NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

December 31, 2025

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of January 8, 2026 Participants Committee Webex Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the January 2026 meeting of the Participants Committee will be held **via Webex on Thursday, January 8, 2026, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

To join the meeting using the enhanced Webex interface, please **download the Webex app** to your desktop or to your phone (whichever device you will be using) **in advance of the meeting** and use the app to join the meeting. You may also access the meeting through the ISO's Webex meetings page by clicking https://iso-newengland.webex.com/webappng/sites/iso-newengland/meeting/home and selecting the meeting (event password = **nepool**).

FOR PARTICIPANTS, PARTICULARLY THOSE WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE THAT ANNUAL NEPOOL MEMBERSHIP FEES FOR 2026 WILL BE INCLUDED ON THE MONTHLY STATEMENTS TO BE ISSUED ON FEBRUARY 17, 2026. Participants that are members on January 1, 2026 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 **February 19, 2026** 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).

A very happy and healthy New Year to each and every one of you.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the December 4, 2025 Participants Committee Annual Meeting. Please provide us with any comments on these draft minutes no later than **noon on Tuesday, January 6, 2025**.

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

3. To receive an ISO Chief Executive Officer report.

4. To receive a Systems and Market Operations Report (f/k/a the COO Report) ("SMOR"). The January SMOR will be circulated and posted in advance of the meeting.

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

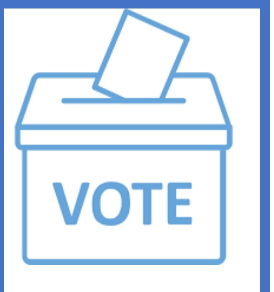
6. To receive reports from Committees, Subcommittees and other working groups:
    - Markets Committee
    - Reliability Committee
    - Transmission Committee
    - Budget & Finance Subcommittee
    - Membership Subcommittee
    - Joint Nominating Committee
    - Others

7. Administrative matters.

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

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.

1 December 4, 2025 Minutes



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RESOLVED, that the Participants Committee approves the preliminary minutes of the December 4, 2025 meeting, as circulated in advance of this meeting, with additional non-material clarifications, as the final minutes of the December 4, 2025 meeting.

PRELIMINARY

Pursuant to notice duly given, the 2025 annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, December 4, 2025, 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 electronically.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates and guests who were present, including ISO and State colleagues. She also welcomed FERC Commissioner David Rosner and his advisors, Messrs. Robert Ferris and Henry Engelstein, as well as Massachusetts Department of Public Utilities (MA DPU) Commissioners Liz Anderson and Stacey Rubin.

APPROVAL OF NOVEMBER 6, 2025 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the November 6, 2025 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.

REMARKS BY FERC COMMISSIONER DAVID ROSNER

Ms. Bresolin introduced FERC Commissioner David Rosner, noting his appointment to the Commission in June 2024, his service as Chair in 2025, and his nearly two decades of experience in energy policy, market design, and regulation. Prior to his appointment, Commr. Rosner served as an energy industry analyst at the FERC and spent two years on assignment to the U.S. Senate Committee on Energy and Natural Resources. In addition, Commr. Rosner had previously held policy roles at the U.S. Department of Energy and the Bipartisan Policy Center. Ms. Besolin concluded by noting ~~the~~ Commr. Rosner's Massachusetts roots, and highlighting his leadership on transmission, fuel security, energy storage, and gas-electric coordination as well as his reputation for a practical, bipartisan approach.

Thanking the Committee for the opportunity to attend and offer remarks, as well as for NEPOOL's ongoing engagement with the FERC, Commr. Rosner provided some insight into his time with and areas of focus as a FERC Commissioner. He began by expressing his appreciation from a Commissioner's perspective for the work of a fully constituted, five-member Commission, especially one that was working hard on a bipartisan basis to achieve durable consensus among a group with a diverse set of experiences, backgrounds and perspectives.

Commr. Rosner stated that the Commission's central focus is ~~on~~ ensuring reliable and affordable energy amid rapidly changing system conditions. He described how growth in artificial intelligence (AI), new manufacturing, and electrification of end uses is driving substantial increases in electricity demand. Meeting this demand, he said, will require significant new investment in generation and transmission infrastructure. Citing a NERC report projecting the need for approximately 130 gigawatts (GW) of new generation by 2030, ~~the~~ Commr. Rosner characterized the challenge as unprecedented in recent decades. He framed this expansion not only as a reliability imperative but also as a major economic opportunity tied to job creation, technological innovation, and U.S. global competitiveness. He emphasized the Commission's commitment to enabling large new loads while maintaining reliability and fairness for existing customers.

Commr. Rosner then identified interconnection reform as another area of FERC strategic focus. He discussed national delays in interconnection and described how *Order 2023* and related process improvements are helping accelerate resource connections while maintaining safety and reliability. He emphasized the importance of applying lessons learned from early implementation efforts.

Turning to competitive wholesale markets, Commr. Rosner underscored their success in delivering substantial customer savings and highlighted capacity accreditation reform as a critical area for aligning investment decisions with reliability needs. He acknowledged the complexity of working through accreditation details and encouraged New England to draw on experiences from other regions.

Commending the region for its leadership in transmission planning and proactive coordination with New England state (State) authorities, Commr. Rosner addressed the FERC's efforts on transmission planning, including its time and effort around *Orders 1000* and *1920/1920-A*. He emphasized that state support for planning processes and cost allocation reduces project risk and strengthens prospects for success.

Commr. Rosner then described the FERC's efforts to streamline ~~permitting and~~ environmental review processes and permitting, reporting that review timelines for both major and minor projects have been significantly reduced while statutory requirements continue to be met. He noted a decline in the number of FERC actions challenged in federal appellate courts, attributing ~~this~~that decline in part to increased Commission consensus and clearer administrative records.

Addressing administrative proceedings, Commr. Rosner highlighted the FERC's openness to innovation, including advanced transmission monitoring technologies and dynamic line ratings, and encouraged stakeholder to identify and support innovative solutions. He then discussed the Commission's Advance Notice of Proposed Rulemaking (ANOPR) on large load interconnection, thanking NEPOOL Participants for their comments and emphasizing the importance of stakeholder input. ~~The~~He described how the ANOPR ~~outlines~~outlined high-level principles and multiple potential approaches for connecting large loads more quickly and cost-effectively. He encouraged New England stakeholders to pursue regionally developed solutions through filings under section 205 ~~filings~~of the Federal Power Act (FPA), noting that such approaches often lead to the most effective and durable outcomes.

Commr. Rosner concluded by inviting stakeholder feedback on capacity auction reforms, interconnection progress, steps states could take to accelerate new generation development, and additional ways the FERC could support the New England region.

During the ensuing discussion, a number of members observed that, as they expected to be demonstrated later in the meeting, the first phase of the Capacity Auction Reforms (CAR) process (CAR-Prompt/Deactivation (CAR-PD)) had gone well. They commended the ISO for its efforts and for listening carefully to stakeholder feedback, and evolving the CAR proposal meaningfully in response, as it moved through the stakeholder process. Some concerns were raised regarding upcoming seasonal accreditation reforms and the potential cost and reliability impacts of large new loads. The Commr. noted that early efforts in other regions demonstrate that existing regulatory tools can be used creatively to address these challenges. Separately, members applauded the FERC's new notice-of-intent-to-act process ~~for~~in connection with FPA section 206 complaints, emphasized the importance of regulatory certainty, and urged a balanced attention to managing price volatility issues that are likely to emerge from the movement to a more prompt capacity market construct.

Referring to time spent, particularly with PJM states, on price volatility and customer impacts, and recalling earlier work he had done at a policy think tank on price volatility, Commr. Rosner acknowledged the inherent tension between minimizing costs and maintaining price stability but expressed optimism that challenges ahead ~~can~~could be managed and encouraged continued, collaborative stakeholder engagement.

Ms. Bresolin, thanking the Commissioner for his thoughtful remarks and advice, noted New England's tradition of, and committed NEPOOL to intensify its efforts to, working collaboratively through difficult issues in the stakeholder process. The Committee thanked Commr. Rosner for his thoughts and time with a warm round of applause.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to his last and relatively short CEO Report, which had been circulated and posted with the materials for the meeting. There were no questions or comments on that summary.

Several members offered comments recognizing Mr. van Welie's impending retirement and expressing appreciation for his service as the ISO's CEO. Members observed that during his roughly 25 years as CEO, Mr. van Welie oversaw the growth of the ISO from a small, fledgling organization into the robust, sophisticated entity today that administers the region's wholesale electricity markets. They remarked that, under his leadership, the ISO had taken bold and innovative steps in market design and system planning and through it all Mr. van Welie had consistently provided a steady hand for the region.

Members thanked Mr. van Welie for his dedication and commitment to working collaboratively with NEPOOL and the New England States. They emphasized that his and the ISO leadership team's willingness to engage directly with stakeholders, to freely share their views on the challenges and opportunities of the clean energy transition, and to do so with both courage and humility, had been particularly valuable. Members noted that the ISO's efforts to maintain a reliable grid while transitioning to a newer resource mix had established New England as an example and leader for the nation's other grid systems.

Members also thanked Mr. van Welie for his role in guiding numerous market changes over the years and for his willingness and professionalism in working through difficult issues with NEPOOL. They appreciated that Mr. van Welie and his leadership team had consistently pursued a common goal with NEPOOL—to maintain reliable markets that serve customers well. Several members highlighted his personal accessibility to individual Participants, with a couple of members noting that his interactions often reflected a genuine sense of collegiality and friendship.

Finally, members expressed confidence that Dr. Vamsi Chadalavada would continue the ISO's collaborative engagement with NEPOOL and the States, viewing the orderly leadership transition as a testament to the success of the organization and the ISO leadership team.

Mr. van Welie thanked members for their generous comments and promised to provide some reflections later that afternoon.

ISO COO REPORT

In his last report as ISO Chief Operating Officer (COO), Dr. Chadalavada referred the Committee to his December report (his 208th report), which had been circulated and posted in advance of the meeting. (Ms. Bresolin noted that beginning in January, the report presenting the same information would be restyled as the System & Market Operations Report, and would be presented by Mr. Steven George, as the ISO's Vice President for System & Market Operations and Capital Projects). Dr. Chadalavada noted that the data in the COO Report was through November 24, 2025, unless otherwise noted. The December report highlighted: (i) that the Peak Hour for November, with 16,526 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on November 17, 2025 during the hour ending 6:00 p.m.; (ii) November averages for Day-Ahead Hub LMP ($58.65/MWh), Real-Time Hub LMP ($61.88/MWh), and natural gas prices ($4.16/MMBtu); (iii) Energy Market value for November 2025 was $572 million, up from $410 million in November 2024 and up from the updated October 2025 Energy Market value of $468 million; (iv) Ancillary Services Markets value ($15.9 million) was up from November 2024 ($6.2 million); (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 98.9% during November (up slightly from 98.3% reported for October 2025); (vi) Daily Net Commitment Period Compensation (NCPC) payments for November totaled $3.1 million (representing just 0.5% of November's monthly Energy Market value), comprised entirely of First Contingency payments (including $426,000 in Dispatch Lost Opportunity Costs, $373,000 in Rapid Response Pricing Opportunity Costs, $525,000 in Generator Performance Auditing, and $346,000 paid to resources at external locations (there were no Second Contingency, voltage or distribution payments); and (vii) a Forward Capacity Market (FCM) value of $88.8 million.

Turning to Day-Ahead Ancillary Services (DAAS) market results, Dr. Chadalavada explained that the DASI outcomes for November were largely a function of how the system was positioned around the November peak for generation and transmission outages. He noted that the number of assets participating in the DAAS market had declined from October to November and said that there would be additional discussion of DAAS trends with the ISO's Internal Market Monitor (IMM) at the Markets Committee meeting the following week, followed in the new year by a more detailed analysis by and discussion with ISO and IMM staff.

Dr. Chadalavada then turned to the Operating Procedure No. 4 (OP-4) event on Sunday, November 23 during which the region experienced an afternoon Capacity Scarcity Condition (CSC) (the November 23 Event). He explained that, as the system was approaching the daily peak period, the region lost approximately 1 GW of generation (when a large thermal resource and two smaller thermal resources, all running on natural gas, went offline). The ISO entered Master/Local Control Center Procedure No. 2 (M/LCC-2) and implemented OP-4 Actions 1 and 2. He further explained that, at the same time, actual load was approximately 230 MW higher than forecast and net imports during the peak hours were approximately 250 MW lower than expected. He stated that reserve shortages during the November 23 Event resulted in Reserve Constraint Penalty Factors (RCPFs) being triggered for roughly 15 minutes and 30 minutes, respectively. He said that the preliminary Capacity Balancing Ratio for the event was 69.3%, and that preliminary Pay-for-Performance (PFP) charges associated with the event were estimated to be approximately $34.7 million (based on a PFP performance rate of $93.75/MWh).

In response to questions regarding the November 23 Event, Dr. Chadalavada said that he did not have at that point information suggesting a potential relationship among the units that tripped. He clarified that the imports in question did not have CSOs. He explained that, during the November 23 Event, New England was importing 1,000 MW from New York and had been scheduled in the Day-Ahead Market to export approximately 600 MW over the Phase 1 and Phase 2 ties to Québec. There had been an expectation that some power would flow back to

New England from Ontario, and that, when netted against those exports, the Phase II flows would result in imports roughly 250 MW higher than what ultimately materialized. This net 250 MW shortfall in imports, relative to the Day-Ahead expectations, contributed to the CSC. He confirmed that there were no underlying gas supply problems associated with the outages.

In response to additional member observations, an ISO representative explained that the relevant curtailments occurred on the Phase II interface, and that there would have been more exports across Phase II in the hour ending 19:00 but for those curtailments. Flows across Phase II dropped to zero later that evening, Dr. Chadalavada explained, as a result of how the market ultimately cleared later in the day and not as a direct result of the scarcity event. He added that Day-Ahead scheduled exports would not have been curtailed until implementation of OP-4 Action 5 and cautioned that the zero flows observed later in the evening should not be interpreted as reflecting any change in Québec's performance or conditions on Phase II.

With respect to the New England Clean Energy Connect (NECEC) project, Dr. Chadalavada reported that test procedures were in place and test power flowing. He expected testing to continue for several weeks and that, while there was not yet a formal in-service date, project completion was progressing well. He observed that, once in service, the NECEC project, together with anticipated offshore wind resources such as Vineyard and Revolution Wind, was expected to improve the region's overall energy supply profile. He indicated that the effects of these resource additions would be considered as part of the CAR impact analysis.

In response to questions regarding the New York ISO's (NYISO) new phase angle regulator (PAR) on the 398 Line (Cricket Valley to Long Mountain), Dr. Chadalavada confirmed that the PAR had been energized and that imports into New England across the New York AC ties were back to 1,600 MW for the winter period. He explained that, while limitations on the

398 Line had constrained imports during the November 23 Event, those limits had been lifted. Work associated with the Dover PARs, an ISO representative noted, had not yet been completed, with any further work on those facilities to be scheduled after the winter period. Dr. Chadalavada said that the ISO had been involved, as an affected system, in coordinating the settings with NYISO, and he expected that the New York AC interface would generally be operated at 1,400 MW for most of the year and up to 1,600 MW for the winter.

Also related to NYISO, but also to PJM, a member expressed disappointment with the decision (to be addressed at the Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting the next day) to conclude the New England Loss-of-Source study that was being conducted with NYISO and PJM. He observed that the study had required a significant ISO budget and staff commitment and had been viewed by some stakeholders as a critical piece of work to support potential strengthening of ties with neighboring regions and integration of offshore wind. Dr. Chadalavada acknowledged the member's concern and shared his disappointment. He explained that the study had been an extraordinary lift for the ISO, given the need to coordinate across three regions, each with different system conditions, priorities, and evolving resource mixes. He stated that the pace of system changes in all three regions had made it very difficult to pin down a stable set of assumptions about what would be required to support a higher loss-of-source limit. He emphasized, however, that the work completed to date had yielded useful information and analysis, and that those results would make it easier to resume and build on the study in the future, if and when priorities and resources allow. He added that other urgent issues had taken precedence in the near term. Another member echoed the importance of exploring opportunities to strengthen ties with neighboring regions and support offshore wind and other large-scale resources. That member observed that the study had reflected a concerted state and regional effort to improve planning, and that prior analyses had shown significant reliability and cost benefits from enhancing transmission in the Northeast. He urged that the region collectively look for opportunities to resume that work when feasible. Dr. Chadalavada acknowledged and expressed his appreciation for that feedback.

Referring to the November 23 Event, members requested that the ISO consider (i) providing an educational walk-through of the PFP event calculations associated with that Event, including how the balancing ratio and charges were determined, (ii) posting preliminary capacity balancing ratios as soon as possible after any PFP event so that Participants could more quickly assess potential performance charges and credits, noting the short, two-business-day window at the end of a month for submitting certain data and data reconciliations, and (iii) promptly pursuing changes to extend PFP obligations to exports, rather than waiting for a FERC order on the pending NEPGA complaint, in order to address potential issues before another PFP event occurs. In response, Dr. Chadalavada said he would ask his team to consider the requested educational session, to publish preliminary balancing ratios with appropriate caveats as soon as they are able after future PFP events, and to begin work on the changes to the stop-loss provisions to extend PFP obligations to exports.

A member thanked the ISO for the detailed load report slide, noting that it was very helpful, and asked about the behavior of imports and exports across the New York AC ties during the November 23 Event. The member observed that flows appeared to be relatively steady and then spiked in both directions during the day and asked whether those patterns were related to the unit outages. Dr. Chadalavada responded that imports on the order of 1,000 MW across the New York interfaces during the CSC roughly aligned with what had cleared in the Day-Ahead Market. An ISO representative added that the unit trips caused flows on the New

York AC ties to increase in response to the sudden loss of generation in New England, and that those flows were then brought back toward the 1,000 MW level as the ISO dispatched additional generation to restore energy balance. The representative also noted that the New Brunswick interface responded similarly, though to a somewhat lesser extent.

Another member, referencing the winter reliability assessment asked whether, in light of the November 23 Event, similar events might occur again in the coming winter. Dr. Chadalavada responded that capacity studies cited in the winter report focus primarily on resources with CSOs and do not fully capture energy from non-CSO resources, so the studies do not reflect all energy that may be available to the system. He added that each CSC was typically a function of unit trips as the system is heading into peak hours, load forecast error, and deviations in net imports from expectations. He said that the ISO would do everything in its power to reduce the likelihood and severity of such events. He reminded the Committee that the November 23 Event was managed through OP-4 actions, did not approach emergency levels, and was of shorter duration than experience earlier in the summer. He concluded that, all else being equal, the system could be expected to be reliable this winter.

In response to concerns regarding recent "alarming" prices in the ~~Day-Ahead Ancillary Services (~~DAAS~~)~~ market, and requests for clarification on the ISO's plans for evaluating the performance and reliability value of that design/market, Dr. Chadalavada said that the ISO had heard and shared concerns about some of the recent pricing outcomes and had been closely reviewing the results. He said that the ISO looked forward, with the benefit of the additional experience of the coming winter, to a more fulsome understanding of the benefits and tradeoffs of the design, particularly the more nuanced reliability benefits that may not be captured in dollar metrics. He explained that the ISO, the IMM, and the ISO's Chief Economist, Mr. ~~Matthew~~Matt

White, had been working together and with the external market monitor (EMM) to analyze the data and examine potential options. Acknowledging cost unpredictability concerns, some members highlighted benefits of the design, including reliability benefits derived from contractually-defined performance expectations, more predictable next-day operating plans and strong performance incentives for Day-Ahead products. While Dr. Chadalavada believed that the DAAS design was providing more reliable performance, he, too, remained sensitive to the cost impacts being experienced and assured Participants that they would receive an honest and robust analysis of the DAAS design and its effects.

Concluding his report, Dr. Chadalavada advised members to be prepared for and stay warm during the Arctic cold blast expected to run through the following Monday. He reported that, operationally, the ISO was prepared for and confident that it would be able to manage the system under the forecasted conditions.

2025 NEPOOL ANNUAL REPORT

Ms. Bresolin referred the Committee to the 2025 NEPOOL Annual Report distributed at the meeting and posted on the NEPOOL website. She thanked the NEPOOL Counsel team for all its efforts on the Report. She also thanked the Vice-Chairs of each Sector and the Technical Committees for their assistance in assembling and completing the Annual Report as well as those Participants at-large who submitted photos for use in the Report. Ms. Bresolin encouraged members to review the Annual Report, which summarized and highlighted NEPOOL's activities and accomplishments during 2025.

ELECTION OF 2026 PARTICIPANTS COMMITTEE OFFICERS

Ms. Bresolin then referred the Committee to the proposed slate of 2026 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting. The following motion was duly made, seconded and unanimously approved, with an abstention noted by Mr. 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 2026 to the offices of Chair and Vice-Chair, as set forth opposite their names; and
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> 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 2026 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Sarah Bresolin
Vice-Chair	Jackie Bihrle
Vice-Chair	Dave Cavanaugh
Vice-Chair	Steve Kirk
Vice-Chair	Aleks Mitreski
Vice-Chair	Dave Norman
Secretary	Sebastian Lombardi
Assistant Secretary	Pat Gerity.

Following the vote, Ms. Bresolin thanked the Committee for the confidence reflected in her re-election as Chair and in the re-election of the incumbent officers, and she welcomed Mr.

Steve Kirk to the NEPOOL officer group. She expressed appreciation to Ms. Michelle Gardner for her many years of service as a Vice-Chair from the Generation Sector and recognized and thanked two other officers leaving the broader officer group -- Mr. Bob Stein (Reliability Committee Vice-Chair) and Mr. Brad Swalwell (Membership Subcommittee Chair).

ESTIMATED BUDGET FOR 2026 NEPOOL EXPENSES

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, reported that B&F reviewed at its November 14, 2025 meeting the estimated budget for 2026 Participant Expenses, a copy of which had been circulated and posted in advance of the meeting and is included as Attachment 2 to these minutes. He reported that, while there were a few questions asked at the November B&F meeting, no objections or concerns with the 2026 NEPOOL Budget were identified by B&F members.

One member, while acknowledging the importance of in-person meetings, expressed concern over the meeting expenses given rising hotel expenses. He explained that one of his clients was abstaining but not opposing the 2026 Budget item, and he requested that the NEPOOL officers consider ways to reduce meeting costs going forward.

Without further discussion, the following motion was duly made, seconded and unanimously approved, with abstentions by Cross Sound Cable and Mr. Lamson noted:

> RESOLVED, that the Participants Committee adopts the estimated budget for NEPOOL expenses for 2026 as presented at this meeting.

FAP REVISIONS: OBLIGATION ROLL-OFF TIMING

Mr. Kaslow, referring members to the materials circulated and posted in advance of the meeting, reported that the B&F had also reviewed at its November meeting proposed revisions to the Financial Assurance Policy (FAP) designed to close certain identified gaps in collateralization arising out of a mismatch between the timing of the calculation of financial assurance (FA) obligations and the payment of invoices (FAP Revisions). By extending FA requirements through the applicable payment dates, the ISO proposed to eliminate any potential gaps in FA posted to cover unpaid charges. No Subcommittee member present at the November meeting expressed opposition or concerns with the FAP Revisions.

Without discussion, the following motion was duly made, seconded, and approved unanimously, with an abstention by Mr. Lamson:

> RESOLVED, that the Participants Committee supports the revisions to the ISO New England Financial Assurance Policy as reflected in the materials circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

CAPACITY AUCTION REFORMS – CAR-PD TARIFF CHANGES

Ms. Emily Laine, Markets Committee Chair, provided an overview of the first phase of the CAR initiative—the CAR-PD proposal—and the associated NEPOOL Technical Committee review. Level setting, Ms. Laine explained that CAR-PD was designed to transition the ~~Forward Capacity Market (~~FCM~~)~~ to a prompt annual market construct with associated deactivation-related reforms that would utilize more current and accurate information. She noted that, under the new prompt annual auction timeframe, Annual Reconfiguration Auctions (ARAs) would no longer be needed, and other related activities had been conformed.

Ms. Laine stated that, in moving from the current forward construct to a prompt capacity market, the region would have the more recent load forecast available as an input to the capacity auction and that Participants would have more current information about their assets and prevailing market conditions when formulating capacity offers. She explained further that a new requirement that resources be commercial before participating in the capacity market was intended to help prevent resources from selling capacity that they ultimately could not deliver (so-called “phantom entry”). Ms. Laine also explained that, with the change to a prompt auction timeframe, adjustments to existing retirement processes were required. Under CAR-PD, the retirement process was restructured such that retirements (to be referred to as deactivations) were decoupled from the capacity market itself.

Ms. Laine reported that the Markets Committee began its consideration of CAR-PD in January 2025 with discussions on deactivation processes, followed by many months of review and design refinement based on stakeholder feedback. As part of that effort, the Markets Committee and, subsequently, the Transmission Committee developed a new binding one-year notification deactivation mechanism through which resources may remove or reduce Interconnection Service MWs. She stated that this one-year timeframe was intended to strike a balance between allowing ~~ISO-NE~~the ISO to perform needed reliability reviews and provide sufficient notice to the market to encourage new entry. She added that the mitigation design had evolved to include a Proxy Capacity Offer, if needed, to safeguard the region against potential market power impacts associated with deactivations.

In addition to the new prompt auction and deactivation rules, Ms. Laine reported that numerous conforming changes had been made and incorporated into areas such as resource qualification, mitigation, Installed Capacity Requirement (ICR) development, and other related provisions. She noted that the Tariff changes enabling the CAR-PD design were reviewed starting in June, with relevant Tariff sections voted on and recommended by each of the NEPOOL Technical Committees at their November meetings.

In addition, Ms. Laine summarized the Markets Committee's consideration of Participant-sponsored amendments to the CAR-PD proposal. She reported that three amendments were offered at the Markets Committee meeting in November concerning the Capacity Offer Price Threshold (COPT). The first amendment, sponsored by Jericho Power LLC (Jericho Power), would have set the COPT at a fixed value for CCP 28/29. The second amendment, sponsored by Calpine Energy Services, LP (Calpine), proposed to change the methodology for calculating the COPT. The third amendment, sponsored by NEPGA, would retain the so-called ambient air de-list exemption under CAR-PD.

Ms. Laine reported that the first and second amendments failed with votes of 56.67% and 52.82% in favor, respectively. The third amendment, however, passed with 83.33% in favor. The once-amended main motion, which included NEPGA's amendment, then passed with 97.92% in favor. She noted that the ISO had not requested a separate Markets Committee vote on its unamended proposal in light of the broad stakeholder support for NEPGA's amendment, and that, if that amendment continued to receive broad support at the Participants Committee, the ISO planned to incorporate the NEPGA amendment into its CAR-PD proposal and subsequent FERC filing.

Finally, Ms. Laine reported that the Transmission and Reliability Committees had each reviewed and voted to recommend Participants Committee support for CAR-PD revisions~~,~~ subject to each Committee's jurisdictional purview.

Mr. Lombardi confirmed that, consistent with NEPOOL's established practice, in the interest of administrative efficiency, amendments that have not received Technical Committee support and are unlikely to receive Participants Committee support need not be presented to the Participants Committee to be deemed to have completed the required Participant Processes. Accordingly, the Jericho and Calpine Amendments need not be considered to preserve those Participants' rights to pursue the amendments at the FERC.

Many members again expressed appreciation for the ISO's approach to the CAR-PD project and the associated stakeholder processes. Members highlighted that the ISO had engaged NEPOOL early, presented the material in manageable ways, and ensured that subject matter experts were available to answer questions, all of which they believed greatly improved both the discussions and the final design.

A member raised concerns about the limited participation by load interests in the CAR-PD process and noted that the design inherently increased price volatility. He emphasized that his concern was not about overall cost levels, noting by way of example that stakeholders had understood that DAAS would increase costs, but that, in his view, the region had not adequately addressed how load could hedge the additional volatility. He expressed worry that the region might be repeating that error with CAR-PD, and stated his view that managing price volatility is part of ~~ISO-NE's~~the ISO's job. While recognizing the broad support CAR-PD had received and crediting ~~ISO-NE~~the ISO for that, he urged the ISO to begin discussions on how load and customers will be able to hedge price volatility in a prompt capacity construct.

Another member stated that he would support the CAR-PD proposal, in significant part because of ~~ISO-NE's~~the ISO's efforts to engage NEPOOL early and listen to stakeholder feedback. He emphasized that CAR-PD is understood to be the first phase ~~one~~ of the broader CAR initiative and expressed an expectation that phase two (i.e., CAR-SA) would be developed in a way that could attract similarly strong stakeholder support.

Another member raised two concerns with the CAR-PD proposal. First, he stated that the changes increase the chance that certain Reliability Must-Run Agreements could extend longer than they otherwise would, thereby exposing consumers to those costs for a longer period of time. Second, he expressed concern that the existing ~~Forward Capacity Market~~FCM construct had functioned well when the region was short on capacity by providing a mechanism and price signal that supported new investment. He reported that his company and others had invested in resources in reliance on those forward signals. He questioned what mechanism would provide a similar signal to build new capacity if and when the region becomes capacity-short, and he suggested that it would be more difficult to respond in time under a prompt-only construct. In a related comment regarding the market transition, another member stated that, in his view, with electrification and new large loads, significant load growth now appears more likely and expressed concern that moving away from a forward construct at this point could cause the region to forego opportunities to secure new entry pricing signals when that growth materializes.

Several members commented on the ~~(~~COPT and related amendments. One member acknowledged lingering concerns about the current COPT treatment but expressed appreciation that ~~ISO-NE~~the ISO had committed to revisit COPT as part of the next phase of the CAR project and said that, for that reason, he would support the CAR-PD proposal and consider returning to COPT issues next year. Another member expressed sympathy for concerns about bilateral trading and suggested that the region should explore better avenues for load to participate through bilateral contracting or other mechanisms under a prompt construct, urging ~~ISO-NE~~the ISO to keep that topic on its radar. A member further noted that the existing market design allows for bilateral transactions between resources and load and said he is looking forward to seeing greater bilateral activity in the future.

Another member, while planning to vote in favor of CAR-PD, expressed concern about potential cost impacts on consumers and stated the hope that, if the design ultimately proves to be excessively costly, the region ~~will~~would identify ways to mitigate those impacts.

On behalf of ~~ISO-NE~~the ISO, Dr. Chris Geissler thanked NEPOOL and the many stakeholders who had provided feedback throughout the CAR-PD process, stating that the extensive input had made the process better and had materially improved the final design. Dr. Chadalavada likewise expressed appreciation for the collaboration, noting that more than 90 people on the ISO team had worked on CAR-related issues and that the CAR team could grow to 125 to 150 people in 2026. He described as extraordinary the level of internal coordination required to develop and present the CAR-PD proposal. He noted that, while work on CAR-SA in 2026 might not proceed as smoothly, the ISO would continue to collect information and feedback and would seek to incorporate with a similar level of commitment that feedback as the CAR-SA design evolves. He emphasized that the CAR reforms were critical to the region's markets and was optimistic that New England could learn from the experiences of other regions and continue to benefit from NEPOOL's support and guidance as the CAR project moves forward.

Without further discussion, a motion to approve the following resolutions in a single vote was duly made and seconded:

RESOLVED, that the Participants Committee supports ISO-NE's CAR-PD Proposal, including related revisions to: Tariff Section I.2.2, Market Rule 1, including new Section III.15 and NEPGA's Amendment, as well as Sections II.52-55 of the Open Access Transmission Tariff (OATT), ***as recommended by the Markets Committee*** at its November 2025 meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

RESOLVED, that in connection with ISO-NE's CAR-PD Proposal, the Participants Committee supports the changes to Sections I.2.2 and Section III.12 (Calculation of Capacity Requirements) of the Tariff, all ***as recommended by the Reliability Committee*** at its November 2025 meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

RESOLVED, that in connection with ISO-NE's CAR-PD Proposal, the Participants Committee supports the changes to Sections I.2.2, I.3.9 (Review of Market Participant's Proposed Plans), OATT Sections II.22 (Operating Arrangements), II.48 (Interconnection Service Capabilities), II.52-55 (Deactivation), and to OATT Attachments K (Regional System Planning Process) and N (Procedures for Reginal System Plan Upgrades), and Schedule 16 (Blackstart Service), all as ***recommended by the Transmission Committee*** at its November 2025 meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

The resolutions were approved, with just one opposition by Brookfield Renewable Trading and Marketing ~~LP~~, and abstentions by BP ~~Energy Company~~, Calpine, Cross-Sound Cable ~~Company, LLC~~, Dominion ~~Energy Generation Marketing, Inc.~~, DTE Energy Trading, ~~Inc.,~~ Mercuria ~~Energy America, LLC~~, Galt Power ~~Inc.~~, the Market Participant End Users represented by the Freedom Companies (Bath Iron Works, Elektrisola, Garland Manufacturing, Hammond Lumber, High Liner Foods, The Moore Company, Nylon Corporation of America, Saint Anselm College, Shipyard Brewing, and Z-TECH), and Mr. Jon Lamson noted.

Ms. Bresolin highlighted the vote outcome as an example of the strength and effectiveness of the NEPOOL stakeholder process, which demonstrates a desire and readiness to move forward with these major market reforms and onto ~~Phase 2~~the second phase, without the added uncertainty of a heavily contested FERC proceeding.

PROPOSED NEPOOL POLICY STATEMENT: GIS WAIVER REQUESTS

Mr. Lombardi referred the Committee to the proposed NEPOOL Policy Statement regarding Generation Information System (GIS) Waiver Requests, which had been discussed at, and revised following, the Committee's November meeting. The revised Policy Statement, with adjustments reflecting comments and questions received, was circulated with the materials for this meeting.

He explained that the justification for a Policy Statement arose from periodic but continuing requests for Participants Committee consideration of GIS account holder requests for waiver of the GIS Operating Rules and GIS Administration Agreement to allow for certificates to be retroactively revised, corrected or issued (outcomes not otherwise provided for in the GIS arrangements) as a result of some unintended action or inaction of the GIS Account Holder. Because such requests had been consistently withdrawn or rejected, the purpose of the Policy Statement, he explained, was to clarify NEPOOL's role and expectations with respect to such requests and, in so doing, preserve market predictability and fairness while deferring to the authority of ~~state~~State regulatory agencies, which remain the ultimate arbiters of compliance with their respective renewable portfolio standard (RPS) programs.

Mr. Lombardi reported that the additional feedback received following the November meeting presentation and discussion of the Policy Statement had focused in particular on how

NEPOOL should approach a situation in which a ~~state~~State regulatory authority might ask NEPOOL to consider a GIS-related matter. He explained that the draft had been revised to state more clearly that, as a matter of general policy and procedure, NEPOOL will not formally consider or take action on GIS waiver requests. He emphasized that the Policy Statement reflected NEPOOL's view of the purpose of the GIS and the preference to defer to the New England ~~states~~States and their jurisdictional authority with respect to compliance with RPS and RPS-like programs. He also underscored that the Policy Statement could be revisited and revised in the future if the circumstances should so warrant, but that it was desirable and more efficient to have a clear policy in place providing advanced notice to GIS Account Holders, the States, and other interested parties as to NEPOOL's role/process.

There were no clarifying questions, but several members offered comments. One member, who described his role in helping to establish the original GIS framework, explained that years ago he had recommended that NEPOOL undertake the development of a platform to support compliance with ~~state~~State portfolio programs for renewable resources. He recounted ~~that he had chaired~~his experience as chair of the working group ~~with ISO-NE and the states~~that included ISO and State representatives that led to the development and establishment of the GIS, that the GIS is owned and operated by NEPOOL under contract with a third-party administrator, and that the GIS Operating Rules are NEPOOL rules adopted to provide this service to Participants. In his view, NEPOOL therefore has both an interest and a responsibility to listen to the ~~states~~States while also considering the circumstances of GIS Account Holders. He expressed concern that, simply because a ~~state~~State has declined to provide relief to an entity that made an administrative error, NEPOOL should not automatically do the same. He expressed his opposition to what he described as a zero-tolerance policy, and encouraged members to vote against the Policy Statement.

Another member respectfully disagreed with the prior comments and stated that it would not be appropriate for NEPOOL to involve itself in ~~state~~State adjudications regarding RPS compliance, explaining the view that NEPOOL should not step in front of the ~~states~~States with respect to compliance with their RPS-related programs.

In addition, another member commented that the Participants Committee does not have either the capability or the mandate to serve as judge and jury on GIS waiver requests, particularly where a ~~state~~State regulatory authority has already considered and rejected a request for relief. That member observed that the situation might be different if a ~~state~~State affirmatively encouraged NEPOOL to consider a matter, but did not believe NEPOOL should insert itself into disputes where ~~states~~States had already acted. The member acknowledged that the GIS platform could be made more user-friendly and noted that Participants ~~are free to~~could bring forward proposals to improve the rules and user experience, but ~~emphasizing~~emphasized the importance of knowing and following the rules as well as cautioning ~~that it would be a~~against the slippery slope ~~to grant~~and precedents that could emerge following individual exceptions ~~for one Participant and not others~~granted for requesting for Participants. The member further stated that, if ~~the states determine it is~~a State determines it appropriate to allow Participants additional opportunities to submit certificates or cure errors, that is for the ~~states~~States to ~~decide~~implement.

After further discussion, the following motion to approve the Policy Statement was duly made and seconded:

> RESOLVED, that the Participants Committee hereby adopts the NEPOOL Policy Statement regarding GIS Waiver Requests, as reflected in the materials circulated to this Committee in advance

of this meeting, together with such non-substantive changes as may be approved by the Chair of the Participants Committee.

The motion was approved, with one opposition by Pawtucket Power Holding Company, and abstentions by Brookfield, CPV, Wheelabrator, Vistra (Dynegy), and Mr. Lamson noted.

RECOGNITION OF BOB LUDLOW

On behalf of NEPOOL, Ms. Bresolin asked Mr. Pete Fuller to say a few words on the occasion of the impending end of 2025 retirement of Mr. Bob Ludlow, ISO Vice President and Chief Financial and Compliance Officer. Mr. Fuller thanked Mr. Ludlow for his years of close collaboration and dedicated service to the region, including his work, which began when the ISO had yet to be formed, through the ISO's start-up efforts, to develop, administer and monitor the region's wholesale markets, to establish needed financial arrangements, supporting the development of the GIS, shaping a robust and successful Financial Assurance Policy, and crafting careful budgeting practices – all to the benefit of the Participants individually and collectively. He commended Mr. Ludlow's steady leadership, financial expertise, collaborative approach with NEPOOL stakeholders, and wry sense of humor, all of which had left a positive and indelible stamp on the markets and the region.

In recognition and appreciation of Mr. Ludlow's more than 28 years of service, Mr. Fuller read a NEPOOL recognition of Mr. Ludlow's service and presented Mr. Ludlow with a token of NEPOOL's gratitude. Mr. Ludlow thanked NEPOOL for the recognition, expressed pride in how far the ISO and NEPOOL had come—from the days of paper bills with long payment windows to the current sophisticated markets, settled twice weekly, and supported increasingly by AI—and remarked that he would miss the camaraderie and collaboration at NEPOOL meetings.

On behalf of the Committee and all of the NEPOOL Participants, Ms. Bresolin again thanked Mr. Ludlow for his service and wished him well in his retirement.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the December 3, 2025 Litigation Report that had been circulated and posted before the meeting. He highlighted ongoing activity in the large load interconnection ANOPR proceeding and reported that NEPOOL Counsel was preparing and would provide to the Transmission Committee a summary of the more than 200 initial comments that had been submitted in that proceeding. He added that NEPOOL Counsel would also track and summarize the reply comments that were expected to be filed. He encouraged those with questions on this or any matter in the Litigation Report to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Ben Griffiths, MC Vice-Chair, reported that the next MC meeting would be on December 9-10, 2025 at the DoubleTree Hotel in Westborough, MA. He indicated that key topics for the first day would be gas accreditation under CAR-SA as well as discussion of the DAAS Market as part of the IMM's Summer Quarterly Markets report. Topics for the second day would include a discussion of how the process and certain annual parameters for the procurement of Net Installed Capacity Requirements (NICR) would be split/updated to reflect seasonal (summer and winter) procurements under CAR-SA and an introductory overview of CAR Impact Analysis.

Reliability Committee (RC). Mr. Nick Gangi, RC Chair, reported that the next RC meeting would be held on December 16, 2025 at the DoubleTree Hotel in Westborough, MA. He said that, in addition to the usual review of Proposed Plan Applications and Transmission Cost Allocations, the RC would discuss seasonal tie benefits and energy storage accreditation under CAR as well as a number of proposed changes to operating procedures.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be held virtually on December 18, 2025. He said that the sole discussion item concerned proposed *Order 2023*-conforming changes (to formalize equivalent Capacity Network Resource Capability (CNRC) for resources not subject to ISO Interconnection Procedures).

Budget & Finance Subcommittee~~ (B&F)~~. Mr. Kaslow reported that the December 11 B&F meeting had been cancelled. The next B&F meeting was scheduled for January 16, 2026.

Membership Subcommittee. Mr. Brad Swalwell reported that the next Membership Subcommittee meeting (and his last as Chair) would be held by Zoom on December 15, 2025. He encouraged all those interested to participate and to reach out to him or NEPOOL Counsel for the Zoom information.

Joint Nominating Committee (JNC). Ms. Bresolin reported that the JNC would begin in January its efforts to identify a slate of candidates for election in 2026, a slate that was expected to include two incumbents and one new board member.

ADMINISTRATIVE MATTERS

On behalf of NECPUC, Mr. George Twigg, NECPUC Executive Director, reported that the NECPUC Demand Response Working Group was wrapping up its work and that a draft report would be available for comment, likely in January. He welcomed comments on that draft once circulated. He also asked Participants to save May 18-20, 2026 on their calendars for the 2026 NECPUC Symposium to be held at the Samoset in Rockport, Maine, noting that the Symposium would include a number of panels on affordability and invited suggestions for panelists and topics.

Mr. Lombardi reminded members that, as noted earlier in the meeting, the January 2026 Participants Committee meeting would be held by Webex and that details for the February meeting would be provided once arrangements were confirmed.

Before adjourning the meeting, Ms. Bresolin encouraged all those in the room to join her for the luncheon in appreciation of Mr. van Welie's service to the region upon his retirement as the ISO's CEO.

There being no other business, the meeting adjourned at 12:43 pm.

Respectfully submitted,

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Sebastian Lombardi, Secretary

RECOGNITION OF GORDON VAN WELIE

During the banquet that followed the meeting, the Committee endorsed by acclimation the following resolution of appreciation for Mr. van Welie:

> WHEREAS, Gordon joined ISO New England Inc. in 2000 as its chief operating officer, and has since 2001 led the ISO as its President and chief executive officer through a remarkable period of market, transmission system and organizational maturation and transformation;
>
> WHEREAS, Gordon has throughout his tenue been a stalwart advocate for efficient and reliable markets, instrumental in launching Standard Market Design (SMD), the continuing foundation for the region's ever-evolving wholesale electric markets, and positioning the region to address energy adequacy through shifting policies, generation resources, and technologies;
>
> WHEREAS, throughout his years of service, Gordon has been a steady and calming influence on the direction and deliberations of this Committee, bringing a determined, collaborative, and untiring sense of intellectual curiosity and vision to the issues facing the Pool; and
>
> WHEREAS, Gordon's leadership, lilt of his voice, and his innovative spirit will be sorely missed.
>
> NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere appreciation for the many outstanding contributions of Gordon van Welie to this Committee, to the New England region, and to the electric industry generally; and
>
> BE IT FURTHER RESOLVED, that the Participants Committee extends to Gordon our very best wishes for his next chapter, one filled with family, travel and joy.

Signed and presented by the Chair of the NEPOOL Participants Committee on behalf of the NEPOOL Participants this 4th day of December, 2025, in Boston, Massachusetts.

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE DECEMBER 4, 2025 ANNUAL MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Assoc. Non-Voting		Alex Lawton	
AR Large RG Group Member	AR-RG	Aidan Foley		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID (CMP/UI)	Transmission	Alan Trotta	Jason Rauch	
Avangrid Power	Transmission	Kevin Kilgallen		
Bath Iron Works	End User			Bill Short
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 Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (W)		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (W)		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	
Conservation Law Foundation	End User	Phelps Turner (W)		
Constellation Energy Generation (Constellation)	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	
Dartmouth Power Associates, L.P.	Generation	Sarah Yasutake (W)		
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (W)		
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie		Bill Fowler
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin	Joe Dalton	
Eversource Energy	Transmission	Vandan Divatia	Dave Burnham	
First Point Power	Supplier	Peter Schieffelin (W)		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Gabel Associates, Inc.	Supplier	Sarah Yasutake (W)		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (W)	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Steve Kirk	Bill Fowler
Generation Group Member	Generation	Dennis Duffy (W)	Abby Krich (W)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Granite Shore Companies	Generation			Bob Stein
Grid United LLC	Provisional Member	Mike Spector		
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault (W)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Doug Hurley
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

(W) = Webex

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE DECEMBER 4, 2025 ANNUAL MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Icetec Energy Services, LLC	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 (W)	
Jupiter Power, LLC	AR-RG			Frank Swigonski
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Kilgoar	
Maine Power LLC	Supplier	Jeff Jones (W)		
Maine Public Advocate's Office	End User			Susan Chamberlin (W)
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Marble River, LLC	Supplier	John Brodbeck (W)		
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihrle	Jamie Donovan	Chris Modlish (W)
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network (MCAN)	End User			Abby Krich (W)
Mass. Department of Capital Asset Management	End User		Paul Lopes (W)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Midcoast Regional Redevelopment Authority	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
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tm Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (W)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
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	
NRG Business Marketing	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti		
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		Zach Gray-Traverso	Doug Hurley
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro		
Rhode Island Division (RI DPUC)	End User		Christy Hetherington	
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette	Janell Fabiano
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	Dan Murphy
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short

(W) = Webex

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE DECEMBER 4, 2025 ANNUAL MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
Sliski, Alan	End User	Alan Sliski		
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	
Tangent Energy	AR-LR	Brad Swalwell (W)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Vermont Electric Company	Transmission	Frank Ettori		
Vermont Energy Investment Corp.	AR-LR			Doug Hurley
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (W)
Versant Power	Transmission		Stephen Johnston (W)	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vineyard Offshore	Generation	Carrie Hitt		
Vistra (Dynegy Marketing and Trade, Inc.)	Generation	Ryan McCarthy		Bill Fowler
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
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	
ZTECH, LLC	End User			Bill Short

(W) = Webex

ESTIMATED 2026 NEPOOL BUDGET COMPARED TO
2025 NEPOOL BUDGET AND 2025 PROJECTED ACTUAL EXPENSES

Line Items	2025 Approved Budget	2026 Proposed Budget	2025 Current Forecast
NEPOOL Counsel Fees (1)	$4,500,000	$4,500,000	$4,500,000
NEPOOL Counsel Disbursements (1)	$30,000	$30,000	$30,000
Independent Financial Advisor Fees and Disbursements (2)	$48,000	$48,000	$46,000
Committee Meeting Expenses (1) (3)	$960,000	$1,050,000	$1,150,000
Generation Information System (5)	$1,183,624	$1,347,237	$1,329,698
Credit Insurance Premium (4)	$604,500	$561,700	$543,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (6)	$0	$0	$0
SUBTOTAL EXPENSES	$7,326,124	$7,536,937	$7,598,698
Revenue			
NEPOOL Membership Fees (4)	($2,500,000)	($2,500,000)	($2,493,200)
Generation Information System (5) (7)	($1,183,624)	($1,347,237)	($1,329,698)
Credit Insurance Premium (4) (8)	($604,500)	($561,700)	($543,000)
TOTAL REVENUE	($4,288,124)	($4,408,937)	($4,365,898)
TOTAL NEPOOL EXPENSES	$3,038,000	$3,128,000	$3,232,800

ESTIMATED 2026 NEPOOL BUDGET COMPARED TO 2025 NEPOOL BUDGET AND 2025 PROJECTED ACTUAL EXPENSES

Notes

(1) Day Pitney LLP, NEPOOL Counsel, provided the 2026 proposed estimate, reflecting a challenging work plan in 2026.

(2) Michael M. Mackles, NEPOOL's Independent Financial Advisor, provided the 2026 proposed estimate, reflecting the review of meeting and travel expenses. The 2025 Current Forecast is lower than the 2025 Approved Budget due to the cancellation of some Budget & Finance Subcommittee meetings.

(3) The 2025 Current Forecast for Committee Meeting Expenses captures higher meeting costs that exceeded the 2025 estimates for each Principal Committee meeting, along with strong attendance at the Summer Meetings.

(4) ISO New England Inc. provided the 2026 proposed estimate.

(5) Based on fee arrangement set forth in the Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the projected annualized fixed fee for 2026 is $1,347,237. This amount includes $15,000 for ~~ISO-NE's~~the ISO's administrative GIS-related costs. The estimate assumes that NEPOOL will remain in the 140,000–149,999 tier of total Account Holders and Generators for the first four months of the year (January through April), increase to the 150,000–159,999 tier for the following five months (May through September), and then increase to the 160,000–169,999 tier for the final three months of the year (October through December), resulting in a higher annual fee.

The 2025 Current Forecast is higher than the 2025 Approved Budget because the number of Account Holders and Generators increased more rapidly than projected in 2024 and several GIS-related changes approved in 2025 were not anticipated in the 2024 projections.

(6) If NEPOOL determines that an audit should be performed in 2026, funding for that audit will be addressed separately.

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

(8) Credit insurance premiums are paid by Qualifying Market Participants in accordance with the methodology set forth in Section IX of the ISO New England Financial Assurance Policy.

ESTIMATED 2026 NEPOOL BUDGET COMPARED TO 2025 NEPOOL BUDGET AND 2025 PROJECTED ACTUAL EXPENSES

3 CEO Report

Jan 8, 2026
Meeting

4 Systems & Market Operations Report

REPORT

Jan 8, 2026
Meeting

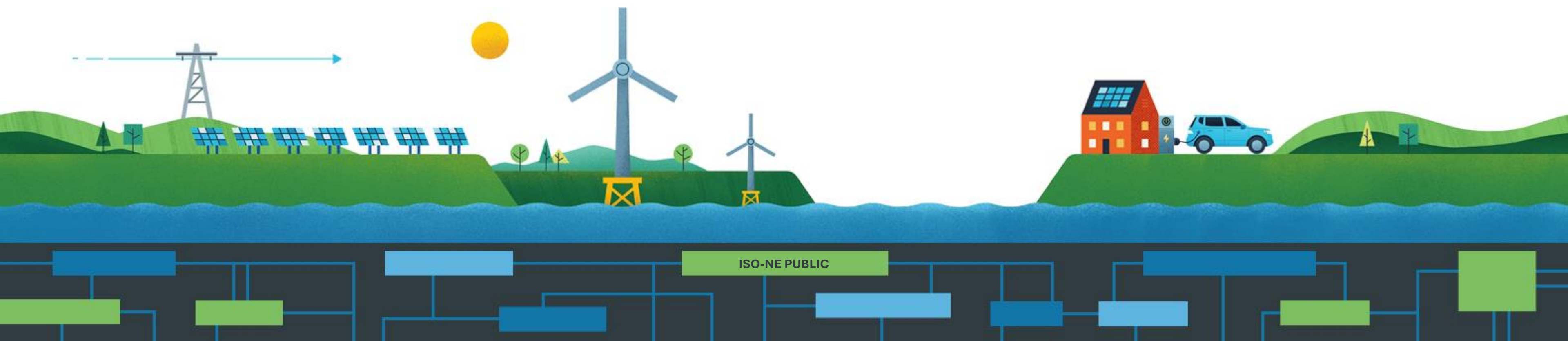
NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

NEPOOL Participants Committee

System & Market Operations Report – January 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



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HIGHLIGHTS

Highlights: December 2025

Settled data through December 30th

- **Peak Hour** on December 15
  - 19,477 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 P.M.
- **Minimum Telemetered Load**
  - 10,642 MW; hour ending 03:00 A.M. on Monday, December 1
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $136.05/MWh
  - Real-Time (RT) Hub LMP: $131.17/MWh
  - Natural Gas: $14.84/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $1.8B up from $1B in December 2024
  - Ancillary Markets* value $27.5M up from $3.8M in December 2024
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 99.9% during December, up from 99.0% during November
  - Updated November Energy Market value: $718M
- **Net Commitment Period Compensation (NCPC)** total $3.9M
  - Represents 0.2% of monthly Energy Market value
  - First Contingency $3.9M
    - Dispatch Lost Opportunity Cost (DLOC) - $1M; Rapid Response Pricing (RRP) Opportunity Cost - $322K; Posturing - $0; Generator Performance Auditing (GPA) - $92K
    - $617K paid to resources at external locations, up $251K from November
      - $77K charged to Day-Ahead Load Obligation (DALO) at external locations; $211K to Day-Ahead Generation Obligation (DAGO) at external locations; $329K to RT Deviations
  - 2nd Contingency, Distribution and Voltage was zero
- **Forward Capacity Market (FCM)** market value $88.9M
  - FCM peak for 2025 is currently 26,086 MWh

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

*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund **DA cleared physical energy is the sum of generation, DRR, and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **26,024 MW**
  - hour ending 7:00 P.M. on Tuesday, June 24
- RQM System Peak Load: **26,586 MW** (initial)
  - hour ending 6:00 P.M. on Tuesday, June 24
- FCM Peak Load: **26,086 MW** (preliminary & subject to change)
  - hour ending 7:00 P.M. on Tuesday, June 24
  - At this hour, the capacity zone-level FCM peak loads were 3,357 MW in Northern New England, 2,026 MW in Maine, 9,920 MW in Rest-of-Pool, and 10,783 MW in Southeast New England.

*Telemetered loads are as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SOG). Due to the difference in calculation methodologies and the impact of SOGs, these values can occur on different days and/or hours. Both are 'net energy for load' concepts and include transmission losses. FCM load values reflect the sum of active, normal load assets that are non-dispatchable, are included in the FCM settlement and do not include transmission losses.

Day-Ahead Ancillary Services (DAAS) Results

- Average daily total DA E&AS Market value: **$60.8M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$2.13M**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$17.54/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **1.7%**
- FER Credits* as % of total DA E&AS Market Value: **8.0%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **106 MWh**
  - Average hourly cleared FER Price: **$13.13/MWh**

DA E&AS refers to DA Energy and Ancillary Services
*FER credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR)
FER credits are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)

DAAS Results (continued)...

Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
3/1/2025	$17.3M	$466K	$202K	$3.35	1.2%	$982K	177K	$3.26	6.2%	176
4/1/2025	$13.9M	$332K	$175K	$3.23	1.3%	$760K	128K	$2.66	5.8%	97
5/1/2025	$11.0M	$190K	$52K	$0.94	0.5%	$563K	164K	$2.06	5.2%	155
6/1/2025	$20.2M	$885K	$173K	$2.97	0.9%	$1,287K	156K	$3.15	6.6%	125
7/1/2025	$35.8M	$1,704K	$1,139K	$19.53	3.2%	$1,277K	97K	$3.06	3.7%	55
8/1/2025	$20.2M	$747K	$544K	$9.57	2.7%	$1,292K	143K	$3.02	6.4%	94
9/1/2025	$12.3M	$320K	$184K	$3.21	1.5%	$587K	134K	$1.94	4.8%	104
10/1/2025	$15.5M	$719K	$478K	$8.21	3.1%	$1,911K	203K	$6.50	12.3%	209
11/1/2025	$24.7M	$1,122K	$457K	$7.85	1.9%	$2,546K	211K	$7.99	10.3%	135
12/1/2025	$60.8M	$2,128K	$1,014K	$17.54	1.7%	$4,849K	215K	$13.13	8.0%	106

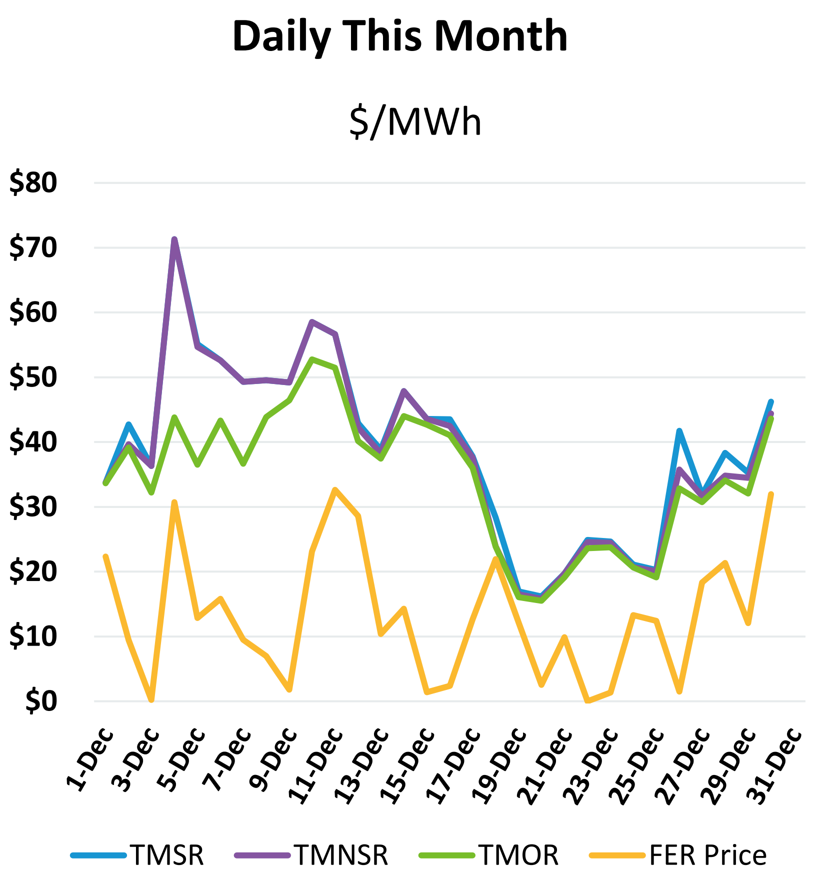
About the Table:

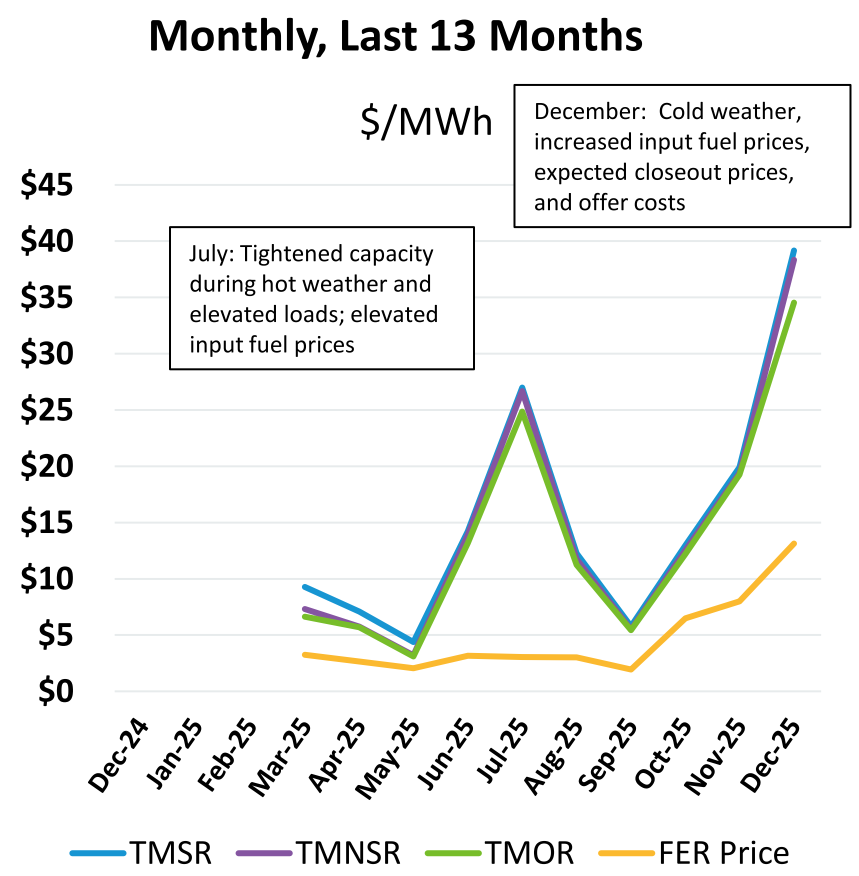
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)
- *'Avg Daily Energy MWh Paid FER Price' reflects Cleared DA Physical Gen and DRR MWh during non-zero FER prices
- Data prior to August (denoted by the line) may not match settlement quality data provided in the Monthly Market Report

Additionally:

- FER Credits are included in the Monthly Market Operations Report (see Section 7.1.1) found on the ISO Website here. Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

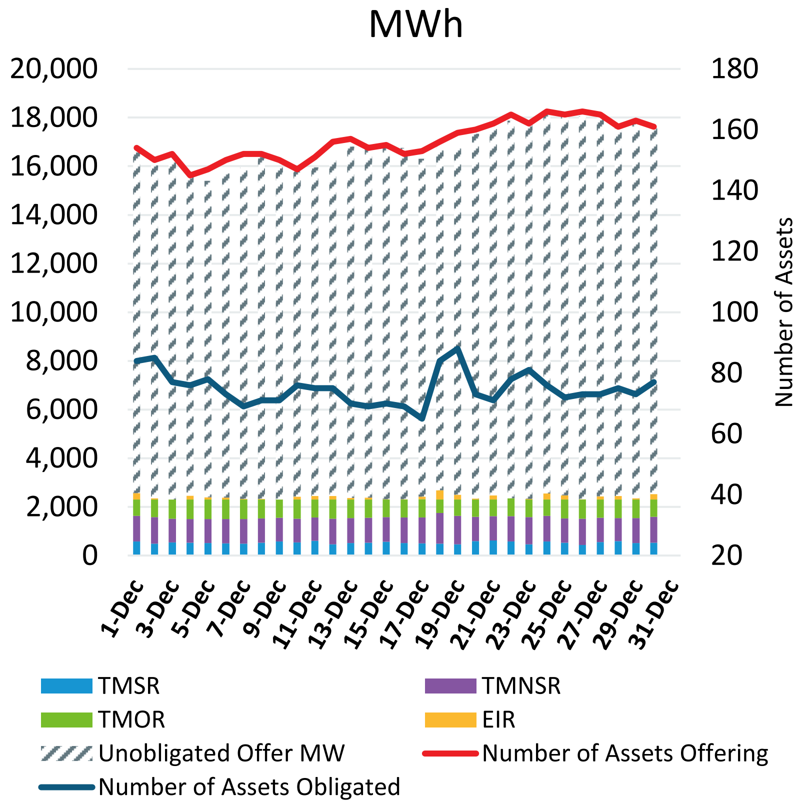
Average Hourly DAAS Prices



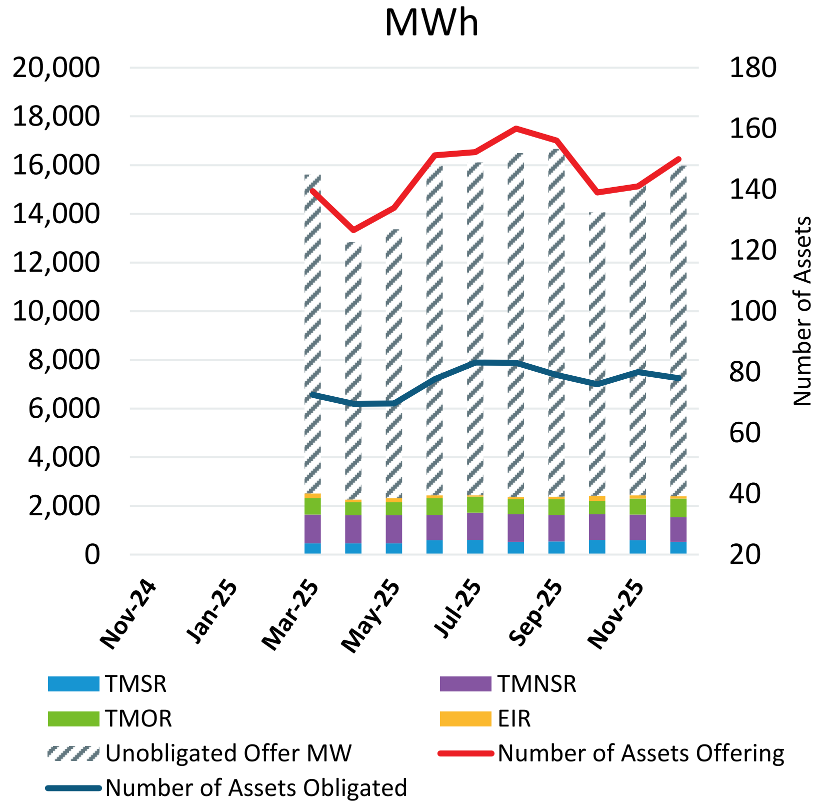


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



Monthly, Last 13 Months



*Unobligated Offer MWh reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not yet consider additional unit parameter constraints or dispatch constraints and should not be equated with actual capacity available in the dispatch solution.

Highlights

- The ISO is evaluating all LTTP RFP submissions and expects to provide an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) in the February/March 2026 timeframe

Forward Capacity Market (FCM) Highlights

- CCP 16 (2025-2026)
  - The third annual reconfiguration auction (ARA3) was held March 3-5 and results were posted on April 1
- CCP 17 (2026-2027)
  - The second annual reconfiguration auction (ARA2) was held August 1-5 and results were posted on September 2
  - The ISO filed the ICR and related values for the ARA3 to be conducted in 2026 with FERC on November 21, with a requested effective date of January 21, 2026
- CCP 18 (2027-2028)
  - The first annual reconfiguration auction (ARA1) was held June 2-4 and results were posted on July 2
  - The ISO filed the ICR and related values for the ARA2 to be conducted in 2026 with FERC on November 21, with a requested effective date of January 21, 2026

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
    - On May 20, 2024 FERC issued an order accepting the additional delay
    - 2024 interim RA qualification process completed on November 1, 2024
      - A total of 1,389 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
    - 2025 interim RA qualification process completed on November 3, 2025
      - A total of 1,455 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
      - The Transitional CNR Group Study was completed with the completion of the 2025 interim RA qualification process
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

Load Forecast

- The 2026 forecast cycle formally began in September
- Stakeholder discussions related to CELT 2026 will continue at the next Load Forecast Committee on February 20

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-4.4°F) Max: 59°F, Min: 12°F Precipitation: 2.39" – Below Normal Normal: 4.30" Snow: 4.3"	Hartford	Temperature: Below Normal (-4.6°F) Max: 58°F, Min: 1°F Precipitation: 3.35" - Below Normal Normal: 4.08" Snow: 8.9"

Peak Load:	19,382 MW	December 15, 2025	18:00 (ending)
Mid-Day Minimum Load - Month:	10,784 MW	December 1, 2025	13:00 (ending)
Mid-Day Minimum Load - Historical:	5,318 MW	April 20, 2025	14:00 (ending)

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

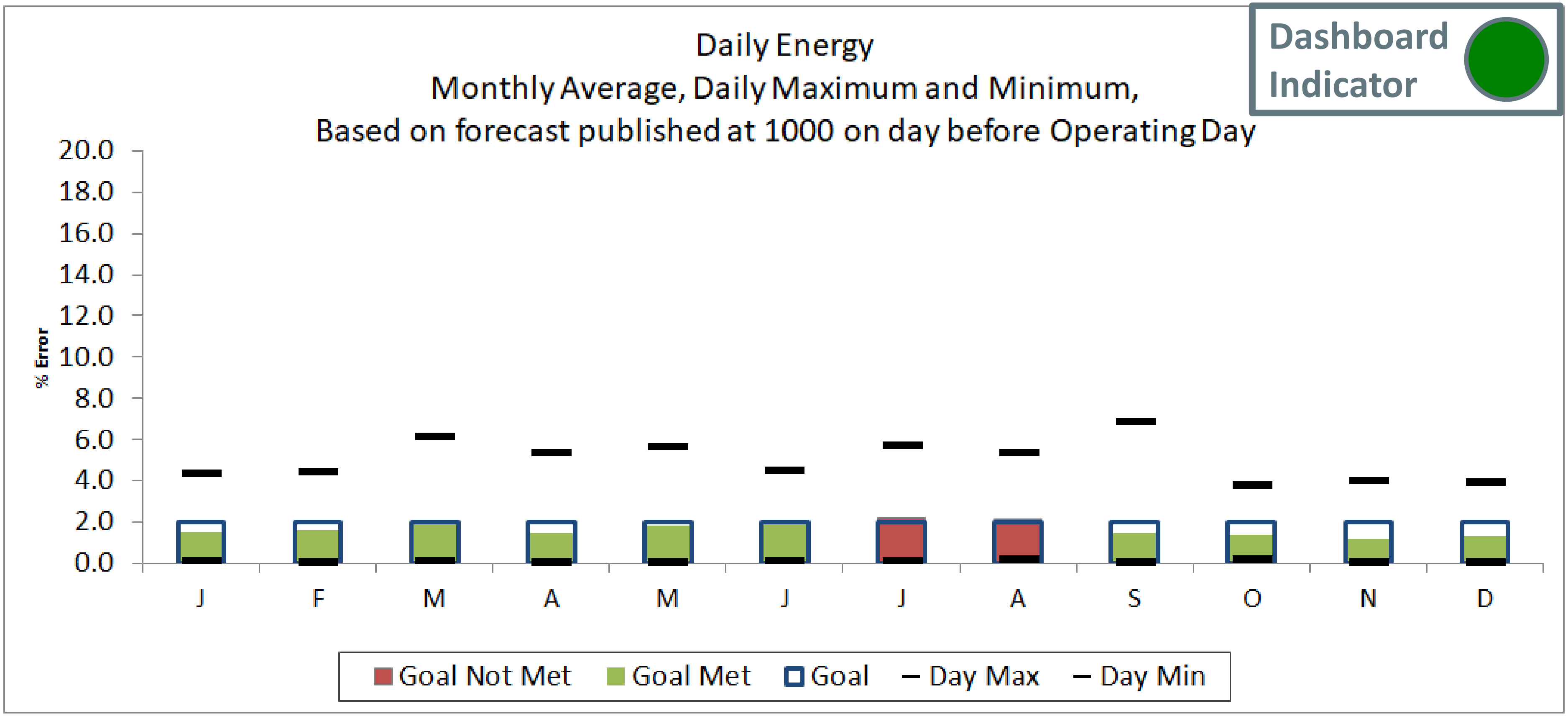
Procedure	Declared	Cancelled	Note
NONE			

System Operations

NPCC Simultaneous Activation of Ten-Minute Reserve Events

Date	Area	MW Lost
12/6/2025	PJM	1335
12/9/2025	NYISO	550
12/16/2025	IESO	950

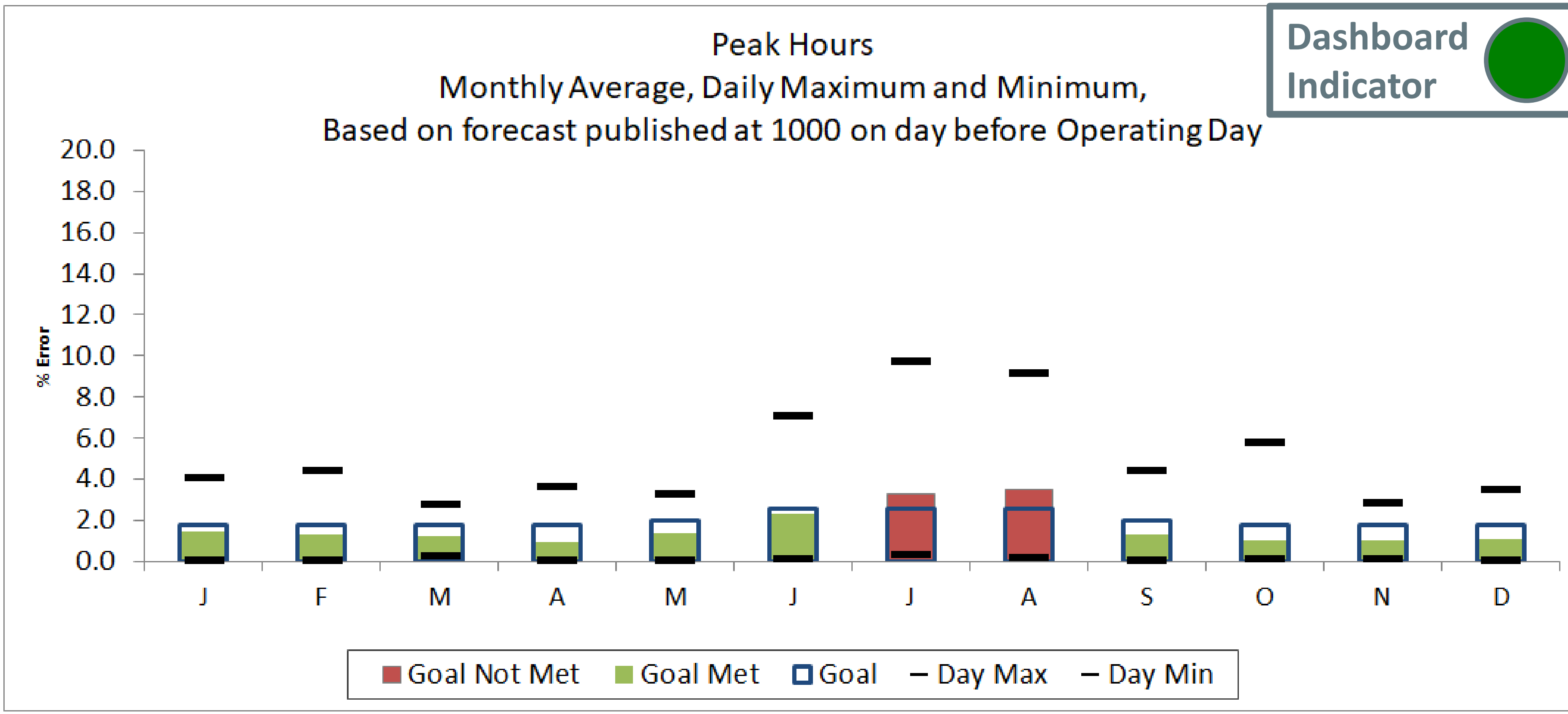
System Operations - Load Forecast Accuracy



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	4.44	6.10	5.36	5.61	4.48	5.70	5.34	6.81	3.73	3.97	3.91	6.81
Day Min	0.12	0.04	0.12	0.05	0.06	0.08	0.11	0.16	0.05	0.18	0.03	0.00	0.00
MAPE	1.54	1.62	1.89	1.45	1.80	1.98	2.24	2.12	1.46	1.39	1.21	1.35	1.67
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	

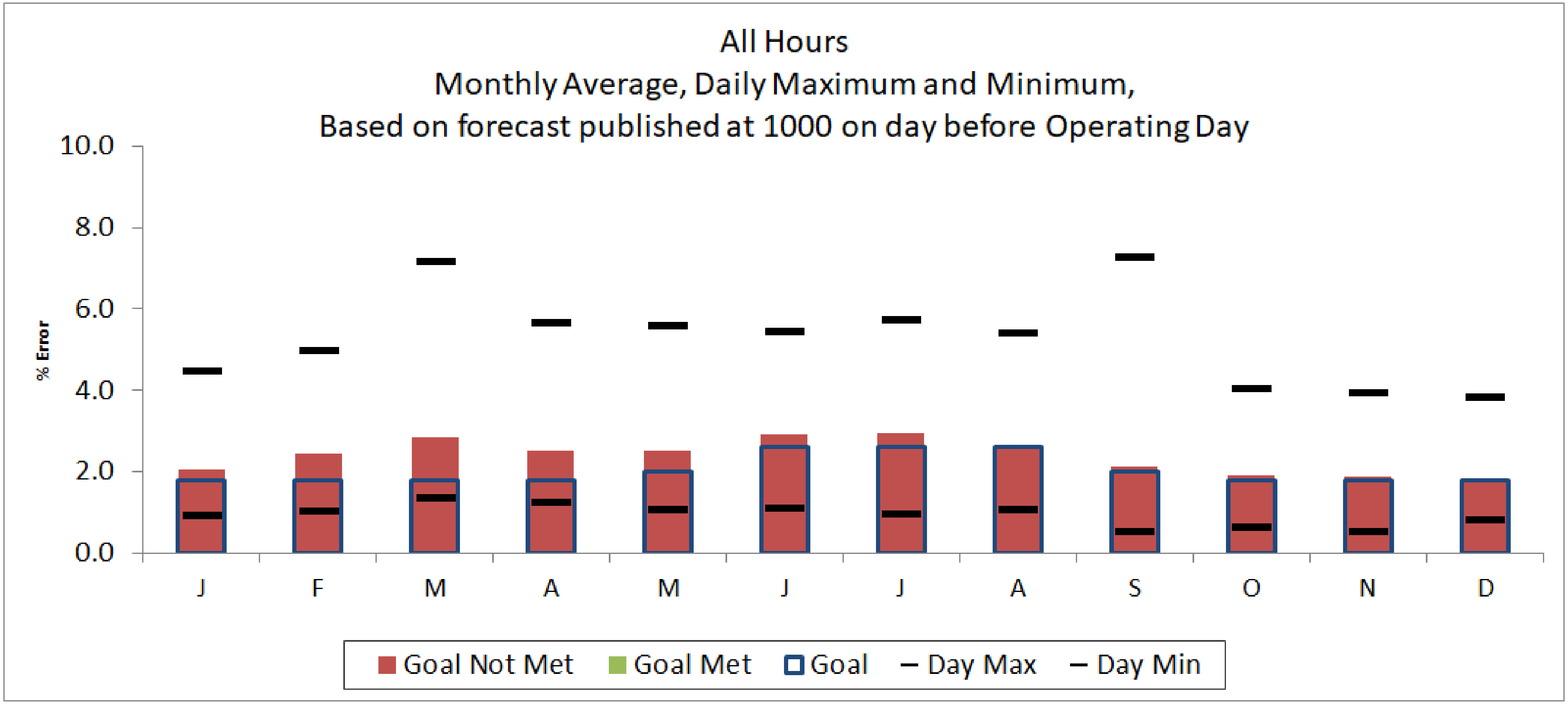
System Operations - Load Forecast Accuracy, cont.

Dashboard Indicator



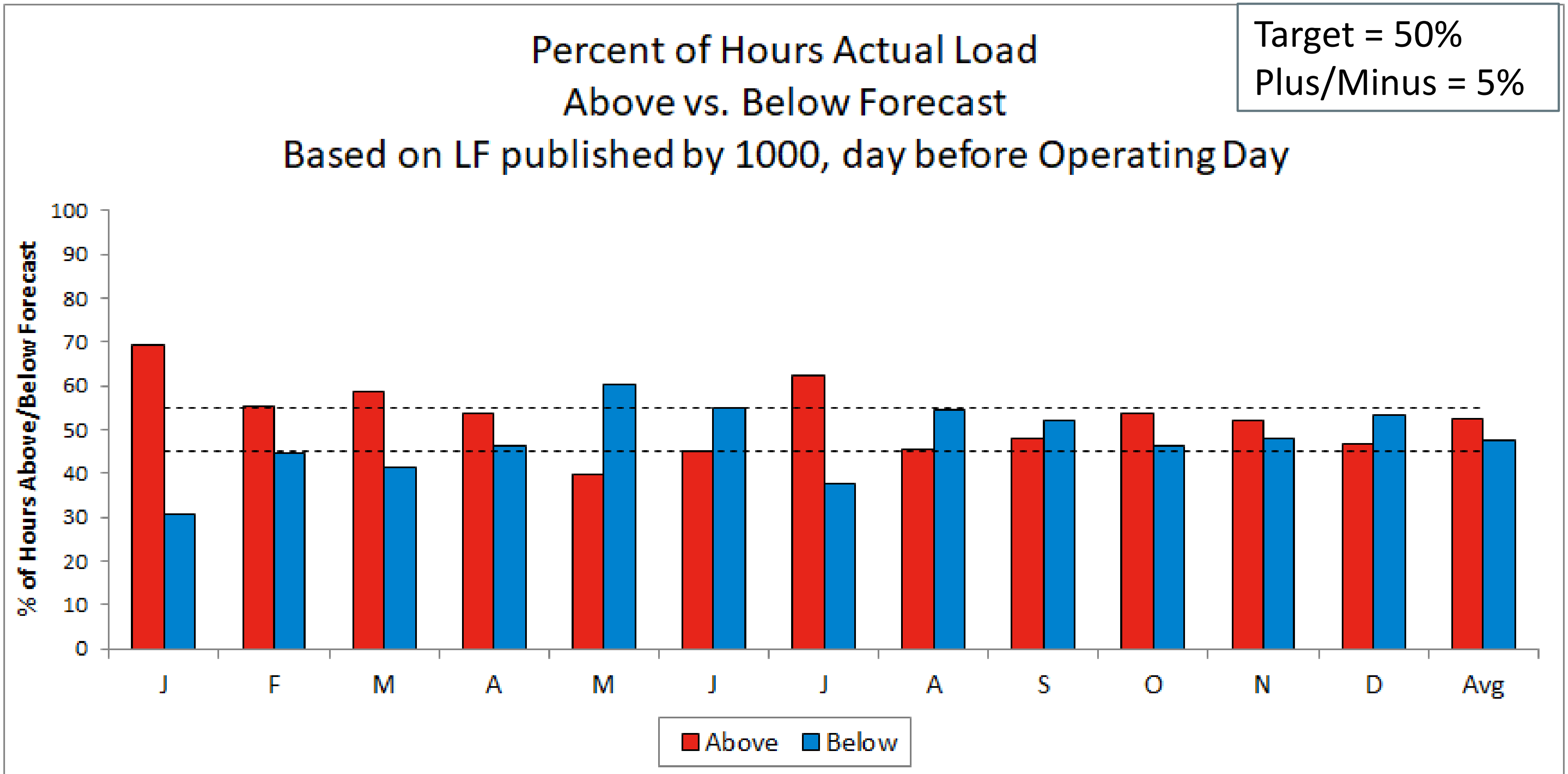
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29	7.08	9.71	9.15	4.43	5.77	2.84	3.51	9.71
Day Min	0.03	0.06	0.24	0.03	0.06	0.11	0.34	0.15	0.05	0.12	0.07	0.00	0.00
MAPE	1.48	1.34	1.29	1.00	1.41	2.30	3.28	3.48	1.30	1.02	1.04	1.12	1.68
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

System Operations - Load Forecast Accuracy, cont.



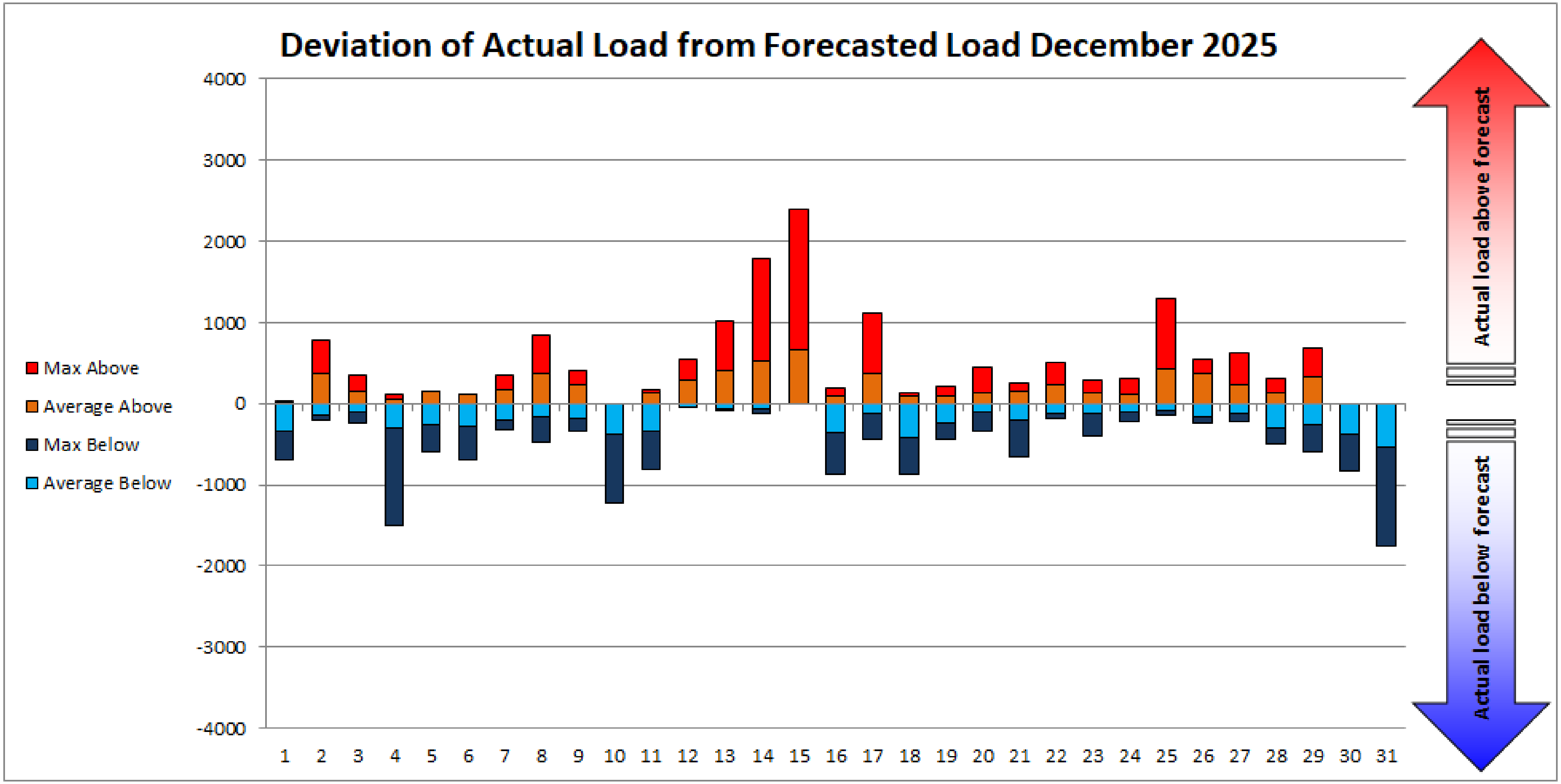
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57	5.44	5.72	5.41	7.24	4.01	3.91	3.82	7.24
Day Min	0.90	1.02	1.33	1.23	1.07	1.11	0.95	1.07	0.52	0.64	0.50	0.80	0.50
MAPE	2.07	2.47	2.83	2.53	2.53	2.93	2.94	2.68	2.13	1.92	1.88	1.84	2.40
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

System Operations - Load Forecast Accuracy, cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	69.2	55.2	58.5	53.5	39.8	45.1	62.5	45.3	48.1	53.5	51.9	46.9	52
Below %	30.8	44.8	41.5	46.5	60.2	54.9	37.5	54.7	51.9	46.5	48.1	53.1	48
Avg Above	280.5	282.1	246.5	255.8	164.5	307.8	397.3	225.4	213.7	161.8	222.3	211.7	397
Avg Below	-178.6	-287.9	-273.2	-190.7	-254.1	-310.2	-270.0	-308.7	-179.5	-157.1	-154.8	-210.7	-310
Avg All	138	24	12	49	-82	-24	145	-81	1	12	35	-7	18

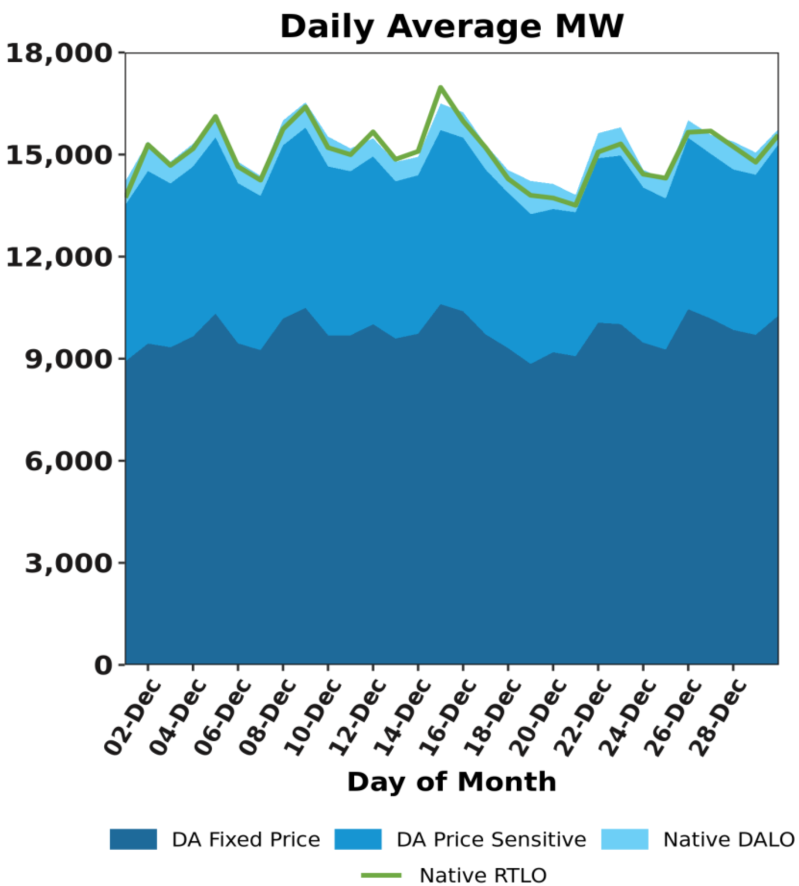
System Operations - Load Forecast Accuracy, cont.

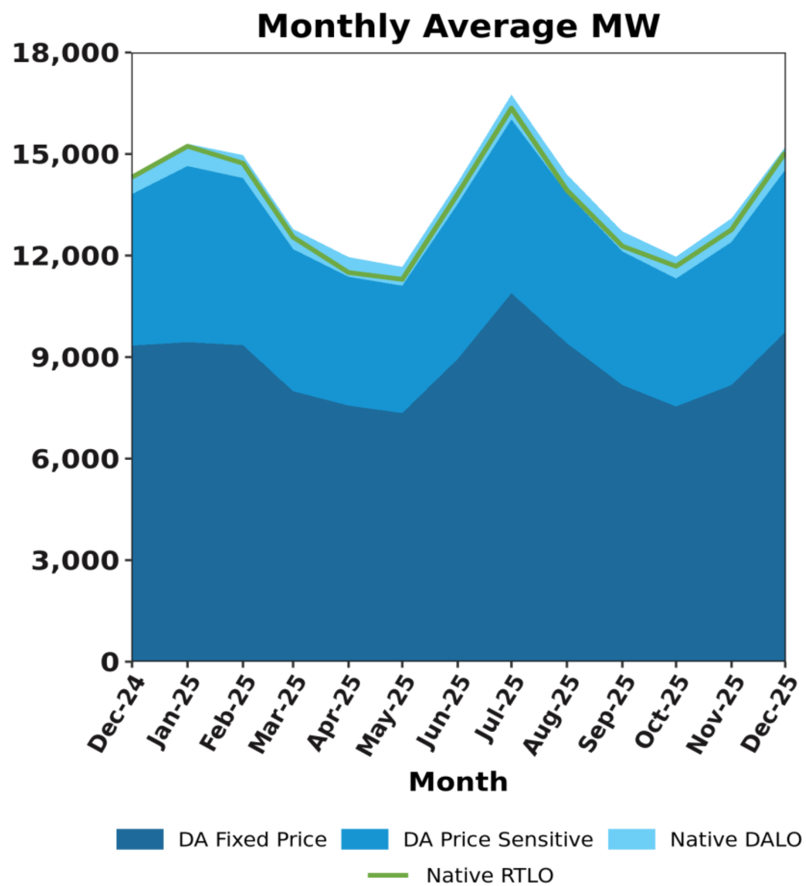


MARKET OPERATIONS

Supply and Demand Volumes

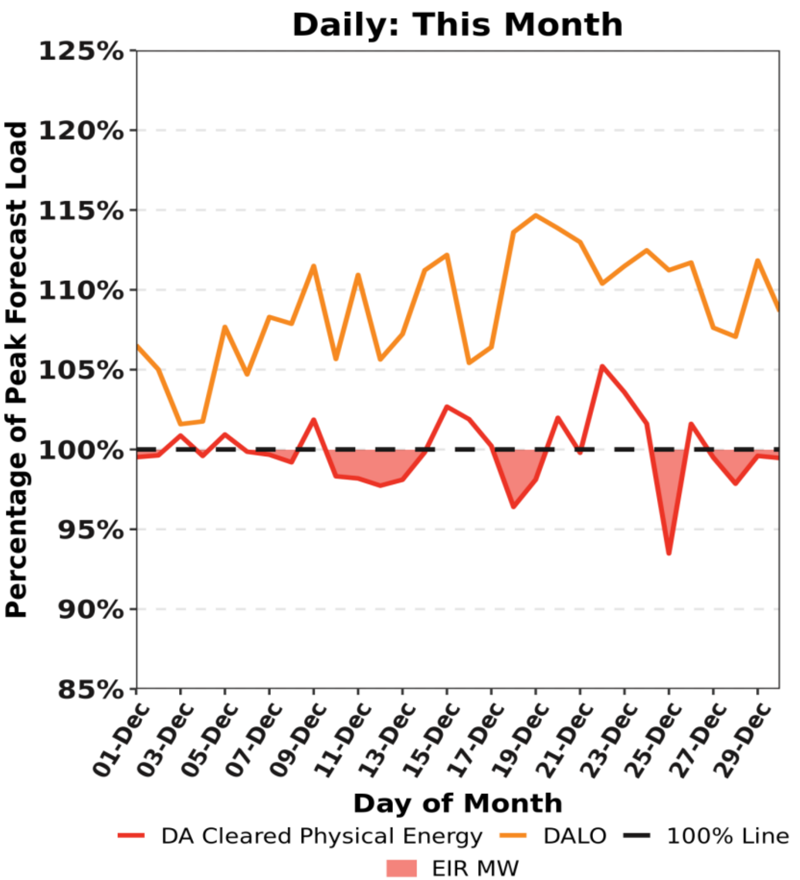
DA Cleared Native Load by Composition Compared to Native RT Load

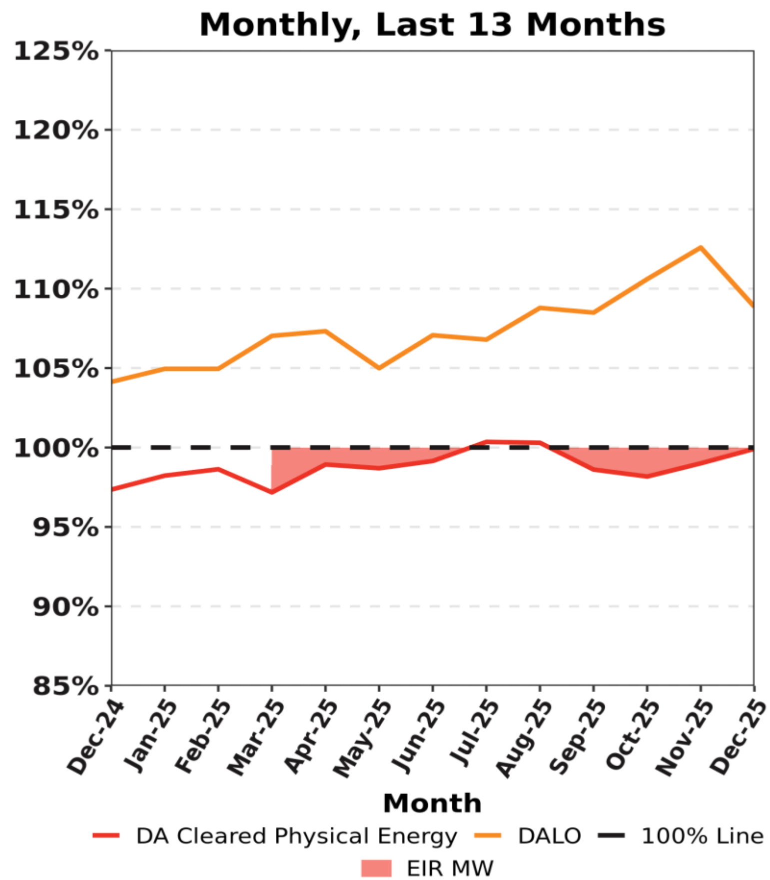




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these charts.

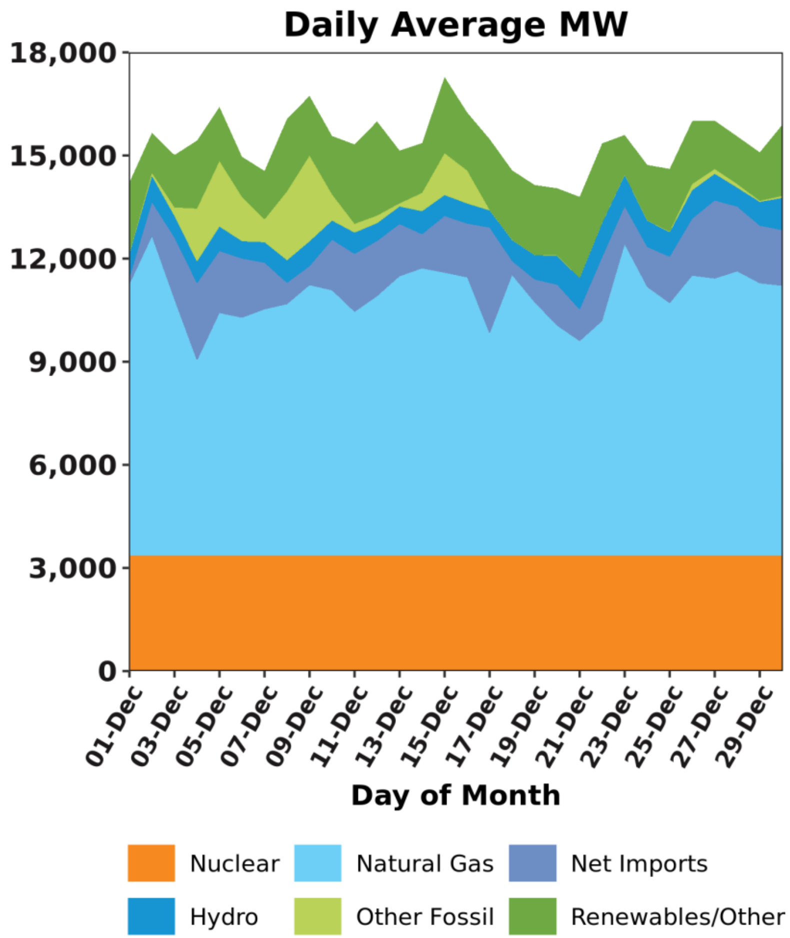
DA Volumes as % of Forecast in Peak Hour

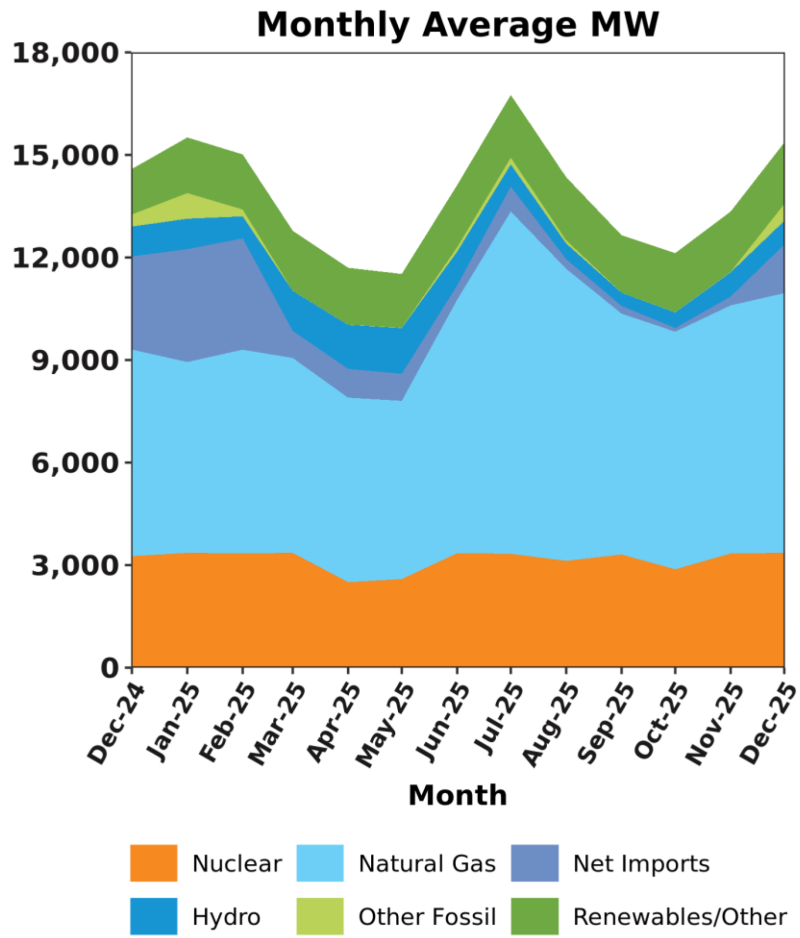




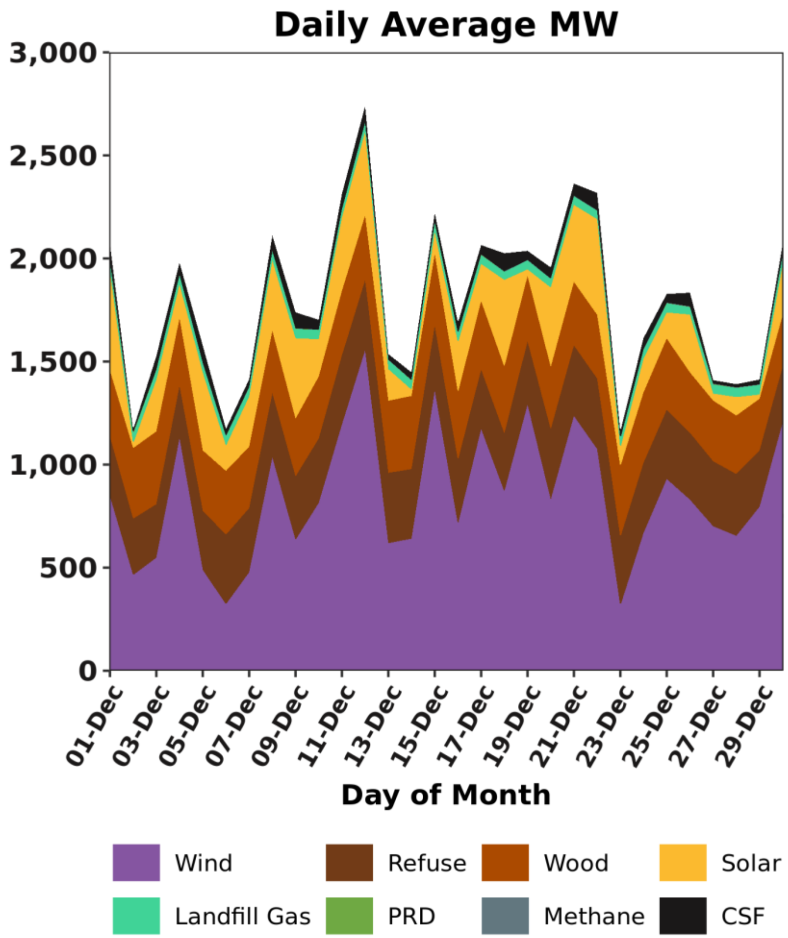
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

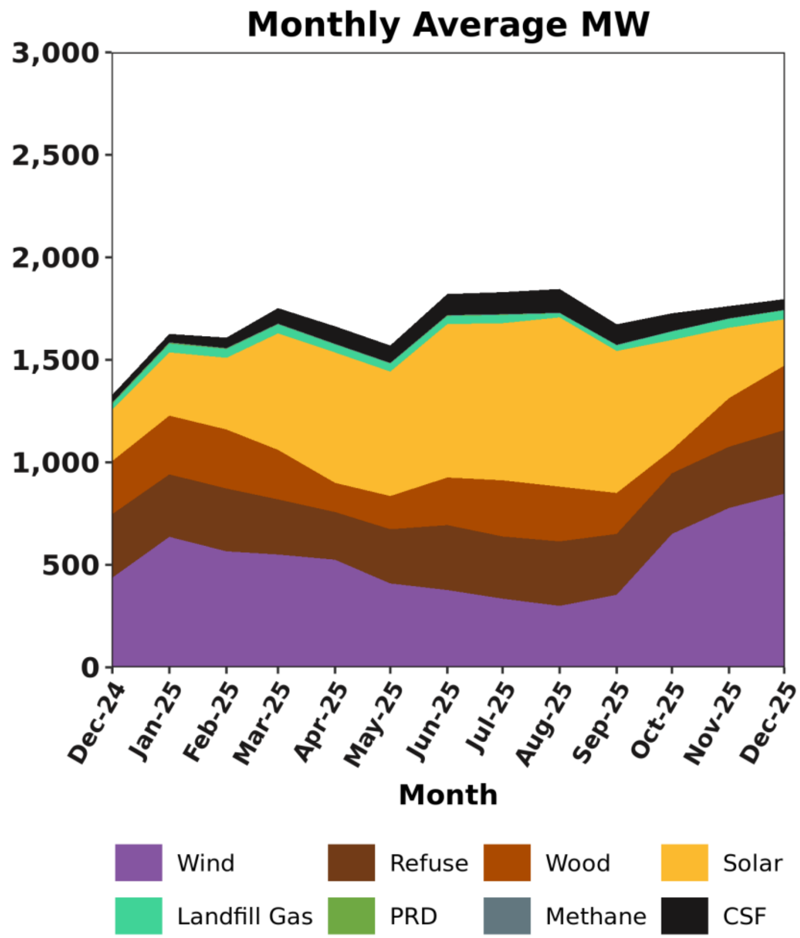
Resource Mix





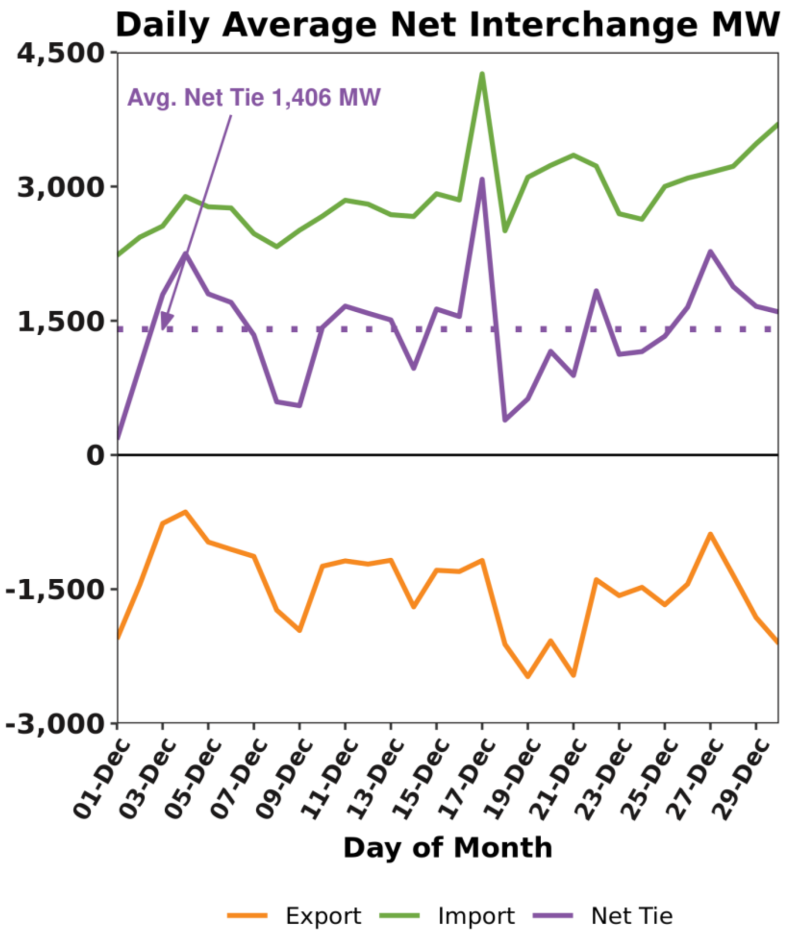
Renewable Generation by Fuel Type

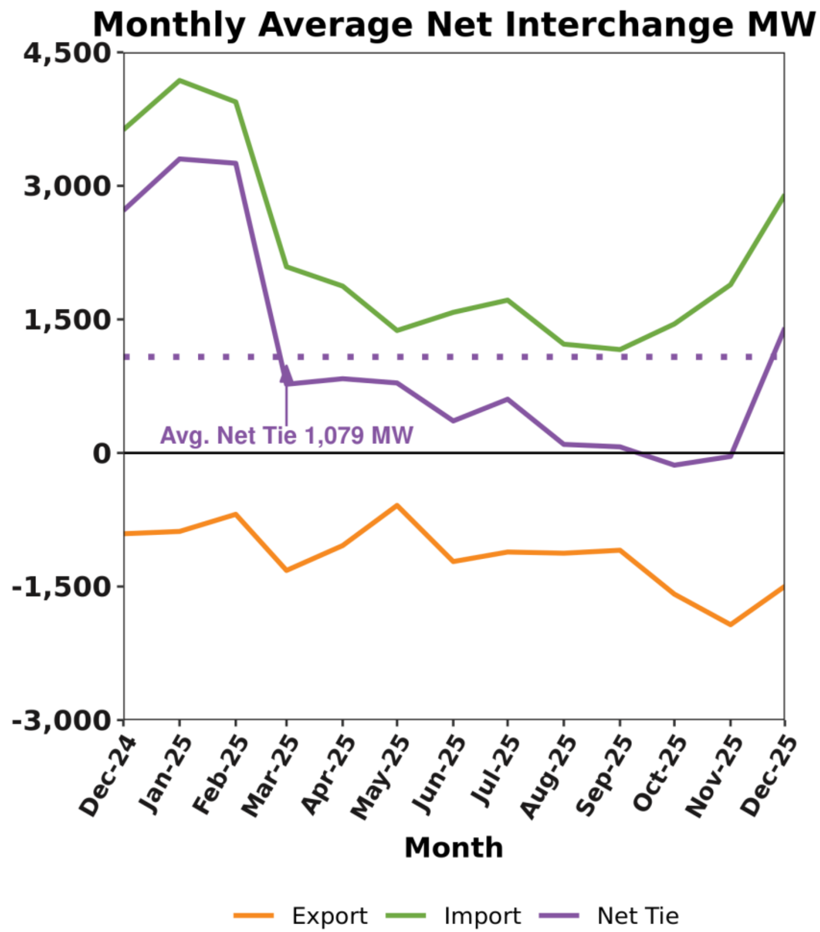




CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

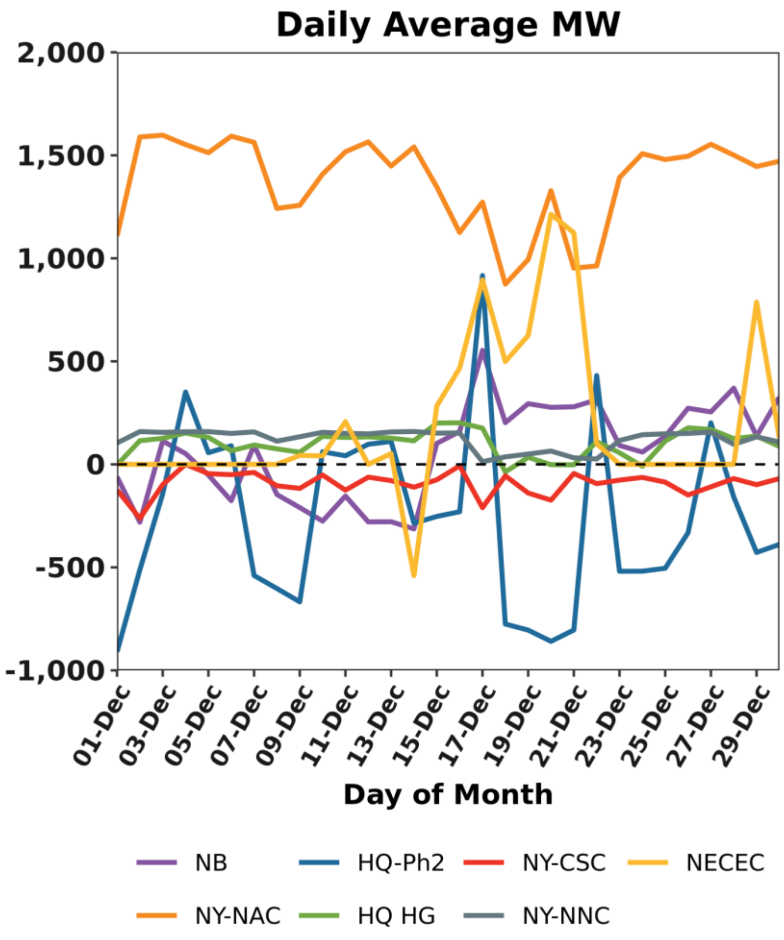
RT Net Interchange

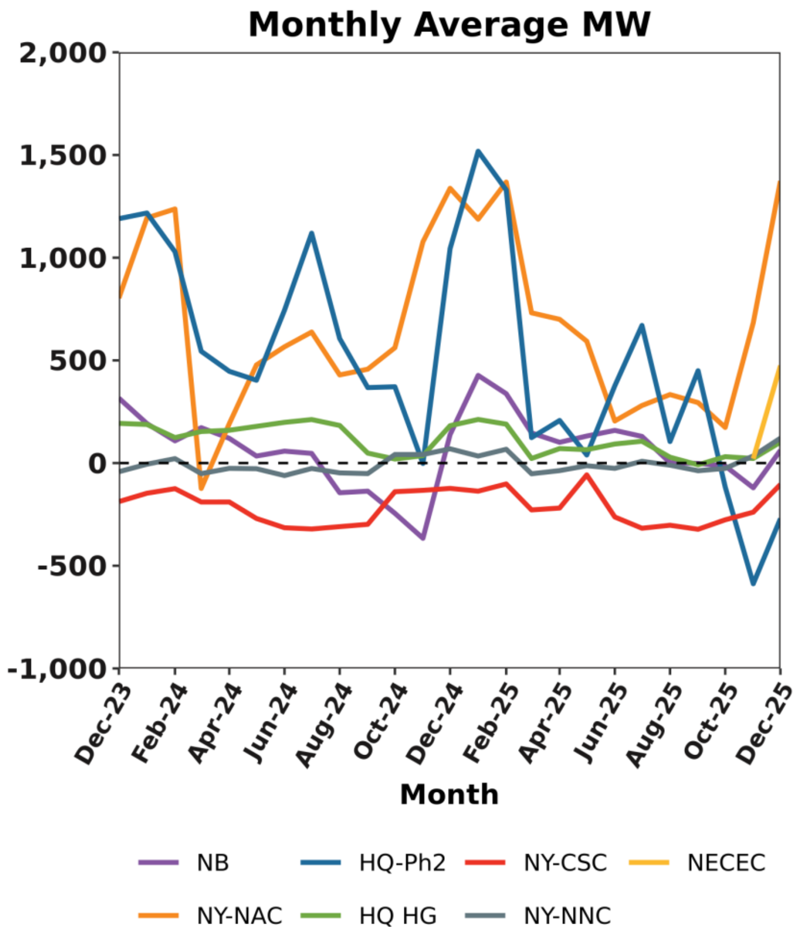




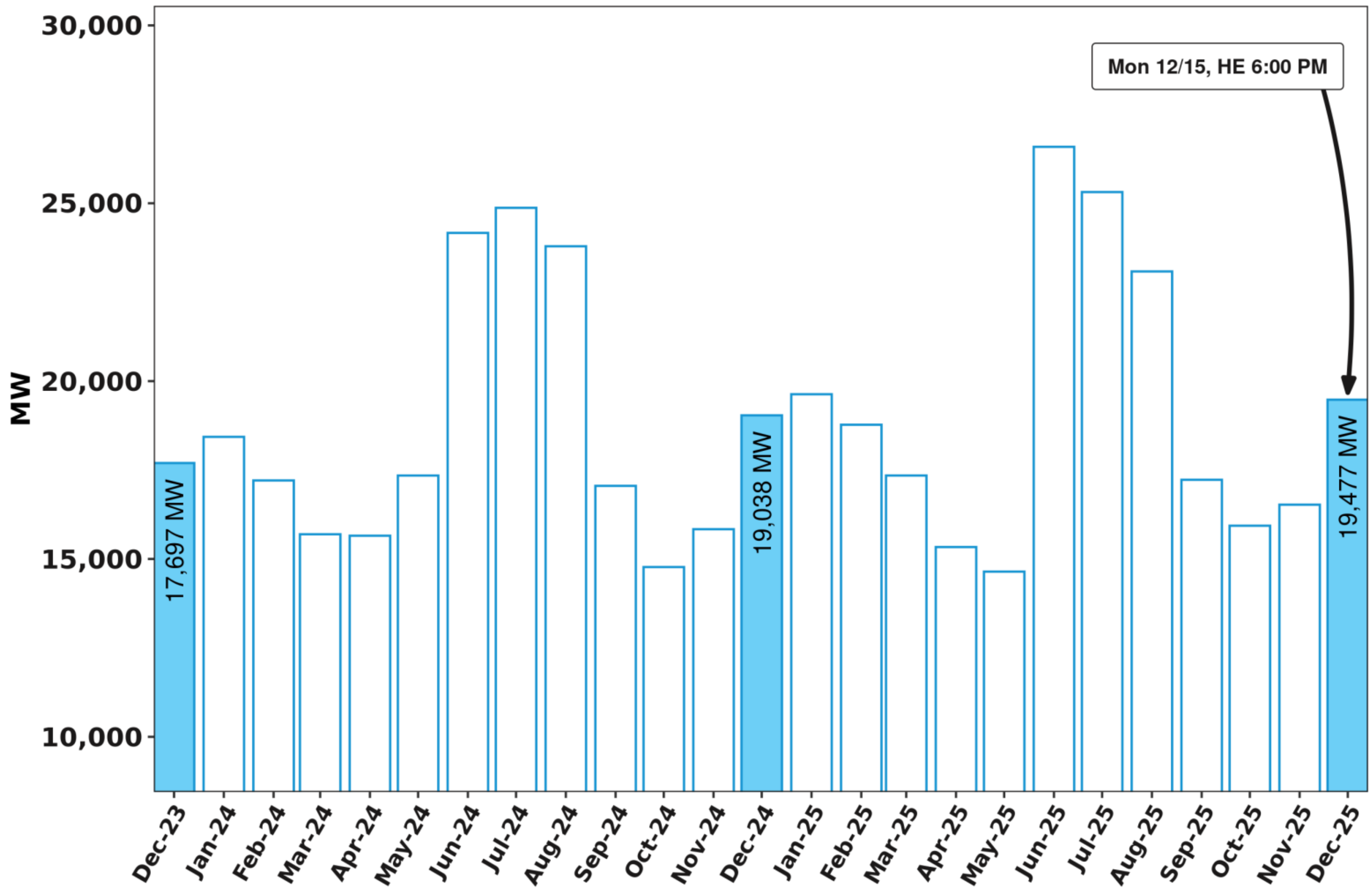
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



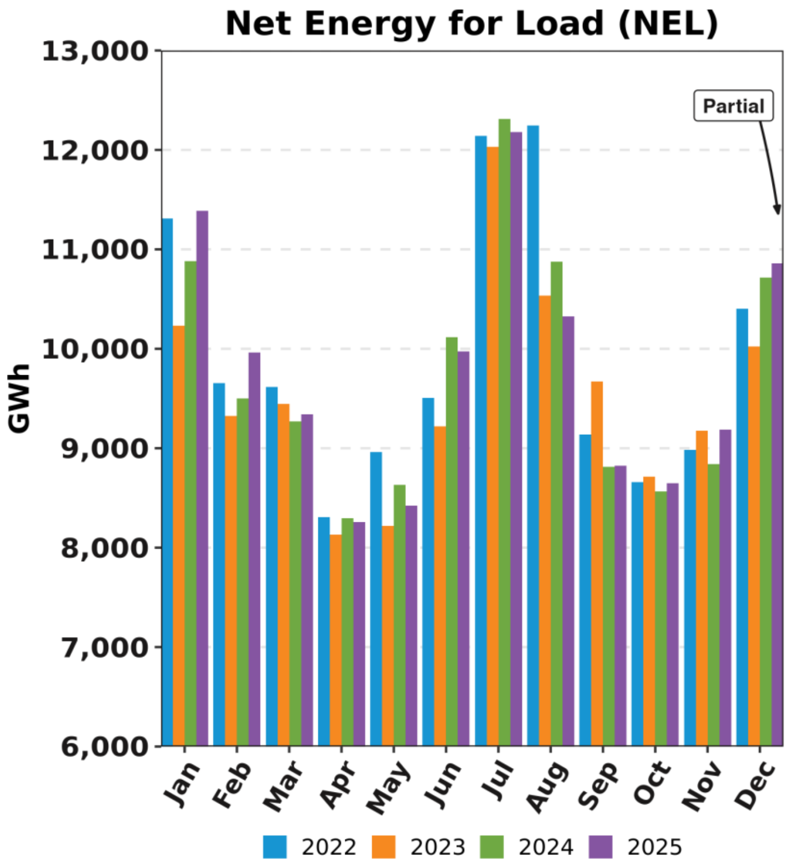


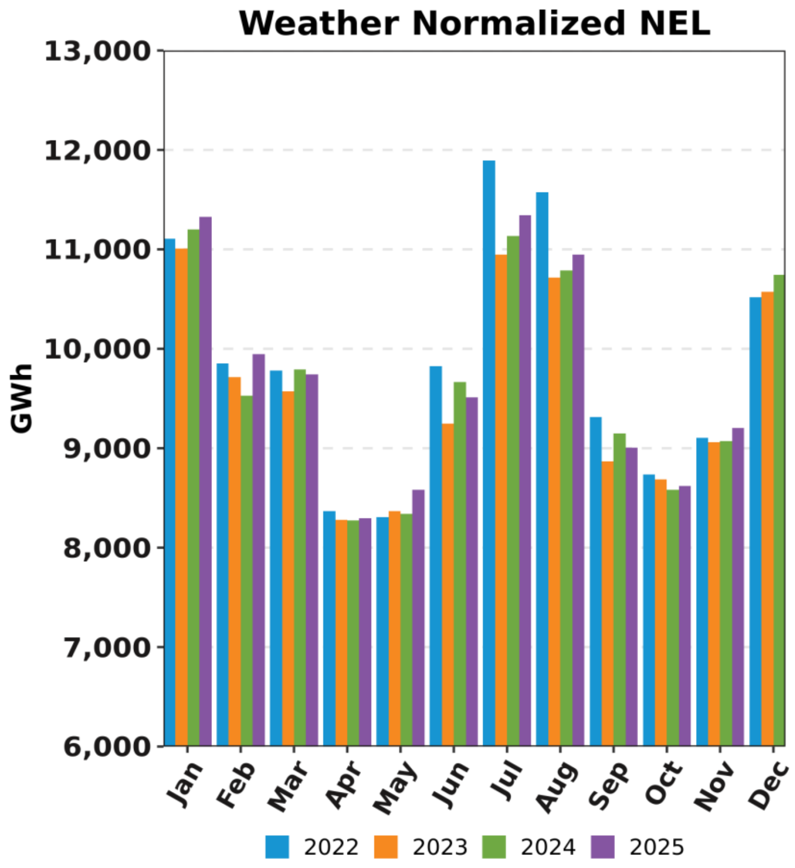
RQM System Peak Load MW by Month



Shaded columns highlight current month and the same month over the prior two years

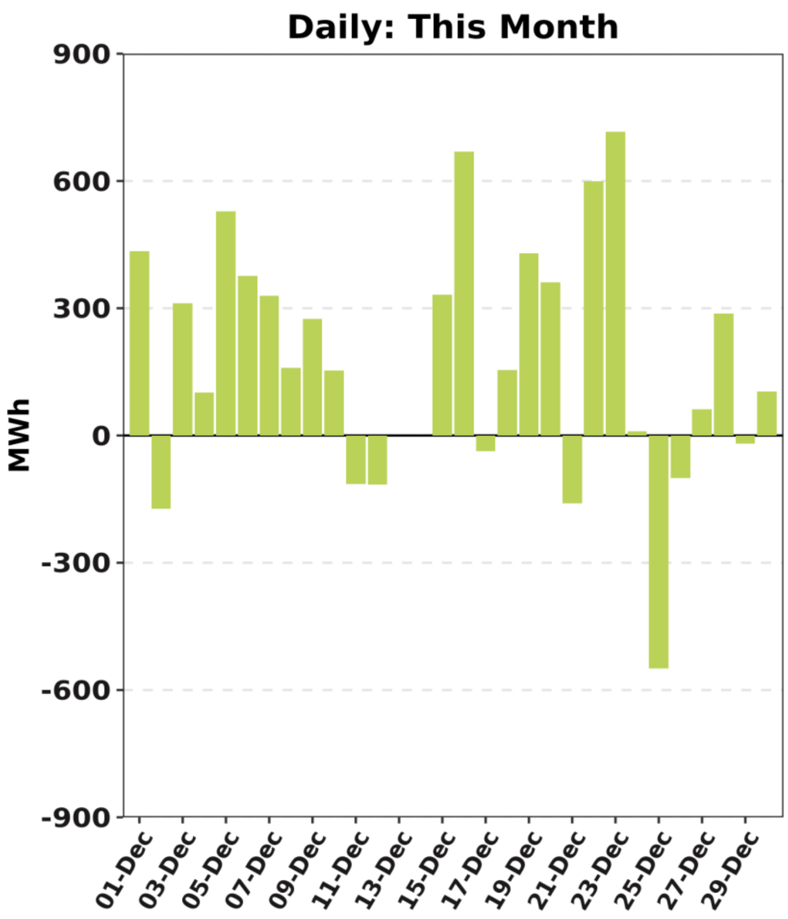
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

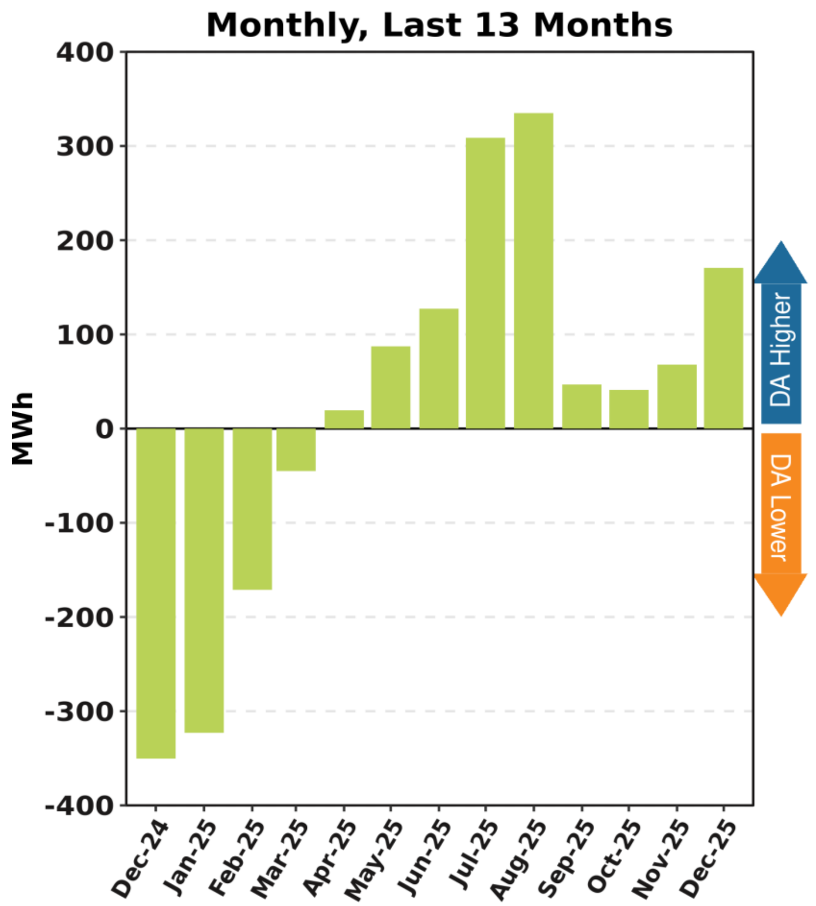




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

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

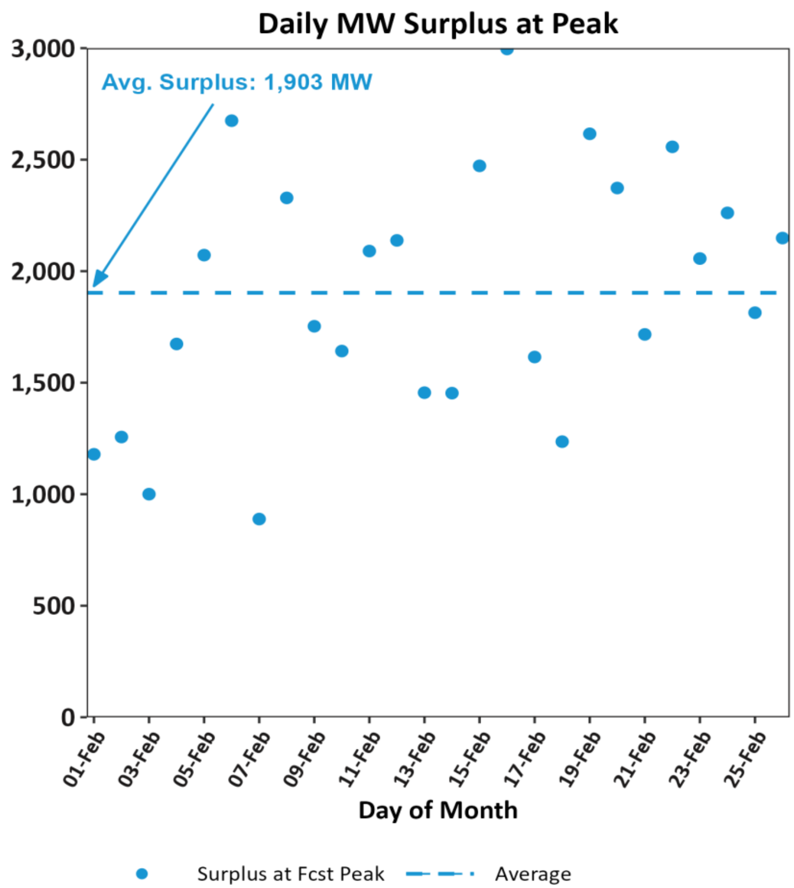


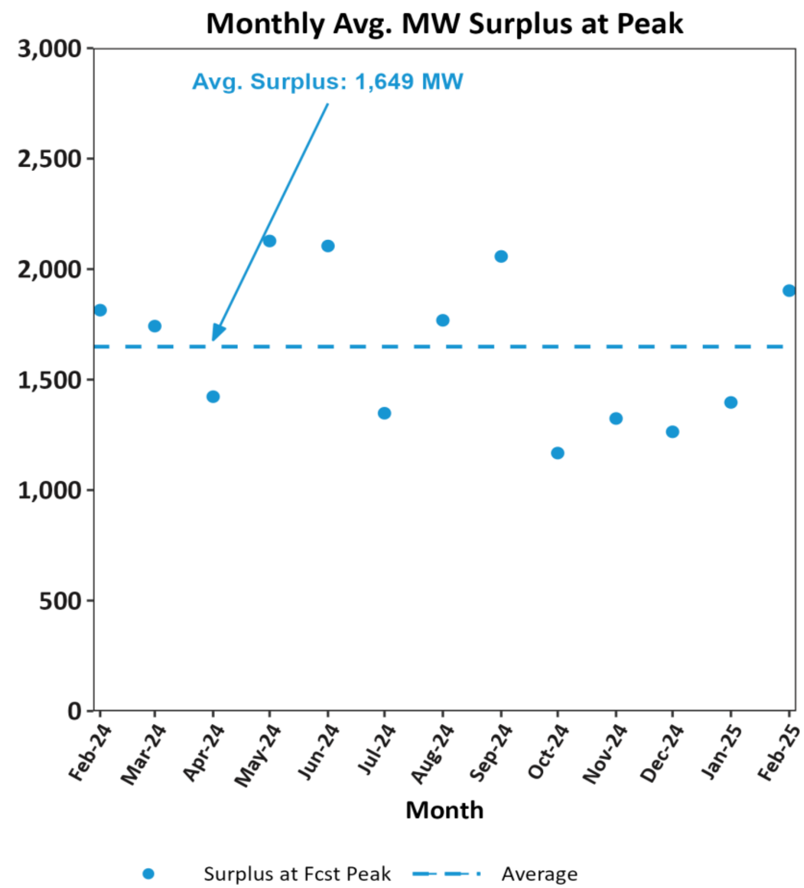


Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

Native Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements

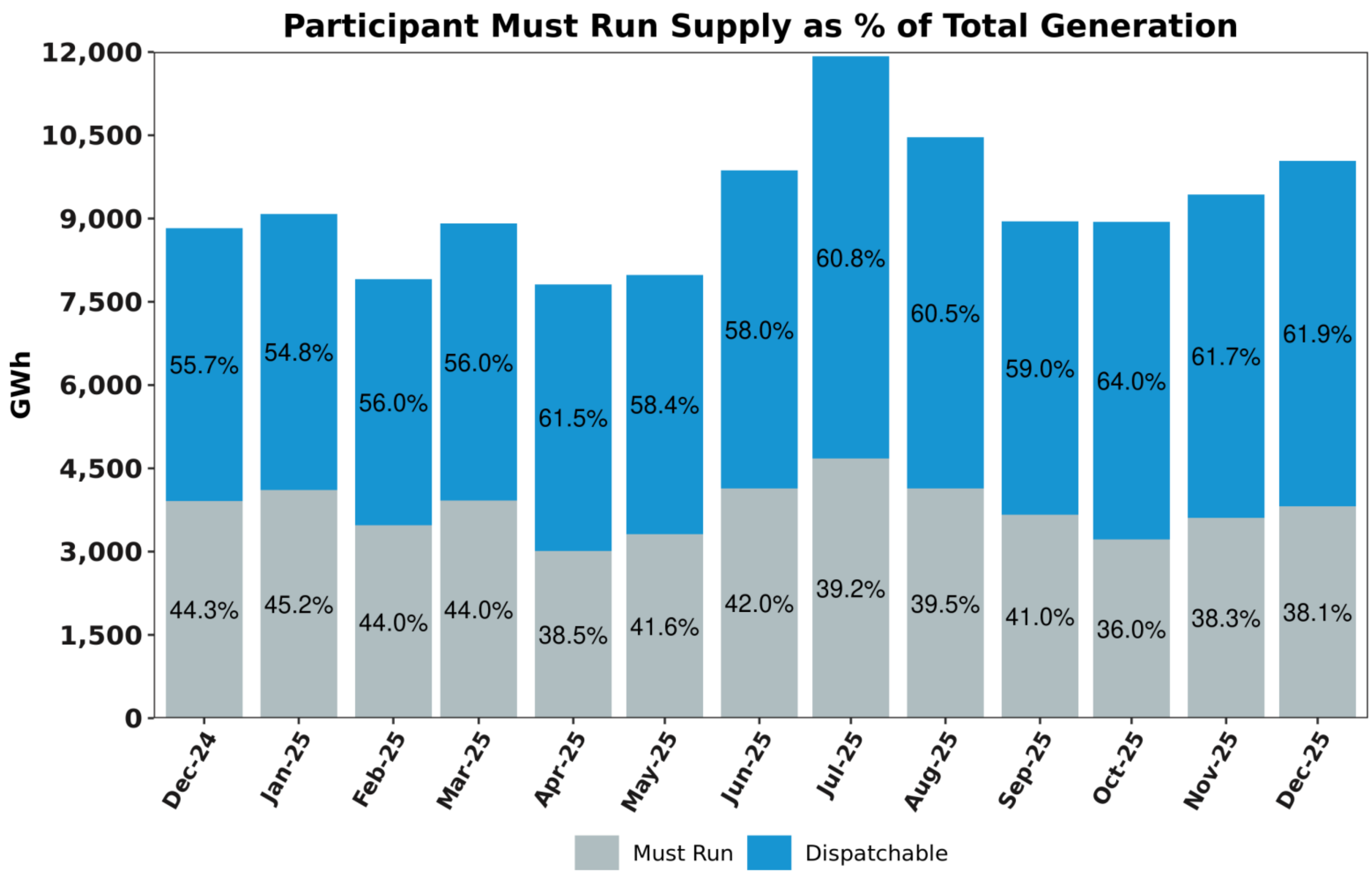
Pre-DAAS Slide





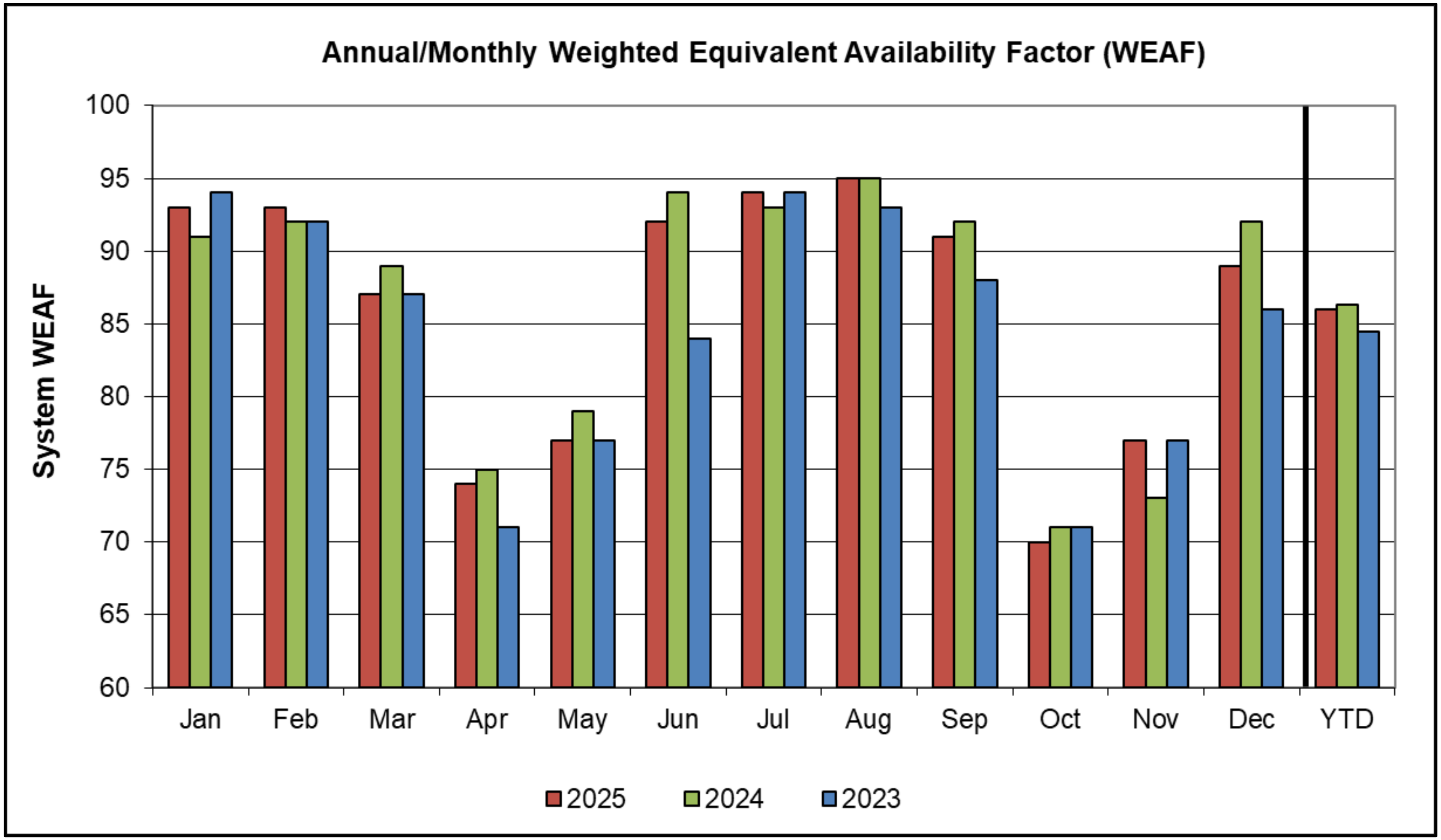
*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

RT Generation Output Offered as Must Run vs Dispatchable



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

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2025	93	93	87	74	77	92	94	95	91	70	77	89	86
2024	91	92	89	75	79	94	93	95	92	71	73	92	86
2023	94	92	87	71	77	84	94	93	88	71	77	86	85

Data as of 12/29/25

MARKET OPERATIONS

Market Pricing

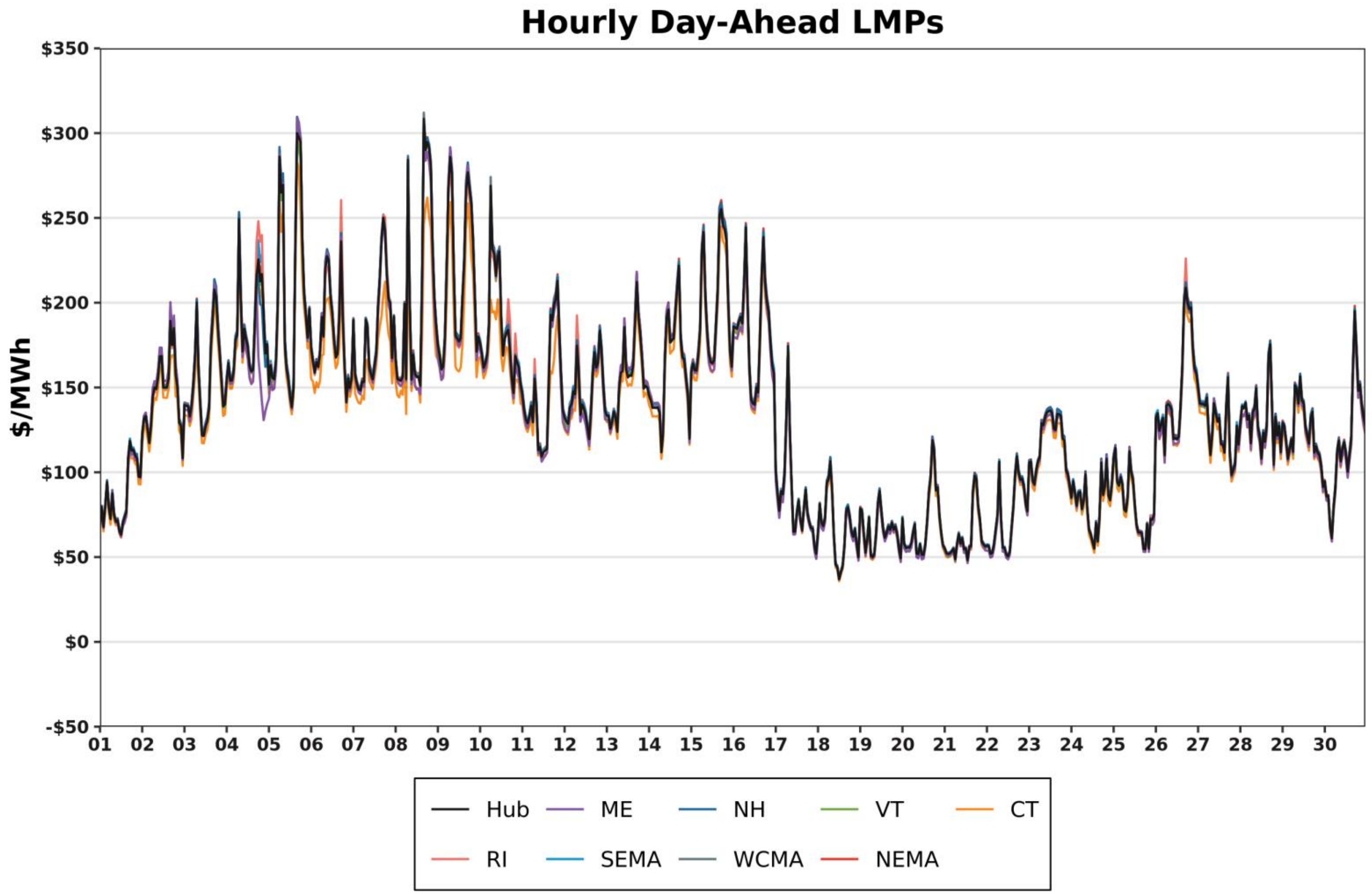
DA vs. RT LMPs ($/MWh)

Arithmetic Average

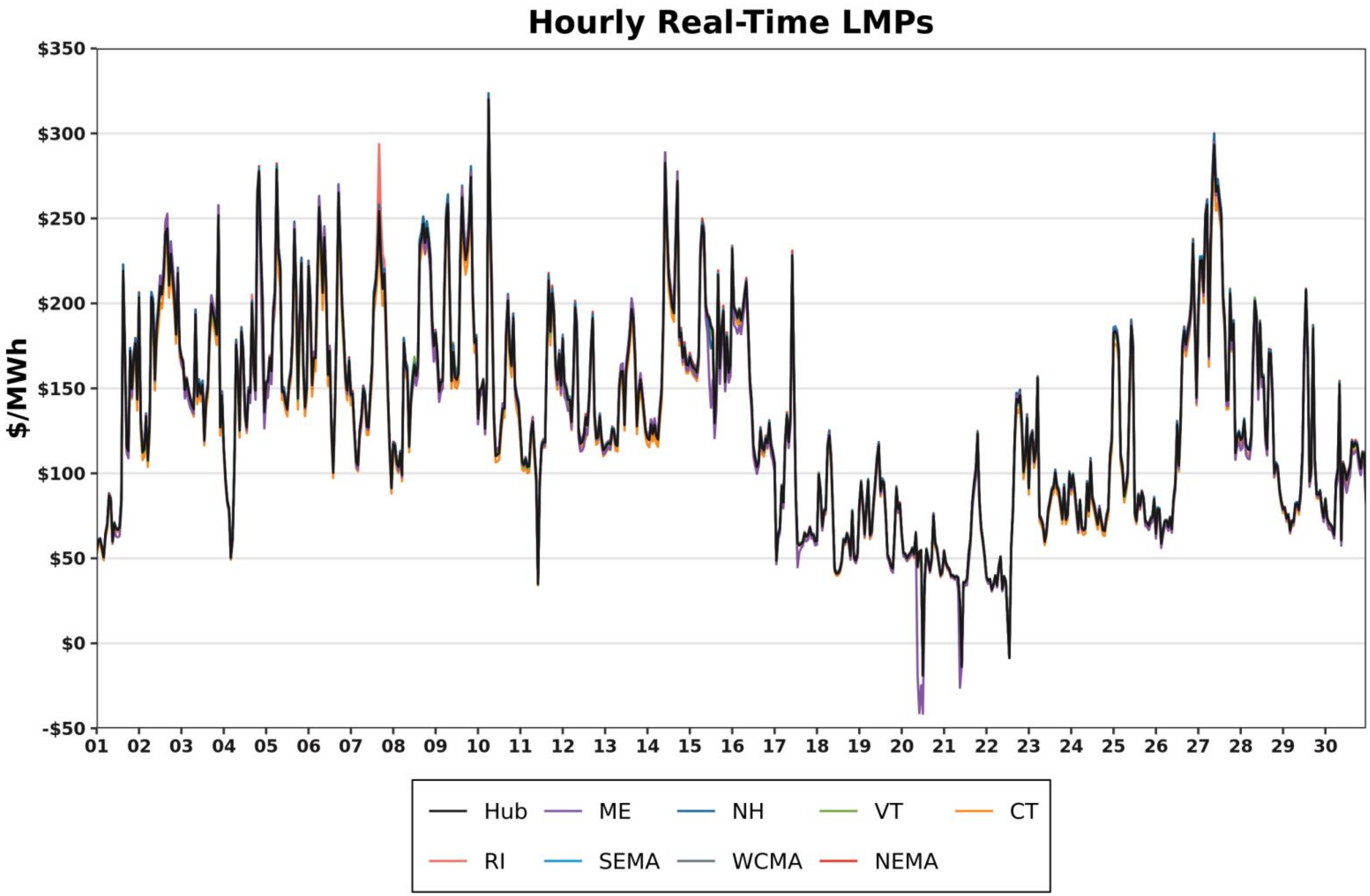
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$41.35	$41.07	$41.72	$41.11	$40.17	$41.28	$41.70	$41.37	$41.91
Real-Time	$39.37	$38.79	$39.65	$39.23	$38.46	$39.17	$39.62	$39.37	$39.77
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%

December-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$87.56	$89.33	$89.11	$86.07	$84.10	$87.60	$88.58	$87.58	$89.75
Real-Time	$84.03	$84.30	$85.01	$82.46	$81.13	$84.10	$84.83	$83.91	$85.29
RT Delta %	-4.03%	-5.63%	-4.60%	-4.19%	-3.53%	-4.00%	-4.23%	-4.19%	-4.97%
December-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$136.05	$134.05	$137.40	$135.65	$129.01	$135.48	$137.21	$136.17	$138.01
Real-Time	$131.17	$128.82	$132.60	$131.09	$126.61	$130.80	$132.00	$131.13	$133.04
RT Delta %	-3.59%	-3.90%	-3.49%	-3.36%	-1.86%	-3.45%	-3.80%	-3.70%	-3.60%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	55.38%	50.06%	54.19%	57.60%	53.40%	54.66%	54.90%	55.48%	53.77%
Yr over Yr RT	56.10%	52.81%	55.98%	58.97%	56.06%	55.53%	55.61%	56.27%	55.99%

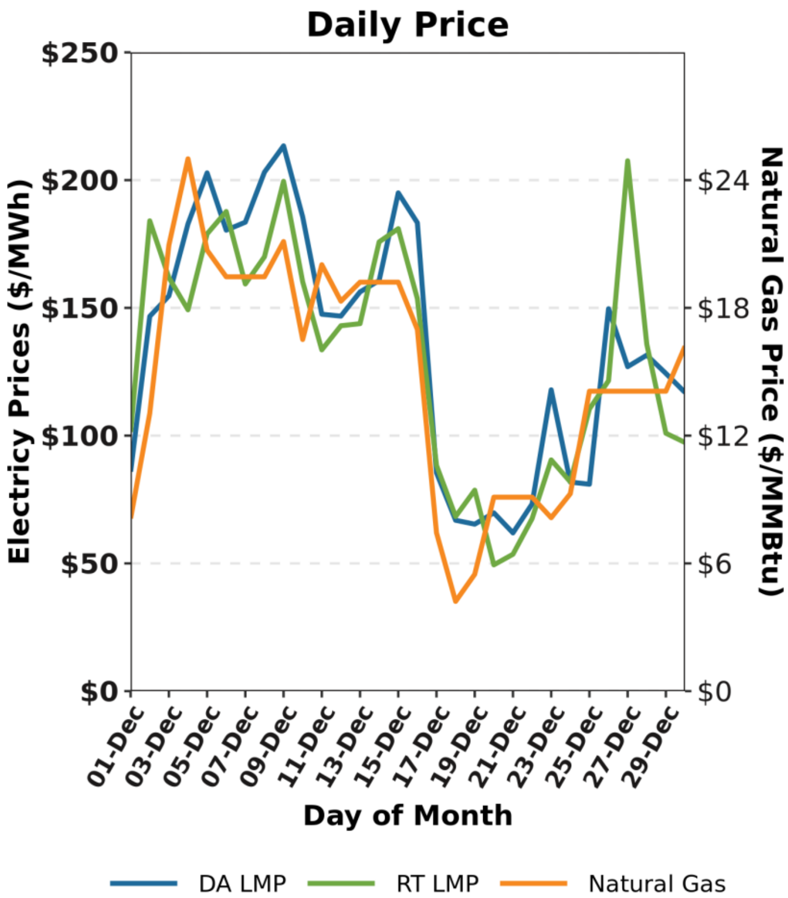
Hourly DA LMPs, December 1-30, 2025

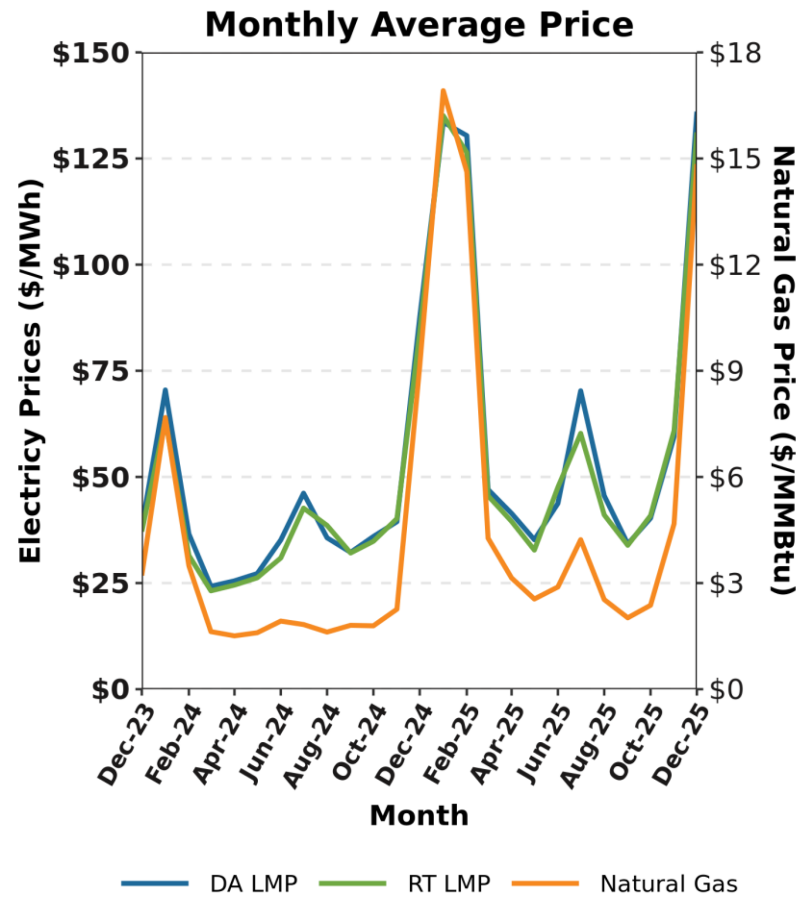


Hourly RT LMPs, December 1-30, 2025



Wholesale Electricity vs Natural Gas Price by Month

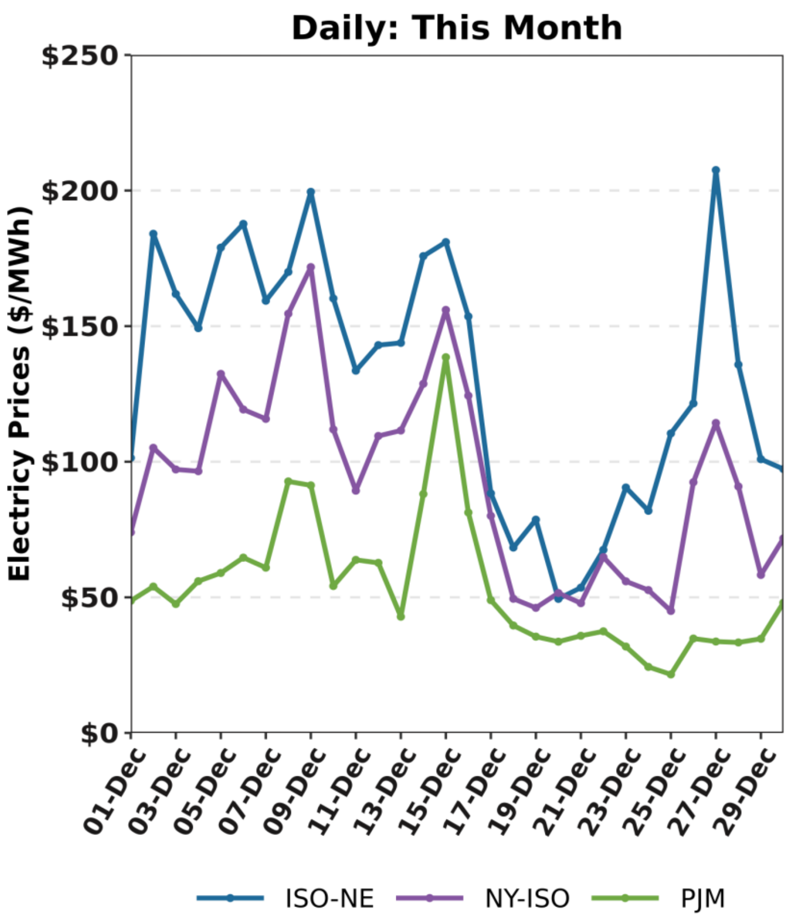


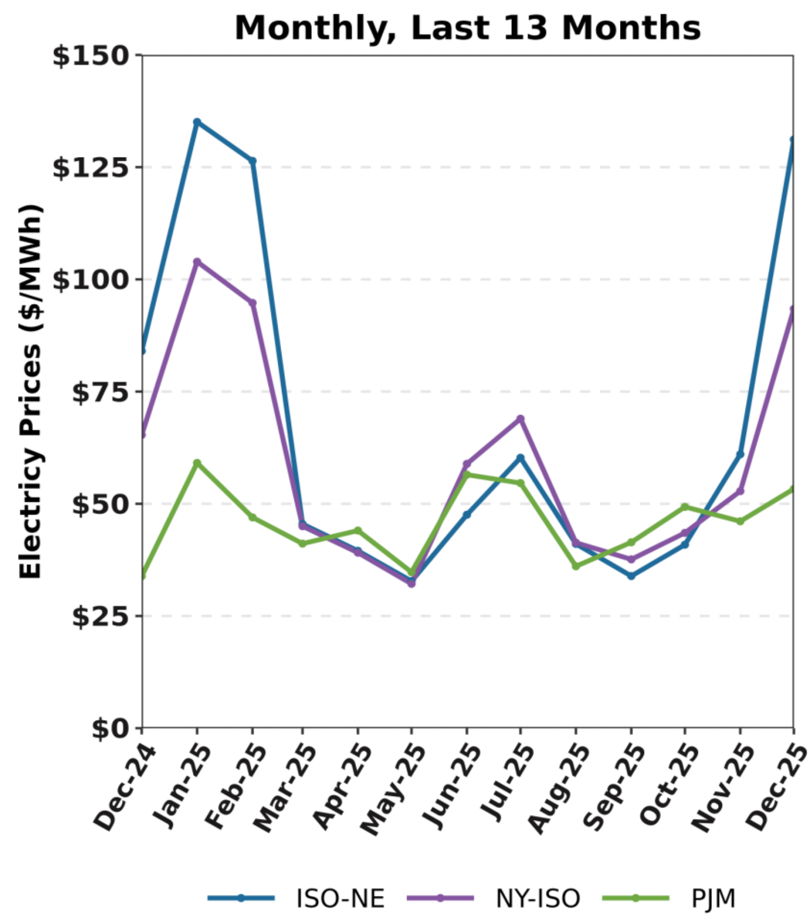


Underlying natural gas data furnished by:

Gas price is average of Massachusetts delivery points

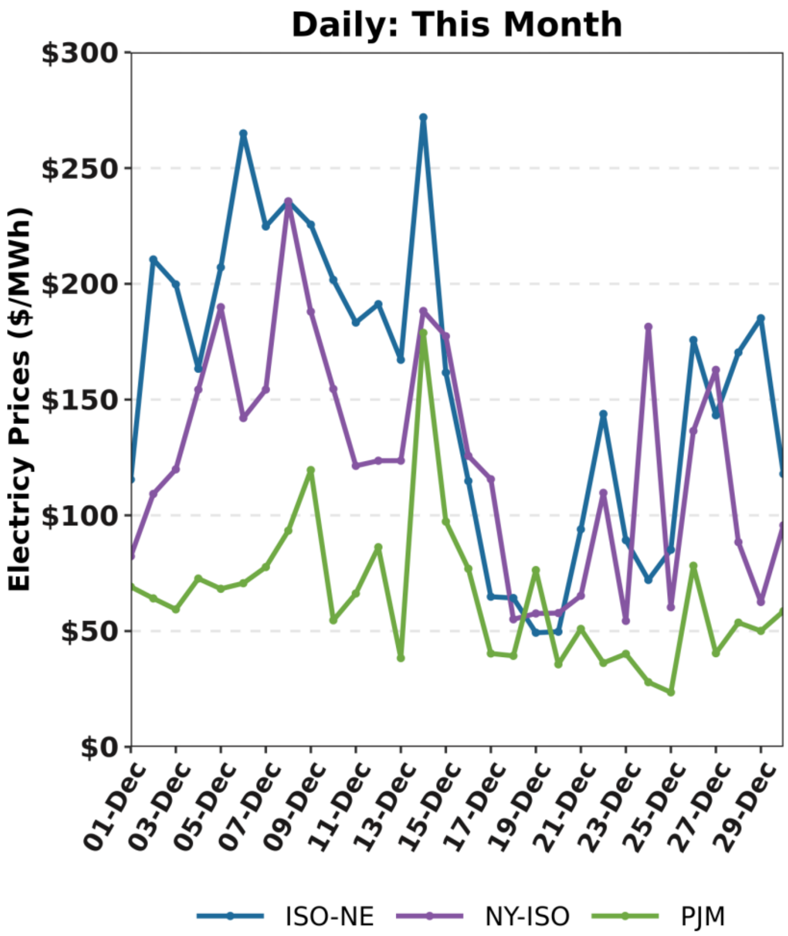
New England, NY, and PJM Hourly Average RT Prices by Month

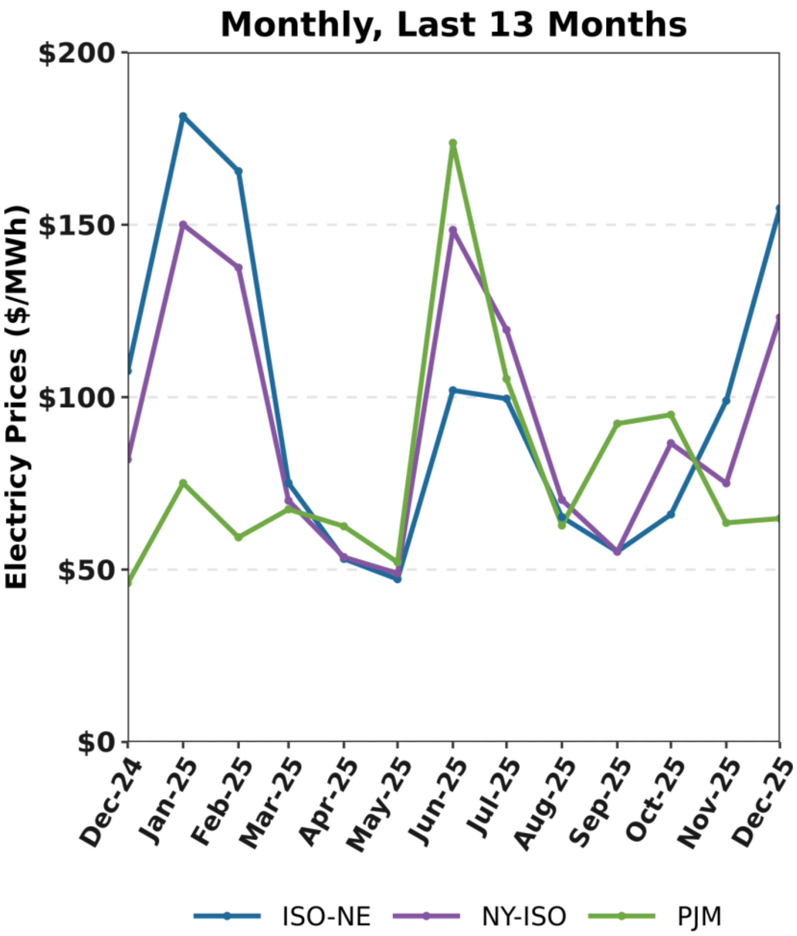




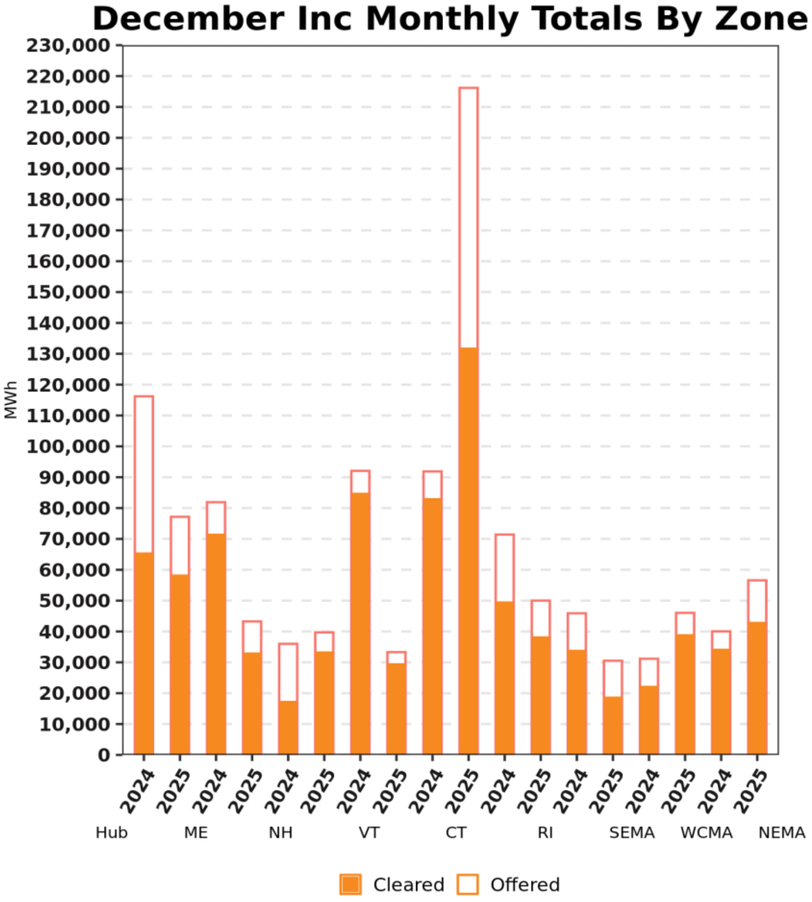
Hourly average prices are shown

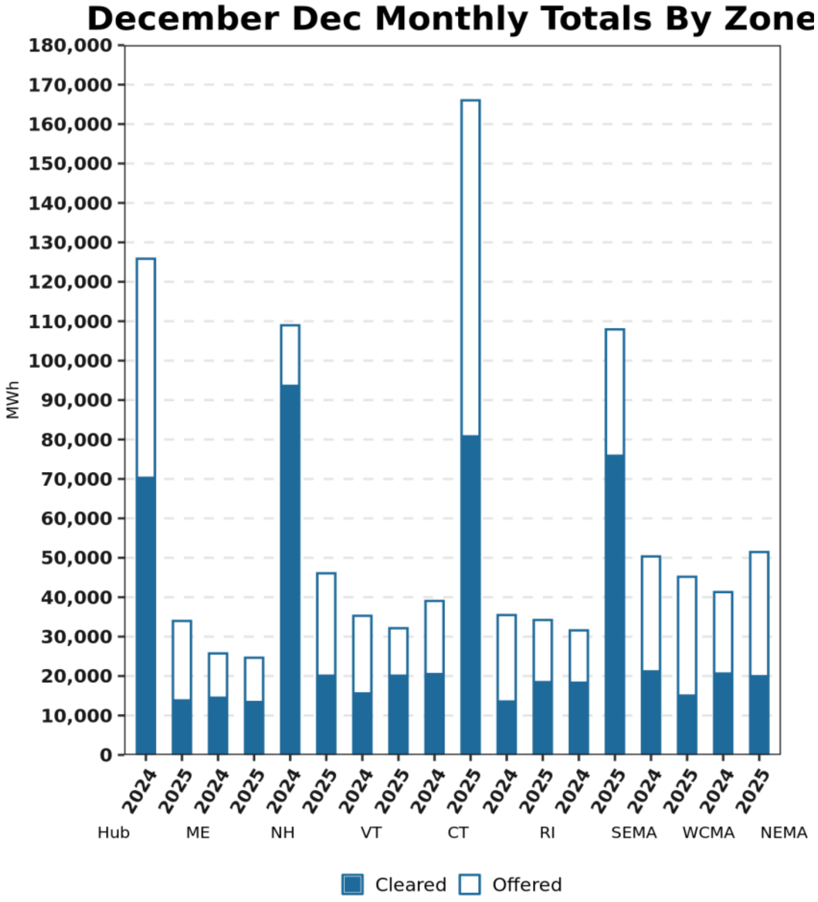
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





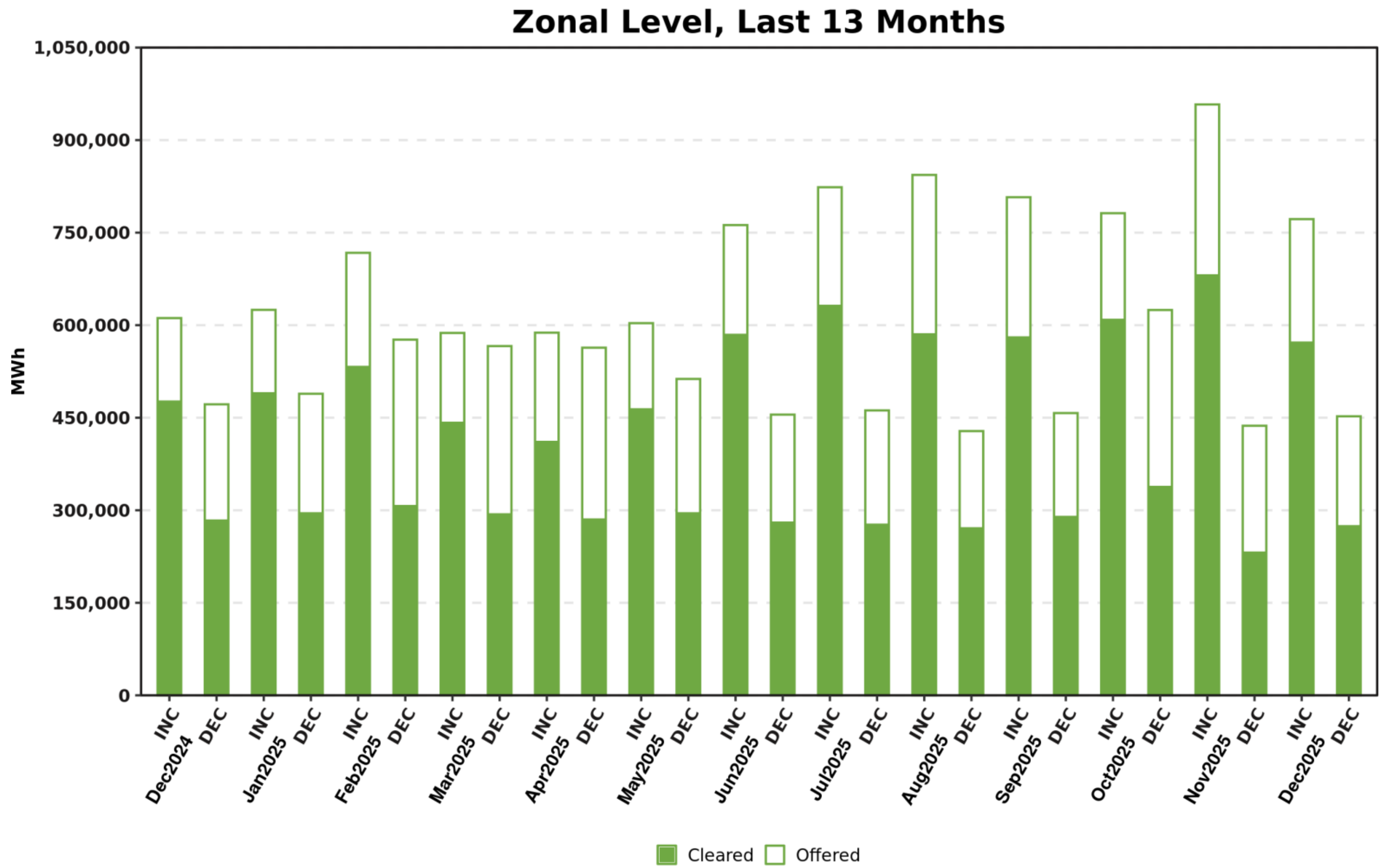
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

NOVEMBER 23, 2025 PFP EVENT SETTLEMENTS SUMMARY

PFP Settlements Summary for November 23, 2025

- **Duration**: 30 minutes (6 consecutive 5-min intervals)
  - Ten-Minute Reserve Requirement violated from 17:50 to 18:05
  - Minimum Total Reserve Requirement violated from 17:50 to 18:15
- **Capacity Balancing Ratio**: 69.6% (event average)
- **Settlements:**
  - PFP charges: $32.3M
- **Capacity Performance Payment Rate**: $9,337/MWh (effective June 1, 2025)

Preliminary performance scores reports were released on Monday, December 1. FCM settlements reflected adjustments for Capacity Performance Bilateral Contracts included in the December 15, 2025 invoice.

Most Recent Capacity Scarcity Condition Events

Date	11/23/2025	6/24/2025
Day of Week	Sunday	Tuesday
Duration	6 intervals	37 intervals
5-min Intervals	17:50 - 18:15	17:35 - 20:35
Average Balancing Ratio	0.696	1.031
Capacity Payment Rate	$9,337/MWh	$9,337/MWh
Pay for Performance Charges[1]	$32.3M	$97.1M

[1]Net of Balancing Fund allocation and stopped losses (if applicable). There were no stop losses for the November 23rd event.

Performance of Resources with CSOs relative to share of System Requirements*

**Resource's Actual MW compared to Balancing Ratio x CSO MW*

Resource Type	Total CSO MW	Zero Performance	Performance < 25%	Performance 25%-50%	Performance 50%-75%	Performance 75%-100%	Performance 100%-125%	Performance >125%
Gen	26,625	26.2%	2.1%	3.9%	10.3%	4.6%	4.6%	48.2%
Import	1,198	55.6%	0.0%	0.0%	0.0%	0.0%	0.0%	44.4%
DR	735	20.4%	24.3%	13.6%	9.7%	5.8%	3.9%	22.3%
SOR	278	36.8%	10.3%	16.1%	7.2%	11.2%	6.3%	12.1%

Percent values are calculated by taking the *Resource count* with average Capacity Performance Scores in each category divided by the total number of Resources in each category. No resource performed at exactly 100% of Balancing Ratio x CSO MW. This information is published in the Monthly Market Operations Report (see Section 13.5.1) found on the ISO Website here.

Summary of Performance Payments

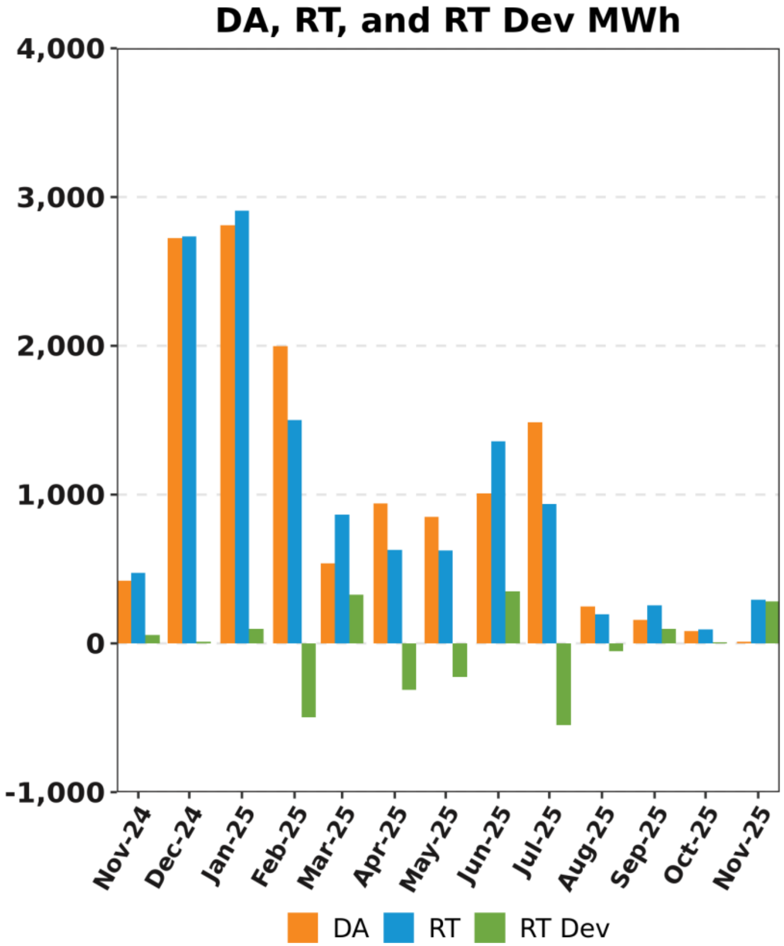
Performance Payment Credits (Charges) (MR1 Sec. III.13.7.2, 13.7.3)	
Performance Payment Credits*	**Million $**
To Resources with CSOs	$ 24.6
To Resources without CSOs	$ 7.3
Total	$ 31.9
Performance Payment Charges	
Before Application of Balancing Fund and Stop-Loss	$ (32.6)
Total Stop-Loss	$ 0.0
Total	$ (32.6)
Excess Poolwide Performance Payments	
Surplus Before Application of Stop-Loss Limit	$ 0.7
Total Stop-Loss	$ 0.0
Balancing Fund (Total After Application of Stop-Loss Limit)	$ 0.7

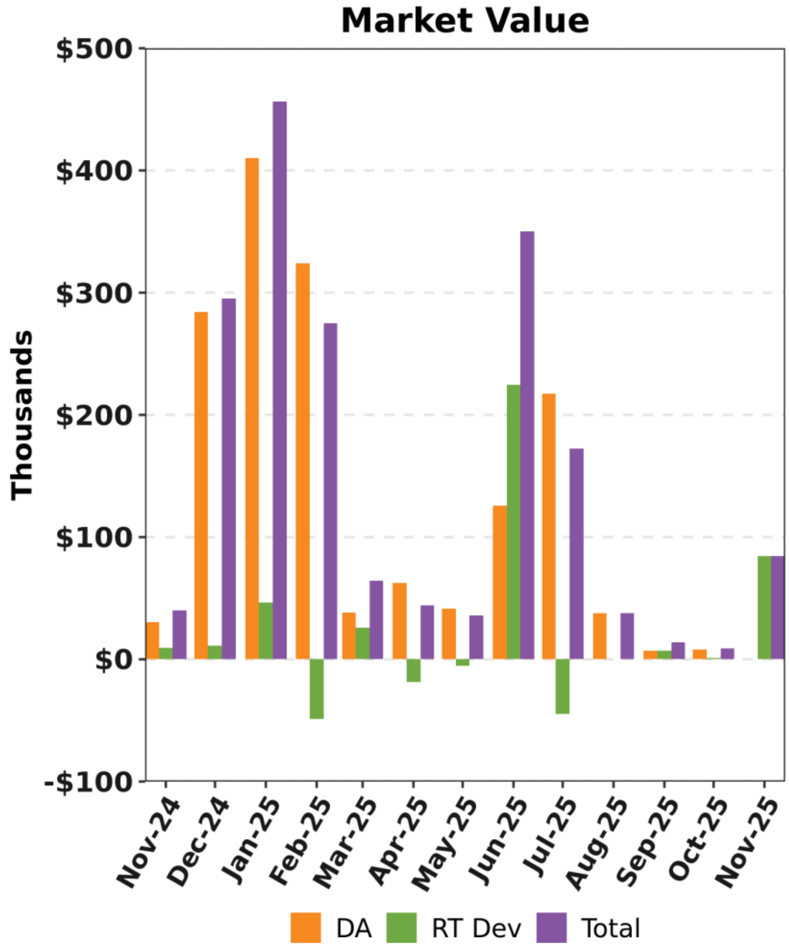
*Performance Credits shown are prior to allocation of Stop-Loss (if any) and/or Balancing Fund.

BACK-UP DETAIL

DEMAND RESPONSE

Demand Response Resource (DRR) Energy Market Activity by Month





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

NEW GENERATION

New Generation Update

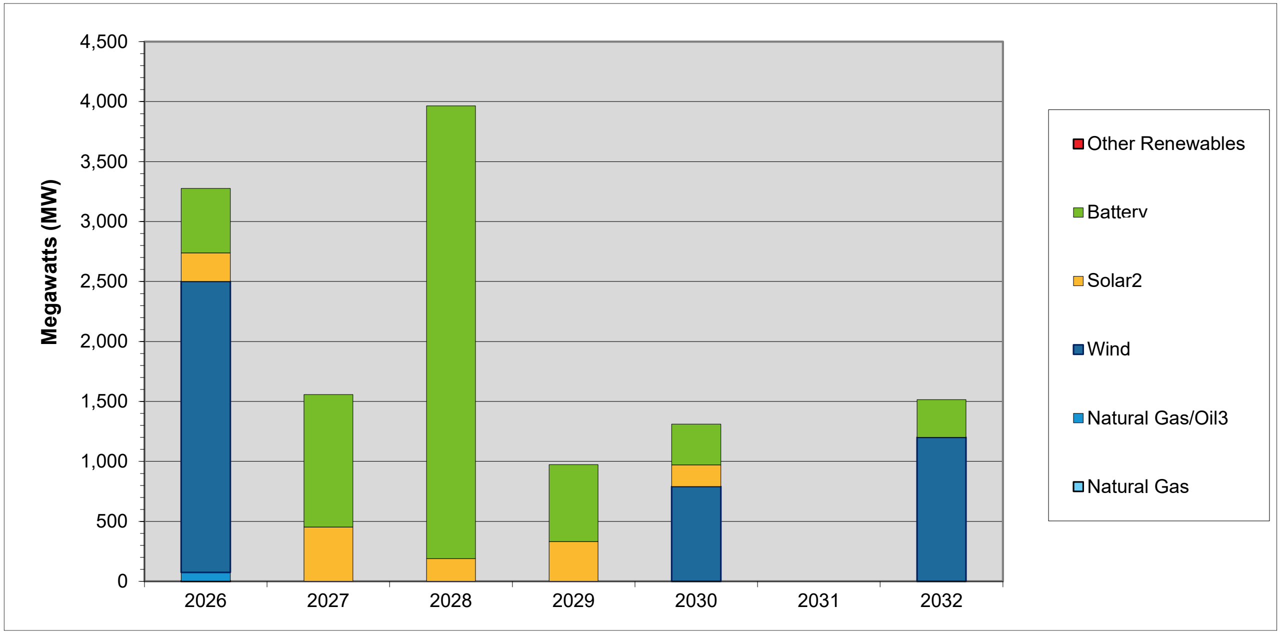
Based on Queue as of 1/01/26

- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 65* generation projects are currently being tracked by the ISO, totaling approximately 14,282 MW

* Total does not include CNR Only requests

Projected Annual Capacity Additions

By Supply Fuel Type



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	538	1,104	3,774	642	340	0	315	6,713	53.3
Solar[2]	237	453	190	332	180	0	0	1,392	11.1
Wind	2,426	0	0	0	791	0	1,200	4,417	35.1
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.6
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	3,274	1,557	3,964	974	1,311	0	1,515	12,595	100.0

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

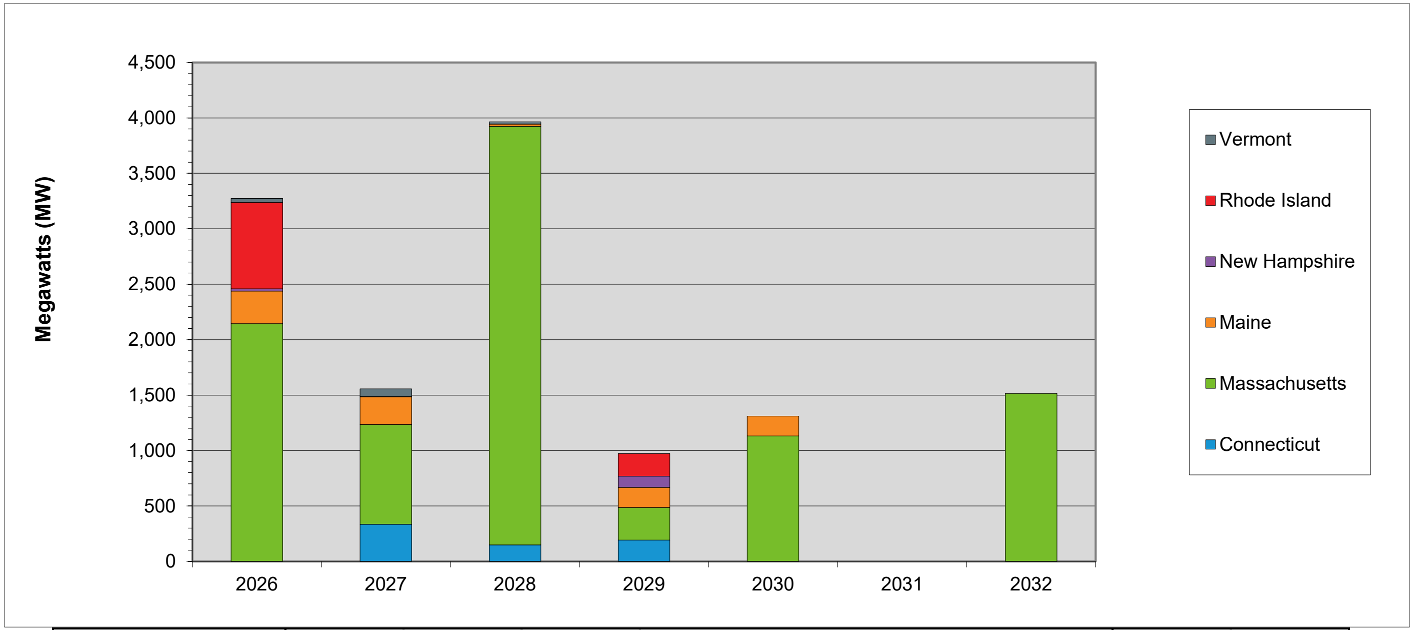
[2] This category includes both solar-only, and co-located solar and battery projects

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

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

Projected Annual Generator Capacity Additions

By State



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Vermont	38	70	20	0	0	0	0	128	1.0
Rhode Island	777	0	0	205	0	0	0	982	7.8
New Hampshire	20	5	0	100	0	0	0	125	1.0
Maine	294	247	20	182	180	0	0	923	7.3
Massachusetts	2,145	899	3,774	295	1,131	0	1,515	9,759	77.5
Connecticut	0	336	150	192	0	0	0	678	5.4
Totals	**3,274**	**1,557**	**3,964**	**974**	**1,311**	**0**	**1,515**	**12,595**	**100.0**

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

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

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	30	6,713	1	250	29	6,463
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	1	73	1	73	0	0
Nuclear	0	0	0	0	0	0
Solar	24	1,392	3	136	21	1,256
Wind	10	6,104	3	877	7	5,227
Total	65	14,282	8	1,336	57	12,946

- 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

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	0	0	0	0	0	0
Intermediate	1	73	1	73	0	0
Peaker	54	8,105	4	386	50	7,719
Wind Turbine	10	6,104	3	877	7	5,227
Total	65	14,282	8	1,336	57	12,946

- 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	30	6,713	0	0	0	0	30	6,713	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	24	1,392	0	0	0	0	24	1,392	0	0
Wind	10	6,104	0	0	0	0	0	0	10	6,104
Total	65	14,282	0	0	1	73	54	8,105	10	6,104

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

FORWARD CAPACITY MARKET

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	461.416	-118.276
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751	3,113.332	-21.32
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**	**3,574.748**	**-139.596**
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125	27,132.413	50.76
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193	865.694	-190.907
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**	**27,998.107**	**-140.147**
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**	**1,193.583**	**-55.962**
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**	**32,766.438**	**-335.705**
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**	**31,380**	**-165**

* 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 2024-2028 CCP Month 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	504.466	-85.416	437.780	-66.686
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753	2,568.703	-5.664
Demand Total		**3,322.606**	**3,169.002**	**-153.604**	**3,078.833**	**-90.169**	**3,006.483**	**-72.350**
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624	26,503.730	-139.649	26,049.059	-454.671
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518	912.376	-76.889
Generator Total		**27,983.936**	**27,790.162**	**-193.774**	**27,492.995**	**-297.167**	**26,961.435**	**-531.560**
Import Total		**1,503.842**	**1,247.601**	**-256.241**	**1,244.601**	**-3.000**	**1,234.800**	**-9.801**
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**	**31,816.429**	**-390.336**	**31,202.718**	**-613.711**
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**	**30,775**	**190**	**30,300**	**-475**

* 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 2024-2028 CCP Month 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	584.913	-37.941	492.363	-92.550		
	Passive Demand	2,316.815	2,314.068	-2.747	2,314.705	0.637		
Demand Total		**2,939.669**	**2,898.981**	**-40.688**	**2,807.068**	**-91.913**		
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069	26,271.866	-443.623		
	Intermittent	1,356.084	1,286.589	-69.495	1,310.622	24.033		
Generator Total		**27,863.504**	**28,002.078**	**138.574**	**27,582.488**	**-419.59**		
Import Total		**566.998**	**564.079**	**-2.919**	**636.310**	**72.231**		
Grand Total*		**31,370.171**	**31,465.138**	**94.967**	**31,025.866**	**-439.272**		
Net ICR (NICR)		**30,305**	**30,395**	**90**	**30,600**	**205**		

* 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 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

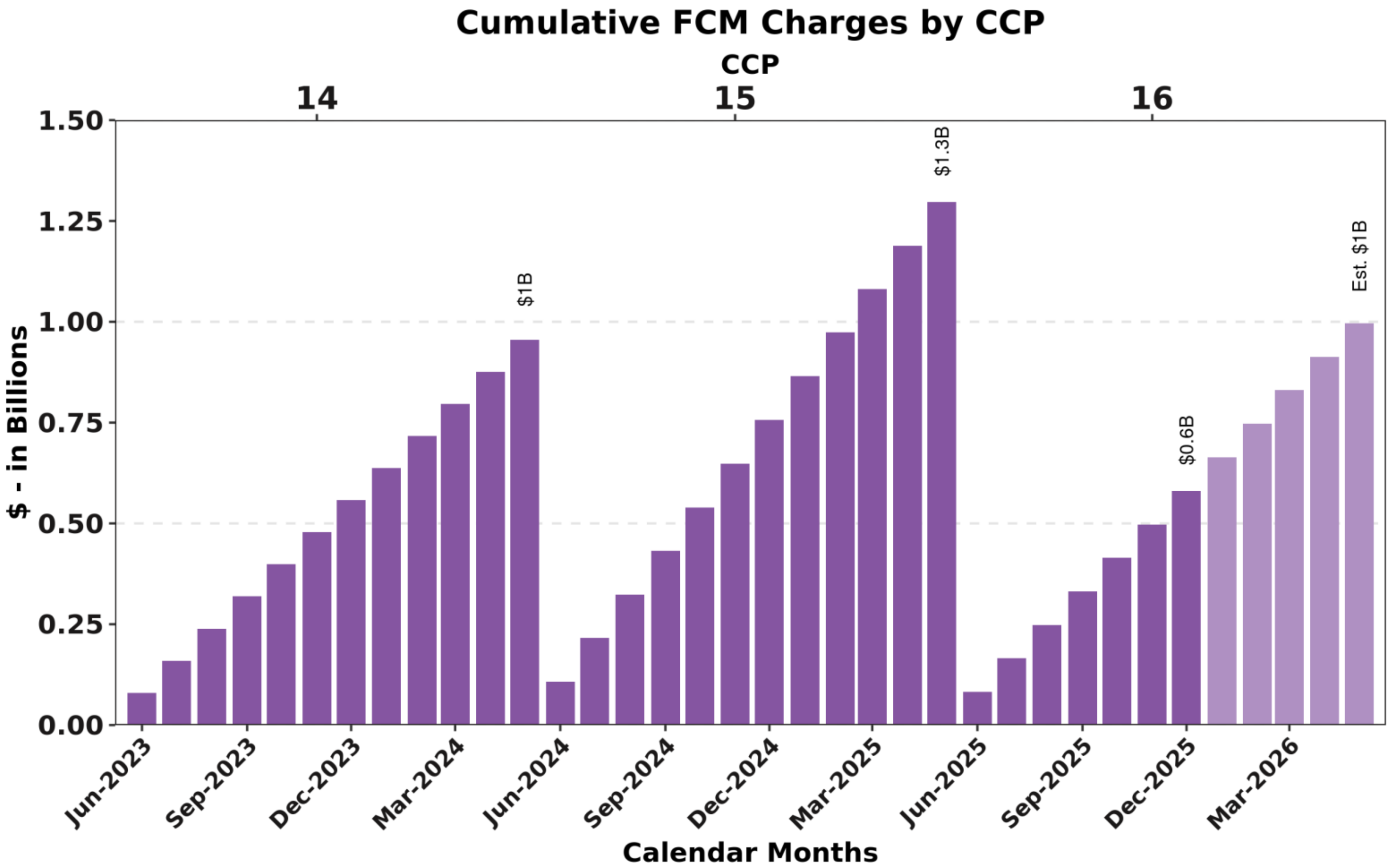
Capacity Supply Obligation FCA 18

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*	543.580	403.884	-139.696				
	Passive Demand	2,070.498	2,851.331	780.833				
Demand Total		**2,614.078**	**3,255.215**	**641.137**				
Generator	*Non-Intermittent*	27,026.635	25,822.288	-1,204.347				
	Intermittent	1,450.872	890.415	-560.457				
Generator Total		**28,477.507**	**26,712.703**	**-1,764.804**				
Import Total		**464.835**	**1,234.800**	**769.965**				
Grand Total*		**31,556.420**	**31,202.718**	**-353.702**				
Net ICR (NICR)		**30,550.000**	**30,415.000**	**-135.000**				

* 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 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

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)

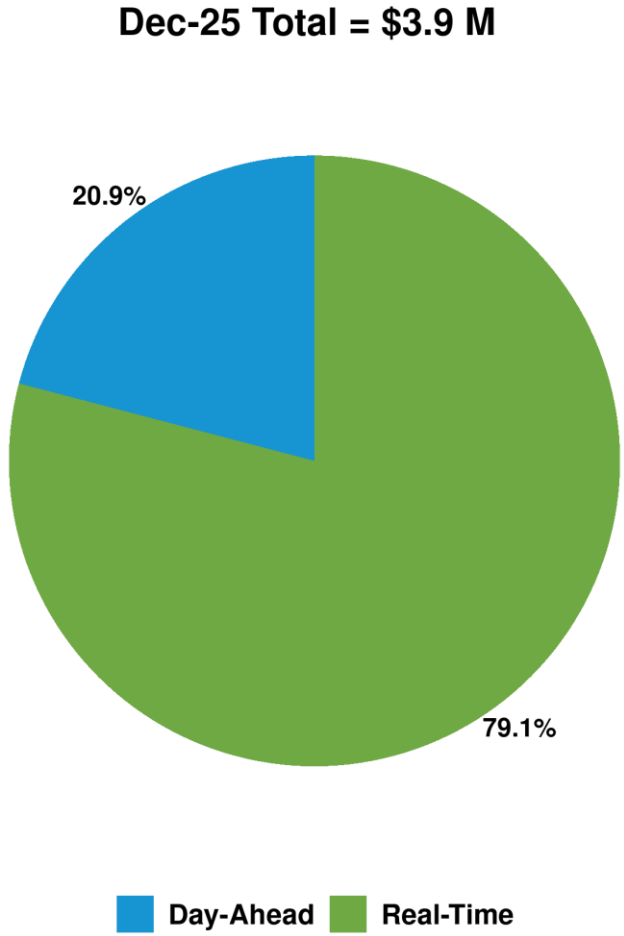
Active/Passive Demand Response

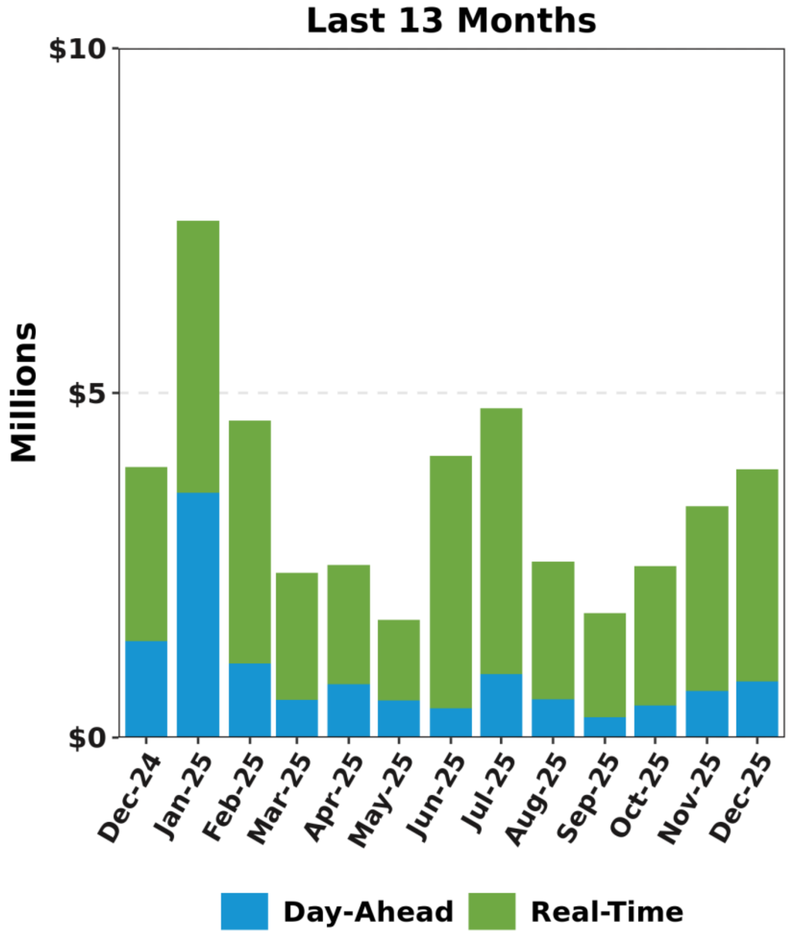
CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
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**
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	**2,809.541**	**130.128**	**2,939.669**
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

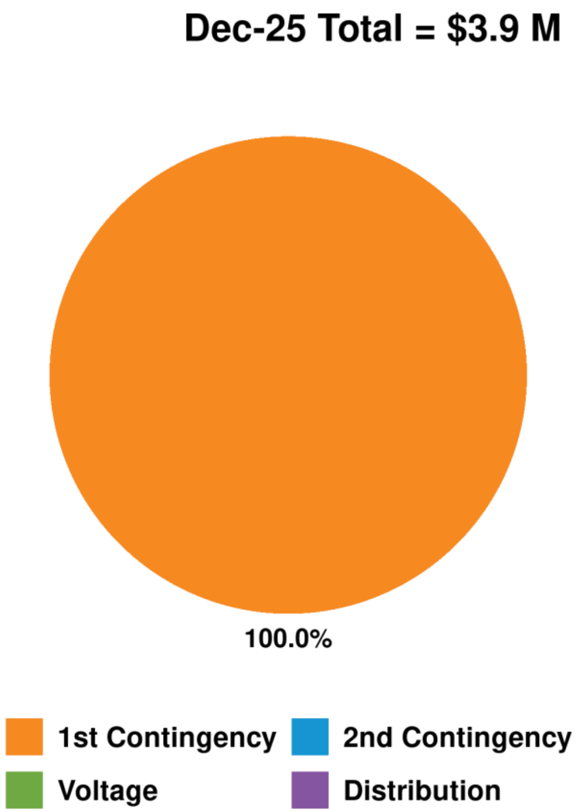
NET COMMITMENT PERIOD COMPENSATION

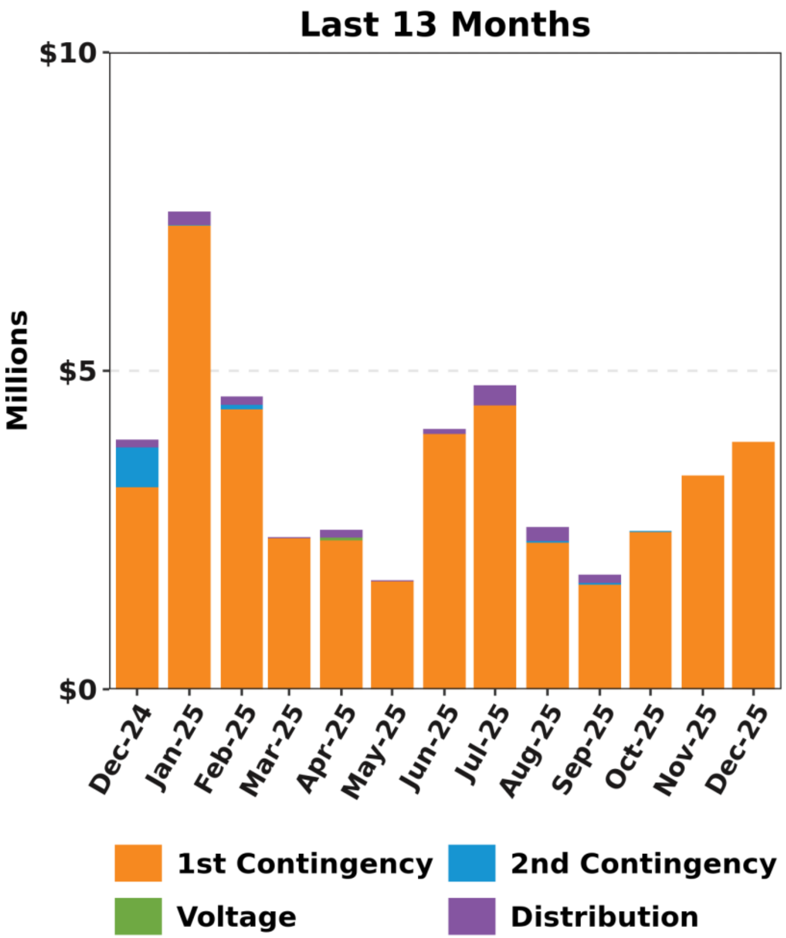
DA and RT NCPC Charges



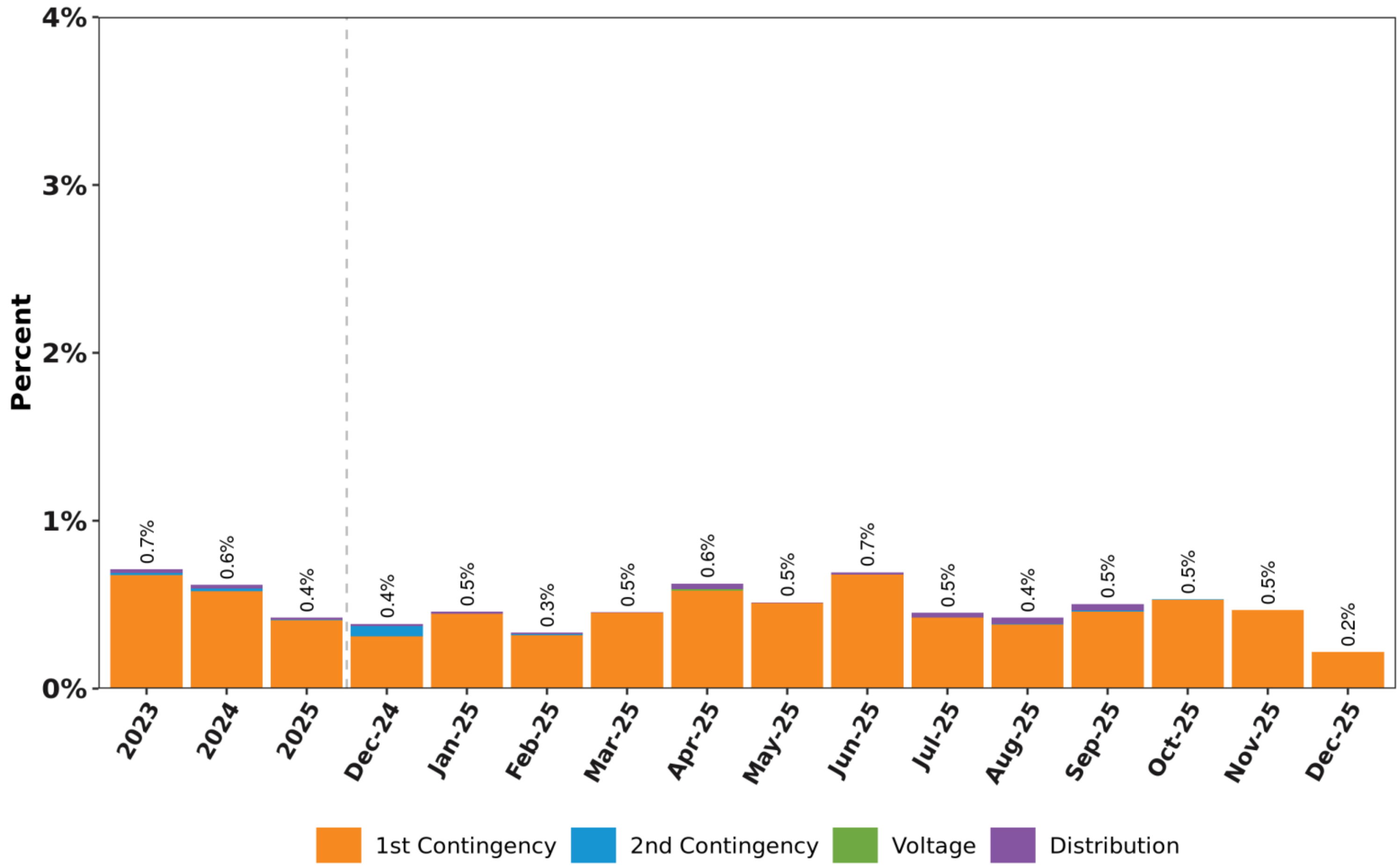


NCPC Charges by Type

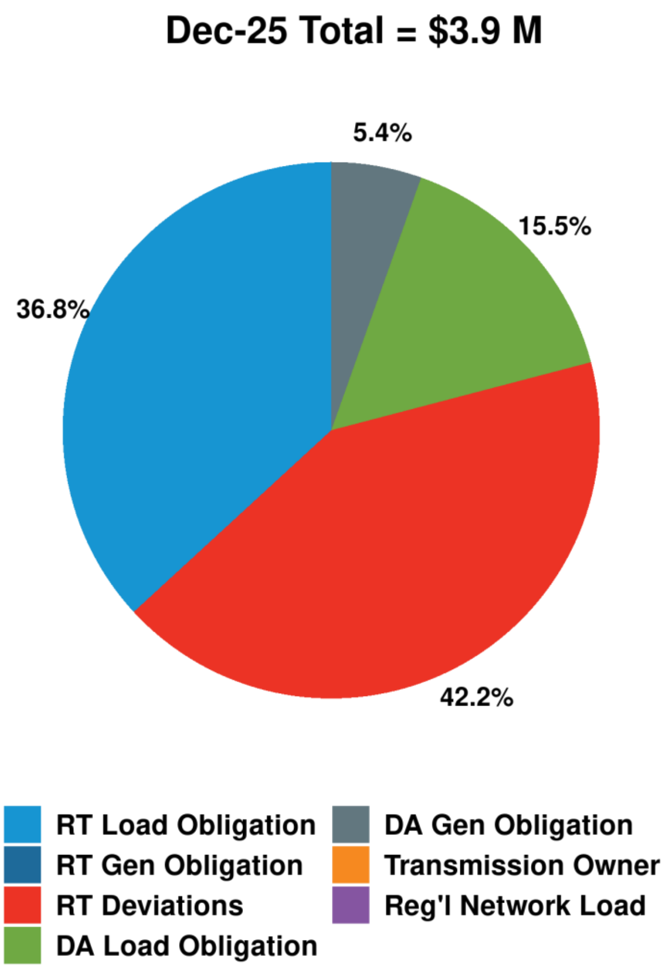


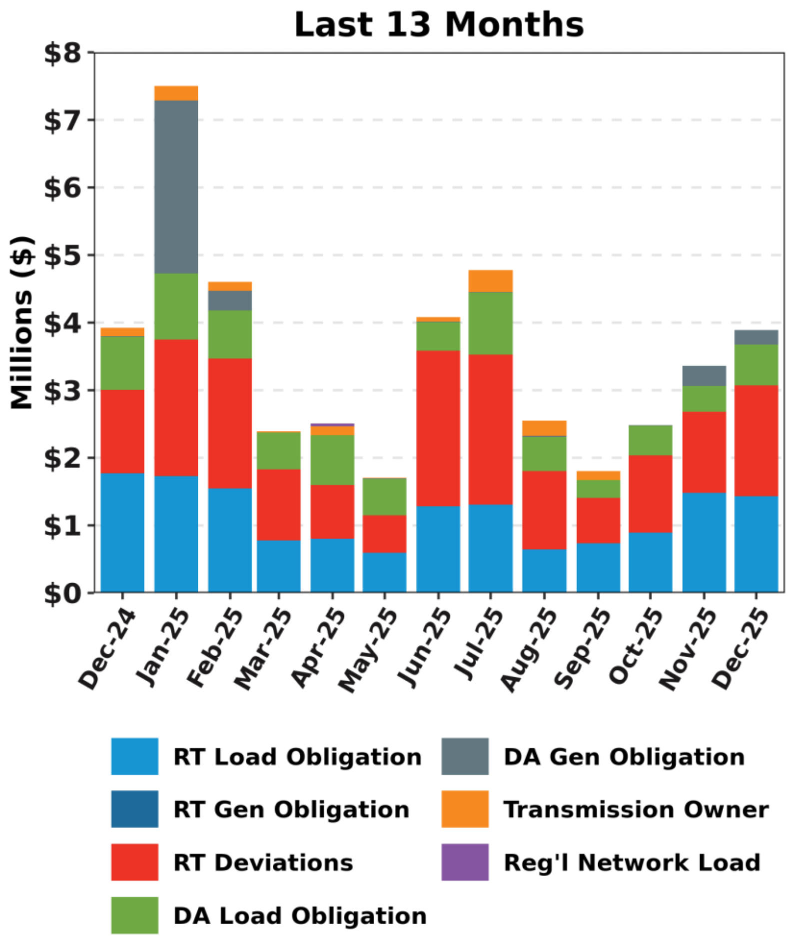


NCPC Charges by Type as Percent of Energy Market Value

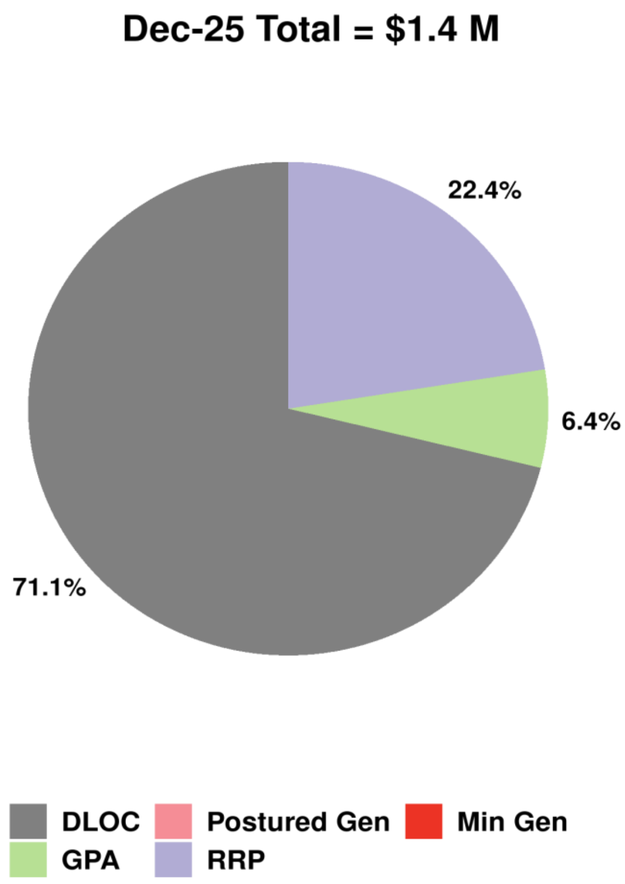


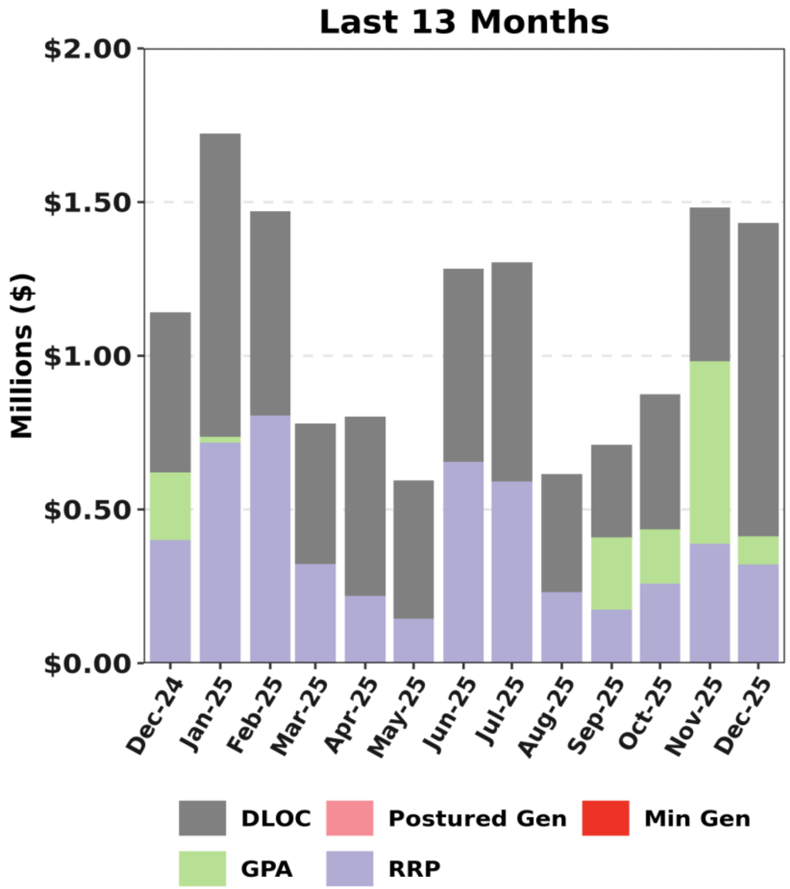
NCPC Charge Allocations





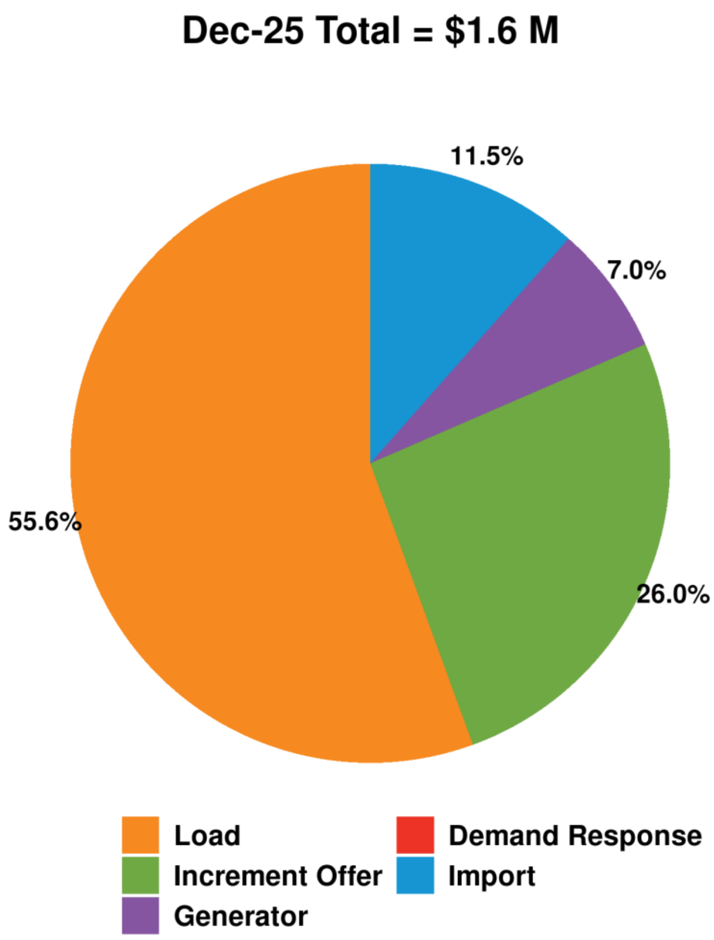
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

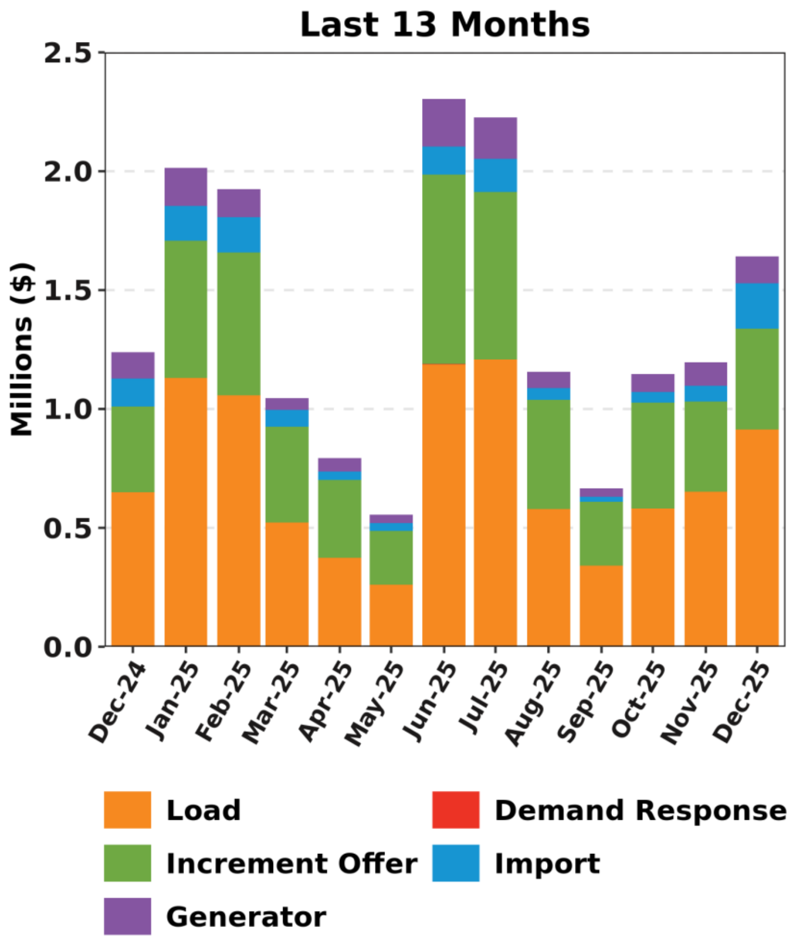




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

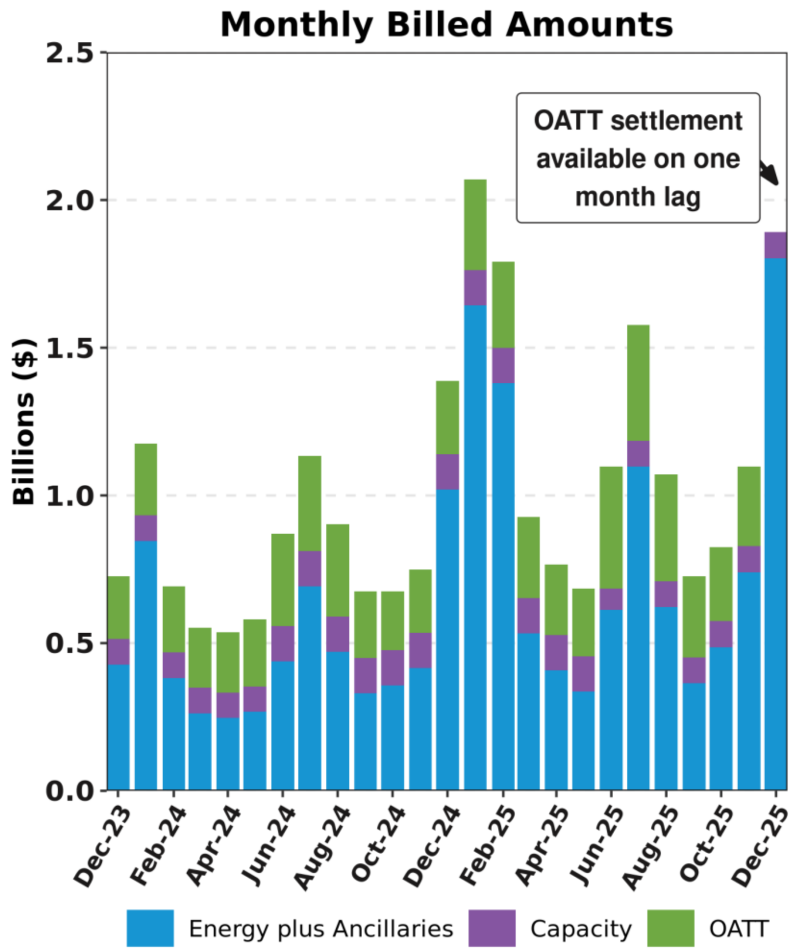
RT First Contingency Charges by Deviation Type

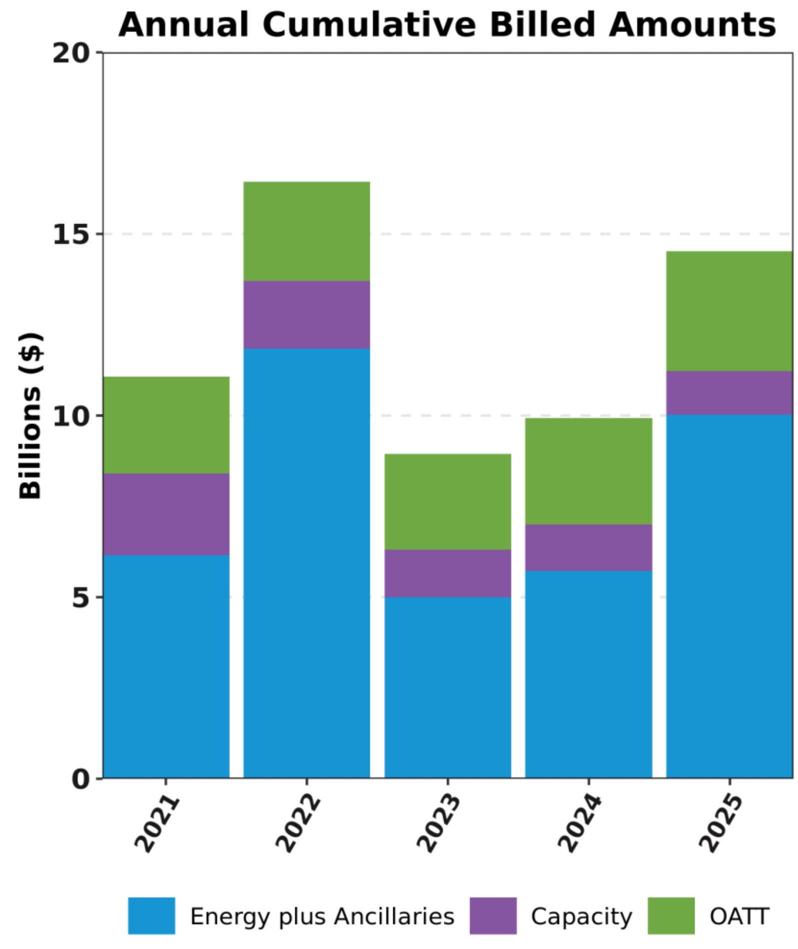




ISO BILLINGS

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)

- January 27 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Belmont #98 Asset Replacements (National Grid)
    - New Hampshire Asset Condition Structure Replacements – Lines 367, A126, A152, B143, K174, and M127 (Eversource)
    - Connecticut River Crossing Projects – Project Update (Eversource)
  - Asset Condition Reviewer – Feedback on Draft List of Projects Subject to Interim Review
  - Asset Condition Reviewer – Conceptual Framework and Stakeholder Feedback
  - 2026 Public Policy Transmission Upgrade Process

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

2025 Longer-Term Transmission Planning (LTTP) RFP

- On 12/13/24, NESCOE provided its LTTP RFP request describing the needs to be addressed by 2035:*
  - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
  - Increase the Surowiec-South interface capacity to at least 3,200 MW
  - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind**
- The ISO issued the RFP on 3/31/25, with proposals due by 9/30/25
- The ISO is evaluating all submissions and expects to provide an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) in the February/March 2026 timeframe

* Unless a bidder can demonstrate supply chain issues that warrant a later in-service date

** Bidders may propose alternate locations which would be more efficient and cost-effective

2025 Longer-Term Transmission Planning (LTTP) RFP, cont.

- Total of 6 Longer-Term Proposals submitted
  – 4 are joint proposals
- Total of 4 different lead QTPSs (3 non-incumbents, 1 incumbent)
  – 4 additional QTPSs are participating as part of joint proposals (all are incumbents)
- Project Designs
  – 3 primarily AC transmission
  – 3 primarily HVDC transmission
  – All designs claim they support 1200 MW of northern ME wind
  – Claimed Surowiec-South Limits: 3200-3800 MW (3200 MW target)
  – Claimed Maine-New Hampshire Limits: 3000-3600 MW (3000 MW target)
- Project Installed Costs*
  – Low of $0.96B
  – High of $4.04B
- In-Service Dates: Q4 2032 to Q3 2035 (12/31/2035 target)

* Costs may include estimates for corollary upgrades

Economic Studies: 2024 Study

- The 2024 Economic Study is complete
  - The final presentation was made at the December PAC
  - A public webinar was held on September 29
  - A report and fact sheet were issued on September 15
  - The System Efficiency Needs Scenario did not trigger an RFP
- The 2026 Economic Study will launch in January

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.

SEMA/RI Reliability Projects

Status as of 12/29/2025

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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	Jun-28	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-26	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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	4
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-26	2

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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	Nov-25	4
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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

Upper Maine Solution Projects

Status as of 12/29/2025

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	Aug-24	4
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-28	2
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	Dec-29	2
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	Aug-25	4

Upper Maine Solution Projects, cont.

Status as of 12/29/2025

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	Nov-24	4
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Jun-26	2

* Cancelled per the Upper Maine Solutions Study Addendum that was published on January 11, 2024

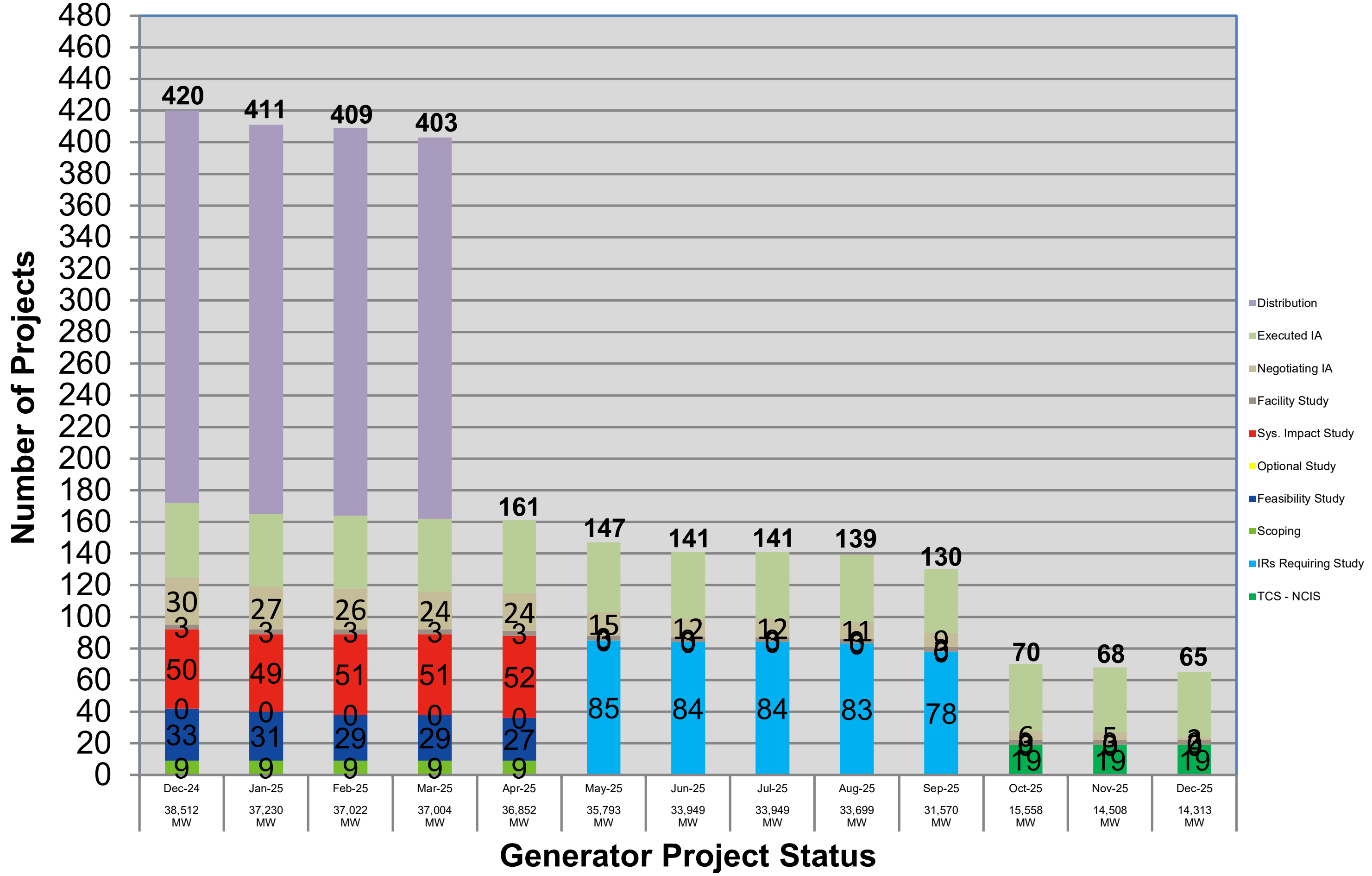
Boston 2033 Solutions Study

Status as of 12/29/2025

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	May-26	1

Status of Tariff Studies as of December 29, 2025



ETUs: 0 in TCS – NCIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 4 with Executed IA
Transmission Service Requests needing study: 0
https://irtt.iso-ne.com/external.aspx

Additional Notes provided on next slide

Status of Tariff Studies as of December 29, 2025, cont.

Additional Notes:

- *As of April 2025, the ISO is no longer tracking Distribution Projects in its interconnection queue.*
- *The values starting in May 2025 reflect that, as a result of the Order No. 2023 response from FERC, the ISO is no longer performing serial interconnection studies.*
- *The "TCS – NCIS" category represents projects that did not complete a system impact study before April 4, 2025 and require study in the Transitional Cluster Study (TCS) according to the Network Capability Interconnection Standard (NCIS). Such projects may also be studied in the TCS according to the Capacity Capability Interconnection Standard (CCIS). There are additional projects in the TCS that are seeking to augment their Network Resource Interconnection Service (NRIS) to Capacity Network Resource Interconnection Service (CNRIS) (and thus will only be studied in the TCS according to the CCIS), but are included in the Executed IA/Negotiating IA totals.*

OPERABLE CAPACITY ANALYSIS

Winter 2026 Analysis

Winter 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2026[2] CSO (MW)	Jan - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,350	29,938
Active Demand Capacity Resource (+) [5]	260	291
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	845	845
Non Commercial Capacity (+)	14	14
Non Gas-fired Planned Outage MW (-)	96	1,223
Gas Generator Outages MW (-)	157	455
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	2,977	2,999
Net Capacity (NET OPCAP SUPPLY MW)	22,439	23,611
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,056	20,056
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,181	22,181
Operable Capacity Margin	258	1,430

[1]Operable Capacity is based on data as of **December 29, 2025** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **December 29, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 17, 2026.**

[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 2026 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2026[2] CSO (MW)	Jan - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,350	29,938
Active Demand Capacity Resource (+) [5]	260	291
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	845	845
Non Commercial Capacity (+)	14	14
Non Gas-fired Planned Outage MW (-)	96	1,223
Gas Generator Outages MW (-)	157	455
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,875	4,029
Net Capacity (NET OPCAP SUPPLY MW)	21,541	22,581
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,125	21,125
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,250	23,250
Operable Capacity Margin	-1,709	-669

[1]Operable Capacity is based on data as of **December 29, 2025** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **December 29, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 17, 2026.**

[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 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 29, 2025 - 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 January through March.

Report created: 12/29/2025

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1/17/2026	27350	260	845	14	96	157	2800	2977	22439	20056	2125	22181	258	Y	Winter 2025/2026
1/24/2026	27350	260	845	14	97	494	2800	2341	22737	20056	2125	22181	556	N	Winter 2025/2026
1/31/2026	27324	260	715	264	39	4	3100	2532	22888	19855	2125	21980	908	N	Winter 2025/2026
2/7/2026	27324	260	715	264	44	4	3100	2233	23182	19615	2125	21740	1442	N	Winter 2025/2026
2/14/2026	27324	260	715	264	112	4	3100	1784	23563	19589	2125	21714	1849	N	Winter 2025/2026
2/21/2026	27324	260	715	264	55	4	3100	1485	23919	19352	2125	21477	2442	N	Winter 2025/2026
2/28/2026	26565	399	1235	393	386	120	2200	294	25592	18461	2125	20586	5006	N	Winter 2025/2026
3/7/2026	26565	399	1235	393	370	0	2200	308	25714	18147	2125	20272	5442	N	Winter 2025/2026
3/14/2026	26565	399	1235	393	374	426	2200	0	25592	17970	2125	20095	5497	N	Winter 2025/2026
3/21/2026	26565	399	1235	393	525	426	2200	0	25441	17641	2125	19766	5675	N	Winter 2025/2026
3/28/2026	26408	399	1235	393	1274	835	2700	0	23626	17132	2125	19257	4369	N	Winter 2025/2026

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 2025 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2026 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

December 29, 2025 - 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 January through March.

Report created: 12/29/2025

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1/17/2026	27350	260	845	14	96	157	2800	3875	21541	21125	2125	23250	-1709	N	Winter 2025/2026
1/24/2026	27350	260	845	14	97	494	2800	3538	21540	21125	2125	23250	-1710	Y	Winter 2025/2026
1/31/2026	27324	260	715	264	39	4	3100	3579	21841	20914	2125	23039	-1198	N	Winter 2025/2026
2/7/2026	27324	260	715	264	44	4	3100	3280	22135	20661	2125	22786	-651	N	Winter 2025/2026
2/14/2026	27324	260	715	264	112	4	3100	2682	22665	20633	2125	22758	-93	N	Winter 2025/2026
2/21/2026	27324	260	715	264	55	4	3100	2233	23171	20384	2125	22509	662	N	Winter 2025/2026
2/28/2026	26565	399	1235	393	386	120	2200	1191	24695	19446	2125	21571	3124	N	Winter 2025/2026
3/7/2026	26565	399	1235	393	370	0	2200	1206	24816	19114	2125	21239	3577	N	Winter 2025/2026
3/14/2026	26565	399	1235	393	374	426	2200	0	25592	18928	2125	21053	4539	N	Winter 2025/2026
3/21/2026	26565	399	1235	393	525	426	2200	0	25441	18582	2125	20707	4734	N	Winter 2025/2026
3/28/2026	26408	399	1235	393	1274	835	2700	0	23626	18045	2125	20170	3456	N	Winter 2025/2026

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 2025 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]

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

Possible Relief Under OP4: Appendix A

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

NOTES:

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

5 Litigation Report

Jan 8, 2026
Meeting

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of January 7, 2026

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated December 3, 2025 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

Executive Orders

*	1	Revolution Wind (and Vineyard Wind) Stop-Work Order II	Dec 22	DOI suspends wind project leases/construction citing national security risks
			Jan 2	Revolution Wind challenges DOI suspension
	2	Revolution Wind Stop-Work Order I	Dec 8	U.S. D. Mass. Ct. vacates Jan 20, 2025 EO (wind ban)

I. Complaints/Section 206 Proceedings

	5	PSNH X-178 Powerline Rebuild Asset Condition Project Complaint (EL26-27)	Dec 8	PSNH files answer and motion to dismiss
			Dec 8-10	ISO-NE, MOPA, MPUC (out-of-time), NHOCA intervene
			Dec 21	Individual Complainants oppose PSNH motion
			Dec 23	MOPA responds to PSNH motion
	6	BP Phantom Load Complaint (EL26-5)	Dec 12	ISO-NE, Eversource/NSTAR, and RESA submit comments
			Dec 26	ISO-NE answers RESA and Eversource comments
			Dec 29	BP answers ISO-NE and Eversource comments

II. Rate, ICR, FCA, Cost Recovery Filings

*	13	PBOP Collections Report (CMP) (ER26-961)	Jan 7	CMP files revisions to Appendix A to Attachment F to report on PBOP expenses; comment deadline ***Jan 28, 2026***
*	13	CIP IROL Cost Recovery Filing: Essential Power Newington (ER26-918)	Dec 30	Essential Power Newington requests recovery of ***$642,105*** in CIP-IROL Costs incurred between Jul 1, 2024 and Sep 30, 2025; comment deadline ***Jan 20, 2026***
	13	ARA ICR-Related Values and HQICCs (ER26-578)	Dec 8	Calpine intervenes
	14	PBOP Collections Report (RI Energy) (ER26-387)	Dec 23	FERC accepts Narragansett's PBOP Collections Report (reporting a ***$938,616*** over recovery), *eff. Jan 1, 2026*
	14	PBOP Collections Report (National Grid) (ER26-172)	Dec 5	FERC accepts National Grid's PBOP Collections Report (reporting a ***$2,954,638*** over-recovery), *eff. Dec 17, 2025*
	14	2026 NESCOE Budget (ER26-145)	Dec 30	FERC accepts 2026 NESCOE Budget, *eff. Jan 1 2026*
	14	2026 ISO-NE Administrative Costs and Capital Budgets (ER26-144)	Dec 30	FERC accepts 2026 ISO-NE Budgets, *eff. Jan 1, 2026*
	15	Kleen Energy CIP-IROL Rate Schedule Filing (ER26-132)	Dec 4	FERC accepts Kleen's CIP-IROL Rate Schedule, *eff. Oct 14, 2025*
	16	Transmission Rate Annual (2025-26) Update/Informational Filing (ER20-2054)	Dec 15	PTO AC, on behalf of CMP, submits a supplement to its Jul 31 Annual Update to reflect a reduction to CMP's LNS revenue requirement to ***$136,774,147***

	16	Transmission Rate Annual (2023-24) Update/Informational Filing (ER20-2054)	Dec 17	MOPA supplements its Formal Challenge to the 2023-24 Transmission Rate Annual Update

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

*	17	CAR-PD (ER26-925)	Dec 30	ISO-NE and NEPOOL jointly file CAR-PD Tariff revisions to the Tariff requesting an order on or before ***Mar 31, 2026;*** *comment deadline* ***Jan 20, 2026***
*	17	Waiver Request: Tariff Section III.13.A.2(b) (Derby Fuel Cell) (ER26-884)	Dec 22	Derby requests waiver, if necessary, of Section III.13.A.2(b) to permit Derby Fuel Cell to participate in upcoming ARAs; comment deadline ***Jan 12, 2026***
			Dec 23	ISO-NE intervenes, opposes request for shortened comment period, and signals opposition to waiver request
	17	*Order 2222* Conforming Changes (ER26-105)	Dec 15	FERC accepts *Order 2022* Conforming Changes; *eff. Nov 1, 2026*

IV. OATT Amendments / TOAs / Coordination Agreements

	18	*Order 898* Compliance Revisions (ER26-439)	Dec 23	FERC accepts revisions, *eff. Dec 21, 2026*
	18	RI Energy Revisions to Fixed PBOP Expense Amount (ER26-390)	Dec 23	FERC accepts revisions, *eff. Jan 1, 2026*

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

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

*	18	Schedule 20-A: NEP Cancellation of Non-Conforming SA (ER26-675)	Dec 5	National Grid files notice of cancellation of the non-conforming Phase I/II HVDC-TF Service Agreement between NEP and Vitol
*	19	Schedule 25: NECEC First Revised ETU IA (CMP-20-01) (ER26-670)	Dec 5	CMP files First Revised Service Agreement No. ETUIA-ISONE/CMP-20-01 under Schedule 25 of the ISO-NE OATT
			Dec 17-18	National Grid, Eversource intervene
	19	Schedule 21-RIE: Block Island Wind Farm Facilities Reclassification (ER26-397)	Dec 23	FERC accepts Narragansett's revisions, *eff. Jan 1 2026*
	19	Sched. 21-GMP: BTM Gen & SSCDC Cost Revisions (ER26-386)	Dec 18	FERC accepts Sched. 21-GMP BTM Gen & SSCDC Cost Revisions, *eff. Dec 31, 2025*
	19	Schedule 21-ES: Removal of Duplicative True-Up of S&D Costs (ER26-321)	Dec 30	FERC accepts changes to Schedule 21-ES to remove duplicative true-up of S&D costs, *eff. Jan 1, 2026*

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

No Activity to Report

IX. Membership Filings

*	20	Jan 2026 Membership Filing (ER26-933)	Dec 31	**New Members**: Balyasny Asset Management, Geodesic 7; **Terminations**: Anbaric Development Partners; EMI; Eoch Energy; Excelerate Energy; and Vineyard Reliability; and a **Name Change**: Six One Energy Corporation); comment deadline ***Jan 21, 2026***
	20	Nov 2025 Membership Filing (ER26-363)	Dec 18	FERC accepts MRRA membership
*	20	Suspension Notice – Actual Energy Inc. (not docketed)	Dec 24	ISO-NE files notice of Dec 22, 2025 suspension of Actual Energy from the New England Markets

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

	21	Revised Reliability Standard: MOD-026-2 (RD26-3)	Dec 8 Dec 19	Joint ISOs (including ISO-NE) submit comments supporting MOD-026-2 approval, *but* with the removal of Requirement R3 NERC submits reply comments
	22	Revised Reliability Standard: EOP-012-3 (RD25-7)	Dec 5	FERC issues Order on Clarification, granting NERC's req. for clarif. and granting in part Joint Associations' req. for clarif.

XI. Misc. - of Regional Interest

	24	203 Application: Ontario Power (Eagle Creek Utilities)/Apollo Global Management (EC26-8)	Dec 23	FERC authorizes Apollo Global Management acquisition of Eagle Creek Utilities (including Brown Bear II Hydro, Eagle Creek Madison Hydro, and Eagle Creek Renewable Energy Holdings)
	24	203 Application: Cricket Valley Energy Center (EC25-116)	Dec 12	CVEC files notice that the transaction was consummated on *Dec 2, 2025*
	25	203 Application: Constellation/ Calpine (EC25-43)	Jan 6	Transaction consummated; Constellation and Calpine become Related Persons
*	26	EMM Contract 2026-2028 (ER26-777)	Dec 15 Dec 19-Jan 5	ISO-NE files new contract for EMM services with Potomac Economics NPOOL, Calpine, National Grid, Public Citizen intervene
	26	LGIA Termination: Eversource-Vineyard Wind I (ER26-767)	Dec 15	ISO-NE, on behalf of Eversource, files a termination for the First Revised LGIA that governed the interconnection of VW1's proposed Large Generating Facility, which has since been superseded by a conforming and to be EQR reported, 3-party LGIA
	27	Versant MPD OATT *Order 904* Compliance Filing: (ER25-1393)	Dec 8	FERC accepts Versant's revisions, *eff. May 26, 2025*

XII. Misc. – Administrative & Rulemaking Proceedings

	29	ANOPR: Interconnection of Large Loads to the Interstate Transmission System (RM26-4)	Dec 9-11	Reply comments filed by PJM and ENGIE; prior comments summarized in Dec 9 memo

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

* 30	Green Mountain Stipulation and Consent Agreement (IN25-15)	Jan 6	FERC approves Agreement that resolves OE's investigation into whether GMP violated the ISO-NE Tariff and Market Behavior Rules by failing to properly report outages at the Bolton Falls Dam project; Green Mountain agreed to ***disgorge $94,833.26*** plus interest to ISO-NE, pay a ***civil penalty of $32,500***, and to submit compliance monitoring reports for 2 years and conduct annual compliance training for 3 years
30	American Efficient Show Cause Order (IN24-2)	Dec 12	American Efficient submits request to terminate this proceeding

XIV. Natural Gas Proceedings

33	Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)	Dec 11 Jan 6	FERC issues data request Algonquin submits response to Dec 11 data request
33	*Order 915*: Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing (RM25-9)	Dec 8	FERC issues an *Allegheny Notice*, noting that the NRDC request for reh'g may be deemed denied by operation of law, but noting that the request will be addressed in a future order

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

35	*Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)	Jan 5	Respondent FERC submits opening brief
37	*Avangrid v. NextEra (NECEC Civil Suit) (D.MA 24-30141)*	Dec 18	A hearing on NextEra's motion to dismiss the State Law Claims held set for ***Dec 18, 2025***
37	Allco PURPA Enforcement Petition (D.CT 3:25CV01321)	Dec 9 Dec 23	Allco files memo in opposition to the motion to dismiss filed by the Defendants and the State Agency Defendants Defendants and State Agency Defendants file motions to dismiss the Complaint

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Joan Bosma, NEPOOL Counsel

DATE: January 7, 2026

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 7, 2026. In addition, in the opening Section immediately below, we continue to summarize recent Executive Orders issued by the President of the United States and Executive Agency directives related to the energy industry. If you have questions on any of these summaries, please contact us.

Executive Orders

Questions concerning any of the Executive Orders ("EO") or Agency Directives summarized below can be directed to Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Joan Bosma (617-345-4651; jbosma@daypitney.com).

- **Revolution Wind Stop-Work Order I**

On December 8, 2025, the U.S. District Court for the District of Massachusetts vacated President Trump's January 20, 2025 executive order that had directed federal agencies to halt leasing and approvals for wind energy projects, finding the blanket prohibition "arbitrary and capricious" and unlawful under the Administrative Procedure Act. As previously reported, the Department of the Interior's ("DIO") Bureau of Ocean Energy Management ("BOEM") issued a Director's Order ("Stop-Work Order") on August 22, 2025 to Revolution Wind, LLC to halt all ongoing activities related to the Revolution Wind Project to allow BOEM to "address concerns that have arisen during the review that the Department is undertaking pursuant to the President's Memorandum of January 20, 2025."[2] In response, the Rhode Island and Connecticut Attorney Generals filed suit against the Trump Administration requesting an injunction on the basis that the federal government arbitrarily reversed course. On September 22, 2025, a DC District Court judge granted a preliminary injunction, allowing construction to resume while the lawsuit against the government proceeds. The Revolution Wind project is about 80% built and remains targeted for commercial operation in 2026.[3] The lawsuit has been amended to include the Second Stop Work Order discussed immediately below.

- **Revolution Wind (and Vineyard Wind) Stop-Work Order II**

On December 22, 2025, the BOEM's Acting Director issued a second order related to Revolution Wind (as well as to 4 other off-shore wind projects, including Vineyard Wind) ordering Ørsted, among others, to suspend all ongoing activities related to the Revolution Wind Project for the next 90 days for reasons of national security ("the

[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] 90 Fed. Reg. 8,363 (Jan. 29, 2025).

[3] The current timeline for completion of the Revolution Wind project is available at: https://revolution-wind.com/construction-updates#3.

Second Stop Work Order").[4] The national security risks, BOEM states, were identified by the Defense Department (Department of War) in recently completed classified reports.[5] In response, Ørsted moved for leave to supplement its pending complaint and moved preliminarily enjoin the Second Stop Work Order. The State of Rhode Island, State of Connecticut, and Katie Dykes ("State Plaintiffs") have filed a motion for (i) stay pending review and (ii) a preliminary injunction. Other parties have also challenged the Second Stop Work Order in federal court (e.g. Dominion in the US District for the Eastern District of Virginia, in connection with the CVOW – Commercial project). These matters are pending before the federal courts

- **Executive Order: Launching the Genesis Mission (EO 14363)**

On November 24, 2025, President Trump issued an Executive Order ("EO") launching the "Genesis Mission." The EO directs the Department of Energy ("DOE") to create an integrated Artificial Intelligence ("AI") and high-performance computing platform to accelerate scientific discovery and advance national, economic, and energy security. The DOE Secretary must establish and operate the American Science and Security Platform, leveraging DOE supercomputers, secure cloud AI environments, and Federal scientific datasets to train scientific foundation models and deploy AI agents for automated experimentation. On or before ***January 23, 2026***, DOE must identify and submit at least 20 national science and technology challenges spanning priority domains such as advanced manufacturing, biotechnology, critical materials, nuclear fission and fusion energy, quantum information science, and semiconductors and microelectronics. On or before ***February 22, 2026***, the DOE Secretary must inventory Federal and industry computing, storage, and networking resources available to support the Genesis Mission. On or before ***March 24, 2026***, the DOE must identify initial data and model assets and develop a cybersecurity-informed plan to incorporate datasets from other agencies, federally funded research, academia, and approved private partners. On or before ***July 22, 2026***, the DOE must review robotic and AI-directed experimentation capabilities across the national labs. And, on or before ***August 21, 2026***, the DOE must demonstrate an initial operating capability of the Platform for at least one of the identified national challenges. The EO also requires the DOE Secretary to report on the Platform's operational status to the President within one year and annually thereafter.

- **Executive Order: Accelerating Federal Permitting of Data Center Infrastructure (EO 14318)**

On July 23, 2025, President Trump issued an EO to facilitate "the rapid and efficient buildout" of AI data centers and associated infrastructure. The EO directs the Secretary of Commerce to launch an initiative to provide financial support for "Qualifying Projects," which are defined as data centers and related infrastructure that require over 100 MW of incremental electric load, a commitment of $500 million or more in capital expenditures, or are otherwise designated as such. All relevant agencies were directed to identify existing National Environmental Policy Act ("NEPA") categorical exclusions that could facilitate the construction of Qualifying Projects to the Council on Environmental Quality within 10 days; the EO also establishes a presumption that federal financial assistance that is less than half of the total project cost does not constitute a "major Federal action" under NEPA. The Environmental Protection Agency ("EPA") is tasked with reviewing and revising permitting regulations under the Clean Air Act, Clean Water Act ("CWA"), and other laws to streamline approval processes, and must issue guidance to support the reuse of Superfund and Brownfield sites for data centers by ***January 19, 2026***. And, the Army must assess whether a new nationwide permit is necessary under the CWA or Rivers and Harbors Appropriation Act to facilitate the efficient permitting of Qualifying Projects. Additionally, the EO instructs the Departments of the Interior, Energy, and Defense to identify and authorize federal and military lands for qualifying development, including streamlined consultations under the Endangered Species Act for construction of Qualifying Projects over the next 10 years and competitively leasing sites for data centers. The EO

[4] *See* https://www.doi.gov/pressreleases/trump-administration-protects-us-national-security-pausing-offshore-wind-leases.

[5] Unclassified US Government reports have found that the movement of massive turbine blades and the highly reflective towers create radar interference called "clutter." The clutter caused by offshore wind projects obscures legitimate moving targets and generates false targets in the vicinity of the wind projects. A 2024 DOE report stated that a radar's threshold for false alarm detection can be increased to reduce some clutter, but an increased detection threshold could cause the radar to "miss actual targets."

also mandates FAST-41 transparency project designation and permitting dashboard integration by August 22, 2025.

- **Executive Order: Ending Market Distorting Subsidies for Unreliable, Foreign Controlled Energy Sources (EO 14315)**

On July 7, 2025, following the recent signing of the One Big Beautiful Bill Act ("OBBB"), President Trump issued an EO directing the Secretary of the Treasury to implement provisions of the OBBB aimed at eliminating federal support for wind and solar energy and directing the Department of the Interior to review and revise any policies that provide preferential treatment to wind and solar energy sources, by August 21, 2025. Specifically, the EO requires the Treasury to issue guidance to enforce the OBBB's termination of Sections 45Y and 48E tax credits, including restricting safe harbor provisions and "beginning of construction" standards. The Treasury is also directed to implement the OBBB's enhanced Foreign Entity of Concern ("FEOC") restrictions.

- **Executive Order: Empowering Commonsense Wildfire Prevention and Response (EO 14308)**

On June 12, 2025, President Trump issued an EO to consolidate wildfire programs, develop a technology roadmap, and revise rules to enable more effective wildfire prevention and response through the use of prescribed burns, improved power system practices, and modernized response metrics and satellite data. As it relates to the FERC, the EO directed the FERC to consider by September 15, 2025 rulemakings to establish best practices to reduce wildfire ignition risk from the bulk-power system ("BPS") without increasing end-user costs. As summarized in Section XII below (AD25-16), the FERC issued on September 10, 2025 a notice of an October 21, 2025 Staff-led technical conference on wildfire mitigation, including cost-effective best practices to reduce the risk of wildfire ignition from the BPS.

- **Executive Order: Reinvigorating the Nuclear Industrial Base (EO 14302)**

On May 23, 2025, President Trump issued an EO directing the U.S. Department of Energy ("DOE") to accelerate the growth of the U.S. nuclear sector. EO 14302 specifically directs the DOE to facilitate 5 GW of power uprates to existing reactors and the start of construction on ten new large reactors ***by 2030***. The DOE Loan Programs Office is directed to prioritize projects including restarts, uprates, new construction, and fuel supply chain improvements. The DOE and the Department of Defense ("DoD") are to assess the use of closed nuclear sites for military energy hubs. EO 14302 also requests a report and sets timelines for action on nuclear fuel recycling, enrichment, and cooperative procurement, including near-term use of Defense Production Act authorities.

- **Executive Order: Reforming Nuclear Reactor Testing at the Department of Energy (EO 14301)**

Also on May 23, 2025, President Trump issued EO 14301 mandating the DOE revise NEPA regulations by June 30, 2025 to streamline environmental reviews for reactor testing through new or existing categorical exclusions. EO 14301 also directs the DOE to issue guidance on "qualified test reactors" and establish a pilot program for at least three test reactors outside the National Laboratories by ***July 4, 2026***.

- **Executive Order: Ordering the Reform of the Nuclear Regulatory Commission (EO 14300)**

Also on May 23, 2025, President Trump issued EO 14300 directing the Nuclear Regulatory Commission ("NRC") to overhaul its licensing and fee structures to expedite approvals. EO 14300 specifically mandates final decisions on applications for new reactors within 18 months, and for continued operation of existing reactors within one year, with caps on hourly fee recovery. EO 14300 also directs the NRC to streamline approval of reactor designs already tested and demonstrated by the DOE or DoD, so to focus reviews only on new application-specific risks.

- **Executive Order: Deploying Advanced Nuclear Reactor Technologies for National Security (EO 14299)**

President Trump issued yet another Executive Order on May 23, 2025 directing the DOE, DOD, and the Secretary of State to accelerate the deployment and export of advanced nuclear reactor technologies to meet national security objectives and support rapid growth of advanced nuclear technologies. EO 14299 requires the

DOE to designate AI data centers at DOE sites as critical defense infrastructure and to select sites within 90 days for deployment of advanced nuclear reactors to support AI and other national security missions, with the first reactor to be operational within 30 months. The DoD must also commence operation of a nuclear reactor at a domestic military installation by no later than ***September 30, 2028***. EO 14299 also directs the Secretary of State to pursue at least 20 new section 123 of the Atomic Energy Act of 1954 Agreements for Peaceful Nuclear Cooperation by the close of the 120th Congress and requires the DOE to review and act on export authorization requests within 30 days of completion.

- **Executive Order: Zero-Based Regulatory Budgeting to Unleash American Energy (EO 14270)**

On April 9, 2025, President Trump issued an EO directing the FERC, along with DOE, EPA, and the NRC, to incorporate conditional sunset provisions into specified "Covered Regulations" that requires these regulations expire after one year unless extended at the agency's discretion for a period of up to five years. The agencies must provide the public with an opportunity to comment on the costs and benefits of each such regulation prior to its expiration. For the FERC, the EO applies to regulations promulgated under the Federal Power Act ("FPA"), Natural Gas Act ("NGA"), and the Powerplant and Industrial Fuel Use Act. On October 1, 2025, the FERC issued a direct final rule (*Order 914*) and a related NOPR, in response to EO 14270, to sunset 53 regulations identified as outdated or unnecessary. *Order 914* establishes a one-year sunset from its effective date (45 days after *Order 914*'s publication in the Federal Register), after which the regulations will be removed from the U.S. Code of Federal Regulations and the FERC will no longer treat them as effective. (*see* Section XII below).

- **Executive Order: Strengthening the Reliability and Security of the United States Electric Grid (EO 14262)**

On April 8, 2025, President Trump issued an EO directing the Secretary of the DOE to strengthen use of emergency authority under Section 202(c) of the FPA and to implement a new national methodology for assessing electric reliability. The EO requires the DOE to streamline and expedite the issuance of 202(c) emergency orders during forecasted supply interruptions and to develop, within 30 days, a uniform framework for evaluating reserve margins across all FERC-jurisdictional regions. This framework will be used to identify regions with insufficient capacity and determine which generation resources are critical to reliability. The DOE is further directed to use the methodology to prevent the retirement or fuel conversion of any resource over 50 MW that would cause a net reduction in accredited capacity. While FERC is not directly tasked under EO 14262, implementation of its provisions may influence FERC-jurisdictional processes.

***DOE Resource Adequacy Report*: Evaluating the Reliability and Security of the United States Electric Grid ("DOE RA Report")**. On July 7, 2025, the DOE released a Report in response to Section 3(b) of EO 14262 (which directed the DOE to develop a uniform methodology for analyzing current and anticipated reserve margins in FERC-regulated regions of the bulk power system). The DOE RA Report provides an assessment of the U.S. grid's ability to meet projected load growth through 2030 using a deterministic approach that simulates system stress in all hours of the year and incorporates grid conditions and scenarios based on historical data.[6] Overall highlights of from the DOE RA Report include conclusions that: (i) the status quo is unsustainable; (ii) grid growth must match the pace of AI innovation; (iii) with projected load growth, retirements increase the risk of power outages by 100 times in 2030; (iv) planned supply falls short, reliability at risk; and (v) old tools won't solve new problems.

Not New England. The DOE RA Report identifies several regions facing acute reliability issues in the near future, though not New England. The DOE RA Report cites sharp load growth from electrification, AI, and data centers as the key drivers of resource adequacy concerns. Noting the absence of additional AI/data center load

[6] The DOE RA Report employs three different 2030 cases: a Plant Closures Case (which assumes all announced retirements occur), a No Plant Closures Case (which assumes no announced retirements proceed and mature additions), and a Required Build Case (which compares impacts of retirements on perfect capacity additions necessary to return 2030 to current level of reliability). In the Plant Closures Case, only New England and NYISO met the reliability thresholds, while all other regions failed. ISO-NE's peak demand is projected to grow from 28 GW in 2024 to 31 GW by 2030, with capacity rising from 40 GW to 45.5 GW in the No Plant Closures case and to 42.8 GW in the Plant Closures case.

growth in New England, the DOE RA Report concludes that no additional capacity in New England would be necessary to meet the study's reliability standards.

Request for Rehearing – DOE RA Report. On August 6, Clean Energy Organizations,[7] concluding that the DOE RA Report is a rule subject to rehearing, despite being styled as a report, requested rehearing of the DOA RA Report, asserting that the Report "fails to account for [] important aspects of the resource adequacy puzzle."[8] Clean Energy Organizations request that DOE "withdraw the Resource Adequacy Protocol or otherwise address the errors contained in it."

- **Executive Order: Reinvigorating America's Beautiful Clean Coal Industry and Amending EO 14241 (EO 14261)**

Also on April 8, 2025, President Trump issued an EO that (i) reclassifies Coal as a Strategic National Asset (granting coal eligibility for federal support programs, including those under the Defense Production Act and DOE's loan authorities, and directing a review of policies that may discourage coal production, with agencies tasked to revise or rescind such policies within 60 days); (ii) accelerates coal access on federal lands (directing federal agencies to identify coal-rich areas on federal lands, address barriers to mining on federal lands and propose actions to maximize coal mining on federal lands, and prioritize coal leasing and encourage the use of emergency authorities to expedite permitting and environmental reviews, including a push for broader use of categorical exclusions under NEPA. The assessment requires an analysis of the impact the use of coal resources could have on electricity costs and grid reliability); and (iii) aligns coal with emerging industrial needs (positioning coal as a critical resource for emerging industries, directing agencies to assess its potential for powering AI data centers and supporting steelmaking, and calling for accelerated development of coal technologies and commercial applications in advanced manufacturing).

- **Executive Order: Protecting American Energy From State Overreach (EO 14260)**

On April 8, 2025, President Trump issued an EO directing the U.S. Attorney General to identify and challenge state and local laws, regulations, and policies that may act as "illegitimate impediments" to the development, siting, production, investment in, or use of domestic energy resources, and further instructs the Attorney General to stop the enforcement of these state climate-related policies. While the EO does not directly implicate FERC, it may affect regional efforts such as the Regional Greenhouse Gas Initiative ("RGGI") and other state-led programs. A report detailing the Attorney General's actions and recommended executive or legislative responses was due to the President within 60 days.

I. Complaints/Section 206 Proceedings

- **PSNH X-178 Powerline Rebuild Asset Condition Project Complaint (EL26-27)**

On November 14, 2025, individual complainants, Kristina Pastoriza and Ruth Ward,[9] filed a complaint requesting that the FERC open an investigation into the Public Service Company of New Hampshire's (Eversource) $400 million proposed rebuild of the X-178 115 kV transmission line from Beebe River to Whitefield, NH (approximately 49 miles, including a 12.4-mile segment in the White Mountain National Forest). The Complaint requests that the FERC direct an objective expert third-party investigation into (i) the need for the project (Physical Condition, Current Demand, Projected Load, Reliability and Safety), (ii) the

[7] "Clean Energy Organizations" are, for the purposes of this matter, the American Clean Power Association ("ACPA"), Advanced Energy United ("AEU"), and American Council on Renewable Energy ("ACORE").

[8] Clean Energy Organizations assert that DOE's analysis "fails to take account of (or simply mischaracterizes) major developments that will affect resource adequacy in the next half-decade and beyond, primarily the pace of new resource development, the retirement of existing resources, and the well-established regulatory and market mechanisms that connect these threads. The [Report] also excludes mention of President Trump's own policies aimed at making the headline outcomes of the [Report] highly unlikely.

[9] Kristina Pastoriza is an owner of the property and lives on the property, and Ruth Ward is an owner of the property and is an Eversource retail electricity customer.

prudence of sunk and projected costs, and (iii) the accounting basis of the formula rate charges, and (iv) if the resulting rates are just and reasonable and not unduly discriminatory. The Complaint asserts that ISO-NE treated the project as an "asset condition" rebuild outside the ISO-NE *Order 890/1000* planning process, and it notes related pending approvals before the New Hampshire Site Evaluation Committee and the U.S. Department of Agriculture Forest Service. Comments were due on or before December 8, 2025. PSNH moved to dismiss the complaint (asserting that the Complaint fails to state a claim and mischaracterizes the scrutiny applicable to the X-178 Project) and alternatively filed an answer opposing the Complaint. ISO-NE, MOPA, MPUC, (out-of-time) and NHOCA intervened doc-lessly. On December 22, 2025, Complainants opposed PSNH's December 8 motion (asserting that material factual questions exist as to whether the X-178 Project is a system expansion improperly being recovered as an asset condition project, and requesting evidentiary hearing and/or settlement judge procedures). This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **BP Phantom Load Complaint (EL26-5)**

On October 14, 2025, as supplemented October 17, BP Energy Retail Company ("BP") filed a complaint seeking relief from invoices issued by ISO-NE for July, August, and September of 2024 based on phantom load shifted from the NEMA to the SEMA zone, which BP asserts was incorrectly assigned to BP by Eversource (NSTAR) due to an IT system error. Answers, comments and interventions were due on or before December 12, 2025.

Answers and comments in response to the BP Complaint were filed by **ISO-NE** (opposing the Complaint and BP waiver request, asserting that the alleged error constitutes a Meter Data Error and that BP requested relief would require resettlement of final bills outside the ISO-NE Tariff and Manual M-28 settlement timelines), **Eversource** (supporting BP's request for waiver of the Market Rule 1 time limitations and requesting that the FERC direct ISO-NE to complete billing adjustments for July, August, and September 2024 based on updated data, with any resettlement extending to all affected Market Participants), and the Retail Energy Supply Association ("**RESA**") (supporting the Complaint, stating that phantom load errors harm Market Participants and requesting that any resettlement ordered by the FERC extend to all Market Participants) filed answers/comments. ISO-NE answered the December 8 comments of Eversource and BP on December 26. On December 29, BP opposed Eversource's motion to dismiss and replied to ISO-NE's December 12 answer and December 26 response (reiterating its request that the FERC direct ISO-NE to correct the July through September 2024 invoices). Interventions only were filed by Calpine, ENGIE, National Grid, NRG, and Public Citizen.

This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NEPGA Balancing Ratio and Stop Loss Allocation Methodology Complaint (EL25-106)**

NEPGA's July 25, 2025 complaint in response to the impacts of the events of June 24, 2025, seeking (i) a Balancing Ratio cap at 1.0; and (ii) a revised allocation of the "bonus pool" that gets collected to pay over-performers, remains pending before the FERC. As previously reported, NEPGA proposed, pointing to precedent established in PJM, that the FERC (a) cap the Balancing Ratio at 1.0 and (b) adopt the PJM charge and bonus allocation (instead of charging resources with a Capacity Supply Obligation to make up any bonus revenue shortfall, simply split the bonus pool that gets collected to pay over-performers). NEPGA asked that the FERC set an immediate refund effective date and requested fast track processing of the Complaint.

On August 21, 2025, ISO-NE filed its answer, requesting (i) with respect to the PFP stop-loss mechanism cost allocation, the FERC deny the Complaint on the merits; (ii) with respect to the Balancing Ratio, the FERC "take account of ISO-NE's arguments and narrow concession", and (iii) provide at least 180 days to file any replacement rate deemed necessary as a result of the Complaint. NEPOOL filed limited comments to provide additional context but taking no substantive position on the Complaint. Comments supporting the Complaint were filed by MMWEC, FirstLight Power, RENEW, LS Power Development, Electric Power Supply Association ("EPSA"), and jointly by Braintree and Taunton. Comments on the Complaint were also filed by NESCOE and the New England

Consumer Advocates ("CANE").[10] Vitol filed a protest requesting the FERC deny the Complaint. Interventions only were filed by the IMM, AEU, Avangrid (out-of-time), Brookfield, Calpine, CPV Towantic, Dominion, Energy New England ("ENE"), Enel, Eversource, LS Power, ME OPA, National Grid, NextEra, RI Energy, Shell, Vistra, MA DPU, the National Hydropower Association ("NHA"), and Public Citizen.

The following parties filed answers: ***ISO-NE*** ((i) answering NEPGA's second answer, reiterating that, while it would not oppose a FERC order capping the Balancing Ratio at 1.0, it continued to oppose NEPGA's position that the current stop-loss cost allocation approach is unjust and unreasonable and opposes adopting PJM's general stop loss approach; and (ii) and asserting that FirstLight's alternative requests for relief are outside the scope of this proceeding); ***NEPGA*** (emphasizing broad support for the Complaint, reiterating its argument that holding capacity resources to obligations beyond their committed capability is unjust and unreasonable, and urging the FERC to adopt PJM's allocation methodology as the replacement rate); ***the IMM*** (expressing sympathy with NEPGA's complaint, supporting a 1.0 cap on the Balancing Ratio, and requesting clarification as to how related payments would be allocated); ***RENEW*** (supporting NEPGA's proposed reforms to ISO-NE's Pay-for-Performance ("PFP") cost allocation rules); and ***Vitol*** (opposing NEPGA's second answer and requesting that the FERC deny the Complaint, stating that the reforms should be addressed through the stakeholder process).

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

- **Local Transmission Planning Complaint (EL25-44)**

As previously reported, a group of "Consumer Complainants"[11] filed a complaint almost one year ago, on December 19, 2024, against all FERC-jurisdictional public utility transmission providers with local planning tariffs (including ISO-NE and the remaining ISO/RTOs) asserting that their tariffs, which authorize individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above ("Local Planning") without regard to whether such Local Planning approach is the more efficient or cost-effective transmission project for the interconnected transmission grid and cost-effective for electric consumers, coupled with the absence of an independent transmission system planner, "are unjust and unreasonable, having produced inefficient planning and projects that are not cost-effective, resulting in unjust and unreasonable rates for both individual projects and cumulative regional transmission plans and portfolios." Specifically, the Consumer Complainants asserted that the FERC must mandate (i) revision of local and regional planning tariffs to (a) prohibit individual transmission owner planning of FERC-jurisdictional transmission facilities 100 kV and above; and (b) require exclusive regional planning of all transmission facilities 100 kV and above, utilizing existing *Order 1000* regions; and (ii) that all regional planning must be conducted through an Independent Transmission Planner as described in their Complaint.

Answers, interventions, comments, and protests to the Consumers RTP Complaint were filed by, among others, ISO-NE, New England Transmission Owners ("NETOs"),[12] AEU, CT OCC, NECPUC, NESCOE, MA AG, NH OCA

[10] The New England Consumer Advocates or "CANE" consist of the: Massachusetts Attorney General's Office ("MA AG"), Connecticut Office of Consumer Counsel ("CT OCC"), Maine Office of the Public Advocate ("ME OPA"), New Hampshire Office of the Consumer Advocate ("NH OCA"), and Rhode Island Division of Public Utilities and Carriers ("RI Division").

[11] "Consumer Complainants" are Industrial Energy Consumers of America, American Forest & Paper Assoc., R Street Institute, Glass Packaging Institute, Public Citizen, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Assoc. of Businesses Advocating for Tariff Equity, Carolina Utility Customers Assoc., PA Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Elec. Energy Consumers, Inc., Public Power Assoc. of NJ, OK Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of PA, MD Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Div. of the Public Service Commission of WV, and Missouri Industrial Energy Consumers.

[12] For purposes of this proceeding, "NETOs" are: Eversource Energy Service Company on behalf of The Connecticut Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), and NSTAR Elec. Co. ("NSTAR", and together with CL&P and PSNH, "Eversource"); Central Maine Power Co. ("CMP"), Maine Elec. Power Co., Inc. ("MEPCO"), and The United Illuminating Co. ("UI"); New

(supporting the Complaint), MPUC (urging the FERC to reject the remedies proposed by the Complainants and open its own investigations pursuant to Section 206 of the FPA), EEI, NARUC, Public Interest Organizations,[13] and WIRES. Interventions only were filed by more than 100 parties, including NEPOOL. On April 4, 2025, ISO-NE answered certain comments and reiterated its request that it be dismissed as a respondent to the proceeding. Answer and reply comments were also filed by Complainants (requesting FERC grant the Complaint and deny the motions to dismiss), NESCOE (addressing the standard of review that may apply to certain reforms), MOPA (asking FERC to reject motions to dismiss and open an investigation), MPUC (requesting FERC accept its motion for to leave to answer and consider its answer), and AMP (asking FERC to deny motions to dismiss). On May 20, 2025, ISO-NE responded to Complainant's Answer and the responses of NESCOE, MPUC, and MOPA, again requesting it be dismissed as a respondent to the proceeding as a matter of law and because the Complainants failed to meet their burden under FPA Section 206. On June 30, 2025, Complainants answered the May 22 answer by "Southeast Respondents"[14] and on July 25, 2025 ATC answered Complainants April 24, 2025 answer. Since the last Report, the Industrial Energy Consumers of America submitted comments rebutting utilities' opposition to competitive transmission development. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Allco PP5 Complaint (EL25-43)**

Still pending is the December 19, 2024 complaint by Allco Finance Limited ("Allco") asking the FERC to (i) direct ISO-NE to abolish its Planning Procedure No. 5 ("PP5") procedures by (ii) finding that PP5's procedures are unjust and unreasonable and unduly discriminatory and/or preferential in violation of section 206 of the FPA; and (iii) find that ISO-NE has violated the FPA by forcing on State jurisdictional interconnections, such as Allco's, the requirement to pay for transmission level interconnection studies, to pay for Power Systems Computer Aided Design ("PSCAD") models in connection with such studies, and by causing delays to the execution by distribution utilities of State jurisdictional generator interconnection agreements (particularly for Allco's 2 MW Winsted solar energy project). ISO-NE answered the Allco PP5 Complaint on January 15, 2025 (as corrected on January 30, 2025). On January 23, 2025, Allco answered ISO-NE's January 15 Answer. On February 7, 2025, ISO-NE answered Allco's January 23 Answer and on February 25, 2025 Allco answered ISO-NE's February 7 Answer. Doc-less interventions only were filed by NEPOOL, Calpine, National Grid, the MA DPU, and Public Citizen. There was no activity in this proceeding since the last Report. As noted, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **206 Proceeding: TO Initial Funding Show Cause Order (EL24-83)**

As previously reported, on June 13, 2024, the FERC instituted a Section 206 proceeding finding that the ISO-NE Tariff appears to be unjust, unreasonable, and unduly discriminatory or preferential because it includes provisions for transmission owners to unilaterally elect transmission owner ("TO") Initial Funding (the funding of network upgrade capital costs that the TO incurs to provide interconnection service to an interconnection customer, with the network upgrade capital costs subsequently recovered from the interconnection customer through charges that provide a return on and of those network upgrade capital costs).[15] TO Initial Funding, the FERC found, may increase the costs of interconnection service without corresponding improvements to that service, may unjustifiably increase costs such that it results in barriers to interconnection, and may result in undue

England Power Co. d/b/a National Grid; The Narragansett Elec. Co. d/b/a Rhode Island Energy ("RI Energy"); Vermont Electric Power Co., Inc. ("VELCO") and Vermont Transco LLC ("VTransco"), and Versant Power ("Versant").

[13] "Public Interest Organizations" or "PIOs" are Earthjustice, Natural Resources Defense Council ("NRDC"), Sustainable FERC Project, and the Southern Environmental Law Center.

[14] Complainants defined "Southeast Respondents" as: Dominion Energy South Carolina, Inc. ("DESC"), Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, and Duke Energy Florida, LLC (together, "Duke Energy"), Louisville Gas and Electric Company and Kentucky Utilities Company (together, "LG&E/KU"), Tampa Electric Company ("TEC"), Florida Power and Light ("FPL"), and Alabama Power Company, Georgia Power Company, and Mississippi Power Company.

[15] *ISO New England Inc. et al.,* 187 FERC ¶ 61,170 (June 13, 2024) ("*TO Initial Funding Show Cause Order*").

discrimination among interconnection customers.[16] The FERC also found that there may be no risks associated with owning, operating, and maintaining network upgrades for which transmission owners are not already otherwise compensated.[17] Accordingly, ISO-NE was directed, on or before September 11, 2024, 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.[18] The refund effective date for this proceeding is June 24, 2024.[19] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:[20] NEPOOL, Advanced Energy United ("AEU"), Avangrid, Calpine, CMEEC (out-of-time), EDP Renewables, Eversource, Invenergy, MA AG, National Grid, NESCOE, NextEra, NRDC, PPL, Maine Public Utilities Commission ("MPUC"), Massachusetts Department of Public Utilities ("MA DPU"), American Clean Power Association ("ACPA"), American Council on Renewable Energy ("ACRE"), Edison Electric Institute ("EEI"), Electric Power Supply Association ("EPSA"), RENEW Northeast ("RENEW"), Solar Energy Industries Association ("SEIA"), WIRES, Cordelio Services, and Public Citizen.

NE Response to Show Cause Order (Attaching Substantive Response by NETOs). On September 11, 2024, ISO-NE submitted a response ("NE Response") explaining that, because the rules identified in the *TO Initial Funding Show Cause Order*[21] fall within the exclusive purview of, and are implemented by, the Participating Transmission Owners ("PTOs") under the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs, it had requested that the PTOs respond to the *TO Initial Funding Show Cause Order* and attached the response of Indicated New England Transmission Owners ("NETOS")[22] to the NE Response. NETOs' response identified several reasons why the FERC's proposal is in their view beyond the FERC's authority and power.

Responses to the September NE Response were due on or before October 25, 2024. Responses from ISO-NE-related parties to this joint proceeding were filed by, among others: NE TOs, Invenergy, Public Interest Organizations, Public Systems, Clean Energy Associations, EEI, WIRES, and the Harvard Law Initiative. Since the last Report, the ISO-NE IMM filed comments in the MISO version of this proceeding to urge the FERC to reject MISO's request for a broad, and what the IMM asserts is an inappropriately limited, declaration on the authority of an IMM to monitor long-term transmission planning for impacts on the wholesale markets and assumed efficiency improvements to those markets. Each of the regional matters, including the New England-specific docket, remain pending before the FERC.

Federal Court Appeals. On August 30, 2024, certain parties[23] filed a petition for review of the FERC's orders in this proceeding in the 8th Circuit, since challenged by the FERC. Developments on the federal court

[16] *Id.* at P 1.

[17] *Id.*

[18] *Id.* at P 2.

[19] Notice of this 206 proceeding was published in the *Fed. Reg.* on June 24, 2024 (Vol. 89, No. 121) pp. 52,454-52,455.

[20] The notice instituting this 206 proceeding was issued in the following four unconsolidated dockets (which resulted in some parties intervening in all four proceedings): EL24-80 (MISO); EL24-81 (PJM); EL24-82 (SPP); and EL24-83 (ISO-NE).

[21] The rules identified in the *Order to Show Cause* were those that establish the methodology to recover costs associated with interconnection-related upgrades, and the related financial obligations of the PTO or the interconnecting party – in New England, set forth in Article 11.3 of the LGIA, Article 5.2 of the SGIA, and Article 11.3 of the ETU IA, as well as Schedule 11 of the OATT.

[22] The NETOs, for purposes of this proceeding, are: Eversource; Central Maine Power Company ("CMP"); The United Illuminating Company ("UI"); New England Power Company ("National Grid"); The Narragansett Electric Company ("RI Energy"); Fitchburg Gas and Electric Light Co. ("Unitil"); and Versant Power ("Versant").

[23] The parties to the 8th Circuit Appeal are: Ameren Services Co., Ameren Illinois Co., Union Elec. Co. d/b/a Ameren Missouri, Ameren Trans. Co. of IL, American Trans. Co. LLC, Duke Energy Corp., Duke Energy Business Services, LLC, Duke Energy Ohio, Inc., Duke

appeals will be reported in Section XVI below. In the meantime, 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, long pending before the FERC, in which the TOs' return on equity ("Base ROE") for regional transmission service has been challenged.

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[24] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE _plus_ transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[25] However, the FERC's orders were challenged, and in *Emera Maine,*[26] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

  - ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[27] and third (EL14-86)[28] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[29] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

Energy KY, Inc., Duke Energy IN, LLC, Exelon Corp., Atlantic City Elec. Co., Baltimore Gas and Elec. Co., Commonwealth Edison Co., Delmarva Power & Light Co., PECO Energy Co., Potomac Elec. Power Co., Northern Indiana Pub. Srvc. Co. LLC, Xcel Energy Services Inc., Northern States Power Co., a MN Corp., Northern States Power Co., a WI Corp., and Southwestern Pub. Srvc. Co. ("8th Circuit Parties").

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

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

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

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

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

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

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[30] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[31] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[32] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[33] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[34] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[35]

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

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

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

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

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

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

34 *Ass'n of 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*.

35 *Id.* at P 19.

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[36] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[37] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[38] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and Complainant-Aligned Parties ("CAPs") opposed the TOs' request and brief. No action was ever taken in response to this activity.

Nov 2023 Supplemental Brief. As reported at the December 5, 2024 Annual Meeting, the TOs filed, on November 13, 2024, a "Motion to File Supplemental Brief Addressing the Inability of the [FERC]'s MISO Methodology to Satisfy the Mandate of the *Emera Maine* Court in these Cases, the Requirements of Section 206, and the Need to Promote Transmission Investment in New England". On December 13, 2024, WIRES/EEI supported the TOs Motion,[39] and CAPs[40] replied in opposition to the Motion. On December 20, 2024, the TOs

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[36] *Id.* at P 59.

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

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

[39] Agreeing with the TOs, the WIRES/EEI comments asserted: (i) that the FERC lacks the statutory authority to order refunds outside the 15-month refund period; (ii) the FERC's claim of remedial authority to correct legal error does not justify retroactive ROE refunds; and (iii) the FERC should accept and give consideration to the NETOs' supplemental brief and supporting affidavits.

[40] "CAPs" are: the Conn. Pub. Utils. Regulatory Authority ("CT PURA"); the Conn. Office of Consumer Counsel ("CT OCC"); Mass. Mun. Wholesale Elec. Co. ("MMWEC"); NH Elec. Coop. ("NHEC"); the RI Div. of Pub. Utils. and Carriers ("RI Div"); and Eastern Mass. Consumer-Owned Systems ("EMCOS"), who consist of the Belmont Mun. Light Dept. ("Belmont"); Braintree Elec. Light Dept. ("Braintree"); Concord Mun. Light Plant ("Concord"); Georgetown Mun. Light Dept. ("Georgetown"); Groveland Elec. Light Dept. ("Groveland"); Hingham Mun. Lighting Plant ("Hingham"); Littleton Elec. Light & Water Dept. ("Littleton"); Merrimac Mun. Light Dept. ("Merrimac"); Middleton Elec.

filed an answer to the CAPs' statements concerning the FERC's authority to order refunds for the period from when the FERC issues its order on remand back to October 16, 2014.

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

- **PBOP Collections Report (CMP) (ER26-961)**

On January 7, 2026, CMP filed a report identifying planned collection activity related to the recovery of transmission-related post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT. No changes to the filed rate were sought. A report is required when the difference between a participating transmission owner's actual PBOP expense and its fixed PBOP expense reflected in the Formula Rate Template exceeds the thresholds identified in OATT Attachment F.[41] The CMP report showed an under-recovery, after interest, of ***$399,703***. An effective date of March 9, 2026 was requested so that CMP may rely on the reported PBOP under-recovery figures in the 2026 Annual Update due July 31, 2026. Comments on this filing are due on or before ***January 28, 2026***. If you have any questions concerning this matter, please contact Joan Bosma (jbosma@daypitney.com; 617-345-4651).

- **CIP-IROL Cost Recovery Filing: Essential Power Newington (ER26-918)**

On December 30, 2025, Essential Power Newington LLC requested that the FERC accept its revised rate schedule to allow recovery of eligible Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE OATT, effective March 1, 2026. Essential Power Newington seeks to recover ***$642,105*** of CIP-IROL Costs incurred between July 1, 2024 and September 30, 2025. Comments are due on or before ***January 20, 2026***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **ARA ICR-Related Values and HQICCs (ER26-578)**

On November 21, 2025, ISO-NE and NEPOOL jointly filed the Installed Capacity Requirements ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and Marginal Reliability Impact ("MRI") Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2026-27 Capability Year and the second ARA for the 2027-28 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 6, 2025 meeting (Consent Agenda Items 3 and 4). An effective date of January 21, 2026 was requested. Comments were due on or before December 12, 2025; none were filed. National Grid and Calpine intervened. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CIP-IROL Rate Schedule Filing: FPL Wyman (ER26-577)**

On November 21, 2025, FPL Energy Wyman IV LLC ("FPL Wyman") requested that the FERC accept its proposed rate schedule to allow recovery of eligible CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff, effective November 22, 2025. FPL Wyman stated that the rate schedule will provide interested parties notice of its intent to recover eligible incremental capital, operations and maintenance, and related administrative and regulatory CIP-IROL Costs for its 600MW generating facility designated as an IROL-Critical Facility, and that an

Light Dept. ("Middleton"); Reading Mun. Light Dept. ("Reading"); Rowley Mun. Lighting Plant ("Rowley"); Taunton Mun. Lighting Plant ("Taunton"); and Wellesley Mun. Light Plant ("Wellesley").

[41] 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 percent of transmission-related PBOP expense)] is greater than 20%. See ISO-NE OATT, Attachment F, Appendix A, Worksheet 9, Note (j).

order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the Schedule 17 pre-filing process and a subsequent FPA section 205 filing identifying the specific costs to be recovered. Comments on this filing were due on or before December 12, 2025; 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).

- **CIP-IROL Cost Recovery Filing: Canal (ER26-517)**

On November 14, 2025, as corrected on November 26, 2025, Canal Marketing LLC ("Canal") requested FERC acceptance of its revised rate schedule to allow recovery of eligible CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff, effective January 13, 2026. Canal seeks to recover ***$1,075,392*** of CIP-IROL Costs incurred between April 1, 2024 and March 31, 2025. Comments on Canal's request were due on or before December 17, 2025; none were filed. National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PBOP Collections Report (RI Energy) (ER26-387)**

On December 23, 2025, the FERC accepted, effective *January 1, 2026* as requested, RI Energy's report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT, after interest, of ***$938,616***.[42] The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F. No changes to the filed rate were sought. The PBOP figures will be used in RIE's 2026 Annual Update. Unless the December 23 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PBOP Collections Report (National Grid) (ER26-172)**

On December 5, 2025, the FERC accepted, effective *December 17, 2025* as requested, the National Grid (New England Power) report identifying planned collection activity related to the refund of an over recovery of PBOP expenses in the 2026 Annual Update, as set forth in Appendices A and B of Attachment F to the ISO-NE OATT.[43] The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F. No changes to the filed rate were sought. The report shows an over-recovery, after interest, of ***$2,954,638***. The PBOP figures will be used in National Grid's 2026 Annual Update. Unless the December 5, order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **2026 NESCOE Budget (ER26-145)**

On December 30, 2025, the FERC accepted the Tariff changes for the funding of NESCOE's 2026 operations, effective *January 1, 2026*, as requested.[44] The 2026 NESCOE Operating Expense Budget is ***$2,731,108***. The amount to be recovered reflects true-ups from 2024 (over-collections of $933,127). Accordingly, the NESCOE budget results in a charge of $0.00806 per kilowatt ("kW") of Monthly Network Load (a $0.00090/kW increase from 2025). Unless the December 30, 2025 is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2026 ISO-NE Administrative Costs and Capital Budgets (ER26-144)**

On December 30, 2025, the FERC accepted ISO-NE's filing for recovery of its 2026 administrative costs (the "2026 Revenue Requirement") and capital budget for calendar year 2026 ("2026 Capital Budget", and together with the 2026 Revenue Requirement, the "2026 ISO Budgets"), effective *January 1, 2026* as requested.[45] The 2026

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[42] *The Narragansett Electric Co.*, ER26-378 (Dec. 23, 2025) (unpublished letter order).

[43] *ISO New England Inc.*, ER26-172-000 (Dec. 5, 2025) (unpublished letter order).

[44] *ISO New England Inc.*, ER26-145-000 (Dec. 30, 2025) (unpublished letter order).

[45] *ISO New England Inc.*, ER26-144-000 (Dec. 30, 2025) (unpublished letter order).

ISO Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 15, 2025 filing, ISO-NE reported that the 2026 Revenue Requirement is $330.0 million (a $23.6 million or 7.7% increase over 2025), which decreases to $314.4 million after the overcollection for 2024 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2026 Core Operating Budget) comprise $281.8 million; depreciation and amortization of regulatory assets total $48.2 million; and a $15.6 million true-up decrease for 2022 over-collections.

ISO-NE further reported that the 2026 Capital Budget is $42.5 million, consistent with 2025, and is comprised of the following (with 2026 projected costs and target completion dates, if available, in parentheses):

nGEM Real-Time Market Clearing Engine Implementation (May 2026)	($3.2 million)	Oracle Platform Replacement (Nov 2026)	($2.2 million)
Single Interval MCE Improvements (2028)	($5 million)	Managing Transmission Line Ratings; *Order 881* (Dec 2026)	($1 million)
Order 2222 Integration (Nov 2026)	($2.6 million)	Adoption of NERC CIP Compliance of Synchrophasor Systems (Aug 2026)	($1 million)
EMS Short-Term Load Forecast (Jan 2026)	($1.2 million)		

Unless the December 30 order is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Kleen Energy CIP-IROL Rate Schedule Filing (ER26-132)**

On December 4, 2025, the FERC accepted, effective *October 14, 2025* as requested, Kleen Energy Systems, LLC ("Kleen Energy") proposed rate schedule to allow Kleen Energy to begin the recovery period for certain CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff.[46] Kleen Energy stated that the rate schedule will provide interested parties notice of Kleen Energy's intent to recover CIP-IROL Costs for its facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent Section 205 filing identifying the specific costs to be recovered. The December 4 order was not challenged and is final and unappealable. Reporting on this proceeding is concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Transmission Rate Annual (2025-26) Update/Informational Filing (ER20-2054)**

On December 15, 2025, the PTO AC, on behalf of CMP, submitted a supplement to its July 31, 2025 Annual Update to reflect a reduction to CMP's LNS revenue requirement for the 2026 Rate Year from $151,420,099 to ***$136,774,147***, reflecting revisions to certain data inputs in CMP's Local Service Annual Transmission Revenue Requirement template. While this filing will not be noticed for public comment, the supplement triggers an information exchange and review period under the ISO-NE OATT protocols, with information and document requests due on or before ***March 5, 2026*** and responses due by ***April 5, 2026***; Informal Challenges may be submitted to CMP by ***May 5, 2026*** and CMP must reply on or before ***June 5, 2026***.

[46] *Kleen Energy Systems, LLC*, Docket No. ER26-132-000 (Dec. 4, 2025) (unpublished letter order).

- **Transmission Rate Annual (2023-24) Update/Info Filing (MOPA Formal Challenge) (ER20-2054)**

On September 18, 2025, the FERC accepted in part and denied in part[47] the Maine Office of the Public Advocate's ("MOPA") formal challenge ("MOPA Formal Challenge")[48] to the TO's 2023-24 Annual Update.[49] Specifically, the FERC directed Eversource, National Grid, and MEPCO to respond to Maine OPA's Information Request Questions 1(b)(1) and 1(c)(2), and directed all of the Identified NETOs (Eversource; National Grid; MEPCO; Narragansett ; and VELCO/VTransco) to respond to Question 4,[50] on or before October 19, 2025. In addition, the FERC granted MOPA's request to permit it to supplement the MOPA Formal Challenge, as requested, with regard to the prudence of Identified NETOs' asset condition project costs reflected in the 2023 Annual Update, with such supplement to be filed on or before December 18, 2025. Of note, Commissioner Chang's concurrence emphasized stakeholders' fundamental right to transmission planning and investment information through existing formula rate protocols and encouraged transmission owners/planners to proactively share information on transmission projects and planning.

Of the 4 Identified TOs, only one (VELCO/VTransco on October 17, 2025) filed its response to Question 4 publicly. On December 17, 2025, MOPA supplemented its Formal Challenge, asserting that it has established serious doubt about the prudence of the NETOs planning practices governing asset management projects to trigger a formal prudence inquiry, and asking the FERC to establish evidentiary hearing and/or settlement judge procedures. The MOPA Formal Challenge is again pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **Waiver Request: Return of CSO Payments (Brookfield) (ER26-143)**

On October 15, 2025, Brookfield Renewable Trading and Marketing LP ("Brookfield") requested a limited waiver of the Tariff to allow it to refund to ISO-NE, with interest, improperly received CSO payments for its Lièvre Power portfolio. The payments were received for the months of October, November, and December 2024 and January 2025 (because Brookfield failed to shed a portion of its full-year CSO through the respective monthly reconfiguration auctions) and would be returned to Participants with Capacity Load Obligations during the corresponding months. While Brookfield would like to refund these payments ("BRTM Refund"), with interest, to ISO-NE, the Tariff does not have a provision that allows ISO-NE to accept the BRTM Refund or specifies how refunds should in turn be made. Brookfield asked the FERC for an order allowing ISO-NE to accept the BRTM Refund and directing ISO-NE to return the BRTM Refund to the FCM's Capacity Load Obligation for the months of

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[47] *ISO New England Inc.*, 192 FERC ¶ 61,234 (Sep. 18, 2025) ("*MOPA 2023-24 Annual Rate Update Challenge Order*").

[48] In the MOPA Formal Challenge, MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, "Identified TOs" (Eversource (CL&P, NSTAR East, NSTAR West, and PSNH); National Grid; MEPCO; Narragansett; and VELCO/VTransco) have refused to answer questions regarding investment policies and practices related to prudence of these investments and (ii) that the Identified TOs' decision not to respond to these questions violates their obligation under the OATT's Protocols.

[49] 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 "2023-24 Annual Update"). 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 stated that the annual updates result in a Pool "postage stamp" RNS Rate of $154.35/kW-year effective Jan. 1, 2024, an increase of $12.71 /kW-year from the charges that went into effect on Jan. 1, 2023. In addition, the filing included updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.95 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.

[50] Question 1(b)(1) requested copies of any written policies that describe the procedures and processes employed to evaluate the need for a particular asset condition project; Question 1(c)(2) requested copies of any documents (or a narrative description if no documents exist) identifying the reasons why those participating in the decision-making process recommended against proceeding with a particular asset condition project; Question 4 related to the existence and employment of safeguards against the placement of asset condition projects into service before they are needed.

October, November, and December 2024 and January 2025 ("FCM Refund"). Brookfield reported that ISO-NE authorized it to state that ISO-NE does not oppose the Waiver Request and can, if the Waiver Request is granted, implement the FCM Refund as described. Comments on this Waiver Request were due on or before November 5, 2025; none were filed. National Grid filed a doc-less intervention. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CAR-PD (ER26-925)**

On December 30, 2025, ISO-NE and NEPOOL jointly filed Tariff revisions establish a prompt capacity market and revised deactivation framework (CAR-PD).[51] CAR-PD if accepted will replace the Forward Capacity Market ("FCM") with annual capacity auctions held about one month before the Capacity Commitment Period, require resources to be commercial and demonstrate deliverability to participate, and use a sealed-bid auction rather than a descending clock, to reduce phantom entry and streamline auction administration. CAR-PD will also replace the de-list bid retirement construct with a deactivation notice one year in advance, eliminate annual reconfiguration auctions, and simplify qualification and offer administration, while largely retaining monthly settlement and PFP and maintaining existing market power mitigation with timing conforming changes. ISO-NE requested an effective date of, and an order on or before, ***March 31, 2026.*** Comments on the CAR-PD filing are due on or before ***January 20, 2026***. Thus far, Boston Energy and Trading and Marketing, Constellation, Dominion, LS Power, NH OCA, NRG, EPSA, SEIA, MA DPU, and Public Citizen have intervened doc-lessly. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: Tariff Section III.13.A.2(b) (Derby Fuel Cell) (ER26-884)**

On December 22, 2025, Derby Fuel Cell, LLC ("Derby") requested waiver, if necessary, of Tariff Section III.13.A.2(b) to permit Derby to participate in the interim Reconfiguration Auctions for the 2027-2028 Capacity Commitment Period. Derby reported that ISO-NE disqualified Derby from the qualification process on the basis that Derby did not formally notify ISO-NE by November 3, 2025 that it elected ISO-NE monitoring of Derby's Critical Path Schedule. Derby asserts that CPS monitoring is optional for a resource that has achieved FCM Commercial Operation (Derby has been commercially operating since December 2023) and seeks the waiver to permit it to participate. Derby also asserts that, in addition to no critical path milestones for ISO-NE to monitor, its receipt of an August 29, 2025 e-mail from ISO-NE Participant Support indicating the ISO was "all set" regarding outstanding items, Derby "reasonably concluded that there were no additional requirements, and did not provide any further communications to ISO-NE regarding CPS monitoring." Derby requested expedited consideration, including a shortened 10-day comment period and an order by January 13, 2026. On December 23, 2025, ISO-NE filed a motion to intervene and opposed Derby's request for a shortened comment period, stating that a 10-day comment period would not provide sufficient time to prepare an answer and that ISO-NE intends to oppose the requested waiver. Comments are due on or before ***January 12, 2026***. If you have any questions concerning this matter, please contact Pat Gerity (860-275¬0533; pmgerity@daypitney.com).

- ***Order 2222*** **Conforming Changes (ER26-105)**

On December 15, 2025, the FERC accepted, effective *November 1, 2026*, as requested, conforming changes to the ISO-NE Tariff to (i) clarify participation rules for Demand Response Distributed Energy Resource Aggregations ("DR DERAs") in the Energy and Ancillary Services Markets, (ii) reduce the minimum size for Generator Assets participating in the Regulation Market consistent with *Order 2222*-compliant resources, and (iii) make other clarifying and conforming Tariff edits to facilitate participation by DERAs.[52] Unless the December 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

[51] This docket supersedes Docket No. ER26-912, opened on Dec. 30, 2025. All activity in the previous docket is included herein.

[52] *ISO New England Inc.*, Docket No. ER26-105-000 (Dec. 15, 2025) (unpublished letter order).

IV. OATT Amendments / TOAs / Coordination Agreements

- ***Order 898* Compliance Revisions (ER26-439)**

On December 23, 2025, the FERC accepted,[53] effective *December 21, 2025* as requested, the Participating Transmission Owners Administrative Committee's ("PTO AC")[54] changes to Appendix A (Transmission Formula Rate Template) and Appendix D (Depreciation/Amortization Rates) to OATT Attachment F (Annual Transmission Revenue Requirements) in response to the requirements of *Order 898* ("Accounting and Reporting Treatment of Certain Renewable Energy Assets") (conforming references in the formula rate to *Order 898*'s revisions to the electric Uniform System of Accounts and associated FERC Forms 1 and 3Q). Unless the December 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).

- **RI Energy Revision to Fixed PBOP Expense Amount (ER26-390)**

On December 23, the FERC accepted revisions to RI Energy's PBOP expense amount under Appendix A to Attachment F of the OATT to limit potential over-recoveries of PBOP expenses.[55] The revisions were accepted effective as of *January 1, 2026*, as requested. Unless the December 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).

- ***Order 676-K* Compliance Filings (ER25-2654; ER25-2657)**

On June 27, 2025, in accordance with *Order 676-K*,[56] the following *Order 676-K* compliance filings to incorporate, or seek waiver of, the WEQ Version 004 Standards were submitted:

- *Order 676-K* Compliance Filing (ISO-NE, NEPOOL, CSC: Tariff Schedule 24 and Schedule 18-Attachment Z) (ER25-2654); and
- *Order 676-K* Compliance Filing (ISO-NE, PTO AC, Schedule 20-A Service Providers: Schedules 20A-Common and 21-Common) (ER23-2657).

Comments on the compliance filings were due on or before July 17, 2025; none were filed. Calpine intervened in each proceeding. The *Order 676-K* compliance filings remain pending before the FERC. If there are questions on any of these compliance filings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements[57]

- **Schedule 20-A: NEP Cancellation of Non-Conforming Service Agreement (ER26-675)**

On December 5, 2025, New England Power Company ("NEP") filed a notice of cancellation of the non-conforming Phase I/II HVDC-TF Service Agreement between NEP and Vitol Inc. designated as Service Agreement

[53] *ISO New England Inc.*, Docket No. ER26-439-000 (Dec. 23, 2025) (unpublished letter order).

[54] The PTO AC filed on behalf of the following New England PTOs: CMP; Eversource on behalf of CL&P, NSTAR, and PSNH; FG&E; Green Mountain Power Corporation ("GMP"); Maine Electric Power Company ("MEPCO"); Rhode Island Energy ("RIE"); National Grid; New Hampshire Transmission, LLC ("NHT"); The United Illuminating Company ("UI"); Vermont Transco, LLC ("VTransco"); and Versant Power.

[55] *The Narragansett Electric Co.*, Docket No. ER26-390-000 (Dec. 23, 2025) (unpublished letter order).

[56] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-K, 190 FERC ¶ 61,116 (Feb. 19, 2025) ("*Order 676-K*").

[57] Reporting on the following Time Value Refunds Reports, which have each been pending before the FERC for more than a year and a half, has been suspended and will be continued if and when there is new activity to report: Schedule 21-VP: Versant/Jonesboro LSA

No. TSA-NEP-101 under Schedule 20A of the ISO-NE OATT. NEP stated that the Service Agreement has been replaced by a conforming service agreement (Service Agreement No. TSA-NEP-120), effective August 1, 2025. A February 4, 2026 effective date was requested. Comments on this filing were due on or before December 26, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 25-CMP: NECEC First Revised ETU IA (CMP-20-01) (ER26-670)**

On December 5, 2025, ISO-NE and CMP filed a First Revised Service Agreement No. ETUIA-ISONE/CMP-20-01 (CMP-20-01) under Schedule 25 of the ISO-NE OATT among ISO-NE, CMP, and NECEC Transmission LLC ("NECEC"). The filing will revise the Elective Transmission Upgrade Interconnection Agreement ("ETU IA") to permit the NECEC Transmission Line to enter Commercial Operation on a limited basis prior to completion of certain sub-synchronous torsional interaction related milestones, including any necessary Affected System Upgrades. A November 10, 2025 effective date was requested. Comments on this filing were due December 26, 2025; none were filed. National Grid and Eversource intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-RIE: Block Island Wind Farm Facilities Reclassification (ER26-397)**

On December 23, 2025, the FERC accepted RI Energy's adjustments to the Block Island Transmission System ("BITS") Surcharge set forth in 2 service agreements with Block Island Power Company ("BIPCO") to reflect a change in the classification of the electric facilities associated with the Block Island Wind Farm from distribution to transmission.[58] The proposed adjustments are expected to increase the BITS Surcharge, but the overall impact on customers is expected to be minimal. The BITS Surcharge adjustments were accepted effective *January 1, 2026*, as requested. Unless the December 23, 2025 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: BTM Gen & SSCDC Cost Revisions (ER26-386)**

On December 18, 2025, the FERC accepted, effective *December 31, 2025*, Green Mountain Power's ("GMP") revisions to Schedule 21-GMP intended to provide more commercially and operationally reasonable terms for generators to take local non-firm point-to-point service on GMP's system.[59] The revisions clarify that behind-the-meter ("BTM") generation is excluded from Local Network Load, which is consistent with how Regional Network Load is calculated under the ISO-NE OATT; and revise the billing methodology for Scheduling, System Control and Dispatch Costs ("SSCDC") to replace the rolling 12-month average billing methodology in Schedule 1. Unless the December 18 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-ES: Eversource Removal of Duplicative True Up of S&D Costs (ER26-321)**

On December 30, 2025, the FERC accepted Eversource's changes, as amended, to Schedule 21-ES to eliminate a duplicative true up of scheduling and dispatch costs ("S&D"), which added to the ISO-NE OATT ("Formula Rate Template") and eliminates the need for the Schedule 21-ES S&D calculation.[60] These Schedule-21 changes were accepted effective *January 1, 2026* as requested. Unless the December 30, 2025

(ER24-24); Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804); and Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035). Reporting has also been suspended and will be continued if and when there is new activity to report on the notice of cancellation of the Green Mountain Power/Hardwick NITSA under Schedule 21-GMP (ER25-298).

[58] *The Narragansett Electric Co.*, Docket No. ER26-397-000 (Dec. 23, 2025) (unpublished letter order).

[59] *Green Mountain Power Corp.*, Docket No. ER26-386-000 (Dec. 18, 2025) (unpublished letter order).

[60] *Eversource Energy Services Co.*, Docket Nos. ER26-321-000 and -001 (Dec. 30, 2025) (unpublished letter order).

order is challenged, this proceeding is concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 2022 Annual Update Settlement Agreement (ER20-2054-003)**
  Still pending is Versant's August 29, 2023 Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC.[61] 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. Although no adverse comments on the Versant 2022 Annual Update Settlement Agreement were filed, this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports[62]

No Activity to Report

IX. Membership Filings

Questions concerning any of the Membership Filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Jan 2026 Membership Filing (ER26-933)**
  On December 31, 2025, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: Balyasny Asset Management (Data-Only Participant); and Geodesic 7 LLC (Supplier Sector); and (ii) the termination of the Participant status of Anbaric Development Partners; EMI; Eoch Energy; Excelerate Energy; and Vineyard Reliability; and (iii) the name change of Six One Energy Corporation (f/k/a Tomorrow Energy Corp). Comments on this filing, if any, are due on or before ***January 21, 2025***.

- **Dec 2025 Membership Filing (ER26-617)**
  On November 26, 2025, NEPOOL requested that the FERC accept: (i) the membership in NEPOOL of The Energy Authority, Inc. ("TEA") (Supplier Sector); and (ii) the name changes of Long Island Power Authority (f/k/a Long Island Lighting Company d/b/a LIPA) and Lighthouse Naugatuck, LLC (f/k/a Naugatuck Avenue Storage LLC). Comments on this filing, if any, were due on or before December 17, 2025; none were filed. This matter is pending before the FERC.

- **Nov 2025 Membership Filing (ER26-363)**
  On December 18, 2025, the FERC accepted the membership in NEPOOL of the Mid-Coast Region Redevelopment Authority ("MRRA") (Publicly Owned Entity Sector).[63] Unless the December 18 order is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**
  Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the

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[61] Joint Offer of Settlement Regarding Versant Power, Bangor Hydro District Charges.

[62] 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.

[63] *New England Power Pool Participants Comm.*, Docket No. ER26-363-000 (Dec. 18, 2025) (unpublished letter order).

FERC noting that the following Market Participant was suspended from the New England Markets on the date indicated (at 8:30 a.m.):

Date of Suspension	*Participant Name*	*Default Type*
December 22, 2025	Actual Energy Inc.	Financial Assurance

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

X. Misc. - ERO Rules, Filings; Reliability Standards[64]

Questions concerning any of the ERO Reliability Standards or ERO-related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NERC FFT/CE Programs Annual Report (RC11-6-021)**

On September 23, 2025, NERC filed its annual report on the Find, Fix, and Track ("FFT") and Compliance Exception ("CE") programs, in accordance with prior orders.[65] Building upon NERC and FERC Staff's annual coordinated review of FFTs and CEs summarized in the last Report, NERC reported that the FFT and CE Programs continue to meet expectations. NERC added that the results of the annual joint review show continued overall improvement in program implementation and significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Comments on the Annual Report were due on or before October 8, 2025; none were filed. This matter is pending before the FERC.

- **Revised Reliability Standard: MOD-026-2 (RD26-3)**

On November 4, 2025, NERC requested FERC approval of proposed Reliability Standard MOD-026-2 (Verification and Validation of Dynamic Models and Data, and the proposed definitions of Model Validation and Model Verification). MOD-026-2 was developed in response to *Order 901*'s Milestone 3 directives on Inverter-Based Resources ("IBRs") and would replace and combine the currently effective standards MOD-026-1 and MOD-027-1 and include new requirements addressing validation of models across modeling domains including electromagnetic transient ("EMT") models of Inverter-Based Resources ("IBR"), high-voltage direct current ("HVDC") systems, flexible alternating current transmission system ("FACTS") devices, and dynamic reactive resources. MOD-026-2 is intended to advance the reliability of the Bulk-Power System by ("BPS") improving the accuracy and dependability of models used in planning and interconnection analyses through requiring Generator Owners and Transmission Owners, particularly of IBRs, to perform Model Validation and Model Verification of positive sequence dynamic and EMT models that are provided to their Transmission Planner. Under the proposed Implementation Plan, MOD-026-2 would become effective on the first day of the first calendar quarter after the effective date of the FERC order approving the standard; MOD-026-1 and MOD-027-1 would be retired immediately prior to the effective date of the revised successor standard.

Comments on the MOD-026-2 were due on or before December 8, 2025. ISO-NE, together with ERCOT, MISO, NYSIO, PJM, and SPP submitted comments (the "Joint ISO comments") supporting approval of MOD-026-2, but with the removal of Requirement R3 (to remove language exempting legacy facilities from the requirement to provide EMT models). On December 19, 2025, NERC submitted reply comments to the Joint ISO comments addressing comment's expressed concerns regarding the proposed exemption within the MOD-026-2 standard for

[64] Reporting on the following ERO Reliability Standards or related rule-making proceedings has been suspended and will be continued if and when there is new activity to report: NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2); *Order 901*: IBR Reliability Standards (RM22-12); and 2024 Reliability Standards Development Plan (RM05-17 *et al.*).

[65] *See N. Am. Elec. Rel. Corp.*, 138 FERC ¶ 61,193 (2012); *N. Am. Elec. Rel. Corp.*, 143 FERC ¶ 61,253 (2013); *N. Am. Elec. Rel. Corp.*, 148 FERC ¶ 61,214 (2014); and *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-004 (Nov. 13, 2015) (unpublished letter order).

legacy facilities requested to provide verified EMT models where the original equipment manufacturer no longer supports EMT models for those facilities. Calpine intervened doc-lessly. This matter is pending before the FERC.

- **Revised Reliability Standard: MOD-033-3 (RD26-2)**

Also on November 4, 2025, NERC requested FERC approval of proposed Reliability Standard MOD-033-3 (Steady-State and Dynamic System Model Validation). MOD-033-3 was developed in response to *Order 901*'s Milestone 3 directives on Inverter-Based Resources ("IBRs") and would replace existing Reliability Standard MOD-033-2. MOD-033-3 is intended to establish a comprehensive process for system model validation and to advance Bulk-Power System ("BPS") reliability by enhancing existing system-level model validation requirements so that planning System models must include BPS-connected IBRs and aggregated Distributed Energy Resources ("DERs") present on the System and be validated against actual system behavior. The proposed Reliability Standard applies to Planning Coordinators, Reliability Coordinators, and Transmission Operators. Under the proposed Implementation Plan, MOD-033-3 would become effective on the first day of the first calendar quarter that is the later of (i) the first day of the calendar quarter that is three months after FERC approval of MOD-033-3 and the associated NERC Glossary definitions of "Model Validation" and "Distributed Energy Resources," or (ii) January 1, 2030; MOD-033-2 would be retired immediately prior to the MOD-033-3 effective date. Comments on the MOD-033-3 filing were due on or before December 8, 2025; none were filed. Calpine intervened doc-lessly. This matter is pending before the FERC.

- **Wildfire Prevention, Detection, and Mitigation Best Practices (RD25-9)**

On September 10, 2025, the FERC directed NERC to submit in an informational filing a report on best practices to reduce the risk of wildfire ignition from the BPS on or before ***May 1, 2026***.[66] The report must assess methods such as "vegetation management, the removal of forest-hazardous fuels along transmission lines, improved engineering approaches, and safer operational practices.[67] The report must also include an assessment of known and emerging technologies that can be deployed to detect and mitigate wildfire in the context of protecting the BPS and its use to provide reliable service to customers. The FERC noted its concurrently issued notice of technical conference on wildfire mitigation (*see* AD25-16 in Section XII below) and said NERC should consider the testimony from that conference as an input for its informational filing, including in its consideration of the need for new or revised Reliability Standards or alternative further action.

- **Revised Reliability Standard: EOP-012-3 (RD25-7)**

On September 18, 2025, the FERC approved Reliability Standard EOP-012-3 (Extreme Cold Weather Preparedness and Operations)[68] and directed NERC, for a period of time,[69] to collect and submit certain information to the FERC.[70] As previously reported, EOP-012-3 is intended to improve the efficiency and

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[66] *N. Am. Elec. Rel. Corp.*, 192 FERC ¶ 61,212 (Sep. 10, 2025).

[67] *See* Exec. Order No. 14308 (Empowering Commonsense Wildfire Prevention and Response), 90 Fed. Reg. 26175 (June 12, 2025), https://www.whitehouse.gov/presidential-actions/2025/06/empowering-commonsense-wildfire-prevention-and-response/ (Executive Order 14308).

[68] *N. Am. Elec. Rel. Corp.*, 192 FERC ¶ 61,229 (Sep. 18, 2025) ("*EOP-012-3 Order*").

[69] Starting no later than ***Oct. 2026*** and ending in ***Oct. 2034*** (*EOP-012-3 Order* at P 37).

[70] The FERC directed NERC to submit: (i) for each Regional Entity, anonymized ***data on***: (a) the number of submitted Generator Cold Weather Constraint declarations, (b) the number of approved declarations, (c) the aggregate MVA of approved declarations, and (d) a summary of the rationale(s) provided for approved declarations. (*EOP-012-3 Order* at P 34); (ii) a ***narrative analysis addressing*** the following issues: (a) whether reliability coordinators, transmission operators, and balancing authorities (or other relevant entities) are timely notified of Generator Cold Weather Constraint declarations and corrective action plan extensions; (b) the reliability impact, if any, of allowing generators 36 months, rather than a shorter time period, such as 24 months, to correct known freeze related issues; and (c) whether the Generator Cold Weather Constraint declarations approval process is consistently interpreted and applied by the CEAs in a timely manner to address the reliability risks presented by extreme cold weather; whether the Generator Cold Weather Constraint declaration criteria in Attachment 1 is adequately defined and clear so that applicable entities understand what is required of them; and the reliability impact on the BPS due to Generator Cold Weather Constraint declarations from each criterion in Attachment 1, in addition to the reliability impact from approved corrective action plan extensions.

effectiveness of the BPS in future cold weather seasons by providing clarity regarding the criteria for declaring Generator Cold Weather Constraints, shortening timelines for implementing corrective action plans following cold weather reliability events, and requiring more frequent review of validated constraints to reflect evolving technologies and operating conditions. Revised EOP-012-3 also includes new requirements for BES generating units entering commercial operation on or after October 1, 2027 to have cold weather capability upon entry, unless a validated constraint applies. EOP-012-3 went into effect on *October 1, 2025*.

Requests for Clarification (-001). Requests for clarification of the *EOP-012-3 Order* were filed by each of NERC and Joint Trade Associations.[71] On December 5, 2025, the FERC granted NERC's request and granted Joint Trade Associations' request in part.[72] The FERC clarified that it will accept aggregate MW (rather than aggregate MVA) in NERC biennial informational filing, and clarified that NERC may consolidate the annual informational filings required by the EOP-012-3 and the EOP-012-3 orders into one consolidated biennial filing, which will sunset in 2034. Unless the December 5, 2025 order is challenged, this proceeding is concluded.

- **NOPR: Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization[73]) (RM24-8)**

On September 18, 2025, the FERC issued a notice of proposed rulemaking ("NOPR")[74] proposing to approve 11 modified CIP Reliability Standards,[75] and 4 new and 18 modified definitions in the NERC Glossary of Terms,[76] to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments.[77] As previously reported, the proposed CIP Reliability Standards would permit Responsible Entities with more "traditional" architecture to continue with their current configurations. In the NOPR, the FERC seek comments specifically on the proposed replacement of the phrase "where technically feasible" with the phrase "per system capability", including alternative approaches, which the FERC said would assist it in formulating a possible directive in a final rule.[78] Comments on the *Visualization NOPR* were due on or before November 24, 2025[79] and were filed by BPA, EEI, GE Vernova, MISO, NERC, and Portland General Electric. This matter is pending before the FERC.

[71] "Joint Trade Associations" are the American Public Power Association ("APPA"), Electric Power Supply Association ("EPSA"), Large Public Power Council ("LPPC"), National Rural Electric Cooperative Association ("NRECA"), and Transmission Access Policy Study Group ("TAPS").

[72] *N. Am. Elec. Rel. Corp.*, 193 FERC ¶ 61,187 (Dec. 5, 2025).

[73] Virtualization is "the process of creating virtual, as opposed to physical, versions of computer hardware to minimize the amount of physical hardware resources required to perform various functions."

[74] *Virtualization Reliability Standards*, 192 FERC ¶ 61,228 (Sep. 18, 2025) ("*Virtualization NOPR*").

[75] The revised Cyber Security Standards are: CIP-002-7 (BES Cyber System Categorization); CIP-003-10 (Security Management Controls); CIP-004-8 (Personnel & Training); CIP-005-8 (Electronic Security Perimeter(s)); CIP-006-7 (Physical Security of BES Cyber Systems); • CIP-007-7 (Systems Security Management); CIP-008-7 (Incident Reporting and Response Planning); CIP-009-7 (Recovery Plans for BES Cyber Systems); CIP-010-5 (Configuration Change Management and Vulnerability Assessments); CIP-011-4 (Information Protection); and CIP-013-3 (Supply Chain Risk Management).

[76] The new and/or revised Glossary Terms are: BES Cyber Asset ("BCA"), BES Cyber System ("BCS"), BES Cyber System Information ("BCSI"), CIP Senior Manager, Cyber Assets, Cyber Security Incident, Cyber System, Electronic Access Point ("EAP"); External Routable Connectivity ("ERC"), Electronic Security Perimeter ("ESP"), Interactive Remote Access ("IRA"), Intermediate System, Management Interface, Physical Access Control Systems ("PACS"), Physical Security Perimeter ("PSP"), Protected Cyber Asset ("PCA"), Removable Media, Reportable Cyber Security Incident, Shared Cyber Infrastructure ("SCI"), Transient Cyber Asset ("TCA"), and Virtual Cyber Asset ("VCA").

[77] The FERC also proposed to approve the associated violation risk factors, violation severity levels, implementation plans, and effective dates for the proposed Reliability Standards, as well as to approve the retirement of the currently effective version of each proposed Reliability Standard.

[78] *Virtualization NOPR* at P 3.

[79] The *Visualization NOPR* was published in the *Fed. Reg.* on Sep. 23, 2025 (Vol. 90, No. 182) pp. 45,679-45,685.

- ***Order 912*: Supply Chain Risk Management ("SCRM") Reliability Standards (RM24-4)**

On September 18, 2025, almost a year to the day the FERC issued its *SCRM Standards NOPR*, the FERC issued its final rule (*Order 912*)[80] largely adopting the NOPR's proposals, directing NERC to develop (i) new or modified Reliability Standards that address the sufficiency of responsible entities' SCRM plans related to the identification of and response to supply chain risks and (ii) modifications related to supply chain protections for protected cyber assets. Although the FERC declined to direct NERC to require responsible entities to validate data received from vendors, it nonetheless encouraged entities to voluntarily implement this security practice as appropriate.[81] *Order 912* became effective *November 24, 2025*.[82] In response to comments, the FERC directed NERC to submit the new or revised Reliability Standards within 18 months of the effective date.

- **ITCS: Strengthening Reliability Through the Energy Transformation (AD25-4)**

On November 19, 2024, NERC submitted for FERC consideration the Interregional Transfer Capability Study ("ITCS") directed by the U.S. Congress in the Fiscal Responsibility Act of 2023 ("Fiscal Responsibility Act"). NERC stated that the ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. The ITCS focuses on transfer capability in accordance with the congressional directive, while acknowledging that other processes and pending projects may help support a reliable future grid. The ITCS was not designed to be a transmission plan or blueprint. NERC stated that the ITCS demonstrates that sufficient transfer capability and resources exist at present to maintain energy adequacy under most scenarios, but when calculating current transfer capability and projected future conditions, the ITCS identifies potential energy inadequacy across several transmission planning regions in the event of extreme weather. The ITCS recommends an increase of 35 GW of transfer capability across different regions as technically prudent additions to demonstrably strengthen reliability. The ITCS also recommends region-specific enhancements to transfer capability, "because a one-size-fits all approach across the U.S. may be inefficient and ineffective."

Comments on NERC's ITCS were filed by, among others: AEU, ENGIE, Eversource, Grid United, Invenergy, National Grid, NRG, ACPA/SEIA, ACORE, APPA, EEI, EIPC, EPSA, Public Interest Organizations, Northeast States, NRECA, NASUCA, R Street, and WIRES. On March 25, 2025, NERC submitted a reply to clarify certain of the matters raised in those comments on the ITCS.

XI. Misc. - of Regional Interest

- **203 Application: Ontario Power (Eagle Creek Utilities)/Apollo Global Management (EC26-8)**

On December 23, 2025, the FERC authorized a proposed transaction pursuant to which Apollo Global Management, Inc. will indirectly acquire the ownership interests in Eagle Creek Utilities from Ontario Power Generation Inc., including Brown Bear II Hydro, Eagle Creek Madison Hydro, and Eagle Creek Renewable Energy Holdings.[83] Pursuant to the December 23 order, Applicants must file a notice within 10 days of consummation of the transaction (January 2, 2026), which as of the date of this Report has not been submitted. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Cricket Valley Energy Center (EC25-116)**

On September 19, 2025, the FERC authorized a transaction pursuant to which certain parties[84] will indirectly acquire voting interest of 10% or more in Cricket Valley Energy Center ("CVEC") and the right to appoint

[80] *Supply Chain Risk Mgmt. Reliability Standards Revisions*, Order No. 912, 192 FERC ¶ 61,230 (Sep. 18, 2025) ("*Order 912*").

[81] *Id.* at P 2.

[82] *Order 912* was published in the *Fed. Reg.* on Sep. 23, 2025, 2025 (Vol. 90, No. 182) pp. 45,661-45,671.

[83] *Apollo Global Management, Inc. et al.*, 193 FERC ¶ 62,192 (Dec. 23, 2025).

[84] Kiwoom US, PE-US Jiminy OFLEX Blocker, LLC and PE-US Jiminy Aggregator, L.P., Cricket Valley Funding, and Cricket Valley Energy Holdings II LLC ("Applicants").

one or more non-independent directors or managers to the board of one of CVEC or its upstream owners.[85] On December 12, 2025, CVEC notified the FERC that the transaction was consummated on *December 2, 2025*. Accordingly, CVEC is now a Related Person to Bridgewater Power and Burgess BioPower (each in the Generation Group Seat). Reporting on this matter is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: CPower/NRG (EC25-102)**

On November 14, 2025, the FERC authorized a proposed transaction pursuant to which, as specifically relevant to New England, NRG[86] will indirectly acquire the membership interests in Enerwise Global Technologies, LLC d/b/a CPower ("CPower"), making NRG and CPower Related Persons.[87] Pursuant to the *NRG/CPower Order*, NRG 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: Burgess BioPower/White Mountain Power (EC25-99)**

On August 13, 2025, the FERC authorized a transaction by which White Mountain Power (an affiliate of, among others, Bridgewater Power and David Energy Supply) will acquire from Burgess BioPower all of the indirect ownership interests of Berlin Station in connection with a plan of reorganization under Chapter 11 of the US Bankruptcy Code.[88] Pursuant to the August 13 order, White Mountain Power 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: Constellation/Calpine (EC25-43)**

On July 23, 2025, the FERC conditionally authorized[89] Constellation's acquisition of Calpine, subject to Applicants' commitments to divest certain generation facilities ("Mitigation Plan"), to extend certain pre-existing commitments that apply to the Constellation Applicants and their public utility subsidiaries in PJM market to all Applicants in the PJM market, to abide by the terms of an agreement reached between Constellation and the PJM IMM, and to implement interim mitigation ("Interim Behavioral Mitigation") until the Mitigation Plan is completed. Pursuant to the July 23 order, Applicants must file a notice within 10 days of consummation of the transaction. The transaction was consummated on January 6, 2026, making Constellation and Calpine Related Persons.

On August 22, 2025, two requests for rehearing of the *Merger Order* were filed, one by the Pennsylvania Office of Consumer Advocate ("PA OCA"); the other by the Public Citizen Petitioners.[90] The Constellation Applicants filed an answer on September 8, 2025, requesting the FERC deny the requests for rehearing. On September 22, 2025, the FERC issued an *Allegheny* Notice,[91] noting that the requests for rehearing may be

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[85] *Cricket Valley Energy Center, LLC*, 192 FERC ¶ 62,181 (Sep. 19, 2025).

[86] For purposes of the Report, "NRG" is NRG East Generation Holdings LLC ("NRG East Holdings"), NRG Demand Response Holdings LLC ("NRG DR Holdings"), and Lightning Power, LLC ("Lightning Power").

[87] *NRG East Generation Holdings, LLC et al.*, 193 FERC ¶ 61,124 (Nov. 14, 2025) ("*NRG/CPower Order*").

[88] *Burgess BioPower, LLC and White Mountain Power, LLC*, 192 FERC ¶ 62,085 (Aug. 13, 2025).

[89] *Constellation Energy Corp. et al.*, 192 FERC ¶ 61,074 (July 23, 2025) ("*Merger Order*").

[90] "Public Citizen Petitioners" are: Public Citizen, PennFuture, Clean Air Council, and Citizens Utility Board.

[91] 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) (*en banc*)) 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 a Federal 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.

deemed denied by operation of law, but noting that the requests will be addressed in a future order.[92] On November 21, 2025, the PA OCA petitioned the DC Circuit Court for review of the *Merger Order* and the *Constellation Merger Order Allegheny Notice*. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **EMM Contract 2026-2028 (ER26-777)**

On December 15, 2025, ISO-NE filed the contract for external market monitor ("EMM") services with Potomac Economics, Ltd. for the 2026-2028 term. ISO-NE stated that the contract largely replicates the current contract and extends the existing EMM contract term while updating rates and making clarifying edits. Comments on this filing were due on or before January 5, 2026; none were filed. NEPOOL, Calpine, National Grid, and Public Citizen intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Joan Bosma (jbosma@daypitney.com; 617-345-4651.

- **LGIA Termination: Eversource-Vineyard Wind I (ER26-767)**

On December 15, 2025,[93] ISO-NE, on behalf of Eversource, filed a termination for the First Revised LGIA (Service Agreement No. LGIA-ISONE/NSTAR-20-01) governing the interconnection of Vineyard Wind 1, LLC's proposed Large Generating Facility. ISO-NE stated that the First Revised LGIA has been superseded by a conforming three-party LGIA that will be reported in the Electric Quarterly Report. An effective date of December 5, 2025 was requested. Comments were due on or before January 5, 2026; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Joan Bosma (jbosma@daypitney.com; 617-345-4651.

- **Wholesale Distribution Tariff (II) – Versant Power (ER26-528)**

On November 17, 2025, Versant Power filed a revised Wholesale Distribution Tariff ("WDT") for Electric Energy Delivery to Energy Storage Systems ("ESS") for its Bangor Hydro District responding to concerns identified by the FERC in its order rejecting Versant's earlier proposed WDT in Docket No. ER25-2500.[94] The revised WDT eliminates transmission service charges and is intended to clarify the terms for ESS taking wholesale distribution service over Versant's facilities and to address the FERC's directives regarding consistency with ISO-NE's Tariff and *Order 841*. An effective date of January 17, 2026 was requested. Comments were due on or before December 8, 2025; 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-K* Compliance Changes Versant Power (ER25-2566)**

On June 23, 2025, Versant filed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT"), which incorporate by reference certain of the revisions required by *Order No. 676-K*. Versant also requested waiver of certain of the standards that Maine Public District ("MPD") is unable to meet. Versant requested effective dates of February 27, 2026 and August 27, 2026. Comments on Versant's *Order 676-K* changes were due on or before July 14, 2025; none were filed. Versant's *Order 676-K* Compliance Changes remain 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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[92] *Constellation Energy Corp. et al.*, 192 FERC ¶ 61,183 (Sep. 22, 2025) ("*Constellation Merger Order Allegheny Notice*").

[93] On Dec. 12, 2025, ISO-NE withdrew the Dec. 10 filing in ER26-720 and re-filed the notice of termination through eTariff in docket number ER26-767, after being notified by the FERC that the notice of termination must be submitted through eTariff.

[94] *Versant Power*, 193 FERC ¶ 61,044 (October 17, 2025) (taking issue with proposed rate schedule because it may result in transmission service charges being assessed at times on energy storage facilities).

- **Versant MPD OATT *Order 904* Compliance Filing (ER25-1393)**

On December 8, 2025, the FERC accepted Versant's compliance filing, filed in response to *Order 904*,[95] proposing revisions to the MPD OATT. The Compliance filing was accepted effective *May 26, 2025*, as requested. Versant's compliance filing: (i) revises Schedule 2 to exclude charges for reactive power within the standard power range; (ii) removes related payment provisions from the *pro forma* LGIA and SGIA; and (iii) removes Note 1 from Exhibit 1a in Attachment J. Unless the December 8 order is challenged, this matter will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CMP ESF Rate (ER24-1177)**

On August 4, 2025, the FERC approved the settlement agreement that resolves all issues set for settlement in this proceeding,[96] effective August 4, 2025.[97] CMP was directed to make a compliance filing with revised tariff records in eTariff format on or before September 3, 2025, reflecting that effective date and the FERC's action in the Settlement Order. CMP submitted that compliance filing on September 3, 2025, with any comments due on or before September 24, 2025; none were filed. On September 15, 2025, CMP submitted a refund report confirming the $365,000 was refunded to Rumford ESS, LLC. Comments on the refund report were due on or before October 6; 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).

XII. Misc. - Administrative & Rulemaking Proceedings[98]

- **Technical Conf: Wildfire Risk Mitigation (AD25-16)**

On October 21, 2025, the FERC convened a Staff-led technical conference (right after the tech conf in AD25-8 discussed below) to discuss cost-effective best practices to reduce the risk of wildfire ignition from the Bulk Power System ("BPS") in response to Executive Order 14308. There were two panel discussions – (i) interagency coordination challenges and grid-focused best practices for wildfires (Panel 1); and (ii) leveraging technology to monitor, evaluate, and mitigate wildfire risks (Panel 2). Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. On October 23, 2025, the FERC invited post-technical conference comments to address issues raised during the technical conference or identified in the October 15, 2025 Second Supplemental Notice. Those comments were due on or before November 24, 2025; National Rural Electric Cooperative Association ("NRECA"), Working for Advanced Transmission Technologies Coalition ("WATT Coalition"), and several others provided comments to inform the FERC's wildfire risk mitigation efforts. On December 1, 2025, the technical conference's transcript was posted in the FERC's eLibrary.

- **Annual Reliability Technical Conference (AD25-8)**

The FERC also convened on October 21, 2025 its annual Commissioner-led Reliability Technical Conference to discuss policy issues related to the reliability and security of the BPS. The following two topics were discussed: (i) leadership perspectives on the state of the BPS and priorities (Panel 1); and ensuring reliability with large loads (Panel 2). Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. Post-technical conference comments addressing issues raised during the

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[95] *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) ("*Order 904*").

[96] *See Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate Order*") (accepting, subject to refund and settlement judge procedures, CMP's rate schedule for distribution services for electric storage facilities ("ESFs") seeking to participate in the ISO-NE Market ("ESF Rate")).

[97] *Central Maine Power Co.,* 192 FERC ¶ 61,110 (Aug. 4, 2025) ("*CMP ESF Rate Settlement Order*").

[98] Reporting on the following administrative and rulemaking proceedings has been suspended and will be continued if and when there is new activity to report: Large Loads Co-Located at Generating Facilities (AD24-11); Annual Reliability Tech. Conf. (AD24-10); Innovations and Efficiencies in Generator Interconnection (AD24-9); and the EQR Filing Process and Data Collection NOPR (RM23-9).

technical conference or identified in the October 15, 2025 Third Supplemental Notice for this technical conference were due on or before November 24, 2025 and were filed by Constellation and by Digital Power Network.

- **Tech Conf: Meeting the Challenge of Resource Adequacy in ISO/RTOs (AD25-7)**

On June 4-5, 2025, the FERC convened a Commissioner-led technical conference to discuss generic issues related to resource adequacy constructs, including the roles of capacity markets in ISO/RTO regions that utilize them and alternative constructs in regions without capacity markets. The conference explored current and impending risks to resource adequacy, including increasing load forecasts and potential resource shortfalls; the effectiveness of capacity markets in ensuring resource adequacy at just and reasonable rates; comparisons between capacity markets and alternative constructs; and the roles and interests of states and other entities with legal authority over resource adequacy. A June 5 panel that addressed Resource Adequacy Challenges in the Northeast RTOs/ISOs included Emilie Nelson (NYISO, Executive Vice President and Chief Operating Officer), Stephen George (ISO-NE, Vice President of System Operations and Market Administration), Adam Evans (NY DPS, Chief of Wholesale and Clean Energy Markets), MPUC Chairman Phil Bartlett, CT DEEP Commissioner Katie Dykes, Michelle Gardner (NextEra Energy Resources, Executive Director Northeast Region), Pallas Lee VanShaick (Potomac Economics), and Sarah Bresolin (NEPOOL Chair).

Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. On June 5, 2025, the FERC invited post-technical conference comments to be filed on or before July 7, 2025. Post-technical conference comments were filed by over 60 parties, including the following: Acadia Center, Dominion, LS Power, National Grid, NEPGA, NESCOE, Shell, ACPA, AMP, APPA, Concentric, EEI, EPSA, FRS, LPPC, NRECA, TAPS, UCS, and Public Citizen.

- **Joint Federal-State Current Issues Collaborative[99] (AD24-7)**

Next Meeting Feb 2026. The next meeting of the Collaborative (previously scheduled for November 12 in Seattle, Washington) has been moved to ***February 2026*** during NARUC's Winter Policy Summit in Washington, DC.

Notice of 2025/26 State Commission Representatives. In accordance with the *Appointment Procedure Order*,[100] the FERC gave notice on September 22, 2025 of NARUC's appointment of the state commission representatives to the Collaborative for the August 28, 2025 through August 27, 2026 term. The NECPUC representatives will again be MPUC Chairman Phil Bartlett and NH PUC Commissioner Pradip Chattopadhyay.[101]

[99] *Joint Federal-State Task Force on Elec. Transmission and Federal and State Current Issues Collaborative*, 186 FERC ¶ 61,189 (Mar. 21, 2024) ("*Order Establishing Collaborative*"). The Collaborative will provide a venue for federal and state regulators to share perspectives, increase understanding, and, where appropriate, identify potential challenges and coordination on matters that impact specific state and federal regulatory jurisdiction, including (but not limited to) the following: electric reliability and resource adequacy; natural gas-electric coordination; wholesale and retail markets; new technologies and innovations; and infrastructure. The Collaborative will be comprised of all FERC Commissioners as well as representatives from 10 state commissions, who will be nominated for and serve one-year terms from the date of appointment by the FERC. The FERC will issue notices announcing the time, place and agenda for each meeting of the Collaborative, after consulting with members of the Collaborative and considering suggestions from state commissions. Collaborative meetings will be on the record, and open to the public for listening and observing. The Collaborative will expire 3 years after its first public meeting but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

[100] *Federal and State Current Issues Collaborative*, 192 FERC ¶ 61,056, at P 3 (July 17, 2025) ("*Appointment Procedure Order*") (explaining that NARUC will fill state commissioner vacancies on the Collaborative without formal FERC appointment and that the FERC will issue periodic notices listing new members).

[101] The remaining representatives are: from the Mid-Atlantic Conf. of Regulatory Utils. Comm'rs ("MACRUC") Comm'r Kelsey Bagot, VA State Corp. Comm'n and Comm'r Kathryn Zerfuss, PA PUC; from the Mid-America Regulatory Conf. Chair Sarah Martz, IA Utils. Comm'n and Comm'r Stacey Paradis, IL Commerce Comm'n; from the Southeastern Assoc. of Regulatory Util. Comm'rs Comm'r Karen Kemerait, NC Utils. Comm'n and Comm'r Gabriella Passidomo Smith, FL Pub. Srvc. Comm'n; and from the Western Conf. of Pub. Srvc. Comm'rs Vice Chair Nick Myers, AZ Corp. Comm'n and Chair Brian Rybarik, WA Utilities and Transportation Comm'n.

- **ANOPR: Interconnection of Large Loads to the Interstate Transmission System (RM26-4)**

On October 27, 2025, the FERC issued a Notice inviting comments on a Department of Energy ("DOE") proposed Advance Notice of Proposed Rulemaking ("ANOPR")[102] concerning standardized procedures for the timely and orderly interconnection of large loads to the interstate transmission system.[103] The ANOPR requests FERC take expeditious action and propose a framework under which "large loads" (defined as >20 MW) interconnecting directly to transmission (including AI data centers) would be studied and processed using LGIP/LGIA-style deposits, readiness requirements, and withdrawal penalties. Comments were due on or before November 14, 2025 and reply comments were due on or before November 28, 2025. U.S. Senator Edward J. Markey together with several other senators filed comments requesting FERC proactively investigate RTOs' treatment of AI data centers and prioritize protection of residential ratepayers. The MA AG, MOPA, NH OCA, Brookfield, LS Power Development, Enel North America, Enerwise Global, Vitol, and Voltus intervened doc-lessly. The FERC granted, the November 4 request for a 2-week extension of time, to November 28, 2025, to file initial comments filed by Organization of MISO States ("OMS") and supported by the Organization of PJM States ("OPSI") on November 5, 2025. On November 21, comments were filed by over 100 parties including by ISO-NE, New England Public Systems,[104] the New England Consumer-Owned Systems ("NECOS")[105] jointly with Energy New England, LLC ("ENE"), Advanced Energy United ("AEU"), Maine Office of the Public Advocate ("MOPA"), MA AG with RI DPUC and CT DEEP, NESCOE, NEPGA, American Public Power Association ("APPA"), American Clean Power Association ("ACPA"), Union of Concerned Scientists, Eversource, Constellation, National Grid, Vistra, Energy New England, ENGIE, Shell, NRG, LS Power Development, Invenergy, Voltus, Google, Microsoft, Meta Platforms, Amazon Energy, PSEG Companies,[106] and the PPL Companies.[107] Since the last report, reply comments were filed by PJM, Vistra, and ENGIE among many others. NEPOOL Counsel's memo to the Transmission Committee summarizing comments filed in this proceeding is available here.

- ***Order 914*: Implementation of EO 14270 (RM25-14)**

On October 1, 2025, the FERC issued a direct final rule (*Order 914*)[108] and a related NOPR, in response to Executive Order 14270 ("Zero-Based Regulatory Budgeting to Unleash American Energy") (*see* Executive Orders Section above),[109] to sunset 53 regulations identified as outdated or unnecessary. *Order 914* establishes a one-year sunset from its *December 5, 2025* effective date,[110] after which the regulations will be removed from the Code of Federal Regulations and the FERC will no longer treat them as effective, unless adverse comments are

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[102] *Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking (Oct. 23, 2025). The FERC Notice and DOE letter accompanying the ANOPR noted that the ANOPR was issued pursuant to the Secretary of Energy's authority in section 403 of the Department of Energy Organization Act.

[103] The full text of the October 23, 2025 ANOPR is available here: https://www.energy.gov/sites/default/files/2025-10/403%20Large%20Loads%20Letter.pdf.

[104] New England Public Systems consists of: Connecticut Municipal Electric Energy Cooperative ("CMEEC"), the Massachusetts Municipal Wholesale Electric Company ("MMWEC"), and the Vermont Public Power Supply Authority ("VPPSA").

[105] NECOS are: Belmont Mun. Light Dept, Block Island Utility District, Braintree Elec. Light Dept, Concord Mun. Light Plant, Danvers Elec. Division, Georgetown Mun. Light Dept, Groveland Elec. Light Dept, Hingham Mun. Lighting Plant, Hudson Light & Power Dept, Littleton Elec. Light & Water Dept, Merrimac Mun. Light Dept, Middleborough Gas & Elec. Dept, Middleton Elec. Light Dept, North Attleborough Elec. Dept, Norwood Mun. Light Dept, Clear River Elec. & Water District, Rowley Mun. Lighting Plant, Stowe Elec. Dept, Taunton Mun. Lighting Plant, Town of Wallingford, CT Dept of Public Utilities Elec. Division, Westfield Gas and Elec. Light Dept, and Mid-Coast Regional Redevelopment Authority.

[106] PSEG Companies are: Public Service and Gas Company ("PSE&G"), PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[107] PPL Companies are: PPL Electric Utilities Corp. ("PPL Electric"), Louisville Gas & Electric Co. ("LG&E") and Kentucky Utilities ("KU") (collectively, "LG&E/KU"), and The Narragansett Electric Company d/b/a Rhode Island Energy ("RIE").

[108] *Implementation of the Executive Order Entitled "Zero-Based Budgeting to Unleash American Energy"*, Order No. 914, 193 FERC ¶ 61,002 (Oct. 1, 2025) ("*Order 914*"); Errata Notice correcting regulatory text section, Oct. 21, 2025.

[109] EO 14270, Zero-Based Regulatory Budgeting to Unleash American Energy (Apr. 9, 2025).

[110] *Order 914* was published in the *Fed. Reg.* on Oct. 21, 2025 (Vol. 90, No. 201) pp. 48,397-48,408.

received by November 20, 2025. If "significant adverse comments"[111] are filed, the FERC will publish a document that withdraws any such part of this action and will address the comments received in a subsequent final rule as a response to the companion NOPR (RM25-14) or take other action as it may deem appropriate. Comments were filed by the American Conservative Union Foundation's Center for Regulatory Freedom (d/b/a Conservative Political Action Coalition Foundation), Our Children's Trust, Joint Comments of the American Gas Association and the American Public Gas Association, and two individuals.[112]

- **ANOPR: Implementation of Dynamic Line Ratings (RM24-6)**

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[113] seeking comments on both the need for a dynamic line ratings ("DLRs")[114] requirement and proposed framework of DLR reforms to improve the accuracy of transmission line ratings. Proposed reforms would require transmission providers to implement, on all transmission lines, DLRs that reflect solar heating, based on the sun's position and forecastable cloud cover, and on certain transmission lines, DLRs that reflect forecasts of wind speed and wind direction. The FERC seeks comments about whether to reflect hourly solar conditions and wind conditions in all transmission line ratings, how transmission congestion levels and environmental factors could identify locations of transmission lines that would most benefit from DLR, and what other technical details of transmission line ratings reflect wind conditions. A more detailed summary of the ANOPR was provided to and reviewed with the Transmission Committee. Comments in response to the ANOPR were due October 15, 2024[115] and were filed by nearly 70 parties, including by the following New England parties: ISO-NE, AEU, Avangrid, Dominion, Eversource, MA AG, National Grid, NESCOE, NextEra (on October 22), EEI, EPSA, NASUCA, NERC, PIOs, Public Power,[116] TAPS, and R Street Institute. Nine sets of reply comments were filed, including from: ISO-NE, DC Energy, and the US DOE.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Green Mountain Stipulation and Consent Agreement (IN25-15)**

On January 6, 2026, the FERC approved a Stipulation and Consent Agreement with Green Mountain Power Corporation ("GMP") to resolve OE's investigation of whether GMP violated the ISO-NE Tariff and/or the FERC's Market Behavior Rules by failing to properly report outages at the Bolton Falls Dam project during the period September 27, 2022 through December 27, 2024. Under the Agreement, GMP stipulated to the facts and admitted the violations. GMP agreed to ***disgorge $94,833.26*** plus interest to ISO-NE, pay a ***$32,500 civil penalty*** to the United States Treasury, submit annual compliance monitoring reports for two years (with a possible third year at OE's discretion), and conduct annual compliance training for three years. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[111] *See Order 914* at P 3 for the definition of "significant adverse comment."

[112] These individuals are "J vd Veen" and "Charlotte Lorthioir."

[113] *Implementation of Dynamic Line Ratings*, 187 FERC ¶ 61,201 (Jun. 27, 2024) ("*DLR ANOPR*"). The ANOPR reflects public comments in response to the FERC's February 17, 2022, Notice of Inquiry ("NOI") on DLRs. The NOI, in turn, found its roots in *Order 881*, which required transmission line ratings to reflect ambient air temperatures to improve efficiency in operating transmission lines.

[114] DLRs, are transmission line ratings that reflect up-to-date forecasts of weather conditions, such as ambient air temperature, wind, cloud cover, solar heating, and precipitation, in addition to transmission line conditions such as tension or sag.

[115] The *ANOPR* was published in the *Fed. Reg.* on July 15, 2024 (Vol. 89, No. 135) pp. 57,690-57,716.

[116] "Public Power" is: The National Rural Elec. Coop. Assoc. ("NRECA"), the American Public Power Assoc. ("APPA"), and the Large Public Power Council ("LPPC").

- **American Efficient Show Cause Order (IN24-2)**

As previously reported, the FERC issued on December 16, 2024 a show cause order[117] in which it directed American Efficient, LLC, its various subsidiary companies,[118] and its corporate parents[119] (collectively, "American Efficient") to show cause why they should not be found to have violated (i) Section 222 of the FPA and § 1c.2 of the FERC's regulations through a manipulative scheme and course of business in PJM and MISO that extracted millions of dollars in capacity payments for a purported energy efficiency project that did not actually cause reductions in energy use;[120] and (ii) provisions of MISO's and PJM's Tariffs for failure to satisfy the tariff requirements for participation as an Energy Efficiency Resource ("EER").[121] American Efficient was also directed to show cause why they should not (i) ***disgorge $2,116,057 and $250,937,821***, back to MISO and PJM, respectively (in each case plus interest); (ii) ***disgorge additional unjust profits*** received between April 2024 and the date of any future FERC order directing disgorgement back to PJM; and (iii) pay a ***$722 million*** civil penalty. American Efficient may seek a modification of these amounts consistent with FPA § 31(d)(4).[122]

On March 17, 2025, American Efficient answered the show cause order explaining that American Efficient did not violate a tariff or commit fraud, requesting the FERC dismiss the proceeding and close its investigation without further action. OE replied to American Efficient's answer on April 15, 2025 and American Efficient subsequently responded to OE's April 15 reply, supplemented its answer with financial information, and provided updates on some related federal court developments, each of which it asserted weigh against rushing if not issuing a penalty order. On July 10, 2025, American Efficient filed another letter supporting its position that this "proceeding should be terminated without further action."

On November 3, 2025, American Efficient requested that the FERC conclude its Order to Show Cause proceeding by declining the Office of Enforcement and Regulatory Accounting's ("OERA") request for an Order Assessing Penalties and closing out this investigation. FERC's OERA Litigation Staff replied to the November 3 motion on November 24, 2025. Since the last Report, American Efficient requested that the FERC terminate this proceeding. This matter remains pending before the Commission. 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

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117 *American Efficient, LLC et al.,* 189 FERC ¶ 61,196 (Dec. 16, 2024) ("*American Efficient Show Cause Order*").

118 Affirmed Energy LLC, Wylan Energy L.L.C., Midcontinent Energy LLC, and Maple Energy LLC.

119 Modern Energy Group LLC and MIH LLC.

120 OE concludes that "[w]hat American Efficient passes off as energy efficiency in its capacity supply offers really is just market research. It buys sales data of energy efficient products from large retailers like The Home Depot, Lowes, and Costco and then figures out how many MWs of electricity would be saved if end-use customers installed those products and used them in accordance with predictive models. It then bids those energy savings into the capacity markets as if it caused the savings. But American Efficient does not cause the energy savings."

121 OE's Report notes that American Efficient initially cleared 10.6 MWs (worth $518,000) in an ISO-NE Forward Capacity Auction. When American Efficient sought to expand its Program in ISO-NE from 10.6 MWs to 189 MWs, "ISO-NE and its IMM sent a series of emails and letters critiquing the Program and then disqualified the Company from expanded participation in the FCA. In one of those letters, ISO-NE explained that it never would have qualified any of American Efficient's capacity if it had understood the true nature of the Program from the beginning." Similar disqualification occurred in MISO. American Efficient expressly kept information about those disqualifications from PJM and expanded the Program in PJM. No disgorgement with respect to American Efficient's New England activity is contemplated.

122 Under Section 31(d)(4) of the FPA, 16 U.S.C. § 823b(d)(4), the Commission may "compromise, modify, or remit, with or without conditions, any civil penalty which may be imposed . . . at any time prior to a final decision by the court of appeals . . . or by the district court."

be the presiding judge for hearings in this matter,[123] 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 FERC issued an Order on Presiding Officer Reassignment,[124] 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.

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

On December 16, 2021, the FERC issued a show cause order[125] 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,[126] 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;[127] (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 ***$40 million*** in civil penalties.

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, 2022, 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.[128] This matter is pending before the FERC.

[123] 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.

[124] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 183 FERC ¶ 61,190 (June 14, 2023) ("*June 14 Order*").

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

[126] *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*").

[127] 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.

[128] *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.

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

- ***Order 915*: Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing (RM25-9)**

On October 7, 2025, the FERC issued its final rule removing from its regulations a rule that precludes the issuance of authorizations to proceed with construction activities with respect to natural gas facilities approved pursuant to section 3 or section 7 of the NGA for a limited time while certain requests for rehearing are pending before the FERC.[129] On November 6, 2025, NRDC requested rehearing of *Order 915*. On December 8, 2025, the FERC issued an *Allegheny* Notice, noting that the request for rehearing may be deemed denied by operation of law, but noting that the request will be addressed in a future order.[130]

New England Pipeline Proceedings

The following New England pipeline projects are currently under construction or before the FERC:

- **Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)**
  - Project to relocate and rebuild the Sagamore and Bourne meter and regulation ("M&R") stations to continue providing uninterrupted natural gas transportation service to National Grid to supply end users on both sides of the Cape Cod Canal. The proposed Project will not result in new or incremental capacity and is therefore not an expansion of the Algonquin system.
  - Abbreviated Application for a Certificate of Public Convenience and Necessity ("CPCN") and for Related Authorizations and Order Approving Abandonment ("Application") filed September 29, 2025. Application includes authorizations to (i) construct, install, own, operate, and maintain approximately 5.24 miles of pipeline; (ii) abandon by removal approximately 0.75 miles of existing pipeline; (iii) abandon by removal 2 existing M&R stations; and (iv) construct, install, own, operate, and maintain 4 new M&R stations.
  - Algonquin submits supplemental information to its Application on October 30, 2025.
  - Interventions filed by NSTAR Electric, NSTAR Gas, National Grid Gas Delivery Companies, and New York State Gas & Electric and Maine Natural Gas Co. Comments filed by a number of Chambers of Commerce on the Cape.
  - FERC issues data request on November 13, 2025 and Algonquin submits response on November 20, 2025
  - FERC issues data request on December 11, 2025 and Algonquin submits response on January 6, 2026
- **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 now requested for ***March 25, 2027***.
  - 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.[131] The certificate was conditioned on: (i) Iroquois' completion of construction

[129] *Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing*, Order No. 915, 193 FERC ¶ 61,014 (Oct. 7, 2025) ("*Order 915*").

[130] *Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing*, 193 FERC ¶ 62,148 (Dec. 8, 2025) ("*Order 915 Allegheny Notice*").

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

of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- On October 28, 2024, Iroquois requested an extension of time, until ***March 25, 2027***, to construct and place into service its Enhancement by Compression Project (Project) located in Greene and Dutchess Counties, New York and Fairfield and New Haven Counties, Connecticut as authorized in the *Iroquois Certificate Order*. (The *Iroquois Certificate Order* required Iroquois to complete construction of the Project and make it available for service within three years of the date of the Order or by March 25, 2025.) Iroquois stated that construction of the Project has been delayed due to pending state permit approvals, specifically air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois asserts that it has been working in good faith with these agencies and expects to receive approvals for the Project in the near future.
- Comments on Iroquois' request were due on or before November 15, 2024. Protests and comments were filed by the Sierra Club of Connecticut, Save the Sound, and nearly 20 individual citizens. A number of others requested an extension of time to comment, but those requests have not been (nor should be expected to be) acted on by the FERC.[132]
- On February 19, 2025, the FERC granted the requested two-year extension of time, to March 25, 2027, to construct the project and place it into service.[133] The FERC found that Iroquois has worked and continues to work toward obtaining the state permits necessary to enable construction to commence, no bad faith or delay on Iroquois's behalf, and therefore good cause to grant the two-year extension of time to complete construction of the project.[134]

XV. State Proceedings & Federal Legislative Proceedings

No Activity 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

[132] The FERC will aim to issue an order acting on the request within 45 days. The FERC will address all arguments relating to whether the applicant has demonstrated there is good cause to grant the extension. The FERC will not consider arguments that re-litigate the issuance of the certificate order, including whether the Commission properly found the project to be in the public convenience and necessity and whether the Commission's environmental analysis for the certificate complied with NEPA.

[133] *Iroquois Gas Transmission System, L.P.*, 190 FERC ¶ 61,112 (Feb. 19, 2025).

[134] *Id*. at P 15.

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 904*: Compensation for Reactive Power Within the Standard Power Factor Range (5th Circuit – 25-60055 et al.) (consolidated)**
  Case Title: Leeward *v. FERC*
  Underlying FERC Proceeding: RM22-22[135]
  Status: Briefing underway

Appeals of *Order 904* have been transferred to and consolidated in the 5th Circuit Court of Appeals, with 25-60055 as the lead docket. A briefing schedule was established on November 18, 2025 following the filing of a certified list in lieu of the administrative record, triggering the following specific dates for the approved briefing schedule: (Procedural Motions (December 2, 2025); Petitioners' Briefs (February 19, 2026); FERC's Brief (April 17, 2026); Response Brief Intervenors in Support of FERC (May 1, 2026); Petitioners' Reply Briefs (June 1, 2026); Deferred Joint Appendix (June 8, 2026); and Final Briefs (June 15, 2026)).

- ***Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)**
  Case Title: *Appalachian Voices v. FERC*
  Underlying FERC Proceeding: RM21-17[136]
  Status: Briefing Underway

As previously reported, on July 18, 2024, AEU/ACPA/SEIA and Invenergy petitioned the DC Circuit Court of Appeals for review of the FERC's *Order 1920*.[137] Petitions were also filed in the First, Second, Fourth, Fifth, Sixth, Seventh, Ninth, and Eleventh Circuits. The Judicial Panel on Multidistrict Litigation randomly selected the Fourth Circuit as the Circuit in which to consolidate the petitions for review. The DC Circuit ordered that its cases be transferred to the 4th Circuit. The 4th Circuit lead case no. is 24-1650. On August 26, 2024, the 4th Circuit granted the FERC's motion to hold the petitions for review in abeyance. On September 10, 2025, Appalachian Voice et al submitted their opening brief. The Organization of PJM States (OPSI) filed and was granted its motion to file an amicus curiae brief, due ***February 4, 2026***. Since the last report, the Commonwealth of Massachusetts and the Institute for Policy Integrity filed and were granted their motions to file an amicus curiae brief, also due by ***February 4, 2026***. FERC's opening brief was filed on January 5, 2026. Petitioners reply briefs will be due ***February 25, 2026***; the Joint Appendix must be filed by ***March 4, 2026***; and final briefs by ***March 11, 2026***.

- ***Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)**
  Case Title: *Advanced Energy United, et al. v. FERC*
  Underlying FERC Proceeding: RM22-14[138]
  Status: Oral Argument Held September 26, 2025; Decision Pending

Several Petitioners have challenged *Orders 2023 and 2023-A*. Those challenges were consolidated, with the AEU docket (23-1282) as the lead docket. Briefing is now complete. Oral argument was held ***September 26, 2025*** before a merits panel comprised of Judges Millett, Walker, and Childs. This matter remains pending before the Court.

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[135] *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (Oct. 17, 2024).

[136] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*"); *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[137] Petitioners for review of *Order 1920* have also been filed in the 1st, 4th, 5th, and 9th Circuits.

[138] *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).

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Case Title: *Sierra Club, et al. v. FERC*
  Underlying FERC Proceeding: ER18-619[139]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Mar 2, 2026

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance now four times. In the most recent request (filed March 1, 2024) (fourth abeyance request), Petitioners asked the Court to hold this matter in abeyance until March 1, 2026 "in light of the continued delay of the revisions to its capacity market that ISO New England previously asserted were a predicate to eliminating the market impediment that is the subject of the underlying claims before the Court". The Court granted the request on May 12, 2024, ordering the parties to file motions to govern future proceedings by ***March 2, 2026***.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Case Title: *Central Maine Power Company, et al. v. FERC*
  Underlying FERC Proceeding: ER15-414[140]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[141] 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*[142] 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 reports at 120-day intervals. The parties were directed to file motions to govern

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

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

[141] 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.

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

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 FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on November 13, 2025.

- ***Avangrid/NextEra NECEC Civil Suit* (D.MA) (Civil Action No. 24-30141-MGM)**
  Case Title: *Avangrid, Inc. et al. v. NextEra Energy, Inc. et al.*
  Status: Federal Anti-Trust Claims Dismissed; State Law Claims Remain Pending

On November 12, 2024, Avangrid sued NextEra in US District Court for the District of Massachusetts ("D.MA") claiming NextEra's illegal use political and regulatory channels to delay or prevent Avangrid from obtaining the approvals needed to construct the NECEC project resulted in damages in excess of $350 million. Specifically, Avangrid alleged NextEra violations of US (Sherman Act) and MA Anti-Trust laws (alleging actual, attempted, and conspiracy to monopolize the markets) (the "Anti-Trust Claims"), as well as state law violations related to NextEra's: (i) conspiracy with others (to perpetuate an attack campaign based on false and misleading claims against NECEC using dark money in violation of campaign finance law, and to intervene without basis in NECEC's permitting process for unlawful purpose), (ii) intentional interference with CMP contracts, (iii) unjust enrichment; and (iv) unfair business practices (together the "State Law Claims").

On September 22, 2025, the presiding US District Judge, Mark Mastroianni, dismissed Avangrid's Antitrust Claims, noting that NextEra's motion to dismiss as to the State Law Claims remains under advisement. On October 6, 2025, Avangrid and NextEra submitted a joint request for a second oral argument to cover the remaining claims after the September 22 order, and Avangrid submitted an unopposed request for a status conference to discuss how to seek relief from the monopolizations claims in the September 22 order (either by seeking leave to amend or request for an appeal). A status conference was scheduled for and held on October 16, 2025. A hearing on NextEra's motion to dismiss the State Law Claims was held on December 18, 2025 and an official transcript was filed.

- **Allco PURPA Enforcement Petition (D.CT) (Case No. 3:25CV01321)**
  Case Title: *Allco Finance Limited Inc. v. Dykes et al.*
  Status: Responses to Motions to Dismiss Due Dec 15, 2025

Following a FERC notice[143] that it had decided not to act on Allco's PURPA Complaint related to Connecticut's[144] implementation under section 210 of PURPA of its Shared Clean Energy Facility ("SCEF") Program,[145] Allco brought an enforcement action against Connecticut in federal district court in Connecticut.[146] *Allco Finance Limited Inc. v. Dykes et al.* (case no. 3:25CV01321). On November 24, 2025, Defendants[147] filed a motion to dismiss the Complaint and stay discovery. DEEP Commissioner, Katie S. Dykes, PURA Commissioners,

[143] *Allco Finance Limited*, 192 FERC ¶ 61,116 (Aug. 4, 2025).

[144] For purposes of this proceeding, "Connecticut" is the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), Connecticut Public Utilities Regulatory Authority ("CT PURA"), and the Connecticut Department of Agriculture ("CT DoA").

[145] Allco asserted that CT is improperly implementing PURPA by requiring the following criteria for participation in the Shared Clean Energy Facility ("SCEF") program: (i) that no more than 10% of the project site contains slopes greater than 15%; (ii) that separate QFs on the same parcel cannot receive a contract even when the total of the two QFs is less than 5MWs; (iii) documentation of "community outreach and engagement" regarding the bid for a contract; (iv) restrictions related to "Prime Farmland" location; (v) a QF cannot have been constructed or started construction; (vi) a workforce development program, and for certain projects a community benefits agreement; (vii) a contract that includes renewable energy credits; and (viii) a bidder must bear costs related to a utility's voluntarily seeking to re-sell the QF's energy in the ISO-NE market, if the utility chooses not to use the energy to supply its own customers. Allco argues that the criteria are neither objective nor reasonable and are unrelated to a QF's commercial viability or financial commitment. Allco further contends that some of CT's SCEF program requirements violate its constitutional rights. Allco also states that bids it submitted in 2024 and 2025 were rejected on the basis of these unlawful requirements.

[146] 16 U.S.C. § 824a-3(h)(2)(B).

[147] Defendants are UI, Avangrid Networks, Inc., Avangrid, Iberdrola, S.A., Charlotte Ancel, and Pedro Azagra Blázquez.

David Arconti, Michael Caron, and Marissa Gillett,[148] and DOAG Commissioner, Bryan P. Hurlburt, (the "State Agency Defendants") also filed a joint motion to dismiss the Complaint; and on December 9, 2025, Allco filed a memo in opposition to the motion to dismiss filed by the Defendants and the State Agency Defendants. On December 23, 2025, a motion to dismiss the complaint was filed by the Defendants and a joint motion to dismiss was filed by the State Agency Defendants.

[148] Marissa Gillett resigned her position as chair of PURA, effective Oct. 10, 2025.

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Admin Matters

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NEPOOL
NEW ENGLAND POWER POOL
Participants Committee