David T. Doot
Secretary

February 24, 2022

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of March 3, 2022 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the Participants Committee will be held **via teleconference on *Thursday*, March 3, 2022, 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**. Please note in the Final Agenda the discussion noticed for this meeting concerning the ISO's Exigent Circumstances filing (Agenda Item #6).

For your information, the March 3 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.

Looking ahead, please mark your calendars for the 2022 Participants Committee Summer Meeting, which at this time is being planned to be held in person at The Samoset Resort, Rockport, ME, on June 21-23, 2022 (https://www.samosetresort.com/). As the date draws nearer, we will provide via future notices detailed information regarding that Summer Meeting, including a link to the registration page and the reservations block, once the block is open.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the February 3, 2022 Participants Committee meeting. A copy of the draft minutes, marked to show the changes since the minutes were circulated with the initial notice, has been included with this supplemental notice.

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

3. To receive an ISO Chief Executive Officer report. A summary of ISO New England Board and Board Committee Meetings since the February 3, 2022 Participants Committee meeting is included and posted with this supplemental notice.

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

5. To consider and take action, as appropriate, on changes to the following proposed by Competitive Power Ventures to address Performance-Based Non-Commercial Capacity Financial Assurance requirements:

   a. Market Rule 1 §§ III.13.1.9.2.3, III.13.1.1.2.2.2 and III.13.3.2.2; and

   b. Financial Assurance Policy §§ VII.B and VII.D.

   Background materials and a draft form of resolution(s) are included and posted with this supplemental notice.

6. To consider NEPOOL's response, if any, to the ISO's February 15 "Exigent Circumstances" filing. Background materials and a draft form of resolution are included and posted with this supplemental notice. Please advise NEPOOL Counsel, preferably in writing, should you have any proposed substantive response to the ISO's February 15 filing you would like members to consider.

7. 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.

8. 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

9. Administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, February 3, 2022, at the Seaport Hotel, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by ~~phone~~telephone.

Mr. David Cavanaugh, Chair, presided, and Mr. David Doot, Secretary, recorded.

APPROVAL OF JANUARY 6, 2022 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the January 6, 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 referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved as circulated, with oppositions by PowerOptions, the New Hampshire Office of the Consumer Advocate and the Maine Office of the Public Advocate, and with abstentions by Harvard Dedicated Energy Limited and Mr. Mintz noted. All but Mr. Mintz indicated that their opposition or abstention related to concerns with the proposed retirement reforms identified in Consent Agenda Item No. 3.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to both the summaries of the ISO Board and Board Committee meetings that had occurred since the January 6, 2022 Participants Committee meeting, as well as to his memo addressing the recent correspondence between the New England states (States) and the ISO regarding winter reliability, each of which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

In response to comments and questions on the winter reliability issues, Mr. van Welie elaborated on the impact to New England resulting from New York's reducing nuclear power and shifting resource mix and other developments in that region. He identified the importance of addressing environmental concerns (underway in the Pathways process) and the consequences of controlled outages in response to extreme weather, which he identified as externalities not reflected in the current market design. He suggested that the retention of the Mystic units for two years and the Inventoried Energy Program (IEP) would be incrementally and moderately helpful in addressing the ISO's winter reliability concerns, but more conversation and work to help ensure reliability was required. A member suggested that in-depth discussion be continued within the NEPOOL process to identify a more enduring solution that sends suitable signals to the market. Another member credited actions already taken by the ISO, including the reflection of opportunity costs in the energy market, that support and contribute to enhanced reliability and proper functioning of the market. Mr. van Welie agreed that market signals do work, albeit within limits. He stressed the need to identify those limits and the carefully balanced actions that could be taken to protect the reliability of the region when outside of those limits. A member questioned a system that relies exclusively on market volatility to address seasonal energy supply concerns, and suggested that prices may be more predictable if the market includes~~-~~ forward actions. The discussion ~~was~~ concluded with assurance to the members that there would be further efforts at future NEPOOL meetings, with the Participants Committee summer meeting identified as one such meeting, to explore solutions that provide certainty, reliability and security during winter weather.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his February report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through January 26, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for January 2022 was $1.4 billion, up $693 million from the updated December 2021 value and $926 million from January 2021; (ii) January 2022 average natural gas prices were 127% higher than December average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for January ($139/MWh) were 133% higher than December averages; (iv) average January 2022 natural gas prices and Real-Time Hub LMPs over the period were up 283% and 217%, respectively, from January 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 98.7% during January (up from the 98.1% reported for December), with the minimum value for the month of 92.7% on January 7; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for January totaled $3.7 million, which was down $1.7 million from December 2021 and up $0.2 million from January 2021. January NCPC payments, which were 0.3% of total Energy Market value, were comprised of $3.6

million in first contingency payments (up $0.6 million from December 2021) and $29,000 in second contingency payments.

Dr. Chadalavada noted that sixteenth Forward Capacity Auction (FCA16) would begin on February 7 and would be conducted remotely.

Turning to January weather, he noted that the average temperature was colder than normal by approximately 2°F, resulting in higher than normal demand. The colder temperatures and high demand were coincident with natural gas prices remaining near $20/MMBtu through most of the month with high LNG sendout and high utilization of oil to produce power.

He summarized power system conditions on January 11 and 12, 2022, during which there were a cascading set of events within several hours that turned an expected 1,300 MW surplus into a 1,200 MW deficit on January 11, and that resulted in a two-hour loss of power supply to Canaport on January 12. He confirmed in response to a question that the January 11 outages were mechanical- or equipment-related issues, and were not fuel-related.

Referring to the COO report, he also summarized the impacts of Winter Storm Kenan, a powerful blizzard that affected Southern & Eastern New England on January 29. He explained that New England was fortunate that the blizzard's winds shifted directionally from northeast to due north with the result of avoiding direct impacts in areas with more load, and minimizing transmission line and customer outages.

Dr. Chadalavada proceeded to respond to member questions. In response to a question on the timing of winter fuel surveys and forecasts, Dr. Chadalavada clarified that, absent a more pronounced fuel depletion, fuel surveys would continue to be issued twice weekly, and the 21-day forecast, weekly. He further confirmed that the Day-Ahead forecasts do not include anticipated customer outages, and that one explanation for the load forecast deviations during the blizzard was that many commercial customers decided the evening before the day of the blizzard to close. Also in response to questions asked of him before the meeting, he explained that, for planning purposes during extremely cold weather, the ISO estimates the amount of gas-fired-only generation (from the region's overall fleet of 10-11 GW of gas-fired-only generation) that is likely to be available and unavailable for commitment and dispatch on a given day based on projected gas availability. The ISO reflects its estimate of the gas-fired-only generation that is likely to be unavailable in the anticipated cold weather outages line item of its capacity forecasts.

Reflecting on plans for a full-winter operations report following ~~this~~ winter 2021-22, Dr. Chadalavada indicated in response to questions and requests that the ISO planned that report to include discussion of the impact of opportunity cost adders on the locational marginal prices. Further, the report would include information on LNG prices as compared to previous years. He explained that oil usage ~~this past~~during winter 2021-22 explained some of the decoupling of electric prices from natural gas prices, which also would discussed in the report, along with a more complete explanation of the very high energy market value ~~during the past winter~~. He noted that the ISO would try to be ready with that report in time for the March Participants Committee meeting, and if not, for the April meeting.

Discussing the status of transmission outages in the region, he noted that no outages had been approved or were anticipated in February. There were applications pending and under consideration for the March timeframe, including an outage on the Alps to Berkshire transmission line that may curtail imports and exports to and from New York, which he would address further in his March report.

MINIMUM OFFER PRICE RULE (MOPR) REFORM PROPOSAL

Ms. Mariah Winkler, the Markets Committee (MC) Chair, provided a high-level summary of background information that led to the ISO's decision to develop a proposal to reform the MOPR. She also described the ISO's proposal to eliminate the current MOPR construct in advance of the seventeenth Forward Capacity Auction (FCA17) and a Participant-sponsored motion to amend that Proposal. Ms. Winkler explained that the motion to amend would establish a two-year transition period before eliminating the current MOPR, with that transition including a Renewable Technology Resource (RTR) exemption for up to 700 MW of State-sponsored Policy Resources to qualify and participate in FCAs 17 and 18 with no application of any MOPR. She identified that amendment as the "Transition Proposal." Ms. Winkler also reported on the votes of the MC, which recommended that the Participants Committee support the elimination of the current MOPR in advance of ~~the~~ FCA17 (referred in materials circulated in advance of the meeting as the "MC-Recommended Proposal") and the MC's failed vote on the motion to amend the Proposal to include the Transition Proposal.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to the Tariff to implement reforms to the MOPR construct, as proposed by the ISO and recommended by the Markets Committee at its January 11, 2022 meeting, and as circulated to this Committee in advance of this meeting, together with any changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

With the main motion before the Participants Committee, a motion was duly made and seconded to amend the main motion to include a revised Transition Proposal. Referring to materials circulated and posted in advance of the meeting, the amendment's proponents reviewed and explained the changes to the Transition Proposal since the MC's consideration. Specifically, the proponents explained that the modified Transition Proposal that they had moved reflected the following changes: removal of the provision that provided for the netting out MW from resources that elected RTR treatment in FCA16; adoption of the revised definition of "Sponsored Policy Resource" contained in the MC-Recommended Proposal; deletion of outdated language in Tariff Section III.13; and adoption of a Union of Concerned Scientists (UCS) /RENEW Northeast (RENEW)-recommended amendment to "rollover" un-cleared MW from FCA17 and increase the FCA18 MW RTR exemption cap. At the proponents' request, a member representative explained the UCS/RENEW recommended change, referencing the UCS/RENEW materials that had been circulated and posted in advance of the meeting.

Following questions and comments to clarify the motion to amend, the Chair turned to the ISO to explain its position on the motion to amend. Dr. Chadalavada referred to the ISO's January 26, 2022 memorandum that expressed the ISO's preference for the Transition Proposal as it had just been presented. He added that the ISO ultimately reached this determination based on its near term reliability concerns - particularly during the upcoming winter periods. He noted that the ISO was concerned that system reliability could be degraded by rapid and inefficient retirements by existing resources, which the ISO counted on to address extreme weather events. Dr. Chadalavada also explained that a transition would provide time to complete critical market reforms that would help mitigate those reliability concerns, citing specifically changes to the ancillary service markets and a more refined determination of the level of contribution each type of capacity resource makes to resource adequacy (which was generally referred to as effective load-carrying capability (ELCC) or Resource Capacity Accreditation). He said the ISO considered the Transition Proposal to be a reasonable compromise, worked on by stakeholders and the States, that would permit up to 700 MW of renewable resources to clear in FCAs 17 and 18. Dr. Chadalavada concluded by stating that the ISO supported the Transition Proposal as a preferred path forward that would allow the region to focus on other critically important changes during the transition rather than prolonged litigation that could result from a failure to compromise.

Addressing questions from members, Dr. Chadalavada stated that the ISO had no intention of preventing resources from retiring, but it rather wished to reduce the risk of inefficient retirements that would adversely impact reliability. He indicated that the ISO's judgement on these matters was informed by its operation of the system during stressed conditions, and that he had no separate, specific study to quantify the degree of risk to reliability from the immediate termination of the existing MOPR. He explained that the ISO supported the 700 MW RTR exemption as a reasonable compromise among stakeholders who objected to immediate MOPR elimination and state representatives and others who were pushing for more rapid elimination of MOPR. Dr. Chadalavada confirmed the ISO's understanding that the modifications to financial inputs for the Cost of New Entry (CONE) and Net CONE that were part of the MC-Recommended Proposal were removed from the Transition Proposal. Instead, the ISO would make a separate filing in advance of FCA19 to reflect necessary changes to those financial inputs, which he committed the ISO to explain in its filing letter to the FERC if the ISO submitted the Transition Proposal.

Following this explanation and clarification of the ISO's position on the motion to amend, that motion to amend was presented for debate, with many members and guests offering their views. Those in support of the motion to amend argued generally that the revised Transition Proposal was a reasonable approach in light of the ISO's system reliability concerns, as expressed in its January 26 memorandum. Others in support suggested that the Transition Proposal would mitigate against regulatory uncertainty resulting from ongoing litigation over an immediate elimination of the existing MOPR, as seen in other ISO/RTO regions. Some supporters suggested that more efficient retirements could minimize the use of out-of-market actions to address reliability needs. Supporters also expressed agreement with the ISO that the transition would provide time for the ISO to develop, with stakeholder input, necessary complementary market reforms to enhance energy security and more precisely define each resource's contribution to reliability (via the planned ELCC project). They thanked the ISO for listening to the input of stakeholders throughout the process and working diligently to consider and address concerns.

Those opposing the motion to amend the MC-Recommended Proposal expressed disappointment and frustration with the ISO's failure to present its views much earlier in the stakeholder process. In those discussions, numerous opponents referenced with support the positions of UCS/RENEW, as summarized in its memorandum that was circulated and posted with the materials for the meeting. Reflecting their frustrations with how this matter had unfolded since the MC meeting, some opponents disagreed with the ISO's characterization of the positions of the States and the ISO's explanation for the evolution of its position on the matter. Some argued that the developments since the MC's consideration and vote compromised their confidence in the independence and transparency of the ISO, undermined the stakeholder process, and could undercut public confidence in the ISO.

Other members argued that any delay in the elimination of the current MOPR extended a market construct that they viewed as an unjust and unreasonable barrier to entry for new renewable resources. They expressed the view that certain FERC Commissioners had made very clear the need for prompt elimination of the MOPR and they cited recent statements by two of those Commissioners concerning the same. Citing those Commissioners, certain opponents of the transition argued that there was a substantial risk that a transition proposal would likely be rejected by the FERC and would inject considerably more uncertainty in future auctions. Some argued that the Transition Proposal with continuation of the Competitive Auctions with Sponsored Policy Resources for two more years continued to provide discriminatory treatment for renewable resources that are subject to payments to existing resources for the opportunity to earn capacity revenues in FCM.

Some opponents argued that the ISO's reliability concerns were opinions and conjecture that were lacking quantitative analysis in support. Those who shared to some extent the ISO's reliability concerns but opposed a transition to eliminate the current MOPR explained their position that a transition would not reduce risks to reliability. One member argued on that point that reliability might even be harmed by transition. Referencing the UCS/RENEW concern that the elimination of the MOPR might be extended to and beyond FCA19, Dr. Chadalavada confirmed that the ISO was fully committed to elimination of the MOPR for FCA19 and would not support further delay ~~beyond~~of its elimination for FCA19 or beyond.

A NESCOE representative noted that NESCOE would not oppose the Transition Proposal. He explained that one of the six New England states, New Hampshire, opposed any elimination of MOPR, but the remaining States all supported elimination of the current MOPR, which would occur both with the MC-Recommended Proposal and the revised Transition Proposal. While noting that NESCOE members did not oppose the transition approach reflected in the motion to amend, if FERC were to approve the revised Transition Proposal with the elimination of the current MOPR for FCA19, the States would vehemently oppose any request to extend the current MOPR ~~beyond~~to FCA19 or beyond. The NESCOE representative also noted that NESCOE would expect the ISO to do the same.

Dr. Chadalavada responded to comments from stakeholders on the process, expressing the ISO's view that the stakeholder process worked as intended. He referenced the ISO's May 2021 memorandum, when the ISO announced its intention to work to eliminate the MOPR in advance of FCA17, in which the ISO had flagged various concerns with that elimination that needed to be considered, including the potential of inefficient retirements from existing resources. He referred to the ISO's early enlistment of the External Market Monitor (EMM) to help address those concerns. Throughout the process, Dr. Chadalavada said, the ISO carefully listened to stakeholder feedback and modified its proposal based on that feedback. It also fully considered the EMM's recommendations. He reminded members that, at no point, had the ISO ever expressed any opposition to the Transition Proposal. Instead, the ISO kept an open mind and continued to listen to and fully and carefully consider stakeholder feedback through the entire process, while further considering the expected impact from the EMM's recommendations, which the ISO supported. With all of that information, the ISO concluded, in its independent judgment, that the Transition Proposal was preferable to an immediate elimination of the current MOPR, for all of the reasons noted in the January 26 memorandum. Dr. Chadalavada acknowledged that it may have helped if the ISO had reached this definitive conclusion earlier, but the speed with which the process to develop the MOPR elimination proposal proceeded limited that possibility. He disagreed with the suggestion that the stakeholder process failed or that it lacked transparency, arguing instead that the outcome should more properly be viewed as a success of the process.

Before voting the amendment, the Transition Proposal proponents argued that the amendment reflected a compromise approach borne out of collaboration, that they viewed the litigation risk differently than those opposing the Transition Proposal, and that the Transition Proposal would mitigate the need for out-of-market actions because it was a measured approach to decarbonizing the region.

Following that discussion, the motion to amend was then voted and passed with a 61.49% Vote in favor (Generation Sector – 8.32 %; Transmission Sector – 16.64%; Supplier Sector – 14.72%; AR Sector – 5.33%; POE Sector – 8.85%; End User Sector – 7.63%; and Provisional Members – 0%). (*See* Vote 1 on Attachment 2).

With the once-amended main motion then before the Committee, a motion was duly made and seconded to further amend the MOPR reform proposal to modify the Interconnection Procedures in Schedules 22 and 23 of the Open Access Transmission Tariff. Specifically, the amendment, which was proposed by RENEW (and sponsored by UCS) and circulated and posted in advance of the meeting, would permit any resource that cleared only a portion of its capacity because it was prorated due to the RTR exemption cap from having the portion of its capacity that did not clear from losing its queue position prior to FCA19. The proponent of this change explained her view that the existing time-out provisions in Schedule 22 and 23 could produce an unfair result if not modified. In response to clarifying questions, the proponent confirmed that the second motion to amend was not seeking changes to Schedule 25 because that schedule was not implicated in what the amendment was trying to address. She also explained that the proposed amendment would help to mitigate elevated risks placed on renewable resources by not eliminating the current MOPR for FCAs 17 and 18.

Members then offered comments on the motion to amend. Members who supported that motion expressed appreciation to UCS/RENEW for bringing the amendment forward because it addressed a long-standing issue in which resources pay all network upgrade costs to support capacity delivery but get timed out of the queue merely because the resource does not clear all of its capacity within the time-out period due to application of the MOPR. Members who spoke against the motion to amend expressed support for what the amendment was seeking to address but argued that the proposed change raised broader and more complex issues that needed to be explored more fully rather than being addressed narrowly, as proposed. The ISO advised the Committee that it did not support the motion to amend because, in its view, the proposed change was not related to MOPR reform. The proponents expressed their disagreement with the ISO's position.

A suggestion was made to consider deferring the vote on this topic until the Transmission Committee had a chance to consider the proposal more fully. That suggestion was not supported, and the vote on the motion to amend was called. By a show of hands in the room, it was determined that the motion to amend would not pass. No roll-call vote was requested.

The Committee then voted the once-amended main motion (i.e., the Transition Proposal). That motion passed with a 69.56% Vote in favor (Generation Sector – 10.19%; Transmission Sector – 16.67%; Supplier Sector – 16%; AR Sector – 8.11%; POE Sector – 8.87%; End User Sector – 9.72%; and Provisional Members – 0%). (*See* Vote 2 on Attachment 2).

LITIGATION REPORT

Mr. Patrick Gerity referred the Committee to the February 1 Litigation Report that had been circulated and posted the day before the meeting. He highlighted the following:

(i) The February 2 submission of the region's Order 2222 compliance filing, which was filed after completion of the February 1 Report;

(ii) The FERC's Jan 21 order accepting the FCA16 qualification information filing;

(iii) The status at that time of the quickly evolving litigation over the ISO's termination of the Capacity Supply Obligation of Killingly Energy Center, which included a pending request before the Circuit Court of Appeals for the D.C. Circuit (DC Circuit) for a stay of ~~FERC"s~~FERC's approval of that termination;

(iv) The request to FERC by ConnectGen South Wrentham for a waiver of Schedule 22, § 4.4 (Queue Position Modifications) to allow it to qualify for and bid into FCA17 with its existing queue position;

(v) The DC Circuit's decision denying the appeal by Cogentrix and Vistra of the FERC's order regarding treatment of expenditures to comply with CIP-IROL requirements; and

(vi) Activity in the FERC proceeding investigating Schedule 25 and Section I.3.10 of the ISO's Tariff.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the MC would hold a one-day meeting virtually on February 8.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled virtually for February 17 and would include a review of FERC Order 881 (Managing Transmission Line Ratings).

Reliability Committee. Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting was scheduled for February 15, with the venue (in-person or virtual) still under evaluation. The meeting's agenda would include a presentation by the ISO on an operational study being jointly conducted by the ISO and the Electric Power Research Institute (EPRI) on the impacts of extreme weather using New England as a model.

Budget & Finance (B&F) Subcommittee. Mr. Cavanaugh reported that the next B&F Subcommittee meeting was scheduled for February 10.

Membership Subcommittee. Ms. Sarah Bresolin, Subcommittee Chair, noted that the next virtual meeting was scheduled, by Zoom, for February 14 at 1:00 p.m.

Joint Nominating Committee (JNC). Mr. Cavanaugh reported that the JNC had met on January 7. He reminded the Committee that two members, Mr. Barney Rush and Ms. Vickie VanZandt, would conclude their service at the end of the 2022 Board year, with one of those vacancies requiring a candidate to be identified (the other already filled in the last JNC process). He added that Board Chairman, Ms. Cheryl LaFleur, was concluding her first term and eligible for re-election. He noted that, toward the end of February, JNC members would provide feedback on proposed specifications for a new candidate to be placed on a recommended slate and the JNC would begin its process for reviewing resumes. Updates on JNC activities would continue to be provided at future NPC meetings.

ADMINISTRATIVE MATTERS

Mr. Doot reported that the next Participants Committee Meeting was scheduled to take place on March 3 at the Seaport Hotel, although a decision may be made to hold the meeting virtually if warranted by the amount of business to discuss. Mr. Cavanaugh reminded stakeholders of the Future Grid Pathways meeting on March 1 to review ~~the~~ a draft ~~report~~Pathways Study Report.

There being no other business, the meeting adjourned at 3:36 p.m.

Respectfully submitted,

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David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 3, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Able Grid Infrastructure Holdings, LLC	Generation		Sam Lines (tel)	Abby Krich (tel)
Acadia Center	End User	Melissa Birchard (tel)		
Advanced Energy Economy (AEE)	Associate Non-Voting	Caitlin Marquis (tel)	Jeff Dennis (tel)	
Agilitas Companies	AR-DG			Sarah Bresolin (tel)
American PowerNet Management	Supplier			Jason Frost
Ampersand Energy Partners	Supplier			Julia Frayer
Anbaric Development Partners LLC	Provisional Member		Theodore Paradise (tel)	
Appian Way Energy Partners	Supplier			Andy Weinstein
AR Large Renewable Gen. (RG) Group Member	AR-RG	Alex Worsley (tel)		
AR Small Distrib. Generation (DG) Group Member	AR-DG			Michael Macrae
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)	Kathy Abernathy (tel)	
AR Small Renew. Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta (tel)	Jason Rauch (tel)	
Bath Iron Works Corporation	End User			Bill Short (tel)
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney (tel)		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
C.N. Brown Electricity, LLC	Supplier			Bill Short (tel)
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler; John Flumerfelt
Castleton Commodities Merchant Trading	Supplier			Bob Stein (tel)
Central Rivers Power	AR-RG			Bill Fowler
Centrica Business Solutions Optimize, LLC	AR-LR		Aaron Breidenbaugh (tel)	Nancy Chafetz (tel)
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller (tel)
Competitive Energy Services, LLC	Supplier		Eben Perkins (tel)	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User		Dave Thompson (tel)	
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Consolidated Edison Energy, Inc.	Supplier	Grant Flagler (tel)		
Constellation Energy Generation	Supplier	Steve Kirk	Bill Fowler	
Covanta Energy Marketing, LLC	AR-RG			Bill Fowler
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier			Brett Kruse
Deepwater Wind Block Island, LLC	Generation	Eric Wilkerson		
Dominion Energy Generation Marketing	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 3, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short (tel)
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
EDF Trading North America, LLC	Supplier			Brett Kruse
Elektrisola, Inc.	End User			Bill Short (tel)
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae (tel)		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin (tel)		
Environmental Defense Fund (EDF)	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission	James Daly (tel)	Dave Burnham	
Excelerate Energy LP	Associate Non-Voting	Gary Ritter		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User			Bill Short (tel)
Generation Group Member	Generation	Dennis Duffy (tel)	Abby Krich- (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein (tel)
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein (tel)	
Hammond Lumber Company	End User			Bill Short (tel)
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Industrial Energy Consumer Group	End User	Hannah Oakes (tel)	Todd Griset (tel)	
Interconnect Storage LLC		Colleen Nash (tel)		
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	
Jupiter Power	Provisional Member			Ron Carrier (tel)
KCE CT 1, LLC	Provisional Member			Abby Krich (tel)
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny (tel)	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate’s Office	End User			Jason Frost
Maine Skiing, Inc.	End User	Hannah Oakes (tel)	Todd Griset (tel)	
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley (tel)
Marble River, LLC	Supplier	Seth Kaplan		Abby Krich (tel)
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Marco DM Holdings	Generation			Andy Weinstein
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew (tel)		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 3, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Mintz, Samuel	End User	Sam Mintz		
Moore Company	End User			Bill Short (tel)
National Grid	Transmission	Tim Brennan (tel)	Tim Martin	
Natural Resources Defense Council (NRDC)	End User	Bruce Ho (tel)		
Nautilus Power, LLC	Generation	Dan Pierpont	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw (tel); Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate	End User	Donald Kreis (tel)		Jason Frost
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
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	
Novatus Energy (Blue Sky West et. al)	AR-RG			Aby Krich (tel
NRG Power Marketing LLC	Supplier		Pete Fuller (tel)	
Nylon Corporation of America	End User			Bill Short (tel)
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User	Heather Takle (tel)		Jason Frost (tel)
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Saint Anselm	End User			Bill Short (tel)
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stonepeak Kestrel Energy Marketing, LLC	Supplier			Andy Weinstein
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller (tel)
Talen Energy Marketing, LLC	Supplier			Brett Kruse
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Tenaska Power Services Co.	Supplier			Andy Weinstein
The Energy Consortium	End User	Bob Espindola (tel)	Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori	Karin Stamy (tel)	
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley (tel)	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission		Dave Norman (tel)	Tim Martin
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Supplier			Brett Kruse
Voltus, Inc.	AR-LR	Nicole Irwin-Vet (tel)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 3, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	Jim Ginnetti (tel)
Z-TECH LLC	End User			Bill Short (tel)

ATTACHMENT 2

FEBRUARY 3, 2022 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON MOPR PROPOSAL

TOTAL

Sector	Vote 1	Vote 2
GENERATION	8.32	10.19
TRANSMISSION	16.64	16.67
SUPPLIER	14.72	16.00
ALTERNATIVE RESOURCES	5.33	8.11
PUBLICLY OWNED ENTITY	8.85	8.87
END USER	7.63	9.72
PROVISIONAL MEMBERS	0.00	0.00
% IN FAVOR	**61.49**	**69.56**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2
Able Grid Infrastructure Holdings	O	A
CPV Towantic, LLC	F	F
Deepwater Wind Block Island	O	O
Dominion Energy Generation Mktg	F	F
FirstLight Power Management, LLC	O	O
Generation Group Member	Split	Split
Energy Management Inc.	O	O
Millennium Power Partners,	F	F
Record Hill Wind LLC	O	O
Waterside Power, LLC	F	F
GSP Companies	F	F
Marco DM Holdings, LLC	F	F
Nautilus Power, LLC	F	F
NextEra Energy Resources, LLC	O	O
Walden Renewables Development	O	A
IN FAVOR (F)	5.5	5.5
OPPOSED (O)	5.5	3.5
TOTAL VOTES	11.0	9.0
ABSTENTIONS (A)	0.0	2.0

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
Avangrid (CMP/UI)	F	F
Eversource Energy	A	F
National Grid	F	F
VELCO	F	F
Versant Power	F	F
IN FAVOR (F)	4	5
OPPOSED (O)	0	0
TOTAL VOTES	4	5
ABSTENTIONS (A)	1	0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
Central Rivers Power	F	F
Covanta Energy Marketing, LLC	F	F
ENGIE Energy Marketing NA, Inc.	O	O
Great River Hydro, LLC	F	F
Jericho Power LLC	F	F
Novatus Energy	O	A
Wheelabrator/Macquarie	F	F
Large RG Group Member	O	A
Small RG Group Member	O	A
Distributed Gen. Sub-Sector		
Agilitas Companies	O	O
Borrego Solar Systems Inc.	O	A
CLEAResult Consulting, Inc.	A	A
Sunrun Inc.	O	O
Small DG Group Member	O	O
Load Response Sub-Sector		
Centrica Bus. Solutions Optimize	F	F
Enel X North America, Inc.	O	A
Maple Energy	O	O
Vermont Energy Investment Corp.	O	O
Voltus, Inc.	O	O
Small LR Group Member	Split	Split
Ameresco CT LLC	O	O
Tangent Energy Solutions, Inc.	A	F
IN FAVOR (F)	6.0	6.5
OPPOSED (O)	12.5	7.5
TOTAL VOTES	18.5	14.0
ABSTENTIONS (A)	1.5	6.0

FEBRUARY 3, 2022 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON MOPR PROPOSAL

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2
American PowerNet Management	O	F
Ampersand Energy Partners LLC	A	A
Appian Way Energy Partners East	F	F
BP Energy Company	F	F
Brookfield Renew. Trading & Mktg	A	A
C.N. Brown Electricity, LLC	F	F
Calpine Energy Services, LP	F	F
Castleton Comm. Merchant Trading	F	F
Clearway Power Marketing LLC	F	F
Competitive Energy Services, LLC	O	O
Consolidated Edison Energy Inc.	A	A
Constellation Energy Generation	F	F
Cross-Sound Cable Company	F	F
DC Energy, LLC	F	F
DTE Energy Trading, Inc.	F	F
Dynegy Marketing and Trade, LLC	F	F
Emera Energy Services Companies	F	F
Emera Energy Companies	F	F
Galt Power, Inc.	F	F
H.Q. Energy Services (U.S.) Inc.	F	F
LIPA	A	A
Maine Power, LLC	F	F
Marble River, LLC	O	A
Mercuria Energy America, Inc.	F	F
NRG Power Marketing, LLC	F	F
Shell Energy North America (US)	F	F
Stonepeak Kestrel Energy Mktg	F	F
Talen Energy Marketing, LLC	F	F
Tenaska Power Services Co.	F	F
Vitol Inc.	F	F
IN FAVOR (F)	23	24
OPPOSED (O)	3	1
TOTAL VOTES	26	25
ABSTENTIONS (A)	4	5

END USER SECTOR

Participant Name	Vote 1	Vote 2
Acadia Center	O	O
Associated Industries of Mass.	O	F
Bath Iron Works Corporation	F	F
Conn. Office of Consumer Counsel	A	F
Conservation Law Foundation	O	O
Durgin and Crowell Lumber Co.	F	F
Elektrisola, Inc.	F	F
Environmental Defense Fund	O	O
Garland Manufacturing Co.	F	F
Hammond Lumber Company	F	F
Harvard Dedicated Energy Limited	O	F
High Liner Foods (USA) Inc.	F	F
Industrial Energy Consumer Group	O	O
Maine Public Advocate Office	O	O
Maine Skiing, Inc.	O	O
Mass. Attorney General's Office	O	O
Mintz, Samuel	A	A
Moore Company	F	F
Natural Resources Defense Council	O	O
New Hampshire OCA	F	A
Nylon Corporation of America	F	F
PowerOptions, Inc.	O	O
St. Anselm College	F	F
The Energy Consortium	O	F
Union of Concerned Scientists	O	O
Z-TECH, LLC	F	F
IN FAVOR (F)	11	14
OPPOSED (O)	13	10
TOTAL VOTES	24	24
ABSTENTIONS (A)	2	2

FEBRUARY 3, 2022 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON MOPR PROPOSAL

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	O	O
Belmont Municipal Light Dept.	O	O
Block Island Utility District	F	F
Boylston Municipal Light Dept.	O	O
Braintree Electric Light Dept.	F	F
Chester Municipal Light Dept.	F	F
Chicopee Municipal Lighting Plant	O	O
Concord Municipal Light Plant	F	F
Conn. Mun. Electric Energy Coop.	A	A
Danvers Electric Division	F	F
Georgetown Municipal Light Dept.	F	F
Groton Electric Light Dept.	O	O
Groveland Electric Light Dept.	F	F
Hingham Municipal Lighting Plant	F	F
Holden Municipal Light Dept.	O	O
Holyoke Gas & Electric Dept.	O	O
Hull Municipal Lighting Plant	O	O
Ipswich Municipal Light Dept.	O	O
Littleton (MA) Electric Light Dept.	F	F
Littleton (NH) Water & Light Dept.	A	A
Mansfield Municipal Electric Dept.	O	O
Marblehead Municipal Light Dept.	O	O
Mass. Bay Transportation Authority	F	F
Mass. Mun. Wholesale Electric Co.	O	O
Merrimac Municipal Light Dept.	F	F
Middleborough Gas and Elec. Dept.	F	F
Middleton Municipal Electric Dept.	F	F
New Hampshire Electric Cooperative	A	A
North Attleborough	F	F
Norwood Municipal Light Dept.	F	F
Pascoag Utility District	F	F
Paxton Municipal Light Dept.	O	O
Peabody Municipal Light Plant	O	O
Princeton Municipal Light Dept.	O	O
Reading Municipal Light Dept.	F	F
Rowley Municipal Lighting Plant	F	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2
Russell Municipal Light Dept.	O	O
Shrewsbury's Elec. & Cable Ops.	O	O
South Hadley Electric Light Dept.	O	O
Sterling Municipal Electric Light Dept.	O	O
Stowe (VT) Electric Dept.	F	F
Taunton Municipal Lighting Plant	F	F
Templeton Municipal Lighting Plant	O	O
Village of Hyde Park (VT) Elec. Dept.	F	F
VT Electric Cooperative	F	F
VT Public Power Supply Authority	A	A
Wakefield Mun. Gas and Light Dept.	O	O
Wallingford, Town of	F	F
Wellesley Municipal Light Plant	F	F
West Boylston Mun. Lighting Plant	O	O
Westfield Gas & Electric Light Dept.	F	F
IN FAVOR (F)	25	25
OPPOSED (O)	22	22
TOTAL VOTES	47	47
ABSTENTIONS (A)	4	4

PROVISIONAL MEMBERS

Participant Name	Vote 1	Vote 2
Anbaric Development Partners, LLC	O	O
Interconnect Energy Storage LLC	O	A
Jupiter Power LLC	O	O
KCE CT 1 & 2	O	A
IN FAVOR (F)	0	0
OPPOSED (O)	4	2
TOTAL VOTES	4	2
ABSTENTIONS (A)	0	2

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's February 15, 2022 meeting, dated February 15, 2022.[1]

1. Changes to PP-11 (NERC Reliability Standard TPL-007-4 Conforming Changes)

Support revisions to Planning Procedure ("PP") No. 11 (Planning Procedure to Support Geomagnetic Disturbances) to conform to and support the requirements of NERC Reliability Standard TPL-007-4 (Transmission System Planned Performance for Geomagnetic Disturbance Events), as recommended by the RC at its February 15, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

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

Summary of ISO New England Board and Committee Meetings

March 3, 2022 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met on February 4. The Audit and Finance Committee, the Markets Committee, and the Nominating and Governance Committee each met on February 17. The Board of Directors met on February 7 and February 17. All of the meetings were held virtually.

The Compensation and Human Resources Committee convened in executive session and discussed the Company's corporate performance for 2021 and officer compensation for 2022.

The Audit and Finance Committee met with the Company's Investment Manager and the Internal ERISA 3(38) Committee for a review of the Company's benefits plan assets and 401(k) plan, and an analysis of investment options and details regarding the mix, cost, and performance of plan investments. The Committee approved significant accounting estimates used in the Company's budgeting and financial statements, including earnings and discount rates, health care trends, and depreciation. In addition, the Committee received a report on consumer electricity costs within the region, including information from Appendix 9 to the 2022 budget presentation. The Committee requested additional information from management on how Company operations and wholesale electricity market design impact consumer electricity costs. The Committee then met in executive session and reviewed Internal Audit Department results for 2021 and considered the performance and 2022 compensation for the Director of Internal Audit.

The Nominating and Governance Committee discussed the Company's annual communications plan, and noted that outreach for 2022 focuses on highlighting the necessary components of a reliable transition to the clean energy future. In furtherance of ongoing education for directors, the Committee discussed the speaker program for 2022 and the importance of understanding new technologies and the clean energy transition, as well as hearing diverse viewpoints. The Committee also contemplated topics for discussion at the Board's meeting with NECPUC in March, and considered the format for the annual board and committee evaluation process.

The Markets Committee convened, with the full Board invited, for a discussion of the preliminary Pathways Study Report performed by the Analysis Group that evaluates pathways to a future grid. Following this discussion, the Committee held its regular session and received an update from the External Market Monitor on changes in the Texas wholesale electricity markets. The Committee also received an update on stakeholder initiatives related to retirement reforms.

The Board of Directors met on February 7 to review the outcome of the NEPOOL Participants' vote on the transition option for MOPR elimination. The Board reviewed a summary of the vote tally, reflected on the stakeholder debates, considered the states' position and statements, and discussed the path forward.

On February 17, the Board of Directors received a report from the CEO with updates on the effort to eliminate the MOPR, winter operations and reliability, the court order regarding Killingly, and management's plan for the workforce to return to the office. The Board also discussed its upcoming meeting with NECPUC in March, and received reports from the standing committees outlining highlights from their recent meetings. The Board then received updates from members of the Board on topics discussed at liaison meetings with state utilities commissions and various communications with stakeholders. In executive session, the Board approved the corporate performance results for 2021 and officer compensation for 2022.

NEPOOL Participants Committee Report

March 2022

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: January 2022 Energy Market value totaled $1.8B
  - February 2022 Energy market value was $960M, down $829M from January 2022 and up $200M from February 2021
    - February 2022 natural gas prices over the period were 35% lower than January average values
    - Average RT Hub Locational Marginal Prices ($108/MWh) over the period were 27% lower than January averages
    - Average February 2022 natural gas prices and RT Hub LMPs over the period were up 52% and 51%, respectively, from February 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.2% during February, up from 98.8% during January*
    - The minimum value for the month was 97.1% on Thursday, Feb. 10th

Data through February 23rd, unless otherwise noted

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

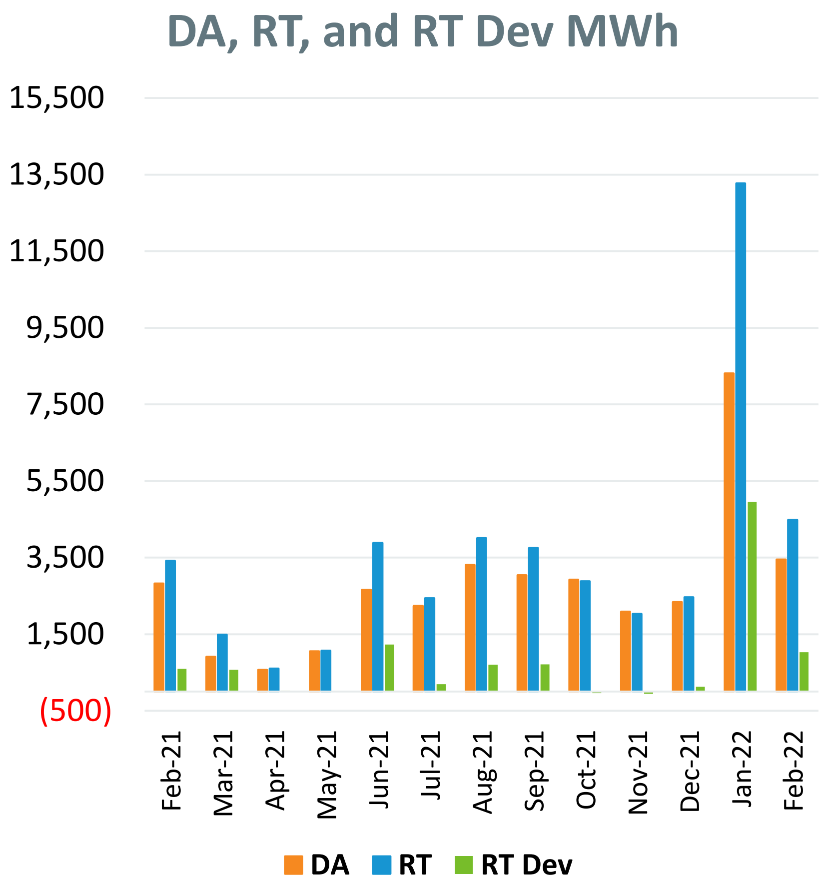
Underlying natural gas data furnished by: ICE Global markets in clear view

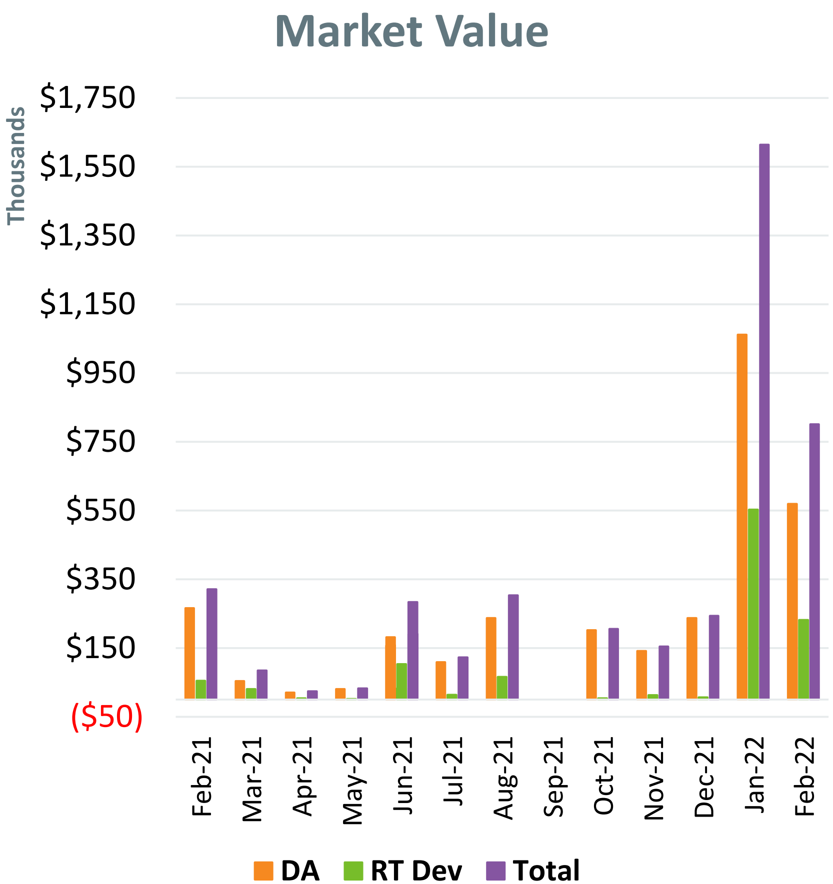
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - February 2022 NCPC payments totaled $3.4M over the period, down $1M from January 2022 and up $0.7M from February 2021
    - First Contingency payments totaled $3.2M, down $1.1M from January
      - $3.1M paid to internal resources, down $1.1M from January
        - » $718K charged to DALO, $1.1M to RT Deviations, $1.3M to RTLO*
      - $75K paid to resources at external locations, down $5K from January
        - » $36K charged to DALO at external locations, $39K to RT Deviations
    - Second Contingency payments totaled $188K, up $158K from January
    - Voltage and Distribution payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 0.4%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $471K; Rapid Response Pricing (RRP) Opportunity Cost - $730K; Posturing - $115K; 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

- ISO expects to provide 2050 Transmission Study initial results at the March 16 PAC meeting
- ISO conducted FCA 16 on February 7, but has not finalized the results because of the ongoing litigation regarding Killingly
- Probabilistic resource adequacy results for the 2021 Economic Study (Future Grid Reliability Study) were discussed at the February PAC meeting and additional FGRS scope was discussed at the February joint MC/RC meeting

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - 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 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) will be held on August 1-3, and results will be posted no later than August 31
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 5

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - ISO conducted the auction on February 7, but has not finalized the results because of the ongoing litigation regarding Killingly
    - ISO included Killingly in the auction in accordance with the D.C. Circuit Court of Appeals order staying FERC's January 3 order, which had accepted the ISO’s termination of Killingly’s Capacity Supply Obligation
    - ISO calculated the FCA 16 results with and without Killingly, creating two sets of results that have unique prices and quantities cleared
    - ISO will release one set of results once there is greater certainty about Killingly's status

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 2, 2021
    - Approved projects were shared with the RC at their January meeting
  - Capacity zone development discussions began at the November 17, 2021 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - ISO needs finalized FCA 16 results to proceed with FCA 17 activities
    - On February 15, ISO submitted revisions to Section III.13 of the Tariff to FERC, pursuant to Section 205 of the Federal Power Act and the "Exigent Circumstances" provisions of the Participants Agreement to add language to allow ISO to move the dates, date ranges and/or deadlines for FCA 17 activities (comments are due March 8)

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
  - Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast
- Efforts to expand/improve the transportation electrification forecast for CELT 2022 are complete
- Upcoming Meetings
  - Distributed Generation Forecast Working Group is scheduled for March 14
  - Energy-Efficiency Forecast Working Group is scheduled for March 18
  - Load Forecast Committee is scheduled for March 25
  - These meetings could be postponed due to delays in the availability of FCA 16 results

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
  - 2022 Annual QTPS Certification
    - All 25 QTPSs submitted completed Annual QTPS Certification forms to the ISO prior to the close of the Certification Window on January 31
    - The ISO has determined that all 25 QTPSs continue to meet the Attachment K requirements and has notified them accordingly

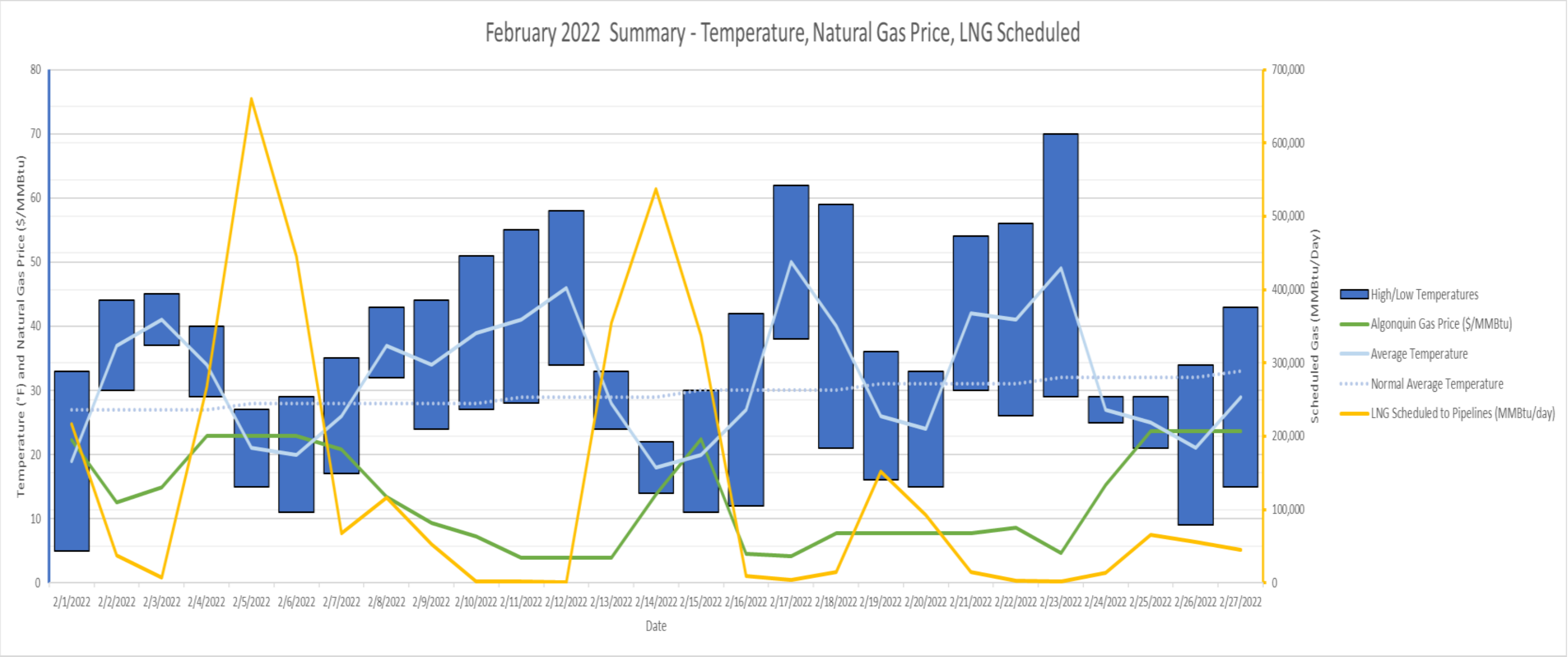
Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning March 26, 2022.

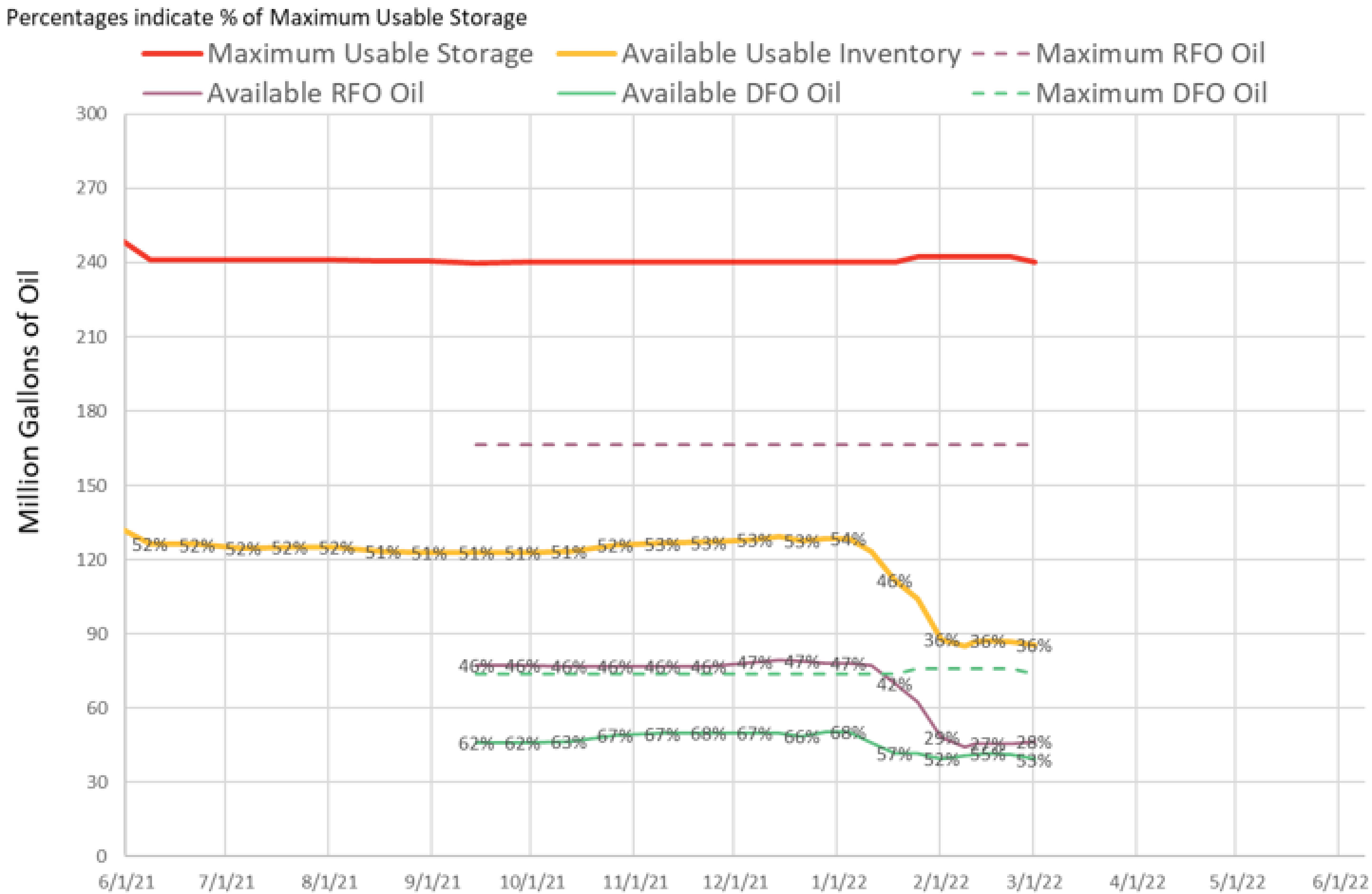
- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 14, 2022.

Highlights – Weather, Gas Prices, LNG Injection

- Average temperature was warmer than normal by approximately 2°F, resulting in lower than normal demand
- Days with colder temperatures is generally coincident with natural gas prices rising to over $20
  - Scheduled LNG sendout was approximately 3.8 Bcf for the month



Highlights – Oil Inventories



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.8°F) Max: 69°F, Min: 10°F Precipitation: 4.61" - Above Normal Normal: 3.08" Snow: 15.3"	Hartford	Temperature: Above Normal (2.4°F) Max: 71°F, Min: 4°F Precipitation: 4.65" - Above Normal Normal: 3.01" Snow: 7.9"

Peak Load:	18,392 MW	February 14, 2022	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for February 2022			

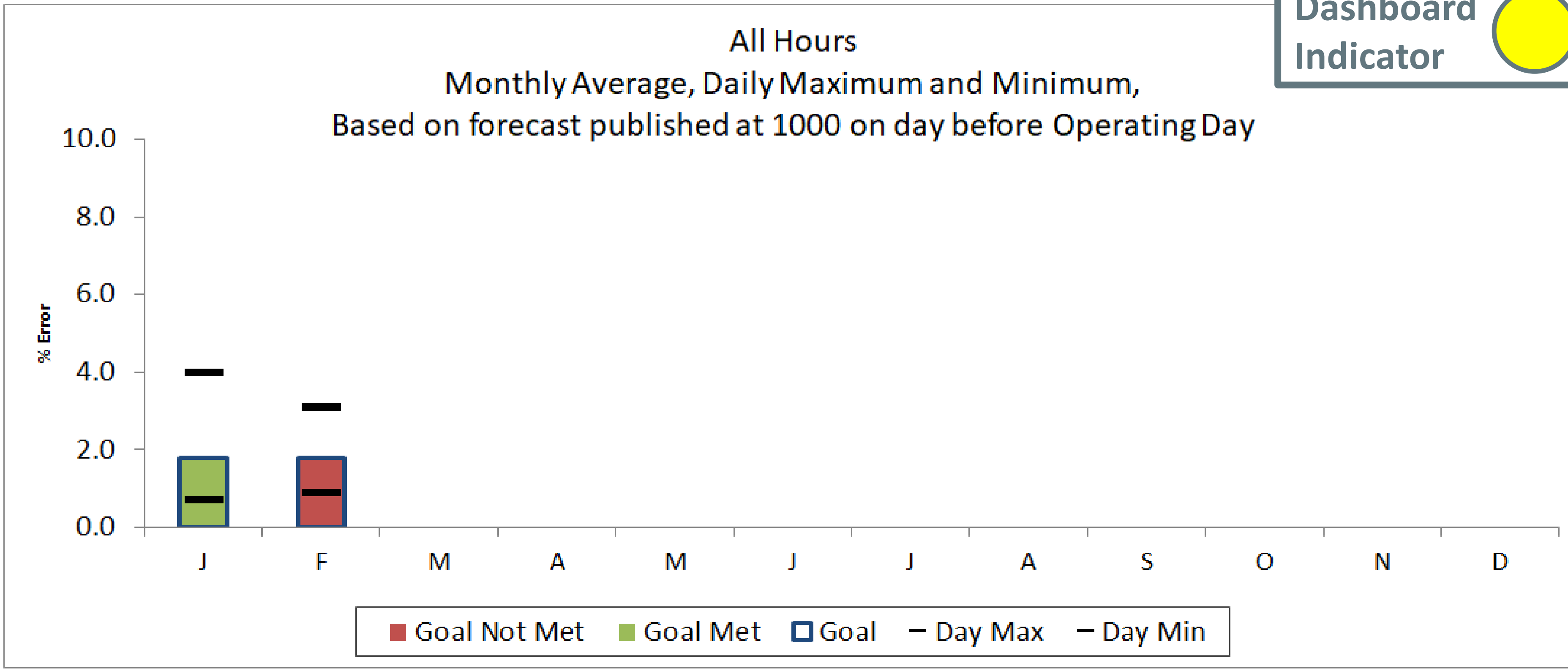
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
2/16	NYISO	550

2022 System Operations - Load Forecast Accuracy

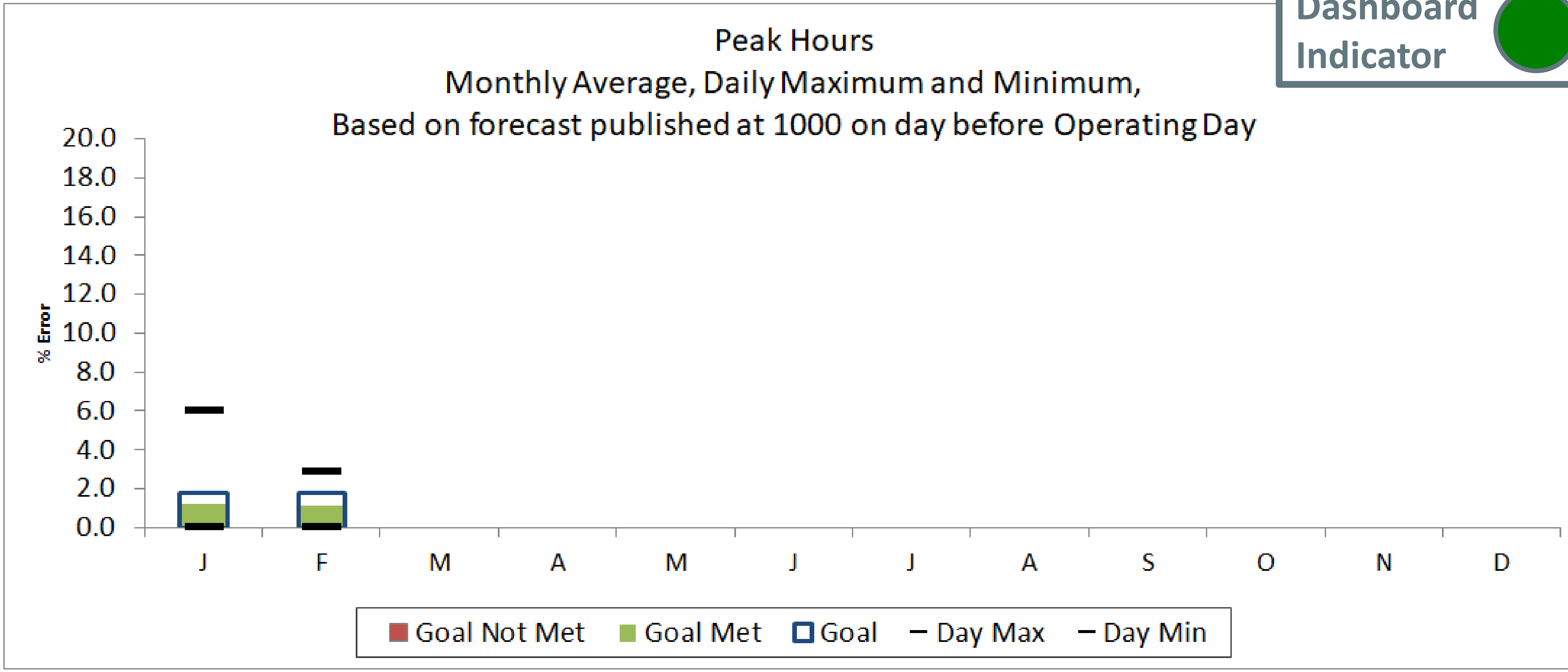
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.97	3.07											3.97
Day Min	0.69	0.87											0.69
MAPE	1.79	1.82											1.80
Goal	1.80	1.80											

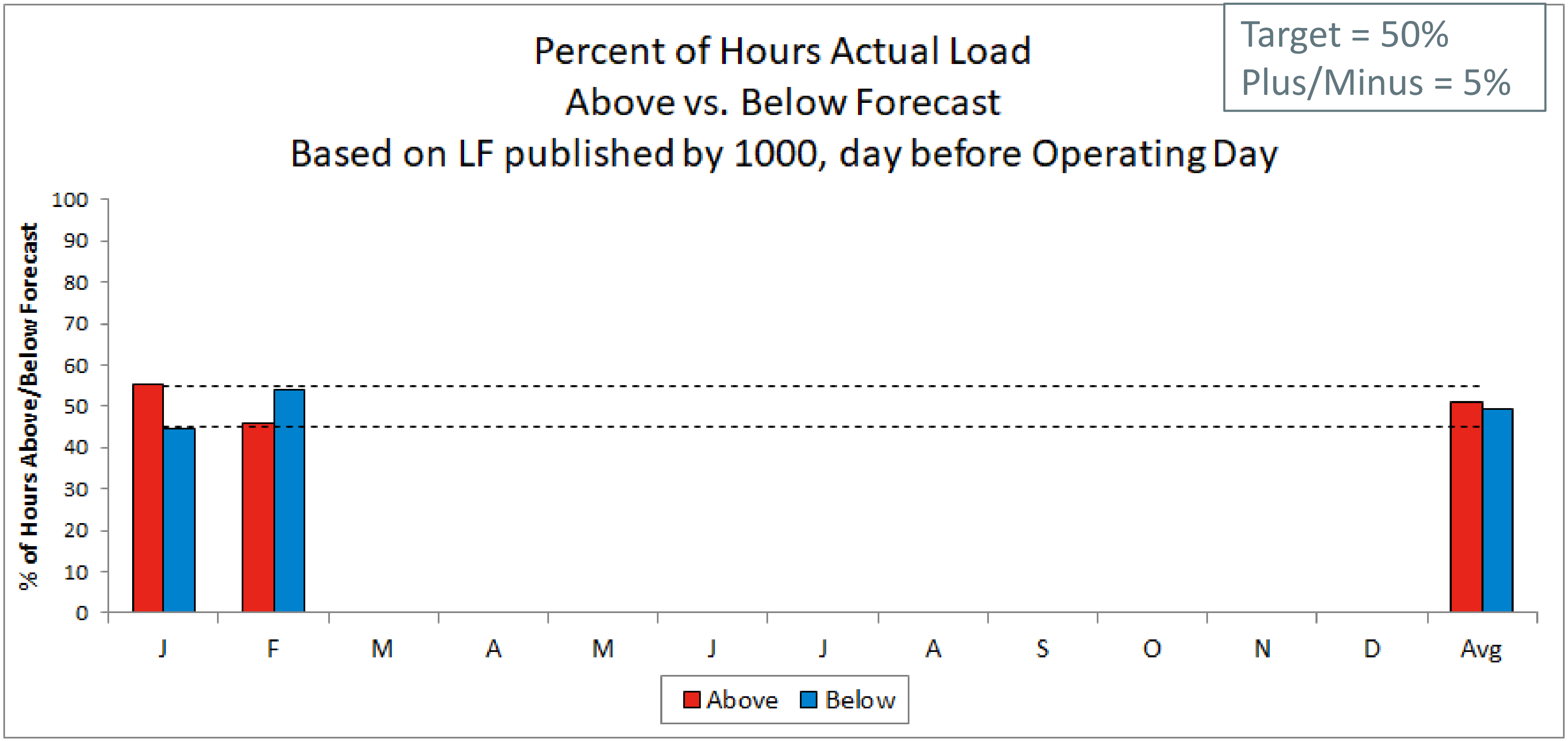
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



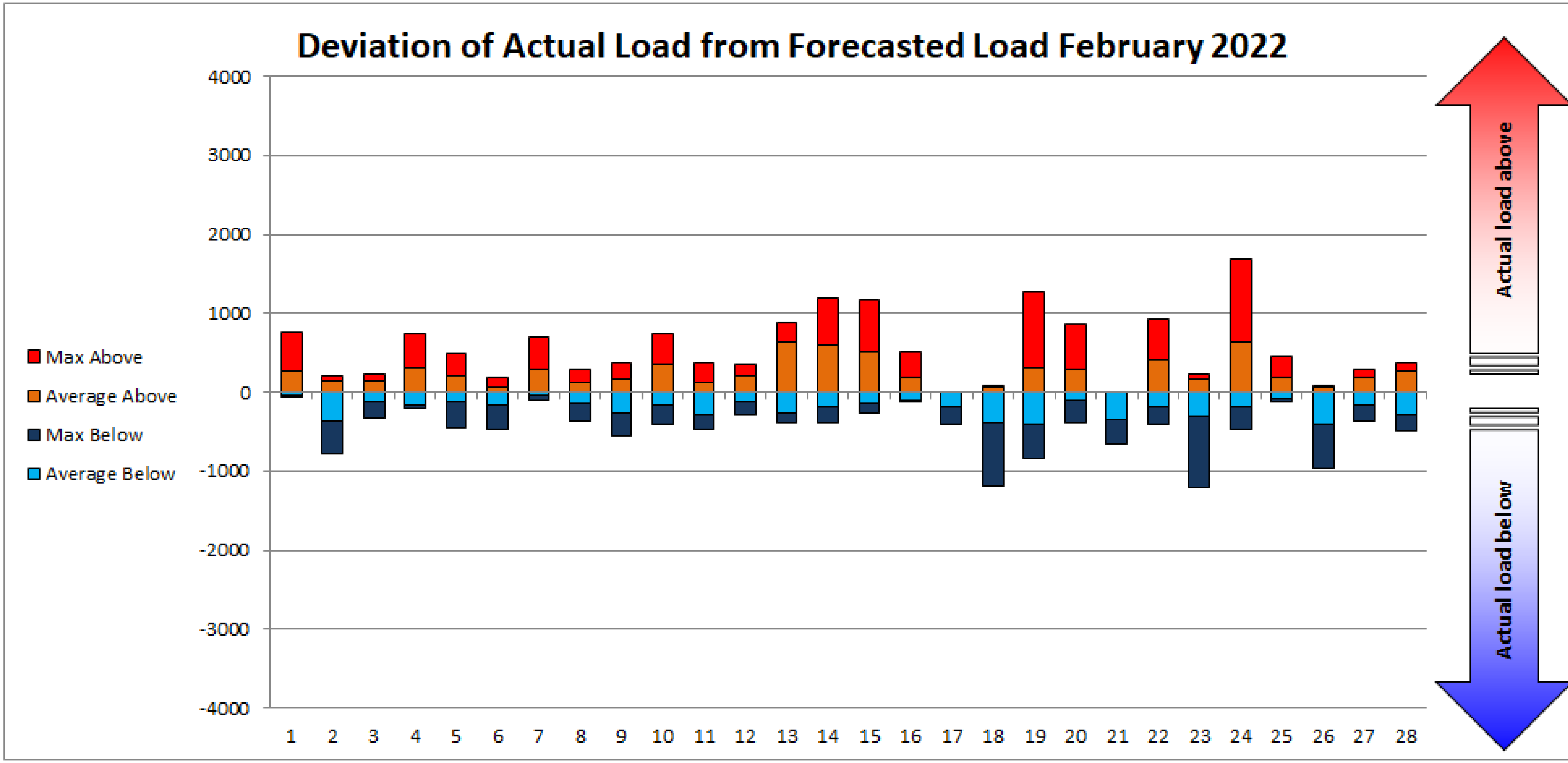
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85											6.01
Day Min	0.02	0.03											0.02
MAPE	1.25	1.11											1.18
Goal	1.80	1.80											1.80

2022 System Operations - Load Forecast Accuracy cont.

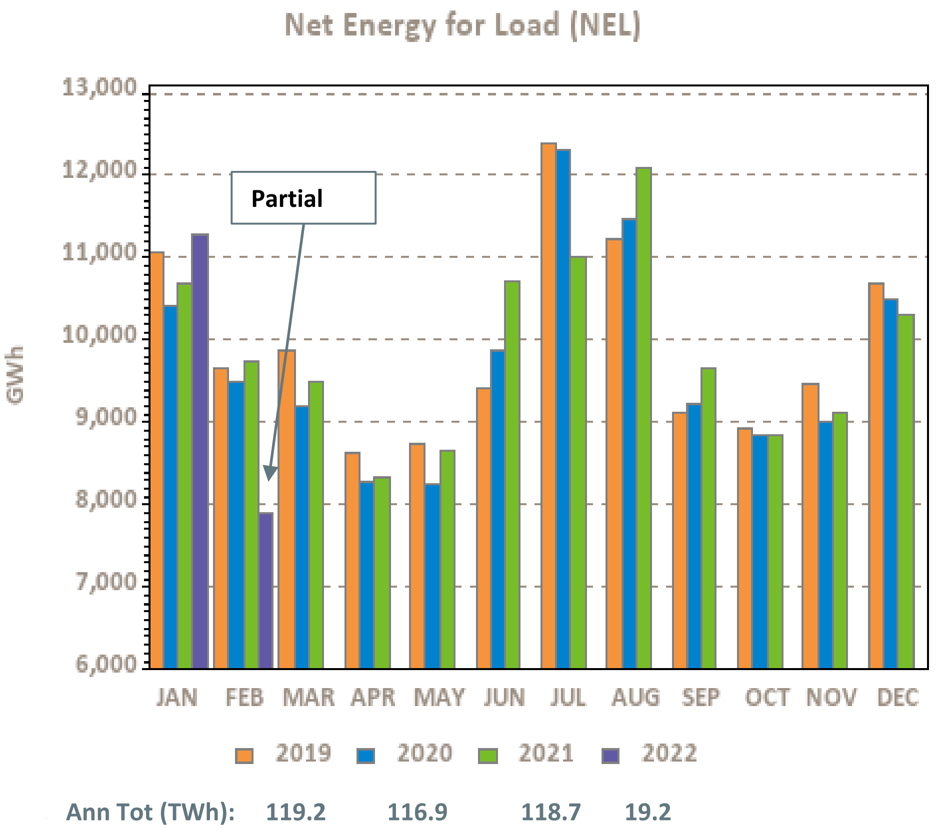


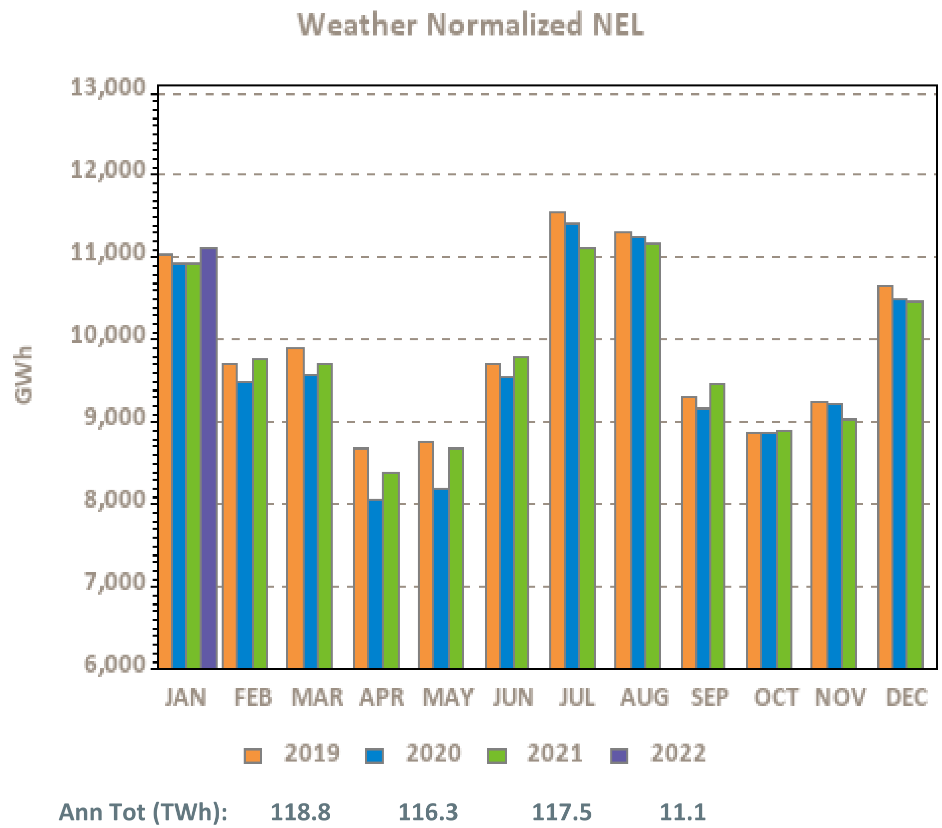
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46											51
Below %	44.8	54											49
Avg Above	219.5	245.7											246
Avg Below	-223.1	-207.7											-223
Avg All	22	6											14

2022 System Operations - Load Forecast Accuracy cont.



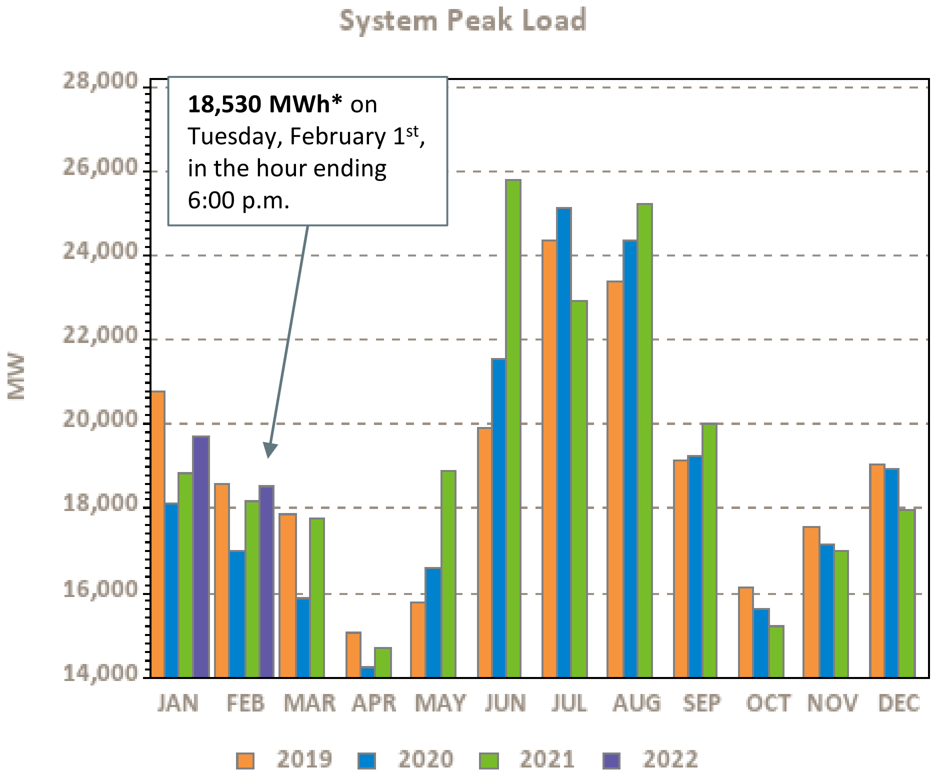
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



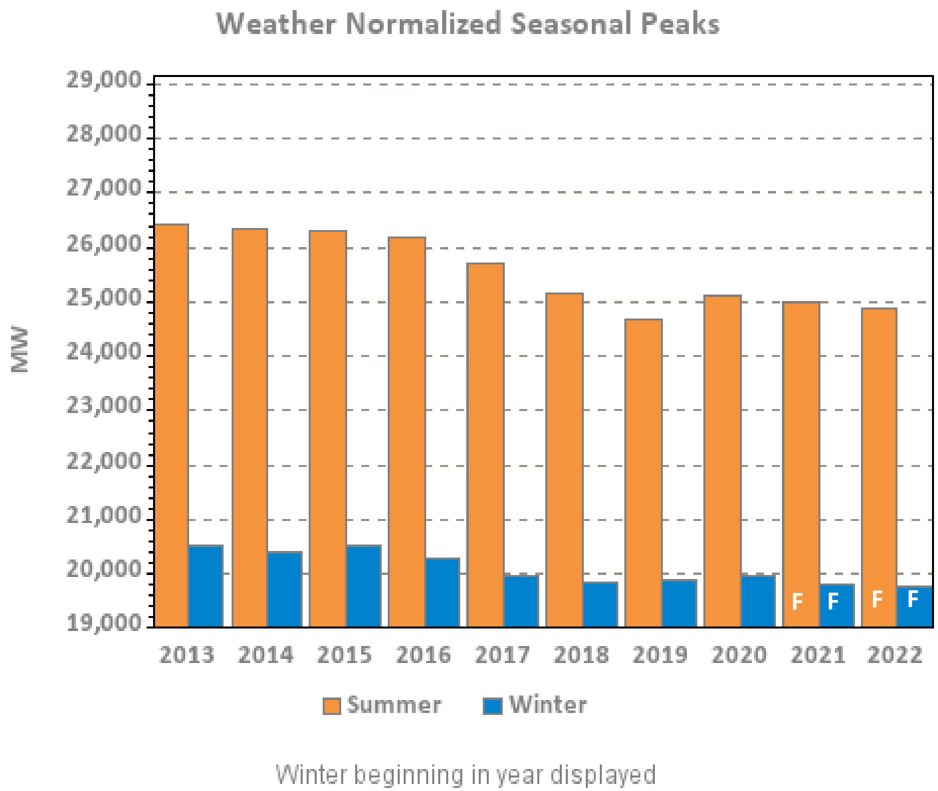


NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



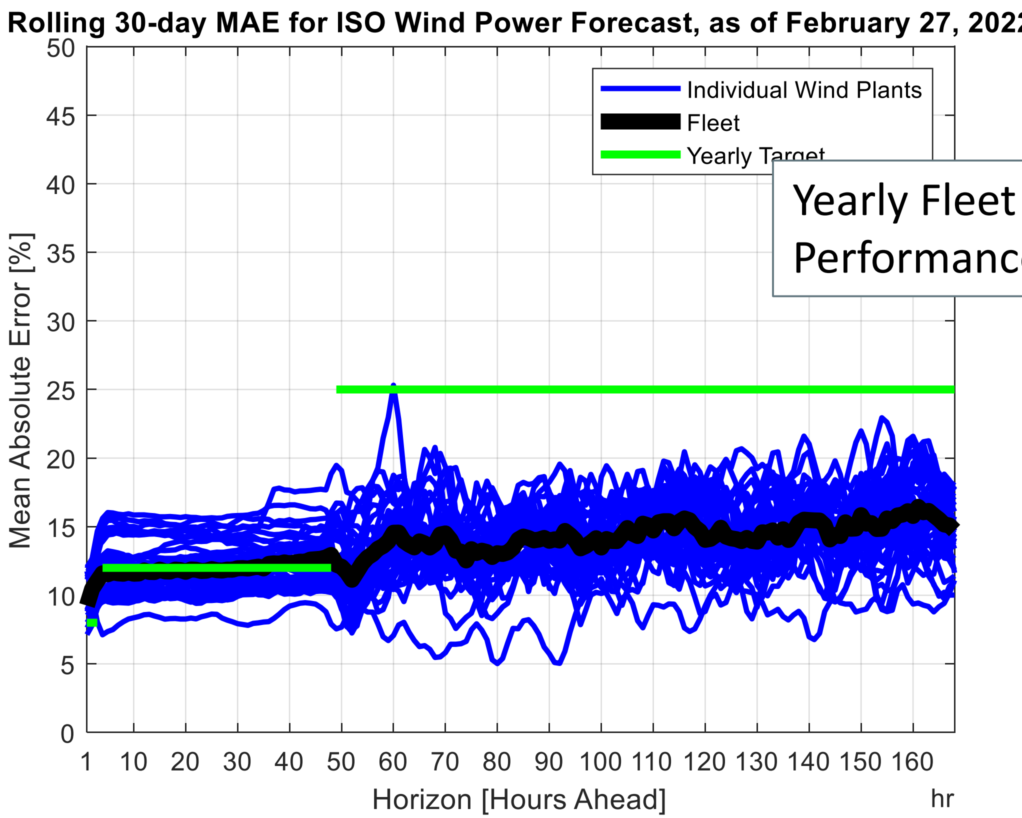
*Revenue quality metered value



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)

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

Dashboard Indicator

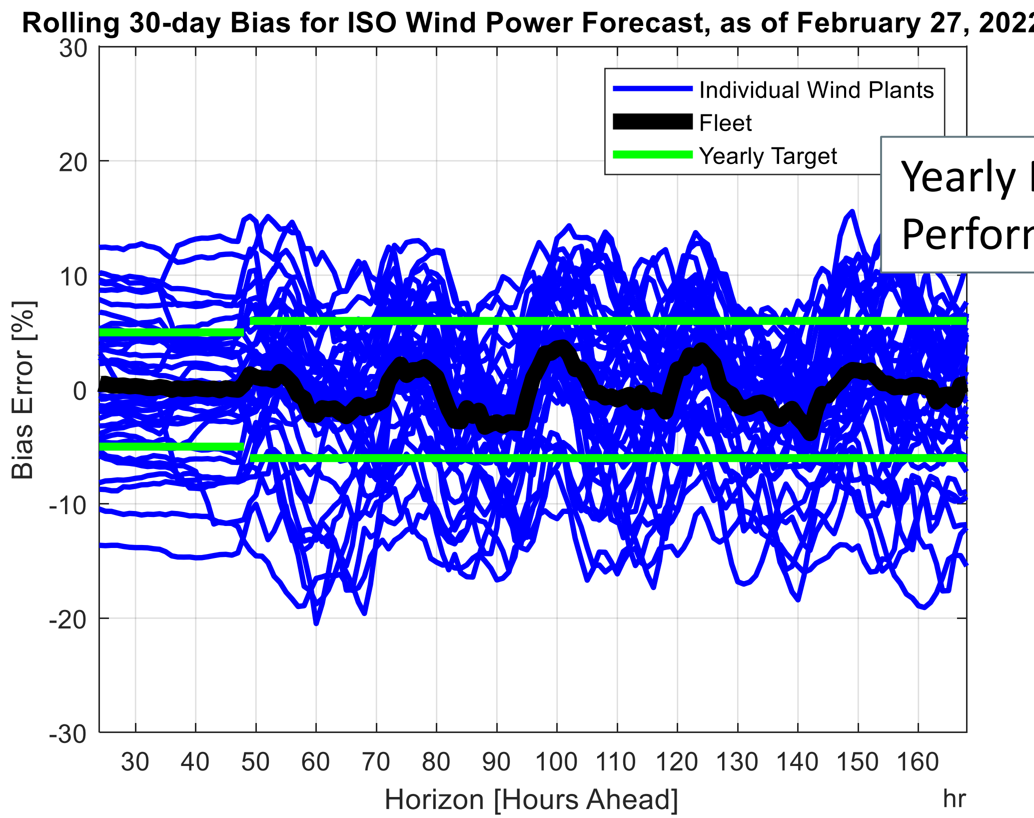


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and monthly MAE (with the exception of hour 1 and hour 49 of look ahead) is within the yearly performance targets.

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

Dashboard Indicator

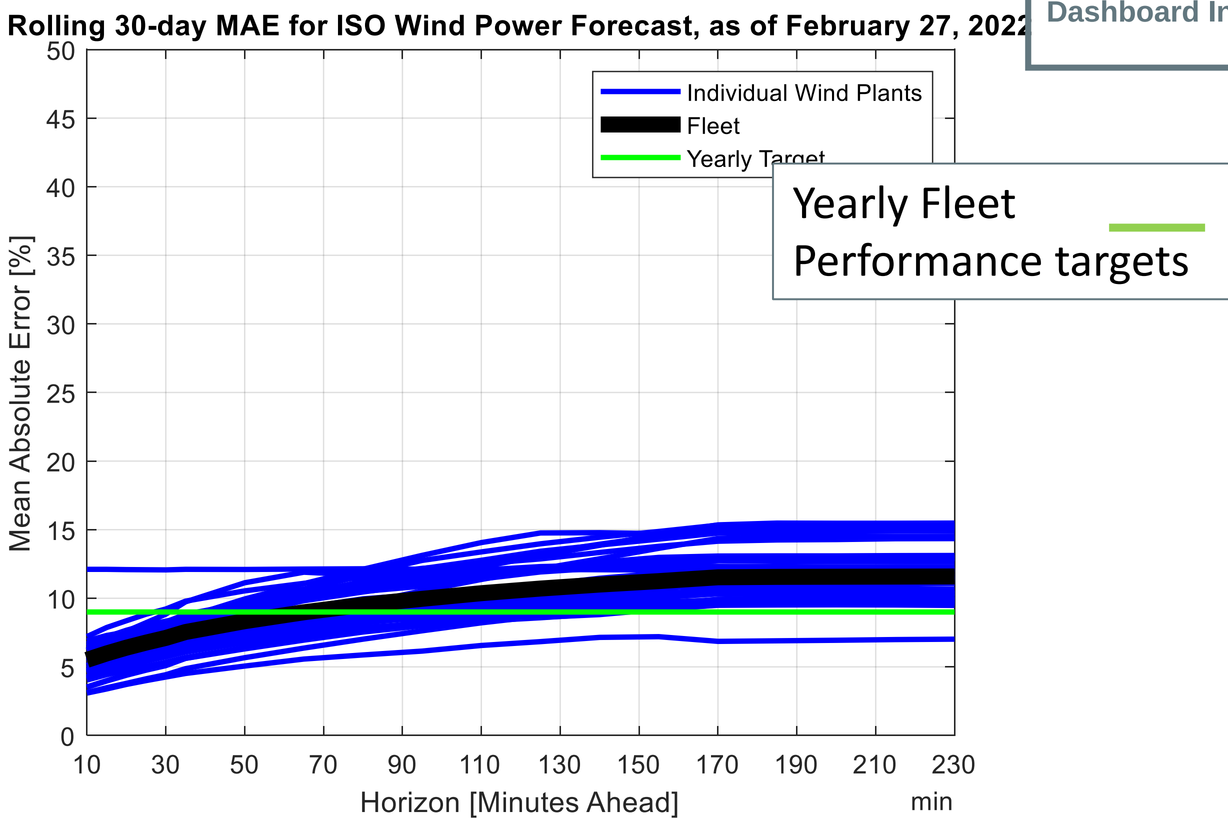


Yearly Fleet Performance targets

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

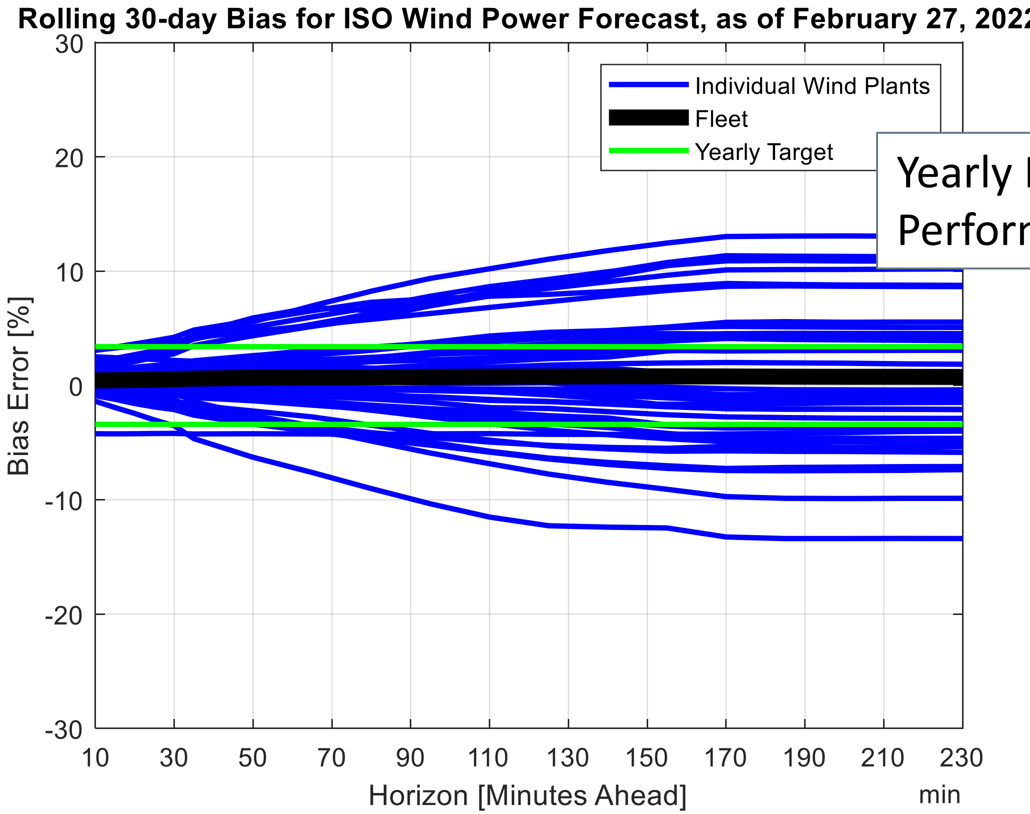
Dashboard Indicator



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 up to 90 minutes look-ahead monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator



Yearly Fleet Performance targets

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

MARKET OPERATIONS

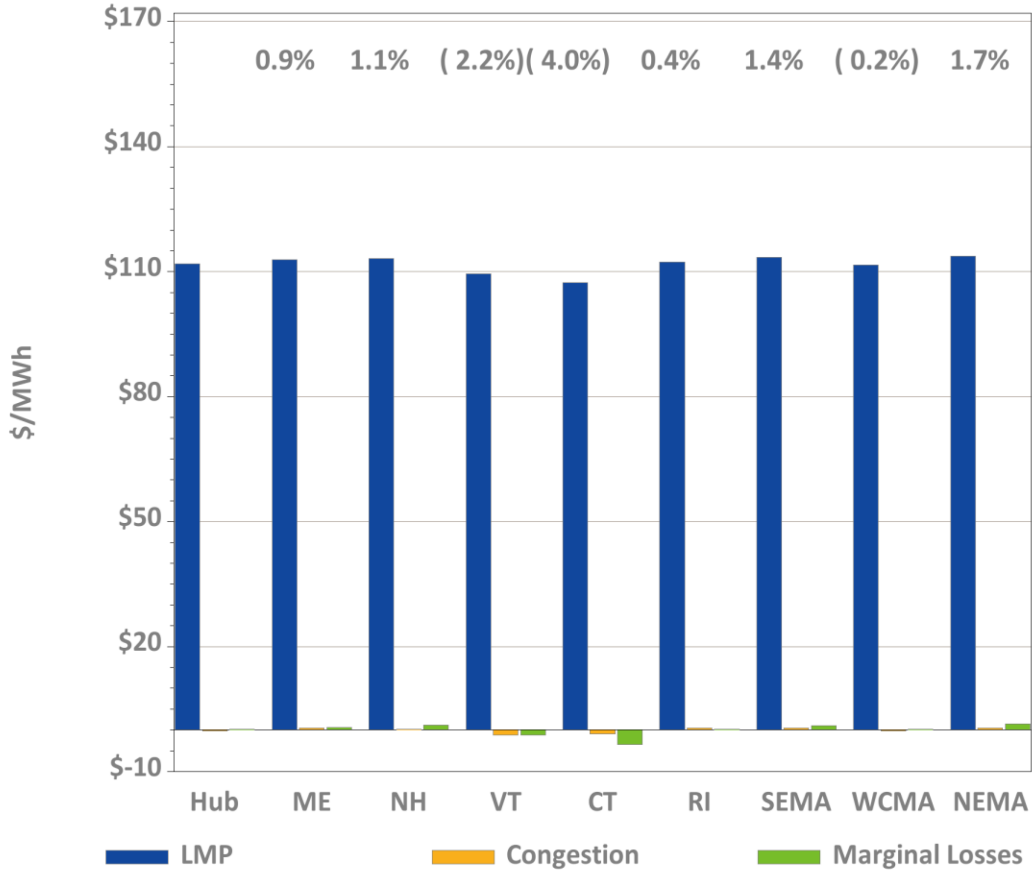
Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: February 1-23, 2022

Underlying natural gas data furnished by:

ice Global markets in clear view

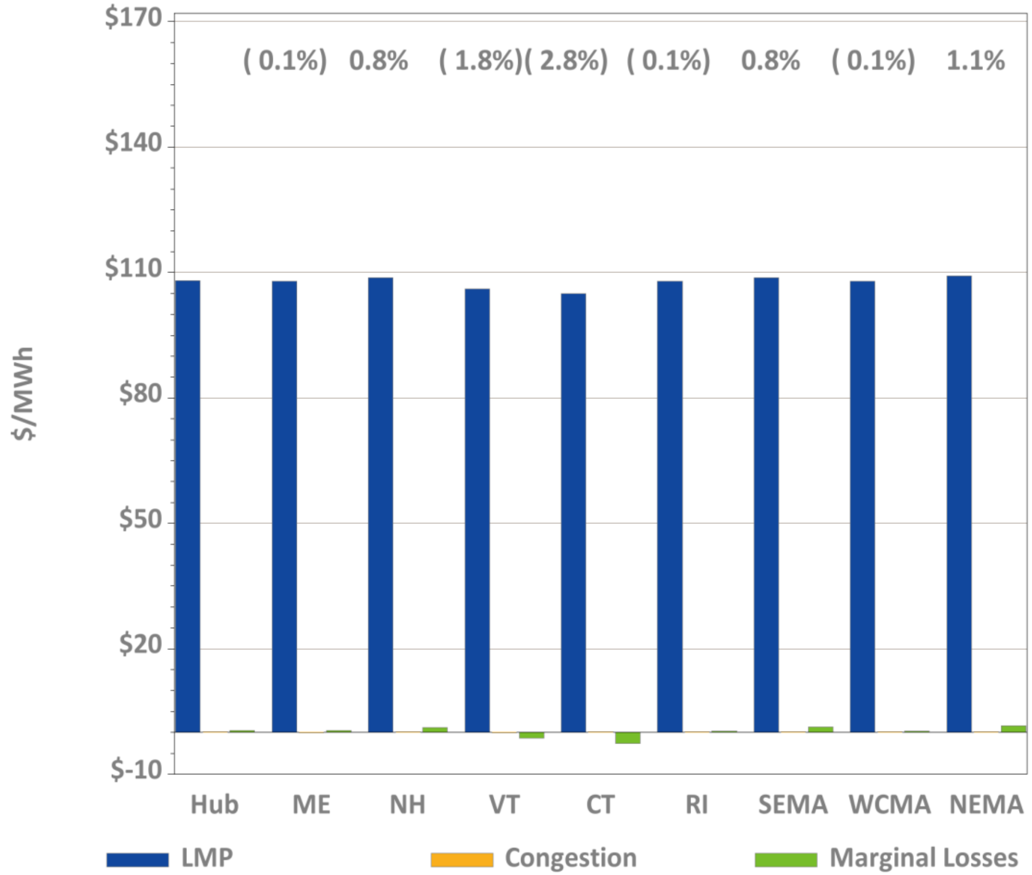
Average price difference over this period (DA-RT): $3.87
Average price difference over this period ABS(DA-RT): $17.04
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, February 2022



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

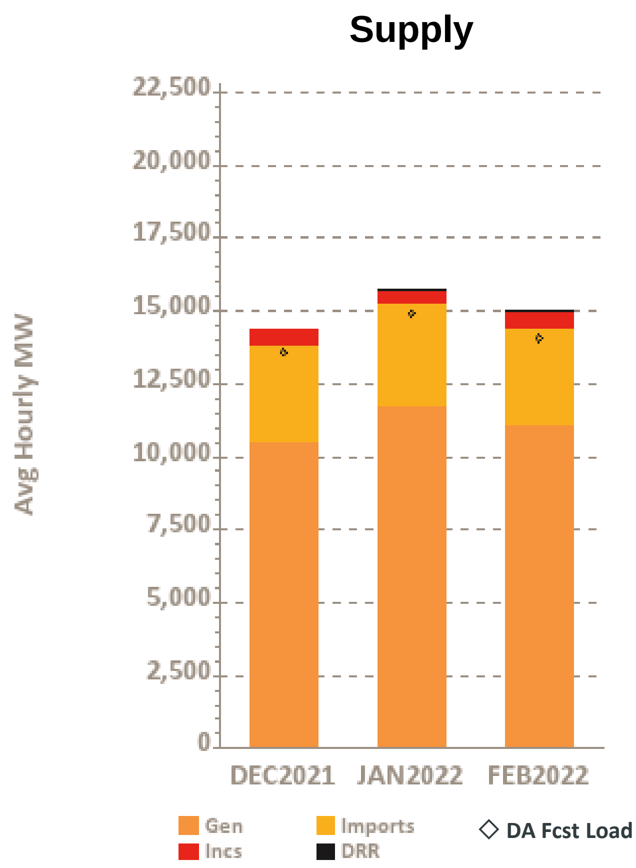
RT LMPs Average by Zone & Hub, February 2022

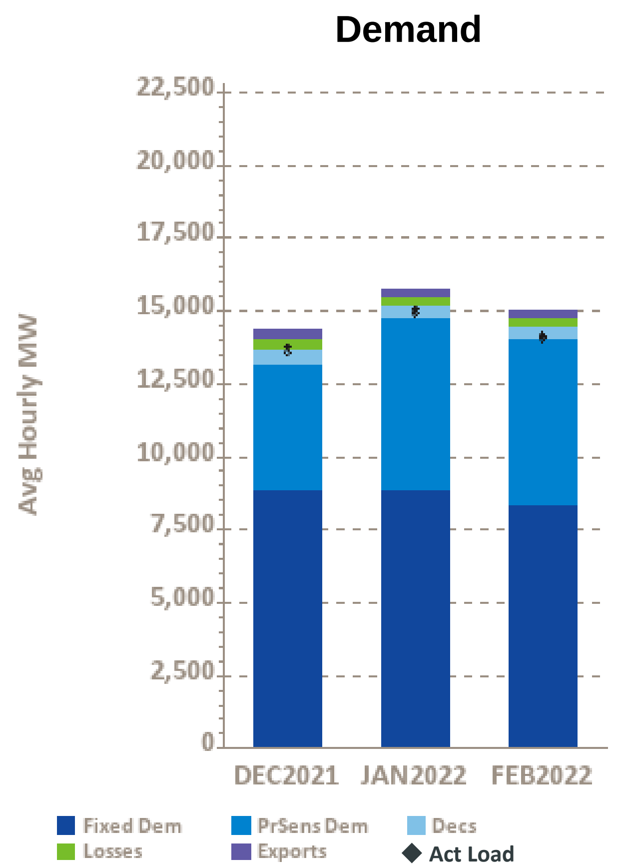


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

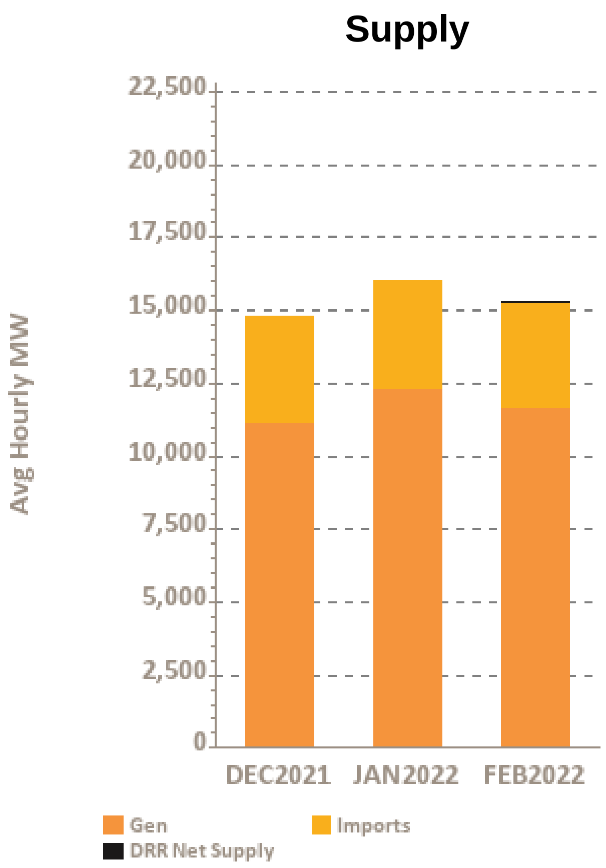


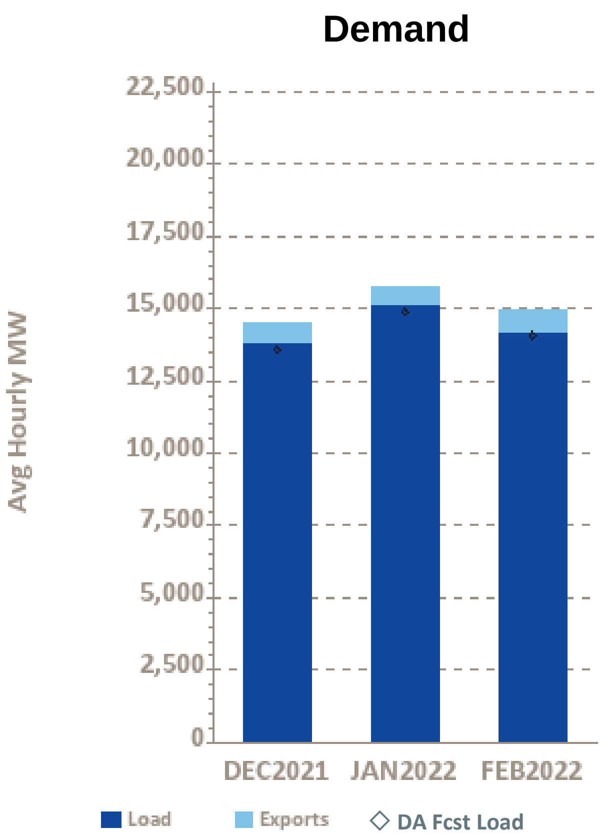


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

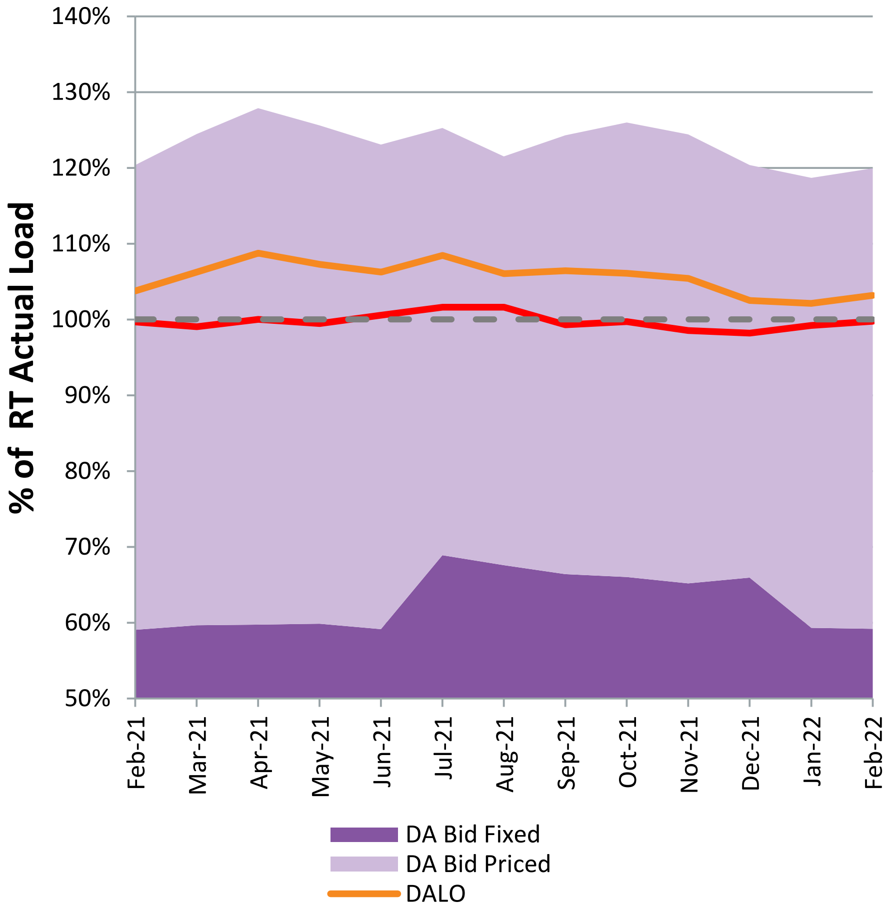
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

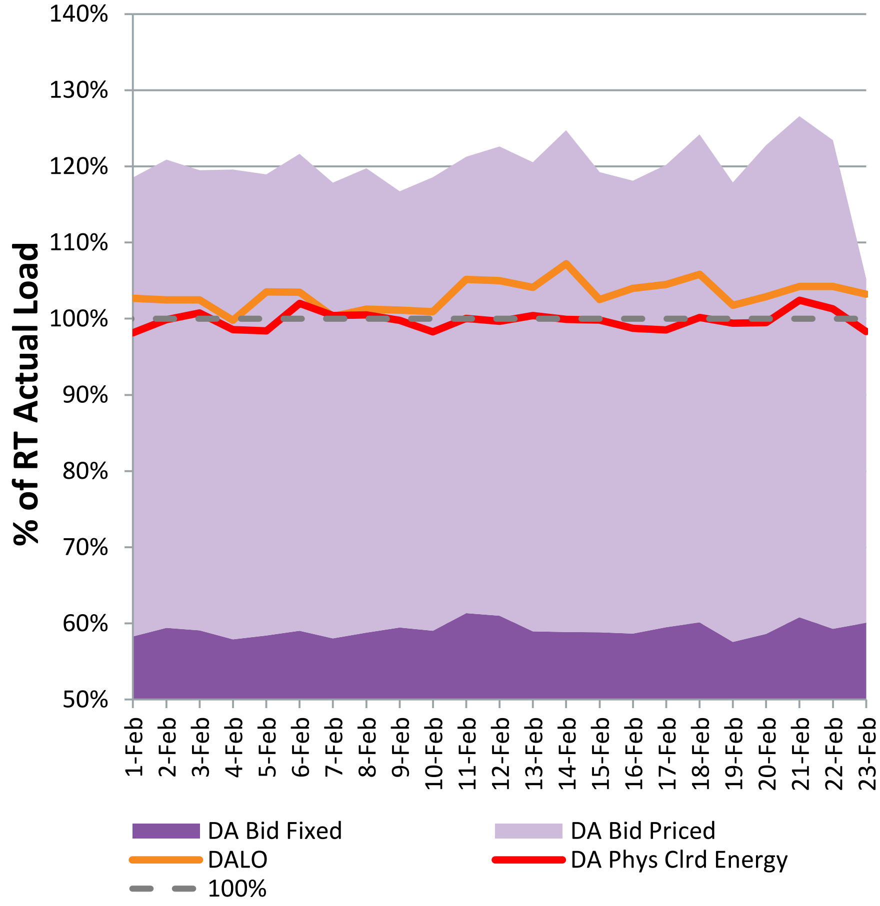
Components of RT Supply and Demand – Last Three Months





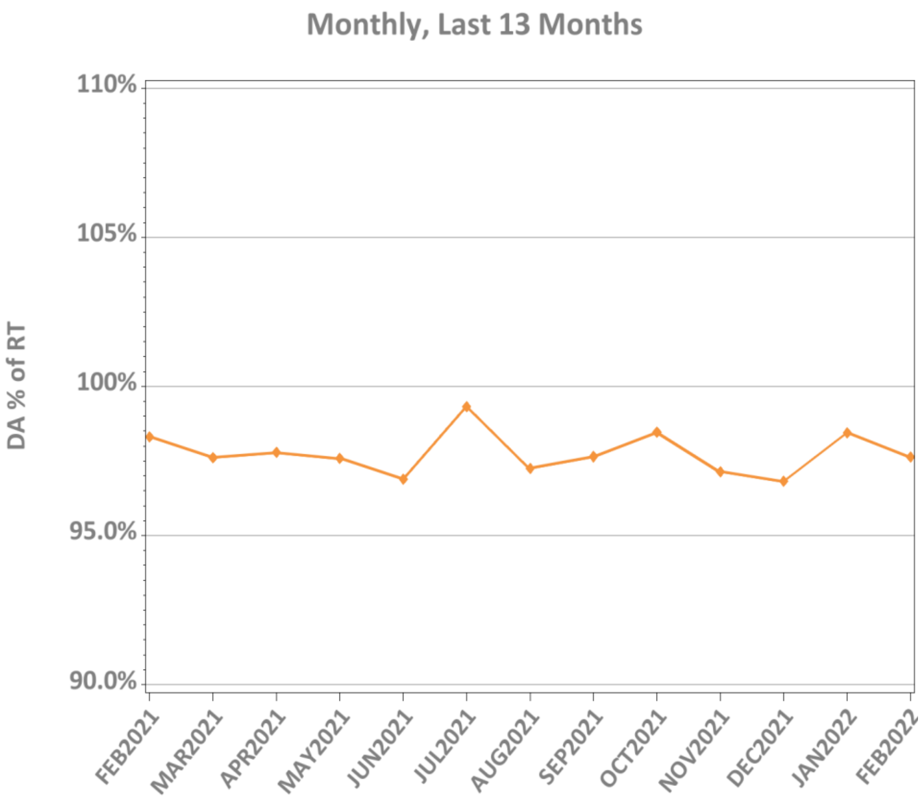
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

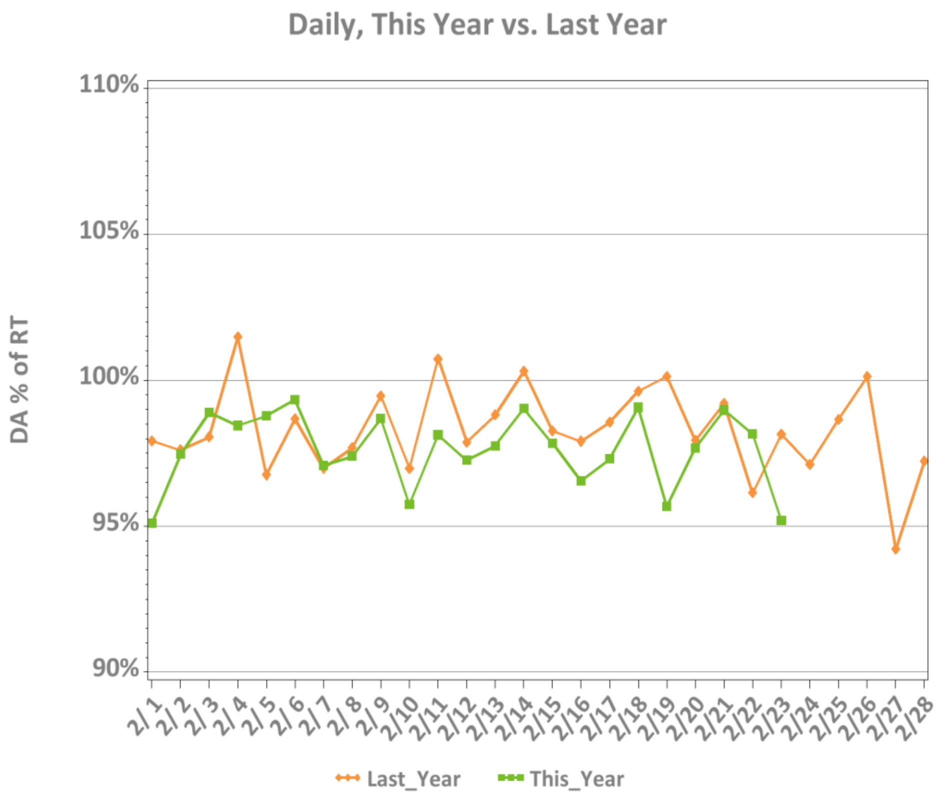




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

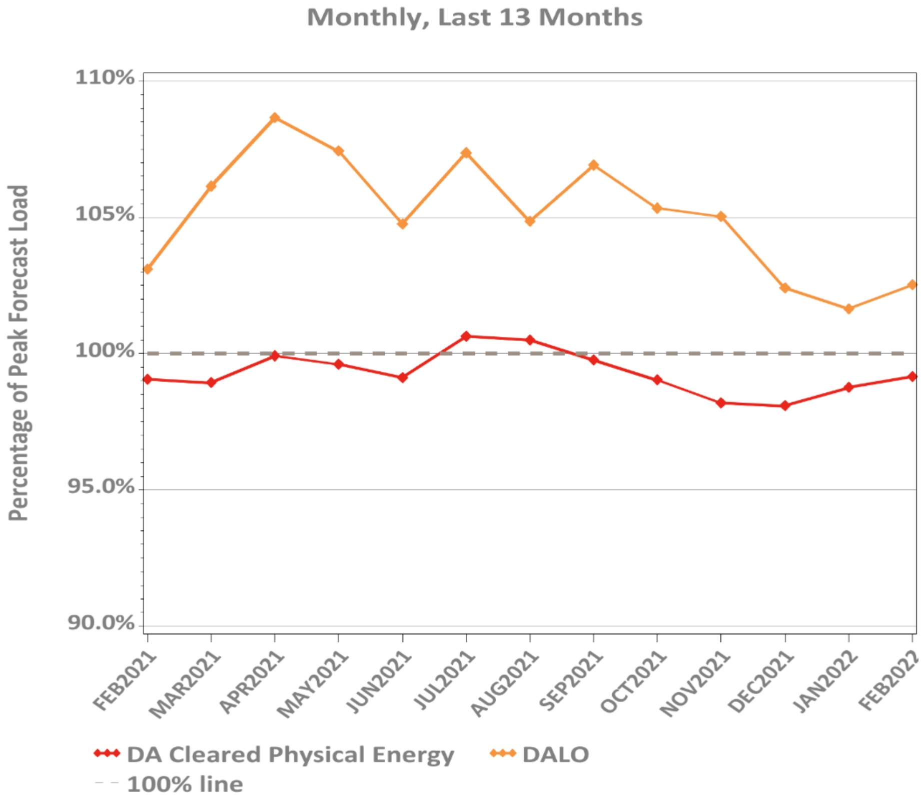
DA vs. RT Load Obligation: February, This Year vs. Last Year

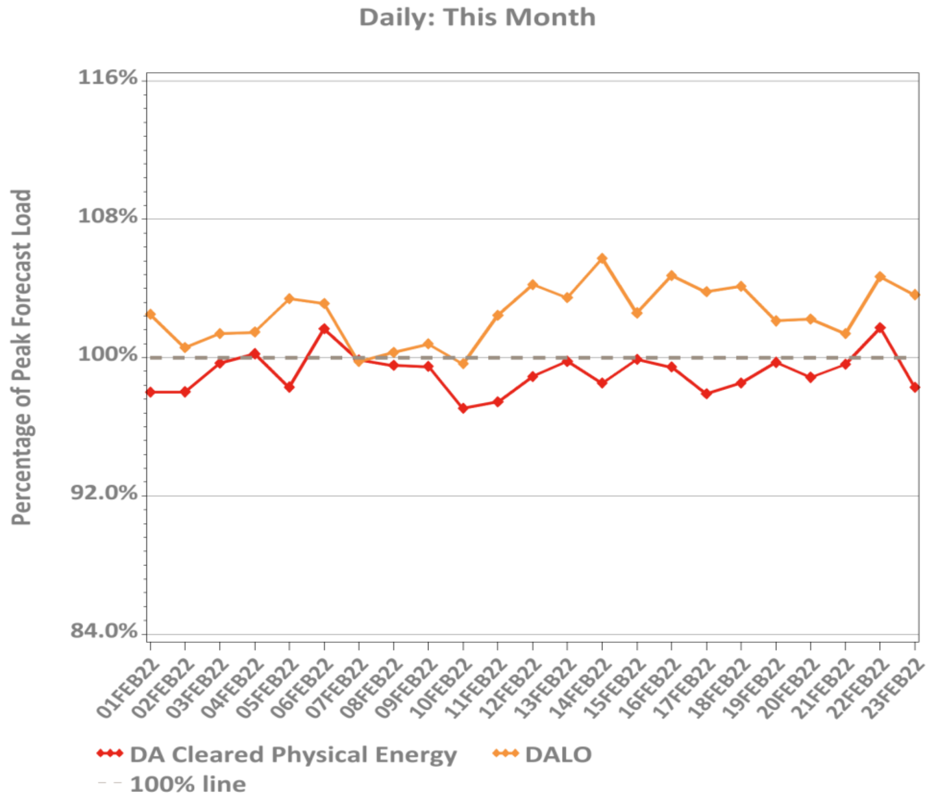




*Hourly average values

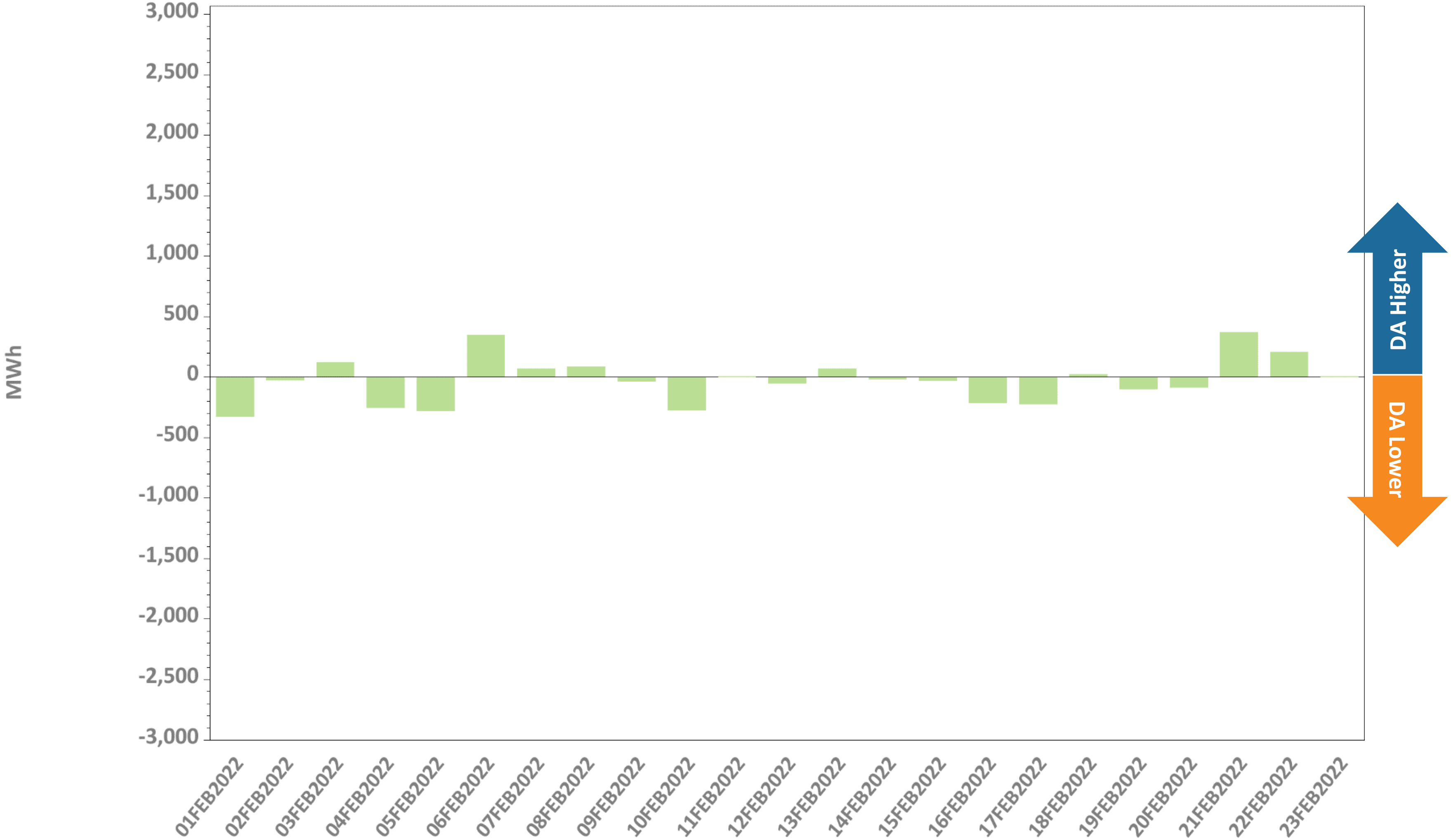
DA Volumes as % of Forecast in Peak Hour





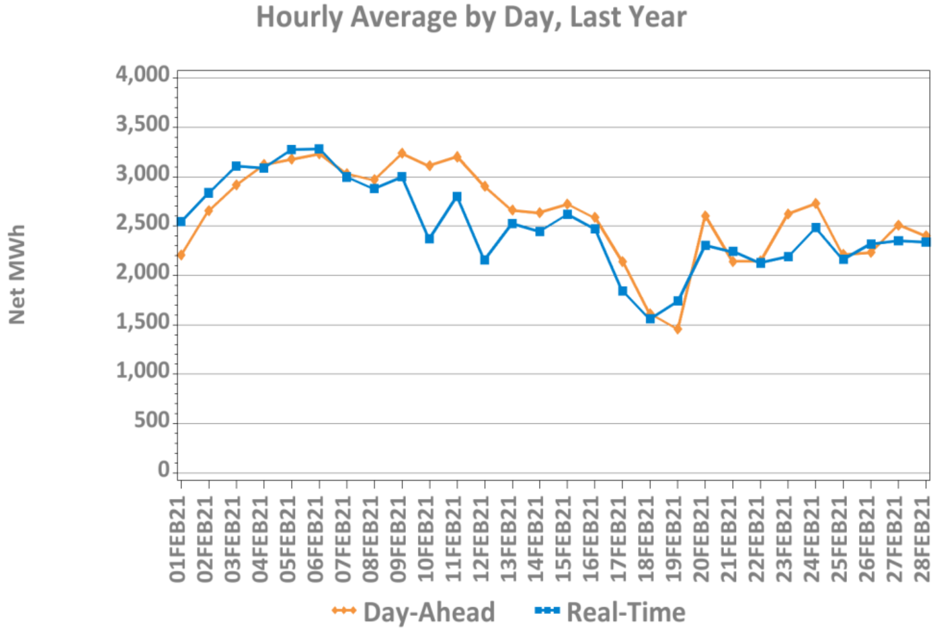
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during the month.

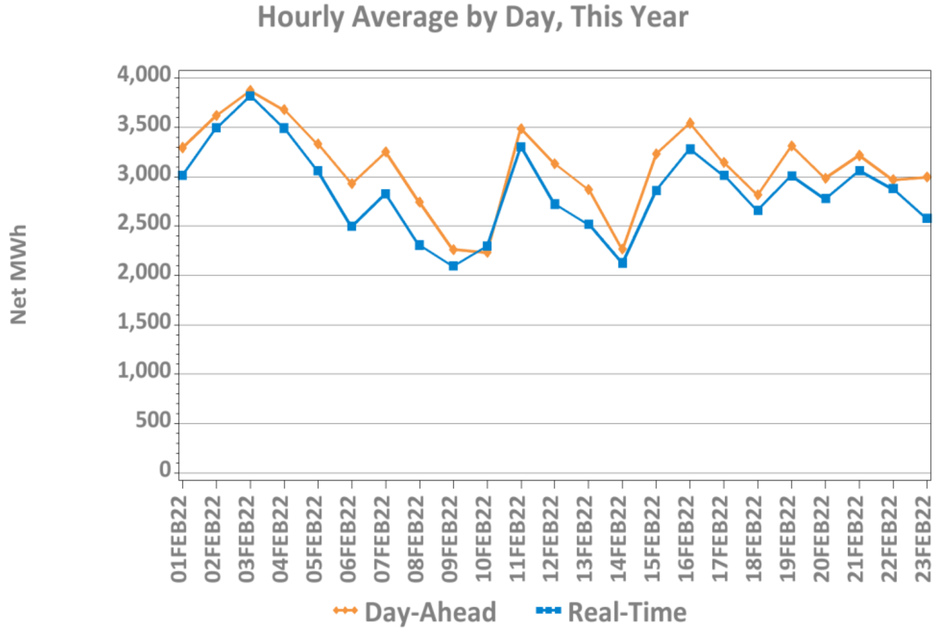
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

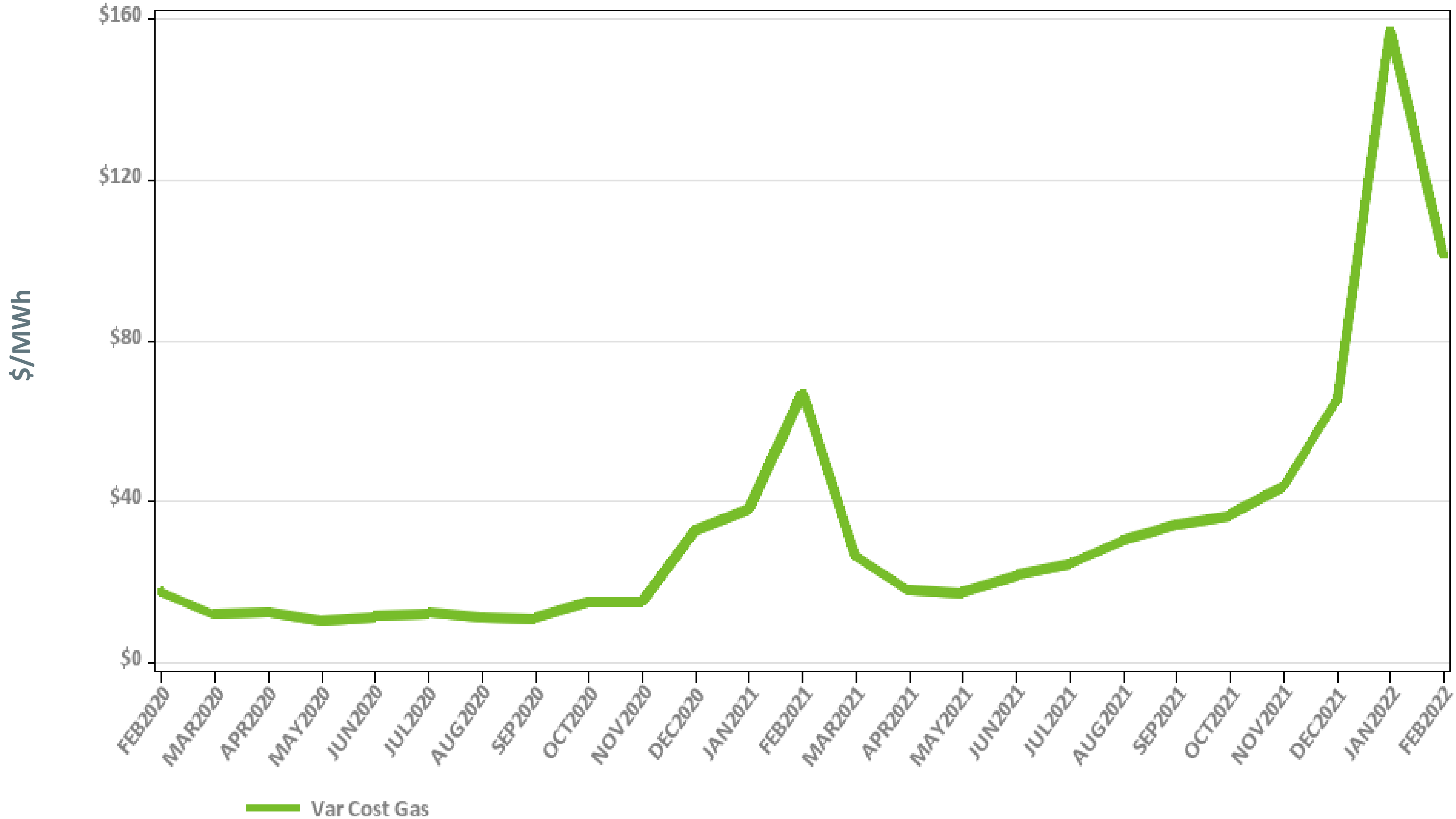
DA vs. RT Net Interchange February 2021 vs. February 2022





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

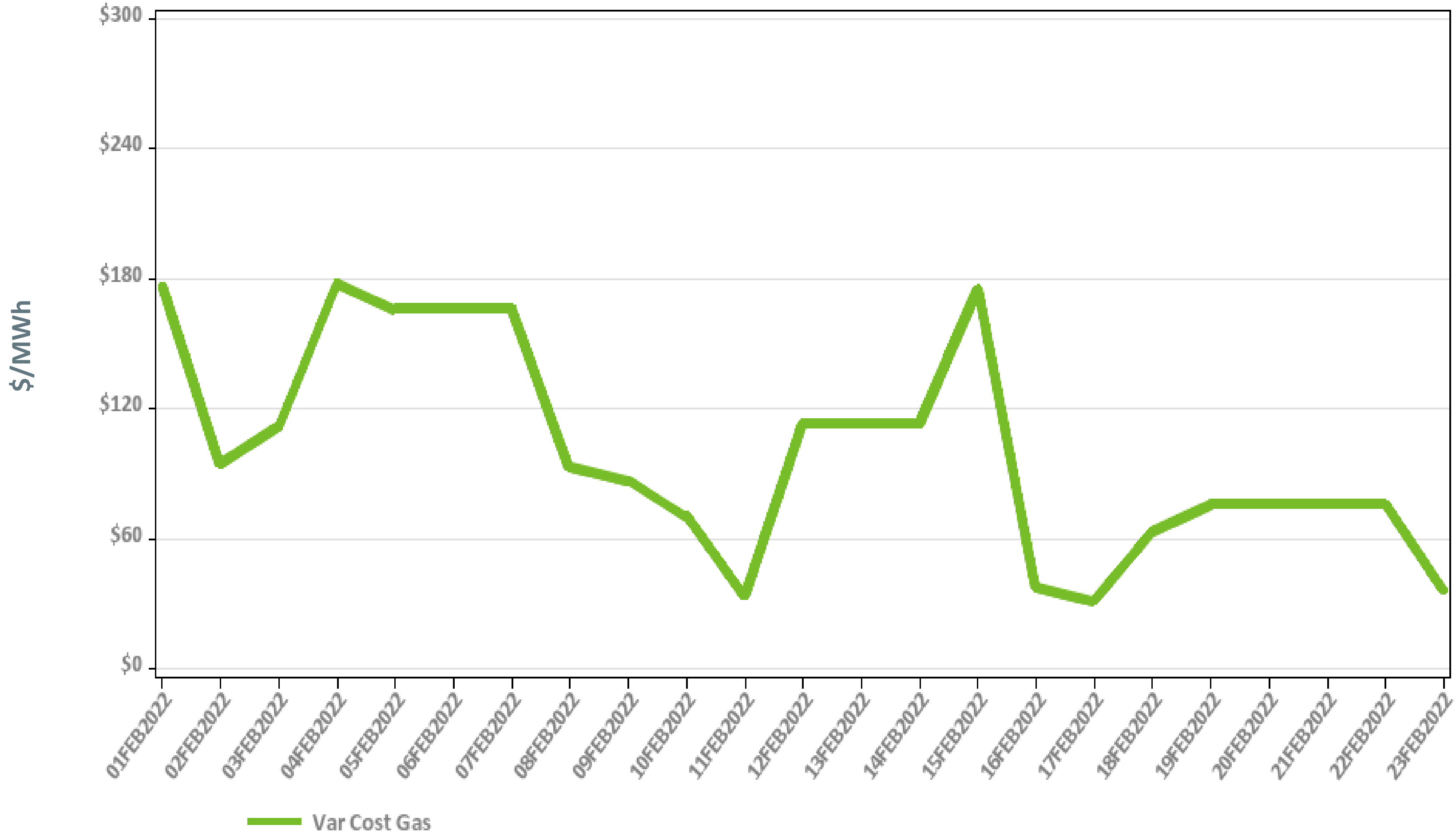
Variable Production Cost of Natural Gas: Monthly



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

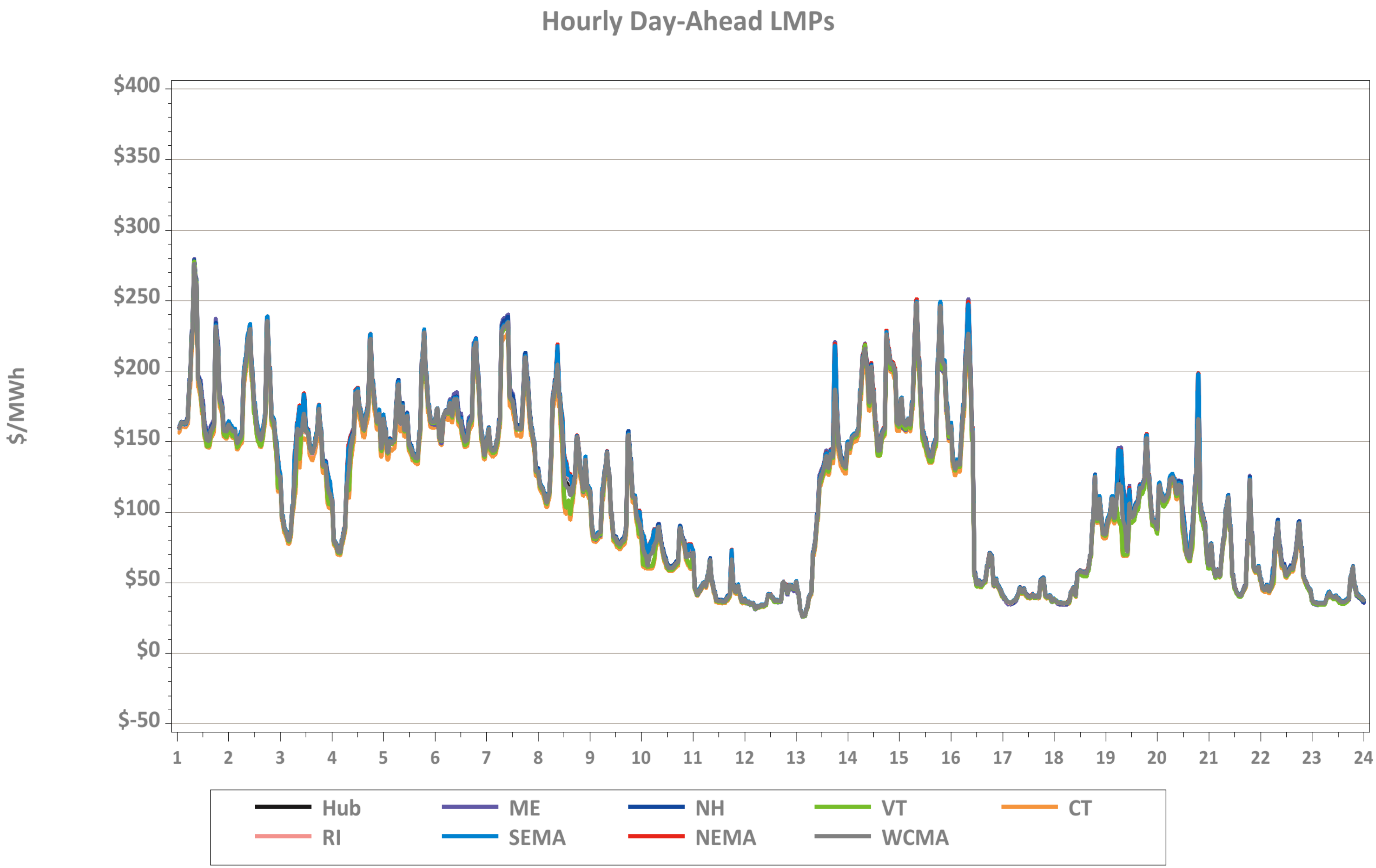


Underlying natural gas data furnished by:

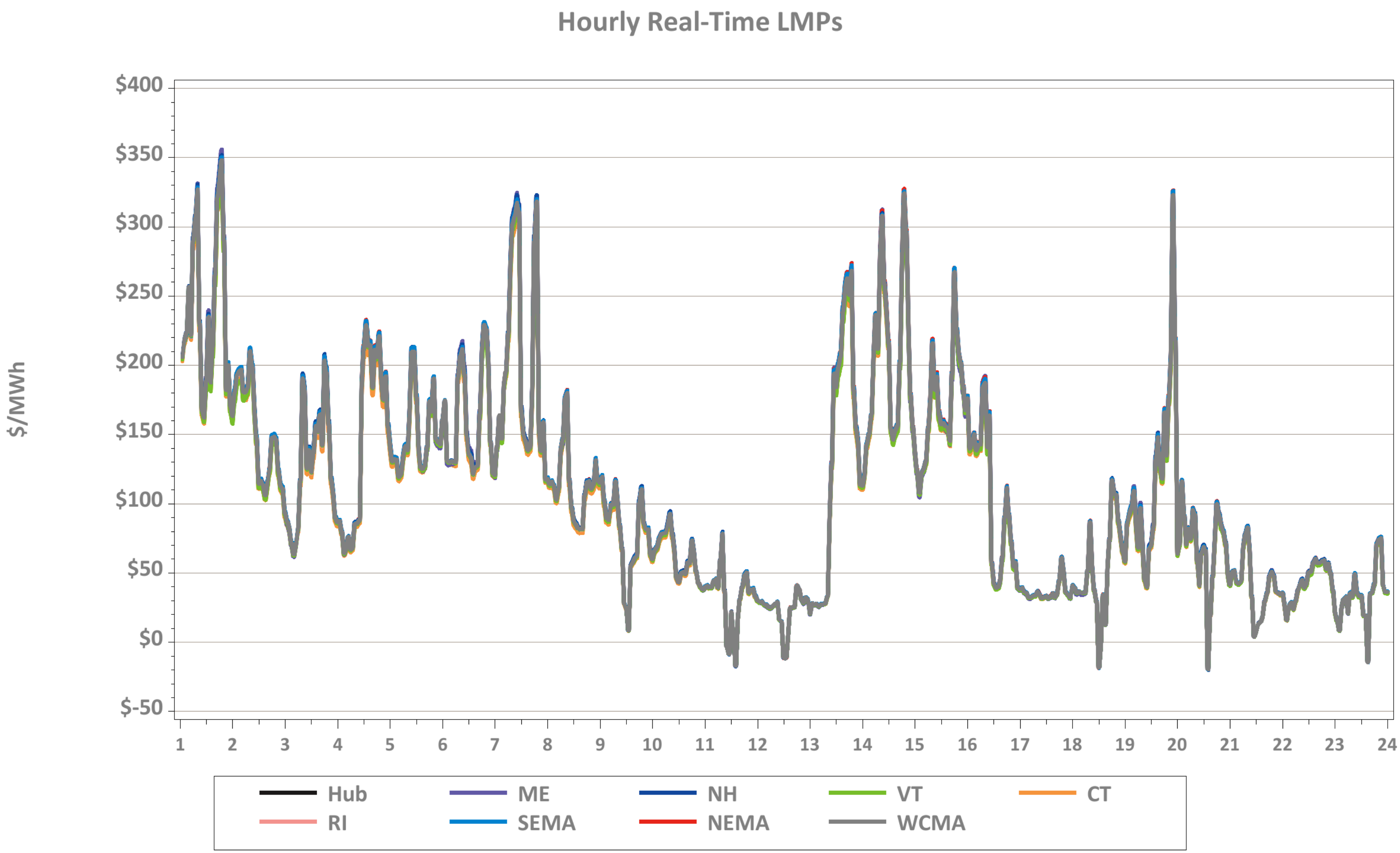
ICE Global markets in clear view

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

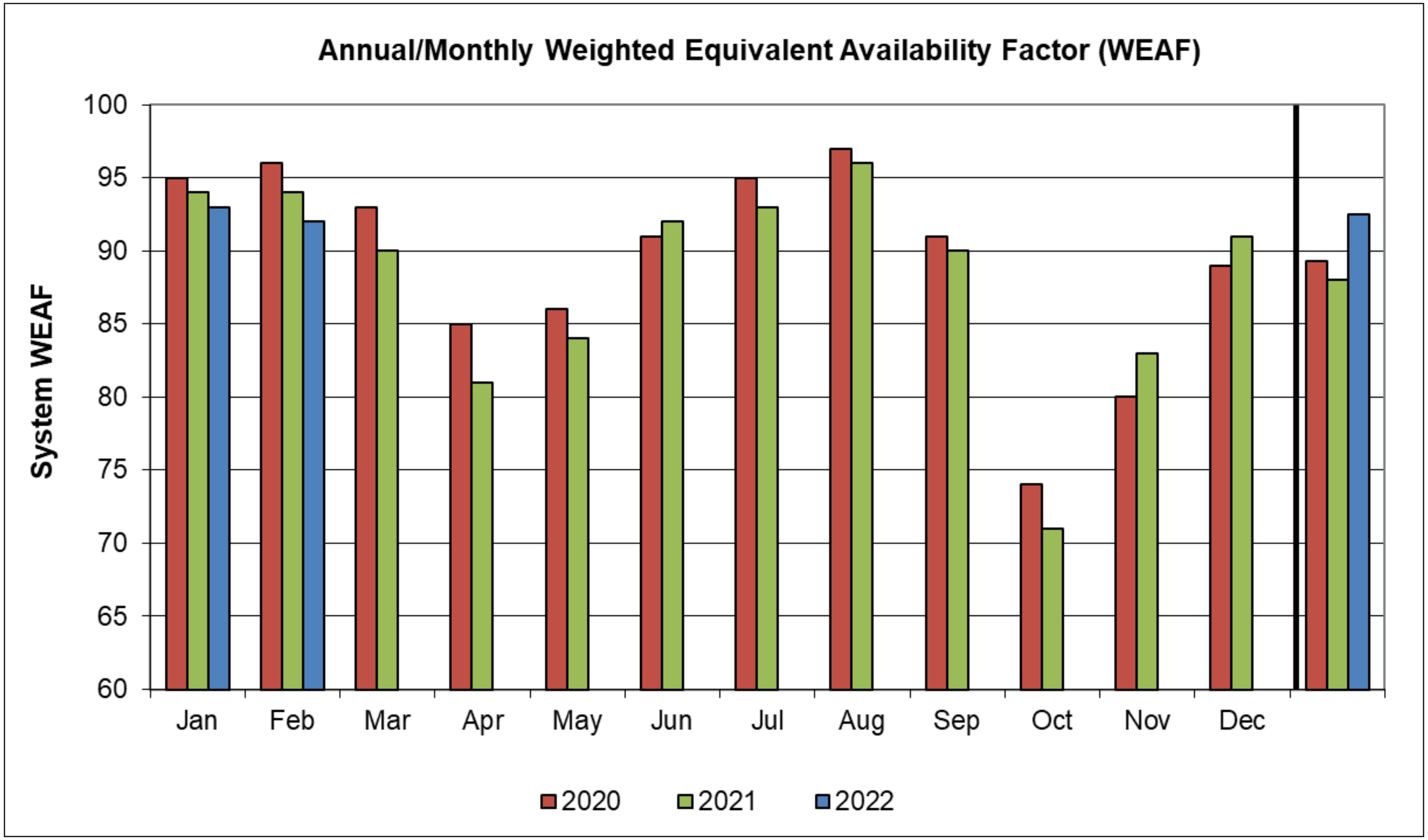
Hourly DA LMPs, February 1-23, 2022



Hourly RT LMPs, February 1-23, 2022



System Unit Availability



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

Data as of 2/22/2022

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	91.2	169.7	0.0	260.9
NH	43.5	148.9	0.0	192.4
VT	43.0	161.9	0.0	204.9
CT	141.5	112.7	754.4	1,008.6
RI	38.4	320.0	0.0	358.4
SEMA	40.7	511.1	0.0	551.8
WCMA	91.9	549.7	18.0	659.6
NEMA	58.7	864.5	0.0	923.2
Total	**548.9**	**2,838.5**	**772.4**	**4,159.8**

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

NEW GENERATION

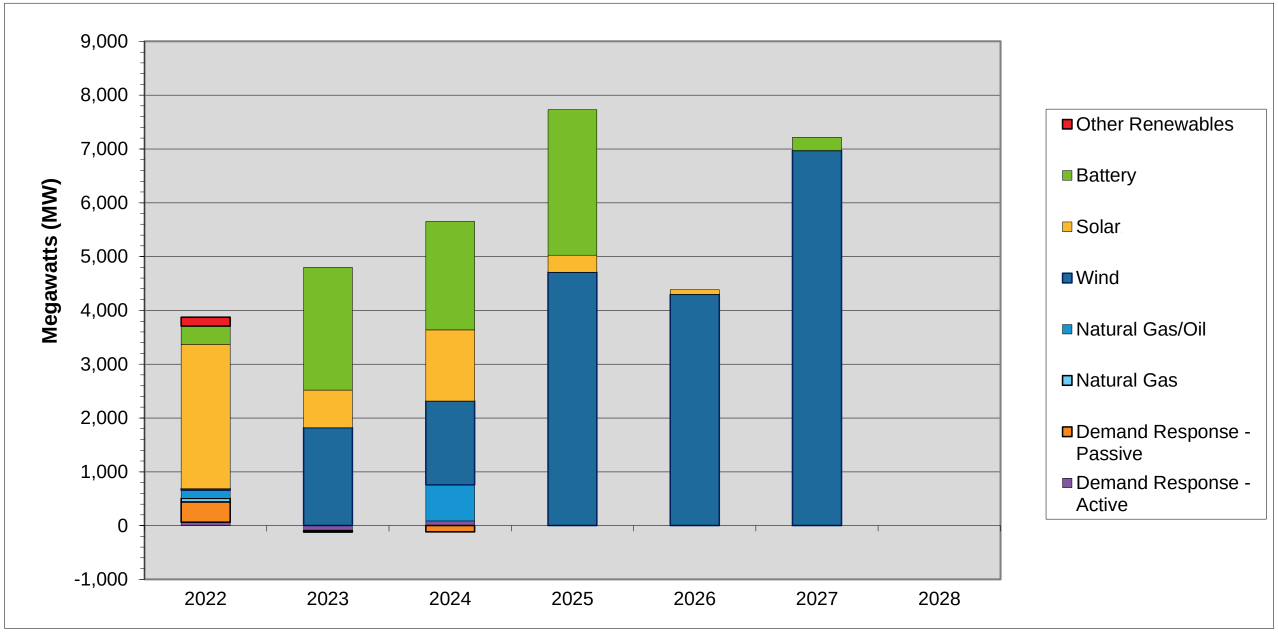
New Generation Update

Based on Queue as of 02/25/22

- Four projects totaling 1,209 MW were added to the interconnection queue since the last update
  - They consist of one wind project, one solar project and two solar with battery projects, with in-service dates of 2022 through 2029
- One project was withdrawn and none went commercial
- In total, 322 generation projects are currently being tracked by the ISO, totaling approximately 34,326 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type

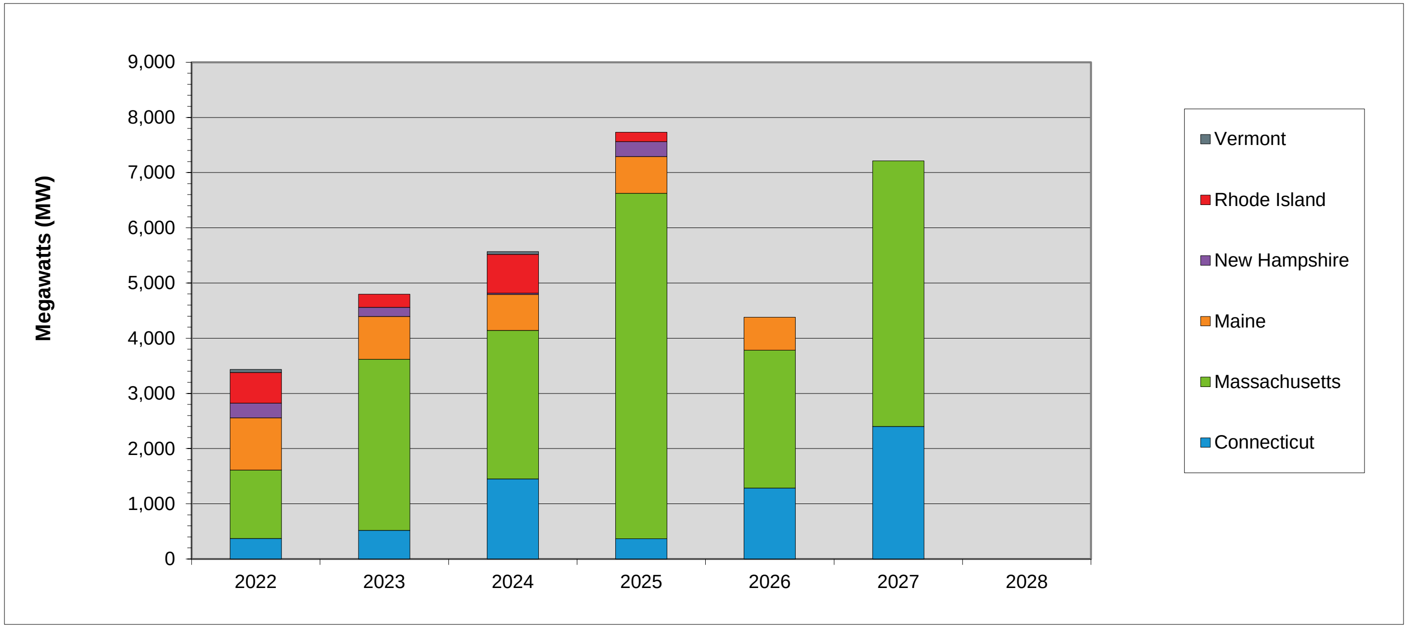


	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	166	0	0	0	0	0	0	166	0.5
Battery	342	2,277	2,019	2,710	0	242	0	7,590	22.7
Solar[2]	2,683	702	1,321	316	83	0	0	5,105	15.3
Wind	24	1,818	1,556	4,707	4,298	6,972	0	19,375	58.0
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.5
Natural Gas	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	**3,875**	**4,675**	**5,540**	**7,733**	**4,381**	**7,214**	**0**	**33,418**	**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	55	0	50	0	0	0	0	105	0.3
Rhode Island	556	240	704	170	0	0	0	1,670	5.0
New Hampshire	266	164	20	272	0	0	0	722	2.2
Maine	943	774	654	664	600	0	0	3,635	11.0
Massachusetts	1,241	3,099	2,691	6,262	2,498	4,814	0	20,605	62.2
Connecticut	372	520	1,449	365	1,283	2,400	0	6,389	19.3
Totals	**3,433**	**4,797**	**5,568**	**7,733**	**4,381**	**7,214**	**0**	**33,126**	**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	48	7,590	1	10	47	7,580
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	1	37	0	0	1	37
Solar	225	5,105	27	310	198	4,795
Wind	31	20,575	1	20	30	20,555
Total	322	34,326	32	473	290	33,853

- 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	6	107	1	5	5	102
Intermediate	7	804	0	0	7	804
Peaker	278	12,840	30	448	248	12,392
Wind Turbine	31	20,575	1	20	30	20,555
Total	322	34,326	32	473	290	33,853

- 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	48	7,590	0	0	0	0	48	7,590	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	225	5,105	0	0	0	0	225	5,105	0	0
Wind	31	20,575	0	0	0	0	0	0	31	20,575
Total	322	34,326	6	107	7	804	278	12,840	31	20,575

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation (CSO) FCA 12

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*	624.445	659.137	34.692	603.776	-55.361	587.270	-16.506
	Passive Demand	2,975.36	3,045.073	69.713	3,123.232	78.159	3,322.722	199.490
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**3,727.008**	**22.798**	**3,909.992**	**182.984**
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159	28,941.276	321.031
	Intermittent	880.317	806.609	-73.708	660.932	-145.677	663.179	2.247
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**	**29,604.455**	**323.278**
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**	**1207.78**	**-99.807**
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**	**34,722.227**	**406.455**
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,230**	**-1,320**	**32,925**	**695**

* 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
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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		
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392		
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**		
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07		
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387		
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**		
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**		
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**		
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**		

* 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.

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				
	Passive Demand	3,327.071	3,327.932	0.861				
Demand Total		**3,919.114**	**4,016.002**	**96.888**				
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241				
	Intermittent	1,160.916	1,128.446	-32.47				
Generator Total		**28,977.818**	**29,403.589**	**425.771**				
Import Total		**1,058.72**	**1,058.72**	**0**				
Grand Total*		**33,955.652**	**34,478.311**	**522.661**				
Net ICR (NICR)		**32,490**	**32,980**	**490**				

* 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.

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						
	Passive Demand	3,212.865						
Demand Total		**3,890.538**						
Generator	*Non-Intermittent*	28,154.203						
	Intermittent	1,089.265						
Generator Total		**29,243.468**						
Import Total		**1,487.059**						
Grand Total*		**34,621.065**						
Net ICR (NICR)		**33,270**						

* 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.

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	**2375.422**	**370.734**	**2746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2571.361**	**639.586**	**3210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3085.734**	**514.072**	**3599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3386.703**	**653.541**	**4040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3596.056**	**323.058**	**3919.114**
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**

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

What are Daily NCPC Payments?

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

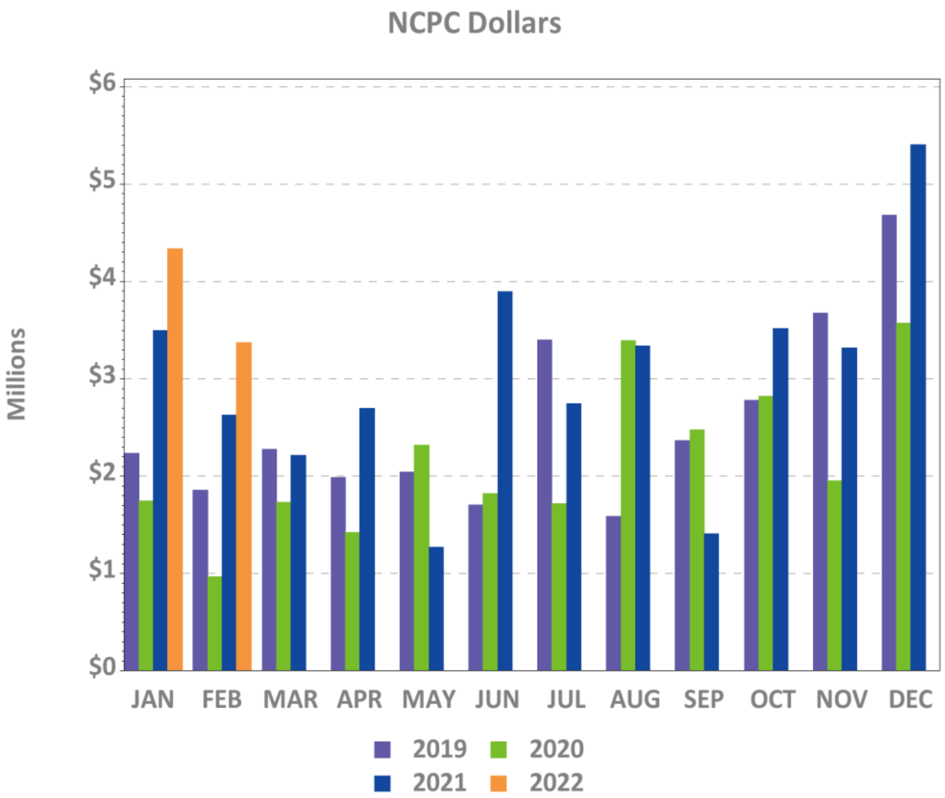
Definitions

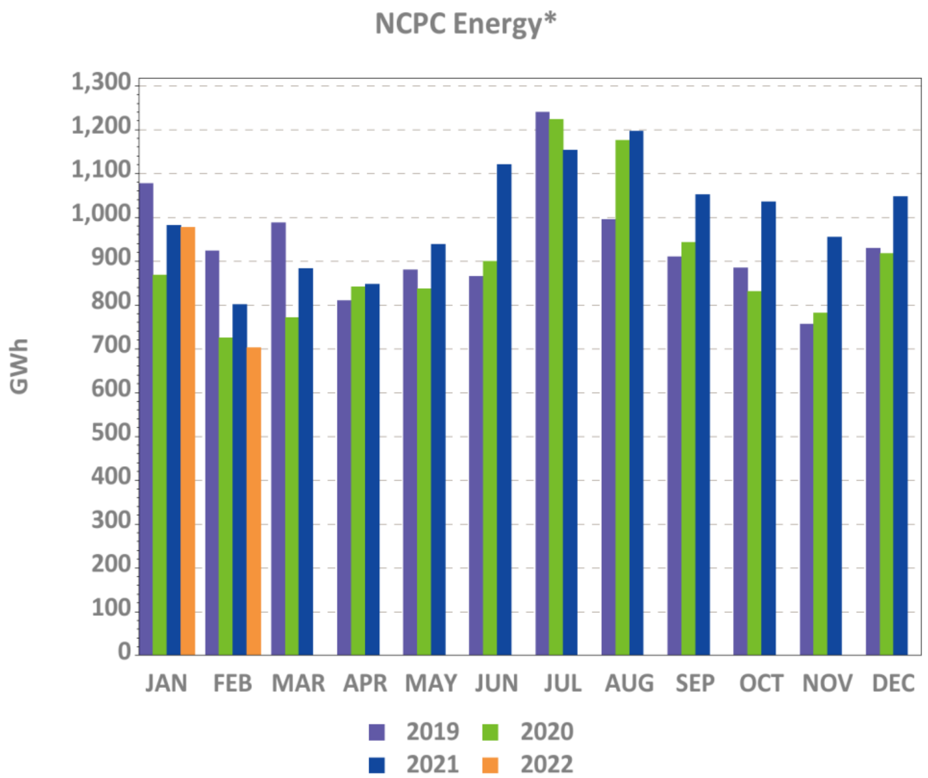
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

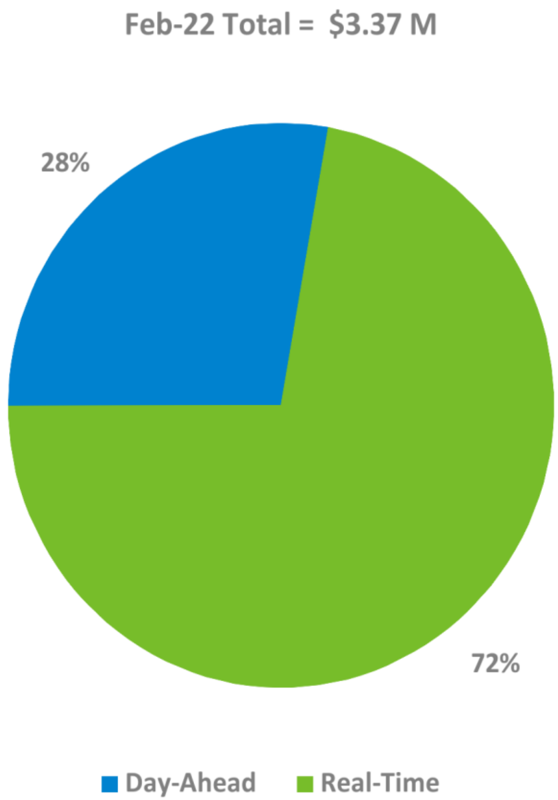
Year-Over-Year Total NCPC Dollars and Energy



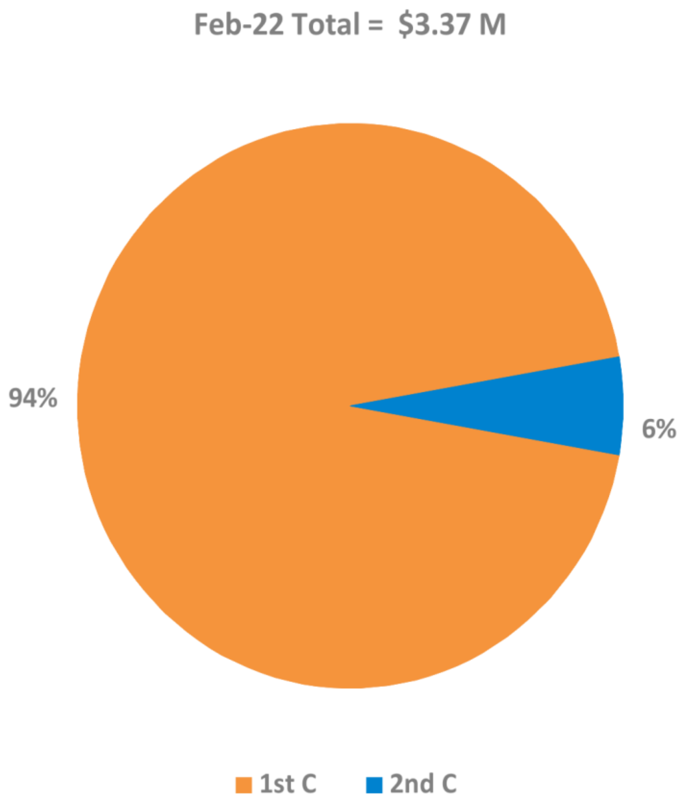


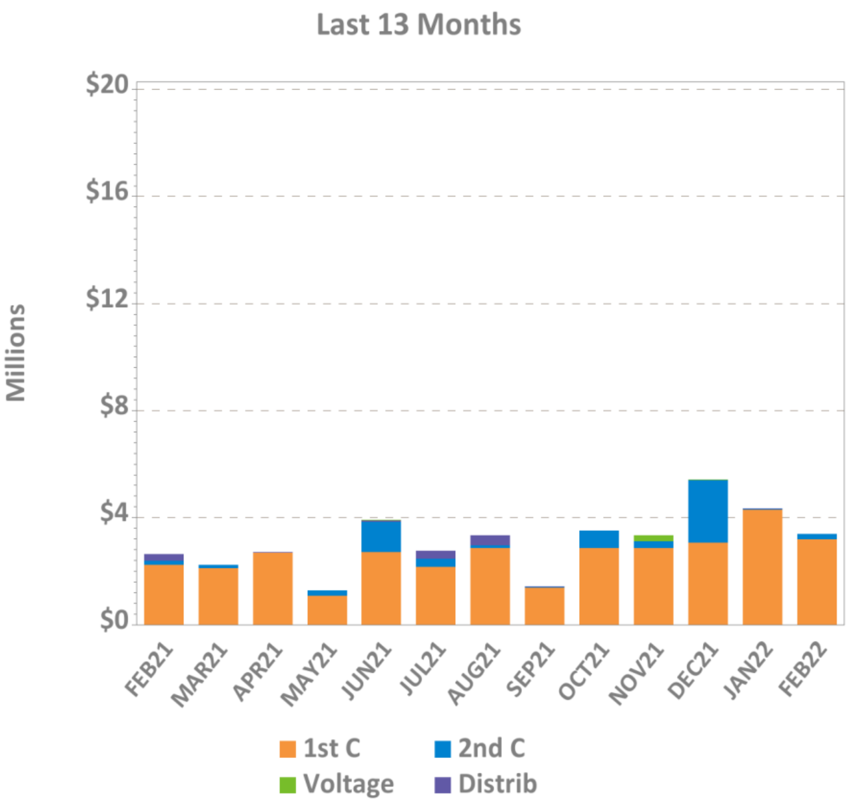
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



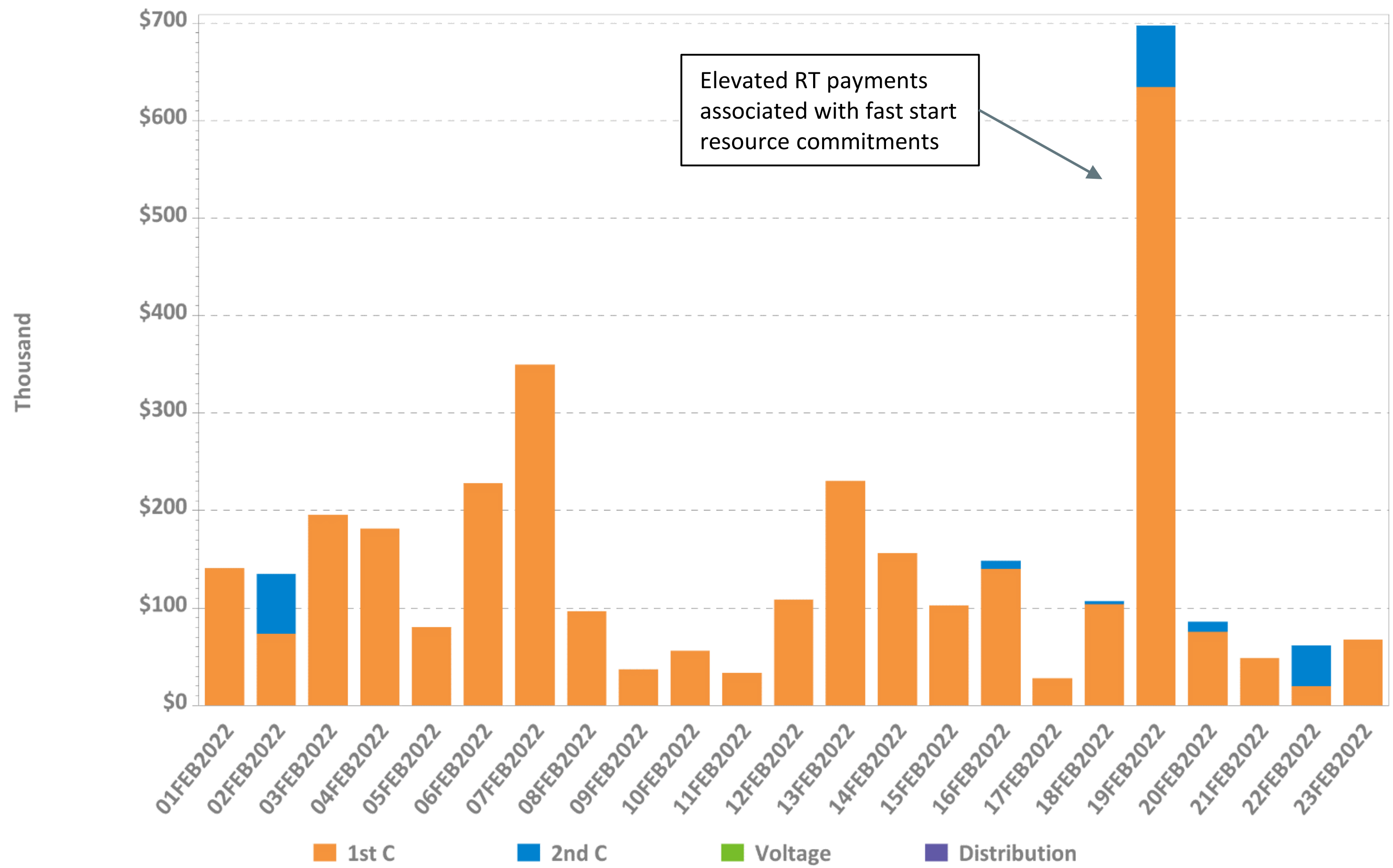
NCPC Charges by Type



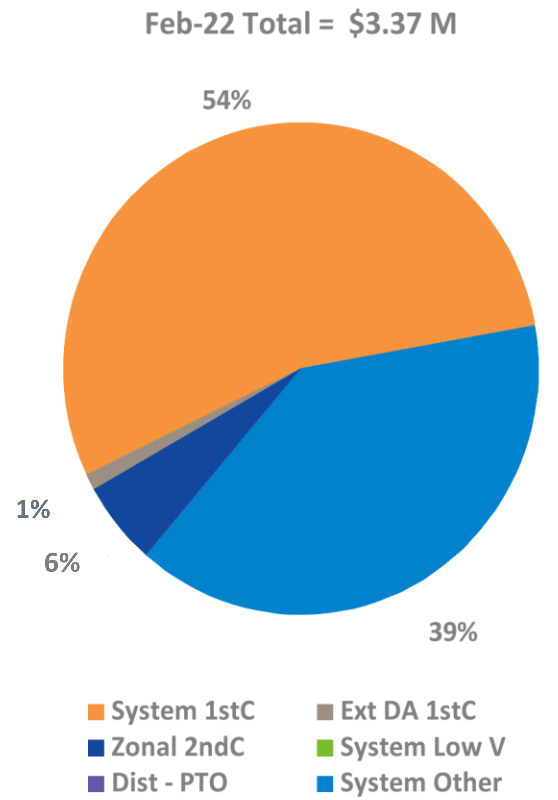


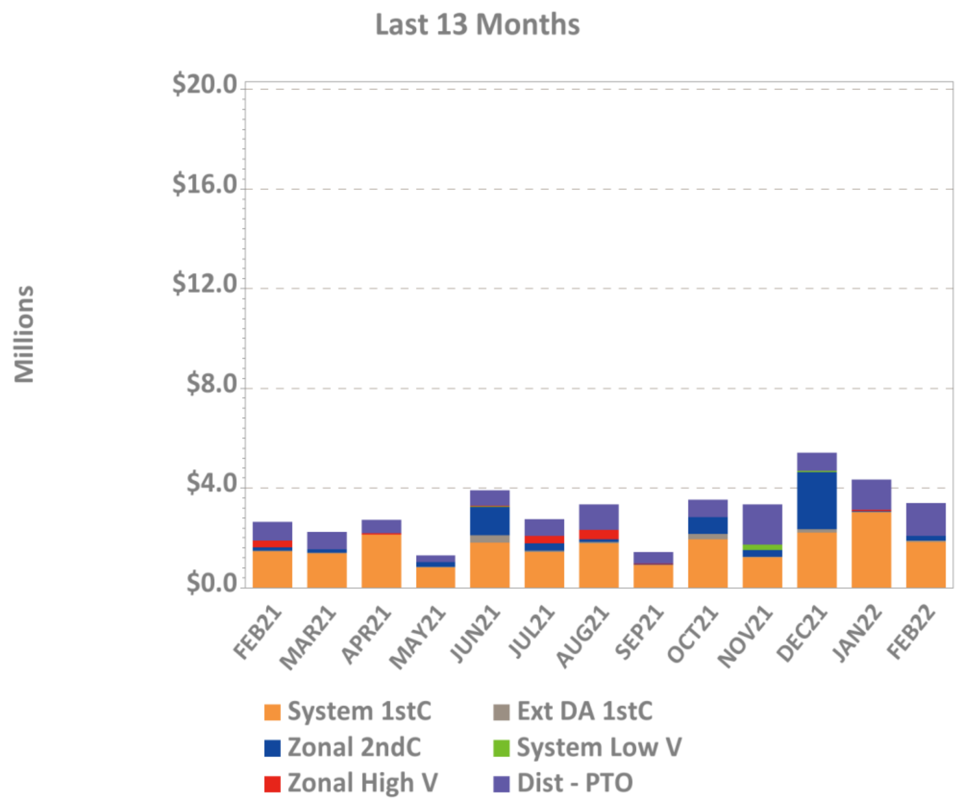
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



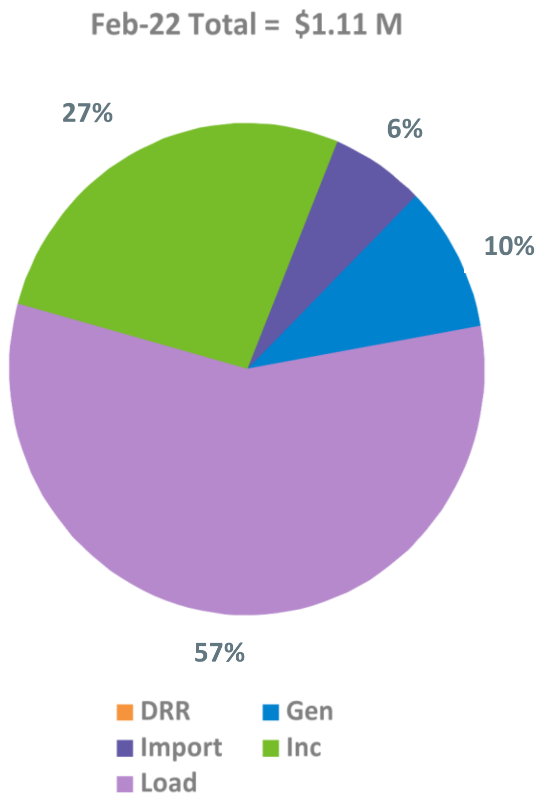
NCPC Charges by Allocation

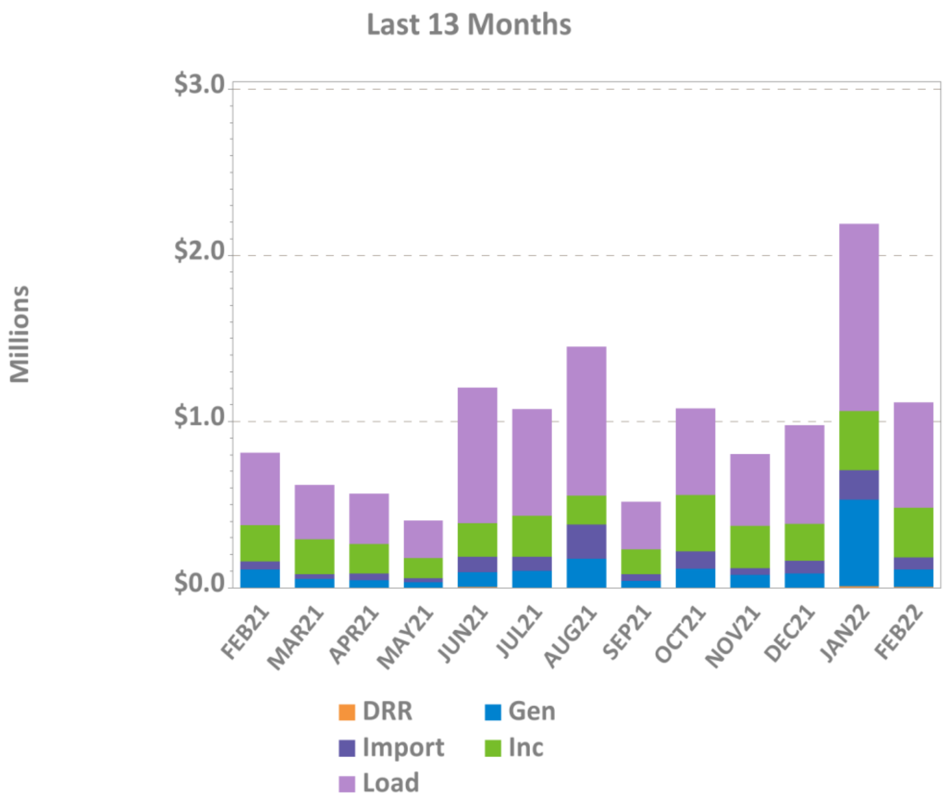




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

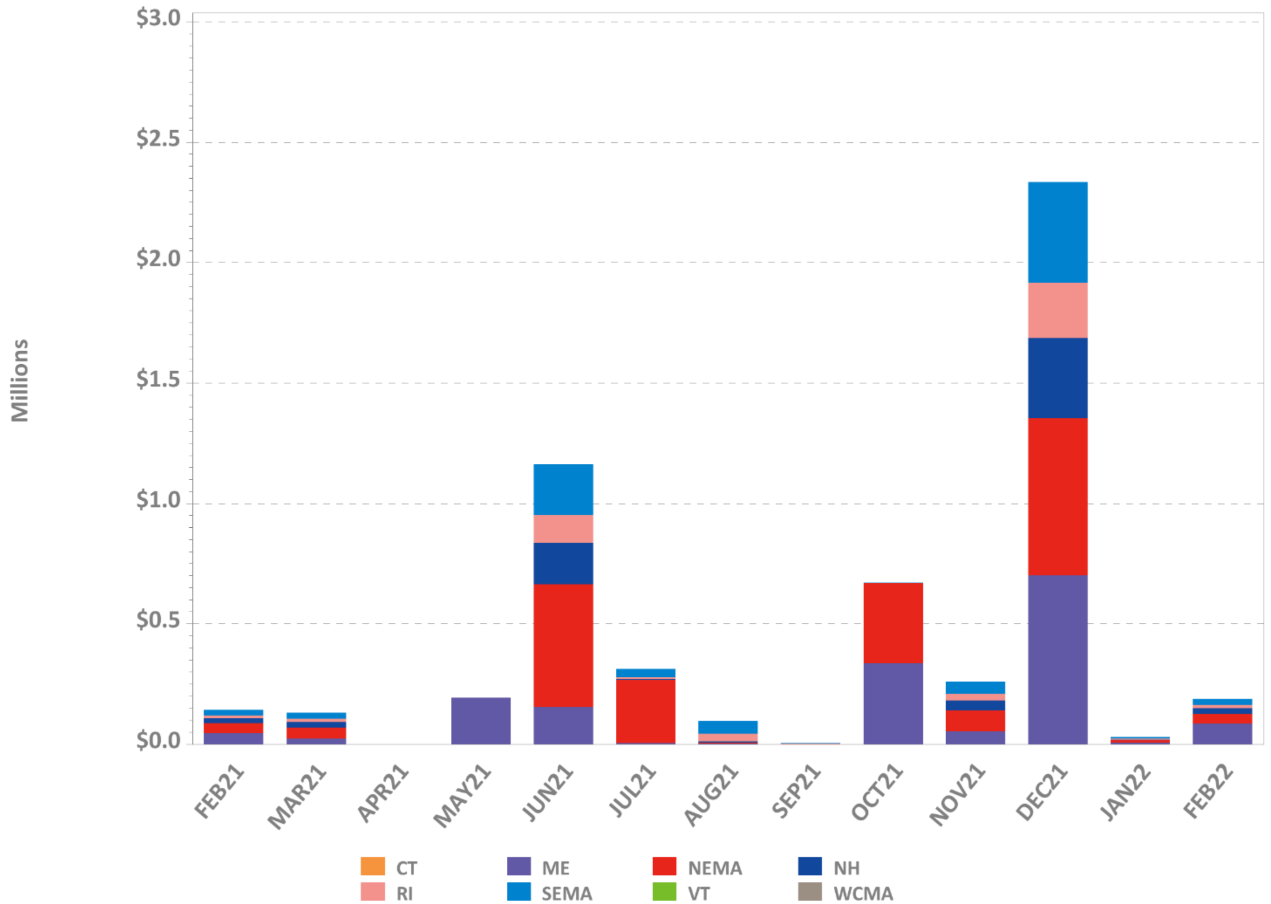
RT First Contingency Charges by Deviation Type





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

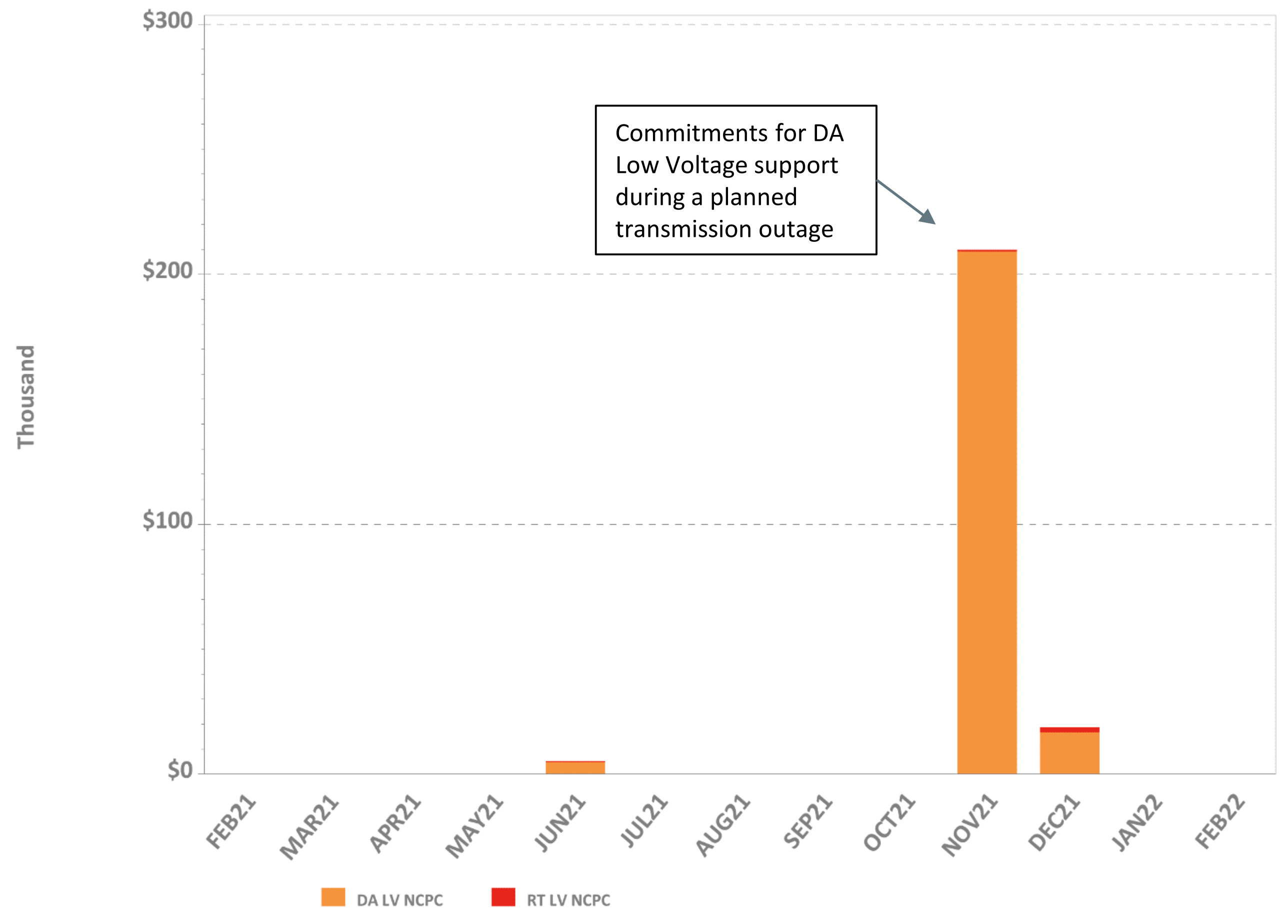
LSCPR Charges by Reliability Region



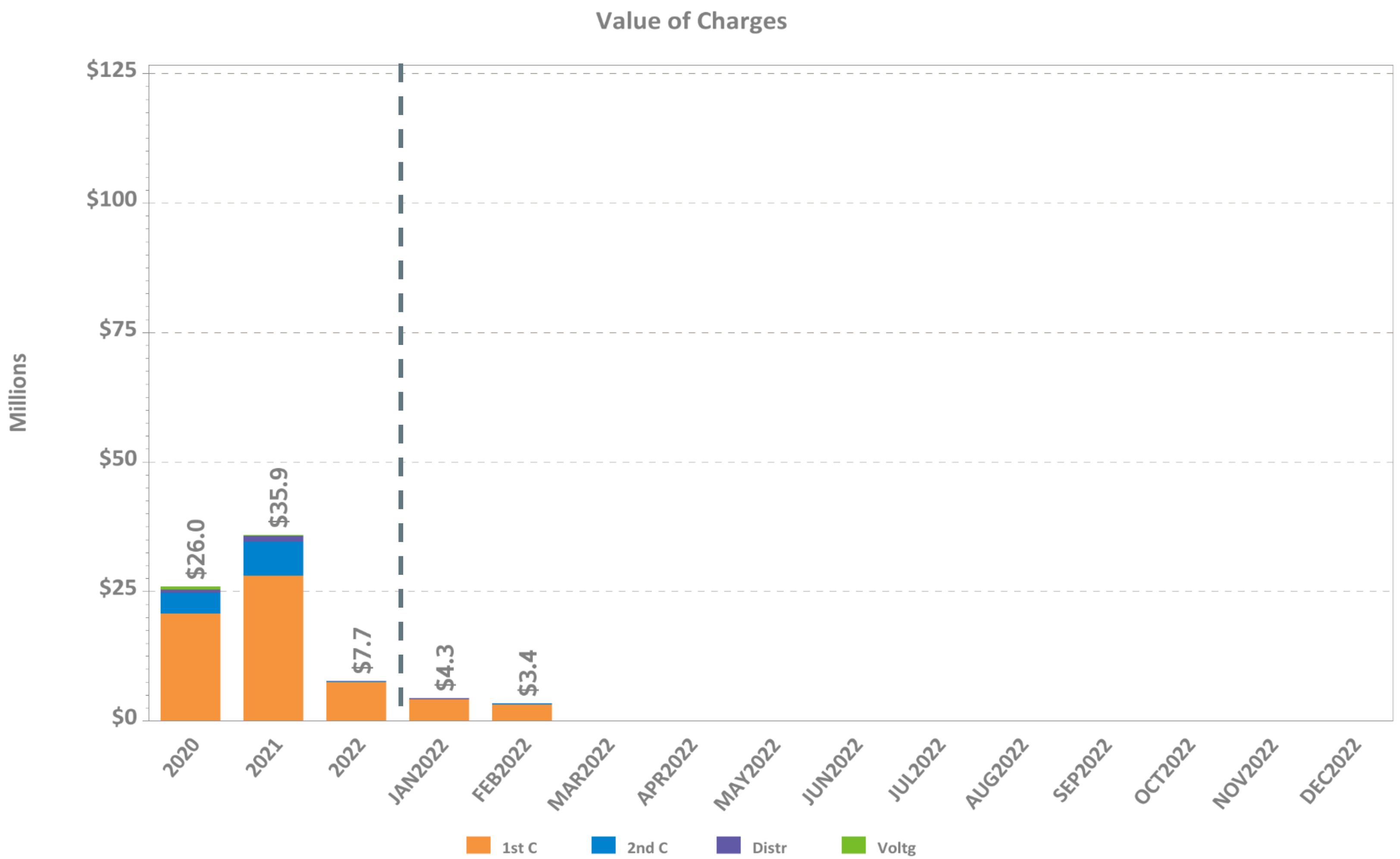
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

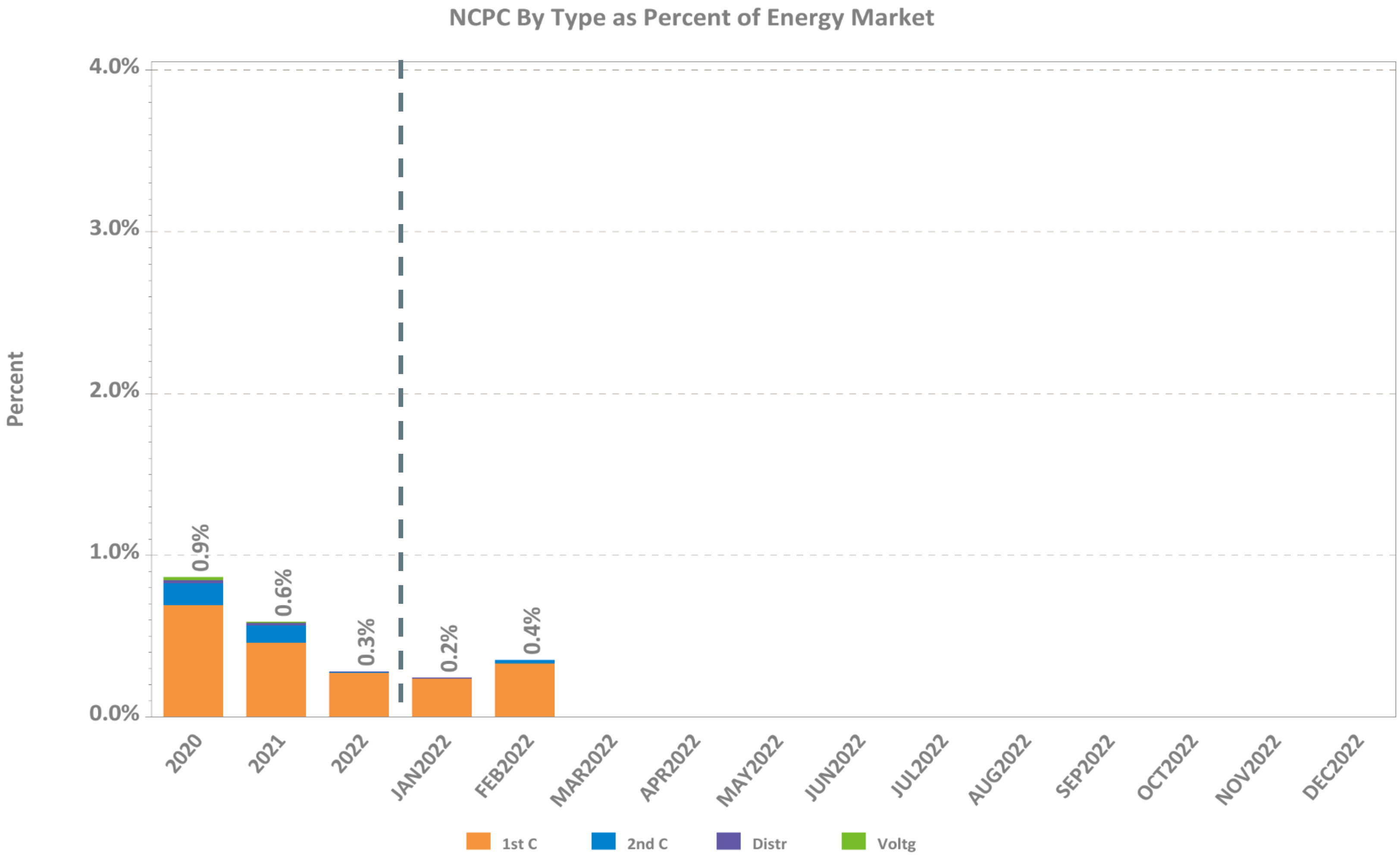
NCPC Charges for Voltage Support and High Voltage Control



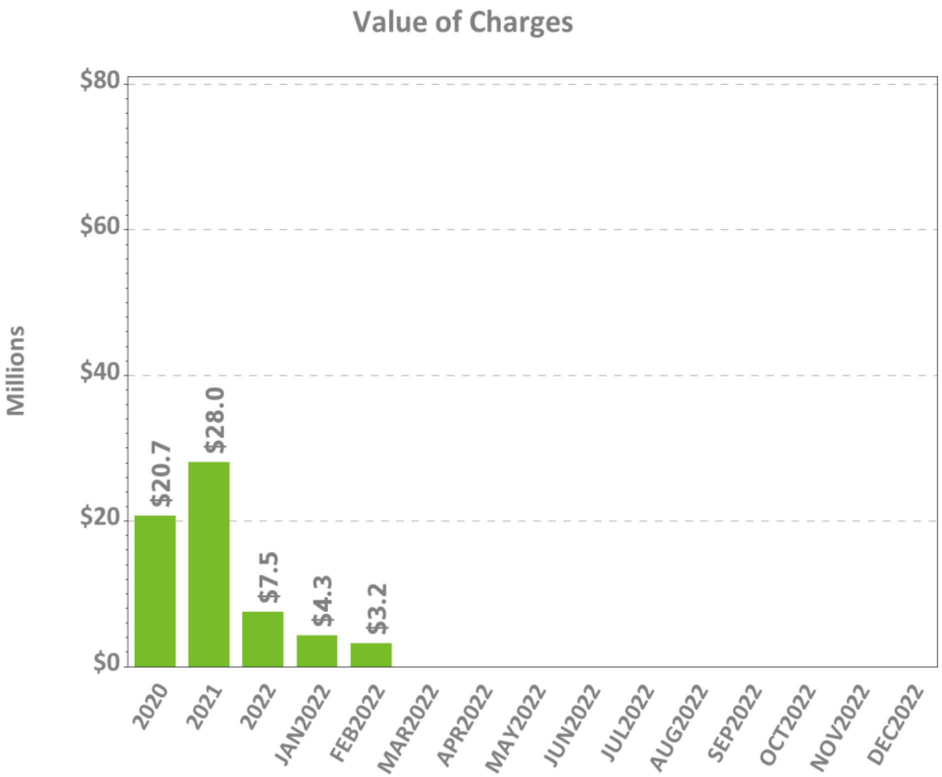
NCPC Charges by Type

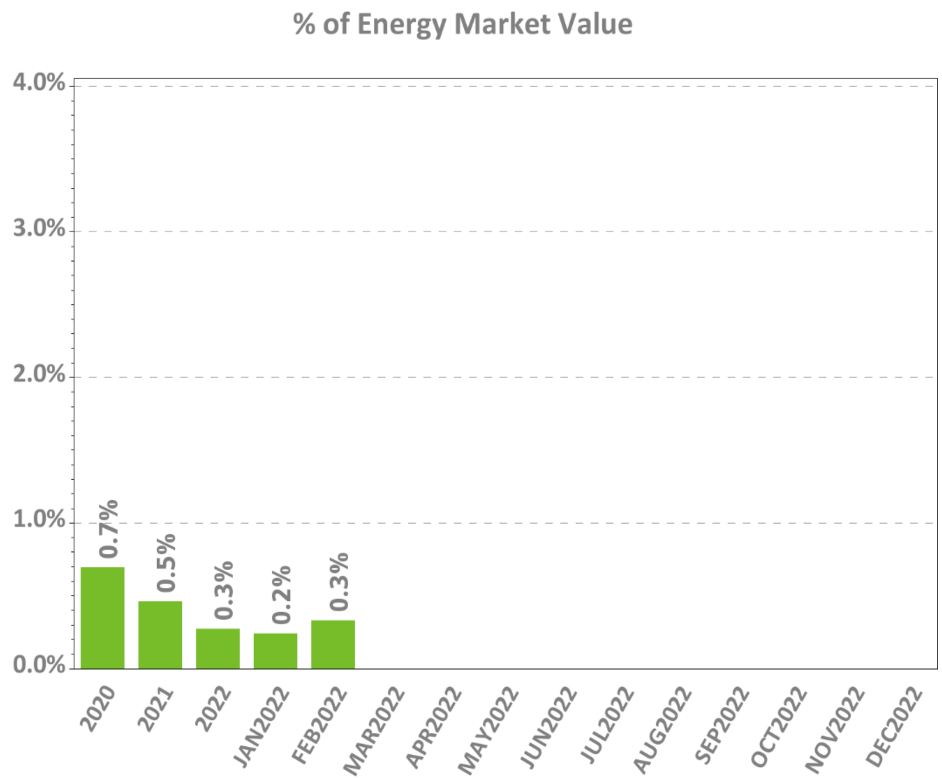


NCPC Charges as Percent of Energy Market



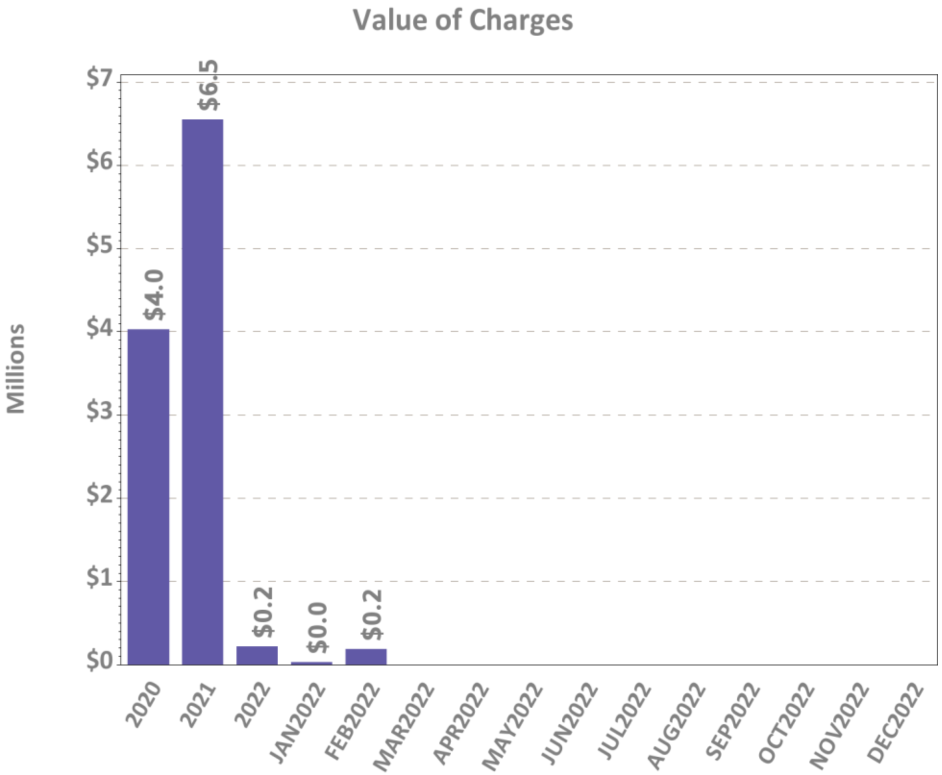
First Contingency NCPC Charges

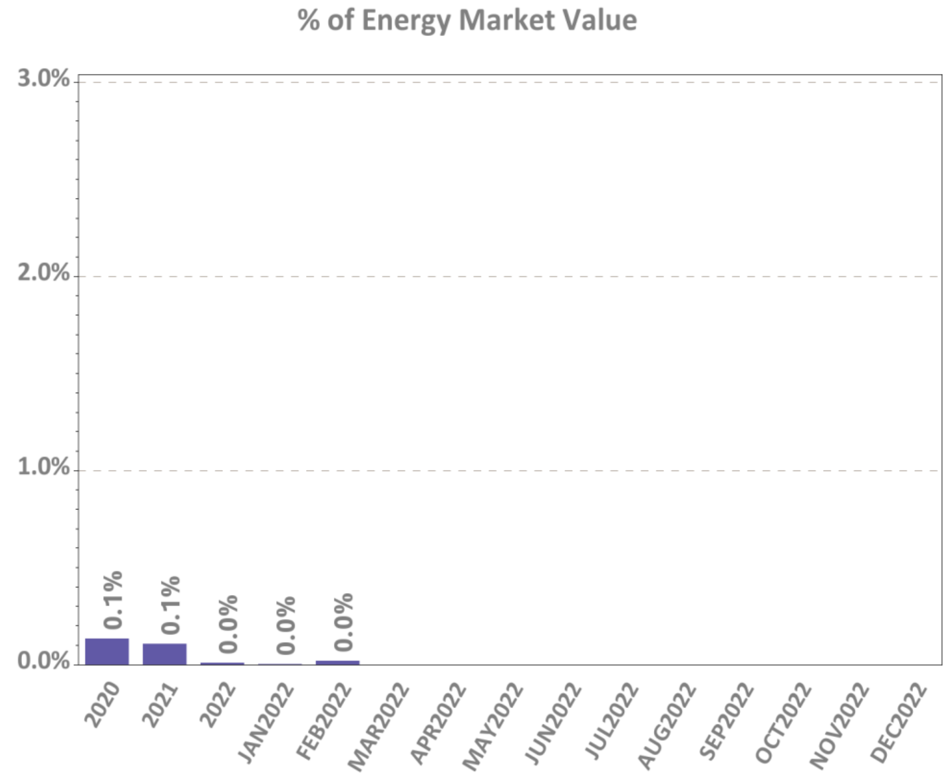




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

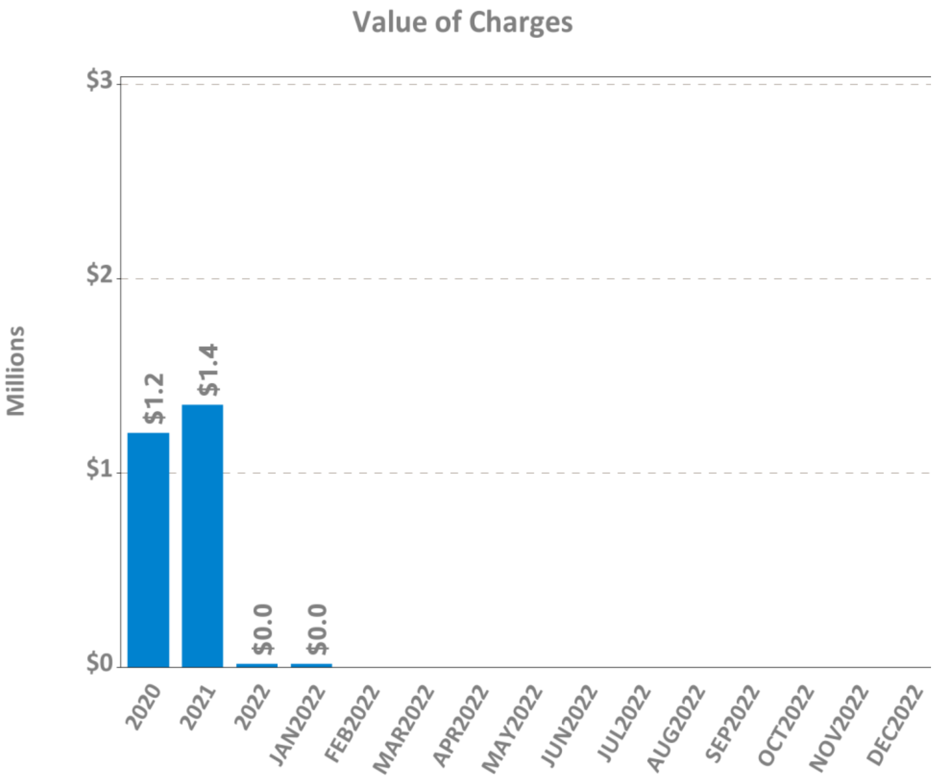
Second Contingency NCPC Charges

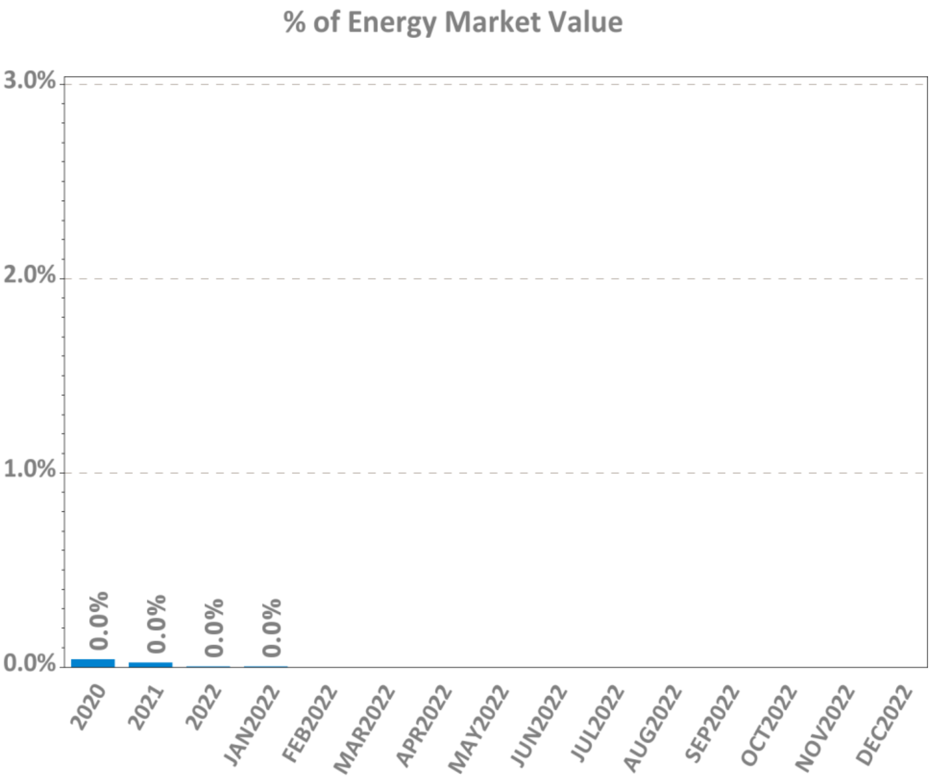




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

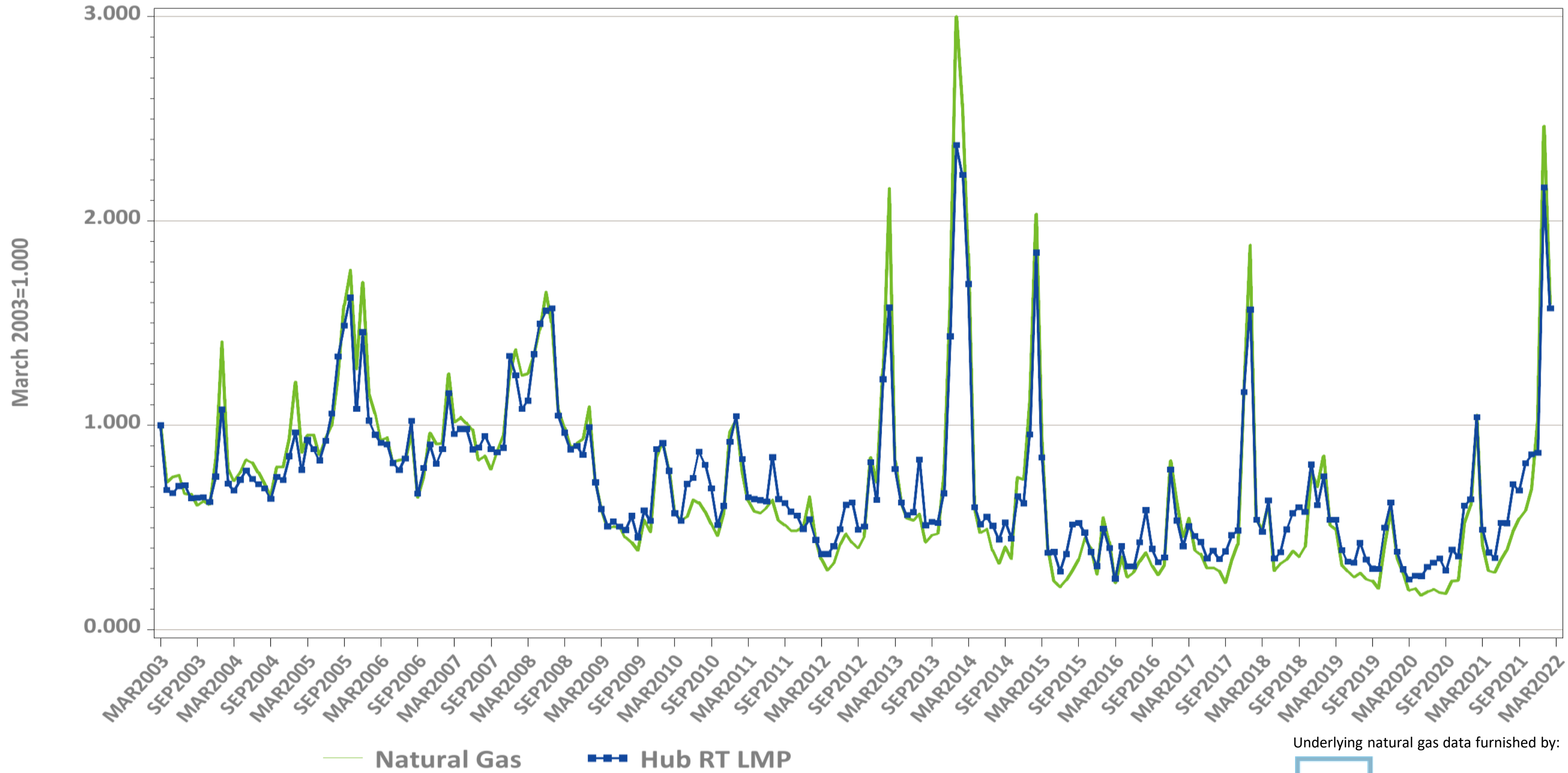
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%
Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.54	$44.60	$45.52	$46.27	$45.05	$45.88	$46.38	$45.91	$45.92
Real-Time	$45.25	$43.97	$44.28	$45.10	$44.15	$44.61	$45.09	$44.85	$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%

February-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$73.49	$71.09	$72.83	$73.29	$72.03	$73.35	$73.57	$73.09	$73.12
Real-Time	$71.92	$69.34	$71.06	$71.60	$70.29	$71.59	$71.89	$71.39	$71.45
RT Delta %	-2.1%	-2.5%	-2.4%	-2.3%	-2.4%	-2.4%	-2.3%	-2.3%	-2.3%
February-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$113.77	$107.37	$112.88	$113.13	$109.42	$112.37	$113.42	$111.66	$111.87
Real-Time	$109.13	$104.97	$107.93	$108.81	$106.05	$107.90	$108.84	$107.90	$108.00
RT Delta %	-4.1%	-2.2%	-4.4%	-3.8%	-3.1%	-4.0%	-4.0%	-3.4%	-3.5%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	54.8%	51.0%	55.0%	54.4%	51.9%	53.2%	54.2%	52.8%	53.0%
Yr over Yr RT	51.8%	51.4%	51.9%	52.0%	50.9%	50.7%	51.4%	51.1%	51.1%

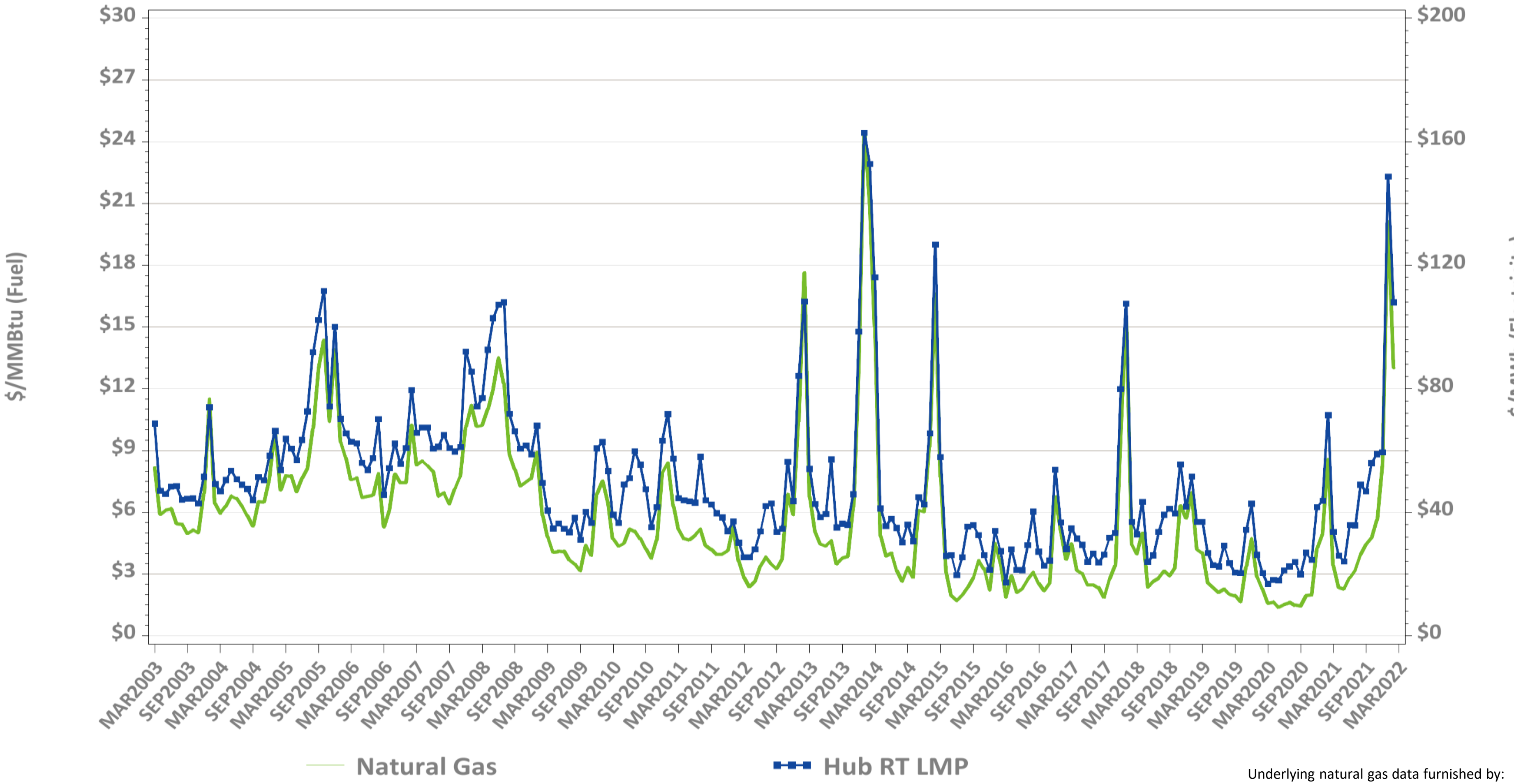
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

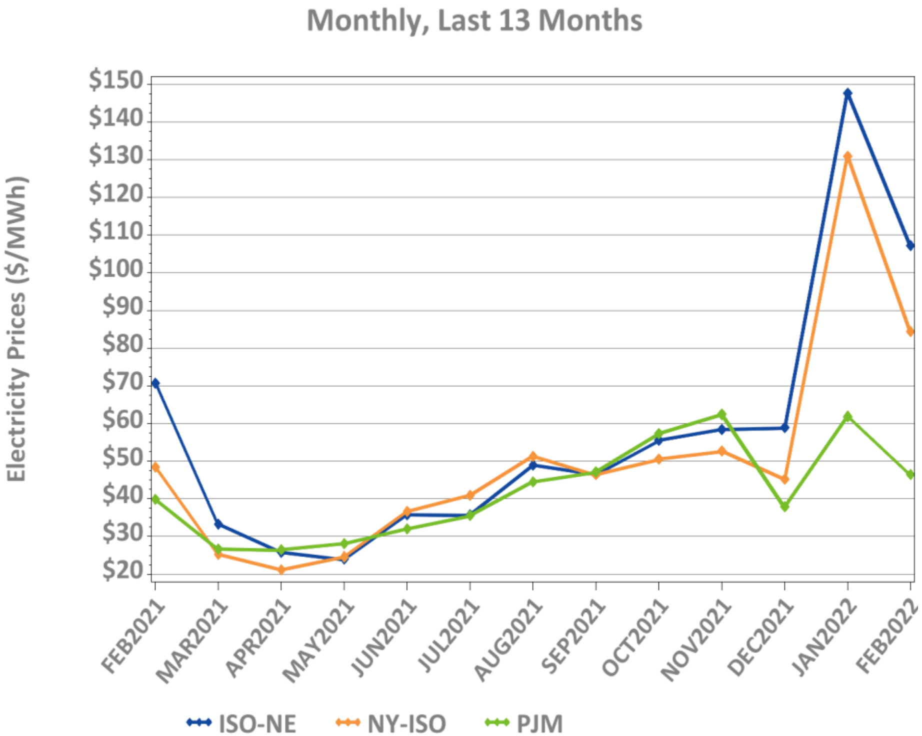
Monthly Average Fuel Price and RT Hub LMP



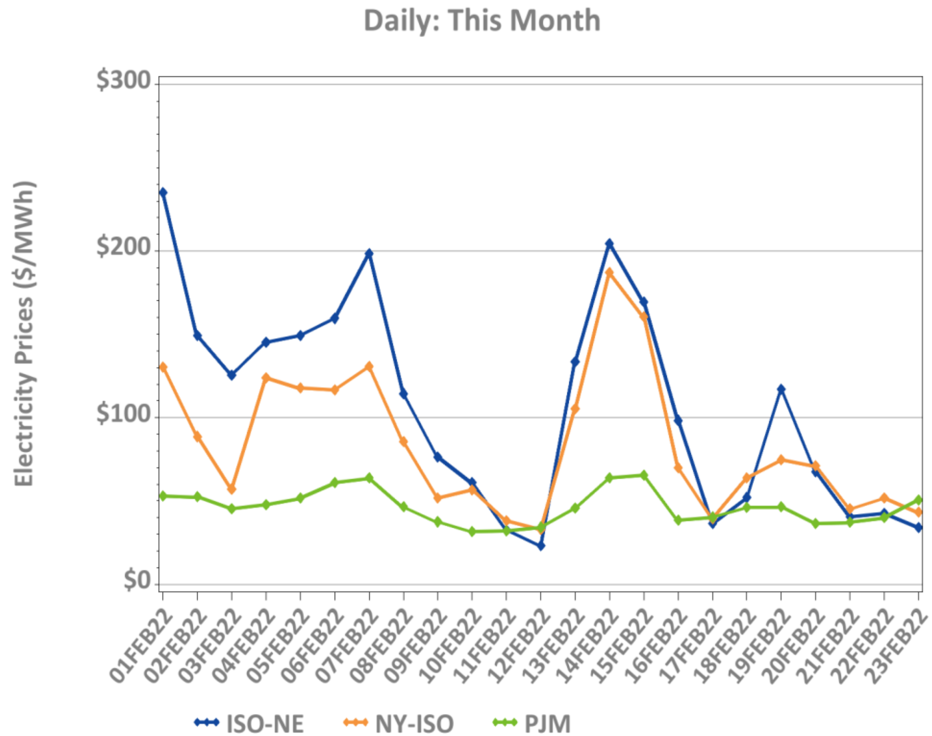
Underlying natural gas data furnished by:

ice Global markets in clear view

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

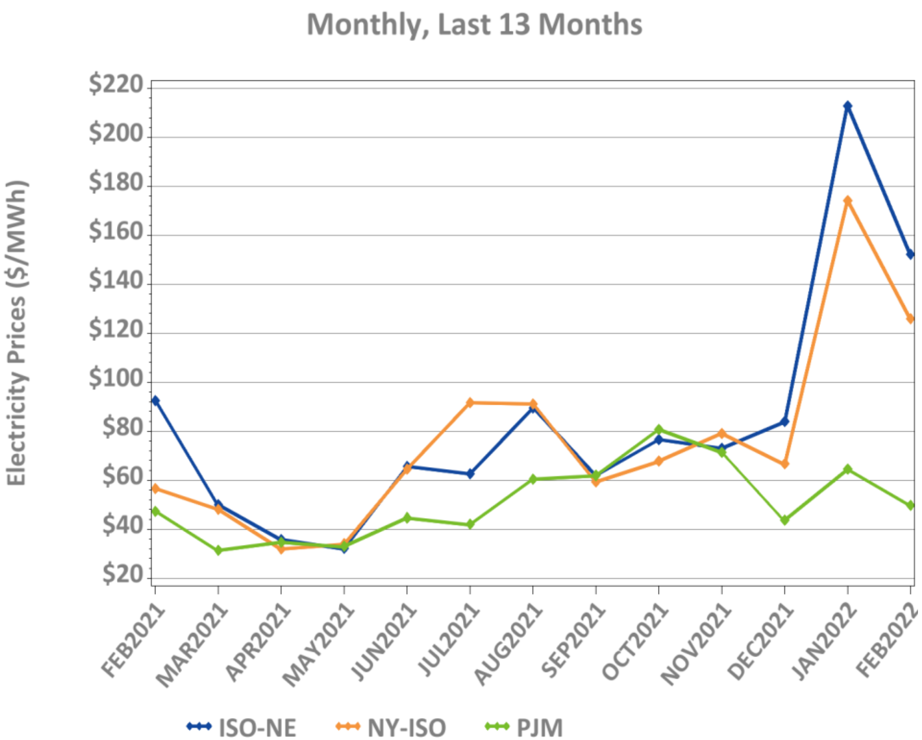


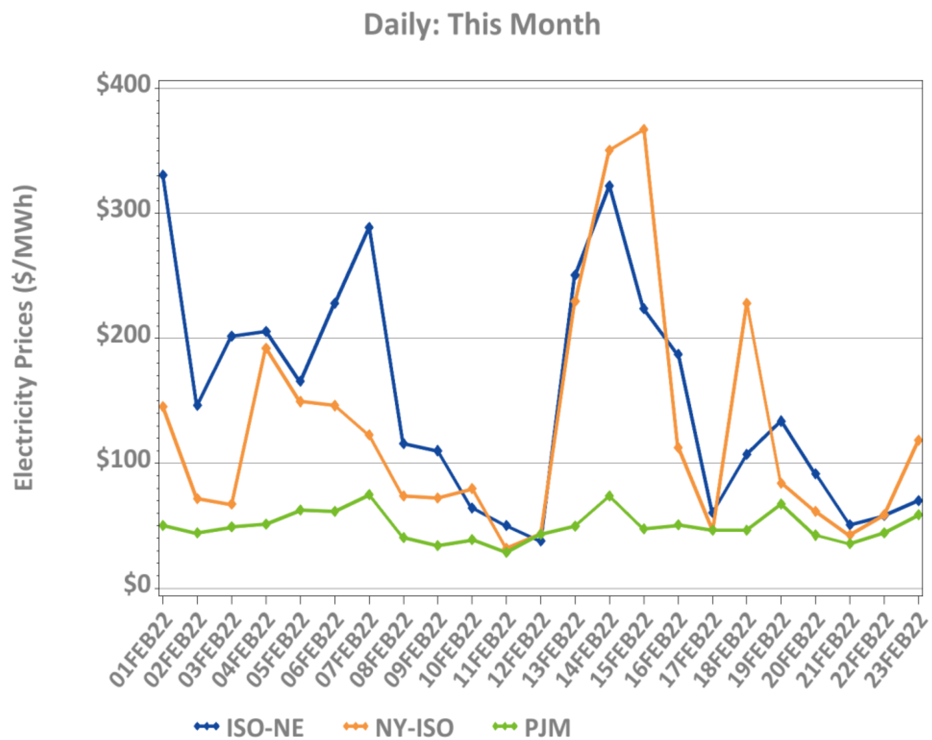
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





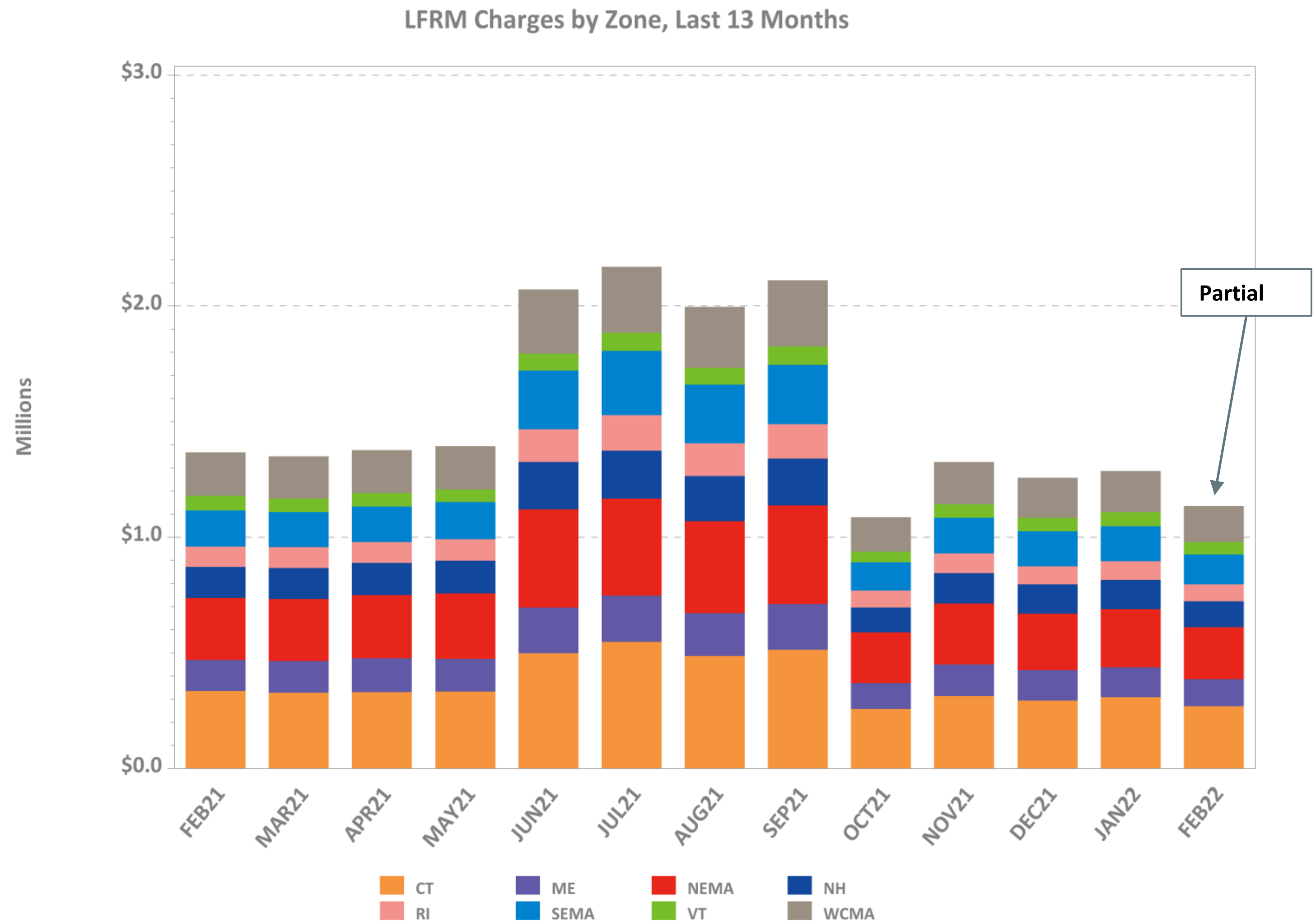
*Forecasted New England daily peak hours reflected

Reserve Market Results – February 2022

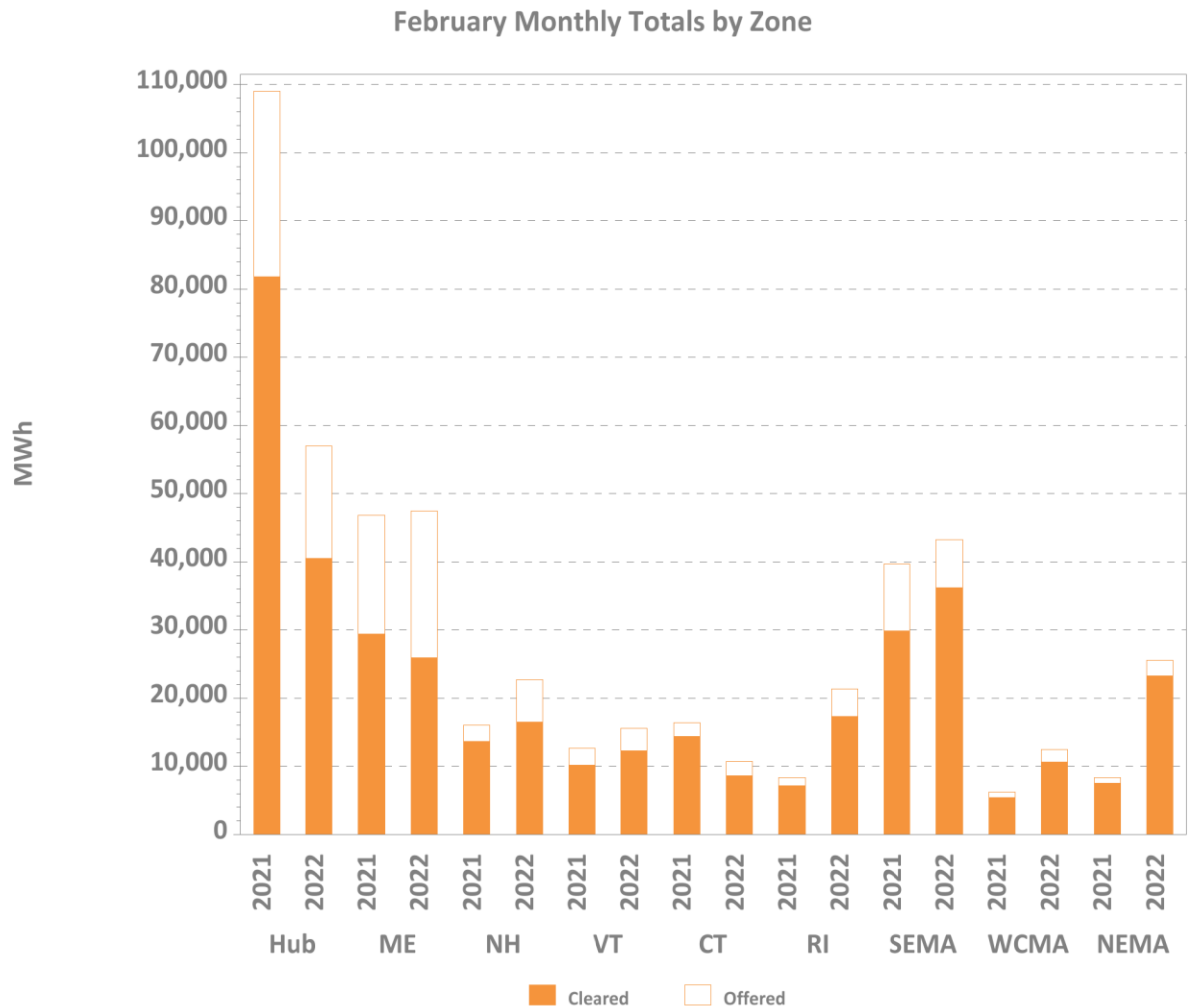
- Maximum potential Forward Reserve Market payments of $1.2M were reduced by credit reductions of $24K, failure-to-reserve penalties of $36K and no failure-to-activate penalties, resulting in a net payout of $1.1M or 95% of maximum
  - Rest of System: $0.82M/0.88M (93%)
  - Southwest Connecticut: $0.03M/0.03M (100%)
  - Connecticut: $0.28M/0.28M (99%)
  - NEMA: $2.2/4.2K (69%)
- $721K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $721K in Real-Time Reserve payments
  - Rest of System: 141 hours, $508K
  - Southwest Connecticut: 141 hours, $112K
  - Connecticut: 141 hours, $65K
  - NEMA: 141 hours, $37K

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

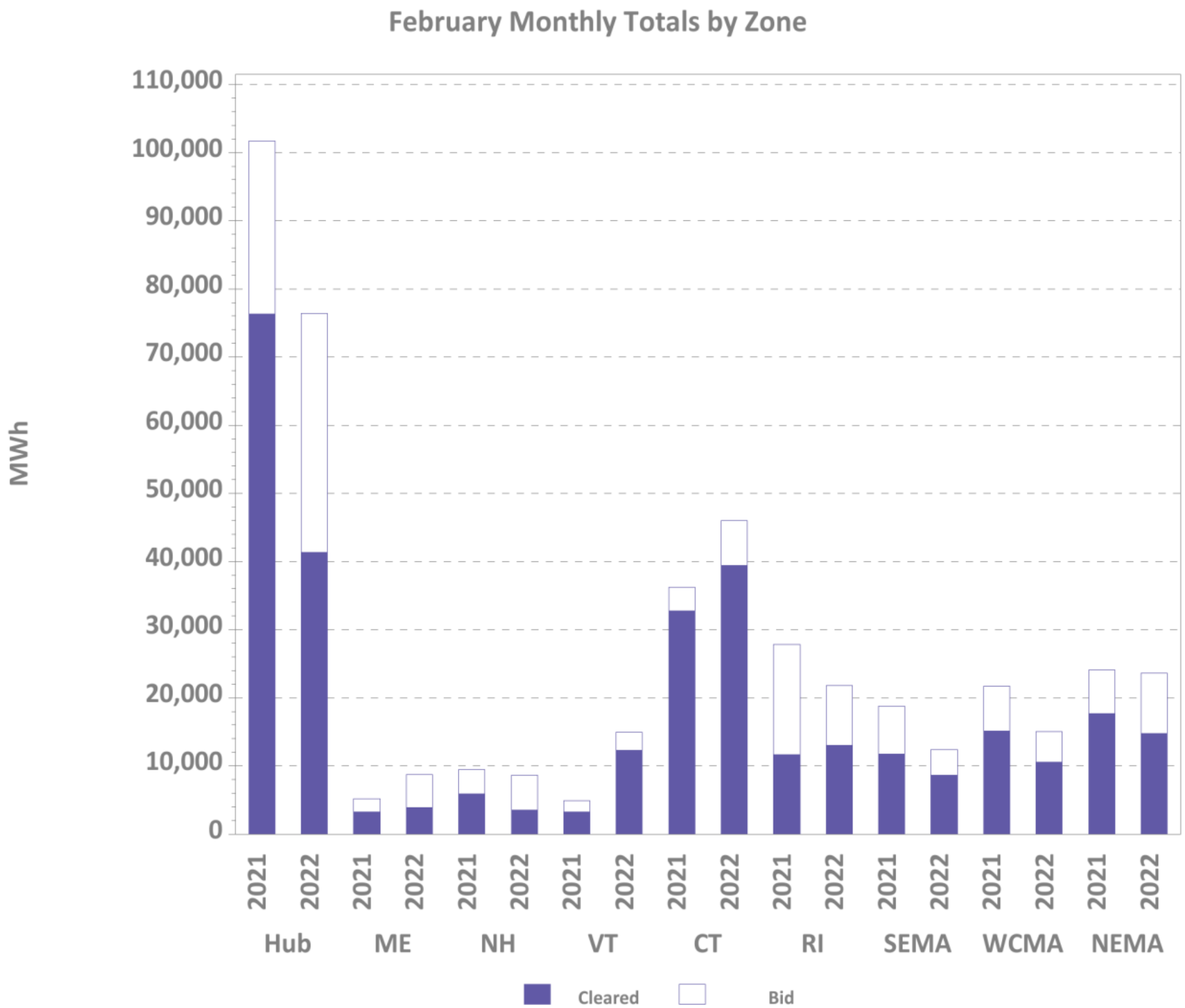
LFRM Charges to Load by Load Zone ($)



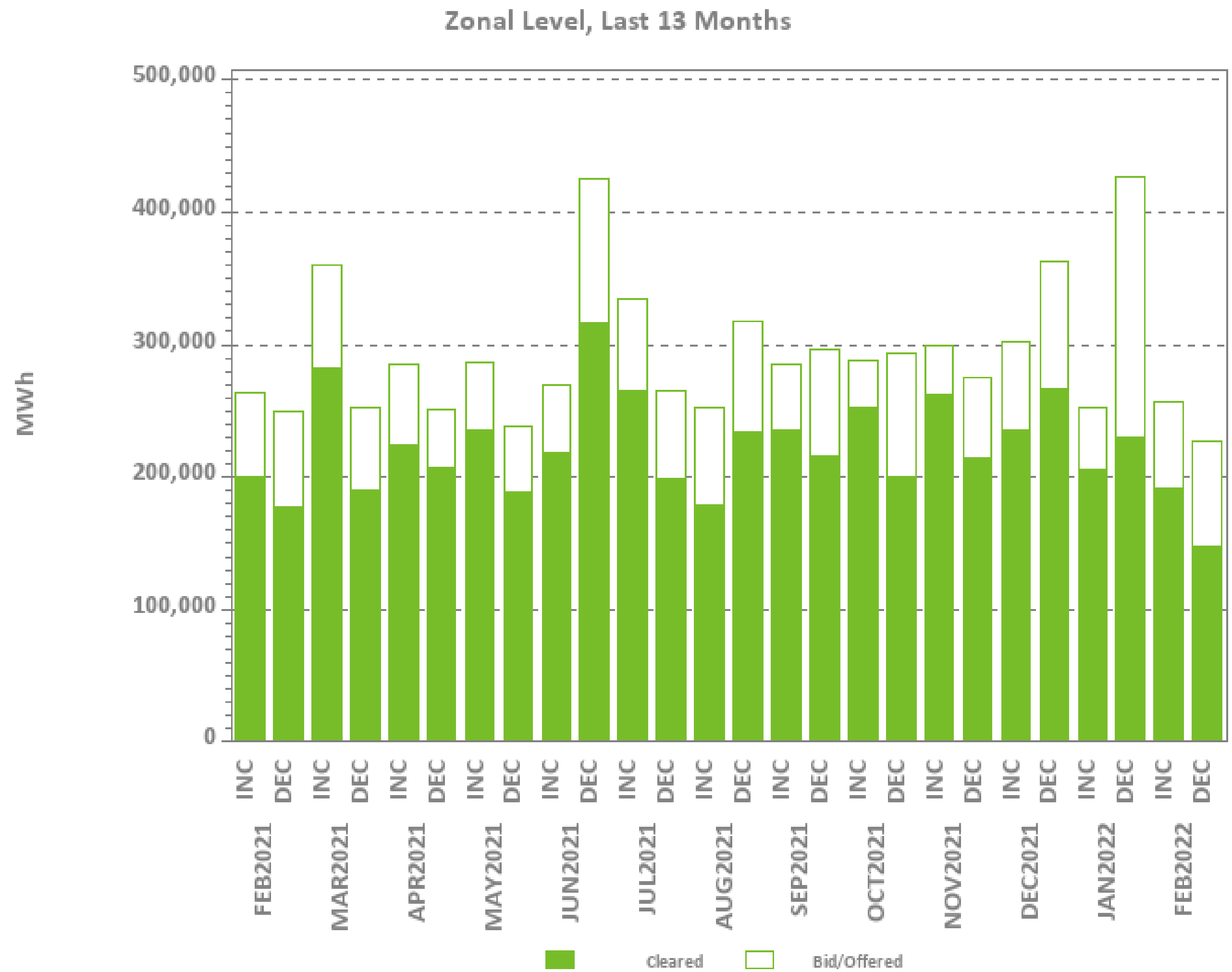
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

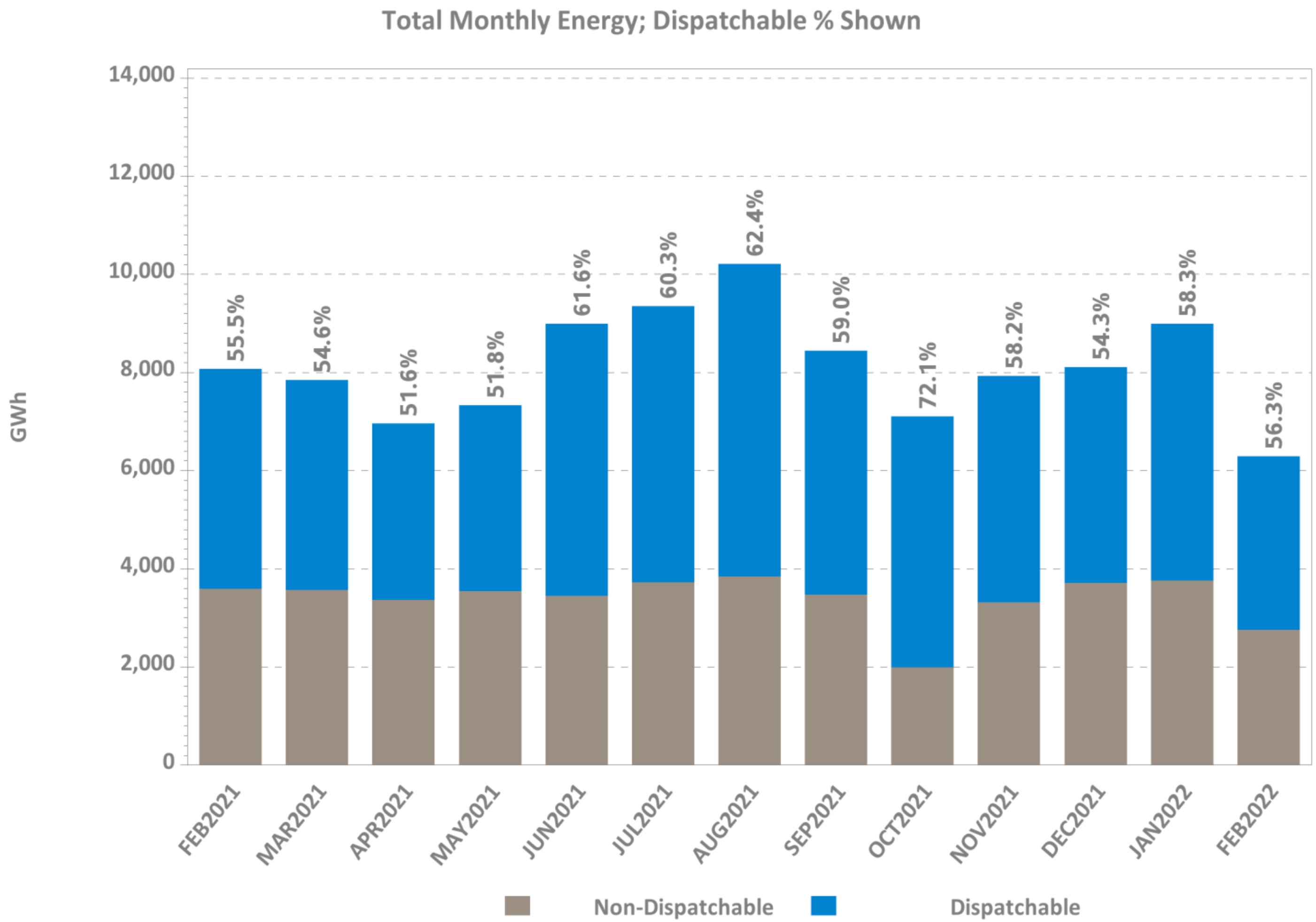


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- March 16 PAC Meeting Agenda Topics*
  - 2021 Economic Study: Future Grid Reliability Study – Phase I
    - Resource Adequacy Screen & Probabilistic Resource Availability Analysis Alternatives B&D Results
    - Additional Production Cost Simulation Metrics
    - Additional Ancillary Services Results
  - 2050 Transmission Study: Preliminary N-1 and N-1-1 Thermal Results
  - Transmission Planning Process Guide and Transmission Planning Technical Guide updates for Longer-Term Transmission Studies
  - Update on Draft 2022 CELT Forecast

* 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 PAC meeting 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
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- 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
- Future testing will focus on transient stability modeling and performance criteria

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 expects to provide initial results at the 3/16/22 PAC meeting

Economic Studies

- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report expected in early 2022
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Additional resource adequacy screen and probabilistic resource adequacy analysis results were discussed at the February 11 PAC meeting
  - Additional scope was discussed at the February 16 joint MC/RC meeting
  - Draft report expected in Q2 2022

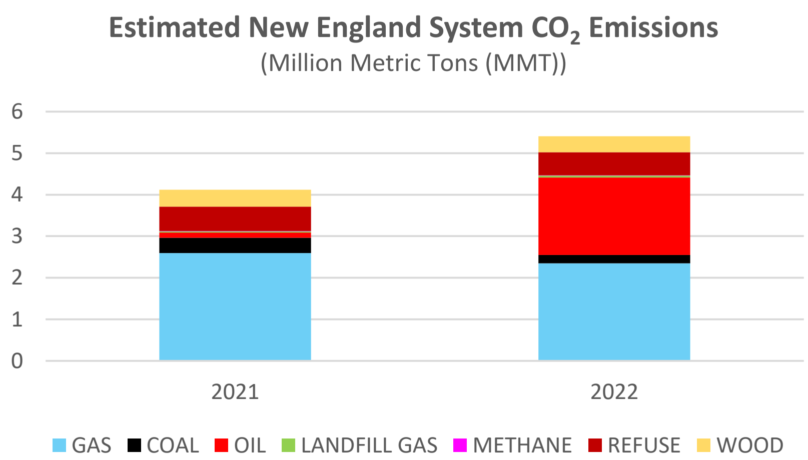
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - Phase 1 work was submitted as the only 2021 economic study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined

New England Power System Carbon Emissions

Long-term decline in direct carbon emissions reversed, variability in recent year-to-year trends

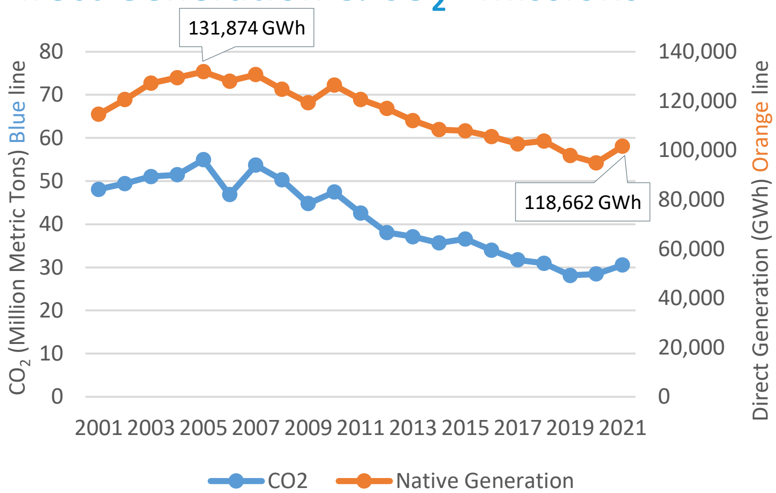
2021 v. 2022 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



- Estimated CO_2 emissions spiked in 2022, up **31%** compared to same period in 2022
- Driven by increased CO_2 emissions from oil generation, CO_2 emissions from natural gas declined by -**10%**
- Difference in generation is relatively small, ~144 GWh (12,666 GWh in 2021, 12,809 GWh in 2022) for the same period (1/1-2/14)

2021, 2022 CO_2 estimated emissions with EPA (eGrid2021) balancing area fuel-specific emission factors with adjustments by ISO-NE for data gaps

Uptick in New England Power System Direct Generation & CO_2 Emissions



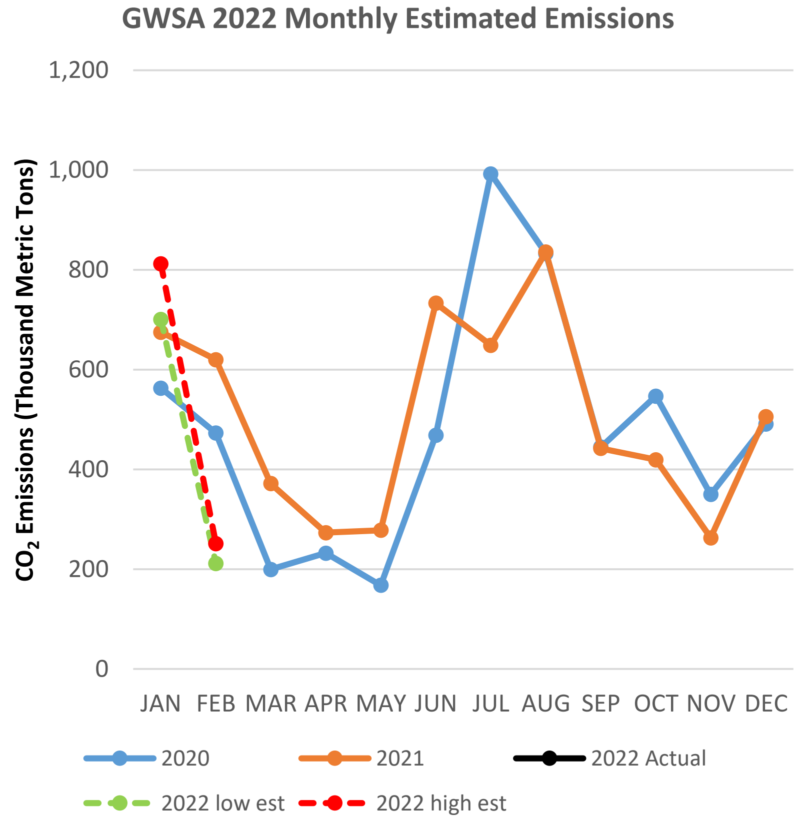
- CO_2 system emissions peaked at **54.9** MMT in 2005, with total system generation reaching **131,874** GWh
- 2005 annual estimated system CO_2 emissions from fossil fuel generation ranged between:
  - **19.0-20.9** MMT for coal generation
  - **15.1 – 15.5** MMT for natural gas generation
  - **4.9 – 6.5** MMT for oil generation

Massachusetts CO_2 Generator Emissions Cap

Uptick in Electric Generation CO_2 Cap Estimated Emissions for 2022

- In 2022**,** estimated GWSA CO_2 emissions range between **0.9** and **1.1** MMT
  - **11%** to **13%** of the 8.06 MMT 2022 cap
- Next GWSA auction set for 3/16/22, offering 1.61 million 2022 vintage allowances
- Last GWSA auction (12/15/21) cleared at $9.75 per metric ton of CO_2 for 2022 vintage GWSA allowances
- IMM estimated compliance costs by fuel type (based on average GWSA emission/heat rates):
  - No. 2 fuel oil - $8.54/MWh
  - No. 6 fuel oil - $8.29/MWh
  - Natural gas - $2.39/MWh

2019-2022 Estimated Past Monthly Emissions (Thousand Metric tons)



GWSA - Global Warming Solutions Act

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 2/23/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-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 2/23/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 2/23/2022

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

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

Greater Boston Projects, cont.

Status as of 2/23/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-22	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 2/23/2022

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

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

SEMA/RI Reliability Projects

Status as of 2/23/2022

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

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

SEMA/RI Reliability Projects, cont.

Status as of 2/23/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Sep-22	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 2/23/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	2

SEMA/RI Reliability Projects, cont.

Status as of 2/23/2022

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 2/23/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Jun-22	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	3
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 2/23/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	2

Eastern CT Reliability Projects, cont.

Status as of 2/23/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	1
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	2
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	1
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-22	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	2
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 2/23/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	Nov-21	4
1862	Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	3
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	3
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

Boston Area Optimized Solution Projects

Status as of 2/23/2022

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Dec 21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Jan-23	2
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	2

New Hampshire Solution Projects

Status as of 2/23/2022

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +50/-25 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Aug-23	2
1879	Install a +50/-25 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Aug-23	2
1880	Install a +100/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	2
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	1

Upper Maine Solution Projects

Status as of 2/23/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line	Dec-27	1
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	June-24	1

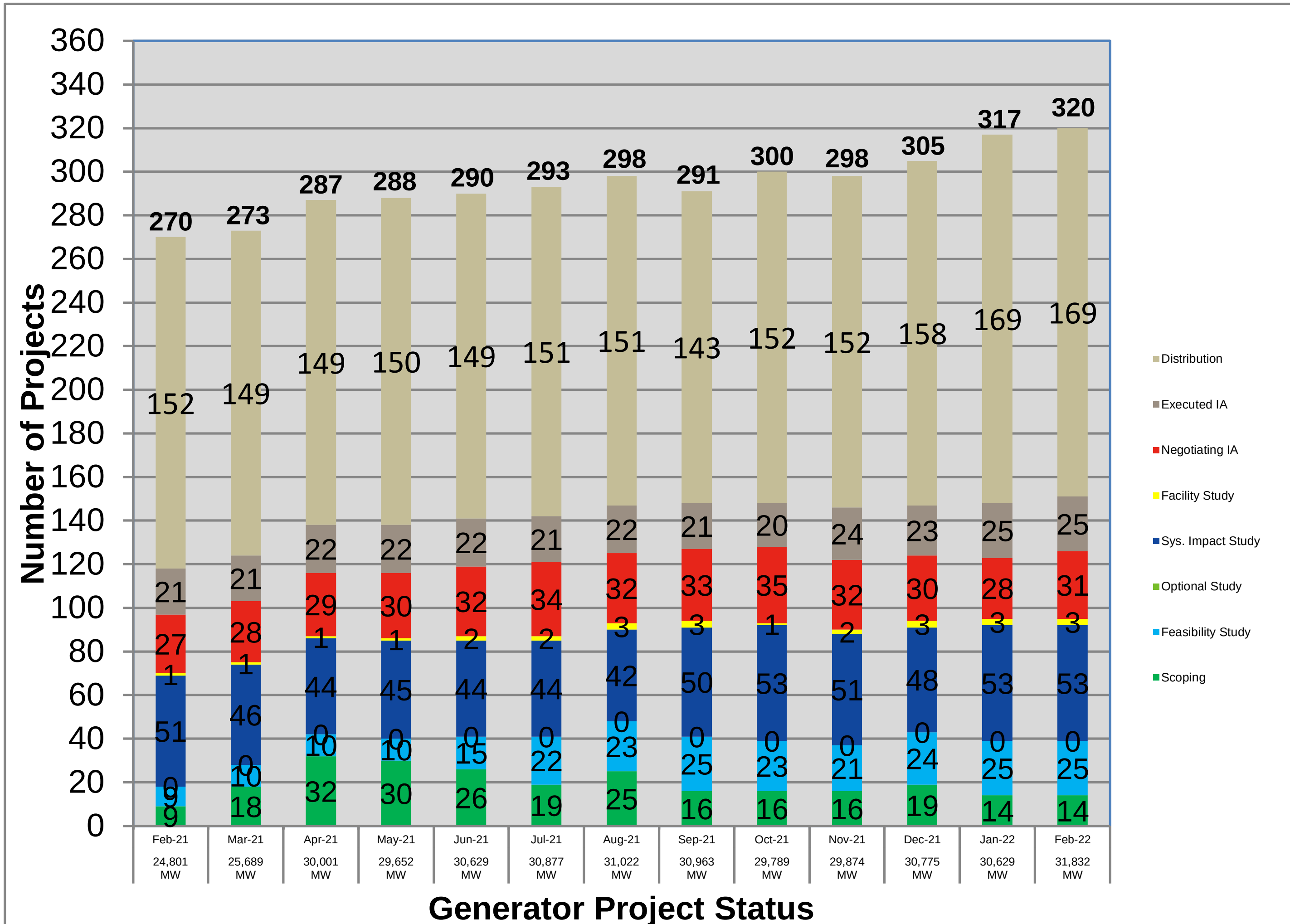
Upper Maine Solution Projects, cont.

Status as of 2/23/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	1
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	1
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	1

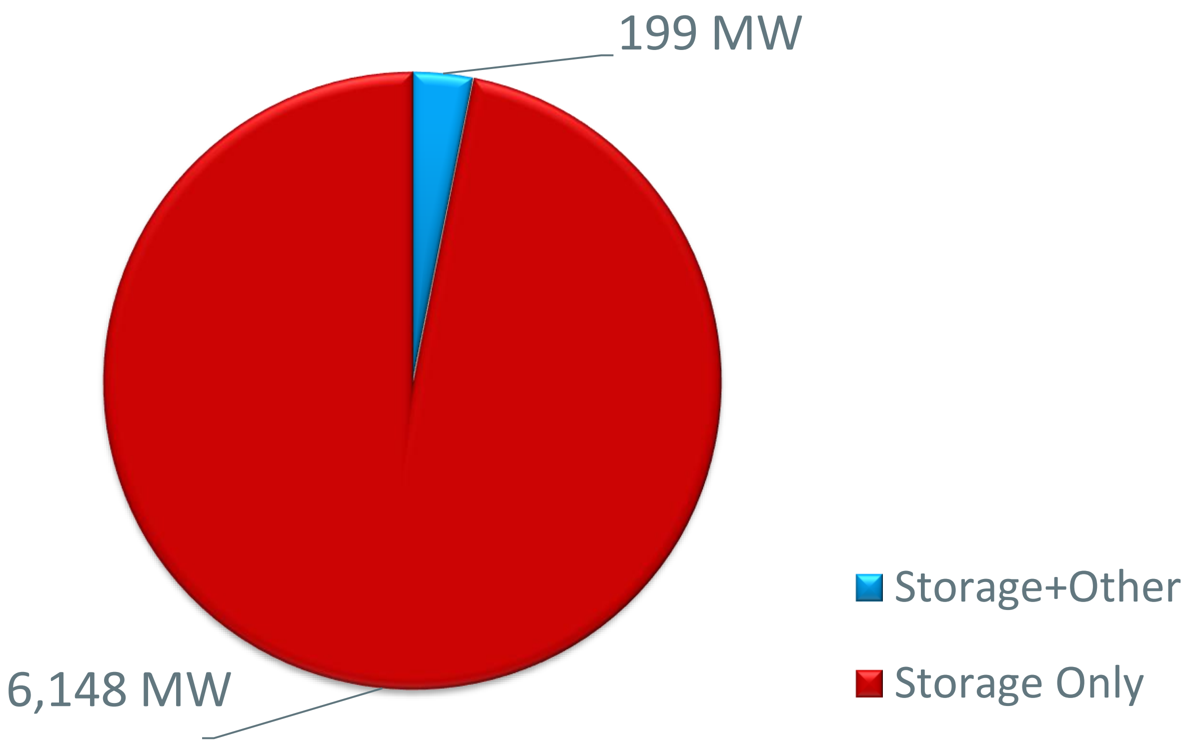
Status of Tariff Studies



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

What is in the Queue (as of February 18, 2022)

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



OPERABLE CAPACITY ANALYSIS

Winter 2022 Analysis

Winter 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	March - 2022[2] CSO (MW)	March - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,763	32,025
Active Demand Capacity Resource (+) [5]	540	423
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	37	37
Non Gas-fired Planned Outage MW (-)	1,789	2,058
Gas Generator Outages MW (-)	1,024	1,208
Allowance for Unplanned Outages (-) [4]	2,700	2,700
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	25,962	27,654
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,472	16,472
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,777	18,777
Operable Capacity Margin	7,185	8,877

[1] Operable Capacity is based on data as of **February 22, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 22, 2022.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 26, 2022.**

[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 2022 Operable Capacity Analysis

90/10 Load Forecast	March - 2022[2] CSO (MW)	March - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,763	32,025
Active Demand Capacity Resource (+) [5]	540	423
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	37	37
Non Gas-fired Planned Outage MW (-)	1,789	2,058
Gas Generator Outages MW (-)	1,024	1,208
Allowance for Unplanned Outages (-) [4]	2,700	2,700
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	25,962	27,654
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,017	17,017
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,322	19,322
Operable Capacity Margin	6,640	8,332

[1] Operable Capacity is based on data as of **February 22, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 22, 2022.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 26, 2022.**

[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 2022 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 2/22/2022

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
3/12/2022	29510	508	1137	29	751	500	2200	98	27635	17400	2305	19705	7930	N	Winter 2021/2022
3/19/2022	29510	508	1137	29	1352	710	2200	0	26922	17036	2305	19341	7581	N	Winter 2021/2022
3/26/2022	29763	540	1135	37	1789	1024	2700	0	25962	16472	2305	18777	7185	Y	Winter 2021/2022

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 2021 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 2022 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 2/22/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
3/12/2022	29510	508	1137	29	751	500	2200	996	26737	17973	2305	20278	6459	Y	Winter 2021/2022
3/19/2022	29510	508	1137	29	1352	710	2200	337	26585	17598	2305	19903	6682	N	Winter 2021/2022
3/26/2022	29763	540	1135	37	1789	1024	2700	0	25962	17017	2305	19322	6640	N	Winter 2021/2022

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
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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.
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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.
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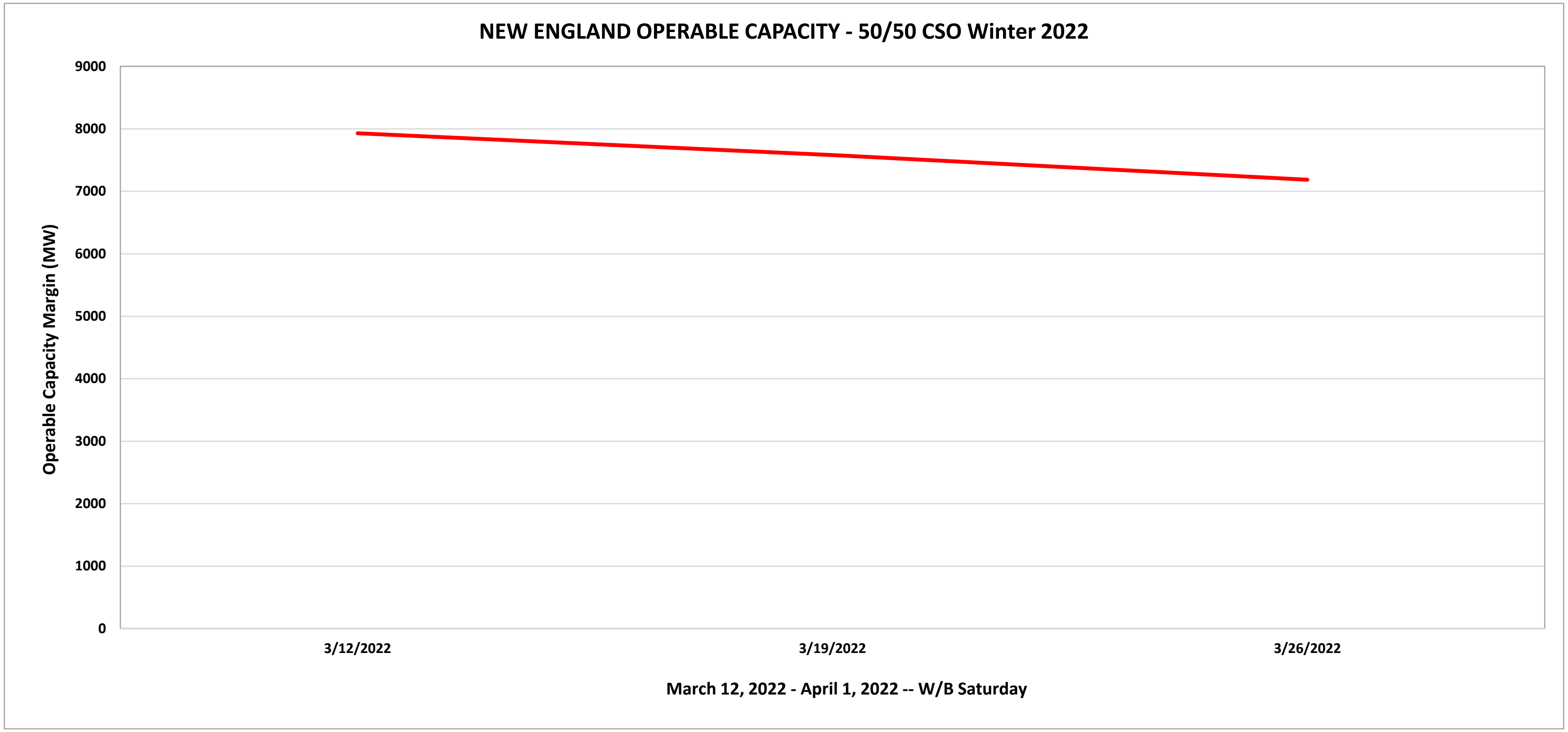
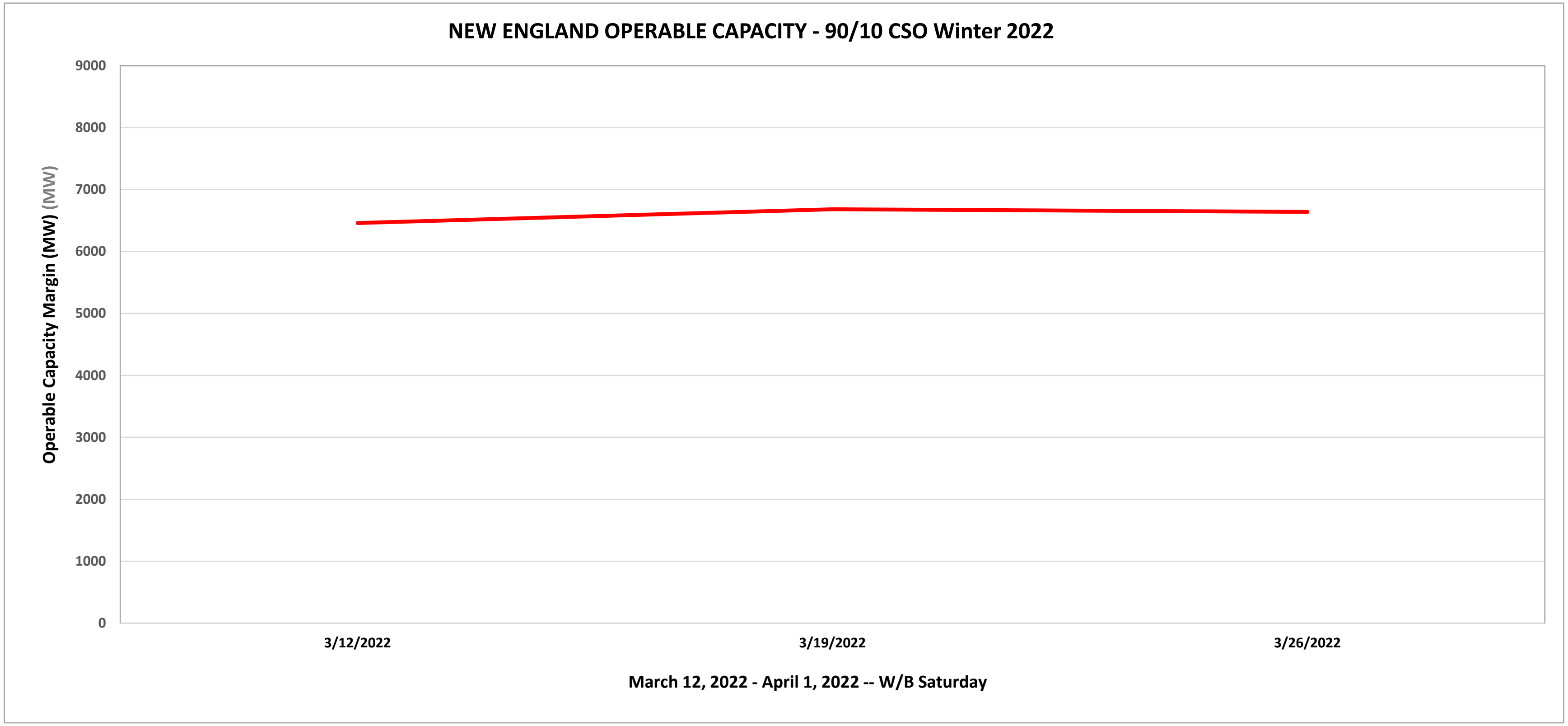
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable 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 2022 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2022 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Spring 2022 Analysis

Spring 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2022[2] CSO (MW)	May – 2022[2] SCC (MW)
Operable Capacity MW [1]	29,763	32,025
Active Demand Capacity Resource (+) [5]	540	423
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	37	37
Non Gas-fired Planned Outage MW (-)	5,329	5,747
Gas Generator Outages MW (-)	823	893
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)	21,923	23,580
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,001	19,001
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,306	21,306
Operable Capacity Margin	617	2,274

[1]Operable Capacity is based on data as of **February 22, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 22, 2022.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 14, 2022.**

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

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

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

Spring 2022 Operable Capacity Analysis

90/10 Load Forecast	May - 2022[2] CSO (MW)	May - 2022[2] SCC (MW)
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Gas Generator Outages MW (-)	823	893
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)	21,923	23,580
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,519	20,519
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,824	22,824
Operable Capacity Margin	-901	756

[1] Operable Capacity is based on data as of **February 22, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 22, 2022.**

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Spring 2022 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 2/22/2022

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4/2/2022	29763	540	1135	37	3390	3175	2700	0	22210	15804	2305	18109	4101	N	Spring 2022
4/9/2022	29763	540	1135	37	4026	3509	2700	0	21240	15553	2305	17858	3382	N	Spring 2022
4/16/2022	29763	540	1135	37	4359	3146	2700	0	21270	15045	2305	17350	3920	N	Spring 2022
4/23/2022	29763	540	1135	37	4360	3469	2700	0	20946	14780	2305	17085	3861	N	Spring 2022
4/30/2022	29763	540	1135	37	4944	4156	3400	0	18975	14754	2305	17059	1916	N	Spring 2022
5/7/2022	29763	540	1135	37	4305	2776	3400	0	20994	18001	2305	20306	688	N	Spring 2022
5/14/2022	**29763**	**540**	**1135**	**37**	**5329**	**823**	**3400**	**0**	**21923**	**19001**	**2305**	**21306**	**617**	**Y**	**Spring 2022**
5/21/2022	29763	540	1078	37	4007	1116	3400	0	22895	19930	2305	22235	660	N	Spring 2022

Column Definitions

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

Spring 2022 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

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

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

Report created: 2/22/2022

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4/2/2022	29763	540	1135	37	3390	3175	2700	0	22210	16336	2305	18641	3569	N	Spring 2022
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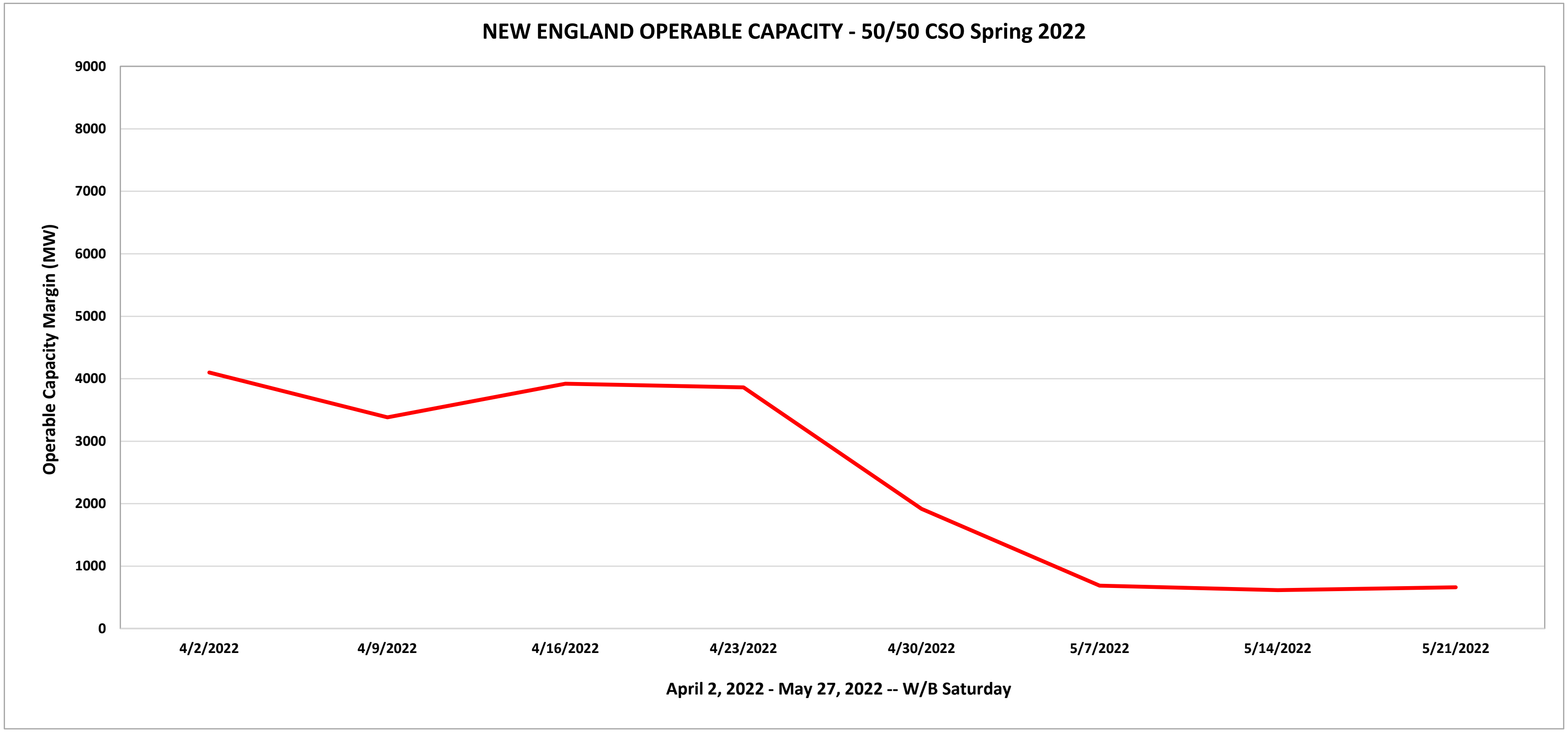
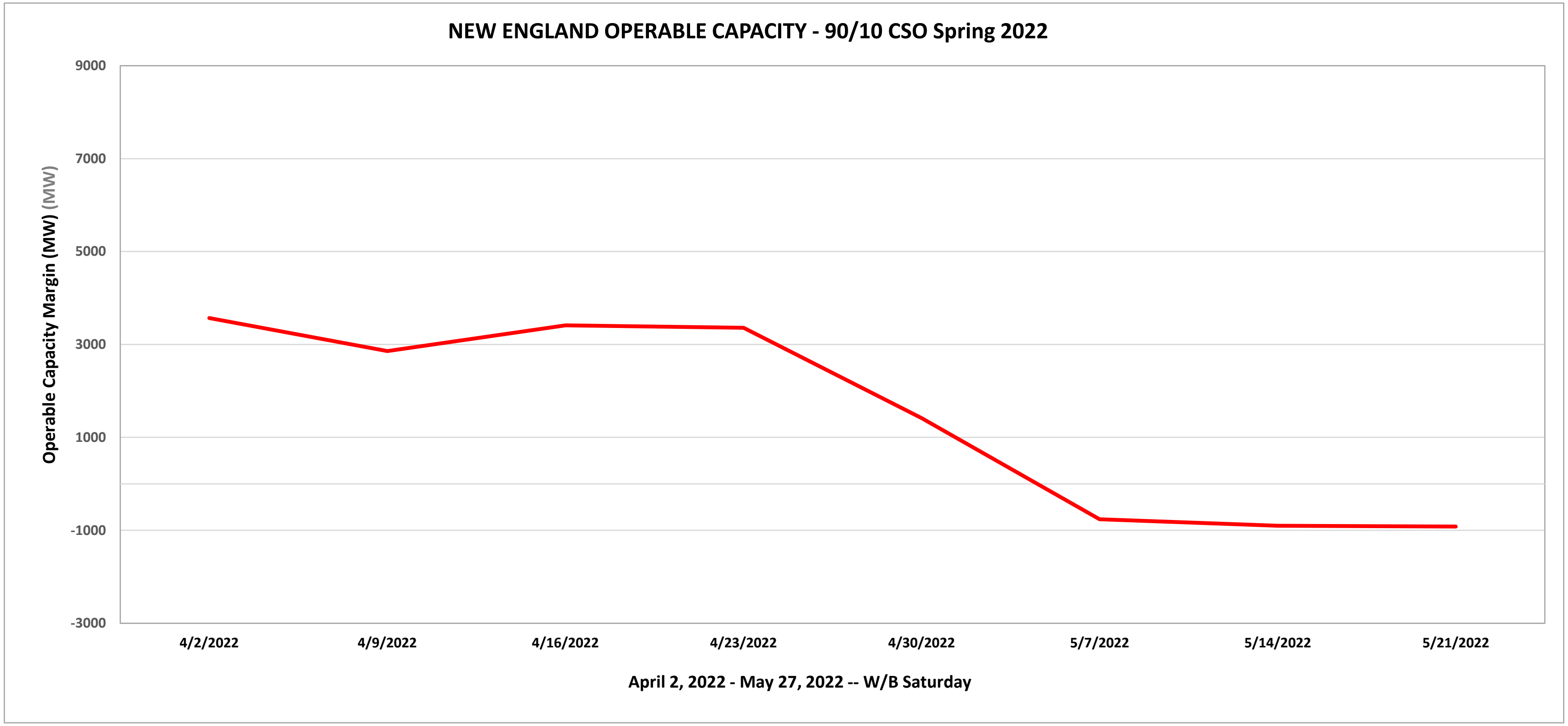


Spring 2022 Operable Capacity Analysis
90/10 Forecast



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:
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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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Rosendo Garza, NEPOOL Counsel

DATE: February 24, 2022

RE: Competitive Power Ventures' Proposal to Reform Financial Assurance Construct for Non-Commercial Capacity Resources

---

At the March 3, 2022 Participants Committee[1] meeting, you will be asked to vote on revisions to Market Rule 1 and the ISO-NE Financial Assurance Policy (FAP), as proposed by Competitive Power Ventures (CPV), to change the financial assurance requirements for Non-Commercial resources in the Forward Capacity Market (FCM), referred to as the "CPV Proposal." CPV seeks for this proposal to be implemented in time for the seventeenth Forward Capacity Auction (FCA 17).

This memorandum provides a high-level summary of the CPV Proposal and the stakeholder process that has vetted the Proposal to date. Included with this memorandum are the following CPV-sponsored materials:

- Attachment A1: Proposed Market Rule 1 Tariff sheets
- Attachment A2: Proposed FAP Tariff sheets
- Attachment B1: PowerPoint presentation provided at the February 8, 2022 Markets Committee meeting
- Attachment B2: PowerPoint presentation provided at the January 26, 2022 B&F Subcommittee meeting
- Attachment C: CPV Towantic LLC's Memorandum dated February 22, 2022 (subject: Performance Based Financial Assurance Proposal for Non-Commercial Capacity)

OVERVIEW OF CPV PROPOSAL

As CPV explained, its Proposal is intended to differentiate the amount of financial assurance required from projects meeting all of their milestone commitments, projects that are delayed in their development, and projects that have failed. To implement the proposed reforms to the financial assurance construct for non-commercial capacity resources in the FCM, CPV is

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

recommending a package of Tariff revisions, with a majority of the changes in the FAP, and a corresponding set of changes in Market Rule 1.

Market Rule 1 Changes

As part of its package of reforms, CPV proposes changes to Market Rule 1. These revisions would modify a non-commercial resource's project financing closing Critical Path Schedule (CPS) milestone and add a new milestone, i.e., "construction notice to proceed," to the CPS (*see* changes to Tariff Section III.13.1.1.2.2.2). Relatedly, the CPV Proposal includes new language in Market Rule 1 concerning the documentation requirements for the project financing closing and the construction notice to proceed milestones. With regards to forfeited financial assurance associated with the NCC Milestone FA and NCC Delay FA (which are described below), CPV proposes to allocate the forfeited amounts pro rata to Participants with Capacity Supply Obligations and Capacity Load Obligations, as indicated in CPV's revisions to Tariff Section III.13.1.9.2.3.

CPV provides additional explanation of its proposed Market Rule 1 revisions in Attachment A1 and Attachment B1.

FAP Changes

Currently, the financial assurance required from Non-Commercial Capacity with a Capacity Supply Obligation increases by a factor of one prior to the first and second Forward Capacity Auctions after the auction in which that Capacity Supply Obligation was awarded. The CPV Proposal would add an additional increment of financial assurance prior to the third Forward Capacity Auction after the auction in which that Capacity Supply Obligation was awarded for projects that have not exceeded 20 percent of budgeted spending on construction activities. For Demand Capacity Resources less than 5 MW, the additional increment would be required if the project has not achieved its first target date percentage obligation of its demand reduction value.

The CPV Proposal also includes two new categories of financial assurance:

(i) "NCC Milestone FA" would establish a new financial assurance requirement that would be applied to a non-commercial project that fails to meet its financing and start of construction and spending milestones (as described in ***Market Rule 1 Changes***) and will not achieve its commercial operation date by the start of the Capacity Commitment Period to which its Capacity Supply Obligation relates; and

(ii) "NCC Delay FA" would add a financial assurance requirement that would be applied to a non-commercial project that fails to achieve its commercial operation date by the start of the Capacity Commitment Period to which its Capacity Supply Obligation relates.

Neither the NCC Milestone FA nor the NCC Delay FA would be applied to Demand Capacity Resources or to New Capacity Resources less than 20 MW.

The CPV Proposal also includes FAP revisions on the timing and return of the financial assurance associated with the NCC Milestone FA once the project exceeds 20 percent of the construction financing costs on construction activities, as well as on the mechanics of how the financial assurance associated with the NCC Delay FA is forfeited.

CPV more fully describes its proposed FAP revisions in Attachment A2 and Attachment B2.

STAKEHOLDER PROCESS TO DATE

Through the Participant Processes to date, the Markets Committee reviewed and offered input to portions of the CPV Proposal, while the Budget and Finance Subcommittee (B&F Subcommittee) reviewed other portions (i.e., the FAP changes). Additional information is provided herein regarding the outcome of each of these committee's deliberations.

Markets Committee Review (Agenda Item 5.a)

The CPV Proposal was presented and discussed at multiple Markets Committee meetings. In the course of those discussions, the ISO explained to stakeholders that although the ISO is in general agreement that incentives for non-commercial resources is a matter that is worthy of further evaluation, the ISO was not able to "devote further resources" that would be necessary to examine fully the potential implications and impacts of CPV's Proposal, including whether adjustments to financial assurance is the best way to address the matter.[2] As such, the ISO stated that it was unable to support the CPV Proposal at this time. The ISO suggested further discussion on whether the matter should be incorporated into the ISO work plan and the matter's relative priority compared to other work plan projects. Following this input, the Markets Committee at its February 8, 2022 meeting, entertained a motion that the Markets Committee recommend Participants Committee support for the Market Rule 1 changes in the CPV Proposal. That motion, which required a 60% Vote or greater to pass, failed with a 40.24% Vote in favor.[3]

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[2] Memorandum from ISO-NE to the NEPOOL Markets Committee and NEPOOL Budget & Finance Subcommittee, subject: Concerns with Competitive Power Ventures' Proposed Financial Assurance Modifications, at 1 (Jan. 7, 2022), https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_iso_memo.pdf. To review CPV's response, see Memorandum from Joel Gordon to NEPOOL Markets Committee and NEPOOL Budget & Finance Subcommittee, subject: ISO Memo "Concerns with Competitive Power Ventures' Proposed Financial Assurance Modifications" dated January 7, 2022 (Jan. 10, 2022), https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_response_memo.docx.

[3] The individual Sector votes were as follows: Generation – 13.92% in favor, 2.78% opposed, 0 abstentions; Transmission – 0% in favor, 16.70% opposed, 0 abstentions; Supplier – 16.7% in favor, 0% opposed, 7 abstentions; Publicly Owned Entity – 0% in favor, 0% opposed, 49 abstentions; Alternative Resources – 9.63% in favor, 6.88% opposed, 4 abstentions; and End User – 0% in favor, 16.7% opposed, 1 abstention. Because the entire Publicly Owned Entity Sector abstained, no portion of the Adjusted

B&F Subcommittee Review (Agenda Item 5.b)

The B&F Subcommittee considered CPV's proposed changes to the FAP at its meetings on August 26, October 12, November 29, January 26, and February 10. The B&F Subcommittee is a non-voting subcommittee, but the Participants attending these various B&F Subcommittee meetings expressed a range of views on the CPV Proposal. Some explained their view that the changes are needed to address certain projects providing unrealistic projections of their ability to reach commercial operation. Others said the magnitude of the additional financial assurance requirements would likely create an undue barrier to entry in the FCM and expressed concerns with the allocation of the forfeited financial assurance. A copy of the FAP changes, which require a 66.67% Vote to be supported by the Participants Committee, are included as Attachment A2.

Participants Committee Review

To be approved by the Participants Committee, CPV's proposed Market Rule 1 modifications require a 60% Vote, and the proposed FAP revisions require a 66.67% Vote. Accordingly, the following forms of resolutions may be used for Participants Committee action, voted either individually or in a single combined vote:

> RESOLVED, that the Participants Committee supports the Market Rule 1 Tariff revisions related to changing the financial assurance requirements for Non-Commercial Capacity, as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.
>
> FURTHER RESOLVED, that the Participants Committee supports revisions to Sections VII.B.2.b, VII.B.3, and VII.D of the ISO New England Financial Assurance Policy to change the financial assurance requirements for Non-Commercial Capacity, as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

Sector Voting Share was reallocated to other Sectors or included in either the totals "in favor" or "opposed" to the motion.

CPV's Proposed Market Rule 1 Revisions

Note: The yellow highlighting indicates changes made on February 28, 2022.

III.13. Forward Capacity Market.

***

III.13.1.1.2.2.2. Critical Path Schedule.
In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing including the cost of construction activities for purposes of determining the requirement in section (d) below; (ii) the expected sources of that financing; and (iii) the expected deadline for the closing date(s) for the project financing (i.e., the date on which the amount of the financing available to the project is at least equal to the stated dollar amount of the required project financing). If the Project Sponsor will self-fund the project and will not rely on external financing from an entity other than the Project Sponsor, then it will so demonstrate its availability of funding as part of the New Capacity Qualification Package.

(b.1) **Construction Notice to Proceed**. In the New Capacity Qualification Package, the Project Sponsor shall provide the date by which it will direct is prime contractor and any direct subcontractors to commence work on the site and the date by which the prime contractor and any direct subcontractors begin construction activity on the site, which directions will not be limited to less than all of the activities necessary to complete construction of the project.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(c) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (c) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent operation of the project in accordance with the design capacity of the resource and in accordance with

Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) and/or the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

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III.13.1.9.2.3. Forfeit of Financial Assurance.

~~Except as provided in this paragraph, W~~~~w~~Where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone. ~~Financial Assurance that is attributable to the NCC Delay FA calculation under Section VII.B.2b of the Financial Assurance Policy that is forfeited pursuant to Section III.13 shall be allocated to Participants with Capacity Supply Obligations and Capacity Load Obligations (excluding the forfeiting resource's Capacity Supply Obligation) for the portion of the Capacity Commitment Period to which such Financial Assurance forfeiture applies (the Delay Forfeiture Period). Allocation of forfeited Delay FA shall be determined by summing the Capacity Supply Obligation and Capacity Load Obligation of each participant across the Delay Forfeiture Period and dividing by the sum of the total Capacity Supply Obligations and Capacity Load Obligations of all participants in the same Forfeiture Period (excluding the forfeiting resource's Capacity Supply Obligation). Financial Assurance that is attributable to the NCC Milestone FA calculation under Section VII.B.2b of the Financial Assurance Policy that is forfeited pursuant to Section III.13 shall be allocated to Participants with Capacity Supply Obligations and Capacity Load~~

~~Obligations (excluding the forfeiting resources Capacity Supply Obligation) for the Capacity Commitments Periods or portions thereof from the start of the Capacity Commitment Period in which the forfeiting resource first obtained a Capacity Supply Obligation through date of termination of or withdrawal by forfeiting resource (the Milestone Forfeiture Period). Allocation of forfeited Milestone FA shall be determined by summing the Capacity Supply Obligation and Capacity Load Obligation of each participant across the Milestone Forfeiture Period and dividing by the total Capacity Supply Obligations and Capacity Load Obligations of all participants in the same Milestone Forfeiture Period (excluding the forfeiting resources' Capacity Supply Obligation~~.

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III.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW (discussed in Section III.13.3.2.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Project Sponsor shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Project Sponsor shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation ~~could~~ should include copies of commitment letters from the sources of financing as well as certification by an officer of the Project Sponsor that all loan and financing arrangements have been executed and all conditions precedent to the initial funding for the project are complete and funds for the financing and construction of the project are available to the Project Sponsor. For Project Sponsors who are self-funding their projects, this milestone will be satisfied by a certification by an officer of the Project Sponsor that all internal approvals have been obtained for such self-funding.

(ii.a) **Construction Notice to Proceed**. The Project Sponsor shall provide documentation and certification attesting to providing notice to its prime contractor and its direct subcontractors to commence fully construction of the project and that the prime contractor and direct subcontractors have commenced construction activity on the project site.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. If during the qualification process it was determined that transmission upgrades (including any upgrades identified in a re-study pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Project Sponsor shall provide documentation showing the total offered demand reduction value achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value must be complete.

(ii) **Additional Requirements**. For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Project Sponsor shall also provide the Asset identification number.

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CPV's Proposed FAP Revisions

Note 1: Changes since the Markets Committee and Budget and Finance Subcommittee meetings are highlighted in yellow and were circulated on February 25, 2022.

Note 2: Green highlighted changes are made to correct an error identified on March 1, 2022.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

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VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

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

A. FCM Delivery Financial Assurance

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

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

Where:

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

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

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

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

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

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

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

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

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

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

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the "FCM Deposit").

2. Non-Commercial Capacity in Forward Capacity Auctions

a. Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction

For Non-Commercial Capacity participating in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction, a Designated FCM Participant that had its supply offer of Non-Commercial Capacity accepted in a Forward Capacity Auction must include in the calculation of its Financial Assurance Requirement under the ISO New England Financial Assurance Policy the following amounts at the following times:

(i) beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day following announcement of the awarded supply offers in that Forward Capacity Auction, an amount equal to $5.737(on a $/kW-month basis) multiplied by the number of kW of capacity awarded to that Designated FCM Participant in that Forward Capacity Auction (such amount being referred to herein as the "Non-Commercial Capacity FA Amount");

(ii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the next annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was awarded, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to two (2) times the Non-Commercial Capacity FA Amount; and

(iii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was accepted, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to three (3) times the Non-Commercial Capacity FA Amount.

b. Non-Commercial Capacity Participating in the Ninth Forward Capacity Auction and All Forward Capacity Auctions Thereafter

A Designated FCM Participant offering Non-Commercial Capacity into the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount equal to the difference between the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4) times the Non-Commercial Capacity qualified for such Forward Capacity Auction and the FCM Deposit.

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA + NCC Milestone FA (if applicable) + NCC Delay FA

Where:
NCC = the Capacity Supply Obligation awarded in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one at the completion of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; ~~and~~ three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; and, four beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the third Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, provided that the increase in the Multiplier from three to four will occur if and only if the Project Sponsor has not provided documentation pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs or for a Demand Capacity Resource less than 5 MW that it achieved its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2 prior to such time.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the sixteenth Forward Capacity Auction, NCC Milestone FA = zero. For Capacity Supply Obligations acquired in the seventeenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Milestone FA shall equal NCC x NCCFCA$ (each as defined above) x Milestone FA Multiplier.

Milestone FA Multiplier = one beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if (1) the Project Sponsor has not demonstrated pursuant to Section III.13.3.2.2 that the applicable Resource has both (x) achieved its project financing milestone (as described in Section III.13.1.1.2.2.2(b)) or other demonstration of its ability to fund its projects, as applicable and (y) provided construction notice to proceed (as described in Section III.13.1.1.2.2.2(b)(i)) to its prime contractor to commence construction activity and (2) Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) will not be achieved by the start of the associated Capacity Commitment Period;

three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if (1) the Project Sponsor has not provided documentation pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of construction financing costs and (2) Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) will not be achieved by the start of the associated Capacity Commitment Period;

six beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the third Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if (1) the Project Sponsor has not provided documentation pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of construction financing costs and (2) Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) will not be achieved by the start of the associated Capacity Commitment Period; and in all other instances, zero.

Notwithstanding the foregoing, NCC Milestone FA shall equal zero for all Demand Capacity Resources and all New Capacity Resources ~~less than 20 MW~~ not subject to Schedules 22 or 25 of Section II of the Transmission, Markets and Services Tariff.

For purposes of determining whether a New Capacity Resource has achieved any of the milestones described in this paragraph by the date set forth in its approved critical path schedule, adjustments to that schedule that have been approved by the ISO will be taken into account, so long as the schedule date for the New Capacity Resource's Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) does not extend beyond the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity acquiring a Capacity Supply Obligation in the seventeenth Forward Capacity Auction or any Forward Capacity Auction thereafter that fails to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) ~~become commercial~~ by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, NCC Delay FA shall equal NCC x NCCFA$ x Delay FA Multiplier less any forfeited Delay FA. For all other Non-Commercial Capacity (including without limitation Non-Commercial Capacity acquiring Capacity Supply Obligations in Forward Capacity Auctions up to an including the sixteenth Forward Capacity Auction), NCC Delay shall equal zero.

Delay FA Multiplier shall equal one ~~the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows:~~ beginning at 8 a.m. (Eastern Time) on the first Business Day of the ~~second~~ fourth month of the Capacity Commitment

Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, and ~~the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount~~ shall increase by one every ~~six~~ three months thereafter until the Non-Commercial Capacity achieves Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) ~~becomes commercial~~ or the Capacity Supply Obligation is terminated.

Notwithstanding the foregoing, NCC Delay FA shall equal zero for all Demand Capacity Resources and all New Capacity Resources ~~less than 20 MW~~ not subject to Schedules 22 or 25 of Section II of the Transmission, Markets and Services Tariff.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the applicable Capacity Commitment Period, at which time NCC Trading FA = the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC) multiplied by the difference (but not less than zero) between: (i) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (ii) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable (except that for monthly Capacity Supply Obligation Bilaterals, the applicable monthly reconfiguration auction clearing price will be used instead of the Capacity Supply Obligation Bilateral price).

c. Non-Commercial Capacity Deferral

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity. Notwithstanding the foregoing but subject to Section VII.D below, (1) the financial assurance requirement due to Project Sponsor failing to provide documentation that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs shall be reduced to zero 30 days following the date on which such Project Sponsor has provided documentation that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of construction financing costs and (2) any financial assurance requirement attributable to the Milestone FA amount shall be reduced to zero on the first day of the calendar month that is at least 30 days following the date upon which the applicable Project Sponsor has provided documentation that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of construction financing costs.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. FCM Capacity Charge Requirements

The FCM Capacity Charge Requirements shall be calculated for the current month and all previously unbilled months. The FCM Capacity Charge Requirements shall be the product of the Estimated Capacity Load Obligation times the FCM Charge Rate for the applicable Capacity Zone. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning prior to June 1, 2022 for a Capacity Zone will be calculated using the same methodology described in Section III.13.7.5 of Market Rule 1 for deriving the Net Regional Clearing Price, with the exception that the FCM Charge Rate will include the balance of the CTR fund after the value of specifically allocated CTRs has been paid, as described in Section III.13.7.5.3.1 of Market Rule 1. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning on or after to June 1, 2022 for a Capacity Zone will be calculated as the sum of the charge and adjustment rates specified in Section III.13.7.5.1.1 of Market Rule 1.

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the "Non-Commercial Capacity Cure Period"), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

In addition, the ISO will draw down the additional financial assurance provided by a Designated FCM Participant under the calculation of NCC Delay FA 90 days following the date upon which that financial assurance is due if the applicable Resource fails to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) by such date. In each case, such financial assurance will be allocated as provided in Section III.13.1.9.2.3.

E. Composite FCM Transactions

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)). The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

3. Financial Assurance for Annual Reconfiguration Transactions

A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

4. Substitution Auctions

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

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Competitive
Power Ventures

Performance Based Non-Commercial Financial Assurance

February 8, 2022
NEPOOL Markets Committee

SILVER SPRING | BRAINTREE

Process, Schedule and Status

- Objective is to have these changes in place for FCA 17.
  - Target is to have a FERC filing in March in order to have a decision by the New Capacity Qualification Package Submission window which closes on June 17.
  - Final deadline would be tied to the New Capacity Qualification Package window

- Seeking MC action for recommendation to the Participants Committee.
  - MR1 changes were discussed at the Jan 12 Markets Committee
    - These address Cost Allocation of the new FA components.
    - These also propose more clarity to existing Critical Path Milestone Schedule.

- Four components of the proposal - #4 below for MC Action:
  1. Add an increment of FA prior to the third subsequent FCA for resources not achieving Substantial Site Construction. (B&F)
  2. Require additional "Milestone FA" during the critical path schedule tracking. (B&F)
  3. Shorten intervals of "Delay FA" installments post COD from six to three months. (B&F)
  4. NEW Change: Allocate forfeited Milestone and Delay FA all buyers and sellers in the FCM. (MC Vote)

- At the B&F, there was discussion regarding exempting all units not subject to LGIP (20MW or greater). CPV will amend its proposal to incorporate this change for the NPC.

The Need for Performance-Based Financial Assurance

- There is no performance-based FA for non-commercial capacity across the range of performance contrary to good market design.
  - The current FA design makes no distinction between a project meeting all its milestone commitments, a delayed project, and a totally failed project.
    - The only performance-based FA is *after* the resource has failed to meet its initial COD, yet even this provision does not consider the status of the project (i.e.: has it even started construction?).

- Lack of performance-based consequences undermine incentives for balanced decision-making for sponsors of highly unlikely projects.
  - In the recent NE example, the project sponsor had little financial incentive to withdraw a failed project:
    - There is no additional posting requirement prior to the third subsequent FCA.
    - There is no incremental financial consequence for missing *any* or *every* single milestone.
    - The opportunity to recover previously posted FA may incent resources to wait for ISO-NE to make a termination decision, and then to challenge that decision.

- The qualification process and the financial assurance requirements are not working together to ensure that cleared projects are “real” or “timely.”
  - The only real tool in the ISO toolbox is a sledgehammer - termination.

Impacts from Current Design Shortfall

- Failed non-commercial capacity participating in capacity auctions financially impact all other capacity sellers in the auction with no recourse by those impacted.
  - A resource that has not achieved COD by its FCA required commitment date will have posted just three months of FA but would have participated in four FCAs (see FCA16 issues currently pending).
  - Financial impacts to other CSO holders is through lower clearing prices in each auction and higher performance risk during the delivery period.
  - Most recent NE example estimated to have a market impact of $380 million over three auctions: $0.31 kw-month average.[#]

- Projects that are not ripe for participation can displace other shovel-ready projects.

- Existing FA requirements are not balanced with either the project cost, or potential market impact for projects failing to meeting their commitments.
  - Most recent NE example using current FA rules:
    - Total FA prior to committed COD: $14.1 million*
    - Total Market impact: $380 million.
    - Total Project Cost: $621MM [@]

Proposed Performance Based FA Enhancements

Current FA includes:

- FA that is collected prior to the primary FCA and then prior to the first and second subsequent auctions.
- Trading FA: FA that is collected in the delivery period as any positive trading revenue from cover transactions.

This proposal establishes two new categories of FA to incorporate a performance-based design– changes impact only resources who fail to perform consistent with their FCA commitments:

- Milestone FA: New FA requirements for projects that fail to meet two critical delivery obligations – Financing/Start of Construction, and 20% construction completed.

- Delay FA: Increased posting of FA and potential forfeiture for projects that fail to deliver physically by their commitment date.

  - And… Adds one increment of FA prior to third subsequent FA for significantly delayed projects.

Milestone FA Proposal:

Add a financial consequence for projects failing to advance in a timely fashion:

- Prior to First Subsequent FCA:
  - Resources that have not achieved Project Finance Closing and Construction Notice to Proceed* according to their approved milestone schedule would be required to post an additional one increment of FA prior to the first subsequent auction.
- Prior to the Second Subsequent FCA:
  - Resources that have not achieved Substantial Site Construction according to their approved milestone schedule would be required to post an incremental two months of FA prior to the second subsequent FCA (3 months total) .
- Prior to the Third Subsequent FCA:
  - Resources that have *still* not achieved Substantial Site Construction according to their approved milestone schedule would be required to post an incremental three months of FA prior to the third subsequent FCA (6 months total).

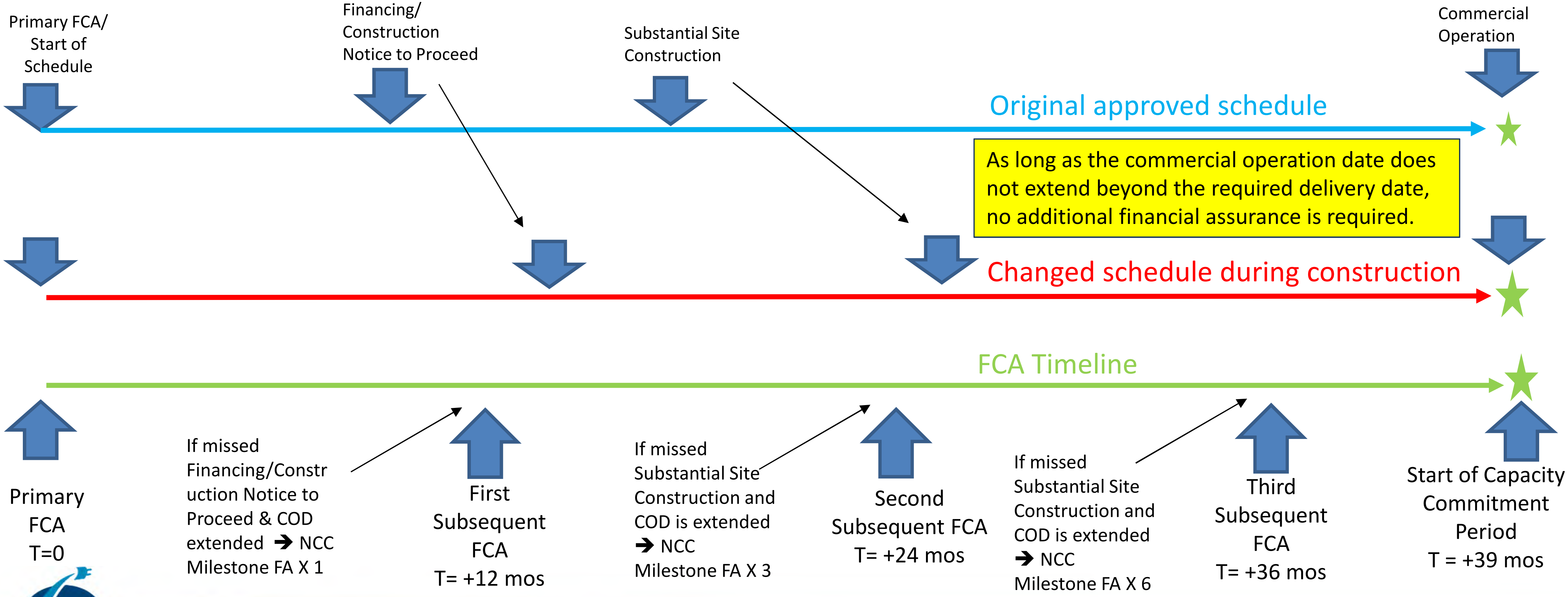
NEW: For purposes of determine Milestone FA, adjustments to the milestone schedule that have been approved by the ISO will be taken into account, so long as the scheduled date for the Resource's Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) does not extend beyond the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

Changes to the Milestone Schedule/ Mechanics

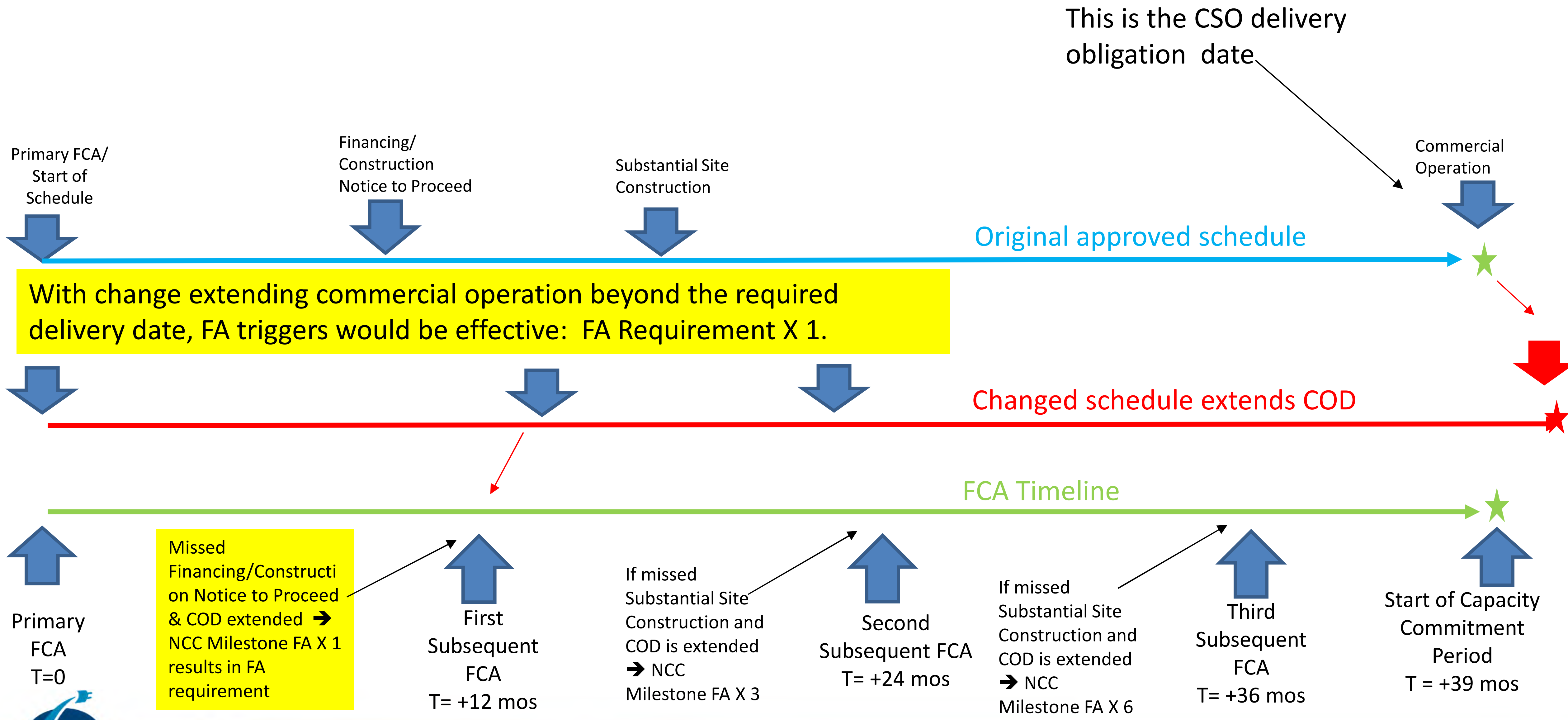
Approved Critical Path Milestone Schedule

- This is established at qualification and is subject to change consistent with current rules. The current rules allow all milestones to be pushed out without any financial consequence.

Performance-based FA proposal allows for all milestones to be adjusted without increased FA as long as the Commercial Operation date remains on or before the start of the Capacity Commitment Period associated with the CSO.

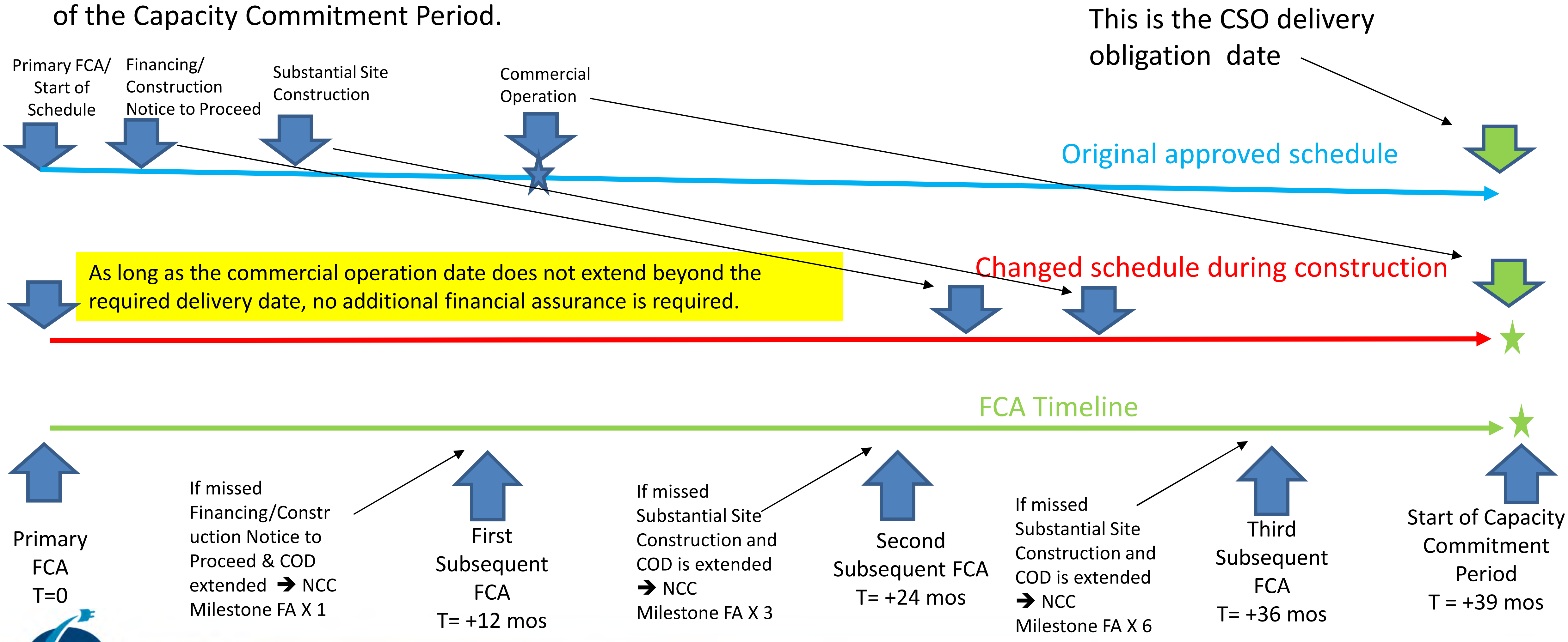


Milestone Requirement/ Example

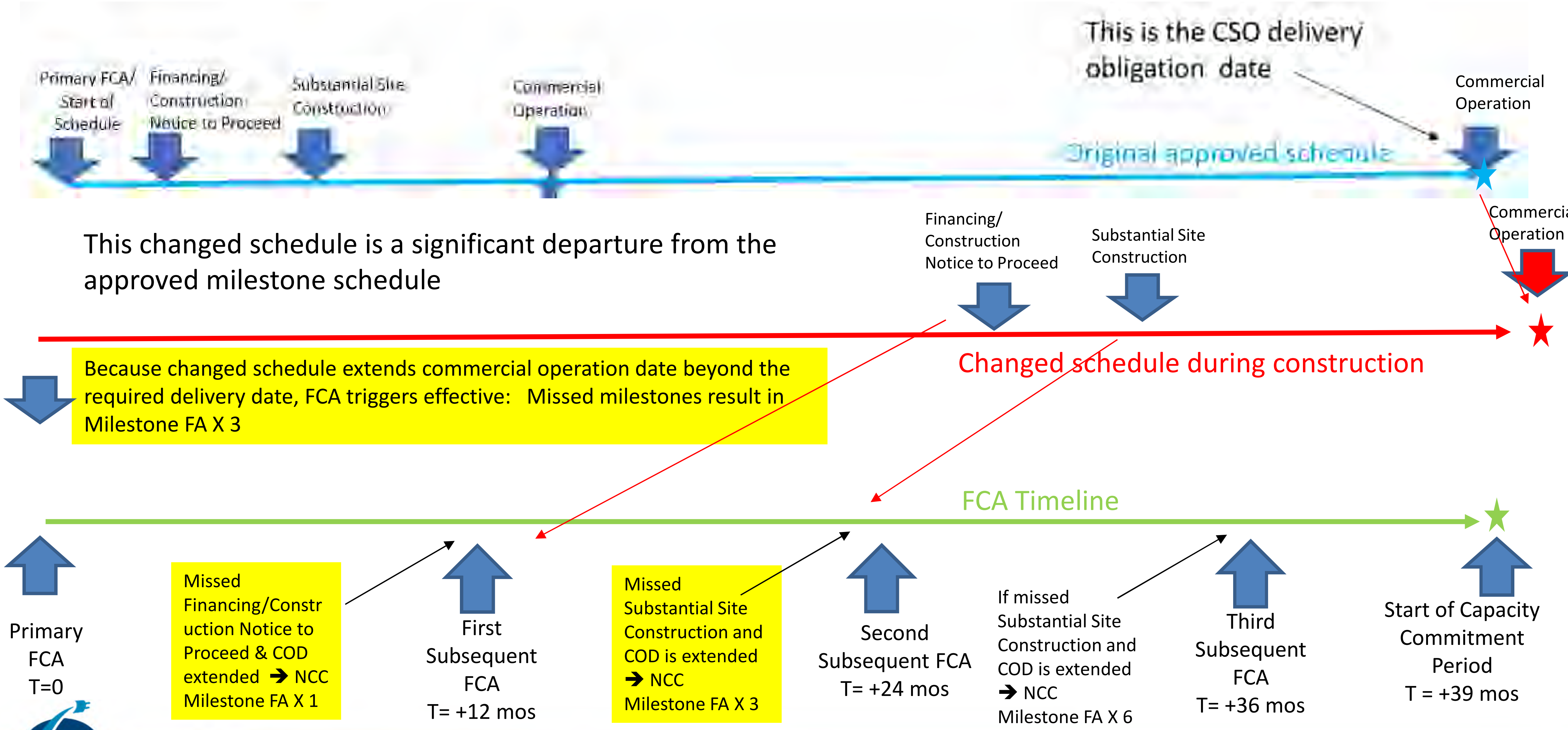


Short Duration Project Example

Some projects with short construction schedules submit milestone schedules with early CODs, however the capacity market obligation is for COD by the start of the Capacity Commitment Period.



Short Duration Project Milestone FA Required - Example



Delay FA Product

- Proposal is to replace current post COD FA with one month of FA for every three months of delayed COD.
  - Current FA requirement is one month of FA for every six months of delay.
- COD in this construct is pursuant to Schedule 22/23/25 – is the project commercial and available to the system:
  - It recognizes some resources will be unable to demonstrate their FCM COD capability due to FCA test procedures.
- Delay FA is collected quarterly after-the-fact and is forfeited if the project has not declared COD by the end of the subsequent quarter – effectively a six-month grace period.

Allocation of Forfeited FA

Original proposal sought to allocate any forfeited Milestone and Delay FA to participants with Capacity Supply Obligations over the impacted time period.

No proposed change to the allocation for NCCAFA and Trading FA.

NEW ALTERNATIVE:
Allocate forfeited Milestone and Delay Financial Assurance pro-rata to both CSO holders and those with Capacity Load Obligations.

- Delay FA forfeited is allocated pro-rata based upon Capacity Supply Obligations and Capacity Load Obligations across all FCM participants during the calendar quarter for which the FA was collected.
    - Since delayed projects cover their CSO obligations, load always receives the capacity procured from the primary auction under the demand curve.

- Milestone FA forfeited is allocated pro-rata based upon CSO and CLO across all FCM market participants during the time in which the forfeiting resource was able to participate in the capacity market.

Tariff Changes   Market Rule 1 Section 13

III.13.1.9.2.3. Forfeit of Financial Assurance.

Amends this paragraph retaining existing allocation of current FA forfeitures. Adds new mechanisms to allocate Milestone FA and Delay FA.

III.13.1.1.2.2.2. Critical Path Schedule.

(b) Tightens the description of Project Financing Closing to include the cost of “construction activities” which is used later in determining Substantial Site Construction. Adds new certification for self-funding options.

NOTE: This provision to address concerns with “soft closings.”

(b.i) Adds this new paragraph of Construction Notice to Proceed as the date in which the project sponsor directs its prime and direct subcontractor to commence construction as well as the date that construction activities to complete the project begin.

NOTE: This provision added to address “soft start” on construction.

Forfeiture Allocation

III.13.1.9.2.3. Forfeit of Financial Assurance.

Except as provided in this paragraph, ~~W~~where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone. Financial Assurance that is attributable to the NCC Delay FA calculation under Section VII.B.2b of the Financial Assurance Policy that is forfeited pursuant to Section III.13 shall be allocated to Participants with Capacity Supply Obligations and Capacity Load Obligations (excluding the forfeiting resource's Capacity Supply Obligation) for the portion of the Capacity Commitment Period to which such Financial Assurance forfeiture applies (the Delay Forfeiture Period). Allocation of forfeited Delay FA shall be determined by summing the Capacity Supply Obligation and Capacity Load Obligation of each participant across the Delay Forfeiture Period and dividing by the sum of the total Capacity Supply Obligations and Capacity Load Obligations of all participants in the same Forfeiture Period (excluding the forfeiting resource's Capacity Supply Obligation). Financial Assurance that is attributable to the NCC Milestone FA calculation under Section VII.B.2b of the Financial Assurance Policy that is forfeited pursuant to Section III.13 shall be allocated to Participants with Capacity Supply Obligations and Capacity Load Obligations (excluding the forfeiting resources Capacity Supply Obligation) for the Capacity Commitments Periods or portions thereof from the start of the Capacity Commitment Period in which the forfeiting resource first obtained a Capacity Supply Obligation through date of termination of or withdrawal by forfeiting resource (the Milestone Forfeiture Period). Allocation of forfeited Milestone FA shall be determined by summing the Capacity Supply Obligation and Capacity Load Obligation of each participant across the Milestone Forfeiture Period and dividing by the total Capacity Supply Obligations and Capacity Load Obligations of all participants in the same Milestone Forfeiture Period (excluding the forfeiting resources' Capacity Supply Obligation

Changes to Critical Path Milestones

(b) Project Financing Closing . In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing including the cost of construction activities for purposes of determining the requirement in section (d) below; (ii) the expected sources of that financing; and (iii) the expected deadline for the closing date(s) for the project financing (i.e., the date on which the amount of the financing available to the project is at least equal to the stated dollar amount of the required project financing). If the Project Sponsor will self-fund the project and will not rely on external financing from an entity other than the Project Sponsor, then it will so demonstrate its availability of funding as part of the New Capacity Qualification Package.

(b.i) Construction Notice to Proceed. In the New Capacity Qualification Package, the Project Sponsor shall provide the date by which it will direct is prime contractor and any direct subcontractors to commence work on the site and the date by which the prime contractor and any direct subcontractors begin construction activity on the site, which directions will not be limited to less than all of the activities necessary to complete construction of the project.

Four Steps for More Effective Financial Assurance

1. Add increment of "Base FA" prior to third subsequent FCA for resources not achieving Substantial Site Construction.

2. Require additional Milestone FA for projects that fail to achieve pre-construction commitments.
   - Milestone FA would be due prior to subsequent FCAs and consistent with approved milestone schedules if COD is extended.
   - Only impacts projects that fail to meet their milestones pre-construction.
   - All Milestone FA would be released upon catch-up to active construction.

3. Increase Delay FA as projects is delayed beyond its original COD.
   - This new "Delay FA" is forfeited after a six- month grace period based upon achievement of Interconnection COD.

4. Allocate Milestone and Delay FA prorate to all FCM participants
   - Base FA and Trading FA would retain existing allocation methodology.

Additional Slides

Current Milestone Schedule

- The current Critical Path Milestone Schedule process requires all non-commercial capacity to provide a schedule for major milestones as part of its qualification.

  III.13.1.1.2.2.2. Critical Path Schedule. In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project *with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones* no later than the start of the relevant Capacity Commitment Period.

- A critical path schedule report is due on a quarterly basis from the Project Sponsor.
  - Each report must update the original schedule, note changes to milestones and project scope. (III. 13.2.2.1)
  - Achievement of milestones must include documentation in support.
    - Failure to provide *the report* can result in termination.

- Failure to meet the original milestone, and changes to the schedule, may result in a monthly reporting requirement (III.13.3.3).
  - Covering obligations for late delivery is optional…
    - Although choosing not to cover will result in failure to cover charge, but only *after* the start of the delivery period (III.13.3.4.(b)).
    - Failure to provide *the monthly reports* can result in termination.

- There are no financial consequences of failing to achieve milestones until after the delivery date has been passed.

Financial Assurance Policy Tariff Changes

Please refer to Budget and Finance Subcommittee posting for most current version of the FAP.

Includes yellow highlighted changes from the last B&F meeting.

Previous Presentations:

Budget and Finance Committee – August 26, 2021

NEPOOL Markets Committee – September 13-14, 2021

Budget and Finance Committee – October 12, 2021

NEPOOL Markets Committee – November 9-10, 2021

NEPOOL Budget and Finance Committee – November 29, 2021

Tariff Language:

NEPOOL Markets Committee – December 9, 2021

NEPOOL Markets Committee – January 12, 2022

NEPOOL Budget and Finance Committee – January 26, 2022

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Competitive
Power Ventures

Performance Based Non-Commercial Financial Assurance

January 26, 2022
NEPOOL Budget & Finance Sub Committee

SILVER SPRING | BRAINTREE

Process, Schedule and Status

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    - Those only address Cost Allocation of the new FA components.
    - Also proposed more clarity to existing Critical Path Milestone Schedule.

- Four components of the proposal for consideration:
  1. Add an increment of FA prior to the third subsequent FCA for resources not achieving Substantial Site Construction. (B&F)
  2. Require additional "Milestone FA" during the critical path schedule tracking. (B&F)
  3. Shorten intervals of "Delay FA" installments post COD from six to three months. (B&F)
  4. Allocate forfeited Milestone and Delay FA to impacted CSO holders. (MC Vote)

- Would also like the sense of B&F as to exempting DR less than 5MW from Milestone FA, or in the alternative exempting units not subject to LGIP (20MW or greater).

The Need for Performance-Based Financial Assurance

- There is no performance-based FA for non-commercial capacity across the range of performance contrary to good market design.
  - The current FA design makes no distinction between a project meeting all its milestone commitments, a delayed project, and a totally failed project.
    - The only performance-based FA is *after* the resource has failed to meet its initial COD, yet even this provision does not consider the status of the project (i.e.: has it even started construction?).

- Lack of performance-based consequences undermine incentives for balanced decision-making for sponsors of highly unlikely projects.
  - In the recent NE example, the project sponsor had little financial incentive to withdraw a failed project:
    - There is no additional posting requirement prior to the third subsequent FCA.
    - There is no incremental financial consequence for missing *any* or *every* single milestone.
    - The opportunity to recover previously posted FA may incent resources to wait for ISO-NE to make a termination decision, and then to challenge that decision.

- The qualification process and the financial assurance requirements are not working together to ensure that cleared projects are "real" or "timely."
  - The only real tool in the ISO toolbox is a sledgehammer - termination.

Impacts from Current Design Shortfall

- Failed non-commercial capacity participating in capacity auctions financially impact all other capacity sellers in the auction with no recourse by those impacted.
  - A resource that has not achieved COD by its FCA required commitment date will have posted just three months of FA but would have participated in four FCAs.
  - Financial impacts to other CSO holders is through lower clearing prices in each auction and higher performance risk during the delivery period.
  - Most recent NE example estimated to have a market impact of $380 million over three auctions: $0.31 kw-month average.[#]

- Projects that are not ripe for participation can displace other shovel-ready projects.

- Existing FA requirements are not balanced with either the project cost, or potential market impact for projects failing to meeting their commitments.
  - Most recent NE example using current FA rules:
    - Total FA prior to committed COD: $14.1 million*
    - Total Market impact: $380 million.
    - Total Project Cost: $621MM [@]

Proposed Performance Based FA Enhancements

Current FA includes:

- FA that is collected prior to the primary FCA and then prior to the first and second subsequent auctions.
- Trading FA: FA that is collected in the delivery period as any positive trading revenue from cover transactions.

This proposal establishes two new categories of FA to incorporate a performance-based design– changes impact only resources who fail to perform consistent with their FCA commitments:

- Milestone FA: New FA requirements for projects that fail to meet two critical delivery obligations – Financing/Start of Construction, and 20% construction completed.

- Delay FA: Increased posting of FA and potential forfeiture for projects that fail to deliver physically by their commitment date.

  - And… Adds one increment of FA prior to third subsequent FA for significantly delayed projects.

Milestone FA Proposal:

Add a financial consequence for projects failing to advance in a timely fashion:

- Prior to First Subsequent FCA:
  - Resources that have not achieved Project Finance Closing and Construction Notice to Proceed* according to their approved milestone schedule would be required to post an additional one increment of FA prior to the first subsequent auction.

- Prior to the Second Subsequent FCA:
  - Resources that have not achieved Substantial Site Construction according to their approved milestone schedule would be required to post an incremental two months of FA prior to the second subsequent FCA (3 months total) .

- Prior to the Third Subsequent FCA:
  - Resources that have *still* not achieved Substantial Site Construction according to their approved milestone schedule would be required to post an incremental three months of FA prior to the third subsequent FCA (6 months total).

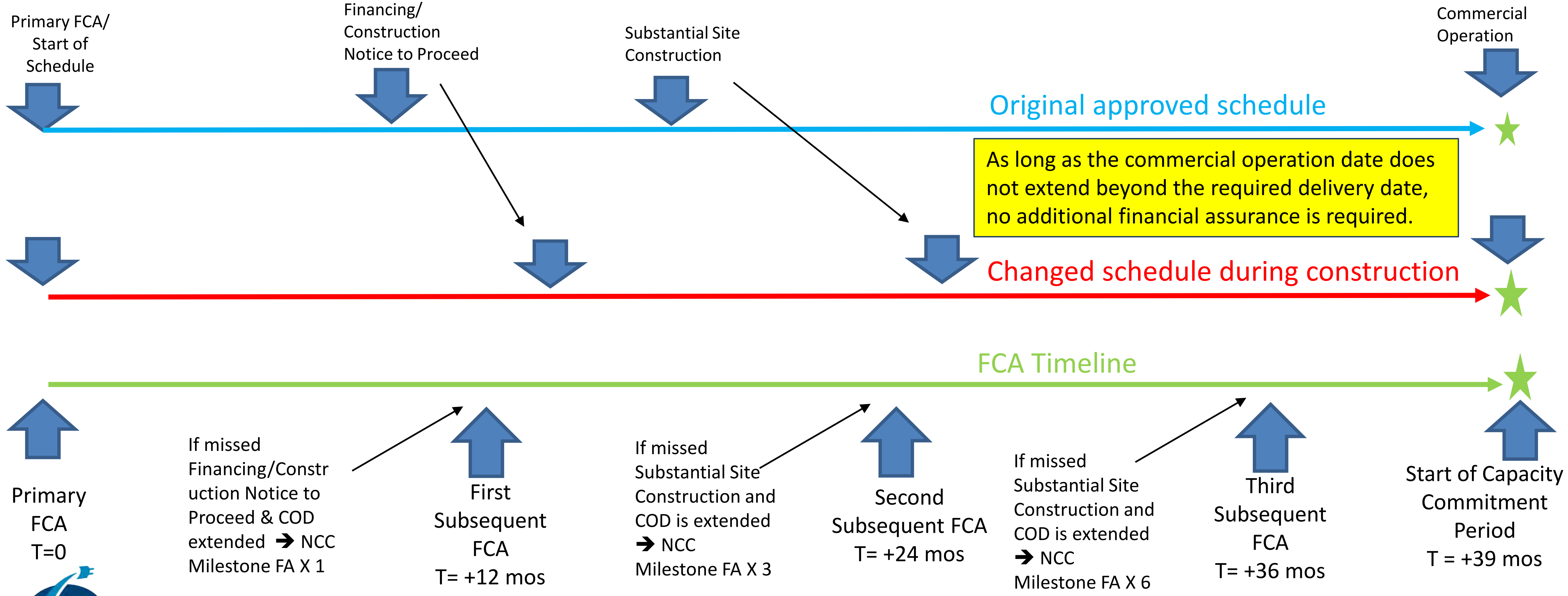
NEW: For purposes of determine Milestone FA, adjustments to the milestone schedule that have been approved by the ISO will be taken into account, so long as the scheduled date for the Resource's Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) does not extend beyond the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

Changes to the Milestone Schedule/ Mechanics

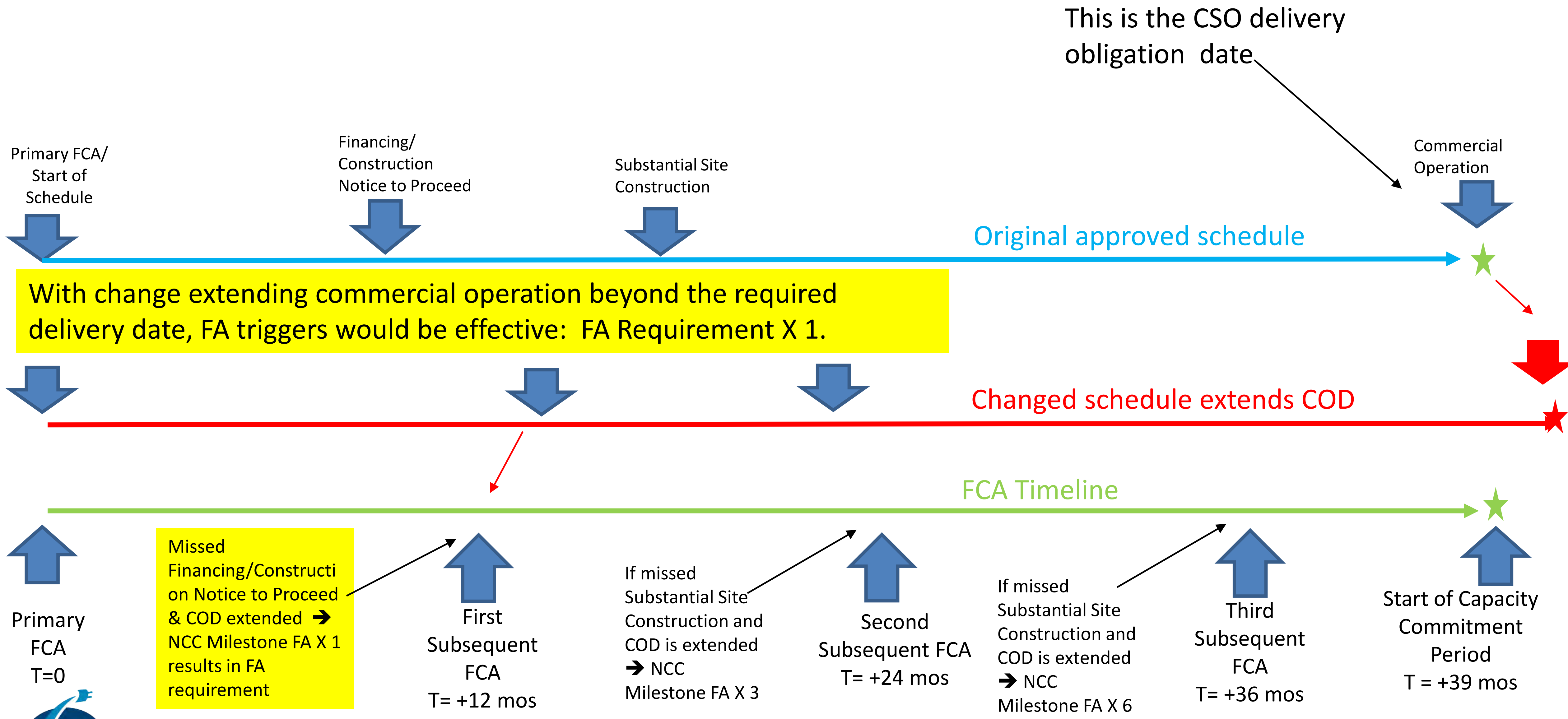
Approved Critical Path Milestone Schedule

- This is established at qualification and is subject to change consistent with current rules. The current rules allow all milestones to be pushed out without any financial consequence.

Performance-based FA proposal allows for all milestones to be adjusted without increased FA as long as the Commercial Operation date remains on or before the start of the Capacity Commitment Period associated with the CSO.

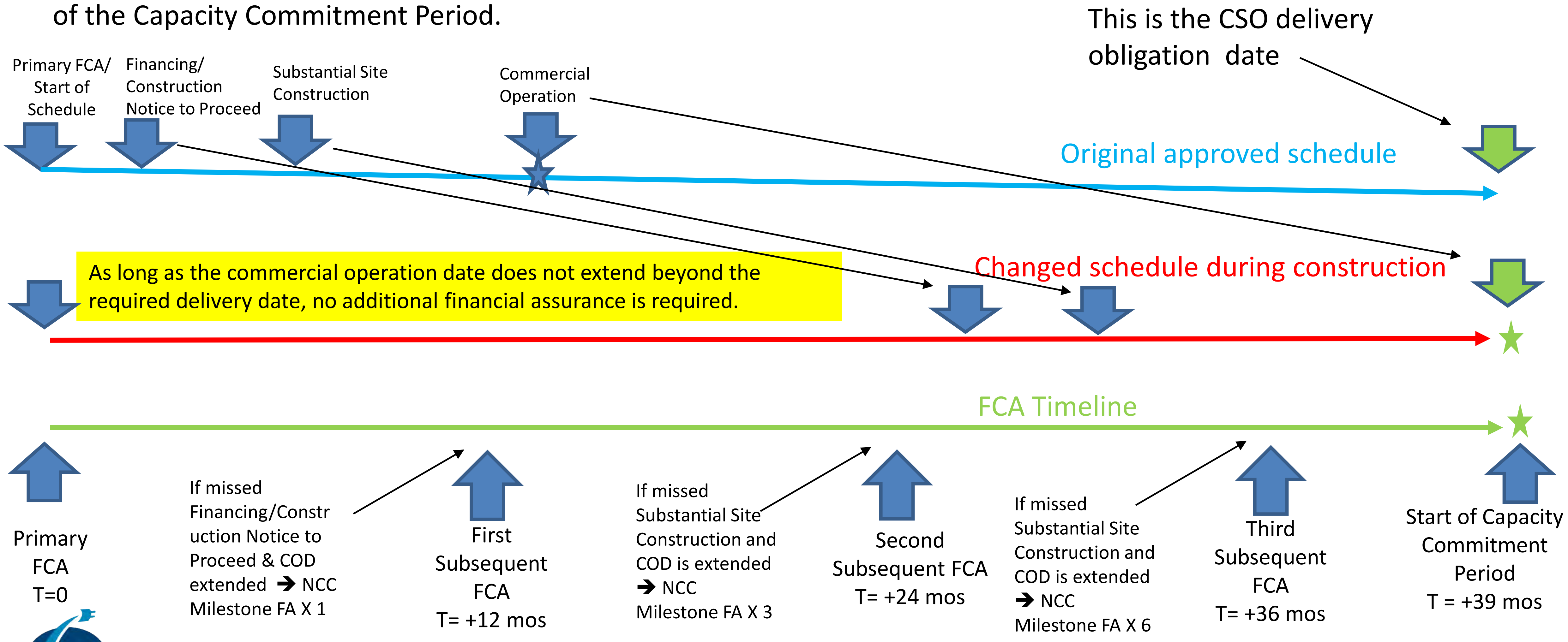


Milestone Requirement/ Example

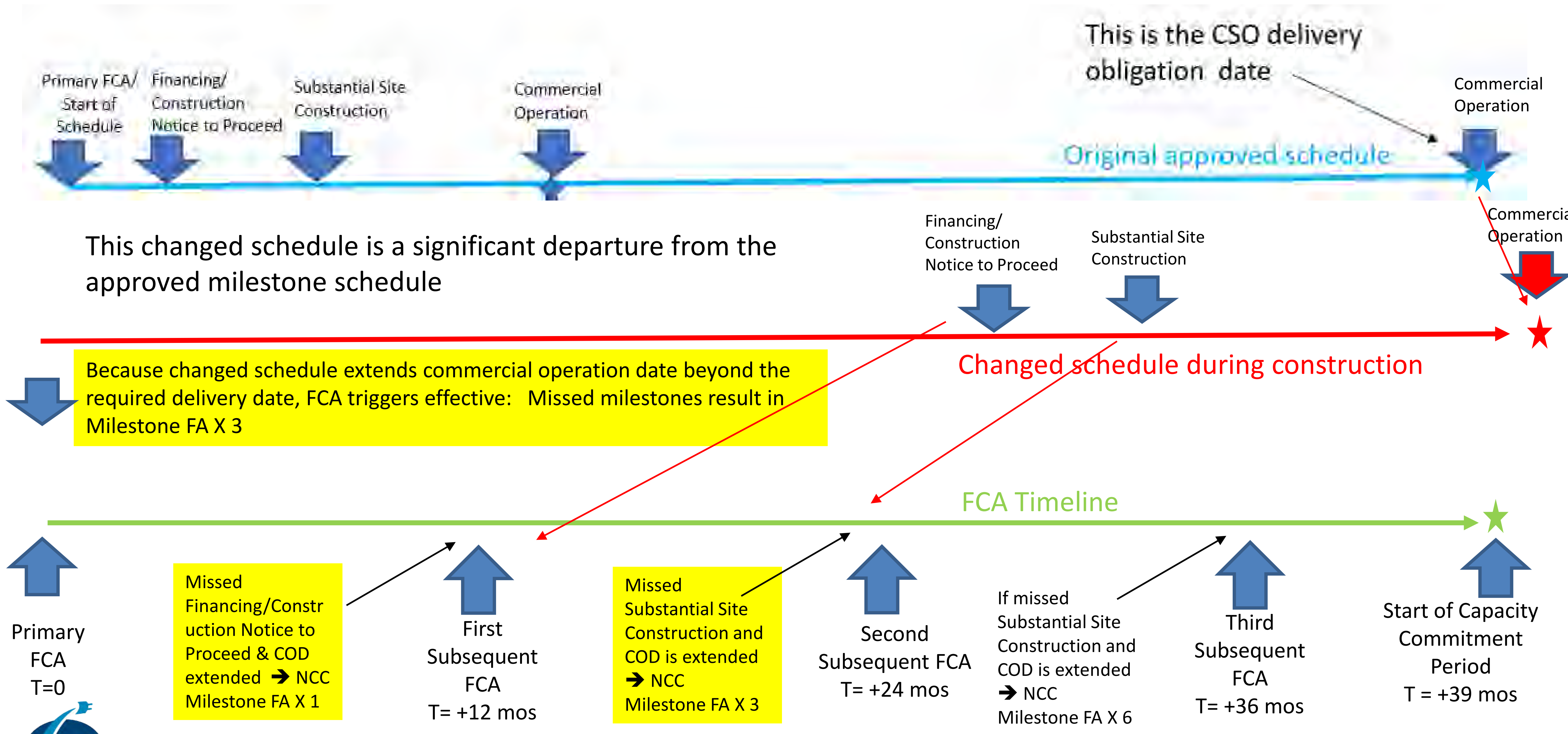


Short Duration Project Example

Some projects with short construction schedules submit milestone schedules with early CODs, however the capacity market obligation is for COD by the start of the Capacity Commitment Period.



Short Duration Project Milestone FA Required - Example



Delay FA Product

- Proposal is to replace current post COD FA with one month of FA for every three months of delayed COD.
  - Current FA requirement is one month of FA for every six months of delay.
- COD in this construct is pursuant to Schedule 22/23/25 – is the project commercial and available to the system:
  - It recognizes some resources will be unable to demonstrate their FCM COD capability due to FCA test procedures.
- Delay FA is collected quarterly after-the-fact and is forfeited if the project has not declared COD by the end of the subsequent quarter – effectively a six-month grace period.

Allocation of Forfeited FA

This proposal seeks to allocate any forfeited Milestone and Delay FA to participants with Capacity Supply Obligations over the impacted time period.

- Delay FA forfeited is allocated pro-rata based upon CSO obligations across all CSO providers during the calendar quarter for which the FA was collected.
  - Since delayed projects cover their CSO obligations, load always receives the capacity procured from the primary auction under the demand curve.

- Milestone FA forfeited is allocated pro-rata based upon CSO obligations across all CSO provides during the time in which the forfeiting resource was able to participate in the capacity market.

No proposed change to the allocation for NCCAFA and Trading FA.

Tariff Changes Exhibit IA ISO New England Financial Assurance Policy

- P55: 2.B Adds new terms NCC Milestone FA and NCC Delay FA
  - Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA + NCC Milestone FA (if applicable) + NCC Delay FA
- P56 2.B Adds provisional increment of NCCFCA$ prior to third subsequent auction
- …..and, four beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the third Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, provided that the increase in the Multiplier from three to four will occur if and only if the Designated FCM Participant has not demonstrated pursuant to Section III.13.3.2.2 that the Resource has expended at least 20 percent of its expected construction financing costs or for a Demand Capacity Resource less than 5MW that it achieved its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2. prior to such time .

Competitive Power Ventures, Inc.

Tariff Changes Exhibit IA ISO New England Financial Assurance Policy

- P56: Defines NCC Milestone FA and establishes mechanism for determining the provisional performance-based posting requirements prior to each of the three subsequent FCAs.

  - For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the sixteenth Forward Capacity Auction, NCC Milestone FA = zero. For Capacity Supply Obligations acquired in the seventeenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Milestone FA shall equal NCC x NCCFCA$ (each as defined above) x Milestone FA Multiplier

  - Milestone FA Multiplier = one beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if the Designated FCM Participant has not demonstrated pursuant to Section III.13.3.2.2 that either (1) the applicable Resource has both (x) achieved its project financing milestone (as described in Section III.13.1.1.2.2.2(b) or other demonstration of its ability to fund its projects, as applicable and (y) provided construction notice to proceed (as described in Section III.13.1.1.2.2.2(b)(i)) to its prime contractor to commence construction and that the prime contractor have mobilized on-site and have commenced construction activity or (2) if the applicable Resource is a Demand Capacity Resource, such Resource has achieved its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2 by such date if required to do by its approved critical path schedule under Section III.13;

Tariff Changes: Milestone FA Triggers, Cont'd

three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if the Designated FCM Participant has not demonstrated pursuant to Section III.13.3.2.2 that the applicable Resource has expended at least 20 percent of its expected construction financing costs or for a Demand Capacity Resource less than 5 MW that it achieved its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2 by such date if required to do by its approved critical path schedule under Section III.13;

six beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the third Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if the Designated FCM Participant has not demonstrated pursuant to Section III.13.3.2.2 that the applicable Resource has expended at least 20 percent of its expected construction financing costs or for a Demand Capacity Resource less than 5 MW that it achieved its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2 by such date if required to do by its approved critical path schedule under Section III.13 and Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) will not be achieved by the start of the associated Capacity Commitment Period; and in all other instances, zero.

Tariff Changes: Milestone FA Triggers, Cont'd

P57: Establishes how the Milestone FA is triggered based upon critical path milestone schedule adjustments, subject to maintaining the original commercial operation date by the start of the Capacity Commitment Period in which the CSO was awarded.

- For purposes of determining whether a Resource has achieved any of the milestones described in this paragraph by the date set forth in its approved critical path schedule, adjustments to that schedule that have been approved by the ISO will be taken into account, so long as the scheduled date for the Resource's Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) does not extend beyond the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

Tariff Changes: Delay FA

- PP 57-58. Defines the Delay FA and establishes the mechanism for determing the provision performance based posting requirement after the start of the relevant Capacity Commitment Period.

  - In the case of Non-Commercial Capacity that fails to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, NCC Delay FA shall equal NCC x NCCFCA$ x Delay FA Multiplier. For all other Non-Commercial Capacity, NCC Delay FA shall equal zero.

  - Delay FA Multiplier shall equal one ~~the Non-Commercial Capacity Financial Assurance Amount (“NCCDFA”) shall be recalculated as follows:~~ beginning at 8 a.m. (Eastern Time) on the first Business Day of the fourth ~~second~~ month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, and ~~the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount~~ shall NE increase by one every three ~~six~~ months thereafter until the Non-Commercial Capacity achieves Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) or the Capacity Supply Obligation is terminated.

Tariff Changes: Release of FA

- P59. Describes the timing and release of FA upon the achievement of Substantial Site Construction

3. Return of Non-Commercial Capacity Financial Assurance

Notwithstanding the foregoing but subject to Section VII.D below, (1) the financial assurance provided because a Resource failed to expend at least 20 percent of its expected construction financing costs or for a Demand Capacity Resource less than 5 MW that failed to achieve its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2 shall be returned to the applicable Designated FCM Participant 30 days following the date on which such Resource has expended at least 20 percent of its expected construction financing costs or for a Demand Capacity Resource less than 5 MW that it achieved its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2 and (2) any financial assurance attributable to the Milestone FA amount shall be returned to the applicable Designated FCM Participant on the first day of the calendar month that is at least 30 days following the date upon which the applicable Resource has expended at least 20 percent of its expected construction financing costs or for a Demand Capacity Resource less than 5 MW achieved its first target date percentage obligation of its demand reduction value pursuant to III.13.1.4.1.1.2.

P62. Describes the mechanics of the grace period for the forfeiture of Delay FA.

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

In addition, the ISO will draw down the additional financial assurance provided by a Designated FCM Participant under the calculation of NCC Delay FA 90 days following the date upon which that financial assurance is due if the applicable Resource fails to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) by such date. In each case, such financial assurance will be allocated as provided in Section III.13.1.9.2.3.

Four Steps for More Effective Financial Assurance

1. Add increment of “Base FA” prior to third subsequent FCA for resources not achieving Substantial Site Construction.

2. Require additional Milestone FA for projects that fail to achieve pre-construction commitments.
   - Milestone FA would be due prior to subsequent FCAs and consistent with approved milestone schedules if COD is extended.
   - Only impacts projects that fail to meet their milestones pre-construction.
   - All Milestone FA would be released upon catch-up to active construction.

3. Increase Delay FA as projects is delayed beyond its original COD.
   - This new “Delay FA” is forfeited after a six- month grace period based upon achievement of Interconnection COD.

4. Allocate Milestone and Delay FA to those with capacity supply obligations.
   - Paid to CSO holders prorata based upon share of capacity holdings during the delivery period.
   - Base FA and Trading FA would retain existing allocation methodology.

Additional Slides

Q: By adding new FA requirements, won't project sponsors increase their offer price which could result in higher clearing prices?

- Projects that are confident in their ability to meet their commitments would not include a "poor performance" adder.

- Projects less confident in their ability to meet their commitments might include a poor performance adder.
  - But the higher offer price will reflect their own individual expected poor performance.

- However, competition to provide capacity should discipline the ability of a "poor performance" adder to find its way into the clearing price.

- The major benefits of this proposal are:
  1. To incent project sponsors to participate in the auction when the project is ready to move forward; and,
  2. To discipline and discourage unrealistically optimistic timelines.
  - This FA proposal moves in these directions.

Q: Doesn't the Trading FA provide appropriate incentive for non-performing resources to perform?

No, for several reasons.

- First, Trading FA isn't necessarily an out-of-pocket cost to the project sponsor – if there was potential profit in cover transactions, those profits are what is held as FA by the ISO.
- Second, there is no obligation for resources to enter into cover transactions, and cover transactions are available up until the third annual reconfiguration (just a few months before the actual delivery obligation).
- Third, failure to cover penalties are only assessed after the delivery date has passed.
- Finally, current rules provide for return of those profits upon COD – thus, creating a incentive for potential failed projects to remain in the auctionsto not withdraw.

Q: In allocating Milestone and Delay FA to CSO holders, doesn't this result in load interests potentially paying more for the capacity? Can't they be charged for capacity that is never delivered?

No. This proposal does not seek to change the allocation of Trading FA.

- Trading FA protects load interests from paying more per kw-month for capacity than purchased in the primary auction from the resource.
  - And since another capacity supplier assumed the CSO, load interests get what they paid for.
    - Alternatively, cover transactions that are underwater are paid for by the CSO holder.
- For resources that are subject to Failure to Cover charges, those are determined as the higher of the clearing price or the reconfiguration auction price.
  - At least the full amount of what would have been paid to the supplier is refunded to load interests.

Current Milestone Schedule

- The current Critical Path Milestone Schedule process requires all non-commercial capacity to provide a schedule for major milestones as part of its qualification.

  III.13.1.1.2.2.2. Critical Path Schedule. In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project *with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones* no later than the start of the relevant Capacity Commitment Period.

- A critical path schedule report is due on a quarterly basis from the Project Sponsor.
  - Each report must update the original schedule, note changes to milestones and project scope. (III. 13.2.2.1)
  - Achievement of milestones must include documentation in support.
    - Failure to provide *the report* can result in termination.

- Failure to meet the original milestone, and changes to the schedule, may result in a monthly reporting requirement (III.13.3.3).
  - Covering obligations for late delivery is optional…
    - Although choosing not to cover will result in failure to cover charge, but only *after* the start of the delivery period (III.13.3.4.(b)).
    - Failure to provide *the monthly reports* can result in termination.

- There are no financial consequences of failing to achieve milestones until after the delivery date has been passed.

Tariff Changes Market Rule 1 Section 13

III.13.1.9.2.3. Forfeit of Financial Assurance.

Amends this paragraph retaining existing allocation of current FA forfeitures. Adds new mechanisms to allocate Milestone FA and Delay FA.

III.13.1.1.2.2.2. Critical Path Schedule.

(b) Tightens the description of Project Financing Closing to include the cost of "construction activities" which is used later in determining Substantial Site Construction. Adds new certification for self-funding options.

NOTE: This provision to address concerns with "soft closings."

(b.i) Adds this new paragraph of Construction Notice to Proceed as the date in which the project sponsor directs its prime and direct subcontractor to commence construction as well as the date that construction activities to complete the project begin.

NOTE: This provision added to address "soft start" on construction.

Previous Presentations:

Budget and Finance Committee – August 26, 2021
https://www.iso-ne.com/static-assets/documents/2021/08/3_competitive_power_ventures_noncommercial_fa_improvements_ii.pdf

NEPOOL Markets Committee – September 13-14, 2021
https://www.iso-ne.com/static-assets/documents/2021/09/2021_09_13_14_mc_a07_cpv_proposed_non_commercial_financial_assurance_improvements.pdf

Budget and Finance Committee – October 12, 2021
https://www.iso-ne.com/static-assets/documents/2021/10/2b_competitive_power_ventures_noncommercial_fa_improvements_ii.pdf

NEPOOL Markets Committee – November 9-10, 2021
https://www.iso-ne.com/static-assets/documents/2021/11/a06_mc_2021_11_09_10_cpv_non_commercial_financial_assurance_improvements_presentation.pdf

NEPOOL Budget and Finance Committee – November 29, 2021
https://www.iso-ne.com/static-assets/documents/2021/11/7b2_competitive_power_ventures_noncommercial_fa_improvements_ii.pdf
Tariff Language: https://www.iso-ne.com/static-assets/documents/2021/11/7b2_proposed_fa_tariff_language_enhanced_fa_noncommercial_capacity_exhibit_1a_redline_pages_only.pdf

NEPOOL Markets Committee – December 9, 2021
https://www.iso-ne.com/static-assets/documents/2021/12/a05_mc_2021_12_07_09_cpv_presentation.pptx

NEPOOL Markets Committee – January 12, 2022
https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_presentation.pptx
https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_iso_memo.pdf
https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_response_memo.docx

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TO: NEPOOL Participants & Stakeholders DATE: February 22, 2022

FROM: Joel Gordon, CPV Towantic LLC

RE: Performance Based Financial Assurance Proposal for Non-Commercial Capacity

Fellow NEPOOL Participants and Stakeholders:

This memo is intended to provide a wrap-up of CPV's Performance Based Financial Assurance proposal that has worked its way through the NEPOOL stakeholder process for the past seven months. That process included presentations, discussions, and debate at five separate Budget & Finance Subcommittee meetings and five separate Markets Committee meetings. We have heard near unanimous recognition that the current Financial Assurance Policy for Non-Commercial Capacity has shortcomings in its design, although acknowledge there is less consensus on the best way to solutions to address those shortcomings.

Throughout this process we listened to and heard the concerns that were raised with our proposal and made changes to address those concerns in a way that would maintain the overall objectives to establish a performance-based financial assurance mechanism. We truly appreciate the efforts that many of you have put forth to improve the proposal during this process and hope that you recognize how your involvement is reflected in the current proposed Market Rules and Financial Assurance Policy (FAP) that you will be voting on at the Participants Committee on March 3rd.

As presented over the course of these meetings, and further explained in the CPV memo of Jan 10, 2021 to the B&F and MC, this proposal attempts to address two significant shortcomings in the current FA design:

1. **Accountability:** There is no performance-based accountability in the current design.
   - The current FAP makes no distinction among projects that are meeting all their delivery obligations, verses those that are delayed but progressing, verses wholly failed developments during the entire 39-months from when a resource clears the auction leading up to their delivery obligation; and
2. **Market Incentive:** There is little incentive for resources to re-evaluate and act on their participation in subsequent FCAs based upon their performance, or lack thereof.
   - The current FAP includes no financial incentive for a wholly failed project to withdraw from participation in the market even as the likelihood of its success diminishes over time.

It is now abundantly clear what the fallout could be from the current deficient financial assurance rules for non-commercial capacity as ISO-NE engages in litigation at both FERC and the DC Circuit Court – withholding FCA 16 auction results, delaying the FCA 17 qualification process, and with possible spillover into further delays of FCA 18.

Status of Current Proposal:

The NEPOOL Participants are being requested to vote on the proposal in two parts: Market Rule 1 changes, and changes to the Financial Assurance Policy.

1. **Market Rule 1 Changes** are specific to better definition of a Critical Path Milestone (III.13.1.1.2.2.2) and the addition of a new critical milestone – Construction Notice to Proceed – that is implicit in the current rules. These are milestones that non-commercial resources are already required to achieve after obtaining a capacity obligation and ones in which the ISO currently monitors.[1] In addition, the proposal seeks to implement a shared allocation of forfeited financial assurance between buyers and sellers of capacity related to the newly proposed provisions.
   - We understand that an amendment may be proposed that will seek to maintain the status quo allocation for all forfeited FA.
     - If such an amendment is offered, CPV will not oppose it.

2. **Financial Assurance Policy Changes** propose new financial assurance requirements that apply only to non-commercial capacity resources that are not achieving their commitments for delivering capacity by their delivery obligation date.

   - *To be clear, the proposed rule changes* <u>*would not*</u> *impact non-commercial capacity resources that are fulfilling their delivery obligations consistent with the commitment it made in accepting a Capacity Supply Obligation.*

   Resources meeting their delivery obligation would see no change to their FA requirements from the current rules. These rule changes are designed to impact resources facing significant delay in their physical delivery obligation, and even more so for projects that are highly unlikely to advance to COD.
   - As such, the proposed rules are designed to provide incentive to a resource owner to make the critical decision of whether to continue within ISO-NE's forward capacity market or withdraw – *based upon financial incentives*. This is opposed to the current construct that effectively places ISO-NE in the delicate position of taking the administrative action of unilateral termination.

A Summary of the proposed FA provisions is provided below. Redline FAP changes are included in the materials:

- **Base Financial Assurance:** Applicable to all non-commercial capacity.
  Add an increment of financial assurance (one month of Net CONE) for all resources that have failed to achieve Substantial Site Construction prior to the third subsequent FCA.
  - Current FA rules require the posting of an increment of FA prior to the first and second subsequent FCAs, but not prior to the third subsequent FCA.
    - Had this rule been in effect for FCA16, the Killingly project would have been obligated to post FA to participate in the auction, most likely obviating the need for the extensive litigation and disruption currently in play.

- **Milestone Financial Assurance:** Resources not subject to Schedules 22 or 25 are exempt (aka: >20MW) from this provision.

[1] ISO-NE has confirmed that they believe these milestones should be better clarified but have not opined on the specific language proposed here.

Adding increasing step-ups in FA requirements for projects that fail to achieve either of two critical milestones[2] *AND* extend their COD beyond the start of Capacity Commitment Period in which they obtained the CSO as follows:

- Additional increment of FA prior to the first Subsequent FCA – only if resource has not achieved Financing/Start of Construction consistent with the approved milestone schedule *AND* has extended its COD.
- Total of three increments of FA prior to the second subsequent FCA – if not achieved Substantial Site Construction consistent with the approved milestone schedule *AND* has extended its COD.
- Total of six increments of FA prior to the third subsequent FCA – if not achieved Substantial Site Construction consistent with the approved milestone schedule *AND* has extended its COD.
    - These are total incremental – not additive. For example, the maximum Milestone FA for a project that fails to achieve Substantial Site Construction prior to the third subsequent FCA is six. Each increment of FA corresponds to one month of non-commercial capacity CSO priced at Net CONE.

Importantly, upon satisfaction of the requisite milestone, this incremental FA is returned to the project sponsor. Thus, this performance-based FA is designed to incent project sponsors to enter the auctions at the appropriate stage of development, but not to be punitive for projects that are under construction and on their way to deliver upon their physical capacity obligation.

- **Delay Financial Assurance:** Resources not subject to Schedules 22 or 25 are exempt (aka: >20MW) from this provision.
    - The current FA policy requires units that do not achieve COD at the start of the Capacity Delivery Period to increase their FA by one increment every six months, with the first increment a month after the start of the delivery period. This proposal shortens the interval of posting to every three months.
    - The performance-based component for this provision is the addition of a forfeiture provision applied to each increment after a reasonable grace period. Specifically, Delay FA would be collected quarterly after the fact and would be forfeited if the resource has not achieved COD 90 days later – effectively an initial seven-month grace period.
    - Like the new performance incentive of the Milestone FA, this new provision should better discipline new resources seeking to participate in an auction to consider the validity of their construction timeline.

Taken together, this financial assurance proposal will result in a more appropriate alignment between the goal of keeping barriers to entry into the forward capacity market low, the objective to ensure that projects participating in the auction are *real* and have a high probability of meeting their delivery commitments, and provide appropriate incentive for resource owners to balance their ongoing participation in the market with their own risk-based assessment of future commerciality.

Again, thank you for your efforts in helping to shape this proposal and your thoughtful consideration.

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[2] Critical milestones being Financing/Start of Construction and Substantial Site Construction…aka 20% construction spend.

TO: NEPOOL Participants & Stakeholders DATE: February 28, 2022

FROM: Joel Gordon, CPV Towantic LLC

RE: Amended Proposal – Performance Based Financial Assurance for Non-Commercial Capacity

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This memo is a follow-up to my earlier memo circulated on February 22, 2022 as part of the Supplemental Notice for the upcoming March 3 NEPOOL Participants Committee meeting.

That memo outlined the status of the current proposal for Performance Based Financial Assurance that had evolved over the several months of stakeholder engagement. At the top of page two, the memo explained the proposal with regard to the changes proposed in Market Rule 1 – specifically addressing better definition of an existing critical path milestone – Project Financing Closing, and the addition of a new milestone – Construction Notice to Proceed. The other component of Market Rule 1 changes are the provisions regarding the allocation of forfeited Financial Assurance found in Section III.13.1.9.2.3.

As we have been developing this proposal, one concern that we heard repeatedly and across various constituents was that the allocation of forfeited financial assurance different from the status quo was for some members preventing them from supporting what they believed was an otherwise sound proposal.

In the memo of Feb 22, we acknowledged a potential amendment to revert the proposal to the status quo allocation methodology and stated, "If such an amendment is offered, CPV will not oppose it."

Today I write to inform you that CPV will officially adopt this change for its proposal and will offer the Market Rule 1 changes without any changes to Section III.13.1.9.2.3. As such allocation of ALL forfeited FA will be handled consistent to the way it is today:

> **III.13.1.9.2.3. Forfeit of Financial Assurance.** Where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone.

Again, thank you for all the engagement and feedback provided to us during this process.

RENEW Northeast

PO Box 383
Madison, CT 06443
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To: NEPOOL Participants Committee Members and Alternates

From: Francis Pullaro, Executive Director, RENEW Northeast

Date: March 1, 2022 (Corrected March 2, 2022)

Subject: Concerns with the CPV Performance Based FA for Non-Commercial Capacity proposal

March 2 Update: We have corrected one mis-statement in the first section of this memo and have revised sections I, VI, and VII to reflect CPV's February 28th modification of the FAP redlines that we had not yet seen when this memo was prepared. These updates are redlined below for clarity, but they do not change the overarching concerns described in the memo.

RENEW Northeast appreciates CPV's efforts over many months to explore the incentives in the FCM for new resources to enter the market only once they have a reasonable level of confidence in project success and, after having secured an obligation, to exit the market voluntarily should the likelihood of success fade away. We agree with CPV's assessment that the current rules do not provide sufficiently targeted incentives to drive this desired behavior, and believe that this is something that should be addressed with a high level of priority. However, we do not believe that the specific proposal put forth by CPV for consideration is an appropriate solution. We believe it calls for excessive levels of Financial Assurance that would create an unnecessarily high burden for new entry, beyond what would be needed to incent the proper behavior. We also believe that there are a number of ways in which the Tariff language does not do what was described, is vague, and is likely unimplementable as written.

In its January 26th memo to the Participants Committee, the ISO expressed strong concerns about delays among new resources entering the capacity market.

> *ISO (January Memo): Furthermore, it is important to recognize the potential reliability risks arising due to delays in the development of the new resources. The challenges of building new infrastructure in the region are real, and it is now well-recognized that major new sponsored policy resources can encounter significant delays in their commercial development. When existing resources are displaced in the FCM by new sponsored resources, the existing resource retirements will occur by a date certain – but development delays in major new resources replacing them can create 'gaps' in the region's resource adequacy in the capacity commitment period.*

This risk of delay is in no way specific to sponsored policy resources; it is a risk faced by all non-commercial resources that enter the FCM. We believe this risk would be best mitigated by directly addressing the incentives for project sponsors to properly time their resource entry and voluntarily pull the plug on their failing projects. We would encourage ISO to take up this issue and examine alternatives to this proposal that would result in stronger incentives for the desired market behavior. We stand ready and willing to work with the ISO and stakeholders on developing such a proposal, but cannot support the specific proposal being presented to the Participants Committee today.

At the time that ISO is able to put this into its work plan, we believe that an appropriate and effective solution would address the following:

1. As with the CPV proposal, we believe there should be *some* amount of increase in the FA requirement prior to every single FCA that a non-commercial resource participates in. This is currently missing prior to the fourth FCA in which a resource clears.
2. The level of FA required should be a careful balance between what is needed to incent the desired behavior without creating an overly punitive barrier to entry for any resource type.
3. High financial barriers to entry disproportionately affect smaller developers without large balance sheets, while large incumbents are likely unphased by any monetary barrier. The level of FA required should be considered carefully so as not to unintentionally decrease market competition.
4. Any charges for delayed commercial operation should be called as such and should be put into Market Rule 1, just as the failure to cover charge is. The Financial Assurance Policy is not the right place in the Tariff to put such a charge.
5. Any charges for delayed commercial operation should consider the interaction with and cumulative effect of this new charge along with the existing failure to cover charge, Trading Financial Assurance, and the two-year grace period for reaching commercial operation. Consideration should also be given to whether the existing policy of paying FCA revenues to non-commercial capacity provides the proper incentives, and whether changes to this policy would obviate the need for some of these other charges or FA requirements.
6. The duration and nature of the grace period should be evaluated to consider the timeline required for the resource termination process to be completed prior to the FCA occurring.
7. Treatment of projects that proceed on-schedule, projects that are delayed but successful, and projects that are never built should be differentiated, with decreased requirements for the former and increased requirements for the latter.
8. FA requirements should decrease as a project proceeds through its critical path schedule, as CPV has attempted to do by tying some of its new FA amounts to milestones such as Substantial Site Construction. However, care should be given to ensure that the milestones selected are appropriate for and can be monitored and achieved by all resource types.
9. Any increase in Financial Assurance over today's requirements should, except in the case of demand resources, be tied to Commercial Operation as defined in Schedules 22, 23, and 25, not to FCM Commercial Operation. This is the case ~~for the Milestone and Delay FA~~ in the CPV proposal ~~but not the fourth Base FA amount added by CPV~~.

10. Reconsideration should be given to whether the existing Non-Commercial Capacity FA amounts should be tied to FCM Commercial Operation or Commercial Operation as defined in Schedules 22, 23, and 25 (or, alternatively, the FCM Commercial Operation audit for intermittent generators should be revised such that it is purely a test of the generator's capabilities and not an attempt to audit the weather forecast).

I. The total dollar amounts of newly-required FA can be unreasonably high in comparison to the value of FCM participation, creating an unnecessary barrier to entry

There are a number of numerical examples at the end of this memo that walk through various scenarios with delayed, but ultimately successful, wind, battery, and solar projects under the current and proposed rules had they been in effect for FCA 15. Under the current rules, the projects in these examples are required to post Non-Commercial Capacity Financial Assurance (NCC FA) equal to between 88% and 615% of their first year of base capacity revenues, and all of this FA is all returned when the resource achieves commercial operation. Under the proposed rules, the same projects would be required to post between 176% and ~~1,230~~967% of their first year of base capacity revenues in addition to paying a delay penalty of between 18% and 527% of their first year of base capacity revenues.

Requiring a project that is delayed but ultimately successful to provide collateral equivalent to more than 12 years of capacity revenue, and pay a penalty of over 5 years worth of capacity revenue is overly punitive. Proper incentives for the desired market actions must be weighed against creating barriers to entry, and this proposal falls heavily on the side of creating unnecessary barriers. The 20 MW exemption does not address this concern.

II. New Critical Path Schedule (CPS) milestone, Construction Notice to Proceed, is worded in a way that some projects may not meet this milestone until they have completed construction, if at all.

The described intent of the first increment of Milestone FA is that it would only apply to delayed projects that haven't achieved financing and begun construction (through the addition of a new Construction Notice to Proceed milestone). But since it may not be possible for many projects to meet the new milestone, the FAP changes (FAP Section VII.B.2.b) would assess the first increment of Milestone FA amounts on any such delayed project even if it has obtained financing and begun construction. The result is that many (most?) delayed projects would be assessed the Milestone FA amount even if they are progressing with their project construction.

> **Construction Notice to Proceed.** In the New Capacity Qualification Package, the Project Sponsor shall provide the date by which it will direct is prime contractor and any direct subcontractors to commence work on the site and the date by which the prime contractor and any direct subcontractors begin construction activity on the site, which

> directions will not be limited to less than all of the activities necessary to complete construction of the project.

First, the language is unclear. If this is an EPC contract, then the owner would only be providing notice to proceed to its EPC contractor and doesn't control timing of the EPC's NTPs to any of its subs. It's unclear what this language means by "any direct subcontractors" – are these direct subs to the EPC? If so, the owner has no control over the EPC's subs. If it means direct to owner that aren't the prime, then they aren't really subs they are just separate contracts.

Second, there may be certain scopes of work that are not authorized until much later in the process, so it is overly broad to require "not less than all of the activities to complete construction…" and this could cause serious issues. What does "complete construction" even mean? Does it include site remediation and permit closeout?

III. Who is exempted from Milestone and Delay FA?

FAP Section VII.B.2.b in the redlines says:

> Notwithstanding the foregoing, NCC Milestone FA shall equal zero for all Demand Capacity Resources and all New Capacity Resources less than 20 MW.

And then further down says:

> Notwithstanding the foregoing, NCC Delay FA shall equal zero for all Demand Capacity Resources and all Resources less than 20 MW.

At the MC it sounded like the intention was to have these FA provisions apply only to resources undergoing interconnection pursuant to Schedules 22 and 25, but that's not what this Tariff language says. The Tariff language specifies 20 MW as the threshold, but what does this 20 MW size refer to? Is it project nameplate? The Network Resource Interconnection Service quantity? FCA Qualified Capacity? These are all different and the Tariff language does not specify.

IV. There is no process by which ISO "approves" updated milestone schedules

The Milestone FA section (FAP Section VII.B.2.b) says:

> For purposes of determining whether a New Capacity Resource has achieved any of the milestones described in this paragraph by the date set forth in its **approved critical path schedule**, adjustments to that schedule **that have been approved by the ISO** will be taken into account, so long as the scheduled date for the New Capacity Resource's Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) does not extend beyond the start of the

Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

As we understand it, there is currently no process by which ISO "approves" a critical path schedule update submitted by a project sponsor. The ISO reviews the submittal and may reach out to the project sponsor with questions. If the ISO determines a CPS date is infeasible they may "deny" the submitted milestone date, but they cannot "override" the date and replace it with an alternate date. Even with this process, there is no defined timeline in which this process occurs after a project sponsor submits its updated Critical Path Schedule. In order for this piece of the proposal to work as intended, we believe a CPS approval process would need to be created, as it does not currently exist.

V. Return of FA language is unclear, inconsistent, and does not appear to do what was described to the committees

The fourth "base" FA increment is only required from projects that have not yet reached Substantial Site Construction (FAP Section VII.B.2.b). The Milestone FA Multiplier increases to three and then to six for projects that have not yet reached Substantial Site Construction by the applicable dates. The proposed language in the section on Return of Non-Commercial Capacity Financial Assurance (FAP Section VII.B.3) is not clear about when either of these FA amounts is released.

Subsection (1) says that any FA requirement that was due to a failure to demonstrate Substantial Site Construction will be reduced to zero 30 days after the date on which the project provides documentation that it has achieved Substantial Site Construction.

- It's unclear if this is referring to the fourth "base" FA increment or if it is also referring to the latter Milestone FA amounts, as each of these are related to substantial site construction not yet being achieved.
- It's unclear if ISO has to approve the project's documentation of achieving Substantial Site Construction or if just having submitted the documentation is sufficient.
- It's unclear when the project can submit this documentation. Can the project provide documentation that it has achieved Substantial Site Construction outside of the regularly-scheduled quarterly (or monthly for certain delayed projects) Critical Path Schedule updates? How would it do that?

Subsection (2) says that any Milestone FA requirement will be reduced to zero on the first day of the calendar month that is at least 30 days after the date on which the project provides documentation that it has achieved Substantial Site Construction.

- Similar questions to Subsection (1) above
- Why are the timelines for (1) and (2) different?

This appears to indicate that if a project were assessed the first Milestone FA amount because it hadn't achieved the financing and notice to proceed milestones yet, that it would not be able to have this amount released until it met Substantial Site Construction. So if a project were to miss the deadline for demonstrating its financing or notice to proceed by a day, it would not be able to have the associated FA released once it met these milestones, it would have to wait until it met the Substantial Site Construction milestone.

There does not appear to be any language that would allow the Delay FA Multiplier to be reduced to zero once the resource reaches COD or is terminated. The language in FAP Section VII.B.2.b that describes the multiplier indicates that it stops increasing once the resource reaches COD or is terminated, but nothing appears to indicate when it would be reduced to zero.

VI. The Delay FA provisions as written require far more FA to be provided than what was described to the committee

The most recent version of the Financial Assurance Policy redlines circulated to the Participants Committee on February 28th included a change to Section VII.B.2.b which address the concern raised in the previous version of this memo.

By setting the value of the NCC Delay FA equal to "NCC x NCCFA$ x Delay FA Multiplier **less any forfeited Delay FA**," the level of NCC Delay FA now matches the descriptions CPV has given in prior presentations.

~~The Delay FA Multiplier is set to one if the project hasn't reached COD within the first three months of the CCP for which it originally cleared in an FCA. The multiplier increases by one every three months thereafter until the project reaches COD or is terminated (FAP Section VII.B.2.b). But when the Delay FA is drawn down (FAP Section VII.D), the Multiplier is not adjusted to reflect this forfeiture.~~

~~Here is a schedule showing how the current Tariff language would work and why this is not as described:~~

~~June 1: CCP start~~

~~Sept 1: Delay FA Multiplier = 1~~

~~November 30: 90 days after first Delay FA increment was due → One increment of Delay FA is drawn down from the account. The Delay FA Multiplier remains 1, so the participant must post a second increment of Delay FA prior to Nov 30 in order to not be in default when its first increment is drawn down.~~

~~December 1: Delay FA Multiplier = 2, participant must post a third increment of Delay FA~~

~~March 1: Delay FA Multiplier = 3 and 90 days after second Delay FA increment was due → One increment of Delay FA is drawn down from the account. The Delay FA Multiplier is now 3, so the participant must post two additional increments of~~

~~Delay FA prior to Mar 1 in order to not be in default when its second increment is drawn down. The participant has now provided a total of five increments of Delay FA, two of which have been drawn down and three of which remain.~~

~~April 1:~~

~~Alternative 1: Project is terminated. ISO draws down the 3 remaining Delay FA increments. The project was terminated 10 months after the start of the CCP. Five increments of Delay FA would have been forfeited.~~

~~Alternative 2: Project reaches COD 10 months after the start of the CCP. There are no provisions for the Delay FA requirement to be eliminated. The project continues to have an FA requirement for three increments of Delay FA in perpetuity.~~

VII. Numerical examples for various (ultimately successful) projects with delayed CODs, had these rules been in effect for FCA 15

All examples assume:

- For wind: winter CSO = 2x summer CSO
- For batteries: winter CSO = summer CSO
- For solar: winter CSO = 0 MW
- project schedule is delayed within the first year after clearing in an FCA
- project cannot meet Construction Notice to Proceed milestone as proposed in Tariff
- substantial site construction reached 9 months before COD
- for solar and wind: project successfully audits at the first opportunity 30-days post-COD (very optimistic)
- for batteries: project successfully audits within days of COD
- all projects are over 20 MW and are not exempt from the new FA requirements
- ~~Delay FA Multiplier is implemented as written in Tariff language presented to B&F on 2/10/2022~~

FCA 15 Pricing:

- Net CONE: $8.707/kW-mo
- FCA clearing prices by zone:
    - ME, NNE: $2.477/kW-mo
    - RoP: 2.611/kW-mo
    - SENE: 3.980/kW-mo

Example 1: Onshore Wind Plant in ME reaches COD 6 months after start of CCP15

Expected base revenue from FCA 15, per kW cleared in FCA: $49.54

Date	**Event**	**Incremental FA**	**Cumulative FA**
11/2020	**FCM Deposit**	**$2**	**$2**
1/2021	**Base NCFA #1**	**$6.707**	**$8.707**
2/2021	**Clear in FCA 15**	**-**	**$8.707**
1/2022	**Base NCFA #2**	**$8.707**	**$17.414**
2/2022	**Clear in FCA 16**	**-**	**$17.414**
1/2023	**Base NCFA #3**	**$8.707**	**$26.121**
2/2023	**Clear in FCA 17**	**-**	**$26.121**
2/2024	**Clear in FCA 18**	**-**	**$26.121**
6/2024	**Start of CCP 15**	**-**	**$26.121**
7/2024	**Delay FA #1**	**$8.707**	**$34.828**
12/2024	**COD**	**-**	**$34.828**
1/2025	**Delay FA #2**	**$8.707**	**$43.535**
1/2025	**Successful FCM Commercial Operation Audit**	**-$43.535**	**$0**

Under the current rules, the FA at risk until the project is fully audited is approximately **88%** of the revenue expected from the FCM in the first year and **no** FA is forfeited.

CPV Proposal

Date	**Event**	**Incremental FA**	**Cumulative FA**	**Cumulative Forfeited FA**
11/2020	FCM Deposit	$2	$2	
1/2021	Base NCFA #1	$6.707	$8.707	
2/2021	Clear in FCA 15	-	$8.707	
1/2022	Base NCFA #2	$8.707	$17.414	
1/2022	Milestone FA #1	$8.707	$26.121	
2/2022	Clear in FCA 16	-	$26.121	
1/2023	Base NCFA #3	$8.707	$34.828	
1/2022	Milestone FA #2	$17.414	$52.242	
2/2023	Clear in FCA 17	-	$52.242	
1/2024	Base NCFA #4	$8.707	$60.949	
1/2024	Milestone FA #3	$26.121	$87.070	
2/2024	Clear in FCA 18	-	$87.070	
3/2024	Achieve Substantial Site Construction	-		

6/2024 (Timing Unclear)	Milestone and 4th Base NCFA Released	-$60.949	$26.121	
6/2024	Start of CCP 15	-	$26.121	
9/2024	Delay FA #1	$8.707	$34.828	
11/2024	Delay FA #1 Forfeited	-	$~~34.828~~26.121	$8.707
12/2024	Delay FA #2	$8.707	$~~43.535~~34.828	$8.707
12/2024	COD → Release of Delay FA #2	-$8.707~~0~~	$~~43.535~~26.121	$8.707
1/2025	Successful FCM Commercial Operation Audit → Release of Base NCFA #1, 2, 3	-$26.121	$~~17.414~~0	$8.707

Under the proposed rules, the FA at risk reaches a peak of approximately **176%** of the revenue expected from the FCM in the first year and FA is forfeited in an amount equivalent to **18%** of the 1st year FCM revenue.

Example 2: Battery in RoP reaches COD 6 months after start of CCP15

Expected base revenue from FCA 15, per kW cleared in FCA: $31.332

Date	**Event**	**Incremental FA**	**Cumulative FA**
11/2020	**FCM Deposit**	**$2**	**$2**
1/2021	**Base NCFA #1**	**$6.707**	**$8.707**
2/2021	**Clear in FCA 15**	**-**	**$8.707**
1/2022	**Base NCFA #2**	**$8.707**	**$17.414**
2/2022	**Clear in FCA 16**	**-**	**$17.414**
1/2023	**Base NCFA #3**	**$8.707**	**$26.121**
2/2023	**Clear in FCA 17**	**-**	**$26.121**
2/2024	**Clear in FCA 18**	**-**	**$26.121**
6/2024	**Start of CCP 15**	**-**	**$26.121**
7/2024	**Delay FA #1**	**$8.707**	**$34.828**
12/2024	**COD**	**-**	**$34.828**
12/2024	**Successful FCM Commercial Operation Audit**	**-$34.828**	**$0**

Under the current rules, the FA at risk until the project is fully audited is approximately **<u>111%</u>** of the revenue expected from the FCM in the first year and **<u>no</u>** FA is forfeited.

CPV Proposal

Date	**Event**	**Incremental FA**	**Cumulative FA**	**<u>Cumulative</u> Forfeited FA**
11/2020	FCM Deposit	$2	$2	
1/2021	Base NCFA #1	$6.707	$8.707	
2/2021	Clear in FCA 15	-	$8.707	
1/2022	Base NCFA #2	$8.707	$17.414	
1/2022	Milestone FA #1	$8.707	$26.121	
2/2022	Clear in FCA 16	-	$26.121	
1/2023	Base NCFA #3	$8.707	$34.828	
1/2022	Milestone FA #2	$17.414	$52.242	
2/2023	Clear in FCA 17	-	$52.242	
1/2024	Base NCFA #4	$8.707	$60.949	
1/2024	Milestone FA #3	$26.121	$87.070	
2/2024	Clear in FCA 18	-	$87.070	
3/2024	Achieve Substantial Site Construction	-		
6/2024 (Timing Unclear)	Milestone and 4th Base NCFA Released	-$60.949	$26.121	

6/2024	Start of CCP 15	-	$26.121	
9/2024	Delay FA #1	$8.707	$34.828	
11/2024	Delay FA #1 Forfeited	-	$~~34.828~~26.121	$8.707
12/2024	Delay FA #2	$8.707	$~~43.535~~34.828	$8.707
12/2024	COD → Release of Delay FA #2	-$8.707~~0~~	$~~43.535~~26.121	$8.707
12/2024	Successful FCM Commercial Operation Audit → Release of Base NCFA #1, 2, 3	-$26.121	$~~17.414~~0	$8.707

Under the proposed rules, the FA at risk reaches a peak of approximately **278%** of the revenue expected from the FCM in the first year and FA is forfeited in an amount equivalent to **28%** of the 1st year FCM revenue.

Example 3: Solar in NNE reaches COD 6 months after start of CCP15

Expected base revenue from FCA 15, per kW cleared in FCA: $9.908

Date	Event	Incremental FA	Cumulative FA
11/2020	**FCM Deposit**	**$2**	**$2**
1/2021	**Base NCFA #1**	**$6.707**	**$8.707**
2/2021	**Clear in FCA 15**	**-**	**$8.707**
1/2022	**Base NCFA #2**	**$8.707**	**$17.414**
2/2022	**Clear in FCA 16**	**-**	**$17.414**
1/2023	**Base NCFA #3**	**$8.707**	**$26.121**
2/2023	**Clear in FCA 17**	**-**	**$26.121**
2/2024	**Clear in FCA 18**	**-**	**$26.121**
6/2024	**Start of CCP 15**	**-**	**$26.121**
7/2024	**Delay FA #1**	**$8.707**	**$34.828**
12/2024	**COD**	**-**	**$34.828**
12/2024	**Successful FCM Commercial Operation Audit**	**-$34.828**	**$0**

Under the current rules, the FA at risk until the project is fully audited is approximately **352%** of the revenue expected from the FCM in the first year and **no** FA is forfeited.

CPV Proposal

Date	**Event**	**Incremental FA**	**Cumulative FA**	**Cumulative Forfeited FA**
11/2020	FCM Deposit	$2	$2	
1/2021	Base NCFA #1	$6.707	$8.707	
2/2021	Clear in FCA 15	-	$8.707	
1/2022	Base NCFA #2	$8.707	$17.414	
1/2022	Milestone FA #1	$8.707	$26.121	
2/2022	Clear in FCA 16	-	$26.121	
1/2023	Base NCFA #3	$8.707	$34.828	
1/2022	Milestone FA #2	$17.414	$52.242	
2/2023	Clear in FCA 17	-	$52.242	
1/2024	Base NCFA #4	$8.707	$60.949	
1/2024	Milestone FA #3	$26.121	$87.070	
2/2024	Clear in FCA 18	-	$87.070	
3/2024	Achieve Substantial Site Construction	-		

6/2024 (Timing Unclear)	Milestone and 4th Base NCFA Released	-$60.949	$26.121	
6/2024	Start of CCP 15	-	$26.121	
9/2024	Delay FA #1	$8.707	$34.828	
11/2024	Delay FA #1 Forfeited	-	$~~34.828~~26.121	$8.707
12/2024	Delay FA #2	$8.707	$~~43.535~~34.828	$8.707
12/2024	COD → Release of Delay FA #2	-$8.707~~0~~	$~~43.535~~26.121	$8.707
1/2025	Successful FCM Commercial Operation Audit → Release of Base NCFA #1, 2, 3	-$26.121	$~~17.414~~0	$8.707

Under the proposed rules, the FA at risk reaches a peak of approximately **879%** of the revenue expected from the FCM in the first year and FA is forfeited in an amount equivalent to **88%** of the 1st year FCM revenue.

Example 4: Solar in NNE reaches COD 22 months after start of CCP15

Expected base revenue from FCA 15, per kW cleared in FCA: $9.908

Date	**Event**	**Incremental FA**	**Cumulative FA**
11/2020	**FCM Deposit**	**$2**	**$2**
1/2021	**Base NCFA #1**	**$6.707**	**$8.707**
2/2021	**Clear in FCA 15**	**-**	**$8.707**
1/2022	**Base NCFA #2**	**$8.707**	**$17.414**
2/2022	**Clear in FCA 16**	**-**	**$17.414**
1/2023	**Base NCFA #3**	**$8.707**	**$26.121**
2/2023	**Clear in FCA 17**	**-**	**$26.121**
2/2024	**Clear in FCA 18**	**-**	**$26.121**
6/2024	**Start of CCP 15**	**-**	**$26.121**
7/2024	**Delay FA #1**	**$8.707**	**$34.828**
1/2025	**Delay FA #2**	**$8.707**	**$43.535**
7/2025	**Delay FA #3**	**$8.707**	**$52.242**
1/2026	**Delay FA #4**	**$8.707**	**$60.949**
4/2026	**COD**	**-**	**$60.949**
5/2026	**Successful FCM Commercial Operation Audit**	**-$60.949**	**$0**

Under the current rules, the FA at risk until the project is fully audited is approximately **615%** of the revenue expected from the FCM in the first year and **no** FA is forfeited.

CPV Proposal

Date	**Event**	**Incremental FA**	**Cumulative FA**	**Cumulative Forfeited FA**
11/2020	FCM Deposit	$2	$2	
1/2021	Base NCFA #1	$6.707	$8.707	
2/2021	Clear in FCA 15	-	$8.707	
1/2022	Base NCFA #2	$8.707	$17.414	
1/2022	Milestone FA #1	$8.707	$26.121	
2/2022	Clear in FCA 16	-	$26.121	
1/2023	Base NCFA #3	$8.707	$34.828	
1/2022	Milestone FA #2	$17.414	$52.242	
2/2023	Clear in FCA 17	-	$52.242	
1/2024	Base NCFA #4	$8.707	$60.949	
1/2024	Milestone FA #3	$26.121	$87.070	
2/2024	Clear in FCA 18	-	$87.070	
6/2024	Start of CCP 15	-	$87.070	
9/2024	Delay FA #1	$8.707	$95.777	

11/2024	Delay FA #1 Forfeited	-	$~~95.777~~87.070	$8.707
12/2024	Delay FA #2	$8.707	$~~104.484~~95.777	$8.707
3/2025	Delay FA #2 Forfeited	-	$~~104.484~~87.070	$17.414
3/2025	Delay FA #3	$8.707	$~~113.191~~95.777	$17.414
5/2025	Delay FA #3 Forfeited	-	$~~113.191~~87.070	$26.121
6/2025	Delay FA #4	$8.707	$~~121.898~~95.777	$26.121
7/2025	Achieve Substantial Site Construction	-	~~$121.898~~95.777	$26.121
8/2028	Delay FA #4 Forfeited	-	$~~121.898~~87.070	$34.828
9/2025 (Timing Unclear)	Milestone and 4th Base NCFA Released	-$60.949	$~~60.949~~26.121	$34.828
9/2025	Delay FA #5	$8.707	$~~69.656~~34.828	$34.828
11/2025	Delay FA #5 Forfeited	-	$~~69.656~~26.121	$43.535
12/2025	Delay FA #6	$8.707	$~~78.363~~34.828	$43.535
3/2026	Delay FA #6 Forfeited	-	$~~78.363~~26.121	$52.242
3/2026	Delay FA #7	$8.707	$~~87.070~~34.828	$52.242
4/2026	COD → Release of Delay FA #7	-$8.707	$~~87.070~~26.121	$52.242
5/2026	Successful FCM Commercial Operation Audit → Release of Base NCFA #1, 2, 3	-$26.121	$~~60.949~~0	$52.242

Under the proposed rules, the FA at risk reaches a peak of approximately **~~1,230~~967%** of the revenue expected from the FCM in the first year and FA is forfeited in an amount equivalent to **527%** of the 1st year FCM revenue.

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M E M O R A N D U M

TO: NEPOOL Participants Committee

FROM: David Doot and Sebastian Lombardi, NEPOOL Counsel

DATE: February 24, 2022

RE: Input on the ISO's February 15 Exigent Circumstances Filing

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You will have the opportunity at the March 3 meeting to consider and provide input on what position, if any, NEPOOL should provide in response to the ISO's February 15 Exigent Circumstances filing. The ISO's Exigent Circumstances filing seeks FERC approval of revisions to Market Rule 1, Section III.13 that provide the ISO the latitude to adjust any of the Schedule Dates[1] for the seventeenth Forward Capacity Auction (FCA 17). The ISO explained that the revisions are needed because it cannot begin or conduct FCM activities for FCA 17 until such time as it can determine the final results for FCA 16, a determination that has been delayed by the litigation-related uncertainty around the Killingly Energy Center's status for FCA 16. Delay in announcing FCA 16 results causes delays in meeting early FCA 17 Schedule Dates that then also cascade into delays of other FCA 17 Schedule Dates. Because the concern with the FCA 17 Schedule Dates was immediate, the ISO filed its Tariff changes ahead of presenting them to stakeholders, citing its authority in Section 11.2 of the Participants Agreement to file changes in Exigent Circumstances before full consultation with NEPOOL.[2] A copy of the ISO's filing is included with this memorandum and the ISO has been asked to discuss more fully at the March 3 meeting its plans for establishing a revised FCA 17 schedule.

Guided by past experience with Exigent Circumstances filings, the key issues for consideration on March 3 are the following:

(1) Do members agree that the circumstances presented justify the Exigent Circumstances filing?
(2) If there is agreement that an Exigent Circumstances filing was justified, do members support the changes the ISO has proposed without revisions, condition or further understandings?
(3) If revisions, conditions or further understandings are desired, what would those be?

In response to past Exigent Circumstances filings, members have been provided an opportunity to discuss the circumstances giving rise to those filings, particularly to ensure that

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[1] As used in this memo and the Exigent Circumstances Filing, "**Schedule Dates**" means any FCA 17 dates, date ranges and/or deadlines included in the Market Rules, the Financial Assurance Policy, and/or Planning Procedures ("PP") (e.g. PP-10 (Planning Procedure to Support the Forward Capacity Market)). Timelines in the Tariff that are not specifically related to FCA 17 activities are not affected.

[2] **"Exigent Circumstances"** are defined in the Section 1 of the Participants Agreement to be circumstances where the ISO determines in good faith "that (i) failure to immediately implement a new Market Rule, Operating Procedure, Reliability Standard, provision of the Information Policy, Non-TO OATT Provision or Manual would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the New England Markets, and (ii) invoking the procedures set forth in Section 11.1, 11.3 or 11.4 would not allow for timely redress of ISO's concerns."

such filings occur only in the most exceptional circumstances, and that the benefits of a meaningful and deliberate stakeholder process are preserved. While the Committee can, but has not always chosen, to act on Tariff changes proposed in the Exigent Circumstances filing, the discussion of the changes has consistently been reflected in NEPOOL-submitted comments before the FERC. Based on the feedback we receive from the Participants Committee on March 3, we will be prepared to file NEPOOL's response to the February 15 filing in time to meet the March 8 deadline established by the FERC for interventions, comments and protests.

In past instances, the Committee has decided not to act formally on ISO-proposed changes filed under Exigent Circumstances, but that option is available if the Committee wishes to do so. If formal Committee action is desired, the following form of resolution, which can be adjusted as needed, could be used:

> RESOLVED that the Participants Committee supports the Exigent Circumstances filing submitted to the FERC on February 15, 2022 by the ISO[, subject to the following clarifications, changes and/or understandings/conditions: [list]].

If any of you wish to press for specific clarifications or changes to the ISO-proposed section III.13 changes, or conditions to NEPOOL's support of those changes, it would be extremely useful if you would identify those to NEPOOL counsel before close of business on Tuesday, March 1, so that additional information can be shared with members to consider in advance of the meeting. Please contact us with your questions, suggestions or comments.

February 15, 2022

VIA E-TARIFF FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ISO New England Inc., Docket No. ER22-___-000;
Exigent Circumstances Filing of Revisions to Section III.13 of the Tariff

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO") hereby electronically submits this transmittal letter and related materials to add language in Section III.13 of the ISO New England Transmission, Markets, and Services Tariff ("Tariff") to specify that provisions of the Tariff and/or other ISO New England Operating Documents[2] which establish or prescribe any dates, date ranges, and/or deadlines (collectively "FCA Schedule Dates") shall not apply for Forward Capacity Auction ("FCA") 17. Under the proposed Tariff revisions, the ISO will be required to publish the FCA Schedule Dates for FCA 17, and any revisions thereto, as soon as practicable. The proposed Tariff revisions also require the ISO to provide reasonable advance notice of each FCA Schedule Date. As explained below, these changes are necessary to recognize the uncertainty created by the February 4, 2022 order of the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") regarding the status of Killingly Energy Center ("Killingly").[3]

The ISO is submitting these proposed revisions to the Tariff as an "Exigent Circumstances" filing under Section 11.2 of the Participants Agreement, for the reasons set forth in Section IV below. The ISO respectfully requests that these revisions become

[1] 16 U.S.C. § 824d (2021).

[2] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the Tariff.

[3] *In re NTE Connecticut, LLC*, No. 22-1011 (D.C. Cir. Feb. 4, 2022) (order granting petition for writ of mandamus and staying Commission order).

effective on February 16, 2022. The ISO requests a waiver of the 60-day notice requirement, a shortened comment period and expedited order.[4]

I. DESCRIPTION OF THE ISO; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO plans and operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

Correspondence and communications in this proceeding should be addressed to:

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II. STANDARD OF REVIEW

This filing is made pursuant to Section 205 of the FPA, which "gives a utility the right to file rates and terms for services rendered with its assets."[5] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[6] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[7] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable -- and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[8] The Tariff modifications herein "need not be the only reasonable methodology, or even the

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[4] During the time this exigent circumstances filing is pending at the Commission, the ISO will be out of compliance with FCA Schedule Dates for FCA 17. The ISO will submit self-reports to the Federal Energy Regulatory Commission's ("FERC" or "Commission") Office of Enforcement to keep it informed of any non-compliance with the Tariff.

[5] *Atlantic City Elec. Co. v. FERC,* 295 F.3d 1, 9 (D.C. Cir. 2002).

[6] *Id.* at 10 (quoting *City of Winnfield v. FERC,* 744 F.2d 871, 876 (D.C. Cir. 1984).

[7] *Id.* at 9.

[8] *Cities of Bethany, et al. v. FERC,* 727 F.2d 1131, 1136 (D.C. Cir. 1984).

most accurate."[9] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept the ISO's Section 205 filing if it is just and reasonable.[10]

III. BACKGROUND

On November 4, 2021, the ISO submitted a filing in Docket No. ER22-355-000 to request that the Commission terminate the Capacity Supply Obligation ("CSO") that NTE Connecticut LLC ("NTE") had previously obtained for Killingly. On January 3, 2022, effective the following day, the Commission issued an order accepting the ISO's request to terminate Killingly's CSO, beginning with the 2022-2023 Capacity Commitment Period and including future Capacity Commitment Periods ("Termination Order").

On January 10, 2022, NTE submitted a Motion for Stay and Rehearing Request to the Commission. The Commission denied NTE's Motion for Stay on January 28, 2022. NTE subsequently filed a petition with the D.C. Circuit seeking a stay of the Commission's Termination Order to permit Killingly to participate in FCA 16 on February 7, 2022. By order issued on February 4, 2022, the D.C. Circuit stayed the Termination Order until 30 days after the Commission resolves NTE's pending Request for Rehearing of the Termination Order.[11]

In accordance with the D.C. Circuit's order, the ISO included Killingly in FCA 16 as an existing resource. Because of the continuing uncertainty regarding Killingly's status, the ISO provided notice to Market Participants on February 4 and 6, 2022 that it would include Killingly in the auction, would calculate clearing prices and quantities with and without Killingly, and would refrain from announcing the auction's results until Killingly's status has been clarified. As things currently stand, the D.C. Circuit's stay will likely delay the Tariff-required filing of auction results with the Commission until mid-March or later.

Until Killingly's status is clarified, the ISO cannot establish which set of FCA 16 results to use in the Forward Capacity Market ("FCM") activities related to FCA 17. For example, the ISO needs FCA 16 results in order to conduct qualification calculations and determinations for FCA 17, and Market Participants have to comply with the qualification requirements for FCA 17 based on those determinations. Until the FCA 16

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[9] *Oxy USA, Inc. v. FERC,* 64 F.3d 679, 692 (D.C. Cir. 1995).

[10] *Cf. Southern California Edison Co., et al.,* 73 FERC ¶ 61,219 at p. 61,608 n.73 (1995) ("Having found the plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (citing *Cities of Bethany,* 727 F.2d at 1136)).

[11] *See supra* note 3. While the Commission issued a Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration on February 11, 2022, the Commission has not yet resolved NTE's pending Rehearing Request.

results are finalized, the ISO will not be able to conduct these activities for FCA 17.[12] Accordingly, the ISO seeks to delay the FCM activities for FCA 17. While similar changes may be required to delay FCM activities for FCA 18, as explained below, the instant filing does not seek to modify the timing of FCA 18 activities.

IV. DESCRIPTION OF EXIGENT CIRCUMSTANCES

As already noted, the ISO is submitting these proposed Tariff revisions as an "Exigent Circumstances" filing under Section 11.2 of the Participants Agreement. Section 11.2 states:

> Exigent Circumstances. In Exigent Circumstances, ISO may unilaterally, upon written notice to the Participants Committee and Individual Participants, file with the Commission pursuant to Section 205, if necessary, and implement a new or amended Market Rule, Operating Procedure, Manual, Reliability Standard, provision of the Information Policy (subject to 11.3), General Tariff Provision, or Non-TO OATT Provision.

"Exigent Circumstances" are defined in the Participants Agreement as circumstances such that the ISO determines in good faith that failure to immediately implement a change would substantially and adversely affect either system reliability or security or the competitiveness or efficiency of the New England Markets, and that invoking the normal stakeholder review procedures set forth in Section 11.1, 11.3 or 11.4 of the Participants Agreement would not allow for timely redress of the ISO's concerns.

Exigent Circumstances are presented here, and the ISO has made the good faith determinations required in Section 11.2 of the Participants Agreement. Prompt implementation of the revisions to the Tariff is necessary to address the lack of finalized FCA 16 results. Failure to implement these changes would substantially and adversely affect the efficiency of the FCM, and would create additional uncertainty.

The ISO has provided written notice of this filing to the New England Power Pool Participants Committee and Individual Participants, as required by Sections 11.2 and 17.11(e) of the Participants Agreement.

V. DESCRIPTION OF, AND JUSTIFICATION FOR, THE TARIFF REVISIONS

The proposed Tariff revisions affect only Section III.13 of the Tariff. Specifically, the ISO proposes to add the following text in Section III.13:

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[12] Concurrent with this filing, the ISO is also submitting to the Commission a request for waiver of Tariff provisions that require the publication of certain data related to FCA 16 by no later than 15 days after the auction.

> For the seventeenth Forward Capacity Auction (associated with the 2026-2027 Capacity Commitment Period), any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Inc. Transmission, Markets, and Services Tariff and all other ISO New England Operating Documents shall not apply. For the seventeenth Forward Capacity Auction, the ISO shall publish each date, date range, and/or deadline for Forward Capacity Auction activities as soon as practicable. The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities if needed and shall publish a revised date, date range and/or deadline as soon as practicable. The ISO shall establish and, as applicable, adjust, such published dates, date ranges and/or deadlines to provide reasonable advance notice of each date, date range, and/or deadline.

It is important to note that the proposed language applies to FCA Schedule Dates included in any part of the Tariff and/or other ISO New England Operating Documents. For example, the language applies to any FCA Schedule Dates included in the ISO New England Financial Assurance Policy and ISO New England Planning Procedure No. 10 – Planning Procedure to Support the Forward Capacity Market. Equally important, the proposed Tariff revisions do not affect other timelines in the Tariff that are not specifically related to FCA activities (*e.g.*, the Interconnection Procedure timelines, including but not limited to, the three-year time-out provisions for CNR Interconnection Service, and the three-year automatic retirement for non-operation established in Section III.13.2.5.2.5 of the Tariff).

As explained above, the revisions are needed because, without final FCA 16 results, the ISO cannot conduct the FCM activities for FCA 17 that, pursuant to the Tariff, must occur in short order following FCA 16. For instance, on February 17, 2022 the ISO has to provide Market Participants with Existing Capacity Resources with the existing Qualified Capacity values for their resources. The definitive calculation of those Qualified Capacity values cannot be made for all resources without final FCA 16 results. Once the ISO moves one FCA Schedule Date, it needs to move subsequent FCA Schedule Dates in the FCA qualification process.

The ISO considered proceeding with FCA 17 qualification activities using two sets of FCA 16 results (*i.e.,* clearing prices and quantities with and without Killingly). However, the ISO identified significant impediments to this approach. The ISO's systems and processes are built with the expectation of a single final set of results from the FCA, and cannot handle multiple sets of results. Proceeding with two sets of FCA 16 results poses an extraordinary risk to all the downstream activities. For example, before the ISO can initiate FCA 17 activities, FCM implementation requires population of FCA 16 results for all resources that cleared in FCA 16 in the ISO's capacity tracking system (this includes clearing prices and megawatt quantities, which are visible to Market Participants for their resources). It would be inappropriate to populate the ISO's capacity tracking with a set of FCA 16 results that is not final. Also, the ISO's capacity tracking system cannot support proceeding into FCA 17 resource qualification with two concurrent sets of results, and, consequently, using more than one set of FCA 16 results would require either the provisional qualification or late qualification of some resources. In addition, processing two sets of results would allow some resources to know the extent to which they were marginal to clearing in FCA 16. Moreover, in response to the qualification determinations that the ISO issues, some Market Participants are required to take certain actions, within specific timelines. Without knowing the auction clearing prices, or if their resources actually cleared (an outcome that could be different in each of the two sets of FCA 16 results), Market Participants would have no firm basis on which to take those actions. For these reasons, the ISO determined that the appropriate approach is to delay the beginning of FCA 17 activities until there is certainty on the FCA 16 results. Such delay requires adjusting the schedule for FCA 17 activities.

Given that the need to move the deadlines arose last week and the FCM activities for FCA 17 start this week, the ISO has not had sufficient time to consider the timing for all deadlines. Moreover, because the ISO still does not know when FCA 16 results will be finalized, it cannot accurately determine the length of the delay. For those reasons, the proposed Tariff revisions are drafted to provide the ISO with the time it needs to fully conduct its analysis. Once the ISO determines each FCA Schedule Date, it will publish it with as much lead-time as possible so that all parties can comply with each FCA Schedule Date. In addition, the Tariff revisions proposed here will give the ISO the flexibility it needs, should further events (such as additional court actions) again require the ISO to move FCA Schedule Dates.

Based on the analysis that the ISO has conducted to date, the ISO envisions that the qualification activities for FCA 17 will begin in April 2022, and FCA 17 will occur in March 2023, approximately one month later than its usual timing. This schedule will require the ISO to compress the approximately one year FCA qualification cycle to eleven months prior to FCA 17. To compress the FCA qualification process, the ISO will seek to minimize disruptions to the currently established order and relative timing of the FCA qualification process events in order to maximize the familiarity and certainty of the process for affected parties, which include Market Participants, the Commission, and all affected business units at the ISO.

The proposed Tariff revisions submitted in the instant filing address FCA 17. The compressed schedule for FCA 17, however, will also require the ISO to similarly compress the schedule for FCA 18. As the changes for FCA 18 do not create exigent circumstances, the ISO will discuss the schedules with stakeholders and will submit a filing to the Commission at a later time.

VI. REQUESTED EFFECTIVE DATE, REQUESTS FOR WAIVER OF 60-DAY PRIOR NOTICE REQUIREMENT, SHORTENED COMMENT PERIOD, AND EXPEDITED COMMISSION ACTION

The ISO respectfully requests that the Commission permit the Tariff revisions submitted herein to become effective on February 16, 2022, without condition, suspension or hearing. Accordingly, the ISO requests waiver of the 60-day prior notice requirement of Section 205 of the Federal Power Act. Such a waiver will serve the public interest because the Tariff revisions proposed in this filing will enable the ISO to begin pursuing FCA 17 activities in an orderly and deliberate manner, and will remove some of the uncertainty regarding FCA 17 that now exists because of the delay in finalization of the FCA 16 results.

The ISO also requests that the Commission either waive, or shorten to the maximum extent possible, the notice and comment periods for this filing, so that the Commission may issue an order as expeditiously as possible.

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the revisions submitted herein do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations. Notwithstanding its request for waiver, the ISO submits the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

35.13(b)(1) – Materials included herewith are as follows:

- This transmittal letter;
- Blacklined Tariff section reflecting the revisions submitted in this filing;
- Clean Tariff section reflecting the revisions submitted in this filing;
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – The ISO respectfully requests that the Commission issue an order accepting the Tariff revisions to become effective on February 16, 2022.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www/committees/directory/default/committee.action?committeeId=1. A copy of this transmittal letter and the accompanying materials have also been sent electronically to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, to the New England Conference of Public Utility Commissioners, and to the Executive Director of the New England States Committee on Electricity. In accordance with Commission rules and practice, there is no need for the Governance Participants or the other entities described above to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in this transmittal letter. Clean and redlined copies of the revised Tariff sheets are included with this eTariff filing.

35.13(b)(5) - The reasons for this filing are discussed in this transmittal letter.

35.13(b)(6) – The ISO's approval of the Tariff revisions is evidenced by this filing.

35.13(b)(7) – The ISO has no knowledge of any relevant expenses or costs-of-service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(1) - The Tariff revisions filed herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) – The ISO does not provide services under other rate schedules that are similar to the sale for resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the revisions proposed herein.

VIII. CONCLUSION

For the reasons stated herein, the ISO respectfully requests that the Commission accept the Tariff revisions submitted in this filing without condition, modification or hearing, to become effective on February 16, 2022.

Respectfully submitted,

/s/ Margoth R. Caley
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Counsel for ISO New England Inc.

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

For the seventeenth Forward Capacity Auction (associated with the 2026-2027 Capacity Commitment Period), any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Inc. Transmission, Markets, and Services Tariff and all other ISO New England Operating Documents shall not apply. For the seventeenth Forward Capacity Auction, the ISO shall publish each date, date range, and/or deadline for Forward Capacity Auction activities as soon as practicable. The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities if needed and shall publish a revised date, date range and/or deadline as soon as practicable. The ISO shall establish and, as applicable, adjust, such published dates, date ranges and/or deadlines to provide reasonable advance notice of each date, date range, and/or deadline.

Special Retirement De-List Bid, Permanent De-List Bid and Substitution Auction Demand Bid Modification and Withdrawal Provisions for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the Internal Market Monitor will modify any submitted Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices (whether or not associated with a Retirement De-List Bid) submitted for the sixteenth Forward Capacity Auction to reflect the impact of updated CONE, Net CONE and Capacity Performance Payment Rate values accepted by the Commission in Docket No. ER21-787.

The Internal Market Monitor will provide Lead Market Participants with updated Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices in the retirement determination notifications that it issues on June 3, 2021. Within 5 Business Days of the issuance of the retirement determination notifications, a Lead Market Participant may withdraw its Retirement De-List Bid, Permanent De-List Bid, or substitution auction demand bid, and the attendant substitution auction test price, by written notification to the Internal Market Monitor. The election to withdraw a Retirement De-List Bid will also withdraw the associated substitution auction demand bid.

Special Dynamic De-List Threshold and Certain Information Publications for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the ISO will recalculate and re-post the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.1.A to reflect the impact of updated CONE and Net CONE values accepted by the Commission for use in the sixteenth Forward Capacity Auction in Docket No. ER21-787.

In addition, the ISO will, on or before June 11, 2021, repost information concerning Permanent De-List Bids and Retirement De-List Bids pursuant to Section III.13.1.8(e) and will repost information about the aggregate quantity of supply offers and demand bids that have elected to participate in the substitution auction pursuant to Section III.13.1.8(g).

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

For the seventeenth Forward Capacity Auction (associated with the 2026-2027 Capacity Commitment Period), any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Inc. Transmission, Markets, and Services Tariff and all other ISO New England Operating Documents shall not apply. For the seventeenth Forward Capacity Auction, the ISO shall publish each date, date range, and/or deadline for Forward Capacity Auction activities as soon as practicable. The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities if needed and shall publish a revised date, date range and/or deadline as soon as practicable. The ISO shall establish and, as applicable, adjust, such published dates, date ranges and/or deadlines to provide reasonable advance notice of each date, date range, and/or deadline.

Special Retirement De-List Bid, Permanent De-List Bid and Substitution Auction Demand Bid Modification and Withdrawal Provisions for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the Internal Market Monitor will modify any submitted Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices (whether or not associated with a Retirement De-List Bid) submitted for the sixteenth Forward Capacity Auction to reflect the impact of updated CONE, Net CONE and Capacity Performance Payment Rate values accepted by the Commission in Docket No. ER21-787.

The Internal Market Monitor will provide Lead Market Participants with updated Permanent De-List Bids, Retirement De-List Bids and substitution auction test prices in the retirement determination notifications that it issues on June 3, 2021. Within 5 Business Days of the issuance of the retirement determination notifications, a Lead Market Participant may withdraw its Retirement De-List Bid, Permanent De-List Bid, or substitution auction demand bid, and the attendant substitution auction test price, by written notification to the Internal Market Monitor. The election to withdraw a Retirement De-List Bid will also withdraw the associated substitution auction demand bid.

Special Dynamic De-List Threshold and Certain Information Publications for the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025). For the sixteenth Forward Capacity Auction (associated with the Capacity Commitment Period beginning on June 1, 2025), on or before June 3, 2021, the ISO will recalculate and re-post the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.1.A to reflect the impact of updated CONE and Net CONE values accepted by the Commission for use in the sixteenth Forward Capacity Auction in Docket No. ER21-787.

In addition, the ISO will, on or before June 11, 2021, repost information concerning Permanent De-List Bids and Retirement De-List Bids pursuant to Section III.13.1.8(e) and will repost information about the aggregate quantity of supply offers and demand bids that have elected to participate in the substitution auction pursuant to Section III.13.1.8(g).

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FERC rendition of the electronically filed tariff records in Docket No. ER22-01053-000
Filing Data:
CID: C000029
Filing Title: ISO-NE; Exigent Circumstances Filing of Revisions to Section III.13
Company Filing Identifier: 898
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: ISO New England Inc. Transmission, Markets and Services Tariff
Tariff ID: 1
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
III.13, III.13 Forward Capacity Market, 4.0.0, A
Record Narative Name: III.13 - Forward Capacity Market
Tariff Record ID: 141
Tariff Record Collation Value: 806019324 Tariff Record Parent Identifier: 127
Proposed Date: 2022-02-16
Priority Order: 50
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

For the seventeenth Forward Capacity Auction (associated with the 2026-2027 Capacity Commitment Period), any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Inc. Transmission, Markets, and Services Tariff and all other ISO New England Operating Documents shall not apply. For the seventeenth Forward Capacity Auction, the ISO shall publish each date, date range, and/or deadline for Forward Capacity Auction activities as soon as practicable. The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities if needed and shall publish a revised date, date range and/or deadline as soon as practicable. The ISO shall establish and, as applicable, adjust, such published dates, date ranges and/or deadlines to provide reasonable advance notice of each date, date range, and/or deadline.

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ISO new england

Discussion on FCA 17 Schedule Modifications

Alex Rost

MANAGER – RESOURCE QUALIFICATION

Background

- On January 3, 2022, the Federal Energy Regulatory Commission (FERC) issued an order accepting the ISO's request to terminate Killingly Energy Center's (Killingly) Capacity Supply Obligation, effective the following day
- On February 4, 2022, the D.C. Circuit Court of Appeals stayed FERC's order until 30 days after FERC resolves NTE Connecticut LLC's request for rehearing*
  - Due to the resulting uncertainty regarding Killingly's status, the ISO provided notice to Market Participants on February 4 and 6, 2022, that it would include Killingly in FCA 16, calculate FCA 16 clearing prices and quantities with and without Killingly, and refrain from announcing FCA 16 results until Killingly's status has been clarified
- Until Killingly's status was clarified, the ISO could not establish which set of FCA 16 results to use for FCA 17 activities

*On February 23, FERC issued an order denying rehearing on Killingly's termination, and, on March 2, 2022, the D.C. Circuit Court of Appeals lifted its stay of the FERC order

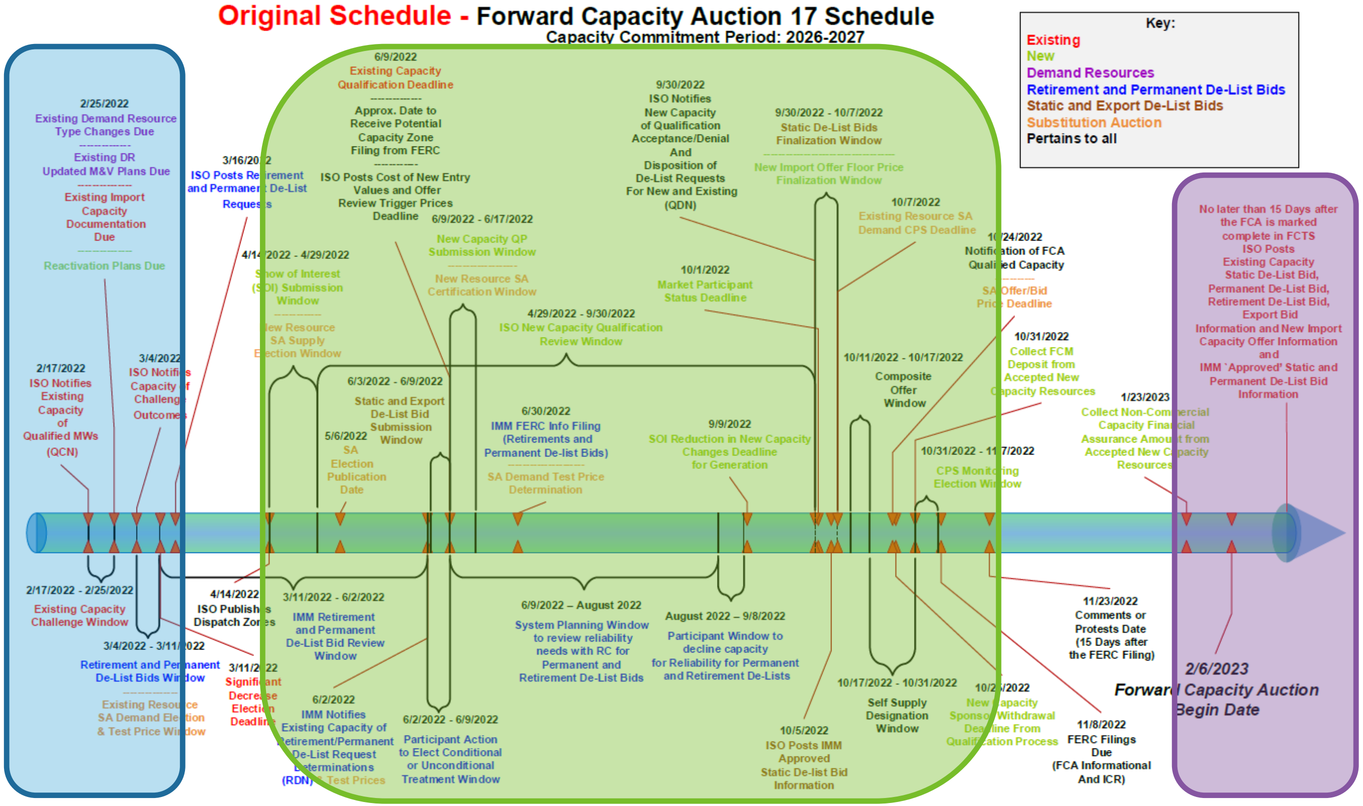
Background, cont.

- On February 15, 2022, the ISO submitted revisions to Section III.13 of the Tariff to FERC pursuant to Section 205 of the Federal Power Act and the "Exigent Circumstances" provisions of the Participants Agreement to add language to allow the ISO to move the dates, date ranges and/or deadlines for FCA 17 activities
  - The situation that gave rise to the need to add this language in the Tariff is unprecedented and, accordingly, the proposed Tariff language provides the ISO with the flexibility it needs under these circumstances

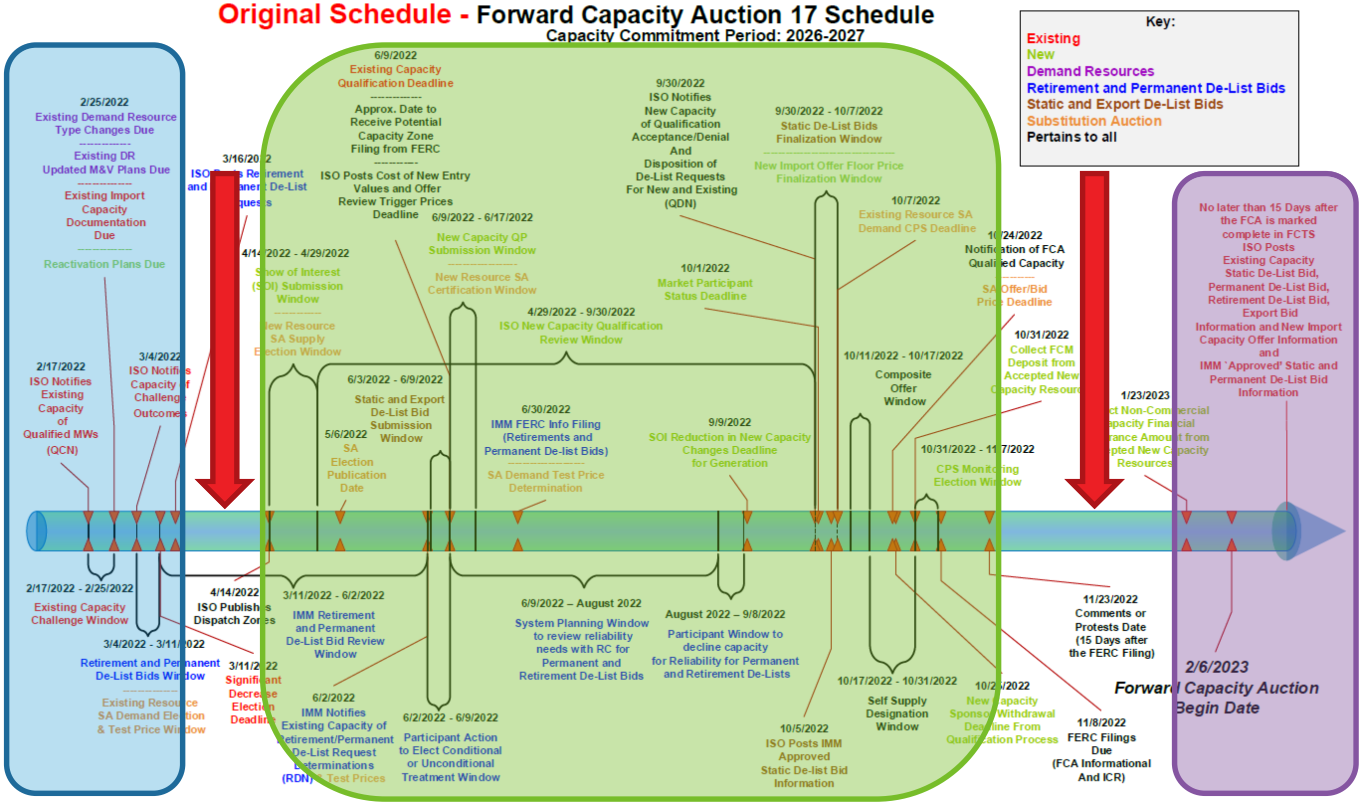
Proposed Approach for Modifying the FCA 17 Schedule

- The ISO seeks to minimize disruptions to the currently established order and relative timing of the FCA qualification process activities in order to maximize the familiarity and certainty of the process for affected parties, which include Market Participants, the Commission, and all affected business units at the ISO
  - In modifying the FCA 17 schedule, the ISO will refrain as much as possible from
    - Compressing “clustered” activities where the ISO and Market Participants are responding to determinations and submittals
    - Reducing Market Participants’ response times to ISO determinations
- The ISO will publish the final FCA 17 schedule (i.e. dates, date ranges and/or deadlines) at least one week before the first FCA 17 events begin
  - If possible, the ISO will publish the final FCA 17 schedule sooner to provide as much lead time as possible
  - The ISO and Market Participants will need to meet all published dates, date ranges, and/or deadlines for the purposes of participating in FCA 17

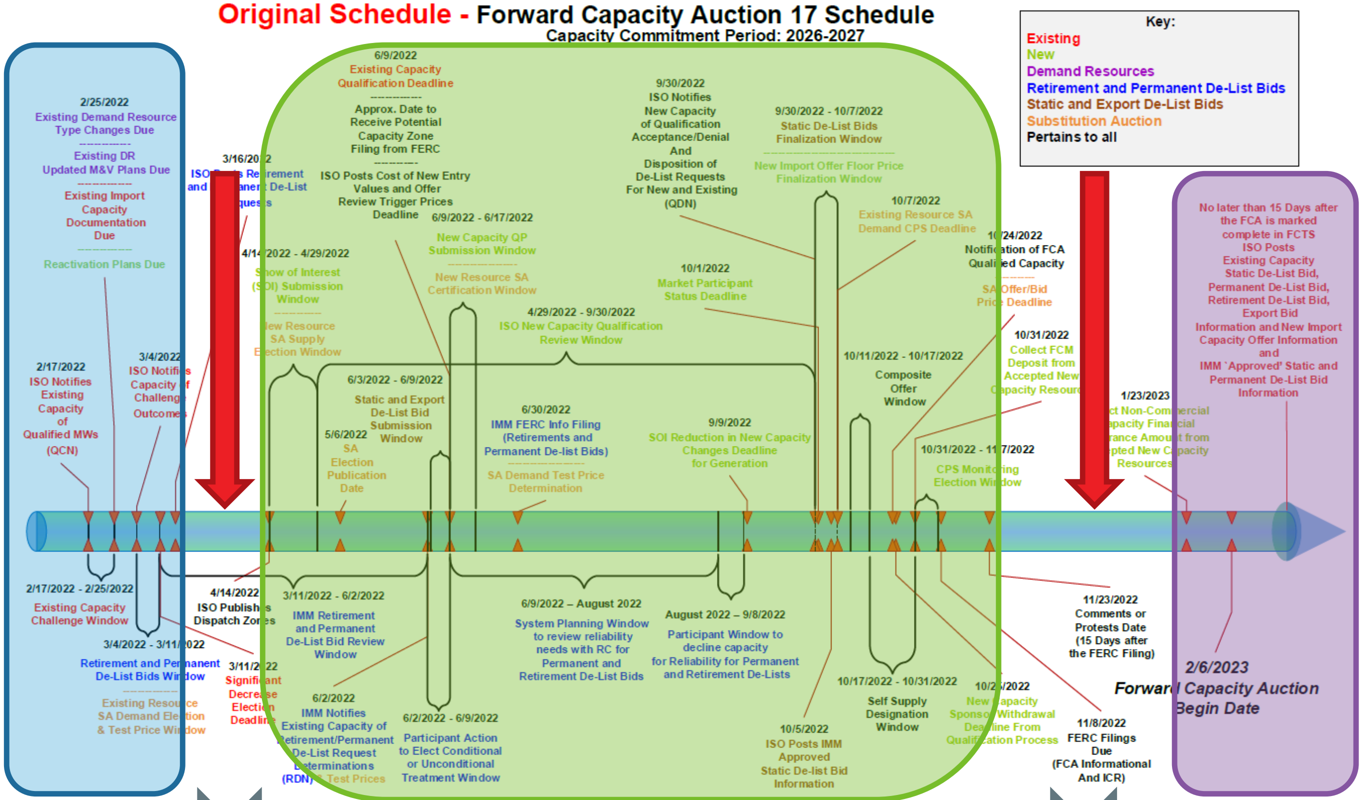
Proposed Approach for Modifying the FCA 17 Schedule, cont.



Proposed Approach for Modifying the FCA 17 Schedule, cont.



Proposed Approach for Modifying the FCA 17 Schedule, cont.



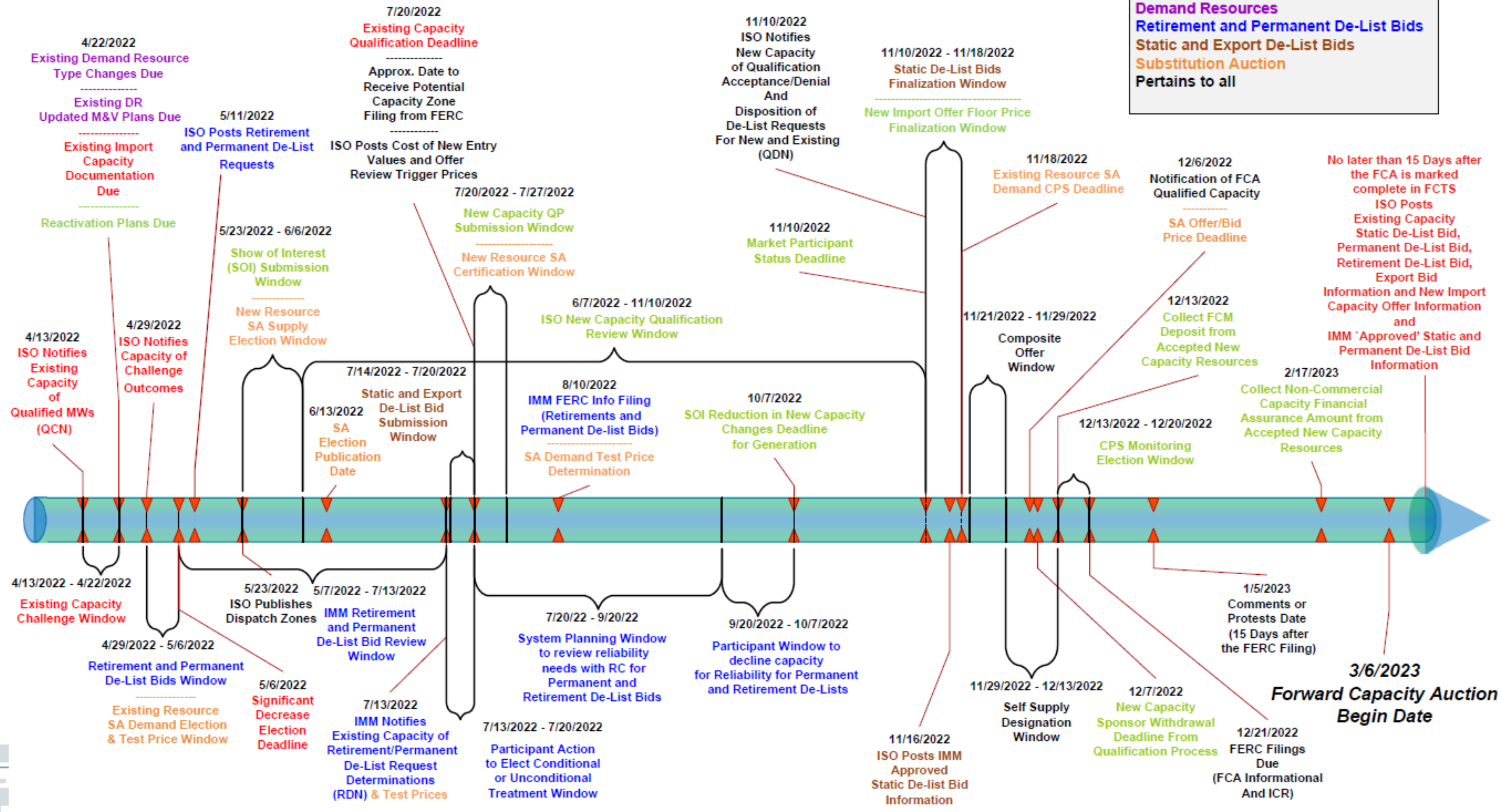
Proposed FCA 17 Schedule

- The following slide presents the proposed FCA 17 schedule that would begin in April 2022 and start the FCA on March 6, 2023
  - The gap between initial Existing Capacity Resource qualification events and the Show of Interest Window is compressed by approximately two weeks
  - The gap between the post-QDN activities and the final FCA events is compressed by approximately two weeks
  - All activities are further shifted ahead by approximately one month
- The ISO welcomes Market Participant feedback on its proposed approach and schedule for FCA 17
  - The proposed dates, date ranges and/or deadlines are for discussion and will not be final until the ISO officially publishes the FCA 17 schedule, which is anticipated no later than April 6, 2022

Proposed Schedule - Forward Capacity Auction 17 Schedule

Capacity Commitment Period: 2026-2027

Key:
Existing
New
Demand Resources
Retirement and Permanent De-List Bids
Static and Export De-List Bids
Substitution Auction
Pertains to all



Conclusion

- For modifying the FCA 17 schedule, the ISO seeks to minimize disruptions to the currently established order and relative timing of the FCA qualification process activities in order to maximize the familiarity and certainty of the process for affected parties, which include Market Participants, the Commission, and all affected business units at the ISO
- The ISO welcomes Market Participant feedback on its proposed approach for modifying the FCA 17 schedule, and on the proposed FCA 17 schedule
  - If stakeholders have additional feedback following the meeting, please provide to Alex Rost (arost@iso-ne.com)
- The ISO will publish the final FCA 17 schedule (i.e. dates, date ranges and/or deadlines) at least one week before the first FCA 17 events begin

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of March 2, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated February 1, 2022 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

No Activity to Report

I. Complaints/Section 206 Proceedings

*	2	NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)	Feb 14	NMISA files complaint against PTO AC (who for these purposes hold exclusive Section 205 rights) for failure to consider and implement a reciprocal discount to the TOUT charges applied to transactions between New England and Northern Maine; comment date ***Mar 7, 2022***
			Feb 16-28	NEPOOL, Calpine, National Grid intervene

II. Rate, ICR, FCA, Cost Recovery Filings

	7	CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (ER21-2334)	Feb 24	FERC issues an Allegheny Order, modifying the discussion in, but sustaining the results of, its *August 31, 2021 CSC CIP-IROL Costs Order*
	8	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Feb 18	FERC issues an Allegheny Order, modifying the discussion in, but sustaining the results of, its *Mystic ROE First Allegheny Order*
			Feb 22	Mystic petitions the DC Circuit for review of the *Mystic ROE Second Allegheny Order* (*see* Section XVI)

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

*	10	Waiver Request: FCA16 Information Publication Deadline (ISO-NE) (ER22-1060)	Feb 15	ISO-NE requests temporary waiver of the Tariff provisions requiring publication of information on FCA16 no later than Feb 22 in light of the ongoing Killingly-related uncertainty regarding the results of FCA16
			Feb 17-Mar 2	NEPOOL, Calpine, Constellation, Eversource, HQ US, LS Power, National Grid, NESCOE, NRG, EPSA, MA DPU (out-of-time) intervene
			Feb 22	NEPGA submits comments supporting FCA16 Publication Waiver Request
*	10	Exigent Circumstances Filing: FCA16 Information Publication Deadline (ISO-NE) (ER22-1053)	Feb 15	ISO-NE files Exigent Circumstances filing; comment date ***Mar 8, 2022***
			Feb 16-Mar 2	NEPOOL, Constellation, Dominion, Eversource, HQUS, National Grid, NESCOE, EPSA, and the MA DPU file doc-less interventions
*	10	New England's *Order 2222* Compliance Filing (ER22-983)	Feb 2	ISO-NE and NEPOOL submit Tariff revisions in response to the requirements of *Order 2222*; comment date now ***Apr 1, 2022***
			Feb 3-Mar 2	Avangrid, Calpine, Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRDC/Sustainable FERC Project, NRG, Voltus, AEMA, APPA, EEI, MA DPU, SEIA intervene
			Feb 11	AEMA requests extension of comment date to Apr 1, 2022
			Feb 18	ISO-NE supports AEMA request; FERC grants extension of comment date to ***Apr 1, 2022***
*	11	Waiver Request: Queue Position Modifications (ConnectGen South Wrentham) (ER22-864)	Feb 10	ISO-NE opposes waiver request; NEPOOL, RENEW intervene
			Feb 25	South Wrentham answers ISO-NE's Feb 10 opposition
			Mar 2	ISO-NE answers South Wrentham's Feb 25 answer

	11	CSO Termination: Killingly Energy Center (ER22-355)	Feb 9	ISO-NE requests expedited consideration of NTE CT's request for reh'g of *Killingly CSO Termination Order*
			Feb 11	FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of NTE CT's request for reh'g of the *Killingly CSO Termination Order*
			Feb 11	FERC issues notice that it was considering the release of information designated as confidential
			Feb 15	ISO-NE and NTE CT confirm no objection to release of information
			Feb 18	ISO-NE files copy of its Emergency Motion for Dissolution of the DC Circuit's Stay Order
			Feb 23	FERC issues *Killingly CSO Termination Allegheny Order*
			Feb 24	ISO-NE and NTE CT file un-redacted versions of their filings submitted in this proceeding; comment date on ISO-NE filing, ***Mar 21, 2022***

IV. OATT Amendments / TOAs / Coordination Agreements

*	12	*Order 676-J* Compliance Filing Part I (CSC-Schedule 18-Attachment Z) (ER22-1168)	Mar 2	ISO-NE and CSC file revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in NAESB's WEQ Version 003.3 Standards; comment date ***Mar 23, 2022***
*	12	Order 676-J Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1161)	Mar 2	TOs file revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new NAESB WEQ Version 003.3 cybersecurity and PFV Standards; comment date ***Mar 23, 2022***
*	13	*Order 676-J* Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1150)	Mar 2	ISO-NE files revisions to Schedule 24 to incorporate the new NAESB WEQ Version 003.3 cybersecurity and PFV Standards; comment date ***Mar 23, 2022***
	13	Tariff Changes Associated with *Order 1000* Lessons Learned (ER22-733)	Feb 2	ISO-NE answers Public Systems' comments, LS Power request for clarification or protest
			Feb 25	FERC accepts Tariff changes, eff. Feb 28, 2022
	14	Attachment K Planning Changes (ER22-727)	Feb 2	ISO-NE answers Public Systems' comments
			Feb 25	FERC accepts Tariff changes, eff. Feb 25, 2022
	14	BTM Generation Proposal (ER21-2337)	Feb 11	FERC accepts the BTM Generation Proposal, eff. Sep 1, 2021

V. Financial Assurance/Billing Policy Amendments

*	16	FCM Billing Acceleration and RBA Changes (ER22-1167)	Mar 2	ISO-NE and NEPOOL jointly file changes; comment date ***Mar 23, 2022***
*	16	Non-Commercial Capacity Trading FA Changes (ER22-863)	Feb 10	Eversource, National Grid intervene

VI. Schedule 20/21/22/23 Changes

*	16	Schedule 21-VP: Schedule 21 Name Update (ER22-1115)	Feb 25	Versant files a revised Schedule 21-VP to rename the Schedule from "Schedule 21-EM" to "Schedule 21-VP" and to replace all references to "Emera Maine" with "Versant Power"
*	16	Schedule 21-NEP: 3rd Revised RI LSAs (ER22-927)	Feb 9	RI PUC submits comments supporting LSAs
*	17	Schedule 23: NSTAR/Berkshire Wind/ISO-NE SGIA (ER22-720)	Feb 17	FERC accepts 2021 SGIA and cancellation of 2014 SGIA, eff. Nov 23, 2021
*	17	Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)	Feb 18	FERC accepts 2[nd] Revised LSA, eff. Jan 1, 2022

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	19	Capital Projects Report - 2021 Q4 (ER21-1041)	Feb 10 Feb 15-Mar 2 Feb 23	ISO-NE files 2021 Q4 Report NEPOOL, Eversource, National Grid intervene NEPOOL files comments supporting Q4 Report
*	19	Interconnection Study Metrics Processing Time Exceedance Report Q4 2021 (ER19-1951)	Feb 14	ISO-NE files required quarterly report
*	20	*Order 2222* Stakeholder Process Status Update; Voltus Tech Conf Request (RM18-9)	Feb 3-11	Comments on Voltus' request filed by: AEE, AEMA, APPA/NRECA, EEI, ISO-RTO Council, MISO, SPP, Sunrun, Ameren, Camus Energy, Energy Web Foundation, Integrity Energy Partners, Environmental Law and Policy Center, Google, Leapfrog Power, Nuvve Holding, Tesla, U Delaware EV Research and Development Group, Utilidata

IX. Membership Filings

*	20	March 2022 Membership Filing (ER22-1131)	Feb 28	NEPOOL requests that the FERC accept (i) the memberships of Emera Energy Services Sub. No. 6 and Tidal Energy; and (ii) the name changes of GB II New Haven, GB II Connecticut, and Generate Colchester Fuel Cells; comment deadline ***Mar 22, 2022***
*	20	Involuntary Termination: Sunwave Holdings USA Inc. (ER22-1039)	Feb 11	NEPOOL and ISO-NE request the involuntary termination of the Participant status of Sunwave USA Holdings Inc.; comment date ***Mar 4, 2022***
	21	January 2022 Membership Filing (ER22-747)	Feb 24	FERC accepts (i) the memberships of EnPowered USA Inc.; and Sheldon Energy LLC; and (ii) the termination of the Participant status of ENGIE Power & Gas
*	21	Suspension Notice – NTE Connecticut, LLC (not docketed)	Feb 11	ISO-NE files notice of Feb 9 suspension of NTE Connecticut, LLC from the New England Markets

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

	21	NERC Annual Report on FFT & Compliance Exception Programs (RC11-6-014)	Feb 25	FERC accepts Annual Report, eff. Feb 25, 2022
*	22	Revised Reliability Standard (CIP-014 Compliance Section) (RD22-3)	Feb 16	NERC requests modifications to the Compliance section of Reliability Standard CIP-014; comment deadline ***Mar 15, 2022***
	22	Revised Reliability Standards (SOL Changes) (RD22-2)	Feb 3	FERC re-dockets this proceeding (from RM21-19) and establishes a Feb 24 comment date (no comments filed)
	24	Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)	Feb 24	FERC issues Deficiency Letter requiring NERC to file additional information as an amendment to its filing; deficiency letter due on or before ***Mar 28, 2022***

XI. Misc. - of Regional Interest

	25	203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)	Feb 14 Feb 23	FERC authorizes PSEG sale of Project Companies to Generation Bridge Transaction consummated and notice of consummation filed
*	25	Versant Power MPD OATT *Order 676-J* Compliance Filing Part I (ER22-1142)	Mar 2	Versant, in response to the requirements of *Order 676-J*, files revisions to Section 4 of the MPD OATT; comment date ***Mar 23, 2022***

*	25	ISA Cancellation: NSTAR/Servistar (ER22-1013)	Feb 10	NSTAR files notice of cancellation of Servistar LLC Interconnection Study Agreement (project withdrawn); comment date ***Mar 3, 2022***
	26	Related Facilities Agreement: CL&P / Revolution Wind (ER22-697)	Feb 15	FERC accepts RFA, eff. Dec 21, 2021
	26	Cost Reimbursement Agreement Cancellation: Narragansett / CV South Street Landing (ER22-612)	Feb 7	FERC accepts notice of cancellation, eff. Feb 9, 202
	26	D&E Agreement Cancellation: CL&P/ NRG Middletown (ER22-599)	Feb 4	FERC accepts notice of cancellation, eff. Dec 31, 2021
	28	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Feb 18 Feb 18-28	*ER20-2572 et al. (New England TOs (RNS)).* FERC grants NEP's requested clarification of *TOs First Order 864 Compliance Filings Order* TOs submit further *Order 864* compliance filings, most to correct the effective date to Jan 27, 2020, some with further changes in response to orders accepting initial filings

XII. Misc. - Administrative & Rulemaking Proceedings

*	30	NOI: Dynamic Line Ratings (AD22-5)	Feb 17	FERC issues a NOI seeking comments on dynamic line ratings; initial comments due ***Apr 25, 2022***; reply comments, ***May 25, 2022***
	30	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Feb 2 Feb 4 Feb 16 Feb 22 Mar 2	FERC issues Notice and Agenda for Feb 16, 2022 Joint Federal-State Task Force meeting on Electric Transmission FERC issues order confirming NARUC nomination of Utah PSC Chairman T. LeVar to replace Commissioner K. Raper Second Joint Federal-State Task Force meeting held Transcript of first JFSTF meeting posted in eLibrary FERC invites post-Feb 16 meeting comments; comment date ***Apr 1, 2022***
	32	Reliability Tech Conf (Sep 30) (AD21-11)	Feb 22	Post-tech conf comments filed by: ISO-NE, Americans for a Clean Energy Grid, AGA/APGA, CAISO, EEI, Energy Systems Integration Group, EPSA, Grain Belt Express, Grid Lab, MISO, Natural Gas Council, Natural Gas Supply Association, Public Power Associations
	32	Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)	Feb 1-Mar 1	Initial post-tech conf comments 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, Public Citizen; reply comments deadline, ***Mar 7, 2022***
*	33	Increasing Market and Planning Efficiency Through Improved Software Tech Conf (Jun 21-23, 2022) (AD10-12)	Feb 24	FERC issues notice that it will hold its 13th annual tech conf addressing from June 21-23; a detailed agenda with the list of and times for the selected speakers will be published on the FERC's website and in eLibrary after ***May 20, 2022***
	34	NOI: Industry Assoc'n Dues & Expenses Rate Recovery, Reporting, and Acc'ting Treatment (RM22-5)	Feb 22	Initial comments filed by AGA, APPA, EEI, EPRI, Harvard Electricity Law Institute, INGA, MA AG, National Grid, NEI, Nexamp, NRECA, PJM, Public Citizen, Public Interest Organizations, Ratepayers, Sunova, UCS; reply comments deadline ***Mar 23, 2022***
	34	ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)	Feb 14	Clean Energy Coalition files supplemental reply comments
	36	*Order 881*: Managing Transmission Line Ratings (RM20-16)	Feb 18	FERC issues notice that requests for rehearing and/or clarification of *Order 881* may be deemed denied by operation of law

XIII. FERC Enforcement Proceedings

39	Rover/ETP (CPCN Show Cause Order) (IN19-4)	Feb 4	Enforcement Litigation Staff answered Respondents request stay of ALJ proceedings
		Feb 16	Presiding ALJ schedules a prehearing videoconference for ***Mar 8, 2022***
		Feb 24	Chief Judge Cintron substitutes ALJ Joel DeJesus in place of ALJ Satten as presiding judge
		Feb 25	Presiding Judge DeJesus adopts time and date for Mar 8 videoconference; directs participants to submit a jointly-proposed procedural schedule by ***Mar 2, 2022***
41	Total Gas & Power North America, Inc. et al. (IN12-17)	Feb 16	Oral argument addressing administrative matters and procedural motions; answers to whistleblower witnesses motions to intervene due on ***Mar 2, 2022***; discussions on disputed data requests not resolved during oral argument to continue
		Feb 23	Presiding ALJ issues order confirming Feb 16 bench rulings

XIV. Natural Gas Proceedings

42	Northern Access Project (CP15-115)	Feb 1-16	Over 150 parties submit comments on Applicants' request for an additional extension of time, until Dec 31, 2024, to complete construction of the Project and enter service

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

*	45	NTE CT Petition for Review of Killingly CSO Termination Orders (22-1027)	Feb 23	NTE CT petitions DC Circuit for review of the FERC's *Killingly CSO Termination Orders*
			Feb 25	Clerk directs initial submissions and appearances by ***Mar 28, 2022***; dispositive motions, Certified Index to the Record by ***Apr 11, 2022***
			Mar 1	ISO-NE moves to intervene
	45	NTE CT Petition to Stay FERC Order Accepting Killingly CSO Termination (22-1011)	Feb 4	FERC issues per curiam order ordering that the *Killingly CSO Termination Order* be stayed until 30 days after the FERC resolves the pending request for rehearing
			Feb 18	ISO-NE files emergency motion to lift Stay
			Feb 22	NEPGA moves to intervene and supports ISO-NE motion to lift Stay
			Feb 23	NTE CT opposes motion to lift Stay
			Feb 24	ISO-NE replies to NTE CT Feb 23 motion; Court issues full opinion on Stay promised in the Feb 4 per curiam order; NTE CT supplements its Feb 23 response
			Feb 25	Court grants NEPGA intervention
			Mar 2	Court issues per curiam order lifting the Feb 4 Stay
	46	CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)	Feb 16	DC Circuit grants the FERC's motion to hold the petition in abeyance, directing (i) the FERC to file status reports at 30-day intervals (first report due ***Mar 18, 2022***) and (ii) the parties to file motions to govern future proceedings on or before ***Mar 28, 2022***
	46	Mystic ROE (21-1198) (consol.)	Feb 8	Clerk issues order granting in part the request for an extension of time to file the certified index to the record; due Feb 22, 2022
			Feb 11	CT Parties file Docketing Statement and Statement of Issues
			Feb 14	Mystic files Docketing Statement and Statement of Issues
			Feb 22	FERC files certified index to the record
			Feb 24	Court consolidates 22-1026 into 21-1198
			Feb 24	Court grants MA AG, Mystic, MMWEC, NHEC motions to intervene
			Mar 1	Court orders proposed briefing formats to be filed by ***Mar 31, 2022***
	47	Mystic 8/9 CoS Agreement (20-1343 et al.)(consolidated)	Feb 3	Reply Briefs filed
			Feb 9	Oral argument scheduled for ***May 5, 2022***
			Feb 17	Joint Appendix filed
			Feb 24	Final Briefs filed, completing briefing
	49	PennEast Project (18-1128 et al.)	Feb 8	Petitions dismissed; mandate issued
	50	Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.);	Feb 15	Court issues order extending the abeyance; directs Petitioners to file motions to govern future proceedings by ***May 31, 2022***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: March 2, 2022

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 March 2, 2022. If you have questions, please contact us.

COVID-19

- **Remote ALJ Hearings (AD20-12)**

All hearings before Administrative Law Judges ("ALJs") are being held remotely through video conference software (WebEx and SharePoint) until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an "IT Day" prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Uniform Hearing Rules for all Office of the ALJ hearings were adopted effective September 15, 2020.[3] The "Remote Hearing Guidance for Participants" was revised on May 18, 2021 to make two additional changes.[4] The Uniform Hearing Rules and Remote Hearing Guidance for Participants are publicly available in this proceeding in eLibrary and on the FERC's Administrative Litigation webpage.

- **Extension of Filing Deadlines (AD20-11)**

On December 8, 2021, the wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations was ***extended for an additional three months, through March 31, 2022***.[5] The December 8 notice extended the waiver first noticed in May, 2020[6] for a fourth time. As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus.[7] The FERC does not anticipate issuing any

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

[2] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (June 17, 2020).

[3] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 1, 2020).

[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (May 18, 2021) (requiring that only attorneys may access Live Litigation (§VI(a)(vii)) and encouraging that privileged sessions be limited and revising guidance on privileged versus public session management (§VI(k)).

[5] *See Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Dec. 8, 2021) ("Fourth Extension").

[6] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (May 8, 2020)("First Extension"); *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Jan. 25, 2021) ("Second Extension"); *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (July 26, 2021) ("Third Extension").

[7] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Apr. 2, 2020).

further blanket extensions after March 31, 2022, but is closely monitoring developments and will make that decision in light of conditions near the end of the Fourth Extension period.

- **Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)**

In light of the continuing nature of the COVID-19 National Emergency, the FERC extended on December 8, 2021, ***for an additional 3 months, through March 31, 2022***, the blanket waivers of ISO/RTO Tariff *in-person*[8] meeting and notarization requirements.[9] The July 26 order extended for a fourth time the blanket waivers first granted in the FERC's April 2, 2020 order and extended in orders issued August 20, 2020, January 25, 2021, and July 26, 2021.[10] The FERC does not anticipate issuing any further blanket extensions after March 31, 2022, but is closely monitoring developments and will make that decision in light of conditions near the end of this fourth extension.

I. Complaints/Section 206 Proceedings

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

On February 14, 2022, the Northern Maine Intendent System Administrator ("NMISA") filed a complaint against the PTO AC (who for these purposes hold exclusive Section 205 rights) for failure to consider and implement a reciprocal discount to the Through and Out ("TOUT") charges applied to transactions between the New England and Northern Maine regions, one which would be identical in substance to the reciprocity between New England and New York. The PTO AC response and comments on this Complaint are due on or before March 7, 2022. Thus far, NEPOOL, Calpine and National Grid have submitted doc-less interventions. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC instituted on September 7, 2021 a proceeding under FPA Section 206 to consider whether Schedule 25 and Tariff section I.3.10 may be unjust and unreasonable.[11] 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.[12]

Accordingly, the FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff section I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff section 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

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[8] The waiver only applies to a specific requirement that meetings be held *in person*. Other than the in-person requirement, such meetings must still be held consistent with the tariff, but should be conducted by other means (e.g. telephonically).

[9] *Temporary Action to Facilitate Social Distancing*, 177 FERC ¶ 61,174 (Dec. 8, 2021).

[10] *Temporary Action to Facilitate Social Distancing*, 171 FERC ¶ 61,004 (Apr. 2, 2020) (waiving notarization requirements through Sep. 1, 2020, contained in any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the Federal Power Act ("FPA"), the Natural Gas Act ("NGA"), or the Interstate Commerce Act); 172 FERC ¶ 61,151 (Aug. 20, 2020) (extending the waivers through Jan. 29, 2021); 174 FERC ¶ 61,047 (Jan. 25, 2021) (extending the waivers through July 31, 2021); 176 FERC ¶ 61,044 (July 26, 2021) (extending the waivers through Jan. 1, 2022).

[11] *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*").

[12] *Id.* at P 20.

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 will be October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021.[13] 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), American Clean Power Association ("ACPA"), EPSA, RENEW Northeast, Inc. ("RENEW"), and Public Citizen intervened.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff section 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 NextEra answered the NECEC/Avangrid comments. On January 28, NECEC answered NextEra's January 20 answer and ISO-NE answered NECEC's Jan 7 comments.

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).

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

As previously reported, NECEC and Avangrid Inc. (together, "Avangrid") filed a complaint (the "Complaint") on October 13, 2020 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[14] 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. NextEra submitted an answer to the October 13 Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid also answered the supplemental answer.

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

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

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

Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[15] Initial briefs[16] were due on or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding), and Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

Comments on Seabrook's Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order Petition. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. NextEra moved to lodge both an August 29, 2021 filing containing an executed Engineering and Procurement Agreement ("E&P Agreement") between Seabrook and NECEC Transmission, LLC ("NECEC") that was filed with the FERC on August 19, 2021 and the NRC Seabrook Report. Avangrid answered that motion, asserting that the NRC Seabrook Report was outside the scope of the proceeding and the motion to lodge should be denied. This matter

[15] *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).

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

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

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

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

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[17] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[18] However, the FERC's orders were challenged, and in *Emera Maine,*[19] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[20] and third (EL14-86)[21] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[22] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

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

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

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

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

[21] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General, together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

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

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[23] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[24] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[25] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[26] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[27] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[28]

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

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium

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23 The 4th ROE Complaint asked the FERC to reduce the TOs’ current 10.57% return on equity (“Base ROE”) to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on Sept ember 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11 -15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) (“*Base ROE Complaint IV Order*”), *reh’g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the “*Base ROE Complaint IV Orders*”). *The Base ROE Complaint IV Orders*, as described in Section XVI below, have been appealed to, and are pending before, the DC Circuit.

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

25 *Id.* at P 2.; Finding of Fact (B).

26 *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) (“*Order Directing Briefs”* or ”*Coakley*”).

27 *Ass’n of 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*.

28 *Id.* at P 19.

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[29] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[30] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[31] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (ER21-2334)**

As previously reported, the FERC denied the request by Cross-Sound Cable Company LLC ("CSC") for authorization to establish a regulatory asset that would include all CIP-IROL Costs[32] that CSC prudently incurred between January 1, 2016 and May 31, 2021 ($1.324 million) and recover those costs under Schedule 17 (from all ISO-NE transmission customers) over a five-year period (beginning on the date the FERC makes

[29] *Id.* at P 59.

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

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

[32] Interconnection Reliability Operating Limits ("IROL") Critical Infrastructure Protection ("CIP") costs under Schedule 17 of the ISO-NE Tariff.

this rate treatment and related cost recovery effective).[33] Relying on its *Schedule 17 Orders*,[34] which found that Schedule 17 permits recovery only of CIP-IROL costs incurred on or after the effective date of a FPA section 205 filing made by an IROL-Critical Facility owner to recover such costs, and recovery of CIP-IROL costs incurred prior to the effective date of any relevant, individual FPA section 205 filing would violate the rule against retroactive ratemaking, the FERC found that permitting the recovery here proposed by CSC would violate the filed rate doctrine.[35] The FERC rejected the alternative bases for FERC approval proposed by CSC.[36] CSC requested rehearing of the *August 31, 2021 CSC CIP-IROL Costs Order*.

CSC Request for Rehearing. On November 1, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[37] The Notice confirmed that the 60-day period during which a petition for review of the *August 31, 2021 CSC CIP-IROL Costs Order* could be filed with an appropriate federal court was triggered when the FERC did not act on CSC's request for rehearing of the *August 31, 2021 CSC CIP-IROL Costs Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." On February 24, 2022, the FERC issued that order, modifying the discussion in, but sustaining the results of, the *August 31, 2021 CSC CIP-IROL Costs Order*.[38] As previously reported, CSC has appealed the FERC's orders in this proceeding to the DC Circuit (*see* Section XVI below, where reporting on this matter will continue). If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Each of the *July 17 Orders*[39] and the *Mystic ROE Orders,*[40] which addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[41] among Constellation Mystic Power ("Mystic"), Exelon

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[33] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*August 31, 2021 CSC CIP-IROL Costs Order*").

[34] *ISO New England Inc.,* 171 FERC ¶ 61,160 ("*Schedule 17 Order*"), *order on reh'g*, 172 FERC ¶ 61,251 (2020) ("*Schedule 17 Rehearing Order*") (collectively, "*Schedule 17 Orders*"), *appeal pending sub nom.*, *Cogentrix Energy Power Mgmt., LLC v. FERC*, D.C. Cir. No. 20-1389 (filed Oct. 14, 2020) (*see* Section XVI).

[35] *August 31 Order* at P 33.

[36] *Id*. at PP 33-37. As previously reported, CSC proposed three alternative bases upon which the FERC could grant its request to use a regulatory asset for CIP IROL cost recovery and rate treatment: (i) FPA section 219 and Order 679 (incentive rate frame work); FPA section 205 (in furtherance of the FERC's expressed policy of ensuring reliability of the BES in response to cybersecurity threats); or (iii) FPA section 309 (FERC's remedial authority). In the *August 31 Order*, the FERC rejected each of these in turn.

[37] *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *August 31, 2021 CSC CIP-IROL Costs Order*).

[38] Cross-Sound Cable Co., LLC, 178 FERC ¶ 61,134 (Feb. 4, 2022) ("*August 31, 2021 CSC CIP-IROL Costs Allegheny Order*").

[39] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order*. *Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[40] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*") (setting the base ROE for the Mystic COS Agreement at 9.33%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE First Allegheny Order*") (re-setting Mystic's ROE to 9.19%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE Second Allegheny Order*", and together with the *Mystic ROE Order* and the *Mystic ROE Allegheny Order,* the *"Mystic ROE Orders"*) (modifying the discussion in, but sustaining the results of, the *Mystic ROE First Allegheny Order*).

[41] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address

Generation Company ("ExGen"), and ISO-NE, have been appealed to, and consolidated before, the DC Circuit (*see* Section XVI below).

Mystic ROE First Allegheny Order. On November 18, 2021, the FERC issued an "Allegheny Order"[42] modifying the discussion in the *Mystic ROE Order* and setting aside that *Order*, in part.[43] In particular, agreeing with Connecticut Parties that "Otter Tail is properly excluded [as an outlier] from the [Discounted Cash Flow model ("DCF")] under the natural break analysis", the FERC found that the resulting average of the medians of the DCF, Capital Asset Pricing, and Risk Premium models (which sets the ROE) is 9.19%.[44] According the FERC directed Mystic to submit a compliance filing revising the Mystic Agreement to reflect a 9.19% (rather than a 9.33%) base ROE. The FERC also clarified that Avangrid's exclusion from the proxy group was based on its controlled status (ownership stakes by a single entity greater than 50%) and not on the particulars of Iberdrola's ownership or operations.[45] The FERC either disagreed with or dismissed as repetitive the remainder of the parties' arguments on rehearing. Mystic requested rehearing of the *Mystic ROE First Allegheny Order* on December 18, 2021. On January 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[46] As noted in Section XVI below, Mystic filed a petition for review of the *Mystic ROE Allegheny Order* with the DC Circuit Court of Appeals on January 18, 2022.

Mystic ROE Second Allegheny Order. On February 18, 2022, the FERC issued its order[47] on Mystic's December 18, 2021 request for rehearing of the *Mystic ROE First Allegheny Order*. The *Mystic ROE Second Allegheny Order* modified the discussion in, but sustained the results of, the *Mystic ROE First Allegheny Order.* As noted in Section XVI below, Mystic filed a petition for review of the *Mystic ROE Second Allegheny Order* with the DC Circuit Court of Appeals on February 22, 2022, and that proceeding has been consolidated with each of the other Mystic appeals, with 21-1198 as the lead Mystic proceeding before the DC Circuit.

Revised ROE (Sixth) Compliance Filing (-014). 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 is pending before the FERC.

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 COS Agreement ("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

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Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility.

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

[43] *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE First Allegheny Order*") (re-setting Mystic's ROE to 9.19%).

[44] *Id.* at P 15.

[45] *Id.* at P 21.

[46] *Constellation Mystic Power, LLC*, 178 FERC ¶ 62,028 (Jan. 18, 2022) (Notice of Denial of Reh'g by Operation of Law).

[47] *Constellation Mystic Power, LLC*, 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*") (modifying the discussion in, but sustaining the results of, the *Mystic ROE First Allegheny Order*).

September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Comments on the formal challenges were due on or before November 17, 2021, and Mystic responded on November 17 asserting that that the challenges should be rejected without further procedures. ENECOS and NESCOE replied to Mystic's November 17, 2021 reply on December 2 and December 6, 2021, respectively. The formal challenges remain pending before the FERC.

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).

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

- **Waiver Request: FCA16 Information Publication Deadline (ISO-NE) (ER22-1060)**

On February 15, 2022, ISO-NE asked the FERC to waive for FCA16 provisions of the Tariff that require ISO-NE to publish information related to an FCA no later than 15 days after the FCA (or in the case of FCA16, February 22, 2022) ("FCA16 Info Publication Waiver Request"). Specifically, ISO-NE asked for a temporary waiver of the requirements in Sections III.13.1.8(a), (b), (c), and (d), and III.13.8.1(c) of the Tariff, until ISO-NE publishes the results of FCA 16. Comments on ISO-NE's waiver request were due on or before February 2, 2022. NEPGA asked the FERC to grant ISO-NE's request. NEPOOL, Calpine, Constellation, Eversource, HQUS, LSPower, National Grid, NESCOE, NRG, EPSA, and the MA DPU (out-of-time) filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Exigent Circumstances Filing: FCA16 Information Publication Deadline (ISO-NE) (ER22-1053)**

Also on February 15, 2022, ISO-NE filed, pursuant to the Exigent Circumstances provision of the Participants Agreement (Section 11.2), a proposed modification to Section III.13 of the Tariff. The modification would, for FCA17, make any of the dates, date ranges, and/or deadlines currently established or prescribed in the Tariff or ISO-NE operating documents ("FCA 17 Schedule Dates") inapplicable for FCA 17. Instead, ISO-NE would be permitted to adjust any FCA17 Schedule Date and required to publish the revised FCA 17 Schedule Dates as soon as practicable (providing reasonable advance notice of the FCA17 Schedule Dates if and as revised). The Exigent Circumstances Filing, including the proposed Tariff provision, is scheduled to be reviewed with the Participants Committee at its March 3, 2022 meeting. Comments on the Exigent Circumstances Filing are due on or before March 8, 2021. Thus far, NEPOOL, Constellation, Dominion, Eversource, HQUS, National Grid, NESCOE, EPSA, and the MA DPU have filed doc-less interventions. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

On February 2, 2022, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted Tariff revisions ("*Order 2222* Changes") in response to the requirements of *Order 2222*. The Filing Parties stated that the *Order 2222* Changes create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes. Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), are now due on or before ***April 1, 2022***. While no comments have been filed thus far, doc-less interventions have been filed by Avangrid (CMP/UI), Calpine, Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRDC/Sustainable FERC Project, NRG, Voltus, AEMA, APPA, EEI, and SEIA. 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).

- **Waiver Request: Queue Position Modifications (ConnectGen South Wrentham) (ER22-864)**

On January 20, 2022, ConnectGen South Wrentham LLC ("South Wrentham") petitioned the FERC for a one-time, limited waiver of the requirements outlined in Schedule 22 section 4.4 of the Tariff (Queue Position. Modifications). Specifically, the waiver request seeks an extension of the FCA resource clearing window under Schedule 22, Section 4.4, to allow South Wrentham to seek qualification for, and bid into, FCA17 with its existing queue position (QP877).[48] Absent the requested waiver, South Wrentham will be required to file a new Capacity Network Resource ("CNR")-only Interconnection Service application and be assigned a new queue position for purposes of participating in FCA 17. South Wrentham asserts that it has not had a meaningful opportunity to meet the Schedule 22, section 4.4 requirement to clear in an FCA under its current CNR Interconnection Service request given the "extensive, 420+ day delay in the completion of feasibility and system impact studies. Comments on South Wrentham's waiver request were due on or before February 10, 2022. ISO-NE opposed the waiver request on February 10, and South Wrentham answered ISO-NE on February 25. On March 2, 2022, ISO-NE answered South Wrentham's February 25 answer. NEPOOL and RENEW filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CSO Termination: Killingly Energy Center (ER22-355)**

As previously reported, the FERC accepted ISO-NE's November 21, 2021 filing[49] to involuntarily terminate the CSO held by NTE Connecticut LLC ("NTE CT") as Project Sponsor for Resource No. 38633, the Killingly Energy Center on January 3, 2022.[50] In accepting the filing, the FERC found that the relevant condition for termination set forth in Tariff section III.13.3.4A was met,[51] and ISO-NE had fulfilled the requirement to consult with NTE CT before termination.[52] The CSO termination was accepted effective January 4, 2022. In response, NTE CT not only requested rehearing of the *Killingly CSO Termination Order*, but also filed a motion for stay of that *Order*, in each case hoping to preserve Killingly's ability to participate in FCA16 on February 7, 2022. When the FERC didn't act on the motion for stay on the expedited basis requested by NTE CT, NTE CT also petitioned the DC Circuit for a stay of the *Killingly CSO Termination Order.*

On January 28, 2022, the FERC denied[53] NTE CT's January 11, 2022 motion for stay. In denying NTE CT's motion for stay, the FERC found that NTE CT was unable to demonstrate that it will suffer irreparable harm absent a stay, and found further that issuing the stay would substantially harm other Market Participants and was not in the public interest.[54] However, as more fully explained in Section XIV below, on February 4, 2022, the DC Circuit granted a stay of the *Killingly CSO Termination Order* and Killingly was able to participate in FCA16.

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[48] South Wrentham is developing a 170 MW lithium-ion battery storage project to be located in Wrentham, Massachusetts.

[49] Comments on this filing were due Dec. 3, 2021, following a request by NTE CT for a one-week extension of time to respond to ISO-NE's filing (which the FERC granted on Dec. 3). NTE CT protested ISO-NE's filing on Dec. 3, 2021. ISO-NE answered NTE CT's protest on Dec. 20, 2021 and NTE CT answered ISO-NE's answer on Dec. 28, 2021. Doc-less interventions were filed by Calpine, Connecticut Light & Power ("CL&P"), Emera Energy Services, NEPGA, NESCOE, National Grid, CT AG, CT DEEP, EPSA, Gemma Power Systems, North Atlantic States Regional Council of Carpenters, Public Citizen, Sierra Club, Yankee Gas, CT OCC, and Mitsubishi Power Americas, Inc.

[50] *ISO New England Inc.*, 178 FERC ¶ 61,001 (Jan. 3, 2022), *reh'g requested* ("*Killingly CSO Termination Order*").

[51] *Id.* at P 25.

[52] *Id.* at P 27.

[53] *ISO New England Inc.,* 178 FERC ¶ 61,063 (Jan. 28, 2022) ("*Order Denying Stay*").

[54] *Id.* at PP 12-19.

On February 11, 2022, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[55] The Notice confirmed that the 60-day period during which a petition for review of the *Killingly CSO Termination Order* could be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Killingly CSO Termination Order*. The Notice also indicated that the FERC would address, as was its right, NTE CT's rehearing request in a future order, and might modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." Before addressing NTE CT's rehearing request, the FERC issued a February 11 notice that it was considering the release of information designated as confidential by ISO-NE and NTE CT in their submissions. On February 15, both ISO-NE and NTE CT confirmed that they had no objection to release of information.

On February 23, 2022, the FERC issued an order addressing NTE's request for rehearing.[56] In the *Killingly CSO Termination Allegheny Order*, the FERC modified the discussion in the *Killingly CSO Termination Order* and continued to reach the same result. Specifically, the FERC concluded that "after [NTE CT] repeatedly delayed its milestones, ISO-NE has sufficiently demonstrated that [NTE CT] will not meet its May 31, 2024 critical path milestone for commercial operation of the Killingly project (or the next-day June 1, 2024 deadline), as required by the ISO-NE Tariff." The FERC also directed ISO-NE and NTE CT to re-file public versions of their confidential submissions on or before February 28, 2022. On February 24, 2022, ISO-NE and NTE CT filed un-redacted versions of their filings submitted in this proceeding, which the FERC curiously noticed for public comment on or before March 21, 2022. As summarized in Section XVI below, NTE CT petitioned the DC Circuit on February 23 for review of the *Killingly CSO Termination* and *Killingly CSO Termination Allegheny Orders*.

If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- ***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*, ISO-NE and Cross-Sound Cable Company ("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").[57] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing are due on or before March 23, 2022. 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").[57] An effective date as of the date the FERC may determine was requested. Comments on this filing are due on or before March 23, 2022. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[55] *ISO New England Inc.*, 178 FERC ¶ 62,082 (Feb. 11, 2022) ("*Killingly CSO Termination Order Notice of Denial of Rehearing by Operation of Law*").

[56] *ISO New England Inc.*, 178 FERC ¶ 61,130 (Feb. 23, 2022) ("*Killingly CSO Termination Allegheny Order*").

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

- ***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 Changes").[57] An effective date no earlier than June 2, 2022 was requested. In its filing, ISO-NE stated that the Schedule 24 Order 676-J Part I Changes will be considered at the next regularly-scheduled meeting of the Transmission Committee and the Participants Committee thereafter. Comments on this filing are due on or before March 23, 2022. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Tariff Changes Associated with *Order 1000* Lessons Learned (ER22-733)**

 On February 25, 2022, the FERC accepted[58] proposed Tariff revisions ("Transmission Planning Improvements") filed by ISO-NE and NEPOOL.[59] As previously reported, the Transmission Planning Improvements were developed after a "lessons learned" process with stakeholders conducted shortly after the conclusion of the Boston RFP, and are intended to improve New England's competitive transmission planning process. The Transmission Planning Improvements were accepted effective as of February 28, 2022, as requested. In accepting the Transmission Planning Improvements, the FERC found that "these revisions enhance the competitive transmission planning process in New England. We encourage ISO-NE to continue to pursue improvements to the competitive transmission solicitation process as it gains additional experience."[60] In response to comments and protests filed,[61] the FERC (i) did not discuss the issues raised by Public Systems because it found those issues not directly pertinent to the Transmission Planning Improvements and already being considered elsewhere;[62] (ii) though it recognized the importance of the issues raised by LS Power, found them not properly part of this proceeding;[63] and (iii) did not discuss AEE's question about whether storage will be allowed to be considered as a transmission asset for purposes of implementing solutions to a Needs Assessment or Public Policy Transmission Study, finding it outside the scope of this proceeding.[64] Unless the *Transmission Planning Improvements Order* is challenged, with any challenges due on or before March 28, 2022, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[58] *ISO New England Inc. and New England Power Pool Participants Comm.*, 178 FERC ¶ 61,138 (Feb. 25, 2022) ("*Transmission Planning Improvements Order*").

[59] The Participants Committee unanimously supported the Transmission Planning Improvements at its Nov. 3, 2021 meeting (Consent Agenda Items #3 & 4).

[60] *Id.* at P 26.

[61] Comments and protests were filed by: (i) Public Systems (highlighting that, while the revisions are incremental improvements, more needs to be done to ensure that New England is able to meet the region's ambitious policy mandates); (ii) LS Power Grid Northeast, LLC ("LS Power") (requesting that the FERC either confirm that Section 4.3(a) permits a QTPS to include as part of its comprehensive proposal, elements that require the PTO to build new facilities not related to the interconnection of the proposal or, if not, reject the filing as unjust and unreasonable because "ISO New England failed to address its discriminatory policy of eliminating proposals from a non-incumbent [Qualified Transmission Project Sponsor ("QTPS")] that include requiring the PTO to build new facilities not related to the interconnection of the proposal"); and (iii) Advanced Energy Economy ("AEE") (which supported LS Power's request regarding ISO-NE's interpretation of Section 4.3(a) of Attachment K and urged the FERC to confirm that "a QTPS can submit a proposal that requires the incumbent Participating Transmission Owner ("PTO") to build new facilities or that relies on property in which the PTO has an interest").

[62] *Transmission Planning Improvements Order* at P 27.

[63] *Id.* at P 28.

[64] *Id.* at P 29.

- **Attachment K Planning Changes (ER22-727)**

Also on February 25, 2022, the FERC accepted[65] proposed Tariff revisions ("Attachment K Planning Changes") filed by ISO-NE and NEPOOL.[66] As previously reported, the Attachment K Planning Changes provide an additional option for the New England states to further their energy policy goals. The FERC accepted the Attachment K Planning Changes effective as of February 25, 2022, as requested. Unless the *Attachment K Planning Changes 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).

- **BTM Generation Proposal (ER21-2337)**

On February 11, 2022, the FERC accepted[67] revisions to Tariff sections I and II, jointly filed by ISO-NE and the Participating Transmission Owners Administrative Committee ("PTO AC"),[68] to clarify that the calculation of Monthly Regional Network Load excludes load served by behind-the-meter ("BTM") generation, which does not participate in the New England wholesale markets as a Generator Asset, as well as the portions of a Generator Asset utilized to net load at the same retail meter ("BTM Generation Proposal"). The FERC accepted the BTM Generation Proposal effective as of September 1, 2021, as requested. In accepting the Proposal, the FERC found among other things that (i) the Proposal "appropriately assigns costs for use of the transmission system among Network Customers";[69] (ii) it is just and reasonable to exclude from the Monthly RNL load served by unregistered [BTM] generation and the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as outlined in this proposal and assign [RNS] charges to Network Customers based on each Network Customer's actual use of the system";[70] (iii) the methods for calculating load in the determination of RNS charges and longer-term transmission planning need not be perfectly aligned;[71] (iv) a shift in transmission costs is not discriminatory under the facts and circumstance of this proceeding's record because all Network Customers are treated equally under the proposed revisions since the allocation is based on the relative observed usage of each Network Customer;[72] (v) BTM Generator Assets and unregistered BTM generators are not similarly situated for purposes of Monthly RNL calculation and corresponding RNS charges;[73] and (vi) "it is not unduly discriminatory to exclude from the Monthly RNL load served by unregistered [BTM] generation, along with the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset."[74] Unless the *BTM Generation Proposal Order* is challenged, with any challenges due on or before March 14, 2022, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[65] *ISO New England Inc. and New England Power Pool*, 178 FERC ¶ 61,137 (Feb. 25, 2022) ("*Attachment K Planning Changes Order*").

[66] The Participants Committee unanimously supported the Attachment K Planning Changes at its Dec. 2, 2021 meeting (Agenda Item # 6A).

[67] *ISO New England Inc. and the Participating Transmission Owners Admin. Comm.*, 178 FERC ¶ 61,086 (Feb. 11, 2022) ("*BTM Generation Proposal Order*"). In separate concurrences, Commissioners Danly and Christie expressed concerns with the Proposal, raised, respectively, by NEPGA and the IMM, but neither found sufficient evidence in the record to support a finding other than the Proposal is just and reasonable, and not unduly discriminatory.

[68] The BTM Generation Proposal was filed on Jul. 1, 2022, and was amended two times by responses to deficiency letters (described in previous Reports) filed on Sep. 20, 2021 and Dec. 13, 2021, respectively. The Participants Committee supported the BTM Generation Proposal at its June 3, 2021 meeting (Consent Agenda Items #3 and 4).

[69] *Id.* at P 49.

[70] *Id.* at P 51.

[71] *Id.* at P 52.

[72] *Id.* at P 53.

[73] *Id.* at PP 54-55.

[74] *Id.* at P 56.

- **TOs *Order 676-I* Compliance Filing (ER21-2529)**

On July 27, 2021, the PTO AC, ISO-NE, Schedule 20A Service Providers, GMP, and VTransco (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedule 21-Common and Schedule 20A-Common in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by NAESB's Wholesale Electric Quadrant and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 19, 2021; none were filed. National Grid filed a doc-less intervention on August 13, 2021.

Amended Revisions (ER21-2529-001). On October 22, 2021, the PTO AC submitted amendments to the July 27 compliance filing to include in Schedules 20A-Common and 21-Common revised and new WEQ standards identified in the FERC's March 3, 2020 errata notice to *Order 676-I* ("*Order 676-I Errata Notice*") but not included in the July 27, 2021 filing. Any comments on the errata filing were due on or before November 12, 2021; 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).

- **CSC Schedule 18 *Order 676-I* Compliance Filing (ER21-2509)**

On July 26, 2021, CSC and ISO-NE filed revisions to ISO-NE Tariff Schedule 18-Attachment Z in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by NAESB's Wholesale Electric Quadrant and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 16, 2021; none were filed. National Grid and CSC filed doc-less interventions on August 13, 2021 and August 16, 2021, respectively.

Amended Revisions (ER21-2509-001). On October 27, 2021, ISO-NE and CSC submitted amendments to the July 26 compliance filing to include in Schedule 18 revised and new WEQ standards identified in the FERC's *Order 676-I Errata Notice* but not included in the July 26, 2021 filing. Any comments on the errata filing were due on or before November 17, 2021; 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).

- **ISO-NE/NEPOOL *Order 676-I* Compliance Filing (ER21-941)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed.

Amended Revisions (ER21-941-001). On October 22, 2021, ISO-NE and NEPOOL submitted amendments to the January 26 compliance filing to include in Schedule 24 revised and new WEQ standards identified in the *Order 676-I Errata Notice* to but not included in the July 26, 2021 filing. Any comments on the errata filing were due on or before November 12, 2021; none were filed.

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

V. Financial Assurance/Billing Policy Amendments

- **FCM Billing Acceleration and RBA Changes (ER22-1167)**

On March 2, 2022, ISO-NE and NEPOOL jointly filed changes to the ISO-NE Financial Assurance Policy ("FAP") to (i) accelerate the settlement and billing of certain Forward Capacity Market ("FCM") charges and payments from a monthly settlement and billing to a daily settlement and bi-weekly billing (the "FCM Acceleration Changes"); (ii) make several corrections and clarifications to the FCM Cost Allocation provisions previously approved by the FERC in 2018 before those go into effect on June 1, 2022 (the "FCM Cost Allocation Changes"); (iii) revise the method to submit Requested Billing Adjustments (the "RBA Changes"); and (iv) make several conforming and clean-up changes (the "Clean-up Changes"). The changes were unanimously supported at the January 6, 2022 Participants Committee meeting. ISO-NE requested a May 1, 2022 effective date for the RBA Changes and a June 1, 2022 effective date for the FCM Acceleration Changes, FCM Cost Allocation Changes, and the Clean-Up Changes. Comments on the changes are due on or before March 23, 2022. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Non-Commercial Capacity Trading FA Changes (ER22-863)**

On January 21, 2022, ISO-NE and NEPOOL jointly filed changes to the FAP to make certain adjustments to the Non-Commercial Capacity ("NCC") Trading Financial Assurance ("FA") calculation ("NCC Trading FA Changes"). Specifically, the NCC Trading FA Changes (i) include the cash flow from any Annual Reconfiguration Transactions ("ARTs") associated with NCC in the NCC Trading FA calculation; and (ii) further refine the Capacity Supply Obligation ("CSO") Bilateral price overwrite provisions in FA calculations. The NCC Trading FA Changes were unanimously approved at the May 6, 2021 Participants Committee meeting. ISO-NE requested a March 22, 2022 effective date for the NCC Trading FA Changes. Comments on the NCC Trading FA Changes were due on or before February 11, 2022; none were filed. Calpine, Eversource, National Grid, and NRG filed doc-less interventions. 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).

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-VP: Schedule 21 Name Update (ER22-1115)**

On February 25, 2022, Versant filed a revised Schedule 21-VP to rename the Schedule from "Schedule 21-EM" to "Schedule 21-VP" and to replace all references to "Emera Maine" with "Versant Power". As of the date of this Report, this filing has not been noticed for public comment. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: 3rd Revised RI LSAs (ER22-927)**

On January 31, 2022, ISO-NE and National Grid filed third revised Local Service Agreements ("LSAs"), one among New England Power, ISO-NE, and The Narragansett Electric Company ("Narragansett"), the other among New England Power, ISO-NE, and Block Island Utility District d/b/a Block Island Power Company ("BIPCO"). The filing revises a surcharge in the LSAs for the recovery of costs for the Block Island transmission system from a carrying charge approach to a formula that uses actual costs in the year the surcharge is calculated, with a true-up mechanism. The revisions are expected to result in lower rates to Rhode Island (RI) customers. A January 1, 2022 effective was requested. Comments on this filing were due on or before February 22, 2022. On February 9, 2022, the Rhode Island Division of Public Utilities and Carriers ("RI PUC") submitted comments in support of the LSAs. No other comments were filed, and 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 23: NSTAR/Berkshire Wind/ISO-NE SGIA (ER22-720)**

On February 17, 2022, the FERC accepted[75] a non-conforming Small Generation Interconnection Agreement ("SGIA") among ISO-NE, NSTAR and Berkshire Wind Power Cooperative Corporation ("Berkshire Wind"), which covers the continued interconnection of Berkshire Wind's 19.6 MW Small Generating Facility at Brodie Mountain in Lanesborough and Hancock, MA. As previously reported, the SGIA, which replaces a 2014 SGIA, was filed as a result of a requested increase in Capacity Network Resource Interconnection Service ("CNRIS"), as well to update facility descriptions and certain milestones in Appendix B associated with two wind turbine additions, the merger into NSTAR of WMECO and update contact information, and incorporate other ministerial clean-up changes. The CNRIS increase required the filing of a new three-party SGIA, and the 2021 SGIA carries forward certain non-conforming provisions from the 2014 SGIA related to indemnification provisions. A notice of cancellation of the 2014 SGIA was also accepted. The 2021 SGIA and cancellation of the 2014 SGIA were accepted effective as of November 23, 2021, as requested. Unless the February 17, 2022 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)**

On February 18, 2022, the FERC accepted a Local Service Agreement ("LSA") among New England Power, The Narragansett Electric Company ("Narragansett") and ISO-NE.[76] As previously reported, 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. The LSA was accepted effective as of January 1, 2022, as requested. The FERC was not persuaded by Green Development's arguments that the revised Narragansett LSA was unjust and unreasonable and should be rejected.[77] Unless the February 18 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 9, 2021; reply comments, December 19, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[75] *ISO New England Inc.*, Docket No. ER22-720 (Feb. 17, 2022) (unpublished letter order).

[76] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb 18, 2022).

[77] *Id.* at P 55.

- **Schedule 21-VP: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

Still pending before the FERC is the MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[78] and certified by Settlement Judge Dring[79] to the Commission.[80] As previously reported, under this Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

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*[81] *and 531-B*[82] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[78] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). The Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following an audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[79] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences -- three in 2016 and two in 2017. With the Settlement pending before the FERC, settlement judge procedures, for now, have not been terminated.

[80] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

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

[82] *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	♦ National Grid	♦ United Illuminating
♦ Emera Maine	♦ NHT	♦ VTransco
♦ Eversource	♦ NSTAR	

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

- **Capital Projects Report - 2021 Q4 (ER22-1041)**

On February 10, 2022, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2021 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) nGEM Hardware Phase II ($4.57 million); (ii) Forecast Enhancements ($1.78 million); (iii) Solar Do-Not-Exceed ("DNE") Dispatch Phase I ($1.595 million); (iv) Physical Security Improvement Project ($1.136 million); (v) Replace Messaging Software ($432,100); (vi) Asset Activation Automation ($408,000); (vii) Browser Standardization ($472,000); (viii) Linear State Estimator Phase I ($362,000); (ix) Short-Term Load Forecast Curve Modification Enhancement ($279,600); (x) FCM Delayed Commercial Resource Treatment Phase II ($253,000); and (xi) Energy Management System Communications Monitoring ($235,200). The one significant change for a Chartered Project was the Replacement of the LMP Monitor (an increase of $265,000). Comments on this filing are due on or before March 3, 2022. NEPOOL filed comments on February 23 supporting the 2021 Q4 Report. Doc-less interventions have been filed by Eversource and National Grid. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q4 2021 (ER19-1951)**

On February 14, 2022, ISO-NE filed, as required,[83] public and confidential[84] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Fourth Quarter of 2021 ("2021 Q4"). ISO-NE reported that four of the five 2021 Q4 ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[85] In addition, five IFS Reports that are not yet completed have exceeded the 90-day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 118.2 days (comparable to 2021 Q3). Both ***System Impact Study ("SIS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days. The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 319 days (down 100 from 2021 Q3). There were no Interconnection Requests with projects in the Interconnection Facilities Study phase of the interconnection process. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

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

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

[85] 90 days from the Interconnection Customer's execution of the study agreement.

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

On January 31, 2022, 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/2022/01/2021-prior-year-projects-section-4-j-iii.pdf. This filing will not be noticed for public comment by the FERC.

- ***Order 2222* Stakeholder Process Status Update; Tech Conf Request (RM18-9)**

Pursuant to the FERC's order granting an extension of time for the filing of the region's *Order 2222* compliance filing,[86] ISO-NE filed on December 20, 2021 an update on the status of the stakeholder process and its schedule for making the required compliance filing (due February 2, 2022). The Participants Committee will consider the proposed compliance filing changes at its January 6, 2022 meeting (Agenda Item #5). This filing is for informational purposes only and will not be noticed for public comment or subject to a FERC order.

Voltus Petition for a FERC Technical Conference on Order 2222. On December 22, 2022, Voltus, Inc. ("Voltus") requested that the FERC convene a technical conference regarding *Order 2222*-related issues sometime in the months of February or March, 2022. Specifically, Voltus requested the technical conference to allow for a collective discussion of key issues arising from the ISO/RTO *Order 2222* compliance proposals, including certain regional variability, roles of industry participants, narrowing perceived knowledge gaps, and subsequent FERC guidance, all of which Voltus asserts supports the request for a technical conference. On January 7, 2022, the FERC issued a notice of Voltus' request, inviting comments on Voltus' request on or before February 7, 2022. Comments supporting Voltus' request were filed by: AEE, AEMA, APPA/NRECA, EEI, ISO-RTO Council, MISO, SPP, Sunrun, Ameren, Camus Energy, Energy Web Foundation, Entegrity Energy Partners, Environmental Law and Policy Center, Fermata LLC, Google, Leapfrog Power, Nuvve Holding, Tesla, U Delaware EV Research and Development Group, and Utilidata. This matter is pending before the FERC.

IX. Membership Filings

- **March 2022 Membership Filing (ER22-1131)**

On February 28, 2022, NEPOOL requested that the FERC accept (i) the following Applicant's membership in NEPOOL: Emera Energy Services Subsidiary No. 6 [Related Person to Emera Energy Services companies (Supplier Sector)]; and Tidal Energy USA (Supplier Sector); and (ii) the name changes of GB II New Haven LLC (f/k/a PSEG New Haven LLC) and GB II Connecticut LLC (f/k/a PSEG Power Connecticut LLC), each of which are now Related Persons to Great River Hydro (AR Sector; RG Sub-Sector) (*see* ER21-125 in Section XI below), and Generate Colchester Fuel Cells, LLC (f/k/a Bloom Connecticut Clean Energy Company, LLC). Comments on this filing are due on or before March 22, 2022.

- **Involuntary Termination Filing: Sunwave USA Holdings Inc. (ER22-1039)**

On February 11, 2022, NEPOOL and ISO-NE jointly requested that the FERC accept the involuntary termination of the NEPOOL membership and MPSA with ISO-NE (Market Participant status) of Sunwave USA Holdings, Inc. (Supplier Sector), effective April 13, 2022. Comments on this filing are due on or before March 4, 2022.

- **February 2022 Membership Filing (ER22-945)**

On January 31, 2022, NEPOOL requested that the FERC accept (i) the following Applicant's membership in NEPOOL: Sam Mintz (End User Sector); (ii) the termination of the Participant status of the following 16 Participants: Aminpour, Farhad (End User Sector); Brooks, Richard (End User Sector); King Forest Industries, Inc.

[86] *Participation of Distributed Energy Resource Aggregations in Mkts. Operated by RTOs and ISOs*, 175 FERC ¶ 61,156 at P 5 (May 24, 2021) ("*May 24 Order*").

(End User Sector); Kuser, Michael (End User Sector); PNE Energy Supply LLC (Supplier Sector); Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, and Montville Power LLC [each Related Persons to Great River Hydro/Generation Bridge Companies (AR Sector; RG Sub-Sector)]; and Ambit Northeast LLC, Connecticut Gas & Electric, Inc., Energy Rewards, LLC, Everyday Energy, LLC, Massachusetts Gas and Electric, Inc., Public Power, LLC, and Viridian Energy, LLC [each Related Persons to Dynegy Marketing and Trade (Supplier Sector)]; and (iii) the name change of Constellation Energy Generation, LLC (f/k/a Exelon Generation Company, LLC) (Supplier Sector). Comments on this filing were due on or before February 21, 2022; none were filed. This matter is pending before the FERC.

- **January 2022 Membership Filing (ER22-747)**

On February 24, 2022, the FERC accepted (i) the memberships of EnPowered USA Inc. (Supplier Sector); and Sheldon Energy LLC [Related Person to Invenergy Energy Management (Supplier Sector)]; and (ii) the termination of the Participant status of ENGIE Power & Gas [Related Person to ENGIE Energy Marketing NA (AR Sector, RG Sub-Sector)].[87] Unless the February 24 order is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**

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

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
Feb 9/11	NTE Connecticut, LLC	Financial Assurance	Feb 24

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

X. Misc. - ERO Rules, Filings; Reliability Standards[88]

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 (RC11-6-014)**

On February 25, 2022, the FERC accepted[89] NERC's annual report on Find, Fix, and Track ("FFT") and Compliance Exception programs, in accordance with prior FERC Orders.[90] As previously reported, 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. NERC also suggested that he report demonstrates significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Unless the February 25 order is challenged, this proceeding will be concluded.

[87] *New England Power Pool Participants Comm.*, Docket No. ER22-747 (Feb. 24, 2022) (unpublished letter order).

[88] Reporting on the following proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: NOI: Enhancements to CIP Standards (RM20-12).

[89] *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-014 (Feb 25, 2022) (unpublished letter order).

[90] *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").

- **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. On December 15, 2021, NERC submitted an informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02")).[91] Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. A revised schedule for Project 2016-02 calls for final balloting of revised standards in March 2022, NERC Board of Trustees Adoption in May 2022 and filing of the revised standards with the FERC in June 2022.

- **Revised Reliability Standard (CIP-014 Compliance Section) (RD22-3)**

On February 16, 2022, NERC filed for approval proposed changes to the compliance section of CIP-014 (Physical Security). The modifications remove from the Compliance section the provision that requires all evidence demonstrating compliance with the standard to be retained at the Transmission Owner's or Transmission Operator's facility. No changes to the mandatory and enforceable provisions of the CIP-014 standard were proposed. Comments on the CIP-014 changes are due on or before March 15, 2022.

- **Revised Reliability Standards (SOL Changes): FAC-003-5, 011-4, 014-3; IRO-008-3; PRC 002-3, 023-5, -026-2; and TOP-001-6 (RD22-2)**

On June 28, 2021, NERC filed for approval proposed changes to the following Reliability Standards related to establishing and communicating System Operating Limits ("SOLs", and together the "SOL Changes"):

- ♦ FAC-011-4 (System Operating Limits Methodology for the Operations Horizon)
- ♦ FAC-014-3 (Establish and Communicate System Operating Limits)
- ♦ FAC-003-5 (Transmission Vegetation Management)
- ♦ IRO-008-3 (Reliability Coordinator Operational Analyses and Real-time Assessments)
- ♦ PRC-002-3 (Disturbance Monitoring and Reporting Requirements)
- ♦ PRC-023-5 (Transmission Relay Loadability)
- ♦ PRC-026-2 (Relay Performance During Stable Power Swings)
- ♦ TOP-001-6 (Transmission Operations)

NERC also requested the retirement of Reliability Standard FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) and modifications to NERC's Glossary of Terms to revise the definition for System Operating Limit and to include "System Voltage Limit". The SOL Changes (NERC Project 2015-09) were developed in response to recommendations from a periodic review of the FAC-010, FAC-011, and FAC-014 Reliability Standards. NERC asked that revised Reliability Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 24 months following FERC approval. Since the last Report, the FERC re-docketed this proceeding (from RM21-19) and established February 24, 2022 as the comment date. No comments were filed on or before the comment date and the SOL Changes are now pending before the FERC.

- **NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)**

On February 20, 2020, the FERC issued a NOI seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in association with bulk electric system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization

[91] 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.

or cloud computing services.[92] On March 25, 2020, Joint Associations[93] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

Dec 2021 Informational Filing. In part in response to the comments filed, the FERC, in a December 17, 2020 order,[94] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards. NERC submitted that informational filing on December 17, 2021. In that filing, NERC addressed the status of NERC's formal process to assess the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, evaluated potential modifications to the CIP Standards to facilitate expanded use of the cloud, and considered topic areas raised in comments to the NOI. NERC requested that the FERC accept the informational filing as consistent with the *Order Directing Info. Filing*. NERC committed to continue to consider ways to support industry in securely adopting evolving technologies as necessary, including conducting BES reliability operating services in the cloud. NERC reported that there is no Standard Authorization Request ("SAR") to initiate standards development or a field test, nor had it identified a reliability gap that would necessitate standards development to facilitate BES reliability operating services in the cloud.

- ***Order 873* - Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[95] concluding that the 18 requirements "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[96] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[97]

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92 *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

93 "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

94 *Virtualization and Cloud Computing Services*, 173 FERC ¶ 61,243 (Dec. 17, 2020) ("*Order Directing Info. Filing*").

95 *Elec. Rel. Org. Proposal to Retire Reqs. in Rel. Standards Under the NERC Standards Efficiency Review*, Order No. 873, 172 FERC ¶ 61,225 (Sep. 17, 2020) ("*Order 873*"). The four Reliability Standards being eliminated in their entirety are FAC-013-2 (Assessment of Transfer Capability for the Near-term Transmission Planning Horizon), INT-004-3.1 (Dynamic Transfers), INT-010-2.1 (Interchange Initiation and Modification for Reliability), MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operations and Reliability Coordinators). The five modified Reliability Standards are INT-006-5 (Evaluation of Interchange Transactions), INT-009-3 (Implementation of Interchange) and PRC-004-6 (Protection System Misoperation Identification and Correction), IRO-002-7 (Reliability Coordination—Monitoring and Analysis), TOP-001-5 (Transmission Operations).

96 *Order 873* at P 2.

97 *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[98] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor NAESB business practice standards (v. 003.3) that include Modeling business practices, which were accepted in *Order 676-J*.[99]

- **Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)**

On September 29, 2021, NERC filed for approval changes to sections 400 (Compliance Monitoring and Enforcement) and 1500 (Confidential Information), Appendix 2 (Definitions) and Appendix 4C (Compliance Monitoring and Enforcement Program) of the NERC Rules of Procedure ("ROP"). The changes were proposed to further enhance the risk-based approach to the Compliance Monitoring and Enforcement Program ("CMEP") whereby registered entities and the ERO Enterprise focus on the greatest risks to the reliability and security of the Bulk Power System ("BPS"). Comments on this filing were due on or before October 20, 2021. Comments were filed by Public Utility District No. 1 of Chelan County and jointly by APPA/LPPC/TAPS. This matter remains pending before the FERC.

- **Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)**

On August 18, 2021, NERC filed for approval revisions to sections 300 (Reliability Standards Development), Appendix 3B (Procedure for Election of Members of the Standards Committee) and Appendix 3D (Development of Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"), which are designed to update language, staff titles, and processes; remove unnecessary or duplicative obligations; and clarify roles and responsibilities related to the development of Reliability Standards (the "Reliability Standards Development ROP Revisions"). Comments on this filing were due on or before September 8, 2021; none were filed.

Deficiency Letter. On February 24, 2022, the FERC issued a deficiency letter, directing NERC to provide, on or before March 28, 2022, additional information and clarifications. NERC's responses to the Deficiency Letter will constitute and must be filed as an amendment to its filing and will publicly noticed upon receipt of NERC's response.

XI. Misc. - of Regional Interest

- **203 Application: Howard Wind / Greenbacker Wind (EC22-13)**

On January 11, 2022, the FERC authorized Greenbacker Wind, LLC's acquisition of 100% of the equity interests in Howard Wind LLC from Everpower Wind Holdings, Inc. ("Everpower").[100] Pursuant to the December 6 order, Greenback Wind 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).

[98] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020) ("*Retirements NOPR*") (proposing to approve the retirement of 74 of 77 Reliability Standard requirements requested to be retired by NERC in these two dockets in connection with the first phase of work under NERC's Standards Efficiency Review, an initiative begun in 2017 that reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability). As previously reported, NERC withdrew its proposed changes to VAR-001-6 on May 14, 2020, reducing to 76 the number of requirements proposed to be retired.

[99] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

[100] *Howard Wind LLC*, 178 FERC ¶ 62,024 (Jan. 11, 2022)

- **203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)**

On February 14, 2022, the FERC authorized[101] the sale of 100% of the membership interests in the PSEG Project Companies[102] to Generation Bridge II, LLC ("Purchaser"), a wholly-owned, indirect subsidiary of ArcLight Fund VII, which is itself affiliated with Great River Hydro. Purchaser and Project Companies filed a notice on February 23, 2022 that the transaction was consummated on that day. PSEG New Haven and PSEG Power Connecticut, now known as GB II New Haven and GB II Connecticut, respectively, are now Related Persons to Great River Hydro. Reporting on this proceeding is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: PPL/Narragansett (EC21-87)**

On September 23, 2021, the FERC authorized a transaction pursuant to which a wholly-owned subsidiary of PPL Corporation will acquire 100% of the outstanding shares of common stock of The Narragansett Electric Company ("Narragansett").[103] This transaction is expected to close in the first quarter of 2022. Pursuant to the September 23 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On March 2, 2022, in response to the requirements of *Order 676-J*, 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 ("Versant MPD OATT Order 676-J Part I Changes").[57] A placeholder effective date was submitted. Comments on this filing are due on or before March 23, 2022. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISA Cancellation: NSTAR/Servistar (ER22-1013)**

On February 15, 2022, NSTAR &P filed a notice of termination of the Interconnection Study Agreement ("ISA") between NSTAR and Servistar. NSTAR reported that Servistar has withdrawn the project and has terminated the ISA. NSTAR has finalized all billing and refunds under the Agreement and no further work is being done pursuant to the Agreement. A February 10, 2022 effective date was requested. Comments on this filing are due on or before March 3, 2022. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P/UCONN (ER22-912)**

On January 28, 2022, CL&P filed a notice of cancellation of an Engineering, Design, and Procurement Agreement ("D&E Agreement") with the University of Connecticut ("UCONN"). The D&E Agreement set forth the terms and conditions under which CL&P would undertake certain preliminary engineering and design activities for a proposed increase in capacity of its transmission interconnection service. The term of the Agreement ended on September 21, 2021. CL&P determined that the upgrades contemplated by the Agreement should be considered a capital project as a result of organic system load growth for customers Eversource is obligated to serve. CL&P fully refunded UConn for all charges under the Agreement. A January 28, 2022 effective date was requested. Comments on this filing were due on or before February 18, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[101] *PSEG New Haven, LLC et al.*, 178 FERC ¶ 61,091 (Feb. 14, 2022).

[102] The "PSEG Project Companies" are: PSEG New Haven LLC ("PSEG New Haven"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC ("PSEG Power NY").

[103] *PPL Corp. and The Narragansett Elec. Co.*, 176 FERC ¶ 61,175 (Sep. 23, 2021).

- **D&E Agreement Cancellation: NSTAR/Ocean State (ER22-911)**

Also on January 28, 2022, NSTAR filed a notice of cancellation of a D&E Agreement with Ocean State Power, LLC ("Ocean State"). The D&E Agreement set forth the terms and conditions under which NSTAR would undertake certain preliminary engineering and design activities consistent with Ocean State's April 26, 2018 interconnection request (queue position #758) (for a proposed increase in capacity of its Large Generating Facility). The term of the Agreement ended on October 23, 2021. NSTAR completed all refunds and billing under the Agreement on January 4, 2022, and no further work will be done under the Agreement. A January 28, 2022 effective date was requested. Comments on this filing were due on or before February 18, 2022; none were filed. This matter is pending before the FERC. . If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement: Narragansett/BIPCO (ER22-817)**

On January 13, 2022, Narragansett filed a Cost Reimbursement Agreement with Block Island Utility District d/b/a Block Island Power Company ("BIPCO"). Under the agreement, Narragansett will perform certain work to modify its substation equipment in order to facilitate voltage modifications that Block Island plans to make to its distribution system. A November 29, 2021 effective date was requested. Comments on this filing were due on or before February 3, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement: CL&P / Revolution Wind (ER22-697)**

On February 15, 2022, the FERC accepted a Related Facilities Agreement ("RFA") between The Connecticut Light & Power Company ("CL&P") and Revolution Wind LLC.[104] As previously reported, the RFA provides the terms and conditions governing CL&P's activities, and Revolution Wind's cost responsibility for, completing the Related Facilities required to interconnect Revolution Wind's facility to National Grid's 115 kV Davisville Substation in Washington County, Rhode Island. The FRA was accepted effective as of December 21, 2021, as requested. Unless the February 15 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement Cancellation: Narragansett / CV South Street Landing (ER22-612)**

On February 7, 2022, the FERC accepted Narragansett's notice of cancellation of its Cost Reimbursement Agreement with CV South Street Landing, LLC ("South Street").[105] As previously reported, performance under the Agreement, which related to work by National Grid to underground a 115 kV transmission line,[106] is complete and all amounts due and owing paid in full. The notice of cancellation was accepted effective as of February 9, 2022, as requested. Unless the February 7 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P/ NRG Middletown (ER22-599)**

On February 4, 2022, the FERC accepted NSTAR's notice of cancellation of the Preliminary Engineering & Design Agreement ("D&E Agreement") with NRG Middletown Repowering LLC ("NRG Middletown").[107] As previously reported, the D&E Agreement set forth the terms and conditions under which CL&P was to undertake certain preliminary design and engineering activities on the Interconnection Facilities for NRG Middletown's proposed Large Generation Facility prior to the execution of an LGIA. , and NRG Middletown provided written notice to CL&P that it was terminating the Agreement effective December 31, 2021. CL&P finalized all billing and invoices and no further work is being done under the Agreement. The notice of cancellation was accepted

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[104] *The Connecticut Light and Power Co.*, Docket No. ER22-697 (Feb. 15, 2022) (unpublished letter order).

[105] *The Narragansett Electric Co.*, Docket No. ER22-612 (Feb. 7, 2022) (unpublished letter order).

[106] *See* Filing of Cost Reimbursement Agreement with CV South Street Landing LLC, *The Narragansett Elec. Co.*, Docket No. ER16-986 (filed Feb. 22, 2016); accepted in *The Narragansett Elec. Co.*, Docket No. ER16-986 (Mar. 21, 2016).

[107] *The Connecticut Light and Power Co.*, Docket No. ER22-599 (Feb. 4, 2022) (unpublished letter order).

effective as of December 31, 2021, as requested. Unless the February 4 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Termination: CL&P / Sterling Property (ER21-2860)**

As previously reported, the FERC rejected the notice of termination filed by CL&P of a 2002 Interconnection Agreement ("IA") governing interconnection service to what CL&P characterized as a since-decommissioned 26 MW waste-tire fueled generator located in Sterling, Connecticut (the "Facility").[108] In rejecting the notice, the FERC found that CL&P had "not provided adequate justification demonstrating that the Facility has been decommissioned in order to terminate the Interconnection Agreement."[109] However, the FERC noted that its determination did not indicate that Sterling retains any interconnection rights under the IA, stating that there had been no interconnection rights associated with the facility since ISO-NE deemed the Facility retired in 2017.

Requests for Rehearing and/or Clarification Denied by Operation of Law. On January 10, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[110] The Notice confirmed that the 60-day period during which a petition for review of the *Sterling IA Order* can be filed with an appropriate federal court was triggered when the FERC did not act on CL&P's and Brookfield's requests for rehearing of the *Sterling IA Order*.[111] The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." There has been no activity in this proceeding since the last Report. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Power MPD OATT *Order 676-I* Compliance Filing (ER21-2498)**

On July 23, 2021, Versant Power filed proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT") to incorporate by reference certain of the revisions required by *Order 676-I* and requested waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT. Comments on this filing were due on or before August 13, 2021; none were filed. Subsequently, on November 1, 2021, Versant submitted amendments to its July 23 compliance filing to include revised and new WEQ standards identified in the Order *676-I* Errata Notice but not included in the July 23, 2021 filing. Comments on the amendment filing were due on or before December 1, 2021; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[108] *The Connecticut Light and Power Co.*, 177 FERC ¶ 61,083 (Nov. 8, 2021) ("*Sterling IA Order*").

[109] *Id*. at P 23.

[110] The Conn. Light & Power Co., 178 FERC ¶ 62,015 (Jan. 10, 2022).

[111] CL&P and Brookfield each requested rehearing and/or clarification of the *Sterling IA Order* on Dec. 8, 2021.

- ***Orders 864/864-A*** **(Public Util. Trans. ADIT Rate Changes): *New England Compliance Filings* (various)**
In accordance with *Order 864*[112] and *Order 864-A,*[113] and extensions of time granted, New England's transmission-owning public utilities submitted their *Order 864* compliance filings, with specific dockets and filing dates identified in the following table. The FERC has addressed a number of the compliance filings, with some yet to be acted on, and others submitting further compliance filings (generally to reflect a January 27, 2020 effective date). The *Order 864* compliance proceedings that remain open are as follows:

Docket(s)	Transmission Provider	Date of Last Filing	Date Accepted
ER21-1130 ER20-2572	New England TOs (RNS)	Feb 18, 2022	Pending
ER20-2429	Central Maine Power ("CMP") (LNS)	Jul 15, 2020 Jul 6, 2021 Nov 8, 2021	Conditionally, Dec 22, 2021
ER21-1702	CMP (Schedule 1 Appendix A Implem. Rule)	Feb 28, 2022	Pending
ER21-1654	CL&P (LNS)	Feb 28, 2022	Pending
ER21-1295	Eversource (CL&P, PSNH, NSTAR) (LNS; Schedule 21-ES)	Feb 23, 2022	Pending
ER21-1154	FG&E (LNS)	Feb 23, 2022	Pending
ER21-1694	Green Mountain Power	Feb 18, 2022	Pending
ER20-1089	New England Elec. Trans. Corp.	Dec 11, 2020 Feb 26, 2020	Pending
ER20-1087	New England Hydro Trans. Corp.	Dec 11, 2020 Feb 26, 2020	Pending
ER20-1088	New England Hydro Trans. Elec. Co.	Dec 11, 2020 Feb 26, 2020	Pending
ER21-1241	NEP (LNS)	Feb 28, 2022	Pending
ER20-2551	NEP (Schedule 21-NEP and TSA-NEP-22 Compliance Revisions)	Jul 30, 2020	Pending
ER20-2219	NEP (Tariff No. 1)	Jun 29, 2020	Pending
ER20-2553	NEP (MECO/Nantucket LSA)	Jul 30, 2020	Pending
ER21-1293	NSTAR (LNS)	Feb 23, 2022	Pending
ER20-2608	PSNH (Seabrook TSA)	Aug 5, 2020	Jan 26, 2022
ER21-1709	VTransco (LNS)	Feb 22, 2022	Pending
ER20-2594	VTransco (1991 VTA)	Feb 25, 2022	Pending
ER20-1839	VETCO	Jan 22, 2021	Jan 26, 2022
ER20-2133 -001, -002	Versant Power	Nov 22, 2021	Conditionally, Feb 28, 2022

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

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

Compliance Filings Accepted. The FERC has accepted the following RNS and LNS-related *Order 864* compliance filings (with those accepted conditionally, subject to 60-day compliance filings, followed by an asterisk):

♦ ***ER20-2572; ER21-1130 (New England Transmission Owners ("TOs") - RNS)***.* The FERC conditionally accepted the *Order 864*-related changes to Tariff Attachment F and the Settlement Agreement attached thereto as Appendix A, subject to a further, 60-day compliance filing.[114] Areas the TOs must address in their compliance filing include: (i) changes to the Rate Base Adjustment and Income Tax Allowance Adjustment Mechanisms (TOs must adjust the Settled Formula Rate with respect to each mechanism to meet *Order 864* transparency requirements by specifying the source of the data used in those mechanisms); (ii) ADIT Worksheet Category 3 Information (TOs must clearly identify if excess and deficient ADIT is protected or unprotected); Category 4 Information (TOs must revise the Revised ADIT Worksheet to show amortized excess ADIT amounts included in Account 411.1 and amortized deficient ADIT amounts included in Account 410.1); Category 5 Information (TOs must correct discrepancies in the Revised ADIT Worksheet and the amortization periods; Versant Power must clarify which amortization method it will use; and UI, MEPCO, CMP, and VTransco must provide further justification for their proposed unprotected non-plant amortization periods). Also, the TOs were directed to file the Revised ADIT Worksheet in eTariff format. The Interim Period Formula Rate was accepted effective as of January 27, 2020; the Settled Formula Rate, January 1, 2022. The TOs filing in response to the requirements of the *TOs First Order 864 Compliance Filings Order* was due and was filed on February 18, 2022. Comments on that filing are due on or before March 11, 2022.

Request for Clarification and/or Rehearing. On January 20, 2022, New England Power ("NEP") requested clarification and/or rehearing of the *TOs First Order 864 Compliance Filings Order*, seeking clarification (or rehearing if not) that the Order was intended to approve NEP's proposed 10-year amortization period for unprotected non-plant related ADIT balances. On February 18, 2022, the FERC granted grant NEP's request for clarification of the *TOs First Order 864 Compliance Filings Order* and, accordingly, dismissed NEP's alternative request for rehearing.[115] The FERC found that NEP's proposal to amortize unprotected non-plant-related excess and deficient ADIT over a 10-year period complies with the requirements of *Order 864* and clarified that, "paragraphs 81 and 82 of the [*TOs First Order 864 Compliance Filings Order]* notwithstanding, NEP's proposed amortization period is accepted in compliance and no further support is required."[116]

♦ ***Various Dockets (TOs LNS Compliance Filings).*** On December 30, 2021, the FERC accepted, with the exception of CMP's filing in ER21-1702, which it conditionally accepted, subject to a further 60-day compliance filing, the TOs' revisions to each of their currently effective local transmission formula rate templates under Schedule 21 of the ISO-NE Tariff.[117] The FERC also accepted revisions to certain TOs' currently effective formula rate templates for scheduling, system control, and dispatch service for various transmission services under the respective Schedule 1 of the ISO-NE Tariff, and VTransco's revisions to its formula rate under its grandfathered 1991 Vermont Transmission Agreement ("VTA").

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[114] *ISO New England Inc. et al.*, 177 FERC ¶ 61,219 (Dec. 22, 2021) ("*TOs First Order 864 Compliance Filings Order*").

[115] *ISO New England Inc. and New England Power Co.*, 178 FERC ¶ 61,117 (Feb. 18, 2022) ("*Order on Clarification*").

[116] *Id.* at P 7.

[117] *ISO New England Inc. et al*., 177 FERC ¶ 61,239 (Dec. 30, 2021) ("*TO's Order 864 LNS Compliance Order*"). *Order 864* LNS compliance filings accepted were those by: FG&E (ER21-1154-001); NEP (ER21-1241-001); NSTAR (ER21-1293-001 and ER21-1650-001); Eversource (ER21-1295-001); NHT (ER21-1325-001); CL&P (ER21-1654-001); GMP (ER21-311-000; ER21-1694-001); CMP (ER21-1702-001); and VTransco (ER21-1709-001; ER20-2594-001.

♦ ***ER20-2429 (CMP - LNS)***.* The FERC conditionally accepted CMP's proposed Tariff revisions, effective January 27, 2020,[118] subject to a further, 60-day compliance filing.[119] CMP must address in that compliance filing, due on or before February 22, 2022, the following aspects of its ADIT Worksheet: (i) Category 1 (provide sufficiently detailed information in the re-measurement portion of the ADIT Worksheets to permit interested parties to tie the amounts provided to the rest of the ADIT Worksheets); (ii) Category 4 (revise the ADIT Worksheets to show amortized excess ADIT amounts recorded to Account 411.1, and deficient ADIT amounts recorded to Account 410.1); and (iii) Category 5 (revise its proposal such that the amortization period for unprotected non-plant, deficient ADIT balances is the same amortization period as unprotected non-plant, excess ADIT balances or demonstrate how its deviation from this requirement is consistent with or superior to this requirement of *Order 864*; and revise note (g) of its ADIT Worksheet to make clear that it will amortize unprotected excess ADIT over a five-year period and unprotected deficient ADIT over a 10-year period).

♦ ***ER20-2133 (Versant)***.* Since the last Report, the FERC conditionally accepted Versant Power's *Order 864* filings, subject to certain compliance obligations (e.g. to clearly identify if excess and deficient ADIT is protected or unprotected in order to satisfy the Order No. 864 ADIT Worksheet category 3 requirements).[120] The Versant compliance filing was accepted effective January 27, 2020.

XII. Misc. - Administrative & Rulemaking Proceedings[121]

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

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[122] 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 are due ***April 25, 2022***; reply comments; ***May 25, 2022***.[123]

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

On June 17, 2021, the FERC established a Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force").[124] 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

118 The FERC denied CMP's request for a Jan. 1, 2018 effective date, which was earlier than the FERC is authorized under section 206 of the FPA to prescribe a rate 'to be thereafter observed'. Rather, the FERC accepted this filing on the earliest possible date, or Jan. 20, 2020, the date the FERC in *Order 864* required parties to make changes to their tariffs.

119 *ISO New England Inc. and Central Maine Power Co.*, 177 FERC ¶ 61,218 (Dec. 22, 2021) ("*CMP First Order 864 Compliance Filings Order*").

120 *ISO New England Inc. and Versant Power*, 178 FERC ¶ 61,152 (Feb. 28, 2022).

121 Reporting on the following proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: Electrification and the Grid of the Future (AD21-12); ISO/RTO Credit Principles and Practices (AD21-6); Offshore Wind Integration in RTOs/ISOs (AD20-18); Waiver of Tariff Requirements (PL20-7); FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4); and NOI: Certification of New Interstate Natural Gas Facilities (PL18-1).

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

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

124 *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021).

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."[125] On July 19, 2021, NARUC nominated the 10 state commissioners to the Transmission Task Force, including New England Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU). Since the last Report, the FERC confirmed NARUC's nomination of Utah PSC Chairman T. LeVar to represent the Western Conference region (to replace Commissioner Kate Raper, who resigned her position with the Idaho PUC on January 21, 2022).[126]

Public Meetings.

♦ ***Nov 10, 2021***. The first Joint Federal-State Task Force meeting, which focused on incorporating state perspectives into regional transmission planning, was convened on November 10, 2021. A transcript of this meeting is posted in eLibrary. Comments on the issues discussed at that meeting were filed by: AEP, LA PSC, MI PSC, PJM, and Public Citizen.

♦ ***Feb 16, 2022***. A second meeting was held February 16, 2022 in Washington, DC. The agenda included a discussion, for purposes of transmission planning and cost allocation, specific categories and types of transmission benefits that transmission providers should consider and cost allocation principles, methodologies, and decision processes. On March 2, 2022, the FERC invited interested persons to file post-meeting comments to address issues raised during the February 16 meeting and identified in the agenda issued February 2, 2022. Post-meeting comments are due on or before April 1, 2022.

- **Climate Change, Extreme Weather, and Electric Sys. Reliability: Jun 1-2 Technical Conference (AD21-13)**

On June 1-2, 2021, FERC staff convened a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events. This technical conference addressed (i) concerns that, because extreme weather events are increasing in frequency, intensity, geographic expanse, and duration, the number and severity of weather-induced events in the electric power industry may also increase; and (ii) specific challenges posed to electric system reliability by climate change and extreme weather, which may vary by region. The FERC seeks to understand the near, medium and long-term challenges facing the regions of the country; how decision makers in the regions are evaluating and addressing those challenges; and whether further FERC action is needed to help achieve an electric system that can withstand, respond to, and recover from extreme weather events. Pre-technical conference comments were due on or before April 15, 2021 and were filed by, among others, ISO-NE, AEE, Dominion, EDF, Eversource, Exelon, LS Power, National Grid, PSEG, Vistra, APPA, Capital Power, EEI, NARUC, NEI, NERC, NRECA, and the R Street Institute. Speaker materials were posted in eLibrary on June 3, 2021; transcripts of the June 1-2 days, July 22, 2021.

On August 11, 2021, the FERC issued a notice inviting post-technical conference comments. Comments could address the questions raised in the notice, as well as any other issues raised during the technical conference or identified in the Supplemental Notices of Technical Conference issued March 15 and May 21, 2021. Comments were due on or before September 27, 2021 and were filed by: CAISO; MISO; NYISO; PJM; AEP; City of New Orleans; City of New York; Columbia Law School's Sabin Center for Climate Change Law; EDF and Sabin Center for Climate Change Law; EEI; EPSA; Eversource; Exelon, Jupiter Intelligence; Louisville Gas and Electric Company and Kentucky Utilities Company; MI PSC; NRDC, Sierra Club, Sustainable FERC Project, and UCS; Old Dominion Electric

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[125] Topics that the Task Force may consider include: (i) identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers; (ii) exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals; (iii) exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions; (iv) reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms; (v) examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and (vi) discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

[126] *Joint Federal-State Task Force on Electric Transmission*, 178 FERC ¶ 61,080 (Feb. 4, 2022).

Cooperative ("ODEC"); NERC; and C. Wright. On October 14, Entergy answered the comments submitted by City of New Orleans. This matter is pending before the FERC.

- **Reliability Technical Conference (Sep 30) (AD21-11)**

On September 30, 2021, the FERC convened its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the Bulk-Power System ("BPS"). Panel discussions addressed: (1) BPS reliability and security (current state, challenges and initiatives); (2) extreme weather, risks and challenges); (3) managing cyber risks in the electric power sector; and (4) maintaining electric reliability with changing resource mix. A detailed final agenda, identifying the presenters and panelists, is available here. Speaker materials have been posted to eLibrary. A transcript of the September 30 technical conference was posted in eLibrary on November 16, 2021. On January 7, 2022, the FERC issued a notice inviting post-technical conference comments, either to address the questions raised in the January 7 notice or any other issues raised during the technical conference. Comments were due on or before February 22, 2022 and were filed by: ISO-NE, Americans for a Clean Energy Grid, AGA/APGA, CAISO, EEI, Energy Systems Integration Group, EPSA, Grain Belt Express, Grid Lab, MISO, Natural Gas Council, Natural Gas Supply Association, Public Power Associations. This matter is pending before the FERC.

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

March 23 Tech Conf (PJM). The FERC convened a Commissioner-led technical conference on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. On April 5, 2021, the FERC issued a notice inviting post-technical conference comments on specific PJM-specific questions. Initial comments were due on or before April 26, 2021; reply comments must be submitted on or before May 10, 2021. More than 45 sets of comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA, some of which addressed issues to be discussed in the May 25 New England technical conference (identified immediately below). On May 10, 2021, reply comments were filed by the American Clean Power Association ("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").

May 25 Tech Conf (New England). On May 25, 2021, the FERC held a Commissioner-led technical conference regarding the wholesale markets administered by ISO New England Inc. Supplemental notices of the technical conference were issued on May 3 and May 17. The May 17 supplemental notice identified panelists and topics/questions for discussion for the technical conference. Panel discussions included: (1) a Commissioner-led discussion of the relationship between state policies and the New England Markets; (2) a Staff-led discussion of short-term options and complementary potential market changes to accommodate state policies in New England; and (3) a Staff-led discussion of long-term options and centralized procurement of clean energy.

Post (New England) Tech Conf Comments. On June 4, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the May 17, 2021 supplemental notice. Post-technical conference comments were due on or before ***July 19, 2021*** and were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

- **Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)**

Tech Conferences. As previously reported, the FERC held in the Fall of 2021 two staff-led technical conferences addressing ISO/RTO energy and ancillary services markets (including potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time).[127] The first technical conference was held September 14, 2021; the second, October 12, 2021. Transcripts of both technical conferences are posted in eLibrary.

Post-Technical Conference Comments. On December 6, 2021, the FERC invited all interested persons to file initial and reply comments on the topics discussed during each of the two technical conferences. Initial comments were due on or before ***February 4, 2022*** and 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, Public Citizen. Reply comments are due on or before ***March 7, 2022***.

- **Hybrid Resources (AD20-9)**

As previously reported, the FERC convened a July 23, 2020 technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location ("hybrid resources"). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials and a transcript of the technical conference have been posted to the FERC's eLibrary. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street Institute, Savion, and SEIA.

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the "Issues"); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the order. The ISO/RTO Reports, including ISO-NE's, were filed on July 19, 2021. Public comments in response to the ISO/RTO reports were filed in September 20, 2021.[128]

Hybrid Resources White Paper. On May 26, 2021, the FERC issued a white paper that discusses the hybrid resources technical conference, as well as information learned in post-technical conference comments. Interested persons were invited to submit comments on the white paper and encouraged to jointly respond to both the white paper and RTO/ISO informational reports where applicable to avoid duplicate comments. Comments on the white paper will also be due on September 20, 2021.

Comments. Comments on the RTO filing and on the FERC's Hybrid Resources White Paper were submitted by the American Council on Renewable Energy ("ACRE"), Clean Grid Alliance, EEI, the City of New York, Hybrid Resource Coalition, NRECA, Pine Gate Renewables, PJM IMM, and UCS. On October 20, 2021, NYISO submitted comments in response to issues raised by those comments. These matters remain pending before the FERC.

- **Increasing Market and Planning Efficiency Through Improved Software Tech Conf (Jun 21-23, 2022) (AD10-12)**

On February 24, 2022, the FERC announced that it will hold its 13th annual technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software from June 21-23. A detailed

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[127] In advance of the technical conferences, in an effort to frame discussions at those 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 energy and ancillary services markets reforms as well as reforms then under consideration.

[128] Public comments were initially due Aug. 18, 2021. However, in response to a request by the Energy Storage Association ("ESA"), the American Clean Power Association ("ACP"), and SEIA, the FERC granted a 30-day extension of time, to Sep. 20, 2021, to file comments in response to the ISO/RTO reports.

agenda with the list of and times for the selected speakers will be published on the FERC's website[129] and in eLibrary after May 20, 2022.

- ***Order 882*: 2022 Civil Monetary Penalty Inflation Adjustments (RM22-6)**

On January 14, 2022, the FERC issued *Order 882*[130] 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.[131] Of particular interest is the increase in potential civil penalties for market manipulation, which were increased from $1,307,164 to $1,388,496 per violation, per day. *Order 882* became effective January 13, 2022.[132]

- **NOI: Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses (RM22-5)**

On December 16, 2021, the FERC issued a notice of inquiry[133] seeking comments on (i) the rate recovery, reporting, and accounting treatment of industry association dues and certain civic, political, and related expenses; (ii) the ratemaking implications of potential accounting and reporting changes; (iii) whether additional transparency or guidance is needed with respect to defining donations for charitable, social, or community welfare purposes; and (iv) a framework for guidance should the FERC determine action is necessary to further define the recoverability of industry association dues charged to utilities and/or utilities' expenses from civic, political, and related activities. Initial comments were due February 22, 2022 and were filed by AGA, APPA, EEI, EPRI, Harvard Electricity Law Institute, INGA, MA AG, National Grid, NEI, Nexamp, NRECA, PJM, Public Citizen, Public Interest Organizations, Ratepayers, Sunova, and UCS. Reply comments are due on or before March 23, 2022.

- **ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)**

On July 15, 2021, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[134] to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained. Specifically, the ANOPR discusses proposals or concepts for changes to existing processes in several broad categories: regional transmission planning, regional cost allocation, generator interconnection funding, generator interconnection queueing processes and consumer protection, and in several instances the ANOPR also offers a potential rationale or argument for potential proposals. The FERC seeks comments from the public on these proposals and welcomes commenters to offer additional or alternative proposals for consideration.

Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEE, 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,

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[129] https://www.ferc.gov/industries-data/electric/power-sales-and-markets/increasing-efficiency-through-improved-software.

[130] *Civil Monetary Penalty Inflation Adjustments*, Order No. 882, 178 FERC ¶ 61,008 (Jan. 7, 2022) ("*Order 882*").

[131] *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).

[132] *Order 882* was published in the *Fed. Reg.* on Jan. 13, 2022 (Vol. 87, No. 9) pp. 2,036-2,037.

[133] *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses*, 177 FERC ¶ 61,180 (Dec. 16, 2021) ("*Dues & Expenses NOI*").

[134] *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*").

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.

November 15, 2021 Tech Conf. On November 15, 2021, the FERC convened a technical conference to examine in detail issues and potential reforms related to regional transmission planning as described in the July 15, 2021 ANOPR. Specifically, the technical conference examined issues related to incorporating sufficiently long-term and comprehensive forecasts of future transmission needs during regional transmission planning processes, including considering the needs of anticipated future generation in identifying needed transmission facilities. Speaker materials were posted to eLibrary on November 16, 2021.

Reply and Post-Tech Conf Comments. ANOPR Reply Comments and Post-November 15 technical conference comments were due on or before ***November 30, 2021*** and 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, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Subsequently, supplemental reply comments were filed by WIRES and a group of former military leaders and former Department of Defense officials filed a statement. Since the last Report, joint supplemental comments were filed by the Clean Energy Coalition.[135] This matter is pending before the FERC.

- **NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)**

On March 18, 2021, the FERC issued a NOI[136] seeking comments on whether to revise its Demand Response ("DR") Opt-Out regulations established in *Orders 719 and 719-A.* Those regulations require an ISO/RTO not to accept bids from an aggregator of retail customers ("ARC") that aggregates DR of the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' DR to be bid into ISO/RTO markets by an ARC. The FERC now seek information to help it examine the potential costs/burdens and benefits, both quantitative and qualitative, of removing the DR Opt-Out, as well as other changes relating to DR since the FERC issued *Orders 719 and 719-A*. The FERC is not seeking comment on the Small Utility Opt-In. Comments on the NOI, following an extension, were due on or before July 23, 2021 and were filed by nearly 30 parties, including by AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC. Reply comments were due on or before August 23, 2021, and were filed by AEP, Armada Power, Entergy, Southern Pioneer Electric, Voltus, State Commissions from LA/MS, MI, MO, NC, APPA/NRECA, Assoc. of Bus. Advocating Tariff Equity ("ABATE"), and PIOs. This matter is pending before the FERC.

- **NOPR: Cybersecurity Incentives (RM21-3)**

On December 17, 2020, the FERC issued a NOPR[137] proposing to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the BPS.

Comments on the *Cyber security Incentives NOPR* were due on or before April 6, 2021. Comments were filed by: NECPUC, APPA, EEI, EPSA, LPPC, NERC, NRECA, TAPS, Accenture, aDolus Inc. et al.,[138] Alliant, Anterix, Bureau of Reclamation, CA Dept of Water Resources State Water Project/CPUC, George Cotter, FRS, Hitachi ABB Power Grids, IECA, ITC, Joint Consumer Advocates, MI PUC, Org of MISO States, MISO TOs, PJM

[135] The "Clean Energy Coalition" are ACPA, AEE and SEIA.

[136] *Participation of Aggregators of Retail Demand Response Customers in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,198 (March 18, 2021) ("*DR Aggregator NOI*").

[137] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Cybersecurity Incentives NOPR*").

[138] These joint comments were filed by aDolus Inc., Fortress Information Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs and Reliable Energy Analytics LLC.

TOs, and Public Citizen. Reply comments were due May 6, 2021[139] and were filed by APPA/TAPS, EEI, SEIA, California Public Utilities Commission and California Department of Water Resources ("CA PUC/DWR"), and the Office of the Ohio Federal Energy Advocate ("Ohio FEA"). This matter remains pending before the FERC.

- ***Order 881*: Managing Transmission Line Ratings (RM20-16)**

On December 16, 2021, the FERC issued its final rule, *Order 881*, on Managing Transmission Line Ratings.[140] In *Order 881*, the FERC reforms both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, *Order 881* requires:

(i) transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service;

(ii) ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly;

(iii) transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s); and

(iv) transmission providers to maintain a database of transmission owners' transmission line ratings and transmission line rating methodologies on the transmission provider's Open Access Same-Time Information System ("OASIS") site or other password-protected website.

Order 881 will become effective March 14, 2022.[141] Requests for rehearing and/or clarification of *Order 881* were filed by ATC, EEI, ITC Holdings, MISO IMM, and the MISO TOs on January 18, 2022, but may be deemed denied by operation of law. On February 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[142] The Notice confirmed that the 60-day period during which a petition for review of *Order 881* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 881*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

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

Supplemental NOPR. In light of comments already received in this proceeding,[143] the FERC issued on April 15, 2021 a *Supplemental NOPR*[144] 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 seeks 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

[139] The *Cybersecurity Incentives NOPR* was published in the *Fed. Reg.* on Feb. 5, 2021 (Vol. 86, No. 23) pp. 8,309-8,325.

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

[141] *Order 881* was published in the Fed. Reg. on Jan. 13, 2022 (Vol. 87, No. 9) pp. 2,244-2,307.

[142] *Managing Transmission Line Ratings*, 178 FERC ¶ 62,104 (Feb. 18, 2022) ("*Order 881 Notice of Denial of Rehearings by Operation of Law*").

[143] 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.

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

transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[145] 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.[146] Since the last Report, reply comments were posted from New England State Parties,[147] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the American Clean Power Association.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[148] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments were due on or before January 14, 2022 and were filed by APPA, CAISO,

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[145] 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 <u>and</u> an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.
- ***Transmission Organization Incentive.*** A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

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

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

[148] 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).

Clean Energy Parties,[149] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

These matters are pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J*: Incorporation of NAESB WEQ Standards v. 003.3 into FERC Regs (RM05-5-029, -030)**

On May 20, 2021, the FERC issued Order 676-J,[150] which revises 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. *Order 676-J* became effective August 2, 2021.[151] Public utilities must make a compliance filing to comply with the requirements of this final rule through eTariff 12 months after implementation of the WEQ Version 003.2 Standards. Compliance filings for cybersecurity and Parallel Flow Visualization standards were due March 2, 2022.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[152] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

[149] The "Clean Energy Parties" are: Working for Advanced Transmission Technologies ("WATT Coalition"), the American Clean Power Association ("ACP"), AEE, American Council on Renewable Energy ("ACORE"), Natural Resources Defense Council ("NRDC"), and the Sustainable FERC Project.

[150] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

[151] *Order 676-J* was published *Fed. Reg.* on June 2, 2021 (Vol. 86, No. 104) pp. 29,491-29,503.

[152] *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement filed its reply on September 14, 2021. This matter remains pending before the FERC. (Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court.) If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

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

On January 20, 2022, the FERC issued an order establishing a hearing to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "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.[153]

As previously reported, on March 18, 2021, the FERC issued a show cause order[154] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity ("CPCN") under NGA section 7(c).[155] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15.

Hearings. On January 25, 2022, Chief ALJ Cintron designated Deputy Chief ALJ Andrew Satten as the Presiding Judge for the purpose of conducting a hearing and issuing an initial decision in this case. Track II procedural time standards were established for this hearing, calling for the hearing to be convened by September 6, 2022 and an initial decision to be issued on or before December 20, 2022. On February 1, 2022, Respondents requested a stay of the ALJ proceedings, which would remain in place until the completion of the Declaratory Judgment Act action that Respondents filed also on February 1, 2022 in the U.S. District Court for the Northern District of Texas challenging the legality of the pending ALJ proceedings. Enforcement Litigation Staff answered the February 1 Motion for Stay on February 4, 2022.

Also since the last Report, then-presiding ALJ Satten issued an order scheduling a prehearing videoconference for March 8, 2022. On February 24, 2022, Chief Judge Cintron substituted ALJ Joel DeJesus in place of ALJ Satten, without modification to any of the schedule for the proceeding. In a February 25, 2022 order, Presiding Judge DeJesus adopted the time and date for the March 8 videoconference and the instructions

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153 Rover Pipeline, LLC, and Energy Transfer Partners, L.P., 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*").

154 *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP CPCN Show Cause Order*").

155 Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

provided by Judge Satten as his own. Presiding Judge DeJesus directed the participants to submit a jointly-proposed procedural schedule by March 2, 2022.

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

On December 16, 2021, the FERC issued a show cause order[156] 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,[157] 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;[158] (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***. Following a request from Respondents, the answer period was extended to and including March 21, 2022.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[159] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[160] *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.[161] 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.[162]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

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

[157] *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").

[158] 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.

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

[160] *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*")).

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

[162] *Id*. at P 319.

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

On April 28, 2016, the FERC issued a show cause order[163] 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.[164]

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.[165] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[166] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference. Judge Krolikowski issued an order confirming her rulings from the August 26 prehearing conference and establishing a procedural schedule that calls for, among other dates, pre-hearing briefs by July 25, 2022, hearings (estimated to take 2-3 weeks) to begin on August 15, 2022, and an initial decision on January 9, 2023. In light of the settlement judge procedures undertaken, Chief Judge Cintron extended the hearing commencement and initial decision deadlines to September 26, 2022, and February 20, 2023, respectively. Since the last Report, an oral argument addressing administrative matters and procedural motions was held on February 16, 2022. Answers to motions to intervene by whistleblower witnesses are due on Mar 2, 2022; discussions between Respondents and FERC Enforcement Litigation Staff on disputed data requests not resolved during oral argument are to continue. Presiding ALJ Krolikowski issued an order confirming his February 16 bench rulings on February 23, 2022.

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

[164] 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 uneconom ic 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.

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

[166] The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

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.
  - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate; National Grid and ConEd submit comments supporting Iroquois' application and request for action.
  - On May 27, 2021, FERC staff issued a notice that it will prepare an environmental impact statement ("EIS") for this Project, which will respond to comments filed on the Environmental Assessment, and plans to release that EIS on September 3, 3021.
  - On June 11, 2021, FERC staff issued a notice that it has prepared a draft EIS for this Project, which responds to comments on the September 30, 2020 Environmental Assessment, and with the exception of greenhouse gas ("GHG") emissions, concludes that approval of the proposed Project, with the mitigation measures recommended in the EIS, would not result in significant environmental impacts. FERC staff did not come to a determination of significance with regards to GHG emissions. Comments on the draft EIS were due on or before August 9, 2021. Since the last Report, 93 sets of individual comments were filed, bring to nearly 300 the number of individual comments have been filed. Algonquin responded to those comments on August 24, 2021.
  - On September 2, 2021, FERC staff modified the issuance date of its final EIS for the Project, due to the "complexity of comments received on the draft EIS". Issuance of a final EIS is now expected on November 12, 2021; the 90-day Federal Authorization Decision Deadline, February 9, 2022.
  - On September 3, 2021, FERC staff issued environmental information request #4, to which Iroquois responded on September 13, 2021.
  - On October 15, 2021, Iroquois submitted a supplemental Life Cycle Greenhouse Gas Analysis Report.
  - On November 12, 2021, FERC staff issued the final EIS for the Project, which responds to comments that were received on the September 30, 2020 Environmental Assessment and June 11, 2021 draft EIS and discloses downstream GHG emissions for the Project. "With the exception of climate change impacts, FERC staff concluded that approval of the proposed Project, with the mitigation measures recommended in this EIS, would not result in significant environmental impacts."
  - Since the last Report, Iroquois, ConEd and National Grid answered/replied to the December 20, 2021 comments on the final EIS by the U.S. Environmental Protection Agency ("EPA").

Non-New England Pipeline Proceedings
The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

- **Northern Access Project (CP15-115)**
  - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2,

2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[167] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).

- As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[168] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[169] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
- The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[170] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[171] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[172] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA,

[167] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[168] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[169] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[170] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[171] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[172] Summary Order, *Nat'l Fuel Gas Supply Corp. v. N.Y. State Dep't of Envtl. Conservation*, Case 17-1164 (2d. Cir., issued Feb. 5, 2019).

even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[173]

- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [174] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[175]
- On January 28, 2022, Applicants again requested an additional extension of time, this time until December 31, 2024, to complete construction of the Project and enter service. Comments on that request were due on or before February 16, 2022.

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, the following series of online technical forums to discuss the issues presented in the Vision Statement were held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report was further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

ISO-NE Board Response. On September 23, 2021, the ISO-NE Board responded to the New England States' Vision Statement and Advancing the Vision Report. A copy of that response was included with the materials for the October 7, 2021 Participants Committee meeting and is posted on the ISO-NE website here.

[173] *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir., filed May 28, 2019) (consolidated).

[174] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[175] *Id.* at P 10.

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).

- **NTE CT Petition for Review of *Killingly CSO Termination Orders* (22-1027)**
  Underlying FERC Proceeding: ER22-355[176]
  Petitioner: NTE CT
  Status: Filing of Initial Submissions Underway

On February 23, 2022, NTE CT petitioned the DC Circuit for review of the FERC's orders accepting the termination of the Killingly Energy Center's CSO. NTE CT must file a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decisions from which the appeal arises by March 28, 2022. Appearances must also be filed by March 28, 2022. Dispositive motions, if any, and a Certified Index to the Record must be filed by April 11, 2022.

- **NTE CT Petition for Writ of Mandamus for Stay of FERC Order Accepting the Killlingly Energy Center CSO Termination (22-1011)**
  Underlying FERC Proceeding: ER22-355[177]
  Petitioner: NTE CT
  Status: Court Lifts Stay

On January 20, 2022, NTE CT petitioned the DC Circuit Court of Appeals for a Writ of Mandamus to stay the *Killingly CSO Termination Order.* The Court granted that Stay in a 2-1, February 4, 2022 per curiam order, which meant that Killingly was able to participate in FCA16. On February 24, 2022, the Court issued its full opinion, as promised in the per curiam order, setting forth its rationale for granting the Stay. The Stay was to remain in effect until 30 days after the FERC resolves NTE's request for rehearing of the *Killingly CSO Termination Order*.

On February 18, 2022, however, ISO-NE filed an emergency motion to lift the Stay. On February 22, NEPGA moved to intervene and support ISO-NE's motion to lift the Stay. NTE CT opposed the motion to lift the Stay and ISO-NE replied to NTE CT's motion to oppose. The FERC filed a response taking no position on ISO-NE's motion, but advising the Court that it had issued the *Killingly CSO Termination Allegheny Order*. On February 24, the Court amended its February 4 per curiam order and issued a full opinion as promised in the per curiam order. Finally, on March 2, 2022, the Court issued an order lifting the Stay. In lifting the Stay, the Court stated that ISO-NE had "demonstrated that, due to changed circumstances, the stay is no longer equitable." The Court highlighted the facts that (i) the FERC had issued the *Killingly CSO Termination Allegheny Order*, "addressing some of the deficiencies in its earlier termination order," and (ii) it was "undisputed that NTE has defaulted on its financial assurance obligations under the ISO-NE Tariff, which default provides an independent ground for terminating the Killingly plant's capacity supply obligation."

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[176] *ISO New England Inc.*, 178 FERC ¶ 61,001 (Jan. 3, 2022) ("*Killingly CSO Termination Order*") (order accepting CSO termination); *ISO New England Inc.*, 178 FERC ¶ 62,082 (Feb. 11, 2022) (notice denying *reh'g by operation of law and providing for further consideration)*; *ISO New England Inc.*, 178 FERC ¶ 61,130 (Feb. 23, 2022) (order addressing arguments raised on reh'g, sustaining results of *Killingly CSO Termination Order*). Together, these orders referred to as the "*Killingly CSO Termination Orders*".

[177] *Killingly CSO Termination Order*.

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)**
  Underlying FERC Proceeding: ER21-2334[178]
  Petitioner: CSC
  Status: Filing of Initial Submissions Underway

On December 30, 2021, CSC petitioned the DC Circuit Court of Appeals for review of the FERC's orders denying it authorization to establish a regulatory asset that would include all CIP-IROL Costs prudently incurred between January 1, 2016 and May 31, 2021 and to recover those costs under Schedule 17 over a five-year period. Appearances are due February 2, 2022. CSC must file a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decision from which the appeal arises by February 2, 2022. Dispositive motions, if any, and a Certified Index to the Record must be filed by February 17, 2022.

NESCOE intervened on January 28, 2022. On February 2, 2022, CSC filed a docketing statement and statement of issues. Also on February 2, the FERC asked that the Court hold the petition for review in abeyance, including suspending the initial filing schedule, until the Commission issues an order addressing Petitioner's request for rehearing. On February 16, 2021, the FERC granted the FERC's motion to hold the petition in abeyance, directing (i) the FERC to file status reports at 30-day intervals (with the first such report due March 18, 2022) and (ii) the parties to file motions to govern future proceedings within 30 days of the completion of FERC's proceedings on rehearing (or March 28, 2022, given the FERC's *CSC CIP-IROL Costs Allegheny Order* summarized in Section II above).

- **Mystic ROE (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)**
  Underlying FERC Proceeding: EL18-1639-010, -011,[179] -013[180]
  Petitioners: Mystic, CT Parties,[181] MA AG, ENECOS
  Status: Filing of Initial Submissions Underway

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198.

Since the last Report, Mystic's appeal of the *Mystic ROE Second Allegheny Order* (22-1026) was also consolidated under 21-1198. On February 8, 2022, the Court issued an order granting in part the FERC's further request, contested by Mystic, for an extension of time to file the Certified Index to the Record.[182] Pursuant to the February 8 order, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 1, 2022, the Court directed that proposed briefing formats be filed by March 31, 2022.

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[178] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*August 31 Order*"); *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *August 31 Order*).

[179] *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).*

[180]

[181] In this appeal, "CT Parties" are the Connecticut Public Utilities Regulatory Authority ("CT PURA"), Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the Connecticut Office of Consumer Counsel ("CT OCC").

[182] The FERC's request was for an extension to March 29, 2022.

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[183]
  Petitioner: LS Power
  Status: Briefing Complete; Oral Argument Held Jan 27, 2022; Awaiting Decision

As previously reported, On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for immediate need reliability projects. Following completion of briefing, oral argument before Judges Rogers, Pillard and Randolph was held on January 27, 2022. This matter is pending before the Court.

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[184]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Briefing Complete; Oral Argument May 5, 2022

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.[185] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. On April 16, 2021, the Court ordered the parties to file, and the parties did file, by May 17, 2021, proposed formats for the briefing of these cases.

Since the last Report, Reply Briefs were filed on February 3, 2022); a Joint Appendix, February 17, 2022; and Final Briefs, February 24, 2022. Briefing is now complete. On February 9, 2022, oral argument was scheduled for ***May 5, 2022***. The composition of the merits panel will be identified at a later time.

- ***CASPR*** **(20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[186]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until June 1, 2022)

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that

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[183] *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding")* (finding (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and *ISO New England Inc.,* 172 FERC ¶ 61,293 (Sep. 29, 2020) *("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

[184] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[185] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

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

an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

On January 12, 2021, the Court dismissed as moot the FERC's October 19 motion to hold this proceeding in abeyance and ordered that the motion to dismiss be referred to the merits panel (Judges Pillard, Katsas and Walker) and addressed by the parties in their briefs. On January 25 and 26, 2021, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, 2021, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases. On March 24, 2021, the Court granted NEPOOL's intervention and established a briefing schedule that, as explained just below, has since been superseded.

On April 7, 2021, the Court granted Petitioners' motion to hold this matter in abeyance, pending further order of the Court. The parties were directed to file motions to govern future proceedings in these cases on or before October 22, 2021. On October 22, 2021, Petitioners Sierra Club, NRDC, Renew Northeast, Inc., and CLF moved the Court to hold this matter in abeyance until June 1, 2022. On October 25, 2021, the Court granted Petitioners' second motion to hold this matter in abeyance. The parties were directed to file motions to govern future proceedings in these cases on or before June 1, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[187]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[188] petitioned the DC Circuit Court of Appeals for review of the FERC's October 6, 2017 order rejecting the TOs' filing that sought to reinstate their transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[189] 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

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

[188] 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.

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

proceedings. On December 15, 2021, the FERC submitted a status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[190]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Briefing Complete; Oral Argument Held Oct 21, 2021; Awaiting Decision

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. Following completion of briefing, oral argument was held October 21, 2021 before Judges Wilkins, Katsas and Jackson. This matter is pending before the Court

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[191]
  Petitioners: SEIA et al.
  Status: Briefing Complete; Oral Argument Scheduled for March 8, 2022

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[192] Briefing is now complete and oral argument has been scheduled for March 8, 2022, though the Court stated that panel to be assigned could decide to submit the case on the briefs instead. The composition of the argument panel will be identified roughly 30 days prior to oral argument.

- **PennEast Project (18-1128 et al.)**
  Underlying FERC Proceeding: CP15-558[193]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel
  Status: Case Dismissed

On January 28, 2022, the FERC filed an unopposed motion to dismiss the petitions in these consolidated cases. The FERC stated that dismissal should be granted, and its December 16 order[194] permitted to go into effect, since PennEast informed the FERC that it has "ceased all further development of the Project." On February 8, 2022, the Court issued a per curiam order granting the FEC's motion and issued the mandate to FERC, concluding these proceedings. Reporting on these proceedings is concluded.

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[190] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[191] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[192] *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

[193] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[194] *PennEast Pipeline Co., LLC*, 177 FERC ¶ 61,197 at P 4 (Dec. 16, 2022) (order (i) vacating the certificate authorization for the PennEast Pipeline Project issued in FERC Docket No. CP15-558, (ii) vacating the authorization of an amendment in FERC Docket No. CP19-78, and (iii) dismissing the pending certificate amendment application in FERC Docket No. CP20-47).

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[195]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Oral Argument Held Nov 18, 2021; Awaiting Decision

The MISO TOs, Transource and "Dec 23 Petitioners",[196] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Following completion of briefing, oral argument was held on November 18, 2021 before Judges Srinivasan, Katsas and Walker. This matter is pending before the Court.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.);**
  Underlying FERC Proceeding: CP16-9-012[197]
  Petitioners: LS Power, Algonquin, INGA
  Status: Case Being Held in Abeyance

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.

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[195] *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).

[196] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperati ve Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Public Service Comm.; MO Joint Municipal Electric Utility Comm.; Organization of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

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

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