FEBRUARY 5, 2026| COLONNADE HOTEL, BOSTON

NEPOOL PARTICIPANTS COMMITTEE | 2/5/2026
Meeting Agenda Item #4

NEPOOL Participants Committee

System & Market Operations Report – February 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS

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HIGHLIGHTS

Highlights: January 2026

Settled data through January 28th

- **Peak Hour** on January 25
  - 20,221 MW system peak (Revenue Quality Metered/RQM); hour ending 2:00 P.M.
- **Minimum Telemetered Load**
  - 10,808 MW; hour ending 4:00 A.M. on Saturday, January 10
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $165.45/MWh
  - Real-Time (RT) Hub LMP: $142.78/MWh
  - Natural Gas: $22.71/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $2.3B up from $1.6B in January 2025
  - Ancillary Markets* value $86.9M up from $6.6M in January 2025
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 99.9% during January, same as December 2025
  - Updated December Energy Market value: $1.8B
- **Net Commitment Period Compensation (NCPC)** total $5.1M
  - Represents 0.2% of monthly Energy Market value
  - First Contingency $5.1M
    - Dispatch Lost Opportunity Cost (DLOC) - $1.2M; Rapid Response Pricing (RRP) Opportunity Cost - $522K; Posturing - $0; Generator Performance Auditing (GPA) - $17K
    - $112K paid to resources at external locations, down $505K from December
      - $0 charged to Day-Ahead Load Obligation (DALO) at external locations; $<1K to Day-Ahead Generation Obligation (DAGO) at external locations; $112K to RT Deviations
  - Second Contingency $8K
  - Distribution and Voltage were zero
- **Forward Capacity Market (FCM)** market value $88.9M
  - FCM peak for 2026 is currently 19,937 MWh
- The New England Energy Connect (NECEC) line achieved commercial operation on Friday, January 16

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

*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund

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

Highlights: January 2026 (Continued)

- A maximum DA natural gas price (MA average) of **~$122/MMBtu** was observed on Tue. January 27, a **new record since SMD** go-live
  - Prior record was ~$82/MMBtu on January 23, 2014
- Monthly Energy Market Value totals **$2.3B** (thru January 28), already making it the **highest monthly** value since SMD go-live
  - Prior record: $2.2B (Jan 2014)
  - Final monthly value projected to be ~**$2.6-$2.7B (estimated)**
- Daily Energy Market Value also set records:
  - Four days (January 25-28) exceeded the prior daily record
  - Highest Daily value: $**422M** (January 27)
    - Prior daily record: ~$170M set on January 23, 2014
- January 2026 average input fuel prices and LMPs were lower than those of January 2014, but DA loads were relatively higher

Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **20,182 MW**
  - hour ending 2:00 P.M. on Sunday, January 25
- RQM System Peak Load: **20,221 MW** (initial)
  - hour ending 2:00 P.M. on Sunday, January 25
- FCM Peak Load: **19,937 MW** (preliminary & subject to change)
  - hour ending 1:00 P.M. on Sunday, January 25
  - At this hour, the capacity zone-level FCM peak loads were 2,814 MW in Northern New England, 1,832 MW in Maine, 7,535 MW in Rest-of-Pool, and 7,756 MW in Southeast New England.

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

Day-Ahead Ancillary Services (DAAS) Results

- Average daily total DA E&AS Market value: **$85.4M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$4.64M**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$56.71/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **3.9%**
- FER Credits* as % of total DA E&AS Market Value: **15.0%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **118 MWh**
  - Average hourly cleared FER Price: **$31.33/MWh**

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

DAAS Results (continued)...

Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
3/1/2025	$17.3M	$466K	$202K	$3.35	1.2%	$982K	177K	$3.26	6.2%	176
4/1/2025	$13.9M	$332K	$175K	$3.23	1.3%	$760K	128K	$2.66	5.8%	97
5/1/2025	$11.0M	$190K	$52K	$0.94	0.5%	$563K	164K	$2.06	5.2%	155
6/1/2025	$20.2M	$885K	$173K	$2.97	0.9%	$1,287K	156K	$3.15	6.6%	125
7/1/2025	$35.8M	$1,704K	$1,139K	$19.53	3.2%	$1,277K	97K	$3.06	3.7%	55
8/1/2025	$20.2M	$747K	$544K	$9.57	2.7%	$1,292K	143K	$3.02	6.4%	94
9/1/2025	$12.3M	$320K	$184K	$3.21	1.5%	$587K	134K	$1.94	4.8%	104
10/1/2025	$15.5M	$719K	$478K	$8.21	3.1%	$1,911K	203K	$6.50	12.3%	209
11/1/2025	$24.7M	$1,122K	$457K	$7.85	1.9%	$2,546K	211K	$7.99	10.3%	135
12/1/2025	$60.9M	$2,130K	$1,053K	$18.20	1.7%	$4,916K	221K	$13.42	8.1%	107
1/1/2026	$85.4M	$4,641K	$3,296K	$56.71	3.9%	$12,762K	196K	$31.33	15.0%	118

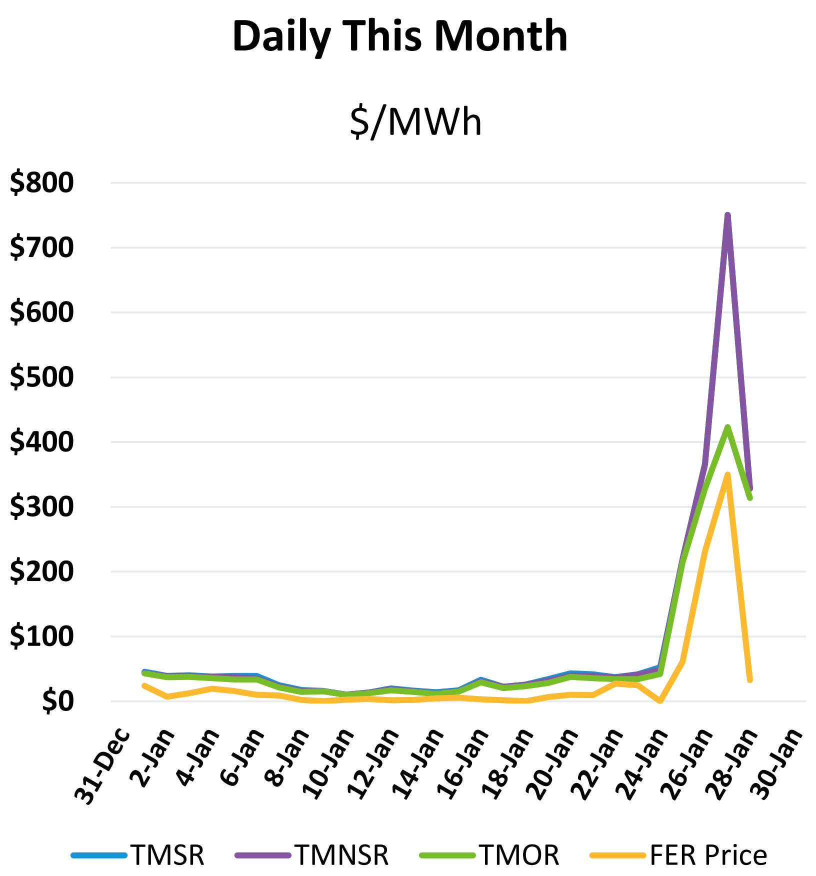
About the Table:

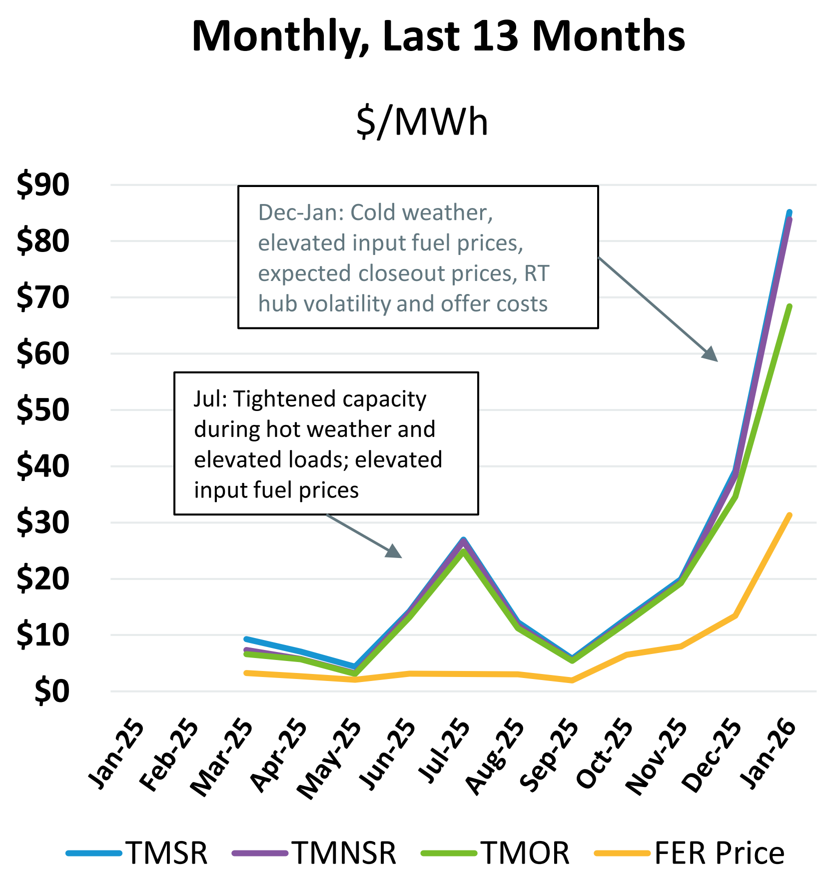
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with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

Additionally:

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

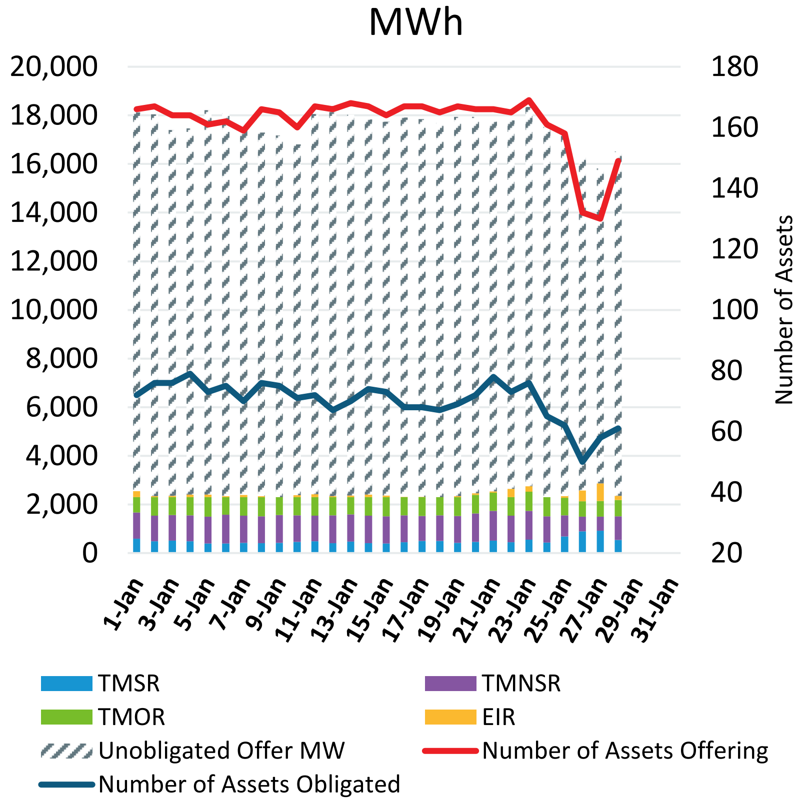
Average Hourly DAAS Prices



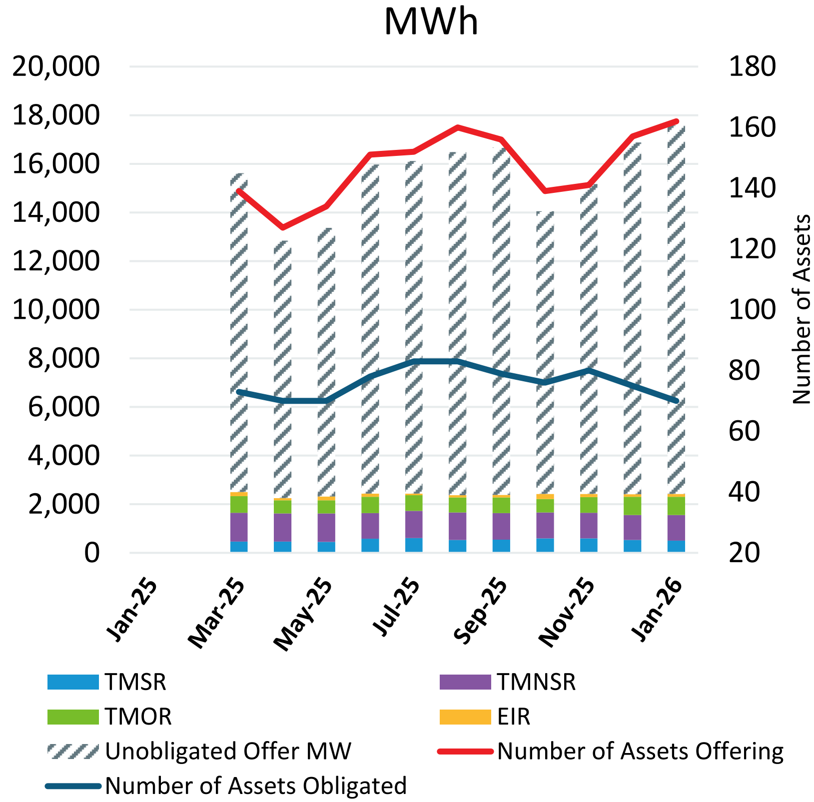


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



Monthly, Last 13 Months



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

System Planning Highlights

- The ISO is evaluating all LTTP RFP submissions and expects to provide an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) at the February Planning Advisory Committee meeting
- The ISO began discussions of the permanent asset condition reviewer function at the January Transmission Committee
- The 2026 Economic Study was launched in January

Forward Capacity Market (FCM) Highlights

- CCP 16 (2025-2026)
  - The third annual reconfiguration auction (ARA3) was held March 3-5, 2025 and results were posted on April 1, 2025
- CCP 17 (2026-2027)
  - The ISO filed the ICR and related values with FERC, for the ARA3 to be conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.
  - The third annual reconfiguration auction (ARA3) will be held March 2-4, 2026
- CCP 18 (2027-2028)
  - The first annual reconfiguration auction (ARA1) was held June 2-4, 2025 and results were posted on July 2, 2025
  - The ISO filed the ICR and related values with FERC, for the ARA2 to be conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.

CCP – Capacity Commitment Period

FCM Highlights, cont.

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

Load Forecast

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

WINTER WEATHER OPERATIONS SUMMARY

January 24 – February 1, 2026

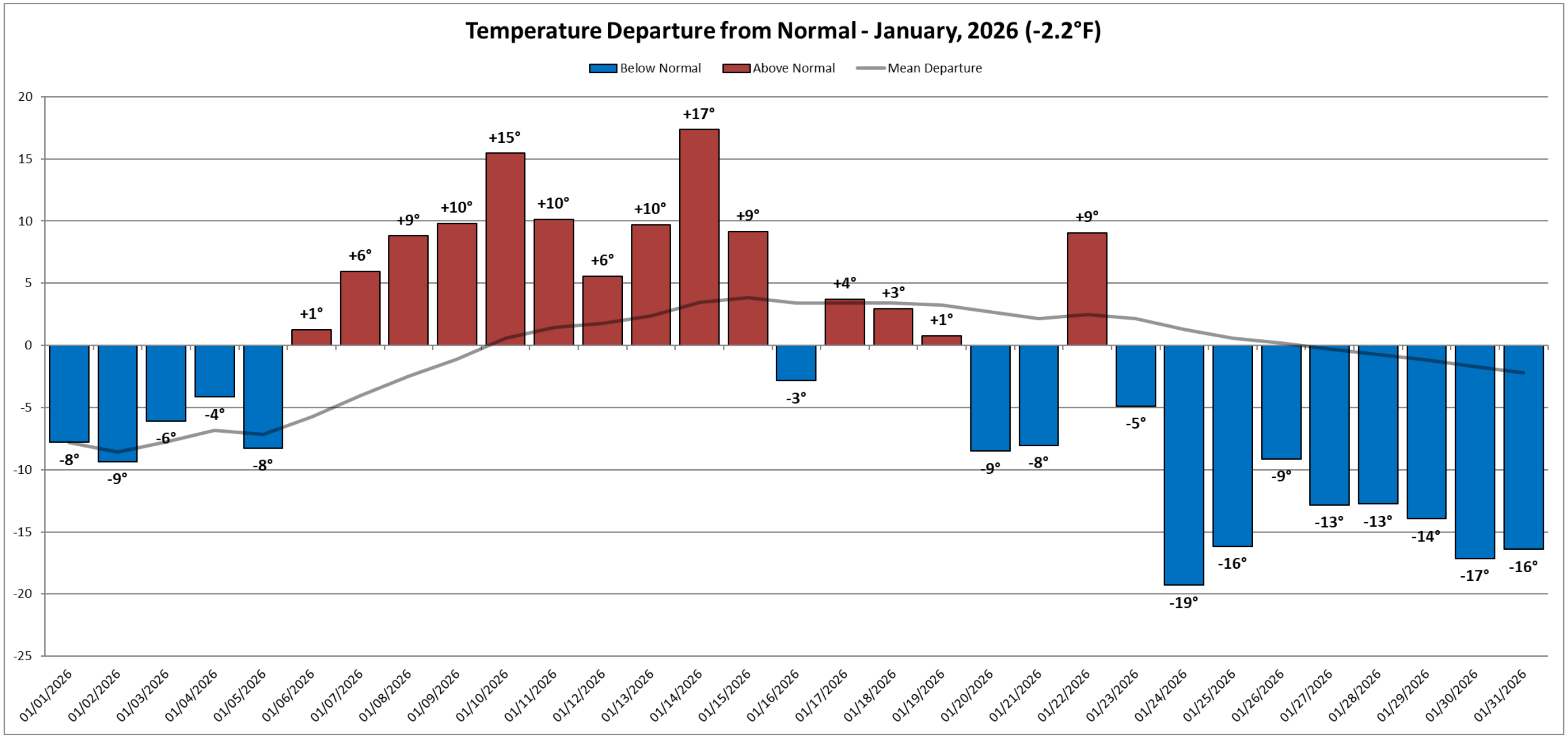
Highlights

- Prolonged cold weather impacted the region beginning on Jan. 24; cold temperatures have been severe at times and have led to the most challenging winter conditions since 2017/18
  - Demand has been elevated, both in terms of peak and overall use
  - Natural gas prices reached record highs, making oil more economical
  - Fuel oil supplies have been reduced significantly; some replenishment has occurred, and more is expected in the coming weeks
- Significant snowfall from Winter Storm Fern had impacts on resources, fuel deliveries
  - Solar production dropped during storm and stayed at low levels in the following days
  - Wide reach of the storm affected fuel delivery logistics across the East Coast
  - Ahead of the storm, ISO implemented M/LCC-2, Abnormal Conditions Alert, due to the expected severe weather
- Neighboring areas also experienced challenging conditions
  - Imports were reduced during coldest periods and increased demand for natural gas nationally drove prices higher

Highlights, cont.

- Significant fuel oil burn at dual fuel generating facilities contributed to a high demand for demineralized water trucks which were in short supply
- As a preventative measure, on Jan. 25, ISO submitted a request to the U.S. Department of Energy (DOE) for an order pursuant to Section 202(c) of the Federal Power Act
  - The DOE issued an order granting the ISO's request which allowed the ISO to maximize the availability of all the generating resources in the New England region
  - On Jan. 30, ISO sought and received an extension of the waiver through Feb. 14 due to the forecasted cold conditions in the weeks ahead
- Beginning Jan. 27, to enhance regional situational awareness of energy supplies, ISO began daily fuel surveys of applicable generators in the region and daily publication of the 21-Day Energy Assessment and Forecast Report
- ISO is forecasting continued cold weather across the region including this coming weekend, Feb. 7 – Feb. 9; continued replenishment of fuel oil supplies in the coming weeks remains critical

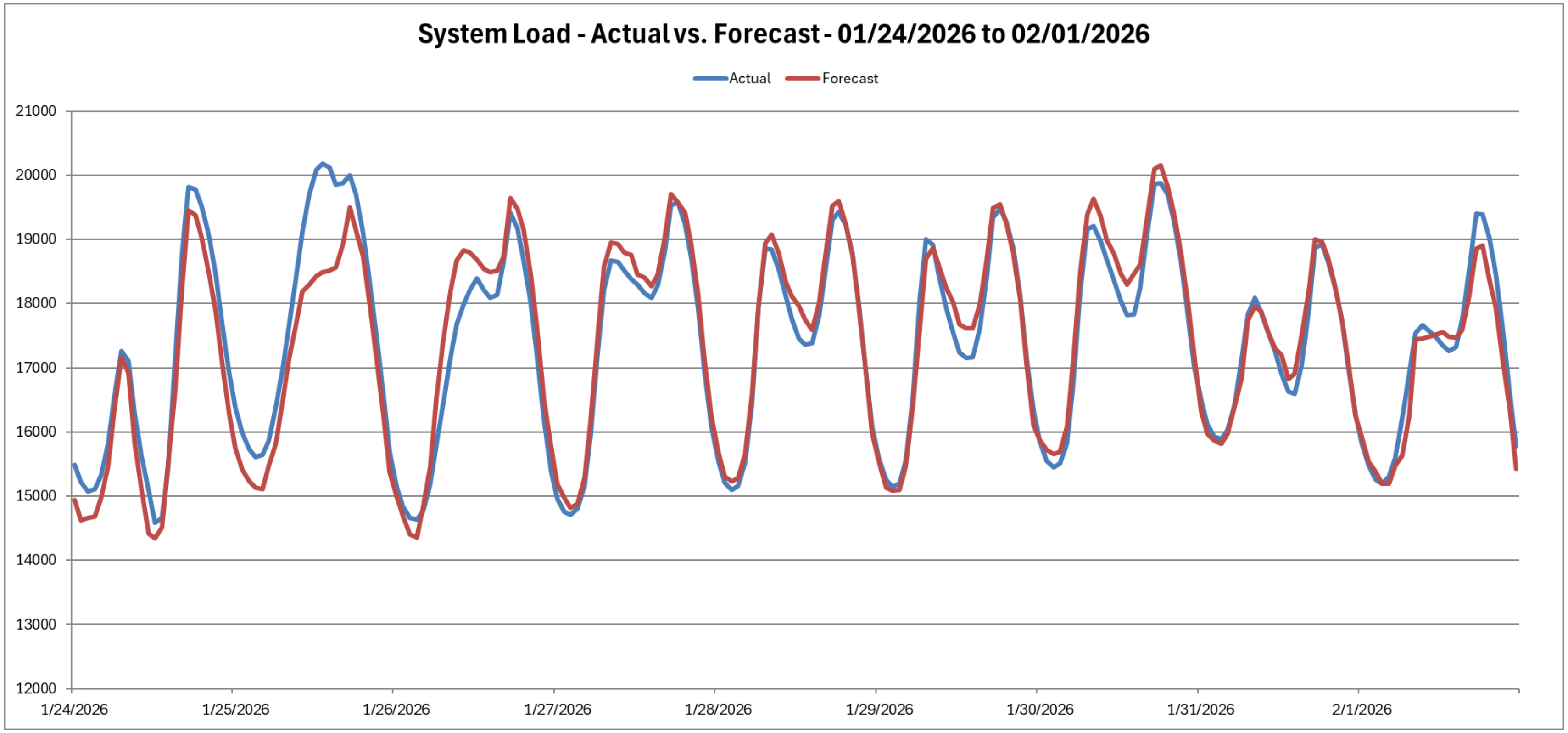
Temperatures Averaged ~14°F Below Normal During the Last 9 Days of Jan. and -2.2°F For the Month



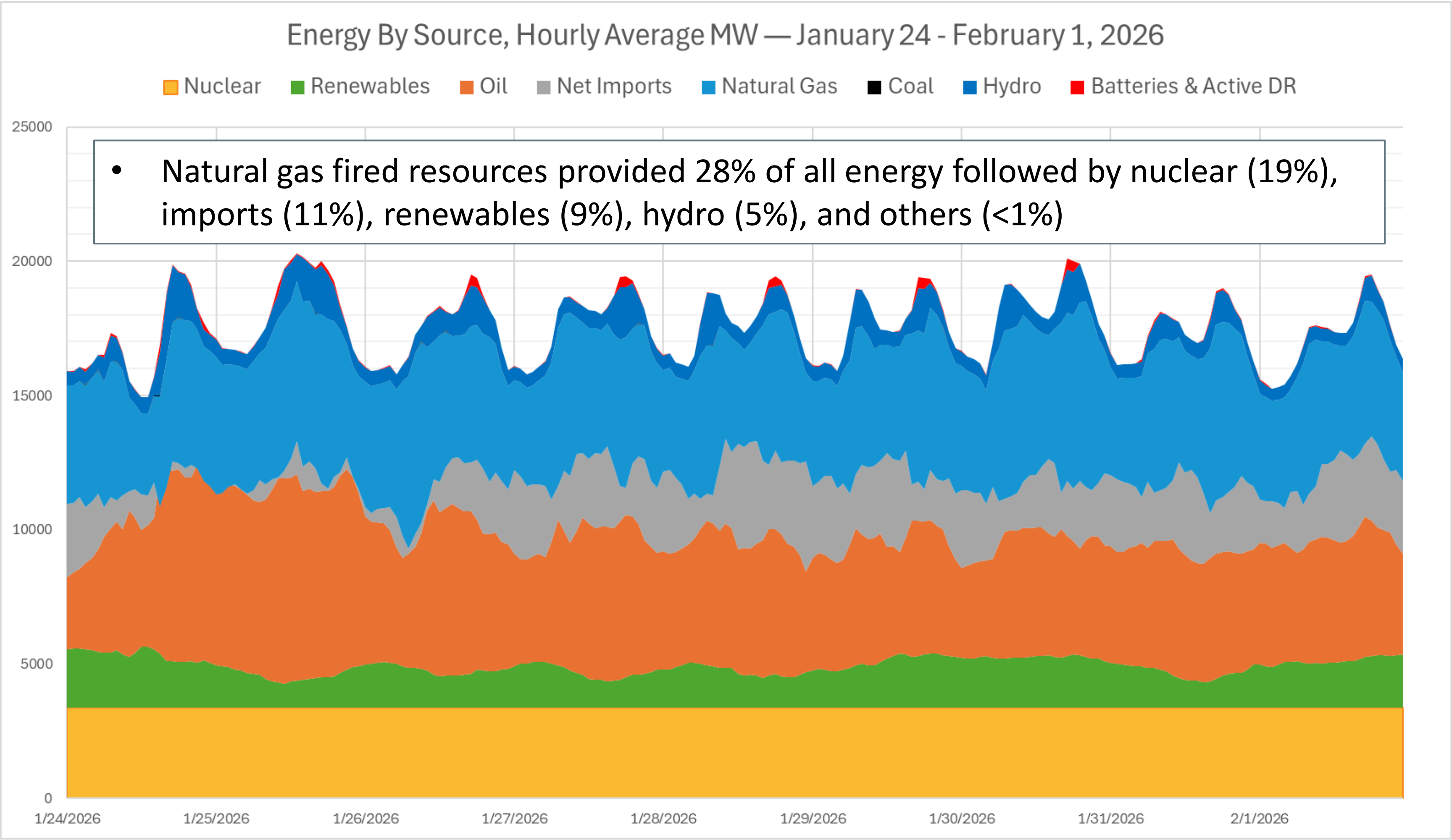
*Temperatures in the figure above are based on a New England 23-city weighted avg.

Extreme Cold Temperatures Led to Consistently High Peaks from Jan. 24 – Feb. 1; Load Peaked at 20,182 MW on Jan. 25

- For the first time since Winter 2017/2018 (Dec. 27, 2017 – Jan. 8, 2018), system load peaked at 18,900 MW or higher on nine consecutive days (*see* below)
- ISO's load forecast was highly accurate, averaging 1.40% peak forecast error across these nine days

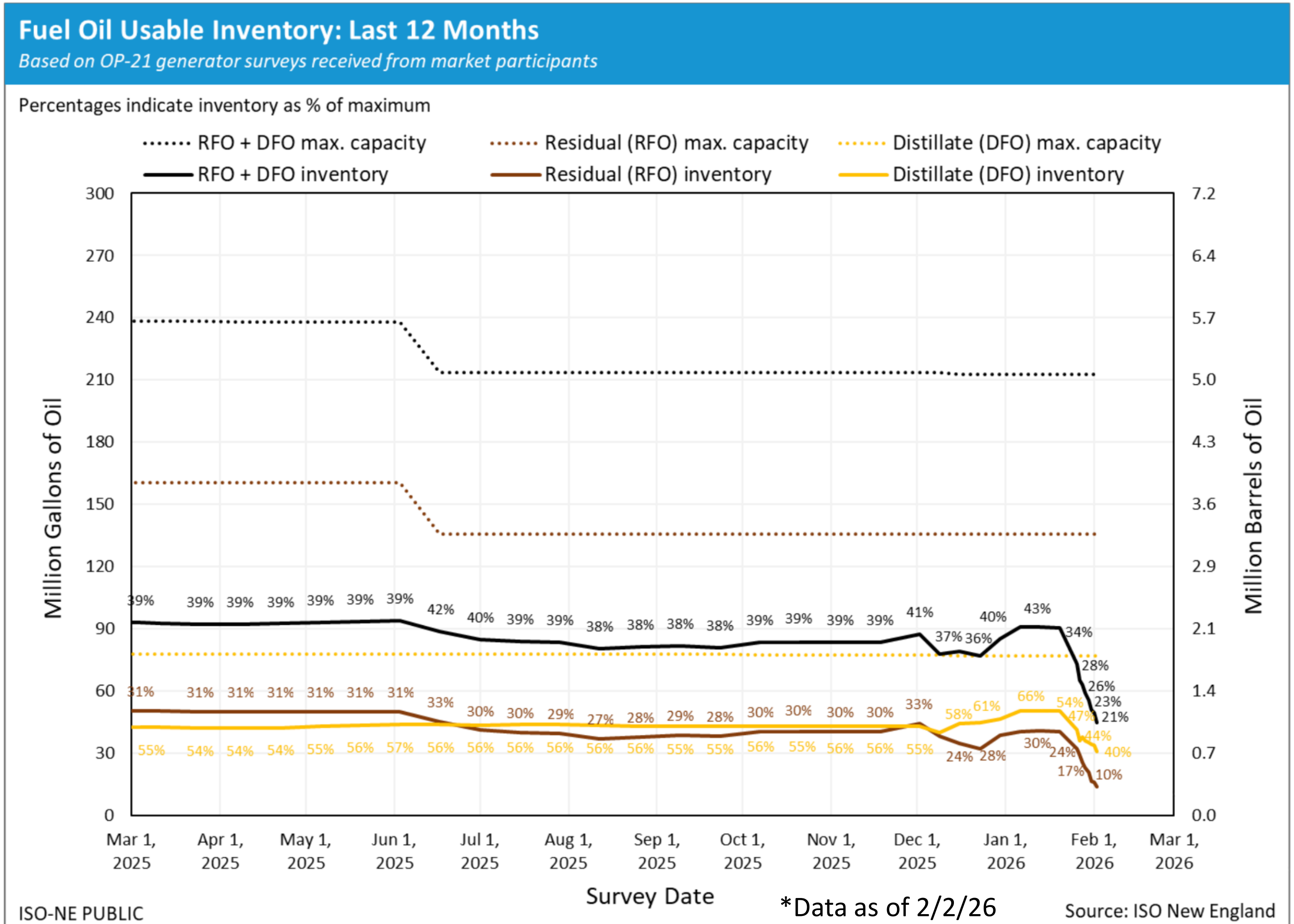


Energy From Oil-Fired Resources Accounted for ~28% of All Energy From Jan. 24 Through Feb. 1



- Natural gas fired resources provided 28% of all energy followed by nuclear (19%), imports (11%), renewables (9%), hydro (5%), and others (<1%)

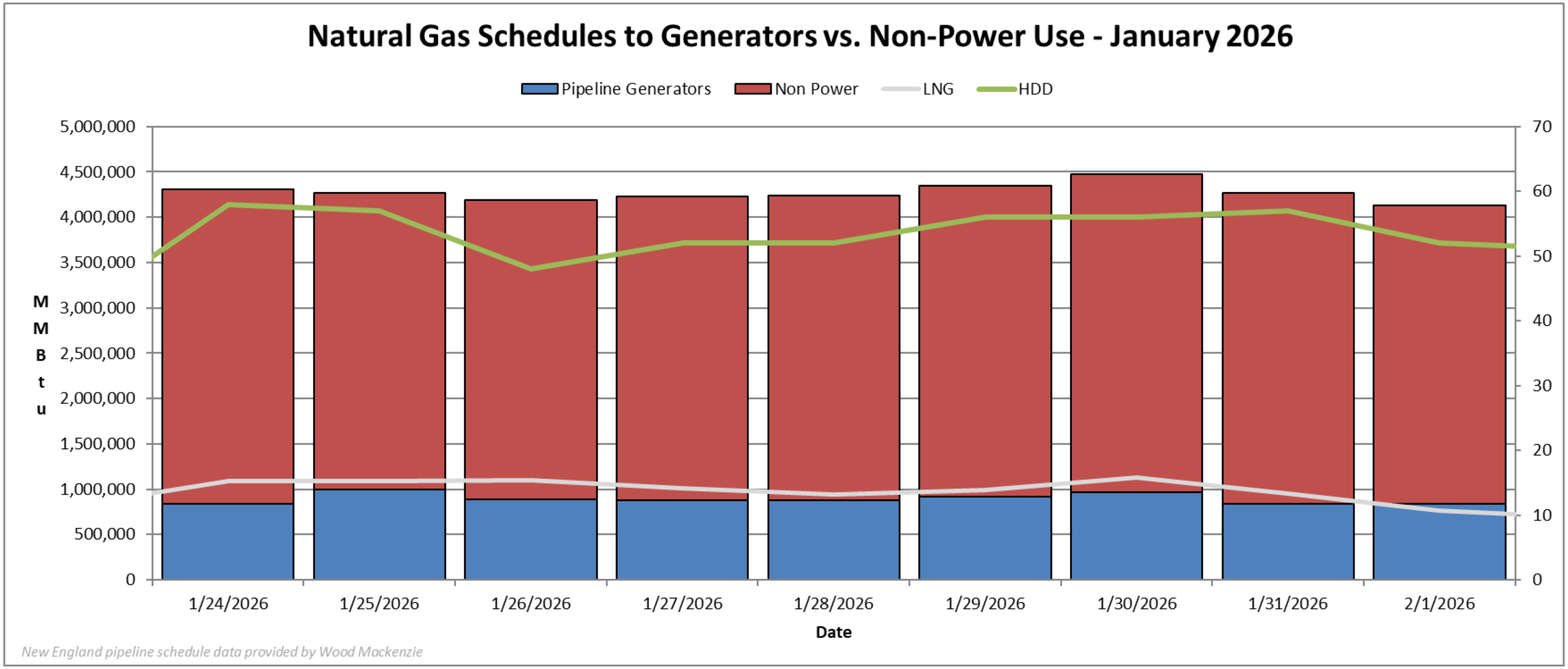
Fuel Oil Inventory Has Steadily Declined Since the Start of the Extreme Cold Weather



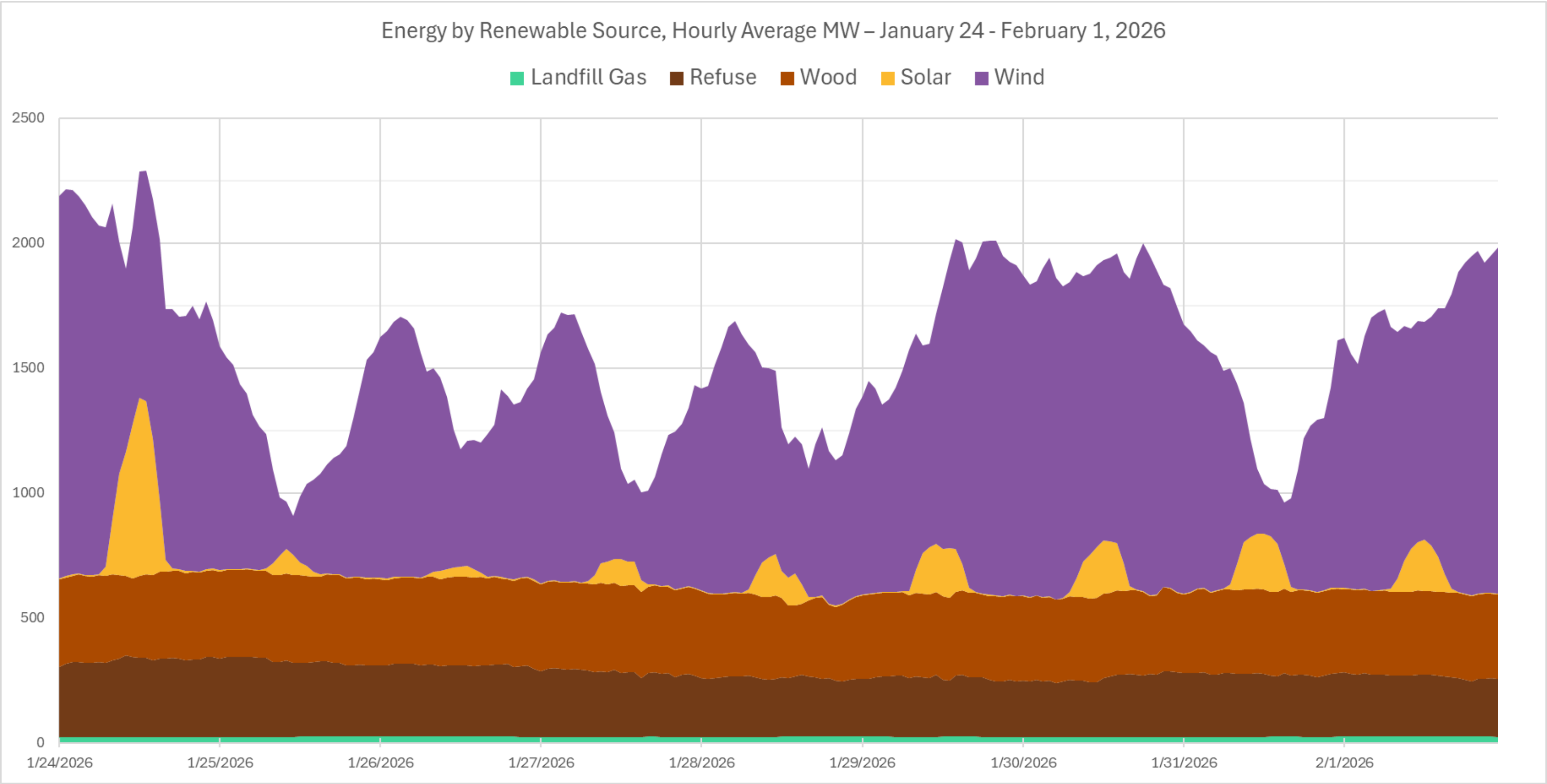
Fuel Oil Utilization and Replenishment

- Total fuel oil burn for the time period of Jan. 24 through Feb. 1 was ~66M gallons
  - ~24.5 million of RFO; ~41.5 million of DFO was burned during this time period, as reported in fuel surveys
  - This quantity exceeds the oil burn from each of the last four winter seasons (Dec., Jan., Feb.) by over 15 million gallons
- Fuel oil stations have replenished ~25M gallons with another ~26M gallons expected prior to Feb. 9

LNG Vaporization To the Pipelines Was ~9 Bcf, averaging ~1 Bcf/d

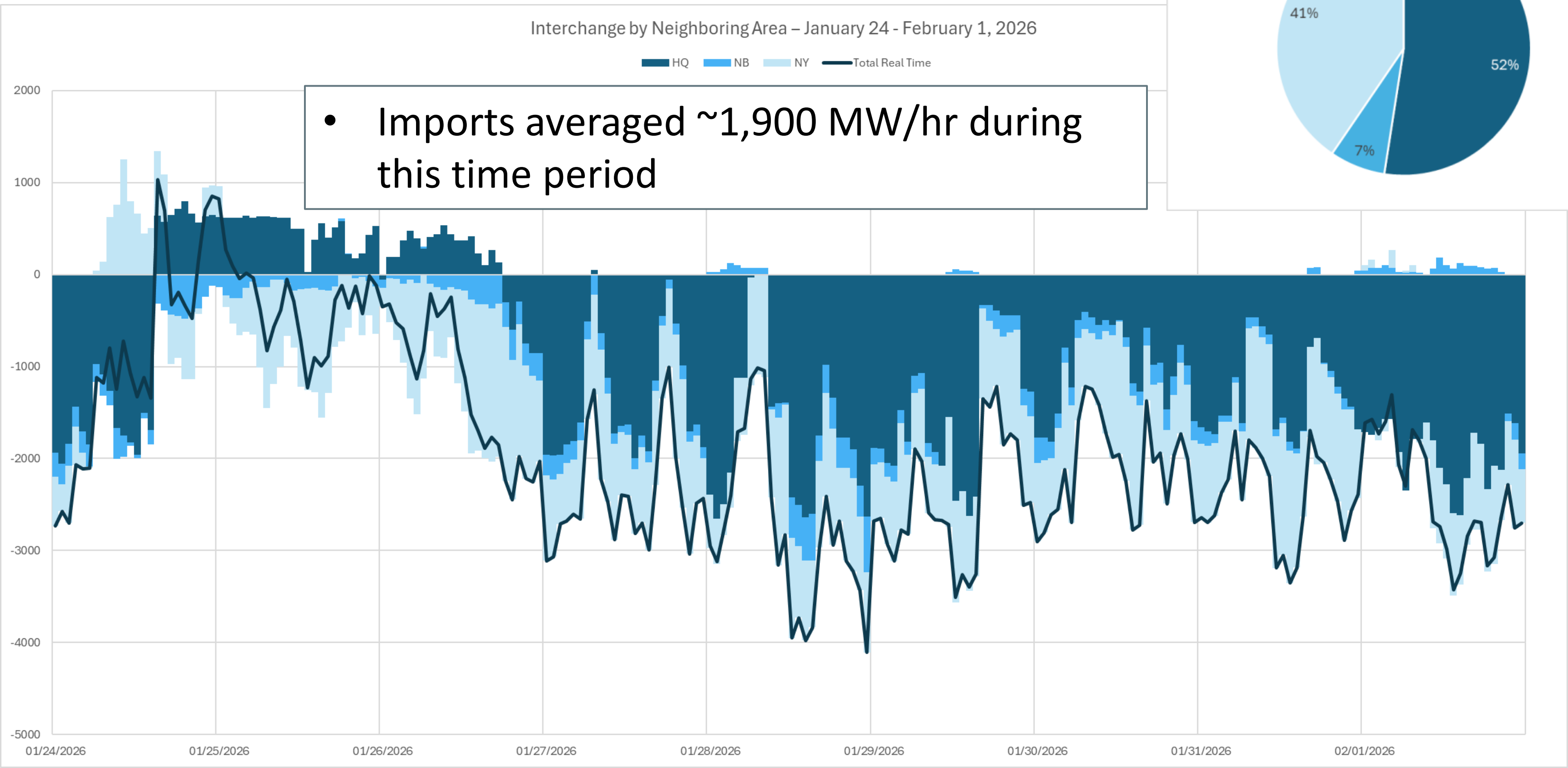


Jan. 25 Snowfall Significantly Impacted PV Availability in the Following Days; On Average, Wind Resources Generated ~885 MW/hr

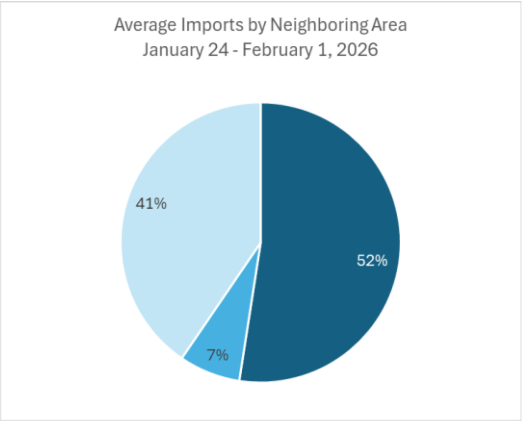


*Note that Solar PV data on this slide is reflective of only utility-scale resources

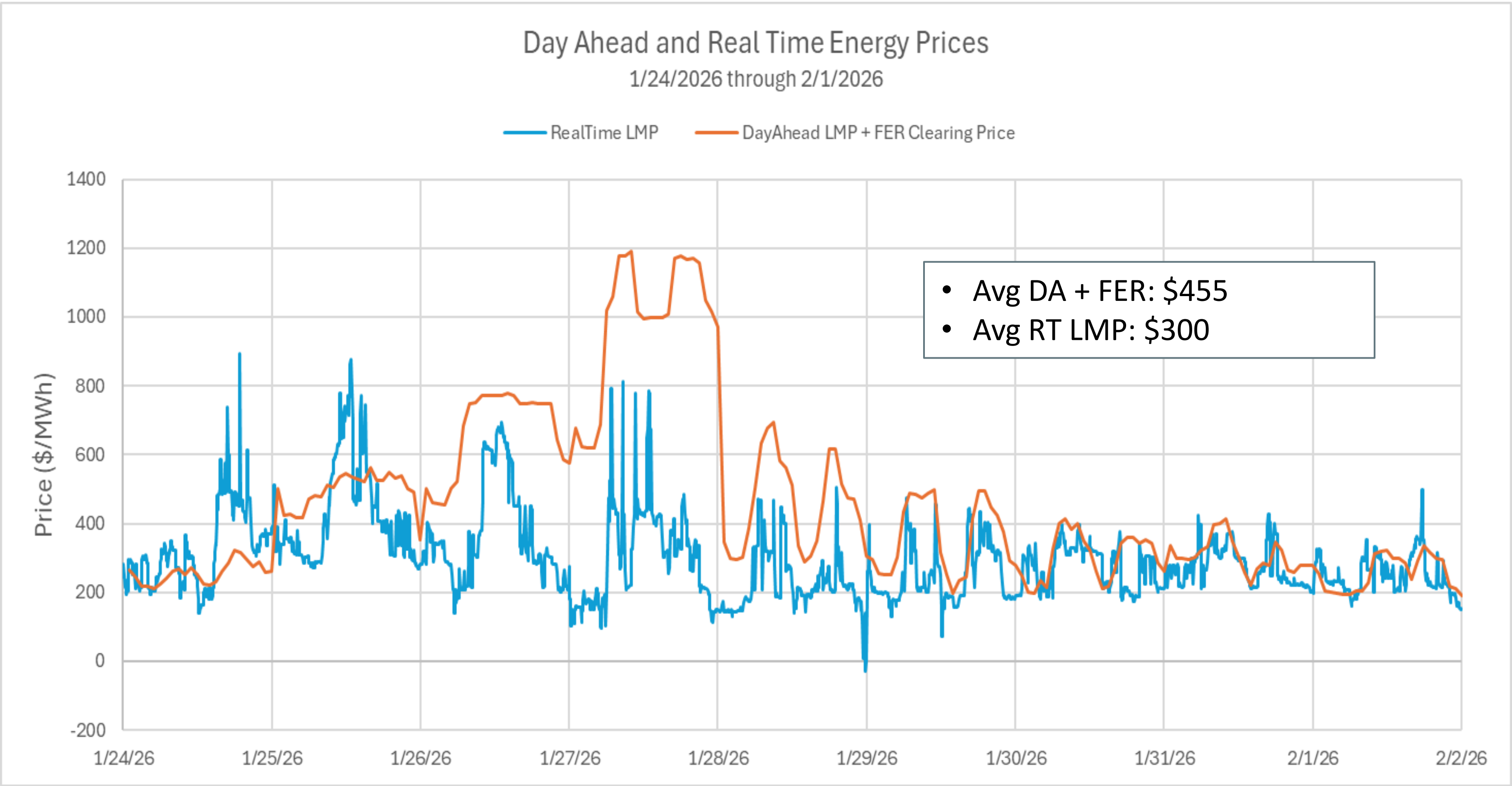
Net Interchange Decreased Notably Beginning on Jan. 24 As Neighboring Areas Managed High Peak Loads



- Imports averaged ~1,900 MW/hr during this time period



Day Ahead and Real Time Prices



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-1.9°F) Max: 53°F, Min: 5°F Precipitation: 2.21” – Below Normal Normal: 3.39” Snow: 29.8”	Hartford	Temperature: Below Normal (-3.1°F) Max: 49°F, Min: -7°F Precipitation: 2.94” - Below Normal Normal: 3.28” Snow: 26.9”

Peak Load:	20,182 MW	January 25, 2026	14:00 (ending)
Mid-Day Minimum Load - Month:	11,307 MW	January 13, 2026	12:00 (ending)
Mid-Day Minimum Load - Historical:	5,318 MW	April 20, 2025	14:00 (ending)

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

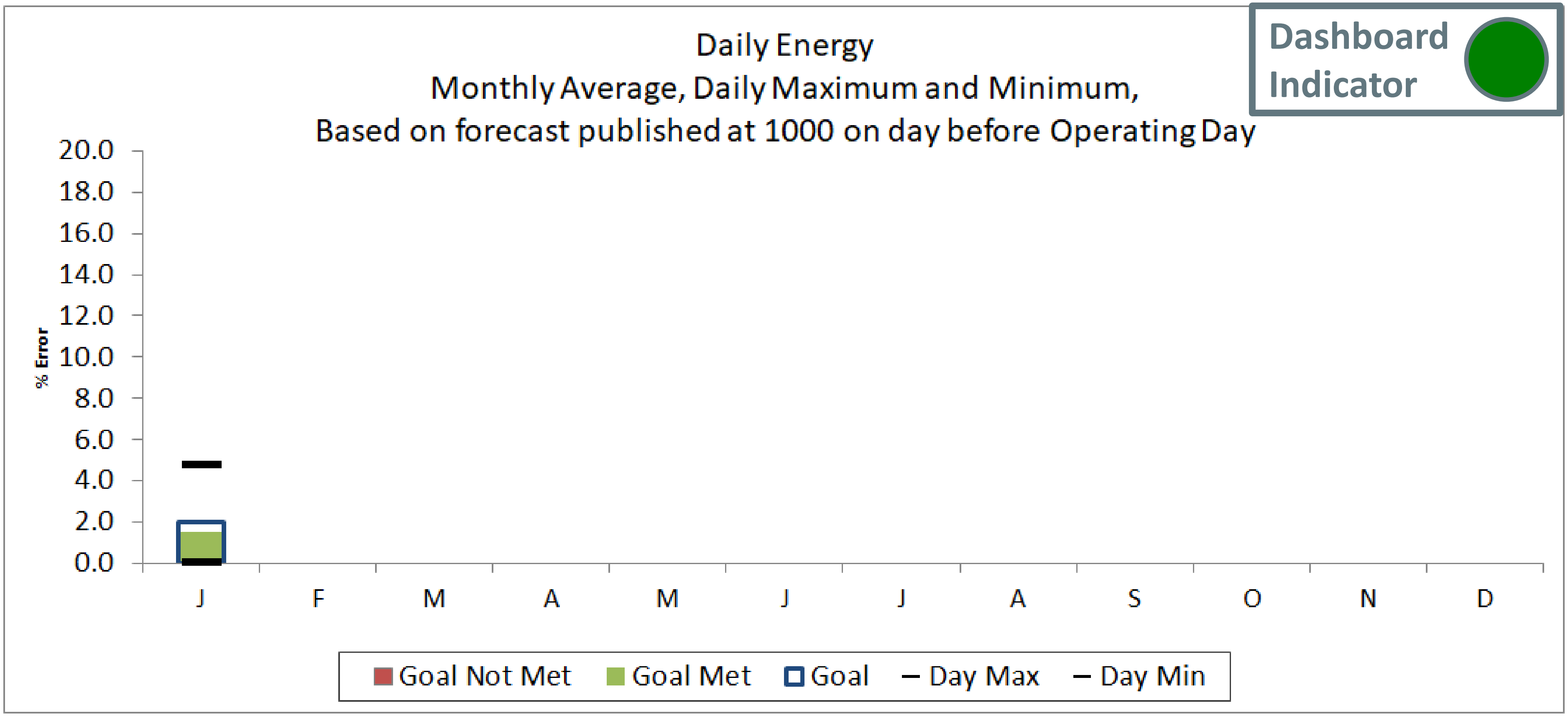
Procedure	Declared	Cancelled	Note
M/LCC 2	01/25/2026 09:00		Severe Weather

System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
01/06/2026	NYISO	550
01/24/2026	IESO	729
01/25/2026	ISONE	500
01/26/2026	NYISO	630

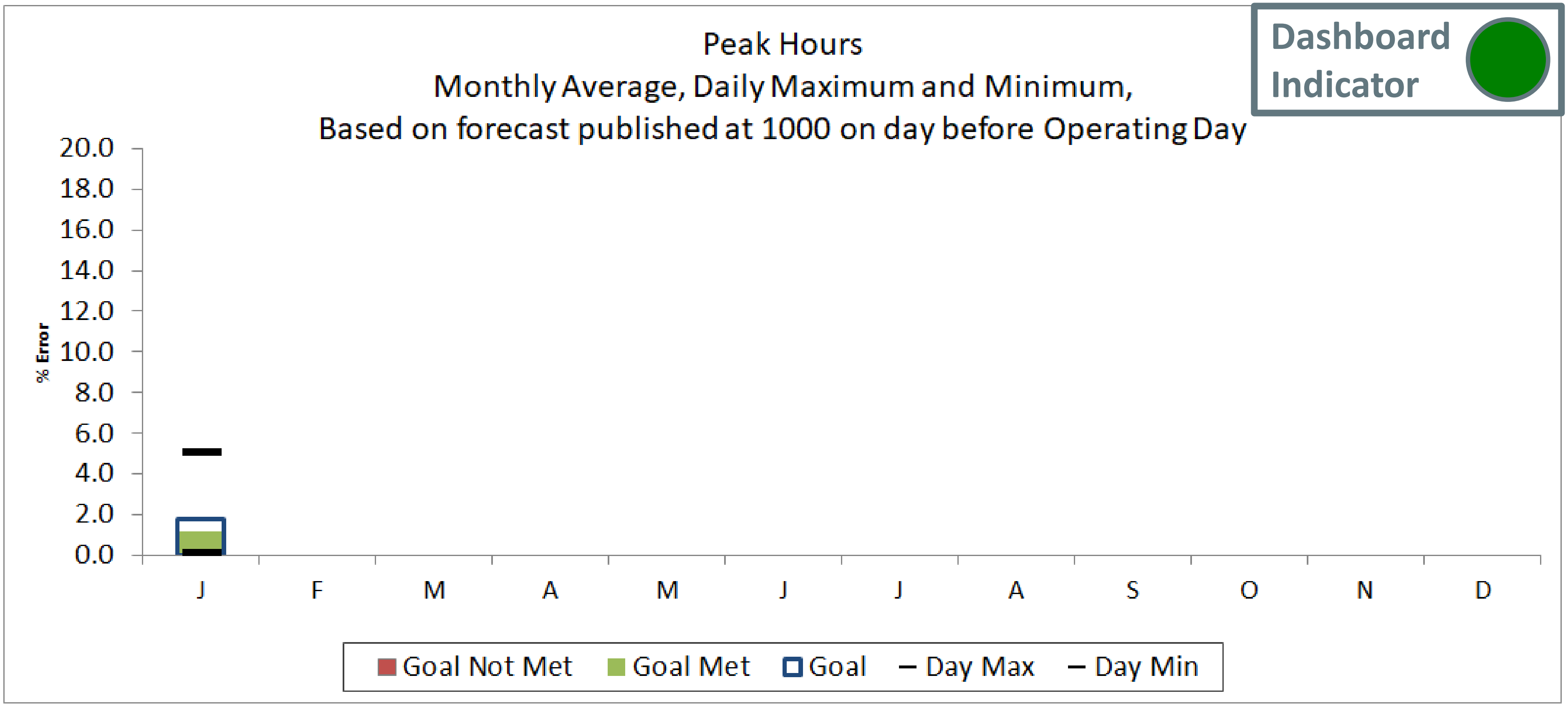
2026 System Operations - Load Forecast Accuracy cont.



Dashboard Indicator

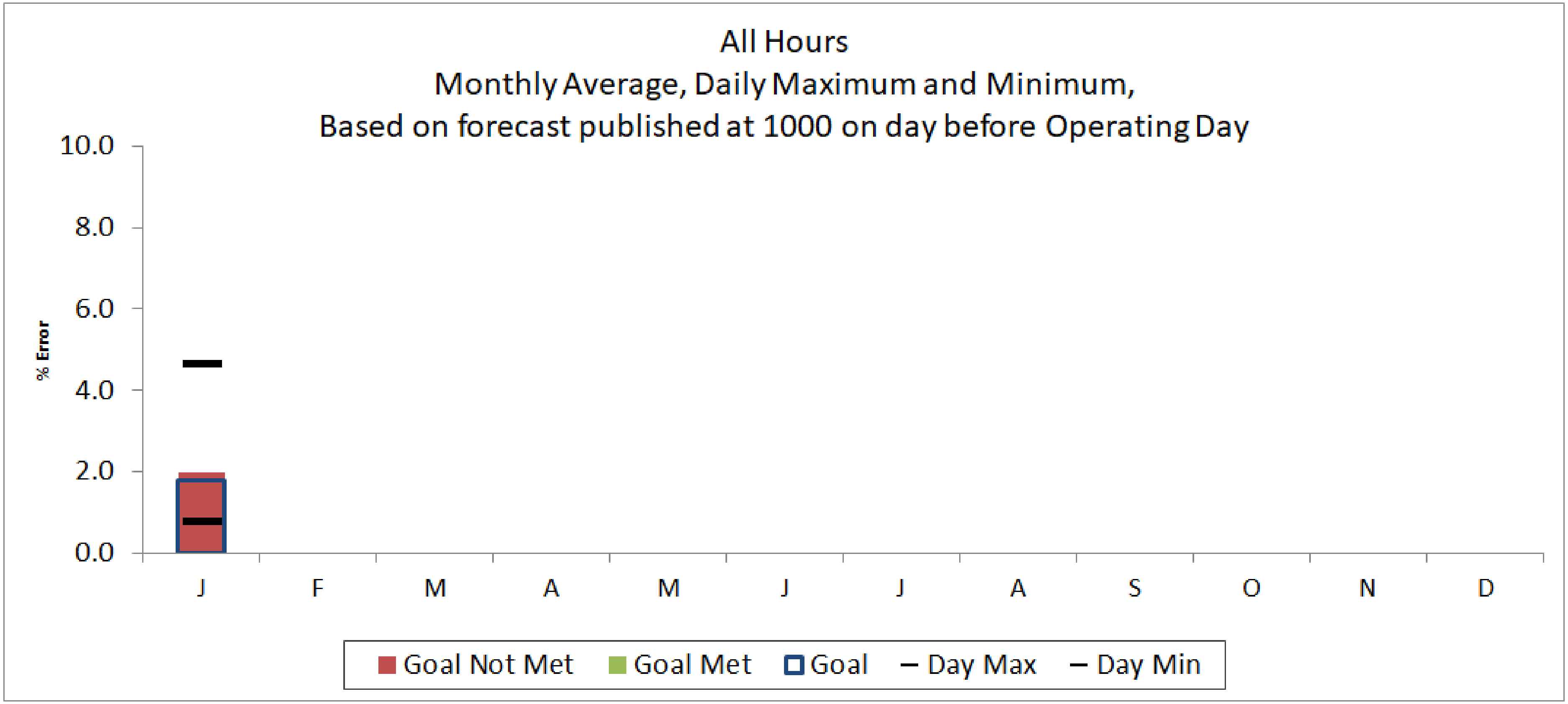
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74												4.74
Day Min	0.01												0.01
MAPE	1.57												1.57
Goal	2.00												

2026 System Operations - Load Forecast Accuracy cont.



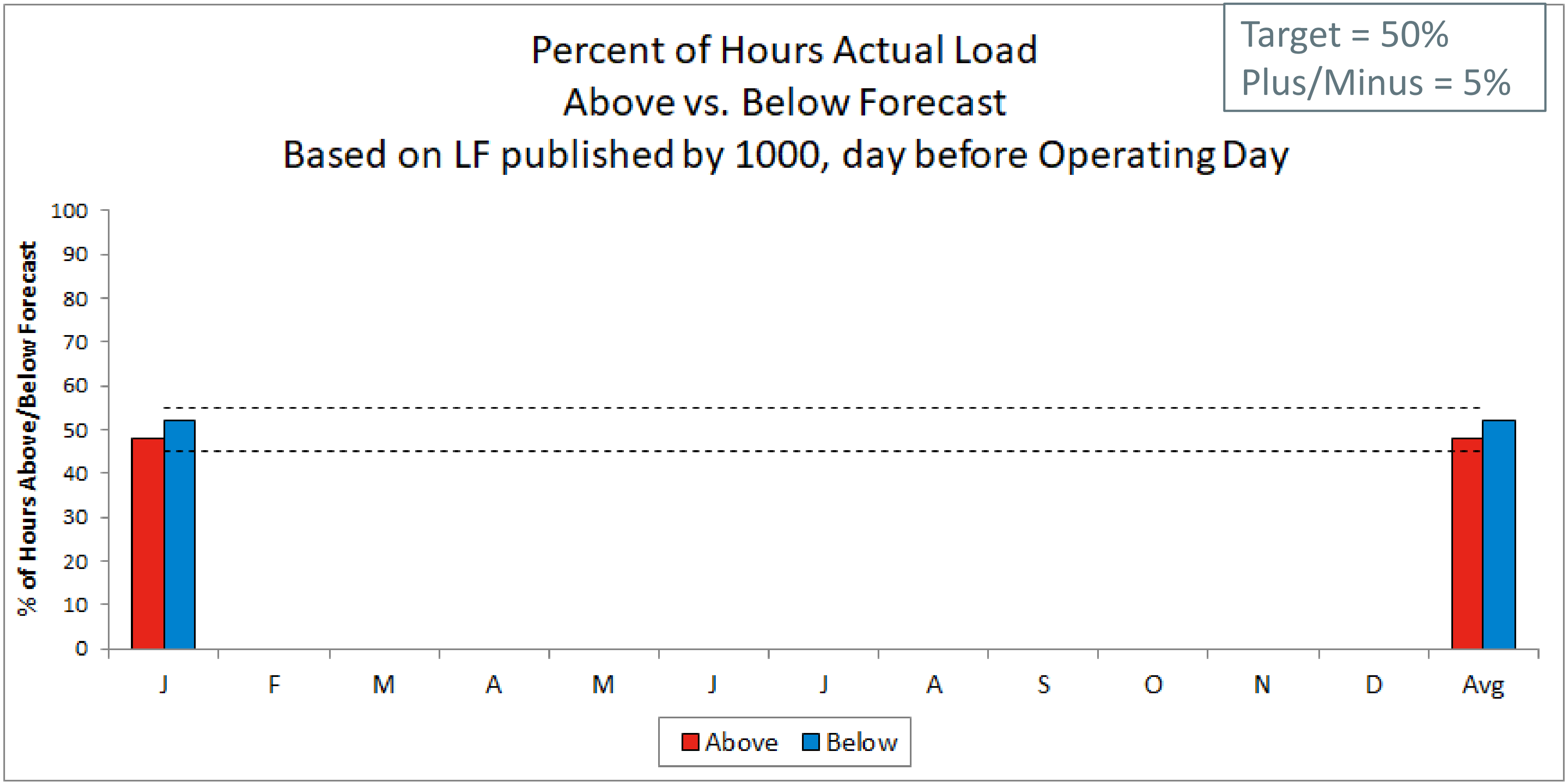
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05												5.05
Day Min	0.08												0.08
MAPE	1.17												1.17
Goal	1.80												

2026 System Operations - Load Forecast Accuracy cont.



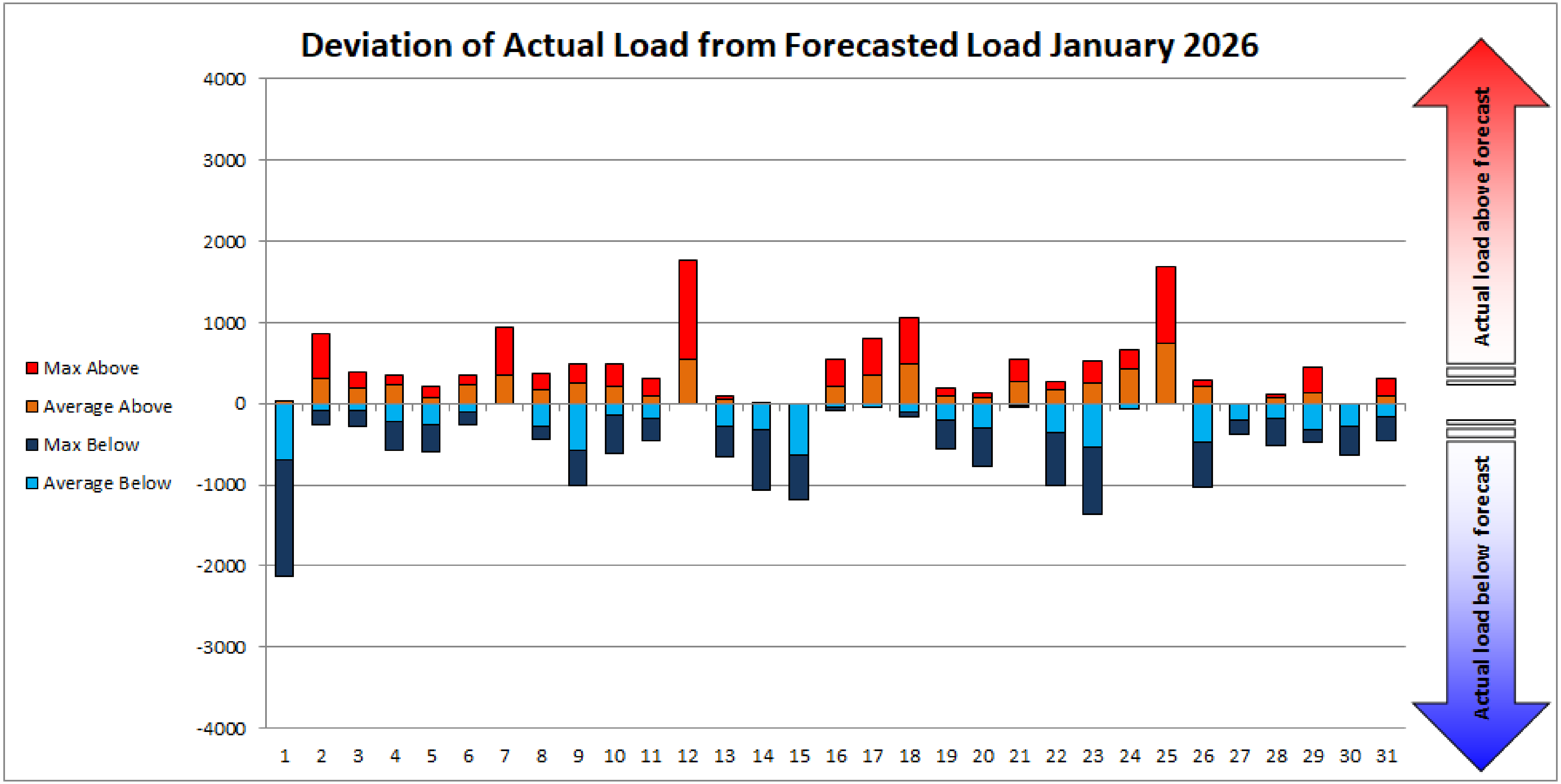
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65												4.65
Day Min	0.76												0.76
MAPE	2.00												2.00
Goal	1.80												

2026 System Operations - Load Forecast Accuracy cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	47.8												48
Below %	52.2												52
Avg Above	204.1												204
Avg Below	-232.5												-233
Avg All	-19												-19

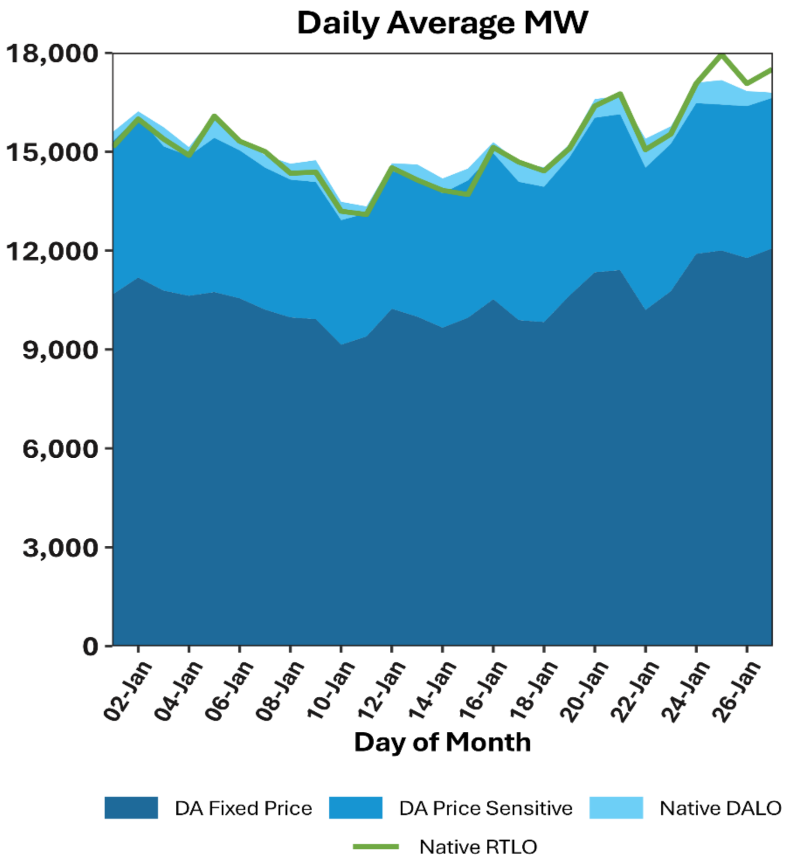
2026 System Operations - Load Forecast Accuracy

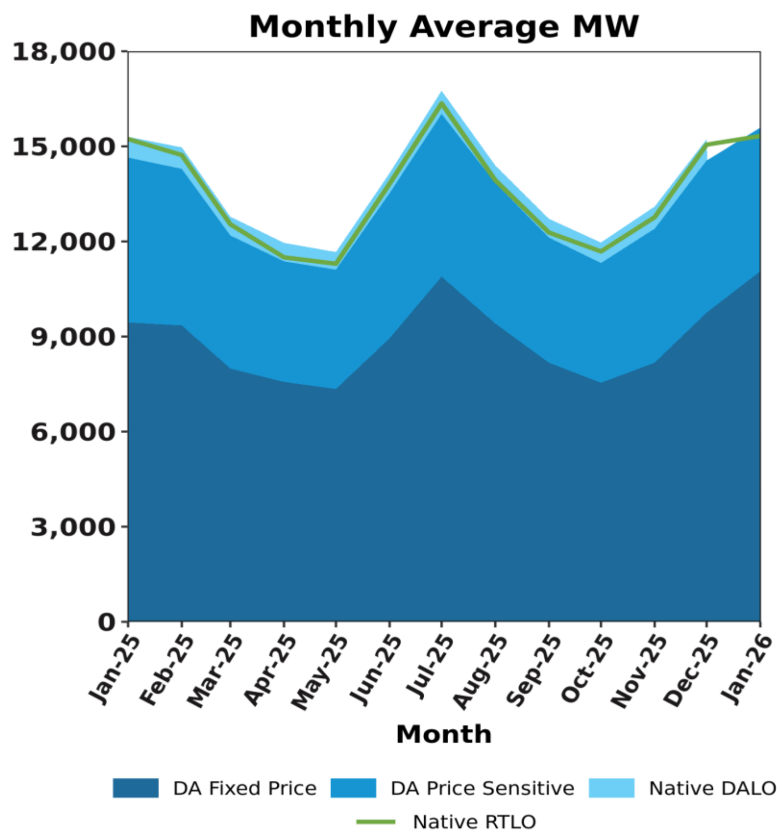


MARKET OPERATIONS

Supply and Demand Volumes

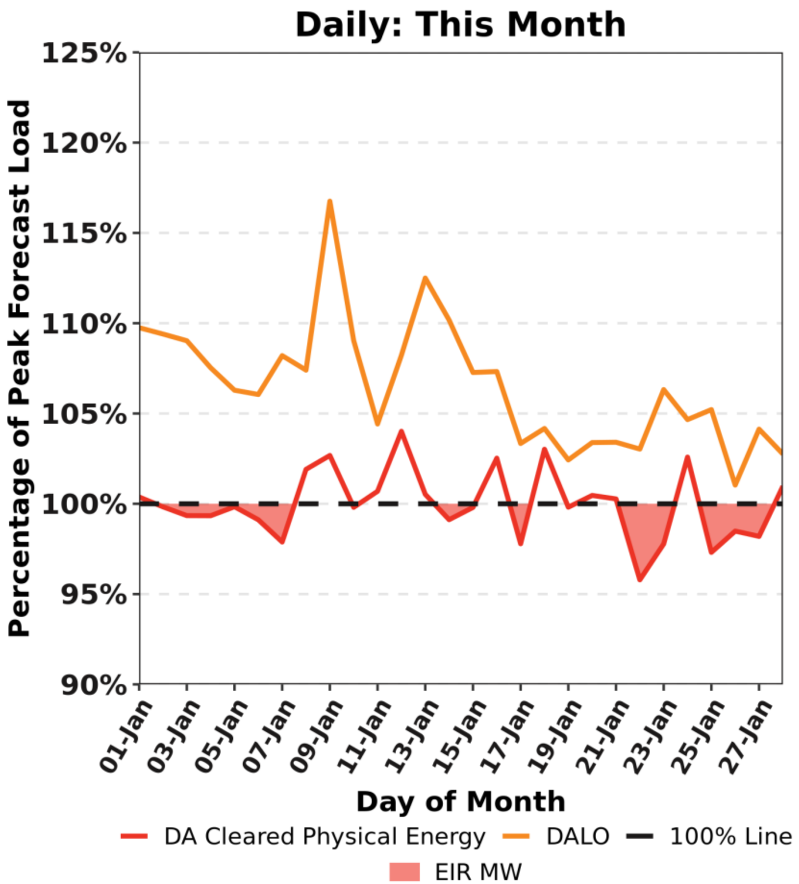
DA Cleared Native Load by Composition Compared to Native RT Load

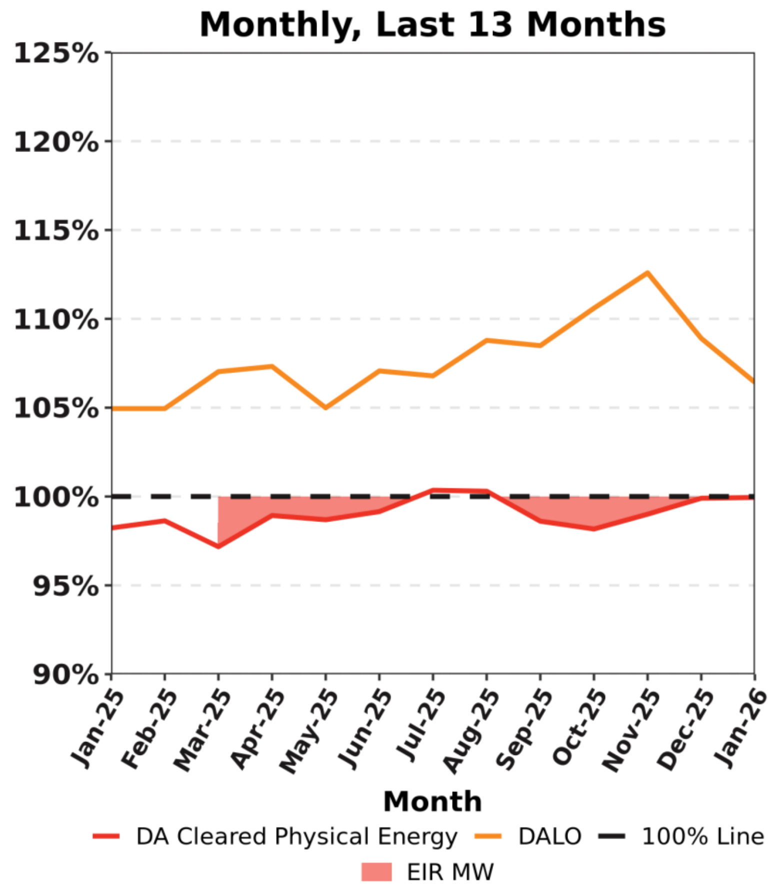




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

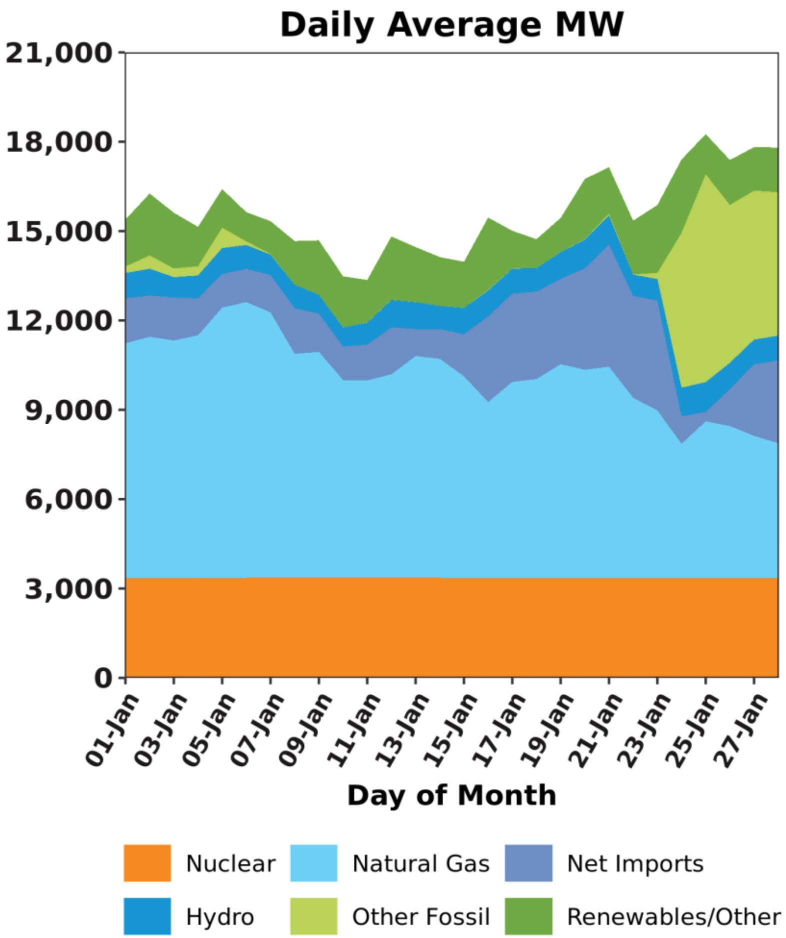
DA Volumes as % of Forecast in Peak Hour

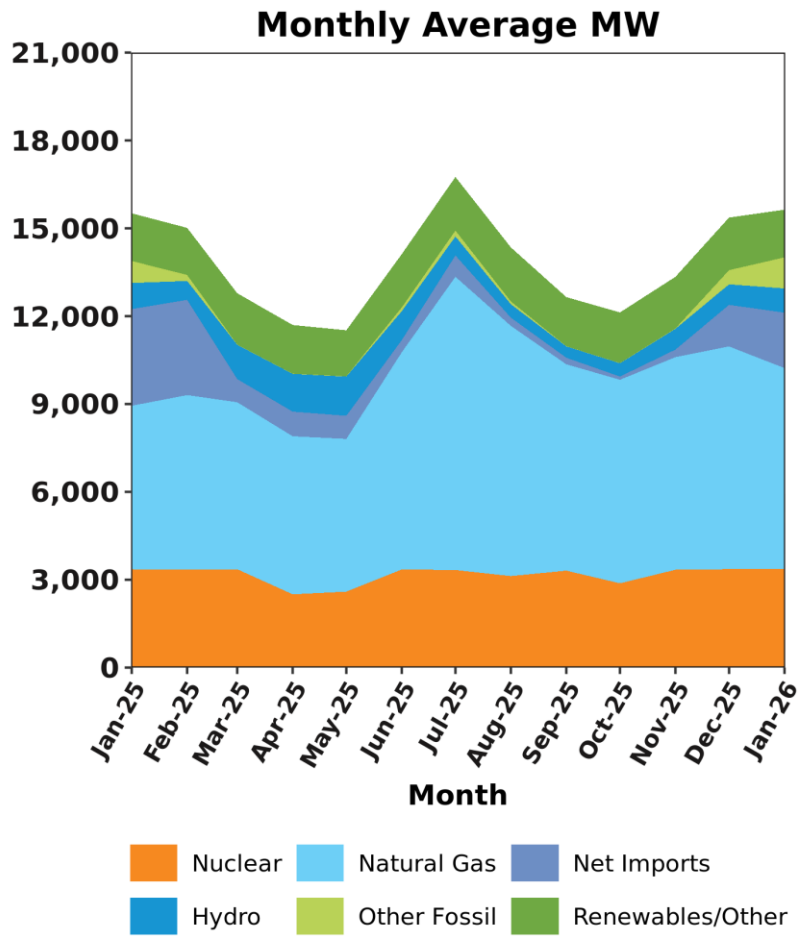




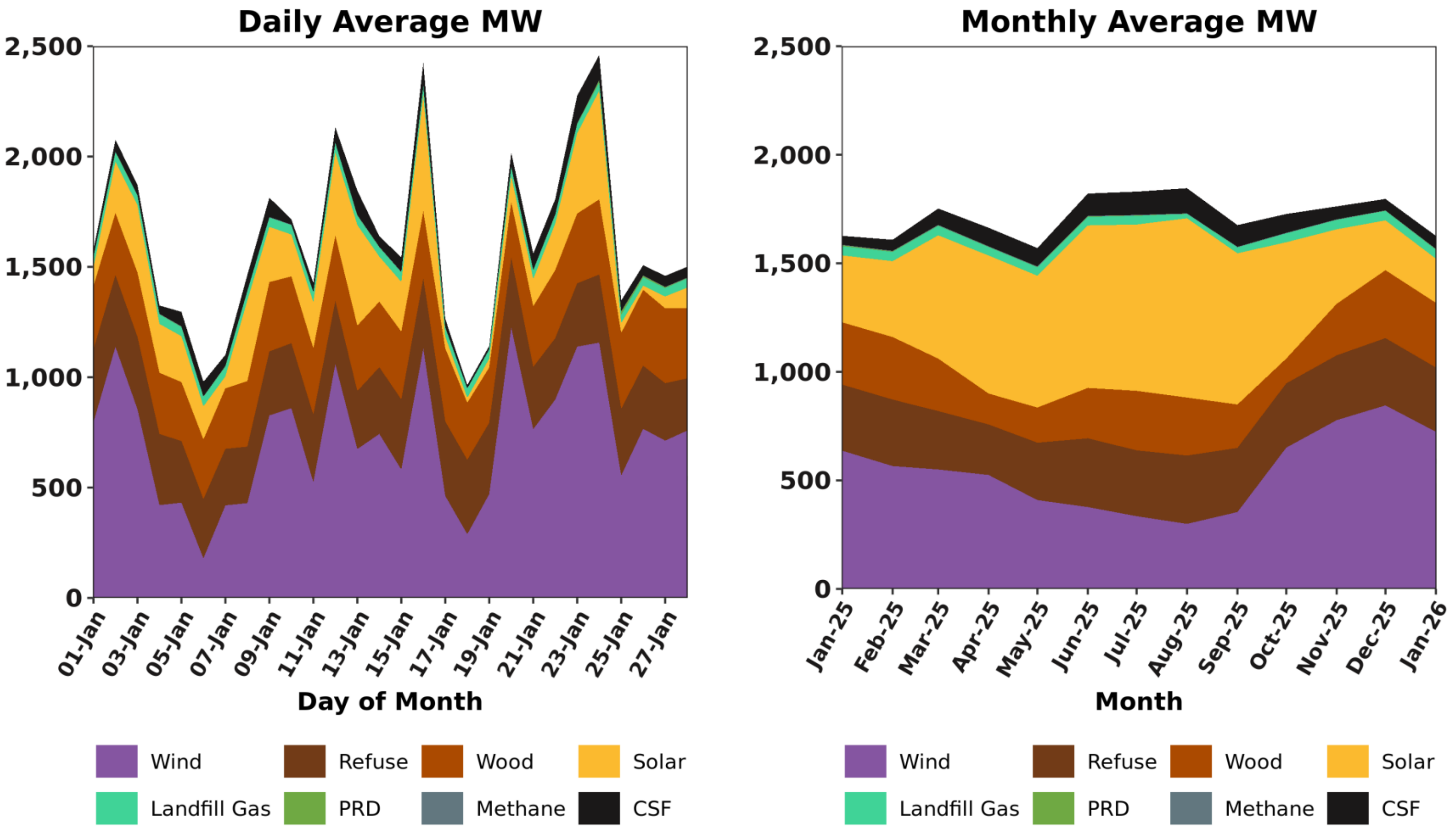
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Resource Mix



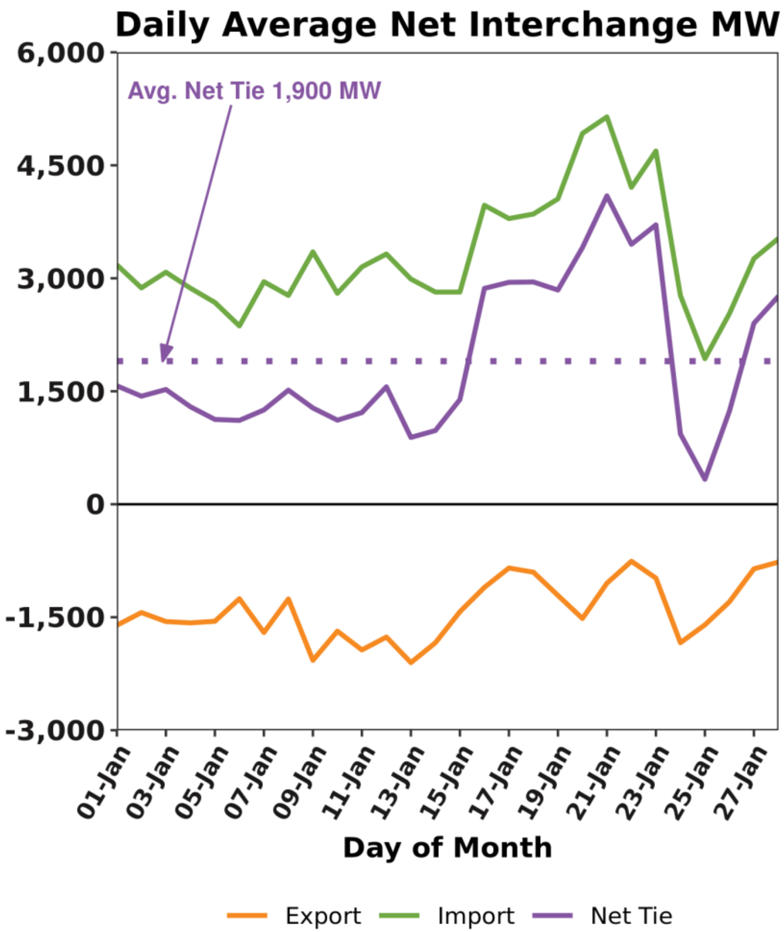


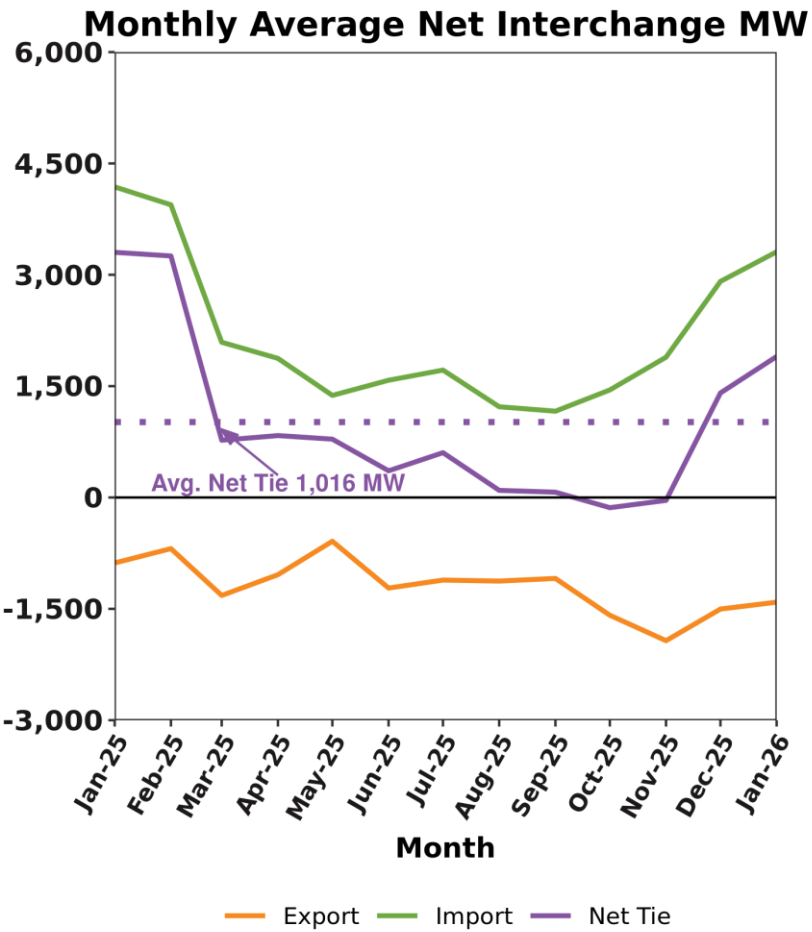
Renewable Generation by Fuel Type



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

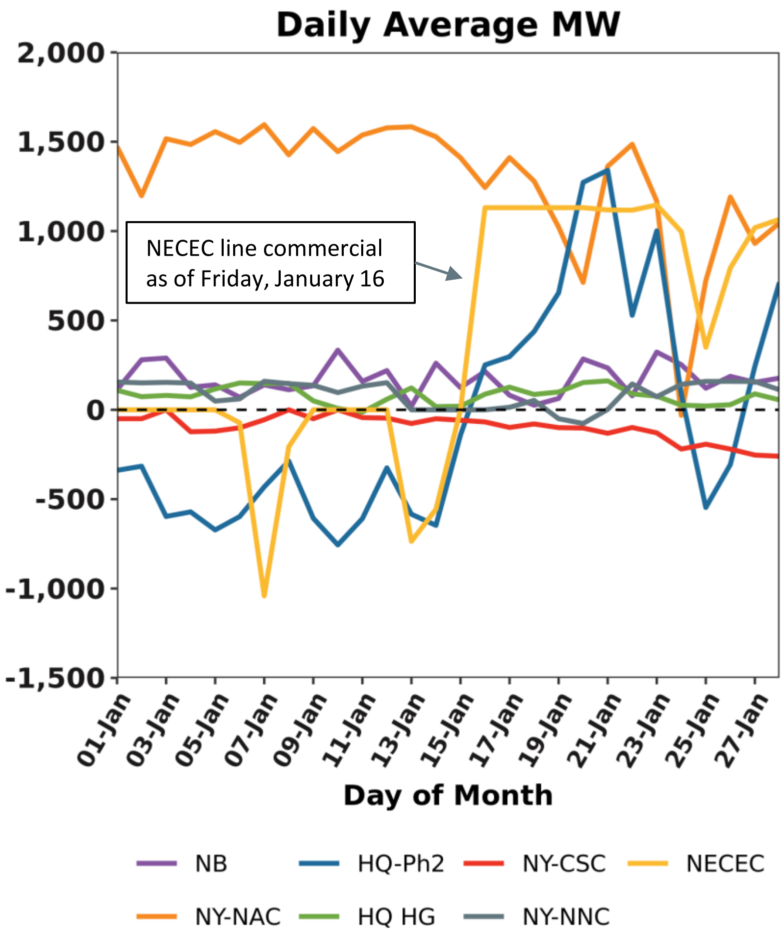
RT Net Interchange

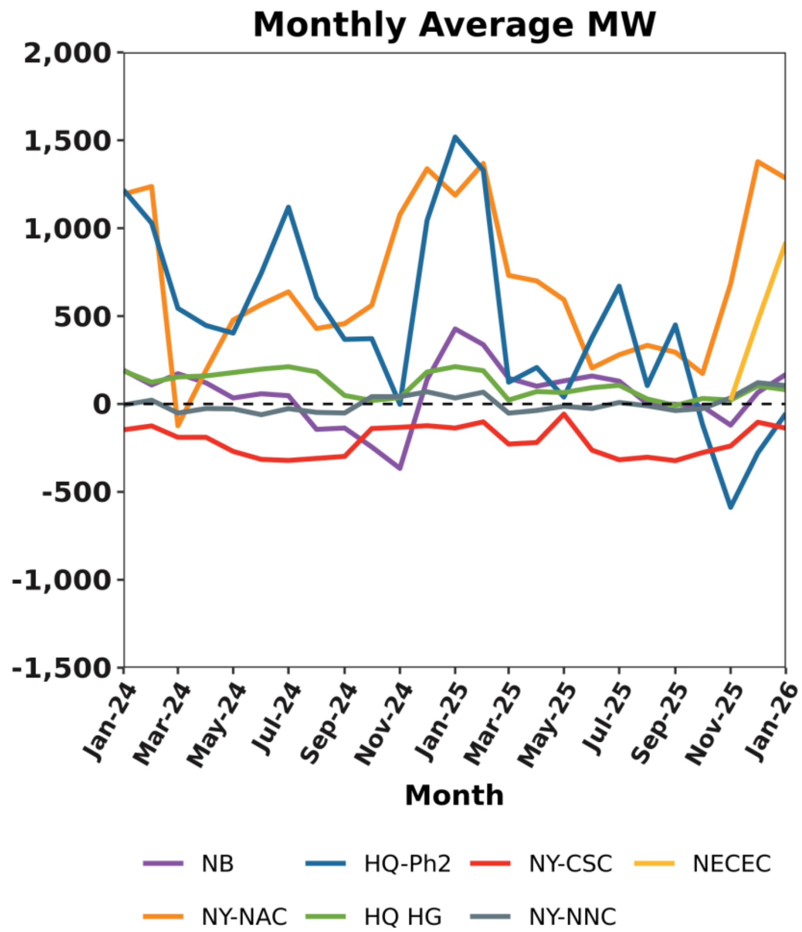




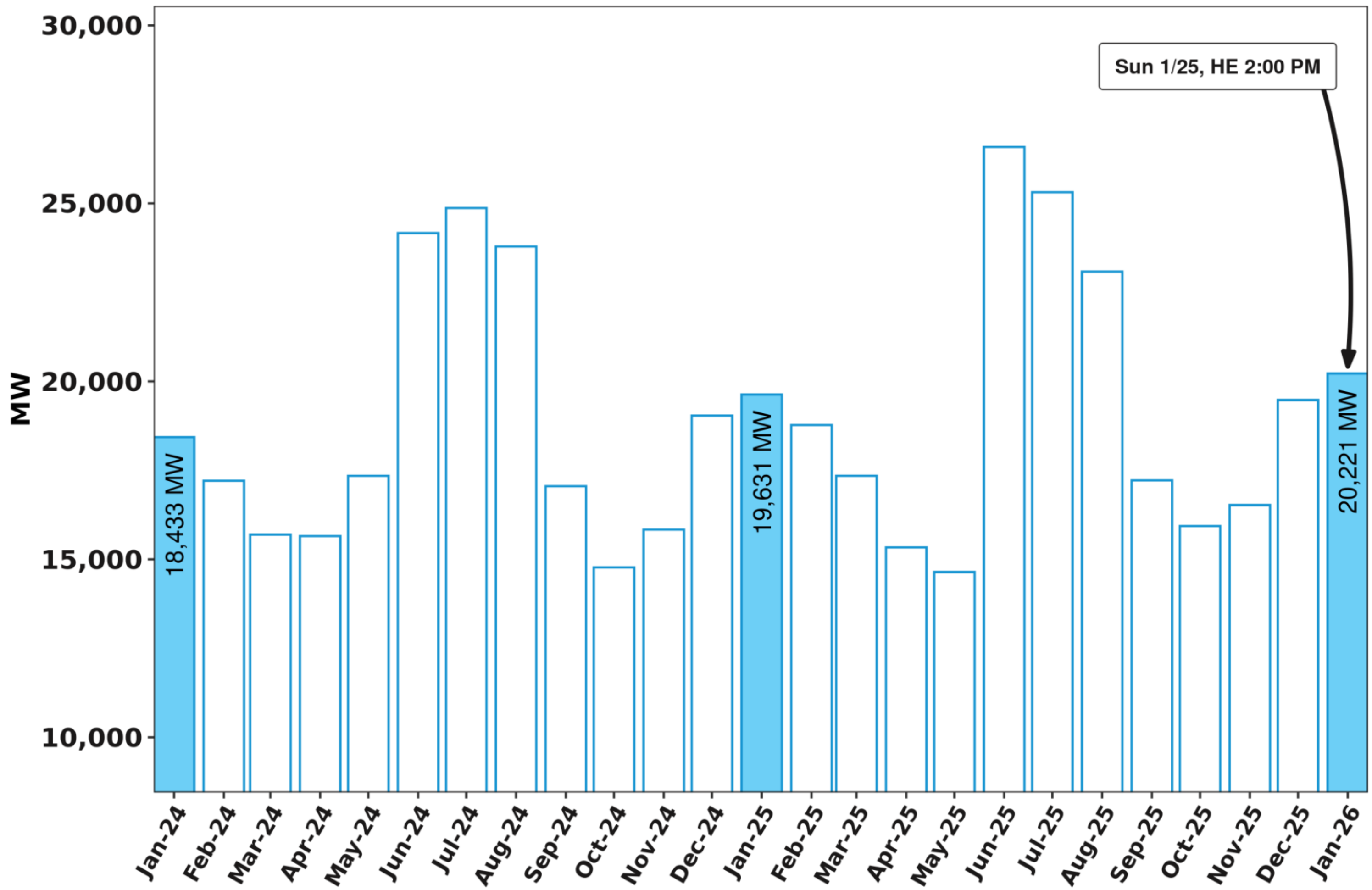
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



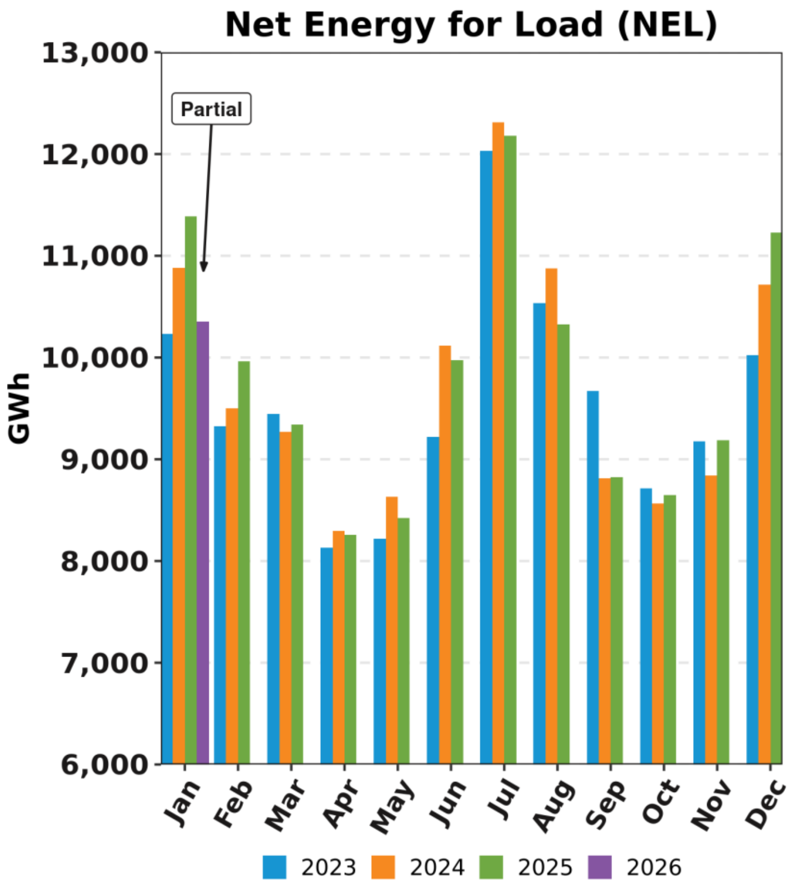


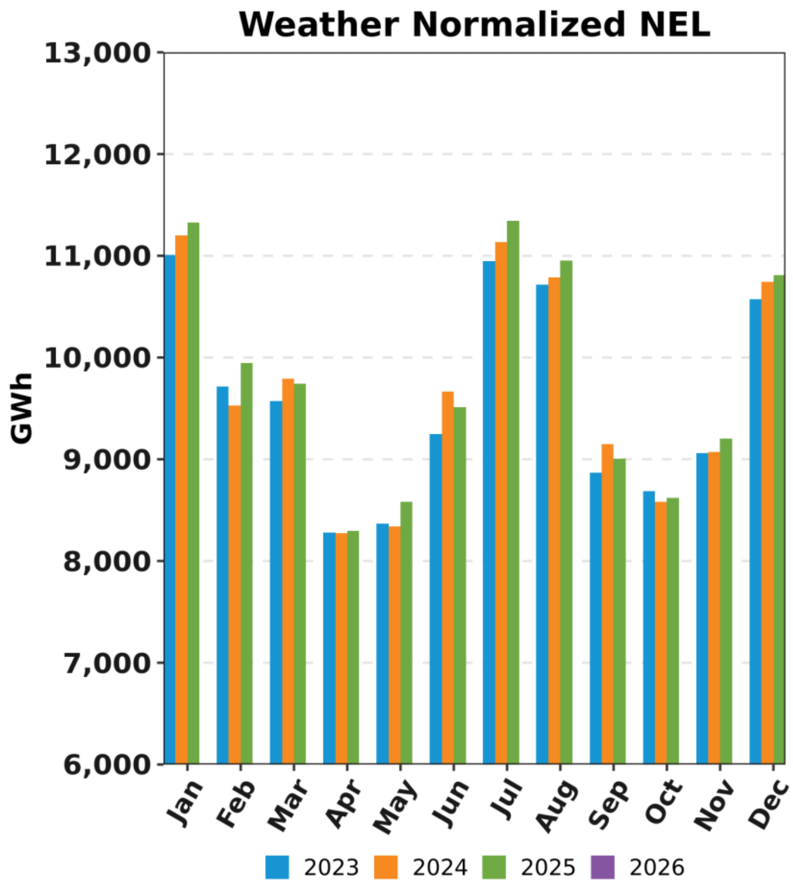
RQM System Peak Load MW by Month



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

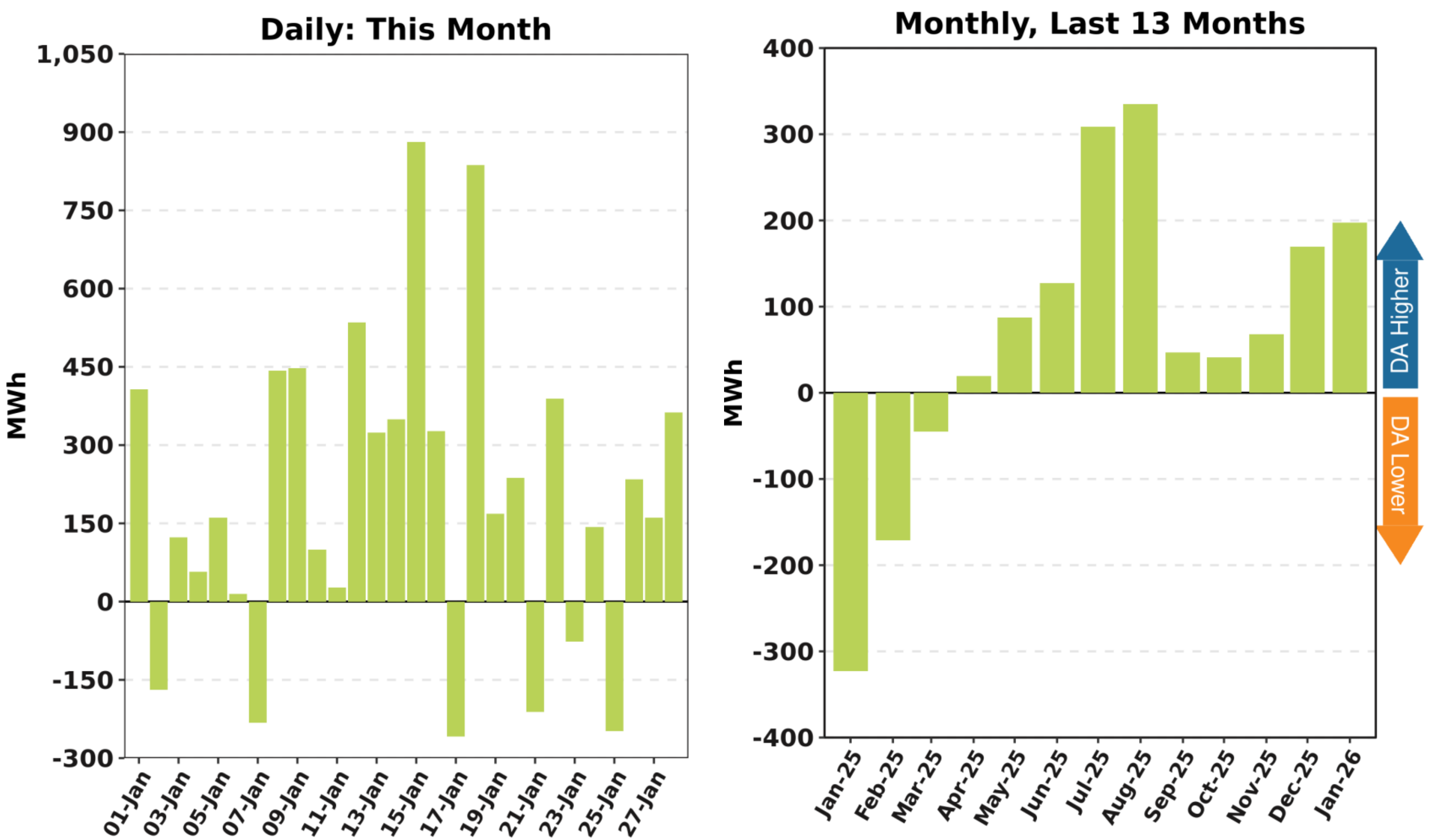
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL





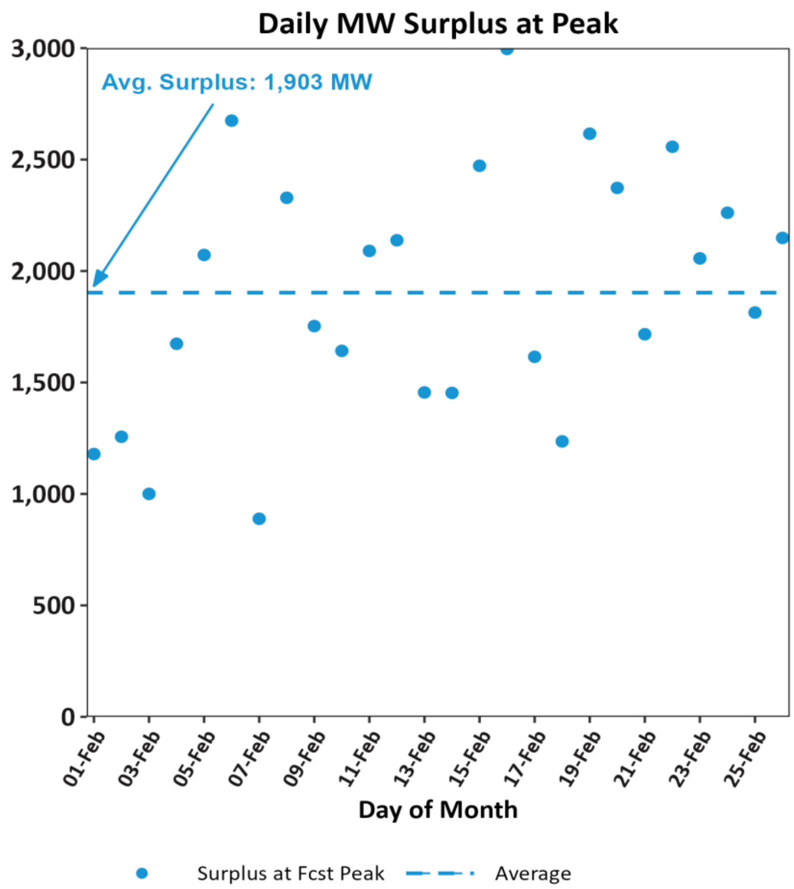
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

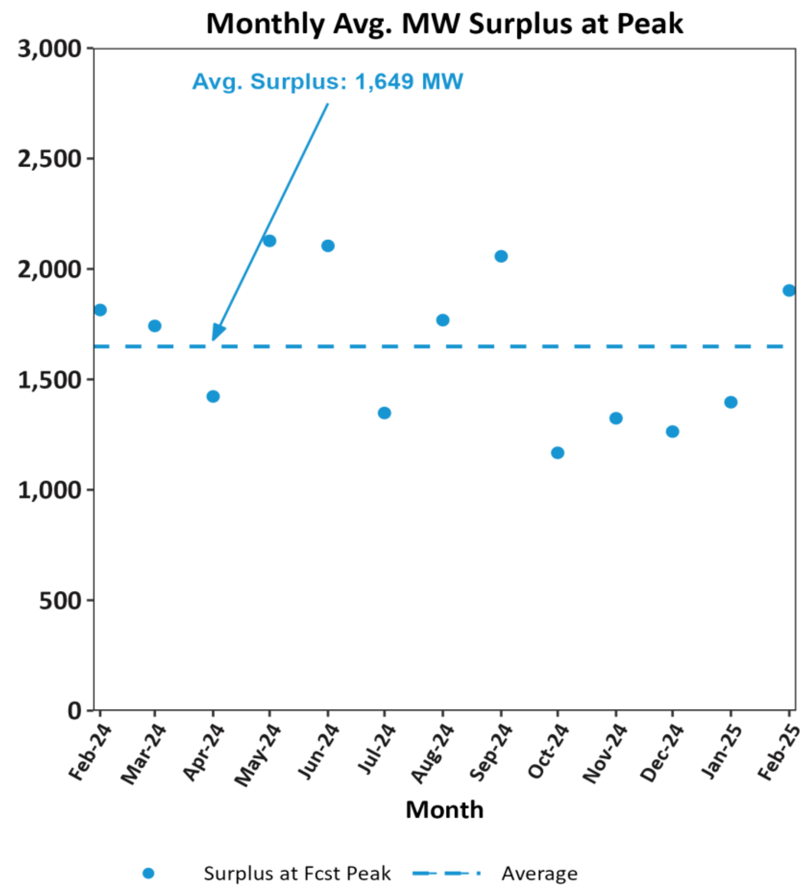
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour



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

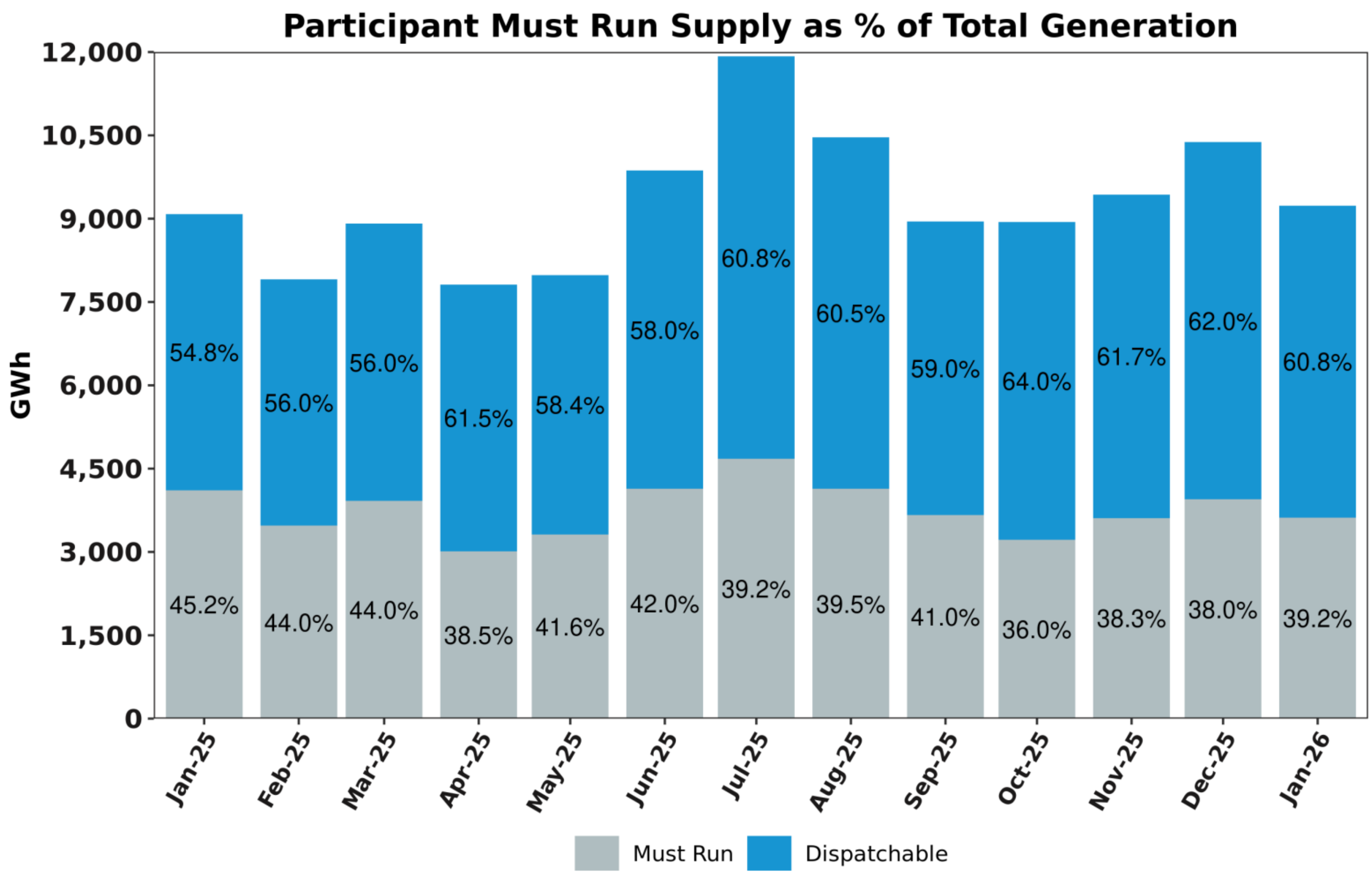
Native Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





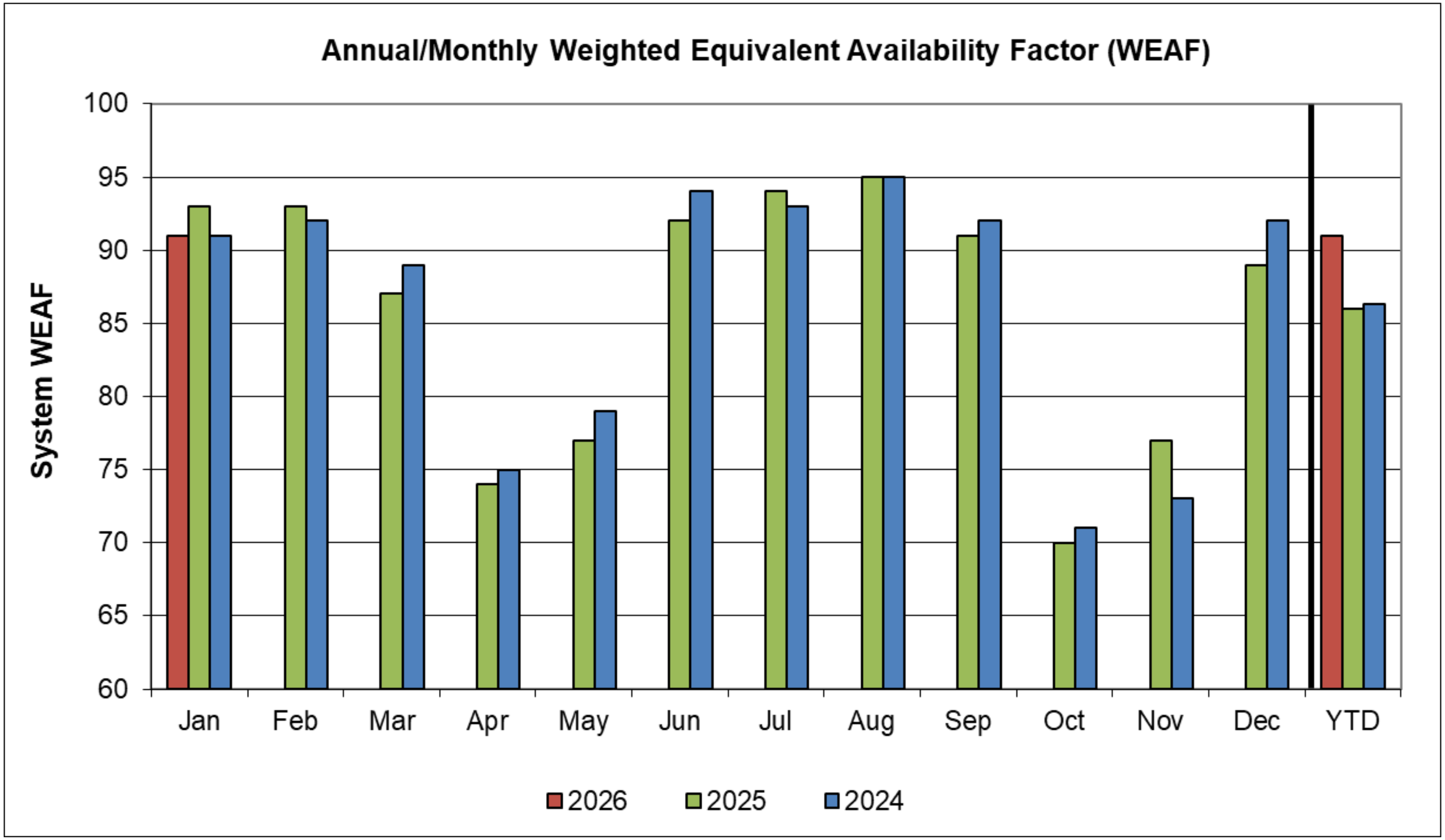
*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

RT Generation Output Offered as Must Run vs Dispatchable



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

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2026	91												91
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 1/27/26

MARKET OPERATIONS

Market Pricing

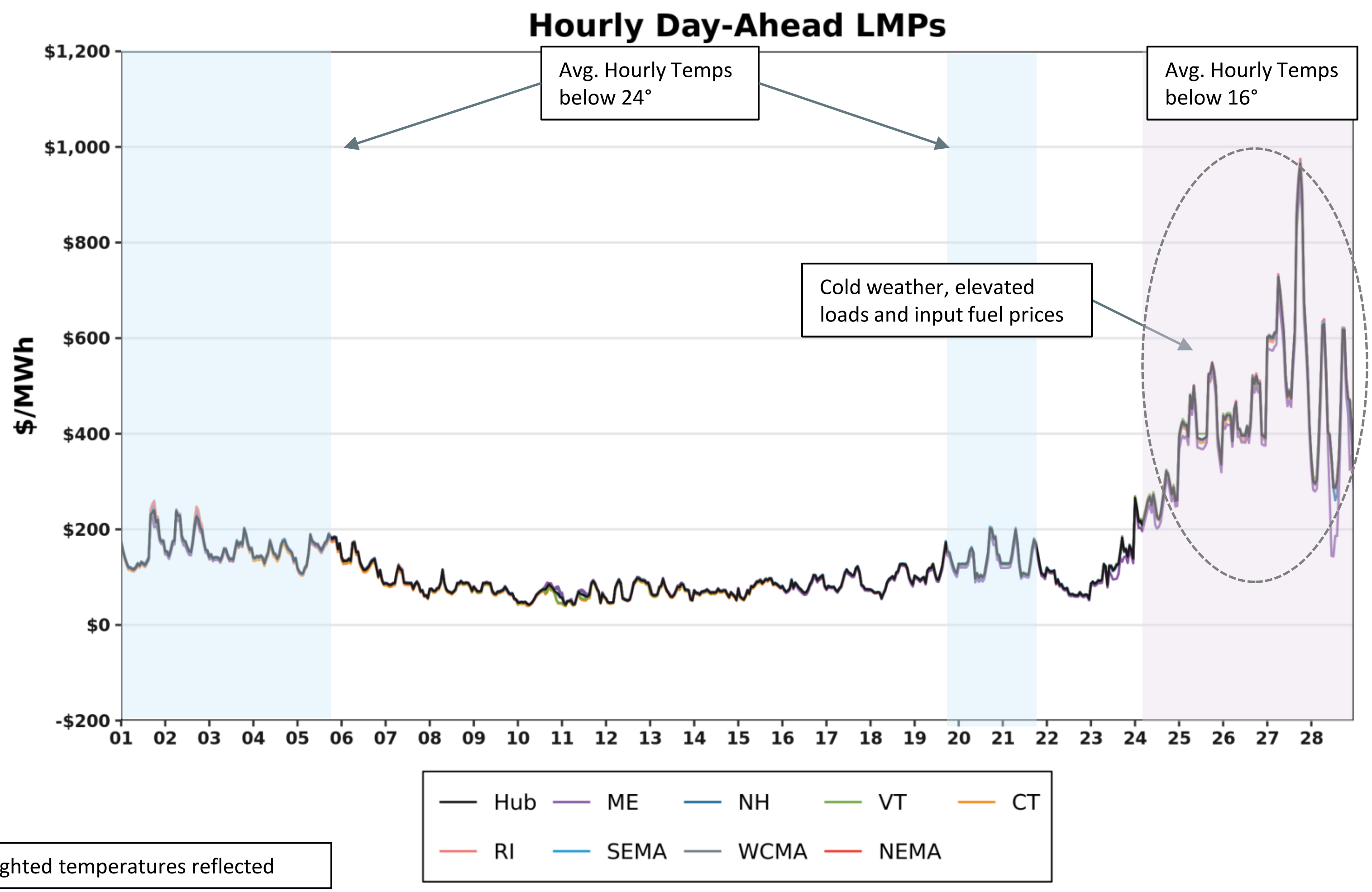
DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

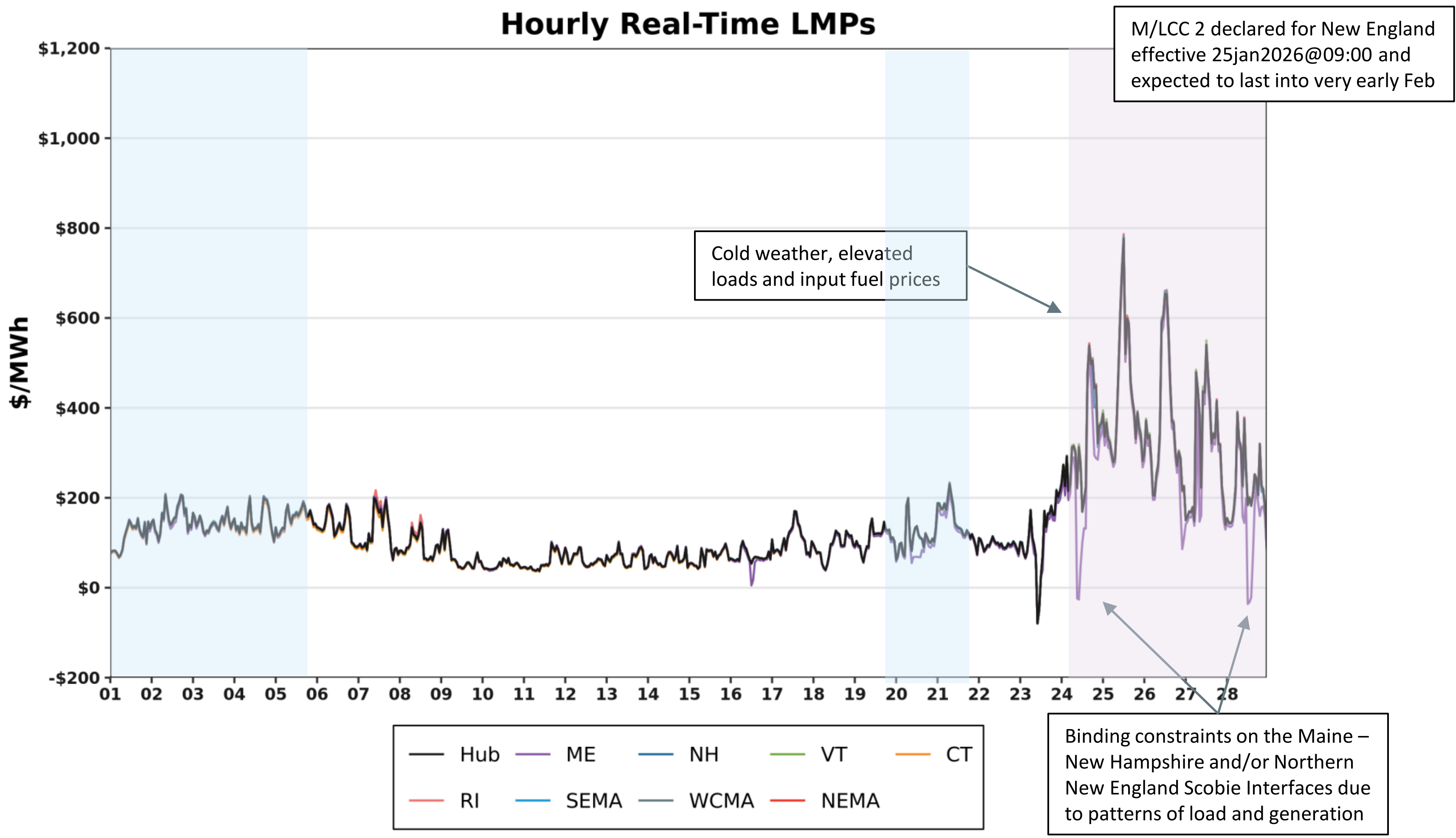
January-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$133.56	$130.89	$134.31	$132.51	$130.30	$133.86	$135.04	$133.52	$134.92
Real-Time	$135.08	$130.68	$135.64	$133.00	$132.13	$135.60	$136.59	$135.00	$136.57
RT Delta %	1.14%	-0.16%	0.99%	0.37%	1.40%	1.30%	1.15%	1.11%	1.22%
January-26	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$165.45	$158.30	$165.63	$164.42	$160.21	$164.92	$166.55	$165.39	$167.21
Real-Time	$142.78	$131.78	$142.70	$143.04	$138.79	$142.32	$143.24	$142.81	$144.19
RT Delta %	-13.70%	-16.75%	-13.84%	-13.00%	-13.37%	-13.70%	-14.00%	-13.65%	-13.77%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	23.88%	20.94%	23.32%	24.08%	22.95%	23.20%	23.33%	23.87%	23.93%
Yr over Yr RT	5.70%	0.84%	5.20%	7.55%	5.04%	4.96%	4.87%	5.79%	5.58%

Hourly DA LMPs, January 1-28, 2026

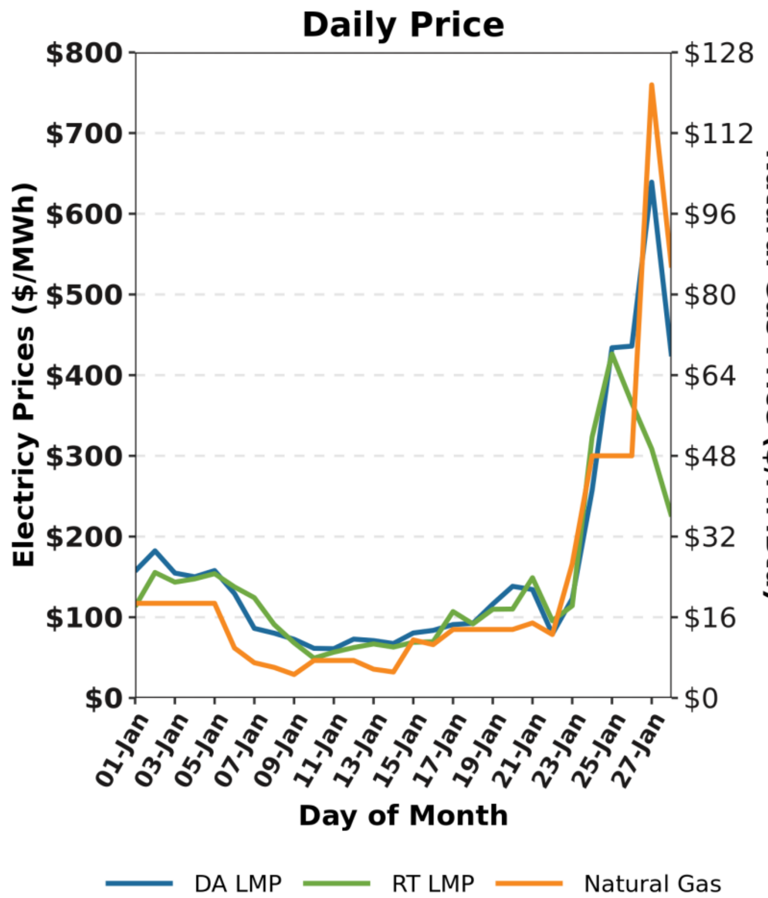


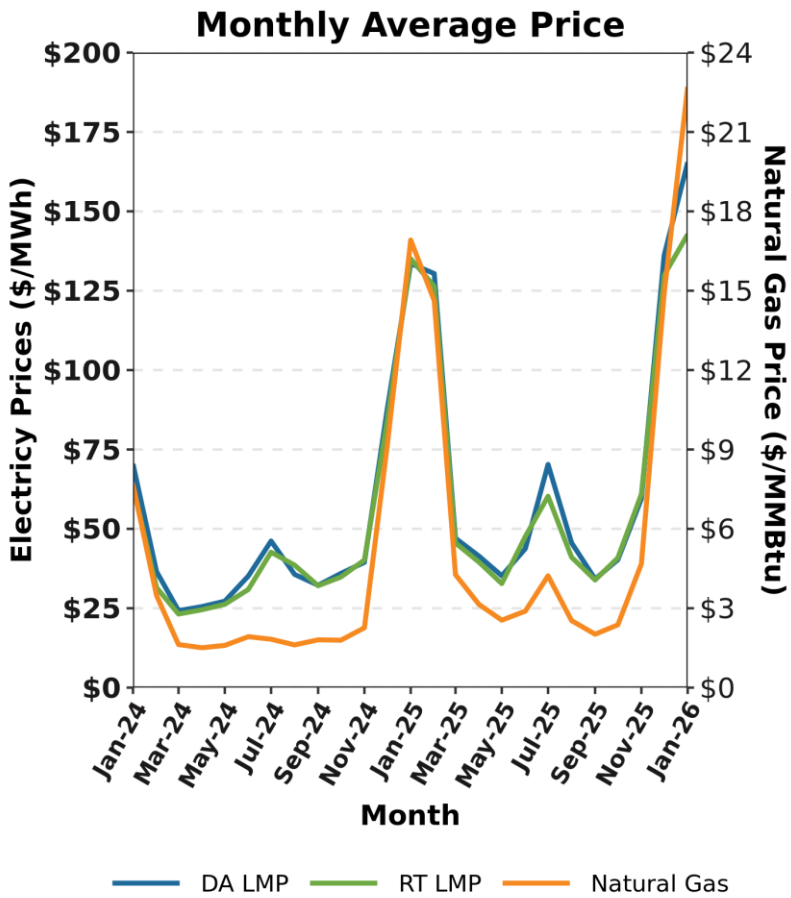
Note: NE Weighted temperatures reflected

Hourly RT LMPs, January 1-28, 2026



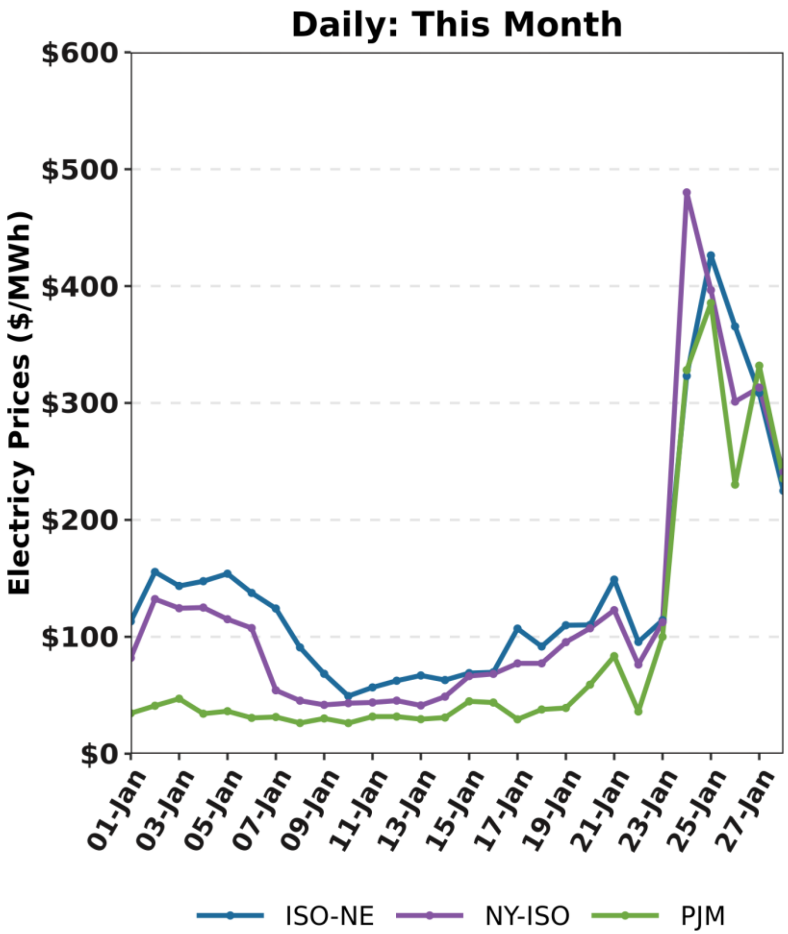
Wholesale Electricity vs Natural Gas Price by Month

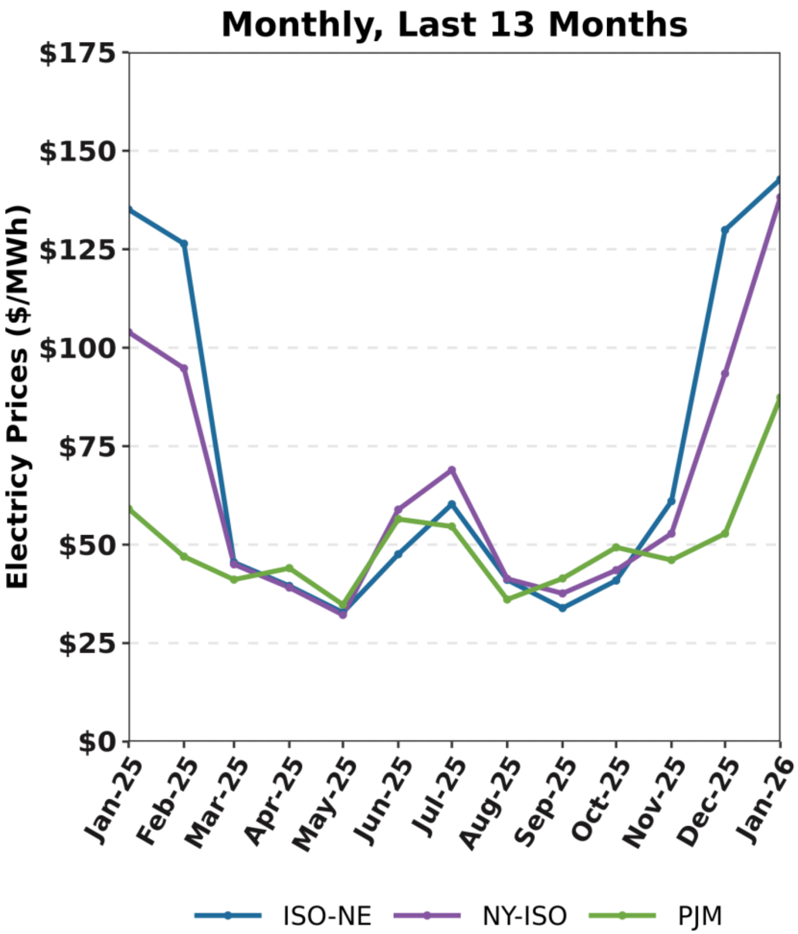




Gas price is average of Massachusetts delivery points

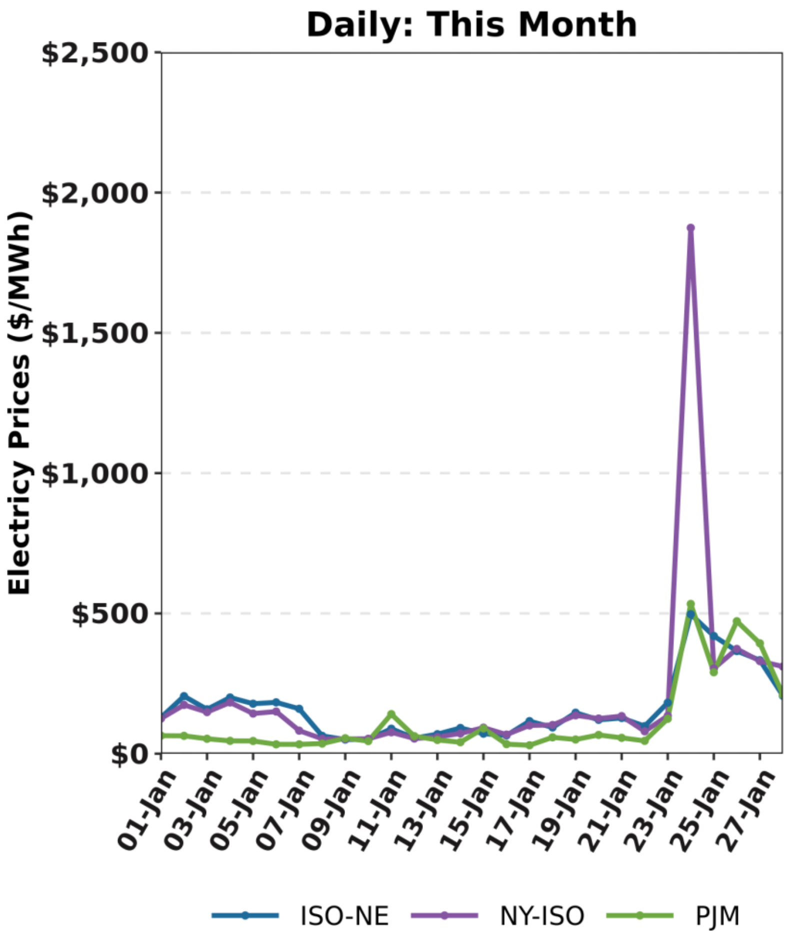
New England, NY, and PJM Hourly Average RT Prices by Month

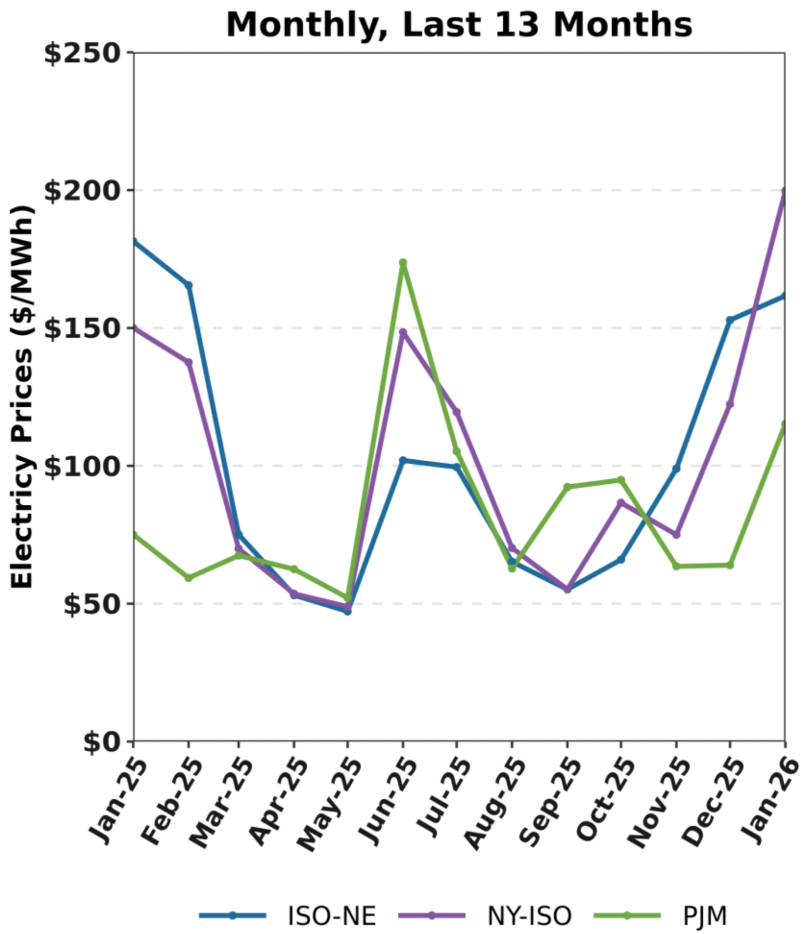




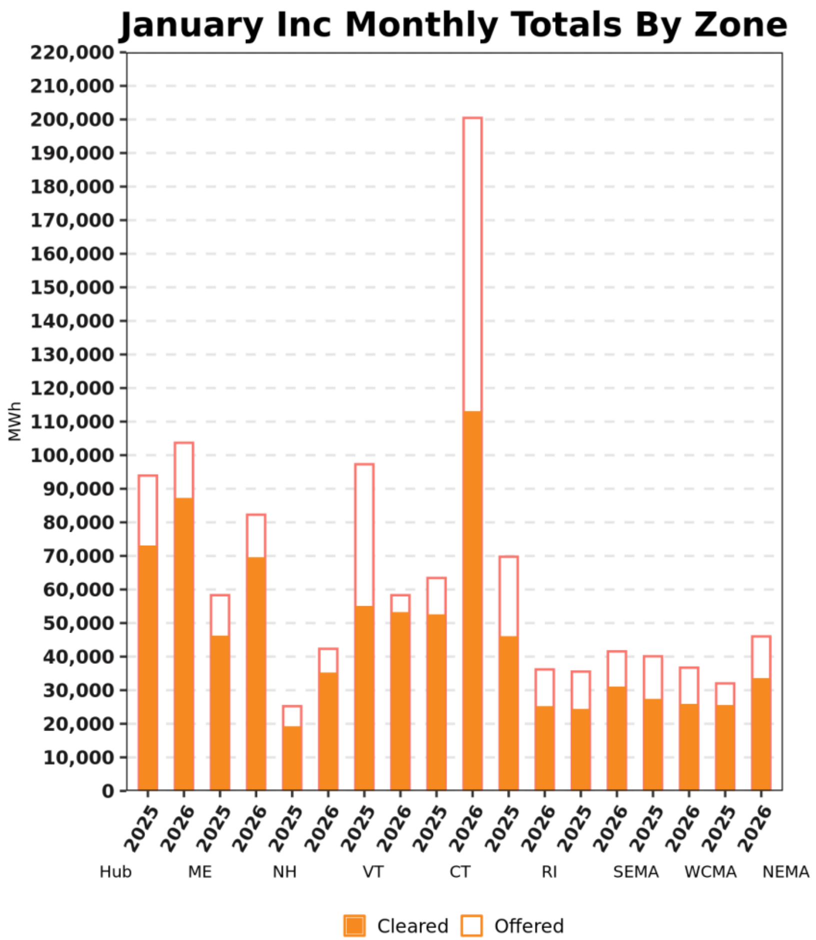
Hourly average prices are shown

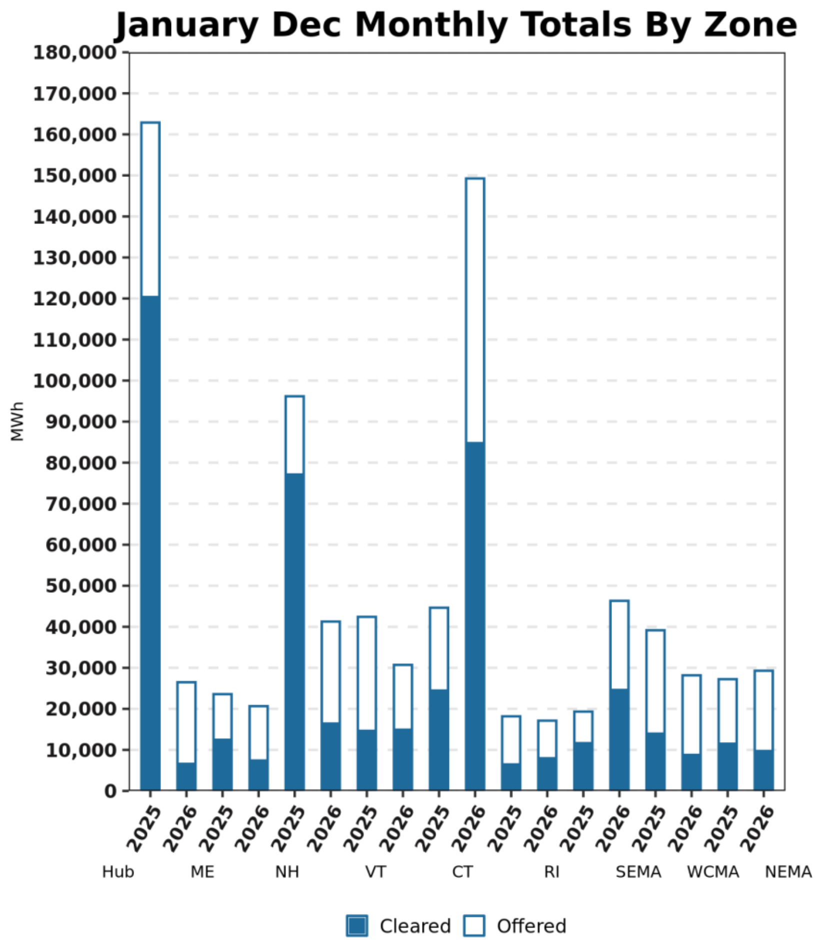
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





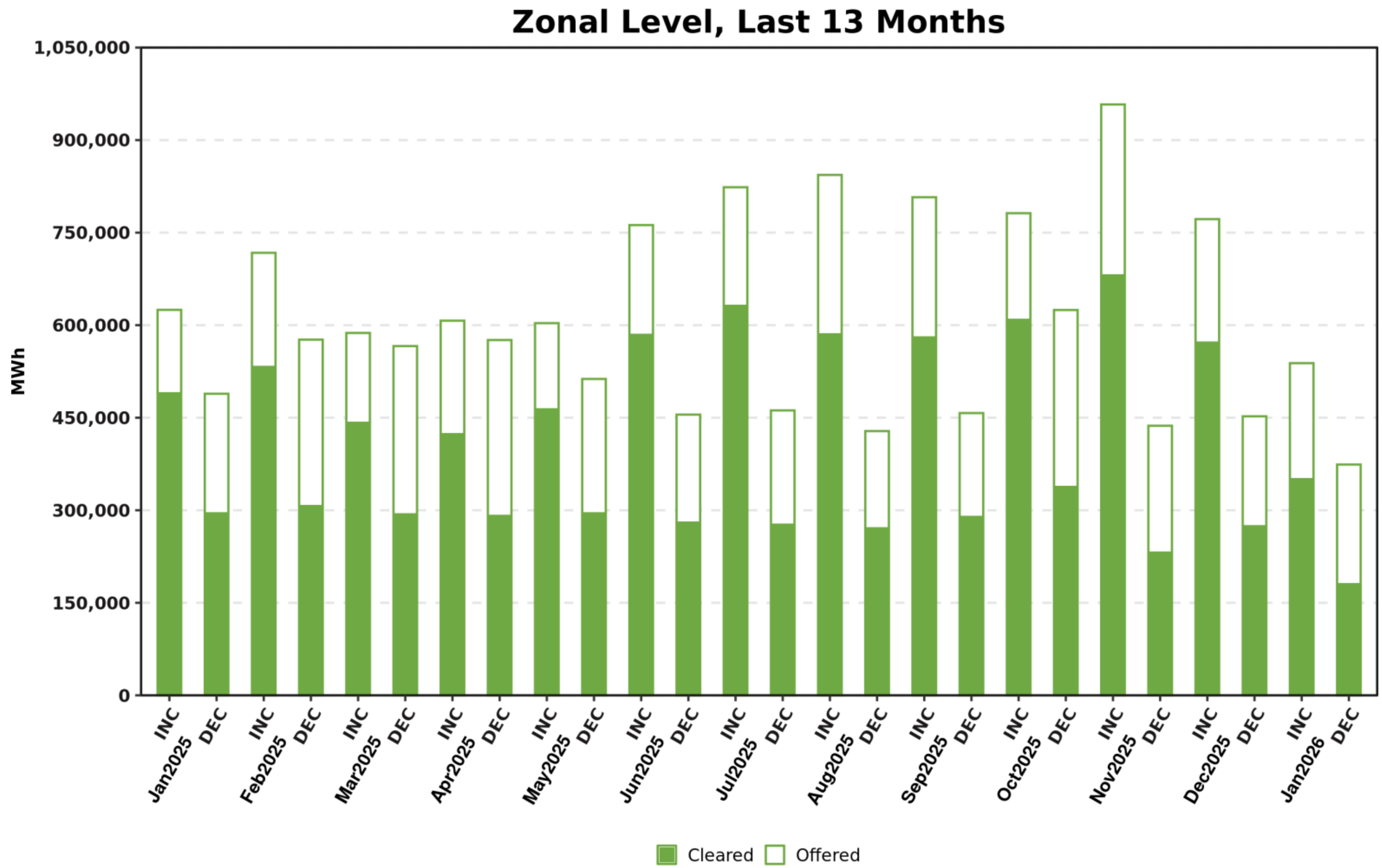
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

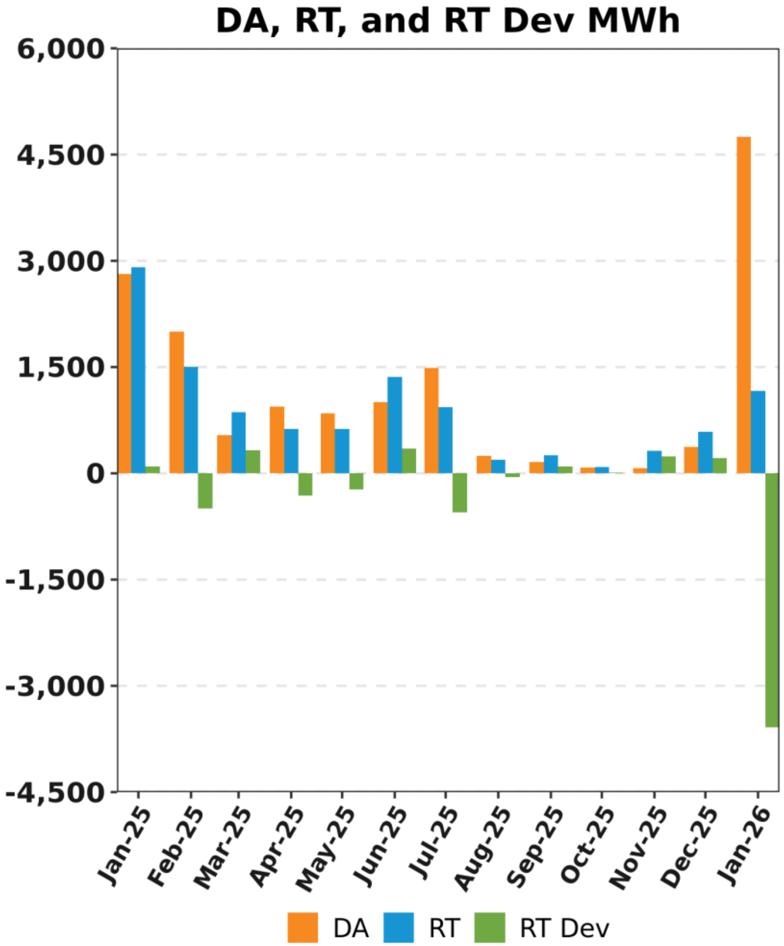


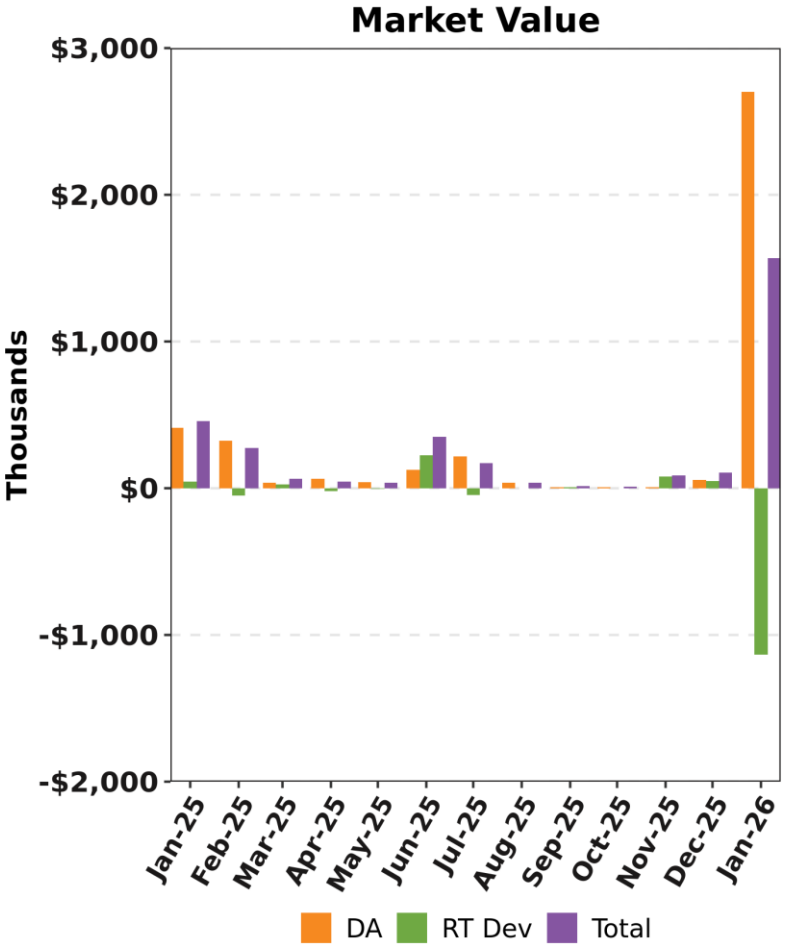
Includes nodal activity within the zone; excludes external nodes

BACK-UP DETAIL

DEMAND RESPONSE

Demand Response Resource (DRR) Energy Market Activity by Month





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

NEW GENERATION

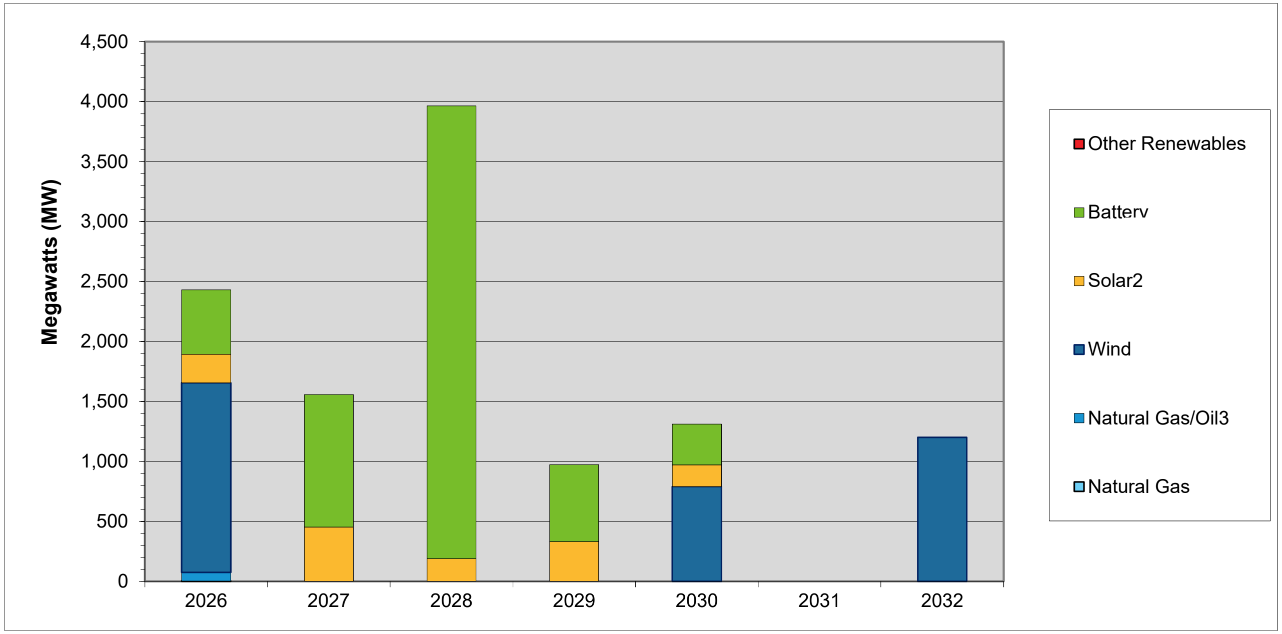
New Generation Update

Based on Queue as of 02/01/26

- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 61* generation projects are currently being tracked by the ISO, totaling approximately 12,635 MW

* Total does not include CNR Only requests

Projected Annual Capacity Additions
By Supply Fuel Type



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	538	1,104	3,774	642	340	0	0	6,398	56.0
Solar[2]	237	453	190	332	180	0	0	1,392	12.2
Wind	1,581	0	0	0	791	0	1,200	3,572	31.2
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.6
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	**2,429**	**1,557**	**3,964**	**974**	**1,311**	**0**	**1,200**	**11,435**	**100.0**

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

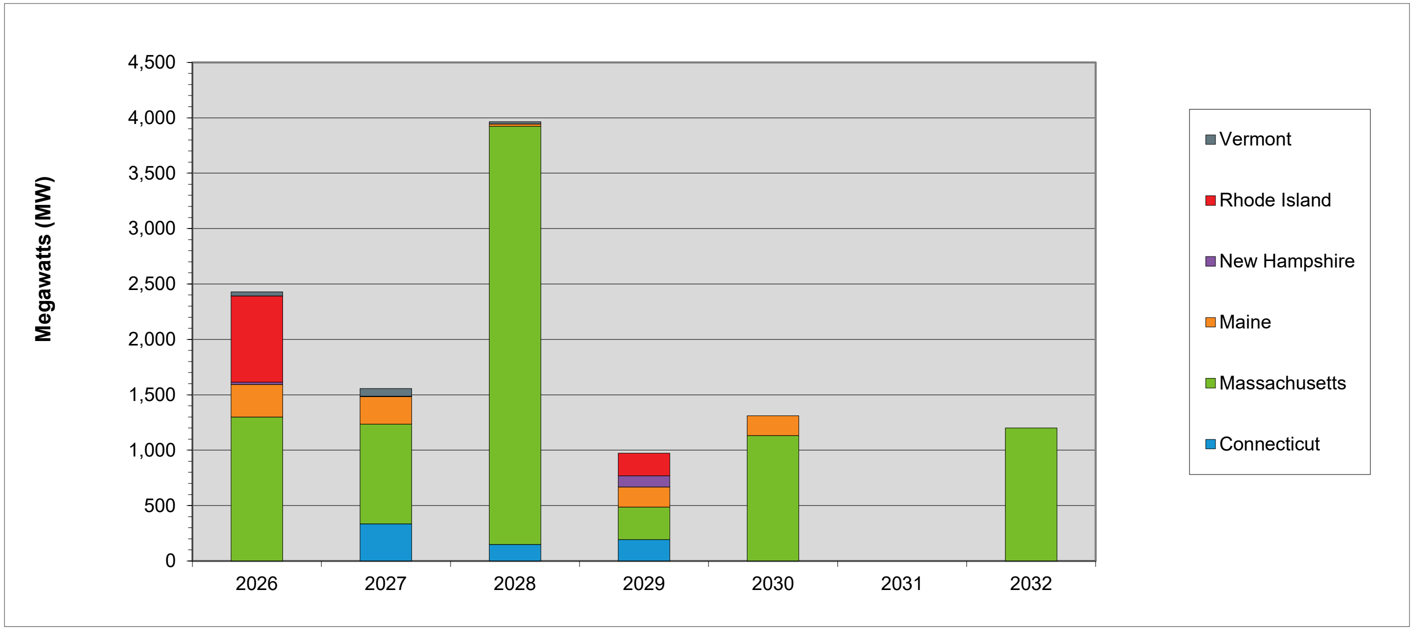
[2] This category includes both solar-only, and co-located solar and battery projects

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

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

Projected Annual Generator Capacity Additions

By State



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Vermont	38	70	20	0	0	0	0	128	1.1
Rhode Island	777	0	0	205	0	0	0	982	8.6
New Hampshire	20	5	0	100	0	0	0	125	1.1
Maine	294	247	20	182	180	0	0	923	8.1
Massachusetts	1,300	899	3,774	295	1,131	0	1,200	8,599	75.2
Connecticut	0	336	150	192	0	0	0	678	5.9
Totals	**2,429**	**1,557**	**3,964**	**974**	**1,311**	**0**	**1,200**	**11,435**	**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	29	6,398	1	250	28	6,148
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	1	73	1	73	0	0
Nuclear	0	0	0	0	0	0
Solar	24	1,392	3	136	21	1,256
Wind	7	4,772	3	877	4	3,895
Total	61	12,635	8	1,336	53	11,299

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	0	0	0	0	0	0
Intermediate	1	73	1	73	0	0
Peaker	53	7,790	4	386	49	7,404
Wind Turbine	7	4,772	3	877	4	3,895
Total	61	12,635	8	1,336	53	11,299

- 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	29	6,398	0	0	0	0	29	6,398	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	24	1,392	0	0	0	0	24	1,392	0	0
Wind	7	4,772	0	0	0	0	0	0	7	4,772
Total	61	12,635	0	0	1	73	53	7,790	7	4,772

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272	579.692	-93.709	461.416	-118.276
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751	3,113.332	-21.32
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**	**3,574.748**	**-139.596**
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125	27,132.413	50.76
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193	865.694	-190.907
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**	**27,998.107**	**-140.147**
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**	**1,193.583**	**-55.962**
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**	**32,766.438**	**-335.705**
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**	**31,380**	**-165**

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

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

Capacity Supply Obligation FCA 16

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

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

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

Capacity Supply Obligation FCA 17

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

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

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

Capacity Supply Obligation FCA 18

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

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

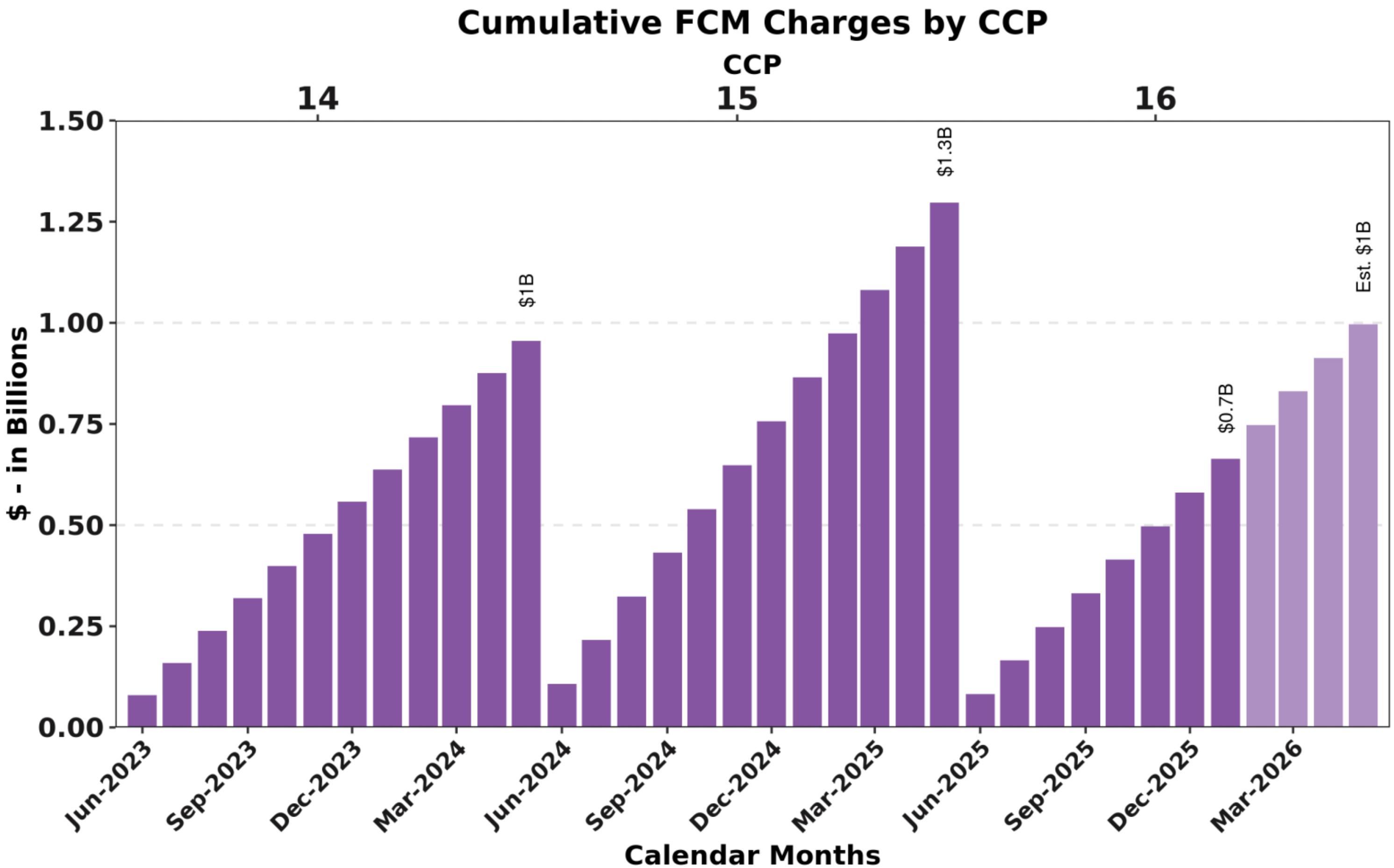
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes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

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**

Forward Capacity Market Auctions



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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
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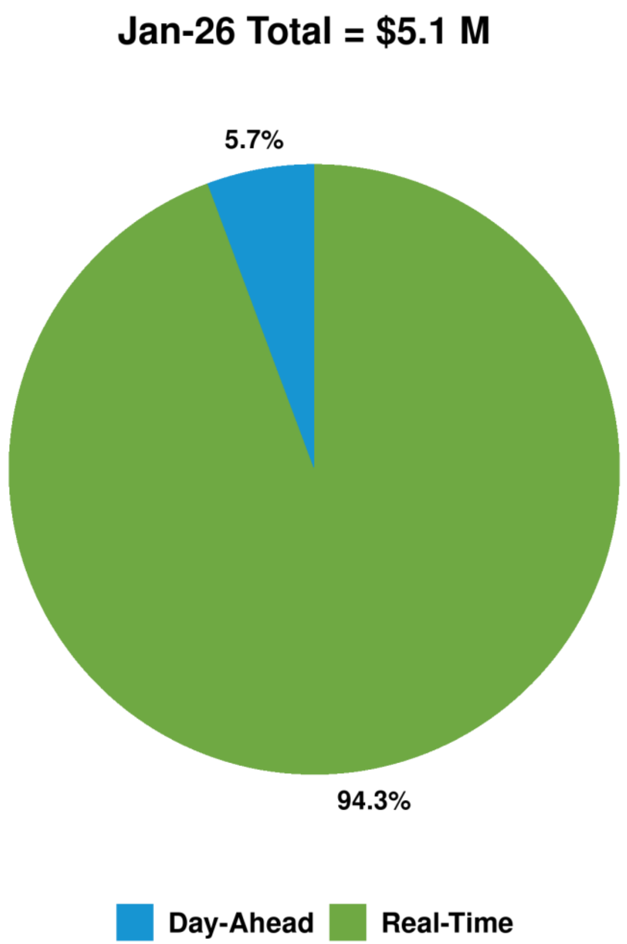
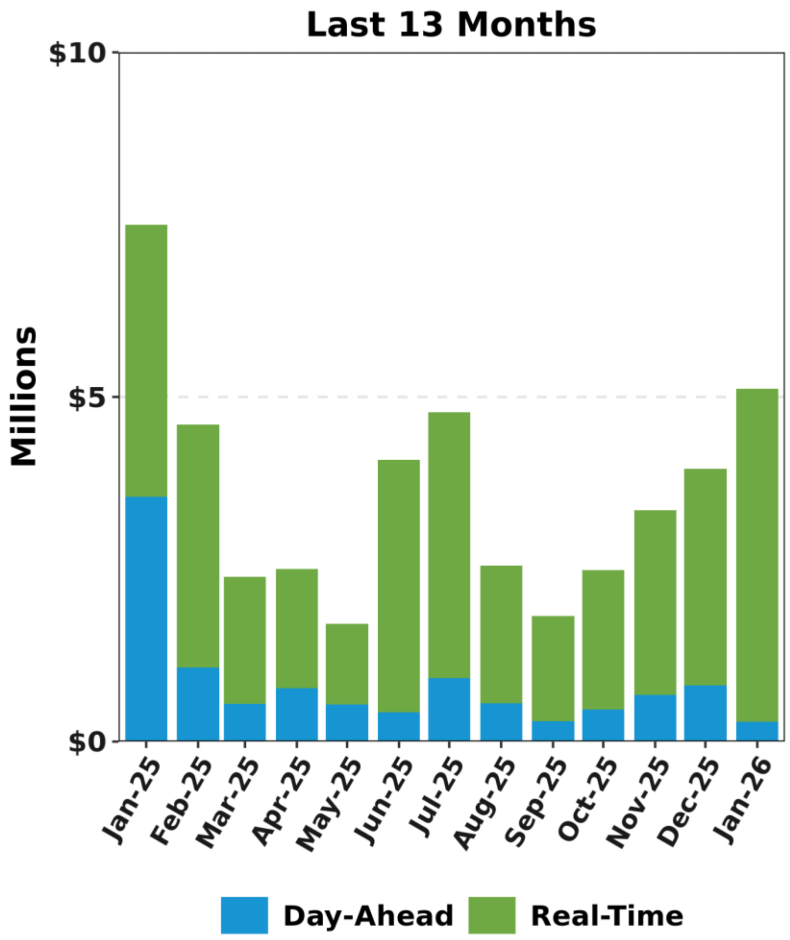
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

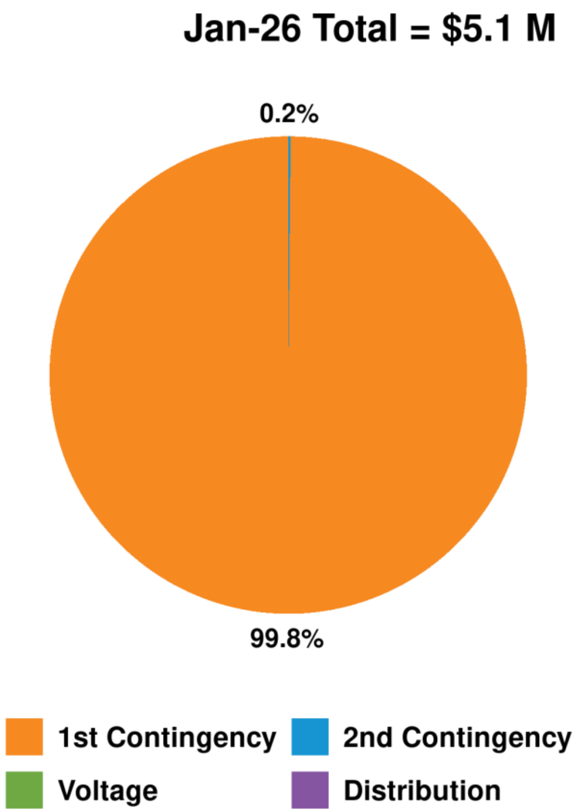
NET COMMITMENT PERIOD COMPENSATION

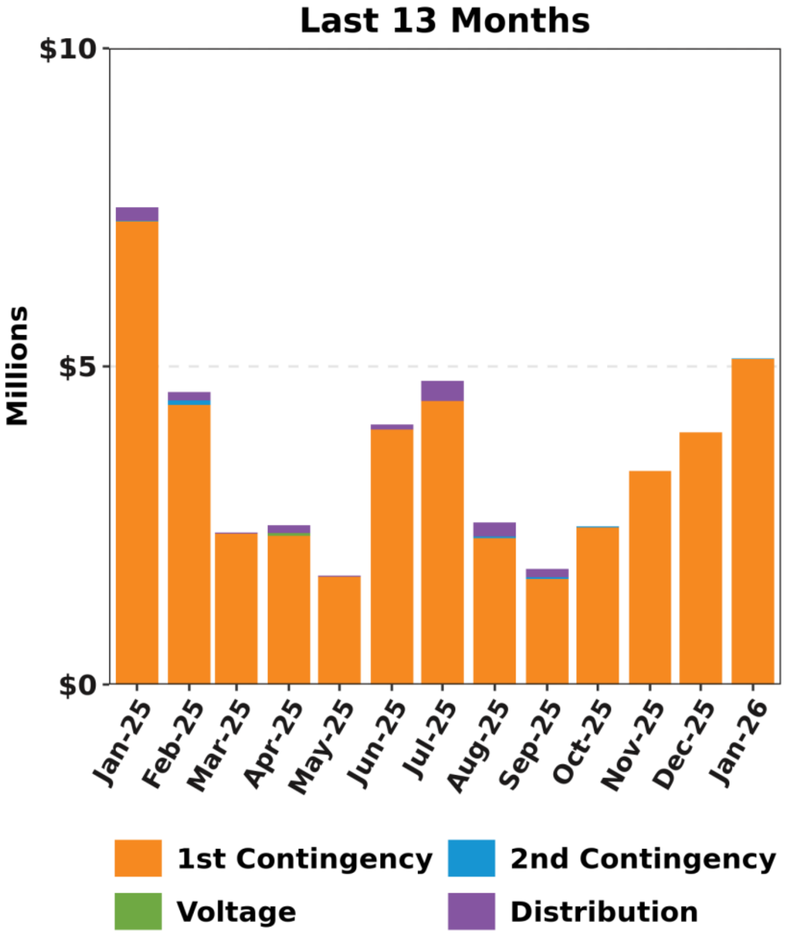
DA and RT NCPC Charges



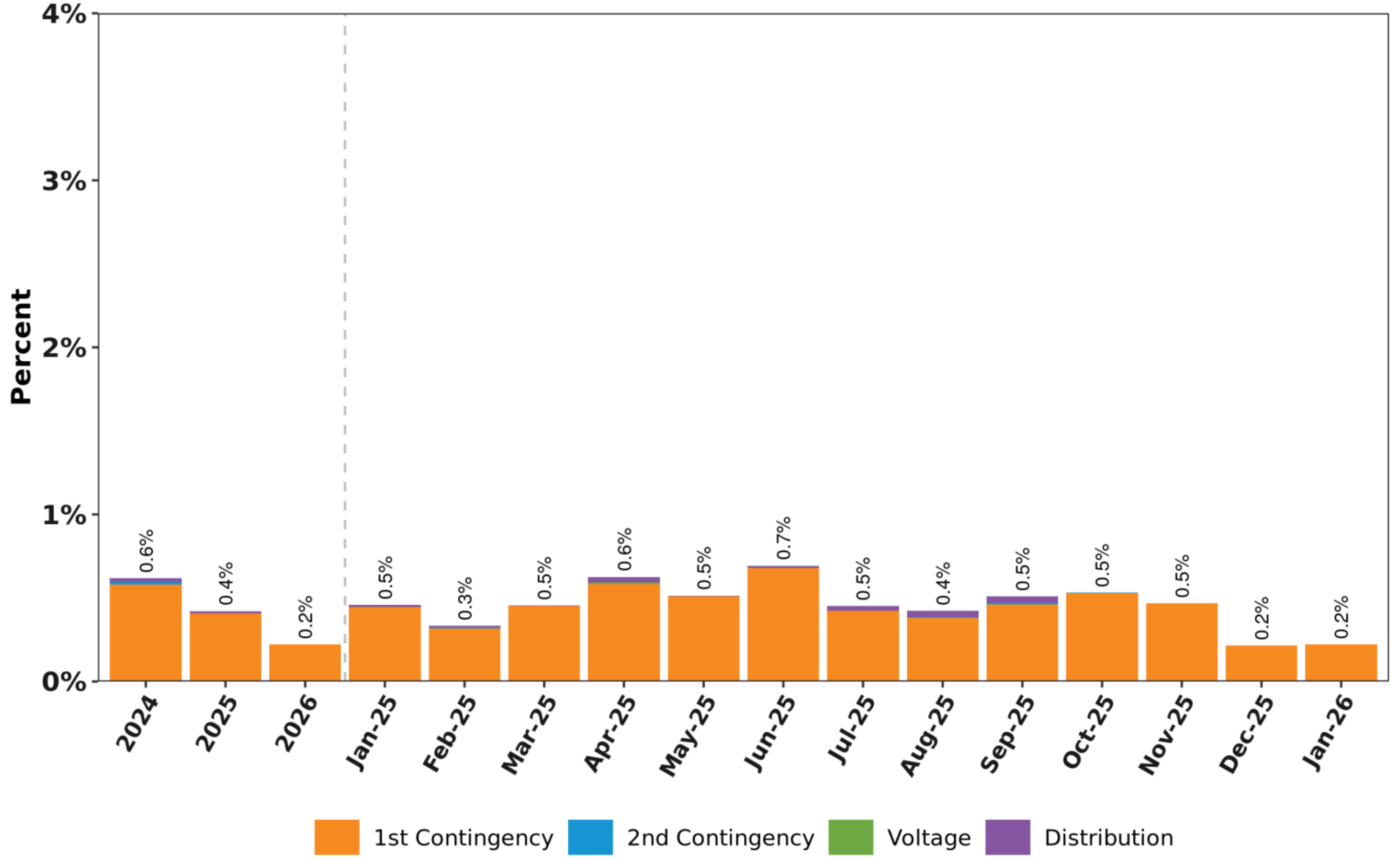


NCPC Charges by Type

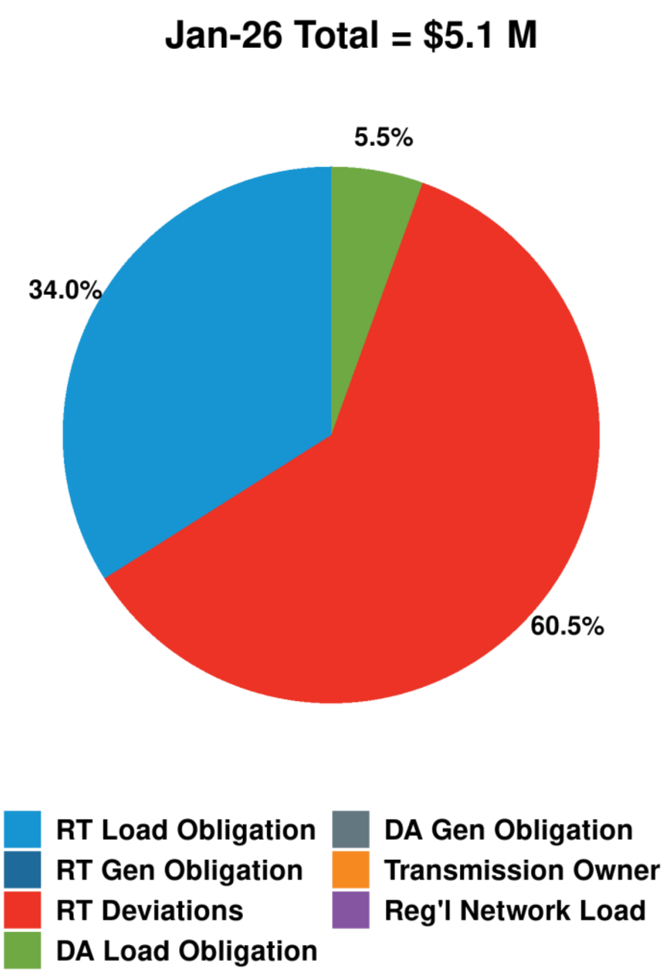


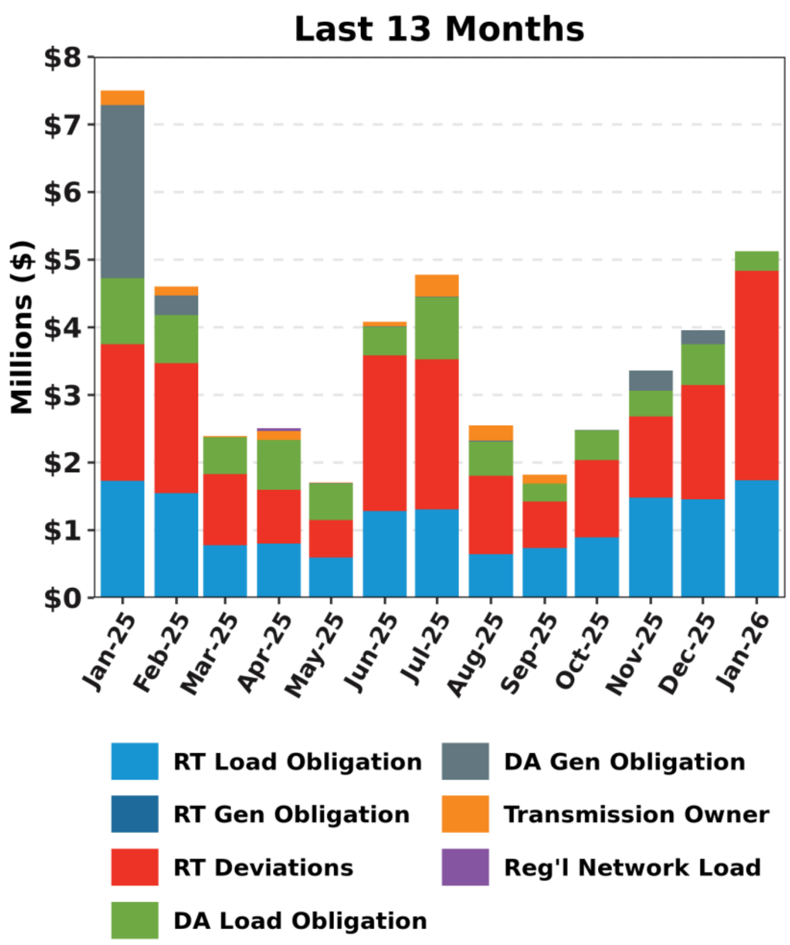


NCPC Charges by Type as Percent of Energy Market Value

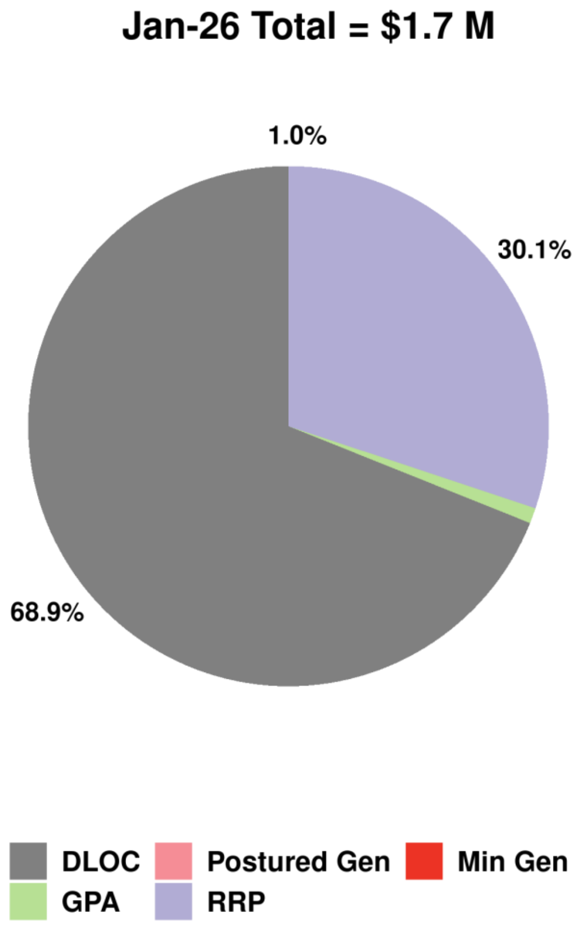


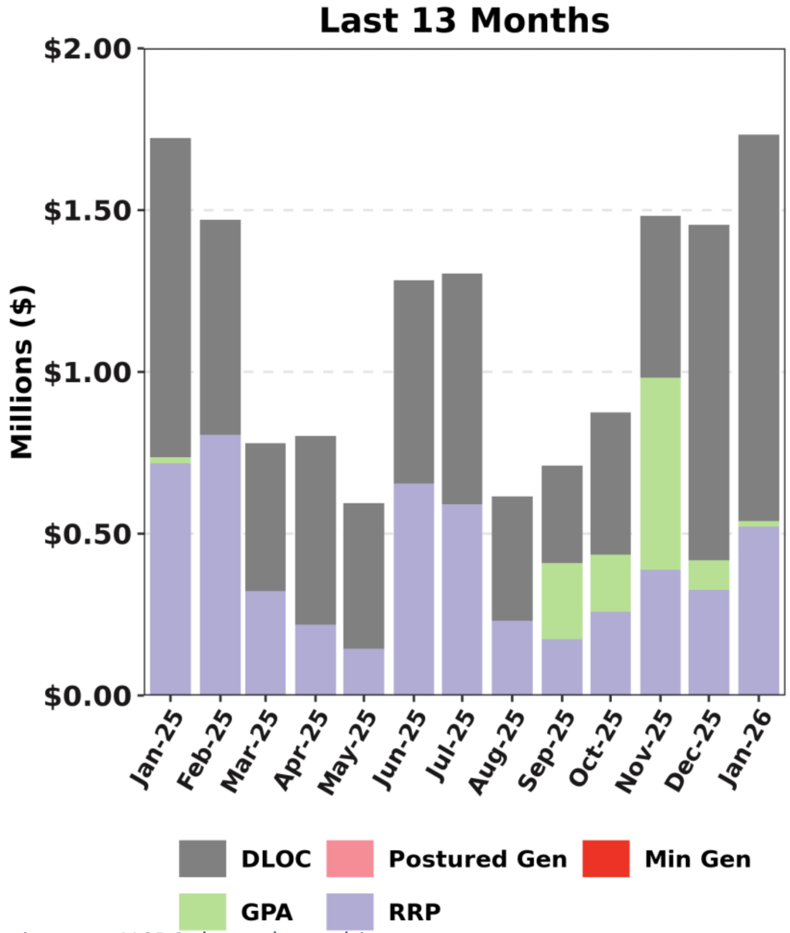
NCPC Charge Allocations





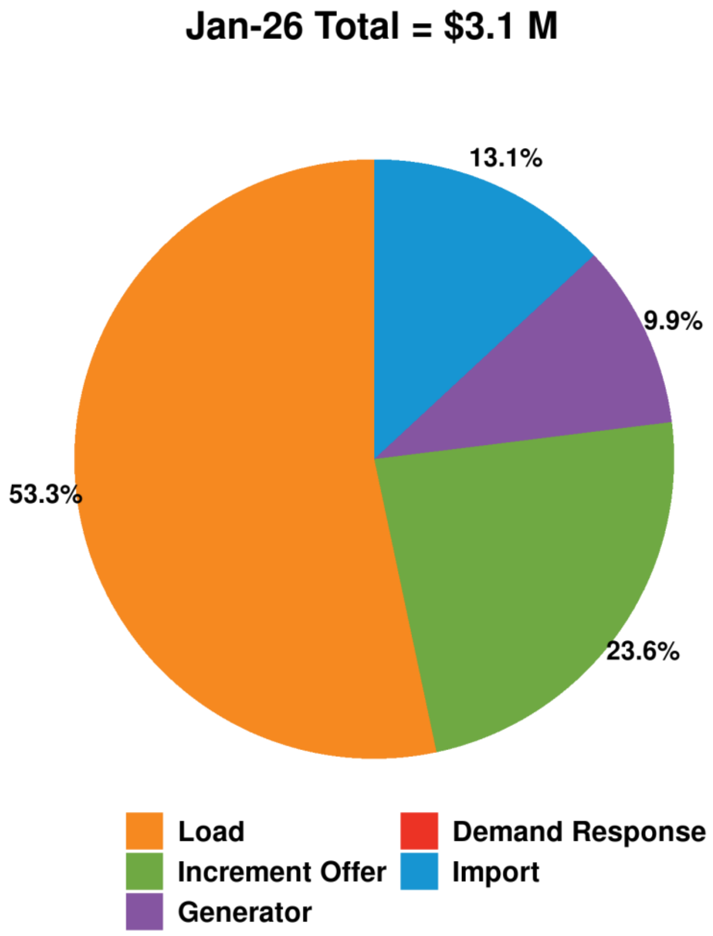
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

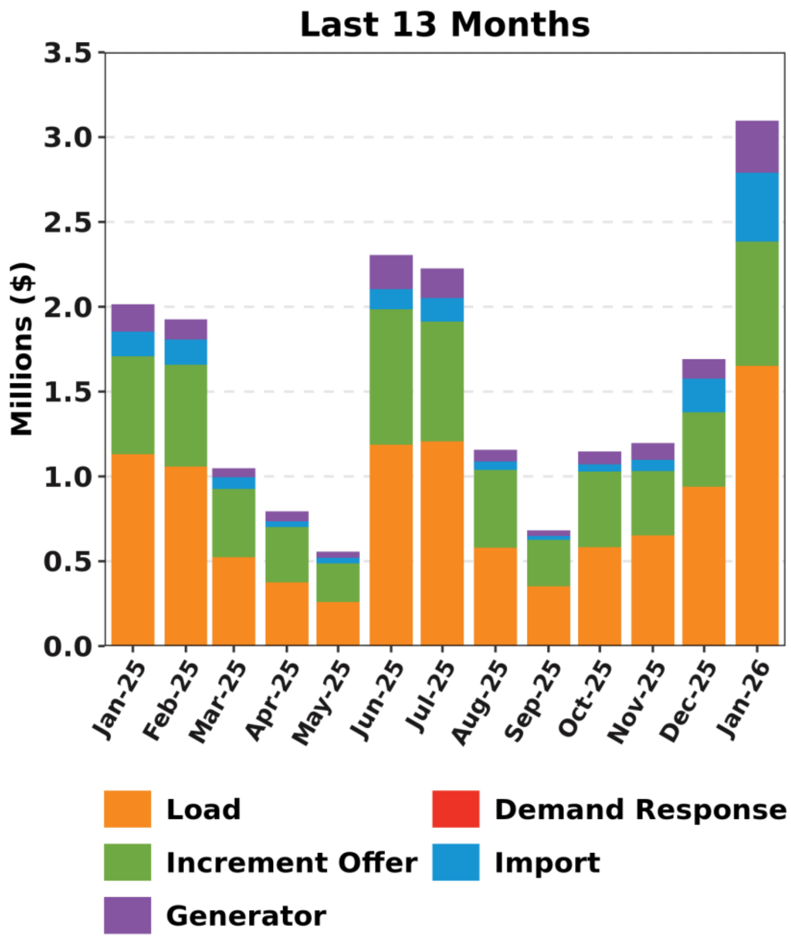




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

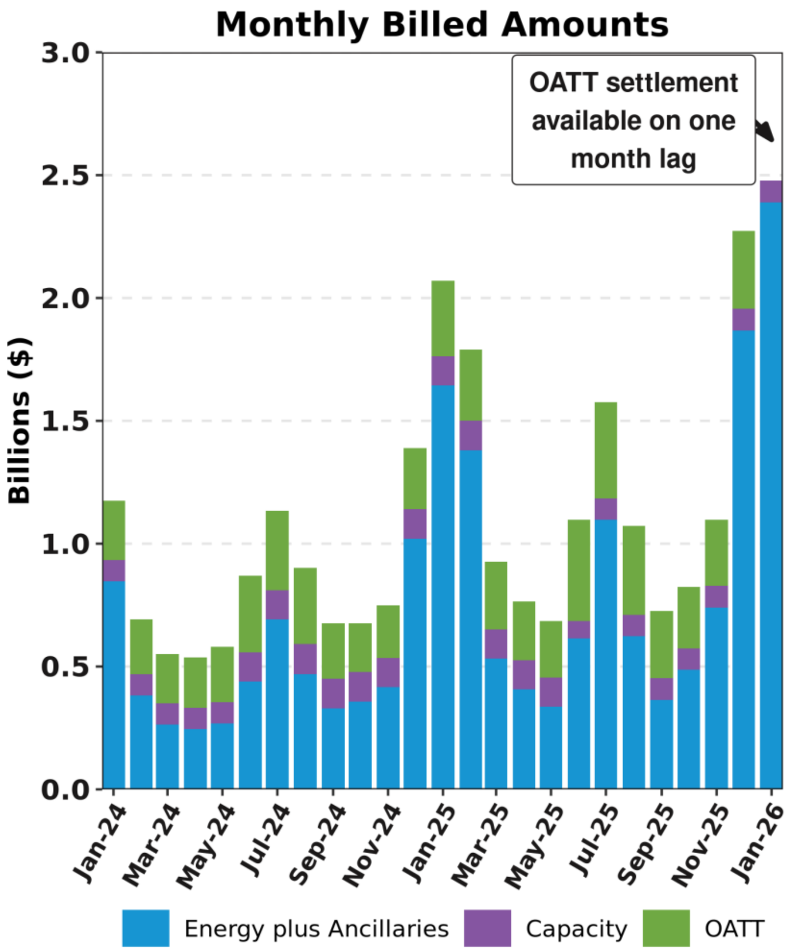
RT First Contingency Charges by Deviation Type

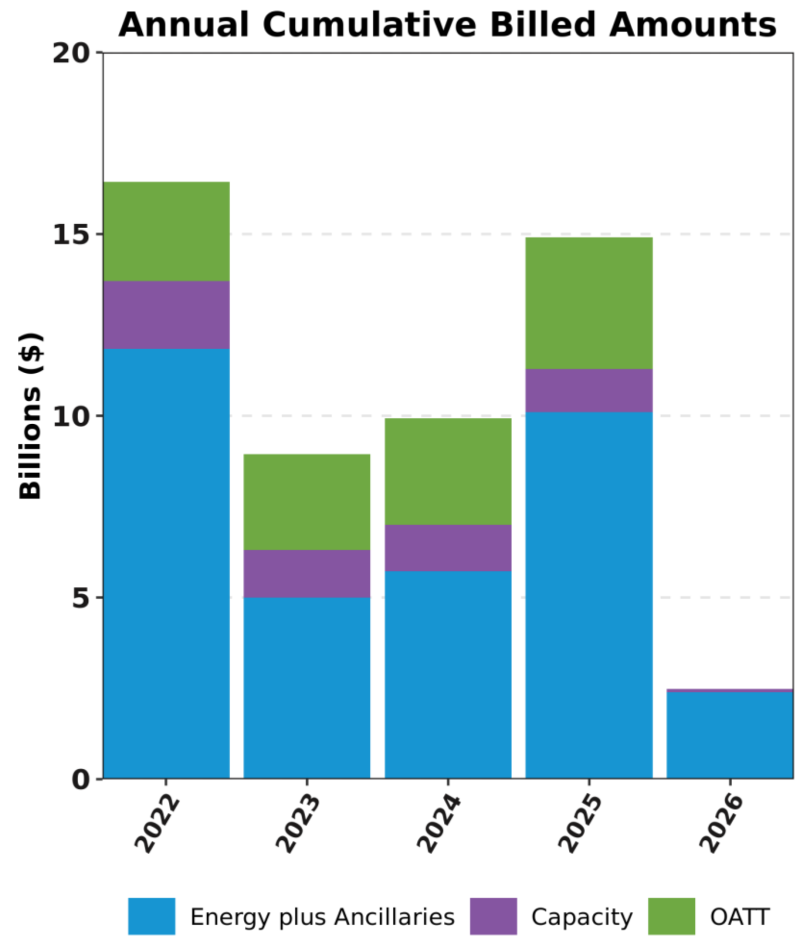




ISO BILLINGS

Total ISO Billings





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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- February 25 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - F206 Structure Replacements (VELCO)
  - 2025 LTTP RFP - Initial Review and RFP Objective Testing

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

2025 Longer-Term Transmission Planning (LTTP) RFP

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

* Unless a bidder can demonstrate supply chain issues that warrant a later in-service date
** Bidders may propose alternate locations which would be more efficient and cost-effective

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

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

* Costs may include estimates for corollary upgrades

Permanent Asset Condition Reviewer

- The ISO began discussions of the permanent asset condition reviewer function at the January Transmission Committee
  - ISO-NE would serve as the region's independent, advisory Asset Condition Reviewer (ACR) for large Asset Condition Projects (ACPs). The function would provide early, technically rigorous reviews of need, scope, alternatives, and cost drivers—without directing projects or making prudency or siting determinations
- Interim project reviews underway to inform permanent design
- Targeting January 2027 go-live, subject to FERC acceptance and operating budget; tariff changes targeted for Q3 2026 filing

Economic Studies: 2026 Study

- The 2026 Economic Study was launched in January
  - The ISO is conducting a public survey as part of a lessons learned
  - The Benchmark scenario will be presented in late Q2 after the lessons learned

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 1/28/2026

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 1/28/2026

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Jun-28	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-26	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 1/28/2026

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	4
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-26	2

SEMA/RI Reliability Projects, cont.

Status as of 1/28/2026

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 1/28/2026

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 1/28/2026

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line	Aug-24	4
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-28	2
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-29	2
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Aug-25	4

Upper Maine Solution Projects, cont.

Status as of 1/28/2026

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	Jun-26	2

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

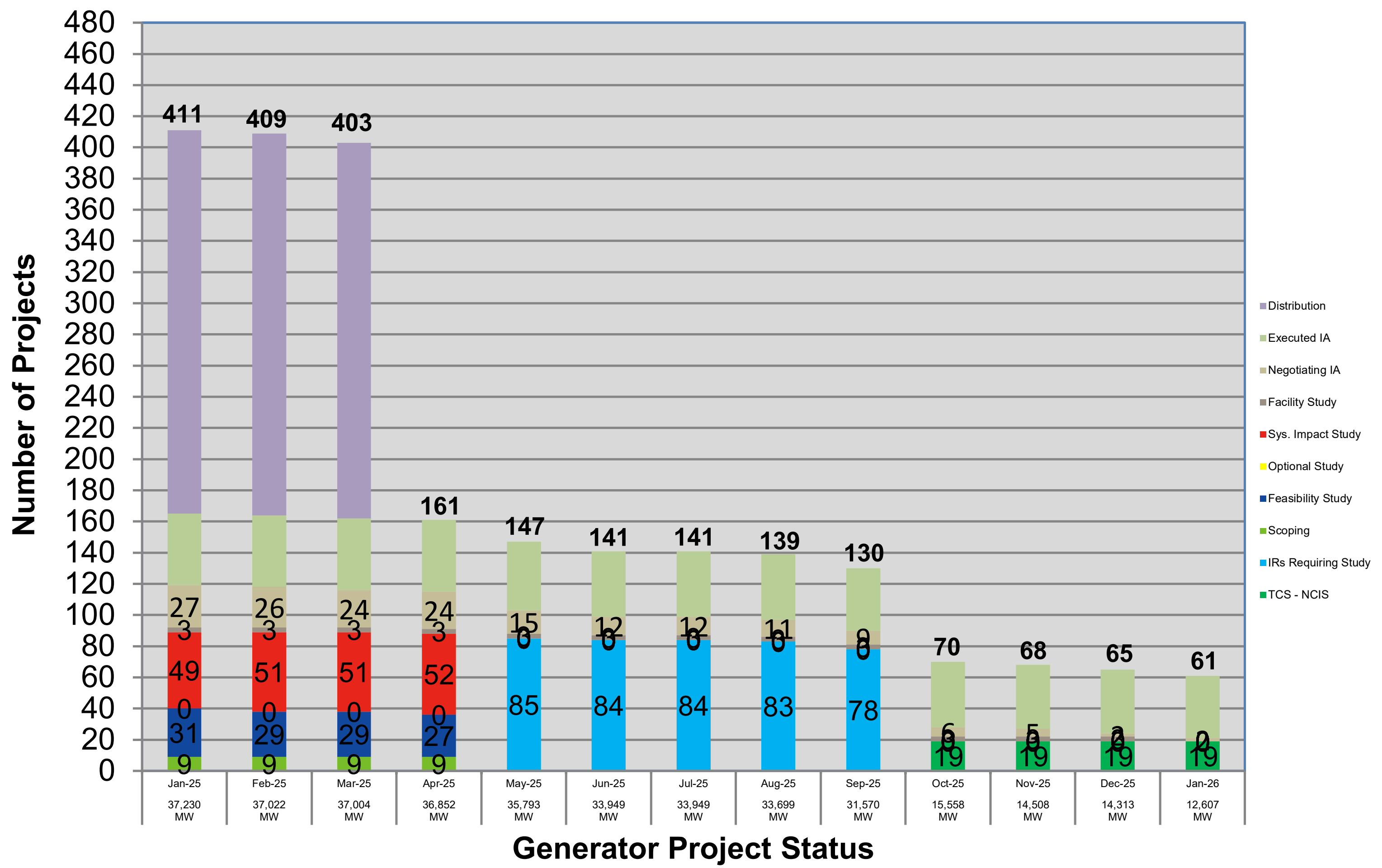
Boston 2033 Solutions Study

Status as of 1/28/2026

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)	May-26	1

Status of Tariff Studies as of January 27, 2026



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

Additional Notes provided on next slide

Status of Tariff Studies as of January 27, 2026, cont.

Additional Notes:

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

OPERABLE CAPACITY ANALYSIS

Winter 2026 Analysis

Winter 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Feb - 2026[2] CSO (MW)	Feb - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,328	29,929
Active Demand Capacity Resource (+) [5]	260	283
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	715	715
Non Commercial Capacity (+)	260	260
Non Gas-fired Planned Outage MW (-)	211	1,366
Gas Generator Outages MW (-)	4	185
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	1,784	1,724
Net Capacity (NET OPCAP SUPPLY MW)	23,464	24,812
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,589	19,589
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,714	21,714
Operable Capacity Margin	1,750	3,098

[1]Operable Capacity is based on data as of **January 28, 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 **January 28, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 14, 2026.**

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

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

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

Winter 2026 Operable Capacity Analysis

90/10 Load Forecast	Feb - 2026[2] CSO (MW)	Feb - 2026[2] SCC (MW)
Operable Capacity MW [1]	27,328	29,929
Active Demand Capacity Resource (+) [5]	260	283
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	715	715
Non Commercial Capacity (+)	260	260
Non Gas-fired Planned Outage MW (-)	211	1,366
Gas Generator Outages MW (-)	4	185
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	2,682	2,754
Net Capacity (NET OPCAP SUPPLY MW)	22,566	23,782
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,633	20,633
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,758	22,758
Operable Capacity Margin	-192	1,024

[1]Operable Capacity is based on data as of **January 28, 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 **January 28, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 14, 2026.**

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

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

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

Winter 2026 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 28, 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 February and March.

Report created: 1/28/2026

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
2/14/2026	27328	260	715	260	211	4	3100	1784	23464	19589	2125	21714	1750	Y	Winter 2025/2026
2/21/2026	27328	260	715	260	111	4	3100	1485	23863	19352	2125	21477	2386	N	Winter 2025/2026
2/28/2026	26648	270	1325	260	476	1	2200	413	25413	18461	2125	20586	4827	N	Winter 2025/2026
3/7/2026	26648	270	1325	260	400	1	2200	307	25595	18147	2125	20272	5323	N	Winter 2025/2026
3/14/2026	26648	270	1325	260	394	598	2200	0	25311	17970	2125	20095	5216	N	Winter 2025/2026
3/21/2026	26648	270	1325	260	548	566	2200	0	25189	17641	2125	19766	5423	N	Winter 2025/2026
3/28/2026	26416	399	1235	385	545	1591	2700	0	23599	17132	2125	19257	4342	N	Winter 2025/2026

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2025 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2026 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

January 28, 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 February and March.

Report created: 1/28/2026

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
2/14/2026	27328	260	715	260	211	4	3100	2682	22566	20633	2125	22758	-192	Y	Winter 2025/2026
2/21/2026	27328	260	715	260	111	4	3100	2233	23115	20384	2125	22509	606	N	Winter 2025/2026
2/28/2026	26648	270	1325	260	476	1	2200	1310	24516	19446	2125	21571	2945	N	Winter 2025/2026
3/7/2026	26648	270	1325	260	400	1	2200	1205	24697	19114	2125	21239	3458	N	Winter 2025/2026
3/14/2026	26648	270	1325	260	394	598	2200	0	25311	18928	2125	21053	4258	N	Winter 2025/2026
3/21/2026	26648	270	1325	260	548	566	2200	0	25189	18582	2125	20707	4482	N	Winter 2025/2026
3/28/2026	26416	399	1235	385	545	1591	2700	0	23599	18045	2125	20170	3429	N	Winter 2025/2026

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2025 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

OPERABLE CAPACITY ANALYSIS

Preliminary Spring 2026 Analysis

Preliminary Spring 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2026[2] CSO (MW)	May - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,416	29,929
Active Demand Capacity Resource (+) [5]	399	283
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	385	385
Non Gas-fired Planned Outage MW (-)	1,978	3,164
Gas Generator Outages MW (-)	2,974	3,282
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,083	21,986
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,794	18,794
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,919	20,919
Operable Capacity Margin	-836	1,067

[1]Operable Capacity is based on data as of **January 28, 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 **January 28, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 9, 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.

Preliminary Spring 2026 Operable Capacity Analysis

90/10 Load Forecast	May - 2026[2] CSO (MW)	May - 2026[2] SCC (MW)
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Active Demand Capacity Resource (+) [5]	399	283
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Non Commercial Capacity (+)	385	385
Non Gas-fired Planned Outage MW (-)	1,978	3,164
Gas Generator Outages MW (-)	2,974	3,282
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,083	21,986
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,620	19,620
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,745	21,745
Operable Capacity Margin	-1,662	241

[1]Operable Capacity is based on data as of **January 28, 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 **January 28, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 9, 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.

Preliminary Spring 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 28, 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 April and May.

Report created: 1/28/2026

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
4/4/2026	26416	399	1235	385	2953	2526	2700	0	20256	16687	2125	18812	1444	N	Spring 2026
4/11/2026	26416	399	1235	385	4485	2854	2700	0	18396	16460	2125	18585	-189	N	Spring 2026
4/18/2026	26416	399	1177	385	4378	3350	2700	0	17949	16001	2125	18126	-177	N	Spring 2026
4/25/2026	26416	399	1177	385	3166	2703	3400	0	19108	15762	2125	17887	1221	N	Spring 2026
5/2/2026	26416	399	1177	385	2477	4413	3400	0	18087	15738	2125	17863	224	N	Spring 2026
5/9/2026	26416	399	1235	385	1978	2974	3400	0	20083	18794	2125	20919	-836	Y	Spring 2026
5/16/2026	26416	399	1235	385	1438	1836	3400	0	21761	19668	2125	21793	-32	N	Spring 2026
5/23/2026	26416	399	1235	385	1035	1836	3400	0	22164	20479	2125	22604	-440	N	Spring 2026

Column Definitions

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These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
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7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2025 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Preliminary Spring 2026 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

January 28, 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 April and May.

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	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4/4/2026	26416	399	1235	385	2953	2526	2700	0	20256	17576	2125	19701	555	N	Spring 2026
4/11/2026	26416	399	1235	385	4485	2854	2700	0	18396	17338	2125	19463	-1067	N	Spring 2026
4/18/2026	26416	399	1177	385	4378	3350	2700	0	17949	16854	2125	18979	-1030	N	Spring 2026
4/25/2026	26416	399	1177	385	3166	2703	3400	0	19108	16602	2125	18727	381	N	Spring 2026
5/2/2026	26416	399	1177	385	2477	4413	3400	0	18087	16577	2125	18702	-615	N	Spring 2026
5/9/2026	26416	399	1235	385	1978	2974	3400	0	20083	19620	2125	21745	-1662	Y	Spring 2026
5/16/2026	26416	399	1235	385	1438	1836	3400	0	21761	20531	2125	22656	-895	N	Spring 2026
5/23/2026	26416	399	1235	385	1035	1836	3400	0	22164	21378	2125	23503	-1339	N	Spring 2026

Column Definitions

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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