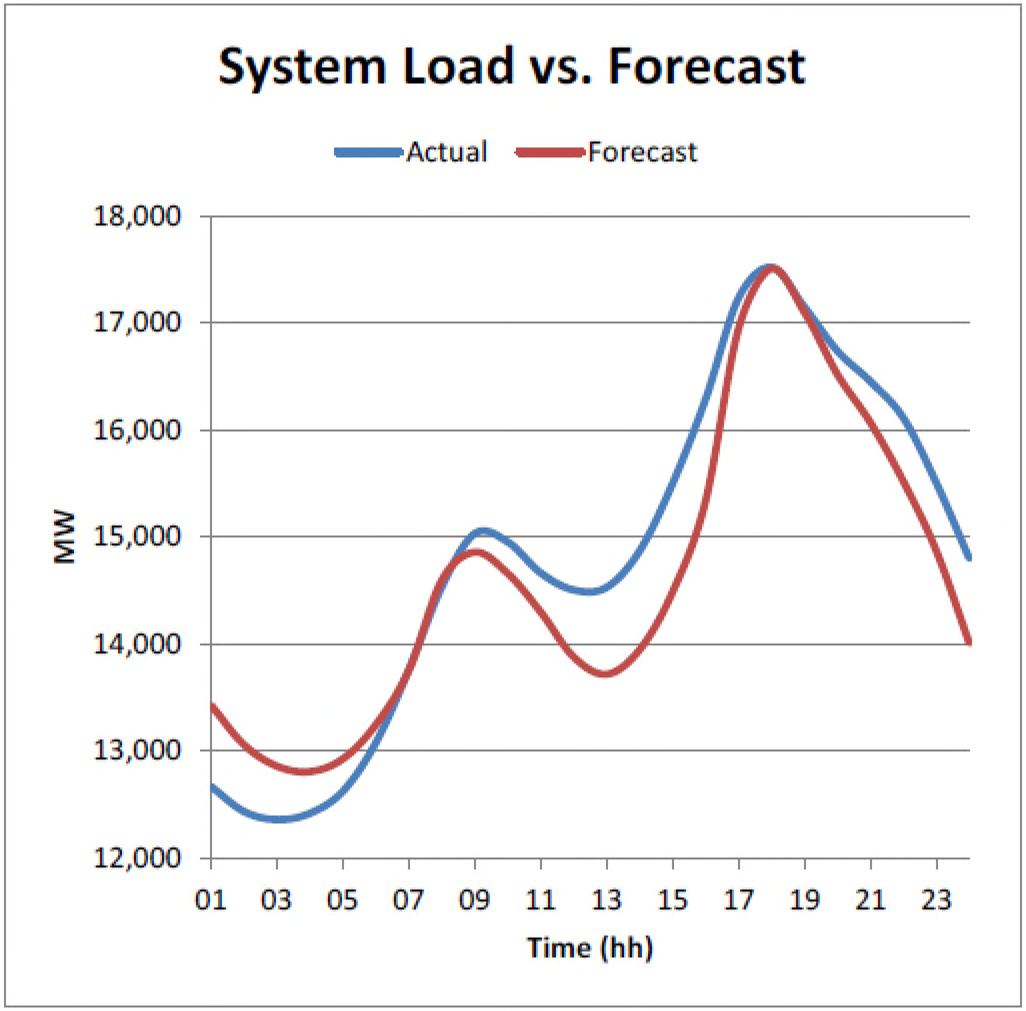
- Temperatures across the region were quite a bit colder than forecast; temperatures in all 8 of ISO's reference cities were below the forecast throughout the day
- Following the storm that impacted the region on December 23rd, an arctic air mass to the west of New England moved a bit further east than had been projected, resulting in temperatures on December 24th below forecast across the region
- Actual temperatures were colder than forecast by ~3-6 degrees throughout the day; peak hour temperatures were ~4°F lower than forecast

Regional Average Temperatures Departed Significantly from Normal



ISO's Peak Hour Load Forecast Was Accurate

- Lower than forecasted daytime temperatures contributed to higher than expected energy demand throughout the daylight hours, however ISO's peak hour load forecast was highly accurate
  - The absolute percent error of ISO's daily load forecast was ~3%; peak load was within ~25 MW of forecast
- Peak integrated load of 17,524MW occurred in HE18



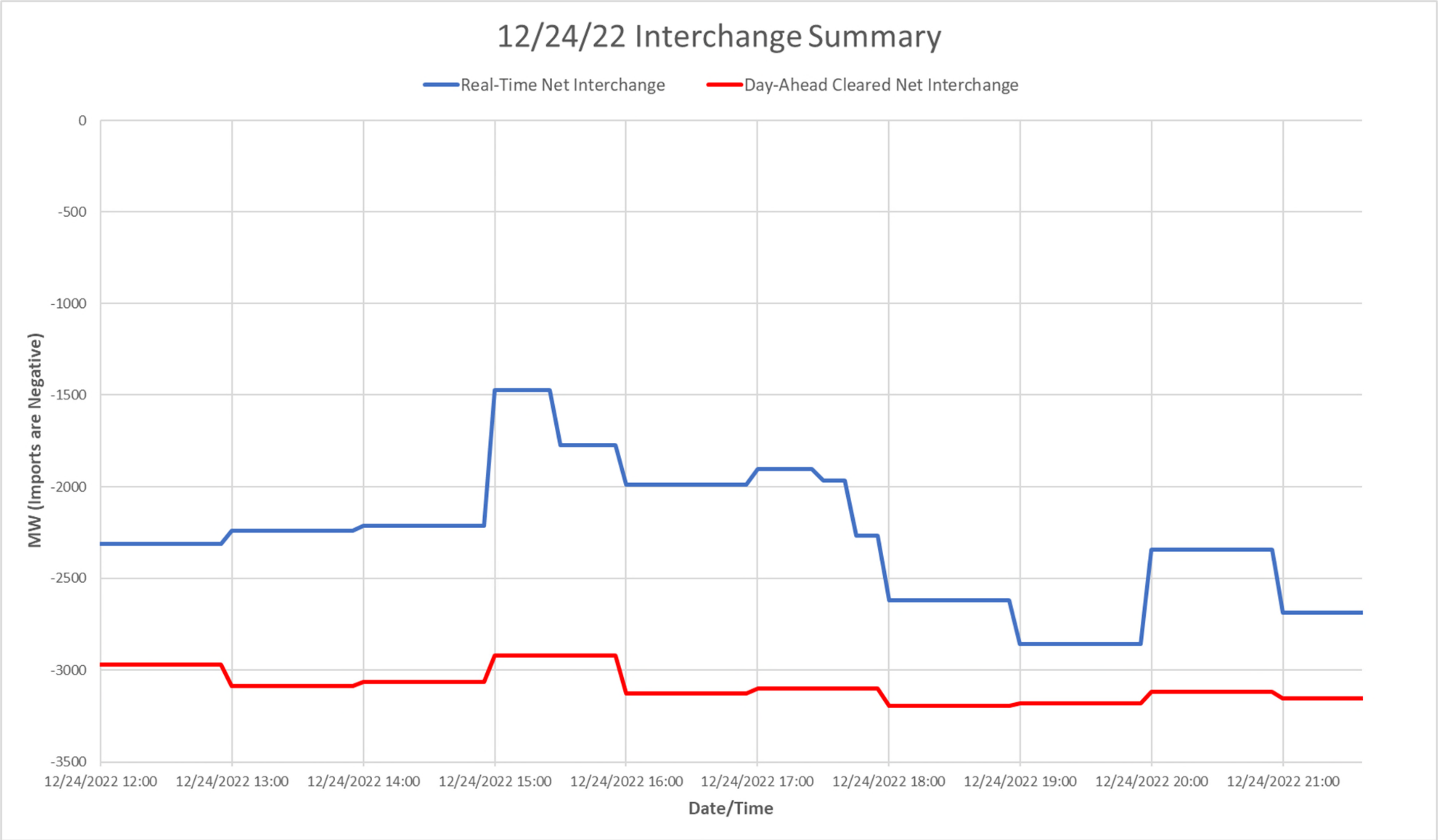
Unplanned Generator Outages and Reductions Occurred Prior to and During OP-4

- Throughout the day and prior to the declaration of M/LCC-2 at 16:00
  - Several generators experienced unplanned outages or reductions resulting in a net loss of ~1,000 MW of generating capacity
  - One resource (~275 MW) self-scheduled and ran through the peak hour
- Following declaration of M/LCC-2, and prior to the implementation of OP-4 at 16:30
  - Several additional generators experienced outages or reductions totaling ~400 MW of generating capacity
  - ISO initiated the commitment of all remaining offline resources that were available to come online for the peak hour (~380 MW)
- Following the implementation OP-4, during HE17-18, ~750 MW of additional generating capacity experienced outages or reductions
- Causes of generator outages and reductions (~2,150 in total) varied; some reported cold weather-related outages or reductions, and ISO expects to follow up with these resources on a case-by-case basis to gather additional details

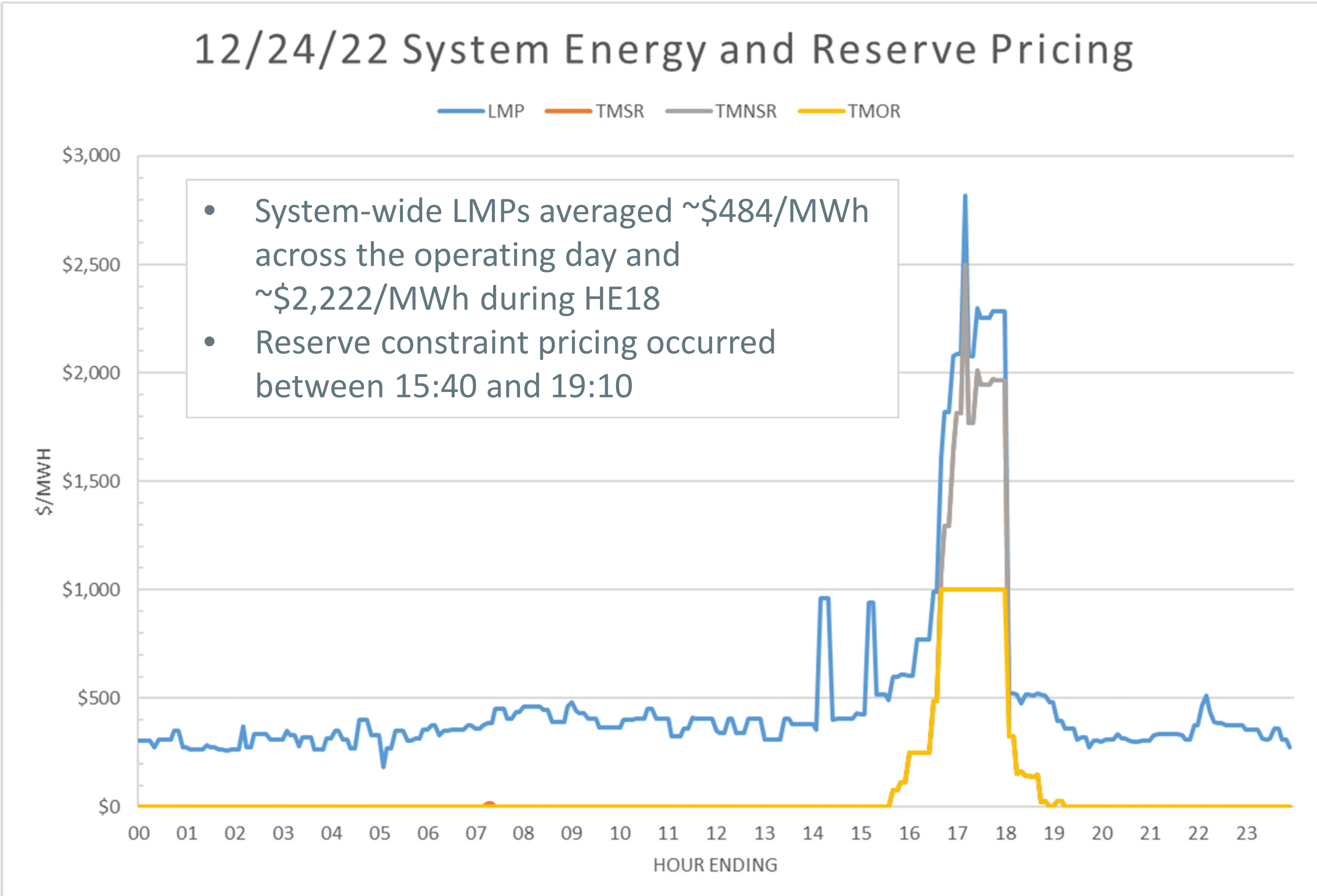
Energy Imports Were Below Day-Ahead Values

- At the time OP-4 actions were implemented (16:30), net imports were ~1,100 MW less than the amount that cleared the Day-Ahead Energy Market
- System Operators took action to curtail export transactions in accordance with Operating Procedures
  - New York North (NYN) interface
    - HE17: 707 MW
    - HE18: 300 MW (beginning at 17:40)
  - Norwalk – Northport Cable (NNC) interface
    - HE17: 124 MW
    - HE18: 164 MW (99 MW beginning at 17:00, an additional 65 MW at 17:35)
  - Cross Sound Cable (CSC) interface
    - HE18: 50 MW (beginning at 17:35)

Energy Imports Were Below Day-Ahead Values



Real-Time System Energy and Reserve Pricing



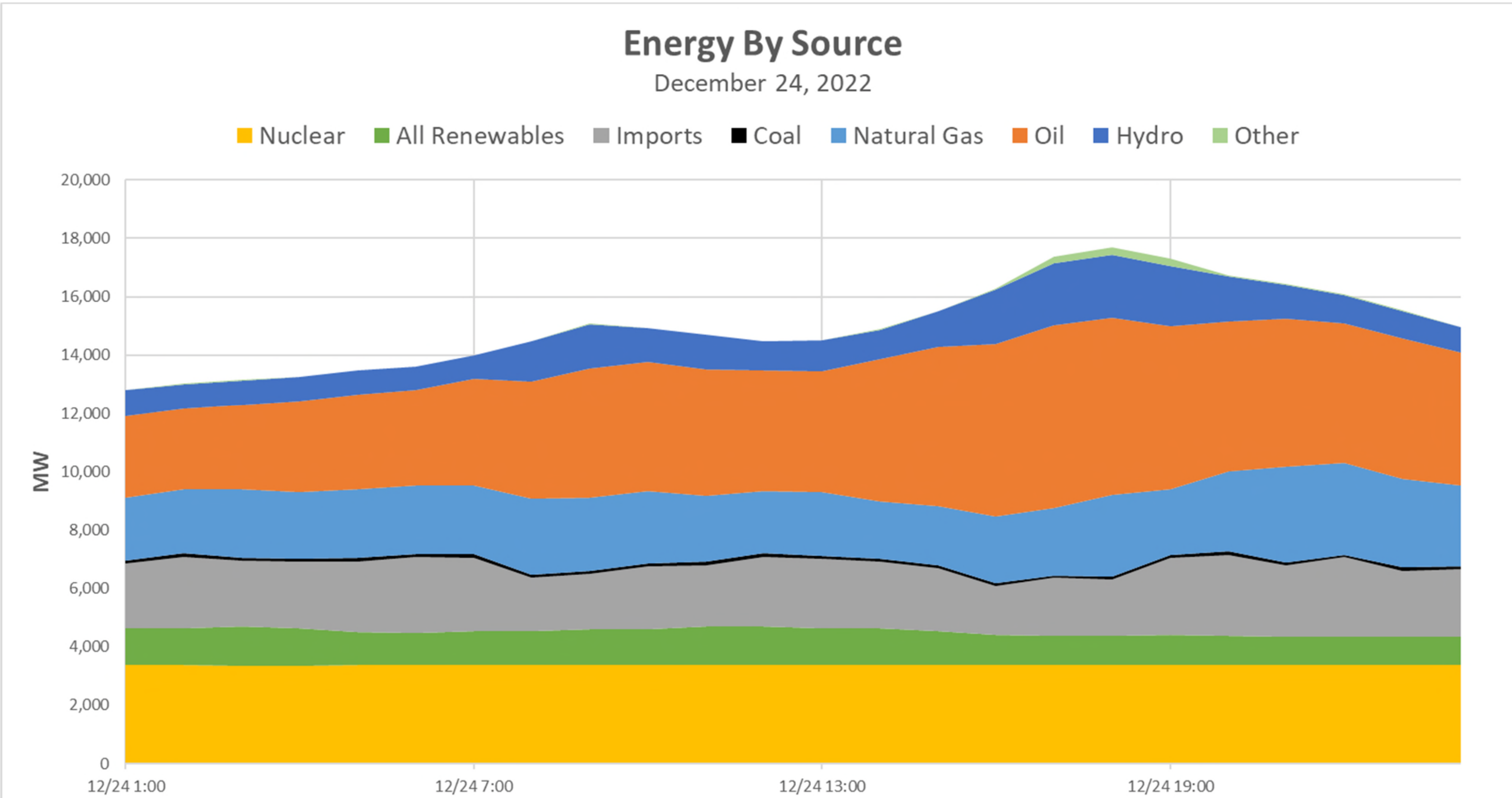
Summary of Capacity Scarcity Condition Intervals

5-Minute Intervals	System 30 Min Reserve Constraint Penalty Factor ($1,000 MW/hr)	System 10 Min Reserve Constraint Penalty Factor ($1,500 MW/hr)
16:40 – 17:05 (6 Intervals)	**Violated**	Binding
17:10 (1 Interval)	**Violated**	**Violated**
17:15 – 18:00 (10 Intervals)	**Violated**	Binding

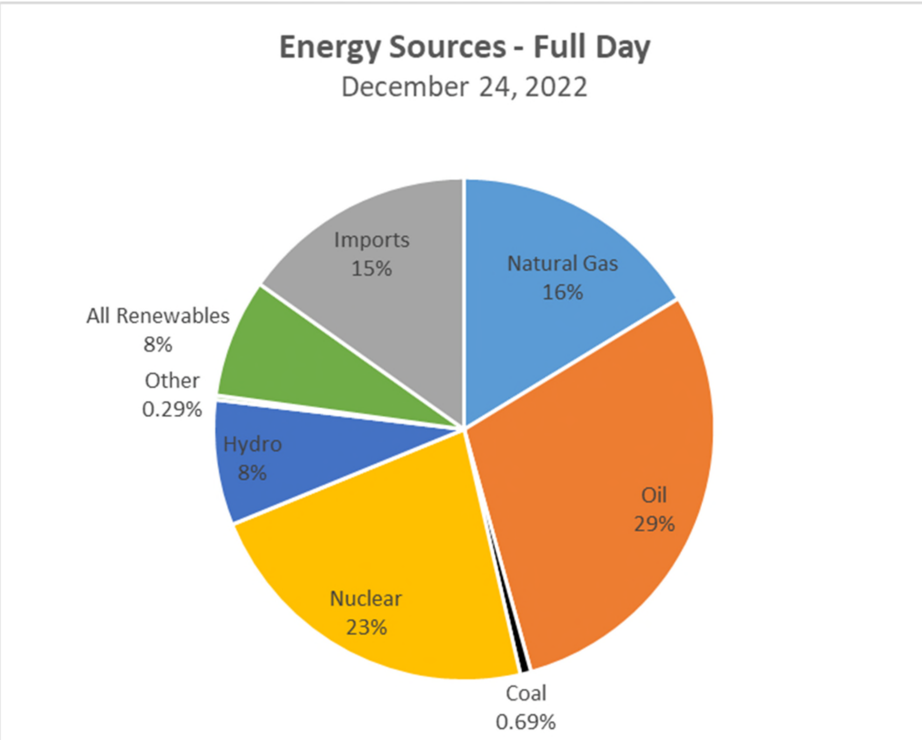
- A Capacity Scarcity Condition results from the **violation** of the System 30 Minute Operating Reserve constraint or the System 10 Minute Operating Reserve constraint in any one 5-minute interval

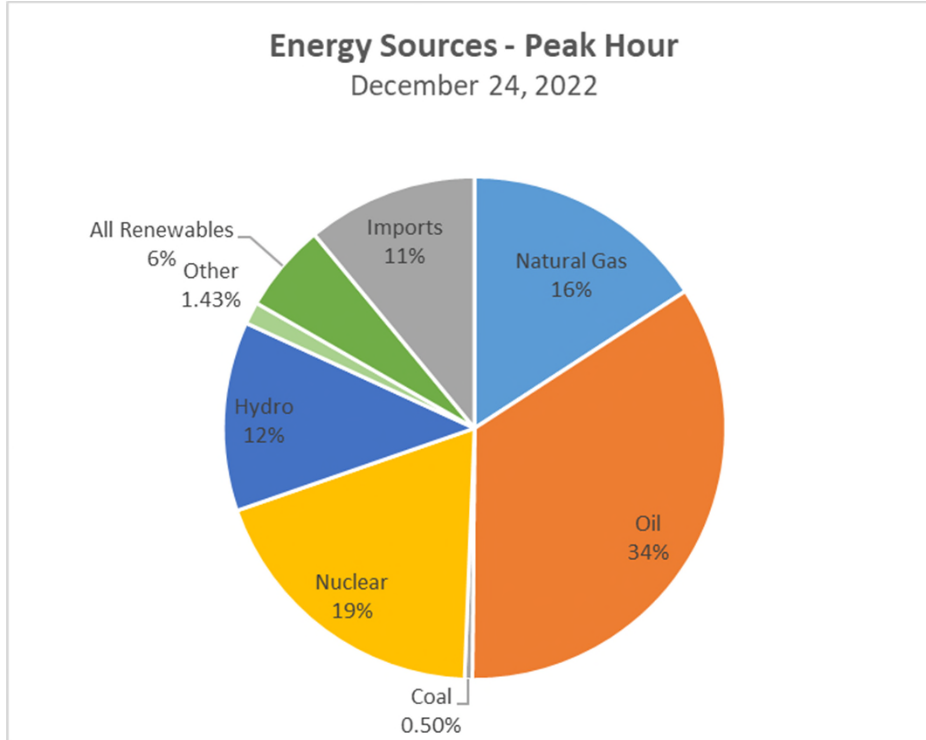
Energy by Source Type –Increased Use of Oil-Fired Generation

- Oil-fired generation operated at high levels throughout the day as many dual-fuel generators switched to burning fuel-oil; ~29% of the region's energy demand was met by oil-fired generation



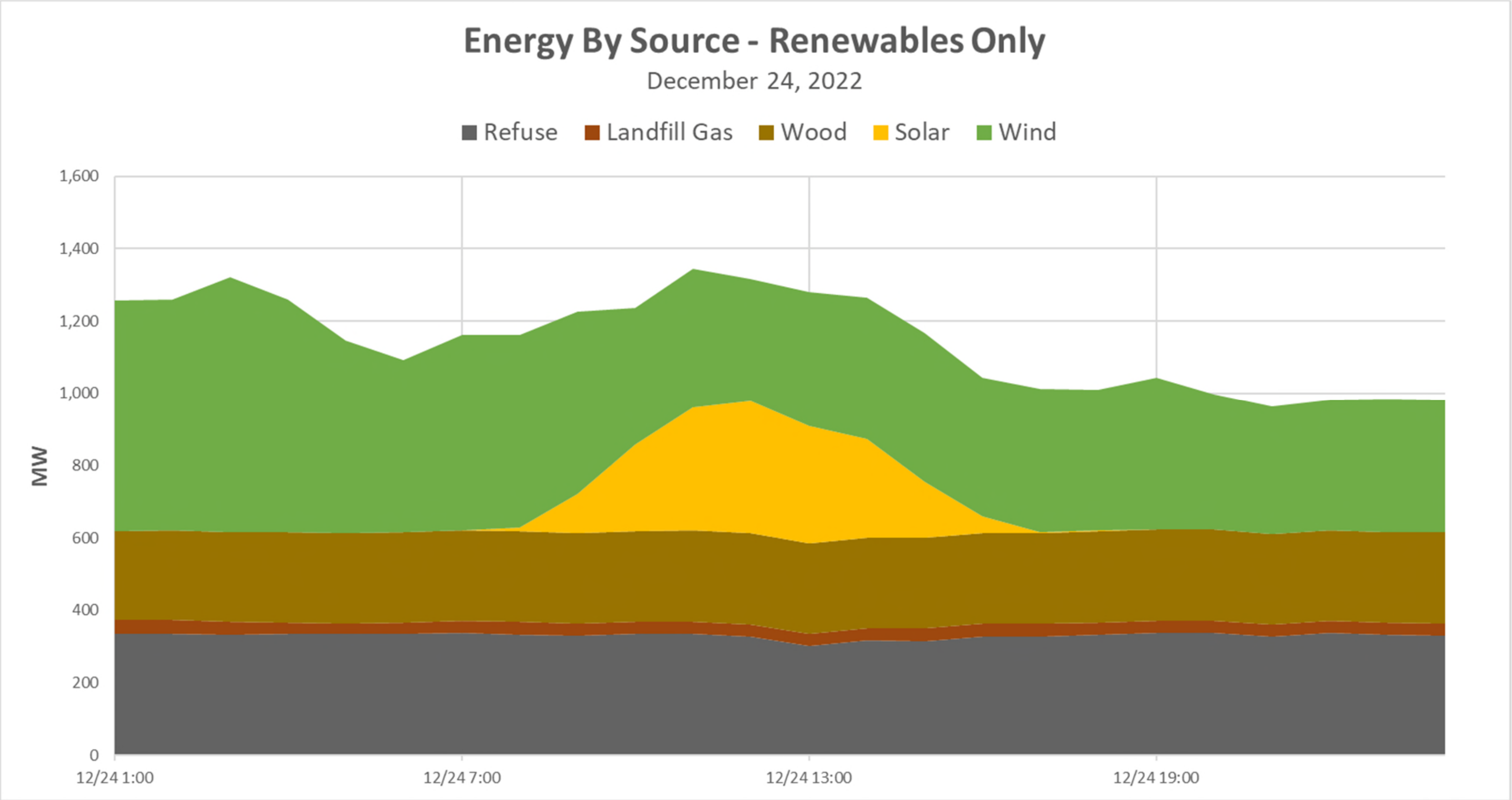
Energy by Source, Daily and Peak Hour





Energy from Renewable Resources

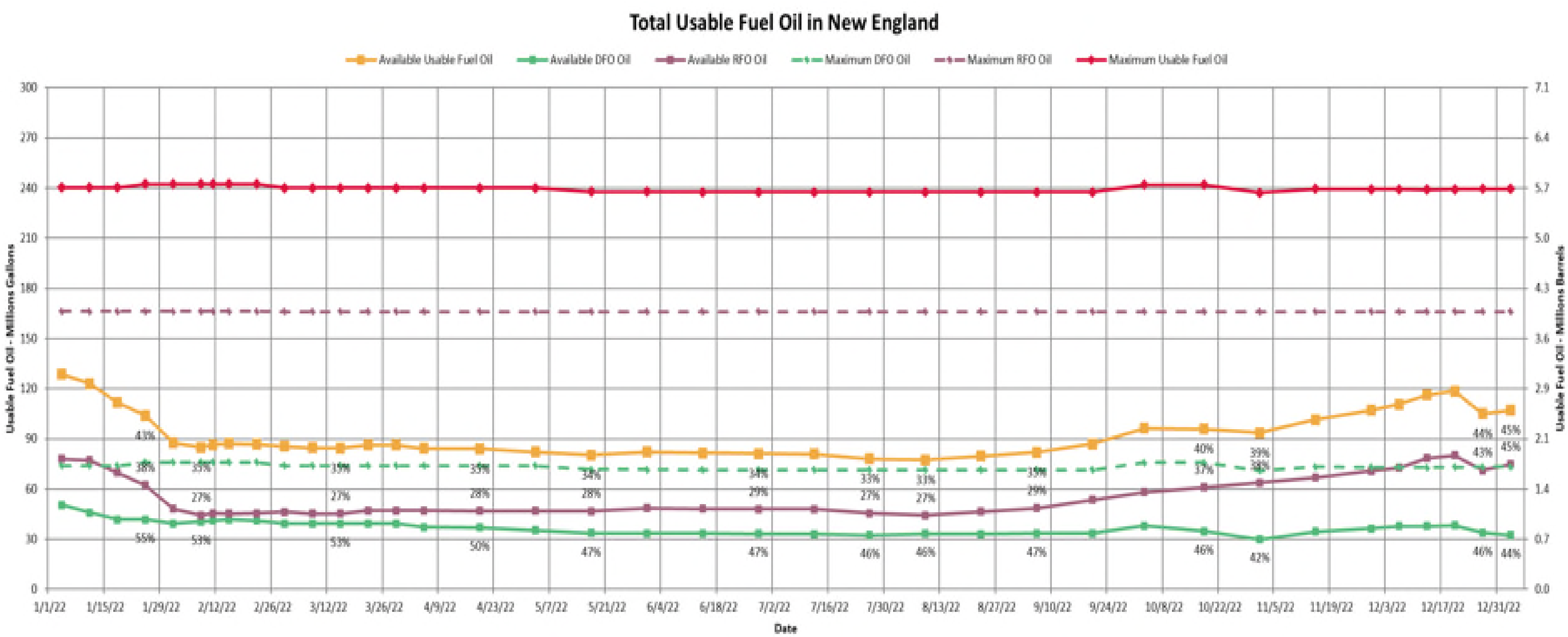
- Renewable resources met ~8% of the region's daily energy demand[1]; energy from wind resources peaked during overnight hours, then remained relatively steady (avg. ~400 MW/hr) during peak hours of the operating day (HE 08-23)



1 – in this figure, "solar" does not include contributions of behind-the-meter or settlement only solar resources. Impacts of behind-the-meter and settlement only solar resources is reflected in the net load.

Following Recent Oil Burn, Regional Usable Fuel-Oil Inventory Is Down ~4% From Pre-Cold Weather High

- Based on recent generator surveys, ISO estimates that ~31.5M gallons of fuel-oil was burned and ~20M gallons of replenishment occurred between December 20th and January 3rd



ISO Anticipates Near-Term Fuel-Oil Replenishment; 21-Day Energy Supplies Remain Adequate

- ISO anticipates fuel-oil replenishment of ~8M gallons over the next week (an increase of ~3% of maximum fuel-oil storage capacity)
- Recent cold weather did not result in significant depletion of regional LNG inventories; based on forecasted weather and energy demand as well as expectations for regional energy supplies, ISO forecasts normal system conditions in its most recent 21-Day Energy Assessment

Questions

M E M O R A N D U M

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: December 28, 2022

RE: Vote on Planning Procedure 5-1 Revisions

At the January 5, 2023 Participants Committee meeting, you will be asked to vote to support revisions to ISO Planning Procedure 5-1 ("PP 5-1 Revisions"). At its December 14 meeting, the Reliability Committee recommended Participants Committee support for the PP 5-1 Revisions, with three opposed and several abstentions. This item is on the Participants Committee discussion agenda at the request of Eversource.[1] The PP 5-1 Revisions and related materials have been included with this memo.[2]

The ISO is proposing to update PP5-1 to clarify the timing and requirements for model and data submissions in association with Proposed Plan Application submittals under Section I.3.9 of the ISO-NE Tariff. The PP 5-1 Revisions will require submission of certain information earlier than currently required.[3] During discussions at the Reliability Committee, some of the Transmission Owners expressed concerns with the PP 5-1 Revisions, saying that the revisions could cause delay in the I.3.9 approval process. Materials outlining their concerns will be circulated in advance of the meeting.

The following resolution could be used for Participants Committee consideration of the PP 5-1 Revisions:

> RESOLVED, that the Participants Committee supports the PP 5-1 Revisions, as recommended by the Reliability Committee at its December 14, 2022 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

---

[1] Eversource asked that this item be on the discussion agenda so that Eversource (i) has an opportunity to briefly explain its concerns with the PP5-1 Revisions and (ii) is able to express its affirmative support for the items on the January 5, 2023 Consent Agenda.

[2] The PP 5-1 Revisions, and the ISO's presentation on them, are also available at: https://www.iso-ne.com/static-assets/documents/2022/12/a07_1_pp_5_1.zip.

[3] As with all changes to manuals, operating procedures and planning procedures, FERC review and approval of the PP 5-1 Revisions ***will not be*** required.

Comments of Eversource Energy, National Grid, Avangrid, and Rhode Island Energy on Proposed Revisions to ISO New England Planning Procedure 5-1

In reference to the above-referenced agenda item, Eversource Energy, National Grid, Avangrid, and Rhode Island Energy submit the following statement for the Committee's consideration.

The regional electric power industry faces the unprecedented challenge to maintain a high level of overall system reliability while responding to the looming threat of climate change by achieving a timely transition to clean energy. Both ISO New England (ISO-NE) and Transmission Owners (TOs) bear the responsibilities of timely ushering an unprecedentedly high number of proposed renewable resources through the interconnection processes in our respective jurisdictions, as well as upgrading the transmission system to meet future reliability needs.

ISO-NE serves a valuable role as the central repository for all steady state and stability power flow modeling data for the region, and any other entities that must perform Proposed Plan Application (PPA) studies are dependent on ISO-NE to provide the necessary modeling data. We acknowledge the difficulties ISO-NE has experienced in gathering, reviewing, and validating study models that are critical for this work. We also acknowledge and appreciate that ISO-NE is taking steps to alleviate inefficiencies in model submission and review by proposing changes to Planning Procedure 5-1 (PP5-1). ISO-NE has made efforts, in response to concerns brought up by our organizations at the Reliability Committee (RC), to alter their proposal from what was originally presented to allow for additional flexibility and acknowledgement of "good faith" efforts to meet the proposed study model and draft study submission deadlines. However, we believe that even with these alterations, this proposal does not fully address the issues regarding model availability that impact the ability of our organizations to expediently and effectively carry out our critical system planning responsibilities.

We believe the proposed changes to PP5-1 will add delays to an already lengthy project study and approval process without solving the underlying problem. In proposing these changes, ISO-NE acknowledges they have struggled to hold study participants, including themselves, accountable for the timely submission of this data. Past practice has allowed for flexibility in the timing of study model submissions and not directly tied the timing of these submissions to a project's RC review and subsequent PPA approval. Requiring study model submissions at a specific point within the Planning Procedure-required review period, as proposed in the PP5-1 changes, will eliminate that flexibility. In some cases, it could add as much as two months of ISO-NE review time to the PPA study and approval process without a clear positive impact at another point in the study timeline.

The primary issue left unaddressed by the proposed PP5-1 changes is that ISO-NE's internal model review and validation processes are time-consuming and often slow. In some cases, it has taken ISO-NE several weeks to approve and provide access to modeling data after it has been submitted, which has caused additional delays for our organizations in performing our own studies and subsequently, submitting PPAs for approval by ISO-NE. For example, Mayflower Wind (QP 837) presented its project to the RC in June 2021 and submitted the corresponding PPAs to the RC in July 2021. ISO-NE provided a positive determination letter on July 15, 2021, but as of this time, the QP 837 as-studied model has still not been included in the ISO-NE Model Administration and Support base case releases. This example was discussed in relation to these proposed PP5-1 changes at the November and December RC meetings. Building study base cases for TO-initiated studies currently requires TO engineers to download a standard base case, then reach out to the ISO-NE Tech Lead directly for individual files and manually apply these to each case. This method introduces the chance that projects can be missed if an ISO-NE Tech Lead or TO engineer performing a study is unaware of a project, which introduces further delays during study scoping and preparation.

Ultimately, these delays have not only impacted TOs but have also hindered the efforts of distributed energy resource developers who, as customers of our respective organizations, seek to interconnect new sources of generation that help meet our region's ambitious clean energy targets. We are supportive of efforts to mitigate inefficiencies in the regional system planning process, but these changes alone do not further that goal. Instead, they introduce additional roadblocks and ultimately hinder our ability to effectively carry out our responsibilities. These proposed changes to PP5-1 only provide a partial solution to the delays being experienced and will not prevent future delays in the processing and redistribution of project models. ISO-NE should take up broader, holistic efforts to further explore creating efficiencies and alleviating bottlenecks. Changes to the planning process should not be overly burdensome to any one category of stakeholder. We need to have processes that allow us all to work effectively together to expedite PPA approval of much-needed transmission reinforcements and new resource interconnections.

Table of Contents

1.0 General

This document outlines the requirements, procedures, and application forms to be used in the submission and review of proposed plans pursuant to Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff (the "Tariff").

Each submittal shall include an applicable completed application. Blank application form(s) are provided in Attachments 1, 2, and 3 of this document.

Proposed plans submitted for review pursuant to Section I.3.9 must be supported by information and analysis. PP5-3 "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses" provides guidance on what information and analysis should be available to support a submittal. The completed applications and supporting materials describing and assessing the impact of the proposed plans together shall constitute submittal of a Proposed Plan Application (PPA).

Establishment and maintenance of approval of a ~~Proposed Plan Application~~PPA establishes the determination that implementation of the proposed plan will not have a significant adverse effect upon the reliability or operating characteristics of the Market Participant's or Transmission Owner's system or of the systems of one or more other Affected Entities[1] and the Market Participant or Transmission Owner is free to proceed with the proposed plan.

As prescribed per this document, a Market Participant or Transmission Owner will submit a ~~Proposed Plan Application~~PPA to the ISO. Where a non-Market Participant or non-Transmission Owner is involved, the non-Market Participant or non-Transmission Owner must meet the same requirements as for a Market Participant or Transmission Owner, except that a Market Participant or Transmission Owner on behalf of the non-Market Participant or non-Transmission Owner must submit any ~~Proposed Plan Application~~PPAs. Typically, the Transmission Owner that interconnects with the non-Market Participant or non-Transmission Owner will submit the ~~Proposed Plan Application~~PPA for the interconnection. If transmission facility changes are required to interconnect non-Market Participant or non-Transmission Owner facilities, the Market Participant or Transmission Owner who owns, or will own, the facilities at the Point of Interconnection with the non-Market Participant or non-Transmission Owner facilities is responsible for submission of the Transmission ~~Proposed Plan Application~~PPAs. Joint Applications may need to be filed if systems of others are involved.

Market Participants or Transmission Owners must follow the "~~Proposed Plan Application~~PPA Submittal Procedure" contained in Attachment 5 to this procedure for their submittal of ~~Proposed Plan Application~~PPAs to the ISO. This attachment details the flow of information required under this planning procedure and Planning Procedure 5-3, "Guidelines for Conducting and Evaluating ~~Proposed Plan Application~~PPA Analysis," to promote a smooth ~~Proposed Plan Application~~PPA review by the Reliability Committee and review and approval by the ISO.

[1] See ISO New England Planning Procedures No. 5-0, "Procedure for Reporting Notice of Intent to Construct or Change Facilities in Accordance with Section I.3.9 of the ISO New England Tariff (Proposed Plan Application Procedure)

1.1 Description of the Proposed Plan Application Process

The ISO will coordinate the ~~Proposed Plan Application~~PPA process.

1.1.1 Initial Assessment

The complexity of proposed changes to the system can range from minor changes to major alterations. The intention of the Proposed Plan process is to match study effort and review effort appropriate to the complexity of the proposed change. In PP5-3 "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses", guidance relative to study effort is provided through a discussion of different study levels. PP5-3 defines four levels of analysis: Level 0, Level I, Level II, and Level III. The Market Participant or Transmission Owner must discuss proposed plans early in the process with the ISO and, as necessary, the host Transmission Owner for guidance regarding the appropriate level of study required or whether a ~~Proposed Plan Application~~PPA is needed.

The ISO will examine the proposed plans and evaluate the potential for significant adverse impact on the stability, reliability, or operating characteristics of the interconnected system. Based on this examination, the ISO will advise the Market Participant or Transmission Owner regarding whether input should be solicited from other committees or any Affected Entity. Other committees include, but are not limited to, the Principal Committees.

The ISO will engage potentially technically impacted Affected Entities during the conduct of the studies that will be used to support a ~~Proposed Plan Application~~PPA.

1.1.2 Submittal of a Proposed Plan Application

~~The completed application form(s)~~All required materials, as described below, shall be sent with supporting documentation to the ISO who will collect, distribute, and provide a ~~permanent~~ record of the ~~Proposed Plan Application~~PPA ~~no later than 10 business days prior~~ to a Reliability Committee meeting for which action is expected. Submittals of PPAs or supporting materials that are received by the ISO after the deadlines described below shall result in deferral of review to a following noticed Reliability Committee meeting that satisfies the submission timing requirements of this procedure, ~~Applications received by the ISO less than 10 business days prior to a Reliability Committee meeting may~~unless, it is decided at the discretion of the officers of the Reliability Committee, ~~be~~ to conduct the ~~reviewed~~ review- at ~~that~~ the requested meeting~~ or will otherwise be deferred to the next noticed meeting that satisfies the10 business day review expectation~~.

In order for the ISO to conduct its review, the Market Participant or Transmission Owner shall provide modeling data adequately representing the planned facility to the ISO prior to the submittal of the PPA documentation. The submission of modeling data as early as possible is encouraged and submissions of modeling data may be made prior to the dates described in the following sections. Model submission and approval will be required for PPA approval.[2] Figure 1 below and accompanying text illustrate and describe the timelines and requirements.

[2] At the ISO's discretion, PPA approval may be provided where the submittal requirements of this procedure were met, but not all of the issues associated with accepting the models have been addressed, provided that the proponent is demonstrating best-efforts to resolve the outstanding model-acceptance issues.

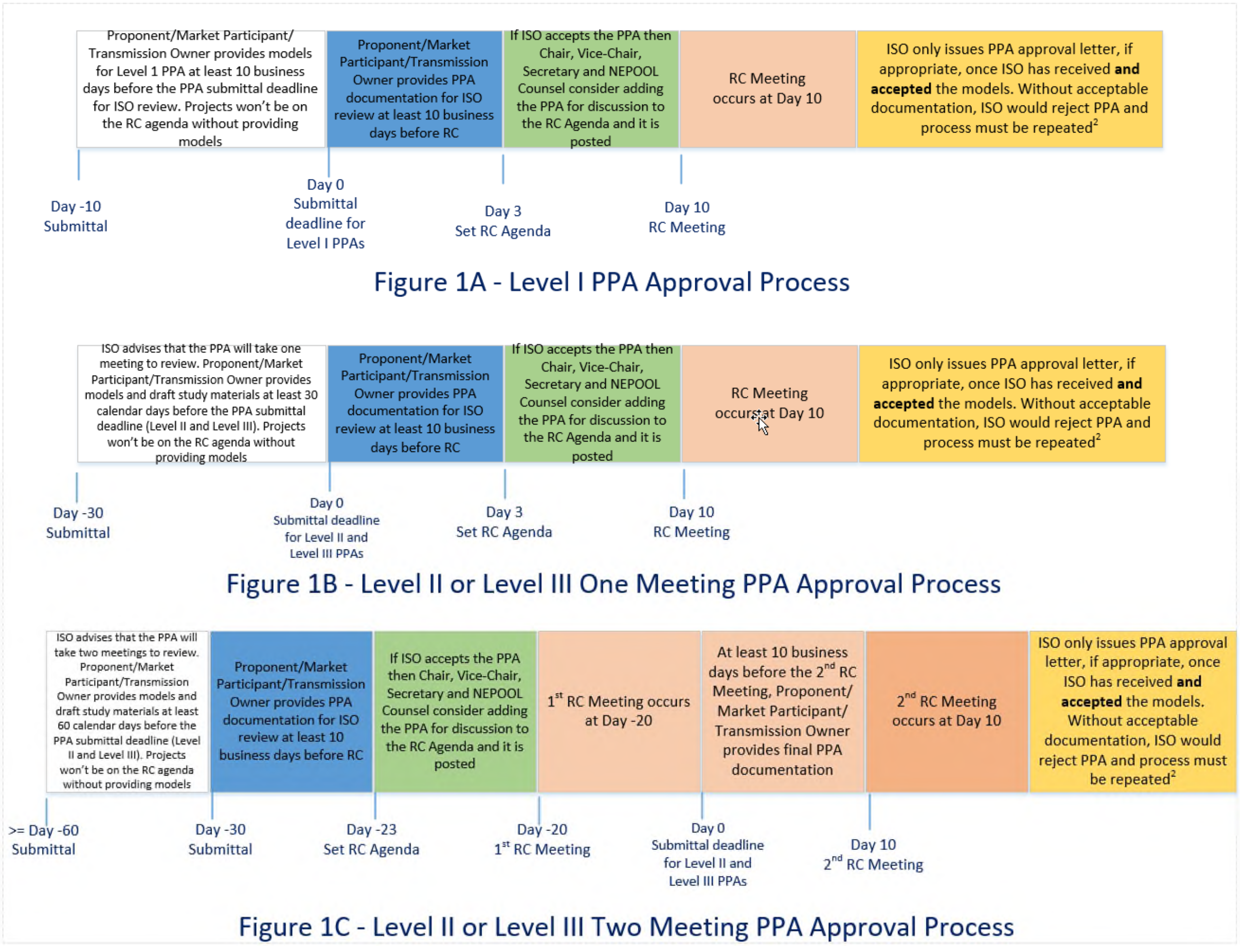


Figure 1 (includes Figures 1A, 1B, and 1C) – PPA Approval Process Typical Timelines[3]

Level 0 Analysis

Proposals requiring Level 0 analysis only require a notification. The Market Participant or Transmission Owner shall provide this notification at least ten Business Days before the Reliability Committee Meeting.

Level I Analysis

For Proposed Plans requiring Level I analysis, the Market Participant or Transmission Owner shall provide models at least ten Business Days prior to the PPA submittal deadline, as shown in the timeline labeled as "Level I PPA Approval Process" in Figure 1A.

Level II or Level III Analysis

[3] At the ISO's discretion, PPA approval may be provided where the submittal requirements of this procedure were met, but not all of the issues associated with accepting the models have been addressed, provided that the proponent is demonstrating best-efforts to resolve the outstanding model-acceptance issues.

For Proposed Plans requiring Level II and Level III analysis, the ISO shall advise and notify the Market Participant or Transmission Owner whether one or two Reliability Committee meetings will be recommended to complete the review. The Market Participant or Transmission Owner shall submit models and draft study materials for review prior to the formal PPA submittal in accordance with the applicable timeline depicted in Figure 1B or 1C, as described below. Note that the PPA review schedule does not begin until the PPA form is submitted.[4]

Level II or Level III Analysis – One Reliability Committee Meeting

If the ISO advises that only one Reliability Committee meeting is recommended for the PPA under consideration, the timeline entitled "Level II or Level III – One Meeting PPA Approval Process" in Figure 1B shall be applicable. The Market Participant or Transmission Owner shall provide models in accordance with Section 1.1.2.1 below and draft study materials[5] at least 30 calendar days prior to the PPA submittal deadline for the RC meeting. Final study materials for posting to the RC must be submitted to the ISO by emailing [ProposedPlans@iso-ne.com], along with the PPA and other supporting materials, at least ten Business Days prior to the Reliability Committee meeting during which action on the PPA is requested.

Level II or Level III Analysis – Two Reliability Committee Meetings

If the ISO recommends two RC meetings for the Level II or Level III PPA under consideration, the timeline entitled "Level II or Level III – Two Meeting PPA Approval Process" in Figure 1C shall apply. The Market Participant or Transmission Owner shall provide models in accordance with Section 1.1.2.1 below and draft study materials[6] at least sixty calendar days prior to the PPA submittal deadline for the Reliability Committee meeting during which action on the PPA is requested. Final study materials for posting to the Reliability Committee must be submitted to the ISO by emailing [ProposedPlans@iso-ne.com], along with the PPA and other supporting materials, at least ten Business Days prior to the Reliability Committee meeting during which action on the PPA is requested.

1.1.2.1 Model Submission Requirements

The following shall be included in the model submission as applicable:[7,8]

[4] PPAs may require either a 60 or 90 day review period in accordance with Section I.3.9 of the ISO Tariff.

[5] The draft study materials shall include a draft of the study report that will be used to support the PPA, as well as any other materials the proponent believes necessary to describe the project. The draft study report shall meet the requirements of Section 3.1.3 of Planning Procedure 5-3.

[6] The draft study materials shall include a draft of the study report that will be used to support the PPA, as well as any other materials the proponent believes necessary to describe the project. The draft study report shall meet the requirements of Section 3.1.3 of Planning Procedure 5-3.

[7] Submissions for Generating Facilities or Elective Transmission Upgrades that are in the ISO-NE interconnection queue shall be made by the ISO. Submissions for transmission projects or those associated with Generating Facilities that are in a non-FERC interconnection queue, and submissions for transmission projects associated with Generating Facilities or Elective Transmission Upgrades that are in the ISO-NE interconnection queue, shall be made by the Transmission Owner that is a Transmission Planner.

[8] Submittals shall use "permanent" bus numbers.

- a steady state model into the Siemens PTI Model on Demand (MOD) and auxiliary modeling information such as, but not limited to, contingency definitions etc. in a format compatible with the ISO Basecase Database (BCDB)
- dynamics data into the Dynamics Data Management System (DDMS) for transmission equipment with dynamic models and for Generating Facilities ≥ 5MW[9]
- short-circuit data as described in OP-16, Appendix K

After the models are submitted as described in this procedure, subsequent model updates during project construction shall be submitted in accordance with ISO Operating Procedures OP-14 and OP-16 and/or the relevant model provisions of the ISO interconnection procedures, as applicable.

1.1.2.2 PPA Submission Requirements

A PPA submission shall include:

- ~~A typical submittal will include~~ the application(s) with a cover letter, a one-line diagram illustrating the proposed change relative to the existing system along with proposed equipment nomenclature, and, ~~if available, and, if applicable, a report that documents the study and supports the application. The report that is distributed to the Reliability Committees typically does not have to include appendices or attachments provided that the appendices and/or attachments are available upon request. A map locating the facilities is desirable. The submittal will be distributed by the ISO to the Reliability Committee. A discussion of the expected analysis and information to be provided in a final report is further discussed in PP5-3 "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses".~~
  - For Level II or Level III analysis, a report that documents the study and supports the application
    - the report shall include appendices with steady-state, dynamics and short circuit models used for the study
  - a map locating the facilities should also be provided if available

For PPAs that require two Reliability Committee meetings, the Market Participant or Transmission Owner shall submit the final PPA materials after the Reliability Committee conducts its initial review during the first meeting, and at least ten Business Days prior to the second Reliability Committee meeting.

Consistent with Attachment 4 of this Planning Procedure, the ISO shall post the relevant submission materials for Reliability Committee review.

It is recommended that a ~~Proposed Plan Application~~PPA not be filed more than 5 years prior to the proposed in-service date. Applications that are submitted for review more than 5 years in advance of the proposed in-service date must include an explanation of the need for this lead time and a schedule of clearly defined milestones related to the pursuit of permitting, licensing and

[9] For equipment installed with a new type of technology that cannot be represented by PSS/E standard library models, refer to OP-16 Appendix J and Planning Procedure 5-6 (PP5-6) Appendix B, which address user-written models.

construction of the proposed plan. The schedule of milestones will be used to demonstrate due diligence to the Reliability Committee and the ISO.

~~A draft motion describing the conditions of the approval for the Proposed Plan Application is recommended. Such motion will be distributed by the ISO consistent with the Technical Committee Bylaws.~~

1.1.3 Review and Consideration of a Proposed Plan Application

The ISO will supply the Reliability Committee brief statements describing the ISO's recommendation on ~~Proposed Plan Application~~PPAs that require Level II or Level III analysis, including any opinions expressed by Affected Entities regarding significant impacts that they believe to be insufficiently addressed. Such recommendations are preferably provided to the Reliability Committee with the distribution of the meeting material and agenda. If any of the recommendations are not available at the time of the distribution of the meeting material and agenda, the recommendations should be provided prior to the Reliability Committee acting on the ~~Proposed Plan Application~~PPA. If the recommendations are not available by the time the Reliability Committee is prepared to act on the application, the committee may elect to defer action subject to the time constraints defined in Section 1.~~3~~1.2.

A draft motion describing the conditions of the approval for the PPA consistent with the Technical Committee Bylaws will be distributed by the ISO.

If in reviewing the application and associated information, the Reliability Committee decides additional information, review, or study is required prior to acting on the application, the Reliability Committee may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the Market Participant or Transmission Owner sponsoring the application, other Market Participants or Transmission Owners, the ISO, and other committees.

The actions the Reliability Committee may take are to defer action, recommend approval by the ISO, or recommend disapproval by the ISO. The Reliability Committee is expected to act on all ~~Proposed Plan Application~~PPAs that require Level II or Level III analysis. Applications requiring Level I analysis do not need approval, but do need Reliability Committee concurrence that only Level I analysis is required.

Reliability Committee members will be responsible for establishing an understanding of each application through their own knowledge, review of the documentation provided with the application, and/or consultation with the ISO, and/or other committees.

The Secretary of the Reliability Committee will notify the Members and Alternates of the Participants Committee and the ISO of the actions taken by the Reliability Committee. This written notice will be delivered prior to the end of the fifth (5th) business day following a meeting of the Reliability Committee as specified by the Technical Committee Bylaws. This notification will constitute formal confirmation that such action was taken. The ISO will consider the recommendations of the Reliability Committee in the process of approving/disapproving each ~~Proposed Plan Application~~PPA. The ISO will transmit an official letter to the Market Participant or

Transmission Owner submitting the Application noting such approval or disapproval. Upon approval the Market Participant or Transmission Owner shall be free to implement the proposed plan in accordance with the Tariff, including compliance with any additional requirements contained therein, e.g. the requirements of the process for the interconnection of new generating resources or modification of existing generating resources pursuant to Schedules 22 and 23 of Part II of the Tariff, subject to the terms of this document. If any Reliability Committee member provides a written objection to a ~~Proposed Plan Application~~PPA, such objection will be conveyed to the ISO. In the event that another Market Participant or Transmission Owner objects to the actions of the ISO, the Tariff specifies avenues for resolution of the objection.

1.1.4 Withdrawal of a Proposed Plan Application

Withdrawal of a ~~Proposed Plan Application~~PPA is indication that a Market Participant or Transmission Owner no longer intends to pursue a proposed plan. Should a Market Participant or Transmission Owner wish to withdraw its ~~Proposed Plan Application~~PPA, a letter to that effect should be sent to the ISO. The ISO will distribute the notice of withdrawal to the appropriate committees. Consideration as to which committees should be notified will be subject to the stage of the processing of the application. ~~Proposed Plan Application~~PPAs associated with projects that have withdrawn from the interconnection queue shall be considered automatically withdrawn.

1.1.5 Currency of Approved Applications

Following review and approval of the proposed plans associated with one or more ~~Proposed Plan Application~~PPAs, implementation of the proposed plans must continue to be actively pursued for such applications to remain current. Any of the following conditions may result in a determination that approval of such applications is revoked:

a. Two years have elapsed from the proposed in-service date on the approved ~~Proposed Plan Application~~PPA(s) and the Market Participant or Transmission Owner has not demonstrated due diligence in pursuit of permitting, licensing and construction of the approved proposed plans. For proposed plans associated with an application submitted pursuant to the Tariff ("Tariff Application"), a valid and current Tariff Application shall constitute due diligence in pursuit of implementation of the proposed plans.

b. The Market Participant or Transmission Owner has not sufficiently modified the proposed plans as required to address the difference between the modeled and actual or expected system.

c. The Market Participant or Transmission Owner has elected not to pursue completion of the proposed plans described in the approved ~~Proposed Plan Application~~PPA(s).

d. The Market Participant or Transmission Owner makes a change in the scope of the proposed plans described by the original ~~Proposed Plan Application~~PPA.

e. The ~~Proposed Plan Application~~PPAs were submitted for review and approved more than 5 years in advance of the proposed in-service date, and the Market Participant or Transmission Owner has not demonstrated due diligence in pursuit of permitting, licensing and construction of the approved proposed plans through annual progress reports. For proposed plans associated with an application submitted pursuant to the Tariff ("Tariff Application"), a valid and current Tariff Application shall constitute due diligence in pursuit of implementation of the proposed plans.

The ISO, in consultation with the Reliability Committee, will notify the Market Participant or Transmission Owner where such conditions have led to the conclusion that the approval of the associated ~~Proposed Plan Application~~PPAs may be revoked. However, within 90 days following notification of such action the Market Participant or Transmission Owner may submit studies and/or information for review and approval by the ISO that addresses the issues leading to this conclusion in order to maintain approval of such applications. The ISO may modify the time limits identified above as appropriate.

Studies must be updated and proposed plans modified accordingly if the actual or expected system is, as of the proposed plans' actual in-service date, sufficiently different from what was modeled in the analysis supporting the approved ~~Proposed Plan Application~~PPA(s). The updated studies will identify whether a part of a proposed plan that is no longer being pursued, as identified per this Procedure, is a necessary component or condition of another proposed plan that has maintained its currency. In this case, a Proposed Plan approval associated with the necessary component or condition will remain current.

1.2 Time Limits Prescribed in Section I.3.9 of the Tariff for Review of a Proposed Plan Application for a New Plan or a Revised Proposed Plan Application for a Revised Plan

Section I.3.9 of the Tariff[10] requires each Market Participant or Transmission Owner to submit a ~~Proposed Plan Application~~PPA to the ISO at least sixty (60) days prior to the proposed in service date. In the case of transmission facilities developed through the Solutions Study process or the competitive solution process, no significant action (other than engineering reasonably necessary to support the Solutions Study or competitive solution process) shall be taken.

Any revisions to a previously approved ~~Proposed Plan Application~~PPA proposed for implementation prior to the in-service date of such previously approved Proposed Plan must be specified on a revised ~~Proposed Plan Application~~PPA form. The completed ~~Proposed Plan Application~~PPA form for a new plan or a revised ~~Proposed Plan Application~~PPA for a revised plan requiring analysis must include documentation of the analyses that have been determined to be required by the ISO, in consultation with Affected Entities, as necessary, or the Reliability Committee. If during the ~~Proposed Plan Application~~PPA review process a significant adverse impact on the New England Control Area system or any Market Participant's or Transmission Owner's system is identified, then the ~~Proposed Plan Application~~PPA will be rejected.

Due to the amount of time required for the Proposed Plan process, Market Participants or Transmission Owners are strongly recommended to supply appropriate data, with adequate lead times for performance and completion of any anticipated analyses and its review by ISO as described in "Level of Analysis Required" (see PP5-3, Section III.A.2.0), prior to formal submittal of a ~~Proposed Plan Application~~PPA to the ISO. If the appropriate data is not supplied with adequate lead times for performance and completion of any anticipated analyses and its review by ISO, then

[10] See also Section 2.06 of the Transmission Operating Agreement.

implementation of the proposed plans may be delayed or rejected regardless of their stage of physical completion.

1.3 Issues Not Covered by These Procedures

For issues not covered by these or any other documented procedure, Market Participants or Transmission Owners are expected to discuss pertinent issues with, and seek guidance first from the ISO. If the issue involves a policy decision, the ISO may suggest an approach for addressing the issue. Such approach may involve raising the issue for discussion, guidance, or decision from one or more committees.

2.0 Additions or Changes Requiring Proposed Plan Applications

This section identifies when a ~~Proposed Plan Application~~PPA is required based upon the type and/or size of facility.

2.1 Generation Additions or Changes in Net Station Output

The following table describes the ~~Proposed Plan Application~~PPA requirements for all new generation or changes in station output that meet the defined conditions.

Generation Change[11][12][13]	Proposed Plan Application Required?	Study and Performance Requirements	Modeling Requirements
New or Increased Generation ≥5MW[14]	Yes	Requirements of Planning Procedure 5-6 and 5-3	Requirements of Planning Procedure 5-6
≥ 5 MVAR Unit or ≥ 10 MVAR Station Change in Reactive Capability[15]	Yes	Requirements of Planning Procedure 5-6 and 5-3	Requirements of Planning Procedure 5-6
New or Increased Generation >1MW and < 5 MW	No. Notification Form[16] only is Required – Unless the ISO identifies that a PPA is required	None, unless the ISO identifies that a PPA is required, in which case Requirements of Planning Procedure 5-6 and 5-3	None, unless the ISO identifies that a PPA is required, in which case Requirements of Planning Procedure 5-6
New or Increased Generation ≤1MW	No	None	None

This language only encompasses requirements related to the submission of ~~Proposed Plan Application~~PPAs under Section 3.9 of Part I of the Tariff. The provisions of Schedules 22 and 23 of the ISO New England Open Access Transmission Tariff with regard to the interconnection of new generation or modification of existing generation or the provisions of Market Rule 1, Section III of the Tariff, with regard to a reduction in the capacity or a retirement of a generator must also be observed. ~~Proposed Plan Application~~PPAs shall be submitted in accordance with this Planning Procedure within 30 calendar days from the end of the Interconnection Customer's comment process following the completion of a System Impact Study pursuant to Schedule 22 or Schedule 23 of the ISO New England Open Access Transmission Tariff.

[11] Changes in MW or MVAR capability reflect a change in the fundamental capability of the unit or station.

[12] For the purposes of this section, a station is a group of generators and associated terminal equipment (including generator interconnections) all contained by a continuous fence and owned by a single entity.

[13] Net station output is output delivered to the Point of Interconnection.

[14] An increase of 5 MW or more of net station output for a single unit within a station or an increase of 5 MW or more of total net station output.

[15] An increase or decrease (lead or lag) of 5 MVAR or more in net station output for a single unit within a station, or, an increase or decrease (lead or lag) of 10 MVAR or more in total net station output

[16] Generation Notification Form submittals are subject to the same timing requirements contained in Section 1.1.2

At the same time (and for the same Reliability Committee meeting) as the submittal of the Generation ~~Proposed Plan Application~~PPA, the Market Participant or Transmission Owner, if necessary, must submit a ~~Proposed Plan Application~~PPA for transmission associated with the generation in accordance with Section 2.2 of this procedure.

2.2 Transmission Changes

All transmission changes that change the topology or characteristics of the transmission system or that change the thermal capability of a portion of the system by replacement of transmission facilities except as exempted in Section 4 require a ~~Proposed Plan Application~~PPA (Attachment 3). Transmission Applications must be approved by the ISO.

For all major changes to transmission facilities with design voltages at or above 69 kV, the Market Participant or Transmission Owner will supply the results of completed studies to the ISO sufficiently in advance of the Proposed Plan Transmission Application so that sufficient time for review is allowed. This includes changes to generator leads and their associated equipment, such as a GSU.

~~Proposed Plan Application~~PPAs associated with Elective Transmission Upgrades shall be submitted in accordance with this Planning Procedure within 30 calendar days from the end of the Interconnection Customer's comment process following the completion of a System Impact Study pursuant to Schedule 25 of the ISO New England Open Access Transmission Tariff.

2.3 Demand Resource Additions and/or Incremental Updates

Any generation additions or changes, including Distributed Generation, should follow the generation submittal and notification requirements of this PP5-1, even if they are intended to participate in ISO New England markets as demand resources. No notification or submittal is required pursuant to this PP5-1, for demand resources that are not comprised of generation.

2.4 Protection Systems

Any addition of, functional change in, or retirement of a Remedial Action Scheme or Automatic Control Scheme (as described in Section 1 of Planning Procedure 5-5) requires submission of a ~~Proposed Plan Application~~PPA. Such application will be treated the same as Section 2.2.

2.5 Interconnections Operating at 69 kV or Above with Non-Market Participants or Non-Transmission Owners

Interconnections operating at 69 kV or above with non-Market Participants or non-Transmission Owners (such as a new connection with a neighboring Control Area) require a ~~Proposed Plan Application~~PPA to be approved by the ISO.

2.6 Dynamic Controls System

Any addition or significant change in a continuously acting control system and associated devices that respond to normal and abnormal system conditions or events, so as to change the stability, reliability, or operating characteristics of the bulk power system requires submission of a ~~Proposed Plan Application~~PPA. Any significant difference in a continuously acting control system and associated devices from those parameters studied and approved under a ~~Proposed Plan~~

~~Application~~PPA or otherwise conveyed to the ISO as part of the Applicant's ongoing data provision requirements requires submission of a new ~~Proposed Plan Application~~PPA to assess the actual operating parameters. This includes, but is not limited to significant changes in control systems associated with static var and synchronous compensators, HVdc, generator excitation systems, power system stabilizers and turbine governor systems. Please note that the provisions of Schedule 22, 23 and 25 of the ISO Open Access Transmission Tariff regarding modifications to existing generators and Elective Transmission Upgrades must also be observed.

3.0 Retirements

This section identifies when a ~~Proposed Plan Application~~PPA is required based upon the type and/or size of facility.

3.1 Requirements

Generator retirements do not require the submission of a ~~Proposed Plan Application~~PPA. However, all requirements in the ISO New England Manual for Registration and Performance Auditing (M-RPA) must be met. Retirement of a capacity resource must follow the requirements of Section III.13 of the Tariff.

4.0 Facility Changes That Do Not Require Proposed Plan Applications or Revisions to Previously Approved Proposed Plan Applications

Facility changes, such as but not limited to the following, do not require ~~Proposed Plan Application~~PPAs or revisions to previously approved ~~Proposed Plan Application~~PPAs:

- Routine protection and relaying changes only if there will be no increase in the fault clearing times and no material change in elements tripped for all events that would be analyzed pursuant to the ~~Proposed Plan Application~~PPA process.
- Minor adjustments of parameters of continuously acting control systems from what had been previously approved under a ~~Proposed Plan Application~~PPA (However, such adjustments must be conveyed to the ISO as part of the Applicant's ongoing data provision requirements.)
- Disconnect switches
- Replacement in kind or with greater energy dissipation of surge arrestors
- Station automation
- SCADA
- Communications
- Metering
- Rehabilitation with like equipment that does not affect transmission capability
- Static wire changes
- Counterpoise changes
- Replacement in kind of line terminal equipment and bus conductor to increase thermal capability (Such changes however require the Market Participant to submit revised NX-9 data to the ISO in accordance with OP 16 "Transmission System Data")

- Reductions in capability that result from the retirement of the resource/asset

5.0 Application Forms

Attachments 1, 2 and 3 are forms to be used to notify the ISO of proposed generation and transmission changes.

5.1 Summary Statement

Each application will include a summary statement describing the proposed change and its purpose, and explaining its impact on the system, if any.

5.2 Design Voltage versus Initial Operating Voltage

Where a transmission line will be operated initially at a voltage lower than its design voltage, both voltage levels will be specified in the space provided. The procedure to be followed is determined by the initial operating voltage. A separate ~~Proposed Plan Application~~PPA is required when the line is to be converted to the higher voltage.

5.3 Protection System and Dynamic Control System Descriptions

5.3.1 Protection System Description

The relaying section of the transmission form will describe the types of line relaying, backup relaying, communications and reclosing to be installed. Breaker failure protection also will be described. Any protective system that requires remote tripping, runback, or fast valving of generating equipment must be described in detail.

5.3.2 Dynamic Control System Description

If applicable, a description of the equipment and design considerations must be provided. If testing and maintenance is an important factor in the overall performance in mitigating any adverse system impact, then a plan of the system testing and maintenance must be provided.

5.4 Transformer Description

Transformer terminal voltages will be stated in the space provided, including tertiary winding, if there is one. The type of transformer or transformer bank should be described in the "comments" section. A separate sheet may be used, if needed.

5.5 Application Identification

A company identification number will be assigned to each application by the Market Participant or Transmission Owner preparing it. The following codes will be used:

- Company initials
- Last two digits of year submitted
- Letter(s) indicating
  G - Generation Addition
  T - Transmission Change

X - Protection System/Dynamic Control System Change or Addition

- Company's serial number of Section I.3.9 filing for year indicated
- REV indicating a revision to a previously completed and approved ~~Proposed Plan Application~~PPA
- Serial number reflecting sequence of revisions to the previously completed and approved ~~Proposed Plan Application~~PPA

These codes will be assembled into a string as shown in the example below:

EXAMPLES: NSTAR-03-T06
NSTAR-03-T06-REV-01

6.0 Document History[17]

Rev. No.	Date	Reason
Rev. 0	Rec: RTPC – 1/18/00; App: PC – 2/4/00	
Rev. 1	Rec: RC – 11/14/00; App: PC – 12/1/00	
Rev. 2	Rec: RC – 6/10/03; App: PC – 6/25/03	
Rev. 3	Eff: 2/1/05	
Rev. 4	App: RC – 9/19/07; PC – 10/12/07; ISO-NE – 10/12/07	
Rev. 4.1	RC – 12/19/07	Revision to Attachment 4
Rev. 4.2	RC – 1/30/08	Revision to Attachment 2
Rev. 4.3	PC – 2/4/09	Revision to Attachment 5
Rev. 5	Rec: RC – 2/24/09; PC – 3/6/09; ISO-NE – 3/6/09	
Rev. 6	App: RC – 5/19/09; PC – 6/5/09; ISO-NE – 6/5/09	
Rev. 7	App: RC – 11/17/10; PC – 12/10/10; ISO-NE – 12/10/10	
Rev. 8	App: RC – 3/19/13; PC – 4/5/13; ISO-NE – 4/5/13	Updated Section 2.4 description of the review of Demand Resources
Rev. 9	App: RC – 2/18/14; PC – 3/7/14; ISO-NE – 4/9/14	Conforming change recognizing paragraph 2.9 had been made Section 4
Rev. 10	App: RC – 8/18/15; PC – 9/11/15; ISO-NE – 10/2/15	Added data field on Attachment 4; updated website links on Attachment 5
Rev. 11	App: RC – 10/17/17; PC – 11/3/17; ISO-NE – 11/8/17	Elimination of Task Force review
Rev. 12	App: RC – 2/13/18; PC – 3/2/18; ISO-NE – 3/9/18	Applicability of the requirements of PP5-6; timely submittal and automatic withdrawal of PPAs; removal of waiver for Settlement-Only Generators from underfrequency protection requirements and PPA forms update
Rev. 13	App: RC – 12/18/19; PC – 2/6/20; ISO-NE – 2/6/20	Updated Section 1.2 to conform with changes to Tariff Section I.3.9. Changed Governance Participant to Market Participant or Transmission Owner to match Section I.3.9.
Rev. 14	App: RC – 6/16/2020; PC – 8/6/2020; ISO-NE – 8/6/2020	Updated section 1.1.2 to clarify 2 week PPA submittal requirement. Formatting changes to Attachment 1 and Attachment 3. Data request change to Attachment 1.
Rev. 15	App: RC – 12/15/2020; PC – 1/7/2021; ISO-NE – 1/7/2021	Updated References and Section 2.4 to conform with NERC and NPCC RAS terminology and changes to Planning Procedure 5-5

[17] This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date.

7.0 Attachment 1 – Generation Proposed Plan Application

GENERATION PROPOSED PLAN APPLICATION
ISO New England Planning Procedure 5-1
Page 1 of 2

Applicant ______________________________________ Date ___________________

Contact Person __________________________________ Phone __________________

1. Station Name ____
and Location ____

Unit Identification ____

	Winter (0 or higher Deg F)*	**Winter (20 Deg F)**	**Summer (50 or higher Deg F)****	**Summer (90 Deg F)**
Gross Unit Rating (MW)				
Net Unit Rating (MW)				
Unit Rating (Lagging MVAR)		N/A		
Unit Rating (Leading MVAR)		N/A		

* Enter all values in this column corresponding to the temperature of 0 degrees F or greater at which gross facility output will be the highest. As an example, if the maximum gross facility output occurs at 12 degrees F, all values in this column shall correspond to the 12 degree F operating condition.

** Enter all values in this column corresponding to the temperature of 50 degrees F or greater at which net facility output will be the highest. As an example, if the maximum net facility output occurs at 67 degrees F, all values in this column shall correspond to the 67 degree F operating condition.

2. Type of Application

☐ Construction ☐ Capacity Change

3. Requested Commercial Operation Date ____________________

4. Will the facility be equipped with a functioning governor? ☐ Yes ☐ No (A "No" response may be grounds for rejection pursuant to OP 14.)

5. Is the unit equipped with under-frequency protection? ☐ Yes ☐ No

If "Yes:"

a. Has the host utility reviewed the settings? ☐ Yes ☐ No

b. Will the unit be tripped for under-frequency conditions in the area above the curve in Figure 1 of Standard PRC-006-NPCC? ☐ Yes ☐ No

i. If "Yes," has additional automatic load shedding been provided equivalent to the amount of generation to be tripped? ☐ Yes ☐ No

Application Identification No. ______________

GENERATION PROPOSED PLAN APPLICATION

ISO New England Planning Procedure 5-1
Page 2 of 2

c. Will the unit be tripped in conjunction with dropping low voltage feeders during load shedding?

☐ Yes ☐ No

i. If "Yes," has the host utility ensured that sufficient automatic load shedding capability will be available to system operators? ☐ Yes ☐ No

Note: A "No" response to b.i or c.i is grounds for rejection.

6. Provide the following information on fuel used by the unit

   a. List the unit's primary fuel ____________.

   b. and secondary fuel ____________.

7. Will the unit have black start capability? ☐ Yes ☐ No

   a. If "Yes," can it be operated on its own auxiliaries prior to synchronization with the system? ☐ Yes ☐ No

8. Attach an electrical one-line diagram showing all essential devices including GSU impedance, station arrangements, station service and connections to the transmission system (69 kV and higher), including the voltage levels.

9. Is a Transmission Proposed Plan Application required? ☐ Yes ☐ No

   a. If "Yes," identify the Transmission Applications associated with this Application, the Transmission Owner or Market Participant responsible for filing and the date the Application was/will be submitted.

   ____

10. System Reliability Studies

Short Circuit	☐ Completed	☐ Planned	☐ Not Needed
Load Flow	☐ Completed	☐ Planned	☐ Not Needed
Stability	☐ Completed	☐ Planned	☐ Not Needed
Other_________________	☐ Completed	☐ Planned	☐ Not Needed

Application Identification No. ______________

Additional Information

(Only to be filled out if unit is <5MW & on the distribution system)

1. Provide the following information on the Location/Interconnection point.
   a. Location/Interconnection Point (Indicate point of coupling with utility system by specifying distribution feeder or transmission line name(s) or substation name. Distribution facilities should include the transmission facility substation(s) that the distribution facilities are supplied from.)
   ____

   b. Address of Plant
   Street Address ____
   Town or City ____
   County___________________State___________________Zip Code _______________

   c. Specify the interconnection bus name and the voltage level the unit is connected to.
   Name:____________________________________Voltage Level (kV):_______

   d. Specify the modeled PSS/E bus name and number that is electrically closest to where the unit is interconnected Name:____________________________Number:_________

   e. What is the maximum net power injection at the point of interconnection?____________(MW)

   f. Is there load reduced by operating this generation? (Check Yes or No) ☐ Yes ☐ No
   If "Yes:"
   By how much is the load reduced?__________(MW)
   Where is the load located?_________________________________

   (Check the appropriate box and provide appropriate diagram(s))

   ☐ The unit is connected to the power system at transmission voltage (69 kV or higher). Provide an electrical one-line diagram showing all essential devices including GSU impedance, station arrangements, station service and connections to the bulk power system, including the voltage levels below 69 kV.

   ☐ The unit is connected to the distribution system. Provide one-line diagram(s) showing the unit connection and where the distribution network connects to the bulk power system

2. Provide the following information on fuel used by the unit.
   a. List the unit's primary energy source code (from "Energy Sources" listed on the following page)
   ____

   b. List the unit's secondary energy source code (from "Energy Sources" listed on the following page)
   ____

3. Comments:

Application Identification No. ______________

8.0 Attachment 2 – Transmission Facilities Proposed Plan Application

TRANSMISSION FACILITIES PROPOSED PLAN APPLICATION
ISO New England Planning Procedure 5-1

1. Applicant ______________________________ Date ________________
2. Type of Facility __________________________ In-Service Date _________________
3. Transmission Line and/or Substations
   a. From ___________________________ To ___________________________________
      (Terminal - Name - Location) (Terminal - Name - Location)
   b Third Terminal or tap (if any) ____
      (Name - Location)
   c. Distance - Overhead _______ miles Underground ______ miles Design Voltage______KV

      Conductor Size ___________ Initial Operation ________KV
   d. Proposed Relaying:
      Type of line relaying
      Backup relaying
      Stuck breaker
      Special protective relaying schemes
4. Transformer Rating ________MVA HV__________KV LV_________KV Tertiary________KV

   Parameters in percent on a 100 MVA Base

   Resistance ________-R Reactance _________ -X
5. Attach simplified one-line diagram(s) of transmission and/or substations with breaker configuration, indicating existing and proposed additions or changes on construction.

   Comments:____
6. Reliability Studies

Short Circuit:	Completed ☐	Planned ☐	Not Needed ☐	Explanation Attached ☐
Load Flow:	Completed ☐	Planned ☐	Not Needed ☐	Explanation Attached ☐
Stability:	Completed ☐	Planned ☐	Not Needed ☐	Explanation Attached ☐
Other ___________	Completed ☐	Planned ☐	Not Needed ☐	Explanation Attached ☐

7. a. If this Application is associated with a Generation Proposed Plan Application, identify the Generator Proposed Plan Application(s) and the Market Participant(s) or Transmission Owner(s) responsible for submitting it. N/A ☐

   ____

   b. Has the Generation Proposed Plan Application(s) been submitted? Yes ☐ No ☐
   If "No," when will the Application(s) be submitted? ________________

Application Identification No. _______________

9.0 Attachment 3 – Generator Notification Form for Units or Changes of Less Than 5 MW

**ISO NEW ENGLAND GENERATOR NOTIFICATION FORM FOR
UNITS OR CHANGES OF LESS THAN 5 MW**

ISO New England Planning Procedure 5-1
Page 1 of 4

Submit Completed Form to ProposedPlans@iso-ne.com

Contact Customer Service at 413-540-4220 or custserv@iso-ne.com to begin market system asset registration process

Applicant ____ Date _____________________

Generation Owner (if different than Applicant) ____

Contact Person ____

Phone # (____)______________ Fax # (____)_______________ E-mail ___________________

1. Station Name ____
   a. Location/Interconnection Point (Indicate point of coupling with utility system by specifying distribution feeder or transmission line name(s) or substation name. Distribution facilities should include the transmission facility substation(s) that the distribution facilities are supplied from.)
   ____

   b. Address of Plant
   Street Address ____
   Town or City ____
   County ____________________ State _____________________ Zip Code _________________

   c. Unit/Aggregate Generation Asset Identification ____

   Net ratings entered in below should reflect the netting of auxiliary loads from the gross unit rating(s) that are directly related to the operation of the unit/aggregate generation.

	Winter (0 or higher Deg F)*	Winter (20 Deg F)	Summer (50 or higher Deg F)**	Summer (90 Deg F)
Gross Unit Rating (MW)				
Net Unit Rating (MW)				
Unit Rating (Lagging MVAR)		N/A		
Unit Rating (Leading MVAR)		N/A		

* Enter all values in this column corresponding to the temperature of 0 degree F or greater at which gross facility output will be the highest. As an example, if the maximum gross facility output occurs at 12 degrees F, all values in this column shall correspond to the 12 degree F operating condition.

** Enter all values in this column corresponding to the temperature of 50 degrees F or greater at which net unit facility output will be the highest. As an example, if the maximum net facility output occurs at 67 degrees F, all values in this column shall correspond to the 67 degree F operating condition.

Application Identification No. ______________

ISO NEW ENGLAND GENERATOR NOTIFICATION FORM FOR UNITS OR CHANGES OF LESS THAN 5 MW

ISO New England Planning Procedure 5-1
Page 2 of 4

d. What is the maximum net power injection at the point of interconnection? ___________________________

e. Is there load reduced by operating this generation? (Check Yes or No) ☐ Yes ☐ No
If "Yes:"
By how much is the load reduced? _________________________________
Where is the load located?____

2. Type of Application (Check one)

☐ Construction ☐ Capacity Change

3. Requested Commercial Operation Date _____________________

4. Is the unit equipped with under-frequency protection? (Check yes or no) ☐ Yes ☐ No

If "Yes:"

a. Has the host utility reviewed the settings? ☐ Yes ☐ No

b. Will the unit be tripped for under-frequency conditions in the area above the curve in Figure 1 of Standard PRC-006-NPCC? ☐ Yes ☐ No

   i. If "Yes," has additional automatic load shedding been provided equivalent to the amount of generation to be tripped? ☐ Yes ☐ No

c. Will the unit be tripped in conjunction with dropping low voltage feeder during load shedding? ☐ Yes ☐ No

   i. If "Yes," has the host utility ensured that sufficient automatic load shedding capability will be available to system operators? ☐ Yes ☐ No

Note: A "No" response to b.i or c.i is grounds for rejection.

5. Provide the following information on fuel used by the unit.

a. List the unit's primary energy source code (from "Energy Sources" listed on the following page)
____

b. List the unit's secondary energy source code (from "Energy Sources" listed on the following page)
____

6. Will the unit have black start capability? (Check Yes or No) ☐ Yes ☐ No
If "Yes," can it be operated on its own auxiliaries prior to synchronization with the system? ☐ Yes ☐ No

Application Identification No. _______________

ISO NEW ENGLAND GENERATOR NOTIFICATION FORM FOR UNITS OR CHANGES OF LESS THAN 5 MW

ISO New England Planning Procedure 5-1

7. Provide the following information on the interconnection point.
   a. Specify the interconnection bus name and the voltage level the unit is connected to.
      Name:______________________________________Voltage Level (kV):_______

   b. Specify the modeled PSS/E bus name and number that is electrically closest to where the unit is interconnected.
      Name:______________________________________Number:________

   (Check the appropriate box and provide appropriate diagram(s))

   ☐ The unit is connected to the power system at transmission voltage (69 kV or higher). Provide an electrical one-line diagram showing all essential devices including GSU impedance, station arrangements, station service and connections to the bulk power system, including the voltage levels below 69 kV.

   ☐ The unit is connected to the distribution system. Provide one-line diagram(s) showing the unit connection and where the distribution network connects to the bulk power system.

8. Has an interconnection request been submitted for the new unit or change of less than 5 MW? Yes ☐ No ☐
   a. If "Yes," when was the interconnection request submitted and to whom?

      ____

   b. If "No," when will the interconnection request be submitted and to whom?

      ____

9. Comments:

Application Identification No. ______________

ISO NEW ENGLAND GENERATOR NOTIFICATION FORM FOR UNITS OR CHANGES OF LESS THAN 5 MW

ISO New England Planning Procedure 5-1

Page 4 of 4

ENERGY SOURCES

CODE	TYPE (FUEL)
AB	Agricultural Crop Byproducts/Straw/Energy Crops
BAT	Battery Energy Storage
BFG	Blast-Furnace Gas
BIT	Bituminous Coal
BLQ	Black Liquor
DFO	Distillate Fuel Oil (includes all Diesel and No. 1, No. 2 and No. 4 Fuel Oils)
GEO	Geothermal
JF	Jet Fuel
KER	Kerosene
LIG	Lignite Coal
LFG	Landfill Gas
MSW	Municipal Solid Waste
NG	Natural Gas
NUC	Nuclear (Uranium, Plutonium, Thorium)
PC	Petroleum Coke
PG	Propane
OBG	Other Biomass Gases (Digester Gas, Methane and other biomass gases)
OBL	Other Biomass Liquids (Ethanol, Fish Oil, Liquid Acetonitrile Waste, Medical Waste, Tall Oil, Waste Alcohol and other biomass liquids not specified)
OBS	Other Biomass Solids (Animal Manure and Waste, Solid Byproducts and other solid biomass not specified)
OG	Other Gas (Butane, Coal Processes, Coke-Oven, Refinery and other processes)
OTH	Other (Batteries, Chemicals, Coke Breeze, Hydrogen, Pitch, Sulfur, Tar Coal and miscellaneous technologies)
RFO	Residual Fuel Oil (includes No. 5 and No. 6 Fuel Oils and Bunker C Fuel Oil)
SC	Coal-based Synfuel, including briquettes, pellets or extrusions, which are formed by binding materials and processes that recycle material
SLW	Sludge Waste
SUB	Sub-bituminous Coal
SUN	Solar (Photovoltaic, Thermal)
TDF	Tires
WAT	Water (Conventional, Pumped Storage)
WC	Waste/Other Coal (Anthracite Coal, Anthracite Culm, Bituminous Gob, Fine Coal, Lignite Waste, Waste Coal)
WDL	Wood Waste Liquids
WDS	Wood/Wood Waste Solids (Paper Pellets, Railroad Ties, Utility Poles, Wood Chips and other wood solids)
WND	Wind
WO	Oil – Other and Waste Oil (Butane (Liquid), Crude Oil, Liquid Byproducts, Oil Waste, Propane (Liquid), Re-refined Motor Oil, Sludge Oil, Tar Oil)

Application Identification No. _______________

10.0 Attachment 4 – Proposed Plan Application Submittal Procedure

~~PROPOSED PLAN APPLICATION~~PPA SUBMITTAL PROCEDURE

Market Participants or Transmission Owners will follow the "Proposed Plan Application Submittal Procedure" contained herein for the submittal of their proposed plans for review pursuant to Section I.3.9 of the ISO New England Inc. Transmission, Markets and Service Tariff (the "Tariff"). The intent of this procedure is to detail the information required under Planning Procedure Nos. 5-1 (PP5-1) and 5-3 (PP5-3) to assure an efficient Proposed Plan Application (PPA) review by the Reliability Committee (RC) and by the ISO. PP5-1 and PP5-3 may be found on the ISO Website at:

http://www.iso-ne.com/participate/rules-procedures/planning-procedures.

The most recent revision of this Attachment 5 may be found on the ISO Website at:

http://www.iso-ne.com/static-assets/documents/trans/pp_tca/forms/ppa_submittal_procedure.pdf

Notification

The Market Participant or Transmission Owner is encouraged to discuss a proposed project (or project revision) with the ISO and, as necessary, the Transmission Owner for guidance regarding the appropriate level of study required and whether a PPA or a "Generator Notification Form for Units or Changes of Less Than 5 MW" should be submitted to the ISO. PPA forms may be found on the ISO Website at:

http://www.iso-ne.com/system-planning/transmission-planning/proposed-plan-applications.

A Market Participant or Transmission Owner wishing to discuss a proposed project with the ISO should notify the ISO via the e-mail address ProposedPlans@iso-ne.com.

Submittal of Study Results and Proposed Plan Application Materials

- **Level 0 Analysis**

  PP5-1 Section 4 lists the types of projects that do not require a PPA submittal under this procedure. Pursuant to this procedure and procedure PP5-3, these types of project require Level 0 analysis. However, subject to the provisions of PP5-1, a "Generator Notification Form for Units or Changes of Less Than 5 MW", should be submitted to the ISO for proposed projects which are less than 5 MWs of new or increased generation. These submittals shall be made to the ISO via the email address ProposedPlans@iso-ne.com for ISO review and for RC distribution.

- **Level I Analysis**

  In the case of a project requiring Level I analysis, as defined in PP5-3, the PPA submittal is for information only, and the reporting of any study results is not required. The Market Participant or Transmission Owner may submit the PPA requiring Level I analysis directly to the ISO for review and distribution. ISO may confer with potentially Affected Entities to confirm that no reporting of analysis is required and that the project requires Level I analysis.

  The complete PPA package[18] for a project requiring Level I analysis shall be submitted to the ISO via e-mail to ProposedPlans@iso-ne.com and shall include:

  - A cover letter that is addressed to the Chair of the Reliability Committee and requests RC review under Section I.3.9 of the Tariff. The letter must identify the project, the submitted PPA(s), the level of analysis (Level I), and additional related materials that are being submitted.
  - PPA(s) completed in accordance with this PP 5-1.
  - One-line diagram(s) showing the proposed modification(s).
  - Additional materials related to the project, as may be requested by the ISO.
  - Once the project PPA package is deemed complete, the RC Secretary shall provide the materials to the RC for their review.

- **Level II or III Analysis**

  A project requiring Level II or III analysis requires RC and ISO review.

  1) The project's proponent must contact the ISO via e-mail at ProposedPlans@iso-ne.com, to coordinate the review of the project.
  2) The project proponent shall submit to the ISO, via e-mail at ProposedPlans@iso-ne.com, the complete PPA package which includes a draft of each PPA for the project along with the study report(s).[19] The complete study report(s) shall include a project description of sufficient detail for review and one-line diagrams showing the elements of the project, and sufficient reporting of the analyses performed to demonstrate that the project will not have any significant adverse effects under Section I.3.9 of the Tariff. The project description must include any additional upgrades necessary to mitigate any adverse effects that may be identified during the review and any specific conditions regarding the construction sequencing of the elements within the project and with the elements of other projects that have been determined to have no adverse effects under Section I.3.9 of the Tariff.

[18] Model submission in accordance with Figure 1 (and accompanying language) shall precede a PPA package submission.

[19] Model submission in accordance with Figure 1 (and accompanying language) shall precede a PPA package submission.

3) The ISO review will ensure consistency of the project description with the one-line diagrams in the report. ISO Planning staff will ensure that the project report and draft PPA(s) are consistent.
4) When the ISO confirms that the study results adequately support the project, it will provide a recommendation letter to the RC indicating the project reports are complete and that the project will not have any significant adverse effects pursuant to Section I.3.9 of the Tariff. This recommendation letter will include any opinions expressed by Affected Entities regarding significant impacts that they believe to be insufficiently addressed.
5) After it has been confirmed that the study results adequately support the project, the Market Participant or Transmission Owner may submit a letter requesting Section I.3.9 review of the project to the RC Chair. The letter must identify the project, the submitted PPA(s), the level of analysis (Level II/III), the study report(s), and additional related materials that are being submitted. The letter shall be submitted to the ISO by email to ProposedPlans@iso-ne.com.
6) ISO Planning staff will provide to the RC Secretary the PPA(s), study report(s) and any additional related materials that were identified in the letter to the RC Chair. The RC Secretary will coordinate the RC review of the project with the project proponent.

General Requirements

The ISO will send an e-mail to the plan proponent to provide:

- confirmation of receipt of the project PPA materials or any appropriate modifications to the submitted materials; and
- verification of the submittal date of the complete project PPA package appropriate for review by the RC.

The appropriate project PPA package will be forwarded to all appropriate ISO personnel, and then distributed to the RC prior to the meeting at which the project is to be considered.

The applicant should provide additional copies of project PPA materials to committee members upon request.

DECEMBER 14, 2022 | NEPOOL RELIABILITY COMMITTEE | DOUBLETREE, WESTBOROUGH, MA

Modeling and Data Requirements for Proposed Plan Applications

Updates to Planning Procedure 5-1

Al McBride

SYSTEM PLANNING

Project Title: Modeling and Data Requirements for Proposed Plan Applications

Proposed Effective Date: January, 2023

- The ISO is proposing to add/clarify modeling and data requirements for new Proposed Plan Applications in Planning Procedure 5-1: Procedure for Review of Market Participant's or Transmission Owner Proposed Plans (Section I.3.9 Applications: Requirements, Procedures, and Forms) (PP5-1)
- Third Reliability Committee (RC) Presentation
  - Presentation of updates to proposed Planning Procedure redlines and requested vote
  - Updates to proposed Planning Procedure redlines were presented at the November 16, 2022 RC meeting
  - Proposed Planning Procedure redlines were presented at the September 20, 2022 RC meeting
  - The ISO introduced the issues and the ISO proposals at the August 16, 2022 RC meeting

Background & Proposal

- In accordance with Section I.3.9 of the ISO Tariff, Market Participants and Transmission Owners are required to submit Proposed Plan Applications (PPAs) before proceeding with changes to the power system
  - PPAs are reviewed by the NEPOOL Reliability Committee (RC) and by the ISO
  - The RC recommends PPA approvals
  - The ISO is responsible for issuing PPA approvals
- PP5-1 contains the implementation details for PPA submittal and review
- The ISO is proposing to update PP5-1 to clarify the timing and requirements for model and data submissions in association with PPA submittals

ADDITIONAL PROCEDURE REDLINES

Procedure Redlines

PP5-1 Section	Procedure Change	Reason for Change
1.1.2 Submittal of a Proposed Plan Application (replicated footnote)	<u>At the ISO's discretion, PPA approval may be provided where the submittal requirements of this procedure were met, but not all of the issues associated with accepting the models have been addressed, provided that the proponent is demonstrating best-efforts to resolve the outstanding model-acceptance issues.</u>	Footnote has been added at a second location for consistency

Procedure Redlines, continued

PP5-1 Section	Procedure Change	Reason for Change
1.1.2 Submittal of a Proposed Plan Application (new footnote)	The draft study materials shall include a draft of the study report that will be used to support the PPA, as well as any other materials the proponent believes necessary to describe the project. The draft study report shall meet the requirements of Section 3.1.3 of Planning Procedure 5-3.	Footnote has been added to provide clarity regarding draft study materials

Procedure Redlines, continued

PP5-1 Section	Procedure Change	Reason for Change

1.1.2.2 PPA Submission Requirements	A PPA submission shall include:
	• the application(s) with a cover letter, a one-line diagram illustrating the proposed change relative to the existing system along with proposed equipment nomenclature, and,
	  • For Level II or Level III analysis, a report that documents the study and supports the application
	    • the report shall include appendices with steady-state, dynamics and short circuit models used for the study
		Clarified that report is only required for Level II or III Analysis

Conclusion

- The ISO is proposing to update PP5-1 to clarify the timing and requirements for model and data submissions in association with PPA submittals
- The ISO is requesting a vote on the proposed redline changes to PP5-1

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee August 16, 2022	Initial Presentation
Reliability Committee September 20, 2022	Introduction and Review of PP5-1 Redlines
Reliability Committee November 16, 2022	Updates to proposed PP5-1 Redlines
Reliability Committee December 14, 2022	Further updates to PP5-1 Redlines & Requested Vote
Participants Committee January 5, 2023	Vote

Questions

memo

To: Participants Committee

From: Nicholas Gangi, Secretary, Reliability Committee

Date: December 14, 2022

Subject: Revised Actions of the Reliability Committee from the December 14, 2022 Meeting

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its December 14, 2022 meeting of the Reliability Committee. A quorum was established.

(Agenda Item 2.0) (66.67% Vote) Confirmation of Vice-Chair Election

ACTION: APPROVED

Resolved, that the Reliability Committee confirms the election result of Mr. Robert Stein as Vice Chair of the Reliability Committee for the new term commencing January 1, 2023.

Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 3.0) (66.67% Vote) Meeting Minutes

ACTION: APPROVED

Resolved, that the Reliability Committee approves the minutes of the following RC meetings as distributed to the committee for the December 14, 2022 meeting together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee:

- November 16, 2022 RC Meeting

Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 5.1) (66.67% Vote) Queue Position 1029 (QP 1029) Bradley Solar Project

ACTION: APPROVED

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-535-4173
ngangi@iso-ne.com

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

recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 7.1) (66.67% Vote) Planning Procedure 5-1 – Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans

ACTION: APPROVED

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Planning Procedure 5-1 – Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans as distributed to the committee for the December 14, 2022 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

Based on a voice vote, the motion passed with 3 opposed (3 Transmission) and 30 abstentions (2 Transmission, 3 Supplier, 2 AR, 23 Publicly Owned).

(Agenda Item 8.1) (66.67% Vote) OP 5 – Resource Maintenance and Outage Scheduling

ACTION: APPROVED

Resolved, that the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 5 – Resource Maintenance and Outage Scheduling, as distributed to the committee for the December 14, 2022 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

Based on a voice vote, the motion passed with none opposed and no abstentions.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of January 4, 2023

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 30, 2022 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

FERC Administrative Developments

*		Acting FERC Chairman Named	Jan 3	President Biden names Willie Phillips as acting chairman of the FERC; Richard Glick departs from the FERC, leaving the FERC with 2 Democrat and 2 Republican Commissioners

I. Complaints/Section 206 Proceedings

*	1	RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)	Dec 13	RENEW files a complaint against ISO-NE and the PTOs seeking changes to Schedules 11 and 21 of the Tariff that would eliminate the direct assignment of Network Upgrade O&M costs to Interconnection Customers; comment deadline ***Jan 23, 2023***
			Dec 14-Dec 23	NEPOOL, Calpine, CPV Towantic, Eversource, MA AG, National Grid, NEPGA, NESCOE, New Leaf Energy, NextEra, NRG, Versant, Glenvale LLC, CT DEEP, MA DPU, and Public Citizen intervene
			Dec 16	PTO AC requests 20-day extension of time to respond
			Dec 21	NEPOOL, MA AG, NESCOE support PTO AC extension request
			Dec 22	FERC grants 20-day extension of time to comment/respond
	1	ENECOS Mystic COSA Complaint (EL23-4)	Dec 1	ENECOS answer Mystic's Nov 16, 2022 answer
			Dec 16	Mystic answers ENECOS' Dec 1, 2022 answer
	5	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Dec 9	Avangrid moves to lodge an Amended E&P Agreement between NextEra Energy Seabrook and NECEC Transmission and to request expedited resolution of remaining issues

II. Rate, ICR, FCA, Cost Recovery Filings

*	10	FCA17 Qualification Informational Filing (ER23-690)	Dec 21	ISO-NE submits required FCA17 informational filing; comment deadline ***Jan 5, 2023***
			Dec 21-Jan 4	NEPOOL, Calpine, Constellation, National Grid, NESCOE intervene
	10	ICR-Related Values and HQICCs – FCA17 (2026-27) Capacity Commitment Period (ER23-405)	Dec 20	FERC accepts the FCA17 (2026-27) ICR-Related Values, eff. Jan 7, 2023
	11	2023 NESCOE Budget (ER23-100)	Dec 20	FERC accepts revised Section IV.A Schedule 5 rate of $0.00701 per kW of Monthly Network Load, eff. Jan 1, 2023
	11	2023 ISO-NE Administrative Costs and Capital Budgets (ER23-94)	Dec 20	FERC accepts revisions to Section IV.A to recover ISO-NE's 2023 Budgets, eff. Jan 1, 2023
	11	NESCOE 5-year (2023-2027) Pro Forma Budget (ER22-2812)	Dec 19	FERC accepts NESCOE's 4th 5-year Pro Forma Budget (2023-2027), eff. Nov 10, 2022
	11	Mystic COSA Updates to Reflect Constellation Spin Transaction (ER22-1192)	Dec 2	Mystic submits compliance filing reflecting the FERC's action in this matter

	12	Mystic I Remand (ER18-1639-019)	Dec 6-7	ISO-NE, CT Parties, ENECOS, MMWEC/NHEC, National Grid, NESCOE, MPUC answer Mystic/Constellation emergency motion requesting expedited action by ***Jan 9, 2022***, on the Cost Allocation and Clawback issues remanded to the FERC in the *Mystic I Remand Order*
			Dec 21	Mystic answers ENECOS' Dec 6 protest to the emergency motion
	12	Mystic 8/9 COSA *Second* CapEx Info Filing (ER18-1639-018)	Dec 6	ENECOS answer Mystic's Nov 17, 2022 answer
			Dec 22	Mystic responds to ENECOS' Dec 6 answer
	12	Mystic 8/9 COSA *First* CapEx Info Filing Settlement Judge Procedures (ER18-1639-015)	Dec 20	Third settlement conference held
			Jan 3	ALJ McBarnette issues status report; schedules fourth settlement conference for ***Jan 18, 2023***
	12	Mystic Fuel Supply Agreement Revision Info Filing (ER18-1639-020)	Dec 9	Mystic submits a revision to its Fuel Supply Agreement that memorializes Constellation LNG's pre-existing business practice of crediting Mystic under the FSA to account for firm gas trans. charges that Constellation LNG collects from forward 3rd party gas sales

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

*	14	SATOA Revisions (ER23-739; ER23-743)	Dec 29	ISO-NE, NEPOOL and the PTO AC file SATOA Revisions in 2 parts (ISO-NE Tariff Revisions (ER23-739)/TOA Revisions (ER23-743); comment date ***Jan 19, 2023***
			Jan 3	Eversource, NESCOE, MA DPU intervene
	15	Waiver Request: Attachment F (NEP) (ER23-370)	Dec 22	FERC grants NEP waiver of provisions in the formula rate template in ISO-NE Tariff Attachment F to account for the change in ownership of certain transmission facilities
	15	FCA18 Schedule Modifications (ER23-50)	Dec 1	FERC accepts FCA18 Schedule Modifications, eff. Dec 10, 2022
	16	IEP Remand (ER19-1428-006)	Dec 5, 12	FirstLight and National Grid file doc-less interventions
			Dec 5-13	NEPOOL, Brookfield, MA AG, National Hydropower Association, and RENEW file comments and limited protests
			Dec 28	NECOS and ENE respond to protests and comments

IV. OATT Amendments / TOAs / Coordination Agreements

*	16	Attachment F, Appendix D-NSTAR: Updates to Depreciation Rates (ER23-637)	Dec 15	NSTAR proposes revisions to the general plant depreciation rates for NSTAR (East) and NSTAR (West); comment deadline ***Jan 5, 2023***
	17	Attachment F Revisions reflecting RI Energy Addition as PTO (ER23-299)	Dec 6	FERC accepts revisions, eff. Jan 1, 2023
	17	Attachment F Depreciation Normalization Requirement Revisions (ER23-197)	Dec 13	FERC accepts revisions, eff. Jan 1, 2023
	17	Attachment F, Appendix D-PSNH: Depreciation Rate for Accounts 357 and 358 (ER22-2953)	Dec 13	FERC accepts revisions, eff. Jan 1, 2023

V. Financial Assurance/Billing Policy Amendments

*	19	FA/Billing Policies IEP Changes; Monthly Statement Issuance Date Update (ER23-705)	Dec 22	ISO-NE and NEPOOL jointly file IEP-related changes to the Billing Policy and FAP and an update to the definition of "Monthly Issuance"; comment deadline ***Jan 12, 2023***
			Dec 28-Jan 3	Calpine, Constellation, National Grid intervene

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

*	19	Schedule 21-RIE: Transfer of SAs from Sched 21-NEP; Updated Thundermist ISA (ER23-678; ER23-681)	Dec 20	RIE submits filing (i) to move certain RIE service agreements to Schedule 21-RIE from Schedule 21-NEP (Docket No. ER23-678) and (ii) to revise RIE's Interconnection Service Agreement with Thundermist Hydropower LLC. In Docket No. ER23-681, RIE and NEP submit a filing to cancel the NEP Tariff database that previously contained the SAs. Comment deadline, ***Jan 10, 2023***
	19	Schedule 21-NEP: Removal of References to Narragansett; Update Ref. to National Grid LCC (ER23-165)	Dec 6	FERC accepts Revisions, eff. Jan 1, 2023
	19	Schedule 21-RIE (ER23-16)	Dec 9	FERC issues deficiency letter directing RIE to address the absence of a permanent ADIT worksheet (as required per *Order 864*)
			Dec 12	RIE responds to deficiency letter, including submission of recently-approved *Order 864* compliance changes
			Dec 28	FERC accepts Schedule 21-RIE/Attachment E Revisions, eff. Jan 1, 2023

VII. NEPOOL Agreement/Participants Agreement Amendments

	20	PA Amendment No. 12 (ISO Board Member Age Limit Increase)	Dec 21	PA Amendment No. 12 approved in balloting

VIII. Regional Reports

	21	Capital Projects Report - 2022 Q3 (ER23-114)	Dec 20	FERC accepts 2022 Q3 Report, eff. Oct 1, 2022

IX. Membership Filings

*	21	Jan 2023 Membership Filing (ER23-756)	Dec 30	***New Members***: Just Energy Limited, Think Energy ***Terminations***: Josco Energy MA, Starion Energy, RI Bioenergy Facility; ***Name Changes***: BP Energy Retail Company LLC, BP Energy Holding Company LLC; RI Bioenergy, LLC; comment date ***Jan 21, 2023***
	22	Nov 2022 Membership Filing II (ER23-402)	Dec 15	FERC accepts Windham Energy Center membership, eff. Nov 10, 2022
	22	Nov 2022 Membership Filing I (ER23-310)	Dec 13	FERC accepts (i) the memberships of Derby Fuel Cell; KCE CT 5, 7, 8, and 9; Rhode Island Bioenergy Facility; RI Division of Public Utilities Carriers; Sunnova Energy; and Triolith Energy Fund; (ii) the termination of the Participant status of EIP Investment; and (iii) the name change of Stones DR, LLC
*	22	Suspension Notice – Manchester Methane, LLC (not docketed)	Dec 6	ISO-NE files notice of Dec 2 suspension of Manchester Methane, LLC from the New England Markets

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

	22	Revised Reliability Standards: EOP-011-3 and EOP-012-1 (RD23-1)	Dec 1-8	EPSA, NEPGA, Invenergy, IRC, TAPS, and the Texas Competitive Power Advocates file comments on the *Cold Weather Standards*
			Dec 16-23	NERC, Competitive Generators, Invenergy, and APPA file reply comments
			Jan 3	IRC files reply comments

	23	CIP Standards Development: Info. Filings on Virtualization and Cloud Computing Services Projects (RD20-2)	Dec 15	NERC files required quarterly report with revised schedule for Project 2016-02 (projected filing of revised standards now ***Jun 2023***)
	24	2023 NERC/NPCC Business Plans and Budgets (RR22-4)	Jan 3	NERC submits compliance filing in response to Nov 2 *2023 Budgets Order*; comment deadline ***Jan 24, 2023***

XI. Misc. - of Regional Interest

*	24	203 Application: Talen Energy Supply Reorganization (EC23-42)	Dec 15	TES requests approval for a change in control transaction whereby 10% or more of the voting securities of a Reorganized Talen will be distributed to some or all of Indicated Noteholders pursuant to a joint plan of reorganization of the TES Debtors subject to confirmation by the Bankruptcy Court; comment deadline ***Jan 30, 2023***
			Dec 19, 23	PJM IMM, Public Citizen intervene
*	24	203 Application: Cogentrix / EGCO (Rhode Island State Energy Center) (EC23-41)	Dec 14	RISEC and EGCO RISEC II, LLC (Buyer) request FERC authorization for a transaction pursuant to which Buyer, a wholly owned indirect subsidiary of EGCO, will acquire a 49% indirect ownership interest in RISEC from Cogentrix Sellers; comment deadline ***Jan 30, 2023***
			Dec 23	Public Citizen intervenes
	25	203 Application: Central Rivers Power / LSPower (EC23-22)	Dec 30	FERC authorizes, as part of a larger transaction, LS Power's acquisition of Central Rivers Power's QF assets in New England
	25	203 Application: Seneca Energy II / BP (EC23-18)	Dec 22	FERC authorizes transaction pursuant to which Seneca Energy II, LLC will ultimately become a Related Person of BP
			Dec 30	BP submits notice of Dec 28, 2022 consummation of transaction; Seneca Energy II is now a BP Related Person
	26	203 Application: EDF Energy / BP Retail (EC22-122)	Dec 5	BP Energy Retail Company (f/k/a EDF Energy Services) et al. submit notice of Nov 30, 2022 consummation of transaction; BP Energy Retail Company is now a BP Related Person
	26	203 Application: Salem Harbor / Lenders (EC22-117)	Dec 19	Salem Harbor files notice of Dec 16, 2022 consummation of transaction
	26	203 Application: Waterside Power / KKR (EC22-79)	Dec 21	Applicants file notice of Dec 20, 2022 consummation of transaction
	26	203 Application: Stonepeak / JERA Americas (EC22-71)	Dec 2	Applicants file notice of Dec 1, 2022 consummation of transaction; Stonepeake Kestrel Energy Marketing and Cricket Valley Energy Center become Related Persons to Marco DM Holdings
*	27	EMM Contract (ER23-682)	Dec 15	ISO files new contract for EMM services with Potomac Economics; comment deadline ***Jan 5, 2023***
			Dec 21-Jan 3	NEPOOL, National Grid, NESCOE, Public Citizen intervene
	27	NEP Tariff No. 1 Revisions (ER23-348)	Dec 6	FERC accepts Revisions, eff. Jan 1, 2023
	27	Versant MPD OATT: Changes to Treatment of CIS Costs and Expenses (ER23-345)	Jan 4	FERC accepts changes, eff. Jun 1, 2023
	28	IA 2nd Amendment: CMP/Sappi Compl. Filing (ER22-1612-001)	Dec 16	CMP submits compliance filing –a 2nd Amendment to its IA with Sappi North America, Inc.; comment deadline ***Jan 6, 2023***
	29	Orders 864/864-A (Public Util. Trans. ADIT Rate Changes) New England Compliance Filings	Dec 29	FERC accepts the last of the region's pending *Order 864* compliance filings (UI's May 10, 2022 filing, Docket No. ER22-1850), eff. Jan 27, 2020

XII. Misc. - Administrative & Rulemaking Proceedings

	29	Interregional HVDC Merchant Transmission (AD22-13)	Dec 5-23	ENGIE NA, Grid United and SEIA file comments supporting Invenergy's Nov 10, 2022 request that the FERC "hold a technical conference to examine and to improve the policy and processes relating to the interconnection of interregional MHVDC systems"
	29	Joint FERC-DOE Supply Chain Risk Management Technical Conference (Dec 7) (AD22-12)	Dec 6 Dec 7	FERC issues 4th supplement notice of tech conference FERC holds tech conf; speaker materials posted to eLibrary Post-tech conf comments due ***Feb 17, 2023***
	30	Reliability Tech Conf (Nov 10) (AD22-10)		Post-tech conf comments due ***Jan 9, 2023***
	30	Transmission Planning and Cost Management Tech Conf (AD22-8)	Dec 23	FERC invites post-technical conference comments on questions listed in notice; comments due on or before ***Mar 23, 2023***
	31	Modernizing Electricity Market Design - Resource Adequacy (AD21-10)	Dec 6 Dec 16, 21	FERC grants EEI request for a 30-day extension of time to file comments on ISO/RTO Reports; comment deadline ***Jan 19, 2023*** ELCON, SPP MMU file comments
	32	NOPR: Duty of Candor (RM22-20)	Dec 12	US Chamber of Commerce submits reply comments
	34	NOPR: Interconnection Reforms (RM22-14)	Dec 14	More than 50 sets of reply comments filed, including by: ACPA, ACORE, Advanced Energy United (f/k/a/ AEE), APPA/LPPC, Avangrid, Dominion, EDF, EEI, Enel, ENGIE, Invenergy, the IRC, Longroad Energy, NERC, NESCOE, NextEra, Orsted, SEIA, Shell, Sierra Club, UCS, WIRES
	38	*Transmission NOPR* (RM21-17)	Dec 6, 12	Harvard Electricity Law Initiative, P. Alaama submit comments

XIII. FERC Enforcement Proceedings

*	41	Todd Meinershagen (IN23-4)	Dec 21	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into Meingershagen's role, both individually and as co-owner of a DR aggregator, in a fraudulent scheme to register DR resources with MISO without those resources' knowledge or consent and to clear LMR capacity that would not have performed if the resources were dispatched during the Relevant Period; Meinershagen must pay ***$525,451.93 in restitution*** to MISO
*	42	FirstEnergy Corp (IN23-2)	Dec 30	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into FirstEnergy's failure to disclose during a FERC audit payments of nearly $60 million made in connection with the passage of Ohio House Bill 6; FirstEnergy must pay a ***$3.86 million civil penalty*** and submit two annual compliance monitoring reports
	42	PacifiCorp (IN21-6)	Dec 30	To fully resolve this matter, in which PacifiCorp was alleged to have violated NERC Reliability Standard FAC-009-1 R1 (which requires a TO to establish and have facility ratings that are consistent with its Facility Ratings Methodology, PacifiCorp agreed to: (a) pay ***a civil penalty of $4.4 million***; and (b) be subject to two years' of semi-annual compliance monitoring
	44	Total Gas & Power North America, Inc. et al. (IN12-17)	Dec 16 Dec 21 Dec 22	Respondents file for a preliminary injunction in the US District Court for the Southern District of Texas FERC issues order holding this proceeding in abeyance for 90 days, and deferring the beginning of the hearing scheduled before ALJ Krolikowski to no earlier than ***Apr 24, 2023*** Presiding ALJ Krolikowski issued a status order

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

48	2nd Revised Narragansett LSA Orders (22-1161, 22-1108) (consolidated)	Dec 12 Dec 19	FERC file Respondent's Brief National Grid files Intervenor for Respondent's Brief
50	Opinion 531-A Compliance Filing Undo (20-1329)	Dec 6	FERC files status report indicating that the proceedings before the FERC remain ongoing and that this appeal should continue to remain in abeyance
51	Northern Access Project (22-1233)	Dec 16	Sierra Club files Petitioner's Brief

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: January 4, 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 January 3, 2023. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

On December 13, 2022, RENEW filed a complaint against ISO-NE and the Participating Transmission Owners ("PTOs") seeking changes to the ISO Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to Interconnection Customers. 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. The proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee on October 26, 2021, and discussed at the November 3, 2021 Participants Committee 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). Following a request by the PTO AC for a 20-day extension of time to submit comments, supported by NEPOOL, the MA AG and NESCOE, and granted by the FERC on December 22, 2022, comments are now due on or before ***January 23, 2023***. Thus far, doc-less interventions have been filed by NEPOOL, Calpine, CPV Towantic, Eversource, MA AG, National Grid, NEPGA, NESCOE, New Leaf Energy, NextEra, NRG, Versant, Glenvale LLC, CT DEEP, MA DPU, and Public Citizen. 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).

- **ENECOS Mystic COSA Complaint (EL23-4)**

As previously reported, On October 17, 2022, Eastern New England Consumer-Owned Systems ("ENECOS") filed a Complaint against Mystic and ISO-NE challenging the pass-through to ISO-NE customers of firm pipeline transportation costs under the 2nd Amended and Restated Mystic Cost-of-Service Agreement ("COSA"), which ENECOS claimed are associated with pipeline facilities that are neither used nor usable to supply fuel to Mystic 8 and 9, and therefore should not be charged to ISO-NE and its customers under the COSA. Specifically, ENECOS asked that all references to "Pipeline Transportation Agreements" be stricken from the COSA, template Line No. 7 "Fixed Pipeline Transportation" be removed from the true-up methodology, and Mystic be precluded from recovering the dollar amounts associated with that line item. ENECOS explained that the Complaint was filed as a procedural precaution as the charges that are the subject of the Complaint can be addressed by the FERC in

[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").

proceedings on the DC Circuit's remand of issues relating to the FERC's allocation of Everett Marine Terminal costs under the COSA.[2]

Responses and Comments. Responses to and comments on ENECOS' Complaint were due on or before November 16, 2022. Mystic and ISO-NE filed responses. In its response, ***Mystic*** urged the FERC to dismiss the Complaint by asserting that (i) ENECOS have not, as required, sufficiently alleged changed circumstances since the pipeline transportation costs recovery mechanisms were found just & reasonable by the FERC; (ii) ENECOS are wrong on the merits; (iii) Mystic and the COSA are cost causative for Everett; and (iv) allocation of the costs is justified by tank management, which allows Mystic to meet the reliability need that the COSA is intended to address. For its part, ***ISO-NE*** also requested that the FERC deny the Complaint because the costs challenged are encompassed by the *Mystic Remand Order*. However, if the FERC does not dismiss the Complaint, ISO-NE urged the FERC to either consolidate the Complaint with the Mystic Remand Proceeding or hold the Complaint in abeyance. Comments supporting the Complaint were filed by MMWEC/NHEC (together, "Public Systems"), and by the Connecticut Public Utilities Regulatory Authority ("CT PURA") and the Connecticut Office of Consumer Counsel ("CT OCC", and together with CT PURA, the "CT Parties"). Doc-less interventions only were filed by NEPOOL, Calpine, Eversource, MA AG, National Grid, NESCOE, NRG, and the CT DEEP have intervened doc-lessly. Since the last Report, ENECOS answered Mystic's November 16, 2022 answer and Mystic answered ENECOS' December 1, 2022 answer. This matter is pending before the FERC. If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

On July 28, 2022, the FERC instituted a Section 206 proceeding finding that the existing tariffs of certain ISO/RTOs, including the ISO-NE Tariff, appear to be unjust and unreasonable.[3] The FERC found that ISO-NE's Tariff appears to be unjust and unreasonable in the absence of volumetric minimum collateral requirements for FTR Market Participants ("volumetric FTR collateral requirements"). Accordingly, ISO-NE was directed, on or before October 26, 2022, to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential.[4] As noted below, ISO-NE answered by explaining why it believes its existing Tariff provisions to be just and reasonable and changes not necessary.

By way of background, the *FTR Collateral Show Cause Order* follows PJM's *Green Hat* experience,[5] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential rulemaking to improve ISO/RTO credit practices,[6] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[7] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific

[2] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1050-1052 (D.C. Cir. 2022) ("*Mystic Remand Order*").

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

[4] *Id.* at P 31.

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

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

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

practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[8] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

The FERC issued on July 28, 2022, a notice of this proceeding and of the refund effective date, August 3, 2022.[9] Those interested in participating in this proceeding were required to intervene on or before August 18, 2022. Doc-less interventions were filed by NEPOOL, Calpine, DC Energy, NRG, the Maine Public Utilities Commission ("MPUC"), Electric Power Supply Association ("EPSA"), PJM, SPP, Public Citizen, and Financial Marketers Coalition[10] (out-of-time).

ISO-NE Response. On October 26, 2022, ISO-NE submitted its answer in response to the *FTR Collateral Show Cause Order*. In its Answer, ISO-NE explained how the FTR financial assurance calculations contained in the Financial Assurance Policy ("FAP") remain just and reasonable, adequately accounting for FTR risk in the absence of a more sophisticated risk management solution such as a clearing solution. ISO-NE asked that, should the FERC not agree and proceed to require volumetric FTR collateral requirements, that it be permitted to follow the Participants Processes to propose revisions to the FAP consistent with any such order. Comments on ISO-NE's response were due on or before November 25, 2022; none were filed. 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).

- **RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)**

As previously reported, RENEW Northeast, Inc. ("RENEW") and the American Clean Power Association ("ACPA") filed a Complaint on March 15, 2022 under Section 206 of the Federal Power Act ("FPA") against ISO-NE seeking a FERC order directing ISO-NE to make changes to its rules for capacity accreditation and operating reserve designations, effective no later than the eighteenth Forward Capacity Auction ("FCA18") with respect to capacity accreditation and promptly with respect to operating reserve designations. RENEW/ACPA asserted that the changes are needed to address undue preferences granted under ISO-NE's rules and procedures to gas-fired generation resources that have neither dual-fuel capability nor dedicated, firm natural gas supply arrangements ("Gas-Only Resources"). Complainants asserted that the undo preferences arise in the context of capacity accreditation through an assumption of 100% fuel availability for Gas-Only Resources, and in the context of operating reserves, through the absence of any pre-dispatch requirements to confirm fuel availability. ISO-NE's response and comments, following a request for extension of time granted by the FERC, were due on or before April 14, 2022.

On April 14, 2022, ISO-NE responded to the Complaint. Protests and comments on the Complaint were filed by: NEPOOL, Advanced Energy United (f/k/a/ AEE) ("AEU"), Calpine, EDF, FirstLight, LS Power, NEPGA,

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

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

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

NESCOE, Public Interest Orgs ("PIOs",[11] Vistra/LSP Power, State Parties,[12] EPSA, National Hydropower Assoc., and the Solar Energy Industries Association ("SEIA"). On April 29, RENEW/ACPA answered the ISO-NE and NEPOOL motions to dismiss and answered the protests and comments filed in opposition to the Complaint. On May 17, ISO-NE answered the April 29 RENEW/ACPA answer. Interventions only were filed by AEP, Avangrid, Avangrid Renewables, Borrego, Brookfield, Constellation, CPV Towantic, Dominion, ENE, Excelerate, National Grid, NextEra, NH OCA, North East Offshore, NRG, Public Systems,[13] CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. On July 20, 2022, ISO-NE submitted a letter requested expeditious action on the Complaint (a request NEPOOL supported). RENEW/ACPA supported the request for expedited action on August 1, 2022 (adding that the FERC "should grant the Complaint and direct ISO-NE to submit a compliance filing that timely implements the proposed remedies", and could address the wish for "constructive *ex parte* communications with [FERC] Staff … with an appropriately crafted waiver of the *ex parte* limitations"). On November 7, 2022, RENEW and ACPA, in comments submitted also in the New England Winter Gas-Electric Forum proceeding (*see* AD22-9 below), drew attention to, reiterated its arguments in, and urged the FERC to expeditiously act on, this Complaint.

There was no activity in this proceeding since the last Report. This Complaint remains pending before the FERC. If you have any questions concerning this Complaint, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)**

On September 26, 2022, the FERC issued a notice[14] that the Northern Maine Independent System Administrator's ("NMISA") request for rehearing of the FERC's order[15] denying NMISA's complaint against ISO-NE and the Participating Transmission Owners ("PTOs") Administrative Committee ("PTO AC")[16] may be deemed denied by operation of law, triggering the 60-day period during which a petition for review of the *NMISA Order* can be filed with an appropriate federal court. The notice also indicated that the FERC, as is its right, "may modify or set aside [the *NMISA Order*], in whole or in part, in such manner as it shall deem proper". The FERC issued that order on November 21, 2022, modifying the discussion in the *NMISA Order*, but reaching the same the result.[17] If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[11] "Public Interest Orgs" are the Sustainable FERC Project, Acadia Center, Conservation Law Foundation ("CLF"), Sierra Club, and Natural Resources Defense Council ("NRDC").

[12] "State Parties" are the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), the Massachusetts Attorney General ("MA AG"), and the Connecticut Attorney General ("CT AG").

[13] "Public Systems" are Connecticut Municipal Electric Energy Cooperative ("CMEEC"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), New Hampshire Electric Cooperative, Inc. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

[14] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 180 FERC ¶ 61,044 (Sep. 23, 2022) (notice that req. for reh'g of July 28 order may be deemed denied).

[15] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 180 FERC ¶ 62,168 (July 28, 2022) ("*NMISA Order*") (order denying reciprocal TOUT discount complaint).

[16] As previously reported, the FERC found in the *NMISA Order* that "NMISA has not demonstrated that the failure of the PTO AC and ISO-NE to offer NMISA reciprocal treatment is unduly discriminatory or preferential". Specifically, the FERC citied its longstanding policy permitting such charges, found for a number of reasons NYISO and NMISA not similarly situated, and noted that NMISA's showing that the proposed approach might be superior for NMISA insufficient to meet its FPA Section 206 statutory burden. In requesting rehearing, NMISA asserted that the FERC erred by (i) failing to provide a reasoned explanation for its determination that NMISA and NYISO are not similarly situated; and (ii) failed to justify its decision not to enforce the requirement that ISO-NE engage in extensive efforts to reduce seams with neighboring control areas.

[17] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 181 FERC ¶ 61,148 (Nov. 21, 2022) ("*NMISA Allegheny Order*") (order modifying the *NMISA Order* and sustaining the result).

- **206 Proceeding: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)**

Still pending before the FERC is the FERC-instituted FPA Section 206 proceeding under which the FERC is considering whether Schedule 25 and Tariff § I.3.10 may be unjust and unreasonable.[18] As previously reported, this proceeding arises out of issues raised in the NECEC Transmission LLC ("NECEC")/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[19]

The FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff § I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff § I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. On September 8, 2021, the FERC issued a notice of the proceeding and of the refund effective date, which is October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021[20] and included NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), ACPA, EPSA, RENEW, and Public Citizen.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff § I.3.10 remain just and reasonable. ISO-NE called for the FERC to "assist Affected Parties and Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties had until January 7, 2022 to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate.

Comments. Comments were filed by the January 7, 2022 deadline by NEPOOL, NECEC/Avangrid, NEPGA, NextEra. On January 20, 2022, NextEra answered the NECEC/Avangrid comments. On January 28, 2022, NECEC answered NextEra's January 20 answer and ISO-NE answered NECEC's Jan 7 comments.

As noted, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)**

Still pending before the FERC is the October 13, 2020 complaint by NECEC and Avangrid Inc. (together, "Avangrid") requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the NECEC Project and seeking, among other things, an initial, expedited order that would grant certain relief[21] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are

---

[18] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021) ("*Sep 7 Order*").

[19] *Id.* at P 20.

[20] The *Notice* was published in the *Fed. Reg.* on Sep. 14, 2021 (Vol. 86, No. 175) p. 51,140.

[21] Directing NextEra to comply with the ISO-NE OATT, to comply with open access requirements, and to cease and desist unlawful interference with the NECEC Project; and to have the FERC temporarily revoke NextEra's blanket waiver under Part 358 of the FERC's regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage (the "Complaint"). NextEra submitted an answer to the Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid subsequently answered the supplemental answer.

Amended Complaint. On March 26, 2021, Avangrid amended the Complaint to reflect that aspects of the relief originally requested in the Complaint were no longer feasible within the timeline previously sought. Avangrid continued to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021 (which did not occur). On April 15, 2021, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. On May 6, 2021, ISO-NE submitted a letter to express importance of prompt resolution of these matters. On May 17, Avangrid submitted a letter supporting ISO-NE's May 6, 2021 letter.

Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[22] Initial briefs[23] were due on or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding). Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again pending before the FERC.

Dec 9, 2022 Motion to Lodge and Request for Expedited Consideration. On December 9, 2022, Avangrid filed a motion to lodge an Amended E&P Agreement between NextEra Energy Seabrook and NECEC Transmission and to request expedited resolution of remaining issues. The Amended E&P Agreement allows for the delivery of the Seabrook Breaker in advance of the scheduled Fall 2024 refueling outage at Seabrook Station. However, the Amended E&P Agreement does not address construction and installation of the Seabrook Breaker, which will require resolution of the disputed issues in this proceeding, and for which the parties again requested FERC action.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

---

[22] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021).

[23] The FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues: (i) whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility; (ii) if Seabrook's breaker is part of Seabrook's generating facility, under what authority, if any, Seabrook may be subject to the upgrade obligations imposed on Affected Parties under the ISO-NE Tariff; (iii) if Seabrook's breaker is part of Seabrook's generating facility, what obligations, if any, Seabrook has under its LGIA with respect to replacement of the breaker and whether or not ISO New England Operating Documents and Applicable Reliability Standards impose an obligation to replace the breaker. If Seabrook's breaker is appropriately classified as a system protection facility, what obligations Seabrook has to replace the breaker. If the Seabrook LGIA obligates Seabrook to act, a description of the scope of Seabrook's obligation under the LGIA; (iv) whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker; and (v) If replacement of Seabrook's breaker is necessary for the interconnection of the NECEC Project, whether there exists any interim solution for the interconnection of the NECEC Project that would allow energization of the NECEC Project prior to the replacement of Seabrook's breaker.

- **NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter, and also still pending before the FERC, is a Petition for a Declaratory Order filed by NextEra Energy Seabrook, LLC ("Seabrook") a week earlier than the Avangrid Complaint that seeks clarity on the scope of Seabrook's "FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC" (the "Seabrook Petition"). Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on the Seabrook Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission (together, "Avangrid") protested the Seabrook Petition. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. NextEra moved to lodge both an August 29, 2021 filing containing an executed Engineering and Procurement Agreement ("E&P Agreement") between Seabrook and NECEC that was filed with the FERC on August 19, 2021 and the NRC Seabrook Report. Avangrid answered that motion, asserting that the NRC Seabrook Report was outside the scope of the proceeding and the motion to lodge should be denied. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[24] 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*).[25] However, the FERC's orders were challenged, and in *Emera Maine,*[26] 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

[24] 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*")).

[25] *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*").

[26] *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).

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)[27] and third (EL14-86)[28] 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.[29] 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[30] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[31] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[32] 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.[33] 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*[34] (EL14-12; EL15-45) in

---

[27] 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%.

[28] 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.

[29] *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*").

[30] 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.

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

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

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

[34] *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

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[35]

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

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[37] 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.

---

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*.

[35] *Id.* at P 19.

[36] *Id.* at P 59.

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

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*[38] 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

- **FCA17 Qualification Informational Filing (ER23-690)**

On December 21, 2022, ISO-NE submitted its informational filing for qualification in FCA17 (the "FCA17 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. FCA17 is scheduled to begin March 6, 2023. The Informational Filing contained ISO-NE's determinations that three Capacity Zones will be modelled for FCA17 -- 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 32,518 MW of existing capacity in FCA17 competing with 5,032 MW of new capacity under a Net ICR of 30,305 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 474 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 2 demand bids, totaling 7.8 MW, and 88 supply offers, totaling 515 MW, to participate in the substitution auction. Comments on the FCA17 Informational Filing are due on or before ***January 5, 2023***. Thus far, NEPOOL, Calpine, Constellation, National Grid, and NESCOE have filed doc-less interventions. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER23-534)**

On November 30, 2022, 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 2023-24 Capability Year, the second ARA for the 2024-25 Capability Year, and the first ARA for the 2025-26 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 2, 2022 meeting (Consent Agenda Items 1 and 2). A January 29, 2023 effective date was requested. Comments on this filing were due on or before December 21, 2022; none were filed. Calpine, Eversource, National Grid, and NESCOE filed doc-less motions to intervene. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ICR-Related Values and HQICCs – FCA17 (2026-27) Capacity Commitment Period (ER23-405)**

On December 20, 2022, the FERC accepted the ICR, LSR for SENE, 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").[39] As previously reported, the 2026-27 ICR will be

[38] *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).

[39] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER23-405-000 (Dec. 20, 2022) (unpublished letter order).

31,306 MW (reflecting tie benefits of 2,100 MW) and HQICCs of 1,001 MW/mo., the net amount of capacity to be purchased in FCA17 to meet the ICR will be 30,305 MW. The MCL for the Maine Capacity Zone is 4,065 MW. The MCL for the NNE Capacity Zone is 8,595 MW. (For FCA17, there are no import-constrained Capacity Zones). The FERC accepted the 2026-27 ICR-Related Values, effective as of January 7, 2023, as requested. Unless the December 20 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).

- **2023 NESCOE Budget (ER23-100)**

Also on December 20, 2022, the FERC accepted the Section IV.A Schedule 5 rate of $0.00701 per kilowatt ("kW") of Monthly Network Load (a $0.00035/kW decrease from 2022) for the funding of NESCOE's 2023 operations.[40] As previously reported, the 2023 Operating Expense Budget for NESCOE is $2,691,505 and the amount to be recovered reflects true-ups from 2022 (over-collections of $1,108,802). The rate became effective January 1, 2023, as requested. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2023 ISO-NE Administrative Costs and Capital Budgets (ER23-94)**

Also on December 20, 2022, the FERC accepted revisions to Section IV.A to recover ISO-NE's 2023 Budgets (for both administrative costs (the "2023 Revenue Requirement") and capital costs ("2023 Capital Budget", and together with the 2023 Revenue Requirement, the "2023 ISO Budgets").[41] As previously reported, the 2023 Revenue Requirement is $240.2 million (a $25.1 million or 11.7% increase over 2022), which decreases to $225.6 million after the over-collection for 2021 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2023 Core Operating Budget) comprise $209.2 million; depreciation and amortization of regulatory assets, $31 million; and a $14.6 million true-up decrease for 2021 over-collections. ISO-NE further reported that the 2023 Capital Budget is $33.5 million, a $1.5 million increase over 2022.[42] Unless the December 20 order in this proceeding is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **NESCOE 5-year (2023-2027) *Pro Forma* Budget (ER22-2812)**

On December 19, 2022, the FERC accepted NESCOE's fourth 5-year *pro forma* budget covering years 2023 - 2027 (the "5-year *Pro Forma* Budget").[43] Unless the December 19 5-year *Pro Forma* Budget order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[44] (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 ("COS Agreement") to reflect Mystic's current upstream ownership.[45] 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,

---

[40] *ISO New England Inc. and New England States Comm. on Electricity*, Docket No. ER23-100-000 (Dec. 20, 2022) (unpublished letter order) ("*2023 NESCOE Budget Order*").

[41] *ISO New England Inc.*, Docket No. ER23-94-000 (Dec 20, 2022) (unpublished letter order) ("*2023 ISO Budgets Order*").

[42] *See* Nov. 1 or Dec. 1, 2022 Reports for Capital Budget highlights.

[43] *New England States Comm. on Elec.*, Docket No. ER22-2812-000 (Dec. 19, 2022) (unpublished letter order).

[44] 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.

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

2022,[46] 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 the compliance filing is now 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 ("COSA") (ER18-1639)**

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[47] 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*.

(-019) Emergency Motion for Expedited Action. On November 22, 2022, as corrected on November 23, Mystic and Constellation filed an emergency motion requesting expedited action by ***January 9, 2023***, on the Cost Allocation and Clawback issues remanded to the FERC in the *Mystic I Remand Order*, asserting that expedited FERC action on remand is needed given the implications for sales of gas from the Everett facility during the term of the COSA and the future of the Everett facility post-COSA. That motion triggered a round of pleadings, most supporting expedited resolution (even if not agreeing with the underlying justification for emergency action presented by Mystic and Constellation); one pleading, by ENECOS, opposed the emergency action in its entirety, and requested post-remand briefing on the allocation of Everett Marine Terminal costs. Mystic and Constellation answered ENECOS' opposition on December 21, 2022. This round of pleadings is pending before the FERC. No remand order has yet been issued.

Other Mystic COSA-Related Matters Still Pending or With Activity Since the Last Report include:

(-000) First CapEx Info. Filing. On September 15, 2021, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6. of Schedule 3A of the COSA ("Protocols"), its informational filing to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between June 1, 2022 to December 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Mystic responded to the formal challenges on November 17, 2021 asserting that that the challenges should be rejected without further procedures. ENECOS and NESCOE replied to Mystic's November 17 reply on December 2 and December 6, 2021, respectively.

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[48] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1, 2022 and the formal challenge process begins on September 15, 202).[49] The FERC reiterated that all items except return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects

---

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

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

[48] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*").

[49] *Id.* at PP 23-24.

Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[50] Accordingly, the FERC set these matters 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 (-015) summarized just below.[51]

(-015) First CapEx Info. Filing Settlement Judge Procedures. On May 4, Chief Judge Cintron designated Judge Andrea McBarnette as the Settlement Judge. Thus far, three settlement conferences have been held, the first on June 15 and the second on November 17, 2022. A third settlement conference was held December 20, 2022. A fourth settlement conference is scheduled for ***January 18, 2023***. In her last status report, submitted on January 3, 2023, Settlement Judge McBarnette recommended the continuation of settlement judge procedures.

(-018) Second CapEx Info Filing. On September 15, 2022, 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 "Second CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects"). Formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS. Comments on NESCOE's and ENECOS' challenges were due on or before November 16, 2022 and November 17, 2022, respectively. Mystic responded separately to NESCOE's and ENECOS' challenges. MMWEC/NHEC filed comments supporting ENECOS' formal challenge, emphasizing its support for formal challenge to the pass through of charges incurred by Everett for pipeline transportation reservations (*see* ENECOS Mystic COSA Complaint (EL23-4) above). Since the last Report, on December 6, 2022, ENECOS answered Mystic's November 17, 2022 answer. On December 22, 2022, Mystic filed a response to ENECOS' December 6 answer, and requested that the FERC reject the Formal Challenges, and accept the Second Filing as expeditiously as possible. The Second CapEx Info Filing, including the formal challenges, and the responses/comments thereon, are pending before the FERC.

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

(-020) Fuel Supply Agreement Revision Info Filing. On December 9, 2022, Mystic submitted a revision to its Fuel Supply Agreement ("FSA") that memorializes Constellation LNG's pre-existing business practice of crediting Mystic under the FSA to account for firm gas transportation ("FT") charges that Constellation LNG collects from forward third-party sales of gas. This crediting mechanism, along with the other credits already included in the FSA, Mystic explained, ensures that Mystic (and thus ISO New England) only bears the cost responsibility for the pipeline transportation costs that are not offset by third-party sales of gas. Mystic stated the credit to the FSA reduces Mystic's cost-of-service. This informational filing was not noticed for public comment.

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 (2022-23) Update/Informational Filing (ER09-1532; RT04-2)**

On July 29, 2022, the PTO AC submitted its 2023 annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting

50 *Id.* at P 26.

51 *Id.* at P 27.

actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. As prescribed in the Interim Protocols,[52] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing 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 $1.75 kW-year (effective June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022. This filing was not noticed for public comment.

The July 29 filing was reviewed with the Transmission Committee at its August 16, 2022 summer meeting and at an August 22, 2022 technical session for Interested Parties. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties have until September 15, 2022 to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 days, but by no later than October 15, 2022. During the Review Period, Interested Parties have until November 15, 2022 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, 2022. Interested Parties have until ***January 31, 2023*** to file a Formal Challenge with the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

On December 29, 2022, ISO-NE, NEPOOL and the PTO AC filed revisions to the Tariff and the TOA, in two parts, to enable electric storage facilities to be planned and operated as transmission-only assets ("SATOA") to address system needs identified in the OATT's regional system planning process ("SATOA Revisions"). The SATOA Revisions were supported by the Participants Committee at its October 6, 2022 meeting (Agenda Item #7). ISO-NE requested a FERC order by March 29, 2023 and indicated that it intends to implement the SATOA Revisions effective July 1, 2024. ISO-NE committed to submit a filing specifying the precise effective date prior to implementation. For eTariff reasons, Part I included the ISO-NE Tariff revisions (ER23-739); Part II, the TOA revisions (ER23-743). Comments on the SATOA Revisions are due on or before ***January 19, 2023***. Thus far, Eversource, NESCOE and the MA PUD have intervened. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Solar DNE Dispatch Changes (ER23-517)**

On November 30, 2022, ISO-NE and NEPOOL filed revisions to the Do Not Exceed ("DNE") dispatch rules in Market Rule 1 to allow front-of-meter solar resources to become Dispatchable Resources ("Solar DNE Dispatch Changes"). The Solar DNE Dispatch Changes were supported by the Participants Committee at its September 1, 2022 meeting (Consent Agenda Item #6). A December 5, 2023 effective date was requested. Comments on the Solar DNE Dispatch Changes were due on or before December 21, 2022; none were filed. Eversource, National Grid and NESCOE filed doc-less interventions. 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).

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

- **Waiver Request: Attachment F (NEP) (ER23-370)**
  On December 22, 2022, the FERC granted New England Power's request for a limited waiver of certain provisions in the Attachment F formula rate template to ensure that, as of the date RI Energy becomes a PTO (January 1, 2023), NEP's transmission revenue requirements collected through regional and local rates will not include a forecast based on historical NEP revenue requirements that included costs of RI Energy-owned transmission facilities.[53] Unless the *Attachment F RIE Waiver 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).

- **FCA18 Schedule Modifications (ER23-50)**
  On December 1, 2022, the FERC accepted Tariff changes that modify the schedule for FCA18 ("FCA18 Schedule Modifications").[54] As previously reported, the FCA18 Schedule Modifications compress the schedule for FCA18 in order that FCA18 can be conducted as originally scheduled (on February 5, 2024) notwithstanding delays in FA16 and FCA17 that otherwise would have caused the FCA18 auction date to slip. The FCA18 Schedule Modifications were accepted effective as of December 19, 2022. The December 1 order was not challenged and is final and unappealable. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **New England's *Order 2222* Compliance Filing (ER22-983)**
  New England's *Order 2222* Compliance Filing remains pending before the FERC. As previously reported, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted on February 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.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before April 1, 2022. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEU/PowerOptions/SEIA; Environmental Organizations;[55] MA AG; Voltus; AEMA and 4 New England US Senators.[56] Doc-less interventions were filed by: Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE (April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. Since the last Report, AEU/PowerOptions/SEIA and AEMA answered the ISO-NE and National Grid/Avangrid/ Eversource answers.

(-001) Deficiency Letter. On May 18, 2022, the FERC issued a 25-page deficiency letter directing ISO-NE to provide, on or before June 17, 2022, additional information and clarifications. ISO-NE filed its 39-page response to the deficiency letter on June 17, 2022. Comments in response to ISO-NE's deficiency letter response were due on or before July 8, 2022 and a joint protest was filed by AEU, AEMA, PowerOptions, and SEIA ("Joint Protest"). The

---

53 *New England Power Co.*, 181 FERC ¶ 61,253 (Dec. 22, 2022) ("*Attachment F RIE Waiver Order*").

54 *ISO New England Inc.*, Docket No. ER23-50-000 (Dec. 1, 2022) (unpublished letter order).

55 Environmental Organizations are Acadia Center, Conservation Law Foundation ("CLF"), Environmental Defense Fund ("EDF"), Massachusetts Climate Action Network, NRDC, Sierra Club, and the Sustainable FERC Project.

56 Senators Markey (MA), Sanders (VT), Warren (MA), and Whitehouse (RI).

Joint Protest, while supportive of certain responses (those regarding the exemption of DERAs from the Small Generator Interconnection Procedures ("SGIP") prior to 2026, locational requirements for DER aggregation, and the role of host utilities in identifying potential conflicts with retail program participation), protested the adequacy of ISO-NE responses regarding proposed metering and telemetering requirements for behind-the-meter ("BTM") DERs. On July 25, 2022, ISO-NE answered the July 8 Joint Protest. On August 9, 2022, AEU, AEMA, PowerOptions, and SEIA answered ISO-NE's July 25 answer.

This matter remains pending before the FERC. 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).

- **IEP Remand (ER19-1428-006)**

On November 22, 2022, ISO-NE filed Tariff provisions governing the Inventoried Energy Program ("IEP") consistent with the D.C. Circuit's *IEP Decision*.[57] ISO-NE's proposed Tariff changes remove nuclear, biomass, coal, and hydroelectric generators from the IEP. ISO-NE's Tariff changes were supported by the Participants Committee at its November 2 meeting (as were alternative Tariff changes proposed by Brookfield that explicitly allow pumped hydro resources to participate in the IEP as Electric Storage Facilities). Comments were due on or before December 13, 2022.

Comments and limited protests were filed by: NEPOOL, Brookfield, MA AG, National Hydropower Association, and RENEW; doc-less interventions only, by Calpine, FirstLight and National Grid. On December 28, 2022, New England Consumer-Owned Systems[58] and Energy New England ("ENE") responded to those protests and comments (urging the FERC to accept ISO-NE's compliance filing without modification). ISO-NE did not respond. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Attachment F, Appendix D-NSTAR: Updates to Depreciation Rates (ER23-637)**

On December 15, 2022, NSTAR proposed revisions to the general plant depreciation rates for NSTAR (East) and NSTAR (West). The depreciation changes included in this filing provide for the same depreciation rates that were approved November 30, 2022 by the Massachusetts Department of Public Utilities ("MA DPU"). NSTAR requested an effective date of January 1, 2023 (the same effective date approved by the MA DPU for the implementation of these depreciation rates for NSTAR's distribution rates. Comments on this filing are due on or before ***January 5, 2023***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[57] *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022) (the "*IEP Decision*"). The *IEP Decision* leaves intact the FERC's *June 2020 IEP Remand Order* (*ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020)) except for the inclusion of nuclear, biomass, coal, and hydroelectric generators in ISO-NE's IEP, the inclusion of which the Court found arbitrary and capricious (because those resources were unlikely to change their behavior in response to the IEP payments). Because the Court believed "there is not substantial doubt that FERC would have adopted IEP if it had not included these resources in the first place [and] IEP can function sensibly without them", the Court found that it had the authority to sever this portion from the overall program and therefore vacated that portion of IEP from the remainder of the IEP. The Court upheld the remainder of the IEP and remanded the matter to the FERC for further proceedings consistent with its opinion.

[58] New England Consumer-Owned Systems ("NECOS") are Belmont, Block Island Utility District, Braintree, Georgetown, Groveland, Hingham, Littleton (MA), Merrimac, Middleborough, Middleton, Norwood, Pascoag, Reading, Rowley, Stowe, Taunton, Wellesley, and Westfield.

- **Attachment F Revisions Reflecting RIE Addition as PTO (ER23-299)**

On December 6, 2022, the FERC accepted revisions to Attachment F of the OATT filed by The Narragansett Electric Company d/b/a Rhode Island Energy ("RI Energy") to reflect RI Energy's addition as an independent Participating Transmission Owner ("PTO").[59] The revisions were accepted effective as of January 1, 2023, as requested. Unless the December 6, 2022 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).

- **Attachment F Depreciation Normalization Requirement Revisions (ER23-197)**

On December 13, 2022, the FERC accepted revisions to Attachment F of the OATT, filed by certain Transmission Owners,[60] that apply the IRS's ADIT proration formula to the TOs' actual (true-up) revenue requirements (thereby maintaining compliance with the IRS's depreciation normalization requirements and ensuring the TOs' continued ability to use accelerated depreciation).[61] The changes were accepted effective as of January 1, 2023, as requested. Unless the December 13 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).

- **Attachment F, Appendix D-PSNH: Establishment of Depreciation Rate for Accounts 357 and 358 (ER22-2953)**

Also on December 13, 2022, the FERC accepted changes to Attachment F, Appendix D-PSNH that establish the transmission plant depreciation rates for Account 357 (Underground Conduit) and Account 358 (Underground Conductors and Devices).[62] Those accounts will be used to calculate PSNH's annual transmission revenue requirements for transmission service under the ISO-NE OATT. The changes were accepted effective as of January 1, 2023, as requested. Unless the December 13 order in this proceeding 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).

- ***Phase I/II HVDC-TF Order 881* Compliance Filing: HVDC TOA (ER22-2467) and Sched. 20-A Common Attachment M (ER22-2468)**

On July 22, 2022, following a requested 10-day extension of time granted by the FERC, a Phase I/II HVDC-TF *Order 881* compliance filing was submitted in two parts ((i) changes to the HVDC TOA and (ii) changes to Schedule 20-Common Attachment M) by: ISO-NE, the Asset Owners,[63] and the Schedule 20A Service Providers.[64] Specifically, the Filing proposed changes to the ***HVDC TOA*** (ER22-2467) to address the Order 881 requirements related to transmission ratings and rating procedures and to ***Schedule 20A-Common*** (ER22-2468) to ensure compliance with Order 881 with respect to transmission rating transparency and transmission service (together, the "Phase I/II HVDC-TF *Order 881* Compliance Filing"). Comments on the Phase I/II HVDC-TF *Order 881* Compliance Filing were due on or before August 12, 2022; none were filed. The IRH

---

[59] *ISO New England Inc.*, Docket No. ER23-299-000 (Dec. 6, 2022) (unpublished letter order).

[60] The TO filers are as follows: Central Maine Power Co. ("CMP"); Eversource Energy Service Co. ("Eversource") on behalf of The Conn. Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), NSTAR Elec. Co. ("NSTAR"); Fitchburg Gas and Elec. Light Co.; Green Mountain Power Corp.; Maine Elec. Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission, LLC; The United Illuminating Co.; Vermont Transco, LLC; and Versant Power.

[61] *ISO New England Inc.*, Docket No. ER23-197-000 (Dec. 13, 2022) (unpublished letter order).

[62] *ISO New England Inc. and Pub. Srvc. Co. of NH*, Docket No. ER22-2953-001 (Dec. 13, 2022) (unpublished letter order).

[63] The "Asset Owners" are, collectively, New England Hydro-Transmission Electric Company, New England Hydro-Transmission Corporation, New England Electric Transmission Corporation, and Vermont Electric Transmission Company ("VETCO").

[64] The "Schedule 20A Service Providers" are: Central Maine Power Co. ("CMP"); The Conn. Light and Power Co. and Public Service Co. of NH ("Eversource"); Green Mountain Power Cor. ("GMP"); New England Power Co. ("NEP"); NSTAR Electric Co.; The United Illuminating Co. ("UI"); Vermont Electric Cooperative, Inc. ("VEC"); and Versant Power.

Management Committee submitted a doc-less intervention. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, ISO-NE, NEPOOL, the PTO AC, and CSC (the "Filing Parties") filed, on July 12, 2022, proposed revisions to the OATT in response to the requirements of *Order 881*[65] ("*Order 881* Compliance Changes"). Specifically, the Filing Parties proposed the addition of a new Attachment Q to the OATT, and to revise OATT Schedules 18 (MTF; MTF Service) and 21 (Local Service - Common). The *Order 881* Compliance Changes (the Attachment Q and Schedule 18 changes) were supported by the Participants Committee at its June 21-23 Summer Meeting (Consent Agenda Item No. 2). An effective date of September 10, 2022 was requested, with changes to Attachment Q and Schedule 21 to become applicable by their own terms in July 2025. Comments on the *Order 881* Compliance Changes were due on or before August 2, 2022; none were filed. Eversource, Narragansett Electric Company ("Narragansett") and National Grid filed doc-less interventions. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (CSC-Schedule 18-Attachment Z) (ER22-1168)**

On March 2, 2022, in response to the requirements of *Order 676-J*,[66] ISO-NE and CSC filed revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards ("Schedule 18 Order 676-J Part I Changes").[67] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by CSC and NEPOOL. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (TOs-Schedule 20/21-Common) (ER22-1161)**

Also on March 2, 2022, in response to the requirements of *Order 676-J*, the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 20/21-Common Order 676-J Part I Changes").[67] An effective date as of the date the FERC may determine was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by NEPOOL and Eversource. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1150)**

Again on March 2, 2022, in response to the requirements of *Order 676-J*, ISO-NE filed revisions to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards) to incorporate the new cybersecurity

[65] *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*").

[66] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*"). *Order 676-J* revised FERC regulations to incorporate by reference the latest version (Version 003.3) of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC") calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC.

[67] Compliance filings for the rest of the WEQ Version 003.3 Standards (Schedule 24 Order 676-J Part II Changes) were due 12 months after implementation of the WEQ Version 003.2 Standards, or no earlier than Oct. 27, 2022.

and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 24 Order 676-J Part I Changes").[67] An effective date no earlier than June 2, 2022 was requested. The Transmission Committee recommended that the Participants Committee support the Schedule 24 Order 676-J Part I Changes at its March 23 meeting, and the Participants Committee supported the changes at the April 7 meeting (Consent Agenda Item # 1). Comments on this filing were due on or before March 23, 2022; none were filed. NEPOOL, Eversource, MA DPU, and National Grid submitted doc-less interventions. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **IEP Changes to Financial Assurance and Billing Policies; Ministerial Change to Monthly Statements Issuance Date (ER23-705)**

On December 22, 2022, ISO-NE and NEPOOL jointly filed IEP-related changes to the Tariff and a definition change revising "Monthly Issuance" in Section I's omnibus definition section (The "FAP/BP Changes"). Specifically, revisions to the FAP are designed to ensure adequate collateral is provided by Market Participants participating in the IEP; revisions to the Billing Policy ("BP") reflect charges and credits related to the IEP; and the definition of "Monthly Issuances" in Section I.2.2 are designed to ensure consistency with the Billing Policy. The FAP/BP Changes were supported by the Participants Committee at its November 2, 2022 meeting (Agenda Item #5). ISO-NE requested a February 23, 2023 effective date for the FAP/BP Changes. Comments on the FAP/BP Changes are due on or before ***January 12, 2023***. Thus far, Calpine, Constellation and National Grid have submitted doc-less interventions. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

- **Schedule 21-RIE: Transfer of SAs from Sched 21-NEP; Updated Thundermist ISA (ER23-678; ER23-681)**

On December 20, 2022, Rhode Island Energy submitted a filing (i) to move certain RIE service agreements ("SAs") to Schedule 21-RIE from Schedule 21-NEP (Docket No. ER23-678) and (ii) to revise RIE's Interconnection Service Agreement ("ISA") with Thundermist Hydropower LLC ("Thundermist"). In a companion filing (Docket No. ER23-681), RIE and NEP submitted a filing to cancel the NEP Tariff database that previously contained the SAs. RIE expects the SA transfers to become effective as of January 1, 2023. Comments on these filings, if any, are due on or before ***January 10, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: Removal of References to Narragansett; Update Ref. to National Grid LCC (ER23-165)**

On December 6, 2022, the FERC accepted revisions to Schedule 21-NEP.[68] The revisions remove references in Schedule 21-NEP to The Narragansett Electric Company ("Narragansett") as an affiliate of the New England Power Company ("NEP") and any Narragansett-specific rate provisions. Minor revisions to Schedule 21-NEP to update references in the local service schedule to the National Grid Local Control Center ("LCC") (f/k/a REMVEC) were also accepted. The Revisions were accepted January 1, 2023, as requested. Unless the December 6, 2022 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-RIE (ER23-16)**

On December 28, 2022, the FERC accepted revisions to Schedule 21 and Attachment E of Section II of the OATT (the "Schedule 21-RIE/Attachment E Revisions") filed by The Narragansett Electric Company d/b/a Rhode

[68] *ISO New England Inc.*, Docket No. ER23-165-000 (Dec. 6, 2022) (unpublished letter order).

Island Energy ("RI Energy"), as amended on December 12, 2022,[69] to establish RI Energy's rates, terms, and conditions for the provision of Local Service and to accommodate RIE as a new Participating Transmission Owner ("PTO").[70] Unless the *REI Schedule 21-RIE Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: 2021 Annual Update Settlement Agreement (ER20-2119-001)**

On March 25, 2022, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2021 annual charges update filed, as previously reported, on June 15, 2021, and as amended on June 20, 2021 and July 8, 2021 (the "Versant 2021 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2021 Annual Update, all of which are resolved by the Versant 2021 Annual Update Settlement Agreement. Comments on the Versant 2021 Annual Update Settlement Agreement were due on or before April 14, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 2020 Annual Update Settlement Agreement (ER15-1434-005)**

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 10, 2021; reply comments, December 19, 2021; none were filed. There was no activity since the last Report and 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

- **Participants Agreement Amendment No. 12 (ISO Board Member Age Limit Increase)**

Following a second balloting period, the Minimum Response Requirement for PA Amendment No. 12 was satisfied and the Participants Committee approved Amendment No. 12 to the Participants Agreement, which would raise the age limitation prohibiting the election or re-election of any candidate to the ISO Board of Directors from 70 to 75. The proposed PA change will be filed later this month. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

---

[69] On Dec. 12, 2022, RI Energy filed, in response to a Dec. 9, 2022 deficiency letter, further amendments to its proposed Schedule 21-RIE to (i) comply with the requirements of *Order 864* by adopting the proposed changes to Schedule 21-NEP that the FERC approved in Docket No. ER20-2551-000 and (ii) to include the ADIT worksheets approved by the FERC for New England Power with slight modifications for RI Energy's name, specific circumstances, and accounting practices, including changing references to "fiscal year" to "calendar year."

[70] *ISO New England, Inc.*, 181 FERC ¶ 61,260 (Dec. 28, 2022) ("*RIE Schedule 21-RIE Order*").

VIII. Regional Reports

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

Fitchburg Gas & Electric's ("FG&E") June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Regional Refund Reports (EL11-66)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[71] *and 531-B*[72] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Capital Projects Report - 2022 Q3 (ER23-114)**

On December 20, 2022, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2022 (the "Report").[73] As previously reported, Report highlights included the following new projects: (i) FCM *Order 2222* ($1.15 million); and (ii) IT Asset Workflow Integration and Updates ($1.06 million). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) 2022 Issue Resolution ($120,000); (ii) Privileged Account Management Security Enhancements ($105,900); and (iii) Packet Broker Infrastructure Replacement Project ($105,500). The Report was accepted effective as of October 1, 2022, as requested. Unless the December 20 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).

IX. Membership Filings

- **January 2023 Membership Filing (ER23-756)**

On December 30, 2022, NEPOOL requested that the FERC accept (i) the memberships of Just Energy Limited [Related Person to Just Energy (U.S.) Corp. and Hudson Energy Services, LLC (Supplier Sector); and Think Energy, LLC (Supplier Sector); (ii) the termination of the Participant status of Josco Energy MA (Supplier Sector), Starion Energy (Supplier Sector), and Rhode Island Bioenergy Facility [Related Person to Rhode Island Bioenergy, LLC (AR Sector, RG Sub-Sector, Small RG Group Seat)]; and (iii) the name changes of BP Energy Retail Company LLC (f/k/a EDF Energy Services, LLC), BP Energy Holding Company LLC (f/k/a BP Energy Retail LLC), and Rhode Island Bioenergy Facility, LLC (f/k/a formerly known as Rhode Island Bioenergy, LLC). Comments on the January membership filing are due on or before ***January 21, 2023***.

---

[71] *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[72] *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

[73] *ISO New England Inc.*, Docket No. ER23-114-000 (Dec. 20, 2022) (unpublished letter order).

- **December 2022 Membership Filing (ER23-518)**

On November 30, 2022, NEPOOL requested that the FERC accept the membership of 11772244 Canada Inc. (Supplier Sector), effective as of December 1, 2022. Comments on the December membership filing were due on or before December 21, 2022; none were filed. This matter is pending before the FERC.

- **November 2022 Membership Filing II (ER23-402)**

On December 15, 2022, the FERC accepted the membership of Windham Energy Center (Provisional Member), effective as of November 10, 2022.[74] Unless the December 15 order is challenged, this proceeding will be concluded.

- **November 2022 Membership Filing I (ER23-310)**

On December 13, 2022, the FERC accepted (i) the memberships of: Derby Fuel Cell, LLC [Related Person to Fuel Cell Energy Companies, DFC ERG CT and Bridgeport Fuel Cell (AR Sector, RG Sub-Sector)]; KCE CT 5, KCE CT 7, KCE CT8, and KCE CT 9 [Related Persons to KCE CT 1 and 2 (Provisional Group Member); Maven Energy, LLC (Supplier Sector); Rhode Island Bioenergy, LLC (since renamed to Rhode Island Bioenergy Facility, LLC (see ER23-756 above)); Rhode Island Division of Public Utilities Carriers (End User Sector); Sunnova Energy Corporation (AR Sector, DG Sub-Sector); and Triolith Energy Fund, LP (Supplier Sector); (ii) the termination of the Participant status of EIP Investment, LLC (Provisional Group Member); and (iii) the name change of Stones DR, LLC (f/k/a Centrica Business Solutions Optimize, LLC).[75] Unless the December 13 order is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Market Participant was suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Financial Assurance Default:

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
Dec 6/2	Manchester Methane, LLC	Financial Assurance	--

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

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).

- **Revised Reliability Standards: EOP-011-3 and EOP-012-1 (RD23-1)**

NERC's October 28, 2022 request for approval of proposed changes to Reliability Standards EOP-011-3 (Emergency Operations) and EOP-012-1 (Extreme Cold Weather Preparedness and Operations) (the "*Cold Weather Standards*") is pending before the FERC. As previously reported, the changes to the *Cold Weather Standards*, which address certain key recommendations from the *Feb 2021 Cold Weather Outages Joint Report,*[76] establish a more comprehensive framework of requirements addressing generator preparedness for cold

[74] *New England Power Pool Participants Comm.*, Docket No. ER23-402-000 (Dec. 15, 2022) (unpublished letter order).

[75] *New England Power Pool Participants Comm.*, Docket No. ER23-310-000 (Dec. 13, 2022) (unpublished letter order).

[76] FERC, NERC, Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texasand-south-central-united-states-ferc-nerc-and ("*Feb 2021 Cold Weather Outages Joint Report*").

weather operations. The *Cold Weather Standards* also address the use of manual load shed during Emergency conditions, requiring Transmission Operators to take steps to minimize the use of manual load shed that could further exacerbate Emergency conditions and threaten system reliability. NERC requested that these *Cold Weather Standards* become effective on the first day of the first calendar quarter that is 18 months after FERC approval ("Effective Date"). Generator Owners would have an additional 42 months from the Effective Date to come into compliance with new freeze protection measures and 60 months from the Effective Date to perform their first five-year update of the Extreme Cold Weather Temperature. Comments on the *Cold Weather Standards* were due, following a request for an extension of time filed by EPSA and partially granted by the FERC on November 29, 2022, on or before December 8, 2022.

Comments on the *Cold Weather Standards* were filed by: EPSA, NEPGA, Invenergy, the IRC, Transmission Access Policy Study Group ("TAPS"), and the Texas Competitive Power Advocates. Reply comments were filed by: NERC, Competitive Generators,[77] Invenergy, and APPA. On January 3, 2023, the IRC answered the reply comments filed by NERC and Competitive Generators, requesting that the FERC, particularly if it assigns the issues raised by the IRC to additional work in Phase II of the stakeholder process, find the issues raised by the IRC have merit and direct they be resolved through changes to the proposed standard within one year. This matter is pending before the FERC.

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

On November 17, 2022, to address FERC concerns regarding the reliability impacts of inverter-based resources ("IBRs")[78] on the Bulk-Power System ("BPS"), the FERC issued an order[79] directing NERC to submit a work plan on or before ***February 15, 2023*** describing how it plans to identify and register owners and operators of IBRs that are connected to the BPS, but that are not currently required to register with NERC under the bulk electric system ("BES") definition ("unregistered IBRs"), and that "have an aggregate, material impact on the reliable operation of the [BPS]". FERC stated that the work plan should explain how NERC will modify its processes to address unregistered IBRs within 12 months of approval of the work plan. The work plan must also include implementation milestones ensuring that owners and operators meeting the new registration criteria are identified within 24 months of the approval date of the work plan, and that they are registered and required to comply with applicable Reliability Standards within 36 months of the approval date of the work plan. The FERC will notice the work plan for public comment. Once approved, NERC must file progress reports every 90 days thereafter detailing the progress towards identifying and registering owners and operators of unregistered IBRs.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[80] on December 15, 2022. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the December 15 report, NERC reported that, because ballot body approval was not achieved for two related Reliability Standards, the schedule for Project 2016-02 has been revised

[77] Competitive Generators are: the New England Power Generators Association, Inc. ("NEPGA"), the Electric Power Supply Association ("EPSA") and the PJM Power Providers Group ("P3").

[78] IBRs include all generating facilities that connect to the BPS using power electronic devices that change direct current ("DC") power produced by a resource to alternating current ("AC") power compatible with distribution and transmission systems. IBRs connected to the distribution system are not addressed in the *IBR Registration Order*.

[79] *Registration of Inverter-based Resources*, 181 FERC 61,124 (Nov. 17, 2022) ("*IBR Registration Order*").

[80] 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.

and now calls for final balloting of revised standards in March 2023, NERC Board of Trustees Adoption in May 2023 and filing of the revised standards with the FERC in June 2023.

- **2023 NERC/NPCC Business Plans and Budgets (RR22-4)**

As previously reported, the FERC accepted, subject to a 60-day compliance filing, NERC's proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2023.[81] In accepting NERC's Business Plan/Budget Filing, the FERC agreed with EEI that additional transparency into certain Electricity Information Sharing and Analysis Center ("E-ISAC") costs would better allow the FERC to fulfill its oversight duties, and thus directed NERC to submit a compliance filing providing additional information related to E-ISAC costs, the E-ISAC vendor affiliate program, and the E-ISAC and natural gas stakeholder partnership. That compliance filing was due, and was filed, on January 3, 2023. Comments on the January 3 compliance filing are due on or before ***January 24, 2023***.

- **NPCC Bylaws Changes (RR22-2)**

As previously reported, the FERC conditionally approved, on July 8, 2022, changes to the NPCC Bylaws (the "Bylaws") designed to, among other things: (1) to improve corporate governance; (2) to ensure consistency with the Not-for-Profit Corporation Law of the State of New York ("N-PCL"), pursuant to which NPCC is organized; and (3) to remove extraneous provisions rom the Bylaws, create efficiencies, and reflect changes at NPCC since 2012 (when the last changes to the Bylaws were filed).[82] In accepting the Bylaws Changes, the FERC directed NERC/NPCC to submit in a compliance filing changes that (i) provide members being terminated for failure to comply with bylaw provisions related to qualifications, obligations, and conditions of membership (a) notice within a reasonable time period of the NPCC Board's membership termination decision and the reason(s) for the action and (b) the option to appeal the membership termination in accordance with the due process requirement in FPA Section 215; and (ii) specifically describe the method of providing public notice of member meetings. On October 5, 2022, NERC and NPCC submitted that compliance filing, with revisions to the Bylaws to (i) require that prior to terminating any NPCC Member under section 4.6, the NPCC Board must provide the affected Member 21 days prior written notice and an opportunity to cure the problem or appeal the reason for the proposed termination; (ii) to specify that the meeting notices shall be posted on NPCC's public website in a "reasonably prominent location; and (iii) to update the NPCC Bylaws' Table of Contents. Comments on the compliance filing were due on or before October 26, 2022; none were filed. The compliance filing remains pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Talen Energy Supply Reorganization (EC23-42)**

On December 15, 2022, Talen Energy Supply, LLC ("TES") requested the required FPA Section 203 approvals for a change in control transaction whereby 10% or more of the voting securities of a new parent of TES and its affiliated debtors ("Reorganized Talen") will be distributed to some or all of Indicated Noteholders pursuant to a joint plan of reorganization of the TES Debtors subject to confirmation by the Bankruptcy Court. Comments on the 203 application are due on or before ***January 30, 2023***. Thus far, the PJM IMM and Public Citizen have intervened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Cogentrix / EGCO (Rhode Island State Energy Center) (EC23-41)**

On December 14, 2022, Rhode Island State Energy Center, LP ("RISEC") and EGCO RISEC II, LLC ("Buyer") requested FERC authorization for a proposed transaction pursuant to which Buyer, a wholly owned indirect subsidiary of Electricity Generating Public Company Limited ("EGCO"), will acquire a 49% indirect ownership

[81] *N. Am. Elec. Rel. Corp.*, 181 FERC ¶ 61,095 (Nov. 2, 2022) ("*2023 Budgets Order*").

[82] *N. Am. Elec. Rel. Corp.*, 180 FERC ¶ 61,016 (July 8, 2022).

interest in RISEC from Cogentrix Sellers.[83] Following the transaction, RISEC will be indirectly owned by Buyer (49%) and the Cogentrix Sellers (51%). Comments on this 203 application are due on or before ***January 30, 2023***. Thus far, Public Citizen has intervened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Agilitas Companies / AB CarVal Funds (EC23-30)**

On November 21, 2022, Agilitas Companies[84] requested authorization for a transaction pursuant to which the AB CarVal Funds[85] will convert their existing passive, non-voting ownership interest in Agilitas Energy, Inc., which indirectly owns all of the membership interests in the Agilitas Companies, into 21.3% of the voting interests in Agilitas Energy. Comments on the 203 application were due on or before December 12, 2022; 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).

- **203 Application: Central Rivers Power / LSPower (EC23-22)**

On December 30, 2022, the FERC authorized[86] a transaction pursuant to which Patriot Hydro, LLC, an indirect, wholly controlled subsidiary of LS Power Development, LLC and affiliate of LS Power (together, "LSPower") will acquire the New England QF assets of Central Rivers Power Super Holdings Holdco, LLC, an affiliate of Hull Street Energy Partners and Central Rivers Power (together, "Central Rivers Power"). Once consummated, NEPOOL Participants Central Rivers Power MA, LLC and Central Rivers Power NH, LLC will become Related Persons to AR Sector member Jericho Power. Pursuant to the December 30 order, notice must be filed 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: Seneca Energy II / BP (EC23-18)**

On December 22, 2022, the FERC authorized a transaction pursuant to which Seneca Energy II, LLC ("Seneca") will ultimately become a Related Person of BP Products North America Inc. ("BP").[87] Pursuant to the December 22 order, BP filed a December 30, 2022 notice that, on December 28, 2022, the authorized transaction closed. Reporting on this matter is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: ConEd / RWE (EC23-17)**

On October 28, 2022, RWE Renewables Americas, LLC ("RWE") and ConEd[88] requested authorization for a transaction pursuant to which RWE will acquire 100% of the equity interests in ConEd's Clean Energy Businesses (including NEPOOL members Consolidated Edison Energy, Inc.; Consolidated Edison Development, Inc.; and Consolidated Edison Solutions, Inc. (but not Consolidated Edison Company of New York)). Comments on the 203 application were due on or before November 28, 2022; none were filed. PJM and Public Citizen filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

---

[83] "Cogentrix Sellers" are RISEC CPP II Holdings, LLC and Cogentrix RISEC CPOCP Holdings, LLC.

[84] For purposes of this proceeding, "Agilitas Companies" are: Madison BTM LLC; Madison ESS, LLC; Rumford ESS, LLC; South Portland ESS, LLC; Sanford ESS, LLC; Ocean State BTM, LLC; and AE-ESS NWS 1, LLC. Madison BTM, Madison ESS, Rumford EES, and Ocean State BTM are each NEPOOL Participants. This transaction will not impact Agilitas' membership in the AR Sector.

[85] The "AB CarVal Funds" are CEF Master Fund IV LP, CVI CEF II Pooling Fund IV LP, and CVI CSF Master Fund II LP.

[86] *Central Rivers Power Super Holdings Holdco, LLC et al.*, 181 FERC ¶ 62,215 (Dec. 30, 2022).

[87] *Seneca Energy, II LLC*, 181 FERC ¶ 62,193 (Dec. 22, 2022).

[88] "ConEd" includes Consolidated Edison, Inc., its wholly-owned subsidiary Con Edison Clean Energy Businesses, Inc. ("CEB"), and CEB's public utility subsidiaries (together, members of the Supplier Sector). RWE's NEPOOL Related Person (Cassadaga Wind LLC) is a member of the Supplier Sector.

- **203 Application: Great River Hydro / HQI US (EC23-16)**
Also on October 28, 2022, Great River Hydro, LLC ("Great River Hydro") and HQI US Holding LLC ("HQUI US"), an indirect and wholly-owned subsidiary of Hydro-Québec ("HQ") requested authorization for a transaction pursuant to which HQI US will indirectly acquire 100% of the membership interests in Great River Hydro. Comments on this 203 application were due on or before December 12, 2022; 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).

- **203 Application: EDF Energy / BP Retail (EC22-122)**
On November 14, 2022, the FERC authorized a transaction pursuant to which BP Retail Energy LLC ("BP Retail") will acquire 100% of the membership interests in EDF Energy Services, LLC ("EDF Energy"),[89] making EDF Energy and BP Retail Related Persons. EDF Energy (now known as BP Energy Retail Company, *see* ER23-756 in Section IX above) filed a notice on December 5, 2022 that the transaction was consummated on November 30, 2022. Reporting on this matter is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Salem Harbor / Lenders (EC22-117)**
As previously reported, the FERC authorized on October 31, 2022[90] a transaction pursuant to which the direct and indirect equity interests in Salem Harbor that are currently directly and indirectly held by Salem Harbor Power FinCo, LP will be transferred to a newly formed Delaware limited liability company ("New HoldCo"), and (2) the equity interests of New HoldCo will be issued to Salem Harbor's lenders (the "Lenders") under a pre-petition credit facility. A notice that the transaction was consummated on December 16, 2022 was filed on December 19, 2022. Reporting on this matter is now concluded. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Waterside Power / KKR (EC22-79)**
As previously reported, the FERC authorized on August 19, 2022 the sale of 100% of the equity interests in Applicants, including Generation Group Seat Member Waterside Power, among others,[91] to Cretaceous Bidco Limited ("Buyer"), a special purpose vehicle indirectly owned by funds, investment vehicles and/or separately managed accounts advised and/or managed by one or more subsidiaries of KKR & Co. Inc. ("KKR & Co." and, together with its subsidiaries, ("KKR")).[92] A notice that the transaction was consummated on December 20, 2022 was filed on December 21, 2022. Reporting on this matter is now concluded. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Stonepeak / JERA Americas (EC22-71)**
On November 23, 2022, the FERC authorized[93] the sale by Stonepeak[94] of 100% of the interests in Canal Power Holdings LLC to a wholly-owned affiliate of JERA Americas Inc. ("JERA Americas").[95] On December 2, 2022, applicants filed a notice that the sale was consummated on December 1, 2022. As a result of the transaction,

---

[89] *BP Energy Retail et al.*, 181 FERC ¶ 62,102 (Nov. 14, 2022).

[90] *Salem Harbor Power Development LP*, 181 FERC ¶ 62,084 (Oct. 31, 2022).

[91] In addition to Waterside Power, "Applicants" are: Lea Power Partners, LLC; Badger Creek Limited; Chalk Cliff Limited; Double C Generation Limited Partnership; High Sierra Limited; Kern Front Limited; McKittrick Limited; Bear Mountain Limited; Live Oak Limited; and WGP Redwood Holdings, LLC.

[92] *Lea Power Partners, LLC*, 180 FERC ¶ 62,086 (Aug. 19, 2022) ("*August 19 Order*").

[93] *Canal Generating LLC et al.,* 181 FERC ¶ 61,157 (Nov. 23, 2022).

[94] "Stonepeak" includes Canal Power Holdings LLC ("Seller"), and its indirect wholly-owned, public utility subsidiaries, Canal Generating LLC ("Canal Generating"), Canal 3 Generating LLC ("Canal 3"), Bucksport Generation LLC ("Bucksport"), and Stonepeak Kestrel Energy Marketing LLC ("Stonepeak Marketing").

[95] JERA Americas Related Persons in NEPOOL include Cricket Valley Energy Center, LLC.

Stonepeake Kestrel Energy Marketing and Cricket Valley Energy Center became Related Persons to Generation Sector voting member Marco DM Holdings. Reporting on this matter is now concluded. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **EMM Contract (ER23-682)**

In a new matter since the last Report, ISO-NE filed on December 15, 2022, pursuant to Section 9.4.5 of the Participants Agreement, a copy of its new 3-year contract with Potomac Economics, Ltd. to continue as its External Market Monitor ("EMM"). In its filing, ISO-NE notes that the new agreement is closely modeled on the existing agreement between Potomac and ISO-NE, including all of the functions laid out for the EMM in Section 9.4.3 of the Participants Agreement. The new EMM contract term will run from January 1, 2023 through December 31, 2025. Comments on the filing are due ***January 5, 2023***. NEPOOL, National Grid, NESCOE, and Public Citizen have thus far filed doc-less interventions. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LGIA-ISO-NE/NSTAR/Vineyard Wind 1 (ER23-488)**

On November 23, 2022, ISO-NE and NSTAR filed a First Revised LGIA with Vineyard Wind 1, LLC to reflect the assignment of the LGIA by Vineyard Wind, LLC to Vineyard Wind I, LLC. A November 4, 2022 effective date was requested. Comments on this filing were due on or before December 14, 2022; 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).

- **Cost Reimbursement Agreement: NEP/Holden (ER23-396)**

On November 9, 2022, New England Power filed a Cost Reimbursement Agreement with Holden Municipal Light Department ("Holden") pursuant to which NEP will perform work to support Holden's plan to rebuild its Chaffins Substation. An October 10, 2022 effective date was requested. Comments on this filing were due on or before November 30, 2022; 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).

- **NEP Tariff No. 1 Revisions (ER23-348)**

On December 6, 2023, the FERC accepted revisions to NEP's Tariff No. 1 that (i) remove certain language in light of PPL's acquisition of The Narragansett Electric Company d/b/a Rhode Island Energy ("RI Energy"), reflect the transition in operational control of RI Energy's transmission facilities, and an associated change in the mechanism through which RI Energy recovers its transmission revenue requirements; and (ii) make non-substantive edits to Tariff No. 1, replacing outdated references therein.[96] The Revisions were accepted January 1, 2023, as requested. Unless the December 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **MPD OATT: Changes to Treatment of CIS Costs and Expenses (ER23-345)**

On January 4, 2023, the FERC accepted Versant Power's changes to the formula rate in its MPD OATT that modify the treatment of costs and expenses associated with the company's Customer Information System ("CIS").[97] The changes: (i) eliminate the inclusion in wholesale transmission charges under the MPD OATT of costs and expenses associated with the CIS and (ii) modify the allocation of CIS costs and expenses as between transmission and distribution functions in order to align such allocation with the ISO-NE OATT. Unless the January 4 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[96] *ISO New England Inc.*, Docket No. ER23-348-000 (Dec. 6, 2022) (unpublished letter order).

[97] *Versant Power*, Docket No. ER23-345-000 (Jan. 4, 2023) (unpublished letter order).

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

On July 12, 2022, in response to the requirements of *Order 881*, Versant Power filed a proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT"). Attachment T, Versant reported, incorporates all the contents of the *pro forma* OATT's new Attachment M. An effective date of July 12, 2025 was requested in an errata filing submitted on August 1, 2022. On August 2, 2022, MPUC submitted comments asserting that Versant's Compliance Filing, without further detail, is insufficient to meet the requirements of *Order 881* and should either (i) be rejected outright, ordering Versant to re-file with sufficient detail, or (ii) subject to a deficiency letter requiring further information with respect to the Compliance Filing. MPUC withdrew those comments on August 31, 2022 in exchange for certain understandings with Versant Power (including MPUC's attendance, as a non-voting participant, at any NMISA working group discussions on *Order 881* implementation planning and Versant Power's submission of informational compliance filings to keep the FERC apprised of versant's progress in developing its AAR implementation plan). On September 6, 2022, Versant Power supplemented its compliance filing to confirm the MPUC's understandings, as delineated in its Notice of Withdrawal. 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).

- **IA 2nd Amendment: CMP/Sappi Compliance Filing (ER22-1612-001)**

On December 16, 2022, and as required in the June 10, 2022 order in this proceeding,[98] CMP submitted a compliance filing that included a Second Amended Agreement and Schedules between CMP and Sappi North America, Inc. ("Sappi"). The Second Amended Agreement reflected the November 17, 2022 closing date of the FERC-authorized transaction in which Sappi transferred its hydroelectric facilities to Presumpscot Hydro LLC ("Presumpscot Hydro") and its membership interests in Presumpscot Hydro to an unrelated third-party buyer. Comments on the compliance filing are due on or before ***January 6, 2023***. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Power MPD OATT *Order 676-J* Compliance Filing Part I (ER22-1142)**

As previously reported, Versant Power filed revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards in response to the requirements of *Order 676-J*, ("Versant MPD OATT *Order 676-J* Part I Changes").[67] A placeholder effective date was submitted. Comments on this filing were due on or before March 23, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[98] *Central Maine Power Co.,* Docket No. ER22-1612-000 (June 10, 2022) (unpublished letter order).

- ***Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): *New England Compliance Filings* (various)**

The last of the region's *Order 864*[99] and *Order 864-A*[100] compliance filings (UI's May 10, 2022 filing, Docket No. ER22-1850) was accepted on December 29, 2022.[101] Consolidated reporting on the *Order 864* compliance filings is now complete.

XII. Misc. - Administrative & Rulemaking Proceedings[102]

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

As previously reported, Invenergy Transmission ("Invenergy") filed a petition, on July 19, 2022, requesting that the FERC hold a technical conference to explore ways to potentially make available and compensate certain grid reliability and resilience benefits associated with interregional high voltage direct current ("HVDC") merchant transmission. Any comments to be considered by the FERC in its determination of any action to be taken were due on or before August 26, 2022. Comments were filed by 13 parties and included, among others, CSC, ENGIE, Invenergy, Phase I/II Asset Owners and IRH, Joint Consumer Advocates, MISO, ACORE, ACPA, SEIA, and Neptune and Hudson. Invenergy answered the comments filed by MISO. On November 10, 202, Invenergy again urged the FERC to "hold a technical conference to examine and to improve the policy and processes relating to the interconnection of interregional MHVDC systems. Since the last Report, ENGIE, Grid United and SEIA file comments supporting Invenergy's November 10 request. This matter remains pending before the FERC.

- **Joint FERC-DOE Supply Chain Risk Management Technical Conference (Dec 7) (AD22-12)**

On December 12, 2022, the FERC and the DOE convened a joint technical conference held its annual Commissioner-led technical conference to discuss supply chain security challenges related to the BPS, ongoing supply chain-related activities, and potential measures to secure the supply chain for the grid's hardware, software, computer, and networking equipment. Speaker materials are posed in eLibrary and a recording of the conference will be available on the FERC website for roughly two more months. On December 19, 2022, the FERC invited all those interested to file post-technical conference comments to address issues raised during the technical conference identified in the Supplemental Notice of Technical Conference issued on December 6, 2022. Comments are due on or before ***February 17, 2023***.

---

99 *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess Accumulated Deferred Income Taxes ("ADIT") from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information ("ADIT Worksheet"). The ***ADIT Worksheet*** must contain the following five specific categories of information: (i) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein ("***Category 1 Information***"); (ii) is the accounting for any excess or deficient amounts in Accounts 254 (Other Regulatory Liabilities) and 182.3 (Other Regulatory Assets) ("***Category 2 Information***"); (iii) whether the excess or deficient ADIT is protected (and thus subject to the Tax Cuts and Jobs Act's normalization requirements) or unprotected ("***Category 3 Information***"); (iv) the accounts to which the excess or deficient ADIT are amortized ("***Category 4 Information***"); and (v) the amortization period of the excess or deficient ADIT being returned or recovered through the rates ("***Category 5 Information***"). In addition, the FERC stated that it expects public utilities to identify each specific source of the excess and deficient ADIT, classify the excess or deficient ADIT as protected or unprotected, and list the proposed amortization period associated with each classification or source.

100 *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 171 FERC ¶ 61,033, Order No. 864-A (Apr. 16, 2020) ("*Order 864-A*").

101 *ISO New England Inc.*, Docket No. ER22-1850-001 (Dec. 29, 2022) (unpublished letter order).

102 Reporting on the following Administrative & Rulemaking proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: Improving Generating Units Winter Readiness (AD22-4); NOI: Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses (RM22-5); NOI: Reactive Power Capability Compensation (RM22-2); NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14).

- **Reliability Technical Conference (Nov 10) (AD22-10)**

On November 10, 2022, the FERC held its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the BPS. The conference's two panels were: (I) "Managing the Electric Grid to Advance Reliability" (to explore the current state of grid reliability and efforts that can be undertaken to improve it); and (II) "Managing Cyber Security Threats, the CIP Reliability Standards, and Best Practices for the Bulk-Power System" (to discuss how cyber security governance encompasses the CIP Reliability Standards and compliance as well as best practices; the challenges of implementing appropriate oversight; and ways in which industry can address these challenges to improve its response to evolving vulnerabilities and threats to reduce the risk to the BPS). On November 22, 2022, the FERC invited all those interested to file post-technical conference comments to address issues raised during the technical conference identified in the Supplemental Notice of Technical Conference issued on November 3, 2022. Comments are due on or before ***January 9, 2023***.

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

The FERC held a New England Gas-Electric Forum on September 8, 2022 in Burlington, VT. The purpose of the Forum was to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are needed to inform the development of solutions to these challenges. On September 21, 2022, the FERC invited parties wishing to submit comments regarding the topics discussed at the Forum to do so on or before November 7, 2022. Post-Forum Comments were submitted by: ISO-NE, Acadia, AEU, AIM, Calpine, Constellation, Excelerate, FirstLight, LS Power, NECOS, NEPGA, NESCOE, Public Systems, Repsol, TOs, VELCO, Vistra, Potomac Economics, CT DEEP, AEMA, APGA, EPSA, INGA, NE LDCs, NGSA, New England Council, NEPPA, NH BIA, PIOs, RENEW/ACPA, Berkshire Action Team, Greater Concord Chamber of Comm., Mass. Alliance for Econ. Dev., Mass. Business Roundtable, Mass. Coalition for Sustainable Energy, Mass. United Assoc. of Journeymen, Middlesex County Chamber of Commerce, Public Citizen, Western Mass. Economic Dev. Council, and Individual Citizens (M. Axner, E. Blank, S. Botkin, D. Heimann, J. Krieger, B. Little, I. McDonald, J. Neville, W. Persons, R. Spector). On November 22, National Grid filed reply comments. This matter is pending before the FERC.

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

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

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. An additional supplemental notice identifying the opportunity for interested parties to submit post-technical conference comments has yet to be issued. On November 1, 2022, a transcript of the technical conference was posted in the FERC's eLibrary. Since the last Report, the FERC issued a notice on December 23, 2022 inviting post-technical conference comments on questions listed in that notice. Those comments are due on or before ***March 23, 2023***.

- **NOI: Dynamic Line Ratings (AD22-5)**

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[103] seeking comments on (i) whether and how the required use of dynamic line ratings ("DLR") is needed to ensure just and reasonable wholesale rates; (ii) whether the lack of DLR requirements renders current wholesale rates unjust and unreasonable; (iii) potential criteria for DLR requirements; (iv) the benefits, costs, and challenges of implementing DLRs; (v) the nature of potential DLR requirements; and (vi) potential timeframes for implementing DLR requirements. This NOI represents the first step in the FERC's effort to gather more information about the costs and benefits, and potentially mandating the use, of DLRs. A more detailed summary was provided to the Transmission Committee and is posted on the Transmission Committee's webpage.

Initial comments were due April 25, 2022 and filed by: ISO-NE; DC Energy; Eversource; Clean Energy Parties; Potomac Economics; CT DEEP; NERC; US DOE; CAISO; MISO; NYISO; Org of MISO States; PJM, SPP; SPP MMU; AEP; Alliant; APPA; APS; AZ PUC; Clean Energy Entities; Dayton Power; EEI; ELCON; Entergy; IN Util. Reg. Comm.; ITC; LA DPW; MISO TOs; NRECA; NYISO TOs; PPL; R Street Institute; Southern Co.; TAPS; Tri-State; Electricity Canada; Electric Grid Monitoring; Line Vision; Idaho Power.

Reply comments were due on or before May 25, 2022[104] and were filed by: AEP, Clean Energy Entities,[105] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter is pending before the FERC.

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

A fifth meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force")[106] was held on November 15, 2022, in New Orleans, LA. Discussion addressed regulatory gaps/challenges in the oversight of transmission development.[107] The FERC's December 23, 2022 notice inviting comments following its October 6, 2022 technical conference on Transmission Planning and Cost Management (*see* AD22-8 above) was also posted in this docket. As noted above, comments on the topics/questions provided in the December 23 notice are due on or before ***March 23, 2023***.

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[108] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before October

[103] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (Feb. 17, 2022) ("*Dynamic Line Ratings NOI*").

[104] The *Dynamic Line Ratings NOI* was published in the Fed. Reg. on Feb. 24, 2022 (Vol. 87, No. 37) pp. 10,349-10,354.

[105] The "Clean Energy Entities" are the Working for Advanced Transmission Technologies Coalition ("WATT"), ACPA, AEU, and SEIA.

[106] *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 Matt Nelson (Chair, MA DPU), each of whom will be serving a second term during the Sept. 1, 2022 – Aug. 31, 2023 term. *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

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

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

18, 2022 a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. The *Order Directing Reports* follows a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[109] and energy and ancillary services markets.[110]

ISO-NE Report. On October 18, 2022, ISO-NE (as well as the other ISO/RTOs) filed its report in response to the *Order Directing Reports.* The FERC will review the RTO/ISO reports and comments related thereto to determine whether further action is appropriate. Comments in response to the RTO/ISO reports were initially due on or before December 19, 2022. However, on November 30, 2022, EEI requested, and on December 6, 2022 the FERC granted, an additional 30 days, until ***January 18, 2023***, to submit comments on the ISO/RTO reports. Thus far, comments have been filed by America's Power (addressing coal retirements), ELCON and the SPP MMU.

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

On July 28, 2022, the FERC issued a NOPR[111] 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.

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

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

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

On September 1, 2022, Joint Associations[112] requested an additional month to submit comments.[113] 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. Since the last Report, the US Chamber of Commerce filed reply comments. This matter is pending before the FERC.

- **NOPR: Advanced Cybersecurity Investment (RM22-19)**

On September 22, 2022, the FERC issued a NOPR[114] proposing to provide incentive-based rate treatments for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by utilities for the purpose of benefitting consumers by encouraging investments by utilities in advanced cybersecurity technology and participation by utilities in cybersecurity threat information sharing programs, as directed by the Infrastructure Investment and Jobs Act of 2021 ("Infrastructure and Jobs Act"). This NOPR also terminated the NOPR proceeding in Docket RM21-3 (*Dec 2020 Cybersecurity Incentives NOPR*)[115] described in previous Reports.

Initial comments on the *Advanced Cybersecurity Investment NOPR* were due on or before November 7, 2022 and reply comments were due November 21, 2022.[116] Nearly 30 sets of initial comments were filed, including by: Avangrid, APPA, EEI, EPSA, INGA, Joint Consumer Advocates, Microsoft, MISO TOs, PJM TOs, NERC, NRECA, TAPS, and the Operational Technology Cybersecurity Coalition. Reply comments were filed by DOE, EEI, ELCON, CA PUC, AEP, and Anterix. This matter is pending before the FERC.

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

On June 16, 2022, as corrected on July 12, 2022, the FERC issued a notice[117] proposing to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[118] (how they 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

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

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

[114] *Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives*, 180 FERC ¶ 61,189 (Sep. 22, 2022) ("*Advanced Cybersecurity Investment NOPR*").

[115] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Dec 2022 Cybersecurity Incentives NOPR*"). As described in previous Reports, the *Dec 2022 Cybersecurity Incentives NOPR* proposed to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the Bulk Power System.

[116] The *Advanced Cybersecurity Investment NOPR* was published in the *Fed. Reg.* on Oct. 6, 2022 (Vol. 87, No. 193) pp. 60,567-60,580.

[117] *One-Time Informational Reports on Extreme Weather Vulnerability Assessments; Climate Change, Extreme Weather, and Elec. Sys. Rel.*, 179 FERC ¶ 61,196 (June 16, 2022) ("*Extreme Weather Vulnerability Assessments NOPR*").

[118] "Extreme weather vulnerability assessments" are proposed to be defined as "analyses that identify where and under what conditions jurisdictional transmission assets and operations are at risk from the impacts of extreme weather events, how those risks will manifest themselves, and what the consequences will be for system operations".

weather risks). Initial comments were due August 30, 2022[119] and were filed by over 13 parties, including among others, Eversource, NRDC, NERC, MISO, PJM, and EPSA. This matter is pending before the FERC.

- **NOPR: Interconnection Reforms (RM22-14)**

On June 16, 2022, the FERC issued a notice of proposed rulemaking ("NOPR"),[120] more than 400 pages long, that proposes 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* Small Generator Interconnection Agreement ("SGIA") to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

Initial Comments. Initial comments were due October 13, 2022[121] and over 130 sets of comments were filed, including: NEPOOL, ISO-NE, NESCOE, AEU, Anbaric, Avangrid, Cypress Creek Renewables, Dominion, EDF Renewables, ENGIE, Envir. Defense Fund, Longroad, National Grid, NextEra, PPL, RWE, Shell, VELCO, Vistra, ACPA, ACRE, APPA, US DOE, EEI, ELCON, EPRI, EPSA, IRC, NARUC, NERC, NRECA, PIOs, R Street Institute, SEIA, State Agencies, and WIRES.

Reply Comments. Following a request by EEI for a 30-day extension of time to submit reply comments, supported by AEU, ACPA, ACRE, and SEI, and granted by the FERC on October 28, 2022, reply comments were due December 14, 2022. More than 50 sets of reply comments were filed, including by ACPA, ACORE, AEU, APPA/LPPC, Avangrid, Dominion, EDF, EEI, Enel, ENGIE, Invenergy, the IRC, Longroad Energy, NERC, NESCOE, NextEra, Orsted, SEIA, Shell, Sierra Club, UCS, WIRES.

As previously reported, the proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process; (2) reforms to increase the speed of interconnection queue processing; and (3) reforms to incorporate technological advancements to the interconnection process. Within each of these categories, the FERC proposes a wide array of reforms, and requests comment.

To implement the **first-ready, first-served cluster study process**, the FERC proposes to:

- Require transmission providers offer an alternative option for an informational interconnection study that would not require a project enter the interconnection queue;
- Make cluster studies the required interconnection study method under the *pro forma* LGIP;
- Allocate the shared costs of the cluster studies so that 90% of the applicable study costs are allocated to interconnection customers on a pro rate basis based on the requested MWs included in the applicable cluster, and 10% of the applicable study costs are allocated to interconnection customers on a per capita basis based on the number of interconnection requests in the applicable cluster;
- Require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method, in which the transmission provider will determine the degree to which each generating facility in the cluster contributes to the need for a specific network upgrade;
- Allow interconnection customers in an earlier-in-time cluster to share the costs of network upgrades with interconnection customers who will significantly benefit from those upgrades but would not share the cost of the network upgrades solely by virtue of being in a later cluster;
- Increase study deposits based on the size of the generating facility from $35,000 to $250,000;

[119] The *Extreme Weather Vulnerability Assessments NOPR* was published in the *Fed. Reg.* on July 1, 2022 (Vol. 87, No. 126) pp. 39,414-39,426.

[120] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) ("*Interconnection* Reforms *NOPR*").

[121] The *Interconnection Reforms NOPR* was published in the *Fed. Reg.* on July 5, 2022 (Vol. 87, No. 127) pp. 39,934-40,032.

- Require more stringent site control requirements, and proposes to require an interconnection customer to demonstrate 100% site control for a proposed generating facility when they submit the interconnection request;[122]
- Implement a commercial readiness framework whereby interconnection customers must show demonstrable milestones towards commercial readiness in order to enter the cluster, such as an executed term sheet, reasonable evidence the project was selected in a resource plan, or a provisional LGIA;[123] and
- Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.[124]

To **increase the speed of the interconnection queue process**, the FERC proposes to:

- Eliminate the "reasonable efforts" standard for transmission providers completing interconnection studies and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines. The penalty imposed would be $500 per day that the study is late and would be distributed to interconnection customers on a pro rata basis;
- Add an entirely *pro forma* affected system study process to address the current lack of uniformity in the study of affected systems, which results in late-stage withdrawals, re-studies and increased costs to remaining interconnection customers;
- Establish two new *pro forma* agreements, a *pro forma* Affected System Study Agreement (new Appendix 15) and a *pro forma* Affected Systems Facilities Construction Agreement (new Appendix 16); and
- Implement an optional resource solicitation study that can be performed by entities required to conduct a resource plan or solicitation. Under this proposed study process, a resource planning agency (such as a state agency or load-serving entity implementing a state mandate) would facilitate a study to group together interconnection requests associated with the qualifying resource solicitation process, and the resources vying for selection in a qualifying state resource solicitation process would be studied together for the purposes of informational interconnection studies.

Finally, as **technological advances to the interconnection process**, the FERC proposes to:

- Require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request;
- Change the way in which transmission providers assess an addition of a generating facility to an interconnection request, requiring that transmission providers evaluate a proposed addition as long as the addition does not change the requested interconnection service level;
- Enable customers with unused interconnection capacity share that surplus capacity with other resources as long as the original interconnection customer executes an LGIA or requests filing of an unexecuted LGIA;

[122] The FERC proposes to limit the option to provide a financial deposit in lieu of site control and would only allow this option when regulatory limitations prohibit the interconnection customer from obtaining site control. In such instances, the interconnection customer would submit a deposit of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million.

[123] *Id.* at P 128.

[124] The proposed withdrawal penalty will increase as the interconnection customer moves through the interconnection queue and proposes a chart demonstrating the possible penalties at P 144.

- Require transmission providers, at the request of the interconnection customer to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located storage resource; and
- Require transmission providers to evaluate grid-enhancing solutions and file an annual informational report on their use of grid-enhancing technologies.

The FERC proposes to require compliance within 180 days of a final rule in this proceeding. Compliance would require transmission providers to file updates to their *pro forma* LGIA, LGIP, SGIA and SGIP, as applicable. If you have any questions concerning the *Interconnection Reforms NOPR*, please contact Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On July 28, 2022, the FERC issued a NOPR[125] proposing to revise its regulations to permit ISO/RTOs to share among themselves[126] credit-related information regarding market participants.[127] The FERC believes that the proposed credit information sharing could improve ISO/RTOs' ability to accurately assess market participants' credit exposure and risks and enable ISO/RTOs to respond to credit events more quickly and effectively (minimizing the overall credit-related risks, including risks of unexpected defaults by market participants, in organized wholesale electric markets). The FERC proposal would not permit the information sharing to be conditioned on the specific consent of the market participant, would permit the receiving ISO/RTO to use market participant credit-related information received from another ISO/RTO to the same extent and for the same purposes that the receiving ISO/RTO may use credit-related information collected from its own market participants, and would not change the existing discretion an ISO/RTO has to act on credit-related information, regardless of the source of that information. The FERC seeks comment on whether ISO/RTOs' credit-related information sharing discretion should be limited in any specific ways or to any specific circumstances.

Initial Comments. Initial comments were due October 7, 2022[128] and were filed by, among others: NEPOOL, Dominion, EEI, Energy Trading Institute, EPSA, and the IRC.

Reply Comments. Reply comments were due November 7, 2022 and were filed by the ISO/RTO Council ("IRC") and a couple of persons from Augusta University.

- **NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)**

On June 16, 2022, the FERC issued a notice[129] proposing to require that NERC modify Reliability Standard TPL-001-5.1 (Transmission System Planning Performance Requirements) within one year of the effective date of a

---

125 *Credit-Related Information Sharing in Organized Wholesale Electric Markets*, 180 FERC ¶ 61,048 (July 28, 2022) ("*ISO/RTO Credit-Related Info Sharing NOPR*").

126 The *ISO/RTO Credit-Related Info Sharing NOPR* does propose credit-related information sharing with markets that are not Commission-jurisdictional (i.e. ERCOT, AESO, IESO or commodities and derivative markets that are subject to the jurisdiction of other regulators, including the Commodity Futures Trading Commission).

127 Revisions would be to 18 CFR § 35.47(h). The changes would "[p]ermit the sharing of market participant credit-related information with, and receipt of market participant credit-related information from, other organized wholesale electric markets for the purpose of credit risk management and mitigation, provided such market participant credit-related information is treated upon receipt as confidential under the terms for the confidential treatment of market participant information set forth in the tariff or other governing document of the receiving organized wholesale electric market; and permit the receiving organized wholesale electric market to use market participant credit-related information received from another organized wholesale electric market to the same extent and for the same purposes that the receiving organized wholesale electric market may use credit-related information collected from its own market participants.

128 The *ISO/RTO Credit-Related Info Sharing NOPR* was published in the *Fed. Reg.* on Aug. 8, 2022 (Vol. 87, No. 151) pp. 48,118-48,125.

129 *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (June 16, 2022) ("*Extreme Weather Transmission System Planning NOPR*").

final rule in this proceeding to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the reliable operations of the Bulk-Power System. Specifically, the FERC proposed modifications to TPL-001-5.1 to require: (i) development of benchmark planning cases; (ii) planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios; and (iii) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Initial comments were due August 26, 2022[130] and were filed by over 37 parties, including, among others, ISO-NE, Eversource, NESCOE, NRDC, UCS, NERC, ERCOT, MISO, NYISO, PJM, ACPA, EPRI, EPSA, NARUC, and Trade Associations. This matter is pending before the FERC.

- **NOPR: Internal Network Security Monitoring for High and Medium Impact BES Cyber Systems (RM22-3)**

On January 20, 2022, the FERC issued a NOPR[131] proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[132] within a trusted Critical Infrastructure Protection networked environment for high and medium impact Bulk Electric System ("BES") Cyber Systems. The FERC stated that "including INSM requirements in the CIP Reliability Standards would ensure that responsible entities maintain visibility over communications between networked devices within a trust zone (i.e., within an ESP), not simply monitor communications at the network perimeter access point(s), i.e., at the boundary of an ESP as required by the current CIP requirements. In the event of a compromised ESP, improving visibility within a network would increase the probability of early detection of malicious activities and would allow for quicker mitigation and recovery from an attack."[133]

Comments on the *Internal Network Security Monitoring NOPR* were due on or before March 28, 2022.[134] Comments were filed by: the IRC, NERC, EEI, EPSA, TAPS, Bonneville Power Admin., Consumers Energy, Cynalytica, CA Department of Water Resources, Electricity Canada, Entergy, Idaho Power, Juniper Networks, ITC, Microsoft, North American Generator Forum, Nozomi Networks, Operational Technology Cybersecurity Coalition, the US Bureau of Reclamation, and T. Conway. This matter is pending before the FERC.

---

130 The *Extreme Weather Transmission System Planning NOPR* was published in the *Fed. Reg.* on June 27, 2022 (Vol. 87, No. 122) pp. 38,021-38,044.

131 *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, 178 FERC ¶ 61,038 (Jan. 20, 2022) ("*Internal Network Security Monitoring NOPR*").

132 INSM is a subset of network security monitoring that is applied within a "trust zone," such as an Electronic Security Perimeter ("ESP"), and is designed to address situations where vendors or individuals with authorized access are considered secure and trustworthy but could still introduce a cybersecurity risk to a high or medium impact BES Cyber System.

133 *Id.* at P 2.

134 The *Internal Network Security Monitoring NOPR* was published in the *Fed. Reg.* on Jan. 27, 2022 (Vol. 87, No. 18) pp. 4,173-4,180.

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

Following its ANOPR process,[135] the FERC issued on April 21, 2022 a NOPR[136] that would require public utility transmission providers to:

(i) conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;

(ii) more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes;

(iii) seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning;

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

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

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

---

[135] *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, and a group of former military leaders and former Department of Defense officials, and ACPA/AEU/SEIA.

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

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[137] 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. Since the last Report, the Harvard Electricity Law Initiative, and P. Alaama submitted comments.

This matter is 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).

- **NOPR: Accounting and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)**

On July 28, 2022, the FERC issued a NOPR[138] proposing reforms to the accounting and reporting treatment of certain renewable energy assets. Specifically, the FERC proposes changes to the Uniform System of Accounts ("USofA") and relevant FERC forms to: (i) include new accounts for wind, solar, and other non-hydro renewable assets; (ii) create a new functional class for energy storage accounts; (iii) codify the accounting treatment of renewable energy credits; and (iv) create new accounts within existing functions for hardware, software, and communication equipment. The FERC also seeks comment on whether the Chief Accountant should issue guidance on the accounting for hydrogen. Comments on the *Renewable Energy Assets USofA and Reporting NOPR* were due November 17, 2022.[139] Seven sets of comments were filed by: Dominion, ACPA/SEIA, EEI, Liquid Energy Pipeline Assoc., RESA, PG&E/SDG&E, C. Pechman. This matter is pending before the FERC.

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

Supplemental NOPR. In light of comments already received in this proceeding,[140] the FERC issued on April 15, 2021 a *Supplemental NOPR*[141] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC sought comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In

[137] 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.

[138] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, 180 FERC ¶ 61,050 (July 28, 2022) ("*Renewable Energy Assets USofA and Reporting NOPR*").

[139] The *Renewable Energy Assets USofA and Reporting NOPR* was published in the *Fed. Reg.* on Oct. 3, 2022 (Vol. 87, No. 190) pp. 59,870-59,963.

[140] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

[141] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[142] A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[143] Reply comments were also posted from New England State Parties,[144] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the ACPA.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[145] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning

---

[142] As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including the following:

- A shift from risks and challenges to a ***consumers' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period and an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.
- ***Transmission Organization Incentive***. A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

[143] "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

[144] "New England State Parties" are CT PURA, CT DEEP and the MA AG.

[145] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

incentives and shared savings. Comments were due on or before January 14, 2022 and were filed by APPA, CAISO, Clean Energy Parties,[146] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

These matters are pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Voltus Petition for a FERC Technical Conference on Order 2222* (RM18-9)**

On December 22, 2021, Voltus, Inc. ("Voltus") requested that the FERC convene a technical conference regarding *Order 2222*-related issues sometime in the months of February or March, 2022. Specifically, Voltus requested the technical conference to allow for a collective discussion of key issues arising from the ISO/RTO *Order 2222* compliance proposals, including certain regional variability, roles of industry participants, narrowing perceived knowledge gaps, and subsequent FERC guidance, all of which Voltus asserts supports the request for a technical conference. On January 7, 2022, the FERC issued a notice of Voltus' request, inviting comments on Voltus' request on or before February 7, 2022. Comments supporting Voltus' request were filed by: AEU, AEMA, APPA/NRECA, EEI, ISO-RTO Council, MISO, SPP, Sunrun, Ameren, Camus Energy, Energy Web Foundation, Entegrity Energy Partners, Environmental Law and Policy Center, Fermata LLC, Google, Leapfrog Power, Nuvve Holding, Tesla, U Delaware EV Research and Development Group, and Utilidata. Voltus' request remains pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Todd Meinershagen (IN23-4)**

On December 21, 2022, the FERC approved a Stipulation and Consent Agreement with Todd Meinershagen, co-owner of a demand response aggregator of retail customers that resolved OE's investigation into Meingershagen's role, both individually and as co-owner of the DR aggregator, in a fraudulent scheme to register DR resources with MISO without those resources' knowledge or consent and clear Load Modifying Resource ("LMR") capacity that would not have performed if the resources were dispatched during the Relevant Period (June 2019 through October 2021).[147] Mr. Meinershagen used a web scraping tool to identify companies that would be eligible to participate in the MISO program, and his co-owner was to contact those companies, enter into contracts with those companies, and then register those companies in the MISO programs. OE determined that, at no point during the Relevant Period, did the DR aggregator ever contact or contract with the customers it registered as LMRs with MISO, and those LMRs would not have curtailed load if dispatched by MISO. During the Relevant Period, however, MISO paid the DR aggregator a total of $1,013,004 in capacity payments. OE concluded that Meinershagen was unaware of the MISO tariff and Anti-Manipulation Rule violations and that, upon becoming aware of the violations,. Meinershagen assisted in stopping payments by MISO to the DR aggregator. Under the settlement agreement, Meinershagen agreed to ***disgorge*** the amounts he received inclusive of interest as restitution to MISO (***$525,451.93***). Further, Meinershagen agreed to continue to cooperate with any investigation into potentially fraudulent DR resources offered in MISO's markets, including by providing any documents or testimony requested by OE, and to participate as a witness in any a lawsuit filed by the FERC in Federal District Court against the DR aggregator or his co-owner. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[146] The "Clean Energy Parties" are: Working for Advanced Transmission Technologies ("WATT Coalition"), ACPA, AEU, American Council on Renewable Energy ("ACORE"), NRDC, and the Sustainable FERC Project.

[147] *Todd Meinershagen*, 181 FERC ¶ 61,251 (Dec. 21, 2022).

- **FirstEnergy Corp (IN23-2)**

On December 30, 2022, the FERC approved a Stipulation and Consent Agreement with FirstEnergy Corp. ("FirstEnergy")[148] that resolved OE's investigation into whether FirstEnergy violated the FERC's Duty of Candor rule, PUHCA's audit provisions, § 301 of the FPA, and related FERC regulations by omitting material information responsive to data requests issued by Enforcement's Division of Audits and Accounting ("DAA") during the course of its audit of FirstEnergy and its affiliates and subsidiaries in Docket No. FA19-1-000 by failing to disclose payments of nearly $60 million made in connection with the passage of Ohio House Bill 6 (a bill that, upon its passage into law, provided a billion-dollar subsidy for FirstEnergy's two Ohio nuclear plants.) Under the Settlement, in which FirstEnergy stipulated to the facts and admitted the violations, FirstEnergy must ***pay a $3.86 million civil penalty*** to the United States Treasury and to submit two annual compliance monitoring reports. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PacifiCorp (IN21-6)**

We have long reported that, on April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[149] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On December 30, 2022, to fully resolve this matter, the FERC approved a Stipulation and Consent Agreement under which PacifiCorp agreed to: (a) pay a ***civil penalty of $4.4 million***, of which (i) $1.9 million will be paid to the United States Treasury, and (ii) as an offset to the remaining $2.5 million in civil penalty, PacifiCorp will invest $2.5 million, subject to Enforcement's approval, in reliability enhancement measures identified in the Agreement, that go above and beyond what the Reliability Standards require; and (b) be subject to two years' of semi-annual compliance monitoring. PacifiCorp stipulated to facts set forth in Section II of the Agreement, but neither admitted nor denied the alleged violations set forth in Section III of the Agreement. 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)**

On January 20, 2022, the FERC issued an order establishing a hearing to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover,

[148] *First Energy Corp.*, 181 FERC ¶ 61,277 (Dec. 30, 2022).

[149] *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

"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.[150]

As previously reported, on March 18, 2021, the FERC issued a show cause order[151] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity ("CPCN") under NGA section 7(c).[152] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15, 2021.

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

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

On December 16, 2021, the FERC issued a show cause order[153] 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,[154] 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;[155] (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***.

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

[151] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP CPCN Show Cause Order*").

[152] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

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

[154] *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").

[155] 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.

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

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[157] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[158] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[159] Opinion 549-A revised Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[160]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

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

On April 28, 2016, the FERC issued a show cause order[161] 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.[162]

---

156 *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.

157 *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*").

158 *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

159 *BP Penalties Allegheny Order* at P 1.

160 *Id*. at P 319.

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

162 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.

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[163] 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. Since the last Report, on December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas. In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance for 90 days, and directed that the hearing scheduled to begin on January 23, 2023, commence no earlier than ***April 24, 2023***.[164]

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.[165] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.

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

[164] *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).

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

- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- The Project is targeted for a 4th quarter, 2023 in-service date.

Non-New England Pipeline Proceedings
The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

- **Northern Access Project (CP15-115)**
  - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[166] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).
  - As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[167] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[168] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
  - The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[169] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
  - Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[170] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.

---

[166] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[167] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[168] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[169] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[170] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they “do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials.” The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[171] provided a “more clearly articulate[d] basis for denial.”
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission’s Waiver Order.[172]
- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants’ request for an extension of time, [173] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions “file their requests no more than 120 days before the deadline to complete construction”, so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC’s prior findings remain valid.[174]
- On January 28, 2022, Applicants again requested an additional extension of time, this time until December 31, 2024, to complete construction of the Project and enter service. Comments on that request were due on or before February 16, 2022. Many individual comments and protests were received.
- On June 29, 2022, the FERC granted Applicants’ request for an additional extension of time. Applicants now have until December 31, 2024 to construct and place the Project into service.[175]
- A request for rehearing of the *Northern Access Project Add’l Extension Order* was denied by operation of law.[176]
- On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of the *Northern Access Project Add’l Extension Order* (*see* Section XVI below).

---

[171] Summary Order, *Nat’l Fuel Gas Supply Corp. v. N.Y. State Dep’t of Envtl. Conservation*, Case 17-1164 (2d. Cir., issued Feb. 5, 2019).

[172] *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir., filed May 28, 2019) (consolidated).

[173] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[174] *Id.* at P 10.

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

[176] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 180 FERC ¶ 62,099 (Aug. 30, 2022).

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,[177] and that effectively halted construction of the NECEC Project,[178] 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).

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
Underlying FERC *Proceeding*: ER22-707[179]
Petitioner: Green Development
Status: Briefing Underway

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[180] On June 17, 2022, the Court directed Green Development to file, and Green Development filed, a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decisions from which the appeal arises. The FERC filed the Certified Index to the Record on July 28, 2022.

---

[177] 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?"

[178] 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.

[179] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*"). *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration). Together, these orders referred to as the "*2nd Revised Narragansett LSA Orders*".

[180] The 2nd Revised Narragansett LSA is a Local Service Agreement ("LSA") among New England Power, Narragansett and ISO-NE. The LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island.

Green Development filed, on August 15, 2022, a Statement of Issues and Docketing Statement. Green Development filed Petitioner's Brief on October 11, 2022. Since the last Report, FERC filed Respondent's Brief on December 12, 2022 and National Grid filed its Intervenor for Respondent's Brief on December 19, 2022. The briefing schedule calls for the following additional submissions: Petitioner's Reply Brief (***January 9, 2023***); Deferred Appendix (***January 17, 2023***); and Final Briefs (***January 31, 2023***).

- **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,[181] -013[182] -017[183]
  Petitioners: Mystic, CT Parties,[184] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Jan 24, 2023

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*.

As previously reported, the Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings in MISO TOs, now on remand at the Commission. Accordingly, on October 25, 2022, Mystic, without opposition, asked the Court for an order keeping these proceedings in abeyance and directing that motions to govern future proceedings be filed within 90 days. On October 26, 2022, the Court effectively granted Mystic's request, ordering that the proceedings remain in abeyance pending further order of the court and directing the parties to file motions to govern future proceedings by ***January 24, 2023***.

---

[181] *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).

[182] *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).

[183] *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*).

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

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[185]
  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 moved the Court 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. The Court granted the third abeyance request on July 25, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[186]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[187] 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*[188] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on December 6, 2022.

---

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

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

[187] 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.

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

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[189]
  Petitioners: Sierra Club
  Status: Filing of Initial Submissions Underway

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. On October 11, 2022, Sierra Club filed a Docketing Statement, a Statement of Issues, and the underlying decision from which the appeal arises. Also on October 11, the FERC moved to hold this proceeding in abeyance. Sierra Club opposed that motion on October 21, 2022. Having issued its further order on rehearing on October 14, 2022,[190] the FERC, on November 4, 2022, withdrew its 's motion to hold this proceeding in abeyance and asked the Court to issue a scheduling order in this proceeding. The Court issued that schedule on November 9, 2022. The Certified Index to the Record was submitted on November 16, 2022 and Petitioner's (Sierra Club's) Brief on December 16, 2022. Remaining submissions include: Respondent's Brief (February 14, 2023); Brief for Respondent-Intervenors (February 21, 2023); Petitioner's Reply Brief (March 14, 2023); Joint Deferred Appendix (March 21, 2023); and Final Briefs (April 4, 2023). Next up is Respondent's Brief.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[191]
  Petitioners: SEIA et al.
  Status: Oral Argument Held March 8, 2022; Awaiting Decision

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[192] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.) and (22-1146, 22-1147 consol.)**
  Underlying FERC Proceeding: CP16-9-012[193]
  Petitioners: LS Power, Algonquin, INGA
  Status: Cases 22-1146/47 Deconsolidated and Briefing Schedule Set; Remaining Cases (21-1115 et al.) Being Held in Abeyance Pending Disposition of 22-1146/47

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to

---

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

[190] *Corpus Christi Liquefaction Stage III, LLC*, 181 FERC ¶ 61,033 (Oct. 14, 2022).

[191] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[192] *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

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

file motions to govern future proceedings by May 31, 2022. On May 31, 2022, Petitioners asked the Court to continue to hold this proceeding in abeyance pending the First Circuit's disposition of Algonquin's pending motions to transfer that Court's cases 20-1458 and 22-1201 (which also challenge the FERC's authorization of the "Atlantic Bridge Project").

On June 30, the First Circuit transferred cases 20-1458 and 22-1201 to the DC Circuit. The DC Circuit docketed those cases as 22-1146 and 22-1147, consolidated them with its cases challenging the Atlantic Bridge Project orders (with 21-1115 remaining the lead case), and directed the parties to file a proposed briefing schedule. On July 19, the parties filed a proposal that cases 22-1146 and 22-1147 be severed, proposed a revised briefing format and schedule for those cases, and asked the Court to continue to hold the remaining cases in abeyance (asserting that abeyance may avoid the need for briefing and adjudication of the issues that Algonquin and INGAA would press).

On August 16, 2022, the Court deconsolidated 22-1146 and 22-1147 from 21-1115 et al., which is to remain in abeyance pending a further order of the Court. The Court consolidated Cases 22-1146 and 22-1147 together and issued a briefing schedule that calls for the remaining submissions: Respondent Brief by ***January 12, 2023***, Joint Brief of Intervenors by ***January 26, 2023***, Joint Reply Brief of Petitioners by ***February 16, 2023***, Deferred Joint Appendix by ***March 2, 2023***, and Final Briefs by ***March 9, 2023***. The date of oral argument and the composition of the merits panel will be provided at a later date. Next up, Respondent (FERC) Brief.

INDEX
Status Report of Current Regulatory and Legal Proceedings as of January 4, 2023

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

[continued on next page]

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

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

VII. NEPOOL Agreement/Participants Agreement Amendments

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