Sebastian Lombardi
Secretary

June 9, 2026

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 16–18, 2026 NEPOOL Participants Committee Summer Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the NEPOOL Participants Committee Summer Meeting will be held on June 16–18, 2026 at Newport Harbor Island (NHI) on Goat Island in Newport, RI. Please see the attached Summer Meeting agenda, which is also posted with the meeting materials.

As reflected on the meeting agenda:

- ***Tuesday (Jun 16)***: General NEPOOL business will be conducted on Tuesday, with a planned ***9:30 a.m. start***. Note that Tuesday's agenda includes the annual markets presentation by the ISO's External Market Monitor (EMM).
- ***Wednesday (Jun 17)***: Wednesday morning has been set aside for a presentation by the ISO's Internal Market Monitor (IMM) of (i) the 2025 IMM Annual Markets Report and (ii) an Assessment of the Day-Ahead Ancillary Services Market.
- ***Thursday (Jun 18)***: On Thursday, modified Sector group meetings are scheduled to begin at 8:30 a.m., with times set aside for each group to meet separately with ISO Board members, State Officials, and FERC representatives. ***Please note when and where your modified Sector group is scheduled to meet.***

We understand that everyone planning to attend the Summer Meeting in person is registered for the meeting. If you cannot make the meeting in person, the June 16 and June 17 plenary sessions will be accessible by Webex for those who otherwise attend NEPOOL meetings, and approved guests. To join via Webex, click this link and enter the event password **nepool**.

The NEPOOL reservations block at NHI is full. If you have a need for overnight accommodations, please contact Laura Clark (lclark@daypitney.com), who may be able to assist you with alternative arrangements. For those staying at NHI, please note that **the cancellation policy is at least 7 days prior to the first day of your reservation. If any of your arrangements have changed, including the number of people you registered, please contact Laura as soon as possible.**

Dress for the Summer Meeting is business casual. Additional information regarding the Summer Meeting is available on the Summer Meeting information page.

We very much look forward to seeing you in Newport.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

TUESDAY, JUNE 16, 2026
9:30 a.m. – 4:30 p.m. General Session**
(Beacon Ballroom)

1. To approve the draft minutes of the Participants Committee meetings held on April 30 and May 7, 2026. A copy of each set of draft minutes is included and posted with this supplemental notice. Please provide us with any comments on the draft minutes **on or before 5:00 p.m., Thursday, June 11, 2026**.

2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials. Consent Agenda Item No. 1 has been removed and will be considered as Item 10A (*see* below).

3. To receive remarks from Vamsi Chadalavada, Chief Executive Officer, ISO New England. A summary of the ISO Board and Board Committee meetings held since the last Participants Committee meeting is included with this supplemental notice and posted with the meeting materials.

4. To receive a Systems and Market Operations Report. The ISO's June Systems and Market Operations Report, reflecting May data, will be circulated and posted in advance of the meeting.

5. To receive a report on the ISO's preliminary 2027 and 2028 Operating and Capital Budgets by Kelly Reyngold, Chief Financial Officer, ISO New England. The 2027 Budget Presentation is included with this supplemental notice and posted with the meeting materials.

6. To consider and take action, as appropriate, on changes to Section IV.A and Section IV.B of the Tariff to clarify how the ISO's annual rates, charges, and capital budget (together, the Calendar Year Rates) will be administered if, by January 1, those Calendar Year Rates have not been authorized by the FERC or have not otherwise become effective. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

7. To consider and take action, as appropriate, on changes to the Pay-For-Performance (PFP) treatment of external transactions during Capacity Scarcity Conditions and settlement calculations, and related revisions to Tariff Sections I, III, the Billing Policy, and the Financial Assurance Policy (FAP). Background materials and draft resolutions are included with this supplemental notice and posted with the meeting materials.

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* 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.

****All start and finish times subject to adjustment.**

8. To consider and take action, as appropriate, on changes to cap the PFP Capacity Balancing Ratio at 1.0 and to make related revisions to Tariff Sections I, III, and the FAP. Background materials and draft resolutions are included with this supplemental notice and posted with the meeting materials.

9. To consider and take action, as appropriate, on the ISO's proposed downward adjustment to the Performance Payment Rate (PPR) and related revisions to Sections III.13.7 and III.15. Background materials, including information on a potential amendment and a request for further assessment of the proposed PPR adjustment, are included with this supplemental notice and posted with the meeting materials.

10. To consider and take action, as appropriate, on Day-Ahead Ancillary Services (DAAS) post-implementation market adjustments in response to recommendations by the Internal Market Monitor (IMM). Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

10A. To consider and take action, as appropriate, on changes to the NEPOOL Generation Information System (GIS) and GIS Operating Rules related to marking of Certificates as being transferred under Section 83D of the Massachusetts Act Relative to Green Communities. This item was removed from the Consent Agenda (Consent Agenda Item 1). Background materials, including a memo from Participant representatives proposing to amend the draft resolution to approve the changes, are included with this supplemental notice and posted with the meeting materials.

11. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts.

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

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

13. FERC Staff Introductions.

14. To receive an External Market Monitor Report by Dr. David Patton, President, Potomac Economics. A presentation with highlights of the EMM's 2025 Annual Assessment of the ISO New England Electricity Markets will be circulated and posted following receipt.

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

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WEDNESDAY, JUNE 17, 2026
9:30 a.m. – 12:00 p.m.**
(Beacon Ballroom)

16. To receive welcoming remarks from a state official(s) of the State of Rhode Island.

17. To receive an IMM Report from David Naughton, Executive Director, Market Monitoring, including highlights from the IMM's:

    - 2025 Annual Markets Report; and
    - Day-Ahead Ancillary Services Market Assessment.

    A copy of the IMM's 2025 Annual Markets Report is included and posted with the composite materials for the meeting. The Day-Ahead Ancillary Services Assessment is included with this supplemental notice and posted with the meeting materials. Further material will be circulated and posted in advance of the meeting.

Wednesday afternoon has been set aside for
separate meetings and organized networking, as desired.

THURSDAY, JUNE 18, 2026
8:30 a.m. – 12:45 p.m.**

Thursday, June 18 has been set aside for
separate, modified Sector meetings with ISO Board Members,
State Officials, and FERC Representatives,
as detailed in the Sector meeting schedule included with this agenda.

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****All start and finish times subject to adjustment.**

NEPOOL
NEW ENGLAND POWER POOL

23nd Annual
Participants Committee Summer Meeting
Newport, RI
June 18, 2026 Schedule

NEWPORT HARBOR
ISLAND RESORT

JUN 9, 2026 DRAFT

SECTOR/GROUP	8:30–9:45 a.m.	10:00–11:15 a.m.	11:30 a.m.–12:45 p.m.	11:45 a.m.–2:00 p.m.
Generation / Long	State Officials Panel 1 ***(Beacon D)***	ISO Board Panel 2 ***(Beacon A)***	FERC Staff (12:15–12:45) ***(Hamilton)***	Lunch (All) ***Rose Island Ballroom***
Transmission	State Officials Panel 2 ***(Beacon B)***	ISO Board Panel 1 ***(Beacon C)***	FERC Staff (11:30–12:00) ***(Hamilton)***	
Supplier / Short (LSE)	ISO Board Panel 1 ***(Beacon C)***	FERC Staff (10:45–11:15) ***(Hamilton)***	State Officials Panel 1 ***(Beacon D)***	
Publicly Owned Entity	FERC Staff (8:30–9:00) ***(Hamilton)***	State Officials Panel 2 ***(Beacon B)***	ISO Board Panel 1 ***(Beacon C)***	
AR	FERC Staff (9:15–9:45) ***(Hamilton)***	State Officials Panel 1 ***(Beacon D)***	ISO Board Panel 2 ***(Beacon A)***	
End User	ISO Board Panel 2 ***(Beacon A)***	FERC Staff (10:00–10:30) ***(Hamilton)***	State Officials Panel 2 ***(Beacon B)***	
ISO Board Panel 1	Supplier / Short (LSE) ***(Beacon C)***	Transmission ***(Beacon C)***	Publicly Owned Entity ***(Beacon C)***	
ISO Board Panel 2	End User ***(Beacon A)***	Generation / Long ***(Beacon A)***	AR ***(Beacon A)***	
State Officials Panel 1	Generation / Long ***(Beacon D)***	AR ***(Beacon D)***	Supplier / Short (LSE) ***(Beacon D)***	
State Officials Panel 2	Transmission ***(Beacon B)***	Publicly Owned Entity ***(Beacon B)***	End User ***(Beacon B)***	
FERC Staff	Publicly Owned (8:30–9:00) AR (9:15–9:45) ***(Hamilton)***	End User (10:00–10:30) Supplier/Short (LSE) (10:45–11:15) ***(Hamilton)***	Transmission (11:30–12:00) Generation/Long (12:15–12:45) ***(Hamilton)***	

ISO Board Panel 1: Caren Anders, Mike Curran, Craig Ivey, Cheryl LaFleur, Mark Vannoy

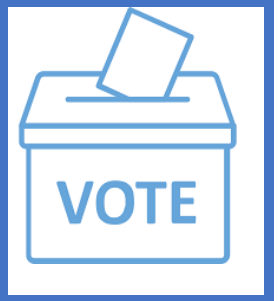
ISO Board Panel 2: Brook Colangelo, Steve Corneli, Catherine Flax, Mel Williams, and Vamsi Chadalavada

State Officials Panel 1: RI PUC Commissioner Karen Bradbury, RI PUC Staff Todd Bianco, CT PURA Chairman Thomas Wiehl, CT DEEP Deputy Commr. Andy Frank, CT DEEP Staff Eric Annes, ME PUC Commr. Patrick Scully, ME DOER Staff Bob Snook, MA DPU Commr. Liz Anderson, MA EEA Asst. Secretary Austin Dawson, NH PUC Commr. Mark Dell'Orfano (virtual), NH DOE Staff Bruce Blair, NH DOE Staff Dan Phelan, VT PUC Chair Ed McNamara, NESCOE Staff Jeff Bentz, NESCOE Staff Shannon Beale, and NECPUC Exec. Dir. George Twigg

State Officials Panel 2: RI PUC Chairman Ron Gerwatowski, CT DEEP Staff Josh Walters, ME PUC Chair Phil Bartlett, ME DOER Staff Celina Cunningham, ME PUC Staff Michael Haskell, MA DPU Chair Jeremy McDiarmid, MA EEA Assistant Secretary Weezie Nuara, MA DPU Staff Gregg Wade, NH PUC Chairman Chris Ellms (virtual), NH DOE Staff Matt Young, VT DPS Commissioner Kerrick Johnson, NESCOE Staff Sheila Keane, NESCOE Staff Nathan Forster, and NESCOE Exec. Dir. Heather Hunt

FERC Staff: Eric Jacobi, Noah Schlosser, and Aaron Siskind

1 April 30, 2026 and May 7, 2026 Minutes



66.67%

RESOLVED, that the Participants Committee approves the preliminary minutes of the April 30, 2026 and May 7, 2026 meetings, as circulated in advance of this meeting, with additional non-material clarifications, as the final minutes of the April 30, 2026 and May 7, 2026 meetings.

PRELIMINARY

Pursuant to notice duly given, a special Webex meeting of the NEPOOL Participants Committee was held beginning at 9:00 a.m. on Thursday, April 30, 2026. 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.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates and guests who were present.

PURPOSE OF SPECIAL MEETING

Ms. Bresolin welcomed the Committee to the special meeting that was being held, at the request of a number of Transmission Sector members, to consider and take action on proposed revisions to Attachment F (Appendix A, Worksheet 2) to Section II of the ISO Tariff (Attachment F Revisions), including a proposed new region-wide base return on equity (ROE). She referred members to the background materials circulated in advance of the meeting and posted to the NEPOOL website. Ms. Bresolin explained that the Participating Transmission Owners Administrative Committee (PTO-AC) planned to file later that day on behalf of the Participating Transmission Owners (PTOs) a prospective new ROE (a proposed change to the 9.57% ROE that had been directed by the FERC in its March 19, 2026 Opinion No. 594 (*Opinion 594*)) and was seeking Participants Committee action ahead of that filing. Ms. Bresolin noted for the Committee that the specific ROE % to be proposed in the PTO-AC filing would be identified and included in the motion to support the Attachment F Revisions before that motion was moved. She further indicated that a motion to amend the ROE % was expected to be offered by a Market Participant End User representative.

PTO-AC ROE PROPOSAL

Mr. Nick Gangi, Transmission Committee (TC) Chair, summarized the Participant Processes undertaken to that point. Mr. Gangi explained that, at the April 21, 2026 TC, the PTO-AC had proposed a revision to Attachment F in response to *Opinion 594*. While the revisions struck the 10.57% base ROE rate in the Tariff, no new % was identified at that time; instead the PTO-AC inserted a placeholder for a new base ROE rate to be filled in later, and as part of the PTO-AC's FERC filing. Ultimately, at the April 21 TC meeting, and based on a roll call vote, the TC did not recommend Participants Committee support for the PTO-AC proposal, with a 19.84% vote in favor (that percentage registered by the Transmission Sector reflected an upward adjustment to the Sector voting share based on the lack of Sector Quorum achieved by the Alternative Resources (AR) Sector at the TC meeting).

Ms. Bresolin then introduced and invited Ms. Jackie Hansen, a PTO-AC representative, to make brief remarks on the Attachment F Revisions. Ms. Hansen thanked the Committee for accommodating the PTO's request for the special meeting, and explained that the PTO-AC would make a filing, under Section 205 of the Federal Power Act, following the meeting that day, to revise the going forward region-wide base ROE to reflect, in their view, current economic conditions for transmission assets included in Attachment F. She noted that the 9.57% base ROE established in *Opinion 594* was based on market data from October 2012 and explained that the PTO-AC filing would propose a new base ROE of 11.39%, employing the same methodology as used by the FERC in *Opinion 594* but reflecting current economic conditions. The contemplated effective date for this newly proposed base ROE would be June 30, 2026.

Members then asked clarifying questions. In response to questions regarding when any new ROE might be reflected in rates, Ms. Hansen said that the PTOs' annual 2027 rate filing

would not initially reflect any change from the FERC-directed 9.57% ROE. However, if the new ROE was accepted, the PTOs were not in a position at this meeting to identify how or when the new ROE would then in turn be reflected in rates. The PTO-AC did not have plans to submit additional redlines, other than to insert the 11.39%, and did not believe that the new percentage would be changed based on discussion at the meeting. Ms. Hansen confirmed that the going-forward ROE would be evaluated on its own merits and would not in and of itself impact the refund ordered in the existing ROE proceedings. She added that additional support for the 11.39% would be presented in the FERC proceeding, but not during the special meeting.

Addressing questions as to what rate applied, and by whom the rate was set, Ms. Hansen confirmed that the base ROE percentage applied to the Pool Transmission Facilities (PTF) asset rate, which an ISO representative confirmed was solely within the purview of the PTOs to set and was used as an input to the Annual Revenue Requirement. The timing of consideration of the Attachment F Revisions was similarly driven by the PTOs, who wished to have the rates be in effect as of July 1 and not push any later into that period as a result of consideration at a later, regularly-scheduled Participants Committee meeting. In response to further questions, Ms. Hansen said that the new ROE would not impact other applicable incentives or adders under the Tariff.

The following main motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports the Attachment F Revisions, as proposed by the PTO-AC, together with such non-substantive changes as may be agreed to after the meeting by the Chair of the Participants Committee.

Market Participant End User Amendment

A Market Participant End User representative then made a motion to amend the main motion, which was duly seconded, so as to set the base ROE at 9.57% (reflecting the same % as directed in *Opinion 594*) in lieu of the PTO-AC's proposed 11.39% base ROE.

Those supporting the motion to amend focused on the very limited opportunity to review or discuss the PTO-AC-proposed change to the FERC-directed ROE and viewed the motion to amend the ROE to 9.57%, therefore, as an appropriate replacement for the placeholder. Others, with similar reservations as to the sufficiency of time to evaluate the End User representative's proposed alternative, indicated they would abstain on the motion to amend. Transmission Sector members noted their opposition to the motion to amend.

Without further discussion, the motion to amend was voted and was determined, by a show of hands, to have failed.

Unamended Main Motion (PTO-AC Proposal)

Members then addressed the PTO-AC Proposal (the proposed 11.39% ROE).

A member of the Publicly Owned Entity Sector, acknowledging that business conditions had changed since those conditions underlying the FERC-established ROE rate, expressed disappointment with the missed opportunity to have a conversation in good faith and potentially reach consensus on a new base ROE rate. He encouraged the TOs to look for opportunities to engage in collaborative discussion.

Others expressed concern with considering and voting on a proposal with minimal notice and information. Echoing those sentiments, a NESCOE representative noted that the PTO-AC's request for stakeholders to form an opinion and vote on an ROE proposal that lacked specificity could undermine the FERC's respect for the region's decision-making predicated on a strong and

respectful stakeholder process. She added that, although NESCOE does not participate in NEPOOL voting, it objected to the PTO-AC's request for an advisory vote on what had been a blank proposal until just minutes before. She stated that the request was particularly concerning because it would directly affect New England consumers' costs. The NESCOE representative concluded that the TC vote the prior week, in which no stakeholder other than the Transmission Owners supported the proposal, was an inevitable outcome for a proposal that was not ripe for consideration.

Following a member's request for a roll call vote, the unamended main motion, including the PTO-AC's proposed base ROE of 11.39%, was then voted and was not approved. The unamended main motion failed with a 16.67% vote in favor (Generation Sector – 0%; Transmission Sector – 16.67%; Supplier Sector – 0%;AR Sector – 0%; Publicly Owned Entity Sector – 0%; and End User Sector – 0%) (*See* Attachment 2).

There being no other business, the meeting adjourned at 9:58 am.

Respectfully submitted,

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Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE SPECIAL APRIL 30, 2026 WEBEX MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	
AVANGRID (CMP/UI)	Transmission	Alan Trotta	Jason Rauch	
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		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	
Braintree Electric Light Department	Publicly Owned Entity	Dave Cavanaugh		
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Clear River Electric and Water District	Publicly Owned Entity		Dave Cavanaugh	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	
Conservation Law Foundation	End User	Phelps Turner		
Constellation Energy Generation (Constellation)	Supplier	Andy Gillespie		
Cross-Sound Cable Company (CSC)	Supplier			Jeff Iafrati
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dartmouth Power Associates, L.P.	Generation	Sarah Yasutake		
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker		
Elektrisola, Inc.	End User			Bill Short
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Fiscal Alliance Foundation, Inc.	End User	Paul Craney		
Gabel Associates, Inc.	Supplier	Sarah Yasutake		
Galt Power, Inc.	Supplier		Jeff Iafrati	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Steve Kirk	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Green Oceans	End User		Lauren Knight	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault	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	
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Icetec Energy Services, LLC	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User		Todd Griset	
Industrial Wind Action Group	End User	Lisa Linowes		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
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 Killgoar	
Maine Public Advocate's Office	End User	Drew Landry		Susan Chamberlin
Maine Skiing, Inc.	End User		Todd Griset	
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE SPECIAL APRIL 30, 2026 WEBEX MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Marble River, LLC	Supplier	John Brodbeck		
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihrle	Jamie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
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
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier	Ben Griffiths		
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	
PowerOptions, Inc.	End User			Doug Hurley
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned Entity	Nick Parrotta	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Vermont Electric Company	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR			Doug Hurley
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
ZTECH, LLC	End User			Bill Short

SPECIAL APRIL 30, 2026 WEBEX PARTICIPANTS COMMITTEE MEETING
VOTE ON ATTACHMENT F REVISIONS (BASE ROE)

TOTAL

Sector/Group	Vote
GENERATION	0.00
TRANSMISSION	16.67
SUPPLIER	0.00[1]
ALTERNATIVE RESOURCES	0.00
PUBLICLY OWNED ENTITY	0.00
END USER	0.00
% IN FAVOR	**16.67**

GENERATION SECTOR

Participant Name	Vote
Dartmouth Power Associates	A
Dominion Energy Generation Mktg	A
FirstLight Power Management, LLC	A
Generation Bridge Companies	O
Granite Shore Power Companies	A
NextEra Energy Resources, LLC	A
Pawtucket Power Holding Co.	A
IN FAVOR (F)	0
OPPOSED (O)	1
TOTAL VOTES	1
ABSTENTIONS (A)	6

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote
Renewable Generation Sub-Sector	
ENGIE Energy Marketing NA, Inc.	O
H.Q. Energy Services (U.S.) Inc.	A
Load Response Sub-Sector	
Icetec Energy Services, LLC	O
Vermont Energy Investment Corp.	A
IN FAVOR (F)	0
OPPOSED (O)	2
TOTAL VOTES	2
ABSTENTIONS (A)	2

TRANSMISSION SECTOR

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

SUPPLIER SECTOR

Participant Name	Vote
Constellation Energy Generation	A
Cross-Sound Cable Company	A
Gabel Associates, Inc.	A
Galt Power, Inc.	A
LIPA	A
Marble River, LLC	X[1]
NRG Business Marketing, LLC	O
Shell Energy North America (US) LP	A
IN FAVOR (F)	0
OPPOSED (O)	1
TOTAL VOTES	2
ABSTENTIONS (A)	6

[1] [note: A vote in favor by a Supplier Sector Participant was incorrectly registered during the meeting. The Supplier Sector Participant voting in favor was, as a result of an ongoing Financial Assurance Default at the time of the vote, suspended from voting on matters before the Participants Committee (see Financial Assurance Policy Section III.B.2.c). The vote tabulation included as Attachment 2 to these minutes has been revised to reflect the removal of that vote, with the Supplier Sector total in favor reduced to 0% and the overall vote in favor reduced to 16.67%.]

SPECIAL APRIL 30, 2026 WEBEX PARTICIPANTS COMMITTEE MEETING
VOTE ON ATTACHMENT F REVISIONS (BASE ROE)

END USER SECTOR

Participant Name	Vote
Acadia Center	O
Bath Iron Works	O
Conn. Office of Consumer Counsel	O
Conservation Law Foundation	O
Elektrisola, Inc.	O
Fiscal Alliance Foundation	O
Garland Manufacturing Co.	O
Green Oceans	O
Hammond Lumber Co.	O
Harvard Dedicated Energy Limited	O
High Liner Foods	O
Industrial Energy Consumer Group	O
Industrial Wind Action Corp.	O
Lamson, John	A
Maine Public Advocate Office	O
Maine Skiing, Inc.	O
Mass. Attorney General's Office	O
Moore Company	O
NH Office of Consumer Advocate	O
Nylon Corporation	O
PowerOptions, Inc.	O
RI Division of Public Utilities Carriers	O
St. Anslem	O
Shipyard Brewing Co.	O
Z-TECH, LLC	O
IN FAVOR (F)	0
OPPOSED (O)	24
TOTAL VOTES	24
ABSTENTIONS (A)	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote
Ashburnham Municipal Light Plant	O
Belmont Municipal Light Dept.	O
Block Island Utility District	O
Boylston Municipal Light Dept.	O
Braintree Electric Light Dept.	O
Chicopee Municipal Lighting Plant	O
Clear River Electric and Water District	O
Concord Municipal Light Plant	O
Conn. Municipal Electric Energy Coop.	A
Danvers Electric Division	O
Georgetown Municipal Light Dept.	O
Groton Electric Light Dept.	O
Groveland Electric Light Dept.	O

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote
Hingham Municipal Lighting Plant	O
Holden Municipal Light Dept.	O
Holyoke Gas & Electric Dept.	O
Hudson Light and Power Dept.	O
Hull Municipal Lighting Plant	O
Ipswich Municipal Light Dept.	O
Littleton (MA) Electric Light Dept.	O
Mansfield Municipal Electric Dept.	O
Marblehead Municipal Light Dept.	O
Mass. Municipal Wholesale Electric Co.	O
Mass. Bay Transportation Authority	O
MDC – The (CT) Metropolitan District	O
Merrimac Municipal Light Dept.	O
Midcoast Regional Redevelopment Authority	O
Middleborough Gas and Elec. Dept.	O
Middleton Municipal Electric Dept.	O
New Hampshire Electric Cooperative	O
North Attleborough Electric Dept.	O
Norwood Municipal Light Dept.	O
Paxton Municipal Light Dept.	O
Peabody Municipal Light Plant	O
Princeton Municipal Light Dept.	O
Reading Municipal Light Dept.	O
Rowley Municipal Lighting Plant	O
Russell Municipal Light Dept.	O
Shrewsbury Electric & Cable Operations	O
South Hadley Electric Light Dept.	O
Sterling Municipal Electric Light Dept.	O
Stowe (VT) Electric Dept.	A
Taunton Municipal Lighting Plant	O
Templeton Municipal Lighting Plant	O
Vermont Public Power Supply Authority	A
Village of Hyde Park (VT) Electric Dept.	A
Wakefield Municipal Gas and Light Dept.	O
Wallingford (CT), Town of	O
Wellesley Municipal Light Plant	O
West Boylston Municipal Lighting Plant	O
Westfield Gas & Electric Light Dept.	O
IN FAVOR (F)	0
OPPOSED (O)	47
TOTAL VOTES	47
ABSTENTIONS (A)	4

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, May 7, 2026, at the Delamar in West Hartford, Connecticut. 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.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates and guests who were present.

EXECUTIVE SESSION

VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Ms. Bresolin indicated that discussion of the proposed slate of candidates for the ISO Board would proceed in executive session. She then introduced Mr. Brook Colangelo, ISO Board Member and Chairman of the Joint Nominating Committee (JNC), who joined this portion of the meeting to present and answer any questions regarding the JNC-recommended slate and the process undertaken to identify that slate. Following general comments on the JNC process, Mr. Colangelo identified the candidates, referring to the materials that were circulated to the Committee's members and alternates in advance of the meeting. Mr. Colangelo then left the meeting.

The slate was then discussed in executive session among members and alternates, with initial comments on the candidates offered by the NEPOOL representatives who participated in the JNC efforts. While there were no concerns with the slate presented, some members identified their continuing concerns with voting on Board candidates by way of a slate, rather

than by individual candidate. Other members noted the benefits to the candidate search and overall satisfaction with the results of the slate voting approach as required under the Participants Agreement. Following further discussion, the following motion was duly made, seconded and approved by more than the 70% Vote required for approval, with the vote accomplished by confidential written ballot:

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in executive session at this meeting.

Members were advised that the election of the slate would officially be taken by the ISO Board, likely at the Board's next regularly-scheduled meeting later that month, with the results of that action to be announced publicly promptly thereafter. Until that time, members were cautioned to keep confidential the composition of the slate, particularly the identity of the candidate proposed for a first term.

GENERAL SESSION

Following a short recess, the Committee came out of executive session at 10:30 a.m. and was joined by ISO representatives, State officials and guests. Ms. Bresolin welcomed the members, alternates, State officials (including three Commissioners from Connecticut's Public Utilities Regulatory Authority -- Vice-Chairman David Arconti and Commissioners Janice Beecher and Holly Cheeseman), and guests who were present.

Before proceeding to the first general session agenda item, Ms. Bresolin briefly summarized meetings that she and Mr. Lombardi had had the week before with FERC Chairman Swett and Commissioner LaCerte, the purpose of which was to provide an introduction to NEPOOL and the New England stakeholder process. The meetings also included a preview of

several filings expected to come before the FERC in the next few months. Ms. Bresolin characterized the meetings, as well as the feedback on New England's efforts, as positive.

APPROVAL OF APRIL 9, 2026 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the April 9, 2026 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 in advance of the meeting, with additional non-material clarifications, and with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

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

ISO SYSTEMS & MARKET OPERATIONS REPORT

Mr. Stephen George, ISO Vice President of System & Market Operations and Capital Projects, referred the Committee to the May System & Market Operations Report (Report), which had been circulated and posted in advance of the meeting. Noting that data in the Report was through April 29, 2026 unless otherwise noted, Mr. George reviewed Report highlights, which included: (i) the Peak Hour for April 2026, with 15,021 MW of Revenue Quality Metered (RQM) Data, occurred on April 2 during the hour ending at 8:00 p.m.; (ii) April averages for Day-Ahead Hub Locational Marginal Price (LMP) ($45.89/MWh), Real-Time Hub LMP ($45.50/MWh), and natural gas prices ($2.31/MMBtu); (iii) Energy Market value for April 2026

was $439 million, up from $400 million in April 2025; (iv) Ancillary Markets value ($2.5 million) was down from $7.3 million in April 2025; (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 99.4% during April, down from 99.7% during March; (vi) Net Commitment Period Compensation (NCPC) payments for April totaled $2.8 million (representing just 0.6% of April's monthly Energy Market value), comprised of (a) $2.7 million in First Contingency payments (including $609,000 in Dispatch Lost Opportunity Costs, $276,000 in Rapid Response Pricing Opportunity Costs, and $3,000 paid to Real-Time Deviations), (b) $117,000 in Second Contingency and less than $1,000 in voltage payments, and (c) $30,000 in Distribution payments; and (vii) a Forward Capacity Market (FCM) value of $88.8 million.

Mr. George highlighted a few additions to the Report that would be updated and included in future reports. The first was a chart that illustrated how, on a daily basis, temperatures departed from normal, with the gray "Mean Departure" line representing a rolling average starting on day one and recalculated each day (the April 2026 average temperature was 1°F warmer than normal). He also highlighted that, in response to member requests for additional visibility into wind and solar forecast errors, links were added to the ISO website where forecast information is updated monthly (typically by the 15th of the month) and those links would be included in monthly reports going forward.

Mr. George also noted that, on May 1, as announced at the April Reliability Committee meeting, the Ten-Minute Reserve Requirement was lowered from 120% (where it had been for the last ten years) to 115% of the largest single contingency on the system. The ISO planned to evaluate that Requirement through the fall, and review with the Reliability Committee any further modifications to that Requirement before the start of the Winter period. That evaluation

would potentially take into account a number of things, including ISO performance and response to operational contingencies, and the performance of resources that will reach commercial status (e.g. large-scale batteries and offshore wind).

In response to members' questions, Mr. George explained why Real-Time exports had been curtailed on a couple of days in April (to avoid reserve deficiencies at or around the peak hour that would have been occurred given exports exceeding those planned for in Day-Ahead clearing, combined with load running above forecast). He also confirmed that, due to planned and force outages, generation outages reached approximately 10,000 MW in April, but were accommodated through the outage coordination process, which maintained sufficient supply to meet demand, even in the face of somewhat volatile weather conditions. April NCPC payments were attributable to a combination of transmission and generation outages, in particular the need to ensure sufficient generation in the east to balance west-to-east flows. Noting that the load forecasting metric for the peak hour had been met, but the all-hours metric had not been met, in April, Mr. George assured members that the ISO's three behind-the-meter photovoltaic (PV) forecasters continued to refine their processes and protocols (with particular focus on the art and science of forecasting cloud cover) and the ISO continued to look for ways to improve its forecasts.

Turning to transmission outages, Mr. George stated that, while there were planned transmission outages throughout May, most were to be of short duration (1 day or less), and not worth specifically calling to members' attention. Mr. George noted plans to add to future monthly reports a slide identifying impactful transmission outages, which members said would be a welcome enhancement.

In response to a question about Day-Ahead Ancillary Services (DAAS) results, Mr. George replied that he would at a future meeting provide clarification as to which cost would most closely resemble the total $/MWh that a customer would see on their bill. He also encouraged members to provide feedback on other potential refinements to the ISO's DAAS reporting.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the May 6, 2026 Litigation Report that had been circulated and posted before the meeting. Mr. Lombardi highlighted a request for rehearing filed by the New England Transmission Owners of the FERC's *Opinion 594*, which reduced the base return on equity (ROE). Recalling the discussion and vote on the PTO-AC's proposed changes to the base ROE at the April 30 special Participants Committee meeting the week before, he confirmed that the proposal was filed with FERC on April 30. Mr. Lombardi stated that NEPOOL would submit a pleading providing additional information about the accelerated process that NEPOOL undertook to consider the changes and the vote taken at the April 30 meeting. In response to a question, Mr. Lombardi, after a brief explanation of the protocol followed by Counsel for filings of this nature, including Participant officer guidance and feedback, clarified that the comments in the ROE proceeding would be procedure-focused and fact-based, identifying the process undertaken to get to the votes and the position ultimately taken by the Committee at the meeting.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Ben Griffiths, MC Vice-Chair, reported that the next MC meeting would be a three-day meeting, from May 12-14, 2026, at the Framingham Renaissance.

He noted that the agenda was expected to be quite full, including votes on Pay-for-Performance (PFP) revisions, including two stakeholder amendments; discussions on a multitude of Capacity Auction Reforms: Seasonal/Accreditation (CAR-SA)-related topics, including natural gas-fired resource contract requirements and demand curves, and stakeholder presentations on resource accreditation.

Reliability Committee. Mr. Frank Ettori, the RC Vice-Chair, reported that the next RC meeting would be held on Thursday, May 21, 2026, also at the Framingham Renaissance. He said that discussion would include operating and planning procedure updates for Storage as a Transmission-Only Asset (SATOA), *Order 881* and *Order 2023*-related issues, discussion on Power System Simulator for Engineering (PSS/E) Version 36, and several CAR-SA presentations addressing tie benefits, capacity zone formation, and distributed energy capacity resources.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be held on May 28, 2026, and if held in person, at the Milford Doubletree. He reported that the agenda was still being developed, but he expected further discussion of the asset condition project (ACP) reviewer subject, including potential Participant amendments to the ISO's ACP reviewer framework.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Chair, reported that the B&F would convene on May 8, 2026. He noted that the agenda would include several "regular" budget reports, as well as amendments to the Financial Assurance Policy (FAP) associated with external transactions and PFP-related balancing ratio changes.

Membership Subcommittee. Mr. Brian Thomson, the Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held virtually on May 11,

2026. He expected the Subcommittee to take action on one application and one termination request.

ADMINISTRATIVE MATTERS

Mr. Lombardi introduced Ms. Laura Clark, who recently joined the NEPOOL team and would be assisting with all Committee administrative matters. He reminded members who had not done so already to register for the June 16-18, 2026 Summer Meeting in Newport, Rhode Island, which was expected to be well attended. Ms. Bresolin added that the Summer Meeting was likely to be quite busy, with votes on both DAAS and PFP changes, and detailed reports from both the external and internal market monitors, in addition to a full slate of modified Sector meetings with the ISO Board, and representatives from the New England States and the FERC.

Ms. Bresolin announced that Ms. Maria Gulluni, ISO New England's General Counsel, would be receiving later that evening the Leadership Award from the New England Women in Energy and the Environment (NEWIEE), recognizing Ms. Gulluni for her 25-year career in the industry, her leadership, and her dedication to advancing equity and mentoring young professionals. On behalf of NEPOOL and its members, she congratulated Ms. Gulluni for the well-deserved recognition.

There being no other business, the meeting adjourned at 11:07 am.

Respectfully submitted,

_____

Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE MAY 7, 2026 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (W)		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton (W)	
Bath Iron Works Corporation	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BP Energy Company	Supplier			Jose Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing LP	Supplier	Aleks Mitreski (W)		
Central Maine Power/UI	Transmission	Alan Trotta	Jason Rauch (W)	
Chester Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
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	
Conn. Municipal Electric Energy Cooperative	Publicly Owned Entity	Brian Forshaw (W)		
Conn. Office of Consumer Counsel	End User	Claire Coleman	Jamie Talbert-Slagle	
Conservation Law Foundation	End User	Nick Krakoff (W)		
Constellation Energy Generation, LLC	Supplier	Andy Gillespie (W)		
Cross-Sound Cable	Supplier		Jose 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.	Supplier			Jose Rotger
Earthjustice	End User		Ada Statler (W)	
Elektrisola, Inc.	End User			Bill Short
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Fiscal Alliance Foundation, Inc.	End User			Lisa Linowes (W)
Gabel Associates, Inc.	Supplier	Sarah Yasutake (W)		
Galt Power, Inc.	Supplier	Jose Rotger		
Garland Manufacturing Company	End User			Bill Short
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Green Oceans	End User		Lauren Knight (W)	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	AR-RG	Louis Guilbault (W)	Robert Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Doug Hurley (W)
High Liner Foods (USA) Incorporated	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Industrial Wind Action Corp	End User	Lisa Linowes (W)		
Lamson, Jon	End User	Jon Lamson (W)		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	
Maine Public Advocate Office	End User			Susan Chamberlin (W)
Mass. Attorney General's Office	End User	Jacquelyn Bihrle	Jamie Donovan	Chris Modlish
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Co.	Publicly Owned Entity			Brian Forshaw (W)
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			Jose 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	

(W) = Webex

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE MAY 7, 2026 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan (W)	Tim Martin	
New England Power Generators Association	Assoc. Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative, Inc.	Publicly Owned Entity			Brian Forshaw (W)
NextEra Energy Resources, LLC	Generation	Michelle Gardner (W)		
NH Office of Consumer Advocate	End User	Matthew Fossum		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier	Ben Griffiths (W)		
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company LLC	Generation	Dan Allegretti		
PowerOptions, Inc.	End User			Doug Hurley (W)
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rhode Island Energy	Transmission	Brian Thomson	Robin Lafayette	
RI Division (DPUC)	End User		Christy Hetherington	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
SYSO Inc.	AR-DG			Alex Worsley
Taunton Municipal Lighting Plant	Publicly Owned Entity	Nick Parrotta (W)	Dave Cavanaugh	
The Moore Company	End User			Bill Short
Union of Concerned Scientists	End User	Susan Muller (W)		
VELCO	Transmission	Frank Ettori		
Veolia Flexible Energy Services North America	AR-LR	Doug Hurley (W)		
Vermont Energy Investment Corporation	AR-LR			Doug Hurley (W)
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (W)
Versant Power	Transmission	Dave Norman	Stephen Johnston	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vistra (Dynegy Marketing and Trade, LLC)	Generation	Ryan McCarthy		
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Z-TECH, LLC	End User			Bill Short

(W) = Webex

2 Consent Agenda

66.67%

2. Revisions to OP Nos. 3, 4, 7, 12, 14 (including a new Appendix J), 18, and 19 (SATOA Conforming Changes)
3. Revisions to OP-16, including its Appendices A, B, C, D, E, G, H, & I (*Orders 881/881-A* Conforming Changes)
4. Retirement of OP-17 Appendix B
5. Revisions to Planning Procedures Nos. 5-3 & 7 (*Order 881* Conforming Changes)
6. Revisions to PP-10 (*Order 2023* Conforming Changes)

RESOLVED, that the Participants Committee approves the Consent Agenda as circulated in advance of this meeting.

CONSENT AGENDA

REMOVED FROM CONSENT AGENDA; TO BE DISCUSSION ITEM #10A

Markets Committee (MC)

*From the previously-circulated notice of actions of the MC's **May 12-14, 2026 meeting**, dated May 15, 2026.*[1]

1. **Changes to the GIS and GIS Operating Rules (MA Section 83D Changes)**[2]

Approve proposed changes to the NEPOOL Generation Information System (GIS) and GIS Operating Rules related to marking of Certificates as being transferred under Section 83D of the Massachusetts Act Relative to Green Communities, as recommended by the MC at its May 12-14, 2026 meeting, together with such further non-material changes as may be approved by the Chair of the GIS Operating Rules Working Group.

The motion to recommend Participants Committee support was approved unanimously, with 2 abstentions noted (1 Supplier, 1 End User).

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **May 21, 2026** meeting, dated May 21, 2026.*[3]

2. **Revisions to OP Nos. 3, 4, 7, 12, 14 (including a new Appendix J), 18, and 19 (SATOA Conforming Changes)**

Support proposed revisions to the following ISO-NE Operating Procedures (OP): No. 3 (Transmission Outage Scheduling), No. 4 (Action During a Capacity Deficiency), No. 7 (Action In An Emergency), No. 12 (Voltage and Reactive Control), No. 14 (Technical Requirements For Assets and Resources), including a new OP No. 14 Appendix J (Storage As Transmission-Only Asset Operator Guide), No. 18 (Metering and Telemetering Criteria), and No. 19 (Transmission Operations), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

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

[2] APX, Inc., the Generation Information System (GIS) Administrator, estimates that implementing this change to the GIS will take 281 development hours. Under Rule 1.3 of the NEPOOL GIS Rules, changes to the GIS that require 50 hours or more of labor or have an estimated cost to NEPOOL of more than $30,000 and that in either case are not required to address a change in law or a change in the ISO Tariff must be approved by the NEPOOL Participants Committee.

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

3. Revisions to OP-16, including its Appendices A, B, C, D, E, G, H, & I (Orders 881/881-A Conforming Changes)

Support proposed revisions to OP No. 16 (Transmission System Data), including its Appendices A (Explanation of Terms and Instructions for Data Preparation of NX9-A), B (Explanation of Terms and Instructions for Data Preparation of NX9-B), C (Explanation of Terms and Instructions for Data Preparation of NX9-C), D (Explanation of Terms and Instructions for Data Preparation of NX-9D), E (Annual Certification), G (Explanation of Terms and Instructions for Data Preparation of NX-9), H (Explanation of Terms and Instructions for Data Preparation of NX-9H), and I (Explanation of Terms and Instructions for Data Preparation of NX-9 (Other Equipment)), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

4. Retirement of OP-17 Appendix B

Support proposed retirement of Appendix B (Methodology For Developing Load Power Factor Standards) to OP-17 (Load Power Factor and System Assessment), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously with one abstention in the Transmission Sector.

5. Revisions to Planning Procedures Nos. 5-3 & 7 (Order 881 Conforming Changes)

Support proposed revisions to ISO-NE Planning Procedure (PP) No. 5-3 (Guidelines for Conducting and Evaluation Proposed Plan Application Analyses) and PP-7 (Procedures for Determining and Implementing Transmission Facility Ratings in New England), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

6. Revisions to PP-10 (Order 2023 Conforming Changes)

Support proposed revisions to PP-10 (Planning Procedure to Support the Forward Capacity Market), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

3 Remarks from Vamsi Chadalavada, ISO-NE CEO

Summary of ISO New England Board and Committee Meetings
June 16, 2026 Participants Committee Meeting

Since the last update, the Audit and Finance Committee and the Nominating and Governance Committee met on May 20, and the Markets Committee met on May 21. The Board of Directors met on May 20 and 21. All of the meetings were held in Holyoke, Massachusetts.

The Audit and Finance Committee reviewed the Company's financial performance against the 2026 budget, and approved the first quarter's unaudited financial statements after management confirmed that all relevant disclosures were included in the financial statements. Next, the Committee discussed the preliminary 2027 operating and capital budgets. The Committee discussed the factors contributing to the increased budgets, including the complexity of various projects, inflationary increases, and the need to invest in artificial intelligence. The Committee also considered the impact on ratepayers of the increase. The Committee reviewed a draft of the Company's 2025 tax return on Form 990. The Committee considered management's proposal to update the Company's purchase order approval levels for management, and agreed to recommend that the Board approve the changes. Finally, the Committee was provided with an update on the potential purchase of land to support a new building, including conference space, in Holyoke.

The Nominating and Governance Committee received an update on the conclusion of the Joint Nominating Committee process for 2025 and formally nominated the slate of directors for election in 2026 (Kathryn Guarini, Craig Ivey, and Mark Vannoy). The Committee held a preliminary discussion regarding assignments to Board committees and succession planning for board leadership positions, all in advance of the next Board year that begins on October 1, 2026. The Committee also discussed the orientation program for director-elect, Kathryn Guarini. Next, the Committee discussed issues that are "top of mind" for the Board, in advance of meetings with the NEPOOL sectors in June. In executive session, the Committee reviewed the Board and committees' self-evaluation responses.

The Markets Committee was provided with a review from both the Internal and External Market Monitors of market performance in winter 2025-2026. Next, the Committee provided final comments on the Internal Market Monitor's draft annual markets report, which assesses the competitiveness of the wholesale markets and reviews market pricing outcomes. The Committee then received updates on Day-Ahead Ancillary Services and the Capacity Auction Reforms projects.

The Board of Directors (acting as the members of the corporation) held its annual meeting of members and elected Ms. Guarini and Messrs. Ivey and Vannoy to the Board of Directors for three-year terms, effective October 1, noting that the slate was previously approved by the NEPOOL Participants Committee at its May 7th meeting. The Board then held a strategic planning session, looking ahead five years. The next day, the Board resumed its meeting and received a report from management on current business, and discussed activities related to the Federal Energy Regulatory Commission, federal executive and legislative branches, and the New England states. The Board also received a report from the Chief Financial Officer, and prepared for the upcoming ISO/RTO Council Conference. The Board received reports from the standing committees, and during the Nominating and Governance Committee report, reviewed topics for discussion with the NEPOOL Sectors in June, and an onboarding program for the new director. The Board concluded its meeting with an executive session.

4 Systems & Market Operations Report

June 16-18, 2026
Summer Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

NEPOOL PARTICIPANTS COMMITTEE | 5/7/2026
Meeting Agenda Item #4

NEPOOL Participants Committee

System & Market Operations Report – June 2026

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VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS

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System & Market Operations Report Enhancements

- This month's report includes several updates to improve clarity and usability
  - Weather information is now summarized in two "Weather At-a-Glance" slides (Slides 5-6)
  - Key system operations events are now summarized on Slide 7
  - Market highlights and peak load statistics (historically included on slides 4-5 of the report) have been replaced with three "Markets-At-a-Glance" slides (Slides 8-10)
  - Day-Ahead Ancillary Services data has been relocated to Slides 44-47
  - Wind and solar power forecast error metrics (introduced last month) are now presented on Slide 21
  - A table of notable planned outages has been added on Slide 22
  - Additional enhancements are planned in upcoming months to further simplify and improve the report

HIGHLIGHTS

Weather At-a-Glance

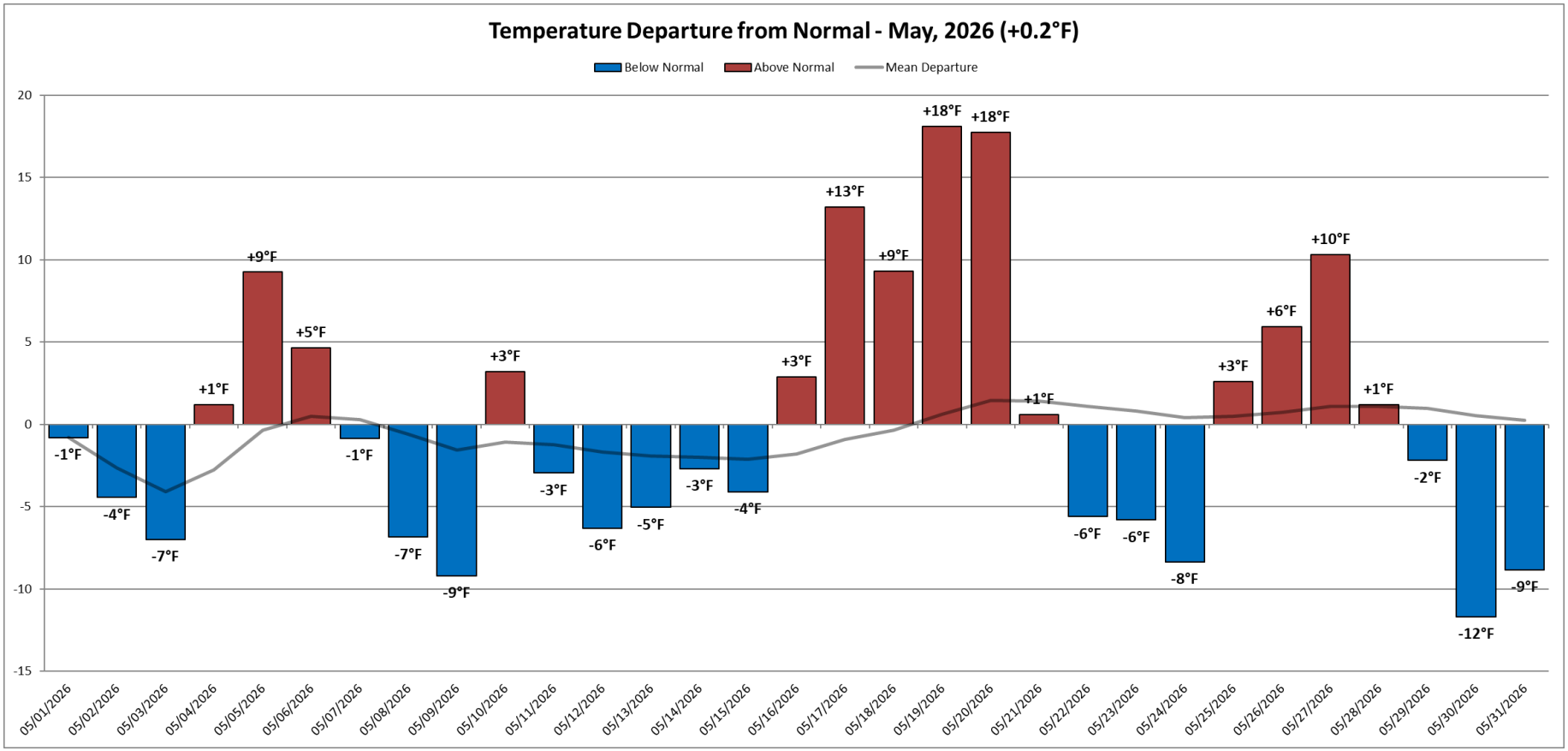
May 2026

New England Weather	**May 2026**	**Change M-O-M**	**Change Y-O-Y**
Avg Hourly Temperature (°F) *(23-City Weighted)*	58	13.9 ↑	.1 ↑
Boston Weather			
Temperature Departure from Normal (°F)	2.4	2.5 ↑	1.6 ↑
Maximum Temperature (°F)	96	18° ↑	12 ↑
Minimum Temperature (°F)	42	13° ↑	1.6 ↓
Precipitation Departure from Normal (inches)	-0.35	1.81 ↑	-4.35 ↓
Hartford Weather			
Temperature Departure from Normal (°F)	-0.6	-2.8 ↓	-1.1 ↓
Maximum Temperature (°F)	96	6 ↑	11 ↑
Minimum Temperature (°F)	36	12 ↑	-3 ↓
Precipitation Departure from Normal (inches)	-0.6	0.25 ↑	-5.04 ↓

NEW SLIDE (Last Month)

Weather At-a-Glance, cont.

New England 23-City Temperature Departure From Normal – May 2026



NEW SLIDE

System Operations Highlights

- ISO declared M/LCC-2, Abnormal Conditions Alert, at 16:00 on May 19 due to a forecasted capacity deficiency
  - The Morning Report (published at ~8:00 a.m.) had projected a ~1,000 MW capacity surplus, based on a peak load forecast of 19,200 MW
  - Higher-than-expected dew points drove demand significantly above forecast throughout the day. The largest forecast error (~1,525 MW) occurred during HE16
  - In response, ISO updated the peak hour load forecast twice:
    - 12:30: increased to 19,700 MW
    - 3:30: increased to 20,200 MW
  - Afternoon and evening thunderstorms were stronger than forecast, contributing to a subsequent drop in actual load below updated projections
  - Peak system load reached 18,707 MW, the highest May load since May 19, 2017
  - The 23-city weighted average temperature reached 90°F, also the highest since May 19, 2017
  - M/LCC-2 was cancelled at 22:00

NEW SLIDE

Markets At-a-Glance: Payments and Prices

*Data Through May 31, 2026**

Market Value ($ millions)[a]	May 2026	% Change M-O-M	% Change Y-O-Y
Energy Market Value[b]	466	2% ↑	40% ↑
Ancillary Services[c]	-10	-2465% ↓	-547% ↓
Forward Capacity Market (FCM)	89	0%	-26% ↓
Net Commitment Period Compensation (NCPC)	4	52% ↑	147% ↑
Total	**549**	**0%**	**21%** ↑
Average Power Prices ($/MWh)			
DA Hub LMP	45.80	-1% ↓	30% ↑
DA Hub LMP Plus Forecast Energy Requirement (FER) Price	48.29	-1% ↓	30% ↑
RT Hub LMP	49.24	8% ↑	50% ↑
Average Generation Fuel Prices ($/MMBtu)			
Natural Gas (MA Avg.)	2.20	-5% ↓	-14% ↓
No.6 Oil	19.91	7% ↑	93% ↑
Diesel	30.18	0%	88% ↑

*Based on available settled days. Complete month data for Energy Market Value, Capacity value, and LMPs are available in the Monthly Market Report published circa the 15th of the month found on the ISO Website here.

[a] Market Value totals are converted to 'equivalent month' values before doing the comparisons to prior months.

[b] Energy Market Value includes net costs associated with satisfying the Forecast Energy Requirement constraint.

[c] Ancillary Services (A/S) = DAAS, Reserves, Regulation, less Marginal Loss Revenue Fund.

Note: April A/S total was -0.4M. Negative May A/S result was driven largely by DAAS and Marginal Loss Revenue Fund results

Underlying natural gas data furnished by:

ICE Global markets in clear view

NEW SLIDE

Markets At-a-Glance: Demand

*Data Through May 31, 2026**

Average Hourly Net Energy for Load (MWh)[a]	May 2026	% Change M-O-M	% Change Y-O-Y	
Revenue Quality Metered (RQM)	11,489	-0.2% ↓	1.5% ↑	
Telemetered	10,842	-0.6% ↓	1.6% ↑	
Max/Min Hourly System Load (MW)				
Maximum RQM	19,496	29.8% ↑	33.1% ↑	
Maximum Telemetered	18,723	25.1% ↑	30.9% ↑	Wed, May 20, 2026 in he19
Minimum Telemetered	5,924	-2.8% ↓	8.7% ↑	Sat, May 16, 2026 in he13
Year-To-Date Hourly Peak Load (MW)[b]				
RQM	20,216	0.0%	3.0% ↑	Sun, Jan 25, 2026 in he14
Telemetered	20,182	0.0%	2.9% ↑	Sun, Jan 25, 2026 in he14
Forward Capacity Market (FCM) Load[c]	19,868	0.0%	2.7% ↑	Sun, Jan 25, 2026 in he13

*Based on available settled days.
[a] Telemetered loads as monitored by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SORs). Both are 'net energy for load' concepts and therefore include transmission losses. Neither of them reflect storage load. Due to the difference in metering quality, derivation, and the impact of SORs, these two peaks can occur on different days and/or hours.
[b] Y-T-D % Change Y-O-Y is based on like periods (i.e., through similar months). Y-T-D values are available in the Weekly Market Report found on the ISO Website here.
[c] FCM load values reflect the sum of active, normal load assets that are non-dispatchable (it excludes storage load), are included in the FCM settlement and do not reflect any transmission losses. FCM Load is Revenue Quality Metered.

NEW SLIDE

Markets At-a-Glance: Supply

*Data Through May 31, 2026**

Average Hourly RQM Supply[a]	May 2026 (MWh)	% Change M-O-M	% Change Y-O-Y
Total RQM Supply	**13,135**	**-1%** ↓	**9%** ↑
Natural Gas	4,368	-22% ↓	-16% ↓
Nuclear	2,631	58% ↑	1% ↑
Hydro	1,148	-7% ↓	-14% ↓
Solar	719	5% ↑	18% ↑
Wind	674	6% ↑	65% ↑
Other[b]	442	7% ↑	-6% ↓
Hybrid/Solar	91	8% ↑	28% ↑
Batteries	40	0%	198% ↑
Oil	10	54% ↑	-19% ↓
Demand Response Resources (DRRs)	2	2084% ↑	195% ↑
Imports	3,009	2% ↑	119% ↑
Average Hourly Behind-The-Meter (BTM) Solar[c]	**1,560**	**6%** ↑	**22%** ↑

*Based on available settled days.
[a] Supply is RQM quality and includes both Modeled and Settlement Only Resources (SORs) and includes DRR and imports. Differs from NEL load due to not being adjusted for exports, Dispatchable Asset Related Demand (DARDs) and inadvertent tie flows.
[b] Other generation includes landfill gas, methane, wood, coal and refuse.
[c] BTM Solar is an average hourly (all hours) estimate. Historically, the majority (~2/3rd) of BTM solar is distributed solar and is not captured in RQM supply numbers.

System Planning Highlights

- The ISO is scheduled to make the preliminary preferred Longer-Term Transmission Solution determination by September 2026
- No load forecast updates to report this month

Forward Capacity Market (FCM)

- CCP 17 (2026-2027)
  - The ISO filed the ICR and related values with FERC, for the ARA3 to be conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.
  - The third annual reconfiguration auction (ARA3) was held March 2-4, 2026. Results were posted on March 31, 2026.
- CCP 18 (2027-2028)
  - The ISO filed the ICR and related values with FERC, for the ARA2 to be conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.
  - The second annual reconfiguration auction (ARA2) will be held August 3-5, 2026 and results will be posted by September 3, 2026

CCP – Capacity Commitment Period

FCM, cont.

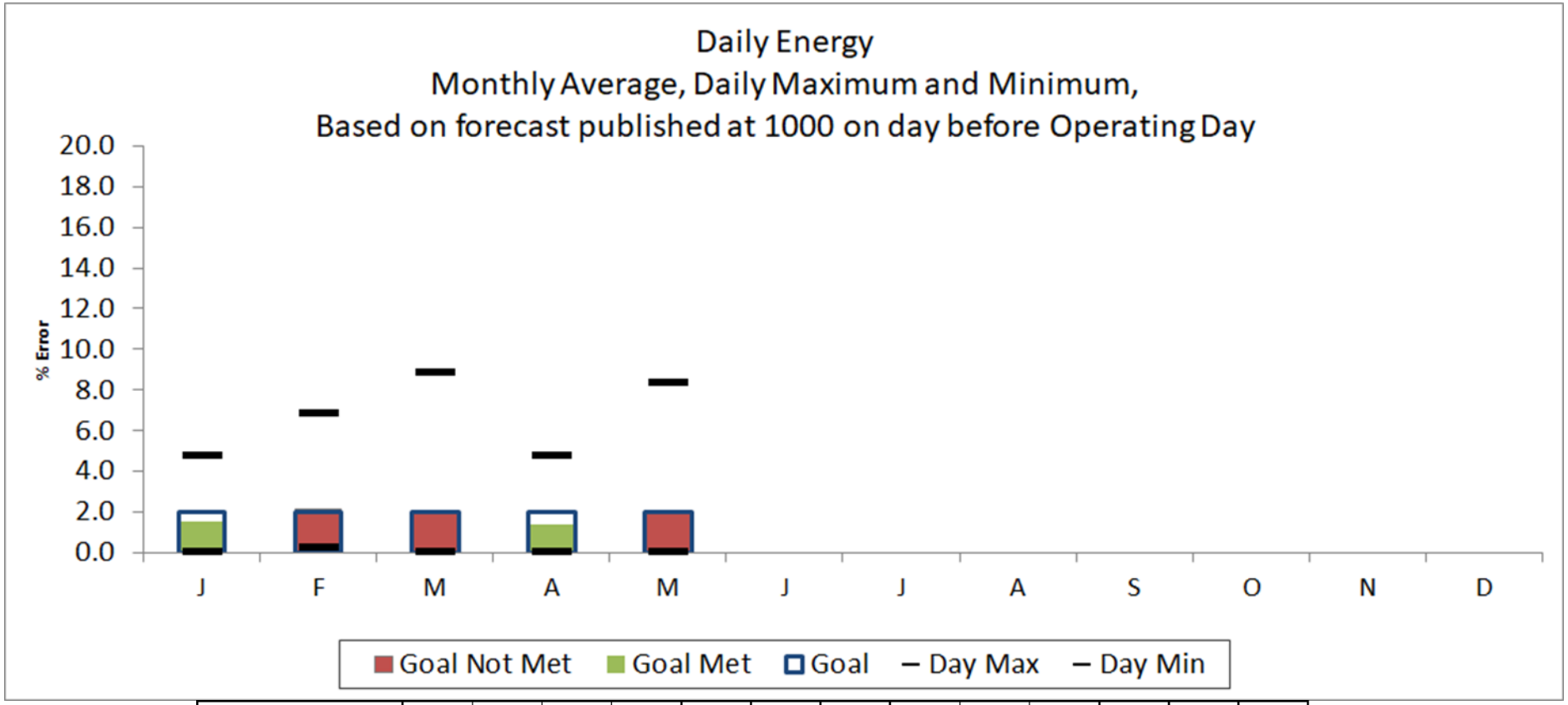
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
    - On May 20, 2024 FERC issued an order accepting the additional delay
    - 2024 interim RA qualification process completed on November 1, 2024
      - A total of 1,389 MW (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
    - 2026 interim RA qualification process
      - The Show of Interest (SOI) window was open April 16-30, 2026
        - 53 SOIs totaling 4,872 MW of requested summer QC were submitted
      - The New Capacity Qualification Package (NCQP) submission window opens on June 15, 2026 and closes on June 23, 2026
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

SYSTEM OPERATIONS

NPCC Simultaneous Activation of Ten-Minute Reserve Events

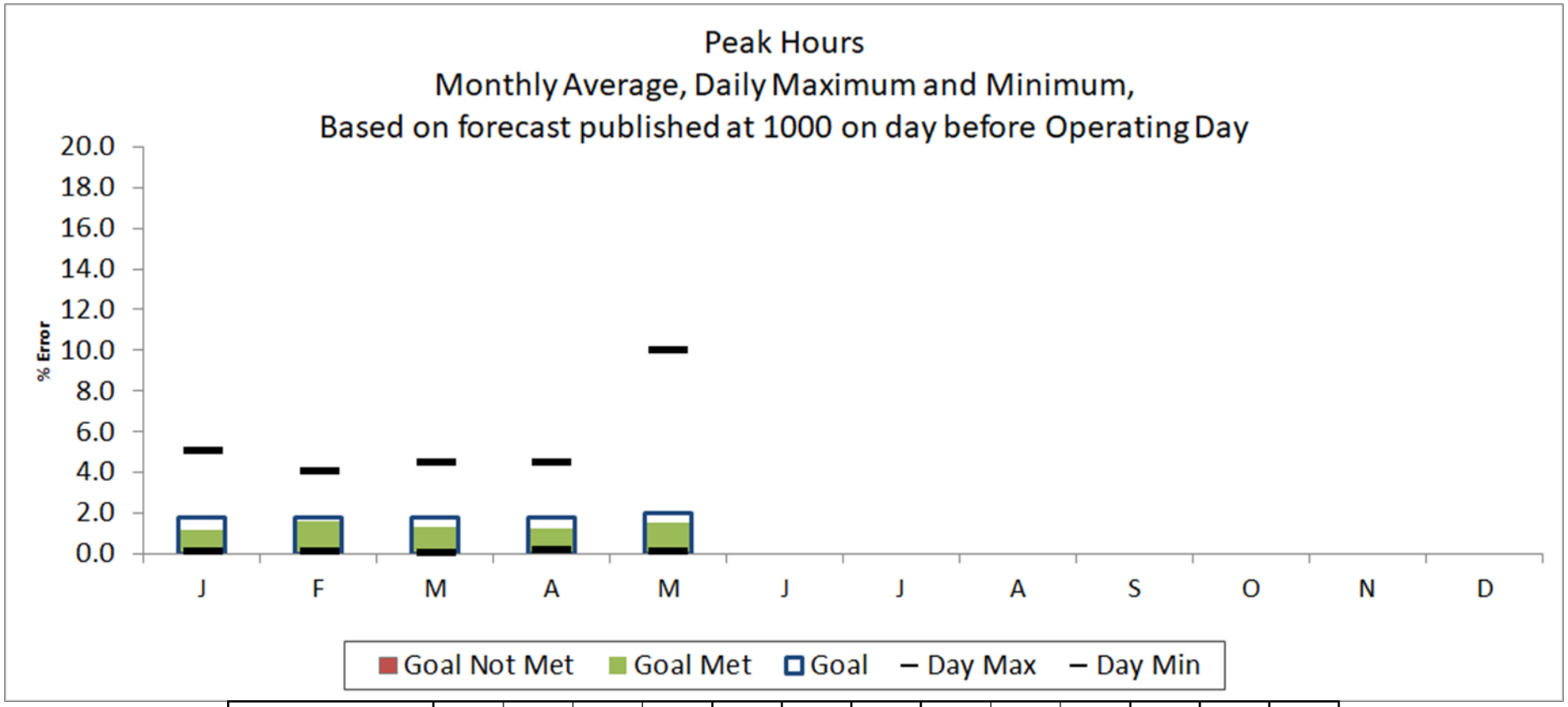
Date	Area	MW Lost
05/01/2026	NYISO	1249
05/09/2026	NYISO	1250
05/19/2026	ISO-NE	1120
05/20/2026	ISO-NE	1119
05/25/2026	ISO-NE	1090

2026 Load Forecast Accuracy



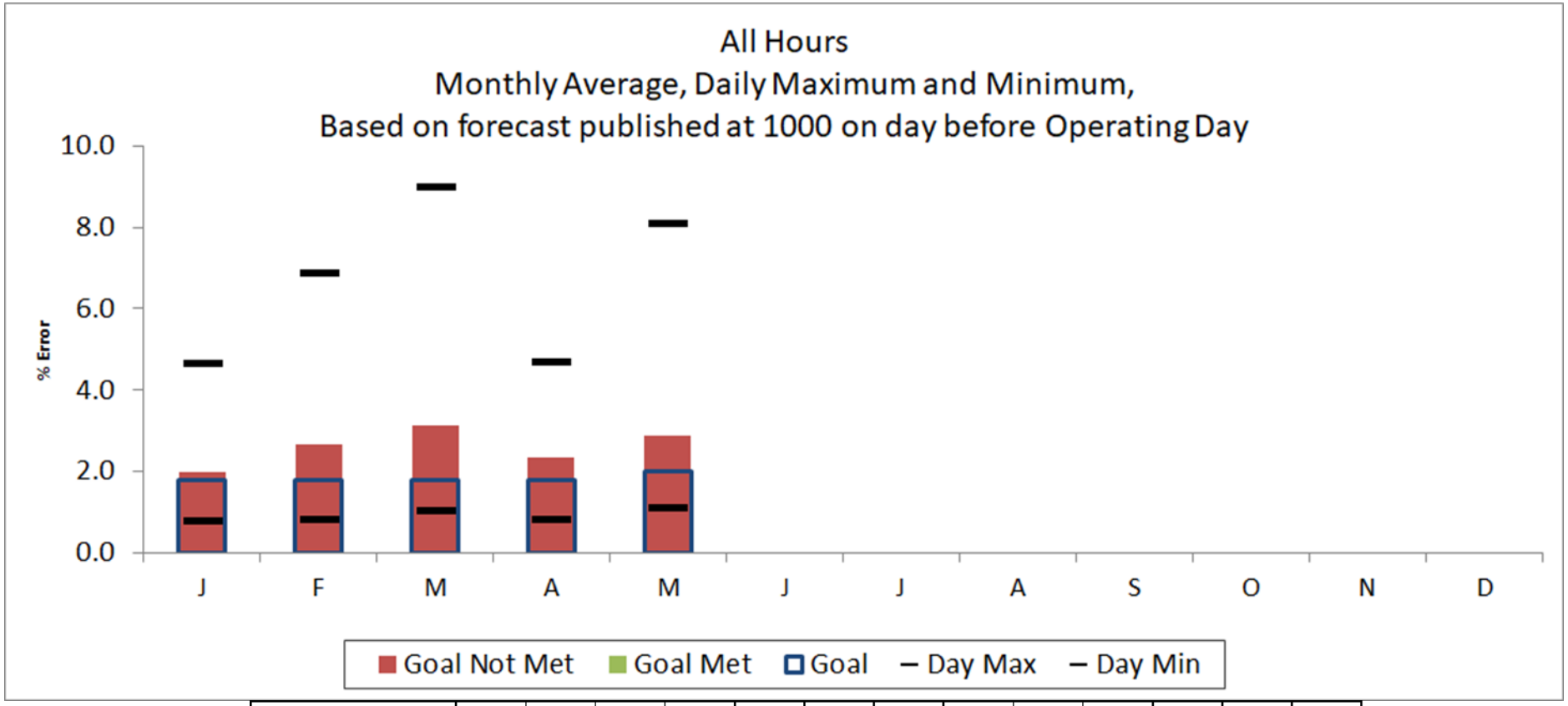
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81	8.85	4.75	8.32								8.85
Day Min	0.01	0.22	0.03	0.00	0.06								0.00
MAPE	1.57	2.12	2.11	1.42	2.06								1.85
Goal	2.00	2.00	2.00	2.00	2.00								

2026 Load Forecast Accuracy, cont.



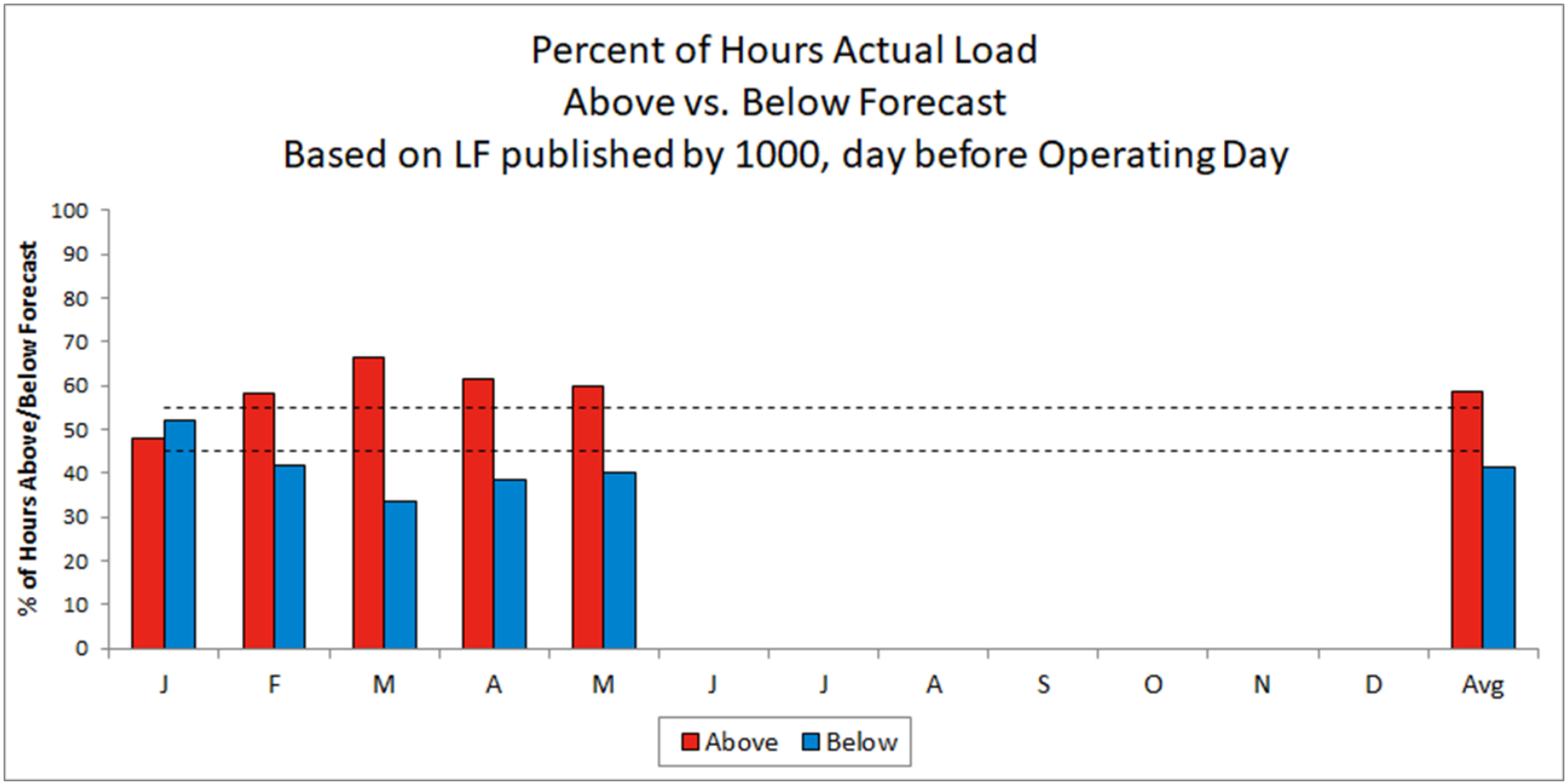
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02	4.51	4.51	10.02								10.02
Day Min	0.08	0.12	0.01	0.16	0.11								0.01
MAPE	1.17	1.64	1.34	1.24	1.52								1.38
Goal	1.80	1.80	1.80	1.80	2.00								

2026 Load Forecast Accuracy, cont.



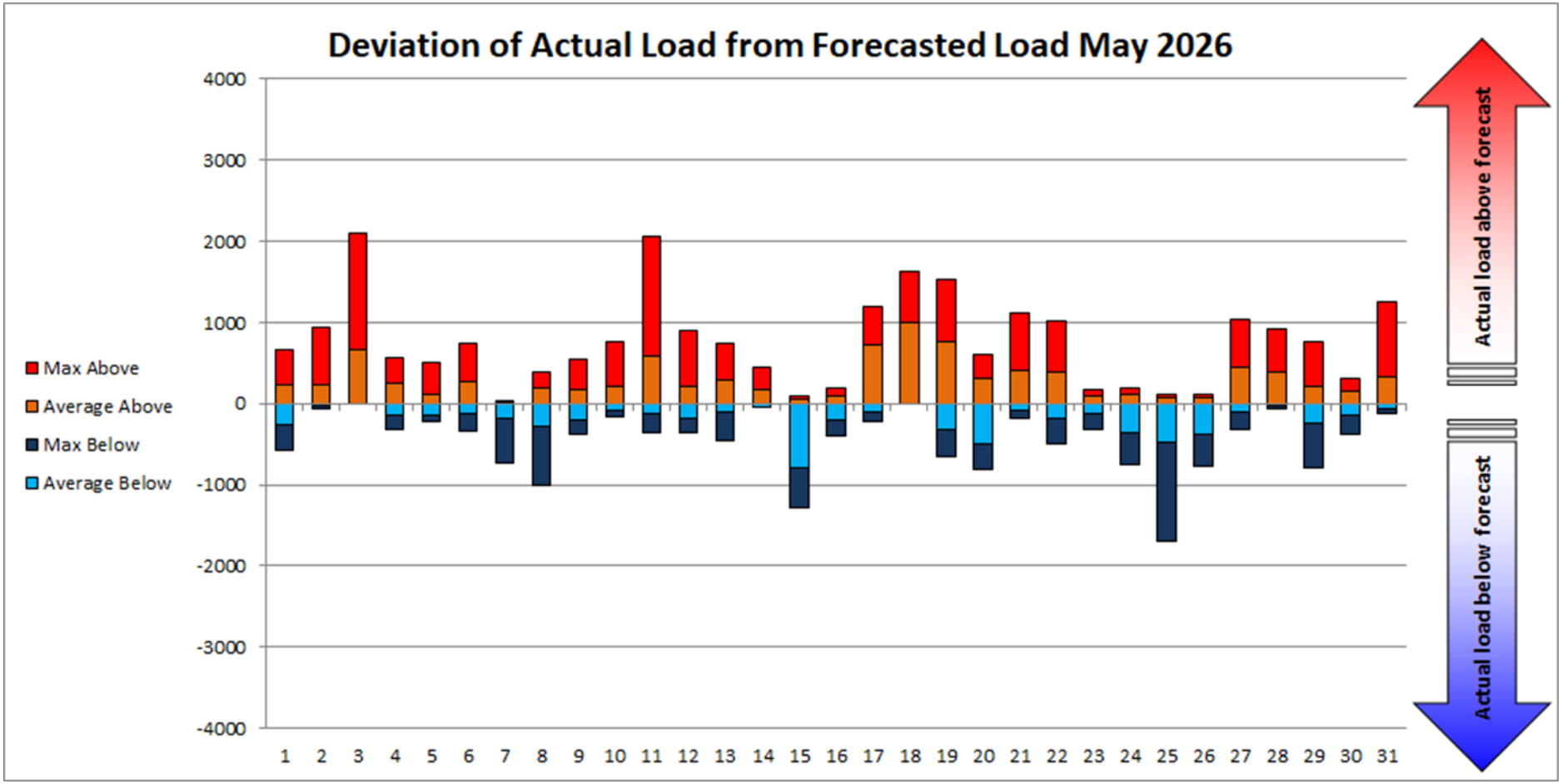
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65	6.85	8.96	4.67	8.09								8.96
Day Min	0.76	0.82	1.01	0.80	1.09								0.76
MAPE	2.00	2.66	3.14	2.33	2.90								2.61
Goal	1.80	1.80	1.80	1.80	2.00								

2026 Load Forecast Accuracy, cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	47.8	58.2	66.4	61.4	59.7								59
Below %	52.2	41.8	33.6	38.6	40.3								41
Avg Above	203	299.6	325	240.4	296.5								325
Avg Below	-233.3	-271.5	-290.0	-157.2	-194.4								-290
Avg All	-20	59	130	91	106								73

2026 Load Forecast Accuracy, cont.



NEW SLIDE

Wind and Solar Power Forecast Error Statistics

- Beginning with the April 2026 System & Market Operations Report, ISO included links to wind and solar forecast error statistics
- Solar forecast error statistics are for front-of-meter solar resources only
- These statistics are updated monthly and published on the ISO-NE external website
- Wind Generation Forecast Error Statistics
- Solar Power Forecast Error Statistics

NEW SLIDE

Notable Planned Outages

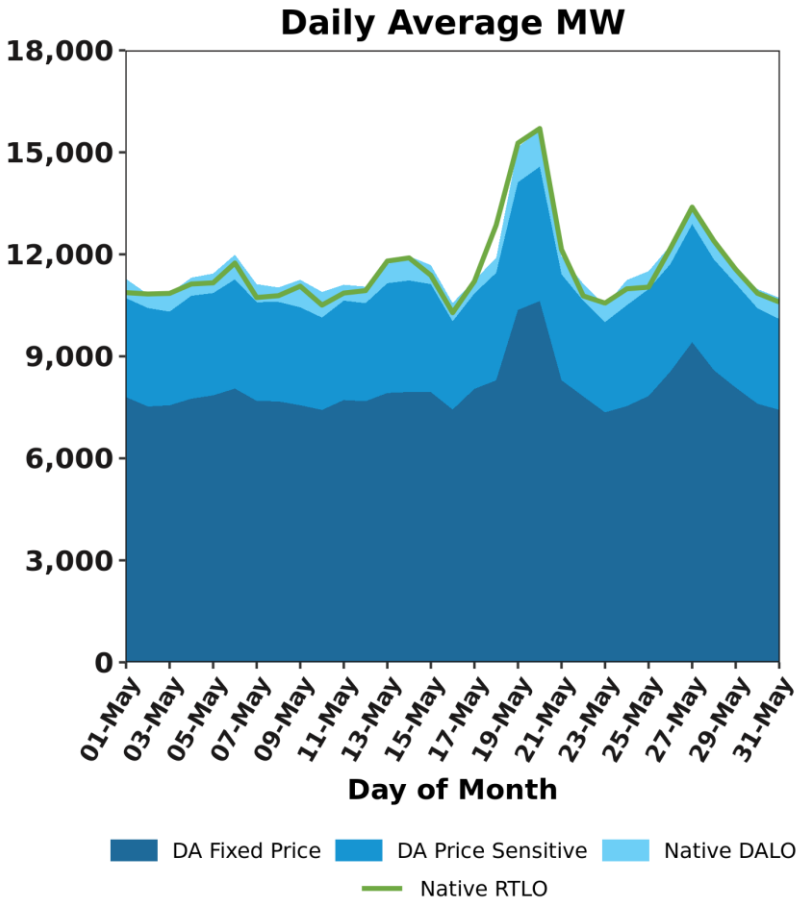
- The table below highlights select longer-duration planned outages that impact transfer capability; it is not a comprehensive list of all outages.

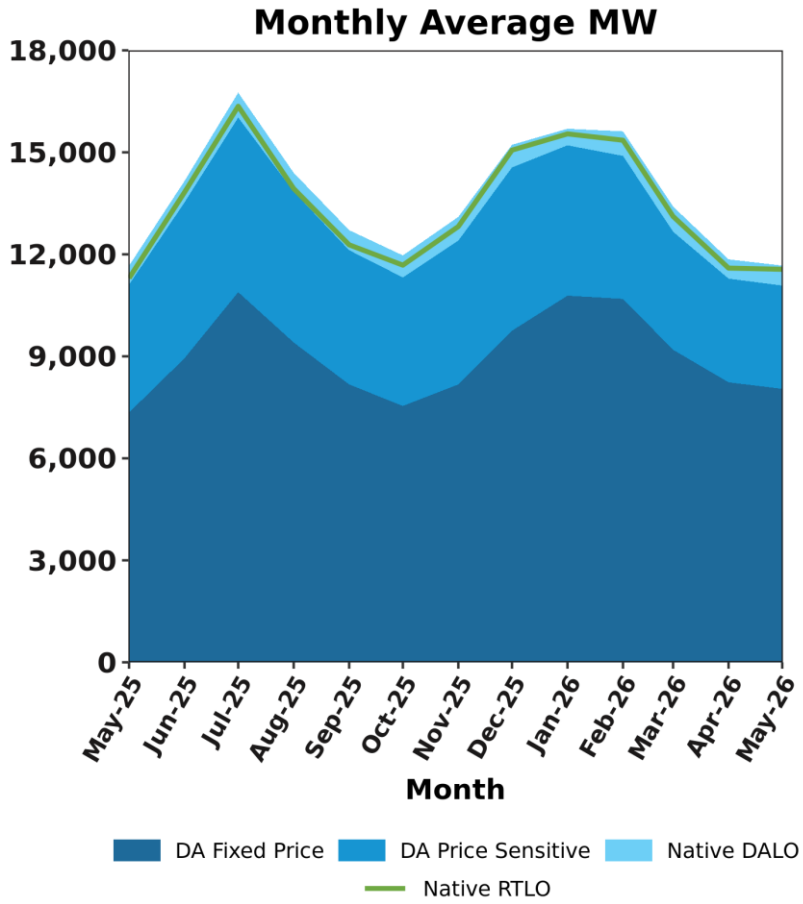
Outage	Start	Planned End	Total Transfer Capability (TTC) Impacts
New Brunswick Generator	04-10-2026	07-27-2026	New Brunswick – New England = 650 MW, New England -New Brunswick = 400 MW
3001	07-20-2026	07-30-2026	New Brunswick – New England = 270 MW, New England -New Brunswick = 0 MW

MARKET OPERATIONS

Supply and Demand Volumes

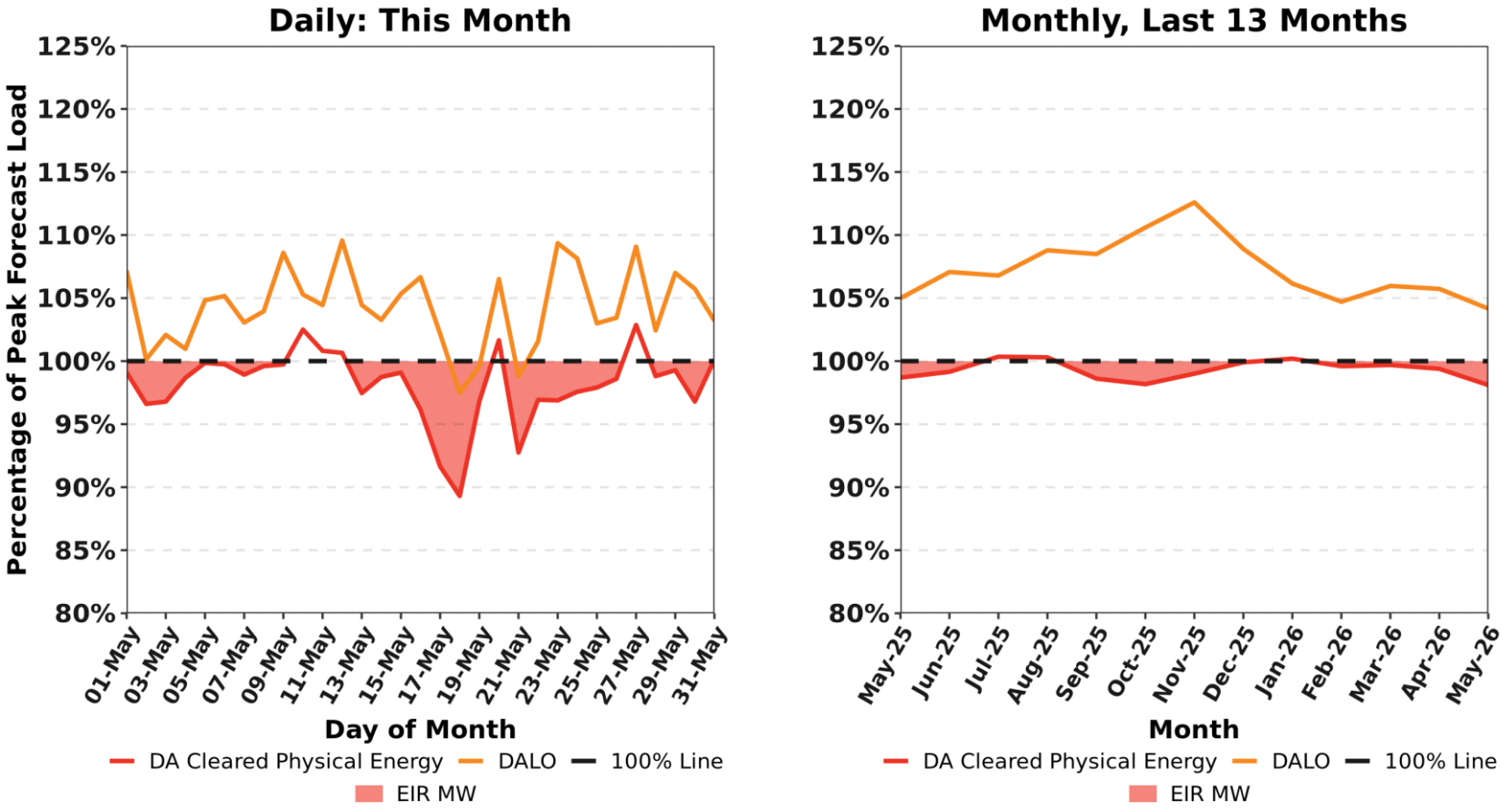
DA Cleared Native Load by Composition Compared to Native RT Load





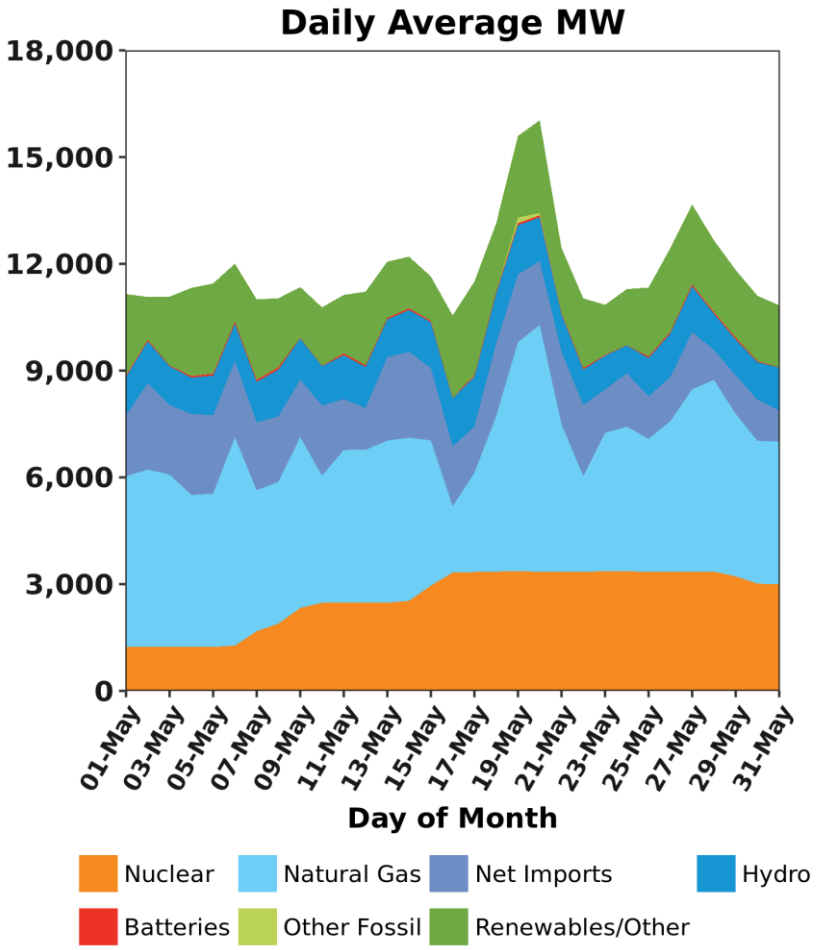
Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

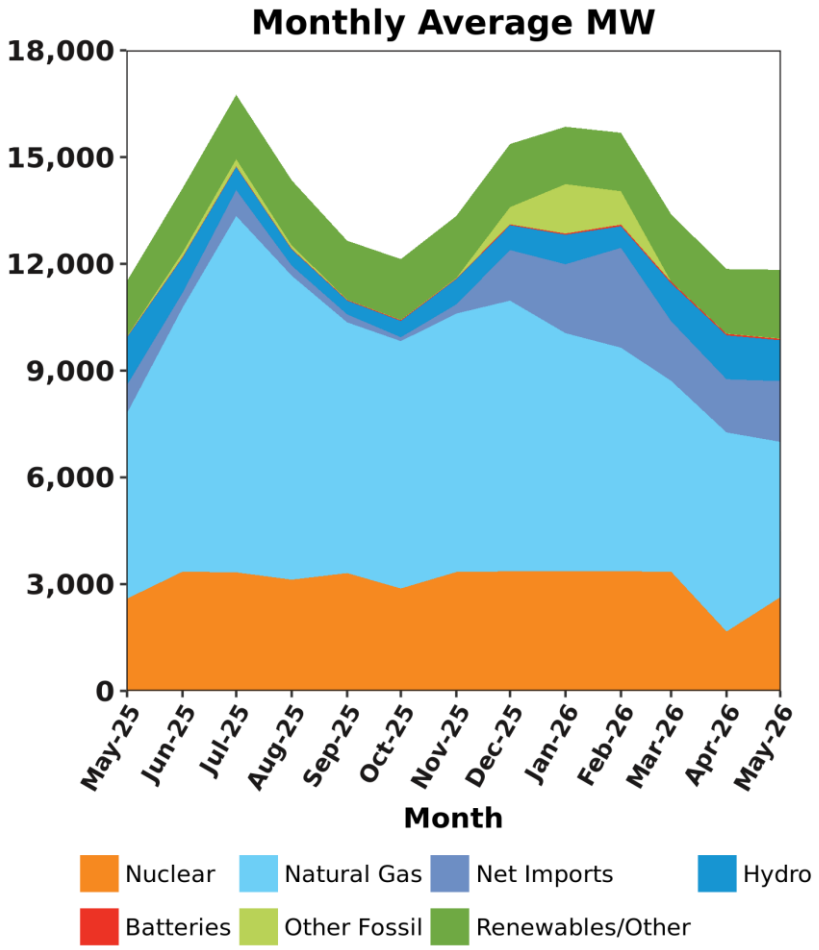
DA Volumes as % of Forecast in Peak Hour



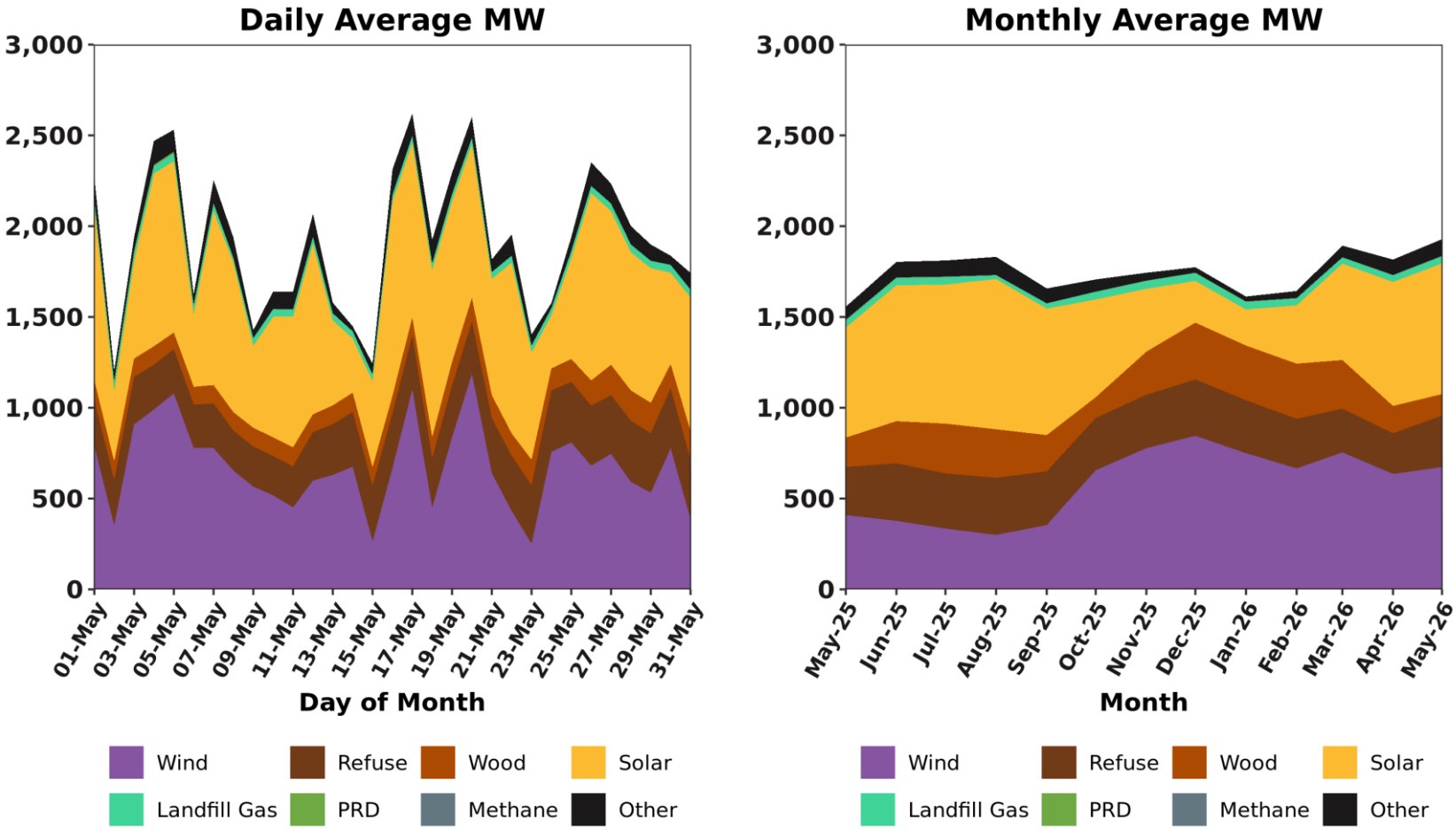
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Resource Mix



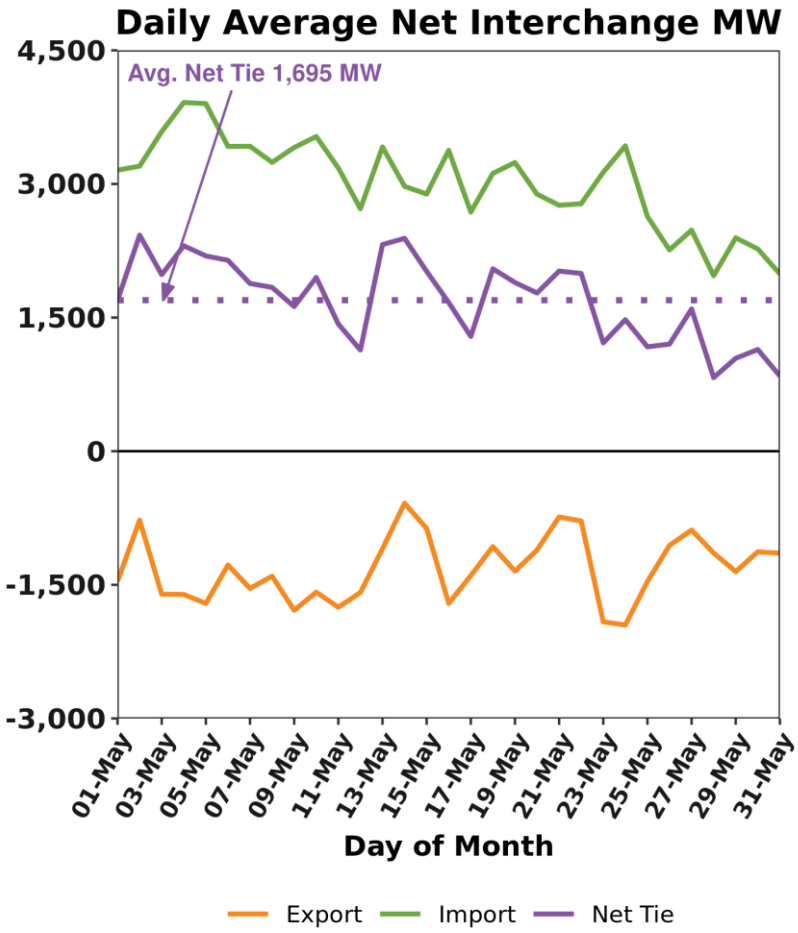


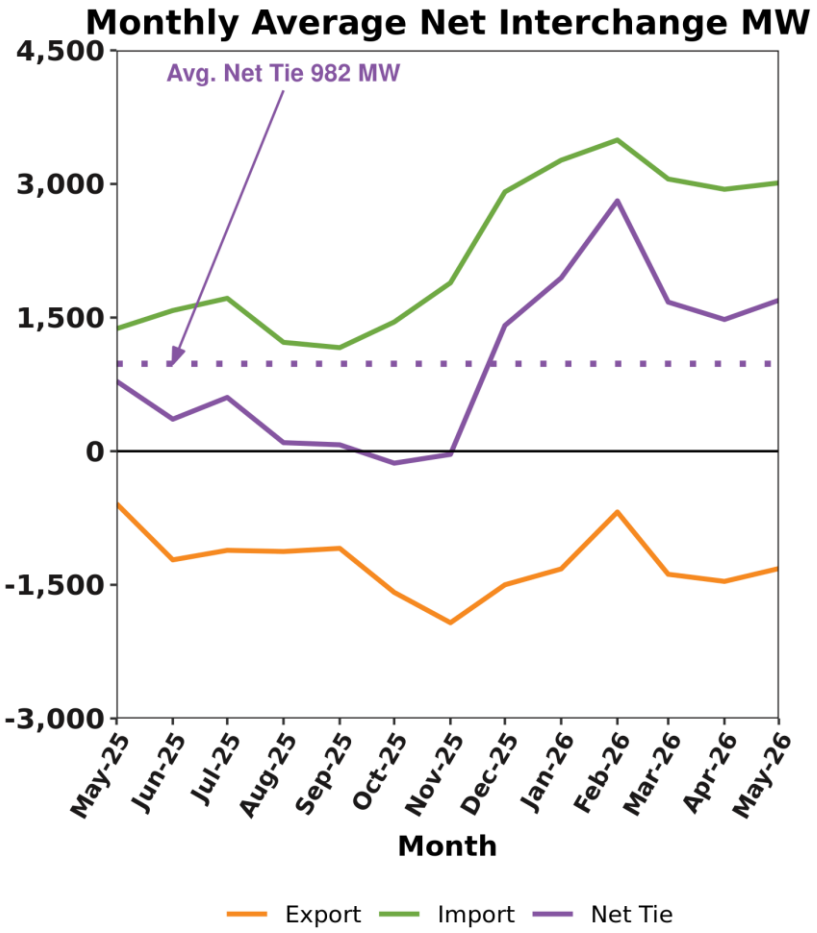
Renewable/Other Generation by Fuel Type



"Other" currently only contains Hybrid Solar/Battery; PRD=Demand Response Resources (DRR)

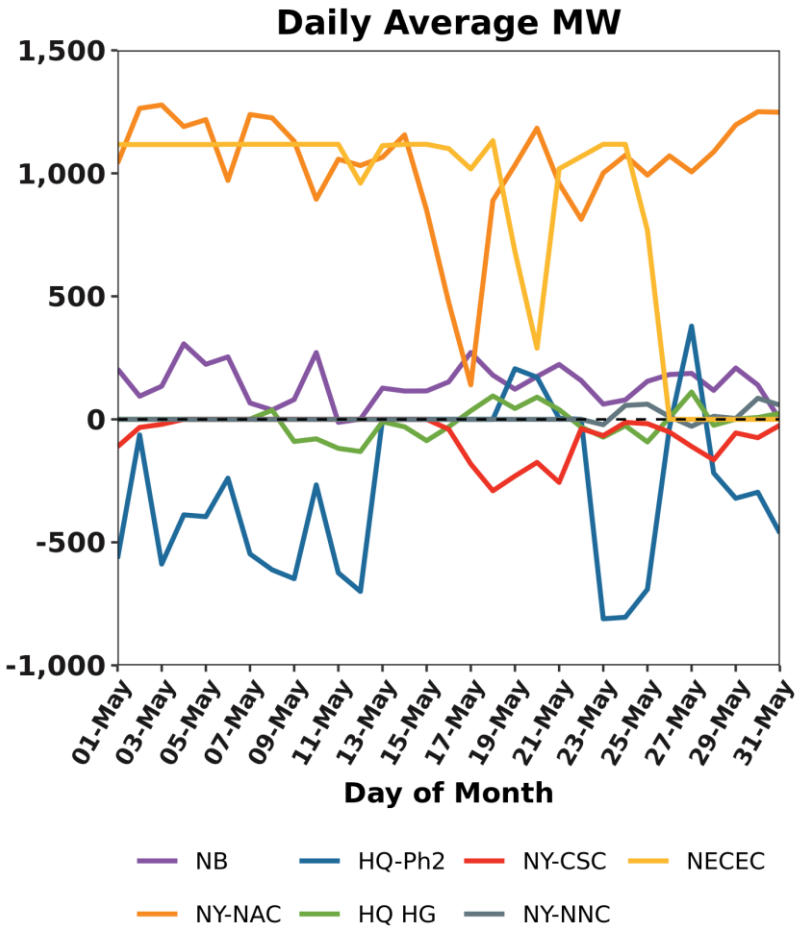
RT Net Interchange

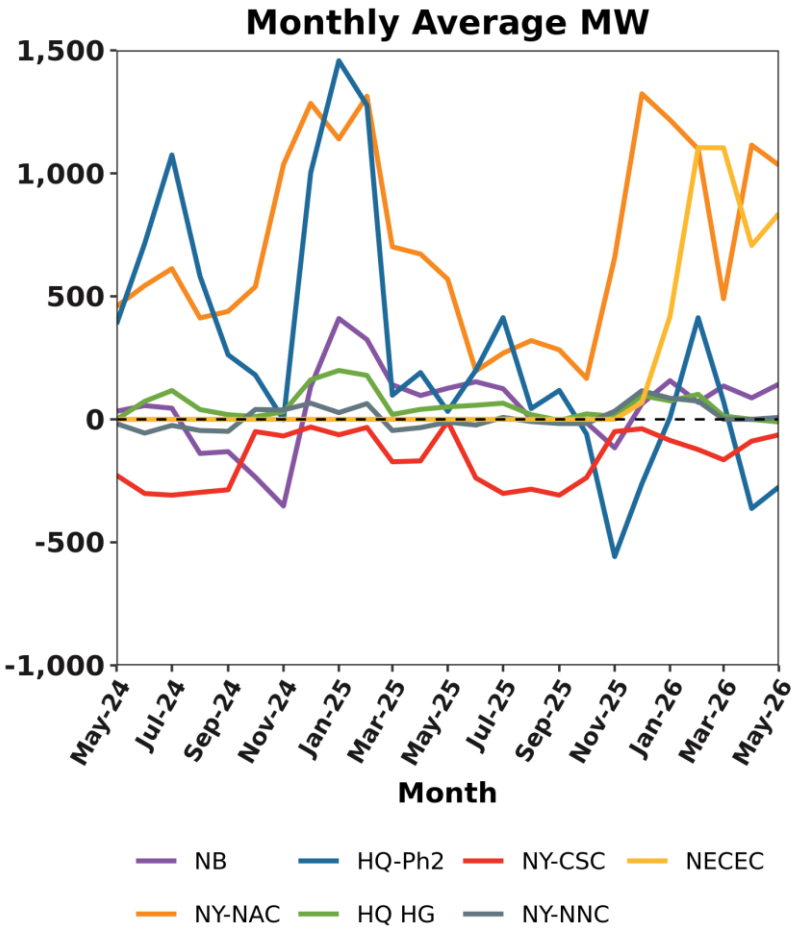




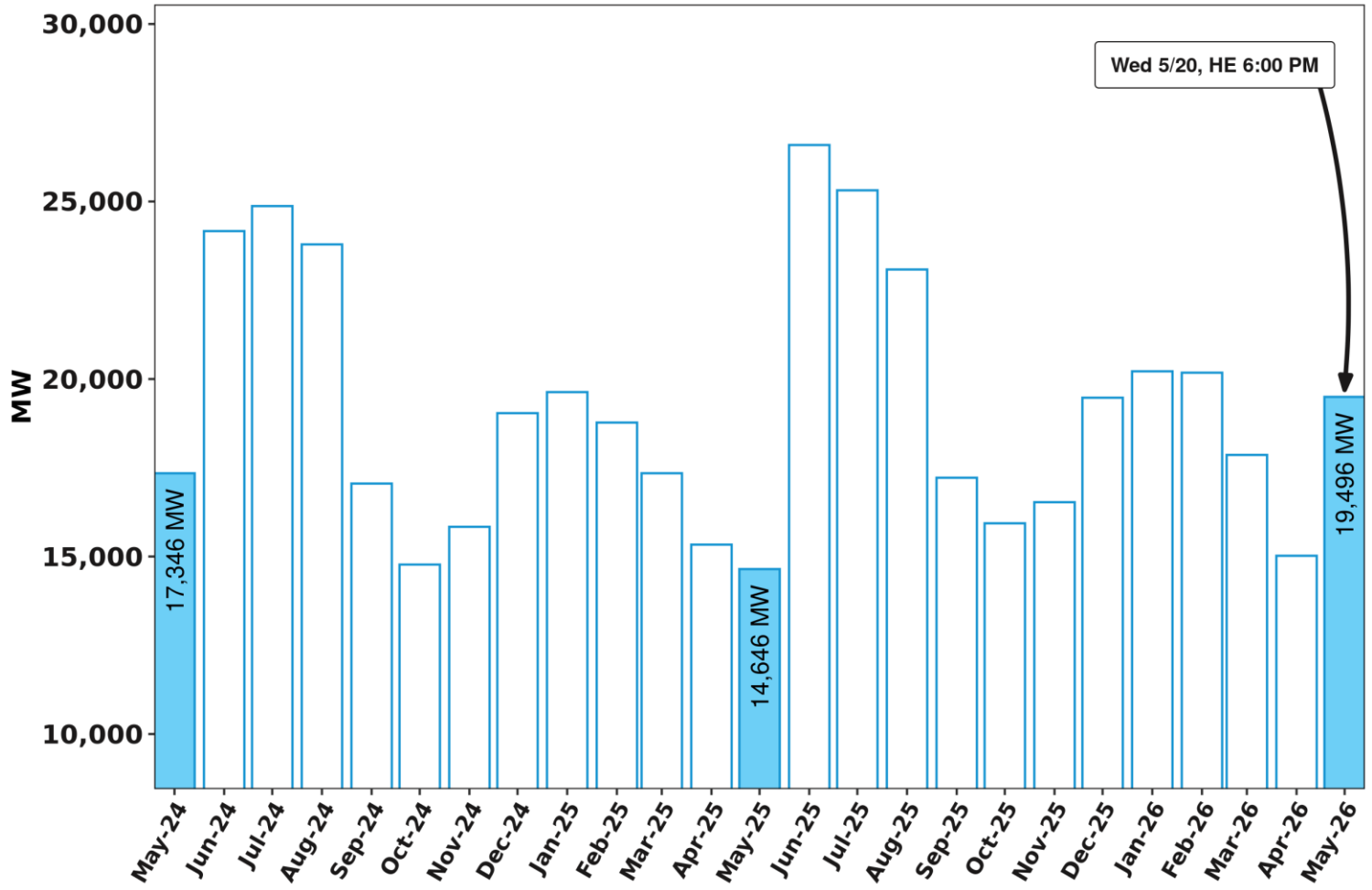
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



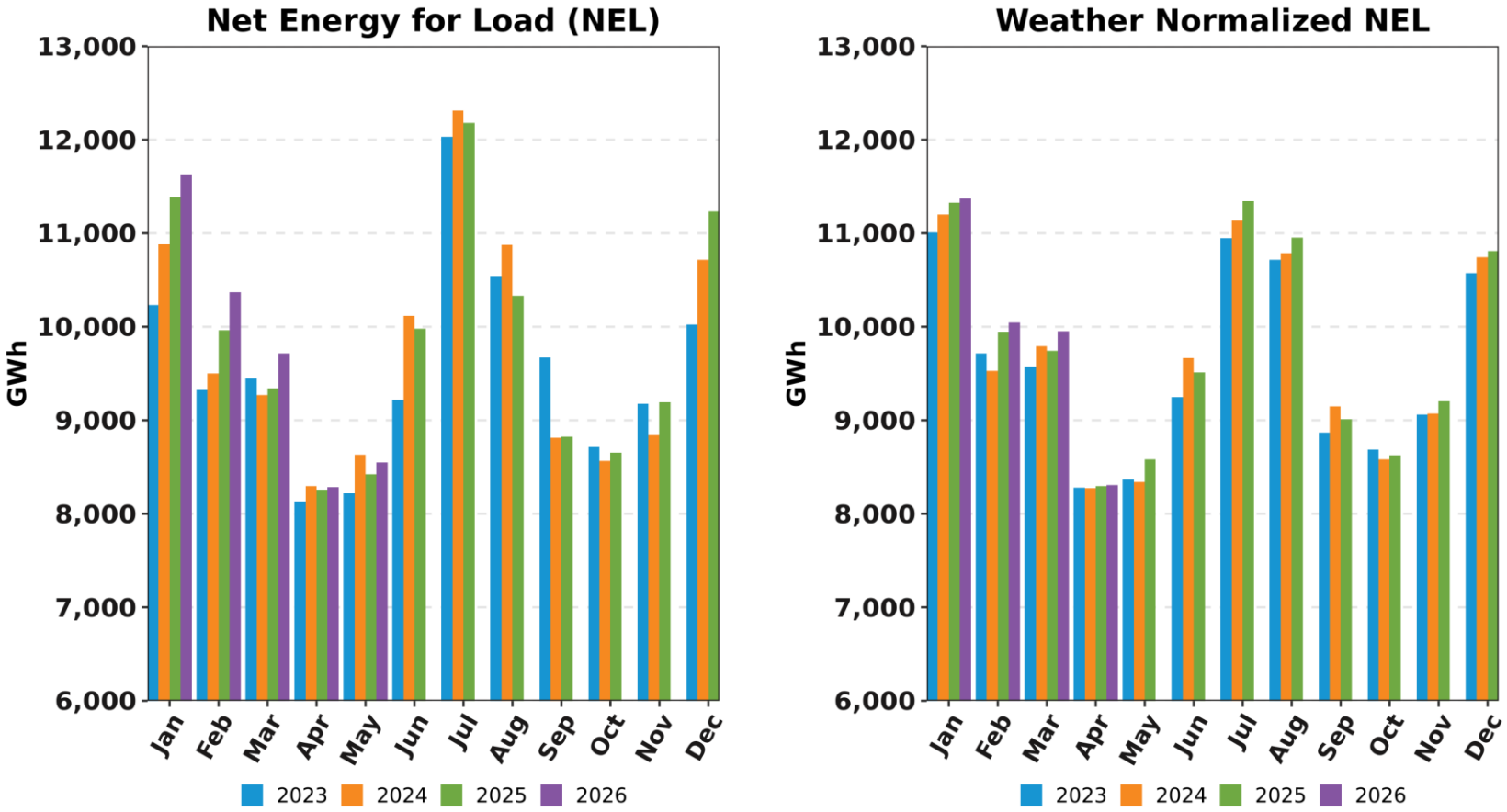


RQM System Peak Load MW by Month



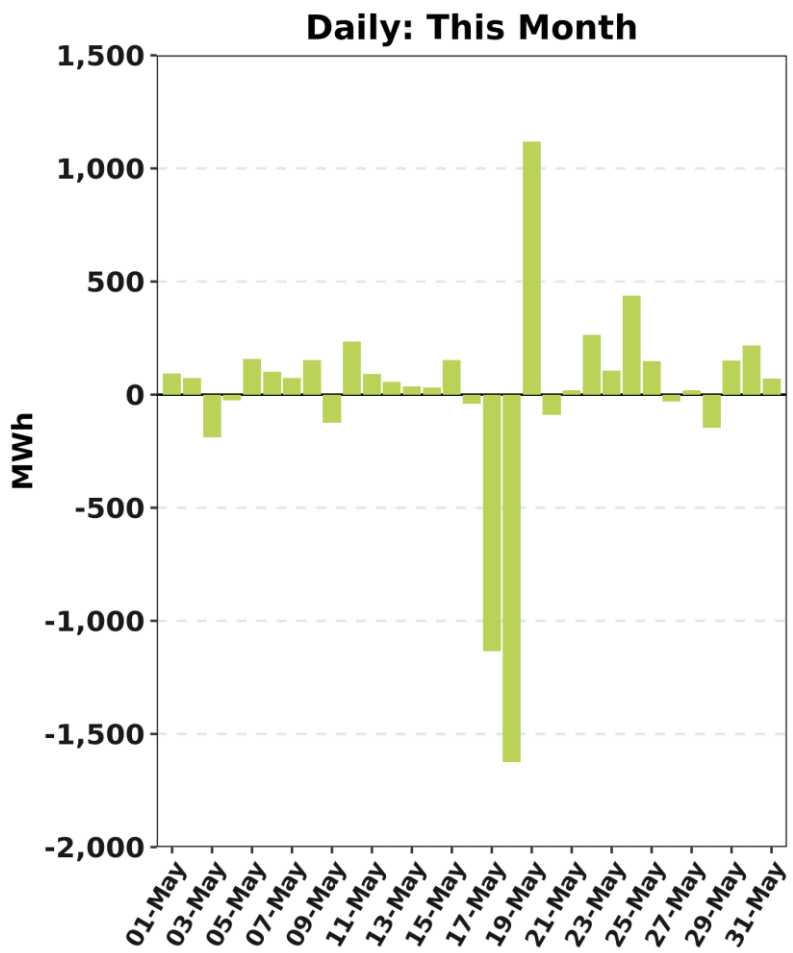
Shaded columns highlight current month and the same month over the prior two years

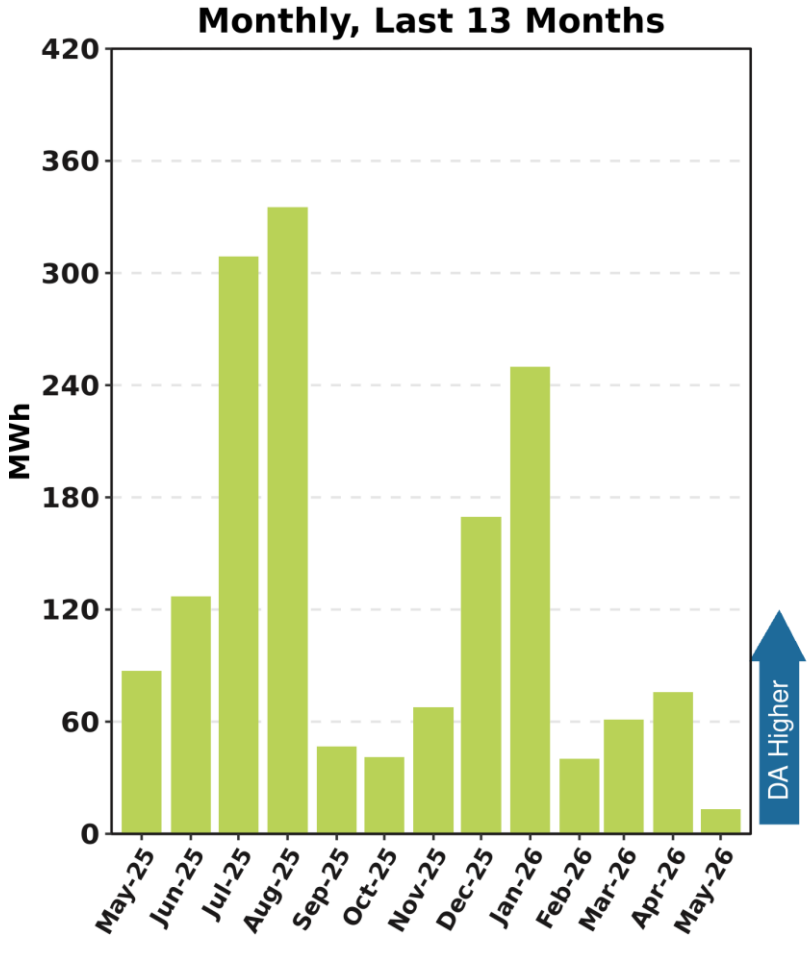
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



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.

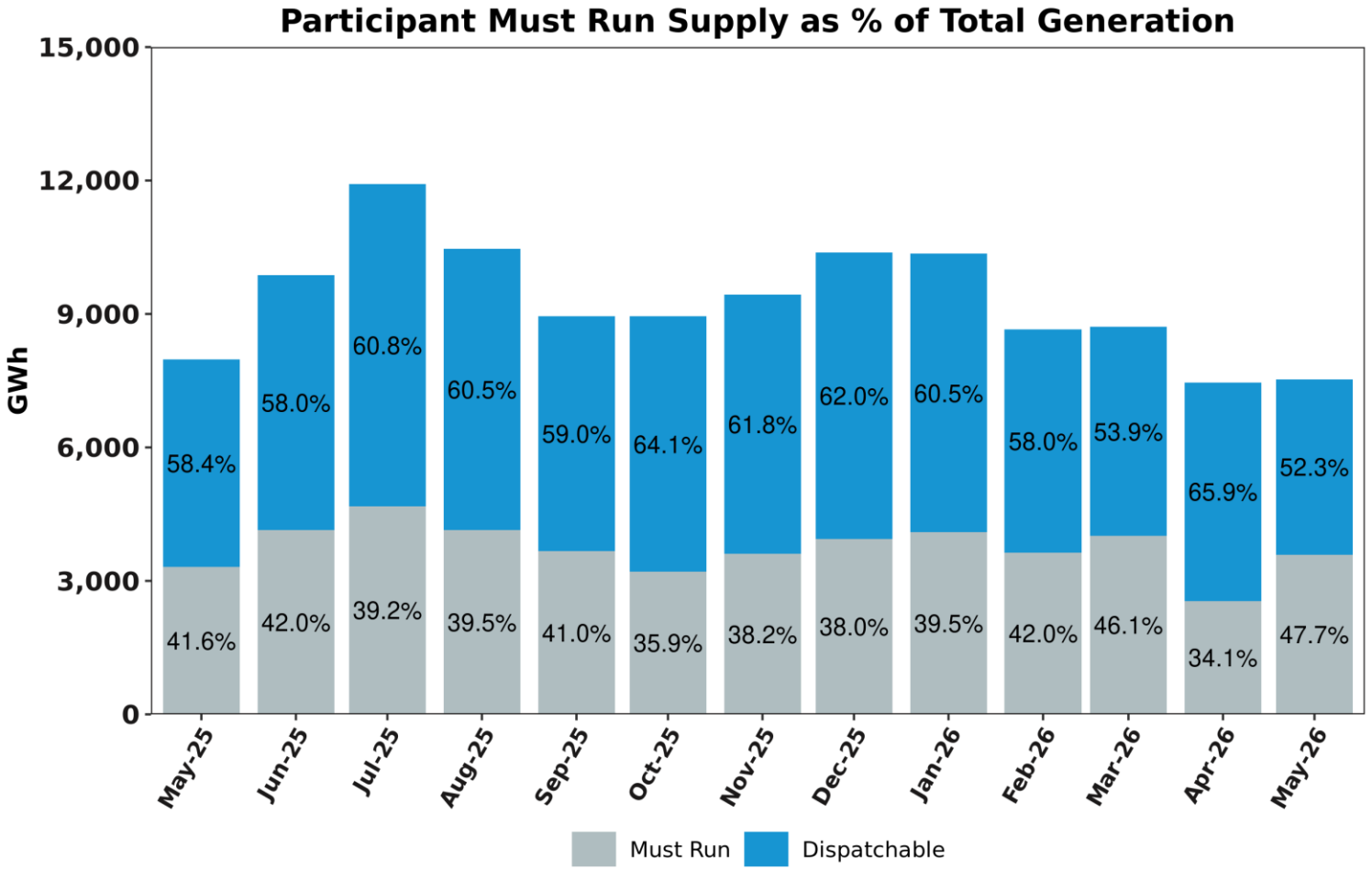
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour





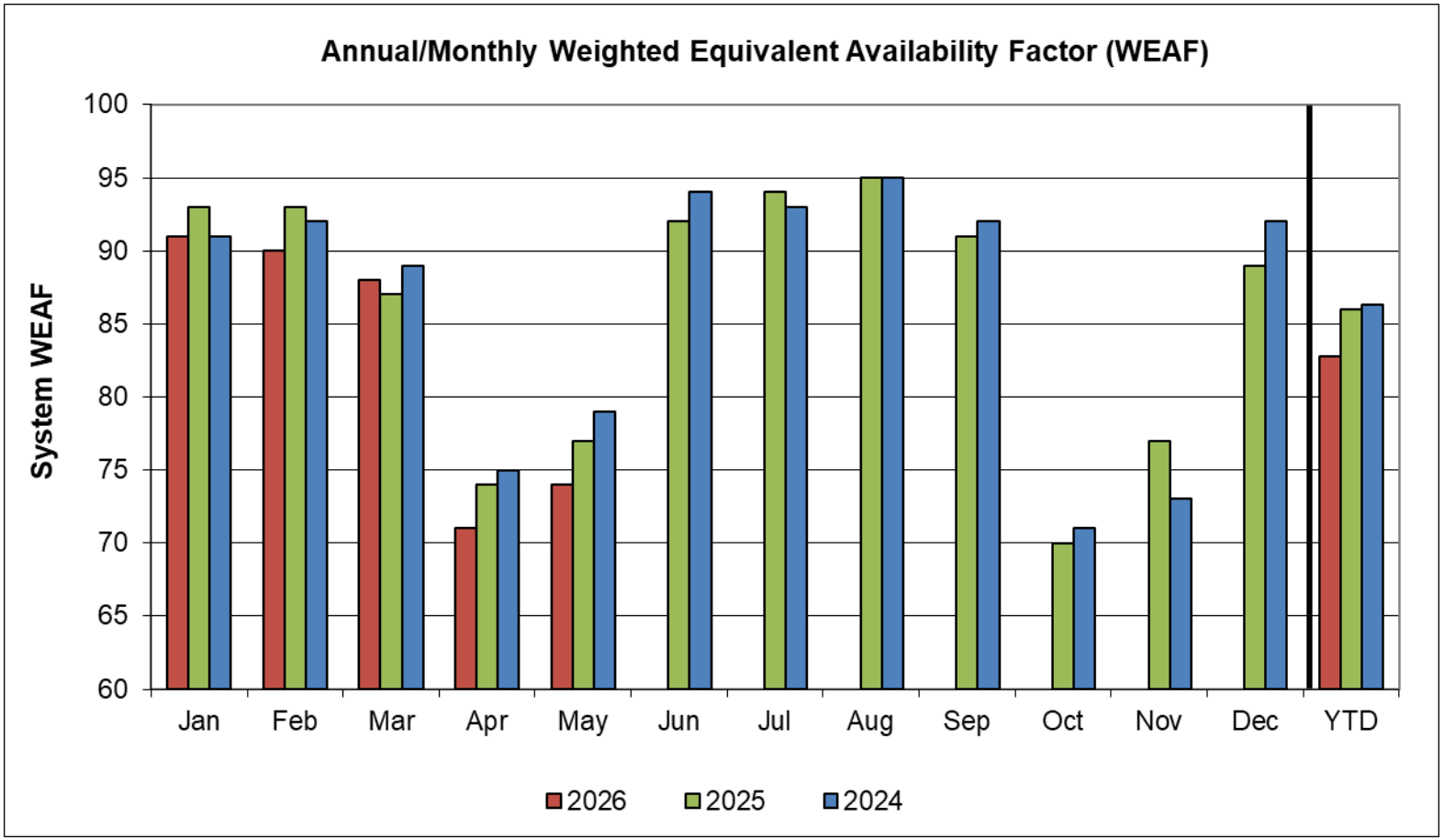
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

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
2026	91	90	88	71	74								83
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

Data as of 6/3/26

MARKET OPERATIONS

Market Pricing

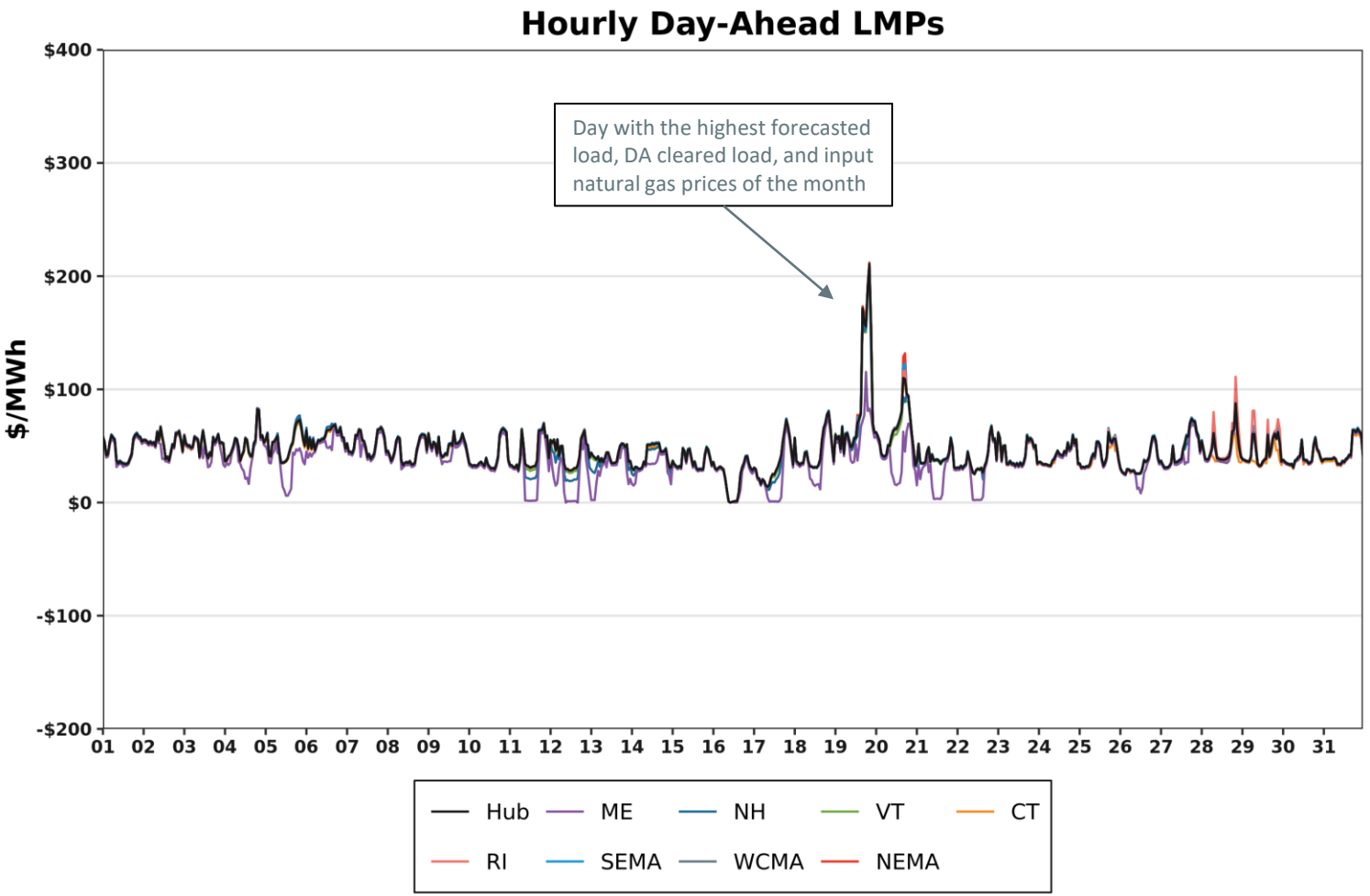
DA vs. RT LMPs ($/MWh)

Arithmetic Average

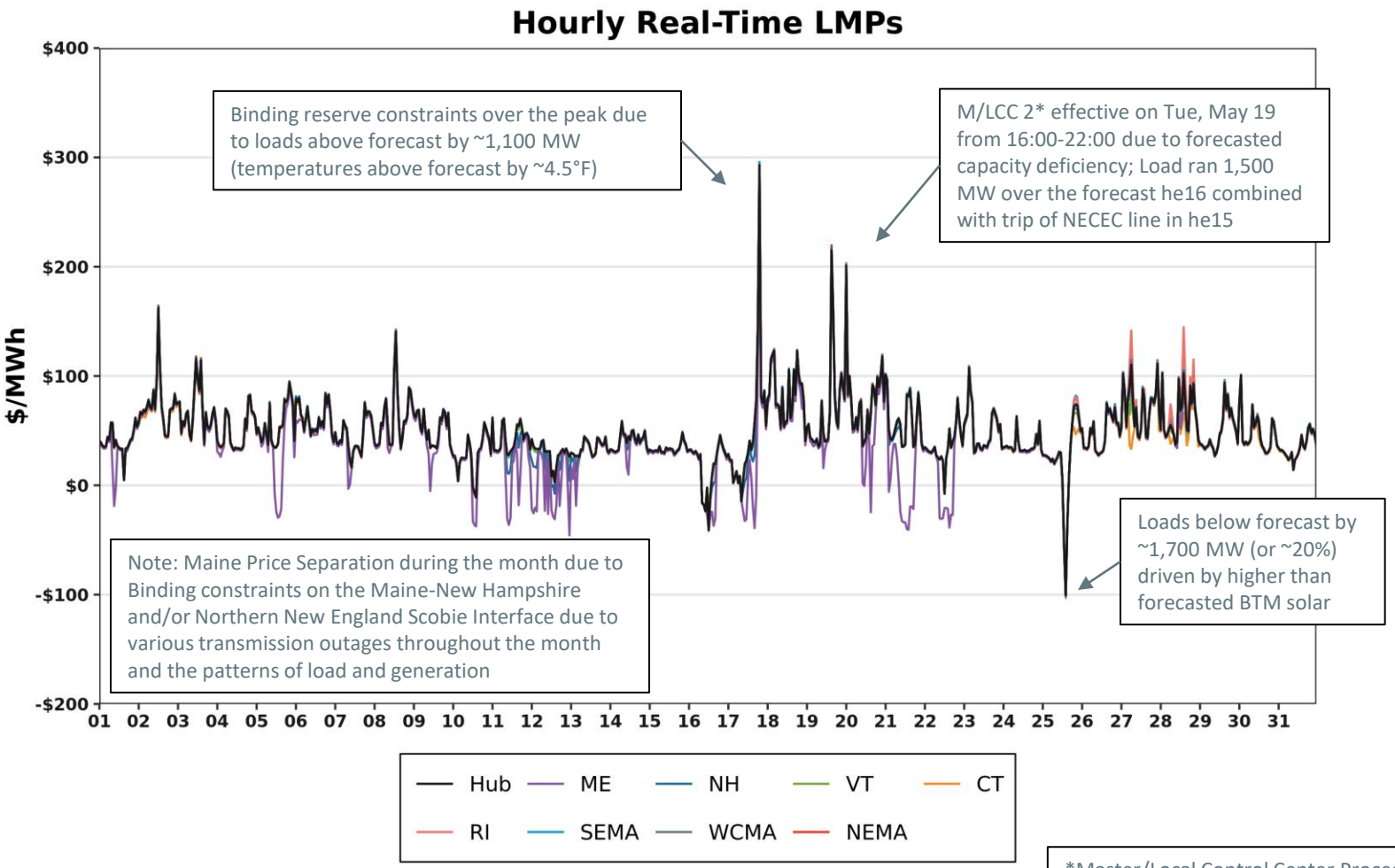
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$41.35	$41.07	$41.72	$41.11	$40.17	$41.28	$41.70	$41.37	$41.91
Real-Time	$39.37	$38.79	$39.65	$39.23	$38.46	$39.17	$39.62	$39.37	$39.77
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%
Year 2025	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Day-Ahead	$68.11	$66.29	$68.63	$68.21	$66.23	$67.78	$68.63	$68.16	$68.93
Real-Time	$66.15	$63.91	$66.63	$66.15	$64.66	$65.85	$66.56	$66.18	$66.93
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%

May-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$35.21	$31.12	$34.94	$34.71	$34.90	$34.96	$35.39	$35.21	$35.46
Real-Time	$32.77	$28.78	$32.54	$32.33	$32.45	$32.47	$32.85	$32.76	$32.97
RT Delta %	-6.93%	-7.52%	-6.87%	-6.86%	-7.02%	-7.12%	-7.18%	-6.96%	-7.02%
May-26	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Day-Ahead	$45.80	$38.27	$44.88	$45.21	$44.08	$46.06	$46.48	$45.73	$46.47
Real-Time	$49.24	$41.08	$48.37	$48.45	$47.23	$49.42	$49.89	$49.09	$49.97
RT Delta %	7.51%	7.34%	7.78%	7.17%	7.15%	7.29%	7.34%	7.35%	7.53%
Annual Diff.	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Yr over Yr DA	30.08%	22.98%	28.45%	30.25%	26.30%	31.75%	31.34%	29.88%	31.05%
Yr over Yr RT	50.26%	42.74%	48.65%	49.86%	45.55%	52.20%	51.87%	49.85%	51.56%

Hourly DA LMPs, May 1-31, 2026

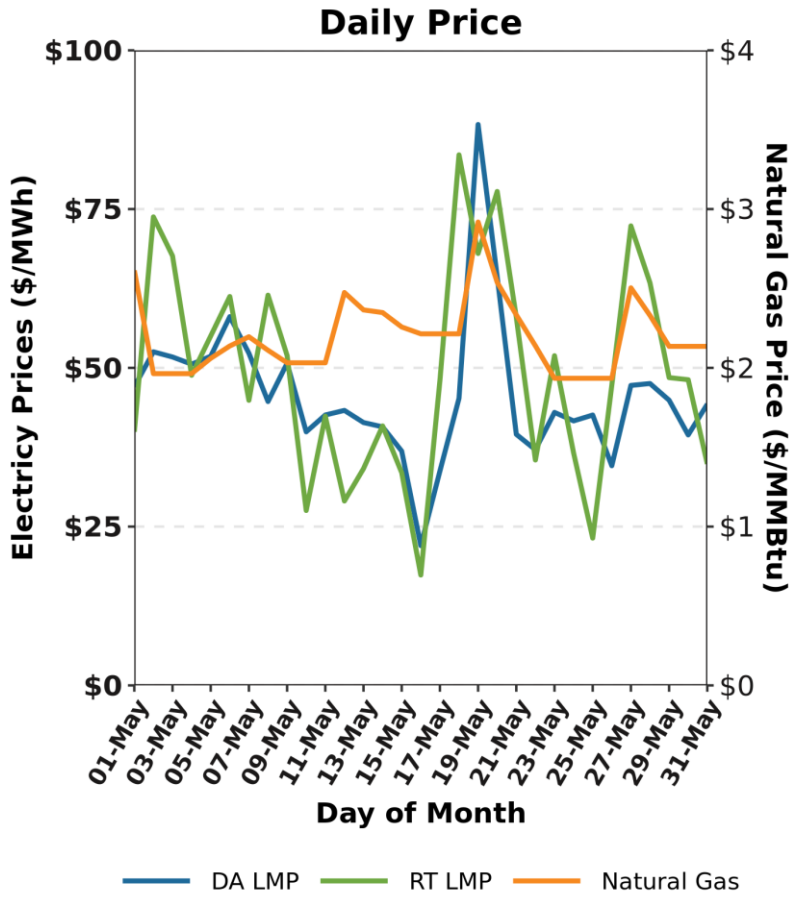


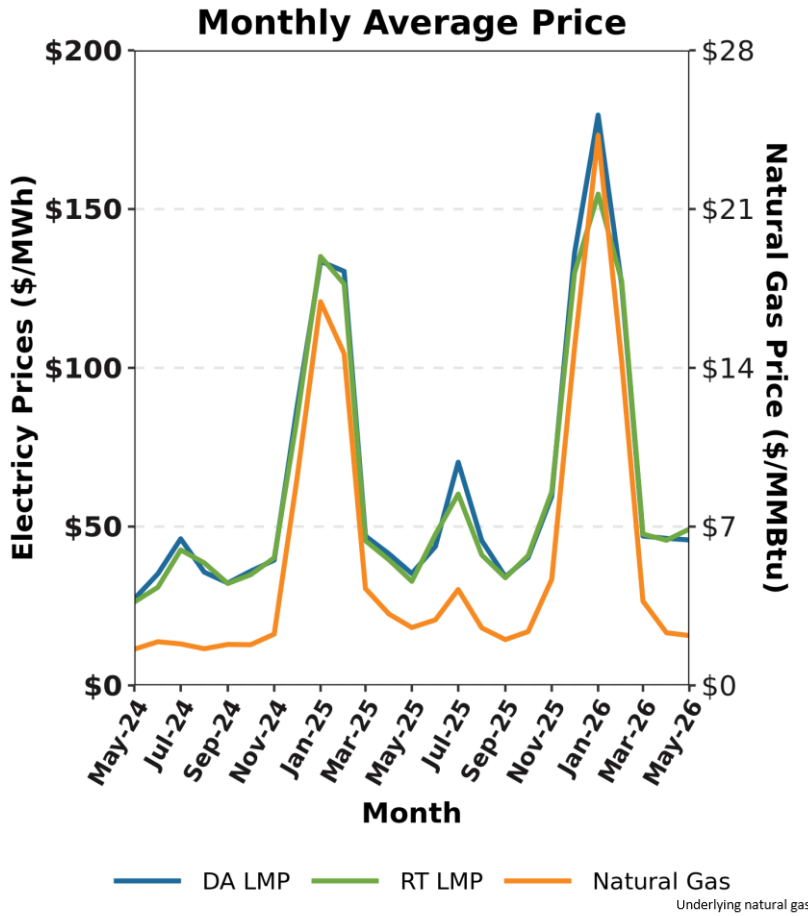
Hourly RT LMPs, May 1-31, 2026



*Master/Local Control Center Procedure No. 2

Wholesale Electricity vs Natural Gas Price by Month



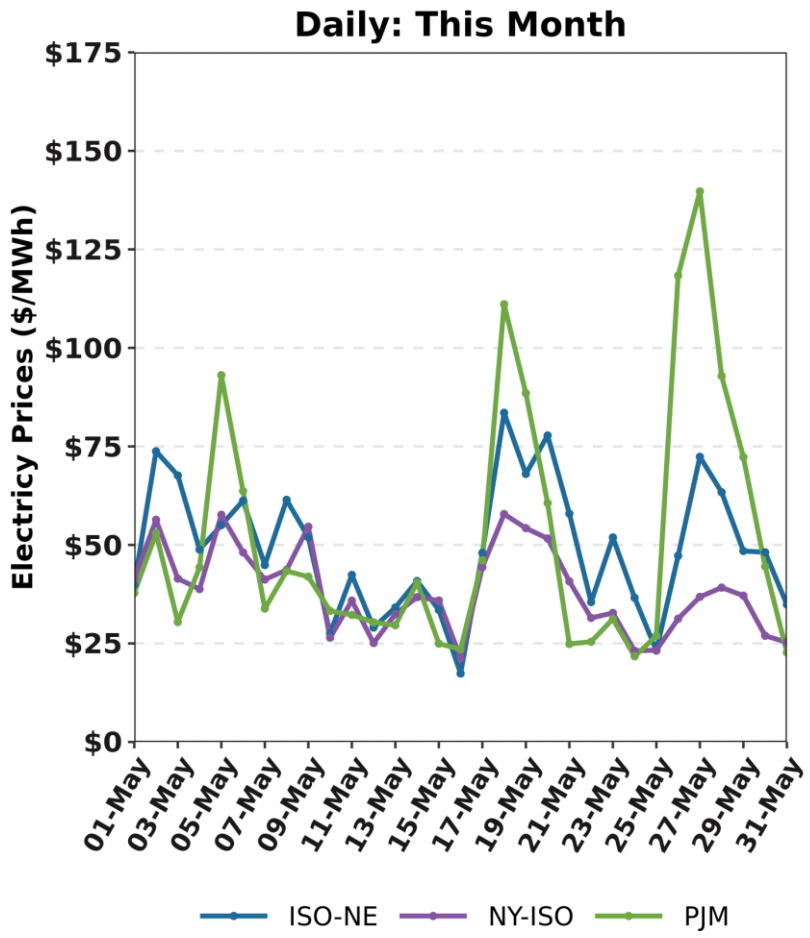


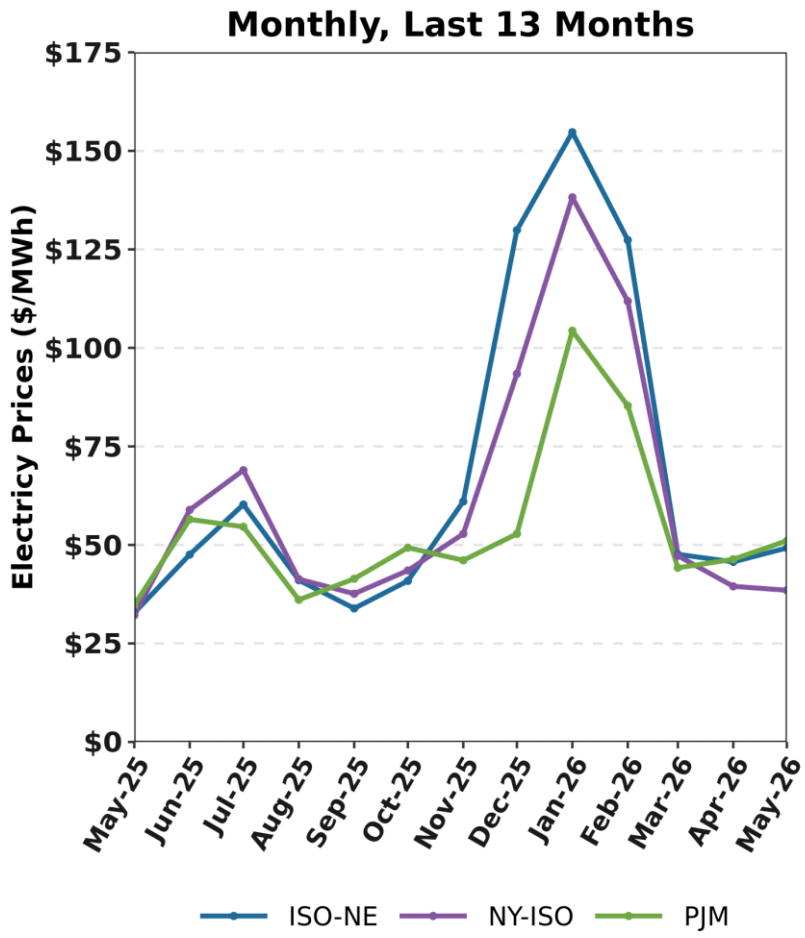
Underlying natural gas data furnished by:

ice Global markets in clear view

Gas price is average of Massachusetts delivery points

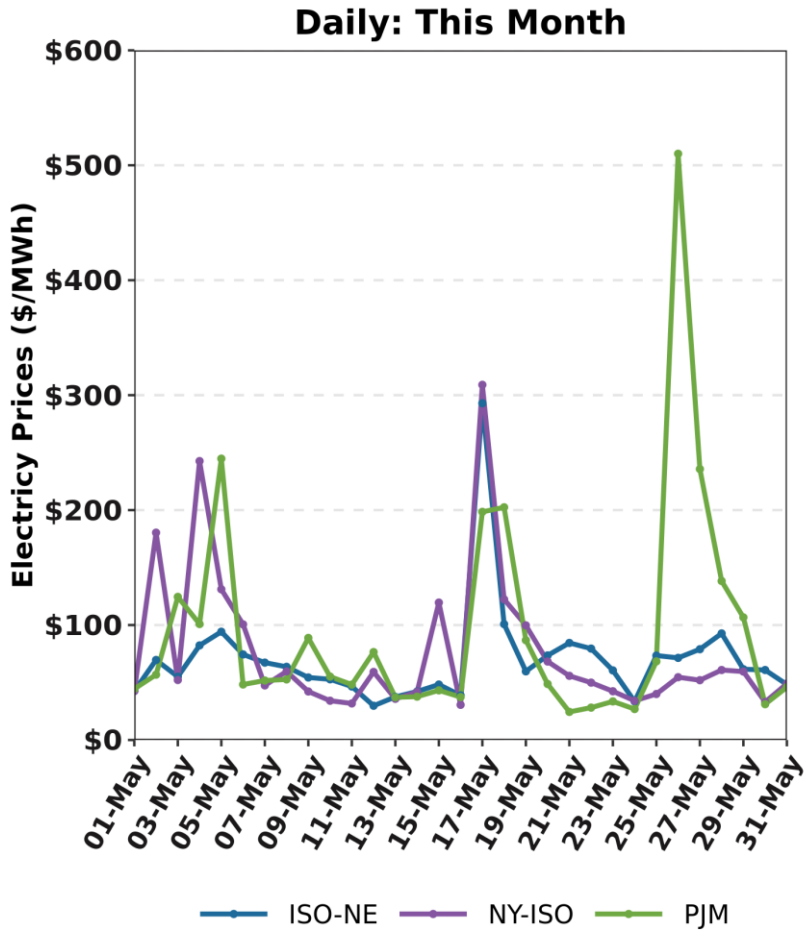
New England, NY, and PJM Hourly Average RT Prices by Month

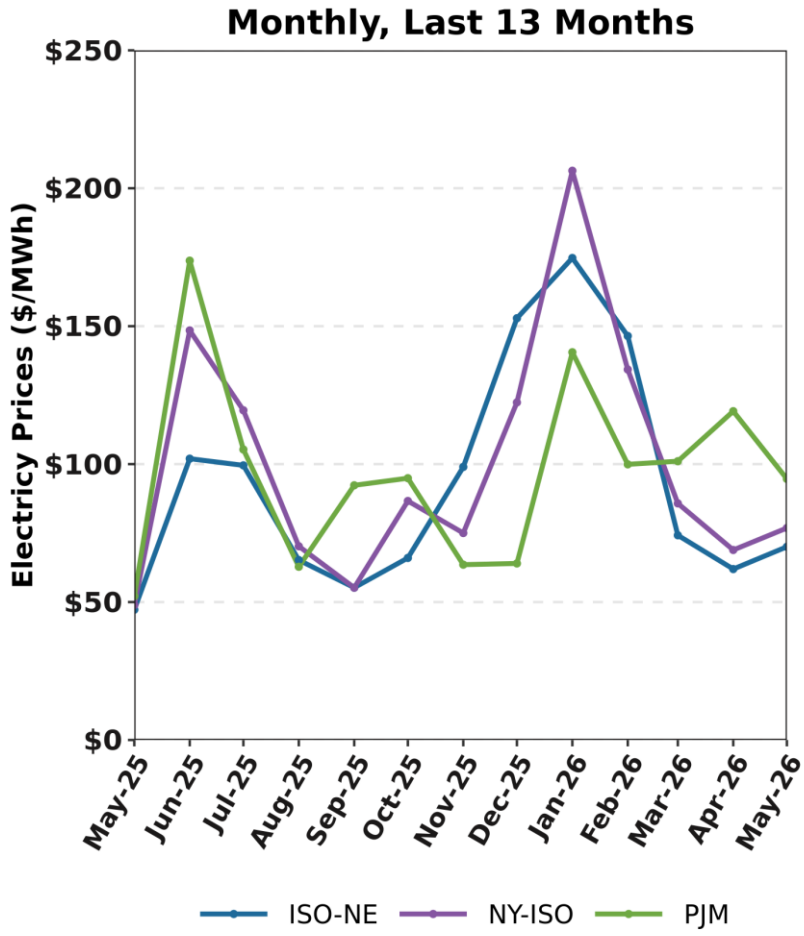




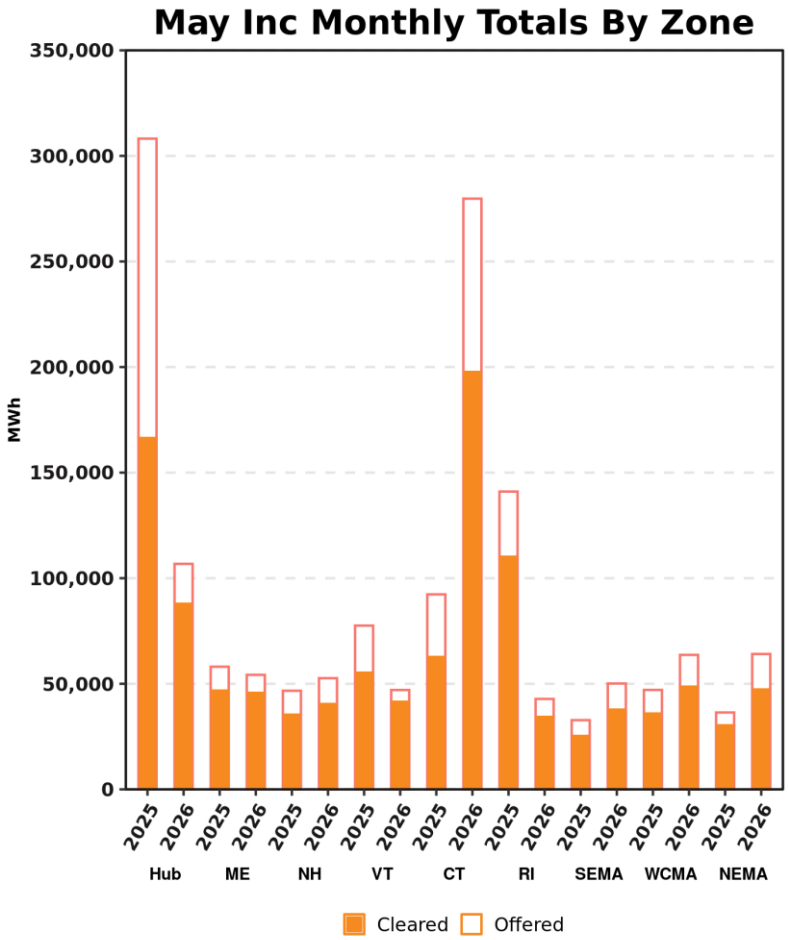
Hourly average prices are shown

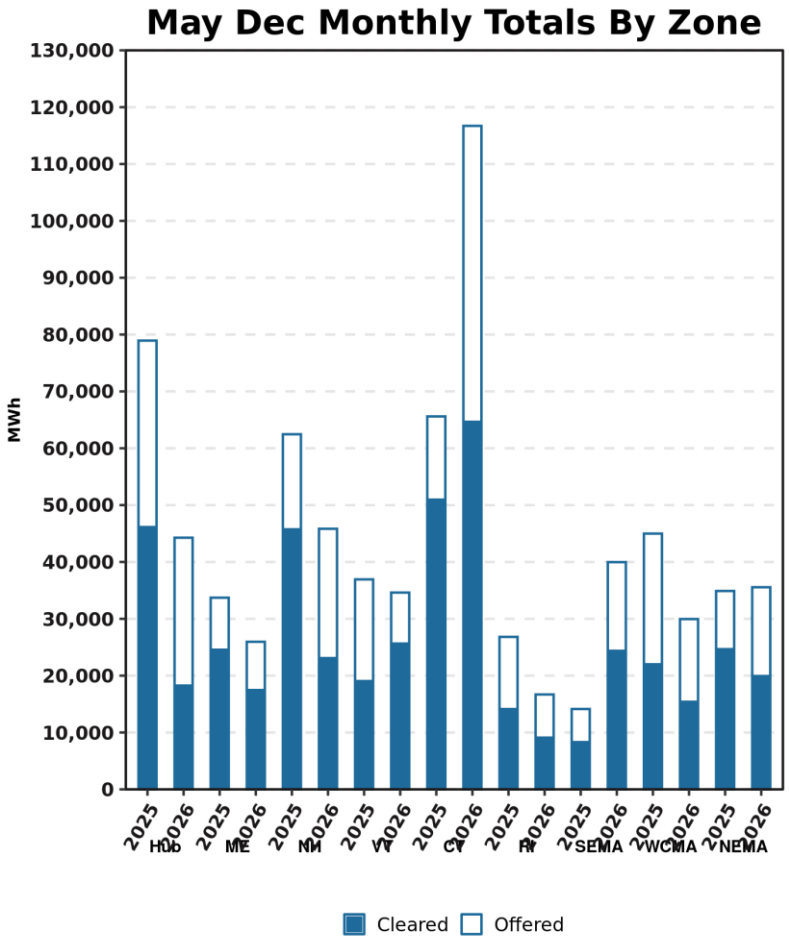
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





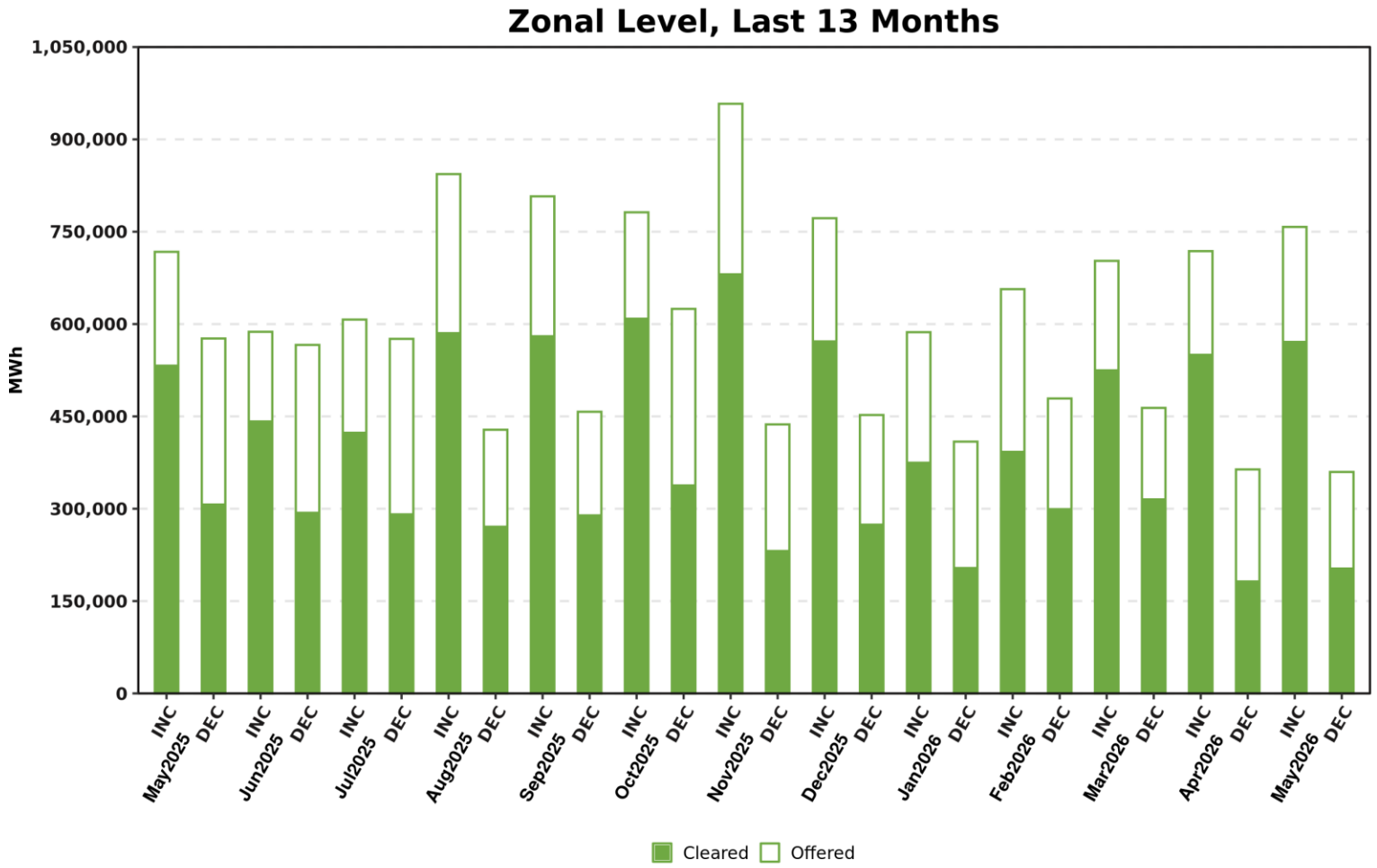
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

DAY-AHEAD ANCILLARY SERVICES (DAAS)

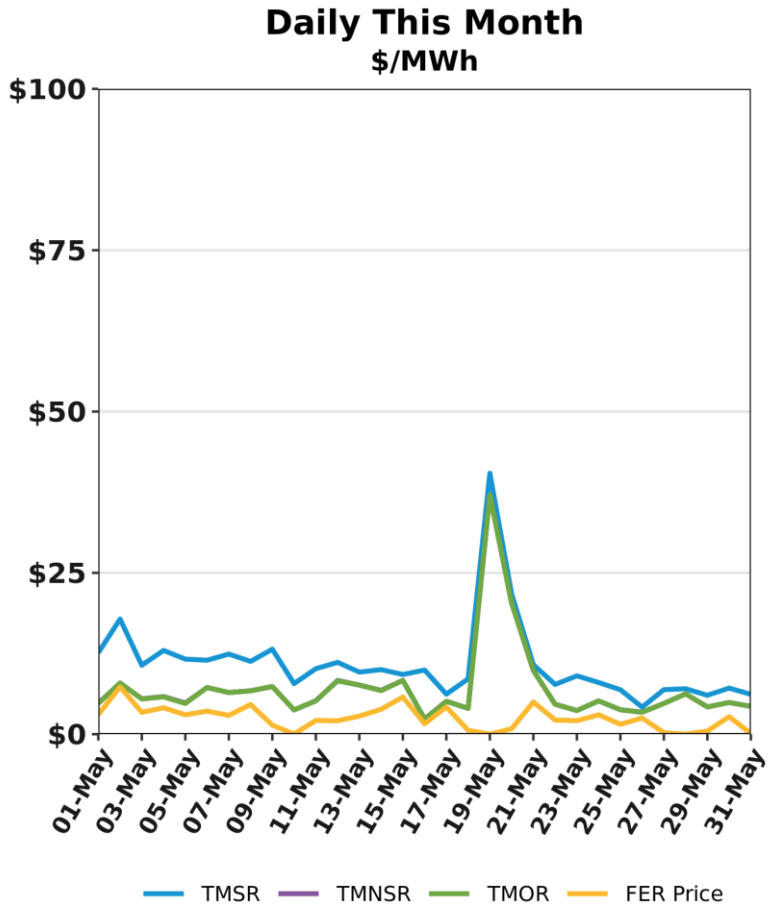
DAAS Results

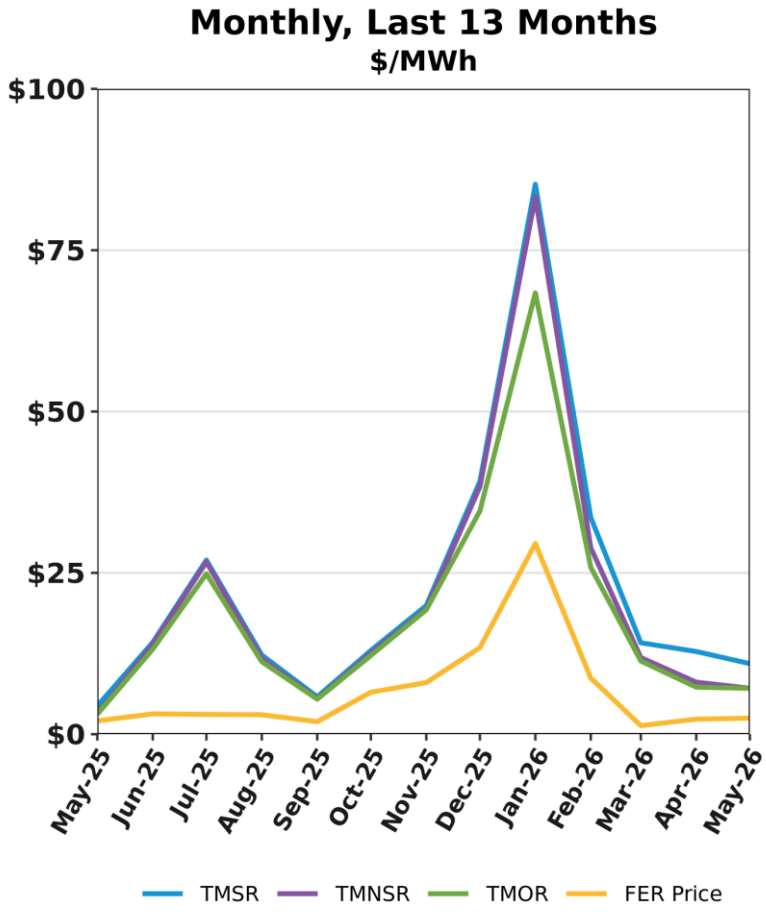
Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg. Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
05/01/2025	$10.9M	$190K	$52K	$0.94	0.5%	$563K	163K	$2.06	5.2%	155
06/01/2025	$20.1M	$885K	$173K	$2.97	0.9%	$1,287K	160K	$3.15	6.4%	125
07/01/2025	$35.6M	$1,704K	$1,139K	$19.53	3.2%	$1,277K	114K	$3.06	3.6%	55
08/01/2025	$20.2M	$747K	$544K	$9.57	2.7%	$1,292K	147K	$3.02	6.4%	94
09/01/2025	$12.3M	$320K	$184K	$3.21	1.5%	$587K	138K	$1.94	4.8%	104
10/01/2025	$15.5M	$719K	$478K	$8.21	3.1%	$1,911K	202K	$6.50	12.3%	209
11/01/2025	$24.8M	$1,123K	$458K	$7.85	1.9%	$2,550K	210K	$8.00	10.3%	135
12/01/2025	$60.9M	$2,131K	$1,053K	$18.20	1.7%	$4,916K	227K	$13.42	8.1%	107
01/01/2026	$91.1M	$4,617K	$3,241K	$55.53	3.6%	$12,042K	203K	$29.54	13.2%	127
02/01/2026	$55.1M	$1,678K	$857K	$14.78	1.6%	$3,369K	157K	$8.70	6.1%	104
03/01/2026	$17.4M	$667K	$357K	$6.43	2.1%	$422K	91K	$1.32	2.4%	32
04/01/2026	$15.4M	$463K	$119K	$2.23	0.8%	$641K	107K	$2.34	4.2%	81
05/01/2026	$15.0M	$425K	$-187K	$-3.40	-1.2%	$674K	133K	$2.49	4.5%	101

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

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)

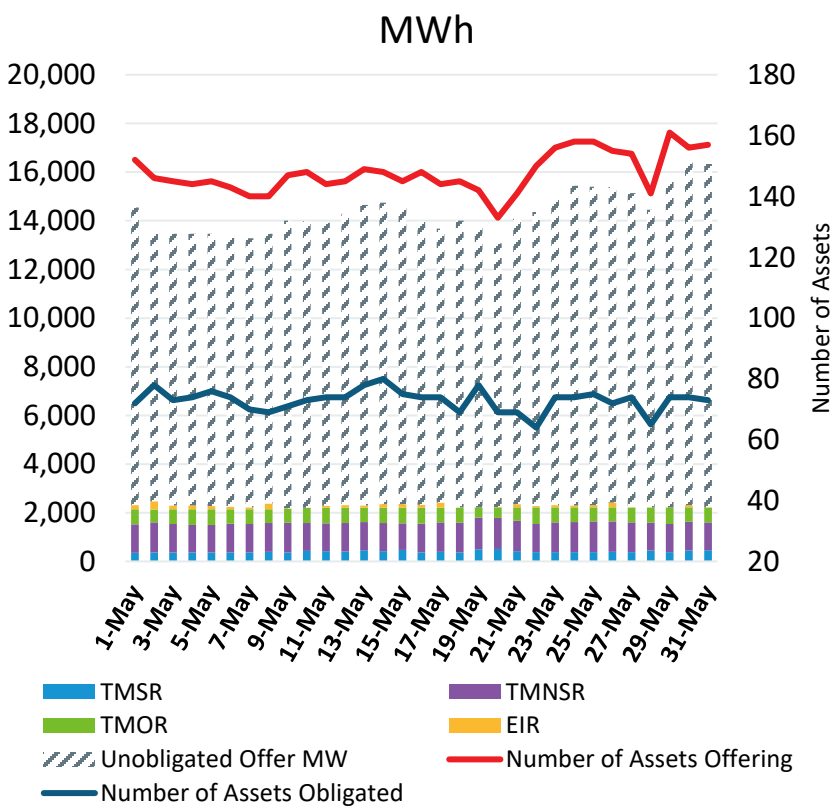
Average Hourly DAAS Prices



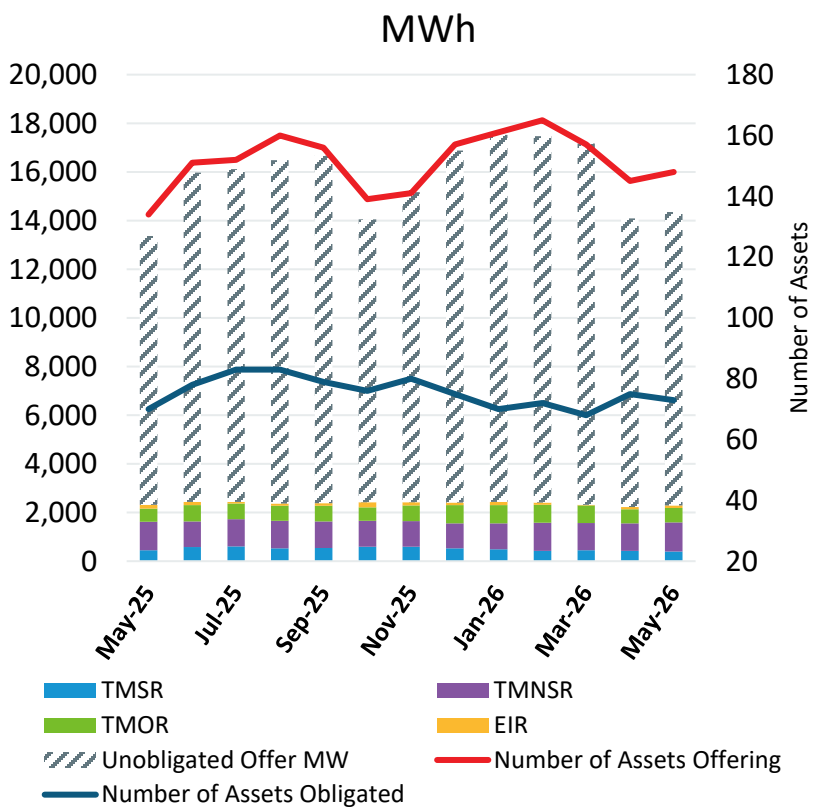


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



Monthly, Last 13 Months

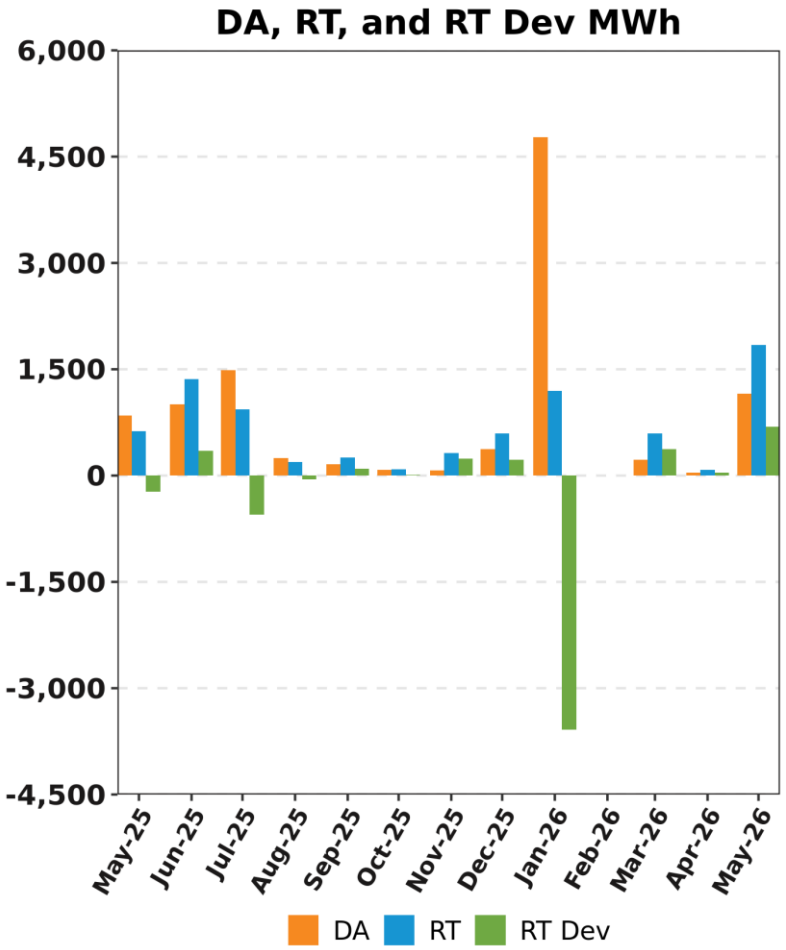


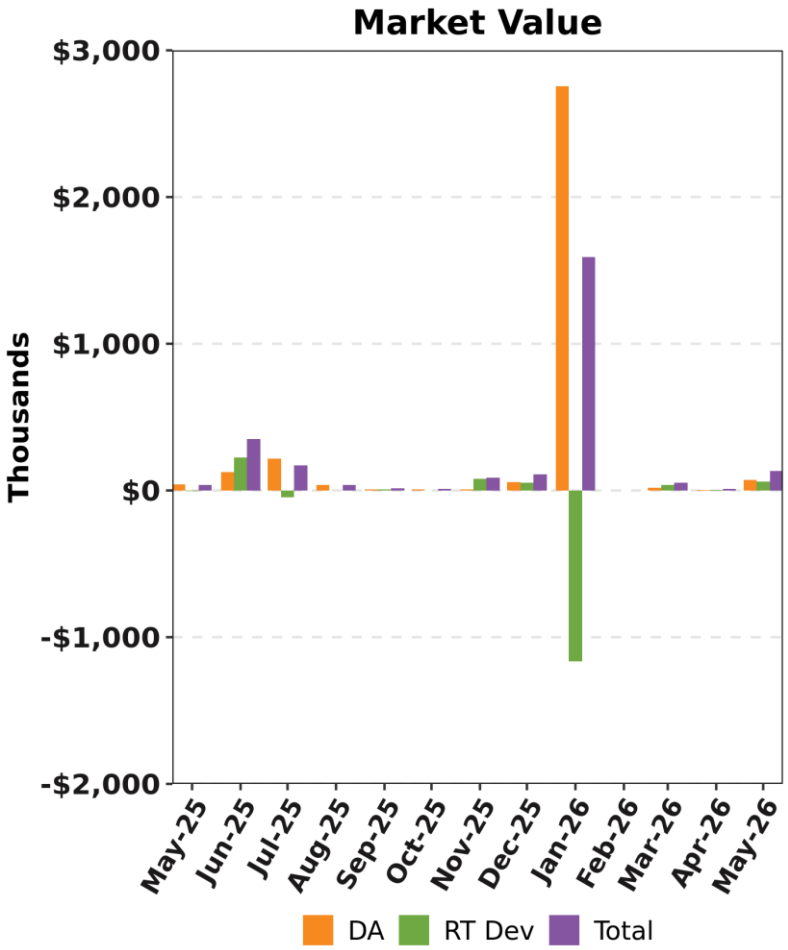
*Unobligated Offer MWh reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not yet consider additional unit parameter constraints or dispatch constraints and should not be equated with actual capacity available in the dispatch solution.

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

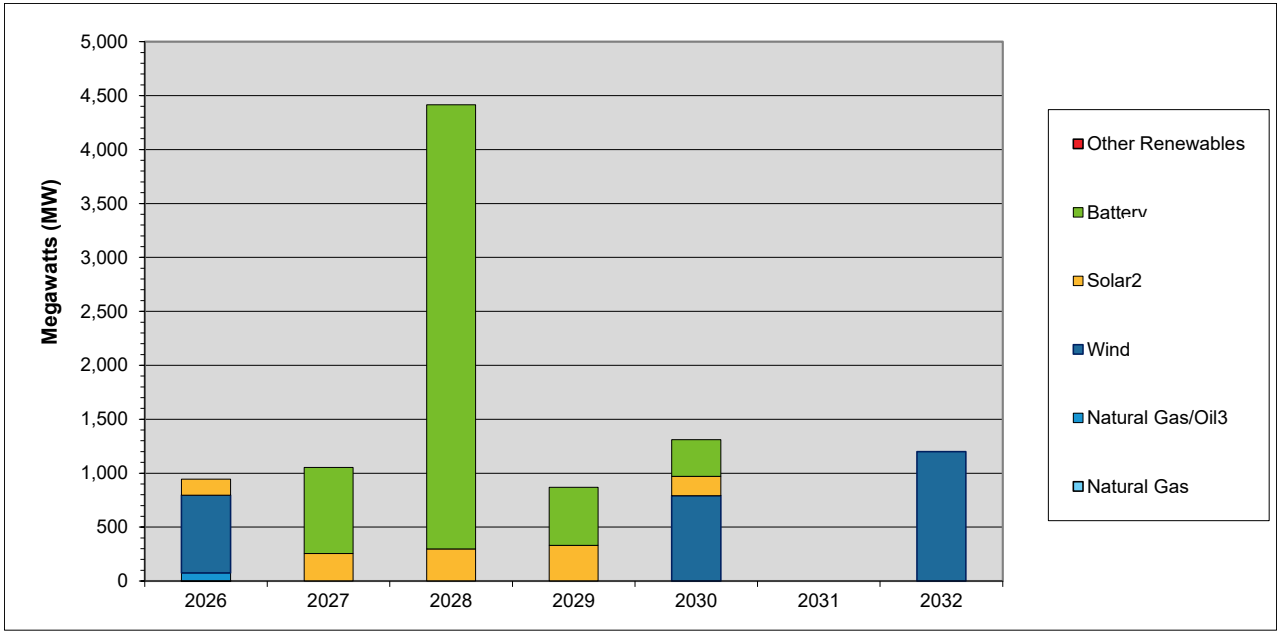
Based on Queue as of 06/01/26

- 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, 56* generation projects are currently being tracked by the ISO, totaling approximately 10,991 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	0	799	4,115	538	340	0	0	5,792	59.2
Solar[2]	147	255	299	332	180	0	0	1,213	12.4
Wind	722	0	0	0	791	0	1,200	2,713	27.7
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.7
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	**942**	**1,054**	**4,414**	**870**	**1,311**	**0**	**1,200**	**9,791**	**100.0**

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

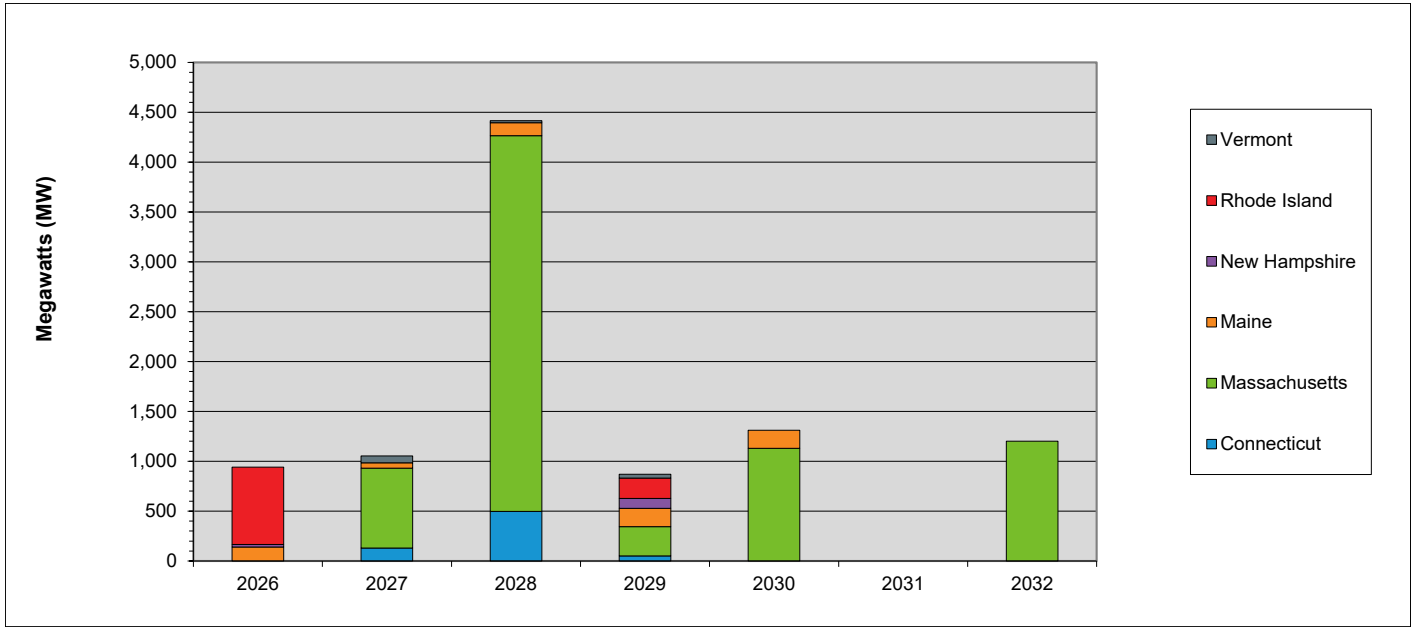
[2] This category includes both solar-only, and co-located solar and battery projects

[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	0	70	20	38	0	0	0	128	1.3
Rhode Island	777	0	0	205	0	0	0	982	10.0
New Hampshire	25	0	0	100	0	0	0	125	1.3
Maine	140	54	129	182	180	0	0	685	7.0
Massachusetts	0	799	3,768	295	1,131	0	1,200	7,193	73.5
Connecticut	0	131	497	50	0	0	0	678	6.9
Totals	**942**	**1,054**	**4,414**	**870**	**1,311**	**0**	**1,200**	**9,791**	**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	27	5,792	2	454	25	5,338
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	23	1,213	4	141	19	1,072
Wind	5	3,913	2	722	3	3,191
Total	56	10,991	9	1,390	47	9,601

- 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	50	7,005	6	595	44	6,410
Wind Turbine	5	3,913	2	722	3	3,191
Total	56	10,991	9	1,390	47	9,601

- 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	27	5,792	0	0	0	0	27	5,792	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	23	1,213	0	0	0	0	23	1,213	0	0
Wind	5	3,913	0	0	0	0	0	0	5	3,913
Total	56	10,991	0	0	1	73	50	7,005	5	3,913

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

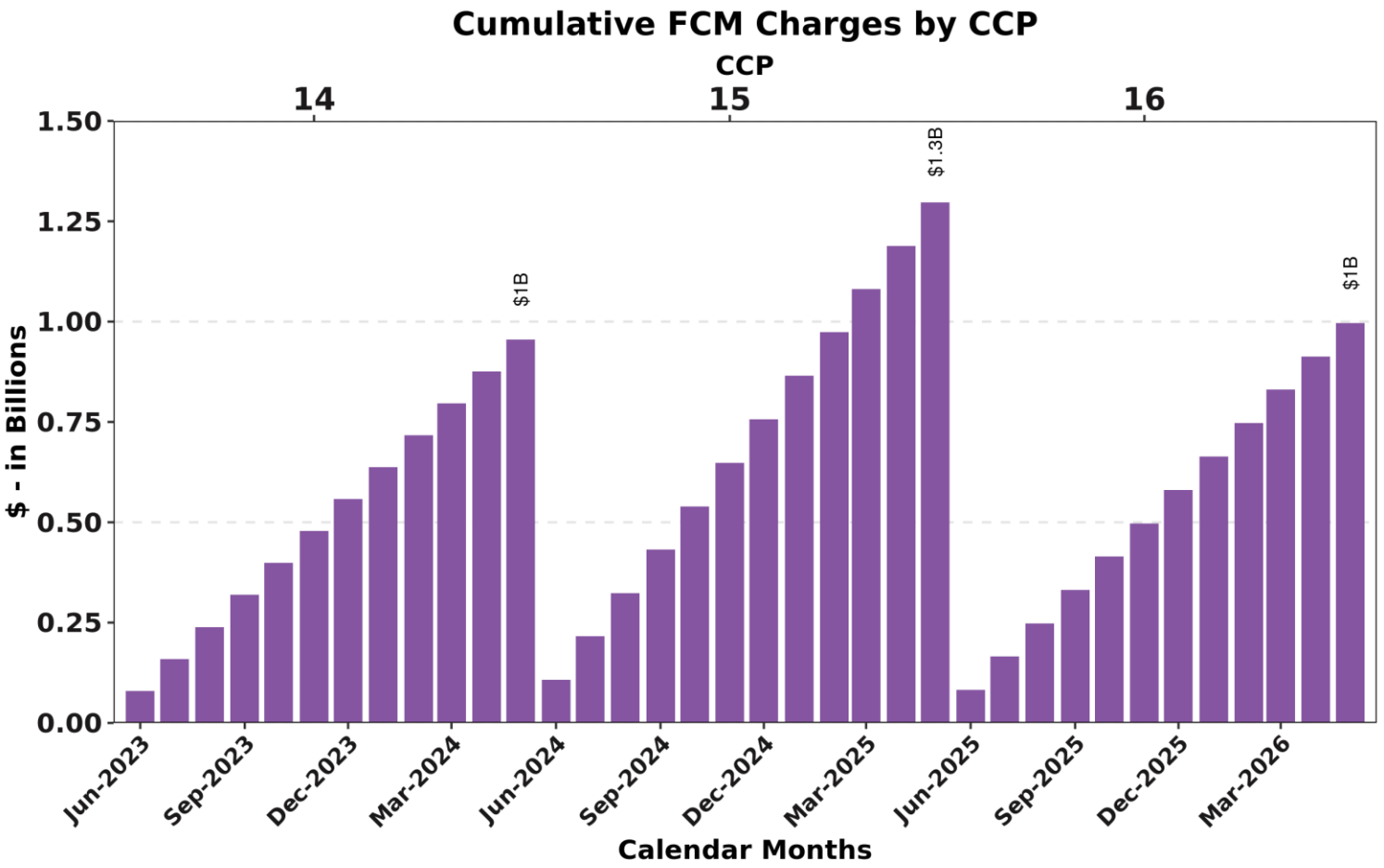
FORWARD CAPACITY MARKET

Observed FCM Peak Load by Capacity Zone

- Observed FCM Peak Load: **19,868 MW**
  - hour ending 1:00 p.m. on Sunday, January 25
  - By Capacity Zone:
    - Northern New England: 2,814 MW
    - Maine: 1,824 MW
    - Rest-of-Pool: 7,473 MW
    - Southeast New England: 7,757 MW

*Telemetered loads are as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SORs). Due to the difference in calculation methodologies and the impact of SORs, 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.
This breakout is available in the Weekly Market Report found on the ISO Website here, and is scheduled for removal from this deck at a future date

Forward Capacity Market Auctions



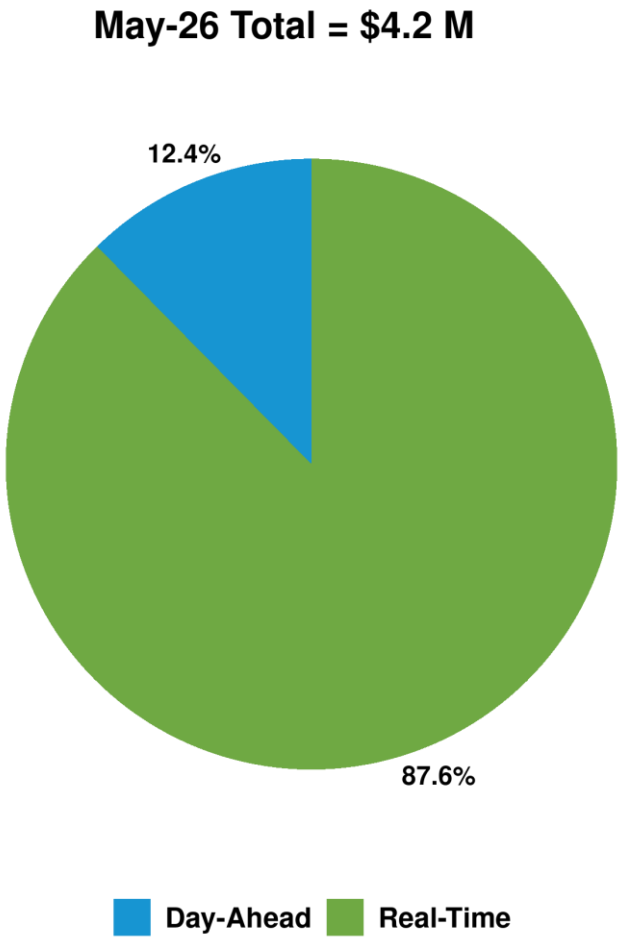
The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

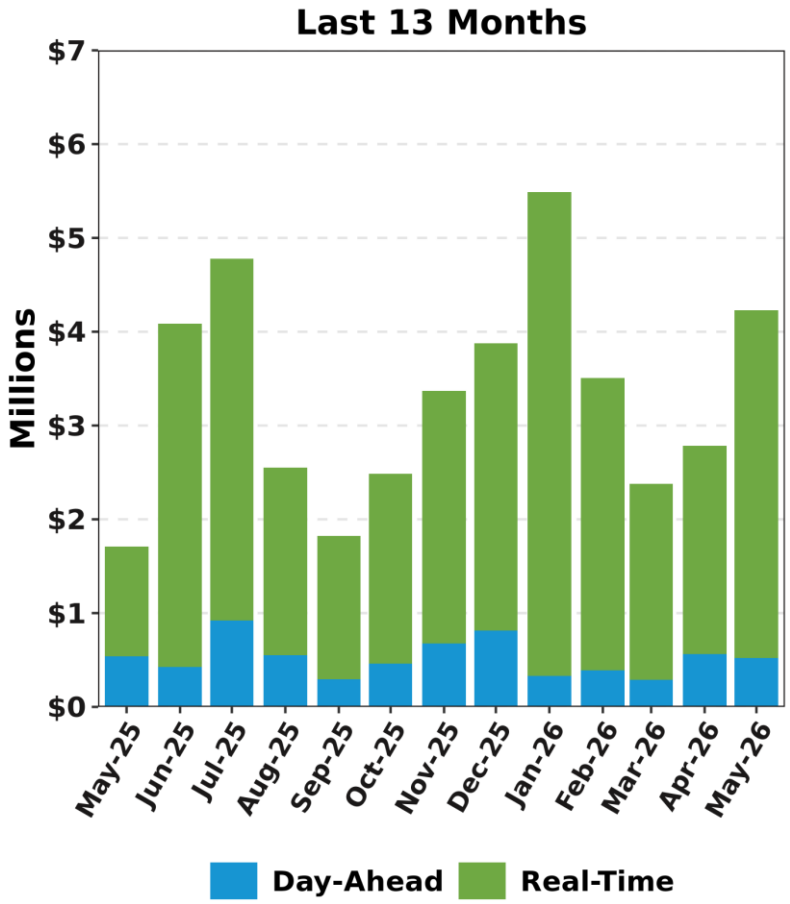
NET COMMITMENT PERIOD COMPENSATION

NCPC Highlights

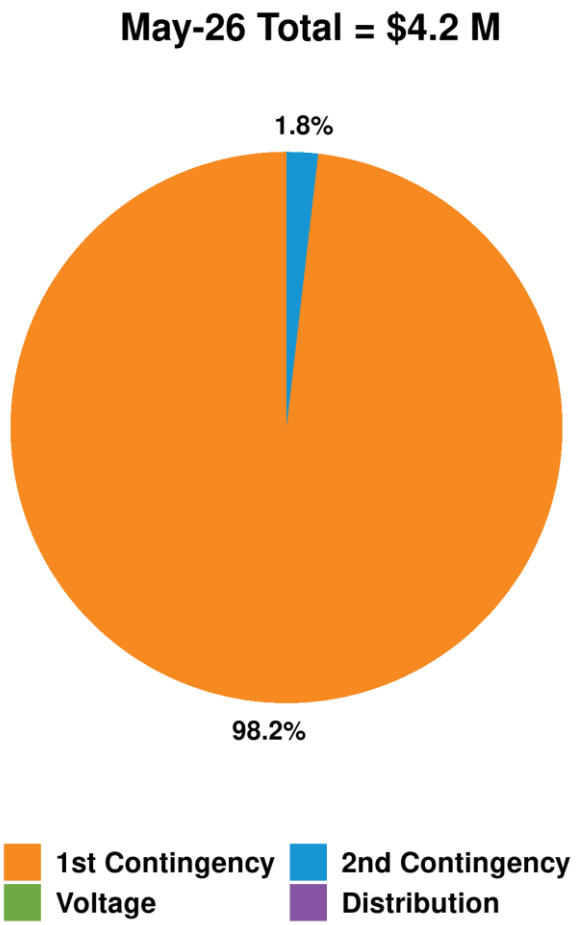
- **Net Commitment Period Compensation (NCPC)** total $4.2M
  - Represents 0.9% of monthly Energy Market value
  - First Contingency $4.2M
    - Dispatch Lost Opportunity Cost (DLOC) - $938.3K; Rapid Response Pricing (RRP) Opportunity Cost - $482.6K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $57.2K paid to resources at external locations, up $47.8K from April
      - $19.3K charged to Day-Ahead Load Obligation (DALO) at external locations; $919.9 to Day-Ahead Generation Obligation (DAGO) at external locations; $36.9K to RT Deviations
  - Second Contingency $77.7K
  - Distribution and Voltage were zero.

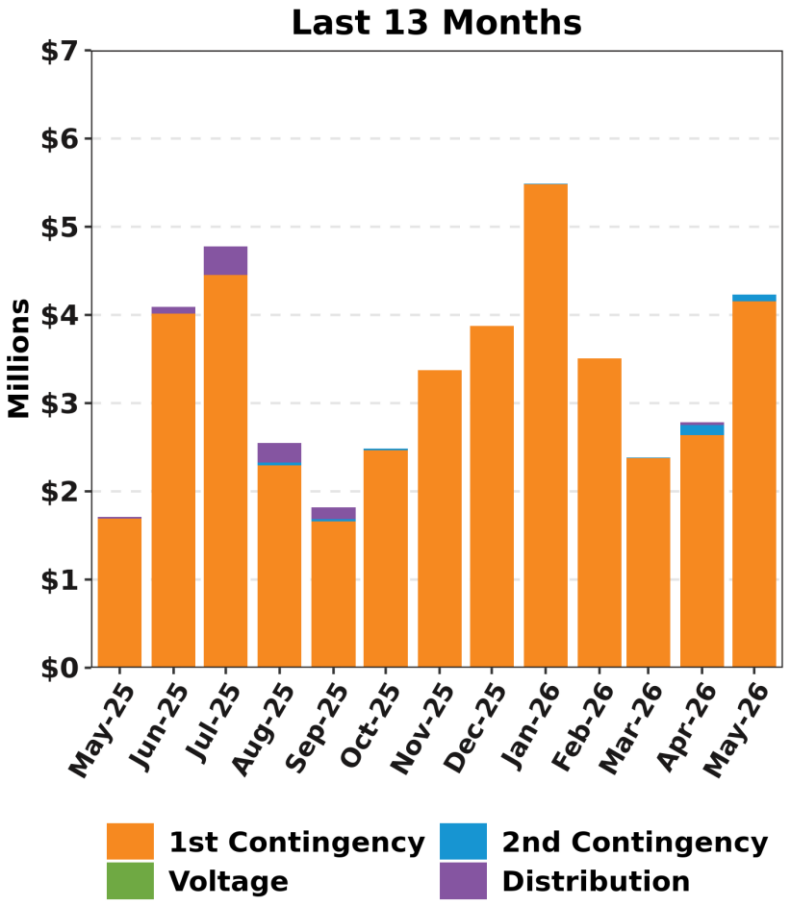
DA and RT NCPC Charges



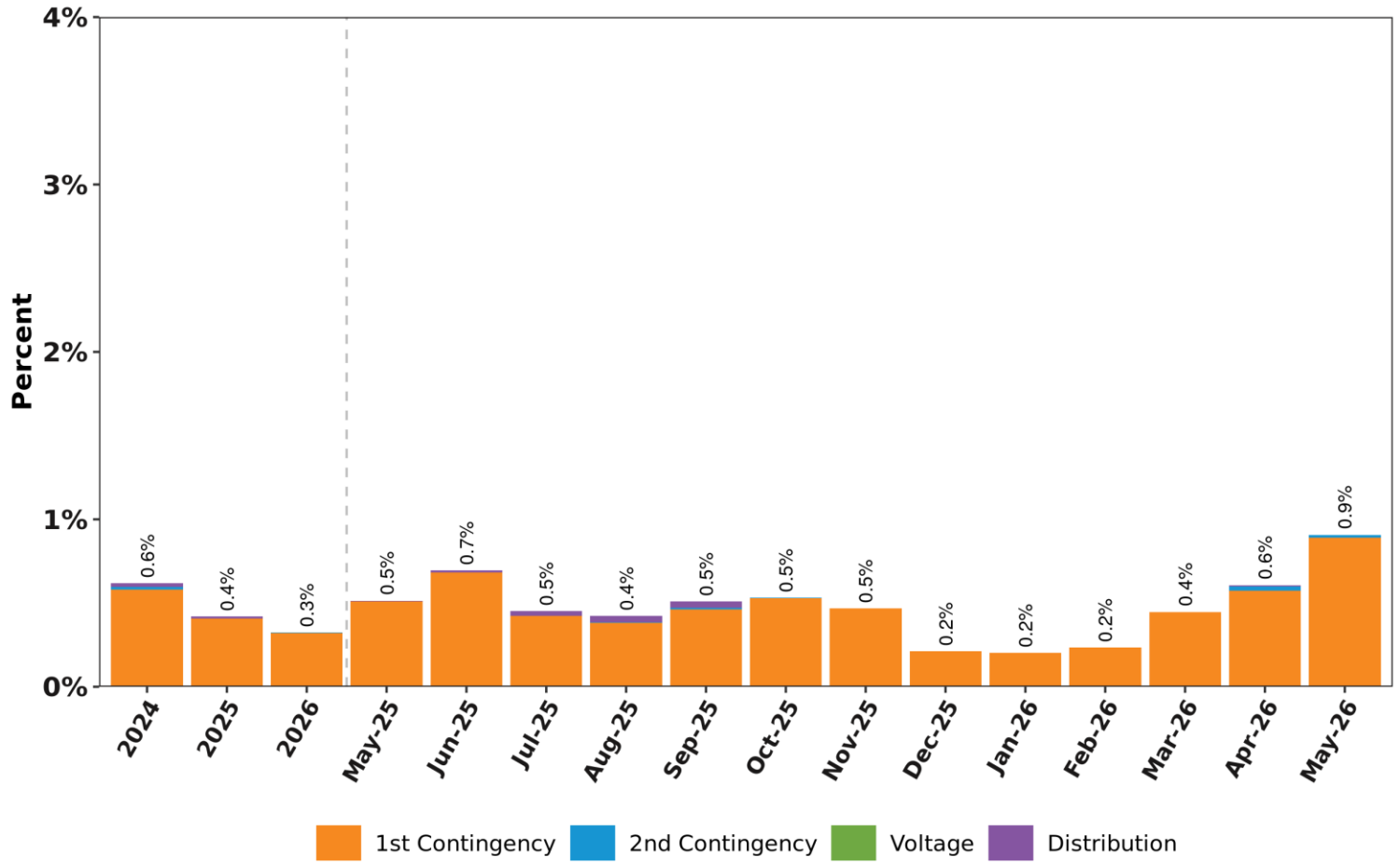


NCPC Charges by Type

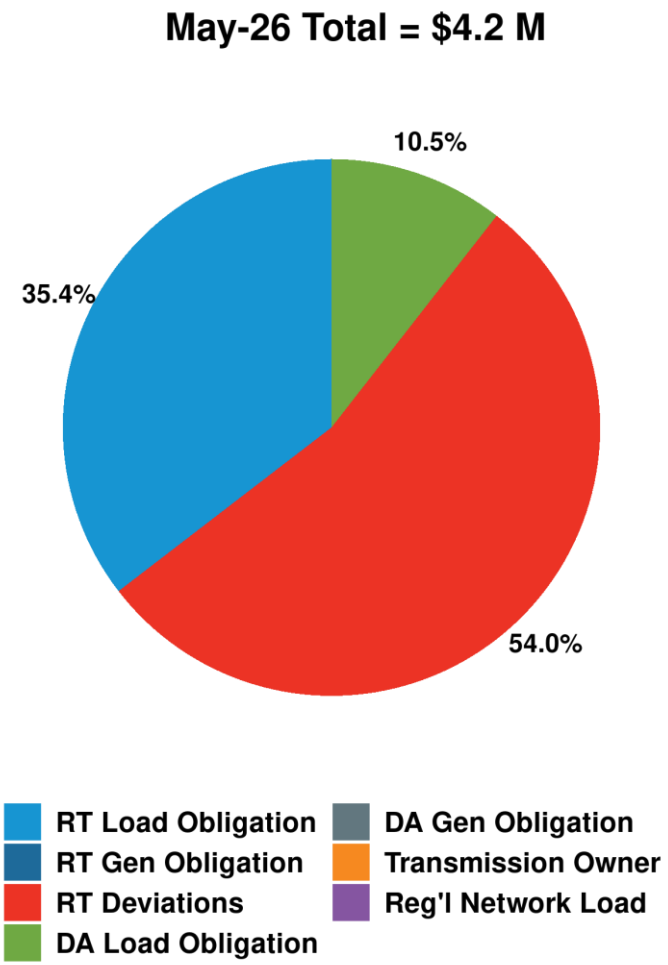


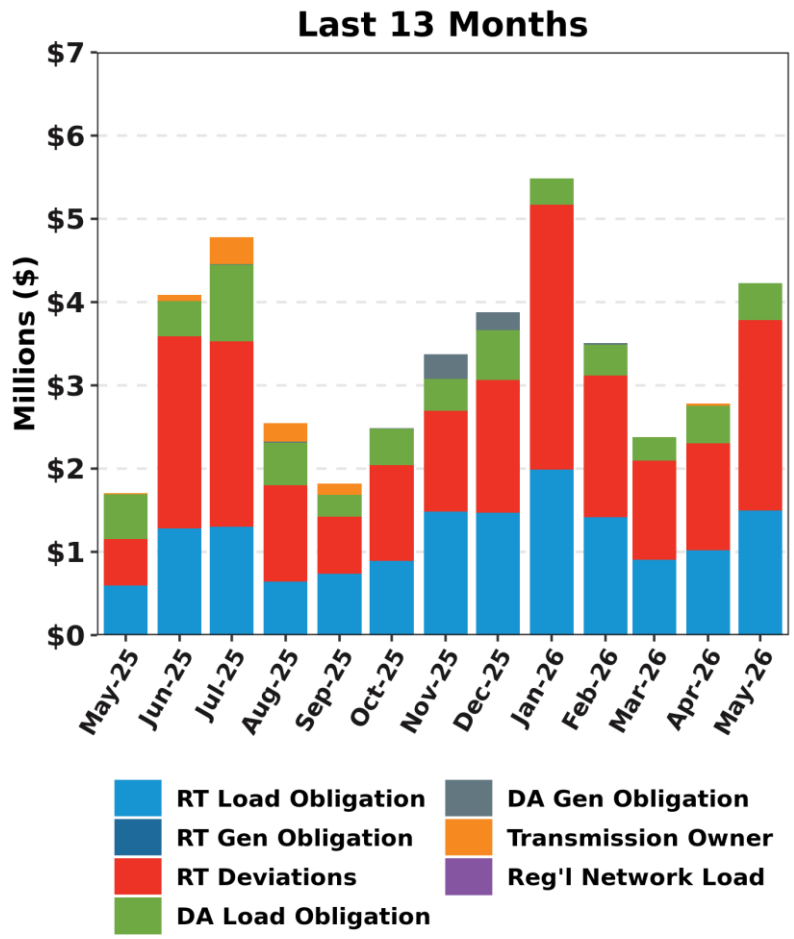


NCPC Charges by Type as Percent of Energy Market Value

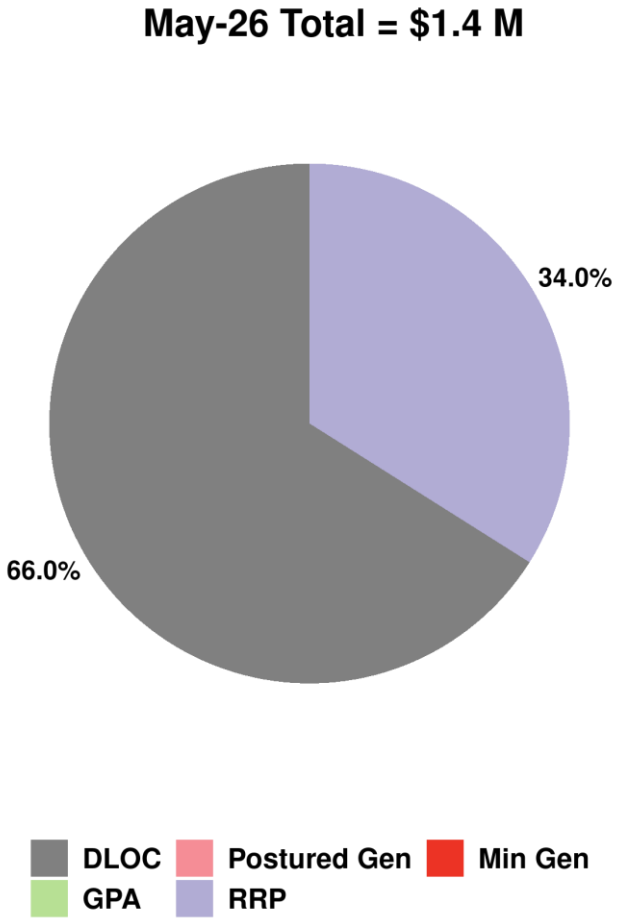


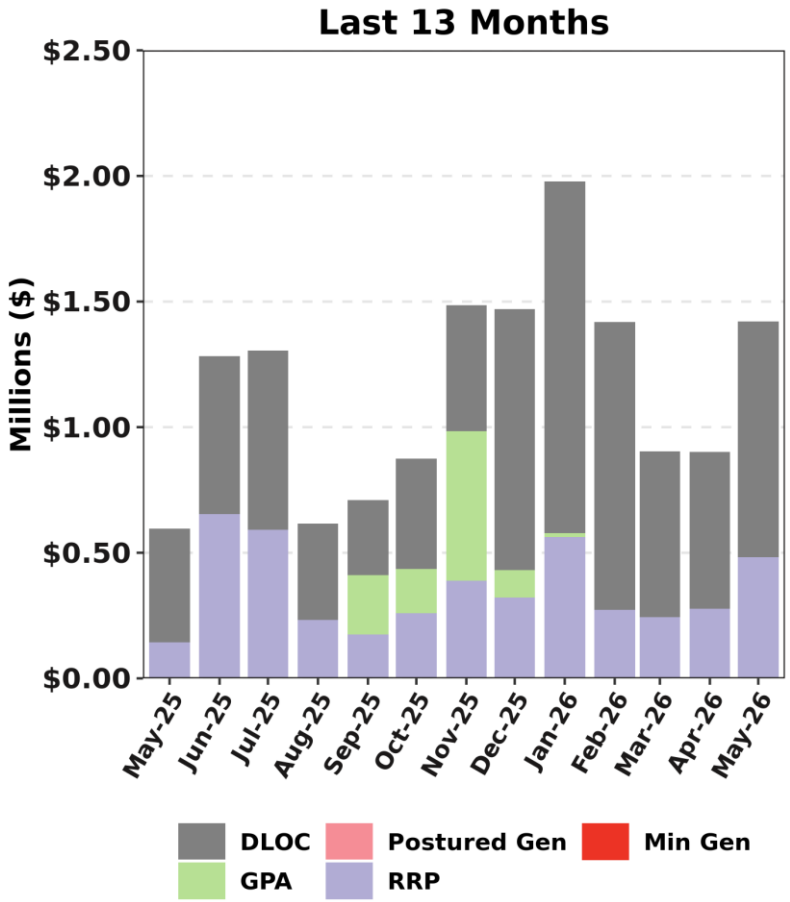
NCPC Charge Allocations





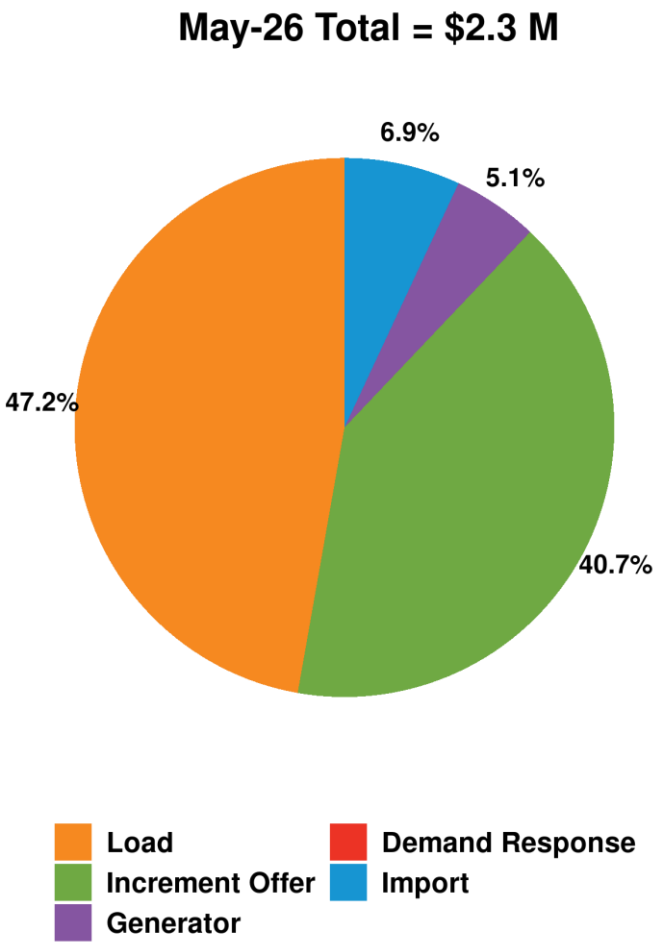
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

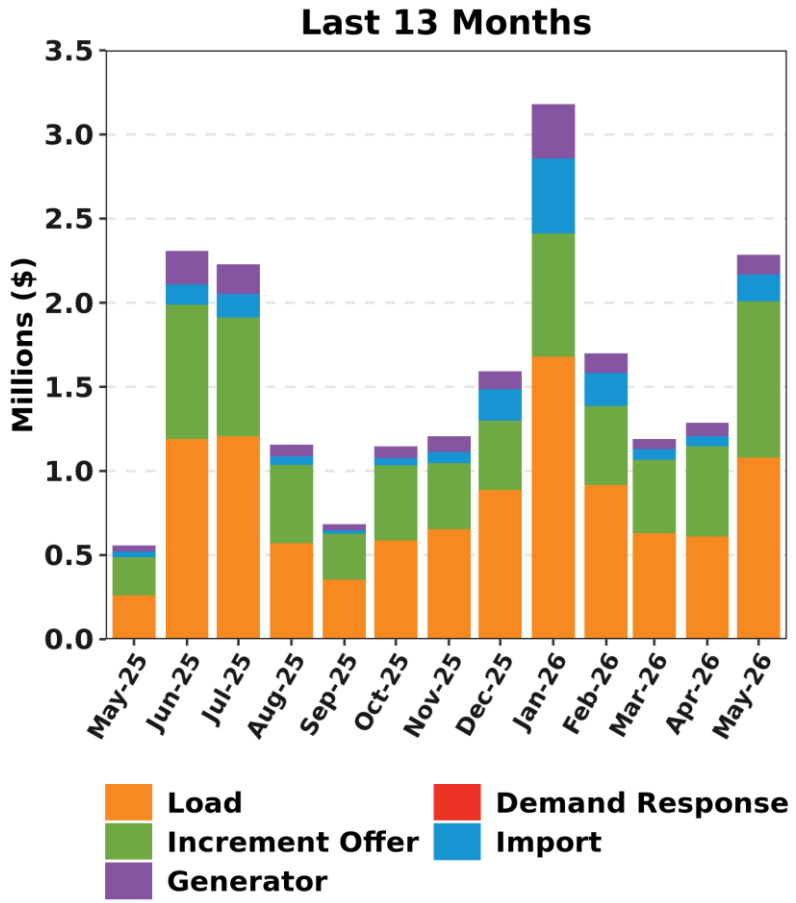




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

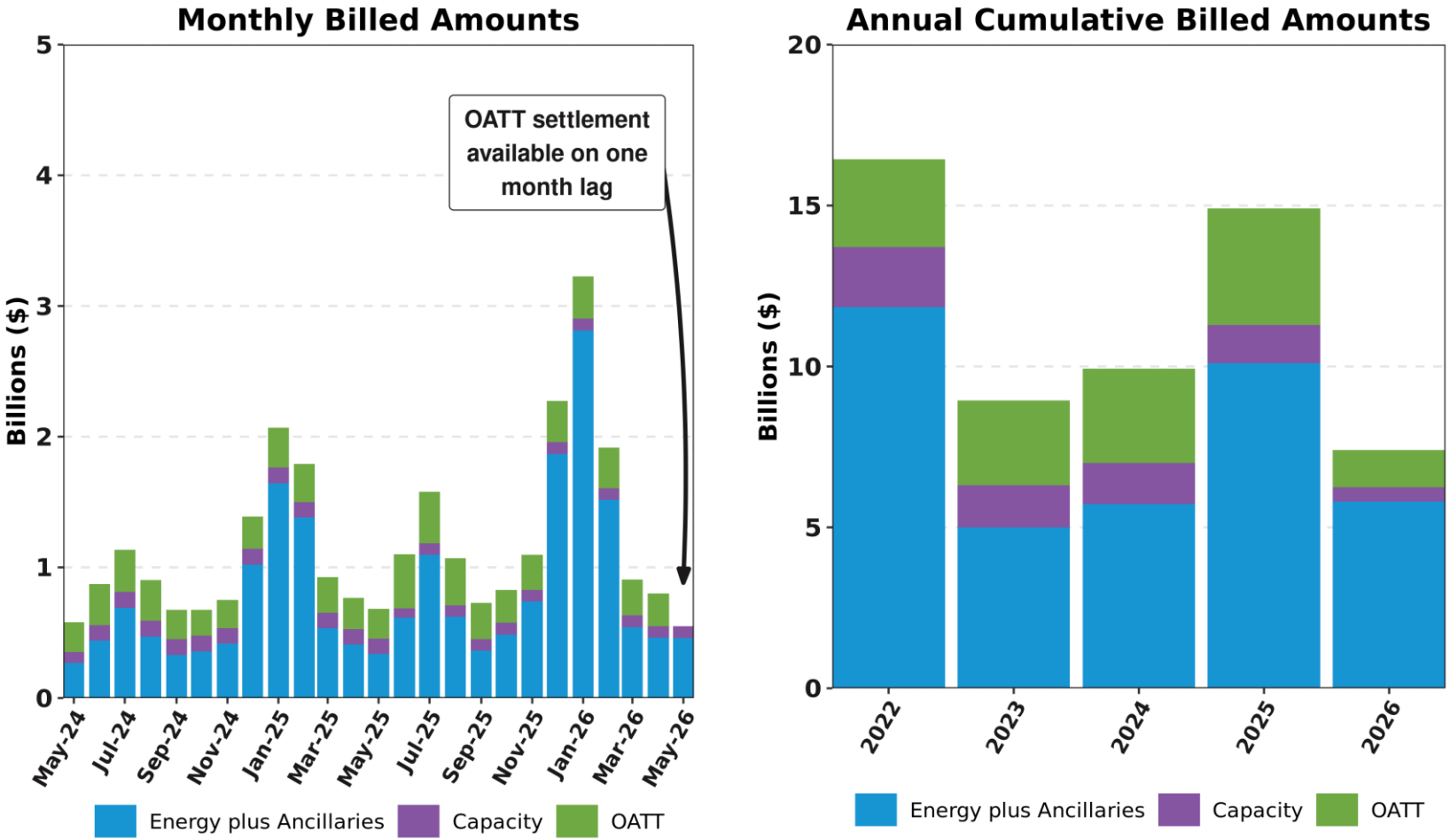
RT First Contingency Charges by Deviation Type





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)

- June 23 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - North Cambridge Substation - Cable System Partial Replacement (Eversource)
    - Canal Station 345 kV Autotransformer Replacements - T120 and T126 (Eversource)
    - New Hampshire Asset Condition Structure Replacements - B172 and C129 (Eversource)
    - Montville Substation, Cable Separation and Shielding (Eversource)
    - S1 Asset Condition Refurbishment (NGRID)
    - W-149 115 kV Line Asset Condition Refurbishment (NGRID)
    - W-23 Asset Condition Refurbishment (NGRID)
  - 2036 New England Short Circuit Needs Assessment
  - 2026 Economic Study - Stakeholder-Requested Scenario Submission
  - Transmission Planning Guide Process Update
  - RSP Project List and Asset Condition List June 2026 Update

* 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 provided an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) at the March PAC meeting and a follow-up at the May PAC meeting
- The ISO is scheduled to make the preliminary preferred Longer-Term Transmission Solution determination by September 2026

* 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

Permanent Asset Condition Reviewer

- The ISO began discussions of the permanent asset condition reviewer function at the January Transmission Committee (TC) and further discussions are ongoing
  - ISO-NE would serve as the region's independent, advisory Asset Condition Reviewer (ACR) for Asset Condition Projects (ACPs). The function would provide early, technically rigorous reviews of need, scope, alternatives, and cost drivers, without directing projects or making prudency or siting determinations
- Incremental changes to the Transmission Operating Agreement (TOA) and ISO's Open Access Transmission Tariff (OATT) were discussed at the May TC meeting
  - Stakeholder amendments were also presented
- Continued incremental proposal adjustments to the TOA and Tariff redlines and stakeholder amendments will be presented at the June TC meeting
  - Anticipate a vote at this meeting
- Interim project reviews underway to inform permanent design
- Targeting January 2027 go-live, subject to FERC acceptance and operating budget; tariff changes targeted for Q3 2026 filing

Economic Studies: 2026 Study

- The 2026 Economic Study was launched in January
  - The ISO presented results of the public survey, as part of a lessons learned, and Benchmark Scenario assumptions at PAC
  - The Benchmark results and the opening of the Stakeholder-Requested scenario window will be presented at PAC this summer

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 6/5/2026

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 6/5/2026

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 6/5/2026

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 6/5/2026

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 6/5/2026

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 6/5/2026

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 6/5/2026

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	Dec-26	3

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

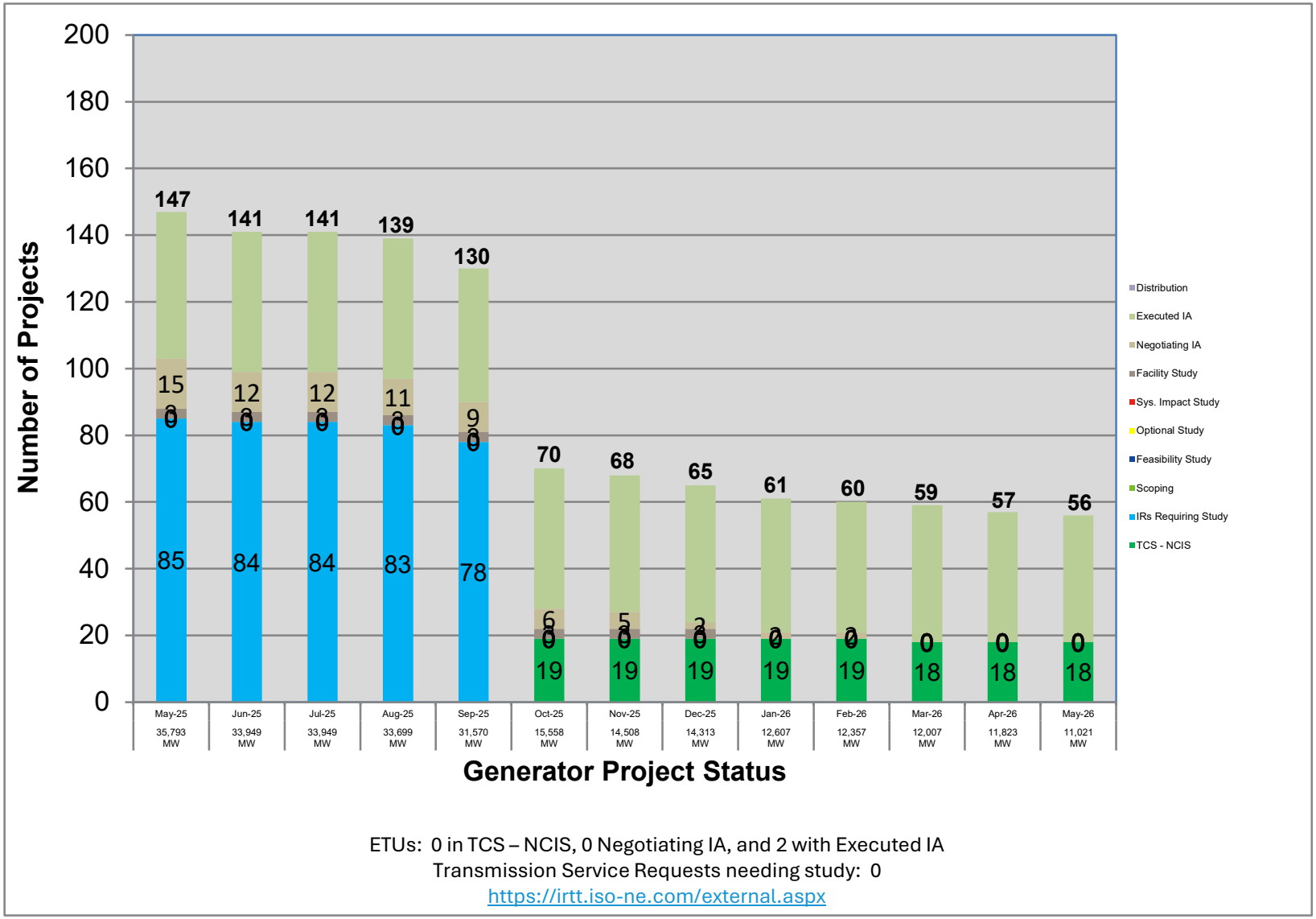
Boston 2033 Solutions Study

Status as of 6/5/2026

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)	Mar-27	1

Status of Tariff Studies as of June 4, 2026



ETUs: 0 in TCS – NCIS, 0 Negotiating IA, and 2 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 June 4, 2026, cont.

- Additional Notes
  - 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.
  - The interim TCS report was issued on June 7, 2026

OPERABLE CAPACITY ANALYSIS

Summer 2026 Analysis

Summer 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2026[2] CSO (MW)	June - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,705	27,074
Active Demand Capacity Resource (+) [5]	320	345
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	598	598
Non Commercial Capacity (+)	13	13
Non Gas-fired Planned Outage MW (-)	89	372
Gas Generator Outages MW (-)	212	212
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,535	24,646
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,228	25,228
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,290	27,290
Operable Capacity Margin	-2,755	-2,644

[1]Operable Capacity is based on data as of **May 22, 2026** 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 **May 22, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 6, 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.

Summer 2026 Operable Capacity Analysis

90/10 Load Forecast	June - 2026[2] CSO (MW)	June - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,705	27,074
Active Demand Capacity Resource (+) [5]	320	345
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	598	598
Non Commercial Capacity (+)	13	13
Non Gas-fired Planned Outage MW (-)	89	372
Gas Generator Outages MW (-)	212	212
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,535	24,646
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,473	26,473
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,535	28,535
Operable Capacity Margin	-4,000	-3,889

[1]Operable Capacity is based on data as of **May 22, 2026** 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 **May 22, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 6, 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.

Summer 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 22, 2026 - 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 June through mid September.

Report created: 5/22/2026

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
6/6/2026	26705	320	598	13	89	212	2800	0	24535	25228	2062	27290	-2755	Y	Summer 2026
6/13/2026	26705	320	598	13	182	14	2800	0	24640	25228	2062	27290	-2650	N	Summer 2026
6/20/2026	26705	320	598	13	80	14	2800	0	24742	25228	2062	27290	-2548	N	Summer 2026
6/27/2026	26705	320	598	13	64	14	2800	0	24758	25228	2062	27290	-2532	N	Summer 2026
7/4/2026	27071	350	409	43	120	14	2100	0	25639	25228	2062	27290	-1651	N	Summer 2026
7/11/2026	27071	350	409	43	45	14	2100	0	25714	25228	2062	27290	-1576	N	Summer 2026
7/18/2026	27071	350	409	43	43	14	2100	0	25716	25228	2062	27290	-1574	N	Summer 2026
7/25/2026	27071	350	409	43	64	14	2100	0	25695	25228	2062	27290	-1595	N	Summer 2026
8/1/2026	27071	350	409	43	61	14	2100	0	25698	25228	2062	27290	-1592	N	Summer 2026
8/8/2026	27071	350	409	43	61	14	2100	0	25698	25228	2062	27290	-1592	N	Summer 2026
8/15/2026	27071	350	409	43	46	14	2100	0	25713	25228	2062	27290	-1577	N	Summer 2026
8/22/2026	27071	350	409	43	52	14	2100	0	25707	25228	2062	27290	-1583	N	Summer 2026
8/29/2026	27071	350	409	43	44	14	2100	0	25715	25228	2062	27290	-1575	N	Summer 2026
9/5/2026	27071	350	409	43	48	45	2100	0	25680	25228	2062	27290	-1610	N	Summer 2026
9/12/2026	27071	350	409	43	48	14	2100	0	25711	25228	2062	27290	-1579	N	Summer 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 2026 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: 115% 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.

Summer 2026 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

May 22, 2026 - 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 June through mid September.

Report created: 5/22/2026

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
6/6/2026	26705	320	598	13	89	212	2800	0	24535	26473	2062	28535	-4000	Y	Summer 2026
6/13/2026	26705	320	598	13	182	14	2800	0	24640	26473	2062	28535	-3895	N	Summer 2026
6/20/2026	26705	320	598	13	80	14	2800	0	24742	26473	2062	28535	-3793	N	Summer 2026
6/27/2026	26705	320	598	13	64	14	2800	0	24758	26473	2062	28535	-3777	N	Summer 2026
7/4/2026	27071	350	409	43	120	14	2100	0	25639	26473	2062	28535	-2896	N	Summer 2026
7/11/2026	27071	350	409	43	45	14	2100	0	25714	26473	2062	28535	-2821	N	Summer 2026
7/18/2026	27071	350	409	43	43	14	2100	0	25716	26473	2062	28535	-2819	N	Summer 2026
7/25/2026	27071	350	409	43	64	14	2100	0	25695	26473	2062	28535	-2840	N	Summer 2026
8/1/2026	27071	350	409	43	61	14	2100	0	25698	26473	2062	28535	-2837	N	Summer 2026
8/8/2026	27071	350	409	43	61	14	2100	0	25698	26473	2062	28535	-2837	N	Summer 2026
8/15/2026	27071	350	409	43	46	14	2100	0	25713	26473	2062	28535	-2822	N	Summer 2026
8/22/2026	27071	350	409	43	52	14	2100	0	25707	26473	2062	28535	-2828	N	Summer 2026
8/29/2026	27071	350	409	43	44	14	2100	0	25715	26473	2062	28535	-2820	N	Summer 2026
9/5/2026	27071	350	409	43	48	45	2100	0	25680	26473	2062	28535	-2855	N	Summer 2026
9/12/2026	27071	350	409	43	48	14	2100	0	25711	26473	2062	28535	-2824	N	Summer 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 2026 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: 115% 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 Preliminary ISO-NE 2027/2028 Budgets

JUNE 16-18, 2026

ISO New England 2027 and 2028 Preliminary Operating and Capital Budgets

NEPOOL Participants Committee 2026 Summer Meeting

Kelly Reyngold
VP, CHIEF FINANCIAL OFFICER

Contents of Presentation

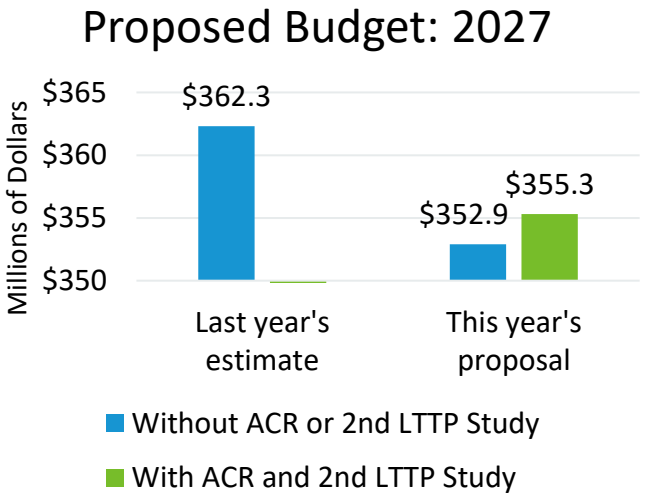
EXECUTIVE SUMMARY

Executive Summary

- The 2027 ISO-NE budget continues to support the region's needs and evolving grid while reinforcing our commitment to affordability, reliability, and long-term value
- Investments are aligned to deliver high-quality services to the region amid increasing uncertainty in regional supply and demand
  - Continued focus on innovation and agility to respond to such uncertainty
    - Appendix 7 highlights examples of how the ISO is currently leveraging innovation and AI to enhance responsiveness and drive operational performance
- Continued emphasis on operational efficiency and disciplined cost management
- Affordability remains a core lens: balancing necessary investment with cost impacts to stakeholders

Executive Summary

- The projected 2027 ISO-NE budget, based on assumptions previewed with stakeholders during the 2026 budget cycle, was $362.3M
  - This budget did not include costs for the permanent Asset Condition (AC) Reviewer role or a second Longer-Term Transmission Planning (LTTP) Study
- The current proposed 2027 ISO-NE budget is $355.3M and includes costs for AC Reviewer and LTTP
  - Excluding costs for AC Reviewer and LTTP, the proposed 2027 budget is $352.9M, which constitutes a decrease of $9.4M or 2.6% from the previously projected budget



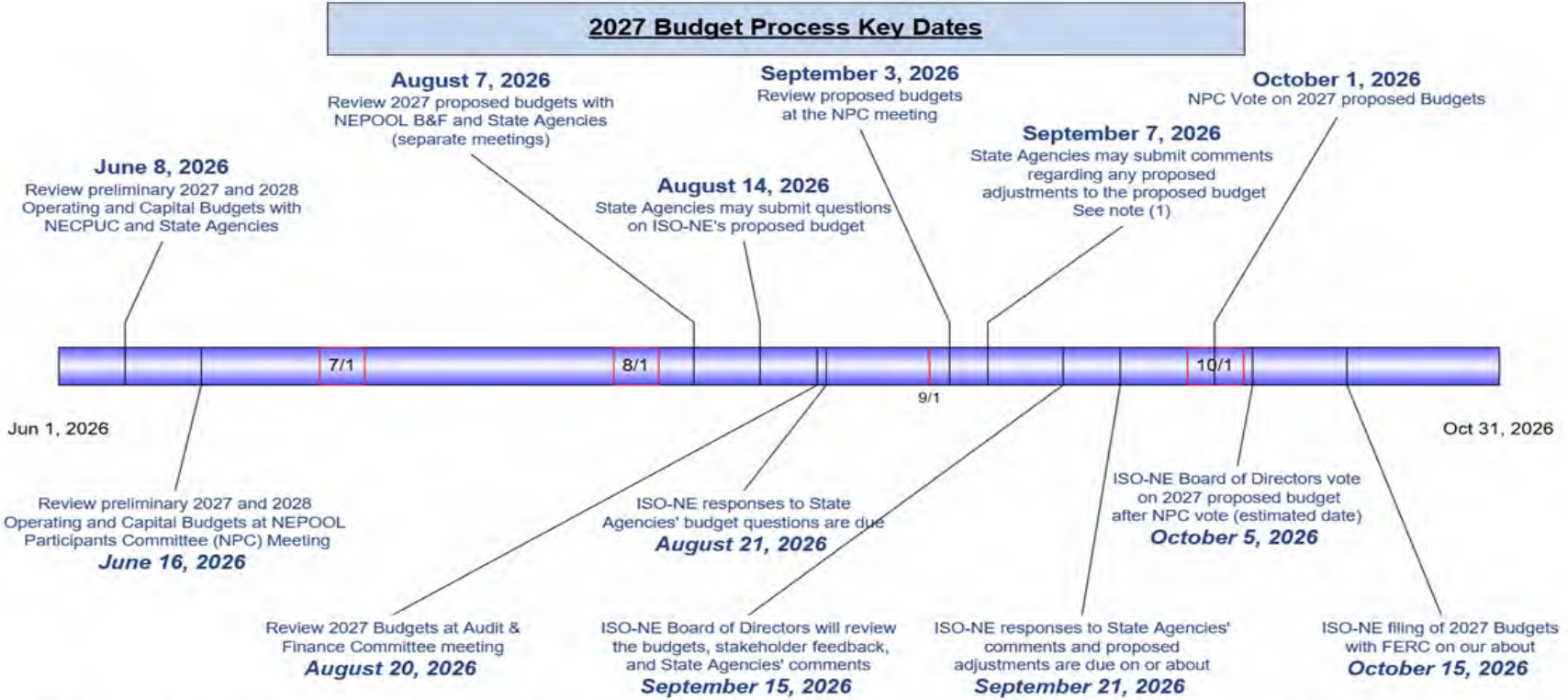
Executive Summary

- 2027 budget increases, over the 2026 approved budget, are driven by multiple factors:
  - Key external drivers:
    - Changing resource mix and customer demand patterns
    - Ongoing system transformation independent of macro uncertainty
    - Inflationary and price escalation trends
  - Internal drivers:
    - Supporting new systems, markets, and infrastructure
    - Maintaining workforce capabilities
  - Affordability consideration: investments prioritized to maintain reliability and avoid higher long-term system costs

Executive Summary

- As ISO-NE seeks to offer increasing value to the region, we have allocated, as separate line items, $2.4M to initiatives requested by the states and other stakeholders:
  - Asset Condition (AC) Reviewer ($2.2M)
    - Other AC Reviewer related costs, not included in the amount above, for existing ISO staff (e.g. legal, management, and support) will be borne by the company to stand up the AC Reviewer function in 2027
  - Longer-Term Transmission Planning – second study ($0.2M)
- Monies not spent on these two initiatives will be returned through the true-up process

2027 Budget Process – Key Dates



(1) According to the budget settlement agreement, State Agencies must submit comments on the proposed budgets five weeks after the August meeting which is September 11, 2026. However, we are requesting comments by September 7, 2026 to allow for timely distribution to the Board when meeting materials are mailed. This is consistent with the acceleration agreed to in 2015.

STRATEGIC PLANNING PROCESS OVERVIEW

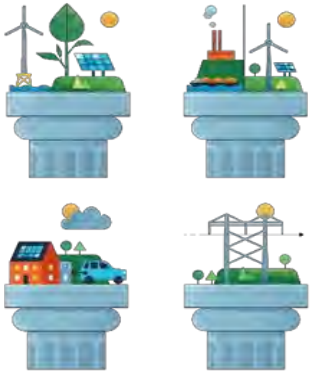
ISO-NE's integrated business and strategic planning framework

Annual Process – Business and Strategic Planning

ISO-NE is guided by a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can get behind, with the aim of creating value for ISO stakeholders

Our Guidepost: The ISO New England Vision Statement

The ISO-NE Vision Statement is an explicit statement about our intent to support the states' policy goals to achieve a reliable transition to clean energy, utilizing competitive markets and transmission planning



Vision Statement:

To harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy

The ISO's Vision represents the company's commitment to work with FERC, the states, and market participants to support the region's grid transition within the limits of our jurisdiction

Our Responsibility to the Region: ISO's Mission

The ISO-NE Mission Statement outlines the core role and responsibilities of the ISO's daily operations

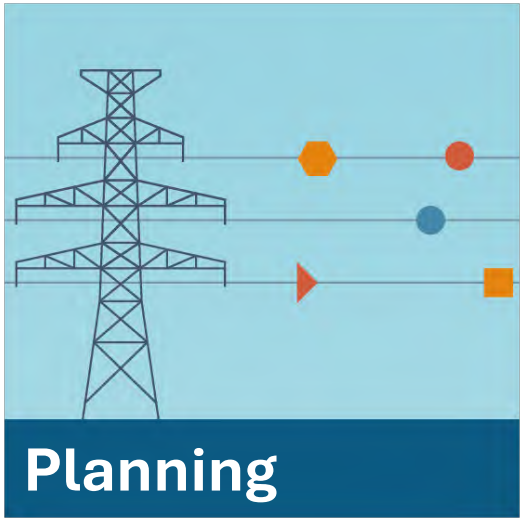
Mission Statement:

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

ISO New England Performs Three Critical Roles to Ensure Reliable Electricity at Competitive Prices

Coordinate and direct the flow of electricity over the region's high-voltage transmission system

Design, run, and administer the billion-dollar markets where wholesale electricity is bought and sold



Study, analyze, and plan to make sure New England's electricity needs will be met over the next 10 years

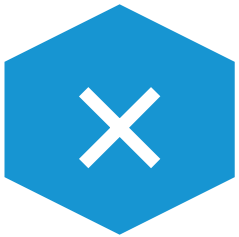
Functions Outside of ISO Jurisdiction

The ISO does not…

Handle retail electricity

Own power grid infrastructure

Have a stake in companies that own grid infrastructure



Have jurisdiction over fuel infrastructure

Have control over siting decisions

Plan the resource mix

2027 AND 2028 PRELIMINARY BUDGET OVERVIEW

Our 2027 Strategy Continues to Support the Region's Grid Transition and Drives our Work and Resource Requirements

- Resources to: sustain ongoing operations; advance new market, planning, and regulatory initiatives; invest in technology and innovation
  - Continue capacity market reforms to better align with the region's evolving energy system
  - Continue to design and develop various products and support new in-service projects to administer our mission
  - Invest in AI and analytics to improve forecasting, modeling, and simulation capabilities
  - Continue strengthening cybersecurity defense mechanisms and ISO computer networks and infrastructure to protect against sophisticated threat vectors
- Resources for additional work requested by states and other stakeholders
  - Adoption of the Asset Condition (AC) Reviewer role
  - Advance additional LTTP study to support states' energy policy and address evolving system needs

2027 Preliminary Budget Overview

- In preparing the 2027 Preliminary Budget, ISO-NE sought to balance supporting the region's evolving needs, implementing new market, planning, and regulatory initiatives, increasing productivity via technology and analytics, with affordability and cost-discipline
  - The preliminary baseline budget is **$22.9M or 6.9%** above the 2026 approved budget
    - This reflects an $9.4M (2.6%) decrease compared to the 2027 budget levels projected based on assumptions previewed with stakeholders during the 2026 budget cycle
  - Incorporating additional AC Reviewer and LTTP services requested by states and other stakeholders increases the preliminary 2027 budget by **$2.4M** resulting in a total increase of **$25.3M (7.7%)** over the 2026 approved budget
  - Including both the requested AC Reviewer and LTTP services and prior year true-ups, the 2027 Revenue Requirement reflects a $33.3M increase

Note: Throughout the presentation some schedules may appear inconsistent due to rounding.

2027 Preliminary Budget Overview *(cont.)*

- Key drivers supporting the proposed increase represent ongoing support of the stakeholder-supported workplan:
  - Changes in the resource mix and customer use patterns in New England: these changes will continue independent of federal policy, inflation, or local siting and permitting hurdles for new supply resources
  - The implementation and support of various market, transmission, and emerging technology initiatives requires increased headcount to build, maintain, and administer
    - In particular, the CAR project will require incremental resources given the volume of change and new functionality, including seasonal auctions and accreditation
  - Execution of these initiatives depends on maintaining a highly skilled workforce, requiring sustained investment in competitive compensation and benefits
- Included in the 2027 Preliminary Budget are 27 additional FTEs to support existing functions, with 7 more for the AC Reviewer role*

*To account for the staggered onboarding of newly budgeted positions, the 2027 Preliminary Budget provides funding for 33.5 additional FTEs, consisting of both proposed 2027 positions and carryover from partially funded 2026 positions.

Resources for Ongoing Operations, Technology and Innovation, Market and Transmission Initiatives and Stakeholder Requests in 2027

There are four main factors for the change to the 2027 ISO budget (separate from the revenue requirement true-up change):

1. Inflationary and Strategic Staffing to Sustain Operations
   - Workforce compensation and benefits; inflationary pressures that are enterprise-wide, with the greatest concentration in Information Technology; investments in cybersecurity defenses; and additional staffing to support Information Technology, Finance, Human Resources, and regulatory fee increases for Northeast Power Coordinating Council and North American Electric Reliability Corporation
2. Technology and Innovation Resources
   - Artificial Intelligence utilization to drive improved productivity and operations; maintenance and support for new and improved tools for System Planning and System/Market Operations
3. Market and Transmission Initiatives
   - Staff additions for CAR; Economic and Planning Studies; full Net CONE recalculation; new generation interconnection tools; and transmission planning responsibilities
4. New Services/Stakeholder Requests
   - Asset Condition Reviewer; Economic and Planning Studies and additional Longer-Term Transmission Planning efforts

Note: See the following slide for the cost impact of each these factors plus the revenue requirement true-up change

Resources for Ongoing Operations, Technology and Innovation, Market and Transmission Initiatives and Stakeholder Requests in 2027 *(cont.)*

Factor	% Increase	$ Amount	$KWh Rate	Average Monthly Consumer Cost Impact *
Inflationary and Strategic Staffing to Sustain Operations	3.4%	$ 10,470,300	$0.00009	$0.06
Technology and Innovation Resources	2.2%	$ 6,810,700	$0.00006	$0.04
Market and Transmission Initiatives	1.6%	$ 5,064,100	$0.00004	$0.03
New Services/Stakeholder Requests	0.9%	$ 2,929,600	$0.00002	$0.02
Net Change in Rev Req True-Up	2.5%	$ 7,984,200	$0.00006	$0.05
Total Change in Revenue Req for 2027:	**10.6 %**	**$33,258,900**	**$0.00027**	**$0.20**

**Average Monthly Consumer Cost Impact* is based on average consumption of 750 kWh per month.

2027 Budget Drivers

- Market Initiatives
  - Capacity Auction Reforms
  - Flexible Response Services and Reserve Products
  - Next-Generation Energy Markets (nGEM) platform
- New/Additional Regulatory Initiatives
  - Longer-Term Transmission Planning
  - Asset Condition Reviewer Role
  - Managing Transmission Line Ratings
  - Grid Enhancing Technologies in Transmission Planning
  - Distributed Energy Resources participation in wholesale energy markets
  - Interconnection improvements
- Forecasting/Modeling Improvements
  - Probabilistic Forecasting Enhancements
  - Inverter-Based Resource (IBR) Integration & Modeling
  - Synchophasor Enhancements for the Future Grid
  - Resource Adequacy and Energy Security Analysis Tools

2027 Budget Drivers *(cont.)*

- Digital transformation and technology modernization efforts to improve security, reliability, and efficiency(1)
  - The ISO's transition to a cloud environment continues to be a major effort over the next several years to reduce reliance on in-house data centers, make system deployment more efficient, and enable faster computing performance as data volume grows
  - Utilization of Artificial Intelligence (AI) and Machine Learning (ML) for items such as technology updates, cloud infrastructure provisioning, and developing of comprehensive knowledge databases
    - The ISO has included additional resources for 2027 to begin to scale AI usage
- Remaining competitive in compensation and benefits in what is still a tight labor market for the skillsets needed at the ISO
- Computer Services(1) including support costs for new or enhanced systems that have/will become operational in 2026 and 2027
  - nGEM Real-Time Market Clearing Engine
  - CIP Synchrophasor Improvements
  - Cyber Security Log Management, AI-enabled Cyber Security tools, and Cloud Security
  - Impact of moving applications to the cloud (noted above under Cloud Modernization) and SaaS solutions

(1) See the following slide for additional details on Cloud Modernization, Computer Service and Information Technology related costs

2027 Budget Drivers *(cont.)*

Like many of our peers, ISO-NE has experienced significant growth in Computer Service and Information Technology needs and related costs over the past several years and expects that to continue in 2027. This is driven by:

- AI and ML for software development and innovation
  - Utilization of AI and ML for items noted on the previous slide
  - Other examples include uses such as On-Line Weather Look-Ahead Study to estimate transmission outages under severe weather and pump storage forecast in 21-day Energy Assessment
- Ongoing support for market and operations technologies
  - Including: a software portfolio designed for grid orchestration, integrating energy data, AI-driven analytics, and grid modeling to help utilities manage modern energy complexities; and PEAT license renewal
- Increase in Data Management Costs
  - Organizations are leveraging Infrastructure-as-a-Service (IaaS) to reduce implementation time, enhance operational efficiency, and support innovation
- Software Licensing and Subscription Fees
  - Increases driven by rising software license costs, expanding user bases, and investments in enhanced tools
- Inflation, Supply-Chain Disruptions, and Tariffs
  - Ongoing geopolitical instability and supply chain challenges are contributing to price increases in electronics, machinery, and other IT-related goods

2027 Preliminary Capital Budget Overview

The 2027 Capital Budget is also presented in summary form

- The 2027 Capital Budget is $45.0M which represents a $2.5M or 5.9% increase over the 2026 capital budget
  - Capital budget increases over the past several years have been driven driven by three primary drivers as explained in further detail in Appendix 3
  - Significant projects expected for 2027 include Capacity Auction Reforms implementation, Single Interval Market Clearing Engine Implementation (transitioning Real-Time study modes to nGEM platform), and EMP 3.5 Upgrade – GridOS (to migrate ISO-NE's Energy Management System customizations to GE's Energy Management Platform version 3.5)
- The 2027 proposed capital budget of $45.0M is provided with a list of projects by strategic goal that are currently chartered and on-going or in planning/conceptual design (see Appendix 4)
- Detailed project descriptions will be presented in August once the final resource requirements are determined

2028 Preliminary Budget Overview

2028 Budget amounts are projected as follows (over 2027 Preliminary Budget amounts presented today):

- Net Expense Before Depreciation and Regulatory Fees is $24.2M or an 7.9% increase, while amounts including Depreciation and Regulatory Fees is a $31.1M or 8.8% increase

2028 Budget Assumptions include:

- The addition of 25 FTEs, primarily for System Planning (for continued build out of Asset Condition Reviewer team, Resource Adequacy, Transmission Planning, and Generation Interconnections); Information Technology resources to continue servicing new market features and advanced technologies; and for support areas including participant support and training, Human Resources, and Finance
- Merit and promotional/equity annual increases consistent with 2027 amounts (4.5% total)
- Estimated increases based on market or historical trends related to: employee benefits (primarily for health insurance); Computer Services; and Insurance Expense
- Inflationary increases in other lines based on consumer price index indicator for 2028

2027 and 2028 Operating Budget Risks

- Additional resources may be needed as the 2027 work plan scope increases based on regulatory and stakeholder initiatives/requests
- Cyber risk is increasingly treated as a balance-sheet issue, with exposure to ransomware-driven downtime, third-party/vendor breaches, regulatory penalties, and critical infrastructure disruptions; risk is expected to intensify through 2027–2028 as AI-assisted attacks increase in frequency and sophistication, driving incremental investment in resilience capabilities, backup systems, identity management, cyber insurance, and incident response retainers
- Technology spend is increasingly unpredictable as AI workloads scale differently than traditional systems, creating exposure to cloud cost. Early-stage AI initiatives are rapidly converting into recurring operating expenses, driving sustained growth in AI usage, data storage, and governance requirements; as a result, software licensing and maintenance, cloud migration, and AI utilization and control frameworks are expected to require incremental and less predictable funding in future budgets
- Insurance policy renewals may be higher than estimated as ISO is not immune to overall increases from the insurance industry due to natural disasters
- Interest Rates may impact the ISO floating rates on tax-exempt debt, pension and post-retirement benefit plans liability costs, and interest income on settlement float balance
- Legal costs from material litigation that may arise during the course of the year would pose a risk to the ISO's ability to operate within the approved budget
- Federal and state policy directives/changing policies could result in additional cost associated with new requirements
- Workforce sourcing and related pay rates, supply chain disruption, and inflationary pressures may each have budgetary impacts

APPENDIX 1: 2027 Detailed Budget Changes by Strategic Goal

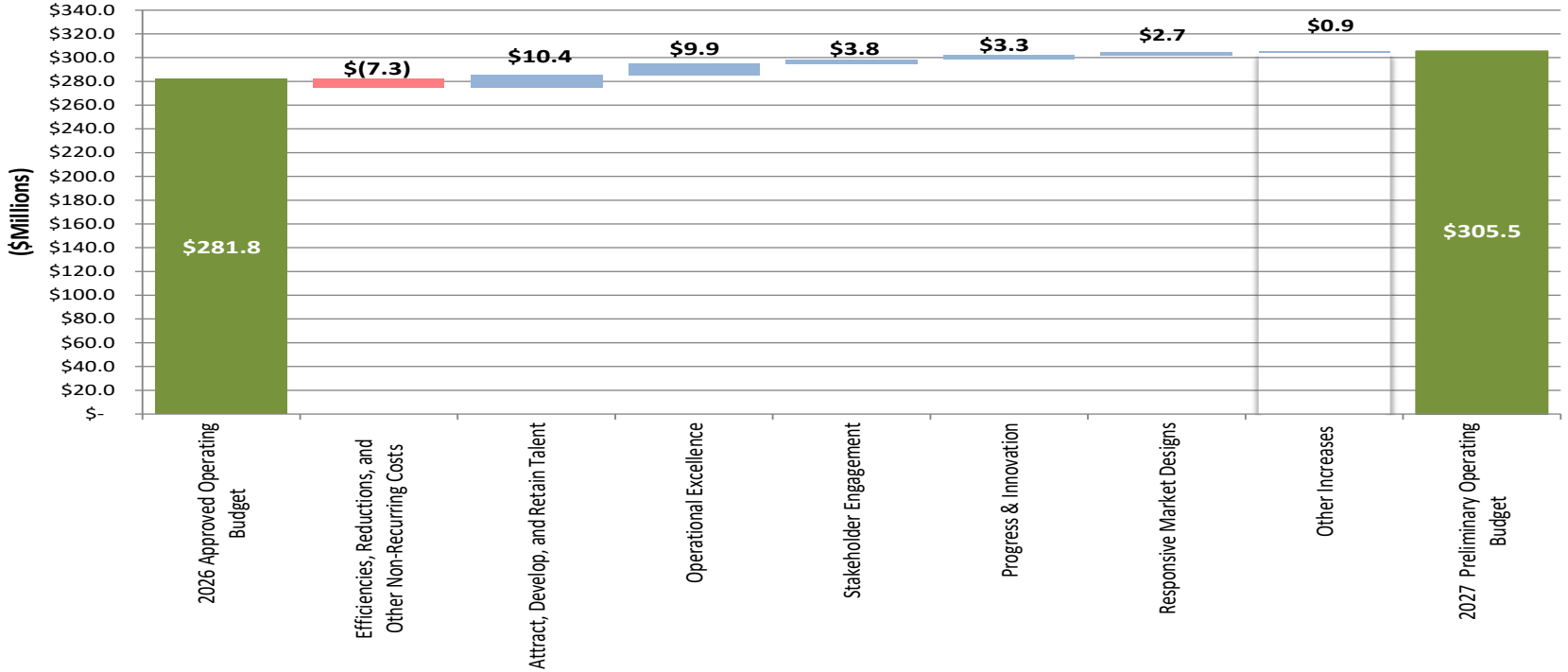
2027 ISO-NE Strategic Goals

The ISO ties its annual budget to resource requirements by Goals, Objectives, and Initiatives

Responsive Market Designs:	Advance the competitive wholesale markets to support the investment and new services required for a reliable clean energy transition
Progress and Innovation:	Expand capabilities to support increasing grid complexity brought about by new technologies and changes to supply mix and customer use
Operational Excellence:	Focus on high quality business operations, prioritize high impact projects, and mitigate implementation risks
Stakeholder Engagement:	Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with regulators and stakeholders in supporting the four pillars of the clean energy transition
Attract, Develop, and Retain Talent:	Continue to promote our Culture, Mission, Vision, and Goals; develop and position the workforce to support the evolving needs of the organization; recognize and reward employees' success and innovation; tailor programs to retain and attract critical, in-demand skills; and foster an inclusive culture that values diversity of career and life experiences

2027 Preliminary Budget

Changes in budget by Strategic Goal



2027 Preliminary Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs(1)

Reductions include: ($7.3M)

- Computer Services reductions driven by retired products and savings achieved through contract renewals ($3.3M)
- Lower costs for Capacity Auction Reforms design consultant and project management as work moves from the design to development ($1.6M)
- Lower required contributions reflect favorable investment performance and the impact of a recent pension lift-out, supporting ongoing plan de-risking ($1.0M)
- Lower salary costs from retirements and backfilling positions with less experienced staff ($0.5M)
- Elimination of the Holyoke facility land lease in anticipation of a planned purchase prior to 2027 ($0.3M)
- Reduced reliance on workforce security consulting through the repurposing of an existing FTE ($0.3M)
- Net favorable impact from changes in interest income and expense, driven by higher settlement balances and lower tax-exempt debt ($0.3M)

(1) The items identified reflect known, quantifiable reductions. The ISO's budget also incorporates incremental savings from contract negotiations and other cost-avoidance initiatives that are not readily quantifiable. As an example, through the Oracle Platform Replacement project, ISO staff conducted a detailed assessment of database requirements and worked with Oracle to appropriately size the target environment. This effort avoided unnecessary capital investment in excess storage capacity and reduced ongoing cost exposure, saving the Company a few million dollars. Similarly, the ISO maintains active oversight of AWS and broader cloud spend, with dedicated resources monitoring usage and aligning pricing models to demand. These efforts have also delivered several million dollars in savings by ensuring efficient use of cloud resources.

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 5: Attract, Develop, and Retain Talent: $10.4M

- Merit and promotion increases reflecting a 3.5% annual merit adjustment and 1.0% for standard and targeted promotions and market-based adjustments ($6.3M)
- Higher employee benefit costs, primarily driven by medical and dental trend increases and growth in participation in the Defined Contribution Benefit Plan ($2.0M)
- Increase in employee incentive compensation aligned with market data and survey benchmarks, along with enhanced funding for employee recognition programs ($1.3M)
- Addition of 1.5 FTEs in Human Resources, including a Business Partner to support client groups in employee engagement, change management, workforce planning, employee relations, and organizational design, as well as a partial FTE focused on developing Information Technology training programs ($0.3M)
- Increased System Planning training investments to support the onboarding and development of newer, entry-level staff and expand proficiency in industry and technology tools ($0.2M)
- Funding for Human Resources performance management and talent acquisition software platforms ($0.2M)
- Increase in external recruiting fees to support hiring needs ($0.1M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 3: Operational Excellence: $9.9M

- Computer services and leasing increases driven by investments in cybersecurity (including security log monitoring and management, email threat detection, threat and risk analytics tools, performance monitoring, and AI-powered platforms); server leasing associated with data center refresh efforts; higher costs to equip staff with laptops and desktops; expanded computing and storage capacity; new or enhanced licensing for System Planning and Operations applications (including power system computer-aided design, forecasting, and simulation tools); and inflationary and vendor-driven price increases across the computer services portfolio ($4.2M)
- Funding for 13.0 FTEs to support this goal, including System Planning resources to address technical challenges associated with the integration of inverter-based resources, perform system assessments and studies, meet NERC/NPCC requirements, support generator interconnection processes, and advance capacity auction reforms; Information and Cybersecurity roles focused on software testing automation, cloud platform infrastructure, site reliability, and strengthening energy market systems; Market Monitoring staff to address growing market complexity, advanced analytics needs, and increasingly sophisticated market behavior; and additional support roles in Finance, Human Resources, and Facilities & Security ($2.7M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 3: Operational Excellence: $9.9M *(cont.)*

- Consulting and Professional Fees increases driven by Information and Cybersecurity needs, including advisory and research services, system patching, and higher consultant utilization due to additional hours, a shift toward support over development activities, and reduced vacancies; expanded Internal Audit efforts to conduct additional system-related audits and reviews; Market Monitoring investments to enhance machine learning capabilities; and Transmission Planning support to incorporate and validate distribution data in system models ($1.8M)
- Network Operations investments to modernize communications with local control centers, enhance tie-line telemetry, and improve ISO workforce communications ($1.0M)
- Inflationary increases related to Information Technology training subscriptions, as well as higher travel costs for ISO workforce participation in stakeholder meetings and industry conferences ($0.2M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 4: Stakeholder Engagement: $3.8M

- Funding to establish the AC Reviewer(2) team, including 5 FTEs and supporting professional services, to build out and manage this function ($2.2M)
- Investment in GridUnity, a SaaS, cloud-based platform designed to accelerate energy project interconnections by automating, standardizing, and streamlining the process ($0.9M)
- Transmission study costs, including a system-wide thermal assessment driven by FERC Order 881 requirements and OATT/Cluster Enabling Transmission Upgrade regional planning studies ($0.3M)
- Inclusion of funding for potential LTTP study anticipated to be requested in 2027 ($0.2M)
- Funding for 0.5 FTE in Legal to support annual RFP activities associated with LTTP requirements ($0.2M)

(2) The buildout of the Asset Condition Reviewer group is expected to occur over the next 3 to 5 years, with FTEs added incrementally throughout this period. The 2027 Preliminary Budget includes 7 planned FTE additions, with funding provided for 5 FTEs to reflect the phased hiring approach and expected onboarding timeline.

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 2: Progress and Innovation: $3.3M

- Funding for 10.5 FTEs across Information Technology and Advanced Technology Solutions to build out capabilities that formalize and expand the use of Artificial Intelligence and Machine Learning across ISO-NE; support the transition of internally developed advanced technologies into production environments to enhance situational awareness; and advance application migration to the cloud; additional resources are included for Planning Services to address growing demands in load forecasting, economic and environmental studies, and resource adequacy, as well as a Market Monitoring position to expand technical capacity for maintaining, enhancing, and modernizing in-house market monitoring systems ($2.5M)
- Investment in optimization software supporting the Probabilistic Energy Adequacy Tool (PEAT) to strengthen analytical and planning capabilities ($0.6M)
- Synchrophasor data management software to handle the high-volume, time-sensitive data generated by PMUs utilized by the ISO; this platform will provide scalable, resilient, and low-latency processing, enabling real-time grid monitoring, analysis, and decision-making ($0.2M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 1: Responsive Market Designs: $2.7M

- Information Technology computer services maintenance costs associated with GE Vernova's Grid Orchestration Software ($1.0M)
- Increased funding to support tariff-required Net CONE (Cost of New Entry) recalculation activities ($1.0M)
- Funding for 3.0 FTEs to support this goal, including Information Technology and Advanced Technology Solutions resources to integrate new market features into applications and tools, and Planning Services staff to support Capacity Requirement and Accreditation and Resource Qualification functions across both pre- and post-CAR implementation phases ($0.6M)
- Market Monitoring support for energy market risk premium analysis ($0.1M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Other Increases: $0.9M

- Insurance policy rate increase ($0.5M)
- Increases for utility expenses due to higher expected rates at both the Windsor and Holyoke facilities ($0.3M)
- Inflationary increases for various Building Services including physical security, janitorial, and HVAC and generator maintenance ($0.1M)

APPENDIX 2: 5 YEAR BUDGET COMPARISON

2027 Preliminary Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2027	% Change	2026	% Change	2025	% Change	2024	% Change	2023
Operating Budget Before Depr and Regulatory Fees	$305.5	8.4%	$281.8	8.3%	$260.2	10.1%	$236.3	17.0%	$201.9
Capital Budget	45.0	5.9%	42.5	0.0%	42.5	21.4%	35.0	4.5%	33.5
Total Cash Budget	**$350.5**	**7.1%**	**$324.3**	**7.1%**	**$302.7**	**11.6%**	**$271.3**	**15.2%**	**$235.4**
Operating Budget Before Depr and Regulatory Fees	$305.5	8.4%	$281.8	8.3%	$260.2	10.1%	$236.3	17.0%	$201.9
Depreciation and Regulatory Fees **(1)**	49.8	3.3%	48.2	4.2%	46.2	13.8%	40.6	6.1%	38.3
Revenue Requirement Before True-up	355.3	7.7%	330.0	7.7%	306.4	10.7%	276.9	15.3%	240.2
True up	(7.6)		(15.6)		4.8		(3.0)		(14.6)
Revenue Requirement	**$347.6**	**10.6%**	**$314.4**	**1.0%**	**$311.2**	**13.6%**	**$273.9**	**21.4%**	**$225.6**
Forecast – TWhs (2)	**124.6**	**(0.0)%**	**124.7**	**0.9%**	**123.6**	**1.7%**	**121.5**	**(0.0)%**	**121.5**
$/KWh Rate	**$0.00279**	**10.6%**	**$0.00252**	**0.1%**	**$0.00252**	**11.7%**	**$0.00225**	**21.4%**	**$0.00186**
Average Monthly Consumer Cost (3)	**$2.09**		**$1.89**		**$1.89**		**$1.69**		**$1.39**

(1) The 2027 *preliminary* depreciation budget is a placeholder. The 2027 *proposed* budget will result in a detailed review of project budgets and estimated go-live dates for the impact on depreciation expenses.

(2) 2027 Forecast based on May 2026 CELT Report (Schedule 1.5.2 - Annual Net Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

(3) Based on average consumption of 750 kWh per month.

Note: Throughout the presentation some schedules may be inconsistent due to rounding.

APPENDIX 3: Forward Looking Capital Budget Spending

Forward Looking Capital Budget Spending

- The capital budget over the next five years and beyond will continue to support the Company's strategic goals with specific focus on three primary drivers :
  - nGem platform (replacing the current market system)
  - Major market and reliability related efforts
  - Cyber security & IT asset and infrastructure replacement
- In order to achieve these goals, ISO has increased the capital spending over the last few years with spending of $42.5M in 2025, $42.5M in 2026, and $45.0M in 2027 with the potential to increase upwards of $50M in future years; the capital costs are dependent on various factors, including regulatory orders and approvals and the use of professional services or internal staff
  - The ISO will continue with its current practice of providing a rolling two-year look-ahead window

nGEM Platform

- The nGEM program (next Generation Markets Management) is intended to upgrade ISO's core market software to support a system with a growing number and type of grid assets, new and more complex market features, ever multiplying security threats, and advancing IT technologies
  - GE developed nGEM in collaboration with ISO-NE, MISO, and PJM; the portion of the software upgrade unique to each ISO will be shouldered by each ISO individually
- Following the scheduled completion of the Real-time Unit Commitment (RTUC) and Coordinated Transaction Scheduling Pricing Engine (CTSPE) functions in the nGEM version of the market clearing engine (MCE) set for mid-2026, the ISO plans to continue with implementation of the next phase
  - The next phase, to be completed under the *Single Interval MCE Improvements* project, includes moving the Unit Dispatch System (UDS) and Location Marginal Pricing Calculator (LMPC) functions to the nGEM MCE; this work is expected to continue through 2028 with an estimated cost of $13.3M

Major Market and Reliability Related Efforts

- Many of these projects are complex efforts that will have long lead times to complete with some having dependencies of stakeholder and regulatory approval
- Projects beyond 2027 (see slide 45) reflect emerging market and reliability needs not yet included in the 2027 capital plan and are presented to provide transparency into future system requirements and potential capital pressures beyond the current planning horizon, although these may fluctuate depending on stakeholder and/or FERC priorities
- Based on the complexity of the projects, the ISO expects the cost for market and reliability efforts will range from approximately $40M - $60M over the next five plus years

Major Market and Reliability Related Efforts *(cont.)*

- Capacity Auction Reforms – Seasonal/Accreditation (CAR-SA) effort; the transition to CAR-SA will require changes to multiple existing software systems including auditing, settlement and financial assurance, as well as new software systems to support the resource adequacy assessment process, the capacity qualification process and new auction clearing mechanisms
- Energy Management Platform (EMP) - Upgrade of the Energy Management System (EMS) and its applications, plus supporting SCADA and modeling systems to stay current with vendor-supported versions

Major Market and Reliability Related Efforts–beyond 2027

- Uncertainty Reserves - Dynamic operational reserve demand curves for incremental 10- and 30-minute reserves, and a potential new (60- or 90-minute) reserve product, to address operational uncertainties during the operating day
- Multi-interval Dispatch and Pricing (MIDAP) - Objective is to improve ISO's suite of intra-day optimization processes to perform forward-looking dispatch and pricing "in the market," over a time horizon of several hours or possibly the balance of the day
- Efficient Storage Integration and Optimization – Includes a suite of enhancements to storage resources' participation, offer formats, and scheduling/optimization in the markets, all of which will enhance these resources' reliability and efficiency benefits to the region

Cyber Security & IT Asset and Infrastructure Replacement

- Costs for IT and cyber security initiatives will vary based on the use of internal resources versus professional services, with total spending estimated at approximately $20M–$40M over the next several years
- The ISO has invested heavily in cyber security maturity over the past several years and will continue doing so over the next 3–5 years; these investments enable enhanced defenses, network segmentation, and email/web filtering to improve monitoring, detection, and recovery against increasingly sophisticated threats
  - Significant focus on upgrading infrastructure to proactively mitigate future quantum computing threats to legacy cryptographic standards
- The ISO's transition to a cloud environment began in 2022 and will remain a major capital initiative over the coming years as application cloud migrations accelerate
  - Operating a modern grid with renewable and storage resources requires large-scale data processing and storage; through phased implementation, the ISO will deploy cloud computing and virtualization to support scalable computing while maintaining reliability

APPENDIX 4: 2027 Preliminary Capital Budget

Capital Budget
2027 Expenditures

Goal: Responsive Market Designs

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Capacity Auction Reforms*	$6.0 M	$8.0 M	12/2028	Conceptual Design
. EMP 3.5 Upgrade - GridOS	$4.0 M	$6.9 M	09/2028	Conceptual Design
. GridOS Connect	$1.5 M	$1.9 M	12/2027	Conceptual Design
. Resource Adequacy Assessment & Accreditation	$1.0 M	$1.5 M	06/2027	Conceptual Design
. Integrated Market Simulator Usability	$1.0 M	$1.1 M	12/2027	Conceptual Design
Total:	**$13.5 M**			

**Capacity Auction Reforms may involve multiple projects, with specific details still under development.*

Goal: Progress and Innovation

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Single Interval MCE Improvements (SIMI)	$6.0 M	$13.3 M	12/2028	Conceptual Design
. Advanced Technology Initiatives	$3.0 M	$4.0 M	12/2027	Conceptual Design
. Migration of MIS FTP to Cloud	$0.1 M	$0.5 M	04/2027	In Development
Total:	**$9.1 M**			

Capital Budget
2027 Expenditures *(cont.)*

- Goal: Operational Excellence

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Non-Project Capital Expenditures	$7.5 M	$7.5 M		
. MW Dependent Fuel Price Adjustment	$1.2 M	$2.6 M	08/2027	Conceptual Design
. TTCU Implementation for Resource Outage Coordination	$0.2 M	$1.1 M	05/2027	In Development
. Solar Do Not Exceed Dispatch Phase III	$0.5 M	$1.0 M	12/2027	Conceptual Design
. Circuit Inventory Management Platform Phase II	$0.2 M	$0.7 M	04/2027	Conceptual Design
. Tie Line Telemetry and PCEC Upgrade Phase II	$0.5 M	$0.7 M	06/2027	Conceptual Design
. Replace Employee & Pager Application	$0.5 M	$0.6 M	12/2027	Conceptual Design
. PowerGADS Update for Capacity Auction Reforms	$0.5 M	$0.5 M	06/2027	Conceptual Design
. Next-Gen Electronic Dispatch & Reliability Voice Networks	$0.3 M	$0.5 M	05/2027	Conceptual Design
. Enterprise Resource Planning (ERP) Enhancements 2027	$0.5 M	$0.5 M	12/2027	Conceptual Design
. EMT Model Repository	$0.4 M	$0.5 M	06/2027	Conceptual Design
. CIP Electronic Security Perimeter Network Services	$0.2 M	$0.3 M	09/2027	Conceptual Design
Total:	**$12.5 M**			

- Goal: Stakeholder Engagement

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Interconnection Request Tracking Upgrade	$0.2 M	$2.1 M	03/2027	Conceptual Design
Total:	**$0.2 M**			

Capital Budget
2027 Expenditures Summary

- 2027 Capital Budget Expenditure Summary

Allocation Category	2027 Budget
Goal: Responsive Market Designs	$13.5 M
Goal: Operational Excellence	$12.5 M
Goal: Progress and Innovation	$9.1 M
Other Emerging Work	$8.5 M
Capital Interest	$1.2 M
Goal: Stakeholder Engagement	$0.2 M
Total:	**$45.0 M**

APPENDIX 5: CAPITAL STRUCTURE

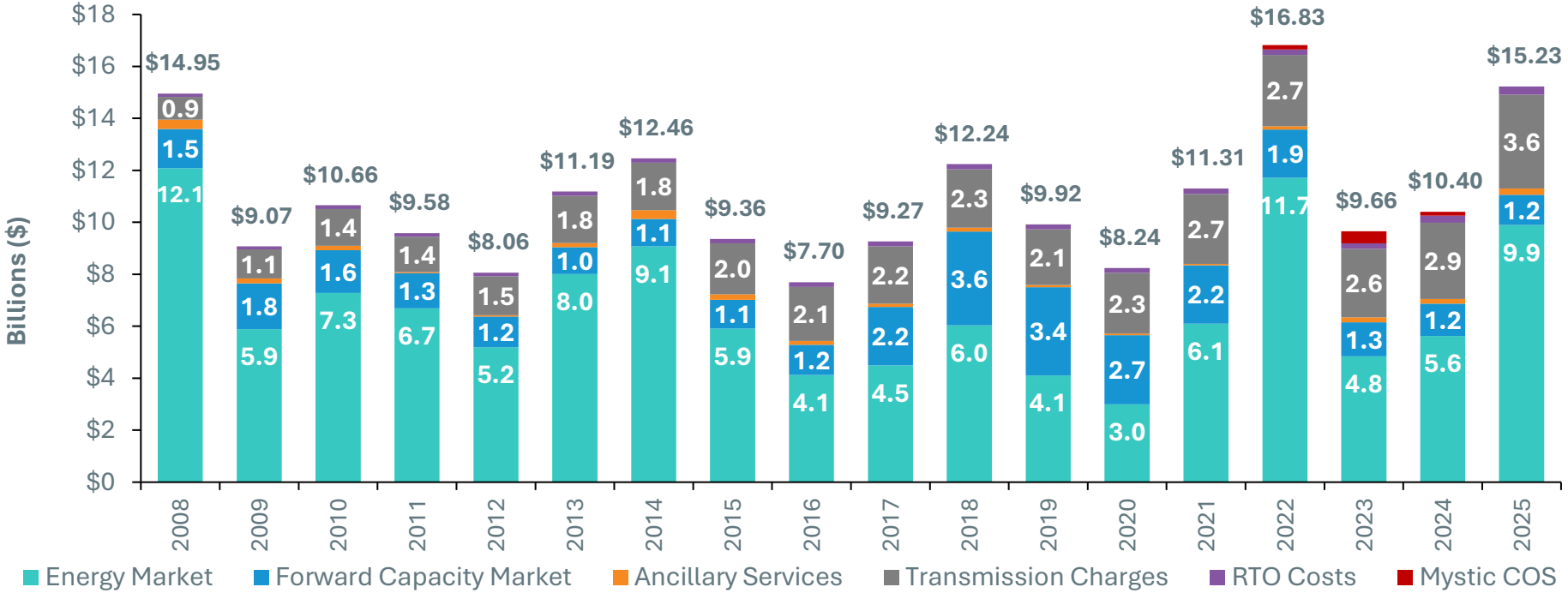
Capital Structure

- The ISO has a $40M working capital line; the working capital line, which will expire on March 1, 2028, funds temporary operating cash flow needs arising from the lag between expenditures and revenue collections, as well as periodic annual payments that are expensed evenly throughout the year (e.g., insurance); it also mitigates cash flow risks related to lower-than-expected load and Tariff collections, timing differences in capital project spending, and fluctuations in reimbursable study deposits and withdrawals
- Capital project costs are largely funded by $75M in Private Placement Notes that went effect in 2024, and require interest only payments until full payment of principal in 2034
- ISO closed on $60M tax-exempt bonds in April 2026 to fund the construction of a new building on the Holyoke campus; monies have been placed into a money market account to help off-set the interest expense while funds are drawn to pay for the construction; the bonds only require interest payments until the building is fully complete, estimated Q2 2028
- For the three months ended March 31, 2026, the ISO's total weighted average cost of capital was 4.34%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

APPENDIX 6: HISTORICAL NEW ENGLAND WHOLESALE AND RETAIL ENERGY COSTS

New England Wholesale Electricity Costs*

Annual wholesale electricity costs have ranged from $7.7 billion to $16.8 billion



(The total costs for each year include Ancillary Services and RTO costs)

Source: ISO New England; ***2025 data is preliminary and subject to resettlement**
Note: Forward Capacity Market values shown are based on auctions held roughly three years prior to each calendar year.

New England Wholesale Electricity Costs[(a)]

	2021		2022		2023		2024		2025*	
	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh
Wholesale Market Costs										
Energy (LMPs)[(b)]	$6,101	4.8	$11,712	9.0	$4,847	3.9	$5,620	4.4	$9,902	7.7
Ancillaries[(c)]	$52	0.0	$124	0.1	$183	0.1	$186	0.1	$241	0.2
Capacity[(d)]	$2,243	1.8	$1,864	1.4	$1,308	1.1	$1,248	1.0	$1,159	0.9
Subtotal	*$8,404*	*6.6*	*$13,701*	*10.5*	*$6,338*	*5.1*	*$7,054*	*5.5*	*$11,302*	*8.8*
Transmission charges[(e)]	$2,688	2.1	$2,739	2.1	$2,640	2.1	$2,934	2.3	$3,613	2.8
RTO costs[(f)]	$216	0.2	$214	0.2	$214	0.2	$274	0.2	$314	0.2
	Mystic COS[(h)]		$173	0.1	$465	0.4	$139	0.1	$0	0.0
Total	**$11,308**	**8.9**	**$16,828**	**13.0**	**$9,657**	**7.8**	**$10,401**	**8.2**	**$15,229**	**11.9**

(a) Average annual costs are based on the 12 months beginning January 1 and ending December 31. Costs in millions = the dollar value of the costs to New England wholesale market load servers for ISO-administered services. Cents/kWh = the value derived by dividing the dollar value (indicated above) by the real-time load obligation. These values are presented for illustrative purposes only and do not reflect actual charge methodologies. ***The wholesale values for 2025 are preliminary and subject to resettlement.**

(b) Energy values are derived from wholesale market pricing and represent the results of the Day-Ahead (DA) Market plus deviations from the DA in Real-Time. Post March 1, 2025 the DA Market total includes costs associated with the Forecast Energy Requirement.

(c) Ancillaries include first- and second-contingency Net Commitment-Period Compensation (NCPC), Forward Reserves, Real-Time Reserves, Regulation service, and a reduction due to the Marginal Loss Revenue Fund. Post Dec. 2023, this total also includes the Inventoried Energy Program (IEP). The IEP ran through Feb. 2025. Post March 1, 2025, the Forward Reserve total reflects costs associated with the Day-Ahead Ancillary Services Market.

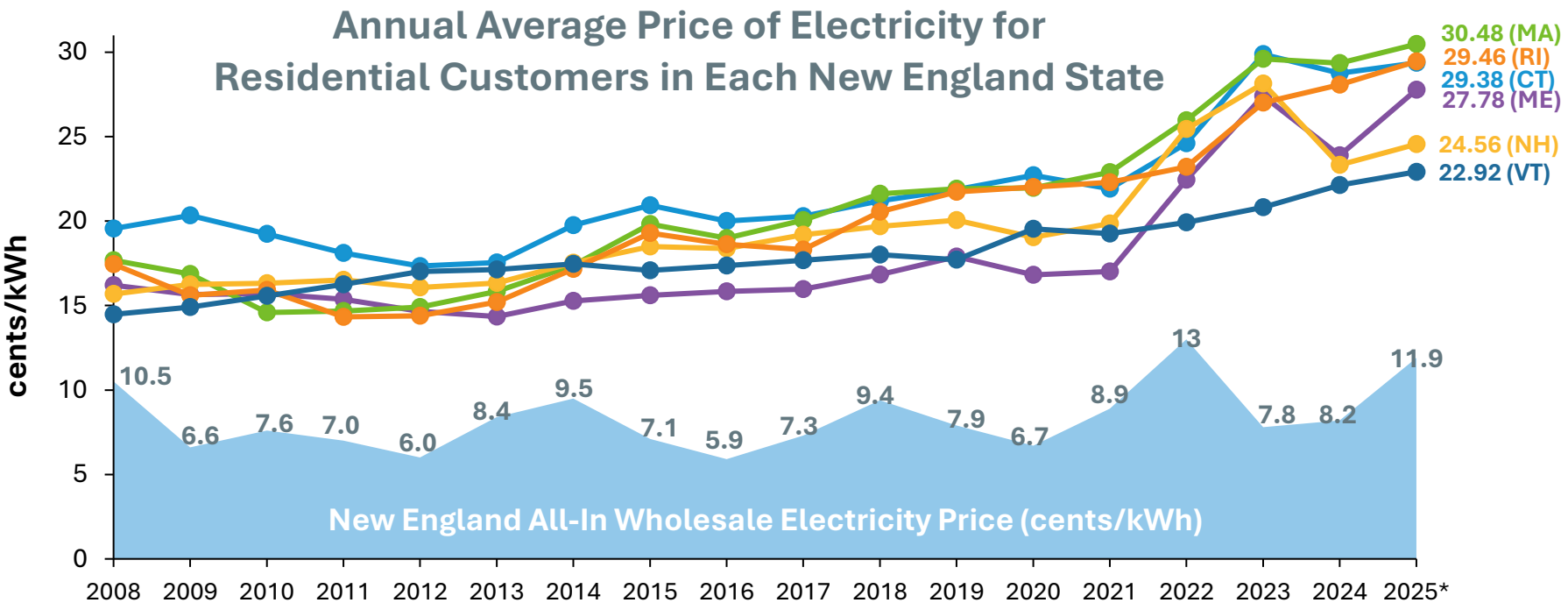
(d) Capacity charges are those associated with the Forward Capacity Market (FCM).

(e) Transmission charges reflect the collection of transmission owners' revenue requirements and tariff-based reliability services, including black start capability, voltage support, IROL CIP, and FCM reliability. In 2025, the cost of payments made to these generators for reliability services under ISO's Open Access Transmission Tariff (OATT) was $65.4 million. Transmission charge totals for years 2010 forward reflect the refund of Schedule 1 TOUT charges to regional network load.

(g) RTO costs are the costs to operate ISO New England and are based on actual collections, as determined under Section IV of the ISO New England Inc. Transmission, Markets, and Services Tariff.

(h) Mystic Cost of Service payments were made through May 2024.

Retail Electricity Prices Follow Wholesale Prices, But Are Also Influenced by Individual State Policies



Sources: U.S. Energy Information Administration, *Electric Power Annual*, Table 2.10 Average Price of Electricity to Ultimate Customers by End-Use Sector, by State; and U.S. Energy Information Administration, *Electric Power Monthly*, Table 5.6.B Average Price of Electricity to Ultimate Customers by End-Use Sector, by State (Through Dec. 2025); the New England all-in wholesale electricity price is derived by dividing total wholesale electricity costs by real-time load obligation (presented for illustrative purposes; does not reflect actual charge methodologies) *2025 values are preliminary

APPENDIX 7: Examples of Innovation and Use of Artificial Intelligence

Improve market design fidelity and operational efficiency through advanced simulation and optimization technology

- *Integrated Market Simulator*
  - Develop a unified simulation framework that captures key real-time market and system processes
  - This framework will enable us to evaluate dynamic operating reserve demand curve, multi-interval dispatch and pricing, enhanced energy storage modeling, and market mitigation design.
- *Capacity Market Clearing Engine*
  - Build clearing engines using the latest optimization technology for the seasonal and prompt capacity markets

Increase business efficiency with agentic artificial intelligence (AI)

- *AI-Driven Workflow Automation*
  - Deploy AI agents to streamline and automate key business processes
- *Interconnection Study*
  - Facilitate interconnection request intake and initial screening, base case creation and maintenance, and support cluster study workflow
  - Accelerate interconnection timelines
  - Enhance consistency and quality control
- *Outage Coordination*
  - Use generative AI to automate outage report generation
  - Reduce manual workload
  - Enable staff to focus on higher-value engineering analysis

Reliable integration of renewable resources through advanced computing and analytics

- *Transition to risk-based operations*
  - Leverage probabilistic forecasting to quantify uncertainty from renewables
  - Develop probabilistic capacity analysis tools, providing a better picture of system capacity margin for both long-term outage coordination and short-term capacity analysis
  - Develop probabilistic transmission security assessment, evaluating transmission system risk under different renewable scenarios.

Reliable integration of renewable resources through advanced computing and analytics

- *Monitor system oscillation*
  - Deploy PMU-based oscillation source location (OSL) software in the control room operations.
  - OSL enables us to identify and mitigate system oscillations from inverter-based resources (IBR) and large data center loads.
- *Enhance Electromagnetic Transient (EMT) modeling and simulation*
  - Analyze stability challenges driven by fast dynamics of IBRs
  - Advance EMT model lifecycle management to scale adoption in operations and planning
  - Enable large-scale EMT simulation to support grid-level assessment