

Weekly Market Summary

March 2-8, 2026



About this Report

This report contains eleven sections. They are:

- 1) The [Weekly Highlights](#) section provides brief explanations of notable events that occurred during the week. The tables provided show market results for the current week, prior week, the same week a year ago, and the percentage change this week vs. the prior week and prior year. The highlights also include a detailed explanation of the Day-Ahead and Real-Time price separation for the current week, along with any Real-Time price corrections.
- 2) The [Pricing](#) section contains various graphs presenting information about Locational Marginal Prices (LMPs) and its components for the Hub, Load Zones, and external nodes. A table showing descriptive LMP statistics for these locations is also provided.
- 3) The [Weekly Demand](#) section contains a table describing total Day-Ahead and Real-Time Load Obligation (DALO & RTLO) for the current week, last week, the percentage change from last week, last year, and the percentage change from last year. In addition, there are graphs showing Day-Ahead demand bids and cleared volumes by type. Also included are tables for daily demand bid and virtual volumes and peak load by day with associated Real-Time pricing.
- 4) The [Weekly Supply](#) section contains tables and graphs of Day-Ahead Generation Obligation accumulated from generation, virtual supply, and imports. These exhibits also include the Day-Ahead Demand Reduction Obligation. Information on Real-Time supply including, metered generation by fuel type, self-scheduled MWh, Real-Time reliability MWh, marginal price setting, and external interface imports.
- 5) [Net Commitment Period Compensation \(NCPC\)](#) section includes information and links to the NCPC Summary report.
- 6) The [Energy Market Payment](#) section contains a table showing the payments associated with the Day-Ahead and Real-Time Energy Markets, a pie chart showing the component percentage of the Day-Ahead Energy Market payment, and a bar chart showing the magnitude of each component's contribution to the total Energy Market payment.
- 7) The [Flexible Response Services \(FRS\)](#) section contains tables and graphs related to the FRS clearing rate, the associated closeout charges, cleared FRS product MWh, and FRS payments.
- 8) The [Forecast Energy Requirement \(FER\) and Energy Imbalance Reserves \(EIR\)](#) section contains tables and graphs related to the Forecast Energy Reserve Price (FERP), FER and EIR Obligation MWh, and FER and EIR payments and closeout charges.
- 9) The [Real-Time Reserve Market](#) section contains a table showing the Real-Time Reserve payments by Reserve Zone, two tables with Real-Time Reserve Clearing Prices data, and a table with information related to Real-Time reserve bias implementation.
- 10) The [Capacity Scarcity Condition \(CSC\)](#) section contains preliminary details of any CSC activity that may have occurred during the week.

- 11) The last section of the report, the [Glossary and Links](#) section, contains additional information concerning the sections listed above, including links to relevant pages on the ISO New England web site.

Note: A supplemental Excel file 'Weekly Market Data 53 Weeks.XLSX', located [here](#), contains the past 53 weeks of data of various concepts including market prices, payments, charges, and MWh values.

 Click this icon in the section header to navigate to the glossary section, where definitions are described in more detail, with links to the ISO New England web site.

Weekly Highlights: March 2-8, 2026

1.1 Weekly Highlights

Notable Events

- Real-Time LMPs in excess of \$215/MWh were caused by loads over the forecast in the hour ending 6:00 A.M. on Friday, March 6.

Locational Marginal Pricing (LMPs)	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
New England Hub; \$/MWh; Average					
Day-Ahead Energy Market; All Hours	\$63.83	\$67.90	-6.0%	\$59.03	8.1%
*Real-Time Energy Market; All Hours	\$74.82	\$64.84	15.4%	\$60.31	24.1%

*This is the average of the 5-minute pricing intervals within the week.

Weekly Demand Statistics (MWh)	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Revenue Quality System Peak Load (MWh - Initial)	17,861	17,593	1.5%	17,346	3.0%
DA Load Obligation (All Zones)	-2,407,685	-2,489,746	-3.3%	-2,252,015	6.9%
RT Load Obligation (All Zones)	-2,380,577	-2,412,112	-1.3%	-2,253,184	5.7%
DA Cleared Exports (All Interfaces)	-27,619	-18,111	52.5%	-176,069	-84.3%
RT Scheduled Exports (All Interfaces)	-135,290	-127,578	6.0%	-280,899	-51.8%

Weekly Supply Statistics	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Input Fuel Price (Natural Gas, \$/MMBtu)	\$4.11	\$5.50	-25.3%	\$4.78	-14.1%
Mass Average Input Fuel Price (Natural Gas, \$/MMBtu)	\$4.98	\$7.12	-30.1%	\$5.21	-4.4%
Metered Generation (MWh)	2,026,810	2,019,388	0.4%	2,078,605	-2.5%
Generation Obligation (MWh)	2,565,164	2,589,500	-0.9%	2,570,981	-0.2%
RT Demand Reduction Obligation (MWh)	24	4	454.0%	356	-93.4%
Self-Scheduled Generation (MWh)	841,764	873,048	-3.6%	867,426	-3.0%
DA Cleared Imports (MWh - All Interfaces)	518,249	552,230	-6.2%	426,972	21.4%
RT Scheduled Imports (MWh - All Interfaces)	538,354	570,112	-5.6%	492,375	9.3%

Market Payments	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead and Real-Time Energy Market Payments (\$)	\$168,575,883	\$190,454,800	-11.5%	\$164,235,575	2.6%
Day-Ahead Ancillary Services Market Payments (\$)	\$2,134,519	\$8,175,169	-73.9%	\$3,361,580	-36.5%
Real-Time Reserve Market Payments (\$)	\$49,600	\$12,223	305.8%	\$138,038	-64.1%

Underlying natural gas data furnished by:



Day-Ahead Price Separation

- Negligible.

Real-Time Price Separation

- On Tuesday, March 3, depressed pricing in the Maine (ME) Load Zone was caused by a binding constraint on the Maine – New Hampshire Interface due to patterns of load and generation.

Real-Time Price Corrections

- None.

Year-to-Date Peak Load Statistics*

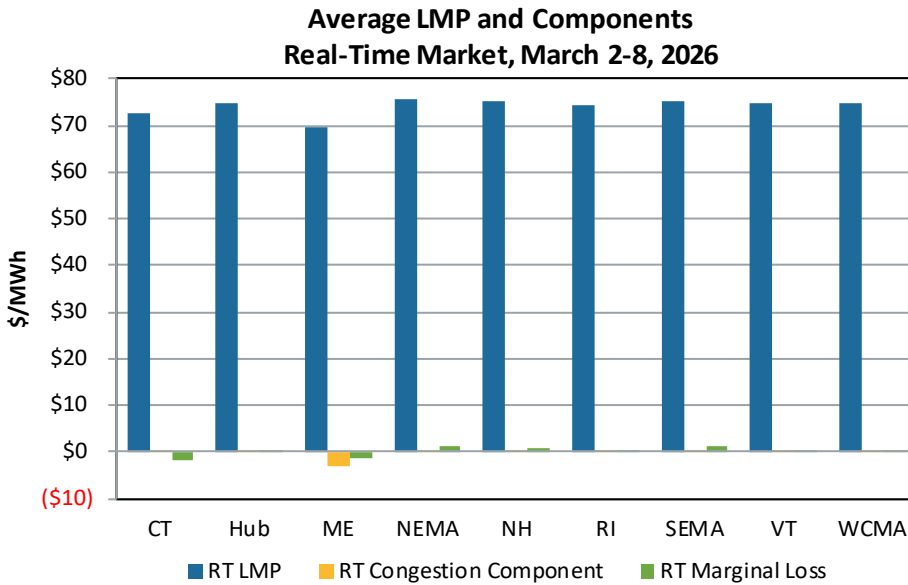
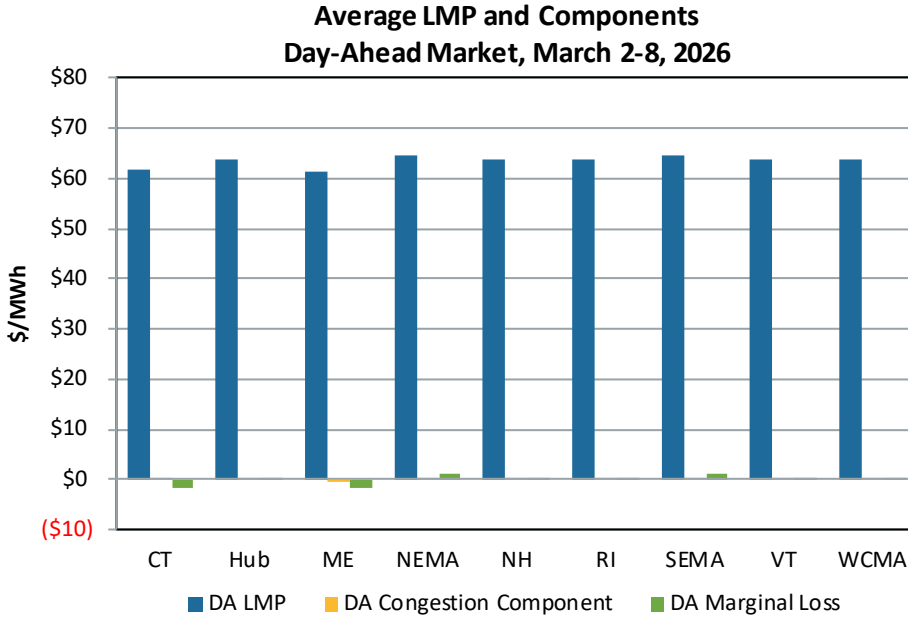
- [FCM Peak Load](#) (preliminary, subject to change) is 19,937 MWh and occurred in the hour ending 1:00 P.M. on Sunday, January 25. At this hour, the Capacity Zone-level FCM peak loads were 2,814 MWh in Northern New England, 1,832 MWh in Maine, 7,535 MWh in Rest-of-Pool, and 7,756 MWh in Southeast New England.
- [Revenue Quality System Peak Load](#) (initial) is 20,221 MWh and occurred in the hour ending 2:00 P.M. on Sunday, January 25.
- [Telemetered System Peak Load](#) is 20,182 MWh and occurred in the hour ending 2:00 P.M. on Sunday, January 25.

*Due to the difference in calculation methodologies, these values can occur on different days and hours.

Pricing

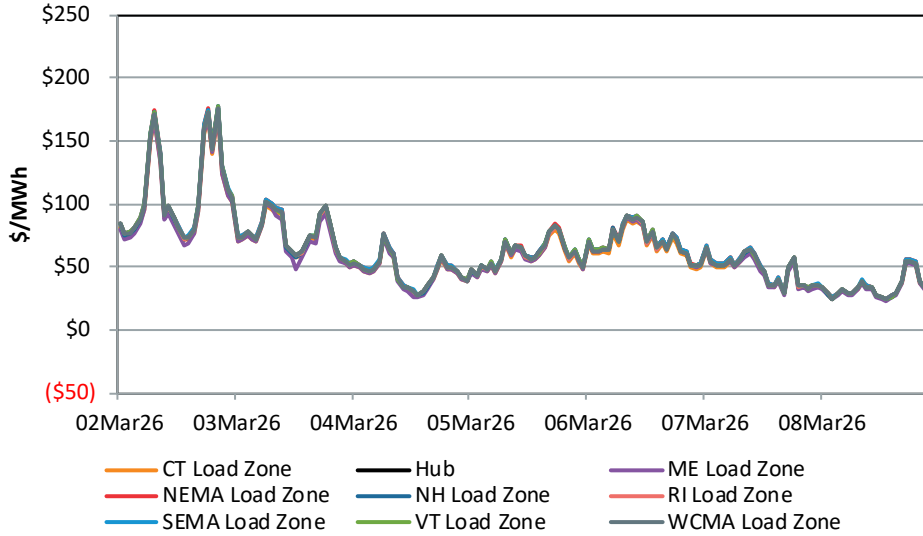
2.1 Pricing

The two graphs below show the weekly average of LMPs, congestion, and marginal loss components at the Hub and Load Zones for both the Day-Ahead and Real-Time Energy Markets.

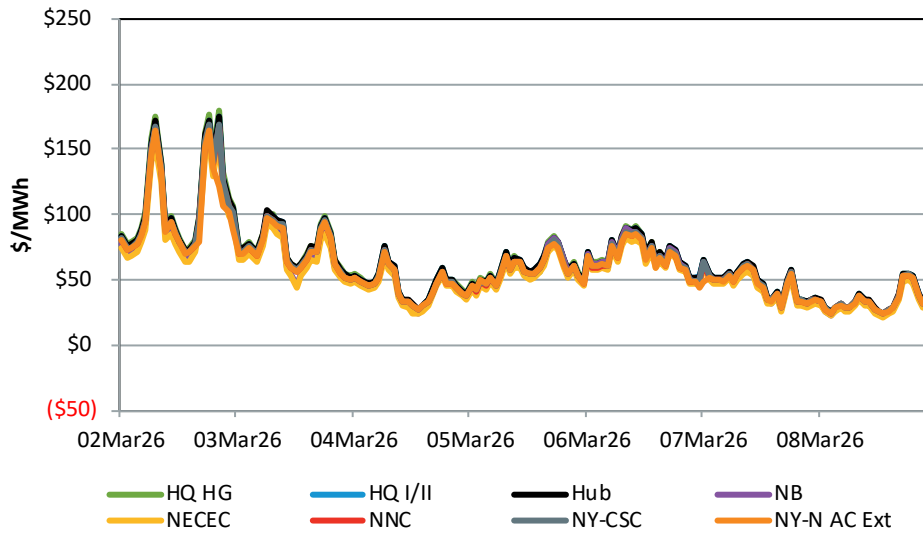


The following two graphs show hourly Day-Ahead LMPs for the Hub, the eight Load Zones, and the seven external nodes. In cases where there is little or no price separation, the lines for multiple locations may be indistinguishable from each other.

Day-Ahead LMPs for Hub and Load Zones
March 2-8, 2026

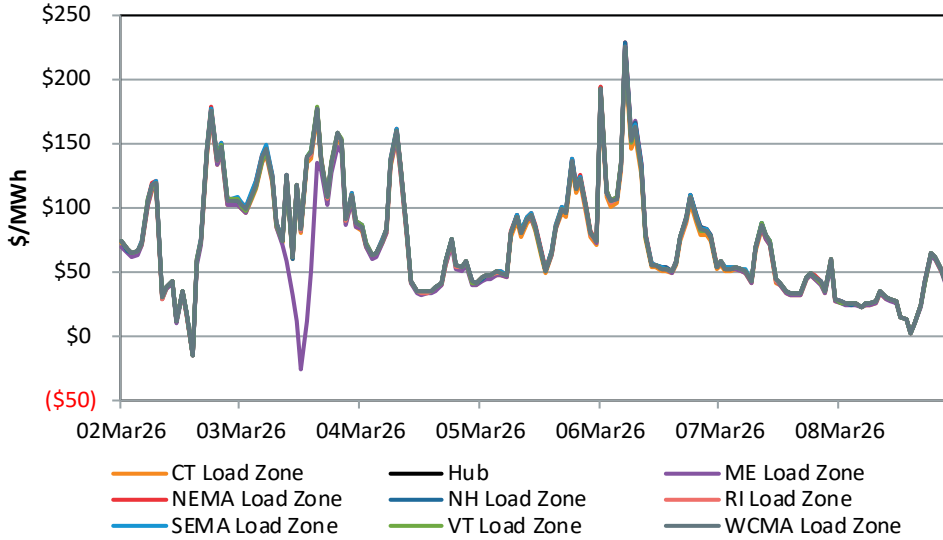


Day-Ahead LMPs for Hub and External Nodes
March 2-8, 2026

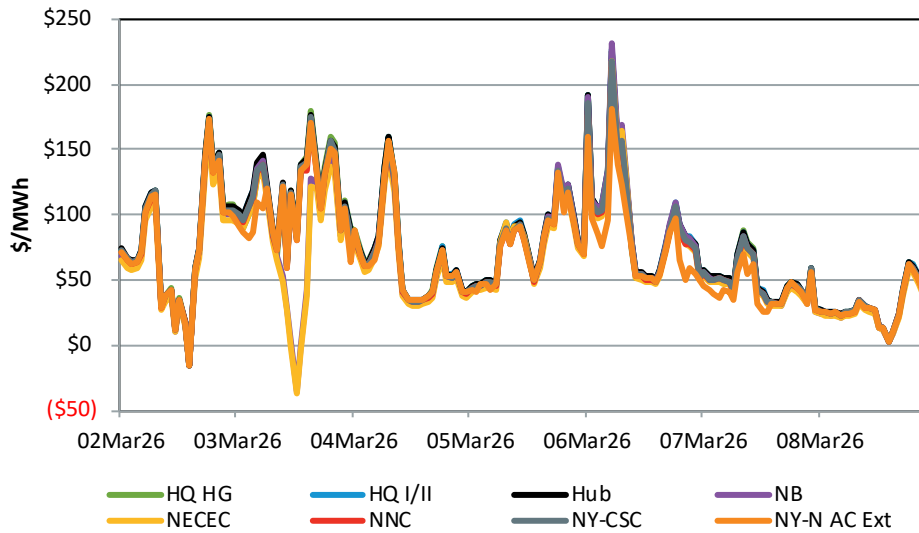


The following two graphs show hourly average Real-Time LMPs for the Hub, the eight Load Zones, and the seven external nodes. The 5-minute LMPs are averaged to create hourly values for comparison. The lines for multiple locations may be indistinguishable from each other.

**Real-Time LMPs for Hub and Load Zones
March 2-8, 2026**



**Real-Time LMPs for Hub and External Nodes
March 2-8, 2026**



LMP Summary Statistics, March 2-8, 2026

Hub/Zone/ Ext. Node	Avg DA LMP (\$/MWh)	*Avg RT LMP (\$/MWh)	Min DA LMP (\$/MWh)	Min RT LMP (\$/MWh)	Max DA LMP (\$/MWh)	Max RT LMP (\$/MWh)	DA as % of Hub	*RT as % of Hub	*RT as % of DA	DA Std Dev	*RT Std Dev	*RT Std/DA Std
Hub	\$63.83	\$74.82	\$24.81	\$-14.90	\$175.70	\$225.05	100%	100%	117%	28.80	42.29	147%
ME	\$61.42	\$69.78	\$23.44	\$-25.90	\$171.17	\$228.87	96%	93%	114%	28.18	41.92	149%
NH	\$63.84	\$75.05	\$24.55	\$-14.90	\$177.64	\$228.17	100%	100%	118%	29.04	42.60	147%
VT	\$63.85	\$74.70	\$24.53	\$-15.05	\$177.44	\$223.28	100%	100%	117%	29.00	42.29	146%
CT	\$61.67	\$72.44	\$24.48	\$-14.77	\$169.44	\$216.06	97%	97%	117%	27.83	40.85	147%
RI	\$63.71	\$74.52	\$24.95	\$-14.83	\$175.15	\$223.17	100%	100%	117%	28.71	42.07	147%
SEMA	\$64.47	\$75.39	\$25.14	\$-15.00	\$177.55	\$225.40	101%	101%	117%	29.10	42.58	146%
WCMA	\$63.76	\$74.82	\$24.85	\$-14.94	\$175.27	\$225.28	100%	100%	117%	28.76	42.31	147%
NEMA	\$64.46	\$75.63	\$24.99	\$-15.05	\$178.25	\$228.22	101%	101%	117%	29.20	42.80	147%
NB Ext	\$60.06	\$68.39	\$22.86	\$-34.85	\$167.20	\$230.92	94%	91%	114%	27.75	42.11	152%
NY-N AC Ext	\$60.25	\$68.48	\$24.18	\$-14.83	\$164.03	\$181.28	94%	92%	114%	26.08	38.62	148%
HQ Ext	\$63.50	\$74.77	\$24.74	\$-14.93	\$175.04	\$226.84	99%	100%	118%	28.62	42.25	148%
HG Ext	\$63.99	\$73.70	\$24.28	\$-15.10	\$179.54	\$214.77	100%	99%	115%	29.52	41.80	142%
CSC Ext	\$61.79	\$72.88	\$24.48	\$-14.82	\$169.81	\$217.39	97%	97%	118%	27.99	41.33	148%
NNC Ext	\$61.22	\$71.85	\$24.48	\$-14.89	\$168.00	\$213.76	96%	96%	117%	27.62	40.42	146%
NECEC Ext	\$56.92	\$64.99	\$21.80	\$-37.39	\$158.18	\$218.62	89%	87%	114%	26.02	39.99	154%

*This is the average of the 5-minute pricing intervals within the week.

5-Minute LMP Summary (RT Only)
March 2-8, 2026

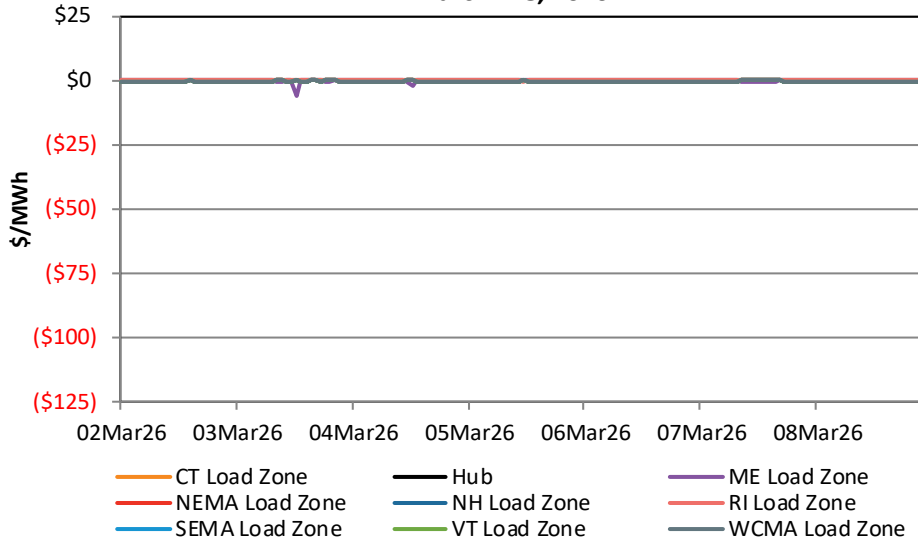
Hub/Zone	Max RT LMP (\$/MWh)	Min RT LMP (\$/MWh)	RT Std Dev	RT as % of Hub
Hub	\$296.09	-\$43.52	\$47.26	100%
ME	\$299.68	-\$41.57	\$46.14	94%
NH	\$300.74	-\$43.61	\$47.56	100%
VT	\$297.47	-\$43.96	\$47.25	100%
CT	\$284.54	-\$43.04	\$45.66	97%
RI	\$293.54	-\$43.30	\$47.02	100%
SEMA	\$296.35	-\$43.83	\$47.58	101%
WCMA	\$296.50	-\$43.64	\$47.28	100%
NEMA	\$300.03	-\$44.00	\$47.82	101%

5-Minute Energy Component of LMP
March 2-8, 2026

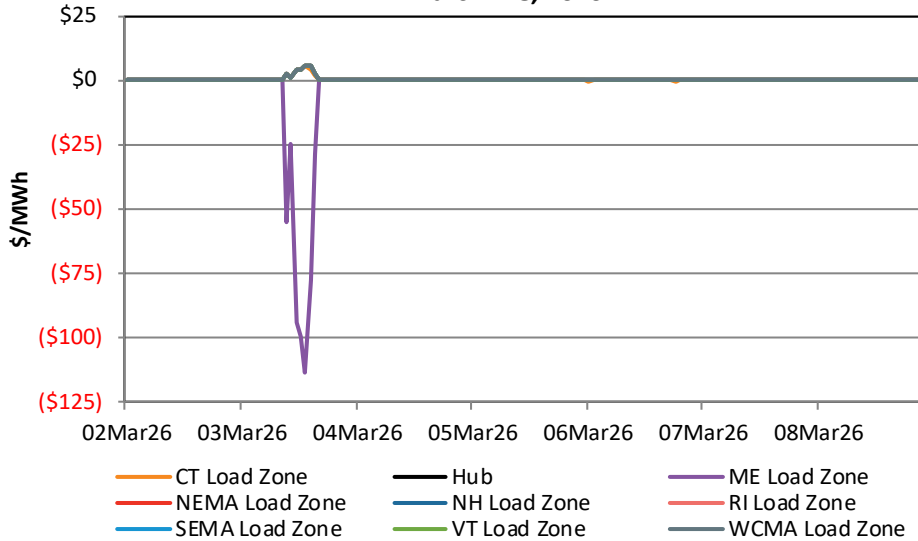
Frequency Tabulation	< \$0.00	\$0.00 - \$20.99	\$21.00 - \$40.99	\$41.00 - \$70.99	\$71.00 - \$100.99	\$100.00 - \$150.99	\$150.00 - \$200.99	\$200.00 - \$500.99	\$500.00 - \$1000.99	> \$1000.99
5-Minute Energy	1.0%	3.4%	19.3%	34.7%	17.0%	17.5%	5.2%	1.9%	0.0%	0.0%

The next two graphs show hourly Day-Ahead and hourly Real-Time congestion components for the Hub and each of the eight Load Zones. The 5-minute values are averaged to create hourly values for comparison. The lines for multiple locations may be indistinguishable from each other.

**Day-Ahead Congestion Component for Hub and Load Zones
March 2-8, 2026**



**Real-Time Congestion Component for Hub and Load Zones
March 2-8, 2026**



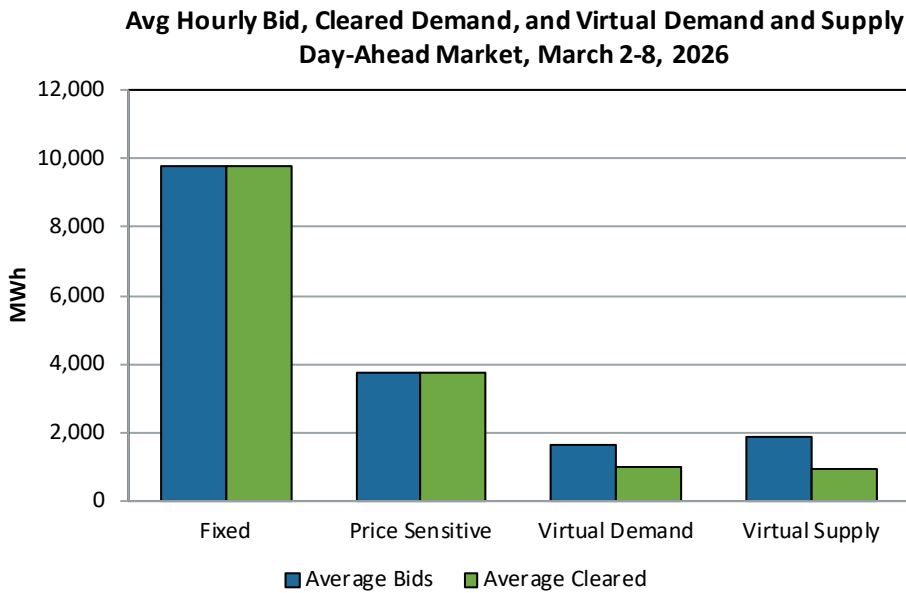
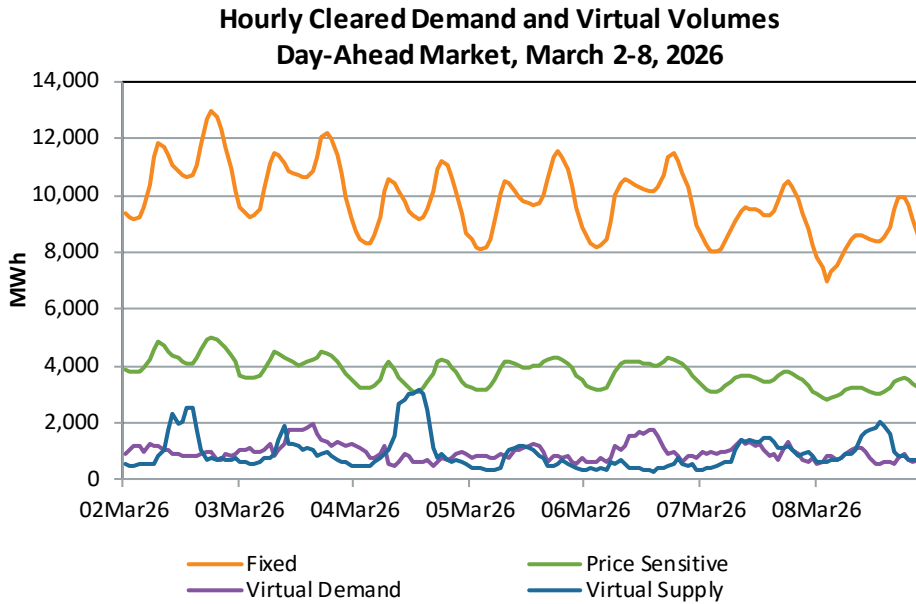
Energy Market Demand

3.1 Day-Ahead Demand

The following table displays the Day-Ahead Load Obligation at the Hub, Load Zones, and external nodes for this week, last week, the same week a year ago and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
Hub	36,279	38,434	-5.6%	16,746	116.6%
ME	214,793	222,096	-3.3%	220,050	-2.4%
NH	223,780	233,646	-4.2%	220,045	1.7%
VT	103,328	115,257	-10.3%	105,332	-1.9%
CT	538,066	562,090	-4.3%	503,661	6.8%
RI	155,713	151,191	3.0%	135,738	14.7%
SEMA	280,615	285,003	-1.5%	260,413	7.8%
WCMA	322,416	338,241	-4.7%	308,871	4.4%
NEMA	476,045	493,811	-3.6%	451,276	5.5%
NB Ext	2,977	366	Large	1,615	84.3%
NY-N AC Ext	28,685	37,827	-24.2%	70,560	-59.3%
HQ Ext	7	0	N/A	76,356	-100.0%
HG Ext	37,181	34,547	7.6%	11,894	212.6%
CSC Ext	8,644	6,143	40.7%	24,268	-64.4%
NNC Ext	0	1	-100.0%	7,866	-100.0%
NECEC Ext	0	0	N/A	N/A	N/A

Participants can bid fixed and price sensitive demand as well as submit virtual demand bids and virtual supply offers into the Day-Ahead Energy Market. The first graph below shows hourly cleared values for these four categories of bids and offers. The second graph shows average hourly values for the week.



Daily Demand Bid and Virtual Volumes by Zone (MWh)
March 2-8, 2026

The following table summarizes Day-Ahead demand bid volumes submitted and cleared at the Hub and in the eight Load Zones (including nodal locations within each Load Zone) along with virtual demand (Decrement or 'Dec') bids and supply (Increment or 'Inc') offers on the same basis.

Location	Day	Fixed Demand Bids	Price Sens. Bids	Dec Bids	Inc Offers	Cleared Fixed Demand	Cleared Price Sens. Demand	Cleared Decs	Cleared Incs	Total DA Demand
Hub	02MAR26	0	0	6,218	5,899	0	0	4,018	5,469	4,018
Hub	03MAR26	0	0	10,974	2,396	0	0	7,901	1,423	7,901
Hub	04MAR26	0	0	4,165	8,488	0	0	3,473	5,542	3,473
Hub	05MAR26	0	0	7,083	2,485	0	0	4,531	1,083	4,531
Hub	06MAR26	0	0	10,606	1,591	0	0	7,090	1,417	7,090
Hub	07MAR26	0	0	7,085	3,306	0	0	5,560	2,099	5,560
Hub	08MAR26	0	0	4,504	5,309	0	0	3,705	4,306	3,705
ME	02MAR26	25,956	9,585	1,470	16,196	25,956	9,585	691	10,386	36,233
ME	03MAR26	23,528	8,326	1,237	17,178	23,528	8,326	799	10,000	32,653
ME	04MAR26	21,871	7,413	1,227	22,739	21,871	7,413	856	12,675	30,140
ME	05MAR26	22,430	7,868	1,375	16,483	22,430	7,868	716	8,107	31,014
ME	06MAR26	23,084	8,153	1,962	10,934	23,084	8,153	1,440	5,092	32,676
ME	07MAR26	21,507	7,515	1,579	20,730	21,507	7,515	1,360	12,191	30,382
ME	08MAR26	18,820	6,603	932	14,719	18,820	6,603	714	11,278	26,136
NH	02MAR26	29,745	6,271	1,656	1,824	29,745	6,271	1,196	1,281	37,212
NH	03MAR26	29,080	5,287	2,153	1,579	29,080	5,287	1,400	701	35,767
NH	04MAR26	26,198	4,912	1,078	3,502	26,198	4,912	419	2,239	31,528
NH	05MAR26	26,346	5,125	1,634	2,453	26,346	5,125	858	566	32,329
NH	06MAR26	27,338	4,951	1,857	1,215	27,338	4,951	916	557	33,205
NH	07MAR26	24,796	4,563	1,152	1,545	24,796	4,563	735	1,143	30,094
NH	08MAR26	22,192	4,072	1,116	1,685	22,192	4,072	729	1,281	26,992
VT	02MAR26	1,424	13,737	2,121	1,560	1,424	13,737	1,661	1,143	16,822
VT	03MAR26	1,400	14,236	1,713	2,833	1,400	14,236	1,024	1,005	16,660
VT	04MAR26	1,238	11,905	949	3,597	1,238	11,905	442	1,752	13,585
VT	05MAR26	1,199	13,232	1,429	2,027	1,199	13,232	748	679	15,179
VT	06MAR26	1,270	13,796	1,609	1,496	1,270	13,796	932	848	15,999
VT	07MAR26	1,353	12,735	1,025	2,380	1,353	12,735	712	1,691	14,801
VT	08MAR26	1,380	10,808	643	1,644	1,380	10,808	474	1,331	12,661
CT	02MAR26	59,713	27,489	3,929	2,034	59,713	27,489	2,060	1,357	89,261
CT	03MAR26	58,937	25,998	3,812	4,091	58,937	25,998	2,207	2,999	87,141
CT	04MAR26	51,433	22,400	2,533	2,628	51,433	22,400	1,998	1,260	75,830
CT	05MAR26	52,076	24,337	4,174	2,014	52,076	24,337	2,399	532	78,812
CT	06MAR26	52,316	23,929	3,975	2,093	52,316	23,929	3,039	526	79,284
CT	07MAR26	47,901	22,209	2,158	1,314	47,901	22,209	1,939	807	72,049
CT	08MAR26	41,855	19,233	1,307	857	41,855	19,233	1,164	687	62,251
RI	02MAR26	16,735	5,868	1,841	2,377	16,735	5,868	814	1,601	23,417
RI	03MAR26	16,402	5,479	3,240	2,265	16,402	5,479	2,328	946	24,209

Weekly Market Summary



Location	Day	Fixed Demand Bids	Price Sens. Bids	Dec Bids	Inc Offers	Cleared Fixed Demand	Cleared Price Sens. Demand	Cleared Decs	Cleared Incs	Total DA Demand
RI	04MAR26	15,274	4,869	2,237	4,035	15,274	4,869	1,494	1,522	21,637
RI	05MAR26	15,375	5,340	3,733	2,371	15,375	5,340	2,094	970	22,809
RI	06MAR26	15,595	5,255	4,148	1,648	15,595	5,255	2,267	694	23,117
RI	07MAR26	14,643	4,566	3,283	2,338	14,643	4,566	3,149	1,267	22,358
RI	08MAR26	12,919	4,138	2,313	1,206	12,919	4,138	2,060	864	19,116
SEMA	02MAR26	32,887	12,060	1,370	1,833	32,887	12,060	603	1,616	45,550
SEMA	03MAR26	31,522	10,616	1,295	2,189	31,522	10,616	745	871	42,883
SEMA	04MAR26	28,347	9,468	949	3,018	28,347	9,468	428	1,692	38,242
SEMA	05MAR26	29,656	10,106	2,090	1,149	29,656	10,106	1,130	435	40,891
SEMA	06MAR26	30,088	10,207	1,861	791	30,088	10,207	1,128	344	41,422
SEMA	07MAR26	28,183	9,070	1,281	1,226	28,183	9,070	1,114	652	38,366
SEMA	08MAR26	25,190	8,065	766	2,684	25,190	8,065	681	1,174	33,936
WCMA	02MAR26	39,028	11,810	5,145	1,853	39,028	11,703	4,520	1,423	55,250
WCMA	03MAR26	38,896	10,780	5,343	2,928	38,896	10,672	4,594	2,080	54,162
WCMA	04MAR26	35,433	9,835	1,208	3,191	35,433	9,727	942	2,013	46,103
WCMA	05MAR26	35,689	10,332	1,984	1,435	35,689	10,226	1,229	969	47,145
WCMA	06MAR26	36,194	10,236	2,149	909	36,194	10,114	1,504	452	47,812
WCMA	07MAR26	33,252	8,588	1,802	1,013	33,252	8,500	1,630	913	43,382
WCMA	08MAR26	29,269	7,771	1,104	1,032	29,269	7,771	993	892	38,033
NEMA	02MAR26	57,936	18,187	2,301	1,663	57,936	18,127	1,165	1,198	77,228
NEMA	03MAR26	55,732	16,614	2,317	1,668	55,732	16,602	1,098	383	73,431
NEMA	04MAR26	51,882	15,064	1,642	4,322	51,882	15,064	955	2,393	67,901
NEMA	05MAR26	52,081	15,813	4,048	1,776	52,081	15,813	1,921	578	69,815
NEMA	06MAR26	52,278	15,956	2,974	1,108	52,278	15,956	1,266	285	69,500
NEMA	07MAR26	48,179	14,054	1,832	1,109	48,179	14,054	1,323	1,080	63,556
NEMA	08MAR26	42,714	12,175	675	1,288	42,714	12,175	630	1,246	55,519

3.2 Real-Time Demand

The following table displays the Real-Time Load Obligation at each Load Zone and external nodes for this week, last week, the same week a year ago, and the percentage change for each.

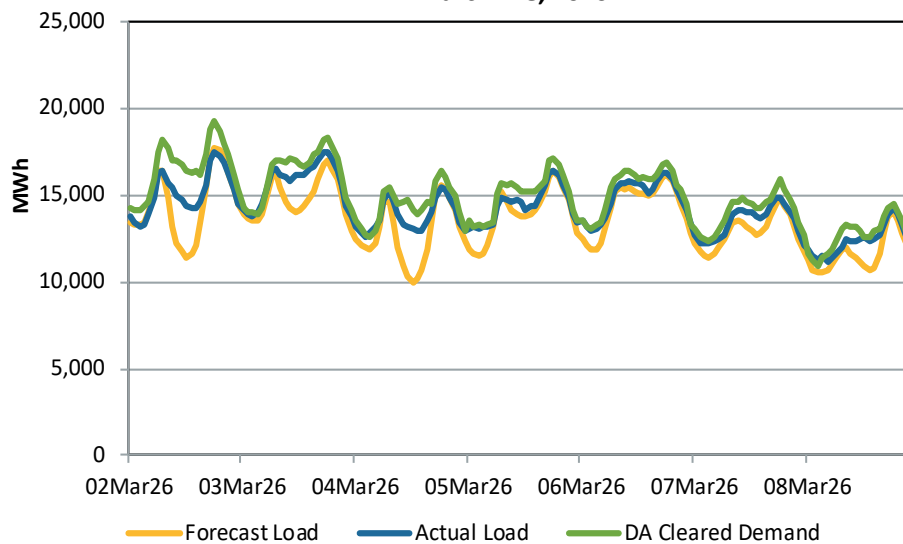
Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
ME	217,390	228,000	-4.7%	219,692	-1.0%
NH	230,918	235,162	-1.8%	223,156	3.5%
VT	98,291	109,521	-10.3%	100,081	-1.8%
CT	542,492	553,837	-2.0%	510,610	6.2%
RI	147,860	147,316	0.4%	142,021	4.1%
SEMA	285,634	274,117	4.2%	267,794	6.7%
WCMA	329,221	333,024	-1.1%	310,705	6.0%
NEMA	477,757	486,494	-1.8%	449,443	6.3%
NB Ext	4,621	3,806	21.4%	6,884	-32.9%
NY-N AC Ext	115,646	109,088	6.0%	158,903	-27.2%
HQ Ext	0	3	-100.0%	76,900	-100.0%
HG Ext	6	52	-88.5%	2,241	-99.7%
CSC Ext	15,017	13,651	10.0%	24,964	-39.8%
NNC Ext	0	978	-100.0%	11,008	-100.0%
NECEC Ext	0	0	N/A	N/A	N/A

Real-Time Peak Hour System Load and Associated Average Hourly LMPs

Day	Hour	System Load (MWh)	Hub	Maine Load Zone	NH Load Zone	VT Load Zone	CT Load Zone	RI Load Zone	SEMA Load Zone	WCMA Load Zone	NEMA Load Zone
02MAR26	19	17,786	\$175.48	\$171.78	\$176.46	\$175.73	\$171.05	\$175.29	\$177.53	\$175.43	\$177.83
03MAR26	19	17,861	\$134.22	\$126.80	\$133.94	\$136.00	\$131.42	\$133.53	\$134.57	\$134.64	\$134.76
04MAR26	19	15,779	\$75.20	\$71.58	\$75.09	\$75.67	\$73.04	\$74.71	\$75.92	\$75.23	\$75.95
05MAR26	19	16,743	\$136.25	\$136.85	\$137.78	\$135.57	\$131.82	\$135.21	\$137.26	\$136.09	\$138.76
06MAR26	19	16,640	\$108.76	\$109.88	\$110.60	\$108.09	\$104.34	\$107.85	\$109.43	\$108.60	\$110.62
07MAR26	19	15,193	\$49.26	\$47.18	\$49.31	\$49.09	\$47.71	\$49.09	\$49.59	\$49.21	\$49.81
08MAR26	20	14,500	\$64.38	\$62.34	\$64.39	\$64.19	\$62.48	\$64.58	\$65.04	\$64.32	\$65.13

The graph below compares the hourly quantities of cleared Day-Ahead demand with the forecast and actual load. Cleared demand is the total of cleared fixed demand bids, cleared price sensitive demand bids, and cleared Decrement bids.

Cleared Demand, Forecast Load, and Actual Load
March 2-8, 2026



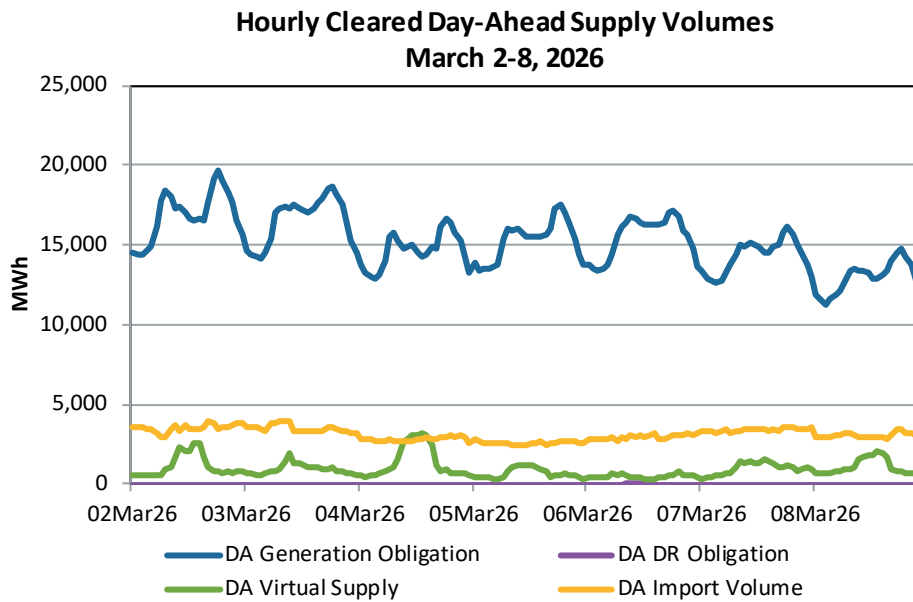
The table below compares the total quantities (MWh) of Day-Ahead Load Obligation with the Real-Time Load Obligation for each Load Zone (including nodal locations within each Load Zone) for the week. Day-Ahead Load Obligation is composed of Day-Ahead cleared demand bids and cleared Decrement bids. Real-Time Load Obligation is comprised of metered load and internal bilateral contracts for load.

Zone	DA Load Obligation (MWh)	RT Load Obligation (MWh)	DA Delta (MWh)	DA % of RT
ME	219,234	220,406	-1,173	99.5%
NH	227,128	231,396	-4,268	98.2%
VT	105,706	98,291	7,414	107.5%
CT	545,570	543,884	1,686	100.3%
RI	156,664	147,860	8,803	106.0%
SEMA	281,291	291,057	-9,766	96.6%
WCMA	358,860	369,839	-10,978	97.0%
NEMA	476,954	477,845	-890	99.8%

Energy Market Supply ?

4.1 Day-Ahead Supply

The following graph displays hourly Day-Ahead Generation Obligation, along with cleared Day-Ahead Increment offers (virtual supply), Day-Ahead Demand Reduction (DR) Obligation, and Day-Ahead Import volume.



The following table displays the average hourly Day-Ahead Generation and Day-Ahead Demand Reduction Obligation, along with cleared Day-Ahead Virtual Supply and Day-Ahead Import Volume, for this week, last week, the same week a year ago, and the percentage change for each.

Type	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
DA Generation Obligation	15,167	15,693	-3.4%	14,867	2.0%
DA Demand Reduction Obligation	0	0	N/A	1	-100.0%
DA Cleared Increments	943	1,045	-9.8%	1,003	-6.0%
DA Imports	3,103	3,307	-6.2%	2,557	21.4%

The following table provides the total Day-Ahead Imports by Interface for This Week, Last Week, the same week a year ago and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	29,298	27,869	5.1%	52,799	-44.5%
NY-N AC Ext	234,009	236,678	-1.1%	239,726	-2.4%
HQ Ext	30,122	52,267	-42.4%	105,861	-71.5%
HG Ext	37,947	46,501	-18.4%	25,765	47.3%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	0	1,921	0.0%	1,471	0.0%
NECEC Ext	186,873	186,993	-0.1%	N/A	N/A

4.2 Real-Time Supply

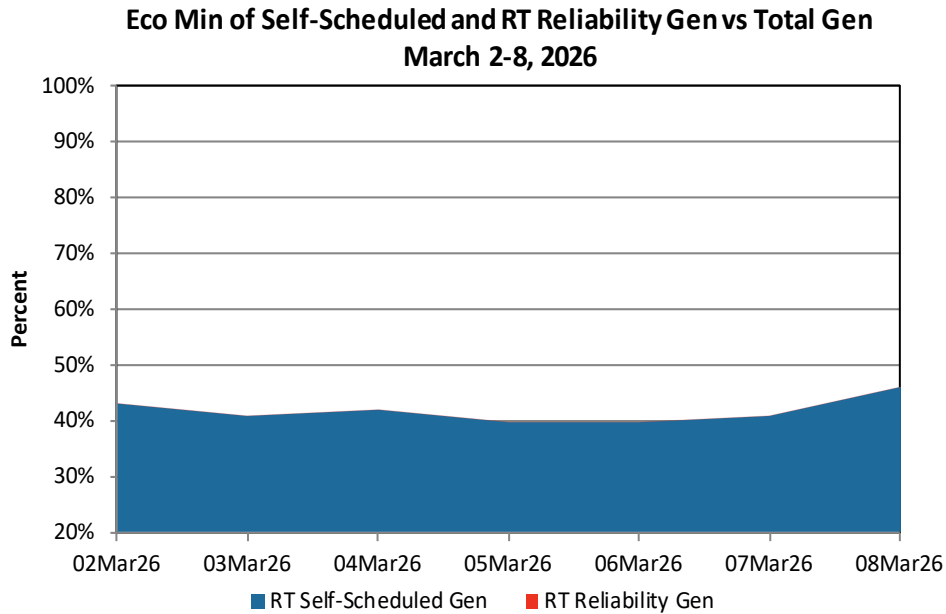
The following table provides daily and weekly totals, in megawatt-hours (MWh), of the amount of electricity produced by classified fuel type during the week. The data provided are for the full system, including “settlement only” resources that do not offer their output into the wholesale markets. The Price Responsive Demand (PRD) category below refers to Demand Reduction from Demand Response Resources (DRR). Annual files of Daily Generation by Fuel Type and further detail of the fuels composing the categories below may be found on the ISO’s web site [here](#).

Category	Metered Generation (Megawatt hours)							Total
	02Mar26	03Mar26	04Mar26	05Mar26	06Mar26	07Mar26	08Mar26	
Coal	138	119	112	97	116	28	4	614
Hydro	20,172	15,217	14,659	18,968	17,513	12,145	12,670	111,344
Landfill Gas	803	795	842	572	343	368	306	4,029
Methane	41	46	45	51	38	30	22	273
Natural Gas	165,386	182,196	144,197	177,540	176,017	127,717	92,958	1,066,011
Nuclear	80,603	80,617	80,628	80,622	80,618	80,630	77,274	560,992
Oil	1,299	3	0	1	33	0	0	1,336
Other	3,567	1,930	3,178	2,027	1,631	949	1,138	14,420
PRD	0	1	0	0	23	0	0	24
Refuse	5,555	5,477	5,493	5,814	5,612	5,495	5,476	38,922
Solar	18,122	7,298	15,157	7,287	5,037	4,795	8,854	66,550
Wind	12,424	15,764	17,103	11,314	10,981	19,352	24,351	111,289
Wood	7,432	7,601	7,483	7,526	7,557	7,005	6,421	51,025
Total	315,542	317,064	288,897	311,819	305,519	258,514	229,474	2,026,829

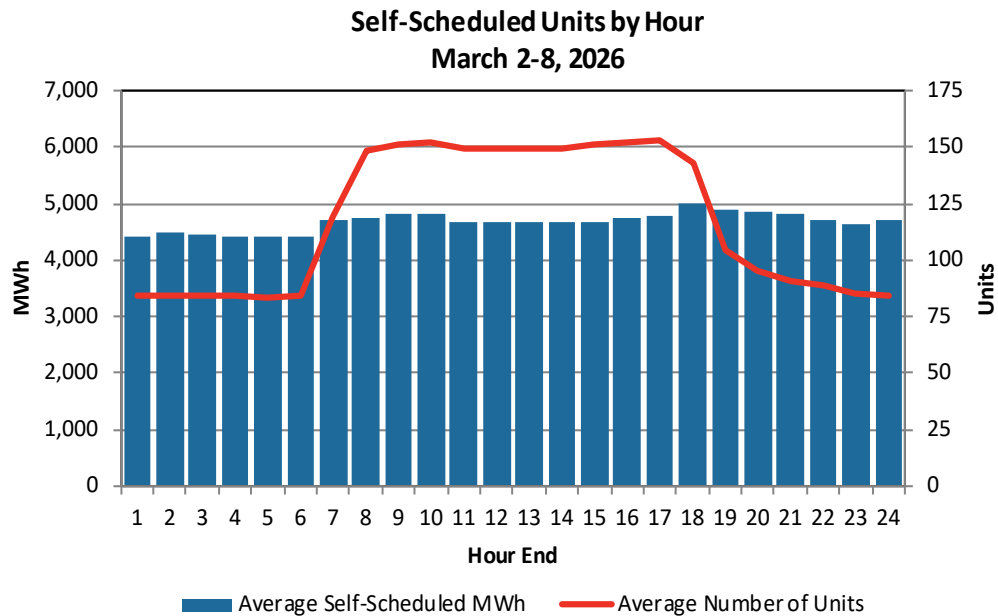
Online generators that are at their Economic Minimum output level are not eligible to set the clearing price. Real-Time Self-Scheduled Generation shown below reflects output by self-scheduled generation and by (non-dispatchable) Settlement Only Resources (SORs). Real-Time Reliability Generation represents the aggregate economic minimum output level of generation committed for reliability reasons. The following table shows the sum of generation self-scheduled (and SORs), and that of Real-Time reliability committed units, and, for reference, the total daily generation in megawatts by day for the current week.

Day	Self-Scheduled MWh	RT Reliability MWh	Total Generation MWh
02Mar26	135,432	0	315,542
03Mar26	128,532	0	317,064
04Mar26	121,620	0	288,897
05Mar26	124,877	0	311,821
06Mar26	121,262	0	305,520
07Mar26	104,876	0	258,514
08Mar26	105,165	0	229,476

The following graph shows the total economic minimum MWh of self-scheduled generation and generation committed for reliability as a percentage of total generation.



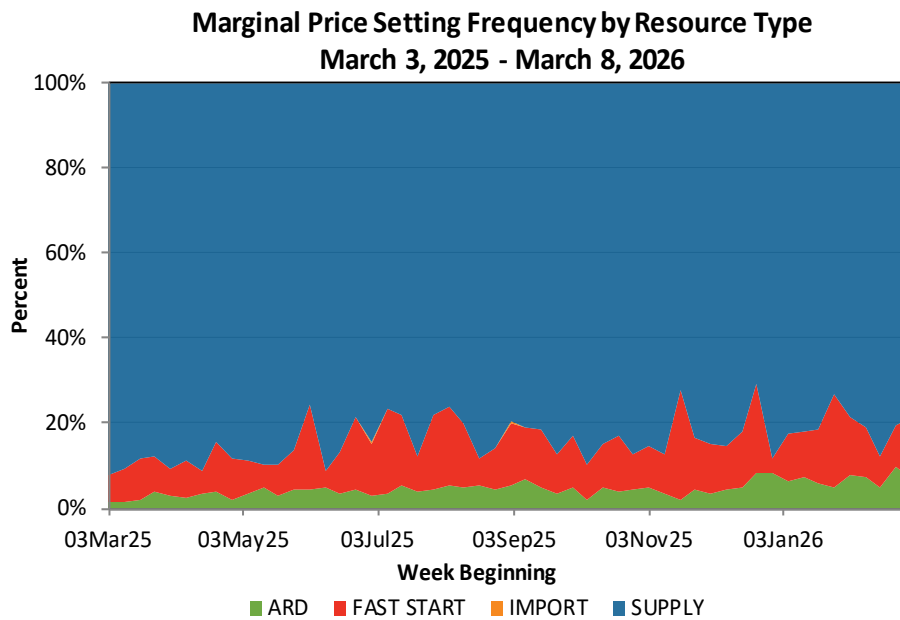
The following graph shows the average number of self-scheduled generating units and MWh for each hour of the last week.



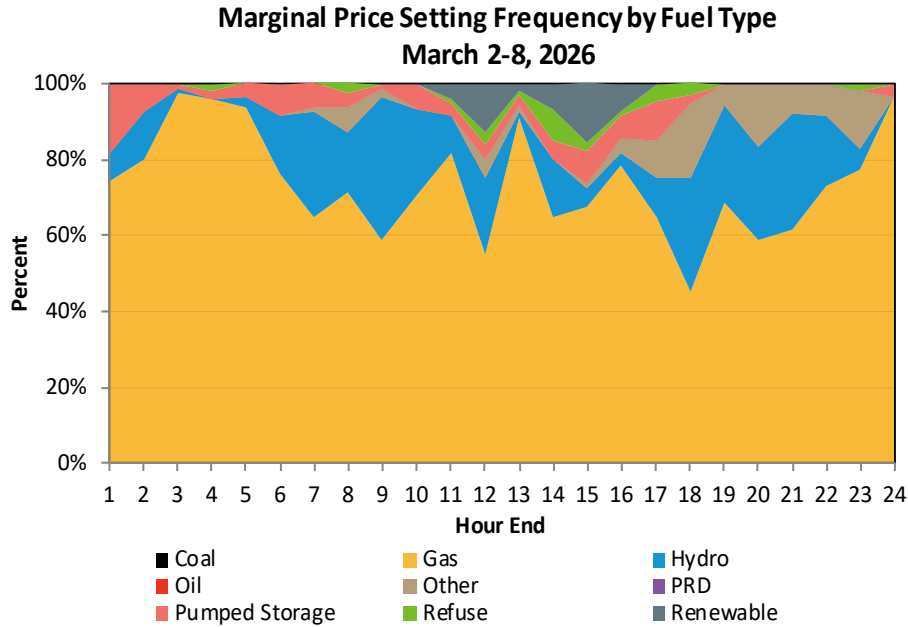
The following table provides the total Real-Time Imports by Interface for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	27,522	26,139	5.3%	37,863	-27.3%
NY-N AC Ext	300,848	298,469	0.8%	322,286	-6.7%
HQ Ext	24,327	45,586	-46.6%	107,851	-77.4%
HG Ext	8,848	10,681	-17.2%	21,922	-59.6%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	0	2,344	-100.0%	2,454	-100.0%
NECEC Ext	176,809	186,893	-5.4%	N/A	N/A

The following graph shows the percentage of time in which a particular resource-type was responsible for setting the price during each of the last 52 weeks.



The next graph shows the percentage of time in which a registered fuel type was responsible for setting the price during each hour of the last week. The Price Responsive Demand (PRD) category below refers to Demand Reduction Obligation from Demand Response Resources (DRR). The exhibit only summarizes the intervals in which one unit was marginal, which was 57% of all intervals during the week. For a load-weighted analysis of marginality, see Section 3.2 of Quarterly Markets Report, located [here](#).



Net Commitment Period Compensation (NCPC)

5.1 Net Commitment Period Compensation

NCPC information does not appear in this report. Aggregate NCPC data continues to be provided in the supplemental Excel file on a one-week lag.

An NCPC Summary report is published to the [Market Performance Reports](#) webpage each Thursday or Friday.

The NCPC summary features daily-level summary charges and includes new detailed information concerning:

- Day-Ahead (DA) and Real-Time (RT) First Contingency payments to both internal and external payees
- DA and RT Second Contingency payments, including reliability region detail
- Voltage, Distribution, and Generator Performance Audit detail
- RT Detail for these concepts: Out of Merit, Canceled Starts, Hourly Shortfall, Posturing, Rapid Response Pricing Opportunity Cost, and Dispatch Lost Opportunity Cost

This report also includes a companion spreadsheet that contains daily, year-to-date totals for each of these concepts. The report and spreadsheet are also posted [here](#), select 'NCPC Summary' from the document type filter on the left side of the page.

Energy Market Payments 

6.1 Energy Market Payments

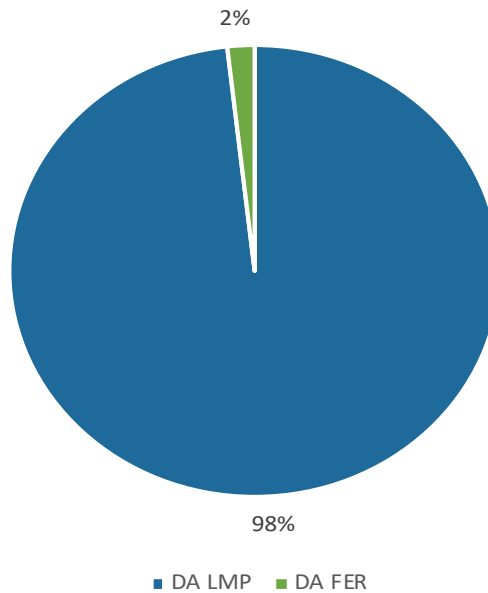
The table below displays the three components that make up the Energy Market payment for the prior week. These are payments made in relation to Day-Ahead LMPs, payments associated with the Day-Ahead Forecast Energy Requirement (FER), and payments related to deviations from Day-Ahead energy positions that occur in Real-Time.

**Energy Market Payment Summary
March 2-8, 2026**

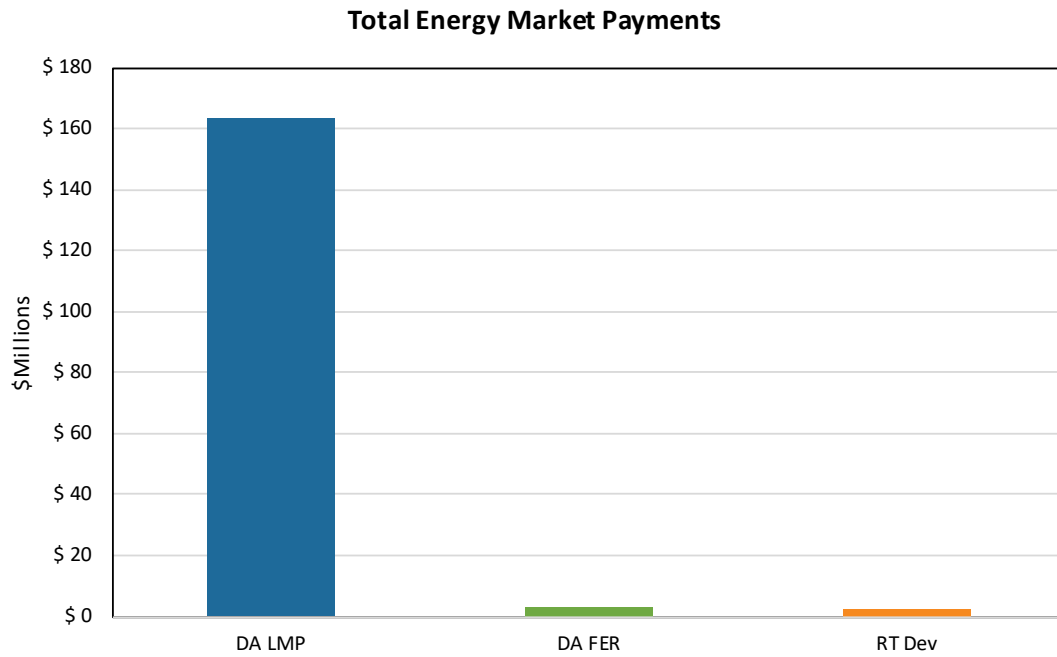
DA LMP Payments (A)	DA FER Payments (B)	RT Dev Payments (C)	Energy Market Payment (D=A+B+C)
\$163,296,185	\$2,977,629	\$2,302,069	\$168,575,883

The following chart shows the percentage contribution of the two components of the Day-Ahead Energy Market payment.

Day-Ahead Energy Market Payments



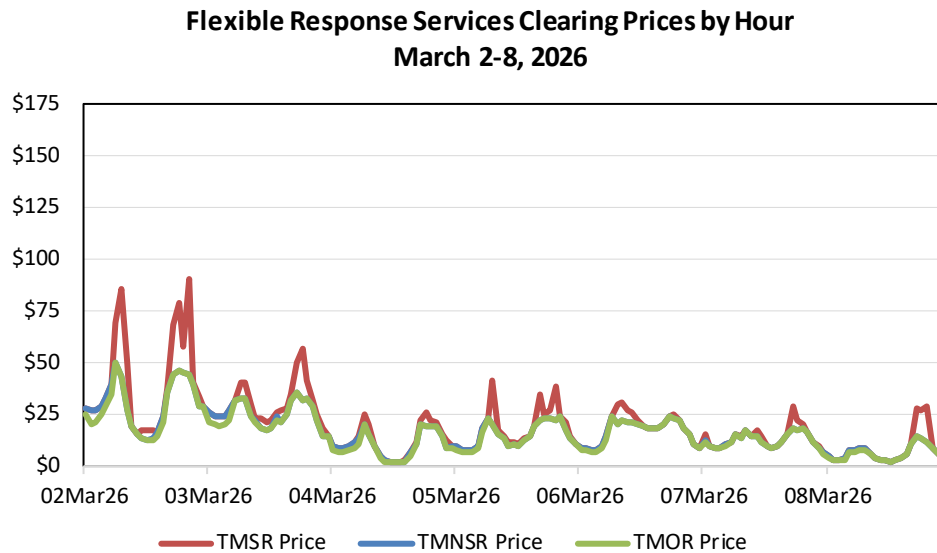
The chart below shows the magnitude of each component's contribution to the total Energy Market payment.



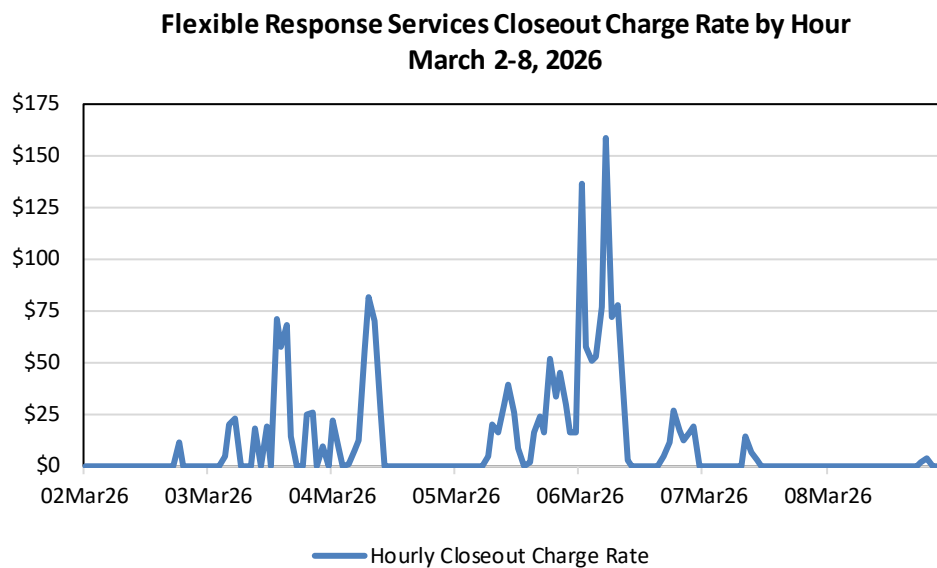
Flexible Response Services (FRS)

7.1 FRS Pricing

The following graph shows the hourly FRS Clearing Prices for the past week.



The hourly closeout charge rate is the max of the (RT Hub LMP – Strike Price) and 0. The graph below shows the hourly closeout charge rate during the week.



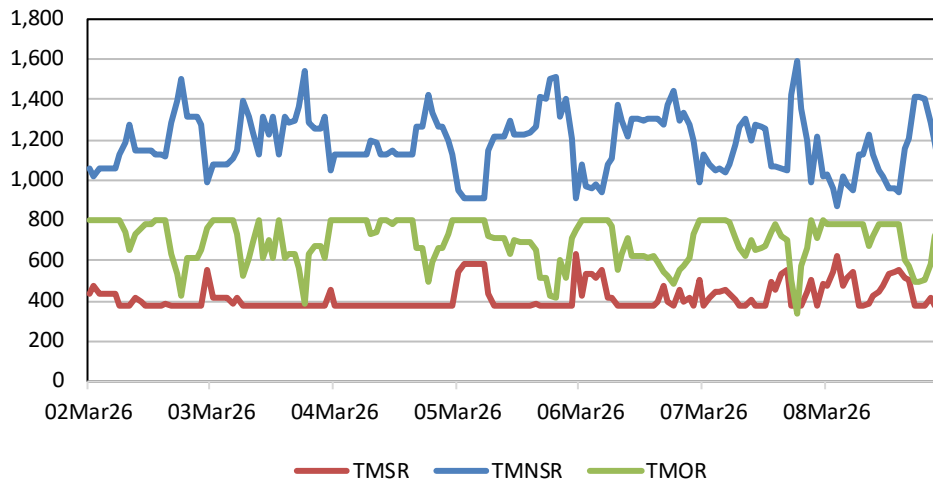
**Percentage of Hours with Closeout Charge Rates
March 2-8, 2026**

Frequency Tabulation	\$0.00	\$0.01 - \$4.99	\$5.00 - \$9.99	\$10.00 - \$19.99	\$20.00 - \$49.99	\$50.00 - \$99.99	>= \$100.00
Hourly Closeout Charge Rate	62.8%	5.4%	3.6%	9.6%	9.6%	7.8%	1.2%

7.2 FRS Quantities

The following graph shows the Hourly Cleared MW of each FRS product.

**Cleared Flexible Response Services MW by Hour
March 2-8, 2026**



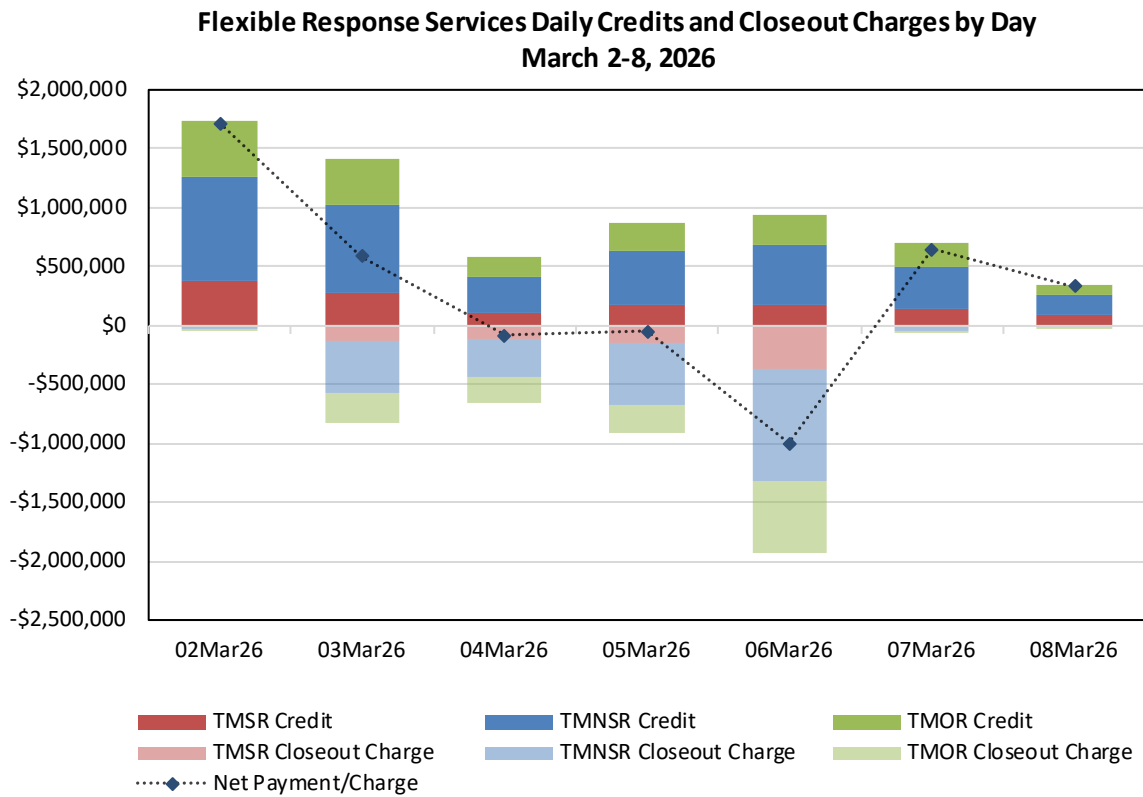
7.3 FRS Payments

FRS payments made to units during the prior week are shown in the following table. FRS procurements are made to satisfy the system level requirement for these services. The figures below are preliminary, and subject to revision during the settlement process.

**Flexible Response Services Payment Summary
March 2-8, 2026**

Product Type	FRS Credits (A)	FRS Closeout Charges (B)	FRS Net Payments/Charges (C=A+B)
TMSR	\$1,332,557	-\$786,485	\$546,072
TMNSR	\$3,426,041	-\$2,296,526	\$1,129,515
TMOR	\$1,818,181	-\$1,351,752	\$466,430
Total	\$6,576,779	-\$4,434,763	\$2,142,016

The following graph shows the daily Credit and Closeout charges by FRS product type:

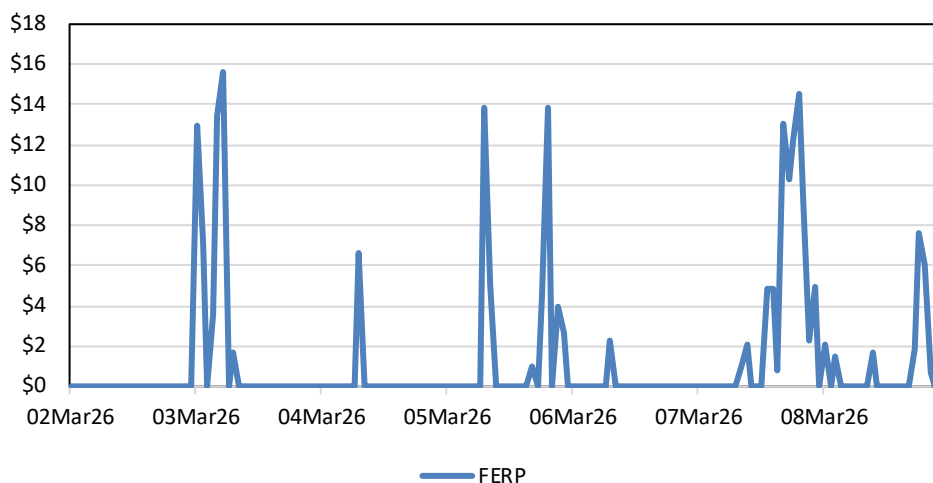


Forecast Energy Requirement (FER) and Energy Imbalance Reserves (EIR)

8.1 FER and EIR Pricing

Payments to units for both FER and EIR Obligations are made based on the Forecast Energy Requirement Price (FERP). The graph below shows the FERP by hour.

**Forecast Energy Requirement Price by Hour
March 2-8, 2026**



The following table shows the Daily and Weekly Average FERP during the reporting week.

**Average Daily and Weekly Forecast Energy Requirement Price (\$/MWh)
March 2-8, 2026**

02Mar26	03Mar26	04Mar26	05Mar26	06Mar26	07Mar26	08Mar26	Weekly Average
\$0.00	\$2.27	\$0.28	\$1.87	\$0.09	\$3.34	\$1.00	\$1.27

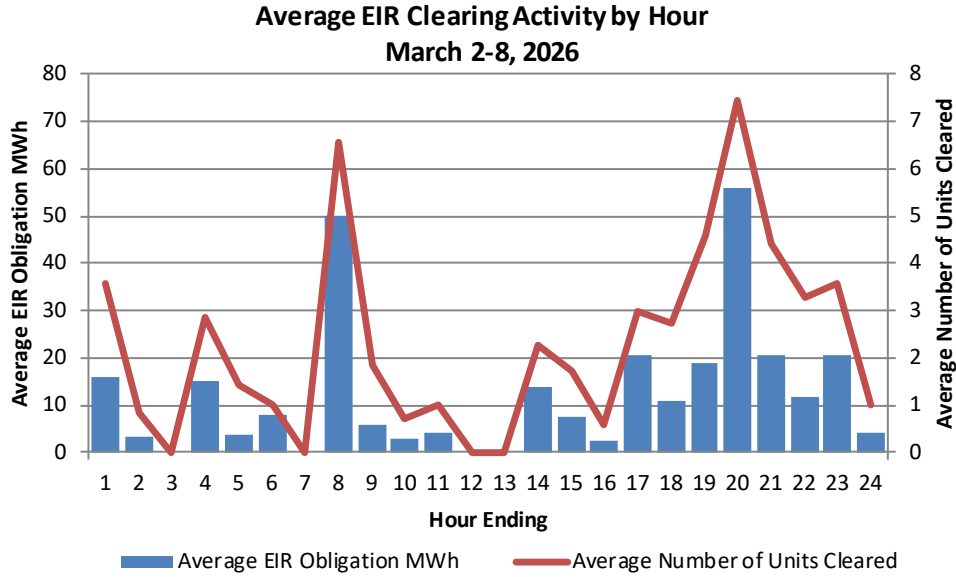
The following table shows the distribution of the hourly FERP during the reporting week.

**Hourly Forecast Energy Requirement Price Distribution
March 2-8, 2026**

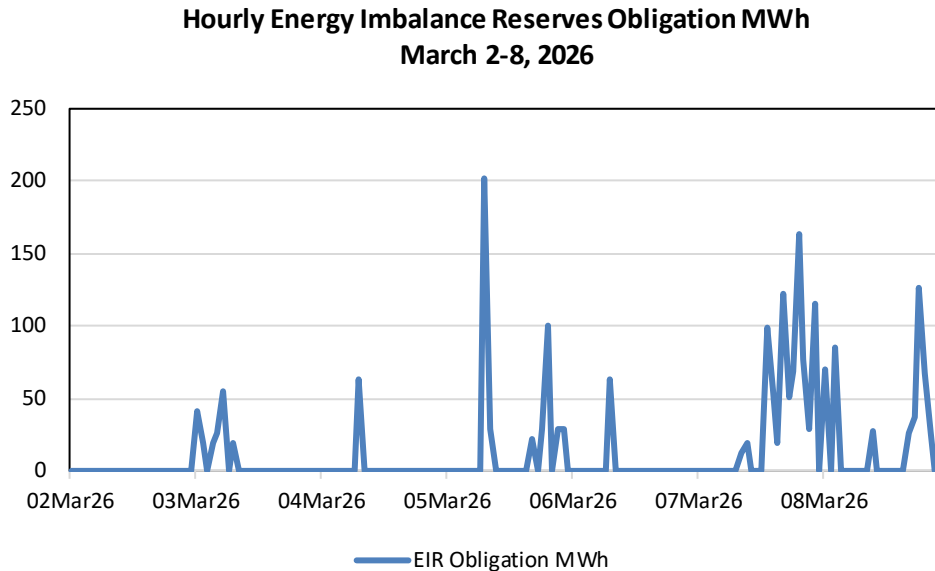
Frequency Tabulation	\$0.00	\$0.01 - \$4.99	\$5.00 - \$9.99	\$10.00 - \$19.99	\$20.00 - \$49.99	\$50.00 - \$99.99	>= \$100.00
FERP	78.4%	12.6%	3.6%	5.4%	0.0%	0.0%	0.0%

8.2 EIR Obligations

The following graph shows both the average hourly cleared EIR Obligation MWh and the average hourly number of units cleared during the reporting week.



The following graph shows the hourly EIR Obligation MWh values for the week.



The table below shows the distribution of the hourly EIR Obligation MWh during the reporting week.

**Energy Imbalance Reserves Obligation MWh Distribution
March 2-8, 2026**

Frequency Tabulation	0 MWh	0.01-49.99 MWh	50.0-99.99 MWh	100.0-249.99 MWh	250.0-499.99 MWh	500.0-999.99 MWh	>= 1,000 MWh
EIR Obligation MWh	78.4%	11.4%	6.6%	3.6%	0.0%	0.0%	0.0%

8.3 FER and EIR Payments

FER payments made to total cleared DA Generation MWh, DA Import MWh, DA DRR MWh, along with EIR Obligation MWh during the reporting week are shown in the following table. These figures are preliminary, and subject to revision during the settlement process.

**Daily Forecast Energy Requirement and Energy Imbalance Reserves Payment Summary
March 2-8, 2026**

Day	DA FER Payments (A)	EIR Payments (B)	EIR Closeout Charges (C)	EIR Net Payments/Charges (D=B+C)	DA FER and EIR Net Payments/Charges (E=A+D)
02Mar26	\$0	\$0	\$0	\$0	\$0
03Mar26	\$764,627	\$1,989	-\$1,930	\$59	\$764,686
04Mar26	\$95,352	\$420	-\$5,180	-\$4,760	\$90,592
05Mar26	\$684,018	\$4,667	-\$11,238	-\$6,572	\$677,447
06Mar26	\$31,973	\$143	-\$4,942	-\$4,799	\$27,174
07Mar26	\$1,105,530	\$7,508	-\$313	\$7,195	\$1,112,725
08Mar26	\$296,128	\$1,821	-\$441	\$1,380	\$297,507
Total	\$2,977,629	\$16,547	-\$24,045	-\$7,498	\$2,970,131

Real-Time Reserve Market

9.1 Real-Time Reserve Payments

**Real-Time Reserve Payment Summary by Reserve Zone
March 2-8, 2026**

DAY	CT	NEMABSTN	ROS	SWCT	Total
02MAR26	\$241.33	\$81.38	\$4,480.54	\$496.14	\$5,299.39
03MAR26	\$1,388.83	\$712.51	\$17,668.90	\$3,562.45	\$23,332.69
04MAR26	\$193.61	\$102.15	\$1,418.29	\$333.90	\$2,047.95
05MAR26	\$905.57	\$260.68	\$7,283.19	\$3,060.51	\$11,509.95
06MAR26	\$651.67	\$170.52	\$4,166.74	\$1,544.25	\$6,533.18
07MAR26	\$58.49	\$24.00	\$678.97	\$115.50	\$876.96
08MAR26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total	\$3,439.50	\$1,351.24	\$35,696.63	\$9,112.75	\$49,600.12

The following table shows Real-Time Reserve clearing prices. These figures are also preliminary and subject to revision during the settlement process.

**Real-Time Reserve Clearing Price Frequency, Local Reserve Zones
March 2-8, 2026**

Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals	Percentage of Non-Zero 5-Minute Intervals During the Week						
			<=\$10	\$10.01-\$50	\$50.01-\$100	\$100.01-\$200	\$200.01-\$500	\$500.01-\$1000	> \$1,000
TMSR	94.0%	6.0%	64.2%	35.8%	0.0%	0.0%	0.0%	0.0%	0.0%
TMNSR	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
TMOR	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

**Real-Time Reserve Clearing Price Frequency, Local Reserve Zones
March 2-8, 2026**

Local Reserve Zone	Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals
Connecticut	TMSR	94.0%	6.0%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
NEMA/Boston	TMSR	94.0%	6.0%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Rest Of System	TMSR	94.0%	6.0%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Southwest Connecticut	TMSR	94.0%	6.0%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%

The table below displays the time intervals, reserve types, and bias adjustment values for any reserve bias adjustments during this week.

**Real-Time Reserve Bias
March 2-8, 2026**

Local Day	Reserve Bias
March 2-8, 2026	None

Capacity Scarcity Conditions (CSC)

10.1 Capacity Scarcity Conditions

A Capacity Scarcity Condition (CSC) occurs when there is a deficiency in one or more of the three reserve requirements and the reserve-constraint penalty factor (RCPF) is setting the Real-Time Reserve price. More information can be found [here](#) in section III.13.7.2.1.

The preliminary balancing ratio is a value representing the initially calculated relationship between the required capacity and the total Capacity Supply Obligation during a CSC. The balancing ratio is computed using the following formula:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

The OP-4 Actions are the eleven actions, outlined by Operating Procedure 4, that ISO-NE uses to restore capacity during periods of capacity deficiency. More information and descriptions of each OP-4 Action can be found [here](#).

The tables below display the time intervals, OP-4 Actions, and preliminary balancing ratio for any Capacity Scarcity Conditions during this week.

System-wide Capacity Scarcity Condition Detail¹ March 2-8, 2026

Day	5-Minute Interval Beginning	Location	OP-4 Actions	Preliminary Balancing Ratio
There were no System-wide Capacity Scarcity Condition events during this period.				

Local Capacity Scarcity Condition Detail March 2-8, 2026

Day	5-Minute Interval Beginning	Location	OP-4 Actions	Preliminary Balancing Ratio
There were no Local Capacity Scarcity Condition events during this period.				

¹ The initial value may change at time of actual market settlement.

Glossary and Links

11.1 Peak Load Statistics

FCM System Load

FCM system load is the sum of active load assets that are non-dispatchable and that are included in the FCM settlement. Information is used to establish a load asset's contribution to the peak system load for purposes of the Forward Capacity Market (FCM). For more information on the FCM annual system peak day, hour, and load, see the ISO website [here](#).

Revenue Quality System Load

The revenue quality system load is the metered settlement value of the system 'net energy' for load concept. It is defined as the sum of generation, net external interchange, and the reduction provided by dispatched Demand Response Resources (DRR), less load from pumped storage units and energy storage devices.

Telemetered System Load

The telemetered system load value represents the calculated 'real-time' demand for electricity in the New England Balancing Authority Area that represents a telemetered aggregation of generation, net interchange, DRR reconstitution and excluding pumping load.

11.2 Locational Marginal Price (LMP)

A LMP is a calculated price of wholesale electric energy at a pricing node, Load Zone, reliability region, or the Hub. LMPs are comprised of three components: energy, congestion, and marginal losses. The energy component is the same at all locations, while the congestion and marginal loss components can vary among locations. More information on LMPs can be found at the ISO web site [here](#).

[Analyze:](#) Weekly Average Day-Ahead LMP Statistics, Hub and Load Zones (53 weeks, Excel format.)
TAB NAME: 'Avg DA and RT LMP Hub and Zones'

[Analyze:](#) Weekly Average Congestion and Loss Components, Hub and Load Zones (53 weeks, Excel format.)
TAB NAME: 'Average Congestion and Loss'

11.3 Day-Ahead and Real-Time Energy Markets

Day-Ahead and Real-Time Demand

Participants can bid fixed and price sensitive demand into the Day-Ahead Energy Market. They can also submit virtual demand bids called Decrement (Dec) bids as well as External Transaction bids. Day-Ahead Load Obligation (DALO) is the result of clearing the Day-Ahead Energy Market, and is aggregated by location. DALO is the total MWh of cleared demand bids, cleared Decs, and cleared External Transaction sales at all locations. Real-Time Load Obligation (RTLO) is the total MWh of a participant's metered load including External Transaction sales.

[Analyze:](#) Weekly Total Day-Ahead and Real-Time Load Obligation, Hub and Zones (53 weeks, Excel format)

TAB NAME: 'Total DA and RT Load Obligation'

Day-Ahead and Real-Time Supply

Participants can bid “must run” and Economic supply into the Day-Ahead Energy Market. They can also submit virtual supply offers called Increment (Inc) offers as well as External Transaction offers. Day-Ahead Generation Obligation (DAGO) is the result of clearing the Day-Ahead Energy Market, and is aggregated by Location. DAGO is the total MWh of cleared supply offers, cleared Inc offers, and cleared External Transaction purchases at all locations. Real-Time Generation Obligation (RTGO) is equal to the MWh of energy provided by Generators and External Transaction purchases at that Location. Real-Time Generation Obligation Deviation is the total MWh of a participant’s metered generation less their DAGO positions.

[Analyze](#): Weekly Total Day-Ahead Generation Obligation, Hub and Zones (53 weeks, Excel format)

TAB NAME: 'DA Supply'

[Analyze](#): Marginal Fuel Type by Week (53 weeks, Excel format).

TAB NAME: 'Percent Marginal Fuel Type'

[Analyze](#): Marginal Resource Type by Week (53 weeks, Excel format).

TAB NAME: 'Percent Marginal Resource Type'

System Load

System Load is 'net energy' for load on the system and is defined as the sum of generation and net external interchange, less pumping load. This total also includes the grossed up demand response value, and excludes demand from energy storage devices. Real-Time Load Obligation is the sum of all revenue quality metered load within the control area plus Real-Time External Transaction sales.

For more information on the Day-Ahead and Real-Time Energy Markets and associated charges, see the ISO web site [here](#) for Day-Ahead and [here](#) for Real-Time.

11.4 Net Commitment Period Compensation (NCPC)

NCPC is the payment to a market participant for its Generator, Asset-Related Demand (ARD), Demand Response Resource (DRR), or External Transaction that did not recover its effective offer costs from the energy market during an operating day. The NCPC payment is intended to make a resource that follows the ISO’s operating instructions “no worse off” financially than the best alternative generation schedule. Typically, a resource receiving NCPC was operated out of merit to protect the overall resource adequacy and transmission security of specific locations or of the entire balancing authority area.

For more information on the Day-Ahead and Real-Time Energy Markets and associated charges, see the ISO web site [here](#) for Day-Ahead and [here](#) for Real-Time.

11.5 Energy Market Payments

The Energy Market payment is made up of three components: payments made in relation to Day-Ahead LMPs, payments associated with Day-Ahead Forecast Energy Requirement (FER), and payments related to deviations in Real-Time.

The Day-Ahead Energy Market is a financial market where market participants purchase and sell electric energy at financially binding Day-Ahead prices for the following day. This market is the financially binding schedule of commitments for the purchase and sale of energy the ISO develops each day according to the bid and offer data that market participants submit to the market. A supply offer or a demand bid will generally clear the Day-Ahead market if its associated price is less than or equal to the hourly Locational Marginal Price (LMP) at its location, as system conditions allow.

The Day-Ahead market allows buyers and sellers to hedge against price volatility in the Real-Time Energy Market by locking in energy prices before the operating day.

The FER is equal to the load forecast, and it is satisfied by a combination of the Day-Ahead Energy Imbalance Reserves (EIR) product and cleared Day-Ahead energy supplied by Generator Assets, Demand Response Resources, and net Imports. The Forecast Energy Requirement Price (FERP) is the clearing price for the FER (analogous to how the LMP is the clearing price for the energy balance constraint). A MWh of cleared Day-Ahead energy from a physical supply resource will be paid the LMP + FERP, because that MWh contributes to both the energy balance and FER constraints. A MWh of cleared EIR, in contrast, is paid only the FERP, because it contributes to the FER, but not to the energy balance constraint. EIR payments are part of the Day-Ahead Ancillary Services market, and are not included in the Day-Ahead Energy Market value.

Payments in the Real-Time Energy Market are based upon deviations in the participants' actual operation in Real-Time from their Day-Ahead energy positions. These deviations are multiplied by the Real-Time LMP at the associated location to arrive at the Real-Time Energy Market payment total.

For more information on the Energy Market Payments, see the ISO web site located [here](#).

[Analyze](#): Energy Market Payments, by Week (53 weeks, Excel format)

TAB NAME: 'Energy Market Payments'

11.6 Flexible Response Services (FRS) Market

The Day-Ahead Ancillary Services (DAAS) Market is designed to procure and transparently price the ancillary service capabilities needed for a reliable, next-day operating plan with an evolving generation fleet.

One component of the DAAS Market clears Day-Ahead flexible response services to ensure that the system is prepared to recover from sudden source-loss contingencies and can respond quickly to fluctuations in net load during the operating day. These are referred to as Flexible Response Services (FRS), and are analogous to the Ten-Minute Spinning Reserves (TMSR), Ten-Minute Non-Spinning Reserves (TMNSR), and Thirty-Minute Operating Reserves (TMOR). These three products (TMSR, TMNSR, and TMOR) will also have a closeout charge based on the Hub Real-Time LMP. All three of the FRS requirements are set on a region-wide basis.

For more information on the DAAS Market, see the ISO web site located [here](#).

[Analyze](#): DAAS Market Results, by Week (53 weeks, Excel format)

TAB NAME: 'DAAS Market'

11.7 Forecast Energy Requirement (FER) and Energy Imbalance Reserves (EIR) Market

For more information on the FER component, see [11.5 Energy Market Payments](#).

The EIR component of the DAAS Market clears a new Day-Ahead ancillary service to cover the “gap” when the Day-Ahead market’s physical energy supply awards are below the ISO’s forecast Real-Time load. These MWh of cleared EIR are paid only the FERP, because they contribute to the FER, but not to the energy balance constraint. EIR is also subject to a closeout charge based on the Hub Real-Time LMP, and the EIR requirement is set on a region-wide basis.

For more information on the DAAS Market, see the ISO web site located [here](#).

[Analyze](#): Energy Market Payments, by Week (53 weeks, Excel format)

TAB NAME: ‘Energy Market Payments’

[Analyze](#): DAAS Market Results, by Week (53 weeks, Excel format)

TAB NAME: ‘DAAS Market’

11.8 Real-Time Reserve Market

The Real-Time LMP calculation process simultaneously sets Real-Time Reserve Market Clearing Prices (RMCP) for Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR), and Thirty-Minute Operating Reserve (TMOR).

For more information on the Real-Time Reserve Market, see the ISO web site located [here](#).

[Analyze](#): Real-Time Reserve Market Results, by Week (53 weeks, Excel format)

TAB NAME: ‘Real-Time Reserve Market’

Document Revision History		
Date	Version	Remarks
3/18/2026	Original	Initial posting.