NEPOOL
NEW ENGLAND POWER POOL

Sebastian Lombardi
Secretary

January 25, 2024

VIA E-MAIL

TO: **PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**

RE: Supplemental Notice of February 1, 2024 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the February 2024 meeting of the Participants Committee will be held **in person on Thursday, February 1, 2024, at 10:00 am at the Renaissance Boston Waterfront Hotel, located at 606 Congress Street, Boston, MA 02210, in the Pacific Ballroom,** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

For those who otherwise attend NEPOOL meetings but plan to participate in the February 1 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

FOR PARTICIPANTS, PARTICULARLY THOSE WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE THAT 2024 ANNUAL FEES WILL BE INCLUDED ON THE MONTHLY STATEMENTS TO BE ISSUED ON FEBRUARY 12, 2024. Participants that were members on January 1, 2024 will be assessed that Annual Fee, which must be paid, if the annual fee billing results in an invoice, on or before the close of business on Wednesday, February 14, 2024 in order to avoid penalties and interest. Please plan accordingly. If there are questions, you can reach out to Pat Gerity (860-275-0533; pmgerity@daypitney.com) or to ISO New England's Participant Support and Solutions (413-540-4220; askISO@iso-ne.com).

Looking ahead, the March Participants Committee meeting is scheduled for Thursday, March 7, 2024 and will be held in person. We will in future notices provide more detailed information regarding the location and arrangements for those seeking accommodations the evening before that meeting.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the December 7, 2023 Participants Committee meeting. A copy of the draft minutes, marked to show the changes from the version circulated on January 23, 2024, is included with this supplemental notice and posted with the meeting materials.

2. To adopt and approve the actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials. Consent Agenda Item No. 3 has been removed and will be considered as Item 5A (see below).

3. To receive an update on activities of the Joint Nominating Committee and information from and about ISO Board member Michael Curran, one of the incumbent ISO Board of Directors who is eligible for re-election to the Board this year.

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

5. To receive an ISO Chief Operating Officer report. The February COO report will be circulated and posted in advance of the meeting. The January COO report was previously circulated and is posted on the NEPOOL and ISO websites.

5A. To consider, and take action, as appropriate, on revisions to Planning Procedure 5-6 (Interconnection Planning Procedure for Generation and Elective Transmission Upgrades). This item was removed from the Consent Agenda (Consent Agenda Item 3). Background materials and a draft resolution are included and posted with this supplemental notice.

6. To consider, and take action, as appropriate, on changes to Tariff §§ I.2.2 (Definitions) and III.9.3 (Forward Reserve Auction Offers), as recommended by the Markets Committee at its January 9, 2024 meeting, to update the Forward Reserve Offer Cap and delay the publication of the Forward Reserve Auction Offer data. Background materials and a draft resolution will be included and posted with the supplemental notice.

6A. To consider, and to take action if and as appropriate, on a request for a waiver of the NEPOOL Generation Information System (GIS) Operating Rules by Saco River Hydro, LLC. Background materials and a draft resolution are included and posted with this supplemental notice.

[continued on next page]

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

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

7. To receive a report on current contested matters before the FERC and the Federal Courts. The end of January litigation report will be circulated and posted in advance of the meeting. The January 11, 2024 Report is posted on the NEPOOL website.

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

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

9. Administrative matters.

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

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PRELIMINARY

Pursuant to notice duly given, the 2023 annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, December 7, 2023, at the Colonnade Hotel, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by telephone.

Mr. David Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and invited guests who were present. Members expressed their appreciation for Mr. Cavanaugh's leadership during his tenure and the grace with which he guided the Committee during the extremely challenging pandemic and afterward. Mr. Cavanaugh then addressed the Committee and remarked that any success achieved had been the direct result of the thoughtful and collaborative engagement among the Participants, together with ~~our~~ NEPOOL's partners at NESCOE, NECPUC and the ISO.

2023 NEPOOL ANNUAL REPORT

Mr. Cavanaugh referred the Committee to the 2023 NEPOOL Annual Report distributed at the meeting and posted on the NEPOOL website. Mr. Cavanaugh thanked the Day Pitney team and the Principal Committee Vice-Chairs ~~of each Sector and the Technical Committees~~ for their efforts assembling and completing the Annual Report. He encouraged members to review the Annual Report.

APPROVAL OF NOVEMBER 2, 2023 MEETING MINUTES

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

CONSENT AGENDA

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

REMARKS BY FERC CHAIRMAN WILLIE PHILLIPS

Mr. Cavanaugh invited ISO Board Chair Ms. Cheryl LaFleur to introduce to the Committee FERC Chairman Willie Phillips, who was accompanied by his Critical Infrastructure and Resilience Advisor, Mr. Kal Ayoub. Ms. LaFleur warmly summarized Chairman Phillips’~~s~~ experience prior to joining the FERC, as well as the hallmarks thus far of his tenure as Chairman, and briefly introduced to Chairman Phillips the key issues facing, and work underway in, New England.

Chairman Phillips t~~T~~hanked ~~ing~~ Ms. LaFleur for her introduction. After~~s~~ a brief pause,[1] Chairman Phillips expressed his appreciation for the opportunity to speak in person to the

[1] As Chairman Phillips began his remarks, a group of Non-Participant representatives of the “No Coal, No Gas” campaign, who had not in advance requested or been invited to attend the meeting as required by the Committee Bylaws, entered the room with no advanced notice and requested the opportunity to listen to Chairman Phillips’ remarks. Following a brief conversation with the Committee Chair, those representatives were invited by the Committee

Committee, notwithstanding the briskness of Boston in December (particularly in comparison to warm and sunny California where he had just been). He was grateful to build upon the efforts and experience of the June New England Winter Gas-Electric Forum (Forum) convened in Maine, by addressing NEPOOL directly. Chairman Phillips emphasized that the FERC continued to take very seriously the comments, remarks, and feedback received following the FERC Forum and appreciated the participation in that process. He stressed the importance to him of the issues facing New England, noting that his team, his office and his door was always open, encouraging members to come by and call on them.

Chairman Phillips acknowledged the critical role and importance he ascribed to the stakeholder process. He remarked that stakeholder groups like NEPOOL were critical to ensuring that wholesale electricity markets work for everyone and providing an opportunity for every sector's perspective to be heard, adding that an effective stakeholder process facilitated efforts to address, better understand and achieve some certainty with respect to the multitude of issues facing the grid system. The Chairman thanked those around the table for their active engagement in the process and specifically thanked NEPOOL leadership for the invitation and opportunity to speak to the Participants Committee. He put forward his commitment to be a Chairman focused on ensuring the reliability of energy delivery systems, affordability for all consumers and businesses, and planning for a sustainable energy future for all, including environmental justice communities. He proceeded in turn to address generally each of those areas.

Chair to remain in the room to listen to Chairman Phillips' remarks, and ultimately stayed in the room through those remarks and the remaining agenda items until the Committee was adjourned.

With respect to his commitment to system reliability and affordability, Chairman Phillips summarized -the recently released joint statement he penned with NERC's CEO, noting his ongoing concerns with the reliability of New England's grid. He suggested that extreme weather of all kinds was restraining both the region's gas and electric systems. Referring also to the FERC/NERC final report on Winter Storm Elliot, he suggested that extreme weather events, with accompanying generator outages/losses, were becoming more the norm, if not predictable. He recounted a couple of examples of reliability-threatening, low pressure events on natural gas delivery pipelines that underscored for him the need to have an entity responsible for the reliability of the natural gas delivery system. That entity did not have to be the FERC, he said, but it would have to be an entity with the responsibility and authority to enact and enforce natural gas reliability standards. He pointed to Winter Storms Elliot and Uri ~~each serve~~ as sobering examples of how extreme weather events could have severe, adverse impacts on both the gas and electric systems, as well as on the well-being of the population as a whole.

Chairman Phillips urged New England's vigilance and proactive efforts in addressing how extreme weather and a changing resource mix impact winter reliability. Noting the region's reliance on natural gas resources and liquefied natural gas (LNG), and the potential, if not likely, effects of a prolonged cold spell, he was pleased that assessments for Winter 2023/24 projected a milder winter, but cautioned that hoping for or relying on milder winters could not be a sustainable plan for ensuring winter reliability. While the Chairman highlighted the ISO's expectation that, under normal conditions, adequate resources would be available for the upcoming winter and that the near-term energy security outlook may not be as dire as initially projected, he remained concerned about winter reliability in New England, for Winter 2023~~-~~/24 and beyond.

Looking ahead to potential solutions, Chairman Phillips opined that there were not simple solutions or easy fixes, nor could any one entity be relied upon to solve the problem. However, he expressed confidence that the critical players and best ideas would be found around the NEPOOL table, and all would have a role to play. He emphasized the importance of information availability, which would support well-informed decision-making. Identifying key sources of such information, he urged continued consideration and evaluation of the assumptions and methodologies underlying the region's assessments and studies. He was optimistic that NPCC's northeastern regional gas infrastructure study (including hydraulic modeling of gas systems in New England and New York) would help address some information gaps identified during the June Forum.

Turning to wholesale electric market design, Chairman Phillips noted the potential for Resource Capacity Accreditation (RCA) and other reforms to help address winter reliability issues by appropriately valuing the capacity of certain resources. He encouraged the region to consider such potential reforms in a holistic manner. He further encouraged the region, including the New England States (States), to ensure that the changing resource mix is implemented in a way that supports grid reliability. He noted concern with the impacts of the premature retirement of certain energy resources, including critical infrastructure like the Everett LNG facility, particularly during extreme weather events. Nonetheless, he applauded the efforts to implement ambitious clean energy goals, and emphasized that, in reaching for those goals, system reliability be kept top of mind.

Chairman Phillips spoke to the FERC's *Order 2023* interconnection reforms, which he characterized as a great first step on the "Transmission Reform Journey", as well as to FERC's long-term regional transmission planning rule efforts. Both of those efforts ~~a~~were intended to build upon developments in the various regions of the country and would be integral to preparing for the goals and a future 20-30 years down the road, by making necessary, critical and foundational decisions today.

Chairman Phillips then addressed environmental justice and equity (EJ). He articulated the industry's obligation to be sensitive to the cost and benefits of how energy is produced, procured and delivered. Noting that impacts had not historically been shared equally, he offered personal testimony to the challenges faced by EJ communities. He said it would be incumbent upon the industry moving forward to improve that balance so that the system planned for benefits all. He reported that the FERC hoped to issue in the near future an outward facing guidance document that would help utilities, advocates, and all those involved in the stakeholder processes better understand the FERC's expectation with respect to EJ communities, how to engage those communities, and how th~~e~~ose issues can be addressed in the stakeholder process.

In response to questions, he suggested that, to achieve a successful transition, many would have to be encouraged and lead, into what for them may be unfamiliar and uncomfortable territory, through education and changed behavior. Education would have to include a focus on the cost (both capital and human) of not taking certain steps/actions. He further challenged the members to work together to help ensure that the transition to a cleaner grid could be achieved~~,~~ reliably. He was also optimistic that the transition solution space would, with ~~the~~ appropriate adjustments, work with competitive wholesale markets, which he firmly believed added value when functioning properly.

When asked for thoughts on cost evaluation, Chairman Phillips referred to ongoing FERC proceedings addressing transmission costs. He believed there could be long-term savings, particularly given the impending need to replace aging infrastructure. He believed it more costly to reactively address aging infrastructure following operational failures, rather than proactively updating/upgrading that infrastructure. The benefits attendant to new projects, including economic, reliability, sustainability, and policy benefits, would all have to be considered, as well as the weighing of the costs of doing nothing.

There being no further questions, and on behalf of the Committee, Mr. Cavanaugh thanked Chairman Phillips for the generosity of his time and for his very thoughtful comments.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of ISO New England Board and Board Committee meetings, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

Reacting to discussion from, and in reference to the Annual Report distributed earlier in, the meeting, Mr. van Welie stressed the importance of the values articulated in the Annual Report's theme – candor, respect and collaboration – as enhanced by "succeeding together". He suggested that the journey to refine and decarbonize the region's energy system could only be achieved through a collective, team effort, which in turn would rely on and be furthered by those values. He expressed his appreciation, not only for the express recognition afforded those values, but to the collaboration between the States, NEPOOL, and the ISO to support and achieve that outcome. He committed the ISO to those values.

Mr. van Welie recognized Mr. Cavanaugh for his "impeccable" leadership as NEPOOL Chair over the prior three years, complimenting him for how he helped NEPOOL navigate through the challenges it faced during his tenure as Chair. He looked forward to working with the next Chair, who he believed would likely face a similar series of challenges.

Finally, Mr. van Welie thanked Chairman Phillips and his staff for the thoughtful and substantive remarks offered earlier in the meeting. He was pleased how, from reliability, to cost and environmental justice, to gas-electric issues, the Chairman had addressed, and was affirmatively working on, many of the dimensions underlying the challenges facing the region.

ISO COO REPORT

Operations Highlights

Dr. Chadalavada referred the Committee to his December operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through November 29, 2023, unless otherwise noted. The report highlighted: (i) Energy Market value for November 2023 was $378 million, up $118 million from the updated October 2023 value and down $275 million from November 2022; (ii) November 2023 average natural gas prices were 144% lower than October average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for November ($35.96/MWh) were 48% higher than October averages; (iv) average November 2023 natural gas prices and Real-Time Hub LMPs over the period were down 40% and down 47%, respectively, from November 2022 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.6% during November (down from 101.6% reported for October), with the minimum value for the month of 95.2% on November 18; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for November totaled $4.9 million, which was up $0.4 million from October 2023 and up $1.1 million from November 2022. November NCPC payments, which were 1.3%

of total Energy Market value, was comprised of $4.9 million in first contingency payments (up $0.4 million from October). There were no second contingency or voltage NCPC payments in November.

Dr. Chadalavada reported that November 2023 was colder than normal -- 6° F colder than November 2022 and 2° F colder than an average November in New England. Loads were slightly higher than November 2022, despite a significant increase in behind-the-meter photovoltaic (PV) installations and output (November 2023 averaged 3,900 MW of PV output, 600 MW more than 2022). He added that the pace of New England PV installations was averaging 600-800 MW per year. Tight system conditions were experienced on three days in November (the 6th, 29th and 30th), with each day having loads slightly higher than forecast, forced outages, and in a couple of instances, imports slightly below the Day-Ahead Energy Market level. On those days, there were binding reserve constraints, but not to the point where any capacity deficiency was forecasted.

Turing to upcoming planned transmission outages, Dr. Chadalavada noted two: (i) Line 312/393 (Northfield to Alps), which would be out of service from December 5 to December 10, and was expected to reduce in both directions the New York-New England interface limit to roughly 900 MW; and (ii) Line 369 (Seabrook-to-Timberswamp), which would be out of service from December 11 to December 16, potentially exposing New Hampshire and Maine to second contingency costs.

Dr. Chadalavada also reported that the Tariff revisions to make front-of-meter solar installations dispatchable under “do not exceed” (DNE) rules that account for the resources’ variable output and any congestion on the transmission system was successfully implemented on December 5, 2023. He said that approximately 50-60 assets, totaling roughly 620 MW, were participating in the Solar DNE program, with 35-40 of those assets having put in place the necessary protocols to receive ISO dispatch instructions, and the remainder expected to submit, as permitted, plans to come into compliance before the expiration of the Tariff's compliance grace period. Implementation was smooth and comparable to implementation of the Wind DNE dispatch provisions. The ISO was pleased with the progress of solar assets' participation in the markets and the additional performance visibility that participation in the Solar DNE program provided to Control Room operators.

In response to questions, Dr. Chadalavada indicated that progress was being made with respect to PV load forecasting. He pointed to increased sampling of data sets, more accurate "machine learning", and better weighting of composite forecasts as contributing to that progress. Also, ISO adjustments had minimized what had previously been a consistent underforecasting bias. Several additional improvements were planned, including as the science would allow improvements to cloud cover forecasts, a key variable to PV forecasting. Dr. Chadalavada committed, with the benefit of additional experience and data, to come back to the Committee to review and discuss the performance of this ongoing effort.

New England 2023/24 Winter Outlook Update

Dr. Chadalavada then updated the Committee on the 2023/24 Winter Outlook. He reported that there was a 40-60% chance that temperatures would be above normal, and a 33-40% chance that, for southern New England, precipitation would be above normal (with an equal chance for above or below normal precipitation for northern New England). He noted that the Mystic cost-of-service agreement would continue through Winter 2023/24 and the Inventoried Energy Program (IEP) program would be in effect both for Winter 2023/24 and 2024/25. Winter demand for Winter 2023/24 was forecast to be roughly 250 MW to 350 MW (or 1.3% to 1.6%) higher than the prior winter. The ISO expected roughly 31 billion cubic feet (Bcf) of LNG to be available to thermal resources. Aggregate fuel-oil inventory was roughly 188 million gallons (48% of the max) and following commissioning earlier in the year, an~~d~~ additional 500 MW of dual-fuel capability/flexibility was available to the ISO. The Energy analysis for Winter 2023/24 remained unchanged from previous reports, with sufficient capacity and energy, with just a few possible but limited exceptions, generally available under both moderate and severe weather scenarios.

Addressing the IEP, Dr. Chadalavada estimated 2023/24's forward cost to be roughly $78 million, with total forward elections at 844,201 MWh. He noted an increase in the spot energy inventory elections, which had jumped since his November report, to an estimated 287,022 MWh. He added that, because spot participation would be compensated at $9.25/MWh on days meeting the IEP day threshold (an IEP Day), each IEP Day would add roughly $2.65 million to the overall program costs.

nGem Program Overview

Dr. Chadalavada then provided a long-anticipated high level overview of the next Generation Electricity Market (nGEM) program that General Electric (GE) had been developing for more than five years and would replace the existing GE platform being used by a number of the RTOs, including ISO-NE, MISO and PJM. nGem, he explained, would not replace the functionality of the ISO's current GE platform, but would introduce flexibility and new features, including a design that incorporates industry standard cyber security requirements, support for faster market rule implementation, improved test automation, and Kubernetes/containers-based technology that parses out and manages application code in smaller, more individually maintained chunks. nGem would be more easily monitored, maintained and standardized. He estimated New England would put up roughly $15 million towards initial development and total expected project cost over the next 10 years and its 20-year lifespan would run approximately $80-90 million.

Members thanked the ISO for the additional information and insight related to this enhanced market tool. In response to questions, Dr. Chadalavada further explained how the containerization of the platform would facilitate more expedited development, testing and implementation of market rule changes. He provided further context and examples of how nGem represented a significant improvement over previous platforms and tools.

ELECTION OF 2024 PARTICIPANTS COMMITTEE OFFICERS

Mr. Cavanaugh referred the Committee to the proposed slate of 2024 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting. The following motion was duly made, seconded and unanimously approved, with an abstentions noted by the New Hampshire Office of Consumer Advocate and Mr. Lamson:

> WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and
>
> WHEREAS, pursuant to those procedures the individuals identified in the following resolution were nominated and elected for 2024 to the offices of Chair and Vice-Chair, as set forth opposite their names; and
>
> WHEREAS Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the annual meeting of the Participants Committee.
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> NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2024 to the offices set forth opposite their names to serve until their successors are elected and qualified:

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

ESTIMATED BUDGET FOR 2024 NEPOOL EXPENSES

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, reported that the B&F Subcommittee reviewed, at its November 28, 2023 meeting, the estimated budget for 2024 Participant Expenses, a copy of which was circulated and posted in advance of the meeting and is included as Attachment 2 to these minutes. He reported that there were no concerns or objections identified by Subcommittee members. Without further discussion, the following motion was duly made, seconded and approved unanimously, with an abstention noted by Mr. Lamson:

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

FAP CHANGES – FCM DELIVERY FINANCIAL ASSURANCE

Mr. Kaslow then introduced proposed changes to the ISO Financial Assurance Policy (FAP) to update the provisions related to the FCM Delivery Financial Assurance requirements (the FCM Delivery FA Changes). He explained that the FCM Delivery FA Changes were intended to better align the financial assurance (FA) required with respect to FCM pay-for-performance (PFP) penalties with the potential risk of non-payment of those penalties. He reported that the FCM Delivery FA Changes were discussed by the B&F Subcommittee at its September 26, October 30 and November 28 meetings, with no Subcommittee member at those meetings objecting to the Changes. Following motion duly made and seconded, the Committee unanimously approved the following motion, with an abstention by Mr. Lamson noted:

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

IMM 2022 ANNUAL MARKETS REPORT

Mr. David Naughton, ISO Internal Market Monitoring (IMM) Executive Director, referred members to the summary of the IMM's 2022 Annual Markets Report (2022 IMM Annual Report) circulated and posted with the materials for the meeting. He also highlighted an accompanying primer, entitled "An Overview of New England's Wholesale Electricity Markets" (Primer). He explained that the Primer was intended to be a resource to explain the underlying mechanics of New England Markets, while the 2022 IMM Annual Report focused on key trends, the drivers of those trends, and an evaluation of the overall competitiveness and performance of the Markets.

Turning to the performance of New England markets in 2022, he reported that, due to high natural gas prices, 2022's energy prices were the highest since standard market design (SMD) was implemented in 2003; the region's overall market costs were the highest experienced since 2008. Looking ahead to 2023, he anticipated that energy prices and overall costs would be significantly lower.

Next, Mr. Naughton presented the IMM's simulation of generator profitability, namely, how much hypothetical combined cycle and combustion turbine generators could have earned in the wholesale markets. Referring to a chart, he explained that the results indicated that revenues for hypothetical combined cycle and combustion turbine generators in 2022 were above their calculated Cost of New Entry (CONE). He explained that this was the first time since 2018 that the wholesale markets provided enough revenues to make it profitable for a new gas-fired generator in the region. The cold spells experienced in Winter 2022/23 contributed to this result. In response to a question, Mr. Naughton confirmed that the simulation model included Regional Greenhouse Gas Initiative (RGGI) costs but not those from the Commonwealth of Massachusetts' Global Warming Solutions Act.

Addressing virtual transactions, Mr. Naughton showed a trend in 2022 indicating a significant increase in virtual supply submissions and clearances between hours ending 9 through 17. Mr. Naughton explained the relationship between virtual supply and PV generation, especially on days with high solar output. Because most solar generation participates as settlement-only generation (SOG) and cannot participate in the Day-Ahead Energy Market, he explained that virtual supply offers replaced the price-taking SOGs that show up in Real-Time. Thus, he reasoned that virtual transactions add value to the market by helping converge Day-Ahead prices downward to Real-Time prices. Relatedly, he discussed virtual transaction profitability. He noted that NCPC charges impact the profitability of virtual transactions. Given the expected increase of intermittent generation, Mr. Naughton pointed to a long-standing IMM recommendation to improve the NCPC-related rules to reduce NCPC charges to virtual transactions.

Mr. Naughton then discussed reserve pricing under fast-start pricing. He observed a higher rate of non-zero reserve pricing when the reserve constraint is not binding, i.e., a physical reserve surplus exists, contrary to the purpose of reserve prices. To explain, he referred to an illustrative example showing that, on December 12, 2022, fast-start pricing generated reserve pricing for 85 minutes despite the reserve constraint binding for only 20 minutes. These points notwithstanding, Mr. Naughton opined that fast-start pricing generally supported better price formation in the Real-Time Energy Market by enabling fast-start generators to set the clearing price. In any case, he recommended that the ISO reassess the reserve pricing mechanism under fast-start pricing to address the frequency of non-zero reserve pricing when there is a physical reserve surplus.

Next, Mr. Naughton noted that energy market mitigation remained very low. He did, however, point out the December 24, 2022 mitigation event where an unusual step was taken to mitigate certain resources upward. Mr. Naughton explained that the FERC issued a show cause order, directing the ISO to review its mitigation rules. Following that review, the ISO filed a NEPOOL-supported proposal to eliminate the risk of upward mitigation, which as of the date of his report remained pending before the FERC. Mr. Naughton also stated that he supported a proposal to revise the Tariff provisions relating to the fuel price adjustment construct. That proposal was still being considered in the stakeholder process. Following this summary of energy market mitigation, he reviewed four recommendations for energy market mitigation design and responded to questions concerning two of the recommendations.

In the final portion of his presentation, Mr. Naughton commented on the Forward Reserve Market (FRM). He stated his concerns with the material offer price increase and related structural market power issues. He explained his recommendation for revisions to the

Forward Reserve ~~o~~Offer ~~c~~Cap and delaying the publication of FRM offer data, both making their way through the stakeholder process.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the December 6 Litigation Report that had been circulated and posted before the meeting. He highlighted (i) the deadline for comments on the ISO's FCA18 Qualification Informational Filing set to end later that day, and (ii) the many joint ISO/NEPOOL filings that were pending FERC action, all the product of significant and recent efforts in the stakeholder process, including: the FCA19 schedule changes; FCM CONE and Net CONE updates; Energy Supply Offer Mitigation changes; Retirement/Permanent De-List Bid Price Flexibility changes; changes to the qualification rules for Distributed Energy Capacity Resources; and the compliance filing to make eligible to participate in the ~~Inventoried Energy Program (~~IEP~~)~~ pumped storage resources participating as Electric Storage Facilities.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting was scheduled for December 12-14 in Westborough, MA. He indicated that key topics would include the RCA project, discussion on Analysis Group's report and key findings on alternative FCM commitment horizons, and various market rule enhancements and compliance-related changes.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that, in addition to the December 12-13 joint meeting with the Markets Committee to consider RCA issues, the RC would itself meet on December 18-19. Key topics for the RC's two-day meeting would include, in addition to continuation of RCA discussions and consideration of a number of

Proposed Plan Applications and Transmission Cost Allocations, an introduction to the Regional Energy Shortfall Threshold (REST), a project to determine what level of reliability the region should strive to attain.

Transmission Committee (TC). Mr. Dave Burnham, the TC Vice-Chair, reported that the next TC meeting was scheduled in person in Westborough for December 21. Key topics would include longer/extended-term transmission planning and the ongoing FERC *Order 2023* compliance effort. With respect to *Order 2023* compliance, TC members could expect to see draft ISO-proposed Tariff redlines posted the following day and an additional TC meeting to be scheduled in early January to allow primarily for consideration of stakeholder amendments. He encouraged those with *Order 2023*-related amendments that had not already done so to reach out to him and the TC Chair, Ms. Emily Laine.

Budget & Finance Subcommittee. Mr. Kaslow reported that the next B&F Subcommittee meeting was scheduled for January 24, 2024.

Membership Subcommittee. Ms. Ashley Gagnon, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for December 11.

ADMINISTRATIVE MATTERS

Mr. Lombardi noted the possibility that January 4, 2024, then the date of the next regularly-scheduled Participants Committee meeting, might instead be used for the additional Transmission Committee discussion needed on amendments to the ISO's *Order 2023* compliance proposal. He encouraged members to stay tuned for further information and confirmation of the schedule for that day. Mr. Cavanaugh noted the membership orientation that would follow the meeting and encouraged members interested in additional information and insight on membership and stakeholder process issues to participate. He wished all a safe and joyful holiday season.

There being no other business, the meeting adjourned at 12:40 p.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 7, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting		Alex Lawton	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Associated Industries of Massachusetts	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti (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		
BlueWave Public Benefit Corp.	AR-DG	Mike Berlinski		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
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 (CT OCC)	End User		Jamie Talbert-Slagle	Jackie Litynski
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)	Priya Gandbnir	
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (tel)		
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short (tel)
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP (Calpine) New Leaf Energy	Generation	Brett Kruse Liz Delaney	Andy Gillespie	Bill Fowler Alex Chaplin
EDF Trading North America, LLC	Supplier	Eric Osborn (tel)		
Elektrisola, Inc.	End User			Bill Short (tel)
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin	Joe Dalton	
Eversource Energy	Transmission	James Daly	Dave Burnham (tel)	Vandan Divatia
Excelerate Energy LP	Associate Non-Voting	Gary Ritter		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc. (Galt)	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User			Bill Short (tel)
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG	Louis Guibault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 7, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	Marji Philips
Jupiter Power	AR-RG		Ron Carrier (tel)	
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieney (tel)	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Ashley Gagnon	Jamie Donovan (tel)	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Department of Capital Asset Management	End User	Paul Lopes	Nancy Chafetz (tel)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short (tel)
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Lindsay Orphanides (tel)	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User	Donald Kreis		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		Molly Connors (tel)
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Nylon Corporation of America	End User			Bill Short (tel)
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company LLC	Generation	Dan Allegretti	Kevin Telford	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
PowerOptions, Inc.	End User			Jackie Litynski
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division (DPUC)	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide		
Saint Anselm College	End User			Bill Short (tel)
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short (tel)

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 7, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
Sierra Club	End User	Casey Roberts (tel)		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
SYSO Inc.	AR-DG	Doug Matheson		
Tangent Energy Inc.	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		Dan Murphy
The Energy Consortium	End User		Mary Smith (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieney (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission	Dave Norman (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH LLC	End User			Bill Short (tel)

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

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

Notes

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

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

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

(4) Based on fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the annualized fixed fee for 2024 is projected to be $1,047,400 for three months and $1,099,700 for nine months. Estimate assumes NEPOOL will not exceed 520 development hours for changes to GIS, and any additional development hours would impose additional charges on NEPOOL.

(5) If NEPOOL determines that an audit should be performed in 2024, funding for that audit will be addressed separately.

(6) GIS costs are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2001 and amended by the NEPOOL Participants Committee on May 6, 2016.

(7) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy. The 2023 sales figure that was estimated using future pricing turned out to be higher than the actual pricing for the 2023 policy period, resulting in a lower actual premium than projected in the 2023 NEPOOL Budget.

CONSENT AGENDA

Markets Committee (MC)

*From the previously-circulated notice of actions of the MC's **January 9-11, 2024 meeting**, dated January 11, 2024.*[1]

1. **Revisions to Market Rule 1 (Further *Order 2222* Compliance)**

   Support revisions to Market Rule 1 to designate the Distributed Energy Resource (DER) Aggregator as the entity responsible for providing metering information for its DER Aggregations (DERAs) and to provide DER Aggregators the option to choose a metering provider for DERAs providing energy injection and/or withdrawal service, as recommended by the MC at its September 12-13, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

   The motion to recommend Participants Committee support was approved with two opposed in the Alternative Resources Sector, and two abstentions in the End User Sector.

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **December 18-19, 2023 meeting**, dated December 19, 2023.*[2]

2. **Revisions to OP-24 and Appendix B to OP-24 (Expansion of the number of facilities where fault clearing information (OP-24B data) is required to be provided on an annual basis)**
   Support revisions to ISO New England Operating Procedure (OP) No. 24 (Protection Outages, Settings and Coordination) and Appendix B to OP-24 (Transmission Relaying Characteristics),[3] as recommended by the RC at its December 18-19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was approved unanimously.

3. **REMOVED FROM CONSENT AGENDA; TO BE DISCUSSION ITEM #5A**

   Revisions to PP 5-6 (system modeling assumption updates, adopt IEEE Standard 2800, and improved IBR modeling requirements)

   Support revisions to Planning Procedure 5-6 (Interconnection Planning Procedure for Generation and Elective Transmission Upgrades),[4] as recommended by the RC at its December 18-19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was approved with one opposed and one abstention, each in the Generation Sector.

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

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

[3] The recommended revisions to OP-24 and Appendix B to OP-24 include changes to: (i) expand the number of facilities where fault clearing information (OP-24B data) is required to be provided on an annual basis; and (ii) the data format in OP-24B to primarily cover single-line-to-ground faults and IPT status of breakers.

[4] The recommended revisions to PP 5-6 include changes to: (i) update system modeling assumptions to align with the operating conditions expected to result from the clean energy transition; (ii) describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems); and (iii) improve modeling requirements for IBRs.

FEBRUARY 1, 2024 I BOSTON

Joint Nominating Committee Process for 2024

Brook Colangelo

ISO-NE DIRECTOR AND CHAIR OF JOINT NOMINATING COMMITTEE

Goal for 2024 JNC

To nominate and present the slate of ISO New England Board of Directors candidates for re-election to the Participants Committee for vote.

Critical Success Factors for Directors

- Belief in our purpose as defined by our Mission, Vision, Values
- Commitment to Inclusion, Equity, and Diversity
- Comfort in an ever-changing environment
- Comprehension and support of our strategic goals
- Expertise in critical skills and experiences required for success and compliance with the Participant Agreement

2024 Slate for Presentation to NEPOOL

In 2024, three directors' terms end, and all three are eligible for re-election. The incumbents are:

- Mike Curran
- Caren Anders
- Steve Corneli

It is the sense of the Nominating and Governance Committee of the ISO New England Board that these three directors should be re-elected, given:

- Their skills (see slide 5)
- The need for continuity on the Board
  - For benchmarking purposes: S&P 500 directors serve, on average, about the same amount of time as our directors (9 years)

Schedule of JNC Process

JNC met on January 30 and developed the following procedural outline for 2024:

Date	Action
January 17	Board N&G discussed candidates
January 30	JNC kick-off
February 1	Brook to give JNC overview to PC; Mike Curran to present to PC
March 7	Caren Anders and Steve Corneli to present to PC; NEPOOL to consider candidates during executive session
March-April	Sectors to provide feedback to JNC representatives
April (TBD)	JNC to regroup
May	NEPOOL PC to vote (tentative)
June	N&G Committee nominates and Board elects directors (tentative)

Critical Skills and Experience

The current incumbents' skills are well aligned with our strategic priorities, critical skills matrix and the Participants Agreement's requirements. The JNC has done a terrific job in selecting highly skilled individuals with diverse backgrounds, experiences, and expertise. The Board works well together and each member is highly committed to the mission, vision, and values of the organization.

Electric Industry/ Transmission Experience (at least three, per the Participants Agreement)	Markets Expertise (F – Financial Markets E – Energy Markets)	Top Corporate Officer with Experience in Leadership, Governance, and Compensation/Human Resources	Public Service, Regulatory Experience (FERC, States)	Audit Committee Financial Expert	IT/Cyber Security Expertise	Demographic consideration: New England Resident (strong preference for directors "from New England" per the Participants Agreement)

ISO-NE Board Committee Assignments

Director (by retirement date)	(1) System Planning and Reliability Committee	(2) Markets Committee	(3) Compensation and HR Committee	(4) Nominating and Governance Committee	(5) Audit and Finance Committee	(6) IT/Cyber Security Committee
Brook Colangelo ’26	X			CHAIR		X
Mike Curran ’27		CHAIR			X	X
Cheryl LaFleur ’28			X	X		
Mark Vannoy ’29		X		X		CHAIR
Caren Anders ‘30	CHAIR		X	X		
Steve Corneli ‘30		X			X	X
Catherine Flax ‘31		X			CHAIR	
Mel Williams ’31	X		CHAIR			
Craig Ivey ‘32	X		X		X	
Gordon van Welie	X	X	X	X	X	X

ISO-NE Board Retirement Schedule

	2024 Class Three	2025 Class One	2026 Class Two	2027 Class Three	2028 Class One	2029 Class Two
Caren Anders	Eligible for re-election to **second** full term			Eligible for re-election to **third** full term		
Mike Curran	Eligible for re-election to **third** full term			Hits **term limit**		
Steve Corneli	Eligible for re-election to **second** full term			Eligible for re-election to **third** full term		
Cheryl LaFleur		Eligible for re-election to **third** full term			Hits **term limit**	
Mel Williams		Eligible for re-election to **second** full term			Eligible for re-election to **third** full term	
Catherine Flax		Eligible for re-election to **second** full term			Eligible for re-election to **third** full term	
Craig Ivey			Eligible for re-election to **second** full term			Eligible for re-election to **third** full term
Mark Vannoy			Eligible for re-election to **third** full term			Hits **term limit**
Brook Colangelo			Hits **term limit**			
JNC External Search Required			**Replacement for Colangelo**	**Replacement for Curran**	**Replacement for LaFleur**	**Replacement for Vannoy**

Candidate for Re-Election, Michael J. Curran

Bio:
Michael Curran joined the ISO New England Board in 2019. Curran spent the majority of his career in the financial services and investment community, including the Boston Stock Exchange, Inc., where he was Chairman and CEO. Before joining the Boston Stock Exchange, he was Managing Director and Chief Operating Officer of Kemper Funds and International Mutual Funds for Zurich Scudder Investments. Curran most recently was Chair of the Midcontinent Independent System Operator (MISO) Board of Directors. He is a graduate of Dickinson College.

ISO Board Service:
Mike was elected to the Board on January 1, 2019. He serves on the Audit and Finance Committee, IT and Cyber Security Committee, and Markets Committee. He is the Chair of the Markets Committee. He has also served on the Joint Nominating Committee, Compensation and Human Resources Committee, and as Chair of the Audit and Finance Committee.

Summary of ISO New England Board and Committee Meetings

February 1, 2024 Participants Committee Meeting

Since the last update, the Information Technology and Cyber Security Committee met virtually on December 14. The Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on January 17 in Holyoke, Massachusetts. The Board of Directors met in Holyoke on January 18.

The Information Technology and Cyber Security Committee conducted its annual review of the IT-related portions of the Internal Audit Department's work plan, and was provided with an update on the Company's three-year cyber security plan. The Committee then received a report on current IT trends and an update on the current use and monitoring of Artificial Intelligence tools. The Committee discussed the status of major IT projects, and reviewed its calendar for 2024. The Committee also held an executive session to discuss the achievement of corporate goals for 2023, and the proposed corporate goals for 2024.

The Compensation and Human Resources Committee considered the Company's proposed corporate goals for 2024, and agreed to recommend to the Board that they be approved. The Committee also discussed, in regular and executive session, various issues related to officer compensation. Those conversations included the officers' and company's performance and the reasonableness of that compensation when compared to similarly-situated companies. Finally, as part of its annual compensation review, the Committee considered the structure of the Board's compensation and, specifically, the trend toward adopting a retainer-only structure, as opposed to the Company's retainer-plus-meeting-fee structure.

The Markets Committee met with the System Planning and Reliability Committee to consider the key risks within the scope of both Committees' oversight. The Committees discussed the risks that are a function of grid transformation, energy adequacy, resource adequacy, and workforce limitations. Following the joint meeting, the Markets Committee met and received reports from both the Internal and External Market Monitors on market issues, including prices, during the 2023 fall season. In executive session, the Committee assessed the achievement of 2023 corporate goals, and, as required by the Committee's charter, reviewed the scope and coverage of the Internal Market Monitor and External Market Monitor for adequacy. The Committee also considered the 2024 work plan of the Internal Market Monitor, and reviewed his 2023 performance.

The Nominating and Governance Committee reviewed the Company's strategic planning process and topics for 2024. The Committee received a report on state and federal political and legislative activities relevant to the industry, and discussed additional comments submitted by the public in connection with the open Board meeting. The Committee also considered improvements to the open Board meeting format for 2024. During executive session, the Committee considered the Joint Nominating Committee process for the upcoming Board election in 2024.

The System Planning and Reliability Committee joined the Markets Committee to consider the key risks within the scope of both Committees' oversight (see above). Following the joint meeting, the Committee reviewed activities and events that were a major focus during the late summer and fall of 2023, including qualifications for Forward Capacity Auction #18 and delay of Forward Capacity Auction #19, economic studies, long-term transmission planning, and integration of Distributed Energy Resources. In addition, the Committee previewed activities anticipated to be a major focus for the first quarter of 2024. The Committee also discussed a dashboard summary of ongoing projects, and received updates on the Company's compliance with NERC and NPCC standards. The Committee then held an executive session to assess achievement of 2023 corporate goals.

The Board of Directors received a report from the CEO and discussed the regulatory and stakeholder climate. The Board received an update on the Resource Capacity Accreditation Project, and was provided with a presentation summarizing the risks and benefits related to the potential transition to a prompt seasonal capacity market. The Board concurred with management's recommendation to transition to a prompt, seasonal capacity market, which it will discuss next with stakeholders. The Board also heard reports from the standing committees outlining highlights from their recent meetings. During the Markets Committee report, the Board approved changes to the Committee's charter. The changes involve clarifying the Committee's review of issues related to wholesale markets, and the Committee's oversight of the Internal Market Monitor. The Board then discussed its members' attendance at the December Consumer Liaison Group meeting, and, while in executive session, approved the Company's corporate goals for 2024.

Message from Dr. Chadalavada Regarding Changes to COO Report Format:

As mentioned at the December 2023 NPC meeting, some slides in the monthly report will be refreshed over the course of 2024 to improve the usefulness and relevance of the presentation, while maintaining overall access to key information. The February presentation introduces refinements to the Market Operations section and related Back-Up Detail sections (DR, FCM, NCPC). Some existing exhibits have been enhanced with improved graphics and information. Some information has been streamlined to reduce redundancy and for more intuitive flow of information. Also, a few new exhibits have been added:

1. Daily and Monthly Generation by Fuel Type and Renewable Generation by Fuel Type (slides 24-25)
2. Maximum Supply Cleared in the DA Market (slide 30)
3. Cumulative FCM Charges by Capacity Commitment Period (slide 58)
4. Monthly and Annual Billed Amounts for Energy plus Ancillaries, Capacity, and OATT (slide 66)

The ISO welcomes your feedback.

NEPOOL Participants Committee Report

February 2024

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights: January 2024

Data is through January 24 unless otherwise noted

- **Peak Hour** on January 17
  - 18,431 MW Revenue Quality Metered (RQM) system peak; hour ending 6:00 pm
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $76.84/MWh
  - Real Time (RT) Hub LMP: $68.91/MWh
  - Natural Gas: $8.83/Mmbtu (MA Natual Gas Avg)
- **Energy Market** value $712M up from $552M in January 2023
  - Ancillary Markets* value $6.6M unchanged from January 2023
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 102.1% during January, down from 102.4% during December*
    - The minimum value for the month was 98.1% on Monday, January 1st
- **Net Commitment Period Compensation (NCPC)** total $2.4M
  - First Contingency $2.3M, down $2.4M from December, 2023
  - Second Contingency and Voltage payments were both zero
  - Distribution $52K
- **Forward Capacity Market (FCM)** market value $86.3M
  - FCM peak for 2024 remains 17,993 MWh; hour ending 6:00 P.M. on Wednesday, January 17

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

*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund (MLRF)
**DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Highlights

- 2024 Economic Study was initiated in January
  – Starting the implementation of Tariff improvements related to the Economic Study Process made in 2023
- Forward Capacity Auction #18 will commence on February 5
- The next LFC meeting will be held on February 23
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 13, 2024

Forward Capacity Market (FCM) Highlights

- CCP 15 (2024-2025)
  - The ISO will hold the third annual reconfiguration auction (ARA3) over March 1-5, 2024, and will post the results no later than April 3, 2024
- CCP 16 (2025-2026)
  - The ISO will hold the second annual reconfiguration auction (ARA2) over August 1-5, 2024, and will post the results no later than September 3, 2024
- CCP 17 (2026-2027)
  - The ISO will hold the first annual reconfiguration auction (ARA1) over June 3-5, 2024, and will post the results no later than July 5, 2024

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - FCA 18 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - ICR and related values were approved at the September 19, 2023 RC and October 5, 2023 PC meetings, filed with FERC on November 7, 2023, and FERC issued an order accepting the results effective January 6, 2024
  - The ISO submitted the FCA 18 informational filing to FERC on November 22, 2023, and errata filing on January 10, 2024
  - The FCA will commence on February 5, 2024
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for one year with FERC on November 3, 2023; FERC issued an order accepting the delay to FCA 19 on January 2, 2024
  - The ISO will commence the interim reconfiguration auction qualification process resulting from the FCA 19 delay in April 2024

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.3°F) Max: 60°F, Min: 14°F Precipitation: 7.55" – Above Normal Normal: 3.08" Snow: 8.70"	Hartford	Temperature: Above Normal (4.2°F) Max: 55°F, Min: 6°F Precipitation: 8.34" – Above Normal Normal: 2.98" Snow: 15.50"

Peak Load:	18,299 MW	January 17, 2024	19:00 (ending)

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

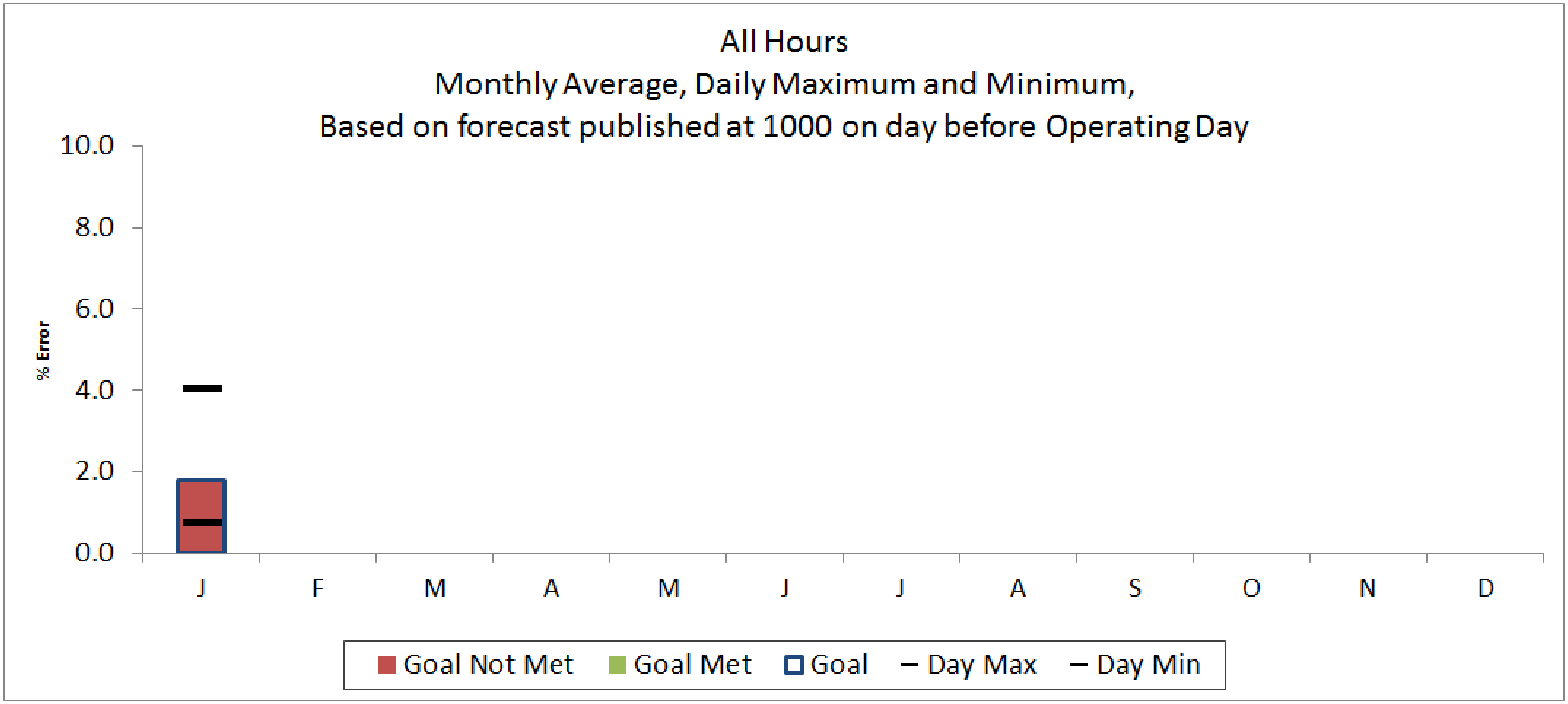
Procedure	Declared	Cancelled	Note
NONE			

System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
01/02/2024	ISO-NE	600

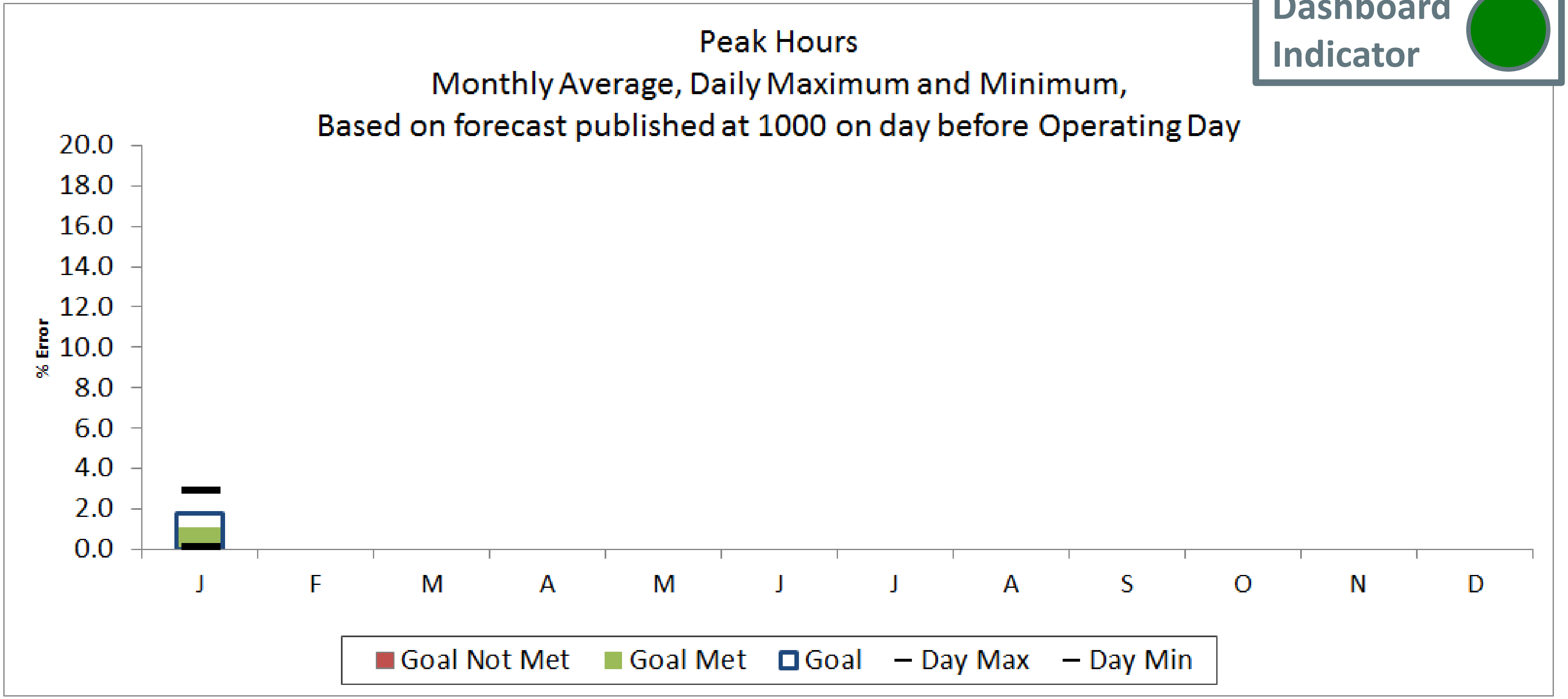
2024 System Operations - Load Forecast Accuracy



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.03												4.03
Day Min	0.73												0.73
MAPE	1.86												1.86
Goal	1.80												

2024 System Operations - Load Forecast Accuracy cont.

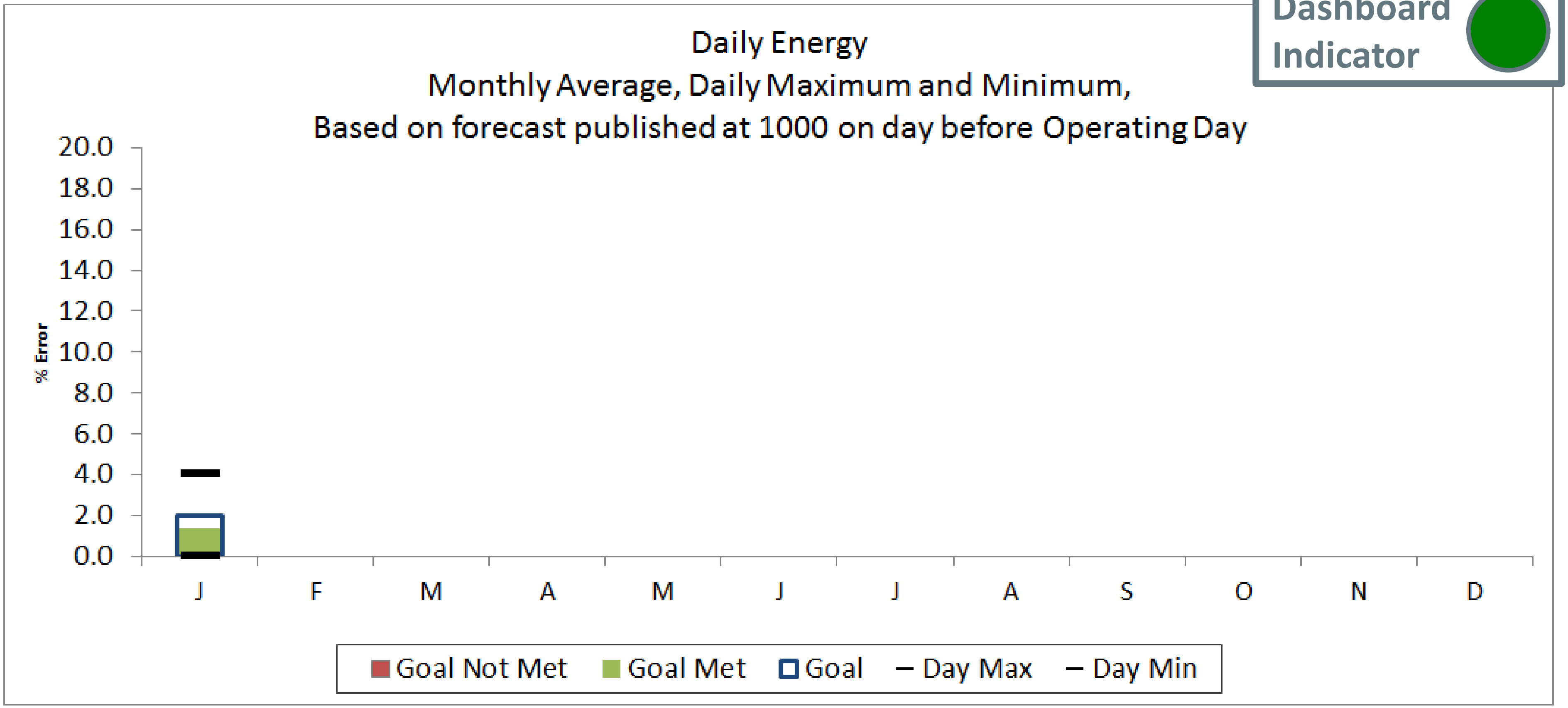
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	2.90												2.90
Day Min	0.08												0.08
MAPE	1.13												1.13
Goal	1.80												

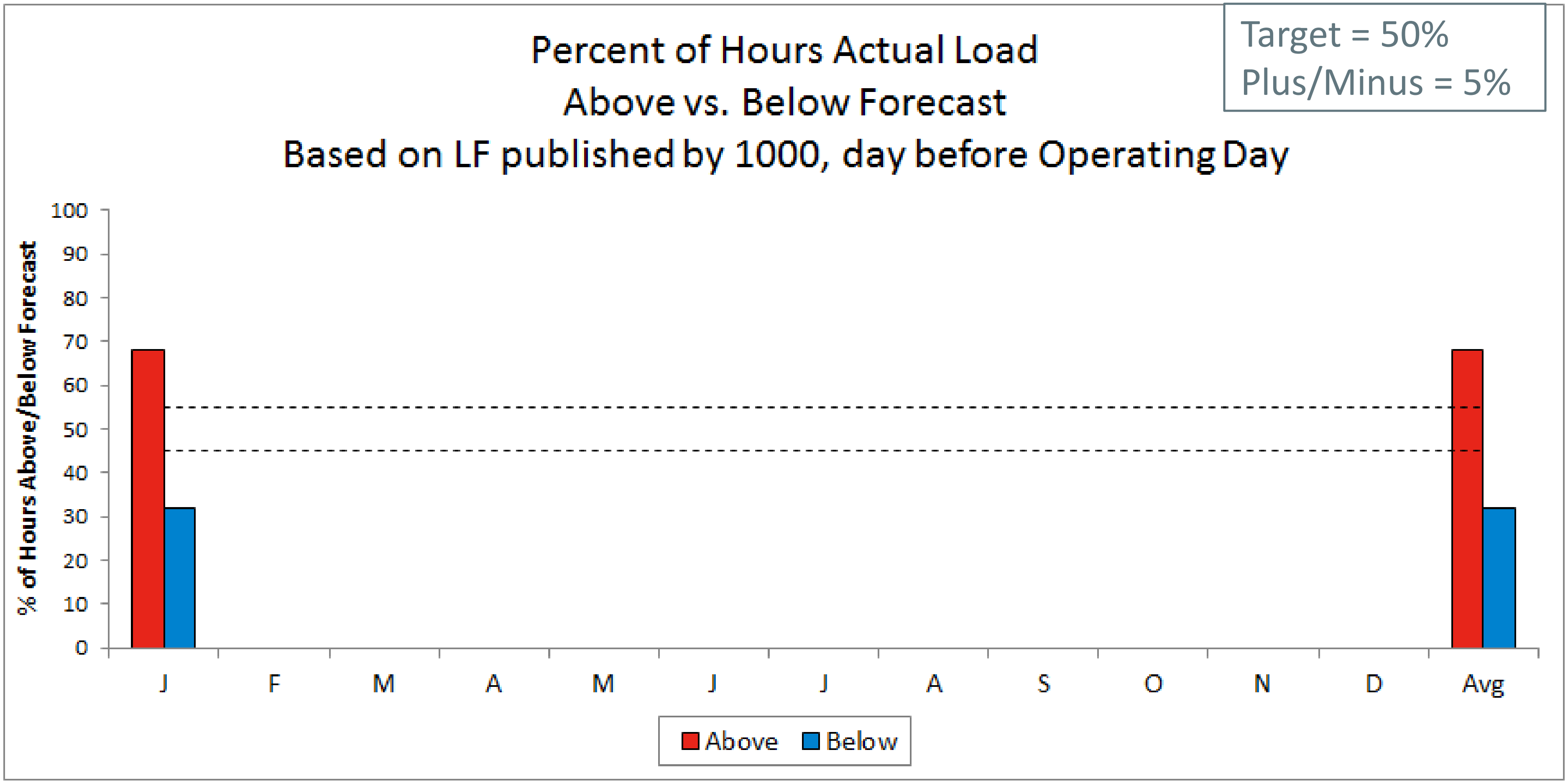
2024 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



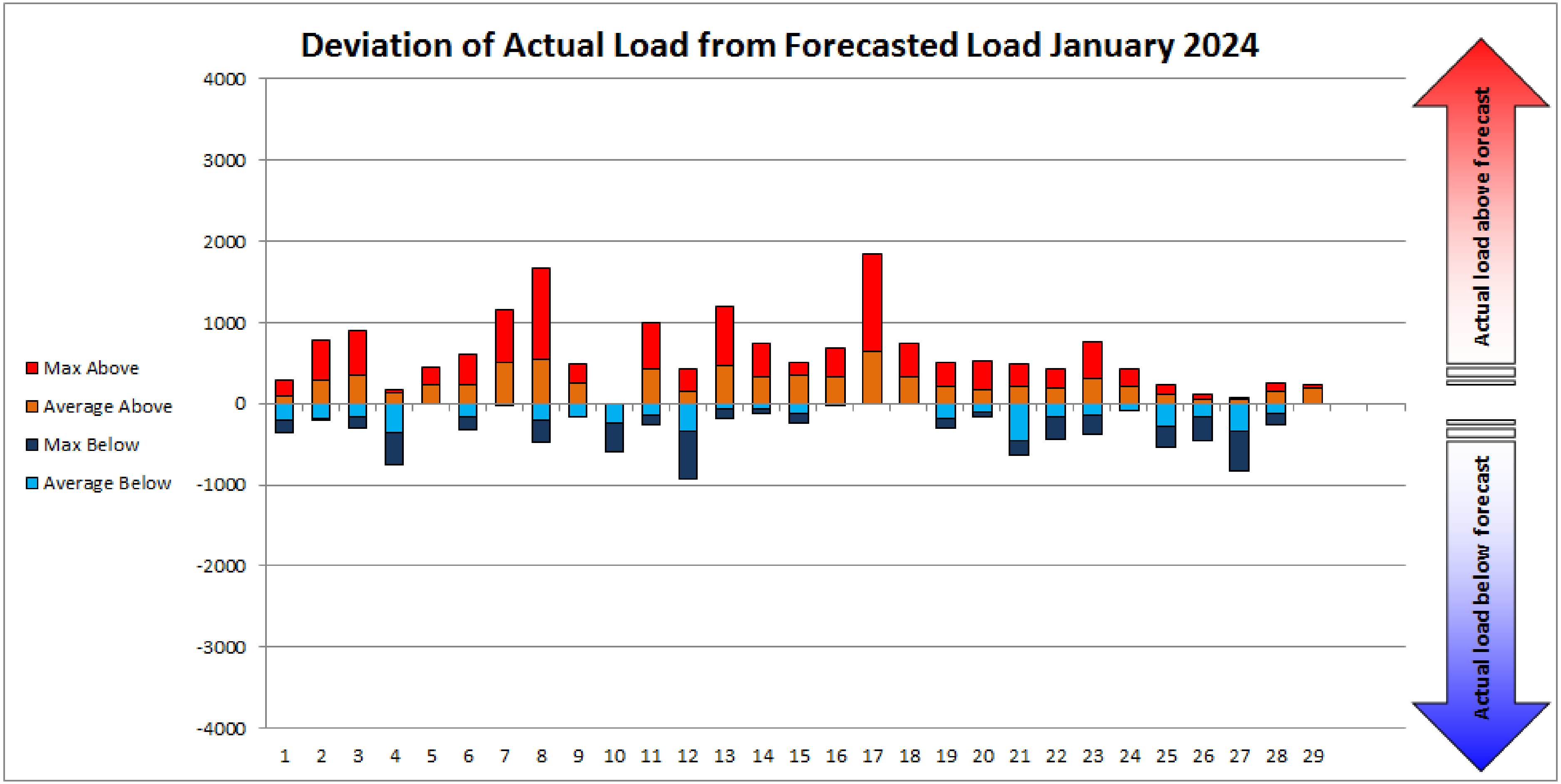
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.02												4.02
Day Min	0.02												0.02
MAPE	1.43												1.43
Goal	2.00												

2024 System Operations - Load Forecast Accuracy cont.



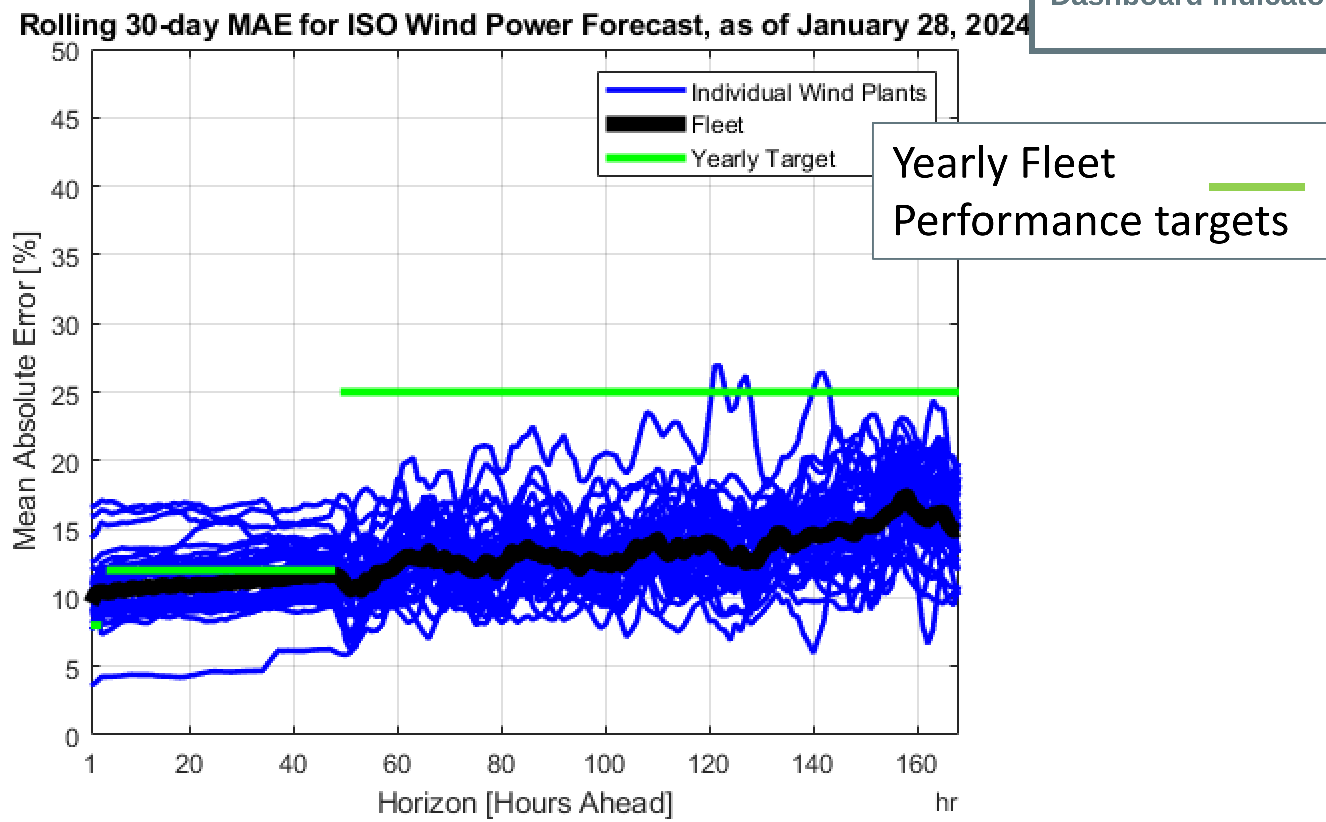
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	68.1												68
Below %	31.9												32
Avg Above	240.9												241
Avg Below	-144.5												-145
Avg All	132												132

2024 System Operations - Load Forecast Accuracy cont.



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

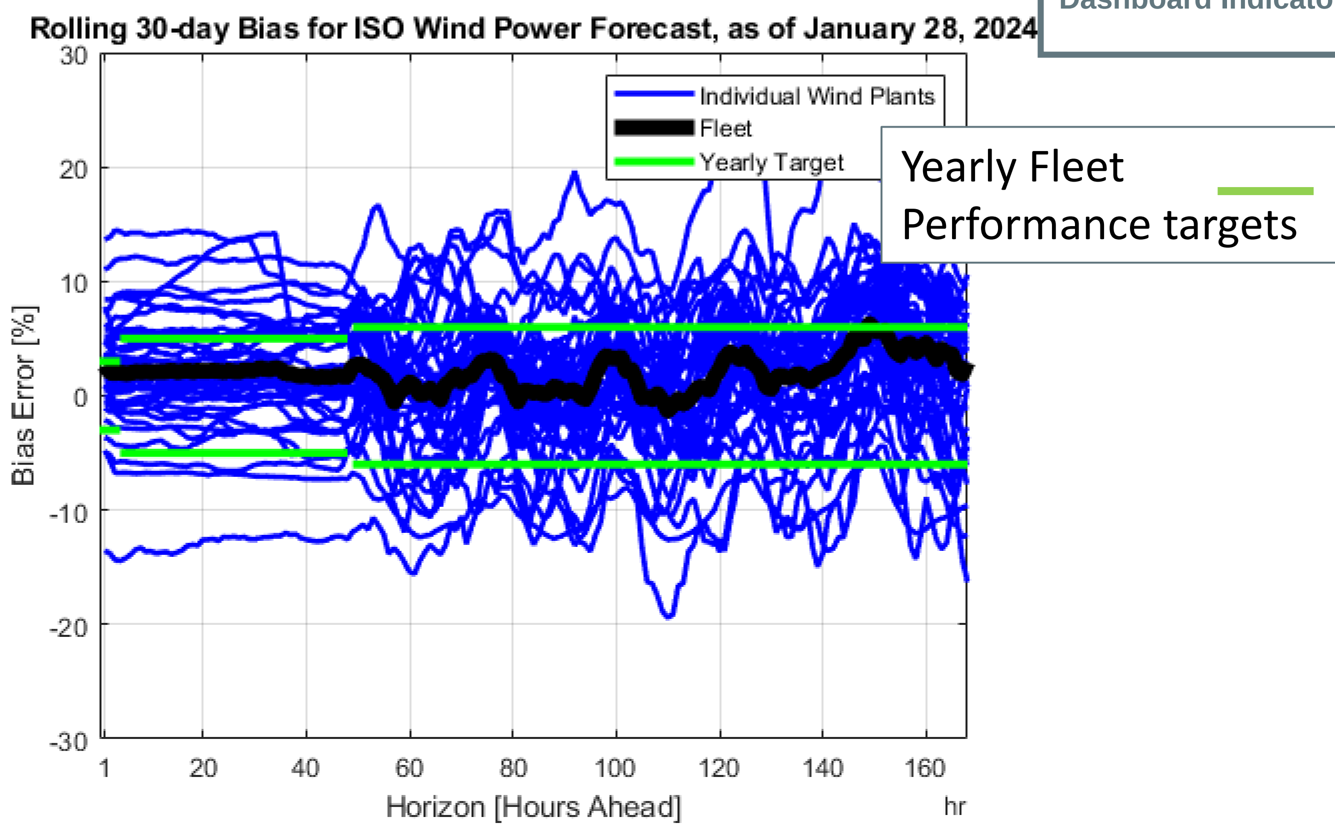
Dashboard Indicator



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

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

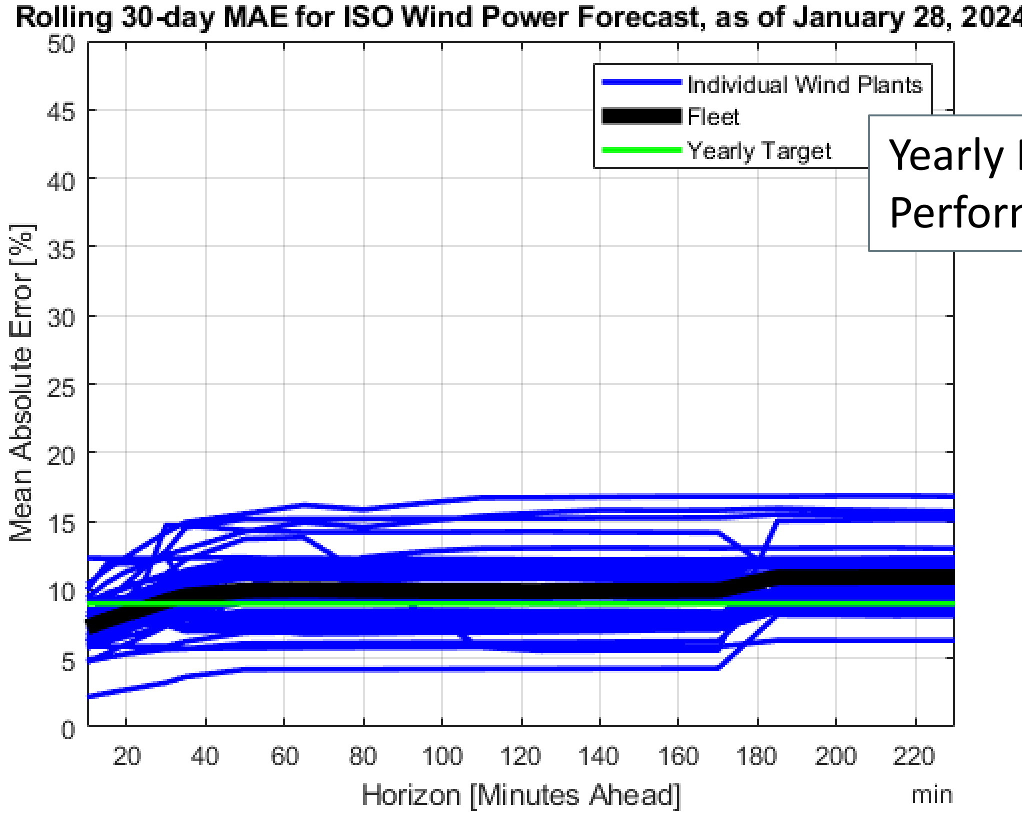
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and monthly Bias is within yearly performance targets except for the 150 hour look-ahead timeframe.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

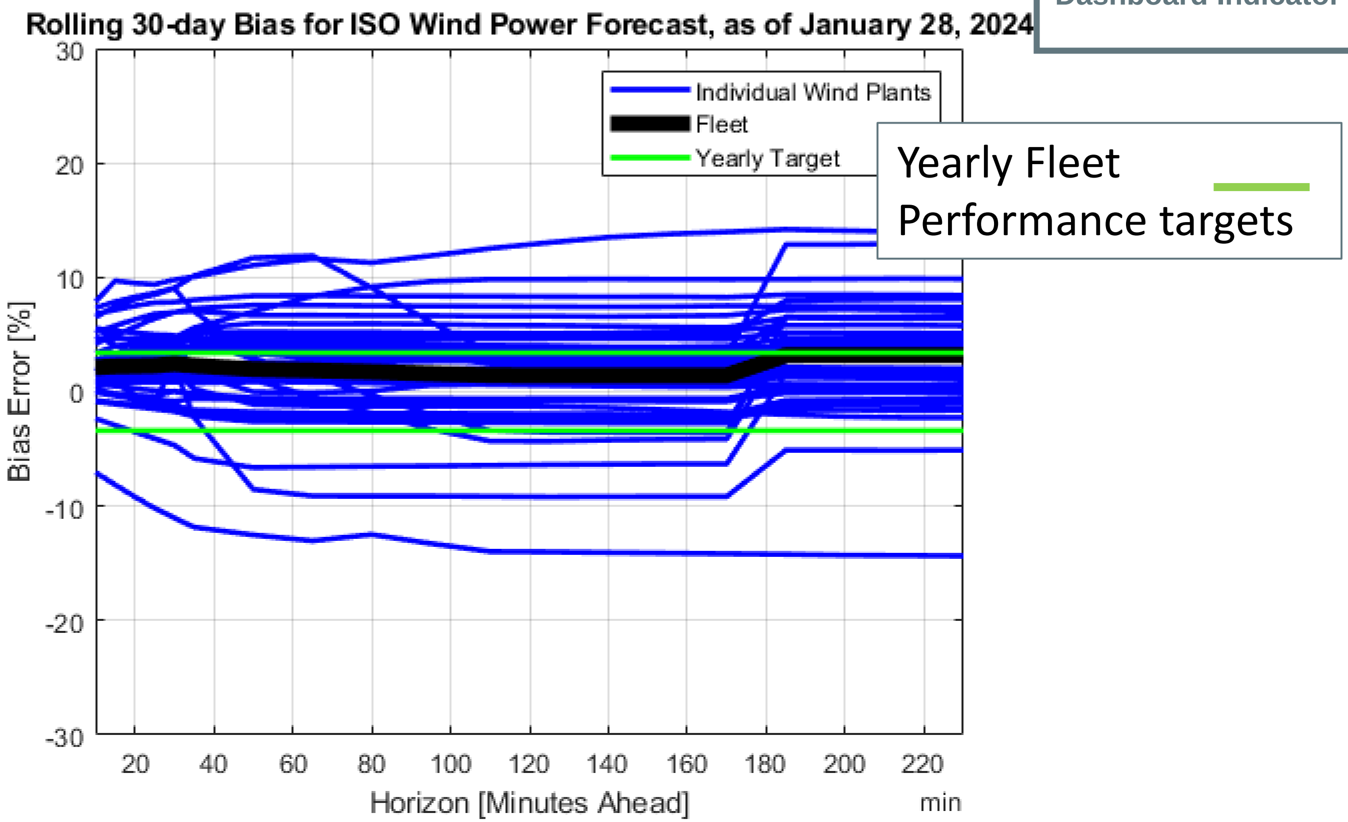


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the forecast compares well with industry standards, but monthly MAE is outside of yearly performance targets at greater than 30 minutes look-ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

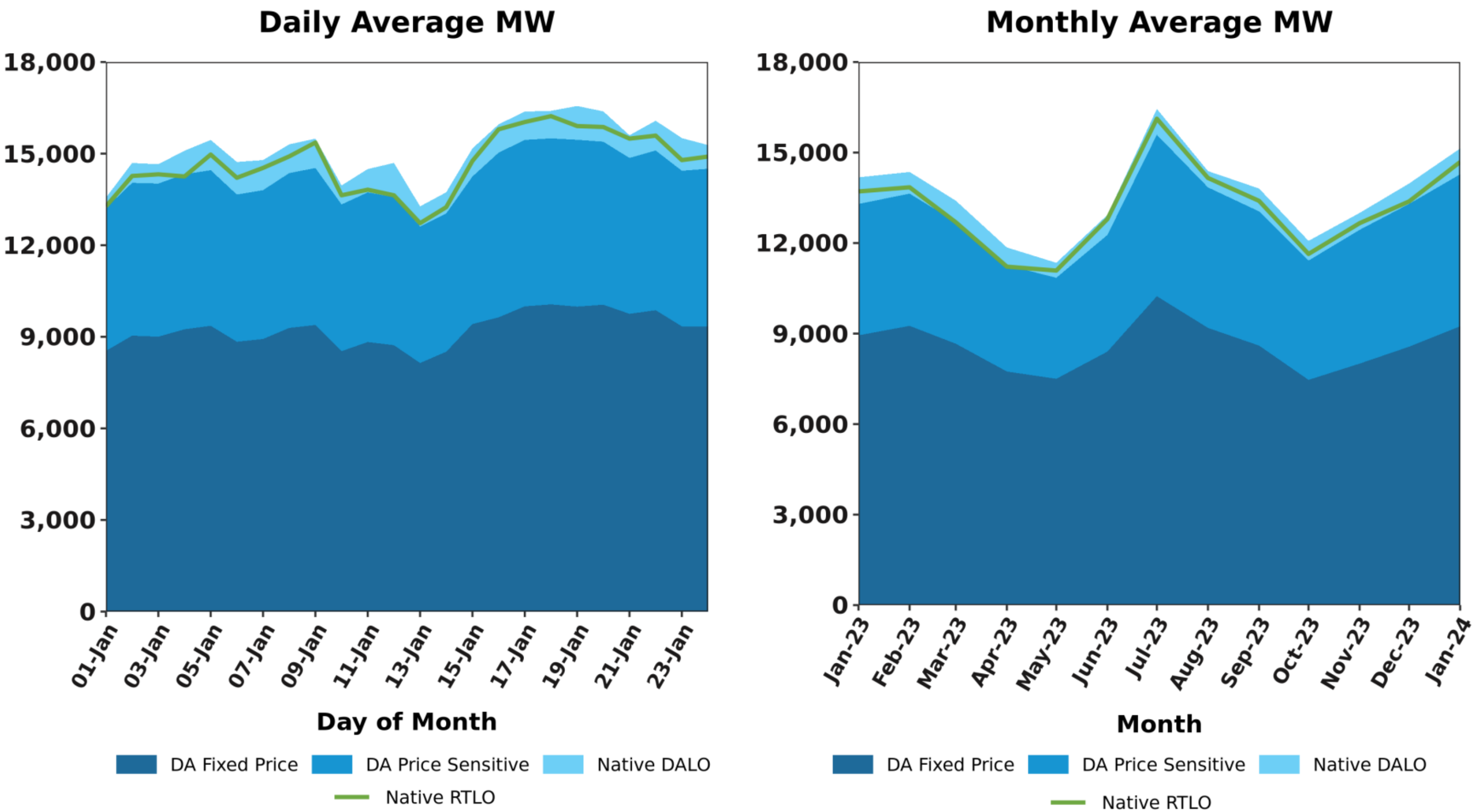


Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and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

MARKET OPERATIONS

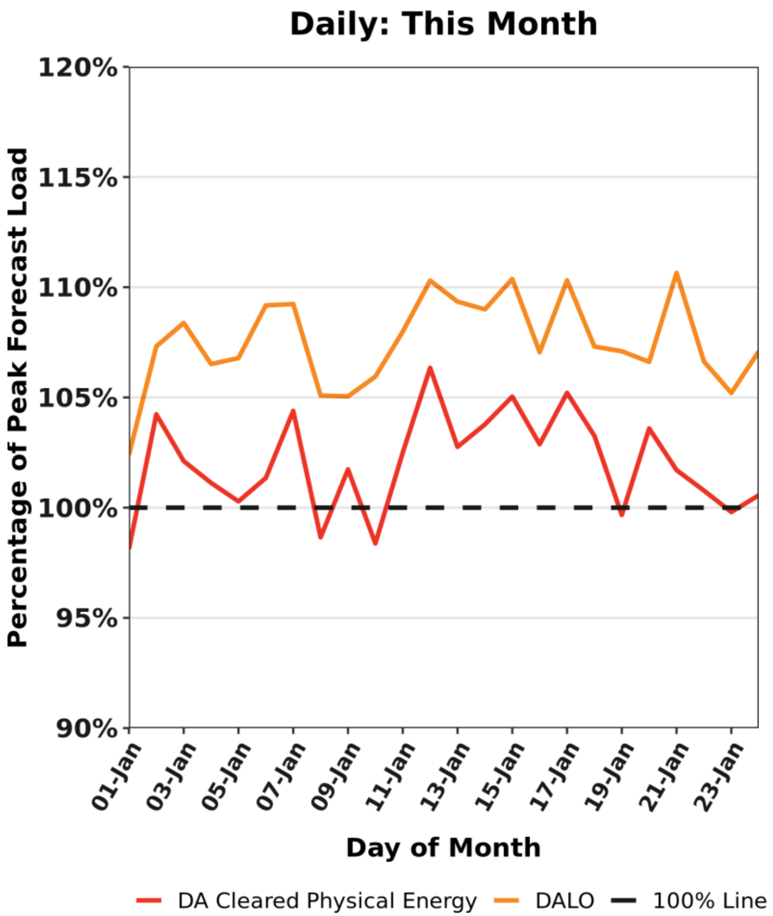
SUPPLY AND DEMAND VOLUMES

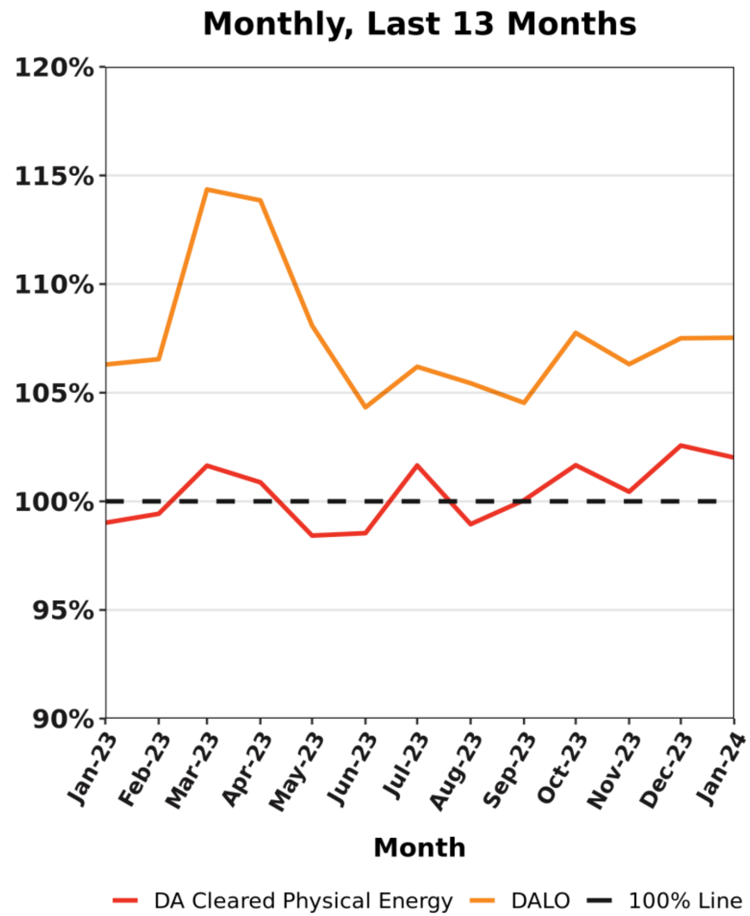
DA Cleared Native Load by Composition Compared to Native RT Load



Native Day-Ahead Load Obligation (DALO) is the sum of all day-ahead cleared load, excluding modeled transmission losses and exports
Native Real-Time Load Obligation (RTLO) is the sum of all real-time load, excluding modeled transmission losses and exports

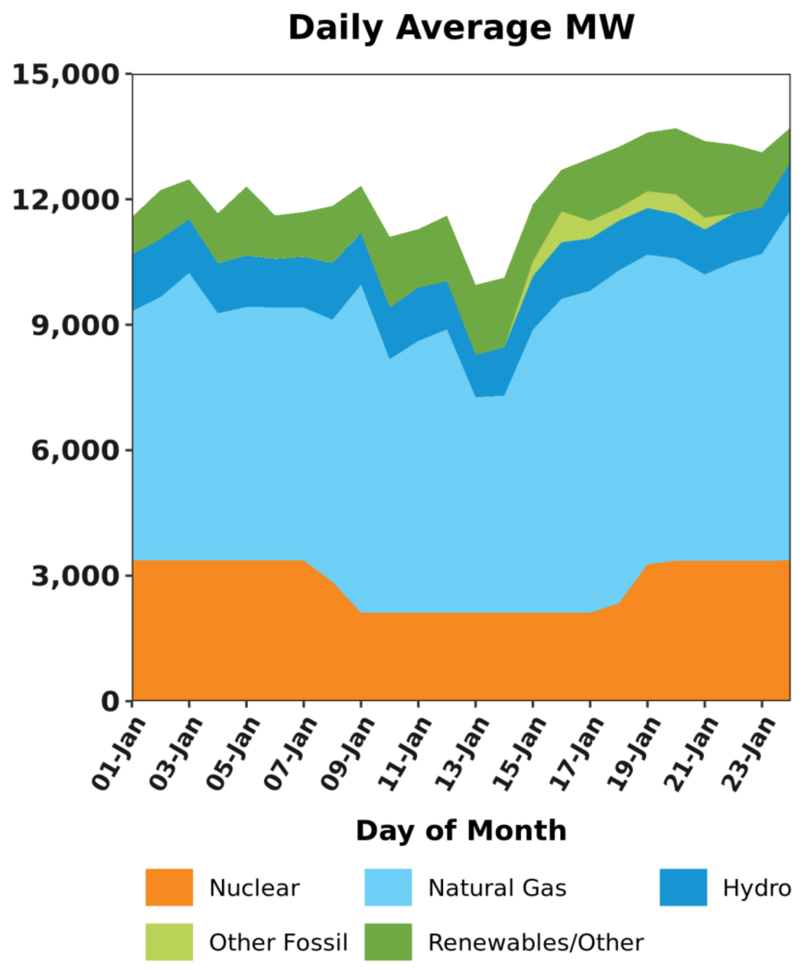
DA Volumes as % of Forecast in Peak Hour

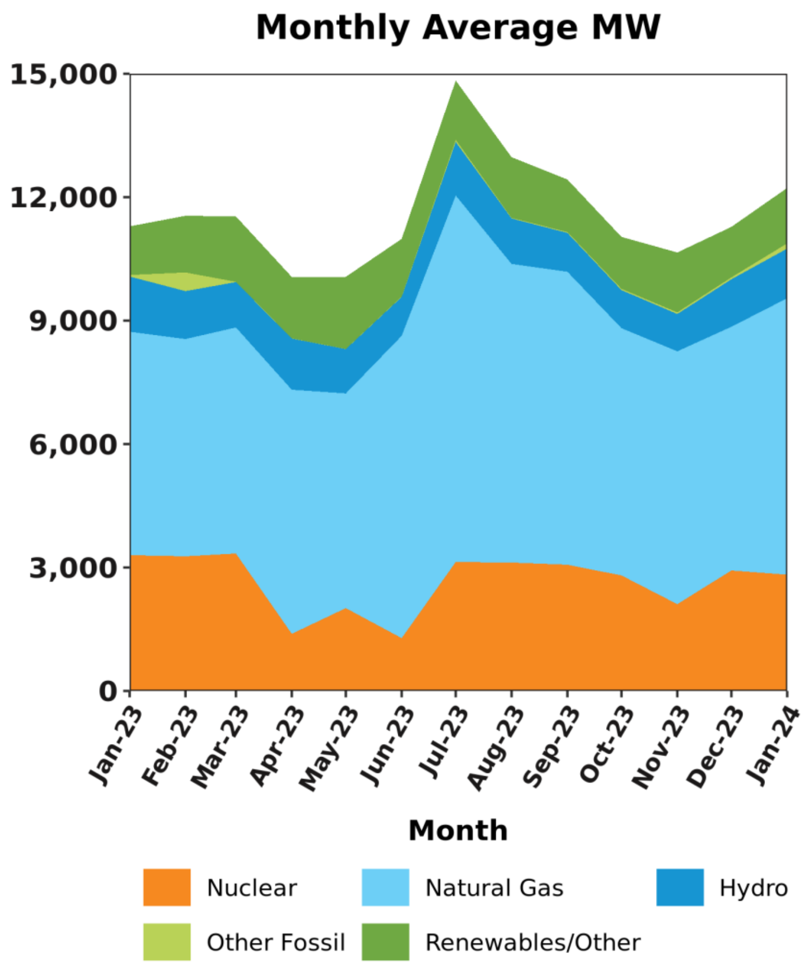




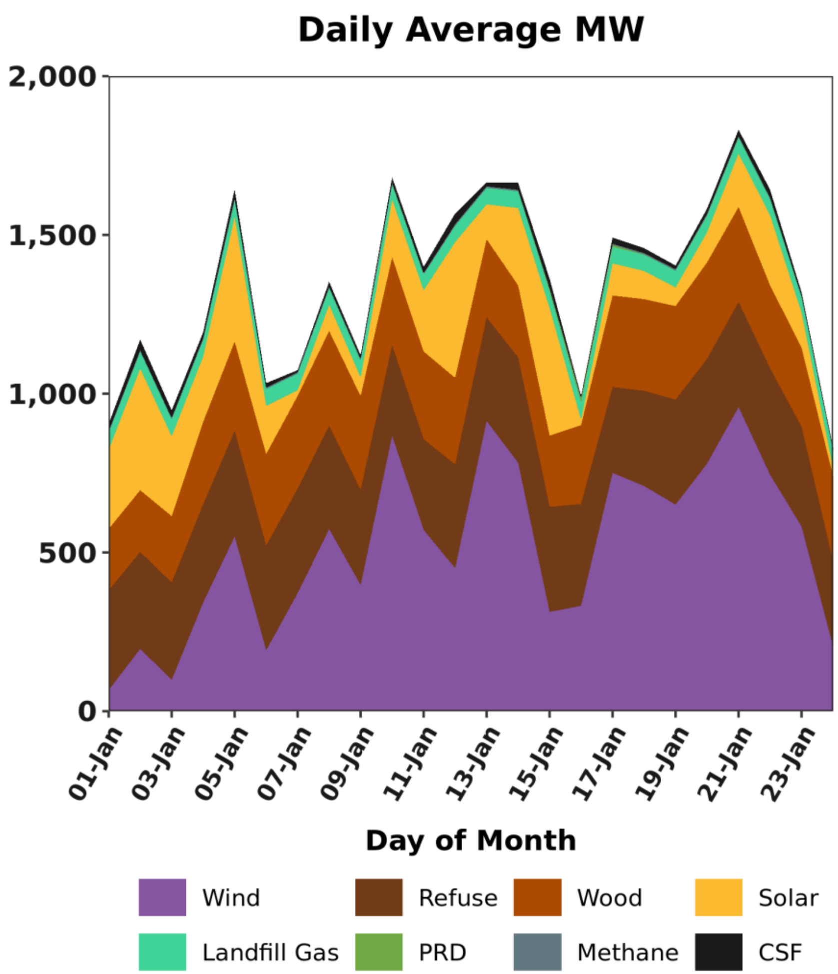
The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

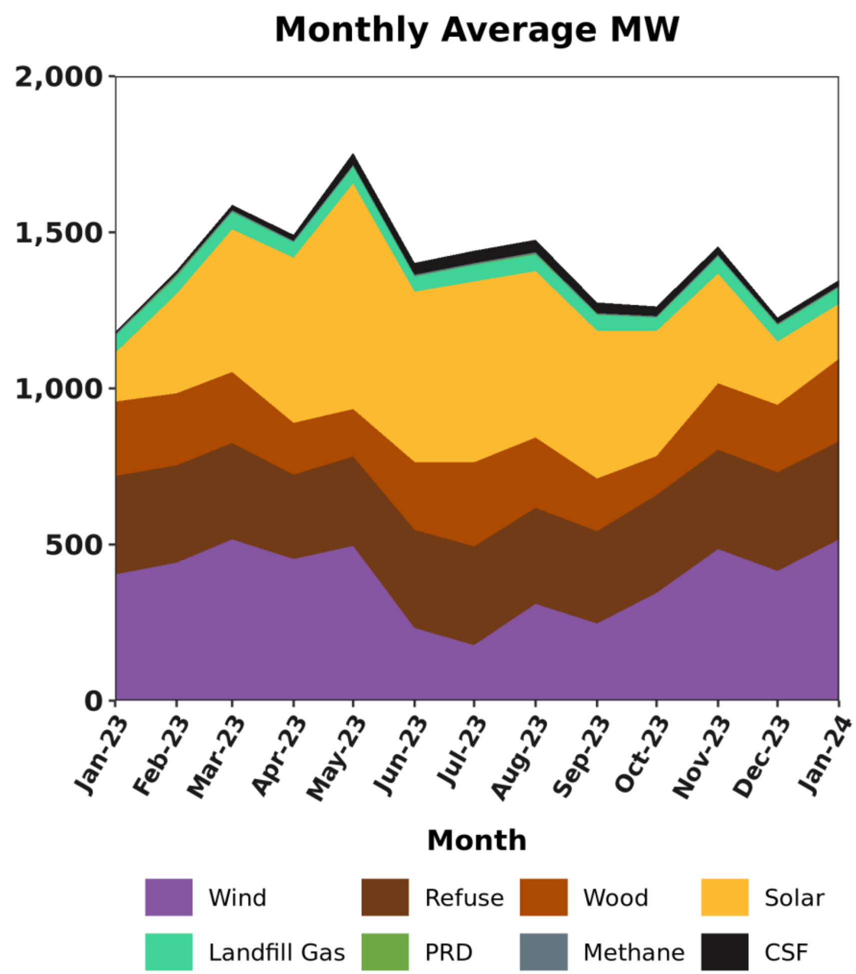
Generation by Fuel Type





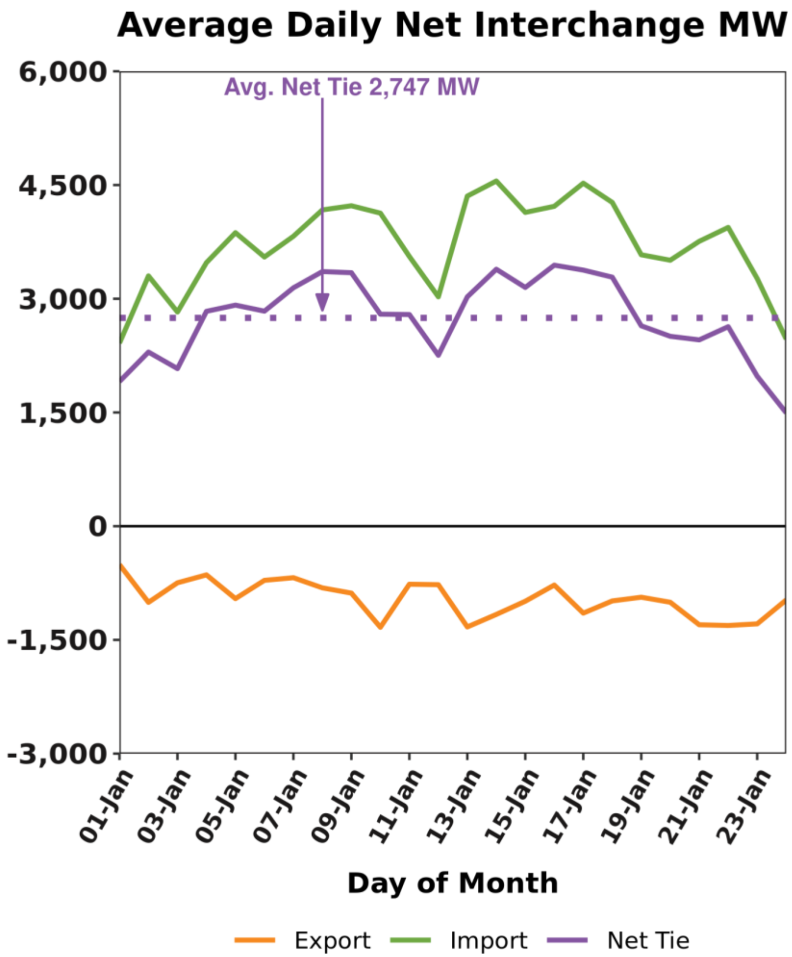
Renewable Generation by Fuel Type

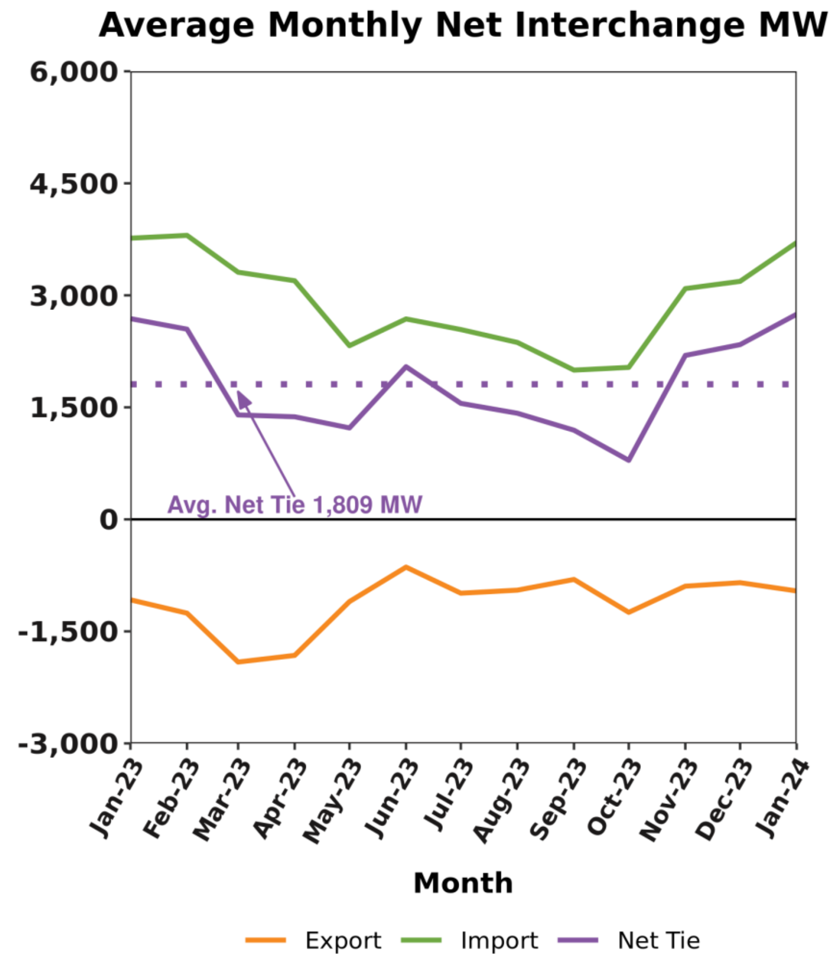




CSF represents Continuous Storage Facilities (a.k.a. Batteries)

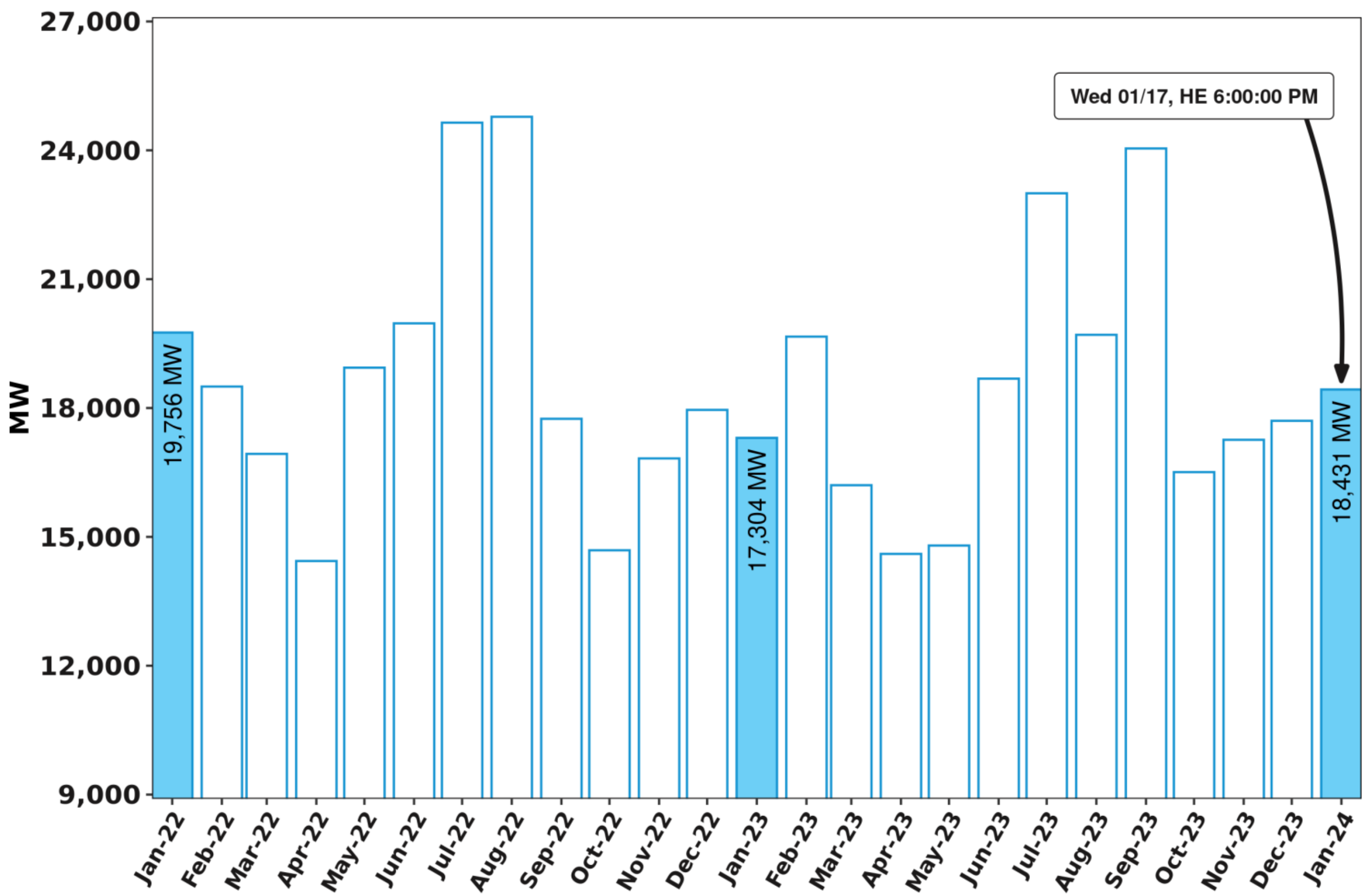
DA vs. RT Net Interchange





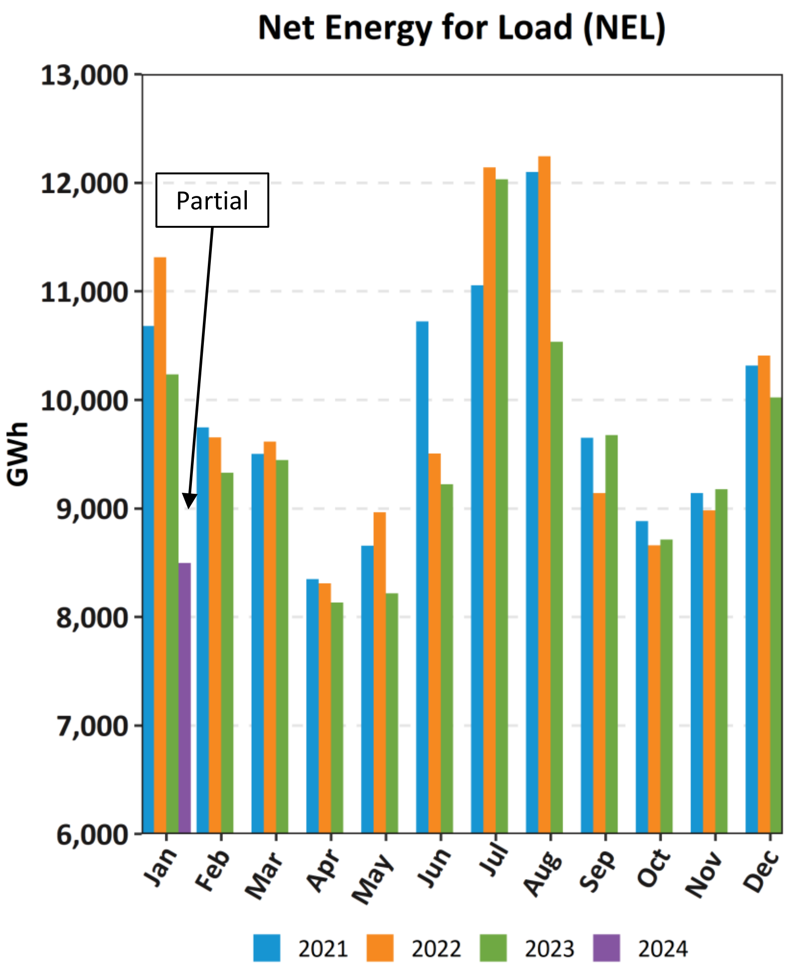
Net Interchange is the participant sum of daily imports minus the sum of daily exports; positive values are net imports

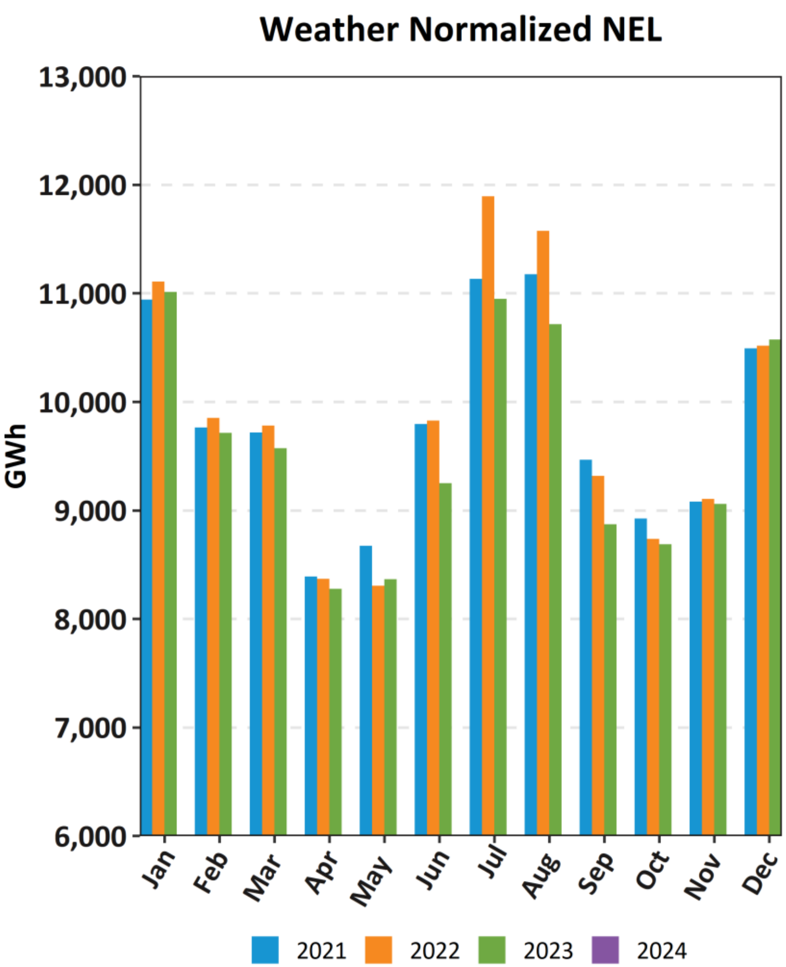
Monthly Revenue Quality Metered (RQM) Peak Load MW by Month



Shaded columns reflect RQM Peak for the current month and the same month the last 2 years

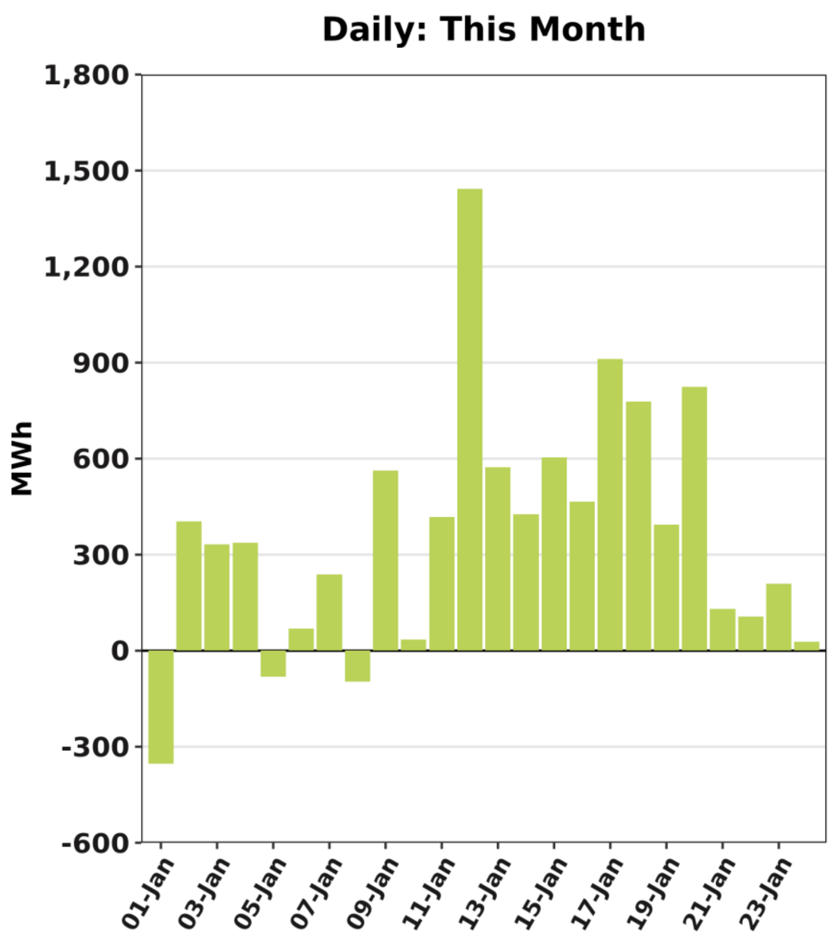
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

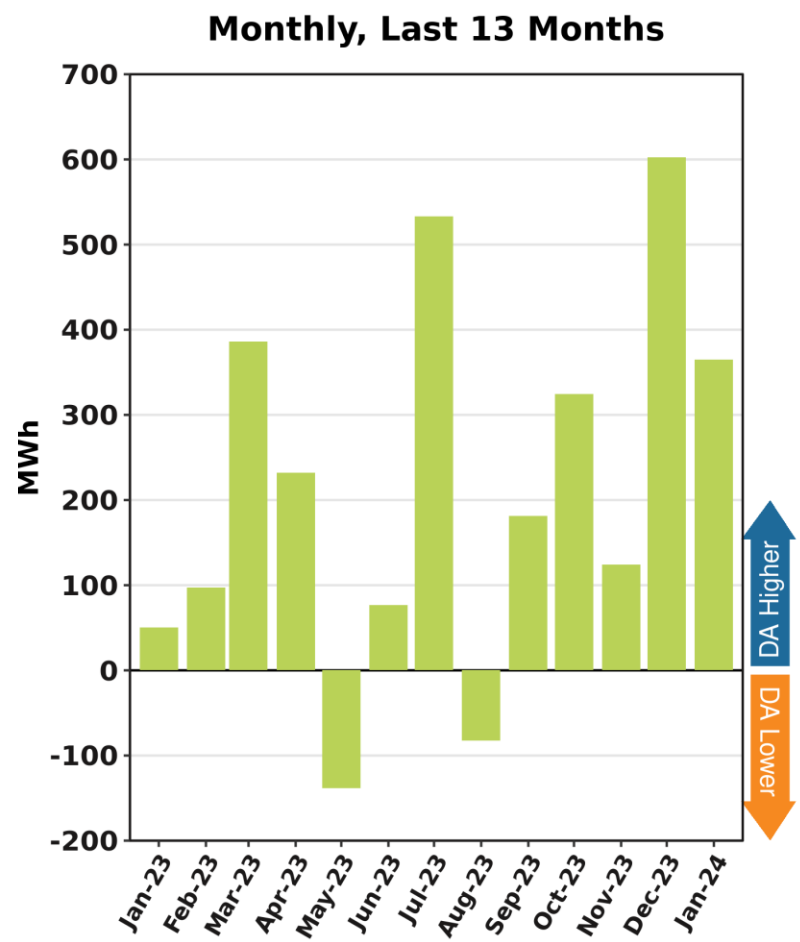




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported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

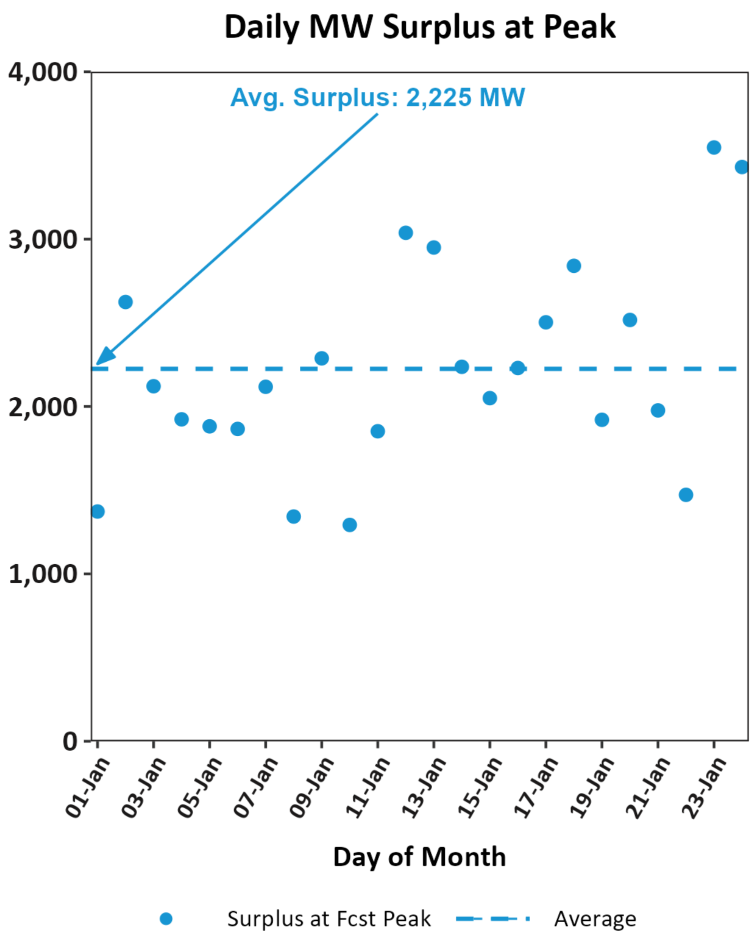
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour

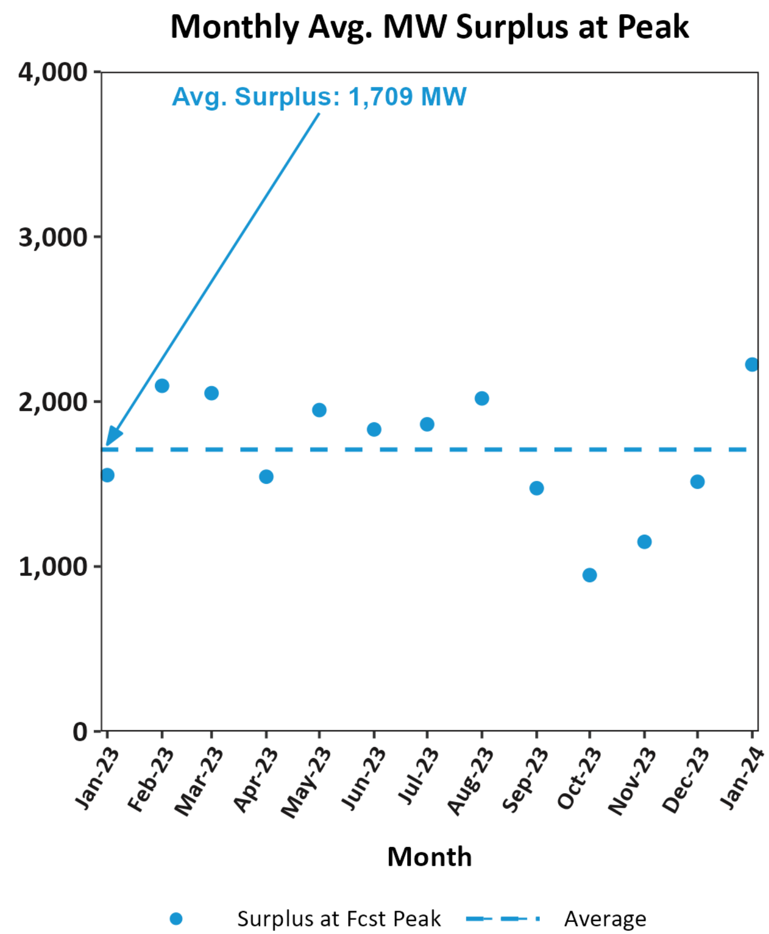




Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.

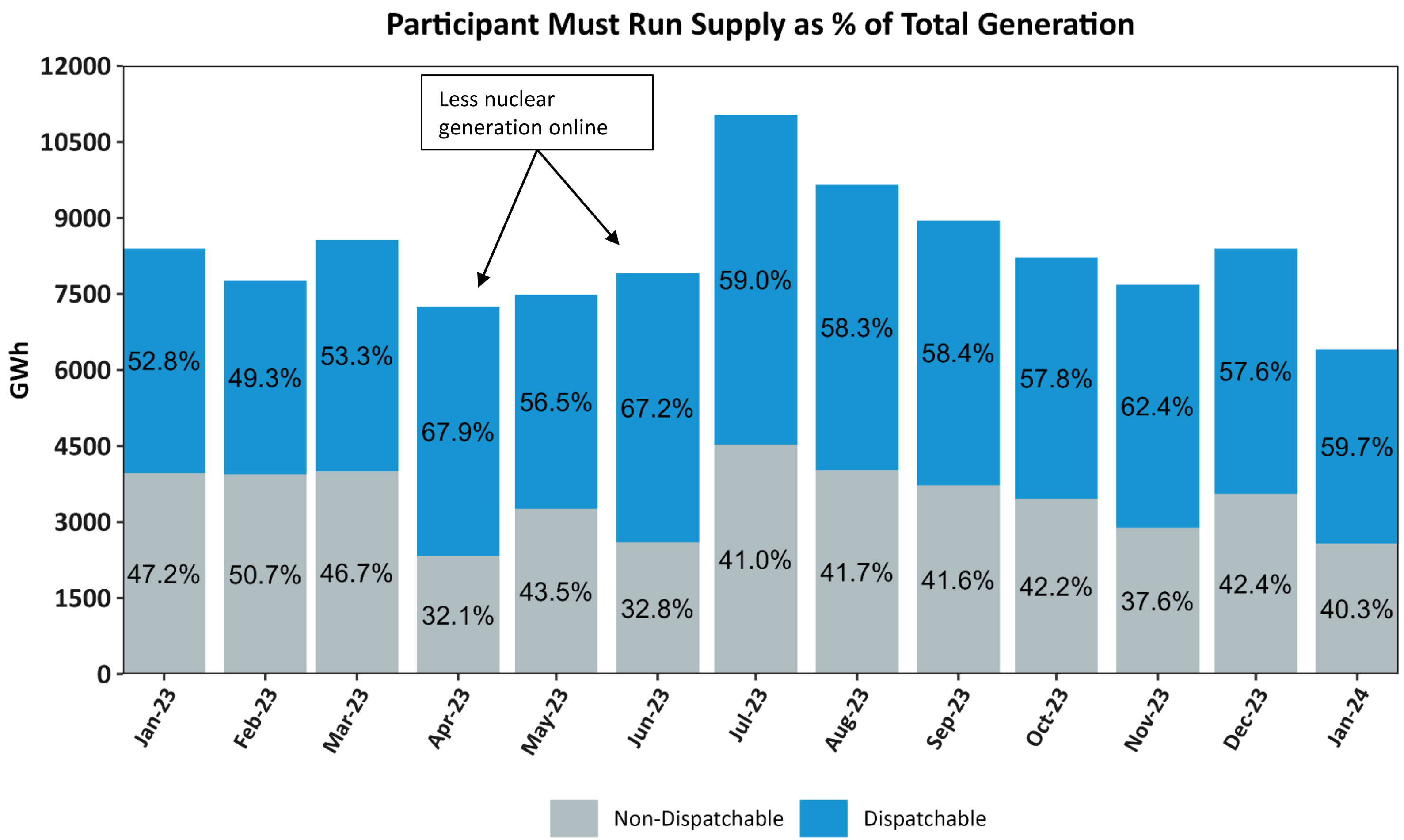
Maximum Supply* Cleared in the DA Market Continues to Meet Forecasted Peak-Hour Requirements





*MWs above are made up of ECO max for cleared assets + offered reserves for non-cleared assets for the forecasted peak hour

RT Generation Output Offered as Must Run vs. Dispatchable



Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of settlement-only generation (SOG) as well as must run offers from modeled units

MARKET PRICING

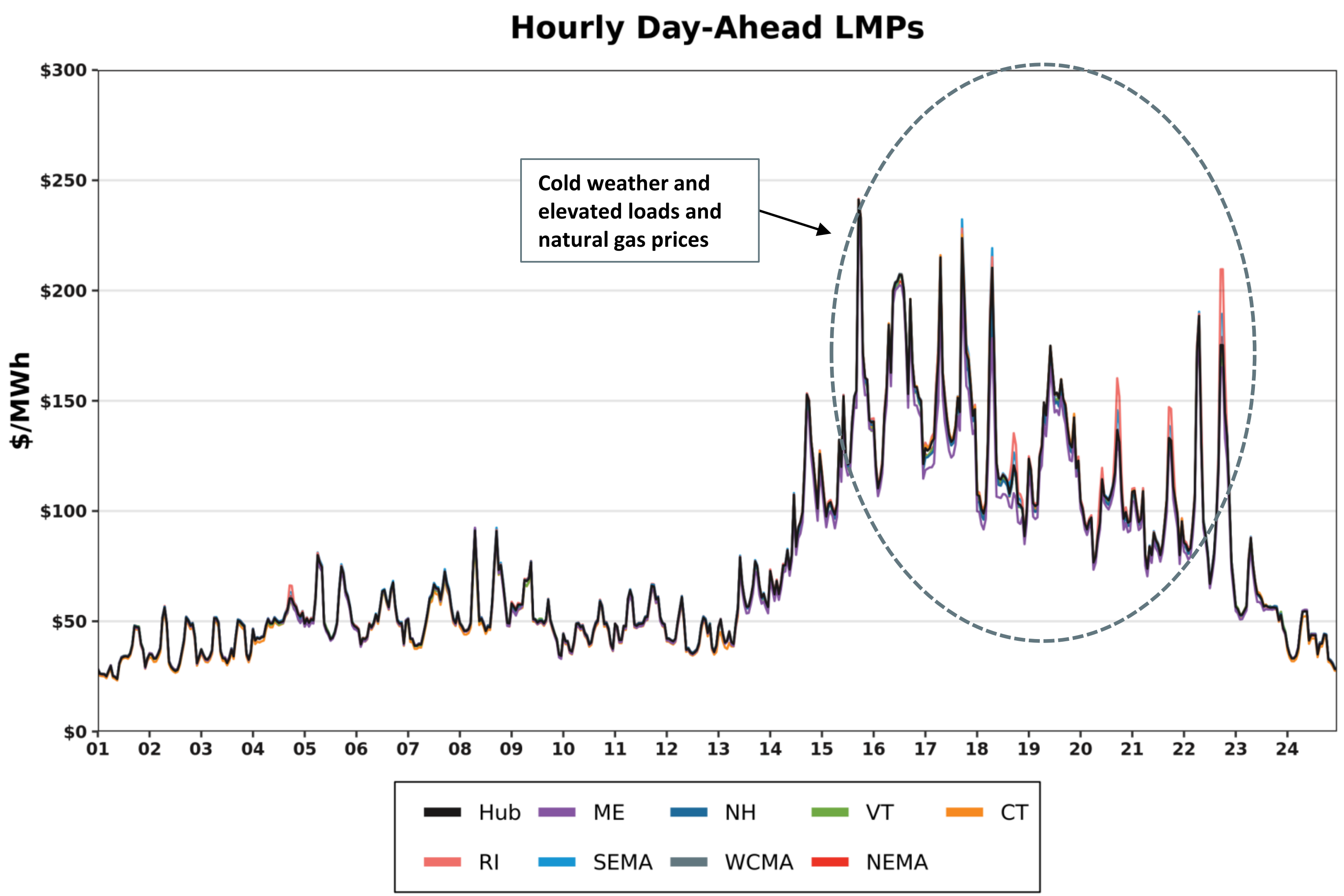
DA vs. RT LMPs ($/MWh)

Arithmetic Average

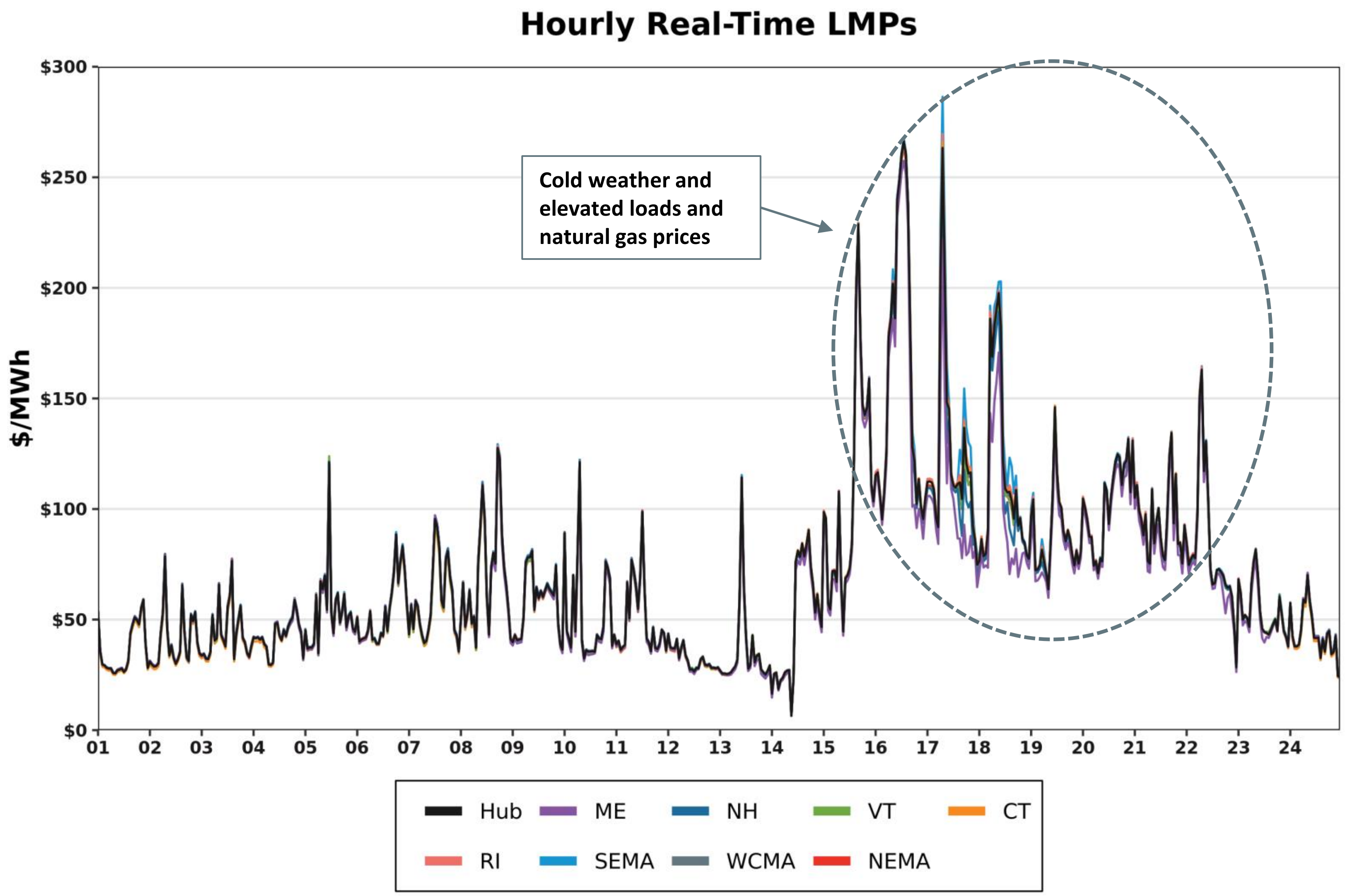
Year 2022	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$86.07	$84.05	$84.15	$85.73	$84.46	$85.35	$86.01	$85.66	$85.55
Real-Time	$85.42	$83.83	$83.06	$85.07	$83.67	$84.71	$85.37	$85.00	$84.92
RT Delta %	-0.8%	-0.3%	-1.3%	-0.8%	-0.9%	-0.7%	-0.7%	-0.8%	-0.7%
Year 2023	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$37.12	$36.04	$36.37	$37.00	$36.56	$36.67	$37.12	$36.85	$36.82
Real-Time	$36.00	$35.06	$35.15	$35.84	$35.34	$35.50	$35.96	$35.71	$35.70
RT Delta %	-3.0%	-2.7%	-3.3%	-3.1%	-3.3%	-3.2%	-3.1%	-3.1%	-3.0%

January-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$49.56	$47.76	$48.95	$49.57	$49.06	$49.02	$49.68	$49.11	$49.14
Real-Time	$51.05	$49.18	$50.27	$50.88	$49.44	$50.45	$51.13	$50.43	$50.51
RT Delta %	3.0%	3.0%	2.7%	2.7%	0.8%	2.9%	2.9%	2.7%	2.8%
January-24	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$76.50	$75.93	$73.85	$76.06	$75.80	$77.63	$77.55	$76.83	$76.84
Real-Time	$68.66	$68.15	$65.18	$67.93	$67.99	$69.18	$69.93	$68.83	$68.91
RT Delta %	-10.2%	-10.2%	-11.7%	-10.7%	-10.3%	-10.9%	-9.8%	-10.4%	-10.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	54.4%	59.0%	50.9%	53.4%	54.5%	58.4%	56.1%	56.4%	56.4%
Yr over Yr RT	34.5%	38.6%	29.7%	33.5%	37.5%	37.1%	36.8%	36.5%	36.4%

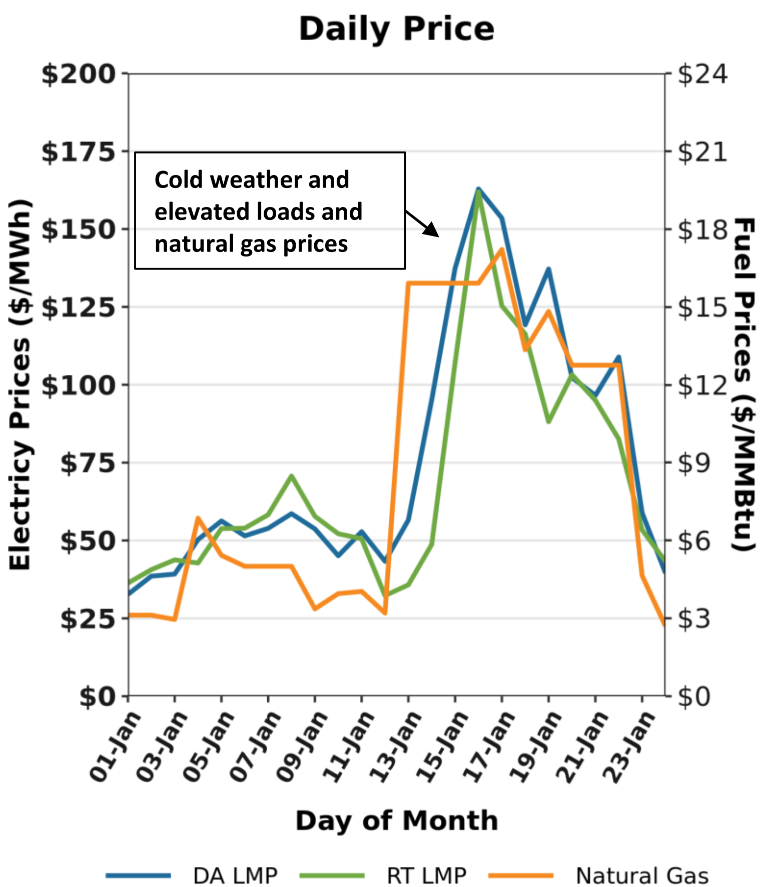
Hourly DA LMPs, January 1-24, 2024



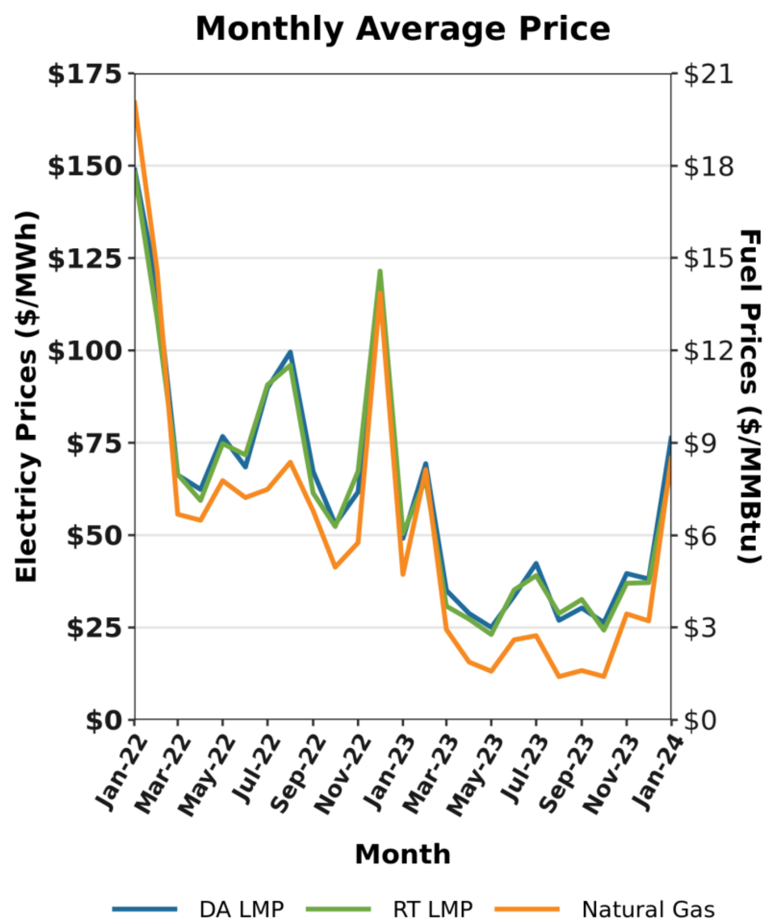
Hourly RT LMPs, January 1-24, 2024



Wholesale electricity vs Natural Gas prices by Month



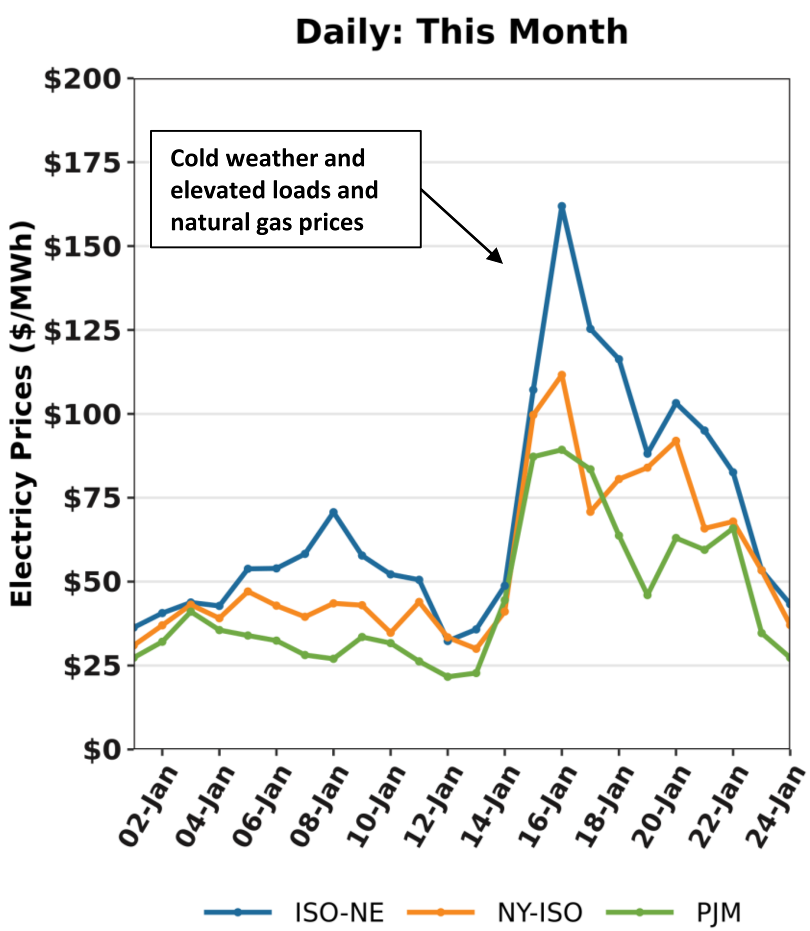
Gas price is average of Massachusetts delivery points



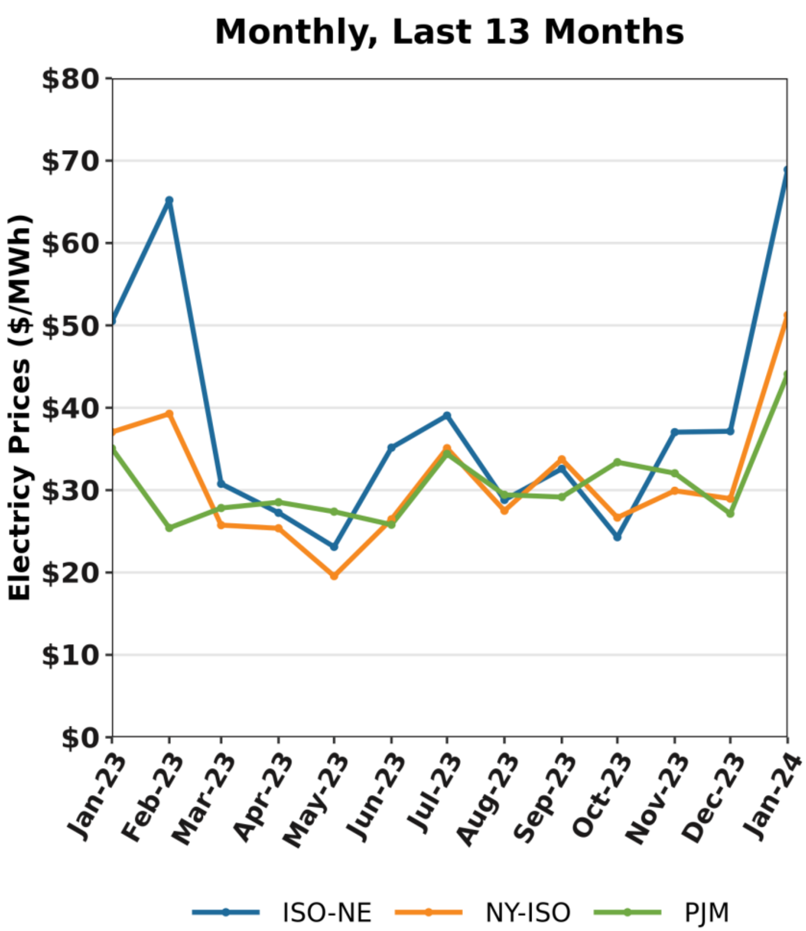
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

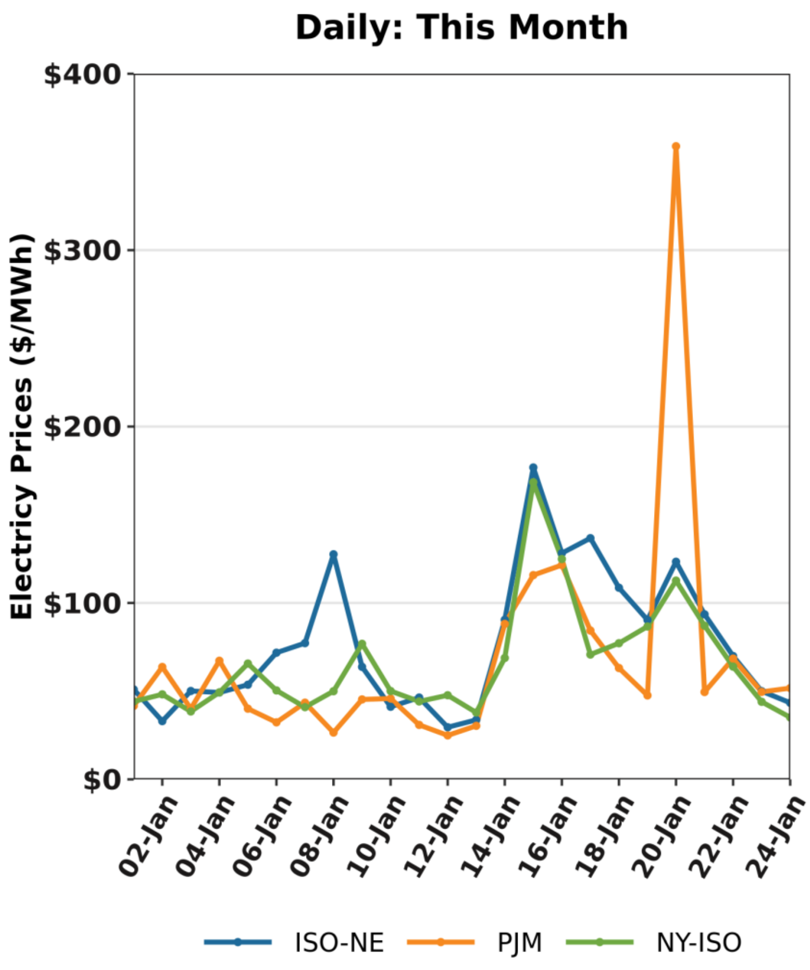


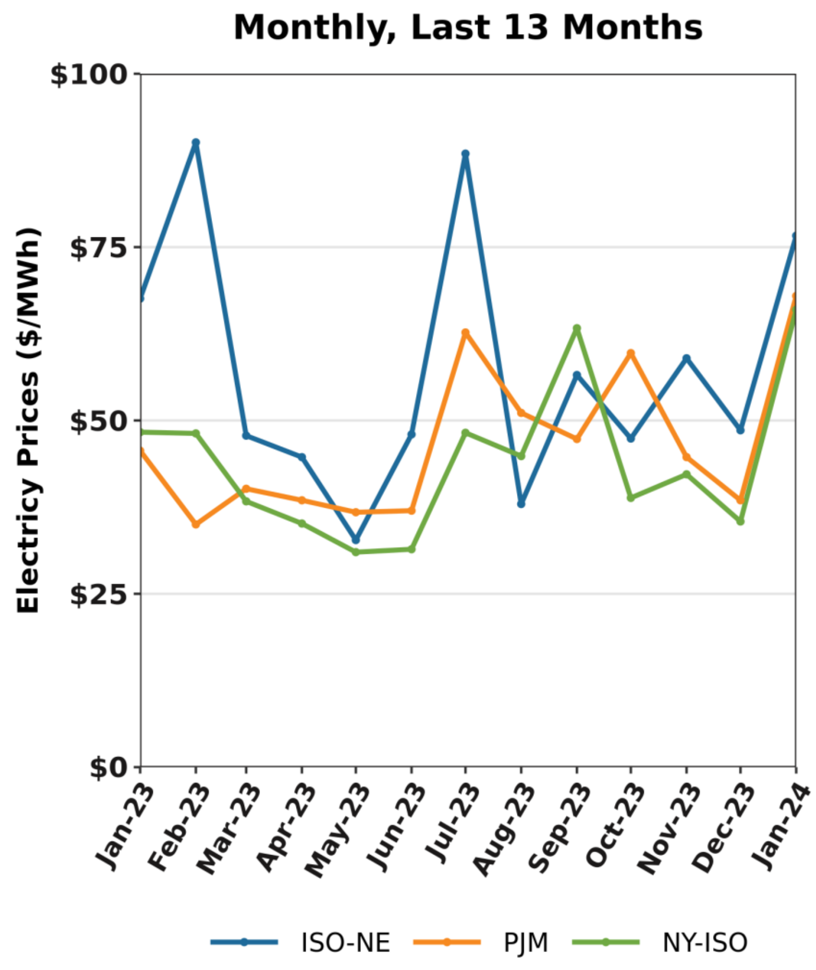
*Note: Hourly average prices are shown.



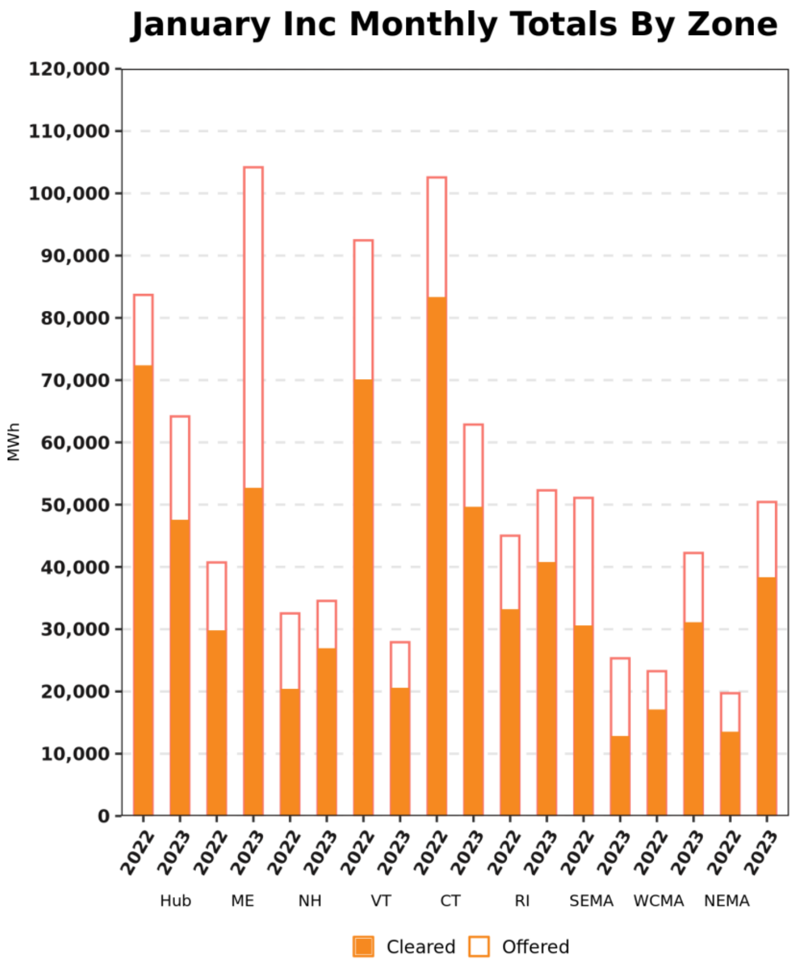
*Note: Hourly average prices are shown.

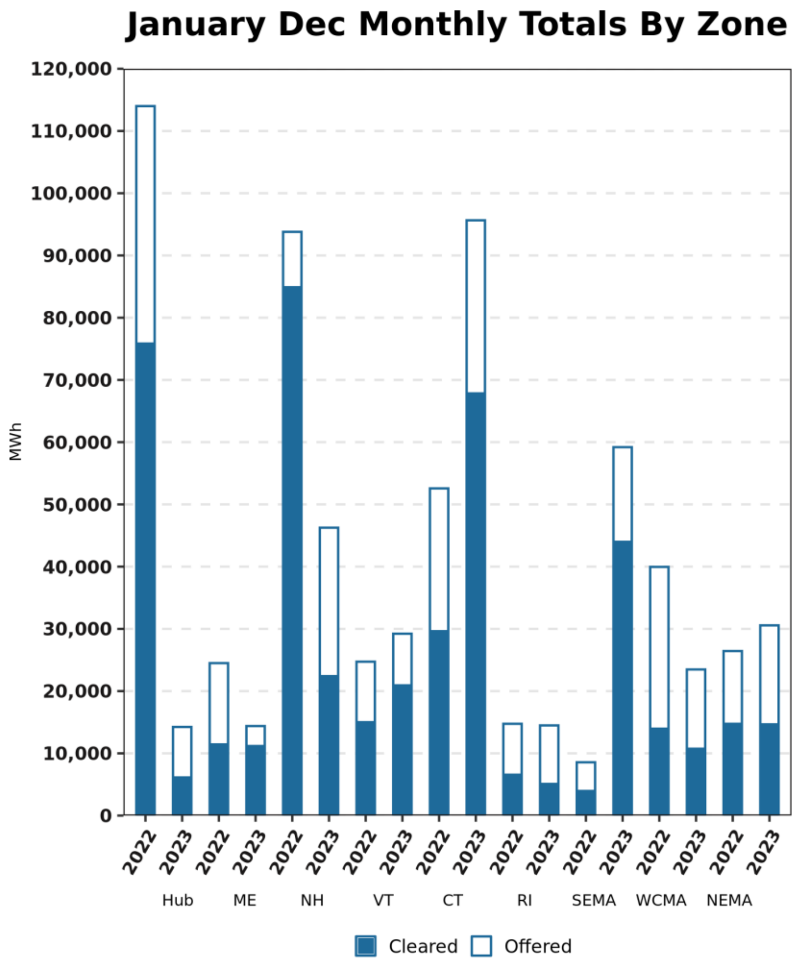
New England, NY, and PJM Average Peak Hour Real-Time Prices





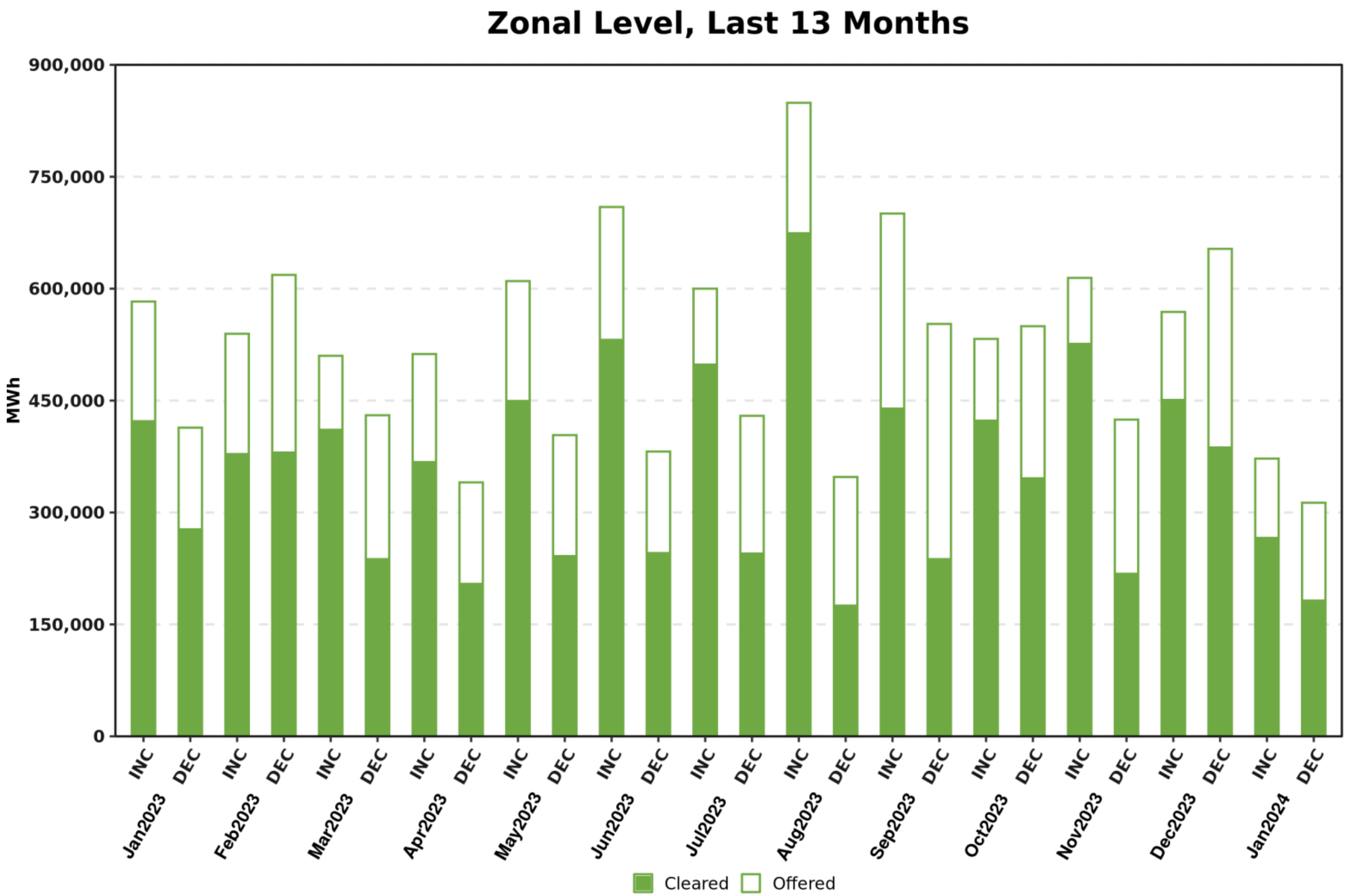
Zonal Increment Offers and Decrement Bid Amounts





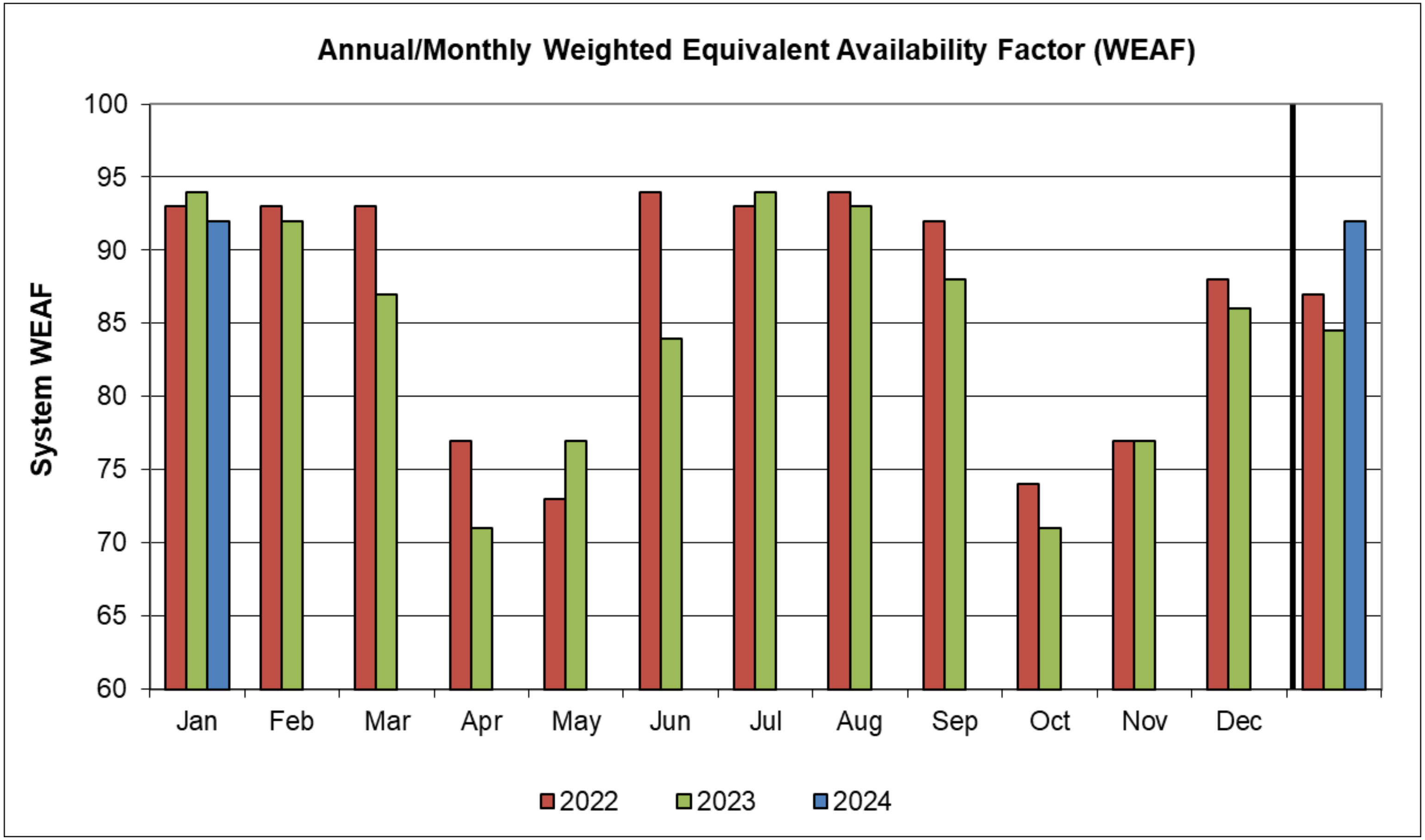
Includes nodal activity within the zone; excludes external nodes

Zonal Increment Offers and Decrement Bid Amounts



Includes nodal activity within the zone; excludes external nodes

System Unit Availability



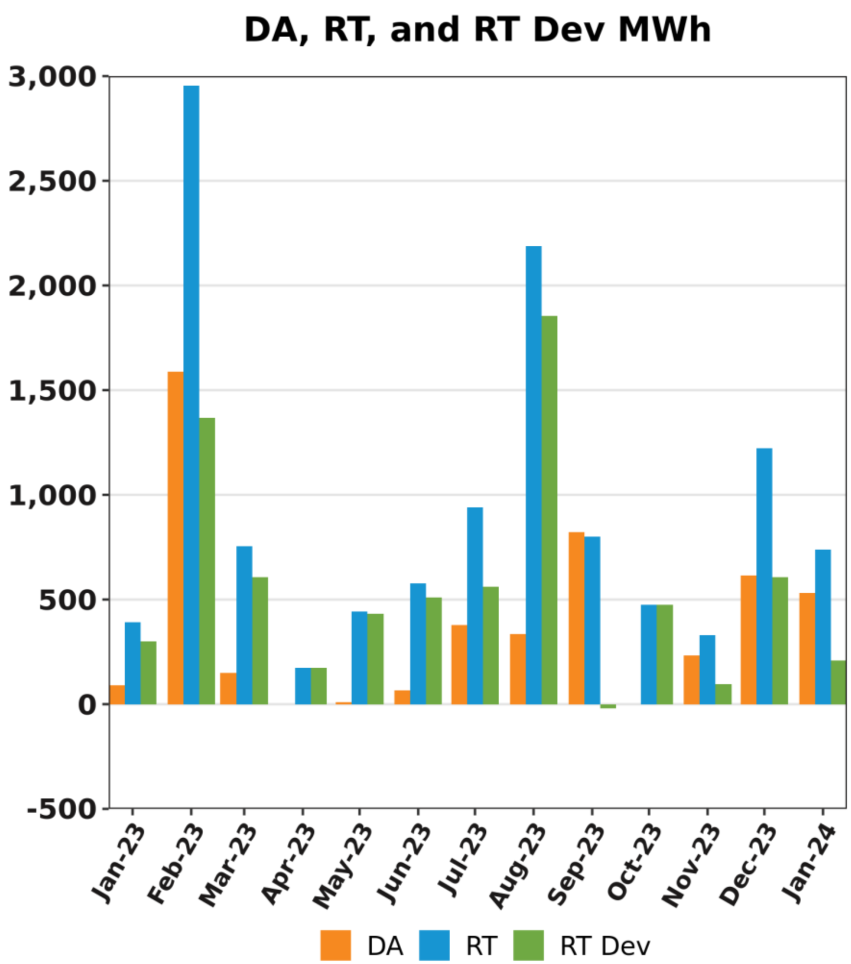
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2024	92												92
2023	94	92	87	71	77	84	94	93	88	71	77	86	85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87

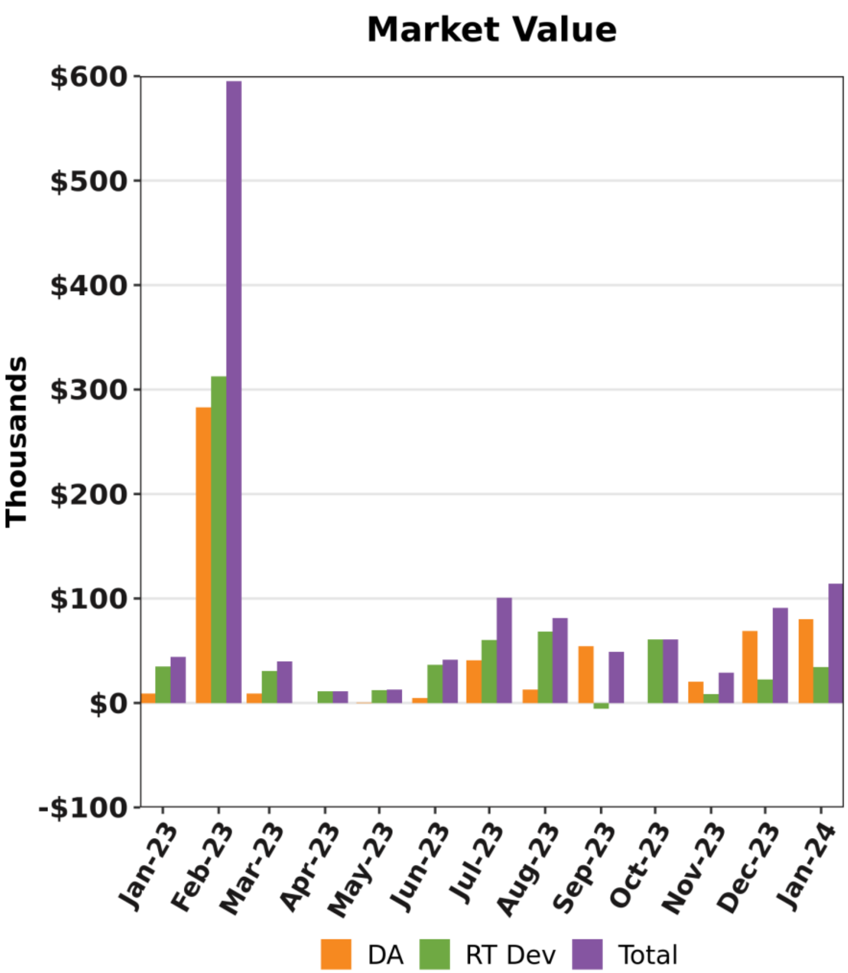
Data as of 1/20/2024

BACK-UP DETAIL

DEMAND RESPONSE

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.

NEW GENERATION

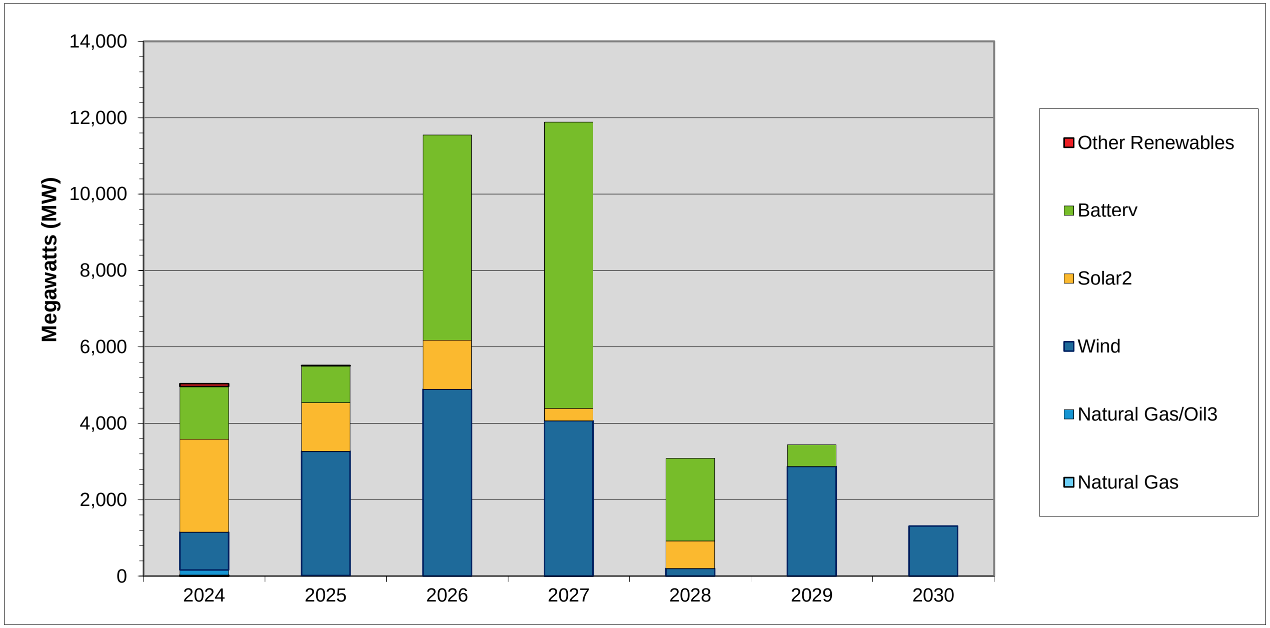
New Generation Update

Based on Queue as of 01/29/24

- Nine projects totaling 1,155 MW were added to the interconnection queue since the last update
  - One wind, two solar, three solar with battery and three battery storage projects with in-service dates between 2025 and 2031
- In total, 406 generation projects are currently being tracked by the ISO, totaling approximately 43,018 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Other Renewables	72	2	0	0	0	0	0	74	0.2
Battery	1,384	965	5,378	7,498	2,160	569	0	17,954	42.9
Solar[2]	2,432	1,278	1,280	323	725	0	0	6,038	14.4
Wind	989	3,249	4,893	4,064	197	2,870	1,309	17,571	42.0
Natural Gas/Oil[3]	135	16	0	0	0	0	0	151	0.4
Natural Gas	26	0	0	4	0	0	0	30	0.1
Totals	**5,038**	**5,510**	**11,551**	**11,889**	**3,082**	**3,439**	**1,309**	**41,818**	**100.0**

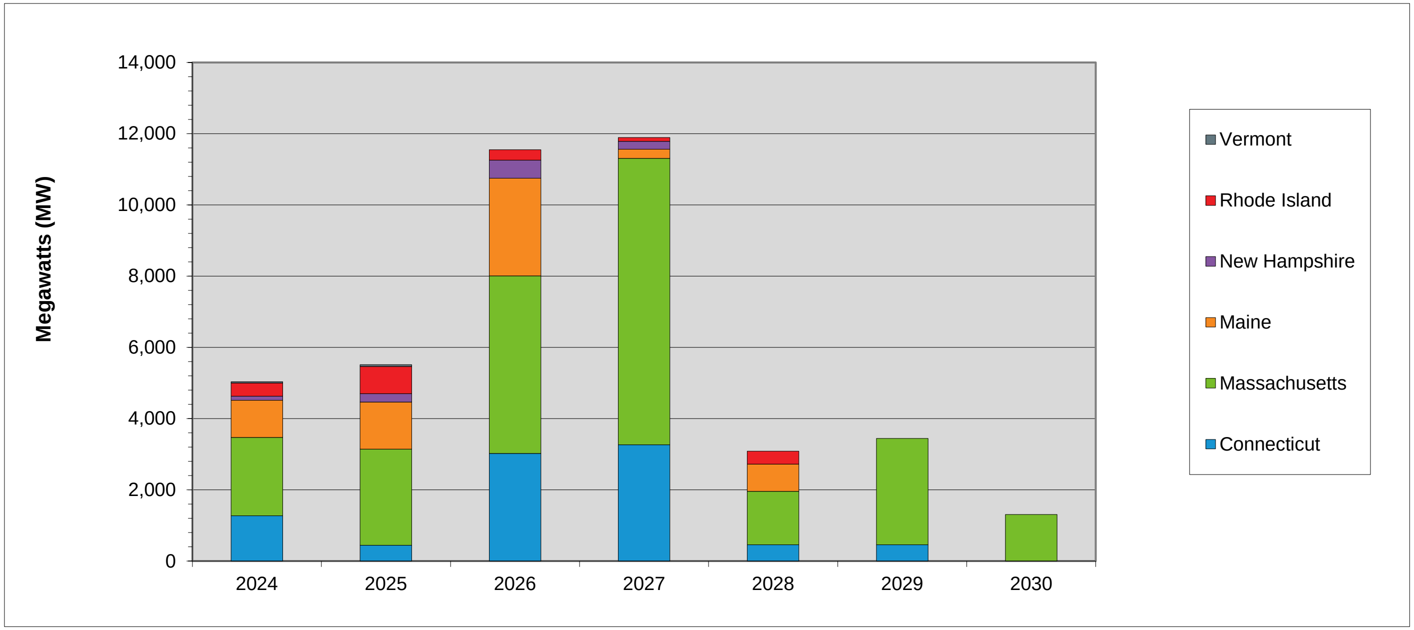
[1] Sum may not equal 100% due to rounding

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Vermont	40	50	0	0	0	0	0	90	0.2
Rhode Island	371	758	295	102	360	0	0	1,886	4.5
New Hampshire	114	239	504	226	0	0	0	1,083	2.6
Maine	1,039	1,323	2,743	254	764	0	0	6,123	14.6
Massachusetts	2,204	2,696	4,985	8,046	1,503	2,985	1,309	23,728	56.7
Connecticut	1,270	444	3,024	3,261	455	454	0	8,908	21.3
Totals	**5,038**	**5,510**	**11,551**	**11,889**	**3,082**	**3,439**	**1,309**	**41,818**	**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	117	17,954	0	0	117	17,954
Fuel Cell	4	46	1	20	3	26
Hydro	1	28	1	28	0	0
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	3	151	1	62	2	89
Nuclear	0	0	0	0	0	0
Solar	248	6,038	15	343	233	5,695
Wind	29	18,771	2	926	27	17,845
Total	406	43,018	20	1,379	386	41,639

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	7	87	2	48	5	39
Intermediate	2	89	0	0	2	89
Peaker	368	24,071	16	405	352	23,666
Wind Turbine	29	18,771	2	926	27	17,845
Total	406	43,018	20	1,379	386	41,639

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

New Generation Projection
By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	117	17,954	0	0	0	0	117	17,954	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	3	151	0	0	2	89	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	248	6,038	0	0	0	0	248	6,038	0	0
Wind	29	18,771	0	0	0	0	0	0	29	18,771
Total	406	43,018	7	87	2	89	368	24,071	29	18,771

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

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

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

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

Capacity Supply Obligation FCA 15

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

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

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

Capacity Supply Obligation FCA 16

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

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

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

Capacity Supply Obligation FCA 17

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

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

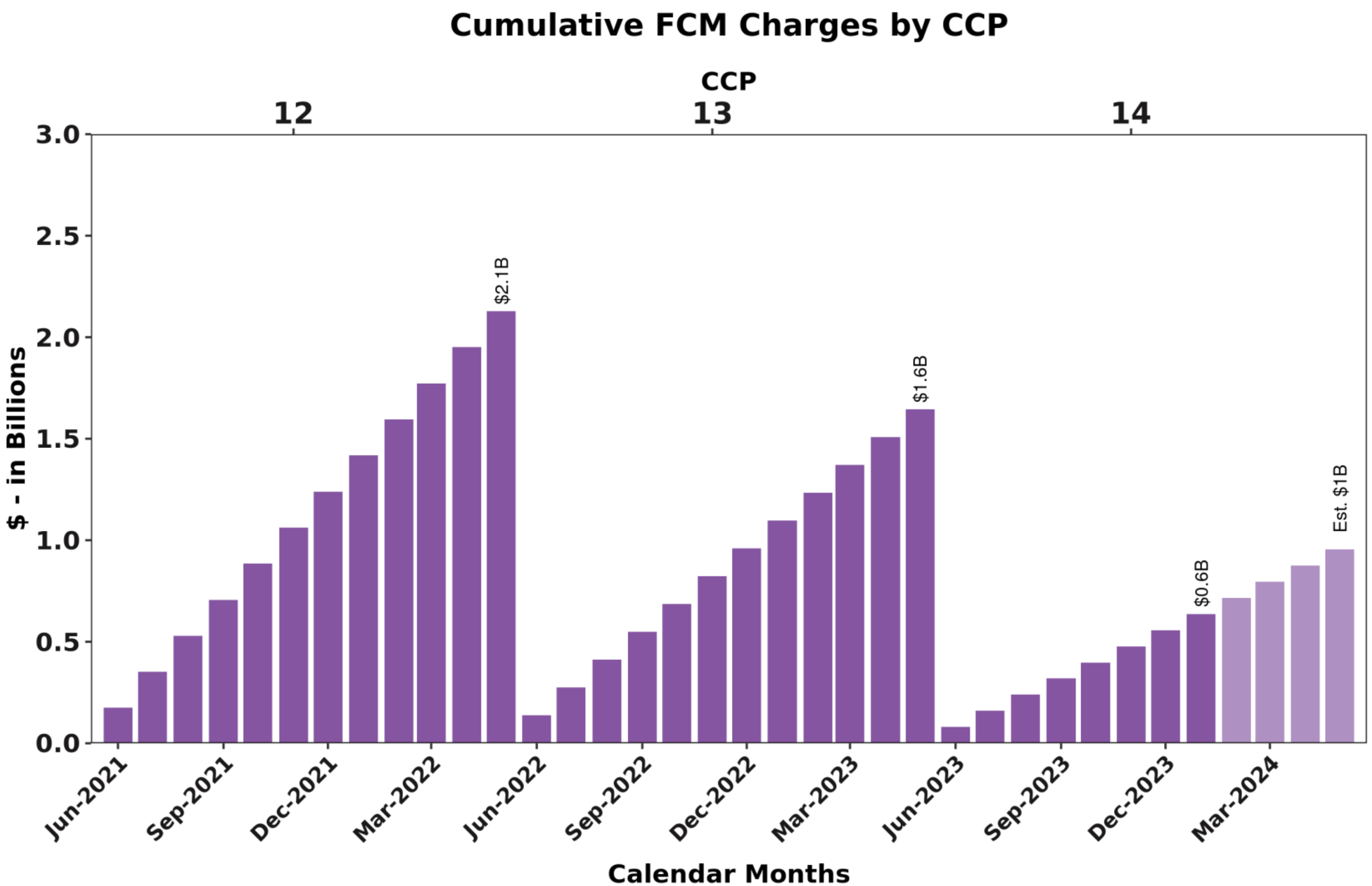
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes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

Active/Passive Demand Response

CSO Totals by Commitment Period

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

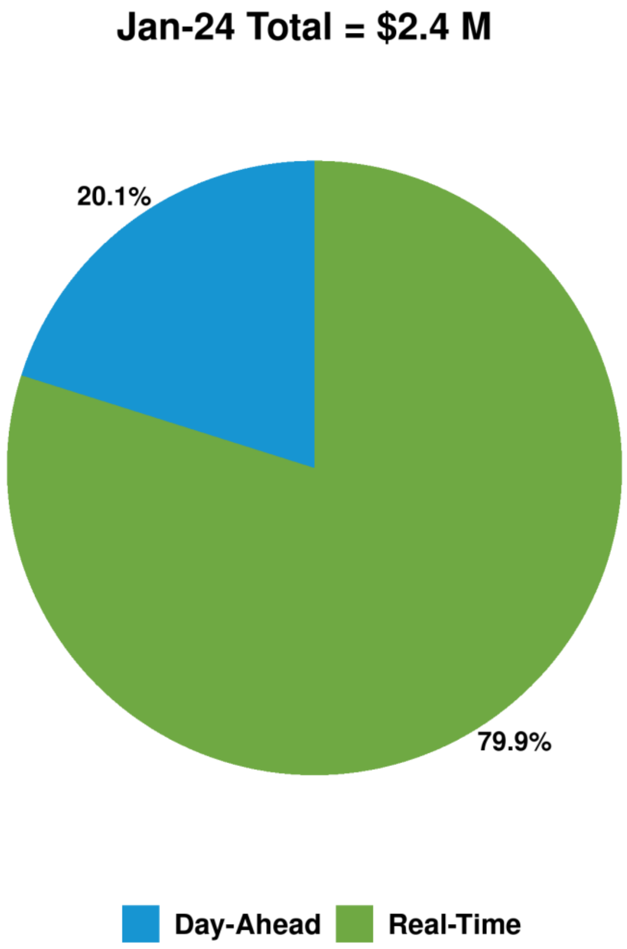
Forward Capacity Market Auctions

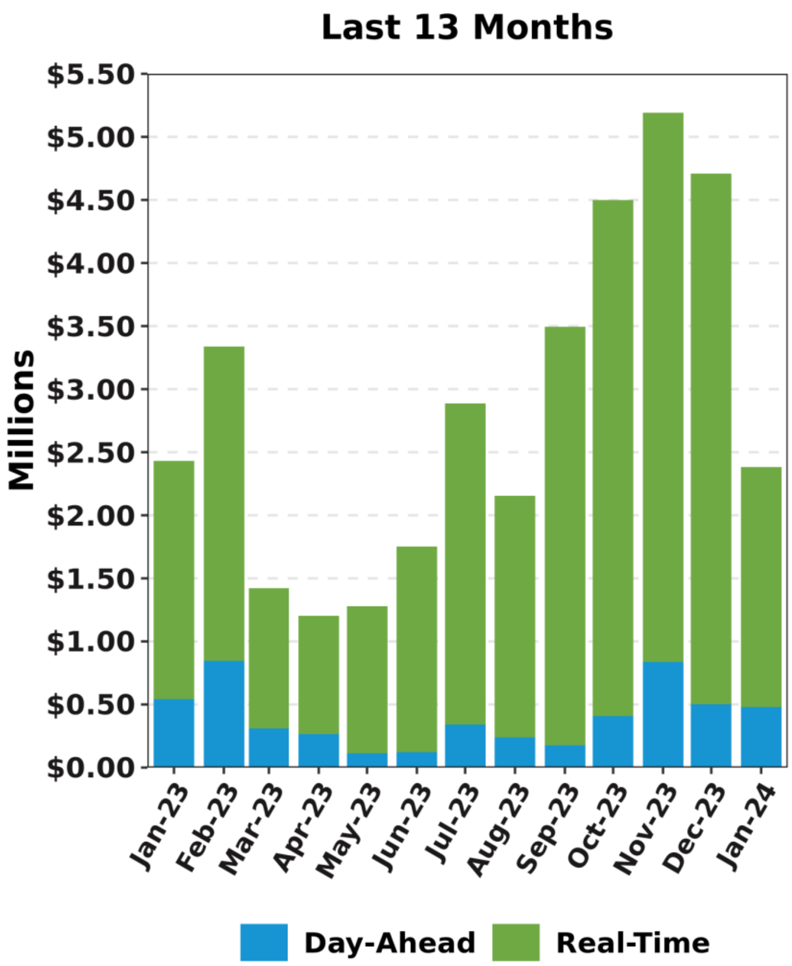


*The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

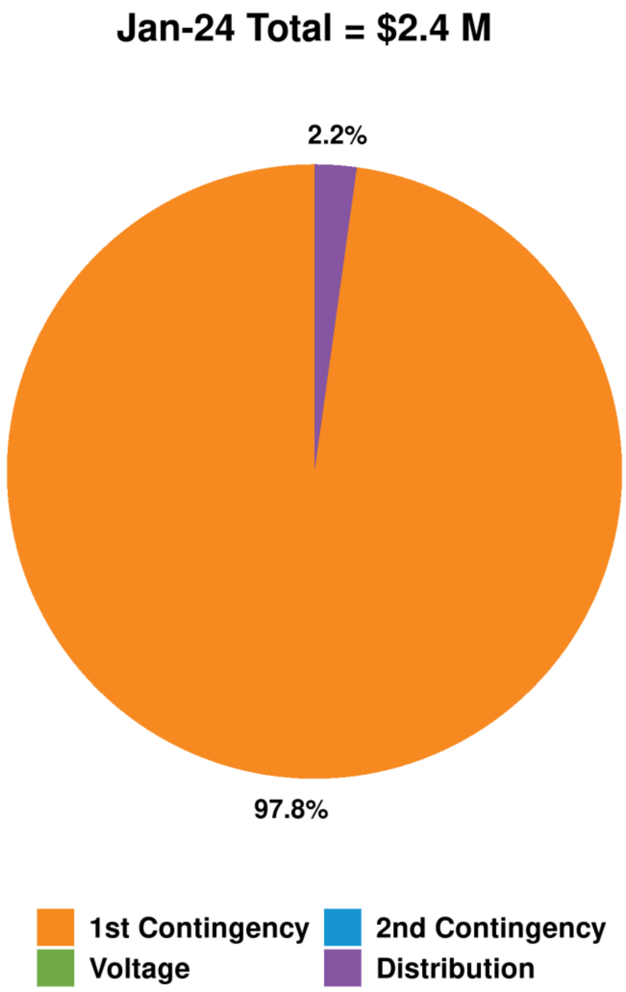
NET COMMITMENT PERIOD COMPENSATION

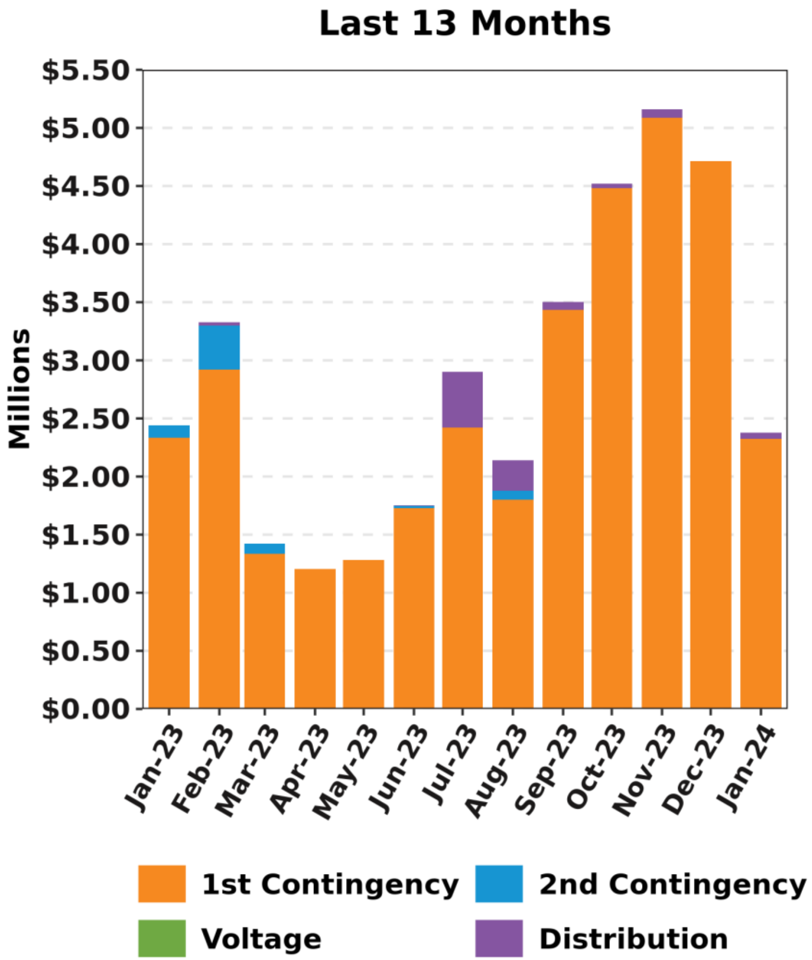
DA and RT NCPC Charges



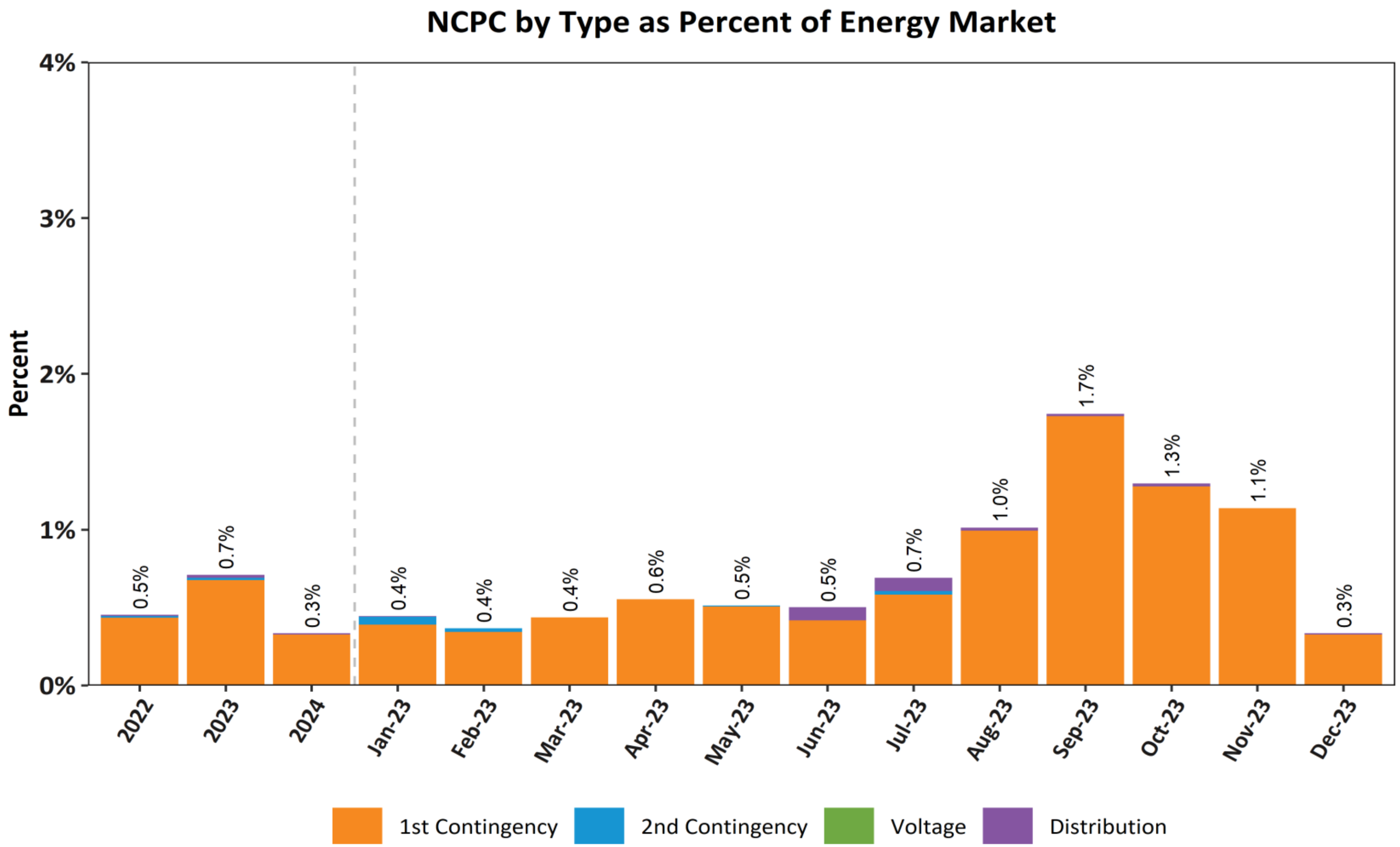


NCPC Charges by Type

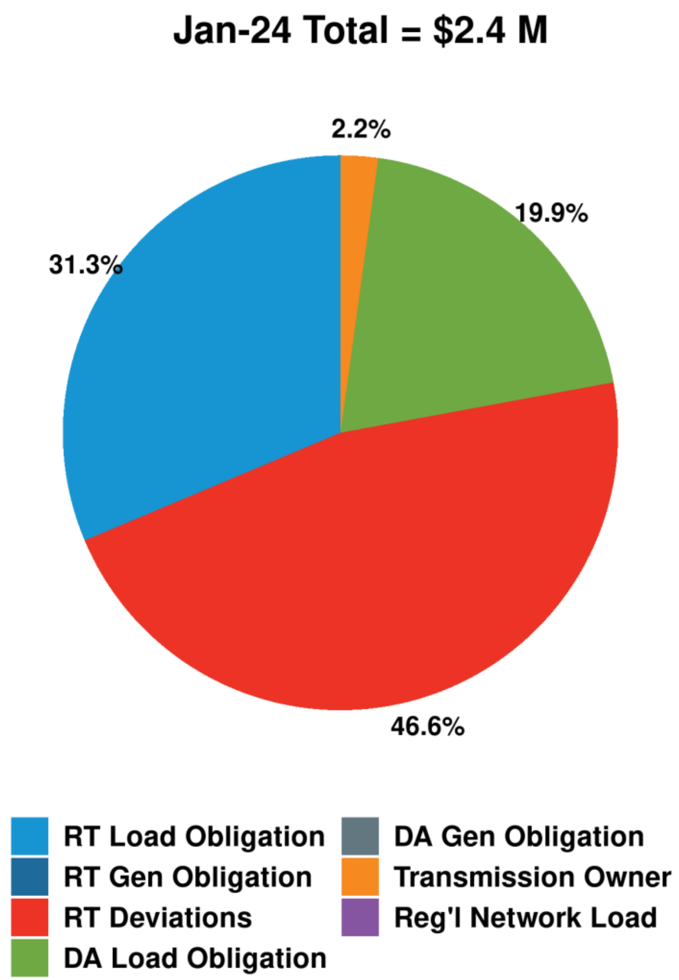


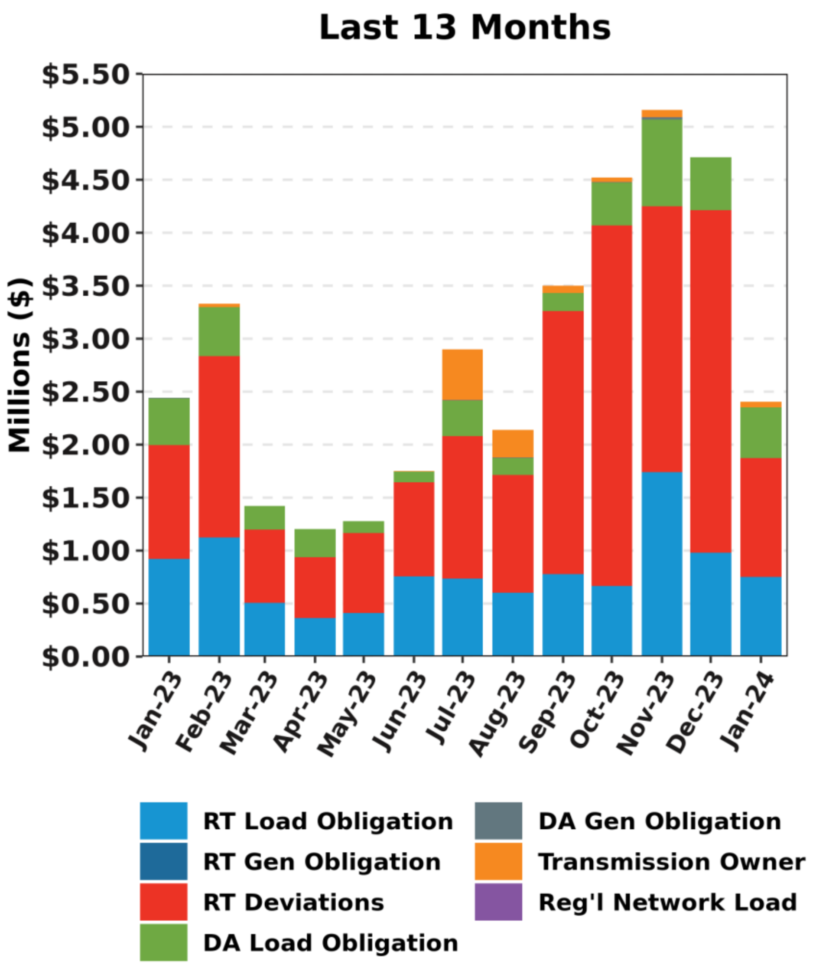


NCPC Charges by Type as percent of Energy Market Value

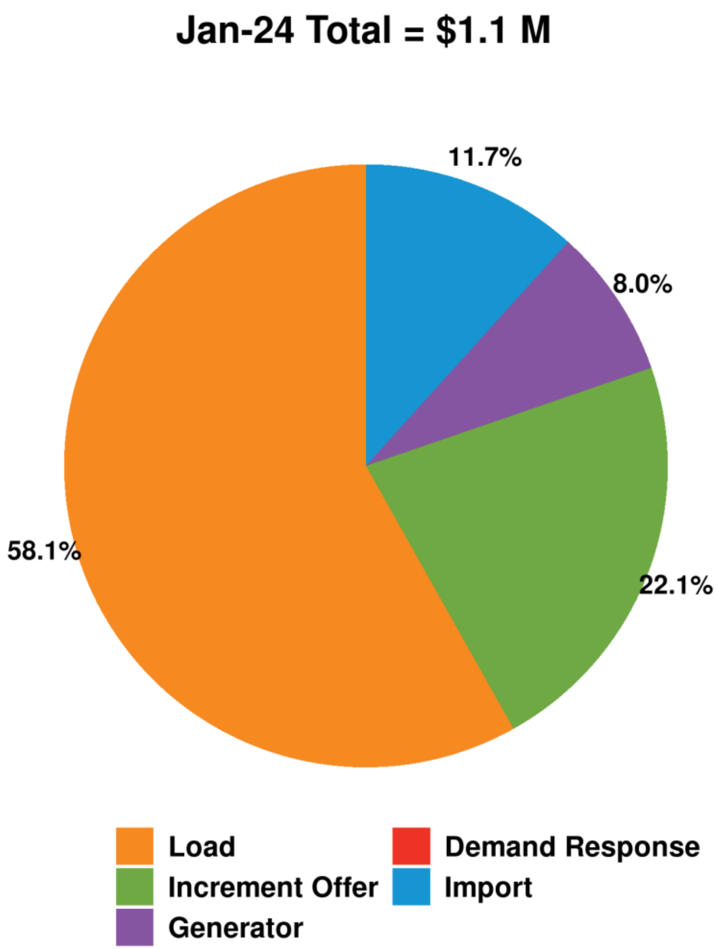


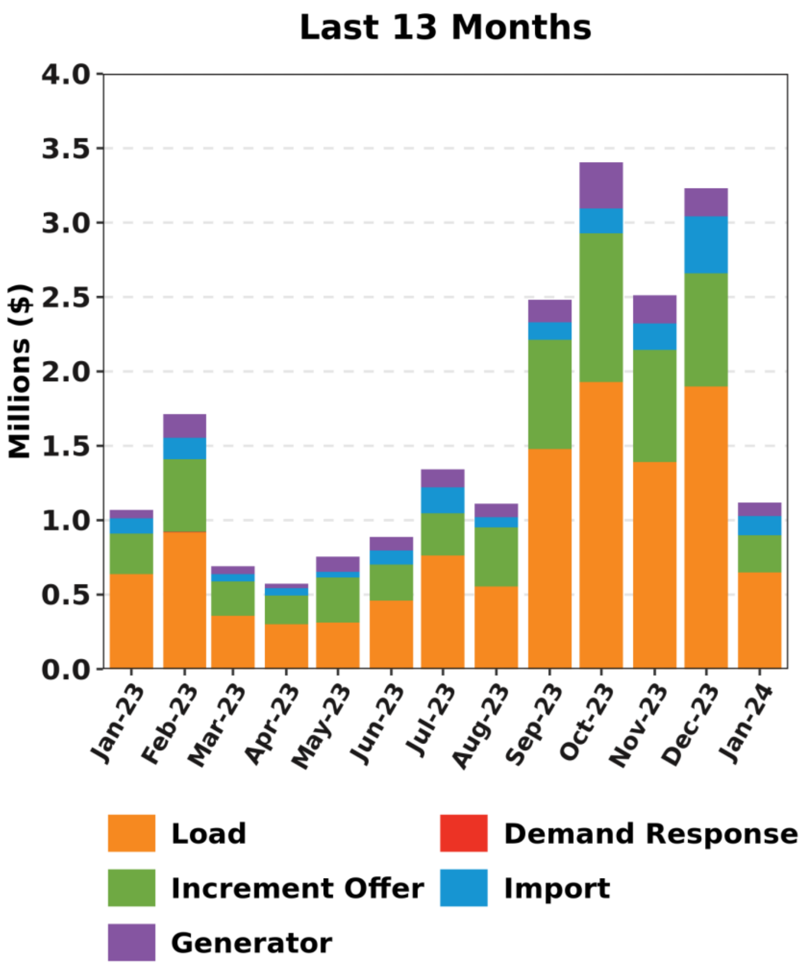
NCPC Charge Allocations





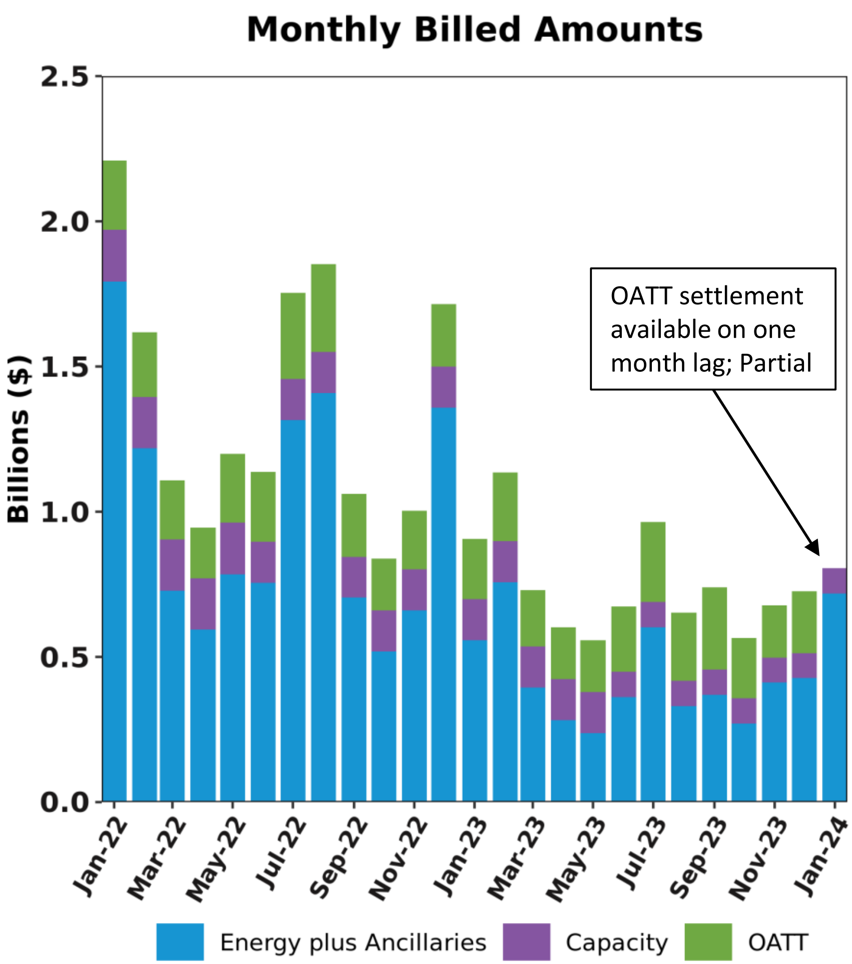
RT First Contingency Charges by Deviation Type

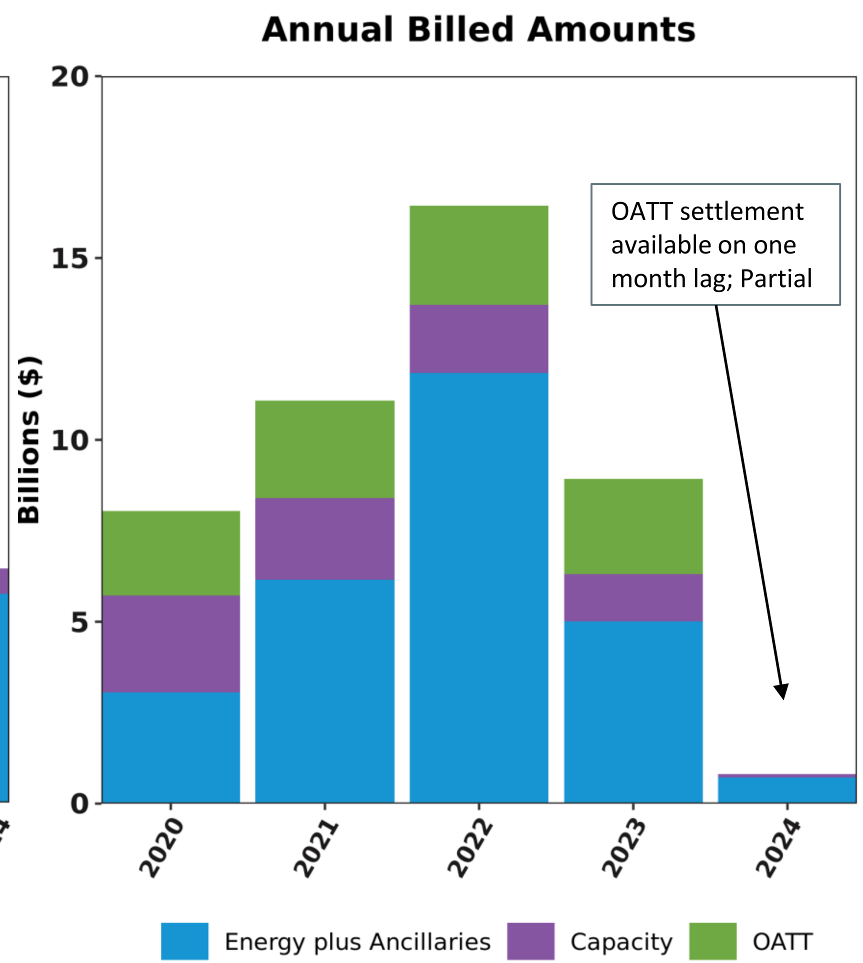




ISO BILLINGS

Total ISO Billings





*Ancillaries = Reserves, Regulation, NCPC, minus Marginal Loss Revenue Fund
*OATT = RNS, Through and Out, Schedule 9

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- February 28 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - X-178 Rebuild (Northern NH Rebuilds) – Eversource
    - MEPCO Sections 396 and 3001 End of Life Strategy – Avangrid
  - Maine 2028 Short Circuit Solutions Study
  - SEMA 2028 Short Circuit Solutions Study
  - Boston 2033 Needs Assessment
  - Order 881 Update
  - 2050 Transmission Study – Scope of Additional Analysis
  - Economic Planning for the Clean Energy Transition (EPCET) – Final Sensitivities
  - Transmission Planning Technical Guide Update – Updates to Load Power Factors

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

2050 Transmission Study

- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Additional discussion on solution development occurred at the 4/20/23 and 7/25/23 PAC meetings
- Development of transmission solutions and associated costs, including work by Electrical Consultants Inc. (ECI) on cost estimates, is now complete
- ISO presented solutions and associated costs at the 10/18/23 PAC meeting
- Draft report was posted on 11/1/23; ISO has received stakeholder comments and is preparing a written response
- Draft technical appendix was posted on 12/4/23, and a written response is being drafted

Economic Studies: EPCET

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

Economic Studies: 2024 Study

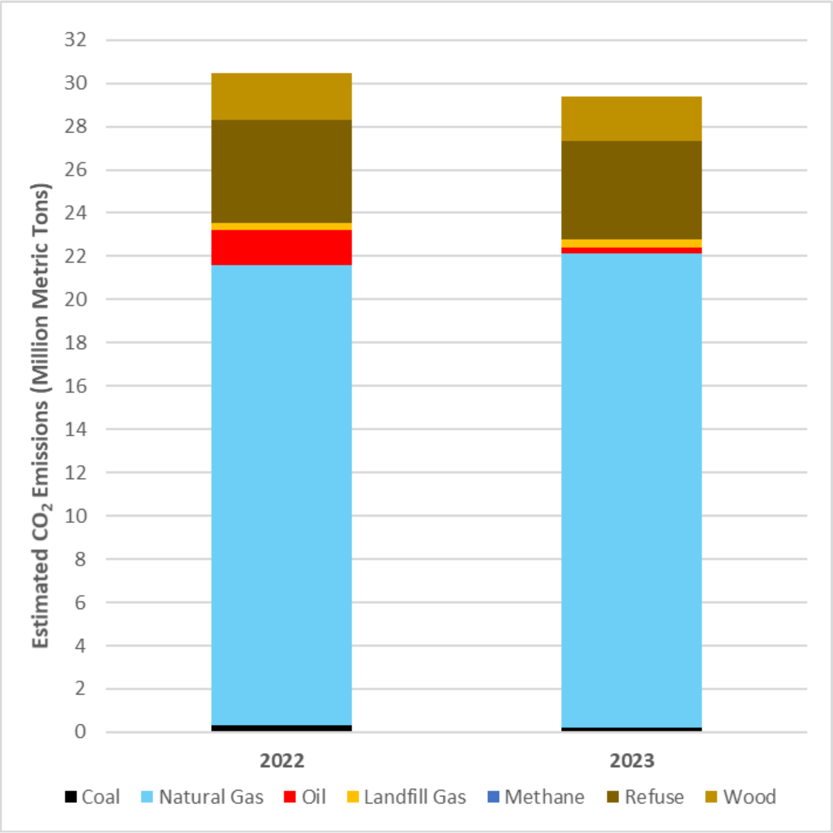
- 2024 Economic Study
  - First use of new Tariff language
    - Study was initiated at the January PAC meeting
  - Study will begin with Benchmark Scenario in Q1-Q2 2024, followed by Policy Scenario in Q3-Q4 2024
  - A Stakeholder-Requested Scenario can be submitted in Q2 2024 for consideration
  - Market Efficiency Needs Scenario will be studied in early 2025

ISO-NE Tie Benefits Evaluation

- The ISO started the tie benefits evaluation at the October 19 PSPC meeting. The second presentation was given at a special January 25 PSPC meeting and topics included:
  - Historical tie benefits results
  - Historical interregional tie flows
  - Load and resource diversity
- The scope of the project includes three major components
  - Historical review of external transfers
  - Future outlook for the northeast
  - Modeling assumptions review
- The evaluation will extend into Q3 of 2024
  - Additional PSPC time will be dedicated for this topic; the next meeting is scheduled for March 15

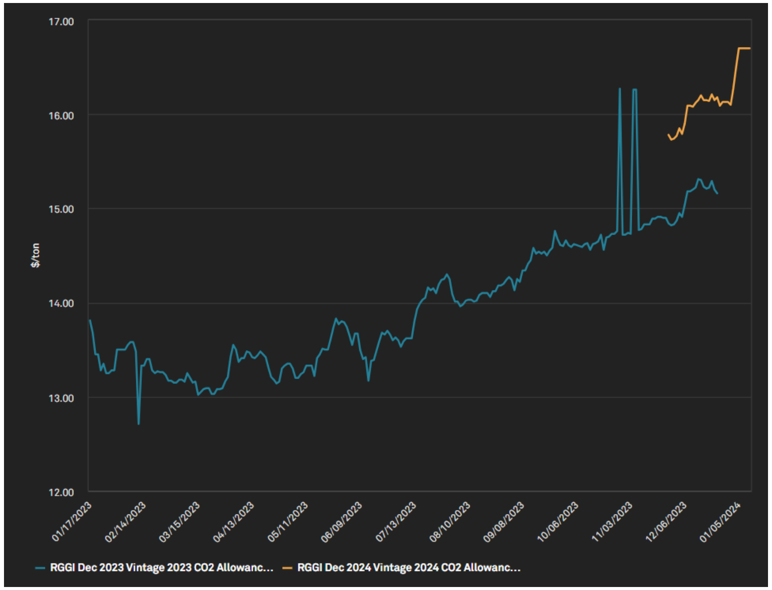
New England Power System Carbon Emissions

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



Data as of 12/31/2023

RGGI Allowance Prices



- 1/11/24: RGGI allowance spot price - $16.70
- The 63rd RGGI Auction is scheduled for March 13, 2024
  - 11 of the 12 participating states are offering CO_2 allowances for sale
  - Pennsylvania is currently prohibited from offering allowances for sale (this ruling is under appeal)
  - Virginia is no longer part of RGGI

RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

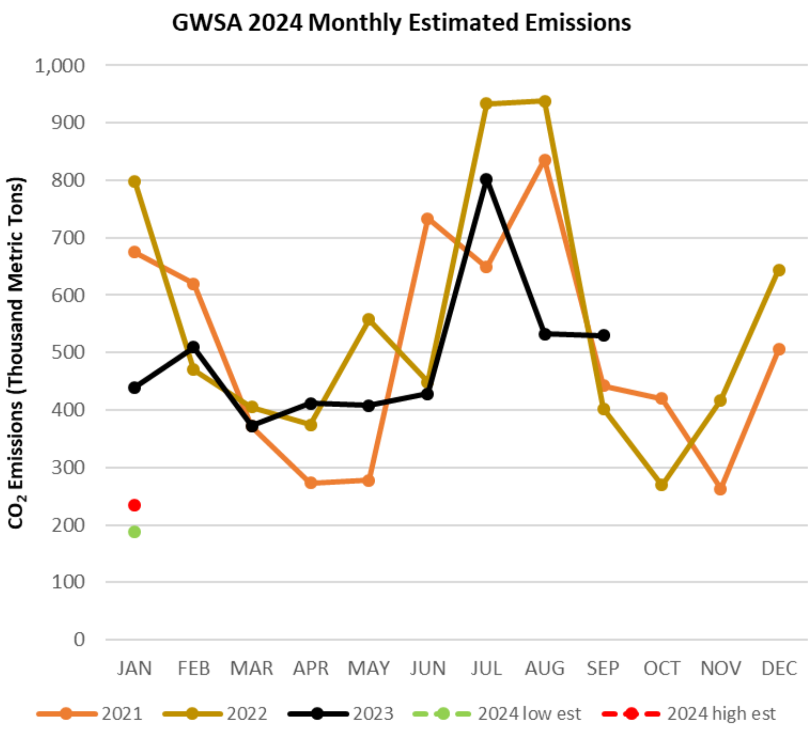
2024 Estimated Emissions Under CO_2 Cap

- As of 1/15/24, January estimated GWSA CO_2 emissions range between **188,771** and **234,000** metric tons
  - Year-to-date 2024 estimated emissions range between **2.5%** and **3.1%** of the 2024 cap of 7.61 MMT

2023 Estimated Emissions Under CO_2 Cap

- 2023 estimated total GWSA CO_2 emissions range between **65.5%** and **78.9%** of the 2023 cap of 7.84 MMT
- According to the EPA, 2023 4th quarter emissions reporting period ends on January 30, 2024

2021-2024 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated emissions)

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 1/18/2024

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*	Apr-24	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

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

Greater Boston Projects, cont.

Status as of 1/18/2024

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

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

Greater Boston Projects, cont.

Status as of 1/18/2024

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

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

Greater Boston Projects, cont.

Status as of 1/18/2024

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	Apr-24	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 1/18/2024

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

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

SEMA/RI Reliability Projects

Status as of 1/18/2024

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

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

SEMA/RI Reliability Projects, cont.

Status as of 1/18/2024

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 1/18/2024

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

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

SEMA/RI Reliability Projects, cont.

Status as of 1/18/2024

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 1/18/2024

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

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

Eastern CT Reliability Projects

Status as of 1/18/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 1/18/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 1/18/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

New Hampshire Solution Projects

Status as of 1/18/2024

Project Benefit: Addresses system needs in the New Hampshire area

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

Upper Maine Solution Projects

Status as of 1/18/2024

Project Benefit: Addresses system needs in the Upper Maine area

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

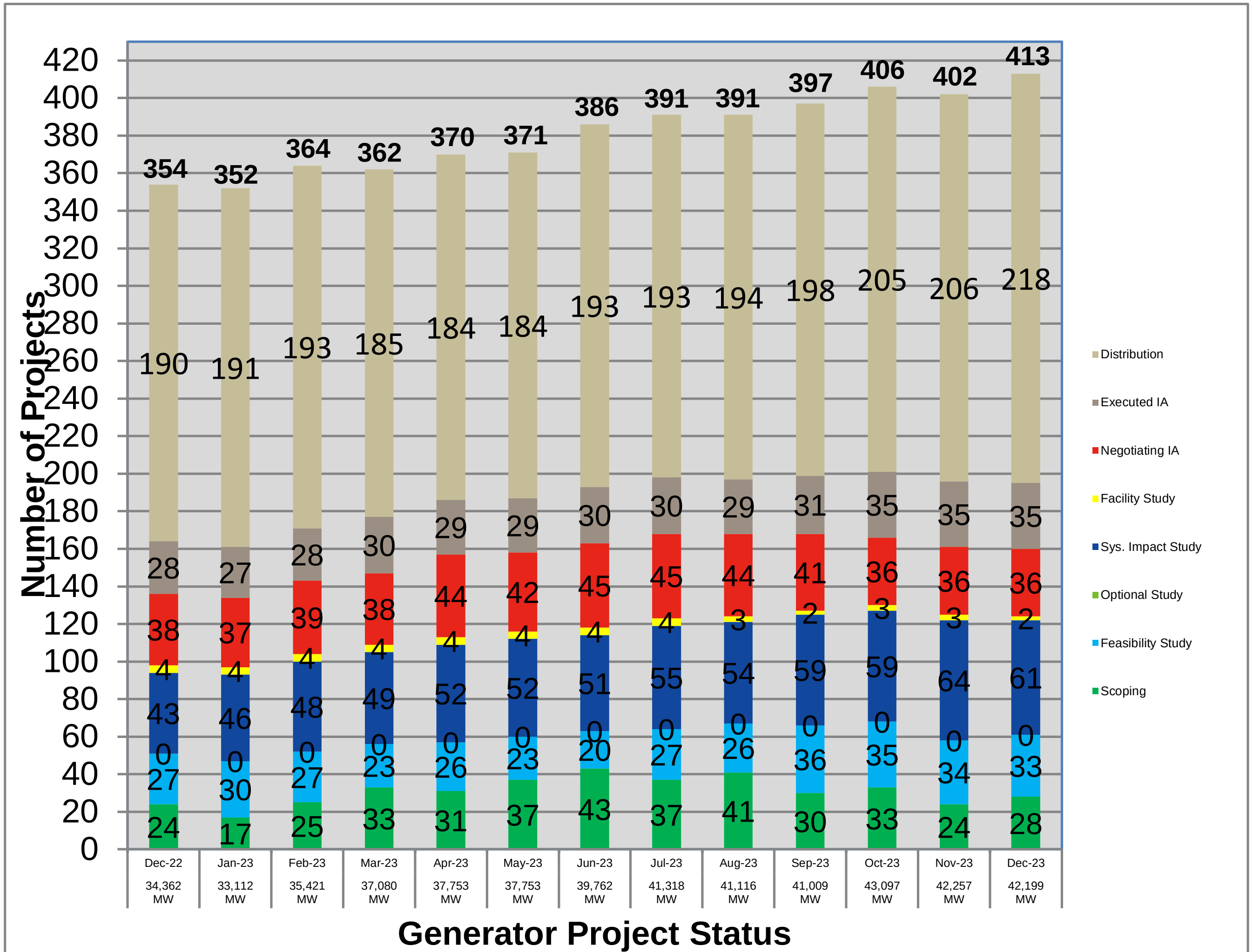
Upper Maine Solution Projects, cont.

Status as of 1/18/2024

Project Benefit: Addresses system needs in the Upper Maine area

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

Status of Tariff Studies as of January 1, 2024



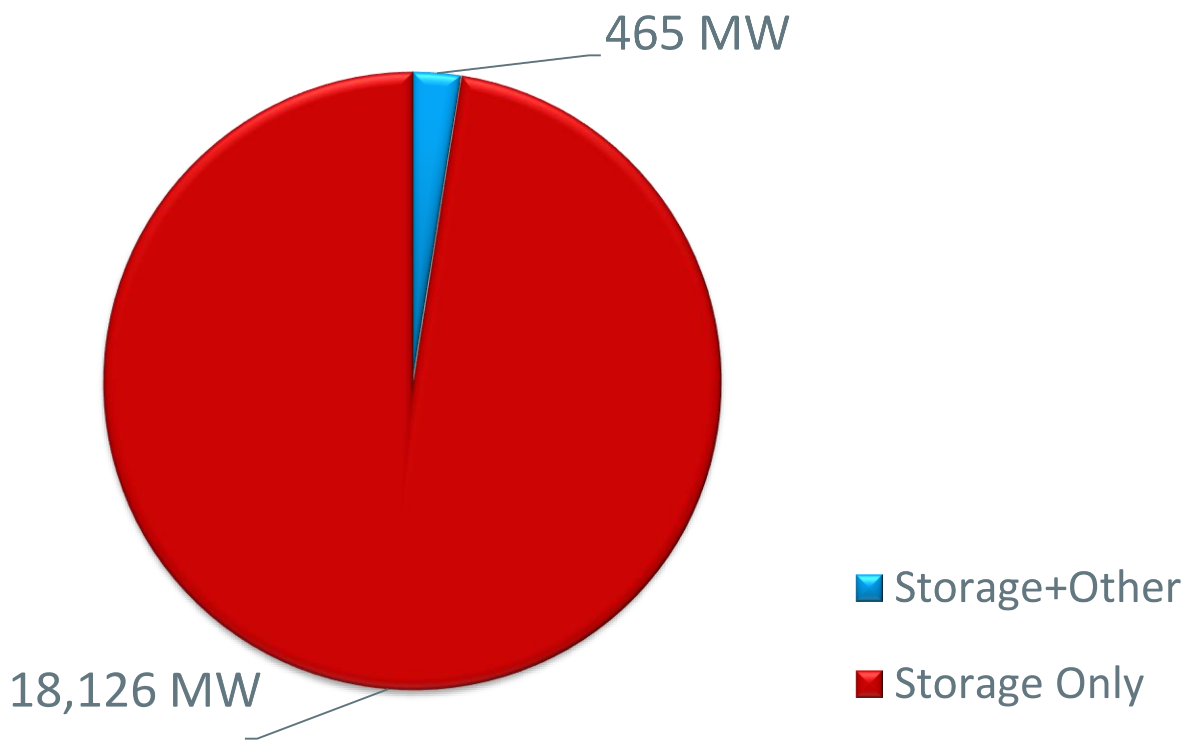
8 ETUs in Scoping, 6 in FS, 1 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 1 in SIS

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

What is in the Queue (as of January 1, 2024)

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



OPERABLE CAPACITY ANALYSIS

Winter 2024 Analysis

Winter 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**Feb. - 2024[2] CSO (MW)**	**Feb. - 2024[2] SCC (MW)**
Operable Capacity MW [1]	28,648	31,731
Active Demand Capacity Resource (+) [5]	346	347
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	869	869
Non Commercial Capacity (+)	20	20
Non Gas-fired Planned Outage MW (-)	202	842
Gas Generator Outages MW (-)	45	237
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	2,193	2,187
Net Capacity (NET OPCAP SUPPLY MW)	24,343	26,601
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,755	19,755
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,060	22,060
Operable Capacity Margin	2,283	4,541

1. Operable Capacity is based on data as of **January 23, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of January 23, 2024.
2. Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning February 10, 2024.
3. Total of (Gas at Risk MW) – (Gas Gen Outages MW).
4. Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.
5. Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2024 Operable Capacity Analysis

90/10 Load Forecast	Feb. - 2024[2] CSO (MW)	Feb. - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,648	31,731
Active Demand Capacity Resource (+) [5]	346	347
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	869	869
Non Commercial Capacity (+)	20	20
Non Gas-fired Planned Outage MW (-)	202	842
Gas Generator Outages MW (-)	45	237
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	3,240	3,389
Net Capacity (NET OPCAP SUPPLY MW)	23,296	25,399
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,500	20,500
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,805	22,805
Operable Capacity Margin	491	2,594

1. Operable Capacity is based on data as of **January 23, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of January 23, 2024.
2. Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning February 10, 2024.
3. Total of (Gas at Risk MW) – (Gas Gen Outages MW).
4. Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.
5. Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2024 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 23, 2024 - 50-50 FORECAST using CSO MW

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

Report created: 1/23/2024

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2/10/2024	28648	346	869	20	202	45	3100	2193	24343	19755	2305	22060	2283	Y	Winter 2023/2024
2/17/2024	28648	346	869	20	212	0	3100	1788	24783	19495	2305	21800	2983	N	Winter 2023/2024
2/24/2024	28648	346	869	20	347	141	3100	1348	24947	18516	2305	20821	4126	N	Winter 2023/2024
3/2/2024	28349	512	958	201	2263	113	2200	301	25143	18170	2305	20475	4668	N	Winter 2023/2024
3/9/2024	28349	512	958	201	1210	660	2200	0	25950	17976	2305	20281	5669	N	Winter 2023/2024
3/16/2024	28349	512	958	201	1212	566	2200	0	26042	17614	2305	19919	6123	N	Winter 2023/2024
3/23/2024	28349	512	958	201	1752	1388	2200	0	24680	17054	2305	19359	5321	N	Winter 2023/2024
3/30/2024	28247	512	958	201	1802	2361	2700	0	23055	16379	2305	18684	4371	N	Winter 2023/2024

Column Definitions

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

The 50/50 Forecast Operable Capacity Analysis is published daily. To download this chart in Excel, go to the Annual Maintenance Schedule webpage and follow the instructions.

Winter 2024 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

January 23, 2024 - 90/10 FORECAST using CSO MW

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

Report created: 1/23/2024

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2/10/2024	28648	346	869	20	202	45	3100	3240	23296	20500	2305	22805	491	Y	Winter 2023/2024
2/17/2024	28648	346	869	20	212	0	3100	2686	23885	20231	2305	22536	1349	N	Winter 2023/2024
2/24/2024	28648	346	869	20	347	141	3100	2096	24199	19218	2305	21523	2676	N	Winter 2023/2024
3/2/2024	28349	512	958	201	2263	113	2200	1198	24246	18860	2305	21165	3081	N	Winter 2023/2024
3/9/2024	28349	512	958	201	1210	660	2200	546	25404	18659	2305	20964	4440	N	Winter 2023/2024
3/16/2024	28349	512	958	201	1212	566	2200	0	26042	18285	2305	20590	5452	N	Winter 2023/2024
3/23/2024	28349	512	958	201	1752	1388	2200	0	24680	17705	2305	20010	4670	N	Winter 2023/2024
3/30/2024	28247	512	958	201	1802	2361	2700	0	23055	17014	2305	19319	3736	N	Winter 2023/2024

Column Definitions

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

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

OPERABLE CAPACITY ANALYSIS

Preliminary Spring 2024 Analysis

Preliminary Spring 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2024[2] CSO (MW)	May - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,247	31,731
Active Demand Capacity Resource (+) [5]	512	347
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	894	894
Non Commercial Capacity (+)	201	201
Non Gas-fired Planned Outage MW (-)	3,140	3,758
Gas Generator Outages MW (-)	1,870	2,282
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)	21,444	23,733
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,945	18,945
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,250	21,250
Operable Capacity Margin	194	2,483

1. Operable Capacity is based on data as of **January 23, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of January 23, 2024.
2. Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning May 11, 2024.
3. Total of (Gas at Risk MW) – (Gas Gen Outages MW).
4. Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.
5. Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Spring 2024 Operable Capacity Analysis

90/10 Load Forecast	May - 2024[2] CSO (MW)	May - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,247	31,731
Active Demand Capacity Resource (+) [5]	512	347
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	894	894
Non Commercial Capacity (+)	201	201
Non Gas-fired Planned Outage MW (-)	3,140	3,758
Gas Generator Outages MW (-)	1,870	2,282
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)	21,444	23,733
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,388	20,388
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,693	22,693
Operable Capacity Margin	-1,249	1,040

1. Operable Capacity is based on data as of **January 23, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of January 23, 2024.
2. Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning May 11, 2024.
3. Total of (Gas at Risk MW) – (Gas Gen Outages MW).
4. Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.
5. Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Spring 2024 Operable Capacity Analysis 50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 23, 2024 - 50-50 FORECAST using CSO MW

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

Report created: 1/23/2024

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
4/6/2024	28247	512	958	201	2334	3433	2700	0	21451	16130	2305	18435	3016	N	Spring 2024
4/13/2024	28247	512	958	201	2899	3760	2700	0	20559	15625	2305	17930	2629	N	Spring 2024
4/20/2024	28247	512	958	201	2716	2478	2700	0	22024	15362	2305	17667	4357	N	Spring 2024
4/27/2024	28247	512	894	201	3735	1719	3400	0	21000	15336	2305	17641	3359	N	Spring 2024
5/4/2024	28247	512	894	201	2994	2800	3400	0	20660	17972	2305	20277	383	N	Spring 2024
5/11/2024	28247	512	894	201	3140	1870	3400	0	21444	18945	2305	21250	194	Y	Spring 2024
5/18/2024	28247	512	894	201	1672	987	3400	0	23795	19849	2305	22154	1641	N	Spring 2024
5/25/2024	28247	512	894	201	1556	313	3400	0	24585	20841	2305	23146	1439	N	Spring 2024

Column Definitions

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

The 50/50 Forecast Operable Capacity Analysis is published daily. To download this chart in Excel, go to the Annual Maintenance Schedule webpage and follow the instructions.

Preliminary Spring 2024 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

January 23, 2024 - 90/10 FORECAST using CSO MW

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

Report created: 1/23/2024

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
4/6/2024	28247	512	958	201	2334	3433	2700	0	21451	16756	2305	19061	2390	N	Spring 2024
4/13/2024	28247	512	958	201	2899	3760	2700	0	20559	16233	2305	18538	2021	N	Spring 2024
4/20/2024	28247	512	958	201	2716	2478	2700	0	22024	15962	2305	18267	3757	N	Spring 2024
4/27/2024	28247	512	894	201	3735	1719	3400	0	21000	15934	2305	18239	2761	N	Spring 2024
5/4/2024	28247	512	894	201	2994	2800	3400	0	20660	19351	2305	21656	-996	N	Spring 2024
5/11/2024	28247	512	894	201	3140	1870	3400	0	21444	20388	2305	22693	-1249	Y	Spring 2024
5/18/2024	28247	512	894	201	1672	987	3400	0	23795	21351	2305	23656	139	N	Spring 2024
5/25/2024	28247	512	894	201	1556	313	3400	0	24585	22409	2305	24714	-129	N	Spring 2024

Column Definitions

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

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

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]

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

Possible Relief Under OP4: Appendix A

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

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

M E M O R A N D U M

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: January 25, 2024

RE: NPC Vote on Planning Procedure 5-6 Revisions

At the February 1, 2024 Participants Committee meeting, you will be asked to vote on proposed revisions to ISO Planning Procedure 5-6 ("PP5-6 Revisions"). At its December 19, 2023 meeting, the Reliability Committee recommended Participants Committee support for the PP 5-6 Revisions, with one opposition and one abstention (each in the Generation Sector) registered. Given this vote outcome at the Reliability Committee, this item was initially placed on the Consent Agenda for the February 1 meeting but was subsequently pulled for Participants Committee discussion at the request of Brookfield. The PP5-6 Revisions and related materials have been included with this memorandum.[1] Additional information from Brookfield may be provided in advance of the meeting and will be circulated and posted upon receipt.

The ISO is proposing to revise PP5-6 to: (i) update system modeling assumptions to align with the operating conditions expected to result from the clean energy transition; (ii) describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems); and (iii) improve modeling requirements for inverter-based resources.

The following resolution could be used for Participants Committee consideration of the PP5-6 Revisions:

> RESOLVED, that the Participants Committee supports the PP5-6 Revisions, as circulated to the Participants Committee in advance of its February 1, 2024 meeting and as recommended by the Reliability Committee at its December 19, 2023 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

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[1] The PP 5-6 Revisions, and the ISO's presentation on them, are also available at: https://www.iso-ne.com/static-assets/documents/100006/a13_1_pp_5_6.zip.

DECEMBER 19, 2023 | NEPOOL RELIABILITY COMMITTEE | DOUBLETREE HOTEL, WESTBOROUGH, MA

PP5-6 Interconnection Planning Procedure for Generation and Elective Transmission Upgrades

Updates for the Clean Energy Transition, Adoption of IEEE 2800 and Improvements to Modeling of Inverter-Based Resources

Brad Marszalkowski

LEAD ENGINEER | TRANSMISSION SERVICE STUDIES

Project Title: PP5-6 Updates

Proposed Effective Date: February 2023

- ISO New England is proposing updates to Planning Procedure 5-6 to:
  - Update system modeling assumptions to align with the operating conditions expected with the clean energy transition
  - Describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems)
  - Improve modeling requirements for inverter-based resources

PROBLEM STATEMENTS AND SUMMARY OF ISO PROPOSALS

Problem Statements

- The system load-level scenarios currently used under PP5-6 no longer match the conditions of concern that will result from the clean energy transition
- New England needs to describe how the region will adopt IEEE 2800
- The modeling requirements for inverter based resources in PP5-6 no longer capture industry best practices

Summary of Proposals

- ISO is proposing updates to PP5-6 to:
  - Update system modeling assumptions to align with the operating conditions expected to result from the clean energy transition
  - Describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems)
  - Improve modeling requirements for inverter-based resources

FEEDBACK SINCE NOVEMBER MEETING

ISO Responses to Feedback:

- **Feedback:** Steady state scenarios may be overly conservative for Energy Storage Systems in both daytime minimum and peak load scenarios
  - **ISO Response:**
    - Daytime minimum load scenario is meant to address when and if batteries have fully charged
    - FERC ESS will not be studied in the charging mode under peak load scenarios
    - Only ASO studies with PV and ESS components may be required to respect Peak Load scenarios with ESS charging
- **Feedback:** "Other Load levels and resource scenarios may be added at the discretion of the ISO where needed." This ISO discretion leads to unknowns for developers.
  - **ISO Response:**
    - Needed to ensure flexibility that benefits both developers and the ISO
- **Feedback:** Clarity requested about which scenarios apply to ASOs and which apply to FERC
  - **ISO Response:**
    - All scenarios will be able to be used by either ASO or FERC studies. Final selections will be up to the Tech Lead and project team.

ISO Responses to Feedback:

- **Feedback:** New EMT Model requirements add lead time and cost to model development and add increased potential for deficiency notices to be issued
  - **ISO Response:**
    - EMT Model requirement updates are needed to align with best industry practices
    - Will help to stream line entry into Clusters
    - Will help reduce the number of potentially non-viable projects
- **Feedback:** The ISO should develop a repository of useable EMT models for developers to choose from
  - **ISO Response:**
    - The ISO does not maintain which models are useable and follows best industry practice

FURTHER REFINEMENTS TO PROPOSED PP5-6 REDLINES

PP5-6 Incremental Updates Since November RC

PP5-6 Section	Procedure Change	Reason for Change
10.0 Additional Considerations for Generating Facilities that include Storage	The study of the discharging (i.e. generating) operating condition of a proposed electrical storage facility shall use the ~~same~~ study approaches described in this procedure except that it will not be studied as charging under any of the Peak Load scenarios listed in Section 3.6 unless it is a state-jurisdictional facility that is required to charge under mid-day load conditions. ~~as that used for a Generating Facility. The charging operating condition shall be studied under similar conditions to the conditions used when studying the discharging mode to ensure the charging operating condition does not introduce reliability criteria violations, diminish transfer capability or increase conditional dependence in accordance with the requirements of this Planning Procedure.~~	Recognize that requirements have been clarified in the procedure

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee September 19, 2023	Initial Presentation
Reliability Committee October 24, 2023	Present PP5-6 Redlines
Reliability Committee November 14, 2023	Present incremental updates to PP5-6 Redlines
Reliability Committee December 18-19, 2023	Vote
Participants Committee February 1, 2024	Vote

Questions

bmarszalkowski@iso-ne.com

ISO NEW ENGLAND PLANNING PROCEDURE NO. 5-6

INTERCONNECTION PLANNING PROCEDURE FOR GENERATION AND ELECTIVE TRANSMISSION UPGRADES

EFFECTIVE DATE: ~~May 6, 2022~~

REFERENCES:

ISO New England Transmission, Markets and Services Tariff

- Section I.3.9 Review of Market Participant's Proposed Plans
- (Schedules 22, 23 and 25 of the Open Access Transmission Tariff)

ISO New England Planning Procedures

- Planning Procedure 3 (PP3): Reliability Standards for the New England Area Pool Transmission Facilities
- Planning Procedure 5-1 (PP5-1): Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans
- Planning Procedure 5-3 (PP5-3): Guidelines for Conducting and Evaluating Proposed Plan Application Analyses
- Planning Procedure 9 (PP9): Major Substation Bus Arrangement Requirements and Guidelines
- Planning Procedure 10 (PP10): Planning Procedure to Support the Forward Capacity Market

ISO New England Operating Procedures

- Operating Procedure No. 12 – Voltage and Reactive Control
- Operating Procedure No. 14 – Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources
- Operating Procedure No. 19 – Transmission Operations
- Operating Procedure No. 24 - Protection Outages, Settings and Coordination

ISO New England Transmission Planning Technical Guide

North American Electric Reliability Corporation (NERC) Reliability Standards

- TPL-001, Transmission System Planning and Performance Requirements
- FAC-001, Facility Interconnection Requirements
- FAC-002, Facility Interconnection Studies
- ~~FAC-013, Assessment of Transfer Capability for the Near-term Transmission Planning Horizon~~

- MOD-026, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
- MOD-027, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- MOD-032, Data for Power System Modeling and Analysis
- PRC-024, Generator Frequency and Voltage Protective Relay Settings

NPCC Directory 1, Design and Operation of the Bulk Power System

Table of Contents

INTERCONNECTION PROCEDURE FOR GENERATION AND ELECTIVE TRANSMISSION UPGRADES

1.0 Introduction

The purpose of this procedure is to describe the scope of Interconnection Studies conducted pursuant to Schedule 22 ("Large Generator Interconnection Procedures" or "LGIP"), Schedule 23 ("Small Generator Interconnection Procedures" or "SGIP") and Schedule 25 ("Elective Transmission Upgrade Interconnection Procedures" or "ETU IP") of Section II of the ISO New England Transmission, Markets and Services Tariff (the "Tariff"). One objective of this document is to provide guidance which ensures that the Network Capability Interconnection Standard ("NCIS") is consistently applied in defining the scope and study assumptions for generator and ETU Interconnection Studies. While not all ETUs are eligible for Network Import Interconnection Service ("NIIS"), all are interconnected in a manner that, at a minimum, meets the requirements of the NCIS. A second objective of this document is also to provide guidance which ensures that the scope and study assumptions for preliminary nonbinding analyses for generators and certain External ETUs that are eligible to request interconnection under the Capacity Capability Interconnection Standard ("CCIS") are consistently applied.

Studies conducted in accordance with this procedure are also used to support applications made pursuant to Section I.3.9 ("Review of Market Participant's Proposed Plans") of the Tariff,~~.~~[1] including studies of proposed distributed energy resources that are processed under state interconnection procedures.[2]

This document (and the relevant documents referenced herein) describes the interconnection requirements and procedures for coordinated studies of new or materially modified existing Generating Facility and ETU interconnections and their impacts on affected system(s) as required by NERC FAC-001, Facility Interconnection Requirements. Those responsible for the reliability of affected system(s) of new or materially modified existing interconnections are notified in accordance with the "coordination with affected systems" provisions of the interconnection procedures.

The studies conducted in accordance with this procedure also serve to meet the requirements of NERC FAC-002, "Facility Interconnection Studies", to demonstrate that the proposed Generating Facility or ETU has been comprehensively studied to identify any reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). As described in this document, studies shall include steady-state, short-circuit, dynamics and other studies, as necessary, to evaluate system performance under both normal and contingency conditions and to ensure that the proposed implementation will not cause non-compliance with the applicable NERC Standards including TPL-001, "Transmission System Planning Performance Requirements".

Studies that follow the guidance provided by this document will typically be sufficient to comply with Tariff requirements; however, that does not preclude the possibility that some situations may require additional analyses.

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[1] Additional information on the relevant planning procedures is found in Planning Procedures PP5-1 and PP5-3.
[2] Studies of proposed distributed energy resources (DER) are sometimes referred to as "affected system operator" studies.

1.1 Interconnection Standards

NCIS describes the minimum requirements to interconnect a proposed new Generating Facility in the New England Control Area, to interconnect an Eligible External ETU,[3] to materially change an existing Generating Facility, to materially change an Eligible External ETU, or to increase the capability of an existing Generating Facility or Eligible External ETU.

The NCIS is defined in the LGIP, the SGIP and the ETU IP of the Tariff.

The basic principle underlying the study approach to making the determination of no significant adverse impact is that the energy, incrementally injected by Generating Facilities or injected by virtue of the requested objective associated with an ETU, is allowed to be dispatched in an economic, security-constrained manner provided that there is no significant adverse impact on the reliability of the system, and that the ability to reliably and practicably operate the system is not compromised. Thus, when the new Generating Facility or ETU is added to the system models used in the study, energy injections from other Generating Facilities, external transactions, other interface transfers or ETUs generally may be reduced by an amount not more than the net energy injection associated with the new Generating Facility or ETU, adjusted for changes in system losses caused by the redispatch.

CCIS is defined in the LGIP, SGIP and ETU IP of the Tariff.[4]

1.2 Interconnection Studies

An Interconnection Study is an Interconnection Feasibility Study, an Interconnection System Impact Study, an Optional Interconnection Study or a re-study thereof. The scopes of these studies are described in the LGIP, SGIP and ETU IP of the Tariff. An Interconnection System Impact Study, or a re-study thereof, shall meet all of the requirements of this procedure. When the alternative Interconnection Feasibility study scope is elected, the analysis may consist of a limited subset of the analyses in this procedure, focusing on the issues that are expected to be most significant for the proposed Generating Facility or ETU.

1.3 Elective Transmission Upgrade Interconnection Requests

The approach used in the study of an Interconnection Request for an ETU will differ depending on the type of ETU.

When addition of a specific technology is identified in an ETU Interconnection Request, the study will take into account the type of the facility and the project's performance objective.

When a performance objective associated with a specific Generating Facility(s) is identified in an ETU Interconnection Request, the study will take into account both the generation and the objectives.

[3] External ETUs eligible for NIIS are controllable Merchant Transmission (MTF) or Other Transmission Facility (OTF). In this Planning Procedure, these External ETUs are referred to as "Eligible External ETUs."
[4] The details regarding the conduct of the CCIS test are contained in Planning Procedure PP-10

When a performance objective of increasing transfer capability between points is identified in an ETU Interconnection Request, the study, while meeting the requirements of Section 7 of this procedure, will address what is specified for:

- Transfer points (from/to)
- Transfer capability increase and direction(s) of flow

2.0 Requirements for Interconnection Studies

2.1 General Requirements

The Interconnection Studies of all Interconnection Requests for Generating Facilities and ETUs, conducted in accordance with Sections 3, 4, 5, 6 & 7 of this procedure, shall identify the minimum required upgrades to meet all of the following requirements:

- The proposed Generating Facility or ETU must satisfy the requirements of ISO New England Planning Procedure 3: "Reliability Standards for the New England Area Pool Transmission Facilities" (the "Reliability Standards") and NPCC Directory 1, "Design and Operation of the Bulk Power System" on a regional (i.e., New England Control Area) and sub-regional basis, subject to the conditions analyzed; and shall not compromise the ability of the system to meet NERC TPL-001: "Transmission System Planning Performance Requirements".

- The proposed Generating Facility or ETU must not diminish system transfer capability, whether limited by an individual constrained element or a relevant interface~~ – including those relevant interfaces evaluated in accordance with NERC FAC-013 "Assessment of Transfer Capability for the Near-term Transmission Planning Horizon"~~, below the level of achievable transfers during reasonably stressed conditions[5] and does not diminish the reliability or operating characteristics of the New England Area bulk power supply system and its component systems.

- For a proposed new Generating Facility in an exporting area, or ETU with a terminal in an exporting area, an increase in the transfer capability out of the exporting area is not required to meet this interconnection standard unless the transfer capability needs to be increased to allow the proposed new Generating Facility or ETU to operate at the requested maximum output even after the allowed redispatch described in this procedure.

- The proposed Generating Facility or ETU must not diminish system transfer capability, whether limited by an individual constrained element or a relevant interface, below the level of possible imports into an importing area during reasonably stressed conditions and does not diminish the reliability or operating characteristics of the New England Area bulk power supply system and its component systems.

- The addition of the proposed Generating Facility or ETU does not create a significant adverse effect on the ISO's or local Transmission Owner's ability to reliably operate and maintain the system. Creation of new constraints, particularly due to stability or dynamic

[5] Reasonably stressed conditions are defined in PP5-3 as "those severe load and generation system conditions which have a reasonable probability of actually occurring." Reference PP5-3 for additional information

voltage performance, may likely be deemed to be unacceptable, as this compromises the ability to operate the system, especially where the number of existing interfaces cannot be increased due to operating complexity. Creation of operating limitations, particularly those caused by short circuit contribution or equipment with limited voltage ratings are also likely be deemed unacceptable.

2.2 System Configuration

Analyses shall be performed with the existing system facilities and topology, with the addition of all Planned transmission projects (those with approved Proposed Plan Applications under Section I.3.9 of the Tariff) and with all relevant Generating Facilities and ETUs with active Interconnection Requests along with their associated upgrades in the Interconnection Queue ahead of the Generating Facility or ETU under study.[6]

In situations where some of the above projects have later in-service dates than the Generating Facility or ETU under study, the Interconnection Study may need to analyze the topology when the Generating Facility or ETU goes into service and the topology when all of the above projects are planned to be in service. In addition, sensitivity analysis shall be performed as appropriate for proposed transmission facilities that are relevant to the Interconnection Study for the Generating Facility or ETU under study.[7]

2.3 Load Levels

The following load levels may be utilized in Interconnection Studies: [8]

- Peak load: Load shall be at 100% of the projected ("90/10 forecast") peak New England Control Area load for the year the Generating Facility or ETU is projected to be in service
- Intermediate Load: 18,000 MW New England Control Area load
- Light Load: 12,500 MW New England Control Area load
- Nighttime Minimum Load: 8,000 MW New England Control Area load
- Daytime Minimum Load: 12,000 MW New England Control Area load

2.4 Resources[9]

For steady-state analysis, the maximum output for a Generating Facility shall be its summer Network Resource Capability ("NRC") value, its maximum output at fifty degrees Fahrenheit or higher. For stability analysis, the maximum output for a Generating Facility shall be its winter NRC value, its maximum output at zero degrees Fahrenheit or higher. For controllable ETUs, steady-state and stability

[6] Reference Section 2.1 of the ISO New England Technical Planning Guide for additional information
[7] Reference Sections 2.1.3, 2.1.4 and 2.1.5 of the ISO New England Technical Planning Guide for additional information
[8] Reference Section 2.2 of the ISO New England Technical Planning Guide for additional information
[9] Reference Section 2.3.1 of the ISO New England Technical Planning Guide for additional information on NRC and Section 2.3 for additional information on treatment of different types of resources

analysis shall be done with the maximum flow (in one direction if unidirectional or in each direction if bidirectional) described in the requested objective. Behind the meter (BTM) Distributed Energy Resources (DER) shall be modeled in steady state and stability analysis.[10]

2.5 Second Contingency Testing

Sufficient steady state and stability N-1-1 testing to assess performance relative to NERC, NPCC and ISO New England criteria shall be performed.[11]

2.6 Data Provision

The LGIP, SGIP and ETU IP specify data submittal requirements for the associated stages of each procedure. Starting with the submission of the Interconnection Request and before the completion of the System Impact Study, resources undergoing the Interconnection Procedures, shall submit all data through the Interconnection Request Tracking Tool (IRTT)[12]. NERC Standard MOD-032[13] requires that dynamic models be provided for Generating Facilities, HVDC lines, and other power electronic devices that are a part of the Bulk Electric System. ISO Operating Procedure OP-14 Section II.A.6 also requires dynamics models for Generating Facilities that are 5 MW or greater in size when ISO New England determines it to be necessary for the ISO to carry out its responsibility to reliably and efficiently operate the power system.

Appendix B describes the usability and acceptability requirements for PSS/E models for use in Interconnection Studies and in accordance with NERC Standard MOD-026 and MOD-027.

Resources undergoing the ISO Interconnection Procedures, shall submit the as-studied data through the Dynamics Data Management System (DDMS) and Short Circuit Data Management System[14] after the System Impact Study results have been accepted by the Interconnection Customer at the System Impact Study Results Meeting.

3.0 Steady-State Analysis

3.1 Steady-State Criteria

Steady-state analyses shall be performed to demonstrate compliance with applicable voltage and thermal loading criteria and shall identify any system upgrades required to satisfy these criteria.

3.2 Steady-State Stresses

Steady-state studies shall be performed with a dispatch of Generating Facilities, with flows on controllable ETUs, and with imports and exports such that it stresses power flows across applicable

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[10] Reference Appendix K of the ISO New England Technical Planning Guide for additional information

[11] Reference Section 3.4 of the ISO New England Technical Planning Guide for additional information

[12] The IRTT system can be accessed from the ISO New England website at: http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue

[13] Refer to ISO New England Compliance Bulletin - MOD-032 – Model Data Requirements and Reporting Procedures for additional information on generator characteristics located at: http://www.iso-ne.com/participate/rules-procedures/nerc-npcc

[14] The DDMS and SDMS systems can be accessed via the SSO/SMD home page by selecting the Dynamic Data Management System application or Short Circuit Data Management System application. Instructions will be provided to Interconnection Customers during the interconnection process.

transmission lines or interfaces. A stressed line or interface shall, to the extent reasonable, be at or near their ratings or transfer limits.

A reasonable condition when power flows may not be at or near their transfer limits would exist when the maximum number of fully loaded Generating Facilities and ETUs that may reasonably be expected to be in service does not result in stressed power flows.

3.3 Steady-State Redispatch

The steady-state portion of an Interconnection Study typically includes an analysis of the transmission system without the proposed Generating Facility or ETU (pre-project case) and an analysis of the transmission system with the proposed Generating Facility or ETU in service (post-project case). The change to output of Generating Facilities and external controllable ETUs from the values in a pre-project case to the values in the post-project case is commonly referred as redispatch.

As a result of the addition of the proposed project, the maximum collective change in the output of other generation and changes to the flows of controllable external ETUs (the maximum redispatch) to meet the Reliability Standards must not exceed the capacity of the proposed Generating Facility or ETU, as measured by its intended high limit.

If the request for interconnection involves multiple generating units at a Generating Facility and the applicant for interconnection controls all the existing generating units at that Generating Facility, the applicant for interconnection shall specify the desired maximum output for the Generating Facility in the Interconnection Study Agreement and the design of the interconnection shall be based on this specified maximum output.

In addition, the following restricts the pre-contingency redispatch of Generating Facilities or external ETUs for first contingency (N-1) conditions:

- Redispatched Generating Facilities and redispatched ETUs and the new Generating Facility or ETU must be able to be automatically monitored and observed for purposes of system operation and unit commitment (for example a facility monitored and controlled by the System Operator via SCADA and security constrained economic dispatch), and,

- Generating Facility and ETU redispatch is not acceptable for limiting system constraints that occur on sub-transmission or lower voltage (less than 100 kV) facilities.

Second contingency (N-1-1) testing considers two initiating events that can occur close together in time. Following the first initiating event, system adjustments can be made in preparation for the next initiating event. [15] In the case of pre-second contingency Generating Facility or ETU runback and/or tripping after a first contingency to be secure for N-1-1 conditions:

- The runback and/or tripping that can be assumed to be achievable in 30 minutes following the first contingency shall utilize available replacement operating reserves consistent with ~~ISO-NE Planning Procedure No.~~ PP3.
- Generating Facilities and ETUs that are assumed to be runback or tripped (which may include the new Generating Facility or ETU) must be able to be automatically monitored and observed for purposes of system operation and unit commitment (for example a facility monitored and controlled by the System Operator via security constrained economic dispatch), and, Generating Facility and ETU runback or tripping is not acceptable for limiting system constraints that occur on sub-transmission or lower voltage (less than 100 kV) facilities, except as follows;
  - where the first and second contingencies are ~~for facilities connected at less than 100 kV~~not contingencies listed in PP3 and where the potential performance violation is for a facility ~~less than 100 kV~~that is not a Pool Transmission Facility, runback or tripping of non-market generation and/or Settlement Only Generators may also be assumed in the assessment. The assessment must confirm that such redispatch is operable[16] and does not introduce any other performance violations.

3.4 No Increase in Conditional Dependence

If no existing Generating Facility or ETU is required to be in service to avoid criteria violations for the conditions studied prior to placing the new Generating Facility or ETU in service, no existing Generating Facility or ETU can become required to operate as a condition for acceptable operation of the new Generating Facility or ETU for that study condition. If an existing Generating Facility or ETU is required to be in service to avoid criteria violations for the conditions studied prior to placing the new Generating Facility or ETU in service, the existing Generating Facility or ETU may continue to be modeled as required to avoid criteria violations, but such reliance shall not be increased. Generating Facilities and ETUs that continue to be required to be in service to avoid criteria violations for the conditions studied shall not be reduced, by redispatch in the study, below the level required for system reliability before the addition of the Generating Facility or ETU. Studies must examine relevant stressed existing Generating Facility and ETU outage conditions in addition to outages or reductions that have been considered as part of Generating Facility and ETU redispatch.

3.5 Post Contingency Resource Adjustments

No Generating Facility or ETU can be manually tripped or manually ramped down to relieve any first contingency facility loading in excess of the more limiting of either the Short Time Emergency Ratings or any other applicable Transmission Owner-specific emergency ratings. Manually ramping down Generating Facilities or ETUs to relieve first contingency overloads within the more limiting of the Short Time Emergency ratings or any other applicable Transmission Owner specific emergency ratings can only be applied to the Generating Facility or ETU under study, provided that the Generating Facility or ETU reduction is acceptable to the ISO. If a reduction in Generating Facility or ETU output is required in the

[15] Reference Section 3.4 of the ISO New England Technical Planning Guide for additional information
[16] For example, the constraints and generation output levels may need to be fully observable to, and controllable by, the operator and the implementation must be scalable and manageable in the context of reliable operating practice.

pre-project system in order to relieve overloads the same reduction shall be allowed in the post project case.

3.6 Steady-State Load Levels

Steady-state analysis shall be performed at the following load levels and in accordance with Table 3-1 below. Not all scenarios will be studied for every project. Scenarios will be selected as part of the project study scoping process:

- Analysis shall be performed at Peak Load with the Generating Facility or ETU operating at full capability.
  - Four scenarios may be analyzed:
    - An evening peak scenario characterized by high load, low solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.
    - An evening peak scenario characterized by high load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability[17]
    - A mid-day peak scenario, characterized by high load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capability
    - A mid-day peak scenario, characterized by high load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capability
  - ~~Two scenarios will be analyzed for stand alone battery energy storage systems, a low renewables scenario with storage in the discharging mode, and a high renewables scenario with storage in the charging mode~~
  - ~~Three scenarios will be analyzed for stand alone solar projects, a high renewables scenario without storage being dispatched, a high renewables scenario with storage being dispatched in the charging mode, and a low renewables scenario with storage in the discharging mode~~

- Analysis shall be performed at Intermediate Load with the Generating Facility or ETU operating at full capability in the cases where conditions such as the preservation of transfer capability are a concern.
  - Two scenarios may be analyzed:
    - A shoulder load scenario characterized by intermediate load, no solar, and energy storage available for charging, while wind and conventional resources are available up to their full capacity
    - A shoulder load scenario characterized by intermediate load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capacity
  - ~~Two scenarios shall be analyzed for stand alone Battery Energy Storage Systems, a no-solar scenario with storage charging, and a no-solar scenario with storage discharging.~~

[17] The evening peak with no solar scenario may be required if there are topology changes associated with the project

- Analysis shall be performed at Light Load as required by the ISO~~in cases when identified as required by the ISO~~to identify any upgrades that are required to allow the Generating Facility or ETU to operate at the requested output level while no other nearby generating facilities (that would contribute to any identified violations) are operating. ~~:~~

    - ~~When a proposed Generating Facility or ETU cannot start up and reach minimum output within two hours. Other Generating Facilities that may be dispatched at Intermediate Load shall also be assumed to be running, but may also be at minimum output except for units which can reach minimum output within 2 hours. Units that can start up and reach minimum output within 2 hours may be off in the Light Load analysis. Careful consideration of realistic operating conditions needs to be provided when simulating nuclear and hydro (run of river or ponding) facilities.~~
    ~~Regardless of the time taken to reach minimum output, a~~Analysis shall be ~~performed at Light Load to identify any upgrades that are required to allow the Generating Facility or ETU to operate at the requested output level while no other nearby generating facilities (that would contribute to any identified violations) are operating.~~
    - Two scenarios may be analyzed:
        - A light load scenario characterized by light load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capacity
        - A light load scenario characterized by light load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capacity

- Analysis shall be performed at Minimum Load in cases where the Generating Facility or ETU, and its Interconnection Facilities and Network Upgrades, add a significant amount of charging current to the system or in areas where there are significant resources without significant voltage control.
    - ~~A Daytime Minimum Load scenario will be analyzed for stand alone solar projects~~
    - ~~Co-Located or Hybrid facilities will be required to analyze the combination of all scenarios listed under the different resources of which they are comprised~~
    - ~~A no-solar (nighttime) minimum load case will be run where there are topology changes due to upgrades from solar projects, or in cases where significant charging is added to the system (ie: long cables for off shore wind)~~
    - Two scenarios may be analyzed:
        - A Day-Time minimum load scenario characterized by minimum load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity
        - A Night-Time minimum load scenario characterized by minimum load, no solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity[18]

- Co-Located or Hybrid facilities may be required to analyze the combination of all scenarios listed under the different resources of which they are comprised

[18] The night time minimum load scenario may be required if there are topology changes associated with the project.

- Other Load levels and resource scenarios may be added at the discretion of the ISO where needed.
- BTM-DERs and other non-Modeled assets will be modelled as dispatched at the resource availability level as shown in ~~the~~ table 3-1 below

Table 3-1 - Steady State Scenarios[19][20][21]

Available Scenarios/For Consideration	Solar Availability Across NE (Both Market and BTM)	Batteries/Stored Hydro Availability	Wind Availability	Conventional Resources Availability
Peak Load 90/10 (Gross) Low Solar*	26%	100% Discharging	100%	100%
Peak Load 90/10 (Gross) High Solar ~~(W/O Bat)~~	85%	0% OFF	100%	100%
Peak Load 90/10 (Gross) High Solar ~~(W/ Bat)*~~	85%	100% Charging	100%	100%
Peak Load 90/10 (NET = Gross) No Solar	0%	100% Discharging	100%	100%
Shoulder Load 18,000MW (NET = Gross)	~~No~~0%	100% Charging	100%	100%
Shoulder Load 18,000MW (NET = Gross)	~~No~~0%	100% Discharging	100%	100%
Light Load 12,500 (NET)	100%	100% Charging	100%	100%
Light Load 12,500 (NET = Gross)	0%	100% Discharging	100%	100%
N-Minload 8,000MW (NET = Gross)	0%	0% OFF	100%	100%
D-Minload 12,000MW (Gross)	100%	0% OFF	100%	100%

[19] Availability is interpreted as projects under their respective fuel types are able to be dispatched anywhere between a projects minimum power (PMIN) and the level listed multiplied by the projects maximum power (PMAX).
[20] Intermittent resources that are dispatched at a lower level than their max availability will not be assumed to be available for re-dispatching post N-1
[21] Gross is interpreted as prior to the addition of the DER, netting down of the load. As where Net is interpreted as the load post addition of the DER. For example, the daytime minimum load scenario lists 12000MW (Gross), if 5000MW of DER is added, the net load is then 7000MW. For the light load scenario with high solar, 12,500 (NET) is listed, if 5000MW of DER is added, the net load would be 7,500MW, so the scalable load would need to be scaled up commensurate to the DER added, to meet the required 12,500MW NET level. In the cases where NET=Gross is listed, this means there is no netting of the load due to the DER because there is no DER assumed.

4.0 Stability Analysis

4.1 Stability Criteria

Stability analyses shall be performed to demonstrate compliance with applicable criteria and shall identify any system upgrades required to satisfy these criteria.

4.2 Stresses in Stability Analysis

For normal contingency testing, power flows across applicable transmission lines or interfaces shall be at the most limiting of the existing stability or thermal (set using winter transmission equipment ratings, with appropriate margin, for light load testing) transfer limits.[22]

4.3 Stability Analysis Scenarios

Stability analysis shall consider reasonable combinations of all relevant Generating Facilities, ETUs and devices that would be expected to have significant interactions.

The Generating Facility or ETU under study as well as all local and relevant Generating Facilities and ETUs shall be modeled at full capacity. If all Generating Facilities and ETUs cannot be dispatched behind the limiting lines or interface, a reasonable number of combinations may need to be studied.

4.4 Stability Load Levels

Stability analysis shall be performed at the following load levels:

- Analysis shall be performed at Light Load with high levels of renewable generation online. Appropriate combinations of relevant Generating Facilities, distributed energy resources and ETUs shall be studied to ensure that stability is maintained for all reasonable conditions.
  - Two scenarios may be analyzed:
    - A light load scenario characterized by light load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capacity
    - A light load scenario characterized by light load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capacity

- Analysis shall be performed at Peak Load when required by the ISO. The emphasis of the stability analyses performed at this load level is to confirm that the response has not significantly changed with the load level. It may also be used to assess changes in damping if the possibility of an oscillatory response is recognized in the light load analyses.

[22] Note: All units modeled as in service for a particular stability case shall be modeled at their full output, which may result in total transfers greater than the existing thermal transfer limit. More detail on modeling is available in PP5-3.

- Two scenarios may be analyzed:
  - An evening peak scenario characterized by high load, low solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.
  - An evening peak scenario characterized by high load, no solar, and energy storage available for discharging. While wind and conventional resources are available up to their full capability[23]

- Analysis shall be performed at Minimum Load in cases where the Generating Facility or ETU, and its Interconnection Facilities and Network Upgrades, add a significant amount of charging current to the system or in areas where there are significant resources without significant voltage control.
  - Two scenarios may be analyzed:
    - A Day-Time minimum load scenario characterized by minimum load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity
    - A Night-Time minimum load scenario characterized by minimum load, no solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity[24]

- Co-Located or Hybrid facilities will be required to analyze the combination of all scenarios listed under the different resources of which they are comprised

~~A no-solar (nighttime) minimum load case will be run where there are topology changes due to upgrades from solar projects, or in cases where significant charging is added to the system (ie: long cables for off shore wind)~~

- Other Load levels and resource scenarios may be added at the discretion of the ISO where needed.

- BTM distributed energy resources and other non-Modeled assets will be modelled as dispatched at the resource availability level as shown in the tables above

Table 3-2 Stability Scenarios[25][26]

Transmission Studies	Solar Availability Across NE (Both FERC	Batteries/Stored Hydro	Wind Availability	Conventional Resources Availability

[23] The evening peak with no solar scenario may be required if there are topology changes associated with the project
[24] The night time minimum load scenario may be required if there are topology changes associated with the project.
[25] Availability is interpreted as projects under their respective fuel types are able to be dispatched anywhere between a projects minimum power (PMIN) and the level listed multiplied by the projects maximum power (PMAX).
[26] Intermittent resources that are dispatched at a lower level than their max availability will not be assumed to be available for re-dispatching post N-1

	and Non-FERC)			
Peak Load 90/10 (Gross) Low Solar	26%	Discharging	100%	100%
Peak Load 90/10 No Solar	0%	Discharging	100%	100%
Light Load 12,500 (NET)	100%	Charging	100%	100%
Light Load 12,500 (NET = Gross)	0%	Discharging	100%	100%
N-Minload 8,000MW (NET = Gross)	0%	OFF	100%	100%
D-Minload 12,000MW (Gross)	100%	OFF	100%	100%

5.0 Short Circuit

Short circuit analyses[27] shall be conducted to demonstrate that short circuit duties will not exceed equipment capability and shall identify any system upgrades required to satisfy this criterion. The short circuit study base case shall include all generation and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. The base case shall include all generating facilities and ETUs (and with respect to (iii), any identified upgrades) that, on the date the study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; and (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request. A Generating Facility that has notified the ISO that it will retire will not be included in short circuit studies for timeframes beyond its retirement date.

6.0 Other Requirements

6.1 Voltage Control and Reactive Power Requirements

Where specified in Schedule 22, 23 or 25, Generating Facilities, ETUs and their associated Interconnection Facilities, that are capable of voltage control, are required to be capable of a composite power delivery at their maximum rated power output (maximum MW) at the Point of Interconnection (or at the high side of the station transformer, or at the Point of Interconnection if there is no station transformer, in the case of a non-synchronous Generating Facility) at both the power factor of 0.95 leading and 0.95 lagging. Further, all Generating Facilities equal to or greater than 5 MW will be required

[27] Reference Section 4.3 of the ISO New England Technical Planning Guide for additional information

to be capable of a composite power delivery at their maximum rated power output (maximum MW) at the Point of Interconnection[28] (or at the high side of the station transformer, or at the Point of Interconnection if there is no station transformer, in the case of a non-synchronous Generating Facility) at both the power factor of 0.95 leading and 0.95 lagging. The Interconnection Study shall verify this capability.

System Impact Study testing shall evaluate the compliance of the voltage control capability with the requirements of OP-14. For all generating facilities equal to or greater than 5 MW, the study will assume that the Generating Facility's responsiveness to voltage changes is active and in-service, unless the study identifies that such responsiveness cannot be activated (for example because of the pre-existing voltage control strategy for a distribution feeder).

While it shall be identified in the Interconnection Study if the voltage control strategy must be designed with the purpose of maintaining a scheduled voltage at the Point of Interconnection (or some other appropriate point), it shall be acceptable for the resource to dynamically control its terminal voltage under transient conditions, unless the Interconnection Study identifies a reliability issue that requires the resource be capable of controlling voltage at another point, such as the Point of Interconnection.

The power factor evaluation shall be conducted with the new Generating Facility or Eligible ETU modeled at unity terminal voltage and maximum rated power output. The maximum leading and lagging reactive power capabilities at maximum rated power output shall be taken from the associated facility "D-Curve" or similar specification. At both the maximum leading reactive output and at the maximum lagging reactive output, the real and reactive power losses in the step-up transformer(s) and other interconnection facilities, station service real and reactive load, as well any additional reactive contribution provided by project auxiliary reactive devices, shall be calculated. The resulting net real and reactive power at the Point of Interconnection (or the high side of the station transformer in the case of a wind generating facility) shall be required to meet the 0.95 leading and 0.95 lagging dynamic reactive power standards. Generating Facilities that operate in a combined mode (such as combined cycle generation) shall be evaluated on an overall combined basis.

System Impact Study testing shall evaluate the compliance of the voltage ride-through capability with the requirements of NERC PRC-024, Generator Frequency and Voltage Protective Relay Settings.

6.2 Governor Control/Frequency Response

System Impact Study testing shall evaluate the compliance of the new Generating Facility frequency response with the droop, deadband and overall response requirements of OP-14. Testing shall include an appropriate frequency changing event such as a large loss of load or generation.

System Impact Study testing shall evaluate the compliance of the frequency ride-through capability with the requirements of NERC PRC-024-1, Generator Frequency and Voltage Protective Relay Settings.

[28] The term "point of common coupling" is more commonly used for distribution-connected resources and will serve as the point of measurement for the purposes of this requirement for resources that are not interconnected pursuant to Schedule 23 (Small Generator Interconnection Procedures).

6.3 Shaft Torque (Delta P) Testing

Where there is a likelihood of large angular difference across an open transmission line, or of a large change in power flow when closing a transmission line, an Interconnection Study for a Generating Facility shall include determination of the largest change in power (Delta P) that the Generating Facility, and other Generating Facilities in proximity, could experience as the result of reclosing following an N-1 contingency. The value of Delta P shall be included in the Interconnection Study report. The Generating Facility or ETU shall be required to mitigate any unacceptable consequence of increased Delta P which they cause.

6.4 Subsynchronous Resonance and Subsynchronous Torsional Interaction Screening

An Interconnection Study for an HVDC facility or any project that includes a series-connected capacitor in Interconnection Facilities or Network Upgrades shall include screening for the potential of causing subsynchronous stresses on nearby generation. This screening shall examine N-1, N-1-1 and other potential contingent or operating conditions specified by the ISO. The results of this screening shall be included in the Interconnection Study report.

6.5 ~~PSCAD~~ Electromagnetic Transient Testing

~~A wind or~~Any inverter-based Generating Facility, including DER, an ETU that includes power electronics as part of the facility or a Generating Facility or ETU that includes power electronics as part of Interconnection Facilities or Network Upgrades shall provide a ~~PSCAD~~ Electromagnetic Transient (EMT) model(s) useable in PSCAD, of that equipment. The need for a ~~PSCAD~~ EMT model will be discussed at the Scoping Meeting for non-inverter based technology. ~~Based on the size of the project and its location in the electric system, the ISO will determine if a study of interactions, such as control interactions, with near-by equipment or an evaluation of equipment performance(for example under low short circuit conditions, if applicable to the proposed location) is required as part of the Interconnection Study~~. The ~~PSCAD~~ EMT study shall examine N-1, N-1-1 and other potential contingent or operating conditions specified by the ISO. Guidance regarding the requirements for PSCAD ~~EMT~~ model submittals and for ~~PSCAD~~ EMT testing is provided in Appendix C. [29]

These ~~PSCAD~~ EMT requirements shall not apply to wind or inverter based Generating Facilities that are not connected to the PTF and that are not subject to the requirements of Schedules 22 or 23 of the OATT, unless ISO New England identifies that the ~~PSCAD~~ EMT requirements are needed to be met by the Generating Facility for reliability reasons.

6.6 Operating Procedure Requirements

An Interconnection Study shall ensure that the Generating Facility or ETU satisfies the relevant equipment design requirements in Operating Procedures OP-12, OP-14 and OP-19.

6.7 IEEE 2800 Requirements

Non-synchronous resources participating in the first ISO-NE Cluster study, pursuant to FERC Order No. 2023, (and all subsequent clusters) must meet the requirements of Appendix F.

[29] Only state jurisdictional projects that are part of studies that will start after the initiation of the T~~t~~ransition C~~c~~luster Study pursuant to FERC Order No. 2023 will be required to meet section 6.5

7.0 Additional Considerations for Studies of ETUs

The appropriate study of an Interconnection Request for an ETU will differ depending on the type and objective of the ETU.

7.1 Eligible External ETUs

The scope of study of Eligible External ETUs is described in Section 2 of this procedure. The analysis of ETUs that have one or more terminals outside of the New England Control Area shall be coordinated with the other Control Area(s). The analysis at the point of injection to the New England transmission system shall be performed similar to the analysis of a Generating Facility connecting at that terminal. The impact of loss of the ETU when it is operating at full output shall be analyzed.

The analysis of a new Eligible External ETU shall include analysis with relevant existing external interfaces modeled with imports and exports at the maximum levels used in planning studies.

7.2 Internal Controllable ETUs

A controllable ETU could be a HVDC line or an AC line with a phase-angle regulator or other control device.

In a manner consistent with other parts of this procedure, the Interconnection Customer shall identify the generator dispatch or dispatches that will be used to provide the energy and/or capacity transmitted by the ETU at each terminal which is drawing power from the transmission system. The analysis shall identify the system upgrades required to maintain the reliability of the sending area in accordance with New England planning standards. This analysis shall be similar to the analysis that would be conducted if a new load was added at the point of withdrawal from the New England system.

The analysis at the point of injection to the transmission system shall be performed similar to the analysis of a Generating Facility connecting at that terminal. The analysis shall identify the system upgrades required to maintain the reliability of the receiving area.

The impact of loss of the ETU when it is operating at full output shall be analyzed.

7.3 Non-controllable ETUs Involving Specified Equipment Additions without Associated Specified Objectives

The analysis of a non-controllable ETU involving specified equipment additions without specified objectives shall be conducted consistent with the analysis of transmission additions pursuant to PP5-3.

7.4 ETUs Involving Specified Objectives

An ETU Interconnection Request may not always specify the equipment that it wishes to install. For example, a request may have the objective to increase the transfer limit across an interface by a certain amount. When an ETU Interconnection Request specifies an objective without specifying facilities, the study shall identify the solution necessary to satisfy the needs identified in the Interconnection Request and shall identify the transmission upgrades required. Section 3.1 of the Elective Transmission Upgrade

Interconnection Procedures states that the ISO, at its sole discretion, determines if a proposed objective is appropriate to propose in a single Interconnection Request.

8.0 Preliminary Nonbinding Overlapping Impact Studies

An Interconnection Customer with a Capacity Network Resource Interconnection Service ("CNRIS") Request or a Capacity Network Import Interconnection Service ("CNIIS") Request may request that the Feasibility Study or System Impact Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer's Generating Facility or External ETU to qualify for participation in a Forward Capacity Auction ("FCA") under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer.

The preliminary, non-binding analysis shall use the same criteria and assumptions that are prescribed in the analysis of overlapping interconnection impacts in Planning Procedure 10: Planning Procedure to Support the Forward Capacity Market ("PP10"). The starting point for the base case to be used in the preliminary analysis shall be the latest developed base case that has been prepared, pursuant to PP10, for the analysis of New Generating Capacity Resources seeking to participate in an FCA.

The set of additional assumptions that may be specified by the Interconnection Customer are limited to additional transmission projects and/or generation projects with active Interconnection Requests under the L/SGIP that the Interconnection Customer requests to be added to the base case.

To the extent the Interconnection Customer requests a preliminary non-binding analysis of Overlapping Interconnection Impacts under the CCIS, a report shall contain the results of the requested preliminary analysis, along with an identification of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a FCA pursuant to Section III.13 of the Tariff.

An Interconnection Customer with an ETU Interconnection Request may specify as its performance objective a capacity transfer capability increase. As part of the Feasibility Study or the System Impact Study for this Interconnection Request, as requested by the Interconnection Customer; an analysis similar to a preliminary, non-binding analysis shall be performed to verify the increase in capacity capability. In this case, the study shall include all relevant Generating Facilities and ETUs with earlier queue positions and all Planned transmission projects.

9.0 Operational Considerations

As appropriate, the analysis shall include an assessment of the operating constraints of the proposed transmission and generation system without identifying the additional upgrades (beyond those identified pursuant to Section 2 of this procedure) necessary to reduce the operating constraints. The analysis shall determine the estimated magnitude of required redispatch of generation under typical and reasonably stressed conditions. If requested by the ISO, limited operating studies may be required to demonstrate viable operability of the proposed Generating Facility or ETU and provide some indication of the system conditions for which the Generating Facilities or ETU's operation may be restricted. The conditions to be considered in these studies shall be coordinated through the ISO. Examples of studies that may be expected include, but are not limited to:

- Examination of the operation of the proposed transmission or generating facilities over expected or suspected constrained conditions with examination of the limiting performance concern (for example thermal, voltage or stability issues). Hour-to-hour operability or performance over longer periods may be considered. Light, intermediate or peak load levels may be considered. Any increased need for operational oversight of the system, such as resource operating restrictions, atypical switching or the creation of additional procedures under outage conditions shall be noted.

- Determination if the system adjustments required to reliably serve the area of interest within 30 minutes following the first contingency change significantly, or are no longer effective, given the proposed change.

(Note: Extensive operating studies, separate from the Interconnection Studies, may be necessary prior to actual operation.)

10.0 Additional Considerations for Generating Facilities that include Storage

The study of the discharging (i.e. generating) operating condition of a proposed electrical storage facility shall use the ~~same~~ study approaches described in this procedure except that it will not be studied as charging under any of the Peak Load scenarios listed in Section 3.6 unless it is a state-jurisdictional facility that is required to charge under mid-day load conditions. ~~as that used for a Generating Facility. The charging operating condition shall be studied under similar conditions to the conditions used when studying the discharging mode to ensure the charging operating condition does not introduce reliability criteria violations, diminish transfer capability or increase conditional dependence in accordance with the requirements of this Planning Procedure.~~

Document History[30]

Rev. No.	Date	Reason
Rev 0	RTPC – 4/13/99	
Rev 1	RC – 2/13/01; PC 3/2/01	
Rev 2	Effective 2/1/05	Addition of overlapping impact language to PP to conform with recently approved updates to the ISO Tariff
Rev 3	RC 5/19/09; NPC 6/5/09; ISO-NE 7/7/09	
Rev 4	RC 7/19/10; NPC 8/6/10; ISO-NE 8/10/10	Administrative document changes to conform to Tariff terminology and to add back miscellaneous footnotes that were lost in prior versions.
Rev 5	RC 8/12/14; NPC 9/12/14; ISO-NE 9/15/14	Additions made to describe load level modeling.
Rev 6	RC 07/14/2015 NPC 08/07/2015	Additions made to address Elective Transmission Upgrades and add clarifications. Format updated to be consistent with Operating Procedures
Rev 7	RC 06/09/16 NPC 06/21/16	Additions made to conform with Interconnection Process Improvements filing (February 18, 2016)
Rev 8	RC 02/13/2018 NPC 03/02/2018	Additions to: (i) clarify alignment with other planning procedures, (ii) clarify certain provisions, (iii) clarify compliance with NERC standards, and (iv) clarify certain requirements for inverter-based generators.
Rev 9	RC 12/18/2020 NPC 02/06/2020	Correcting the title of PP5-1 in the References section.
Rev 10	RC 03/17/2020 NPC 04/02/2020	Update to loss-of-source interconnection design requirement in Appendix A.
Rev 11	RC 04/27/2022 NPC 05/05/2022	Additional guidance for Distributed Energy Resources

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

Appendix A – General Transmission System Design Requirements for the Interconnection of New Generating Facilities and ETUs to the Administered Transmission System

All electrical facilities must be designed, built and operated in accordance with applicable NERC, NPCC, ISO New England (including Planning Procedure 9) and the Interconnecting Transmission Owners' standards, guidelines, criteria, or the equivalent. This document describes only the general transmission system design requirements for new Generating Facilities and ETUs to interconnect to the Pool Transmission Facilities (PTF). Additional technical and design requirements related to resource interconnection and operation may also apply.

Point of Interconnection

The following shall be applied to the design of a new Generating Facility (resource) or ETU interconnection:

1. All new Generating Facilities or ETUs shall be connected to the system at a new or existing station on the existing Administered Transmission System.
2. The station shall be designed to provide independent switching of each Generating Facility or ETU interconnection to the system and each transmission line terminating in the station. The intent is to design the interconnection in a manner that does not adversely affect the ability to maintain major components of the transmission system.
3. A ring bus or breaker-and-a-half connection shall be used at the point of Generating Facility or ETU interconnection with the transmission system. Transmission system needs and use may require a breaker-and-a-half arrangement. Alternative interconnection designs to Non-PTF facilities shall be considered where appropriate. Additionally, two circuit breakers placed in series may be required to mitigate the consequences of a stuck breaker that would otherwise result in an unacceptable system performance.
4. Transmission system circuit breakers shall not be used for synchronization of new Generating Facilities.

Interconnection Design – Loss-of-Source

The interconnection shall be designed such that, with all lines initially in service, there is no normal design contingency or common mode transmission system, station, or internal plant failure which could result in a net loss of more than 1,200 MW of resources, except in the case of an increase of no more than 2% above the maximum capability, in place at the time of the original incorporation of this provision into PP5-6 in June 2016, of an existing facility that already corresponded to a loss of more than 1,200 MW of resource for a normal design contingency.

Out of Step Protection

Each PTF connected synchronous generating resource shall be required to have out-of-step protection installed. This protection shall detect an out-of-step condition and trip the Generating Facility to protect the transmission system against adverse impact associated with the Generating Facility losing synchronism with the system. Additionally, the Transmission Owner and/or the ISO may require that supplementary supervisory detection be used in conjunction with the out-of-step protection when necessary to prevent unnecessary and undesirable out-of-step protection operation.

Transmission Circuit Breakers
All new 345 kV and, where identified as necessary, 230 kV and 115 kV, circuit breakers must meet the requirements of Planning Procedure 9.

Appendix B – Requirements of PSS/E Models

All power flow and dynamic models must be made available for use in the version of PSS/E that is in use by ISO New England and must accurately model all of the relevant control modes and characteristics of the equipment, such as:

- All available voltage/reactive power control modes
- Frequency/governor response control modes (which may be provided by a park controller)
- Low voltage ride through characteristics, if applicable
- Low frequency ride-through characteristics, if applicable
- Park controller or group supervisory functionality (e.g. for a wind farm)
- Appropriate aggregate modeling capability (e.g. for a wind farm)
- Charging or pumping mode, if applicable (e.g., for a battery energy storage device or pumped storage hydro Generating Facility)

Standard Dynamics Models
For all Interconnection Studies all models must be standard library models in PSS/E or applicable applications. Where applicable, the most up-to-date revision of the models must be used. User-written models will not be accepted.

User-Written Dynamics Models
A user written model is any model that is not a standard Siemens PSS/E library model. For all Interconnection Studies commencing before January 1, 2017, when no compatible PSS/E standard dynamics model(s) can be used to represent the dynamics of a device, accurate and appropriate user written models can be used, if accepted by ISO New England after testing.

User-written models for the dynamic equipment and associated data can be in either dynamic model source code (.lib) or dynamic model object code (.obj) or dynamic linked library (dll):

- User-written source code, object code, and parameters shall be updated for the latest PSS/E version in use and specified by ISO New England:
    a. Dynamics models related to individual units shall be editable in the PSS/E graphic user interface. All model parameters (CONS, ICONS, and VARS) shall be accessible and shall match the description in the model's accompanying documentation. Certain CONEC or CONET models may be acceptable.
    b. Dynamics models shall have all their data reportable in the "DOCU" listing of dynamics model data, including the range of CONS, ICONS, and VARS numbers. Models that apply to multiple elements (e.g., park controllers) shall also be fully formatted and reportable in DOCU.
    c. Dynamics models shall be capable of correctly initializing and run through the simulation throughout the range of expected steady state starting conditions without additional manual adjustments.
    d. Dynamics models shall be capable of allowing its accompanying element or elements to be switched out-of-service (including when the bus is disconnected) in the steady-state network without additional steps and without errors. Documentation of any special requirements for this condition shall be clearly defined in the model documentation.
    e. Dynamics models shall be capable of allowing all documented (in the model documentation) modes of operation without error.

f. A park controller model to control more than one generator (e.g., in a wind farm or photovoltaic park) shall be able to accurately control multiple equivalent generators. The relative reactive output of each generator shall be correctly representative of its representation of number of units and impedance data. The park controller shall be able to regulate a minimum of eight equivalent generator units.
g. Dynamic models shall be coded in such way that any internal changes of model variables or parameters incurred in one simulation run shall not be automatically passed on to the same models in subsequent simulation runs given both load-flow file and snapshot file are restored in the same PSS/E application.

- Models requiring allocation of bus numbers shall be compatible with the New England bus numbering system, and shall allow the user to determine the allocation of the bus numbers.
- Models shall initialize correctly and be capable of successful “flat start” and “ring down” testing using the following guideline (models shall be capable of meeting these requirements when operating at full rated (nameplate) power, and also at partial power within the physical operating range of the equipment, across a range of feasible reactive power output conditions and terminal voltages):
  a. 20 Second No-Fault Simulation (a/k/a “flat start”): This test consists of a 20 second simulation with no disturbance applied. The test will be considered to be passed if the following criteria are met:
     i. No generator MW change of 0.1 MW or more
     ii. No generation MVAR change of 0.1 MVAR or more
     iii. No line flow changes of 0.3 MW or more
     iv. No line flow changes of 0.3 MVAR or more
     v. No voltage change of 0.0001 p.u. or more
  b. 60 Second Disturbance Simulation (a/k/a “ring down”): This test consists of the application of a 3-phase fault for a few cycles at a key transmission bus, followed by removal of the fault without any lines being tripped. The simulation is run for 60 seconds to allow the dynamics to settle and will be considered to be passed if the following criteria are met:
     i. No generator MW change of 1 MW or more from pre-fault to steady-state post-fault conditions
     ii. No generator MVAR change of 1 MVAR or more, except for exciters with dead band control (typically IEEE Type 4) from pre-fault to steady-state post-fault conditions
     iii. No voltage change of 0.0001 p.u. or more, except in vicinity of exciters with dead band control from pre-fault to steady-state post-fault conditions
     iv. No undamped oscillations related to the addition of the new user-written model

User-written model(s) shall be accompanied by the following documentation:

- A user’s guide for each model
- Appropriate procedures and considerations for using the model in dynamic simulations
- Technical description of characteristics of the model
- Block diagram for the model, including overall modular structure and block diagrams of any sub-modules
- Values, names and detailed explanation for all model parameters
- Text form of the model parameter values (PSSE dyr file format)
- List of all state variables, including expected ranges of values for each variable

Appendix C – Requirements of PSCAD Models

1.0 ~~PSCAD~~ EMT model requirement

As the penetration of inverter-based resources (IBR) and distributed energy resources (DER) continues to grow, EMT~~PSCAD~~ models are required to support current and future study efforts which are required to maintain a reliable power system. Models are required for one or more of the following reasons. Other specialty studies may also be performed from time to time.

- Integration of IBR into low system strength networks
- Sub-synchronous control interactions (plant-to-grid)
- IBR controls interactions (plant-to-plant and within the plant)
- IBR controls stability (large and small disturbance)
- IBR frequency and voltage ride-through capability and performance
- IBR short-circuit current analysis
- Power quality studies (e.g., harmonics, rapid voltage change)
- Black start and system restoration studies
- Benchmarking and verifying RMS positive sequence dynamic models

~~1.1 Weak System Analysis~~

~~In simple terms, when a device (such as a wind plant) connecting to a supporting transmission system (or collection of devices such as a cluster of wind farms) is large relative to the rest of the system, it has a relatively large dynamic influence on the system, and the system may be termed weak. "Weak" is a relative term, and typically does not have hard quantitative metrics associated with it.~~
~~It is not always initially clear when a system will become too weak to support generation. Conventional modeling tools such as PSSE may not be sufficiently detailed to represent the issues which will be encountered in actual equipment. Power electronic equipment provided by different manufacturers may respond differently to similar network conditions. Additionally, influences from nearby devices may or may not have a significant impact on a particular generator interconnection. Usually, if there is any consideration by planners that the network may be too weak to support additional generation, detailed studies are performed using electromagnetic transient type tools such as PSCAD.~~

~~1.2 Sub-synchronous Oscillation (SSO) Analysis~~

~~Series compensated transmission lines introduce the risk of SSO. SSO is a family of stability phenomena where the electrical resonance introduced by a capacitor causes the capacitor to exchange energy with either conventional generators, or renewable generators like wind.~~

~~In the case of conventional generators, these interactions are termed "Subsynchronous Resonance" or SSR (although more specific and formal definitions exist, and other phenomena are also studied in relation to conventional generation).~~

~~In the case of wind, these interactions are termed "Subsynchronous Control Interactions", or SSCI. SSCI is most probable when certain types of wind turbines are operated in very close proximity to series capacitors, particularly if there are no other parallel outlets for the wind energy ("radial" connections). If unchecked, SSCI can introduce oscillations onto the power system which can very quickly grow to~~

~~damaging levels. In the worst cases, it can lead to electrical instability which can trigger power system protection, damage wind turbines, or damage series capacitor equipment.~~

~~Many modern wind turbines are susceptible to SSCI, and therefore a direct connection to a series compensated line, or a connection which may (through outages) become radial or near-radial, requires careful study. An SSCI study is performed using very detailed electromagnetic transient type computer models such as PSCAD. These models shall represent the turbine controls in minute detail, and any possible network conditions requiring operation of the wind plant directly (or nearly directly) into a series capacitor shall be simulated to ensure the specific turbines chosen will be immune to SSCI phenomena. Conventional transient stability models such as PSS/E are unable to represent the SSCI phenomena due to inherent limitations in the model type.~~

~~Other power electronic devices such as HVDC ties also require consideration of SSO phenomena, and usually require electromagnetic transient based studies to evaluate this and other concerns.~~

~~1.3 Control Interaction Analysis~~

~~Power electronic based devices such as wind turbines, HVDC transmission systems, STATCOMs, and SVCs are highly controllable, and the controls may operate to perform specific functions within a wide range of timeframes and operating conditions. If two or more of these devices are in operation in close electrical proximity to each other, but have been designed and commissioned in isolation from each other, there is a potential for the controllers to interfere with each other, and the overall system performance could be degraded. Due to the level of detail required in the models to accurately represent the fast control loops used in these devices, electromagnetic transient models such as PSCAD are normally used to test for adverse control interactions.~~

~~1.4 Dynamic Performance Studies~~

~~For devices which are very influential in the system, represent unique designs, or of concern to the reliable operation of the grid, very detailed PSCAD models are sometimes requested to perform studies to test the general dynamic performance of the system. Specific control functions or stressed network conditions are sometimes tested for correct behavior. Typical devices which warrant PSCAD dynamic performance studies as part of routine connection processes include HVDC converters, SVCs, STATCOMs, and large renewable energy projects.~~

~~1.5 Other Studies~~

~~It is noted that there are many other types of studies which may require PSCAD models (e.g. harmonic studies), which are not described here. Such specific type of PSCAD model may be necessary as part of a System Impact Study and may vary depending on the specific analysis being done. If required, the appropriate modeling and analysis shall be specified as part of the individual system impact study.~~

2.0 ~~PSCAD~~ EMT Model Requirements

As mentioned above, specific model requirements for a ~~PSCAD~~ EMT study depend on the type of study being done. A study with a scope covering weak system interconnection, ride-through, voltage control and event response, and islanding performance (for example) would require a model which must meet the requirements stated in Appendix C-1~~has the following characteristics~~, and unless specified otherwise, this type of model is what is required.

~~2.1 Model Accuracy Features~~

~~For the model to be sufficiently accurate, it shall:~~

- ~~Represent the full detailed inner control loops of the power electronics. The model cannot use the same approximations classically used in transient stability modeling, and shall fully represent all fast inner controls, as implemented in the real equipment. It is possible to create models which embed the actual hardware code into a PSCAD component, and this is the best type of model.~~[31]
- ~~Represent all pertinent control features (e.g., external voltage controllers, plant level controllers, phase locked loops, etc). Operating modes that require system specific during the system impact study adjustment shall be user-accessible. In particular, plant level voltage control shall be represented along with adjustable droop characteristics.~~
- ~~Represent all pertinent electrical and mechanical configurations, such as filters and specialized transformers. There may be other mechanical features (such as gearboxes, pitch controllers, etc.) which shall be modeled if they impact electrical performance.~~
- ~~Have all pertinent protections that are relevant to network performance shall be modeled in detail for both balanced and unbalanced fault conditions. Typically this includes various OV and UV protections (individual phase and RMS), frequency protections, DC bus voltage protections, and overcurrent protection. There may be other pertinent protections that shall be included.~~

~~2.2 Model Usability Features~~

~~In order to allow study engineers to perform system analysis using the model, the PSCAD model must:~~

- ~~Have control or hardware options which are pertinent to the study accessible to the user. (For example, adjustable protection thresholds or real power recovery ramp rates) Diagnostic flags (e.g. flags to show control mode changes or which protection has been activated) shall be accessible to aid in analysis.~~
- ~~Be capable of running at a minimum time step of 20 microseconds, or no less than 10 microseconds if required by specific control parameters. Most of the time, requiring a smaller time step means that the control implementation has not used the interpolation features of PSCAD, or is using inappropriate interfacing between the model and the larger~~

~~[31] The model must be a full thyristor representation (preferred) if thyristors are used, or may use a voltage source interface that mimics thyristor switching (ie. A firing pulse based model). A three phase sinusoidal source representation is not acceptable. Models manually (ie. block-by-block) translated from MATLAB are often unacceptable because the method used to model the electrical network and interface to the controls may not be accurate. Note, however, that Matlab may be used to generate C code which is used in the real control hardware, and if this approach is used by the developer, the same C code may be directly used to create an extremely accurate PSCAD model of the controls. The controller source code may be compiled into DLLs if the source code is unavailable due to confidentiality restrictions.~~

~~network. Lack of interpolation support introduces inaccuracies into the model at higher time-steps.~~

- ~~Include user model guide and a sample implementation test case. Access to technical support engineers is desirable.~~

~~2.3 Model Efficiency Features~~

~~In addition, the following elements are required to improve study efficiency and enable other studies which include the model to be run as efficient as possible:~~

- ~~Initializes as quickly as possible (e.g. < 1-3 seconds) to user supplied terminal conditions.~~
- ~~Support multiple instances of the model in the same simulation.~~
- ~~Support the PSCAD "snapshot" feature.~~
- ~~Support the PSCAD "multiple run" feature.~~

3.0 Model Submission Report Requirements

Studies utilizing electromagnetic transient tools such as PSCAD rely heavily on model accuracy and quality to be conducted in a timely manner. Failures in model quality control or insufficient care in preparing site specific models can (and often does) result in long study delays. In order to allow ISO New England planning studies which may involve electromagnetic transient analysis to be conducted efficiently and accurately, PSCAD model submissions are required to be delivered along with a basic model submission report, outlined as follows:

3.1 Section 1: Statement of model compliance

In this section, a statement of model compliance is required which affirms ~~basic~~ conformance with the model requirements ~~stated above~~in Appendix C-1.

3.2 Section 2: Plant and Model Overview

In this section, details of what the plant consists of and how it connects to the ISO-NE system must be provided. This includes:

- A single-line diagram of the plant up to the POI
- Details of the POI (e.g. existing or new substation, voltage level, distance from the closest existing terminal stations on either side) including any other relevant configuration information
- In tabular format, details of the planned (or installed) inverter capability, generator step-up transformer (GSU), collector network, main power transformer (MPT),[32] gen-tie line, static and dynamic reactive devices (if any)

~~3.2~~3.3 Section ~~2~~3: Instructions for model use

In this section, a list of instructions for model use shall be included. This list shall include (at least):

- Directions for compiling and running the model
- Any special requirements for the model (e.g. simulation time-step, run-time settings, etc)
- Instructions on directory path settings if applicable, including a list of libraries, object files, or other files which may be required to run the model.

~~3.3~~3.4 Section ~~3~~4: List of plant-specific settings and description of control scheme

In this section, any control parameters which are specific to an individual plant must be stated. These parameters may include (among others):

- Ride-through thresholds and parameters
- Active power ramp rates following faults
- Plant-level voltage controller gains and time constants
- Interface parameters with non-turbine plant devices such as STATCOMs, if applicable
- Description of the planned (or installed) control schemes (such voltage, frequency, reactive power and/or power factor, runback etc.). The description should include:
  - The target of the control scheme
  - Overview of how it achieves its intended result
  - Parameters which directly impacts the performance, trigger levels, deadband etc.
  - Limitations of the control scheme

Where applicable, these parameters shall be matching with PSSE model settings, which studies are usually performed ahead of or in parallel to PSCAD studies.

~~3.4~~3.5 Section ~~4~~5: Basic performance testing at approximate connection location

In this section, a brief demonstration of model performance is required based on the location in the ISONE network where the plant will be connecting (POI).

Create Network Model

Using a provided PSSE network as a reference,[33] a small passive PSCAD model shall be built surrounding the POI which represents the correct short circuit MVA under system intact, fault, and under line outage conditions. As noted above, the presence of nearby devices can degrade performance, and this shall be born in mind, although detailed studies will follow (in other words, performance in simplified models may be better than performance when nearby devices are included, and design margin may be desirable). A short description of the SCMVA values resulting from the fault conditions considered shall be provided.

Apply Faults
Basic fault and contingency performance shall be tested to show plant recovery and stability under these approximated network conditions. Plant shall be capable of riding through faults with acceptable oscillations, and maintaining stable and accurate terminal voltage control. A set of representative plots shall be provided to demonstrate performance[34].

Important Note
These basic tests are requested to provide basic quality control and site-specific testing of the plant model. More detailed studies are required to analyze the phenomena described above, and the results of these studies may indicate problems which are not evident in these basic tests. For example, interactions with nearby devices will be impossible to test in a simple model without detailed models of the nearby devices available. Other issues may be found as more detailed system models and network conditions are tested.

~~3.4.1~~3.5.1 Detailed Instructions for the conduct of benchmarking analysis to confirm acceptable performance of the PSS/E model in comparison to the PSCAD model

PSS/E Simulation

1. The project shall be modeled at full output per the project's Interconnection Request.
2. Sufficient data channels shall be included in the snapshot file for reporting purposes. Example channel data would include bus voltages within the project and around the project's POI, line and transformer flows (both real and reactive), and LVRT status signal. Channel selection shall enable PSCAD modeling results to be directly compared against the PSS/E results.
3. Two fault simulations, each using a 6 cycle clearing time, at a bus close to the point of interconnection, for both pre-project (without the project modeled in-service) and post-project (with the project modeled in-service) :

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[32] For the purpose of this document, the MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

[33] Reference cases can be found at the following location on the ISO-NE website: http://www.iso-ne.com/system-planning/transmission-planning/ferc-form-no-715-reports

[34] Note: It will be possible for manufacturers to re-use basic model performance testing across multiple locations, provided:

- The site-specific model parameters are identical
- The SCMVA levels (for N-0 and N-1 conditions) used for the testing are the same or lower than those at the POI
- The inverter control topology and mechanical performance is expected to be identical

   a. With all lines in service
   b. With one line close to the point of interconnection out of service.
4. Plot scales shall be set appropriately for the reviewers to discern the entirety of the plotted signals, without clipping. Multiple signals may be plotted together in the same plot, as long as the signals are discernible from one another—otherwise, some of those signals should be separated out into multiple plot diagrams.

PSCAD Simulation

1. PSCAD simulation shall be performed under as similar conditions as possible to the PSS/E simulations discussed above, for the best possible comparison.
2. The Project and its associated auxiliary equipment shall be modeled with comparable parameters between the PSS/E and PSCAD modeling, with each model's parameters detailed in the summary report.
3. The PSCAD transmission system case model shall be created from the PSS/E case model, with sufficient buses included after forming the system equivalent to allow simulation of the line outage and fault conditions modeled in the PSS/E simulations discussed above.
4. Steady-state line outage scenarios shall be created similar to those in the PSS/E simulation. For each scenario, a short description of the SCMVA values resulting from the fault conditions considered shall be provided.
5. The PSCAD model shall initialize properly and that the same power flow and voltage conditions shall be observed between the PSCAD and PSS/E models.
6. Output channels shall be set up to capture similar data to that of the PSS/E simulations
7. Fault simulations using the same modeling as those for PSS/E shall be run
8. Comparison plot sets modeling the same data channels from PSS/E and PSCAD shall be developed.

Evaluation of Results

1. Comparison plots shall show similar results between PSS/E and PSCAD. If any significant differences are shown between the traces, sufficient explanation shall be included about why these differences should be considered acceptable.

Report

1. Statement of Model Compliance—a statement of model compliance is required which affirms basic conformance with the PSCAD model requirements
2. List of Plant-Specific Settings—data shall be included for both PSCAD and PSS/E models. Any control parameters which are specific to the plant must be stated. Where applicable, these parameters shall be matching with PSS/E model settings. These parameters may include (among others):
   a. Ride-through thresholds and parameters (e.g., undervoltage thresholds or fault-Q contribution limits)
   b. Active power ramp rates following faults
   c. Plant-level voltage controller gains and time constants
   d. Interface parameters with non-turbine plant devices such as STATCOMs
3. Results Documentation—Plots and related discussion regarding acceptability
   a. PSS/E
      i. Initialization Results
      ii. Flat Run (No Disturbance)
      iii. Fault simulation results

b. PSCAD
   i. Initialization Results
   ii. Power flow and voltage matching to PSS/E
   iii. Fault simulation plots comparison to PSS/E
c. PSS/E steady-state raw data (.RAW) data file and dynamics data (.DYR) file, in the latest version of PSS/E in use by ISO-NE, shall be included in the report. These files shall be ready to be incorporated into the base case and snapshot without further modifications. These files shall be also fully-compatible with the PSS/E model(s) designated (and if user-defined, provided to ISO New England) for the Project.

Appendix D – Detailed Considerations for the Study of an Inverter Based Generating Facility

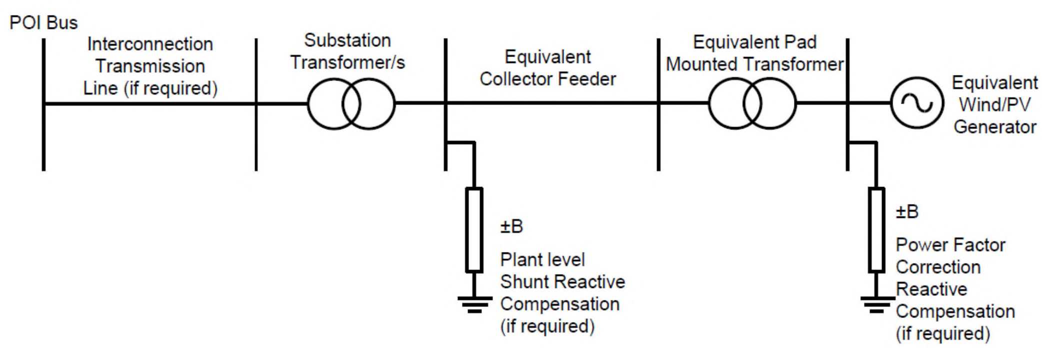
Typical Order of Study for an Inverter Based Generating Facility

1. Short Circuit Ratio calculation
2. Review of PSS/E-PSCAD benchmarking
3. PSCAD analysis of performance if Short Circuit Ratio is low
4. Review of performance of PSS/E model
5. Collector system/GSU tap setting/voltage control strategy calculation
6. Steady state reactive margin analysis
7. Initial dynamic fault testing
8. Full steady state testing to meet the requirements of this Planning Procedure
9. Full dynamic testing to meet the requirements of this Planning Procedure

Use of Aggregate Models for Collector-Based Generating Facilities

For the steady-state portion of the System Impact Study, including the detailed collector system analysis described below, a fully explicit model of the collector system, including all branch connections and step-up transformers shall be used.

For the stability portion of the System Impact Study, an equivalent model shall be used for each major feeder branch of the Generating Facility. The following figure provides a representation of the appropriate equivalent to be used.



Collector system/GSU tap setting/voltage control strategy calculation

A detailed evaluation using a fully explicitly modeled collector-based Generating Facility allows for analysis of voltage control strategies by showing the real and reactive power flow and losses across every element of the facility. Being able to monitor the terminal voltage at each individual generating unit makes it possible to ensure each unit remains within a reasonable voltage range to avoid tripping. All collector branches, junctions, individual high and low voltage busses (including the GSUs and generating units) shall be modeled using the configuration, network impedances, generating unit reactive capabilities and facility ratings for the project.

- The following voltage regulation modes should be reviewed as appropriate:
    - Generating units regulating voltage at a remote bus
    - Generating units regulating voltage at a Park transformer high side bus
    - Generating units regulating voltage at a Park transformer low side bus
    - Generating units regulating voltage at a fixed power factor

Step 1 – Reactive Power Capability

This step investigates the reactive power range of the overall Generation Facility and seeks to determine if the collector system design allows full reactive power capability. It also tries to determine what unit and station transformer taps allow for the largest reactive power injection range of the generating units.

- The POI may be modeled as a swing bus for this analysis. A fictitious machine may be placed at the swing bus to consume the Project output and to allow for adjustment of transmission system voltages.
- Testing is performed to determine if the generating units would violate any voltage trip settings given the full leading and lagging reactive power range of the generating units.
- The reactive power output of the generating units is ramped to the maximum leading negative MVAR and to the maximum lagging capability positive MVAR for various system voltages and transformer tap settings.
- If any bus voltage within the Project or collector system is outside of the specified range, the generating unit reactive power output for the wind park should be recorded along with the first bus that showed a voltage outside of the range. This information is used to determine which transformer tap settings result in the greatest usable reactive power range of the generating units as a way to pre-screen the testing required for Step 2.

Step 2 – Collector System Voltage Range

The goal of this testing is to develop a strategy to maintain sufficient margin to the generating unit trip settings and if possible maintain a preferred Generation Facility terminal voltage range (typically 0.95 to 1.05pu) for any transmission system voltage (typically 0.9 pu to 1.1 pu).

- Testing is performed at different plant output levels 0% to 100% output in 10% intervals with equal loading across all individual generating units.
- For each of the applicable control strategies described above, and optimum tap settings from Step 1, a voltage profile is created and the minimum and maximum voltages within the facility is recorded.

Step 3 – VAR impact to the System and Voltage Schedule Margin

- The goal of this testing is to identify a strategy that will minimize the reactive power demand from the system under normal conditions, but also provide VAR support under low voltage conditions and consume MVAR under high voltage conditions.
- To ensure there is proper margin with the scheduled voltage (as determined by ISO during the study), +/-2% from scheduled voltage is evaluated.

Appendix E – Procedures for Material Modification Determinations

This Appendix E provides implementation guidance in the application of the material modification procedures contained in Schedules 22, 23 & 25 of the OATT.

Different thresholds for determining Material Modification of a Generating Facility or ETU depend on the stage of the project:

1. After an Interconnection Request is received and before a Feasibility Study Agreement is executed
2. After the Feasibility Study Agreement is executed and before the Feasibility Study is completed
3. After the Feasibility Study is completed and before a System Impact Study has commenced
4. After the System Impact Study has commenced and before the System Impact Study is completed
5. After the System Impact Study, including evaluation of "as purchased data," "as built/as tested data" and changes to existing facilities (e.g., equipment upgrade, replacement of failed equipment)
    - "As purchased data" is required to be submitted no later than 180 Calendar Days prior to the Initial Synchronization Date and shall be reviewed prior to the project being allowed to be synchronized to the New England system
    - "As built/as tested" is required to be submitted prior to the Commercial Operation Date and shall be reviewed prior to the project being allowed to become Commercial

1 (a). After an Interconnection Request is received and before a Feasibility Study Agreement is executed the following will be deemed material and require a new Interconnection Request

- Any increase to the energy capability or capacity capability output of a Generating Facility or ETU above that specified in an Interconnection
- A change from Network Resource (NR) Interconnection Service to Capacity Network Resource (CNR) Interconnection
- An extension of three or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU unless provisions of Section 4.4.5 of the Schedules 22 or 25 are satisfied

1 (b). After an Interconnection Request is received and before a Feasibility Study Agreement is executed the following will not be deemed material

- Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator
- A decrease of up to 60 percent of electrical output (MW) of the proposed project
- Modification of the technical parameters associated with the Large Generating Facility or ETU technology
- Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics
- Modification of the interconnection configuration
- Modification of the Point of Interconnection (POI) based on information from the Scoping Meeting and identified within five (5) business days of the Scoping Meeting

2 (a) Changes after the Feasibility Study Agreement is executed and before the Feasibility Study is completed

- Once the Feasibility Study has started, it will be completed without making any changes except those based on study results that were not anticipated at the Scoping Meeting and are agreed to by the System Operator and the Interconnecting Transmission Owner. Other changes will be addressed in the System Impact Study.

2 (b). The following changes after the Feasibility Study Agreement is executed and before the Feasibility Study is completed will be deemed material and require a new Interconnection Request

- Any increase to the energy capability or capacity capability output of a Generating Facility or ETU above that specified in an Interconnection
- A change from NR Interconnection Service to CNR Interconnection
- An extension of three or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU unless provisions of Section 4.4.5 of the Schedules 22 or 25 are satisfied
- Modification of the POI that is not based on unanticipated study results

2 (c). The following changes after the Feasibility Study Agreement is executed and before the Feasibility Study is completed will not be deemed material and will not require a new Interconnection Request

- Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator
- A decrease of up to 60 percent of electrical output (MW) of the proposed project
- Modification of the technical parameters associated with the Large Generating Facility or ETU technology
- Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics
- Modification of the interconnection configuration
- Modification of the POI based on study results that were not anticipated at the Scoping Meeting and are agreed to by the System Operator and the Interconnecting Transmission Owner
- Modification of settings of the project’s controls, such as wind farm voltage control scheme

3. Changes after the Feasibility Study is completed and before the System Impact Study has commenced

- ISO-NE will notify the Interconnection Customer 65 days before the study begins and allow the Interconnection Customer 60 days to refresh its data to the degree allowed under the same materiality standards for changes prior to execution of the System Impact Study Agreement
- Once the System Impact Study has started, it will be completed without making any changes except those based on study results that were not anticipated and are agreed to by the System Operator and the Interconnecting Transmission. Other changes will be addressed in the same way as changes made after the System Impact Study is complete.

4 (a). During the System Impact Study the following will be deemed material and require a new Interconnection Request

- Any increase the energy capability or capacity capability output of a Generating Facility or ETU above that specified in an Interconnection

- A decrease of the electrical output (MW) of the proposed project where the decrease would result in the transfer of an upgrade obligation to a later queued project
- A change from NR Interconnection Service to CNR Interconnection
- An extension of three or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU unless provisions of Section 4.4.5 of the Schedules 22 or 25 are satisfied
- Modification of the POI and/or interconnection configuration that is not based on unanticipated study results

4 (b). During the System Impact Study the following may be deemed material and will require review after the System Impact Study is completed using the post System Impact Study criteria

- A decrease of the electrical output (MW) of the proposed project where the decrease would not result in the transfer of an upgrade obligation to a later queued project
- Modification of the technical parameters associated with the Large Generating Facility or ETU technology
- Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics

4 (c). During the System Impact Study the following will not be deemed material and will not require a new Interconnection Request

- Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator
- Modification of the POI and/or the interconnection configuration based on study results that were not anticipated and are agreed to by the System Operator and the Interconnecting Transmission Owner

5. Changes after the System Impact Study is completed

- A proposed project that has a completed System Impact Study, or an existing generating facility or ETU can request that a proposed change be evaluated to determine if the change is a Material Modification. If this happens, the proposed change will be evaluated using technical screening criteria. However, there may be proposed changes that have not been contemplated and might require additional analysis beyond the normal screening criteria
- The following will be deemed material and require a new Interconnection Request
  - Where the change(s) would either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact (i.e., an evaluation of the proposed modification cannot be completed in less than ten (10) Business Days) on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date

5 (a). Screening Criteria for Changes in Dynamic Models or Voltage Control Schemes

- The following will not be deemed material and require a new Interconnection Request
  - There is no voltage or dynamic stability problem that may be adversely affected by the change to the project that is found in any base cases for the most severe N-1 and N-1-1 contingencies

- The new models provide similar or better dynamic voltage and stability performance based on dynamic simulation of a few severe faults

5 (b). Screening Criteria for Short Circuit Impacts of Changes in Generation or ETU or Interconnection Facility Impedances

- The following will not be deemed material and require a new Interconnection
  - The total impedance is greater than that of the previously submitted unit(s) and X/R ratio is less than or equal to that of the previously submitted unit(s)
  - A short circuit study at only the interconnecting bus confirms that short circuit duty is less than or equal to that of the previously submitted unit(s)

5 (c). Screening Criteria for Stability Impacts of Changes in Generation or ETU or Interconnection Facility Impedances

- The following will not be deemed material and require a new Interconnection
  - The new models provide similar or better dynamic performance (better damping, smaller angular swing) based on dynamic simulation of a few severe faults

5 (d). Screening Criteria for Voltage Impacts of Changes in Generation or ETU or Interconnection Facility Impedances

- The following will be deemed material and require a new Interconnection Request
  - A change that will result in the Generating Facility or ETU not meeting the Tariff's power factor requirement
- The following will not be deemed material and require a new Interconnection
  - The change of impedance is small (less than 10% of the impedance used in the SIS), the power factor requirement is satisfied, and there is no pre-existing voltage problem

5 (e). Screening Criteria for PSCAD Changes to Generating Facilities or ETUs that Required a PSCAD model

- The following will not be deemed material and require a new Interconnection Request
  - The new models provide similar or better performance for the most severe N-1 and N-1-1 contingencies

Appendix F – IEEE 2800 Requirements

This Appendix E provides implementation guidance in the application of the material modification procedures contained in Schedules 22, 23 & 25 of the OATT.

- For the purposes of this appendix, figures 1,2 and 3 of clause 1.4 shall be adhered to

- This appendix defers to clause 3 of IEEE 2800-2022 for definitions, acronyms, and abbreviations

- Shall be compliant with clause 4 of IEEE 2800-2022
  - Shall be compliant with clause 4.1
  - Shall be compliant with clause 4.2
  - Shall be compliant with clause 4.3
  - Shall be compliant with clause 4.4
  - Shall be compliant with clause 4.7 items d-g
  - Shall be compliant with clause 4.9

- Shall be compliant with clause 5 of IEEE 2800-2022
  - Shall be compliant with clause 5.1
    - Default RPA shall be the POM
    - ICR and ICAR shall be defined as the Rated Active Power Output Rated Active Power Absorption as listed in the IBRs interconnection agreement.
    - Table 4 RPA Voltage Ranges will be defined based on the interconnection TOs requirements.
  - Shall be compliant with clause 5.2
    - Resources shall be enabled in voltage control mode by default
    - Response times under table 5 are adopted as the default
    - Proposed maximum step response timing will be subject to review during SIS to ensure no adverse impact during low system strength conditions

- Shall be compliant with clause 6 of IEEE 2800-2022
  - The default RPA for clause 6 is as written as the default in 6.1.1
  - Shall be compliant with 6.1.1
    - Both under and over frequency response shall be enabled to the fullest extent
    - Default parameters under table 7 are adopted
  - Shall be compliant with 6.1.2
    - Default parameters under table 8 are adopted

- Shall be compliant with clause 7 of IEEE 2800-2022
  - The Default RPA for clause 7 is as written for each sub clause within the standard

- Shall be compliant with 7.1
- Shall be compliant with 7.2.1
- Shall be compliant with 7.2.2.1
    - For resources that will cease to inject current in the permissive operation region, a notification to the ISO must be made.
- Shall be compliant with 7.2.2.2
    - IBRs shall by default be configured in reactive power priority mode
- Shall be compliant with 7.2.2.3.1
- Shall be compliant with 7.2.2.3.2
- Shall be compliant with 7.2.2.3.3
- Shall be compliant with 7.2.2.3.4
    - IBRs shall by default be configured in reactive current priority mode
- Shall be compliant with 7.2.2.3.5
    - Timing will be subject to review during SIS to ensure no adverse impact during low system strength conditions
- Shall be compliant with
    - Inverter-based resources are expected to ride through a post-fault dynamic voltage oscillation with the following envelope characteristics:
        - Upper and lower limits of 1.15 and 0.8 p.u. settling to between 1.05 and 0.90 p.u.
        - A frequency of oscillation between 0.25 Hz and 2 Hz in a synchronous reference frame
        - A damping ratio of 3% or better
- Shall be compliant with 7.2.2.5
- Shall be compliant with 7.2.2.6
    - Active power recovery time will by default be 1s. This will be confirmed and reviewed during the SIS to ensure no adverse impact during low system strength conditions
- Shall be compliant with 7.2.3
- Shall be compliant with 7.3
    - Fnom is 60, default values from table 15 shall be adopted

Exceptions:

- 4.5 is not adopted at this time
- 4.6 is not adopted at this time
- 4.7 items a-c are not adopted at this time
- 4.10 is not adopted at this time
- 4.11 is not adopted at this time
- 4.12 is not adopted at this time
- Capability to provide reactive power support when the primary energy source is not available as described in clause 5.1 is not adopted at this time
- 6.2 is not adopted at this time
- 7.4 is not adopted. Generators return to service after trip shall be coordinated with ISO-NE Control Room.
- Clauses 8, 9, 10, 11, and 12 are not adopted at this time

Clarifications:

- The measurement accuracy requirements of clause 4.4 are subject to coordination with all applicable ISO-NE Operating Procedures and NERC standards and the aforementioned will take precedence over compliance with this clause
- The default RPA is the POM as detailed in clause 4.2.1 unless otherwise specified within this Appendix F of PP5-6
- IBR's are not required to pre-curtail output in order to reserve under frequency response availability
- Resources tripping offline, going into blocking modes, or reducing power output outside of allowable ranges within clause 7 of this standard during SIS review will be treated as significant adverse impact, and mitigations will be required.
- Voltage disturbance oscillations and voltage excursions are defined differently under 7.2.2.4. Voltage excursions are separate events as where oscillations are not.
- Clause 5.1 shall be treated as a minimum reactive capability requirement for non-synchronous generation
- System Impact Study testing shall evaluate the compliance of the minimum reactive capability with the requirements of clause 5.1 of IEEE 2800.
- System Impact Study testing shall evaluate the compliance of the voltage and reactive power control with the requirements of clause 5.2 of IEEE 2800.
- System Impact Study testing shall evaluate the compliance of the active power and frequency response with the requirements of clause 6 of IEEE 2800.
- System Impact Study testing shall evaluate the compliance of the ride through capability with the requirements of clause 7 of IEEE 2800.

Appendix C-1. Electromagnetic Transient Modeling Requirements

In support of an Interconnection Request (IR) all equipment-level Electromagnetic Transient (EMT) models must be supplied by the respective Original Equipment Manufacturers (OEM) and combined into a plant-level model[1] by the Interconnection Customer (IC). These models must meet the requirements included in this checklist Sections A, B and C. Each checklist must be accompanied with an equipment Model Quality Attestation[2] (e-MQA) that is submitted by the respective OEM. Additionally, for each IR, the IC shall submit a single plant-level Model Quality Attestation (p-MQA)[2] above~~[2] above~~ that covers all equipment-level EMT models and other equipment[3] within the plant.

For the EMT models to be usable by ISO-NE, they must be in a format usable by the PSCAD™/EMTDC™ simulation tool. Any requirement within the checklist that is not met shall be documented with sufficient technical justification and will be subject to review.

Model Quality Attestation (MQA)[4]

Each IR (for which an equipment-level EMT model is provided) must be accompanied by an equipment Model Quality Attestation (e-MQA) from the respective OEM and a plant-level Model Quality Attestation (p-MQA) from the IC. An e-MQA and/or p-MQA shall be provided any time significant changes are made to the model[5] that may affect the performance of the plant. An e-MQA and p-MQA form is provided in Appendix C-1A and Appendix C-1B.

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[1] A combination of system components (e.g. transformers, cables, auxiliary devices etc) and unit-level models provided by the inverter and plant-level controller OEMs to represent the expected behavior of the equipment

[2] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline-EMT_Modeling_and_Simulations.pdf

[3] Examples of equipment include, but are not limited to, the following: gen-tie line, main power transformers, collector system, generator step-up transformer, coupling or scaling transformers, static reactive power devices, and any other equipment necessary

[4] MQA must be provided for the Planned, As-Purchased and As-Built project

[5] Significant changes include, but are not limited to, make and model of inverter or controller including software version, control parameters, plant configuration

Checklist for EMT Model

The following model submission summary table and model requirement checklist shall be submitted for each equipment-level EMT model.

EMT Model Submission Summary	
Interconnection Request ID	
Submission date:	
Revision Number:	
Equipment OEM:	
OEM Contact for model related questions	
Technology type: (eg. Wind, Solar, BESS, Fuel Cell etc.)	
Equipment Type[6]:	
Equipment Model:	
Hardware Firmware Version:	
EMT Model Release Version and Date:	
Model Documentation file(s) (Model User document etc.):	
Model Files supplied (e.g. DLL, lib, obj, txt etc.):	

[6] Examples of equipment include, but are not limited to, the following: ~~main power transformers, generator step-up transformer,~~ inverter models, plant-level controllers, dynamic ~~or static~~ reactive power devices, HVDC and any other applicable equipment

A. Model Accuracy Features[7]

In order to be sufficiently accurate, the model provided for each facility shall:

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
1	Represent the full detailed inner control loop of the power electronics. Models cannot use the same approximations classically used in transient stability modeling and must fully represent all fast inner controls, as implemented in the real equipment. Models manually translated block-by-block from MATLAB or control block diagrams are unacceptable.A full power transistor (e.g. IGBT) representation is the preferred model. Models must embed the actual hardware code into a PSCAD component[8].		
2	An average source representation is strongly discouraged. However, if an average source representation is utilized (e.g., switching frequency greater than 40 kHz), it shall maintain full detail in the inner controls and DC side protection features. Sufficient technical justification must be provided on the usage of an average source representation.		
3	DC side protections, and any current, power or energy limitations that could ~~impact~~ affect plant ride-through shall be represented in the model. Modelling the DC side with an ideal voltage source is not acceptable if such a representation prevents the possibility of protection operation during external system events.		
4	Represent all pertinent control features as they are implemented in the real controls (e.g. customized PLLs, ride-through controllers, etc.) using actual hardware code.		
5	Represent Power Plant Controller (PPC) as implemented in the real controls and represent the specific controllers used in the plant. This includes automatic voltage regulation, specific measurement methods, and transitions into and out		

[7] The ISO-NE acknowledges the Electranix Technical Memo which was used to develop ISO-NE's EMT model requirements: http://www.electranix.com/wp-content/uploads/2022/09/PSCAD-Model-Requirements-Rev.-12-Sept-2022.pdf

[8] The controller source code may be compiled into DLLs or binaries if the source code is unavailable due to confidentiality restrictions.

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
	of ride-through modes among others.Generic PPC representations are not acceptable.		
6	Communication and sample and hold delays between PPC and inverter must be modeled.		
7	Represent common plant controller functionality if there are multiple plants using the same technology or multiple technologies (eg. Hybrid BESS/PV). If supplementary or multiple voltage control devices (eg. STATCOM) are included in the plant, these should be coordinated with the PPC.		
8	Represent Sub Synchronous Oscillation (SSO) mitigation and/or protection including the ability to enable and disable SSO mitigation/protection, if applicable.		
9	Represent shunt capacitor and reactor banks and any dynamic reactive devices. The controls should be modeled if the equipment dynamically responds within 10 seconds following a disturbance.		
10	Represent all pertinent electrical and mechanical configurations, such as filters and specialized transformers. Mechanical features (such as gearboxes, pitch controllers, etc.) should be included in the model if they ~~impact~~ affect electrical performance. Any control or dynamic features of the actual equipment that may influence behaviour in the simulation period (up to 30 second post-disturbance) but are not represented or are approximated must be clearly identified.		
11	Have all pertinent protections modeled in detail for both balanced and unbalanced fault conditions. Typically, this includes various over-voltage and under-voltage protections (individual phase and RMS), frequency protections, DC bus voltage protections, and overcurrent protection among others. Any protection, which can influence dynamic behavior or plant ride-through in the simulation period (up to 30 second post-disturbance), must be included.		

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
12	Accurately reflect behavior throughout the valid (MW and MVAr) output range from minimum power through maximum power.		
13	Model main power transformer[9] (MPT) and generator step up -saturation based upon transformer test reports available. If such data is not available, reasonable approximate data for transformer saturation shall be used and documented[10].		
14	Include detailed representation of any hardware or software filters for the wind turbine controllers, if necessary		
15	The specific implementation of frequency measurement equipment should be modeled. If actual equipment model is not available, a smoothed master library FFT or master library PLL shall be used.		
16	Be configured to match planned (or installed) site-specific equipment settings[11]. Any user-tunable parameters or options must be set in the model to match the equipment at the specific site being evaluated. It is unacceptable to use default parameters.		

B. Model Usability Features

In order to allow study engineers to perform system studies and analyze simulation results, the model provided for each facility shall:

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
1	Have pertinent control or hardware options accessible to the user (e.g. adjustable protection thresholds, real power recovery ramp rates frequency or voltage droop settings, voltage control response time).Diagnostic flags (e.g. flags to show control mode changes or which protection has been activated) should		

[9] The MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.
[10] Data includes magnetization model, magnetizing current, air-core reactance, knee voltage of winding-limb, loop width and any other relevant information
[11] If POI SCR is unknown at the time of model submission, it is recommended to parametrize to a POI level SCR of 3 and X/R of 10 as an approximate representation of a weak system. If studies show a SCR lower than 3, additional model tuning may be required

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
	be accessible to facilitate analysis and should clearly identify why a model trips during simulations.		
2	Be capable of accurately running for a time step of 10 µs or higher and not be restricted to operating at a single time step but within a range (eg. 10µs - 20 µs).Models requiring a smaller time step may mean that the control implementation has not used the interpolation features of PSCAD[12] or is using inappropriate interfacing between the model and the larger network. Smaller time step will be considered on a case-by-case basis.		
3	Be capable of initializing itself. Models shall initialize and ramp to full output without external input from simulation engineers. Any slower control functions which are included (such as switched shunt controllers or power plant controllers) must also accept initial condition variables if required[13].		
4	Accept external reference values. This includes real and reactive power reference values (for Q control modes), or voltage reference values (for V control modes) and utilize a single parameter for adjusting real power, and separately, a single parameter for adjusting voltage setpoints. Model must accept these reference variables for initialization, and be capable of changing these reference variables mid-simulation, i.e. dynamic signal references.		
5	Allow protection models to be disabled. Many studies result in inadvertent tripping of converter equipment, and the ability to disable protection functions temporarily provides study engineers with valuable system diagnostic information.		
~~6~~	~~Allow saturation on the main power transformer and the inverter step-up transformers to be disabled.~~		

[12] If power transistor switching frequency prevents accurate switching representation at 10 µs using interpolation, an average source approximation may be used. See Section A, Requirement 2 for more details.

[13] Note that during the first few seconds of simulation (eg. 0-2 seconds), the system voltage and corresponding terminal conditions may deviate from nominal values due to other system devices initializing, and the model must be able to tolerate these deviations or provide a variable initialization time.

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
~~7~~6	Allow the active power capacity of the model to be scaled. This is distinct from a dispatchable power order and is used for modeling different plant capacities (e.g. if a portion of the plant is offline).		
~~8~~7	Allow the plant to be dispatched at any output within its operating range. If a minimum output is required, sufficient technical justification shall be provided. This is distinct from scaling a plant from one unit to more than one, and is used for testing plant behavior at various operating points.		

C. Model Efficiency Features

In order to improve study efficiency and model compatibility the following efficiency features are required. Note that no feature should compromise model accuracy. The model shall:

Requirement	Description	Y/N	Provide details if model does not meet requirements
1	Be compatible with Intel Fortran compiler versions 15 and higher and be compiled with Visual Studio 2015 or newer.		
2	Be compatible with PSCAD version 4.6.3 and higher.		
3	Initialize to user defined terminal conditions within five seconds of simulation time		
4	Support multiple instances of its own definition in the same simulation case.		
5	Support the PSCAD “snapshot” and “multiple run” feature.		
6	Allow replication in different PSCAD cases or libraries through the “copy” or “copy transfer” features.		
7	Not use or rely upon global variables in the PSCAD environment and not use multiple layers in the PSCAD environment, including ‘disabled’ layers		

Requirement	Description	Y/N	Provide details if model does not meet requirements
8	Inform the user through messages to the progress output device when the system conditions are beyond plant operational limits or otherwise not consistent with valid operating conditions for the plant.		
10	Show error/status codes[14]		
11	Clearly identify the OEM's EMT model release version and the applicable corresponding hardware firmware version.		

D. Accessible Parameters

All models shall allow modification to parameters typically requiring site-specific adjustments. Where applicable, these include:

- All applicable set-points including but not limited to(shall be adjustable before and during a simulation run):
  - Active and Reactive power
  - Voltage and Frequency
  - Power Factor
- Deadband, droop, delays (including communication delays) and slow outer loop controls for any applicable control system such voltage and frequency control
- Active power ramp rate adjustment
- Voltage and frequency protection settings
- Fault ride through activation and deactivation thresholds
- Active and reactive current injection/absorption settings during a fault
- Number of in-service inverters which can be adjusted before and during a simulation run
- Other parameters such as PI gains for inner/outer current/voltage control loops (including PLL, DC link current and voltage control, and any other control loops which can have an impact on system performance)

E. Model Documentation

At a minimum, the EMT model document shall include the following:

1. The specific equipment model(s) for which the provided document is valid

[14] Only those error/status codes which translate into a distinct electrical system response at the low voltage terminals of the unit, for example, normal, fault, stop, low or high voltage ride-through activation, unstable mode identification

2. Detailed description of all control schemes that respond to voltage or frequency disturbances on the system. These include but not limited to:
    a. Voltage and frequency control
    b. Power factor and/or reactive power control
    c. Priority modes and controls including description of voltage and frequency ride-through characteristics such as activation/deactivation thresholds, control mode during ride through etc.
    d. Protection schemes and settings for (but not limited to):
        i. Over-and-under-voltage protection
        ii. Over-and-under-frequency protection
        iii. Inter-trip or runback protection scheme
        iv. Any other relevant protections (e.g. frequency rate of change protections)
3. A table of all user-definable settings and status code outputs, range of acceptable values for each user-modifiable variable and a description of each entry's function. An image of the of model instance corresponding to the table must also be provided.
4. A table of all signals fed to the Power Plant Controller such as feedback from inverter, grid measurements, reference set-points etc., parameter unit (specify the base of all per unit parameters) and a description of each entry's function
5. A table of all trip signals and a description of each entry

Appendix C-1A. Equipment Model Quality Attestation (e-MQA) Form~~s~~

Respective OEM must complete the follow equipment Model Quality Attestation (e-MQA) form

Equipment Model Quality Attestation	
Interconnection Request ID	
Point of Interconnection	
Technology type (Wind, Solar, BESS, Fuel Cell etc)	
Equipment Type[1]	
Equipment OEM	
OEM Attester (Name)	
Equipment Model	
Equipment Software version	
Date of Attestation (mm/dd/yyyy)	
Attestation Revision Number	

Please provide any additional comments here including list of changes since last revision.

Attester Signature

I hereby certify that, to the best of my knowledge, the equipment-level Electromagnetic Transient (EMT) model provided in support of Interconnection Request _____________ has been parametrized to be site specific and meets the requirements listed in Appendix ~~X~~C

[1] Examples of equipment include, but are not limited to, the following: ~~main power transformers, generator step-up transformer,~~ inverter models, plant-level controllers, dynamic ~~or static~~ reactive power devices, HVDC and any other applicable equipment

Appendix C-1B Plant-level Model Quality Attestation (p-MQA) Form

The Interconnection Customer (IC) must complete the following plant-level Model Quality Attestation (p-MQA) form

Plant-level Model Quality Attestation			
Interconnection Request ID			
Technology type (Wind, Solar, BESS, Fuel Cell etc)			
Point of Interconnection (POI)			
SCR at POI[2]			
IC Attester (Name)			
Date of Attestation (mm/dd/yyyy)			
Attestation Revision Number			
Equipment OEMs	Equipment Type[3]	Equipment Model	Hardware Firmware version

Please provide any additional comments here including list of changes since last revision.

Attester Signature

I hereby certify that, to the best of my knowledge, the plant-level Electromagnetic Transient (EMT) model provided in support of Interconnection Request _____________ has been parametrized to be site specific and meets the requirements listed in Appendix ~~X~~C

[2] If POI SCR is unknown at the time of model submission, it is recommended to parametrize to a POI level SCR of 3 and X/R of 10 as an approximate representation of a weak system. If studies show a SCR lower than 3, additional model tuning may be required

[3] Examples of equipment include, but are not limited to, the following: gen-tie line, main power transformers, generator step-up transformer, inverter models, plant-level controllers, dynamic or static reactive power devices, HVDC and any other applicable equipment

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: January 25, 2024

RE: Proposed Revisions to the Forward Reserve Market (FRM) Rules

At the February 1, 2024 Participants Committee meeting, you will be asked to consider Tariff revisions to modify the Forward Reserve Offer Cap and to delay the publication of the Forward Reserve Auction Offer data. At its January 9-11, 2024 meeting, the Markets Committee considered and voted to recommend that the Participants Committee support an alternative Participant-sponsored proposal to the ISO's proposed revisions.

This memorandum provides an overview of the proposed revisions to the FRM rules and the associated stakeholder review process to date, including material developments since the Markets Committee considered and took action on this item.

Included with this memorandum are the following materials:

- Attachment A: ISO-NE's memorandum (dated January 25, 2024)
- Attachment B: LS Power's January 2024 PowerPoint presentation
- Attachment C: The Markets Committee-Recommended Proposed Tariff Redlines

BACKGROUND & OVERVIEW OF THE FRM REVISIONS

By way of brief background, through the FRM's auctions conducted for the summer and winter reserve periods, the ISO enters into forward obligations with resources to provide reserve capacity in Real-Time. In its *Spring 2023 Quarterly Markets Report*, the ISO's Internal Market Monitor (IMM) emphasized that the Forward Reserve Offer Cap is an important safeguard to limit the exercise of market power in those FRM auctions.[1] That IMM report concluded that the "current offer cap of $9,000/MW-month significantly overstate[d] a reasonable upper bound on competitive offers" and that the IMM's analysis indicated that a revised (lower) cap would constitute a "more reasonable reflection of the upper bound of competitive offers."[2] Moreover, the IMM expressed "concern[ ] that the publication of auction offer data may provide strategic

[1] Internal Market Monitor, ISO New England Inc., *Spring 2023 Quarterly Markets Report*, at 43 (Aug. 1, 2023), https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf at 47.

[2] *Id.*

information to participants in the auctions" due to the frequency of the structurally-uncompetitive auctions and elevated pricing in the summer 2023 auction.[3]

Given this assessment with respect to the existing FRM rules, the ISO developed Tariff revisions to address the IMM's stated concerns. In the proposal considered and voted on by the Markets Committee, the ISO proposed to: (1) revise the definition of "Forward Reserve Offer Cap" by lowering the offer cap from $9,000/MW-month to $6,400/MW-month; and (2) add Tariff language stating that it will publish the Forward Reserve Auction Offer data one year after the FRA offer effective month.

NEPOOL MARKETS COMMITTEE CONSIDERATION

Since its October 2023 meeting, the Markets Committee reviewed and evaluated the ISO's proposal to modify certain of the FRM Tariff provisions. At its January 9, 2024 meeting, the Markets Committee voted on the ISO's proposal and one amendment to that proposal, which was offered by LS Power, through its Lead Market Participant, Jericho Power, LLC. The LS Power amendment considered by the Markets Committee modified the ISO's proposal by increasing the revised FRM offer cap from $6,400/MW-month to $7,200/MW-month.[4] That amendment passed at the Markets Committee, with a 79.09% Vote in favor.

The Markets Committee then considered and recommended for Participants Committee support a once-amended main motion, with a 66.6% Vote in favor,[5] referred here as the MC-Recommended FRM Proposal and described below. The ISO's un-amended proposal also was voted on by the Markets Committee but failed to achieve Committee support, with a 49.95% Vote in favor.[6]

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[3] *Id.* at 52.

[4] Attachment B at 10; Attachment C. Note that the Markets Committee reviewed various Forward Reserve Offer Cap values, as LS Power presented. Attachment B at 8–9 (explaining how different adjustment to inputs could produce a higher Forward Reserve Offer Cap than ISO-NE's proposed number at the January Markets Committee meeting). Notably, the MC-Recommended FRM Proposal *does not* propose any modification to the ISO's proposal to delay publishing the Forward Reserve Auction Offer data.

[5] The individual Sector votes at the Markets Committee on the once-amended main motion were as follows: Generation – 16.7% in favor, 0% opposed, 1 abstention; Transmission – 0% in favor, 16.7% opposed, 3 abstentions; Supplier – 16.7% in favor, 0% opposed, 7 abstentions; Publicly Owned Entity – 16.7% in favor, 0% opposed, 22 abstentions; Alternative Resources – 16.5% in favor, 0% opposed, 3 abstentions; and End User – 0% in favor, 16.7% opposed, 0 abstentions.

[6] The individual Sector votes on ISO's unamended proposal were as follows: Generation – 0% in favor, 16.7% opposed, 1 abstention; Transmission – 16.7% in favor, 0% opposed, 0 abstentions; Supplier – 12.53% in favor, 4.18% opposed, 4 abstentions; Publicly Owned Entity – 1.67% in favor, 15.03% opposed, 19 abstentions; Alternative Resources – 2.36% in favor, 14.14% opposed, 3 abstentions; and End User – 16.7% in favor, 0% opposed, 0 abstentions.

DEVELOPMENTS SINCE THE MARKETS COMMITTEE JAN 9, 2024 VOTES

Following the Markets Committee's consideration and votes, the ISO continued to evaluate its proposal as well as the alternative supported by the Markets Committee, taking into account various stakeholder feedback received. As a result of that further evaluation, the ISO is now proposing a revised Forward Reserve Offer Cap value of $7,100/MW-month (rather than its earlier proposal of $6,400/MW-mo.).[7] In addition to the movement on the ISO's end, it is our understanding that LS Power, the Participant-sponsor of the MC-Recommended Proposal, has indicated that it too supports the ISO's revised FRM Offer Cap of $7,100/MW-month.

PROCESS FOR PARTICIPANTS COMMITTEE ACTION

Consistent with past practice and procedure, the Participants Committee will begin its consideration of this matter with the MC-Recommended Proposal. However, in light of the significant developments described above and in more detail within the accompanying materials, the Participants Committee will likely be asked, absent any objection, to amend and incorporate into the main motion the newly proposed Forward Reserve Offer Cap value of $7,100/MW-month in place of the previously recommended $7,200/MW-month value.

The following form of resolution may be used to initiate Participants Committee consideration at its February 1 meeting:

> RESOLVED, that the Participants Committee supports the revisions to Tariff Sections I.2.2 and III.9.3, as recommended by the Markets Committee at its January 9, 2024 meeting, and 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.

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[7] Attachment A.

ISO new england

memo

To: NEPOOL Participants Committee Members and Alternates

From: ISO New England

Date: January 25, 2024

Subject: Forward Reserve Market Offer Cap – ISO Supported Amendment

Between October 2023 and January 2024, the ISO presented to the NEPOOL Markets Committee (MC) an updated Forward Reserve Market (FRM) Offer Cap.[1] Over the course of the MC discussions, the ISO refined its modeling and the resulting proposal. Following the January MC, the ISO has further considered stakeholder feedback regarding the representative asset parameters and performed further analysis to validate a reasonable alternative for deriving the asset parameters. As a result, the ISO now recommends incorporating a broader set of assets for purposes of modeling a representative asset and its estimated foregone energy and reserve revenues. With this memorandum, the ISO explains its support for a FRM Offer Cap value of $7,100/MW-month. The remainder of this memo explains the limited change in the ISO's analysis that supports the $7,100/MW-month value and the rationale.

The intent of the FRM Offer Cap is to reflect the upper bound of the estimated costs for a representative, installed unit to assume an obligation to provide Forward Reserves.[2] Updating the cap, as has been proposed by the ISO, better reflects the expected costs and revenues under current market conditions and, in practical terms, it reduces the upper bound of prices that Market Participants may include in their FRM offers, potentially reducing total FRM costs. Specifically with this updated proposal, the ISO would reduce the FRM Offer Cap from the currently effective $9,000/MW-month to $7,100/MW-month.

As discussed at the MC, to develop the estimates of foregone energy and reserve revenues, the ISO derived reasonable cost parameters for a representative asset (*i.e.*, its heat rate, capacity, startup costs, variable O&M costs, and emissions rates). Broadly, the ISO determined that natural gas units located in Connecticut provided the best basis for deriving these parameters based on the relevant asset characteristics and estimated costs.[3]

[1] This FRM Offer Cap update was undertaken at the recommendation of the Internal Market Monitor ("IMM"), in light of concerns over FRM structural competitiveness and recently elevated offer prices identified in the IMM's Spring 2023 Quarterly Markets Report. *See* ISO New England Internal Market Monitor, *Spring 2023 Quarterly Markets Report*, at 39–52 (Aug. 1, 2023) ("IMM Spring 2023 Quarterly Markets Report"), *available at* https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf.

[2] IMM Spring 2023 Quarterly Markets Report at 9, 44, and 48.

[3] Connecticut was chosen as the representative asset's location because it was identified as the Load Zone with the vast majority of FRM and FRM-eligible units in New England.

Previously, the ISO had performed its sampling to derive the asset parameters considering only assets that were *assigned forward reserve obligations during the two most recent forward reserve procurement periods*. The limited change the ISO now has incorporated in its updated analysis instead derives the asset parameters from all assets that are *eligible to participate in the FRM*.[4] In each case, the ISO's sampling method to derive reasonable asset cost and operating parameters is otherwise equivalent. The ISO proposes no changes to the other directly estimated cost components or to the structure for calculating the total cap value.

The rationale for considering all FRM-eligible units, instead of limiting consideration to assets recently participating in the FRM, is to avoid potentially understating the competitive population of existing units available to participate in the FRM. The concern otherwise is that the offer cap might be below some participating assets' — or potential competitive entrants' — actual cost of assuming a forward reserve obligation. This administrative constraint could limit auction participation and contestability, exacerbate concerns with structural competitiveness, and potentially result in the FRM auctions not procuring supply adequate to meet the requirements.

This alternative proposes a decrease from the FRM's current value of $9,000/MW-month. The direction of the change and magnitude aligns with the recommendation of the IMM.[5] Importantly, the FRM Offer Cap update has incorporated updated expectations for the number of Capacity Scarcity Condition hours, with a reduction from 12.8 hours to 5.4 hours, which aligns with the ISO's 2022 analysis for the MC.[6]

In summary, the ISO recommends the revised $7,100/MW-month FRM Offer Cap value in light of the above-described considerations, and based on the opportunity it has had to consider stakeholder feedback and conduct further analysis following the January MC.

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[4] Specifically, this includes all natural gas units located in Connecticut capable of providing reserves within 30 minutes or less of being called upon.

[5] IMM Spring 2023 Quarterly Markets Report at 9, 49, and 51.

[6] *See generally* ISO New England Memorandum to NEPOOL Markets Committee, *Performance of Capacity Resources and Pay for Performance* (Sept. 7, 2022) (explaining conditions leading to fewer Capacity Scarcity Conditions), *available at* https://www.iso-ne.com/static-assets/documents/2022/09/a03_mc_2022_09_13-14_performance_of_capacity_resources_memo_rev1.pdf.

FRM Offer Cap Amendment

Ben Griffiths | Markets Committee | January 9-11 2024

About LS Power

LS Power is a development, investment and operating company focused on the North American power and energy infrastructure sector

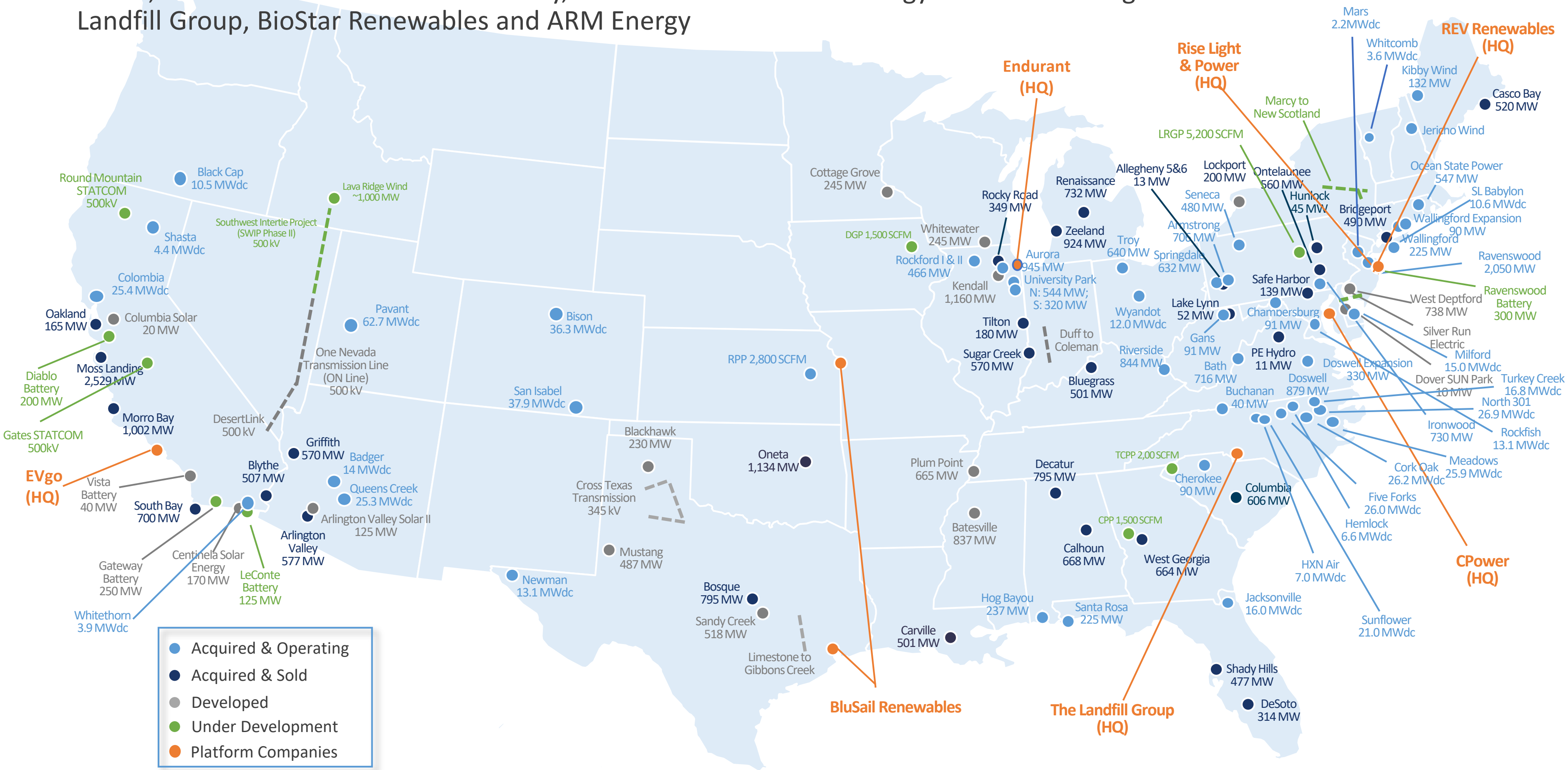
- Founded in 1990, LS Power has 280 employees across its principal and affiliate offices in New York, New Jersey, Missouri, Texas and California
- LS Power is at the leading edge of the industry's transition to low-carbon energy by commercializing new technologies and developing new markets.
  - **Utility-scale power projects across multiple fuel and technology types**, such as pumped storage hydro, wind, solar and natural gas-fired generation
  - **Battery energy storage**, market-leading utility-scale solutions that complement weather dependent renewables like wind and solar energy
  - **High voltage electric transmission infrastructure**, which is key to increasing grid reliability and efficiency, as well as carrying renewable energy from remote locations to population centers
  - **EVgo, the nation's largest public fast charging platform for electric vehicles** and first platform to be 100% powered by renewable energy
  - **CPower Energy Management**, the largest demand response provider in the country that is dedicated solely to the commercial and industrial sector
- Since inception, LS Power has developed, constructed, managed and acquired competitive power generation and transmission infrastructure, for which **we have raised over $47 billion in debt and equity financing.**
  - **Developed over 11,000 MW of power generation** (both conventional and renewable) across the United States
  - **Acquired over 34,000 MW of power generation assets** (both conventional and renewable)
  - **Developed over 660 miles of high voltage transmission**, with ~400 miles of additional transmission under development

Utilize deep industry expertise as owner/operator

LS Power Project Portfolio

Extensive development/operating experience across multiple markets and technologies

- With over $47 billion in equity and debt raised, LS Power has developed and acquired 120 Power Generation projects (renewable and conventional generation), 7 Transmission projects, and 5 Battery Energy Storage projects
- LS Power's Energy Transition Platforms includes CPower Energy Management, Endurant Energy, EVgo, Rise Light & Power, and REV Renewables. Additionally, LS Power has Waste to Energy initiatives through its Joint Ventures with the Landfill Group, BioStar Renewables and ARM Energy



LS POWER

Position Summary

- Setting a reasonable FRM offer cap is essential to a well functioning market
  - A too low offer cap may discourage resources from participating in FRM, which would increase the likelihood of the market clearing at its cap
- LS agrees with the IMM's suggestion that the current $9,000/MW-mo offer cap is too high, largely because PfP events are a lot less common than region anticipated in 2016
- LS also agrees that the FRM offer cap should be "based on an expectation of a reasonable upper-limit on the bid-in cost for a hypothetical forward reserve resource" [1]
- The ISO's estimation approach does *not* reflect a "reasonable upper-limit" on costs
  - Worse, changes made by ISO-NE in December lead to erroneous results
- Correcting flaws in the ISO analysis yields reasonable FRM Offer Cap estimates between $7,100 and $8,200/MW-month, compared to the ISO's final $6,400 value
- **Based on feedback, LS is revising its amendment and is now proposing to set the FRM Offer Cap at $7,200/MW-month**

1. 1. IMM 2023 Spring Quarterly Markets Report at 44; see also ER16-921 Filing Letter at 8: "the FRM offer cap will be **set reflecting the high end of the ISO's estimate of costs** for a representative, existing resource to assume an obligation to provide forward reserves"

ISO-NE's Foregone E&AS Revenue Estimates are in Error

- ISO-NE relies on a dispatch model (derived from the 2020 CONE analysis) to estimate foregone revenues from FRM participation
  - The dispatch model relies on certain unit parameters (e.g. Heat-rate, VOM, Start-up costs) to generate offers, dispatch profiles, and the foregone revenue estimates
- In December, ISO noted that it selected its heat-rate by estimating the 25th percentile of "all natural gas units to which forward reserve obligations have been assigned during the two most recent forward reserve procurement periods" (Dec MC presentation at Slide 7)
  - In effect, this is a conditional probability: the ISO takes its percentile having already filtered out all the non-FRM gas resources
- This means that **one-quarter of gas units that actually participate on a day-to-day basis** in the FRM would have higher foregone E&AS revenue than the ISO model indicates.
  - ISO acknowledges this: "Using parameters for actual assets, the dispatch model does yield some instances of … revenue higher than the proposed $2,070/MW-month" [1]
- By throwing out the costs of a quarter of the most efficient units it *actually relies on for the FRM*, units plausibly setting price in the FRM, the ISO is creating an unreasonable downward bias on the offer cap

1. ISO-NE Jan MC Presentation at 5

LS POWER

How to Remedy? Rely on ISO's original heat-rate estimate

- The ISO *could have done* one of two things to create un-biased estimates
  1. Take the minimum (or near minimum) heat-rate of units that were *actually designated* for FRM, instead of taking the 25th percentile
  2. Take the 25th percentile heat-rate of *all FRM eligible resources*, irrespective of their participation in the FRM market
- The ISO's *original* approach to estimating parameters for a reference unit **did not** rely on conditional probabilities, but instead picked a heat-rate based on a "representative, installed unit….representing the upper-end of opportunity costs….for relatively-efficient natural gas units" (Oct MC presentation at 8)
  – ISO's original approach aligned with IMM's selection of a "actual, relatively fuel-efficient, dual-fuel peaking resources in New England" (IMM Spring 2023 Report at 50)
- LS proposes to rely on the ISO's original, un-biased 9,575 Btu/kWh heat-rate estimate
  – Making on this one change to the ISO's dispatch model [1] increases the foregone E&AS revenue estimate to **$2,579/MW-mo** (a 25% increase over the ISO's $2,070)

1. https://www.iso-ne.com/static-assets/documents/100006/a07_mc_2023_12_12_14_frm_offer_cap_iso_dispatch_model.xlsx

LS POWER

Other changes would push the offer cap even higher

- ISO is relying on downward-biased estimates for VOM and start-up costs, too
  - LS is not proposing to account for these issues because no public estimates were released, but use of unbiased estimates would result in higher foregone revenues
- LS previously noted that the ISO's assumption that the indicative FRM resource must be located in Connecticut (which has a 5% tax on natural gas) is unreasonable. There are quick-start units, such as the Medway peakers, that are located outside of that state
  - Assuming the unit is located outside of CT, all else equal, yields an E&AS revenue estimate of **$2,524/MW-mo**
  - Pairing this location assumption with the un-biased HR assumption would increase the E&AS revenue to **$3,047/MW-mo**
- LS previously suggested that ISO should treat energy and reserve revenues as uncorrelated (as the IMM did in its revenue estimates)
  - IMM estimated E&AS revenues at **$3,233/MW-mo** [1]
- LS previously showed that forward-adjustments to historical prices may increase cap, too

1. IMM 2023 Spring Quarterly Markets Report at 50

Reasonable parametrizations suggest offer cap should fall in range of $7,100 and $8,200/MW-month

Updated Offer Cap ($/MW-Month)							
Item Number	Item Description	IMM E&AS Value	Lower HR + Unit Located outside CT	Lower HR	Unit Not Located in CT	ISO Value (Jan MC)	Item Units
1	**Foregone Revenue**						
1.1	Number of Reserve Shortage Hours	5.4	5.4	6.4	7.4	5.4	hours/year
1.2	Reserve Shortage Hour Reserve Revenue	1,990	1,990	1,990	1,990	1,990	$/MW-month
1.2(a)	*Minimum Total Reserve Req. Shortage Revenue*	*1,350*	*1,350*	*1,351*	*1,352*	*1,350*	$/MW-month
1.2(b)	*Ten-Minute Reserve Req. Shortage Revenue*	*640*	*640*	*640*	*640*	*640*	$/MW-month
1.3	Energy and Reserve Market Revenue	3,233	3,047	2,579	2,524	2,070	$/MW-month
Item 1 Subtotal	***Foregone Revenue Subtotal***	***5,223***	***5,037***	***4,569***	***4,514***	***4,060***	***$/MW-month***
2	**Penalties**						
2.1	Failure to Reserve (32.12%)*	1,678	1,618	1,468	1,450	1,304	$/MW-month
2.2	Failure to Activate (5.17%)**	270	260	236	233	210	$/MW-month
Item 2 Subtotal	***Penalty Subtotal***	***1,948***	***1,878***	***1,704***	***1,683***	***1,514***	***$/MW-month***
3	**Supplier Risk Premium** ([Item 1 subtotal + Item 2 subtotal]*15%)	***1076***	***1037***	***941***	***930***	***836***	$/MW-month
4	Total Offer Cap (Item 1 + Item 2 + Item 3)	8,246	7,952	7,214	7,127	6,410	$/MW-month
Item 4 Rounded	**Updated Forward Reserve Offer Cap**	8,200	8,000	7,200	7,100	6,400	**$/MW-month**

LS POWER

Amendment

- LS considers reasonable its suggestion that the FRM offer cap be set at $8,200 MW-mo
  - This cap estimate is based on IMM-derived values, after all
- However, in the spirit of compromise, LS proposes to revise its FRM offer cap amendment to reflect a reasonable lower bound of its four analytical different scenarios: **$7,200/MW-month**
- **Redlines are simple: a single value is changed**

Tariff Section	Description of Change	Reason for Change
I.2.2	Modify definition of Forward Reserve Offer Cap to "is ~~$9,000~~$7,200/megawatt-month."	Update offer cap

LS POWER

Questions?

Appendix: Additional Materials from December MC

Presented at November MC

Energy & (Non-Scarcity) Ancillary Service Revenues

- 50% difference in EAS revenue from IMM & ISO using conceptually similar approaches
  - ISO-NE estimates foregone E&AS revenues at **$2,170/MW-mo**
    - Estimate relies on the "CONE reset" dispatch models, several years of historic pricing data, and unit parameters based on a "more efficient unit" [1]
  - IMM estimated the same foregone revenues at **$3,233/MW-mo**; nearly 50% higher!
    - Energy estimated at $2,091/MW-mo based on the 90% percentile of observed summer energy revenues, over six summer seasons for a relatively new dual-fuel peaking resource [2]
    - Non-Scarcity Reserve Revenues estimated at $1,142/MW-mo based on 90% percentile value of available reserve revenue on observed over four summer seasons [2]
  - The difference in these two estimates, **$1,063/MW-mo**, is larger than the *entire* 15% risk premium offered by the ISO ($836/MW-mo)!
- [**Dec Update**: ISO-NE's estimate is now $2,070/MW-mo, $100 lower than previously estimated, which results in even larger differences in revenue estimates]

1. November MC presentation, Slides 20-24; Oct MC presentation, Slide 8 suggests HR of 9,575 BTU/kWh
2. IMM 2023 Spring Quarterly Markets Report at 50

LS POWER

Concern with ISO's current approach to calculating E&AS revenues

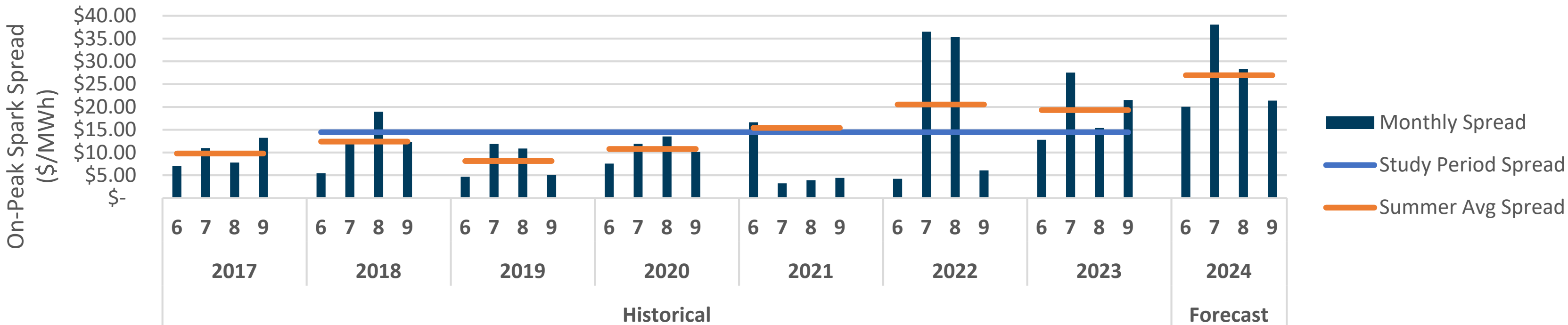
- The ISO is currently relying on a "lookback" approach to computing foregone E&AS revenues, based on observed pricing data from the 2018-2023 period
  - The IMM, using a conceptually similar approach found revenues would be 50% higher
- Last month, LS expressed concern that the ISO's approach to computing E&AS revenues will fail to capture salient differences between **(a)** past market performance and **(b)** current expectations for the upcoming summer seasons
- The ISO retorted that their historic approach "captures the high costs of summer 2022" and that "July 2022 and August 2022 prices exceed current futures prices"
  - LS readily agrees that current power forwards are *lower* than those in 2022
- But, foregone revenues aren't a function of the *absolute price* of commodities. Instead, revenues are based on *energy margin*, the spread between prices for power and gas
  - As shown on next slide, Summer 2024 has spreads 87% higher than the 2018-2023 average and 31% higher than Summer 2022.
- **Historic prices used by ISO are still *not* representative of future market conditions**

LS POWER

Presented at November MC

Forwards suggest higher spark spreads in Summer 2024

- FRM will likely be sunset starting March 2025, so any changes to the cap should reflect a reasonable upper-limit on offers for the June 2024 – February 2025 timeframe
- Historic prices used by ISO are *not* representative of future market conditions
  - Using unadjusted prices will lead to downward bias in revenue estimates and FRM cap because historical period had lower margin than forwards suggest for Summer 2024
- Chart below estimates on-peak spark spreads for each month in study period as well as based on current forward prices (as of 11/3/2023)
  - Recall, Spark Spread = [Avg On-Peak LMP] – [9.575 MMBtu/MWh HR] x [Avg Algonquin Price]
    - Historical sparks range from $4 to $36/MWh (avg = $14.44/MWh)
    - Forward sparks range from $20 to $38/MWh (avg = $26.96/MWh) → **87% higher**



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Lack of correlation between reserves & energy revenues mean that values should be treated as independent

Presented at November MC

- While reserve prices and energy prices are correlated on an hour to hour basis, there is no real correlation between energy revenues and reserve revenues on a monthly basis
  - E.g., a generally low margin month from an energy perspective might have high reserve revenues due to the system tightening (but not hitting scarcity)
- A review of historical summer data from June 2017 to July 2023 shows the lack of relationship between energy and reserve prices. The correlation between
  - the (a) number of hours with positive reserve prices and (b) average DA LMP is -0.28
  - The (a) average combined TMNSR+TMOR price and (b) average DA LMP is +0.22
- As regressions, same variables yield R-squared value of 0.009 and 0.08 respectively
- **Separate estimates for energy and ancillaries, like IMM proposed, better reflects the lack of relationship**

LS POWER

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $7,200~~9,000~~/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

III.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy Forward Reserve requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 System Forward Reserve Requirements.

The Forward Reserve requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum forward ten-minute reserve requirement to be purchased.

(ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time

Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

(iii) The minimum forward ten-minute reserve requirement plus one half of the second contingency supply loss will be specified as the minimum forward total reserve requirement to be purchased.

(iv) The minimum forward total reserve requirement described in subsection (iii) will be increased by an amount of Replacement Reserve as specified in ISO New England Operating Procedure No. 8.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Zonal Forward Reserve Requirements.

Zonal Forward Reserve requirements will be established for each Reserve Zone. The zonal Forward Reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The zonal Forward Reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the zonal Forward Reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the zonal requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System
Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource.

For the addition of a new Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The zonal Forward Reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted. Notwithstanding the publication timeline specified in Section 3(a) of the ISO New England Information Policy, the ISO shall publish Forward Reserve Auction Offer data on the first day of the twelfth calendar month following the month during which the applicable supply offers were in effect, and not prior thereto.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone Forward Reserve requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

ISO new england

memo

To: NEPOOL Participants Committee

From: ISO New England

Date: January 29, 2024

Subject: Revised Analysis for Calculating an Updated Forward Reserve Offer Cap

This memo describes ISO New England's revised analysis to calculate the updated Forward Reserve Offer Cap.[1]

The ISO proposes an updated Forward Reserve Offer Cap ("offer cap") of $7,100/megawatt-month. As is currently the case, the Forward Reserve Market (FRM) offer cap will apply to each seasonal auction (summer and winter), location, and forward reserve product (Thirty-Minute Operating Reserve (TMOR) and Ten-Minute Non-Spinning Reserve (TMNSR)). Table 1 lists each component of the updated offer cap and their proposed values. The remainder of this memo describes the derivation of these values.

Table 1 – Proposed Forward Reserve Offer Cap Value and Components

Updated Offer Cap ($/MW-Month)			
Item Number	Item Description	Item Value	Item Units
1	**Foregone Revenue**		
1.1	Number of Reserve Shortage Hours	5.4	hours/year
1.2	Reserve Shortage Hour Reserve Revenue	1,990	$/MW-month
1.2(a)	*Minimum Total Reserve Req. Shortage Revenue*	*1,350*	$/MW-month
1.2(b)	*Ten-Minute Reserve Req. Shortage Revenue*	*640*	$/MW-month
1.3	Energy and Reserve Market Revenue	2,530	$/MW-month
Item 1 Subtotal	***Foregone Revenue Subtotal***	***4,520***	$/MW-month
2	**Penalties**		
2.1	Failure to Reserve (Item 1 Subtotal*32.12%)	1,452	$/MW-month
2.2	Failure to Activate (Item 1 Subtotal*5.17%)	233	$/MW-month
Item 2 Subtotal	***Penalty Subtotal***	***1,685***	$/MW-month
3	**Supplier Risk Premium** ([Item 1 subtotal + Item 2 subtotal]*15%)	***931***	$/MW-month
4	Total Offer Cap (Item 1 + Item 2 + Item 3)	7,136	$/MW-month
Item 4 Rounded	**Updated Forward Reserve Offer Cap**	**7,100**	$/MW-month

[1] ISO-NE previously proposed updating the offer cap to $6,400/MW-month, but has revised its analysis as explained in a January 25, 2024 memo to the Participants Committee. The previous version of this technical memo is available at: https://www.iso-ne.com/static-assets/documents/100006/a07_mc_2023_12_12_14_frm_offer_cap_iso_memo.pdf.

Approach

In arriving at the updated value of the offer cap, the ISO adhered to the method and objectives used to derive the current value of the offer cap (effective since 2016),[2] but employed updated models and incorporated updated data to reflect present information about market and system conditions. The method to calculate the offer cap aims to estimate a reasonable upper end of a supplier's direct costs and opportunity costs to meet a forward reserve obligation with a representative, installed unit.

Seasonal Consideration

Calculation of the updated offer cap primarily used historical data from months comprising the summer forward reserve procurement period (*i.e.*, June, July, August, and September). Summer-period estimates of suppliers' costs generally exceed winter-period estimates. Thus, the analysis focused on summer-period cost estimates to establish a single offer cap value that is an upper-end estimate of FRM offers for both seasons.

Representative Asset

Using historical observations of the assets eligible to fulfill forward reserve obligations, the ISO identified as the representative asset natural gas units with a heat rate of 9,990 BTU per kWh.[3] This selection of a relatively efficient representative asset aims to capture an upper end of foregone energy and reserve market revenues. This choice of representative asset departs from the assumptions used in the last offer cap update (which modeled a representative fast-start oil resource)[4] in order to reflect more current asset participation in the FRM. This also aligns with the representative technology used in the IMM's 2023 Spring Quarterly Markets Report.[5] The representative unit is modeled as operating in Connecticut (thus, Connecticut historical price data and a Connecticut fuel tax is used).[6] Other parameters characterizing the representative asset — specifically, the asset capacity, startup cost, variable operations and maintenance

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[2] *See ISO New England Inc. and New England Power Pool*, Revisions to Forward Reserve Market Offer Cap and Elimination of Price Netting, Docket No. ER16-921 (2016) ("2016 Offer Cap Filing"), https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf.

[3] 9,990 BTU per kWh is the 25th percentile heat rate of all natural gas-capable units eligible to fulfill forward reserve obligations. Section III.9.5.2 of the ISO New England Tariff sets forth forward reserve resource eligibility requirements. For instance, off-line generators must be fast-start, and on-line generators must be capable of responding to dispatch signals within 10-minutes or 30-minutes, in accordance with the reserve product for which a forward reserve obligation is secured.

[4] 2016 Offer Cap Filing, Testimony of at Christopher A. Parent on behalf of ISO New England, Inc., 24:1-4.

[5] *See* ISO New England Internal Market Monitor, 2023 Spring Quarterly Markets Report, p.50 (Aug. 1, 2023), https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf.

[6] The representative asset location is Connecticut because establishing the dispatch model parameters based on units located in Connecticut yields the greatest estimated foregone energy and reserve revenue. This is consistent with efforts to capture the upper end of foregone energy and reserve market revenues. Additionally, Connecticut was chosen as the representative asset's location because it is the Load Zone with the greatest proportion of New England's FRM and FRM-eligible units.

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cost (VO&M), CO_2 emissions intensity, and SO_2 emissions intensity — are based on the parameters of assets with heat rates near the representative heat rate.[7]

Energy and operating reserve market revenue foregone as a result of participating in the FRM depends on the efficiency of the unit designated to fulfill forward reserve obligations. More efficient assets face more foregone energy and reserve revenue because efficient assets are more likely to have lower-cost offers and be in-merit more frequently. In short, assets with lower heat rates generally face higher foregone revenue. However, foregone energy and reserve market revenue also depends on an asset's startup cost (and, to a lesser extent, variable O&M costs and emissions costs).

Data periods

The Appendix of this memo describes the time periods of datasets used to derive the updated offer cap. Data periods were selected to capture up-to-date information about the ISO system and markets. For instance, selected data periods reflect pay-for-performance implementation and system reliability improvements. When feasible, publicly-available datasets were used, and links to such datasets are cited where relevant throughout this memo.

Components of the Offer Cap

1. Foregone Revenue

The first component of the offer cap is *Foregone Revenue*. This is the estimated energy and real-time operating reserve market revenue foregone as a result of fulfilling forward reserve obligations. This value consists of two sub-components:

- *Reserve Shortage Hour Reserve Revenue* (Item 1.2), which is reserve revenue earned during hours of operating reserve shortage (those hours identified in Item 1.1), and

- *Energy and Reserve Market Revenue* (Item 1.3), which is the combination of energy and operating reserve revenue earned during hours outside of an operating reserve shortage.

1.1 Number of Reserve Shortage Hours

Reserve Shortage Hours is the estimated number of hours during which the system cannot meet system-wide operating reserve requirements. Two categories of reserve shortage hours comprise the quantity Reserve Shortage Hours: peak load reserve shortage hours and transient reserve shortage hours.[8] Since

[7] Heat rates "near" the representative heat rate are those within 1% of the representative heat rate. The representative asset's capacity is the *average* capacity of assets with heat rates near the representative heat rate. The representative asset's startup cost, variable O&M cost, CO_2 emissions intensity, and SO_2 emissions intensity are the *25th percentile* parameters of assets with heat rates near the representative heat rate.
[8] The total number of expected annual reserve shortage hours also includes winter reserve shortage hours, which capture the risks of fuel supply constraints during periods of cold weather. However, since the FRM offer cap analysis focuses on summer period estimates, this analysis does not include estimates of winter reserve shortage hours.

these values are estimated or occur over annual periods, we used a weighting method to determine summer reserve shortage hours.

The proposed cap relies upon an estimated **5.4 reserve shortage hours**. Each step of determining the number of reserve shortage hours is explained below.

Peak Load Reserve Shortage Hours

Peak load reserve shortage hours are the GE MARS-estimated hours of system-wide operating reserve shortage.[9] To determine peak load reserve shortage hours, we calculated the 95th percentile of estimated annual hours of system operating reserve deficiency at the average, actual level of capacity over the four Capacity Commitment Periods (CCPs) spanning 2021-22 through 2024-25. The actual level of capacity for each CCP is measured as the quantity of CSO MW in excess of the Net Installed Capacity Requirement (Net ICR) for each period. We consider the expected reserve shortage hours associated with the average, actual level of capacity experienced in recent years as reflective of current market and system conditions. The four CCPs used capture recent system conditions as well as expected conditions for the 2024–2025 timeframe encompassing upcoming forward reserve delivery periods.

Table 2 – Estimated Number of Peak Load Reserve Shortage Hours

Capacity Commitment Period (CCP)	Actual level of capacity relative to Net ICR (CSO MW – Net ICR MW)	Estimate 95th Percentile of Operating Reserve Shortage Hours at Net ICR+1600MW	Estimate 95th Percentile of Operating Reserve Shortage Hours at Net ICR+2000MW
2021-2022	1796.99	7.8	6.7
2022-2023	1838.53	6.3	5.1
2023-2024	1648.65	8.3	5.8
2024-2025	1557.14	5.5	4.3
Average	1710.33	7.0	5.5

Table 2 lists the quantity of CSO MW in excess of the Net ICR, the 95th percentile of estimated operating reserve shortage when CSO MW exceed Net ICR by 1600 MW, the 95th percentile of estimated operating reserve shortage when CSO MW exceed Net ICR by 2000 MW, and calculated averages of each column, for the four considered CCPs. A linear interpolation for 1710.33 MW between 7.0 reserve shortage hours estimated at Net ICR plus 1600 MW and 5.5 reserve shortage hours estimated at Net ICR plus 2000 MW yields an expected value of **6.6 peak load reserve shortage hours**.

[9] *See* ISO-NE studies forecasting the expected number of system-wide operating reserve deficiency hours for capacity-resource levels at, below, and above the net ICR: https://www.iso-ne.com/system-planning/system-plans-studies/installed-capacity-requirement/.

The four-CCP average approach is consistent with the "smoothing" approach, and associated rationale, used to determine peak load reserve shortage hours for ORTPs in the 2020 FCM Parameters Update for CCP 2025-26.[10]

Transient Reserve Shortage Hours

Transient reserve shortage events are reserve shortage events that result from operational risks such as under-commitment due to load forecast error or the loss of critical transmission elements. These estimates are not obtained from GE MARS since the operational uncertainties and conditions that drive non-peak load reserve shortage events are not modeled for planning studies that use GE MARS.[11]

To determine the number of transient reserve shortage hours to consider in the offer cap, we use the 95th percentile of transient reserve shortage hours occurring annually between 5/1/2015 and 9/30/2023.

From the publicly-reported data on Reserve Constraint Penalty Factor (RCPF) activations,[12] we identify transient reserve shortage hours using the definition set forth in the July 8, 2020 ISO-NE memo regarding FCA16 Net CONE Parameters.[13] In particular, reserve shortage events are identified as transient according to their causes (*i.e.*, whether they arise from operational risks such as system under-commitment, under-estimating load in the load forecast, or loss of critical transmission elements); durations (transient events are generally of shorter duration); and the load at which they occur (transient events occur at lower load levels than peak load shortage hours).

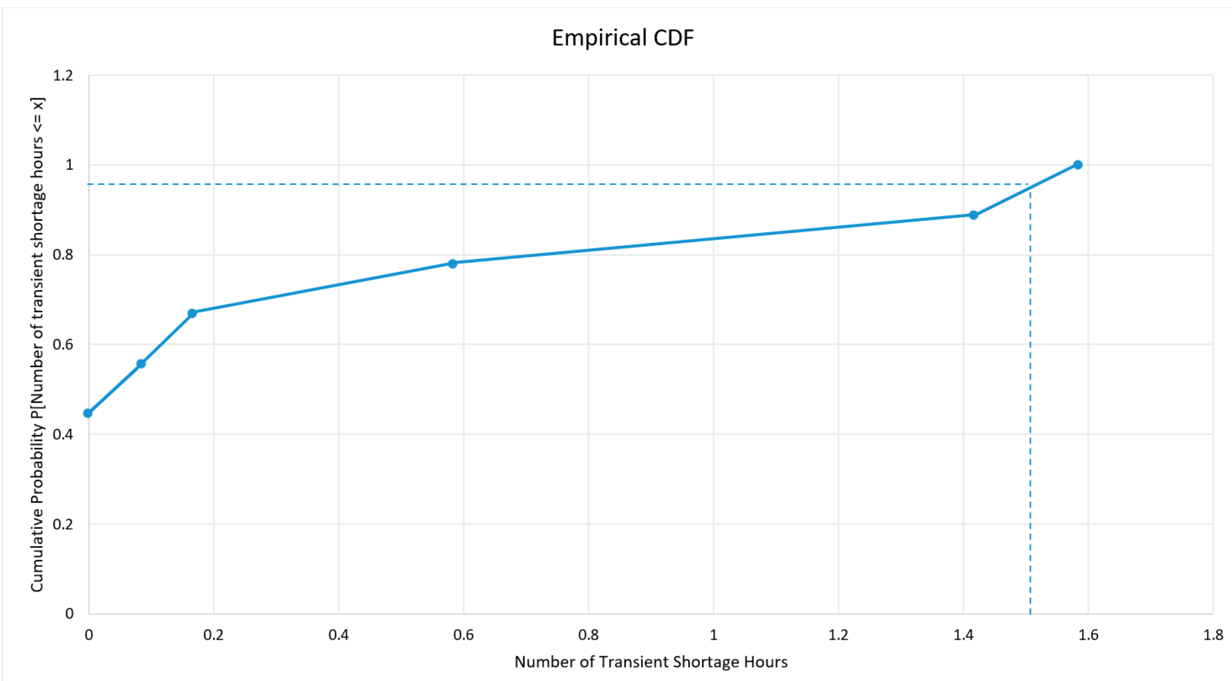
Using the historical annual hours of RCPF activation events identified per the above considerations as *transient* reserve shortage events, we obtain the nine values of historical annual transient reserve shortage hours listed in the table below.

Year	Duration (hours)
2015	1.6
2016	0.1
2017	0.6
2018	0.2
2019	0

[10] See *Expected Capacity Scarcity Condition (CSC) Hours and Capacity Balancing Ratios (BR)* (Oct. 26, 2020) at Slide 11, https://www.iso-ne.com/static-assets/documents/2020/10/a00_iso_presentation_scarcity_hours_and_balancing_ratios.pptx; *Expected Capacity Scarcity Condition Hours and Capacity Balancing Ratios* (Aug. 11, 2020), Slide 10, https://www.iso-ne.com/static-assets/documents/2020/08/a4_b_iso_presentation_expected_scarcity_hours.pptx.
[11] *See* Memo re: Operating Reserve Deficiency Information – Capacity Commitment Period 2024-2025 (Dec. 16, 2020), p.2, https://www.iso-ne.com/static-assets/documents/2020/12/a00_pspc_2020_12_iso_memo_or_def_fca_15.pdf.
[12] https://www.iso-ne.com/static-assets/documents/2017/01/rcpf_activation_data_2006_10_thru_present.zip.
[13] Memo re: FCA16 Net CONE Parameters – Expected Capacity Scarcity Hours and Balancing Ratio (Jul. 8, 2020), https://www.iso-ne.com/static-assets/documents/2020/07/a5_a_iso_memo_scarcity_hours_balancing_ratio.pdf.

2020	0
2021	0
2022	1.4
2023	0

Considering the limited number of observations of annual transient hours, we construct an empirical cumulative distribution function (CDF) to determine a 95th percentile estimate of annual transient reserve shortage hours. The piecewise linear empirical CDF constructed from the observations in the table above is shown in the figure below. The x-axis depicts annual transient reserve shortage hours. The nine observed annual transient reserve shortage hours in the table above define the endpoints of linear intervals on the CDF. The y-axis depicts the cumulative probability of values along the x-axis — that is, the probability of annual transient reserve shortage hours less than or equal to the value on the x-axis. We assume piecewise linearity — that is, the cumulative probability increases linearly between observations. The 95th percentile of annual transient reserve shortage hours is the number of hours (on the x-axis) corresponding to a cumulative probability of 0.95 (on the y-axis). We obtain this value through linear interpolation on the observation interval enclosing 0.95 (shown with dotted lines below).



We obtain a value of **1.5 transient reserve shortage hours**.

Allocation of reserve shortage hours to summer

To determine the summer-period estimates of peak load reserve shortage hours and transient reserve shortage hours, we use a seasonal allocation factor as used in the last offer cap update. We calculate the seasonal allocation factor as the ratio of: (i) the total number of Minimum Total Reserve Requirement and Ten-Minute Reserve Requirement RCPF activation events *in summer* during the period of 5/1/2015 through 9/30/2023 to (ii) the total number of Minimum Total Reserve Requirement and Ten-Minute Reserve Requirement RCPF activation events during this same period. The data used here is from the above-cited RCPF activation report.

We thus allocate **66% of annual reserve shortage hours to summer**.

Summation of Reserve Shortage Hours

Applying the 66% summer allocation factor to the annual peak load reserve shortage hours and transient reserve shortage hours, we obtain **4.4 peak load reserve shortage hours** and **1.0 transient reserve shortage hours for the summer period**. Adding these values yields the **5.4 reserve shortage hours** (Item 1.1) used to calculate the Reserve Shortage Hour Reserve Revenue (Item 1.2).

1.2 Reserve Shortage Hour Reserve Revenue

The Reserve Shortage Hour Reserve Revenue component estimates the total reserve revenue foregone by forward reserve suppliers during system-wide reserve shortage hours. It is the sum of estimated revenue from providing TMOR or TMNSR during hours in which the Minimum Total Reserve Requirement is violated and estimated revenue from providing TMNSR during hours in which the Ten-Minute Reserve Requirement is violated. The use of the sum of these two revenues captures the fact that the price of the TMOR product cascades up into the price of the TMNSR product, since TMNSR contributes toward meeting ten-minute and total reserve requirements. Accordingly, a supplier of the TMNSR product faces higher foregone revenue as a result of forward reserve obligations. The proposed offer cap includes ***$1,990 per MW-month reserve shortage reserve revenue*** (Item 1.2). The calculations of the Minimum Total Reserve Requirement and Ten-Minute Reserve Requirement components of reserve shortage revenue are described next.

1.2(a) Minimum Total Reserve Requirement Shortage Revenue

Revenue during Minimum Total Reserve Requirement shortage hours is the product of the number of Minimum Total Reserve Requirement shortage hours and the Minimum Total Reserve Requirement RCPF of $1,000 per MW-hour.[14] The number of Minimum Total Reserve Requirement shortage hours estimated for summer periods is the product of: (i) total summer reserve shortage hours (Item 1.1), and (ii) the historical relative frequency of Minimum Total Reserve Requirement shortages during summer months. The historical relative frequency of summer Minimum Total Reserve Requirement shortages is the ratio of: (i) the number of five-minute intervals including a Minimum Total Reserve Requirement RCPF activation during summer months to (ii) the total number of five-minute intervals of either a

[14] *See* ISO New England Inc. Transmission, Markets, and Services Tariff ("Tariff"), Section III.2.7A – Calculation of Real-Time Reserve Clearing Prices.

Minimum Total Reserve Requirement or Ten-Minute Reserve Requirement RCPF activation during summer months over the period 6/1/2018 through 9/30/2023.

During this period, 100% of relevant reserve shortage hours featured a Minimum Total Reserve Requirement RCPF activation.

The proposed offer cap uses a value of ***$1,350 per MW-month Minimum Total Reserve Requirement shortage revenue***, which is the result of first, multiplying this 100% frequency, the 5.4 hours of reserve shortage, and the Minimum Total Reserve Requirement RCPF value of $1000 per MW-hour, and second, dividing the resulting product by 4 months to get the dollar per MW-month value.

1.2(b) Ten-Minute Reserve Requirement Shortage Revenue

Revenue during Ten-Minute Reserve Requirement shortage hours is the product of the number of Ten-Minute Reserve Requirement shortage hours and the Ten-Minute Reserve Requirement RCPF of $1,500 per MW-hour.[15] The number of Ten-Minute Reserve Requirement shortage hours estimated for summer periods is the product of: (i) total summer reserve shortage hours (Item 1.1), and (ii) the historical relative frequency of Ten-Minute Reserve Requirement shortages during summer months. The historical relative frequency of summer Ten-Minute Reserve Requirement shortages is the ratio of: (i) the number of five-minute intervals including a Ten-Minute Reserve Requirement RCPF activation during summer months to (ii) the total number of five-minute intervals of either a Minimum Total Reserve Requirement or Ten-Minute Reserve Requirement RCPF activation during summer months over the period 6/1/2018 through 9/30/2023.

During this period, 31.6% of relevant reserve shortage hours featured a Ten-Minute Reserve Requirement RCPF activation.

The proposed offer cap uses a value of ***$640 per MW-month Ten-Minute Reserve Requirement shortage revenue***, which is the result of first, multiplying the 31.6% frequency, the 5.4 hours of reserve shortage, and the Ten-Minute Reserve Requirement RCPF value of $1,500 per MW-hour, and second, dividing the resulting product by 4 months to get the dollar per MW-month value.

1.3 Energy and Reserve Market Revenue

The Energy and Reserve Market Revenue foregone during non-shortage hours is the difference between: (i) energy and non-FRM reserve revenues for the representative asset when simulating its energy market participation assuming that it is *assigned* to meet forward reserve obligations and (ii) energy and non-FRM reserve revenues for the representative asset when simulating its energy market participation assuming it is *not assigned* to meet forward reserve obligations. The revenue values for (i) and (ii) were computed using the dispatch model created in 2020 for the ISO's FCA 16 parameters update.[16]

[15] *See* Tariff, Section III.2.7A – Calculation of Real-Time Reserve Clearing Prices.

[16] The dispatch model used for this project is available here: https://www.iso-ne.com/static-assets/documents/100006/a07_mc_2023_12_12_14_frm_offer_cap_iso_dispatch_model.xlsx. It is based on a prior version of the dispatch model available here: https://www.iso-ne.com/static-assets/documents/2020/11/a4_a_i_simple_cycle_cone_dispatch_with_frm_posted_nov_24.xlsx. Note that model

The proposed offer cap uses the 95th percentile of the monthly total of simulated foregone revenue during summer months, which is ***$2,530 per MW-month of energy and reserve market revenue***.

Total Foregone Revenue

The sum of reserve shortage hour foregone reserve revenue ($1,990) and non-shortage hour foregone energy and reserve revenue ($2,530) is $4,520 per MW-month.

2. Penalties

The second component of the offer cap is *Penalties*, or the expected value of penalties arising from failure to meet forward reserve obligations. The approach used to determine a representative upper-end estimate of penalty costs analyzed actual, historical penalty costs incurred as a proportion of suppliers' base forward reserve revenues. The total penalty value consists of two sub-components:

- *Failure to Reserve Penalties* (Item 2.1), and
- *Failure to Activate Penalties* (Item 2.2).

2.1 Failure to Reserve

Failure to reserve penalties arise when a market participant fails to assign forward reserve obligations to resources or fails to submit energy market offers above the FRM threshold price for all assigned megawatts.[17]

The monthly failure to reserve penalty included in the proposed cap is the product of: (i) the 95th percentile monthly failure to reserve penalty rate, and (ii) the monthly foregone revenue (Item 1 Subtotal).

The monthly failure to reserve penalty rate is the ratio of: (i) the historical monthly dollar amount of failure to reserve penalties incurred by each market participant, by product, during the period 6/1/2018 through 9/30/2023 to (ii) the historical monthly base forward reserve revenue for each market participant, by product, during this same period.

The historical monthly base forward reserve revenue for each market participant, for each product, is computed by multiplying the relevant historical forward reserve payment rate ($/MW-month) by the forward reserve obligation (MW) acquired by the market participant, for the specified product, during the historical forward reserve auctions of the study period. The forward reserve obligation acquired by a market participant during a forward reserve auction refers to megawatts of forward reserve obligations *prior to* transfers via internal bilateral transactions (IBTs). Forward reserve obligations secured prior to IBTs are used to reflect market participant estimates of penalty exposure at the time of the forward reserve auction.

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parameters and data inputs have been updated for this project. For example, historical fuel prices, historical day-ahead and real-time LMPs, and historical day-ahead and real-time reserve prices from 6/1/2018 through 9/30/2023 were used as hourly input values to the updated dispatch model.

[17] *See* Tariff, Section III.9.7.1 – Real-Time Failure to Reserve. *See also* Section III.9.5.1 (describing assignment of forward reserve megawatts); Section III.9.6 (describing delivery of forward reserve).

The 95th percentile monthly failure to reserve penalty rate is the larger of the 95th percentile monthly failure to reserve penalty rate for the TMNSR product and the 95th percentile monthly failure to reserve penalty rate for the TMOR product. This value is 32.12%.

The proposed cap includes ***$1,452 per MW-month for failure to reserve***, the value obtained by multiplying the 32.12% rate by the total monthly foregone revenue.

2.2 Failure to Activate

Failure to activate penalties arise when an asset assigned to provide forward reserves fails to provide energy in response to the ISO's dispatch instruction under specified system conditions.[18]

The monthly failure to activate penalty included in the proposed cap is the product of: (i) the 95th percentile monthly failure to activate penalty rate, and (ii) the monthly foregone revenue (Item 1 Subtotal).

The monthly failure to activate penalty rate is the ratio of: (i) the historical monthly dollar amount of failure to activate penalties incurred, by market participant, during the period of 6/1/2018 through 9/30/2023 to (ii) the historical monthly base forward reserve revenue for each lead market participant, during this same period.

As with failure to reserve penalties, the historical monthly base forward reserve revenue for each market participant, for each product, is computed by multiplying the relevant historical forward reserve payment rate ($/MW-month) by the forward reserve obligation (MW) acquired by the market participant, for the specified product, during the historical forward reserve auctions of the study period. (Again, the forward reserve obligation here refers to megawatts of forward reserve obligations *prior to* transfers via internal bilateral transactions (IBTs) to reflect market participant estimates of penalty exposure at the time of the forward reserve auction).

The 95th percentile monthly failure to activate penalty rate is the larger of the 95th percentile monthly failure to activate penalty rate for energy associated with the TMNSR product and the 95th percentile monthly failure to activate penalty rate for energy associated with the TMOR product.[19] This value is 5.17%.

The proposed cap includes ***$233 per MW-month for failure to activate***, the value obtained by multiplying the 5.17% rate by the total monthly foregone revenue.

Total Penalties

The sum of estimated failure to reserve penalties ($1,452) and estimated failure to activate penalties ($233) is $1,685 per MW-month.

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[18] Tariff, Section III.9.7.2 – Failure to Active Penalties.

[19] Per Tariff III.9.7.2, megawatts of delivered TMNSR energy are megawatts delivered within 10 minutes of receipt of a dispatch instruction, and megawatts of delivered TMOR energy are megawatts delivered within 30 minutes of receipt of a dispatch instruction.

3. Supplier Risk Premium

The proposed offer cap uses a **15% supplier risk premium** to account for uncertainty in the estimates of the above component values. The risk premium percent is the same as that used to derive the current offer cap.

The proposed cap includes ***$931 per MW-month for supplier risk premium*** (Item 3), the value obtained by multiplying the 15% rate by the sum of: (i) foregone revenue (Item 1) and (ii) penalties (Item 2).

4. Updated Forward Reserve Offer Cap

The sum of the components above, rounded to the nearest one hundred dollars yields an ***offer cap of $7,100 per MW-month***. This value reflects a reduction in estimated costs associated with forward reserve obligations under current market and system conditions, relative to conditions when the offer cap was last updated.

Appendix: Summary of Study and Data Periods Used to Update Offer Cap

The table below summarizes the date ranges and periods used to derive the updated offer cap.

Summary of Study/Data Periods Used to Derive Updated Forward Reserve Offer Cap

Offer Cap Component	Data Period	Rationale for Use
Peak Load Reserve Shortage Hours	CCP 2021-22 through 2024-25	This is a set of recent, consecutive operating reserve deficiency studies conducted by the ISO whose study periods cover the upcoming forward reserve auctions. It is also the set of operating reserve deficiency studies used in recent FCM parameter update methods. Available at https://www.iso-ne.com/system-planning/system-plans-studies/installed-capacity-requirement/.
Transient Reserve Shortage Hours	5/1/2015 through 09/30/2023	This is the most up-to-date publicly-available data. Available at https://www.iso-ne.com/static-assets/documents/2017/01/rcpf_activation_data_2006_10_thru_present.zip.
Seasonal Share of Reserve Shortage Hours	5/1/2015 through 09/30/2023	This is the most up-to-date publicly-available data. Available at https://www.iso-ne.com/static-assets/documents/2017/01/rcpf_activation_data_2006_10_thru_present.zip.
Minimum Total Reserve and Ten-Minute Reserve Shortage Relative Frequencies	6/1/2018 through 09/30/2023	This date range accounts for PFP implementation and improved system reliability.
Foregone Energy and Reserve (Fuel Price Data, LMPs, RMCPs, FRM Prices)	6/1/2018 through 09/30/2023	This date range accounts for PFP implementation and improved system reliability.
Failure to Reserve Relative Frequency	6/1/2018 through 09/30/2023	This date range accounts for PFP implementation and improved system reliability.
Failure to Activate Relative Frequency	6/1/2018 through 09/30/2023	This date range accounts for PFP implementation and improved system reliability.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: January 25, 2024

RE: Request by Saco River Hydro for Waiver of GIS Operating Rules and GIS Agreement

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At the February 1, 2024 Participants Committee meeting, you may be asked to consider a request to waive certain NEPOOL Generation Information System ("GIS") requirements in order to change renewable energy Certificates for a generator for the first and second quarters of 2023. To provide the requested relief NEPOOL would need to waive provisions of both the GIS Operating Rules ("Rules") and the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. ("APX") and NEPOOL, as amended and extended (the "GIS Agreement"). As further explained below, Saco River Hydro, LLC ("Saco River")[1] is seeking to have the first and second quarter Certificates for its Swans Falls project (the "Project") reclassified as Class I qualified under the Connecticut renewable portfolio standard ("RPS").

Relevant Background & Overview

Saco River's Project has a total nameplate capacity of 0.82 MW and is registered in the ISO MSS. The Project was qualified as a Connecticut Class I RPS unit in 2005. Until last year, the Project was interconnected with Public Service Company of New Hampshire ("PSNH"). In February 2023, the Project dropped the interconnection with PSNH and was interconnected with Central Maine Power ("CMP"). As a result of the change in the interconnection, the Project was assigned a new asset ID number in the MSS, with CMP listed as the asset owner.

Because the Swan Falls Project had a new asset ID number in the MSS, APX, the GIS Administrator, needed a new confirmation of the Project's Class I status from the Connecticut Public Utilities Regulatory Authority ("PURA") aligning with the new ID, which it received in November 2023.[2] Because APX did not have that confirmation by July 10 (the deadline under the Rules[3]), the Project's first quarter Certificates were not denoted as Connecticut Class I qualified,

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[1] Saco River is not a NEPOOL Participant and is a Non-Participant Account Holder under the GIS Rules.

[2] APX noted that Connecticut PURA would have needed someone to contact it to inform them that the new asset ID was for the generator that was qualified as Class I in 2005, so that PURA could in turn inform APX that the Certificates for the new asset ID were Connecticut Class I qualified.

[3] GIS Operating Rule 2.3(a) states, "Any update provided after the fifth calendar day preceding any Creation Date shall not apply to the Certificates created on such Creation Date." The Creation Date for first quarter Certificates in any year is July 15, and the Creation Date for second quarter Certificates in any year is October 15.

and because APX did not have that confirmation by October 10, the project's second quarter Certificates also were not denoted as Connecticut Class I qualified. The total number of Certificates for the Project for the first two quarters was 1,260. The Project's Certificates will be denoted as Connecticut Class I qualified going forward, starting with the third quarter of 2023.

Through its waiver request, Saco River is seeking to have its first and second quarter Certificates be retroactively designated as Connecticut Class I qualified in the GIS. APX does not have the authority to change the RPS designation on the Certificates without both APX and NEPOOL waiving Section 4.2 of the GIS Agreement and Rule 1.4, which require APX to administer and operate the GIS in accordance with the Rules. APX, as the GIS Administrator, has under those provisions "the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the GIS Operating Rules." Since APX believes it has administered correctly what is prescribed by the Rules and GIS Agreement, the only way it can change Saco River's Certificates as requested is if Rule 1.4 and Section 4.2 of the GIS Agreement are waived. APX has indicated that it would be willing to waive the applicable requirements but only if NEPOOL, as the counterparty to the GIS Agreement, agrees to such a waiver and directs APX to correct the Certificates.

The following resolution can be used for Participants Committee action on Saco River's request:

> RESOLVED, that the Participants Committee [grants] [denies] Saco River Hydro, LLC's request to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL as discussed in the materials circulated for this meeting.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of January 30, 2024

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated January 11, 2024 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

1	206 Proceeding: ISO Market Power Mitigation Rules (EL23-62)	Jan 29	ISO-NE requests continued abeyance of this proceeding, to ***Aug 30, 2024***, pending completion of the stakeholder process

II. Rate, ICR, FCA, Cost Recovery Filings

5	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER24-528)	Jan 23	FERC accepts ICR-Related Values for the 3rd ARA for the 2024-25 Capability Year, the 2nd ARA for the 2025-26 Capability Year, and the 1st ARA for the 2026-27 Capability Year, *eff. Jan 29, 2024*
5	FCA18 Qualification Info. Filing (ER24-476)	Jan 22	FERC accepts FCA18 Qualification Info. Filing, as amended; directs ISO-NE to use certain corrected Qualified Capacity values identified in its Jan 10, 2024 Errata Filing; FCA18 to begin ***Feb 5, 2024***
6	**Mystic 8/9 COSA (ER18-1639)**		
7	Mystic's Request for Reh'g of the *Second CapEx Info Filing Order* (-028)	Jan 19	ENECOS answer Mystic's request for clarification and/or reh'g of the *Second CapEx Info Filing Order*
9	Transmission Rate Annual (2023) Update/Informational Filing (ER20-2054)	Jan 31	MOPA files formal challenge to the 2023 Annual Update
11	ISO Securities: Authorization for Future Drawdowns (ES24-18)	Jan 22	FERC authorizes ISO-NE drawdowns under a $40 million Revolving Credit Line and a $4 million line of credit supporting the Payment Default Shortfall Fund, *eff. Feb 1, 2024 through Jan 31, 2026*

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

11	IEP Compliance Filing (ER24-492)	Jan 18	FERC accepts IEP Compliance Filing, *eff. Aug 2, 2023*
11	DECR FCM Qualification Revisions (ER24-484)	Jan 24	FERC accepts Revisions, *eff. Mar 1, 2024*
11	Waiver Request: OP-14 Solar Dispatch Point Requirements (Galt Power) (ER24-478)	Jan 24	FERC denies waiver
12	Downward De-List Bid Price Flexibility (ER24-420)	Jan 11	FERC accepts changes, eff. *Mar 1, 2024*
12	DASI Proposal (ER24-275)	Jan 29	FERC accepts DASI Proposal, *eff. Mar 1, 2025*
13	New England's *Order 2222* Compliance Filings (ER22-983)	Jan 31	ISO-NE submits compliance filing; Participants Committee to consider supporting the compliance filing changes at its ***Feb 1, 2024*** meeting

IV. OATT Amendments / TOAs / Coordination Agreements

	14	Attachment F App. A PBOP Fixed Expense Revisions (CMP; UI) (ER24-774; ER24-775)	Jan 19	MPUC intervenes in CMP proceeding (ER24-774)
	15	Eversource Attach. F App. A PBOP Collections Report (ER24-696)	Jan 25	FERC accepts report showing over-collections for each of the Eversource PTOs, *eff. Feb 16, 2024*
	15	*Order 676-J* Compliance Filings Part II Further Compliance Filings (ER23-1771; ER23-1782)	Jan 30	FERC accepts New England Schedule 24 and Versant MPD OATT further compliance changes, eff. *Feb 1, 2024*

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

*	17	Schedule 21-GMP: 2024 True Up Calc. Forecast Info Rpt (ER12-2304)	Jan 16	GMP supplements 2024 forecasted rates info filing

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

*	18	Transmission Projects Annual Info Filing (ER13-193)	Jan 30	ISO-NE files annual informational filing of projects on the RSP project list that had a year of need 3 years or less from the completion of the Needs Assessment as required under OATT § 4.1(j)(iii)
*	18	LFTR Implementation: 61st Quarterly Status Report (ER07-476)	Jan 12	ISO-NE files its 61st quarterly report
*	18	IMM Quarterly Markets Reports - 2023 Fall (ZZ24-5)	Jan 25	IMM files Fall 2023 Report; to be reviewed at ***Feb 7, 2024*** Markets Committee meeting

IX. Membership Filings

*	18	Feb 2024 Membership Filing (ER24-1024)	Jan 31	***New Members:*** Agile Energy Trading; Command Power Corp.; Eagle Creek Renewable Energy Holdings; Ocean State Power; and ***Termination of Participant status:*** Community Eco Power; MPower Energy; Pixelle Energy Services; Power Ledger Pty Ltd; Union Atlantic Electricity; Utility Services of VT; comment deadline ***Feb 21, 2024***
	19	Dec 2023 Membership Filing (ER24-512)	Jan 26	FERC accepts (i) the memberships of Citadel Energy Marketing LLC; Downeast Wind, LLC; JGT2 Energy LLC; and Qnti.fyi Inc.; and (ii) the termination of the Participant status of Sam Mintz

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

	19	Revised Reliability Standard: PRC-023-6 (RD23-5)	Jan 26	FERC approves PRC-023-6
	20	*Order 901*: IBR Reliability Standards (RM22-12)	Jan 17	NERC submits *Order 901* Work Plan; to be kept up-to-date on NERC website

XI. Misc. - of Regional Interest

* 21	IA Cancellation Versant / PERC (ER24-965)	Jan 22	Versant files a notice of cancellation of an IA between itself and Penobscot Energy Recovery Co.; comment deadline ***Feb 12, 2024***
22	E&P Agreement, 2d Amendment: Seabrook / NECEC Transmission (ER24-508)	Jan 26	Seabrook files amendment to correct the eTariff record of the Amended E&P Agreement; comment deadline ***Feb 16, 2024***

XII. Misc. - Administrative & Rulemaking Proceedings

22	Reliability Technical Conference (AD23-9)	Jan 16-22 Jan 25	FERC Commissioners post Additional members of Congress submit comments
23	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Jan 23	NARUC nominates Chair Mary Throne of the Wyoming PSC to represent the Western Conf. of Public Service Commissioners region
23	RTO/ISO Common Performance Metrics (AD19-16)	Jan 31	FERC Staff issues Report on performance metrics data on RTOs/ISOs activities and data related to RTO/ISO administrative functions, energy markets, and capacity markets for the 2019 to 2022 reporting period
27	Transmission NOPR (RM21-17)	Jan 19 Jan 22	Members of Congress file comments urging FERC to strengthen and finalize the Transmission NOPR Clean Energy Buyers Assoc. files comments

XIII. FERC Enforcement Proceedings

No Activity to Report

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

33	*Order 2222* Compliance Orders (23-1167 et al.)(consolidated)	Jan 22	FERC proposes continued abeyance until expiration of period for filing petitions for review of the FERC's forthcoming order on rehearing of the *Order 2222 60-Day Compliance Filing Order*
34	Seabrook Dispute Order (23-1094, 23-1215) (consol.)		Oral argument scheduled for ***Feb 6, 2024*** and will be heard by Judges Millet, Katsas and Rao
35	Mystic II (ROE & True-Up)	Jan 25 Jan 26	Constellation proposes continued abeyance for an additional 90 days Court orders cases to remain in abeyance; parties directed to file motions to govern future proceedings by ***Apr 24, 2024***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: January 31, 2024

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through January 31, 2024. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

As previously reported, this Section 206 proceeding is being held in abeyance.[2] This proceeding was instituted by the FERC on May 5, 2023, pursuant to its finding that the existing ISO-NE Tariff provisions related to the mechanics of its market power mitigation and the consideration of any proposed fuel price adjustment, may be unjust and unreasonable.[3] Parties to this proceeding include: NEPOOL, Calpine, Connecticut Office of Consumer Counsel ("CT OCC"), Massachusetts ("MA") Attorney General ("MA AG"), New England Power Generators Association ("NEPGA"), New England States Committee On Electricity ("NESCOE"), Public Systems,[4] Electric Power Supply Association ("EPSA"), MA Department of Public Utilities ("MA DPU"), Maine Public Utilities Commission ("MPUC"), and Public Citizen.

ISO-NE Request for Continued Abeyance. On January 29, 2024, ISO-NE requested that this proceeding continue to be held in abeyance, through ***August 30, 2024***, "pending completion of the stakeholder process through which further revisions to [the Tariff] are being proposed and vetted.[5] As previously reported, changes in response to some of the requirements of the *Dynegy Mitigation Order* ("Upward Mitigation Revisions") were

[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] On July 14, 2023, the FERC granted ISO-NE's June 28, 2023 motion, supported by NEPOOL on July 5, 2023, requesting that the FERC hold this proceeding in abeyance to allow potential ISO-NE Tariff design changes to be vetted through the Participant Processes. The FERC stated that it would not take any action on this 206 proceeding before ***Feb. 1, 2024***.

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

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

[5] ISO-NE identified as additional topics not fully addressed by the Upward Mitigation Revisions the following: (1) whether the duration of general threshold energy mitigation is appropriate; and (2) whether a Resource should be permitted to submit multiple fuel price adjustments that reflect the cost of fuel for segments of its Supply Offer that exceed a Resource's Day-Ahead Energy Market awards.

supported by the Participants Committee, jointly filed with ISO-NE, accepted by the FERC,[6] and became effective as of *December 12, 2023*. The request for further abeyance updates a statement in the Upward Mitigation Revisions filing that ISO-NE would "be in a position to provide the Commission with its next filing no later than April 2024, rather than in February 2024." The motion for further abeyance is pending before the FERC.

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

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

The December 13, 2022 complaint by RENEW Northeast, Inc. ("RENEW") against ISO-NE and the Participating Transmission Owners ("PTOs"), which seeks changes to the ISO-NE Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to Interconnection Customers,[7] remains pending before the FERC. As previously reported, the proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee at its October 26, 2021 meeting, and were discussed at the Participants Committee's November 3, 2021 meeting. RENEW asked the FERC to issue an order granting the Complaint by April 14, 2023 (approximately 60 days prior to the June 15, 2023 deadline for the NE PTOs to publish a draft of the Annual Update to the data used in the transmission formula rate). Both of those dates have since passed.

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

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

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

  - ***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,[8] 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*

[6] *ISO New England Inc.*, Docket No. ER24-324-000 (Dec. 12, 2023) (unpublished letter order).

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

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

531-A).[9] However, the FERC's orders were challenged, and in *Emera Maine,*[10] 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)[11] and third (EL14-86)[12] 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.[13] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[14] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[15] 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.[16] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

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[9] *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*").

[10] *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 b oth 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).

[11] 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%.

[12] 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 component s 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 proceedi ngs.

[13] *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*").

[14] 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 FER C established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4 th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that or der 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.

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

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

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[17] 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*[18] (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.[19]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[20] 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

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

[18] *Ass'n of Bus. 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*.

[19] *Id.* at P 19.

[20] *Id.* at P 59.

proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[21] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[22] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

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

II. Rate, ICR, FCA, Cost Recovery Filings

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

On January 23, 2024, the FERC accepted the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2024-25 Capability Year, the second ARA for the 2025-26 Capability Year, and the first ARA for the 2026-27 Capability Year.[23] The ICR-Related Values were accepted effective as of *January 29, 2024*, as requested. Unless the January 23 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).

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

On January 22, 2024, the FERC accepted[24] ISO-NE's informational filing, as amended on January 10, 2024,[25] for qualification for FCA18 (the "FCA18 Informational Filing"). As previously reported, the FCA18 Informational Filing contained ISO-NE's determinations that three Capacity Zones will be modelled for FCA18 -- Northern New England ("NNE"), Maine, and Rest of Pool. NNE and Maine will be modeled as export-constrained. The Informational Filing reported that there will be 29,855 MW of existing capacity in FCA18 competing with 4,108 MW of new capacity under a Net ICR of 30,550 MW (ICR minus HQICCs). ISO-NE

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

[22] *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).

[23] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER24-528-000 (Jan. 23, 2024) (unpublished letter order).

[24] *ISO New England Inc.*, 186 FERC ¶ 61,060 (Jan. 22, 2024) ("*FCA18 Info. Filing Order*").

[25] ISO-NE amended the FCA18 Information Filing on Jan. 10, 2024, with corrected Qualified Capacity values, and the aggregate numbers using those values, of three resources (44587 (4.875 MW corrected to 3.625 MW); 44601 (4.950 MW corrected to 3.300 MW) and 44728 (4.998 MW corrected to 3.240 MW)), who's values were calculated and filed based on an intermittent, rather than a non-intermittent, status ("Errata Filing"). ISO-NE asked the FERC, in its order on the FCA18 Informational Filing, to direct ISO-NE to correct those values.

reported also that there were a total of 1,391 MW of De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 8 demand bids, totaling 858 MW, and 47 supply offers, totaling 341 MW, to participate in the substitution auction. As requested, the FERC directed ISO-NE to run FCA18 using the corrected values for the three resources identified in its Errata Filing. FCA18 is scheduled to begin on ***February 5, 2024***. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[26] (ER22-1192)**

As previously reported, on May 2, 2022, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COSA") to reflect Mystic's current upstream ownership.[27] The changes were accepted effective as of June 1, 2022, but subject to refund and to the outcome of paper hearing (or settlement procedures) on the issues of capital structure and cost of debt raises issues. Mystic filed an offer of settlement on September 8, 2022 to resolve all issues set for hearing and settlement proceedings and the FERC accepted that offer of settlement on November 2, 2022,[28] directing Mystic to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action in the November 2 order. Mystic submitted that compliance filing on December 2, 2022 (ER22-1192-003). Mystic's compliance filing was accepted on October 27, 2023,[29] concluding this proceeding. If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[30] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's *December 2020 Rehearing Order*.

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

Second CapEx Info Filing (-018). On December 5, 2023, the FERC issued an order[31] on the formal challenges to Mystic's September 15, 2022 "Second CapEx Info Filing".[32] As previously reported, formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS[33] (with ENECOS challenges supported

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

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

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

[29] *Constellation Mystic Power, LLC*, Docket No. ER22-1192-003 (Oct. 27, 2023) (unpublished letter order).

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

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

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

[33] ENECOS Formal Challenges included failures by Mystic: (1) to adequately support its July 1, 2004 – Dec. 31, 2017 Rate Base on Attachment B to Mystic 8&9 Schedule D (with the majority of the cost appearing to O&M expenses that should have been expensed prior to the term); (2) to adequately support its Jan. 1, 2018 – May 31, 2022 Rate Base in line with the requirements of Schedule 3A and the

separately by MMWEC/NHEC). Several rounds of answers, described in previous reports, followed. In February 2023, Mystic asked that the Formal Challenges to the Second CapEx Info Filing be held in abeyance pending submission of a settlement agreement to resolve challenges to the First CapEx Info Filing. ENECOS protested that request, identifying issues in their challenges to the Second CapEx Info Filing that would not be resolved by a First CapEx Settlement Agreement. The First CapEx Settlement Agreement was filed and approved, leaving for resolution certain of ENECOS' challenges.

Second CapEx Info Filing Order (-026). In the *Second CapEx Info Filing Order*, the FERC granted in part, subject to hearing and settlement judge procedures, and dismissed in part, ENECOS' Formal Challenges. Specifically, the FERC found that, issues of material fact, that could not be resolved on the record before it, continued with respect to a number of ENECOS' Formal Challenges. Accordingly, the FERC set for hearing and settlement judge procedures issues raised, in whole or in part, in ENECOS Formal Challenges 1, 2, 6, and 7. The FERC summarily dismissed ENECOS' Formal Challenges 3-5 and 8 (as outside the scope of the proceeding).

Second CapEx Info Filing Settlement Proceedings (-027). While the FERC set several aspects of ENECOS Formal Challenges for a trial-type evidentiary hearing, the FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures. As directed, the Chief ALJ appointed a settlement judge, Judge Patricia M. French, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action. Judge French was directed to submit her first report on or before ***February 12, 2024***, and to submit a report every 60 days thereafter as to the parties' progress toward settlement. Judge French convened a first settlement conference on January 4, 2024, and scheduled a second settlement conference for ***March 20, 2024***.

(-028) Mystic's Request for Rehearing of the Second CapEx Info Filing Order**.* On January 4, 2024, Mystic requested clarification, and in the alternative rehearing, of the *Second CapEx Info Filing Order*.[34] Specifically, Mystic requested clarification and/or rehearing of (i) the FERC's ruling on ENECOS's Formal Challenge No. 7 related to Everett's projected 2023 capital expenditures, (ii) that the FERC denied the accounting argument that ENECOS included in their Formal Challenge No. 1; and (iii) the FERC's rulings related to capital costs incurred prior to the start of the term of the COS Agreement (its grant in part of ENECOS's Formal Challenge No. 1 on the basis that Mystic did not adequately "support" Mystic 8&9 capital costs between July 2004 and December 31, 2017 ("Pre-2018 Rate Base"), and its grant of ENECOS's Formal Challenges Nos. 2 and 6). On January 19, 2024, ENECOS answered Mystic's request. The FERC must take action on Mystic's request for rehearing by ***February 5, 2024, or the request will be deemed denied by operation of law.

Deemed Denied by Operation of Law - ENECOS Request for Rehearing of Mystic I Order on Remand Modification Order (-026). On November 6, 2023, ENECOS requested rehearing of the *Mystic I Order on Remand Modification Order*.[35] Specifically, ENECOS requested that the FERC both (i) reinstate its conclusions as to the

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Methodology of the Mystic COSA; (3-5) to prove that certain costs under Mystic's 2022 CapEx Projects - specifically, its Campus Segregation Project and comprehensive rotor inspections - are necessary to meet the reliability need of the Mystic COSA and the least-cost commercially reasonable option consistent with Good Utility Practice; (6) to sufficiently support Everett's Nov. 1, 2018 – May 31, 2022 Rate Base in Attachment B; (7) to properly classify certain of Everett's 2022 and 2023 CapEx Projects costs (some of which should have been characterized as maintenance expenses charged before the term of the Mystic COSA); and (8) to include costs of firm interstate and intrastate pipeline transportation reservations in Everett Schedule B of the populated template.

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

[35] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*"). The *Mystic I Order on Remand Modification Order* set aside the FERC determinations in the *Mystic I Order on Remand* that: (i) interested parties may review and challenge revenues and Revenue Credits during the true-up process; (ii) interested parties may review and challenge Tank Congestion Charges during the true-up process; and (iii) the revenues from the sliding scale revenue sharing mechanism for third-party vapor sales should be included within the true-up. As previously reported, the FERC concluded in the *Mystic I Order on Remand* that "the language of the true-up and Protocol provisions of the [COS] Agreement, Schedule 3A, does not include these three items within the scope of the true-up, nor is calculation of these items consistent with purpose for the true-up mechanism in the [COS] Agreement because none

scope of customer scrutiny of formula rate inputs under the COSA set forth in its March 28, 2023 *Mystic I Order on Remand*[36] and (ii) grant Public Systems' motion for additional disclosure to facilitate customer review of the extraordinary costs incurred during the first 18 months of the COSA's operation. On December 7, 2023, the FERC issued an "Allegheny Notice",[37] noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but noting that ENECOS' request will be addressed in a future order.[38]

As previously reported, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand (*-024*)*. Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[39]

The FERC then issued the *Mystic I Order on Remand Modification Order* which modified the discussion in the *Mystic I Order on Remand* and set aside that *Order* in part.[40] In addition, the *Order* also denied Public Systems[41] May 19, 2023 request that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request").[42]

(-014) Revised ROE (Sixth) Compliance Filing*.* Also still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[43] The sixth compliance filing revised (i) the Cost

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of them are projected in advance, but rather they are each settled and audited on a monthly basis. The FERC found that "existing cost review and audit processes, … facilitated by ISO-NE, its auditors, and the Internal Market Monitor, are sufficient to ensure that Mystic adheres to its filed rate with respect to these items and continues to appropriately balance customers' interest in transparency of the formula rate with Mystic's interests in protecting commercially-sensitive information, reducing security risks, and avoiding burdensome audit obligations".

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

[37] The FERC issues an "Allegheny Notice" when it does not act within 30 days after receiving a challenge (a request for clarification and/or rehearing) to a FERC order. An Allegheny Notice confirms that the request is deemed denied by operation of law (*see Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020)) and the FERC order is final and ripe for appeal. The FERC has the right, up to the point when the record in a proceeding is filed with the court of appeals, to modify or set aside, in whole or in part, any finding or order made or issued by it. The FERC's intention to avail itself of its right and to issue a further order addressing the issues raised in the request (a "merits order") is signaled by the phrase "and providing for Further Consideration"; the absence of that phrase signals that the FERC does not intend to issue a merits order in response to the rehearing request.

[38] *Constellation Mystic Power, LLC*, 185 FERC ¶ 62,120 (Dec. 7, 2023) ("*Mystic I Order on Remand Modification Order Allegheny Notice*").

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

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

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

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

[43] An "Allegheny Order" is a merits rehearing order issued on or after the 31st day after receipt of a rehearing request, reflecting the FERC's authority to "modify or set aside, in whole or in part," its order until it files the record on appeal with a reviewing federal court. An Allegheny Order will use "modifying the discussion" if the FERC is providing a further explanation, but is not changing the outcome, of

of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

30-Day Compliance Filing per Order on ENECOS Mystic COSA Complaint (ER23-1735). On April 27, 2023, Mystic filed, as directed by the FERC's March 28, 2023 *Order on ENECOS Mystic COSA Complaint*,[44] changes to the Mystic COSA to include pipeline-related crediting as an explicit provision in the COSA. Mystic also provided additional information/COSA changes to (i) describe the crediting process; (ii) differentiate, through both an explanation in its compliance filing and creation of two new line items in Schedule 3A, the credits and charges included as part of the Fixed Pipeline Costs; (iii) address how and whether the pipeline-related crediting procedure interacts or should interact with the true-up procedure already included in the COSA and revise the true-up as necessary; and (iv) differentiate in the COSA the Pipeline Transportation Costs as Fixed O&M/Return on Investment Costs from the Pipeline Transportation Agreement Costs. Comments on the 30-day compliance filing were due on or before May 18, 2023. ISO-NE and Monitoring Analytics, LLC filed doc-less motions to intervene.

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

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

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

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

The July 31 filing also triggered the commencement of an Information Exchange Period and a Review Period under the Protocols. Interested Parties had until September 15, 2023 to submit information and document requests, and the PTOs were required to make a good faith effort to respond to all requests within

the underlying order; or "set aside" if the FERC is changing the outcome of the underlying order. Aggrieved parties have 60 days after a deemed denial to file a review petition, even if FERC has announced its intention to issue a further merits order.

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

15 calendar days, but by no later than October 15, 2023. During the Review Period, Interested Parties had until November 15, 2023 to submit Informal Challenges to the PTOs, and the PTOs were required to make a good faith effort to respond to any Informal Challenges no later than December 15, 2023. Interested Parties had until January 31, 2024 to file a Formal Challenge with the FERC.

Formal Challenge by MOPA. On January 31, 2024, the Maine OPA filed a formal challenge to the 2023 Annual Update. MOPA asserted that, with respect to the cost of asset condition projects placed into service in 2022, the NETOs have refused to answer questions regarding investment policies and practices related to prudence of these investments and asserts that the NETOs' decision not to respond to these questions violates their obligation under the OATT's Protocols.

- **Versant MPD OATT 2023 Annual Update Settlement Agreement (ER20-1977-006)**

On January 5, 2024, Versant submitted a Joint Offer of Settlement ("Versant MPD OATT 2023 Annual Update Settlement Agreement") between itself and the Eastern Maine Electric Cooperative, Inc. ("EMEC") and the Maine Public Utilities Commission (together, the "Maine Parties") which, if approved, would resolve all issues raised by the Maine Parties with regards to Versant's 2023 annual update to the transmission charges under the MPD OATT. Comments on the Versant MPD OATT 2023 Annual Update Settlement Agreement were due on or before January 26, 2024; none were filed. The Versant MPD OATT 2023 Annual Update Settlement Agreement is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

RENEW Formal Challenge. RENEW's January 31, 2023 formal challenge ("Challenge") to the 2022/23 Update/Informational Filing[45] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's

[45] The 2022/23 annual filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. The formula rates in effect for 2023 included a billing true up of seven months of 2021 (June-Dec.). The Pool "postage stamp" RNS Rate, effective Jan. 1, 2023, was $140.94 /kW-year, a decrease of $1.84 /kW-year from the charges that went into effect the year prior. The updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate) resulted in a Schedule 1 charge of $1.75 kW-year (eff. June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022.

Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, Eversource answered RENEW's March 31 answer. There has been no activity in this proceeding since Eversource's answer. This matter remains pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO Securities: Authorization for Future Drawdowns (ES24-18)**

On January 22, 2024, the FERC authorized ISO-NE drawdowns under a $40 million (up from $20 million) Revolving Credit Line and a $4 million line of credit supporting the Payment Default Shortfall Fund.[46] As previously reported, each of the Credit Lines are with TD Bank, are for a term of three years ending June 30, 2027, and replace similar arrangements that will expire June 30, 2024.[47] The order is effective from *February 1, 2024 through January 31, 2026*. Unless the *2024 Authorization Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

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

On January 18, 2023, the FERC accepted the changes that make eligible to participate in the IEP pumped storage resources participating as Electric Storage Facilities in the New England Markets.[48] As previously reported, those changes had been directed by the FERC.[49] The changes were accepted effective as of *August 2, 2023*. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On January 24, 2024, the FERC accepted changes to the Forward Capacity Market ("FCM") qualification rules for Distributed Energy Capacity Resources ("DECRs") ("DECR Qualification Revisions") to allow for a more streamlined qualification process for DECRs as early as Forward Capacity Auction 19 ("FCA19"), and to correct inadvertent errors in the DECR qualification rules.[50] Unless the January 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On January 24, 2024, the FERC denied the waiver requested by Galt Power, Inc. and GSRP Pipeline Acquisition I LLC (together, "Galt Power").[51] As previously reported, Galt Power had requested a waiver of the

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[46] *ISO New England Inc.*, 186 FERC ¶ 62,024 (Jan. 22, 2024) ("*2024 Authorization Order*") (order authorizing securities issuances).

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

[48] *ISO New England Inc.*, Docket No. ER24-492-000 (Jan. 18, 2024) (unpublished letter order) (accepting IEP Compliance Filing changes).

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

[50] *ISO New England Inc.*, Docket No. ER24-484-000 (Jan. 24, 2024) (unpublished letter order) (accepting DECR Qualification Revisions).

[51] *GSRP Pipeline Acquisition I LLC and Galt Power, Inc.*, 186 FERC ¶ 61,057 (Jan. 24, 2024) ("*Order Denying Galt Waiver*").

requirements for solar resources to receive and respond to Do Not Exceed ("DNE") Dispatch Points[52] for certain of its resources (the "FR/SR Facilities").[53] Galt Power asserted that, due to the size and characteristics of the FR/SR Facilities, "full compliance with the DNE Requirements would be technically challenging and would impose significant costs that are not necessary to ensure reliability, which is the underlying purpose of the DNE Requirements." ISO-NE opposed the Galt Power request. In denying the requested waiver, the FERC found Galt Power had "failed to demonstrate that the[] waiver request is limited in scope,"[54] one of the four required prongs of the FERC's test for granting waivers.[55] Unless the *Order Denying Galt Waiver* is challenged, with any challenges due on or before ***February 23, 2024***, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On January 11, 2024, the FERC accepted changes to allow Lead Market Participants greater flexibility for submitting Permanent De-List Bids and Retirement De-List Bids in a Forward Capacity Auction ("FCA").[56] The changes were accepted effective as of *March 1, 2024*, as requested. Unless the January 11 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On January 29, 2024, the FERC accepted the changes to the Tariff to establish a jointly optimized Day-Ahead Market for Energy and Ancillary Services ("DASI") (jointly field by ISO-NE and NEPOOL ("Filing Parties" on October 31, 2023).[57] The DASI Proposal was accepted effective *March 1, 2025*. In accepting the DASI Proposal, the FERC found that the Filing Parties demonstrated (i) that the DASI Proposal "will procure and compensate the resources ISO-NE relies on in its next day Operating Plan in an efficient, transparent, and cost-effective manner based on the distinct set of services ISO-NE requires"; (ii) that "DASI's jointly optimized clearing structure will result in Day-Ahead awards that achieve a reliable next-day Operating Plan in a more cost-efficient manner than the status quo"; and (iii) that the use of a fixed $10/MWh strike price adder is appropriate.[58] The FERC further found: (i) LS Power's assertions that eliminating the FRM will result in significant retirements for certain resource types were unsupported in the record; (ii) unpersuasive LS Power's assertion that DASI's market design imposes a *de facto* must-offer requirement; and (iii) beyond the scope of the proceeding requests from several parties for ISO-NE to continue to review its market design and consider additional ancillary service products.[59] Unless the *DASI Order* is challenged, with any challenges due on or before *February 28, 2024*, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

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

[54] *Id.* at P. 30.

[55] The FERC will grant waiver of tariff provisions where each of the following four prongs are met: (1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.

[56] *ISO New England Inc.*, Docket No. ER24-420-000 (Jan. 11, 2024) (unpublished letter order) (accepting Downward De-List Bid Price Flexibility Changes).

[57] *ISO New England Inc.*, 186 FERC ¶ 61,076 (Jan. 29, 2024) ("*DASI Order*").

[58] *Id.* at PP 34-36.

[59] *Id.* at PP 37-39.

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

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

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

In a lengthy compliance Order[60] issued March 1, 2023, the FERC approved in part, and rejected in part, ISO-NE, NEPOOL and the PTO AC's ("Filing Parties") *Order 2222* compliance filing[61] ("*Order 2222 Compliance Order*").[62] In the *Order 2222 Compliance Order*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order.* As previously reported, the FERC has accepted the 30- and 180-day compliance filings.[63]

The 60-day compliance filing was conditionally accepted,[64] subject to a further 90-day compliance filing, and granted in part ISO-NE's request for an extension of time to address directives in the *First Order 2222 Compliance Order*.[65] In the *Order 2222 60-Day Compliance Filing Order*, the FERC directed ISO-NE to submit a

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

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

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

[63] *ISO New England Inc.*, Docket Nos. ER22-983-003 and ER22-983-005 (Oct. 25, 2023) (unpublished letter order) ("*30/180-Day Order 2222 Compliance Order*"). The 30-Day compliance filings explained how current Tariff capacity market mitigation rules would apply to DECRs participating in FCA18 and provided an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. The 180-Day compliance filing explained how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond and the Mar. 1, 2024 effective date for the rules allowing DECRs to participate in the FCM).

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

[65] The FERC ordered ISO-NE in its 60-day compliance filing to revise the Tariff to: (1) have RERRA make the determination of whether to allow customers of small utilities to participate in ISO-NE's markets through aggregation; (2) require that each DER Aggregator maintain and submit aggregate settlement data for the DERA; (3) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and if necessary, establish protocols for sharing meter data that minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity; (4) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; and (5) add specificity regarding existing resource non-performance penalties that would apply to a DERA when a Host Utility overrides ISO-NE dispatch instructions. ISO-NE was also directed to: (1) identify the existing rules requiring a Market Participant that provides energy withdrawal service to be a load serving entity that is billed for energy withdrawal ("LSE Requirement") and explain whether the LSE Requirement is required of all resources seeking to provide wholesale energy withdrawal

further compliance filing, on or before ***January 31, 2024***, to comply with the directives of the *First Compliance Order* regarding the submission of DERA meter data.[66] At its January 9-11, 2024 meeting, the Markets Committee recommended Participants Committee support for the ISO's proposed further compliance changes. Those further compliance changes will be considered by the Participants Committee at its February 1 meeting.

Request for Rehearing of Order 2222 60-Day Compliance Filing Order Deemed Denied By Operation of Law (-006). On December 4, 2023, AEU requested rehearing of the *Order 2222 60-Day Compliance Filing Order*. AEU asserted that the *Order 2222 60-Day Compliance Filing Order* is arbitrary and capricious because (i) it concludes, contrary to substantial record evidence, that ISO-NE's metering configurations do not pose an undue barrier to participation for most behind-the-meter DERs, and as such, are consistent with Order No. 2222; (ii) it fails to respond meaningfully to the arguments and record evidence submitted by AEU; (iii) it concludes that "ISO-NE satisfactorily discusses the steps that it contemplated and the less burdensome alternative approaches it considered" in connection with its metering proposal; (iv) it concludes that ISO-NE's description of submetering requirements for DERAs participating as Alternative Technology Regulation Resources ("ATRR") conforms to the FERC's orders; and (v) it concludes that ISO-NE's proposal to extend its existing requirements for Binary Storage Facilities ("BSF") and Continuous Storage Facilities ("CSF") to DERAs seeking to provide withdrawal service are consistent with *Order 2222*. On January 4, 2024, the FERC issued an Allegheny Notice, noting that AEU's request for rehearing may be deemed to have been denied by operation of law, but noting that AEU's request will be addressed in a future order.[67]

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

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

IV. OATT Amendments / TOAs / Coordination Agreements

- **Avangrid (CMP/UI) Attachment F Appendix A PBOP Collections Reports (ER24-774; ER24-775)**

On December 29, 2023, CMP and UI (the "Avangrid Companies") filed a report identifying planned collection activity related to the recovery of post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT. A report was required to be filed with the FERC because the difference between each of the Avangrid Companies' actual PBOP expense and its fixed PBOP expense exceeded the threshold identified in OATT Attachment F.[68] No changes to the filed rate were sought. For CMP

service in the energy market; (2) explain why its proposed metering and telemetry requirements were just and reasonable and did not pose an unnecessary and undue barrier to individual DERs joining a DERA; (3) establish protocols for sharing metering data that minimize costs and other burdens and address privacy and cybersecurity concerns; and (4) address how ISO-NE will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA.

[66] Specifically, the FERC directed ISO-NE to revise the Tariff to designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and to require that each DER Aggregator maintain and submit aggregate settlement data for the DERA, so that ISO-NE can regularly settle with the DER Aggregator for its market participation. To the extent that ISO-NE proposes in that further compliance filing that metering data come from or flow through distribution utilities, the FERC directed ISO-NE to coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing such metering data, and explain how such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity. *Id.* at P 34.

[67] *ISO New England Inc.*, 186 FERC ¶ 62,002 (Jan. 4, 2023) ("*Order 2222 60-Day Compliance Filing Order Allegheny Notice*").

[68] A Report is required when "the absolute value of [(Cumulative Under/(Over) Recovery, including Current Year interest)] is greater than $100,000 and the absolute value of [(Cumulative Under/(Over) recovery, including Current Year interest, as a per cent of transmission-related PBOP expense)] is greater than 20%. *See* ISO-NE OATT, Attachment F, Appendix A, Worksheet 9, Note (j).

(ER24-774), the report shows an under-recovery, after interest, of $300,133; for UI (ER24-775), an over-recovery of $275,075. If accepted, the PBOP figures will be used in the Avangrid Companies' 2024 Annual Updates. Comments on these filings were due on or before January 19, 2024; none were filed. The MPUC filed a doc-less intervention in the CMP proceeding only. The Avangrid Reports are pending before the FERC. If you have any questions concerning these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Eversource Attachment F Appendix A PBOP Collections Report (ER24-696)**

On January 25, 2024, the FERC accepted Eversource's report identifying planned collection activity related to the recovery of PBOP under Appendix A to Attachment F to the ISO-NE OATT.[69] A report was required to be filed with the FERC because the difference between each of the Eversource PTOs' (CL&P, NSTAR East and West, and PSNH) actual PBOP expense and its fixed PBOP expense exceeded the threshold identified in OATT Attachment F. No changes to the filed rate were sought. The report showed an over-recovery, after interest, for each of the Eversource PTOs as follows: CL&P - $1,013,183; NSTAR East - $3,278,312; NSTAR West - $184,895; and PSNH - $224,086. The PBOP report was accepted effective *February 16, 2024* and the PBOP figures will be used as the basis for refunds in the Eversource TOs' 2024 Annual Updates. Unless the January 25 order is challenged, this proceeding will be concluded. If you have any questions concerning these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FG&E Attachment F App. D Depreciation Rate Changes (ER24-684)**

On December 15, 2023, Fitchburg Gas & Electric Company ("FG&E") filed changes to FG&E Appendix D to Attachment F of the ISO-NE OATT to correct the depreciation rates identified in the Tariff sheets (as approved in Docket No. ER20-2215, but not reflected in the ISO-NE Tariff sheets). Comments on this filing were due on or before January 5, 2024; 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).

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

On January 30, 2024, the FERC accepted the compliance filings submitted by ISO-NE (with changes to New England's Schedule 24) and by Versant (with changes to the MPD OATT).[70] As previously reported, the FERC issued orders conditionally accepting the Schedule 24[71] and Versant's MPD-OATT[72] *Order 676-J* Compliance Filings Part II, effective *February 1, 2024*, requiring in each case ISO-NE/NEPOOL[73] and Versant[74] to revise its tariff record to include the citation to its order granting the waivers requested. The compliance changes were accepted effective *February 1, 2024*, as requested. Unless the January 30 orders are challenged, these proceedings will be concluded. If there are questions on either of these proceedings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[69] *ISO New England Inc. and Eversource Energy Service Co.*, Docket No. ER24-696-000 (Jan. 25, 2024) (unpublished letter order) (accepting Eversource PTOs' PBOP report).

[70] *ISO New England Inc.*, Docket No. ER23-1771-001 (Jan. 30, 2024) (unpublished letter order) (accepting ISO-NE/NEPOOL's Order 676-J further compliance II filing); *Versant Power*, Docket No. ER23-1782-001 (Jan. 30, 2024) (unpublished letter order) (accepting Versant's Order 676-J further compliance II filing).

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

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

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

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

V. Financial Assurance/Billing Policy Amendments

- **FCM Delivery FA Calculation Changes (ER24-661)**

On December 14, 2023, ISO-NE and NEPOOL jointly filed changes to the FCM Delivery Financial Assurance ("FA") calculation ("Changes") in the Financial Assurance Policy ("FAP"). Specifically, the Changes are designed to reduce the risk of collateral shortfalls from defaulting Market Participants with Capacity Supply Obligations ("CSOs") that incur net payment obligations (i.e., penalties) under FCM's pay for performance ("PFP") construct. The Changes were supported by the Participants Committee at its December 7, 2023 Annual Meeting (Agenda Item #8A). ISO-NE requested a March 1, 2024 effective date for the Changes. Comments on the Changes were due on or before January 4, 2024; none were filed. Calpine, Dominion, National Grid, and NRG intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

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

As previously reported, the FERC accepted for filing a Local Service Agreement ("LSA") by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro, LLC ("Jonesboro"), effective *December 4, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[75] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties (i) to refund the time value of revenues collected for the time period the rate was collected without FERC authorization, with refunds limited so as not to cause Filing Parties to operate at a loss ("Time Value Refunds"); and (ii) to file a refund report, including information supporting calculation of the Time Value Refunds.

Time Value Refunds Report. On December 18, 2023, Versant Power filed a refund report ("Report") detailing the Time Value Refunds it paid to NE Renewable Power and Jonesboro on December 15, 2023. Comments on the Report were due on or before January 8, 2024; none were filed. The Report is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804)**

As previously reported, ISO-NE and New England Power ("National Grid", and together with ISO-NE, the "Filing Parties") filed on September 11, 2023, a 20-year LSA by and among National Grid, ISO-NE and Green Mountain Power ("GMP").[76] The Filing Parties stated that the LSA conformed to the *pro forma* LSA contained in the ISO-NE Tariff and superseded and replaced another conforming LSA among ISO-NE, National Grid, and GMP that listed an expiration date of September 30, 2022 (TSA-NEP-25). The Parties requested that the FERC grant waiver of its notice requirement[77] to the extent necessary to permit a requested October 21, 2022 effective date. The LSA was filed separately given that requested effective date.

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

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

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

[77] 18 CFR § 35.11 (which permits, upon application and for good cause shown, the FERC to allow a rate schedule, tariff, service agreement, or a part thereof, to become effective as of a date prior to the date of filing or the date such change would otherwise become effective in accordance with the FERC's rules (e.g. 60 days after filing)). FERC policy is to deny waiver of the prior notice requirement when an agreement for new service is filed on or after the date that services commence, absent a showing of extraordinary circumstances.

filing.[78] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties to make Time Value Refunds. On December 4, 2023, Filing Parties requested, and on December 6, 2023 the FERC granted, a 45-day extension of time (to ***January 22, 2024***) to make the Time Value Refunds, with the corresponding refund report to be filed no later than ***February 21, 2024***.

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

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

On July 28, 2023, the FERC accepted seven fully executed, non-conforming LSAs by and among Versant Power, ISO-NE and Black Bear Hydro Partners, LLC or Black Bear SO, LLC (together with Black Bear Hydro Partners, "Black Bear").[79] The service agreements are based on the Form of Local Service Agreement contained in Schedule 21-Common under the ISO-NE OATT, but were filed because they are non-conforming insofar as they reflect different rates from those set forth in Schedule 21-VP. The LSAs were accepted for filing effective *August 1, 2023*, rather than January 1, 2021 as requested, triggering a Time Value Refund requirement.[80] On August 29, 2023, Versant Power submitted a Refund Report detailing the Time Value Refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments on the Refund Report were due on or before September 19, 2023; none were filed. The Refund Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

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

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

On January 16, 2024, pursuant to Section 4 of Schedule 21-GMP, Green Mountain Power supplemented its annual informational filing containing the forecast of its costs for the January 1, 2024 through December 31, 2024 time period. The supplement does not change the 2024 forecasted rates previously filed. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

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

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

[80] The FERC denied the requested waiver of its 60-day prior notice requirement (18 C.F.R. § 35.11), finding that the Filing Parties did not make an adequate showing of extraordinary circumstances. Accordingly, Versant was required to refund the time value of revenues collected for the time period the rate was collected without FERC authorization (with refunds limited so as not to cause Versant to operate at a loss) and file a refund report with the FERC.

VIII. Regional Reports[81]

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

On January 30, 2024, 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/search?query=Prior%20Year%20List%20of%20Projects%20Designated%20to%20the%20PTOs. This filing will not be noticed for public comment by the FERC.

- **LFTR Implementation: 61st Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 61st of its quarterly status reports regarding LFTR implementation on January 12, 2024. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

- **IMM Quarterly Markets Reports – Fall 2023 (ZZ24-5)**

On January 29, 2024, the IMM filed with the FERC its Fall 2023 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Fall 2023 Report will be discussed with the Markets Committee at the February 7, 2024 Markets Committee meeting.

IX. Membership Filings

- **February 2024 Membership Filing (ER24-1024)**

On January 31, 2024, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: Bristol BESS, LLC and Frankland Road Solar, LLC [Related Persons to the Agilitas Companies (AR Sector, DG Sub-Sector)]; Dare US LLC (Supplier Sector); Eoch Energy LLC (Supplier Sector); and Phillips 66 Energy Trading LLC (Supplier Sector); and (ii) the termination of the Participant status of Community Eco Power, LLC (AR Sector, RG Sub-Sector, Small RG Group Seat); MPower Energy LLC (Supplier Sector); Pixelle Energy Services LLC (Generation Sector); Power Ledger Pty Ltd (GIS-Only Member); Union Atlantic Electricity (Supplier Sector); and Utility Services of Vermont LLC [Related Person to ENE (Publicly Owned Entity Sector)]. Comments on this filing, if any, are due on or before ***February 21, 2024***.

- **January 2024 Membership Filing (ER24-769)**

On December 28, 2023, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: Bristol BESS, LLC and Frankland Road Solar, LLC [Related Persons to the Agilitas Companies (AR Sector, DG Sub-Sector)]; Dare US LLC (Supplier Sector); Eoch Energy LLC (Supplier Sector); and Phillips 66 Energy Trading LLC (Supplier Sector); and (ii) the termination of the Participant status of Astral Energy LLC (Supplier Sector). Comments on this filing were due on or before January 18, 2024; none were filed This matter is pending before the FERC.

[81] Reporting on the *Opinion 531* Refund Reports (EL11-66) has been suspended and will be continued if and when there is new activity to report.

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

On January 26, 2024, the FERC accepted: (i) the following Applicants' membership in NEPOOL: Citadel Energy Marketing LLC (Supplier Sector); Downeast Wind, LLC [Related Person to Kleen Energy (Generation Sector)]; JGT2 Energy LLC (Generation Sector); and Qnti.fyi Inc. (Supplier Sector); and (ii) the termination of the Participant status of Sam Mintz (End User Sector).[82] Unless the January 26 order is challenged, this proceeding will be concluded.

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

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

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

On January 24, 2024, the FERC approved, effective January 24, 2024, an amended petition for the approval of PRC-023-6 (Transmission Relay Loadability).[83] NERC stated that PRC-023-6 would retire "redundant and unnecessary language that has contributed to confusion regarding the proper application of the PRC-023 standard to out-of-step blocking relays." Unless the January 24 order is challenged, this proceeding will be concluded.

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

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

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

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

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

[82] *New England Power Pool Participants Comm.*, Docket No. ER24-524-000 (Jan. 26, 2024).

[83] *N. Amer. Elec. Rel. Corp.*, Docket No. RD23-5-000 (Jan. 24, 2024) (unpublished letter order) (approving PRC-023-6).

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

development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[85] on December 15, 2023. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the December 15 report, NERC reported that the schedule for Project 2016-02 has been further revised and now calls for final balloting of revised standards in March 2024, NERC Board of Trustees Adoption in May 2024 and filing of the revised standards with the FERC in **June 2024**.

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

On October 19, 2023, the FERC issued a final rule[86] directing NERC to develop new or modified Reliability Standards that address reliability gaps related to inverter-based resources ("IBR") in the following areas: data sharing; model validation; planning and operational studies; and performance requirements. The FERC directed NERC to submit an informational filing that includes a detailed, comprehensive standards development plan providing that all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in *Order 901.* NERC submitted its "*Order 901* Work Plan" on January 17, 2024. NERC submitted the *Order 901* Work Plan for informational purposes only and it will not be noticed by the FERC for public comment. NERC committed to maintain an up-to-date copy of the *Order 901* Work Plan on the NERC website.

- **2024 Reliability Standards Development Plan (RM05-17 et al.)**

On December 15, 2023, NERC submitted its 2024–2026 Reliability Standards Development Plan ("2024 Development Plan") in accordance with Section 310 of the NERC Rules of Procedure. The 2024 Development Plan provides a status update on active development projects, a forecast of future work to be undertaken by NERC and its stakeholders throughout the upcoming year, and a progress report comparing results achieved to the prior year's Reliability Standards Development Plan. The NERC Board of Trustees approved the 2024 Development Plan on December 12, 2023. NERC submitted this filing and the attached 2024 Development Plan for informational purposes only and it will not be noticed by the FERC for public comment.

XI. Misc. - of Regional Interest

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

On July 28, 2023, the FERC authorized[87] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). Pursuant to the July 28 order, Lessor and Lessee must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On April 17, 2023, Energy Harbor Corp., on behalf of Energy Harbor, LLC and Energy Harbor Nuclear Generation LLC (collectively, the "Energy Harbor Public Utilities"), and Vistra Corp. ("Vistra"), requested FERC authorization for a proposed transaction pursuant to which the Energy Harbor Public Utilities and certain Vistra subsidiaries that are public utilities will become indirectly owned by a newly-formed subsidiary holding company of Vistra – Vistra Vision. Comments on this 203 application were due on or before June 23, 2023. Protests and comments were filed by Northeast Ohio Public Energy Council ("NOPEC"), Office of the Ohio Consumers' Counsel ("OH OCC"), and Monitoring Analytics, LLC (the PJM IMM). Public Citizen filed a doc-less intervention. Vistra and

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[85] 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.

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

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

the Energy Harbor Public Utilities responded to the protests and comments. Answers to that answer were filed by PJM's IMM. Comments were filed by the Justice Department's Antitrust Division on August 22; Vistra and Energy Harbor answered those comments on September 5, 2023.

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

Tolling Order. On October 13, 2023, the FERC issued a notice that it requires additional time to "fully analyze the Application" and tolled the deadline to act on the Application until ***April 11, 2024***.[88]

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

- **IA Cancellation Versant / PERC (ER24-965)**

On January 22, 2024, Versant filed a notice of cancellation of an Interconnection Agreement ("IA") between itself and Penobscot Energy Recovery Company ("PERC"). Versant reported that PERC discontinued operations of an approximately 25 MW solid waste-fired generating facility that interconnected to its Orrington Substation. The facility was later sold to C&M Faith Holdings LLC, and is no longer connected or operating. Comments on the notice of cancellation are due on or before ***February 12, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Viridon Incentive Rate Treatments (ER24-771)**

On December 26, 2023, Viridon New England LLC ("Viridon"), an affiliate of Blackstone Inc., requested authorization to utilize three incentive rate treatments – (i) a regulatory asset incentive, (ii) a hypothetical capital structure incentive, and (iii) an RTO participation incentive[89] – for the development of transmission projects within the New England region. Viridon also asked the FERC to authorize any Viridon subsidiaries created to own or develop specific transmission assets in New England to use the same rate incentives without re-litigation. Costs for any Viridon project would flow through ISO-NE transmission rates once Viridon becomes a New England Transmission Owner. Viridon stated that it will request that ISO-NE file any required conforming changes to incorporate the Viridon rate incentives approved in this docket into the OATT formula rate before collecting revenue requirements through the OATT. Comments on this filing were due on or before January 16, 2024; 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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88 *Energy Harbor Corp. and Vistra Corp.*, 185 FERC ¶ 61,024 (Oct. 13, 2023).

89 Specifically, the incentive rate treatments for which authorization is sought are (i) recovery of all prudently incurred pre-commercial, start-up and formation costs, and establishment of a regulatory asset that will include all expenses that are incurred prior to the rate year in which Viridon's costs are first flowed through to customers under the Tariff, including authorization to accrue carrying charges and to amortize the regulatory asset over five years for cost recovery purposes ("Regulatory Asset Incentive"); (ii) use of a hypothetical capital structure of 40% debt and 60% equity until the first transmission project awarded to Viridon achieves commercial operation ("Hypothetical Capital Structure Incentive"); and (iii) inclusion of a 50 basis-point return on equity ("ROE") adder to the base ROE ("RTO Participation Incentive") in recognition that Viridon has committed to turn over functional control of all transmission assets it develops and owns to ISO-NE. Viridon states that it will become a transmission-owning member of ISO-NE at the earliest possible date permitted under the Tariff and governing documents and will transfer functional control of any transmission project to ISO-NE once such project is placed in service.

- **D&E Agreement 2d Amendment: NSTAR/Park City Wind (ER24-747)**

On December 21, 2023, NSTAR filed a second amendment to the Design & Engineering ("D&E") Agreement between NSTAR and Park City Wind LLC ("Park City Wind") (the "Park City Wind D&E Agreement"). The second amendment to the Park City Wind D&E Agreement further extends the term and amends the scope of work under the Agreement to (i) address the risks and impacts of new milestone revisions under consideration; (ii) conduct engineering associated with an additional 115 kV breaker at West Barnstable Station; and (iii) conduct engineering to support foundation expansion and line exists at NSTAR's West Barnstable and Bourne Stations. Comments on this filing were due on or before January 11, 2024; 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).

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

On November 30, 2023, NextEra Energy Seabrook, LLC ("Seabrook") filed a second amendment to the Engineering and Procurement ("E&P") Agreement between Seabrook and NECEC Transmission LLC ("NECEC") (the "A&R E&P Agreement"). The A&R E&P Agreement covers the final engineering drawings through the procurement and delivery of the 24.5 kV generator circuit breaker and ancillary equipment to Seabrook Station in advance of the Fall 2024 outage. The second amendment seeks approximately $2 million in additional funding to cover higher engineering costs as well as changes to the scope of work related to a hydraulic controller, the generator breaker monitoring system, and other items. Comments on the November 30 filing were due on or before December 21, 2023; none were filed. Avangrid and National Grid submitted doc-less interventions only. Since the last Report, Seabrook filed an amendment to correct the eTariff record of the Amended A&R E&P Agreement by submitting a complete eTariff record. Additional comments are due on or before ***February 16, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[90]

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

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

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

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

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

FERC's October 30, 2023 Second Supplemental Notice of Technical Conference. Speaker materials have been posted to FERC's eLibrary.

On November 14, 2023, the FERC invited all interested persons to file post-technical conference comments addressing issues raised during the Reliability Technical Conference and identified in the Second Supplemental Notice. Post technical conference comments were filed by: Constellation, NRDC, ACPA, ACRE, AEP, American Forest & Paper Assoc., American Municipal Power, America's Power, Duke, Earthjustice, EEI 1, EEI 2, Energy Strategy Coalition, Energy Transfer, Florida Municipal Power Agency, INGA, ITC, LPPC, OH Fed. Energy Advocate, PJM Cities and Communities Coalition, Southern Company Services, TAPS, US Chamber of Commerce, Reliable Energy Analytics, US EPA Office of Air and Radiation, and Sue Tierney (who attached her prepared statement from the technical conference and her recently-prepared report on the same issues). Since the last Report, each of the three FERC commissioners posted responses to members of Congress who had commented or had inquired about the Technical Conference. In addition, on January 25, 2024, a group of Senators, including a few from the New England delegation, filed comments. This matter is pending before the FERC.

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

An eighth meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF")[91] will be held on Wednesday, ***February 28, 2024***, from approximately 1:30 pm to 4:00 pm Eastern time, at the Weston Washington in Washington, DC.[92] All interested persons were invited to file comments in this docket suggesting agenda items by January 8, 2024. Comments were filed by American Council on Renewable Energy ("ACRE"), AEP, Harvard Electricity Law Initiative, Invenergy Transmission, Rocky Mountain Institute, and Thomas Donahue. Since the last Report, NARUC nominated Chair Mary Throne of the Wyoming Public Service Commission to represent the Western Conference of Public Service Commissioners region for the remainder of the one-year term of Chair Thad LeVar, who recently resigned his position at the Utah Public Service Commission.

- **RTO/ISOs Common Performance Metrics (AD19-16)**

On January 31, 2024, FERC Staff issued its summary of its review of performance metrics data on RTOs/ISOs activities and data related to RTO/ISO administrative functions, energy markets, and capacity markets for the 2019 to 2022 reporting period. The data collection consisted of, and the discussion is organized by 29 Common Metrics divided into 3 groups from the 6 RTO/ISOs;[93] no non-RTO/ISO responded. As previously

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

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

[93] There are seven ***Group 1 metrics***: Reserve Margins, Average Heat Rates, Fuel Diversity, Capacity Factor by Technology Type, Energy Emergency Alerts (("EEA") Level 1 or Higher), Performance by Technology Type during EEA Level 1 or Higher, and Resource Availability (Equivalent Forced Outage Rate Demand ("EFORd")). There are 12 ***Group 2 metrics***: Number and Capacity of Reliability Must-Run Units, Reliability Must-Run Contract Usage, Demand Response Capability, Unit Hours Mitigated, Wholesale Power Costs by Charge Type, Price Cost Markup, Fuel Adjusted Wholesale Energy Price, Energy Market Price Convergence, Congestion Management, Administrative Costs, New Entrant Net Revenues, and Order No. 825 Shortage Intervals and Reserve Price Impacts; There are 10 ***Group 3 metrics***: Net Cost of New Entry ("Net CONE") Value, Resource Deliverability, New Capacity (Entry), Capacity Retirement (Exit), Forecasted Demand, Capacity Market Procurement and Prices, Capacity Obligations and Performance Assessment Events, Capacity Over-Performance, Capacity Under-Performance, and Total Capacity Bonus Payments and Penalties. The update metrics eliminate previously-collected metrics on reliability, RTO/ISO billing controls and customer satisfaction, interconnection and transmission processes, and system lambda.

reported, ISO-NE submitted its Form 922 on April 24, 2023. The metrics included in the 2023 Report are identical to the metrics from the 2021 Report.

- ***Order 903*: 2024 Civil Monetary Penalty Inflation Adjustments (RM24-3)**

On January 5, 2024, the FERC issued *Order 903*[94] 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.[95] Of particular interest is the increase in potential civil penalties for market manipulation, which were increased from $1,496,035 to $1,544,521 per violation, per day. *Order 903* became effective *January 9, 2024*.[96]

- **NOPR: EQR Filing Process and Data Collection (RM23-9)**

On October 19, 2023, the FERC issued a NOPR[97] proposing various changes to current Electric Quarterly Report ("EQR") filing requirements, including both the method of collection and the data being collected. The proposed changes are designed to update the data collection, improve data quality, increase market transparency, decrease costs, over time, of preparing the necessary data for submission, and streamline compliance with any future filing requirements. Among other things, the FERC proposes to implement a new collection method for EQR reporting based on the eXtensible Business Reporting Language ("XBRL")-Comma-Separated Values standard; amend its regulations to require ISO/RTOs to produce reports containing market participant transaction data; and modify or clarify EQR reporting requirements. Requests for additional time to comment on the *EQR NOPR* were filed by EEI/EPSA, the IRC and the Bonneville Power Administration ("BPA"). On December 7, 2023, the FERC extended the deadline for submitting comments to and including ***February 26, 2024***. Thus far, one set of comments was filed by XBRL US.

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

On July 28, 2022, the FERC issued a NOPR[98] proposing to add a new section to its regulations to require that any entity communicating with the FERC or other specified organizations (e.g. ISO/RTOs, FERC-approved market monitors, NERC and its Regional Entities, or transmission providers) related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information, or omit material information ("Duty of Candor Requirements"). An entity would be shielded from violation of the new regulation if it has exercised due diligence to prevent such occurrences. The FERC's current regulations prohibit, in defined circumstances, inaccurate communications to the FERC and other organizations upon which the FERC relies to carry out its statutory obligations. However, because those requirements cover only certain communications and impose a patchwork of different standards of care for such communications, the FERC believes that a broadly applicable duty of candor will improve its ability to effectively oversee jurisdictional

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94 *Civil Monetary Penalty Inflation Adjustments*, Order No. 903, 186 FERC ¶ 61,017 (Jan. 5, 2024) ("*Order 903*").

95 *See* Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, Sec. 701, Pub. L. 114-74, 129 Stat. 584, 599. The FERC made its first adjustment under the Act in July 2016. *See Civil Monetary Penalty Inflation Adjustments*, Order No. 826, 81 FR 43937 (July 6, 2016), FERC Stats. & Regs. ¶ 31,386 (2016). The second adjustment was made January 9, 2017. *Civil Monetary Penalty Inflation Adjustments*, Order No. 834, 158 FERC ¶ 61, 170 (Jan. 9, 2017). The third adjustment as made January 8, 2018. *Civil Monetary Penalty Inflation Adjustments*, Order No. 839, 162 FERC ¶ 61,010 (Jan. 8, 2018). The fourth adjustment was made January 9, 2019. *Civil Monetary Penalty Inflation Adjustments*, Order No. 853, 166 FERC ¶ 61,041 (Jan. 8, 2019). The fifth adjustment was made January 14, 2020. *Civil Monetary Penalty Inflation Adjustments*, Order No. 865, 170 FERC ¶ 61,001 (Jan. 2, 2020). The sixth adjustment was made January 8, 2021. *Civil Monetary Penalty Inflation Adjustments*, Order No. 875, 174 FERC ¶ 61,015 (Jan. 8, 2021). The seventh adjustment was made January 7, 2022. *Civil Monetary Penalty Inflation Adjustments*, Order No. 882, 178 FERC ¶ 61,008 (Jan. 7, 2022). The eighth adjustment was made January 12, 2023. *Civil Monetary Penalty Inflation Adjustments*, Order No. 886, 178 FERC ¶ 61,002 (Jan. 6, 2023).

96 *Order 903* was published in the *Fed. Reg.* on Jan. 9, 2024 (Vol. 89, No. 6) pp. 1,025-1,029.

97 *Revisions to the Filing Process and Data Collection for the Electric Quarterly Report*, 185 FERC ¶ 61,043 (Oct. 19, 2023) ("*EQR NOPR*").

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

markets. It further indicated that its proposed due 'diligence standard' and other limitations are intended to minimize the additional burdens to industry that come with the new Duty of Candor Requirements.

On September 1, 2022, Joint Associations[99] requested an additional month to submit comments.[100] On September 14, 2022, the FERC granted that request. Accordingly, initial comments were due November 11, 2022 and over 30 sets of comments were filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA, APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange. The US Chamber of Commerce filed reply comments on December 12, 2022. There was no activity in the proceeding since the last Report. This matter is pending before the FERC.

- ***Order 2023*: Interconnection Reforms (RM22-14)**

On July 28, 2023, the FERC issued *Order 2023*,[101] its final rule on proposed reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("LGIA"), and *pro forma* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. *Order 2023* adopts reforms to: (i) implement a first-ready, first-served cluster study process;[102] (ii) increase the speed of interconnection queue processing;[103] and (iii) incorporate technological advancements into the interconnection process.[104] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of

[99] "Joint Associations" included the following trade associations on behalf of their respective members: the American Gas Assoc. ("AGA"), American Public Gas Assoc. ("APGA"), Interstate Natural Gas Assoc. of America ("INGA"), Edison Electric Institute ("EEI"), EPSA, Energy Trading Institute ("ETI"), Natural Gas Supply Assoc. ("NGA"), and Process Gas Consumers Group ("PGCG").

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

[101] *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*").

[102] A first-ready, first-served cluster study process improves efficiency in the interconnection study process by including the following elements: increased access to information prior to entering the queue; a mechanism to study interconnection requests in groups where all interconnection requests in the group are equally queued and of equal study priority; and increased financial commitments and readiness requirements to enter and proceed through the queue. In contrast, the existing first-come, first-served serial study process in the *pro forma* LGIA and LGIP provides limited information to interconnection customers prior to entering the queue, assigns interconnection requests an individual queue position based solely on the date of entry into the queue, and contains limited financial and readiness requirements.

In order to implement a first-ready, first-served cluster study process, *Order 2023* requires: (1) transmission providers to publicly post available information pertaining to generator interconnection; (2) transmission providers to use cluster studies as the interconnection study method; (3) transmission providers to allocate cluster study costs on a pro rata and per capita basis; (4) transmission providers to allocate network upgrade costs based on a proportional impact method; (5) interconnection customers to pay study and commercial readiness deposits as part of the cluster study process; (6) interconnection customers to demonstrate site control at the time of submission of the interconnection request; and (7) transmission providers to impose withdrawal penalties on interconnection customers for withdrawing from the interconnection queue, with certain exceptions. We also require transmission providers to adopt a transition process to move from the existing serial interconnection process to the new cluster study process.

[103] In order to increase the speed of interconnection queue processing, *Order 2023*: (1) eliminates the reasonable efforts standard for conducting interconnection studies and imposes a financial penalty on transmission providers that fail to meet interconnection study deadlines; and (2) establishes an affected system study process and associated *pro forma* affected system agreements.

[104] In order to incorporate technological advancements into the interconnection process, *Order 2023* requires transmission providers to: (1) allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request; (2) evaluate the proposed addition of a generating facility at the same point of interconnection prior to deeming such an addition a material modification if the addition does not change the originally requested interconnection service level; (3) allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA; (4) use operating assumptions in interconnection studies that reflect the proposed charging behavior of an electric storage resource; and (5) evaluate the list of alternative transmission technologies enumerated in this final rule during the generator interconnection study process.

Proposed Rulemaking.[105] However, the FERC did revise aspects of the reforms.[106] *Order 2023* became effective November 6, 2023[107] (60 days from its publication in the *Federal Register* ("Publication Date")).

A more detailed summary of, and a presentation on, *Order 2023* was provided to, and discussed with, the Transmission Committee. Compliance will require changes to the Tariff's *pro forma* LGIA, LGIP, SGIA and SGIP. Absent further changes to the compliance schedule, there will be much to accomplish in a relatively short amount of time.

Requests for Clarification and/or Rehearing. Requests for rehearing, clarification and/or an extension of time were filed by 35 parties. Those parties raised, among other issues, the following:

- The FERC erred in removing the Reasonable Efforts standard and imposing penalties for late studies;
- The FERC must clarify aspects of the transition process and use of Transitional Cluster Studies and Transitional Serial Studies;
- Transmission Providers need additional details on the FERC's requirement for Transmission Provider's to publish heatmaps;
- The FERC must provide insight on the process of performing cluster studies as well as the cost allocation methodology; and
- Transmission Providers require further clarity regarding the alternative transmission technologies that they are required to review.

Requests for Clarification and/or Rehearing Denied by Operation of Law. On September 28, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[108] The *Order 2023 Allegheny Notice* confirmed that the 60-day period during which a petition for review of *Order 2023* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of *Order 2023* within the required 30-day period. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." Several parties submitted petitions in Federal Court challenging *Order 2023*. Developments in those federal court proceedings will be summarized in Section XVI below.

October 25, 2023 Order Extending Compliance Deadline. On October 25, 2023, the FERC issued an order modifying the discussion in *Order 2023* and setting aside the *Order*, in part, to extend the deadline to submit

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[105] *Order 2023* also requires: (i) interconnection customers requesting to interconnect a non-synchronous generating facility to: (a) provide the transmission provider with the models needed for accurate interconnection studies; and (b) have the ability to maintain power production at pre-disturbance levels and provide dynamic reactive power to maintain system voltage during transmission system disturbances and within physical limits; (ii) all newly interconnecting large generating facilities provide ride through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis; and (iii) with respect to the *pro forma* SGIP and *pro forma* SGIA, the incorporation of enumerated alternative transmission technologies into the interconnection process, and the provision of modeling and ride through requirements for non-synchronous generating facilities.

[106] Reforms revised in *Order 2023* pertain to the cluster study process, allocation of cluster study and network upgrade costs, increased financial commitments and readiness requirements, financial penalties for delayed interconnection studies, the affected system study process, pro forma affected system agreements, the material modification process, operating assumptions for interconnection studies, incorporating the enumerated alternative transmission technologies, and ride through requirements. In addition, the FERC declined to adopt the NOPR proposals pertaining to informational interconnection studies, shared network upgrades, the optional resource solicitation study, and the alternative transmission technologies annual report.

[107] *Order 2023* was published in the Fed. Reg. on Sep. 6, 2023 (Vol. 88, No. 171) pp. 61,041-61,349.

[108] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 62,163 (Sep 28, 2023) ("*Order 2023 Allegheny Notice*").

compliance filings to ***April 3, 2024*** (210 days after the publication of *Order 2023* in the *Federal Register*).[109] The FERC clarified that its Order does not change or modify any other determination or other deadlines established by *Order 2023*, including the deadline for eligibility for interconnection customers to opt to proceed with a transitional serial study (for those interconnection customers tendered a facilities study agreement) or transitional cluster study (for those interconnection customers assigned a queue position) or to withdraw their interconnection requests without penalty (i.e., 30 calendar days after the transmission provider submits its initial compliance filing (or ***May 3, 2024***)).[110] A revised stakeholder schedule for consideration of New England's Order 2023 compliance filing was discussed at the November 9, 2023 Transmission Committee meeting.

If you have any questions concerning this matter, please contact Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On December 15, 2022, the FERC issued a NOPR[111] proposing to revise its regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act. The *Transmission Siting NOPR* is intended to ensure consistency with the Infrastructure and Jobs Act's amendments to FPA section 216, to modernize certain regulatory requirements, and to incorporate other updates and clarifications to provide for the efficient and timely review of permit applications. Following a NARUC request for an extension of time granted by the FERC, comments on the *Transmission Siting NOPR* were due on or before May 17, 2023. Comments were filed by CLF, AL PSC, National Wildlife Federation Action Fund, National Wild Life Federation and State-Affiliated Organizations, AEU, CLF (May 16), NESCOE, ACPA, ACRE, Clean Energy Buyers Assoc., EDF, EEI/WIRES, Joint Consumer Advocates, Public Interest Organizations, SEIA, and US Chamber of Commerce. Commissioner Phillips' and each of the Commissioners' responses to Senator Schumer's and Senator Barrasso's letters have been posted to eLibrary. This matter is pending before the FERC.

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

Following its ANOPR process,[112] the FERC issued on April 21, 2022 a NOPR[113] that would require public utility transmission providers to:

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

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[109] *Improvements to Generator Interconnection Procedures and Agreements*, 185 FERC ¶ 61,063 (Oct. 25, 2023).

[110] *Id.* at P 11.

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

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

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

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

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

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

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

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

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

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[114] Nearly 200 sets of comments were filed, including comments by NEPOOL, ISO-NE, Acadia/CLF, Anbaric, AEU, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

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

[114] A July 27, 2022, request by the Georgia Public Service Commission ("GA PUC") for an additional 30 days of time to submit comments and reply comments was denied on Aug. 9, 2022.

stated demonstrates that competitive transmission solicitations can provide significant value to consumers. In December 2022, the Harvard Electricity Law Initiative, and P. Alaama submitted further comments.

LS Power and NRG filed comments in this proceeding, as well as in (Transmission Planning and Cost Management Joint Federal-State Task Force on Electric Transmission) (AD22-8) and JFSTF proceeding (AD21-15). They asserted that the FERC "cannot sufficiently address the transmission planning issues raised in its Transmission NOPR without addressing the intertwined cost management issues raised in AD22-8-000 and during the October 6, 2022 Technical Conference in AD22-8." Additional comments were filed by ACRE, Breakthrough Energy, Clean Energy Buyers Association, the Cross Sector Coalition, Developers Advocating Transmission Advancements, Environmental Advocates,[115] Institute for Policy Integrity at NYU, and Rocky Mountain Institute. Since the last Report, members of Congress (Senators and Congressmen) filed comments urging the FERC to strengthen and finalize the *Transmission NOPR*.

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

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Linde / NIPSCO (MISO DR Program Violations) (IN24-3)**

  On January 4, 2024, the FERC approved a Stipulation and Consent Agreement with Linde Inc. ("Linde") and Northern Indiana Public Service Company LLC ("NIPSCO") to resolve OE's investigation of Linde's participation, through NIPSCO as its market participant, in MISO's demand response ("DR") program.[116] OE determined that between August 2017 and July 2022 ("Relevant Period"), Linde planned the sequence and duration of its facility's load levels so as to artificially inflate its baseline and thereby its DR program payments. It "enhanced" its strategy starting in 2020 by operating certain equipment solely for the purpose of increasing its electricity use and further raising its baseline. OE thus found that Linde did not reduce energy consumption levels when MISO accepted its DR offers; instead, Linde operated at load levels at which it planned to operate. Because NIPSCO was the market participant for Linde's participation in the DR program, OE concluded that NIPSCO, consistent with the MISO Tariff, was responsible for Linde's conduct that violated the MISO Tariff.

  Under the Stipulation and Consent Agreement, Linde agreed to ***disgorge $48.5 million*** it received through its participation in MISO's DR program during the Relevant Period. Linde also agreed to pay a ***civil penalty of $10.5 million*** to the United States Treasury and to a series of training and compliance monitoring steps if it resumes participation in MISO's DR program prior to January 1, 2027. ***NIPSCO agreed to disgorge $7.7 million*** it received in connection with Linde's DR program participation. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Vitol & F. Corteggiano (CAISO CRR Violations) (IN14-4)**

  Also on January 4, 2024, the FERC approved a Stipulation and Consent Agreement with Vitol Inc. ("Vitol") and Federico Corteggiano ("Corteggiano") to resolve (i) the FERC's claim, as described more fully in

[115] The "Environmental Advocates" included: AEU, ACPA, Clean Air Task Force, Earthjustice, Environmental Defense Fund, Evergreen Action, Fresh Energy, Interwest Energy Alliance, League of Conservation Voters, National Wildlife Federation, NRDC, Northwest Energy Coalition, Rewiring America, Sierra Club, Southern Environmental Law Center, The Environmental Law & Policy Center, UCS, WE ACT for Environmental Justice, and Western Resource Advocates.

[116] *Linde Inc. and Northern Indiana Public Service Company LLC*, 186 FERC ¶ 61,009 (Jan. 4, 2024).

its 2019 *Vitol Penalties Order*,[117] that Vitol and its co-head of FTR trading operations violated the Anti-Manipulation Rule by selling physical power at a loss in CAISO's market in order to eliminate congestion that they expected to cause losses on Vitol's congestion revenue rights ("CRRs"); and (ii) the Federal Court lawsuit that followed,[118] initiated by the FERC, for an order affirming the penalties assessed in the *Vitol Penalties Order* following a *de novo* review of the law and the facts involved.

Under the Stipulation and Consent Agreement, Vitol and Corteggiano will pay ***civil penalties of $2.225 million*** and ***$75,000***, respectively (a total of ***$2.3 million***). The FERC agreed to dismiss with prejudice its claims against Vitol and Corteggiano in the Federal Court Lawsuit. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

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

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[119] suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[120] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

[117] *Vitol Inc. and Federico Corteggiano*, 169 FERC ¶ 61,070 (Oct. 25, 2019) ("Vitol Penalties Order"). As previously reported, OE alleged that Vitol and Corteggiano (together, "Vitol") sold physical power at a loss at the Cragview node in CAISO's day-ahead market from Oct. 28 through Nov. 1, 2013, in order to eliminate congestion costs that they expected would negatively affect Vitol's CRRs. On Vitol's behalf, Corteggiano purchased CRRs sourcing at Cragview in CAISO's annual CRR auction for 2013. In mid-October 2013, CAISO derated the Cascade intertie to "0" in only the export direction, while still allowing imports. During the derate, an unusually high LMP appeared at Cragview due to congestion costs. The congestion costs caused Vitol's CRRs to lose money. CAISO announced that identical derates would occur during the week of October 28 through November 1 and on additional dates later in November and in December. Vitol was able to protect against losses on its CRR positions for November and December by buying counter-flow CRRs in the CRR auctions for those months (i.e., "flattening" the CRR position). However, because the monthly CRR auction for October had closed, it was too late for Vitol to flatten its CRR position for the last week of October. Facing over $1.2 million in potential losses on its CRRs during that week's scheduled partial derate, Vitol imported physical power in the day-ahead market at an offering price of $1/MWh, which prevented a recurrence of the congestion costs that Vitol had observed during the October 18-19 derate. In the *Vitol Penalties Order*, the FERC assessed civil penalties of $1,515,738 against Vitol itself and $1 million against Corteggiano. In addition, the FERC directed Vitol to disgorge unjust profits, plus applicable interest of $1,227,143.

[118] *FERC v. Vitol Inc. and Federico Corteggiano*, Case No.: 2:20-CV-00040-KJM-AC (E.D. Cal.) ("Federal Court Lawsuit").

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

[120] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 183 FERC ¶ 61,190 (June 14, 2023) ("*June 14 Order*").

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

On December 16, 2021, the FERC issued a show cause order[121] 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,[122] 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;[123] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[124] This matter is pending before the FERC.

- **Total Gas & Power North America, Inc. et al. (IN12-17)**

On April 28, 2016, the FERC issued a show cause order[125] 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.[126]

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

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

122 *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").

123 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.

124 *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 179 FERC ¶ 61,090 (May 11, 2022) ("*Designation Notice Rehearing Order*"). The "Designation Notice" provided updated notice of designation of the staff of the FERC's Office of Enforcement ("OE") as non-decisional in deliberations by the FERC in this docket, with the exception of certain staff named in that notice.

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

126 The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated NGA section 4A and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trade s 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.

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

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas ("Southern District"). In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance.[128]

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[129] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *TGPNA Presiding Officer Reassignment Order* takes effect; (ii) held that the *TGPNA Presiding Officer Reassignment Order* will take effect once the Southern District clarifies or lifts its stay for the limited purpose of allowing the *TGPNA Presiding Officer Reassignment Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; (iii) stated that this proceeding otherwise remains suspended until the Southern District's stay is lifted or dissolved such that hearing procedures may resume; and (iv) provided procedural guidance to the new presiding officer. On July 18, Judge Patricia M. French was substituted as Presiding Judge (relieving Judge Krolikowski of all of her duties with respect to this proceeding).

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

New England Pipeline Proceedings
The following New England pipeline projects are currently under construction or before the FERC:

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[130] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25,

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

[128] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 181 FERC ¶ 61,252 (Dec. 21, 2022).

[129] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 183 FERC ¶ 61,189 (June 14, 2023) ("*TGPNA Presiding Officer Reassignment Order*").

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

2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- In its January 8, 2024 monthly status report, Iroquois indicated that it is still awaiting issuance of air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois has not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in December 2023 and no construction was planned for January.

XV. State Proceedings & Federal Legislative Proceedings

No activities to report.

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).

- **Order 2023 (23-1282 (AEU); 23-1284 (MISO); 23-1289 (PacificCorp); 23-1293 (FPL); 23-1297 (SPP); 23-1299 (PJM); 23-1305 (FirstEnergy); 23-1310 (NYISO); 23-1312 (Dominion); 23-1313 (Exelon); 23-1320 (MISO TOs); 23-1327 (Avangrid); 23-1330 (Central Hudson); 23-1346 (PacifiCorp)) (consolidated)**
Underlying FERC Proceeding: RM22-14[131]
Petitioners: AEU et al.
Status: Being Held In Abeyance; Motions to Govern Future Proceedings Due Feb 16, 2024

Several Petitioners have challenged *Order 2023*. Those challenges have now been consolidated, with the AEU docket (23-1282) as the lead docket. On December 11, 2023, the FERC asked that the consolidated cases be held in abeyance pending further order of the court. In response, on December 12, 2023, the Court suspended the filing deadlines for initial submissions and procedural/dispositive motions and directed the parties to file motions to govern future proceedings by ***February 16, 2024***.

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)**
Underlying FERC Proceeding: ER22-983[132]
Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
Status: Being Held In Abeyance

On June 30, 2023, ISO-NE (23-1168), CMP/UI (23-1170), Eversource (23-1167), and National Grid (23-1169) petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the FERC's *Order 2222*

[131] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*"); 184 FERC ¶ 62,163 (Sep. 28, 2023) (Notice of Denial of Rehearing by Operation of Law).

[132] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*Order 2222 Compliance Order*"); *ISO New England Inc. and New England Power Pool Participants Comm.*, 183 FERC ¶ 62,050 (May 1, 2023) ("*Order 2222 Compliance Allegheny Notice*", and together with the *Order 2222 Compliance Order*, the "*Order 2222 Compliance Orders*").

Compliance Orders.[133] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case. On July 24, 2023, the FERC moved to have the consolidated cases held in abeyance pending the issuance of the Commission's further order on rehearing. The Court granted that motion on July 27, 2023, with the case to be held in abeyance pending further order of the Court. Since the last Report, on October 10, 2023, the FERC asked that the consolidated appeals be held in abeyance for a period of 90 days to allow time for all parties to assess the FERC's recent order and to make further filings either with the FERC or with the Court. On October 12, 2023, the Court ordered that the consolidated cases remain in abeyance pending further order of the court. The parties were directed to file motions to govern future proceedings in this case by January 24, 2024. On January 22, 2024, the FERC filed a request that the consolidated petitions for review continue to be held in abeyance until the expiration of the period for filing petitions for review of the FERC's forthcoming order on rehearing of the *Order 2222 60-Day Compliance Filing Order* (*see* Section III above). The FERC's request is pending before the Court.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[134]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Briefing Completed; Oral Argument Scheduled for Feb 6, 2024

On April 4, 2023, NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC (collectively, "NextEra") petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the Seabrook Dispute.[135] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. Briefing is completed. Oral argument has been scheduled for ***February 6, 2024*** and will be heard by Judges Millett, Katsas and Rao.

[133] In response to the region's *Order 2222 Changes*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*, as described in previous Reports. When filed, the Filing Parties stated that the *Order 2222 Changes* create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

[134] *NextEra Energy Seabrook, LLC and NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC*, 182 FERC ¶ 61,044 (Feb. 1, 2023) *("Seabrook Dispute Order")*, *reh'g denied by operation of law*, *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Notice*"); *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 61,196 (June 15, 2023) ("*Seabrook Dispute Allegheny Order*").

[135] In the Seabrook Dispute Order, the FERC (i) both denied and granted in part the Seabrook Complaint; (ii) dismissed the Seabrook Declaratory Order Petition; and (iii) directed Seabrook to replace the Seabrook Station breaker pursuant to its obligations under the Seabrook LGIA and Good Utility Practice. Specifically, the FERC denied the Seabrook Complaint in part because it found that Avangrid had "not shown that Seabrook is obligated to replace the breaker due to Seabrook failing to meet certain open access obligations or because Seabrook has failed to comply with Schedule 25 of the ISO-NE Tariff". However, the FERC found that, "under Seabrook's LGIA, Seabrook may not refuse to replace the breaker because it is needed for reliable operation of Seabrook Station and required by Good Utility Practice" and thus, given the specific facts and circumstances in the record, granted the Seabrook Complaint in part. With respect to cost issues, the FERC agreed with Avangrid that, in this case, Seabrook should not recover opportunity costs (e.g. lost profits, lost revenues, and foregone Pay for Performance ("PFP") bonuses) or legal costs. In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the Seabrook Dispute Order, that additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition. The breaker replacement is currently expected to take place during the Fall 2024 refueling outage and the commercial operation date for the NECEC Project is December 2024. Seabrook plans to file an agreement governing installation at the earlier of 30 days prior to delivery of the breaker or 120 days prior to the start of the Fall 2024 outage. The FERC noted its expectation that such an agreement would resolve whatever remaining issues exist between the parties to allow replacement of the breaker to move forward during the 2024 outage, or if not, an unexecuted agreement would be filed.

- **Mystic II (ROE & *True*-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
  Underlying FERC Proceeding: EL18-1639-010, -011,[136] -013[137] -017[138]
  Petitioners: Mystic, CT Parties,[139] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Jan 24, 2024

This case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*. The Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings related to MISO TOs, now on remand at the FERC. Most recently, on January 24, 2024, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the *MISO TOs* case. On October 26, 2023, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***April 24, 2024***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[140]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until March 1, 2024)

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was

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[136] *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).

[137] *Constellation Mystic Power, LLC,* 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*")*; Constellation Mystic Power, LLC,* 178 FERC ¶ 62,028 (Jan. 18, 2022) ("*January 18 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Second Allegheny Order).

[138] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*"); *Constellation Mystic Power, LLC*, 179 FERC ¶ 62,179 (June 27, 2022) ("*June 27 Notice*") (Notice of Denial By Operation of Law of Rehearings of *Mystic First CapEx Info. Filing Order*).

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

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

dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance three times. The Court has granted each request. The most recent request was submitted on July 22, 2022 (third abeyance request) and the Court granted a few days later the request to hold this matter in abeyance until March 1, 2024, the date on which the elimination of MOPR is to be implemented, with motions to govern due 30 days thereafter.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[141]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[142] 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*[143] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on November 28, 2023.

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

[142] 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.

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

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[144]
  Petitioner: Sierra Club
  Status: Oral Argument Held Sep 18, 2023; Awaiting Decision

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. Briefing is complete. Oral argument before Judges Henderson, Pan and Rogers was held on September 18, 2023. This matter is pending before the Court.

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

INDEX
Status Report of Current Regulatory and Legal Proceedings as of January 31, 2024

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

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

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. FERC Enforcement Proceedings

XIV. Natural Gas Proceedings

XV. State Proceedings & Federal Legislative Proceedings

No activities to Report

XVI. Federal Courts