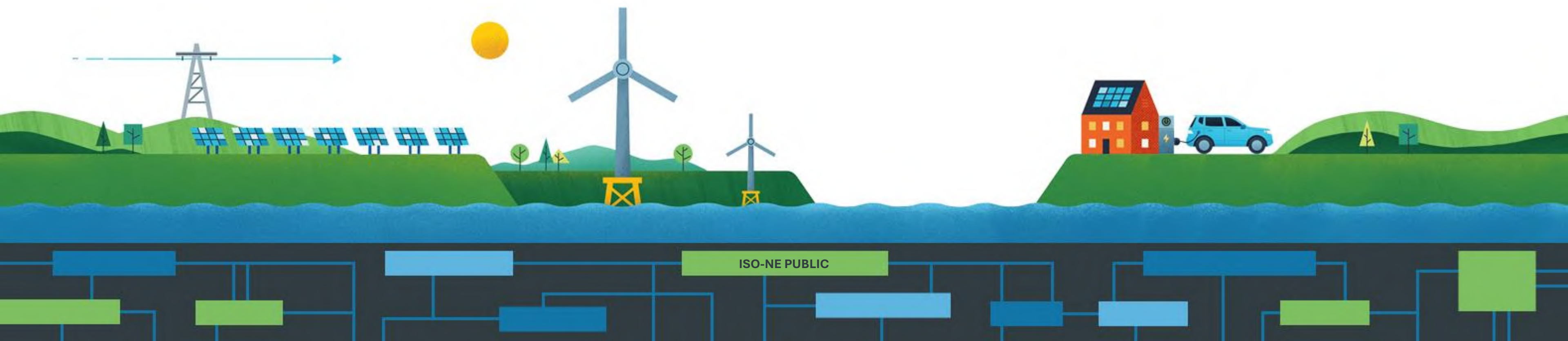
MARCH 5, 2026| SHERATON BOSTON HOTEL, BOSTON

NEPOOL Participants Committee

System & Market Operations Report – March 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



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HIGHLIGHTS

Settled data through February 25th

Highlights: February 2026

- **Peak Hour** on February 8
  - 20,178 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 p.m.
- **Minimum Telemetered Load**
  - 11,064 MW; hour ending 1:00 p.m. on Sunday, February 15
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $134.93/MWh
  - Real-Time (RT) Hub LMP: $136.29/MWh
  - Natural Gas: $15.44/MMBtu (MA Natural Gas Avg)
- **Energy Market** value $1.44B up from $1.38B in February 2025
  - Ancillary Markets* value $15.8M up from $4.8M in February 2025
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 99.6% during February, down from 100.2% during January
  - Updated January Energy Market value: $2.7B
- **Net Commitment Period Compensation (NCPC)** total $3.4M
  - Represents 0.2% of monthly Energy Market value
  - First Contingency $3.4M
    - Dispatch Lost Opportunity Cost (DLOC) - $1.1M; Rapid Response Pricing (RRP) Opportunity Cost - $258K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $28K paid to resources at external locations, down $85K from January
      - $9K charged to Day-Ahead Load Obligation (DALO) at external locations; $18K to Day-Ahead Generation Obligation (DAGO) at external locations; $1K to RT Deviations
  - 2nd Contingency, Distribution and Voltage was zero
- **Forward Capacity Market (FCM)** market value $88.9M
  - FCM peak for 2026 is currently 19,937 MWh

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

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

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

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **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 (SORs). Due to the difference in calculation methodologies and the impact of SORs, these values can occur on different days and/or hours. Both are 'net energy for load' concepts and include transmission losses. FCM load values reflect the sum of active, normal load assets that are non-dispatchable, are included in the FCM settlement and do not include transmission losses.

Day-Ahead Ancillary Services (DAAS) Results

- Average daily total DA E&AS Market value: **$59.3M**
- DAAS Settlements:
  – Average daily Gross (pre-closeout) DAAS Credits: **$1,784K**
    - Includes EIR, TMOR, TMNSR, and TMOR
  – Net (post-closeout) DAAS Credits per MWh Cleared: **$15.09/MWh**
  – Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **1.5%**
- FER Credits* as % of total DA E&AS Market Value: **6.3%**
- Energy Gap:
  – Average hourly cleared EIR MWh: **115 MWh**
  – Average hourly cleared FER Price: **$9.56/MWh**

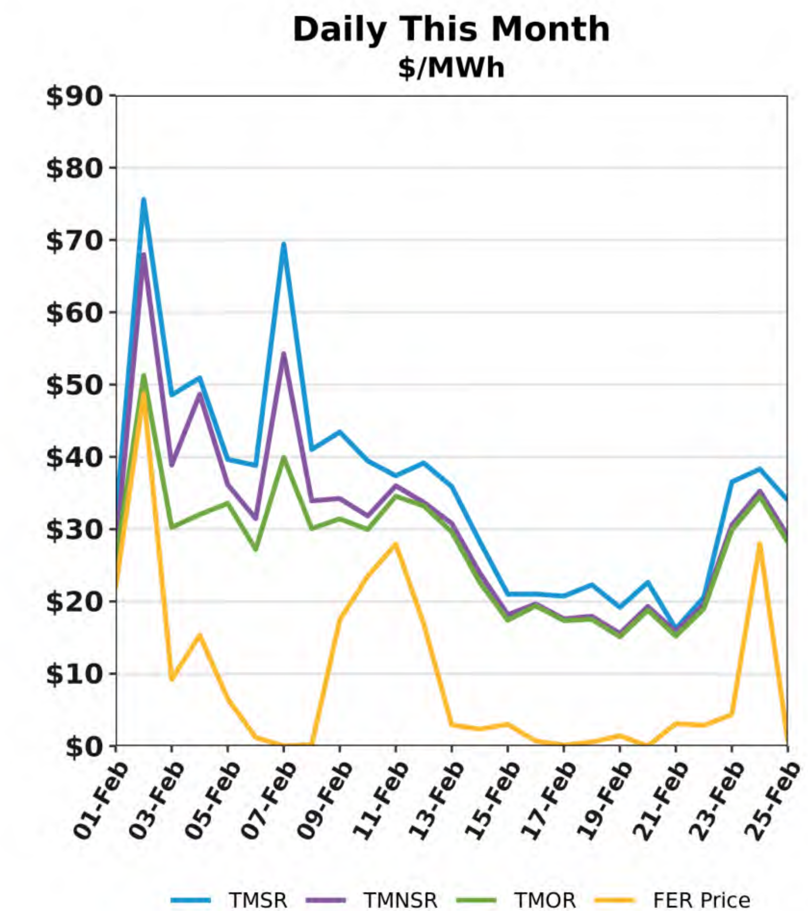
DA E&AS refers to DA Energy and Ancillary Services
*FER credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR)
FER credits are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)

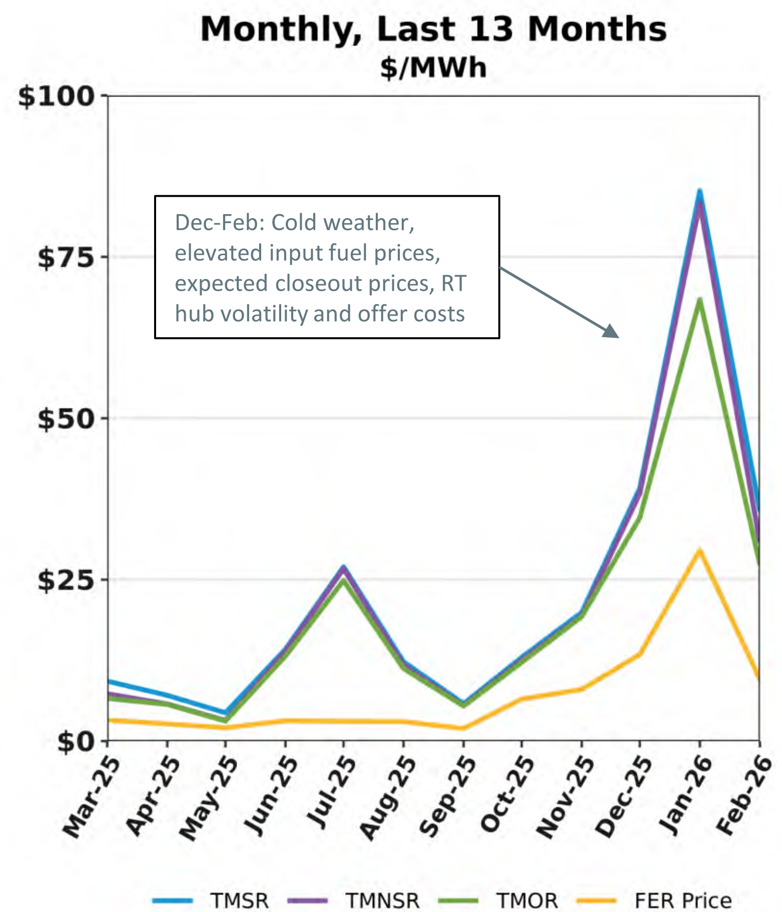
DAAS Results (continued)...

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
03/01/2025	$17.1M	$466K	$202K	$3.37	1.2%	$979K	175K	$3.25	5.7%	176
04/01/2025	$13.6M	$332K	$175K	$3.23	1.3%	$760K	127K	$2.66	5.6%	97
05/01/2025	$10.9M	$190K	$52K	$0.94	0.5%	$563K	163K	$2.06	5.2%	155
06/01/2025	$20.1M	$885K	$173K	$2.97	0.9%	$1,287K	160K	$3.15	6.4%	125
07/01/2025	$35.6M	$1,704K	$1,139K	$19.53	3.2%	$1,277K	114K	$3.06	3.6%	55
08/01/2025	$20.2M	$747K	$544K	$9.57	2.7%	$1,292K	147K	$3.02	6.4%	94
09/01/2025	$12.3M	$320K	$184K	$3.21	1.5%	$587K	138K	$1.94	4.8%	104
10/01/2025	$15.5M	$719K	$478K	$8.21	3.1%	$1,911K	202K	$6.50	12.3%	209
11/01/2025	$24.8M	$1,123K	$458K	$7.85	1.9%	$2,550K	210K	$8.00	10.3%	135
12/01/2025	$60.9M	$2,131K	$1,053K	$18.20	1.7%	$4,916K	227K	$13.42	8.1%	107
01/01/2026	$91.1M	$4,617K	$3,241K	$55.53	3.6%	$12,042K	203K	$29.54	13.2%	127
02/01/2026	$59.3M	$1,784K	$879K	$15.09	1.5%	$3,708K	165K	$9.56	6.3%	115

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
- 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)

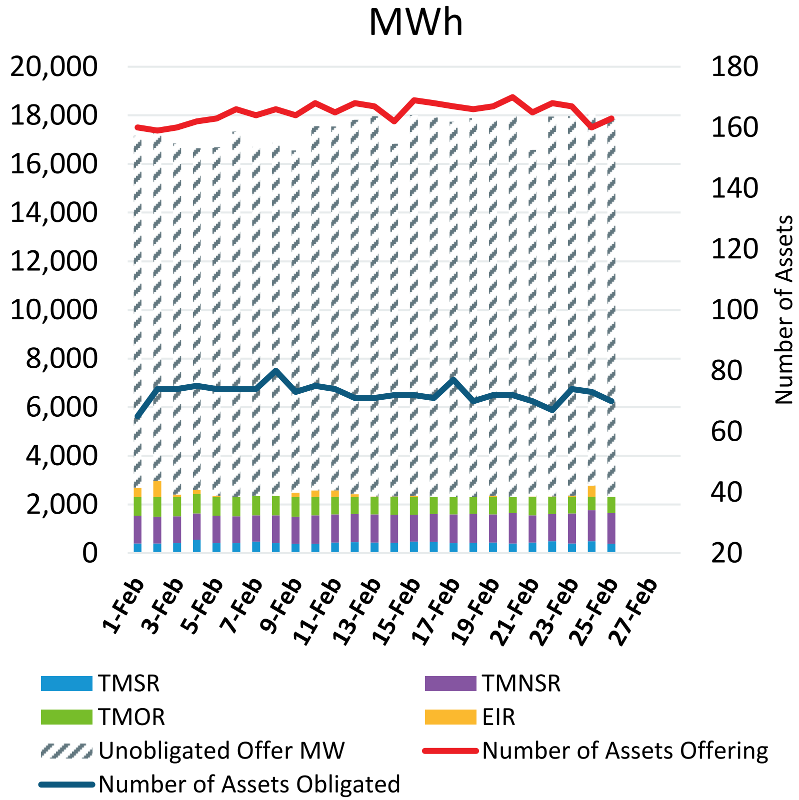
Average Hourly DAAS Prices



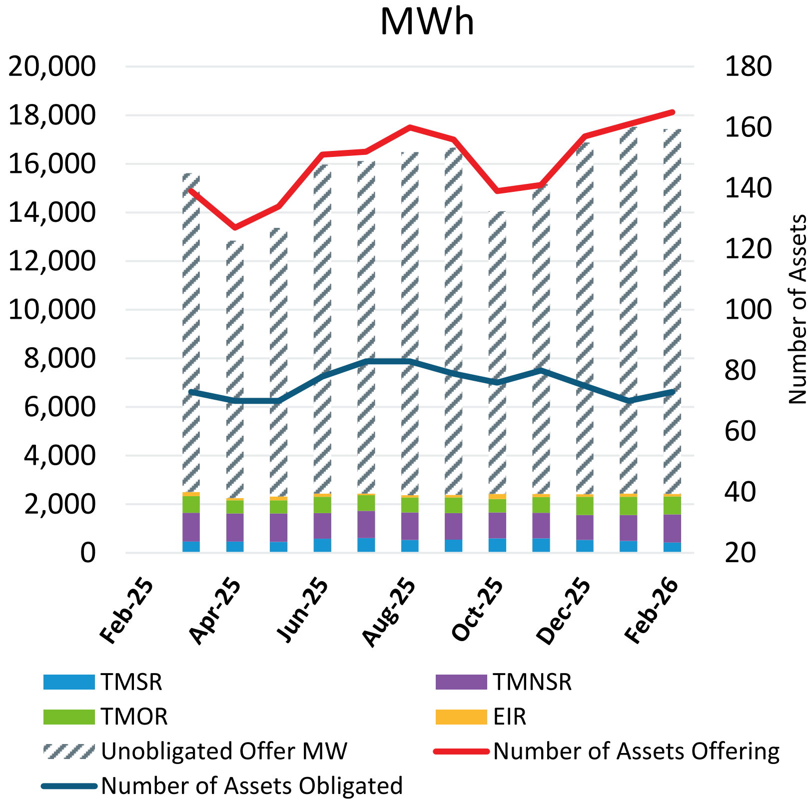


Average Hourly DAAS Offered* and Awarded Amounts

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 March Planning Advisory Committee meeting

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. Final qualified capacities were issued on February 13, 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
    - The Show of Interest window for the 2026 interim RA qualification process will open on April 16, 2026
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

Load Forecast

- Stakeholder discussions related to CELT 2026 will continue at the next Load Forecast Committee on March 27

NEW ENGLAND WINTER REVIEW 2025/2026

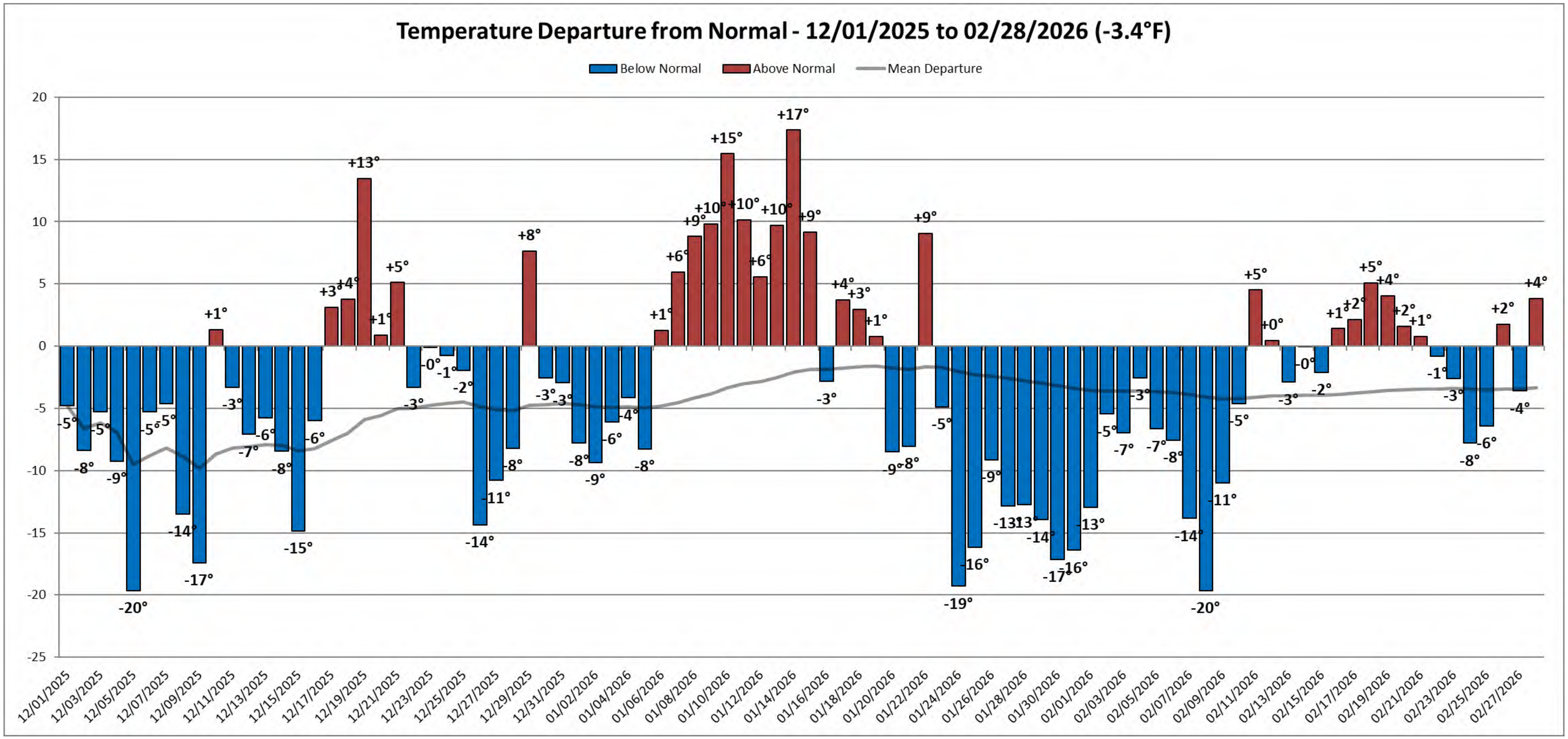
Winter 2025/2026 Highlights

- Winter 2025/2026 temperatures in New England were consistently below normal, making it the region's coldest winter in 20 years; average temperature departure from normal was -3.4°F
- Peak winter load reached 20,182 MW on January 25 - slightly above the 50/50 forecast of 20,056 MW; total winter energy demand was the highest in 11 years
- A widespread and long-duration cold weather outbreak occurred from January 23 through February 10
- Timely replenishment of LNG and fuel oil was essential to maintaining reliable operations; fuel oil inventories ended the winter ~19M gallons below starting levels following a record burn of ~139M gallons
- The New England generation fleet and transmission system performed well overall; surplus generating capacity was available throughout the winter and no capacity deficiency events occurred
- New records for Energy Market value were set this winter, both in total and for the months of December and January

Winter Preparations

- ISO staff met with industry and governmental officials to review communication protocols and seasonal expectations including capacity, energy, and demand forecasts
- ISO System Operations staff hosted a Generator Winter Readiness Webinar on October 29, 2025
- Annual Winter Generator Readiness Survey was distributed to all generating resources in the region
- The Annual Natural Gas Critical Infrastructure Survey process was completed to ensure critical infrastructure is not part of automatic or manual load shed schemes
- Dual fuel audits of ~30 generators totaling ~6,500 MW of capacity were completed ahead of winter
- ISO staff performed probabilistic winter energy assessments using the Probabilistic Energy Adequacy Tool (PEAT)

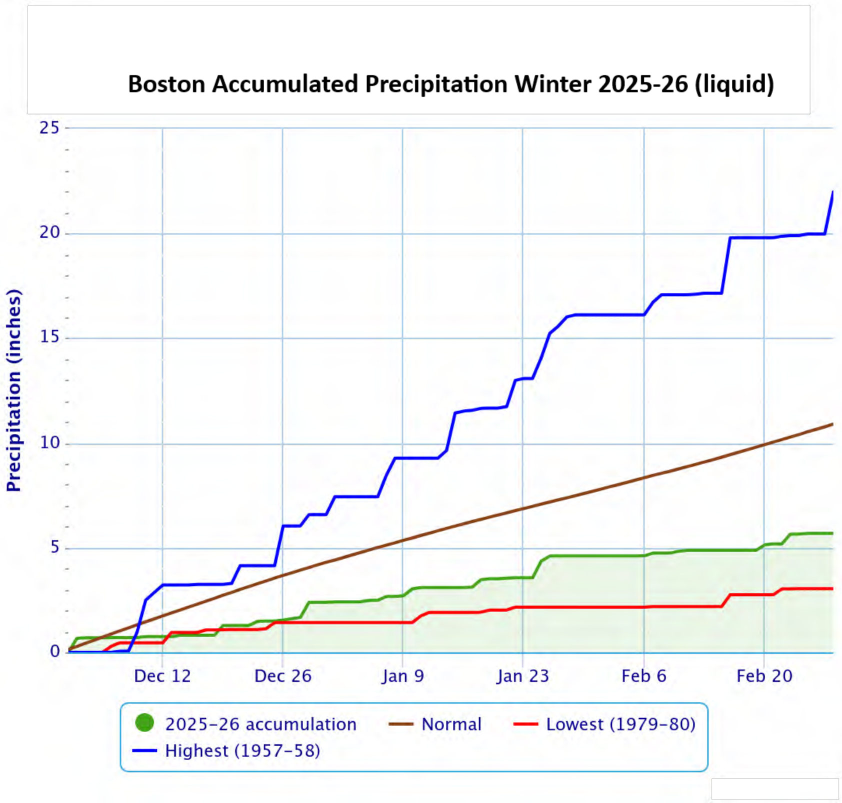
Winter Average Temperature Was 3.4°F Below Normal Resulting in the Coldest Winter in 20 Years

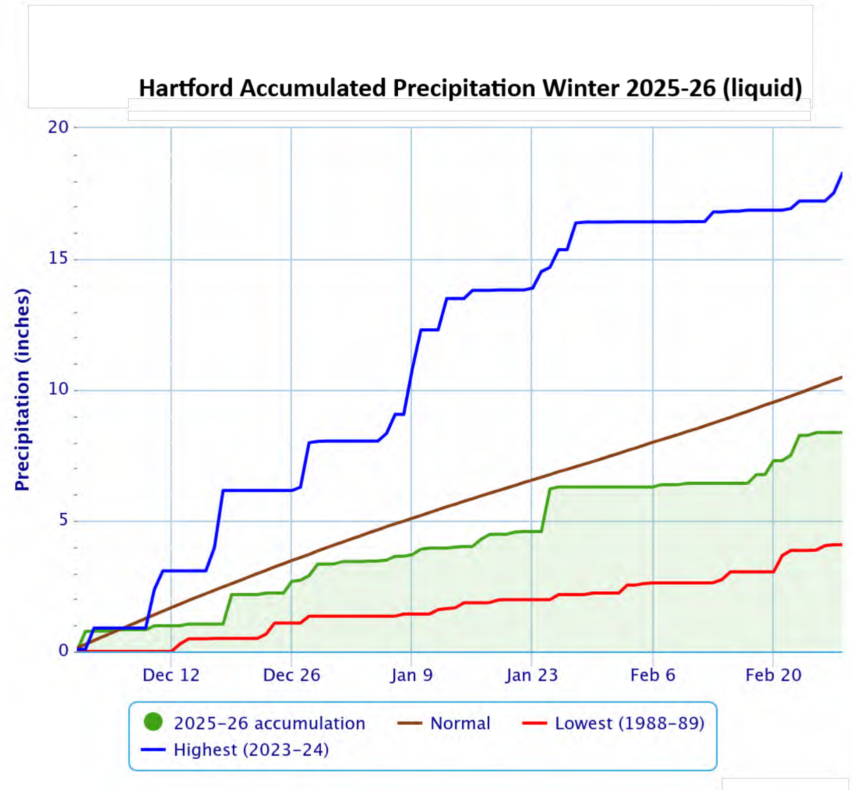


*Temperatures in the figure above are based on a New England 23-city weighted average

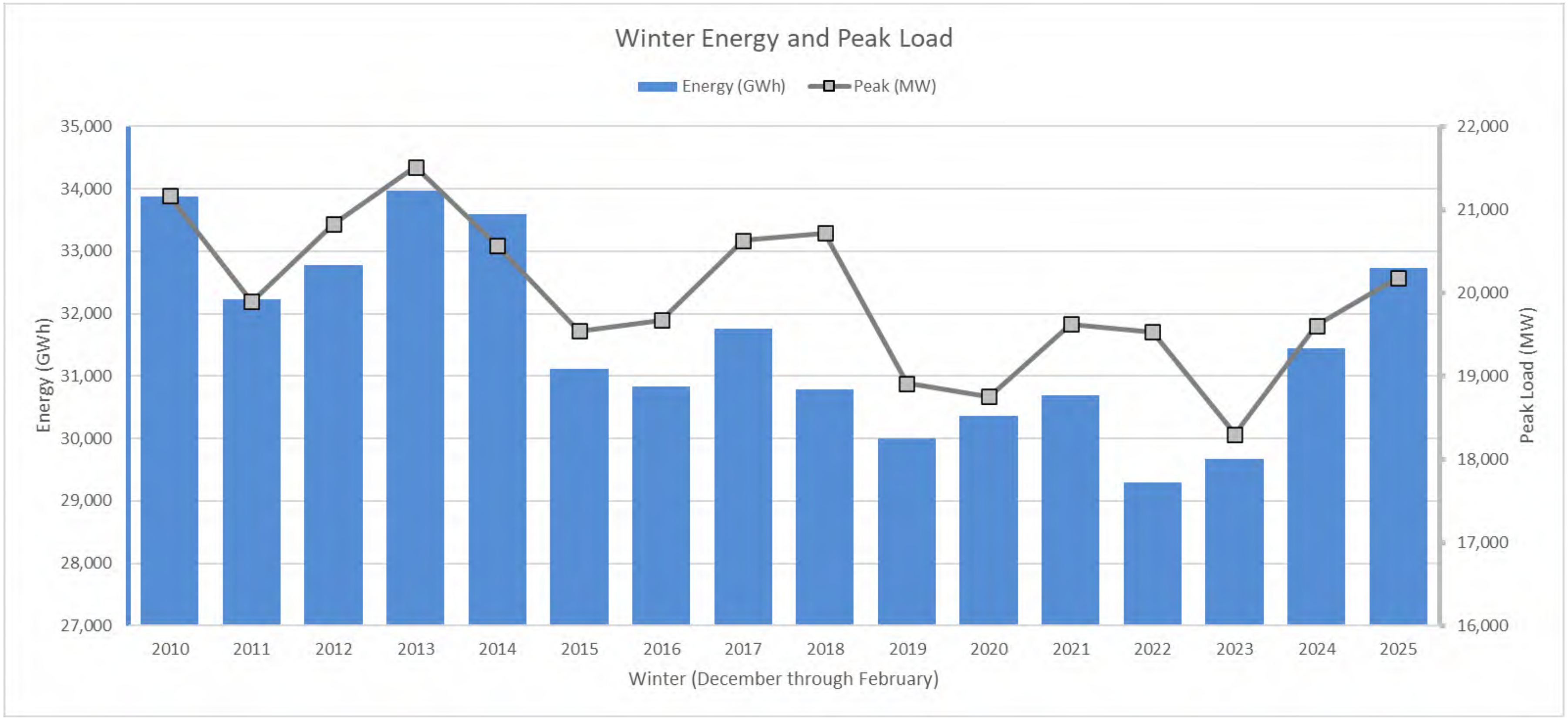
Total Precipitation Amounts Were Below Normal Across the Region

- Boston
  - 60.9” of snowfall recorded; 23.2” above normal
  - Total precipitation was 5.22” below normal
- Hartford
  - 52.3” of snowfall recorded; 13.2” above normal
  - Total precipitation was 2.12” below normal

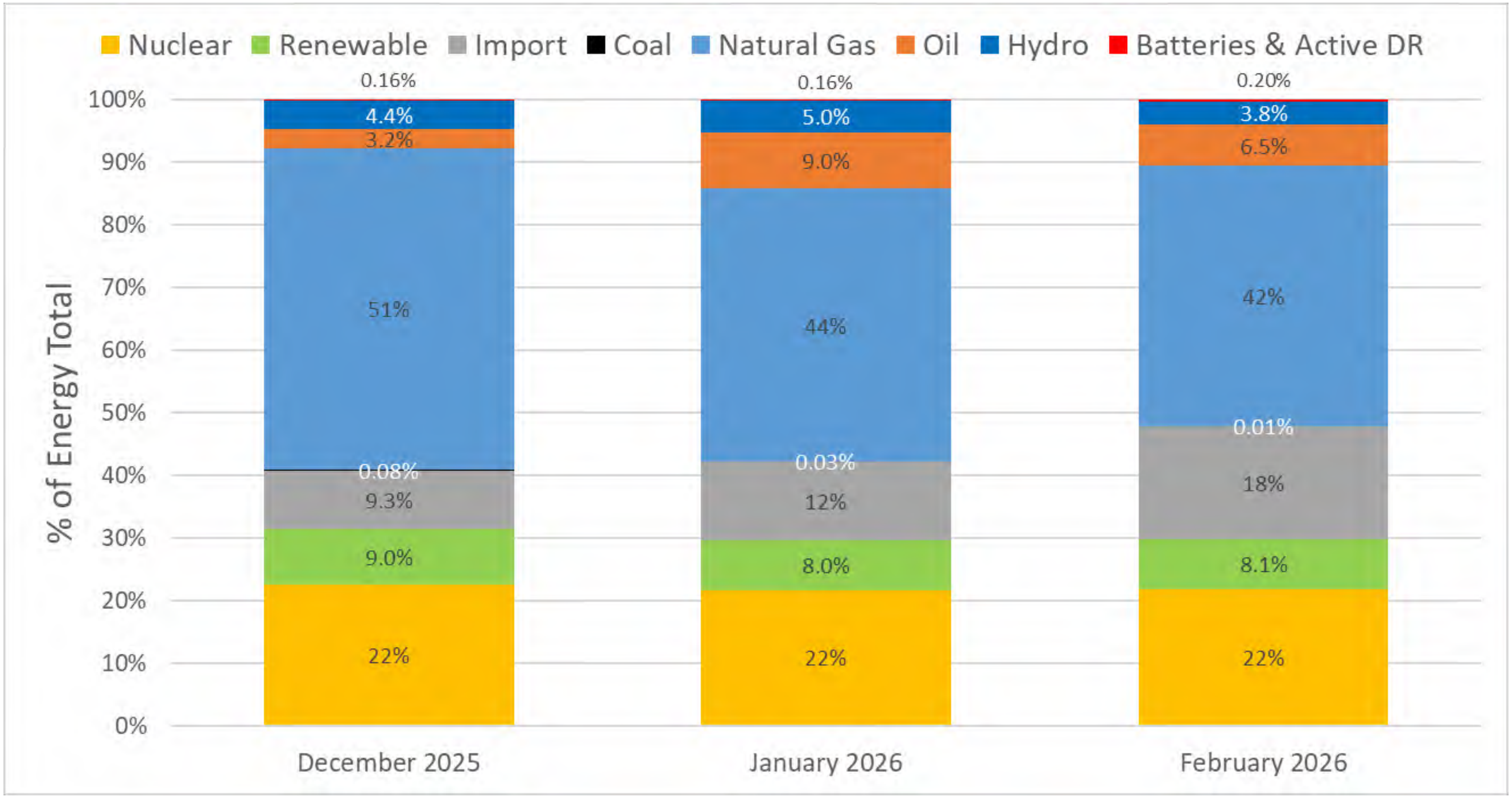




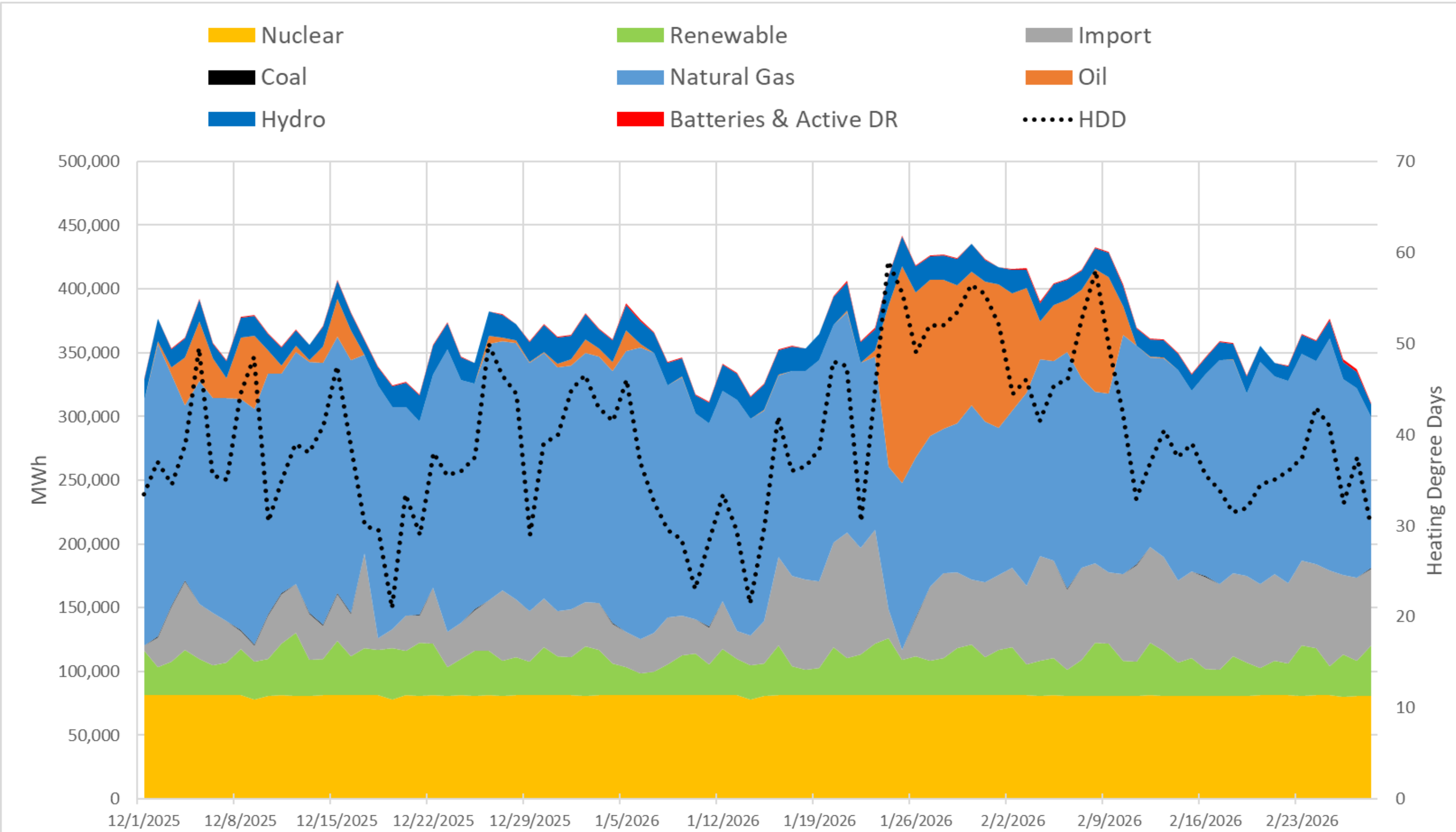
Winter Energy Demand Was the Highest Since 2014



Winter Energy Sources, by Month

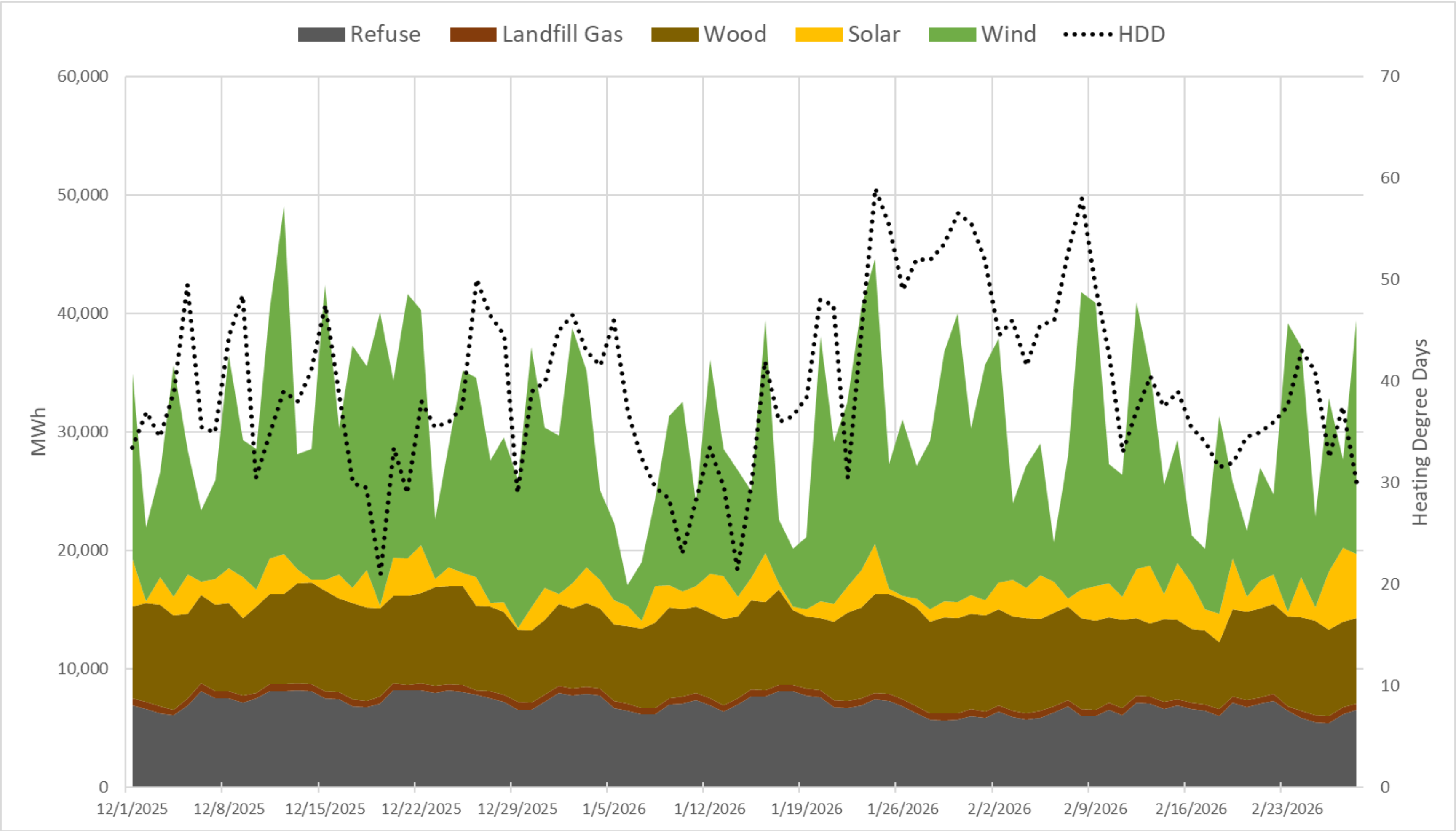


Winter Energy Sources, by Day



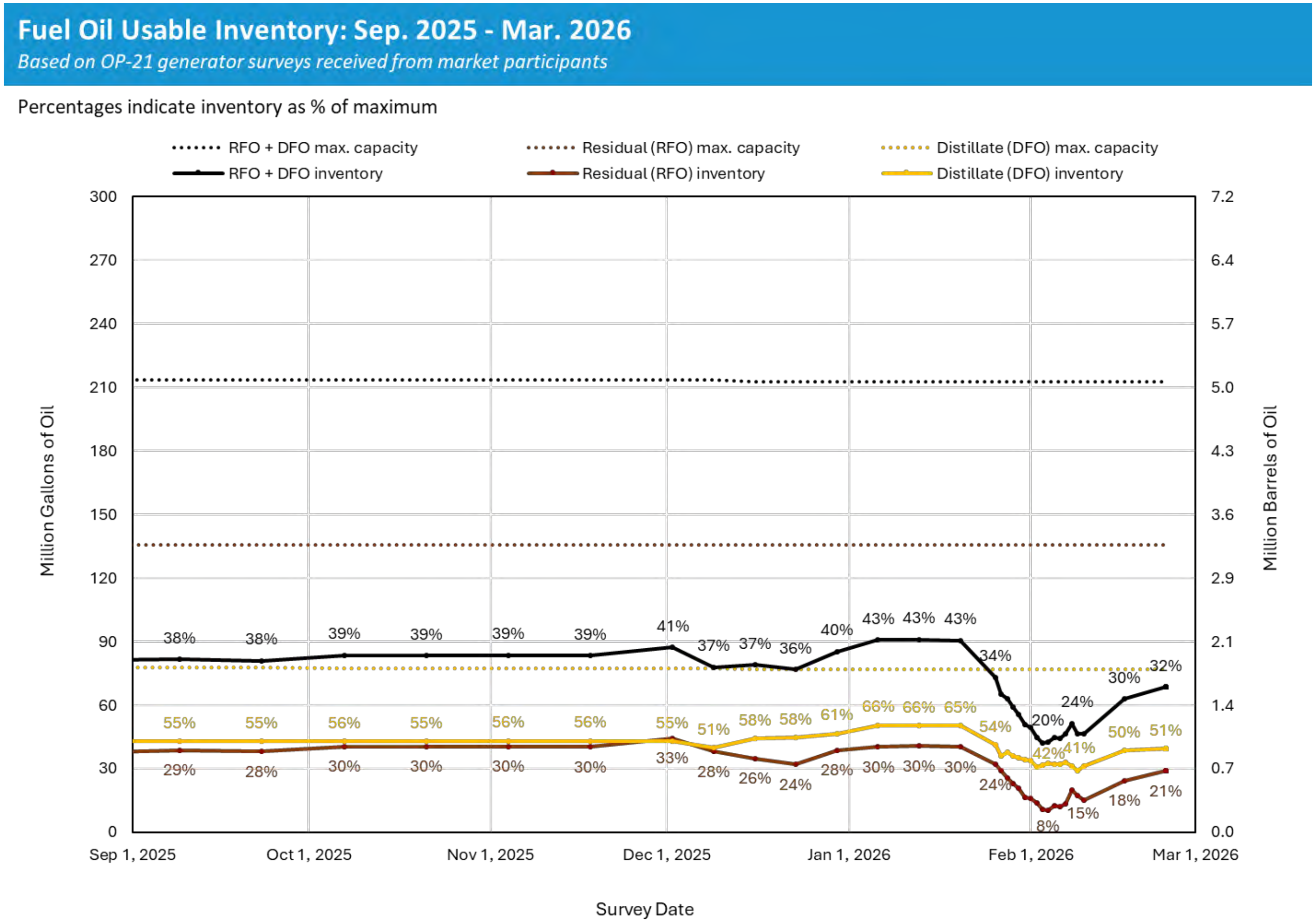
*Renewable data on this slide includes energy only from utility-scale solar PV installations

Winter Energy Sources, by Day
Renewables Only



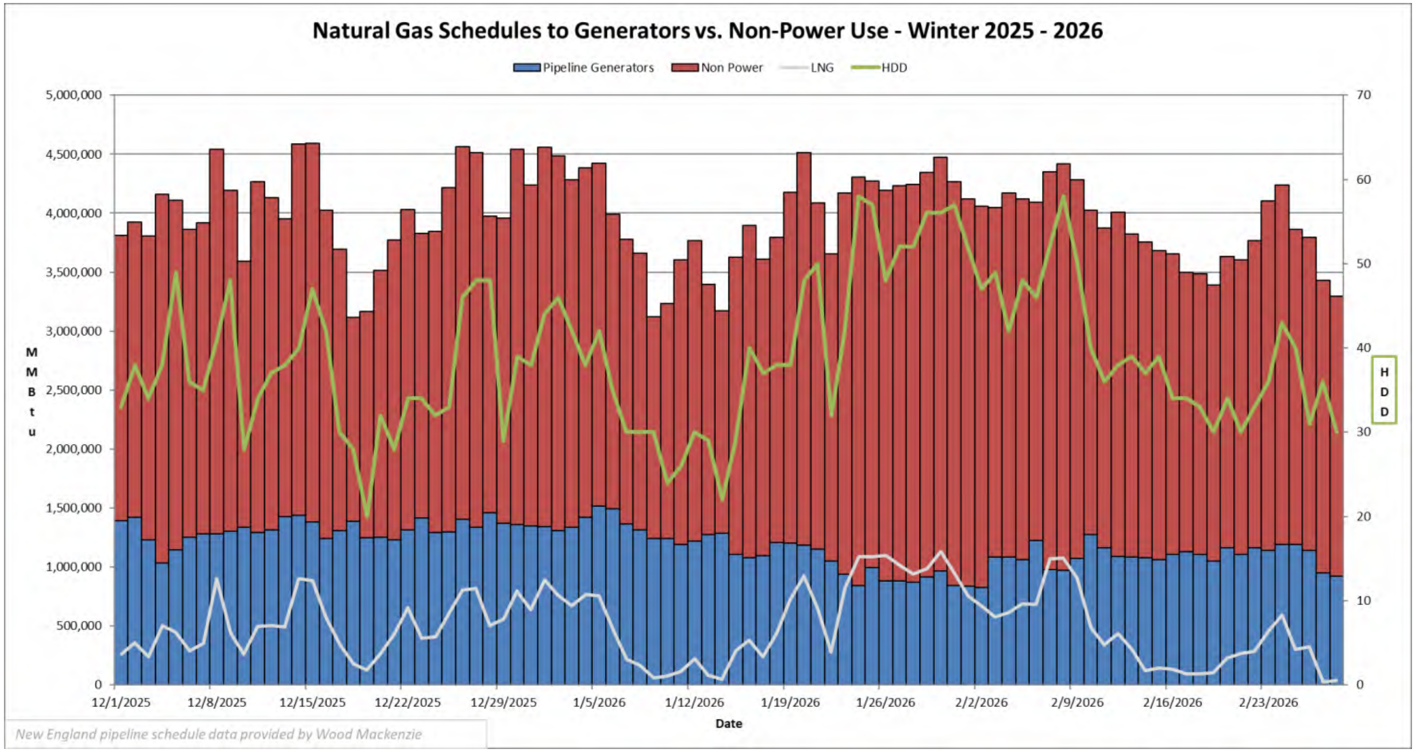
*Solar data on this slide includes energy only from utility-scale solar PV installations

Following Significant Fuel Oil Burn, Inventories Are Projected to Return to Pre-Winter Levels by Mid-March



Natural Gas Demand – Winter 2025/2026

- Scheduled LNG vaporization to the pipelines was ~45.6 Bcf, significantly higher than the previous 5-year average of ~16.6 Bcf



Winter 2025/2026 Wholesale Market Summary

- December
  - Average RT Hub LMP: **$129.89/MWh,** up ~55% from prior December
    - Highest December value since SMD
  - Average natural gas price: **$14.90/MMBtu,** up 63% from prior December
    - Highest December value since SMD
  - Temperatures* averaged **~28.0°F**, ~4.0°F colder than the prior December
    - Coldest December since 2017
  - RT Loads** averaged ~**14,870 MW**, up ~720 MW (or 5%) from the prior December
    - Highest December value since 2017
- January
  - Average RT Hub LMP: **$154.73/MWh,** up ~15% from prior January
    - 2nd highest January value since SMD
  - Average natural gas price: **$24.25/MMBtu,** up ~43% from prior January
    - 2nd highest January value since SMD
  - Temperatures averaged **~24.1°F** , ~1.4°F colder than the prior January
  - RT Loads averaged **~15,420 MW**, up ~410 MW (or 3%) from the prior January
    - Highest January value since 2015
- February***
  - Average RT Hub LMP: **$127.38/MWh,** up ~1% from prior February
    - 2nd highest February value since SMD
  - Average natural gas price: **$14.31/MMBtu**, down ~2% from prior February
  - Temperatures averaged **~25.0°F**, ~2.6°F colder than the prior February
    - Coldest February since 2015
  - RT Loads averaged **~15,160 MW**, up ~650 MW (or 5%) from the prior February
    - Highest February value since 2015

Note: Natural gas prices reflect the trade weighted average of natural gas price locations in Massachusetts
*Temperatures reflect 23-City New England weighted average
**RT Loads reflect telemetered values on this slide
***February 2026 Energy Market value includes estimations for days of February 26-28, 2026 based on pool wide DA LMP and cleared DA volumes and FER cost

Underlying natural gas data furnished by:

Comparison of Recent Winter Wholesale Energy Market Value

- The 2025/26 Winter Season set new records for Energy Market value, both in total and for respective similar months

Winter	December ($M)	January ($M)	February ($M)	Total ($M)	Rank[2]
2013/14	$1,161	$2,190	$1,703*	$5,054	2
2017/18	$856	$1,340	$401	$2,597	10
2018/19	$530	$671	$366	$1,568	19
2019/20	$468	$297	$233	$998	23
2020/21	$450	$489	$759	$1,698	17
2021/22	$720	$1,792	$1,216	$3,728	4
2022/23	$1,338	$552	$750	$2,640	9
2023/24	$415	$838	$375	$1,628	18
2024/25	$1,017	$1,637	$1,376	$4,030	3
2025/26	$1,839*	$2,721*	$1,500[3]	$6,060*	1

[1] Energy Market value is driven primarily by day-ahead load and pricing, since most obligations are settled day-ahead; Beginning in March 2025, FER Net Costs related to co-optimization with the DA Ancillary Services (DAAS) Market are being reflected in Energy Market value
[2] Since the beginning of Standard Market Design (SMD) in March 2003
[3] February 2026 Energy Market value includes estimations for days of February 26-28, 2026 based on pool wide DA LMP and cleared DA volumes and FER cost
* December 2025 ($1.8B), January 2026 ($2.7B), February 2014 ($1.7B) values were the highest for their respective similar months since SMD

Winter 2026/2027 Look Ahead

- ISO will continue to perform annual winter energy assessments using PEAT, in accordance with Operating Procedure 21
- Beginning in 2026, the Regional Energy Shortfall Threshold (REST) is now incorporated into seasonal and long-term energy assessments
- Winter weather forecasts will remain a critical factor in the operational outlook and will be closely monitored throughout the season
- ISO will continue to track fuel-oil replenishment and monitor potential emissions constraints following this winter's elevated oil use
- Communications with states, utilities, resource owners, and the public are expected to follow a similar approach to last year

COLD WEATHER OUTBREAK

January 23 through February 10, 2026

Key Takeaways

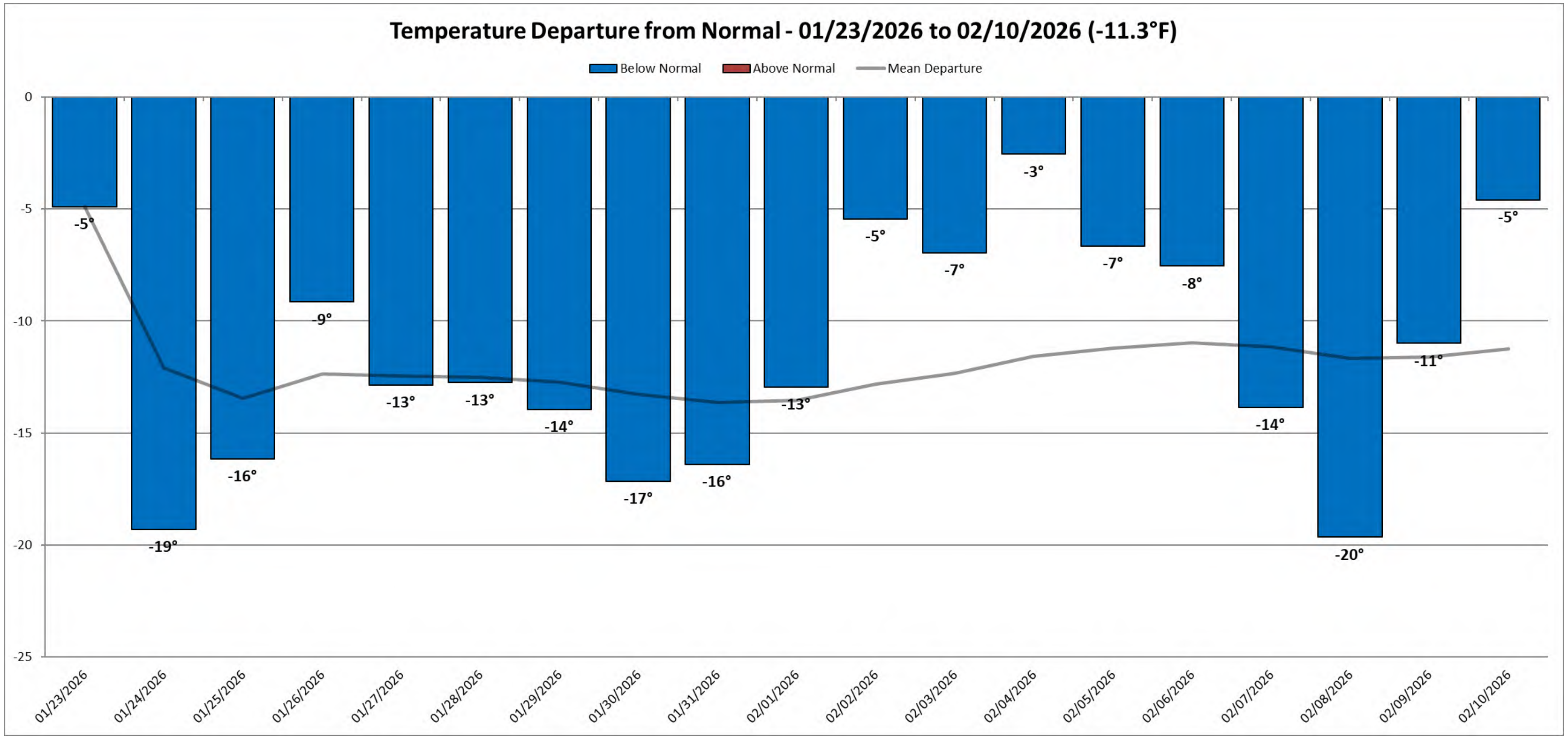
- A prolonged and widespread cold weather outbreak affected the region from January 23 through February 10, resulting in the most challenging winter conditions since 2017/18. Temperatures were consistently well below normal, leading to elevated demand and stressed system conditions.
  - Demand remained high, both in terms of peak load and overall energy use
  - Natural gas prices reached record levels, making fuel oil more economical
  - Fuel oil supplies fell to historical lows, though inventories are expected to recover to near pre-winter levels by mid-March
  - Timely replenishment of stored fuels was essential for maintaining reliable operations and opportunity-cost mechanisms helped generators optimize limited fuel supplies
- Winter Storm Fern brought widespread snowfall, impacting generation resources and fuel deliveries
  - Ahead of the storm, ISO implemented M/LCC-2, Abnormal Conditions Alert (in effect from January 25 - February 11)
  - Solar output declined due to the snowfall and remained low for several days as snow cover persisted
  - The storm's broad geographic footprint affected fuel delivery logistics across the East Coast

Key Takeaways, cont.

- Neighboring regions also faced difficult operating conditions during the cold weather outbreak, which reduced imports into New England and contributed to higher natural gas prices
- At the ISO's request, the U.S. Department of Energy issued a Section 202(c) emergency order, providing the additional operational flexibility needed during this period of extreme cold
- Throughout the event, the ISO's 21-day Energy Assessment offered transparent, actionable information on evolving energy adequacy risks with daily reports highlighting changing conditions
- Wholesale energy prices were very high due to historic gas prices and elevated consumer demand (both peak and overall)
- Close collaboration among ISO New England, industry partners, and federal and state agencies played a key role in maintaining system reliability

New England Average Temperature Was Below Normal From January 23 through February 10

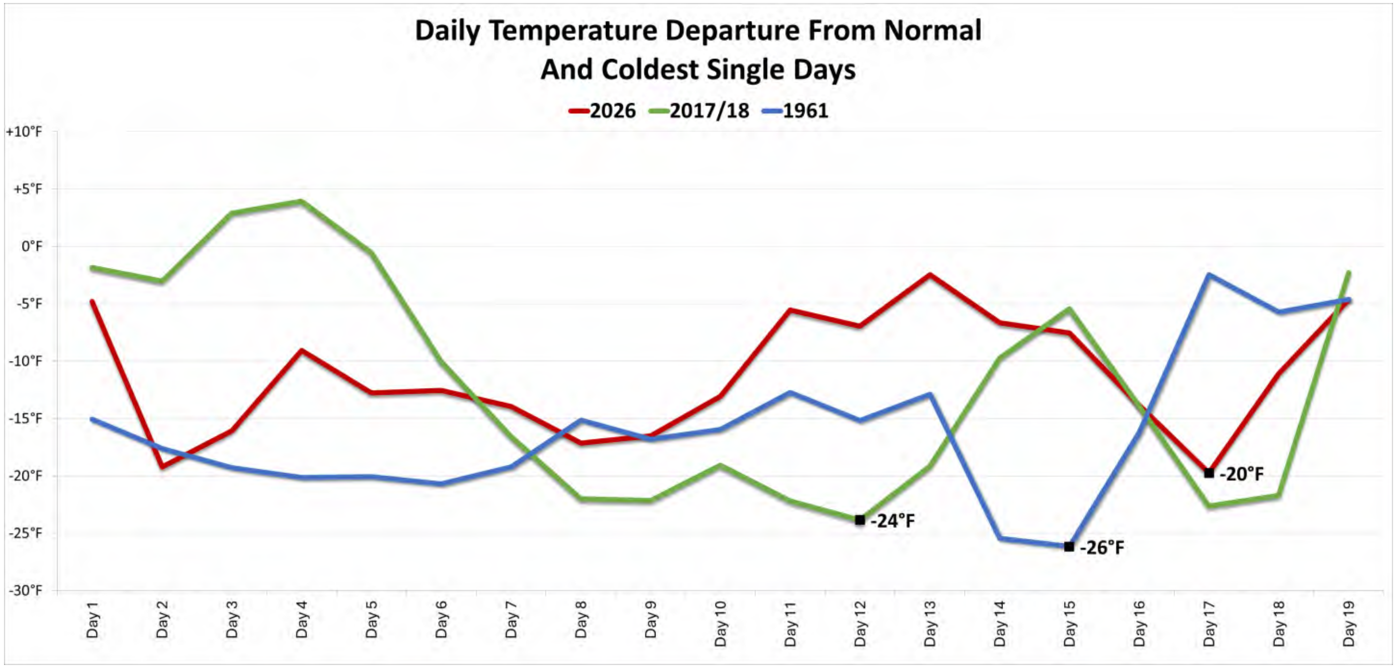
Temperature Averaged ~11.3°F Below Normal During the Cold Weather Outbreak



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

Average Temperature During the Cold Weather Outbreak Was Less Extreme Than Benchmark Historical Events

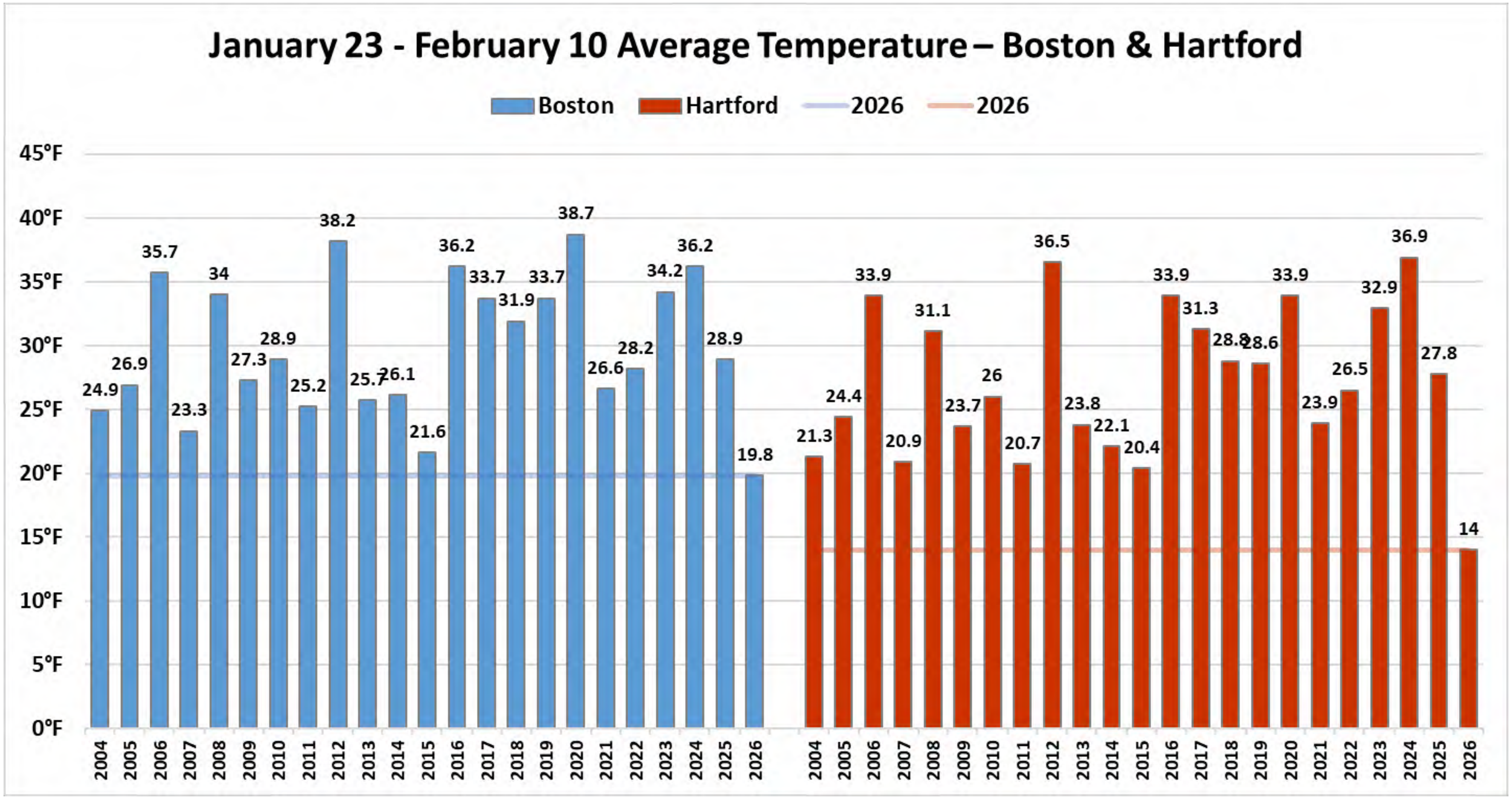
- Benchmarking the 2026 cold weather outbreak against past long-duration events shows that New England's average temperature departure from normal was significant, but not as severe as in earlier historical events*
- The average temperature departure from normal in the 2017/18 and 1961 events were -12°F and -16°F, respectively



**Note:* The two comparison events were selected because they represent historically significant cold periods:

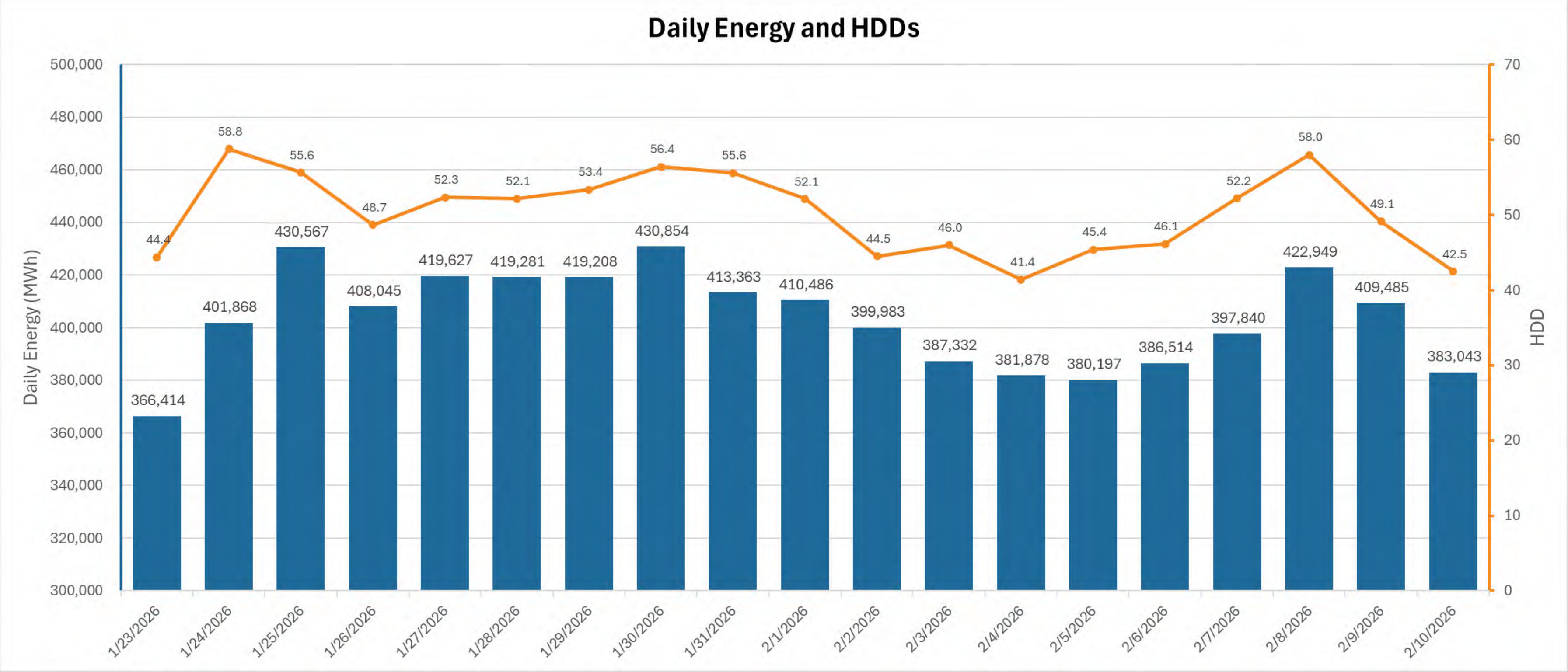
- The **2017/18 event** (Dec. 25, 2017–Jan. 8, 2018) and the **1961 event**, which was identified in the *Operational Impacts of Extreme Weather Events* study as producing the highest winter energy adequacy risk among modeled 21-day winter periods

Boston & Hartford Experienced the Coldest Jan. 23 Through Feb. 10 In More Than 20 Years



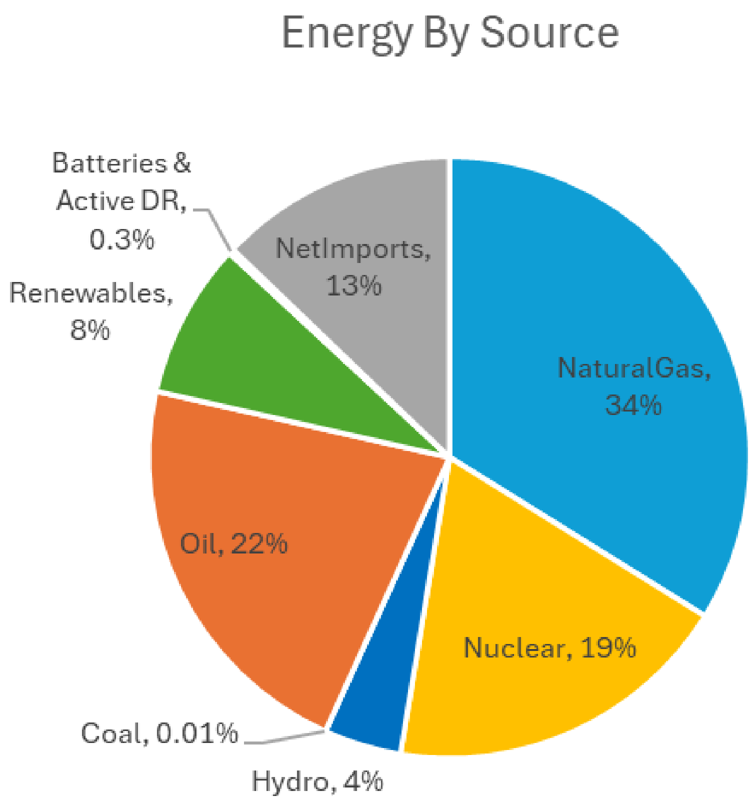
Extended Period of Bitter Cold Led to Consistently High Loads and Energy Demand

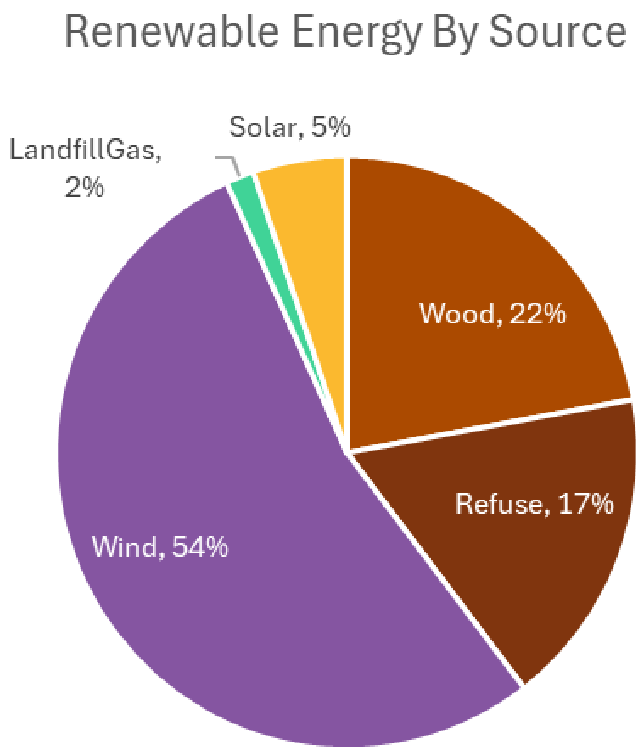
- Daily energy demand reached 430,567 MWh on Jan. 25 - the highest winter demand since 2018 (Jan. 2 at 429,960 MWh); energy demand was even higher on Jan. 30, rising to 430,854 MWh



Total Energy, By Source

January 23 – February 10, 2026

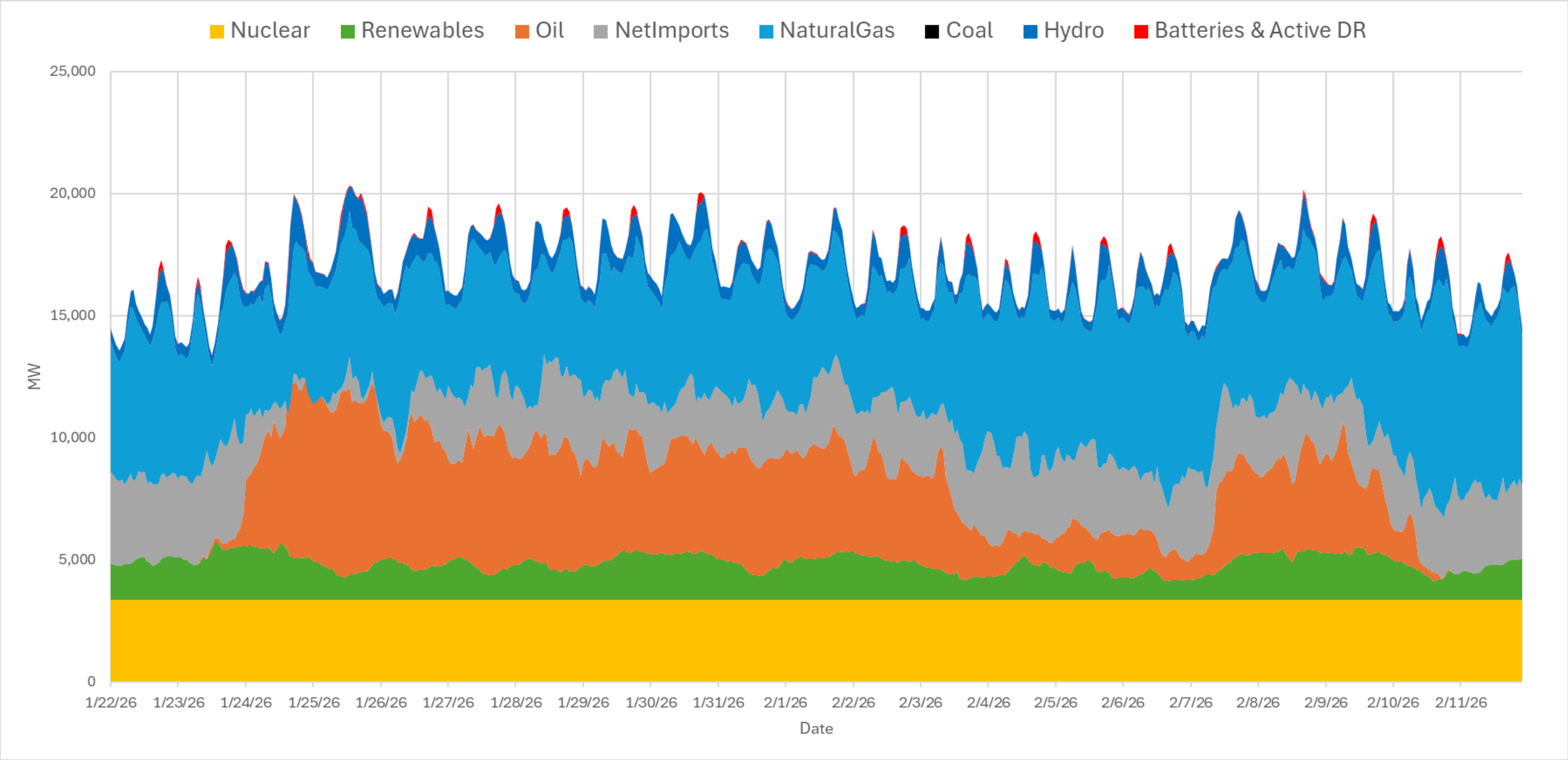




*Renewable and Solar data on this slide includes energy only from utility-scale solar PV installations

Energy Contributions From Oil-Fired Resources Increased Notably At the Onset of Severe Cold Weather

Energy from natural gas and oil-fired resources was 34% and 22%, respectively



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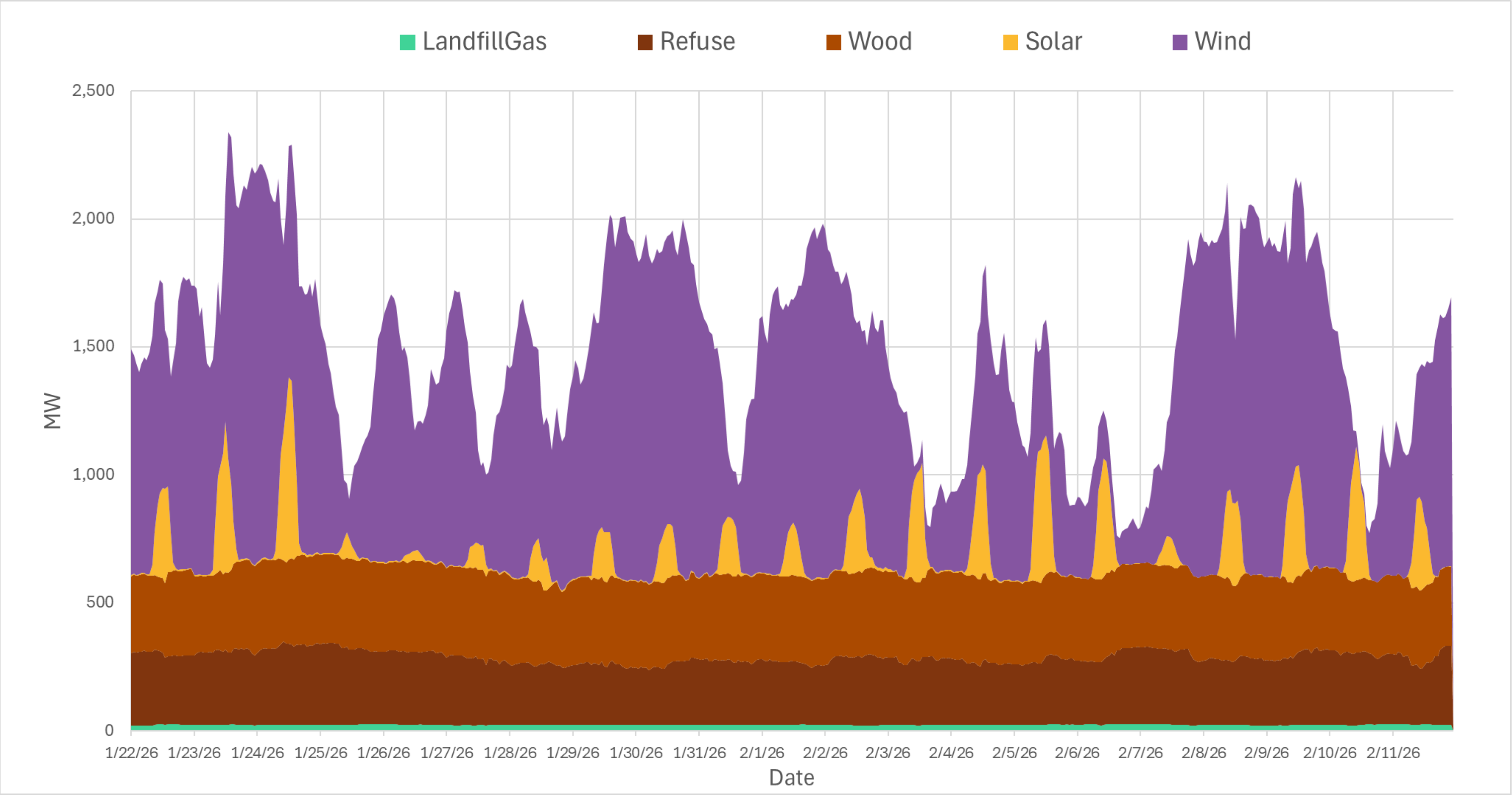
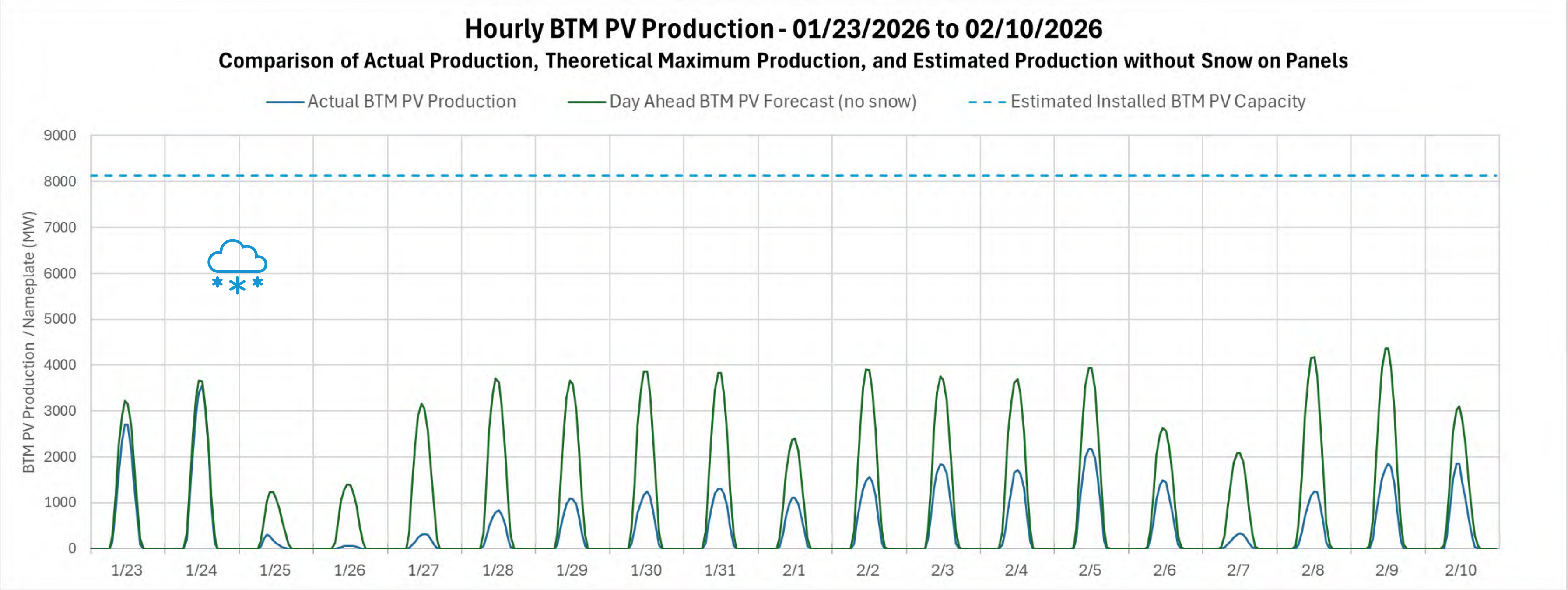
Renewable Energy, by Source



*Solar data on this slide includes energy only from utility-scale solar PV installations

Solar PV Output Was Reduced by Significant Snowfall During Winter Storm Fern

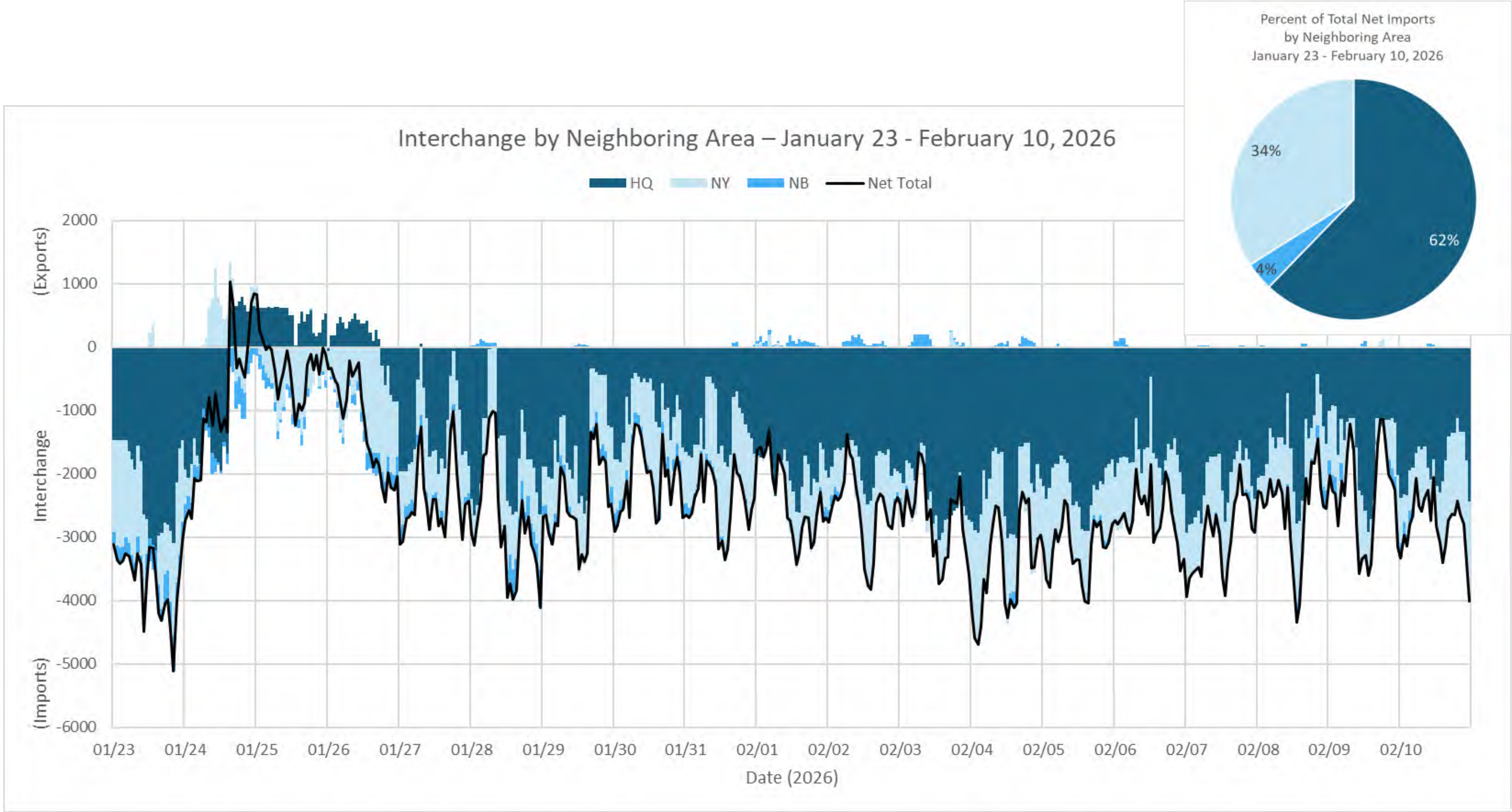
- Nearly two feet of snow fell across New England on January 25, covering many PV panels and sharply reducing solar output. Because temperatures remained below freezing for several days, snow stayed on the panels and continued to limit production.



*Day Ahead BTM PV Forecast (no snow) represents the forecast assuming no snow on the PV panels

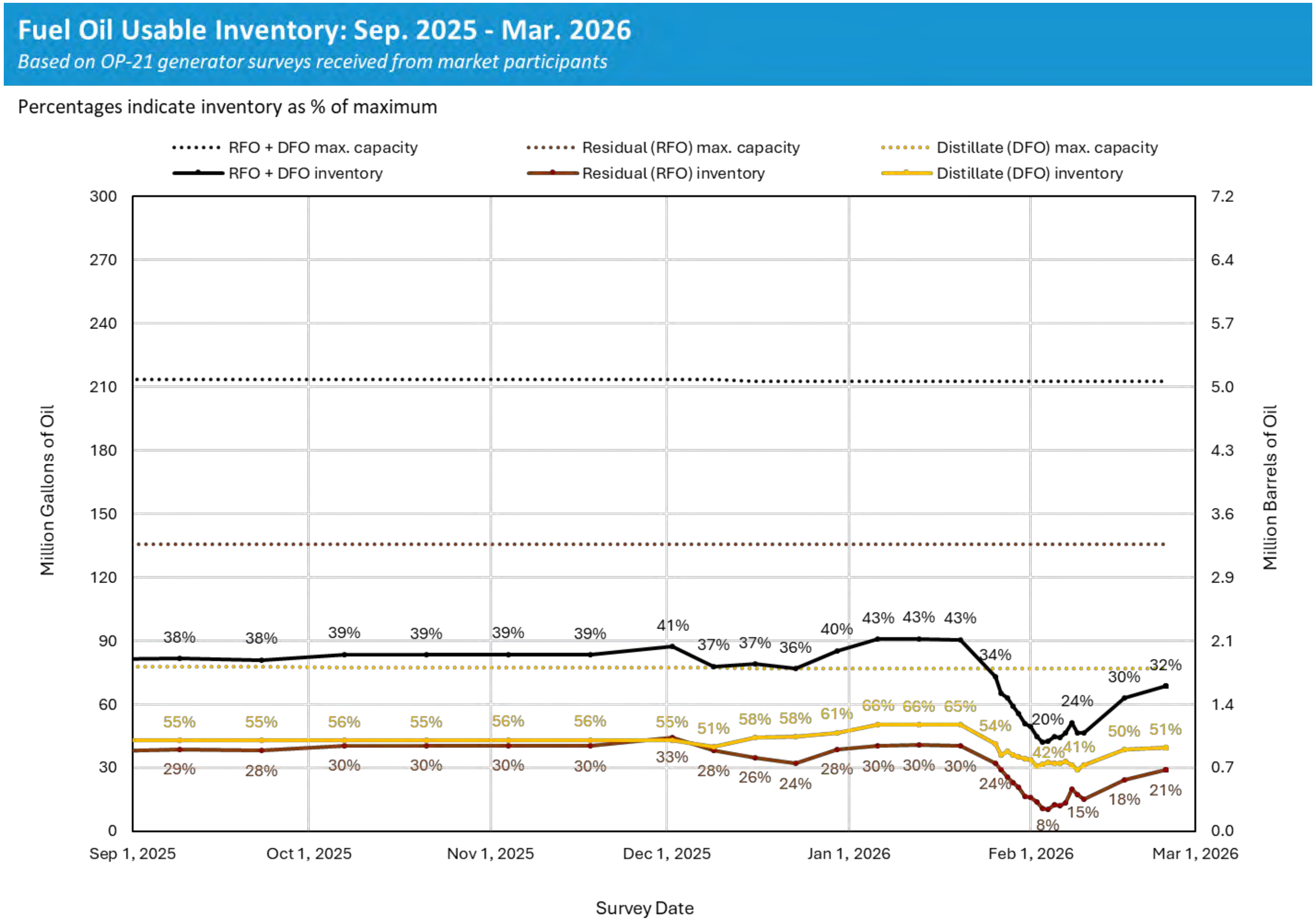
Net Interchange Decreased on January 24 As Neighboring Areas Managed Peak Loads

Imports to New England Averaged ~2,400 MW/hr During the Cold Weather Outbreak



Fuel Oil Burn During the Cold Weather Outbreak Totaled ~111M Gallons

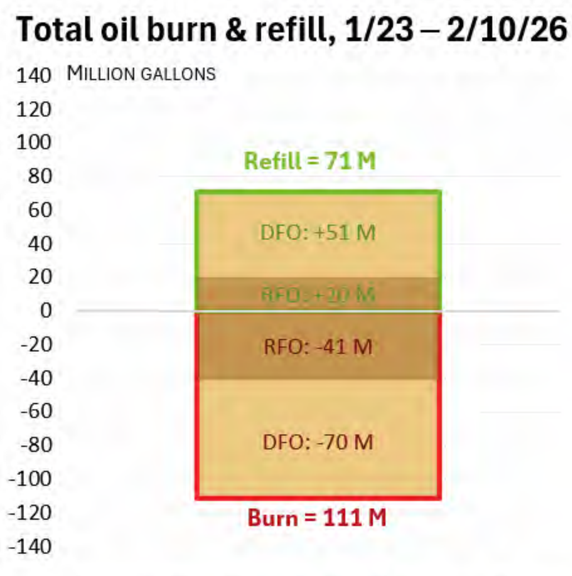
*Total Fuel Oil Burn During This Period Was Greater Than Burn in Every Winter Since 2015/16**



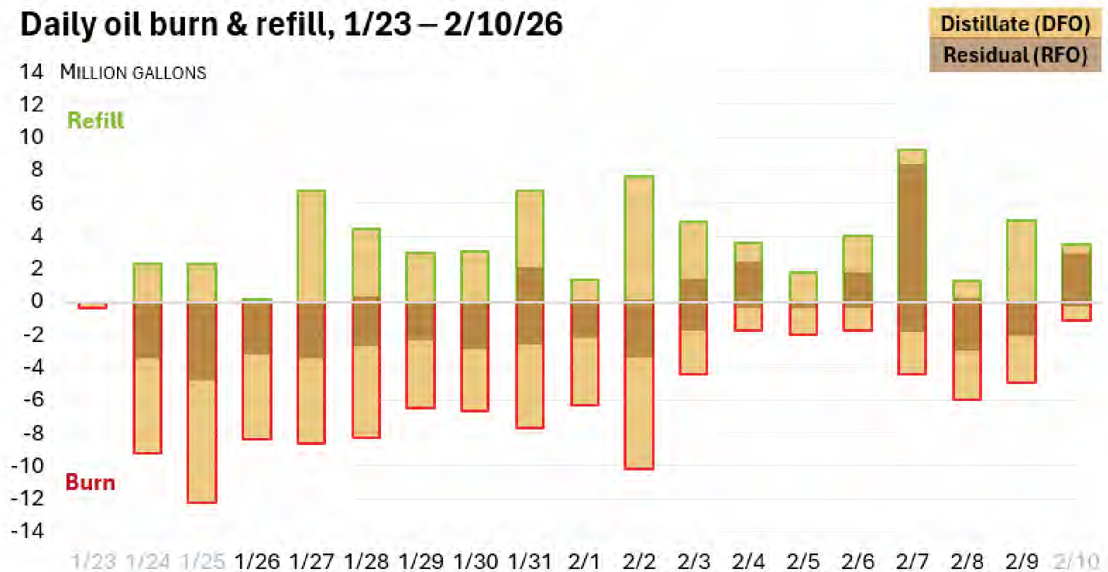
*ISO began tracking fuel oil burns starting in Winter 2015/16

Fuel Oil Burn Ramped Up At the Onset of the Cold Weather Outbreak and Persisted Throughout

- ISO began daily fuel surveys on Jan. 26; more frequent surveys allowed for enhanced situational awareness of fuel oil inventories and replenishment plans
- Impacts of the Winter Storm Fern delayed truck-based distillate fuel replenishment at the outset; in some cases, the limited availability of barges impacted the rate of residual fuel oil replenishment
- Significant fuel oil burn at dual fuel generating facilities contributed to a high demand for demineralized water trucks which were in short supply



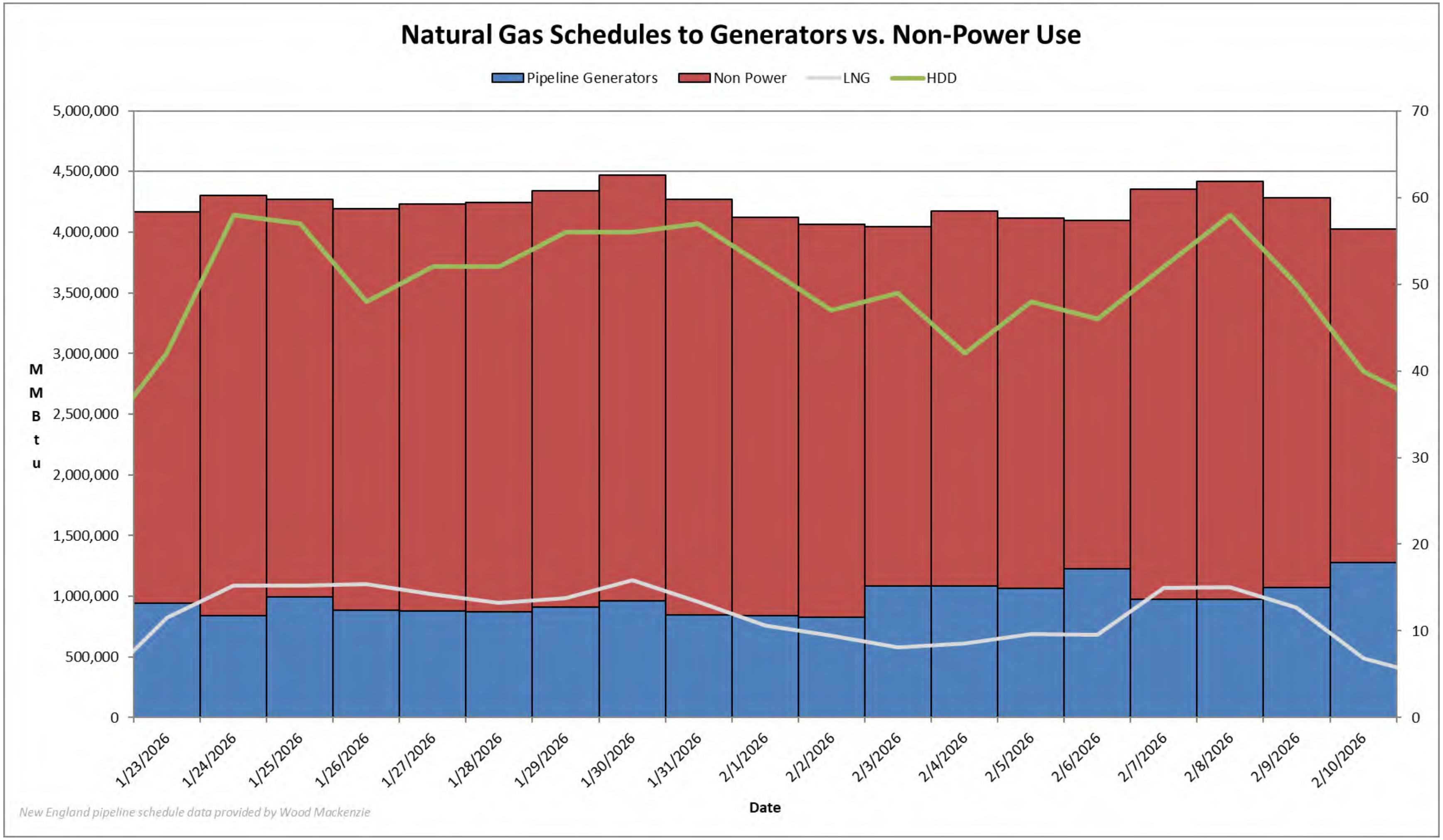
Estimated from Generator Fuel & Emissions Surveys



Estimated from Generator Fuel & Emissions Surveys; gray dates rely on apportioning **weekly survey** amount

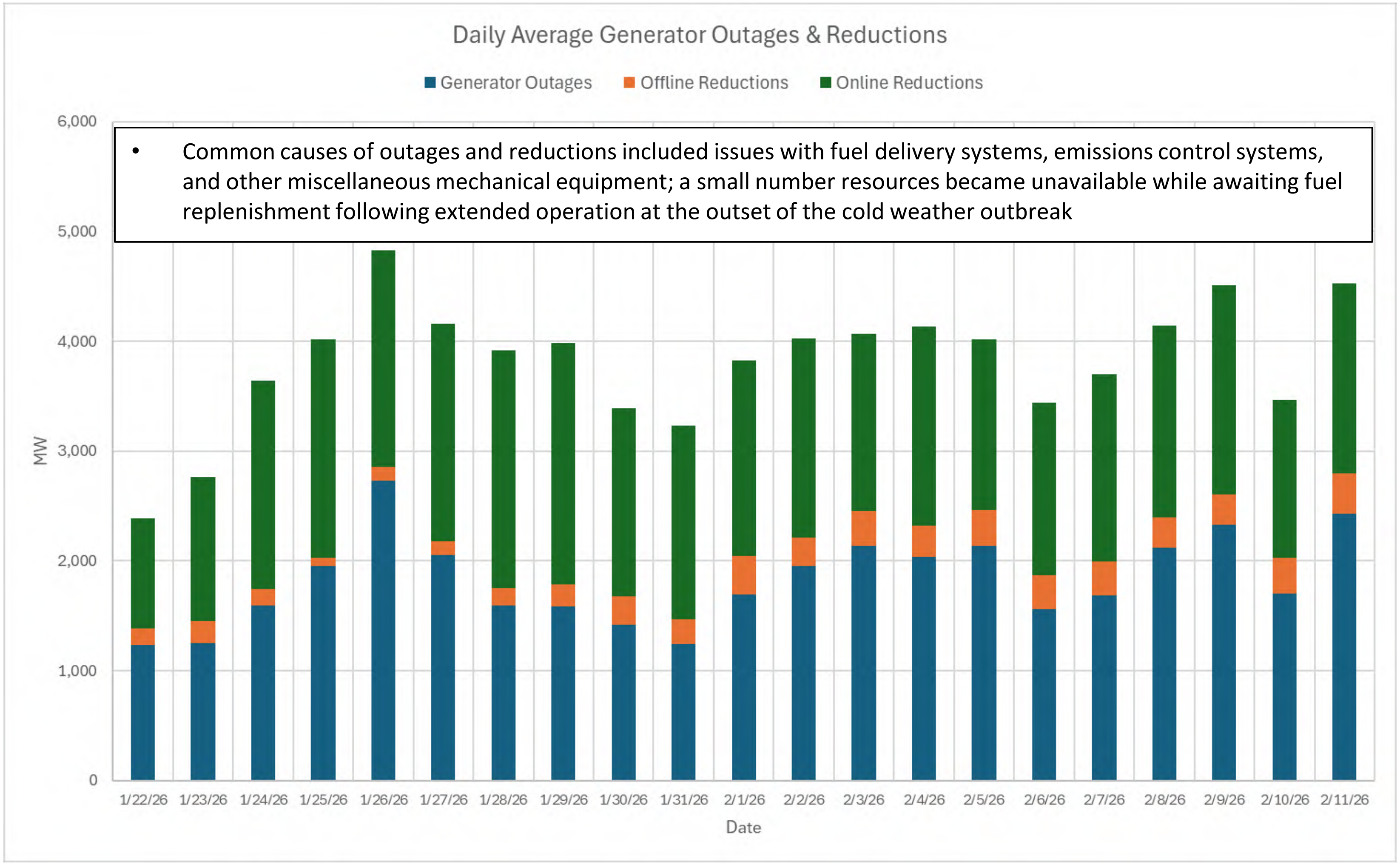
LNG Vaporization to the Pipelines Was ~16.7 Bcf During the Cold Weather Outbreak, ~0.88 Bcf/day

Natural gas demand for power generation was ~18.6 Bcf, ~0.98 Bcf/day



Generator Outages and Reductions

Averaged ~3,800 MW/hr During the Cold Weather Outbreak



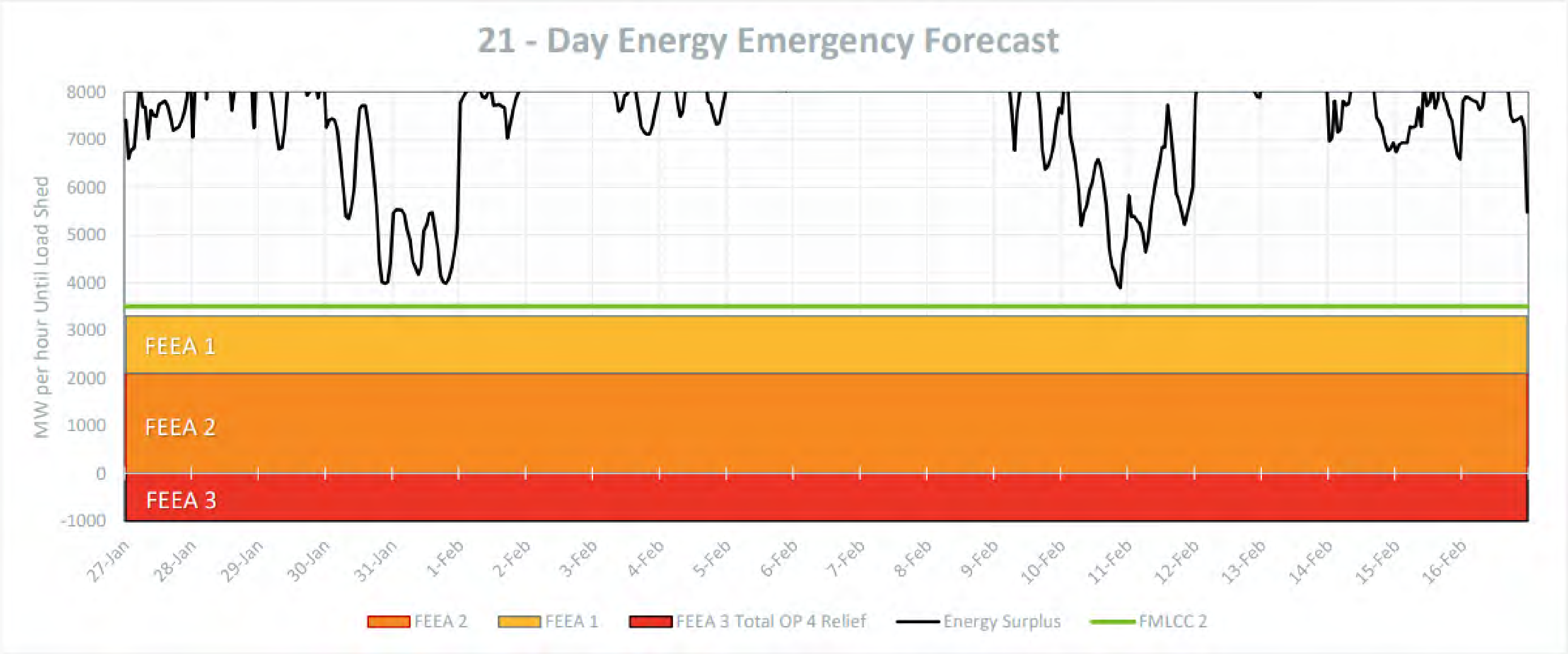
- Common causes of outages and reductions included issues with fuel delivery systems, emissions control systems, and other miscellaneous mechanical equipment; a small number resources became unavailable while awaiting fuel replenishment following extended operation at the outset of the cold weather outbreak

Section 202(c) Order

- As a precaution, the ISO requested a Section 202(c) order from the U.S. Department of Energy (DOE) on January 25
  - The DOE granted the request, allowing the ISO to maximize the availability of all generating resources in New England
  - On January 30, the ISO requested—and received—an extension of the order through February 14 due to the forecast of continued severe cold weather
- A total of 57 resources requested and were designated as "Specified Resources," meaning they could operate in reliance on the allowances available under the 202(c) order
  - These units represent approximately 11,215 MW of winter capacity, or about 39% of the region's total winter generating capacity
  - Of these, 26 resources reported an exceedance of a specified emissions limit during the period the 202(c) order was in effect
- Specified Resources consisted primarily of dual-fuel (gas/oil), gas-only, or generators operating on residual fuel oil

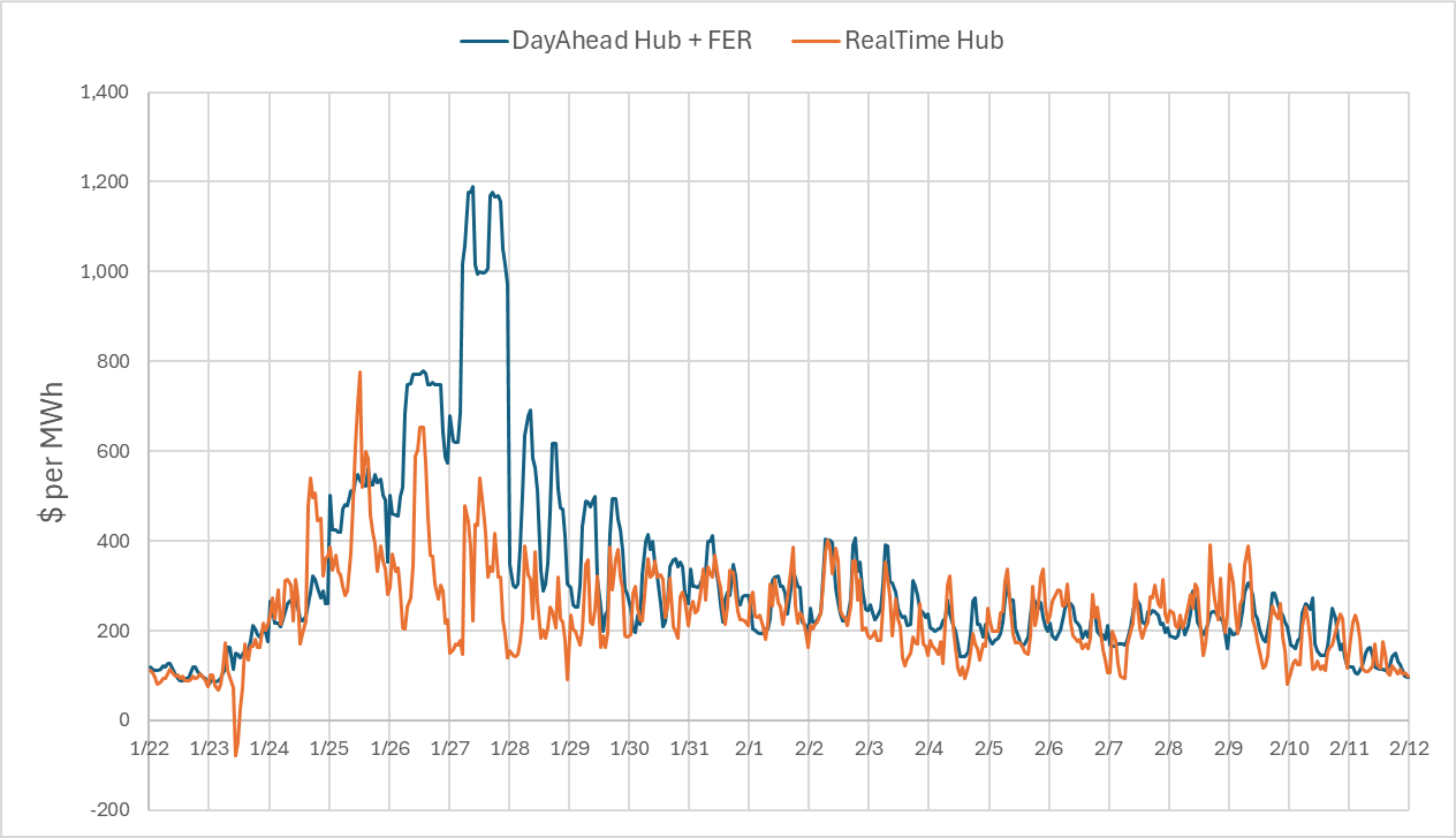
Daily Publication of the 21-day Energy Assessment Enhanced Regional Situational Awareness

- Beginning on January 27, the ISO began publishing the 21-Day Energy Assessment and Forecast Report on a daily basis to improve regional situational awareness of energy supplies
- The report highlighted periods of reduced energy surplus (see example from the Jan. 27 assessment which was posted on Jan. 28), though the forecast never indicated conditions severe enough to trigger an Energy Alert or Energy Emergency



Real-Time LMPs Averaged $250/MWh During the Cold Weather Outbreak

Day Ahead LMPs + Forecast Energy Requirement (FER) Averaged $331/MWh



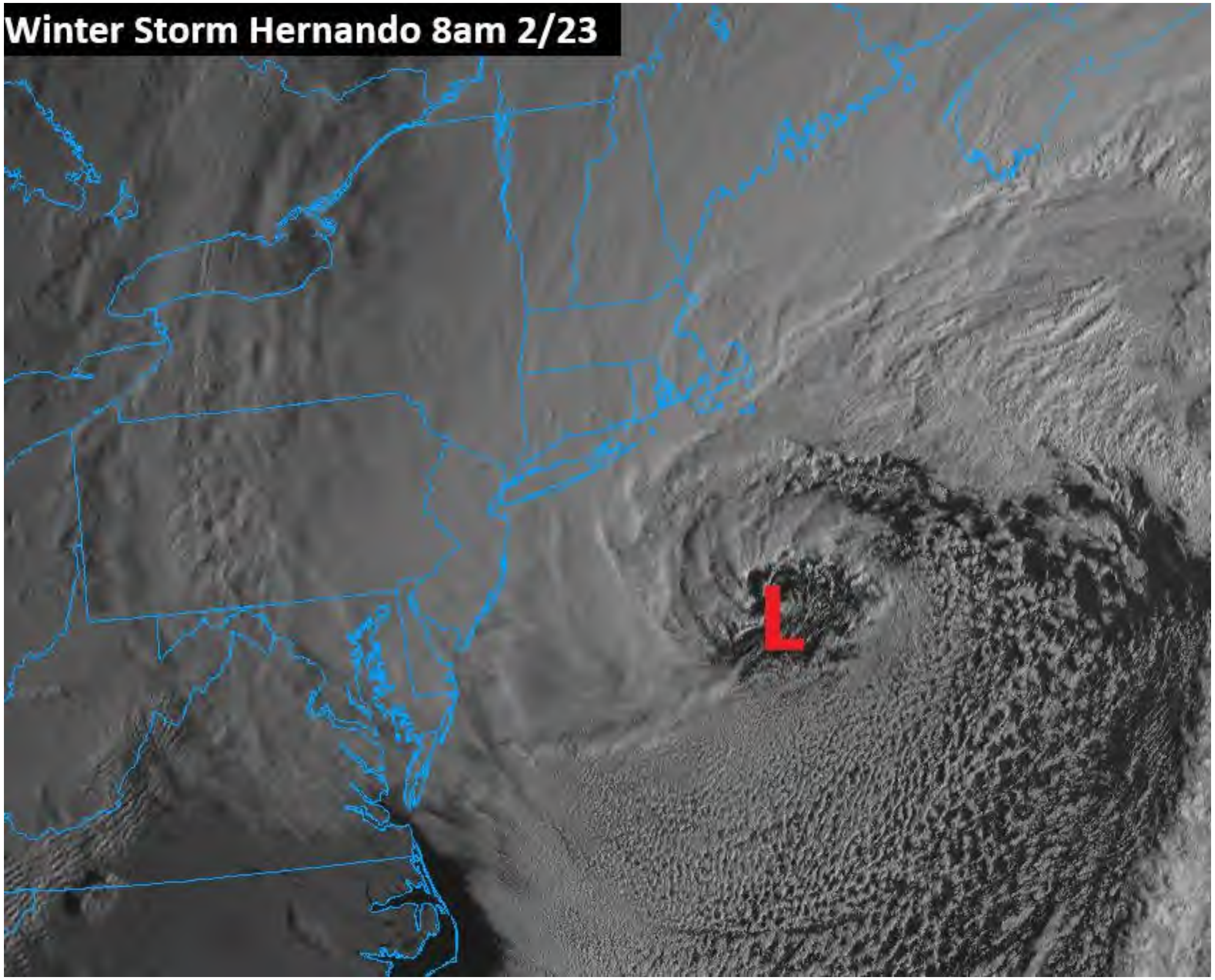
WINTER STORM HERNANDO

Winter Storm Hernando Summary

- Winter Storm Hernando impacted New England beginning on Monday, February 23 with blizzard conditions, winds of 65 mph and higher, coastal flooding, and heavy snow in excess of 3 feet in some locations
- Customer outages peaked at ~350,000 around noon on February 23
  - Most customers were restored by Friday, February 27 though some areas in Southeastern Massachusetts and Cape Cod required more time to fully restore
- The most significant impacts to the transmission system were concentrated in Southeastern Massachusetts and Cape Cod; three 345 kV circuits and nine 115 kV circuits tripped during the storm but resulted in no reliability issues
- Generation resources remained highly dependable throughout the storm with ~425 MW of generation becoming unavailable due to control and communications problems or electrical issues

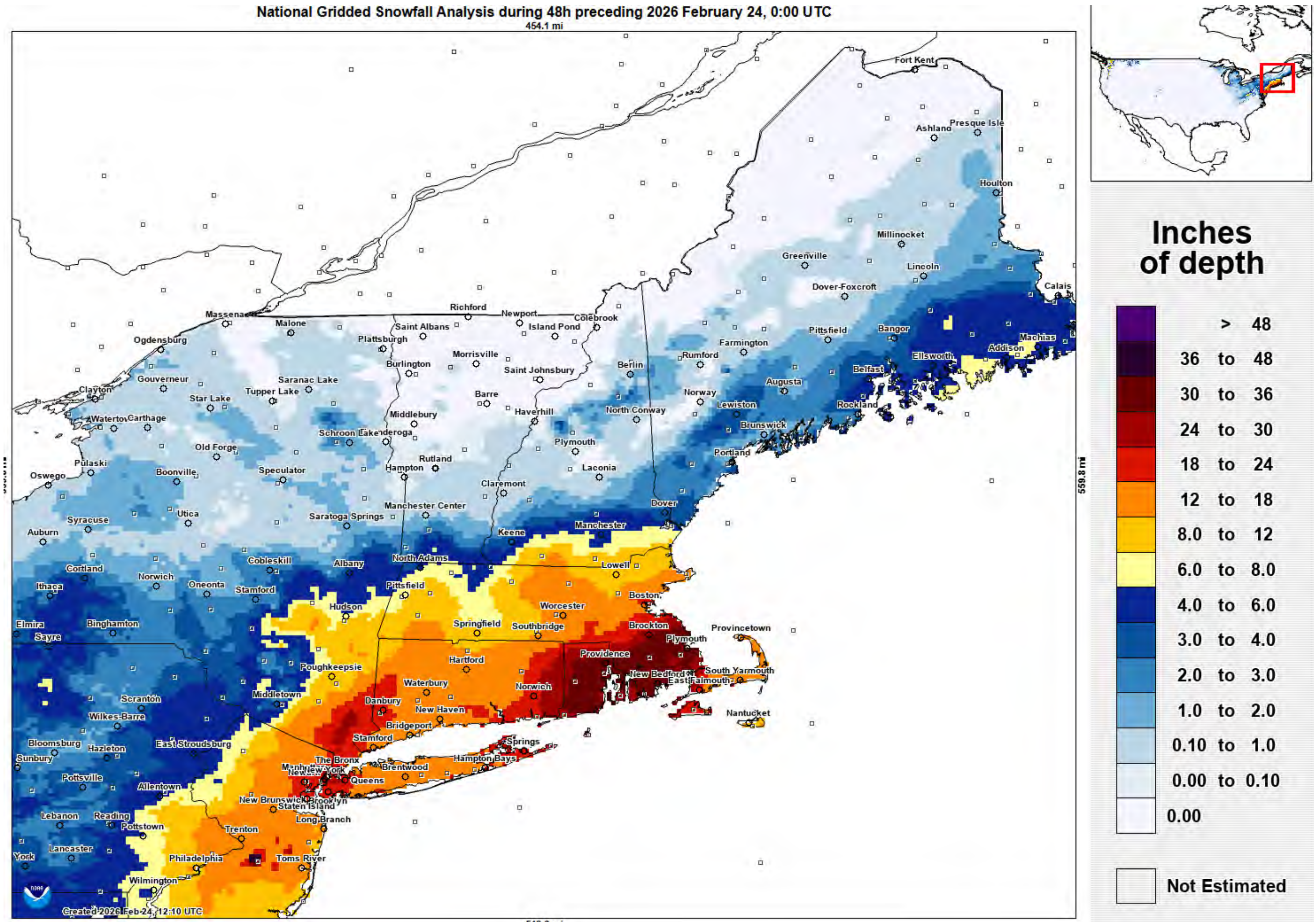
Winter Storm Hernando Became a Powerful Nor'easter Early Monday, February 23

- The storm resembled what meteorologists call a "winter hurricane" - a rapidly intensifying system that takes on the appearance of tropical cyclone with few clouds in the center, also called a "bomb cyclone"
- ISO's forecasting team closely monitored the storm in the days prior and staff was in close communication with Local Control Centers throughout



Winter Storm Hernando, Snowfall Totals

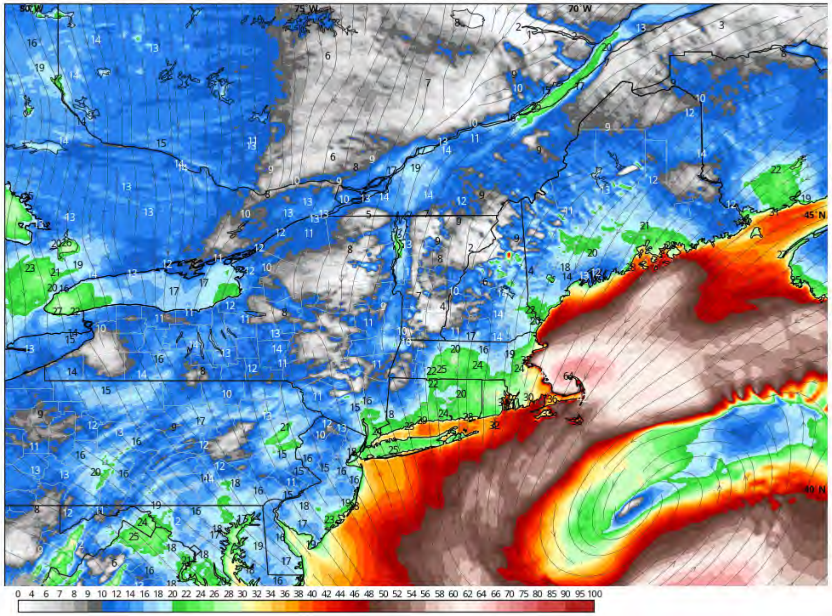
Over 3 Feet of Snow Fell in Parts of MA & RI



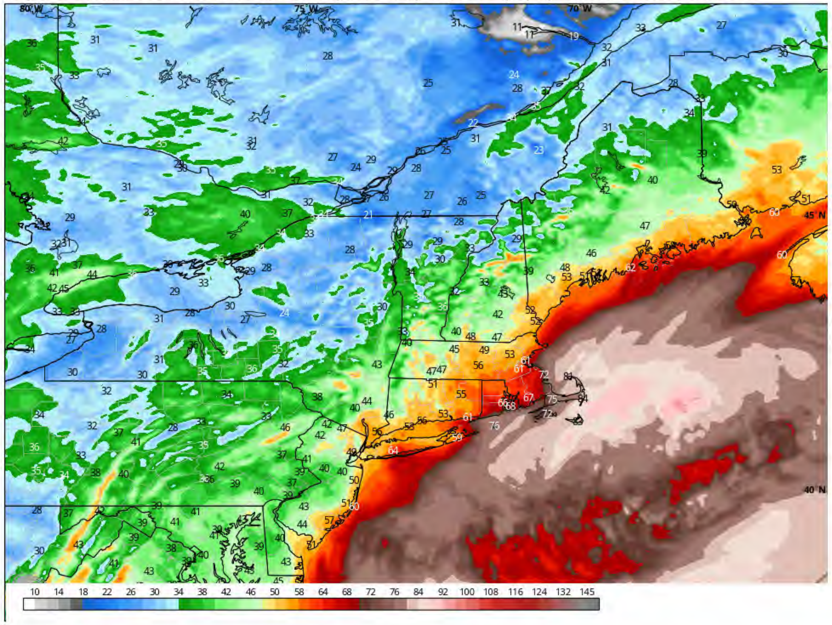
Winter Storm Hernando, Winds Summary

Winds Gusted 60-70 MPH in Parts of Eastern MA & RI, As High As 83 MPH on Nantucket

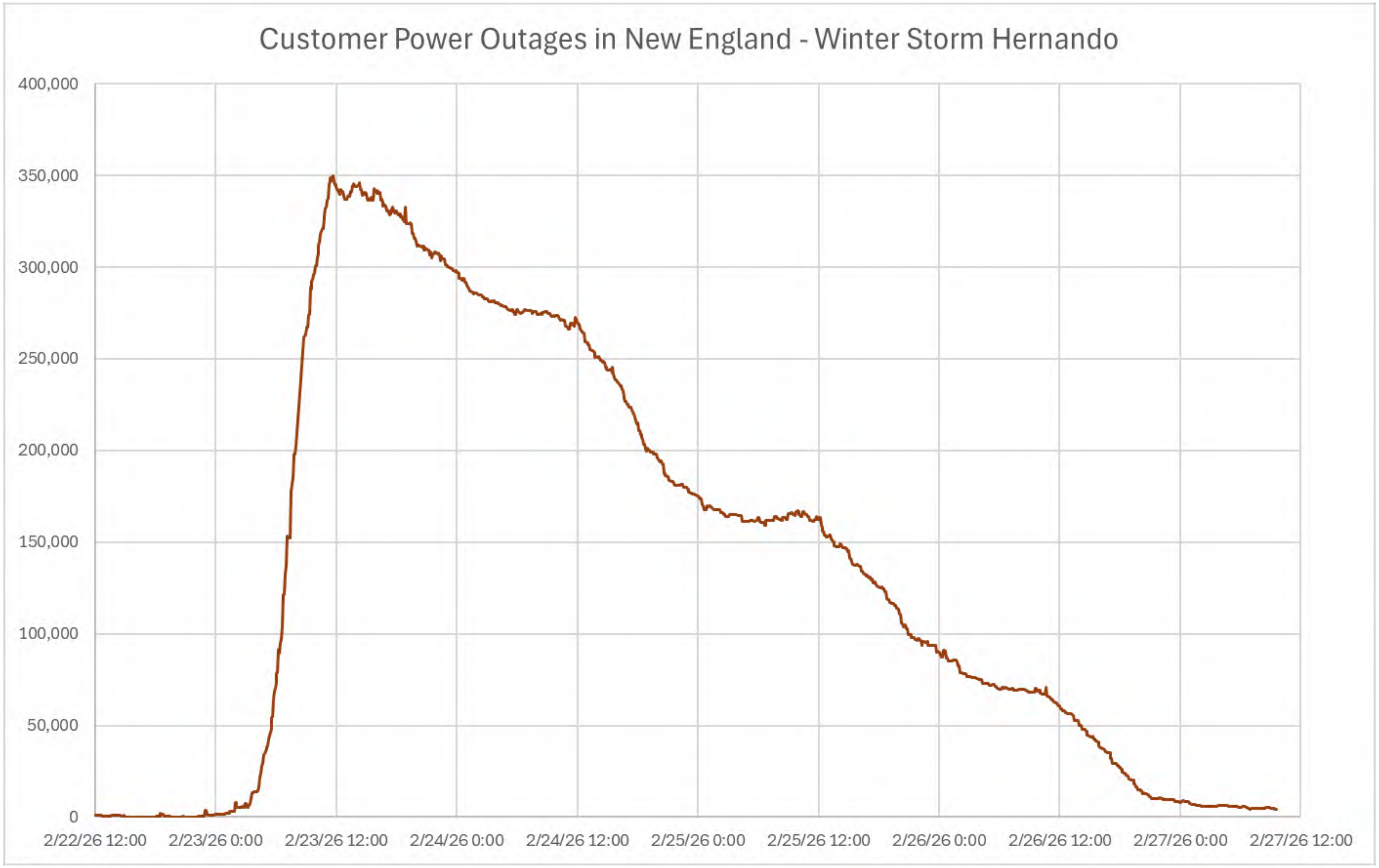
Reported Maximum Sustained Winds Monday February 23, 2026 (mph) Winter Storm Hernando



Reported Maximum Wind Gusts Monday February 23, 2026 (mph) Winter Storm Hernando



Customer Outage Totals Peaked at ~350,000 on February 23



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-3.3°F) Max: 49°F, Min: 4°F Precipitation: 2.08" – Below Normal Normal: 3.21" Snow: 26.8"	Hartford	Temperature: Below Normal (-4.8°F) Max: 50°F, Min: -2°F Precipitation: 2.08" – Below Normal Normal: 3.13" Snow: 16.5"

Peak Load:	20,172 MW	February 8, 2026	18:00 (ending)
Mid-Day Minimum Load - Month:	10,514 MW	February 28, 2026	14:00 (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)

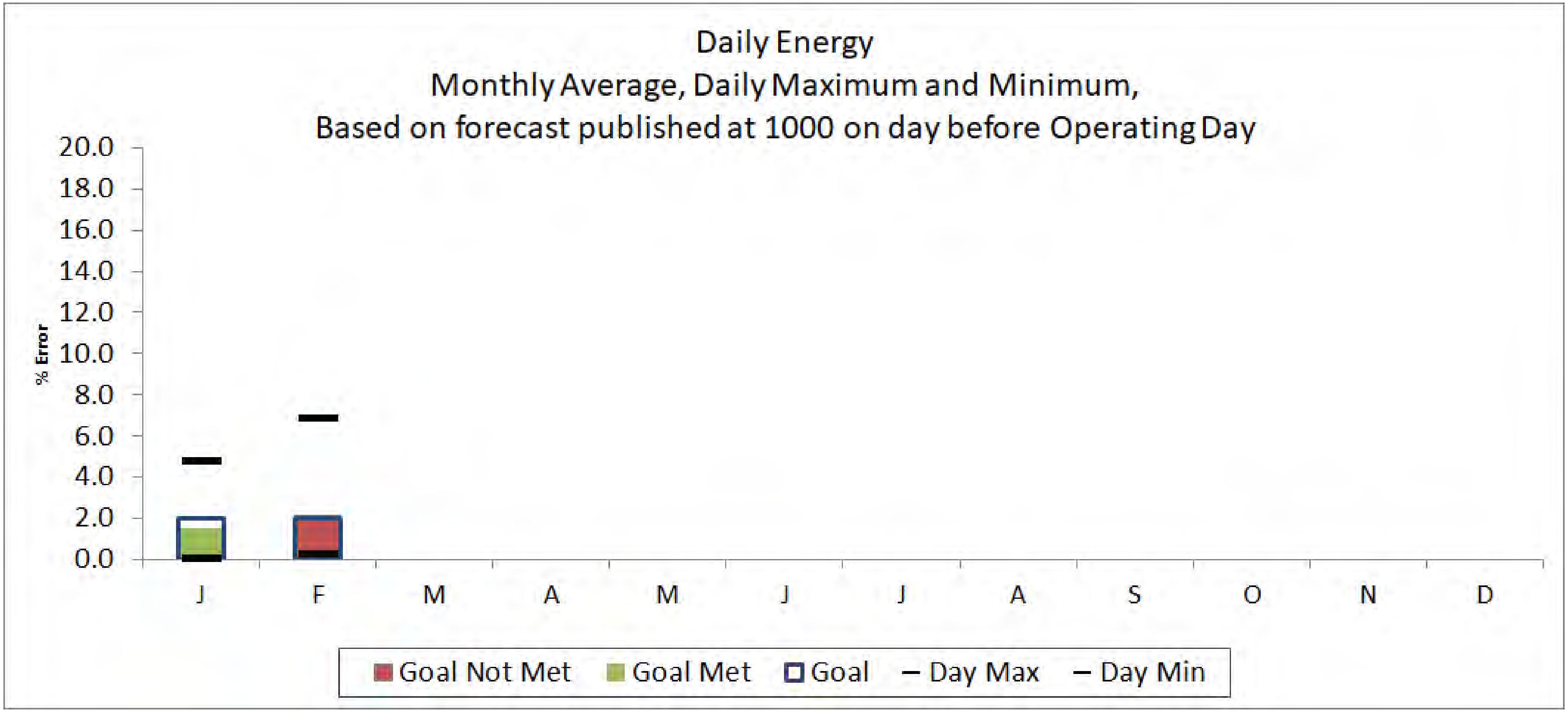
Procedure	Declared	Cancelled	Note
M/LCC 2	1/25/2026 09:00	2/11/2026 21:00	Severe Weather

System Operations

NPCC Simultaneous Activation of Ten-Minute Reserve Events

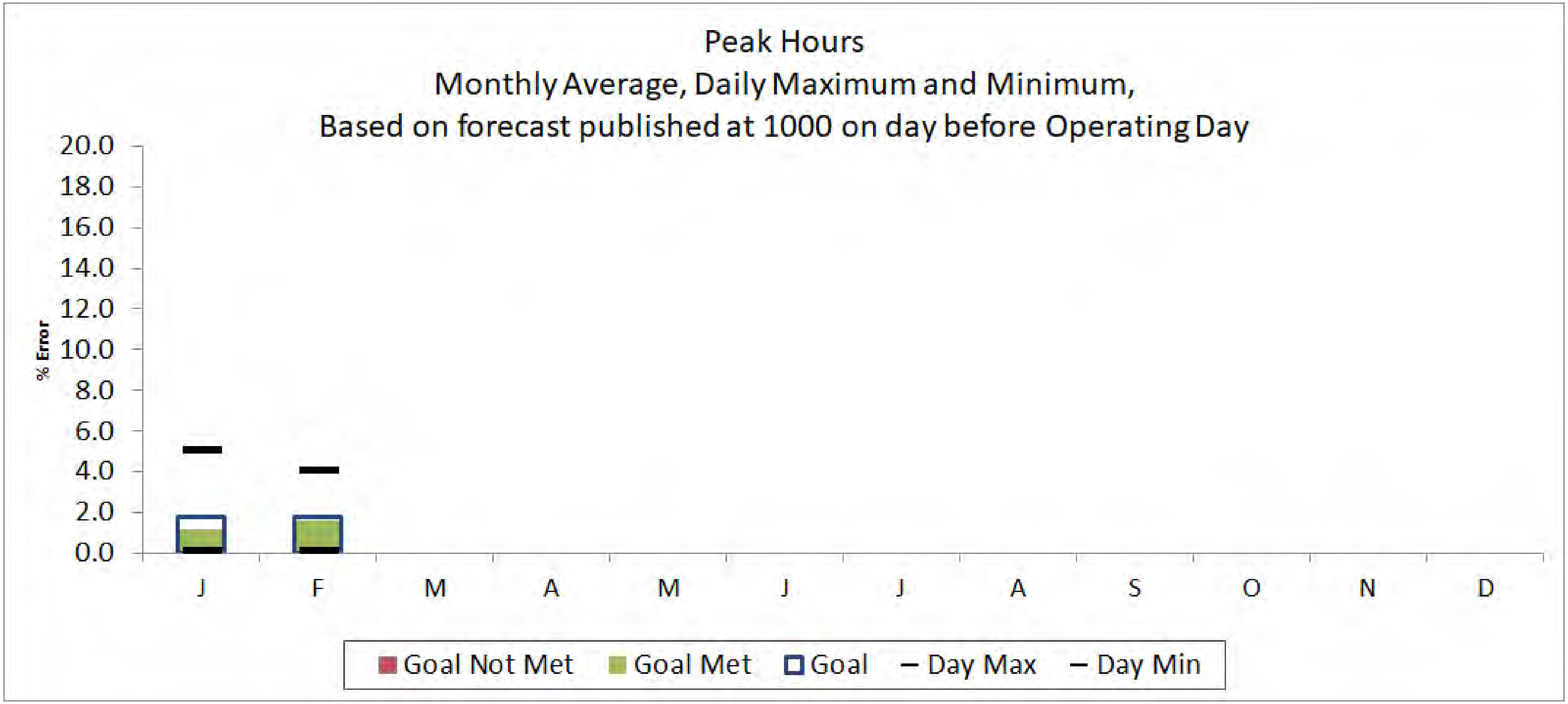
Date	Area	MW Lost
02/06/2026	NYISO	750
02/06/2026	NYISO	515
02/22/2026	NYISO	553

2026 System Operations - Load Forecast Accuracy cont.



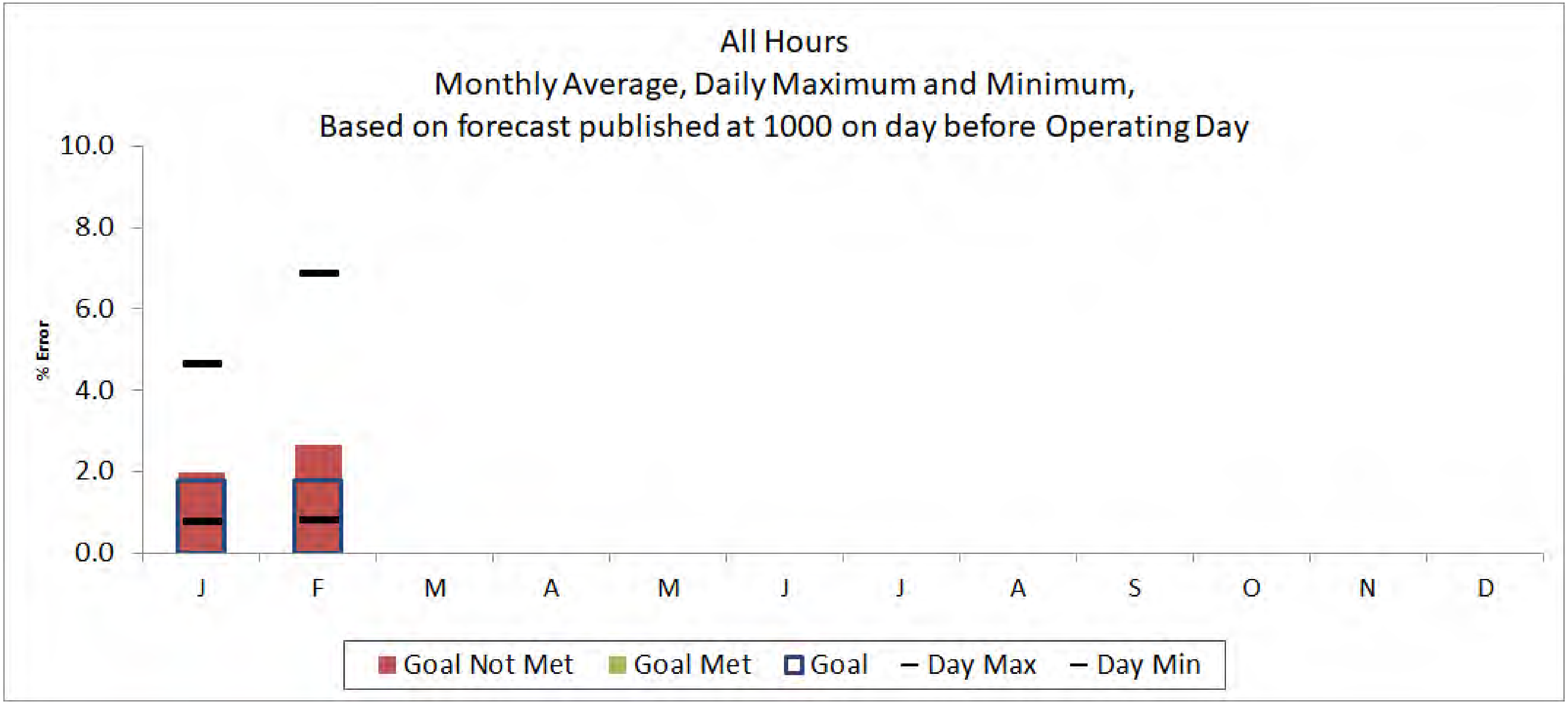
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81											6.81
Day Min	0.01	0.22											0.01
MAPE	1.57	2.12											1.83
Goal	2.00	2.00											

2026 System Operations - Load Forecast Accuracy cont.



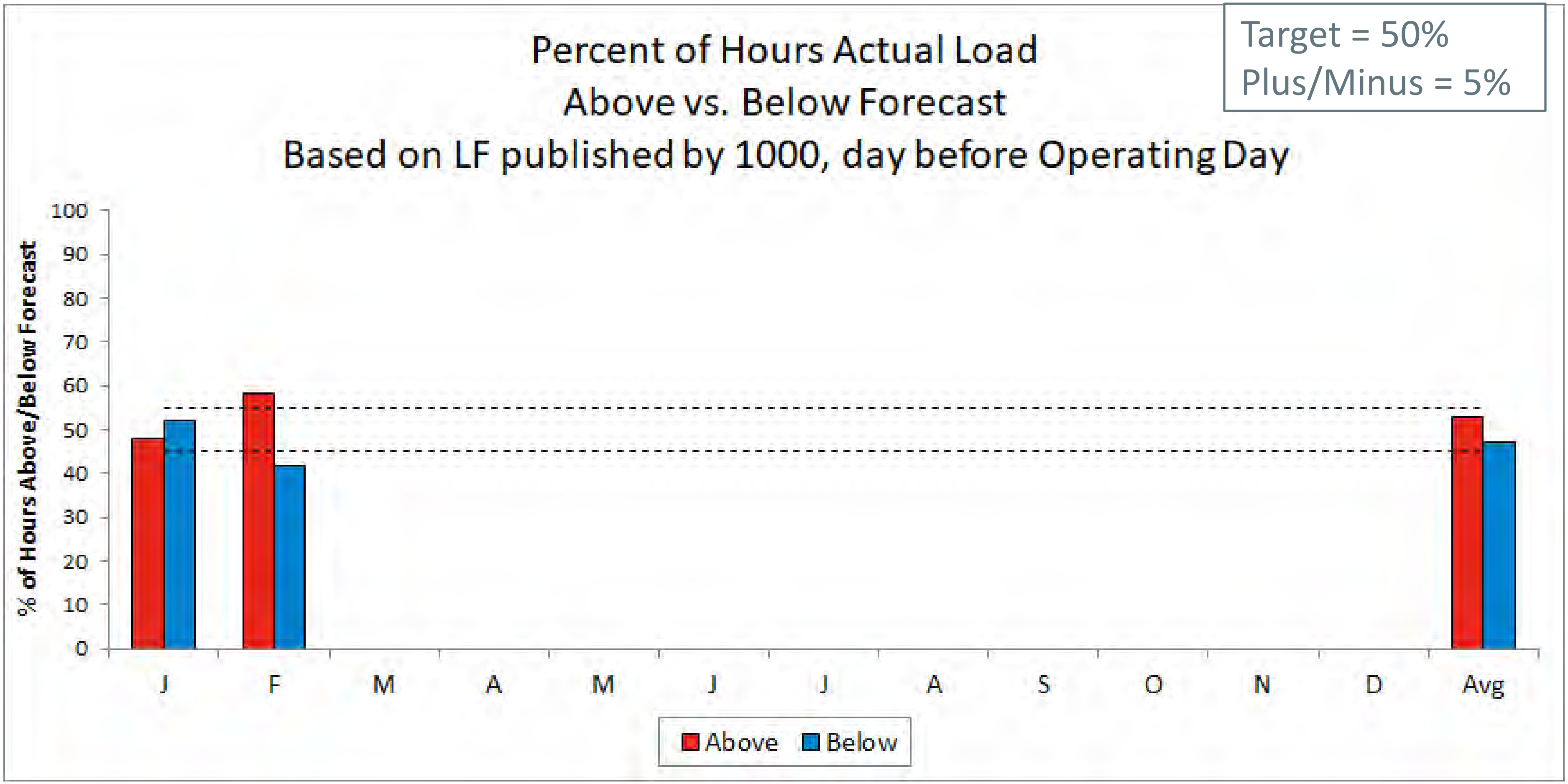
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02											5.05
Day Min	0.08	0.12											0.08
MAPE	1.17	1.64											1.39
Goal	1.80	1.80											

2026 System Operations - Load Forecast Accuracy cont.



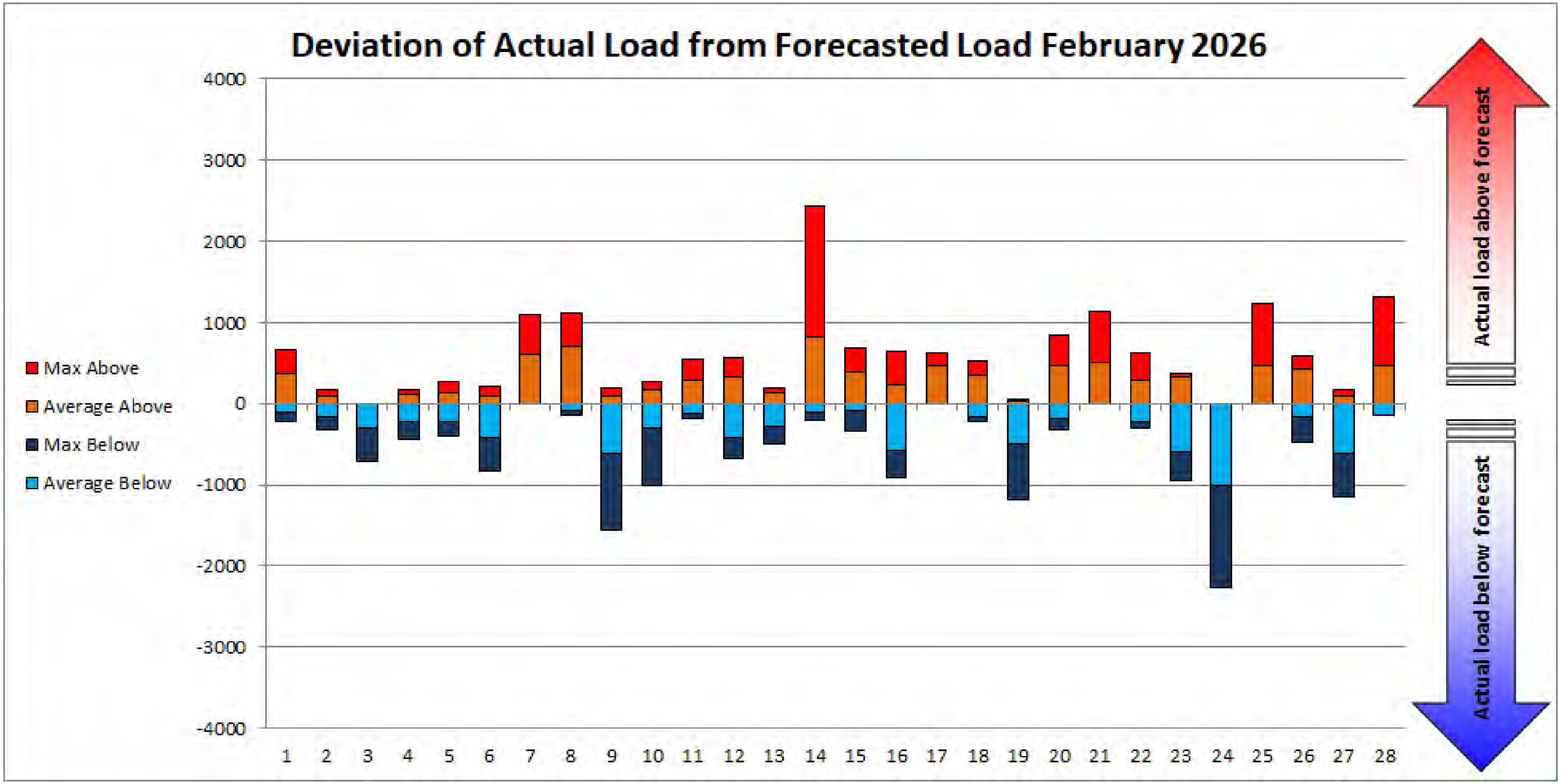
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65	6.85											6.85
Day Min	0.76	0.82											0.76
MAPE	2.00	2.66											2.31
Goal	1.80	1.80											

2026 System Operations - Load Forecast Accuracy cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	47.8	58.2											53
Below %	52.2	41.8											47
Avg Above	204.1	299.6											300
Avg Below	-232.5	-271.5											-272
Avg All	-19	59											18

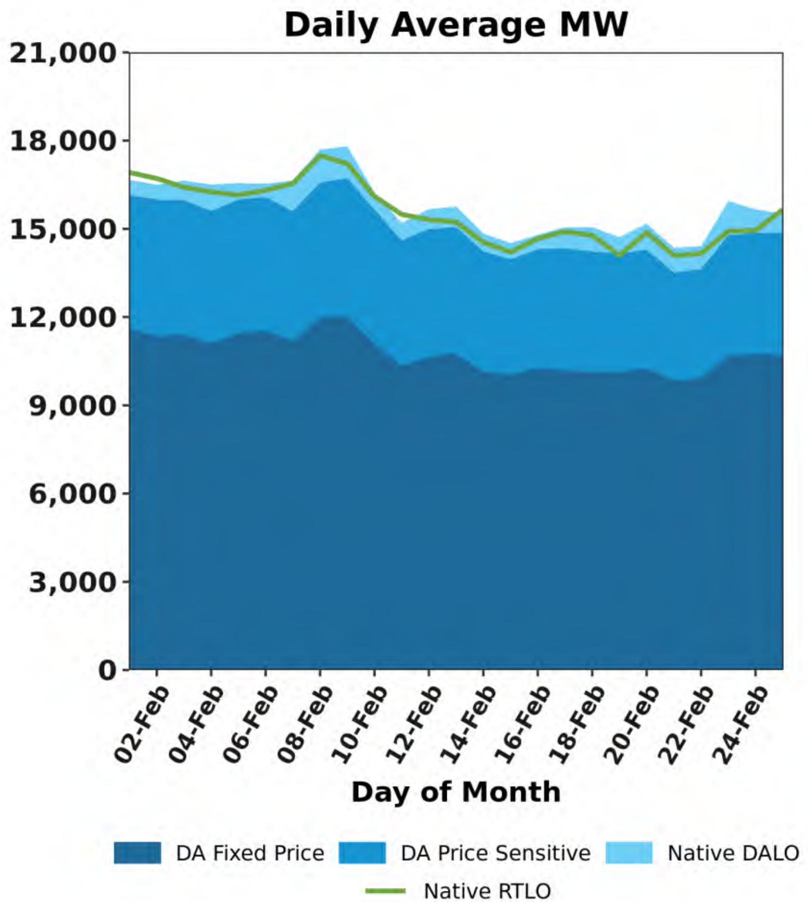
2026 System Operations - Load Forecast Accuracy

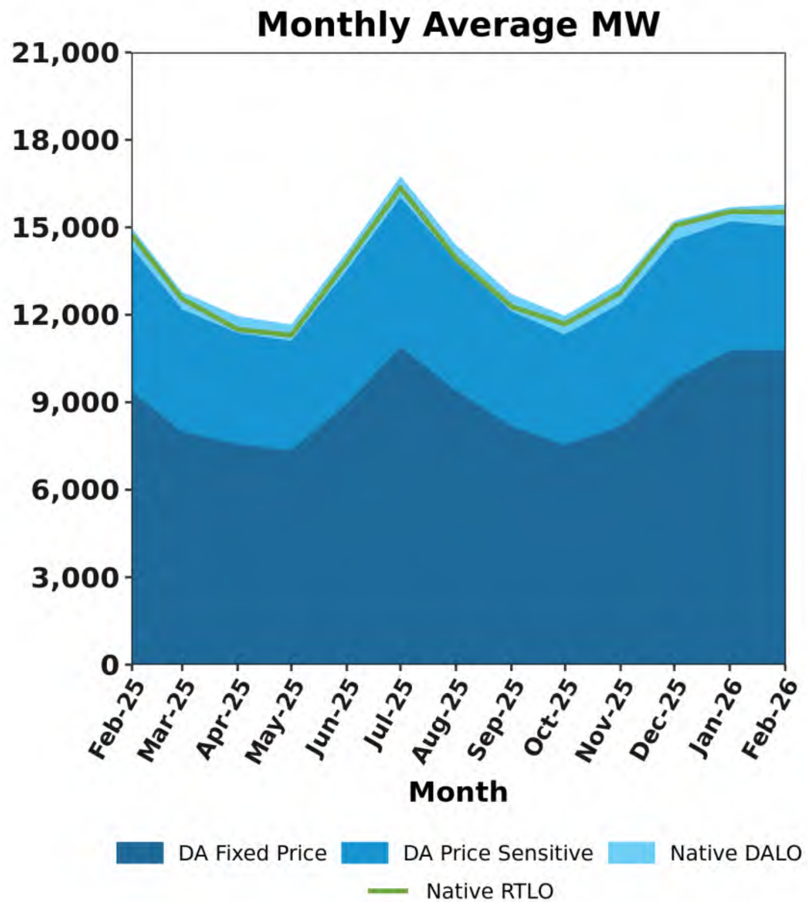


MARKET OPERATIONS

Supply and Demand Volumes

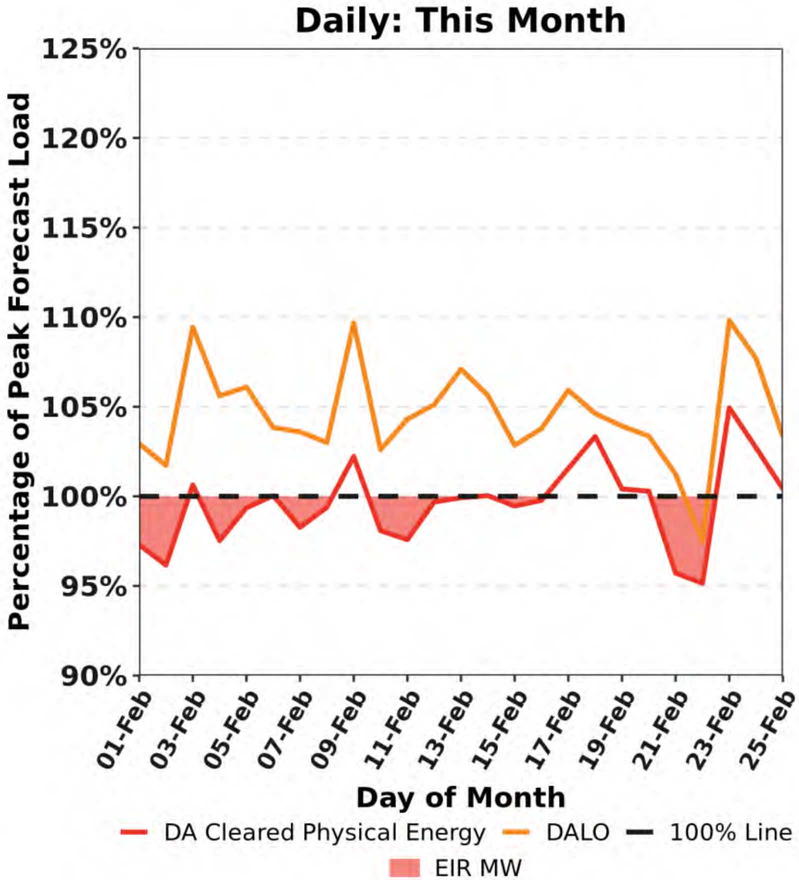
DA Cleared Native Load by Composition Compared to Native RT Load

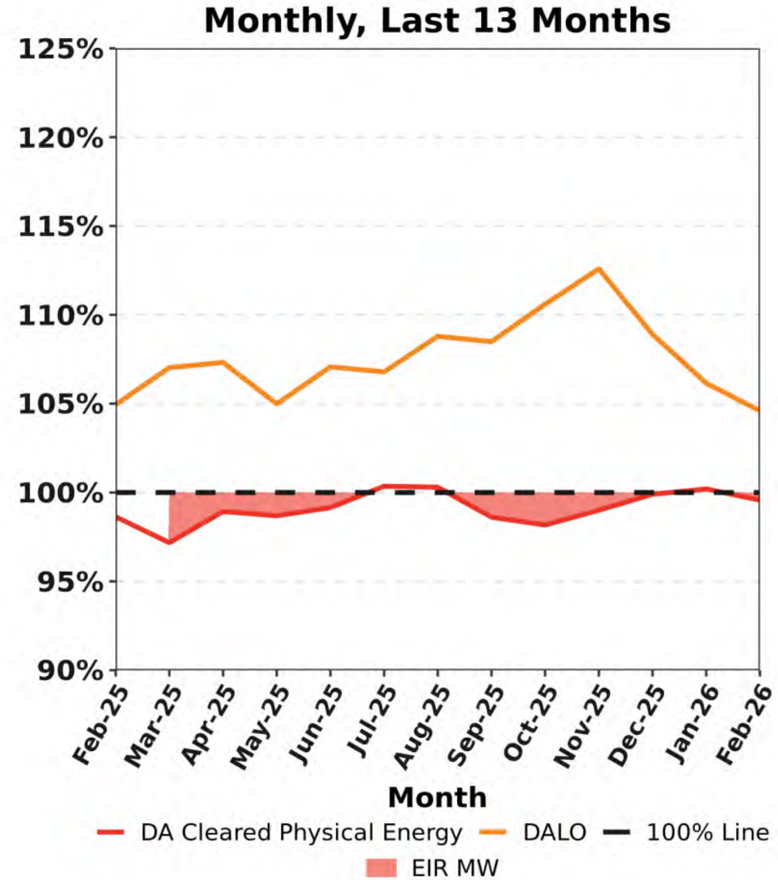




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

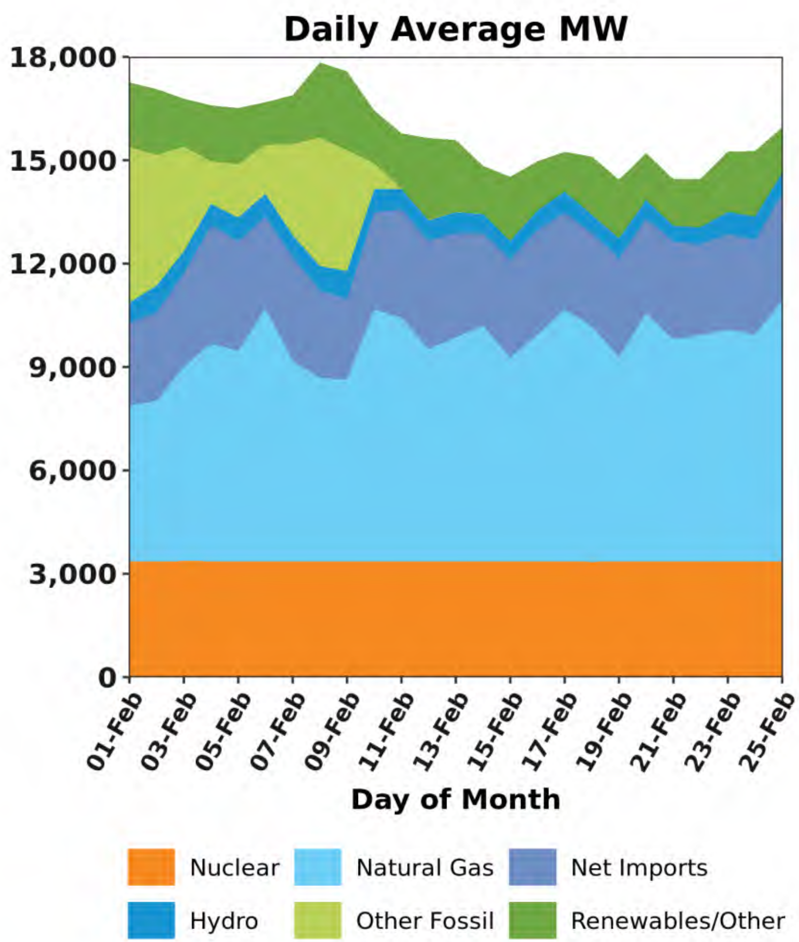
DA Volumes as % of Forecast in Peak Hour

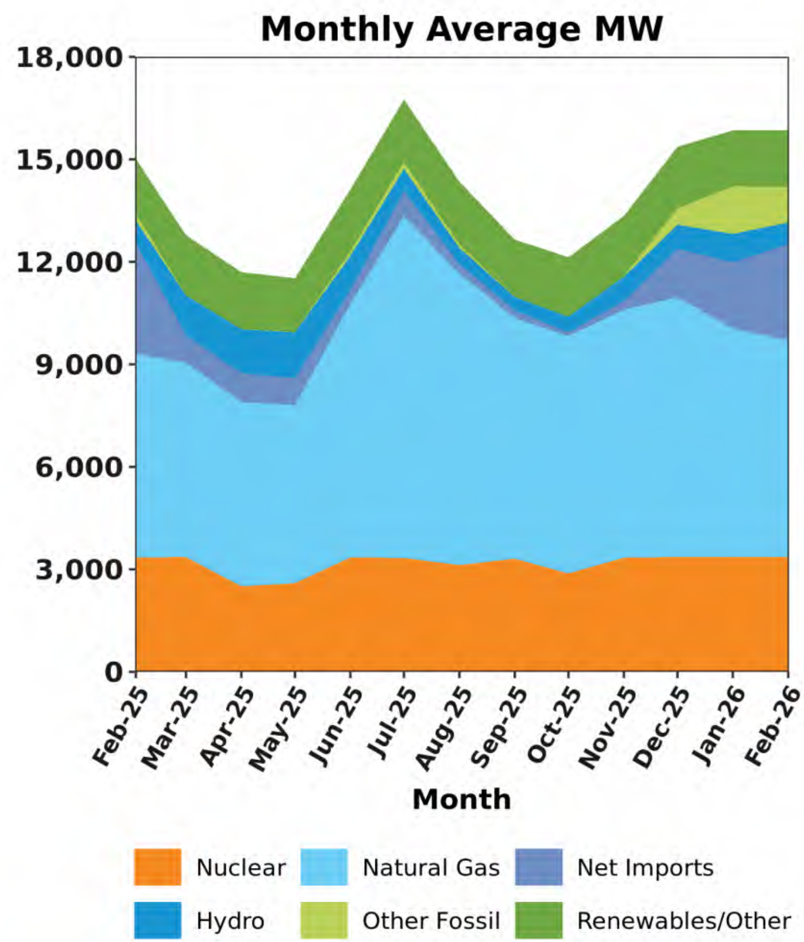




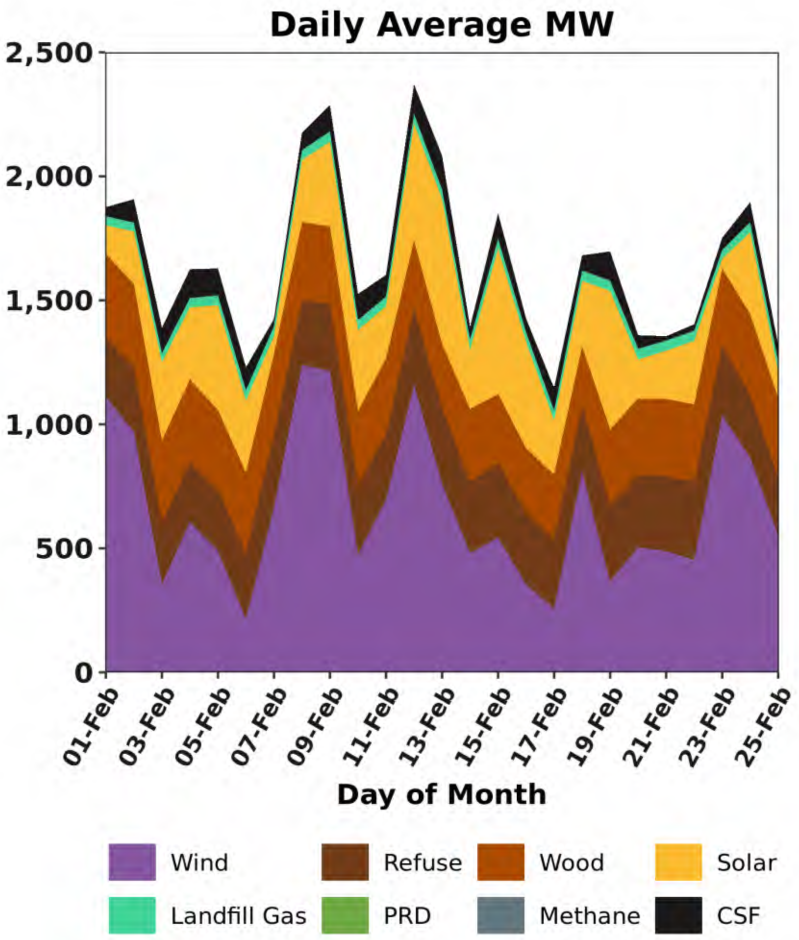
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

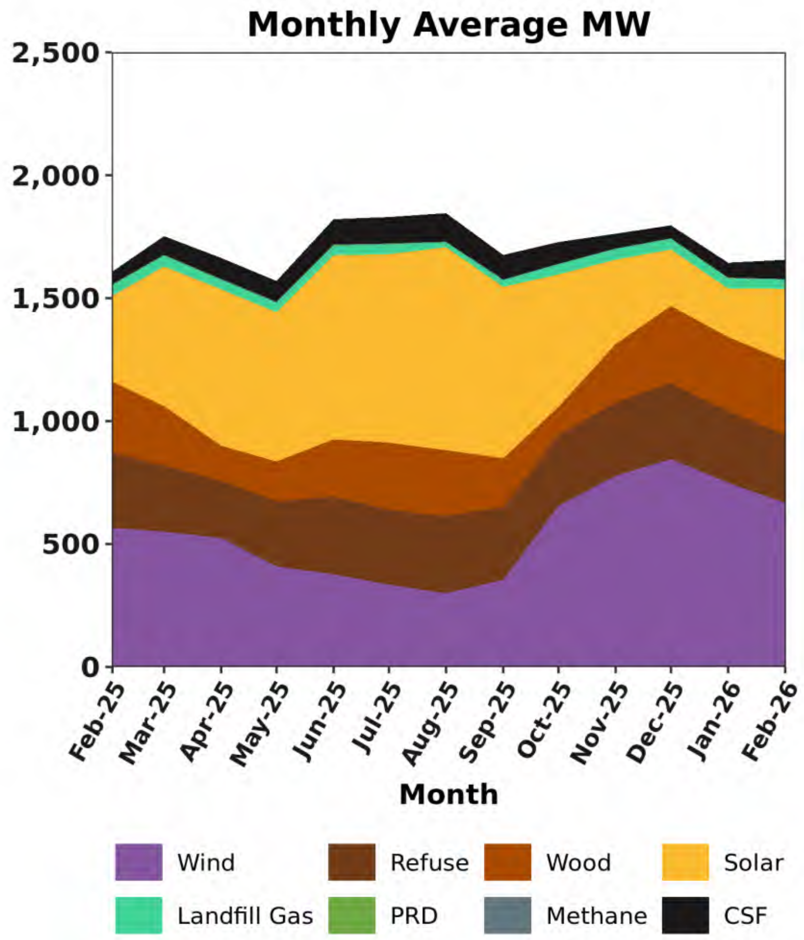
Resource Mix





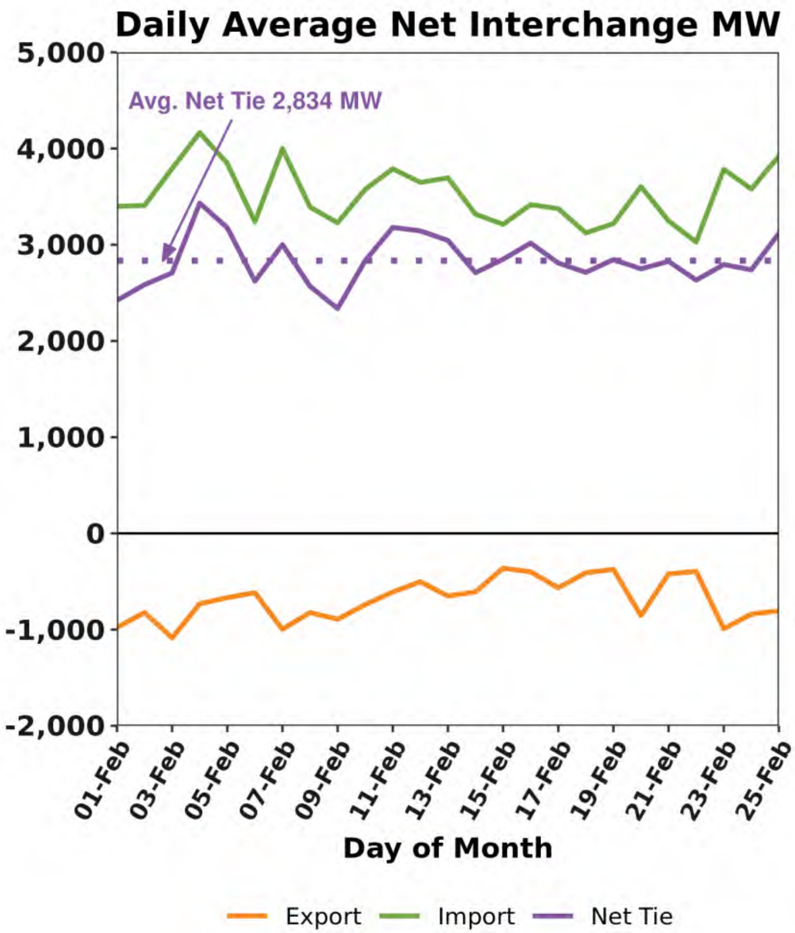
Renewable Generation by Fuel Type

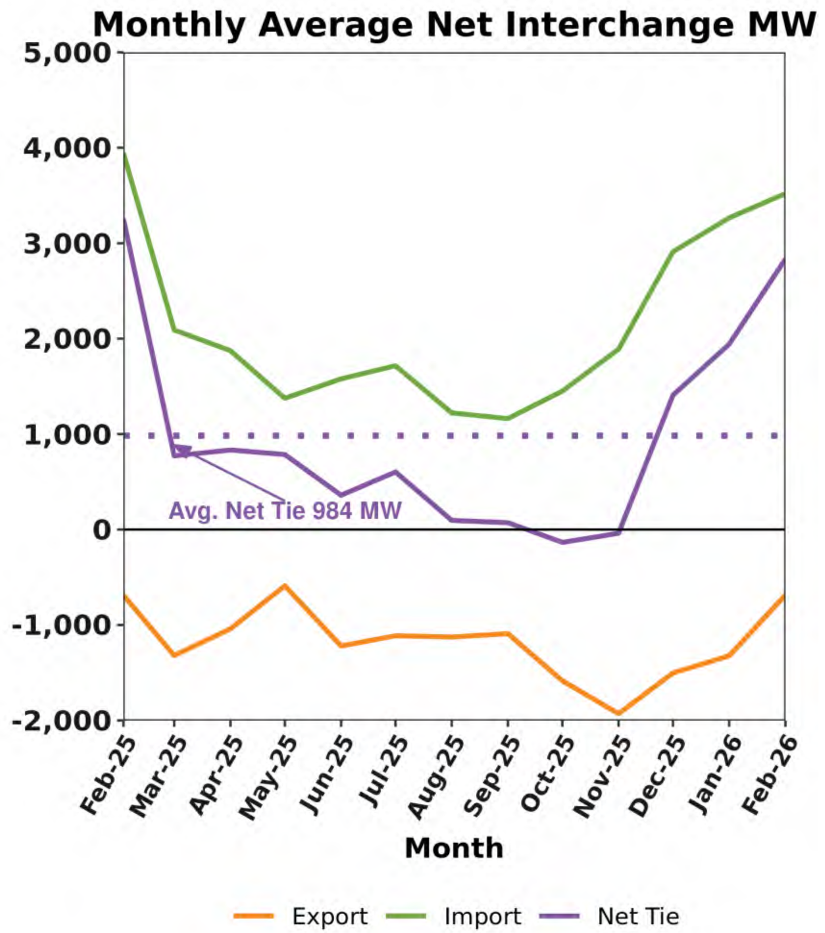




CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

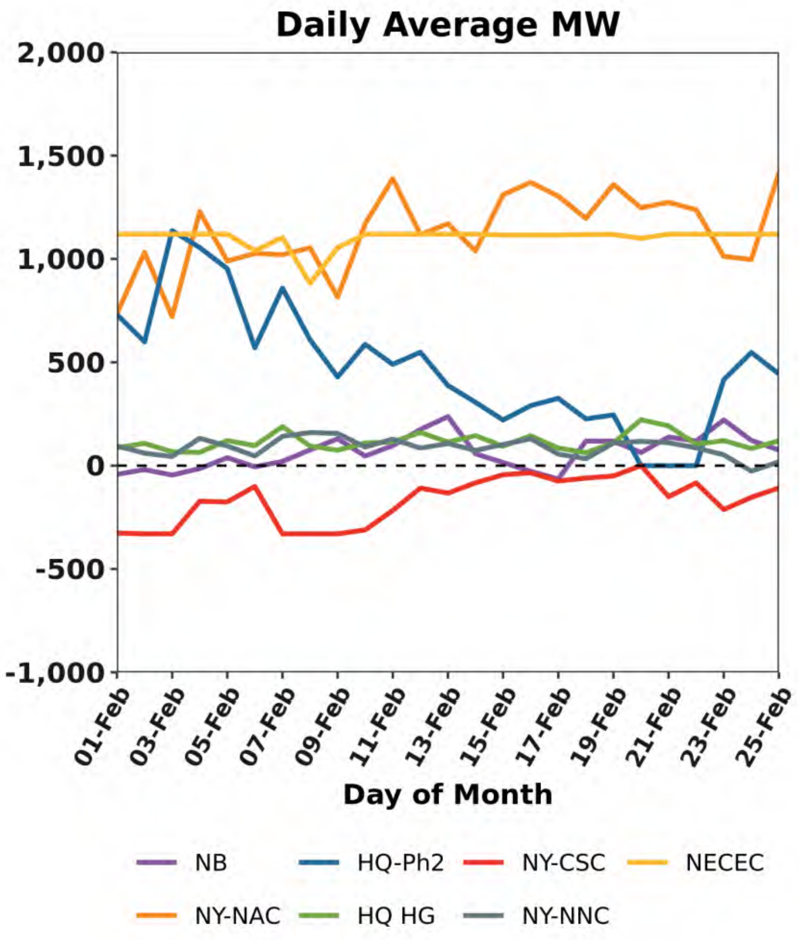
RT Net Interchange

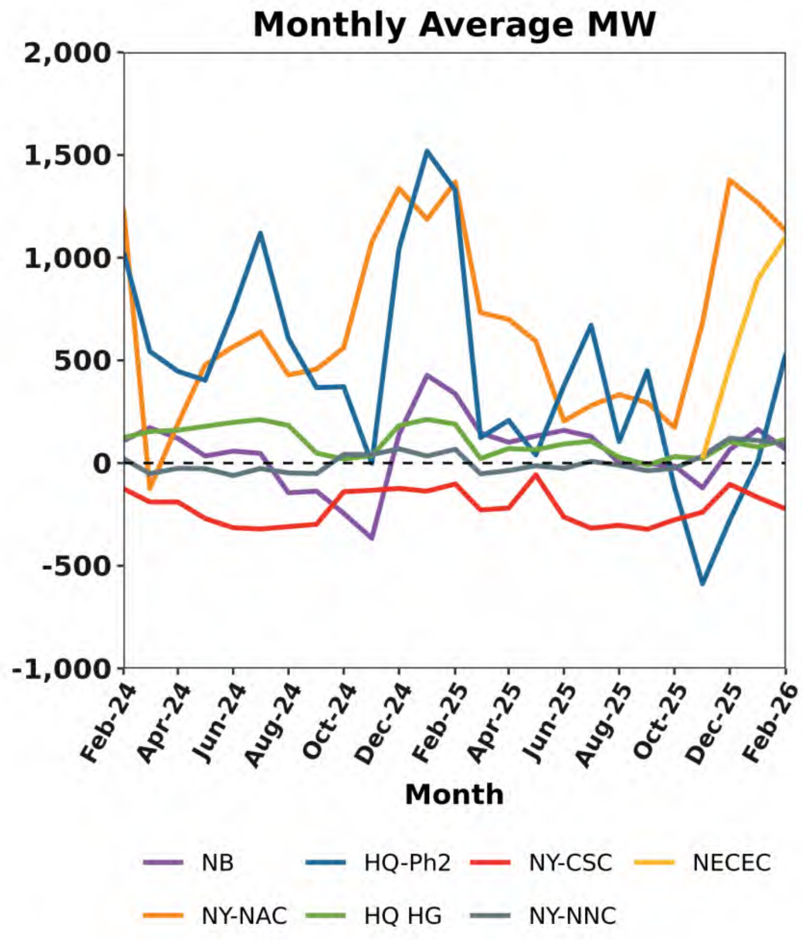




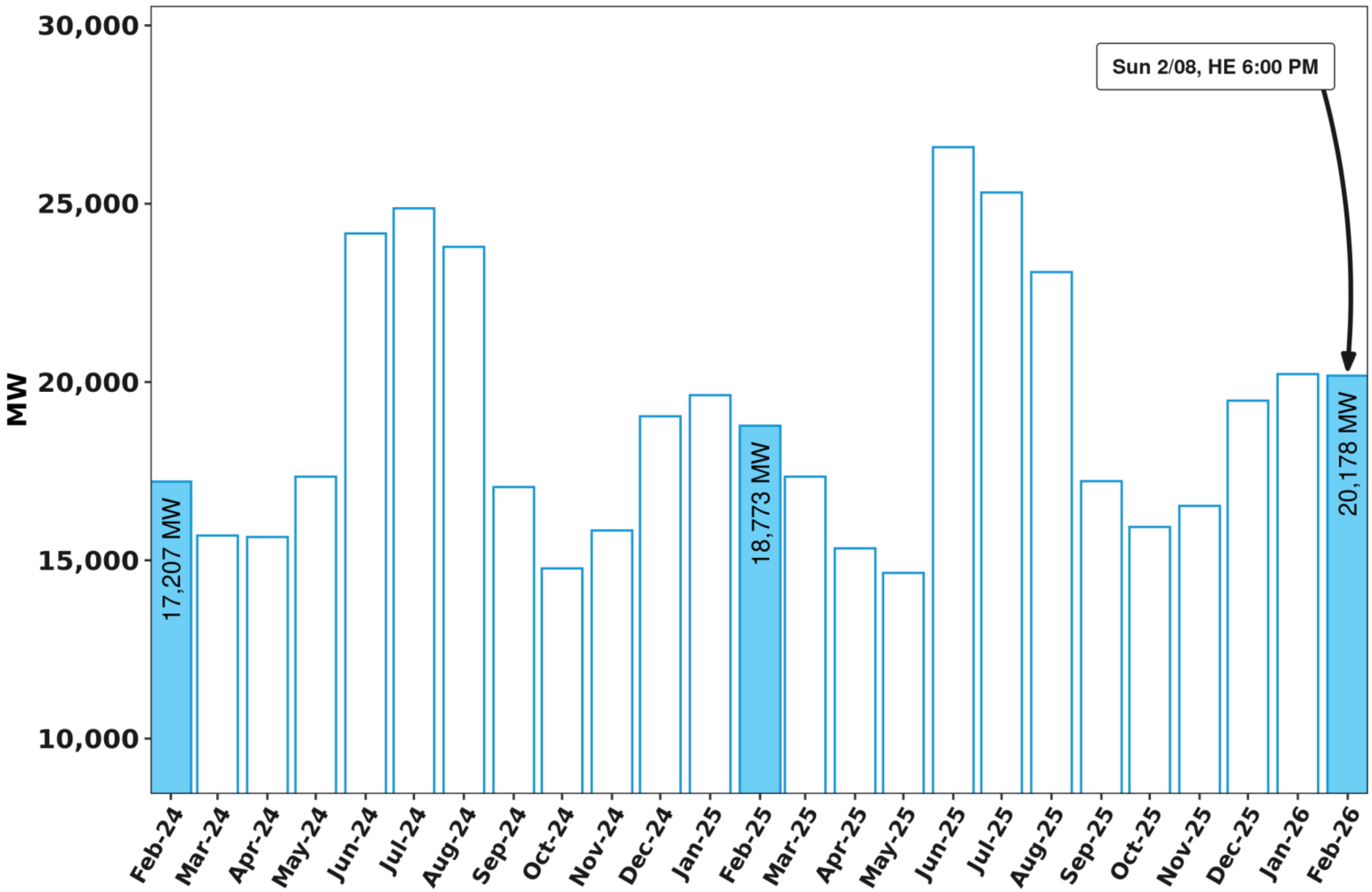
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



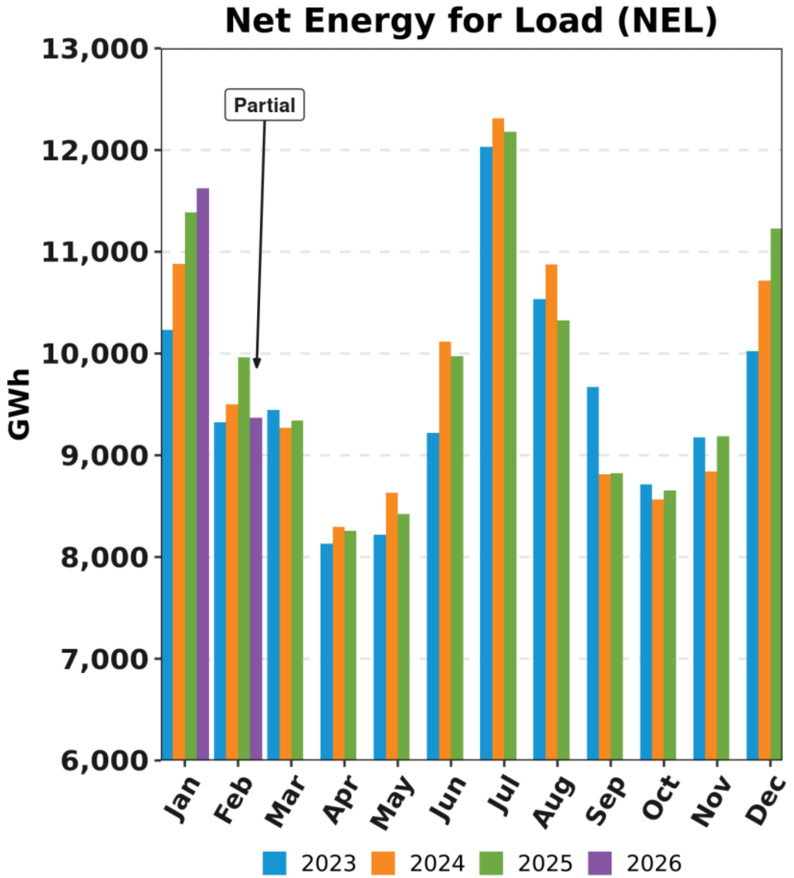


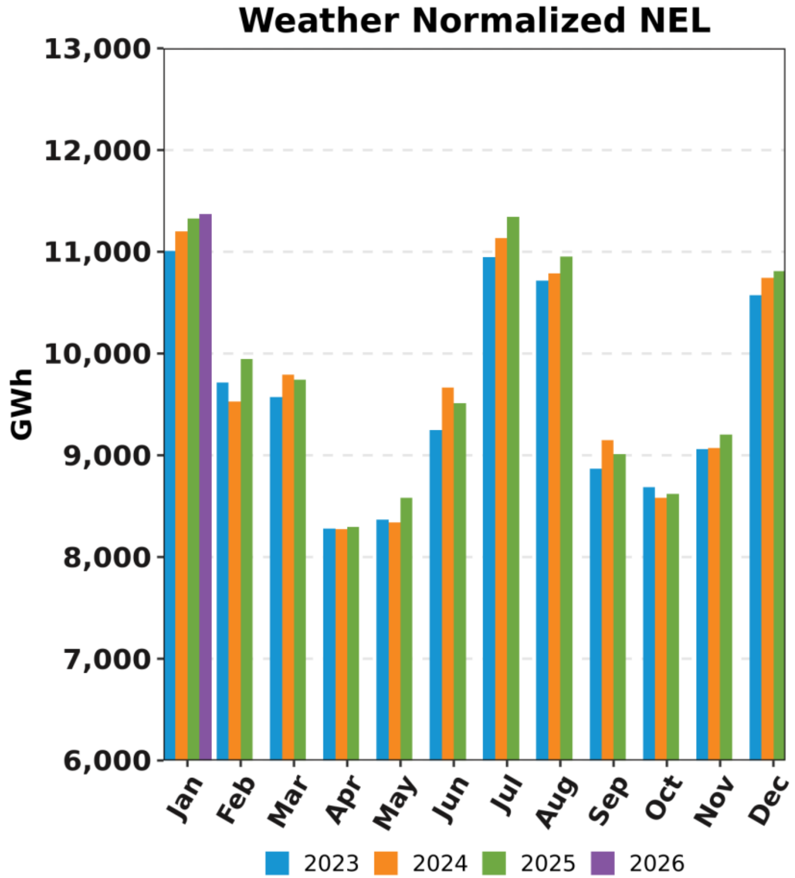
RQM System Peak Load MW by Month



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

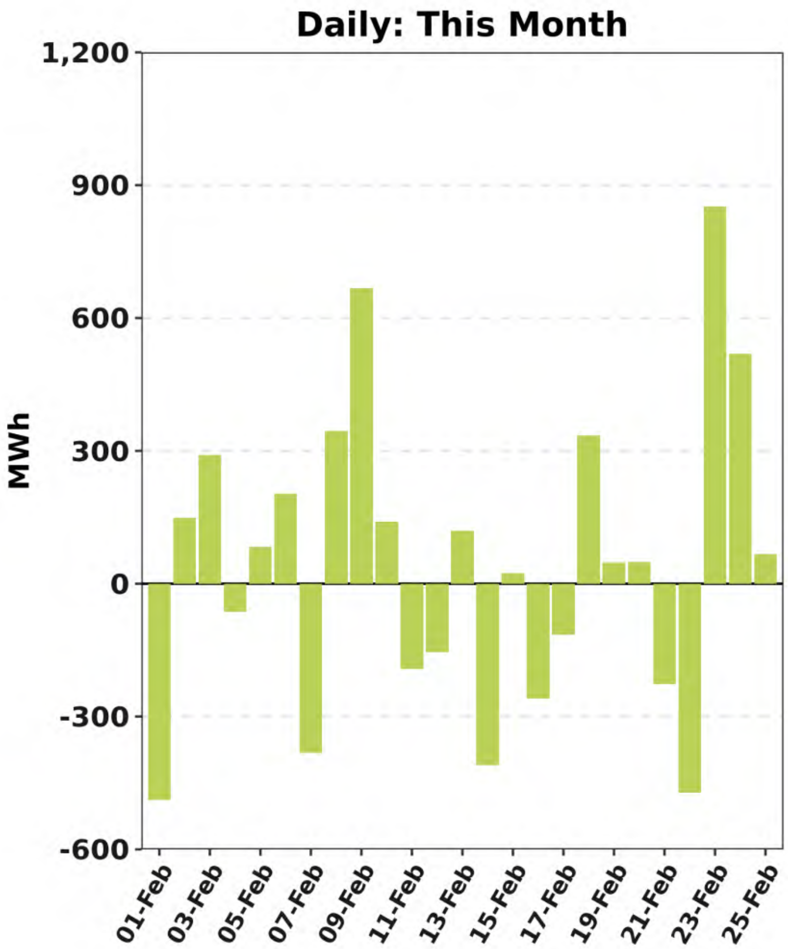
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

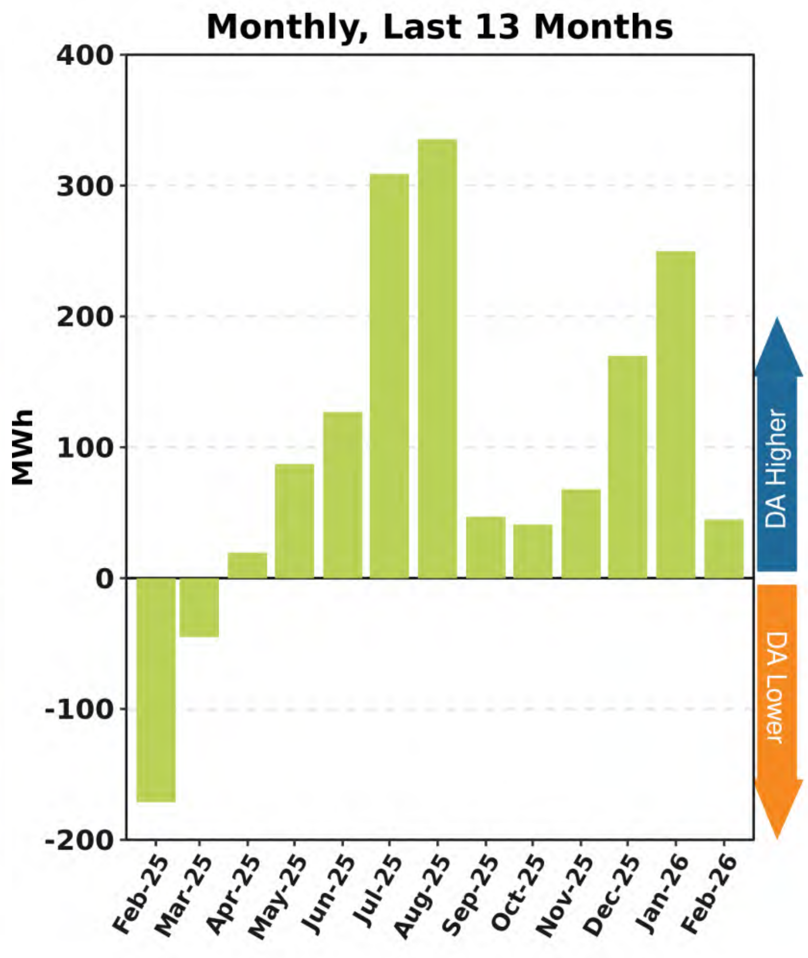




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

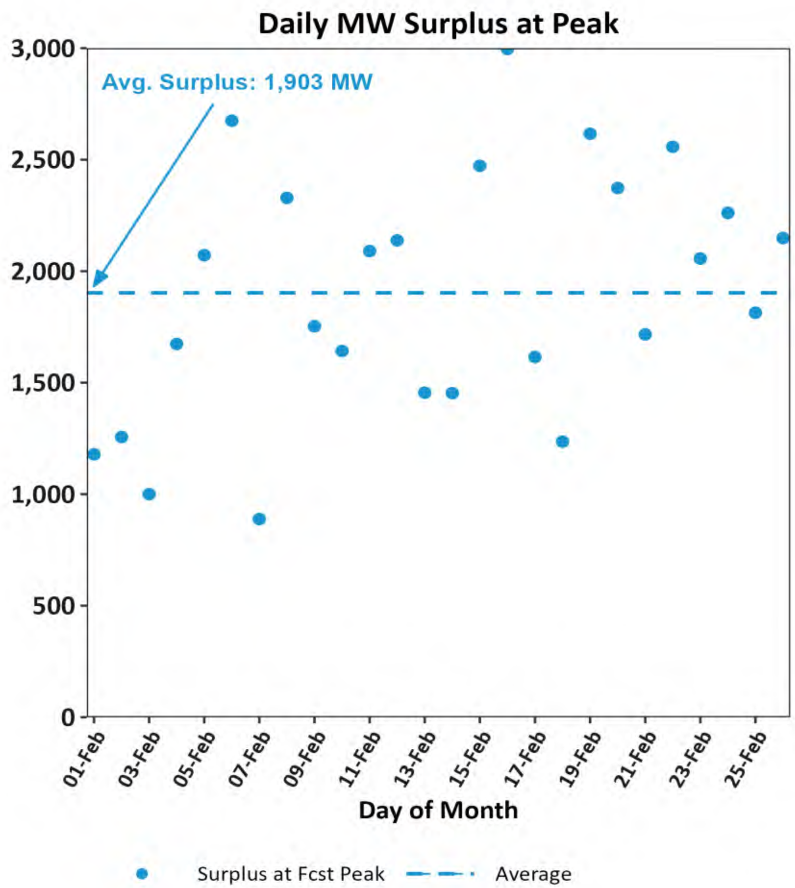
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour

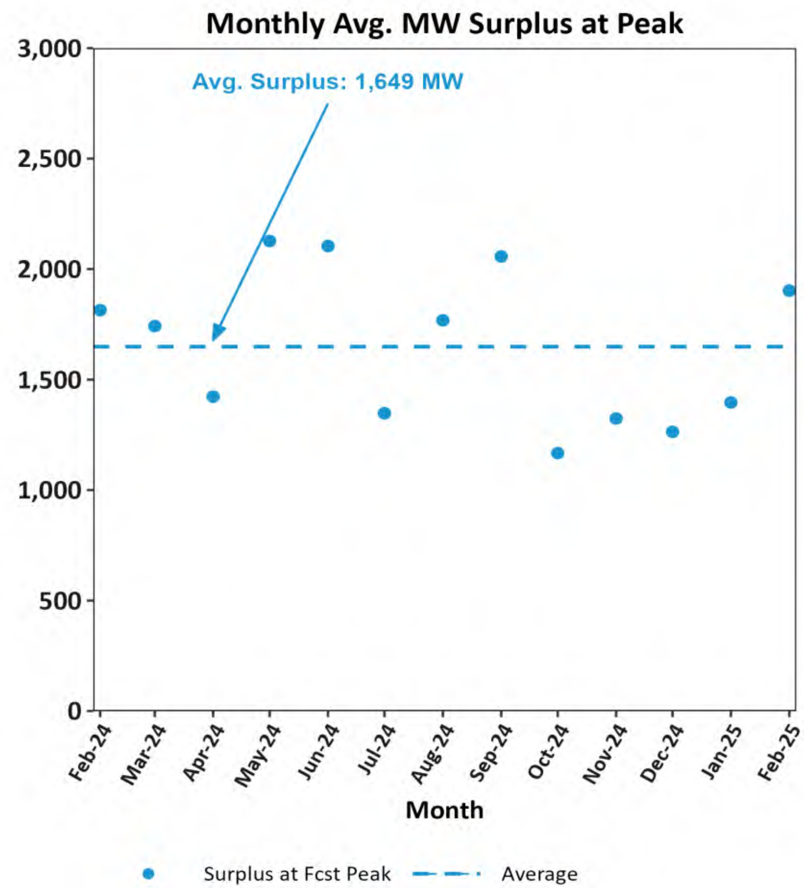




Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

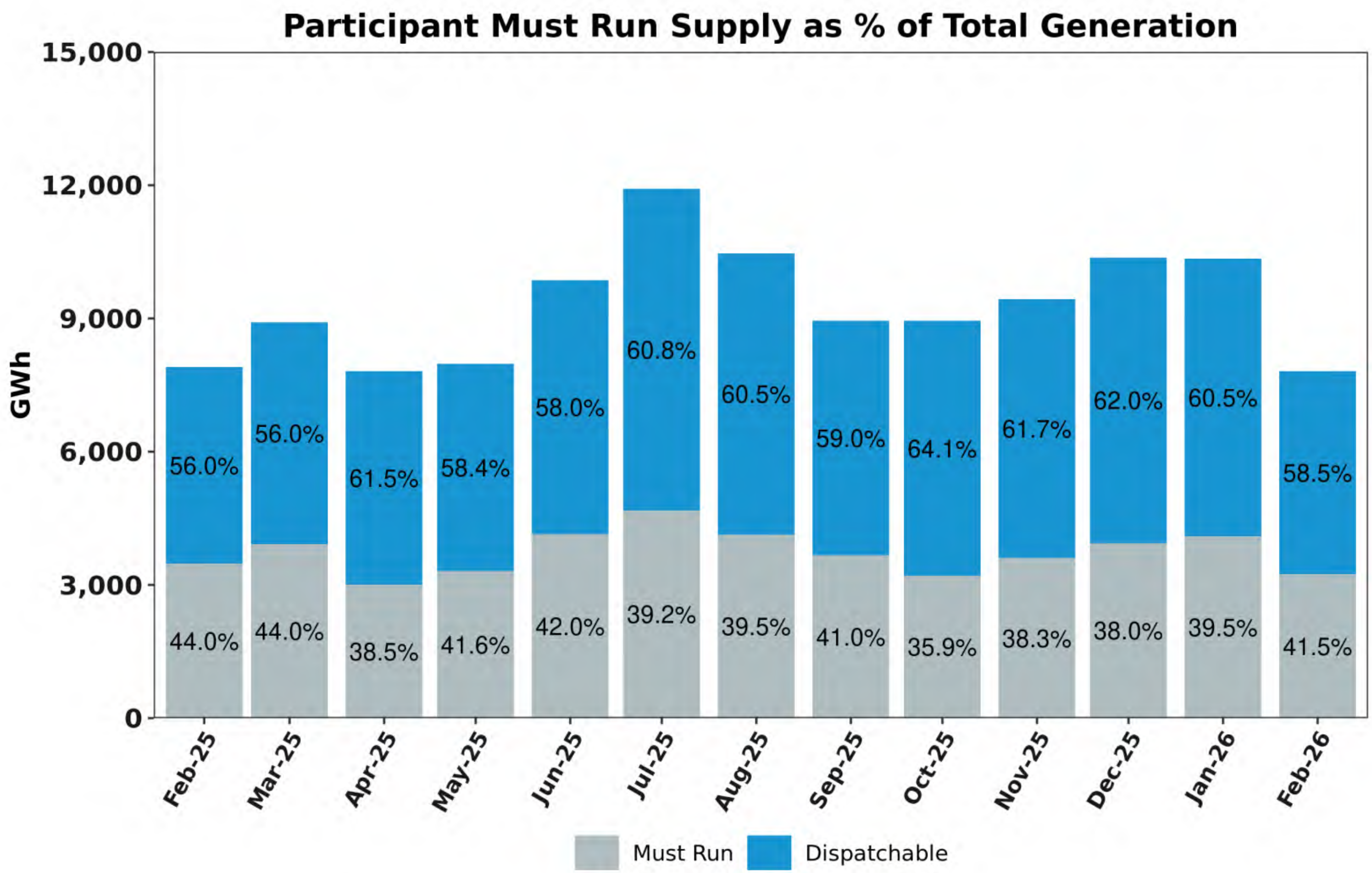
Native Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





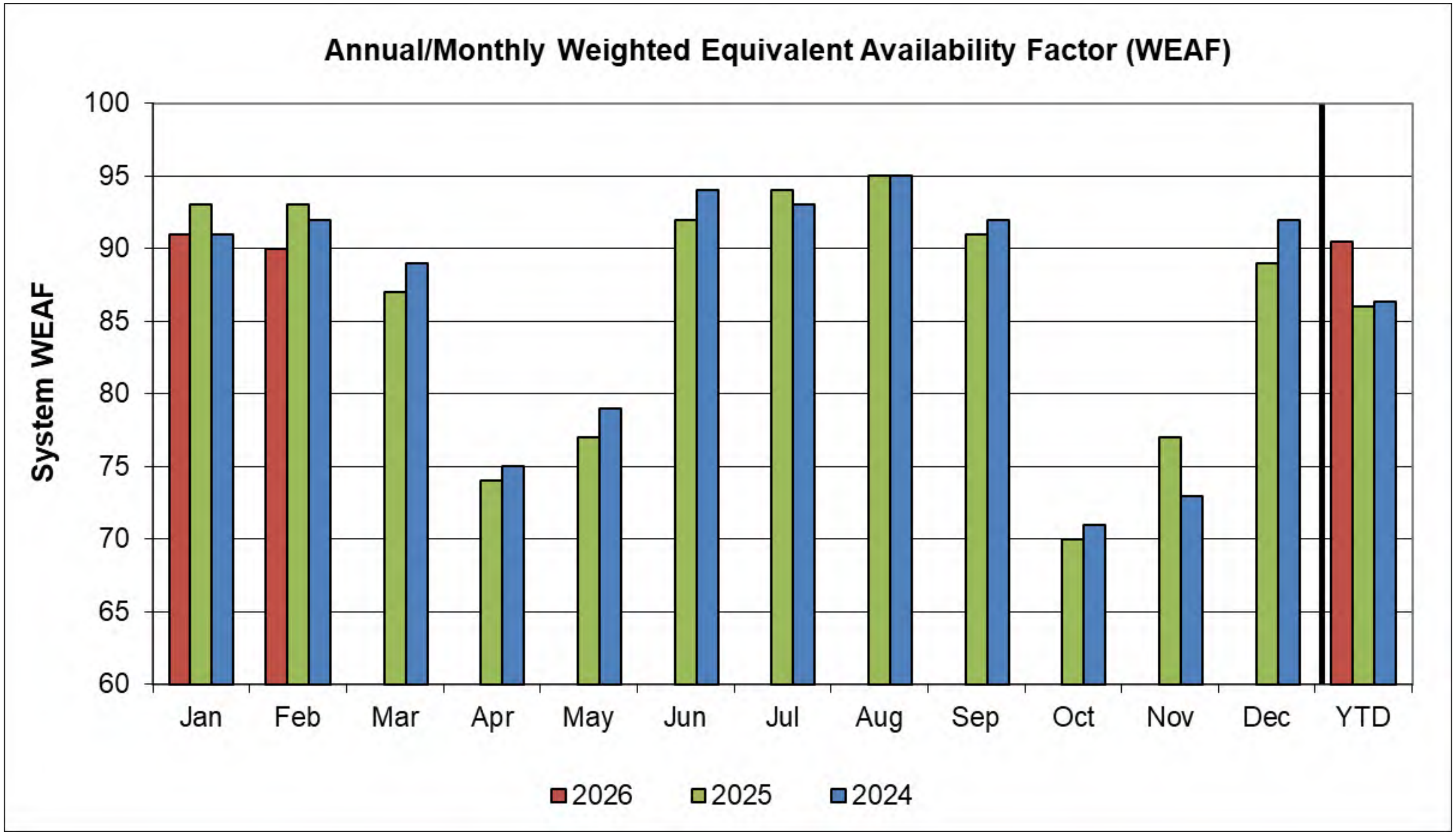
*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

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	90											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 2/24/26

MARKET OPERATIONS

Market Pricing

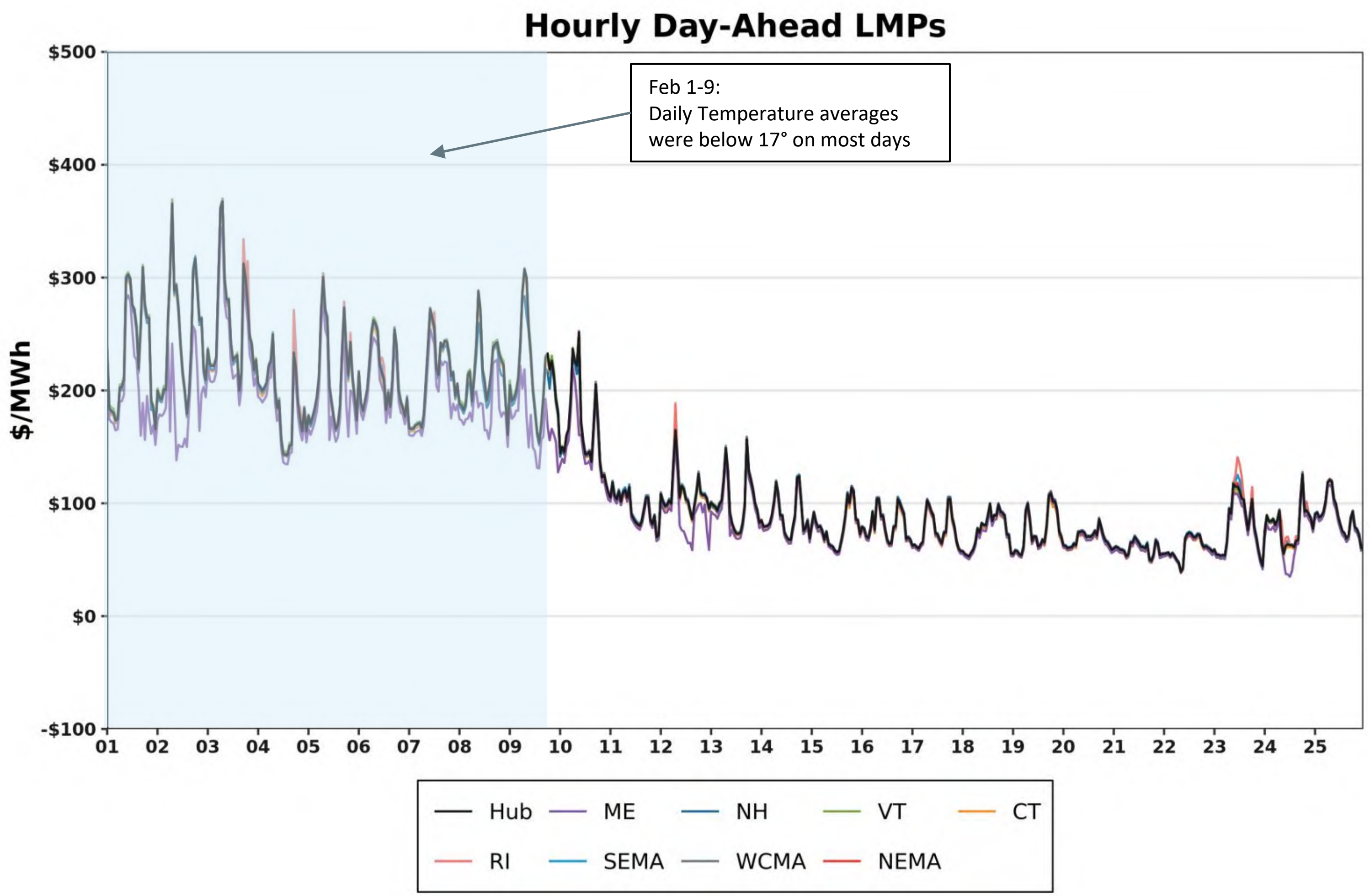
DA vs. RT LMPs ($/MWh)

Arithmetic Average

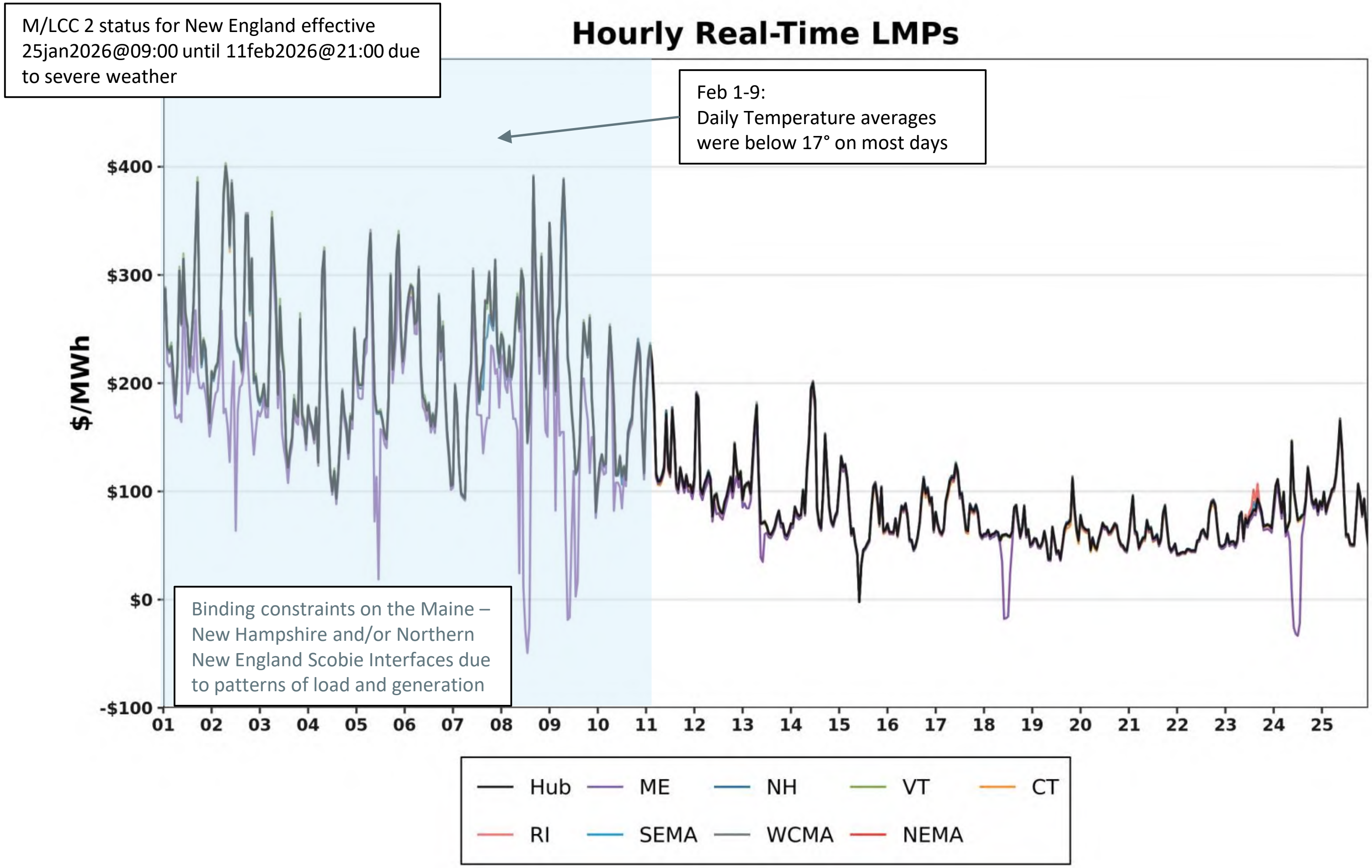
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$41.35	$41.07	$41.72	$41.11	$40.17	$41.28	$41.70	$41.37	$41.91
Real-Time	$39.37	$38.79	$39.65	$39.23	$38.46	$39.17	$39.62	$39.37	$39.77
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%
Year 2025	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	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%

February-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$130.39	$128.41	$131.80	$129.23	$126.40	$130.69	$131.80	$130.38	$131.97
Real-Time	$126.40	$124.22	$127.69	$124.72	$122.89	$126.85	$127.74	$126.40	$128.00
RT Delta %	-3.06%	-3.26%	-3.12%	-3.49%	-2.78%	-2.94%	-3.08%	-3.05%	-3.01%
February-26	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$134.93	$121.90	$133.57	$134.93	$131.58	$135.45	$136.02	$134.93	$135.75
Real-Time	$136.29	$116.03	$135.34	$136.67	$133.55	$136.25	$136.88	$136.45	$137.17
RT Delta %	1.01%	-4.82%	1.33%	1.29%	1.50%	0.59%	0.63%	1.13%	1.05%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	3.48%	-5.07%	1.34%	4.41%	4.10%	3.64%	3.20%	3.49%	2.86%
Yr over Yr RT	7.82%	-6.59%	5.99%	9.58%	8.67%	7.41%	7.16%	7.95%	7.16%

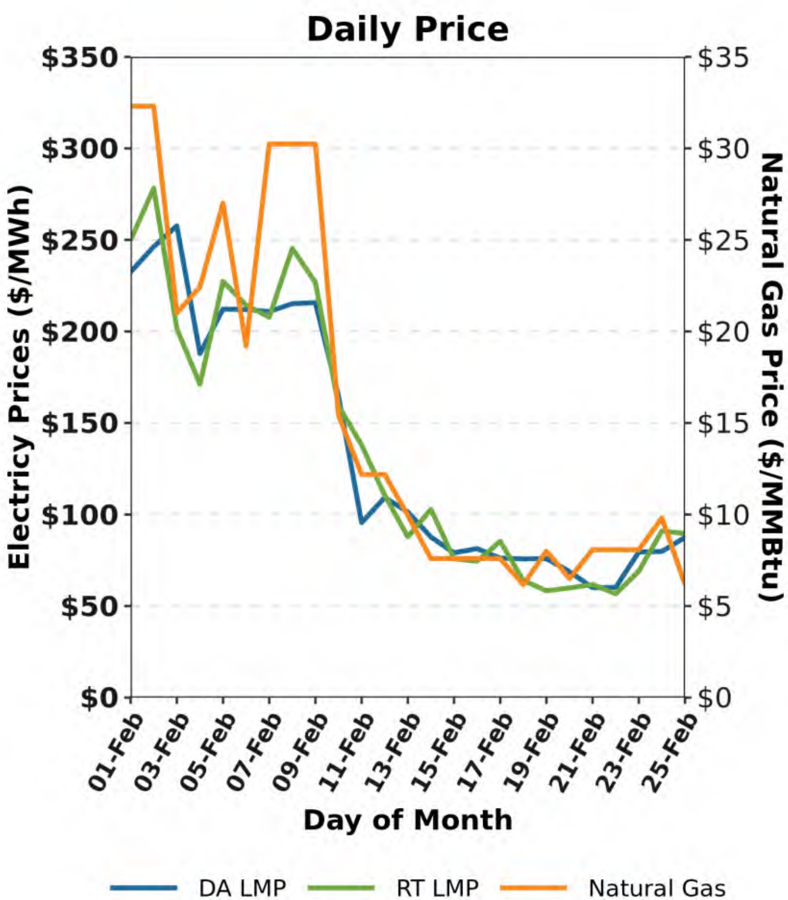
Hourly DA LMPs, February 1-25, 2026

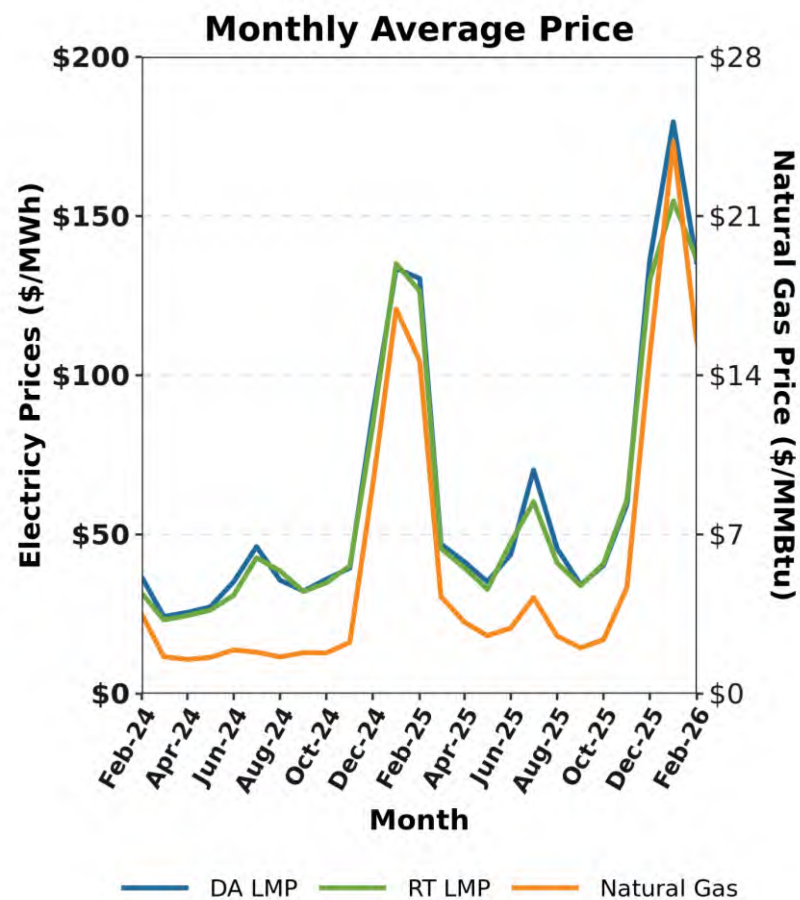


Hourly RT LMPs, February 1-25, 2026



Wholesale Electricity vs Natural Gas Price by Month

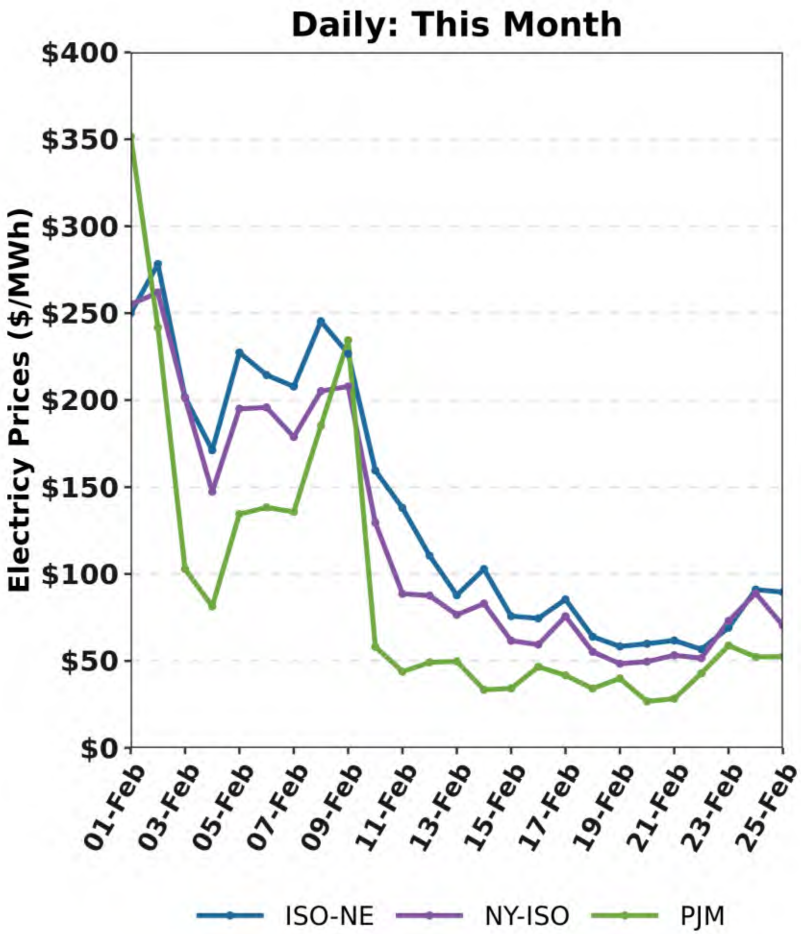


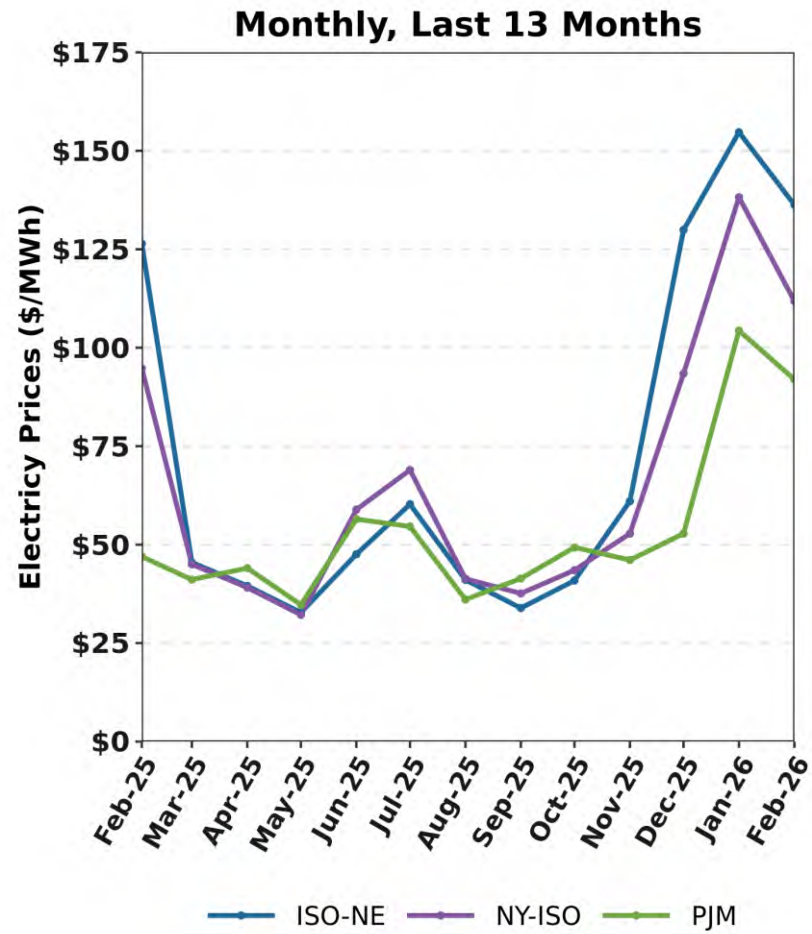


Underlying natural gas data furnished by:

Gas price is average of Massachusetts delivery points

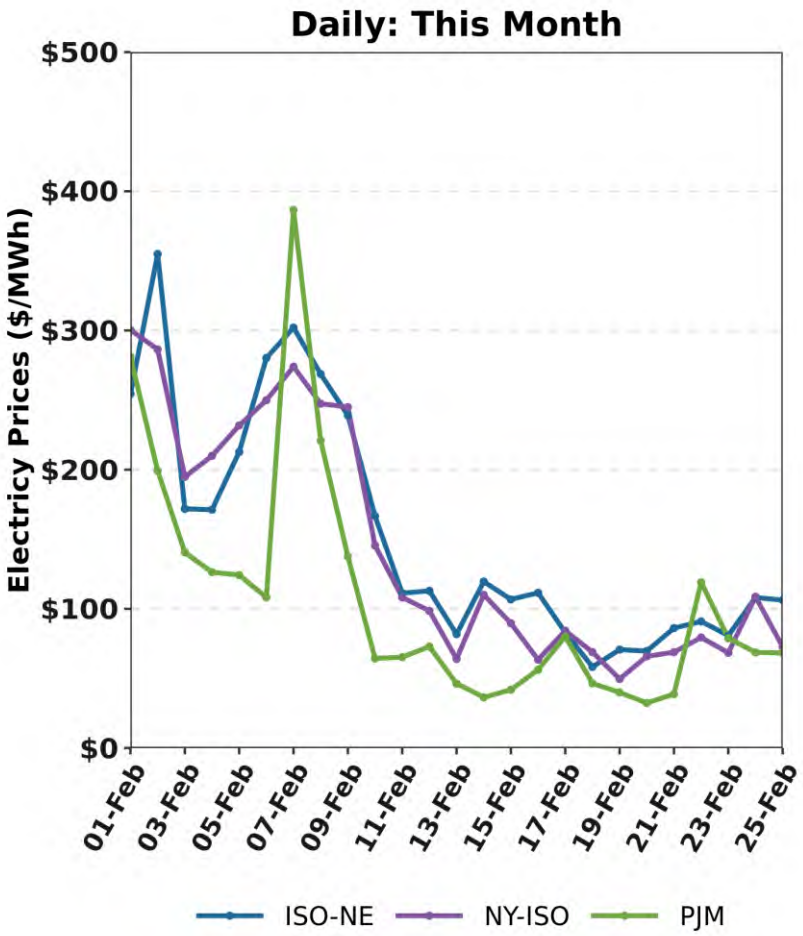
New England, NY, and PJM Hourly Average RT Prices by Month

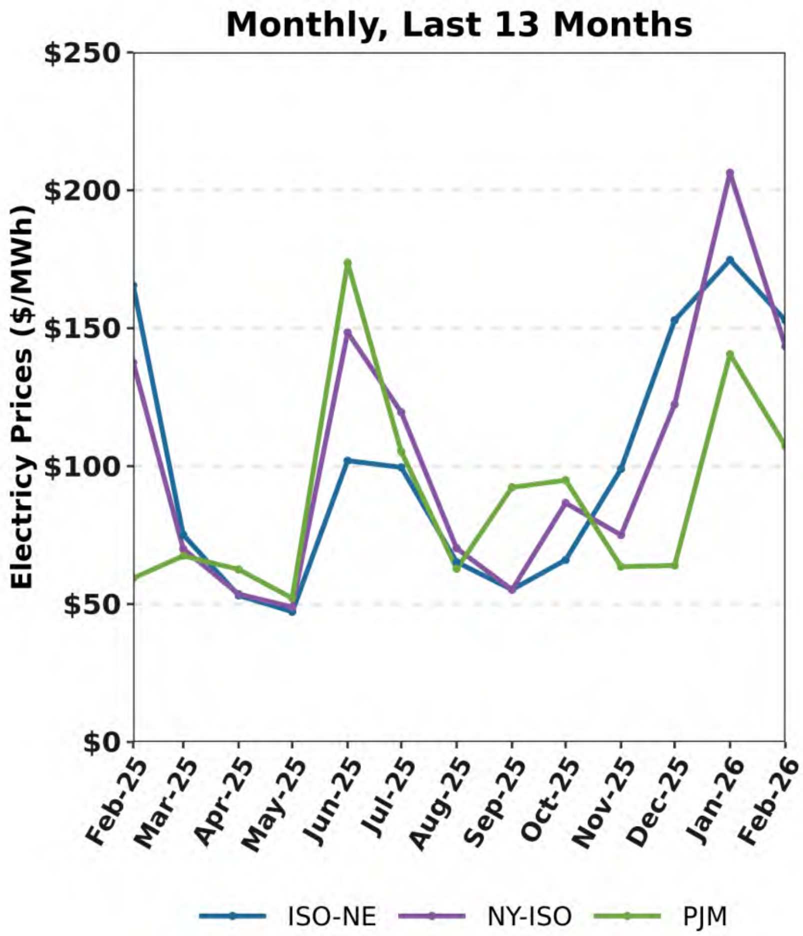




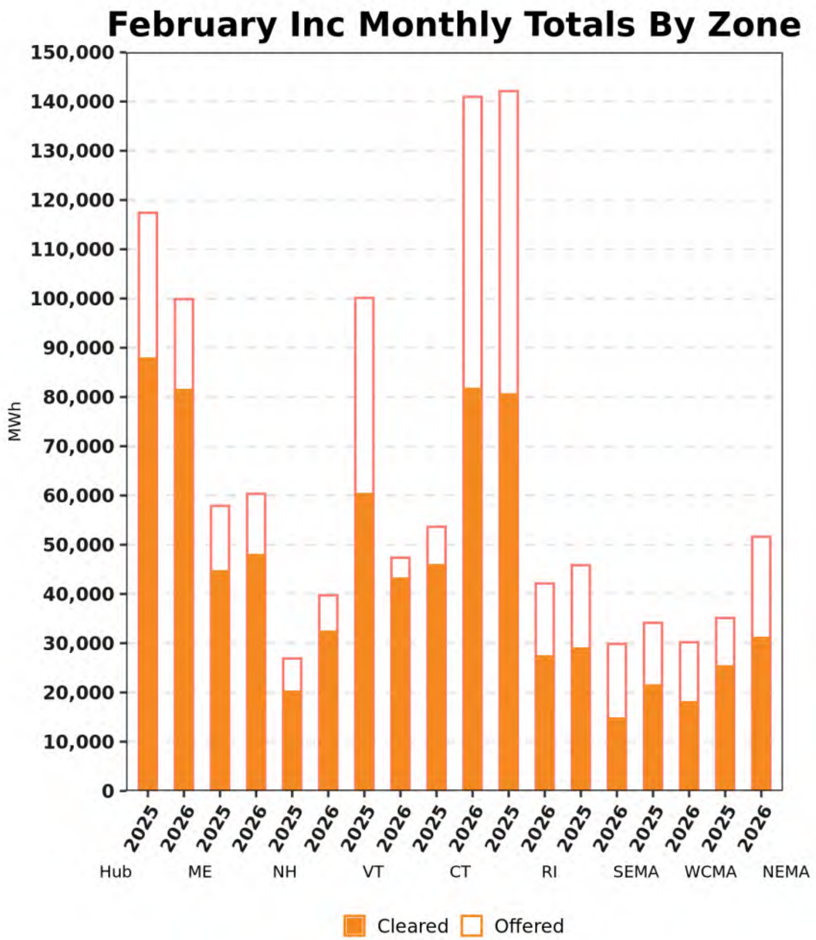
Hourly average prices are shown

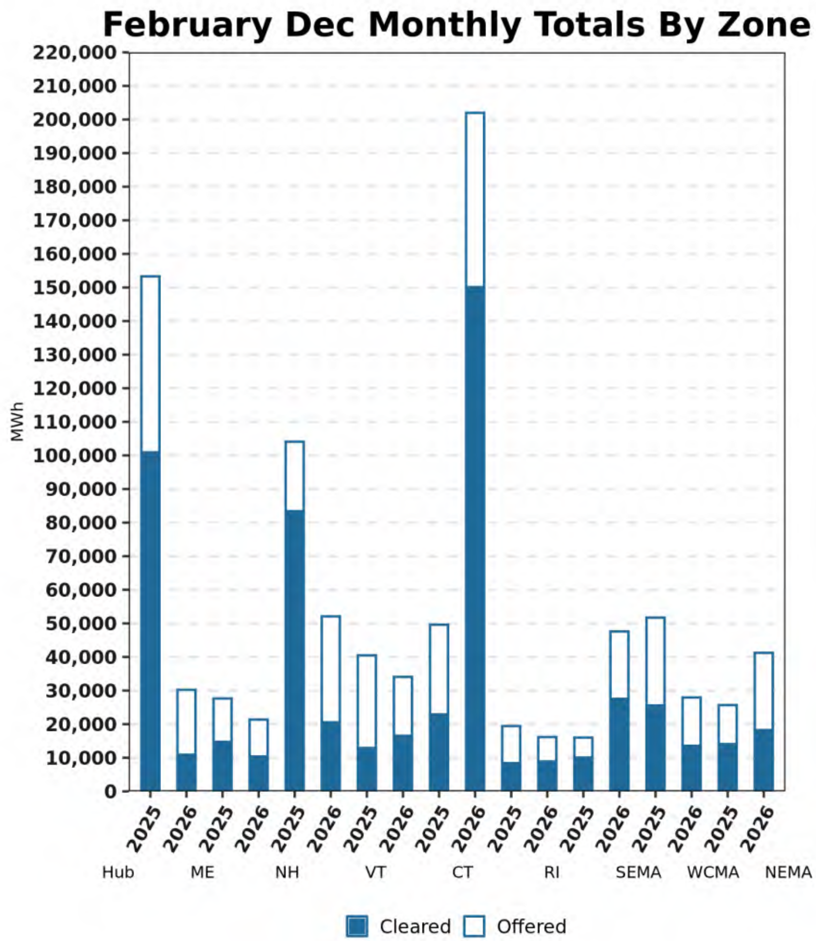
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





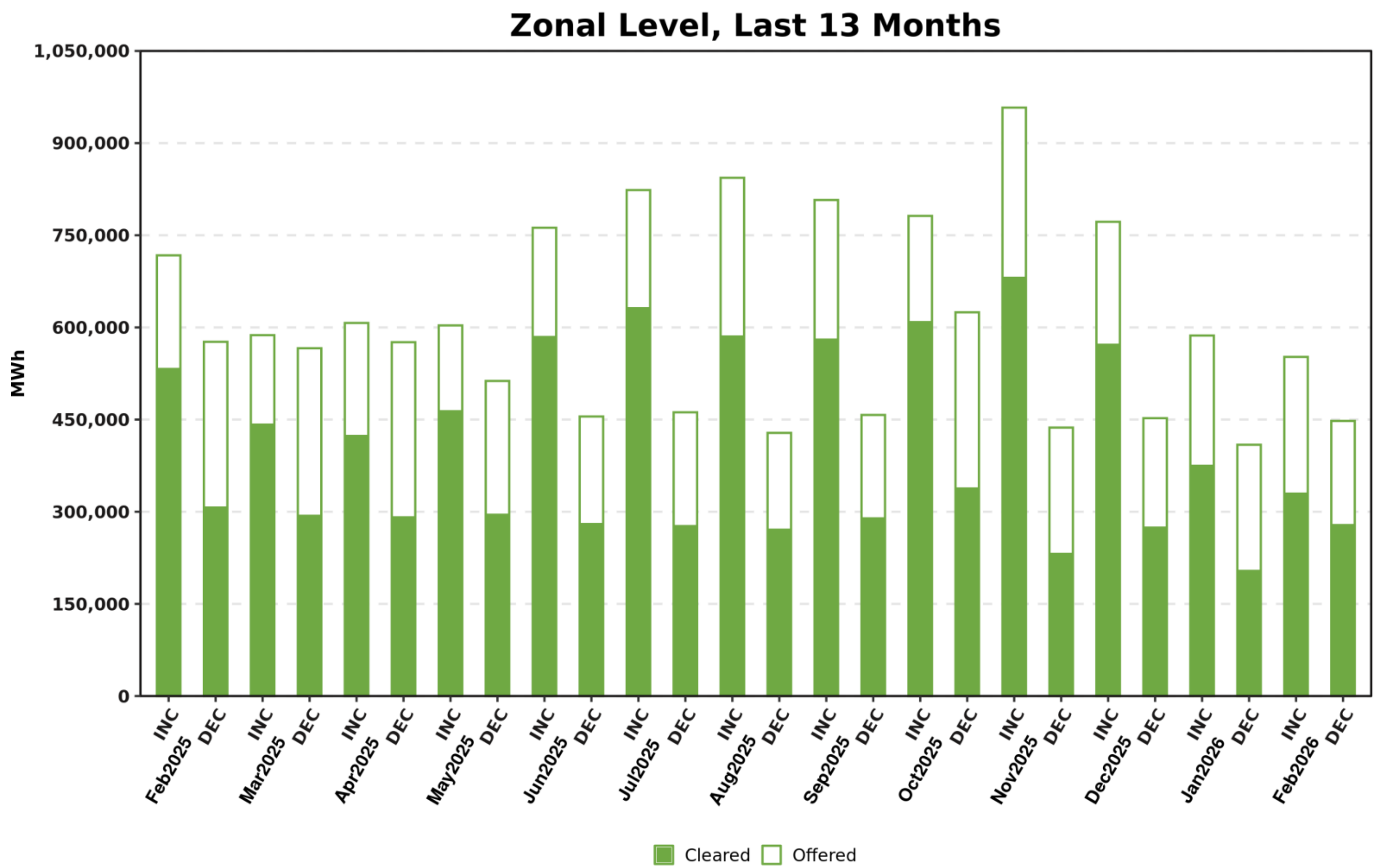
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

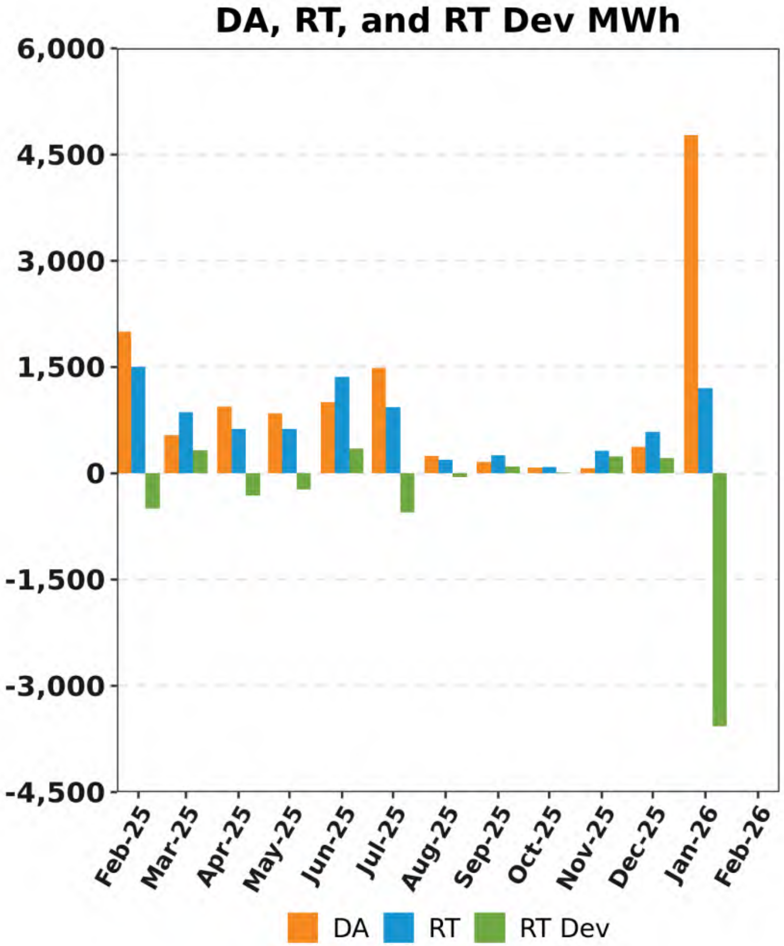


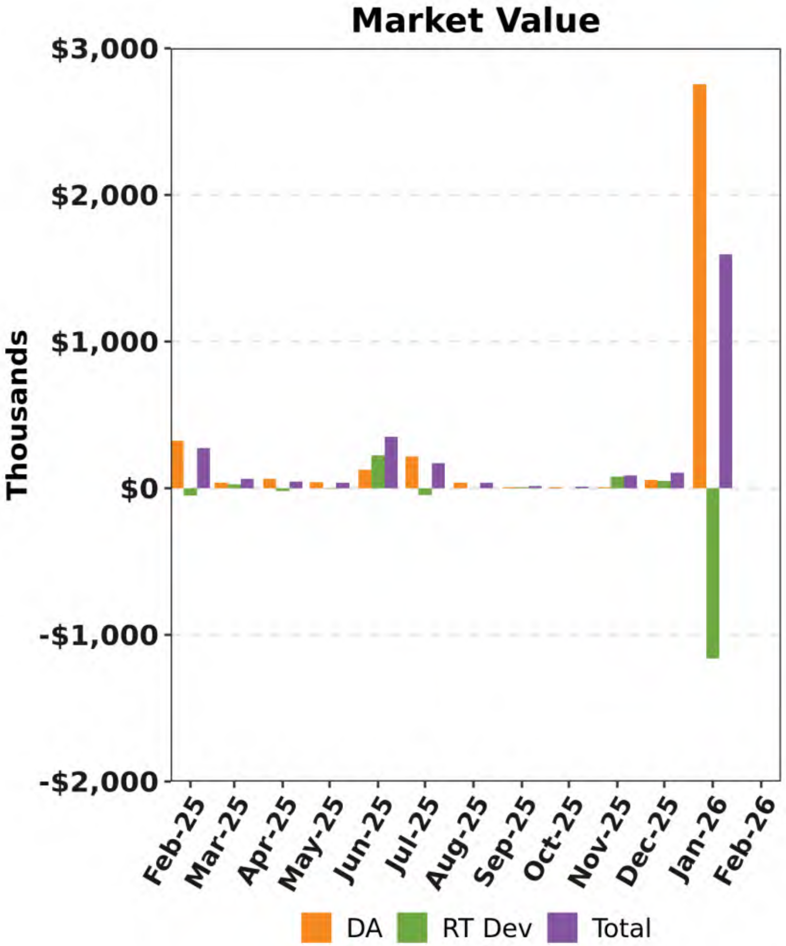
Includes nodal activity within the zone; excludes external nodes

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

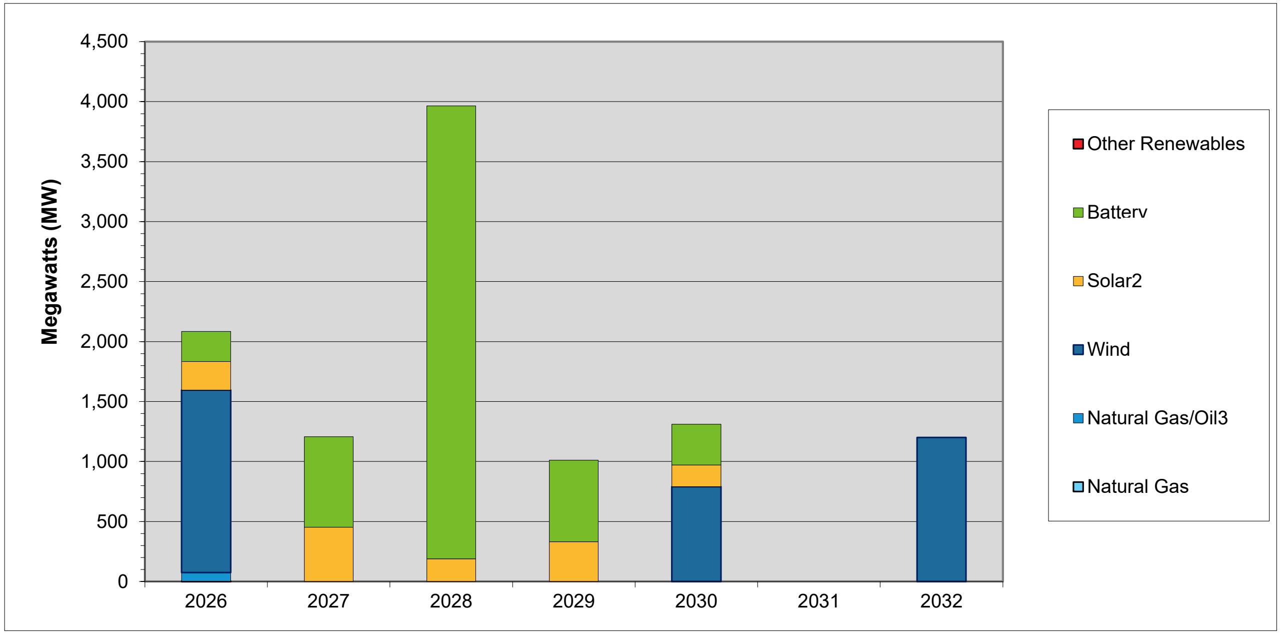
New Generation Update
Based on Queue as of 03/02/26

- 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, 58* generation projects are currently being tracked by the ISO, totaling approximately 11,976 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	250	754	3,774	680	340	0	0	5,798	53.8
Solar[2]	237	453	190	332	180	0	0	1,392	12.9
Wind	1,522	0	0	0	791	0	1,200	3,513	32.6
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.7
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	2,082	1,207	3,964	1,012	1,311	0	1,200	10,776	100.0

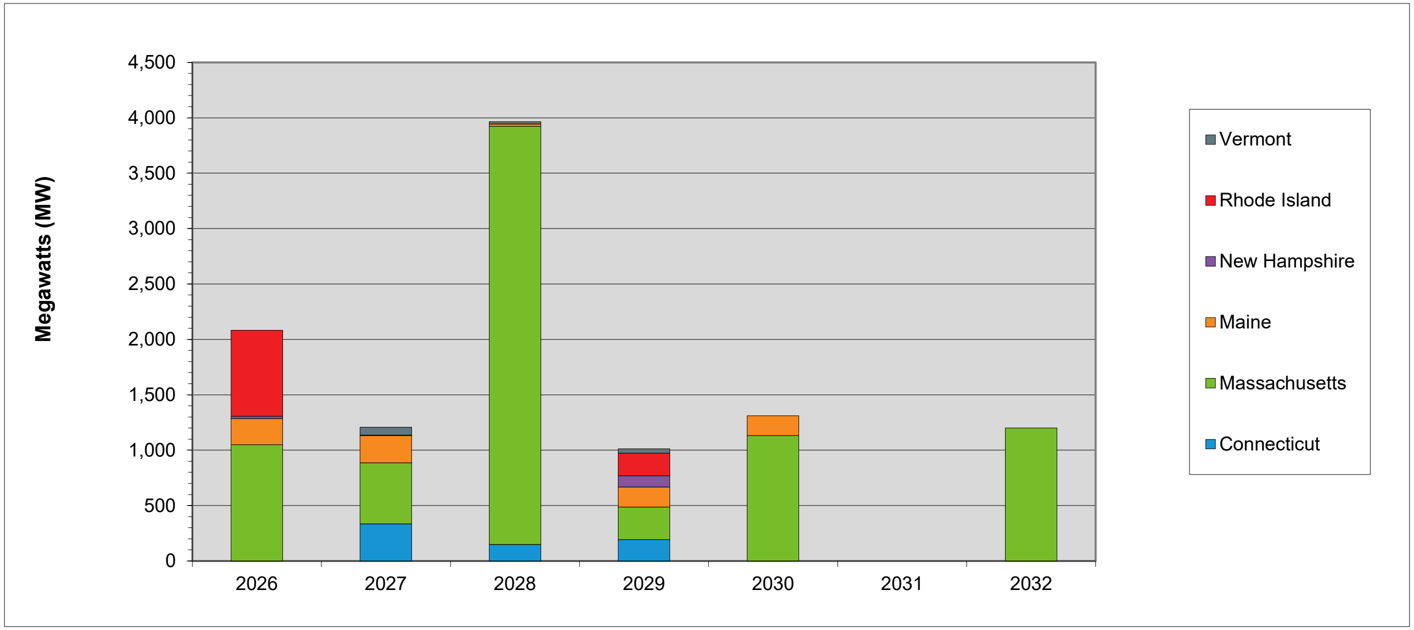
[1] Sum may not equal 100% due to rounding

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

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

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

Projected Annual Generator Capacity Additions
By State



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Vermont	0	70	20	38	0	0	0	128	1.2
Rhode Island	777	0	0	205	0	0	0	982	9.1
New Hampshire	20	5	0	100	0	0	0	125	1.2
Maine	235	247	20	182	180	0	0	864	8.0
Massachusetts	1,050	549	3,774	295	1,131	0	1,200	7,999	74.2
Connecticut	0	336	150	192	0	0	0	678	6.3
Totals	**2,082**	**1,207**	**3,964**	**1,012**	**1,311**	**0**	**1,200**	**10,776**	**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

	Total		Green		Yellow	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	27	5,798	1	204	26	5,594
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	4	141	20	1,251
Wind	6	4,713	3	1,522	3	3,191
Total	58	11,976	9	1,940	49	10,036

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

New Generation Projection
By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	0	0	0	0	0	0
Intermediate	1	73	1	73	0	0
Peaker	51	7,190	5	345	46	6,845
Wind Turbine	6	4,713	3	1,522	3	3,191
Total	58	11,976	9	1,940	49	10,036

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	27	5,798	0	0	0	0	27	5,798	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	6	4,713	0	0	0	0	0	0	6	4,713
Total	58	11,976	0	0	1	73	51	7,190	6	4,713

- 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
Demand	*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
Generator	*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

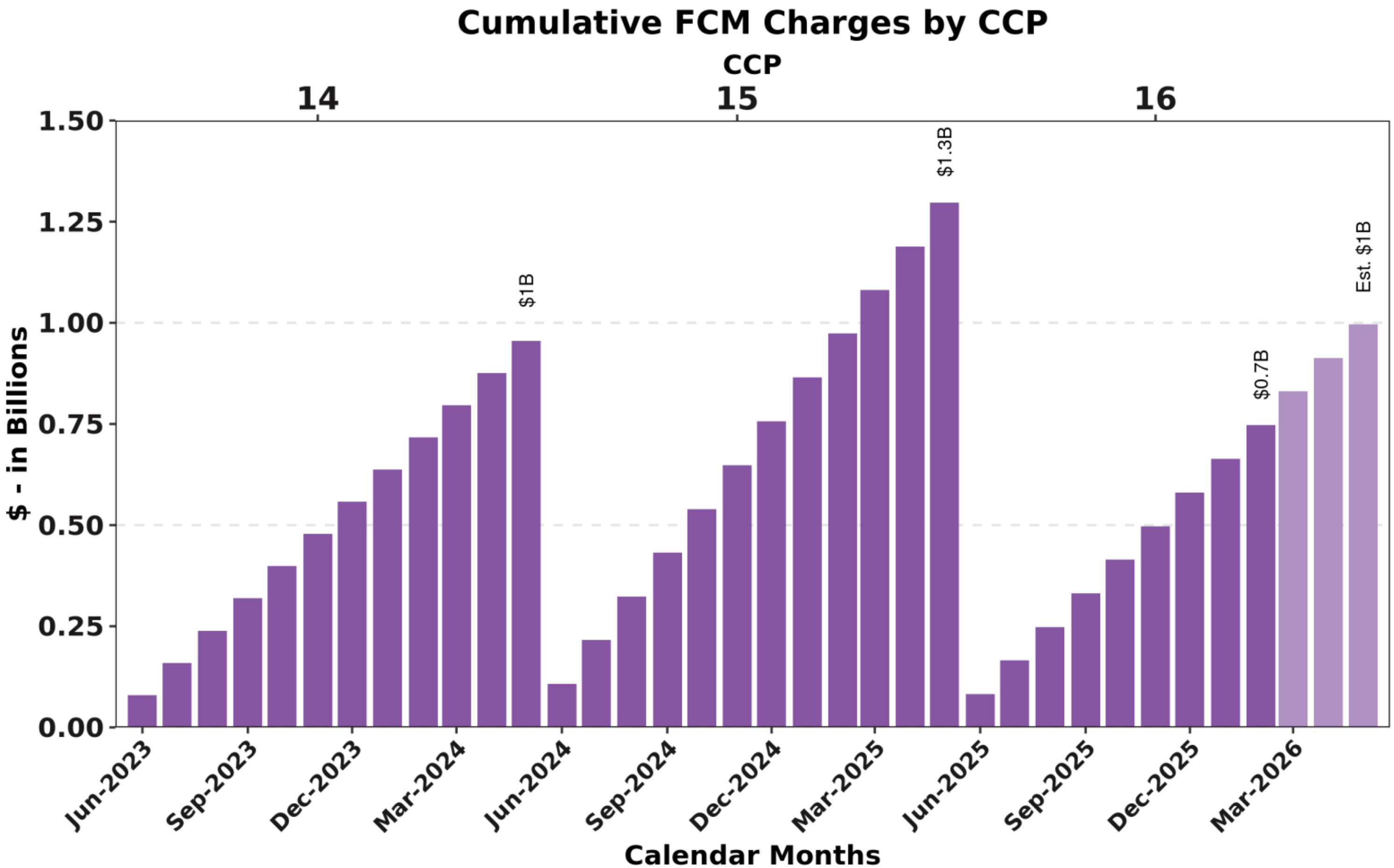
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes 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**

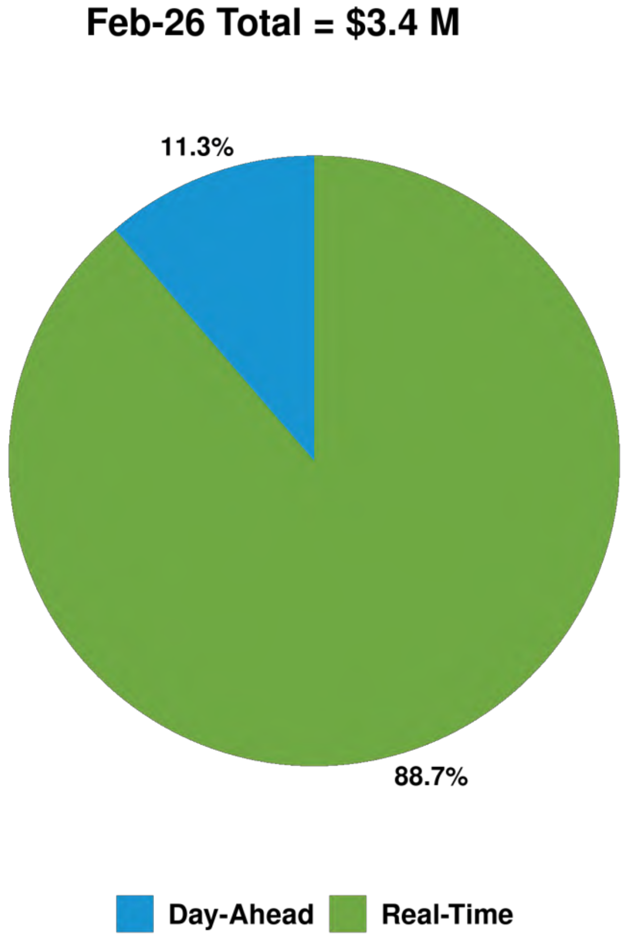
Forward Capacity Market Auctions

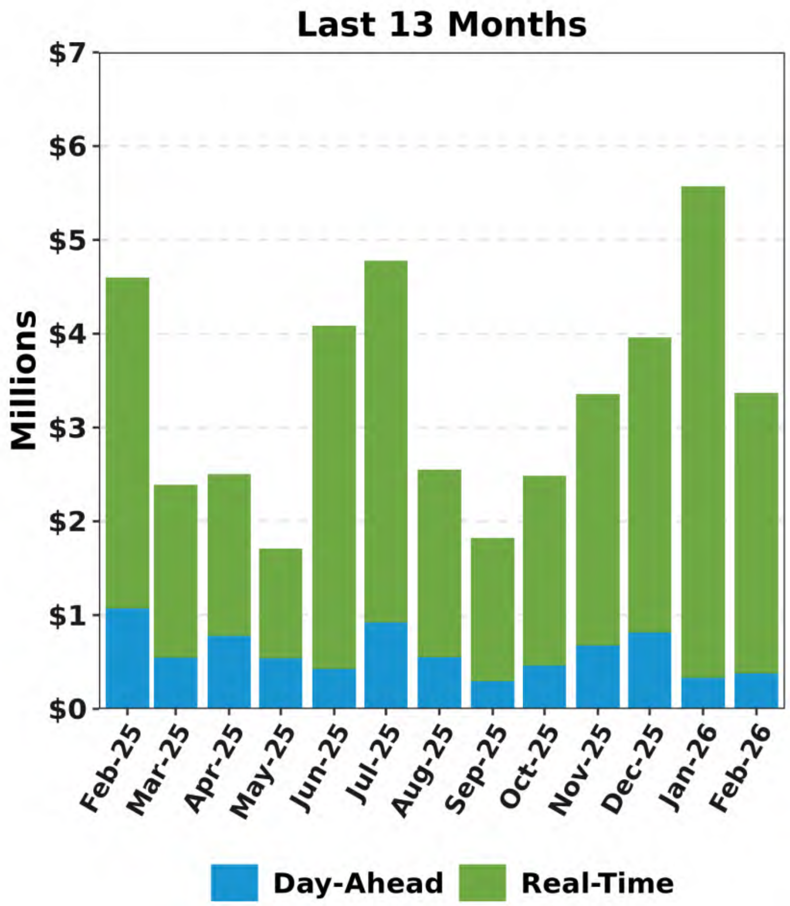


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

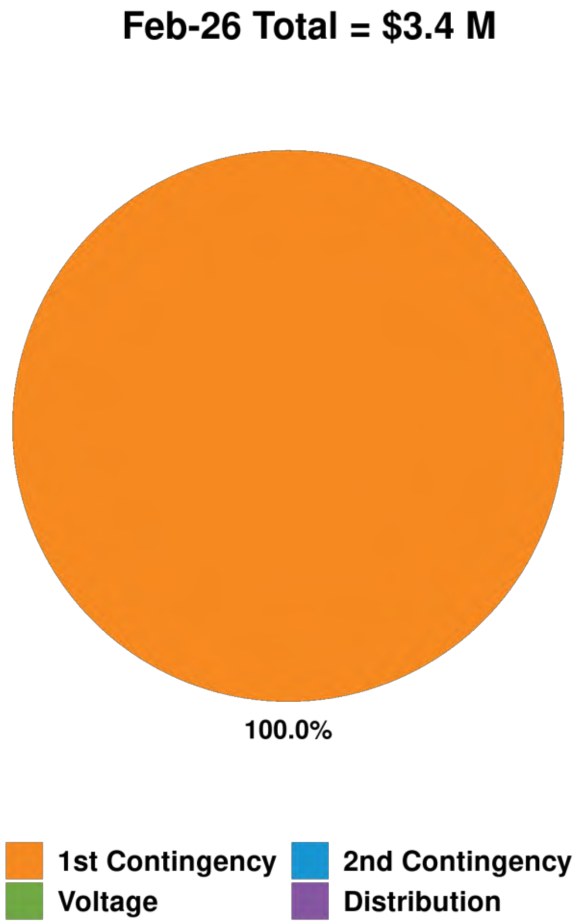
NET COMMITMENT PERIOD COMPENSATION

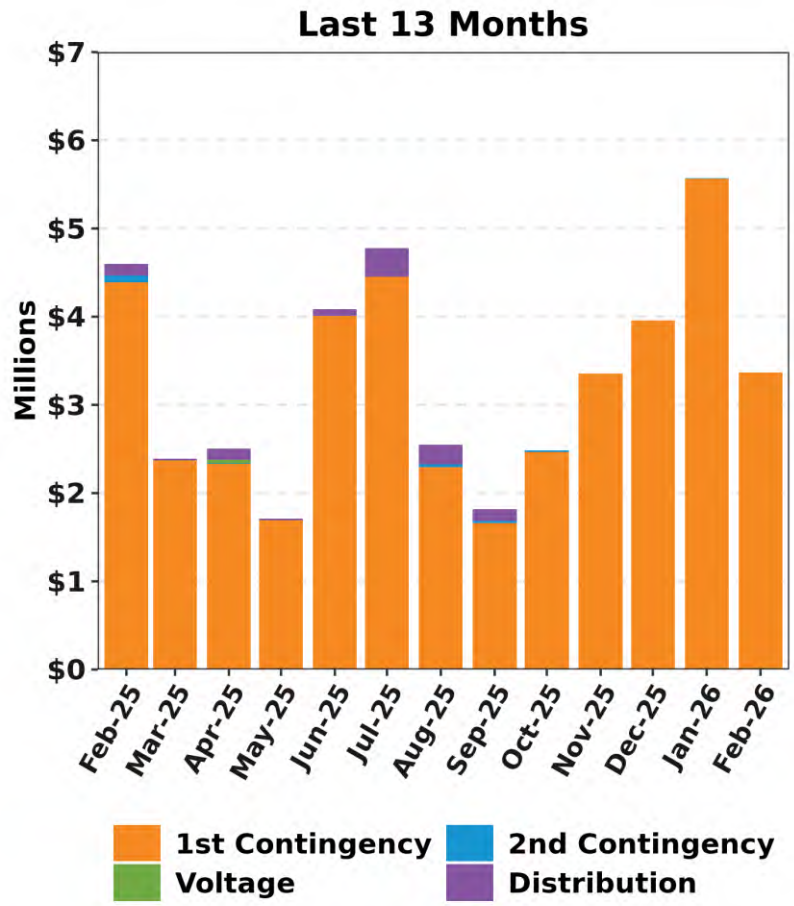
DA and RT NCPC Charges



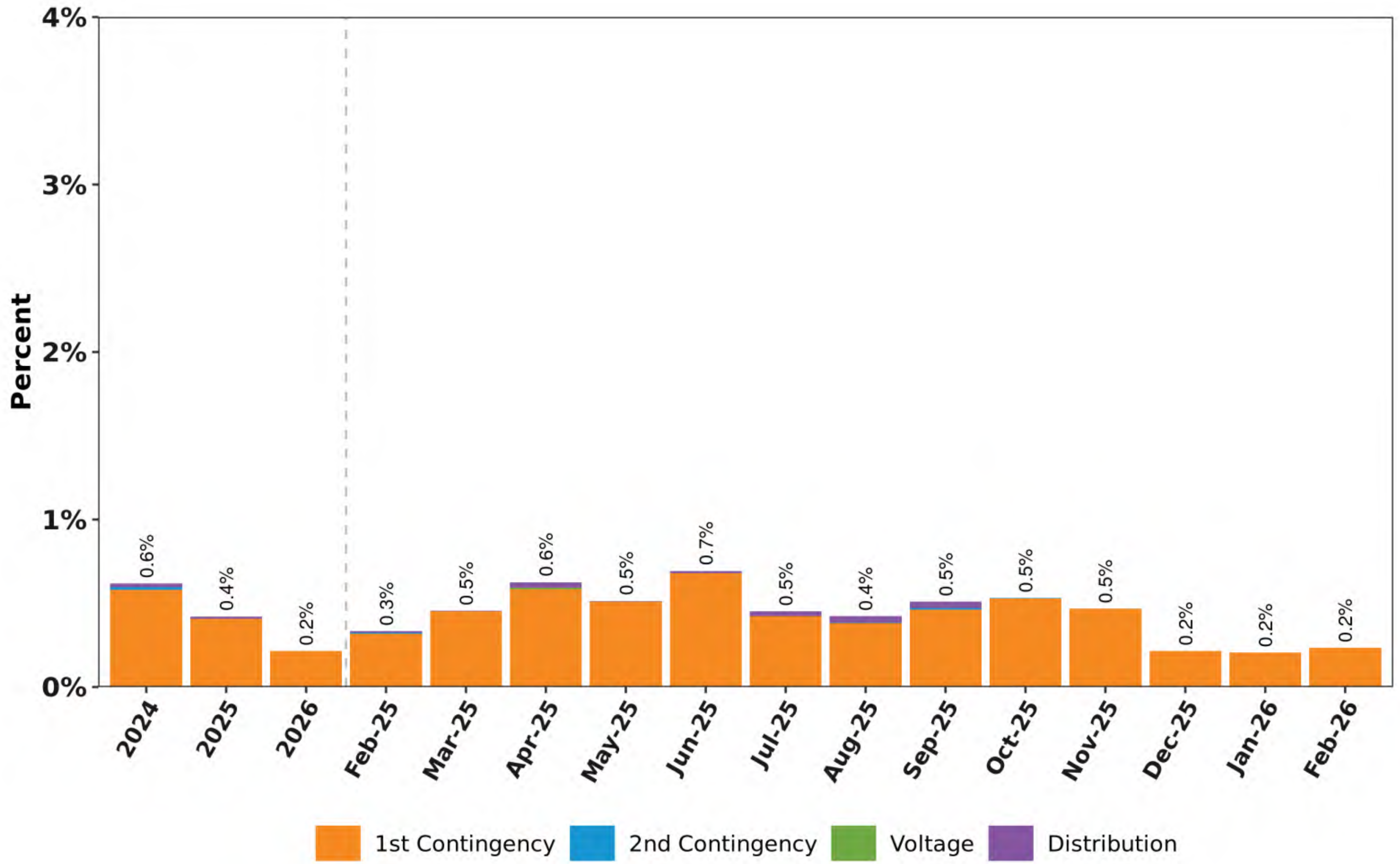


NCPC Charges by Type

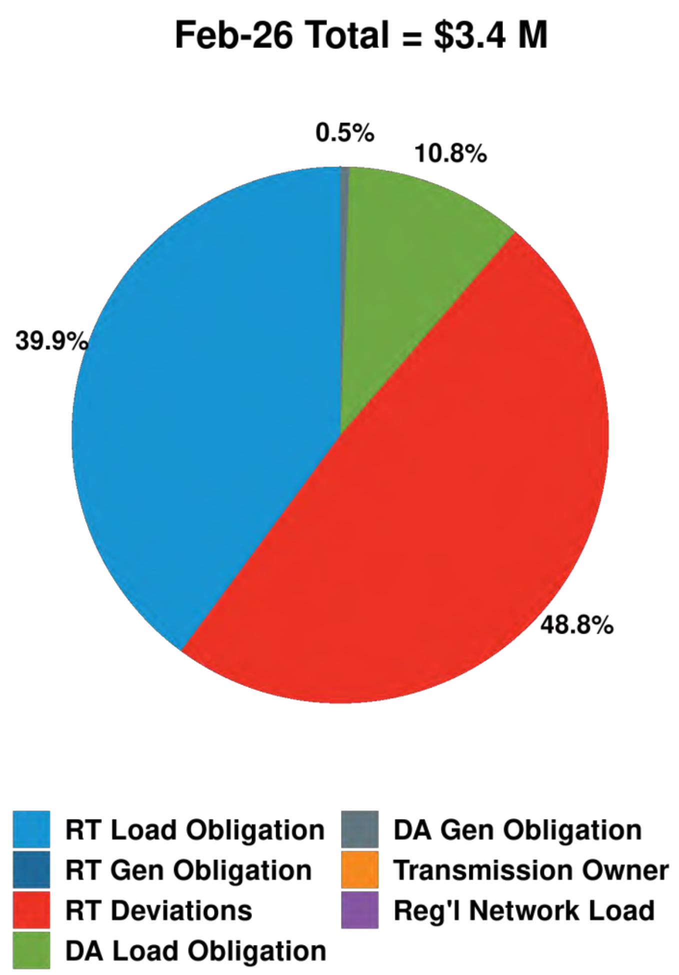


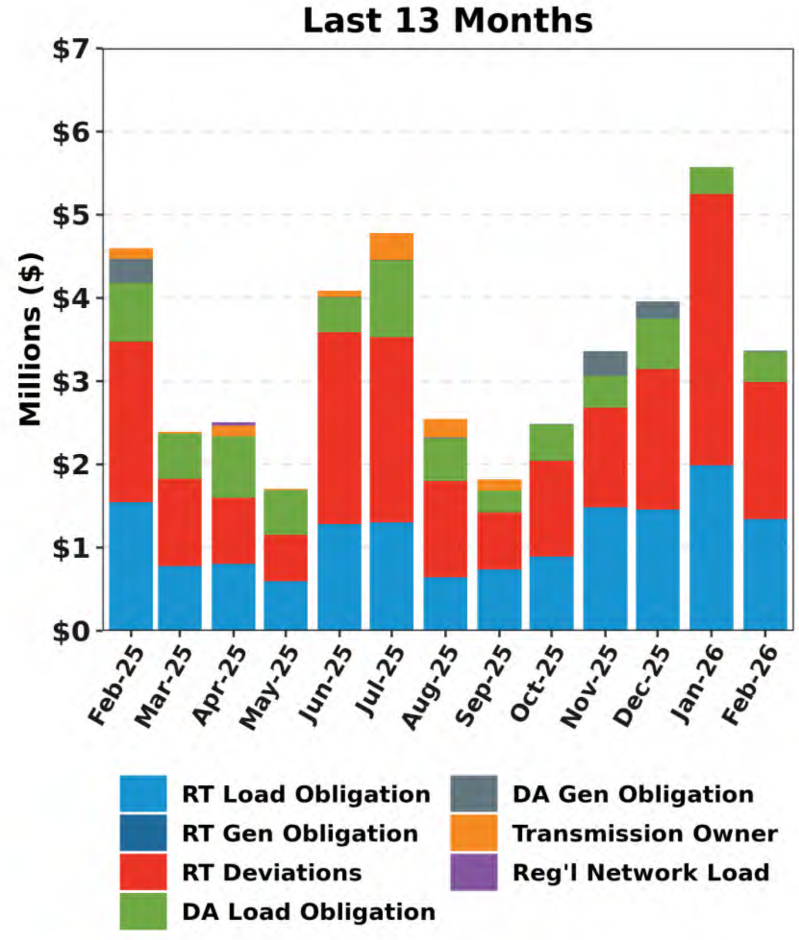


NCPC Charges by Type as Percent of Energy Market Value

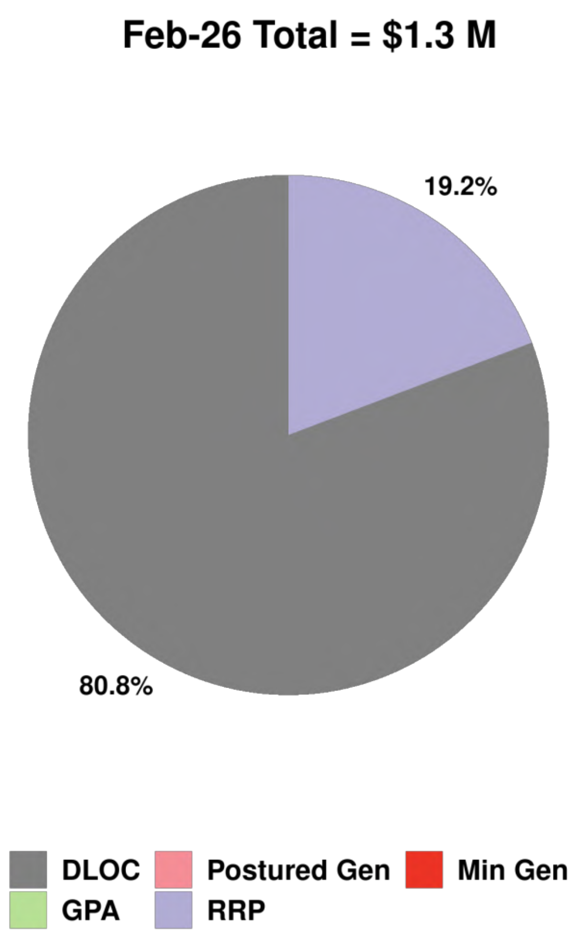


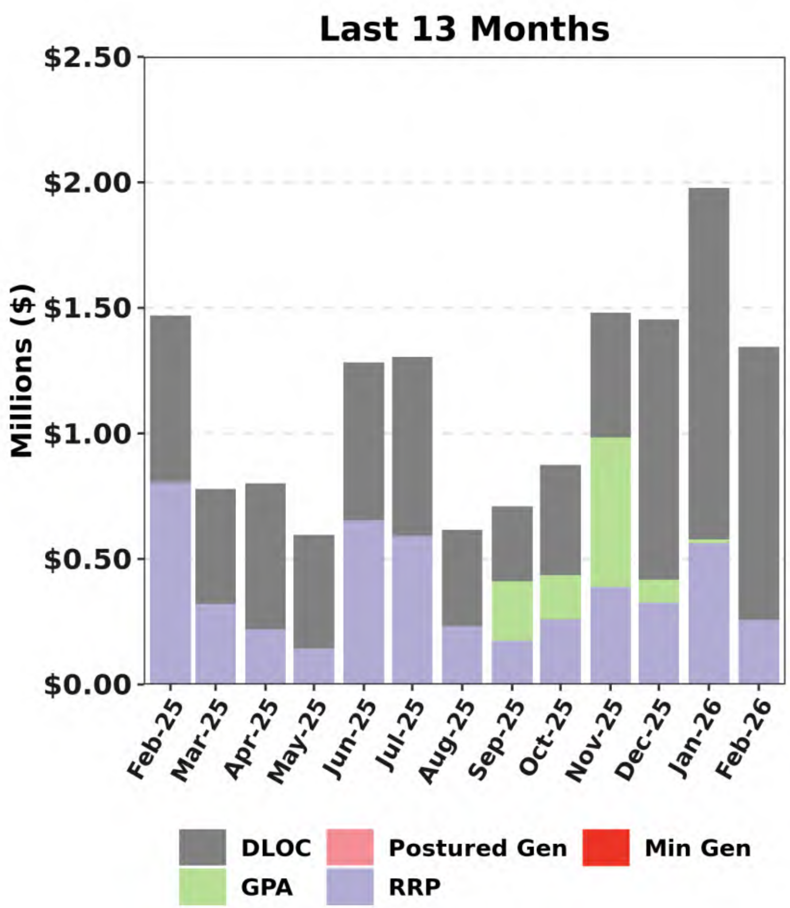
NCPC Charge Allocations





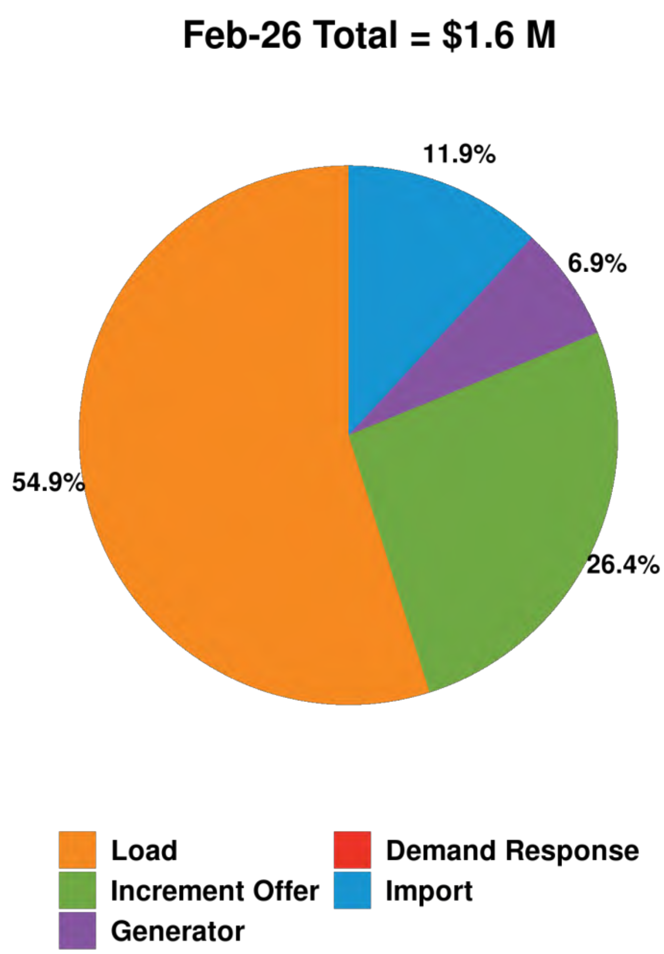
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

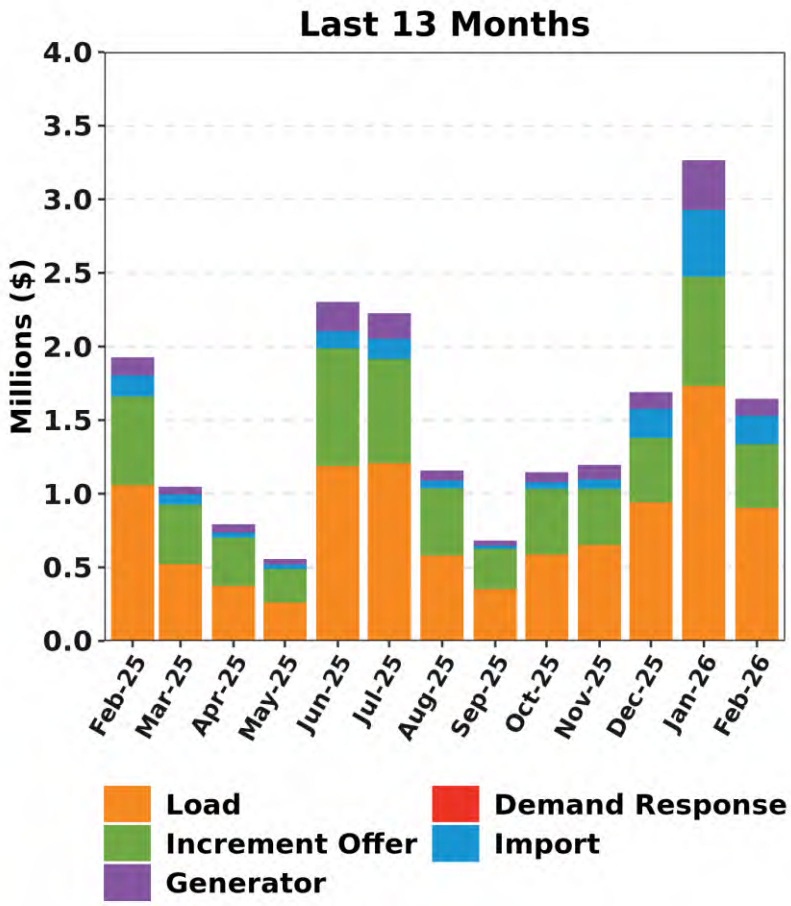




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

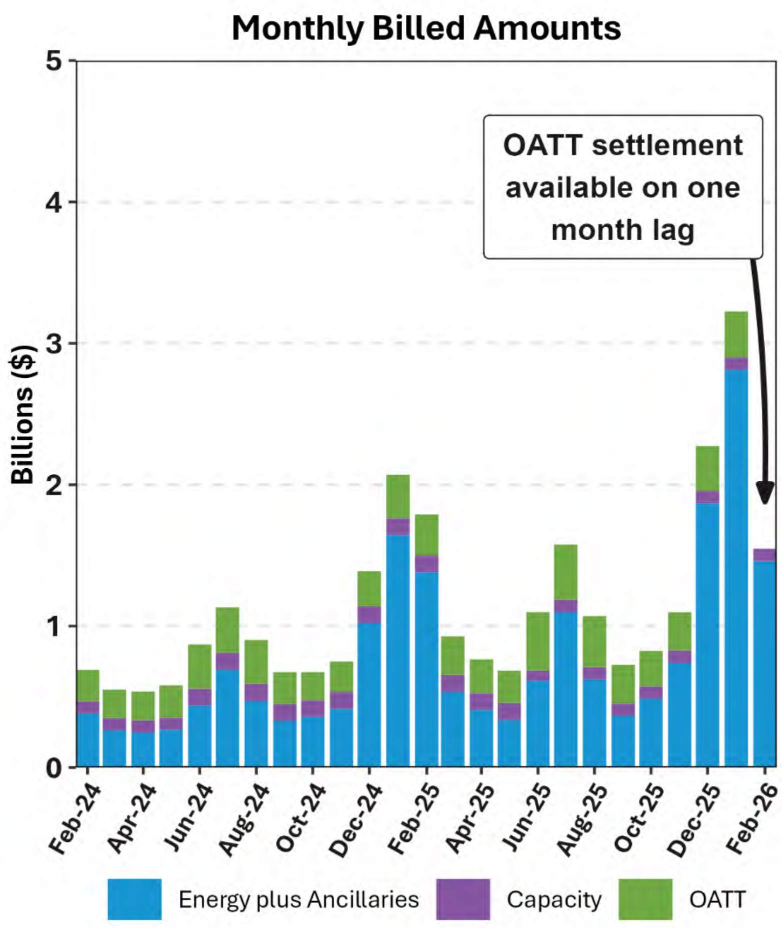
RT First Contingency Charges by Deviation Type

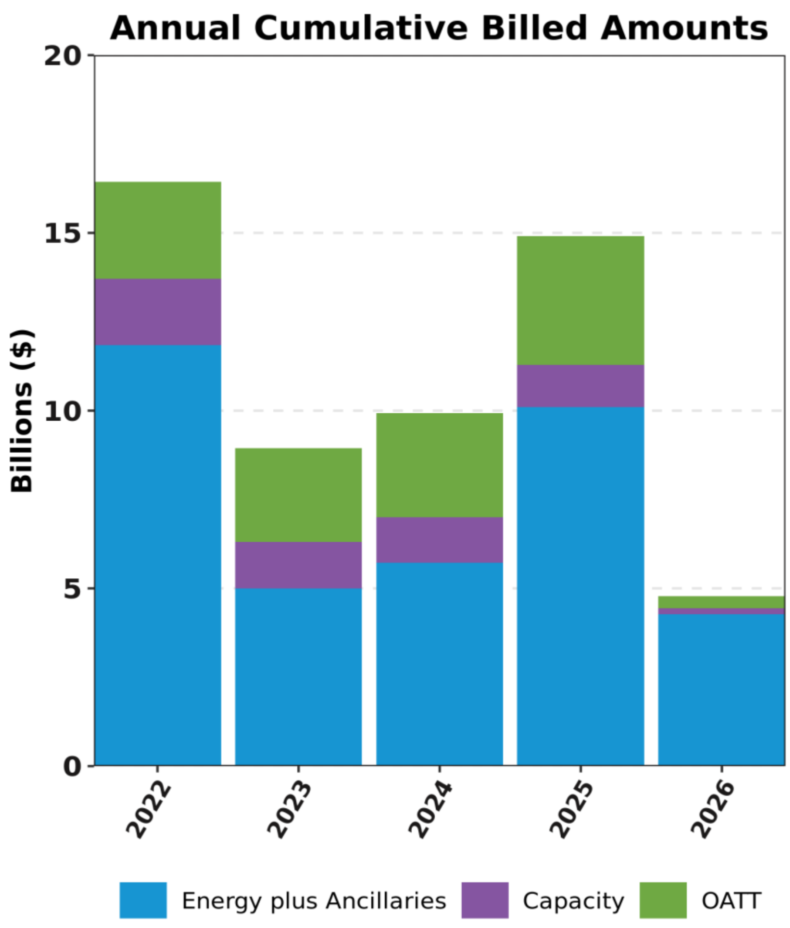




ISO BILLINGS

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)

- March 24 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Chester SVC Valves and Controls Update (CEII – Avangrid)
    - Long Mountain 345 kV Breaker Replacement and Cable Separation & Shielding Project (Eversource)
    - Stony Hill 48C 115 kV Substation Relay Upgrades (Eversource)
  - 2025 LTTP RFP - Initial Review and RFP Objective Testing
  - 2026 Economic Study Workshop
  - RSP Project List and Asset Condition List March Update

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

2025 Longer-Term Transmission Planning (LTTP) RFP

- On 12/13/24, NESCOE provided its LTTP RFP request describing the needs to be addressed by 2035:*
  - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
  - Increase the Surowiec-South interface capacity to at least 3,200 MW
  - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind**
- The ISO issued the RFP on 3/31/25, with proposals due by 9/30/25
- The ISO 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 March 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 (TC) and continued the discussion at the February TC meeting
  – 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 2/18/2026

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 2/18/2026

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 2/18/2026

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 2/18/2026

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 2/18/2026

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 2/18/2026

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 2/18/2026

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	Aug-26	2

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

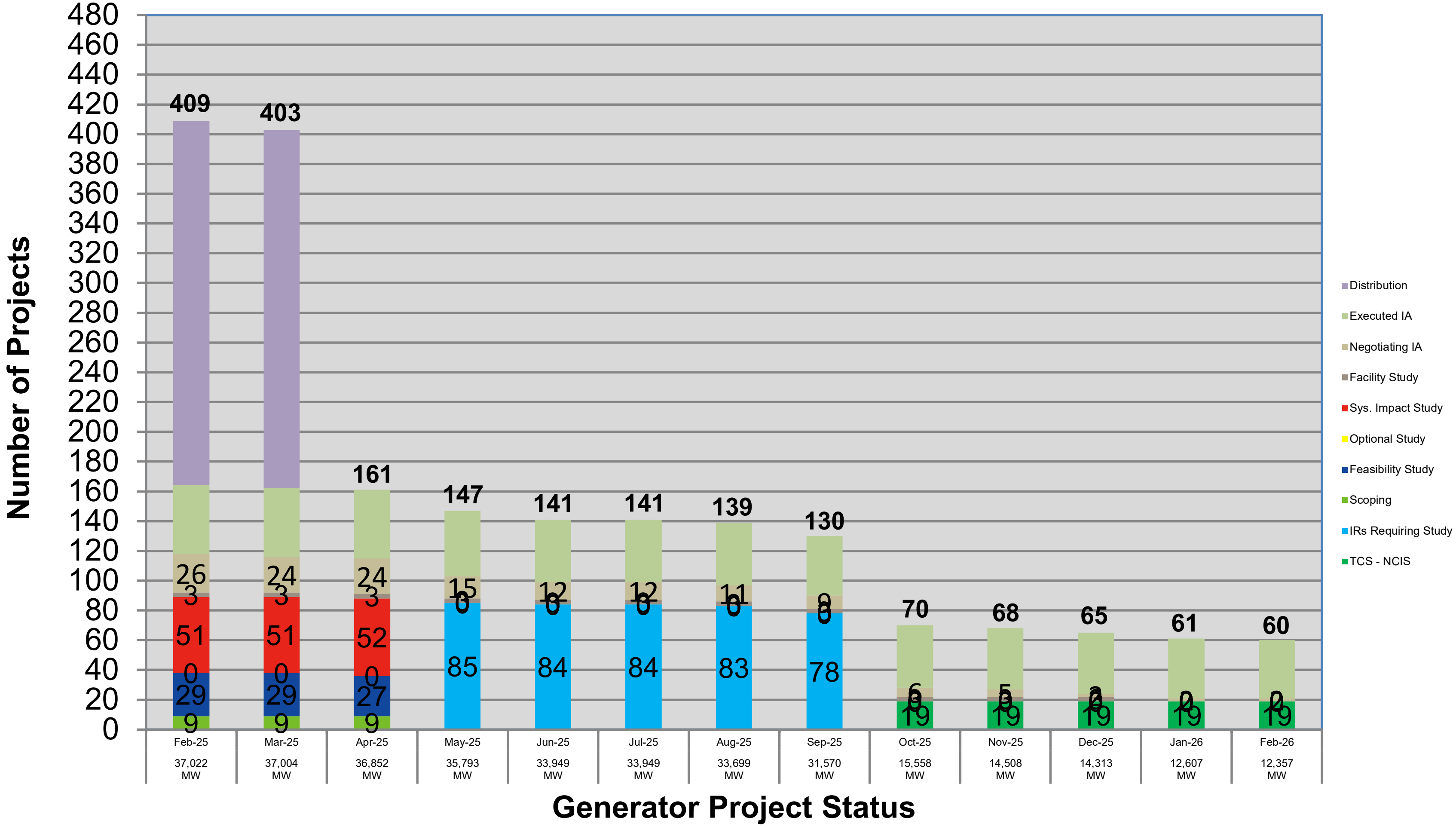
Boston 2033 Solutions Study

Status as of 2/18/2026

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	Mar-27	1

Status of Tariff Studies as of February 25, 2026



ETUs: 0 in TCS – NCIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA
Transmission Service Requests needing study: 0
https://irtt.iso-ne.com/external.aspx

Additional Notes provided on next slide

Status of Tariff Studies as of February 25, 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)	Mar - 2026[2] CSO (MW)	Mar - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,667	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	545	1,718
Gas Generator Outages MW (-)	1,638	1,893
Allowance for Unplanned Outages (-) [4]	2,700	2,700
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,547	25,150
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,132	17,132
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,257	19,257
Operable Capacity Margin	4,290	5,893

[1]Operable Capacity is based on data as of **February 24, 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 **February 24, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 28, 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	Mar - 2026[2] CSO (MW)	Mar - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,667	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	545	1,718
Gas Generator Outages MW (-)	1,638	1,893
Allowance for Unplanned Outages (-) [4]	2,700	2,700
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,547	25,150
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,045	18,045
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,170	20,170
Operable Capacity Margin	3,377	4,980

[1] Operable Capacity is based on data as of **February 24, 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 **February 24, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 28, 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

February 24, 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 March.

Report created: 2/24/2026

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
3/14/2026	26898	270	1325	10	673	690	2200	0	24940	17970	2125	20095	4845	N	Winter 2026
3/21/2026	26898	270	1325	10	557	550	2200	0	25196	17641	2125	19766	5430	N	Winter 2026
3/28/2026	26667	393	1235	135	545	1638	2700	0	23547	17132	2125	19257	4290	Y	Winter 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

February 24, 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 March.

Report created: 2/24/2026

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
3/14/2026	26898	270	1325	10	673	690	2200	0	24940	18928	2125	21053	3887	N	Winter 2026
3/21/2026	26898	270	1325	10	557	550	2200	0	25196	18582	2125	20707	4489	N	Winter 2026
3/28/2026	26667	393	1235	135	545	1638	2700	0	23547	18045	2125	20170	3377	Y	Winter 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

Spring 2026 Analysis

Spring 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2026[2] CSO (MW)	May - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,666	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	1,934	3,119
Gas Generator Outages MW (-)	2,641	2,939
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)	20,454	22,003
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	-465	1,084

[1] Operable Capacity is based on data as of **February 24, 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 **February 24, 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.

Spring 2026 Operable Capacity Analysis

90/10 Load Forecast	May - 2026[2] CSO (MW)	May - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,666	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	1,934	3,119
Gas Generator Outages MW (-)	2,641	2,939
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)	20,454	22,003
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	-1,291	258

[1]Operable Capacity is based on data as of **February 24, 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 **February 24, 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.

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

ISO-NE OPERABLE CAPACITY ANALYSIS

February 24, 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: 2/24/2026

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	26667	393	1235	135	2913	2573	2700	0	20244	16687	2125	18812	1432	N	Spring 2026
4/11/2026	26667	393	1235	135	4401	3003	2700	0	18326	16460	2125	18585	-259	N	Spring 2026
4/18/2026	26667	393	1177	135	4247	3683	2700	0	17742	16001	2125	18126	-384	N	Spring 2026
4/25/2026	26667	393	1177	135	3614	3604	2700	0	18454	15762	2125	17887	567	N	Spring 2026
5/2/2026	26666	393	1177	135	2715	4309	3400	0	17947	15738	2125	17863	84	N	Spring 2026
5/9/2026	26666	393	1235	135	1934	2641	3400	0	20454	18794	2125	20919	-465	Y	Spring 2026
5/16/2026	26666	393	1235	135	1439	1836	3400	0	21754	19668	2125	21793	-39	N	Spring 2026
5/23/2026	26666	393	1235	135	1037	1836	3400	0	22156	20479	2125	22604	-448	N	Spring 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.

Spring 2026 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

February 24, 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.

Report created: 2/24/2026

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
4/4/2026	26667	393	1235	135	2913	2573	2700	0	20244	17576	2125	19701	543	N	Spring 2026
4/11/2026	26667	393	1235	135	4401	3003	2700	0	18326	17338	2125	19463	-1137	N	Spring 2026
4/18/2026	26667	393	1177	135	4247	3683	2700	0	17742	16854	2125	18979	-1237	N	Spring 2026
4/25/2026	26667	393	1177	135	3614	3604	2700	0	18454	16602	2125	18727	-273	N	Spring 2026
5/2/2026	26666	393	1177	135	2715	4309	3400	0	17947	16577	2125	18702	-755	N	Spring 2026
5/9/2026	26666	393	1235	135	1934	2641	3400	0	20454	19620	2125	21745	-1291	N	Spring 2026
5/16/2026	26666	393	1235	135	1439	1836	3400	0	21754	20531	2125	22656	-902	N	Spring 2026
5/23/2026	26666	393	1235	135	1037	1836	3400	0	22156	21378	2125	23503	-1347	Y	Spring 2026

Column Definitions

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

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

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 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