NEW ENGLAND POWER POOL
Sebastian M. Lombardi
Secretary

March 23, 2023

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of April 6, 2023 Participants Committee Teleconference/Webex Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the April 2023 meeting of the Participants Committee will be held **via teleconference/Webex on Thursday, April 6, 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 April 6 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.

2023 NPC Summer Meeting. The Participants Committee Summer Meeting will be ***June 27-29, 2023*** (with an opening coffee & dessert reception Monday evening, June 26) at ***The Equinox***, 3567 Main Street, Manchester Village, VT (https://www.equinoxresort.com/). Rooms go quickly so we encourage you to register early. You can make your Equinox room reservation(s) through the Equinox Resort Room Booking Link, via the NEPOOL 2023 Summer Meeting webpage, or by contacting the Equinox (802-362-4700) and identifying yourself as part of NEPOOL. The NEPOOL group discounted room rate is ***$199*** per room, per night (single/double occupancy). The negotiated rate is only available through ***June 5***, after which rooms will only be available on a first-come, first-served basis at the Equinox's rate available at that time. We ask that members register for the meeting, including an indication of which meals/events you plan to attend and the number of family members you expect to join you, by completing the meeting registration available on the NEPOOL Summer Meeting website. We will provide and post on that page additional information related to the Summer Meeting as it becomes available.

Respectfully yours,

/s/

Sebastian M. Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the March 2, 2023 Participants Committee meeting. A copy of the draft minutes has been included with this initial notice. 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 initial notice and posted with the meeting materials.

3. To receive an ISO Chief Executive Officer report. The April 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 monthly (March) Operations Report will be circulated and posted in advance of the meeting.

5. To receive an ISO update on the 2023 Annual Work Plan. Materials regarding the updated 2023 Annual Work Plan will be circulated and posted in advance of the meeting.

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

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

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

8. Administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, March 2, 2023, at the Seaport Hotel, Boston, MA. 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. Sebastian Lombardi, Secretary, recorded.

JOINT NOMINATING COMMITTEE (JNC)

Mr. Cavanaugh, referring members to the materials circulated in advance of the meeting and setting the context for the incumbent Board member presentations, introduced Ms. Cheryl LaFleur, ISO Board Chair, inviting her to provide some preliminary remarks and more detailed introductions of the incumbent Board members being considered for re-nomination. Ms. LaFleur introduced Messrs. Brook Colangelo and Mark Vannoy, each of whose current term on the ISO Board would expire in September. Ms. LaFleur stated that the Board supported their re-nomination and re-election for another term (a third term in the case of Mr. Colangelo; a second in the case of Mr. Vannoy). Ms. LaFleur shared thoughts and anecdotes about each of Messrs. Colangelo and Vannoy and highlighted some of their contributions to the ISO Board. In particular, she focused not only on their respective expertise, diversity of experiences and thoughtful perspectives, but also on their collaborative commitment to the Board. She then invited each to discuss their experiences serving on the Board.

Brook Colangelo

To start, Mr. Colangelo provided a brief overview of his background and professional experience, highlighting his time with the Obama Administration, which led him to his current position as Chief Information Officer for Waters Corporation, and to his election to the ISO Board in 2017. He summarized his ISO Board experience, including his service as JNC Chair the prior year, as well as his role in the establishment of the Board's Information Technology (IT) and Cyber Security Committee, and the Board's newly-adopted Diversity, Equity, and Inclusion (DEI) mission statement. For the 2022-2023 Board year, Mr. Colangelo was a member of the Board's IT and Cyber Security, Nominating and Governance, and System Planning and Reliability Committees. Mr. Colangelo expressed his appreciation for the opportunity to interact with the Participants collectively, which he found complemented the smaller group meeting opportunities afforded by the JNC process, side bars, Sector, and other group meetings with Participants.

Mr. Colangelo reflected that his biggest challenge when he initially joined the ISO Board was his relative inexperience within the industry. However, he explained how he had leveraged that inexperience to view and evaluate the various issues before the Board from a different, "outsider" perspective and, with an open mind to continually advocate for innovation within the Board's processes and the ISO's mission.

Mark Vannoy

Mr. Vannoy similarly began his remarks with a brief overview of his background and professional experience, as an engineer, former Chairman of the Maine Public Utilities Commission and current President of the Maine Water Company. As a member of the ISO

Board, Mr. Vannoy had served on the Audit and Finance Committee, Nominating and Governance Committee, and for the 2022-2023 Board year, was the Chair of the IT and Cyber Security Committee, and a member of the Board's Markets Committee. He described the IT and Cyber Security Committee's role in connection with the development of a new generation electric market software by the ISO in conjunction with General Electric, which he reported was progressing as planned.

Responding to questions, both Board Members agreed that it was important that NEPOOL clearly define and communicate its priorities and objectives to the ISO Board, so that the Board may address more effectively broadly-held targets and goals. Members voiced appreciation for the opportunity to engage with the ISO Board, and with these members in particular.

Before moving to the next agenda item, Mr. Cavanaugh congratulated Mr. Jason Marshall and Ms. Mary Louise "Weezie" Nuara on their new positions at the Massachusetts Executive Office of Energy and Environmental Affairs. Mr. Marshall had been appointed to serve as the Deputy Secretary and Special Counsel for Federal and Regional Energy Affairs; Ms. Nuara, as Assistant Secretary for Federal and Regional Energy Affairs. On behalf of the Committee, Mr. Cavanaugh wished them much success in those roles and looked forward to their continued engagement with the region's stakeholders.

APPROVAL OF FEBRUARY 2, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the February 2, 2023 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Sam Mintz.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of the ISO Board and Board Committee meetings that had occurred since the February 2, 2023 Participants Committee meeting, which had been circulated and posted with the materials for the meeting. There were no questions or comments on that summary.

Mr. van Welie then shared some preliminary thoughts, prompted by a discussion with NEPOOL officers the day before, related to the FERC's 2nd New England Winter Gas-Electric Forum scheduled for June 20, 2023 (June Forum). Acknowledging that energy adequacy (particularly in the face of severe winter storms) was front of mind for the FERC, and its June Forum would be focused on potential solutions for New England, Mr. van Welie suggested that the region would be better positioned to shape its preferred path forward if it presented at the Forum a unity of interest and demonstration of the progress being made by the region, and the continued commitment to work together to address the region's energy adequacy challenges. He highlighted the short-, medium-, and long-term projects that the ISO had, or planned to, undertake to address energy adequacy and reliability, citing as examples the ongoing efforts on the Resource Capacity Accreditation (RCA) and Day-Ahead Ancillary Services Initiative (DASI) projects, and the ISO's planned evaluation of the potential to replace the Forward Capacity Market with a prompt capacity market.

He also opined that, just as it was on the minds of those around the table, the status/future of the Mystic generating units and the Everett LNG terminal was likely to be a topic of discussion at the Forum. He said that the ISO had been clear that it had no intention to retain Mystic after its Cost-of-Service Agreement (COSA) expires the following year, and would be uninterested in exploring options inconsistent with those plans. As such, he emphasized to attendees that the ISO would not have any direct authority or apparent jurisdictional means to retain Everett, the retirement of which he viewed as an undesirable outcome for the region. Mr. van Welie suggested that, to facilitate progress on any medium-term solutions, there needed to also be clarity regarding the responsibility or authority for addressing the retention of the Everett facility (which he emphasized was beyond the ISO's reach), a point he hoped would crystalize or be clarified at the June Forum.

Members expressed support for furthering regional dialogue and reaching, to the maximum extent possible, consensus or common understanding on the issues for discussion in advance of the Forum. Specifically, members encouraged further opportunities for dialogue on the Electric Power Research Institute (EPRI) study on extreme weather, as well as the potential for RCA and DASI to serve as energy adequacy solutions. Mr. van Welie stated that plans called for the EPRI study results to become available in May, with an opportunity to review, and to discuss to a limited extent, those results before the Forum. He added that RCA and DASI were expected to narrow the energy adequacy gap, though admittedly by how much would not be known definitively until after implementation. Accordingly, he viewed the June Forum as an early opportunity for the region to collectively support at a conceptual level, and even influence the FERC's high level view of, the benefits of adopting those and other market enhancements/tools.

Addressing Mr. van Welie's comment on the Everett LNG Facility, members acknowledged and generally agreed with the ISO's position that it did not have the direct authority or jurisdictional means to retain Everett. Some urged the ISO to be more vocal on this point to incent those that might have an interest in Everett's future availability to come forward and/or prepare accordingly.

In response to further comments, Mr. van Welie observed, as he had previously, that there existed a number of issues constraining the inputs to and functioning of the competitive markets, all of which could not reasonably be expected to be solved wholly by competitive market design or changes thereto. Rather, by articulating these challenges, he hoped to incentivize and secure needed help from regulators and policy makers to help solve for the constraint-rooted issues he identified. He reinforced the ISO's commitment to continually improve the region's market design to support the health and sustainability of the competitive markets, but also called for broader discussion on systemic risks not being addressed, and the potential development of other solutions that may be needed to close identified gaps. He added that the ISO had recently implemented a platform that allowed the ISO to model many of the region's dynamic energy security risks, to evaluate risk mitigation actions taken, and planned to speak to this tool at the June Forum.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to his operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the operations report was through February 22, 2023, unless otherwise noted. The report highlighted: (i) Energy Market value for February 2023 was $512 million, down $40 million from the updated January 2023 value and down $740 million from February 2022; (ii) February 2023 average natural gas prices were 58% higher than January average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for February ($52.84/MWh) were 4.6% higher than January averages; (iv) average February 2023 natural gas prices and Real-Time Hub LMPs over the period were down 49% and 51%, respectively, from February 2022 average prices; (v) average Day-Ahead cleared physical energy during February's peak hours as a percent of forecasted load was 99.7% (up from 98.9% reported for January), with a minimum value for the month of 92.1% on Sunday, February 5; (vi) Daily Net Commitment Period Compensation (NCPC) payments for February totaled $2.4 million, which was down $46,000 from January 2023 and down $1.6 million from February 2022. February NCPC payments, which were 0.5% of total Energy Market value, were compromised of (a) $2.3 million in first contingency payments (down $49,000 from January); (b) $58,000 in second contingency payments (down $50,000 from January); and (c) $27,000 in distribution payments (up $27,000 from January) (there were no voltage payments in February).

Commenting on the operational highlights, Dr. Chadalavada noted that February was a relatively quiet month and, with the exception of February 3-4, was a warmer than average month. On February 3 and 4, the region experienced cold temperatures, with wind chill values of 30° to 50° Fahrenheit below 0 (certain areas experienced sub-zero temperatures that were among the coldest since 1950). He stated that, for the February 3 operating day, the ISO forecasted a peak load of 19,300 MW, with an approximately 4,200 MW capacity surplus. For that day, nearly 20,000 MW of supply cleared the Day-Ahead Energy Market. He noted that, in the days leading up to the cold snap, Market Participants self-scheduled resources to mitigate the risk of another Capacity Scarcity Condition Event (Scarcity Event) and related penalties (given the recent December 24 Scarcity Event). For the February 4 operating day, the ISO initially forecasted a peak load of 18,320 MW, but had to revise the February 4 load forecast upward twice (to 19,600 MW). Dr. Chadalavada added that, for cold temperature days, Market Participants could assume and expect up to 4,000 MW of forced outages across resource types and imports (in line with forced outages experienced on December 24, and February 3- 4). Further, he highlighted challenges of load forecasting (noting, by way of example, the February 20 Minimum Generation (Min Gen) Warning triggered by an inaccurate forecast). He reported that the ISO would continue its efforts to enhance its load forecasting models. Finally, Dr. Chadalavada noted New England exported 800 MW on an economic/Market Participant-scheduled basis (and not on an ISO-initiated emergency assistance basis) to Hydro-Quebec across the Phase 2 interface (the first time eEnergy had been exported to HQ for either reason since May 2016) and 200 MW across the Highgate interface between February 3 and February 4.

In response to requests for specifics on the February 3-4 cold snap, Dr. Chadalavada noted that roughly one-third of Energy on those days was self-scheduled (the highest that the ISO had ever experienced). He explained that it was difficult to assess the impact of such self-scheduling on LMPs. He then reported that the Everett LNG facility injected 0.5 Bcf of liquefied natural gas (LNG) into the pipeline systems, while Saint John LNG injected 1.2 Bcf. Responding to additional questions on the February 3 and 4 operating days and exports to Hydro-Quebec, Dr. Chadalavada clarified that the exports to Quebec were not emergency sales but market sales scheduled by Quebec and supplied by Market Participants. Communications between the ISO and Hydro-Quebec had improved since the December 24 Scarcity Event, but given increasing extreme weather conditions, Dr. Chadalavada anticipated further conversation and focus through 2024 on tie benefits and coordination agreements with neighboring Control Areas ~~through 2024~~.

Turning to the February 20 Min Gen Warning, Dr. Chadalavada clarified that the Min Gen Warning was triggered by a combination of inaccurate forecasts of cloud cover and irradiance and higher actual temperatures, resulting in an extra 1,000 MW of photovoltaic (pv) output and decreased demand. He noted the increased frequency of such patterns and reiterated the ISO's commitment to improving its forecasting models and technology to mitigate such events.

In response to an inquiry for information as to any upcoming transmission line outages that could result in out-of-merit commitments, Dr. Chadalavada stated that none were expected. He then noted that the New Scotland to Alps (NY-2) Line was scheduled to be out of service from March 1 to April 24. The outage would curtail New England to New York transfer capabilities to 700 MW, but would not affect New York to New England transfers.

A member then requested any available updated information related to Mystic's COSA. Dr. Chadalavada reported that a $120 million reliability-must-run (RMR) payment was made to Mystic in January, the most expensive month since the COSA started in June 2022. He noted that the majority of the $120 million payment was due to the Actual Fuel Cost Adjustment (as defined in the COSA), while 20% was allocable to the Tank Congestion Charge (as defined in the COSA). He added that the ISO had learned from the Mystic experience and that no extension of the COSA was planned. Finally, he reminded the members that Levitan & Associates, Inc.'s Q1 2023 audit report (concerning charges associated with the Mystic COSA) was expected to be released shortly. Moving forward, members could expect the quarterly audit reports to be published on a routine basis.

INVENTORIED ENERGY PROGRAM (IEP) PARAMETER UPDATES

Ms. Mariah Winkler, Markets Committee (MC) Chair, referred the Committee to the materials circulated in advance of the meeting and posted on the NEPOOL and ISO websites. She summarized the proposed updates designed to align certain IEP parameters with current market conditions and improve the possibility of attracting inventoried energy (IEP Parameter Updates or Updates), as well as the process leading up to the MC's action on the Updates. She reported that, at the February 7–9, 2023 MC meeting, Generation Bridge Connecticut Holdings LLC (Generation Bridge) had offered an amendment to the ISO's IEP Parameter Updates to increase the duration of inventoried energy from 72 hours to 120 hours (Generation Bridge Amendment). That Amendment failed to garner MC support, with a 26.82% Vote in favor. The MC, however, recommended with a 81.63% Vote in favor that the Participants Committee support the ISO's proposed IEP Parameter Updates.

Following her overview, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Appendix K of Market Rule 1 to update certain Inventoried Energy Program (IEP) parameters (the IEP Parameter Updates), as recommended by the Markets Committee at its February 2023 meeting, and circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee, it being understood that a vote in favor of this resolution reflects solely support for the IEP Parameter Updates, and is without prejudice to any position taken by a Participant(s) on the underlying IEP construct.

Before discussion ensued, Mr. Lombardi confirmed that, consistent with past practice, neither NEPOOL nor the ISO would raise procedural objections at the FERC should the Generation Bridge Amendment not be presented to the Participants Committee for a vote. With that understanding, he reported that Generation Bridge representatives had indicated to NEPOOL Counsel that they would not seek a Participants Committee vote on the Generation Bridge Amendment. Mr. Lombardi added that NEPOOL Counsel would provide for the record in the FERC proceeding a summary of the MC consideration of the Generation Bridge Amendment.

Committee members then commented on the proposed IEP Parameter Updates. Those supporting the Updates were generally of the view that the changes improved the IEP. Some of those that opposed or abstained from the vote opined that there was a need for more evidence that modifying the IEP was necessary, particularly because the Mystic COSA remained in place. Others expressed concern that the IEP could be extended beyond the intended timeframe (i.e., beyond Winter 2024/25).

Members encouraged the ISO to continue to develop market solutions, such as the DASI and RCA projects, to address the underlying issues affecting the region's reliability. A NESCOE representative noted that the States, which did not share a collective position during the initial consideration of the IEP matter, viewed the IEP Parameter Updates as narrow in focus, and the move to indexing likely a positive development for consumers. Accordingly, the States did not oppose the Updates and looked forward to working with the region to move towards long-term solutions based, to the greatest extent practicable, on tangible data and analysis.

The Committee then considered and approved the main motion, with a 92.33 % Vote in favor (Generation Sector – 16.7%; Transmission Sector – 16.7%; Supplier Sector – 15.66%; AR

Sector – 15.66%; Publicly Owned Entity Sector – 16.7%; End User Sector – 11.13%). (See Vote 1 on Attachment 2.)

In response to a member's question, the ISO stated that it intended to file the IEP Parameter Updates with the FERC by the end of March.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the February 28 Litigation Report that had been circulated and posted before the meeting. He highlighted the following developments:

(i) *RENEW/ACPA RCA & Operating Reserve Designation Complaint (EL22-42).* The FERC had dismissed RENEW/ACPA's Complaint asserting undue preferences under ISO-NE's rules and procedures for gas-fired generation resources. Challenges, if any, to the Complaint Order were due on or before March 20, 2023;

(ii) *FCA17 Qualification Informational Filing (ER23-690).* The FERC accepted the ISO's informational filing for qualification in FCA17, as amended, and directed the ISO to use the corrected Qualified Capacity values when it conducts FCA17. FCA17 was scheduled to begin on March 6, 2023;

(iii) *New England Gas-Electric Forum (AD22-9).* As noted earlier in the meeting, the second New England Winter Gas-Electric Forum was scheduled for June 20, 2023 in Portland, Maine. The FERC had committed to issue a supplemental notice with further details regarding the Forum agenda; and

(iv) *New England Order 2222 Compliance Filing (ER22-983).* In a lengthy order issued the evening before the meeting, the FERC accepted in part, and rejected in part, the ISO's compliance filing, to become effective November 1, 2022 and November 1, 2026, as requested, subject to further 30-, 60-~~,~~ and 180-day compliance filings to be submitted on or before March 31, May 1, and August 28, 2023, respectively. A further summary of the order would be circulated to Committee members shortly.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, MC Vice-Chair, reported that the next MC meeting was scheduled for March 7-9, 2023 at the Westborough, MA DoubleTree Hotel. He reported that, given its workload, the MC was expected to expand its scheduled monthly meetings to three-day meetings through the summer.

Reliability Committee (RC). Mr. Robert Stein, RC Vice-Chair, reported that the next RC meeting was scheduled for March 14-15, 2023. The meeting would include a discussion on RCA and extreme weather events. Mr. Stein also noted that, due to its workload, the RC was expected to schedule two-day meetings for the next few months.

Transmission Committee (TC). Mr. David Burnham, TC Vice-Chair, reported that the next TC meeting was scheduled by teleconference/Webex for March 21 and would include a vote on the elimination of the timeout rules in the Forward Capacity Market.

Budget and Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Subcommittee Chair, reported that the next B&F Subcommittee meeting was scheduled for March 23.

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled by Zoom for March 13.

Joint Nominating Committee. Mr. Cavanaugh noted that the JNC's next meeting was scheduled to be held via teleconference the following day. The JNC planned to review the position description and some candidate resumes for the presumptively one open Board position. He added that the JNC was scheduled to meet at end of March to narrow the list of potential candidates and conduct interviews.

ADMINISTRATIVE MATTERS

Ms. Heather Hunt, NESCOE Executive Director, highlighted NESCOE's February 8, 2023 memorandum to the New England Transmission Owners and ISO-NE Planning Advisory Committee (PAC) concerning Asset Condition Projects. She stated that NESCOE sought to improve transparency in the consideration of Asset Condition Projects, as well as "right-sizing" such projects.

Mr. George Twigg, NECPUC Executive Director, reminded members of NECPUC's Annual Symposium, to be held from May 22-24, 2023 in Stowe, Vermont. He previewed that Dr. Shalanda Baker from the U.S. Department of Energy (DOE) was scheduled to speak and there would be discussions around reliability, grid resilience, federal funding, and more. He stated that more detailed information would follow.

Finally, Mr. Lombardi reminded members that the next Participants Committee meeting was scheduled for April 6 and highlighted the upcoming Summer Meeting scheduled for June 27-29 at The Equinox in Manchester Village, Vermont. He stated that details concerning both meetings would follow.

There being no other business, the meeting adjourned at 12:22 p.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

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

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting	Caitlin Marquis	Kat Burnham	
AR Large Renewable Gen. (RG) Group Member	AR-RG	Abby Krich (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity			Dan Murphy
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
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity			Dan Murphy
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Bridgeport Fuel Cell (Fuel Cell Energy)	AR-RG	Lauren Mix (tel)		
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Clearway Power Marketing LLC	Supplier			Pete Fuller (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)	Jason Frost
Conservation Law Foundation (CLF)	End User		Priya Gandbnir	
Constellation Energy Generation	Supplier	Gretchen Fuhr (tel)	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Wes Walker (tel)		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein (tel)		Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Brett Kruse Liz Delaney		Bill Fowler
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin (tel)		
Eversource Energy	Transmission		Dave Burnham	
First Point Power, LLC	Supplier	Peter Scheiffelin (tel)		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation		Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
GF Power	Supplier		Moses Gadzey (tel)	
Granite Shore Power Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity			Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short

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

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity			Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity			Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumers Group	End User	Dan Collins (tel)		
Ipswich Municipal Light Department	Publicly Owned Entity			Dan Murphy
Jericho Power LLC (Jericho)	AR-RG		Nancy Chafetz (tel)	Brett Kruse
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 Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate’s Office	End User	Drew Landry		
Maine Skiing	End User	Dan Collins (tel)		
Mansfield Municipal Electric Department	Publicly Owned Entity			Dan Murphy
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity			Dan Murphy
Mass. Attorney General’s Office (MA AG)	End User	Ashley Gagnon		Tina Belew (tel)
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			Dan Murphy
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Mintz, Samuel	End User	Sam Mintz (tel)		
Moore Company	End User			Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		
Nautilus Power, LLC	Generation	Dan Pierpont (tel)	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Brian Calnan (tel)		Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User	Jason Frost		
New England Power (d/b/a National Grid)	Transmission		Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors (tel)
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier		Pete Fuller (tel)	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Co.	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity			Dan Murphy
PowerOptions, Inc.	End User			Jackie Litynski
Princeton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti		Bill Short
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity			Dan Murphy

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

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity			Dan Murphy
South Hadley Electric Light Department	Publicly Owned Entity			Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity			Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller (tel)
Tangent Energy Solutions, Inc.	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Tenaska Power Services Co.	Supplier		Eric Stallings (tel)	
The Energy Consortium	End User		Mary Smith (tel)	
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)
Versant Power	Transmission	Lisa Martin (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity			Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH LLC	End User			Bill Short

MARCH 2, 2023 PARTICIPANTS COMMITTEE MEETING
VOTE ON IEP PARAMETER UPDATES

TOTAL

Sector	Vote 1
Generation	16.70
Transmission	16.70
Supplier	15.66
Alternative Resources	15.44
Publicly Owned Entity	16.70
End User	11.13
% IN FAVOR	92.33

GENERATION SECTOR

Participant Name	Vote 1
CPV Towantic, LLC	F
Dominion Energy Generation Mktg	F
ECP Companies	Split
Calpine	F
New Leaf Energy	F
FirstLight Power Management, LLC	A
Generation Bridge Companies	F
Generation Group Member	F
Granite Shore Power Companies	A
Nautilus Power, LLC	F
NextEra Energy Resources, LLC	F
Pawtucket Power Holding Co.	F
Walden Renewables Development Co.	F
IN FAVOR (F)	10
OPPOSED (O)	0
TOTAL VOTES	10
ABSTENTIONS (A)	2

TRANSMISSION SECTOR

Participant Name	Vote 1
Avangrid (CMP/UI)	F
Eversource Energy	F
Narragansett Electric (d/b/a Rhode Island Energy)	F
New England Power (d/b/a National Grid)	F
VELCO	F
Versant Power	F
IN FAVOR (F)	6
OPPOSED (O)	0
TOTAL VOTES	6
ABSTENTIONS (A)	0

SUPPLIER SECTOR

Participant Name	Vote 1
BP Energy Company	F
Brookfield Renew. Trading & Mktg	O
Castleton Comm. Merchant Trading	F
Clearway Power Marketing LLC	F
Constellation Energy Generation	F
Cross-Sound Cable Company	F
DTE Energy Trading, Inc.	F
Dynegy Marketing and Trade, LLC	F
Emera Energy Services Companies	F
First Point Power, LLC	F
Galt Power, Inc.	F
GF Power LLC	F
LIPA	F
Maine Power, LLC	F
Mercuria Energy America, Inc.	F
NRG Power Marketing, LLC	A
Shell Energy North America (US)	F
Tenaska Power Services Co.	A
IN FAVOR (F)	15
OPPOSED (O)	1
TOTAL VOTES	16
ABSTENTIONS (A)	2

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1
Renewable Generation Sub-Sector	
Bridgeport Fuel Cell, LLC (Fuel Cell Energy)	F
ENGIE Energy Marketing NA, Inc.	F
H.Q. Energy Services (U.S.) Inc.	F
Jericho Power LLC	F
Wheelabrator/Macquarie	F
Large RG Group Member	F
Distributed Generation Sub-Sector	
Sunrun Inc.	F
Load Response Sub-Sector	
Enel X North America, Inc.	F
Icetec Energy Services, Inc.	F
Maple Energy	F
Tangent Energy Solutions, Inc.	F
Vermont Energy Investment Corp.	O
IN FAVOR (F)	11
OPPOSED (O)	1
TOTAL VOTES	12
ABSTENTIONS (A)	0

MARCH 2, 2023 PARTICIPANTS COMMITTEE MEETING
VOTE ON IEP PARAMETER UPDATES

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1
Ashburnham Municipal Light Plant	F
Belmont Municipal Light Dept.	A
Block Island Utility District	A
Boylston Municipal Light Dept.	F
Braintree Electric Light Dept.	A
Chester Municipal Light Dept.	A
Chicopee Municipal Lighting Plant	F
Concord Municipal Light Plant	A
Conn. Mun. Electric Energy Coop.	F
Danvers Electric Division	A
Georgetown Municipal Light Dept.	A
Groton Electric Light Dept.	F
Groveland Electric Light Dept.	A
Hingham Municipal Lighting Plant	A
Holden Municipal Light Dept.	F
Holyoke Gas & Electric Dept.	F
Hull Municipal Lighting Plant	F
Ipswich Municipal Light Dept.	F
Littleton (MA) Electric Light Dept.	A
Mansfield Municipal Electric Dept.	F
Marblehead Municipal Light Dept.	F
Mass. Bay Transportation Authority	A
Mass. Municipal Wholesale Electric Co.	F
Merrimac Municipal Light Dept.	A
Middleborough Gas and Elec. Dept.	A
Middleton Municipal Electric Dept.	A
New Hampshire Electric Cooperative	F
North Attleborough	A
Norwood Municipal Light Dept.	A
Pascoag Utility District	A
Paxton Municipal Light Dept.	F
Peabody Municipal Light Plant	F
Princeton Municipal Light Dept.	F
Reading Municipal Light Dept.	A
Rowley Municipal Lighting Plant	A
Russell Municipal Light Dept.	F
Shrewsbury's Electric & Cable Operations	F
South Hadley Electric Light Dept.	F
Sterling Municipal Electric Light Dept.	F
Stowe (VT) Electric Dept.	A
Taunton Municipal Lighting Plant	A
Templeton Municipal Lighting Plant	F
Village of Hyde Park (VT) Elec. Dept.	A
VT Public Power Supply Authority	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1
Wakefield Municipal Gas and Light Dept.	F
Wallingford, Town of	A
Wellesley Municipal Light Plant	A
West Boylston Municipal Lighting Plant	F
Westfield Gas & Electric Light Dept.	A
IN FAVOR (F)	24
OPPOSED (O)	0
TOTAL VOTES	24
ABSTENTIONS (A)	25

END USER SECTOR

Participant Name	Vote 1
Associated Industries of Mass.	A
Bath Iron Works Corporation	F
Conn. Office of Consumer Counsel	O
Conservation Law Foundation	A
Durgin and Crowell Lumber Co.	F
Elektrisola, Inc.	F
Garland Manufacturing Co.	F
Hammond Lumber Company	F
Harvard Dedicated Energy Limited	O
High Liner Foods (USA) Inc.	F
Industrial Energy Consumer Group	A
Maine Public Advocate Office	O
Maine Skiing	A
Mass. Attorney General's Office	O
Mintz, Sam	A
Moore Company	F
New Hampshire OCA	O
Nylon Corporation of America	F
PowerOptions, Inc.	O
RI Division of Public Utilities Carriers	A
Shipyard Brewing Co.	F
St. Anselm College	F
The Energy Consortium	F
Z-TECH, LLC	F
IN FAVOR (F)	12
OPPOSED (O)	6
TOTAL VOTES	18
ABSTENTIONS (A)	6

CONSENT AGENDA

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's March 7-9, 2023 meeting, dated March 9, 2023.[1]

1. **Manuals M-20 and M-28 Clean-Up Revisions**

Support revisions to Manual M-20 (FCM) (to remove obsolete language and other copy edits) and Section 7.2.1 of Manual M-28 (Market Rule 1 Accounting, Metering Domains) (to remove obsolete language), as recommended by the MC at its March 7-9, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was unanimously approved.

Transmission Committee (TC)

From the previously-circulated notice of actions of the TC's March 21, 2023 meeting, dated March 21, 2023.[2]

2. **Revisions to OATT Schedules 22 & 25 § 4.4 and Schedule 23 § 1.5.5 (Removing NCRIS Time-Out Rules)**

Support revisions to the OATT that remove the Capacity Network Resource Interconnection Service (CNRIS) time-out rules from Section 4.4 of Schedules 22 and 25 and from Section 1.5.5 of Schedule 23 for Queue Positions that have not timed-out (in whole or part) by FCA17, as recommended by the RC at its March 21, 2023 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.

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's February 22, 2023 meeting, dated February 22, 2023.[3]

3. **Revisions to PP-3 and PP-5-6 (Changes to Stability Performance Requirements and Generator Outputs in Planning Studies)**

Support revisions to ISO New England Planning Procedure (PP) Nos. 3 (Reliability Standards for the New England Area Pool Transmission Facilities) and 5-6 (Interconnection PP for Generation and Elective Transmission Upgrades),[4] as recommended by the RC at its February 22, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

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

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

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

[4] The changes to PP-3 revise the stability performance criteria applied in planning studies to appropriately accommodate the performance of legacy Distributed Energy Resources; the changes to PP-5-6 align generator outputs in steady-state and transient stability analyses.

4. Revisions to OP-14 (DE/DDE MPSA or DE/DDE Agreement Requirement; Removal of Minimum Droop Requirement)

Support revisions to ISO New England Operating Procedure (OP) No. 14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands, and Alternative Technology Regulation Resources),[5] as recommended by the RC at its February 22, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

From the previously-circulated notice of actions of the RC's March 14-15, 2023 meeting, dated March 15, 2023.

5. Revisions to OP-23 Appendix J (Biennial Review, Clarifying Updates)

Support biennial review revisions to Appendix J to OP-23 (Reactive Capability Audit Waiver Request Form),[6] as recommended by the RC at its March 14-15, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

[5] The recommended revisions to OP-14 (i) require the Designated Entity (DE) or Demand Designated Entity (DDE) identified by a Lead Market Participant to have entered into a Market Participant Service Agreement (MPSA) or a DE/DDE Agreement; and (ii) remove the minimum speed droop requirement (previously set at 4%).

[6] The recommended revisions to Appendix J to OP-23 include: the removal of contact mailing address; an update to the second prompt in Section 1 to read "Reactive Resource"; the removal of yes/no boxes from Section 3 (Extended Outage); and minor grammatical changes.

Summary of ISO New England Board and Committee Meetings

April 6, 2023 Participants Committee Meeting

Since the last update, the Board of Directors met on March 15 and 16. The Audit and Finance Committee, the Information Technology and Cyber Security Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on March 16. All of the meetings were held in Holyoke. In addition, the Compensation and Human Resources Committee met virtually on March 23.

The Audit and Finance Committee met with the Company's external auditors, KPMG, along with management, and reviewed the 2022 audited financial statements and discussed disclosure controls. The Committee voted to recommend the adoption of the audited financial statements by the Board of Directors. The Committee met further with KPMG to review the work plan for the 2023 System and Organization Controls Report. The Committee discussed the scope of the work, including objectives, audit team and methodology, and then held an executive session with KPMG. Next, the Committee received an update on current Internal Audit Department activities, together with the risk assessment process and audit planning cycle. The Committee approved the Internal Audit Department's audit plan for 2023. Finally, the Committee received updates on the Company's financial performance against the 2023 budget.

The Compensation and Human Resources Committee reviewed a report from Mercer, the Company's compensation consultant, regarding market-based compensation for critical employee roles and considered the talent and financial implications of the findings. During executive session, the Committee considered Mercer's findings regarding executive compensation, and received an update on the Company's succession plans for executive positions.

The Information Technology and Cyber Security Committee received an update on the Company's cyber security plan, along with a summary of the three-year work plan for cyber security projects currently underway. The Committee discussed the rolling three-year infrastructure plan, which is part of the Company's overall information technology strategic plan. The Committee was also provided with an overview of major information technology projects, including the next Generation Electricity Market ("nGEM") project, the market system platform being developed to replace the current platform currently installed at multiple ISOs. Following an executive session, the Committee undertook a tour of the Company's Security Operations Center.

The Markets Committee received an update on market development activities, including the Day-Ahead Ancillary Services Initiative and the Resource Capacity Accreditation project. The Committee discussed the engagement contemplated with the External Market Monitor to update the Cost of New Entry parameter in the FCM as a result of the elimination of the Minimum Offer Price Rule, and received a summary of other ISO/RTO filings to the FERC on modernizing wholesale electricity market design. The Committee then met with the System Planning and Reliability Committee to receive a report on the outcome of the 17th Forward Capacity Auction.

The Nominating and Governance Committee received an update on Joint Nominating Committee activities. The Committee then received a report from Russell Reynolds Associates regarding best practices to facilitate board diversity, equity, and inclusion, and diversity statistics for the board search conducted in 2022. The Committee also reviewed potential topics for discussion at the upcoming ISO/RTO Council (IRC) board conference in May, and considered plans for a transmission-focused open board meeting in November.

The System Planning and Reliability Committee discussed key messages for the 2023 Regional System Plan. The Committee was provided with an update on economic studies, and a report on winter operations for the 2022/2023 season. The Committee then discussed transmission cost increases, and approaches to asset condition projects. The Committee then met with the Markets Committee to discuss results of the 17th Forward Capacity Auction.

The Board of Directors met in executive session to discuss its oversight of the Company's compliance program. In regular session, the Board received a report from the CEO, including FERC's order on the Company's compliance with FERC Order 2222 regarding distributed energy aggregations. The Board also prepared for its meeting with state regulators, and reviewed the Company's annual communications plan for 2023. The Board was provided with an overview of the strategic planning process and timeline for 2023, and discussed strategic objectives and future initiatives. Following its meeting with state regulators, the Board received reports from its standing committees. During the Audit and Finance Committee report, the Board approved the audited financial statements for 2022. Finally, the Board received a presentation from Richard Dewey, CEO of the New York ISO. Mr. Dewey discussed a variety of topics, including the evolving resource mix and its impact on energy adequacy in New York.

NEPOOL Participants Committee Report

April 2023

Vamsi Chadalavada
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through March 29th unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: February 2022 Energy Market value totaled $749M
  - March 2023 Energy market value was $367M, down $382M from February 2023 and down $355M from March 2022
    - March natural gas prices over the period were 63% lower than February average values
    - Average RT Hub Locational Marginal Prices ($31.21/MWh) over the period were 52% lower than February averages
    - Average March 2023 natural gas prices and RT Hub LMPs over the period were down 55% and 53%, respectively, from March 2022 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 101% during March, up from 99.6% during February*
    - The minimum value for the month was 95.4% on Friday, March 24th**

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market
**Daily values shown on current slide 19

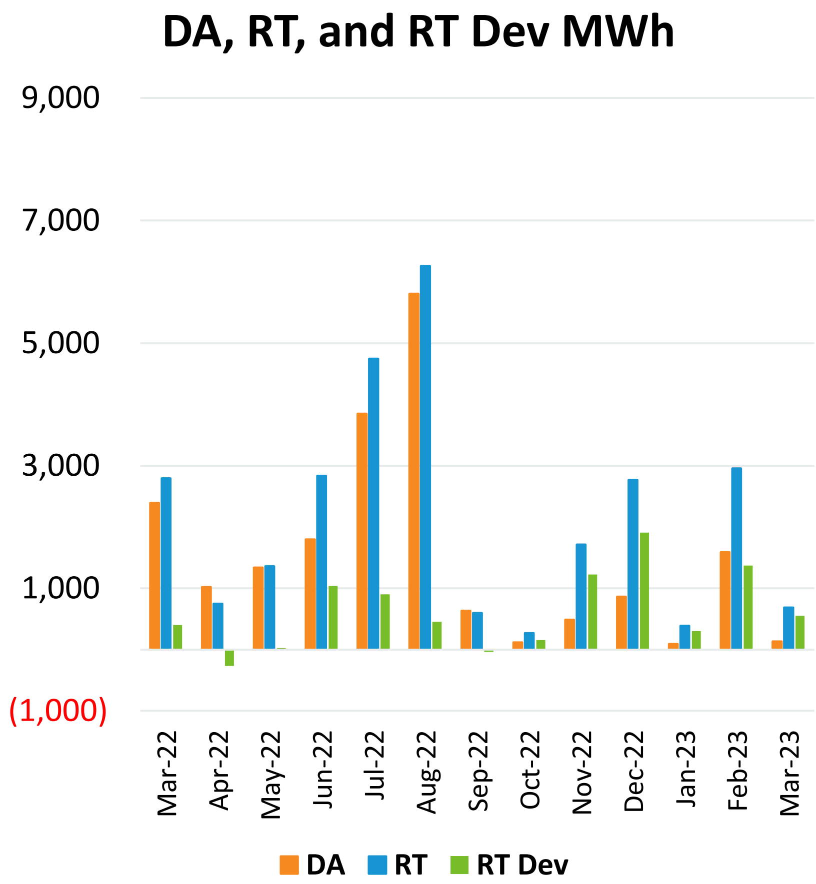
Underlying natural gas data furnished by: ICE Global markets in clear view

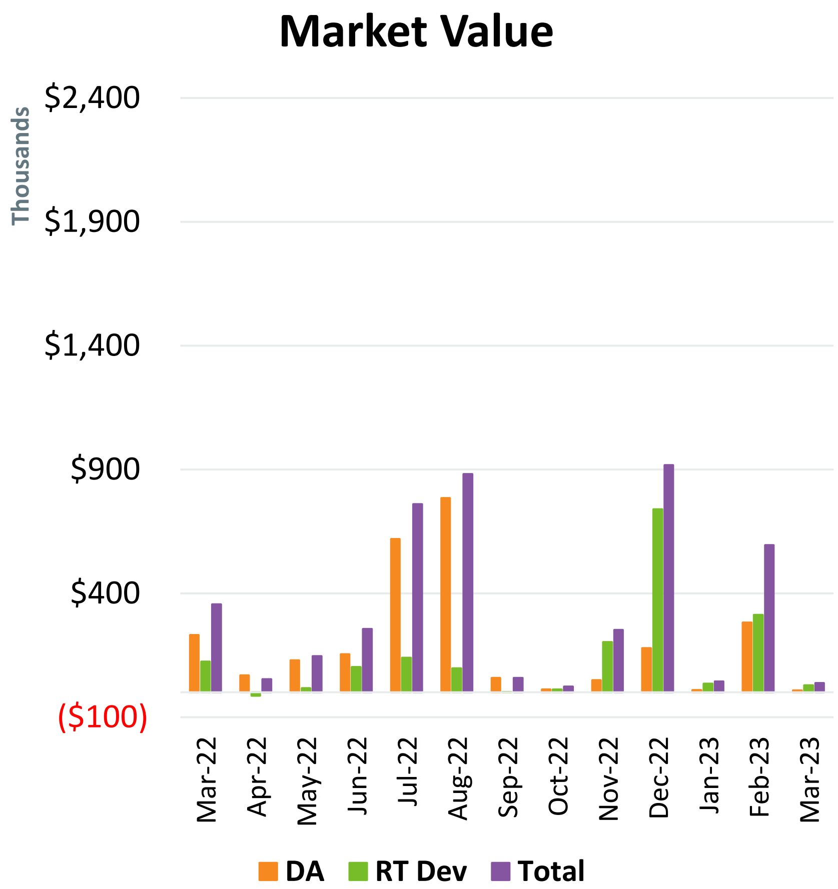
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - March 2023 NCPC payments totaled $1.3M over the period, down $2M from February 2023 and down $2.8M from March 2022
    - First Contingency payments totaled $1.3M, down $1.7M from February
      - $1M paid to internal resources, down $1.8M from February
        - » $182K charged to DALO, $522K to RT Deviations, $397K to RTLO*
      - $157K paid to resources at external locations, up $98K from February
        - » $14K charged to DALO at external locations, $143K to RT Deviations
    - Second Contingency payments totaled $89K, down $289K from February
    - Voltage and Distribution payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 0.4%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $258K; Rapid Response Pricing (RRP) Opportunity Cost - $139K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- FCA 17 results were filed with FERC on March 21 and the filing is pending
  - Comments are due May 5 and ISO requested an effective date of July 19
- The Economic Study Process Improvement project to update Attachment K of the OATT was filed with FERC on January 27
- Public Meeting date for the 2023-24 RSP is set for November 1 and will be held concurrently with the ISO Open Board Meeting
- The next Load Forecast Committee meeting will be held on April 14 and will focus on final draft electrification, energy and demand forecasts

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results will be posted no later than March 31
- CCP 15 (2024-2025)
  - Second annual reconfiguration auction (ARA2) will be held on August 1-3, and results will be posted no later than August 31
- CCP 16 (2025-2026)
  - First annual reconfiguration auction (ARA1) will be held on June 1-5, and results will be posted no later than July 3
- CCP 17 (2026-2027)
  - Auction results were filed with FERC on March 21 and the filing is pending
    - Comments are due May 5 and ISO requested an effective date of July 19

CCP – Capacity Commitment Period

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
    - Approved projects were shared with the RC at their January meeting
  - Capacity zone development discussions began at the December 13, 2022 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - ISO to calculate and post the FCA 18 dynamic delist bid threshold price in March

Highlights

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 13, 2023.

- The lowest 50/50 and 90/10 Preliminary Summer Operable Capacity Margins are projected for week beginning June 17, 2023.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.5°F) Max: 61°F, Min: 28°F Precipitation: 4.29" – Above Normal Normal: 4.17" Snow: 0.9"	Hartford	Temperature: Above Normal (2.4°F) Max: 65°F, Min: 22°F Precipitation: 4.15" - Above Normal Normal: 3.81" Snow: 7.9"

Peak Load:	16,041 MW	March, 07, 2023	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
NONE			

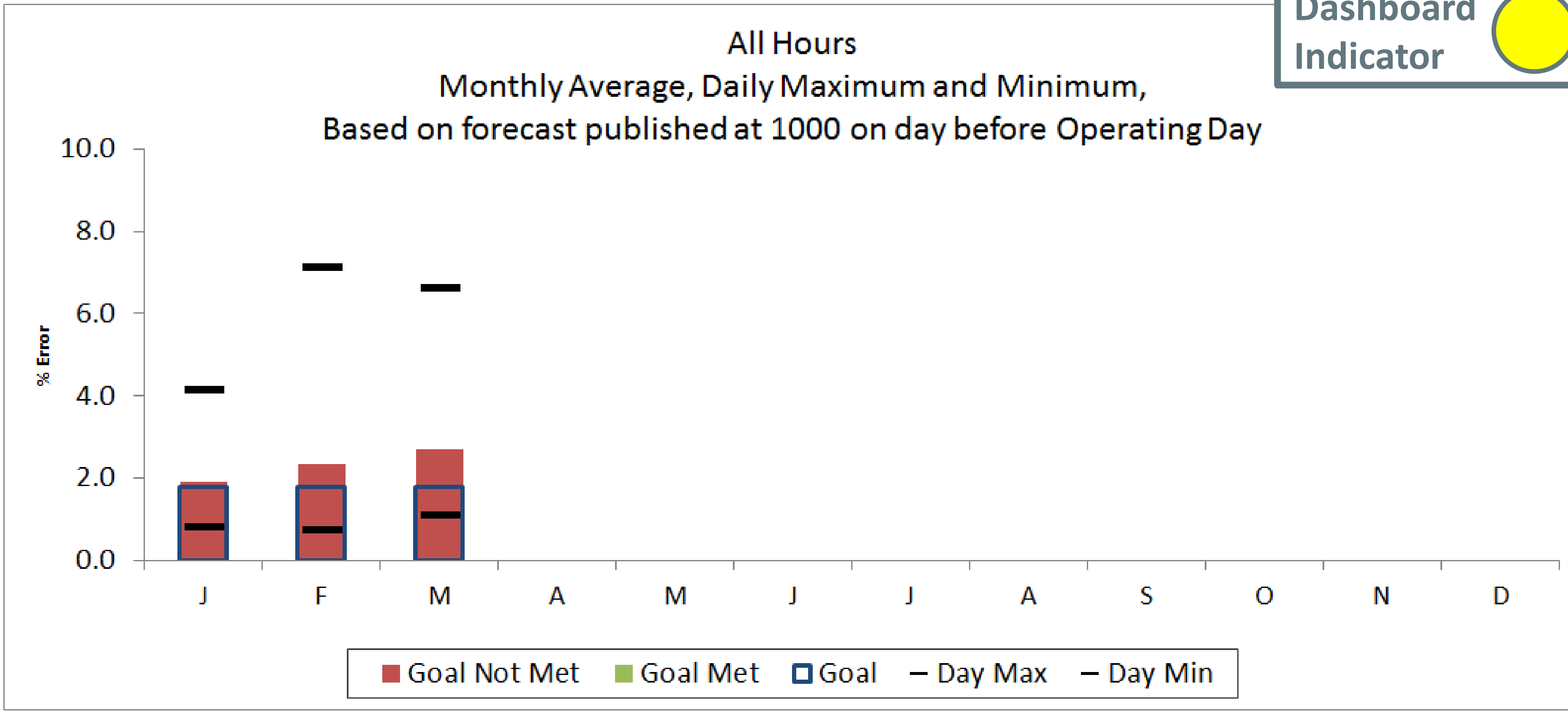
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
03/07/2023	IESO	900
03/28/2023	IESO	850

2023 System Operations - Load Forecast Accuracy

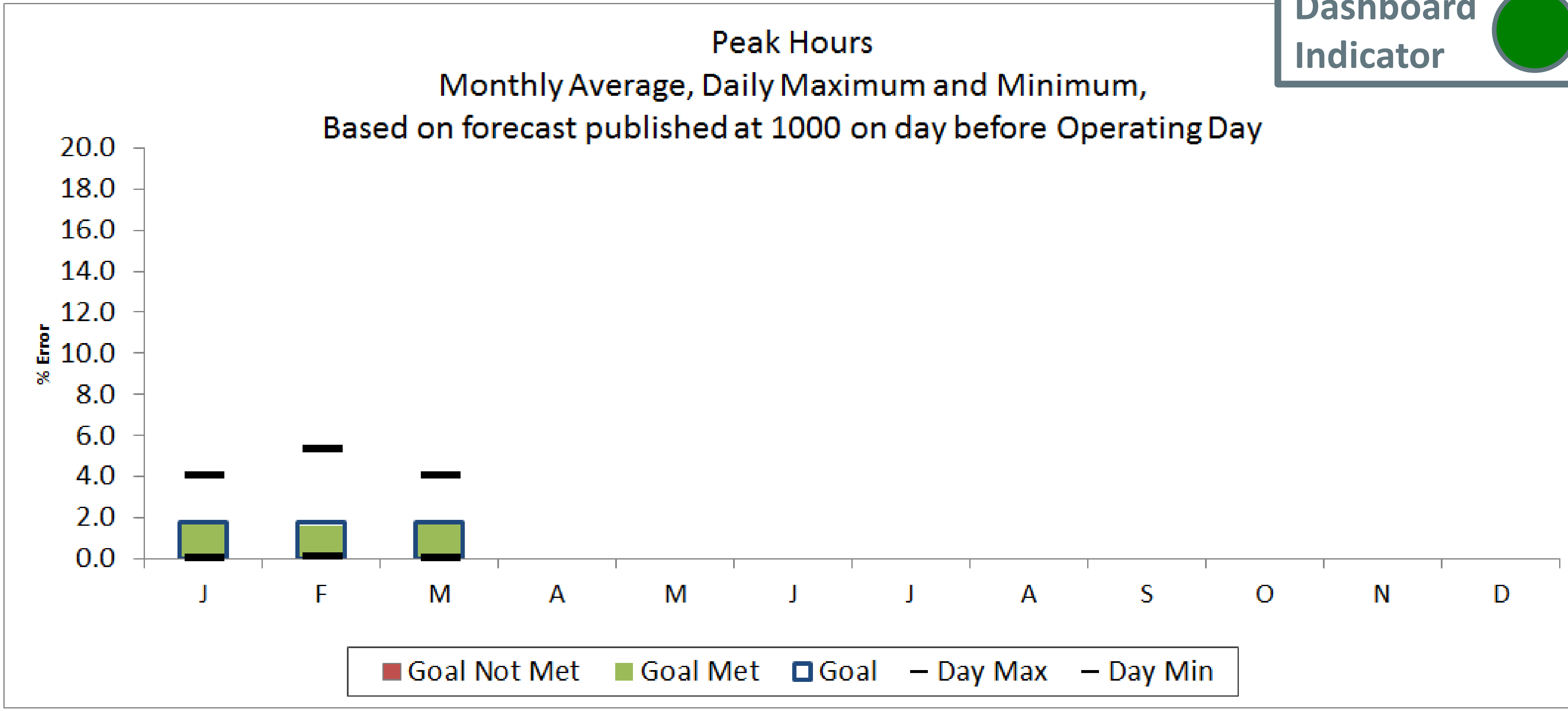
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14	7.12	6.59										7.12
Day Min	0.80	0.74	1.08										0.74
MAPE	1.91	2.34	2.70										2.32
Goal	1.80	1.80	1.80										

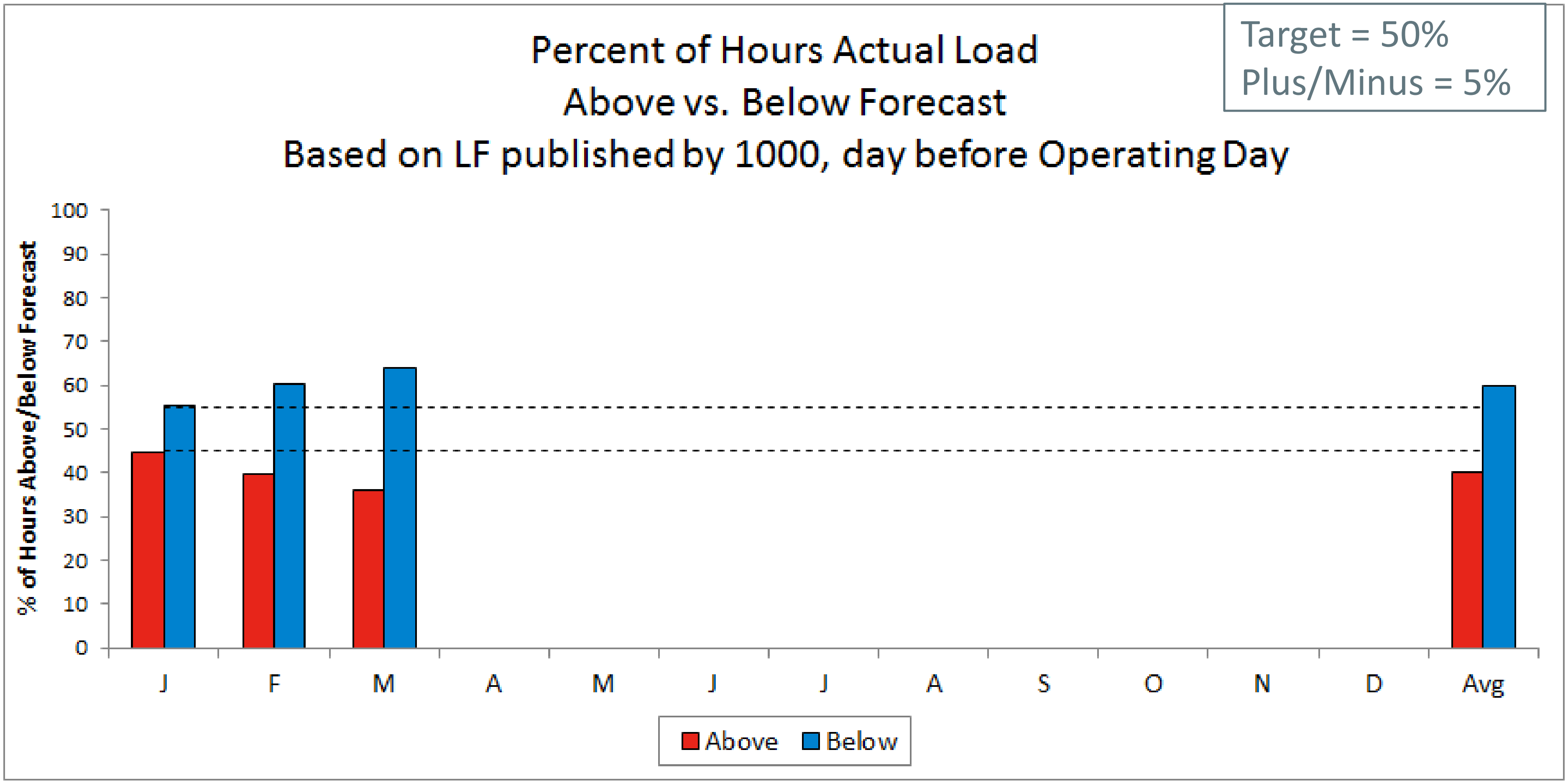
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



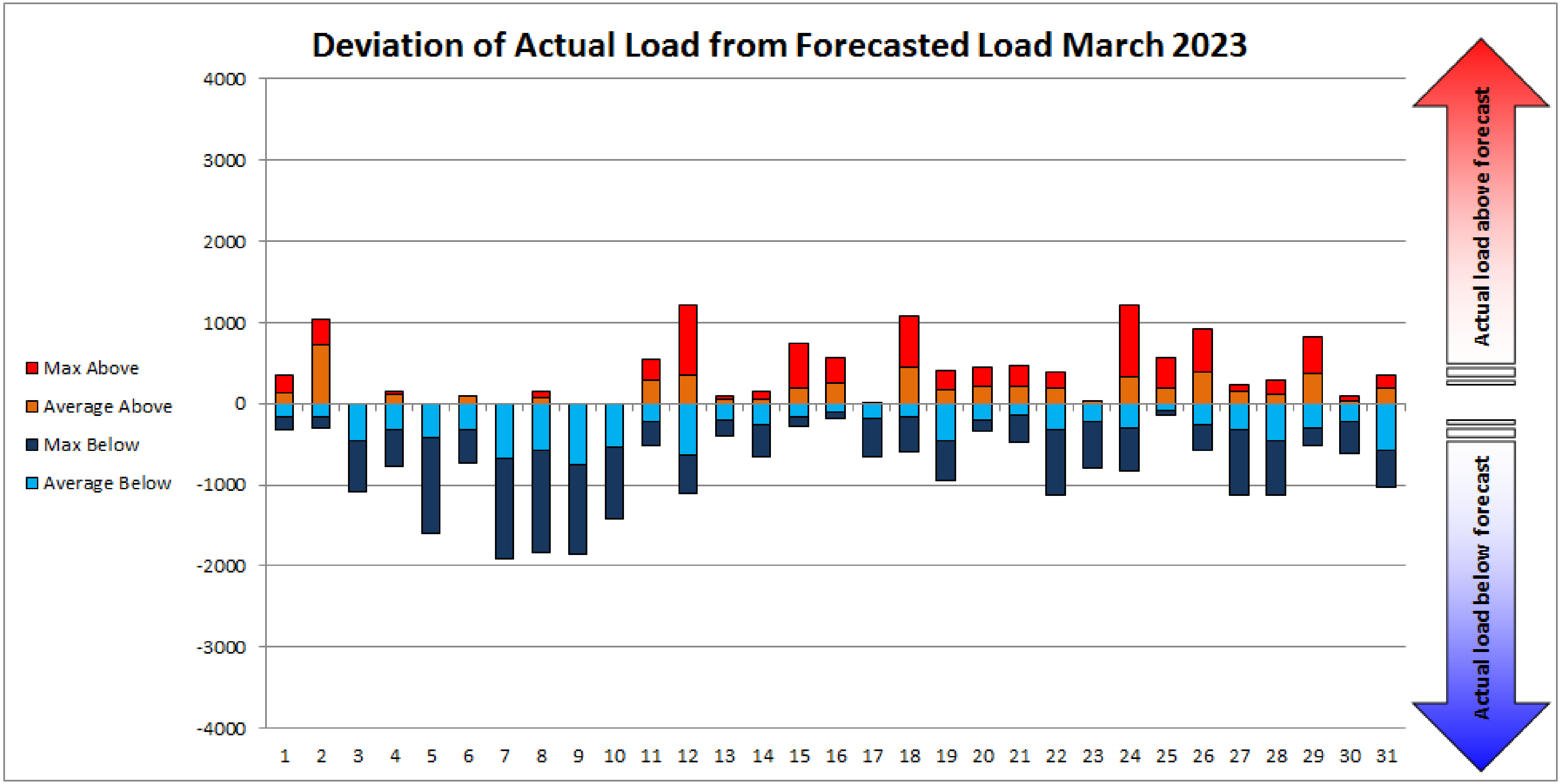
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06										5.32
Day Min	0.01	0.08	0.06										0.01
MAPE	1.70	1.64	1.72										1.69
Goal	1.80	1.80	1.80										

2023 System Operations - Load Forecast Accuracy cont.

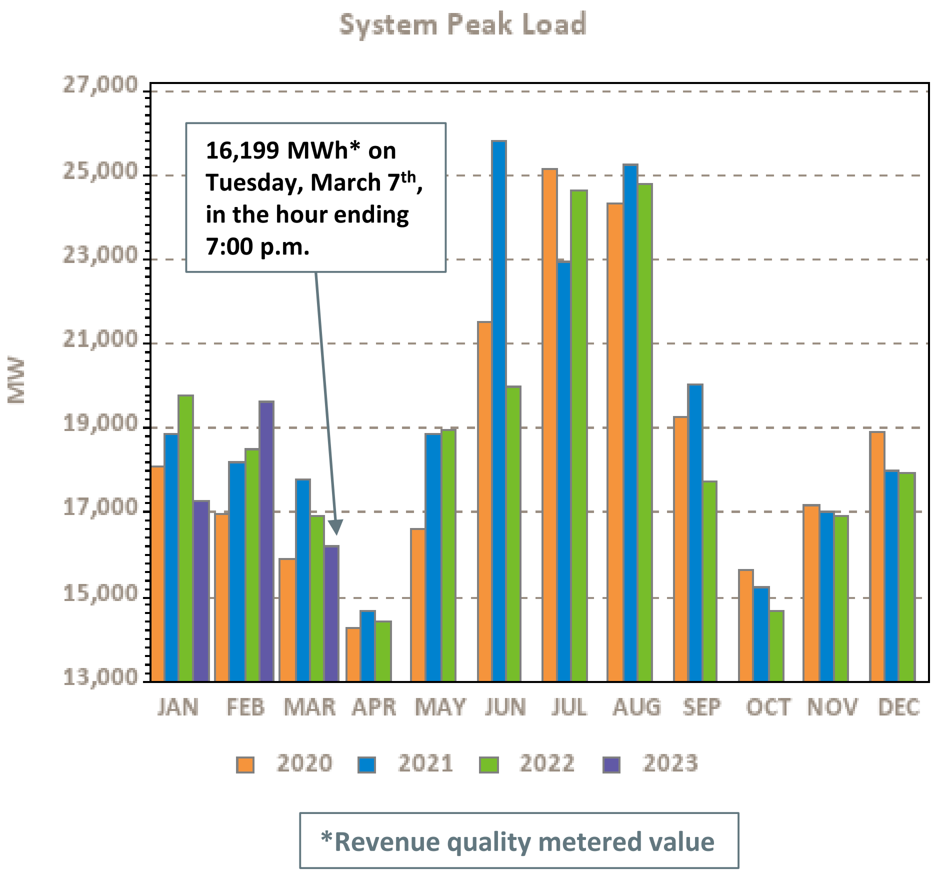


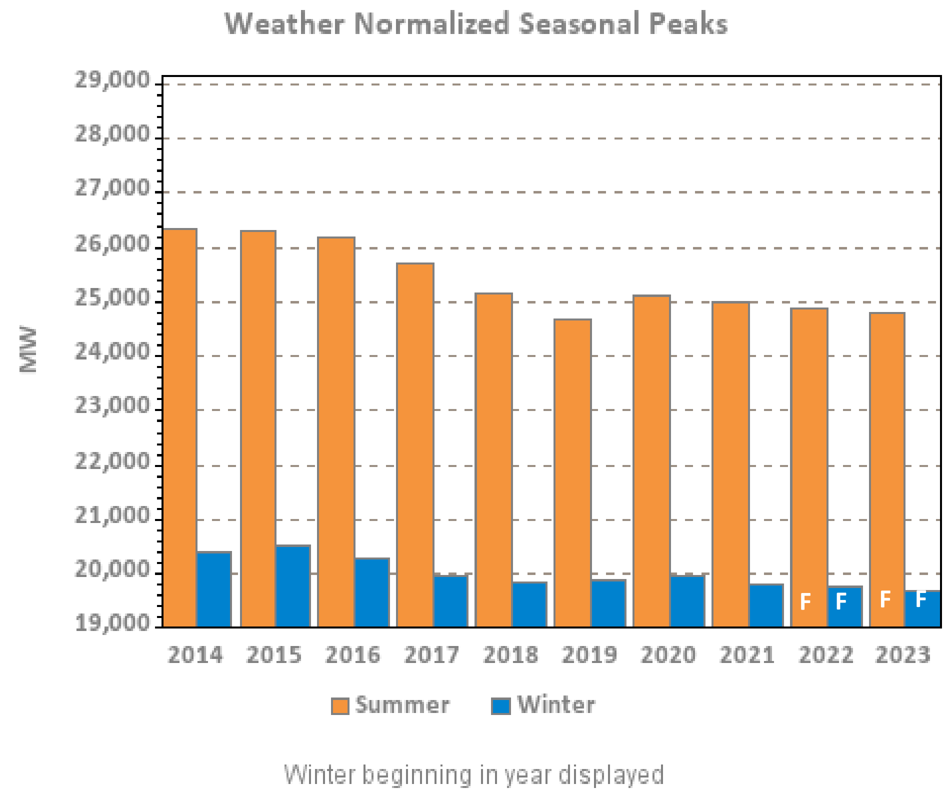
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2										40
Below %	55.4	60.3	63.8										60
Avg Above	471.4	456	345.7										471
Avg Below	-394.6	-497.7	-656.5										-657
Avg All	-10	-28	-142										-61

2023 System Operations - Load Forecast Accuracy cont.



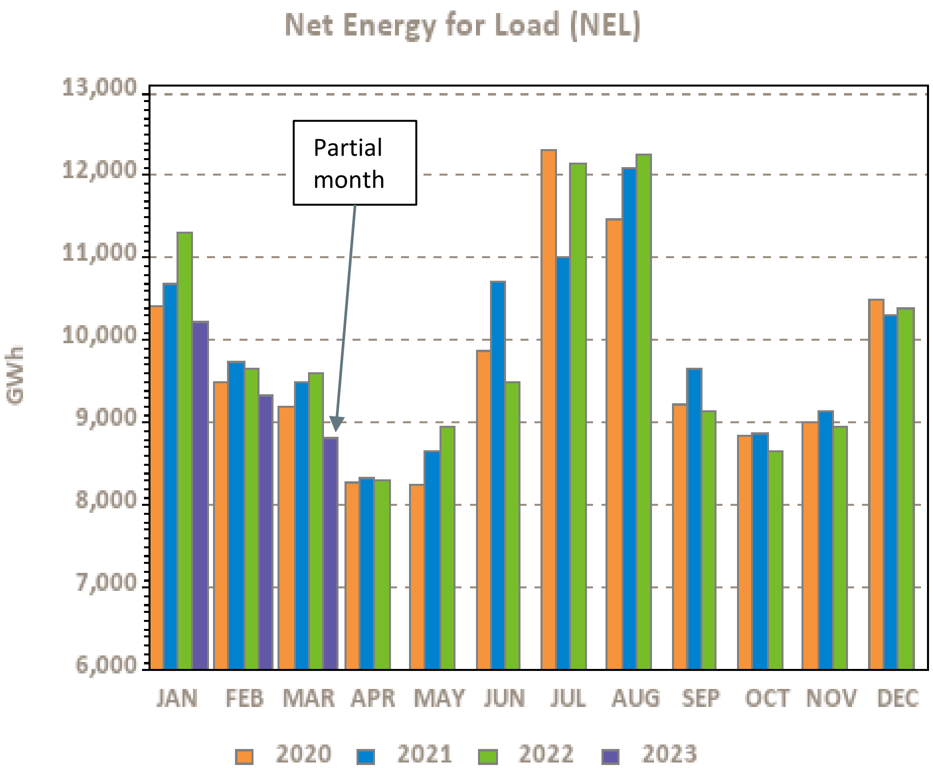
Monthly Peak Loads and Weather Normalized Seasonal Peak History



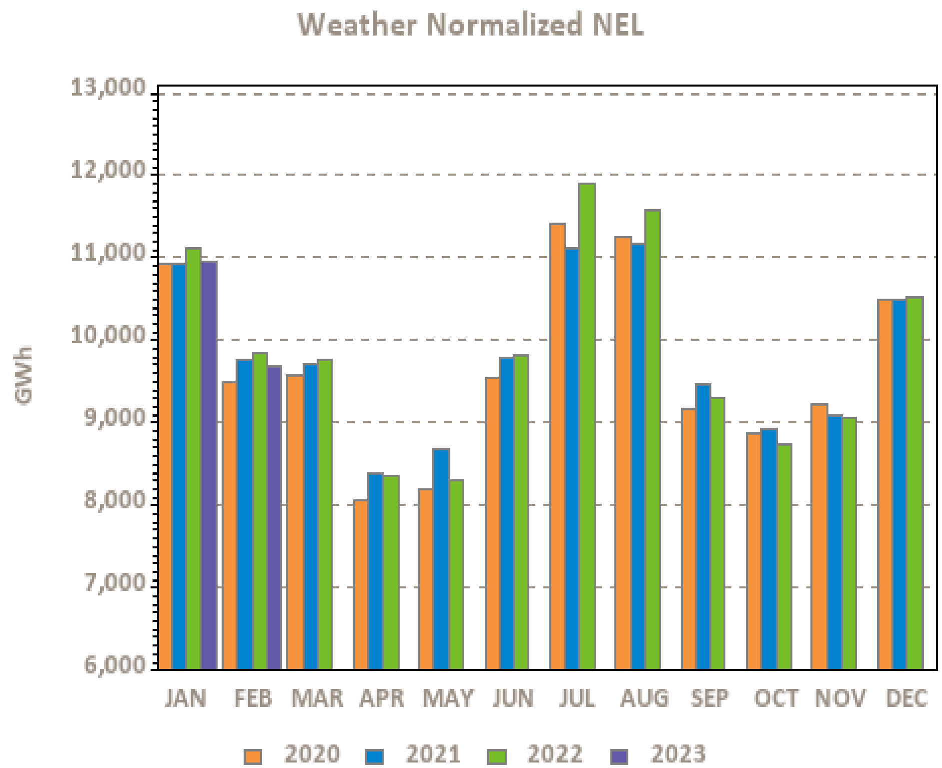


F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



Ann Tot (TWh): 116.9 118.8 118.9 28.4

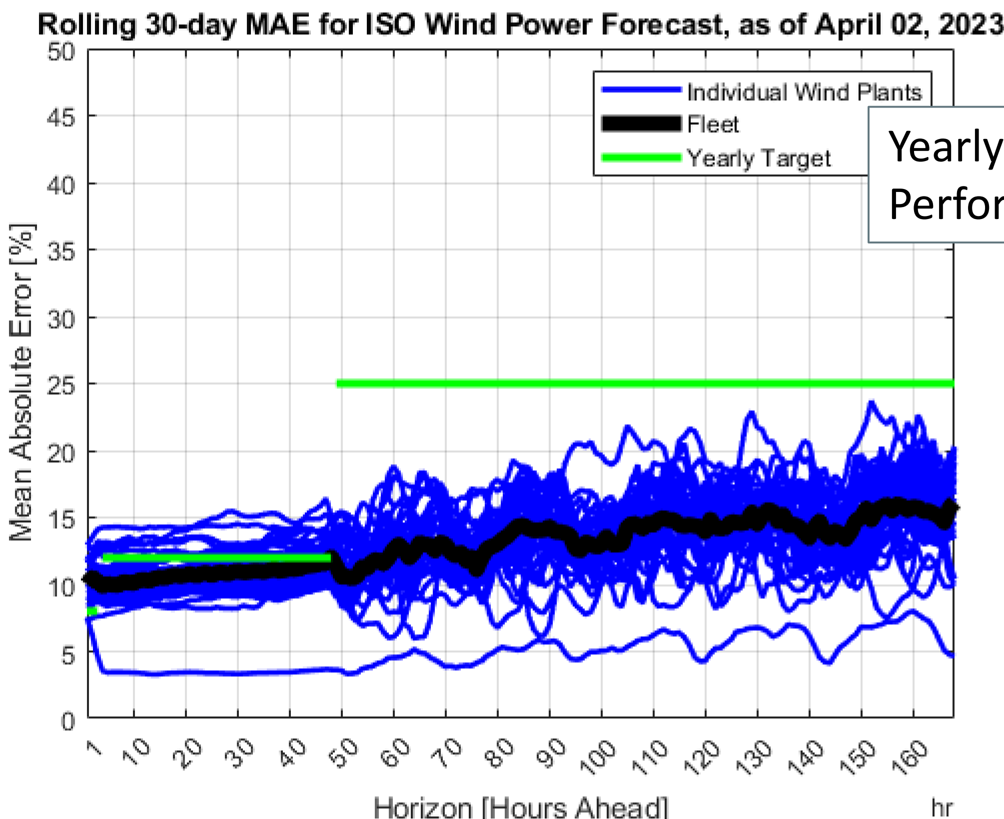


Ann Tot (TWh): 116.3 117.6 118.3 20.6

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

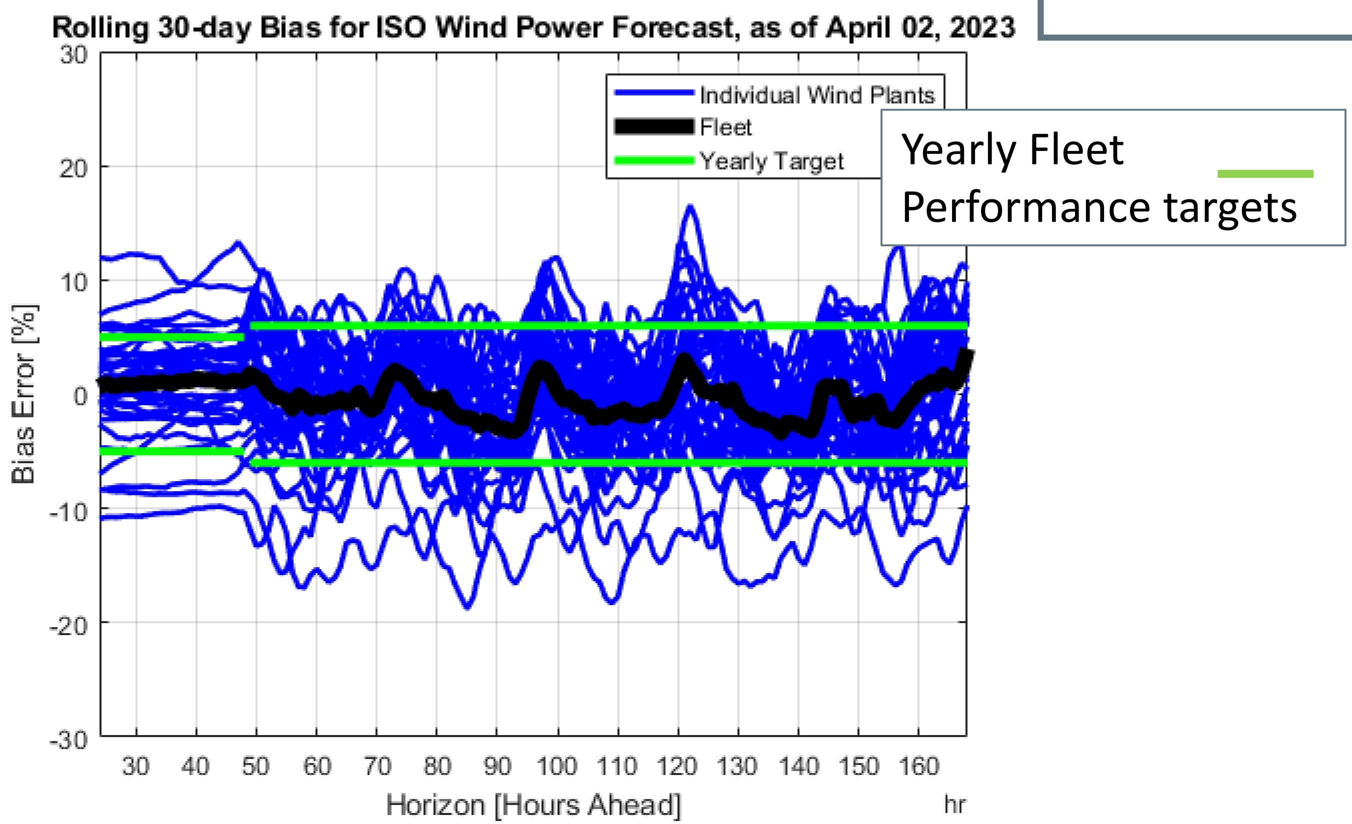


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the 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

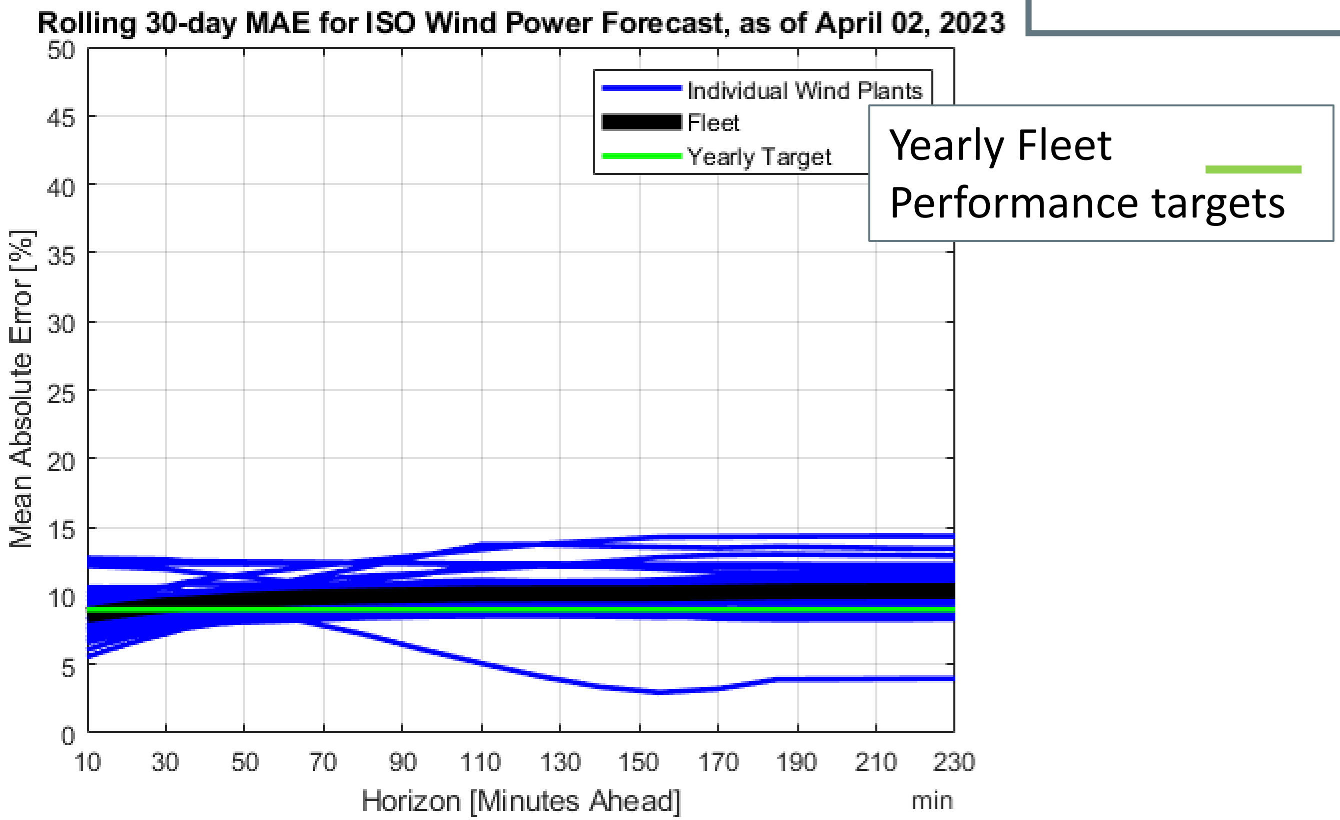
Dashboard Indicator



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

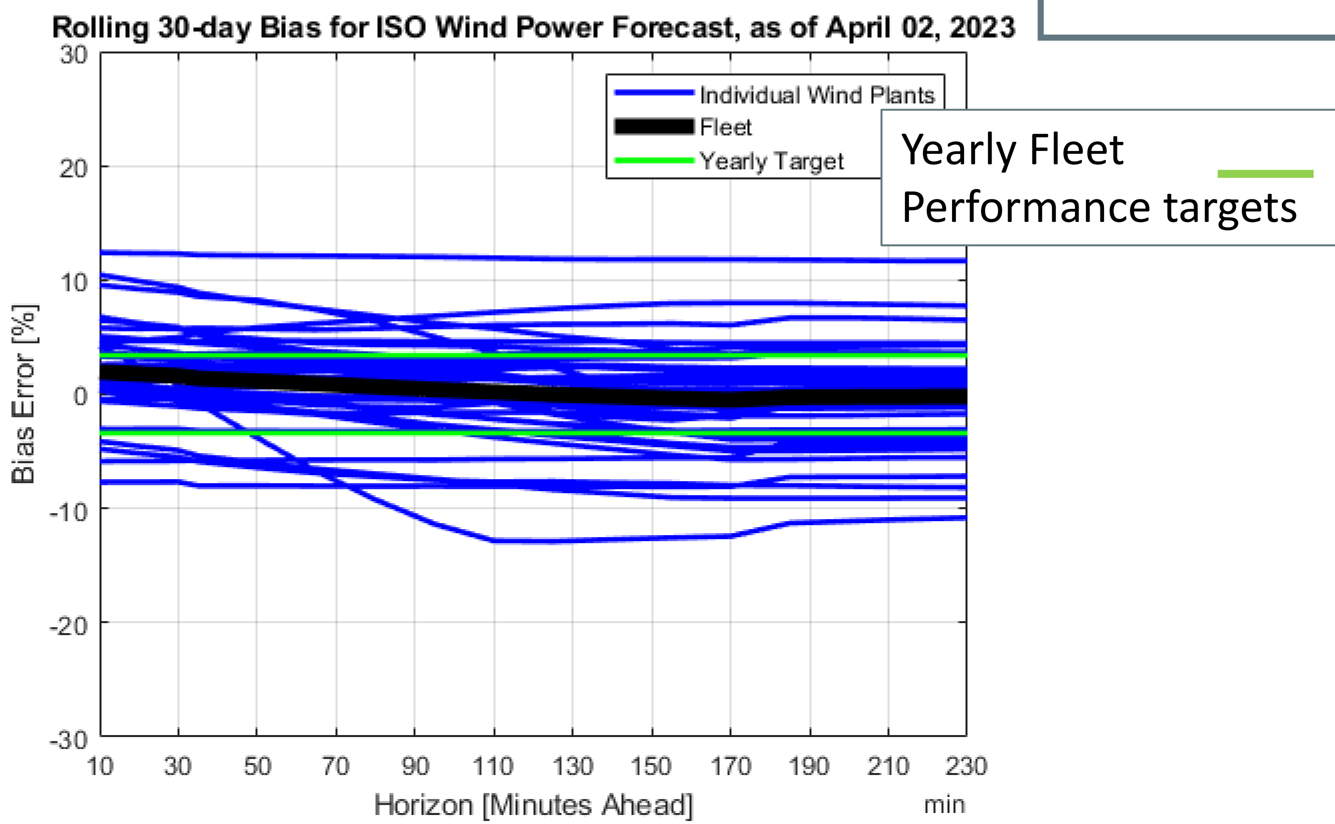
Dashboard Indicator



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 forecast compares with industry standards, monthly MAE is mostly outside yearly performance targets. Input data corrections are beginning to reduce error of dataset.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

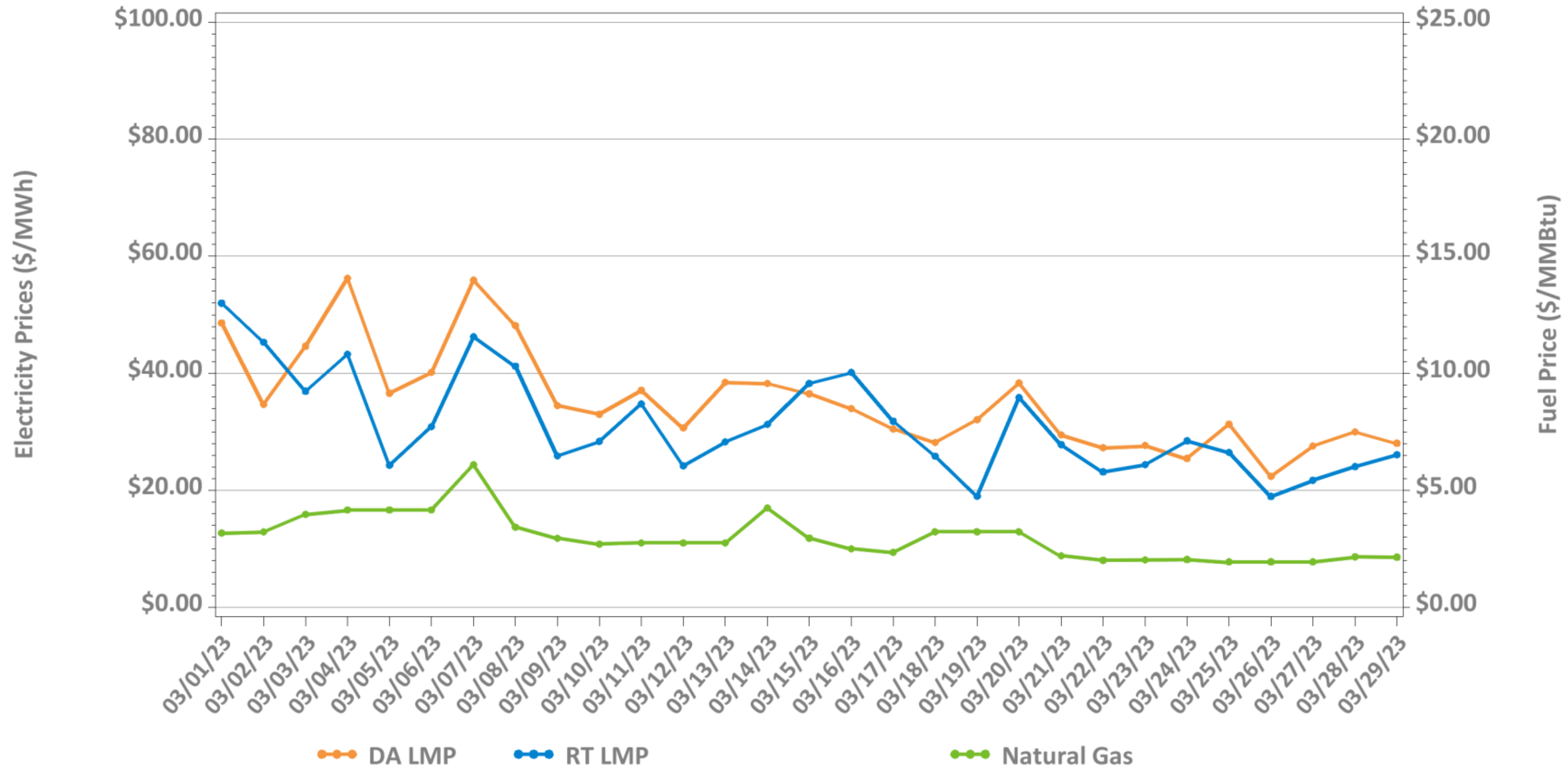
Dashboard Indicator



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

MARKET OPERATIONS

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



Underlying natural gas data furnished by:

ICE Global markets in clear view

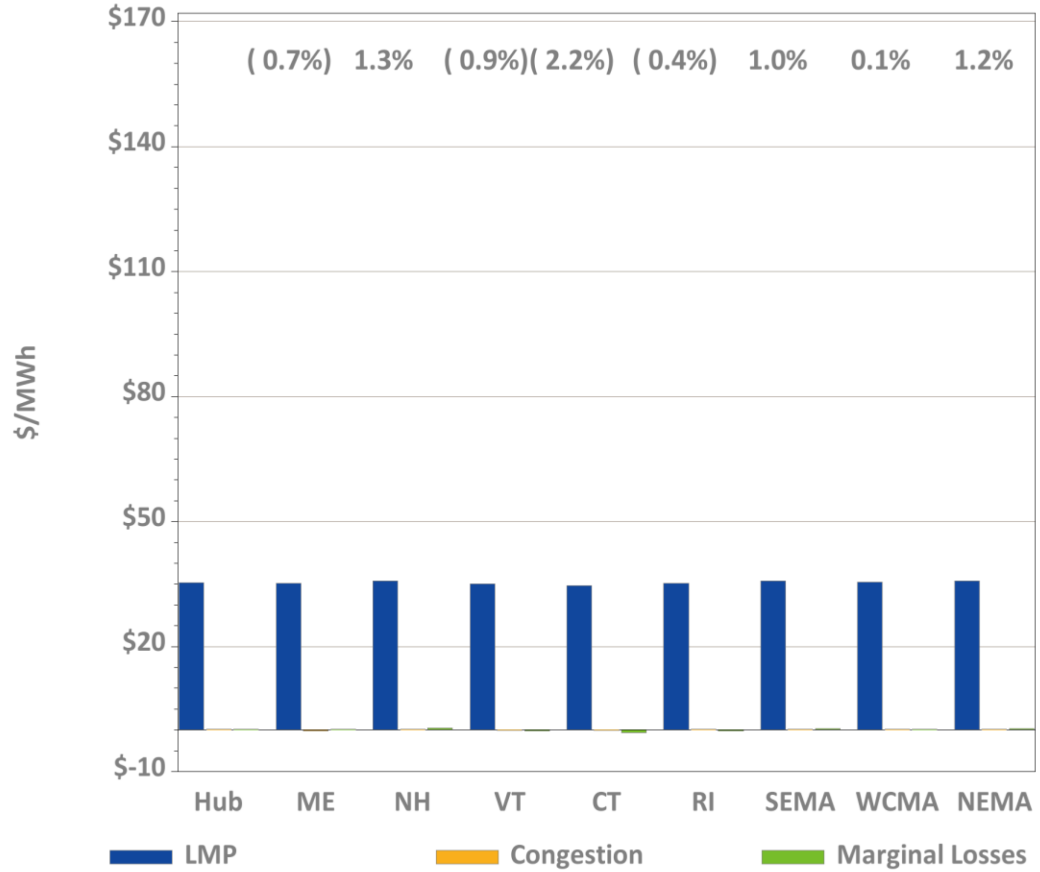
Average price difference over this period (DA-RT): $4.16

Average price difference over this period ABS(DA-RT): $5.98

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%

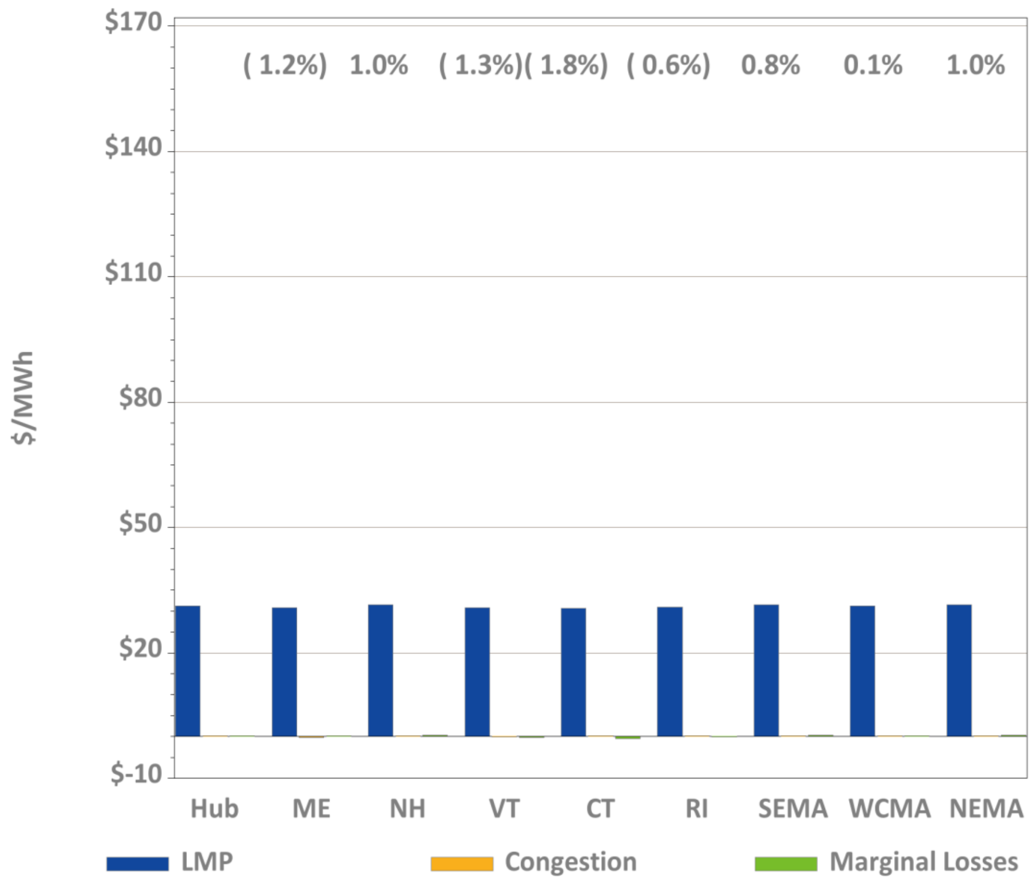
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, March 2023



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

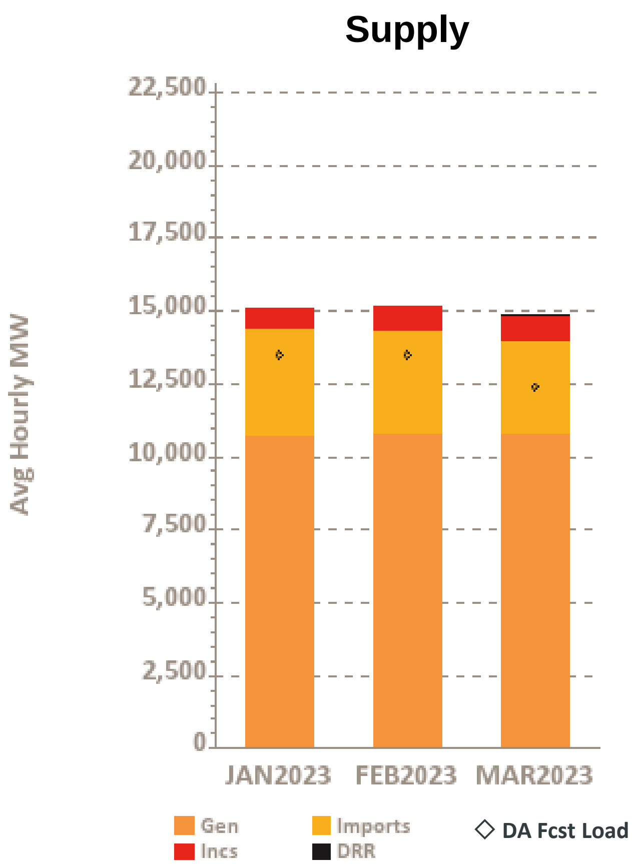
RT LMPs Average by Zone & Hub, March 2023

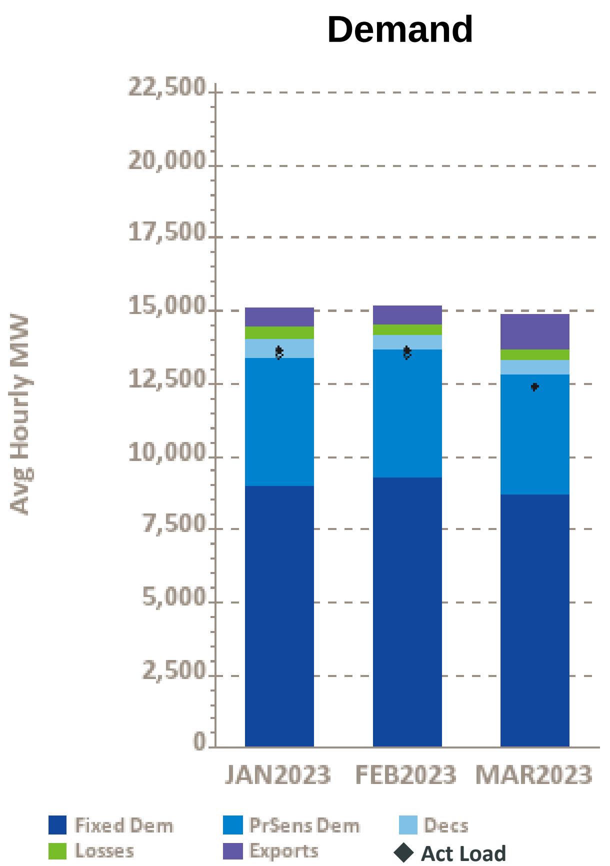


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

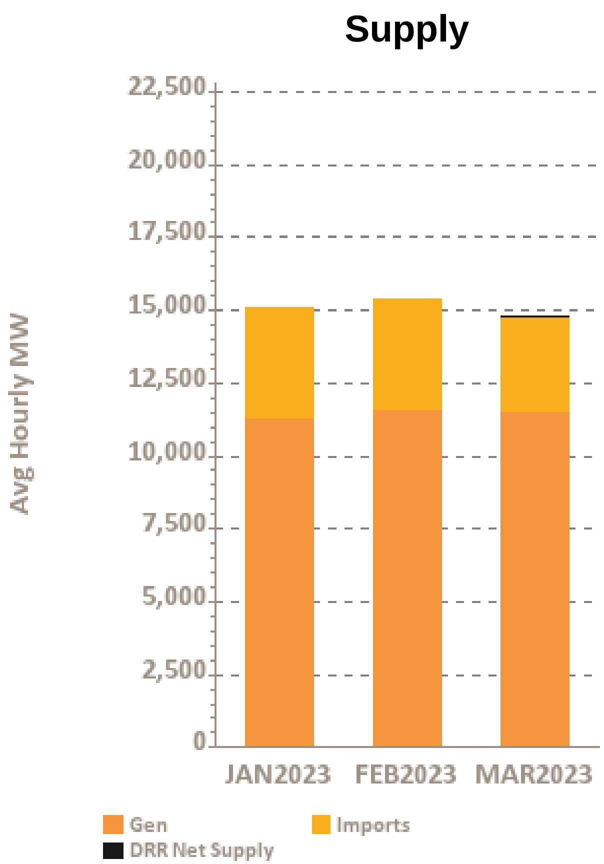


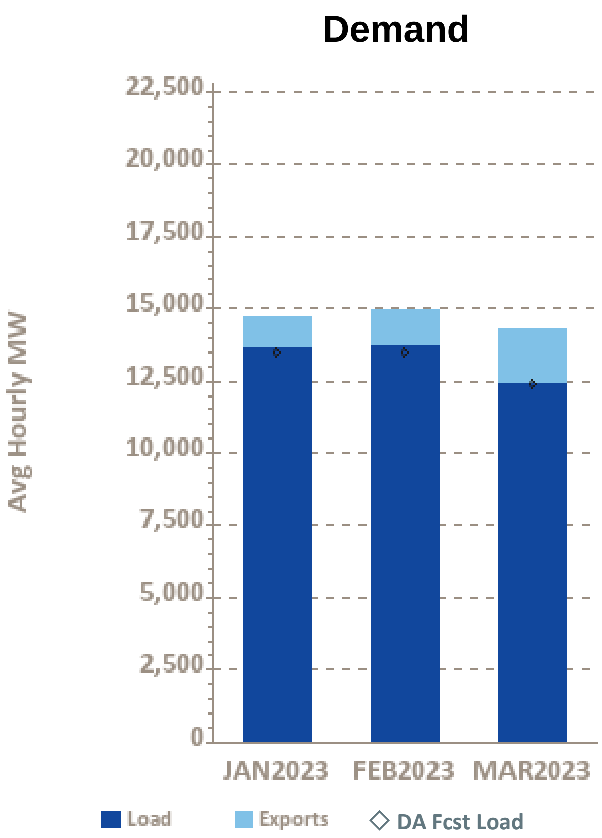


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

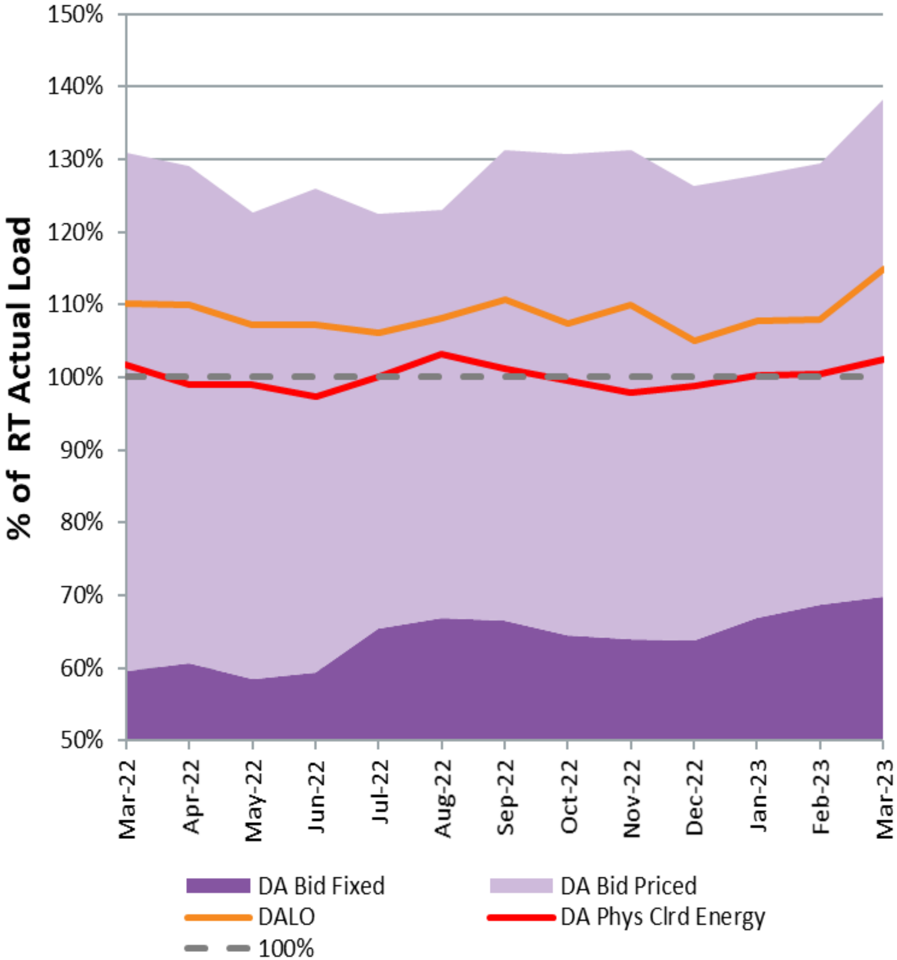
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

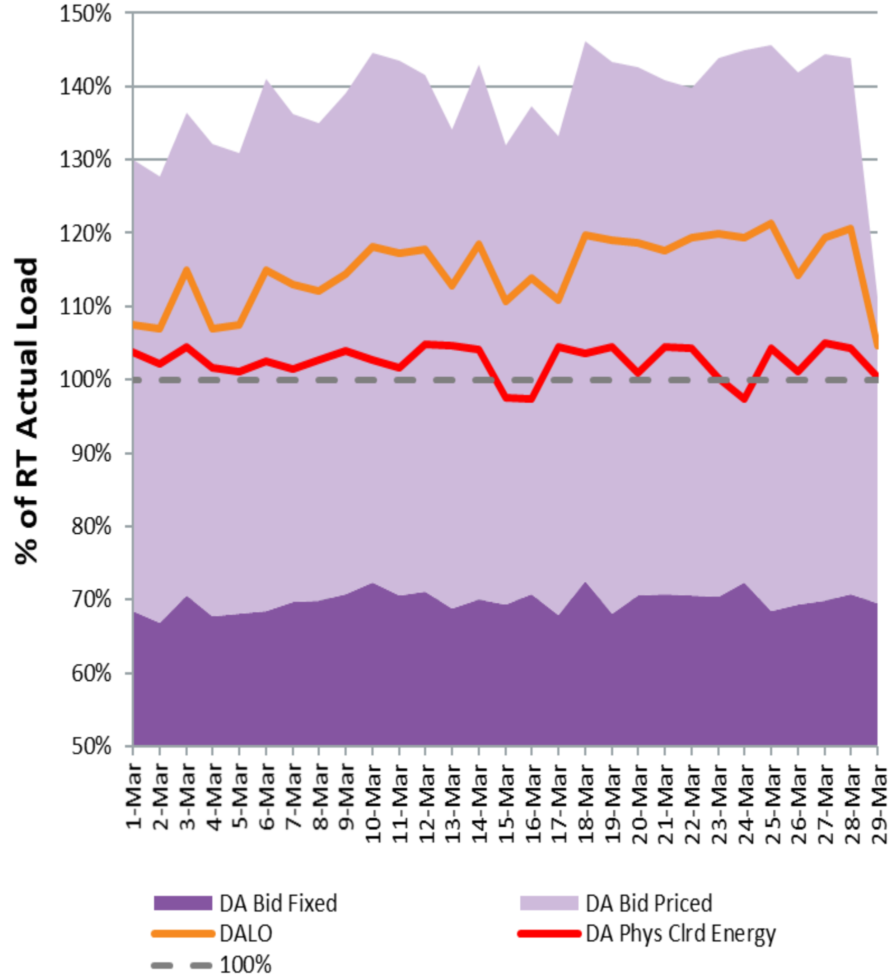
Components of RT Supply and Demand – Last Three Months





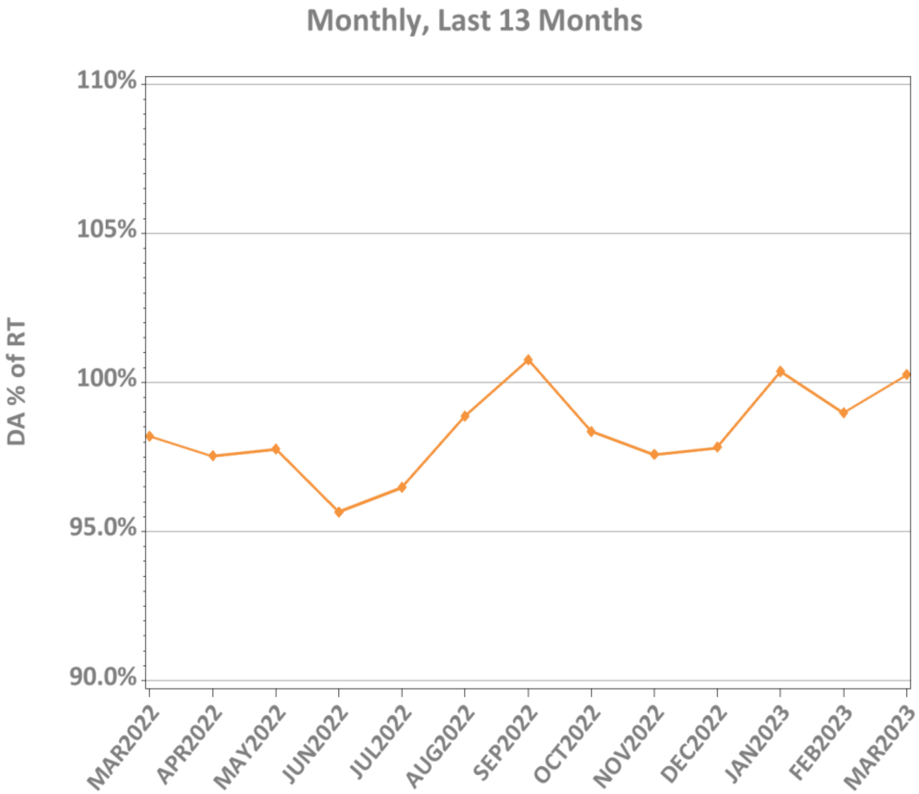
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

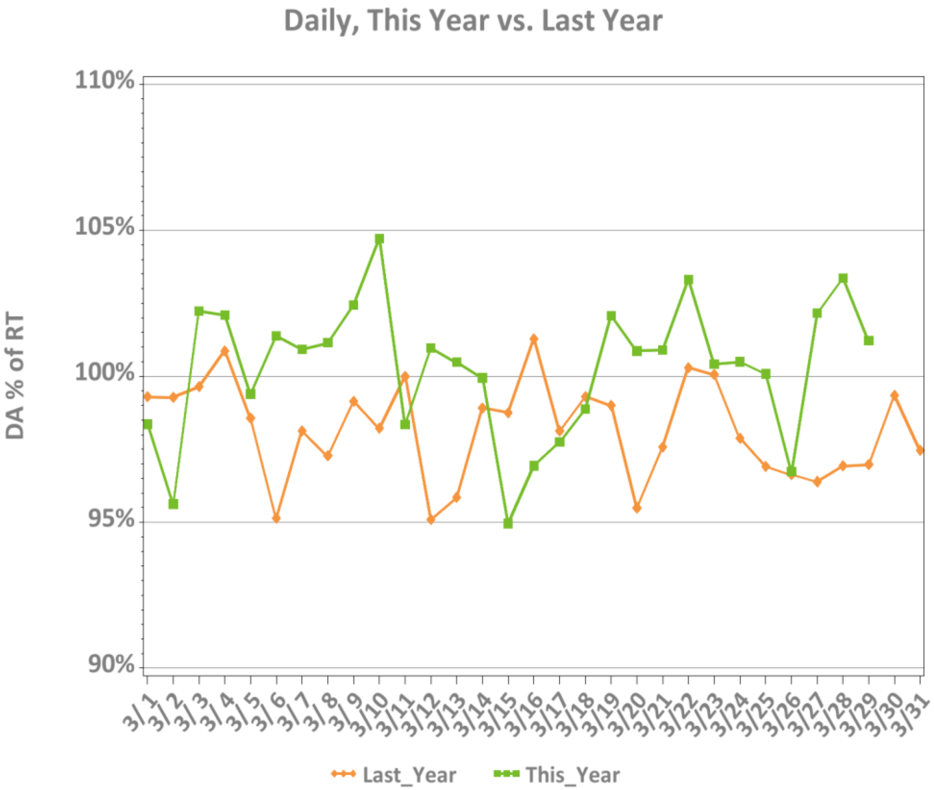




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

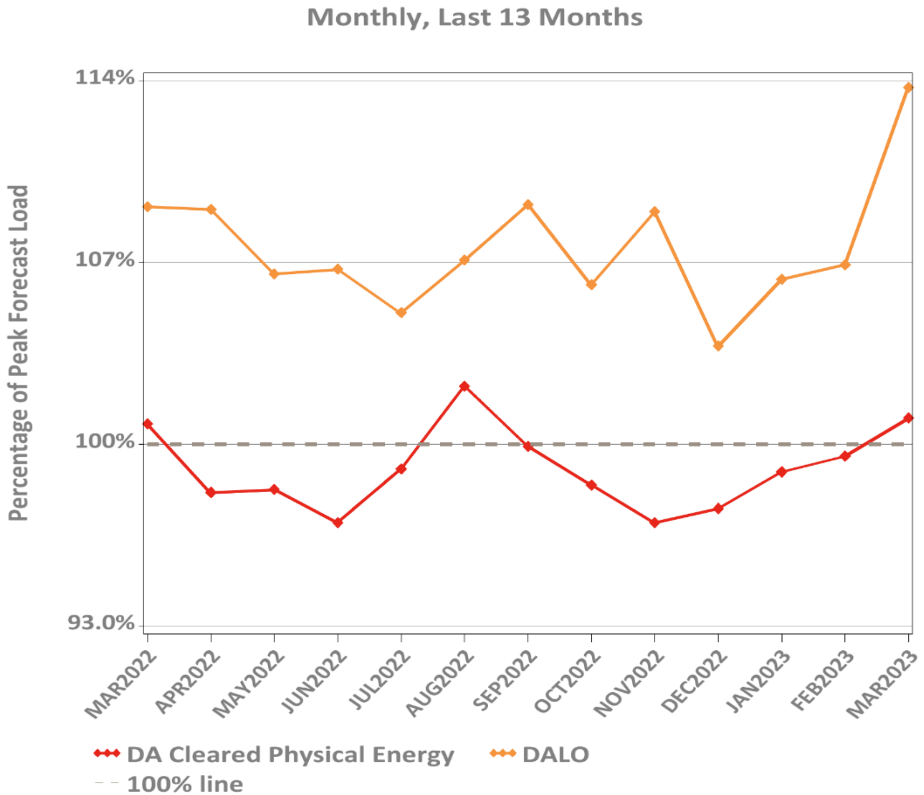
DA vs. RT Load Obligation: March, This Year vs. Last Year

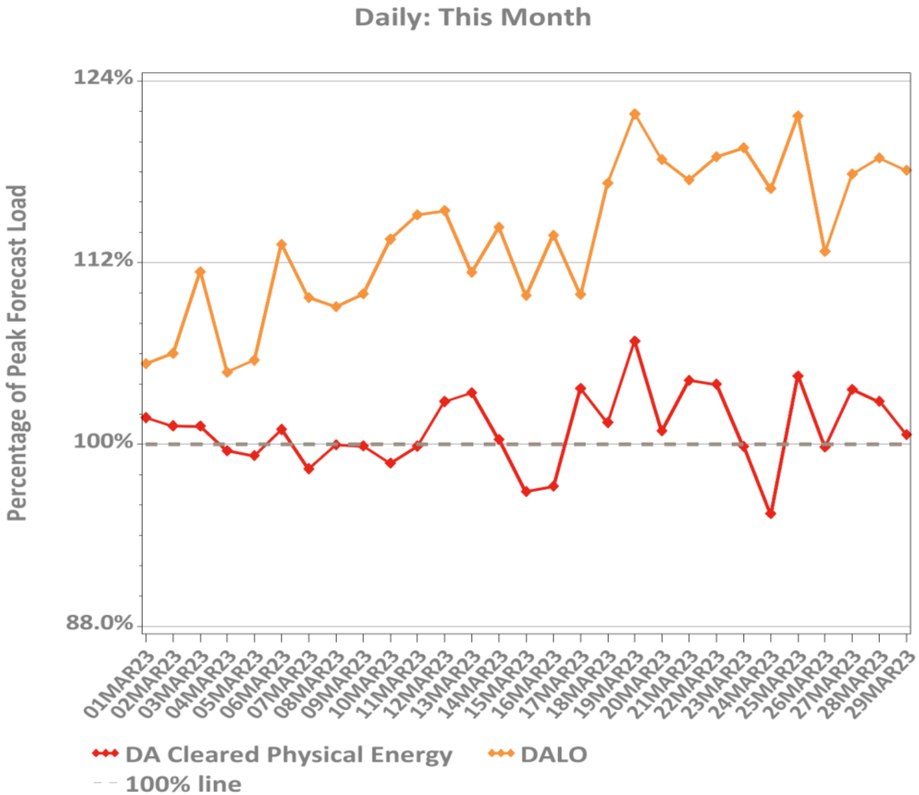




*Hourly average values

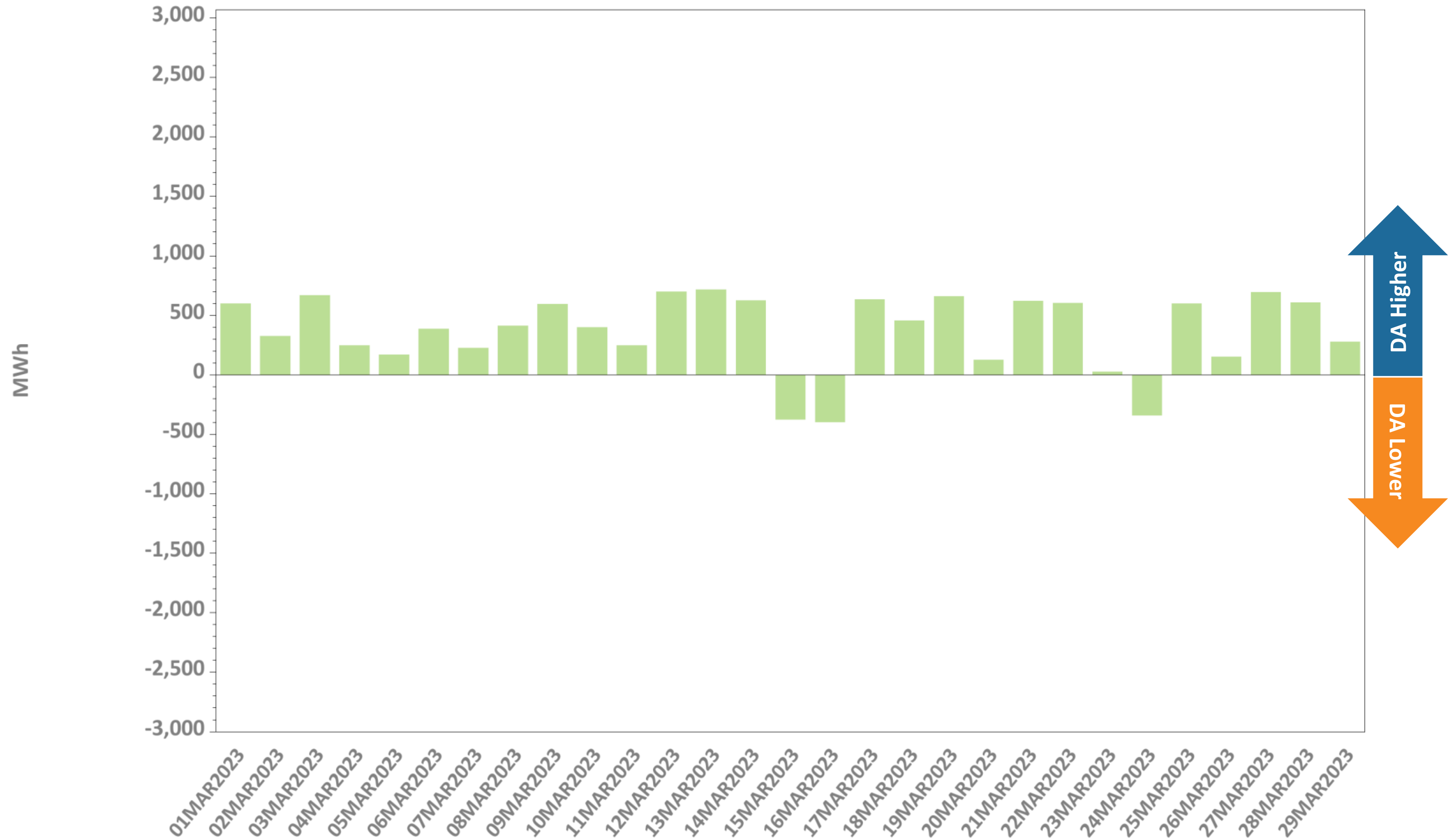
DA Volumes as % of Forecast in Peak Hour





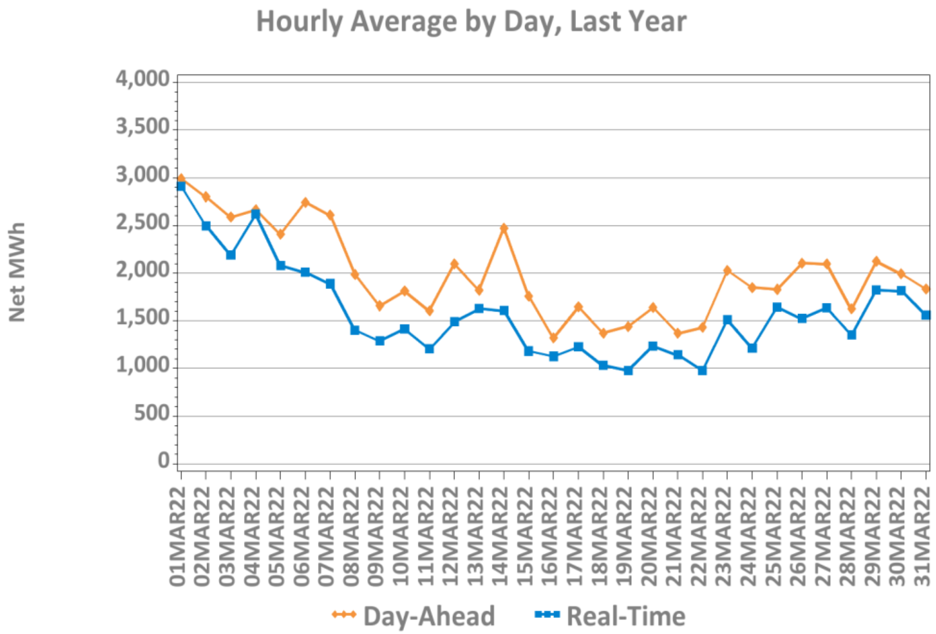
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

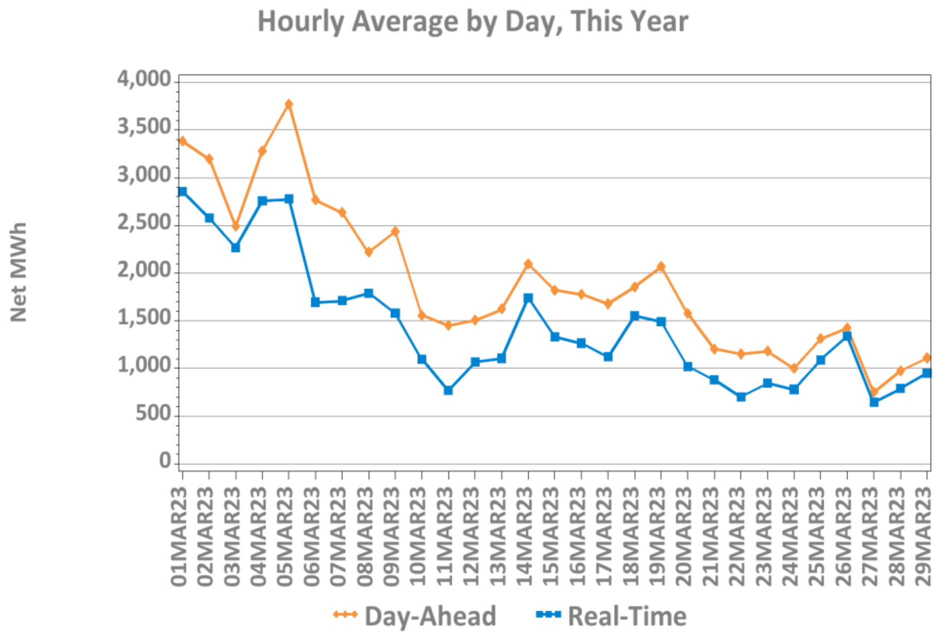
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

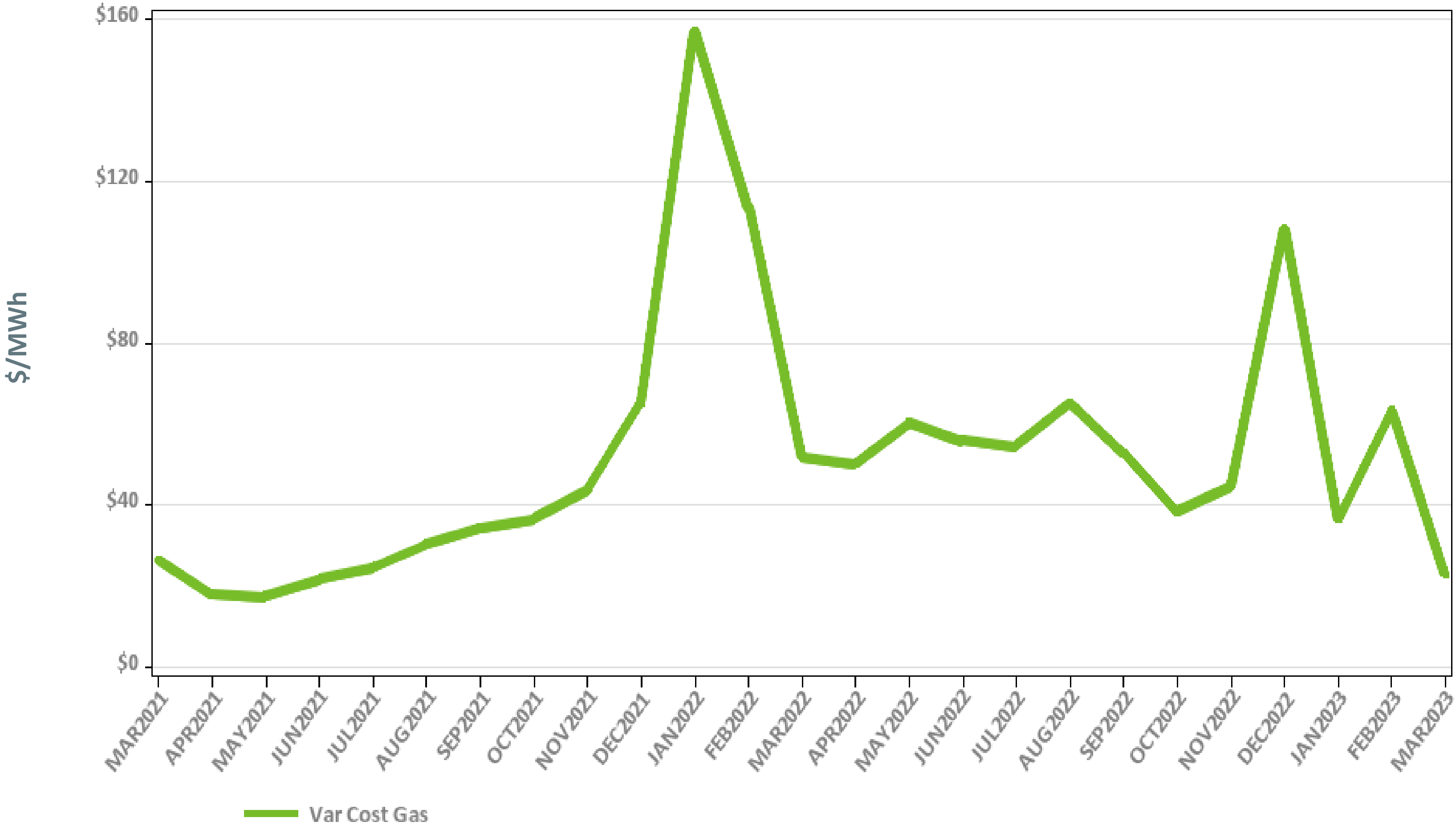
DA vs. RT Net Interchange March 2023 vs. March 2022





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

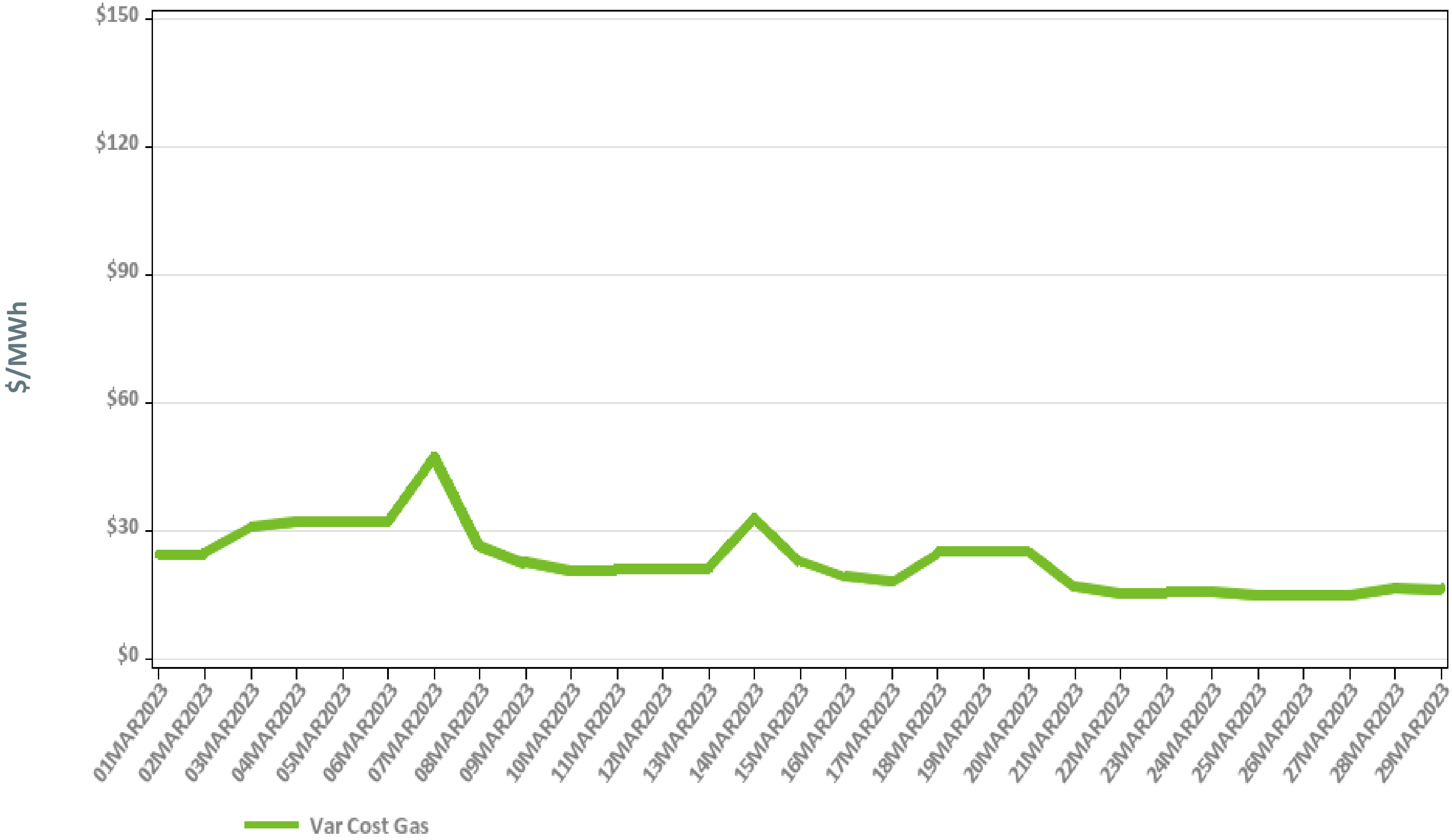


Underlying natural gas data furnished by:

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

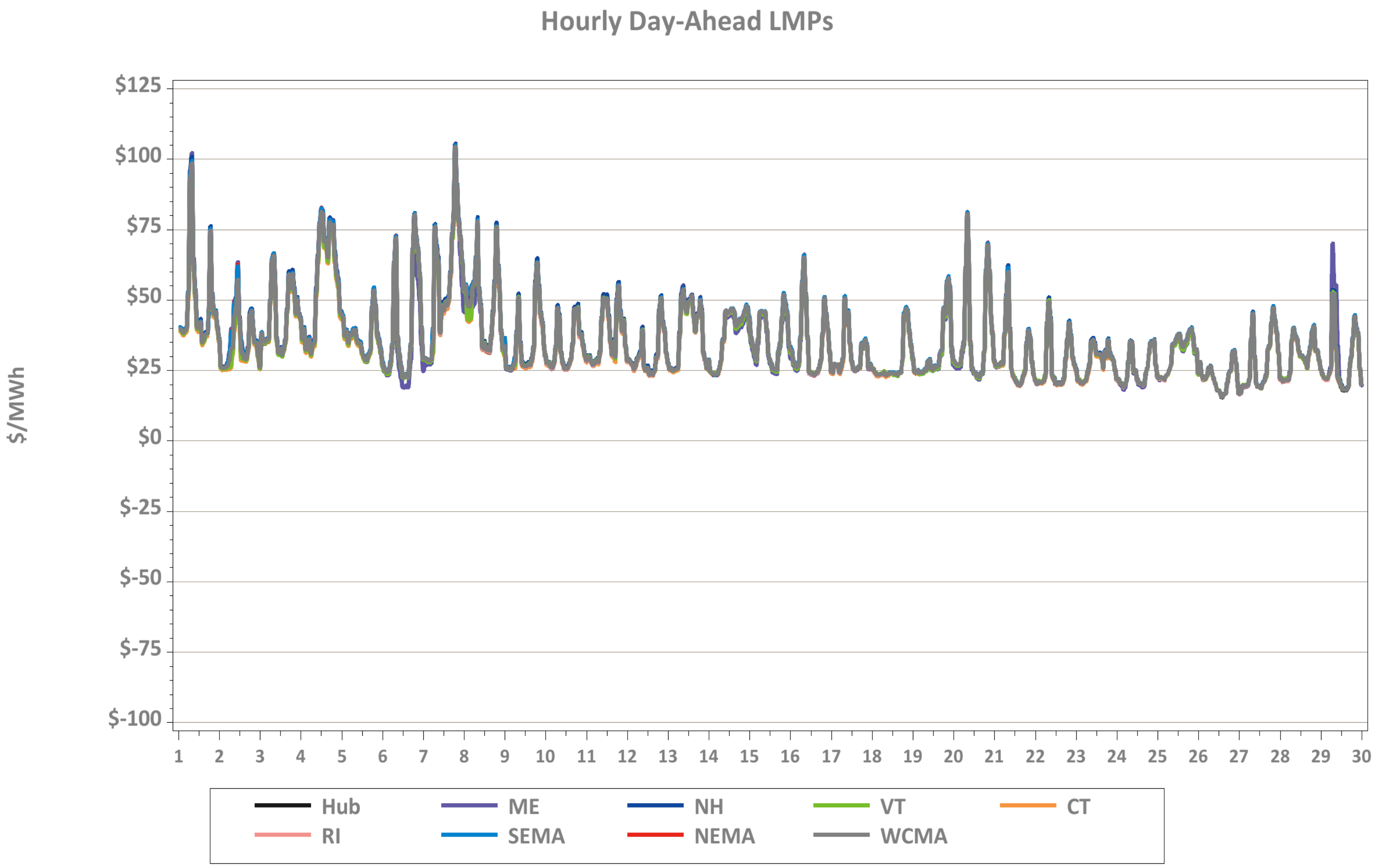


Underlying natural gas data furnished by:

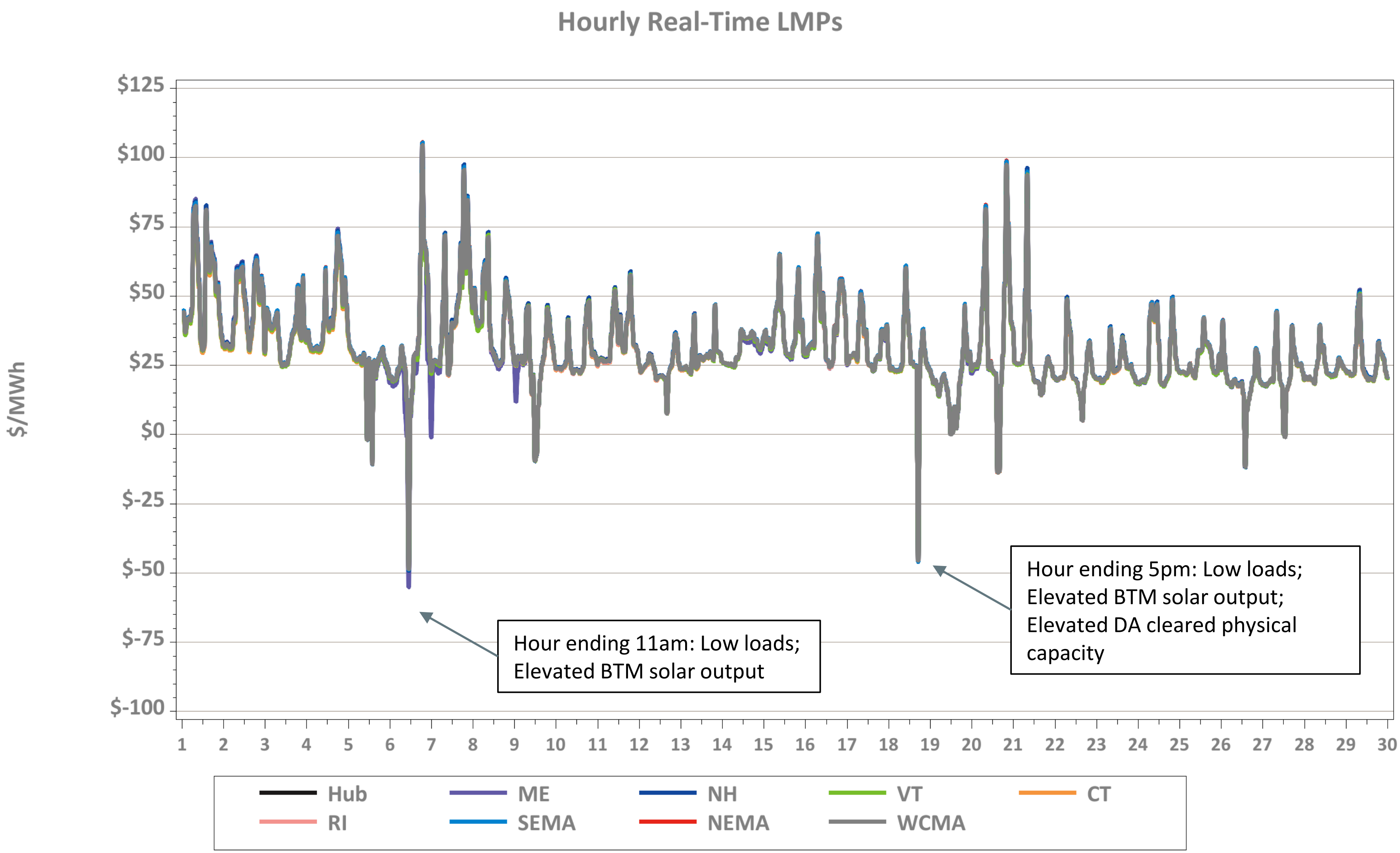
ice Global markets in clear view

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

Hourly DA LMPs, March 1-29, 2023

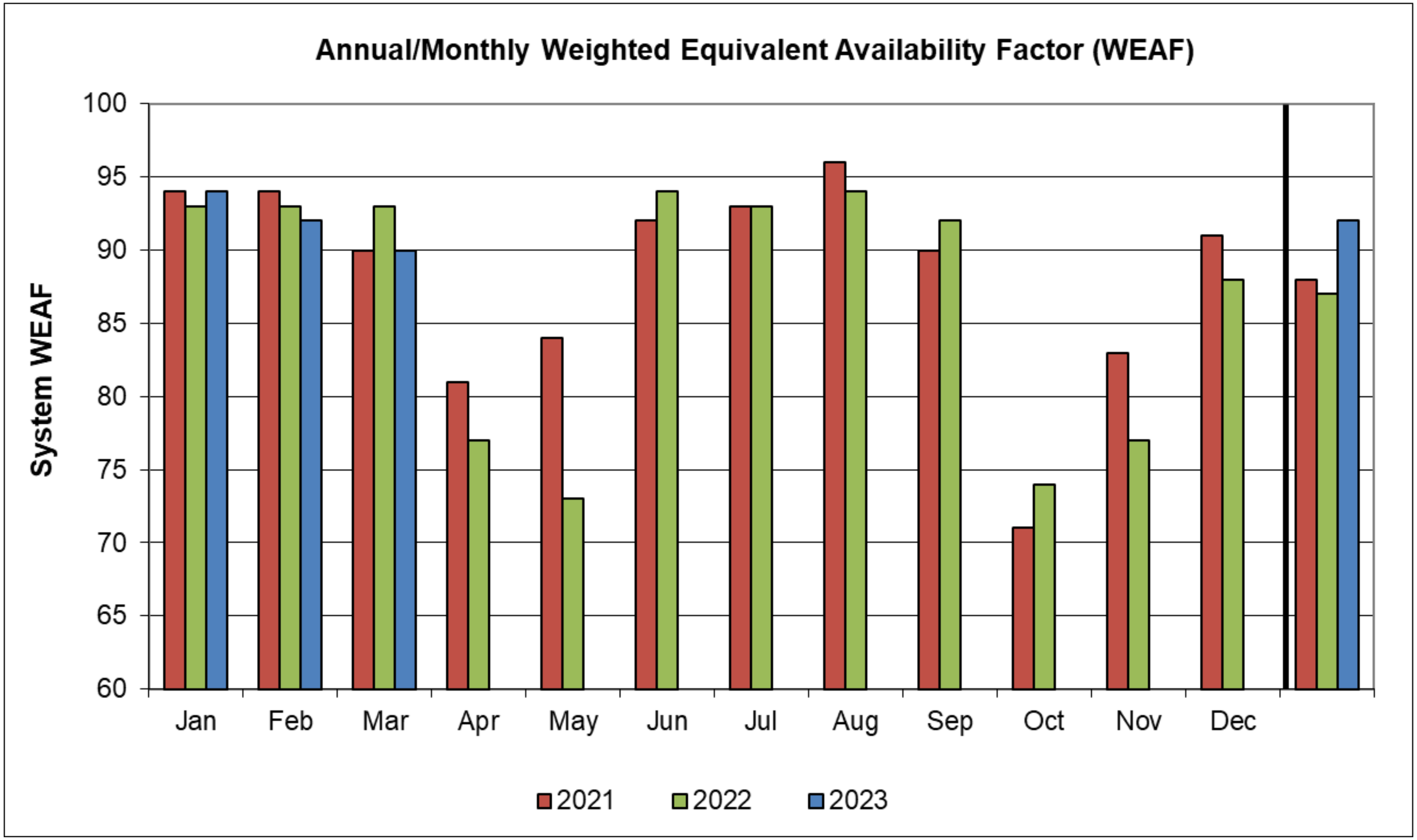


Hourly RT LMPs, March 1-29, 2023



* BTM (Behind the meter)

System Unit Availability



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

Data as of 3/23/2023

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	49.2	217.2	0.0	266.4
NH	38.6	174.1	0.0	212.7
VT	39.3	135.1	0.0	174.4
CT	117.8	244.1	614.4	976.3
RI	30.3	346.2	0.0	376.4
SEMA	40.1	508.9	0.0	549.0
WCMA	76.9	541.7	35.2	653.8
NEMA	64.3	873.7	0.0	938.0
Total	**456.5**	**3,040.9**	**649.5**	**4,146.9**

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

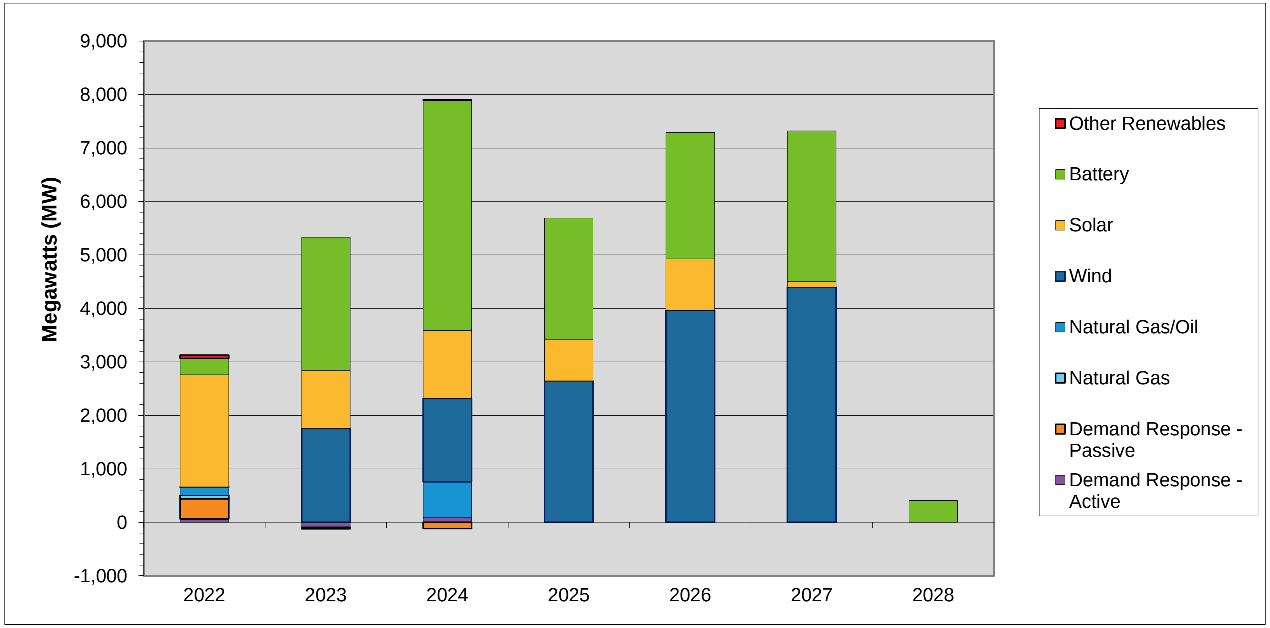
NEW GENERATION

New Generation Update
Based on Queue as of 3/29/23

- Nine projects totaling 2,085 MW were added to the interconnection queue since the last update
  - Eight battery projects and one solar project with in-service dates of 2025 to 2027
- Four projects were withdrawn and no projects went commercial
- In total, 374 generation projects are currently being tracked by the ISO, totaling approximately 40,297 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



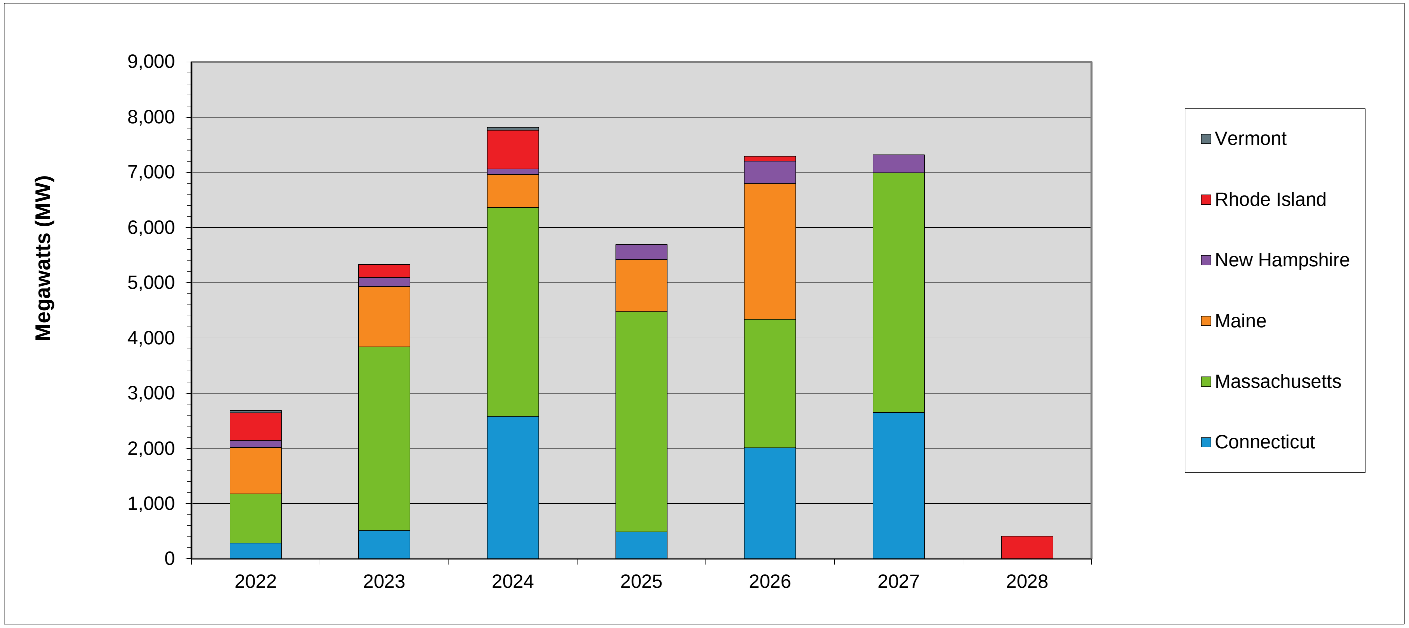
	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	63	0	2	0	0	0	0	65	0.2
Battery	305	2,486	4,306	2,276	2,367	2,818	410	14,968	40.6
Solar[2]	2,095	1,094	1,277	772	964	102	0	6,304	17.1
Wind	4	1,752	1,556	2,645	3,962	4,399	0	14,318	38.9
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.2
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.6
Demand Response - Active	62	-94	86	0	0	0	0	54	0.1
Totals	3,127	5,210	7,785	5,693	7,293	7,319	410	36,837	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	0.2
Rhode Island	502	236	704	0	91	0	410	1,943	5.3
New Hampshire	129	164	97	272	402	328	0	1,392	3.8
Maine	838	1,092	597	944	2,461	0	0	5,932	16.2
Massachusetts	893	3,324	3,786	3,989	2,327	4,343	0	18,662	51.1
Connecticut	283	516	2,579	488	2,012	2,648	0	8,526	23.3
Totals	**2,685**	**5,332**	**7,813**	**5,693**	**7,293**	**7,319**	**410**	**36,545**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	94	14,968	3	32	91	14,936
Fuel Cell	3	32	0	0	3	32
Hydro	2	33	1	5	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	235	6,304	17	381	218	5,923
Wind	28	18,070	0	0	28	18,070
Total	374	40,297	22	480	352	39,817

- 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	6	72	1	5	5	67
Intermediate	7	804	0	0	7	804
Peaker	333	21,351	21	475	312	20,876
Wind Turbine	28	18,070	0	0	28	18,070
Total	374	40,297	22	480	352	39,817

- 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

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	94	14,968	0	0	0	0	94	14,968	0	0
Fuel Cell	3	32	3	32	0	0	0	0	0	0
Hydro	2	33	2	33	0	0	0	0	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	235	6,304	0	0	0	0	235	6,304	0	0
Wind	28	18,070	0	0	0	0	0	0	28	18,070
Total	374	40,297	6	72	7	804	333	21,351	28	18,070

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	592.043	688.07	96.027	659.671	-28.399		
	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		
	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 reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272				
	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 and reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35						
	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 reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

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

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

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

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

What are Daily NCPC Payments?

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

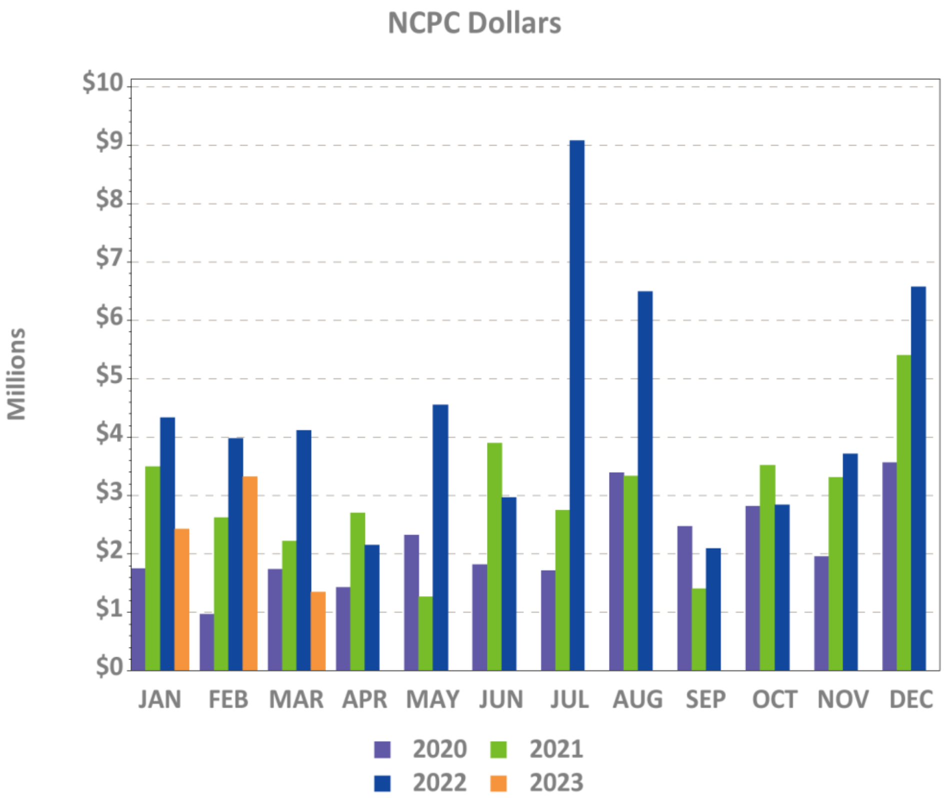
Definitions

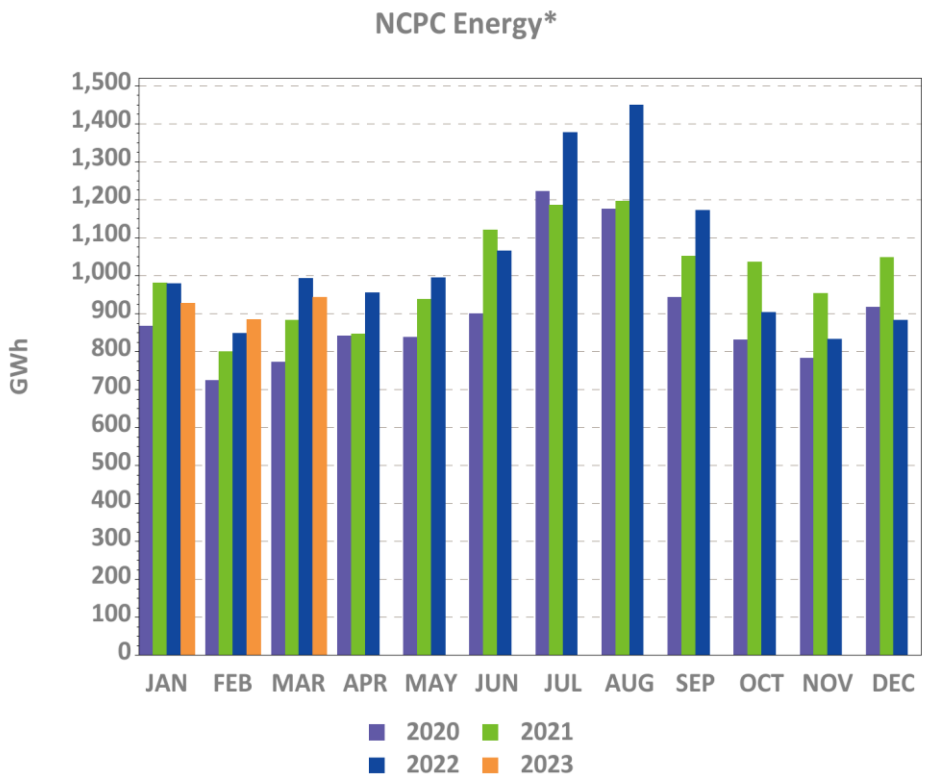
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

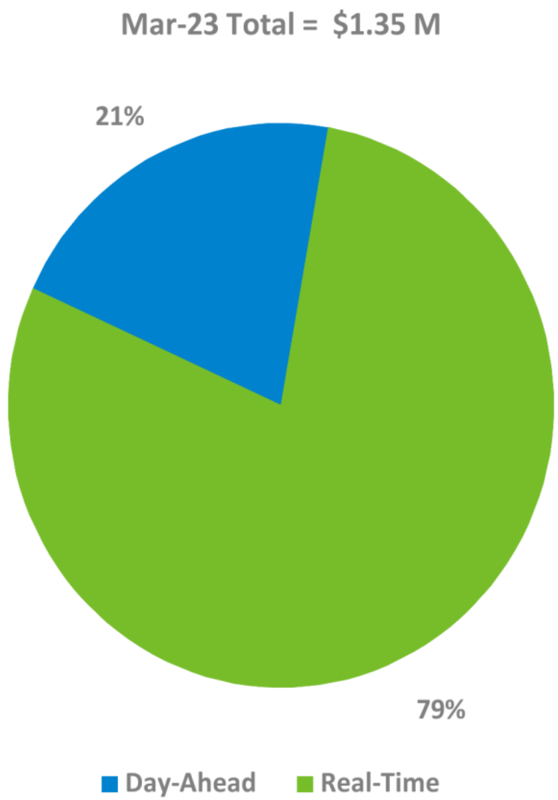
Year-Over-Year Total NCPC Dollars and Energy

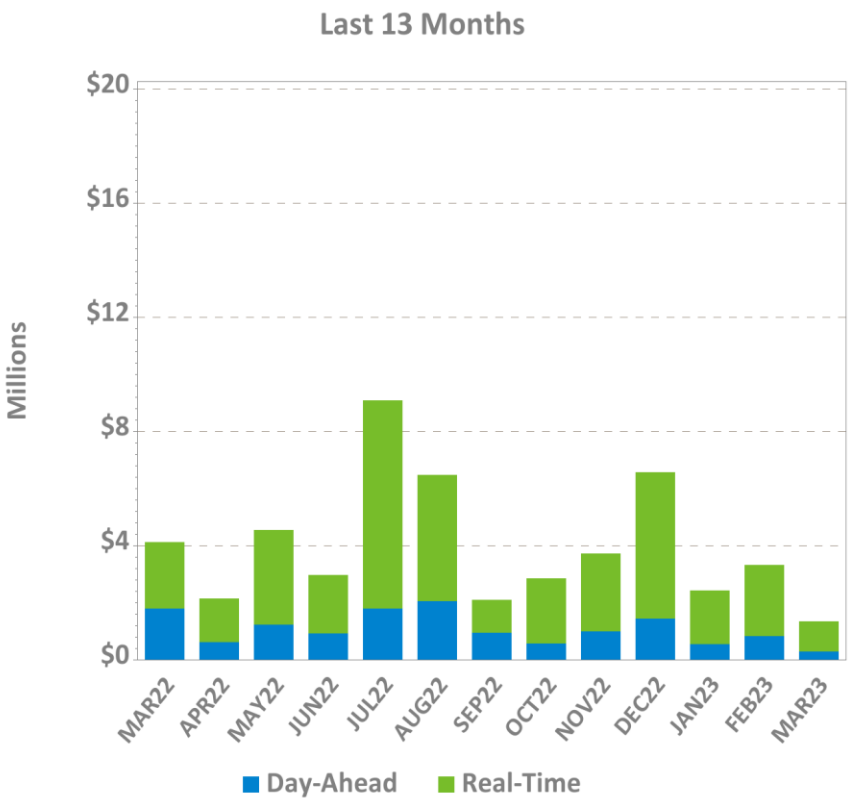




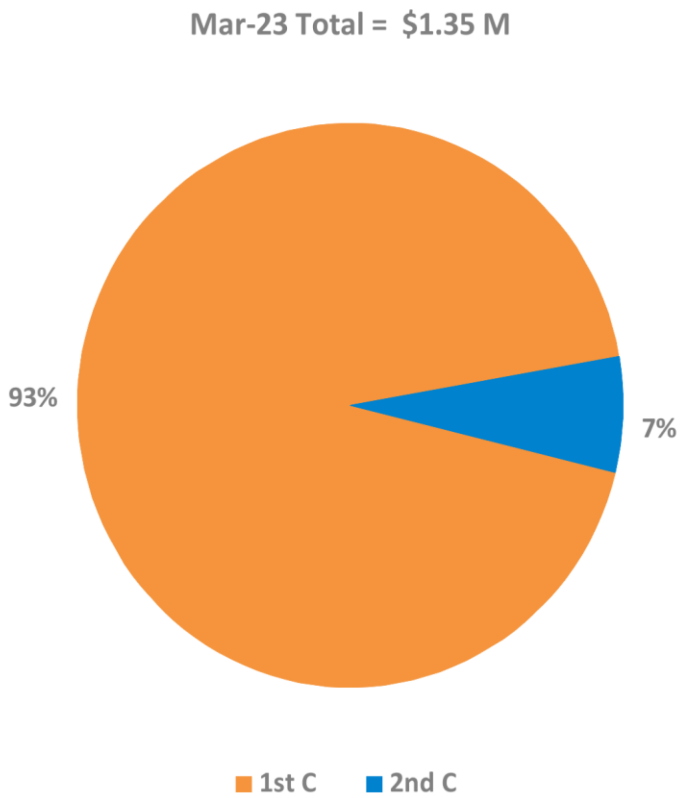
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

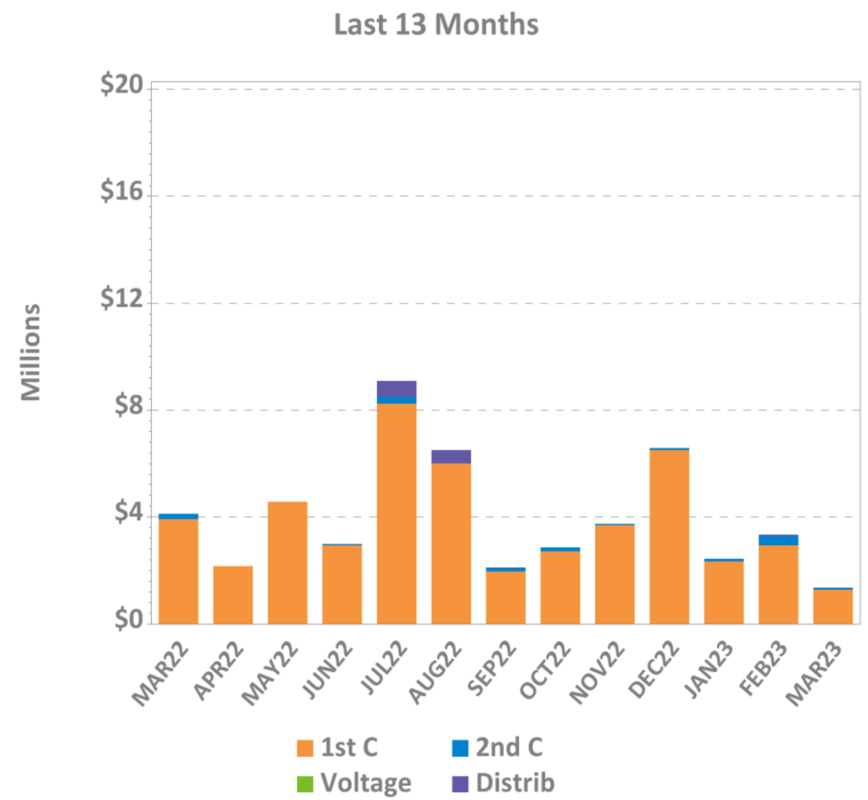
DA and RT NCPC Charges





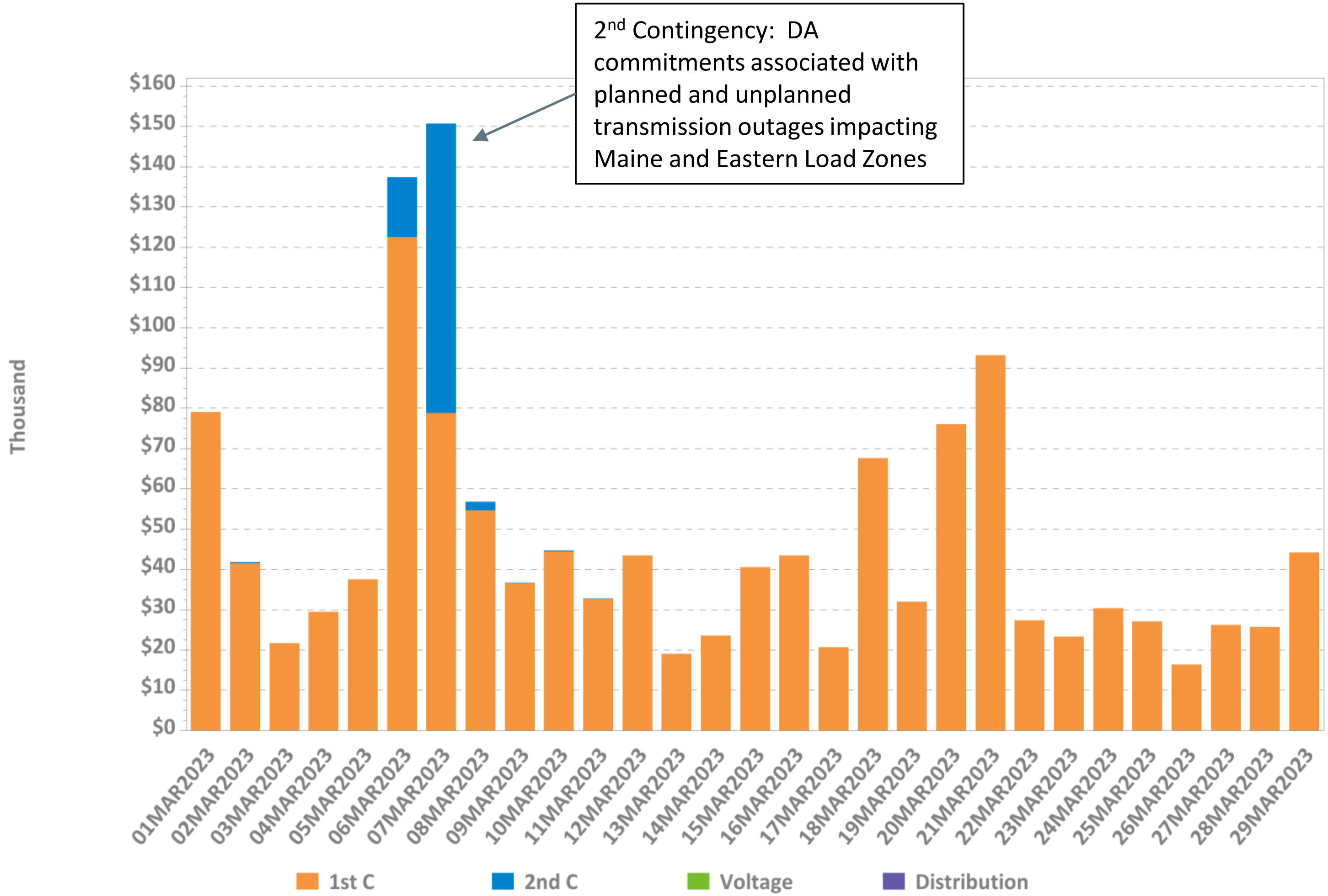
NCPC Charges by Type



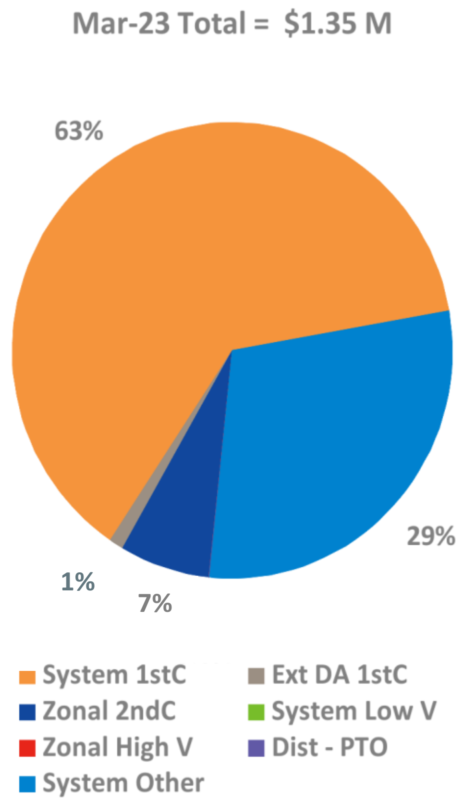


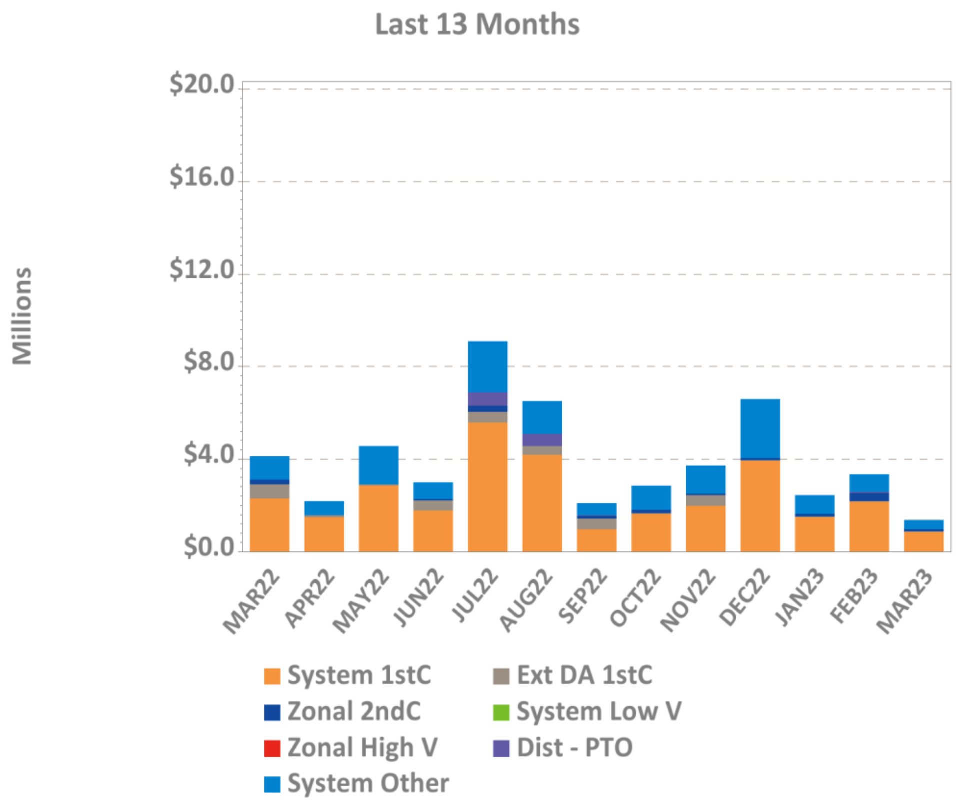
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



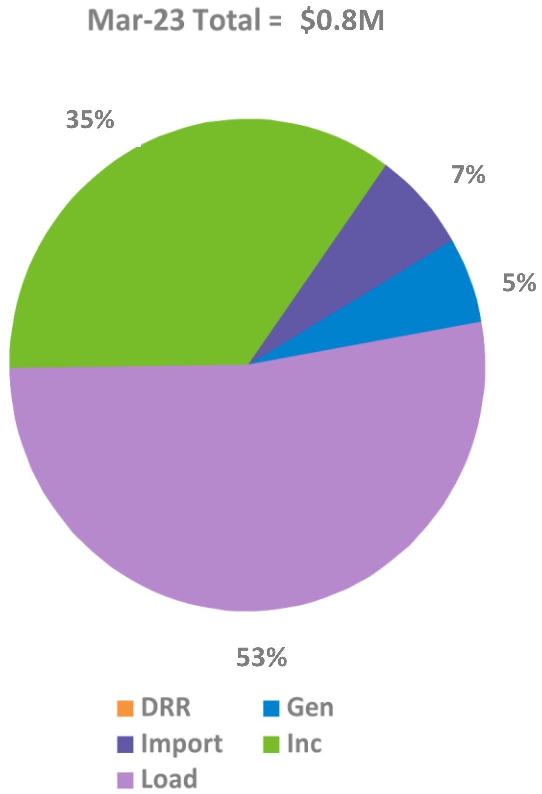
NCPC Charges by Allocation

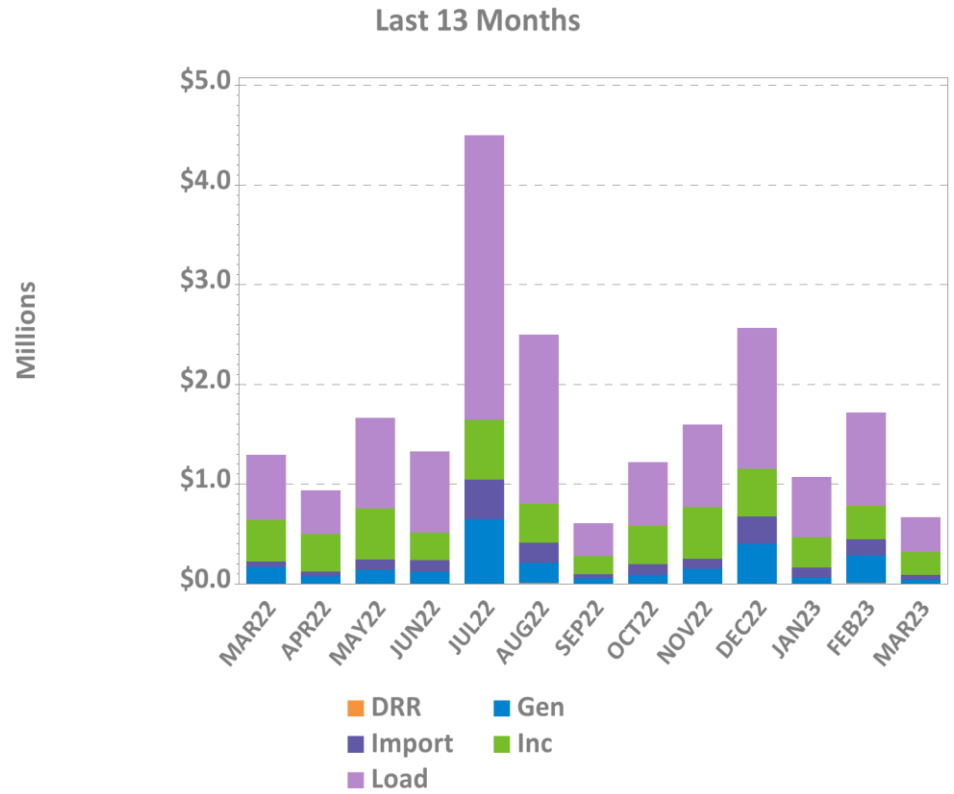




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

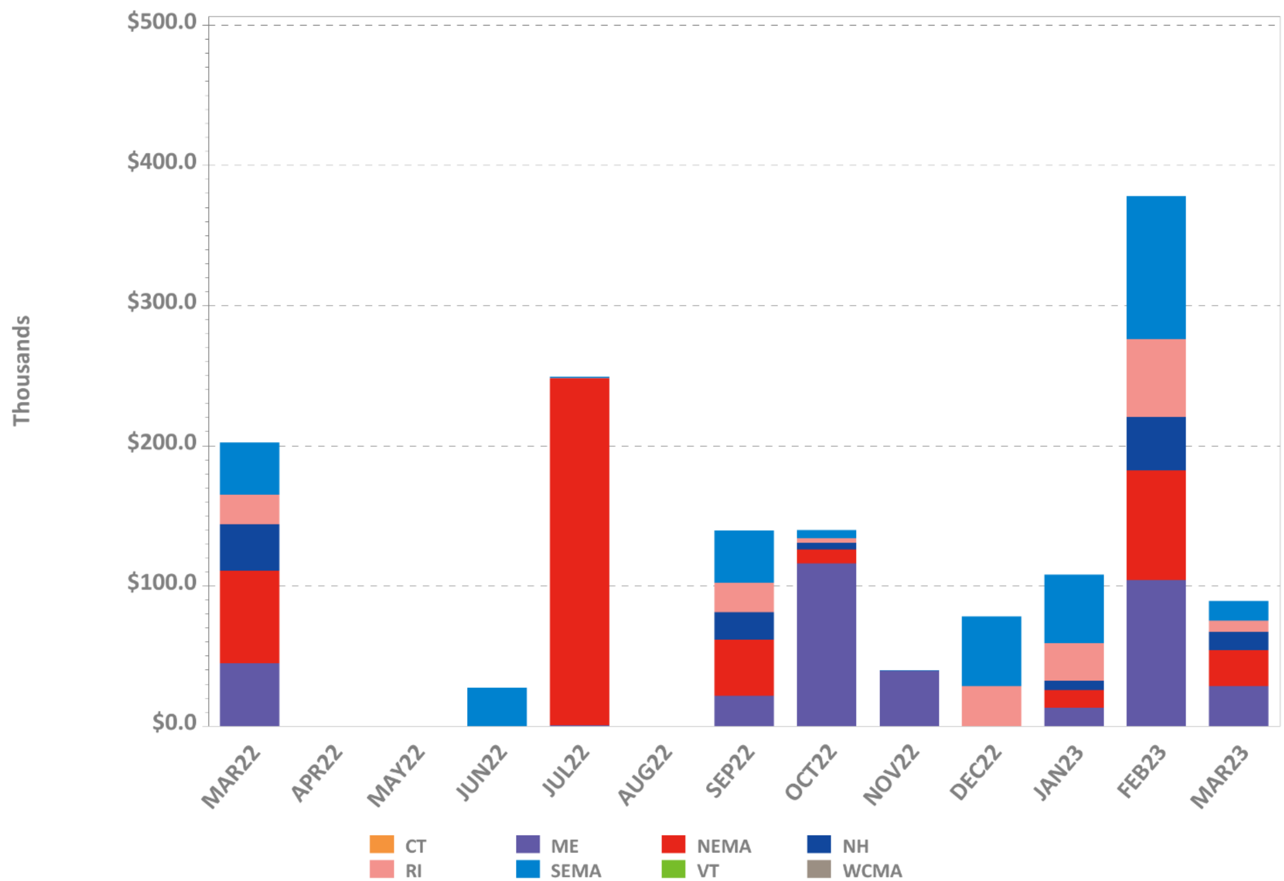
RT First Contingency Charges by Deviation Type





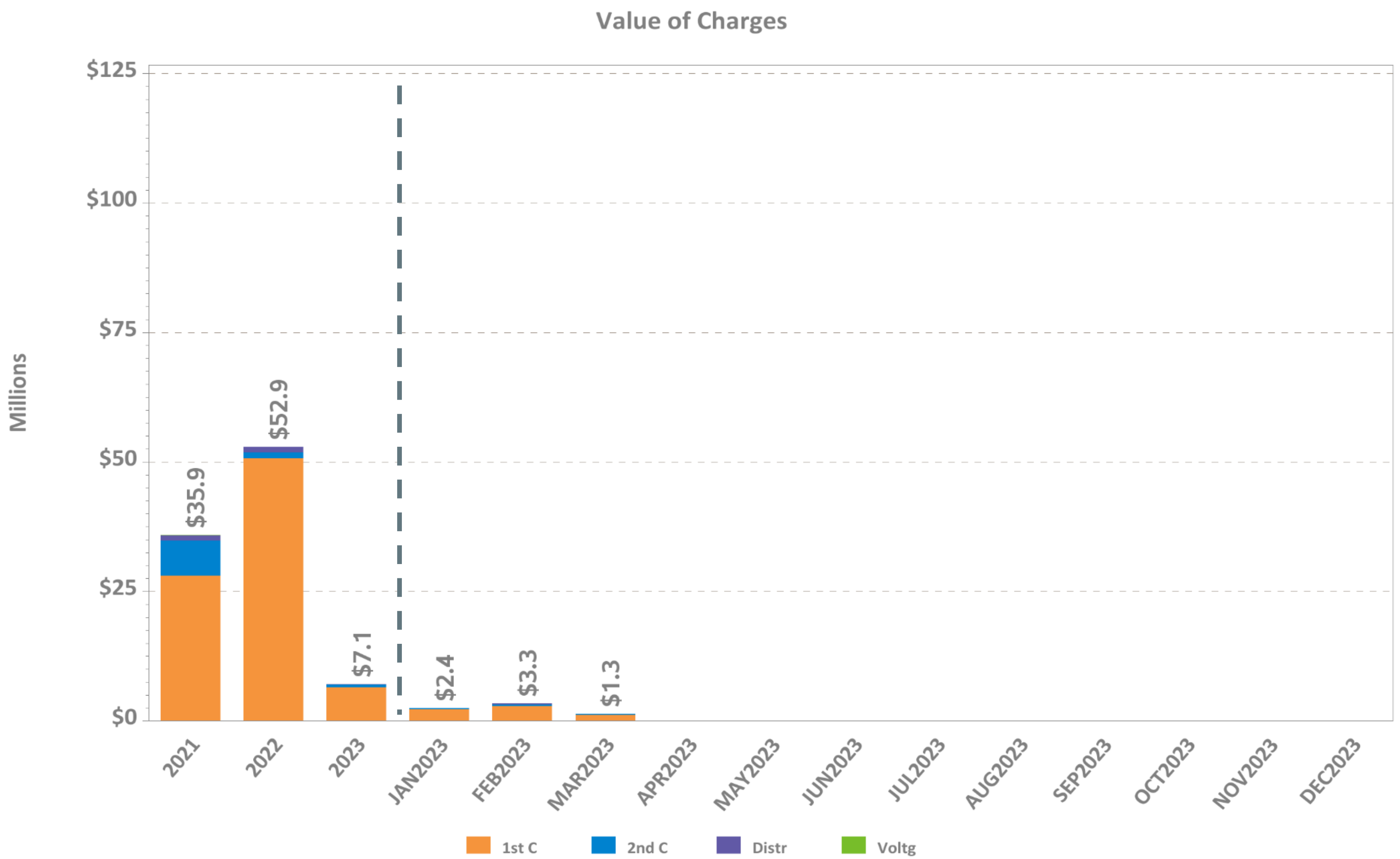
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

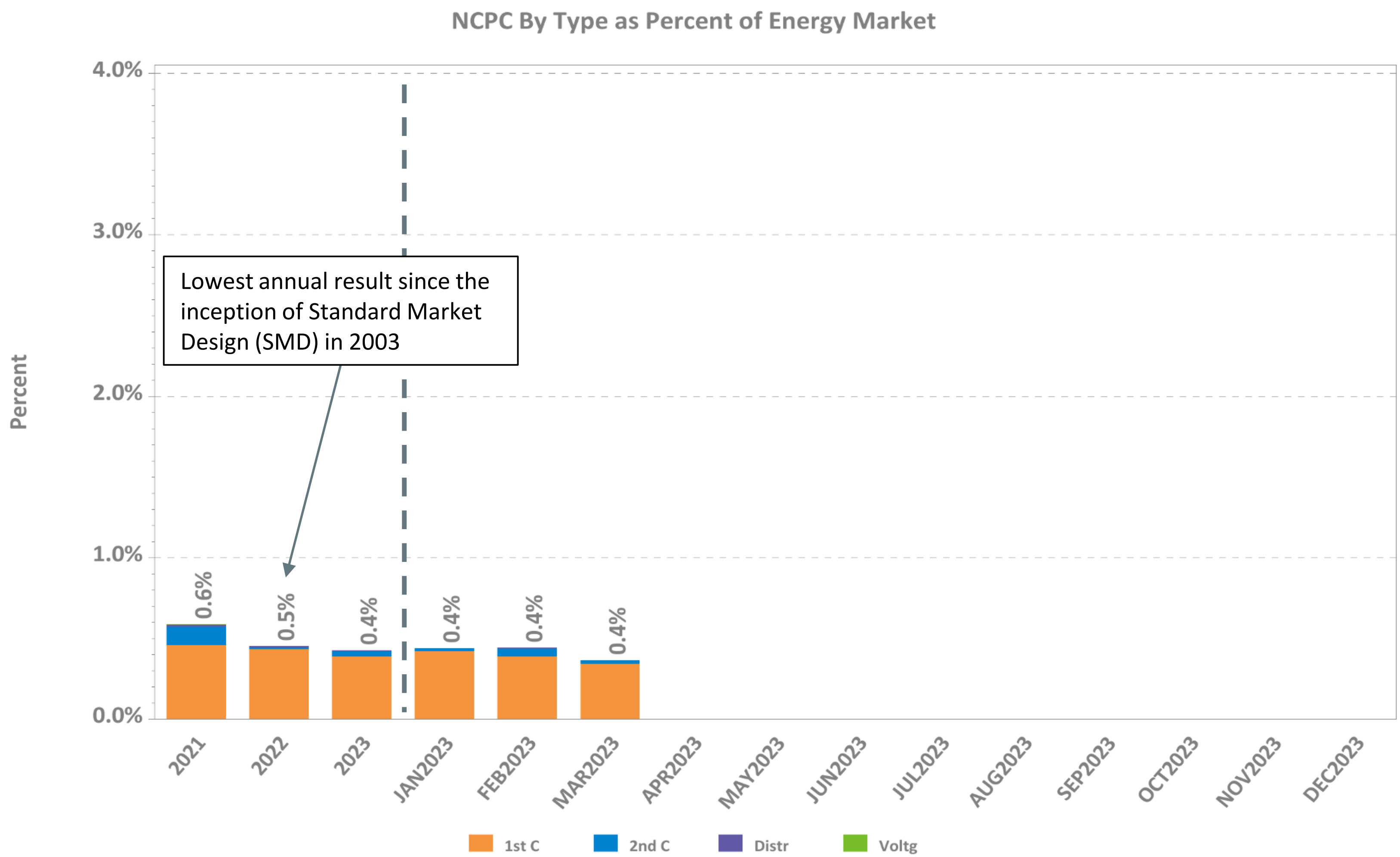


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

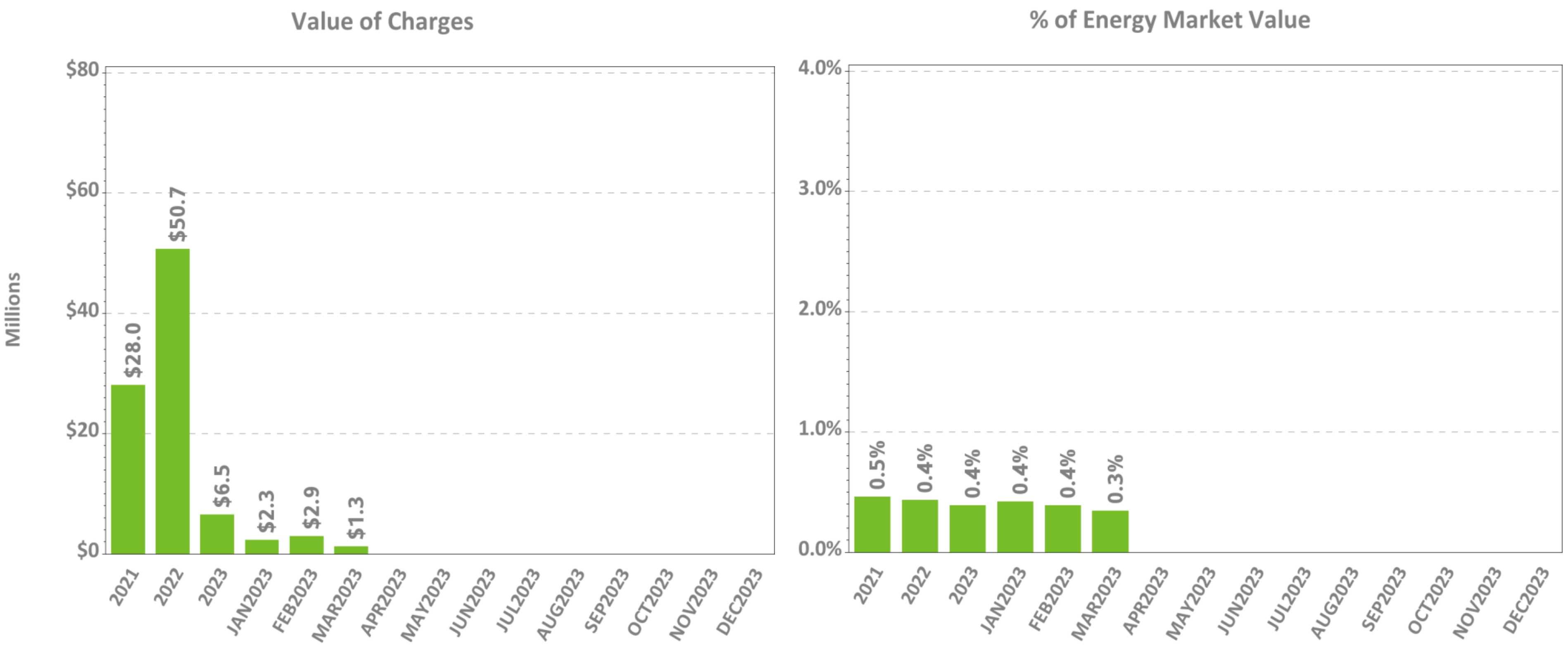
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

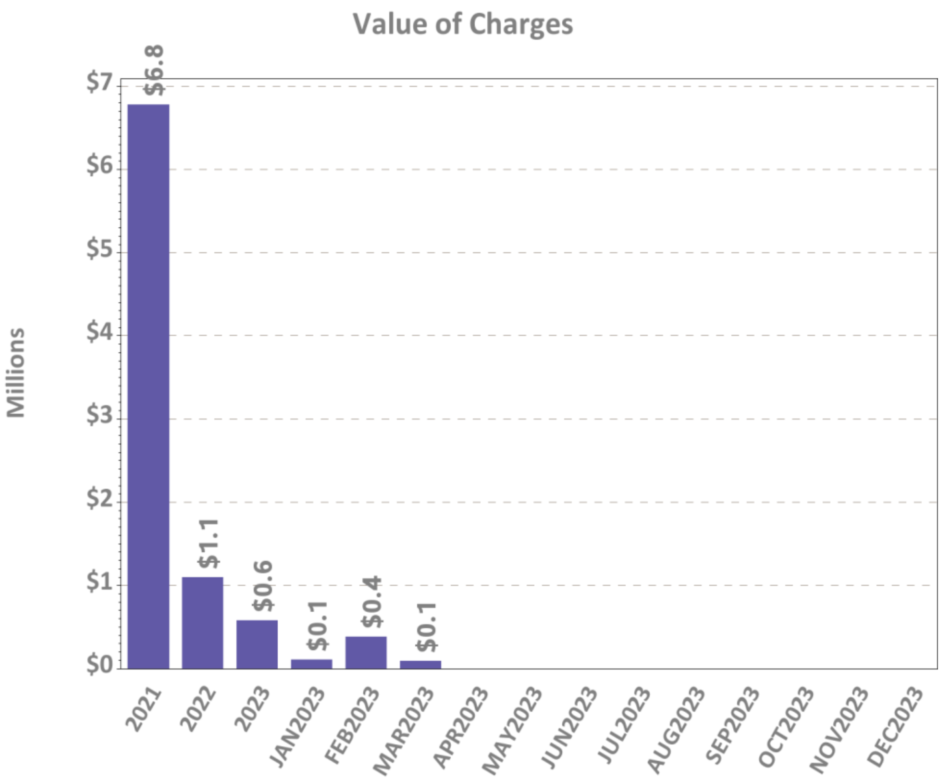


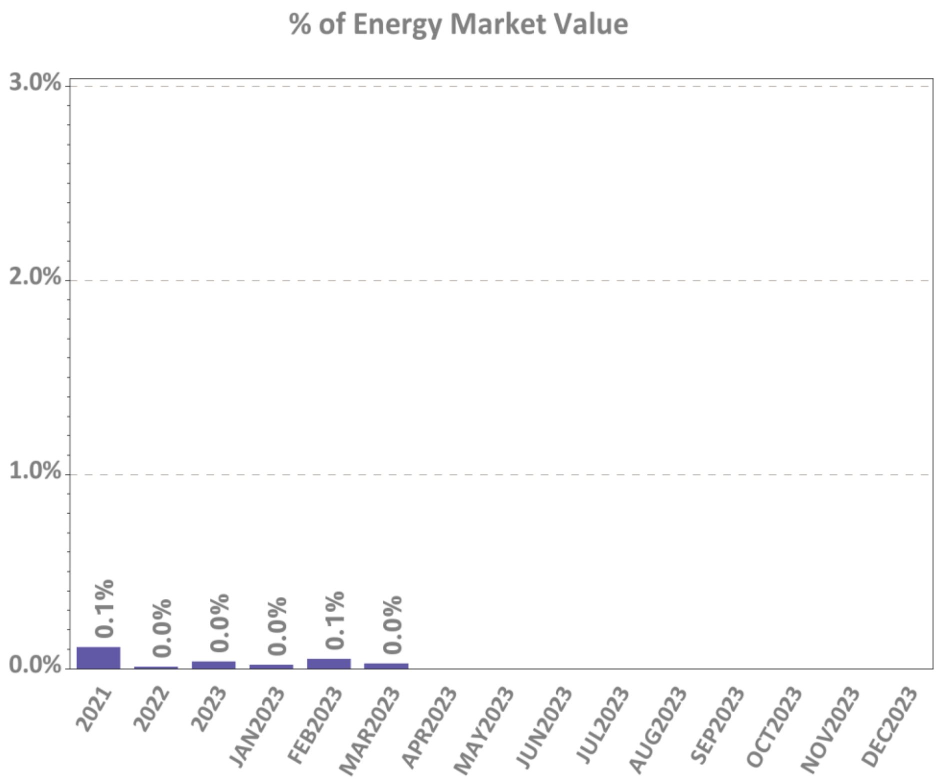
First Contingency NCPC Charges



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

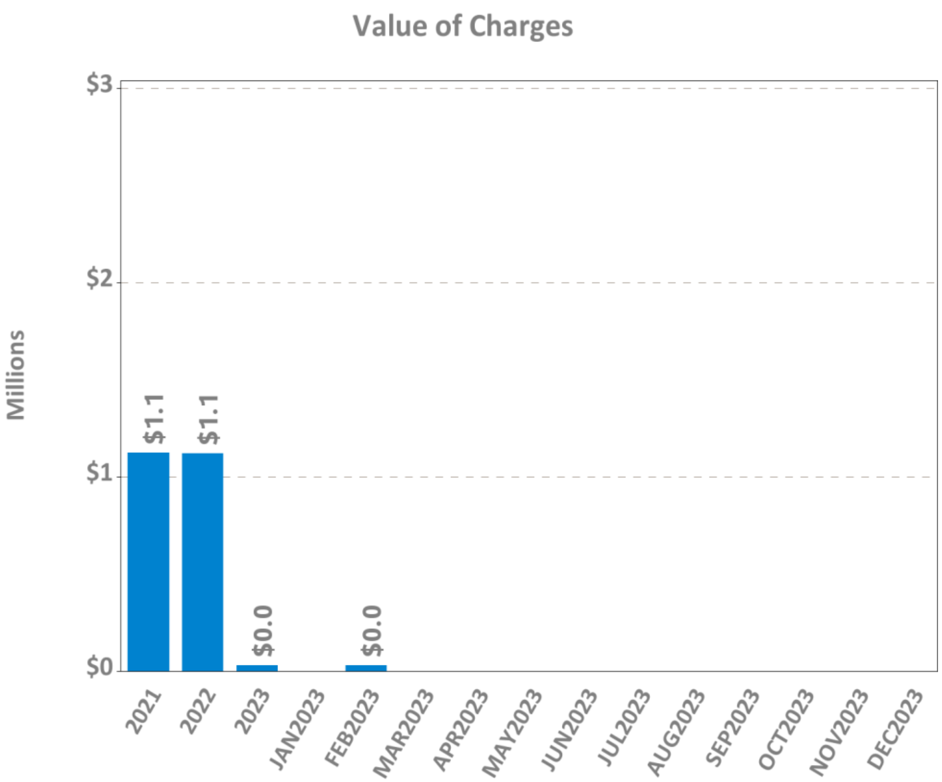
Second Contingency NCPC Charges

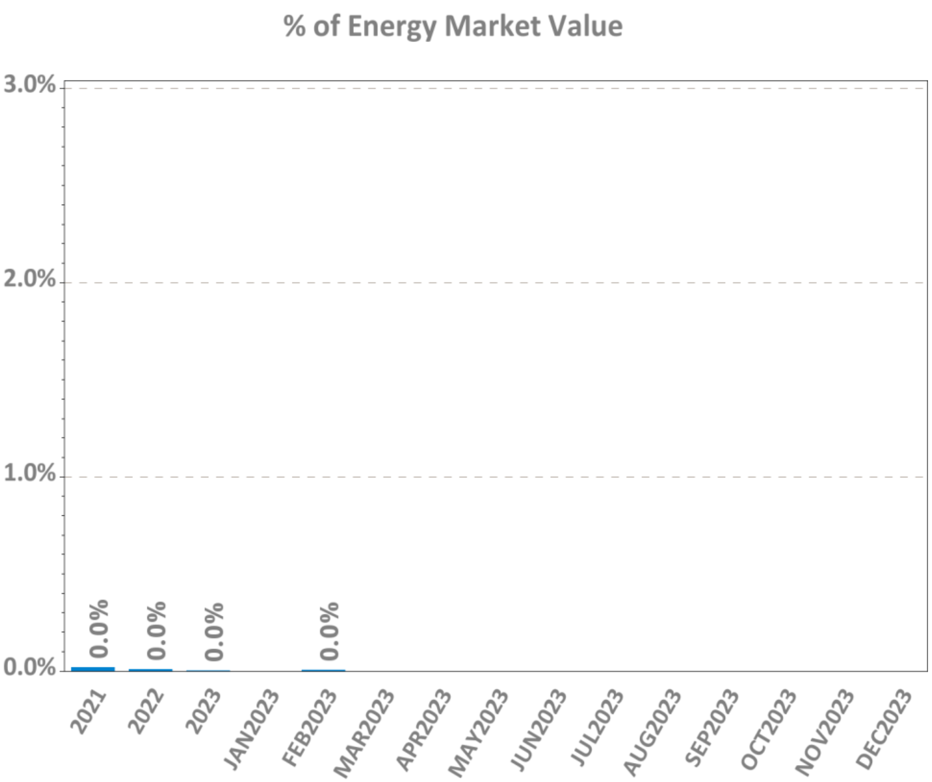




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

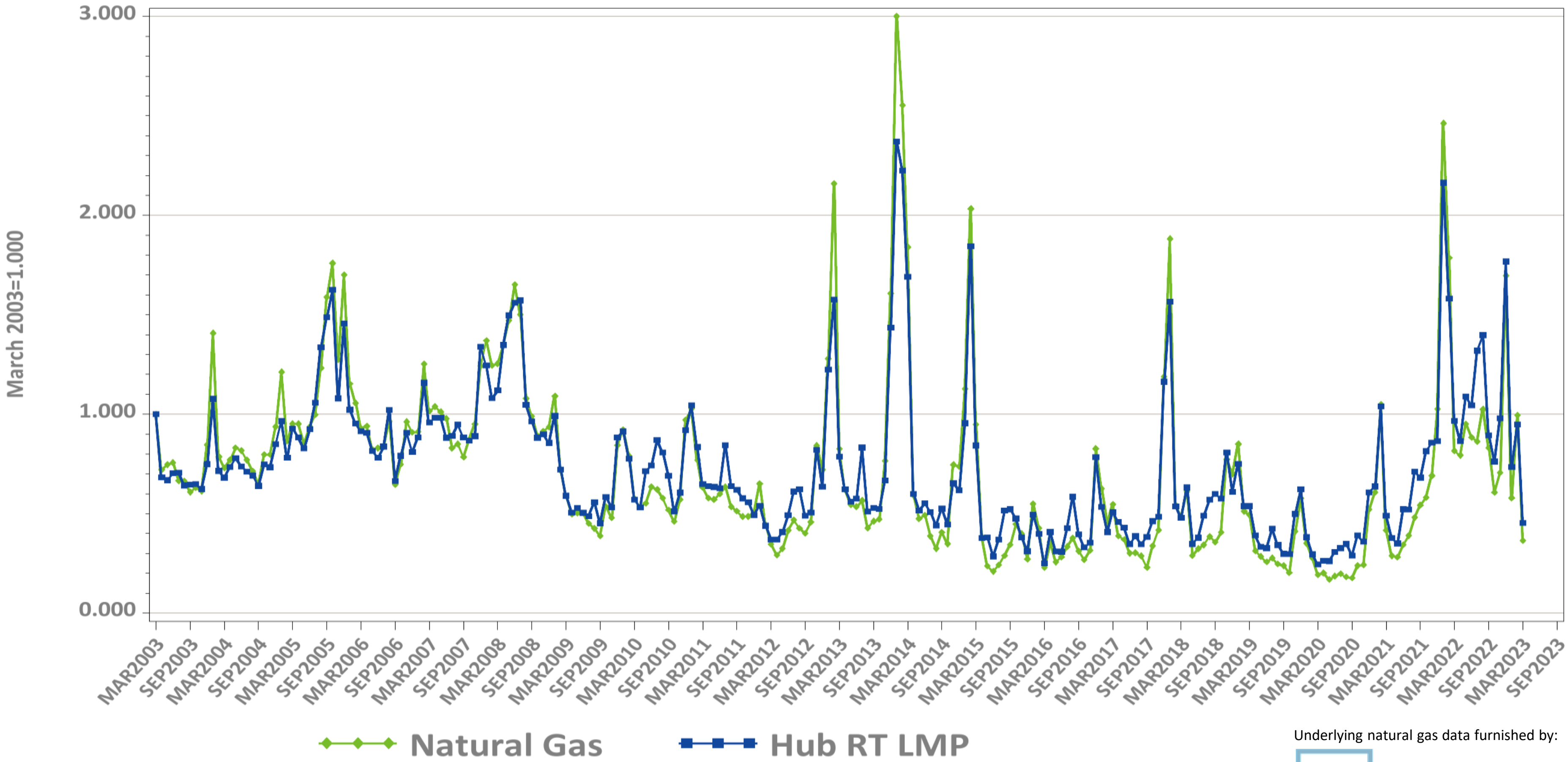
DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

March-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$66.67	$64.32	$65.37	$66.15	$64.34	$65.99	$66.63	$66.22	$66.18
Real-Time	$66.68	$65.15	$65.21	$66.14	$64.37	$66.06	$66.65	$66.34	$66.32
RT Delta %	0.0%	1.3%	-0.2%	0.0%	0.1%	0.1%	0.0%	0.2%	0.2%
March-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$35.78	$34.61	$35.13	$35.83	$35.05	$35.23	$35.72	$35.41	$35.37
Real-Time	$31.53	$30.64	$30.85	$31.51	$30.80	$31.03	$31.46	$31.23	$31.21
RT Delta %	-11.9%	-11.5%	-12.2%	-12.0%	-12.1%	-11.9%	-11.9%	-11.8%	-11.8%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-46.3%	-46.2%	-46.3%	-45.8%	-45.5%	-46.6%	-46.4%	-46.5%	-46.6%
Yr over Yr RT	-52.7%	-53.0%	-52.7%	-52.4%	-52.2%	-53.0%	-52.8%	-52.9%	-52.9%

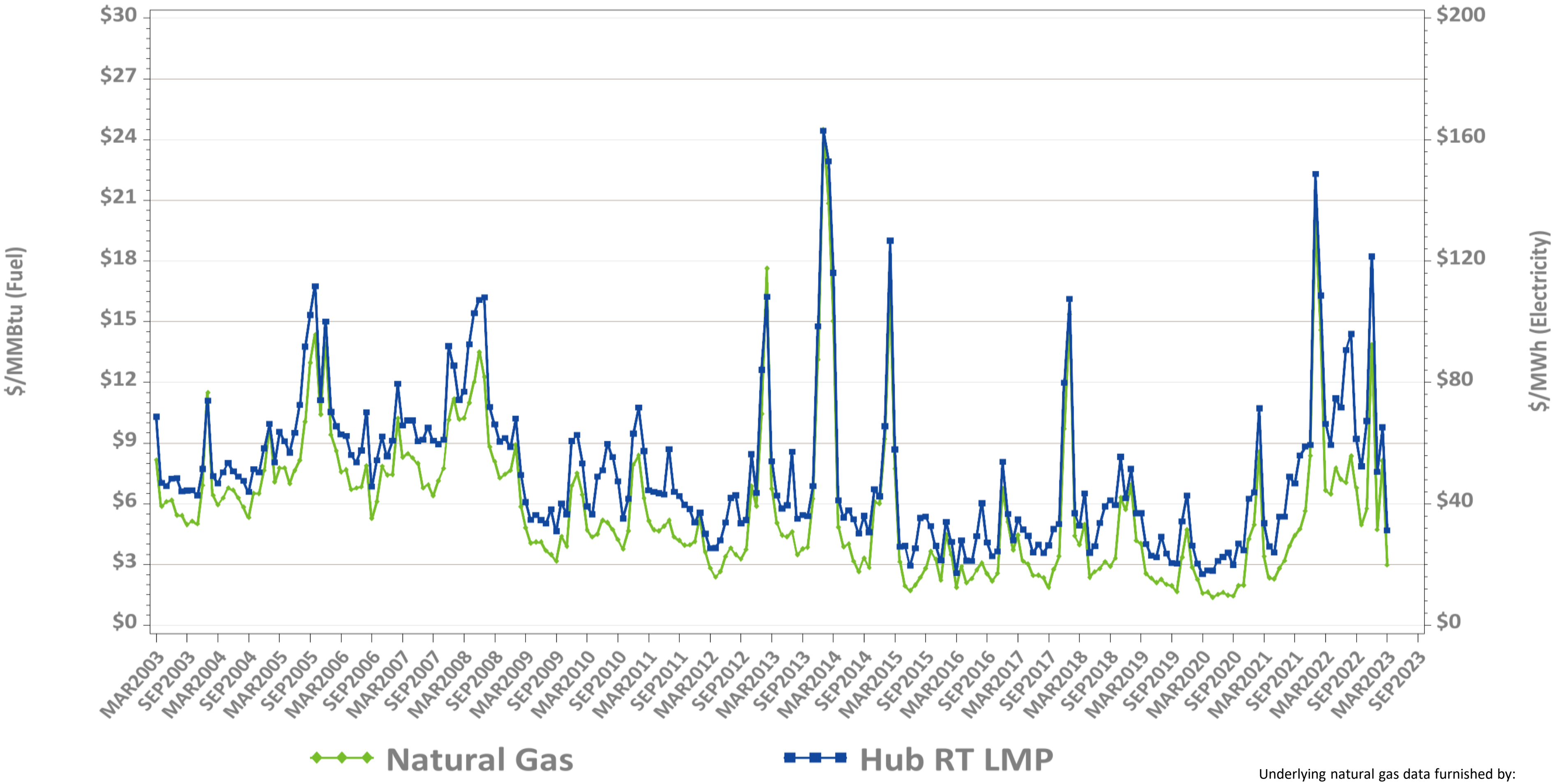
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

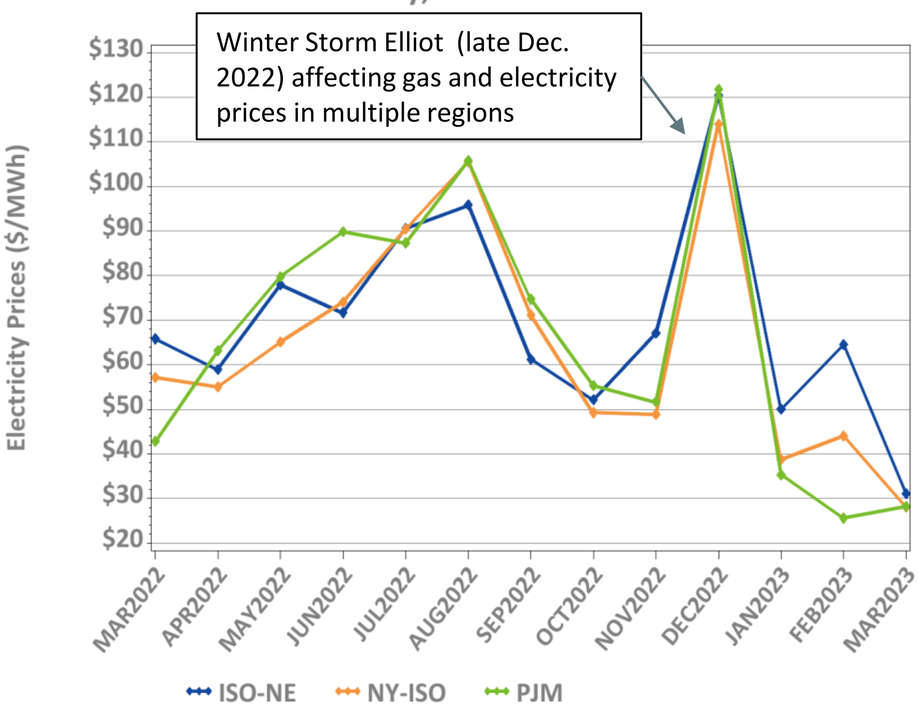
Monthly Average Fuel Price and RT Hub LMP



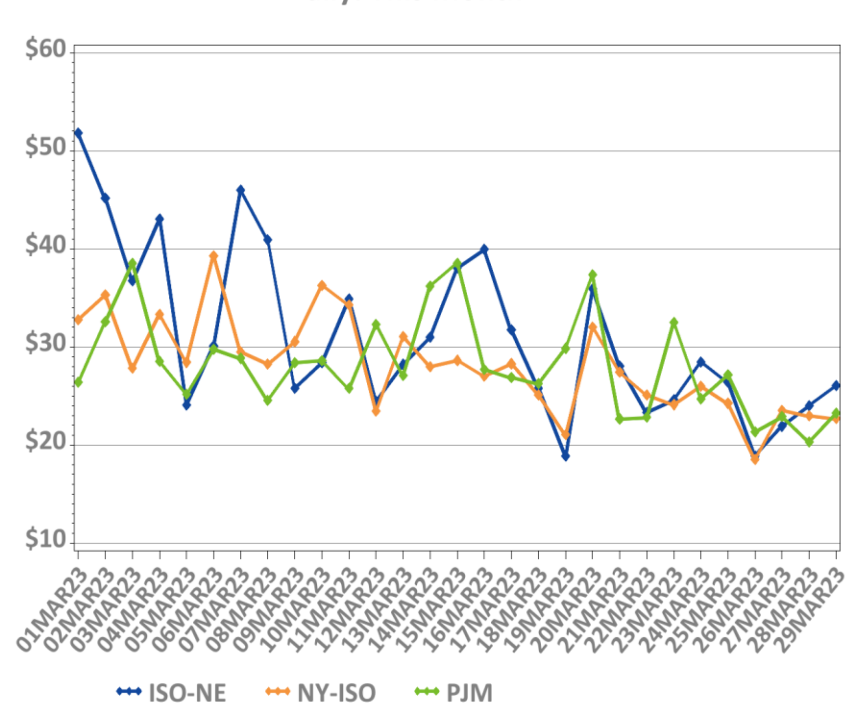
Underlying natural gas data furnished by:

ice Global markets in clear view

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



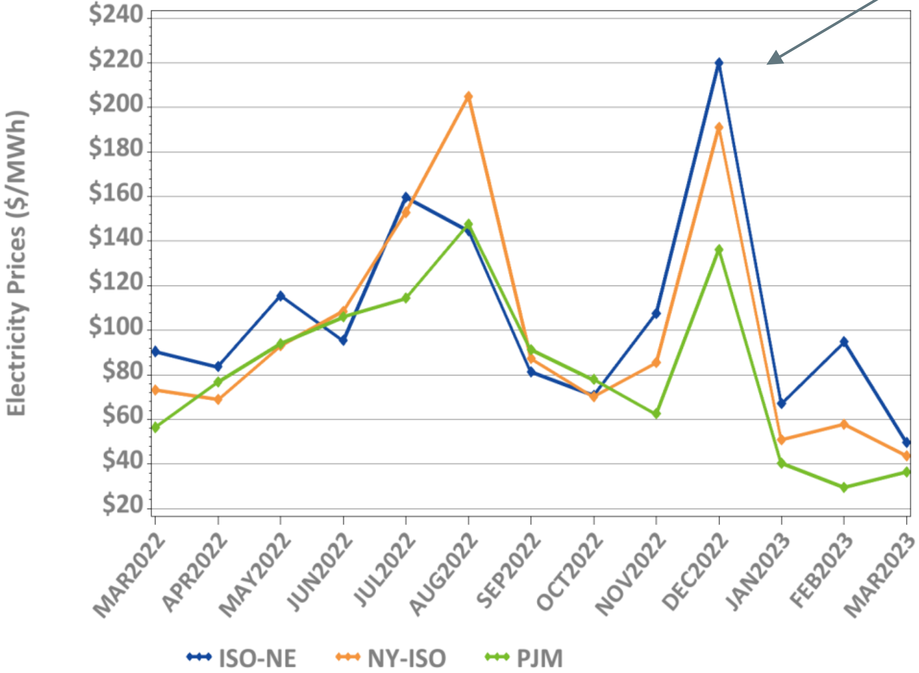
*Note: Hourly average prices are shown.

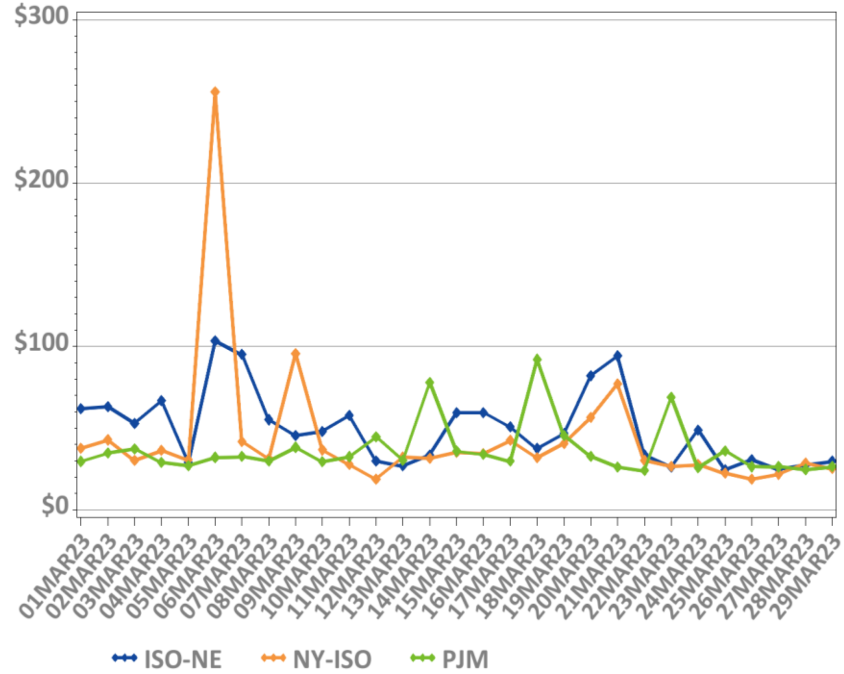


*Note: Hourly average prices are shown.

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

Winter Storm Elliot (late Dec. 2022) affecting gas and electricity prices in multiple regions





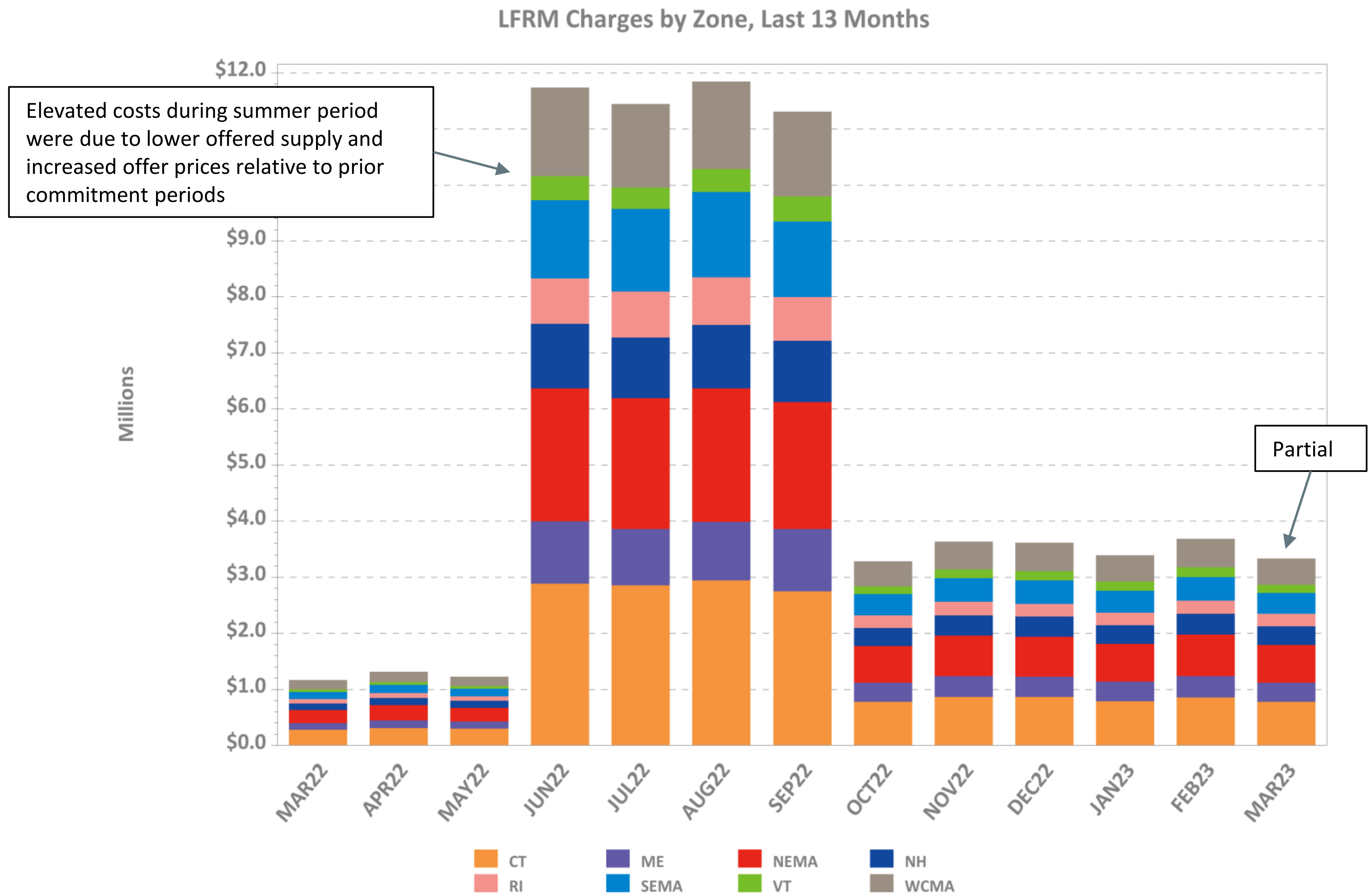
***Forecasted New England daily peak hours reflected**

Reserve Market Results – March 2023

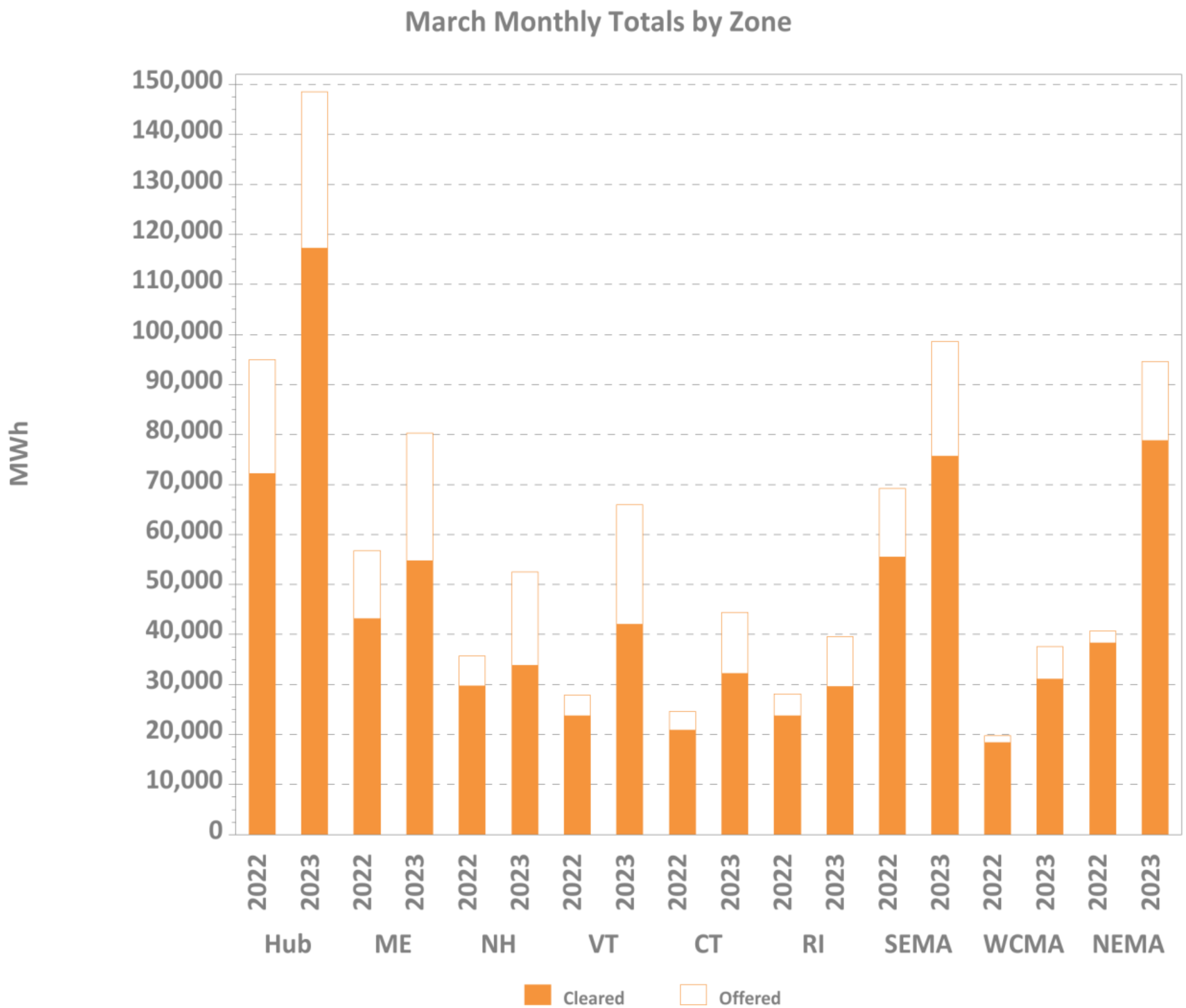
- Maximum potential Forward Reserve Market payments of $3.4M were reduced by credit reductions of $40K, failure-to-reserve penalties of $60K and negligible failure-to-activate penalties, resulting in a net payout of $3.3M or 97% of maximum
  - Rest of System: $2.31M/2.37M (98%)
  - Southwest Connecticut: $0.04M/0.04M (100%)
  - Connecticut: $0.98M/1.03M (96%)
- $170K total Real-Time credits were reduced by $0K in Forward Reserve Energy Obligation Charges for a net of $170K in Real-Time Reserve payments
  - Rest of System: 117 hours, $119K
  - Southwest Connecticut: 117 hours, $28K
  - Connecticut: 117 hours, $15K
  - NEMA: 117 hours, $7K

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

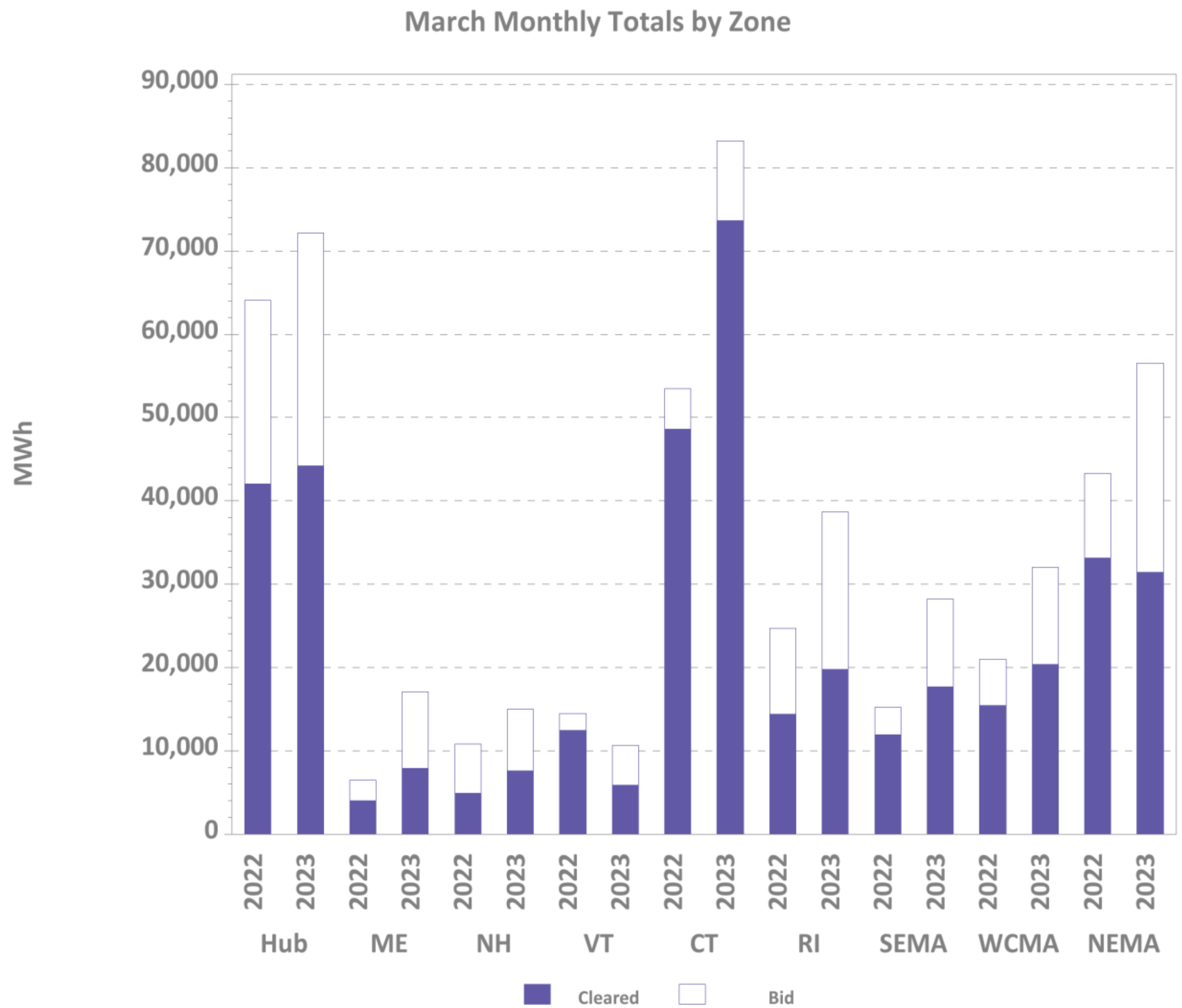
LFRM Charges to Load by Load Zone ($)



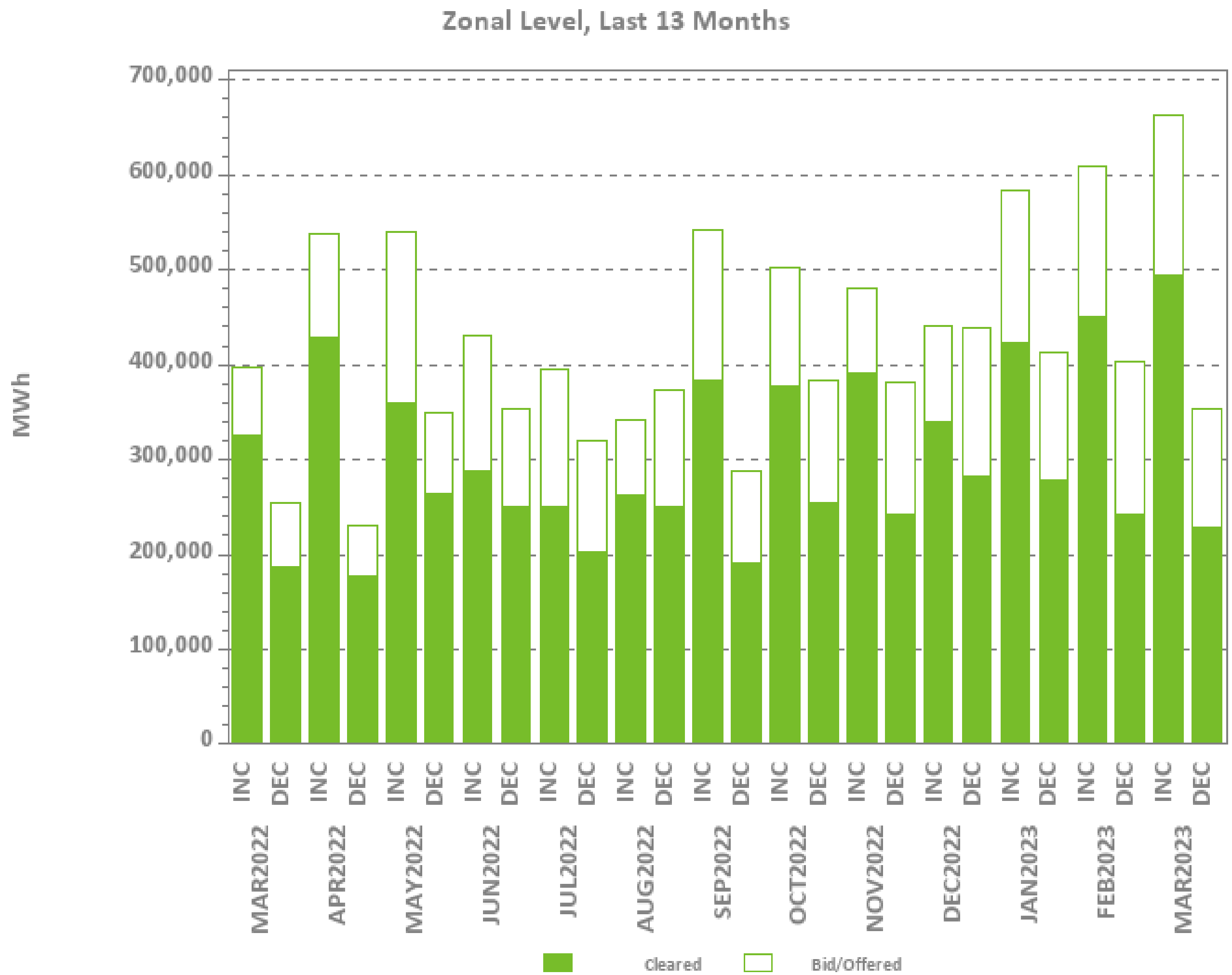
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

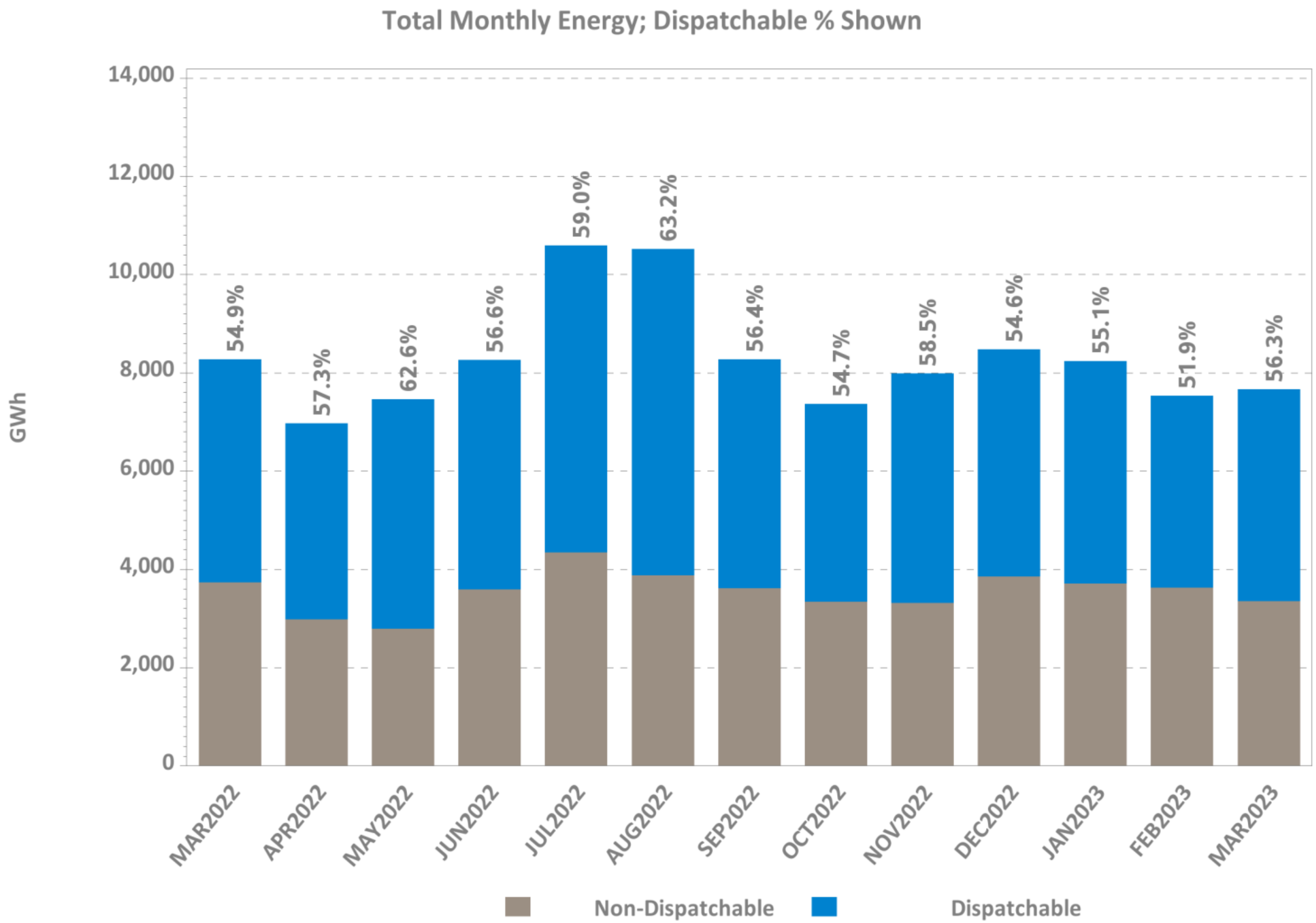


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- 2023 is an RSP publication year
- 2023-24 RSP will continue the streamlining efforts started with the 2021 RSP
- 2023-24 RSP will focus on being an overview narrative about ISO's system planning and the outlook for the New England grid
- 2023-24 RSP Public Meeting date is set for November 1 and will be held concurrently with the ISO Open Board Meeting

Planning Advisory Committee (PAC)

- April 20 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - E131 Asset Condition Refurbishment (National Grid)
    - Adams #21 Substation Relocation (National Grid)
    - CT Lines 1132 & 1505 Asset Condition Replacements (Eversource)
    - K43 Line Refurbishment (VELCO)
  - Economic Planning for the Clean Energy Transition (EPCET): Policy Case Assumptions
  - 2050 Transmission Study – Solutions Development Update

* 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
- The ISO is reviewing comments and revising the TPTG as appropriate; changes are expected to be finalized in March

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)
- ECI is working on developing cost estimates for potential transmission additions
- Development of transmission solutions will continue throughout the first half of 2023
- An update is expected at the 4/20/23 PAC meeting

Economic Studies

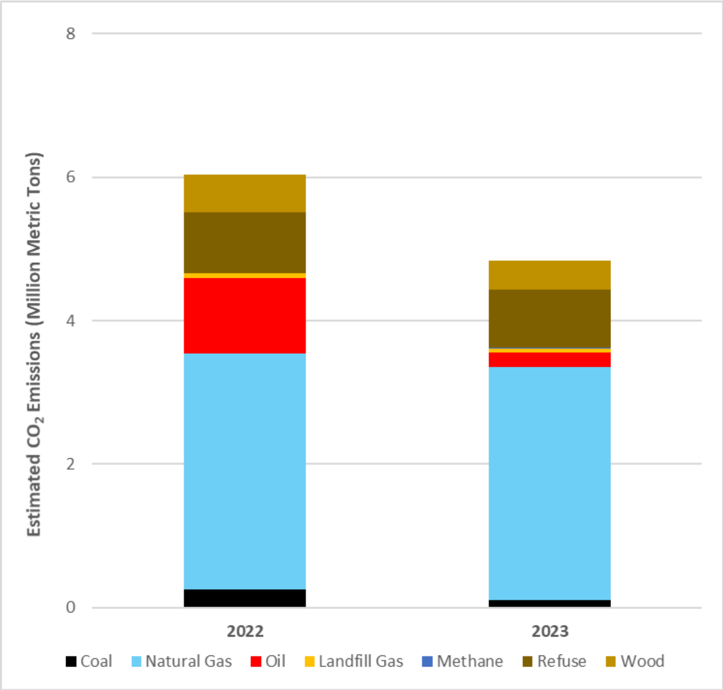
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, assumptions and results from the Benchmark and Market Efficiency Need scenarios, an overview of the capacity expansion model and how it will be used in the Policy scenario. The ISO is expecting to present the first round of Policy scenario assumptions in April 2023

Future Grid Reliability Study (FGRS)

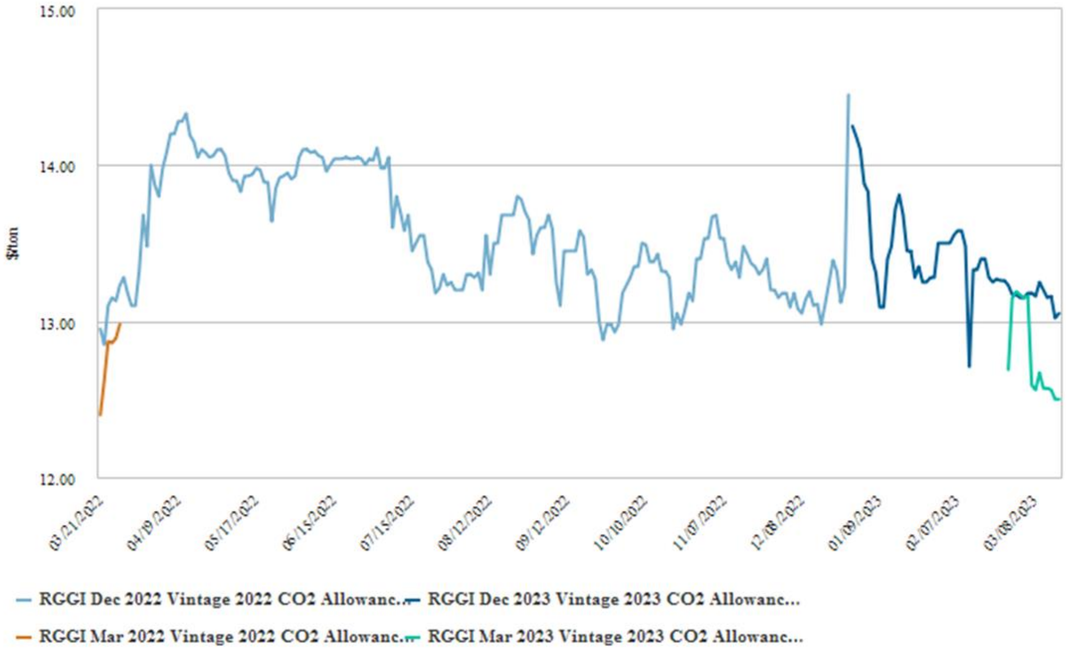
- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways 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 vs. 2023 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



RGGI Allowance Prices



- 03/08/23 59th RGGI auction cleared at $12.50 per ton
  - 21,522,877 CO_2 allowances sold
  - 11,245,778 Cost Containment Reserve (CCR) allowances available
  - CCR trigger price is $14.88 per ton in 2023, therefore, no CCR allowances were sold

Data as of 03/05/2023

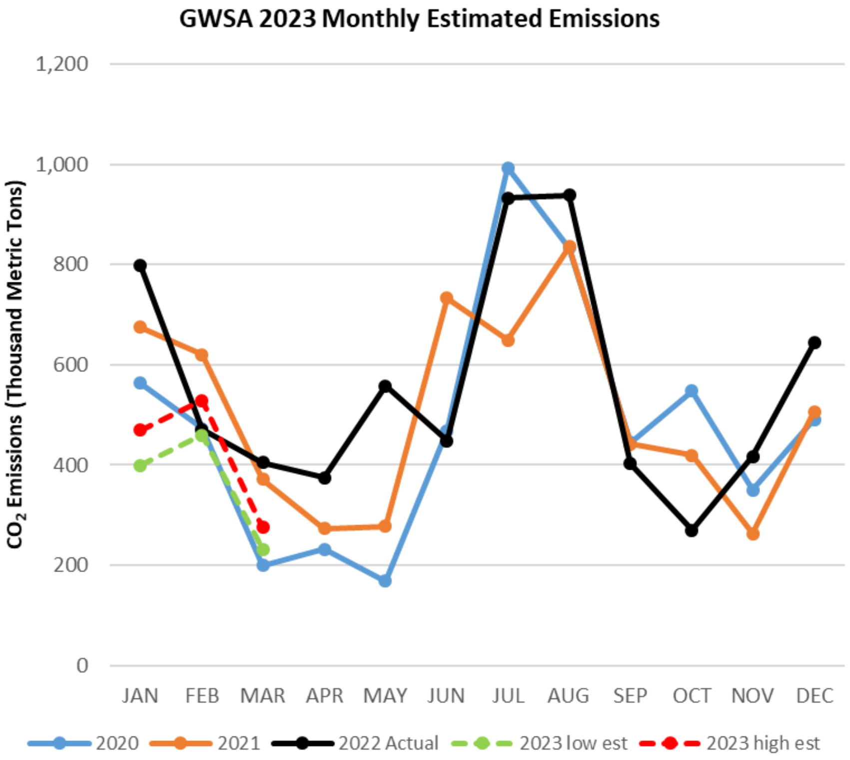
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 03/20/2023, estimated GWSA CO_2 emissions range between **231,851** and **274,989** metric tons
  - **13.9%** and **16.2%** of the 2023 cap of 7.84 MMT
- The total actual 2022 CO_2 emissions were **6.66 MMT**, 83% of 2022 cap (8.06 MMT)
- 12/14/2022: The first GWSA auction for the current (2023) vintage year cleared at $14.20 per metric ton
- Clearing price of $6.03 for future vintage (2024) allowances

2020-2023 Estimated Monthly Emissions (Thousand Metric tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

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

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 3/23/2023

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

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

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

Greater Boston Projects, cont.

Status as of 3/23/2023

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	3

Greater Boston Projects, cont.

Status as of 3/23/2023

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

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

Greater Boston Projects, cont.

Status as of 3/23/2023

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

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

Greater Boston Projects, cont.

Status as of 3/23/2023

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

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

SEMA/RI Reliability Projects

Status as of 3/23/2023

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

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

SEMA/RI Reliability Projects, cont.

Status as of 3/23/2023

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	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	Aug-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 3/23/2023

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	2
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 3/23/2023

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 3/23/2023

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

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

Eastern CT Reliability Projects

Status as of 3/23/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 3/23/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 3/23/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	Nov-21	4
1862	Install a +55/-29 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-23	3
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Mar-22	4
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington)	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 3/23/2023

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	May-23	3

New Hampshire Solution Projects

Status as of 3/23/2023

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	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	Mar-24	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 3/23/2023

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line	Dec-24	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

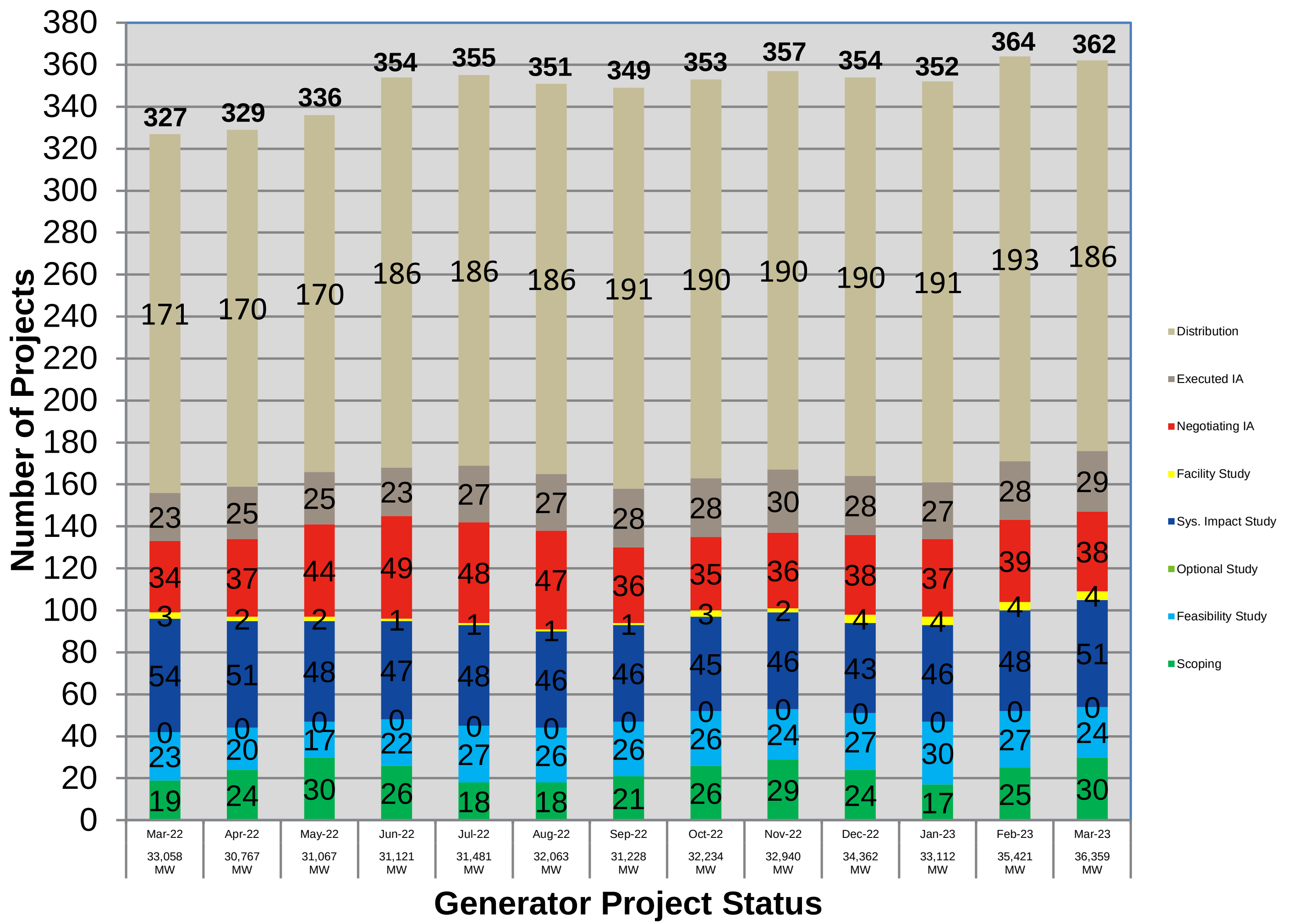
Upper Maine Solution Projects, cont.

Status as of 3/23/2023

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	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 March 22, 2023



Note: March 2023 is based on partial data.

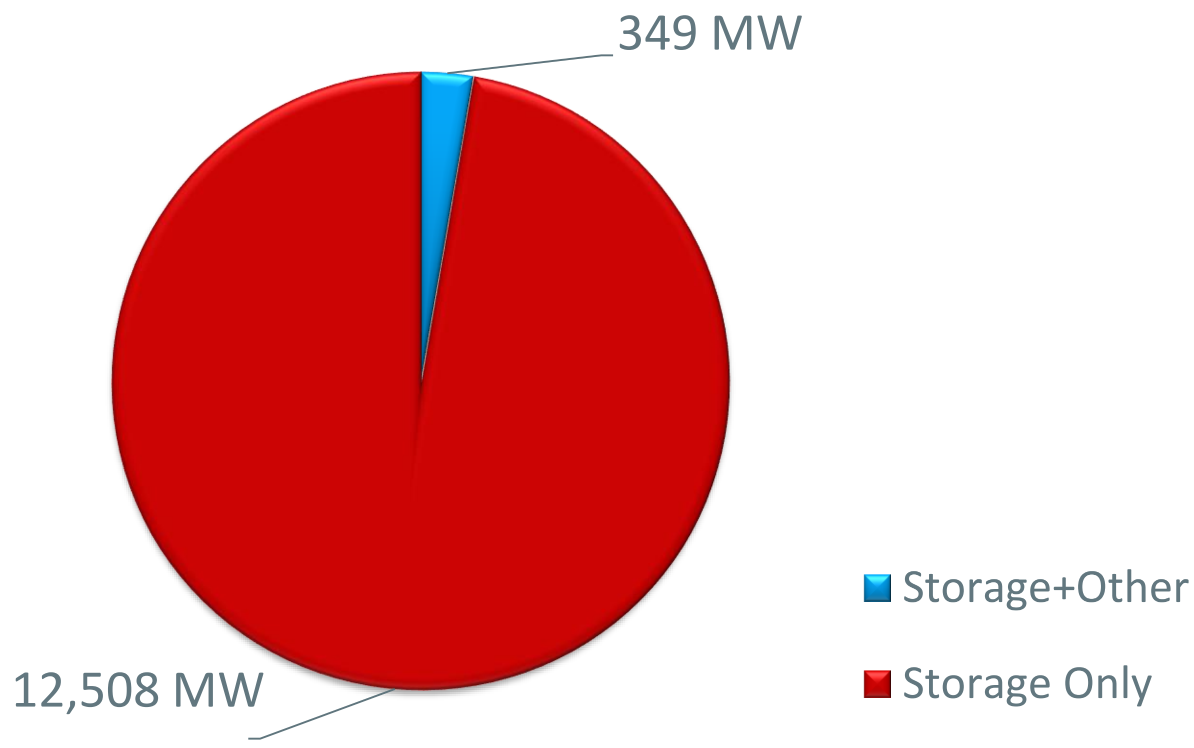
9 ETUs in Scoping, 6 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 2 Negotiating IA, and 3 with Executed IA

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 March 22, 2023)

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



OPERABLE CAPACITY ANALYSIS

Spring 2023 and Preliminary Summer 2023

OPERABLE CAPACITY ANALYSIS

Spring 2023 Analysis

Spring 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2023[2] CSO (MW)	May - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,103	32,029
Active Demand Capacity Resource (+) [5]	426	382
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,043	1,043
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-)	2,563	3,340
Gas Generator Outages MW (-)	2,341	2,995
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,278	23,729
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,001	19,001
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,306	21,306
Operable Capacity Margin	-28	2,423

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

[2] Load forecast that is based on the Preliminary 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 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.

Spring 2023 Operable Capacity Analysis

90/10 Load Forecast	**May - 2023[2] CSO (MW)**	**May - 2023[2] SCC (MW)**
Operable Capacity MW [1]	28,103	32,029
Active Demand Capacity Resource (+) [5]	426	382
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,043	1,043
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-)	2,563	3,340
Gas Generator Outages MW (-)	2,341	2,995
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,278	23,729
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,437	20,437
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,742	22,742
Operable Capacity Margin	-1,464	987

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

[2] Load forecast that is based on the Preliminary 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 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.

Spring 2023 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 3/28/2023

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4/15/2023	28111	423	1100	11	4223	3284	2700	0	19438	15503	2305	17808	1630	N	Spring 2023
4/22/2023	28111	423	1100	11	4160	2527	2700	0	20258	15244	2305	17549	2709	N	Spring 2023
4/29/2023	28103	426	1094	10	3864	3733	3400	0	18636	15217	2305	17522	1114	N	Spring 2023
5/6/2023	28103	426	1094	10	3136	2378	3400	0	20719	18033	2305	20338	381	N	Spring 2023
5/13/2023	28103	426	1043	10	2563	2341	3400	0	21278	19001	2305	21306	-28	Y	Spring 2023
5/20/2023	28103	426	1094	10	1475	1605	3400	0	23153	19901	2305	22206	947	N	Spring 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 Preliminary 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Spring 2023 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 3/28/2023

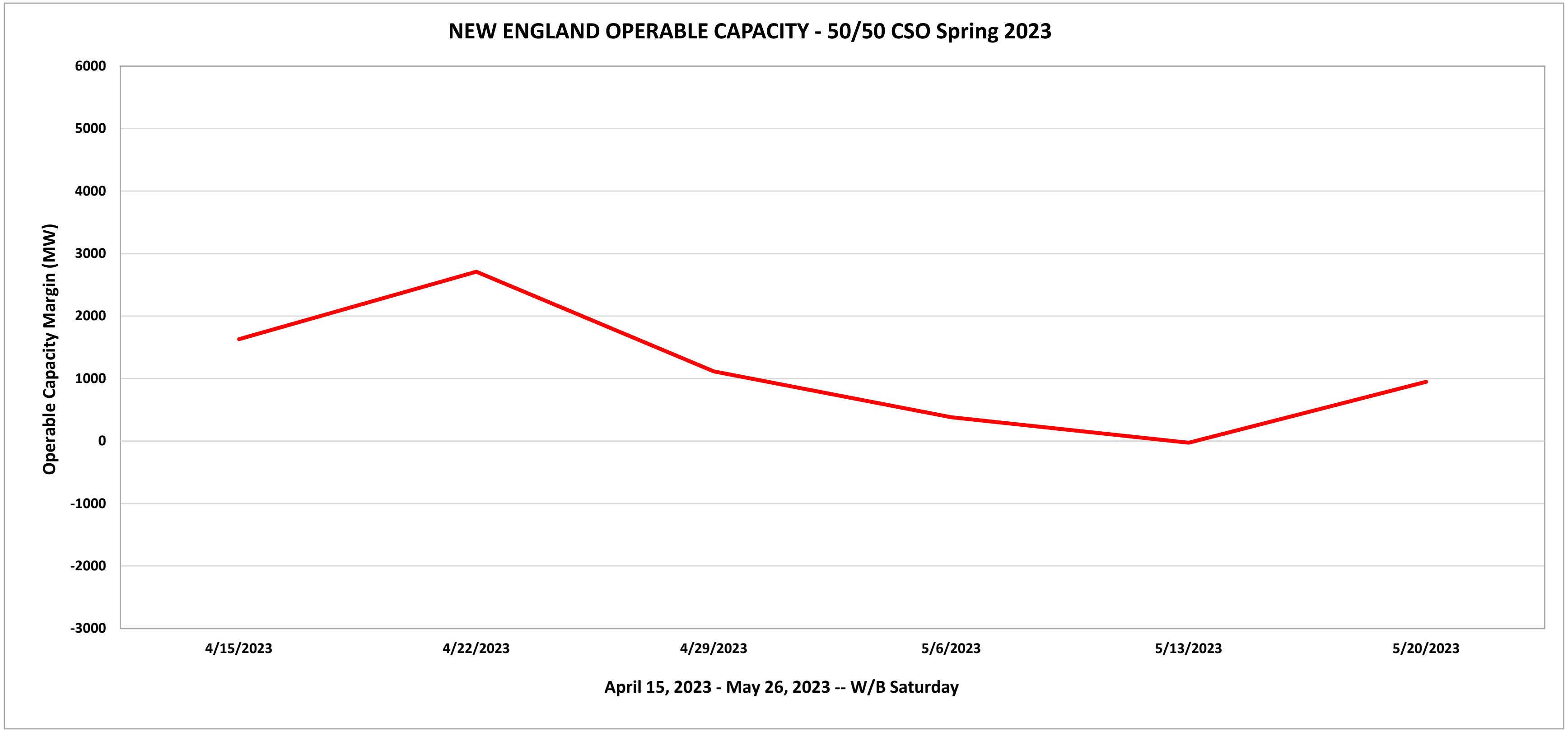
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4/15/2023	28111	423	1100	11	4223	3284	2700	0	19438	16055	2305	18360	1078	N	Spring 2023
4/22/2023	28111	423	1100	11	4160	2527	2700	0	20258	15788	2305	18093	2165	N	Spring 2023
4/29/2023	28103	426	1094	10	3864	3733	3400	0	18636	15761	2305	18066	570	N	Spring 2023
5/6/2023	28103	426	1094	10	3136	2378	3400	0	20719	19404	2305	21709	-990	N	Spring 2023
5/13/2023	28103	426	1043	10	2563	2341	3400	0	21278	20437	2305	22742	-1464	Y	Spring 2023
5/20/2023	28103	426	1094	10	1475	1605	3400	0	23153	21396	2305	23701	-548	N	Spring 2023

Column Definitions

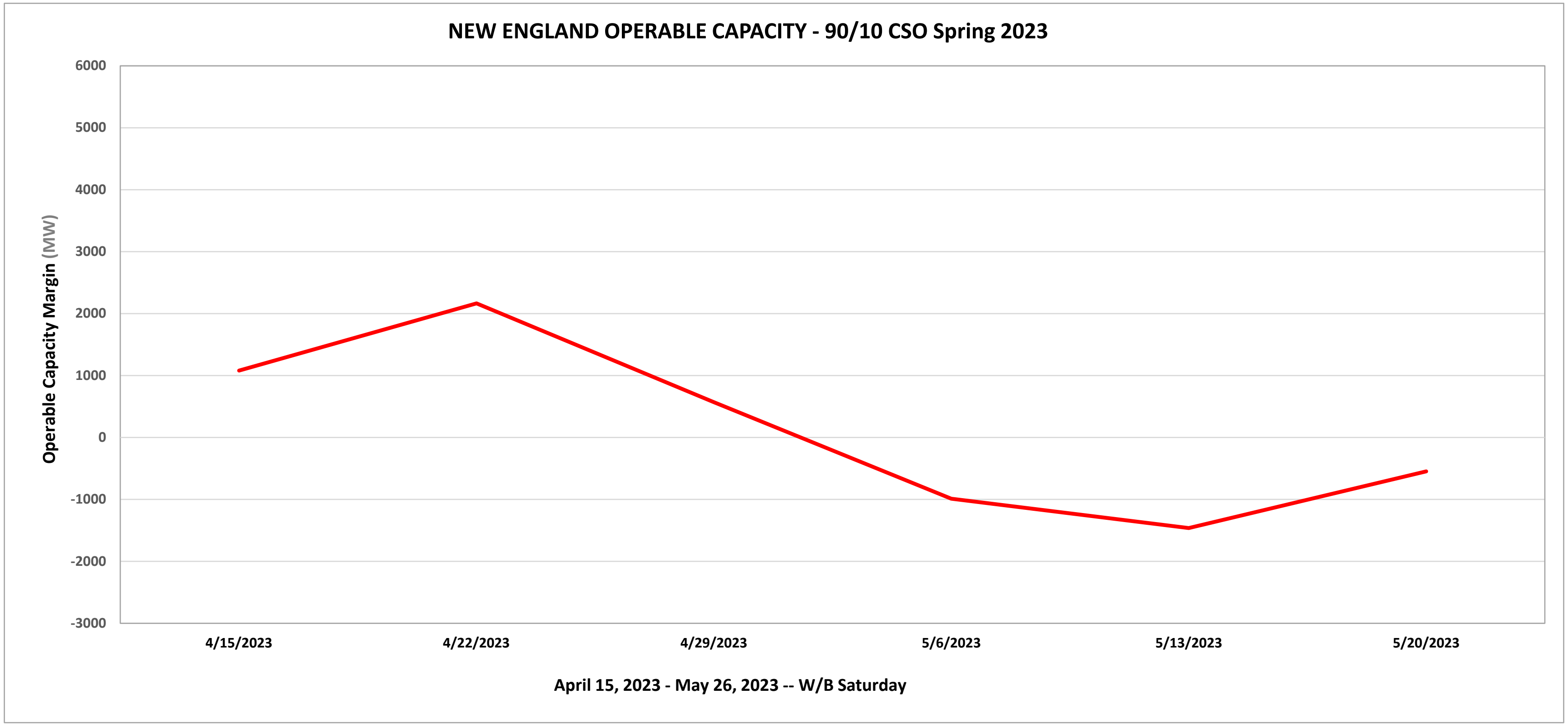
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 Preliminary 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



Spring 2023 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Summer 2023 Analysis

Preliminary Summer 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2023[2] CSO (MW)	June - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,068	28,869
Active Demand Capacity Resource (+) [5]	603	447
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,030	1,030
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-)	346	346
Gas Generator Outages MW (-)	129	130
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,436	27,080
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,664	24,664
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,969	26,969
Operable Capacity Margin	-533	111

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

[2] Load forecast that is based on the Preliminary 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 17, 2023.**

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

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

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

Preliminary Summer 2023 Operable Capacity Analysis

90/10 Load Forecast	June - 2023[2] CSO (MW)	June - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,068	28,869
Active Demand Capacity Resource (+) [5]	603	447
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,030	1,030
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-)	346	346
Gas Generator Outages MW (-)	129	130
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,436	27,080
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,479	26,479
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,784	28,784
Operable Capacity Margin	-2,348	-1,704

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

[2] Load forecast that is based on the Preliminary 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 17, 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.

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Preliminary Summer 2023 Operable Capacity Analysis 50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 3/28/2023

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/27/2023	28103	426	1094	10	1718	502	3400	0	24013	20889	2305	23194	819	N	Summer 2023
6/3/2023	28068	603	1030	10	343	129	2800	0	26439	24664	2305	26969	-530	N	Summer 2023
6/10/2023	28068	603	1030	10	343	129	2800	0	26439	24664	2305	26969	-530	N	Summer 2023
6/17/2023	28068	603	1030	10	346	129	2800	0	26436	24664	2305	26969	-533	Y	Summer 2023
6/24/2023	28068	603	1030	10	346	129	2800	0	26436	24664	2305	26969	-533	N	Summer 2023
7/1/2023	28068	603	1030	10	346	129	2100	0	27136	24664	2305	26969	167	N	Summer 2023
7/8/2023	28068	603	1030	10	353	129	2100	0	27129	24664	2305	26969	160	N	Summer 2023
7/15/2023	28068	603	1030	10	333	129	2100	0	27149	24664	2305	26969	180	N	Summer 2023
7/22/2023	28068	603	1030	10	350	129	2100	0	27132	24664	2305	26969	163	N	Summer 2023
7/29/2023	28068	603	1030	10	353	129	2100	0	27129	24664	2305	26969	160	N	Summer 2023
8/5/2023	28068	603	1030	10	356	129	2100	0	27126	24664	2305	26969	157	N	Summer 2023
8/12/2023	28068	603	1030	10	15	129	2100	0	27467	24664	2305	26969	498	N	Summer 2023
8/19/2023	28068	603	1030	10	15	129	2100	0	27467	24664	2305	26969	498	N	Summer 2023
8/26/2023	28068	603	1030	10	14	129	2100	0	27468	24664	2305	26969	499	N	Summer 2023
9/2/2023	28068	603	1030	10	98	129	2100	0	27384	24664	2305	26969	415	N	Summer 2023
9/9/2023	28068	603	1030	10	246	389	2100	0	26976	24664	2305	26969	7	N	Summer 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 Preliminary 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

14. Operable Capacity Season Label: Applicable season and year.

15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Preliminary Summer 2023 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 3/28/2023

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/27/2023	28103	426	1094	10	1718	502	3400	0	24013	22449	2305	24754	-741	N	Summer 2023
6/3/2023	28068	603	1030	10	343	129	2800	0	26439	26479	2305	28784	-2345	N	Summer 2023
6/10/2023	28068	603	1030	10	343	129	2800	0	26439	26479	2305	28784	-2345	N	Summer 2023
6/17/2023	28068	603	1030	10	346	129	2800	0	26436	26479	2305	28784	-2348	Y	Summer 2023
6/24/2023	28068	603	1030	10	346	129	2800	0	26436	26479	2305	28784	-2348	N	Summer 2023
7/1/2023	28068	603	1030	10	346	129	2100	0	27136	26479	2305	28784	-1648	N	Summer 2023
7/8/2023	28068	603	1030	10	353	129	2100	0	27129	26479	2305	28784	-1655	N	Summer 2023
7/15/2023	28068	603	1030	10	333	129	2100	0	27149	26479	2305	28784	-1635	N	Summer 2023
7/22/2023	28068	603	1030	10	350	129	2100	0	27132	26479	2305	28784	-1652	N	Summer 2023
7/29/2023	28068	603	1030	10	353	129	2100	0	27129	26479	2305	28784	-1655	N	Summer 2023
8/5/2023	28068	603	1030	10	356	129	2100	0	27126	26479	2305	28784	-1658	N	Summer 2023
8/12/2023	28068	603	1030	10	15	129	2100	0	27467	26479	2305	28784	-1317	N	Summer 2023
8/19/2023	28068	603	1030	10	15	129	2100	0	27467	26479	2305	28784	-1317	N	Summer 2023
8/26/2023	28068	603	1030	10	14	129	2100	0	27468	26479	2305	28784	-1316	N	Summer 2023
9/2/2023	28068	603	1030	10	98	129	2100	0	27384	26479	2305	28784	-1400	N	Summer 2023
9/9/2023	28068	603	1030	10	246	389	2100	0	26976	26479	2305	28784	-1808	N	Summer 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.
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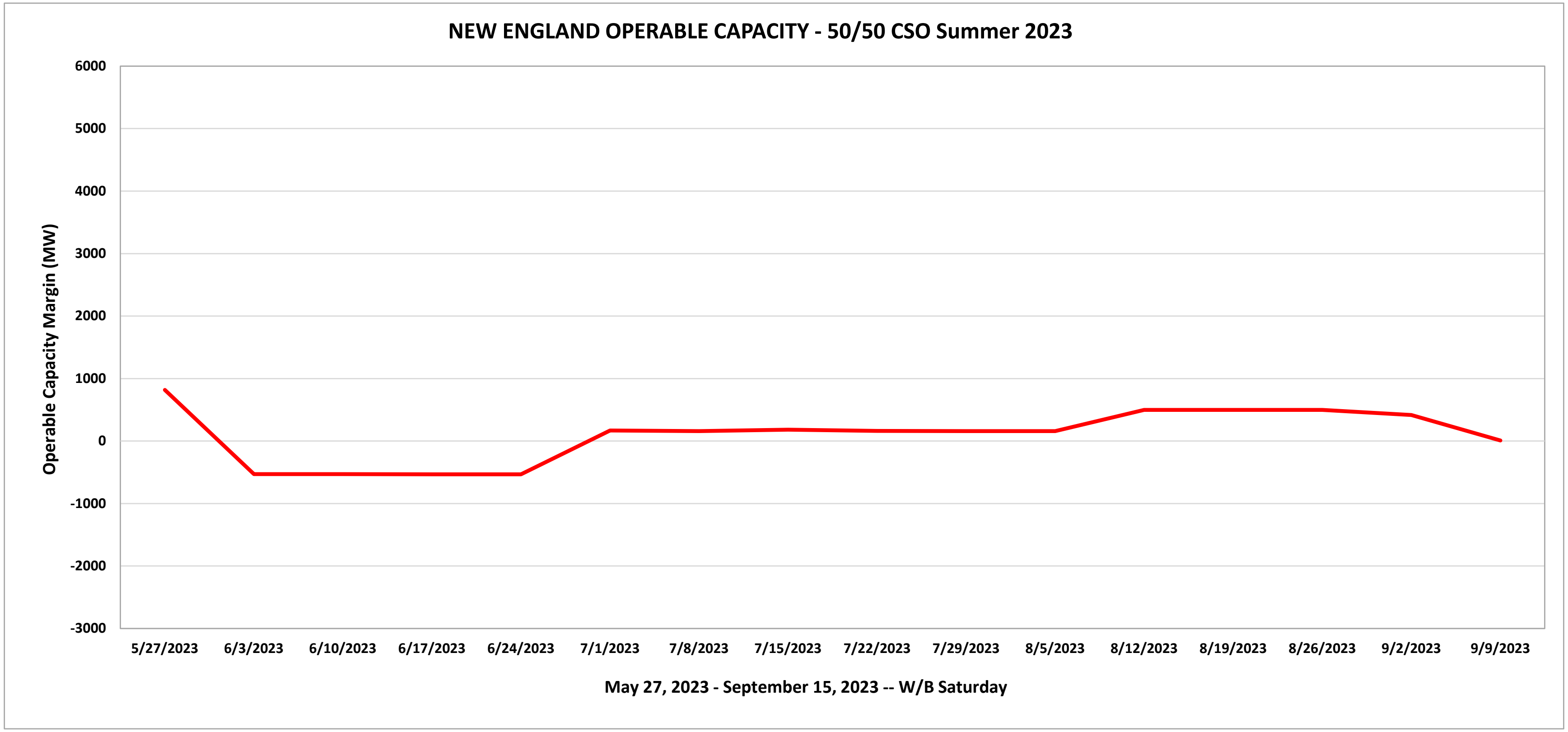
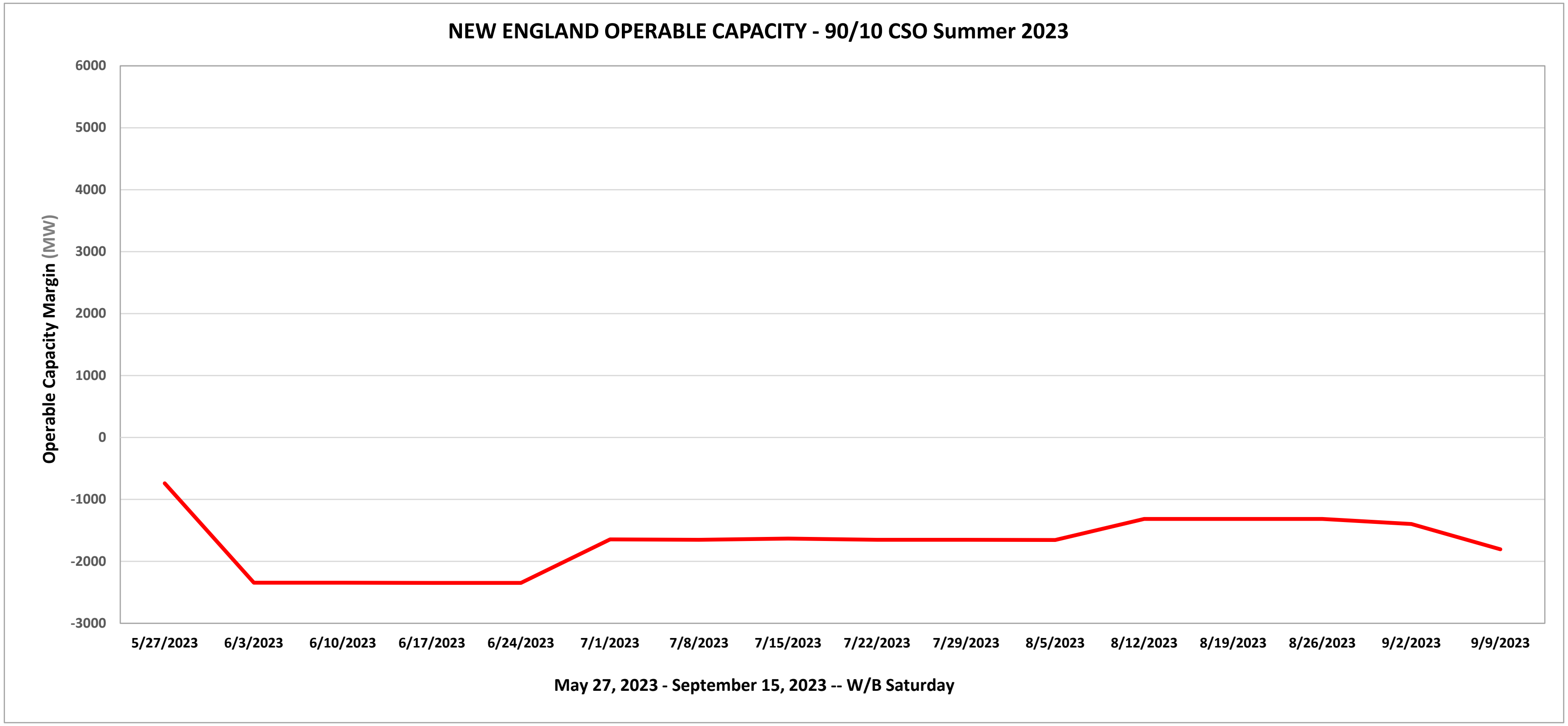
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Preliminary Summer 2023 Operable Capacity Analysis 50/50 Forecast (Reference)



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

Possible Relief Under OP4: Appendix A

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

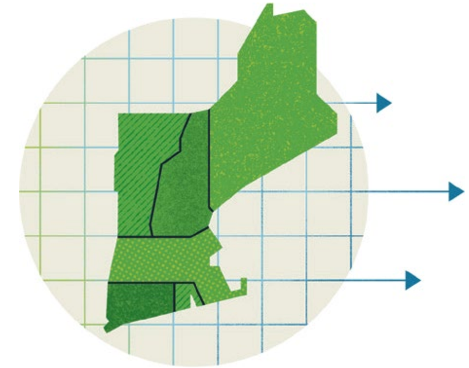
NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values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

Updated 2023 Annual Work Plan

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Objectives and Highlights



- This report reflects updates to the *2023 Annual Work Plan* (2023 AWP) since its publication in October 2022
  - The AWP underscores the ISO's and the region's continued focus on advancing a reliable clean-energy transition through innovation and collaboration
- The update summarizes work on track or with refined scope or schedule
  - Plans and timeframes remain largely unchanged due to effective, coordinated planning and prioritization efforts by the ISO and stakeholders
- Stakeholders can submit new requests for the ISO's 2024 AWP through the NEPOOL priorities process, which kicked off in March 2023
  - Over the following months, the requests are discussed, narrowed, and a final list is chosen for incorporation into the 2024 plan
  - Note that the AWP focuses on larger initiatives and also does not represent the ISO's full workload, including project implementation work or the extensive day-to-day operations related to running the grid, the markets, and its organization

Anchor Projects on Track

Scopes and schedules unchanged since 2023 AWP publication

- **Resource Capacity Accreditation (RCA)**: Stakeholder discussions continue from 2022; a FERC filing is expected in November 2023 for Forward Capacity Auction 19 (FCA 19)
- **Day-Ahead Ancillary Services Initiative (DASI)**: Stakeholder discussions continue from 2022; a FERC filing is expected in Q3 2023
- **2050 Transmission Study**: Stakeholder discussions began in 2021; in 2022, study results were presented and development of possible transmission solutions began; further development of solutions and associated cost estimates continue throughout 2023
- **nGem Market Clearing Engine**: The day-ahead version of the new market clearing engine software and infrastructure is expected to be in service in Q2 2023 (implementation is not connected to FCM cycle)

Notable Initiatives on Track

Scopes and schedules unchanged since 2023 AWP publication

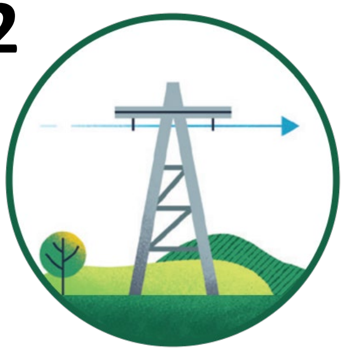
- **Updates to Interim Energy Program (IEP) for Winters 23/24, 24/25**: Proposal voted by Participants Committee in March then to file with FERC
- **Day-Ahead and Real-Time Energy Shortage Pricing Assessment**: ISO evaluations to take place in 2023 with stakeholder discussions to begin in 2024
- **Alternative FCM Commitment Horizons**: ISO evaluations of both prompt and seasonal horizons to take place in 2023 with stakeholder discussions to begin in 2024
- **FCM Retirement Reforms: Bid Flexibility:** Stakeholder discussions to continue with a potential FERC filing by end of 2023 targeting FCA 19 implementation
- **FCM Retirement Reforms: Return to Service**: Stakeholder discussions to continue with a potential FERC filing by end of 2023 targeting FCA 19 implementation
- **Capacity Network Resource Interconnection Service Time-Out Removal** (Formerly called FCM Three-Year Capacity Time-Out): Proposal to be voted by Participants Committee in April, with a FERC filing expected in Q2
- **Expanded Weather Analytics for 21-Day to Intra-Day Load Forecasting**: The ISO plans to present to stakeholders in Q2-3 and implement in Q3
- **Models and Simulators to Support Future Grid Studies**: Work on the Inverter-Based Resource Integration and Modeling and the Integrated Market Simulator are on track
- **Cloud Computing and Cyber-Security**: Projects are on track for 2023 implementation

Notable Initiatives on Track, cont'd

- **Future Grid Reliability Study (FGRS) Phase 2**
  - The study will leverage elements of Pathways and FGRS Phase 1 to solve for a set of clean-energy resources that meet the states' decarbonization goals, which 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
  - The ISO is considering efficiency gains from aligning Phase 2 work with the Economic Planning for the Clean Energy Transition (EPCET) pilot study
- **Pathways Next Steps**
  - In addition to the work above, the ISO expects to engage with the states and stakeholders on discussions of jurisdiction and governance frameworks for a preferred market pathway, which may include discussion of the Massachusetts Department of Energy Resources' Forward Clean Energy Market (FCEM) Design Proposal

Updated Anchor Project: Extended-Term/ Longer-Term Transmission Planning Phase 2

Scopes and schedules refined since 2023 AWP publication



- This item has been delayed to allow additional time for NESCOE/states to work with the ISO on development of a framework to inform the proposed changes
- Stakeholder discussions are expected to begin in first half of 2023, with a potential FERC filing in early 2024
  - Stakeholder discussions were originally planned for early 2023 with a potential filing in Q3 2023
- NESCOE is separately asking Transmission Organizations to improve planning processes around Asset Condition Projects, discussions on which could intersect with this initiative in terms of sizing of transmission projects
- As stated in the 2023 AWP, Phase 2 along with process changes that may arise from FERC's potential RM21-17 Order, likely will create channels for input about sizing the transmission system for future needs

Updated Anchor Project: Energy Adequacy

- **Accomplished Since 2023 AWP Publication**
  - Immediate-term: Confirm protocols to work with the DOE on emissions restrictions; maintain lines of communication for Jones Act waivers
  - Short-term: Update the Inventoried Energy Program for Winters 2023/2024, 2024/2025
  - Medium/longer-term: Present and gather feedback on Operational Impacts of Extreme Weather Events Step 1

Reminder, the following time horizons are used to help guide discussions:

- Immediate-term: Winter 2022/23
- Short-term: Winters 2023/2024 and 2024/2025
- Medium-term: The subsequent seven winters–2025/2026 through 2032/2033
- Longer-term: Beyond 2033 (roughly a decade from now)

Updated Anchor Project: Energy Adequacy, cont'd

- **Considerations and Actions Underway in Addition to Other Reliability-Improvement Initiatives**
  - Short-term: Prepare review of past winter and confirmation of readiness plans for winter 2023/2024
  - Short/medium-term: Continue regional dialogue with respect to the Everett LNG Facility
  - Medium/longer-term: Present and gather feedback on Operational Impacts of Extreme Weather Events Step 2
    - Includes presentation of the new Risk Screening Model and Scenario Generation process that identifies the extreme events for input to the energy assessment performed in Step 3

Updated Anchor Project: Energy Adequacy, cont'd

- **Additional Considerations and Actions Planned**
  - Medium/longer-term: Present results of Operational Impacts of Extreme Weather Step 3
    - Results reveal probability distribution (estimated likelihood) of system risks under extreme events identified in Step 2
    - Upon completion of Steps 1-3, the final resulting product will be a tool that can be used over time to analyze the probability of extreme system risk
  - Medium/longer-term: Use Step 3 results to identify problem statement
  - Medium/longer-term: Discuss objectives, scope, and viability of energy adequacy solutions and define the list of options to pursue
  - Medium/longer-term: Participate in FERC's *Second New England Winter Gas-Electric Forum re New England Winter Gas-Electric Forum under AD22-9* (June 20, 2023)
    - New item since 2023 AWP publication

Updated Anchor Project: Energy Adequacy, cont'd

- **Timeline of Planned Actions**
  - **May Participants Committee**: Present 2023/24 winter analysis (akin to the 2022/2023 analysis)
  - **May Reliability Committee**: Present initial results of Operational Impacts of Extreme Weather Study (Step 3)
  - **June FERC Forum**: Discussion on the need for Everett; present progress made since the September forum, including Operational Impacts of Extreme Weather study results and DASI/RCA reliability initiatives
  - **Q3**: Initiate a solution study process following the June FERC technical conference, no later than August
    - Finalize problem statement based on the Operational Impacts of Extreme Weather study results, by September 1
    - Initially focus on winters 2025/26 through 2028/29 (winters without the IEP program and before DASI and RCA are both in effect)

Updated Notable Initiatives

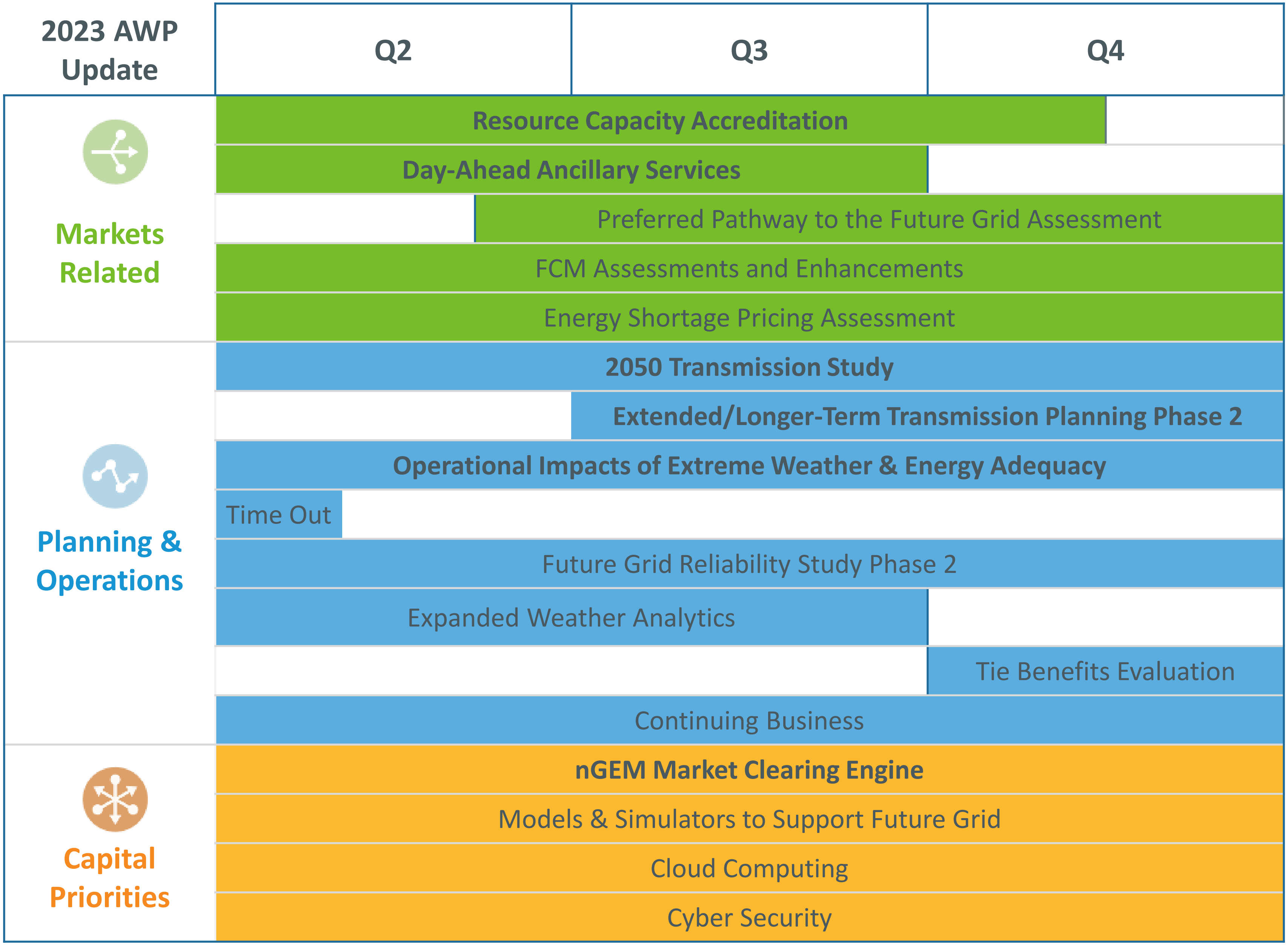
Scopes and schedules refined since 2023 AWP publication

- **FCM-Related Assessments and Enhancements**
  - **Financial Assurance Policy/Entry-Related Improvement:** The ISO plans to assess whether and why new capacity resources are clearing in the FCA when they may not be commercial by the associated Capacity Commitment Period and discuss possible reforms with stakeholders, including any impacts on this issue should FCM move to alternative FCM commitment horizons
    - Stakeholder discussions are expected to begin in second half of 2023, with a potential FERC filing in early 2024
    - The 2023 AWP noted a potential FERC filing by end of 2023
  - **FCM Parameters Updates Supporting MOPR Reforms for FCA 19:** The ISO plans to discuss with stakeholders adjustments to capital cost assumptions related to mitigation reforms applicable beginning with FCA 19
    - Stakeholder discussions expected to begin in Q3 2023 with a FERC filing by early 2024

Other Timely Efforts

Work that improves processes

- **Tie Benefits Evaluation**: The ISO plans to conduct and report on a broad evaluation of tie benefits beginning in Q4 and into 2024
  - To evaluate past performance of tie benefits and expected short- to mid-term future performance, possibly including:
    - Review historical exchanges at times of peak
    - Review our neighbors' 5-10 yr. plans of resource/load/ transmission changes
    - Gather intelligence from ongoing NPCC/NERC or other studies
  - To evaluate impacts to ICR from RCA modeling changes, which will enable a more informed, broad evaluation of tie benefits
  - Initial reporting and discussion will be initiated at the Power Supply Planning Committee (PSPC) in Q4 2024
  - This assessment aligns with recent stakeholder requests for an evaluation of tie benefits beyond the scope for the FCA 19 RCA package


2023 AWP Update
Q2
Q3
Q4
Markets Related
Resource Capacity Accreditation
Day-Ahead Ancillary Services
Preferred Pathway to the Future Grid Assessment
FCM Assessments and Enhancements
Energy Shortage Pricing Assessment
Planning & Operations
2050 Transmission Study
Extended/Longer-Term Transmission Planning Phase 2
Operational Impacts of Extreme Weather & Energy Adequacy
Time Out
Future Grid Reliability Study Phase 2
Expanded Weather Analytics
Tie Benefits Evaluation
Continuing Business
Capital Priorities
nGEM Market Clearing Engine
Models & Simulators to Support Future Grid
Cloud Computing
Cyber Security

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of April 5, 2023

The following activity, as more fully described in the attached litigation report, has occurred since the report dated February 28, 2023 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	Page	Matter	Date	Activity
	4	NextEra/Avangrid/NECEC Seabrook Complaint (EL21-6) and Seabrook Declaratory Order (EL21-3)	Mar 3	NextEra requests rehearing and Avangrid requests clarification of the *Seabrook Dispute Order*
			Apr 3	FERC issues notice that NextEra and Avangrid requests may be deemed denied by operation of law

II. Rate, ICR, FCA, Cost Recovery Filings

	Page	Matter	Date	Activity
*	8	FCA17 Results Filing (ER23-1435)	Mar 21	ISO-NE files FCA17 results; comment date ***May 5, 2023***
			Mar 22-Apr 4	NEPOOL, Calpine, Constellation, Dominion, NESCOE, EPSA, No Coal, No Gas, intervene
*	9	Add'l Cost Recovery Due to Dec 24 General Threshold Energy Mitigation: Dynegy (ER23-1261)	Mar 6-Apr 4	NEPOOL, ISO-NE, CT PURA, CT AG, EPSA, Public Citizen intervene
			Mar 20	MA AG, ME OPA, Public Citizen request extension of comment deadline to Apr 4, 2023
			Mar 27	FERC extends comment deadline to Apr 4, 2023
			Apr 4	NEPGA supports filing; MA AG/CT OCC, ME OPA protest
	9	VTransco Deferral of Retiree Lump Sum Payment Cost Recovery (ER21-2627)	Mar 17	VTransco submits informational filing for lump sum payment elections taken in 2022 (24 elections totaling $14.38 million resulting in $2.15 million recorded VTransco's balance sheet)
	10	**Mystic 8/9 COSA (ER18-1639)**		
	10	(-019) *Mystic I Order on Remand* and Motion to Hold in Abeyance	Mar 28	FERC issues *Mystic I Order on Remand*; 30-day compliance filing (revising the COSA to reinstate the revenue sharing mechanism) due on or before ***Apr 27, 2023***
	10	(-022) First CapEx Info. Filing Settlement Agreement Interim Rate Implementation	Mar 15	Mystic requests authorization to implement on an interim basis an Interim Settlement Rate
			Mar 27	Acting Chief ALJ Satten grants Mystic's Mar 15 request
	10	(-021) First CapEx Info. Filing Settlement Agreement	Mar 15	Mystic submits Settlement Agreement to resolve all issues raised by the formal challenges to its First CapEx Info. Filing and set for hearing in the Apr 28, 2023 *Mystic First CapEx Info. Filing Order*
			Mar 16-Apr 4	NESCOE, National Grid, CT PURA, ENECOS, FERC Trial Staff, MA AG file comments on the Settlement Agreement; reply comments due on or before ***Apr 14, 2023***
	11	Limited Waiver of Certain Mystic COSA True-Up Deadlines (ER23-1159)	Mar 20	FERC grants waiver of certain Mystic COSA true-up deadlines
	11	Transmission Rate Annual (2022-23) Update/Info Filing (ER09-1532; RT04-2)	Mar 16	Avangrid, Eversource, National Grid, RI Energy, Unitil, VTransco/GMP file comments/protests on RENEW Challenge
			Mar 31	RENEW answers comments/protests to its Challenge

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

	12	PPU CTR Clarifications (ER23-911)	Mar 21	FERC accepts PPU CTR Clarifications, eff. Mar 21, 2023
	13	SATOA Revisions (ER23-739; ER23-743)	Mar 3	ISO-NE answers Feb 16 National Grid answer
	13	New England's *Order 2222* Compliance Filing (ER22-983)	Mar 1	FERC accepts in part, and rejects in part, ISO-NE's compliance filing, to become effective Nov 1, 2022 and Nov 1, 2026, as requested, subject to further compliance filings to be submitted on or before Mar 31, May 1 and Aug 28, 2023
			Mar 23	NEPOOL requests 8-day extension of time, to ***May 9, 2023***, of 60-day compliance filing deadline
			Mar 31	ISO-NE and New England Public Utilities request rehearing and/or clarification of the *Order 2222 Compliance Order*

IV. OATT Amendments / TOAs / Coordination Agreements

	15	Attachment K Economic Study Revisions (ER23-971)	Mar 30	FERC accepts Economic Study Revisions, eff. Mar 31, 2023

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

	16	Schedule 21-NEP: NEP/Dichotomy Collins Hydro SGIA (ER23-888)	Mar 17	FERC issues deficiency letter; response deadline ***Apr 16, 2023***

VII. NEPOOL Agreement/Participants Agreement Amendments

	17	PA Amendment No. 12 (ISO Board Member Age Limit Increase) (ER23-980)	Mar 3	FERC accepts ISO Board Member Age Limit Increase (to 75), eff. Apr 1, 2023

VIII. Regional Reports

	17	Capital Projects Report - 2022 Q4 (ER23-1125)	Mar 3	Eversource, National Grid intervene
			Apr 5	FERC accepts 2022 Q4 Report, eff. Jan 1, 2023
*	19	Reserve Market Compliance (34th) Semi-Annual Report (ER06-613)	Mar 31	ISO-NE submits 34th semi-annual report
*	19	ISO-NE FERC Form 715 (undocketed)	Mar 29	ISO-NE submits 2021 annual report of total MWh of trans. service

IX. Membership Filings

	19	Mar 2023 Membership Filing (ER23-1197)	Mar 24	FERC accepts (i) ***the memberships of*** CommonWealth New Bedford Energy; GF Power; and Industrial Wind Action Corp; (ii) ***the termination of the Participant status of*** Backyard Farms Energy and Backyard Farms; Bruce Power; CommonWealth Resource Management Corp.; Darby Energy; DFC ERG CT; Stones DR; and Vineyard Wind; and (iii) ***the name change of*** Advanced Energy United Inc. ("AEU")

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

	20	Revised Reliability Standard: CIP-003-9 (RD23-3)	Mar 16	FERC approves CIP-003-9, eff. Apr 1, 2026

	20	Revised Rel. Standards: EOP-011-3 and EOP-012-1 (RD23-1)	Mar 20	EPSA, NEPGA, P3 jointly request rehearing of *Cold Weather Standards Order*; FERC action required on or before ***Apr 19, 2023***
	21	Inverter-Based Resource Registration (RD22-4)	Mar 20	ACPA, APPA, NRECA, Arizona Public Service Co., Pine Gate Renewables file comments
	22	CIP Standards Development: Info Filings on Virtualization and Cloud Computing Srvs. Projects (RD20-2)	Mar 15	NERC files required quarterly report with further revised schedule for Project 2016-02 (projected filing of revised standards now ***Sep 2023***)
	22	NOPR: IBR Reliability Standards (RM22-12)	Mar 6	ISO-NE, APPA, CA DWP file reply comments

XI. Misc. - of Regional Interest

*	23	203 Application: Weaver Wind / Greenbacker (EC23-68)	Mar 27	Weaver Wind requests the FERC authorize the acquisition of all of its membership interests by a wholly-owned subsidiary of Greenbacker Renewable Energy Co. (upon consummation, making Weaver Wind a Related Person to Howard Wind and Hectate Energy); comment deadline ***Apr 17, 2023***
	24	203 Application: Saddleback / CPV (EC23-52)	Mar 23	FERC authorizes CPV's acquisition of Saddleback Transaction consummated
	24	203 Application: Salem Harbor / Castleton Commodities (EC23-50)	Apr 4	FERC authorizes Castleton Commodities acquisition of at least 67%, and up to 100%, of the issued and outstanding Series A-1 or A-2 Common Units of Salem Harbor
	24	203 Application: Talen Energy Supply Reorganization (EC23-42)	Mar 30	FERC authorizes transaction
	24	203 Application: Cogentrix / EGCO (Rhode Island State Energy Center) (EC23-41)	Mar 16 Mar 24 Apr 3	FERC authorizes transaction Transaction consummated RISEC files notice that the transaction was consummated
	25	203 Application: ConEd / RWE (EC23-17)	Mar 1	RWE informs FERC that the transaction was consummated on Mar 1, 2023; Clean Energy Businesses join Supplier Sector and are renamed
*	25	Study Work Agreemt Cancellation: CL&P/NYISO (ER23-1483)	Mar 28	CL&P submits Notice of Termination of a Study Work Agreement with NYISO; comment deadline ***Apr 18, 2023***
*	25	PSNH / National Grid D&E Agreement (ER23-1481)	Mar 28	Eversource files D&E Agreement in connection with National Grid's asset separation project with Great River Hydro; comment deadline ***Apr 18, 2023***
*	25	LGIA: CL&P/Generate NB Fuel Cells/ISO-NE (ER23-1479)	Mar 27	CL&P and ISO-NE file a revised non-conforming LGIA with Generate NB to govern the interconnection of Generate NB's 20 MW fuel cell project in New Britain, CT; comment deadline ***Apr 17, 2023***
	26	Shared Structure Participation Agreement: VELCO/GMP (ER23-1101)	Mar 21	FERC accepts ShSPA VTransco files Shared Structure Participation Agreement with Green Mountain Power, eff. Feb 1, 2023
	26	LGIA: RI Energy / Deepwater Block Island Wind (ER23-1023)	Mar 27	FERC accepts LGIA, eff. Jan 1, 2023
	26	IA: RI Energy / Manchester Street (ER23-1007)	Mar 27	FERC accepts IA revisions, eff. Jan 1, 2023
	26	LSAs: RI Energy/ISO-NE/BIPCO (ER23-1003; ER23-1000)	Mar 31	FERC conditionally accepts one LSA (ER23-1003) and issues a deficiency letter requesting additional information regarding the LSA filed in ER23-1003; response to deficiency letter and compliance filing both due on or before ***May 1, 2023***

*	27	VELCO Phase II Vermont DMNRC Support Agreement Info Filing (ER90-591)	Mar 31	VELCO submits annual informational filing pursuant to the Phase II Vermont DMNRC Support Agreement

XII. Misc. - Administrative & Rulemaking Proceedings

27	Interregional HVDC Merchant Transmission (AD22-13)	Mar 8	Comments on Invenergy's request for a tech. conf. filed by: AEU, NRDC, IRC, SPP, NARUC, ACRE, Assoc Industries of MO, Clean Energy Buyers Assoc, Converge Strategies, ELCON, Grid United, IL Manufac. Assoc, MN PSC, Natl. Elec. Manufac. Assoc, ND PSC, Public Citizen, Niskanen Center, Prysmian Group, P. Stockton, R Street Institute, Rail Electrification Council, Renew Missouri Advocates, SOO Green HVDC Link ProjectCo, World Resources Institute
29	Transmission Planning and Cost Management Technical Conference (AD22-8)	Mar 23	Post-tech. conf. comments filed by: ISO-NE, AEU, Avangrid, Cypress Creek, Eversource, LS Power, MA AG, NE Public Systems, NESCOE, NextEra, NRDC, NRG, Maine PUC, ACRE, APPA, EEI, Harvard Elec. Law Inst., LPPC, NASUCA, NRECA, R Street Institute
30	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Mar 6	Transcript of Feb 15, 2023 (6th) JFSTF meeting posted to eLibrary
32	NOPR: Interconnection Reforms (RM22-14)	Apr 3	Elevate submits comments out-of-time
35	NOPR: Transmission Siting (RM22-7)	Mar 3	FERC grants 30-day extension of time, to ***May 17, 2023***, to file comments

XIII. FERC Enforcement Proceedings

No Activity to Report

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

41	2nd Revised Narragansett LSA Orders (22-1161, 22-1108) (consolidated)	Mar 20	Oral argument held before Judges Henderson, Pillard and Katsas
42	*Opinion 531-A* Compliance Filing Undo (20-1329)	Apr 4	FERC files status report indicating that proceedings before the FERC remain ongoing and appeal should continue to remain in abeyance
43	Northern Access Project (22-1233)	Mar 14 Mar 21 Apr 4	Sierra Club files Reply Brief Sierra Club files Joint Deferred Appendix Sierra Club, the FERC, INGA (Amicus for FERC) and Empire Pipeline and National Fuel Gas Supply (Intervenor for Respondent FERC) file Final Briefs
44	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.)	Mar 2 Mar 9	Petitioners file Deferred Appendix Final Briefs filed; oral argument set for ***Apr 20, 2023*** before Judges Srinivasan, Millett and Tatel

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: April 5, 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 April 5, 2023. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

The December 13, 2022 complaint by RENEW Northeast, Inc. ("RENEW") against ISO-NE and the Participating Transmission Owners ("PTOs"), which seeks changes to the ISO-NE Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to Interconnection Customers,[2] is pending before the FERC. As previously reported, the proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee at its October 26, 2021 meeting, and were discussed at the Participants Committee November 3, 2021 meeting. RENEW asked the FERC to issue an order granting the Complaint by April 14, 2023 (approximately 60 days prior to the June 15, 2023 deadline for the NE PTOs to publish a draft of the Annual Update to the data used in the transmission formula rate).

Following a request by the PTO AC for a 20-day extension of time to submit comments, supported by NEPOOL, the Massachusetts Attorney General's Office ("MA AG") and NESCOE, and granted by the FERC on December 22, 2022, comments were due on or before January 23, 2023. On January 19, 2023, ISO-NE moved to dismiss itself as a party or, in the alternative, answer the Complaint ("ISO-NE Jan 19 Motion"). On January 23, responses, comments and protests were filed by the PTO AC, NEPOOL, AEU/Clean Energy Council, CPV Towantic, Glenvale, MA AG, NECOS, NEPGA, and NESCOE. Doc-less interventions only were filed by Calpine, CMMEC, EMI, Eversource, Narragansett, National Grid, New Leaf Energy, NextEra, NRG, Versant, CT DEEP, MA DPU, the American Clean Power Association ("ACPA"), Solar Energy Industries Association ("SEIA"), and Public Citizen.

Since the last Report, RENEW answered ISO-NE's Jan 19 Motion. On February 7, 2023, RENEW, the PTO AC, and National Grid filed answers to the January 23 protests/comments. On February 16, 2023, ISO-NE answered RENEW's February 7 answer. On February 22, 2023, CPV Towantic, Glenvale, and the MA AG filed answers to the February 7 answers. This matter is pending before the FERC. If you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

[2] 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.

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

On March 28, 2023, the FERC denied in part, and accepted in part, Eastern New England Consumer-Owned Systems' ("ENECOS") 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").[3] The FERC found that ENECOS did not demonstrate that it is unjust and unreasonable for Mystic customers to pay for firm pipeline transportation service. However, the FERC also found that the COSA is unjust and unreasonable to the extent that it allocates the Pipeline Transportation Costs entirely to Mystic without an offset to ensure that third parties who benefit from the pipelines reasonably contribute to Pipeline Transportation Costs. The FERC went on to conclude that the practice of crediting Mystic to account for firm gas transportation charges that Constellation LNG collects from third-party sales of gas is a just and reasonable method of allocating the Pipeline Transportation Costs and directed Mystic to include as part of a 30-day compliance filing this pipeline-related crediting as an explicit provision in the Mystic COSA.[4] Challenges, if any, to the *Order on ENECOS Mystic COSA Complaint* are due on or before ***April 27, 2023***. 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.[5] 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.[6] 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,[7] 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,[8] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[9] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical

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[3] *Belmont Municipal Light Dept., et al. v. Constellation Mystic Power, LLC and ISO New England, Inc.*, 182 FERC ¶ 61,199 (Mar. 28, 2023) ("*Order on ENECOS Mystic COSA Complaint*").

[4] Specifically, the FERC directed Mystic in a 30-day compliance filing to revise the COSA to (1) provide all necessary details as to how the crediting process works; (2) differentiate, through both an explanation in its compliance filing and creation of two new line items in Schedule 3A, the credits and charges included as part of the Fixed Pipeline Costs; (3) address how and whether this pipeline-related crediting procedure interacts or should interact with the true-up procedure already included in the Mystic Agreement and revise the true-up as necessary; and (4) differentiate in the Mystic Agreement the Pipeline Transportation Costs as Fixed O&M/Return on Investment Costs from the Pipeline Transportation Agreement Costs. *Id.* at P 29.

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

[6] *Id.* at P 31.

[7] *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.

[8] 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).

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

conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[10] 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.[11] 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[12] (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).

- **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.[13] 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.[14]

[10] 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.

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

[12] "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."

[13] *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*").

[14] *Id.* at P 20.

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[15] 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).

- **NextEra / Avangrid/NECEC Dispute - ("Seabrook Complaint") (EL21-6)[16] and ("Seabrook Declaratory Order Petition") (EL21-3)[17]**

As previously reported, the FERC issued, on February 1, 2023, a single order addressing these two proceedings.[18] In the *Seabrook Dispute Order*, the FERC (i) both denied and granted in part the Seabrook Complaint; (ii) dismissed the Seabrook Declaratory Order Petition; and (iii) directed Seabrook to replace the Seabrook Station breaker pursuant to its obligations under the Seabrook LGIA and Good Utility Practice. Specifically, the FERC denied the Seabrook Complaint in part because it found that Avangrid had "not shown that Seabrook is obligated to replace the breaker due to Seabrook failing to meet certain open access obligations or because Seabrook has failed to comply with Schedule 25 of the ISO-NE Tariff".[19] However, the FERC found that, "under Seabrook's LGIA, Seabrook may not refuse to replace the breaker because it is needed for reliable operation of Seabrook Station and required by Good Utility Practice" and thus, given the specific facts and circumstances in the record, granted the Seabrook Complaint in part.[20] With respect to cost issues, the FERC

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

[16] On Oct. 13, 2020, NECEC and Avangrid Inc. (together, "Avangrid") filed a complaint 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 and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage (the "Seabrook Complaint").

[17] On Oct. 5, 2020, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order seeking 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 Declaratory Order Petition" or "Petition"). Please see prior Reports for additional procedural details related to these proceedings.

[18] *NextEra Energy Seabrook, LLC and NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC*, 182 FERC ¶ 61,044 (Feb. 1, 2023) *("Seabrook Dispute Order")*.

[19] *Id*. at P 74.

[20] *Id*.

agreed with Avangrid that, in this case, Seabrook should not recover opportunity costs (e.g. lost profits, lost revenues, and foregone Pay for Performance ("PFP") bonuses) or legal costs.[21] In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the *Seabrook Dispute Order*, that additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition.[22] The breaker replacement is currently expected to take place during the Fall 2024 refueling outage and the commercial operation date for the NECEC Project is December 2024.[23] Seabrook plans to file an agreement governing installation at the earlier of 30 days prior to delivery of the breaker or 120 days prior to the start of the Fall 2024 outage.[24] The FERC noted its expectation that such an agreement would resolve whatever remaining issues exist between the parties to allow replacement of the breaker to move forward during the 2024 outage, or if not, an unexecuted agreement would be filed.[25]

Request for Rehearing Denied by Operation of Law. On March 3, 2023, NextEra filed a request for rehearing of the *Seabrook Dispute Order* on the basis that, among other things, the FERC lacked authority to require Seabrook to replace its generation breaker and to rule that Seabrook cannot recover all its costs. On April 3, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[26] The Notice confirmed that the 60-day period during which a petition for review of the *Seabrook Dispute Order* can be filed with an appropriate federal court was triggered when the FERC did not act on NextEra's request for rehearing of the *Seabrook Dispute Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

Avangrid Request for Clarification. As previously reported, Avangrid filed a motion for clarification on March 17, 2023 requesting that the FERC clarify the basis for its jurisdiction in the *Seabrook Dispute Order*. Avangrid's request for clarification remains pending, with FERC action required on or before April 17, 2023 or that request, too, may be deemed denied by operation of law.

If you have any questions concerning these matters, 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,[27] 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*

[21] *Id.* at P 100. The FERC noted that Avangrid has agreed to pay for the direct costs of the engineering, procurement and construction of the Seabrook breaker replacement. The FERC further noted that it did not address arguments over consequential damages in light of the fact that both Seabrook and Avangrid both asserted that consequential damages were no longer a live issue.

[22] *Id.* at P 112.

[23] A&R E&P Agreement Between NextEra Energy Seabrook and NECEC Transmission at 2, NextEra Energy Seabrook, LLC, Docket No. ER22-2807-000 (filed Sep. 7, 2022).

[24] Amended E&P Agreement, Art. VI, Docket No. ER22-2807-000 (filed Sept. 7, 2022).

[25] *Id.* at P 88.

[26] *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Order*").

[27] 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*")).

531-A).[28] However, the FERC's orders were challenged, and in *Emera Maine,*[29] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[30] and third (EL14-86)[31] 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.[32] 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[33] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[34] 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.[35] 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*.

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[28] *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*").

[29] *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).

[30] 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%.

[31] 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.

[32] *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*").

[33] 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.

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

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

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.[36] 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*[37] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[38]

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%.[39] 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

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

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

[38] *Id.* at P 19.

[39] *Id.* at P 59.

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

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[41] 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 Results Filing (ER23-1435)**

On March 21, 2023, ISO-NE filed the results of the seventeenth FCA ("FCA17") held March 6, 2023 for the June 1, 2026 - May 31, 2027 Capacity Commitment Period ("CCP"). ISO-NE reported the following highlights:

- FCA17 Capacity Zones were the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones), the Maine Capacity Zone (the Maine Load Zone) and the Rest-of-Pool ("ROP") Capacity Zone (the Southeastern Massachusetts, Rhode Island, Northeastern Massachusetts/Boston, Connecticut and Western/Central Massachusetts Load Zones). NNE was modeled as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- FCA17 commenced with a starting price of $12.76/kW-mo. and concluded for all Capacity Zones after four rounds.
- Capacity Clearing Prices were as follows (prices expressed per kw-mo.): All Capacity Zones - $2.59; imports over the NY AC Ties (390 MW); and imports over the New Brunswick external interface (177 MW) - $2.55.[42]
- There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.
- No resources cleared as Conditional Qualified New Generating Capacity Resources.
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- No De-List Bids were rejected for reliability reasons.

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

[41] *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).

[42] The HQ Highgate external interface and Phase I/II HQ Excess external interface were priced at $2.59, with no imports receiving a Capacity Supply Obligation over either interface.

ISO-NE asked the FERC to accept the FCA17 rates and results, effective July 19, 2023. Comments on this filing are due on or before ***May 5, 2023***. Thus far, NEPOOL, Calpine, Constellation, Dominion, NESCOE, EPSA, No Coal No Gas, and Public Citizen have filed doc-less interventions. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Add'l Cost Recovery Due to Dec 24 General Threshold Energy Mitigation: Dynegy (ER23-1261)**

On March 6, 2023, Dynegy Marketing and Trade, LLC ("Dynegy") requested, pursuant to § 15 of Appendix A to Market Rule 1, that the FERC authorize the recovery of $903,400 in unrecovered costs incurred by Dynegy because its Resources were subject to General Threshold Energy Mitigation on December 24, 2022. Specifically, Dynegy requested (i) $903,400 in under-recovered fuel and variable operating and maintenance costs consistent with calculations set forth in ISO-NE IMMU's Report and (ii) reasonable, related regulatory costs ($62,000 plus any further regulatory costs to be identified in a compliance filing). Comments on this filing were due, after an extension of time requested by Public Citizen, Maine Office of the Public Advocate ("ME OPA"), and MA AG, and subsequently granted by the FERC, on or before April 4, 2023. On April 4, NEPGA filed comments supporting Dynegy's request. Protests were filed by ME OPA and jointly by MA AG and the Connecticut Office of Consumer Counsel ("CT OCC"). The protests generally asserted that Dynegy did not demonstrate that its request for recovery associated with Upward Mitigation is consistent with or required by the Market Rules (recovery, which they assert, is limited to fuel and variable operating and maintenance costs of a Resource for the hours during which a supply offer was capped). Should the FERC grants Dynegy's cost recovery request, they suggested that the FERC utilize the Day-Ahead Real-Time approach described in the proceeding as the basis to calculate any cost recovery. Doc-less interventions only were filed by NEPOOL, ISO-NE, National Grid, CT AG, EPSA, and Public Citizen. This matter is now pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[43] (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.[44] The changes were accepted effective as of June 1, 2022, but subject to refund and to the outcome of paper hearing (or settlement procedures) on the issues of capital structure and cost of debt raises issues. Mystic filed an offer of settlement on September 8, 2022 to resolve all issues set for hearing and settlement proceedings and the FERC accepted that offer of settlement on November 2, 2022,[45] directing Mystic to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action in the November 2 order. Mystic submitted that compliance filing on December 2, 2022 (ER22-1192-003). No comments were received by the December 23, 2022 comment date, and there was no activity in this proceeding since the last Report. This compliance filing remains pending before the FERC. FERC action on the compliance filing will conclude this proceeding. If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **VTransco Deferral of Retiree Lump Sum Payment Cost Recovery (ER21-2627)**

On March 17, 2023, Vermont Transco LLC ("VTransco") submitted an informational filing for lump sum payment elections taken in 2022. As previously reported, the FERC authorized VTransco to defer for future

[43] 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.

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

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

recovery costs associated with lump sum payments to employees who retire in 2021 and 2022.[46] VTransco reported that 24 plan participants elected lump sum payments in 2022, with the lump sum payments totaling approximately $14.38 million. As a result, $2.15 million was recorded as a regulatory asset on VTransco's balance sheet and will be amortized pursuant to the FERC-approved methodology and recovered from Vermont distribution utilities under the 1991 Vermont Transmission Agreement. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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) FERC* Order *on Remand and Motion to Hold in Abeyance*.** On March 28, 2023, the FERC issued its order on Remand[48] (1) finding the initial allocation of 91% of Everett's fixed operating costs to Mystic remains just and reasonable and requiring that the revenue sharing mechanism be reinstated in the COSA; (2) holding its ruling on the clawback issue in abeyance pending resolution in the settlement proceeding; (3) finding that the existing language of the COSA mitigates the incentive to unduly delay capital projects; and (4) clarifying that all interested parties can review and challenge Mystic's revenue credits and tank congestion charges during a subsequent true-up process. The FERC directed Mystic to submit a 30-day compliance filing, on or before ***April 27, 2023, revising the COSA to reinstate the revenue sharing mechanism. Challenges, if any, to the *Mystic I Order on Remand* are also due on or before ***April 27, 2023***.

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

(-022) First CapEx Info. Filing Settlement Agreement Interim Rate Implementation. On March 27, 2023, Acting Chief ALJ Satten granted Mystic's March 15, 2023 request to implement the settlement rates on an interim basis, effective as of June 1, 2022. The interim rates will remain in effect pending FERC action on the First CapEx Settlement Agreement (-021).[49]

(-021) First CapEx Info. Filing Settlement Agreement. On March 15, 2023, Mystic filed a Settlement Agreement to resolve all issues raised by the formal challenges to its First CapEx Info. Filing[50] and set for hearing in the April 28, 2023 Mystic *First CapEx Info. Filing Order* ("Settlement Agreement").[51] The Settling Parties asked that the FERC act on the Settlement Agreement as soon as possible, but no later than September 1, 2023. Initial comments on the Settlement Agreement were due by April 4, 2023. Comments on the Settlement Agreement

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[46] *Vermont Transco LLC*, Docket No. ER21-2627 (Sep. 22, 2021) (unpublished letter order).

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

[48] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,200 (Mar. 28, 2023) ("*Mystic I Order on Remand*").

[49] *Constellation Mystic Power, LLC*, 182 FERC ¶ 63,026 (Mar. 27, 2023) (Chief ALJ order granting motion to implement settlement rate on an interim basis).

[50] As previously reported, Mystic submitted, on Sep. 15, 2021, 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 projected would be collected as an expense between June 1, 2022 and Dec. 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the First CapEx Projects Info. Filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE.

[51] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*") (granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and establishing hearing and settlement judge procedures).

were filed by ENECOS, CT PURA, FERC Trial Staff, MA AG, NESCOE, and National Grid. Reply comments, if any, are due on or before ***April 14, 2023***.

(-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.

(-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). On December 6, 2022, ENECOS answered Mystic's November 17, 2022 answer. Later, on December 22, 2022, Mystic filed a response to ENECOS' December 6 answer, and requested that the FERC reject the Formal Challenges, and accept the Second Filing as expeditiously as possible.

On February 17, 2023, reporting that it intends to file a settlement agreement in the *First CapEx Info. Filing* proceeding that would also impact certain pending Formal Challenges filed in response to the *Second CapEx Info. Filing*, Mystic requested that the FERC hold off on acting on the pending Formal Challenges in this proceeding until after the FERC acts on the Settlement Agreement (summarized in (-021) above) ("Motion for Abeyance"). On March 6, 2023, ENECOS filed a protest to Mystic's Motion for Abeyance. That request is 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.

Limited Waiver of Certain Mystic COSA True-Up Deadlines (ER23-1159). On March 20, 2023, the FERC granted Mystic's request for waiver of certain deadlines required by Schedule 3A of the Mystic COSA.[52] to provide Settling Parties sufficient time to implement the terms of the Settlement Agreement as part of the Mystic COSA annual true-up process.

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

[52] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,181 (Mar. 20, 2023).

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,[53] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC stated that the annual updates result in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing included updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.75 kW-year (effective June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022. This filing was not noticed for public comment.

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

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

If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **PPU CTR Clarifications (ER23-911)**

On March 21, 2023, the FERC accepted the revisions to Section III.13.7.5.4.5 of Market Rule 1 that clarify the calculation of FCM Capacity Transfer Rights ("CTR") that are related to Pool-Planned Units ("PPU") (the "PPU

[53] 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").

CTR Clarifications").[54] Specifically, the PPU CTR Clarifications make clear (i) the allocation of PPU CTRs for each Capacity Commitment Period; (ii) PPU CTR self-supply designations; and (iii) the settlement of any remaining PPU CTRs not designated as self-supply. The PPU CTR Clarifications were accepted effective as of March 21, 2023, as requested. Unless the March 21 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On December 29, 2022, ISO-NE, NEPOOL and the PTO AC filed revisions to the Tariff and the TOA, in two parts, to enable electric storage facilities to be planned and operated as transmission-only assets ("SATOA") to address system needs identified in the OATT's regional system planning process ("SATOA Revisions"). The SATOA Revisions were supported by the Participants Committee at its October 6, 2022 meeting (Agenda Item #7). ISO-NE requested a FERC order by March 29, 2023 and indicated that it intends to implement the SATOA Revisions effective July 1, 2024. ISO-NE committed to submit a filing specifying the precise effective date prior to implementation. For eTariff reasons, Part I included the ISO-NE Tariff revisions (ER23-739); Part II, the TOA revisions (ER23-743). Comments on the SATOA Revisions were due on or before January 19, 2023.

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

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

In a lengthy compliance Order[55] issued March 1, 2023, the FERC approved in part, and rejected in part, ISO-NE, NEPOOL and the PTO AC's ("Filing Parties") *Order 2222* compliance filing[56] ("*Order 2222 Compliance Order*").[57]

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

  - ***30-Day Compliance Requirements (-003)***. ISO-NE was directed to submit two filings by March 31, 2023. The first, a compliance filing to explain how current Tariff capacity market mitigation rules

[54] *ISO New England Inc. and New England Power Pool Participants Comm.,* Docket No. ER23-911-000 (Mar. 21, 2023) (unpublished letter order).

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

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

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

would apply to Distributed Energy Capacity Resources ("DECR") participating in FCA18. The second, an informational filing that provides an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. Those compliance filings were submitted on March 31, 2023. Comments on the DECT compliance filing (ER22-983-003) are due on or before ***April 21, 2023***. The March 31 informational filing was not noticed for public comment,

- ***60-Day Compliance Filing***. On or before ***May 1, 2023*** (NEPOOL's March 23 request that the 60-day compliance deadline be extended by 8 days, to May 9, 2023, is pending before the FERC), the FERC ordered ISO-NE:

  - ♦ to revise the Tariff to (1) have RERRA make the determination of whether to allow customers of small utilities to participate in ISO-NE's markets through aggregation; (2) require that each DER Aggregator maintain and submit aggregate settlement data for the DERA; (3) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and if necessary, establish protocols for sharing meter data that minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity; (4) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; and (5) add specificity regarding existing resource non-performance penalties that would apply to a DERA when a Host Utility overrides ISO-NE dispatch instructions.

  - ♦ ISO-NE was also directed to (1) identify the existing rules requiring a Market Participant that provides energy withdrawal service to be a load serving entity that is billed for energy withdrawal ("LSE Requirement") and explain whether the LSE Requirement is required of all resources seeking to provide wholesale energy withdrawal service in the energy market; (2) explain why its proposed metering and telemetry requirements were just and reasonable and did not pose an unnecessary and undue barrier to individual DERs joining a DERA; (3) establish protocols for sharing metering data that minimize costs and other burdens and address privacy and cybersecurity concerns; and (4) address how ISO-NE will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA.

- ***180-Day Compliance Filing***. On or before **August 28, 2023**, the FERC directed ISO-NE to file a further compliance filing explaining how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond.

Requests for Rehearing and/or Clarification (-002). On March 31, 2023, ISO-NE and New England Public Utilities[58] requested rehearing and/or clarification of the *Order 2222 Compliance Order*. ***ISO-NE*** urges the FERC to reconsider allowing DECRs to participate in FCA18 and designating DER Aggregator as the entity responsible for transmitting DERA metering data. ***New England Public Utilities*** urge the FERC to adopt the DER metering and settlement approach proposed by the Filing Parties (*Order 2222* Changes) and clarify (1) that PTOs and distribution utilities are not prohibited from requiring metering and settlement data from DERs to satisfy their obligations to perform wholesale settlement and retail customer billing and (2) that it would not be unjust and unreasonable for utilities to recover costs related to investment and expenses incurred to modify its metering, billing, settlement, cyber security and other systems, to accommodate submetering of Behind-the-Meter DER participating in the wholesale market as part of a DERA. The FERC must take action on these challenges by May 1, 2023, or the

[58] "New England Public Utilities" are: National Grid USA on behalf of Massachusetts Electric Co., Nantucket Electric Co., and New England Power Co. ("NGUSA"); Avangrid Networks, Inc. on behalf of CMP and UI ("Avangrid Networks"); and Eversource on behalf of The Connecticut Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), and NSTAR Electric Co. ("NSTAR").

challenges will be deemed denied by operation of law. 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*.[59] 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, and 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[60] 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 K Economic Study Revisions (ER23-971)**

On March 30, 2023, the FERC accepted the Attachment K Economic Study Revisions, effective March 31, 2023.[61] As previously reported, the Attachment K Economic Study Revisions require ISO-NE (1) to identify market efficiency issues, and as applicable, market efficiency needs on the Pool Transmission Facilities ("PTF") portion of the New England Transmission System as part of the Economic Study process; (2) to provide the New England region more insight into system trends and consistent analysis; and (3) to facilitate comparison across Economic Study cycles, all of which can inform future decisions in transmission investment. Unless the *Economic Study Revisions 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).

- ***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,[62] and the Schedule 20A Service

[59] *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.

[60] 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.

[61] *ISO New England Inc.*, 182 FERC ¶ 61,211 (Mar. 30, 2023) ("*Economic Study Revisions Order*").

[62] 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").

Providers.[63] 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 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*[64] ("*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 ("RI Energy") 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).

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

- **Schedule 21-NEP: NEP/Dichotomy Collins Hydro SGIA (ER23-888)**

As previously reported, on January 18, 2023, NEP filed a non-conforming Small Generation Interconnection Agreement ("SGIA") with Dichotomy Collins Hydro LLC ("Dichotomy") to cover the continued interconnection of Dichotomy's 1.3 MW hydroelectric (run-of-river) generating facility in Wilbraham, Massachusetts. National Grid requested a December 19, 2022 effective date for the SGIA. Initial comments on this filing were due on or before February 8, 2023; none were filed. On March 17, 2023, the FERC issued a deficiency letter requesting additional information related to the QF status of the Dichotomy facility to be submitted on or before ***April 16, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: Revised 2021 Annual Update Settlement Agreement (ER20-2119-002)**

On January 12, 2023, Versant submitted a revised uncontested Joint Offer of Settlement ("Revised 2021 Annual Update Settlement") between itself and the MPUC that replaces in full the Versant 2021 Annual Update Settlement Agreement submitted March 25, 2022. Versant stated that, if approved, the Revised 2021 Annual Update Settlement would resolve all issues raised by the MPUC with respect to the 2021 Annual Update. Comments on the Revised 2021 Annual Update Settlement were due on or before February 2, 2023;

[63] 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 Corp. ("GMP"); New England Power Co. ("NEP"); NSTAR Electric Co.; The United Illuminating Co. ("UI"); Vermont Electric Cooperative, Inc. ("VEC"); and Versant Power.

[64] *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*").

none were filed. There was no activity in this proceeding since the last Report; the Revised 2021 Annual Update Settlement 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: Revised 2020 Annual Update Settlement Agreement (ER15-1434-006)**

Similarly, Versant's January 12, 2023 submission of a revised, uncontested Joint Offer of Settlement ("Revised 2020 Annual Update Settlement") between itself and the MPUC, which replaces in full the Versant 2020 Annual Update Settlement Agreement submitted November 19, 2021,[65] remains pending before the FERC. Versant stated that, if approved, the Revised 2020 Annual Update Settlement would resolve all issues raised by the MPUC with respect to the 2020 Annual Update. Comments on the Revised 2020 Annual Update Settlement were due on or before February 2, 2023; none were filed. This matter is 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) (ER23-980)**

On March 3, 2023, the FERC accepted, effective April 1, 2023, Amendment No. 12 to the Participants Agreement ("PA 12"), which raises the age limitation prohibiting the election or re-election of any candidate to the ISO Board of Directors from 70 to 75.[66] The *PA 12 Letter Order* was not challenged and is final and unappealable. Reporting on this proceeding has now concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports

- ***Opinion* 531 Refund Reports (EL11-66)**

The following refund reports filed in response to *Opinions No. 531-A*[67] *and 531-B*[68] remain pending:

- The TOs' November 2, 2015 regional refund report;
- The TOs'[69] local refund reports; and
- Fitchburg Gas & Electric's ("FG&E") June 29, 2015 local refund report.

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

- **Capital Projects Report - 2022 Q4 (ER23-1125)**

On April 5, 2023, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2022 (the "Report").[70] As previously reported, Report highlights included the following new projects: (i) Solar Do-Not-Exceed ("DNE") Dispatch Phase II ($2 million); (ii) Windows Server 2019R Deployment Phase I ($1.15 million); (iii) Security Orchestration and Automation Response

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[65] As previously reported, on Nov. 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 (the "Versant 2020 Annual Update Settlement Agreement").

[66] *ISO New England Inc.*, Docket No. ER23-980-000 (Mar. 3, 2023) ("*PA 12 Letter Order*").

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

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

[69] TOs filing local refund reports include: CMP, National Grid, UI, Versant Power (f/k/a Emera Maine), NHT, VTransco, Eversource, and NSTAR.

[70] *ISO New England, Inc.*, Docket No. ER23-1125-000 (Apr. 5, 2023) (unpublished letter order).

($359,400); (iv) Control Room Voice Recorder Upgrade ($297,000); and (v) Mobile Application Rebuild ($195,400). Due to a reallocation of funds from 2022 to 2023, significant changes to the 2023 capital budget projects included increases of $678,600 for the nGEM Market Clearing Engine Implementation and nGEM Software Development Part II project and $411,200 for Windows Server 2019R2 Deployment Phase I project. The Q4 2022 Report was accepted effective as of January 1, 2023, as requested. Unless the April 5 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q3 2022 (ER19-1951)**

On February 14, 2023, ISO-NE filed, as required,[71] public and confidential[72] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Fourth Quarter of 2022 ("2022 Q4"). ISO-NE reported that with respect to:

- ***Interconnection Feasibility Study ("IFS") Reports***
  - All 10 of the 2022 Q4 IFS Reports delivered to Interconnection Customers were delivered ***later*** than the best efforts completion timeline (90 days from the Interconnection Customer's execution of the study agreement).
  - 7 IFS Reports not yet completed have exceeded the 90-day completion expectation.
  - The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 192 days (roughly 5 days longer than in 2022 Q3).
- ***System Impact Study ("SIS") Reports***
  - 7 of the 8 SIS Reports delivered to Interconnection Customers were delivered ***later*** than the best efforts completion timeline of 270 days.
  - 16 SIS Studies that are not yet completed have exceeded the 270-day completion expectation.
  - The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 446 days (a decrease of roughly 3 days from 2022 Q3).
- ***Facility Study Reports***
  - There were no Facility Study reports were delivered to an Interconnection Customer and no Facility Studies are in process that have exceeded completion expectations.

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

- **Transmission Projects Annual Informational Filing (ER13-193)**

On January 30, 2023, ISO-NE filed, as required under Section 4.1(j)(iii) of the OATT, its annual informational filing of projects on the Regional System Plan ("RSP") project list that had a year of need three years or less from the completion of the Needs Assessment. The list of prior year designations is maintained

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

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

on the ISO-NE website at https://www.iso-ne.com/static-assets/documents/2023/01/2022-prior-year-projects-section-4-j-iii.pdf. This filing was not be noticed for public comment.

- **Reserve Market Compliance (34th) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[73] as modified,[74] ISO-NE submitted its 34th semi-annual reserve market compliance report on March 31, 2023. In the 34th report, ISO-NE stated that it "is currently discussing with stakeholders the development of day-ahead ancillary services, and it anticipates filing proposed market design changes by the end of 2023. It is contemplated that those changes will include a ten-minute reserve product procured in the day-ahead market, which may satisfy the region's need for a forward TMSR market. [ISO-NE] will continue to update the [FERC] on the progress of the Day-Ahead Ancillary Services project and its relation to a forward TMSR market through future reports in this docket."

- **ISO-NE FERC Form 715 (not docketed)**

On March 29, 2023, ISO-NE submitted its 2022 Annual Transmission Planning and Evaluation Report. These filings are not noticed for public comment.

IX. Membership Filings

- **March 2023 Membership Filing (ER23-1197)**

On February 28, 2023, NEPOOL requested that the FERC accept (i) the membership of Calpine Community Energy [Related Person to Calpine Energy Services et al. (Generation Sector)]; (ii) the termination of the Participant status of Clean Choice Energy (Supplier Sector); InBalance, Inc. (Supplier Sector); and Stored Solar J&WE, LLC (AR Sector, RG Sub-Sector); and (iii) the name change of Interstate Gas Supply, LLC (f/k/a Interstate Gas Supply, Inc.). Comments on the March membership filing were due on or before March 21, 2023; none were filed. The March 2023 Membership Filing is pending before the FERC.

- **February 2023 Membership Filing (ER23-1020)**

On March 24, 2023, the FERC accepted[75] (i) the memberships of CommonWealth New Bedford Energy LLC (AR Sector, RG Sub-Sector, Small RG Group Seat); GF Power LLC (Supplier Sector); and Industrial Wind Action Corp (End User Sector); (ii) the termination of the Participant status of Backyard Farms Energy, LLC and Backyard Farms LLC (End User Sector); Bruce Power Inc. (Supplier Sector); CommonWealth Resource Management Corporation (Replaced by CommonWealth New Bedford Energy); Darby Energy, LLC [Related Person to Protor Energy, LLC (Supplier Sector)]; DFC ERG CT, LLC [Related Person to Bridgeport and Derby Fuel Cell (AR Sector, RG Sub-Sector)]; Stones DR, LLC [Related Person to Jericho Power, CPower, et al. (AR Sector, RG Sub-Sector)]; and Vineyard Wind LLC [Related Person to Avangrid (Transmission Sector)]; and (iii) the name change of Advanced Energy United Inc. (f/k/a Advanced Energy Economy Inc.) ("AEU").

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).

[73] *See NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) ("*ASM II Order*") (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh'g denied* 117 FERC ¶ 61,106 (2006).

[74] *See NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve ("TMSR")).

[75] *New England Power Pool Participants Comm.,* Docket No. ER23-1020-000 (Mar. 24, 2023).

- **NERC Annual Report on FFT & Compliance Exception Programs (RC11-6-016)**

On March 7, 2023, the FERC accepted NERC's most recent annual report on Find, Fix, and Track ("FFT") and Compliance Exception programs.[76] In the report, NERC stated that the ERO Enterprise appropriately handles noncompliance posing a minimal or moderate risk through these programs and that the results of the annual report show consistent improvement in program implementation. The report also demonstrates, NERC suggests, significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Unless the March 7 order is challenged, this proceeding will be concluded.

- **Revised Reliability Standard: CIP-003-9 (RD23-3)**

On March 16, 2023, the FERC approved NERC's changes to Reliability Standards CIP-003-9 (Cyber Security – Security Management Controls).[77] CIP-003-9 improves upon CIP-003-8 by adding new requirements focused on supply chain risk management for low impact bulk electric system ("BES") Cyber Systems. The changes to CIP-003-9 will become effective on April 1, 2026.

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

On February 16, 2023, the FERC approved NERC's changes to Reliability Standards EOP-011-3 (Emergency Operations) and EOP-012-1 (Extreme Cold Weather Preparedness and Operations) (the "*Cold Weather Standards*").[78] As previously reported, the changes to the *Cold Weather Standards*, which address certain key recommendations from the *Feb 2021 Cold Weather Outages Joint Report,*[79] establish a more comprehensive framework of requirements addressing generator preparedness for cold 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.

In accepting the *Cold Weather Standards*, the FERC directed a number of changes and follow-up items. For example, the FERC directed NERC to modify EOP-012-1:

♦ to ensure that it captures all bulk electric system generation resources needed for reliable operation and excludes only those generation resources not relied upon during freezing conditions by clarifying "the language of the applicability section to align with NERC's explanation of the entities that should already be preparing to comply with the Standard, and should not need additional implementation time";[80]

♦ Requirements R1 and R7, to address concerns related to the ambiguity of generator-defined declarations of technical, commercial, or operational constraints that exempt a generator owner from implementing the appropriate freeze protection measures by including "objective criteria on permissible technical, commercial, and operational constraints, to identify the appropriate entity that would receive the generator owners' constraint declarations under [] Requirements R1 and R7, to describe how that entity would confirm that the generator owners comply with the objective criteria, and to describe the consequences of providing a

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[76] *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-016 (Mar. 7, 2023) (unpublished letter order).

138 FERC 61,193 (2012) ("March 2012 Order"); *N. Am. Elec. Rel. Corp.,* 143 FERC 61,253 (2013) ("June 2013 Order"); *N. Am. Elec. Rel. Corp.,* 148 FERC 61,214 (2014) ("September 2014 Order"); and *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-004 (Nov. 13, 2015) (unpublished letter order) ("November 2015 Order").

[77] *N. Amer. Elec. Rel. Corp.*, 182 FERC ¶ 61,155 (Mar. 16, 2023).

[78] *N. Amer. Elec. Rel. Corp.*, 182 FERC ¶ 61,094 (Feb. 16, 2023).

[79] 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*").

[80] *Id.* at P 4.

constraint declaration," ensuring that "declarations cannot be used to opt out of mandatory compliance with the Standard or obligations set forth in a corrective action plan";[81]

♦ to clarify R1 to ensure that generators that are technically incapable of operating for 12 continuous hours (e.g., solar facilities during winter months with less than 12 hours of sunlight) are not excluded from complying with the Standard;[82]

♦ to increase the length of R2's continuous operations requirement (one hour being too short);[83]

♦ to include in R7 deadlines for implementation completion of corrective action plans, as recommended in the *November 2021 Report*;[84]

♦ to shorten the implementation plan for existing generating units, staggering the implementation for existing unit(s) in a generator owner's fleet;[85] and

♦ to work with FERC staff to submit a plan no later than February 16, 2024 explaining how it will collect and assess data prior to and after the implementation of the following elements of EOP-012-1: (1) generator owner declared constraints and explanations thereof; and (2) the adequacy of the Extreme Cold Weather Temperature definition.[86]

The FERC deferred its decision on whether to approve or modify NERC's proposed implementation date for EOP-011-3 (and proposed retirement of EOP-011-2) until NERC submits its revised applicability section for EOP-012. The FERC stated that "allowing EOP-011-2 requirements to remain mandatory and enforceable until such time as the revised applicability is effective for EOP-012 will ensure all bulk electric system generating units are required to maintain cold weather preparedness plans."[87]

Request for Rehearing. On March 20, 2023, EPSA, NEPGA and the PJM Power Providers Group ("P3") filed a joint request for rehearing. The petitioners allege that, by approving the *Cold Weather Standards* without addressing how generators can recover the costs associated with complying with EOP-012-1, the FERC "breached its duty to ensure that proposed reliability standards are 'just' and 'reasonable' … and failed to engage in reasoned decision-making." The request for rehearing is pending before the FERC, with FERC action required on or before ***April 19, 2023***, or the request will be deemed denied by operation of law.

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

On November 17, 2022, to address FERC concerns regarding the reliability impacts of inverter-based resources ("IBRs")[88] on the Bulk-Power System ("BPS"), the FERC issued an order[89] 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

[81] *Id.* at P 6.

[82] *Id.* at P 7.

[83] *Id.* at P 8.

[84] *Id.* at P 9.

[85] *Id.* at P 10.

[86] *Id.* at P 11.

[87] *Id.* at P 5.

[88] 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*.

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

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.

On February 16, 2023, NERC filed its IBR Work plan, which outlined NERC's proposed approach to identify and register owners and operators of IBRs within 36 months of FERC approval of the Work Plan. Comments on the IBR Work Plan were due on or before March 20, 2023. Comments were filed by ACPA, APPA, NRECA, Arizona Public Service Co., and Pine Gate Renewables. This matter is pending before the FERC.

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

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

On November 17, 2022, the FERC issued a notice[91] proposing to direct NERC (i) to develop new or modified Reliability Standards that address the following reliability gaps related to inverter-based resources ("IBR"): data sharing; model validation; planning and operational studies; and performance requirements; and (ii) to submit a 90-day compliance filing that includes a detailed, comprehensive standards development and implementation plan to ensure all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in the final rule are submitted to the FERC within 36 months of FERC approval of the plan. Initial comments were due February 6, 2023[92] and were filed by nearly 20 parties, including, among others, ISO-NE, the IRC, SPP, CAISO, Advanced Energy United, ACPA/SEIA, EEI, and EPRI. Reply comments were due on March 6, 2023 and were filed by ISO-NE, APPA, and CA DWP. This matter is pending before the FERC.

- **NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)**

On June 16, 2022, the FERC issued a notice[93] 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 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,

[90] 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.

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

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

[93] *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (June 16, 2022) ("*Extreme Weather Transmission System Planning NOPR*").

2022[94] 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.

- ***Order 887*: Internal Network Security Monitoring for High and Medium Impact BES Cyber Systems (RM22-3)**

One year after the FERC issued its *Internal Network Security Monitoring NOPR,*[95] the FERC issued *Order 887*.[96] *Order 887* directs NERC to develop and submit, on or before July 10, 2024[97] for FERC approval, new or modified Reliability Standards that require internal network security monitoring ("INSM")[98] within a trusted Critical Infrastructure Protection ("CIP") networked environment for all high impact bulk electric system ("BES") Cyber Systems with and without external routable connectivity and medium impact BES Cyber Systems with external routable connectivity. In addition, the FERC directed NERC to perform a study of all low impact BES Cyber Systems with and without external routable connectivity and medium impact BES Cyber Systems without external routable connectivity, and to submit its study report to the FERC on or before January 19, 2024. *Order 887* will become effective April 10, 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.[99] 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 were due on or before January 24, 2023; none were filed. The 60-day compliance filing is pending before the FERC.

XI. Misc. - of Regional Interest

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

On March 27, 2023, Weaver Wind, LLC and Weaver Wind Maine Master Tenant, LLC ("Weaver Wind") requested FERC authorization for a proposed transaction pursuant to which Jade Energy LLC, a wholly-owned subsidiary of Greenbacker Renewable Energy Company, will acquire all the membership interests in Weaver Wind (upon consummation, making Weaver Wind a Related Person to Howard Wind and Hectate Energy). Comments on this 203 application are due on or before ***April 17, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[94] 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.

[95] *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*").

[96] *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, Order No. 887, 182 FERC ¶ 61,021 (Jan. 19, 2023) ("*Order 887*").

[97] *Order 887* was published in the *Fed. Reg.* on Feb. 9, 2023 (Vol. 88, No. 27) pp. 8,354-8,368.

[98] 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.

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

- **203 Application: Saddleback / CPV (EC23-52)**

On March 23, 2023, the FERC authorized CPV Mountain Wind Holdings, LLC's ("Buyer") acquisition of all of the membership interests in Saddleback Ridge Wind, LLC ("Saddleback").[100] Pursuant to the March 23 order, Saddleback must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Salem Harbor / Castleton Commodities (EC23-50)**

On April 4, 2023, the FERC authorized a proposed transaction pursuant to which CCI U.S. Asset Holdings LLC ("Castleton Commodities") will acquire at least 67%, and up to 100%, of the issued and outstanding Series A-1 Common Units and/or Series A-2 Common Units of Salem Harbor Power Holdco LLC ("Salem Harbor").[101] Pursuant to the April 4 order, Salem Harbor must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On March 30, 2023, the FERC issued an order authorizing a change in control transaction whereby 10% or more of the voting securities of a new parent of Talen Energy Supply, LLC ("TES") and its affiliated debtors 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.[102] 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 March 16, 2023, FERC issued an order authorizing the proposed transaction between Rhode Island State Energy Center, LP ("RISEC") and EGCO RISEC II, LLC ("Buyer"),[103] pursuant to which Buyer, a wholly owned indirect subsidiary of Electricity Generating Public Company Limited ("EGCO"), will acquire a 49% indirect ownership interest in RISEC from Cogentrix Sellers.[104] On April 3, 2023, RISEC informed the FERC that the transaction was consummated on March 24, 2023. RISEC is now indirectly owned by Buyer (49%) and the Cogentrix Sellers (51%). Reporting on this matter is concluded. If you have any remaining questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On January 24, 2023, the FERC authorized[105] a transaction pursuant to which the AB CarVal Funds[106] 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,[107] into 21.3% of the voting interests in Agilitas Energy. Pursuant to the January 24 order, AB CarVal Funds must file a notice within 10 days of consummation of the

[100] *Saddleback Ridge Wind, LLC*, 182 FERC ¶ 62,168 (Mar. 23, 2023).

[101] *Salem Harbor Power Development LP*, 183 FERC ¶ 62,005 (Apr. 4, 2023).

[102] *Talen Energy Supply, LLC*, 182 FERC ¶ 62,183 (Mar. 30, 2023).

[103] *Rhode Island State Energy Center, LP and EGCO RISEC II, LLC*, 182 FERC ¶ 62,159 (Mar. 16, 2023).

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

[105] *Madison BTM, LLC et al.*, 182 FERC ¶ 62,048 (Jan. 24, 2023).

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

[107] 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.

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: ConEd / RWE (EC23-17)**

On January 20, 2023, the FERC authorized a transaction pursuant to which RWE Renewables Americas, LLC ("RWE") will acquire 100% of the equity interests in ConEd's[108] "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)).[109] On March 1, 2023, RWE filed a notice that the transaction was consummated on March 1, 2023.[110] Reporting on this proceeding is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Study Work Agreement Cancellation: CL&P / NYISO (ER23-1483)**

On March 28, 2023, CL&P submits a Notice of Termination of the Study Work Agreement with NYISO that was accepted by FERC in Docket No. ER21-2946. All work contemplated by the Agreement was completed in February 2023 and all billing and invoices have been finalized. An effective date of March 29, 2023 was requested. Comments on this filing are due on or before ***April 18, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PSNH / National Grid D&E Agreement (ER23-1481)**

On March 28, 2023, Eversource Energy, on behalf of Public Service Company of New Hampshire ("PSNH"), filed a Design & Engineering ("D&E") Agreement that sets forth the terms and conditions under which PSNH will perform necessary engineering, procurement and design services in connection with National Grid's asset separation project with Great River Hydro. An effective date of March 29, 2023 was requested. Comments on this filing are due on or before ***April 18, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: CL&P/Generate NB Fuel Cells/ISO-NE (ER23-1479)**

On March 27, 2023, as supplemented on March 28 and April 4, CL&P and ISO-NE filed a revised non-conforming Large Generation Interconnection Agreement ("LGIA") with Generate NB Fuel Cells, LLC ("Generate NB") to govern the interconnection of Generate NB's 20 MW fuel cell project in New Britain, Connecticut (Stanley Black & Decker campus). The original non-conforming LGIA was accepted by FERC on July 11, 2022.[111] The revised LGIA includes, among others, changes reflecting the sale of the fuel cell project by Generate NB from EIP Investment. A February 23, 2023 effective date was requested. Comments on this filing are due on or before ***April 17, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **National Grid/ GRH SGIA (ER23-1152)**

On February 21, 2023, National Grid filed a non-conforming SGIA with Great River Hydro to cover the continued interconnection of GRH's 13 MW hydro facility in the towns of Barnet, VT and Monroe, NH. The SGIA, which replaces a 2005 SGIA, was filed to supersede and replace the 2005 SGIA. A January 30, 2023

[108] "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.

[109] *RWE Aktiengesellschaft et al.*, 182 FERC ¶ 62,042 (Jan. 20, 2023).

[110] In connection with the transaction, the Clean Energy Businesses joined Cassadaga Wind as members of the Supplier Sector and were each re-named as follows: RWE Clean Energy Wholesale Services, Inc. (f/k/a Consolidated Edison Energy, Inc.); RWE Clean Energy Asset Holdings, Inc. (f/k/a Consolidated Edison Development, Inc.); and RWE Clean Energy Solutions, Inc. (f/k/a Consolidated Edison Solutions, Inc.).

[111] *ISO New England Inc., and The Conn. Light and Power Co.*, Docket No. ER22-1862 (July 11, 2022) (unpublished letter order).

effective date was requested. Comments on this filing were due on or before March 14, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VTransco/GMP Shared Structure Participation Agreement (ER23-1101)**

On March 21, 2023, the FERC accepted the Shared Structure Participation Agreements ("ShSPA") between VTransco and GMP.[112] As previously reported, the ShSPA establishes the allocation of costs associated with the design, construction, repair, replacement, general maintenance, operation, and preventative maintenance of certain structures that VTransco and GMP share, where those facilities are used either exclusively by GMP or in common with VTransco. The purpose of the Agreement is to calculate and allocate those costs that are not recovered through a regional transmission tariff. The ShSPA was accepted effective as of February 1, 2023, as requested. Unless the March 21 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: RI Energy / Deepwater Block Island Wind (ER23-1023)**

On March 27, 2023, the FERC accepted the LGIA between Narragansett Electric Company ("RI Energy") and Deepwater Block Island Wind, LLC ("Deepwater Wind").[113] As previously reported, the LGIA governs the interconnection of Deepwater Wind's 30 MW off-shore wind facility that interconnects to RI Energy's transmission facilities. The LGIA replaces the current LGIA and reflects revisions primarily related to the transition of ownership from New England Power to RI Energy. The LGIA revisions were accepted effective as of January 1, 2023, as requested. Unless the March 27 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: RI Energy / Manchester Street (ER23-1007)**

On March 27, 2023, the FERC accepted a replacement Interconnection Agreement ("IA") between RI Energy and Manchester Street, LLC ("Manchester Street"). As previously reported, the IA governs the interconnection of Manchester Street's 468 MW combined-cycle generating facility that interconnects to RI Energy's transmission facilities. The IA replaces the current IA and reflects revisions primarily related to the transition of ownership from New England Power to RI Energy, but also to reflect Manchester Street corporate changes. The IA revisions were accepted effective as of January 1, 2023, as requested. Unless the March 27 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).

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

On January 31, 2023, ISO-NE and RI Energy filed two Local Service Agreements ("LSAs"), as replacements to two current New England Power TSAs (TSA-NEP-83 and TSA-NEP-86), to allow RI Energy to fully recover the Block Island Transmission System ("BITS") surcharge now that it is both Transmission Owner and Customer under these arrangements. On March 31, 2023, the FERC conditionally accepted the LSA replacing TSA-NEP-86 (ER23-1003), effective January 1, 2023, [114] and directed RI Energy, on or before May 1, 2023, to add language to the LSA to make explicit that the BITS Surcharge shall be subject to the Protocols for Schedule 21-RIE. On the same day, FERC also issued a deficiency letter asking for additional information regarding whether the LSA replacing TSA-NEP-83 (ER23-1000) is subject to the Schedule 21-RIE Protocols. The response to the deficiency letter is also due

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[112] *Vermont Transco LLC*, Docket No. ER23-1101-000 (Mar. 21, 2023) (unpublished letter order).

[113] *The Narragansett Electric Co.*, Docket No. ER23-1023-000 (Mar. 27, 2023) (unpublished letter order).

[114] *ISO New England Inc.*, ER23-1003-000 (Mar. 31, 2023).

on or before May 1, 2023. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **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).

- **VELCO Phase II Vermont DMNRC Support Agreement Informational Filing (ER90-591)**

On March 31, 2023, Vermont Electric Power Company, Inc. ("VELCO"), on behalf of Phase II Joint Owners, submitted its annual Informational Filing pursuant to the Phase II Vermont DMNRC Support Agreement. This informational filing will not be noticed for public comment.

XII. Misc. - Administrative & Rulemaking Proceedings[115]

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

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

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

[115] Reporting on the following Rulemaking proceeding has been suspended since the last Report and will be continued if and when there is new activity to report: Electric Transmission Incentives Policy NOPR (RM20-10).

- **Joint FERC-DOE Supply Chain Risk Management Technical Conference (Dec 7, 2022) (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 posted in eLibrary and a recording of the conference will be available on the FERC website for roughly one more month. On December 19, 2022, the FERC invited all those interested to file, by February 17, 2023, post-technical conference comments addressing issues raised during the technical conference. Comments were filed by AEP, APPA, EEI, the North American Transmission Forum. In addition, on February 13, 2023, the FERC posted a transcript of the December 12 technical conference in eLibrary. This matter is pending before the FERC.

- **Reliability Technical Conference (Nov 10, 2022) (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 were due on or before January 23, 2023 and were filed by EPSA and Public Power Associations.[116] A transcript of the technical conference was posted in the FERC's eLibrary on January 17, 2023. This matter is pending before the FERC.

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

The Second New England Gas-Electric Forum (June 20, 2023 in Portland, ME). On February 16, 2023, the FERC issued a notice of a Second New England Winter Gas-Electric Forum to be held the week before the NPC Summer Meeting, on Tuesday, ***June 20, 2023*** in Portland, Maine. The purpose of this forum is to continue discussions from the September 8, 2022 forum (summarized immediately below) regarding the electricity and natural gas challenges facing the New England Region. The objective of the forum is to shift from defining electric and natural gas system challenges in the New England Region to discussing potential solutions, including both infrastructure and market-based solutions.

Registration for in-person attendance, which will be open to the public, will be required and there will be no fee for attendance. The forum will also be available on webcast. A supplemental notice will be issued with further details regarding the forum agenda, as well as any updates on timing and logistics, including registration for members of the public and the nomination process for panelists. For more information, technical or logistical questions about this forum, please contact NewEnglandForum@ferc.gov.

The First New England Gas-Electric Forum (September 8, 2022 in Burlington, VT). The purpose of the Forum was to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are needed to inform the development of solutions to these challenges. On September 21, 2022, the FERC invited parties wishing to submit comments regarding the topics discussed at the Forum to do so on or before November 7, 2022. Post-Forum Comments were submitted by: ISO-NE, Acadia, AEU, AIM, Calpine, Constellation, Excelerate,

[116] "Public Power Associations" are American Public Power Association ("APPA"), the Large Public Power Council ("LPPC"), and Transmission Access Policy Study Group ("TAPS").

FirstLight, LS Power, NECOS, NEPGA, NESCOE, Public Systems, Repsol, TOs, VELCO, Vistra, Potomac Economics, CT DEEP, AEMA, APGA, EPSA, INGA, NE LDCs, NGSA, New England Council, NEPPA, NH BIA, PIOs, RENEW/ACPA, Berkshire Action Team, Greater Concord Chamber of Comm., Mass. Alliance for Econ. Dev., Mass. Business Roundtable, Mass. Coalition for Sustainable Energy, Mass. United Assoc. of Journeymen, Middlesex County Chamber of Commerce, Public Citizen, Western Mass. Economic Dev. Council, and Individual Citizens (M. Axner, E. Blank, S. Botkin, D. Heimann, J. Krieger, B. Little, I. McDonald, J. Neville, W. Persons, R. Spector). On November 22, National Grid filed reply comments.

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

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

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. On November 1, 2022, a transcript of the technical conference was posted in the FERC's eLibrary. On December 23, 2022, the FERC issued a notice inviting post-technical conference comments on questions listed in that notice. Those comments were due by March 23, 2023 and were filed by: ISO-NE, AEU, Avangrid, Cypress Creek Renewables, Eversource, LS Power, MA AG, NE Public Systems, NESCOE, NextEra, NRDC, NRG, Maine PUC, American Council on Renewable Energy ("ACRE"), APPA, EEI, Harvard Elec. Law Inst., LPPC, NASUCA, NRECA, and R Street Institute.

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

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[117] 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.

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

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[118] and were filed by: AEP, Clean Energy Entities,[119] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter remains pending before the FERC.

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

A sixth meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF")[120] was held February 15, 2023 in Washington, DC.[121] An agenda for the February 15 meeting was posted on February 1, 2023. The one topic noticed was "Physical Security of the Transmission System", with Jim Robb, NERC President and CEO, and Puesh Kumar, Director of DOE's Office of Cybersecurity, Energy Security, and Emergency Response, as the principal speakers. A transcript of the February 15 meeting was posted to eLibrary on March 6, 2023.

Comments on the topics/questions related to the FERC's October 6, 2022 technical conference on Transmission Planning and Cost Management, also posted in this docket, were due on or before March 23, 2023. *See* AD22-8 above for a more information.

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[122] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before October 18, 2022 a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. The *Order Directing Reports* followed a series of staff-

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

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

120 *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021). The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective." New England is represented by Commissioners Riley Allen (VT PUC) and Marissa Gillett (Chair, CT PURA). *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

121 Summaries of the first – fifth meetings of the Transmission Task Force can be found in previous Reports.

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

led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[123] and energy and ancillary services markets.[124]

ISO-NE Report. On October 18, 2022, ISO-NE (as well as the other ISO/RTOs) filed its report in response to the *Order Directing Reports.* Comments in response to the RTO/ISO reports were due, following an EEI request, on or before January 18, 2023. Comments were filed by, among others: Advanced Energy United, API, Constellation, New England Public Systems,[125] Shell, Clean Energy Assocs, Clean Energy Buyers Association, EEI, EPSA, Public Interest Orgs, R Street Institute.

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

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

On July 28, 2022, the FERC issued a NOPR[126] proposing to add a new section to its regulations to require that any entity communicating with the FERC or other specified organizations (e.g. ISO/RTOs, FERC-approved market monitors, NERC and its Regional Entities, or transmission providers) related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information, or omit material information ("Duty of Candor Requirements"). An entity would be shielded from violation of the new regulation if it has exercised due diligence to prevent such occurrences. The FERC's current regulations prohibit, in defined circumstances, inaccurate communications to the FERC and other organizations upon which the FERC relies to carry out its statutory obligations. However, because those requirements cover only certain communications and impose a patchwork of different standards of care for such communications, the FERC believes that a broadly applicable duty of candor will improve its ability to effectively oversee jurisdictional markets. It further indicated that its proposed due 'diligence standard' and other limitations are intended to minimize the additional burdens to industry that come with the new Duty of Candor Requirements.

On September 1, 2022, Joint Associations[127] requested an additional month to submit comments.[128] 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,

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

[124] 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.

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

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

[127] "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").

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

APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange. The US Chamber of Commerce filed reply comments on December 12, 2022. There was no activity in the proceeding since the last Report. This matter is pending before the FERC.

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

On September 22, 2022, the FERC issued a NOPR[129] 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*)[130] 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.[131] 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[132] 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[133] (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 weather risks). Initial comments were due August 30, 2022[134] 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"),[135] more than 400 pages long, that proposed reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement

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[129] *Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives*, 180 FERC ¶ 61,189 (Sep. 22, 2022) ("*Advanced Cybersecurity Investment NOPR*").

[130] *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.

[131] The *Advanced Cybersecurity Investment NOPR* was published in the *Fed. Reg.* on Oct. 6, 2022 (Vol. 87, No. 193) pp. 60,567-60,580.

[132] *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*").

[133] "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".

[134] 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.

[135] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) ("*Interconnection* Reforms *NOPR*").

("LGIA"), and *pro forma* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

As previously reported, the proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process;[136] (2) reforms to increase the speed of interconnection queue processing;[137] and (3) reforms to incorporate technological advancements to the interconnection process.[138] Within each of these categories, the FERC proposes a wide array of reforms, and requested comment.

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[136] To implement the **first-ready, first-served cluster study process**, the FERC proposed 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;
- ♦ 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;[136]
- ♦ 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; and
- ♦ Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.

[137] 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.

[138] 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;
- ♦ 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.

Initial Comments. Initial comments were due October 13, 2022[139] 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. Since the last Report, Elevate Renewables F7, LLC ("Elevate") submitted comments out-of-time.

The *Interconnection Reforms NOPR* is pending before the FERC. 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[140] proposing to revise its regulations to permit ISO/RTOs to share among themselves[141] credit-related information regarding market participants.[142] 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 sought comment on whether ISO/RTOs' credit-related information sharing discretion should be limited in any specific ways or to any specific circumstances.

[139] The *Interconnection Reforms NOPR* was published in the *Fed. Reg.* on July 5, 2022 (Vol. 87, No. 127) pp. 39,934-40,032.

[140] *Credit-Related Information Sharing in Organized Wholesale Electric Markets*, 180 FERC ¶ 61,048 (July 28, 2022) ("*ISO/RTO Credit-Related Info Sharing NOPR*").

[141] 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 ("CFTC")).

[142] 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.

Initial Comments. Initial comments were due October 7, 2022[143] 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 IRC and a couple of persons from Augusta University.

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

On December 15, 2022, the FERC issued a NOPR[144] proposing to revise its regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act. The *Transmission Siting NOPR* is intended to ensure consistency with the Infrastructure and Jobs Act's amendments to FPA section 216, to modernize certain regulatory requirements, and to incorporate other updates and clarifications to provide for the efficient and timely review of permit applications. Following a NARUC request for an extension of time, granted by the FERC on March 3, 2023, comments on the *Transmission Siting NOPR* are due on or before ***May 17, 2023***.

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

Following its ANOPR process,[145] the FERC issued on April 21, 2022 a NOPR[146] 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.

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143 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.

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

145 *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*"). The FERC convened a tech. conf. on Nov. 15, 2021, to examine in detail the issues and potential reforms described in the *ANOPR*. Speaker materials and a transcript of the tech. conf. are posted in FERC's eLibrary. Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEU, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute. *ANOPR* reply comments and post-technical conference comments were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEU, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, a group of former military leaders and former Department of Defense officials, and ACPA/AEU/SEIA.

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

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

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[147] Nearly 200 sets of comments were filed, including comments by NEPOOL , ISO-NE, Acadia/CLF, Anbaric, AEU, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

Reply Comments. Reply comments were due ***September 19, 2022***. Nearly 100 sets of reply comments were filed, including by: ISO-NE, AEU, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, and SEIA. On November 28, 2022, the New Jersey BPU moved to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's State Agreement Approach ("SAA") for the purpose of supporting New Jersey's offshore wind ("OSW") goals, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report, which it stated demonstrates that competitive transmission solicitations can provide significant value to consumers. In December 2022, the Harvard Electricity Law Initiative, and P. Alaama submitted further comments.

LS Power and NRG filed comments in this proceeding, as well as in (Transmission Planning and Cost Management Joint Federal-State Task Force on Electric Transmission) (AD22-8) and JFSTF proceeding (AD21-15). They asserted that the FERC "cannot sufficiently address the transmission planning issues raised in its Transmission NOPR without addressing the intertwined cost management issues raised in AD22-8-000 and during the October 6, 2022 Technical Conference in AD22-8.

This matter remains pending before the FERC. If you have any questions concerning the *Transmission NOPR*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

[147] 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.

- **NOPR: Accounting and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)**

On July 28, 2022, the FERC issued a NOPR[148] 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.[149] Comments were filed by: Dominion, ACPA/SEIA, EEI, Liquid Energy Pipeline Assoc., RESA, PG&E/SDG&E, C. Pechman. There was no activity in this proceeding since the last Report. This matter remains pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **No activity to report**

Natural Gas-Related Enforcement Actions

- **Rover Pipeline, LLC and Energy Transfer Partners, L.P. (CPCN Show Cause Order) (IN19-4)**

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[150] 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[151] 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,[152] 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;[153] (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

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148 *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, 180 FERC ¶ 61,050 (July 28, 2022) ("*Renewable Energy Assets USofA and Reporting NOPR*").

149 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.

150 See *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*"). The hearings will be to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.

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

152 *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").

153 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.

hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[154] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[155] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[156] *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.[157] 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.[158]

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[159] 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.[160]

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[154] *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.

[155] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*").

[156] *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*")).

[157] *BP Penalties Allegheny Order* at P 1.

[158] *Id*. at P 319.

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

[160] 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

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.[161] On July 27, 2021, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule for the proceeding.

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas. 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***.[162]

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.[163] 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

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.

[161] *Total Gas & Power North America, Inc. et al.,* 176 FERC ¶ 61,026 (July 15, 2021).

[162] *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).

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

fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- The Project is targeted for a 4th quarter 2023 in-service date.

XV. State Proceedings & Federal Legislative Proceedings

- **Maine - NECEC Transmission LLC et al. v. Bureau of Parks and Lands et al. (BCD-21-416)**

On August 30, 2022, the Maine Supreme Judicial Court concluded that the legislation enacted as a result of the passage of Maine's November 2, 2021 ballot question,[164] and that effectively halted construction of the NECEC Project,[165] 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).

[164] 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?"

[165] 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.

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
  Underlying FERC *Proceeding*: ER22-707[166]
  Petitioner: Green Development
  Status: Briefing Completed; Oral Argument Held March 20, 2023; Decision Pending

Oral argument in this case was held before Judges Henderson, Pillard and Katsas on March 20, 2023. This matter, which as previously reported was initiated on June 15, 2022 by a Green Development petition challenging the FERC's *2nd Revised Narragansett LSA Orders,*[167] is pending before the Court.

- **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,[168] -013[169] -017[170]
  Petitioners: Mystic, CT Parties,[171] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Apr 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

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[166] *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*".

[167] 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.

[168] *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).

[169] *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).

[170] *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*).

[171] In this appeal, "CT Parties" are the CT PURA CT PURA, Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the CT OCC.

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 related to MISO TOs, now on remand at the FERC. Accordingly, on January 24, 2023, Mystic, without opposition, asked the Court for an order keeping these proceedings in abeyance and directing that motions to govern future proceedings be filed in late April, 2023. On February 3, 2023, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***April 24, 2023***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[172]
  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[173]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[174] 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*[175] 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

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

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

[174] 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.

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

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 April 4, 2023.

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[176]
  Petitioners: Sierra Club
  Status: Briefing Complete; Oral Argument Not Yet Scheduled

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,[177] 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. Respondent's (FERC's) Brief was filed on February 14, 2023); Brief for Respondent-Intervenors and an amicus brief by the Natural Gas Association of America were filed on February 21, 2023. Since the last Report, briefing in this case was completed, with Petitioner's (Sierra Club's) Reply Brief filed on March 14, 2023; a Joint Deferred Appendix filed on March 21, 2023; and Final Briefs filed on April 4, 2023 by Sierra Club, the FERC, INGA (Amicus for FERC) and Empire Pipeline and National Fuel Gas Supply (Intervenor for Respondent FERC). The date of oral argument and the composition of the merits panel will be provided at a later date.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[178]
  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*.[179] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

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[176] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

[177] *Corpus Christi Liquefaction Stage III, LLC*, 181 FERC ¶ 61,033 (Oct. 14, 2022).

[178] *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).

[179] *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.

- **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[180]
  Petitioners: LS Power, Algonquin, INGA
  Status: Cases 22-1146/47 Deconsolidated, Briefing Completed and Oral Argument Set for Apr 20, 2023; 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 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 directed briefing in the consolidated cases. As previously reported, the FERC filed its Respondent Brief on January 12, 2023 and Algonquin and INGA filed a Joint Brief of Intervenors on January 26, 2023. Petitioners filed their Joint Reply Brief on February 16, 2023. Since the last Report, the Deferred Joint Appendix was filed on March 2, 2023 and Final Briefs were filed on March 9, 2023. Briefing in 22-1146/47 is now complete. Oral argument has been scheduled for April 20, 2023 before Judges Srinivasan, Millett and Tatel.

[180] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law.*

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