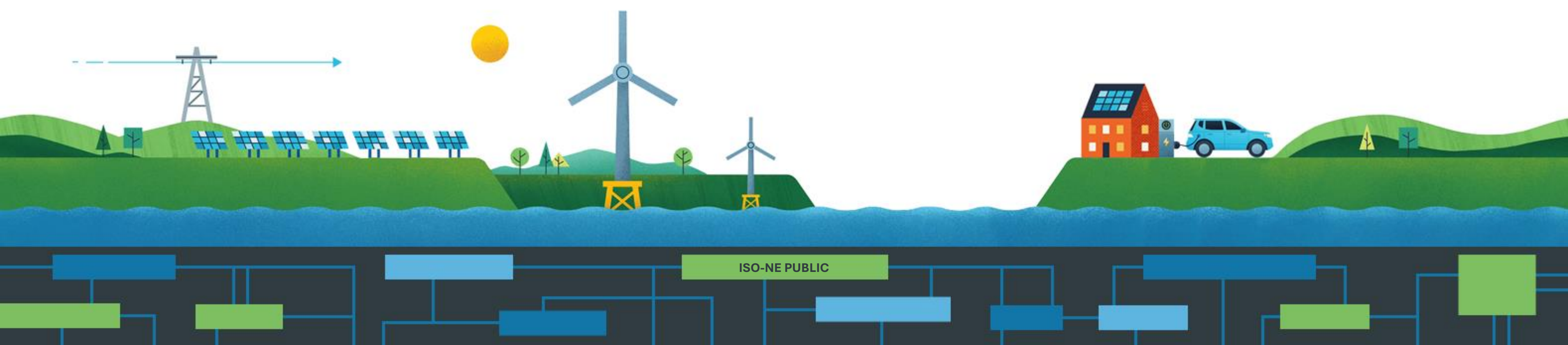
MAY 7, 2026| THE DELAMAR, WEST HARTFORD, CT

NEPOOL Participants Committee

System & Market Operations Report – May 2026

Stephen M. George

VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



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HIGHLIGHTS

Data through April 29th, unless otherwise noted

Highlights: April 2026

- **Peak Hour** on April 2
  - 15,021 MW system peak (Revenue Quality Metered/RQM); hour ending 8:00 p.m.
- **Minimum Telemetered Load**
  - 6,094 MW; hour ending 1:00 p.m. on Sunday, April 12
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $45.89/MWh
  - Real-Time (RT) Hub LMP: $45.50/MWh
  - Natural Gas: $2.31/MMBtu (MA Natural Gas Avg)
- **Energy Market** value $439M up from $400M in April 2025
  - Ancillary Markets* value $2.5M down from $7.3M in April 2025
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 99.4% during April, down from 99.7% during March
  - Updated March Energy Market value: $533M
- **Net Commitment Period Compensation (NCPC)** total $2.8M
  - Represents 0.6% of monthly Energy Market value
  - First Contingency $2.7M
    - Dispatch Lost Opportunity Cost (DLOC) - $609K; Rapid Response Pricing (RRP) Opportunity Cost - $276K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $9K paid to resources at external locations, down $1K from March
      - $6K charged to Day-Ahead Load Obligation (DALO) at external locations; $0 to Day-Ahead Generation Obligation (DAGO) at external locations; $3K to RT Deviations
  - Second Contingency $117K (Protection for SEMA or the East early in the month)
  - Distribution $30K
  - Voltage <$1K
- **Forward Capacity Market (FCM)** market value $88.8M
  - FCM peak for 2026 is currently 19,937 MW

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. 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**
  - hour ending 2:00 p.m. on Sunday, January 25
- FCM Peak Load: **19,937 MW**
  - 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: **$15.2M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$461K**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$2.15/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **0.8%**
- FER Credits* as % of total DA E&AS Market Value: **4.3%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **83 MWh**
  - Average hourly cleared FER Price: **$2.37/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)

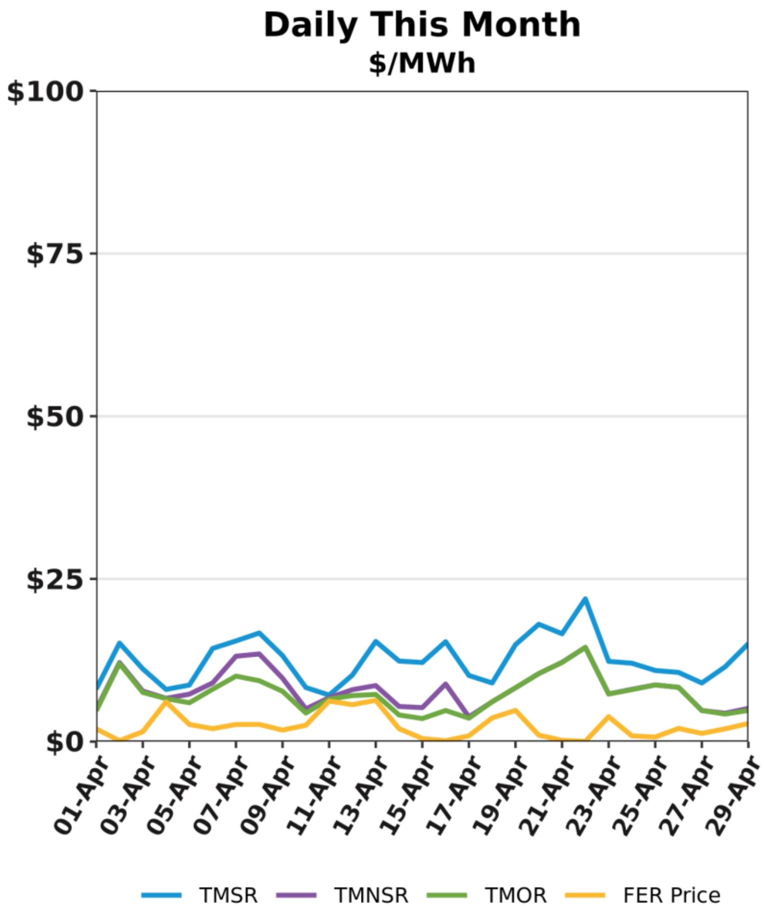
DAAS Results (continued)...

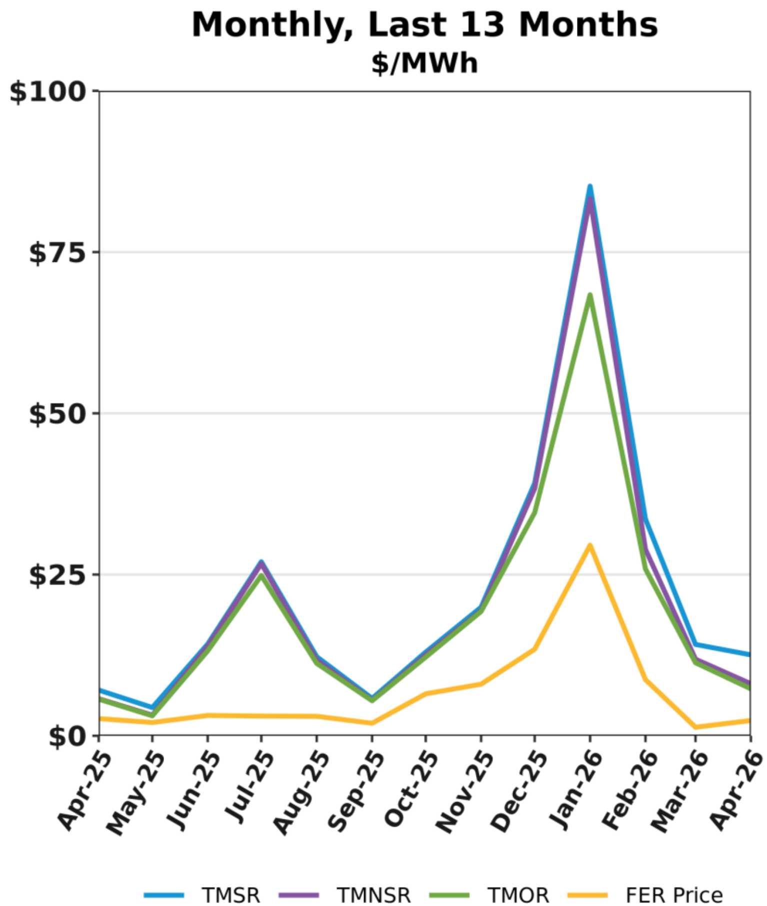
Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg. Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
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	$55.1M	$1,678K	$857K	$14.78	1.6%	$3,369K	157K	$8.70	6.1%	104
03/01/2026	$17.4M	$667K	$357K	$6.43	2.1%	$422K	91K	$1.32	2.4%	32
04/01/2026	$15.2M	$461K	$115K	$2.15	0.8%	$650K	108K	$2.37	4.3%	83

About the Table:
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)
- *'Avg Daily Energy MWh Paid FER Price' reflects Cleared DA Physical Gen and DRR MWh during non-zero FER prices

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

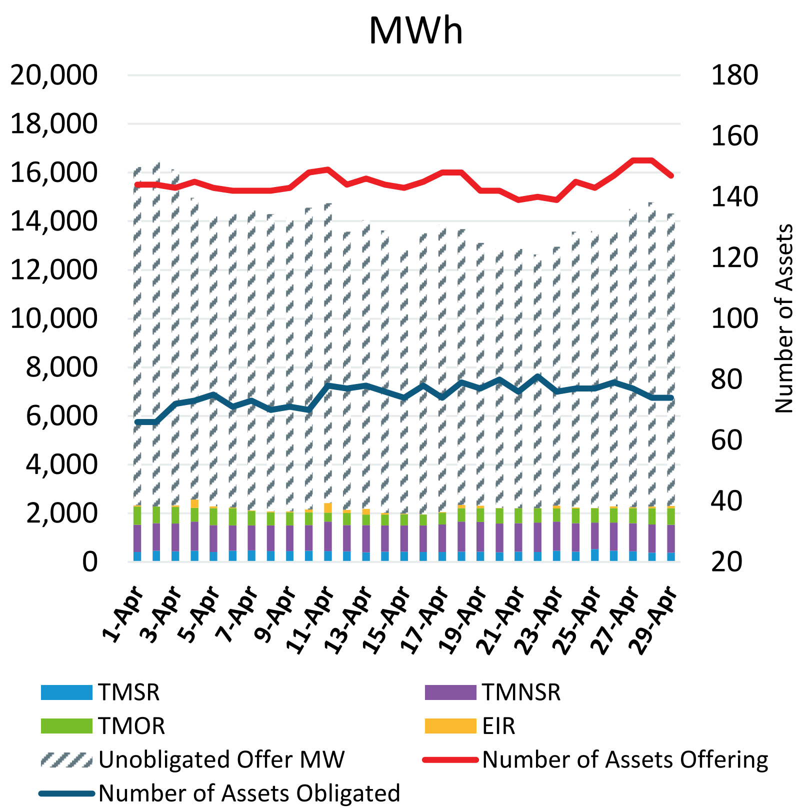
Average Hourly DAAS Prices



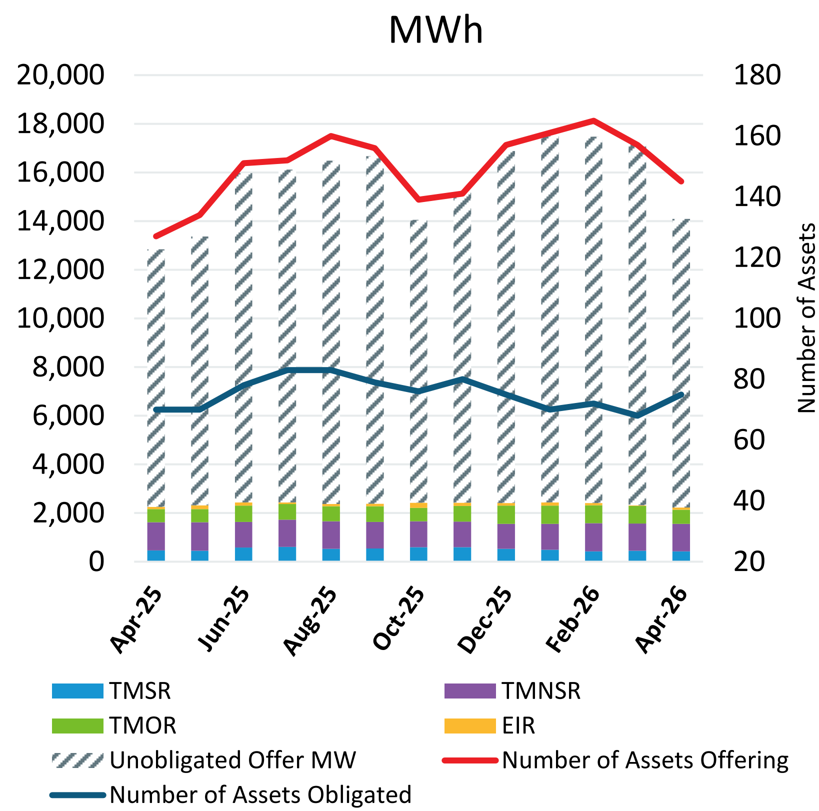


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



Monthly, Last 13 Months



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

System Planning Highlights

- 2026 CELT Report was published on May 1
- The next 2025 Longer-Term Transmission Planning (LTTP) RFP update is scheduled for the May 27 PAC 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) was held March 2-4, 2026. Results were posted on March 31, 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 (SOI) window for the 2026 interim RA qualification process opened on April 16, 2026 and closed on April 30, 2026
      - 53 SOIs totaling 4,872 MW of requested summer QC were submitted
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

Load Forecast

- The 2026 CELT Report was published on May 1

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-0.1°F) Max: 78°F, Min: 29°F Precipitation: 1.47" – Below Normal Normal: 3.63"	Hartford	Temperature: Above Normal (2.2°F) Max: 90°F, Min: 24°F Precipitation: 3.03" - Below Normal Normal: 3.88"

Peak Load:	14,969 MW	April 2, 2026	20:00 (ending)
Mid-Day Minimum Load - Month:	6,094 MW	April 12, 2026	13:00 (ending)
Mid-Day Minimum Load - Historical:	5,318 MW	April 20, 2025	14:00 (ending)

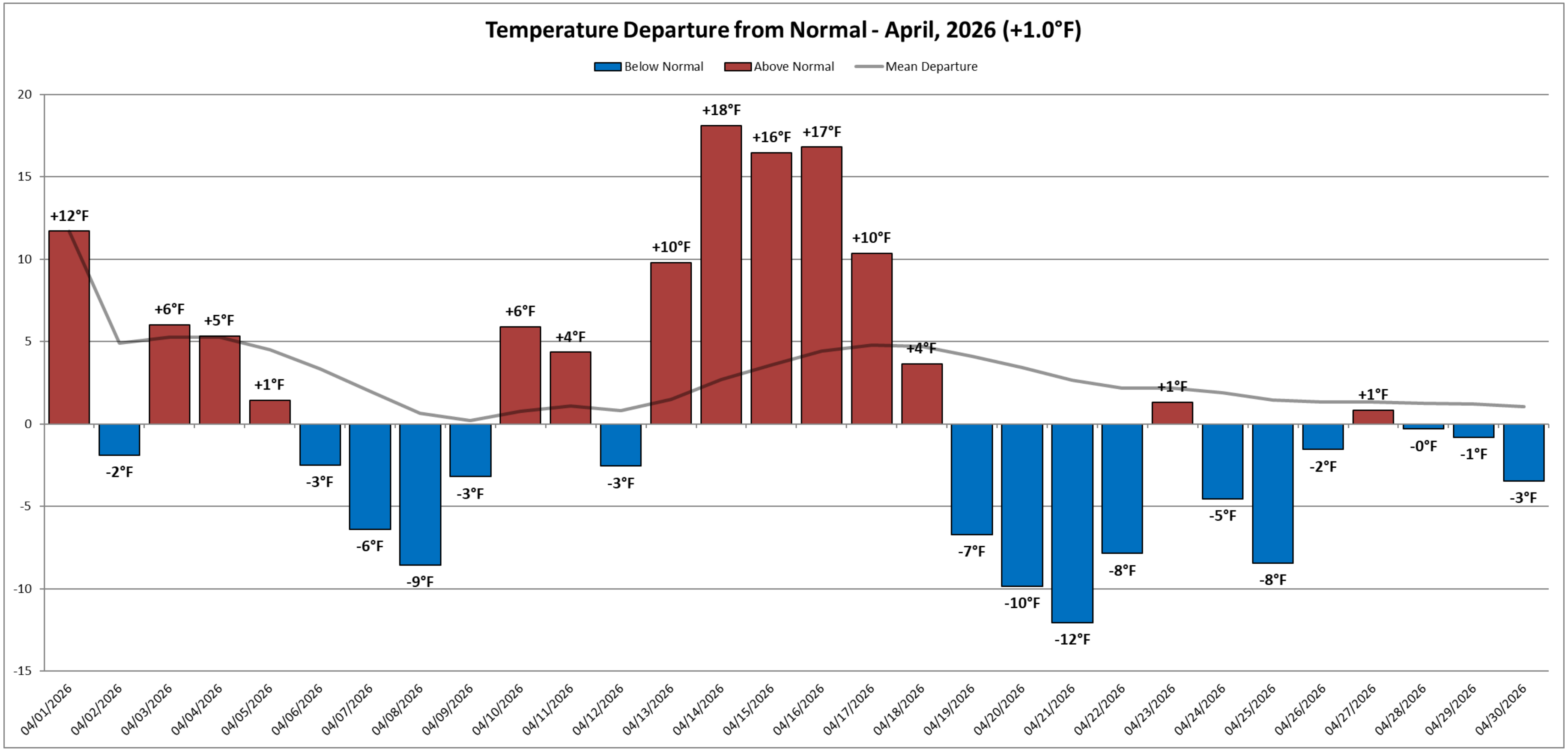
Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
NONE			

- Wind Generation Forecast Error Statistics (updated monthly)
- Solar Power Forecast Error Statistics, front-of-meter only (updated monthly)

System Operations

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

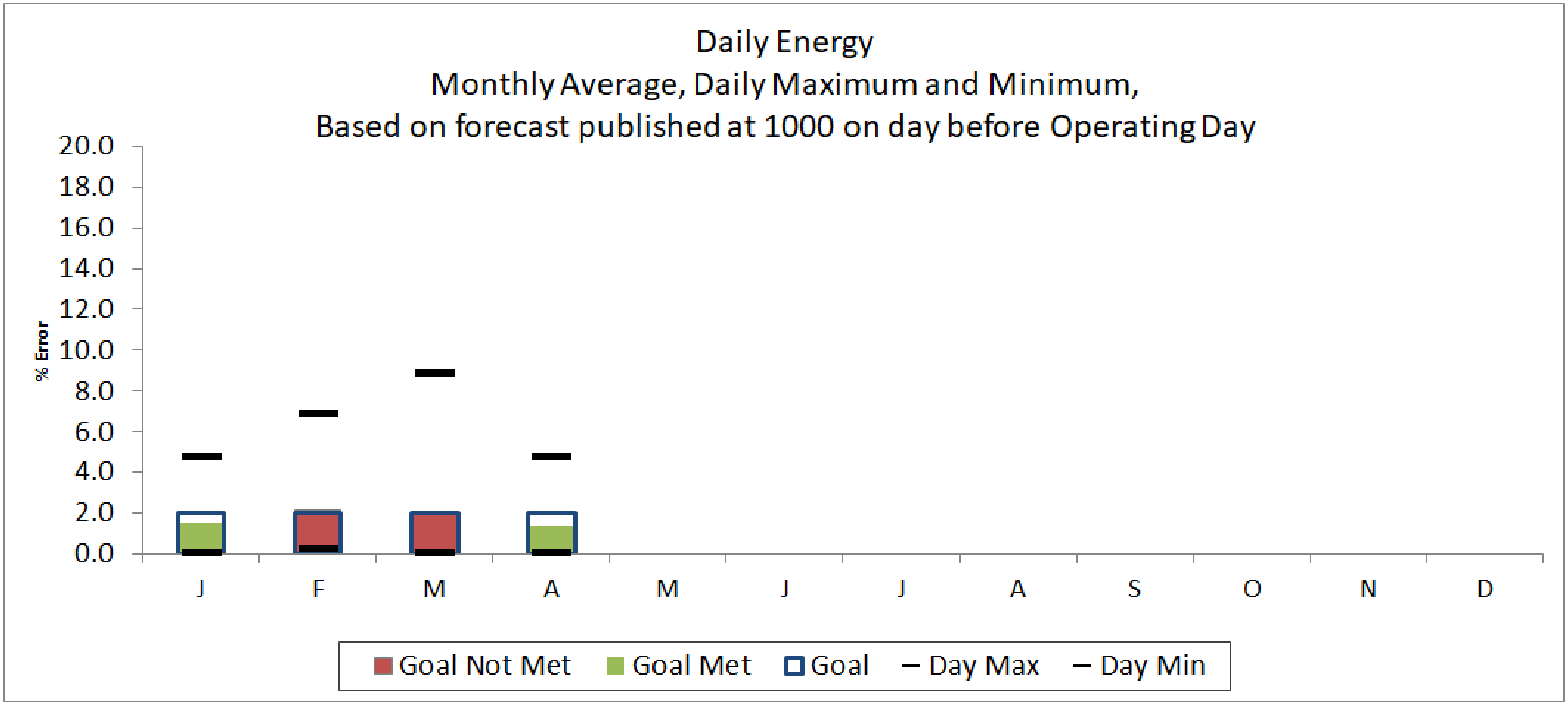


System Operations

NPCC Simultaneous Activation of Ten-Minute Reserve Events

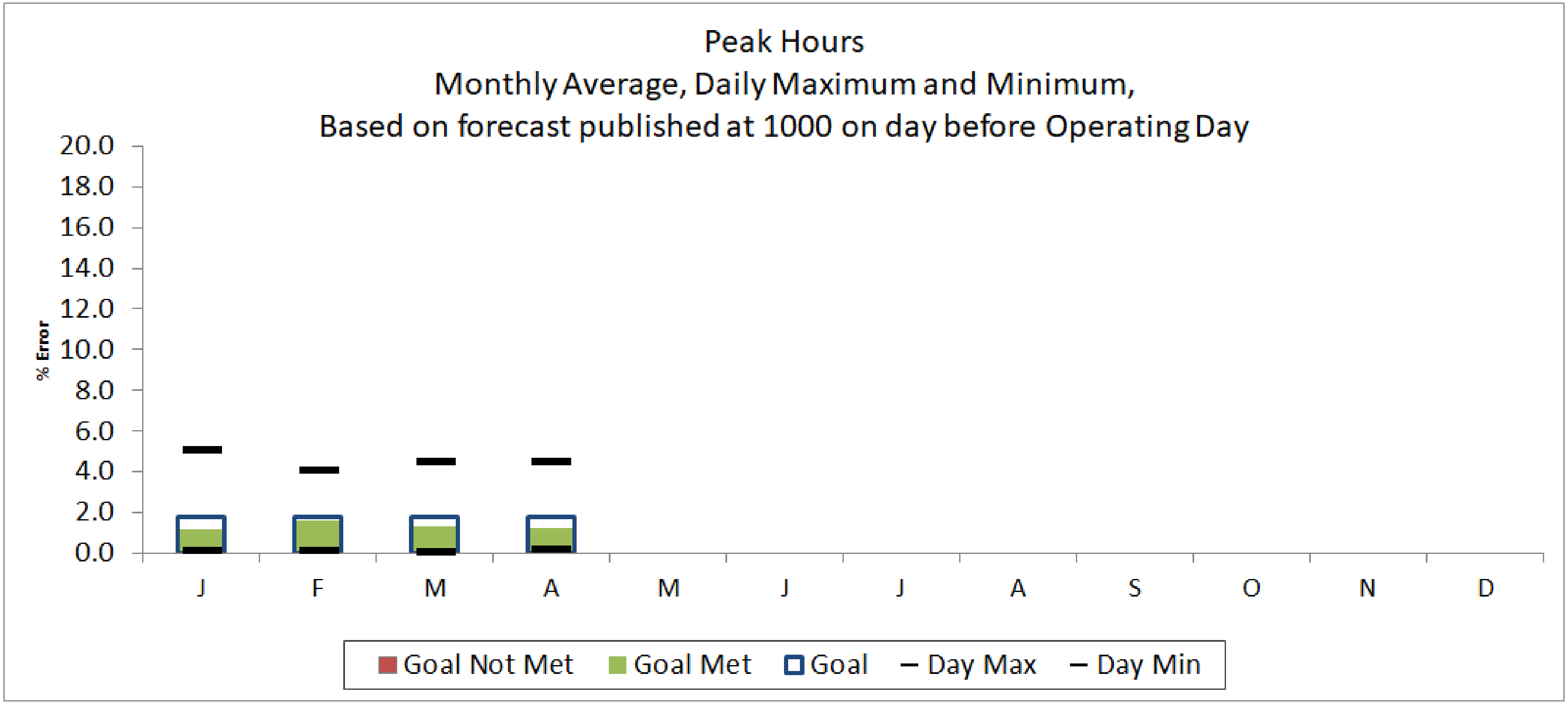
Date	Area	MW Lost
04/28/2026	ISO-NE	1120

2026 System Operations - Load Forecast Accuracy



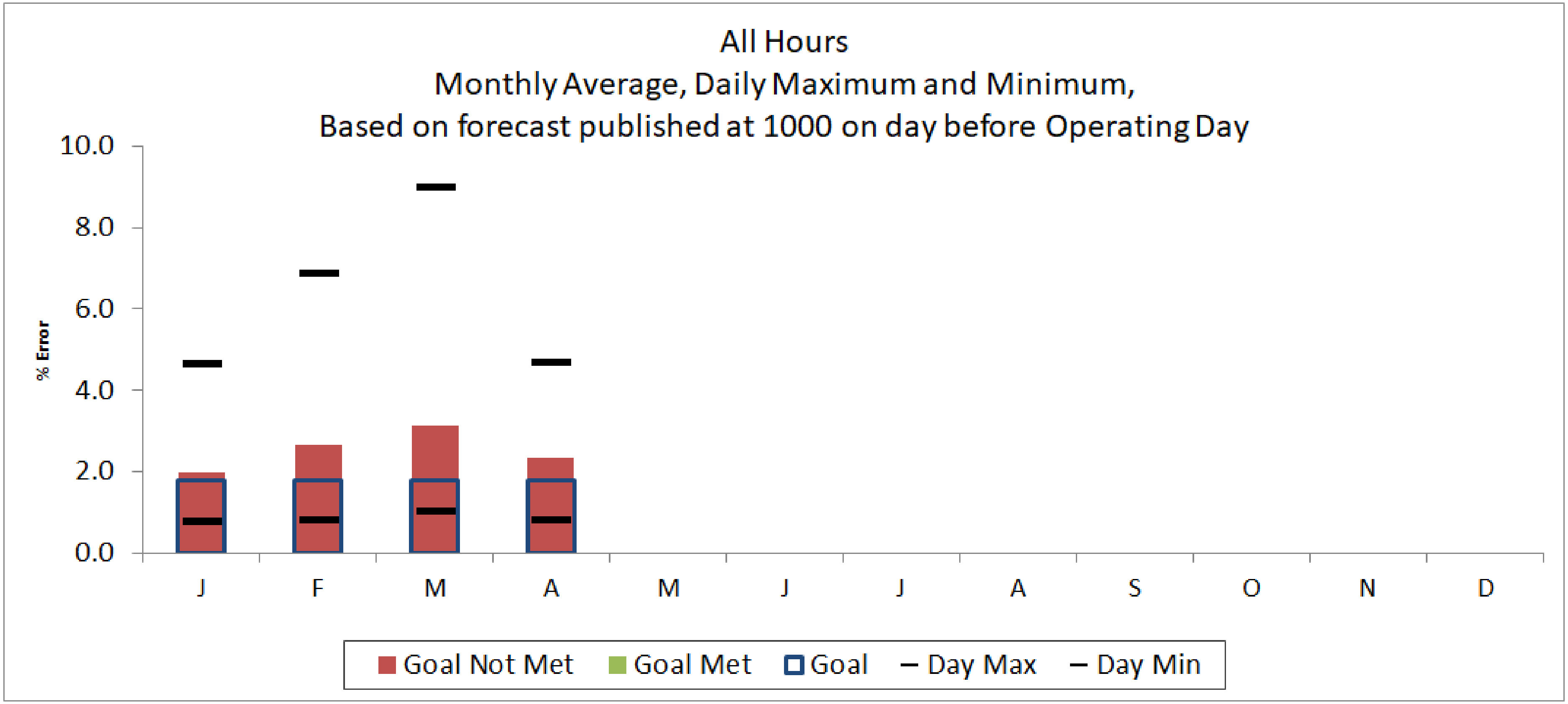
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81	8.85	4.75									8.85
Day Min	0.01	0.22	0.03	0.00									0.00
MAPE	1.57	2.12	2.11	1.42									1.80
Goal	2.00	2.00	2.00	2.00									

2026 System Operations - Load Forecast Accuracy cont.



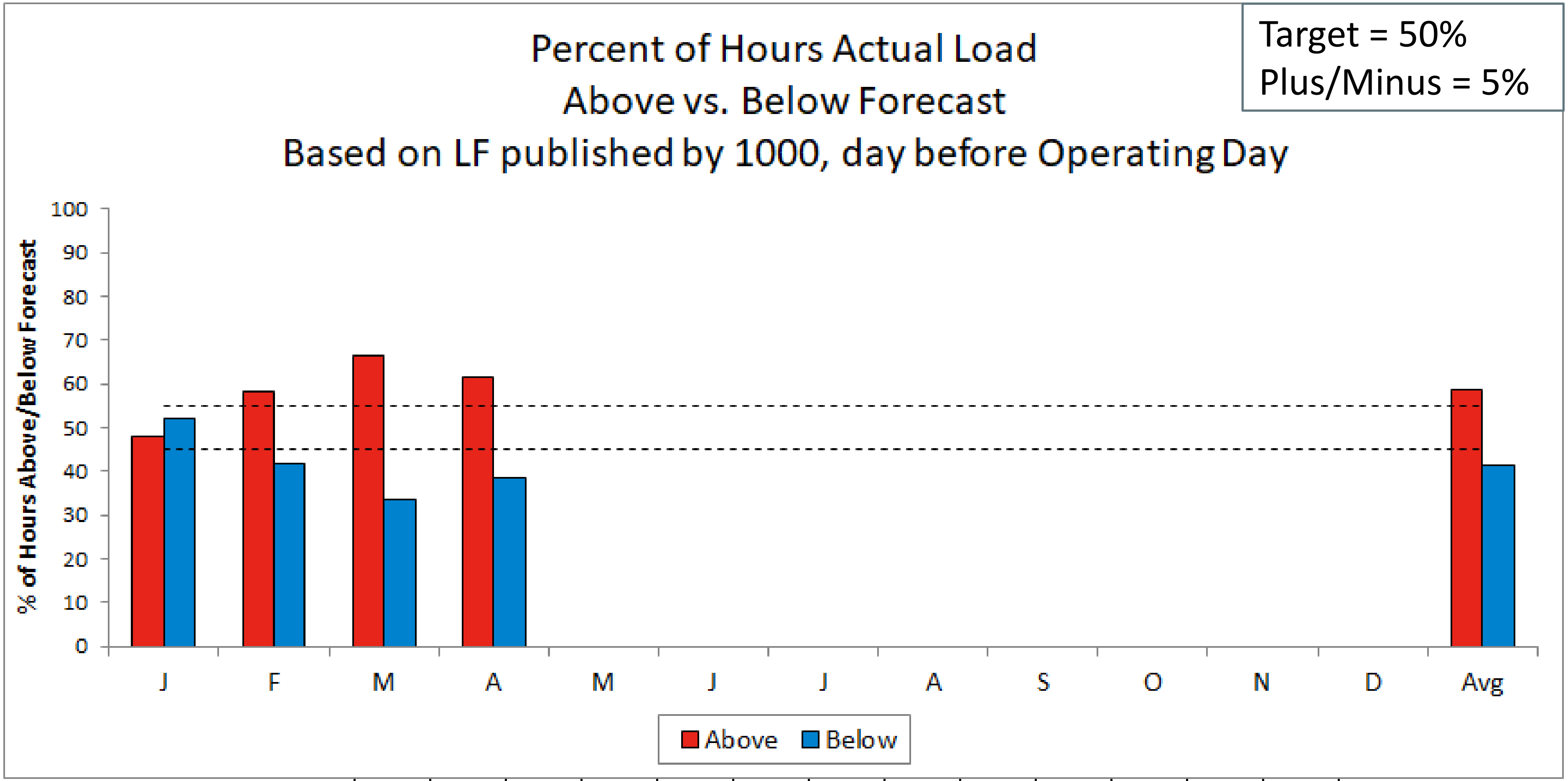
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02	4.51	4.51									5.05
Day Min	0.08	0.12	0.01	0.16									0.01
MAPE	1.17	1.64	1.34	1.24									1.34
Goal	1.80	1.80	1.80	1.80									

2026 System Operations - Load Forecast Accuracy cont.



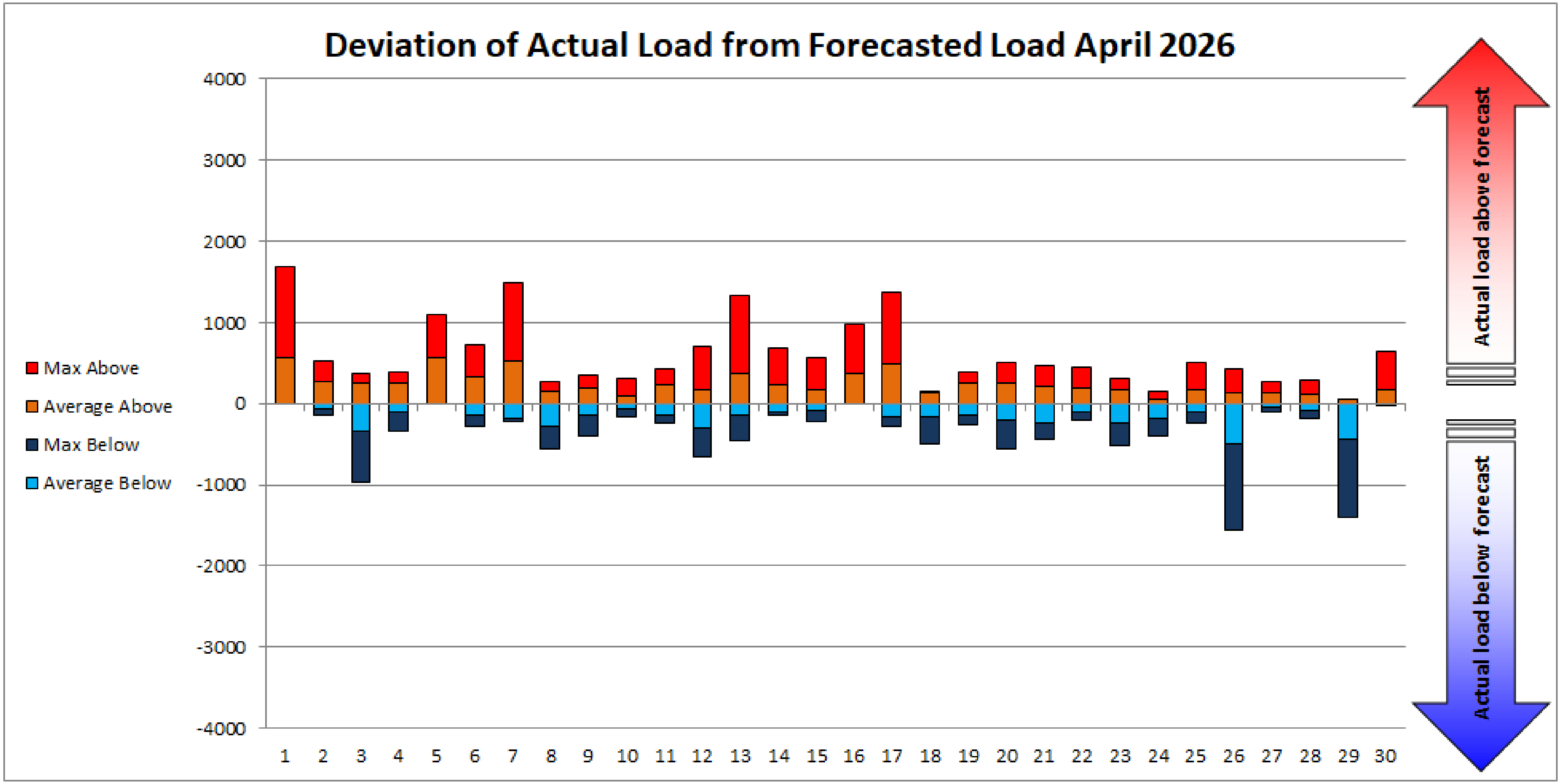
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65	6.85	8.96	4.67									8.96
Day Min	0.76	0.82	1.01	0.80									0.76
MAPE	2.00	2.66	3.14	2.33									2.53
Goal	1.80	1.80	1.80	1.80									

2026 System Operations - Load Forecast Accuracy cont.



Above %	47.8	58.2	66.4	61.4									58
Below %	52.2	41.8	33.6	38.6									42
Avg Above	203	299.6	325	240.4									325
Avg Below	-233.3	-271.5	-290.0	-157.2									-290
Avg All	-20	59	130	91									65

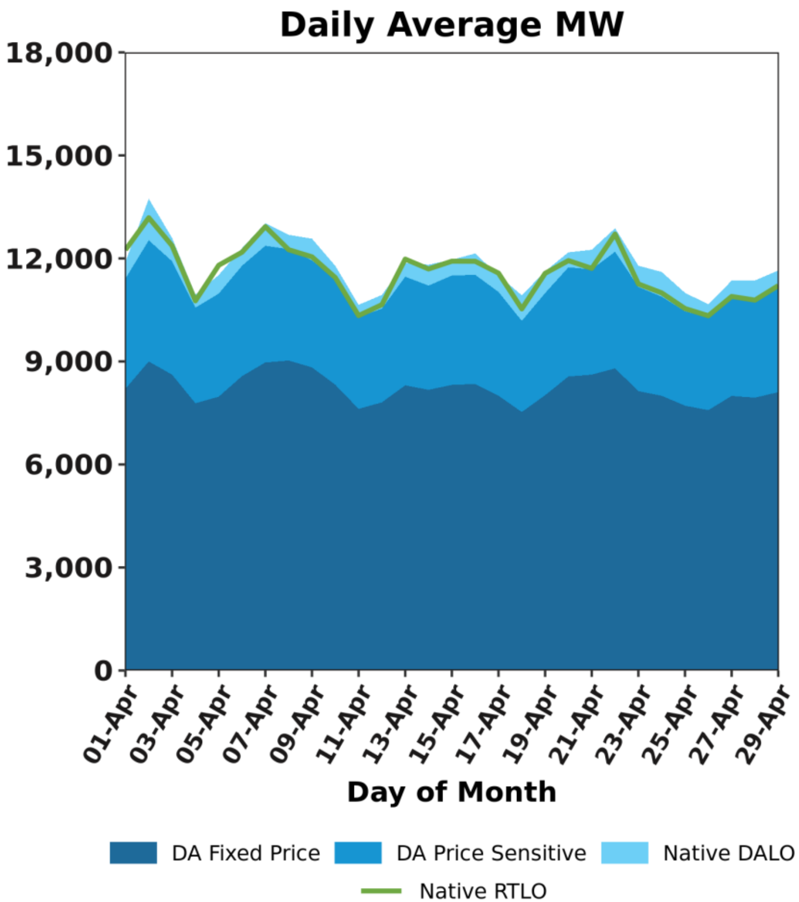
2026 System Operations - Load Forecast Accuracy cont.

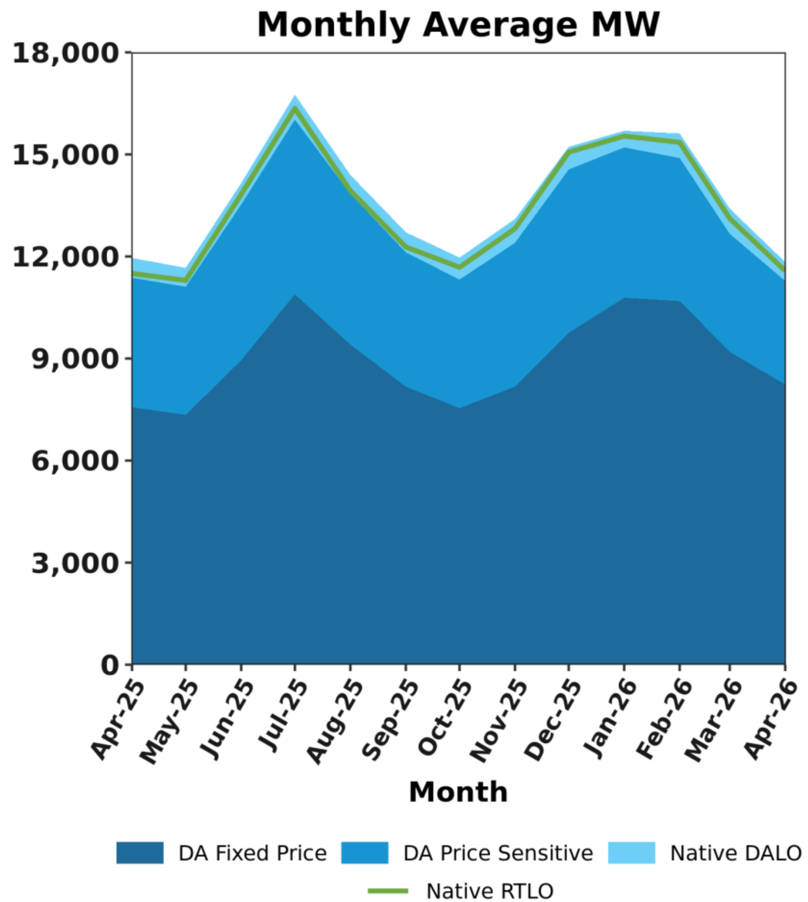


MARKET OPERATIONS

Supply and Demand Volumes

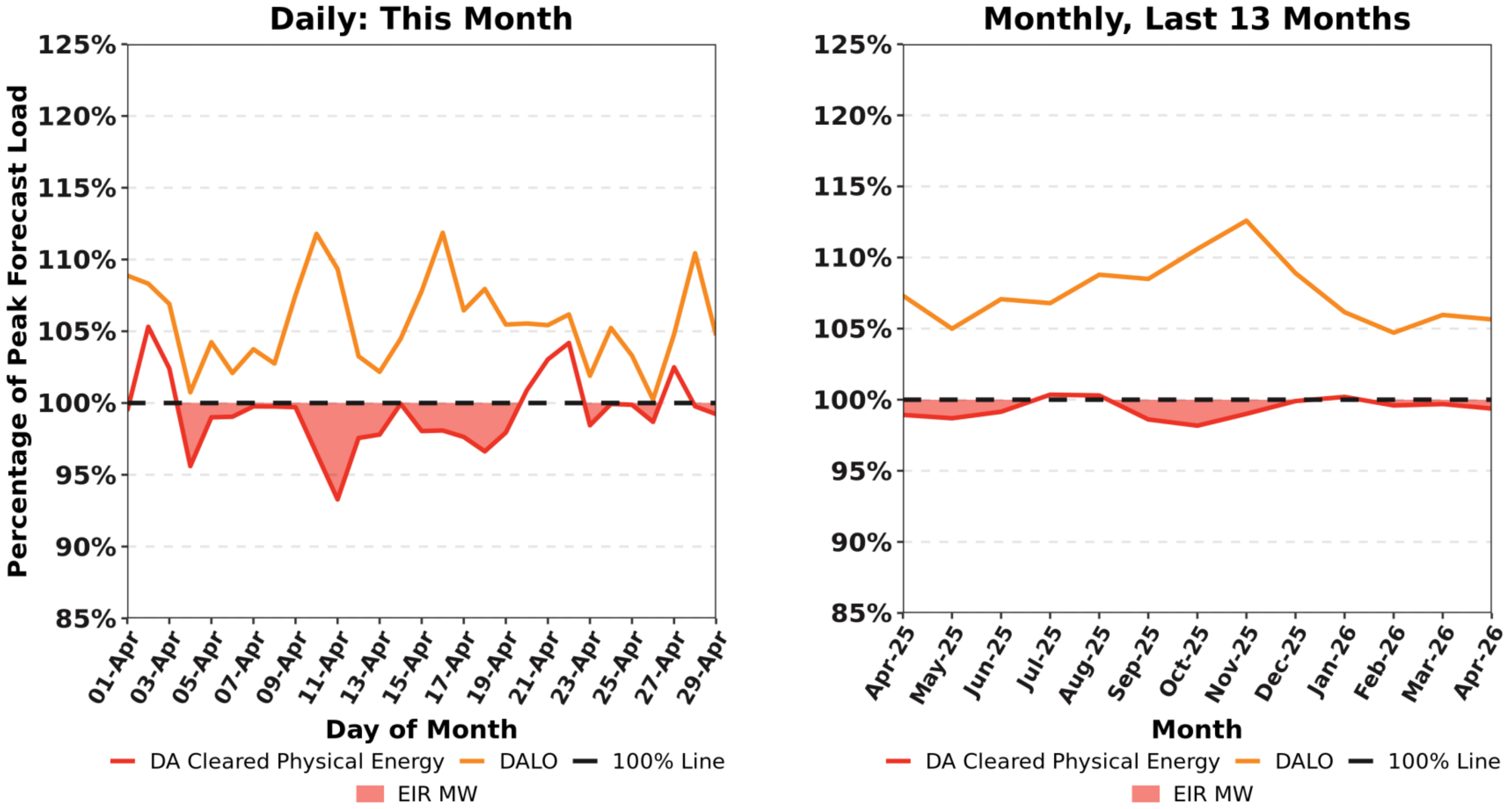
DA Cleared Native Load by Composition Compared to Native RT Load





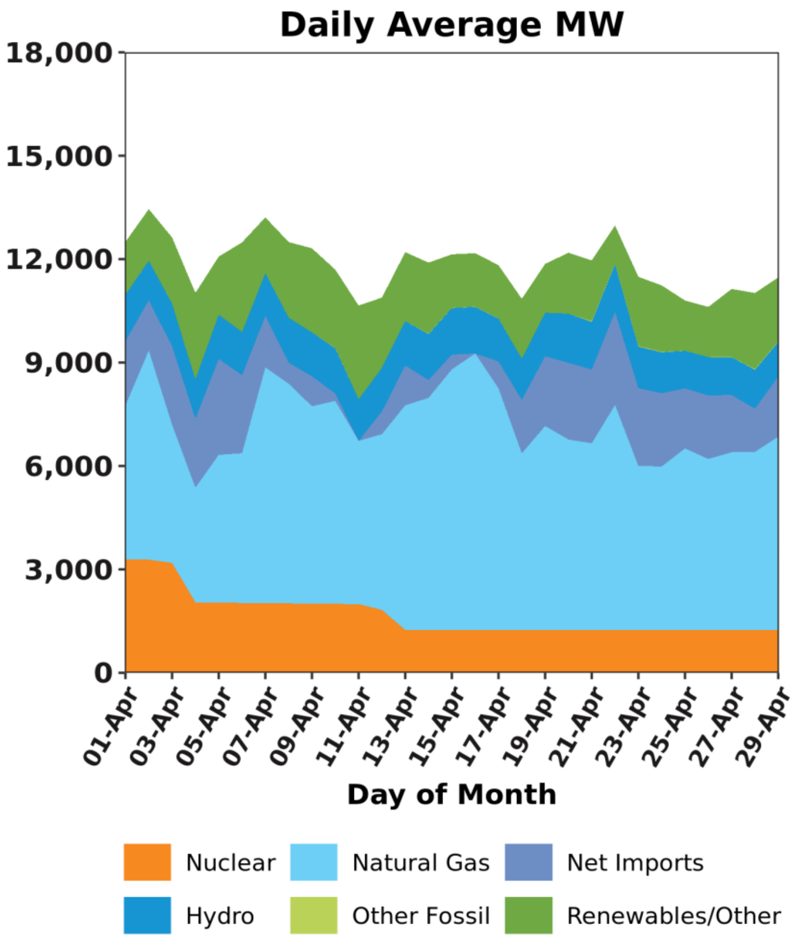
Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

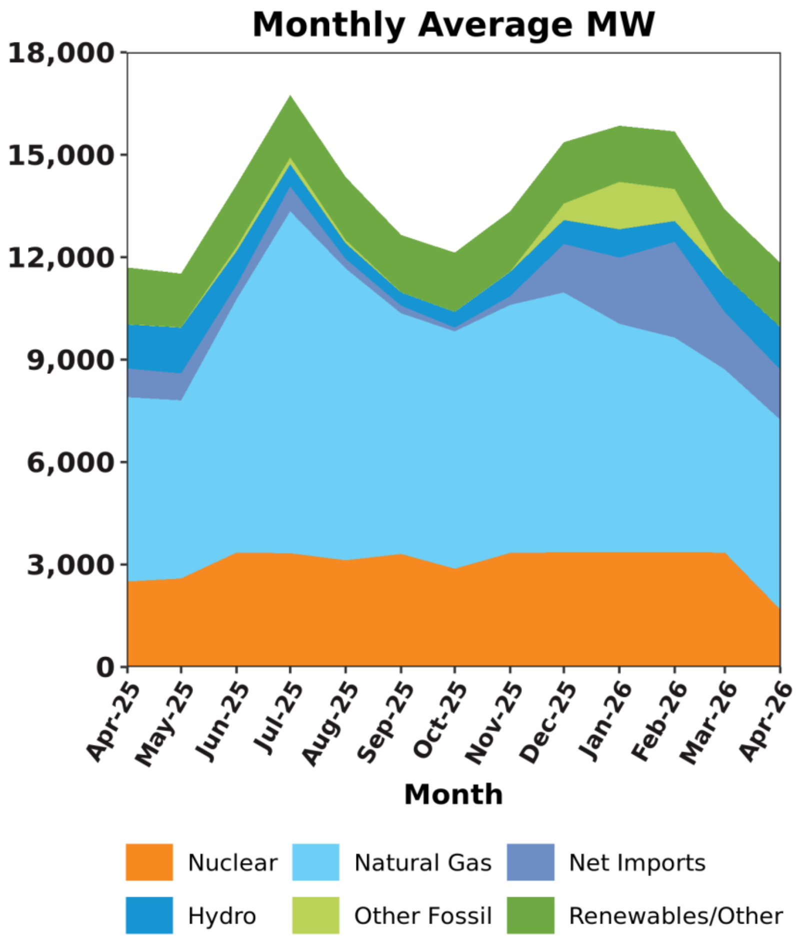
DA Volumes as % of Forecast in Peak Hour



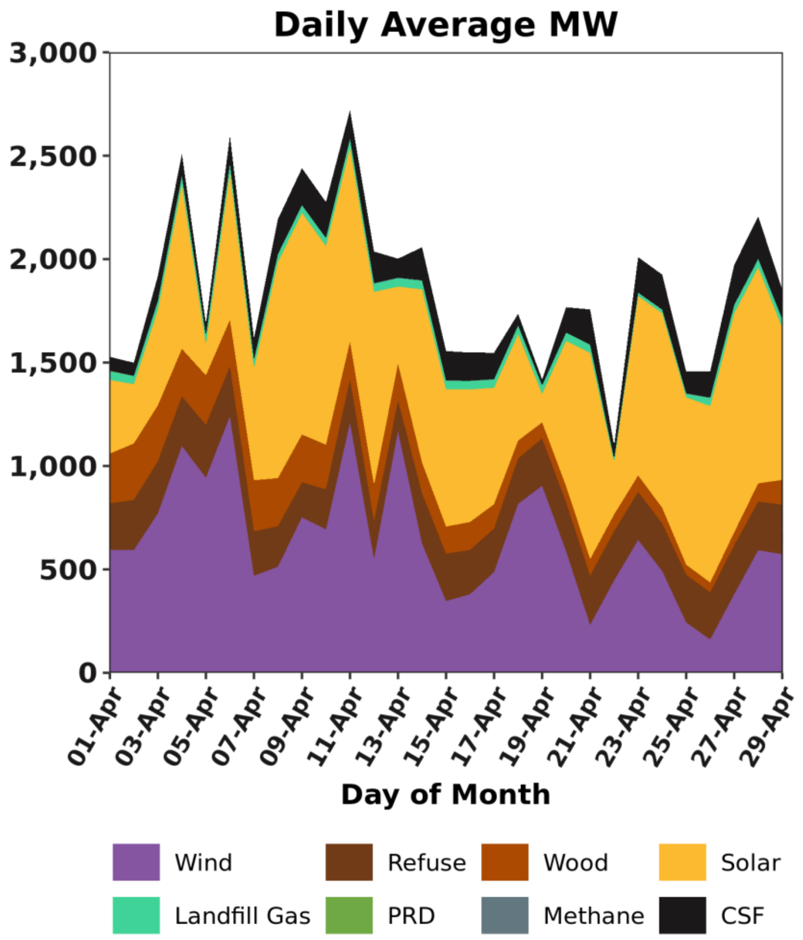
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

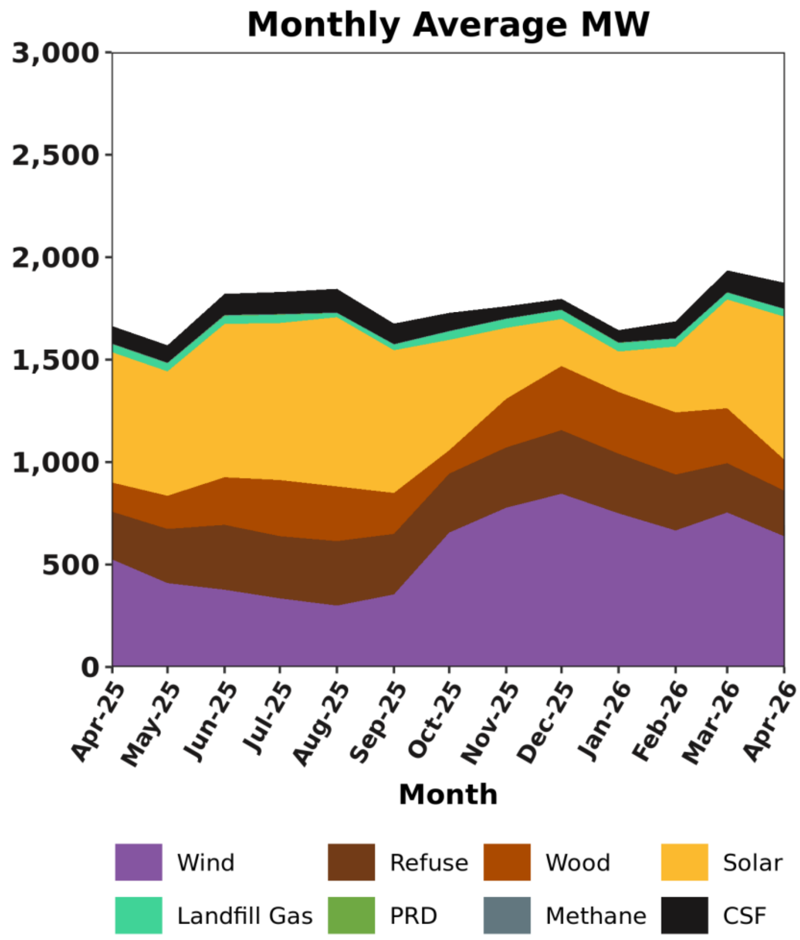
Resource Mix





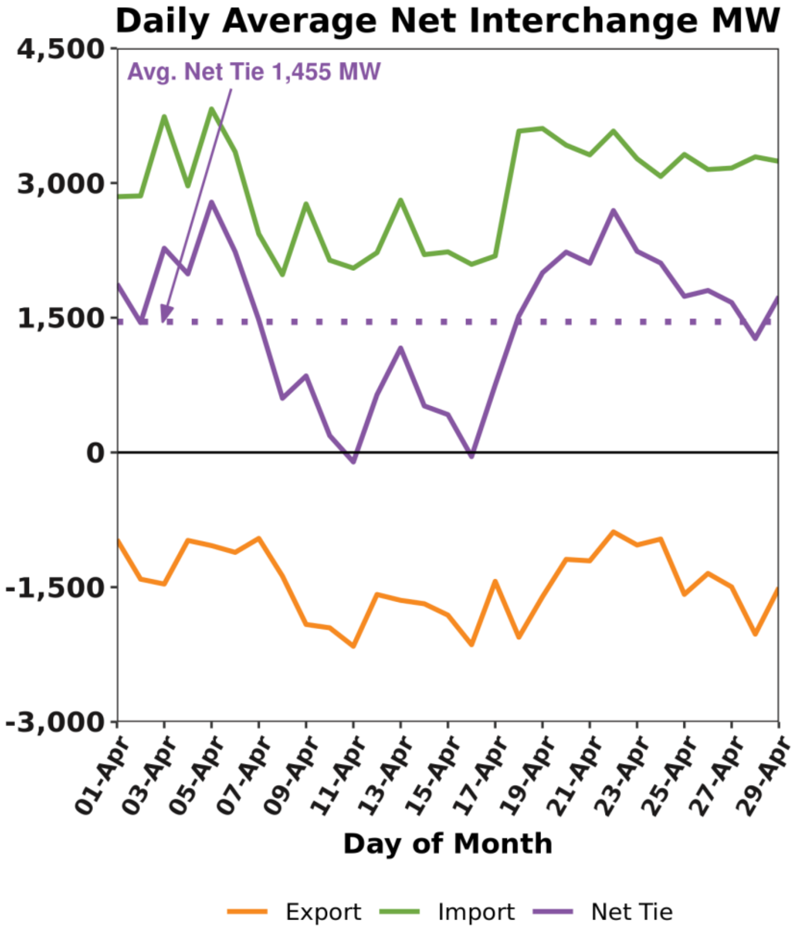
Renewable Generation by Fuel Type

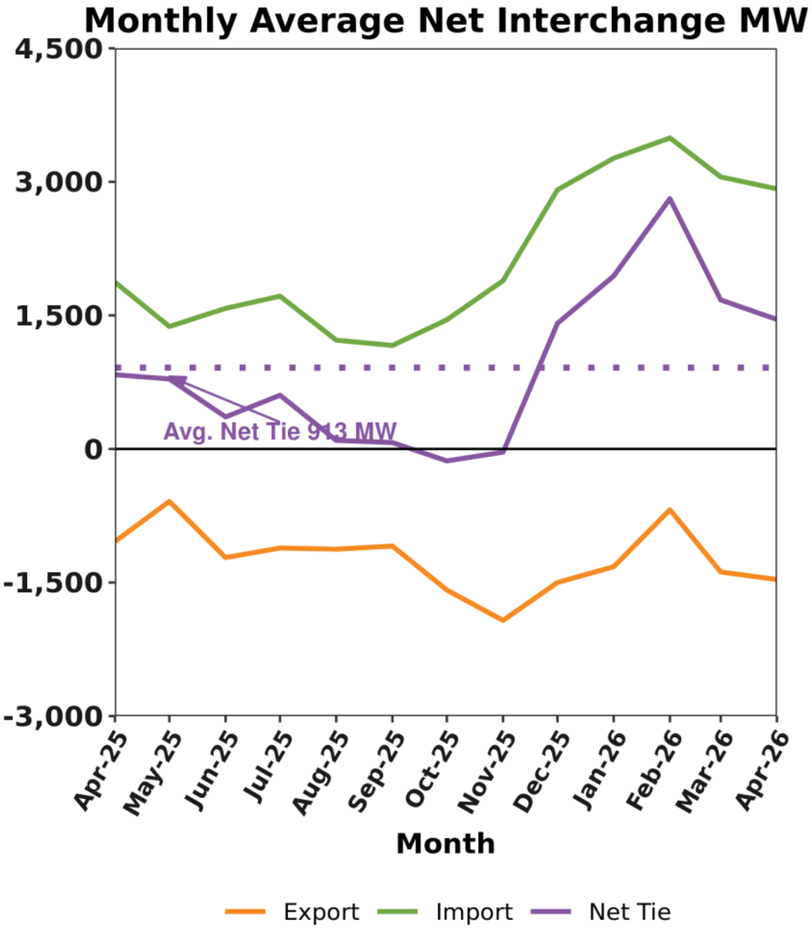




CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

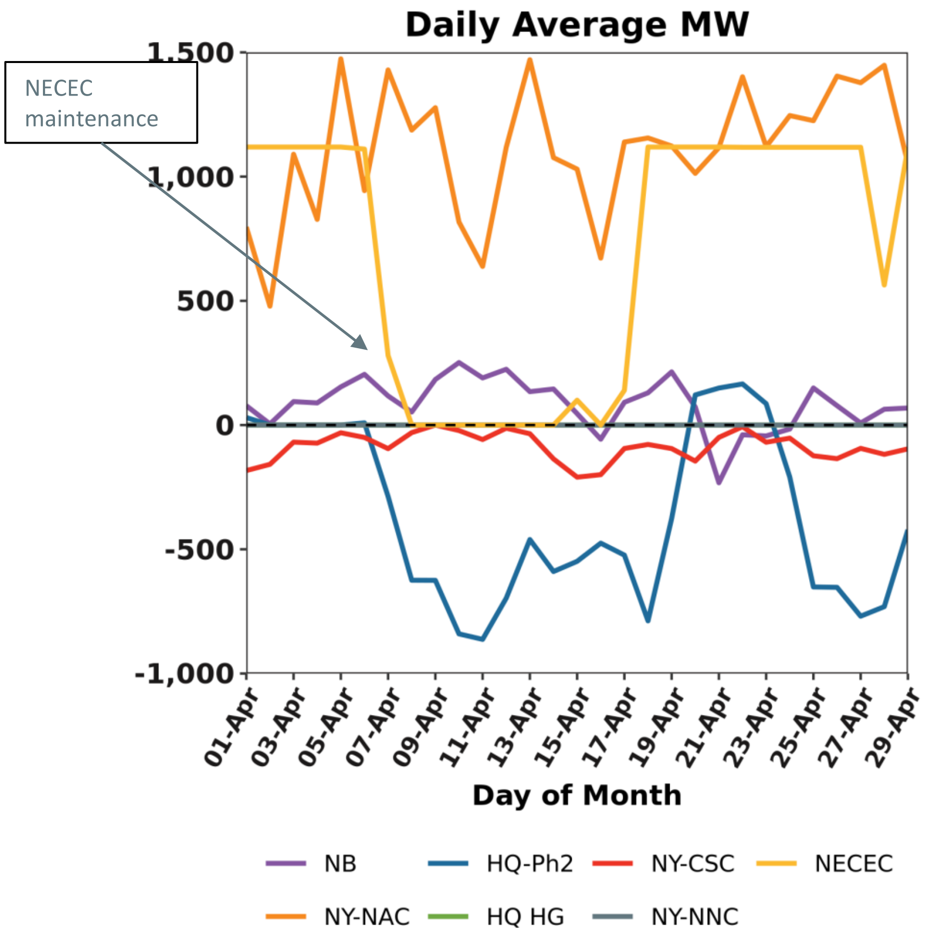
RT Net Interchange

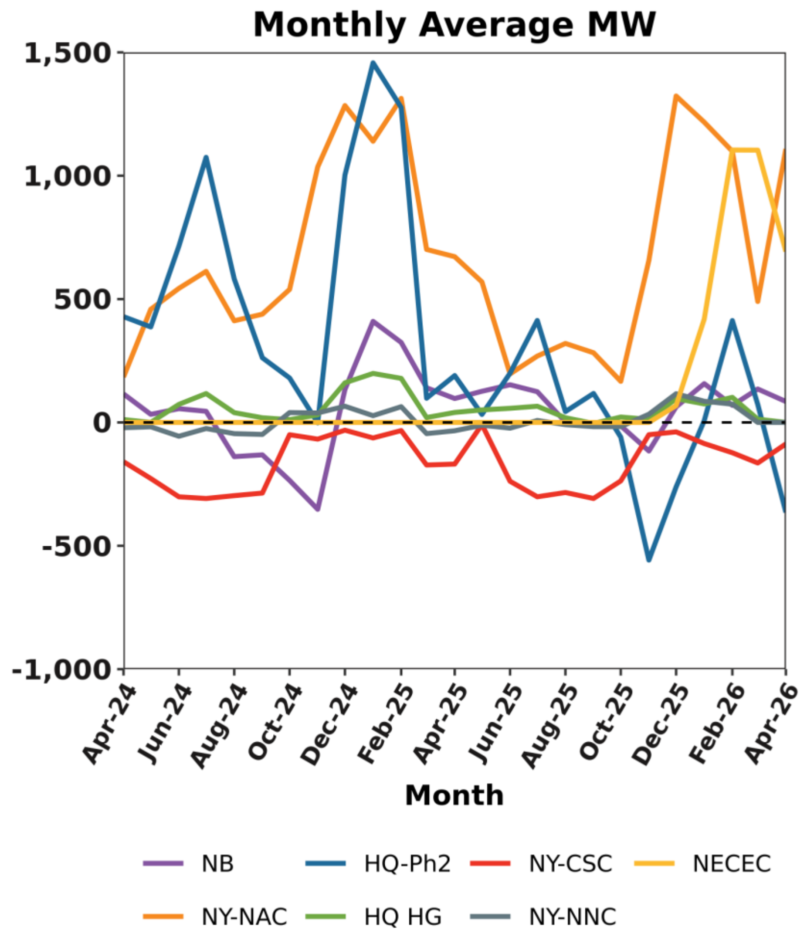




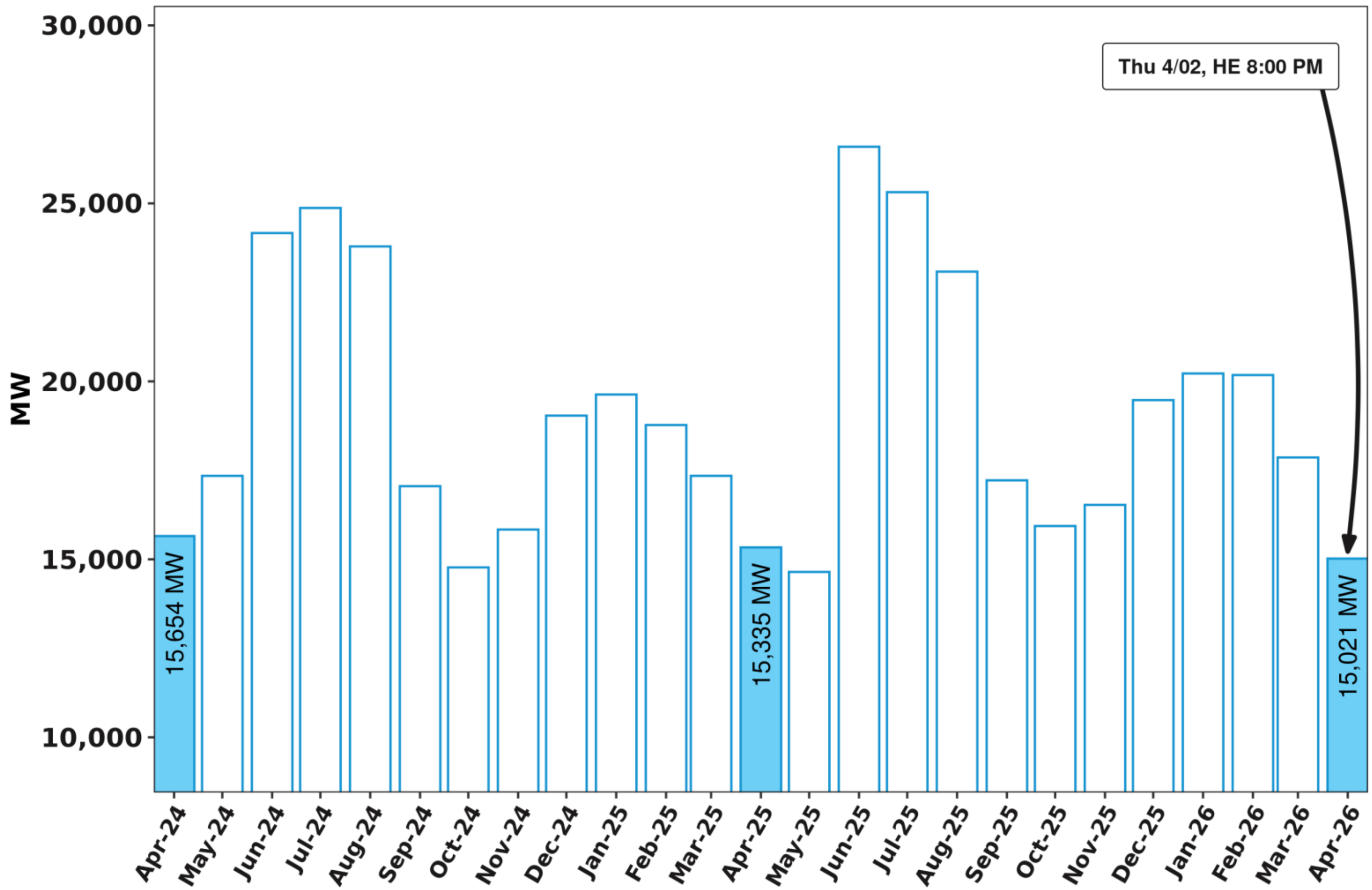
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



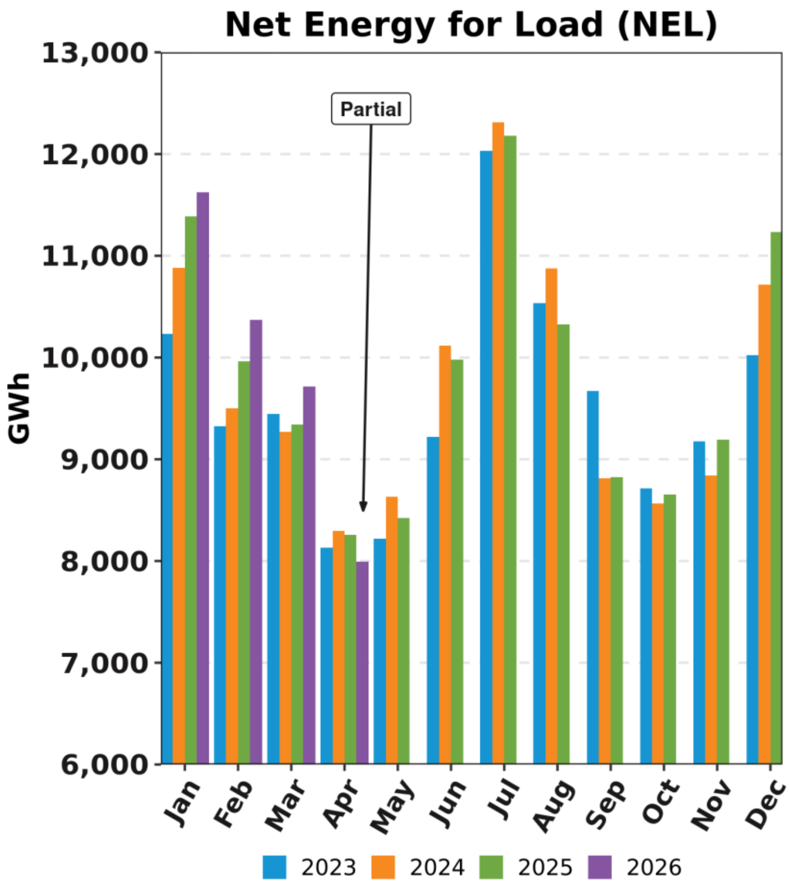


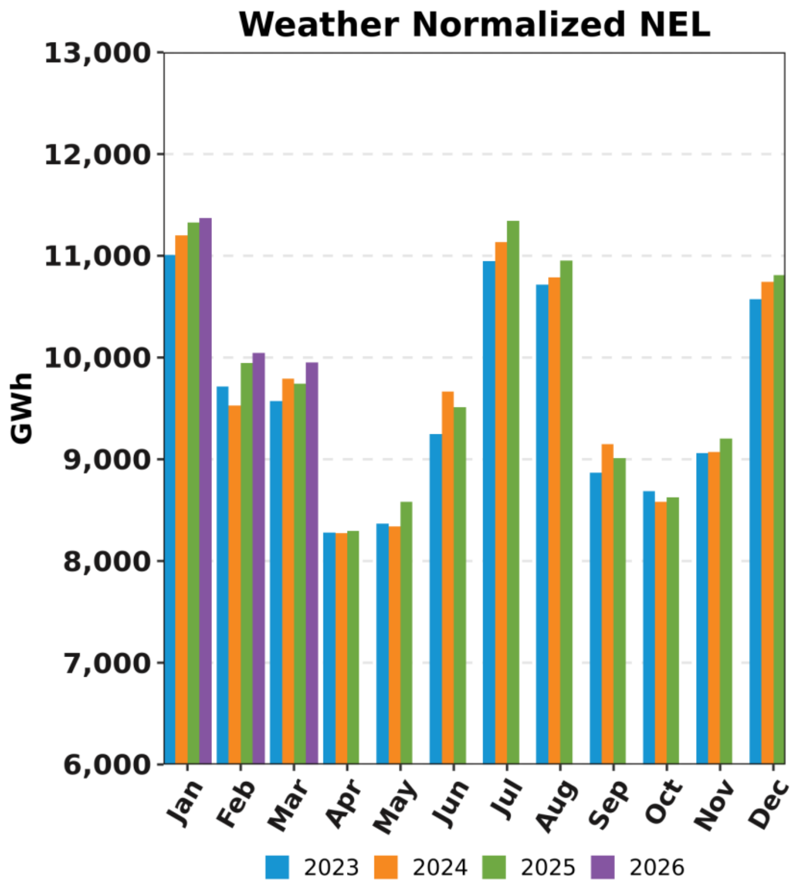
RQM System Peak Load MW by Month



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

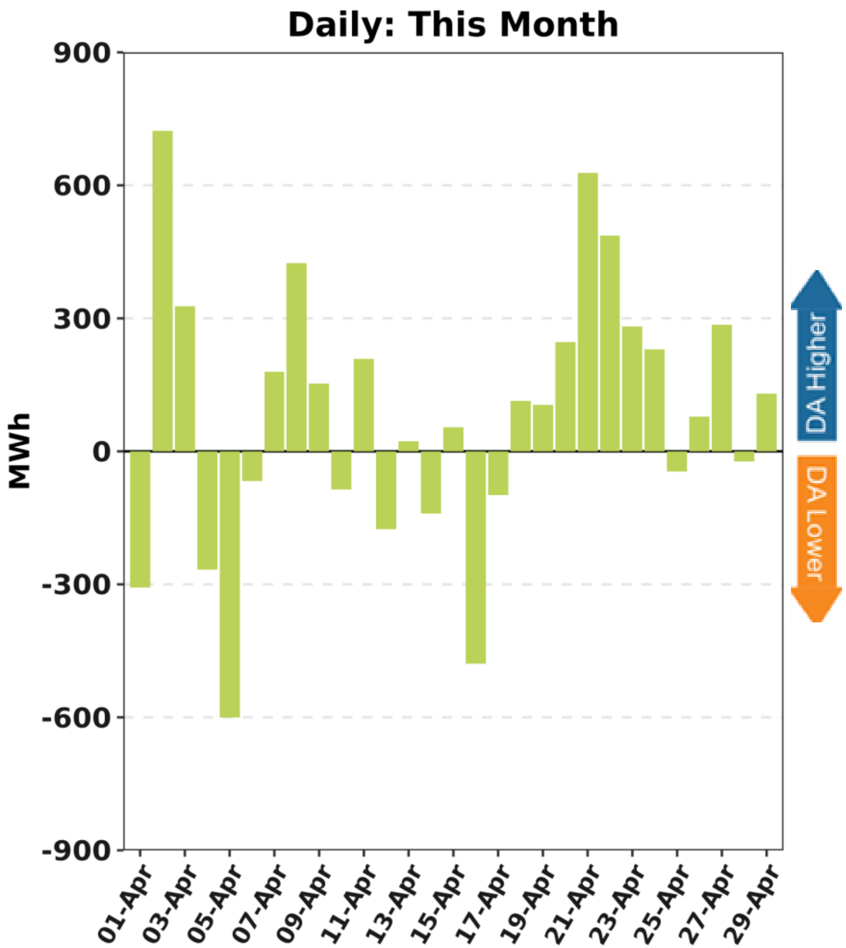
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

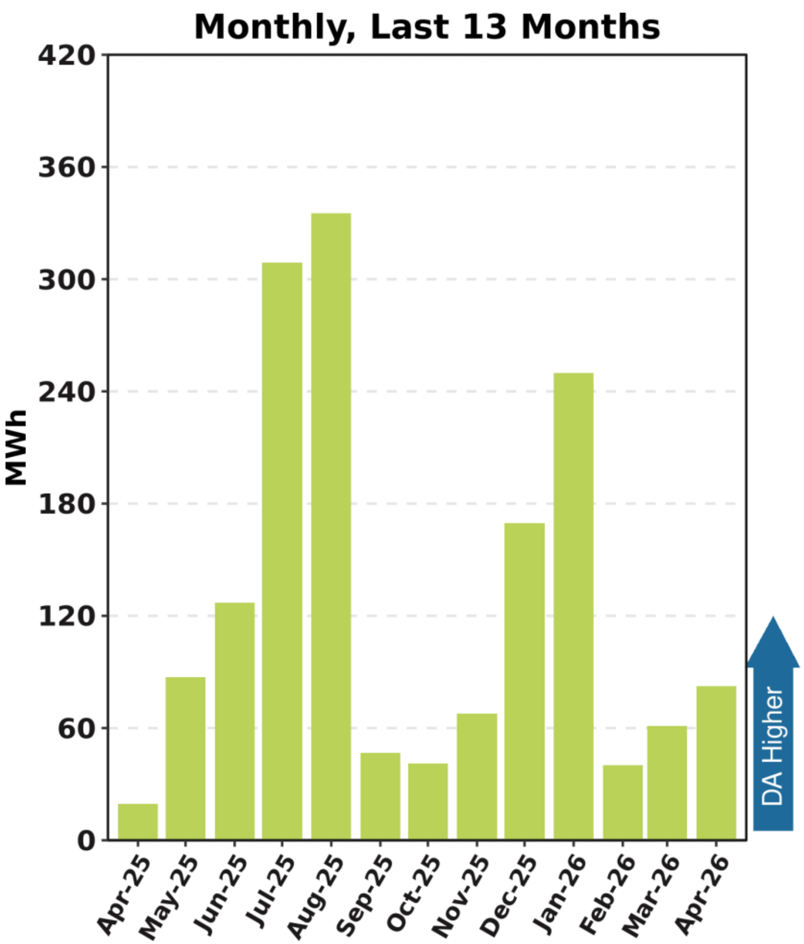




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

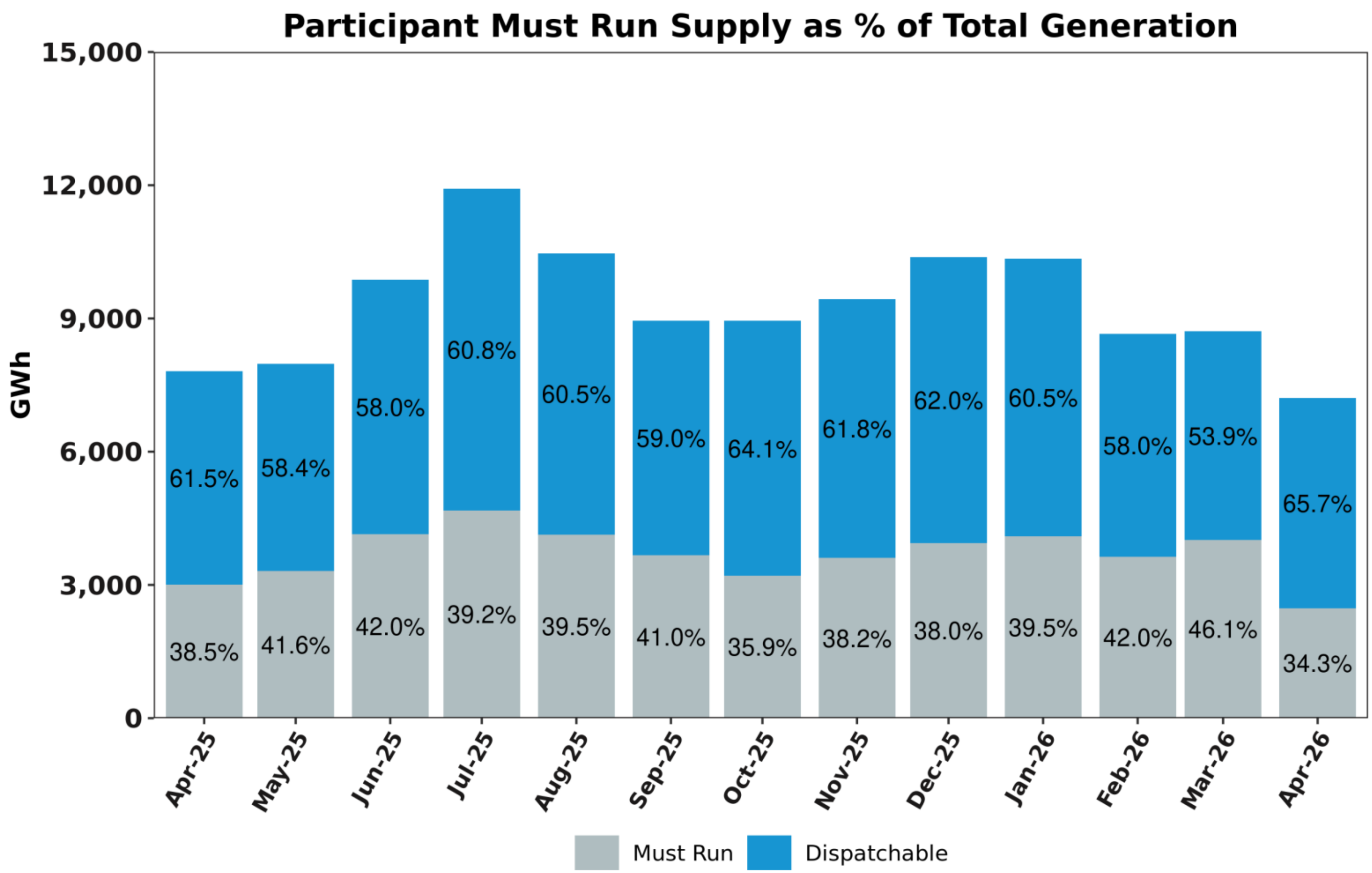
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour





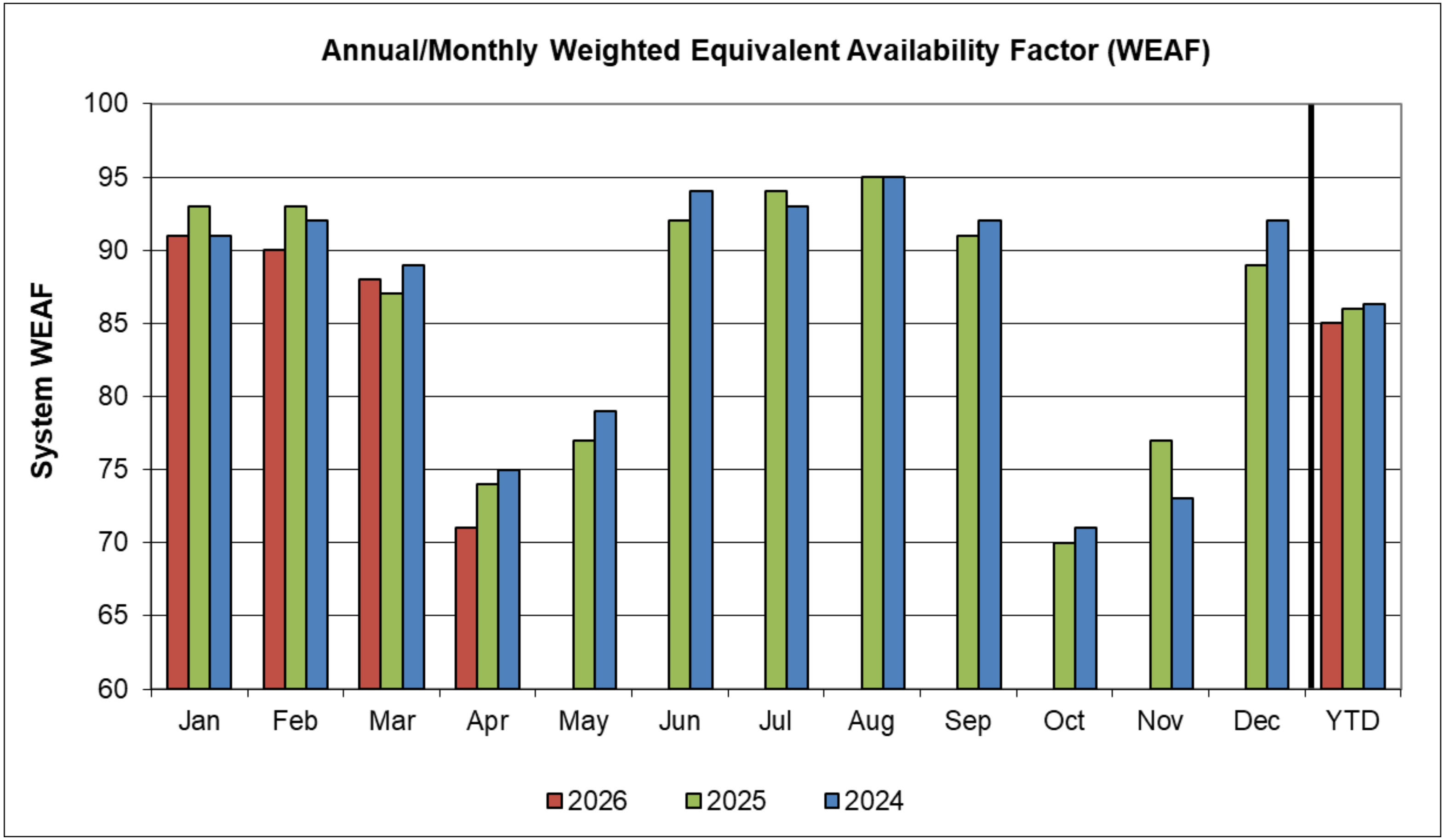
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

RT Generation Output Offered as Must Run vs Dispatchable



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

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2026	91	90	88	71									85
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 4/27/26

MARKET OPERATIONS

Market Pricing

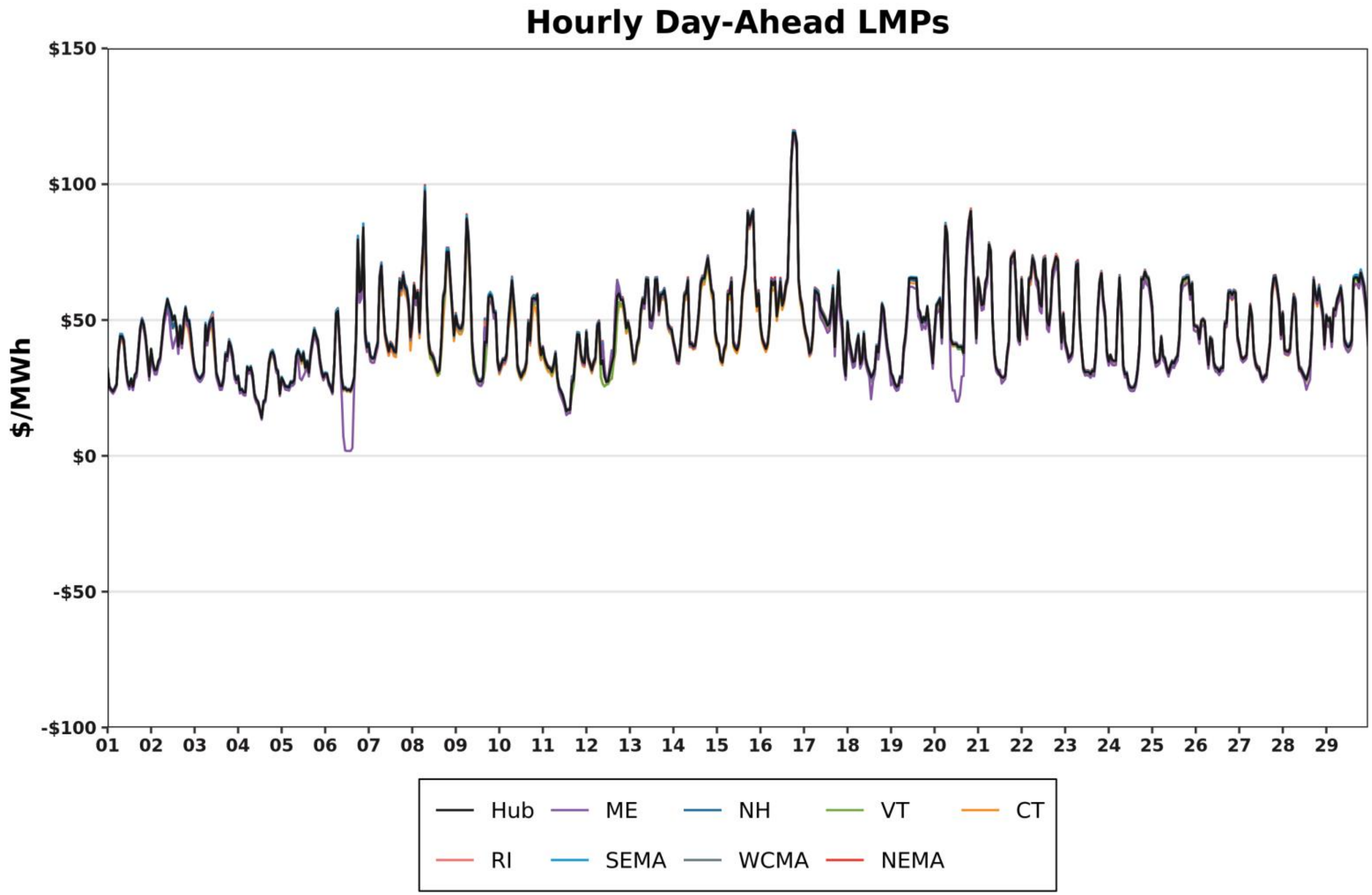
DA vs. RT LMPs ($/MWh)

Arithmetic Average

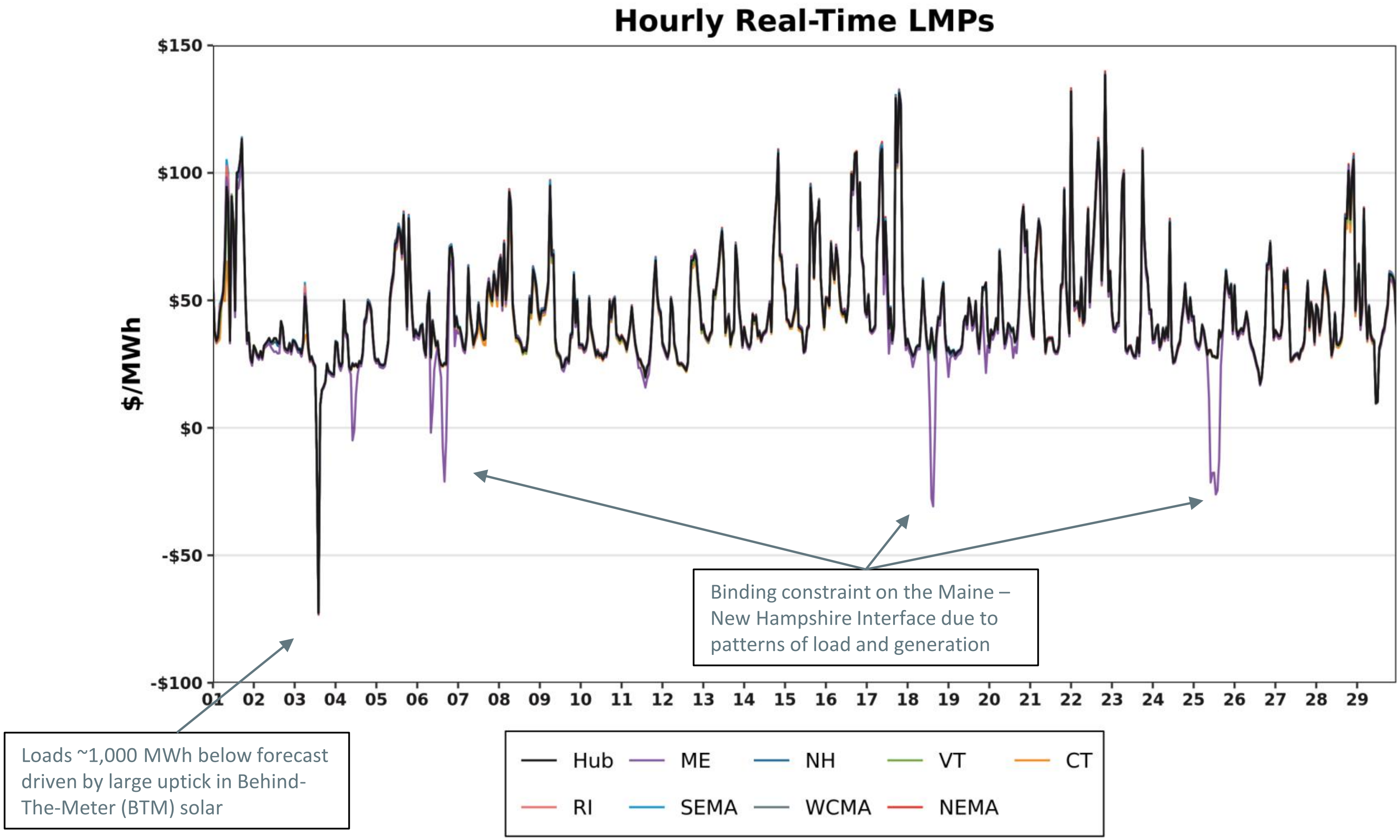
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$41.35	$41.07	$41.72	$41.11	$40.17	$41.28	$41.70	$41.37	$41.91
Real-Time	$39.37	$38.79	$39.65	$39.23	$38.46	$39.17	$39.62	$39.37	$39.77
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%
Year 2025	Hub	ME	NH	VT	CT	RI	SEMA	WCMA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

April-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$41.41	$36.28	$41.16	$40.76	$40.45	$41.16	$41.70	$41.29	$41.77
Real-Time	$39.52	$32.85	$39.21	$38.94	$38.68	$39.25	$39.78	$39.46	$39.89
RT Delta %	-4.56%	-9.45%	-4.74%	-4.47%	-4.38%	-4.64%	-4.60%	-4.43%	-4.50%
April-26	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$45.89	$44.04	$45.90	$45.12	$44.16	$45.86	$46.47	$45.83	$46.63
Real-Time	$45.50	$42.98	$45.54	$44.82	$43.90	$45.38	$45.93	$45.47	$46.18
RT Delta %	-0.85%	-2.41%	-0.78%	-0.66%	-0.59%	-1.05%	-1.16%	-0.79%	-0.97%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	10.82%	21.39%	11.52%	10.70%	9.17%	11.42%	11.44%	11.00%	11.64%
Yr over Yr RT	15.13%	30.84%	16.14%	15.10%	13.50%	15.62%	15.46%	15.23%	15.77%

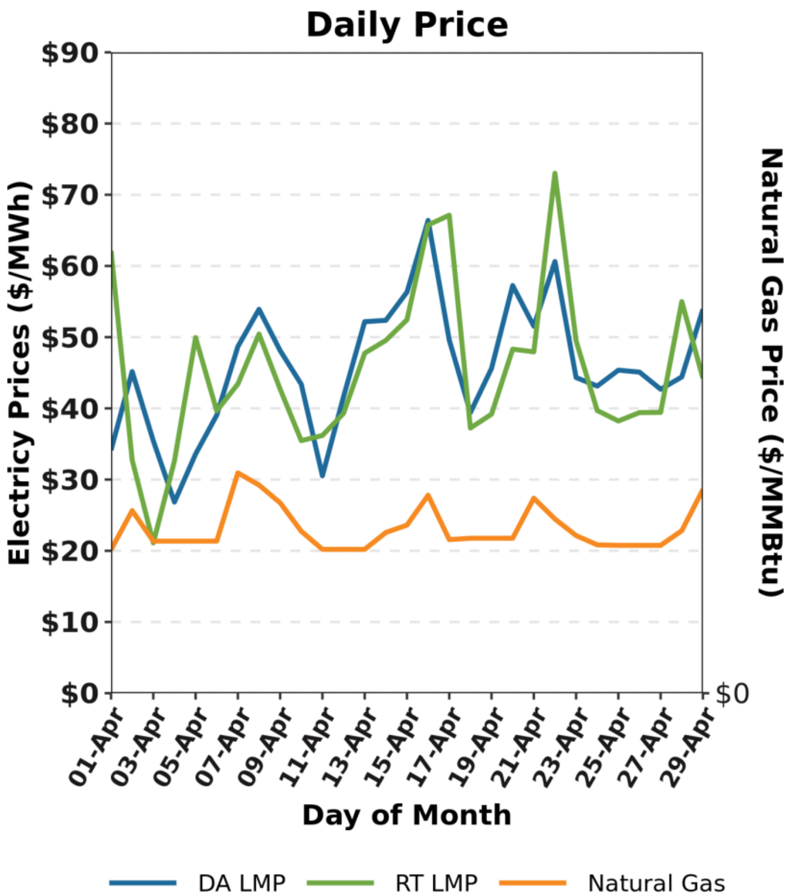
Hourly DA LMPs, April 1-29, 2026

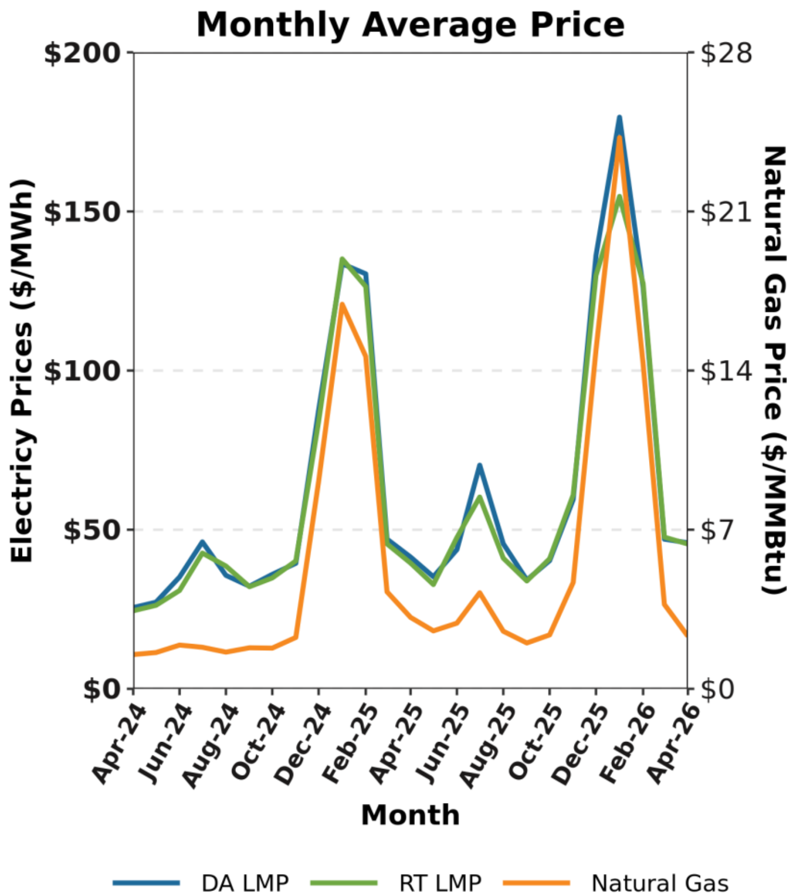


Hourly RT LMPs, April 1-29, 2026



Wholesale Electricity vs Natural Gas Price by Month

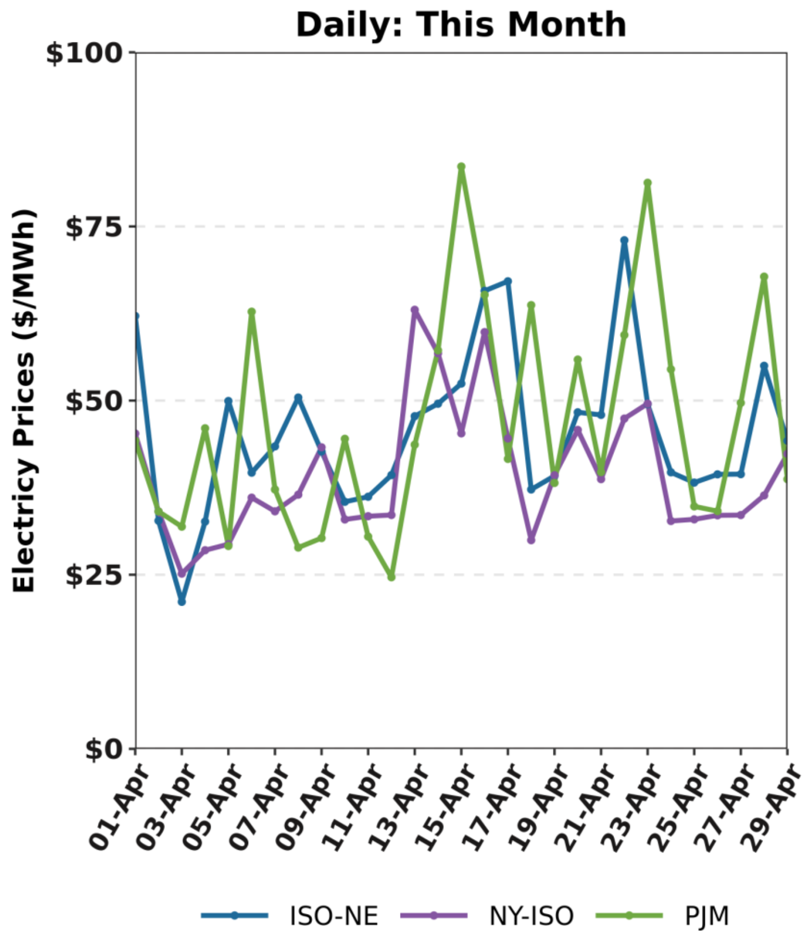


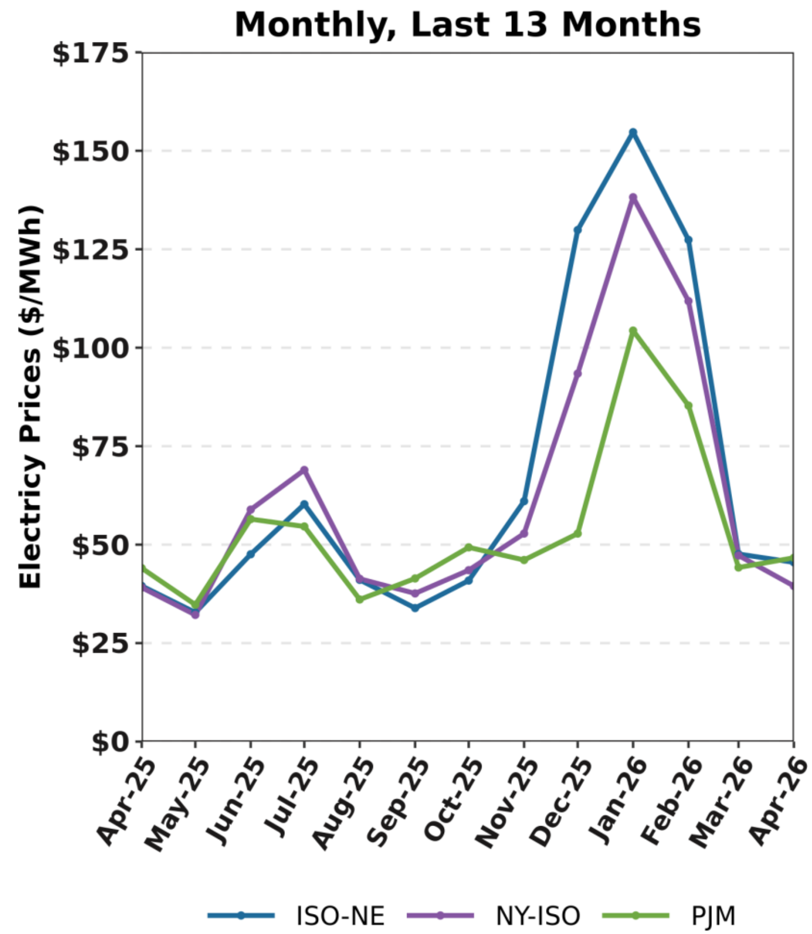


Underlying natural gas data furnished by: ice Global markets in clear view

Gas price is average of Massachusetts delivery points

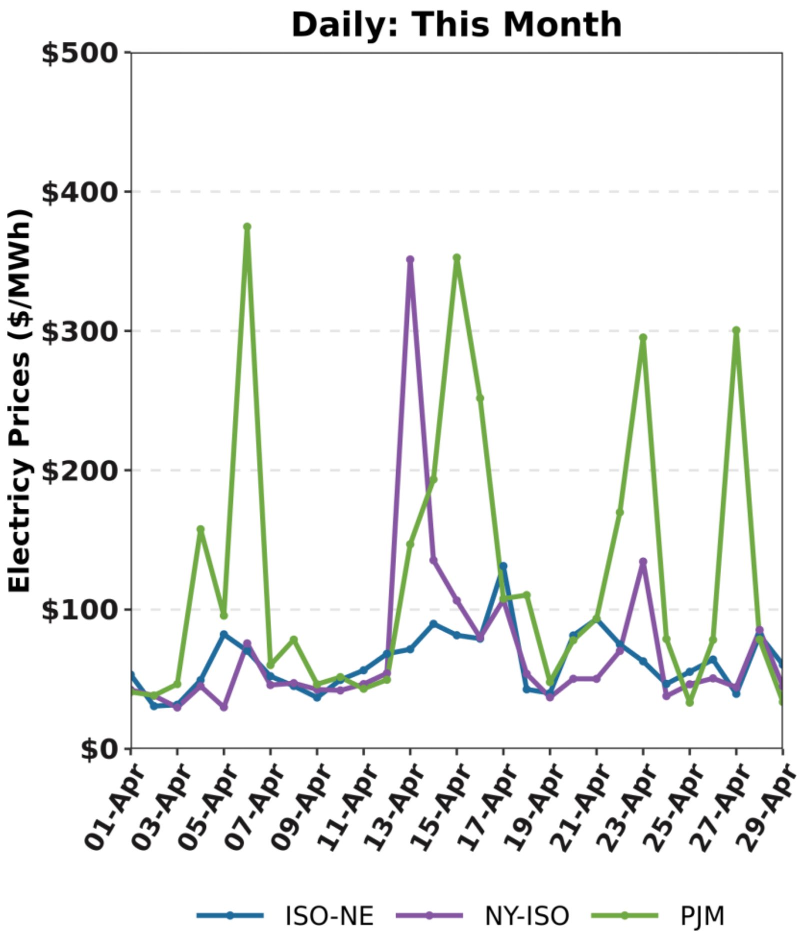
New England, NY, and PJM Hourly Average RT Prices by Month

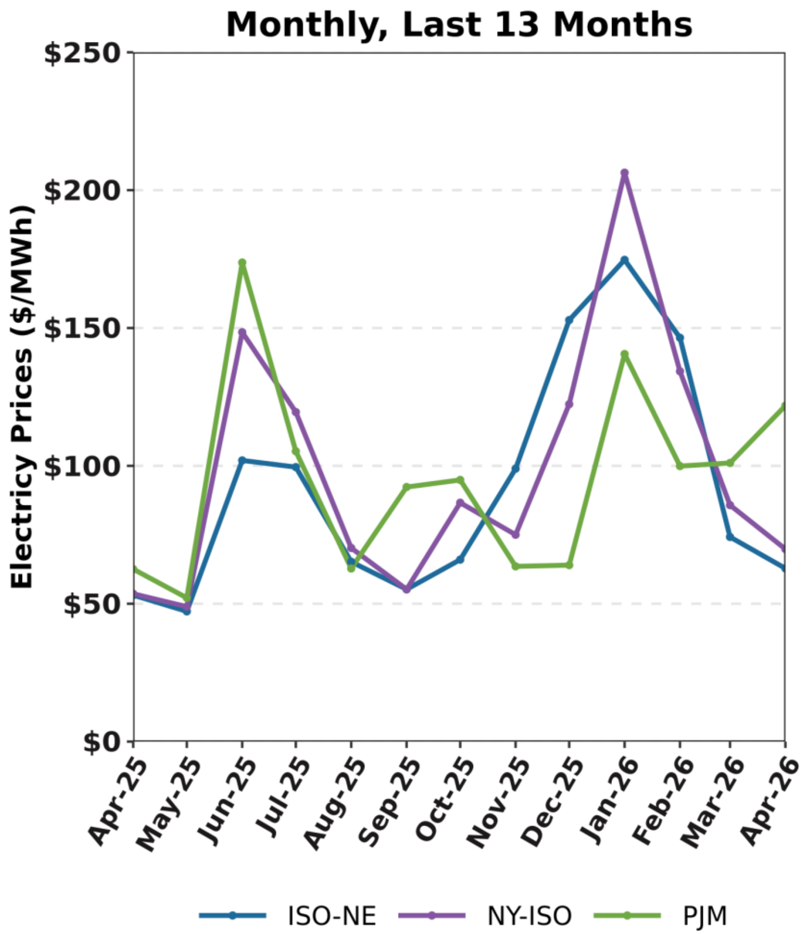




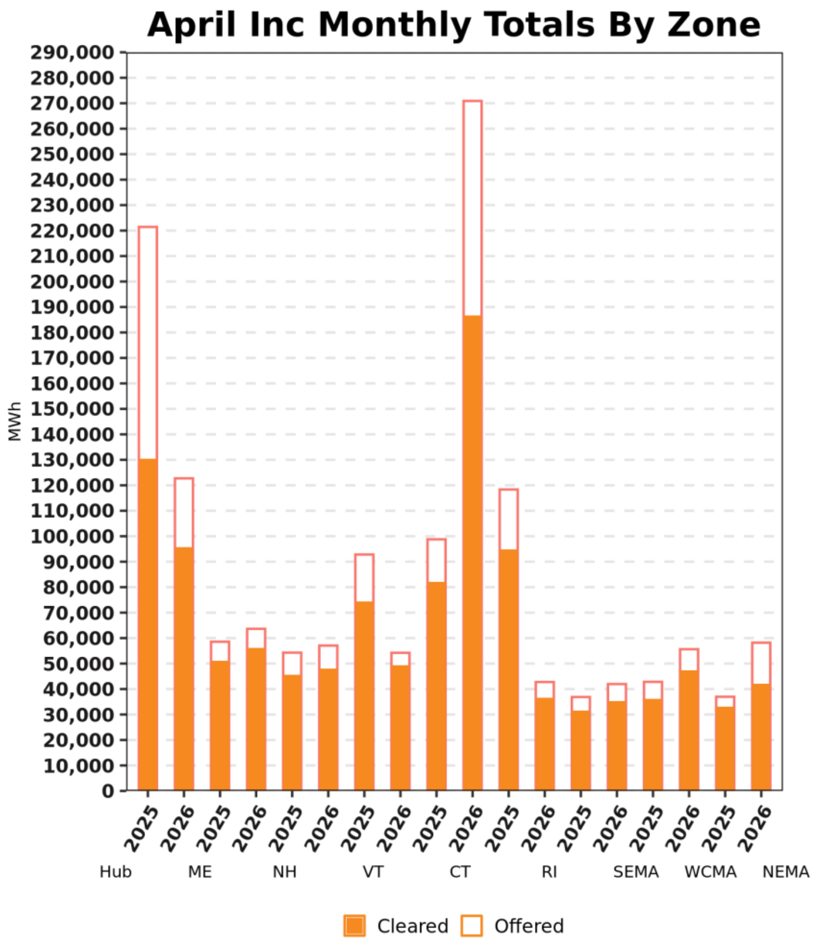
Hourly average prices are shown

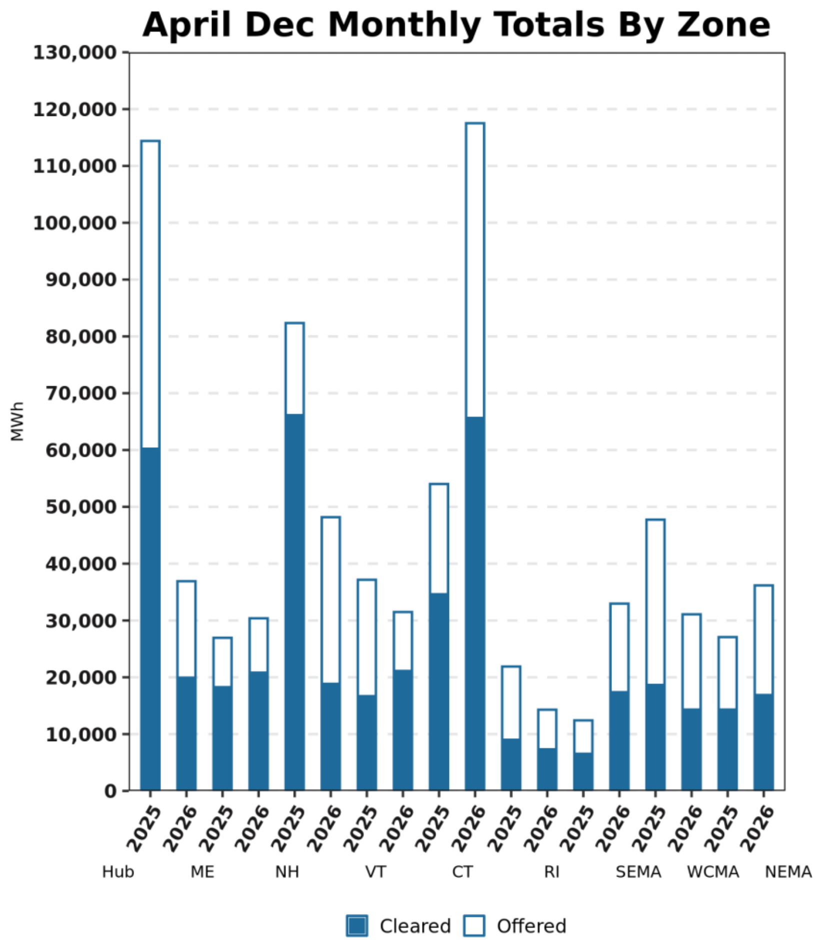
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





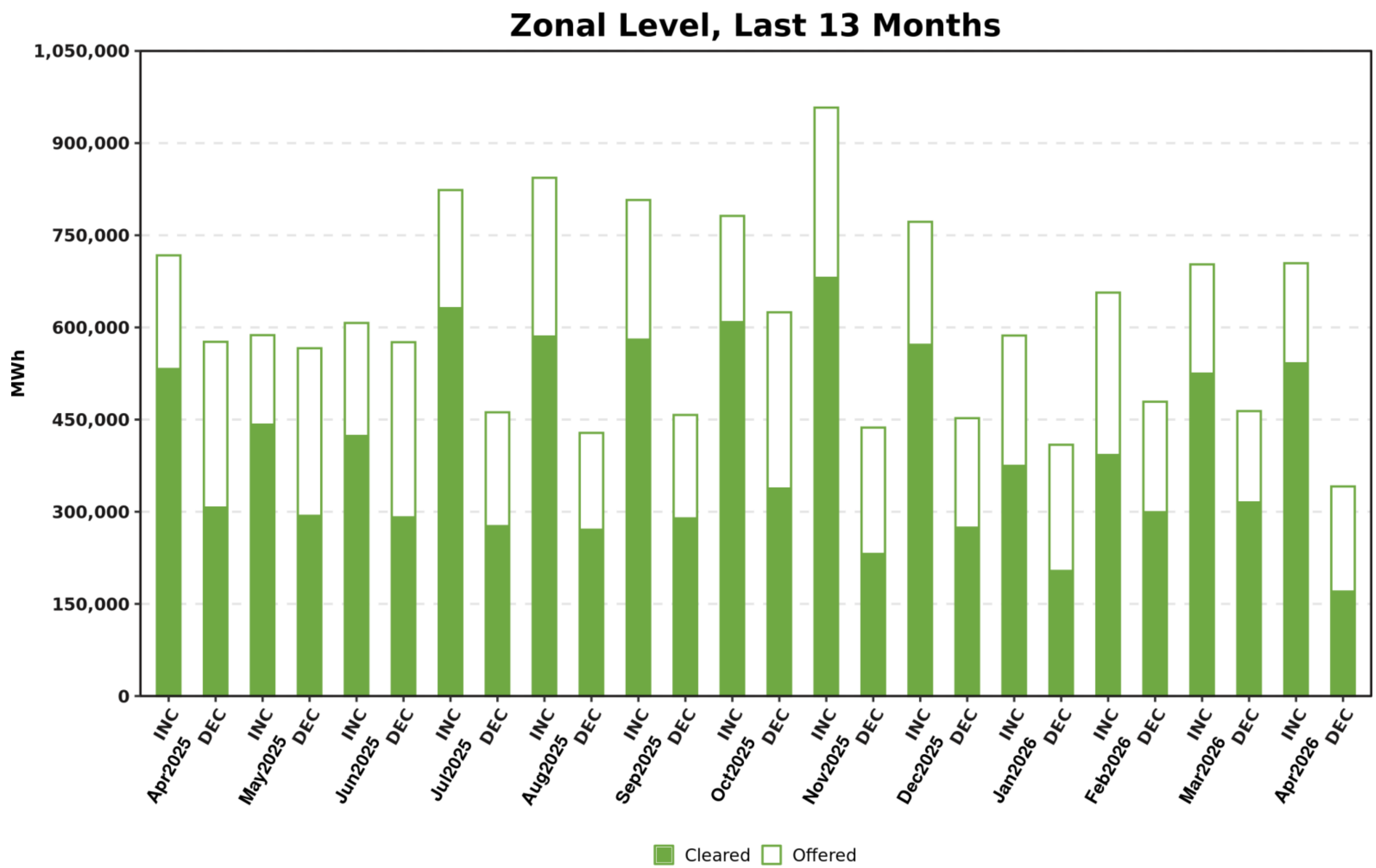
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

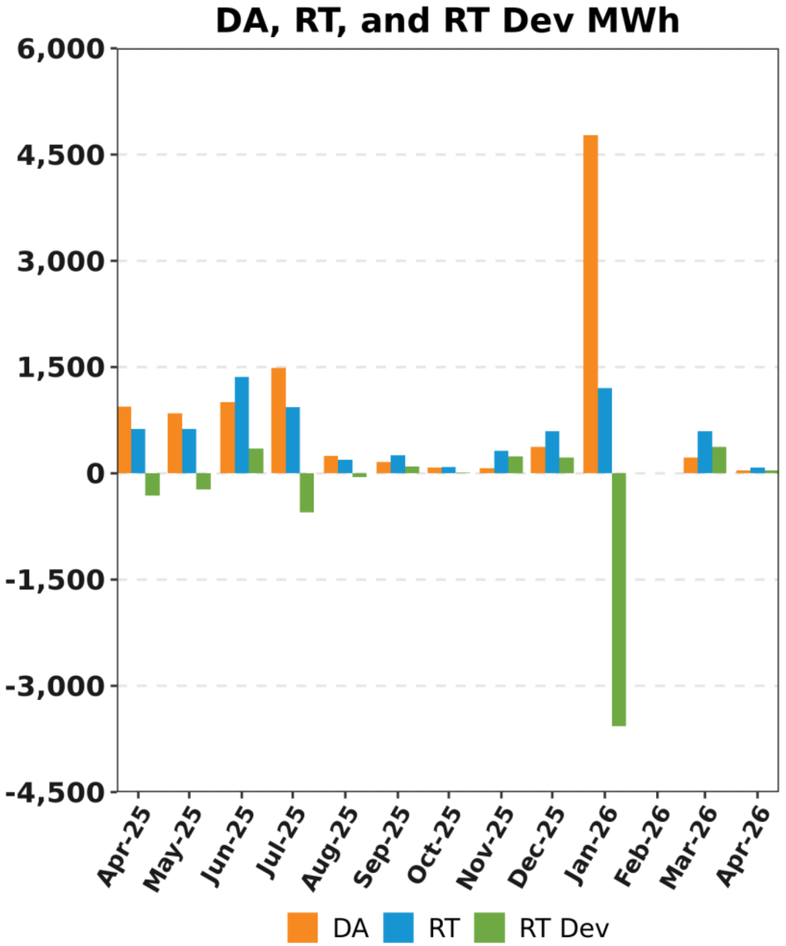


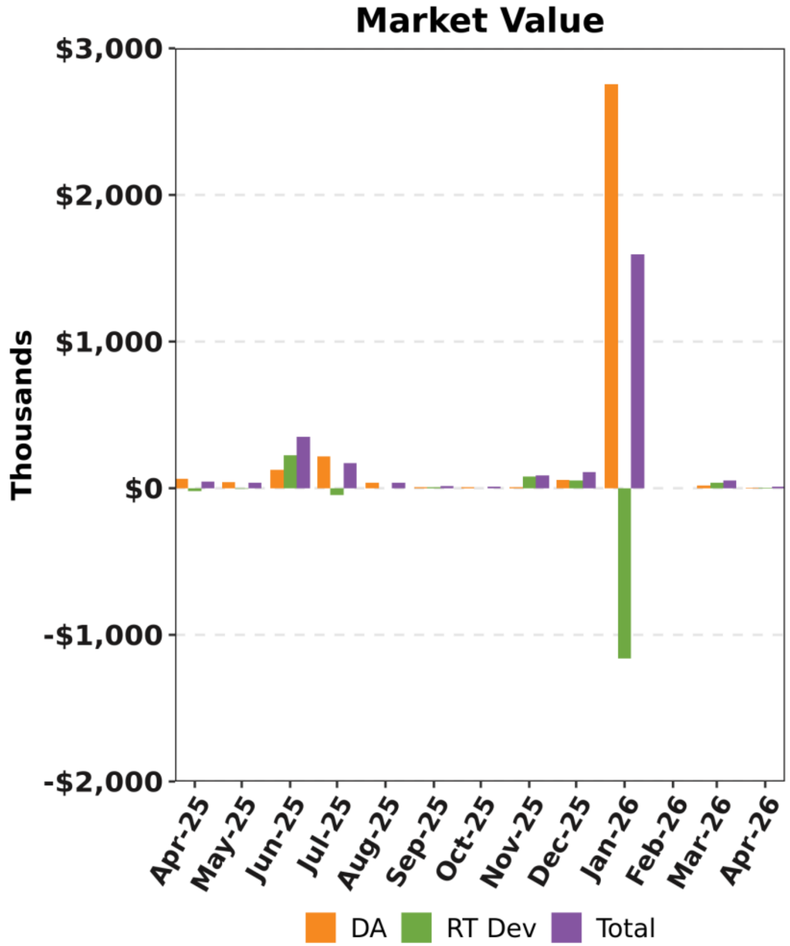
Includes nodal activity within the zone; excludes external nodes

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

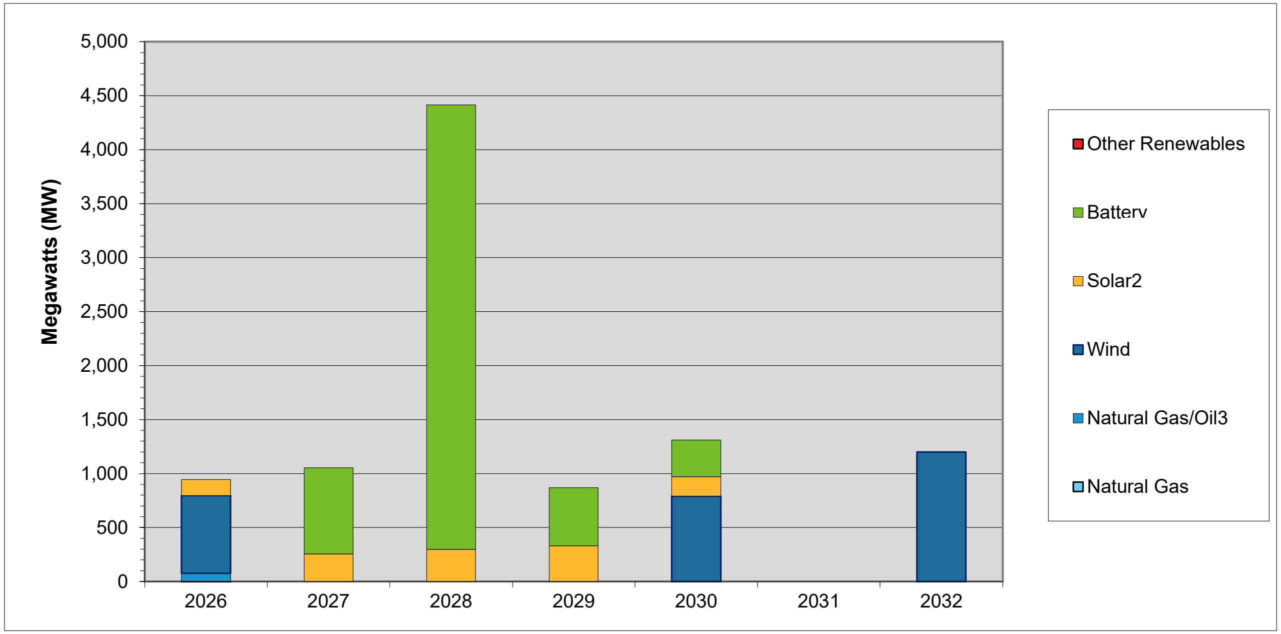
Based on Queue as of 05/01/26

- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 56* generation projects are currently being tracked by the ISO, totaling approximately 10,991 MW

* Total does not include CNR Only requests

Projected Annual Capacity Additions

By Supply Fuel Type



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	0	799	4,115	538	340	0	0	5,792	59.2
Solar[2]	147	255	299	332	180	0	0	1,213	12.4
Wind	722	0	0	0	791	0	1,200	2,713	27.7
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.7
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	942	1,054	4,414	870	1,311	0	1,200	9,791	100.0

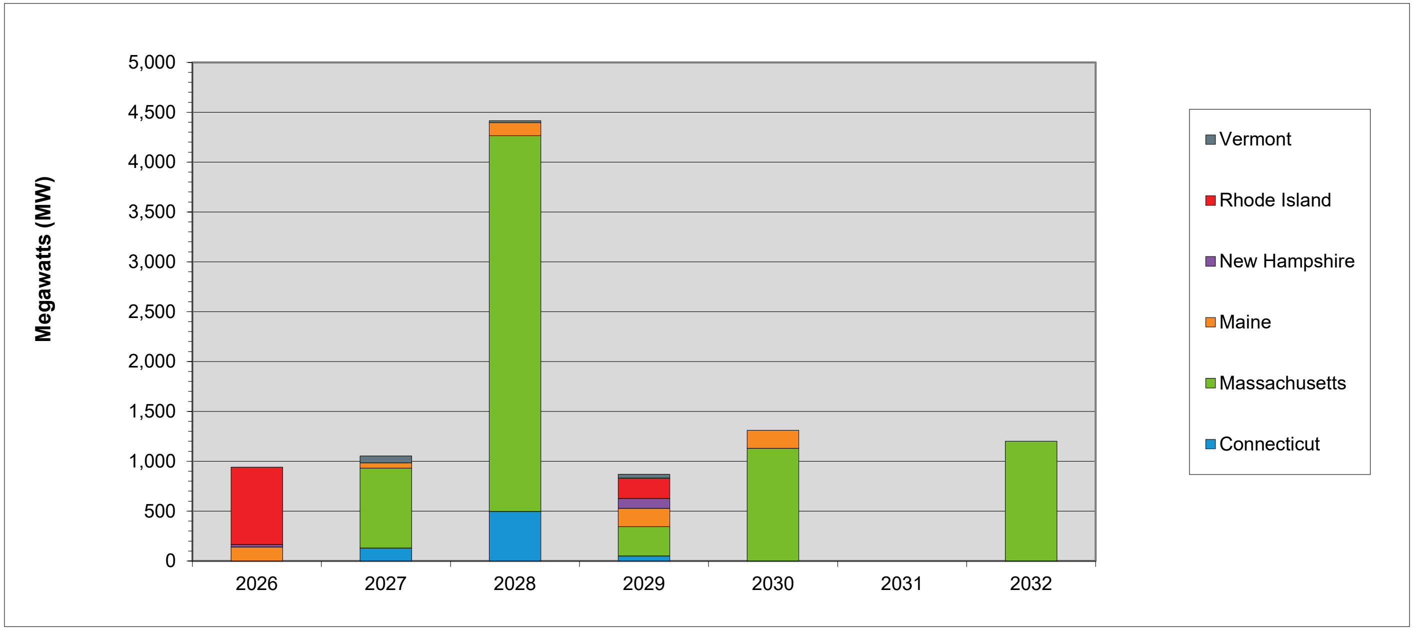
[1] Sum may not equal 100% due to rounding

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

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

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

Projected Annual Generator Capacity Additions
By State



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Vermont	0	70	20	38	0	0	0	128	1.3
Rhode Island	777	0	0	205	0	0	0	982	10.0
New Hampshire	25	0	0	100	0	0	0	125	1.3
Maine	140	54	129	182	180	0	0	685	7.0
Massachusetts	0	799	3,768	295	1,131	0	1,200	7,193	73.5
Connecticut	0	131	497	50	0	0	0	678	6.9
Totals	**942**	**1,054**	**4,414**	**870**	**1,311**	**0**	**1,200**	**9,791**	**100.0**

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

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

New Generation Projection

By Fuel Type

	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	5,792	2	454	25	5,338
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	1	73	1	73	0	0
Nuclear	0	0	0	0	0	0
Solar	23	1,213	4	141	19	1,072
Wind	5	3,913	2	722	3	3,191
Total	56	10,991	9	1,390	47	9,601

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	0	0	0	0	0	0
Intermediate	1	73	1	73	0	0
Peaker	50	7,005	6	595	44	6,410
Wind Turbine	5	3,913	2	722	3	3,191
Total	56	10,991	9	1,390	47	9,601

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	27	5,792	0	0	0	0	27	5,792	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	23	1,213	0	0	0	0	23	1,213	0	0
Wind	5	3,913	0	0	0	0	0	0	5	3,913
Total	56	10,991	0	0	1	73	50	7,005	5	3,913

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 16

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

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

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

Capacity Supply Obligation FCA 17

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

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

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

Capacity Supply Obligation FCA 18

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	543.580	403.884	-139.696				
	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

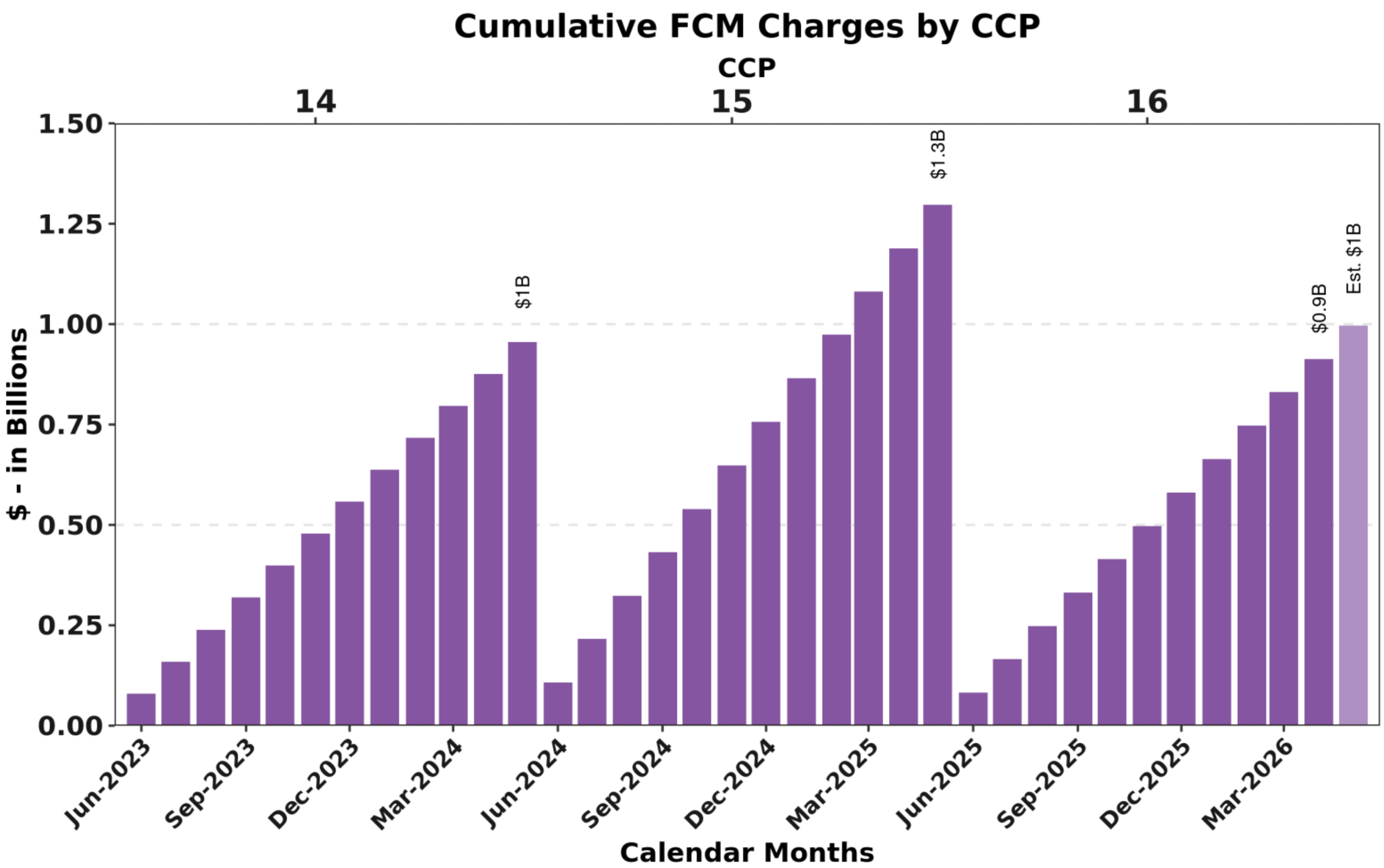
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes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

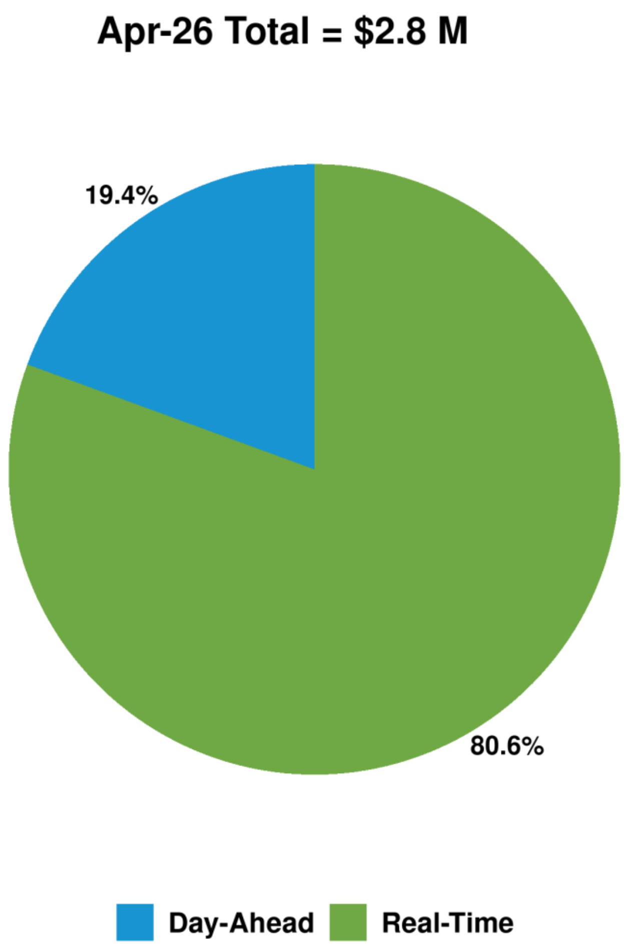
Forward Capacity Market Auctions

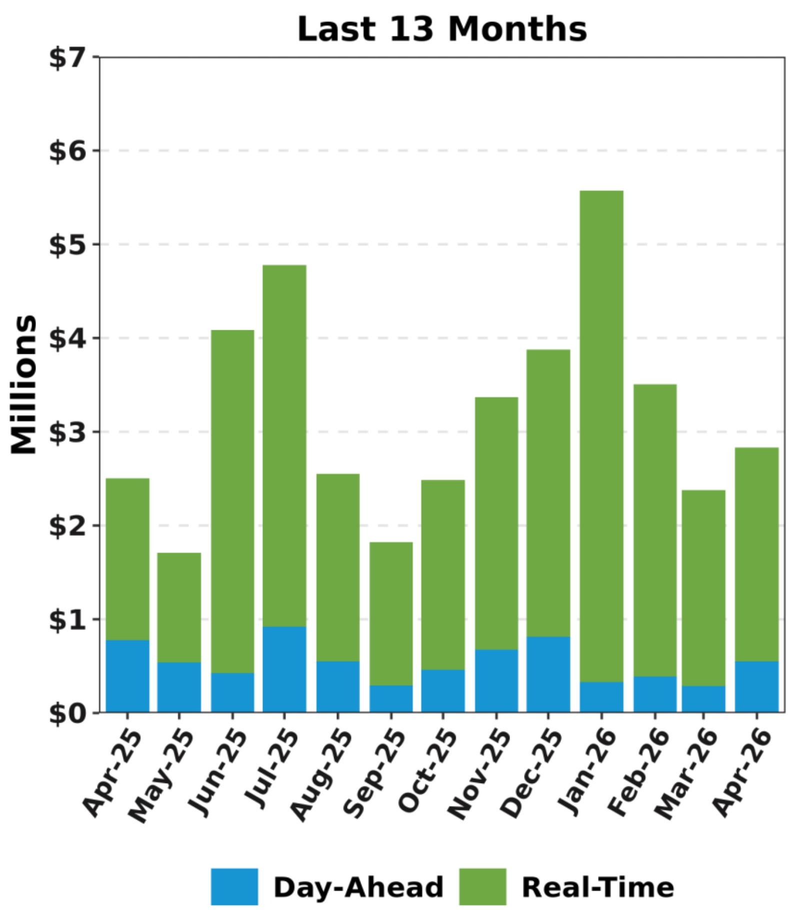


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

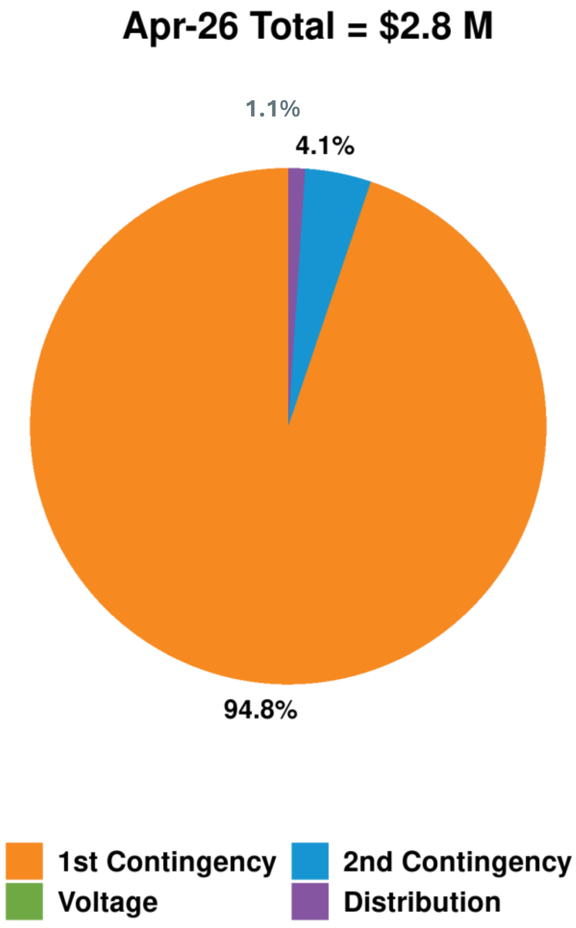
NET COMMITMENT PERIOD COMPENSATION

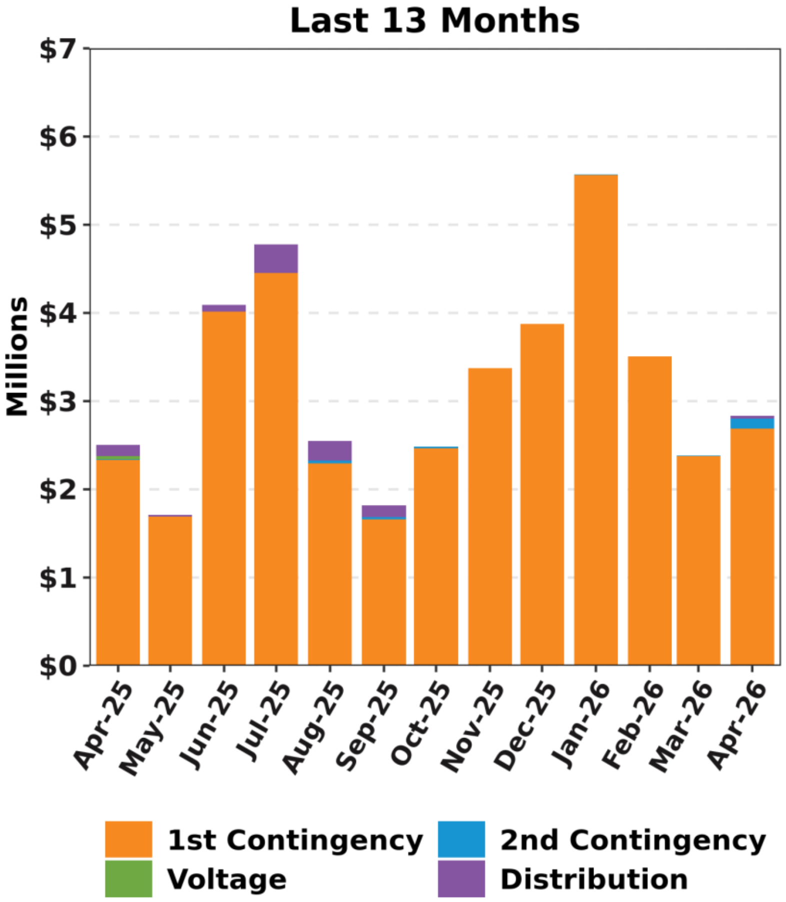
DA and RT NCPC Charges



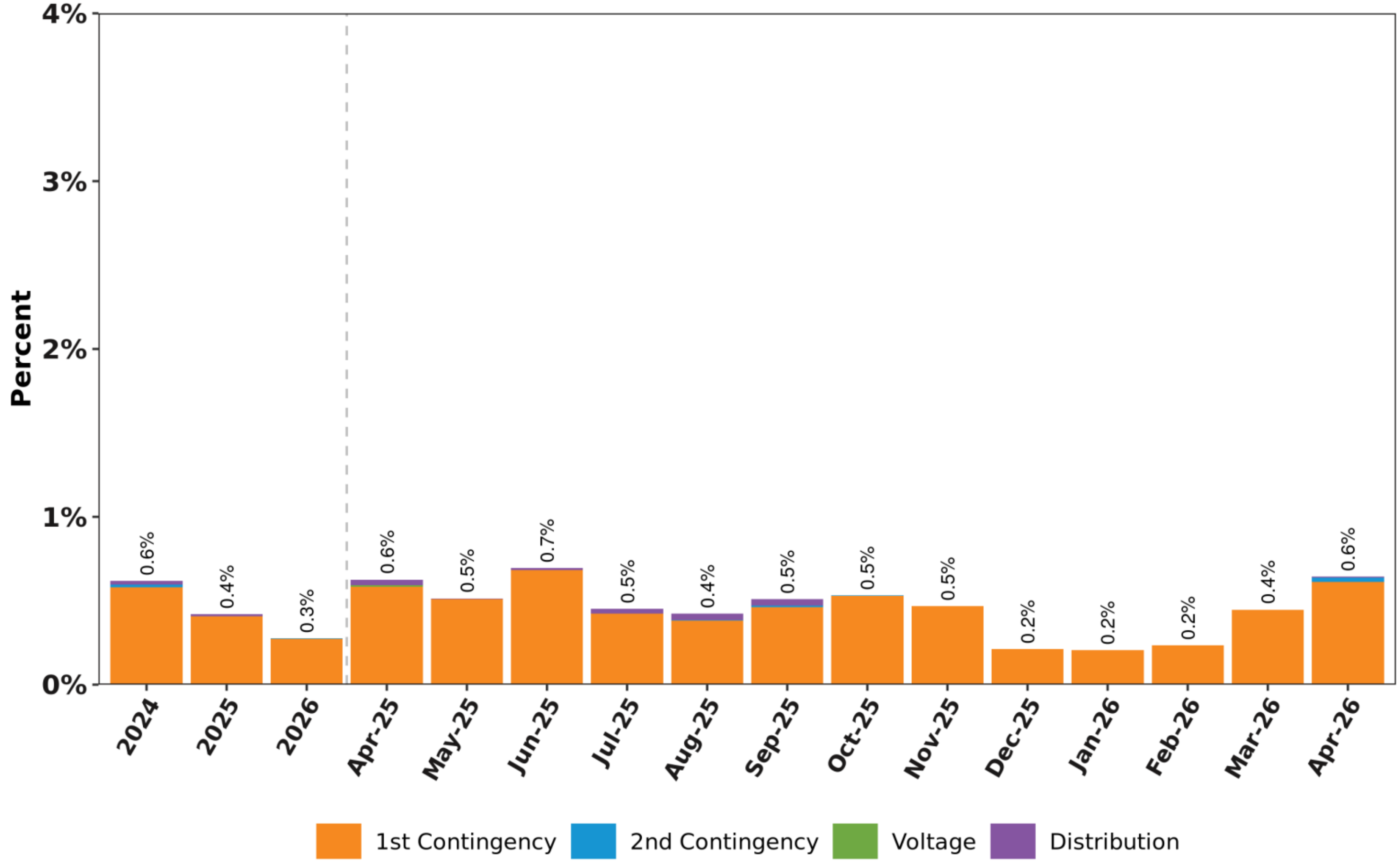


NCPC Charges by Type

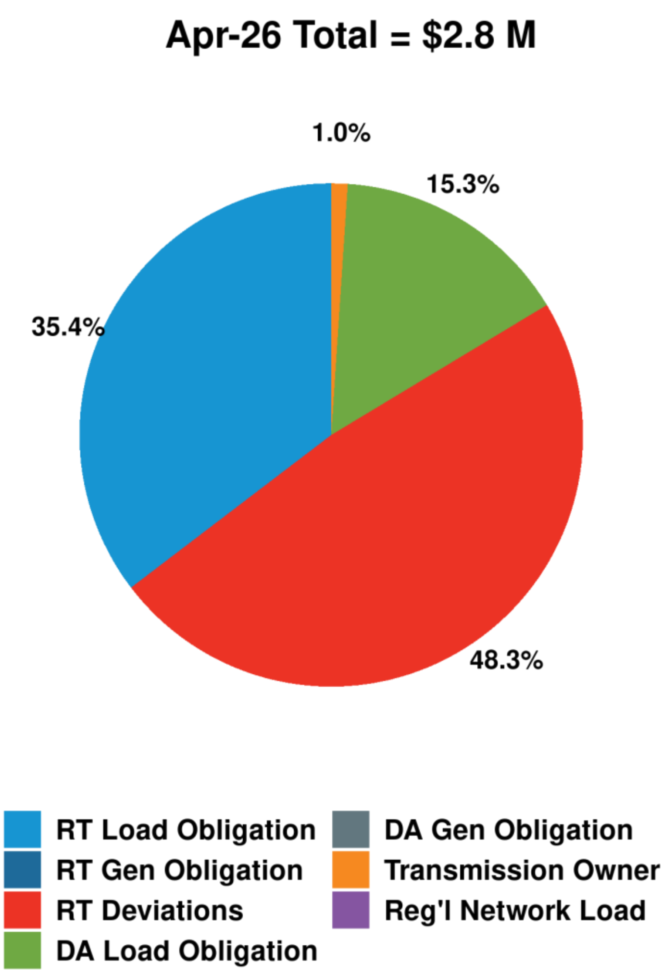


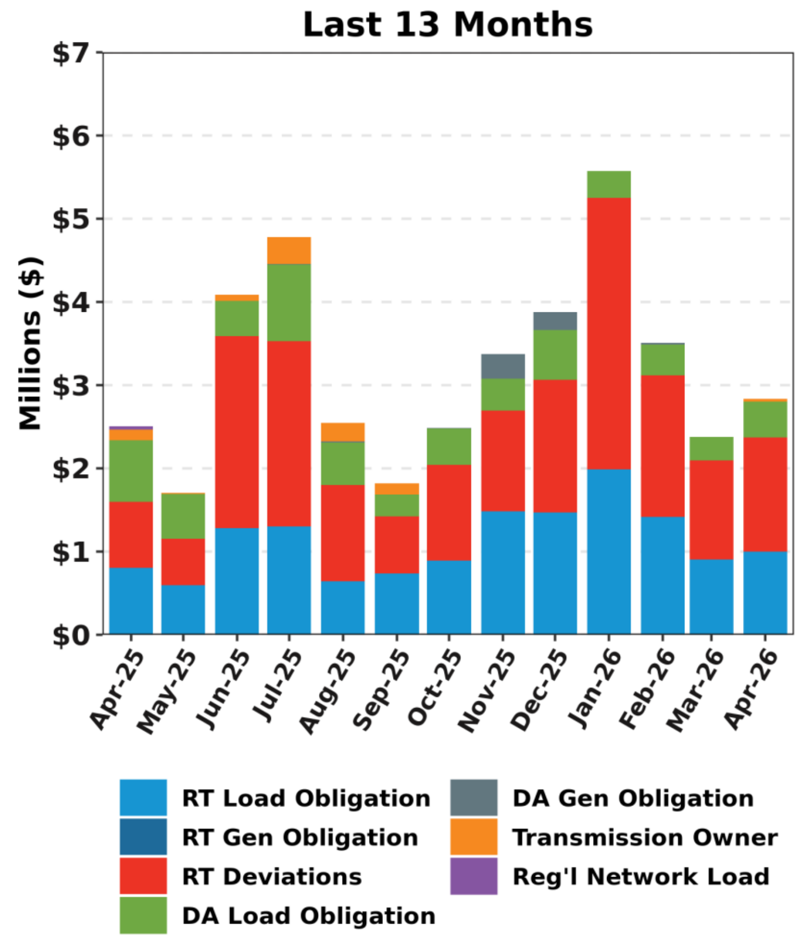


NCPC Charges by Type as Percent of Energy Market Value

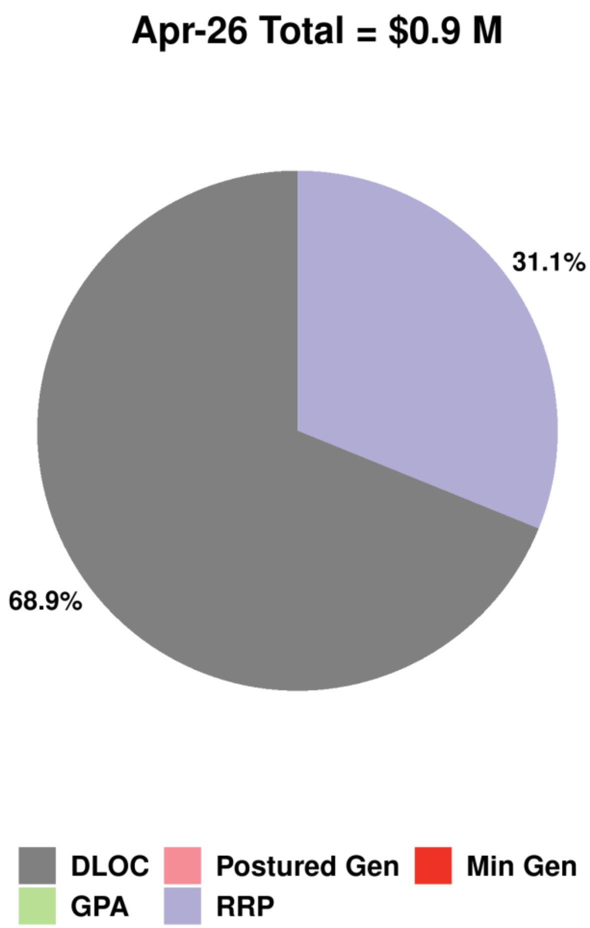


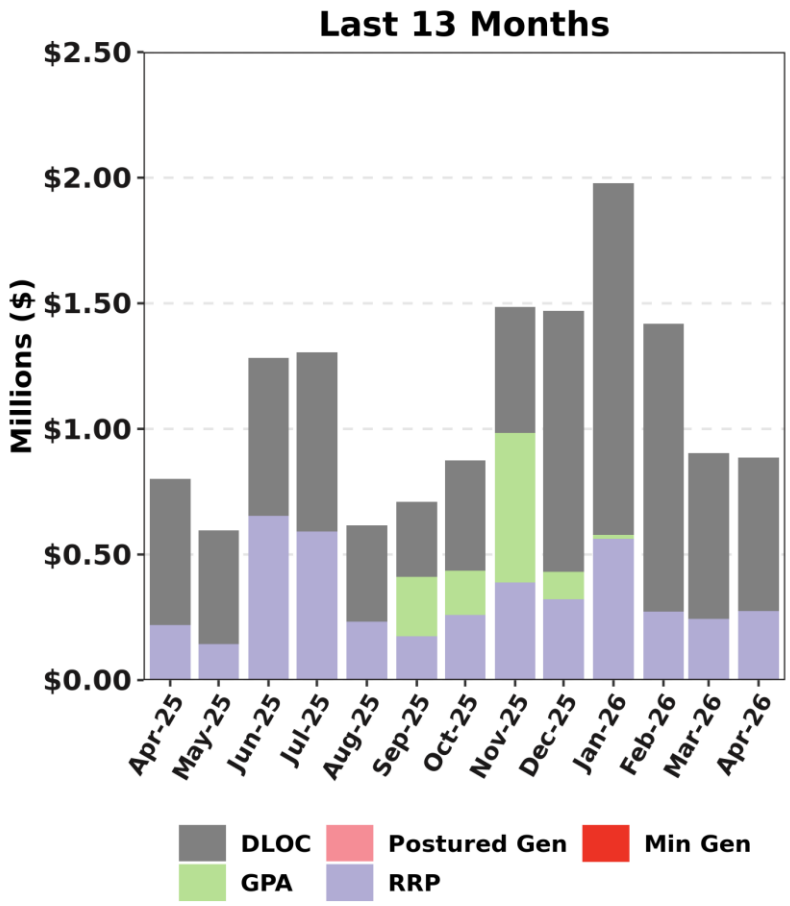
NCPC Charge Allocations





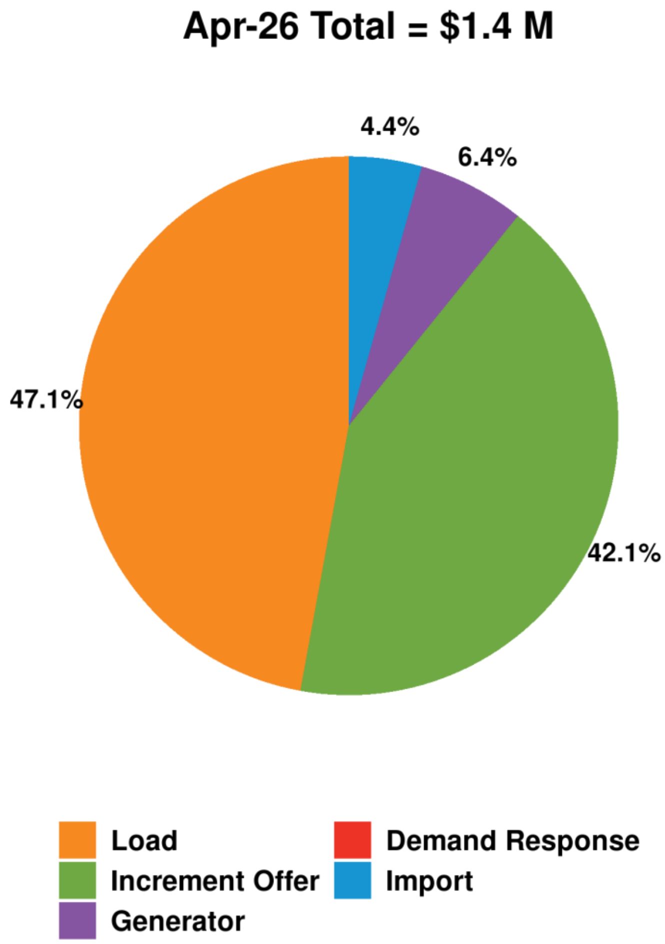
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

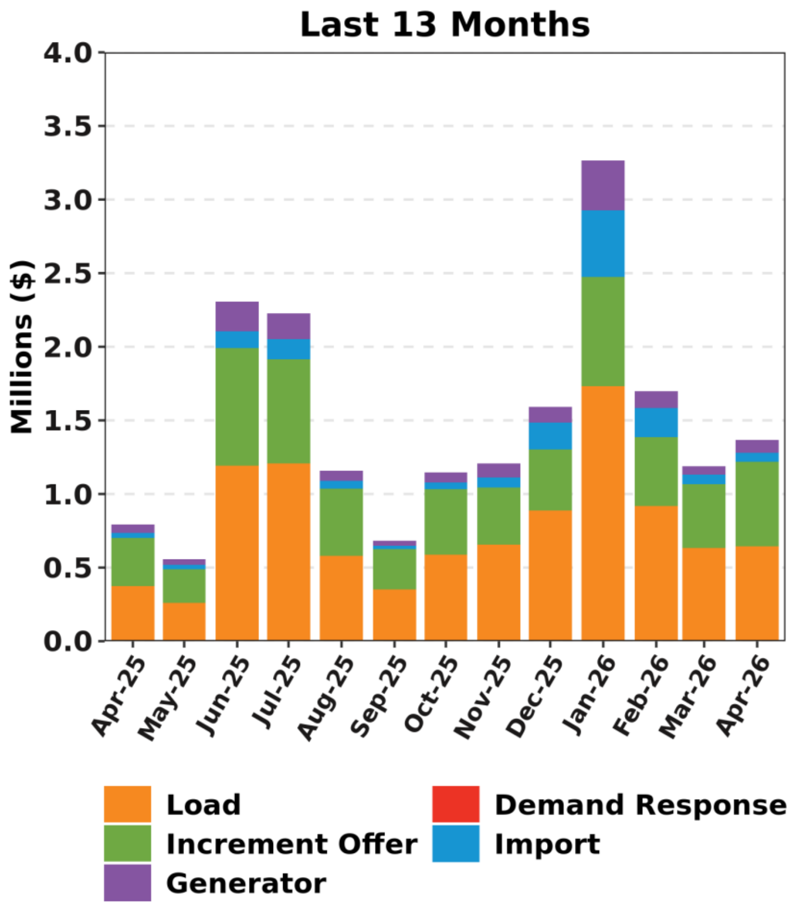




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

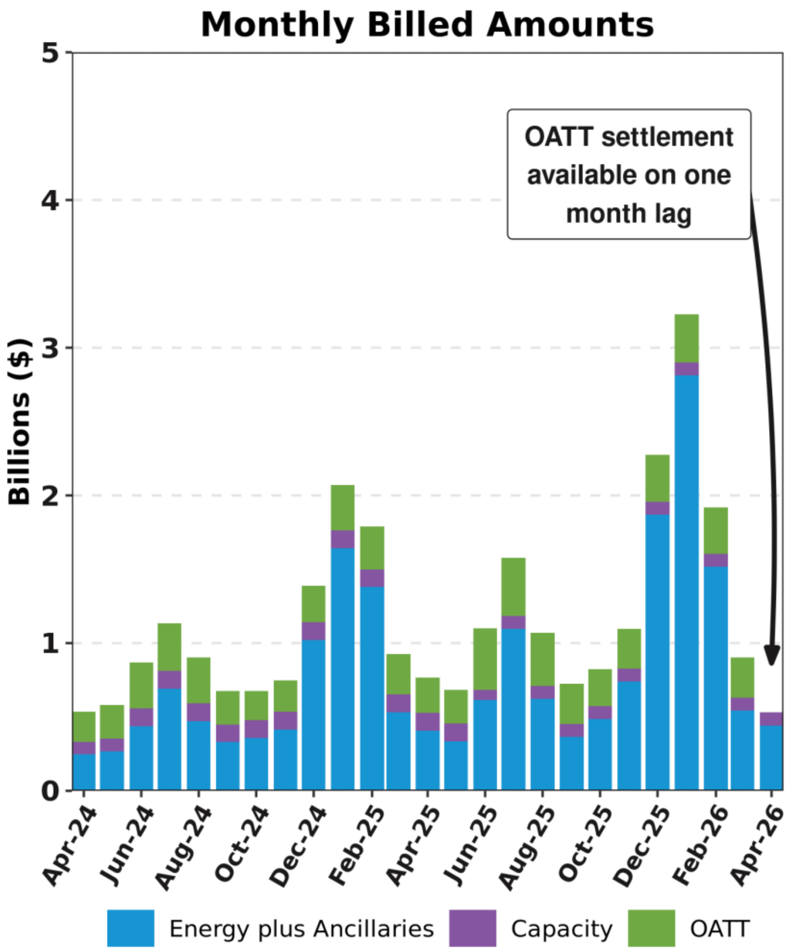
RT First Contingency Charges by Deviation Type

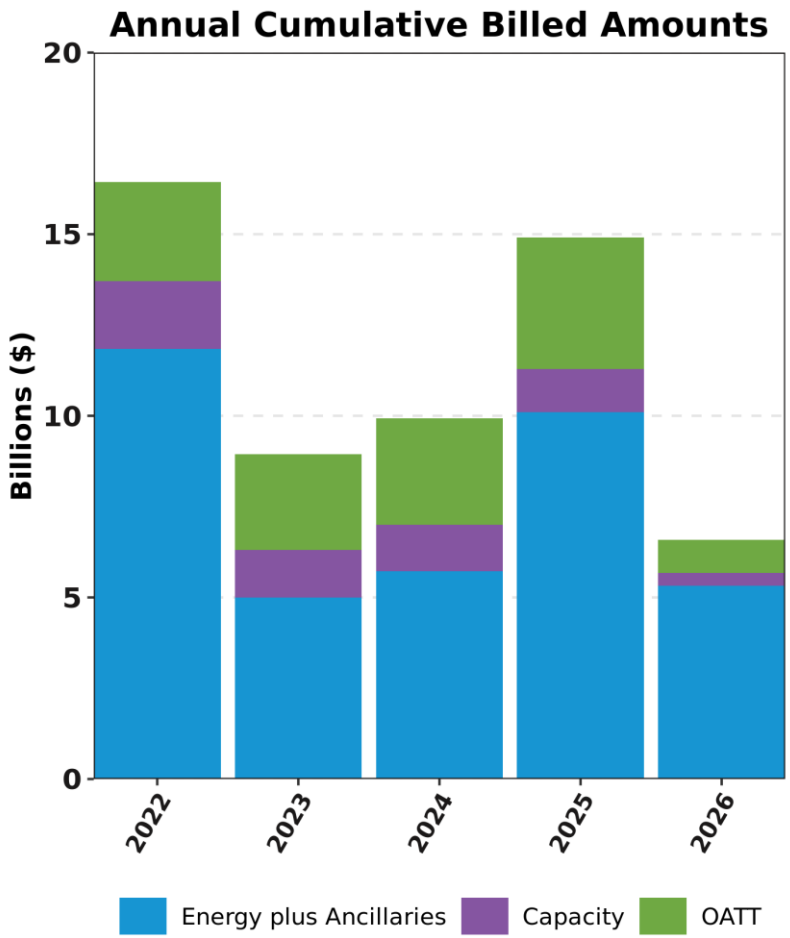




ISO BILLINGS

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)

- May 27 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Low-Pressure Fluid Filled Cable Replacement - Needs Assessment (Avangrid UI)
    - 332 West Farnum to Kent County 345 kV Line Rebuild (RIE)
    - 301 Asset Condition Replacement (NGRID)
    - E-157/E-157E/E-157W Asset Condition Replacement (NGRID)
    - Canal Station 345 kV Autotransformer Replacements – T120 and T126 (Eversource)
  - 2036 New England Short Circuit Needs Assessment Scope
  - Transmission Planning Guide Process Update
  - Transmission Planning Study Assumption Updates
  - 2026 Economic Study - Benchmark Scenario Assumptions
  - 2025 LTTP RFP - Follow-up to RFP Objective Analysis

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

2025 Longer-Term Transmission Planning (LTTP) RFP

- On 12/13/24, NESCOE provided its LTTP RFP request describing the needs to be addressed by 2035:*
  - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
  - Increase the Surowiec-South interface capacity to at least 3,200 MW
  - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind**
- The ISO issued the RFP on 3/31/25, with proposals due by 9/30/25
- The ISO provided an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) at the March PAC meeting
- The next update is scheduled for the May 27 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 further discussions are ongoing
  - ISO-NE would serve as the region's independent, advisory Asset Condition Reviewer (ACR) for Asset Condition Projects (ACPs). The function would provide early, technically rigorous reviews of need, scope, alternatives, and cost drivers—without directing projects or making prudency or siting determinations
- Changes to the Transmission Operating Agreement (TOA) and ISO's Open Access Transmission Tariff (OATT) were introduced at the April TC meeting
  - Some items are subject to further discussions with PTOs
  - Incremental revisions will be presented at the May TC meeting
- Interim project reviews underway to inform permanent design
- Targeting January 2027 go-live, subject to FERC acceptance and operating budget; tariff changes targeted for Q3 2026 filing

Economic Studies: 2026 Study

- The 2026 Economic Study was launched in January
  - The ISO conducted a public survey as part of a lessons learned and presented results at the April 28 PAC meeting
  - 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 4/27/2026

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 4/27/2026

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 4/27/2026

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 4/27/2026

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 4/27/2026

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 4/27/2026

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 4/27/2026

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Nov-24	4
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Dec-26	3

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

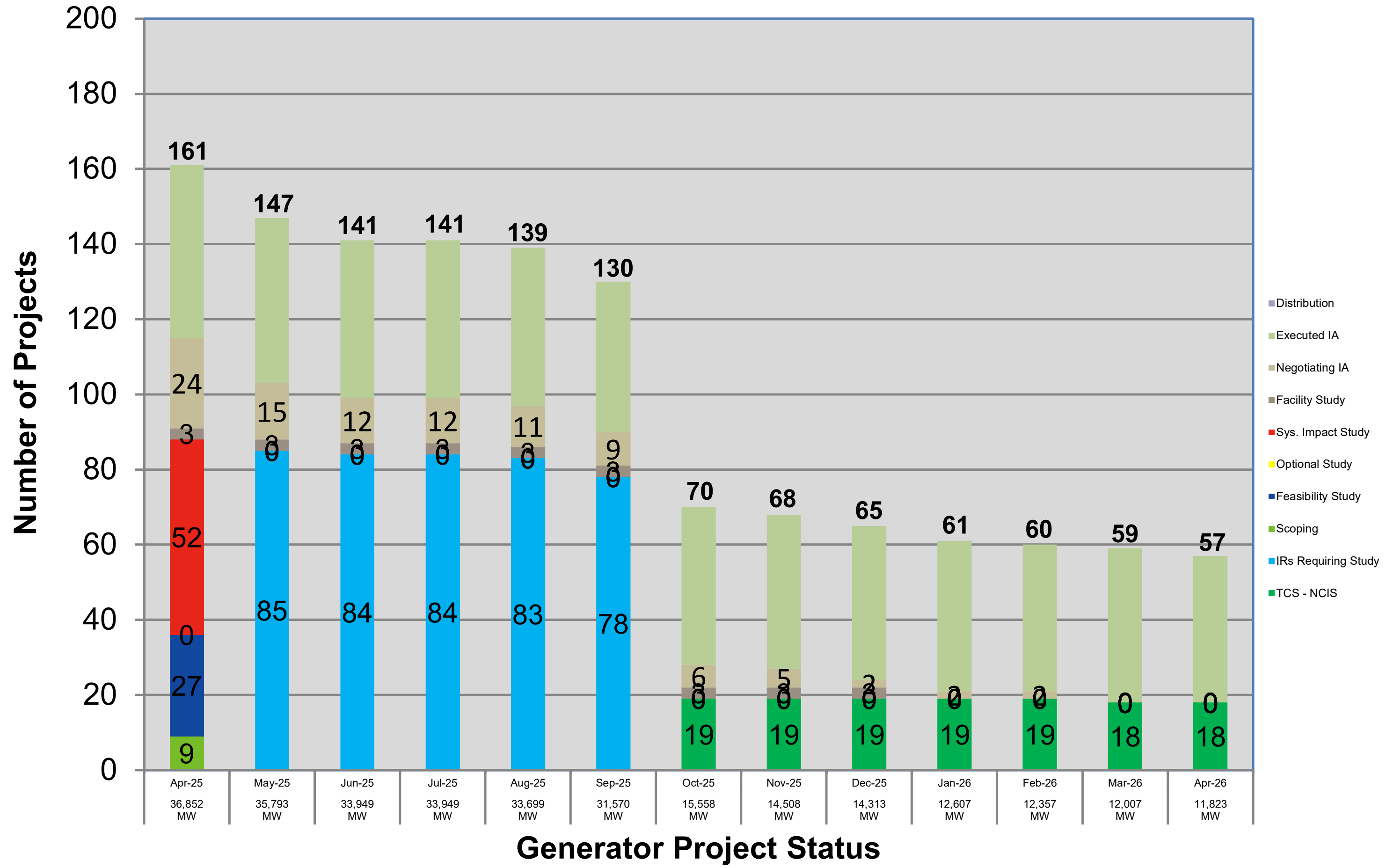
Boston 2033 Solutions Study

Status as of 4/27/2026

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 April 27, 2026



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

Additional Notes provided on next slide

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

Additional Notes:

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

OPERABLE CAPACITY ANALYSIS

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]	26,720	29,941
Active Demand Capacity Resource (+) [5]	345	282
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,073	1,073
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-)	1,908	3,346
Gas Generator Outages MW (-)	2,894	3,351
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)	19,946	21,209
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,668	19,668
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,730	21,730
Operable Capacity Margin	-1,784	-521

[1]Operable Capacity is based on data as of **April 29, 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 **April 29, 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 16, 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]	26,720	29,941
Active Demand Capacity Resource (+) [5]	345	282
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,073	1,073
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-)	1,908	3,346
Gas Generator Outages MW (-)	2,894	3,351
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)	19,946	21,209
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,531	20,531
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,593	22,593
Operable Capacity Margin	-2,647	-1,384

[1]Operable Capacity is based on data as of **April 29, 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 **April 29, 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 16, 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

April 29, 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 May.

Report created: 4/29/2026

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
5/16/2026	26720	345	1073	10	1908	2894	3400	0	19946	19668	2062	21730	-1784	Y	Spring 2026
5/23/2026	26720	345	1073	10	1260	2106	3400	0	21382	20479	2062	22541	-1159	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

April 29, 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 May.

Report created: 4/29/2026

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
5/16/2026	26720	345	1073	10	1908	2894	3400	0	19946	20531	2062	22593	-2647	Y	Spring 2026
5/23/2026	26720	345	1073	10	1260	2106	3400	0	21382	21378	2062	23440	-2058	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.

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

OPERABLE CAPACITY ANALYSIS

Summer 2026 Analysis

Summer 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2026[2] CSO (MW)	June - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,599	27,143
Active Demand Capacity Resource (+) [5]	320	341
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	598	598
Non Commercial Capacity (+)	13	13
Non Gas-fired Planned Outage MW (-)	144	431
Gas Generator Outages MW (-)	119	119
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,467	24,745
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,877	24,877
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,939	26,939
Operable Capacity Margin	-2,472	-2,194

[1]Operable Capacity is based on data as of **April 29, 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 **April 29, 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 30, 2026.**

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

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

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

Summer 2026 Operable Capacity Analysis

90/10 Load Forecast	June - 2026[2] CSO (MW)	June - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,599	27,143
Active Demand Capacity Resource (+) [5]	320	341
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	598	598
Non Commercial Capacity (+)	13	13
Non Gas-fired Planned Outage MW (-)	144	431
Gas Generator Outages MW (-)	119	119
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,467	24,745
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,969	25,969
Operating Reserve Requirement MW	2,062	2,062
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,031	28,031
Operable Capacity Margin	-3,564	-3,286

[1]Operable Capacity is based on data as of **April 29, 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 **April 29, 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 30, 2026.**

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

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

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

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

ISO-NE OPERABLE CAPACITY ANALYSIS

April 29, 2026 - 50-50 FORECAST using CSO MW

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

Report created: 4/29/2026

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
5/30/2026	26599	320	598	13	144	119	2800	0	24467	24877	2062	26939	-2472	Y	Summer 2026
6/6/2026	26599	320	598	13	47	14	2800	0	24669	24877	2062	26939	-2270	N	Summer 2026
6/13/2026	26599	320	598	13	47	14	2800	0	24669	24877	2062	26939	-2270	N	Summer 2026
6/20/2026	26599	320	598	13	60	14	2800	0	24656	24877	2062	26939	-2283	N	Summer 2026
6/27/2026	26599	320	598	13	47	14	2800	0	24669	24877	2062	26939	-2270	N	Summer 2026
7/4/2026	26965	350	409	43	120	14	2100	0	25533	24877	2062	26939	-1406	N	Summer 2026
7/11/2026	26965	350	409	43	42	14	2100	0	25611	24877	2062	26939	-1328	N	Summer 2026
7/18/2026	26965	350	409	43	42	14	2100	0	25611	24877	2062	26939	-1328	N	Summer 2026
7/25/2026	26965	350	409	43	55	14	2100	0	25598	24877	2062	26939	-1341	N	Summer 2026
8/1/2026	26965	350	409	43	55	14	2100	0	25598	24877	2062	26939	-1341	N	Summer 2026
8/8/2026	26965	350	409	43	55	14	2100	0	25598	24877	2062	26939	-1341	N	Summer 2026
8/15/2026	26965	350	409	43	42	14	2100	0	25611	24877	2062	26939	-1328	N	Summer 2026
8/22/2026	26965	350	409	43	42	14	2100	0	25611	24877	2062	26939	-1328	N	Summer 2026
8/29/2026	26965	350	409	43	42	14	2100	0	25611	24877	2062	26939	-1328	N	Summer 2026
9/5/2026	26965	350	409	43	42	45	2100	0	25580	24877	2062	26939	-1359	N	Summer 2026
9/12/2026	26965	350	409	43	42	14	2100	0	25611	24877	2062	26939	-1328	N	Summer 2026

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 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.

Summer 2026 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

April 29, 2026 - 90/10 FORECAST using CSO MW

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

Report created: 4/29/2026

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
5/30/2026	26599	320	598	13	144	119	2800	0	24467	25969	2062	28031	-3564	Y	Summer 2026
6/6/2026	26599	320	598	13	47	14	2800	0	24669	25969	2062	28031	-3362	N	Summer 2026
6/13/2026	26599	320	598	13	47	14	2800	0	24669	25969	2062	28031	-3362	N	Summer 2026
6/20/2026	26599	320	598	13	60	14	2800	0	24656	25969	2062	28031	-3375	N	Summer 2026
6/27/2026	26599	320	598	13	47	14	2800	0	24669	25969	2062	28031	-3362	N	Summer 2026
7/4/2026	26965	350	409	43	120	14	2100	0	25533	25969	2062	28031	-2498	N	Summer 2026
7/11/2026	26965	350	409	43	42	14	2100	0	25611	25969	2062	28031	-2420	N	Summer 2026
7/18/2026	26965	350	409	43	42	14	2100	0	25611	25969	2062	28031	-2420	N	Summer 2026
7/25/2026	26965	350	409	43	55	14	2100	0	25598	25969	2062	28031	-2433	N	Summer 2026
8/1/2026	26965	350	409	43	55	14	2100	0	25598	25969	2062	28031	-2433	N	Summer 2026
8/8/2026	26965	350	409	43	55	14	2100	0	25598	25969	2062	28031	-2433	N	Summer 2026
8/15/2026	26965	350	409	43	42	14	2100	0	25611	25969	2062	28031	-2420	N	Summer 2026
8/22/2026	26965	350	409	43	42	14	2100	0	25611	25969	2062	28031	-2420	N	Summer 2026
8/29/2026	26965	350	409	43	42	14	2100	0	25611	25969	2062	28031	-2420	N	Summer 2026
9/5/2026	26965	350	409	43	42	45	2100	0	25580	25969	2062	28031	-2451	N	Summer 2026
9/12/2026	26965	350	409	43	42	14	2100	0	25611	25969	2062	28031	-2420	N	Summer 2026

Column Definitions

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***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:
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3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
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