Sebastian M. Lombardi
Secretary

January 26, 2023

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of February 2, 2023 Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the February meeting of the Participants Committee will be held **via teleconference on Thursday, February 2, 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 February 2 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

FOR PARTICIPANTS, PARTICULARLY THOSE WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE THAT 2023 ANNUAL FEES WILL BE INCLUDED ON THE MONTHLY STATEMENTS TO BE ISSUED ON FEBRUARY 13, 2023. Participants that were members on January 1, 2023 will be assessed that Annual Fee, which must be paid on or before the close of business on Wednesday, February 15, 2023 in order to avoid penalties and interest. Please plan accordingly. If there are questions, you can call ISO New England or Pat Gerity (860-275-0533).

Looking ahead, the March Participants Committee meeting is scheduled for Thursday, March 2, 2023 at the Seaport Boston Hotel. We will provide in future notices detailed information regarding arrangements for those seeking accommodations the evening before that meeting.

Respectfully yours,

/s/
Sebastian M. Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the January 5, 2023 Participants Committee teleconference meeting. A copy of the draft minutes, marked to show the changes made since the minutes were circulated with the initial notice, is included with this supplemental notice and posted with the meeting materials.

2. [There is no Consent Agenda for this meeting.]

3. To receive an ISO Chief Executive Officer report. The February CEO report will be circulated and posted in advance of the meeting.

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

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

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

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

7. Administrative matters

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

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference on Thursday, January 5, 2023, at 10:00 a.m. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

Mr. David Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and guests who were present, including Mr. George Twigg, the newly-appointed Executive Director of the New England Conference of Public Utilities Commissioners (NECPUC).

APPROVAL OF THE DECEMBER 1, 2022 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the December 1, 2022 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Sam Mintz noted.

CONSENT AGENDA

Mr. Cavanaugh then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Mintz noted.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), offered his well-wishes for the New Year and then referred the Committee to the summary of the Information Technology and Cyber Security Board Committee meeting, the one Board Committee that had met since the December Participants Committee meeting, which had been circulated and posted with the materials for this meeting. There were no questions or comments on that summary.

ISO COO REPORT

Operations Highlights Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his December operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through December 27, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for December 2022 was $1.2 billion, up $530 million from the updated November 2022 value and up $459 million from December 2021; (ii) December 2022 average natural gas prices were 157% higher than November average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for December ($126.19/MWh) were 87% higher than November averages; (iv) average December 2022 natural gas prices and Real-Time Hub LMPs over the period were up 77% and 112%, respectively, from December 2021 average prices; (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 97.4% during December (up from 97% reported for November), with the minimum value for the month of 91% on Friday, December 23; (vi) Daily Net Commitment Period Compensation (NCPC) payments for December totaled $6.2 million, which was up $2.5 million from November 2022 and up $0.8 million from December 2021. December NCPC payments, which were 0.5% of total Energy

Market value, were compromised of (a) $6.1 million in first contingency payments (up to $2.5 million from November); and (b) $78,000 in second contingency payments (up $38,000 from November) (there were no voltage or distribution payments in December).

Commenting on the operational highlights, Dr. Chadalavada noted that the annual Energy Market value for 2022 was approximately $11.7 billion, the second most expensive value recorded by the ISO (the highest, $12.1 billion, was recorded in 2008, when average hourly natural gas prices for the year averaged $10 MMBtu/hr). He also noted that December 2022's average Real-Time Hub LMP ($126.19/MWh) was the highest ever recorded for the month of December. Turning to NCPC payments, he noted that $1.5 million of the total $6.1 million in December NCPC payments were made on December 24. In general, 2022 NCPC payments represented 0.5% of the total annual Energy Market value, which was the lowest percentage ever recorded for NCPC as a percentage of the overall annual Energy Market value.

In response to questions, Dr. Chadalavada explained that most of the NCPC payments made for December 24 were make-whole payments. Looking ahead, he confirmed that there were no scheduled transmission outages through the end of February 2023, and would report closer in time on projections for transmission outages scheduled for March and April 2023. When asked to comment on the potential impact that additional natural gas pipeline infrastructure/capacity might have had on 2022's Energy Market value, Dr. Chadalavada said that he did not have specific information or data to rely on, but he thought it reasonable to presume that additional natural gas pipeline infrastructure/capacity would likely have had a material impact on overall Energy market value.

OP-4 Event and Capacity Scarcity Condition Report

Referring to an additional presentation that was circulated and posted in advance of the meeting, Dr. Chadalavada summarized the factors leading up to, and conditions during, the December 24, 2022 Capacity Scarcity Condition and OP-4 (Action During a Capacity Deficiency) Event (December 24 Event). He identified two primary contributing factors: (i) generator outages and reductions throughout the operating day (totaling 2,150 MW on the supply side) and (ii) net imports being 1,100 MW less than scheduled in the Day-Ahead Energy Market. System-wide LMPs averaged approximately $484/MWh through the operating day, and $2,222/MWh during the 6:00 p.m. hour. He reported that the 30-minute Reserve Constraint Penalty Factor ($1,000/MWh) was violated during 17 intervals and the 10-Minute Reserve Constraint Penalty Factor ($1,500/MWh) was violated during 1 interval. System conditions required the implementation of M/LCC 2, Abnormal Conditions Alert, and OP-4, Actions 1, 3 and 5.

Elaborating, Dr. Chadalavada noted preliminary settlement reports for December 24 were released on Friday, December 30, 2022 and a final settlement report was estimated for release on January 9, 2023. Estimated Pay-for-Performance (PFP) penalties (based on preliminary data) totaled $39 million, which was roughly similar to the $36 million in PFP penalties incurred during the previous Capacity Scarcity Condition event (September 3 (Labor Day), 2018). Final settlement, he stated, would be adjusted for any Capacity Performance Bilateral Contracts. He highlighted that lower-than-forecasted temperatures contributed to higher-than-expected Energy demand throughout the daylight hours, though the ISO's peak hour morning load forecast was highly accurate. Based upon its peak load forecast of 17,510 MW, the ISO projected a capacity surplus of 950 MW above requirements, but the projected surplus did not materialize given the unplanned generator outages and reductions that occurred throughout the operating day. While the causes for the outages and reductions varied, many of them were mechanical or cold-weather related, ~~and~~ not fuel-related, and occurred within the couple of hours prior to the December 24 peak hour. ~~.~~ When it became apparent that additional resources would be needed for the peak hour, the ISO called those resources that could start-up and be available during the needed time frame (roughly 380 MWs, but short of the MWs sought); remaining available resources were not called, not for a lack of fuel, but because they could not be dispatched in time for the peak hour due to longer start-up times. ~~The December 24 Event was attributable to supply shortfall, rather than to fuel shortages.~~

Turning to energy production by resource type, Dr. Chadalavada said wind resources performed above their ~~c~~Capacity S~~s~~upply O~~o~~bligation (CSO) for the peak hour. With LMPs high, oil-fired generation was in-merit much of the day, and met roughly 29% of the region's energy demand. Accordingly, there was heavy oil burn, including on the days preceding and on the day following, December 24, but the impacted oil inventory had been adequately replenished. He said, in response to questions, that the Saint John and Everett liquefied natural gas (LNG) terminals had the capacity to inject natural gas into the pipeline system. ~~ISO called upon available resources during the December 24 Event; however, many resources could not be dispatched promptly due to longer start-up times.~~ There were no transmission outages in New England on December 24, but there were two major outages in Quebec, Canada. Dr. Chadalavada further noted that the ISO Control Room lacked sufficient certainty on transmission schedules during the December 24 Event, but moving forward, the ISO planned to work towards obtaining better and more concrete schedule information. He also committed to have prepared and to present at a later meeting, aggregated, but more granular information, with respect to performance and outages/reductions by resource type.

In response to a question regarding the impact of curtailed export transactions with NYISO, Dr. Chadalavada noted that there were curtailments of Real-Time exports, but not scheduled exports, resulting in little material impact to New York. One member noted that imports from New York increased over the operating day. Another member noted that the December 24 Event and the previous OP-4 event on the system both occurred on a holiday weekend, and questioned whether the December 24 Event would have occurred or would have been as severe if it had not occurred on a holiday weekend. Dr. Chadalavada noted that the last scarcity event occurred due to outages and a load forecast issue, but the ISO planned to consider further any correlation with holidays.

In response to questions on how the December 24 Event might have been impacted had certain products under development or being proposed been in place, Dr. Chadalavada speculated that the Day-Ahead Ancillary Services Initiative (DASI) design, as then contemplated, might have helped. He further speculated that longer duration Ancillary Service products (e.g., 90-minute or more), serving as back-up to 10-Minute and 30-Minute Reserves, would have likely provided some additional support. Following some commentary and questions triggered by the flows over the ties during the December 24 Event, Dr. Chadalavada committed, with the benefit of additional time, to provide added information that would help parse the percentages of imports that were ~~Capacity Supply Obligation (~~CSO~~)~~ and non-CSO backed transactions during the December 24 Event.

Following questions and comments on the role of Day-Ahead load forecasting, Dr. Chadalavada stated that the December 24 Event did not occur as a result of the day's forecast, but acknowledged the potential for, and the ISO's commitment generally, to pursue all reasonable, forecasting model and process improvements. Mr. van Welie, referring to a recent discussion among organized market chief executives in which he had participated, explained the common theme that, as the weather becomes more volatile and extreme, the ability to forecast load during low probability extreme events is exponentially more challenging than it has been historically. He affirmed the ISO's commitment to explore and invest in modeling improvements, but opined that the forecasting challenges presented by extreme weather would continue for the foreseeable future and potentially become more acute.

PP 5-1 REVISIONS

Ms. Amy Crowley, the Acting Chair of the Reliability Committee (RC), introduced proposed changes to ISO Planning Procedure No. 5-1 (Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans) (PP 5-1), which were designed to clarify the timing and requirements for model and data submissions associated with Proposed Plan Application (PPA) submittals under Section I.3.9 of the Tariff (PP 5-1 Revisions). She reported that the ISO had modified the proposed changes several times based on RC feedback, and at its December 14 meeting, the RC recommended Participants Committee support for the PP 5-1 Revisions, with three oppositions and several abstentions registered. Mr. Cavanaugh noted this PP 5-1 item would have been on the Consent Agenda but for the request by certain Transmission Owners for separate consideration. A representative of one of those Transmission Owners referred members to the materials they prepared, and that were circulated with the meeting materials, that explained their concerns with the proposed PP 5-1 Revisions and their desire to have the changes considered and voted separately.

Mr. Lombardi reminded members that FERC review and approval was not necessary for the PP 5-1 Revisions to be implemented. Some members expressed their appreciation for the ISO's work and collaboration in refining the planning study process, with others encouraging additional work to address the remaining concerns raised.

The following motion was then duly made and seconded, and approved, with oppositions expressed by Avangrid, Eversource, National Grid, and Rhode Island Energy, and abstentions by AIM, Brookfield, Calpine, Clearway, Competitive Energy Services, FirstLight, Great River Hydro, Harvard, Jupiter Power, Mr. Mintz, Nautilus, New Leaf Energy, VELCO, Versant Power, and Wheelabrator:

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

LITIGATION REPORT

Mr. Lombardi referred the Committee to the January 4 Litigation Report that had been circulated and posted before the meeting. He highlighted the following:

(i) *FERC Administrative Matters*. Commissioner Richard Glick's departure from the FERC on January 3, leaving the FERC with four Commissioners, and designation of Commissioner Willie Phillips as Acting Chairman.

(ii) *RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16).* RENEW Northeast's complaint, filed December 13, 2022, seeking changes to Schedules 11 and 21 of Tariff that would eliminate the direct assignment of the Network Upgrade Operating and

Maintenance (O&M) costs to Interconnection Customers. Comments on the RENEW complaint were due on or before January 23, 2023.

(iii) *ISO's FCA17 Qualification Informational Filing (ER23-690).* ISO's submission of its required FCA17 informational filing on December 21, 2022. Comments on this filing were due at the end of the day (January 5).

(iv) *IEP Remand Proceeding (ER19-1428-006).* Mr. Lombardi reported that NEPOOL submitted comments explaining the history and process leading up to the Participants Committee's approval of both the Tariff changes proposed by the ISO that would exclude hydroelectric resources from participating in the Inventoried Energy Program (IEP), as well as the alternative changes proposed by Brookfield that would expressly permit pumped-storage hydro resources operating as Electric Storage Facilities (ESFs) to participate in the IEP. This matter was pending before the FERC.

Mr. Lombardi then noted for the Committee that the proposal to amend § 9.2.3(a) of the Participants Agreement, to raise the age cap prohibiting the election or re-election of any candidate to the ISO-NE Board of Directors from 70 to 75, was approved after two rounds of balloting. The supported changes to the Participant Agreement would be jointly filed by NEPOOL and the ISO for FERC approval later in January.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting was scheduled from January 10-12, 2023 in Westborough, MA. The agenda and materials for that meeting had been posted to the ISO website.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting was scheduled for January 18 and discussions would focus on the extreme weather modeling completed by the Electric Power Research Institute and the ISO.

Transmission Committee (TC). Mr. David Burnham, nominated to be the 2023 TC Vice-Chair, reported that the next and annual TC meeting was scheduled for January 24 via teleconference. A confirmation vote for Vice-Chair would be~~ill~~ conducted. All TC members were encouraged to attend or vote by proxy to ensure TC quorum requirements would be met.

Budget and Finance Subcommittee (B&F). Mr. Tom Kaslow, the B&F Subcommittee Chair, reported that the next B&F Subcommittee meeting was scheduled for January 17 and would be confirmed later in the month.

Membership Subcommittee. Ms. Sarah Bresolin, the Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for January 9 via Zoom.

Joint Nominating Committee (JNC). Mr. Cavanaugh noted that the JNC's first meeting was scheduled to be held on January 13 via teleconference. He confirmed that Messrs. Mark Vannoy and Brook Colangelo had been invited to join a future Participants Committee meeting to discuss their experiences serving on the ISO Board, and Participant feedback on those Board members would be solicited following that discussion.

ADMINISTRATIVE MATTERS

Mr. Lombardi reminded members that the next Participants Committee meeting was scheduled for February 2, 2023 and likely to be held virtually. Mr. Twigg then reminded members of NECPUC's Annual Symposium, to be held in 2023 from May 22 through 25 in Stowe, Vermont. He said that more detailed information would follow in the next few months, and encouraged all those interested to register and attend.

There being no other business, the meeting adjourned at 12:03 p.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN JANUARY 5, 2023 TELECONFERENCE MEETING

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

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JANUARY 5, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User	Dan Collins		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	AR-RG			Ron Carrier
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity	Craig Kieny		
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		José Rotger
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate’s Office	End User	Drew Landry		
Maine Skiing, Inc.	End User	Dan Collins		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General’s Office (MA AG)	End User	Ashley Gagnon	Jaimie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Dept. Capital Asset Management	End User		Paul Lopes	Nancy Chafetz
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Mintz, Sam	End User	Sam Mintz		
Moore Company	End User			Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		Lindsay Orphanides
Nautilus Power, LLC	Generation	Dan Pierpont	Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned Entity		Brian Callnan	Brian Forshaw
New Hampshire Office of Consumer Advocate	End User		Jason Frost	
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	
Nylon Corporation of America	End User			Bill Short

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN JANUARY 5, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunnova Energy Corporation	AR-DG			David Skillman
Sunrun Inc.	AR-DG			Peter Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
The Energy Consortium	End User	Bob Espindola	Mary Smith	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori	Karin Stamy	
Vermont Energy Investment Corp (VEIC)	AR-LR		Jason Frost	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin	Dave Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

Summary of ISO New England Board and Committee Meetings

February 2, 2023 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee met on January 18. The Board of Directors met on January 19. All of the meetings were held in Holyoke, Massachusetts.

The Compensation and Human Resources Committee received an update on a benchmarking analysis of the Company's compensation of certain key positions. In executive session, the Committee held preliminary discussions related to the achievement of corporate goals for 2022 and 2023 officer compensation. On the latter topic, the Committee considered the reasonableness of that compensation when compared to similarly-situated companies. The Committee also agreed to recommend that the Board approve the Company's corporate goals for 2023.

The Markets Committee received reports from both the Internal and External Market Monitors on key market issues during the 2022 fall season. The Committee was then provided with an update on management's plans to modify the Inventoried Energy Program. The Committee discussed with the External Market Monitor his recommendations regarding a prompt capacity market and accepted management's recommendation to evaluate the implications of the proposal before making any decisions. In executive session, the Committee assessed the achievement of 2022 corporate goals, and, as required by the Committee's charter, reviewed the scope and coverage of the Internal Market Monitor and External Market Monitor for adequacy. The Committee considered the 2023 work plan of the Internal Market Monitor, and reviewed his 2022 performance.

The Nominating and Governance Committee received a report on Joint Nominating Committee activities, and reviewed the Company's strategic planning process and topics for 2023. The Committee reviewed a draft of the Company's 2023 Communications Plan. The Committee also discussed Board diversity and inclusion initiatives, and agreed to recommend that the Board approve a mission statement regarding board diversity, equity and inclusion. Last, the Committee discussed the Board's oversight of the Company's risk and compliance functions.

The System Planning and Reliability Committee held an executive session to assess achievement of 2022 corporate goals. The Committee then received a report on the root-cause analysis of the error discovered in preparation for the 2022 Annual Reconfiguration Auctions. The Committee discussed digital modeling of the New England electrical grid and progress on implementing FERC's order regarding dynamic line ratings. The Committee also discussed the scope of work for the 2023 Regional System Plan. The Committee reviewed activities and events that were a major focus during the late summer and fall of 2022, including regional planning activities, qualifications for Forward Capacity Auction #17, long-term transmission planning, and integration of Distributed Energy Resources. In addition, the Committee previewed activities anticipated to be a major focus for the first quarter of 2023. The Committee also discussed a dashboard summary of ongoing projects, received updates on the Company's compliance with NERC and NPCC standards, and was informed of updates to Regional System Plan projects.

The Board of Directors received a report from the CEO and discussed winter preparedness. The Board was also updated on federal, FERC and state political activities. The Board heard reports from the standing committees outlining highlights from their recent meetings. During the Nominating and Governance Committee report, the Board approved the following mission statement regarding board diversity, equity and inclusion:

> The Board of Directors of ISO New England Inc. recognizes that a diversity of experience and background among its members will facilitate the Board's ability to serve the New England region and navigate the future. Accordingly, the Board values all of the factors that contribute to this diversity of experience and background, including age, gender, race and ethnicity, LGBTQ status, veteran status, and disability. The Board's Nominating and Governance Committee, which oversees the ISO's role in electing members to the Board, has committed to work with stakeholders through the Joint Nominating Committee process to ensure that each pool of candidates includes candidates who will add to the Board's diversity of experience and background.

The Board plans to post this mission statement on the ISO's website, and to discuss it with the Joint Nominating Committee and the states during upcoming meetings. The Board also received a report on the 2023 strategic planning process and, while in executive session, approved the Company's corporate goals for 2023.

NEPOOL Participants Committee Report

February 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through January 25th, unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: December 2022 Energy Market value totaled $1.3B
  - January 2023 Energy market value was $455M, down $873M from December 2022 and down $1.3B from January 2022
    - January 2023 natural gas prices over the period were 66% lower than December average values
    - Average RT Hub Locational Marginal Prices ($52.89/MWh) over the period were 56% lower than December averages
    - Average January 2023 natural gas prices and RT Hub LMPs over the period were down 77% and down 64%, respectively, from January 2022 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.9% during January, up from 97.5% during December*
    - The minimum value for the month was 92.1% on Tuesday, January 3rd

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

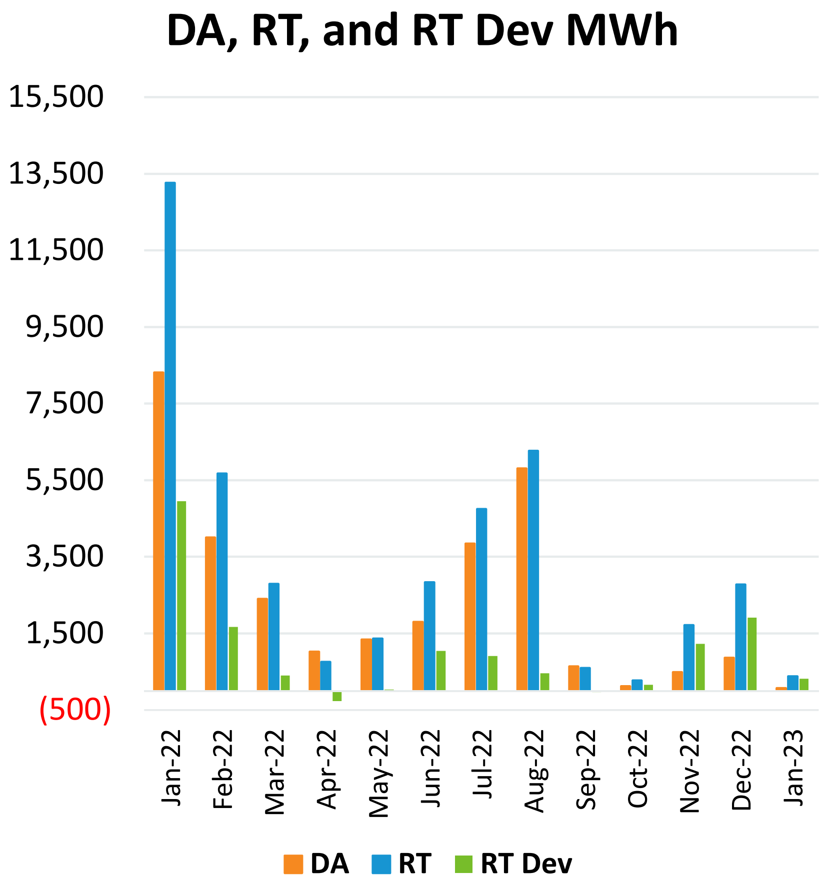
Underlying natural gas data furnished by: ICE Global markets in clear view

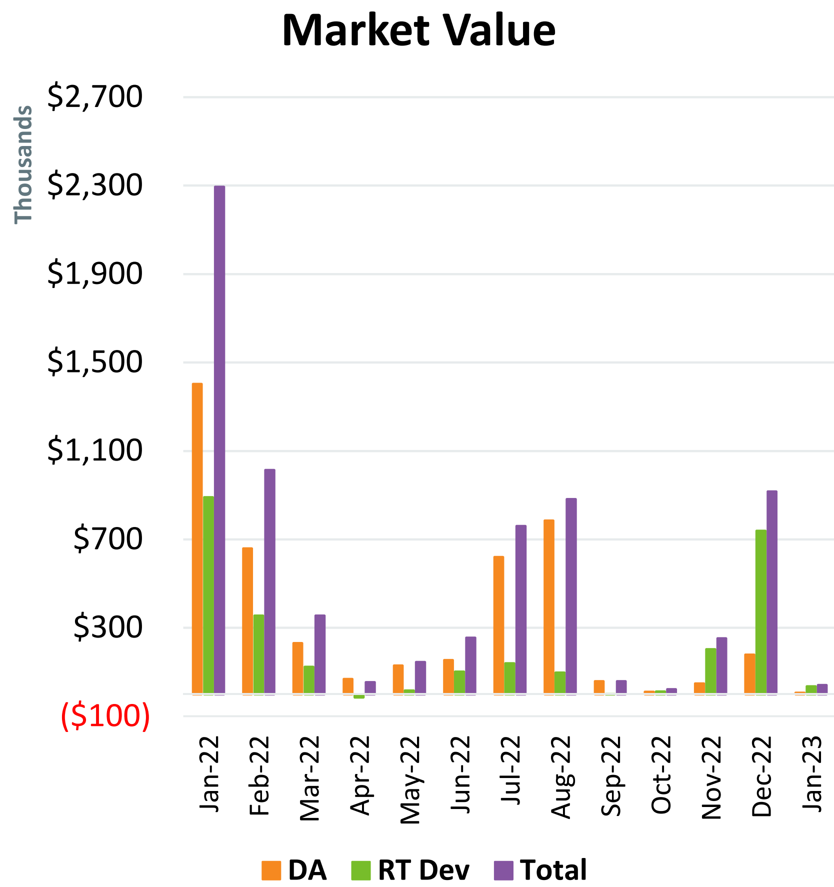
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - January 2023 NCPC payments totaled $2.1M over the period, down $4.5M from December 2022 and down $2.3M from January 2022
    - First Contingency payments totaled $2M, down $4.5M from December
      - $1.9M paid to internal resources, down $4.5M from December
        - » $384K charged to DALO, $872K to RT Deviations, $687K to RTLO*
      - $33K paid to resources at external locations, up $3K from December
        - » $3K charged to DALO at external locations, $31K to RT Deviations
    - Second Contingency payments totaled $75K, down $3K from December
    - Voltage and Distribution payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $284K; Rapid Response Pricing (RRP) Opportunity Cost - $403K; 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

- The Economic Study Process Improvement project to update Attachment K of the OATT was filed with FERC on January 27
- Preparations are ongoing for FCA 17, which will commence on March 6
- 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 is scheduled for February 24 and will include discussions of electrification forecasts and draft energy and demand forecasts

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning February 11, 2023.
- The lowest 50/50 and 90/10 Preliminary Spring Operable Capacity Margins are projected for week beginning May 13, 2023.

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) will be 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 – Capacity Commitment Period

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - FCA 17 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - FCA 17 Installed Capacity Requirement and related values were filed with FERC on November 8, 2022
  - ISO submitted the FCA 17 informational filing to FERC on December 21, 2022
  - Preparations are ongoing for the auction, which will commence on March 6

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 11, 2022
    - TOs identified in-service dates for new transmission projects and revisions to previously certified projects
    - 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

FOLLOW UP TO QUESTIONS FROM THE JANUARY NPC MEETING ON THE DECEMBER 24, 2022 CAPACITY SCARCITY EVENT

Timing of Generator Outages and Reductions

- The following is a timeline of the generator outages and reductions that occurred through the day (this does not include the reductions in imports between day-ahead and real-time)
  - ~1,245 MW of those outages or reductions occurred between the morning report and noon
  - ~340 MW of additional outages or reductions occurred between noon and 16:00
  - ~150 MW of generator outages or reductions following the declaration of M/LCC-2 and prior to the implementation of OP-4 at 16:30
  - ~540 MW of generator outages or reductions following the implementation of OP-4 and through the peak hour (HE18)
- In total, ~2,275 MW[1] of generating capacity that was expected to be available for the peak hour became unavailable during the operating day for a variety of reasons (see next slide)

1: The total MW amount of generator outages and reductions is slightly higher than originally reported at the January NPC meeting

Types of Generator Reductions and Outages

- Several types of generation technologies and fuel types experienced outages or reductions
  - Dual fuel generators, residual fuel oil (RFO) generators, natural gas-only generators, and distillate fuel oil (DFO) generators comprised ~33%, ~29%, ~15%, and ~13% of the generating capacity reductions (MWs) on that day
- A majority (~65%) of all generating capacity reductions were due to mechanical problems such as stuck valves, fuel pump failures, vibration, other unexpected equipment failures
- Other factors contributing to generator outages or reductions included gas scheduling issues (~15%), emissions-related restrictions (~7%)

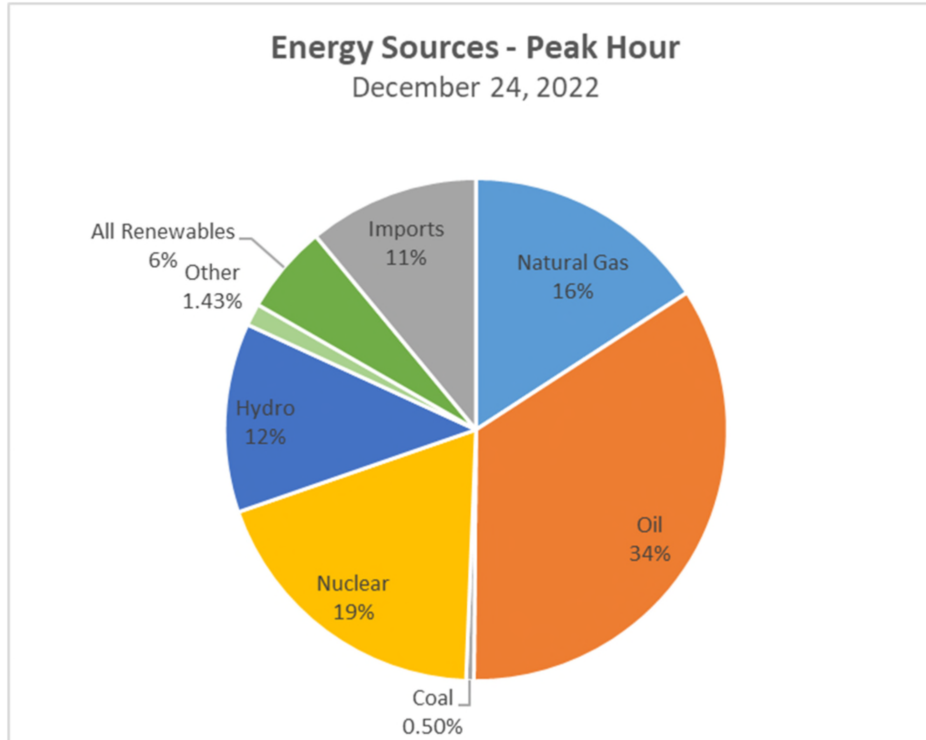
Estimated Fuel-Oil Burn and Replenishment Between December 20th and January 3rd

- Based on generator surveys submitted by Market Participants, ISO estimates that between December 20th and January 3rd
  - ~30.6M gallons of fuel-oil was burned and ~19.1M gallons of fuel-oil replenishment occurred[1]
  - Fuel-oil burn was ~51% RFO and ~49% DFO
  - Of the fuel-oil replenishment that occurred, ~54% was RFO and ~46% was DFO

1: ISO's estimates for fuel-oil burn and replenishment are slightly lower than originally reported at the January NPC meeting due to revised generator survey responses submitted by Market Participants

Peak Hour Energy From Dual Fuel Resources

- Of the energy produced by oil-fired generators (~34% of total energy) during the peak hour of the operating day, ISO estimates that ~50% was produced by dual fuel resources that were burning DFO



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (7.9°F) Max: 58°F, Min: 23°F Precipitation: 5.19" – Above Normal Normal: 3.18" Snow: 6.6"	Hartford	Temperature: Above Normal (9.6°F) Max: 56°F, Min: 23°F Precipitation 5.81" – Above Normal Normal: 3.08" Snow: 2.3"

Peak Load:	17,114 MW	January 16, 2023	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

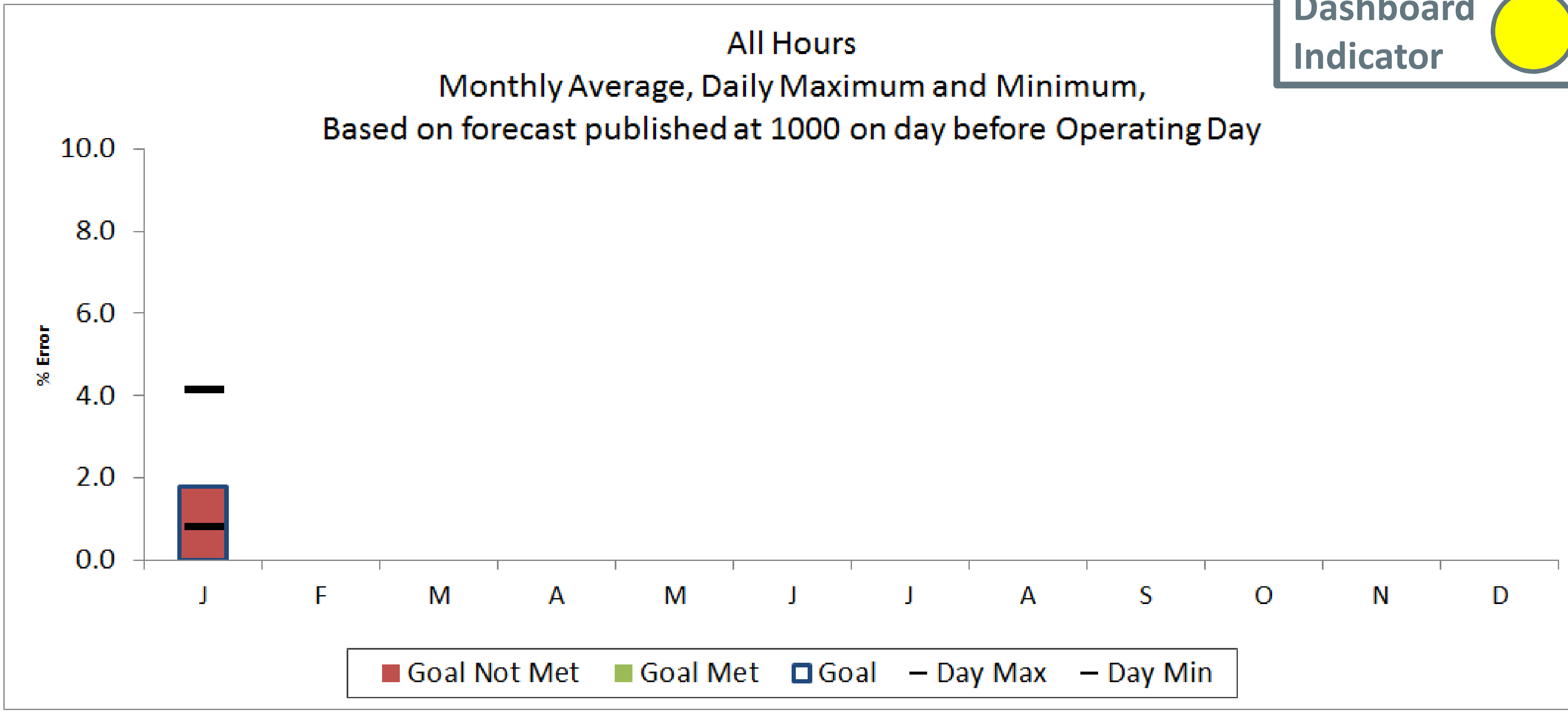
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
1/05/2023	IESO	1050
1/05/2023	PJM	1248

2023 System Operations - Load Forecast Accuracy

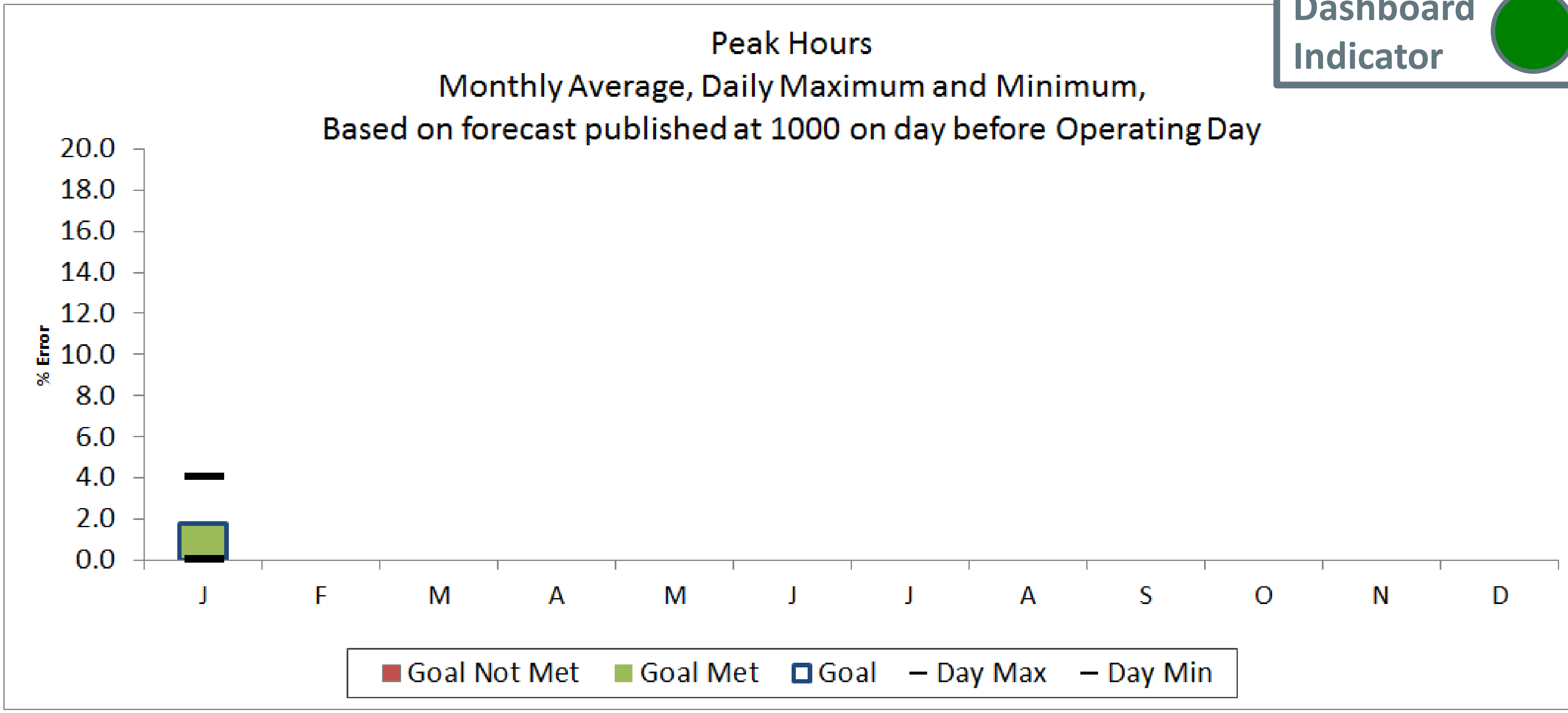
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14												4.14
Day Min	0.80												0.80
MAPE	1.83												1.83
Goal	1.80												

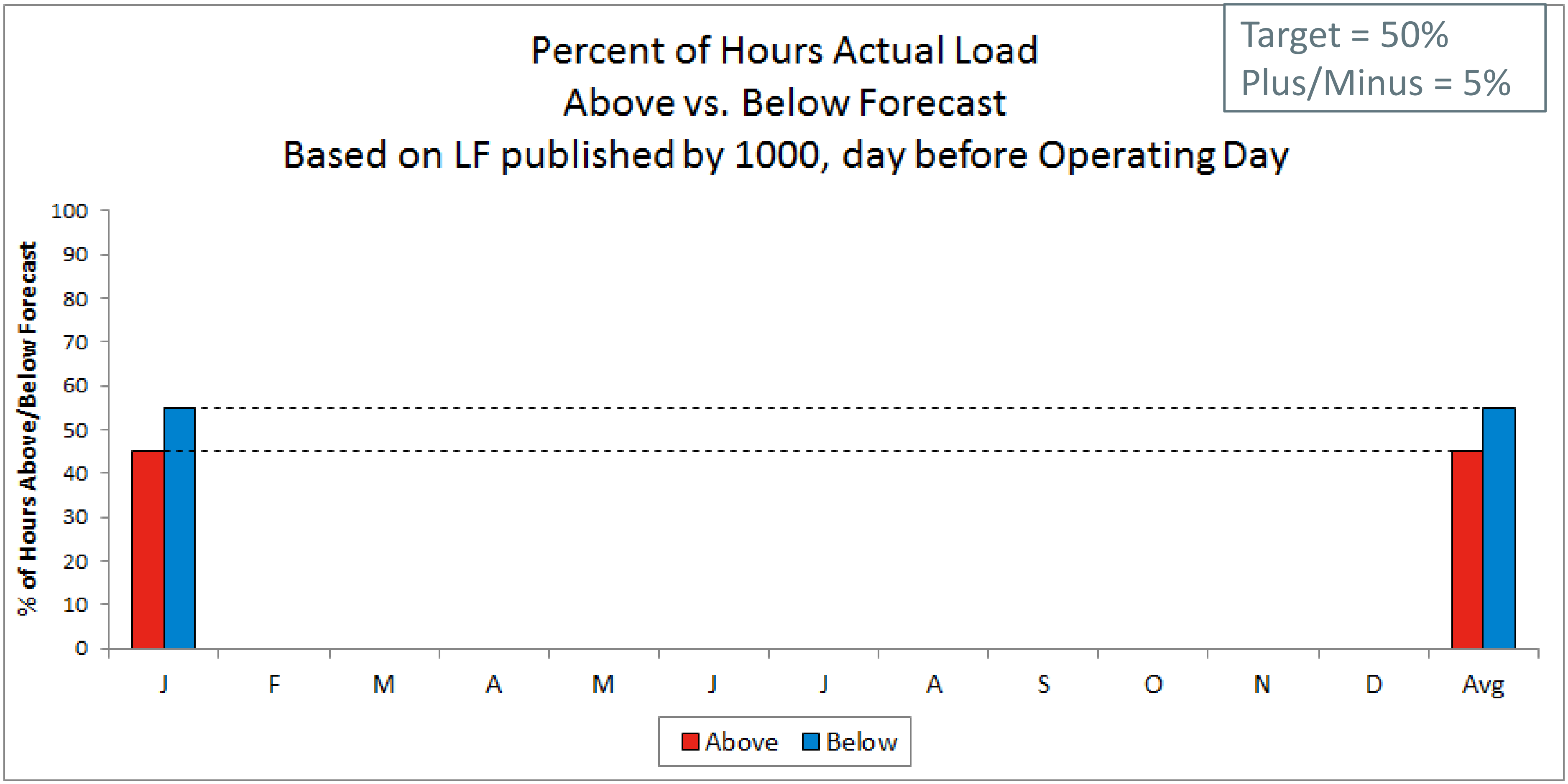
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



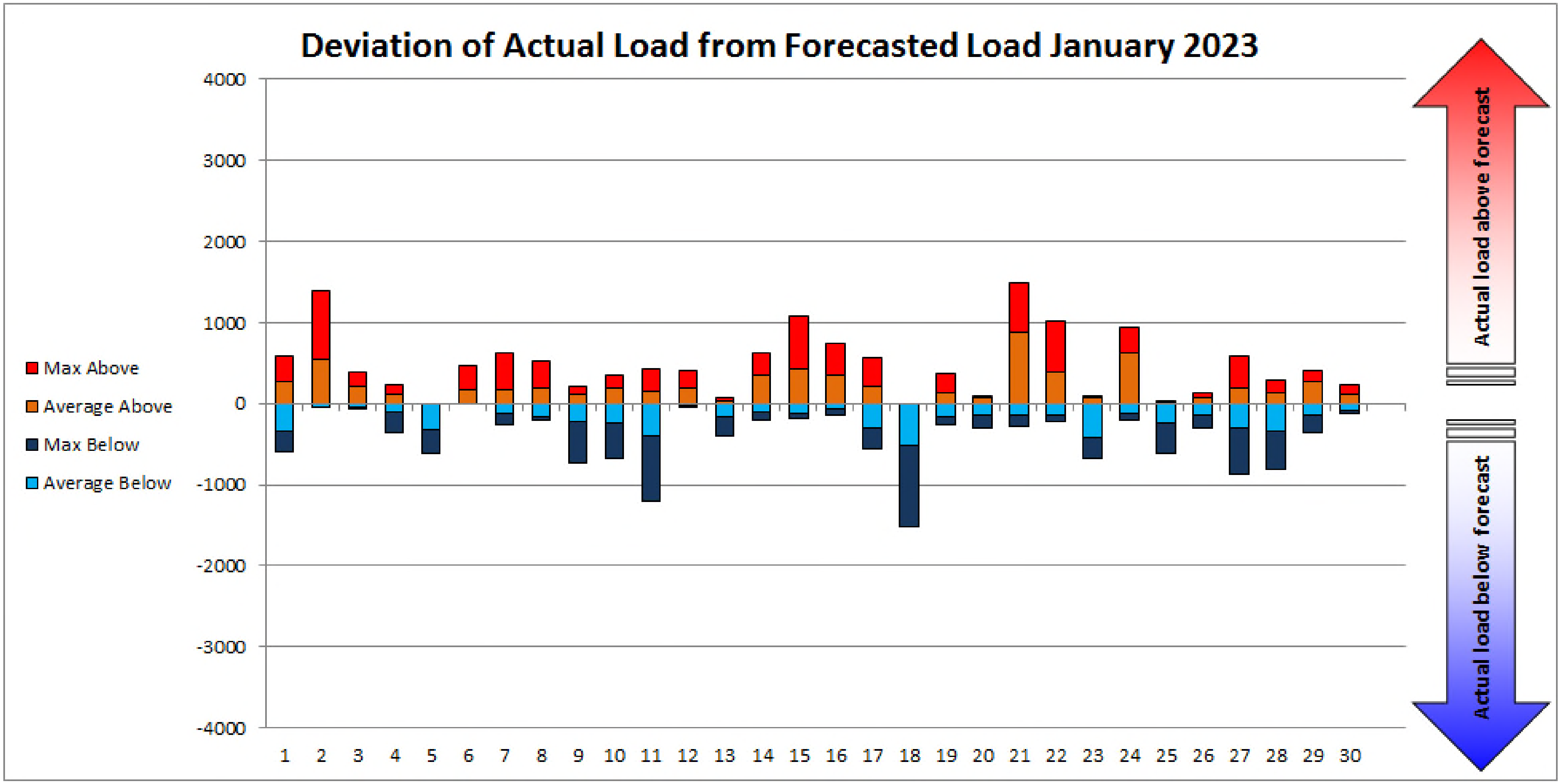
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05												4.05
Day Min	0.01												0.01
MAPE	1.65												1.65
Goal	1.80												

2023 System Operations - Load Forecast Accuracy cont.

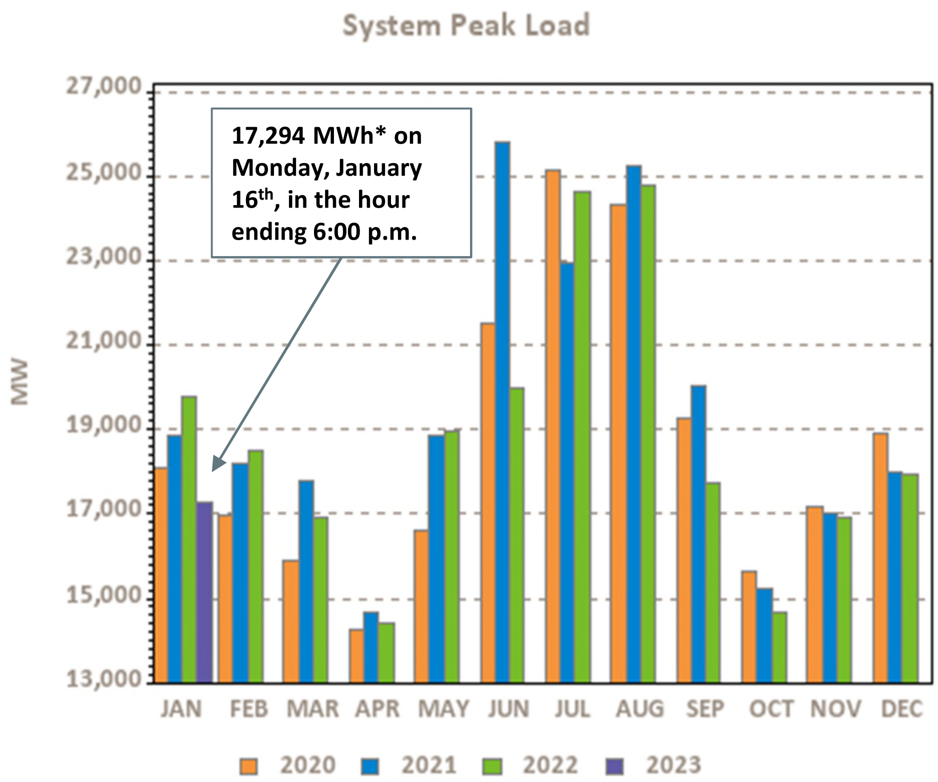


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	45.2												45
Below %	54.8												55
Avg Above	213.2												213
Avg Below	-184.3												-184
Avg All	-10												-10

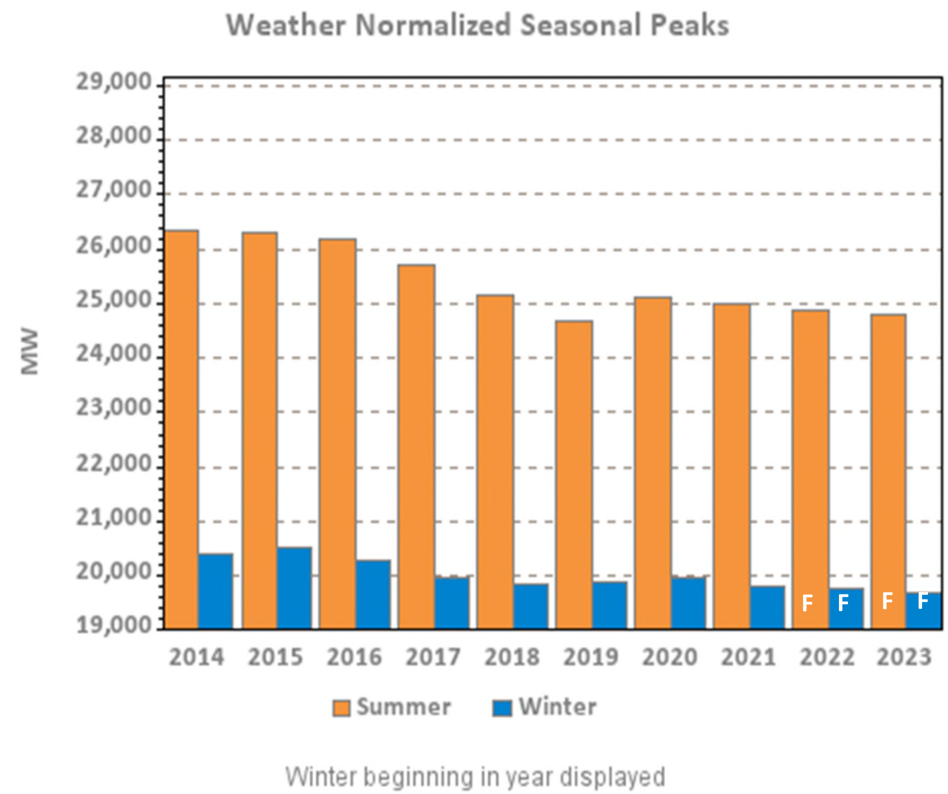
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History

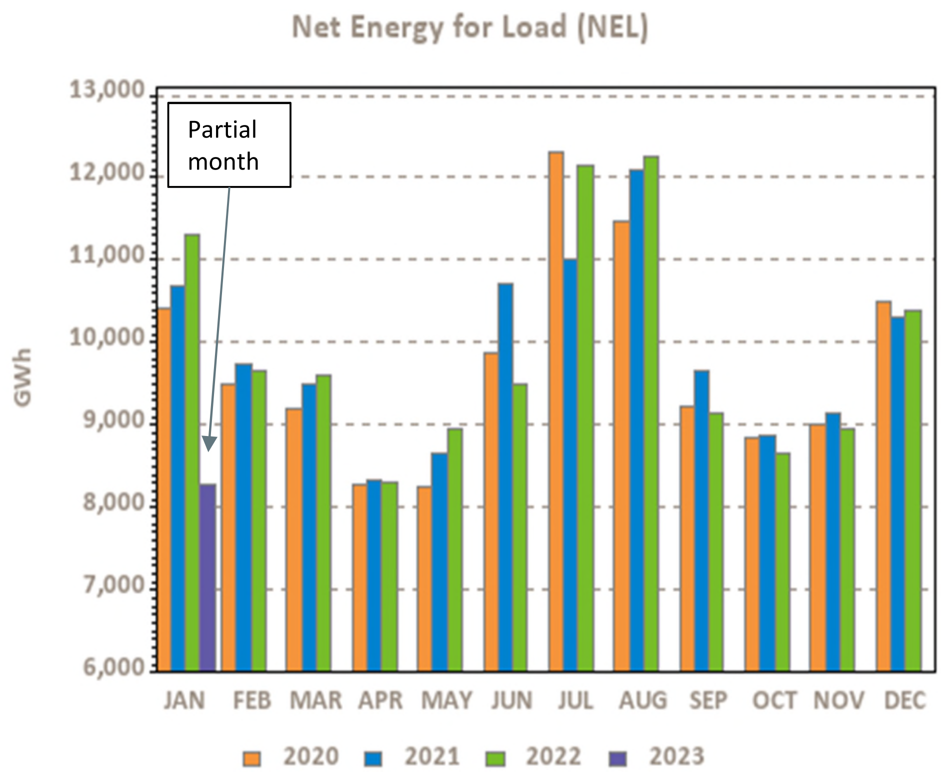


*Revenue quality metered value

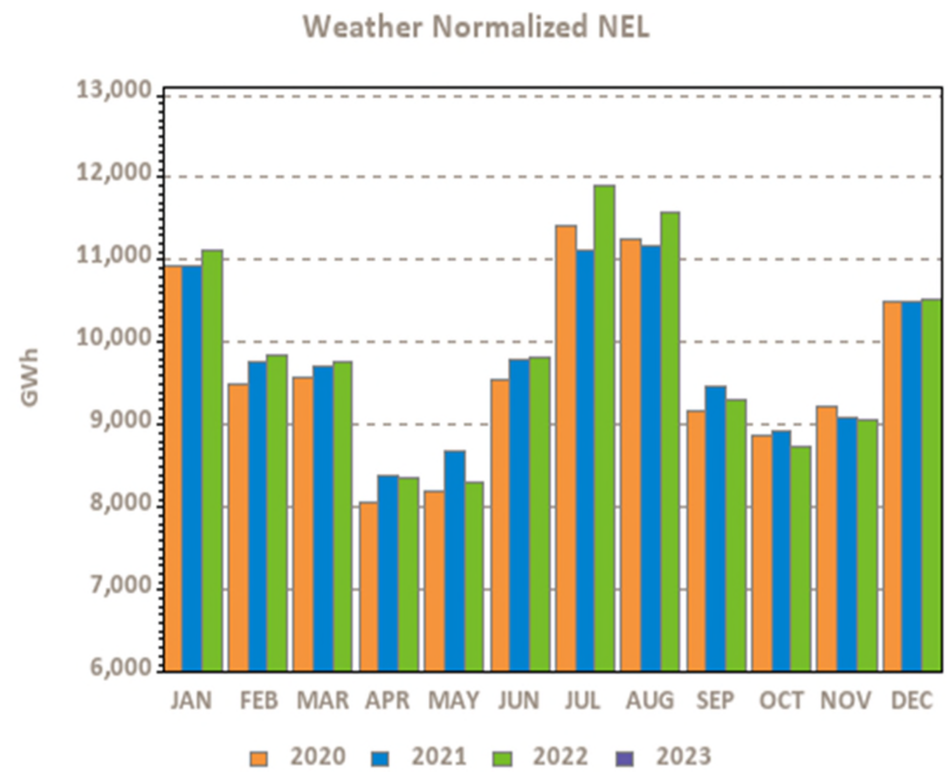


F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



Ann Tot (TWh): 116.9 118.8 118.9 8.3

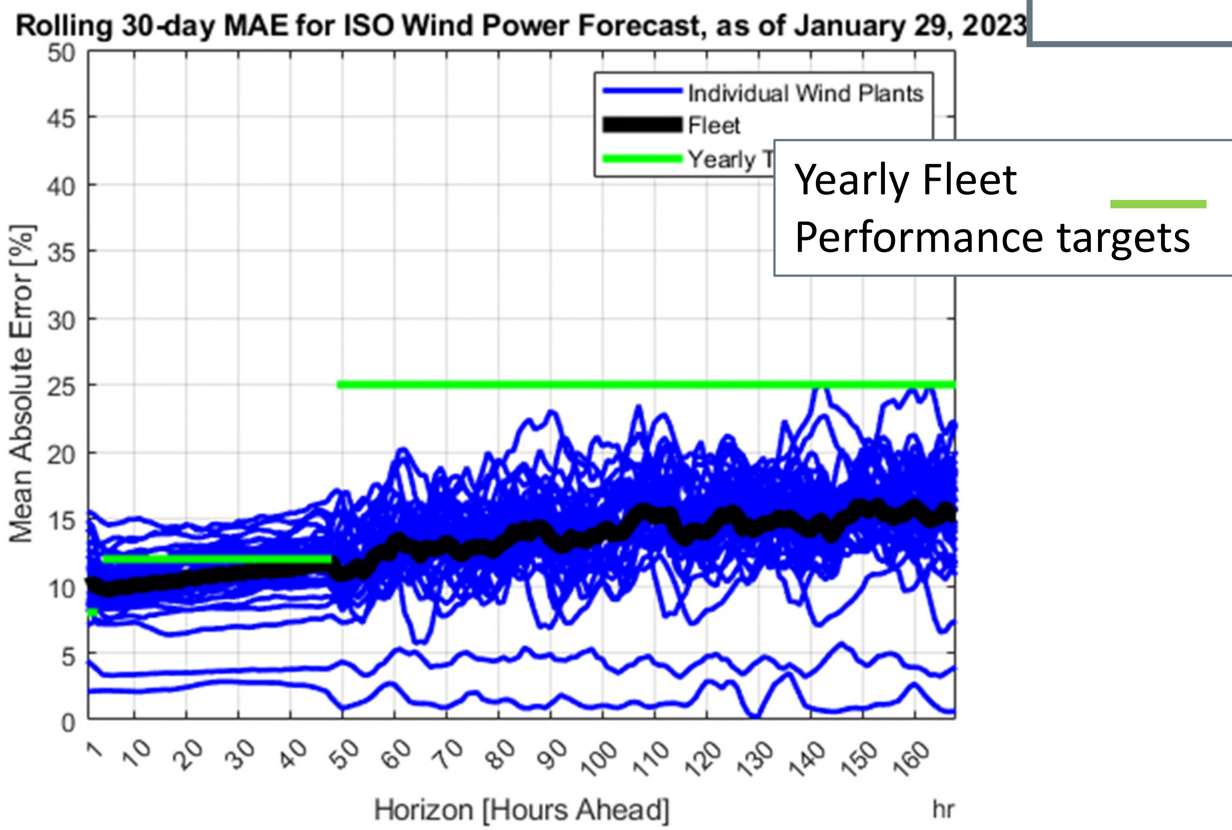


Ann Tot (TWh): 116.3 117.3 118.3 0

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

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

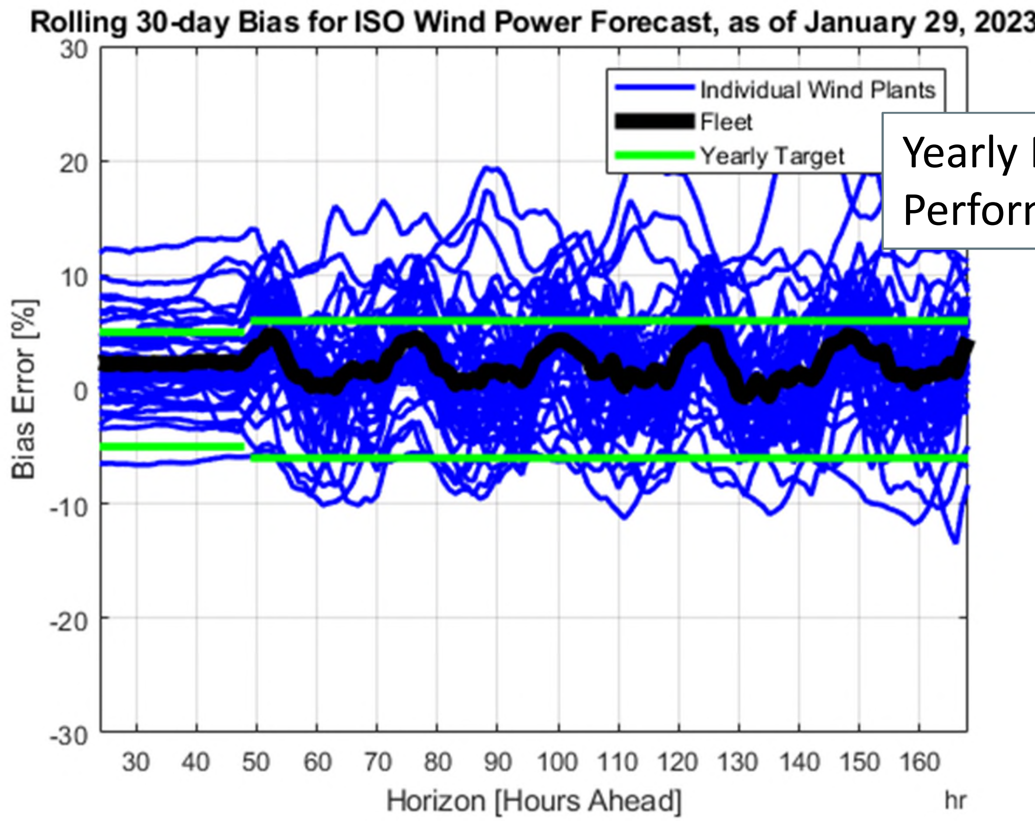
Dashboard Indicator



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

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

Dashboard Indicator

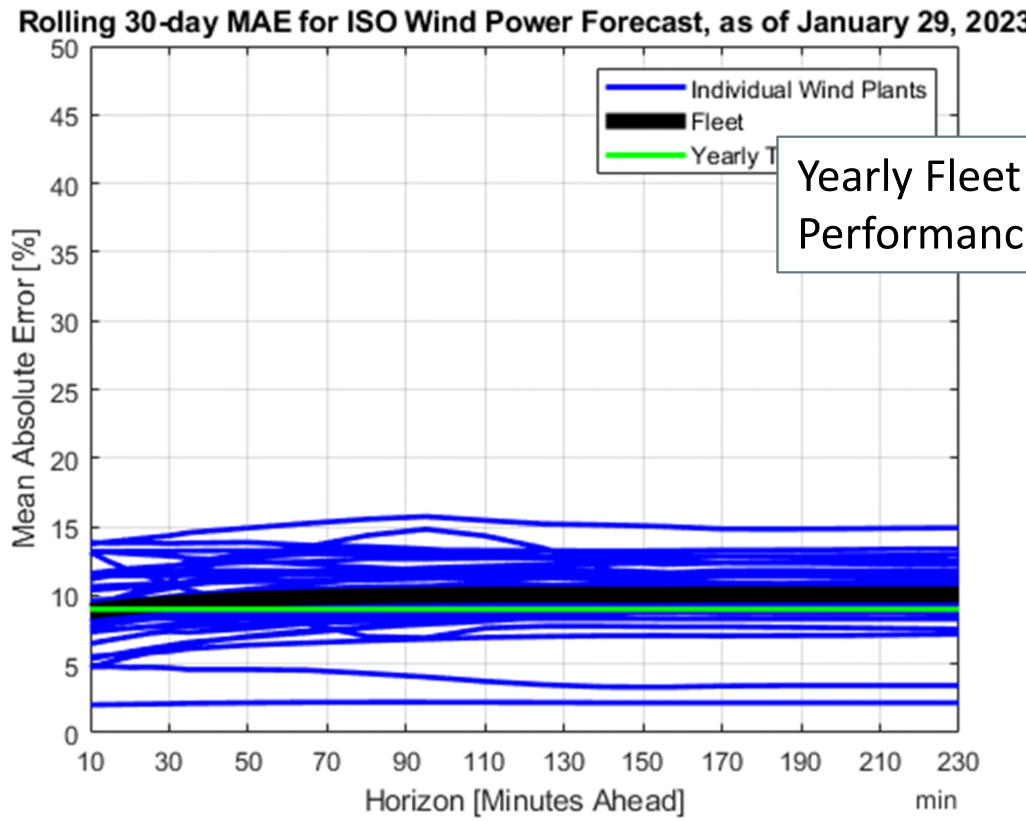


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

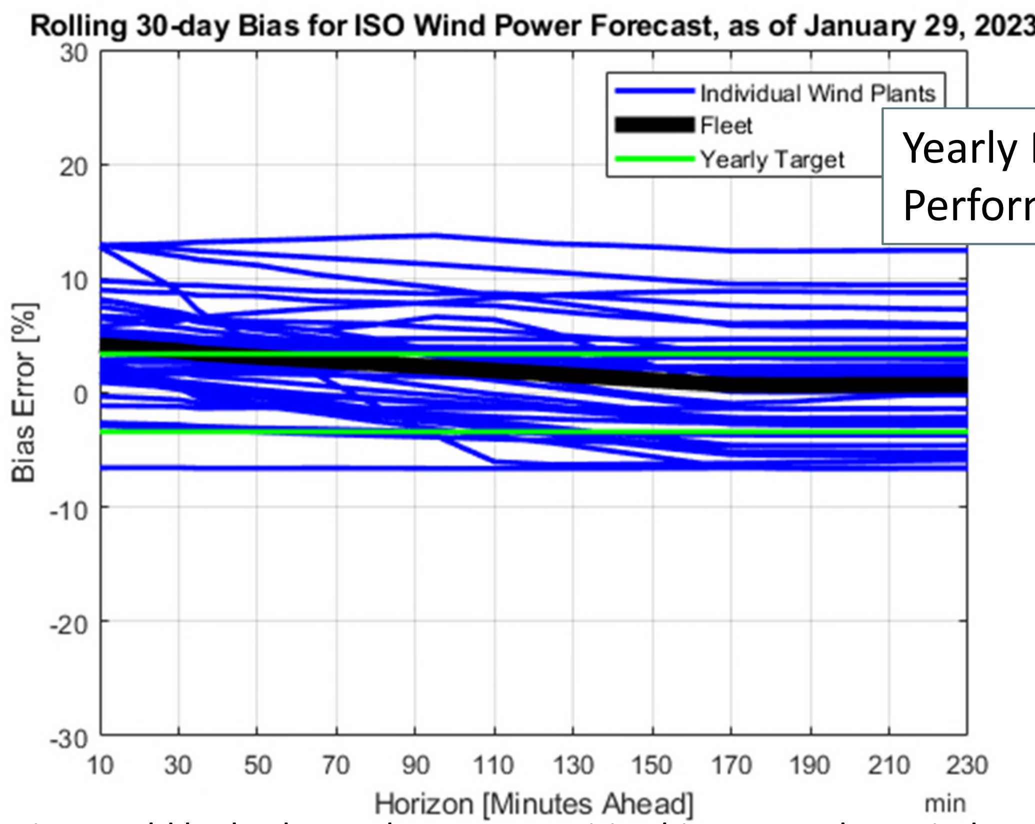


Yearly Fleet Performance targets

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. While the forecast compares with industry standards, monthly MAE is outside yearly performance targets. The error seems related to the quality of the input data – ISO is working with wind plants to correct.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

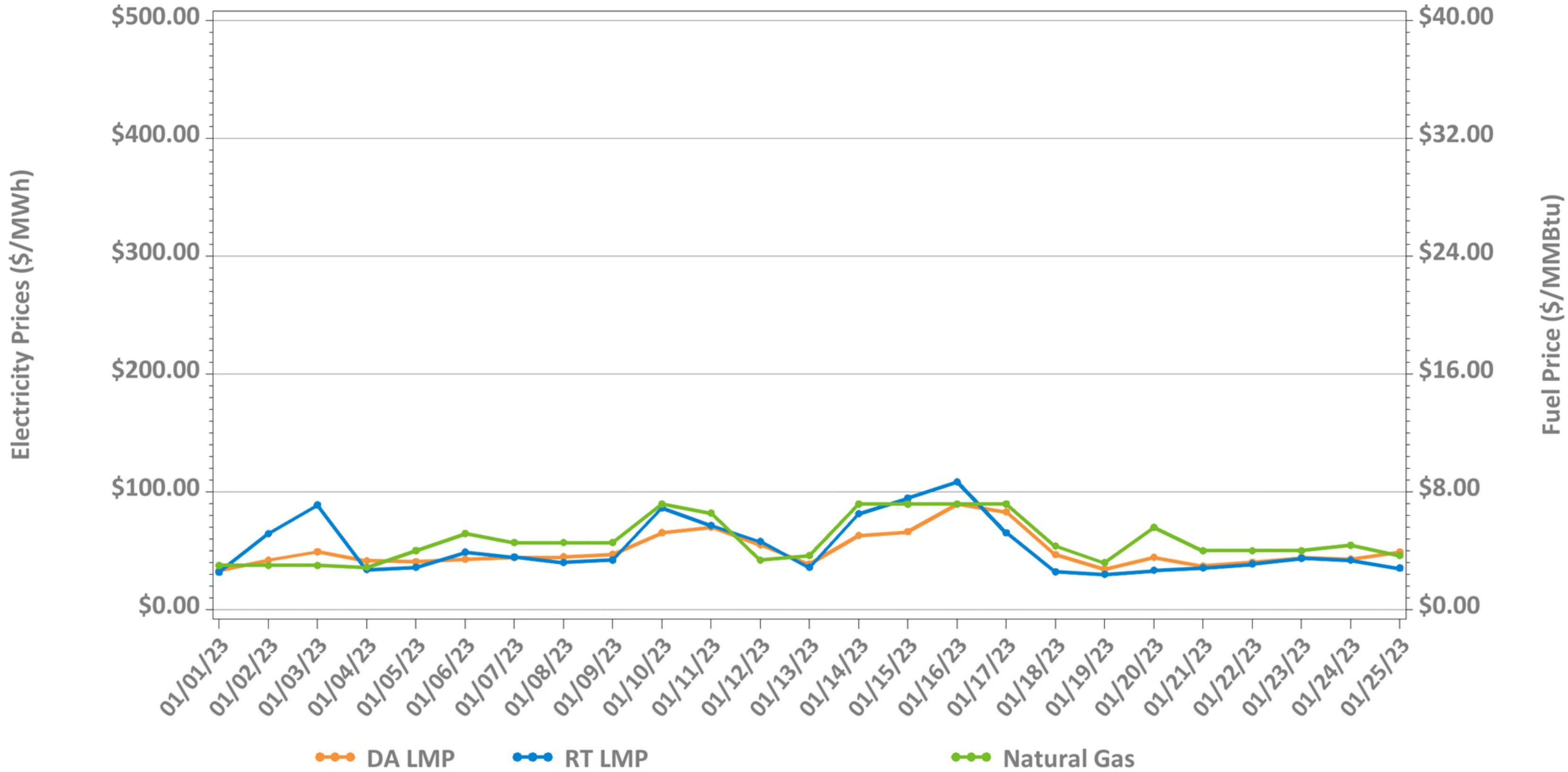


Yearly Fleet Performance targets

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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: January 1-25, 2023

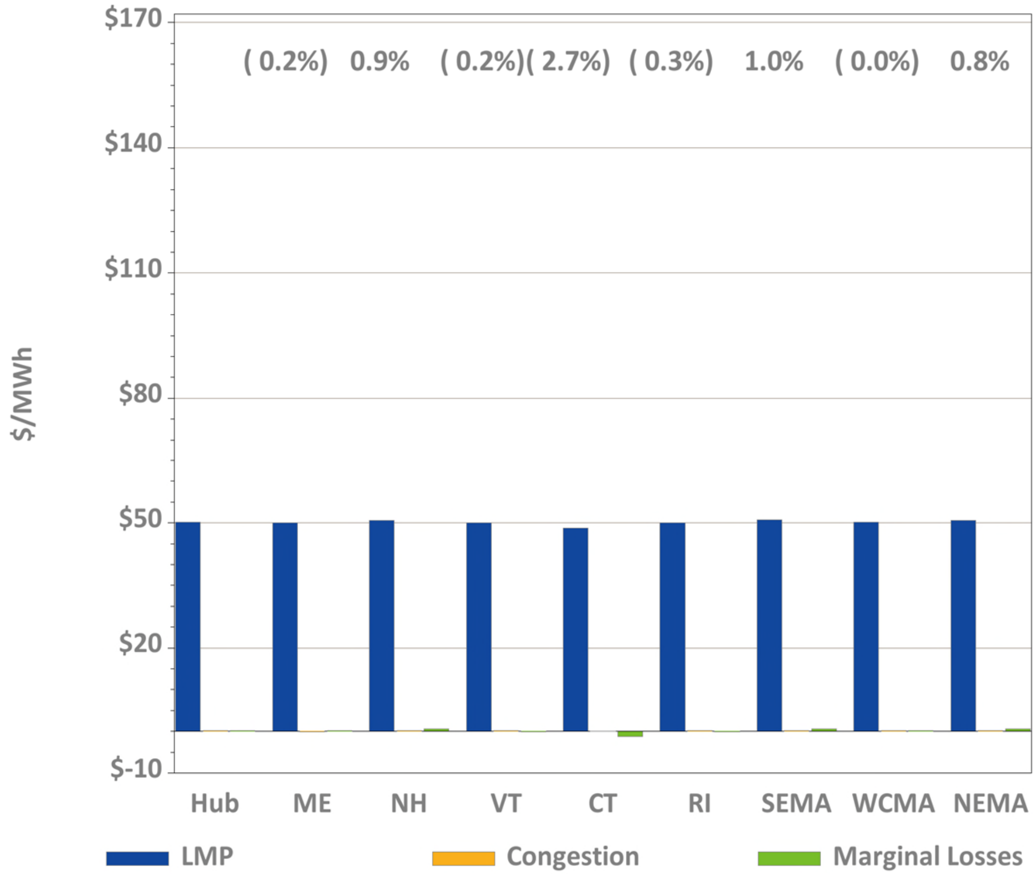


Underlying natural gas data furnished by:

ICE Global markets in clear view

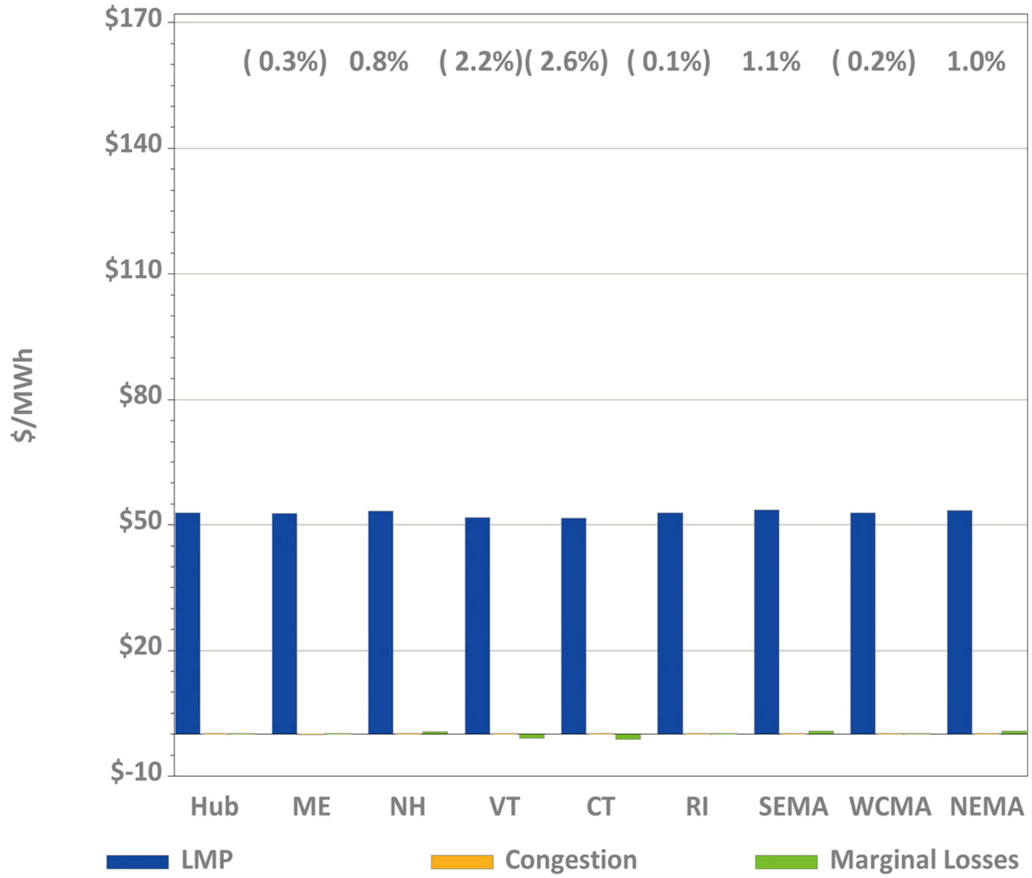
Average price difference over this period (DA-RT): $-2.73
Average price difference over this period ABS(DA-RT): $10.06
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, January 2023



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

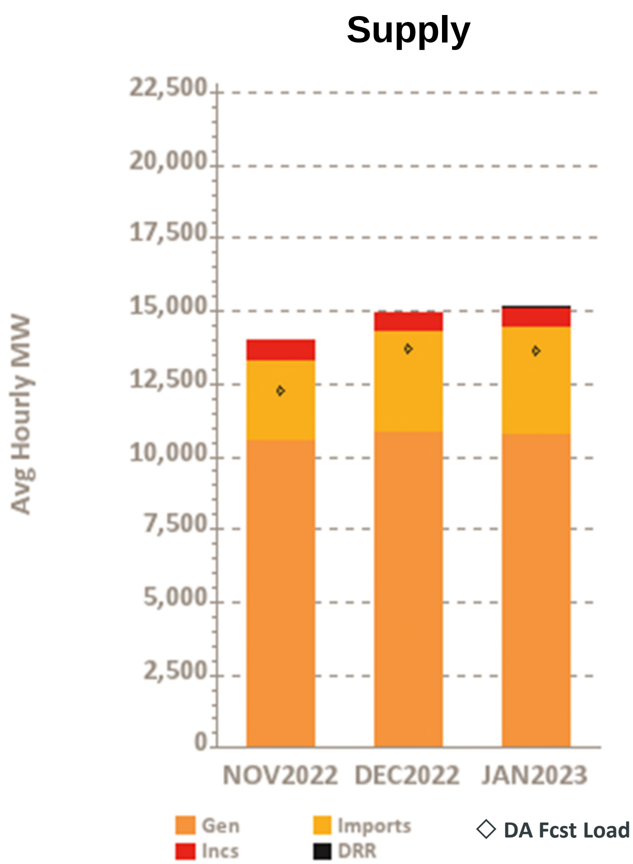
RT LMPs Average by Zone & Hub, January 2023

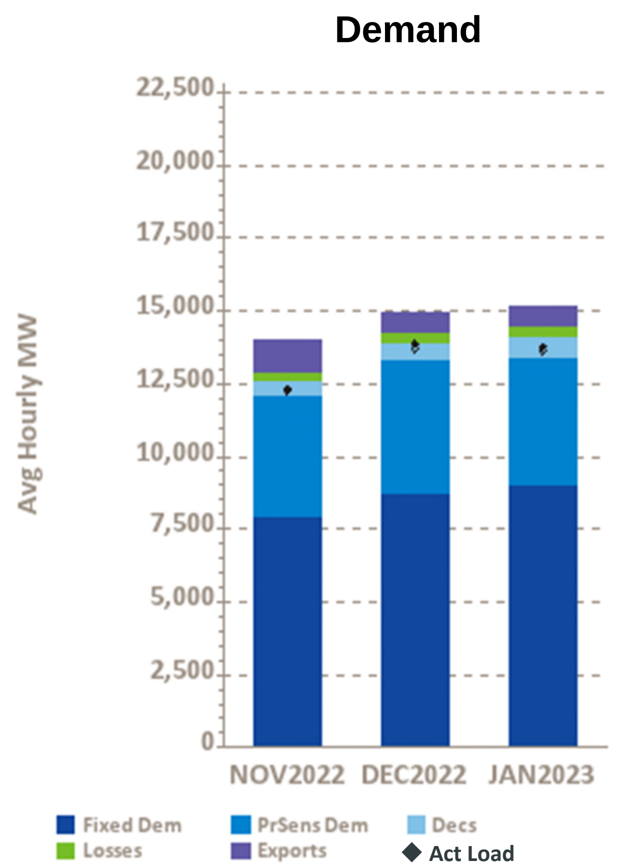


Definitions

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

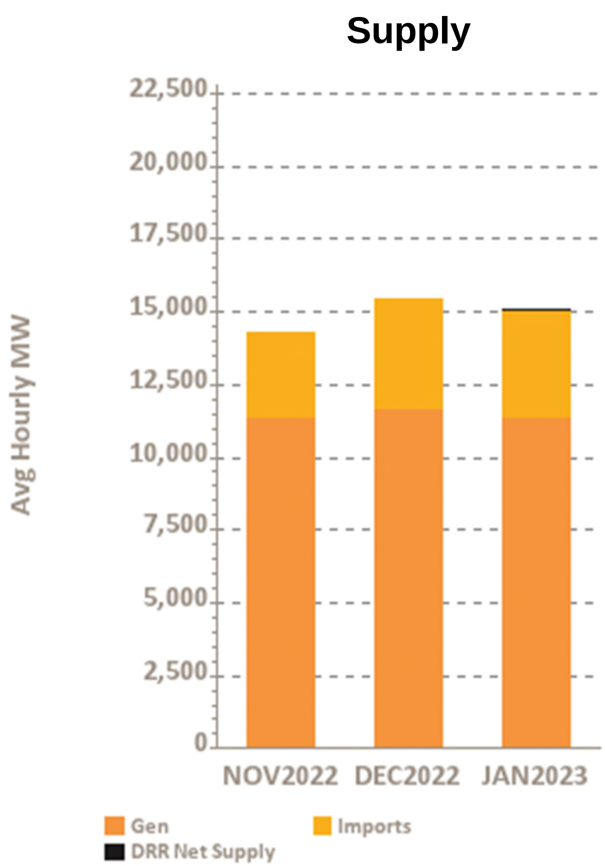


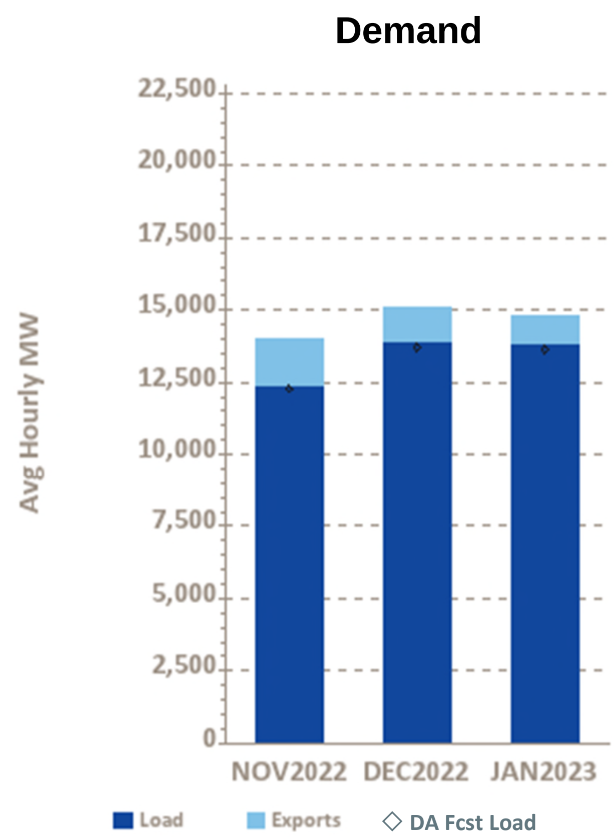


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

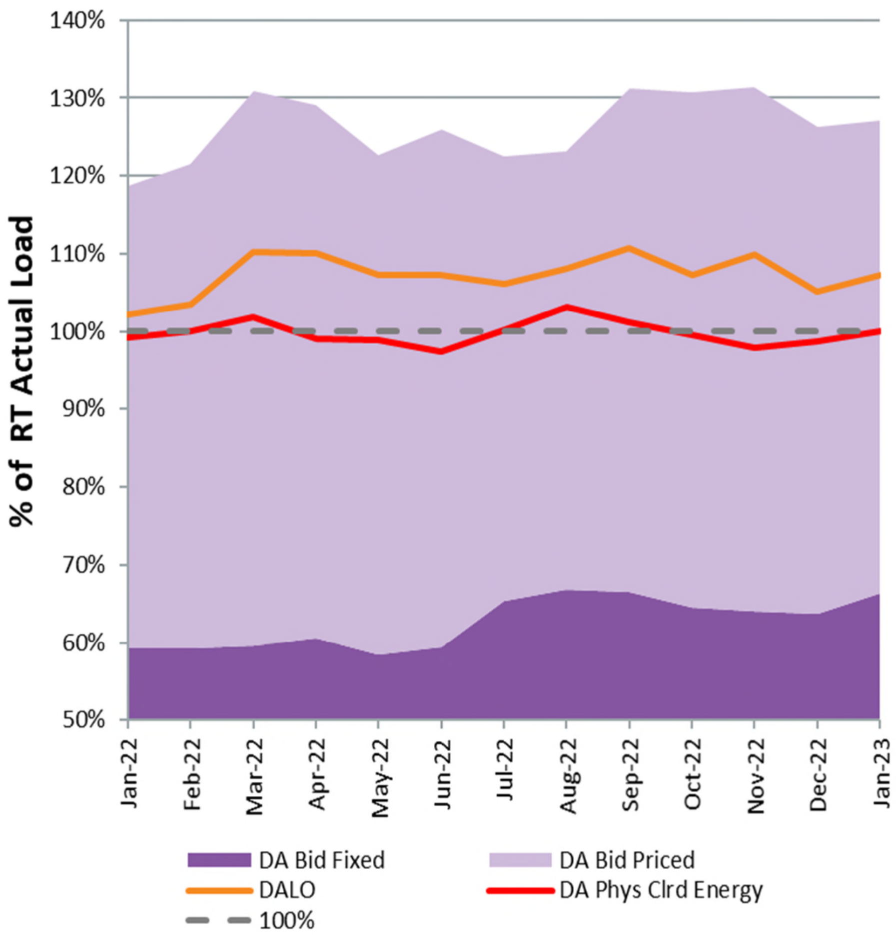
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

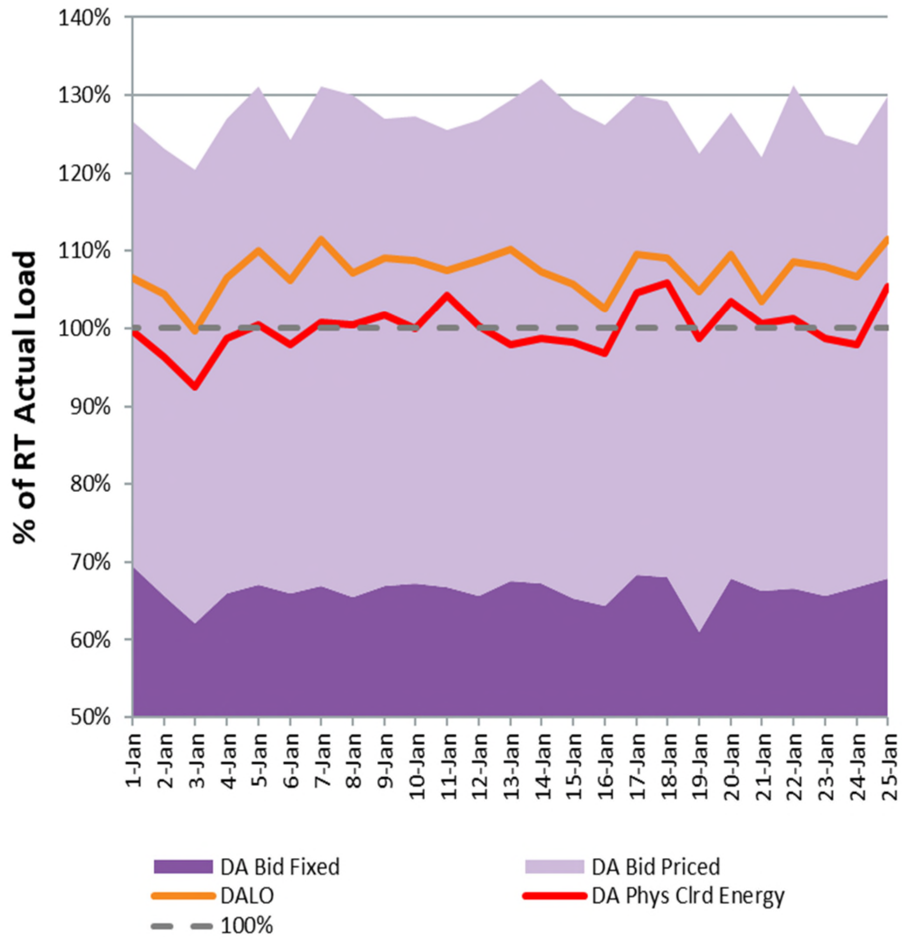
Components of RT Supply and Demand – Last Three Months





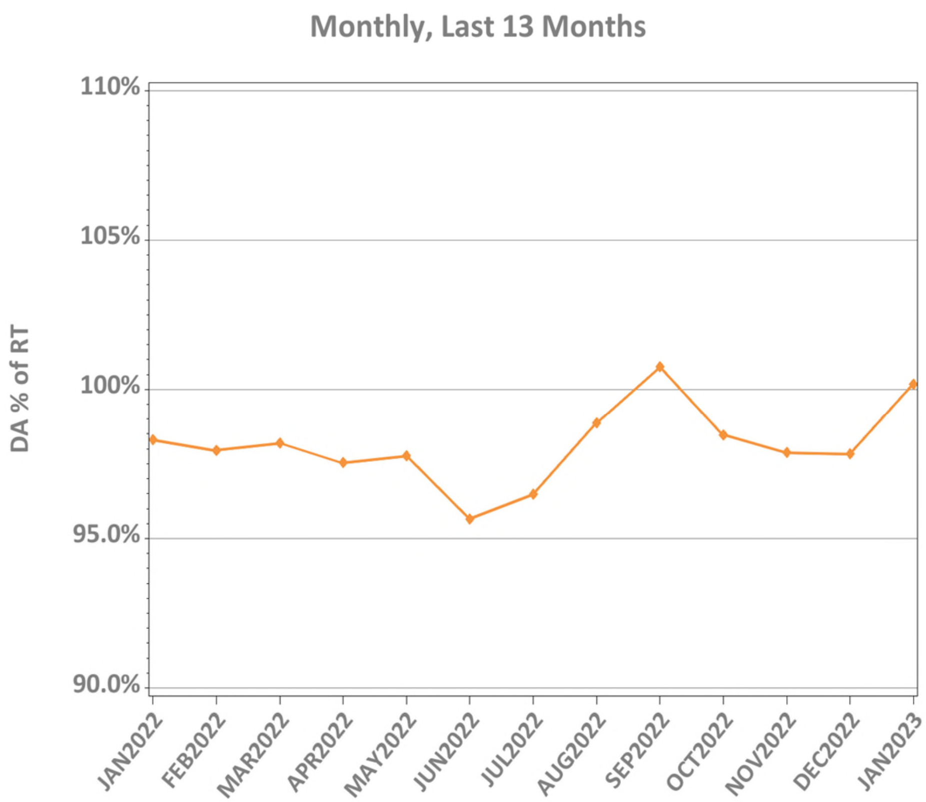
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

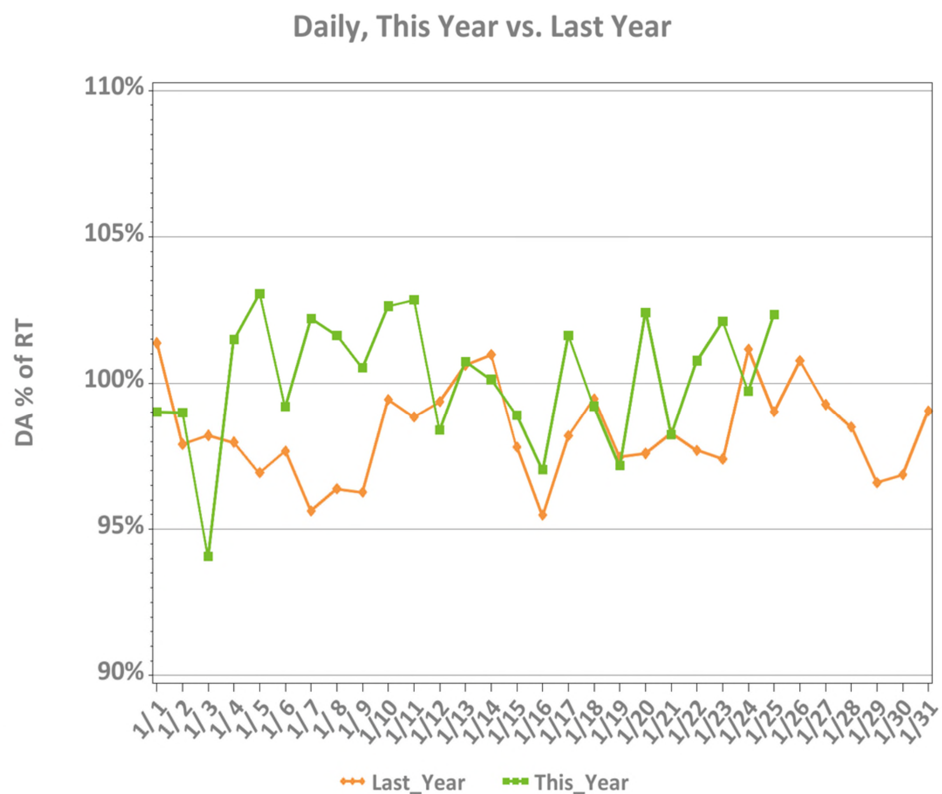




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

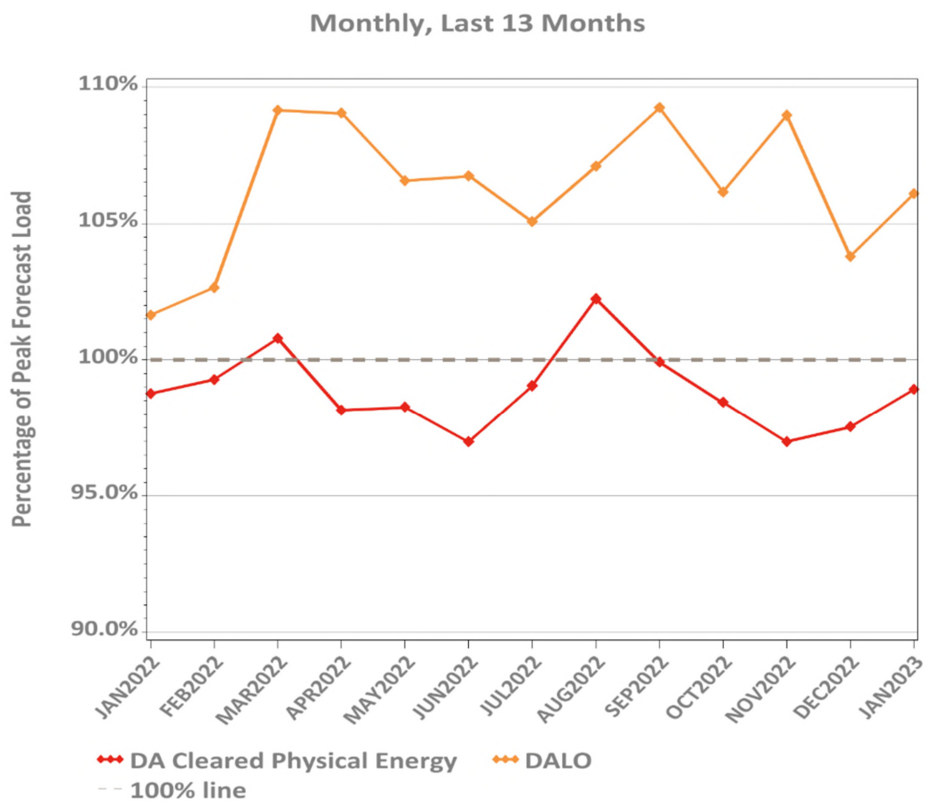
DA vs. RT Load Obligation: January, This Year vs. Last Year

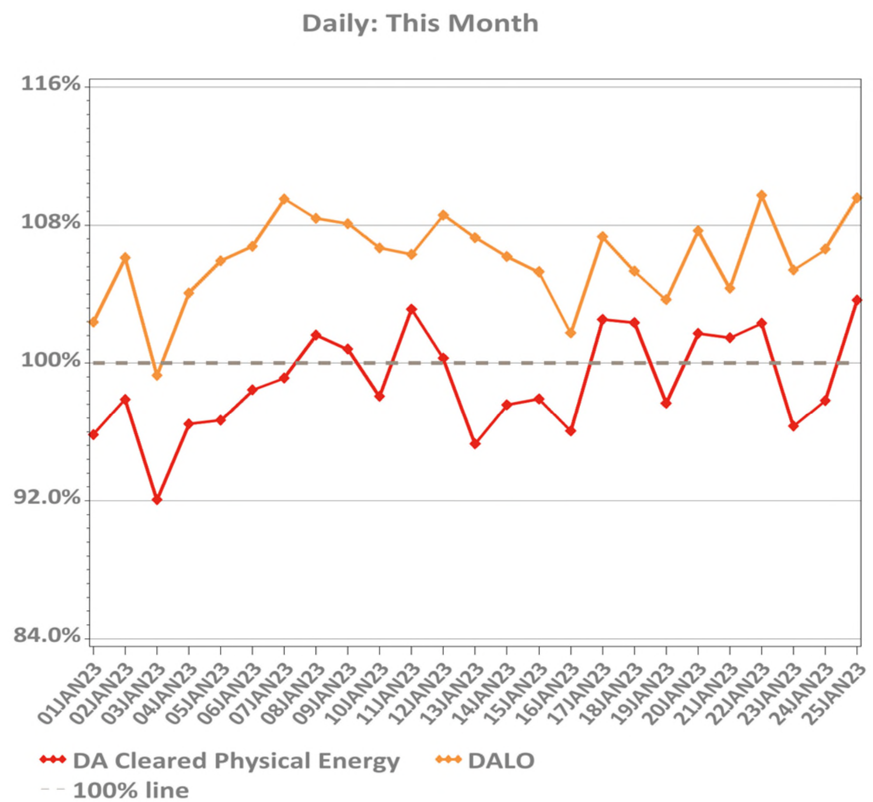




*Hourly average values

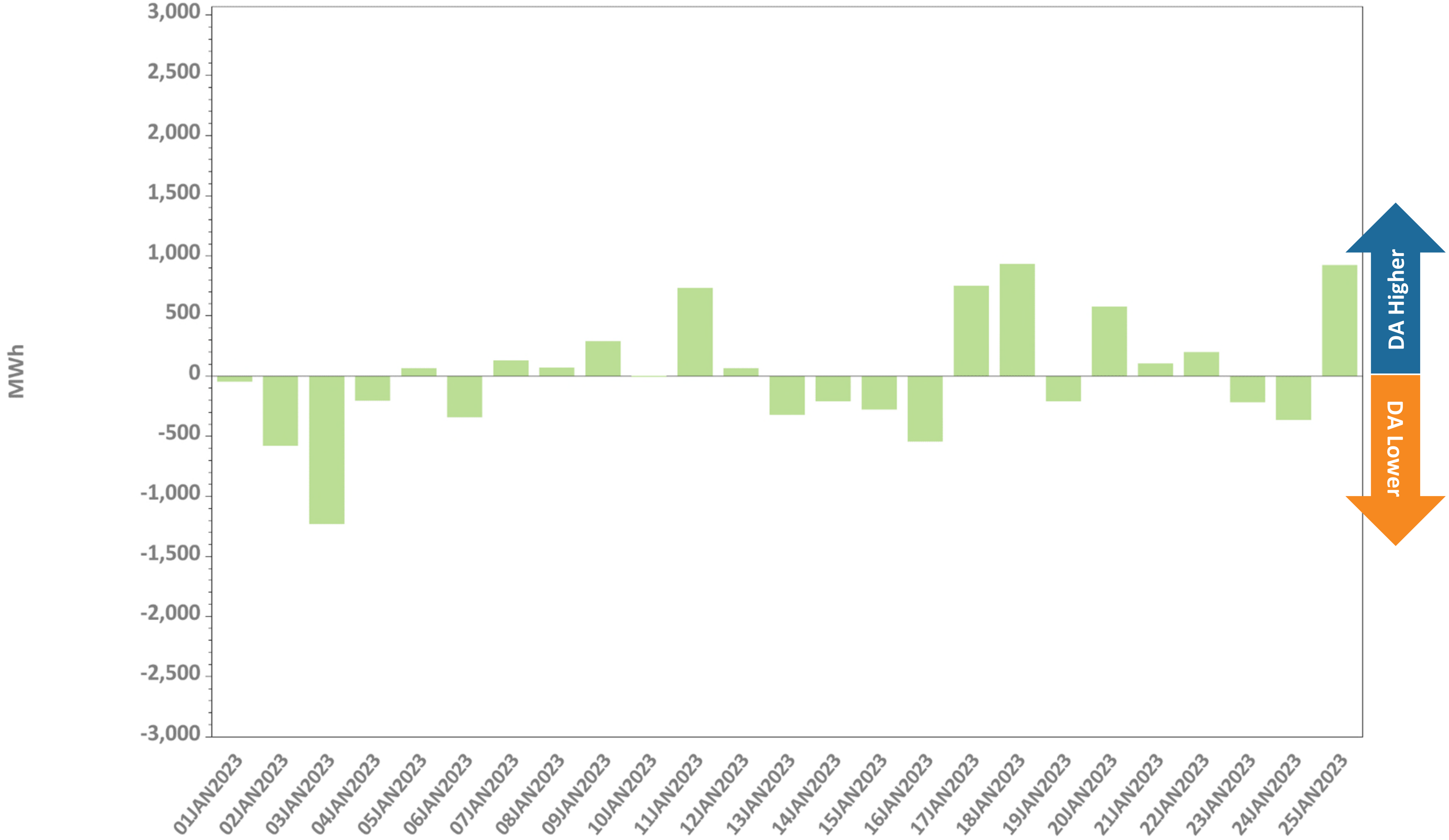
DA Volumes as % of Forecast in Peak Hour





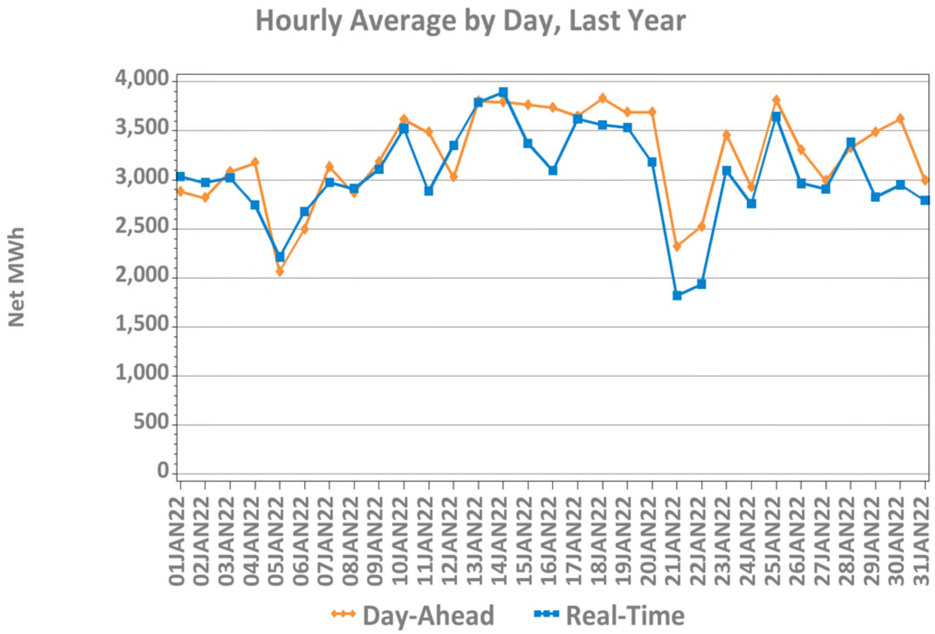
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

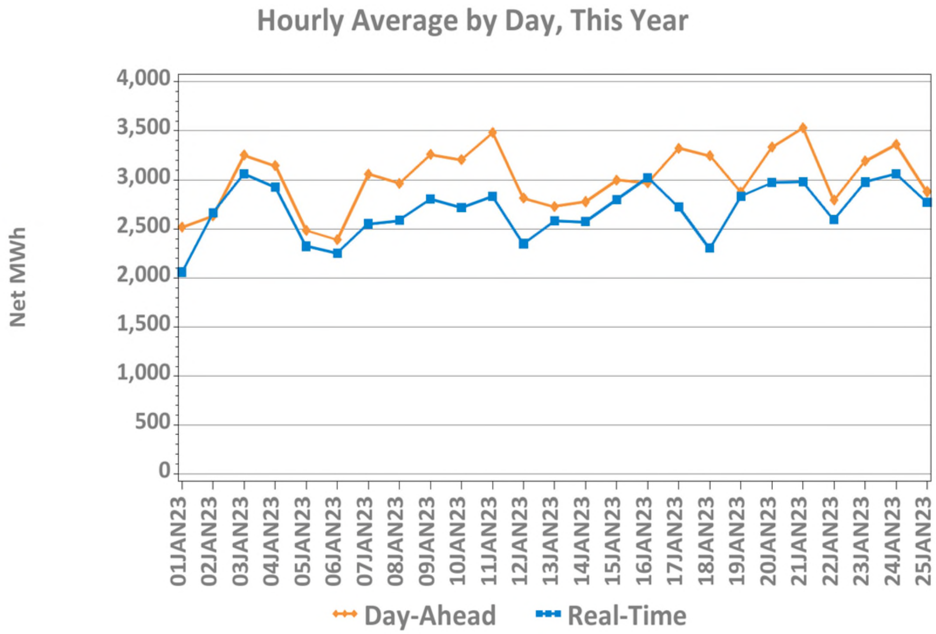
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

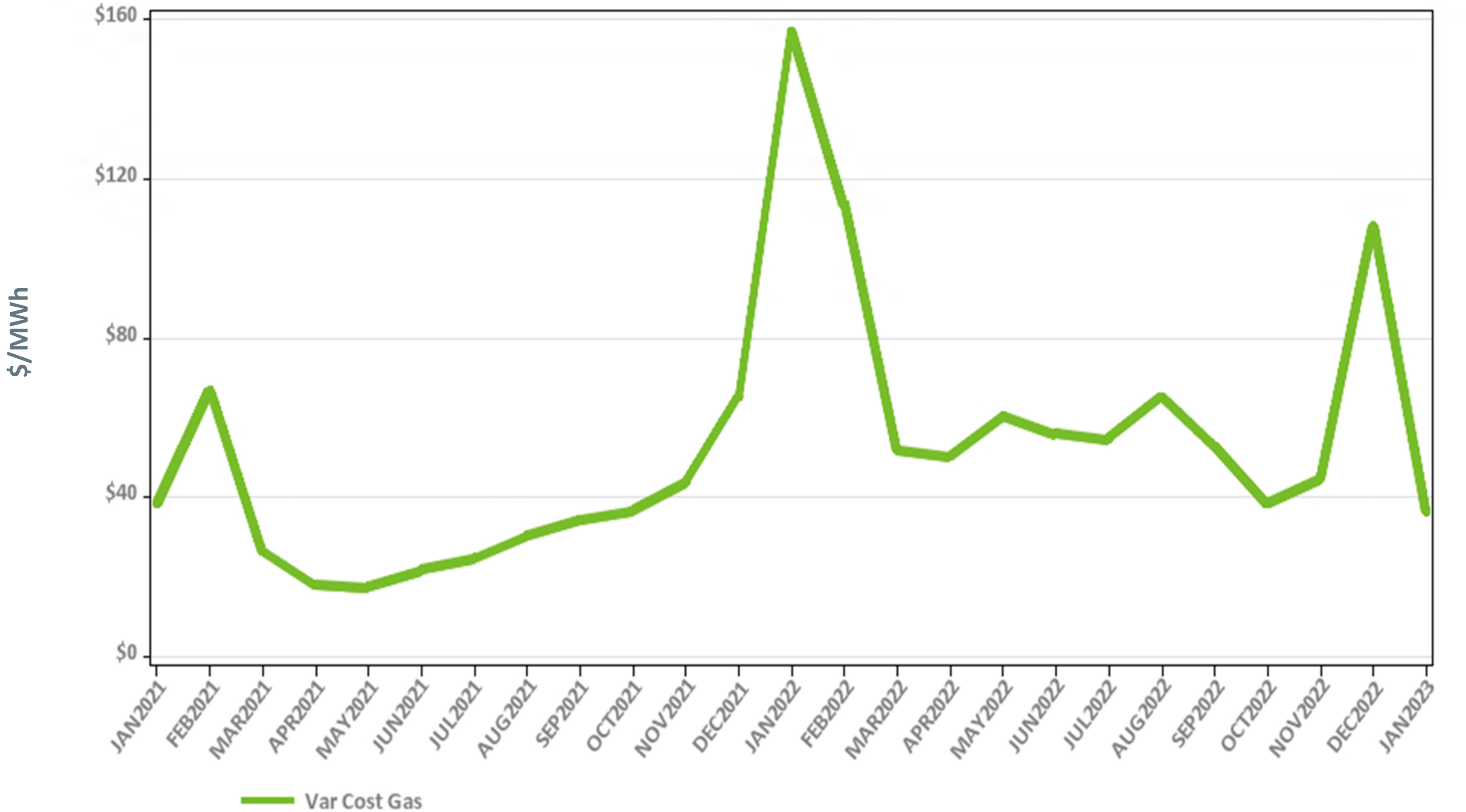
DA vs. RT Net Interchange January 2023 vs. January 2022





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

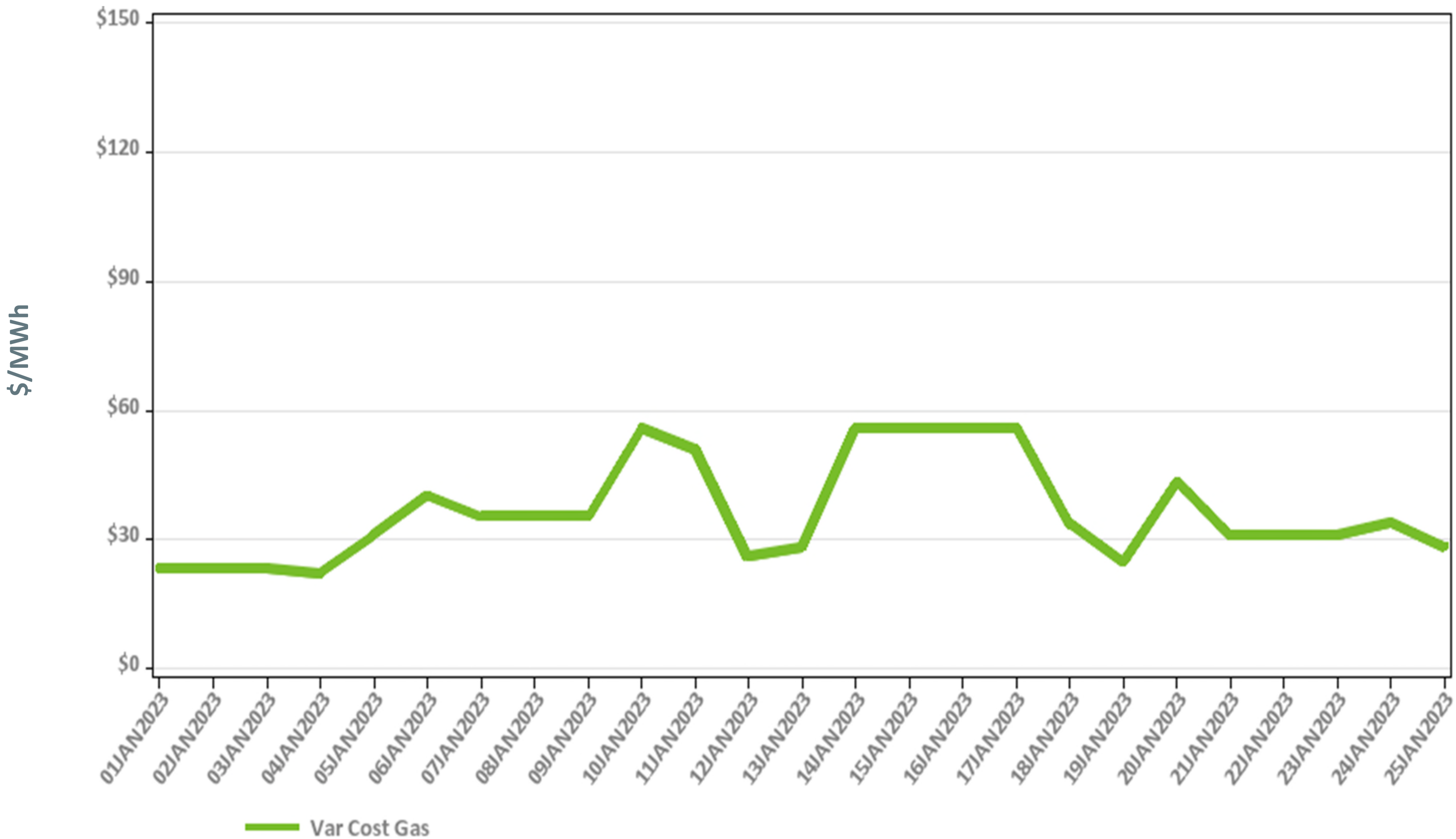


Underlying natural gas data furnished by:

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

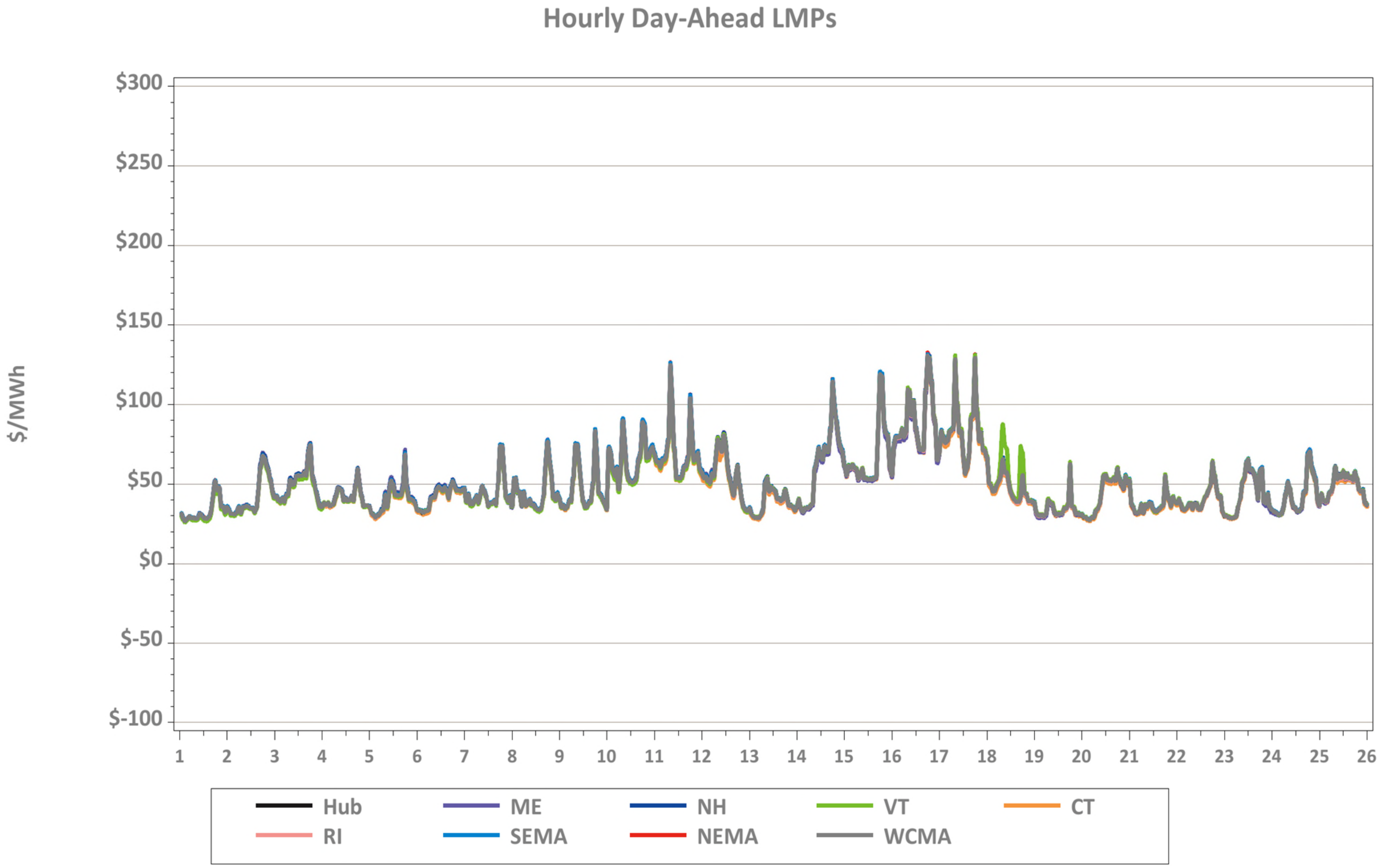


Underlying natural gas data furnished by:

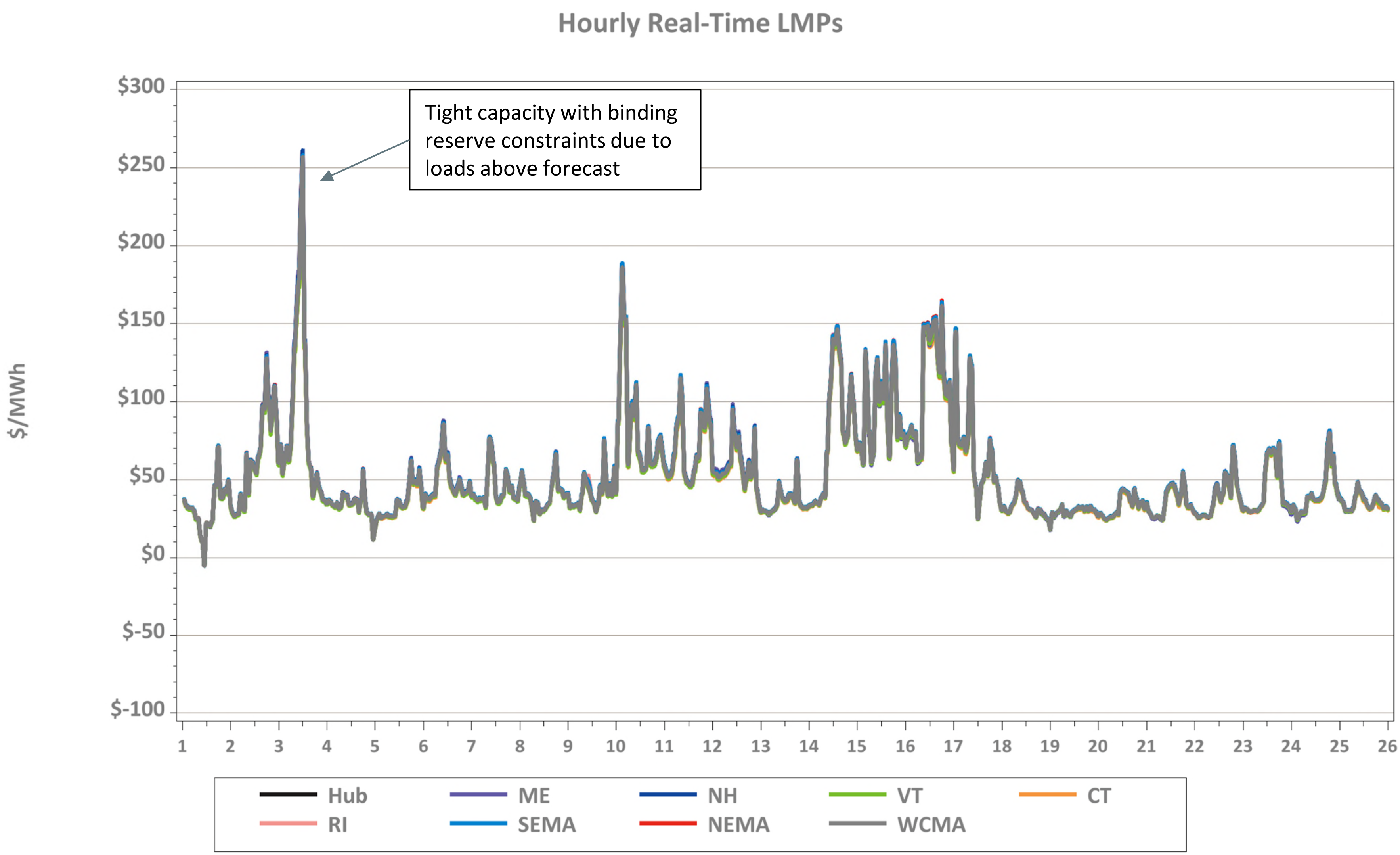
ICE Global markets in clear view

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

Hourly DA LMPs, January 1-25, 2023

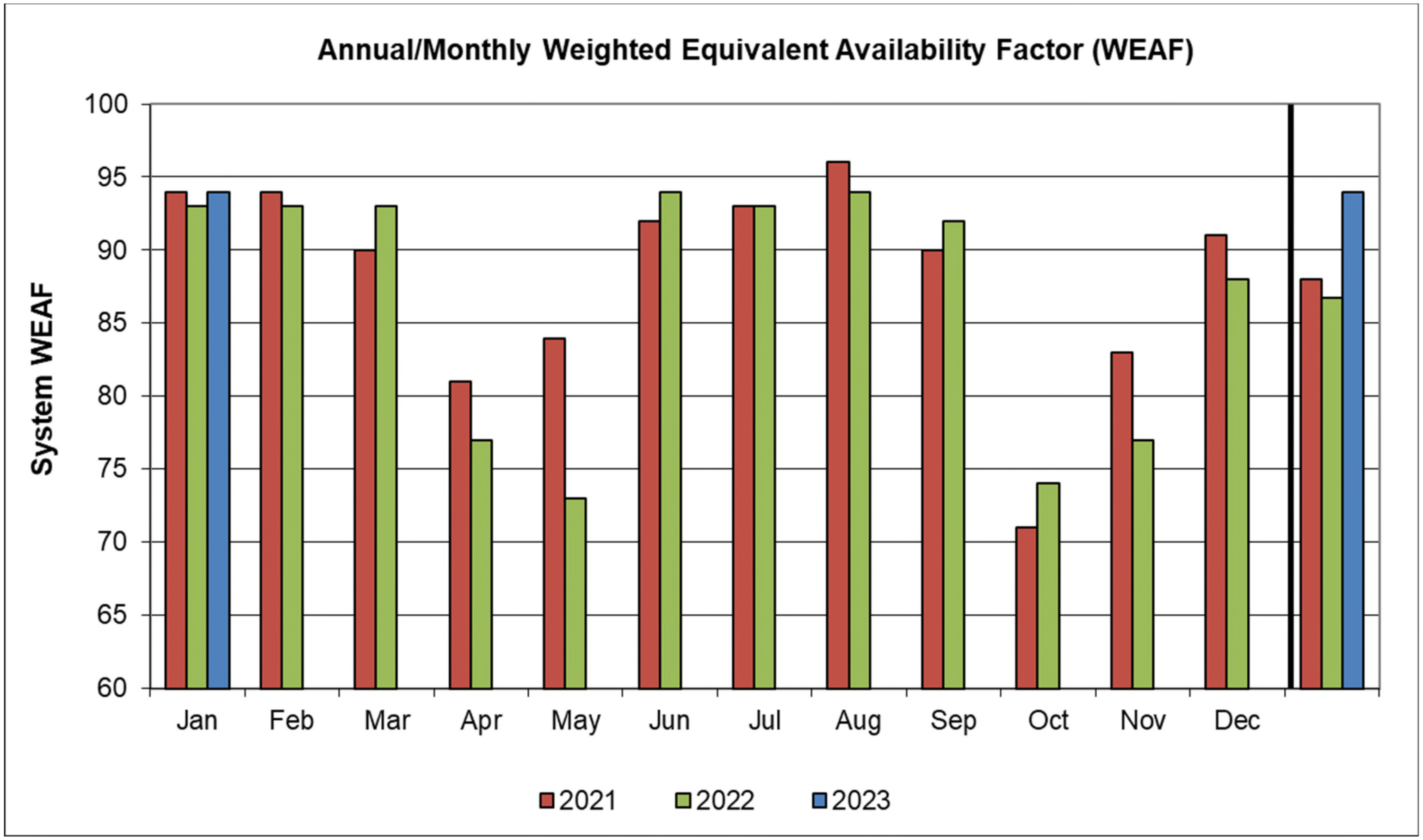


Hourly RT LMPs, January 1-25, 2023



* Telemetered load is referenced

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94												94
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 1/25/2023

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	89.1	181.6	0.0	270.6
NH	32.7	180.0	0.0	212.6
VT	44.7	164.7	0.0	209.4
CT	78.2	110.9	687.4	876.5
RI	19.8	342.9	0.0	362.7
SEMA	35.2	494.1	0.0	529.2
WCMA	64.8	535.4	14.4	614.7
NEMA	46.9	840.9	0.0	887.8
Total	**411.2**	**2,850.5**	**701.8**	**3,963.6**

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

NEW GENERATION

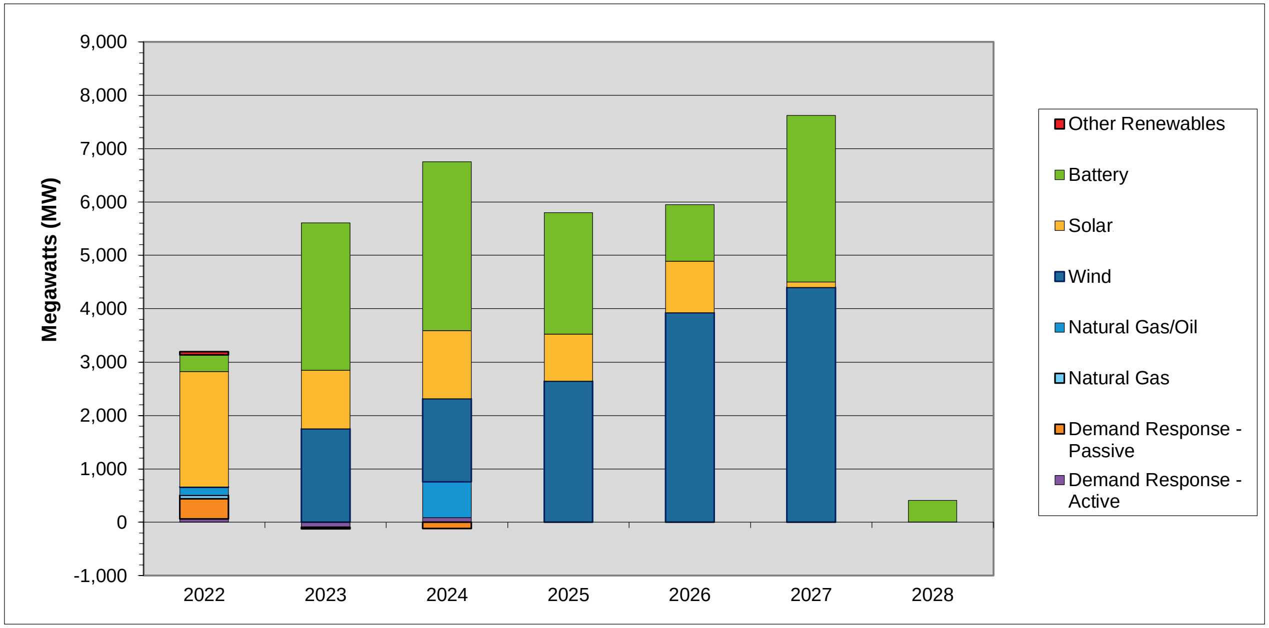
New Generation Update

Based on Queue as of 1/30/23

- Five projects totaling 300 MW were added to the interconnection queue since the last update
  - Three battery projects and two solar-with-battery projects with in-service dates of 2024 to 2026
- No projects were withdrawn and one project went commercial
- In total, 364 generation projects are currently being tracked by the ISO, totaling approximately 37,677 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type

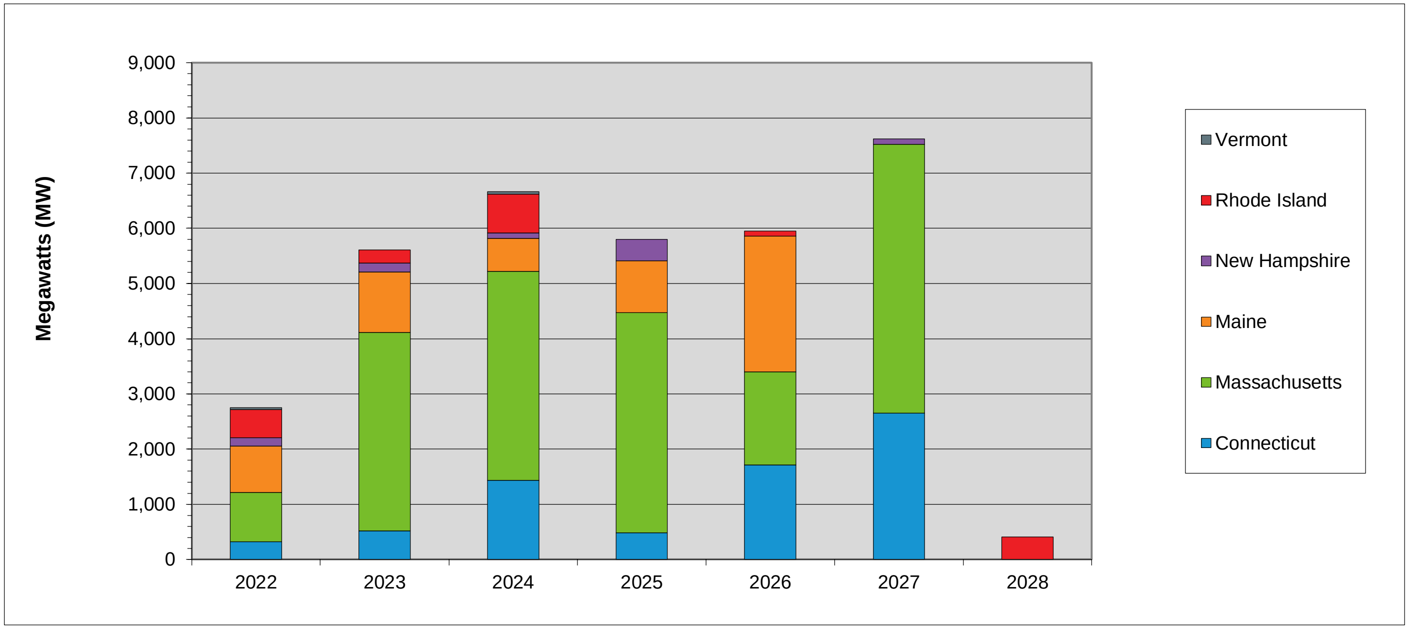


	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	63	0	0	0	0	0	0	63	0.2
Battery	305	2,756	3,163	2,276	1,062	3,122	410	13,094	37.3
Solar[2]	2,162	1,098	1,277	878	964	102	0	6,481	18.5
Wind	4	1,752	1,556	2,645	3,923	4,399	0	14,279	40.7
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.3
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	3,194	5,484	6,640	5,799	5,949	7,623	410	35,099	100.0

[1] Sum may not equal 100% due to rounding
[2] This category includes both solar-only, and co-located solar and battery projects
[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

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

Actual and Projected Annual Generator Capacity Additions
By State



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	40	0	50	0	0	0	0	90	0.3
Rhode Island	502	236	704	0	91	0	410	1,943	5.6
New Hampshire	156	164	97	385	0	102	0	904	2.6
Maine	838	1,092	597	942	2,461	0	0	5,930	17.0
Massachusetts	893	3,594	3,786	3,989	1,686	4,873	0	18,821	54.1
Connecticut	323	520	1,434	483	1,711	2,648	0	7,119	20.5
Totals	**2,752**	**5,606**	**6,668**	**5,799**	**5,949**	**7,623**	**410**	**34,807**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	84	13,094	3	32	81	13,062
Fuel Cell	2	30	0	0	2	30
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	238	6,481	18	401	220	6,080
Wind	26	17,149	0	0	26	17,149
Total	364	37,677	23	500	341	37,177

- 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

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	70	1	5	4	65
Intermediate	7	804	0	0	7	804
Peaker	326	19,654	22	495	304	19,159
Wind Turbine	26	17,149	0	0	26	17,149
Total	364	37,677	23	500	341	37,177

- 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	84	13,094	0	0	0	0	84	13,094	0	0
Fuel Cell	2	30	2	30	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	238	6,481	0	0	0	0	238	6,481	0	0
Wind	26	17,149	0	0	0	0	0	0	26	17,149
Total	364	37,677	5	70	7	804	326	19,654	26	17,149

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 13

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

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

Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	592.043	688.07	96.027	659.671	-28.399		
	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 beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272				
	Passive Demand	3,212.865	3,211.403	-1.462				
Demand Total		**3,890.538**	**3,884.804**	**-5.734**				
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425				
	Intermittent	1,089.265	1,073.794	-15.471				
Generator Total		**29,243.468**	**28,788.572**	**-454.896**				
Import Total		**1,487.059**	**1297.132**	**-189.927**				
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**				
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**				

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35						
	Passive Demand	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
	Intermittent	1,178.933						
Generator Total		**27,983.936**						
Import Total		**1,503.842**						
Grand Total*		**32,810.384**						
Net ICR (NICR)		**31,645**						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

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

What are Daily NCPC Payments?

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

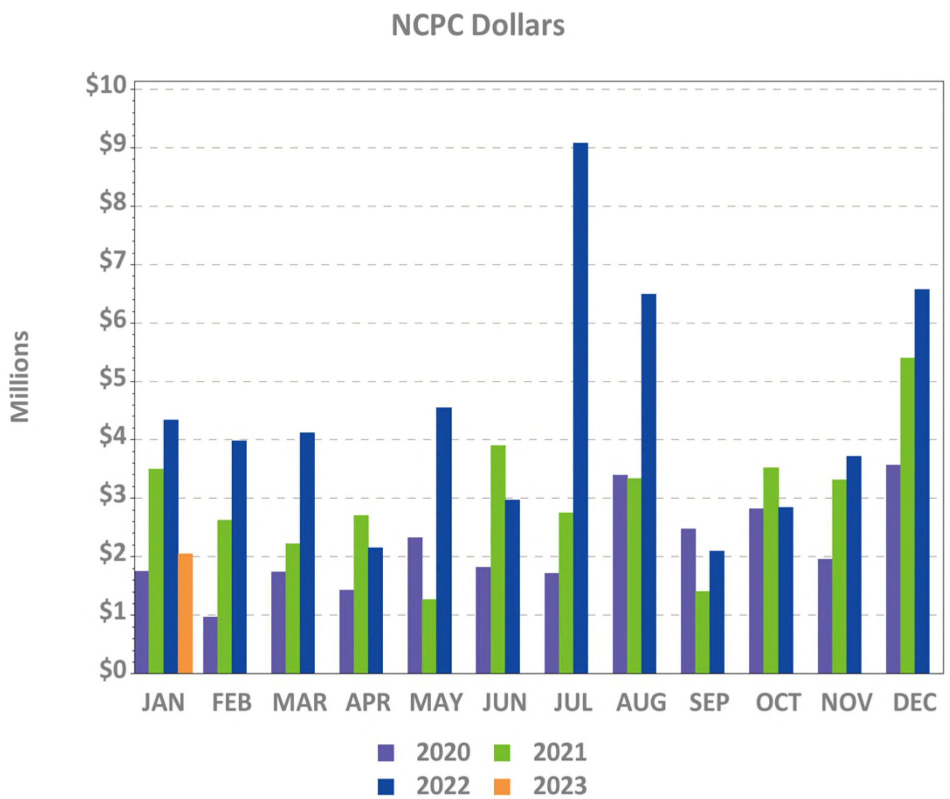
Definitions

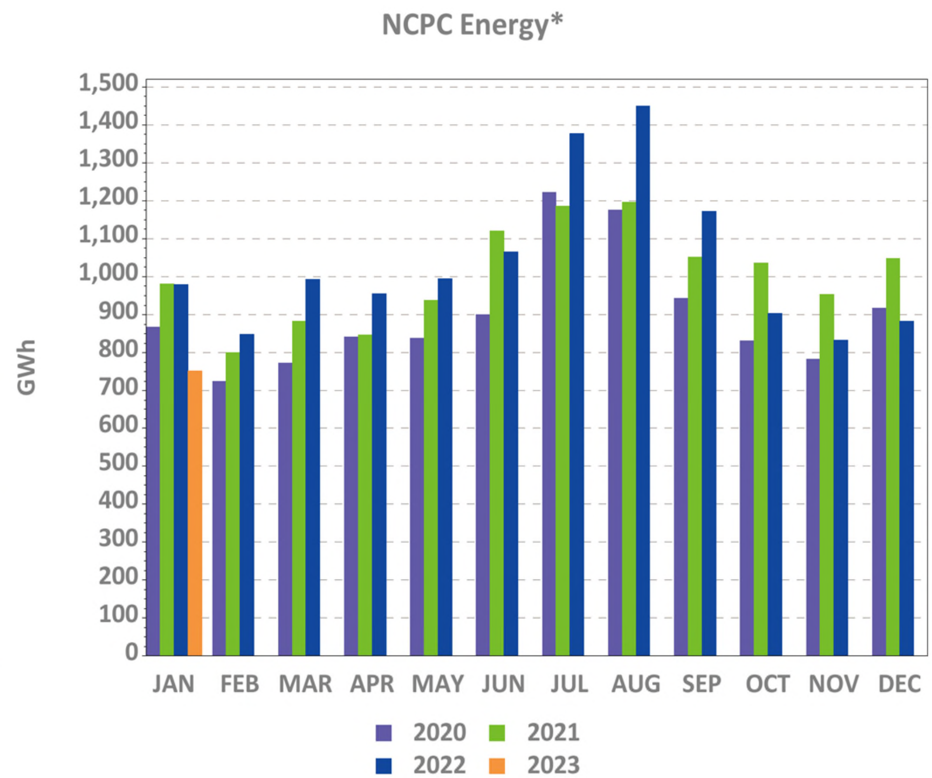
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

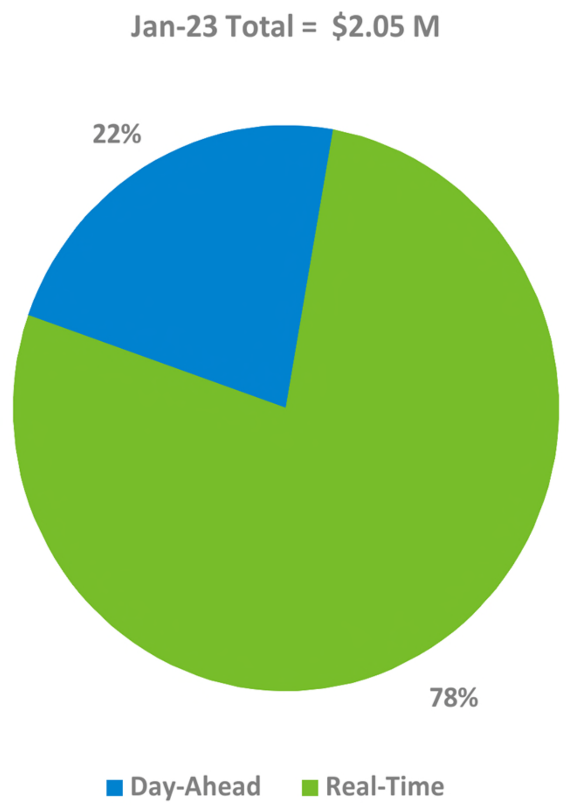
Year-Over-Year Total NCPC Dollars and Energy

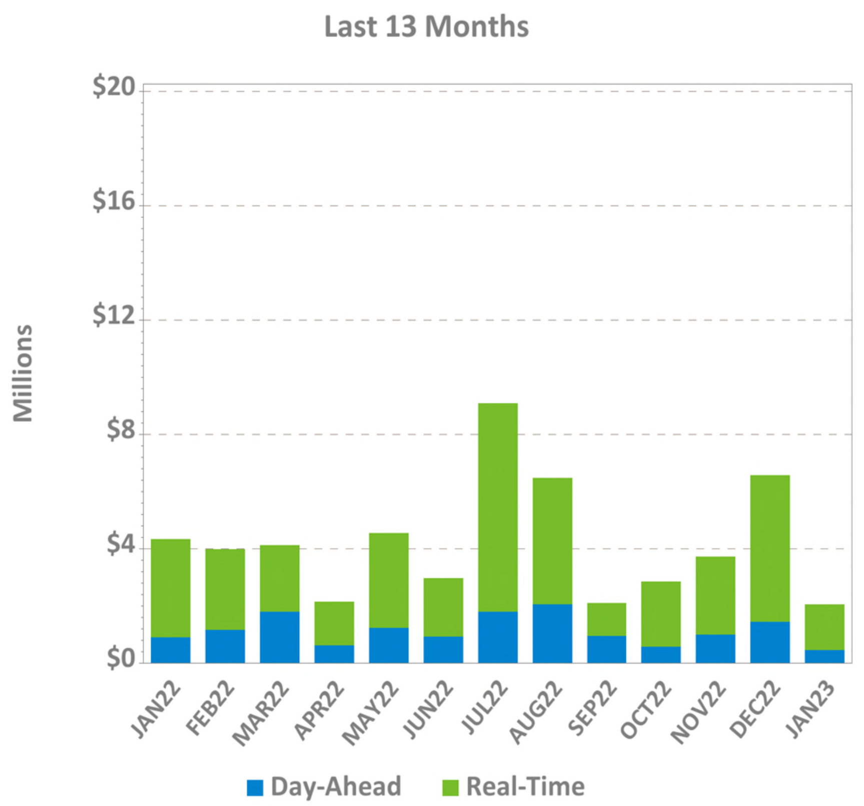




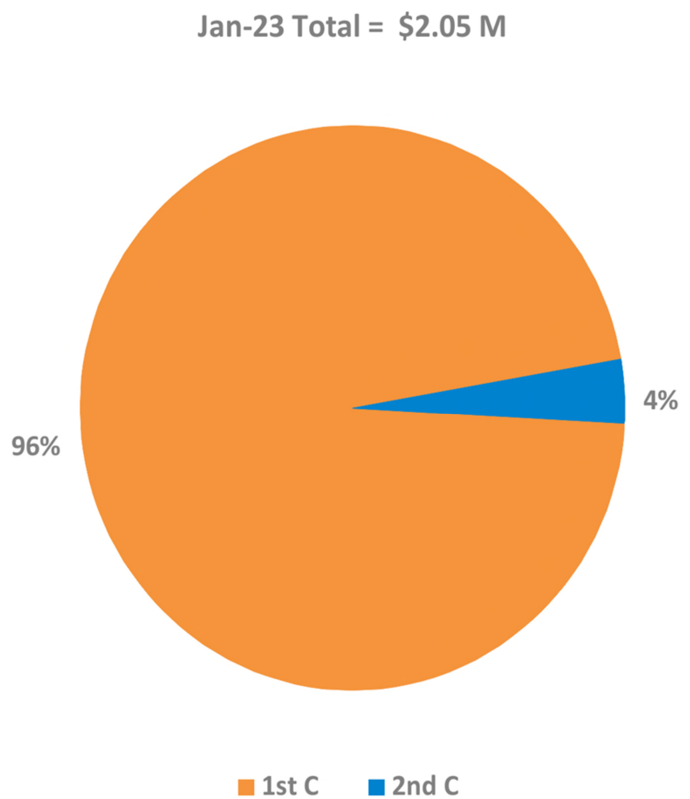
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

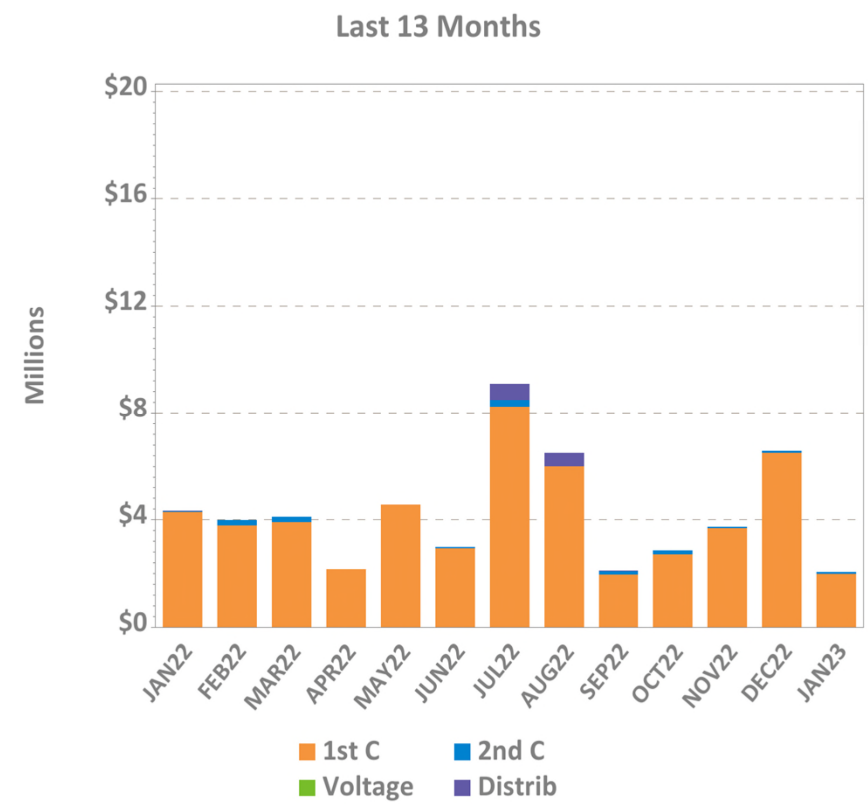
DA and RT NCPC Charges





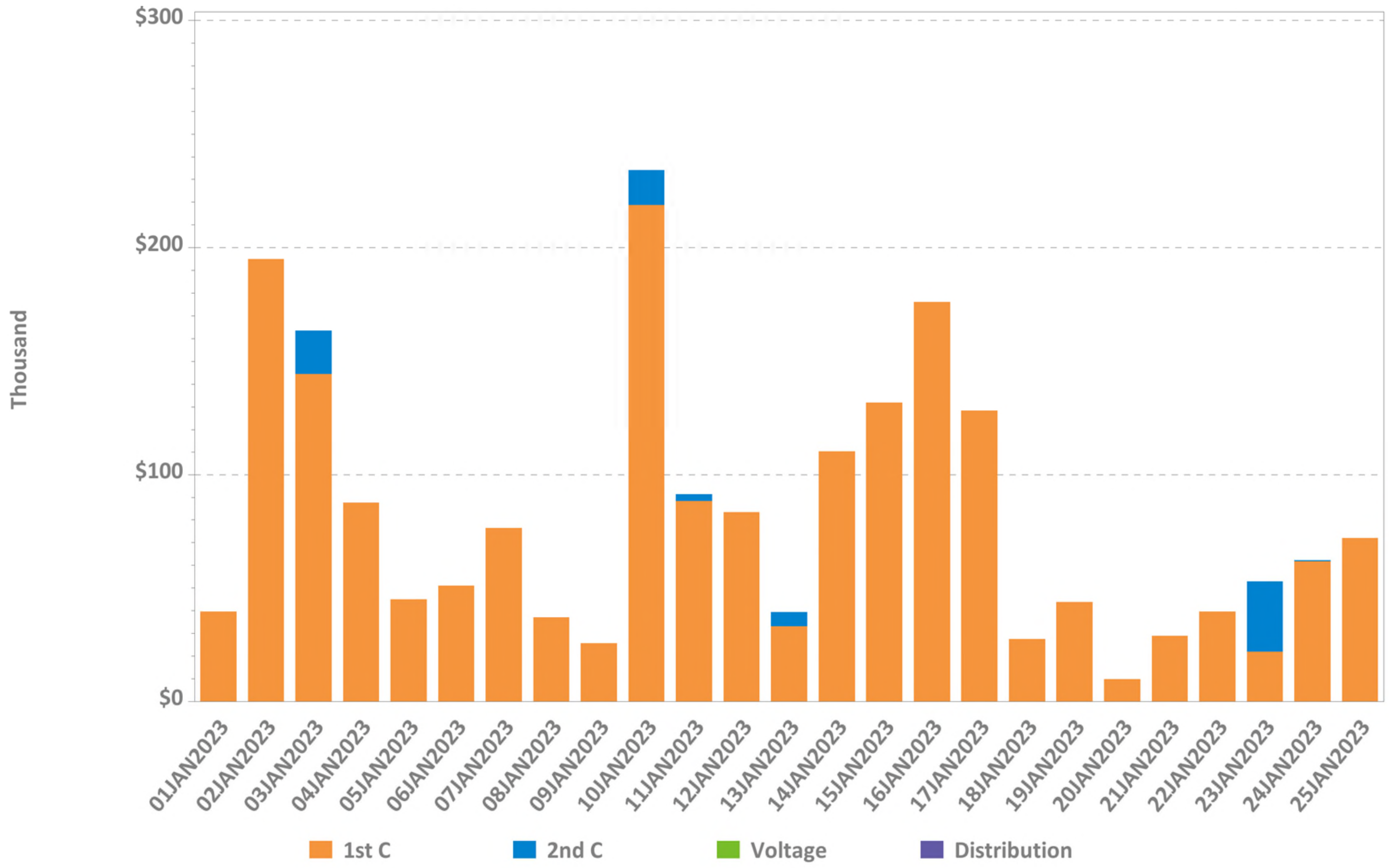
NCPC Charges by Type



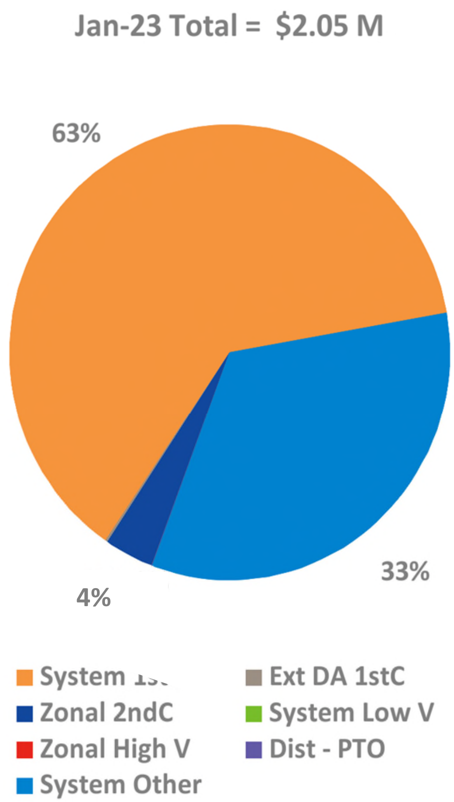


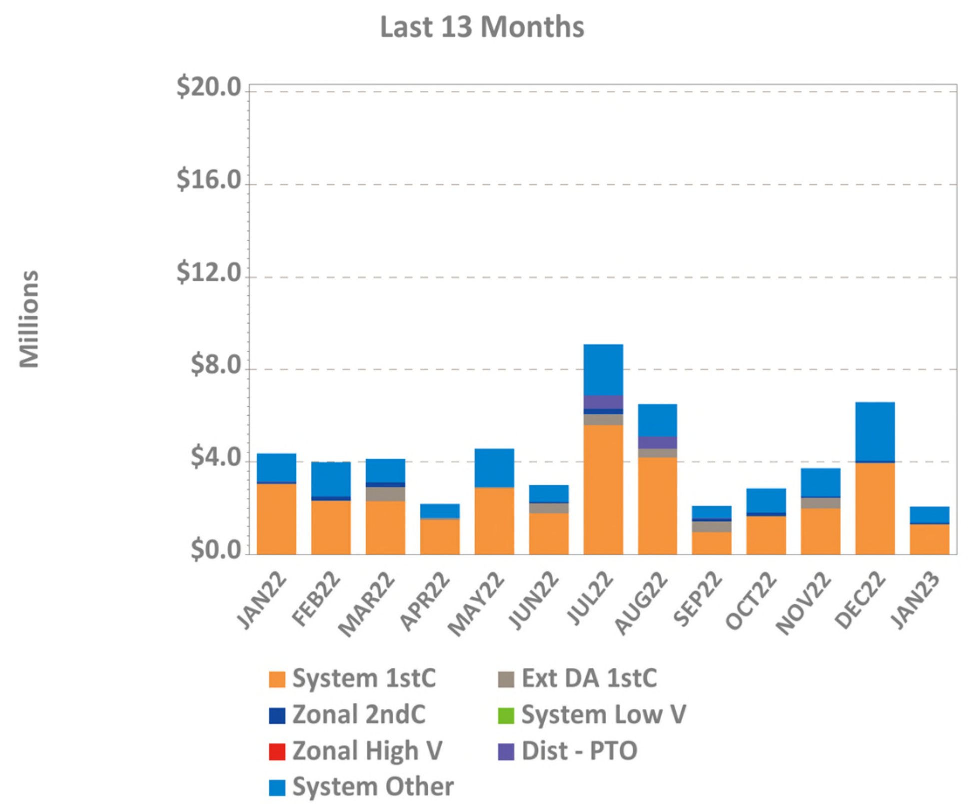
1^{st} **C – First Contingency**
2^{nd} **C – Second Contingency**
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



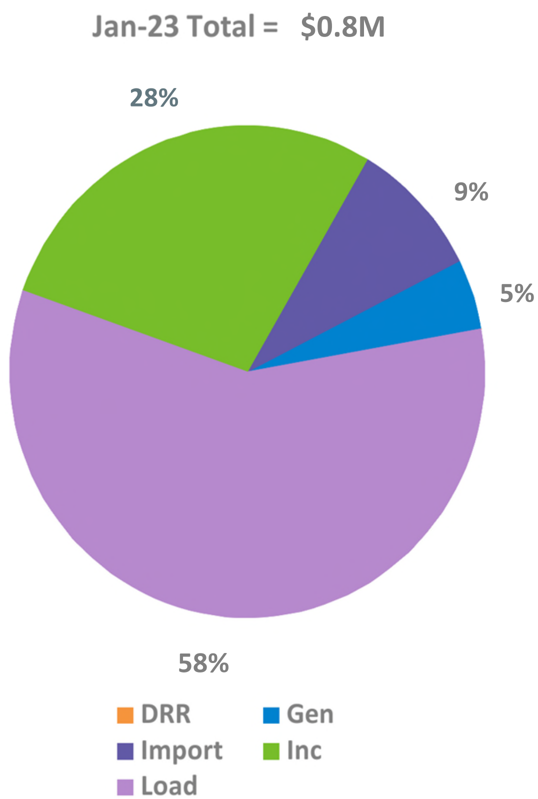
NCPC Charges by Allocation

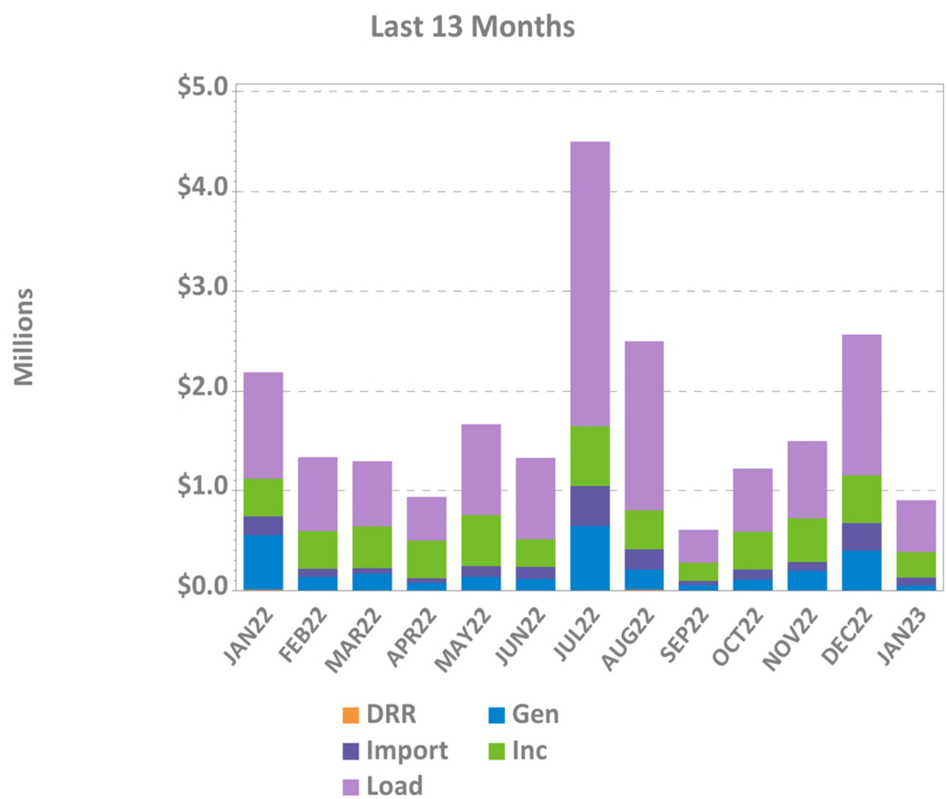




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

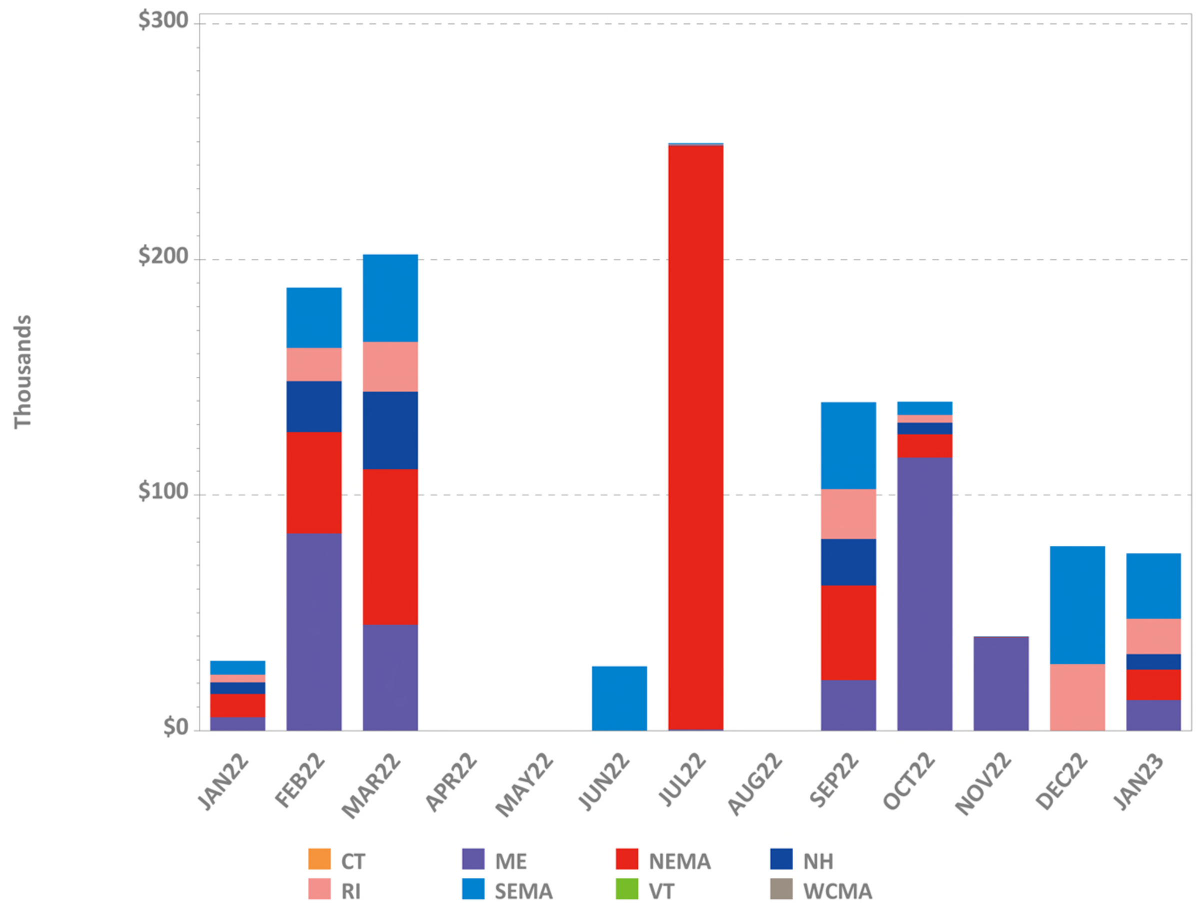
RT First Contingency Charges by Deviation Type





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

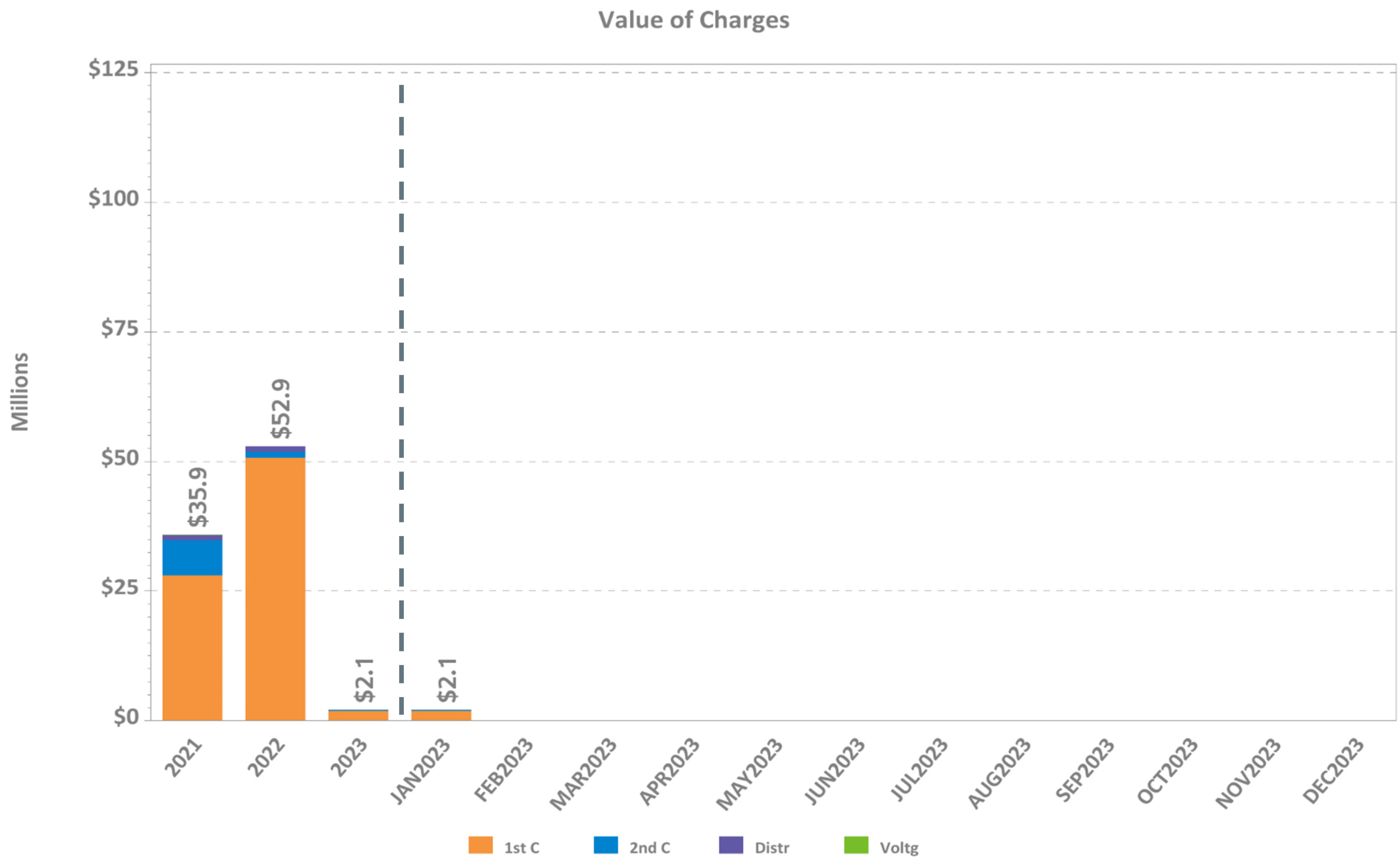
LSCPR Charges by Reliability Region



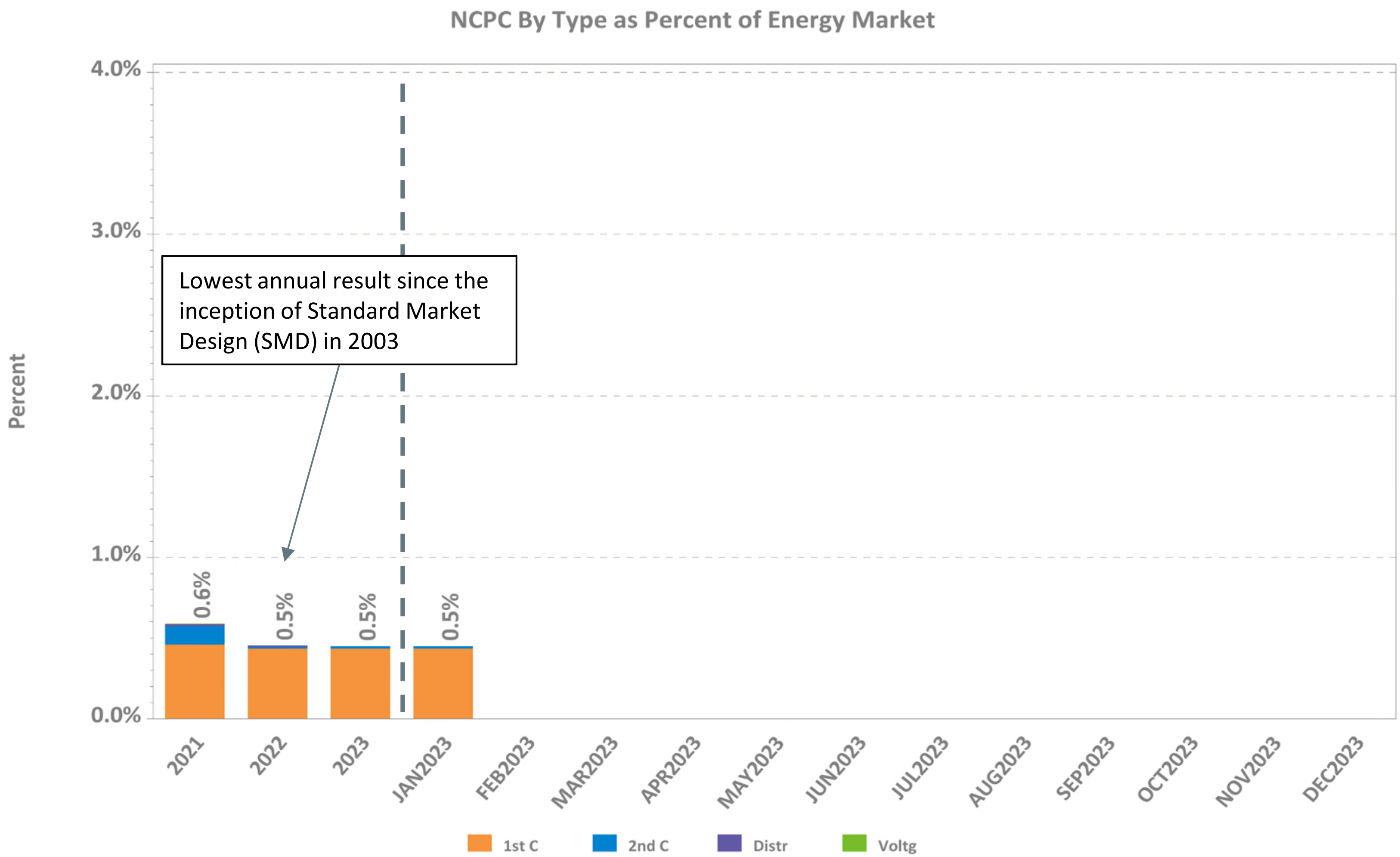
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

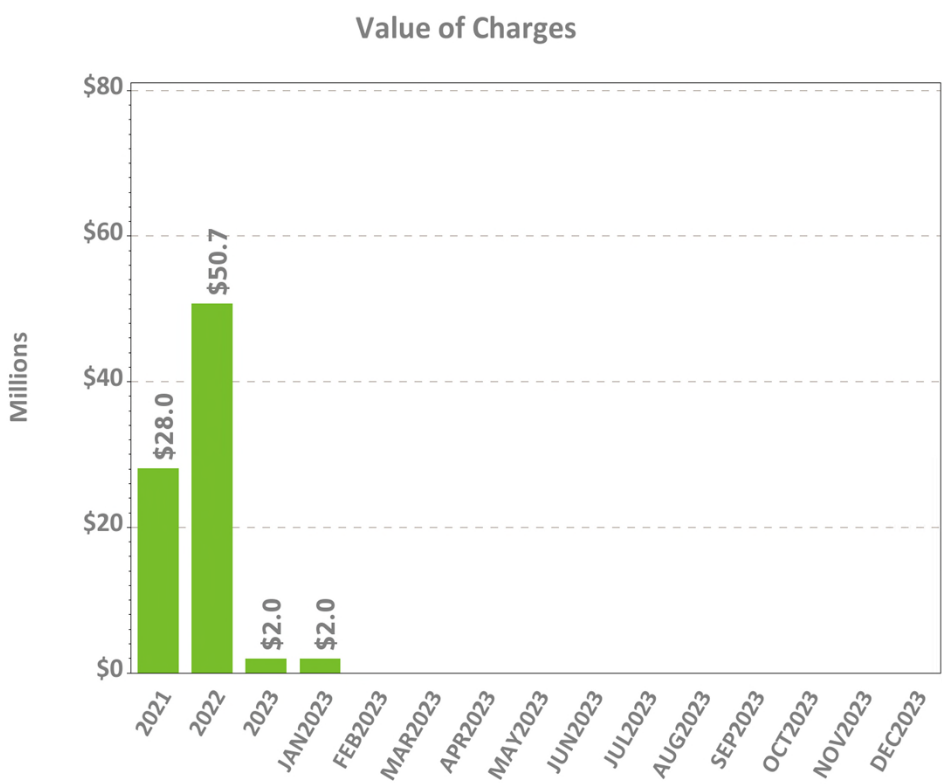
NCPC Charges by Type

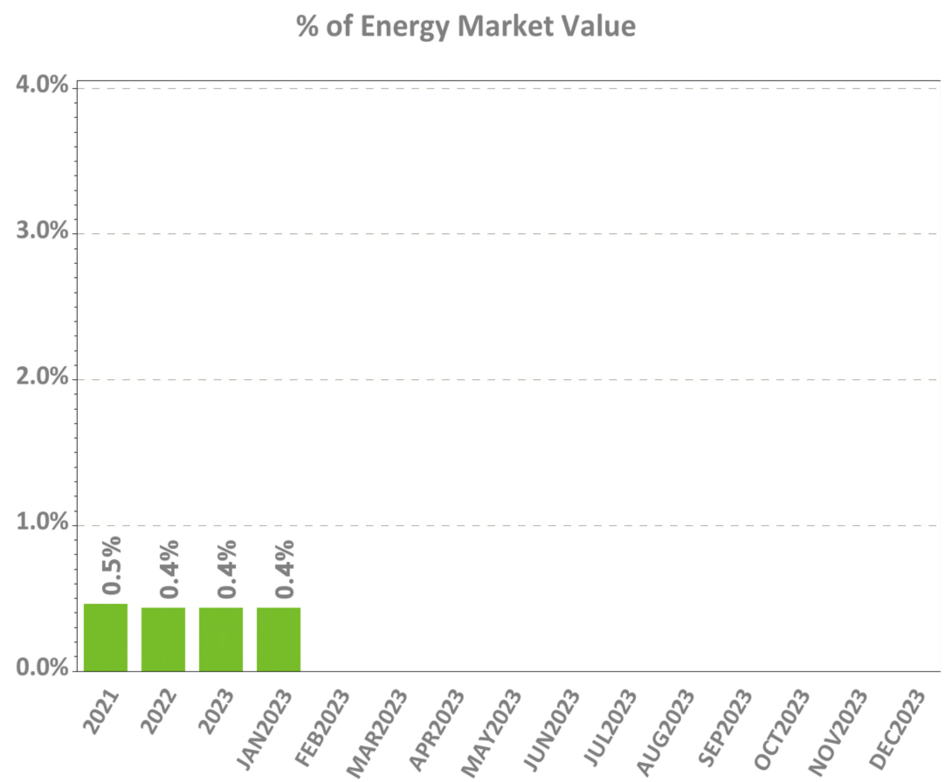


NCPC Charges as Percent of Energy Market



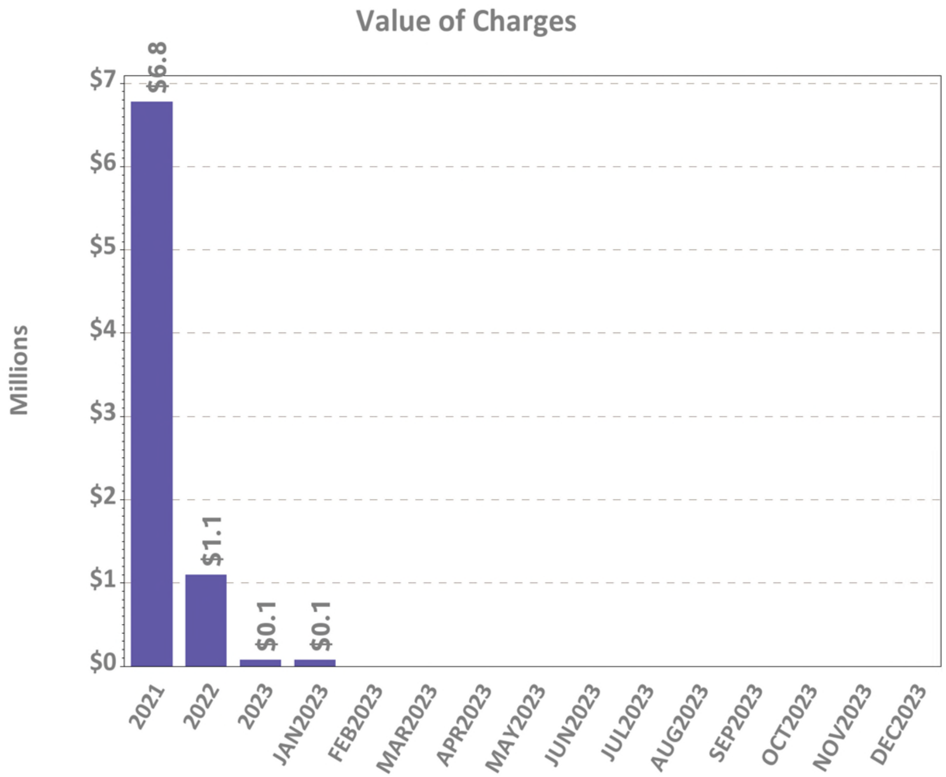
First Contingency NCPC Charges

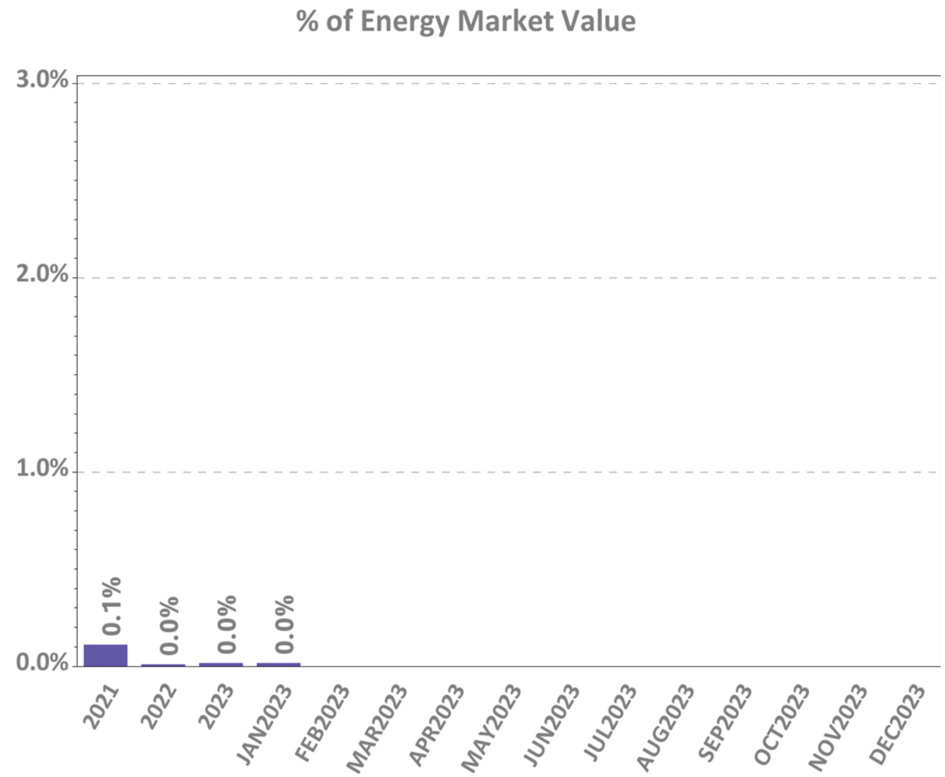




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

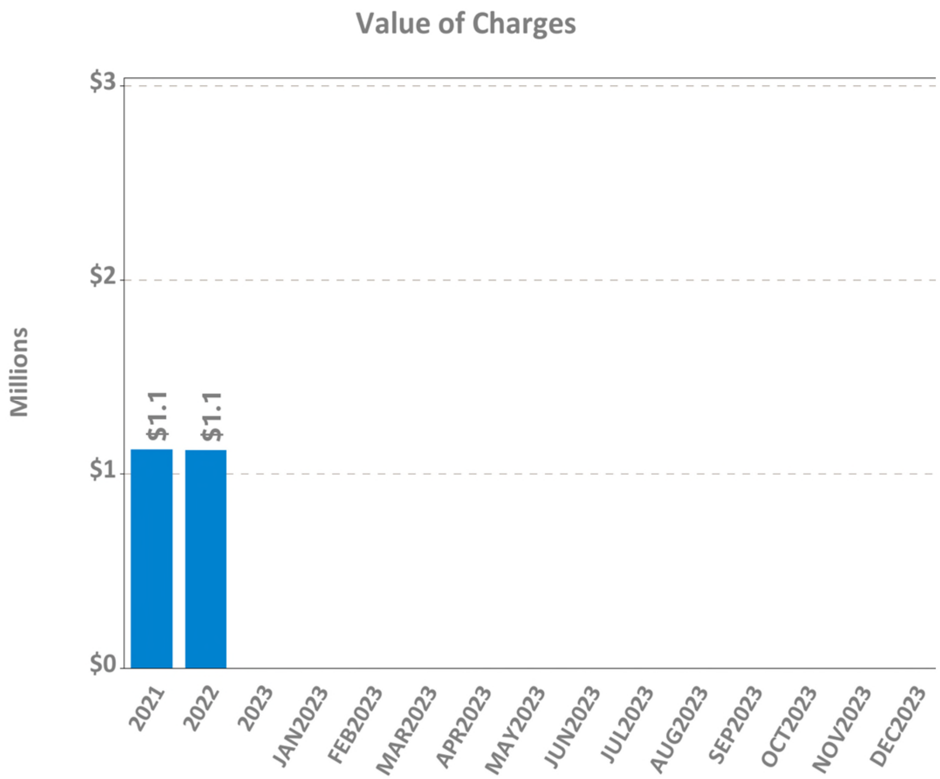
Second Contingency NCPC Charges

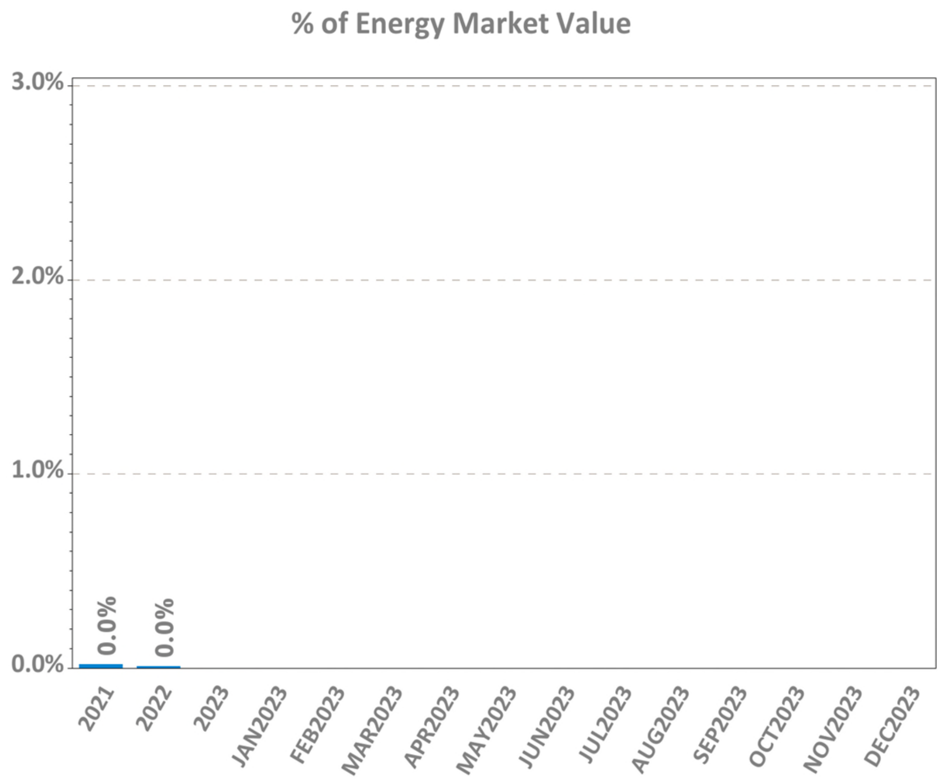




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

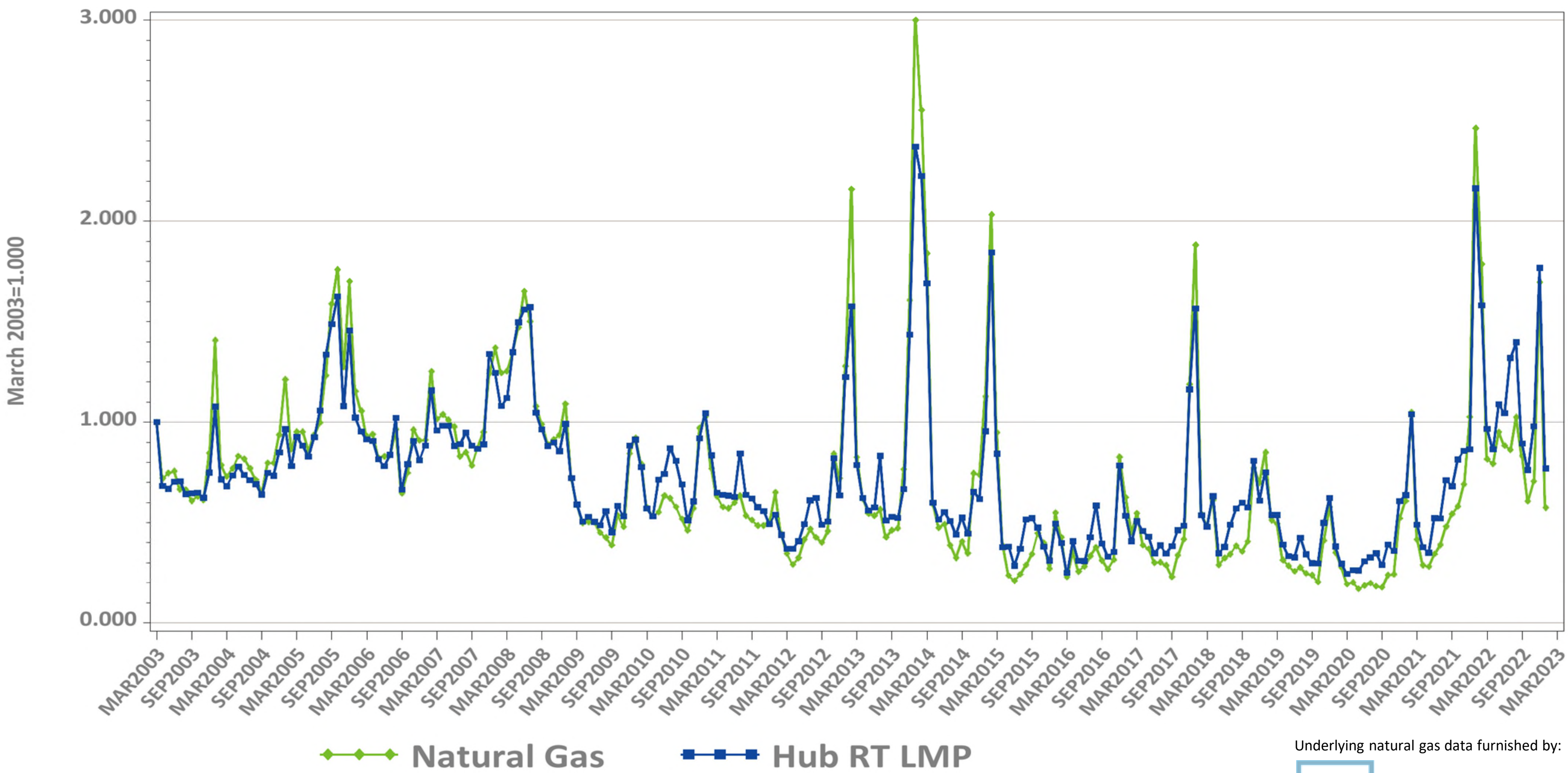
DA vs. RT LMPs ($/MWh)

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%

January-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$149.64	$146.73	$146.69	$148.97	$148.45	$149.26	$149.68	$149.61	$149.46
Real-Time	$148.95	$146.50	$145.22	$148.63	$147.16	$148.65	$149.12	$148.80	$148.66
RT Delta %	-0.5%	-0.2%	-1.0%	-0.2%	-0.9%	-0.4%	-0.4%	-0.5%	-0.5%
January-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$50.59	$48.80	$50.05	$50.62	$50.07	$50.03	$50.68	$50.14	$50.16
Real-Time	$53.44	$51.51	$52.74	$53.30	$51.74	$52.81	$53.49	$52.80	$52.89
RT Delta %	5.6%	5.5%	5.4%	5.3%	3.3%	5.6%	5.5%	5.3%	5.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-66.2%	-66.7%	-65.9%	-66.0%	-66.3%	-66.5%	-66.1%	-66.5%	-66.4%
Yr over Yr RT	-64.1%	-64.8%	-63.7%	-64.1%	-64.8%	-64.5%	-64.1%	-64.5%	-64.4%

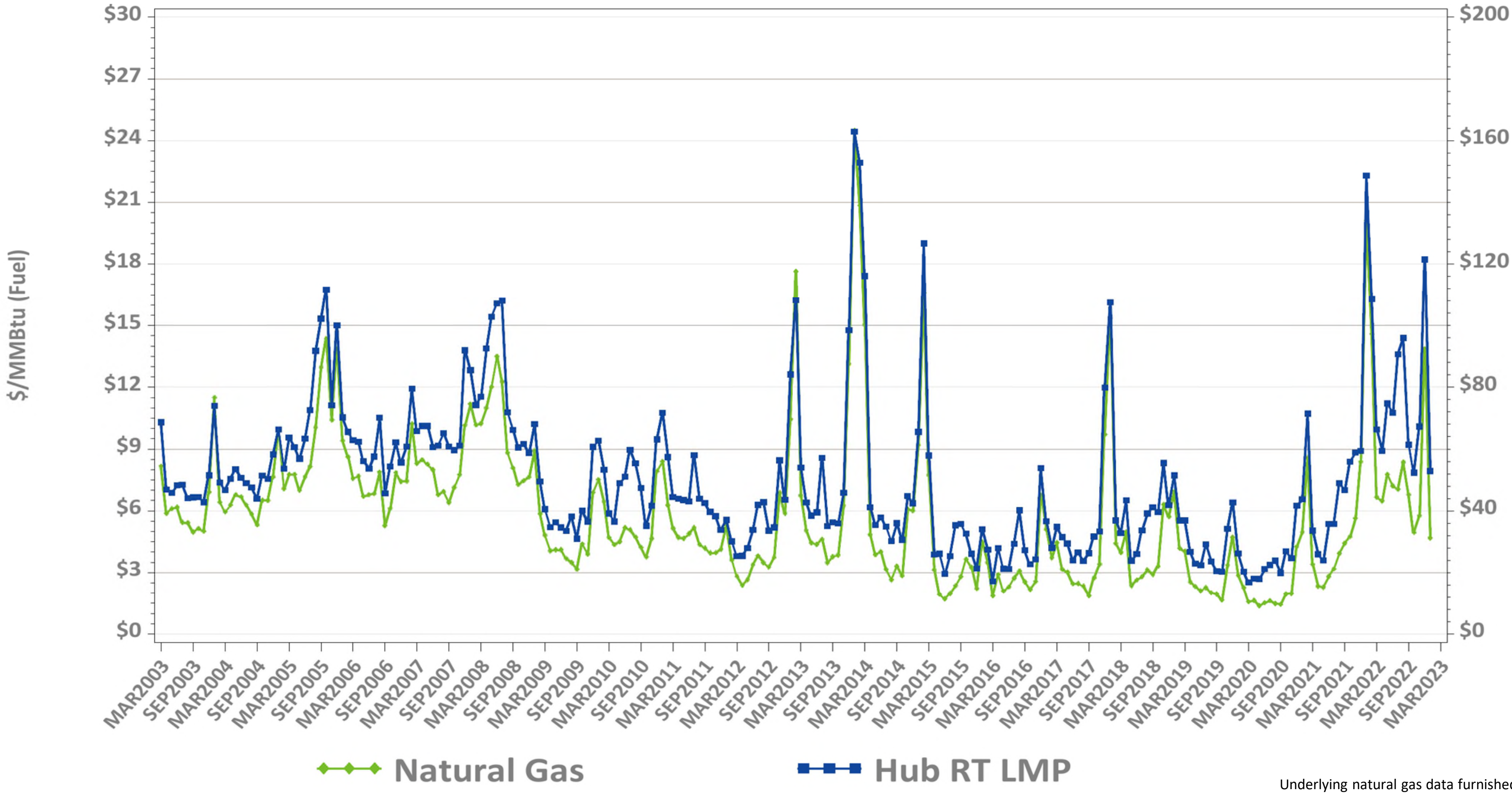
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

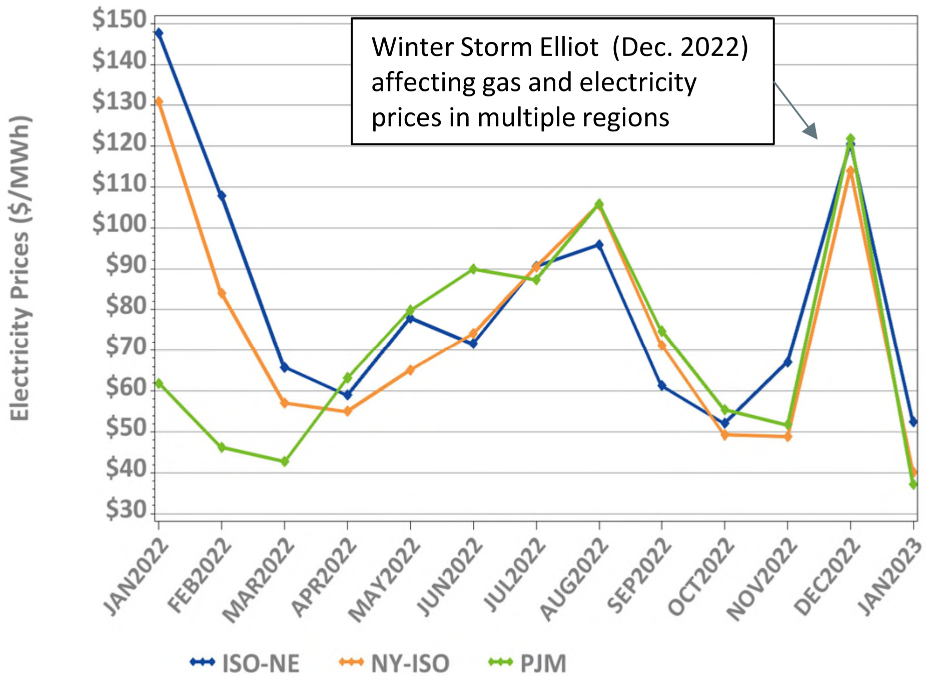
ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

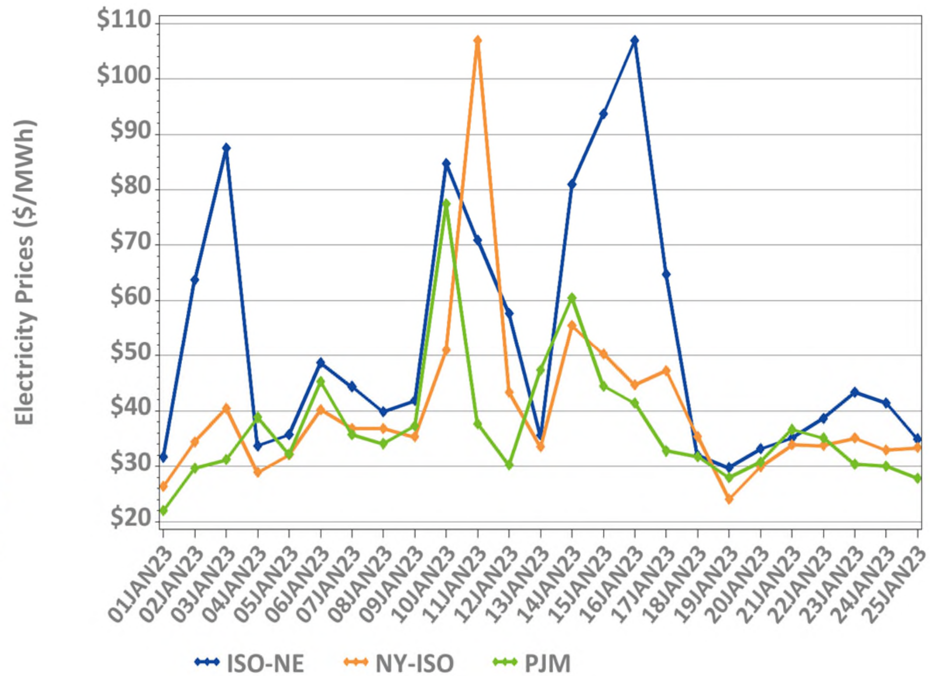


Underlying natural gas data furnished by: ICE Global markets in clear view

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

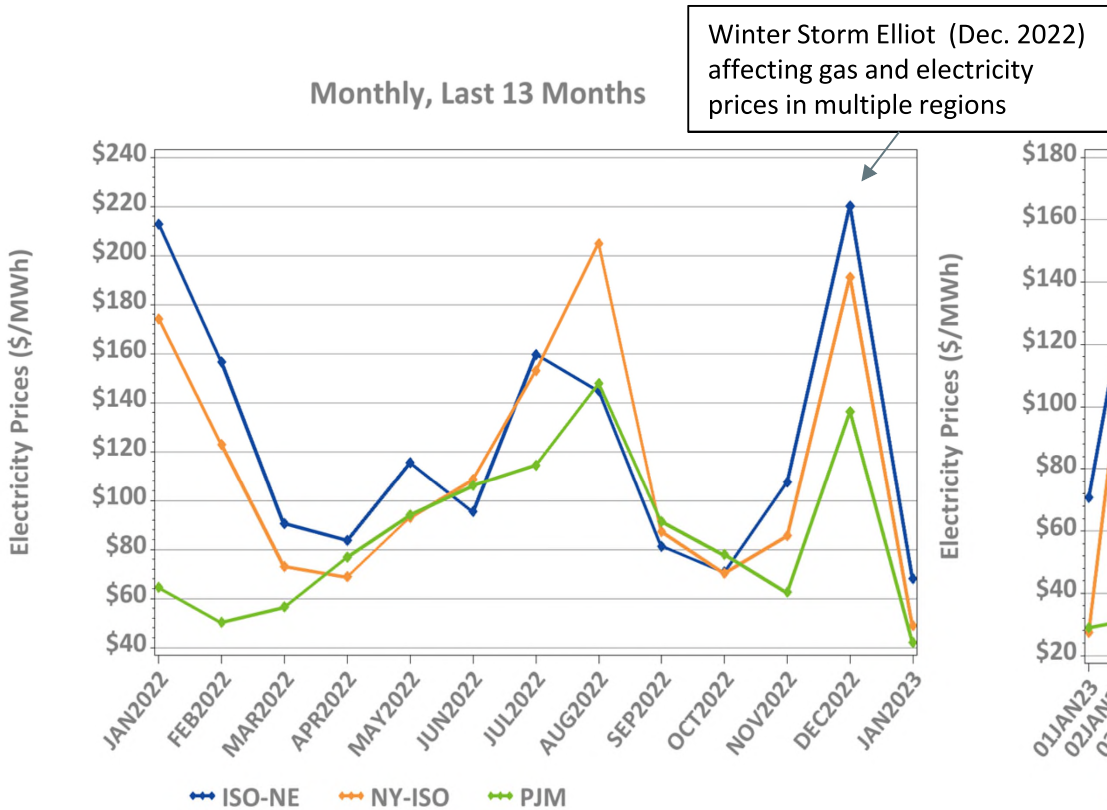


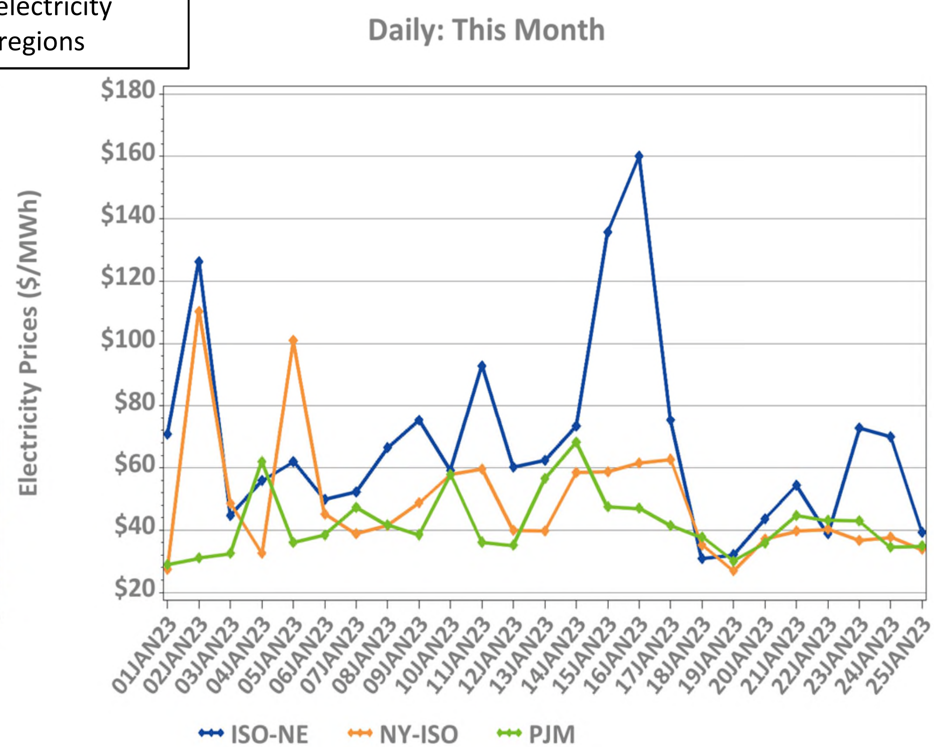
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





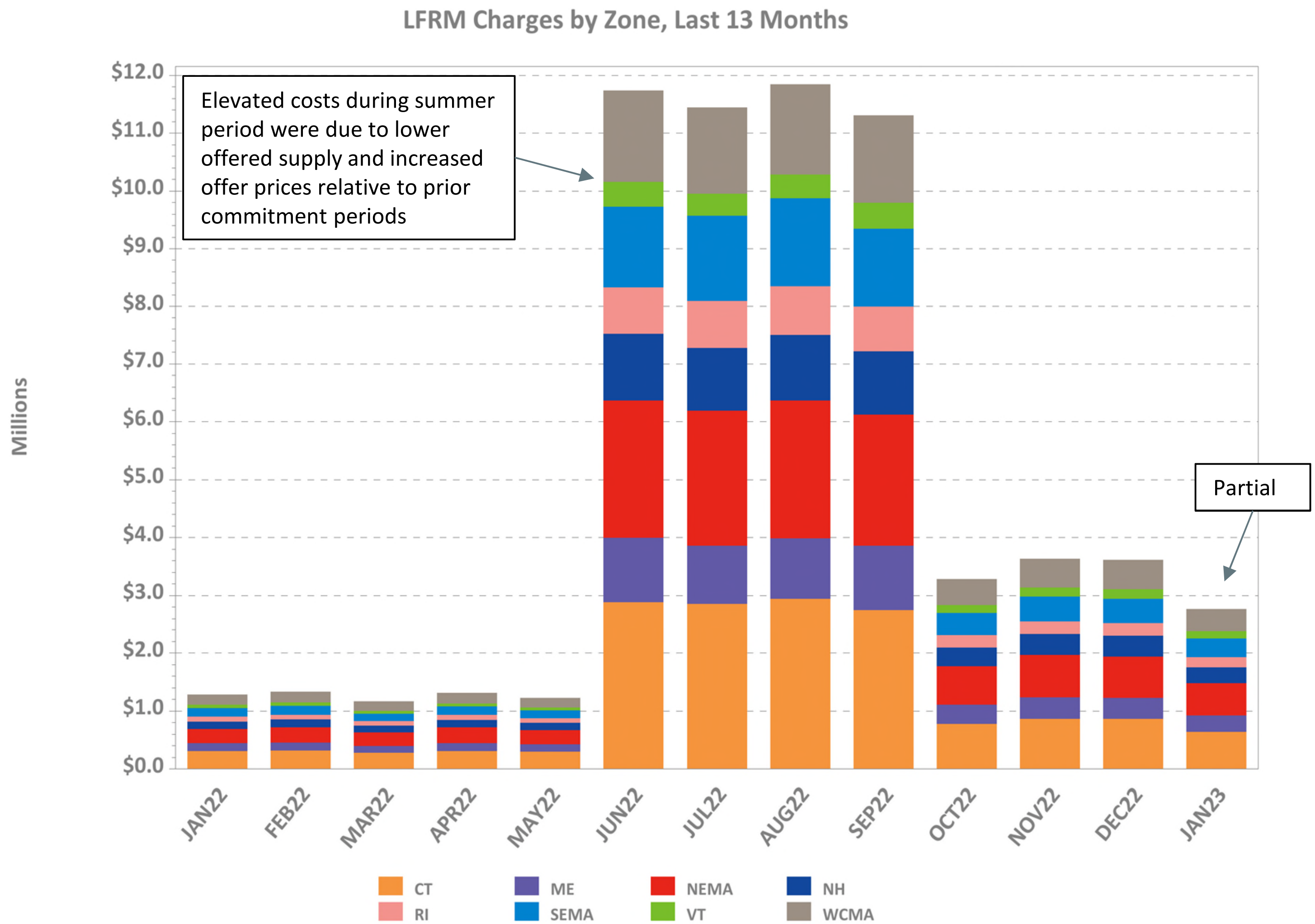
***Forecasted New England daily peak hours reflected**

Reserve Market Results – January 2023

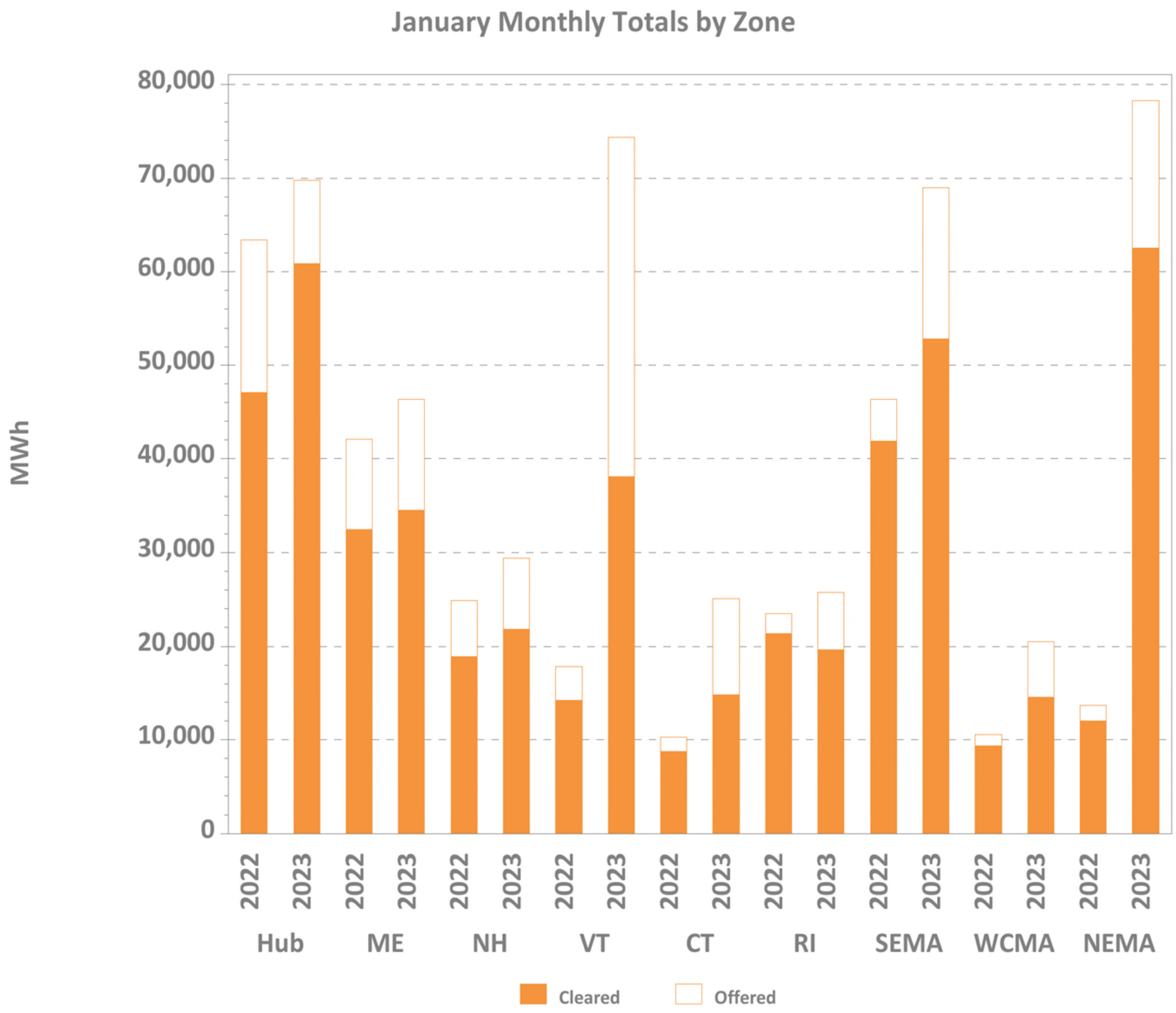
- Maximum potential Forward Reserve Market payments of $3M were reduced by credit reductions of $113K, failure-to-reserve penalties of $169K and no failure-to-activate penalties, resulting in a net payout of $2.8M or 91% of maximum
  - Rest of System: $1.83M/2.1M (87%)
  - Southwest Connecticut: $0.03M/0.03M (100%)
  - Connecticut: $0.9M/0.91M (99%)
- $454K total Real-Time credits were reduced by $8K in Forward Reserve Energy Obligation Charges for a net of $446K in Real-Time Reserve payments
  - Rest of System: 176 hours, $327K
  - Southwest Connecticut: 176 hours, $65K
  - Connecticut: 176 hours, $38K
  - NEMA: 176 hours, $16K

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.

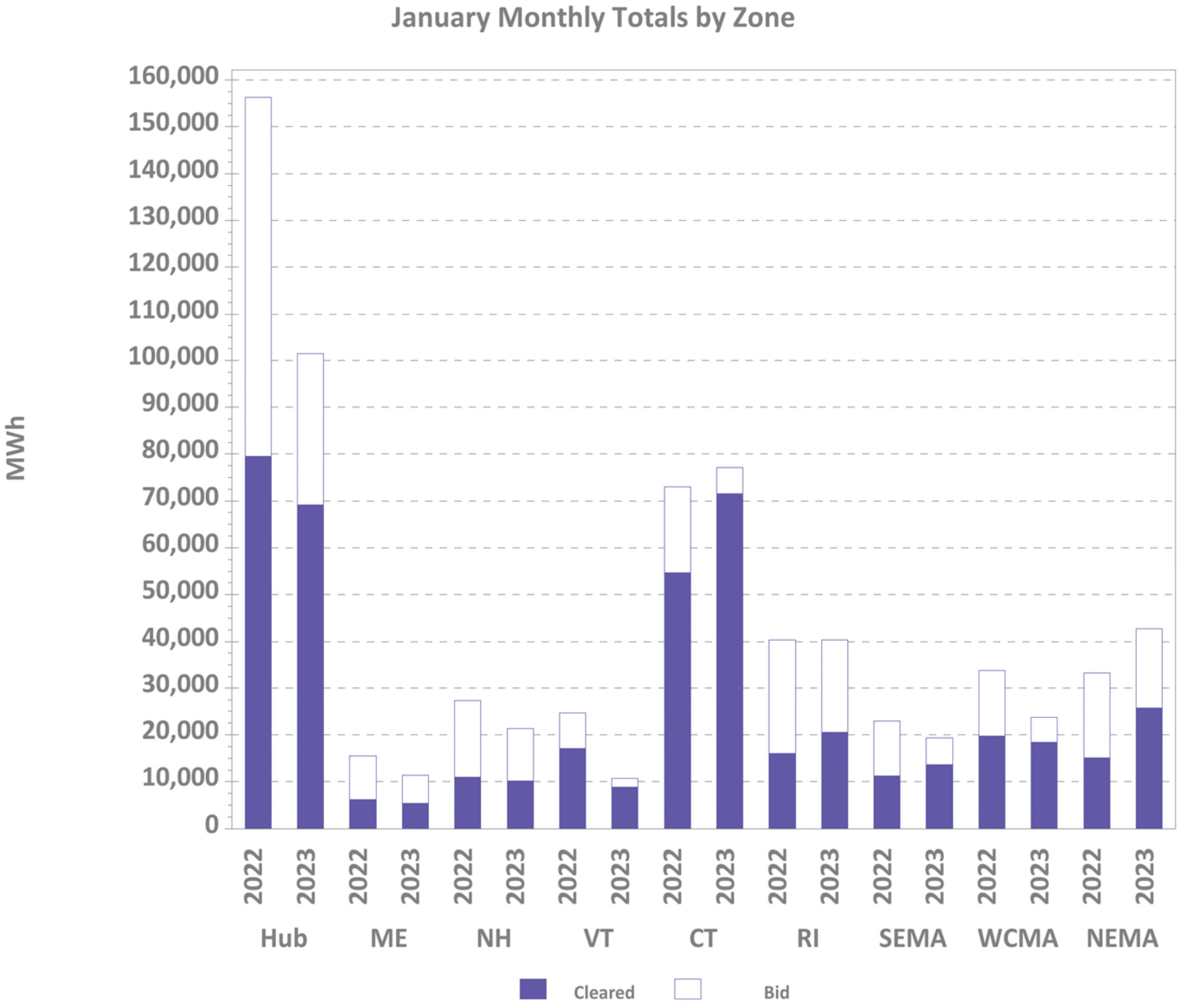
LFRM Charges to Load by Load Zone ($)



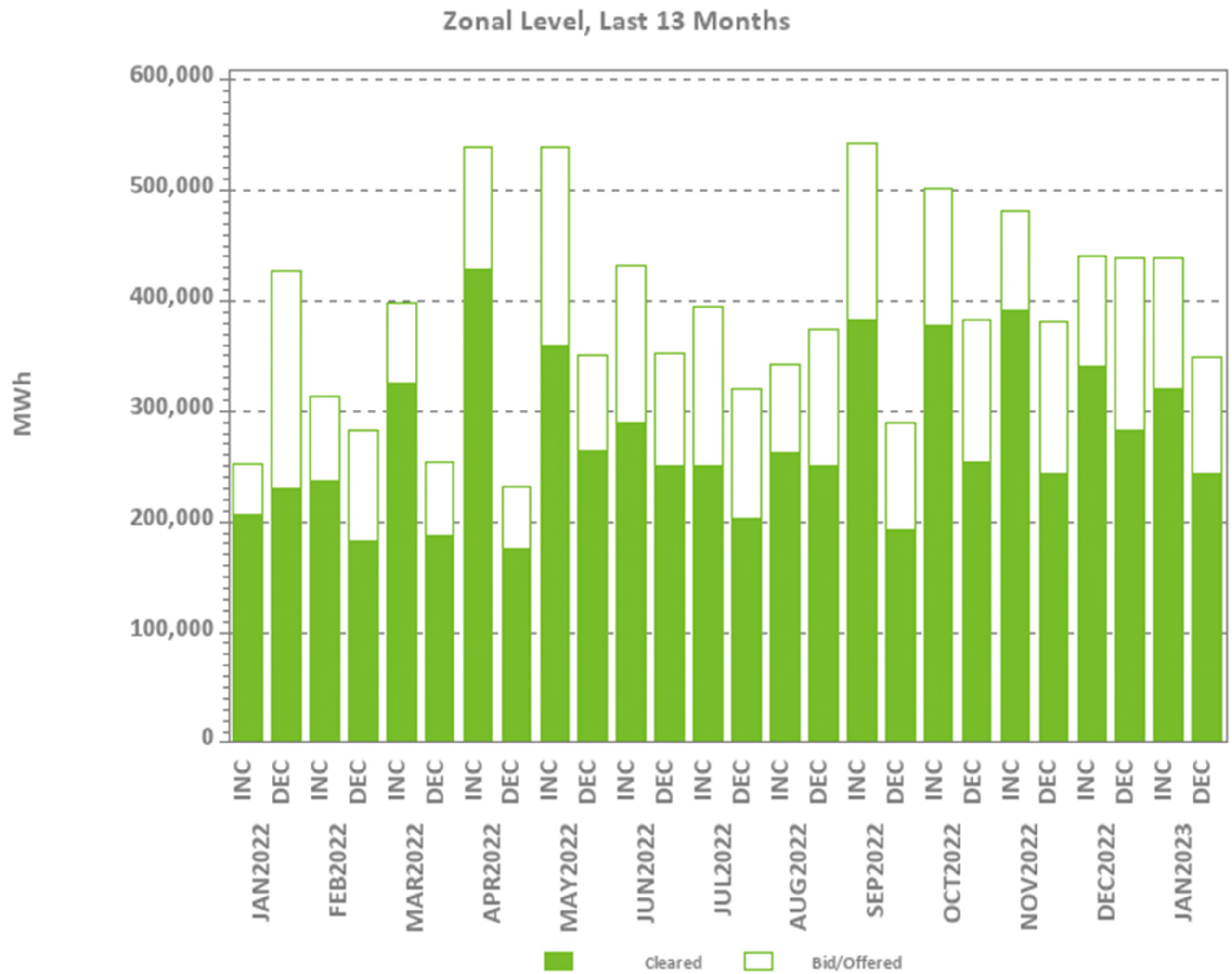
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

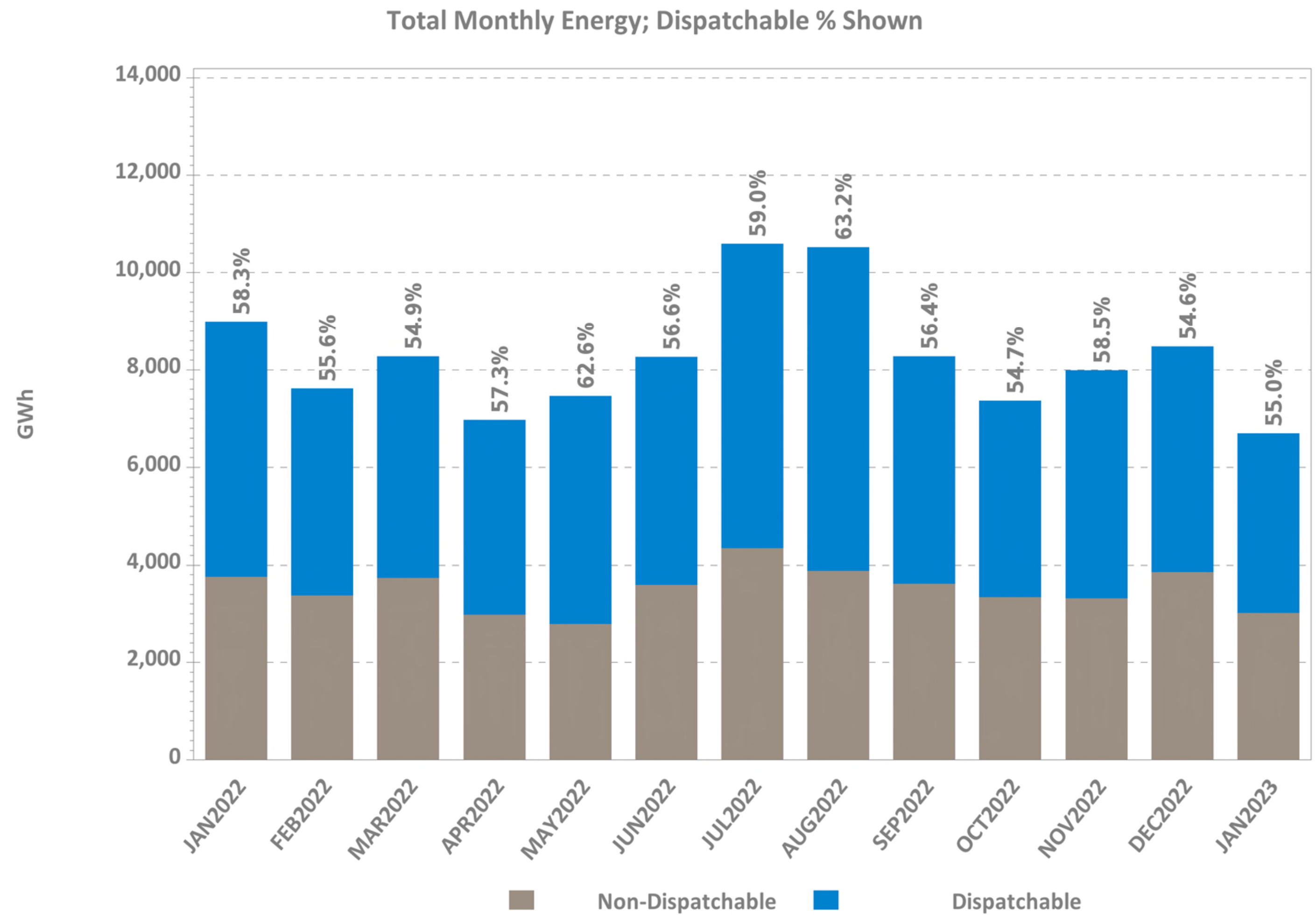


Total Increment Offers and Decrement Bids



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)

- February 15 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - South Naugatuck to Devon Corridor Rebuild (Eversource)
    - Overview of Upcoming Pipe-Type Cable (PTC) Replacements Projects (Eversource)
    - 1704 & 1722 High Pressure Fluid Filled (HPFF) to Cross-linked Polyethylene (XLPE) Rebuild (Eversource)
  - 2023 Public Policy Stakeholder Presentations (as needed)
  - Vermont 2032 Needs Assessment Scope of Work – Winter Peak Scenarios
  - Economic Planning for the Clean Energy Transition (EPCET) – February 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 by mid-February

2050 Transmission Study

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

Economic Studies

- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Final report was posted on 7/29/22
  - Final production cost, ancillary services, and resource adequacy technical appendices were posted on 12/5/22, 12/30/22, and 1/18/23 respectively
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - Initial scope of work was presented at the April 2022 PAC meeting; new modeling features, initial benchmark and market efficiency scenario assumptions and results were presented at the August, October, and December 2022 PAC meetings

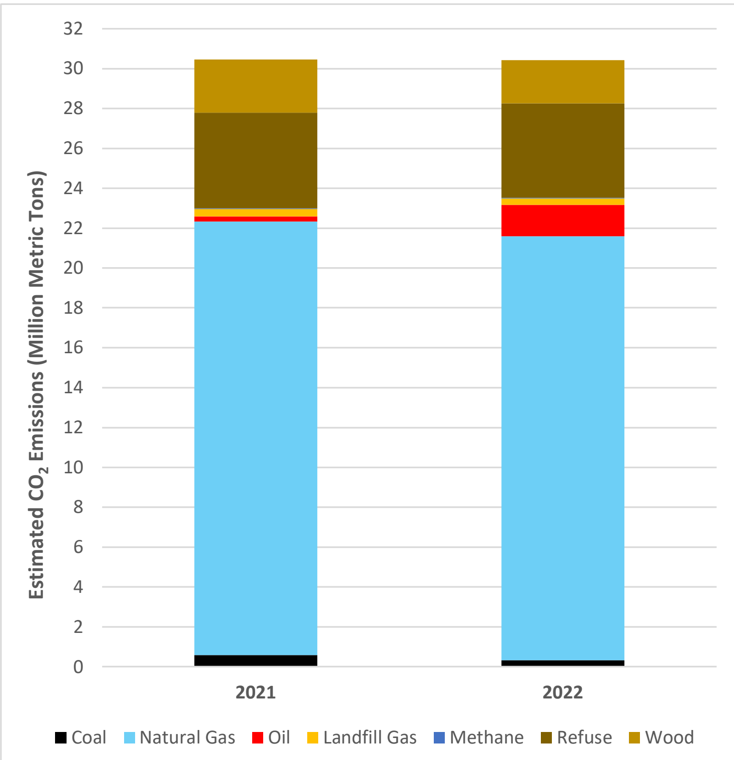
Future Grid Reliability Study (FGRS)

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

New England Power System Carbon Emissions

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

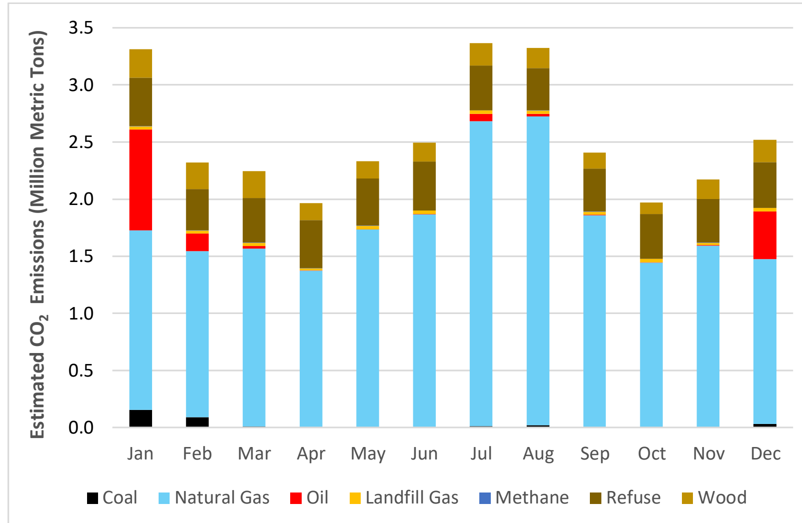
- Spike in oil-fired generation in January and December 2022



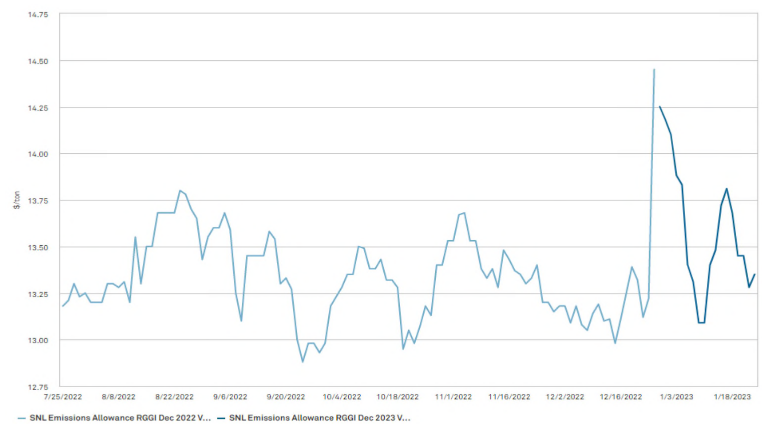
Data as of 12/31/22

RGGI – Regional Greenhouse Gas Initiative

2022 Estimated Monthly CO_2 Emissions by Fuel Type



RGGI Allowance Prices



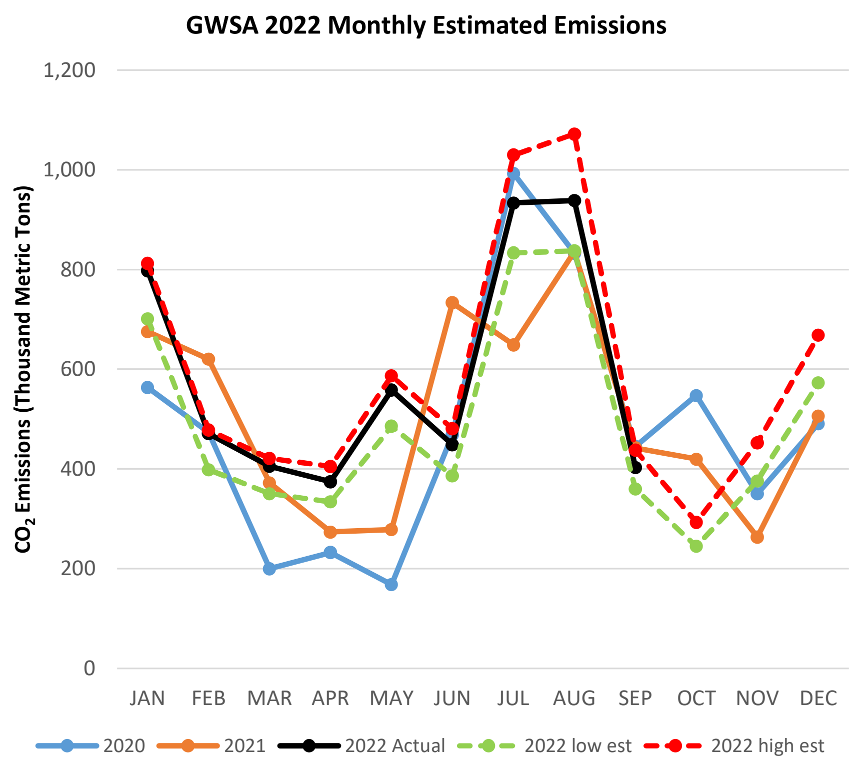
- 1/24/23: RGGI allowance spot price - $13.35 per allowance (1 allowance = 1 short ton CO_2)

Massachusetts CO_2 Generator Emissions Cap

2022 Estimated Emissions Under CO_2 Cap

- 12/31/22: 2022 estimated GWSA CO_2 emissions range between 5.9 and 7.1 MMT
  - 73% to 89% of the 8.06 MMT 2022 cap
- 12/14/22 GWSA auction cleared at $14.20; 1.18 million 2023 vintage allowances sold
  - 0.38 million 2024 vintage GWSA allowances were also offered, clearing at $6.03

2020-2022 Estimated Monthly Emissions (Thousand Metric tons)



2022 Q4 actual data (from EPA) will be available in February

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 1/19/2023

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 1/19/2023

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	2

Greater Boston Projects, cont.

Status as of 1/19/2023

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 1/19/2023

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 1/19/2023

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 1/19/2023

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 1/19/2023

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 1/19/2023

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 1/19/2023

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 1/19/2023

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 1/19/2023

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	2
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	Mar-23	3
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	3

Eastern CT Reliability Projects, cont.

Status as of 1/19/2023

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.)	Apr-23	3
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	3
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Sept-22	4
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Apr-23	3
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 1/19/2023

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 1/19/2023

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 1/19/2023

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

Upper Maine Solution Projects

Status as of 1/19/2023

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

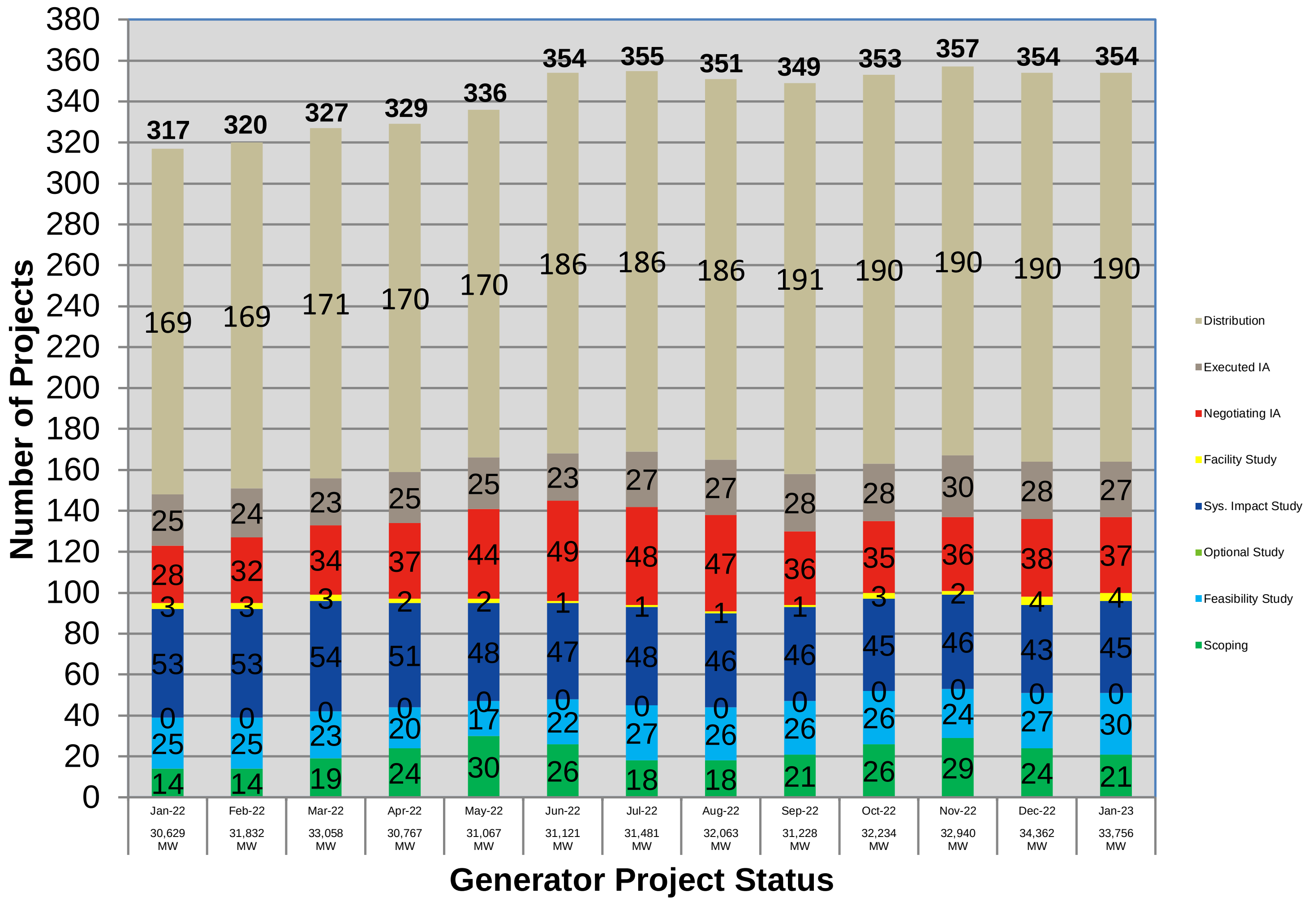
Upper Maine Solution Projects, cont.

Status as of 1/19/2023

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

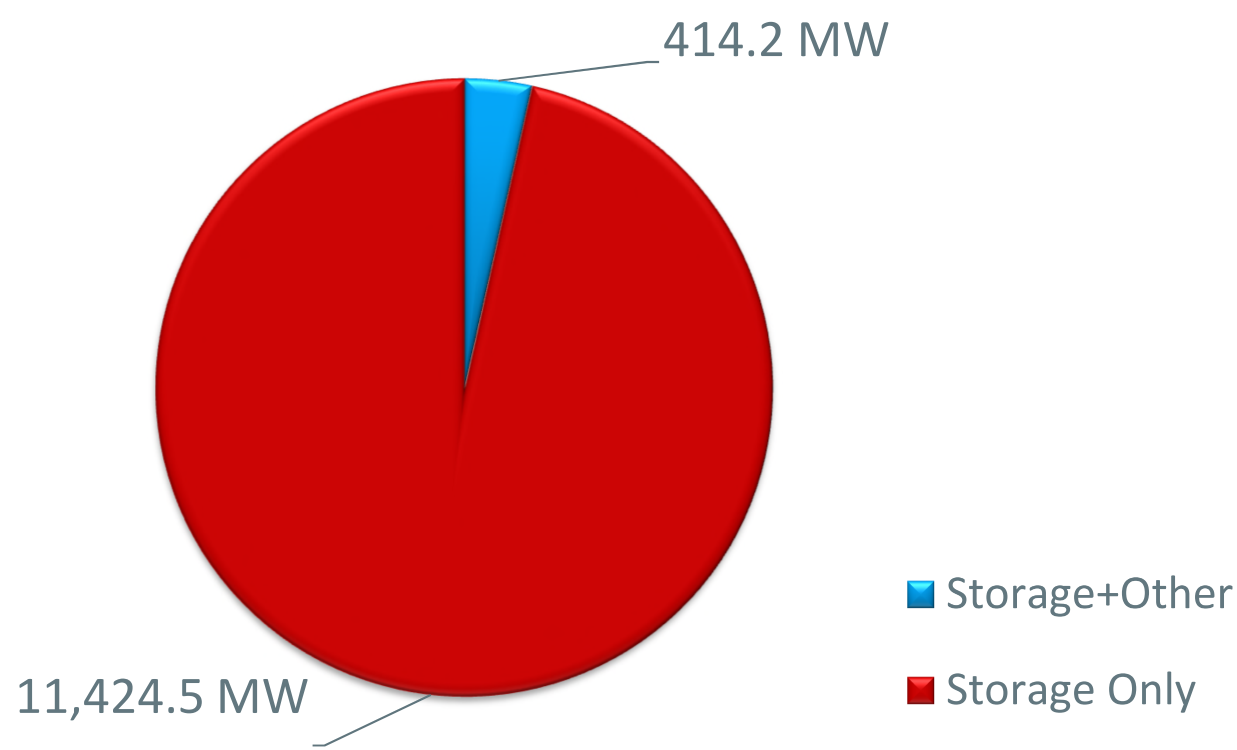
Status of Tariff Studies as of January 26, 2023



Note: January 2023 is based on partial data.
8 ETUs in Scoping, 3 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 January 26, 2023)

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



OPERABLE CAPACITY ANALYSIS

Winter 2023 Analysis

Winter 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	February - 2023[2] CSO (MW)	February - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,497	31,971
Active Demand Capacity Resource (+) [5]	381	393
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	900	900
Non Commercial Capacity (+)	12	12
Non Gas-fired Planned Outage MW (-)	123	262
Gas Generator Outages MW (-)	370	472
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	1,874	2,103
Net Capacity (NET OPCAP SUPPLY MW)	24,323	27,339
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,496	19,496
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,801	21,801
Operable Capacity Margin	2,522	5,538

[1]Operable Capacity is based on data as of **January 24, 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 **January 24, 2023.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 11, 2023.**

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

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

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

Winter 2023 Operable Capacity Analysis

90/10 Load Forecast	February - 2023[2] CSO (MW)	February - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,497	31,971
Active Demand Capacity Resource (+) [5]	381	393
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	900	900
Non Commercial Capacity (+)	12	12
Non Gas-fired Planned Outage MW (-)	123	262
Gas Generator Outages MW (-)	370	472
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	2,921	3,305
Net Capacity (NET OPCAP SUPPLY MW)	23,276	26,137
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,166	20,166
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,471	22,471
Operable Capacity Margin	805	3,666

[1]Operable Capacity is based on data as of **January 24, 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 **January 24, 2023.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 11, 2023.**

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

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

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

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

ISO-NE OPERABLE CAPACITY ANALYSIS

January 24, 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 February through March.

Report created: 1/24/2023

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
2/11/2023	28497	381	900	12	123	370	3100	1874	24323	19496	2305	21801	2522	Y	Winter 2022/2023
2/18/2023	28497	381	900	12	50	370	3100	1425	24845	19236	2305	21541	3304	N	Winter 2022/2023
2/25/2023	28497	381	900	12	115	370	3100	1126	25079	18258	2305	20563	4516	N	Winter 2022/2023
3/4/2023	28251	557	1070	60	262	848	2200	349	26279	17912	2305	20217	6062	N	Winter 2022/2023
3/11/2023	28251	557	1070	60	179	1075	2200	0	26484	17718	2305	20023	6461	N	Winter 2022/2023
3/18/2023	28251	557	1070	60	1445	1729	2200	0	24564	17357	2305	19662	4902	N	Winter 2022/2023
3/25/2023	28251	557	1070	60	1407	2899	2200	0	23432	16797	2305	19102	4330	N	Winter 2022/2023

Column Definitions

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

Winter 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

January 24, 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 February through March.

Report created: 1/24/2023

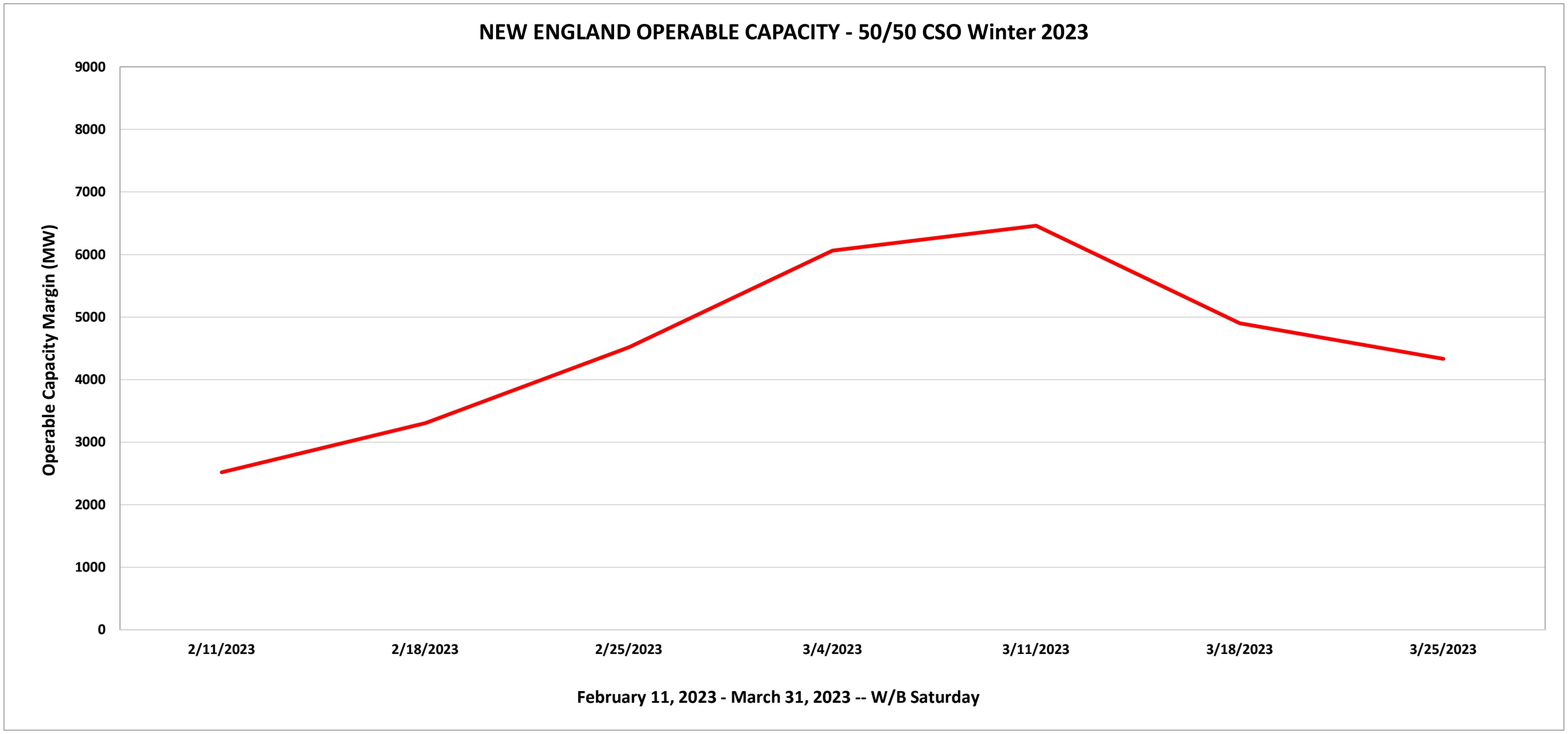
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
2/11/2023	28497	381	900	12	123	370	3100	2921	23276	20166	2305	22471	805	Y	Winter 2022/2023
2/18/2023	28497	381	900	12	50	370	3100	2323	23947	19898	2305	22203	1744	N	Winter 2022/2023
2/25/2023	28497	381	900	12	115	370	3100	1874	24331	18889	2305	21194	3137	N	Winter 2022/2023
3/4/2023	28251	557	1070	60	262	848	2200	1246	25382	18533	2305	20838	4544	N	Winter 2022/2023
3/11/2023	28251	557	1070	60	190	805	2200	691	26052	18333	2305	20638	5414	N	Winter 2022/2023
3/18/2023	28251	557	1070	60	1445	1729	2200	0	24564	17960	2305	20265	4299	N	Winter 2022/2023
3/25/2023	28251	557	1070	60	1407	2899	2200	0	23432	17383	2305	19688	3744	N	Winter 2022/2023

Column Definitions

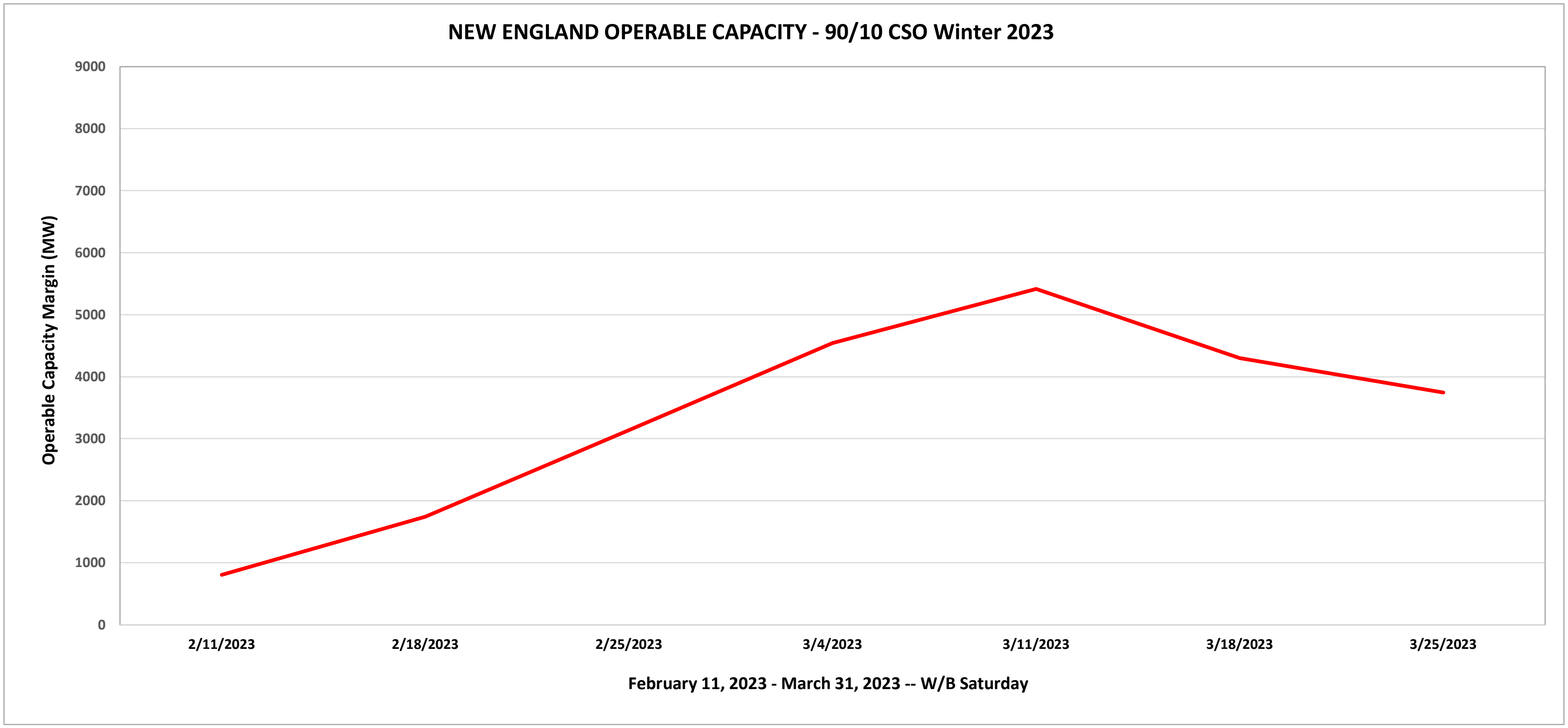
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can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

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

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



Winter 2023 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Spring 2023 Analysis

Preliminary Spring 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2023[2] CSO (MW)	May - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,170	31,971
Active Demand Capacity Resource (+) [5]	555	393
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,019	1,019
Non Commercial Capacity (+)	60	60
Non Gas-fired Planned Outage MW (-)	2,545	2,947
Gas Generator Outages MW (-)	2,422	2,790
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)	21,437	24,306
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,934	18,934
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,239	21,239
Operable Capacity Margin	198	3,067

[1] Operable Capacity is based on data as of **January 24, 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 **January 24, 2023.**

[2] Load forecast that is based on the 2022 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.

Preliminary Spring 2023 Operable Capacity Analysis

90/10 Load Forecast	May - 2023[2] CSO (MW)	May - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,170	31,971
Active Demand Capacity Resource (+) [5]	555	393
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,019	1,019
Non Commercial Capacity (+)	60	60
Non Gas-fired Planned Outage MW (-)	2,545	2,947
Gas Generator Outages MW (-)	2,422	2,790
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)	21,437	24,306
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,309	20,309
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,614	22,614
Operable Capacity Margin	-1,177	1,692

[1]Operable Capacity is based on data as of **January 24, 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 **January 24, 2023.**

[2] Load forecast that is based on the 2022 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.

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

ISO-NE OPERABLE CAPACITY ANALYSIS

January 24, 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: 1/24/2023

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
4/1/2023	28170	555	1070	60	4444	2978	2700	0	19733	16176	2305	18481	1252	N	Spring 2023
4/8/2023	28170	555	1070	60	4554	2635	2700	0	19966	15927	2305	18232	1734	N	Spring 2023
4/15/2023	28170	555	1070	60	4391	3698	2700	0	19066	15423	2305	17728	1338	N	Spring 2023
4/22/2023	28170	555	1070	60	4077	2800	2700	0	20278	15160	2305	17465	2813	N	Spring 2023
4/29/2023	28170	555	1070	60	4424	2581	3400	0	19450	15134	2305	17439	2011	N	Spring 2023
5/6/2023	28170	555	1070	60	3188	2728	3400	0	20539	17956	2305	20261	278	N	Spring 2023
5/13/2023	28170	555	1019	60	2545	2422	3400	0	21437	18934	2305	21239	198	Y	Spring 2023
5/20/2023	28170	555	1070	60	926	1377	3400	0	24152	19842	2305	22147	2005	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 annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Preliminary Spring 2023 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

January 24, 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: 1/24/2023

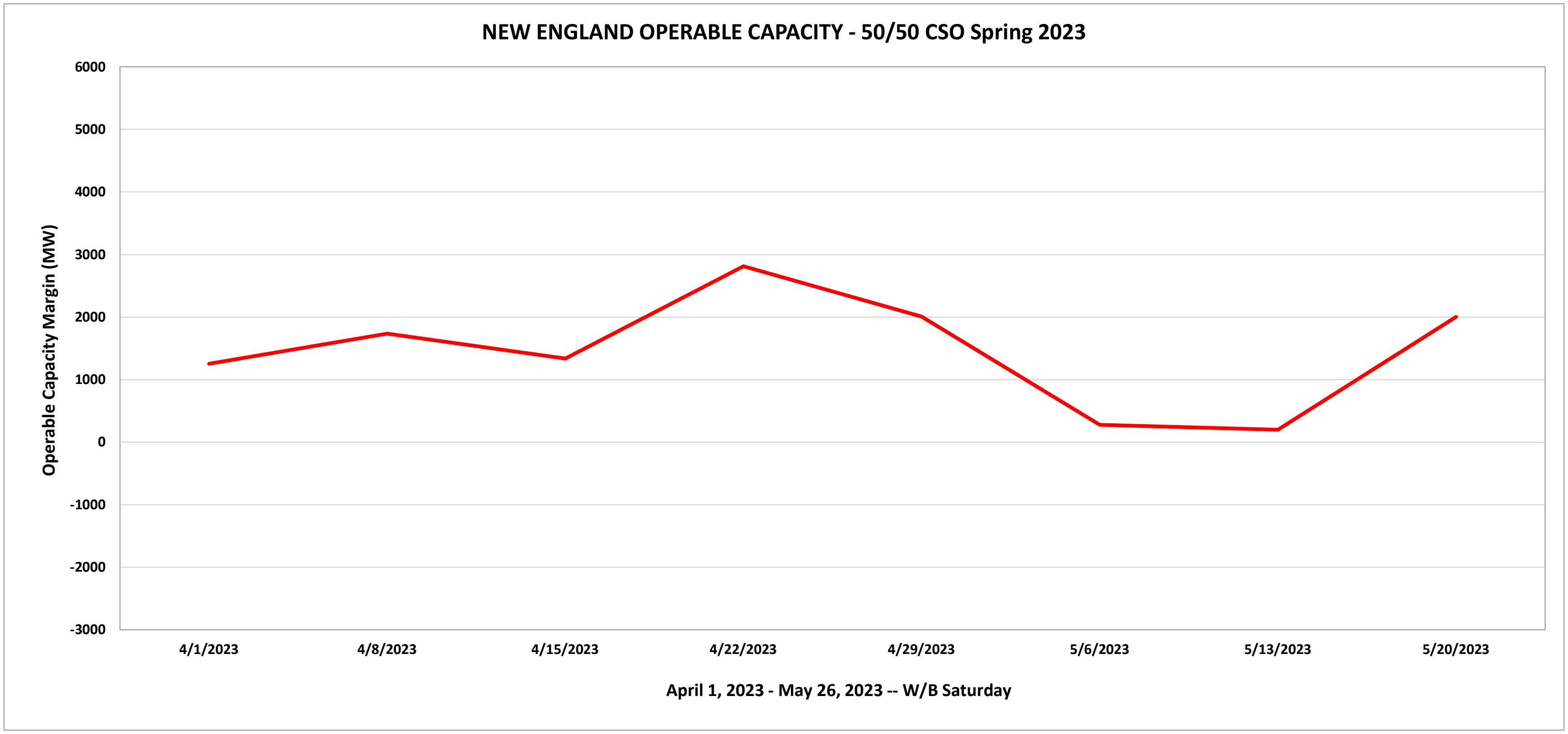
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
4/1/2023	28170	555	1070	60	4444	2978	2700	0	19733	16747	2305	19052	681	N	Spring 2023
4/8/2023	28170	555	1070	60	4554	2635	2700	0	19966	16490	2305	18795	1171	N	Spring 2023
4/15/2023	28170	555	1070	60	4391	3698	2700	0	19066	15970	2305	18275	791	N	Spring 2023
4/22/2023	28170	555	1070	60	4077	2800	2700	0	20278	15700	2305	18005	2273	N	Spring 2023
4/29/2023	28170	555	1070	60	4424	2581	3400	0	19450	15672	2305	17977	1473	N	Spring 2023
5/6/2023	28170	555	1070	60	3188	2728	3400	0	20539	19270	2305	21575	-1036	N	Spring 2023
5/13/2023	28170	555	1019	60	2545	2422	3400	0	21437	20309	2305	22614	-1177	Y	Spring 2023
5/20/2023	28170	555	1070	60	926	1377	3400	0	24152	21274	2305	23579	573	N	Spring 2023

Column Definitions

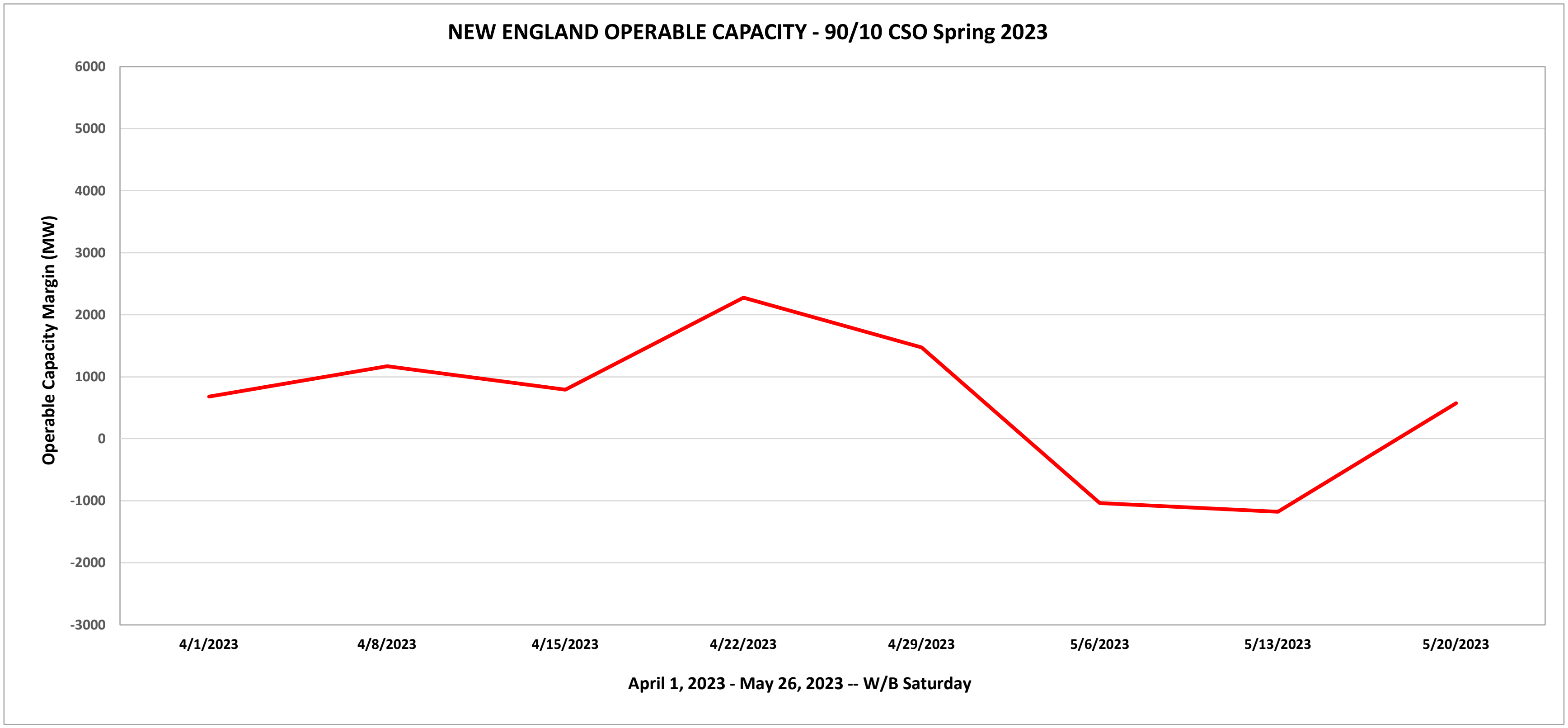
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



Preliminary Spring 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

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of February 1, 2023

The following activity, as more fully described in the attached litigation report, has occurred since the report dated January 4, 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

*	1	RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)	Jan 5-Jan 23	CMMEC, EMI, Narragansett, ACPA, SEIA intervene
			Jan 19	ISO-NE moves to dismiss itself as a party or, in the alt., answer the Complaint
			Jan 23	Responses, comments and protests filed by PTO AC, NEPOOL, AEU/Clean Energy Council, CPV Towantic, Glenvale, MA AG, NECOS, NEPGA, and NESCOE
	5	NextEra / Avangrid/NECEC Seabrook Complaint (EL21-6) and Seabrook Declaratory Order Petition (EL21-3)	Feb 1	FERC (i) both denies and grants in part the Seabrook Complaint; (ii) dismisses the Seabrook Declaratory Order Petition; and (iii) directs Seabrook to replace the Seabrook Station breaker pursuant to its obligations under the Seabrook LGIA and Good Utility Practice; breaker replacement expected during Fall 2024 refueling outage and NECEC Project commercial operation expected Dec 2024

II. Rate, ICR, FCA, Cost Recovery Filings

*	9	FCA17 Qualification Informational Filing (ER23-690)	Jan 10	Eversource intervenes (out-of-time)
			Jan 12	ISO-NE files an errata disclosing an error in the winter Qualified Capacity of one New Generating Resource; reports impacts of its error were "1 MW or less"
*	9	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER23-534)	Jan 6	FERC accepts ICR-Related Values, eff. Jan 29, 2023
	10	Mystic 8/9 COSA *First* CapEx Info Filing Settlement Judge Procedures (ER18-1639-015)	Jan 18	Fourth settlement conference held
			Jan 24	ALJ McBarnette schedules fifth settlement conference for Jan 27
			Jan 27	Fifth settlement conference held
	12	Transmission Rate Annual (2022-23) Update/Informational Filing (ER09-1532; RT04-2)	Jan 31	PTO AC supplements its Jul 29 filing with updated rates and associated revenue requirements for Regional and Local Service by RIE and NEP, eff. Jan 1, 2023 – Dec 31, 2023, under transition arrangements to the Attachment F Settled Formula Rate
			Jan 31	RENEW submits formal challenge to Jun 29, 2022 Annual Info Filing

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

*	13	PPU CTR Clarifications (ER23-911)	Jan 20	ISO-NE and NEPOOL file revisions to Market Rule 1 § III.13.7.5.4.5 to clarify (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; comment deadline ***Feb 10, 2023***
			Jan 30	National Grid intervenes
	13	SATOA Revisions (ER23-739; ER23-743)	Jan 19	Advanced Energy United, FirstLight, National Grid, NEPGA, NESCOE, UCS, VELCO file comments and protests Avangrid, Eversource, Narragansett ,Vistra, MA DPU, LSP Transmission Holdings, RENEW, ACPA, EPSA

	13	Solar DNE Dispatch Changes (ER23-517)	Jan 19	FERC accepts changes, eff. Dec 5, 2023

IV. OATT Amendments / TOAs / Coordination Agreements

*	15	Attachment K Economic Study Revisions (ER23-971)	Jan 27	ISO-NE and NEPOOL file changes to Attachment K; comment deadline ***Feb 17, 2023***
*	15	Attachment F, Appendix D-NSTAR: Updates to Depreciation Rates (ER23-637)	Jan 31	FERC accepts revisions to the general plant depreciation rates for NSTAR (East) and NSTAR (West), eff. Jan 1, 2023

V. Financial Assurance/Billing Policy Amendments

*	17	FA/Billing Policies IEP Changes; Monthly Statement Issuance Date Update (ER23-705)	Jan 12	Eversource, NRG intervene

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

*	17	Schedule 21-NEP: NEP/Dichotomy Collins Hydro SGIA (ER23-888)	Jan 18	NEP files an SGIA to cover the continued interconnection of Dichotomy's 1.3 MW run-of-river hydro generating facility in Wilbraham, MA; comment deadline ***Feb 8, 2023***
*	17	Schedule 21-RIE: Transfer of SAs from Sched 21-NEP; Updated Thundermist ISA (ER23-678; ER23-681)	Jan 6 Jan 10	NEP files comments supporting filing Narragansett submits notice of Jan 1, 2023 PTO status and effective date of termination of RIE's Service Agreements under Schedule 21-NEP; RI Division intervenes
	17	Schedule 21-VP: Revised 2021 Annual Update Settlement Agreement (ER20-2119-002)	Jan 12	Versant submits Revised 2021 Annual Update Offer of Settlement between itself and the MPUC to replace previous Settlement Agreement; comment deadline ***Feb 2, 2023***
	18	Schedule 21-VP: Revised 2020 Annual Update Settlement Agreement (ER15-1434-006)	Jan 12	Versant submits Revised 2020 Annual Update Offer of Settlement between itself and the MPUC to replace previous Settlement Agreement; comment deadline ***Feb 2, 2023***
*	18	Schedule 21-GMP True Up Calc. Forecast Info Report (ER12-2304)	Jan 17	GMP supplements 2023 forecasted rates info filing

VII. NEPOOL Agreement/Participants Agreement Amendments

	18	PA Amendment No. 12 (ISO Board Member Age Limit Increase) (ER23-980)	Jan 30	ISO-NE and NEPOOL file PA Amendment No. 12; comment deadline ***Feb 21, 2023***

VIII. Regional Reports

*	19	Transmission Projects Annual Info Filing (ER13-193)	Jan 30	ISO-NE files annual informational filing of projects on the RSP project list that had a year of need 3 years or less from the completion of the Needs Assessment as required under OATT § 4.1(j)(iii)
*	19	LFTR Implementation: 57th Quarterly Status Report (ER07-476)	Jan 13	ISO-NE files its 57th quarterly report
*	19	IMM Quarterly Markets Reports - 2022 Fall (ZZ22-4)	Jan 25	IMM files Fall 2022 Report; to be reviewed at Feb 7-9 Markets Committee meeting

IX. Membership Filings

*	19	Feb 2023 Membership Filing (ER23-1020)	Jan 31	***New Members***: CommonWealth New Bedford Energy, GF Power and Industrial Wind Action Corp; ***Terminations***: Backyard Farms Energy, Backyard Farms, Bruce Power, CommonWealth Resource Mgmt. Corp., Darby Energy, DFC ERG CT, Stones DR, and Vineyard Wind; ***Name Change***: Advanced Energy United (f/k/a Advanced Energy Economy); comment date ***Feb 21, 2023***
	20	Dec 2022 Membership Filing (ER23-518)	Jan 20	FERC accepts filing, eff. Dec 1, 2022

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

	22	*Order 887*: INSM for High and Medium Impact BES Cyber Systems (RM22-3)	Jan 19	FERC issues *Order 887* directing NERC (i) to develop and submit new or modified Reliability Standards that require INSM within a trusted CIP networked environment for all high impact and some medium impact BES Cyber Systems; and (ii) study and submit a report on some medium and all low impact BES Cyber Systems with and without external routable connectivity
	22	NPCC Bylaws Changes (RR22-2)	Jan 3	FERC accepts compliance filing changes

XI. Misc. - of Regional Interest

*	23	203 Application: Saddleback / CPV (EC23-52)	Jan 13	Saddleback requests FERC authorization for the acquisition by CPV Mountain Wind Holdings of 100% of the membership interests in Saddleback; comment deadline ***Feb 3, 2023***
*	23	203 Application: Salem Harbor / Castleton Commodities (EC23-50)	Jan 6	Salem Harbor requests authorization for a transaction pursuant to which CCI U.S. Asset Holdings LLC 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
			Jan 13	Public Citizen intervenes
	23	203 Application: Talen Energy Supply Reorganization (EC23-42)	Jan 26-30	PPL, Unsecured Noteholders intervene
	24	203 Application: Agilitas Companies / AB CarVal Funds (EC23-30)	Jan 24	FERC authorizes transaction
	24	203 Application: Central Rivers Power / LSPower (EC23-22)	Jan 5	Transaction consummated; Central Rivers Power MA and Central Rivers Power NH became Related Persons to Jericho Power
	24	203 Application: ConEd / RWE (EC23-17)	Jan 20	FERC authorizes transaction
*	25	LGIA: RI Energy / Deepwater Block Island Wind (ER23-1023)	Feb 1	RI Energy files LGIA with Deepwater Block Island Wind to govern the interconnection of Deepwater's 30 MW off-shore wind project; comment deadline **Feb 21, 2023**
*	25	IA: RI Energy / Manchester Street (ER23-1007)	Jan 31	RI Energy files replacement IA to govern Manchester Street's interconnection with its facilities; comment deadline **Feb 21, 2023**
*	25	LSAs: RI Energy/ISO-NE/BIPCO (ER23-1003; ER23-1000)	Jan 31	ISO-NE and RI Energy file LSAs as replacements to current NEP TSAs to allow RI Energy to fully recover the BITS surcharge now that it is both Transmission Owner and Customer under these arrangements; comment deadline ***Feb 21, 2022***
	25	EMM Contract (ER23-682)	Jan 17	FERC accepts EMM Contract for informational purposes

	25	LGIA-ISO-NE/NSTAR / Vineyard Wind 1 (ER23-488)	Jan 19	FERC accepts LGIA, eff. Nov 4, 2022
	26	Cost Reimbursement Agreement: NEP/Holden (ER23-396)	Jan 5	FERC accepts Agreement, eff. Oct 10, 2022

XII. Misc. - Administrative & Rulemaking Proceedings

	27	Reliability Tech Conf (Nov 10, 2022) (AD22-10)	Jan 17 Jan 23	Tech conf transcript posted to eLibrary EPSA, Public Power Associations file comments
	29	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Jan 5 Jan 10, 20 Jan 13 Jan 20 Feb 1	FERC issue notice of 6th JFSTF meeting to be held Wed, ***Feb 15, 2023*** NECPUC nominates, and FERC names, CT PURA Chair Marissa Gillett as one of the two NECPUC representatives on the JFSTF FERC posts transcript of 5th meeting to eLibrary AEP, Americans for a Clean Energy Grid and ACRE suggest topics for 6th meeting's agenda FERC posts agenda for 6th JFSTF meeting
	29	Modernizing Electricity Market Design - Resource Adequacy (AD21-10)	Jan 18	Comments on ISO/RTO Reports filed by, among others: Advanced Energy United, API, Constellation, New England Public Systems, Shell, Clean Energy Assocs, Clean Energy Buyers Assoc, EEI, EPSA, Public Interest Orgs, R Street Institute
*	30	*Order 886*: 2023 Civil Monetary Penalty Inflation Adjustments (RM23-3)	Jan 6	FERC issues *Order 886*, which increases the maximum civil monetary penalties that FERC may assess
*	31	2023 FERC Filing Fees Update (RM23-2)	Jan 22	FERC issues annual order increasing filing fees

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)	Jan 9 Jan 17 Jan 23 Jan 27 Jan 31	Green Development files Reply Brief Green Development files Joint Appendix Court schedules oral argument for ***Mar 20, 2023*** NEP files Final Brief Green Development file final Brief and Reply Brief
41	Mystic II (ROE & True-Up) (21-1198 et al.) (consolidated)	Jan 24	Mystic asks the Court for an order keeping these proceedings in abeyance and directing that motions to govern future proceedings be filed in late ***April 2023***
44	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.)	Jan 12 Jan 26	FERC files Respondent Brief Algonquin and INGA file Joint Brief of Intervenors Petitioner's Joint Reply Brief is due ***Feb 16, 2023***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: February 1, 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 February 1, 2023. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

On December 13, 2022, RENEW Northeast, Inc. ("RENEW") filed a complaint against ISO-NE and the Participating Transmission Owners ("PTOs") seeking changes to the ISO Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to Interconnection Customers. RENEW also requested (i) that it be considered an Interested Party or afforded adequate opportunity to participate and access transmission rate information under the PTOs' Formula Rate Protocols and (ii) the PTOs be directed to provide greater transparency regarding O&M costs in the interconnection process. The proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee on October 26, 2021, and discussed at the November 3, 2021 Participants Committee meeting. RENEW asked the FERC to issue an order granting the Complaint by April 14, 2023 (approximately 60 days prior to the June 15, 2023 deadline for the NE PTOs to publish a draft of the Annual Update to the data used in the transmission formula rate). Following a request by the PTO AC for a 20-day extension of time to submit comments, supported by NEPOOL, the MA AG and NESCOE, and granted by the FERC on December 22, 2022, comments 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. 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"), SEIA and Public Citizen. If you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

As previously reported, On October 17, 2022, Eastern New England Consumer-Owned Systems ("ENECOS") filed a Complaint against Mystic and ISO-NE challenging the pass-through to ISO-NE customers of firm pipeline transportation costs under the 2nd Amended and Restated Mystic Cost-of-Service Agreement ("COSA"), which ENECOS claimed are associated with pipeline facilities that are neither used nor usable to supply fuel to Mystic 8 and 9, and therefore should not be charged to ISO-NE and its customers under the COSA. Specifically, ENECOS

[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").

asked that all references to "Pipeline Transportation Agreements" be stricken from the COSA, template Line No. 7 "Fixed Pipeline Transportation" be removed from the true-up methodology, and Mystic be precluded from recovering the dollar amounts associated with that line item. ENECOS explained that the Complaint was filed as a procedural precaution as the charges that are the subject of the Complaint can be addressed by the FERC in proceedings on the DC Circuit's remand of issues relating to the FERC's allocation of Everett Marine Terminal costs under the COSA.[2]

Responses and Comments. Responses to and comments on ENECOS' Complaint were due on or before November 16, 2022. Mystic and ISO-NE filed responses. In its response, ***Mystic*** urged the FERC to dismiss the Complaint by asserting that (i) ENECOS have not, as required, sufficiently alleged changed circumstances since the pipeline transportation costs recovery mechanisms were found just & reasonable by the FERC; (ii) ENECOS are wrong on the merits; (iii) Mystic and the COSA are cost causative for Everett; and (iv) allocation of the costs is justified by tank management, which allows Mystic to meet the reliability need that the COSA is intended to address. For its part, ***ISO-NE*** also requested that the FERC deny the Complaint because the costs challenged are encompassed by the *Mystic Remand Order*. However, if the FERC does not dismiss the Complaint, ISO-NE urged the FERC to either consolidate the Complaint with the Mystic Remand Proceeding or hold the Complaint in abeyance. Comments supporting the Complaint were filed by MMWEC/NHEC (together, "Public Systems"), and by the Connecticut Public Utilities Regulatory Authority ("CT PURA") and the Connecticut Office of Consumer Counsel ("CT OCC", and together with CT PURA, the "CT Parties"). Doc-less interventions only were filed by NEPOOL, Calpine, Eversource, MA AG, National Grid, NESCOE, NRG, and the CT DEEP have intervened doc-lessly. ENECOS answered Mystic's November 16, 2022 answer and Mystic answered ENECOS' December 1, 2022 answer. There was no activity in this proceeding since the last Report. This matter is pending before the FERC. If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

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

By way of background, the *FTR Collateral Show Cause Order* follows PJM's *Green Hat* experience,[5] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential rulemaking to improve ISO/RTO credit practices,[6] and a two-day technical conference in February 2021 that

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

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

[4] *Id.* at P 31.

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

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

discussed principles and best practices for credit risk management in organized wholesale electric markets.[7] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[8] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

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

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

If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

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

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

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

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

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

On April 14, 2022, ISO-NE responded to the Complaint. Protests and comments on the Complaint were filed by: NEPOOL, Advanced Energy United (f/k/a/ AEE) ("AEU"), Calpine, EDF, FirstLight, LS Power, NEPGA, NESCOE, Public Interest Orgs ("PIOs",[11] Vistra/LSP Power, State Parties,[12] EPSA, National Hydropower Assoc., and the Solar Energy Industries Association ("SEIA"). On April 29, RENEW/ACPA answered the ISO-NE and NEPOOL motions to dismiss and answered the protests and comments filed in opposition to the Complaint. On May 17, ISO-NE answered the April 29 RENEW/ACPA answer. Interventions only were filed by AEP, Avangrid, Avangrid Renewables, Borrego, Brookfield, Constellation, CPV Towantic, Dominion, ENE, Excelerate, National Grid, NextEra, NH OCA, North East Offshore, NRG, Public Systems,[13] CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. On July 20, 2022, ISO-NE submitted a letter requested expeditious action on the Complaint (a request NEPOOL supported). RENEW/ACPA supported the request for expedited action on August 1, 2022 (adding that the FERC "should grant the Complaint and direct ISO-NE to submit a compliance filing that timely implements the proposed remedies", and could address the wish for "constructive *ex parte* communications with [FERC] Staff … with an appropriately crafted waiver of the *ex parte* limitations"). On November 7, 2022, RENEW and ACPA, in comments submitted also in the New England Winter Gas-Electric Forum proceeding (*see* AD22-9 below), drew attention to, reiterated its arguments in, and urged the FERC to expeditiously act on, this Complaint.

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

- **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.[14] 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.[15]

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

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

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

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

[14] *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*").

[15] *Id.* at P 20.

to intervene on or before October 5, 2021[16] 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)[17] and ("Seabrook Declaratory Order Petition") (EL21-3)[18]**

Nearly two and one-half years after these proceedings began, the FERC issued, on February 1, 2023, a single order addressing these two proceedings.[19] 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".[20] 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.[21] With respect to cost issues, the FERC agreed with Avangrid that, in this case, Seabrook should not recover opportunity costs (e.g. lost profits, lost revenues, and foregone Pay for Performance ("PFP") bonuses) or legal costs.[22] In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the *Seabrook Dispute Order*, that

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

[17] 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").

[18] 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.

[19] *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*").

[20] *Id*. at P 74.

[21] *Id*.

[22] *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.

additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition.[23]

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.[24] 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.[25] 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.[26]

Challenges, if any, to the *Seabrook Dispute Order* are due on or before Friday, ***March 3, 2023***. 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 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

[23] *Id.* at P 112.

[24] 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).

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

[26] *Id.* at P 88.

[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*")).

[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

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*.

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

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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).

[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.

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 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.

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[39] *Id.* at P 59.

[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).

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

II. Rate, ICR, FCA, Cost Recovery Filings

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

On December 21, 2022, ISO-NE submitted its informational filing for qualification in FCA17 (the "FCA17 Informational Filing"). ISO-NE is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by ISO-NE for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA17 is scheduled to begin March 6, 2023. The Informational Filing contained ISO-NE's determinations that three Capacity Zones will be modelled for FCA17 -- Northern New England ("NNE"), Maine, and Rest of Pool. NNE and Maine will be modeled as export-constrained. The Informational Filing reported that there will be 32,518 MW of existing capacity in FCA17 competing with 5,032 MW of new capacity under a Net ICR of 30,305 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 474 MW of De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 2 demand bids, totaling 7.8 MW, and 88 supply offers, totaling 515 MW, to participate in the substitution auction. Comments on the FCA17 Informational Filing were due on or before January 5, 2023; no comments were filed. NEPOOL, Calpine, Constellation, Eversource (out-of-time), National Grid, and NESCOE filed doc-less interventions.

On January 12, 2023, ISO-NE filed an errata disclosing that it had discovered a minimal error in the winter Qualified Capacity of one New Generating Resource, which resulted in an erroneous FCA Qualified Capacity for that resource, as well as for the post-RTR proration FCA Qualified Capacity of other resources that elected RTR treatment. ISO-NE stated that the impacts of its error were "1 MW or less". ISO-NE provided corrected FCA Qualified Capacity values in a revised confidential Attachment D. Comments on the errata filing were due on or before January 20, 2023; none were filed. 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).

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

On January 6, 2023, the FERC accepted the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2023-24 Capability Year, the second ARA for the 2024-25 Capability Year, and the first ARA for the 2025-26 Capability Year.[42] The ICR-Related Values were accepted effective as of January 29, 2023, as requested. Unless the January 6 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).

- **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

[42] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER23-534-000 (Jan. 6, 2023) (unpublished letter order).

[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.

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 the compliance filing is now pending before the FERC. FERC action on the compliance filing will conclude this proceeding. If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[46] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's *December 2020 Rehearing Order*.

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

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

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

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[47] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1,

[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).

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

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

2022 and the formal challenge process begins on September 15, 202).[48] The FERC reiterated that all items except return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[49] Accordingly, the FERC set these matters for a trial-type evidentiary hearing. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures (-015) summarized just below.[50]

(-015) First CapEx Info. Filing Settlement Judge Procedures. On May 4, Chief Judge Cintron designated Judge Andrea McBarnette as the Settlement Judge. Thus far, five settlement conferences have been held, the first on June 15; the second, November 17, 2022; the third, December 20, 2022. Since the last Report, fourth and fifth settlement conferences were held January 18, 2023 and January 27, 2023, respectively. In her last status report, submitted on January 3, 2023, Settlement Judge McBarnette recommended the continuation of settlement judge procedures.

(-018) Second CapEx Info Filing. On September 15, 2022, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "Second CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects"). Formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS. Comments on NESCOE's and ENECOS' challenges were due on or before November 16, 2022 and November 17, 2022, respectively. Mystic responded separately to NESCOE's and ENECOS' challenges. MMWEC/NHEC filed comments supporting ENECOS' formal challenge, emphasizing its support for formal challenge to the pass through of charges incurred by Everett for pipeline transportation reservations (*see* ENECOS Mystic COSA Complaint (EL23-4) above). Since the last Report, on December 6, 2022, ENECOS answered Mystic's November 17, 2022 answer. On December 22, 2022, Mystic filed a response to ENECOS' December 6 answer, and requested that the FERC reject the Formal Challenges, and accept the Second Filing as expeditiously as possible. The Second CapEx Info Filing, including the formal challenges, and the responses/comments thereon, are pending before the FERC.

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

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

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

[49] *Id.* at P 26.

[50] *Id.* at P 27.

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

The July 29 filing was reviewed with the Transmission Committee at its August 16, 2022 summer meeting and at an August 22, 2022 technical session for Interested Parties. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties 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.

Formal Challenge by RENEW. On January 31, 2023, RENEW filed a formal 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. RENEW's formal challenge is pending before the FERC.

Supplement. On January 31, 2023, the PTO AC supplemented its July 29 filing with updated rates and associated revenue requirements for Regional and Local Service, effective January 1, 2023 – December 31, 2023, under transition arrangements to the Attachment F Settled Formula Rate. The changes relate to revisions to Attachment F to establish transmission revenue requirements for Narragansett Electric Co.

[51] 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").

("Narragansett" or "RIE") and a related tariff waiver submitted by New England Power Company ("NEP"), both recently accepted by the FERC and that became effective on January 1, 2023, the date RIE became a PTO.

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 January 20, 2023, ISO-NE and NEPOOL jointly filed revisions to Section III.13.7.5.4.5 of Market Rule 1 (the "PPU CTR Clarifications") to clarify the calculation of FCM Capacity Transfer Rights ("CTR") that are related to Pool-Planned Units ("PPU"). Specifically, the revisions clarify (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 supported by the Participants Committee at its October 6, 2022 meeting (Consent Agenda Item #1). ISO-NE requested a March 21, 2023 effective date. Comments on the PPU CTR Clarifications are due on or before ***February 10, 2023***. Thus far, National Grid has intervened doc-lessly. 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: Advanced Energy United, FirstLight, National Grid, NEPGA, NESCOE, UCS, and VELCO. Doc-les interventions only were filed by Avangrid, Narragansett ,Vistra, MA DPU, LSP Transmission Holdings, RENEW, ACPA, EPSA. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On January 19, 2023, the FERC accepted revisions to the Do Not Exceed ("DNE") dispatch rules in Market Rule 1 to allow front-of-meter solar resources to become Dispatchable Resources ("Solar DNE Dispatch Changes").[52] The Solar DNE Dispatch Changes were accepted effective as of December 5, 2023, as requested. Unless the January 19 letter order is challenged, this matter will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

New England's *Order 2222* Compliance Filing remains pending before the FERC. As previously reported, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted on February 2, 2022 Tariff revisions ("*Order 2222* Changes") in response to the requirements of *Order 2222*. The Filing Parties stated that the *Order 2222* Changes create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual

[52] *ISO New England Inc.*, Docket No. ER23-517-000 (Jan. 19, 2023) (unpublished letter order).

Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before April 1, 2022. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEU/PowerOptions/SEIA; Environmental Organizations;[53] MA AG; Voltus; AEMA and 4 New England US Senators.[54] Doc-less interventions were filed by: Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE (April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. Since the last Report, AEU/PowerOptions/SEIA and AEMA answered the ISO-NE and National Grid/Avangrid/ Eversource answers.

(-001) Deficiency Letter. On May 18, 2022, the FERC issued a 25-page deficiency letter directing ISO-NE to provide, on or before June 17, 2022, additional information and clarifications. ISO-NE filed its 39-page response to the deficiency letter on June 17, 2022. Comments in response to ISO-NE's deficiency letter response were due on or before July 8, 2022 and a joint protest was filed by AEU, AEMA, PowerOptions, and SEIA ("Joint Protest"). The Joint Protest, while supportive of certain responses (those regarding the exemption of DERAs from the Small Generator Interconnection Procedures ("SGIP") prior to 2026, locational requirements for DER aggregation, and the role of host utilities in identifying potential conflicts with retail program participation), protested the adequacy of ISO-NE responses regarding proposed metering and telemetering requirements for behind-the-meter ("BTM") DERs. On July 25, 2022, ISO-NE answered the July 8 Joint Protest. On August 9, 2022, AEU, AEMA, PowerOptions, and SEIA answered ISO-NE's July 25 answer.

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

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

On November 22, 2022, ISO-NE filed Tariff provisions governing the Inventoried Energy Program ("IEP") consistent with the D.C. Circuit's *IEP Decision*.[55] ISO-NE's proposed Tariff changes remove nuclear, biomass, coal, and hydroelectric generators from the IEP. ISO-NE's Tariff changes were supported by the Participants Committee at its November 2 meeting (as were alternative Tariff changes proposed by Brookfield that explicitly allow pumped hydro resources to participate in the IEP as Electric Storage Facilities). Comments were due on or before December 13, 2022.

Comments and limited protests were filed by: NEPOOL, Brookfield, MA AG, National Hydropower Association, and RENEW; doc-less interventions only, by Calpine, FirstLight and National Grid. On December 28,

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

[54] Senators Markey (MA), Sanders (VT), Warren (MA), and Whitehouse (RI).

[55] *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.

2022, New England Consumer-Owned Systems[56] 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 January 27, 2023, ISO-NE and NEPOOL filed revisions to Attachment K to the OATT to 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 (the "Economic Study Revisions"). The Economic Study Revisions were supported by the Participants Committee at its January 5, 2023 meeting (Consent Agenda Item #1). ISO-NE requested a March 31, 2023 effective date for the Economic Study Revisions. Comments on the Economic Study Revisions are due on or before ***February 17, 2023***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On January 31, 2023, the FERC accepted revisions proposed by NSTAR to the general plant depreciation rates for NSTAR (East) and NSTAR (West).[57] The depreciation changes included in this filing provide for the same depreciation rates that were approved November 30, 2022 by the Massachusetts Department of Public Utilities ("MA DPU"). The revisions were accepted effective as of January 1, 2023 (the same effective date approved by the MA DPU for the implementation of these depreciation rates for NSTAR's distribution rates). Unless the January 31 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,[58] and the Schedule 20A Service Providers.[59] 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

[56] 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.

[57] *ISO New England Inc. and NSTAR Elec. Co.*, Docket No. ER23-637-000 (Jan. 31, 2023) (unpublished letter order).

[58] 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").

[59] 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.

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

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

On March 2, 2022, in response to the requirements of *Order 676-J*,[61] ISO-NE and CSC filed revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards ("Schedule 18 Order 676-J Part I Changes").[62] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by CSC and NEPOOL. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Also on March 2, 2022, in response to the requirements of *Order 676-J*, the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 20/21-Common Order 676-J Part I Changes").[62] An effective date as of the date the FERC may determine was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by NEPOOL and Eversource. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Again on March 2, 2022, in response to the requirements of *Order 676-J*, ISO-NE filed revisions to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards) to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 24 Order 676-J Part I

[60] *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*").

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

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

Changes").[62] An effective date no earlier than June 2, 2022 was requested. The Transmission Committee recommended that the Participants Committee support the Schedule 24 Order 676-J Part I Changes at its March 23 meeting, and the Participants Committee supported the changes at the April 7 meeting (Consent Agenda Item # 1). Comments on this filing were due on or before March 23, 2022; none were filed. NEPOOL, Eversource, MA DPU, and National Grid submitted doc-less interventions. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

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

On December 22, 2022, ISO-NE and NEPOOL jointly filed IEP-related changes to the Tariff and a definition change revising "Monthly Issuance" in Section I's omnibus definition section (the "FAP/BP Changes"). Specifically, revisions to the FAP are designed to ensure adequate collateral is provided by Market Participants participating in the IEP; revisions to the Billing Policy ("BP") reflect charges and credits related to the IEP; and the revisions to the definition of "Monthly Issuances" in Section I.2.2 are designed to ensure consistency with the Billing Policy. The FAP/BP Changes were supported by the Participants Committee at its November 2, 2022 meeting (Agenda Item #5). ISO-NE requested a February 23, 2023 effective date for the FAP/BP Changes. Comments on the FAP/BP Changes were due on or before January 12, 2023; none were filed. Calpine, Constellation, Eversource, National Grid, and NRG submitted doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

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

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. A December 19, 2022 effective date for the SGIA was requested. Comments on this filing are due on or before ***February 8, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On December 20, 2022, Rhode Island Energy submitted a filing (i) to move certain RIE service agreements ("SAs") to Schedule 21-RIE from Schedule 21-NEP (Docket No. ER23-678) and (ii) to revise RIE's Interconnection Service Agreement ("ISA") with Thundermist Hydropower LLC ("Thundermist"). In a companion filing (Docket No. ER23-681), RIE and NEP submitted a filing to cancel the NEP Tariff database that previously contained the SAs. RIE expects the SA transfers to become effective as of January 1, 2023. Comments on these filings were due on or before January 10, 2023. On January 6, 2023, National Grid filed comments supporting the filings. The RI Division intervened on January 10, 2023. Also on January 10, 2023, Narragansett filed a notice that it became a PTO on January 1, 2023 and that January 1, 2023 was thus an appropriate effective date for the SAs filed in these proceedings. 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).

- **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 Versant 2021 Annual Update Settlement Agreement") 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 Offer of Settlement would resolve all issues raised by the MPUC with respect to the

2021 Annual Update. Comments on the Revised Versant 2021 Annual Update Settlement Agreement are due on or before ***February 2, 2023***. 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, and also on January 12, 2023, Versant submitted a revised uncontested Joint Offer of Settlement ("Revised 2020 Annual Update Offer of Settlement") between itself and the MPUC that replaces in full the Versant 2020 Annual Update Settlement Agreement submitted November 19, 2021.[63] Versant stated that, if approved, the Revised 2020 Annual Update Offer of Settlement would resolve all issues raised by the MPUC with respect to the 2020 Annual Update. Comments on the Revised 2020 Annual Update Offer of Settlement are due on or before ***February 2, 2023***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP Annual True Up Calculation Forecast Info Report (ER12-2304)**

On January 17, 2023, pursuant to Section 4 of Schedule 21-GMP, Green Mountain Power ("GMP") supplemented its annual informational filing containing the forecast of its costs for the January 1, 2023 through December 31, 2023 time period. The supplement does not change the 2023 forecasted rates previously filed. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, 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 January 30, 2023, ISO-NE and NEPOOL filed for approval Amendment No. 12 to the Participants Agreement ("PA12"), which would raise the age limitation prohibiting the election or re-election of any candidate to the ISO Board of Directors from 70 to 75. PA12 was approved by NEPOOL following a second balloting period during which the Minimum Response Requirement was satisfied. Comments, if any, on PA12 are due on or before ***February 21, 2023***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports

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

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

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[64] *and 531-B*[65] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[63] As previously report, 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").

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

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

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

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

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

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

- **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 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 will not be noticed for public comment by the FERC.

- **LFTR Implementation: 57th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 57th of its quarterly status reports regarding LFTR implementation on January 13, 2023. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

- **IMM Quarterly Markets Reports – Fall 2022 (ZZ22-4)**

On January 31, 2023, the IMM filed with the FERC its Fall 2022 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Fall 2022 Report will be discussed with the Markets Committee at the February 7-9, 2023 Markets Committee meeting.

IX. Membership Filings

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

On January 31, 2023, NEPOOL requested that the FERC accept (i) 3 memberships - those 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 8 Participants -- 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) one name change – that of Advanced Energy United Inc. (f/k/a Advanced Energy Economy Inc.) ("AEU"). Comments on the February membership filing are due on or before ***February 21, 2023***.

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

On December 30, 2022, NEPOOL requested that the FERC accept (i) the memberships of Just Energy Limited [Related Person to Just Energy (U.S.) Corp. and Hudson Energy Services, LLC (Supplier Sector); and Think Energy, LLC (Supplier Sector); (ii) the termination of the Participant status of Josco Energy MA (Supplier Sector), Starion Energy (Supplier Sector), and Rhode Island Bioenergy Facility [Related Person to Rhode Island Bioenergy, LLC (AR Sector, RG Sub-Sector, Small RG Group Seat)]; and (iii) the name changes of BP Energy Retail Company LLC (f/k/a EDF Energy Services, LLC), BP Energy Holding Company LLC (f/k/a BP Energy Retail LLC), and Rhode Island Bioenergy Facility, LLC (f/k/a formerly known as Rhode Island Bioenergy, LLC). Comments on the January membership filing were due on or before January 21, 2023; none were filed. This matter is pending before the FERC.

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

On January 20, 2023, the FERC accepted the membership of 11772244 Canada Inc. (Supplier Sector), effective as of December 1, 2022.[66] Unless the January 20 order is challenged, this proceeding will be concluded.

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).

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

On November 29, 2022, NERC filed its annual report on Find, Fix, and Track ("FFT") and Compliance Exception programs, in accordance with prior FERC Orders.[67] 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. Comments on the FFT annual report were due on or before January 24, 2023; none were filed. This matter is pending before the FERC.

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

NERC's October 28, 2022 request for approval of proposed changes to Reliability Standards EOP-011-3 (Emergency Operations) and EOP-012-1 (Extreme Cold Weather Preparedness and Operations) (the "*Cold Weather Standards*") is pending before the FERC. As previously reported, the changes to the *Cold Weather Standards*, which address certain key recommendations from the *Feb 2021 Cold Weather Outages Joint Report,*[68] 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. NERC requested that these *Cold Weather Standards* become effective on the first day of the first calendar quarter that is 18 months after FERC approval ("Effective Date"). Generator Owners would have an additional 42 months from the Effective Date to come into compliance with new freeze protection measures and 60 months from the Effective Date to perform their first five-year update of the Extreme Cold Weather Temperature. Comments on the *Cold Weather Standards* were due, following a request for an extension of time filed by EPSA and partially granted by the FERC on November 29, 2022, on or before December 8, 2022.

Comments on the *Cold Weather Standards* were filed by: EPSA, NEPGA, Invenergy, the ISO/RTO Council ("IRC"), Transmission Access Policy Study Group ("TAPS"), and the Texas Competitive Power Advocates. Reply

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[66] *New England Power Pool Participants Comm.*, Docket No. ER23-518-000 (Jan. 20, 2023) (unpublished letter order).

[67] *See N. Am. Elec. Rel. Corp.*, 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").

[68] 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*").

comments were filed by: NERC, Competitive Generators,[69] Invenergy, and APPA. On January 3, 2023, the IRC answered the reply comments filed by NERC and Competitive Generators, requesting that the FERC, particularly if it assigns the issues raised by the IRC to additional work in Phase II of the stakeholder process, find the issues raised by the IRC have merit and direct they be resolved through changes to the proposed standard within one year. This matter is pending before the FERC.

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

On November 17, 2022, to address FERC concerns regarding the reliability impacts of inverter-based resources ("IBRs")[70] on the Bulk-Power System ("BPS"), the FERC issued an order[71] directing NERC to submit a work plan on or before ***February 15, 2023*** describing how it plans to identify and register owners and operators of IBRs that are connected to the BPS, but that are not currently required to register with NERC under the bulk electric system ("BES") definition ("unregistered IBRs"), and that "have an aggregate, material impact on the reliable operation of the [BPS]". FERC stated that the work plan should explain how NERC will modify its processes to address unregistered IBRs within 12 months of approval of the work plan. The work plan must also include implementation milestones ensuring that owners and operators meeting the new registration criteria are identified within 24 months of the approval date of the work plan, and that they are registered and required to comply with applicable Reliability Standards within 36 months of the approval date of the work plan. The FERC will notice the work plan for public comment. Once approved, NERC must file progress reports every 90 days thereafter detailing the progress towards identifying and registering owners and operators of unregistered IBRs.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[72] on December 15, 2022. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the December 15 report, NERC reported that, because ballot body approval was not achieved for two related Reliability Standards, the schedule for Project 2016-02 has been revised and now calls for final balloting of revised standards in March 2023, NERC Board of Trustees Adoption in May 2023 and filing of the revised standards with the FERC in June 2023.

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

On June 16, 2022, the FERC issued a notice[73] 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

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

[70] 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*.

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

[72] 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.

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

extreme weather scenarios; and (iii) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Initial comments were due August 26, 2022[74] 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,*[75] the FERC issued *Order 887*.[76] *Order 887* directs NERC to develop and submit [within 15 months of the effective date of Order 887][77] for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[78] within a trusted Critical Infrastructure Protection 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 [60 days after its publication in the *Federal Register*].

- **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.[79] 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. This matter is pending before the FERC.

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

As previously reported, the FERC conditionally approved, on July 8, 2022, changes to the NPCC Bylaws (the "Bylaws") designed to, among other things: (1) to improve corporate governance; (2) to ensure consistency with the Not-for-Profit Corporation Law of the State of New York ("N-PCL"), pursuant to which NPCC is organized; and (3) to remove extraneous provisions rom the Bylaws, create efficiencies, and reflect changes at NPCC since 2012 (when the last changes to the Bylaws were filed).[80] In accepting the Bylaws Changes, the FERC directed NERC/NPCC to submit in a compliance filing changes that (i) provide members being terminated for failure to comply with bylaw provisions related to qualifications, obligations, and conditions of membership (a) notice within

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[74] 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.

[75] *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*").

[76] *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*").

[77] *Order 887* has not yet been published in the *Federal Register*.

[78] 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.

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

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

a reasonable time period of the NPCC Board's membership termination decision and the reason(s) for the action and (b) the option to appeal the membership termination in accordance with the due process requirement in FPA Section 215; and (ii) specifically describe the method of providing public notice of member meetings. On October 5, 2022, NERC and NPCC submitted that compliance filing, with revisions to the Bylaws to (i) require that prior to terminating any NPCC Member under section 4.6, the NPCC Board must provide the affected Member 21 days prior written notice and an opportunity to cure the problem or appeal the reason for the proposed termination; (ii) to specify that the meeting notices shall be posted on NPCC's public website in a "reasonably prominent location; and (iii) to update the NPCC Bylaws' Table of Contents. The FERC accepted the compliance filing on January 3, 2023.[81] Unless the January 3 order is challenged, this proceeding will be concluded.

XI. Misc. - of Regional Interest

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

On January 13, 2023, Saddleback Ridge Wind, LLC ("Saddleback") requested FERC authorization for a proposed transaction pursuant to which CPV Mountain Wind Holdings, LLC ("Buyer") will acquire all of the membership interests in Saddleback. Comments on this 203 application are due on or before ***February 3, 2023***. 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 January 6, 2023, Salem Harbor Power Development LP ("Salem Harbor") requested FERC authorization for a proposed transaction pursuant to which CCI U.S. Asset Holdings LLC 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. Once consummated, Salem Harbor will become a Related Person of Supplier Sector member Castleton Commodities Merchant Trading LP. Comments on this 203 application were due on or before January 27, 2023; none were filed. Public Citizen filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On December 15, 2022, Talen Energy Supply, LLC ("TES") requested the required FPA Section 203 approvals for a change in control transaction whereby 10% or more of the voting securities of a new parent of TES and its affiliated debtors ("Reorganized Talen") will be distributed to some or all of Indicated Noteholders pursuant to a joint plan of reorganization of the TES Debtors subject to confirmation by the Bankruptcy Court. Comments on the 203 application were due on or before January 30, 2023; none were filed. Doc-less interventions were filed by the PJM IMM, Public Citizen, PPL and an ad hoc group of Noteholders. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On December 14, 2022, Rhode Island State Energy Center, LP ("RISEC") and EGCO RISEC II, LLC ("Buyer") requested FERC authorization for a proposed transaction pursuant to which Buyer, a wholly owned indirect subsidiary of Electricity Generating Public Company Limited ("EGCO"), will acquire a 49% indirect ownership interest in RISEC from Cogentrix Sellers.[82] Following the transaction, RISEC will be indirectly owned by Buyer (49%) and the Cogentrix Sellers (51%). Comments on this 203 application were due on or before January 30, 2023; none

[81] *N. Am. Elec. Rel. Corp. and Northeast Power Coordinating Council, Inc.*, Docket No. RR22-2-001 (Jan. 3, 2023) (unpublished letter order).

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

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

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

On January 24, 2023, the FERC authorized[83] a transaction pursuant to which the AB CarVal Funds[84] 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,[85] 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 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: Central Rivers Power / LSPower (EC23-22)**

As previously reported, the FERC authorized a transaction pursuant to which Patriot Hydro, LLC, an indirect, wholly controlled subsidiary of LS Power Development, LLC and affiliate of LS Power (together, "LSPower") will acquire the New England QF assets of Central Rivers Power Super Holdings Holdco, LLC, an affiliate of Hull Street Energy Partners and Central Rivers Power (together, "Central Rivers Power").[86] On January 13, 2023, notice was filed that the transaction was consummated on January 5, 2023. As a result of the transaction, NEPOOL Participants Central Rivers Power MA, LLC and Central Rivers Power NH, LLC became Related Persons to AR Sector member Jericho Power. The Central Rivers Participants former Related Persons, Pawtucket Power and Waterbury Generation, switched to the Generation Sector at the 2022 Annual Meeting). Reporting on this matter has now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On 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[87] 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)).[88] Pursuant to the January 20 order, RWE 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: Great River Hydro / HQI US (EC23-16)**

Also on October 28, 2022, Great River Hydro, LLC ("Great River Hydro") and HQI US Holding LLC ("HQUI US"), an indirect and wholly-owned subsidiary of Hydro-Québec ("HQ") requested authorization for a transaction pursuant to which HQI US will indirectly acquire 100% of the membership interests in Great River Hydro. Comments on this 203 application were due on or before December 12, 2022; none were filed. This matter is

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

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

[85] 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.

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

[87] "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.

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

pending before the FERC. 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 February 1, 2023, Narragansett Electric Company ("RI Energy") filed an LGIA with Deepwater Block Island Wind, LLC ("Deepwater Wind") to govern 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 reflect revisions primarily related to the transition of ownership from New England Power to RI Energy. A January 1, 2023 effective date was requested. Comments on this filing are due on or before ***February 22, 2023***. 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 January 31, 2023, RI Energy filed an replacement Interconnection Agreement ("IA") with Manchester Street, LLC ("Manchester Street") to govern 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. A January 1, 2023 effective date was requested. Comments on this filing are due on or before ***February 21, 2023***. 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. A January 1, 2023 effective date was requested. Comments on the LSAs are due on or before ***February 21, 2022***. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **EMM 2023-2025 Contract (ER23-682)**

On January 17, 2023, the FERC accepted for informational purposes ISO-NE's 3-year contract (2023-2025) with Potomac Economics, Ltd. to continue as ISO-NE's External Market Monitor ("EMM").[89] ISO-NE noted in its filing that the new agreement is closely modeled on the previous agreement between Potomac and ISO-NE, including all of the functions laid out for the EMM in Section 9.4.3 of the Participants Agreement. The new EMM contract term will run from January 1, 2023 through December 31, 2025. Unless the January 17 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On January 19, 2023, the FERC accepted a First Revised LGIA between NSTAR and Vineyard Wind 1, LLC to reflect the assignment of the LGIA by Vineyard Wind, LLC to Vineyard Wind I, LLC.[90] The First Revised LGIA was accepted effective as of November 4, 2022, as requested. Unless the January 19 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).

[89] *ISO New England Inc.*, Docket No. ER23-682-000 (Jan. 17, 2023) (unpublished letter order).

[90] *ISO New England Inc.,* Docket No. ER23-488-000 (Jan. 19, 2023) (unpublished letter order).

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

On January 5, 2023, the FERC accepted a Cost Reimbursement Agreement between New England Power Company and Holden Municipal Light Department ("Holden") pursuant to which NEP will perform work to support Holden's plan to rebuild its Chaffins Substation.[91] The Agreement was accepted effective as of October 10, 2022, as requested. Unless the January 5 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 12, 2022, in response to the requirements of *Order 881*, Versant Power filed a proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT"). Attachment T, Versant reported, incorporates all the contents of the *pro forma* OATT's new Attachment M. An effective date of July 12, 2025 was requested in an errata filing submitted on August 1, 2022. On August 2, 2022, MPUC submitted comments asserting that Versant's Compliance Filing, without further detail, is insufficient to meet the requirements of *Order 881* and should either (i) be rejected outright, ordering Versant to re-file with sufficient detail, or (ii) subject to a deficiency letter requiring further information with respect to the Compliance Filing. MPUC withdrew those comments on August 31, 2022 in exchange for certain understandings with Versant Power (including MPUC's attendance, as a non-voting participant, at any NMISA working group discussions on *Order 881* implementation planning and Versant Power's submission of informational compliance filings to keep the FERC apprised of versant's progress in developing its AAR implementation plan). On September 6, 2022, Versant Power supplemented its compliance filing to confirm the MPUC's understandings, as delineated in its Notice of Withdrawal. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On December 16, 2022, and as required in the June 10, 2022 order in this proceeding,[92] CMP submitted a compliance filing that included a Second Amended Agreement and Schedules between CMP and Sappi North America, Inc. ("Sappi"). The Second Amended Agreement reflected the November 17, 2022 closing date of the FERC-authorized transaction in which Sappi transferred its hydroelectric facilities to Presumpscot Hydro LLC ("Presumpscot Hydro") and its membership interests in Presumpscot Hydro to an unrelated third-party buyer. Comments on the compliance filing were due on or before January 6, 2023; none were filed. This matter is pending before the FERC. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

As previously reported, Versant Power filed revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards in response to the requirements of *Order 676-J*, ("Versant MPD OATT *Order 676-J* Part I Changes").[62] A placeholder effective date was submitted. Comments on this filing were due on or before March 23, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[91] *New England Power Co.*, Docket No. ER23-396-000 (Jan. 5, 2023) (unpublished letter order).

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

XII. Misc. - Administrative & Rulemaking Proceedings[93]

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

As previously reported, Invenergy Transmission ("Invenergy") filed a petition, on July 19, 2022, requesting that the FERC hold a technical conference to explore ways to potentially make available and compensate certain grid reliability and resilience benefits associated with interregional high voltage direct current ("HVDC") merchant transmission. Any comments to be considered by the FERC in its determination of any action to be taken were due on or before August 26, 2022. Comments were filed by 13 parties and included, among others, CSC, ENGIE, Invenergy, Phase I/II Asset Owners and IRH, Joint Consumer Advocates, MISO, ACORE, ACPA, SEIA, and Neptune and Hudson. Invenergy answered the comments filed by MISO. On November 10, 202, Invenergy again urged the FERC to "hold a technical conference to examine and to improve the policy and processes relating to the interconnection of interregional MHVDC systems". In December, ENGIE, Grid United and SEIA filed comments supporting Invenergy's November 10 request. There was no activity since the last Report. This matter remains pending before the FERC.

- **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 post-technical conference comments to address issues raised during the technical conference identified in the Supplemental Notice of Technical Conference issued on December 6, 2022. Comments are due on or before ***February 17, 2023***.

- **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.[94] A transcript of the technical conference was posted in the FERC's eLibrary on January 17, 2023. This matter is now pending before the FERC.

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

The FERC held a New England Gas-Electric Forum on September 8, 2022 in Burlington, VT. The purpose of the Forum was to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are

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[93] Reporting on the following Administrative & Rulemaking proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: Voltus Petition for a FERC Technical Conference on *Order 2222* (RM18-9).

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

needed to inform the development of solutions to these challenges. On September 21, 2022, the FERC invited parties wishing to submit comments regarding the topics discussed at the Forum to do so on or before November 7, 2022. Post-Forum Comments were submitted by: ISO-NE, Acadia, AEU, AIM, Calpine, Constellation, Excelerate, FirstLight, LS Power, NECOS, NEPGA, NESCOE, Public Systems, Repsol, TOs, VELCO, Vistra, Potomac Economics, CT DEEP, AEMA, APGA, EPSA, INGA, NE LDCs, NGSA, New England Council, NEPPA, NH BIA, PIOs, RENEW/ACPA, Berkshire Action Team, Greater Concord Chamber of Comm., Mass. Alliance for Econ. Dev., Mass. Business Roundtable, Mass. Coalition for Sustainable Energy, Mass. United Assoc. of Journeymen, Middlesex County Chamber of Commerce, Public Citizen, Western Mass. Economic Dev. Council, and Individual Citizens (M. Axner, E. Blank, S. Botkin, D. Heimann, J. Krieger, B. Little, I. McDonald, J. Neville, W. Persons, R. Spector). On November 22, National Grid filed reply comments. This matter is pending before the FERC.

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

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

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. 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 are due on or before ***March 23, 2023***.

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

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[95] 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.

[95] *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[96] and were filed by: AEP, Clean Energy Entities,[97] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter is pending before the FERC.

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

A sixth meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF")[98] will be held on Wednesday, February 15, 2023, from approximately 1:30 pm to 4:00 pm Eastern time, at the Renaissance Washington Downtown Hotel in Washington, DC.[99] All interested persons were invited to file comments in this docket suggesting agenda items by January 20, 2023. Comments were filed by AEP, Americans for a Clean Energy Grid and American Council on Renewable Energy ("ACRE"). An agenda for the February 15 meeting was posted on February 1, 2023. The one topic noticed is "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 identified as guest speakers.

The FERC's December 23, 2022 notice inviting comments following its October 6, 2022 technical conference on Transmission Planning and Cost Management (*see* AD22-8 above) was also posted in this docket. As noted above, comments on the topics/questions provided in the December 23 notice are due on or before ***March 23, 2023***.

New NECPUC Representative. On January 10, 2023, and in a FERC order issued January 20, 2023, CT PURA Chair Marissa Gillett was nominated and named, respectively, as one of the two NECPUC representatives on the Transmission Task Force. Chair Gillett replaces MA DPU Commissioner Matt Nelson, who resigned his position with the MA DPU on January 6, 2023. Vermont PUC Commissioner Riley Allen continues as the other NECPUC representative on the Transmission Task Force.

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[100] 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* follows a series of staff-led

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

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

[98] *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).

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

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

technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[101] and energy and ancillary services markets.[102]

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. Since the last Report, comments were filed by, among others: Advanced Energy United, API, Constellation, New England Public Systems,[103] Shell, Clean Energy Assocs, Clean Energy Buyers Association, EEI, EPSA, Public Interest Orgs, R Street Institute.

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

- ***Order 886*: 2022 Civil Monetary Penalty Inflation Adjustments (RM23-3)**

On January 6, 2023, the FERC issued *Order 886*[104] to amend its regulations governing the maximum civil monetary penalties assessable for violations of statutes, rules, and orders within FERC's jurisdiction. The FERC is required to update each such civil monetary penalty on an annual basis every January 15.[105] Of particular interest is the increase in potential civil penalties for market manipulation, which were increased from $1,388,496 to $1,496,035 per violation, per day. *Order 886* became effective January 12, 2023.[106]

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

[102] 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.

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

[104] *Civil Monetary Penalty Inflation Adjustments*, Order No. 886, 182 FERC ¶ 61,002 (Jan. 6, 2023) ("*Order 886*").

[105] *See* Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, Sec. 701, Pub. L. 114-74, 129 Stat. 584, 599. The FERC made its first adjustment under the Act in July 2016. *See Civil Monetary Penalty Inflation Adjustments*, Order No. 826, 81 FR 43937 (July 6, 2016), FERC Stats. & Regs. ¶ 31,386 (2016). The second adjustment was made January 9, 2017. *Civil Monetary Penalty Inflation Adjustments*, Order No. 834, 158 FERC ¶ 61, 170 (Jan. 9, 2017). The third adjustment as made January 8, 2018. *Civil Monetary Penalty Inflation Adjustments*, Order No. 839, 162 FERC ¶ 61,010 (Jan. 8, 2018). The fourth adjustment was made January 9, 2019. *Civil Monetary Penalty Inflation Adjustments*, Order No. 853, 166 FERC ¶ 61,041 (Jan. 8, 2019). The fifth adjustment was made January 14, 2020. *Civil Monetary Penalty Inflation Adjustments*, Order No. 865, 170 FERC ¶ 61,001 (Jan. 2, 2020). The sixth adjustment was made January 8, 2021. *Civil Monetary Penalty Inflation Adjustments*, Order No. 875, 174 FERC ¶ 61,015 (Jan. 8, 2021). The seventh adjustment was made January 7, 2022. *Civil Monetary Penalty Inflation Adjustments*, Order No. 882, 178 FERC ¶ 61,008 (Jan. 7, 2022).

[106] *Order 886* was published in the *Fed. Reg.* on Jan. 12, 2023 (Vol. 88, No. 8) pp. 1,989-1,991.

- **2023 Annual FERC Filing Fees Update (RM23-2)**

On January 23, 2023, the FERC issued a final rule updating its filing fees.[107] Because the FERC concluded that the rule will not significantly affect regulated entities or the general public, no public comment period was required. The rule will become effective on March 2, 2023.[108]

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

On July 28, 2022, the FERC issued a NOPR[109] 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[110] requested an additional month to submit comments.[111] On September 14, 2022, the FERC granted that request. Accordingly, initial comments were due November 11, 2022 and over 30 sets of comments were filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA, APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange. The US Chamber of Commerce filed reply comments on December 12, 2022. There was no activity in the proceeding since the last Report. This matter is pending before the FERC.

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

On September 22, 2022, the FERC issued a NOPR[112] 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*)[113] described in previous Reports.

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[107] *Annual Update of Filing Fees*, 182 FERC ¶ 62.043 (Jan. 23, 2023).

[108] The *Annual Update of Filing Fees* final rule was published in the *Fed. Reg.* on Jan. 31, 2023 (Vol. 88, No. 20) pp. 6,614-6,165.

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

[110] "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").

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

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

[113] *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

Initial comments on the *Advanced Cybersecurity Investment NOPR* were due on or before November 7, 2022 and reply comments were due November 21, 2022.[114] 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[115] 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[116] (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[117] 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"),[118] 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 ("LGIA"), and *pro forma* Small Generator Interconnection Agreement ("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;[119] (2) reforms to increase the speed of interconnection queue

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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.

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

[115] *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*").

[116] "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".

[117] 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.

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

[119] 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;

processing;[120] and (3) reforms to incorporate technological advancements to the interconnection process.[121] Within each of these categories, the FERC proposes a wide array of reforms, and requested comment.

Initial Comments. Initial comments were due October 13, 2022[122] 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.

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).

- 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;[119]
- 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.

[120] 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.

[121] 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.

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

- **NOPR: ISO/RTO Credit Information Sharing (RM22-13)**

On July 28, 2022, the FERC issued a NOPR[123] proposing to revise its regulations to permit ISO/RTOs to share among themselves[124] credit-related information regarding market participants.[125] 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.

Initial Comments. Initial comments were due October 7, 2022[126] 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.

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

Following its ANOPR process,[127] the FERC issued on April 21, 2022 a NOPR[128] that would require public utility transmission providers to:

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

[124] 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).

[125] 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.

[126] 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.

[127] *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.

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

(i) conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;

(ii) more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes;

(iii) seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning;

(iv) adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to "right-size" replacement transmission facilities; and

(v) revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms proposed in this NOPR.

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

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

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[129] 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

[129] 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.

("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. There was no activity in this proceeding since the last Report.

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).

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

On July 28, 2022, the FERC issued a NOPR[130] 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.[131] Seven sets of comments were filed by: Dominion, ACPA/SEIA, EEI, Liquid Energy Pipeline Assoc., RESA, PG&E/SDG&E, C. Pechman. This matter is pending before the FERC.

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

Supplemental NOPR. In light of comments already received in this proceeding,[132] the FERC issued on April 15, 2021 a *Supplemental NOPR*[133] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC sought comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[134]

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

[131] 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.

[132] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

[133] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

[134] As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including the following:

- A shift from risks and challenges to a ***consumers' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period and an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.

A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[135] Reply comments were also posted from New England State Parties,[136] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the ACPA.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[137] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The FERC posted a transcript of the workshop in eLibrary on October 13, 2021. Post-workshop comments were filed by APPA, CAISO, Clean Energy Parties,[138] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS. 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).

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,[139] suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

- ***Transmission Organization Incentive***. A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

[135] "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

[136] "New England State Parties" are CT PURA, CT DEEP and the MA AG.

[137] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

[138] The "Clean Energy Parties" are: Working for Advanced Transmission Technologies ("WATT Coalition"), ACPA, AEU, American Council on Renewable Energy ("ACORE"), NRDC, and the Sustainable FERC Project.

[139] 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.

- **Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)**

On December 16, 2021, the FERC issued a show cause order[140] 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,[141] 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;[142] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[143] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[144] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[145] *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.[146] 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.[147]

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

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

[141] *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").

[142] 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.

[143] *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.

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

[145] *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*")).

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

[147] *Id*. at P 319.

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[148] 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.[149]

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

Discovery in this case closed on December 2, 2022. Since the last Report, on December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas. In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance for 90 days, and directed that the hearing scheduled to begin on January 23, 2023, commence no earlier than ***April 24, 2023***.[151]

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

[149] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated NGA section 4A and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

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

[151] *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).

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.[152] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
  - 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,[153] and that effectively halted construction of the NECEC Project,[154] 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

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

[153] 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?"

[154] 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.

substantial construction in good faith according to a schedule that was not created or expedited for the purpose of generating a vested rights claim (which it suggested appeared to be the case from the limited record developed in connection with the request for preliminary injunctive relief in this matter).

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***2nd Revised Narragansett LSA Orders*** **(22-1161, 22-1108) (consolidated)**
  Underlying FERC *Proceeding*: ER22-707[155]
  Petitioner: Green Development
  Status: Briefing Completed; Oral Argument Scheduled for March 20, 2023

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[156] Since the last Report, briefing was completed with Petitioner's Reply Brief filed on January 9, 2023; Joint Appendix, January 17, 2023; New England Power's (Intervenor for Respondent FERC) Final Brief, January 27, 2023; and Green Development's Final Brief and Reply Brief, January 31, 2023. On January 23, 2023, the Court scheduled oral argument in this matter for ***March 20, 2023*** (with the composition of the argument panel to be revealed approximately 30 days prior to the date of oral argument).

- **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,[157] **-013**[158] **-017**[159]
  Petitioners: Mystic, CT Parties,[160] **MA AG, ENECOS**
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Jan 24, 2023

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%.

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155 *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*".

156 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.

157 *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).

158 *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).

159 *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*).

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

The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*.

As previously reported, the Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings 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. The January 24 request is pending before the Court.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[161]
  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[162]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[163] 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

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

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

[163] 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.

FERC's orders later vacated by the DC Circuit's *Emera Maine*[164] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on December 6, 2022.

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[165]
  Petitioners: Sierra Club
  Status: Filing of Initial Submissions Underway

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. On October 11, 2022, Sierra Club filed a Docketing Statement, a Statement of Issues, and the underlying decision from which the appeal arises. Also on October 11, the FERC moved to hold this proceeding in abeyance. Sierra Club opposed that motion on October 21, 2022. Having issued its further order on rehearing on October 14, 2022,[166] the FERC, on November 4, 2022, withdrew its 's motion to hold this proceeding in abeyance and asked the Court to issue a scheduling order in this proceeding. The Court issued that schedule on November 9, 2022. The Certified Index to the Record was submitted on November 16, 2022 and Petitioner's (Sierra Club's) Brief on December 16, 2022. Remaining submissions include: Respondent's Brief (February 14, 2023); Brief for Respondent-Intervenors (February 21, 2023); Petitioner's Reply Brief (March 14, 2023); Joint Deferred Appendix (March 21, 2023); and Final Briefs (April 4, 2023). Next up is Respondent's Brief.

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

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

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

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
Underlying FERC Proceeding: RM19-15[167]
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*.[168] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.) and (22-1146, 22-1147 consol.)**
Underlying FERC Proceeding: CP16-9-012[169]
Petitioners: LS Power, Algonquin, INGA
Status: Cases 22-1146/47 Deconsolidated and Briefing Schedule Set; Remaining Cases (21-1115 et al.) Being Held in Abeyance Pending Disposition of 22-1146/47

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to 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. Since the last Report, the FERC filed its Respondent Brief on January 12, 2023 and Algonquin and INGA filed a Joint Brief of Intervenors on January 26, 2023. Petitioner's Joint Reply Brief is due ***February 16, 2023***; Deferred Joint Appendix, ***March 2, 2023***, and Final Briefs, ***March 9, 2023***. The date of oral argument and the composition of the merits panel will be provided at a later date. As just noted, next up to be filed is Petitioner's Joint Reply Brief.

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[167] *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).

[168] *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.

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

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