Weekly Market Summary

March 23-29, 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 23-29, 2026

1.1 Weekly Highlights

Notable Events

- None.

Locational Marginal Pricing (LMPs) New England Hub; $/MWh; Average	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead Energy Market; All Hours	$39.51	$46.13	-14.4%	$42.96	-8.0%
*Real-Time Energy Market; All Hours	$31.14	$50.49	-38.3%	$45.05	-30.9%
*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)	16,204	16,259	-0.3%	15,829	2.4%
DA Load Obligation (All Zones)	-2,189,269	-2,256,619	-3.0%	-2,139,372	2.3%
RT Load Obligation (All Zones)	-2,130,414	-2,196,771	-3.0%	-2,105,265	1.2%
DA Cleared Exports (All Interfaces)	-98,691	-96,404	2.4%	-100,943	-2.2%
RT Scheduled Exports (All Interfaces)	-259,511	-273,960	-5.3%	-197,387	31.5%

Weekly Supply Statistics	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Input Fuel Price (Natural Gas, $/MMBtu)	$2.76	$3.27	-15.8%	$3.39	-18.6%
Mass Average Input Fuel Price (Natural Gas, $/MMBtu)	$2.81	$3.48	-19.3%	$3.34	-15.9%
Metered Generation (MWh)	1,913,879	2,028,263	-5.6%	2,072,818	-7.7%
Generation Obligation (MWh)	2,436,555	2,521,288	-3.4%	2,342,270	4.0%
RT Demand Reduction Obligation (MWh)	98	352	-72.2%	142	-31.2%
Self-Scheduled Generation (MWh)	948,968	928,176	2.2%	858,873	10.5%
DA Cleared Imports (MWh - All Interfaces)	468,852	439,647	6.6%	212,037	121.1%
RT Scheduled Imports (MWh - All Interfaces)	522,676	493,025	6.0%	269,452	94.0%

Market Payments	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead and Real-Time Energy Market Payments ($)	$99,445,848	$117,154,386	-15.1%	$104,937,945	-5.2%
Day-Ahead Ancillary Services Market Payments ($)	$3,880,724	$2,332,444	66.4%	$203,498	Large
Real-Time Reserve Market Payments ($)	$8,819	$20,409	-56.8%	$25,684	-65.7%

Underlying natural gas data furnished by:

Day-Ahead Price Separation

- On Monday, March 23, depressed pricing in the Maine (ME) Load Zone was caused by a binding constraint on the Orrington South Interface due to the planned outage of the 3024 (Coopers Mills – Albion Road) line. The 3024 line was restored the same day.
- On Tuesday, March 24, depressed pricing in the ME Load Zone was caused by a binding constraint on the Maine – New Hampshire + Newington Generation Interface due to a planned equipment outage. The equipment was restored on March 23.
- On Wednesday, March 25, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine – New Hampshire and the Coopers Mill – South Interfaces due to a planned equipment outage and patterns of load and generation. The equipment was restored the same day.
- On Friday, March 27, depressed pricing in the 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 Separation

- On Wednesday and Friday, March 25 and 27, depressed pricing in the 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*

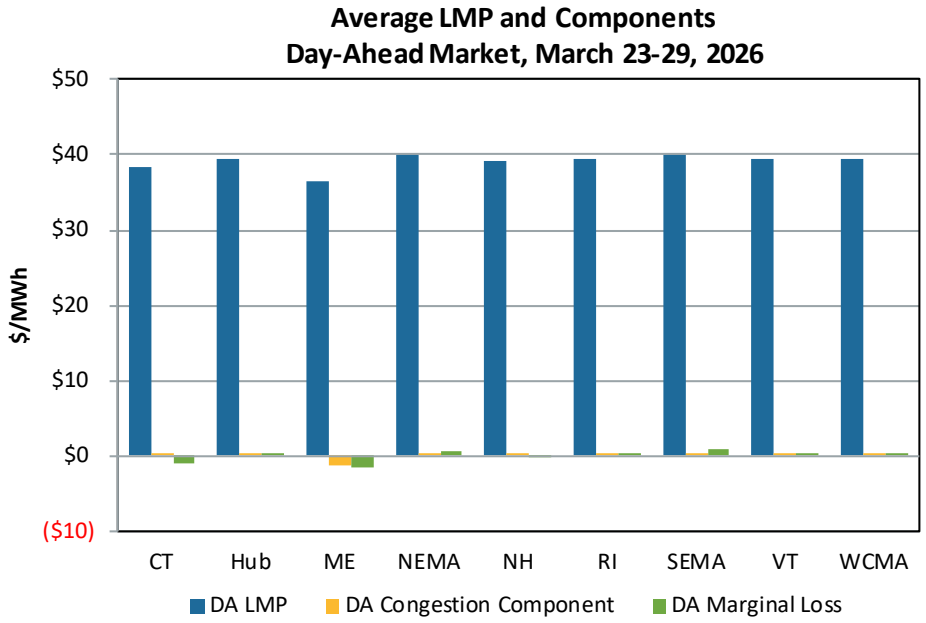
- FCM Peak Load (preliminary, subject to change) is 19,937 MWh and occurred in the hour ending 1:00 P.M. on Sunday, January 25. At this hour, the Capacity Zone-level FCM peak loads were 2,814 MWh in Northern New England, 1,832 MWh in Maine, 7,535 MWh in Rest-of-Pool, and 7,756 MWh in Southeast New England.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

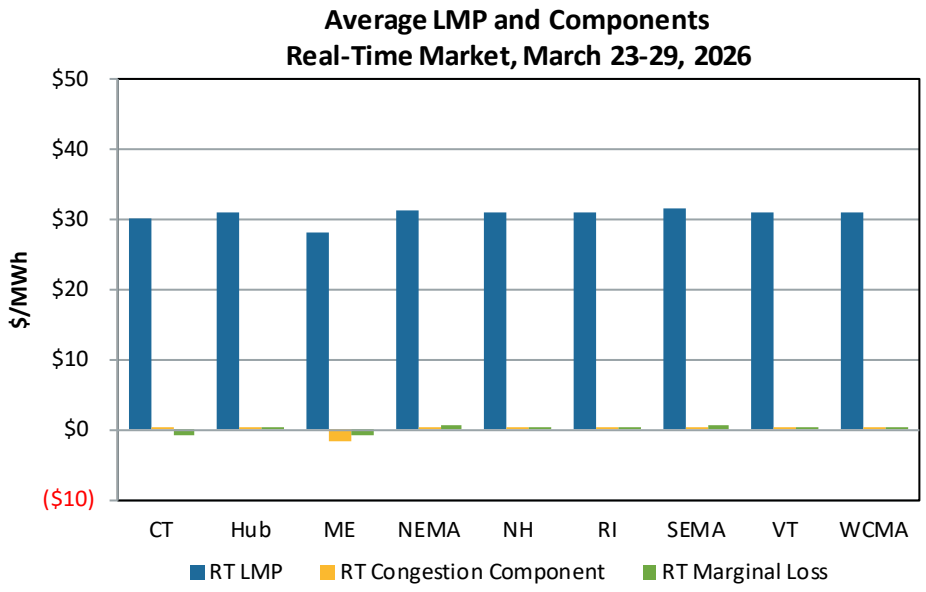
*Due to the difference in calculation methodologies, these values can occur on different days and hours.

Pricing

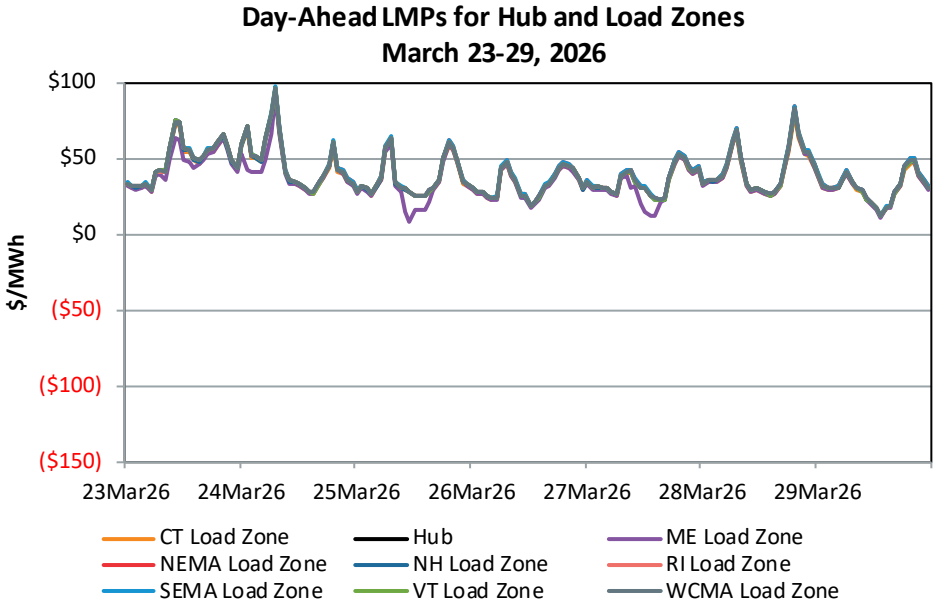
2.1 Pricing

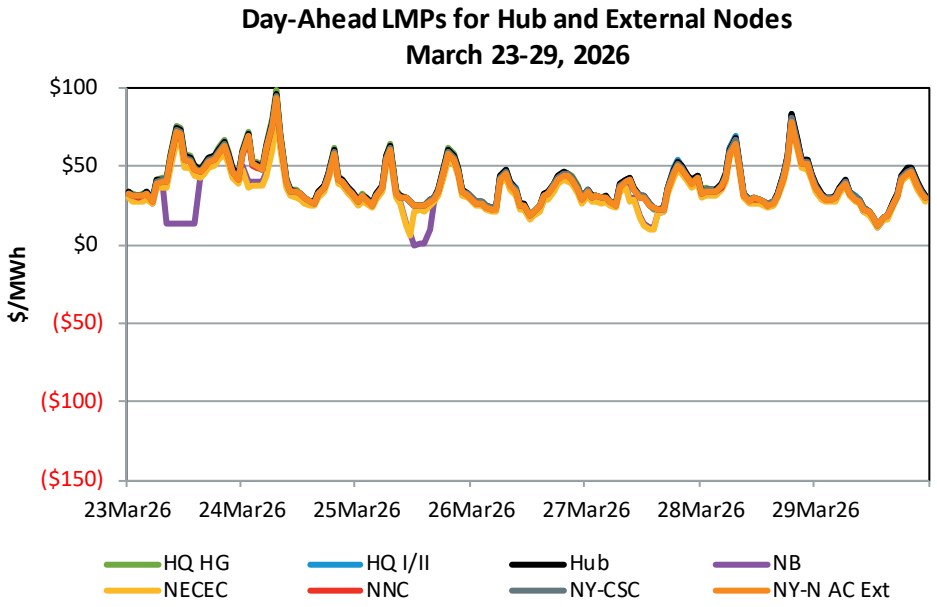
The two graphs below show the weekly average of LMPs, congestion, and marginal loss components at the Hub and Load Zones for both the Day-Ahead and Real-Time Energy Markets.



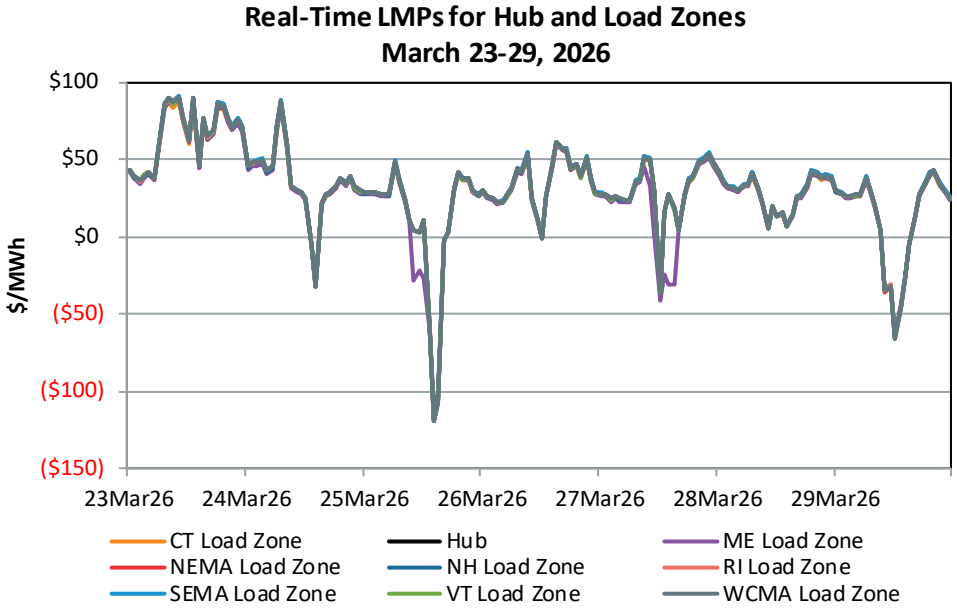


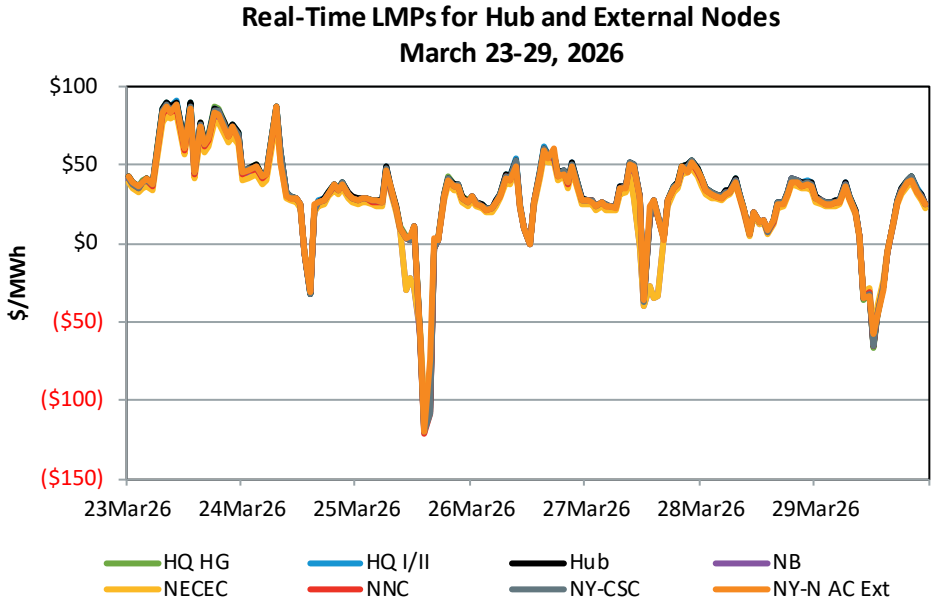
The following two graphs show hourly Day-Ahead LMPs for the Hub, the eight Load Zones, and the seven external nodes. In cases where there is little or no price separation, the lines for multiple locations may be indistinguishable from each other.





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.





LMP Summary Statistics, March 23-29, 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	$39.51	$31.14	$11.83	$-119.01	$96.39	$90.24	100%	100%	79%	14.14	30.27	214%
ME	$36.47	$28.29	$8.00	$-111.68	$90.98	$88.69	92%	91%	78%	13.67	31.03	227%
NH	$39.17	$30.90	$11.75	$-117.19	$95.07	$90.26	99%	99%	79%	14.03	30.06	214%
VT	$39.32	$30.93	$11.75	$-119.01	$96.62	$89.38	100%	99%	79%	14.15	30.20	213%
CT	$38.33	$30.19	$11.69	$-119.89	$94.02	$87.14	97%	97%	79%	13.58	29.72	219%
RI	$39.53	$31.08	$11.88	$-118.09	$96.39	$89.91	100%	100%	79%	14.06	30.11	214%
SEMA	$40.12	$31.48	$12.03	$-119.21	$97.82	$91.01	102%	101%	78%	14.34	30.48	213%
WCMA	$39.45	$31.11	$11.87	$-119.33	$96.20	$90.29	100%	100%	79%	14.08	30.30	215%
NEMA	$39.90	$31.43	$11.96	$-118.69	$96.87	$91.38	101%	101%	79%	14.28	30.47	213%
NB Ext	$33.79	$27.70	$-0.03	$-107.40	$89.32	$87.38	86%	89%	82%	14.39	30.50	212%
NY-N AC Ext	$38.01	$30.43	$11.64	$-120.43	$93.26	$87.89	96%	98%	80%	13.41	28.75	214%
HQ Ext	$39.33	$31.12	$11.86	$-117.12	$95.37	$90.71	100%	100%	79%	14.03	30.12	215%
HG Ext	$39.64	$31.15	$11.67	$-114.22	$98.71	$89.94	100%	100%	79%	14.45	29.98	208%
CSC Ext	$38.66	$30.72	$11.74	$-120.35	$95.09	$88.33	98%	99%	79%	13.75	30.12	219%
NNC Ext	$38.08	$29.99	$11.67	$-120.80	$93.52	$86.42	96%	96%	79%	13.42	29.65	221%
NECEC Ext	$34.08	$26.15	$5.98	$-103.02	$84.34	$82.48	86%	84%	77%	12.75	29.11	228%

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

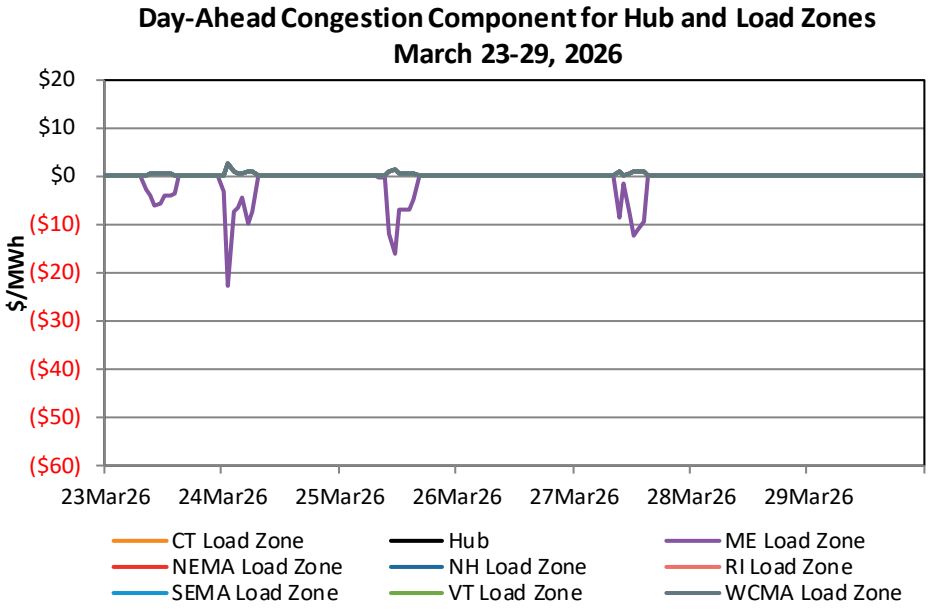
5-Minute LMP Summary (RT Only)
March 23-29, 2026

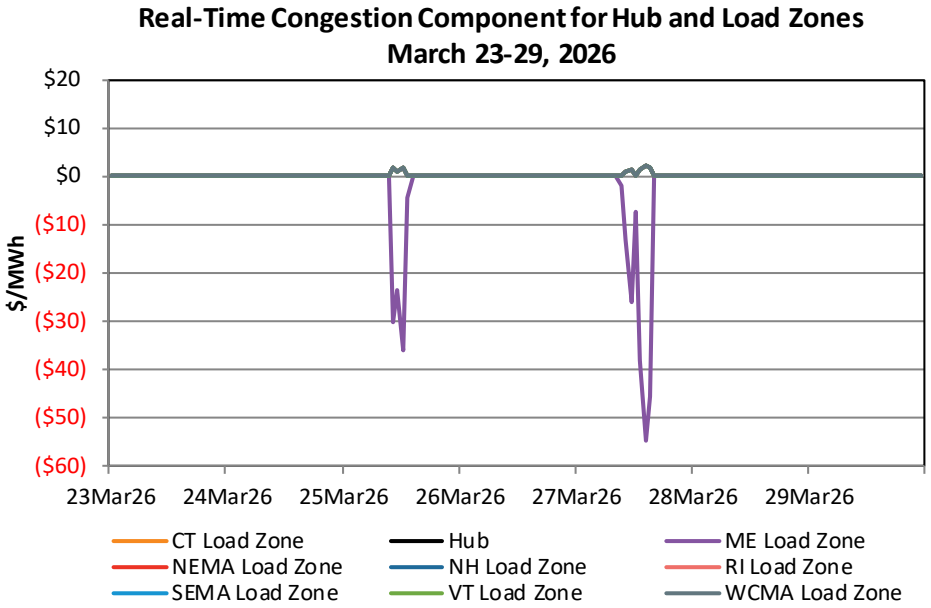
Hub/Zone	Max RT LMP ($/MWh)	Min RT LMP ($/MWh)	RT Std Dev	RT as % of Hub
Hub	$159.06	-$164.42	$33.33	100%
ME	$154.52	-$155.00	$33.54	-363%
NH	$158.75	-$162.12	$33.09	100%
VT	$158.25	-$163.28	$33.26	100%
CT	$153.86	-$165.54	$32.75	98%
RI	$157.76	-$163.19	$33.15	100%
SEMA	$159.75	-$164.73	$33.56	101%
WCMA	$159.22	-$164.86	$33.36	100%
NEMA	$160.73	-$164.09	$33.54	101%

5-Minute Energy Component of LMP
March 23-29, 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	8.3%	7.2%	57.6%	18.9%	6.7%	1.2%	0.1%	0.0%	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.





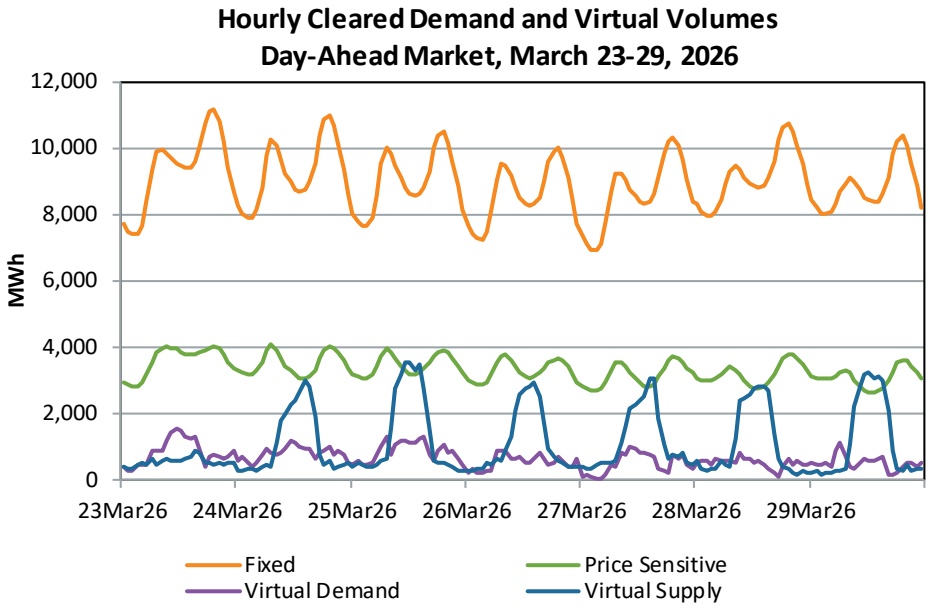
Energy Market Demand

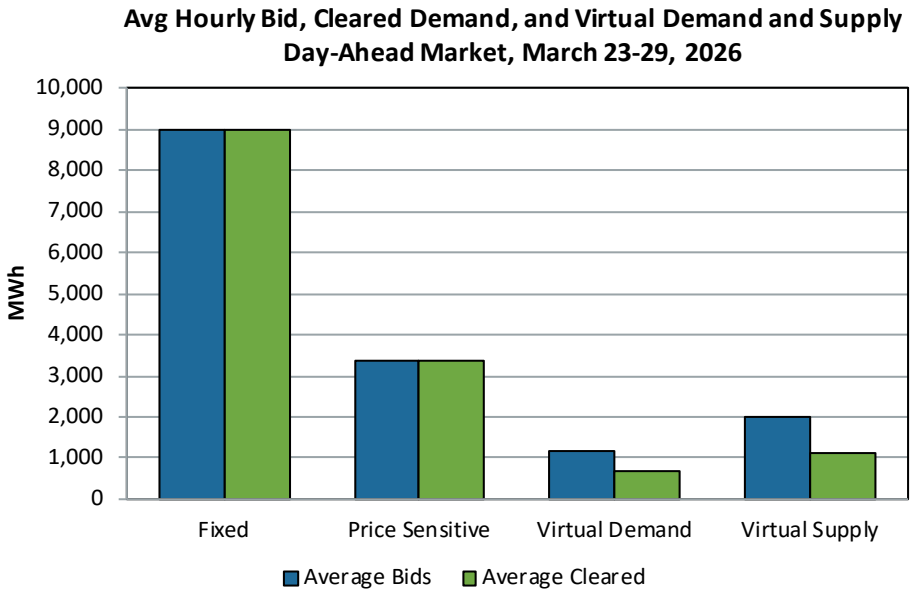
3.1 Day-Ahead Demand

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	24,028	38,069	-36.9%	13,948	72.3%
ME	200,118	203,707	-1.8%	212,776	-5.9%
NH	210,111	215,173	-2.4%	211,155	-0.5%
VT	94,658	102,255	-7.4%	97,546	-3.0%
CT	484,047	498,097	-2.8%	480,622	0.7%
RI	136,405	141,093	-3.3%	126,782	7.6%
SEMA	252,267	259,036	-2.6%	245,114	2.9%
WCMA	290,988	299,936	-3.0%	290,630	0.1%
NEMA	441,794	445,898	-0.9%	425,671	3.8%
NB Ext	121	96	26.0%	1,559	-92.2%
NY-N AC Ext	92,490	109,211	-15.3%	55,547	66.5%
HQ Ext	76	81	-6.2%	60	26.7%
HG Ext	6	0	N/A	3,611	-99.8%
CSC Ext	39,916	27,768	43.7%	34,950	14.2%
NNC Ext	0	0	0.0%	8,242	-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 23-29, 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	23MAR26	0	0	7,070	2,120	0	0	4,865	1,825	4,865
Hub	24MAR26	0	0	5,792	7,757	0	0	3,716	6,464	3,716
Hub	25MAR26	0	0	7,291	8,350	0	0	6,071	6,793	6,071
Hub	26MAR26	0	0	3,596	9,172	0	0	2,496	5,012	2,496
Hub	27MAR26	0	0	4,212	8,394	0	0	3,029	6,434	3,029
Hub	28MAR26	0	0	3,073	9,749	0	0	2,111	8,212	2,111
Hub	29MAR26	0	0	2,475	11,140	0	0	1,739	8,264	1,739
ME	23MAR26	21,413	7,750	2,151	10,048	21,413	7,750	1,694	5,626	30,857
ME	24MAR26	20,895	7,097	1,604	11,744	20,895	7,097	957	7,008	28,949
ME	25MAR26	20,525	7,006	2,065	20,347	20,525	7,006	1,499	12,004	29,030
ME	26MAR26	20,704	7,046	1,689	16,803	20,704	7,046	1,034	11,299	28,785
ME	27MAR26	20,400	6,392	750	16,881	20,400	6,392	495	10,772	27,287
ME	28MAR26	21,847	7,008	2,528	9,255	21,847	7,008	2,033	5,378	30,888
ME	29MAR26	20,917	6,546	1,855	14,931	20,917	6,546	1,634	8,175	29,096
NH	23MAR26	26,149	5,175	1,851	445	26,149	5,175	1,185	325	32,509
NH	24MAR26	25,800	5,156	1,486	1,578	25,800	5,156	778	1,236	31,734
NH	25MAR26	24,818	4,969	1,205	1,823	24,818	4,969	605	1,516	30,392
NH	26MAR26	23,910	4,589	940	2,310	23,910	4,589	528	1,576	29,027
NH	27MAR26	24,091	4,508	699	2,218	24,091	4,508	396	1,552	28,994
NH	28MAR26	25,168	4,512	648	1,564	25,168	4,512	297	1,354	29,976
NH	29MAR26	24,239	4,147	482	2,276	24,239	4,147	373	1,579	28,759
VT	23MAR26	1,547	13,547	1,907	682	1,547	13,547	1,452	447	16,545
VT	24MAR26	1,522	11,800	1,404	1,728	1,522	11,800	994	1,127	14,316
VT	25MAR26	1,165	11,802	950	1,682	1,165	11,802	808	1,279	13,776
VT	26MAR26	1,031	12,073	795	2,031	1,031	12,073	607	1,602	13,711
VT	27MAR26	1,043	10,985	682	3,486	1,043	10,985	500	1,572	12,527
VT	28MAR26	1,273	11,138	908	2,007	1,273	11,138	497	1,217	12,908
VT	29MAR26	1,232	11,464	592	1,990	1,232	11,464	460	1,493	13,156
CT	23MAR26	49,189	21,524	3,965	873	49,189	21,524	2,521	424	73,233
CT	24MAR26	50,359	21,342	2,580	2,764	50,359	21,342	1,990	1,800	73,691
CT	25MAR26	48,299	21,547	2,408	2,517	48,299	21,547	2,213	1,927	72,059
CT	26MAR26	44,867	19,689	1,123	2,096	44,867	19,689	935	1,360	65,491
CT	27MAR26	46,118	19,792	1,052	2,136	46,118	19,792	710	1,453	66,620
CT	28MAR26	49,589	19,988	2,253	2,735	49,589	19,988	1,753	1,922	71,331
CT	29MAR26	46,739	19,086	1,401	2,806	46,739	19,086	1,160	1,850	66,985
RI	23MAR26	14,239	5,008	1,822	1,457	14,239	5,008	1,522	712	20,769
RI	24MAR26	14,359	5,079	3,109	3,455	14,359	5,079	1,661	1,985	21,099

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	25MAR26	13,974	4,817	1,440	3,547	13,974	4,817	1,351	2,280	20,141
RI	26MAR26	13,318	4,766	703	3,023	13,318	4,766	410	1,886	18,493
RI	27MAR26	13,244	4,643	1,261	3,362	13,244	4,643	934	1,584	18,820
RI	28MAR26	13,593	4,817	873	2,767	13,593	4,817	747	1,550	19,157
RI	29MAR26	13,339	4,654	742	2,441	13,339	4,654	380	1,408	18,373
SEMA	23MAR26	28,099	9,605	1,911	1,032	28,099	9,605	1,085	640	38,789
SEMA	24MAR26	27,458	9,489	779	2,157	27,458	9,489	564	1,829	37,511
SEMA	25MAR26	26,668	9,214	634	2,258	26,668	9,214	469	1,983	36,350
SEMA	26MAR26	25,515	8,749	712	2,927	25,515	8,749	327	1,373	34,591
SEMA	27MAR26	25,374	8,220	629	3,228	25,374	8,220	321	1,618	33,915
SEMA	28MAR26	27,115	8,712	869	3,304	27,115	8,712	771	2,213	36,598
SEMA	29MAR26	26,230	8,279	825	3,473	26,230	8,279	433	1,789	34,942
WCMA	23MAR26	33,790	9,324	1,792	1,062	33,790	9,324	1,358	924	44,471
WCMA	24MAR26	33,352	9,662	1,315	2,017	33,352	9,662	1,076	1,662	44,091
WCMA	25MAR26	32,846	9,321	1,136	1,952	32,846	9,321	1,047	1,734	43,213
WCMA	26MAR26	30,820	8,658	730	1,240	30,820	8,658	517	939	39,995
WCMA	27MAR26	30,711	8,475	920	1,852	30,711	8,475	596	1,468	39,782
WCMA	28MAR26	32,596	7,778	1,050	2,105	32,596	7,778	988	1,659	41,362
WCMA	29MAR26	31,864	7,749	973	2,051	31,864	7,749	640	1,446	40,253
NEMA	23MAR26	50,183	14,973	2,280	894	50,183	14,973	1,668	611	66,824
NEMA	24MAR26	49,184	15,111	2,011	3,134	49,184	15,111	1,085	2,191	65,380
NEMA	25MAR26	47,850	14,662	1,771	2,959	47,850	14,662	1,098	2,208	63,610
NEMA	26MAR26	46,660	13,957	1,419	2,446	46,660	13,957	1,006	1,325	61,623
NEMA	27MAR26	46,287	13,238	1,780	2,452	46,287	13,238	1,343	1,569	60,867
NEMA	28MAR26	48,723	13,296	1,234	3,762	48,723	13,296	778	2,602	62,797
NEMA	29MAR26	47,681	12,586	995	3,052	47,681	12,586	995	1,819	61,261

3.2 Real-Time Demand

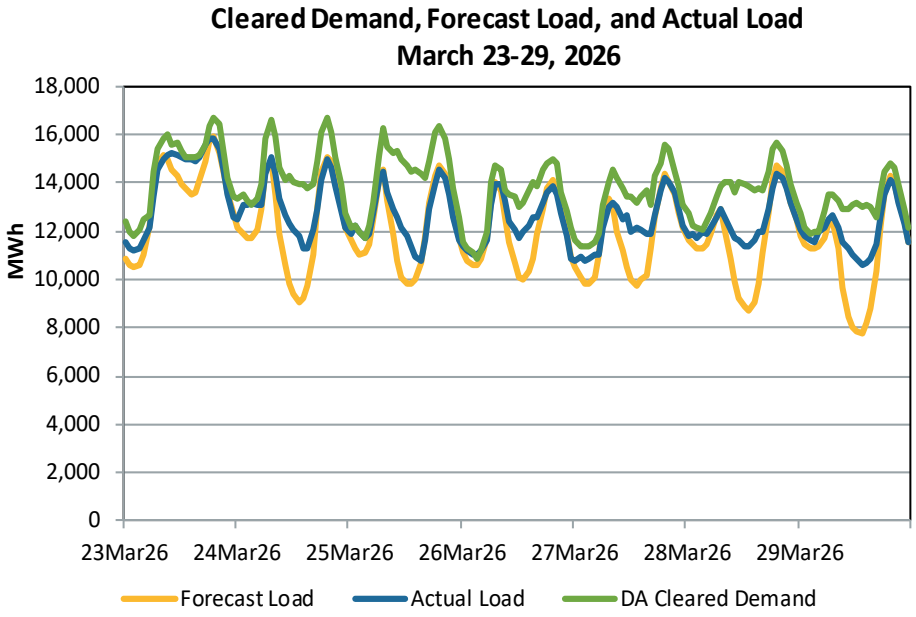
The following table displays the Real-Time Load Obligation at each Load Zone and external nodes for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
ME	203,088	211,648	-4.0%	212,487	-4.4%
NH	208,627	214,972	-3.0%	212,547	-1.8%
VT	83,983	97,614	-14.0%	91,906	-8.6%
CT	470,050	494,229	-4.9%	461,990	1.7%
RI	132,192	131,676	0.4%	131,529	0.5%
SEMA	251,643	254,263	-1.0%	243,207	3.5%
WCMA	287,632	299,561	-4.0%	290,800	-1.1%
NEMA	430,018	435,540	-1.3%	424,112	1.4%
NB Ext	4,213	3,171	32.9%	5,330	-21.0%
NY-N AC Ext	213,143	234,128	-9.0%	132,746	60.6%
HQ Ext	0	362	-100.0%	0	N/A
HG Ext	0	0	0.0%	13,610	-100.0%
CSC Ext	42,155	36,299	16.1%	35,723	18.0%
NNC Ext	0	0	N/A	9,978	-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
23MAR26	20	16,204	$84.91	$82.77	$84.64	$84.57	$82.52	$84.52	$85.49	$84.83	$85.76
24MAR26	08	15,333	$87.62	$84.00	$86.63	$86.75	$84.98	$87.39	$88.80	$87.49	$88.25
25MAR26	20	14,812	$41.95	$41.05	$41.91	$41.86	$40.86	$41.83	$42.38	$41.91	$42.38
26MAR26	09	14,242	$42.33	$40.63	$42.11	$41.70	$40.87	$42.39	$42.96	$42.16	$42.90
27MAR26	20	14,472	$38.77	$37.31	$38.56	$38.47	$37.51	$38.70	$39.30	$38.65	$39.24
28MAR26	20	14,696	$41.74	$40.84	$41.50	$41.10	$40.09	$41.54	$42.57	$41.50	$42.42
29MAR26	20	14,384	$40.50	$39.64	$40.44	$40.06	$39.02	$40.31	$41.11	$40.32	$41.13

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.



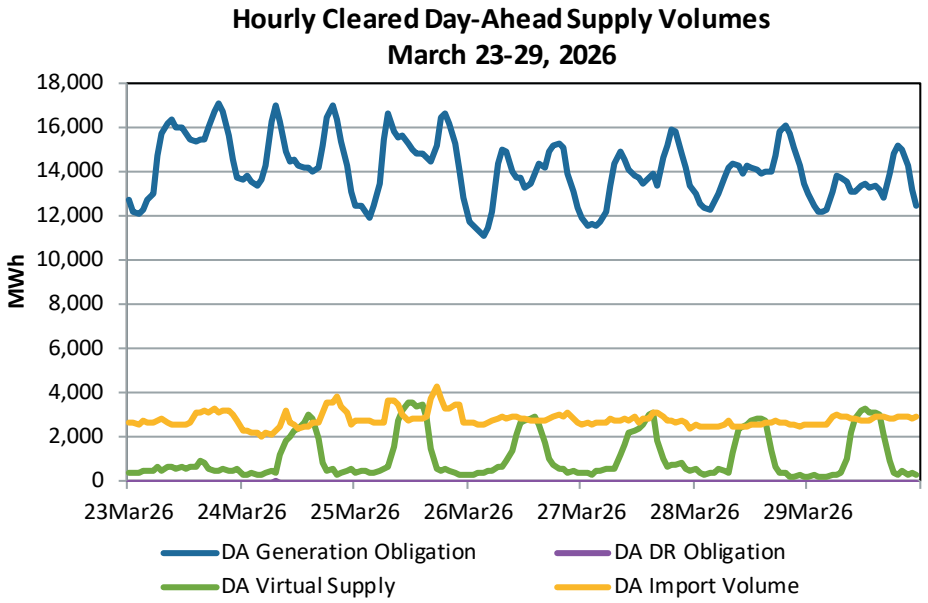
The table below compares the total quantities (MWh) of Day-Ahead Load Obligation with the Real-Time Load Obligation for each Load Zone (including nodal locations within each Load Zone) for the week. Day-Ahead Load Obligation is composed of Day-Ahead cleared demand bids and cleared Decrement bids. Real-Time 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	204,891	205,118	-226	99.9%
NH	211,390	209,142	2,248	101.1%
VT	96,940	83,983	12,957	115.4%
CT	490,449	471,821	18,628	103.9%
RI	136,852	132,192	4,660	103.5%
SEMA	252,711	256,776	-4,065	98.4%
WCMA	329,632	341,236	-11,604	96.6%
NEMA	442,377	430,146	12,231	102.8%

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	14,088	14,532	-3.1%	13,553	3.9%
DA Demand Reduction Obligation	0	1	-100.0%	1	-100.0%
DA Cleared Increments	1,107	1,127	-1.8%	930	19.0%
DA Imports	2,791	2,617	6.6%	1,262	121.1%

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	33,424	32,491	2.9%	21,546	55.1%
NY-N AC Ext	225,833	214,941	5.1%	184,233	22.6%
HQ Ext	21,363	4,198	408.9%	2,141	Large
HG Ext	0	0	N/A	2,745	-100.0%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	0	0	N/A	1,171	-100.0%
NECEC Ext	188,232	188,016	0.1%	N/A	N/A

4.2 Real-Time Supply

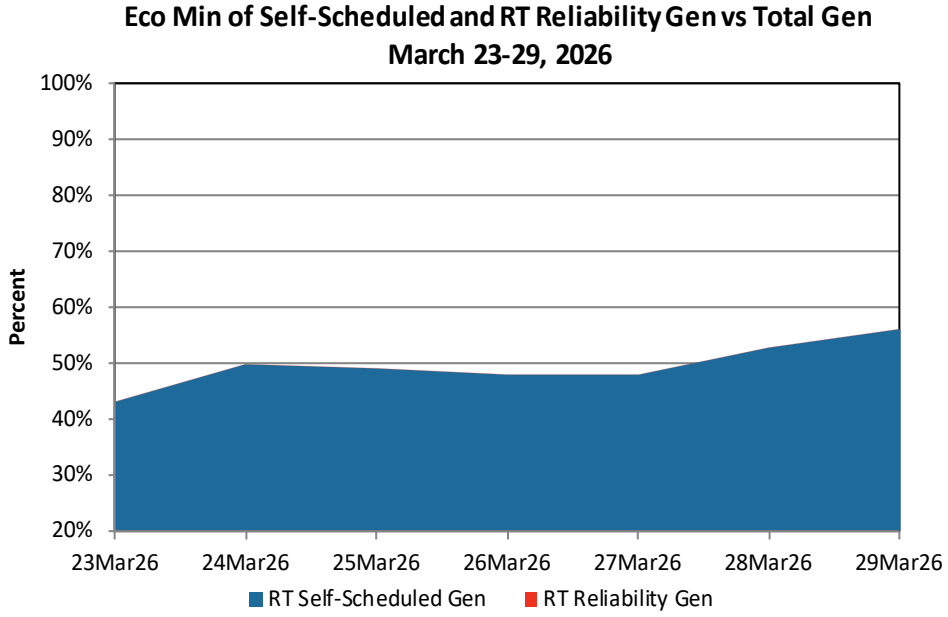
The following table provides daily and weekly totals, in megawatt-hours (MWh), of the amount of electricity produced by classified fuel type during the week. The data provided are for the full system, including "settlement only" resources that do not offer their output into the wholesale markets. The 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.

	Metered Generation (Megawatt hours)							
Category	23Mar26	24Mar26	25Mar26	26Mar26	27Mar26	28Mar26	29Mar26	Total
Coal	18	44	0	0	0	0	0	62
Hydro	32,944	30,363	26,015	30,942	30,768	28,066	26,745	205,843
Landfill Gas	1,020	926	897	961	924	914	939	6,581
Methane	47	48	59	57	44	48	47	350
Natural Gas	158,346	128,284	111,635	101,906	99,974	113,445	96,998	810,588
Nuclear	80,182	80,403	80,302	80,329	80,341	80,244	79,877	561,678
Oil	2	1	0	13	49	0	0	65
Other	1,591	3,552	3,767	2,685	2,835	2,591	3,097	20,118
PRD	50	48	0	0	0	0	0	98
Refuse	5,390	6,011	5,533	4,922	6,074	6,233	5,514	39,677
Solar	3,128	19,783	21,126	11,957	14,874	21,207	22,294	114,369
Wind	12,663	9,797	17,307	20,181	22,621	11,045	15,376	108,990
Wood	7,322	7,052	6,557	6,625	6,624	5,939	5,443	45,562
Total	302,703	286,312	273,198	260,578	265,128	269,732	256,330	1,913,981

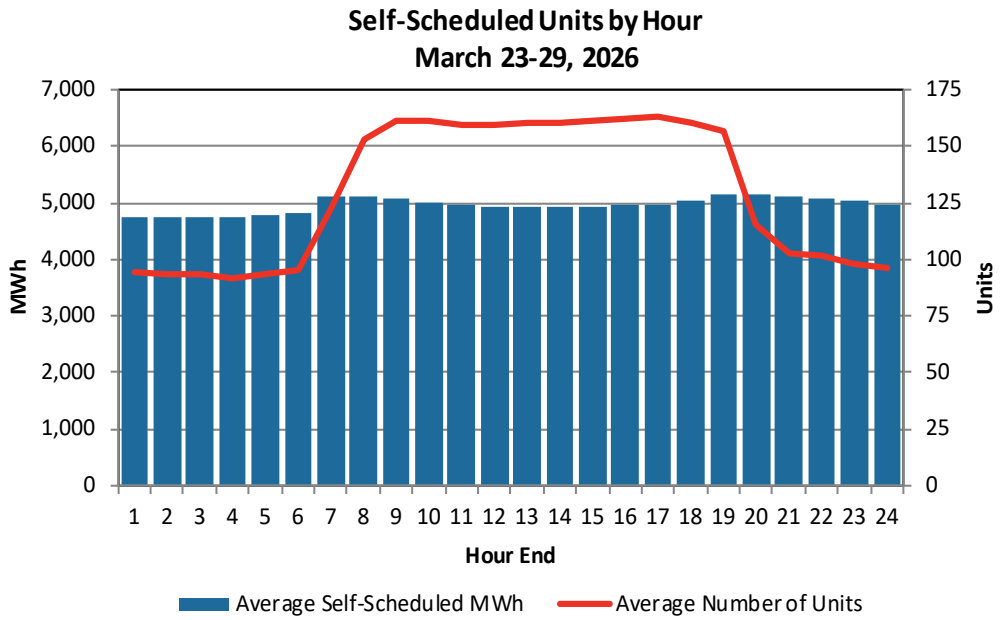
Online generators that are at their Economic Minimum output level are not eligible to set the clearing price. Real-Time Self-Scheduled Generation shown below reflects output by self-scheduled generation and by (non-dispatchable) Settlement Only Resources (SORs). Real-Time Reliability Generation represents 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
23Mar26	131,175	0	302,704
24Mar26	143,531	0	286,311
25Mar26	133,662	0	273,198
26Mar26	125,586	0	260,577
27Mar26	127,840	0	265,126
28Mar26	142,353	0	269,732
29Mar26	144,822	770	256,330

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



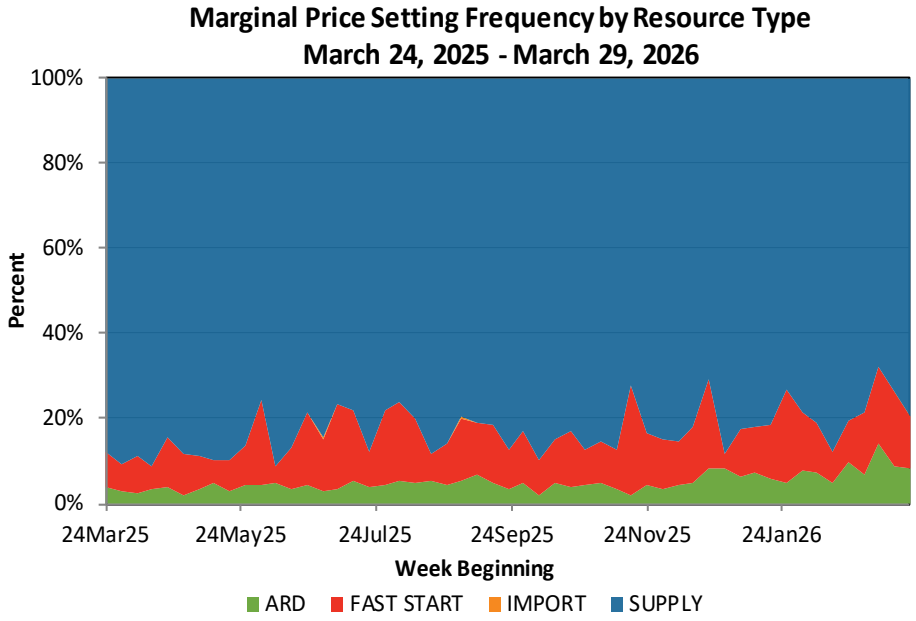
The following graph shows the average number of self-scheduled generating units and MWh for each hour of the last week.



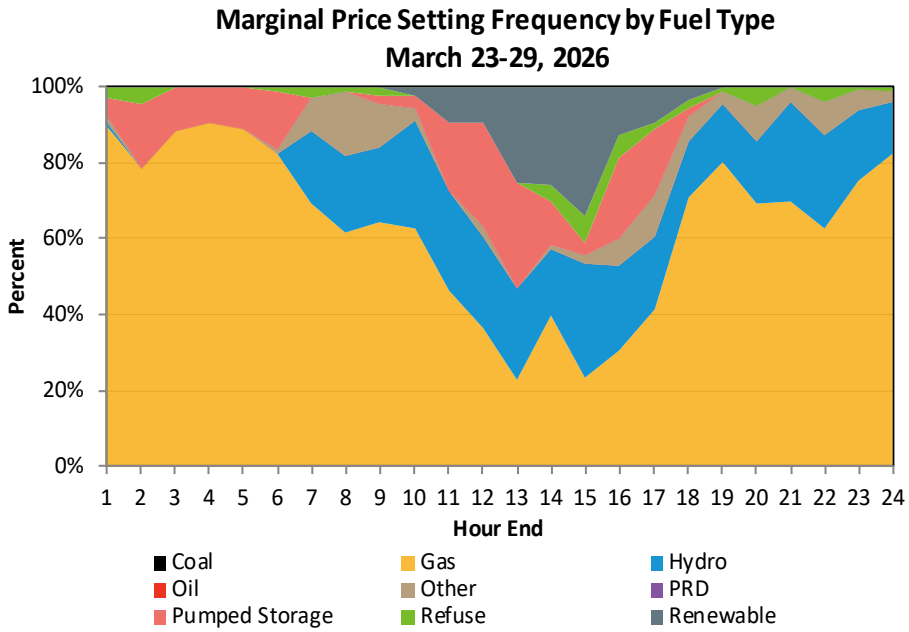
The following table provides the total Real-Time Imports by Interface for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	29,259	27,426	6.7%	13,877	110.8%
NY-N AC Ext	284,528	275,407	3.3%	240,662	18.2%
HQ Ext	20,108	2,484	Large	0	N/A
HG Ext	550	0	N/A	13,146	-95.8%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	0	0	N/A	1,767	-100.0%
NECEC Ext	188,232	187,709	0.3%	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 91% 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

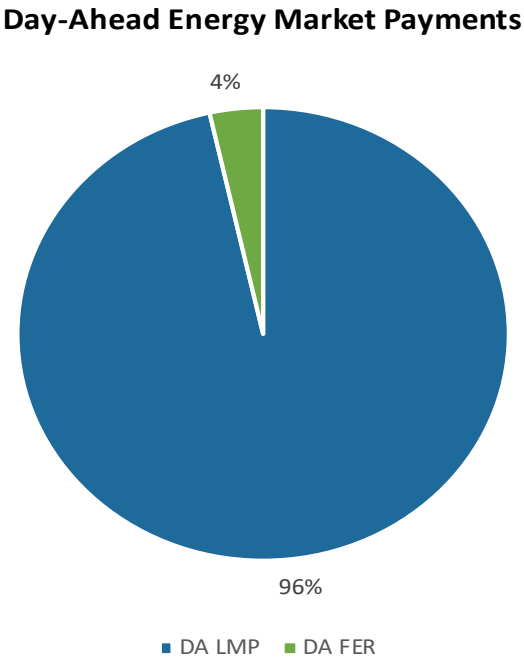
6.1 Energy Market Payments

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.

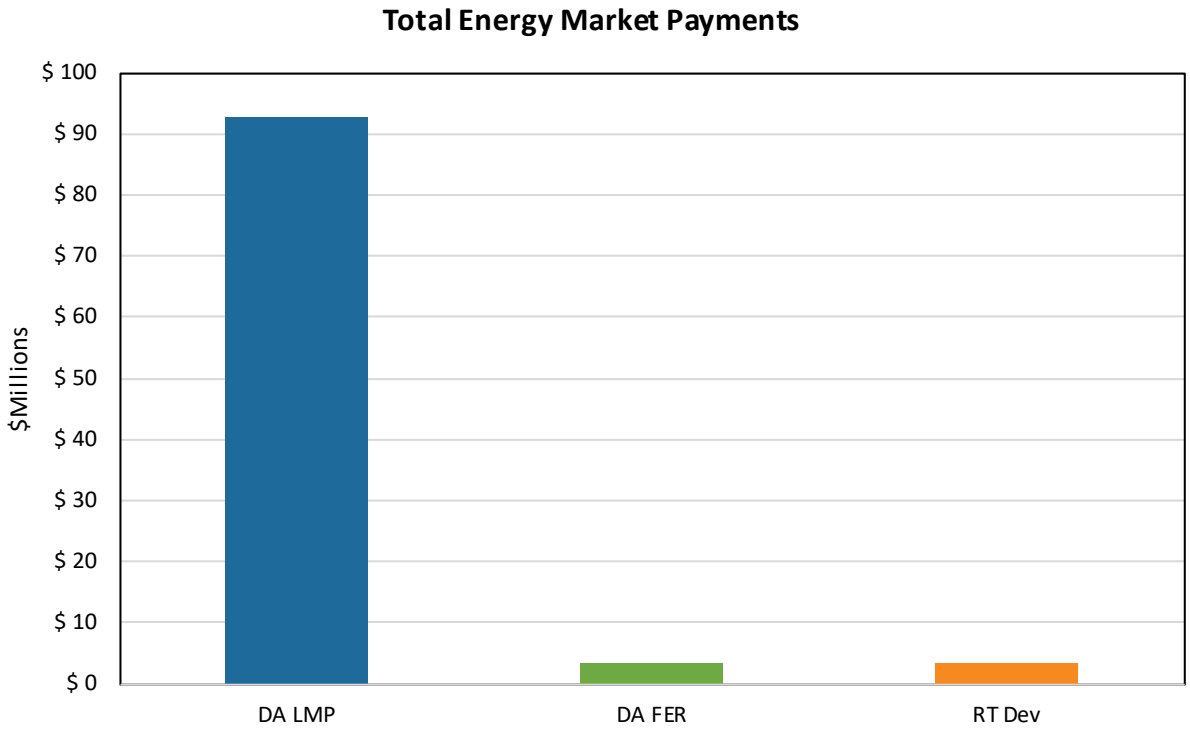
Energy Market Payment Summary
March 23-29, 2026

DA LMP Payments (A)	DA FER Payments (B)	RT Dev Payments (C)	Energy Market Payment (D=A+B+C)
$92,616,005	$3,361,345	$3,468,498	$99,445,848

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



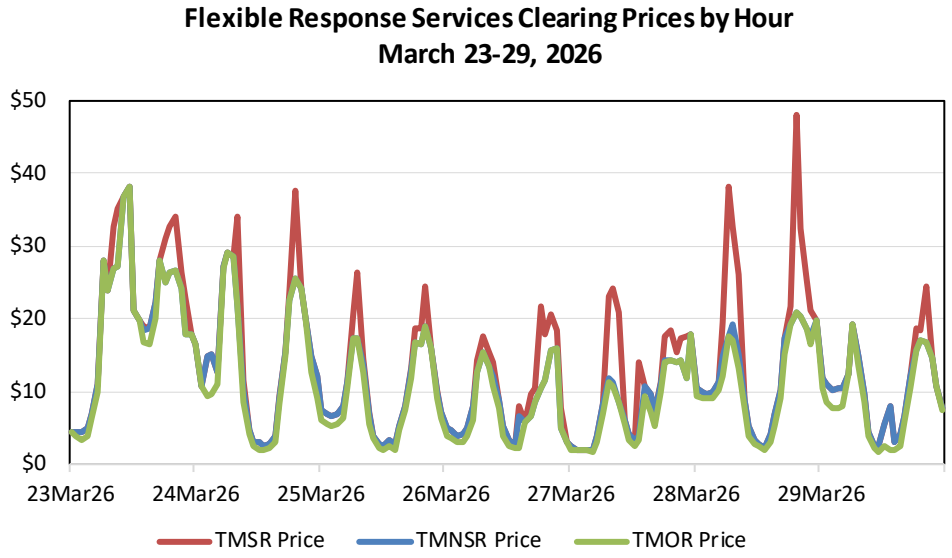
The chart below shows the magnitude of each component's contribution to the total Energy Market payment.



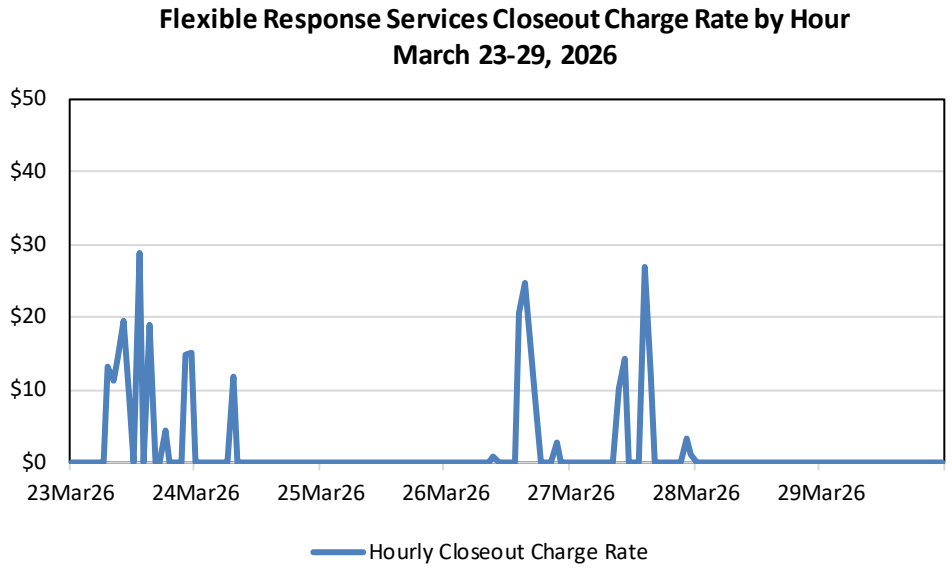
Flexible Response Services (FRS)

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.



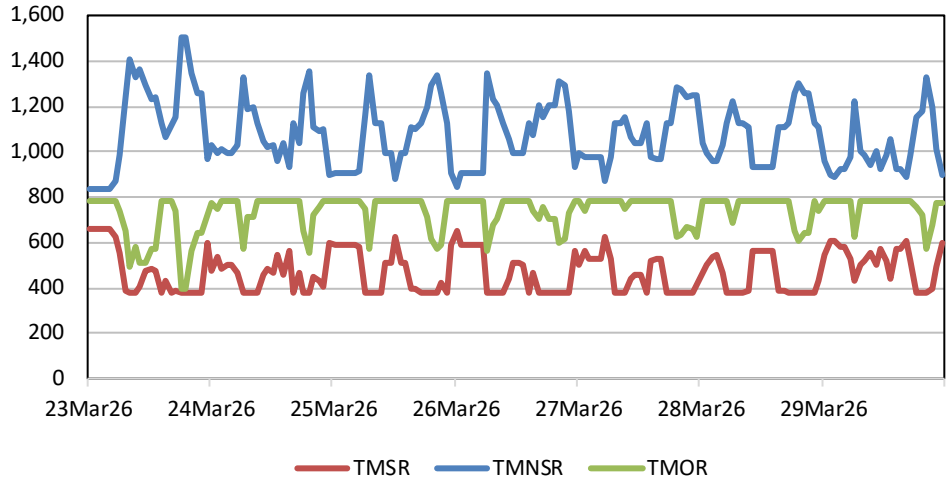
Percentage of Hours with Closeout Charge Rates
March 23-29, 2026

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	86.3%	3.0%	1.2%	7.1%	2.4%	0.0%	0.0%

7.2 FRS Quantities

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

Cleared Flexible Response Services MW by Hour
March 23-29, 2026



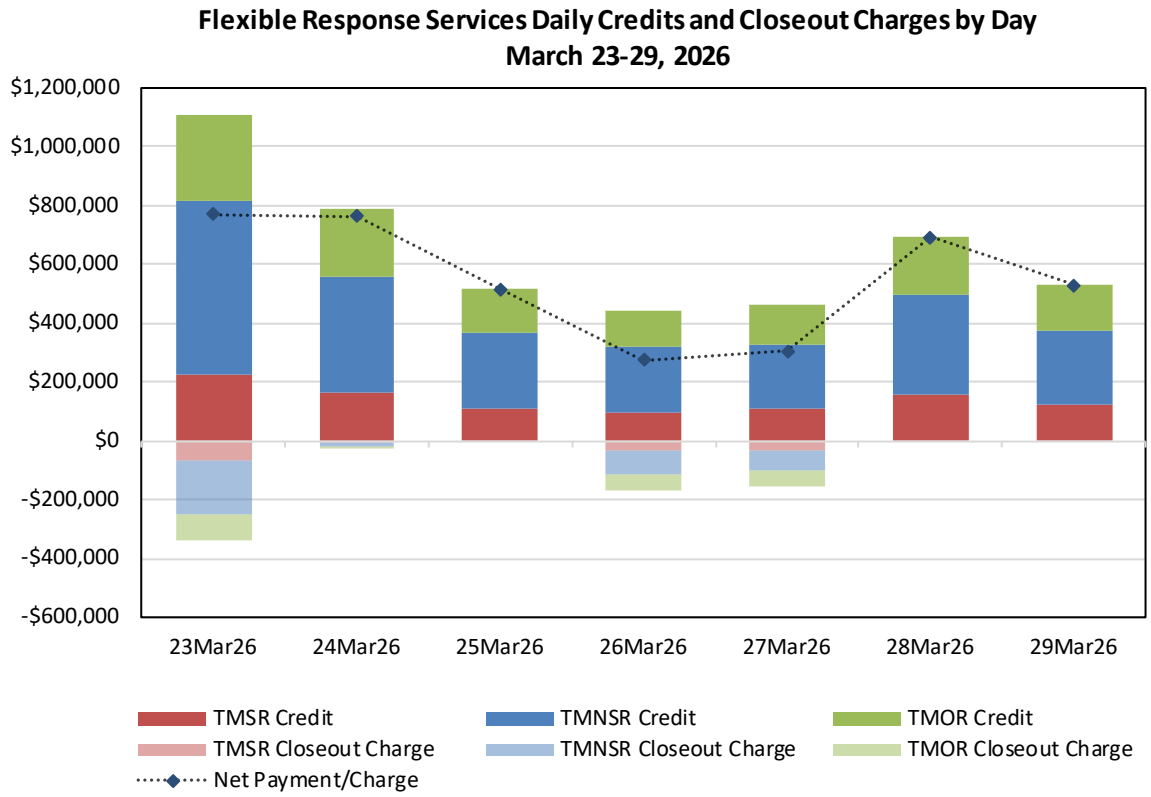
7.3 FRS Payments

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 23-29, 2026

Product Type	FRS Credits (A)	FRS Closeout Charges (B)	FRS Net Payments/Charges (C=A+B)
TMSR	$988,514	-$131,019	$857,495
TMNSR	$2,272,803	-$351,850	$1,920,953
TMOR	$1,284,294	-$205,500	$1,078,794
Total	$4,545,611	-$688,370	$3,857,241

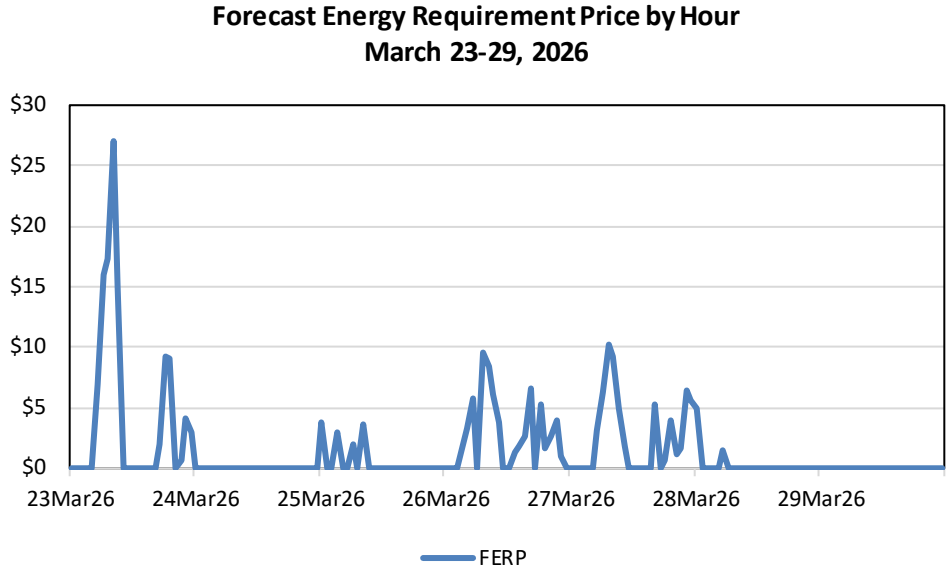
The following graph shows the daily Credit and Closeout charges by FRS product type:



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.



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

Average Daily and Weekly Forecast Energy Requirement Price ($/MWh)
March 23-29, 2026

23Mar26	24Mar26	25Mar26	26Mar26	27Mar26	28Mar26	29Mar26	Weekly Average
$4.59	$0.00	$0.52	$2.74	$2.52	$0.27	$0.00	$1.52

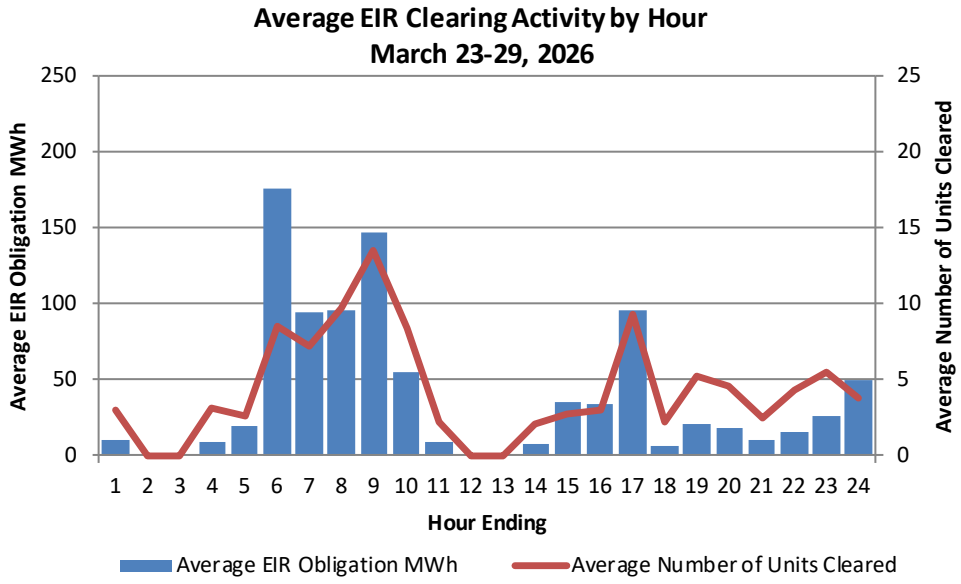
The following table shows the distribution of the hourly FERP during the reporting week.

Hourly Forecast Energy Requirement Price Distribution
March 23-29, 2026

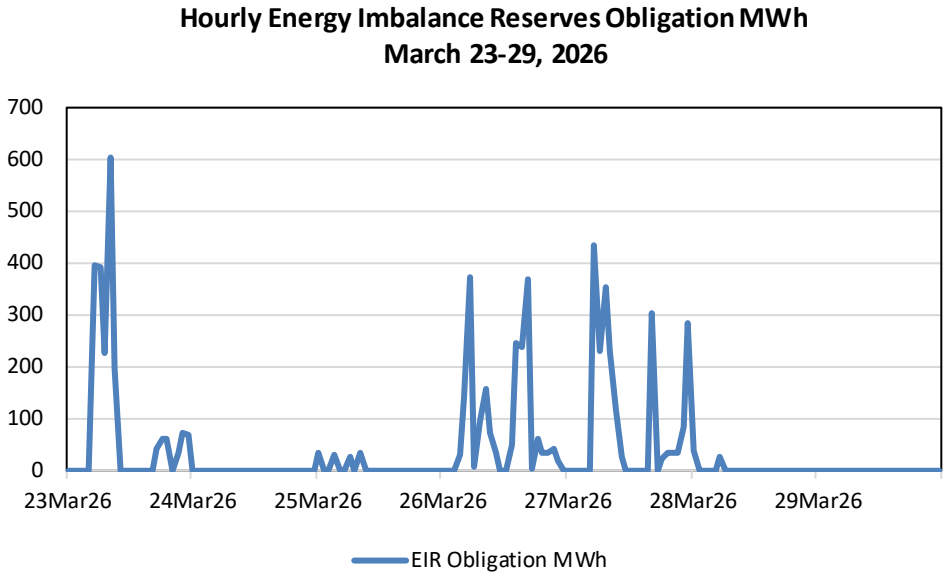
Frequency Tabulation	$0.00	$0.01 - $4.99	$5.00 - $9.99	$10.00 - $19.99	$20.00 - $49.99	$50.00 - $99.99	>= $100.00
FERP	72.6%	16.1%	8.3%	2.4%	0.6%	0.0%	0.0%

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 23-29, 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	71.3%	12.5%	5.4%	5.4%	4.8%	0.6%	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 23-29, 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)
23Mar26	$1,569,413	$33,887	-$14,959	$18,928	$1,588,341
24Mar26	$0	$0	$0	$0	$0
25Mar26	$153,030	$402	$0	$402	$153,432
26Mar26	$812,900	$9,731	-$16,849	-$7,118	$805,781
27Mar26	$751,731	$13,253	-$2,211	$11,042	$762,773
28Mar26	$74,272	$229	$0	$229	$74,500
29Mar26	$0	$0	$0	$0	$0
Total	$3,361,345	$57,501	-$34,019	$23,482	$3,384,827

Real-Time Reserve Market

9.1 Real-Time Reserve Payments

Real-Time Reserve Payment Summary by Reserve Zone
March 23-29, 2026

DAY	CT	NEMABSTN	ROS	SWCT	Total
23MAR26	$512.12	$198.87	$4,322.32	$558.72	$5,592.03
24MAR26	$0.00	$0.00	$0.00	$0.00	$0.00
25MAR26	$0.00	$0.00	$0.00	$0.00	$0.00
26MAR26	$102.51	$50.05	$422.12	$245.41	$820.09
27MAR26	$0.00	$0.00	$0.00	$0.00	$0.00
28MAR26	$429.23	$67.11	$1,454.89	$456.13	$2,407.36
29MAR26	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,043.86	$316.03	$6,199.33	$1,260.26	$8,819.48

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 23-29, 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	98.8%	1.2%	62.5%	37.5%	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 23-29, 2026

Local Reserve Zone	Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals
Connecticut	TMSR	98.8%	1.2%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
NEMA/Boston	TMSR	98.8%	1.2%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Rest Of System	TMSR	98.8%	1.2%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Southwest Connecticut	TMSR	98.8%	1.2%
	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 23-29, 2026

Local Day	Reserve Bias
March 23-29, 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:

(Load + Reserve Requirement) / 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 Detail[1]
March 23-29, 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 23-29, 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**
4/1/2026	Original	Initial posting.