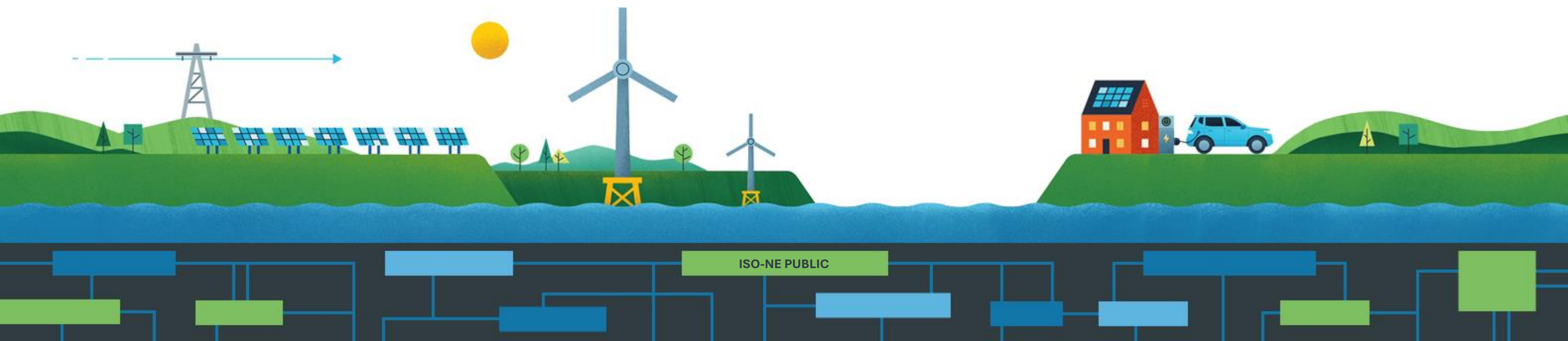
NEPOOL PARTICIPANTS COMMITTEE | 1/8/2026
Meeting Agenda Item #4

NEPOOL Participants Committee

System & Market Operations Report – January 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



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HIGHLIGHTS

Highlights: December 2025

Settled data through December 30th

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

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

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

Year-to-Date Peak Load* Statistics

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

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

Day-Ahead Ancillary Services (DAAS) Results

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

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

DAAS Results (continued)...

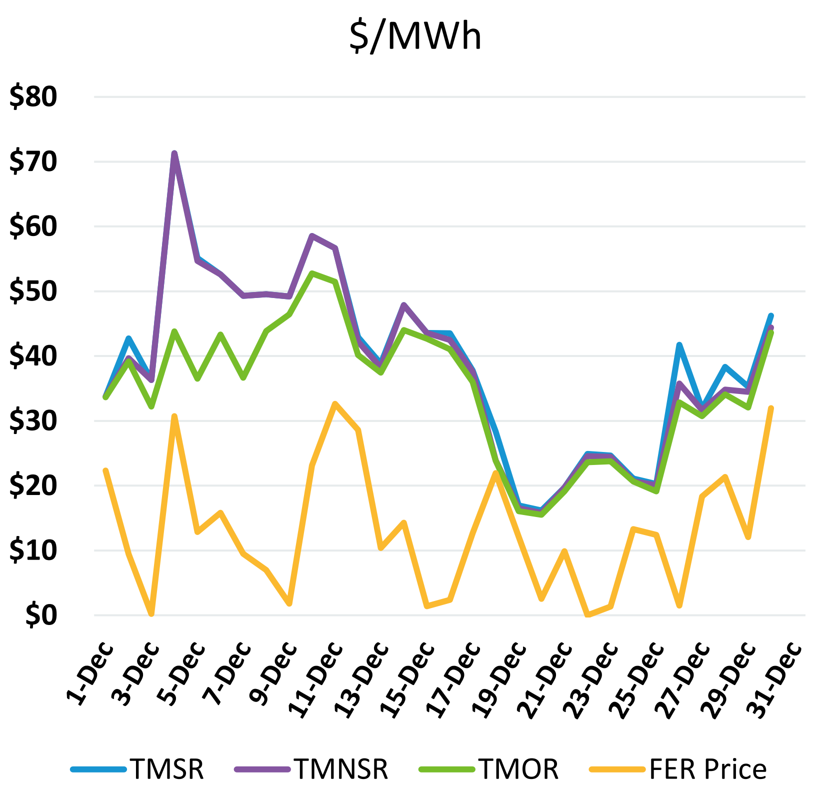
Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg.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

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

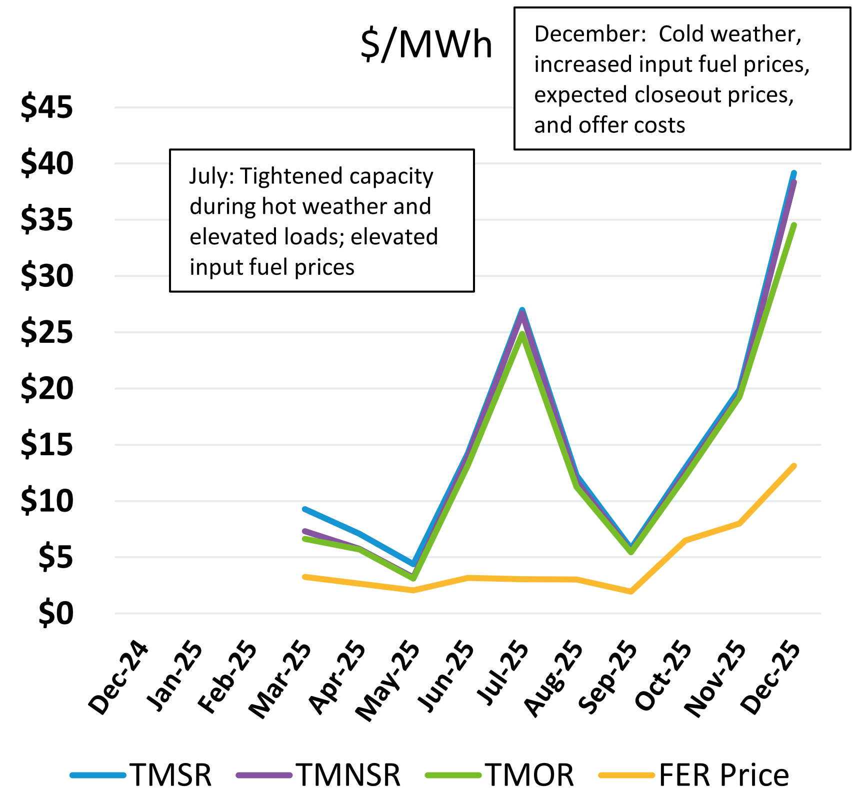
Additionally:
- FER Credits are included in the Monthly Market Operations Report (see Section 7.1.1) found on the ISO Website here. Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices

Daily This Month

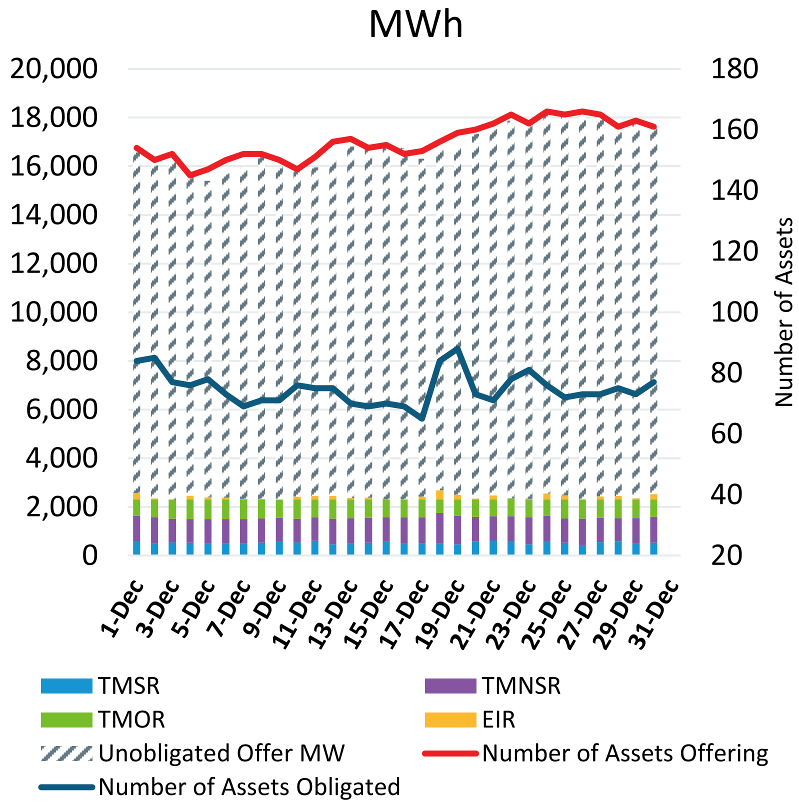


Monthly, Last 13 Months

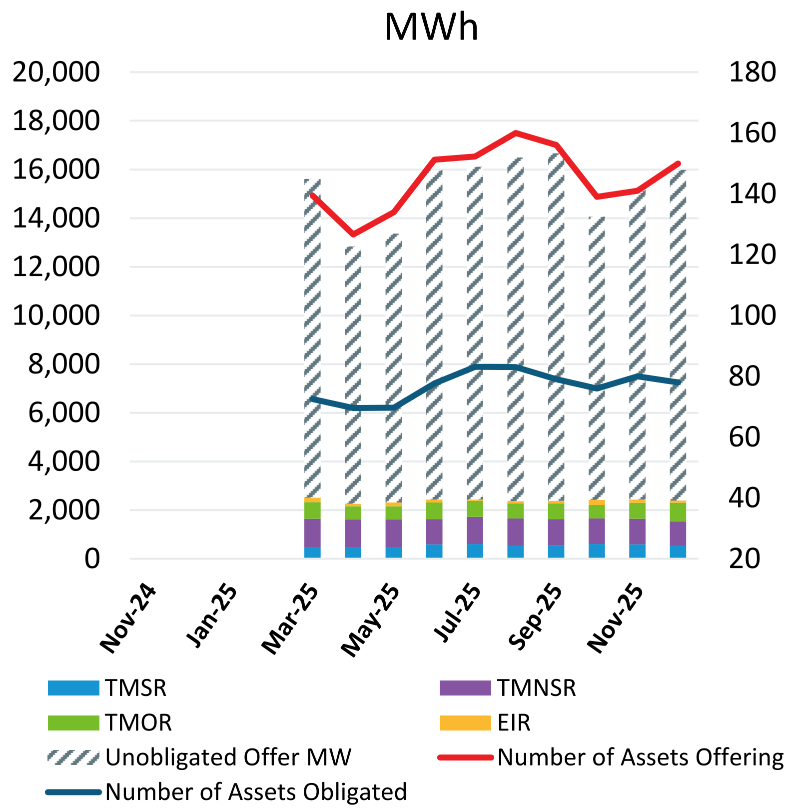


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



Monthly, Last 13 Months



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

Highlights

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

Forward Capacity Market (FCM) Highlights

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

CCP – Capacity Commitment Period

FCM Highlights, cont.

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

Load Forecast

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

SYSTEM OPERATIONS

System Operations

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

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

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

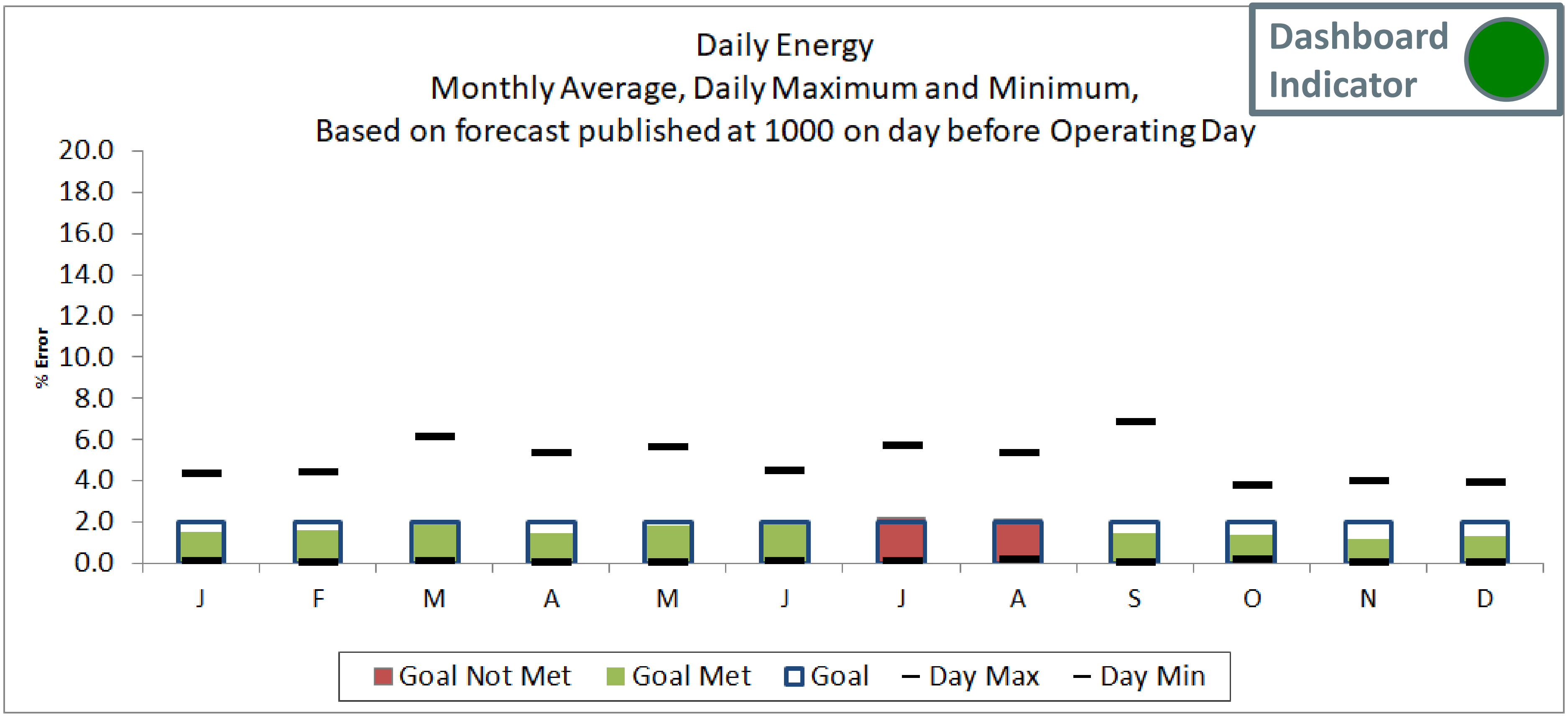
Procedure	Declared	Cancelled	Note
NONE			

System Operations

NPCC Simultaneous Activation of Ten-Minute Reserve Events

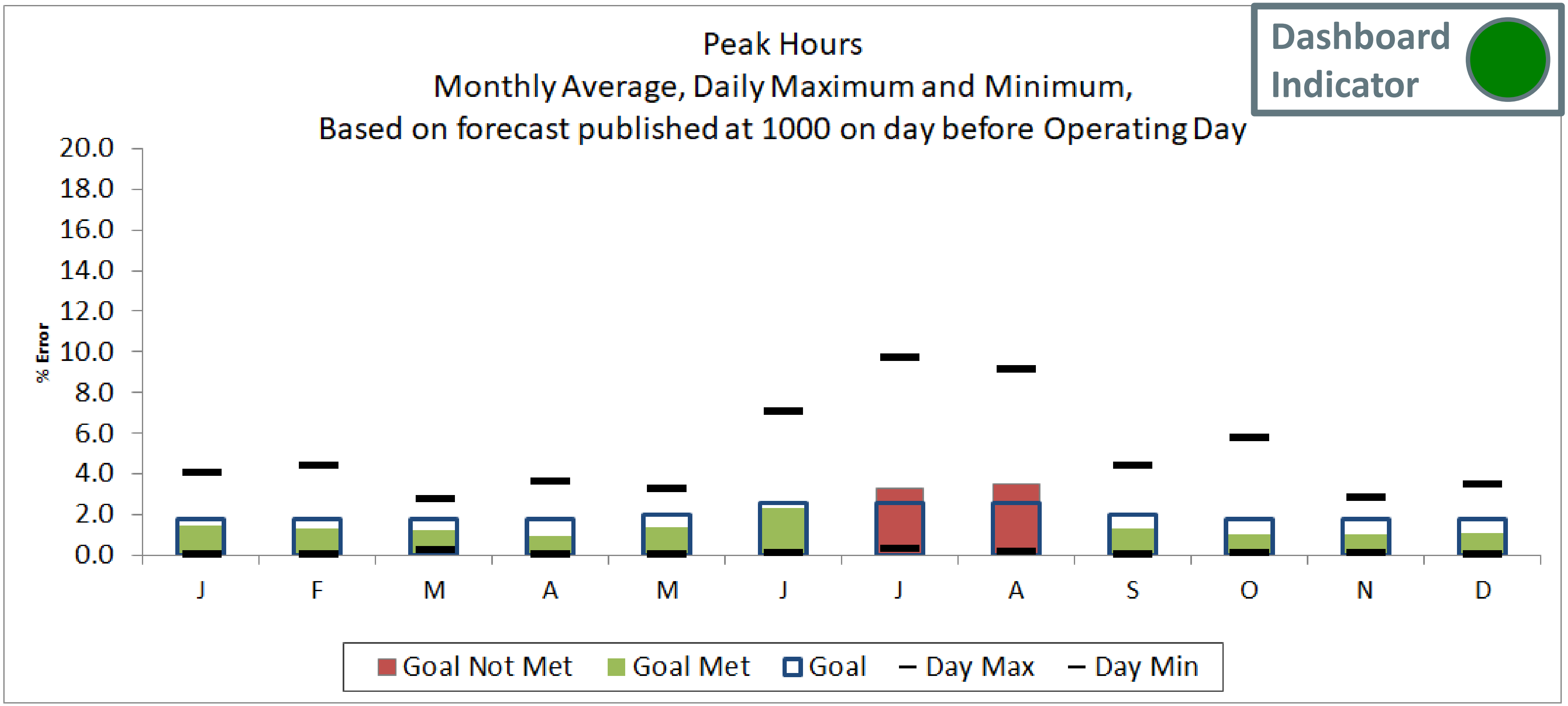
Date	Area	MW Lost
12/6/2025	PJM	1335
12/9/2025	NYISO	550
12/16/2025	IESO	950

System Operations - Load Forecast Accuracy



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

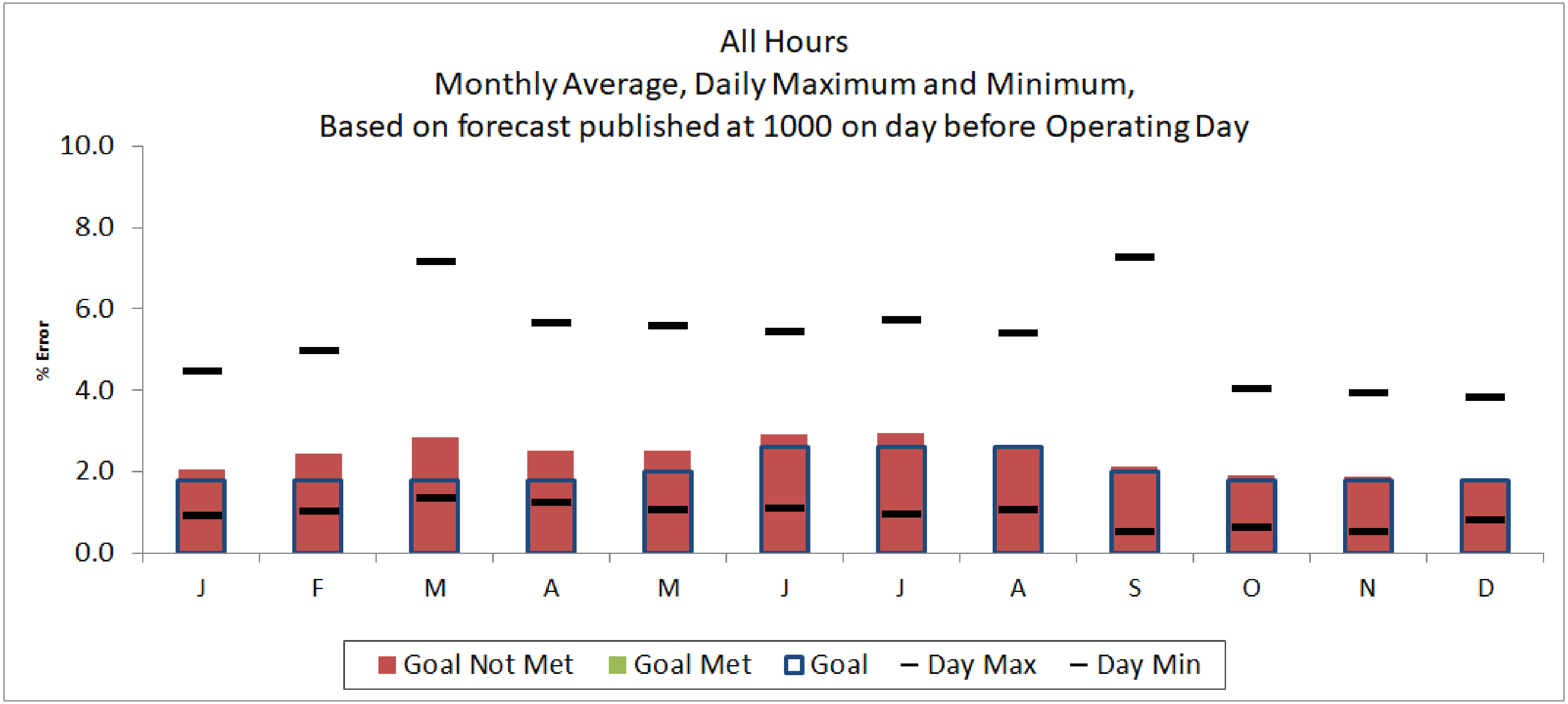
System Operations - Load Forecast Accuracy, cont.



Dashboard Indicator

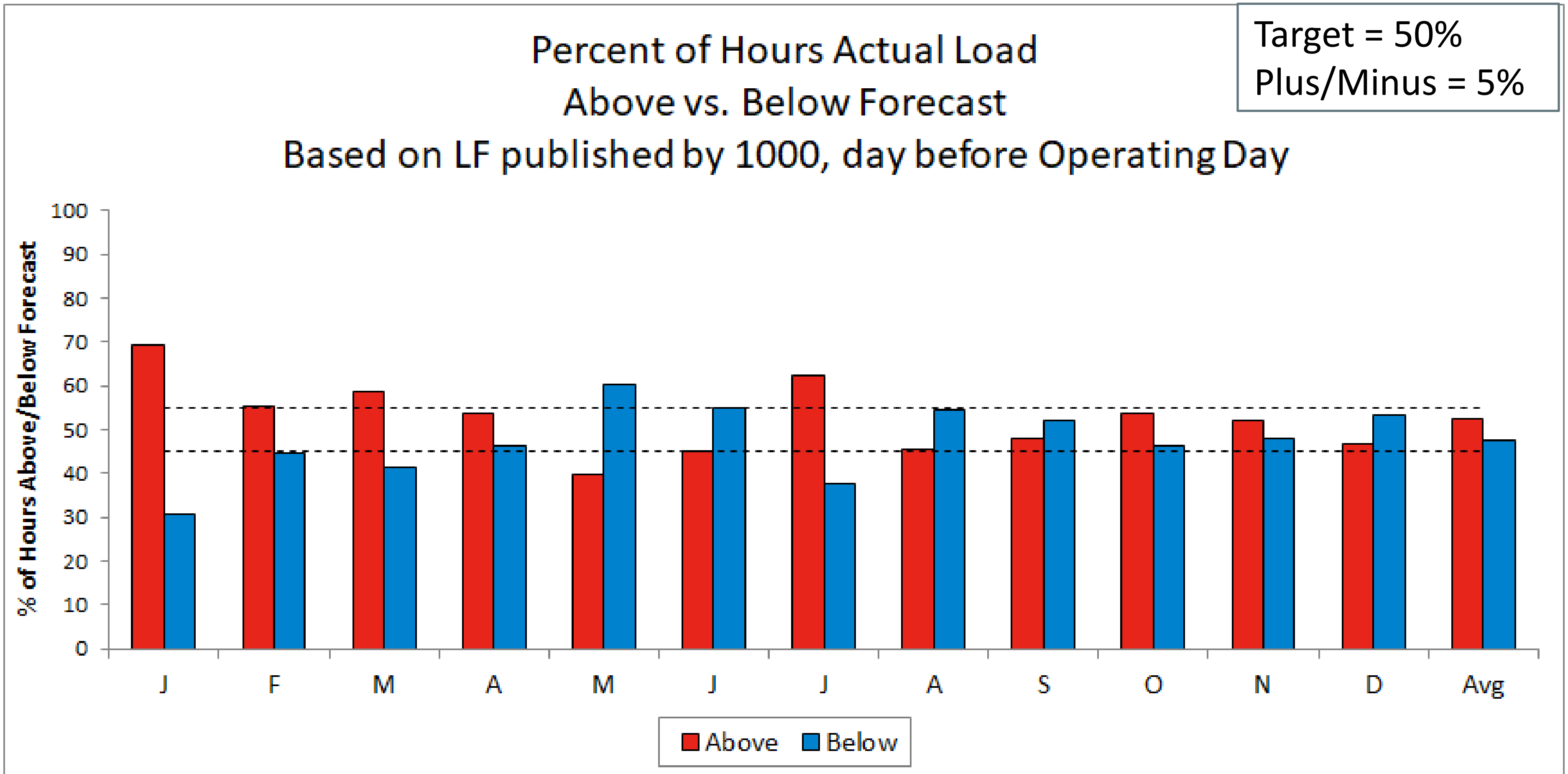
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29	7.08	9.71	9.15	4.43	5.77	2.84	3.51	9.71
Day Min	0.03	0.06	0.24	0.03	0.06	0.11	0.34	0.15	0.05	0.12	0.07	0.00	0.00
MAPE	1.48	1.34	1.29	1.00	1.41	2.30	3.28	3.48	1.30	1.02	1.04	1.12	1.68
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80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

System Operations - Load Forecast Accuracy, cont.



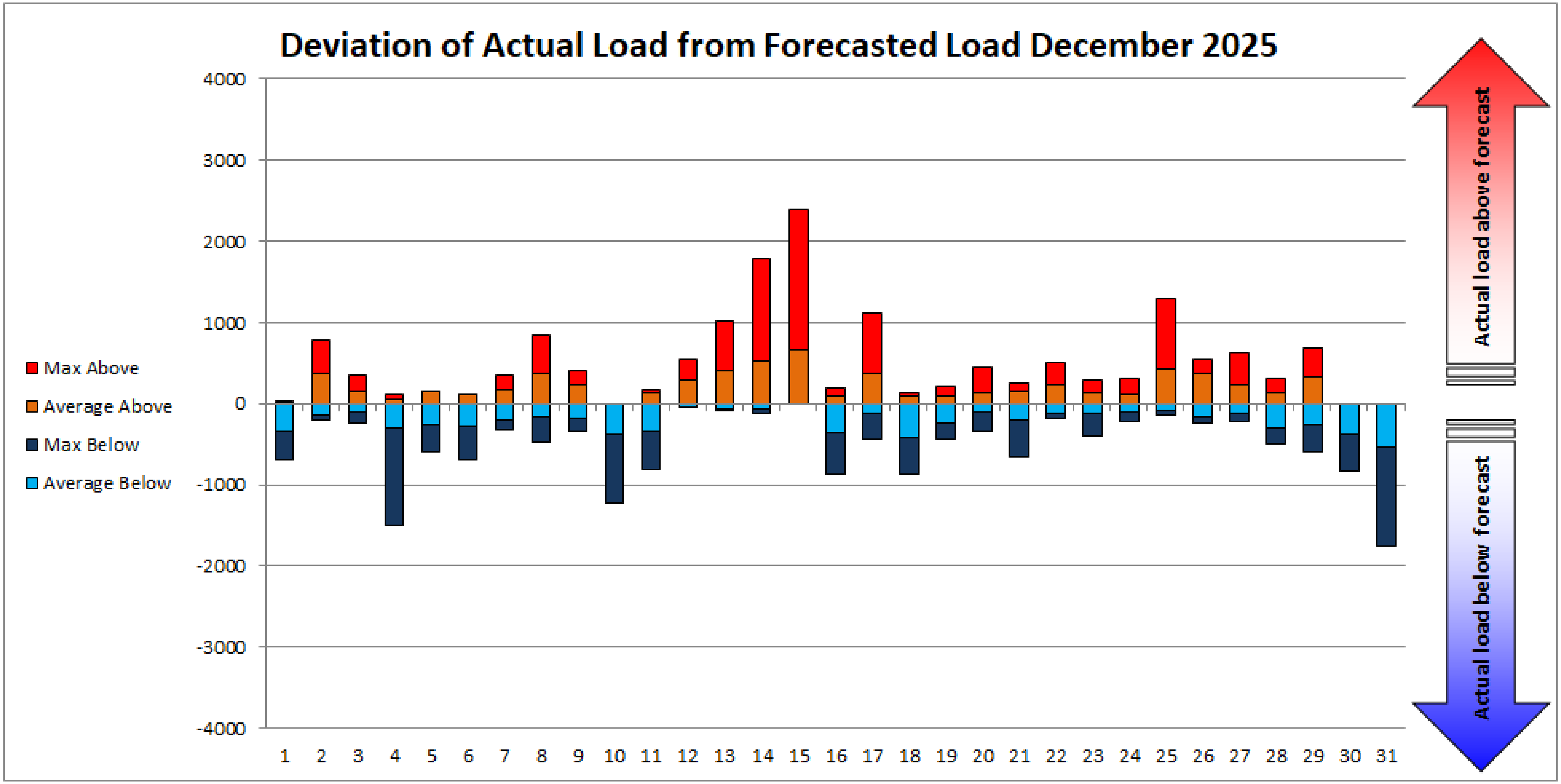
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57	5.44	5.72	5.41	7.24	4.01	3.91	3.82	7.24
Day Min	0.90	1.02	1.33	1.23	1.07	1.11	0.95	1.07	0.52	0.64	0.50	0.80	0.50
MAPE	2.07	2.47	2.83	2.53	2.53	2.93	2.94	2.68	2.13	1.92	1.88	1.84	2.40
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80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

System Operations - Load Forecast Accuracy, cont.



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

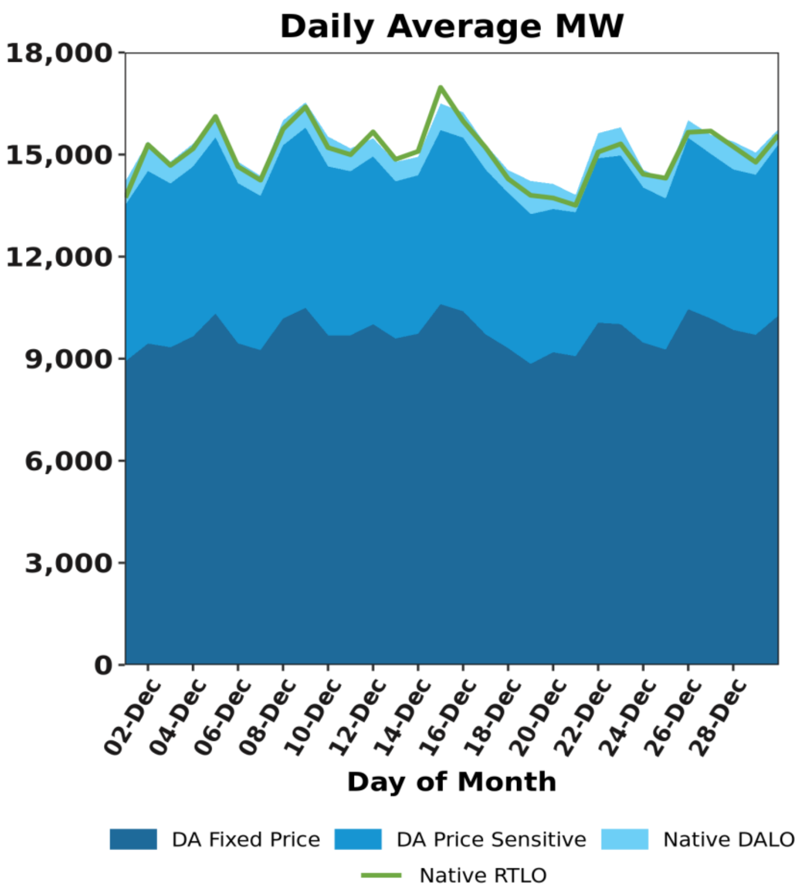
System Operations - Load Forecast Accuracy, cont.

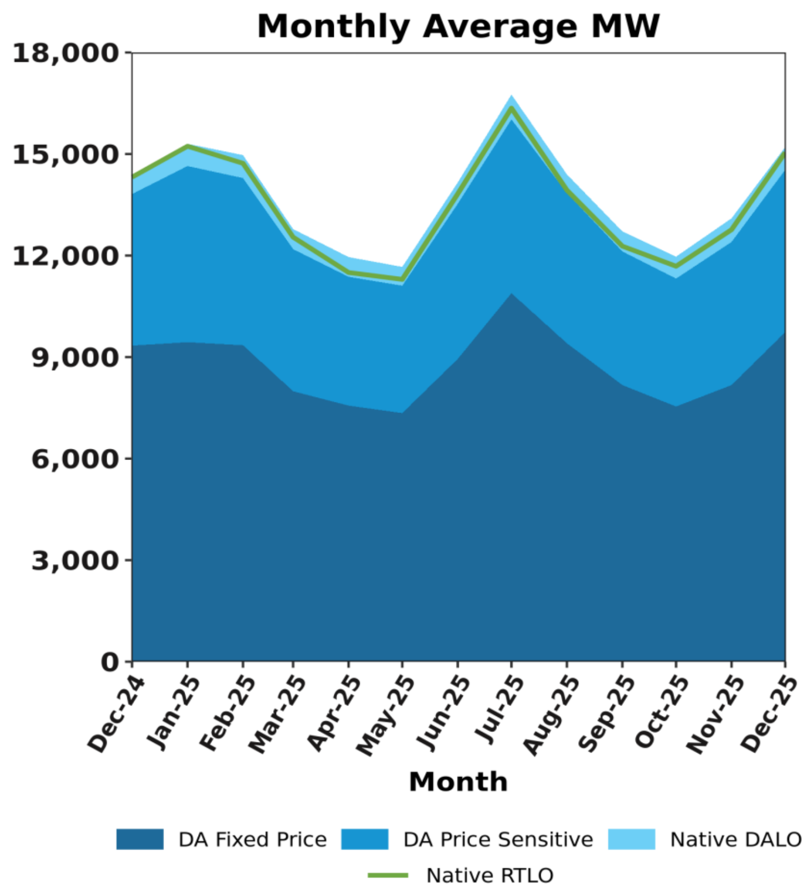


MARKET OPERATIONS

Supply and Demand Volumes

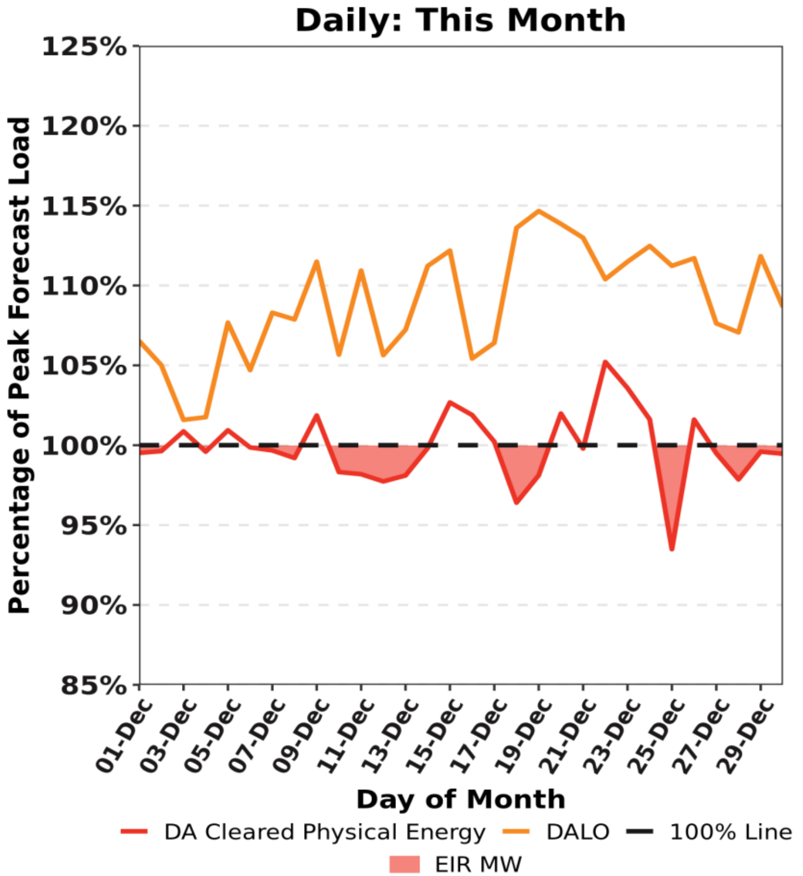
DA Cleared Native Load by Composition Compared to Native RT Load

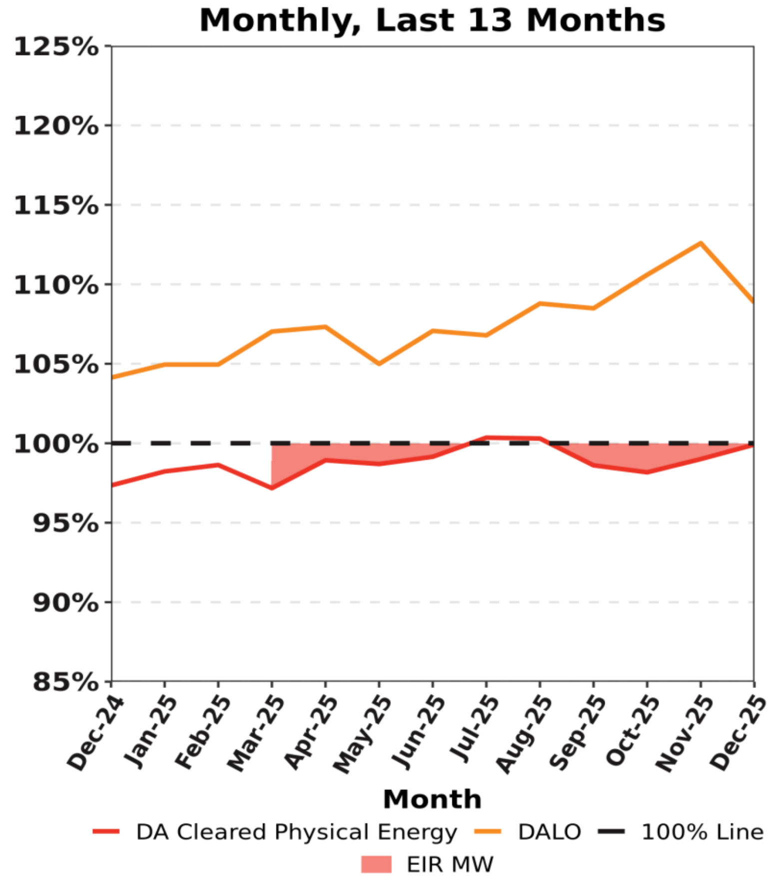




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

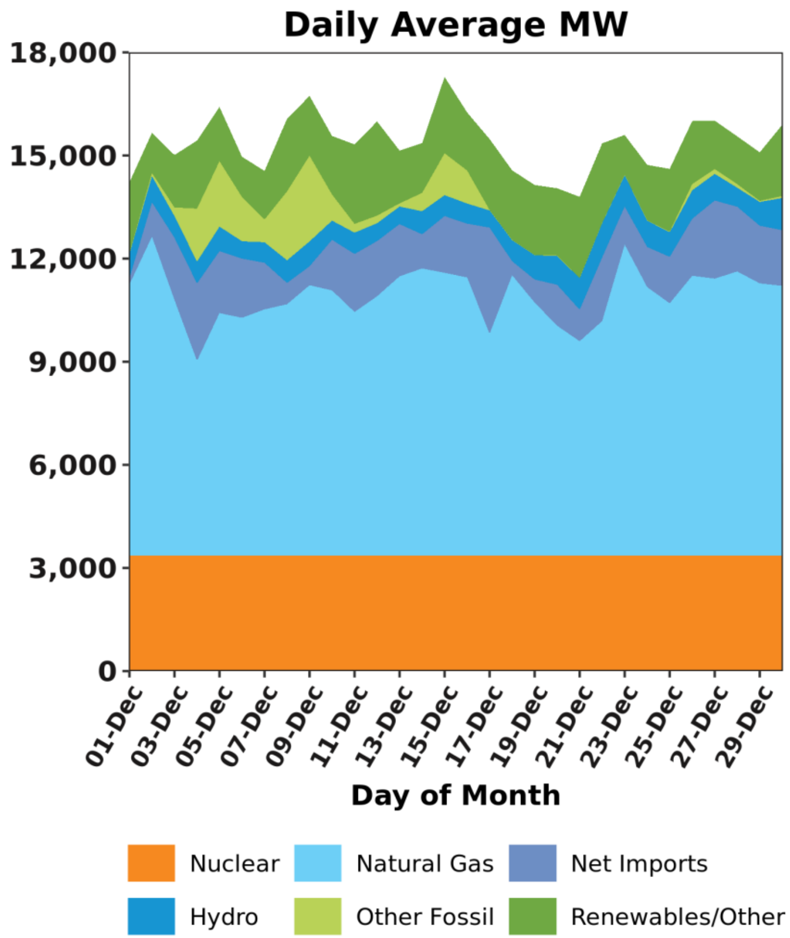
DA Volumes as % of Forecast in Peak Hour

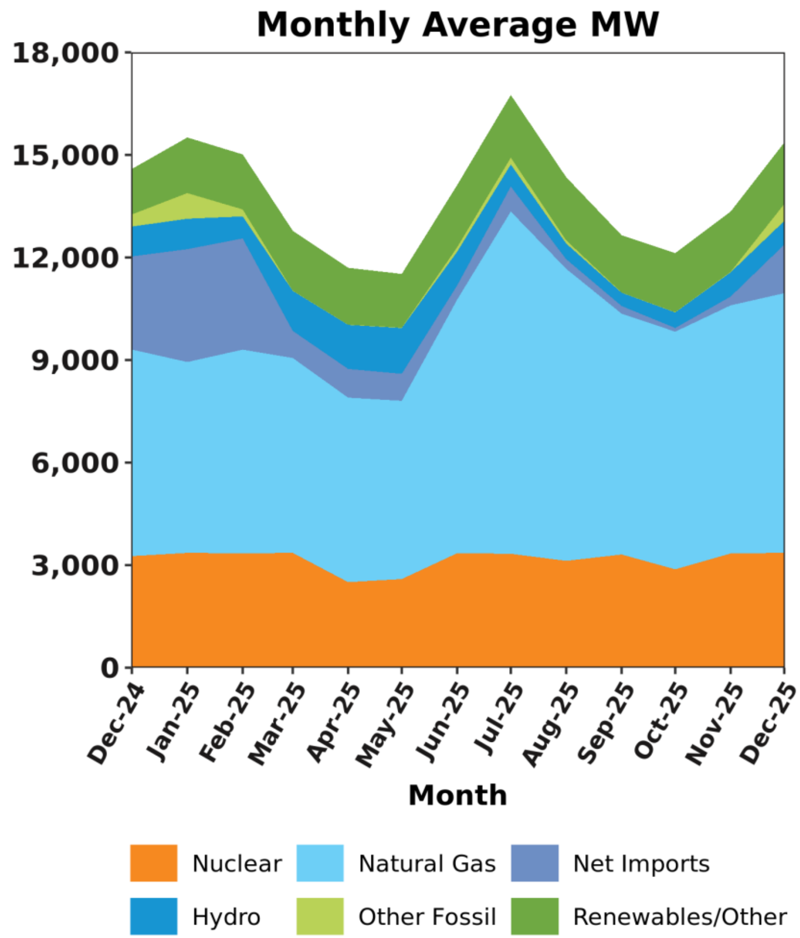




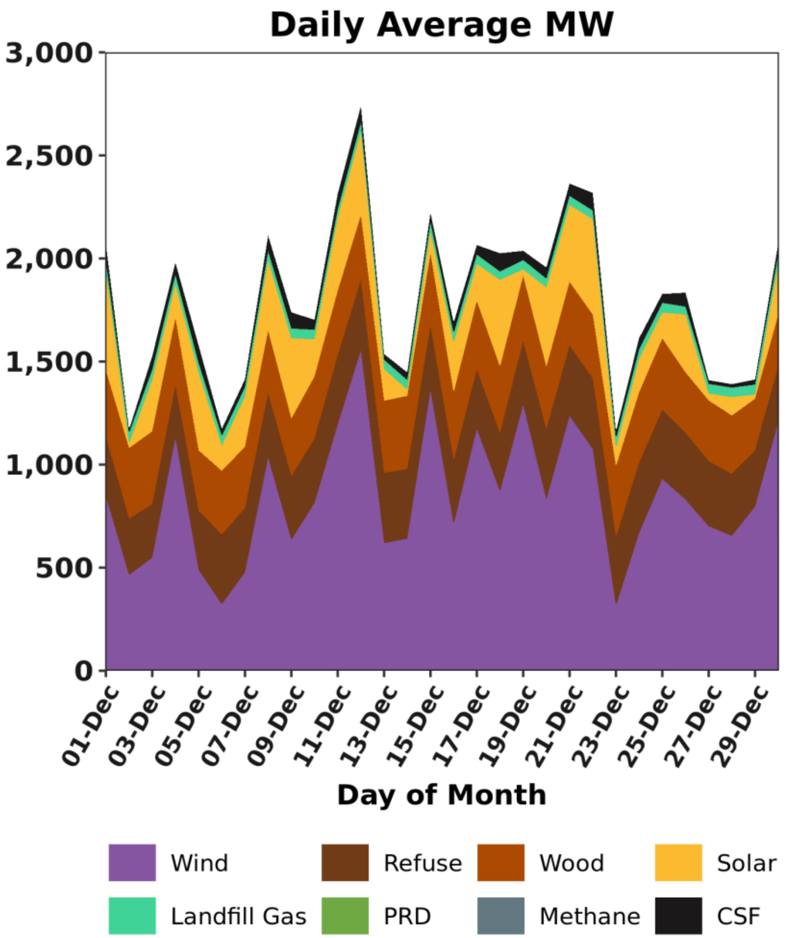
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

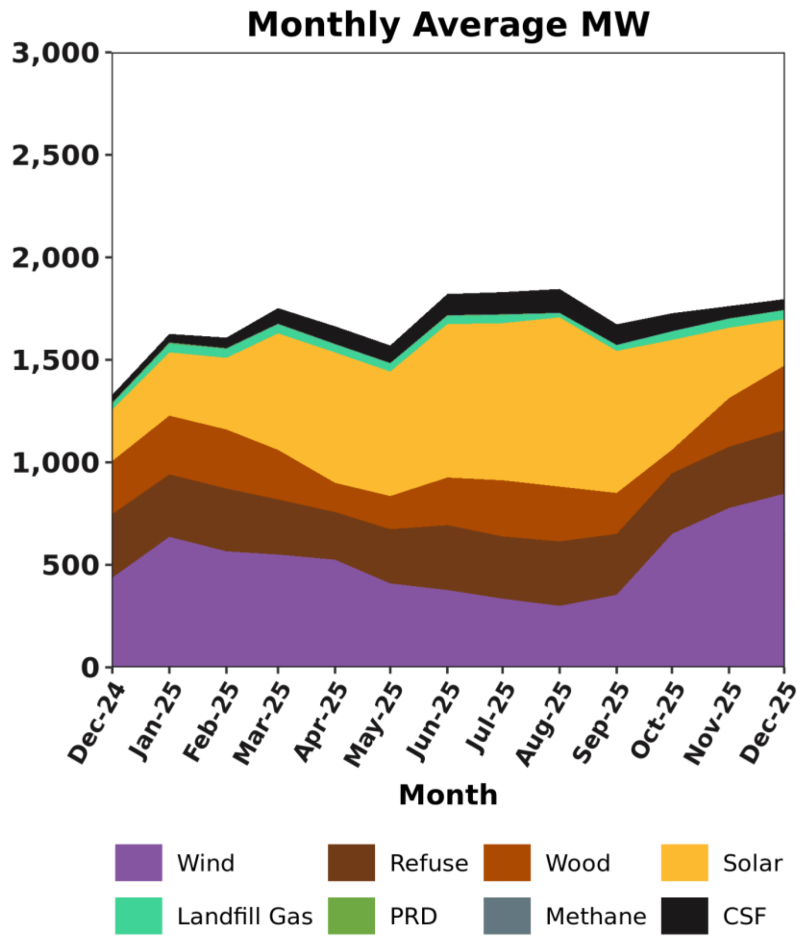
Resource Mix





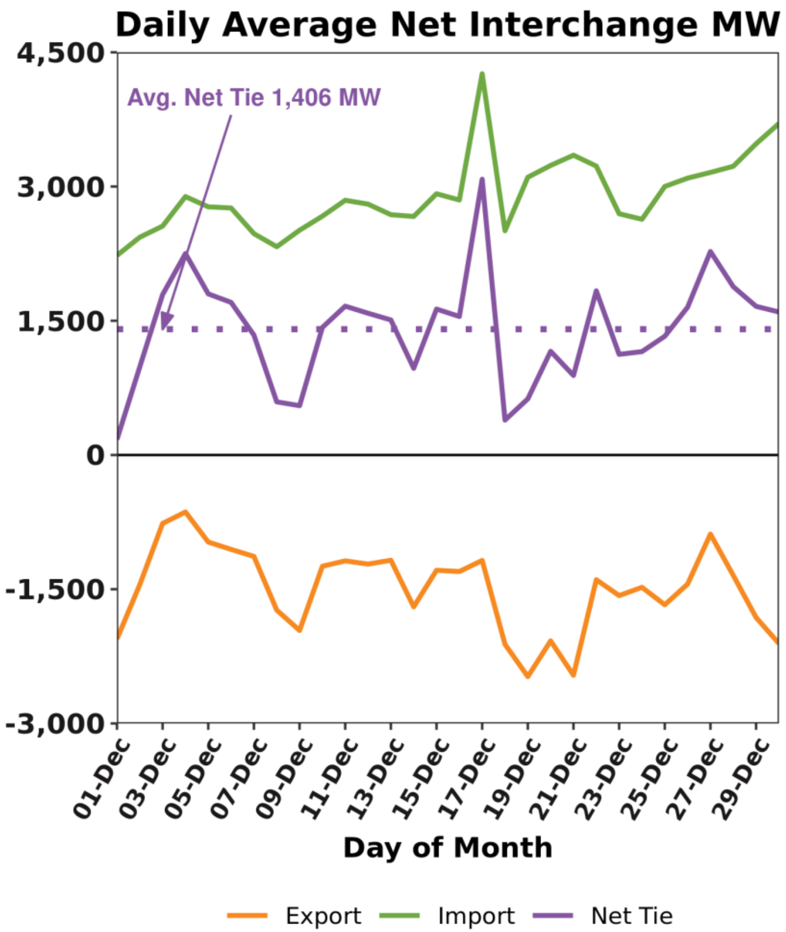
Renewable Generation by Fuel Type

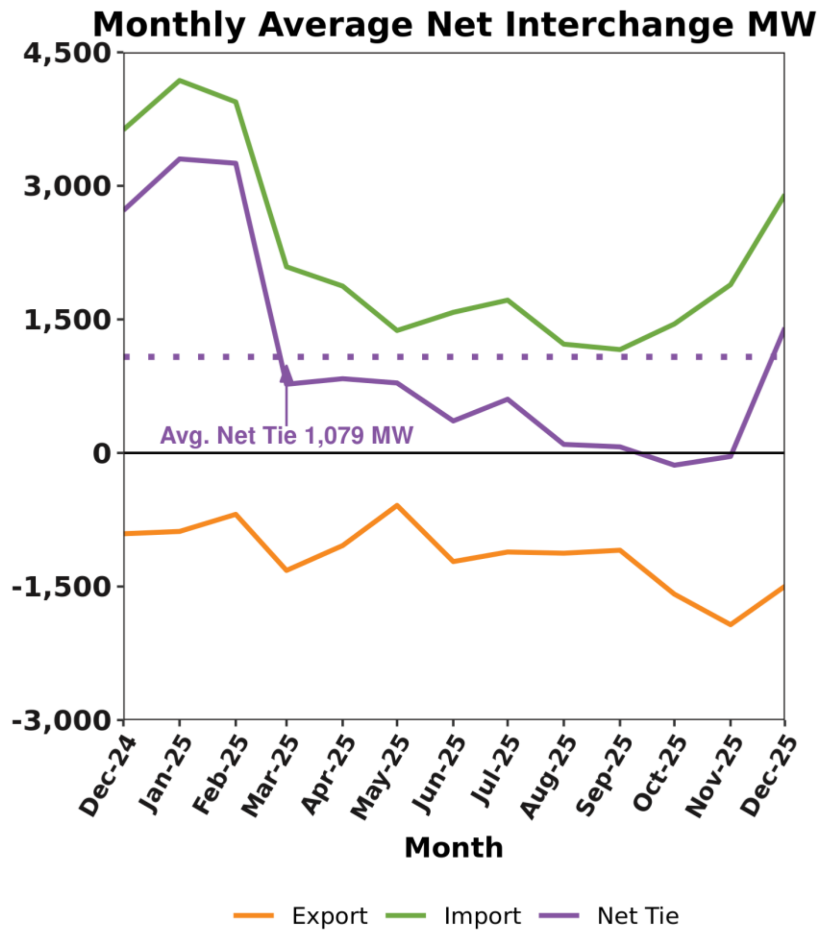




CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

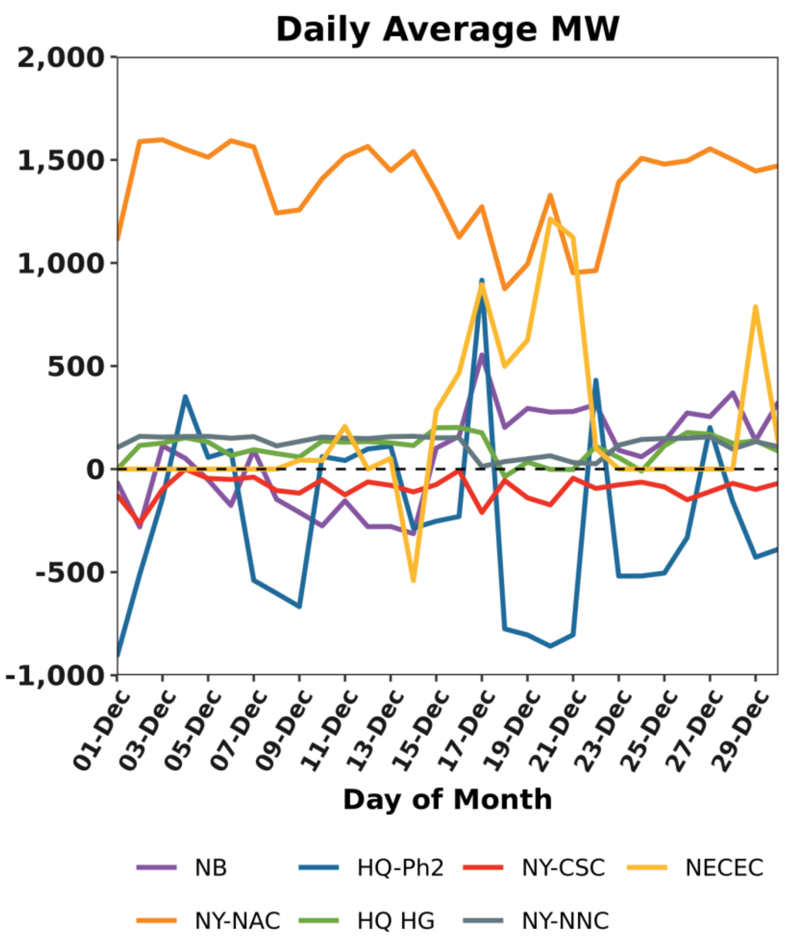
RT Net Interchange

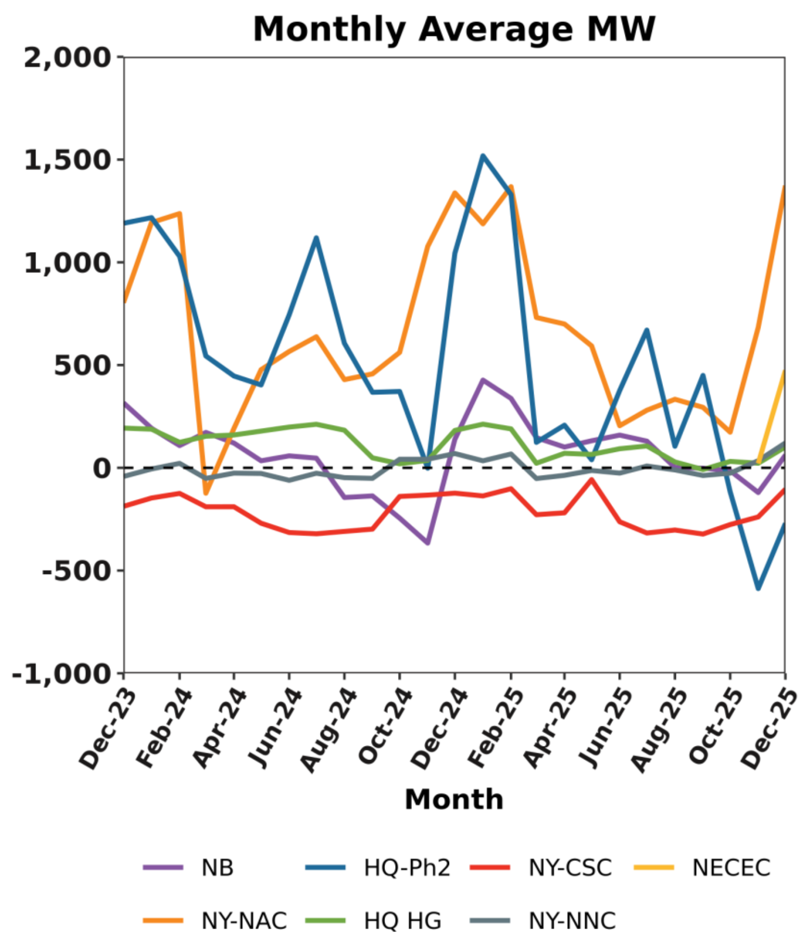




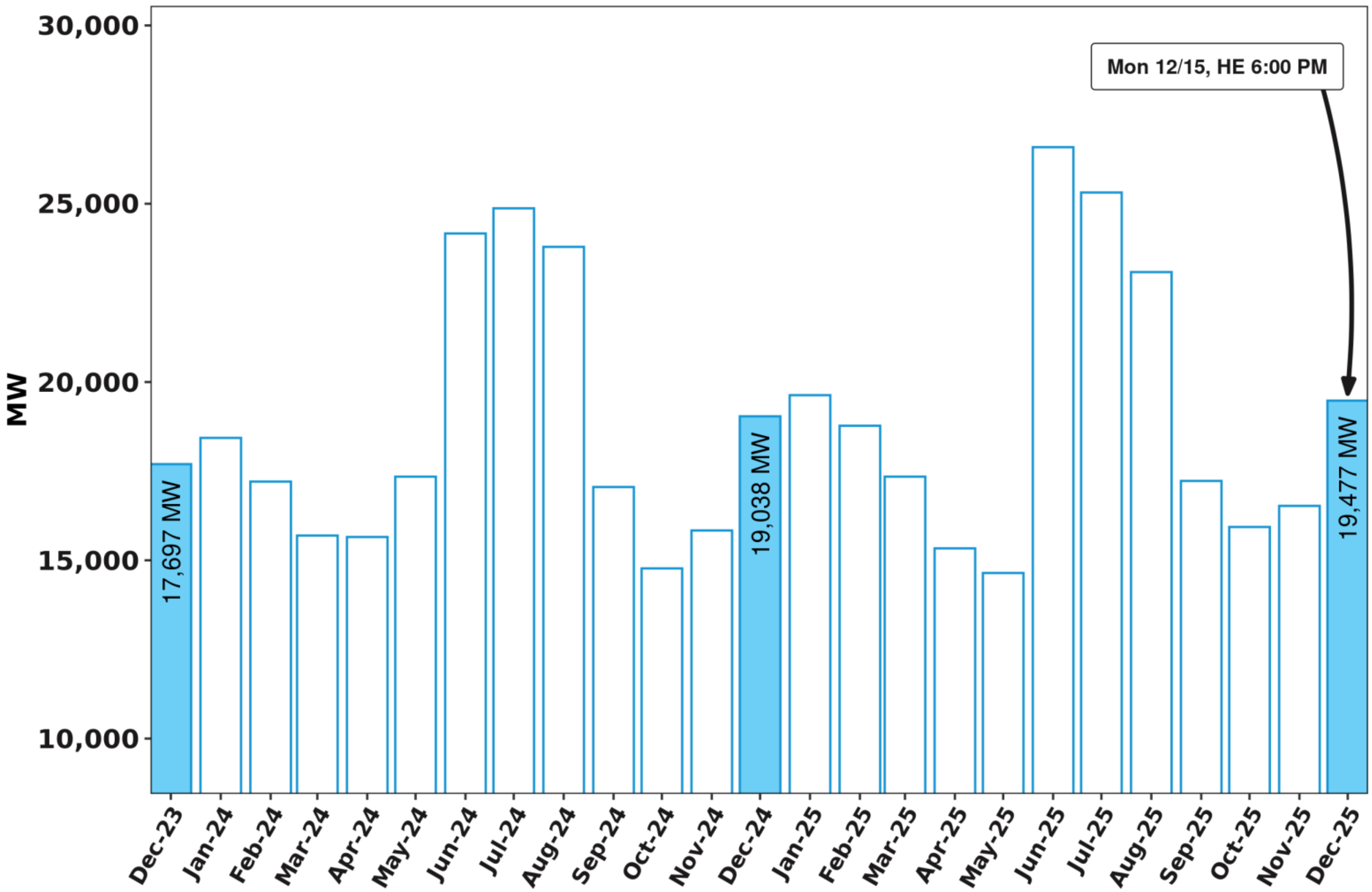
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



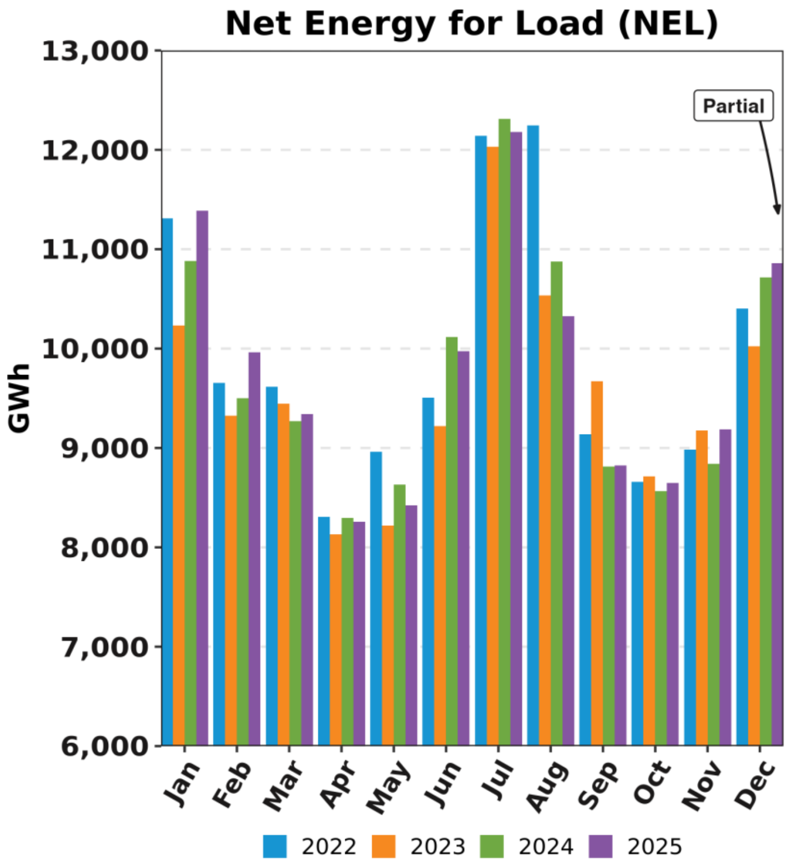


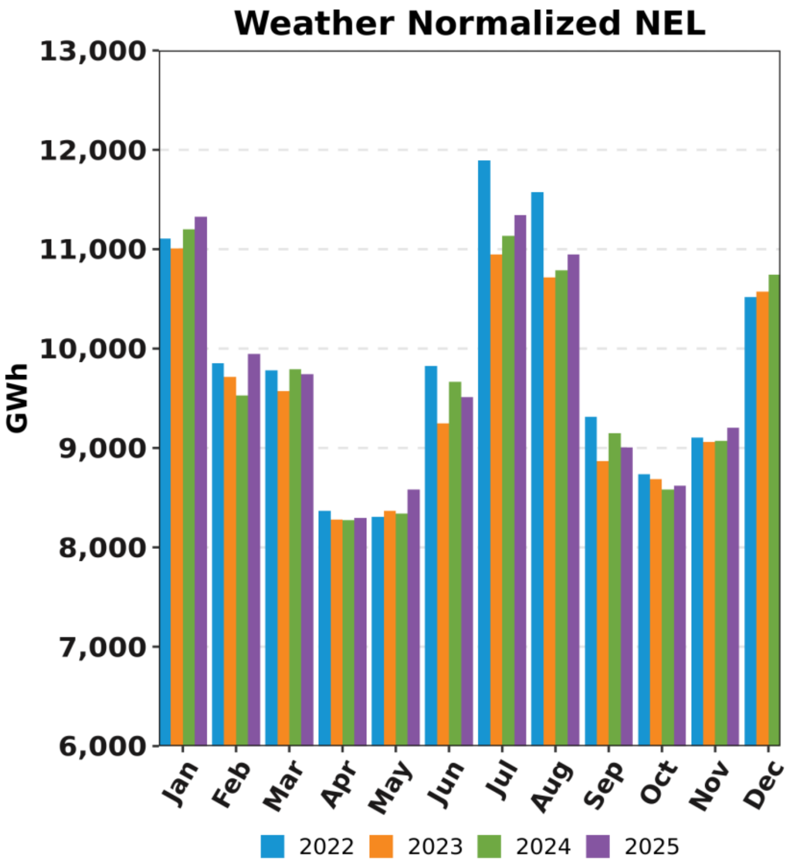
RQM System Peak Load MW by Month



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

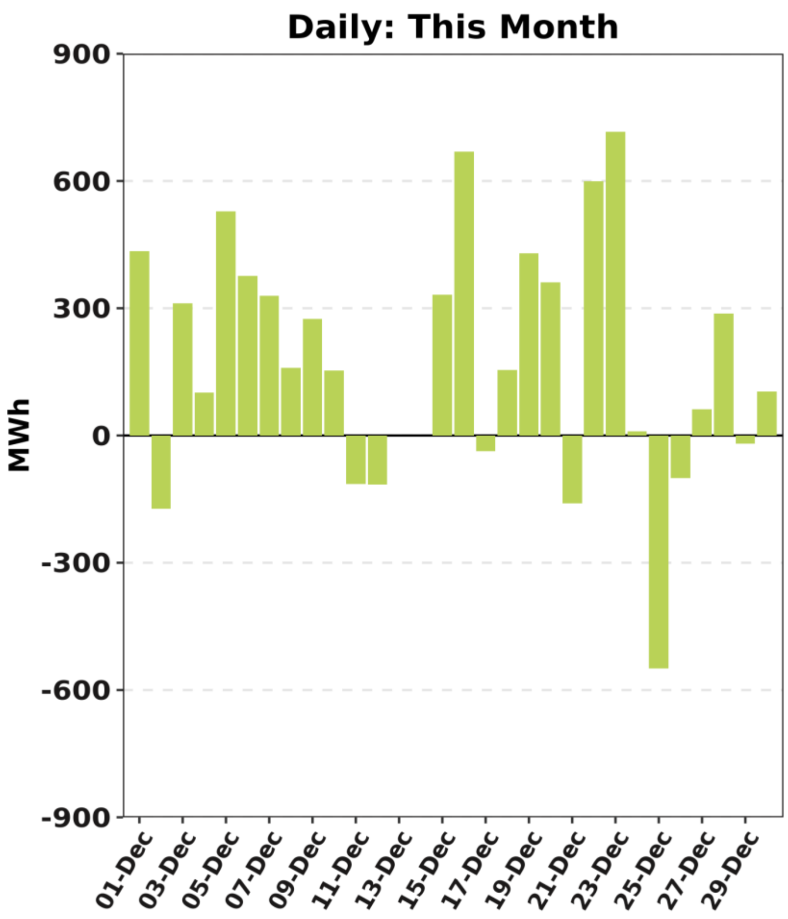
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

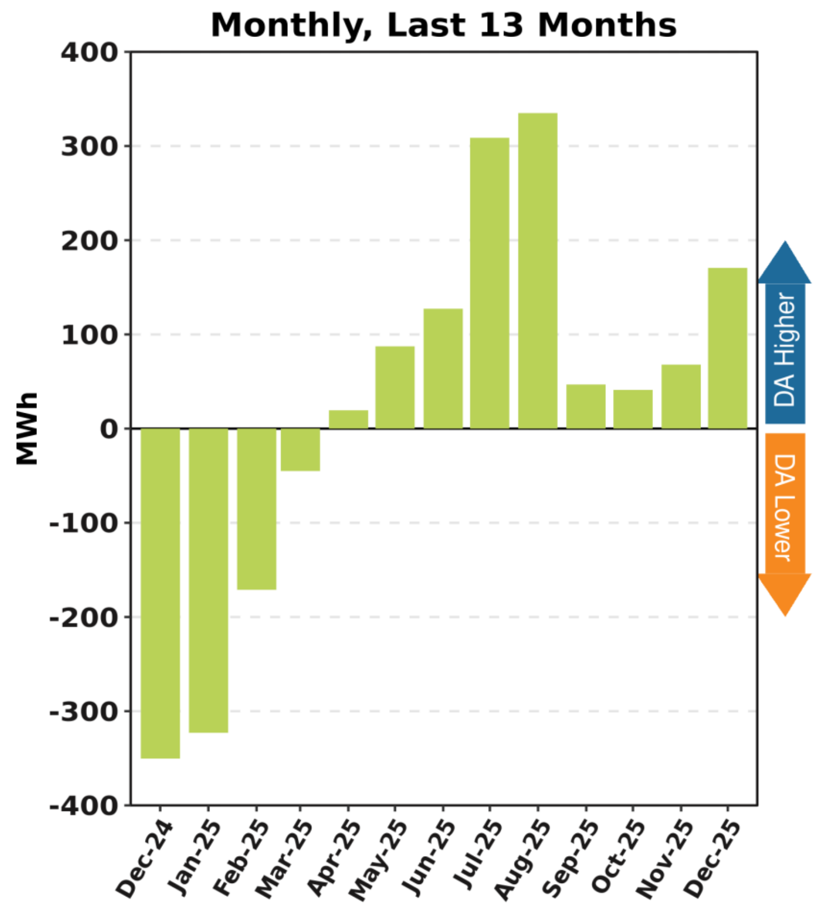




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

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

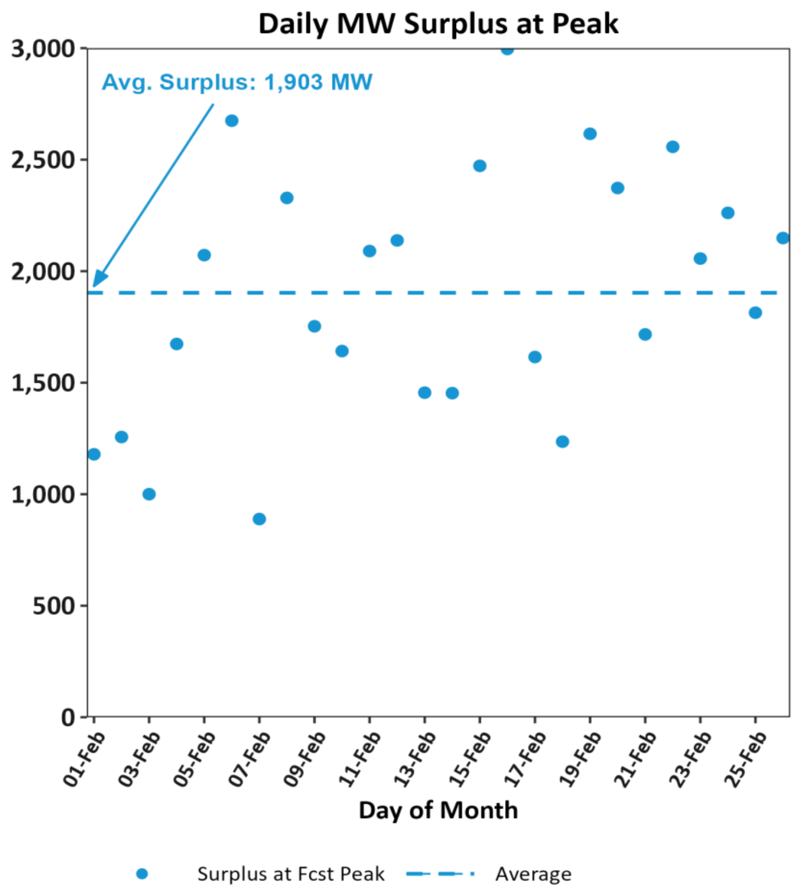


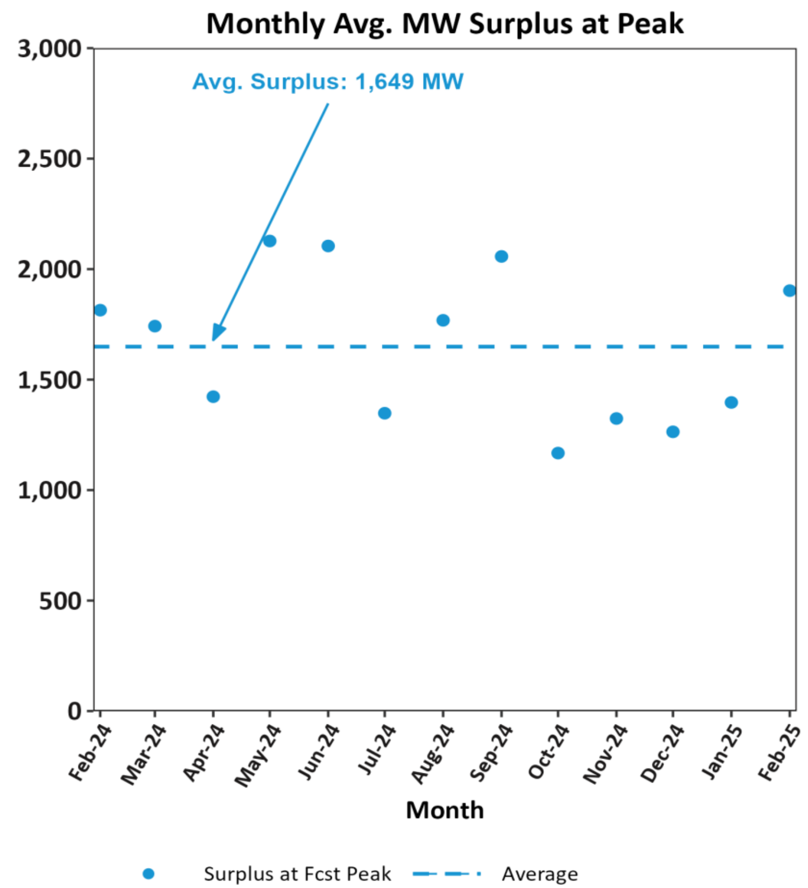


Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

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

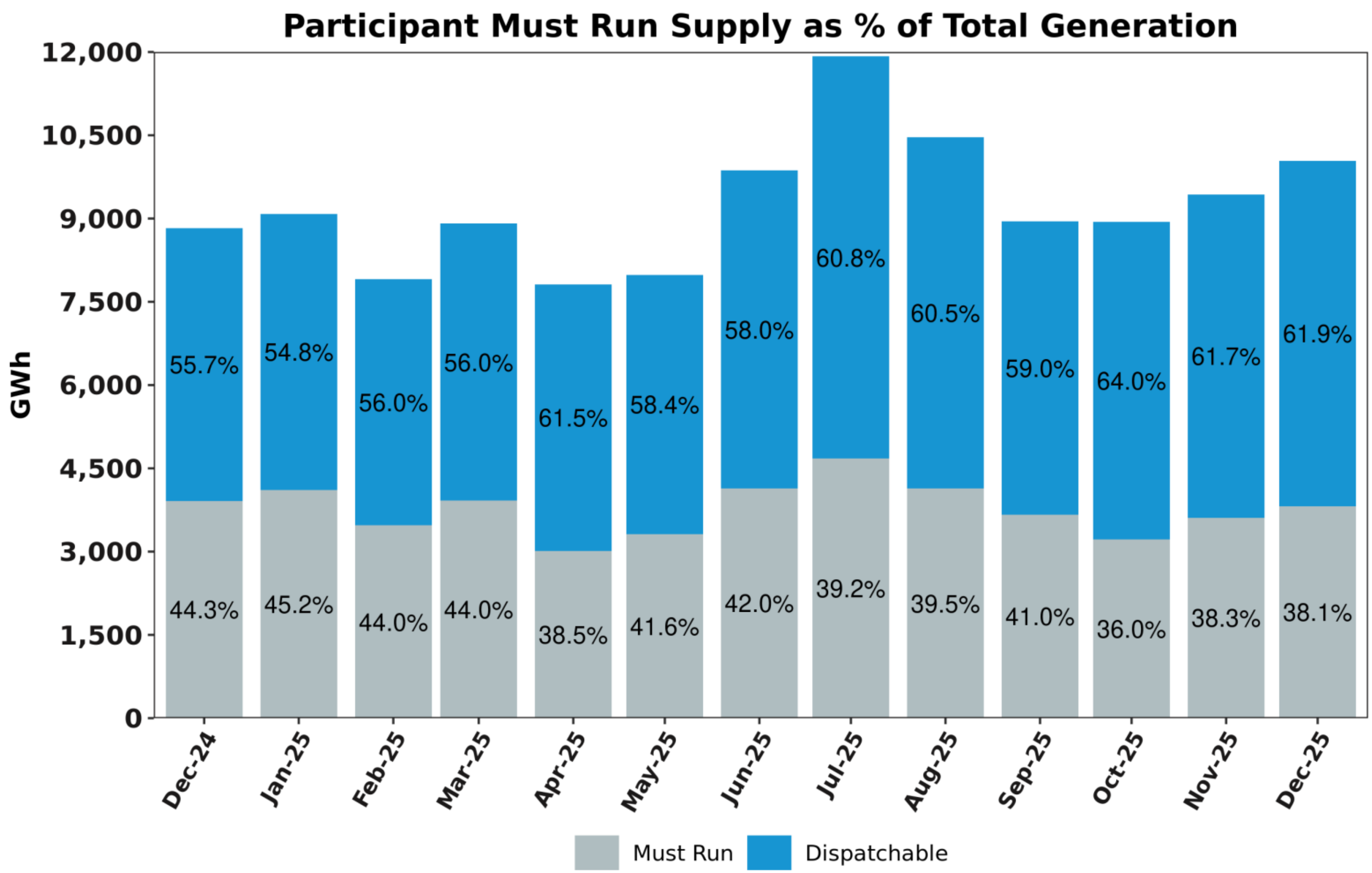
Pre-DAAS Slide





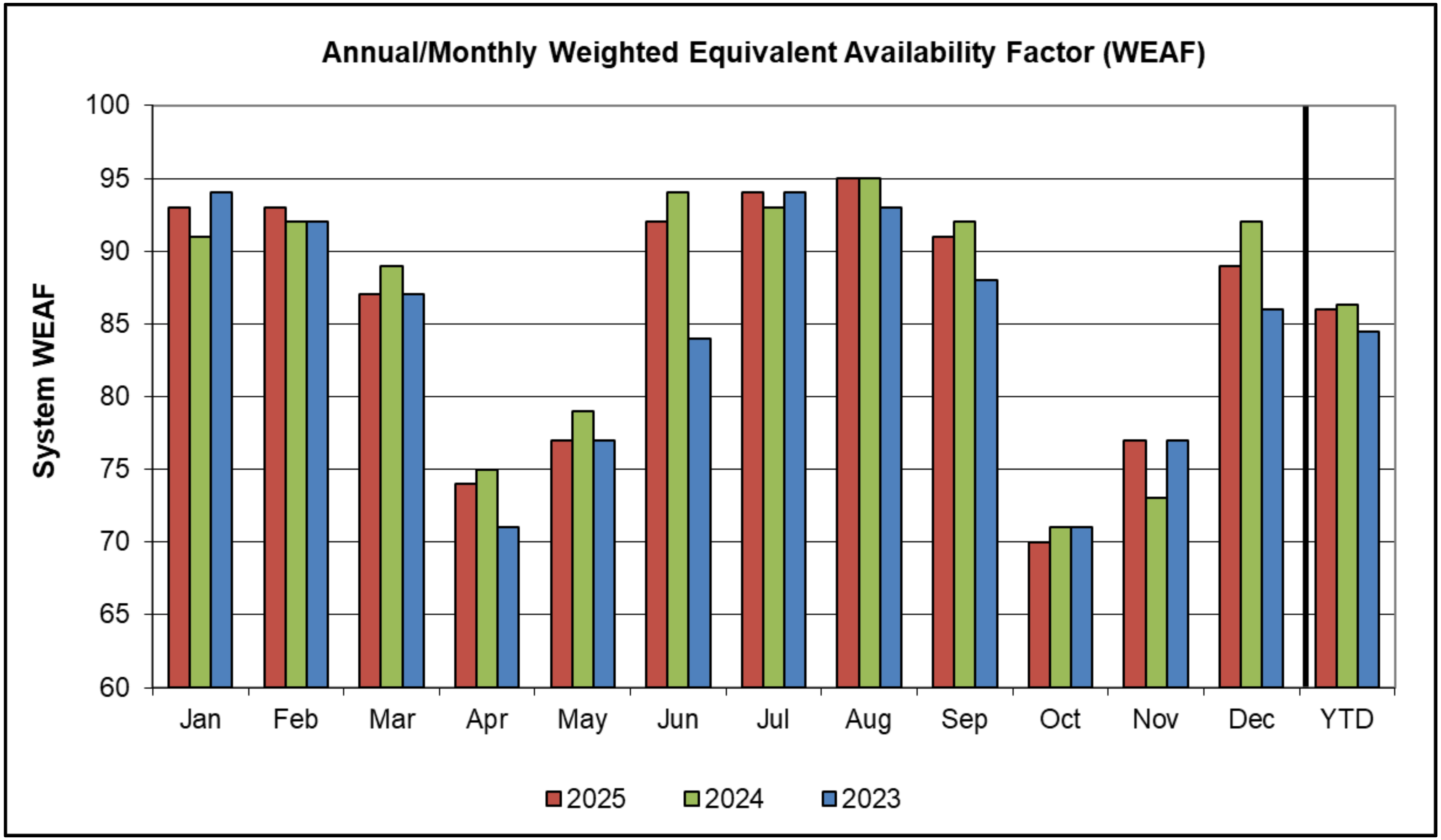
*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

RT Generation Output Offered as Must Run vs Dispatchable



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

System Unit Availability



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

Data as of 12/29/25

MARKET OPERATIONS

Market Pricing

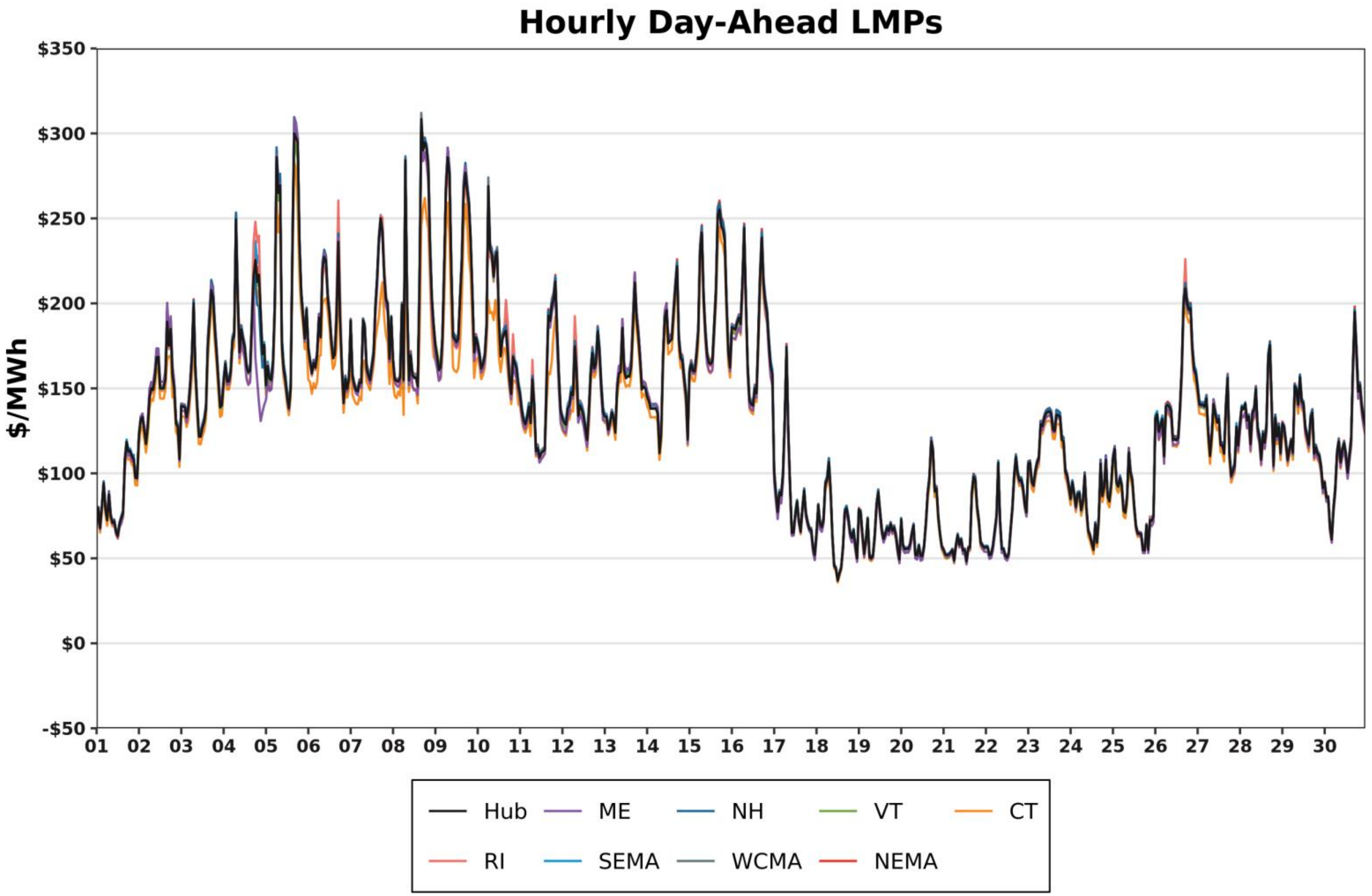
DA vs. RT LMPs ($/MWh)

Arithmetic Average

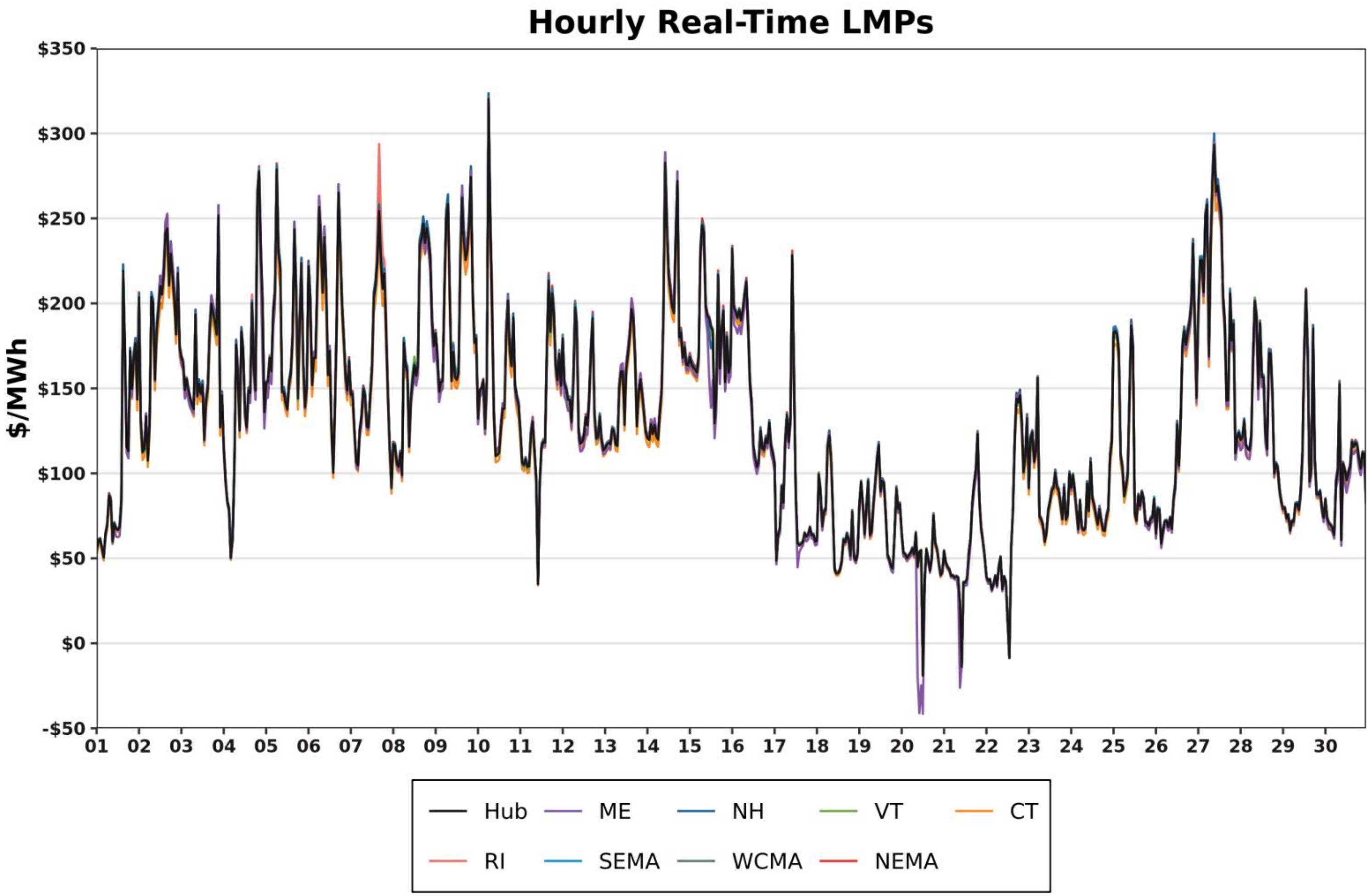
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA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

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

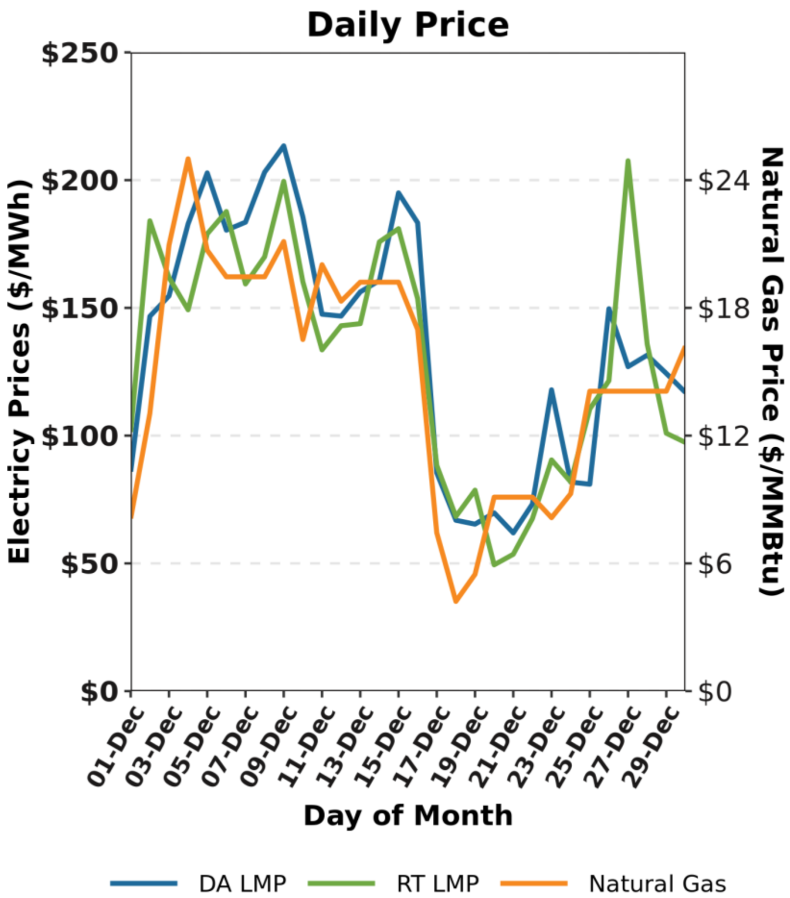
Hourly DA LMPs, December 1-30, 2025

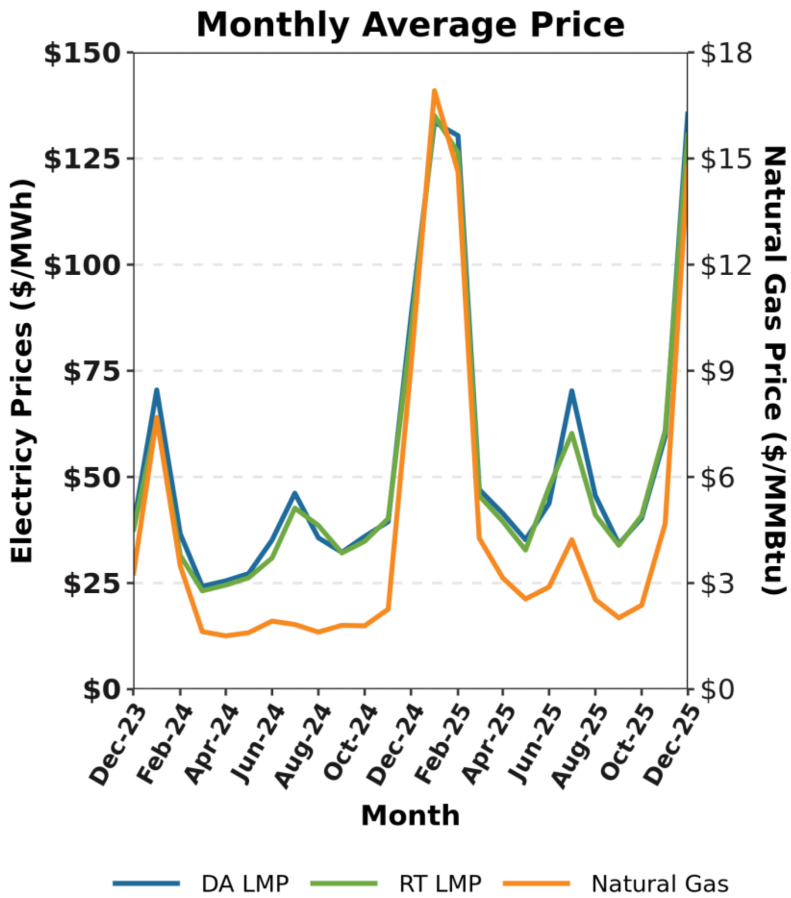


Hourly RT LMPs, December 1-30, 2025



Wholesale Electricity vs Natural Gas Price by Month

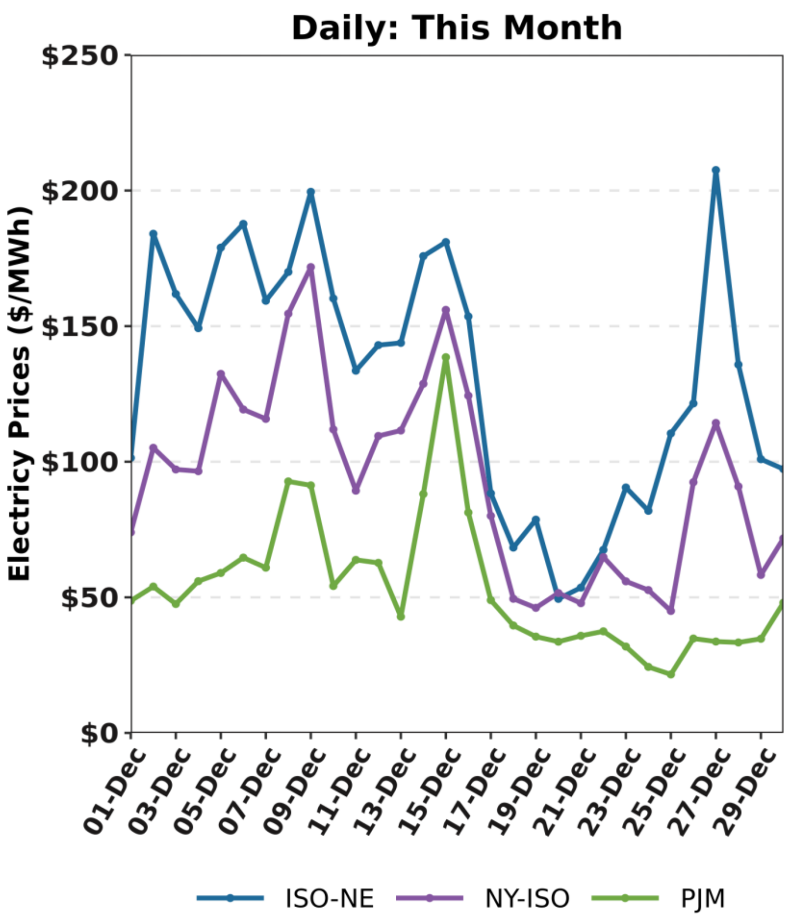


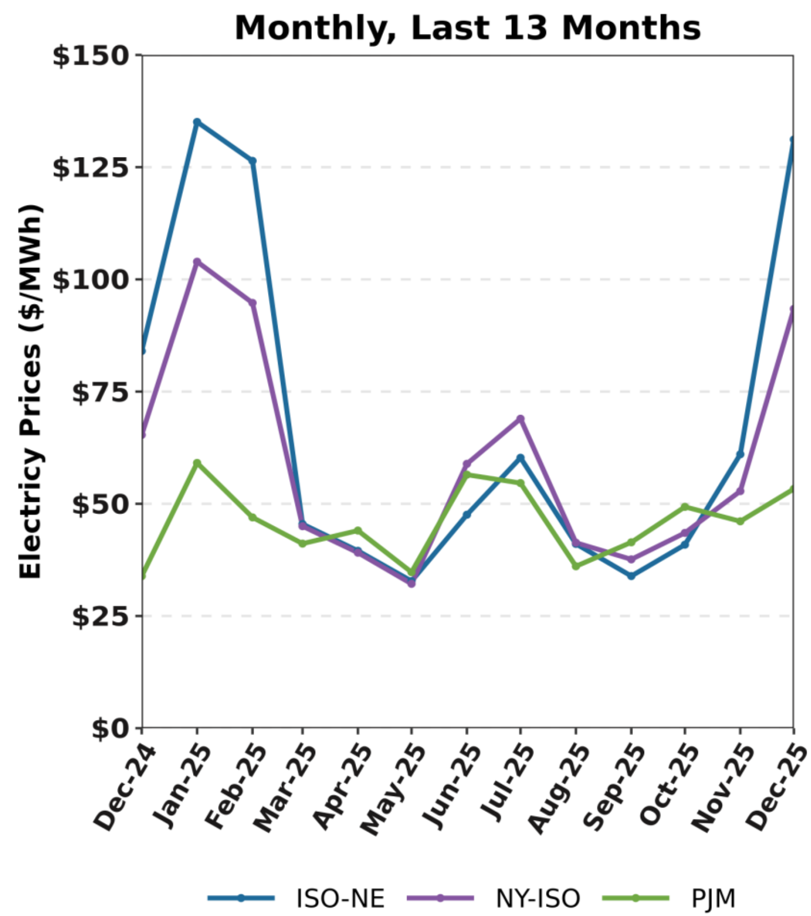


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

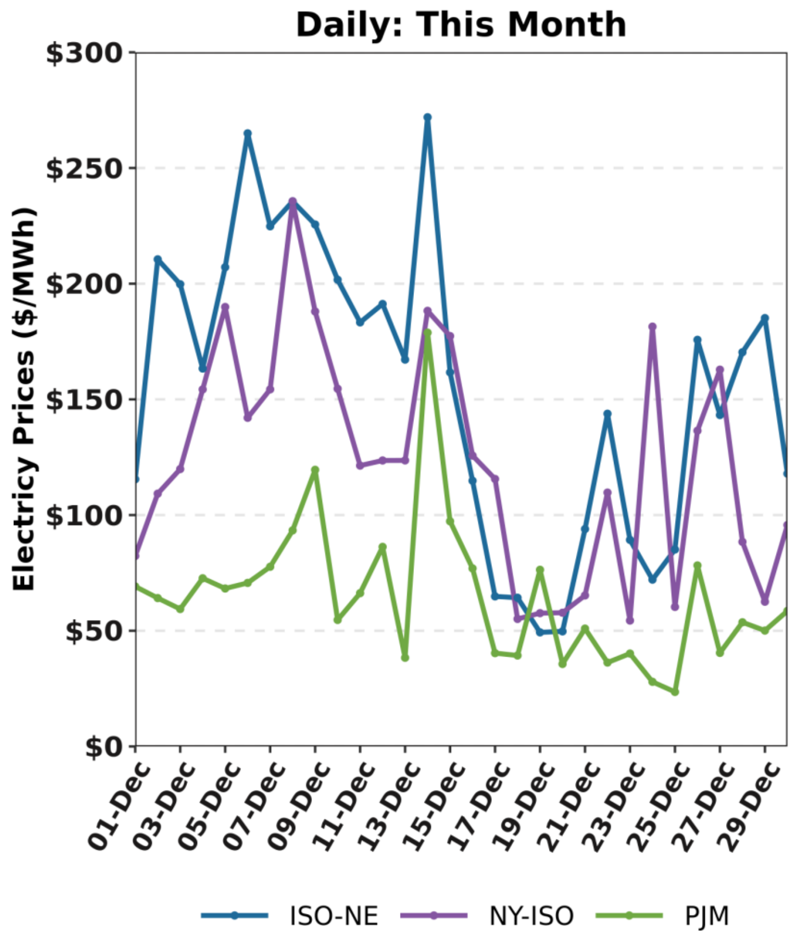
New England, NY, and PJM Hourly Average RT Prices by Month

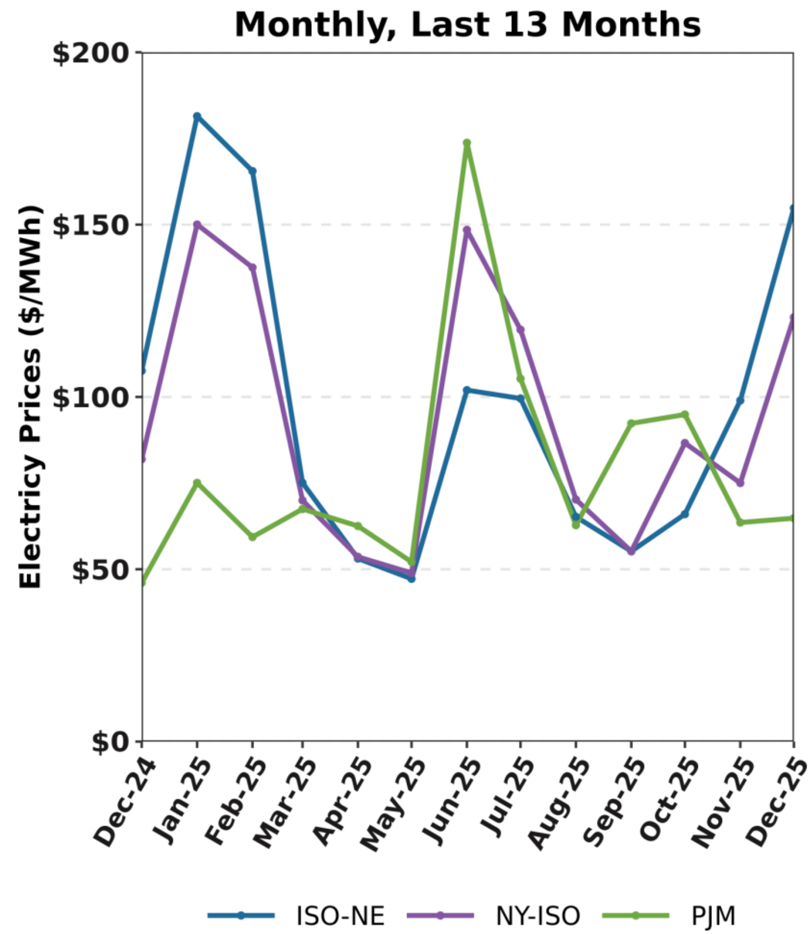




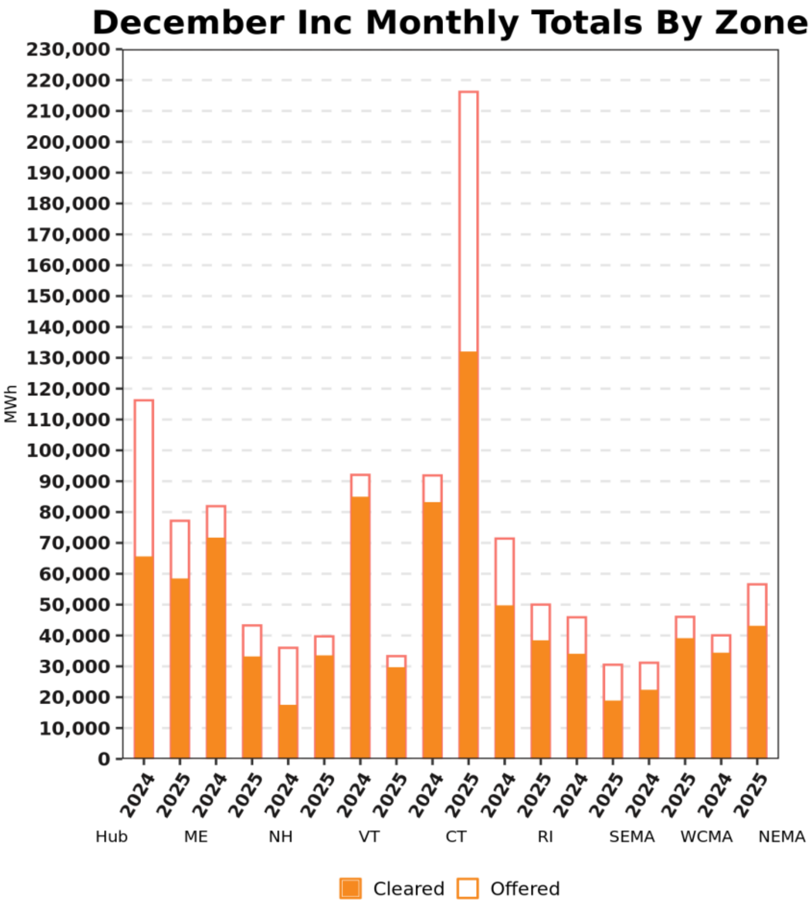
Hourly average prices are shown

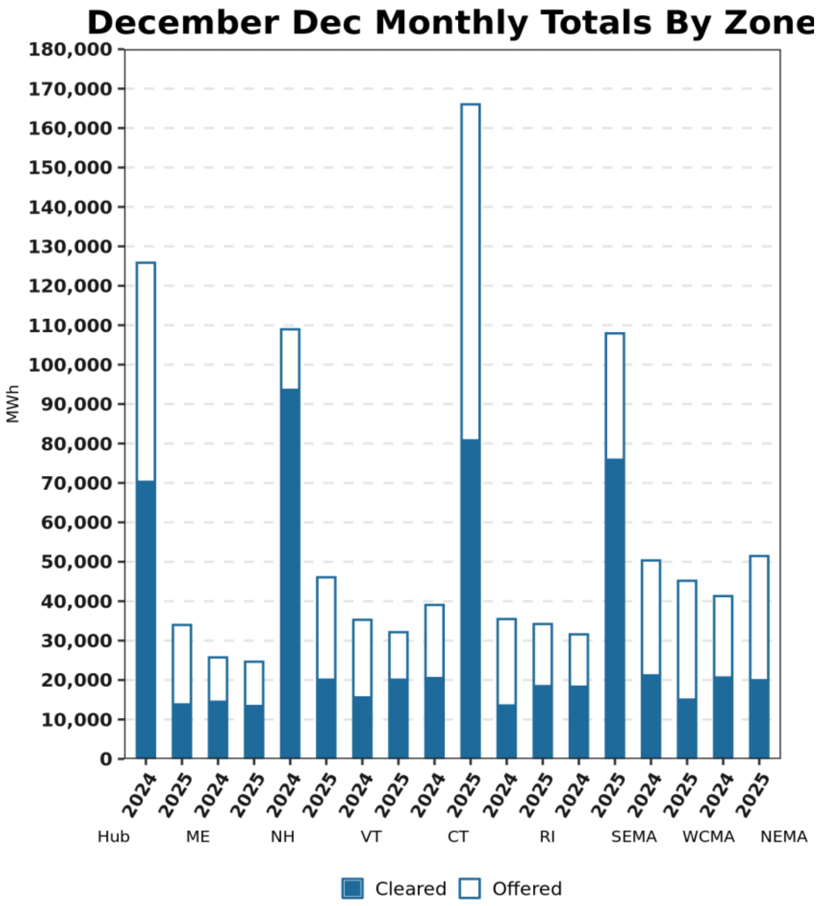
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





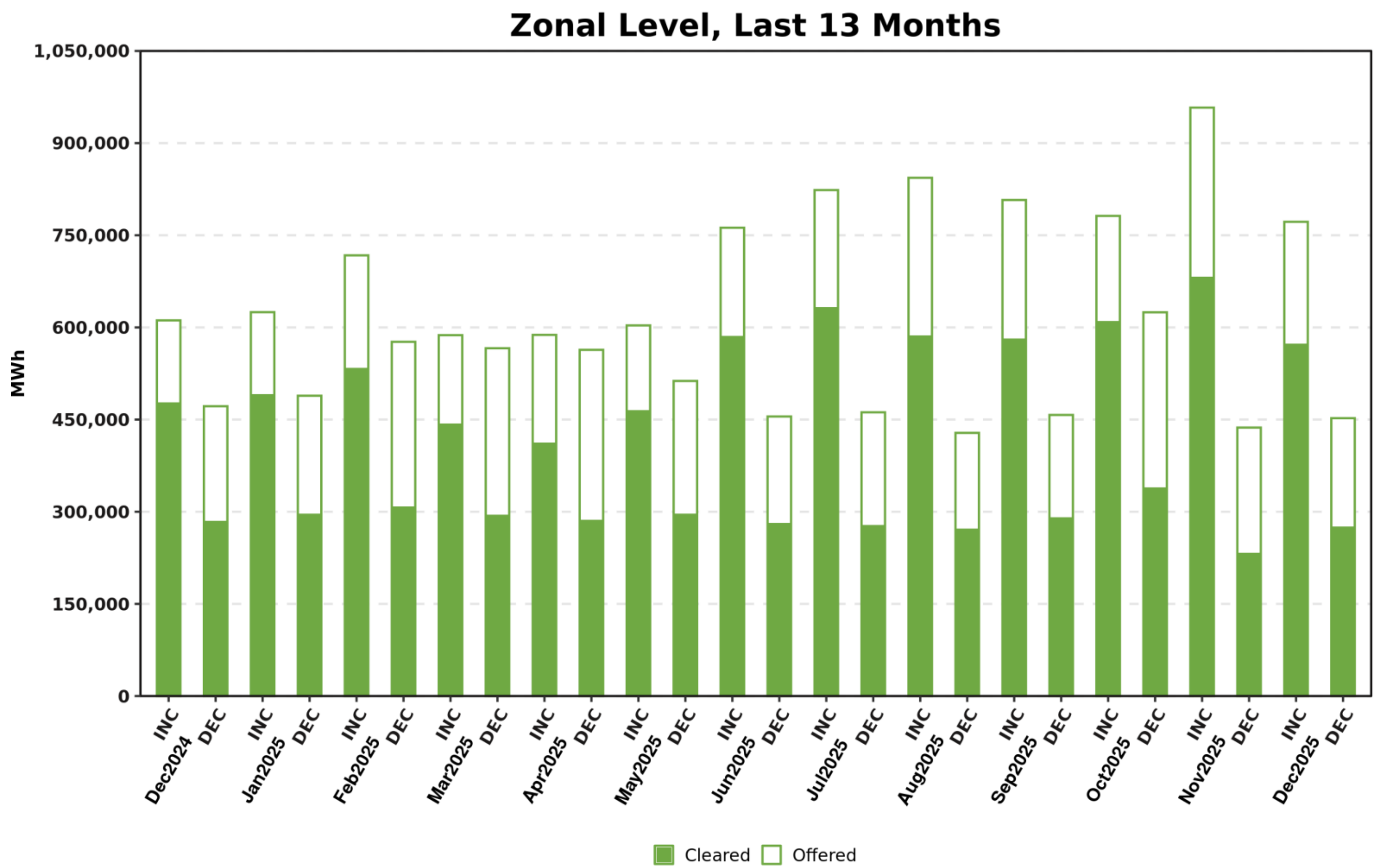
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

NOVEMBER 23, 2025 PFP EVENT SETTLEMENTS SUMMARY

PFP Settlements Summary for November 23, 2025

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

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

Most Recent Capacity Scarcity Condition Events

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

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

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

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

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

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

Summary of Performance Payments

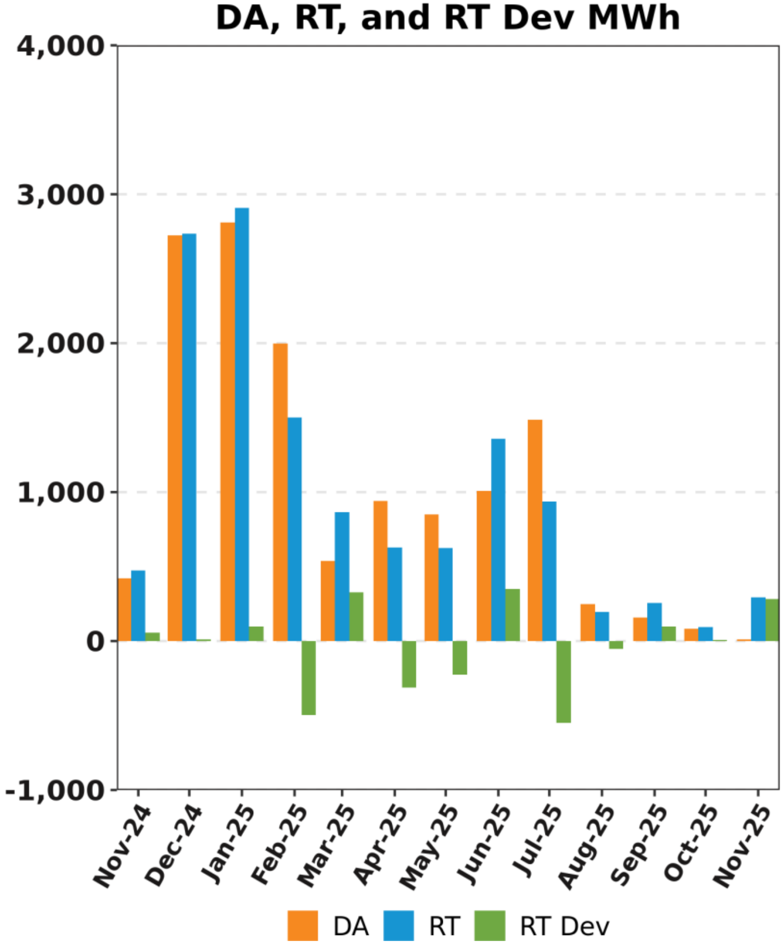
Performance Payment Credits (Charges) (MR1 Sec. III.13.7.2, 13.7.3)	
Performance Payment Credits*	**Million $**
To Resources with CSOs	$ 24.6
To Resources without CSOs	$ 7.3
Total	$ 31.9
Performance Payment Charges	
Before Application of Balancing Fund and Stop-Loss	$ (32.6)
Total Stop-Loss	$ 0.0
Total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

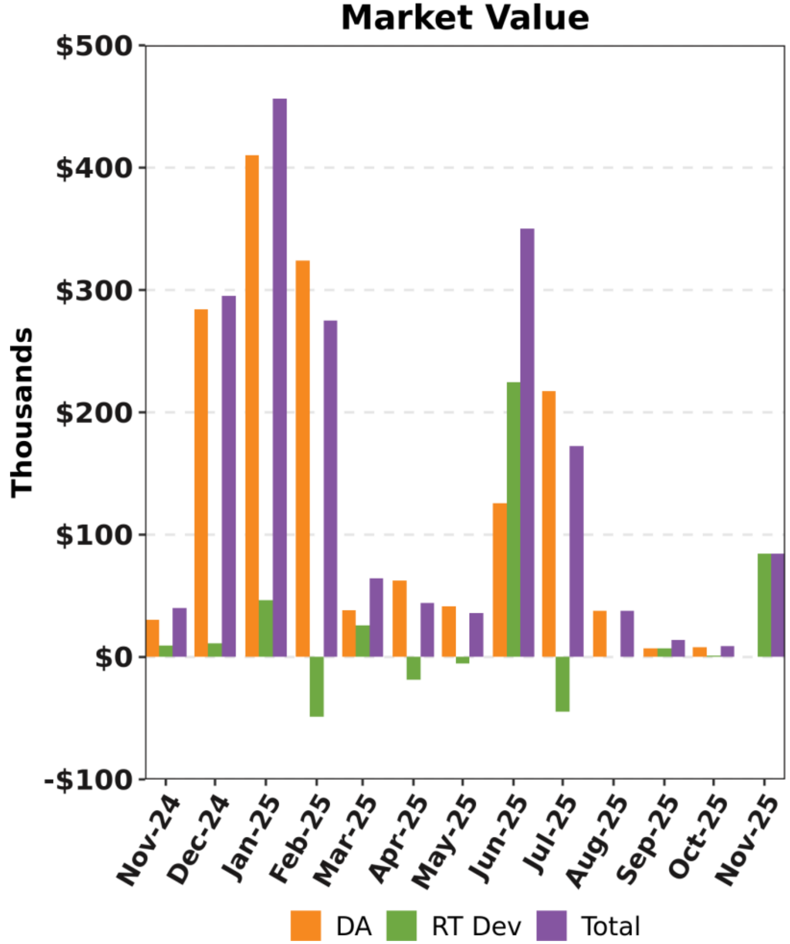
*Performance Credits shown are prior to allocation of Stop-Loss (if any) and/or Balancing Fund.

BACK-UP DETAIL

DEMAND RESPONSE

Demand Response Resource (DRR) Energy Market Activity by Month





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

NEW GENERATION

New Generation Update

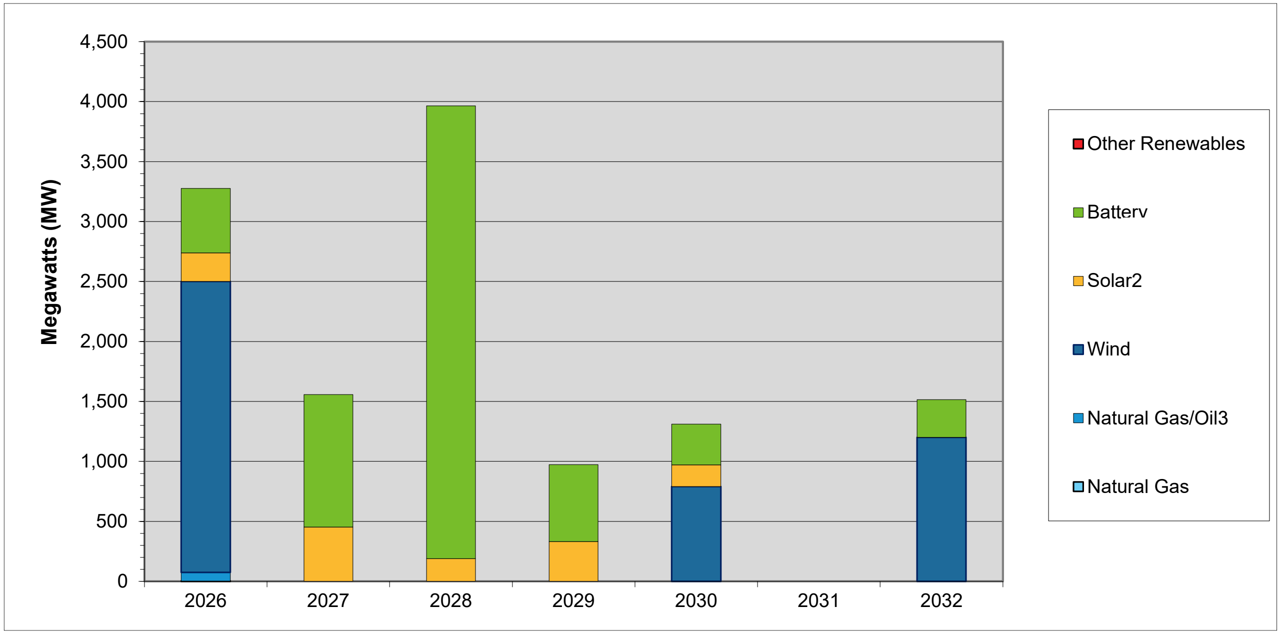
Based on Queue as of 1/01/26

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

* Total does not include CNR Only requests

Projected Annual Capacity Additions

By Supply Fuel Type



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

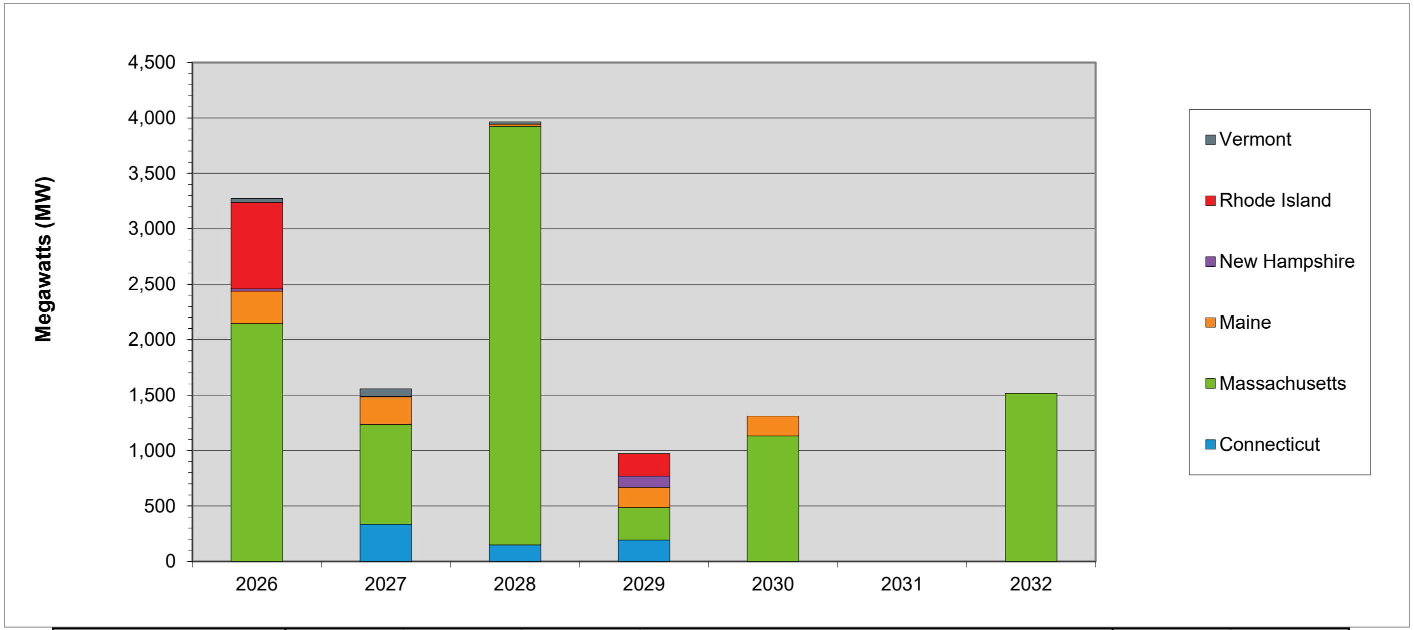
[1] Sum may not equal 100% due to rounding

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

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

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

Projected Annual Generator Capacity Additions
By State



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

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

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	30	6,713	1	250	29	6,463
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	1	73	1	73	0	0
Nuclear	0	0	0	0	0	0
Solar	24	1,392	3	136	21	1,256
Wind	10	6,104	3	877	7	5,227
Total	65	14,282	8	1,336	57	12,946

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

New Generation Projection

By Operating Type

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

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	30	6,713	0	0	0	0	30	6,713	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	24	1,392	0	0	0	0	24	1,392	0	0
Wind	10	6,104	0	0	0	0	0	0	10	6,104
Total	65	14,282	0	0	1	73	54	8,105	10	6,104

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 15

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

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

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

Capacity Supply Obligation FCA 16

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

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

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

Capacity Supply Obligation FCA 17

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

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

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

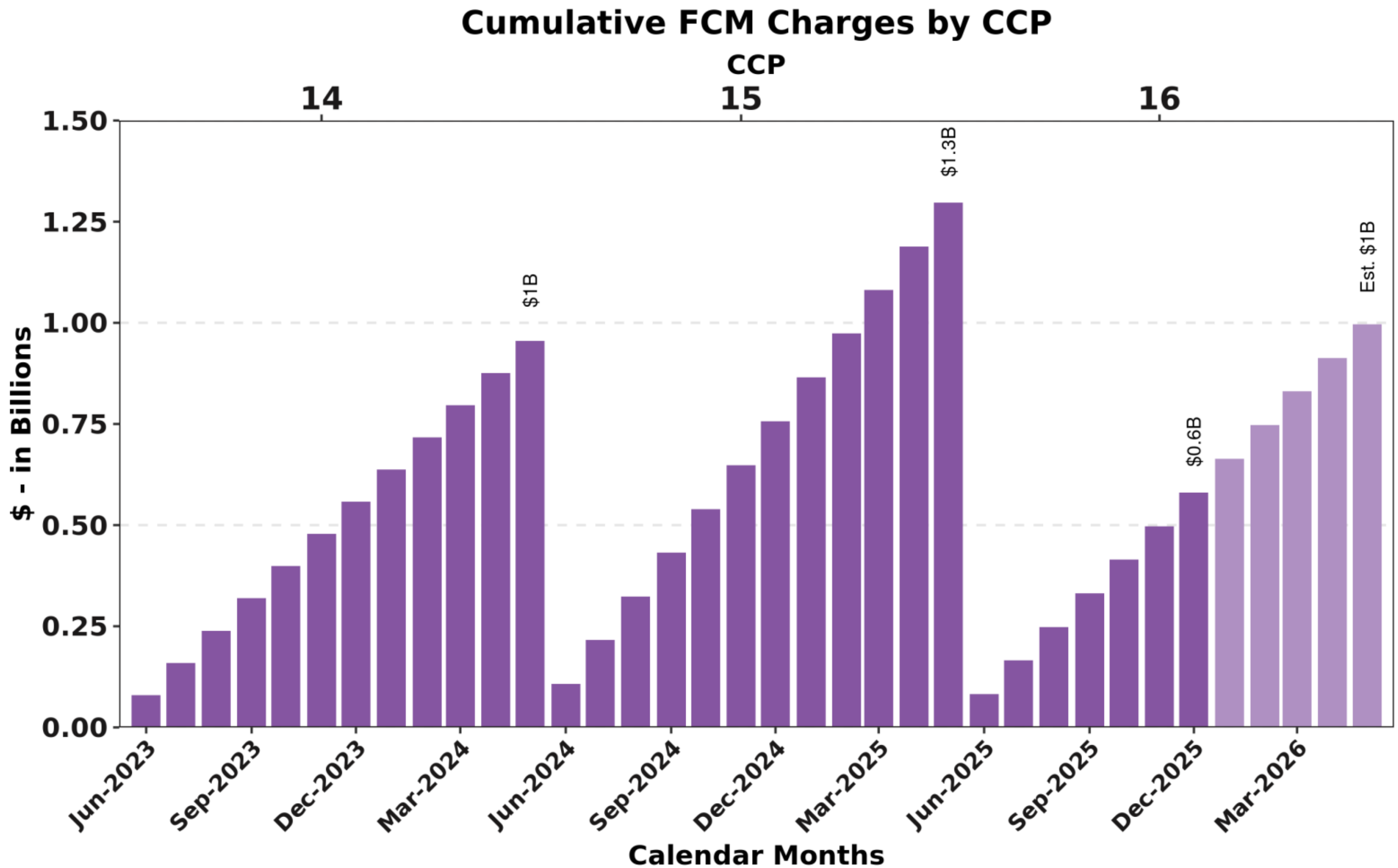
Capacity Supply Obligation FCA 18

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

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

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

Forward Capacity Market Auctions



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

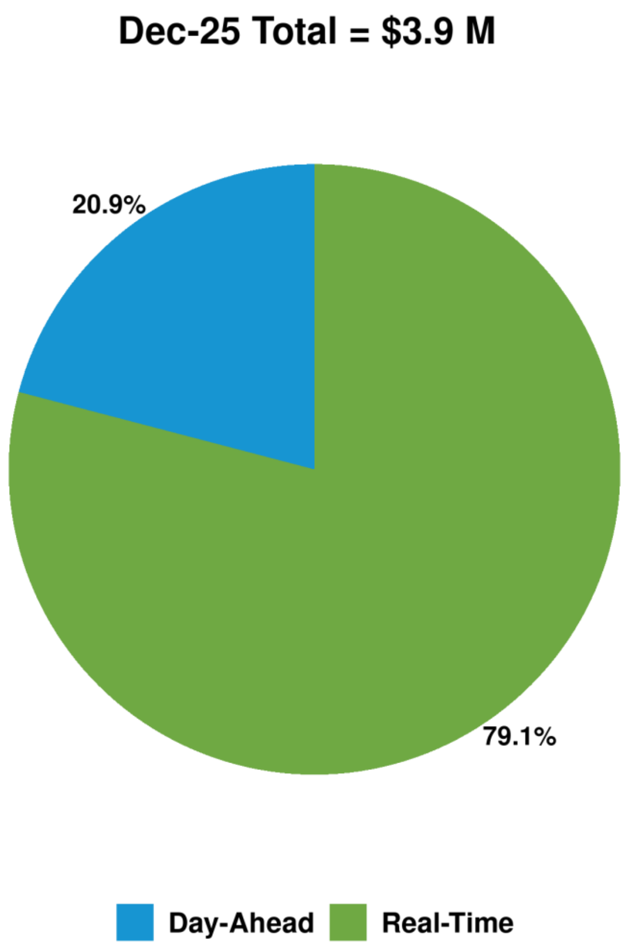
Active/Passive Demand Response

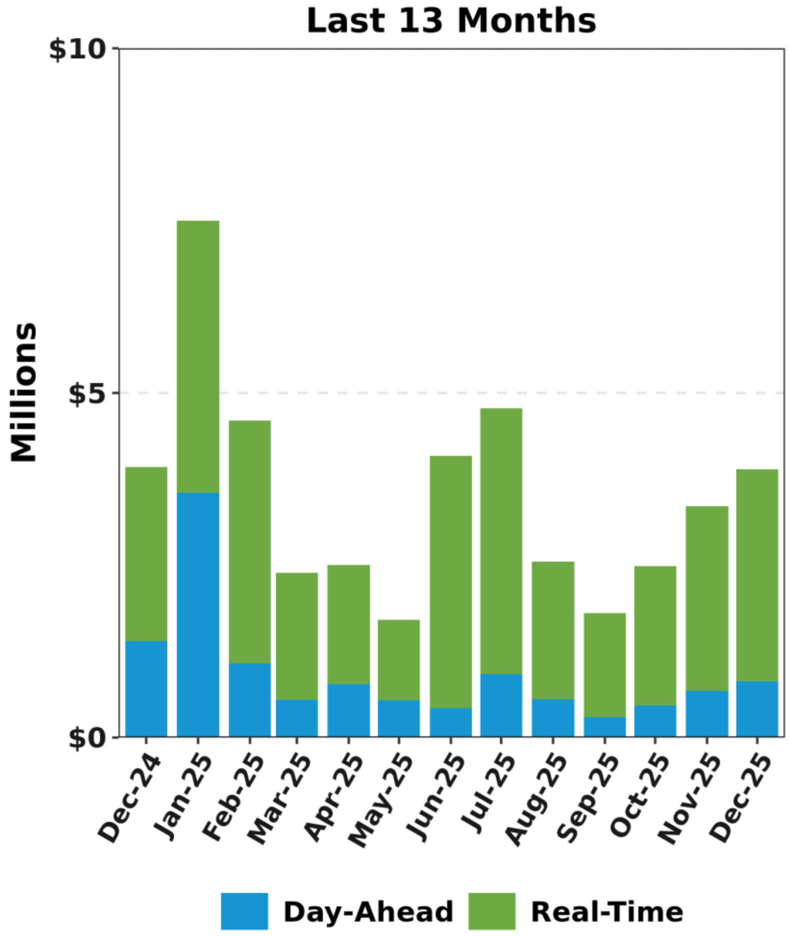
CSO Totals by Commitment Period

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

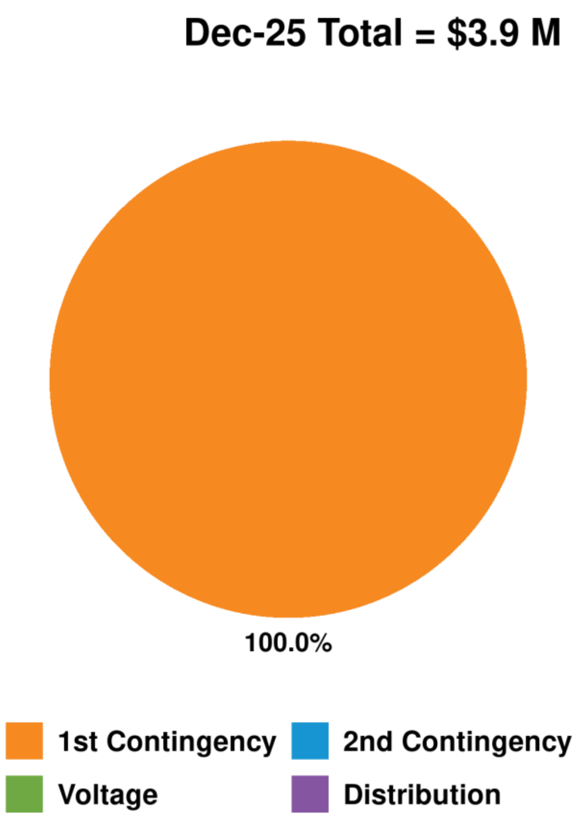
NET COMMITMENT PERIOD COMPENSATION

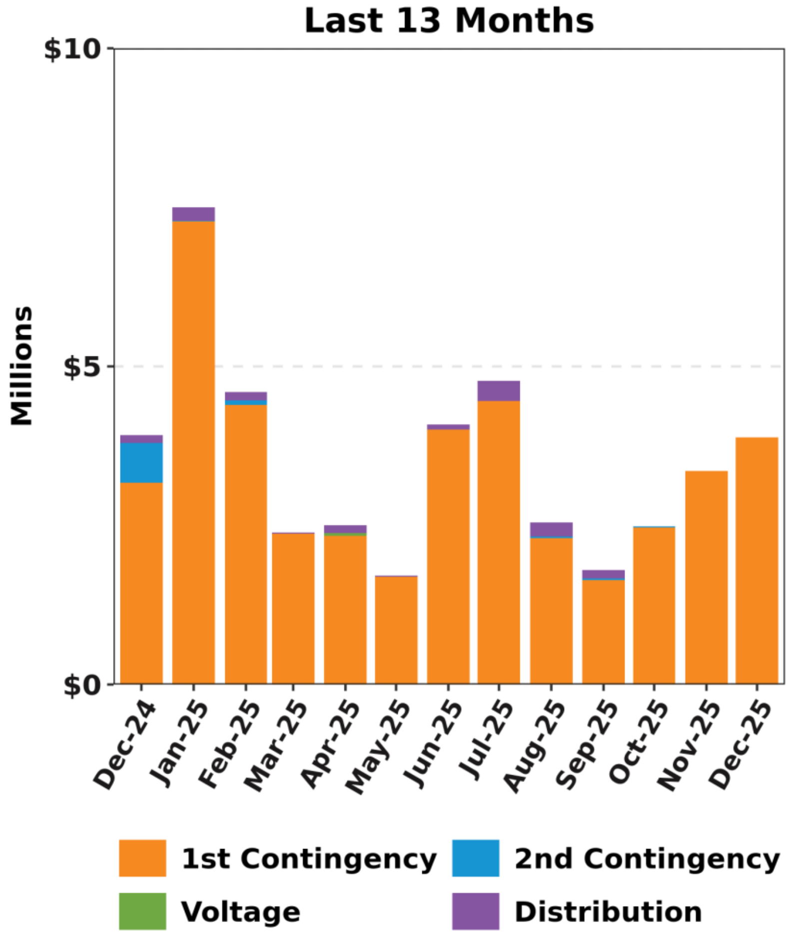
DA and RT NCPC Charges



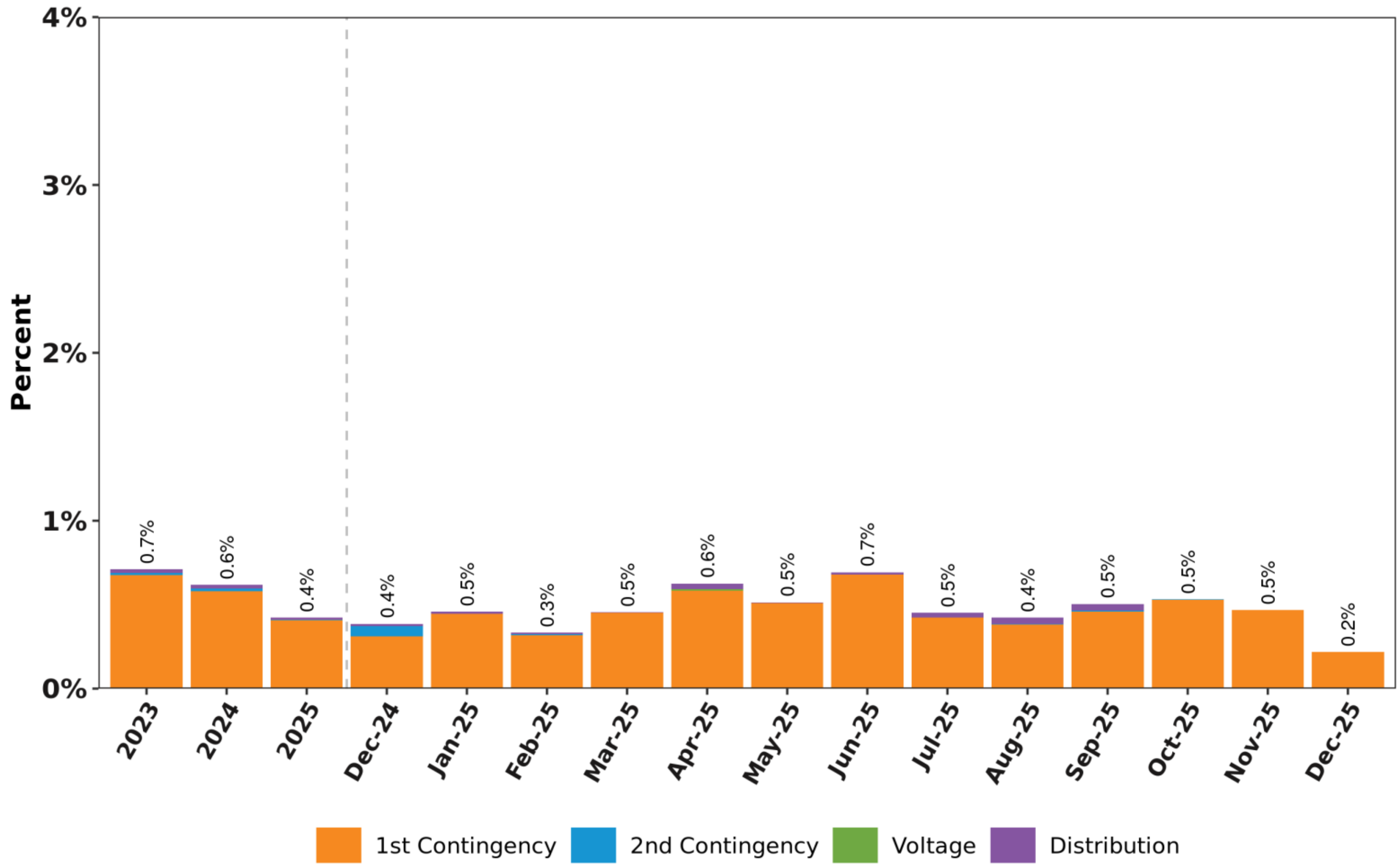


NCPC Charges by Type

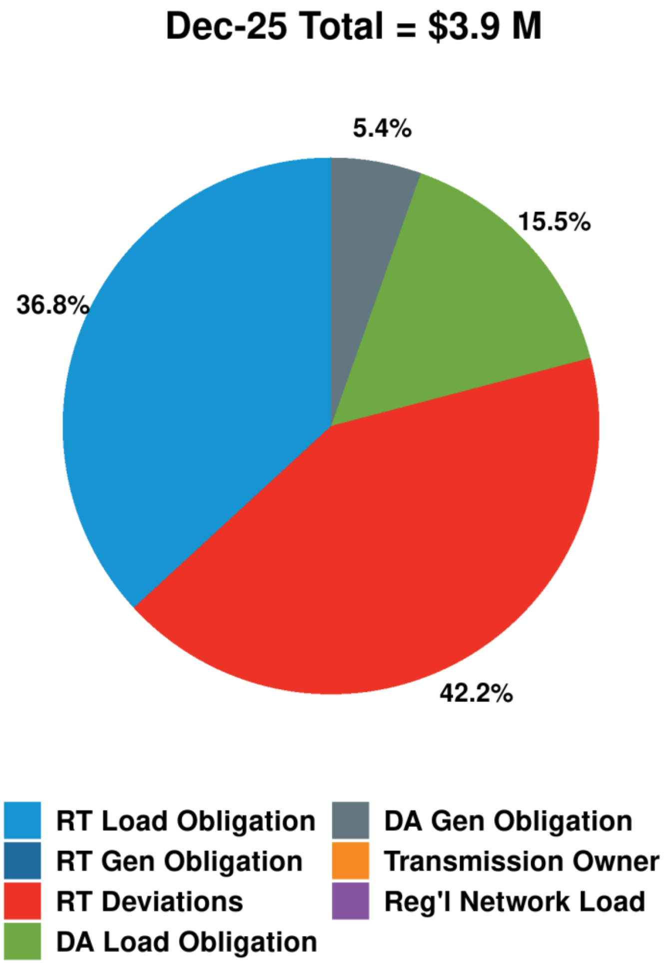


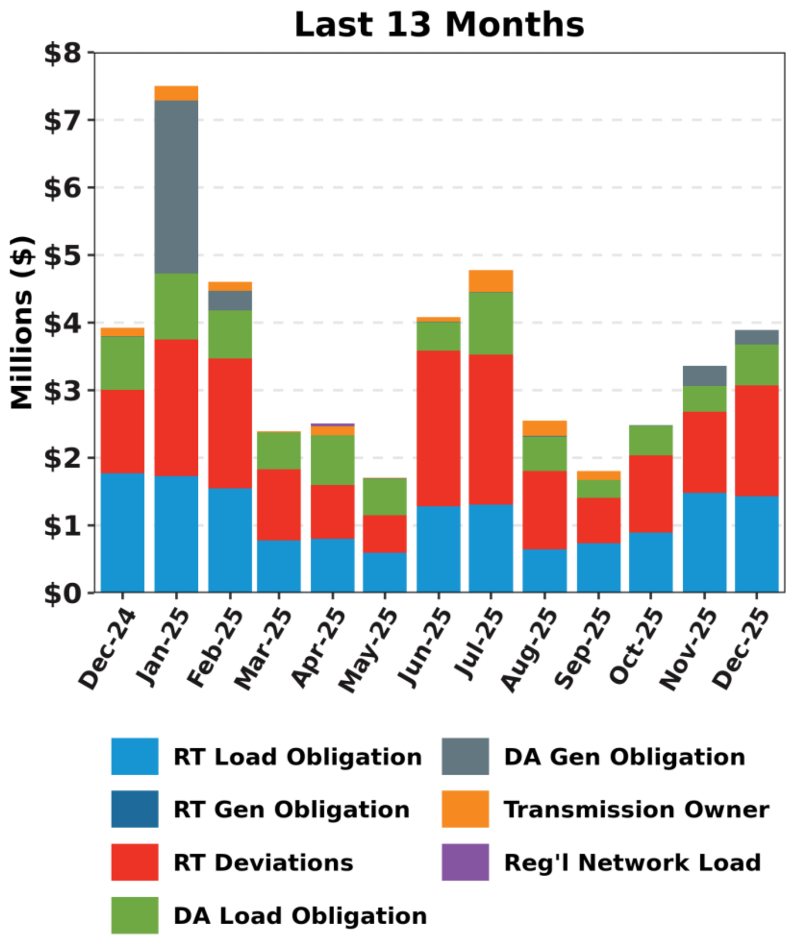


NCPC Charges by Type as Percent of Energy Market Value

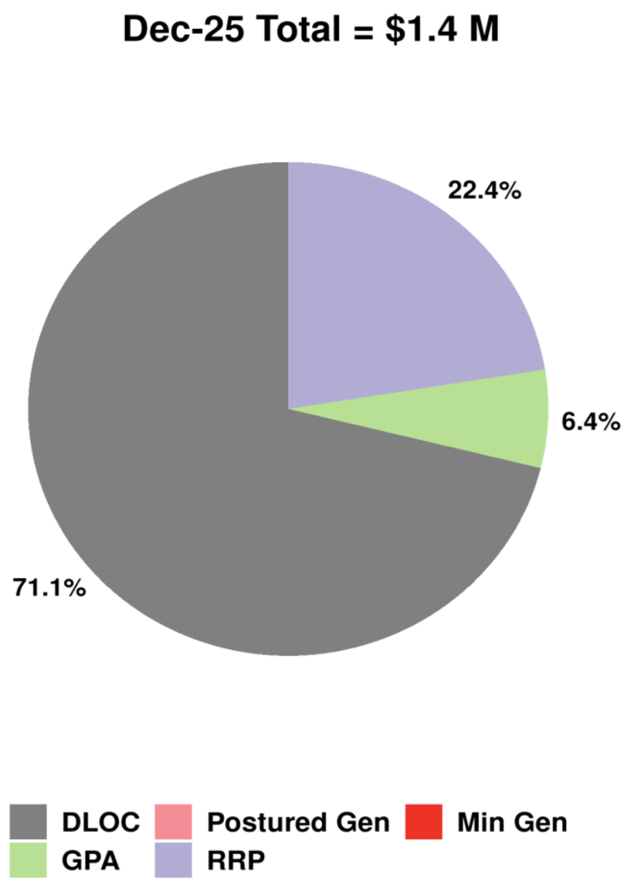


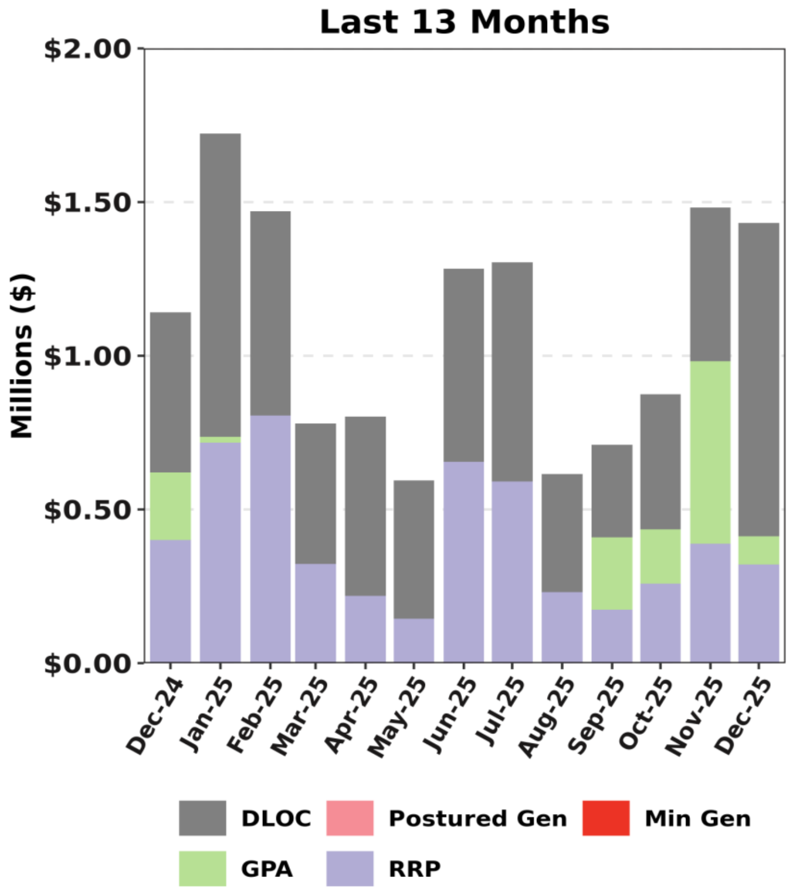
NCPC Charge Allocations





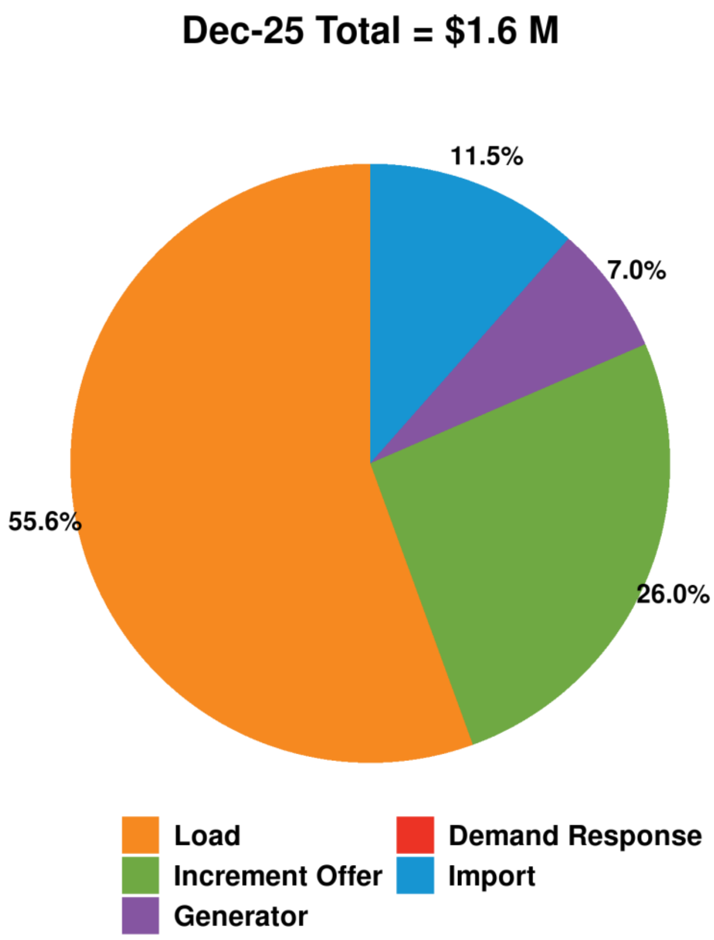
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

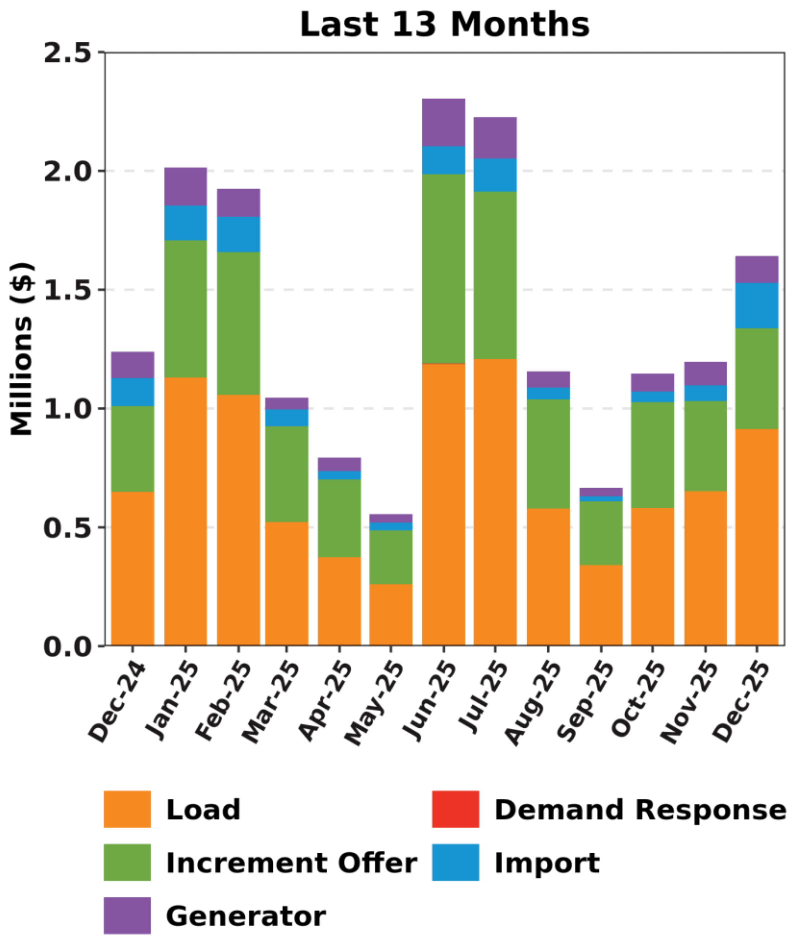




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

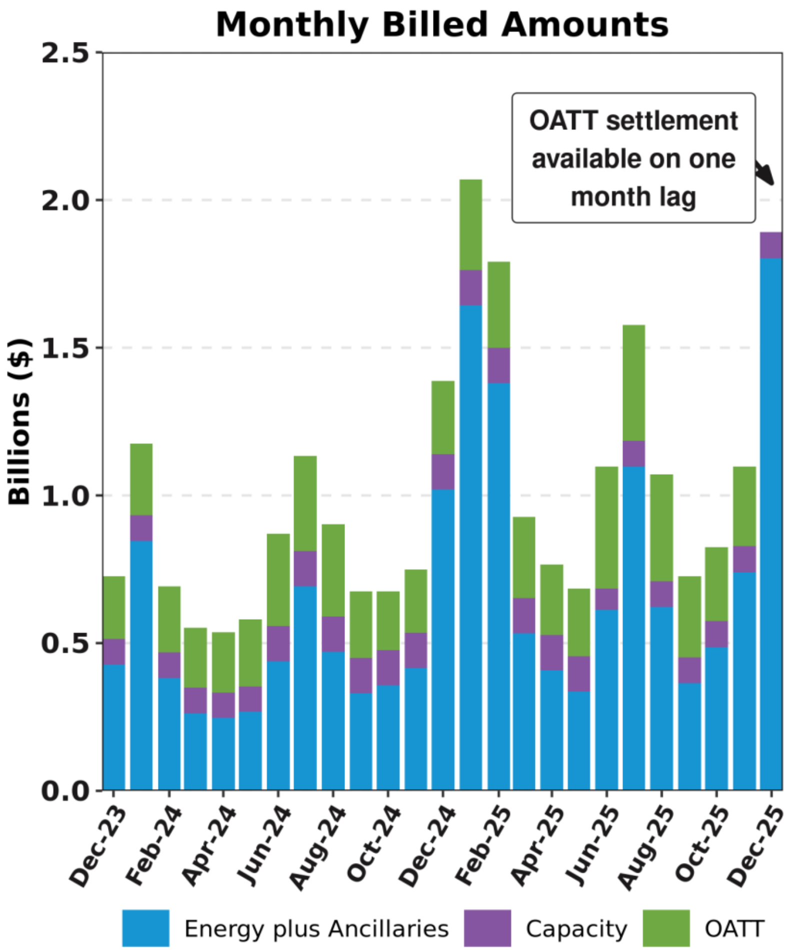
RT First Contingency Charges by Deviation Type

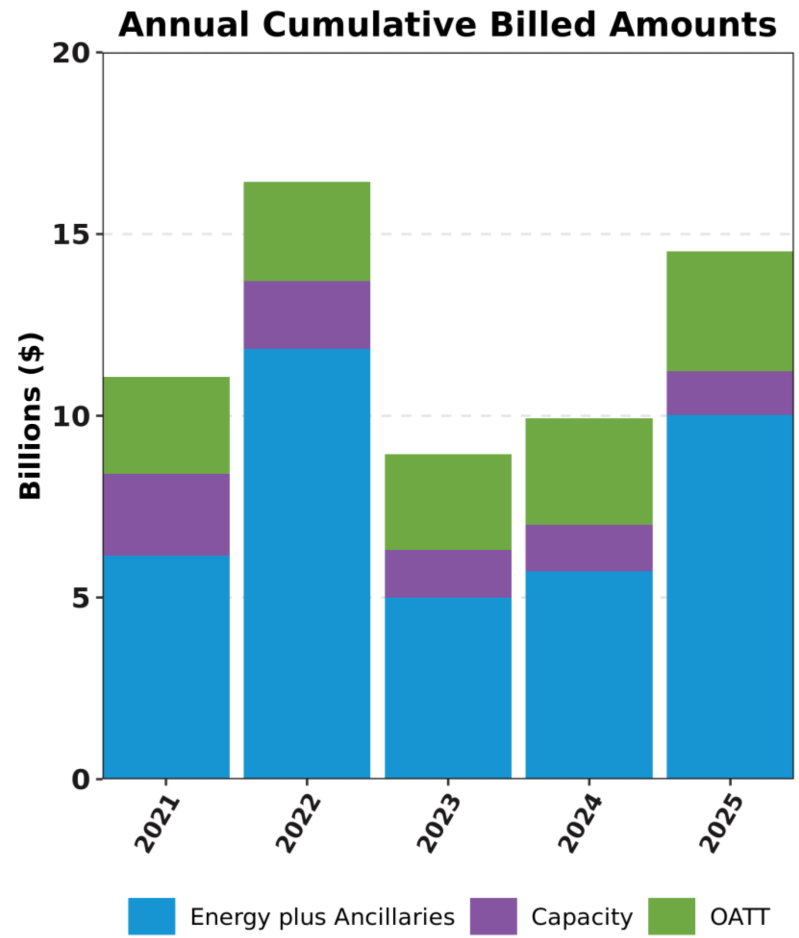




ISO BILLINGS

Total ISO Billings





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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

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

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

2025 Longer-Term Transmission Planning (LTTP) RFP

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

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

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

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

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

* Costs may include estimates for corollary upgrades

Economic Studies: 2024 Study

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

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

Note: The listings in this section focus on major transmission line construction and rebuilding.

SEMA/RI Reliability Projects

Status as of 12/29/2025

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Nov-25	4
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

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

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

SEMA/RI Reliability Projects, cont.

Status as of 12/29/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	May-22	4
1724	Replace the Kent County 345/115 kV transformer	Mar-22	4
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Upper Maine Solution Projects

Status as of 12/29/2025

Project Benefit: Addresses system needs in the Upper Maine area

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

Upper Maine Solution Projects, cont.

Status as of 12/29/2025

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Nov-24	4
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Jun-26	2

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

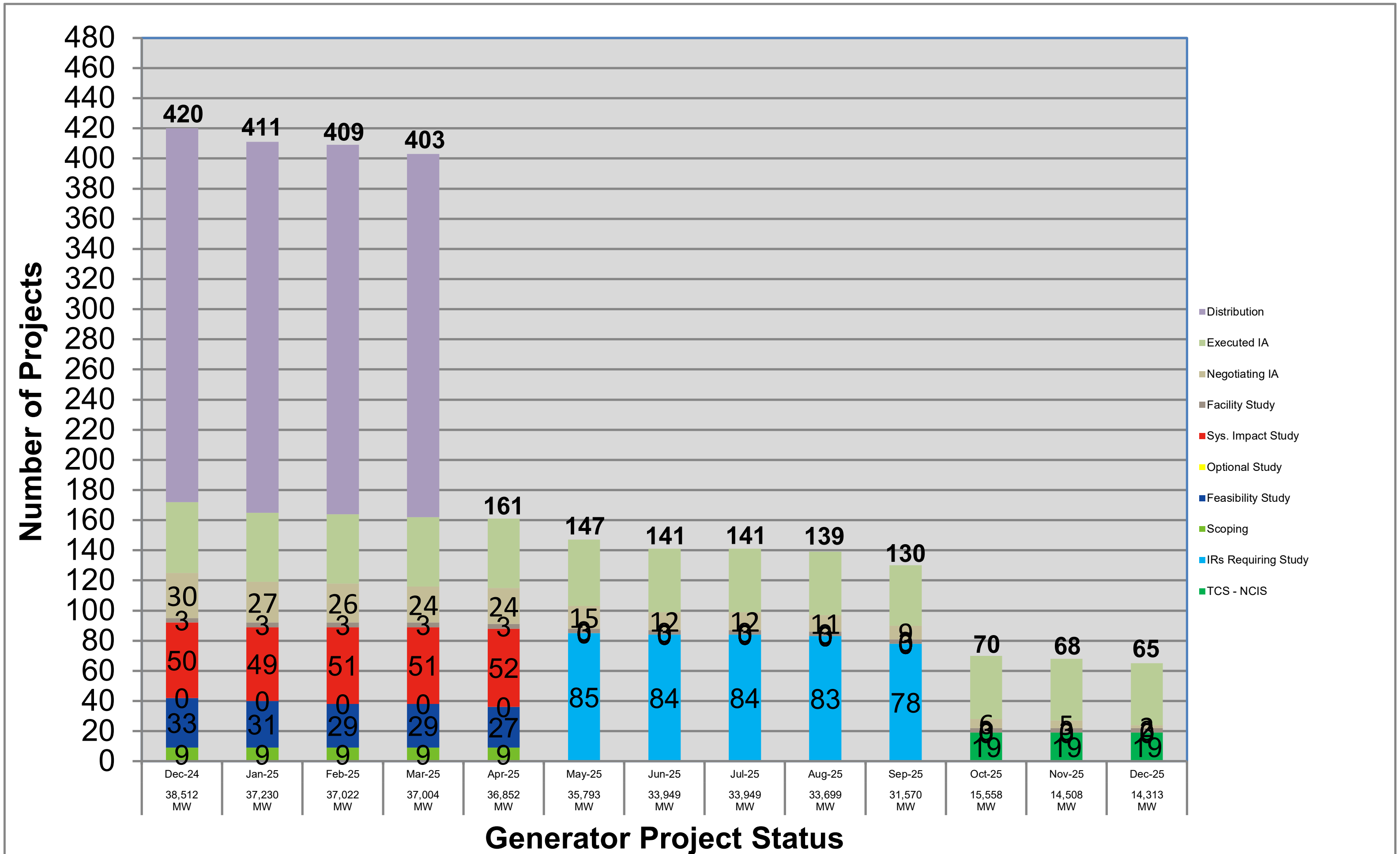
Boston 2033 Solutions Study

Status as of 12/29/2025

Project Benefit: Addresses system needs in the Boston area

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

Status of Tariff Studies as of December 29, 2025



ETUs: 0 in TCS – NCIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 0

https://irtt.iso-ne.com/external.aspx

Additional Notes provided on next slide

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

Additional Notes:

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

OPERABLE CAPACITY ANALYSIS

Winter 2026 Analysis

Winter 2026 Operable Capacity Analysis

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

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

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

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

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

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

Winter 2026 Operable Capacity Analysis

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

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

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

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

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

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

Winter 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 29, 2025 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in January through March.

Report created: 12/29/2025

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

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).

These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2025 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

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

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

Winter 2026 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

December 29, 2025 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in January through March.

Report created: 12/29/2025

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

Column Definitions

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

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

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	125 [3]

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

Possible Relief Under OP4: Appendix A

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

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