NEPOOL PARTICIPANTS COMMITTEE | 11/12/2026
Meeting Agenda Item #4

NEPOOL Participants Committee

Winter Outlook and System & Market Operations Report – November 2026

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VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



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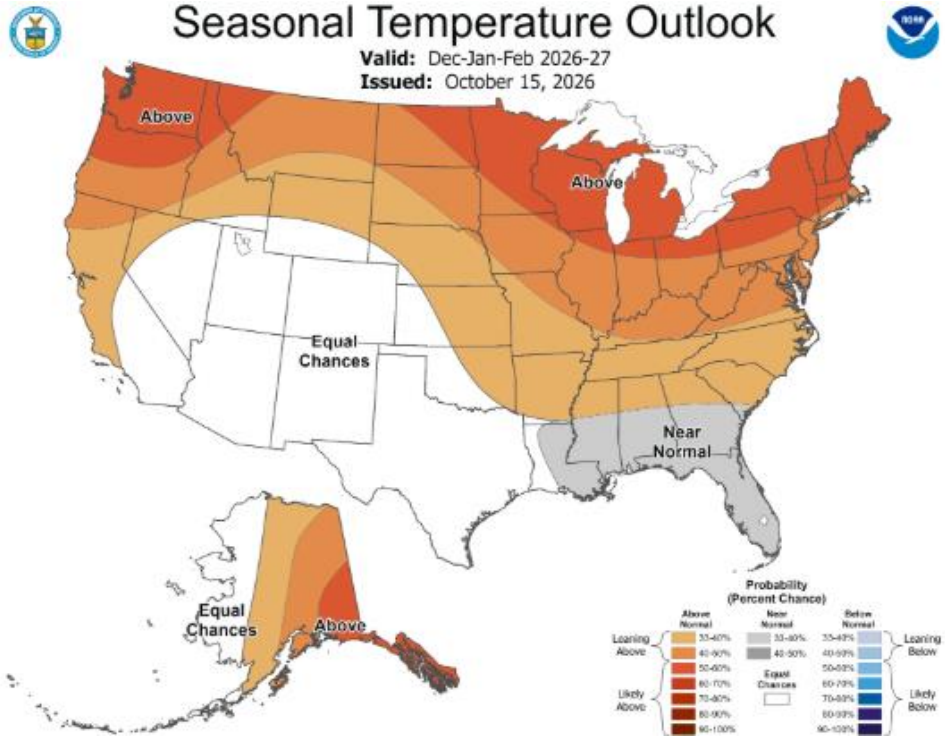
2026/2027 WINTER OUTLOOK

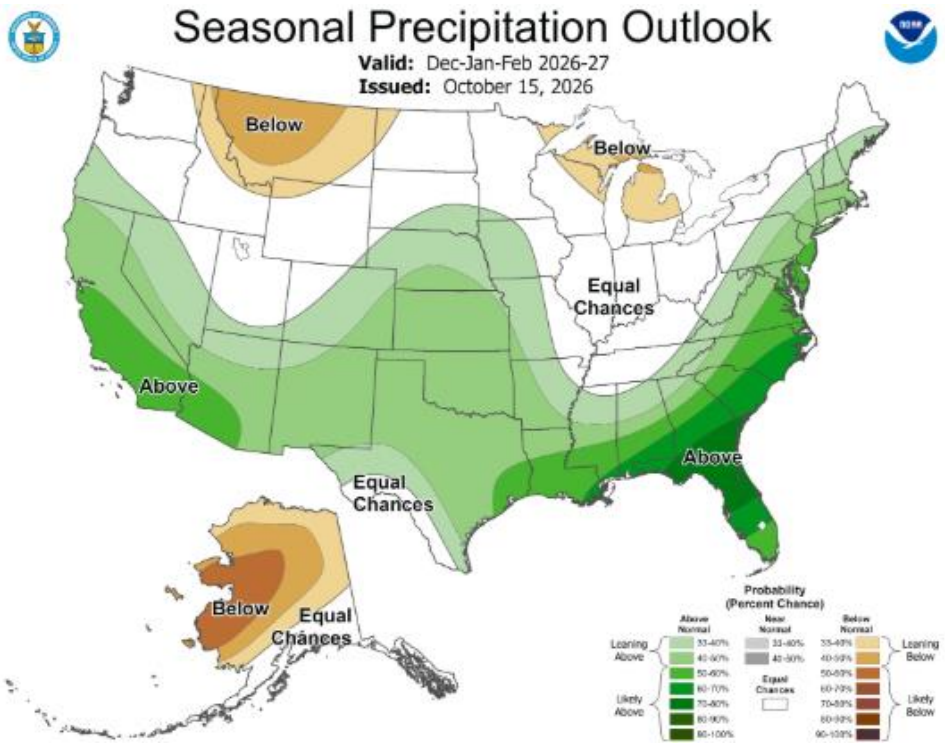
2026/2027 Winter Outlook Highlights

- Seasonal outlooks show a 50-60% probability of above-normal temperatures and a 33-50% probability of above-normal precipitation across most of New England
- Winter peak demand forecasts are slightly higher than last year
- Newly commercial offshore wind facilities are expected to bolster winter operations
- Fuel oil supplies are expected to start the winter higher than last year, with more replenishment anticipated in the next month
- Sufficient capacity and energy are expected this winter
  - Lowest capacity margin is forecasted for the week beginning January 9[1]
  - Energy shortfall risk from extreme winter events does not exceed the Regional Energy Shortfall Threshold (REST), given the existing resource mix and expected loads

1 - Based on ISO's November 2, 2026 Annual Maintenance Schedule

Winter Temperature and Precipitation Outlook





Winter Expectations

- Demand Forecast
  - 50/50 winter peak demand forecast of 20,483 MW, which is ~112 MW (~0.6%) higher than the 2025/26 forecast
  - 90/10 winter peak demand forecast of 21,457 MW, which is ~11 MW (~0.1%) higher than the 2025/26 forecast
  - The Winter 2025/2026 peak demand of 20,182 MW occurred on January 25, 2026
- Scheduled Generation and Transmission Outages
  - Generation and transmission outages have been coordinated to minimize any adverse impacts; no significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Per the normal protocol, transfer capability on the New York Northern AC ties has been increased (effective 11/1/26) from 1,400 to 1,600 MW for the winter period

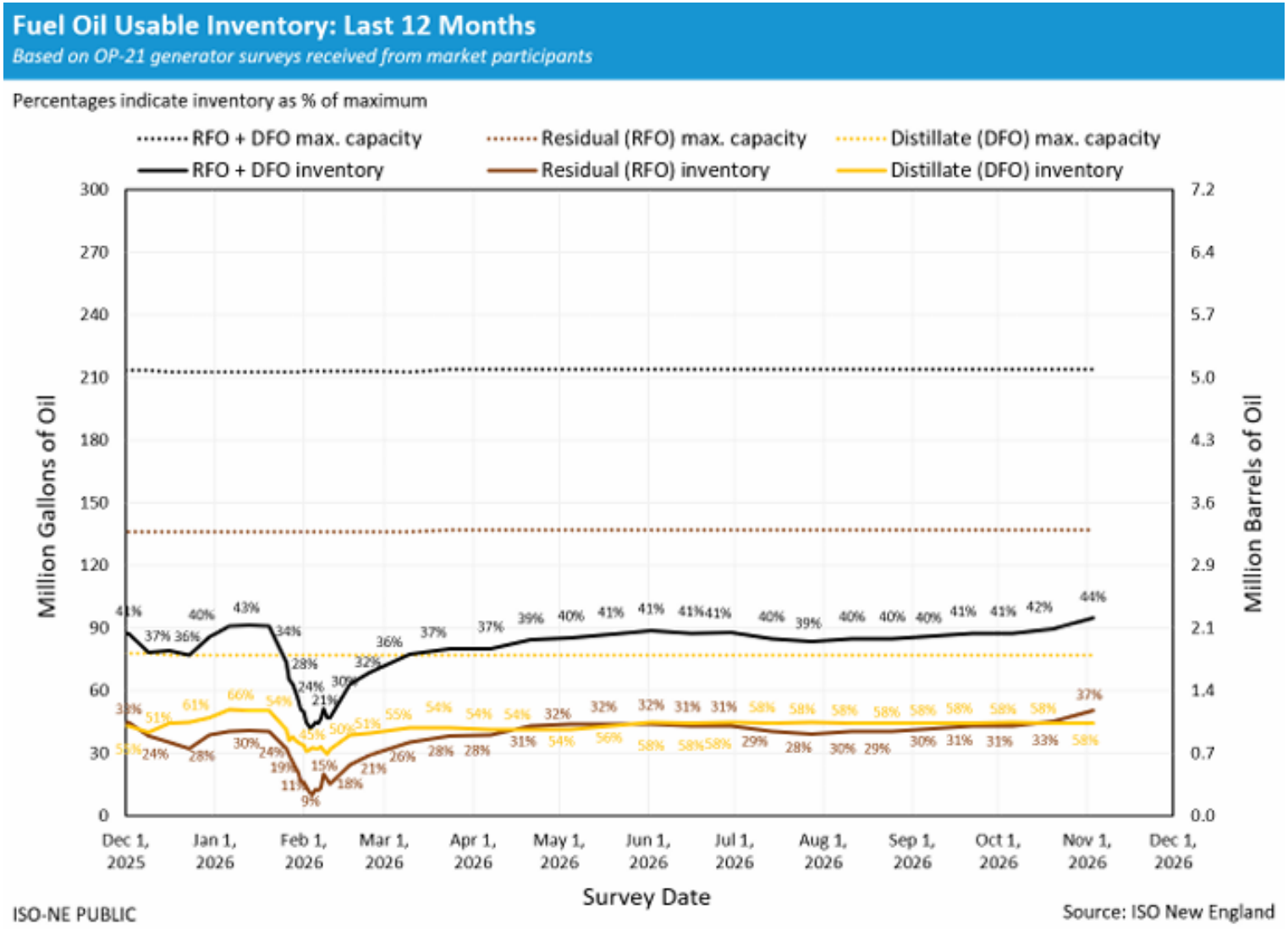
Winter Expectations, cont.

- Natural Gas Deliverability
  - ISO will monitor natural gas deliverability using its normal operating protocols
  - As in past winters, ISO assumes approximately 3,900–4,800 MW of gas-only generation may be unavailable on the coldest days due to constrained natural gas pipelines
- Capacity Outlook
  - The lowest projected capacity margins are ~3,100 MW (50/50 forecast) and ~2,100 MW (90/10 forecast), both for the week beginning January 9
  - Extended cold weather could quickly deplete stored fuel, and ISO's capacity outlook and 21-day energy assessments will be adjusted accordingly

LNG and Fuel Oil Expectations

- Current fuel oil inventory is ~94.5 M gallons (~44% of maximum storage capacity)
- Pre-winter fuel oil replenishment is underway with more expected in the next month
- Saint John LNG tanks are expected to be full (~10 Bcf) heading into the winter
- Fuel oil delivery times are expected to be longer than normal though supplies are expected to be adequate; ISO staff remains attentive to geopolitical factors that may impact fuel supply chains

Total Usable Fuel Oil in New England



Winter Energy Analysis

- Extreme weather events were studied to evaluate the region's energy shortfall risk this winter
  - Studies were performed using ISO's Probabilistic Energy Adequacy Tool (PEAT) and results were compared to the Regional Energy Shortfall Threshold (REST)
- Similar to the methodology employed for ISO's prior PEAT-based analysis, the events studied were those identified as having the most significant shortfall risk
- Each weather event was studied 720 times (*i.e.*, "cases"); each case represented different combinations of fuel oil inventories, LNG inventories, imports, and generator forced outages

Winter Energy Analysis, cont.

- Key Assumptions
  - Existing resource mix, including Revolution Wind, Vineyard Wind, and New England Clean Energy Connect (NECEC), in-service
  - ~9 GW of behind-the-meter (BTM) PV nameplate capacity
  - Up to 1.3 Bcf/d of LNG injection capability from Saint John LNG and the Everett Marine Terminal (EMT)
    - EMT is expected to be available to aid in meeting LDC demand; ISO assumes that in extreme weather conditions when prices are very high, EMT will sell gas to electric power generation

Energy Analysis Results Show Minimal Risk When Compared Against REST Criteria

- The REST criteria is defined as follows:
  - acceptable shortfall **magnitude** of **3%**
  - acceptable shortfall **duration** of **18 hours**
  - magnitude and duration must **both** be exceeded for the REST to be violated
- ISO's PEAT-based evaluation of extreme events for this winter resulted in shortfall magnitude of 0.1% and shortfall duration of 0.33 hours, **both well below the established REST criteria**
- Study results are consistent with the existing resource mix and ISO's expectations for load this winter

Winter Preparations

- ISO staff hosted the Generator Winter Readiness Seminar with Market Participants on October 27, 2026
- Winter Generator Readiness Surveys responses are due by December 1, 2026
- Annual Natural Gas Critical Infrastructure Surveys were completed earlier in 2026, ensuring that critical gas infrastructure is not part of automatic or manual load shed schemes
- Dual fuel audits of ~30 generators totaling ~6,700 MW of capacity are to be completed prior to December 1, 2026
- Generator Fuel and Emissions Surveys and 21-Day Energy Assessments will be performed weekly (or daily, if required) during the winter season

SYSTEM & MARKET OPERATIONS REPORT

November 2026

System & Market Operations Report Enhancements

- This month's report carries forward several clarity and usability improvements first introduced in the June 2026 System & Market Operations Report (see slide 7 of the June report for a summary)
- To streamline the report, several slides are now marked with footnotes noting that they will be removed in future reports since the information is part of ISO's routine reporting and is readily available elsewhere; in addition to the slides previously noted, these slides to be removed in future reports now also include:
  - Slide 71, DA and RT NCPC Charges
  - Slide 72, NCPC Charges by Type
  - Slide 73, NCPC Charges by Type as a Percent of Energy Market Value
  - Slide 74, NCPC Charge Allocations
  - Slide 75, RT First Contingency Paid Allocated to RTLO/RTGO
  - Slide 76, RT First Contingency Charges to Deviation Type
- Slide 55, Average Hourly DAAS Prices, has been retained in response to feedback received at last month's committee meeting.
- Further enhancements are planned in the coming months to continue simplifying and improving the report

HIGHLIGHTS

System & Market Operations Report
Key Takeaways

- October peak demand (RQM) was ~1% higher than in October 2025 and ~14% lower than in September 2026 (see slide no. 20)
- October total market value was ~13% lower than in October 2025 and ~6% lower than in September 2026 (see slide no. 21)
- Day-Ahead Ancillary Services (DAAS) post-implementation adjustments, including the Forecast Energy Requirement (FER) Demand Quantity Adjustment and the Strike Price Adjustment, took effect with the October 22 Day-Ahead market
- As reviewed at the October 20 Reliability Committee meeting, the ISO made two changes effective with the November 1 operating day:
  - Reduced the reserve Non-Performance Factor (NPF) from 115% to 110%
  - Shortened the normal Unit Dispatch System (UDS) Look Ahead from 15 to 10 minutes
- Several significant transmission and generation outages are scheduled to finish before winter (see slide no. 34 for a summary)

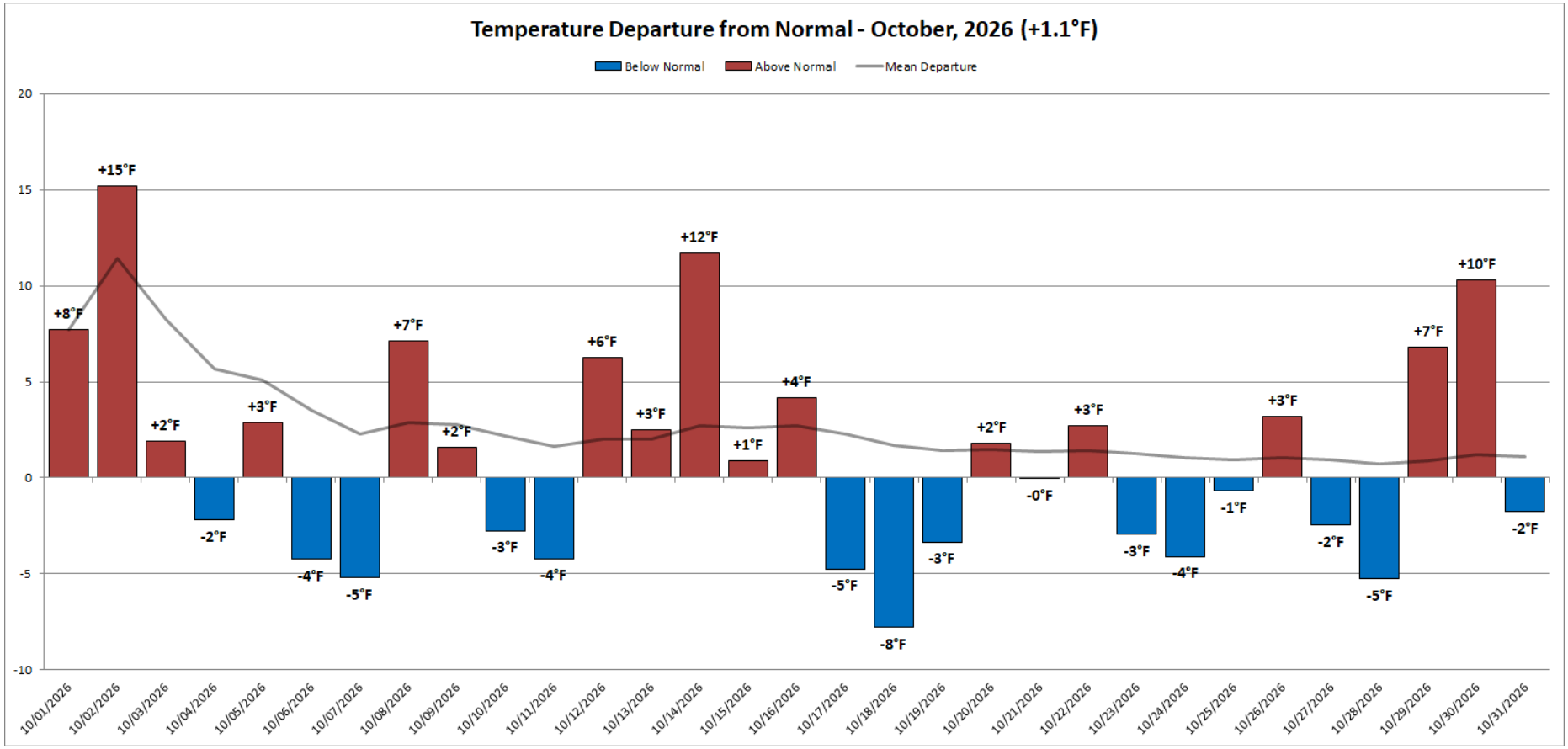
Weather At-a-Glance

October 2026

New England Weather	**OCT 2026**	**Change M-O-M**	**Change Y-O-Y**
Avg Hourly Temperature (°F) ***(23-City Weighted)***	52.5°	-10.2° ↓	-1.0° ↓
Boston Weather			
Temperature Departure from Normal (°F)	1.4°	2.4° ↑	-.2° ↓
Maximum Temperature (°F)	87.0°	0.0° —	3.0° ↑
Minimum Temperature (°F)	37.0°	-12.0° ↓	-3.0° ↓
Avg Hourly Temperature (°F)	56.2°	-8.4° ↓	-.2° ↓
Precipitation Departure from Normal (inches)	-1.95"	-3.74" ↓	-2.88" ↓
Precipitation (inches)	2.08"	-3.27" ↓	-2.88" ↓
Hartford Weather			
Temperature Departure from Normal (°F)	1.1°	1.9° ↑	0.1° ↑
Maximum Temperature(°F)	88.0°	1.0° ↑	3.0° ↑
Minimum Temperature(°F)	28.0°	-15.0° ↓	-1.0° ↓
Avg Hourly Temperature (°F)	54.1°	-9.9° ↓	0.1° ↑
Precipitation Departure from Normal (inches)	-2.14"	-3.33" ↓	-2.24" ↓
Precipitation (inches)	2.38"	-3.20" ↓	-2.24" ↓

Weather At-a-Glance, cont.

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



Markets At-a-Glance: Demand

*Data through October 31, 2026**

Average Hourly Net Energy for Load (MWh) [a]	Oct 2026	% Change M-O-M	% Change Y-O-Y	
Revenue Quality Metered (RQM)	11,627	-6.7% ↓	-0.04% ↓	
Telemetered	11,114	-7.2% ↓	-0.6% ↓	
Max/Min Hourly System Load (MW)				
Maximum RQM	16,106	-13.7% ↓	1.1% ↑	Fri, Oct 2, 2026 in HE18
Maximum Telemetered	15,881	-13.1% ↓	0.2% ↑	Fri, Oct 2, 2026 in HE18
Minimum Telemetered	6,964	-5.4% ↓	-5.7% ↓	Sat, Oct 10, 2026 in HE13
Year-To-Date Hourly Peak Load (MW) [b]				
RQM	25,832	0.0%	-2.9% ↓	Thu, Jul 2, 2026 in HE19
Telemetered	25,361	0.0%	-2.5% ↓	Thu, Jul 2, 2026 in HE19
Forward Capacity Market (FCM) Load [c]	25,303	0.0%	-2.6% ↓	Thu, Jul 2, 2026 in HE19
Other RT Load (Average Hourly MW)				
Scheduled Exports	1,505	-19% ↓	-5% ↓	
Energy Storage Load	308	14% ↑	19% ↑	

*Based on available settled days.

[a] RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SORs). Telemetered loads as monitored by the Control Room. Both are 'net energy for load' concepts and therefore include transmission losses. Neither of reflect storage load. Due to the difference in metering quality, derivation, and the impact of SORs, the RQM and Telemetered 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.

[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.

Markets At-a-Glance: Payments and Prices

*Data through October 31, 2026**

Market Value ($ millions)[a]	Oct 2026	% Change M-O-M	% Change Y-O-Y
Energy Market Value[b]	412	-8% ↓	-12% ↓
Ancillary Services[c]	10	41% ↑	-42% ↓
Forward Capacity Market (FCM)	78	0%	-13% ↓
Net Commitment Period Compensation (NCPC)	3	100% ↑	23% ↑
Total	**502**	**-6% ↓**	**-13% ↓**
Average Power Prices ($/MWh)			
DA Hub LMP	39.26	-5% ↓	-3% ↓
DA Hub LMP Plus Forecast Energy Requirement (FER) Price	41.62	-3% ↓	-11% ↓
RT Hub LMP	37.48	-5% ↓	-8% ↓
Average Generation Fuel Prices ($/MMBtu)			
Natural Gas (MA Avg.)	1.46	-16% ↓	-38% ↓
Diesel	37.66	1% ↑	115% ↑
No. 6 Oil	17.92	2% ↑	68% ↑
Regional Greenhouse Gas (RGGI) Spot Price[d]	2.32	1% ↑	65% ↑
MA Electricity Generator Emissions Limits (MA EGEL) Price[d]	0.73	-45% ↓	15% ↑

*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.

[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 FER constraint.

[c] Ancillary Services (A/S) = Day-Ahead and Real-Time Reserves, Regulation, less Marginal Loss Revenue Fund.

[d] Assumes an emissions rate of 117 lbs/MMBtu.

Underlying natural gas data furnished by:

ICE Global markets in clear view

Markets At-a-Glance: Supply

*Data through October 31, 2026**

Average Hourly RQM Supply[a]	**Oct 2026 (MWh)**	**% Change M-O-M**	**% Change Y-O-Y**
Total RQM Supply	13,440	-8% ↓	-0.15%
Natural Gas	5,509	-10% ↓	-21% ↓
Nuclear	2,524	-24% ↓	-12% ↓
Solar	632	4% ↑	17% ↑
Hydro	473	8% ↑	3% ↑
Wind	1,163	37% ↑	77% ↑
Onshore Wind	590	38% ↑	25% ↑
Offshore Wind	573	35% ↑	214% ↑
Other[b]	462	-22% ↓	4% ↑
Hybrid/Solar	79	8% ↑	19% ↑
Oil	4	413% ↑	-38% ↓
Batteries	34	10% ↑	58% ↑
Demand Response Resources (DRRs)	0.04	-69% ↓	-71% ↓
Scheduled Imports	2,559	1% ↑	78% ↑
Average Hourly Behind-The-Meter (BTM) Solar[c]	**1,193**	**-4% ↓**	**17% ↑**

*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 posted the preferred Longer-Term Transmission Solution on 8/14/26, and notified the Qualified Transmission Project Sponsors (QTPSs) they were selected
  - The QTPSs executed all Selected QTPS Agreements by 10/15/26, and they are posted on the ISO website
- CELT 2027 forecast discussions began at the October 23 Load Forecast Committee meeting
- The next LFC meeting will be held on December 11

Forward Capacity Market (FCM) Highlights

- CCP 17 (2026-2027)
  - The ISO filed the ICR and related values with FERC, for the ARA3 that was 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 second annual reconfiguration auction (ARA2) was held August 3-5, 2026 and results were posted on September 2, 2026.
  - The ISO presented the assumptions for the ICR and related values studies for the ARA3 at the August PSPC meeting.
  - The ISO reviewed the proposed tie benefits values for the ARA3 at the September 17, PSPC meeting.
  - At the October 15 PSPC meeting and October 20 RC meeting, the ISO presented proposed ICR and related values for the ARA 3 that will be conducted in 2027. RC voted to approve the values.

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

FCM Highlights, cont.

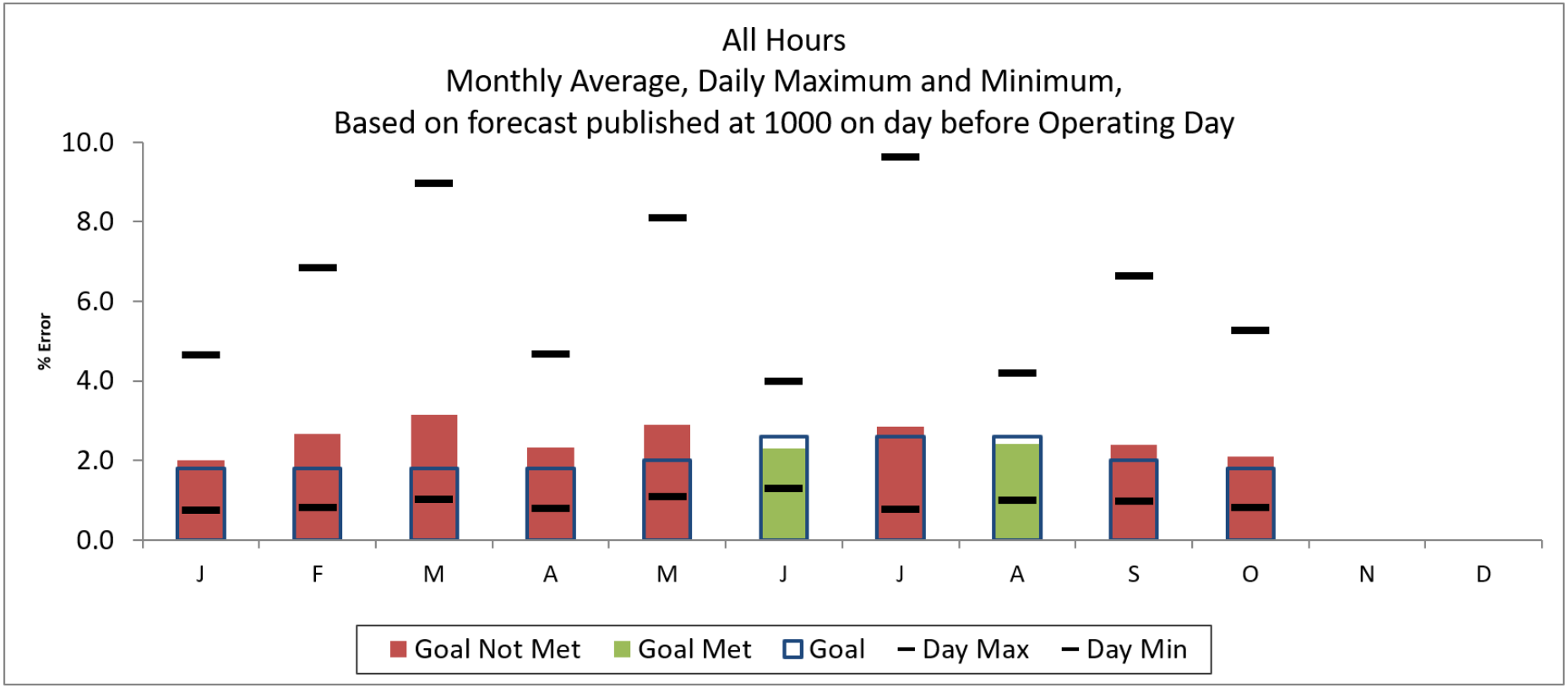
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
    - On May 20, 2024 FERC issued an order accepting the additional delay
    - 2024 interim RA qualification process completed on November 1, 2024
      - A total of 1,389 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
    - 2025 interim RA qualification process completed on November 3, 2025
      - A total of 1,455 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
      - The Transitional CNR Group Study was completed with the completion of the 2025 interim RA qualification process
    - 2026 interim RA qualification process
      - The New Capacity Qualification Package (NCQP) submission window was open June 15-23, 2026
      - Qualification Determination Notifications were issued on October 16, 2026 and Qualified Capacities will be finalized on November 2, 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

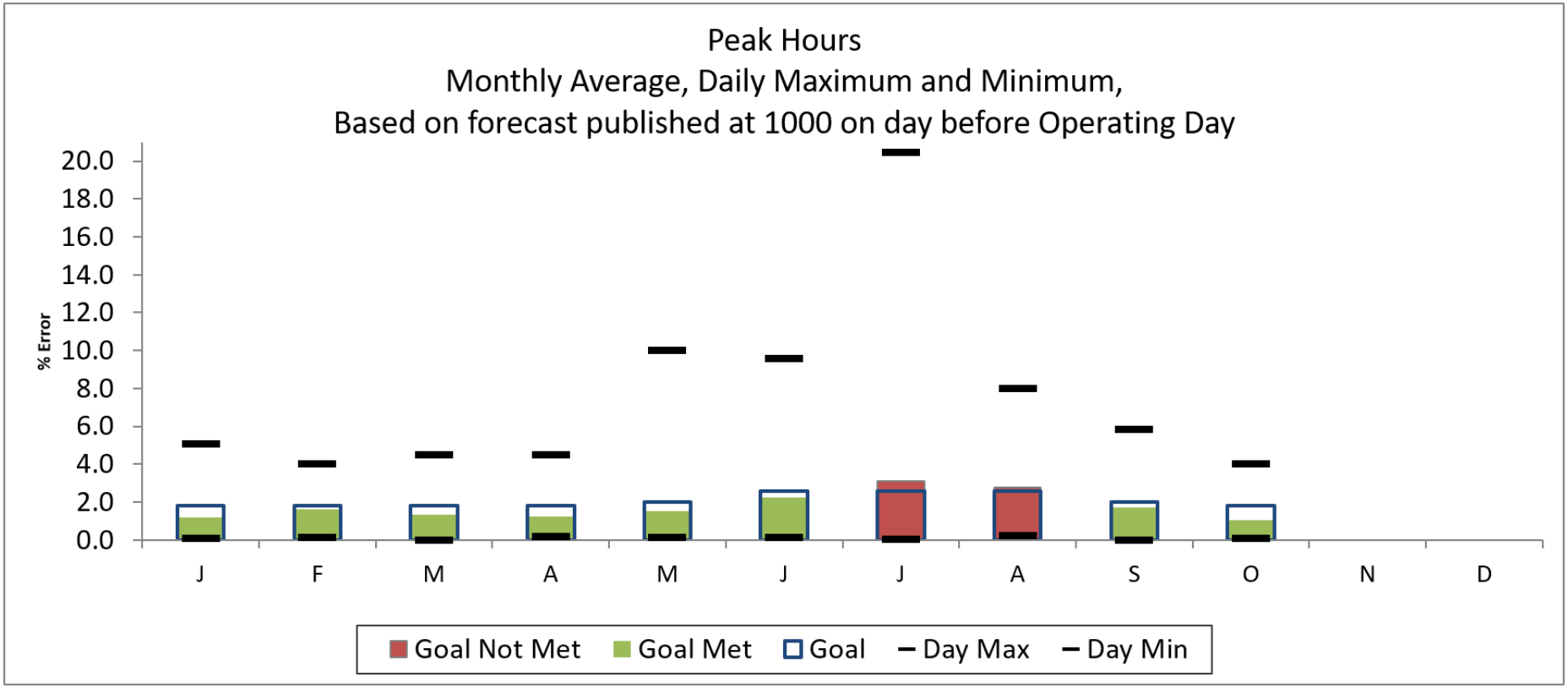
Date	Area	MW Lost
10/13/2026	NYISO	650
10/21/2026	NYISO	1000

2026 Load Forecast Accuracy



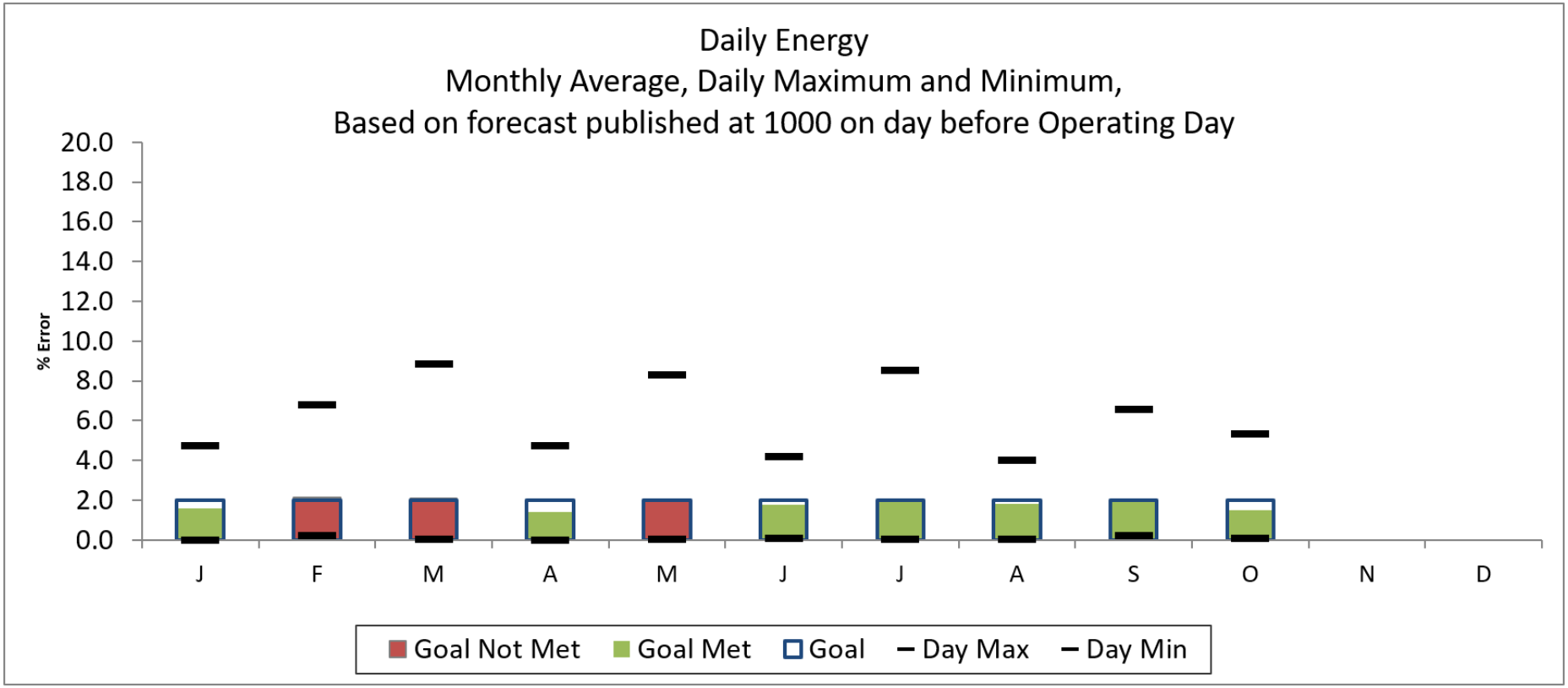
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65	6.85	8.96	4.67	8.09	3.99	9.64	4.19	6.64	5.28			9.64
Day Min	0.76	0.82	1.01	0.80	1.09	1.29	0.77	1.01	0.98	0.81			0.76
MAPE	2.00	2.66	3.14	2.33	2.90	2.30	2.86	2.41	2.40	2.10			2.51
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2026 Load Forecast Accuracy, cont.



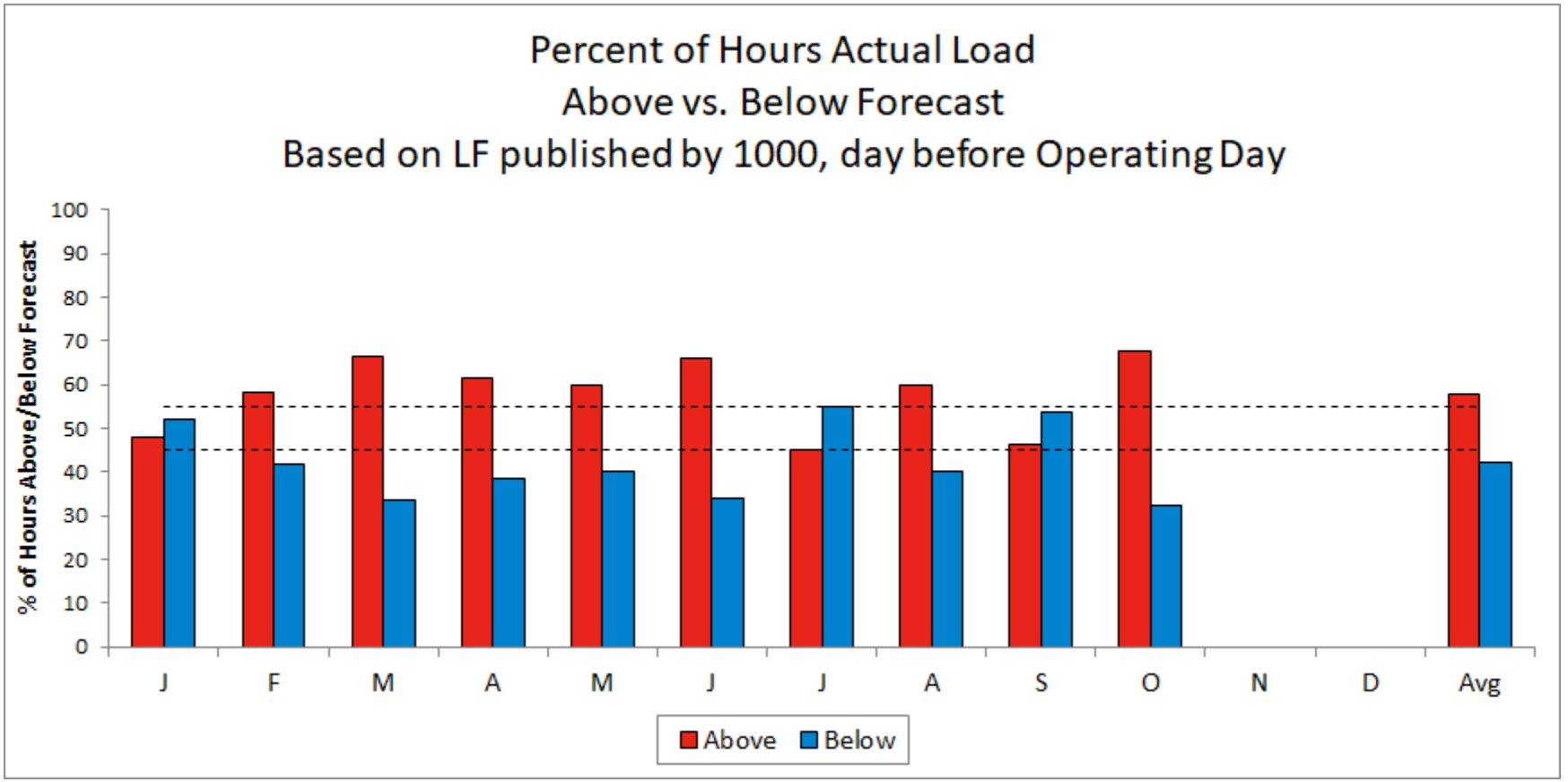
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02	4.51	4.51	10.02	9.58	20.46	8.02	5.82	4.00			20.46
Day Min	0.08	0.12	0.01	0.16	0.11	0.14	0.03	0.24	0.01	0.07			0.01
MAPE	1.17	1.64	1.34	1.24	1.52	2.23	3.08	2.77	1.71	1.06			1.78
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2026 Load Forecast Accuracy, cont.



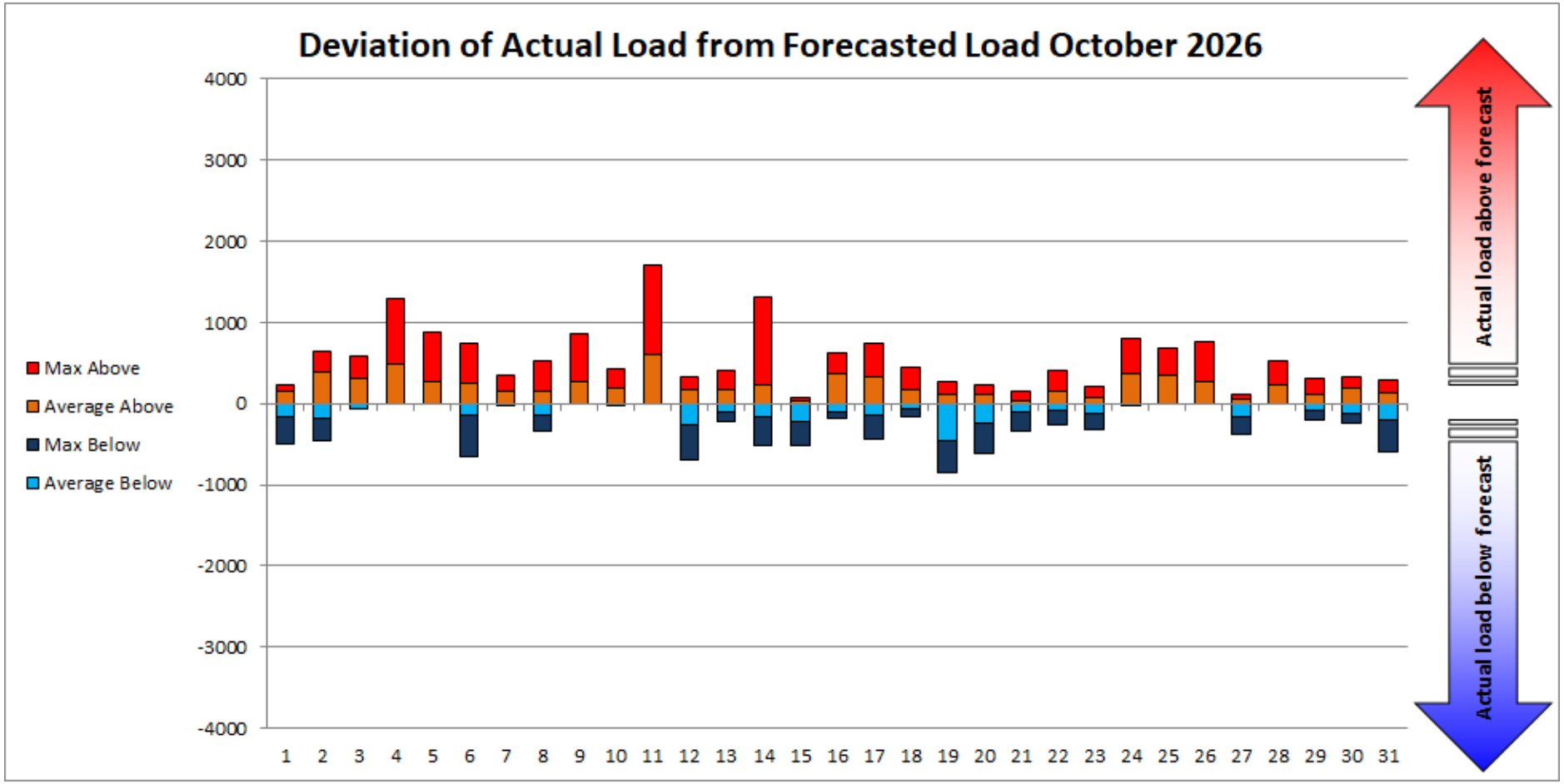
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81	8.85	4.75	8.32	4.17	8.54	4.03	6.57	5.32			8.85
Day Min	0.01	0.22	0.03	0.00	0.06	0.07	0.03	0.05	0.24	0.07			0.00
MAPE	1.57	2.12	2.11	1.42	2.06	1.75	1.94	1.82	1.95	1.48			1.82
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00			

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	66.1	44.9	59.9	46.2	67.7			58
Below %	52.2	41.8	33.6	38.6	40.3	33.9	55.1	40.1	53.8	32.3			42
Avg Above	203	299.6	325	240.4	296.5	304	259.1	298.3	210.4	222			325
Avg Below	-233.3	-271.5	-290.0	-157.2	-194.4	-160.0	-432.7	-256.5	-210.6	-110.1			-433
Avg All	-20	59	130	91	106	138	-139	51	2	115			53

2026 Load Forecast Accuracy, cont.



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

Notable Planned Transmission Outages

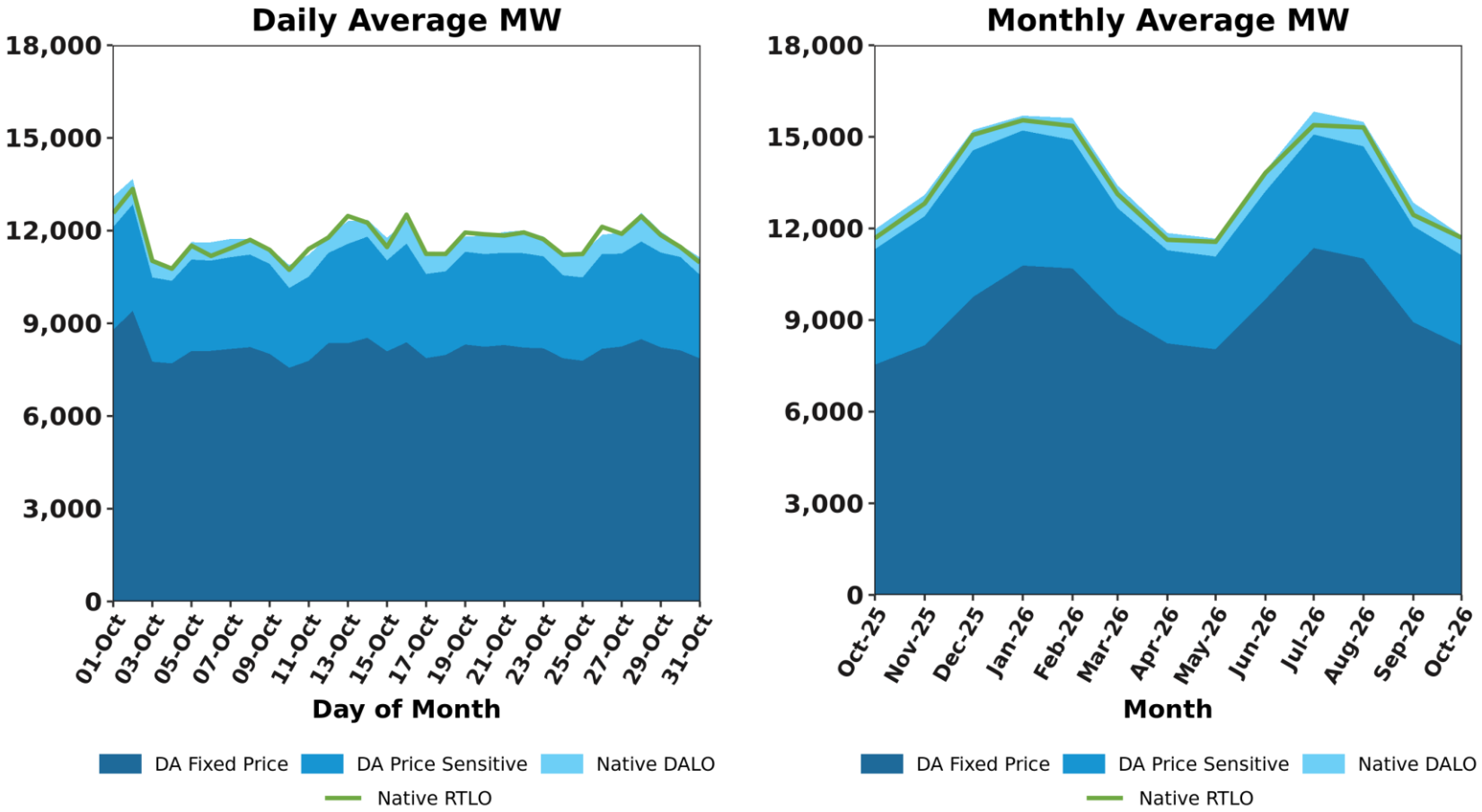
- The table below highlights select longer-duration planned outages that impact transfer capability; it is not a comprehensive list of all outages

Outage	Start	Planned End	Total Transfer Capability (TTC) Impacts
NECEC	11-05-2026	11-17-2026	TTC = 0 MW
390/3016	11-16-2026	11-20-2026	New Brunswick-New England = 575 MW New England-New Brunswick = 0 MW
393	11-17-2026	11-19-2026	New York – New England = 800 MW New England – New York = 600 MW NNC = 0 MW in both directions
398	11-21-2026	11-24-2026	New York – New England = 1000 MW New England – New York = 600 MW NNC = 60 MW in both directions Phase 2 – New England = 1400 MW

MARKET OPERATIONS

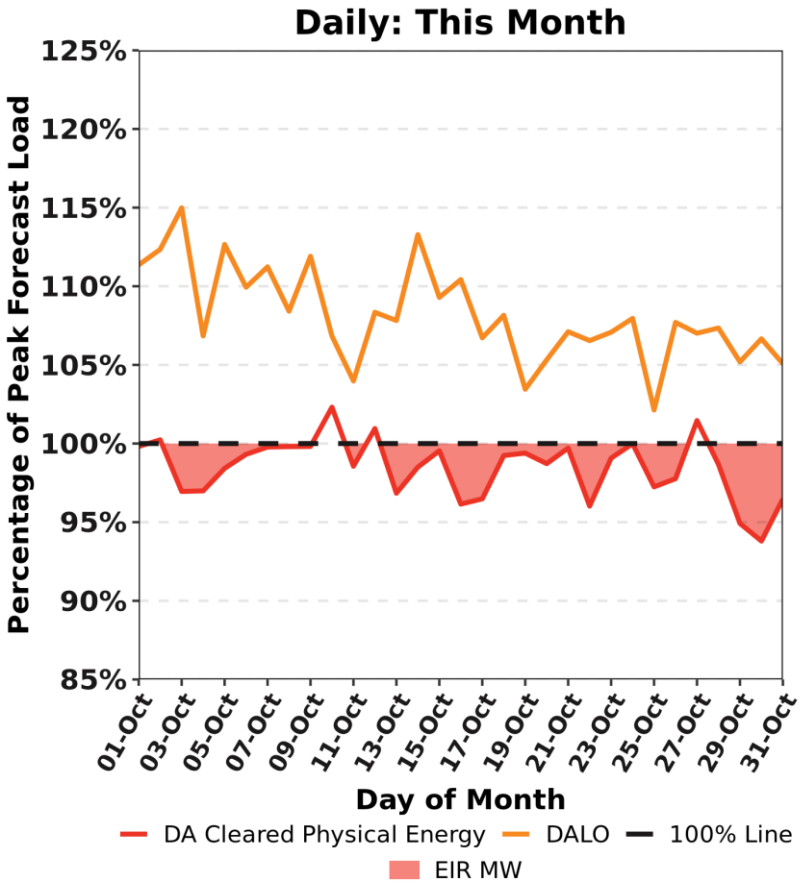
Supply and Demand Volumes

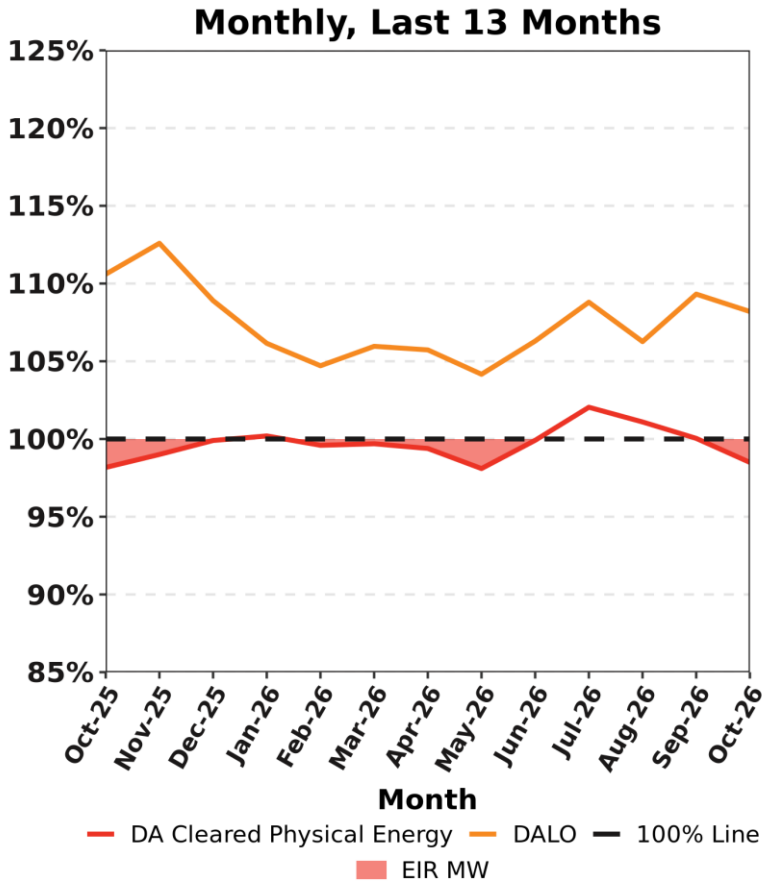
DA Cleared Native Load by Composition Compared to Native RT Load



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.

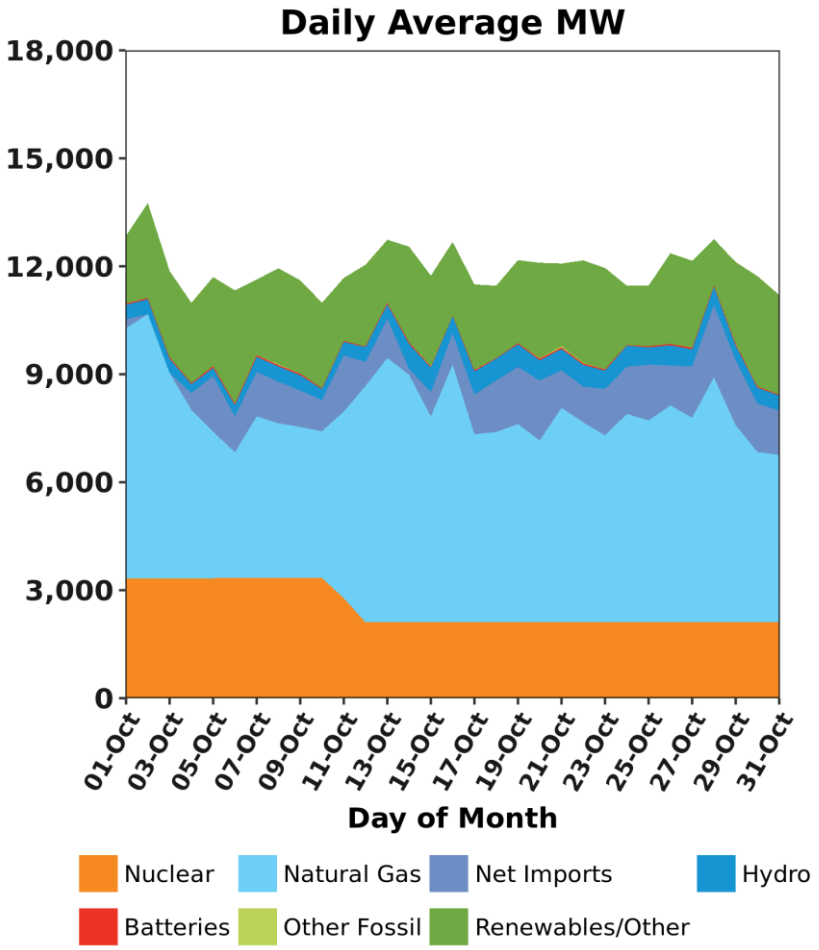
DA Volumes as % of Forecast in Peak Hour

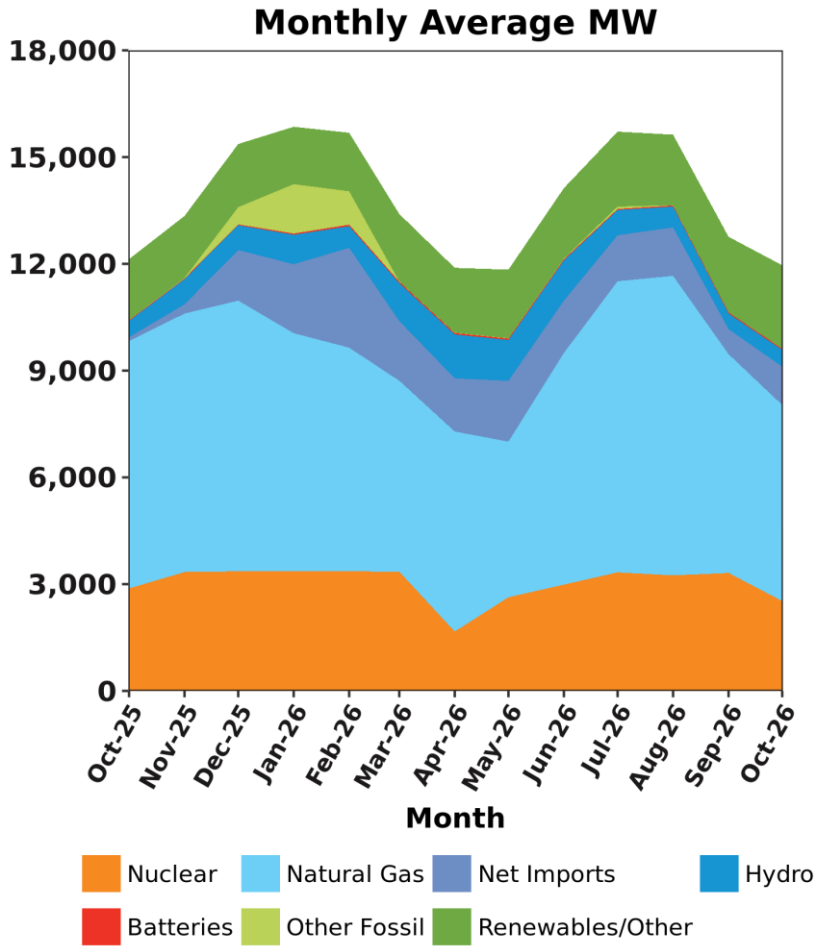




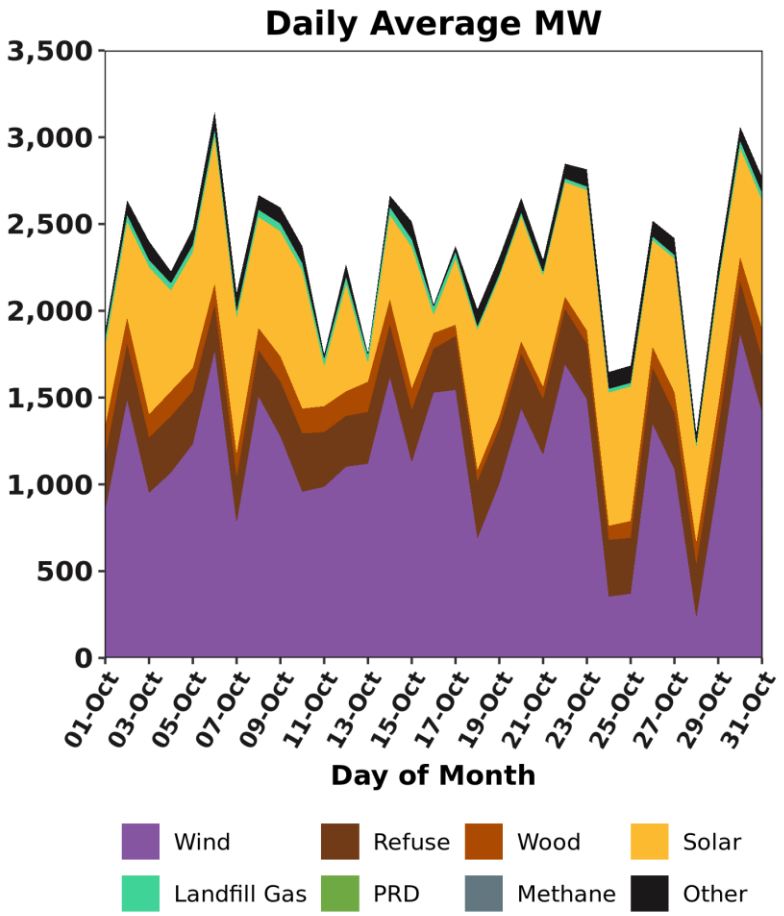
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

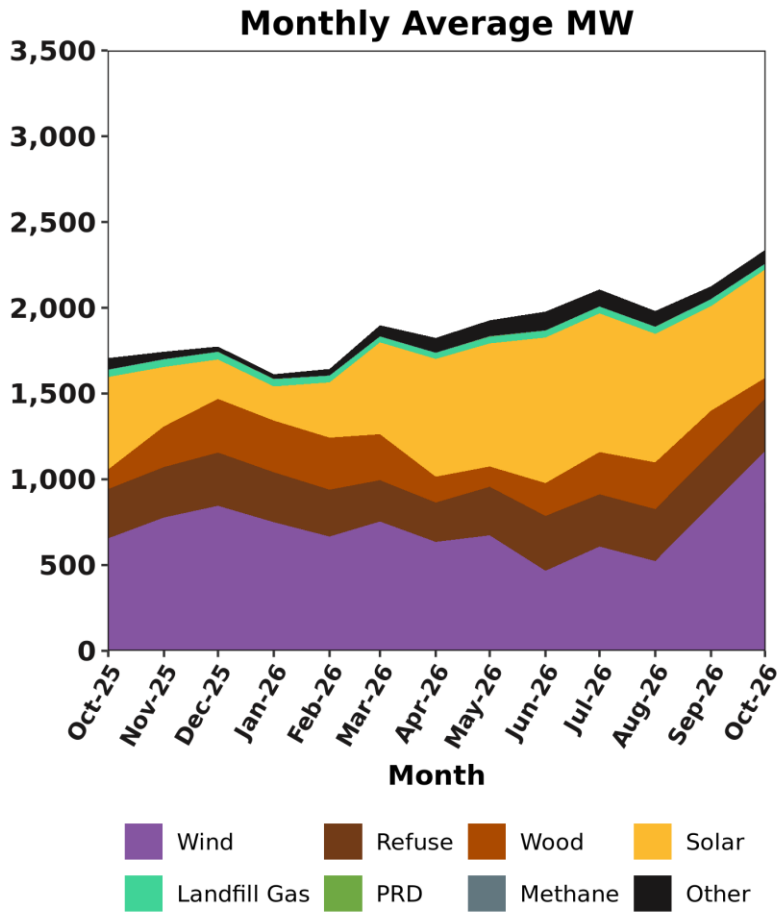
Resource Mix





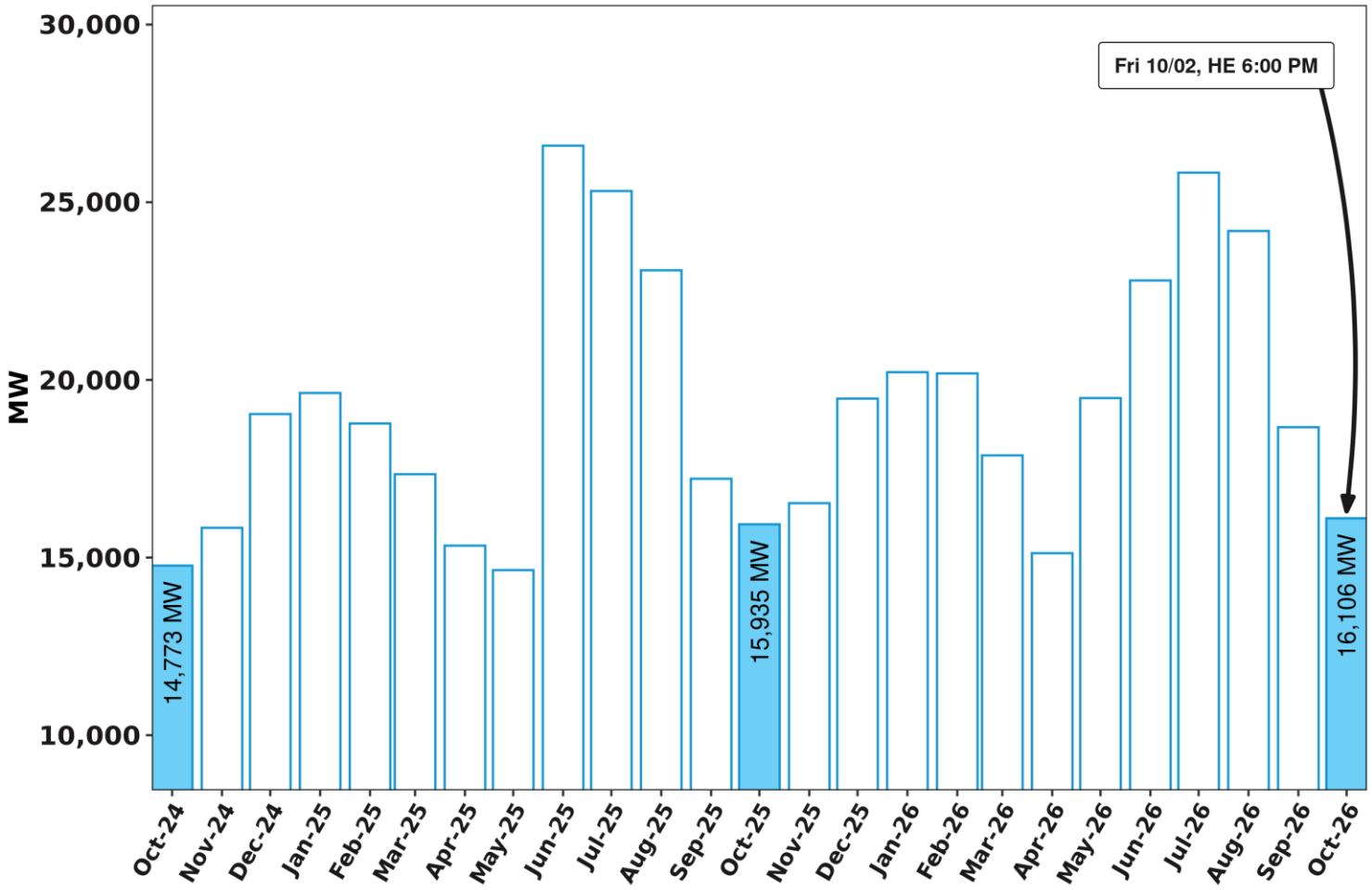
Renewable/Other Generation by Fuel Type





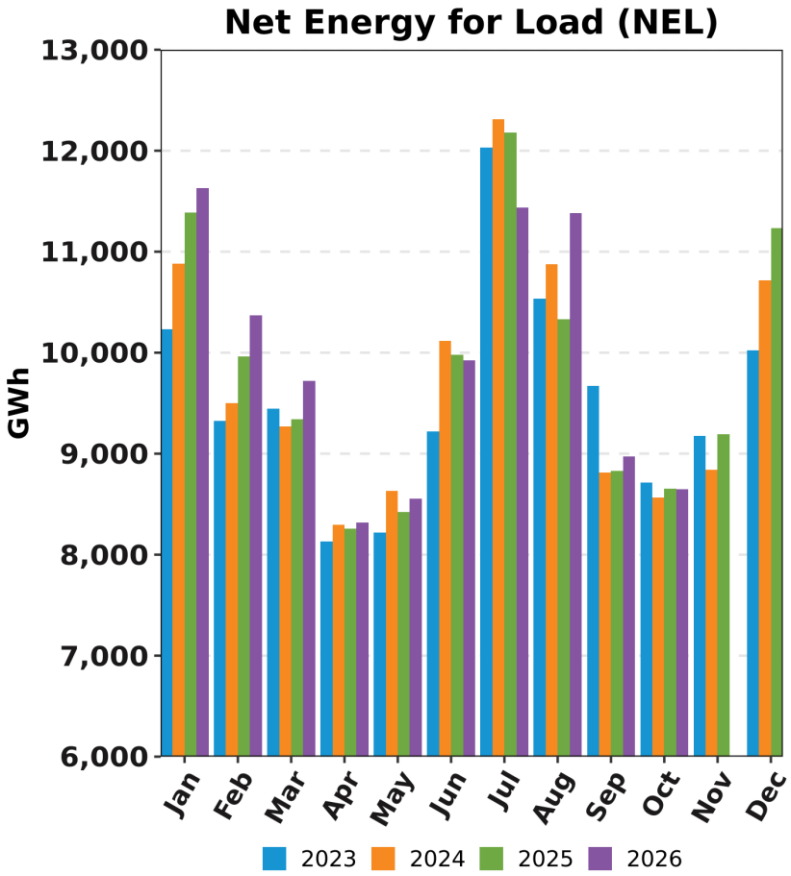
"Other" currently only contains Hybrid Solar/Battery; PRD=Demand Response Resources (DRR)

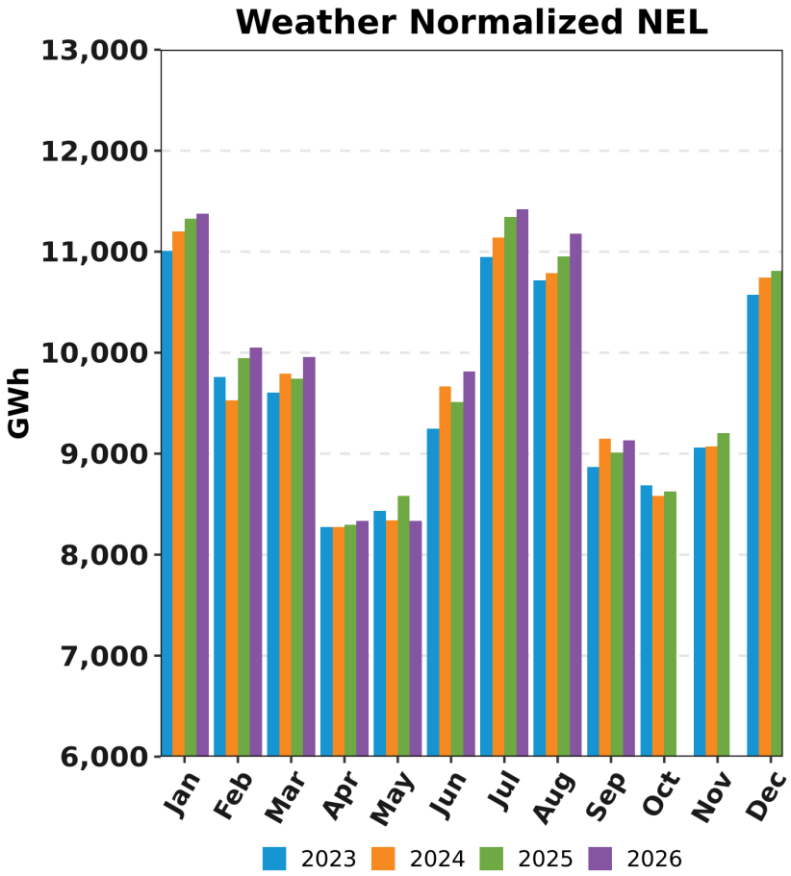
RQM System Peak Load MW by Month



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

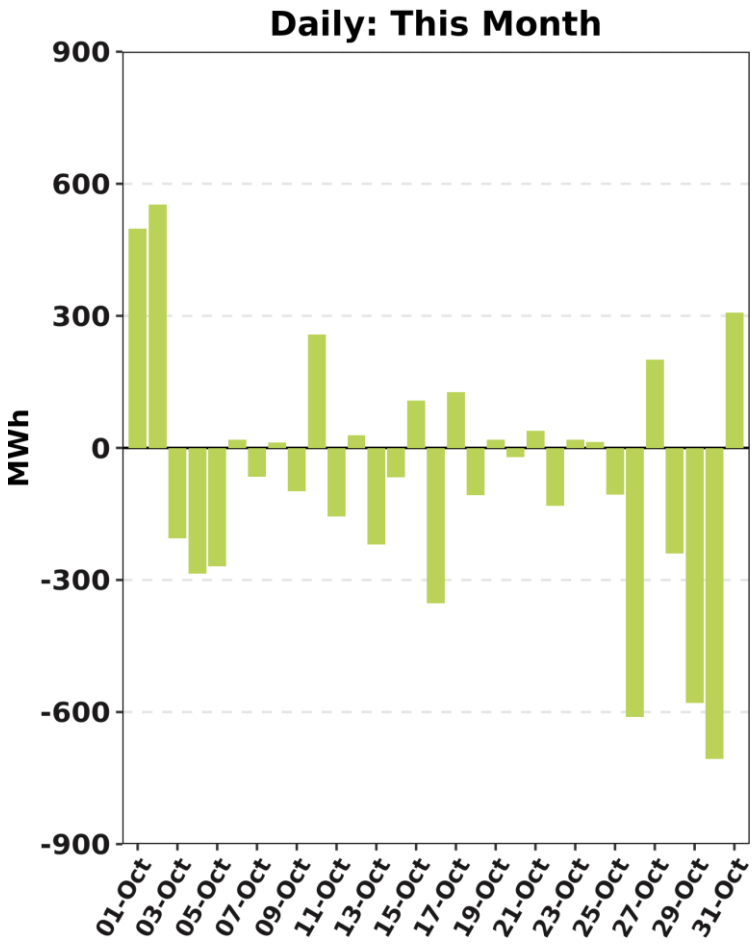
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

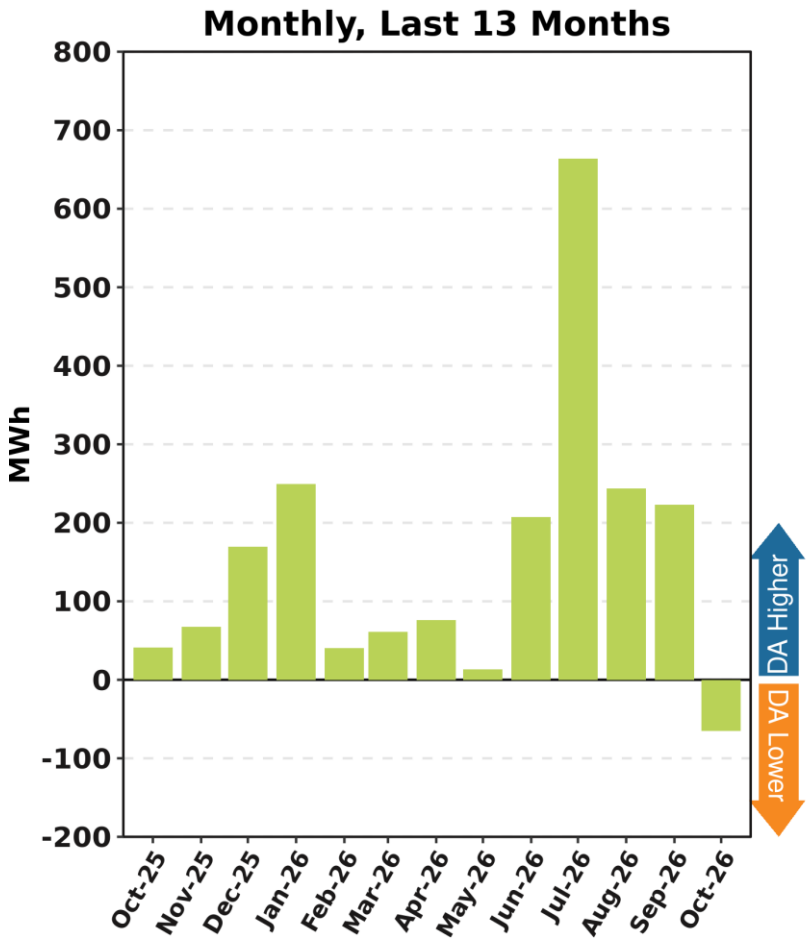




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

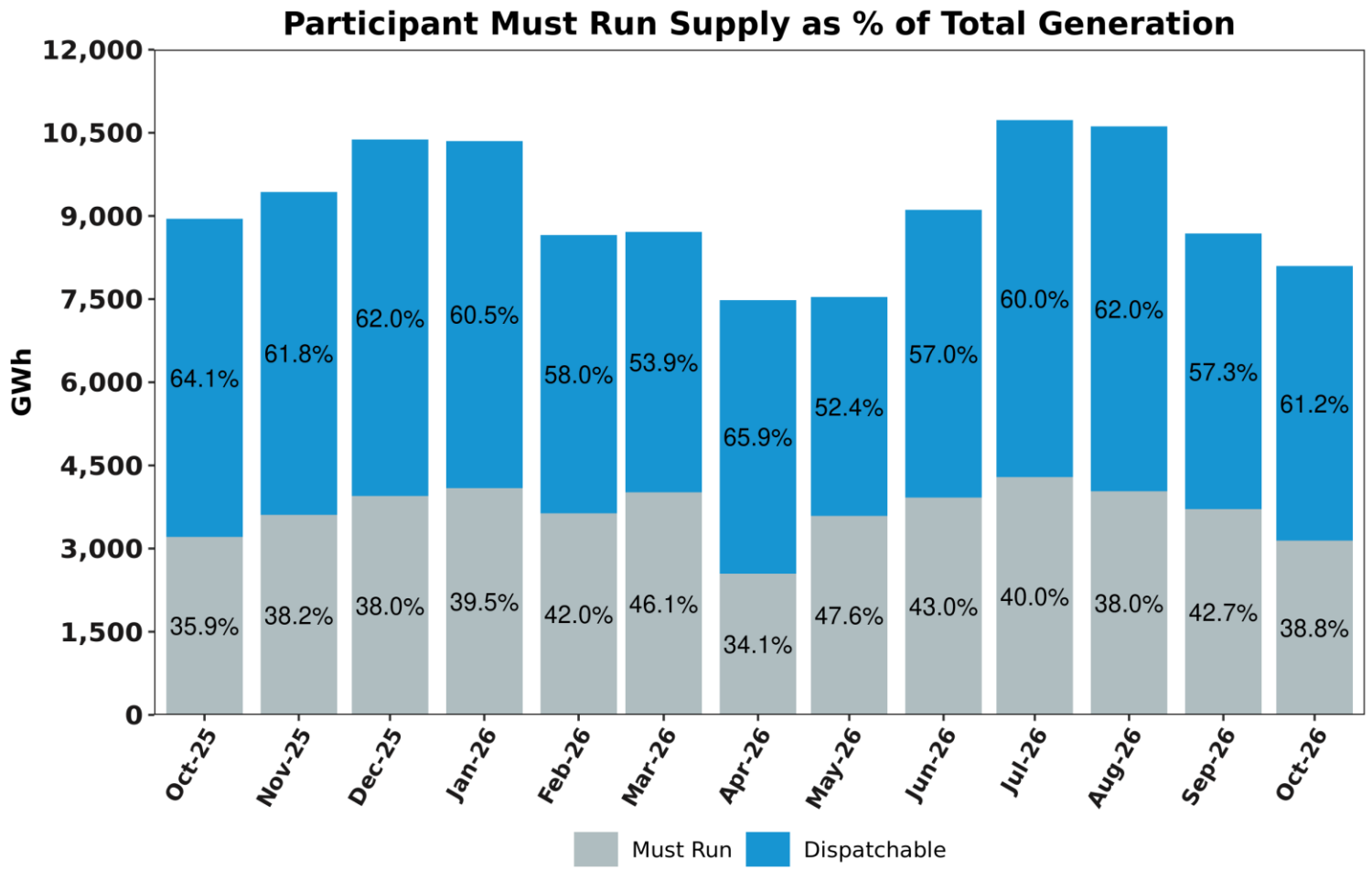
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour





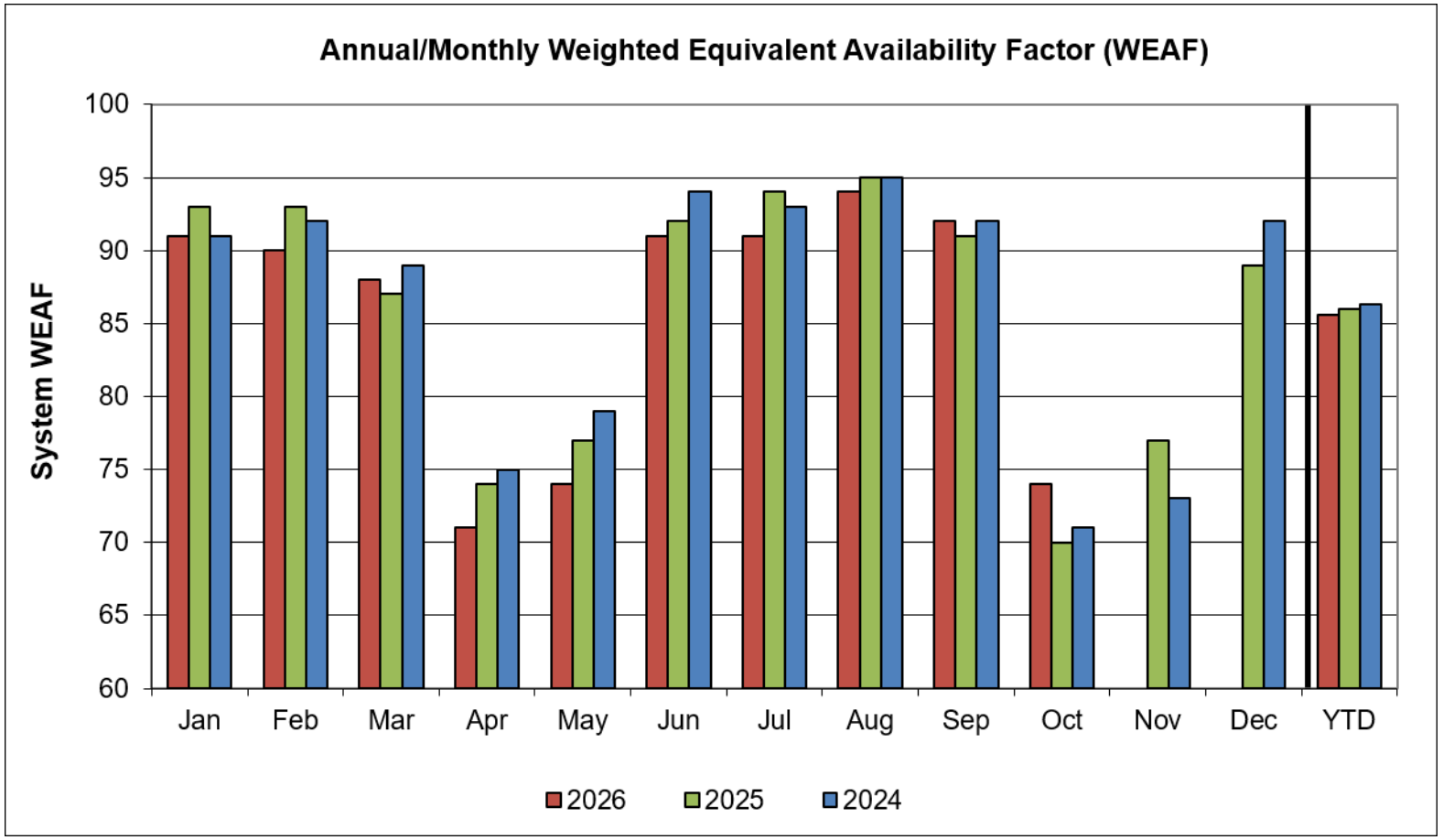
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

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



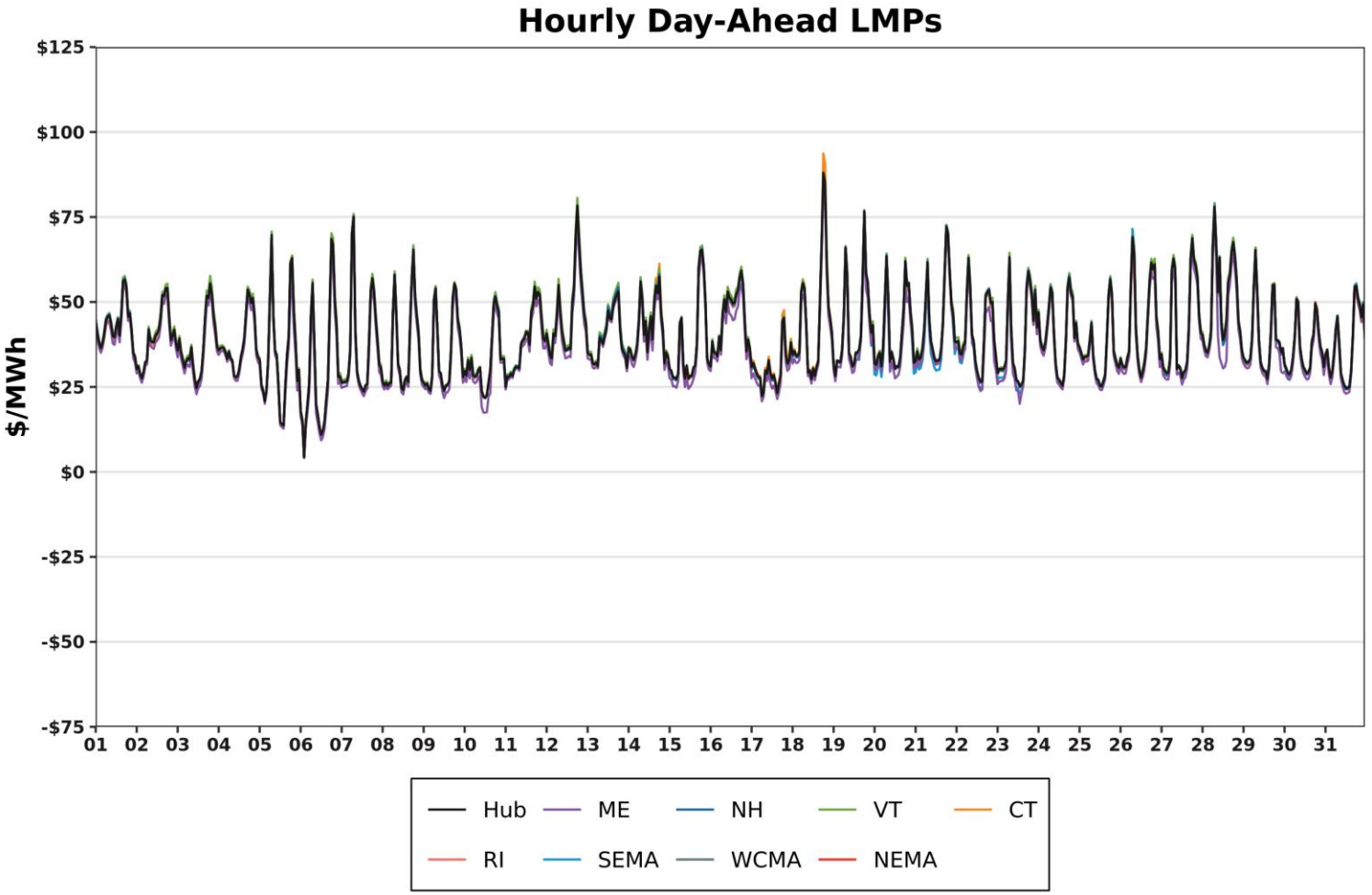
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2026	91	90	88	71	74	91	91	94	92	74			86
2025	93	93	87	74	77	92	94	95	91	70	77	89	86
2024	91	92	89	75	79	94	93	95	92	71	73	92	86

Data as of 11/2/26

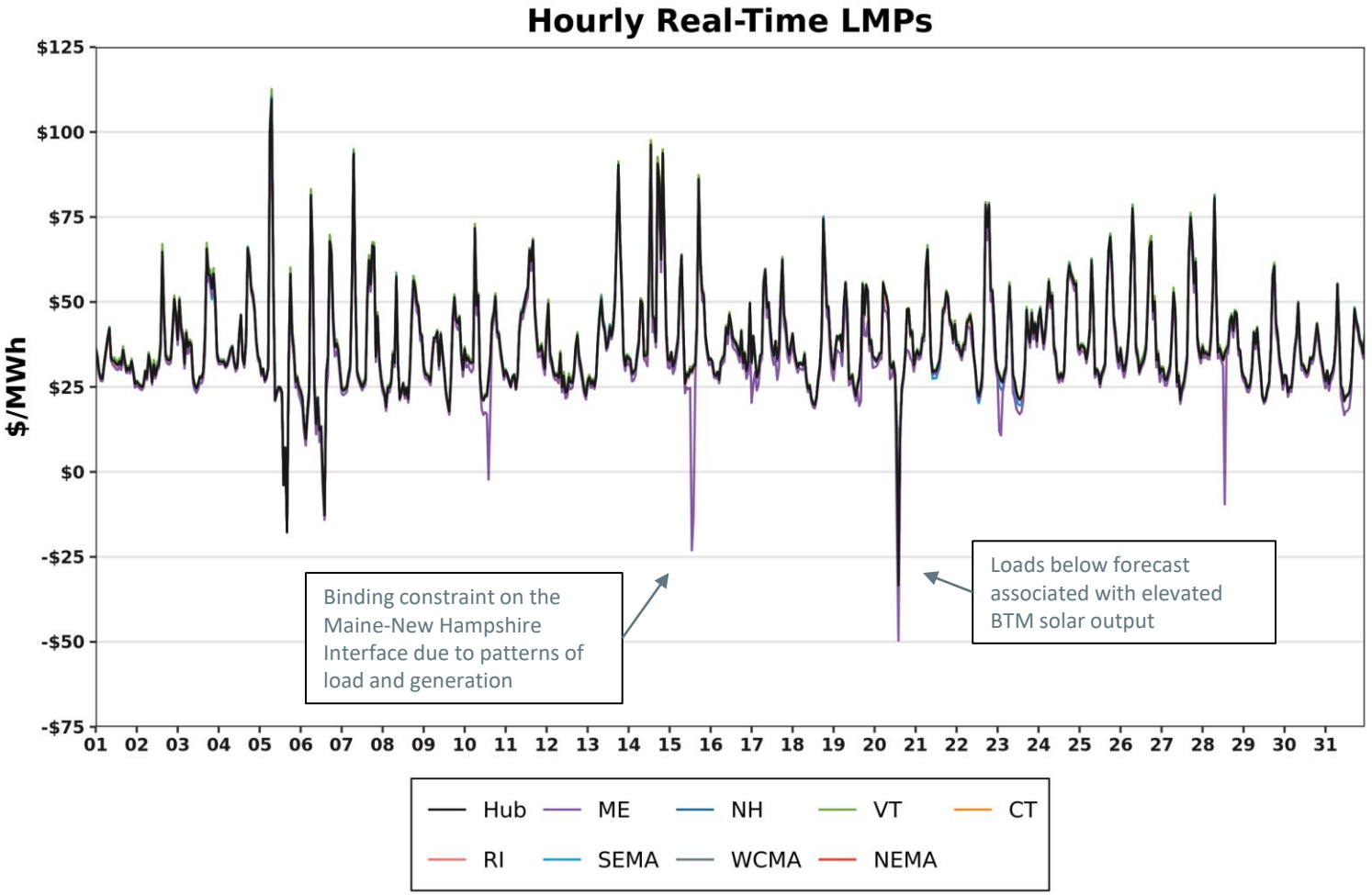
MARKET OPERATIONS

Market Pricing

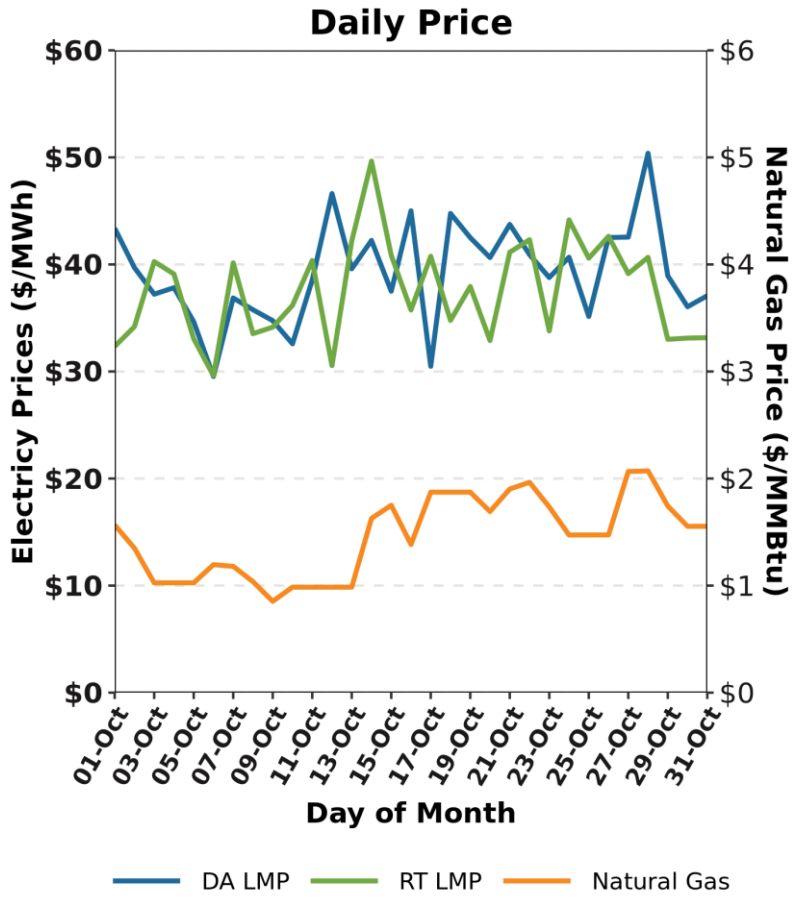
Hourly DA LMPs, October 1-31, 2026

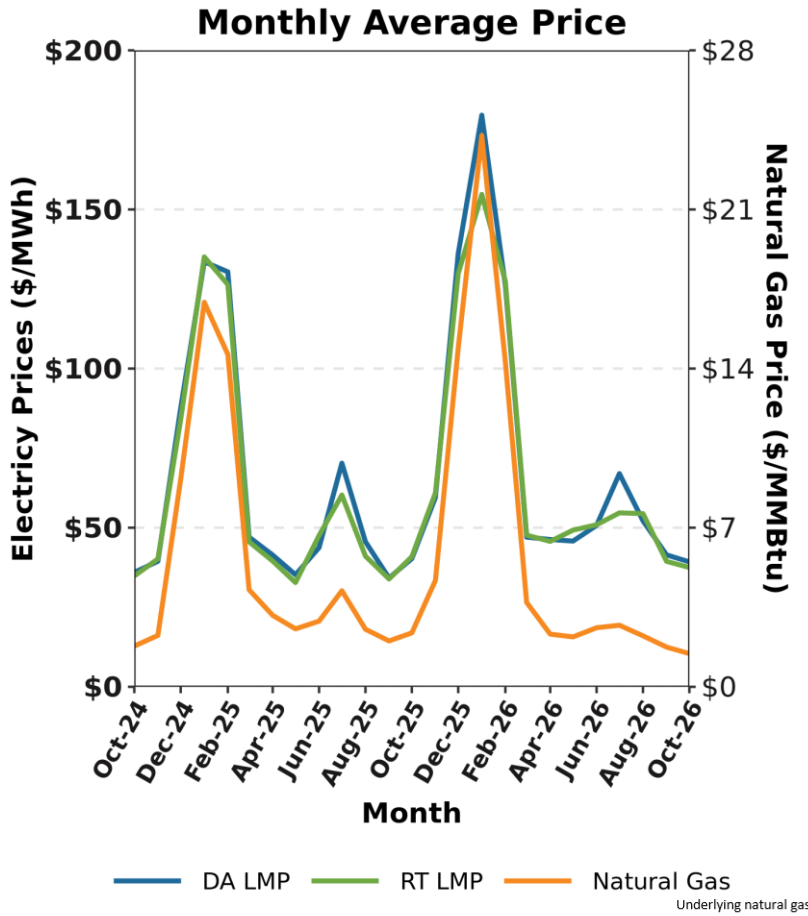


Hourly RT LMPs, October 1-31, 2026



Wholesale Electricity vs Natural Gas Price by Month



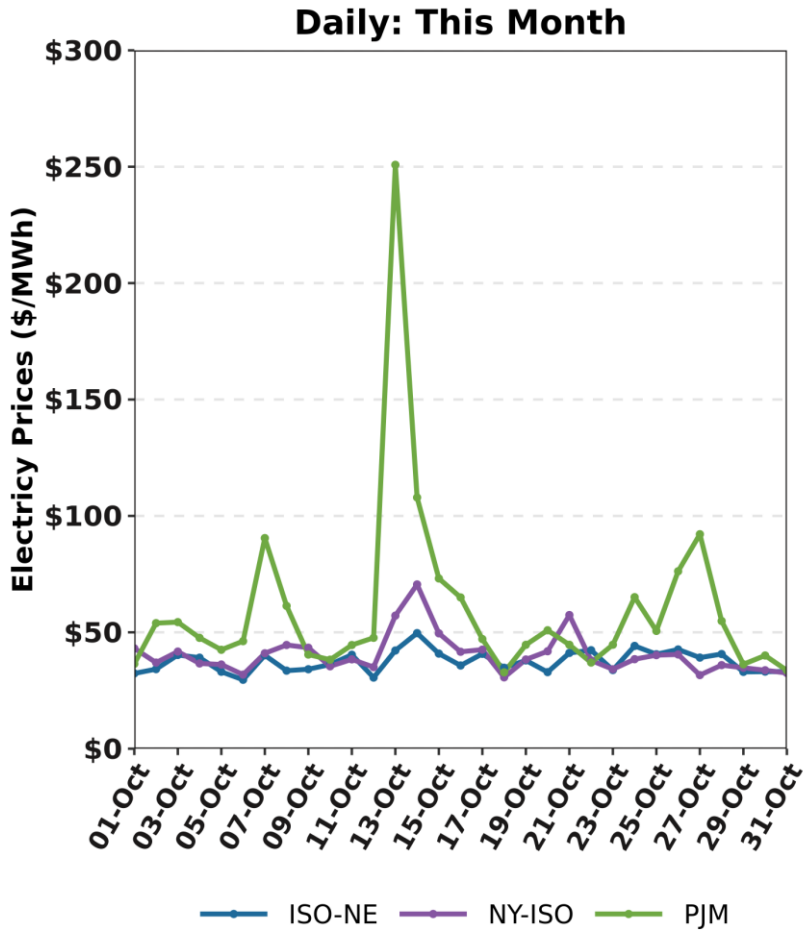


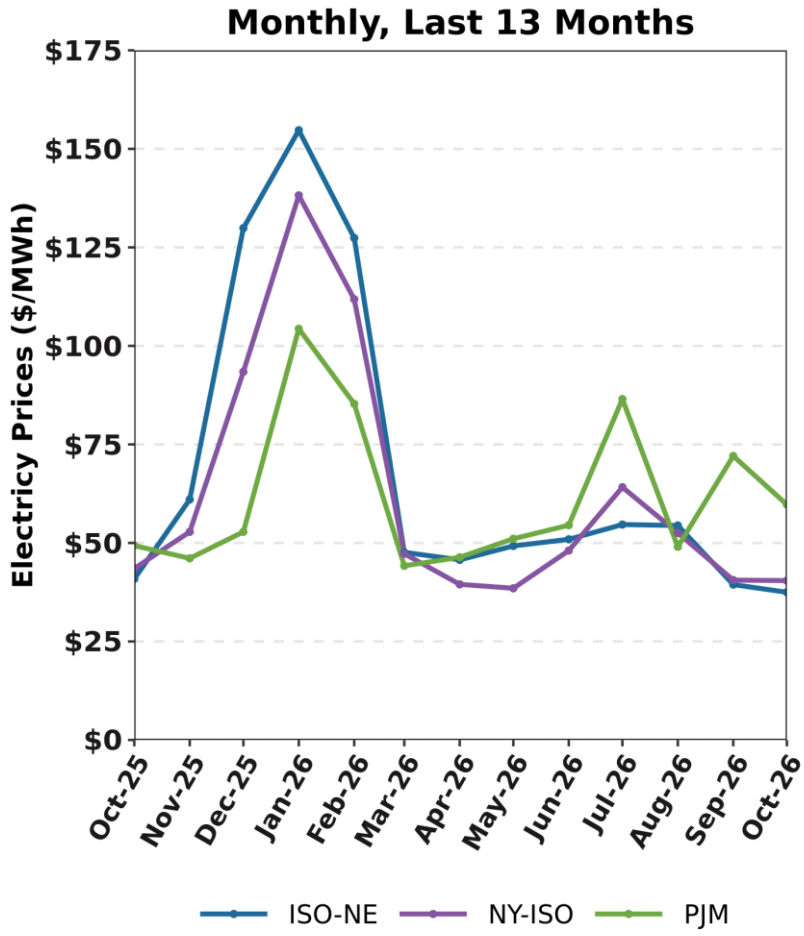
Underlying natural gas data furnished by:

ice Global markets in clear view

Gas price is average of Massachusetts delivery points

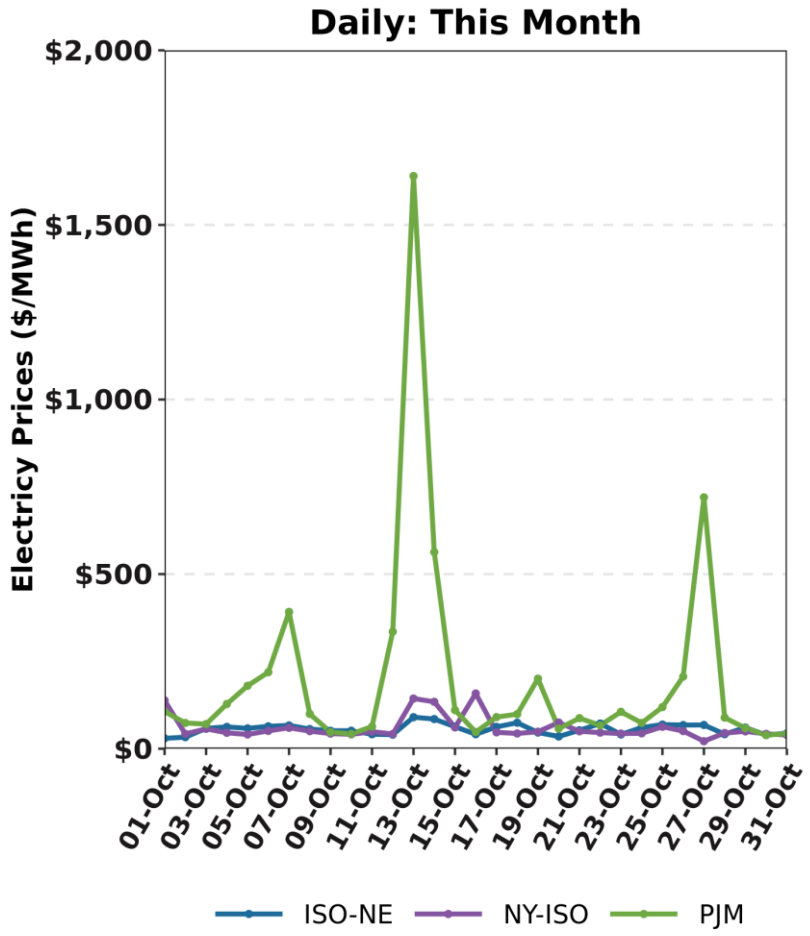
New England, NY, and PJM Hourly Average RT Prices by Month

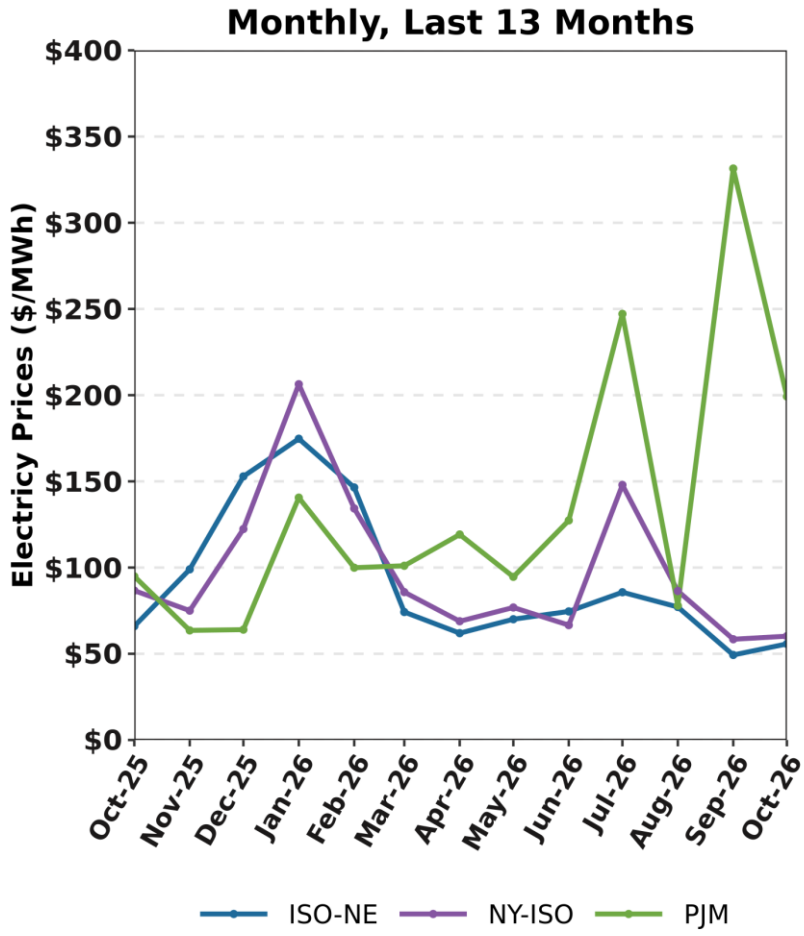




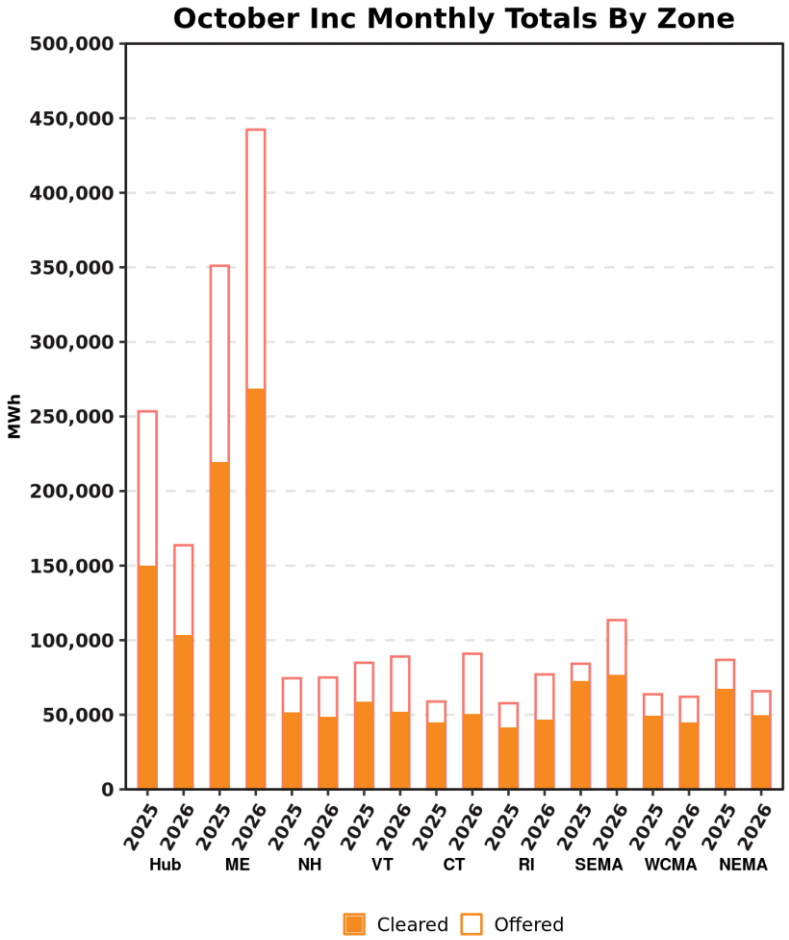
Hourly average prices are shown

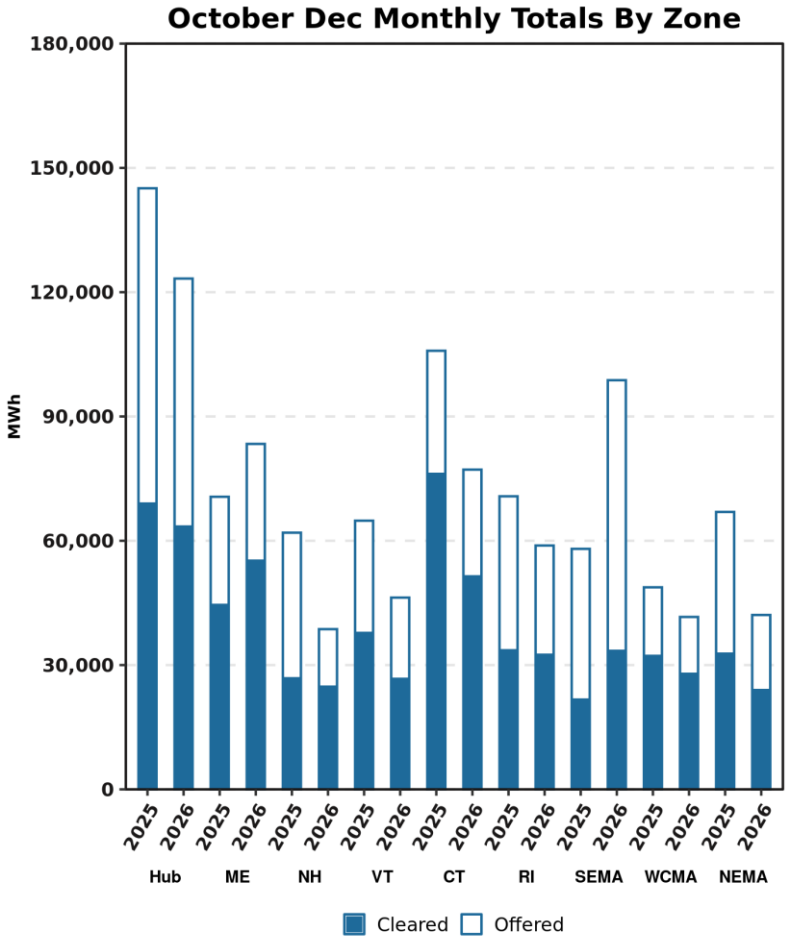
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





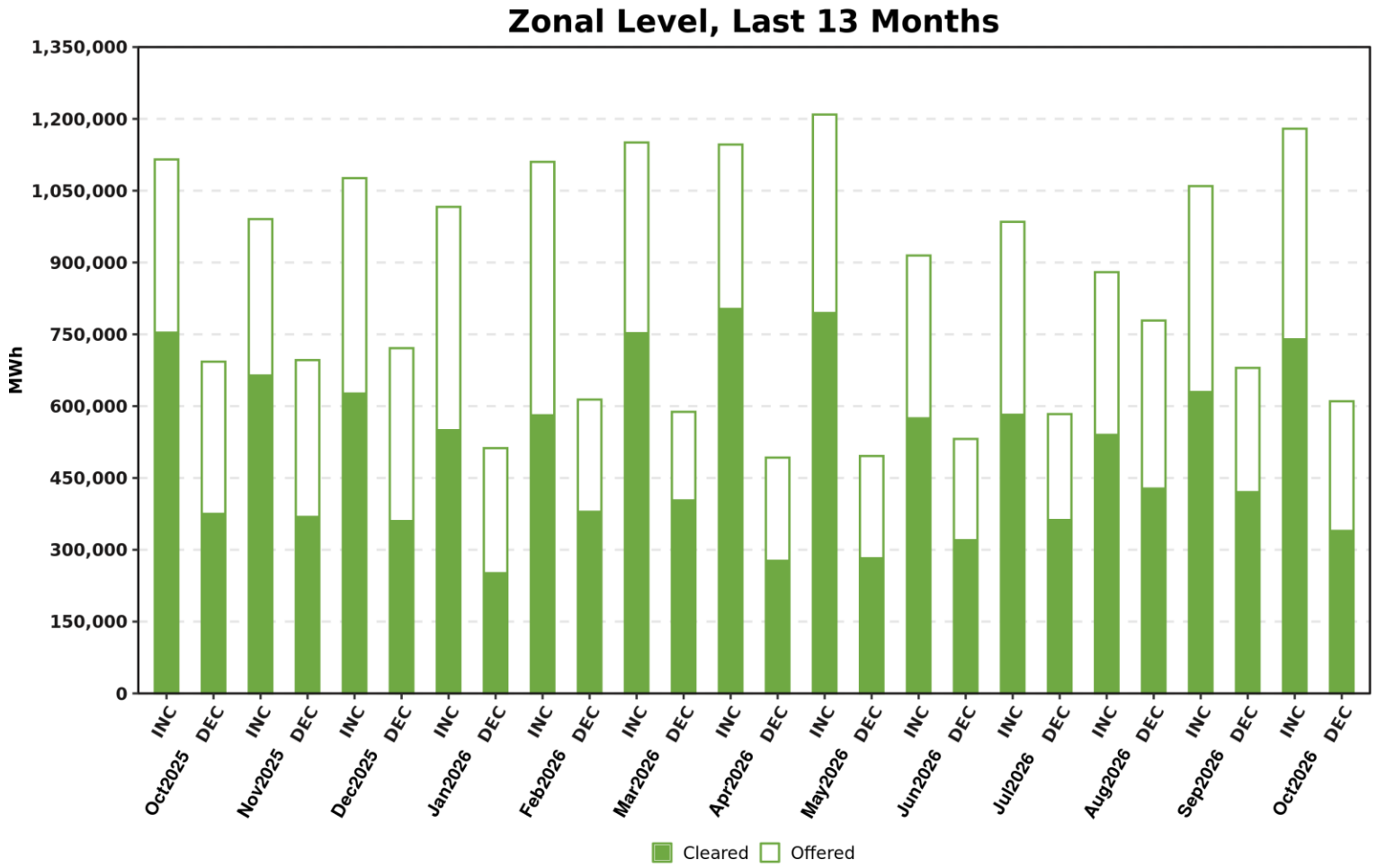
Zonal Increment Offers and Decrement Bid Amounts





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)

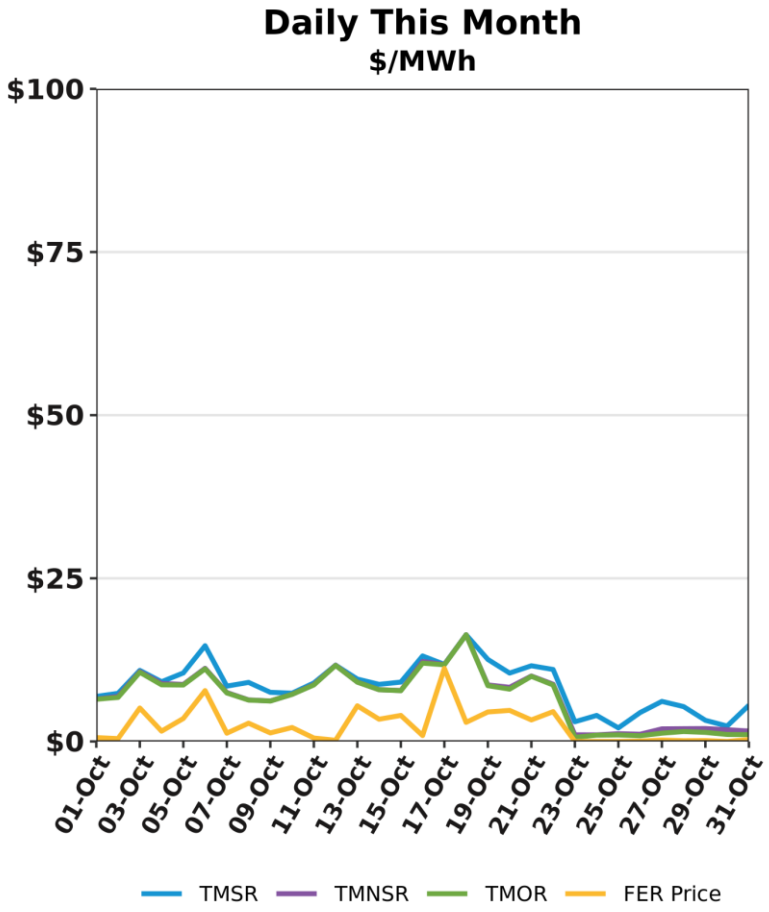
DAAS Results

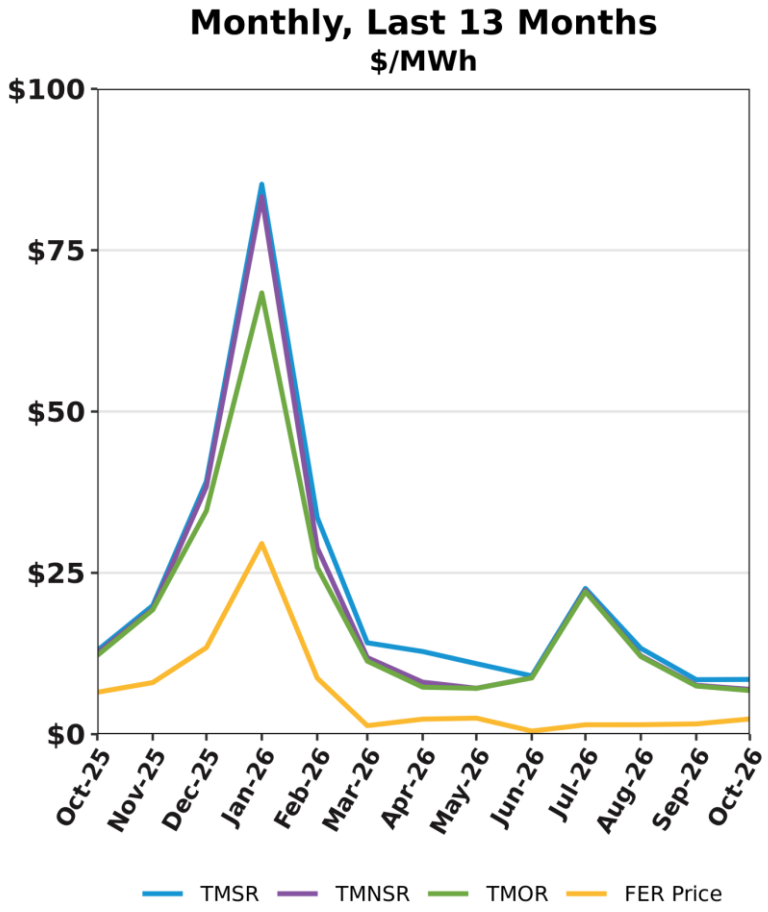
Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg. Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
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	$15M	$425K	-$187K	-$3.40	-1.2%	$674K	133K	$2.49	4.5%	101
06/01/2026	$19.3M	$483K	$63K	$1.17	0.3%	$186K	60K	$0.48	1.0%	17
07/01/2026	$32.1M	$1,161K	$784K	$14.55	2.4%	$649K	126K	$1.46	2.0%	35
08/01/2026	$22.1M	$665K	$418K	$7.78	1.9%	$642K	114K	$1.47	2.9%	31
09/01/2026	$15M	$417K	$342K	$6.29	2.3%	$484K	126K	$1.59	3.2%	61
10/01/2026	$13.1M	$390K	$349K	$6.48	2.7%	$665K	122K	$2.36	5.1%	72

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. Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices





This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

BACK-UP DETAIL

NEW GENERATION

New Generation Update

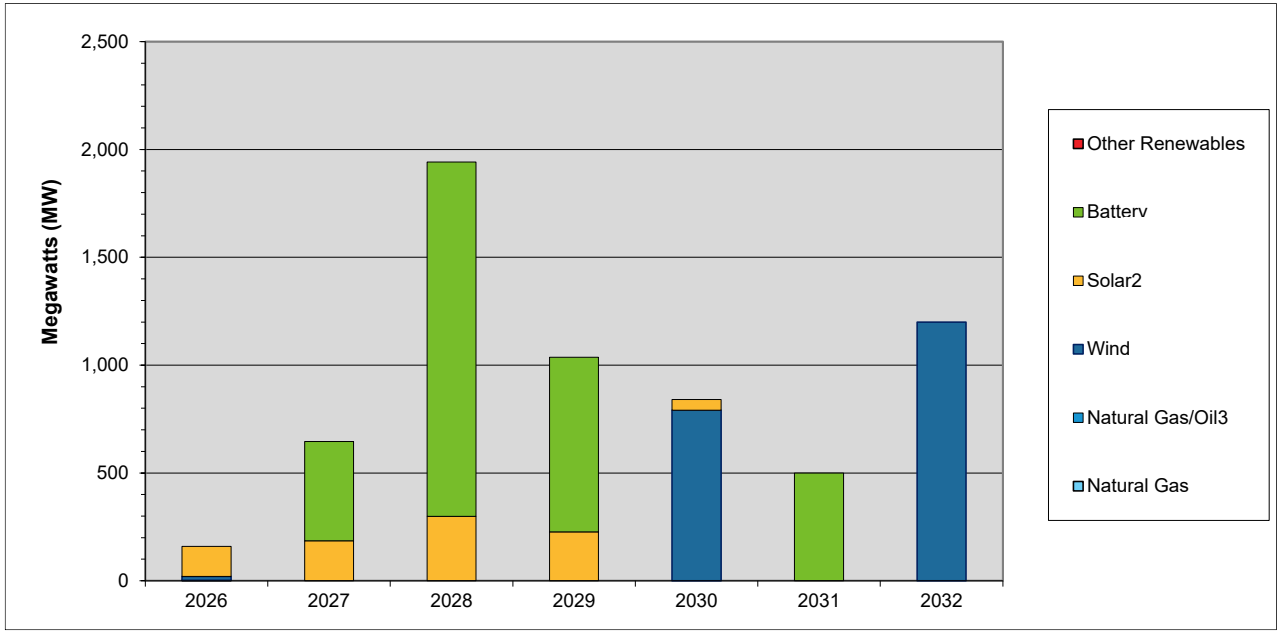
Based on Queue as of 11/02/26

- In total, 38* generation projects are currently being tracked by the ISO, totaling approximately 7,524 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	461	1,643	810	0	500	0	3,414	54.0
Solar[2]	140	185	299	227	50	0	0	901	14.2
Wind	18	0	0	0	791	0	1,200	2,009	31.8
Natural Gas/Oil[3]	0	0	0	0	0	0	0	0	0.0
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	**158**	**646**	**1,942**	**1,037**	**841**	**500**	**1,200**	**6,324**	**100.0**

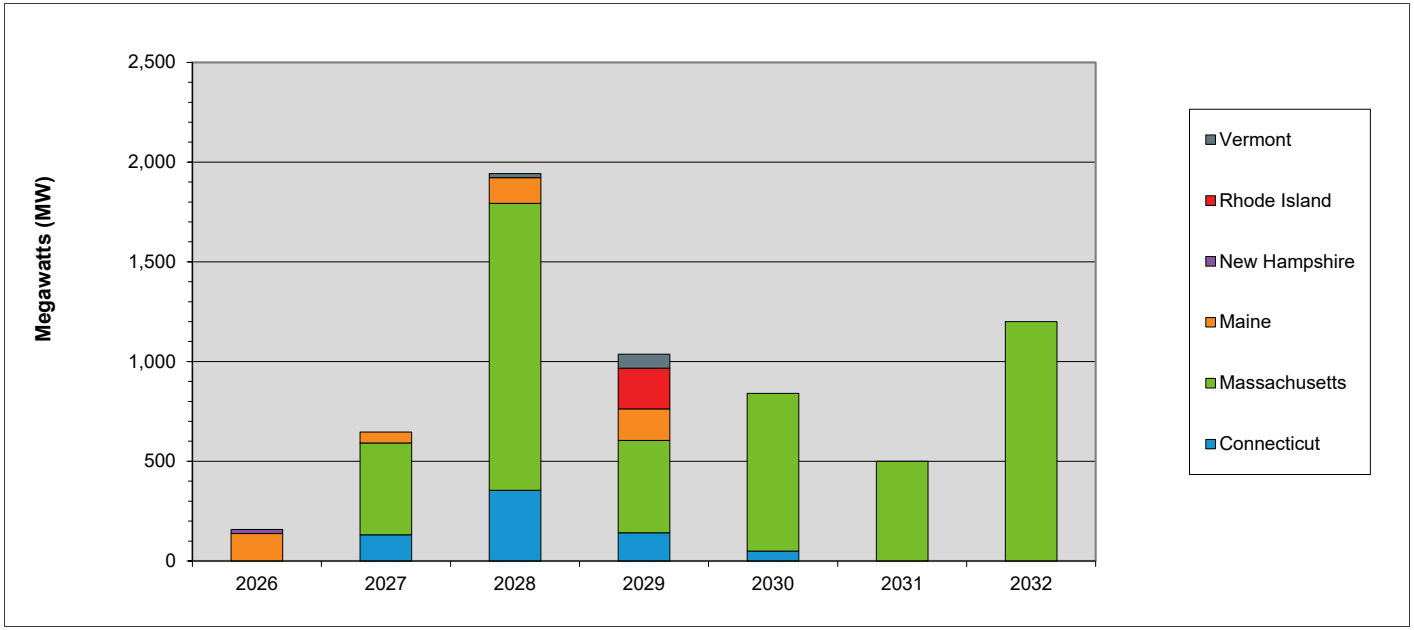
[1] Sum may not equal 100% due to rounding

[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	0	20	70	0	0	0	90	1.4
Rhode Island	0	0	0	205	0	0	0	205	3.2
New Hampshire	20	0	0	0	0	0	0	20	0.3
Maine	138	54	129	157	0	0	0	478	7.6
Massachusetts	0	461	1,438	463	791	500	1,200	4,853	76.7
Connecticut	0	131	355	142	50	0	0	678	10.7
Totals	**158**	**646**	**1,942**	**1,037**	**841**	**500**	**1,200**	**6,324**	**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	15	3,414	2	454	13	2,960
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	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0
Solar	19	901	3	136	16	765
Wind	4	3,209	1	18	3	3,191
Total	38	7,524	6	608	32	6,916

- 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	0	0	0	0	0	0
Peaker	34	4,315	5	590	29	3,725
Wind Turbine	4	3,209	1	18	3	3,191
Total	38	7,524	6	608	32	6,916

- 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	15	3,414	0	0	0	0	15	3,414	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	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	19	901	0	0	0	0	19	901	0	0
Wind	4	3,209	0	0	0	0	0	0	4	3,209
Total	38	7,524	0	0	0	0	34	4,315	4	3,209

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35	589.882	-175.468	504.466	-85.416	437.780	-66.686
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753	2,568.703	-5.664
Demand Total		**3,322.606**	**3,169.002**	**-153.604**	**3,078.833**	**-90.169**	**3,006.483**	**-72.350**
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624	26,503.730	-139.649	26,049.059	-454.671
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518	912.376	-76.889
Generator Total		**27,983.936**	**27,790.162**	**-193.774**	**27,492.995**	**-297.167**	**26,961.435**	**-531.560**
Import Total		**1,503.842**	**1,247.601**	**-256.241**	**1,244.601**	**-3.000**	**1,234.800**	**-9.801**
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**	**31,816.429**	**-390.336**	**31,202.718**	**-613.711**
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**	**30,775**	**190**	**30,300**	**-475**

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	622.854	584.913	-37.941	492.363	-92.550	384.960	-107.403
	Passive Demand	2,316.815	2,314.068	-2.747	2,314.705	0.637	2,254.722	-59.983
Demand Total		**2,939.669**	**2,898.981**	**-40.688**	**2,807.068**	**-91.913**	**2,639.682**	**-167.386**
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069	26,271.866	-443.623	26,314.531	42.665
	Intermittent	1,356.084	1,286.589	-69.495	1,310.622	24.033	1,205.314	-105.308
Generator Total		**27,863.504**	**28,002.078**	**138.574**	**27,582.488**	**-419.59**	**27,519.845**	**-62.643**
Import Total		**566.998**	**564.079**	**-2.919**	**636.310**	**72.231**	**409.310**	**-227.000**
Grand Total*		**31,370.171**	**31,465.138**	**94.967**	**31,025.866**	**-439.272**	**30,568.837**	**-457.029**
Net ICR (NICR)		**30,305**	**30,395**	**90**	**30,600**	**205**	**30,050**	**-550**

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	543.580	403.884	-139.696	410.941	7.057		
	Passive Demand	2,070.498	2,851.331	780.833	2,010.568	-840.763		
Demand Total		**2,614.078**	**3,255.215**	**641.137**	**2,421.509**	**-833.706**		
Generator	*Non-Intermittent*	27,026.635	25,822.288	-1,204.347	26,192.205	369.917		
	Intermittent	1,450.872	890.415	-560.457	1,479.423	589.008		
Generator Total		**28,477.507**	**26,712.703**	**-1,764.804**	**27,671.628**	**958.925**		
Import Total		**464.835**	**1,234.800**	**769.965**	**614.235**	**-620.565**		
Grand Total*		**31,556.420**	**31,202.718**	**-353.702**	**30,707.372**	**-495.346**		
Net ICR (NICR)		**30,550.000**	**30,415.000**	**-135.000**	**29,855.000**	**-560.000**		

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	**2,809.541**	**130.128**	**2,939.669**
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

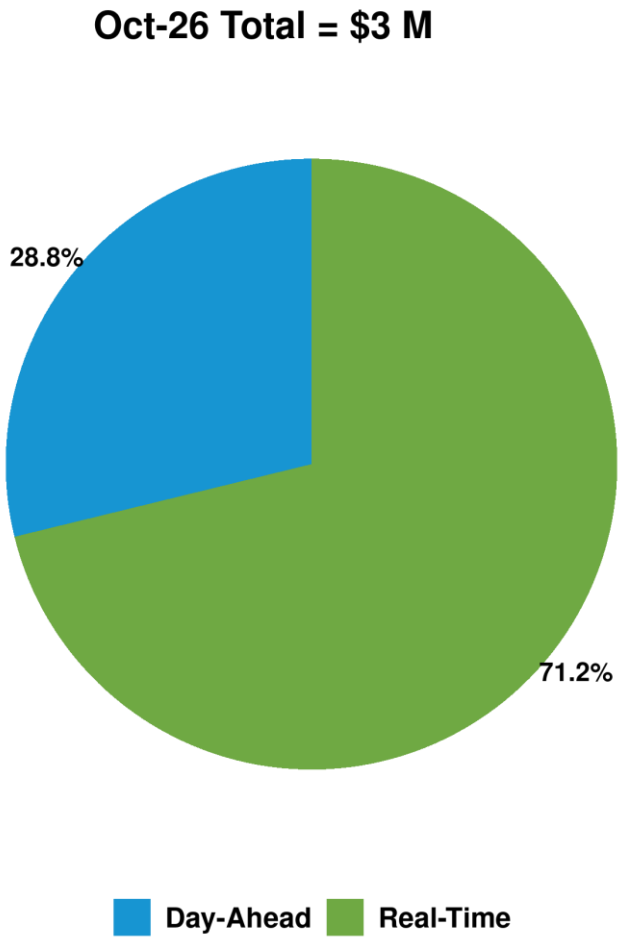
NET COMMITMENT PERIOD COMPENSATION

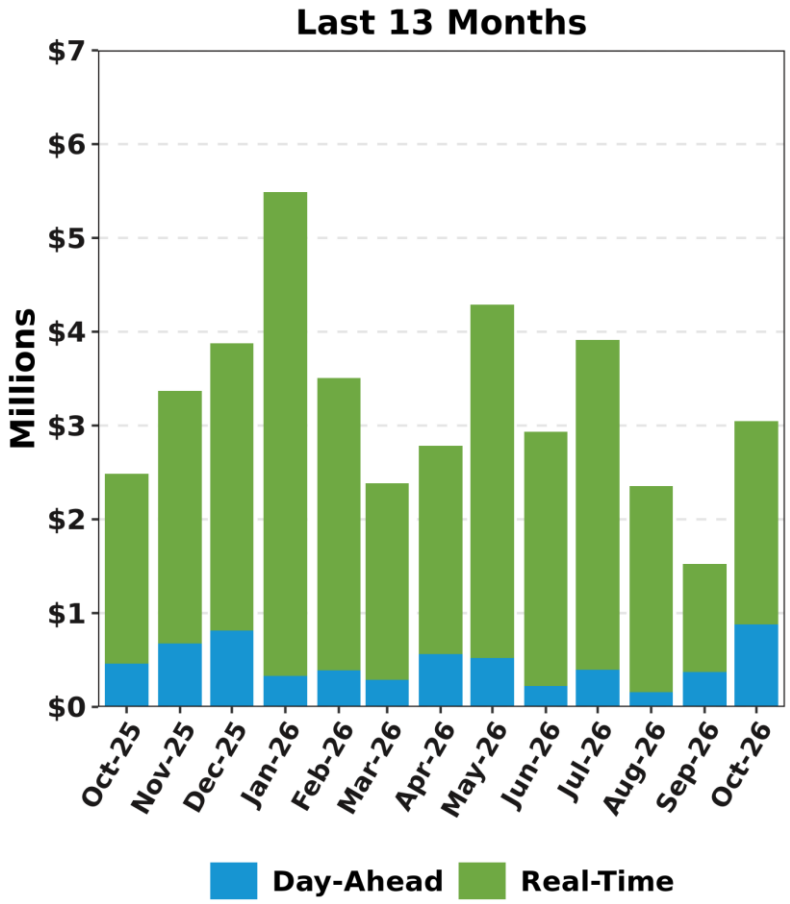
NCPC Highlights

- **Net Commitment Period Compensation (NCPC)** total $3M
  - Represents 0.7% of monthly Energy Market value
  - First Contingency $3M
    - Dispatch Lost Opportunity Cost (DLOC) - $521K; Rapid Response Pricing (RRP) Opportunity Cost - $156K; Posturing - $0; Generator Performance Auditing (GPA) - $775K
    - $394K paid to resources at external locations, up $185K from September
      - $391K charged to Day-Ahead Load Obligation (DALO) at external locations; <$1K to Day-Ahead Generation Obligation (DAGO) at external locations; $3K to RT Deviations
  - 2nd Contingency, Distribution and Voltage were zero

This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

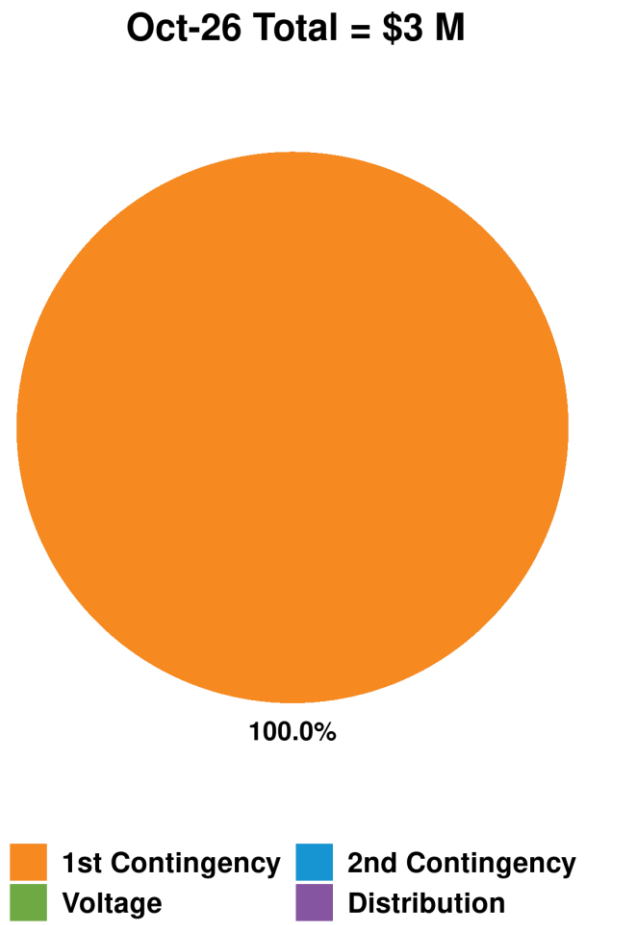
DA and RT NCPC Charges

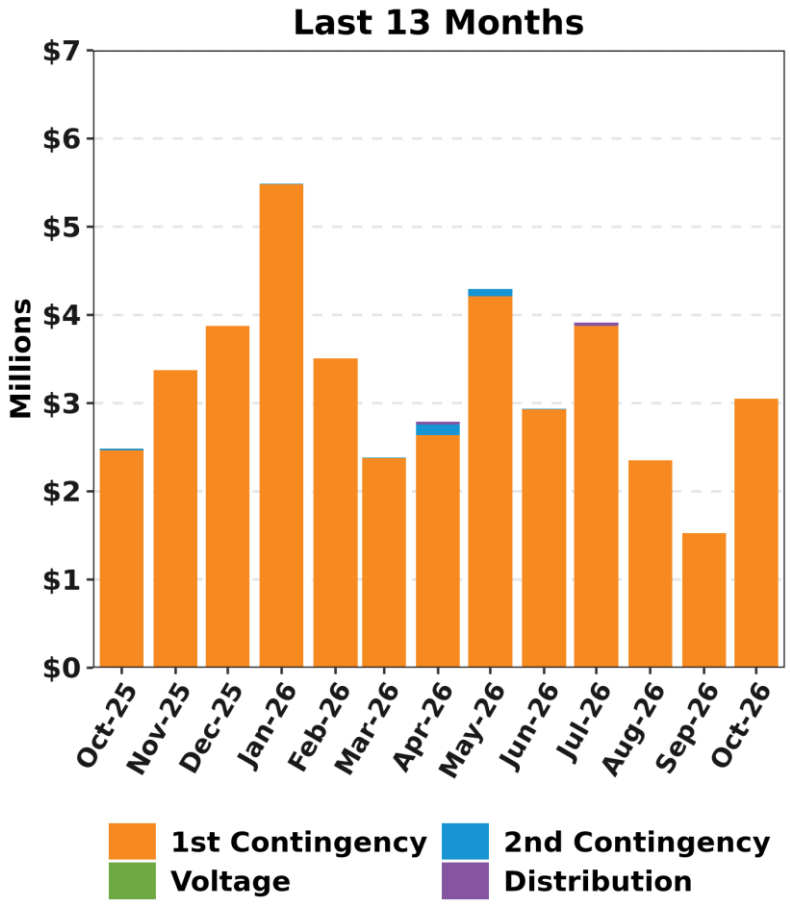




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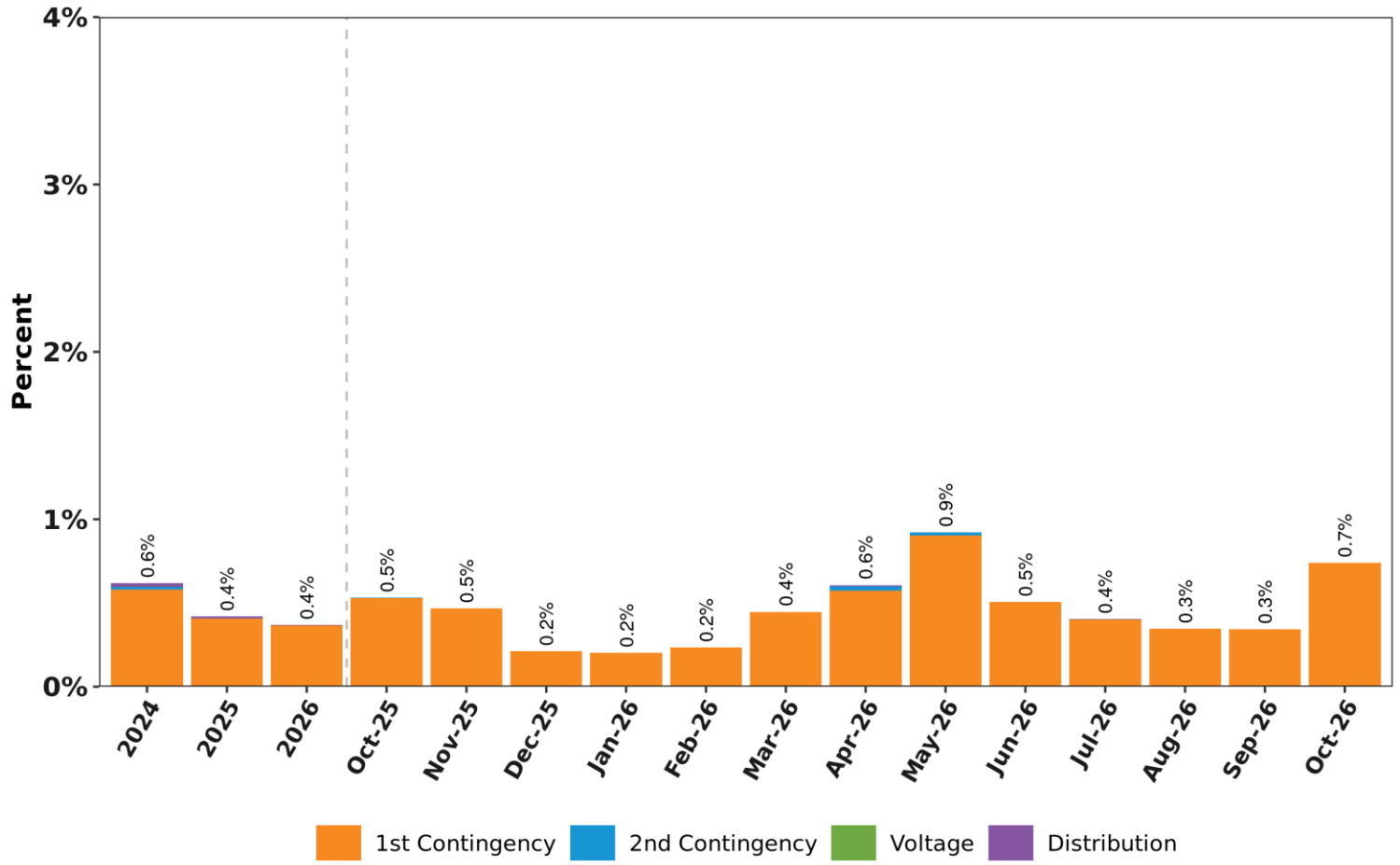
NCPC Charges by Type





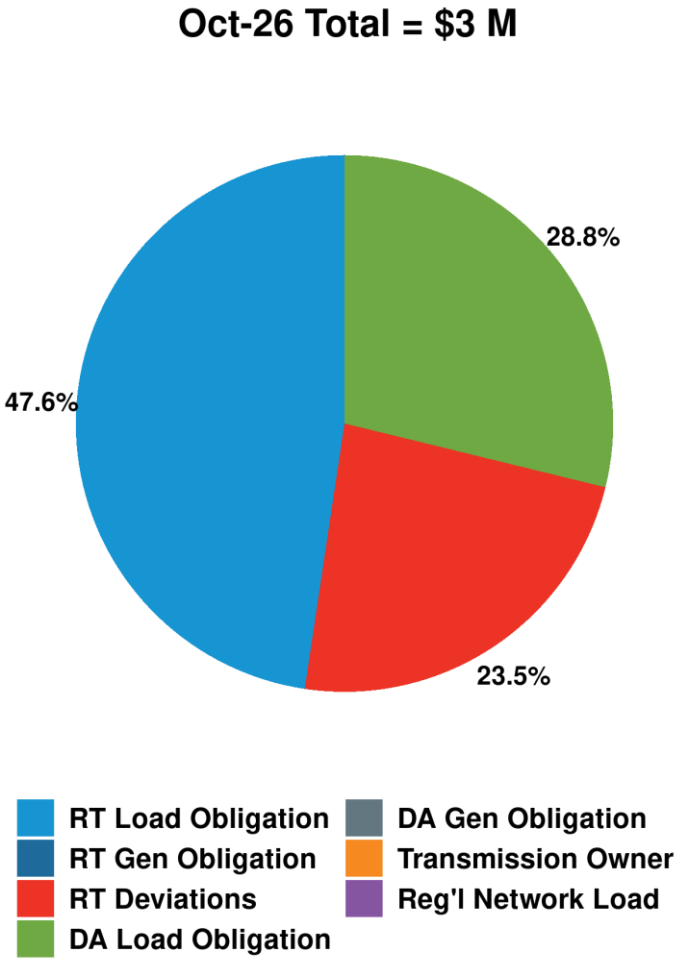
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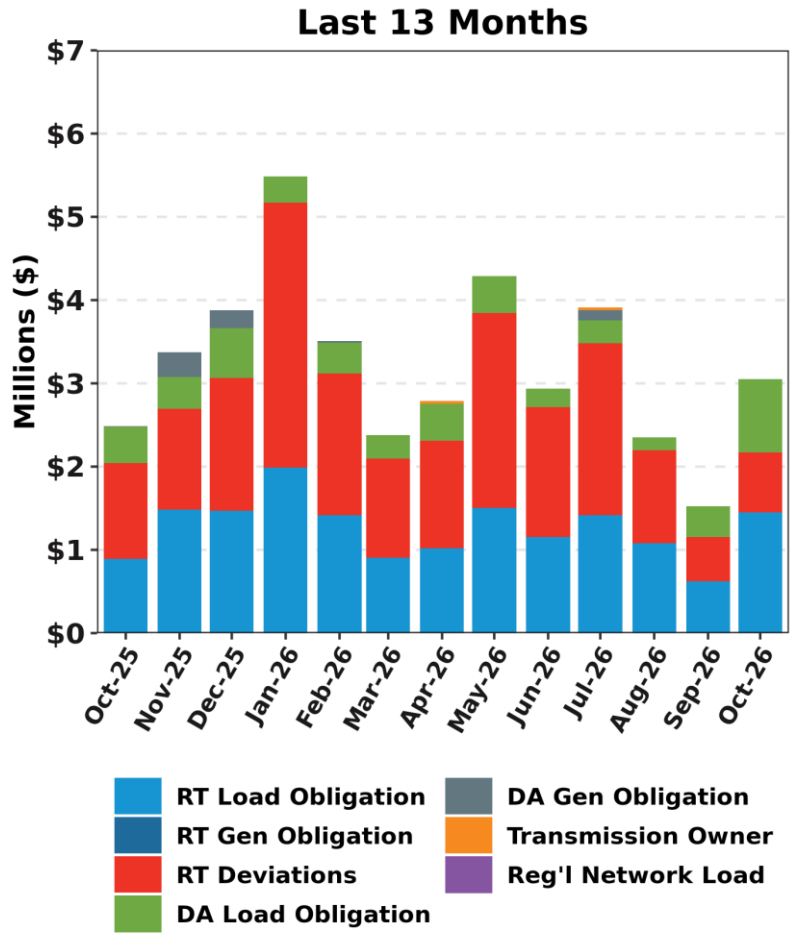
NCPC Charges by Type as Percent of Energy Market Value



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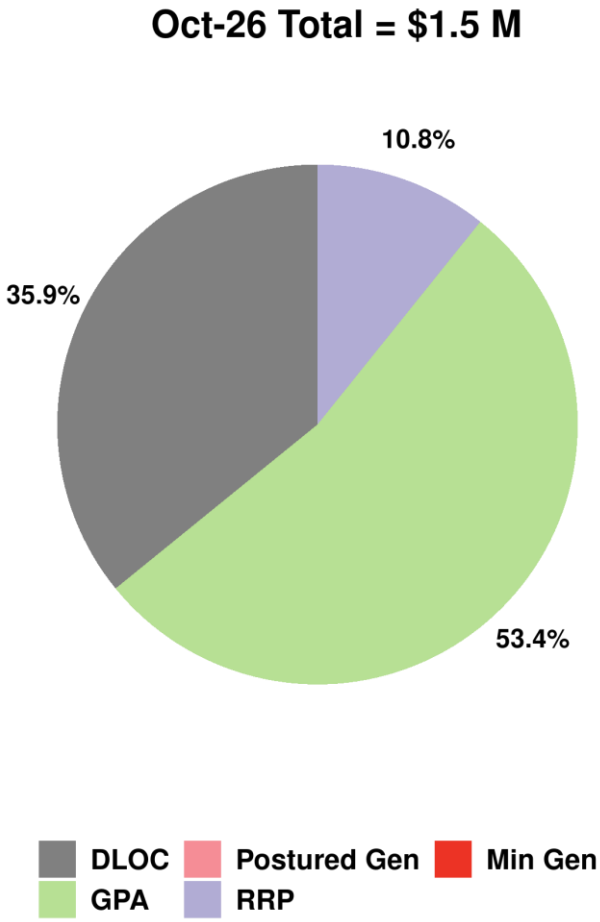
NCPC Charge Allocations

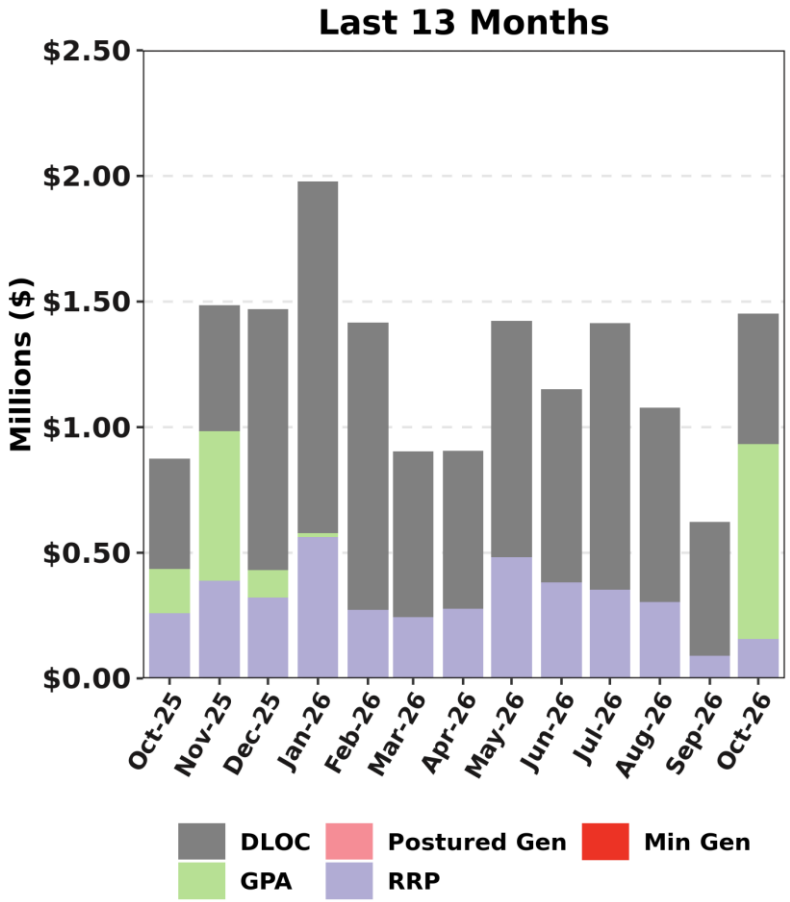




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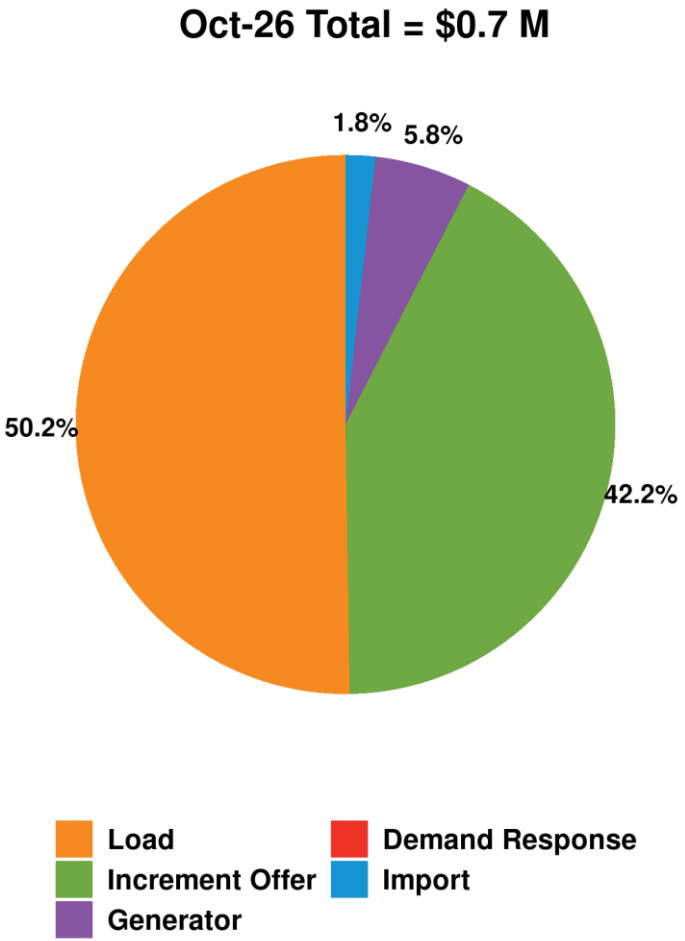
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

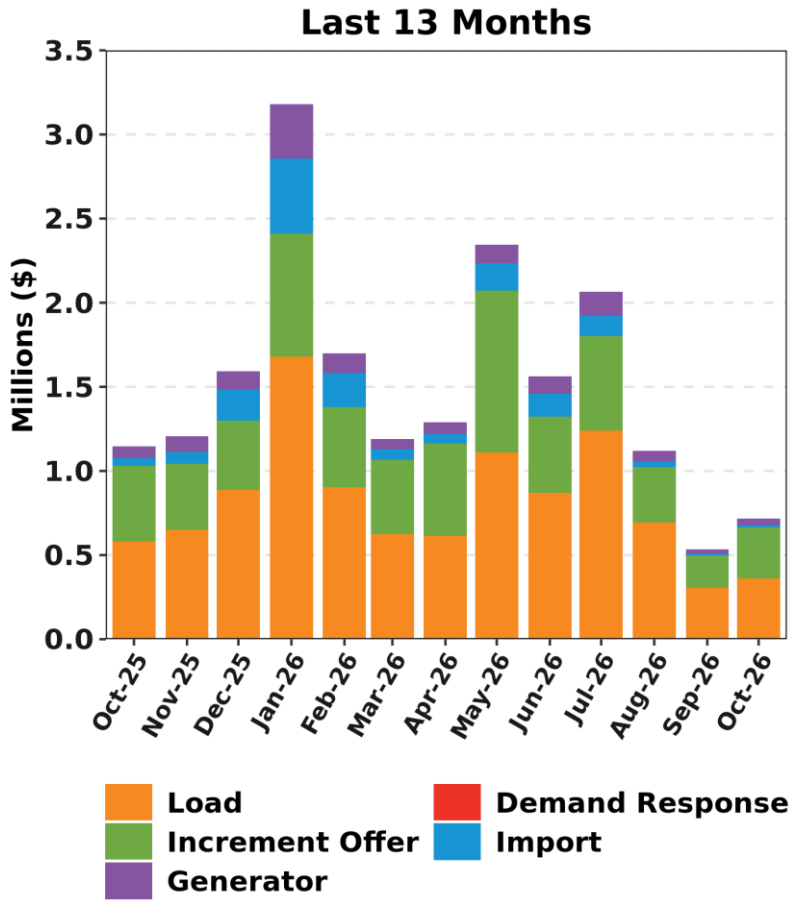




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.
This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

RT First Contingency Charges by Deviation Type





This information is available in the Monthly Market Report found on the ISO website and is scheduled for removal from this deck at a future date.

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- November 18 PAC Meeting Tentative Agenda Topics (note that the agenda is still under review)*
  - Asset Condition Projects
    - Otter River #615 Substation Asset Replacement (NGRID)
    - Line 330 ACR Project (Eversource)
  - 2026 Economic Study – Follow-up on the Stakeholder-Requested Scenario
  - 2026 Economic Study – Final Benchmark Scenario Results
  - 2026 Economic Study – Policy Scenario Assumptions
  - Transmission Planning Guide Process Update

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

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 ISO opened the Stakeholder-Requested scenario window through July 24, and one stakeholder submitted a request. ISO will provide feedback at the November PAC.
  - The preliminary Benchmark results were presented at PAC this summer. The final Benchmark, Policy assumptions, and Stakeholder-Requested requests will be discussed in November.
    - Results from the latter scenarios will come out over the next 3-6 months, followed by the System Efficiency Needs Scenario in Q2-Q3 2027

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 presented the preliminary preferred Longer-Term Transmission Solution at the July 2026 PAC meeting, posted the preferred Longer-Term Transmission Solution on 8/14/26, and notified the Qualified Transmission Project Sponsors (QTPSs) they were selected
  - The QTPSs executed all Selected QTPS Agreements by 10/15/26 and they are posted on the ISO website

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

- Transmission Initiative Down East (TIDE) project (was designated as LTP A1 during the 2025 LTTP RFP) RSP IDs: 1940-1977
  - Lead QTPS: Central Maine Power (CMP)
  - Joint Proposal: Yes, w/ Public Service of New Hampshire (PSNH) and NSTAR (Eversource)
  - Type: AC transmission in ME and NH
  - Cost Containment: Yes
  - Projected Benefit-to-Cost Ratio: 2.10
  - Construction Start: Q1 2029, In-Service Date: Q4 2032
  - Design Summary
    - Wind interconnection POI: Pittsfield
    - New 345 kV lines: Pittsfield-Coopers Mills & Buxton-Deerfield (70 mi total)
    - Rebuild Larrabee Rd-Surowiec 115 kV line to operate at 345 kV
    - Several reconductored 345 & 115 kV lines
    - Retire ME Yankee 345 kV substation, build new adjacent Old Ferry Rd 345 kV
    - New STATCOMs: Eight 400 MVAR @ 345 kV
    - New Phase Angle Regulators: Four 750 MVA @ 345 kV
    - Minor corollary upgrade: Three upgraded 115 kV breakers at Orrington

Permanent Asset Condition Reviewer

- ISO engaged with the Transmission Committee (TC) and the PTO Administrative Committee (PTO-AC) regarding the development of this new role. The proposal was the product of robust discussion and incorporated numerous stakeholder-suggested revisions
- Final changes to the Transmission Operating Agreement (TOA) and ISO's Open Access Transmission Tariff (OATT) were filed on August 17, 2026
- On October 16, 2026, FERC issued an Order fully accepting the revisions to establish the ISO as the New England region's Asset Condition Reviewer (ACR), effective January 1, 2027
- Interim project reviews underway to inform permanent design
- ISO is working on staffing and implementation towards January 2027 go-live

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 10/26/2026

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 10/26/2026

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	Dec-29	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	Jul-27	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 10/26/2026

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	Jul-27	3

SEMA/RI Reliability Projects, cont.

Status as of 10/26/2026

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 10/26/2026

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 10/26/2026

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-29	2
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-29	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-30	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 10/26/2026

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 10/26/2026

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

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1940	New P-C - A new 38.5 mile overhead 345 kV line between Coopers Mills substation (Windsor, ME) and the new Pittsfield substation (Pittsfield, ME)	Dec-32	1
1941	3023 - Reconductor 17.4 miles of overhead 345 kV line between Albion Road substation (Benton, ME) and new Pittsfield substation (Pittsfield, ME), split this line and terminate into the new Pittsfield substation	Dec-32	1
1942	3026 - Relocate 3.4 mile section of overhead 345 kV line between the Larrabee Road substation (Lewiston, ME) and the Surowiec substation (Pownal, ME)	Dec-32	1
1943	374 - Reconductor 26.5 miles of overhead 345 kV line between Surowiec substation (Pownal, ME) and Buxton substation (Buxton, ME)	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1944	3038 - Reconductor 26.5 miles of overhead 345 kV line between Surowiec substation (Pownal, ME) and Buxton substation (Buxton, ME)	Dec-32	1
1945	391-ME - Rebuild 30.6 miles of overhead 345 kV line on monopoles between Buxton substation (Buxton, ME) and the ME/NH border	Dec-32	1
1946	385-ME - Replace 0.24 miles of overhead structures between Buxton substation (Buxton, ME) and the ME/NH border	Dec-32	1
1947	New B-D-ME - Build new 30.6 mile overhead 345 kV line between Buxton substation (Buxton, ME) and the ME/NH border	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1948	64 - Convert 16.4 miles of existing overhead line 64 from 115 kV to 345 kV between Larrabee Road substation (Lewiston, ME) and Surowiec substation (Pownal, ME)	Dec-32	1
1949	81 - Reconductor 28.5 miles of overhead 115 kV line between Mason substation (Wiscasset, ME) and Surowiec substation (Pownal, ME)	Dec-32	1
1950	200 - Rebuild 13.8 miles of overhead 115 kV line between Larrabee Road substation (Lewiston, ME) and Leeds substation (Leeds, ME)	Dec-32	1
1951	167 - Reconductor 16.3 miles of overhead 115 kV line between Surowiec substation (Pownal, ME) and Section 167A Tap (Westbrook, ME)	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1952	257 - Rebuild 21.1 miles of overhead 115 kV line on a double-circuit with line 258 between Coopers Mills substation (Windsor, ME) and Albion Road substation (Benton, ME)	Dec-32	1
1953	258 - Rebuild 21.1 miles of overhead 115 kV line on a double-circuit with line 257 between Coopers Mills substation (Windsor, ME) and Albion Road substation (Benton, ME)	Dec-32	1
1954	67 - Rebuild 21.1 miles of overhead 115 kV line in a double circuit configuration with the new P-C line between Albion Road substation (Benton, ME) and Pittsfield substation (Pittsfield, ME)	Dec-32	1
1955	Bypass 345 kV S388 Series Capacitor	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1956	Bypass 345 kV S3023 Series Capacitor	Dec-32	1
1957	Old Ferry Road - Retire existing Maine Yankee substation (Wiscasset, ME) and build new 345 kV substation called Old Ferry Road (Wiscasset, ME) in a breaker-and-a-half configuration - 345 kV Maine Yankee substation Decommissioned - Reterminate 392, 3027, 378, 377, 375 345 kV lines and existing STATCOM into new substation - Add two 345 kV Phase Angle Regulators (PAR) on Line 377 at Old Ferry Road substation - Add two 345 kV Phase Angle Regulators (PAR) on Line 375 at Old Ferry Road substation	Dec-32	1
1958	Pittsfield - Build new 345 kV air-insulated substation called Pittsfield (Pittsfield, ME) in a breaker-and-a-half configuration, terminate split 3023 line and new P-C 345 kV line into the station	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1959	Surowiec - Expand Surowiec substation (Pownal, ME) with additional 345 kV bay, upgrading eight existing 345 kV breakers, installing five new 345 kV breakers, and reterminate 64 line into 345 kV station	Dec-32	1
1960	Larrabee Road - Upgrade/Expand existing Larrabee Road substation (Lewiston, ME) with upgrading two existing 345 kV breakers, installing two new 345 kV breakers, and reterminate 64 line into 345 kV station	Dec-32	1
1961	Buxton - Upgrade Buxton substation (Buxton, ME) with additional 345 kV bay, upgrading 11 existing 345 kV breakers, installing two new 345 kV breakers, and terminate new B-D-ME 345 kV line into the station	Dec-32	1
1962	Albion Road - Upgrade Albion Road substation (Benton, ME) with upgrading two existing 345 kV breakers and installing one new 345 kV series breaker	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1963	Coopers Mills - Upgrade Coopers Mills substation (Windsor, ME) with additional 345 kV bay, installing five new 345 kV breakers, and terminate new P-C 345 kV line into the station	Dec-32	1
1964	South Gorham - Upgrade South Gorham substation (South Gorham, ME) with two new 345 kV breakers and uprates of existing T1 and T2 autotransformers	Dec-32	1
1965	Surowiec STATCOM - Install new 345 kV +/-400 MVAR STATCOM near Surowiec substation (Pownal, ME)	Dec-32	1
1966	Coopers Mills STATCOM - Install new 345 kV +/-400 MVAR STATCOM at Coopers Mills substation (Windsor, ME)	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1967	Old Ferry Road STATCOM - Install new 345 kV +/-400 MVAR STATCOM at Old Ferry Road substation (Wiscasset, ME)	Dec-32	1
1968	Pittsfield STATCOM - Install new 345 kV +/-400 MVAR STATCOM at Pittsfield substation (Pittsfield, ME)	Dec-32	1
1969	Woburn (Woburn, MA) - Construction, installation and interconnection of a 400 MVAR STATCOM	Dec-32	1
1970	New B-D-NH - New overhead 345 kV line from Deerfield substation (Deerfield, NH) to the NH/ME state line	Dec-32	1

Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1971	391-NH - Reconstruction of existing portion of the 345 kV 391 line between Deerfield substation (Deerfield, NH) and the NH/ME state line	Dec-32	1
1972	373 - Reconductoring of existing 345 kV 373 line between Deerfield substation (Deerfield, NH) and Scobie Pond substation (Londonderry, NH)	Dec-32	1
1973	N133 - Reconductoring of a portion of the existing 115 kV N133 line between Bolt Hill tap (Eliot, ME) and Three Rivers substation (Eliot, ME)	Dec-32	1
1974	Deerfield (Deerfield, NH) - Construction, installation and interconnection of two 400 MVAR STATCOMs; including new 345 kV bay, installing three new 345 kV breakers and upgrading four existing 345 kV breakers, and terminate the new B-D-NH line	Dec-32	1

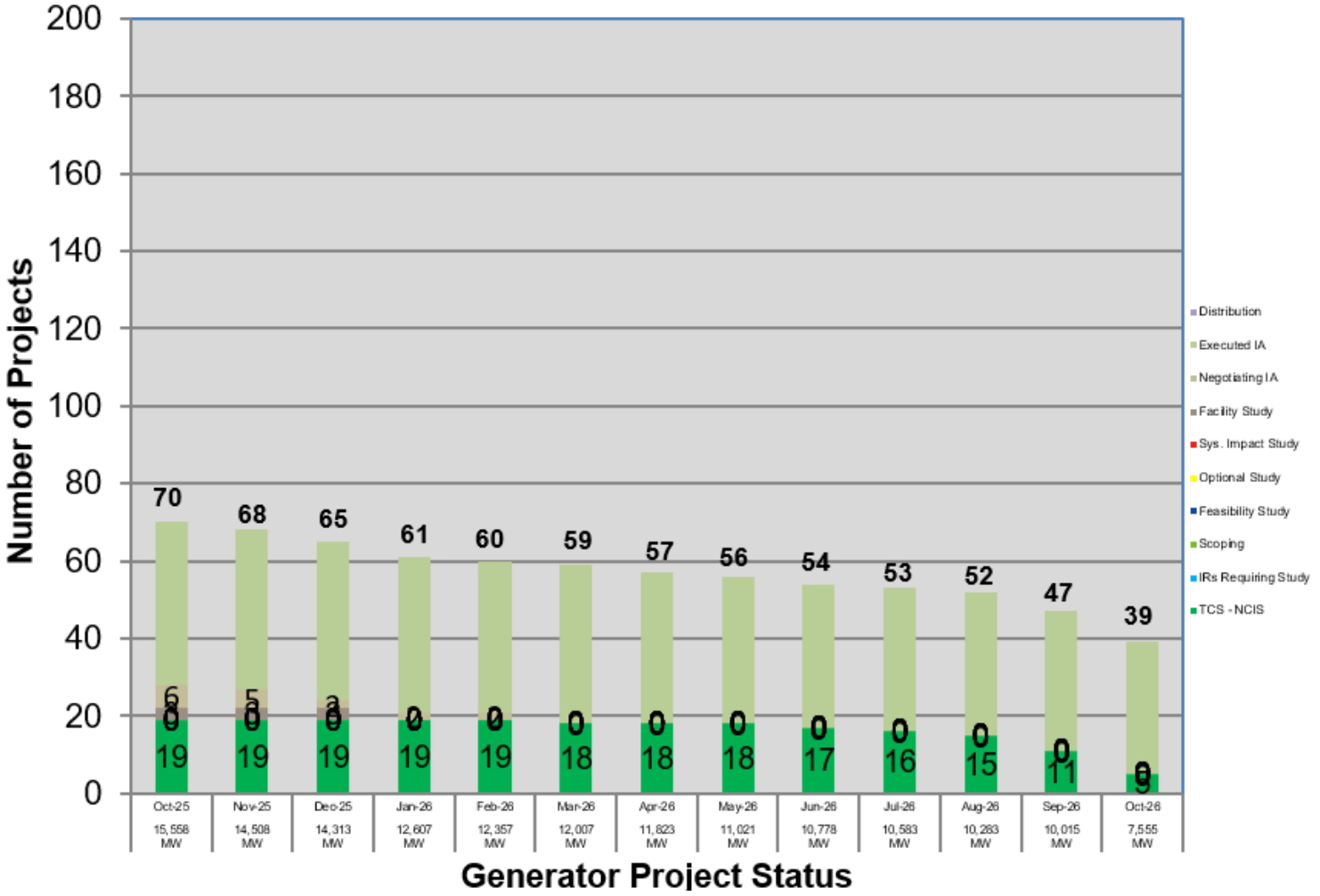
Transmission Initiative Down East (TIDE)

Status as of 10/26/2026

Project Benefit: Accommodates interconnection of 1,200 MW at Pittsfield, ME, and increases transfer capability on the ME-NH and Surowiec-South interfaces

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1975	Scobie Pond (Londonderry/Derry, NH) - Construction, installation and interconnection of a 400 MVAR STATCOM; including new 345 kV bay, installing two new 345 kV breakers, and upgrading four existing 345 kV breakers	Dec-32	1
1976	Three Rivers (Eliot, ME) - Termination of reconductored N133 line	Dec-32	1
1977	Upgrade of three existing 115 kV breakers at Orrington substation (Orrington, ME)	Dec-32	1

Status of Tariff Studies as of November 2, 2026



ETUs: 0 in TCS – NCIS, 0 Negotiating IA, and 1 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 November 2, 2026, cont.

- Additional Notes
  - The final Transitional Cluster Study Report was issued on August 6, 2026
  - The Cluster Request Window for the first regular Cluster Study opens on October 5, 2026 and will be open for 45 Calendar Days
  - The interconnection queue has been closed since June 13, 2024

OPERABLE CAPACITY ANALYSIS

Fall 2026 Analysis

Fall 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov - 2026[2] CSO (MW)	Nov - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,106	29,545
Active Demand Capacity Resource (+) [5]	340	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	334	334
Non Commercial Capacity (+)	16	16
Non Gas-fired Planned Outage MW (-)	3,859	4,668
Gas Generator Outages MW (-)	1,269	1,379
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,068	20,522
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,623	17,623
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,623	19,623
Operable Capacity Margin	-555	899

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 7, 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.

Fall 2026 Operable Capacity Analysis

90/10 Load Forecast	Nov - 2026[2] CSO (MW)	Nov - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,106	29,545
Active Demand Capacity Resource (+) [5]	340	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	334	334
Non Commercial Capacity (+)	16	16
Non Gas-fired Planned Outage MW (-)	3,859	4,668
Gas Generator Outages MW (-)	1,269	1,379
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,068	20,522
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,461	18,461
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,461	20,461
Operable Capacity Margin	-1,393	61

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 7, 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.

Fall 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 November.

Report created: 10/23/2026

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
11/7/2026	27106	340	334	16	3859	1269	3600	0	19068	17623	2000	19623	-555	Y	Fall 2026
11/14/2026	27106	340	334	16	3168	1280	3600	0	19748	17941	2000	19941	-193	N	Fall 2026
11/21/2026	27106	340	334	16	676	0	3600	1370	22150	18621	2000	20621	1529	N	Fall 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: 110% 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. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

15. Operable Capacity Season Label: Applicable season and year.

Fall 2026 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 November.

Report created: 10/23/2026

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
11/7/2026	27106	340	334	16	3859	1269	3600	0	19068	18461	2000	20461	-1393	Y	Fall 2026
11/14/2026	27106	340	334	16	3168	1280	3600	0	19748	18794	2000	20794	-1046	N	Fall 2026
11/21/2026	27106	340	334	16	676	0	3600	1535	21985	19506	2000	21506	479	N	Fall 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: 110% 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. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.
15. Operable Capacity Season Label: Applicable season and year.

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

OPERABLE CAPACITY ANALYSIS

Winter 2026/27 Analysis

Winter 2026/27 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2027[2] CSO (MW)	Jan - 2027[2] SCC (MW)
Operable Capacity MW [1]	27,429	29,545
Active Demand Capacity Resource (+) [5]	348	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	98	98
Non Gas-fired Planned Outage MW (-)	598	931
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,728	4,136
Net Capacity (NET OPCAP SUPPLY MW)	21,158	22,459
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,483	20,483
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,483	22,483
Operable Capacity Margin	-1,325	-24

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 9, 2027.**

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

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

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

Winter 2026/27 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2027[2] CSO (MW)	Jan - 2027[2] SCC (MW)
Operable Capacity MW [1]	27,429	29,545
Active Demand Capacity Resource (+) [5]	348	274
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	409	409
Non Commercial Capacity (+)	98	98
Non Gas-fired Planned Outage MW (-)	598	931
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,539	5,066
Net Capacity (NET OPCAP SUPPLY MW)	20,347	21,529
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,457	21,457
Operating Reserve Requirement MW	2,000	2,000
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,457	23,457
Operable Capacity Margin	-3,110	-1,928

[1]Operable Capacity is based on data as of **October 23, 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 **October 23, 2026.**

[2] Load forecast that is based on the 2026 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 9, 2027.**

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

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

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

Winter 2026/27 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 December through March.

Report created: 10/23/2026

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
11/28/2026	27106	340	334	16	482	0	3600	1662	22052	19285	2000	21285	767	N	Winter 2026/2027
12/5/2026	27578	348	261	97	760	822	3200	982	22520	19469	2000	21469	1051	N	Winter 2026/2027
12/12/2026	27578	348	261	97	851	0	3200	2368	21865	19735	2000	21735	130	N	Winter 2026/2027
12/19/2026	27578	348	261	97	648	0	3200	2745	21691	19746	2000	21746	-55	N	Winter 2026/2027
12/26/2026	27578	348	261	97	607	0	3200	3134	21343	19803	2000	21803	-460	N	Winter 2026/2027
1/2/2027	27429	348	409	98	598	0	2800	3733	21153	20055	2000	22055	-902	N	Winter 2026/2027
1/9/2027	27429	348	409	98	598	0	2800	3728	21158	20483	2000	22483	-1325	Y	Winter 2026/2027
1/16/2027	27429	348	409	98	599	0	2800	3583	21302	20483	2000	22483	-1181	N	Winter 2026/2027
1/23/2027	27429	348	409	98	599	0	2800	3134	21751	20483	2000	22483	-732	N	Winter 2026/2027
1/30/2027	27429	348	409	98	359	0	3100	2835	21990	20278	2000	22278	-288	N	Winter 2026/2027
2/6/2027	27429	348	409	98	349	0	3100	2536	22299	20032	2000	22032	267	N	Winter 2026/2027
2/13/2027	27429	348	409	98	406	0	3100	2237	22541	20006	2000	22006	535	N	Winter 2026/2027
2/20/2027	27429	348	409	98	379	0	3100	1788	23017	19764	2000	21764	1253	N	Winter 2026/2027
2/27/2027	27429	348	409	98	765	263	2200	1226	23830	18854	2000	20854	2976	N	Winter 2026/2027
3/6/2027	27429	348	409	98	780	906	2200	0	24398	18533	2000	20533	3865	N	Winter 2026/2027
3/13/2027	27429	348	409	98	1286	600	2200	0	24198	18353	2000	20353	3845	N	Winter 2026/2027
3/20/2027	27429	348	409	98	1268	794	2200	0	24022	18017	2000	20017	4005	N	Winter 2026/2027
3/27/2027	27213	349	409	98	1741	693	2700	0	22935	17496	2000	19496	3439	N	Winter 2026/2027

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: 110% 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. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

15. Operable Capacity Season Label: Applicable season and year.

Winter 2026/27 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 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 December through March.

Report created: 10/23/2026

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
11/28/2026	27106	340	334	16	482	0	3600	2576	21138	20201	2000	22201	-1063	N	Winter 2026/2027
12/5/2026	27578	348	261	97	760	822	3200	1970	21532	20394	2000	22394	-862	N	Winter 2026/2027
12/12/2026	27578	348	261	97	851	0	3200	3355	20878	20673	2000	22673	-1795	N	Winter 2026/2027
12/19/2026	27578	348	261	97	648	0	3200	3864	20572	20684	2000	22684	-2112	N	Winter 2026/2027
12/26/2026	27578	348	261	97	607	0	3200	4280	20197	20744	2000	22744	-2547	N	Winter 2026/2027
1/2/2027	27429	348	409	98	598	0	2800	4408	20478	21008	2000	23008	-2530	N	Winter 2026/2027
1/9/2027	27429	348	409	98	598	0	2800	4539	20347	21457	2000	23457	-3110	Y	Winter 2026/2027
1/16/2027	27429	348	409	98	599	0	2800	4331	20554	21457	2000	23457	-2903	N	Winter 2026/2027
1/23/2027	27429	348	409	98	599	0	2800	4032	20853	21457	2000	23457	-2604	N	Winter 2026/2027
1/30/2027	27429	348	409	98	359	0	3100	4032	20793	21242	2000	23242	-2449	N	Winter 2026/2027
2/6/2027	27429	348	409	98	349	0	3100	3583	21252	20984	2000	22984	-1732	N	Winter 2026/2027
2/13/2027	27429	348	409	98	406	0	3100	3284	21494	20957	2000	22957	-1463	N	Winter 2026/2027
2/20/2027	27429	348	409	98	379	0	3100	2686	22119	20703	2000	22703	-584	N	Winter 2026/2027
2/27/2027	27429	348	409	98	765	263	2200	1974	23082	19751	2000	21751	1331	N	Winter 2026/2027
3/6/2027	27429	348	409	98	780	906	2200	405	23993	19414	2000	21414	2579	N	Winter 2026/2027
3/13/2027	27429	348	409	98	1286	600	2200	606	23592	19225	2000	21225	2367	N	Winter 2026/2027
3/20/2027	27429	348	409	98	1268	794	2200	0	24022	18873	2000	20873	3149	N	Winter 2026/2027
3/27/2027	27213	349	409	98	1741	693	2700	0	22935	18328	2000	20328	2607	N	Winter 2026/2027

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: 110% 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. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.
15. Operable Capacity Season Label: Applicable season and year.

***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