Weekly Market Summary

June 29-July 5, 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: June 29-July 5, 2026

1.1 Weekly Highlights

Notable Events

- Real-Time LMPs in excess of $310/MWh were caused by loads over the forecast and binding reserve constraints in the hour ending 7:00 P.M. on Friday, July 3.
- In response to severe weather conditions in all of New England, Master/Local Control Center Procedure #2 (M/LCC 2) was implemented from Wednesday, July 1 at 5:00 P.M through Friday, July 3 at 10:00 P.M.

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	$114.79	$48.30	137.7%	$52.02	120.7%
*Real-Time Energy Market; All Hours	$74.48	$48.20	54.5%	$49.07	51.8%
*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 (MW - Initial)	25,832	17,841	44.8%	22,917	12.7%
DA Load Obligation (All Zones)	-3,058,876	-2,312,666	32.3%	-2,678,452	14.2%
RT Load Obligation (All Zones)	-3,009,189	-2,296,421	31.0%	-2,590,737	16.2%
DA Cleared Exports (All Interfaces)	-105,651	-108,122	-2.3%	-115,567	-8.6%
RT Scheduled Exports (All Interfaces)	-237,140	-206,487	14.8%	-214,020	10.8%

Weekly Supply Statistics	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Input Fuel Price (Natural Gas, $/MMBtu)	$3.87	$2.73	41.9%	$3.15	23.0%
Mass Average Input Fuel Price (Natural Gas, $/MMBtu)	$3.76	$2.68	40.3%	$3.10	21.3%
Metered Generation (MWh)	2,800,217	2,111,665	32.6%	2,602,241	7.6%
Generation Obligation (MWh)	3,309,753	2,556,762	29.5%	2,847,766	16.2%
RT Demand Reduction Obligation (MWh)	57	57	0.9%	73	-21.7%
Self-Scheduled Generation (MWh)	1,105,066	938,629	17.7%	1,026,833	7.6%
DA Cleared Imports (MWh - All Interfaces)	494,472	409,552	20.7%	205,144	141.0%
RT Scheduled Imports (MWh - All Interfaces)	509,536	445,097	14.5%	245,526	107.5%

Market Payments	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead and Real-Time Energy Market Payments ($)	$432,476,393	$123,782,437	249.4%	$161,087,489	168.5%
Day-Ahead Ancillary Services Market Payments ($)	$15,170,264	$172,347	Large	$2,873,295	428.0%
Real-Time Reserve Market Payments ($)	$1,433,350	$37,835	Large	$316,587	352.8%

Underlying natural gas data furnished by:

Day-Ahead Price Separation

- On Monday and Tuesday, June 29 and 30, depressed pricing in the Maine (ME) Load Zone was caused by a binding constraint on the 374 (Surowiec – Buxton) line due to the planned outage of the 3020 (Raven Farm – Surowiec) line. The 3020 line was restored on June 30.
- From Wednesday through Saturday, July 1-4, 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 Monday, June 29, depressed pricing in the ME Load Zone was caused by binding constraints on the 374 and 3038 (Buxton – Surowiec) lines due to the planned outage of the aforementioned 3020 line.
- On Wednesday, July 1, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine – New Hampshire and Orrington-South Interfaces due to patterns of load and generation.
- On Thursday, July 2, 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.
- On Friday, July 3, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine – New Hampshire, Keene Road Export, and Northern New England Scobie 345kV – Scobie + 394 Interfaces due to patterns of load and generation.
- On Saturday, July 4, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine – New Hampshire and Keene Road Export Interfaces due to patterns of load and generation.

Real-Time Price Corrections

- On the intervals beginning at 2:30 P.M. and 2:55 P.M. on Tuesday, June 30 due to a planned software outage. The resulting five-minute LMPs for these intervals at the Hub and Load Zones ranged between $108.21/MWh and $131.74/MWh.
- On the interval beginning at 11:25 P.M. on Tuesday, June 30 due to a software outage. The resulting five-minute LMPs for these intervals at the Hub and Load Zones ranged between $42.12/MWh and $45.91/MWh.
- On the intervals beginning at 12:30 A.M. and 12:35 A.M. on Wednesday, July 1 due to a software error. The resulting five-minute LMPs for these intervals at the Hub and Load Zones ranged between $47.26/MWh and $50.65/MWh.

Year-to-Date Peak Load Statistics*

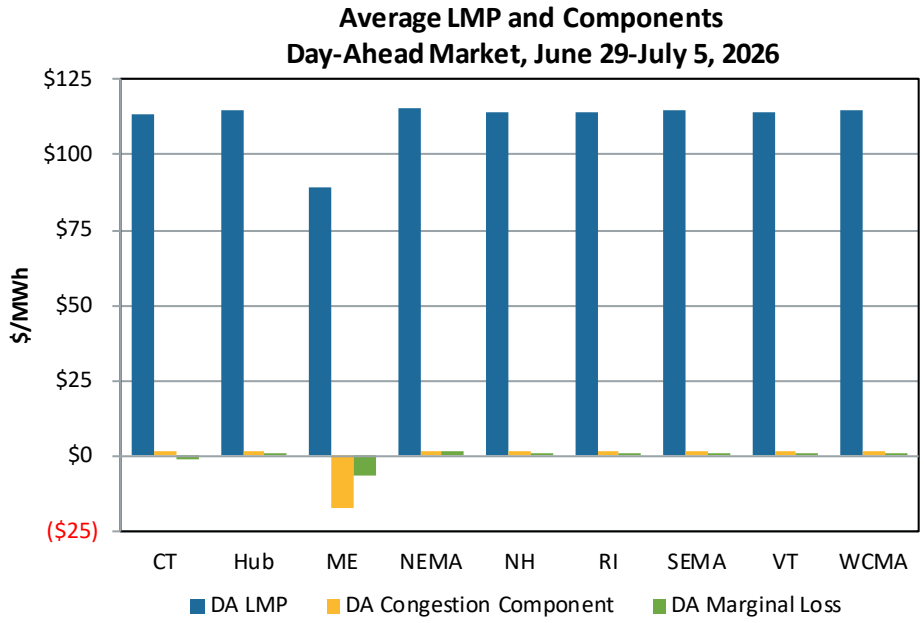
- FCM Peak Load (preliminary, subject to change) is 25,303 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2. At this hour, the Capacity Zone-level FCM peak loads were 3,231 MW in Northern New England, 2,034 MW in Maine, and 20,038 MW in Rest-of-Pool.
- Revenue Quality System Peak Load (initial) is 25,832 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2.
- Telemetered System Peak Load is 25,361 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2.

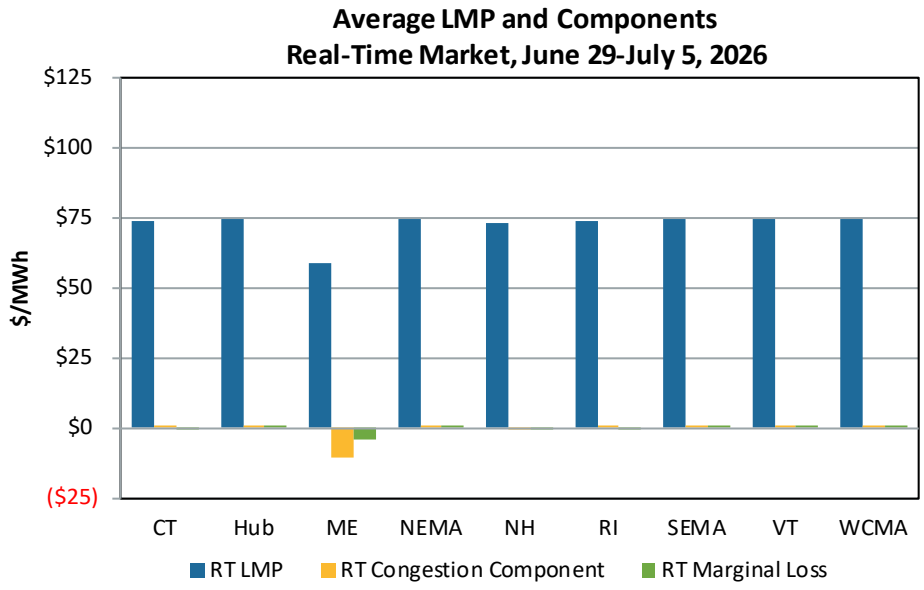
*Due to the difference in calculation methodologies, these values can occur on different days and hours.

Pricing

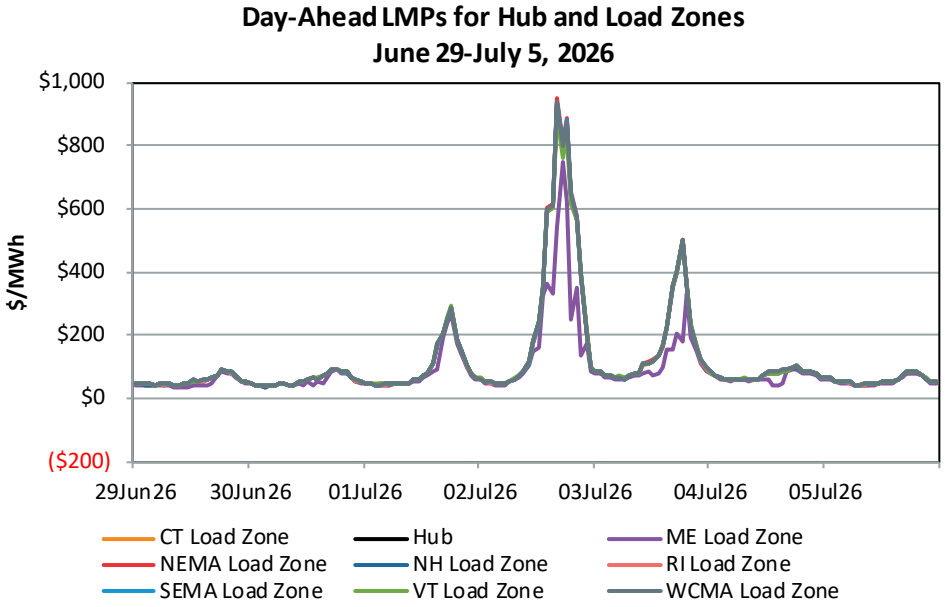
2.1 Pricing

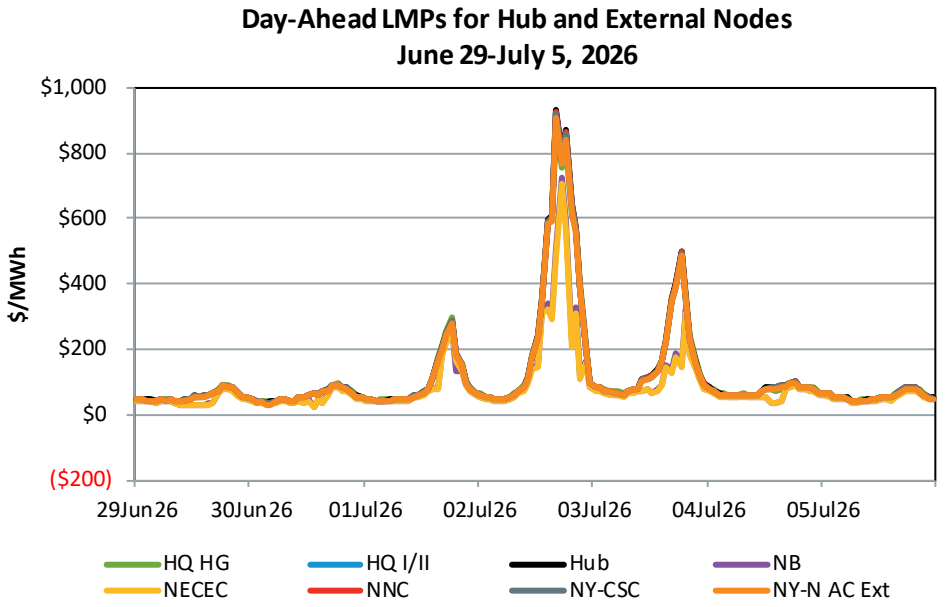
The two graphs below show the weekly average of LMPs, congestion, and marginal loss components at the Hub and Load Zones for both the Day-Ahead and Real-Time Energy Markets.



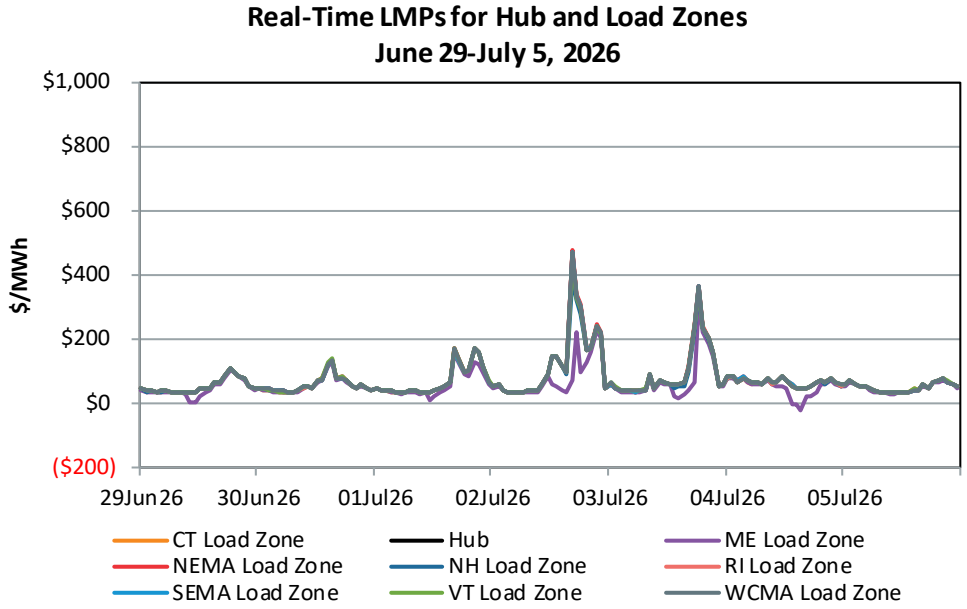


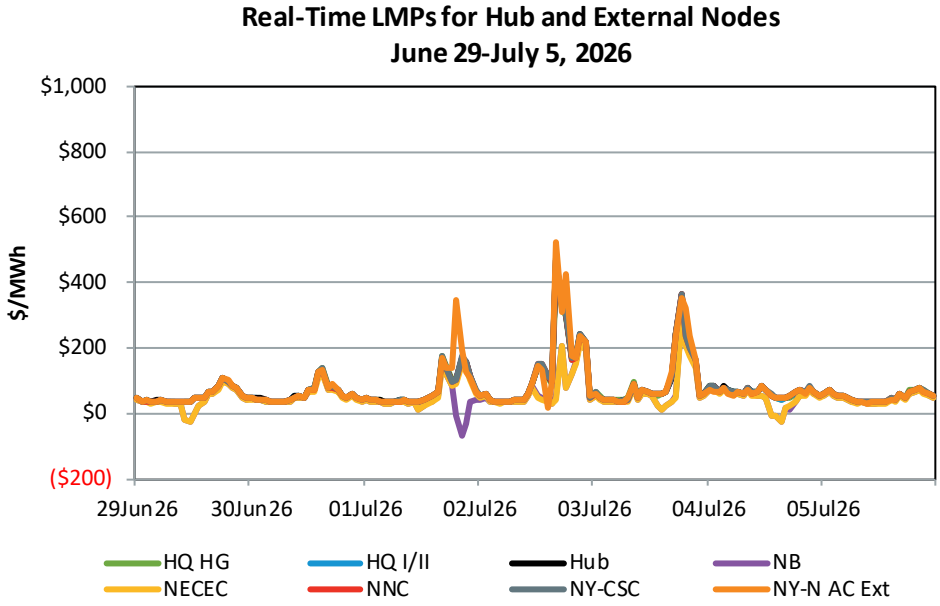
The following two graphs show hourly Day-Ahead LMPs for the Hub, the eight Load Zones, and the seven external nodes. In cases where there is little or no price separation, the lines for multiple locations may be indistinguishable from each other.





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, June 29-July 5, 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	$114.79	$74.48	$38.05	$32.47	$934.98	$470.51	100%	100%	65%	148.63	62.75	42%
ME	$88.89	$58.84	$33.94	$-20.99	$747.40	$312.55	77%	79%	66%	97.25	43.52	45%
NH	$114.07	$72.93	$37.72	$32.13	$930.04	$389.01	99%	98%	64%	147.91	58.49	40%
VT	$114.45	$74.59	$38.24	$32.31	$891.98	$445.68	100%	100%	65%	144.17	61.37	43%
CT	$113.14	$74.01	$36.89	$32.21	$922.87	$469.17	99%	99%	65%	146.86	62.61	43%
RI	$114.10	$74.03	$37.84	$32.22	$934.85	$470.10	99%	99%	65%	148.44	62.72	42%
SEMA	$115.08	$74.71	$38.31	$32.84	$939.98	$473.65	100%	100%	65%	149.05	62.96	42%
WCMA	$115.01	$74.65	$38.04	$32.48	$937.93	$471.43	100%	100%	65%	149.00	62.88	42%
NEMA	$115.67	$75.04	$38.24	$32.71	$947.42	$477.20	101%	101%	65%	150.34	63.48	42%
NB Ext	$84.30	$52.95	$25.00	$-68.38	$726.96	$303.77	73%	71%	63%	92.45	44.03	48%
NY-N AC Ext	$111.75	$76.52	$26.58	$16.92	$905.20	$524.81	97%	103%	68%	144.05	72.59	50%
HQ Ext	$113.47	$73.82	$37.75	$32.42	$923.75	$467.09	99%	99%	65%	146.96	62.11	42%
HG Ext	$114.35	$73.82	$38.48	$31.70	$868.07	$419.93	100%	99%	65%	142.95	60.02	42%
CSC Ext	$113.44	$75.03	$37.01	$32.52	$923.06	$474.97	99%	101%	66%	146.77	63.28	43%
NNC Ext	$113.40	$74.33	$36.58	$32.38	$926.73	$471.30	99%	100%	66%	147.53	62.97	43%
NECEC Ext	$81.50	$54.77	$22.95	$-26.62	$703.84	$296.02	71%	74%	67%	88.94	42.75	48%

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

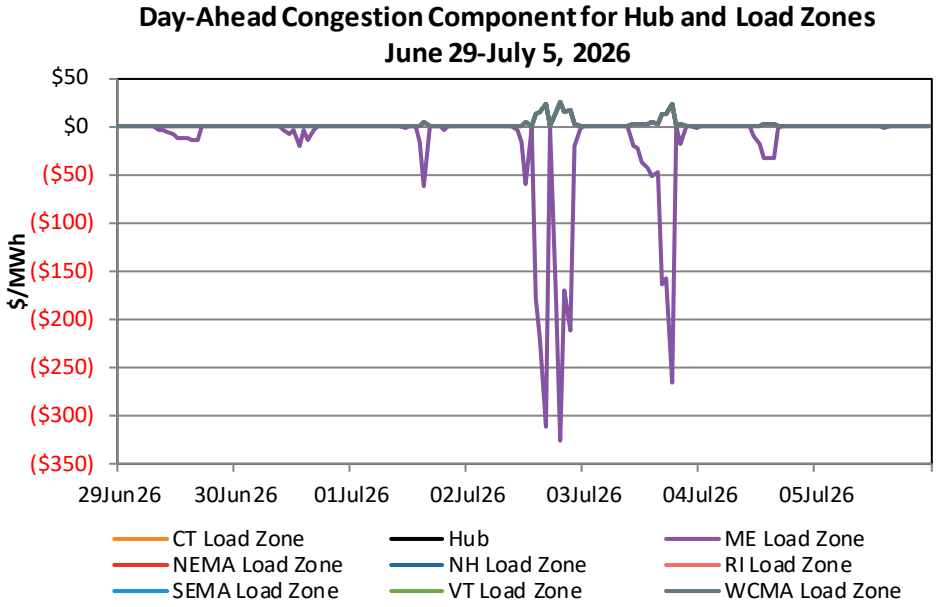
5-Minute LMP Summary (RT Only)
June 29-July 5, 2026

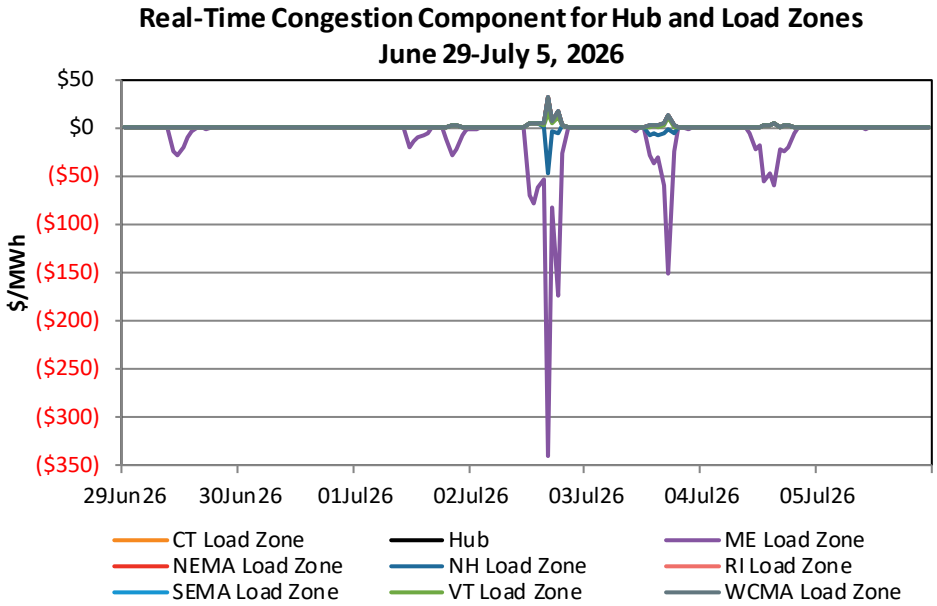
Hub/Zone	Max RT LMP ($/MWh)	Min RT LMP ($/MWh)	RT Std Dev	RT as % of Hub
Hub	$995.70	$30.60	$73.78	100%
ME	$457.66	-$21.84	$50.55	84%
NH	$794.10	$30.29	$67.79	99%
VT	$938.26	$30.74	$71.88	101%
CT	$992.39	$30.46	$73.60	99%
RI	$994.37	$30.45	$73.73	99%
SEMA	$1,001.77	$30.99	$74.04	100%
WCMA	$997.34	$30.61	$73.93	100%
NEMA	$1,009.22	$30.84	$74.62	101%

5-Minute Energy Component of LMP
June 29-July 5, 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	0.0%	0.0%	31.2%	41.6%	12.2%	8.7%	1.9%	4.1%	0.3%	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.





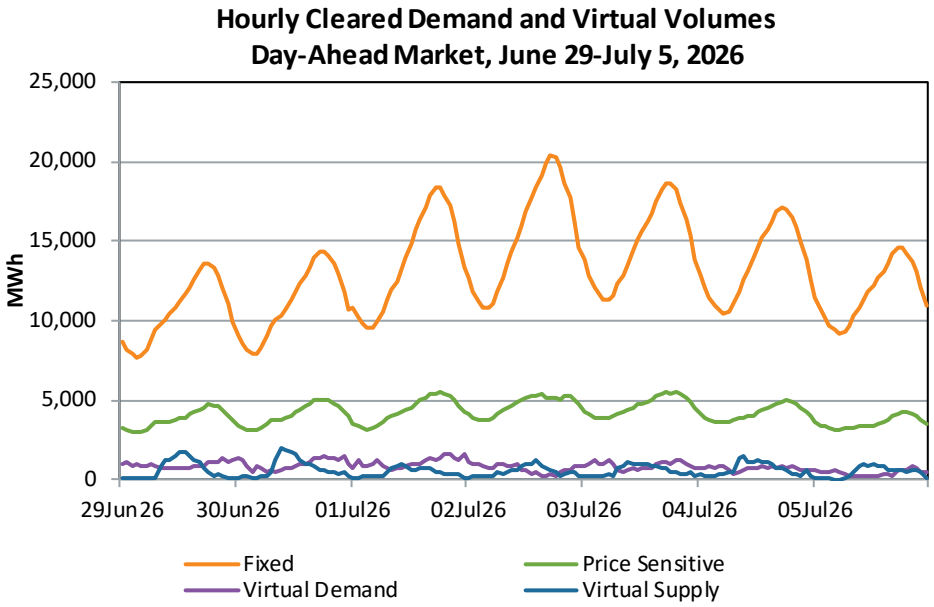
Energy Market Demand

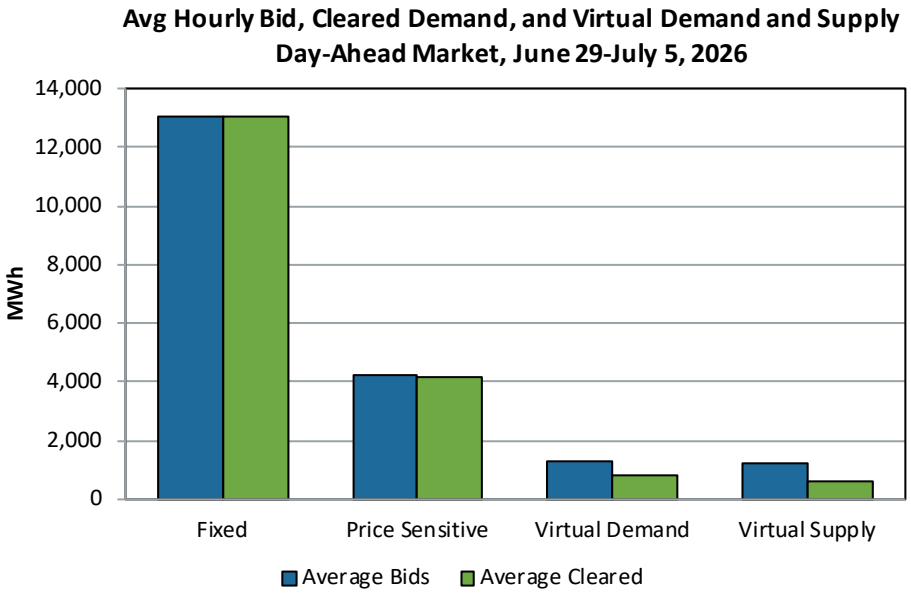
3.1 Day-Ahead Demand

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	28,757	13,806	108.3%	21,676	32.7%
ME	222,570	179,161	24.2%	214,185	3.9%
NH	287,257	223,627	28.5%	251,456	14.2%
VT	90,528	79,236	14.3%	91,101	-0.6%
CT	710,722	527,600	34.7%	626,089	13.5%
RI	214,571	159,746	34.3%	189,238	13.4%
SEMA	384,318	278,839	37.8%	341,165	12.6%
WCMA	406,573	306,990	32.4%	344,019	18.2%
NEMA	614,863	478,734	28.4%	562,178	9.4%
NB Ext	44	13	238.5%	25	76.0%
NY-N AC Ext	65,849	50,949	29.2%	65,580	0.4%
HQ Ext	3,916	23,958	-83.7%	0	N/A
HG Ext	32,644	5,189	Large	2,950	Large
CSC Ext	37,083	43,310	-14.4%	52,394	-29.2%
NNC Ext	6,803	8,067	-15.7%	2,184	211.5%
NECEC Ext	72	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)

June 29-July 5, 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	29JUN26	0	0	5,966	4,559	0	0	4,673	3,652	4,673
Hub	30JUN26	0	0	5,545	5,708	0	0	4,056	1,866	4,056
Hub	01JUL26	0	0	8,758	3,707	0	0	6,596	1,230	6,596
Hub	02JUL26	0	0	12,245	3,220	0	0	4,980	2,132	4,980
Hub	03JUL26	0	0	6,440	4,496	0	0	4,239	1,832	4,239
Hub	04JUL26	0	0	3,872	8,781	0	0	3,004	2,766	3,004
Hub	05JUL26	0	0	2,386	2,586	0	0	1,210	1,620	1,210
ME	29JUN26	19,708	6,424	3,523	5,873	19,708	6,424	2,939	3,213	29,070
ME	30JUN26	20,596	7,002	2,471	8,362	20,596	7,002	1,460	5,743	29,058
ME	01JUL26	24,837	7,951	1,977	5,912	24,837	7,951	1,305	2,905	34,093
ME	02JUL26	27,174	8,809	1,033	4,443	27,174	8,809	591	3,126	36,574
ME	03JUL26	27,252	8,554	2,003	8,071	27,252	8,554	760	4,833	36,566
ME	04JUL26	24,754	7,932	2,192	9,300	24,754	7,932	1,041	5,962	33,727
ME	05JUL26	21,657	6,705	1,108	5,112	21,657	6,705	1,023	3,067	29,384
NH	29JUN26	28,672	5,529	946	1,017	28,672	5,529	691	944	34,892
NH	30JUN26	30,853	5,558	952	1,507	30,853	5,558	639	1,324	37,049
NH	01JUL26	39,832	5,973	1,934	929	39,832	5,973	1,276	859	47,081
NH	02JUL26	41,774	6,531	1,277	938	41,774	6,512	755	831	49,041
NH	03JUL26	38,464	5,582	1,916	2,743	38,464	5,582	1,057	1,104	45,103
NH	04JUL26	35,029	5,141	1,102	3,340	35,029	5,141	486	1,033	40,657
NH	05JUL26	31,361	4,433	606	3,288	31,361	4,433	532	974	36,325
VT	29JUN26	1,149	10,032	1,745	1,054	1,149	10,032	806	835	11,987
VT	30JUN26	1,057	12,098	1,559	1,621	1,057	12,098	652	1,240	13,806
VT	01JUL26	1,258	13,504	1,471	899	1,258	13,504	733	700	15,495
VT	02JUL26	1,275	14,501	1,196	1,073	1,275	10,889	673	917	12,837
VT	03JUL26	1,275	12,877	1,894	1,898	1,275	12,593	866	948	14,735
VT	04JUL26	1,052	10,732	1,147	761	1,052	10,732	392	428	12,177
VT	05JUL26	1,017	10,457	1,022	1,102	1,017	10,457	665	643	12,138
CT	29JUN26	55,919	26,287	3,953	2,208	55,919	26,287	3,051	1,221	85,257
CT	30JUN26	60,072	27,900	3,932	2,458	60,072	27,900	3,305	1,624	91,277
CT	01JUL26	79,431	25,552	3,215	1,847	79,431	25,552	2,496	1,269	107,478
CT	02JUL26	90,485	28,812	2,416	1,158	90,485	28,812	913	879	120,210
CT	03JUL26	88,417	26,910	4,123	2,225	88,417	26,910	3,432	1,335	118,758
CT	04JUL26	79,166	24,935	3,914	2,806	79,166	24,935	2,847	1,215	106,947
CT	05JUL26	66,123	20,511	2,633	2,216	66,123	20,511	2,568	1,457	89,202
RI	29JUN26	22,187	4,559	1,442	1,327	22,187	4,559	739	934	27,484
RI	30JUN26	20,082	4,644	4,302	1,647	20,082	4,644	3,961	978	28,686

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	01JUL26	23,411	5,371	5,536	1,646	23,411	5,371	4,348	960	33,130
RI	02JUL26	27,834	6,053	6,474	1,224	27,834	6,053	2,218	835	36,105
RI	03JUL26	25,395	7,876	5,427	2,238	25,395	7,876	3,549	818	36,820
RI	04JUL26	26,195	6,820	1,679	2,036	26,195	6,820	911	802	33,925
RI	05JUL26	22,622	5,695	619	1,521	22,622	5,695	561	537	28,878
SEMA	29JUN26	33,195	10,738	1,679	2,076	33,195	10,738	905	1,391	44,837
SEMA	30JUN26	33,698	10,873	1,100	1,799	33,698	10,873	712	1,115	45,283
SEMA	01JUL26	42,112	12,974	1,195	1,268	42,112	12,974	597	951	55,684
SEMA	02JUL26	48,333	15,249	1,040	909	48,333	15,249	349	783	63,930
SEMA	03JUL26	48,789	15,752	1,241	1,829	48,789	15,752	613	1,265	65,154
SEMA	04JUL26	45,040	14,633	1,006	1,624	45,040	14,633	417	1,016	60,089
SEMA	05JUL26	38,189	11,570	958	936	38,189	11,570	889	571	50,647
WCMA	29JUN26	37,313	11,260	1,868	1,011	37,313	11,260	1,418	853	49,991
WCMA	30JUN26	39,816	11,896	1,761	1,231	39,816	11,896	1,361	1,018	53,073
WCMA	01JUL26	48,216	13,081	1,849	1,248	48,216	13,081	1,417	1,012	62,715
WCMA	02JUL26	53,271	14,238	1,827	1,045	53,271	14,238	867	889	68,376
WCMA	03JUL26	50,454	13,222	1,675	2,576	50,454	13,222	950	1,301	64,627
WCMA	04JUL26	46,026	12,021	803	2,031	46,026	12,021	550	881	58,596
WCMA	05JUL26	40,557	10,614	1,621	1,852	40,557	10,614	1,516	823	52,688
NEMA	29JUN26	56,827	16,789	1,187	1,268	56,827	16,789	738	998	74,353
NEMA	30JUN26	60,764	17,943	1,070	1,799	60,764	17,943	767	1,581	79,474
NEMA	01JUL26	72,480	20,264	1,172	1,432	72,480	20,257	802	1,057	93,539
NEMA	02JUL26	81,235	22,764	1,231	968	81,235	22,432	339	839	104,005
NEMA	03JUL26	75,112	21,181	1,387	1,540	75,112	21,181	776	987	97,069
NEMA	04JUL26	70,669	18,703	711	2,742	70,669	18,703	361	844	89,733
NEMA	05JUL26	61,443	16,157	914	2,311	61,443	16,157	862	941	78,462

3.2 Real-Time Demand

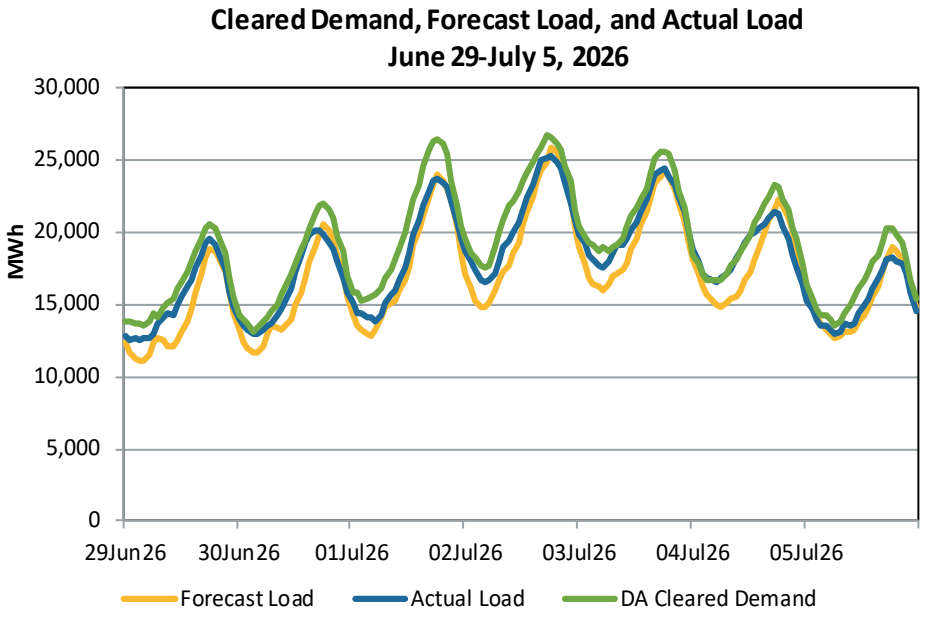
The following table displays the Real-Time Load Obligation at each Load Zone and external nodes for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
ME	239,058	195,324	22.4%	214,265	11.6%
NH	284,778	218,486	30.3%	248,292	14.7%
VT	93,066	75,890	22.6%	88,581	5.1%
CT	719,056	531,873	35.2%	615,938	16.7%
RI	210,932	158,922	32.7%	183,824	14.7%
SEMA	390,866	290,320	34.6%	332,682	17.5%
WCMA	384,942	299,783	28.4%	338,693	13.7%
NEMA	614,445	472,378	30.1%	535,435	14.8%
NB Ext	5,055	9,175	-44.9%	2,107	139.9%
NY-N AC Ext	168,306	116,879	44.0%	156,512	7.5%
HQ Ext	4,936	21,987	-77.6%	84	Large
HG Ext	149	518	-71.2%	0	N/A
CSC Ext	44,392	44,997	-1.3%	51,485	-13.8%
NNC Ext	14,302	12,931	10.6%	3,832	273.2%
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 (MW)	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
29JUN26	19	19,872	$110.48	$104.48	$109.58	$110.23	$109.56	$109.88	$110.82	$110.61	$110.85
30JUN26	18	20,542	$80.89	$77.57	$80.93	$81.79	$80.51	$80.14	$80.68	$81.10	$81.57
01JUL26	19	24,209	$96.52	$90.67	$96.77	$99.10	$96.48	$95.84	$95.96	$96.98	$97.25
02JUL26	19	25,832	$304.26	$94.21	$280.56	$298.39	$301.57	$304.40	$305.53	$304.47	$307.78
03JUL26	19	24,818	$363.55	$312.55	$353.14	$358.25	$361.61	$363.76	$365.18	$363.87	$367.62
04JUL26	18	21,866	$52.02	$22.86	$51.63	$52.03	$52.35	$52.15	$52.64	$52.08	$52.33
05JUL26	19	18,617	$66.94	$63.80	$67.06	$68.75	$66.60	$66.54	$67.42	$67.08	$67.31

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.



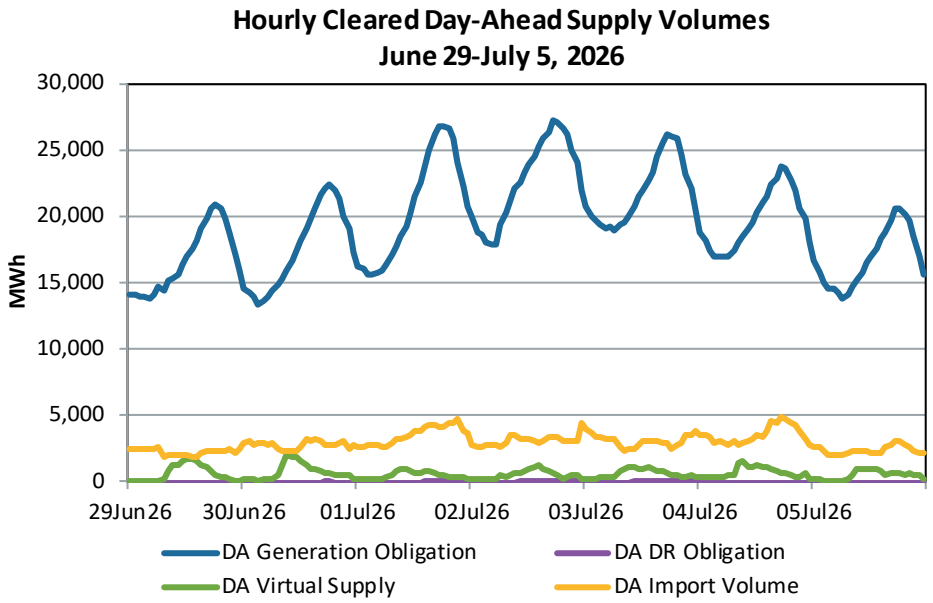
The table below compares the total quantities (MWh) of Day-Ahead Load Obligation with the Real-Time Load Obligation for each Load Zone (including nodal locations within each Load Zone) for the week. Day-Ahead Load Obligation is composed of Day-Ahead cleared demand bids and cleared Decrement bids. Real-Time 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	228,571	241,562	-12,991	94.6%
NH	290,148	285,450	4,698	101.6%
VT	93,174	93,066	108	100.1%
CT	719,130	719,070	60	100.0%
RI	225,029	210,932	14,097	106.7%
SEMA	385,707	393,432	-7,724	98.0%
WCMA	471,714	451,081	20,632	104.6%
NEMA	616,646	614,596	2,050	100.3%

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	19,422	14,839	30.9%	16,903	14.9%
DA Demand Reduction Obligation	3	0	N/A	0	N/A
DA Cleared Increments	591	683	-13.4%	1,207	-51.0%
DA Imports	2,943	2,438	20.7%	1,221	141.0%

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	19,101	10,299	85.5%	31,358	-39.1%
NY-N AC Ext	175,757	185,306	-5.2%	115,249	52.5%
HQ Ext	71,534	15,385	365.0%	48,951	46.1%
HG Ext	35,064	10,658	229.0%	7,423	372.4%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	4,677	357	Large	1,488	214.3%
NECEC Ext	188,340	187,546	0.4%	N/A	N/A

4.2 Real-Time Supply

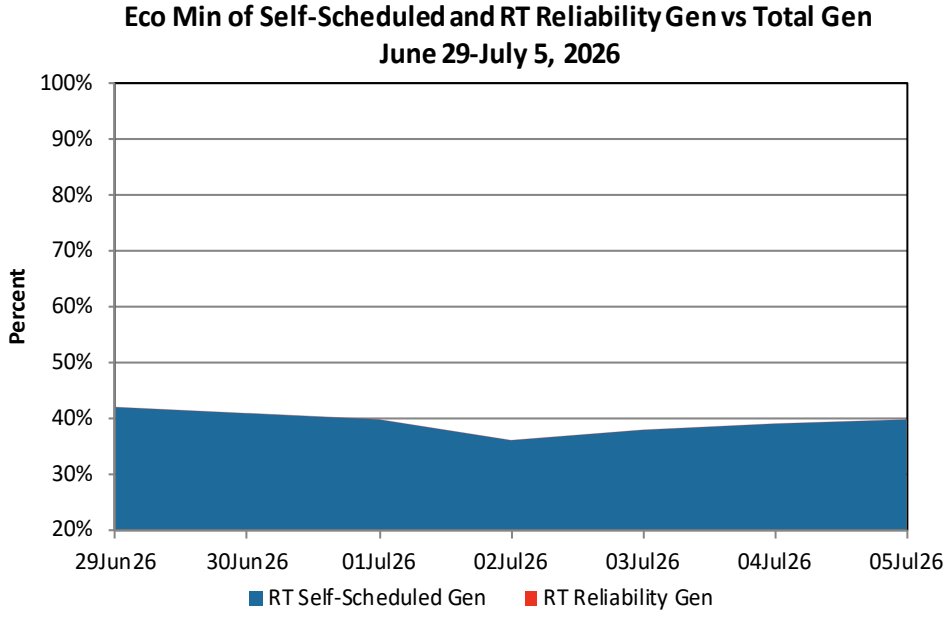
The following table provides daily and weekly totals, in megawatt-hours (MWh), of the amount of electricity produced by classified fuel type during the week. The data provided are for the full system, including "settlement only" resources that do not offer their output into the wholesale markets. The 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	29Jun26	30Jun26	01Jul26	02Jul26	03Jul26	04Jul26	05Jul26	Total
Batteries	731	533	825	675	804	282	164	4,014
Hydro	29,848	25,587	29,881	32,832	30,719	18,779	17,299	184,945
Landfill Gas	958	953	944	912	935	943	941	6,586
Methane	47	29	28	30	31	32	35	232
Natural Gas	201,857	213,095	238,866	277,823	263,463	239,760	208,957	1,643,821
Nuclear	80,115	80,070	80,016	80,037	80,011	80,001	80,029	560,279
Oil	225	1,259	7,520	17,617	16,701	758	0	44,080
Other	2,946	2,380	2,860	2,892	2,959	2,471	2,250	18,758
PRD	19	5	-2	29	6	0	0	57
Refuse	7,798	7,623	7,774	7,257	6,753	7,517	7,523	52,245
Solar	24,544	20,422	23,162	23,813	24,183	20,818	19,679	156,621
Wind	1,860	7,134	14,611	20,275	22,421	17,821	4,684	88,806
Wood	5,050	6,017	5,772	6,005	6,060	5,846	5,080	39,830
Total	355,998	365,107	412,257	470,197	455,046	395,028	346,641	2,800,274

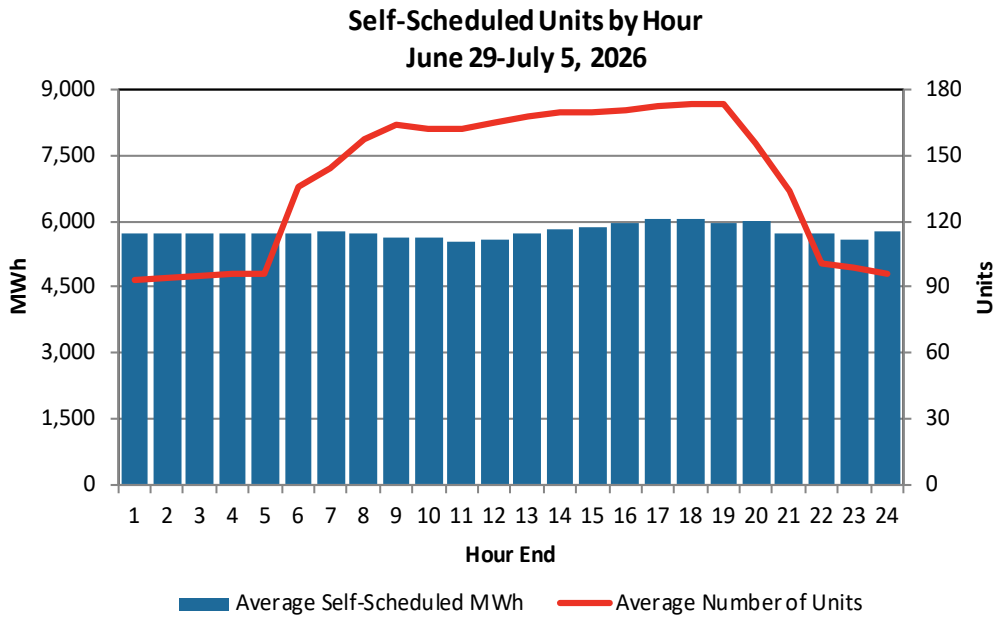
Online generators that are at their Economic Minimum output level are not eligible to set the clearing price. Real-Time Self-Scheduled Generation shown below reflects output by self-scheduled generation and by (non-dispatchable) Settlement Only Resources (SORs). Real-Time Reliability Generation represents 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
29Jun26	150,728	0	355,997
30Jun26	151,064	0	365,108
01Jul26	166,724	0	412,257
02Jul26	168,895	108	470,196
03Jul26	173,904	112	455,047
04Jul26	153,404	240	395,028
05Jul26	140,346	0	346,642

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



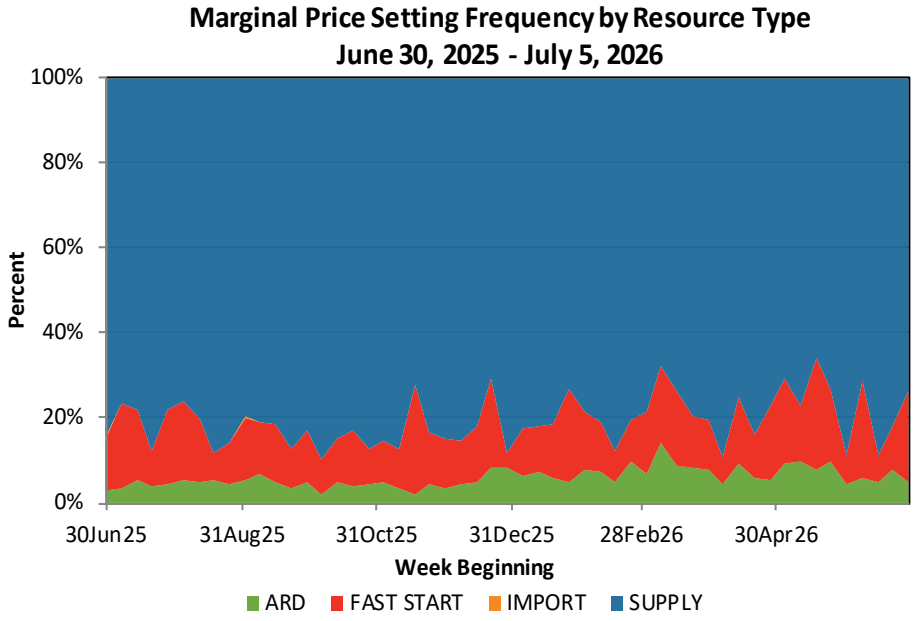
The following graph shows the average number of self-scheduled generating units and MWh for each hour of the last week.



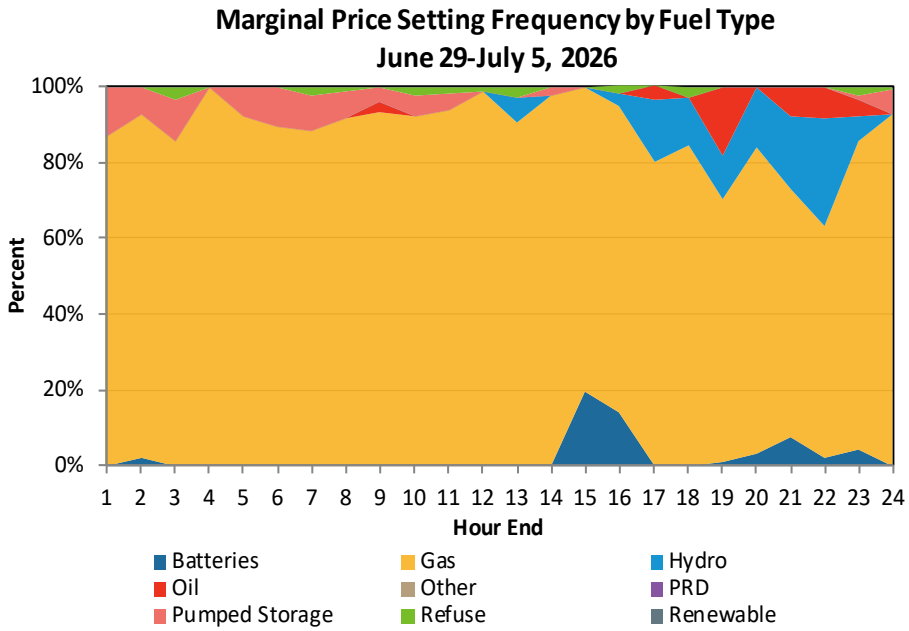
The following table provides the total Real-Time Imports by Interface for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	21,894	8,524	156.9%	25,117	-12.8%
NY-N AC Ext	216,233	231,569	-6.6%	160,039	35.1%
HQ Ext	68,821	3,251	Large	49,721	38.4%
HG Ext	9,212	10,852	-15.1%	7,041	30.8%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	5,637	3,353	68.1%	3,608	56.2%
NECEC Ext	187,739	187,548	0.1%	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 56% 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

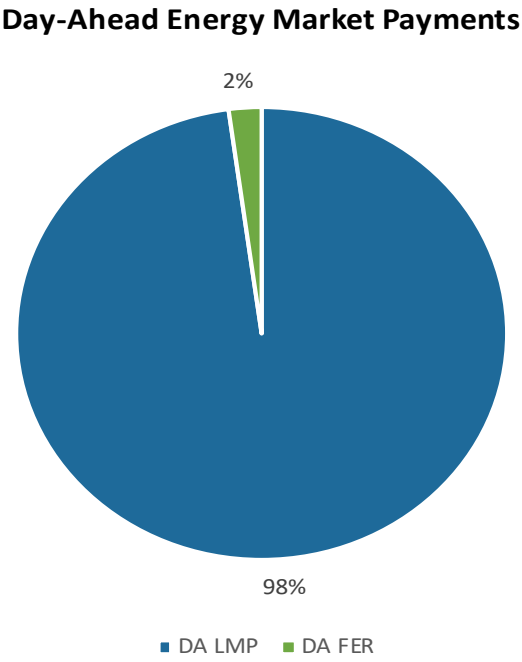
6.1 Energy Market Payments

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.

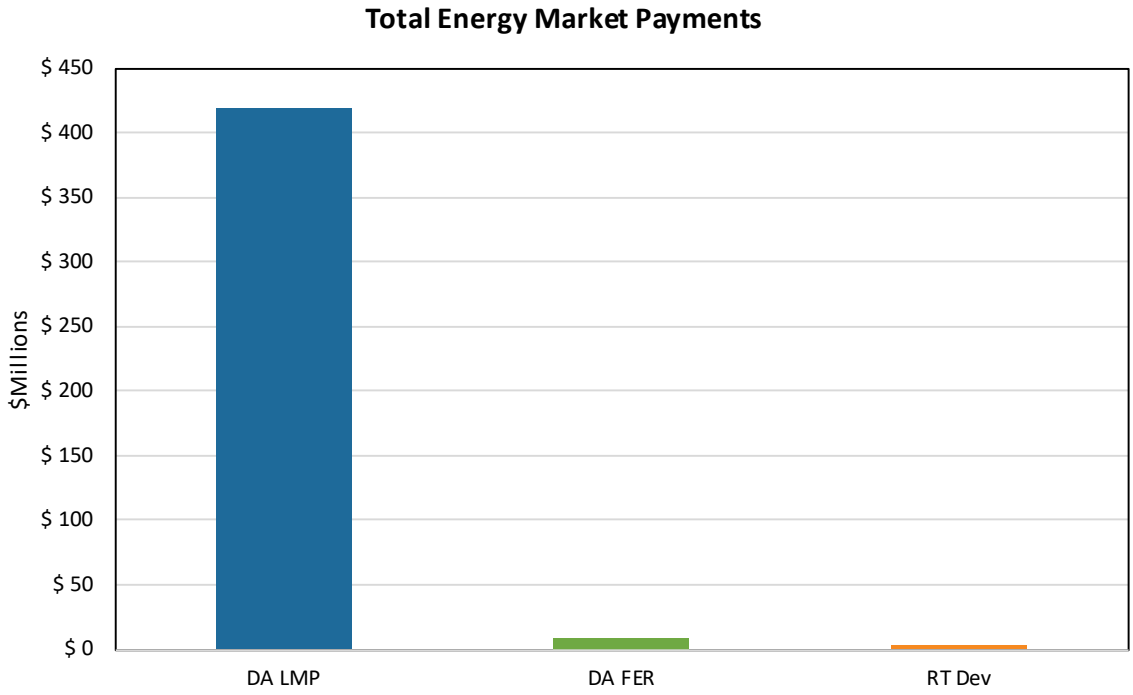
Energy Market Payment Summary
June 29-July 5, 2026

DA LMP Payments (A)	DA FER Payments (B)	RT Dev Payments (C)	Energy Market Payment (D=A+B+C)
$419,454,741	$9,253,544	$3,768,108	$432,476,393

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



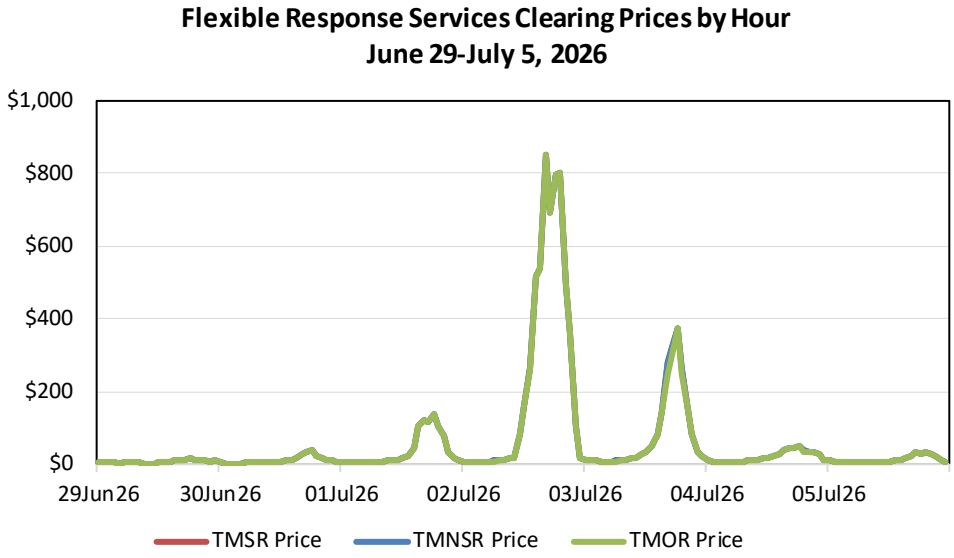
The chart below shows the magnitude of each component's contribution to the total Energy Market payment.



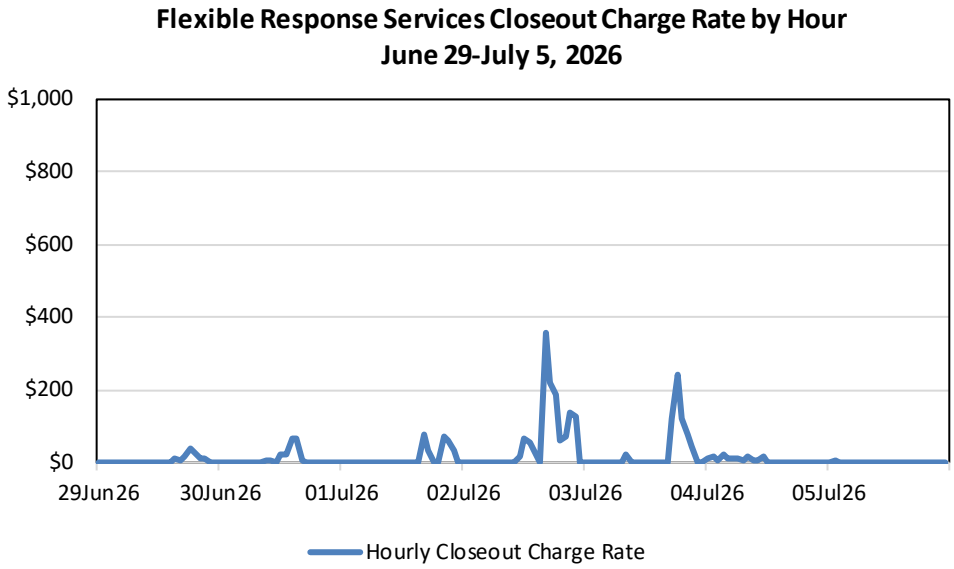
Flexible Response Services (FRS)

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.



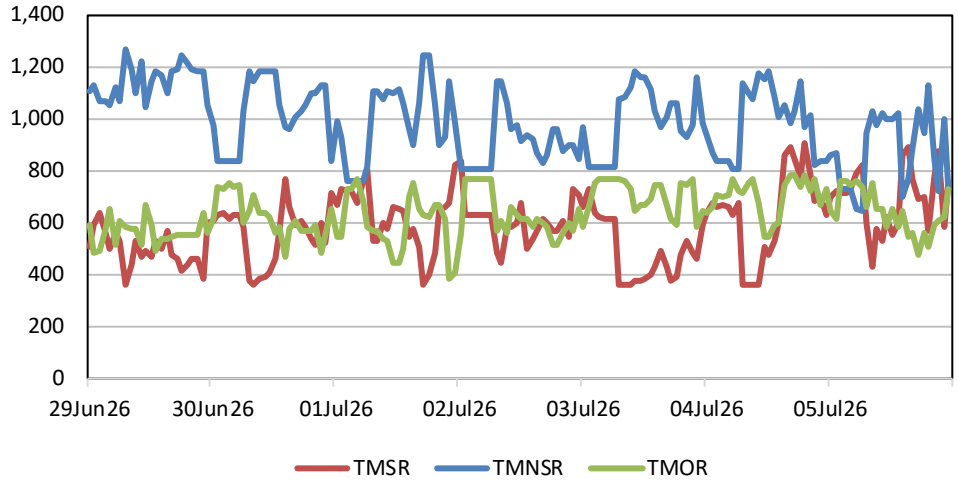
Percentage of Hours with Closeout Charge Rates
June 29-July 5, 2026

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	66.5%	6.0%	4.8%	6.5%	5.4%	6.0%	4.8%

7.2 FRS Quantities

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

Cleared Flexible Response Services MW by Hour
June 29-July 5, 2026



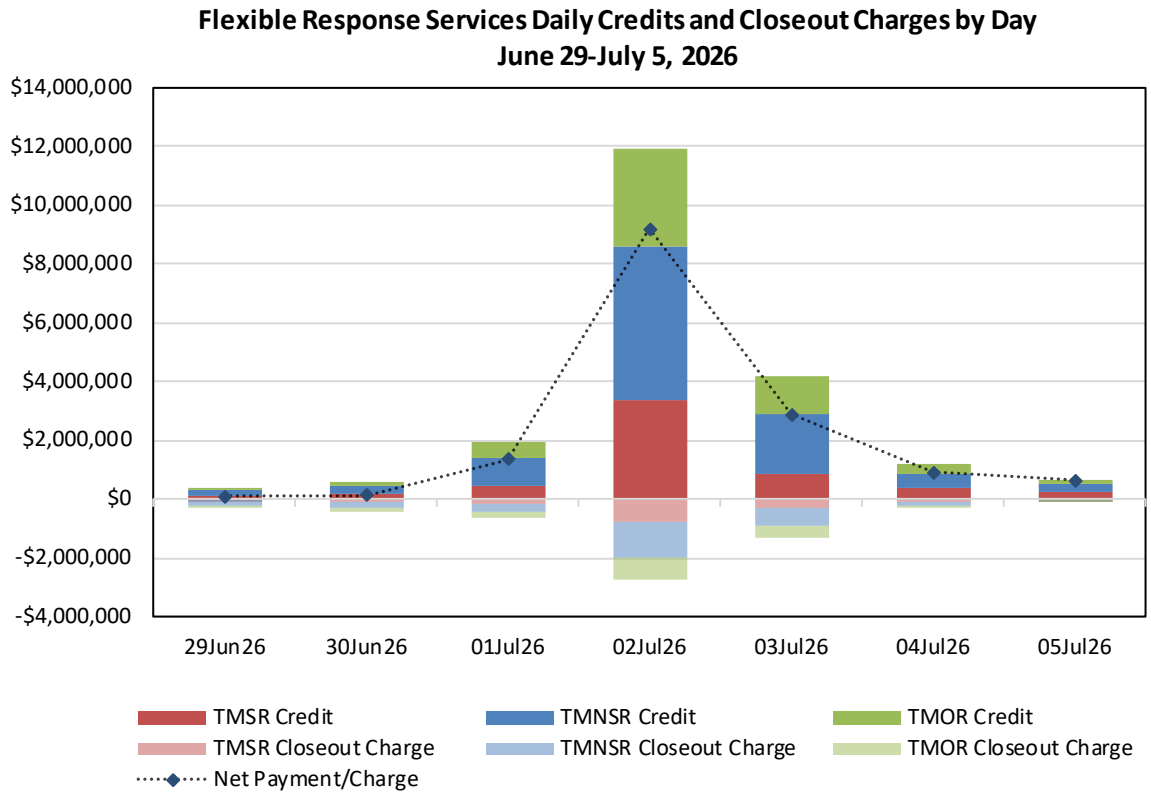
7.3 FRS Payments

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
June 29-July 5, 2026

Product Type	FRS Payments (A)	FRS Closeout Charges (B)	FRS Net Payments/Charges (C=A+B)
TMSR	$5,512,259	-$1,501,853	$4,010,405
TMNSR	$9,438,517	-$2,593,379	$6,845,137
TMOR	$5,962,324	-$1,632,684	$4,329,640
Total	$20,913,099	-$5,727,917	$15,185,182

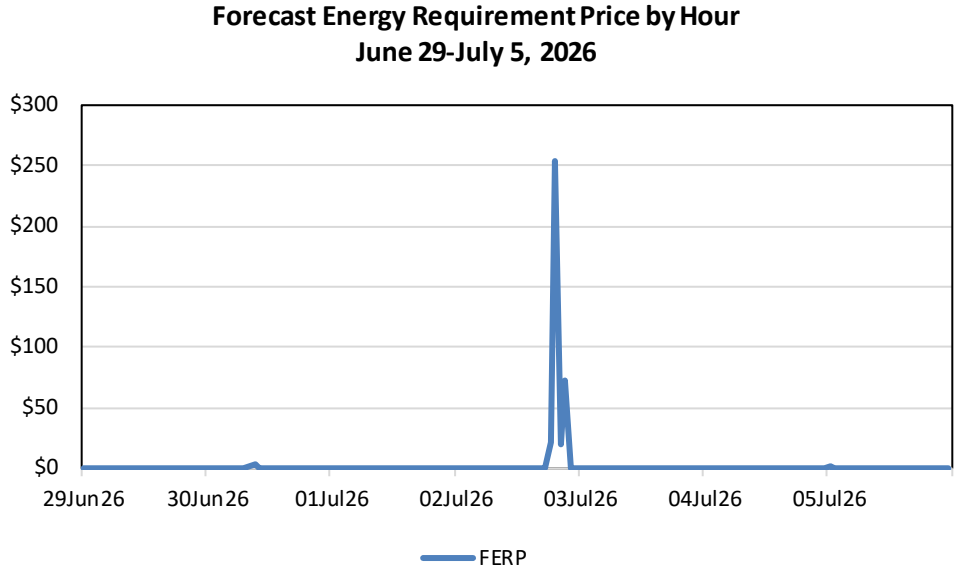
The following graph shows the daily Credit and Closeout charges by FRS product type:



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)
June 29-July 5, 2026

29Jun26	30Jun26	01Jul26	02Jul26	03Jul26	04Jul26	05Jul26	Weekly Average
$0.00	$0.24	$0.00	$15.25	$0.00	$0.00	$0.04	$2.22

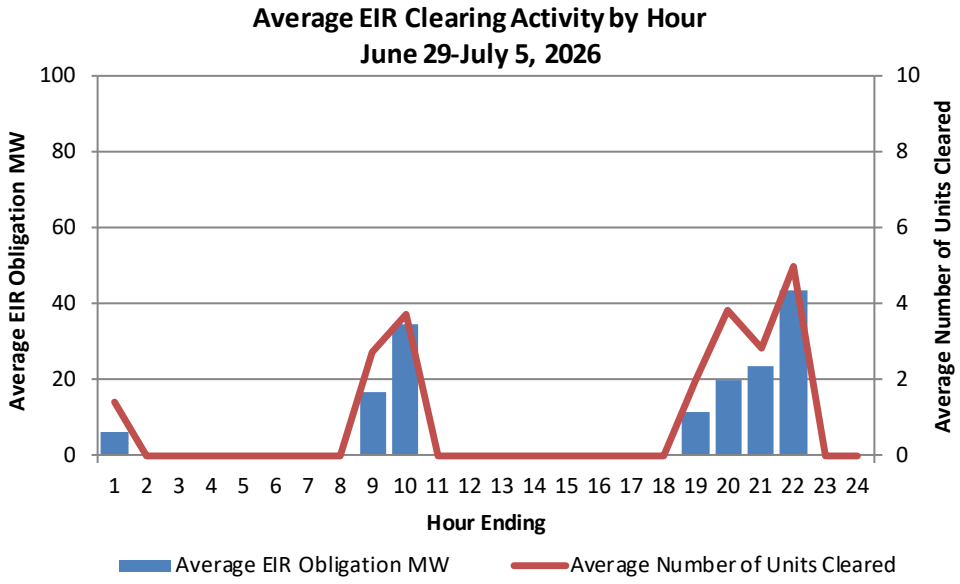
The following table shows the distribution of the hourly FERP during the reporting week.

Hourly Forecast Energy Requirement Price Distribution
June 29-July 5, 2026

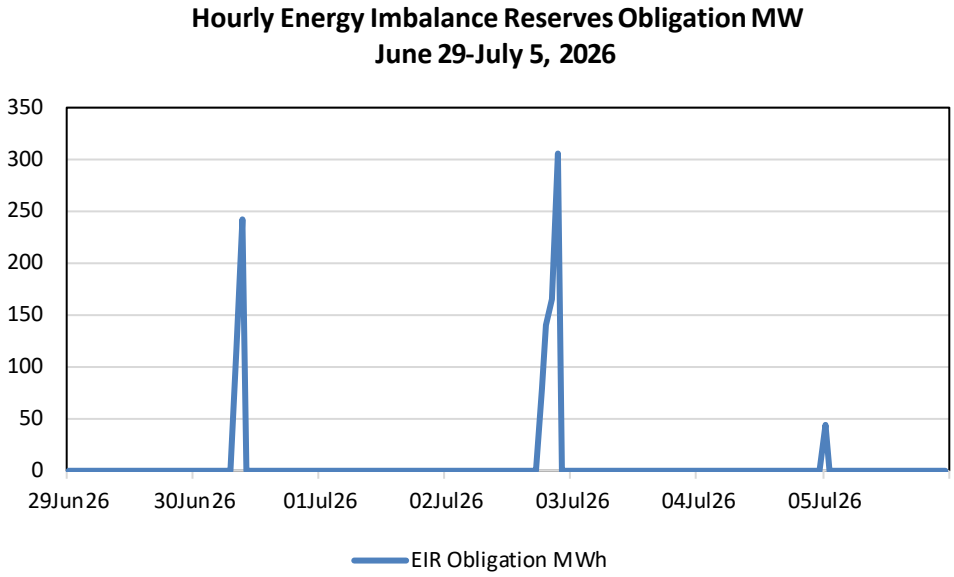
Frequency Tabulation	$0.00	$0.01 - $4.99	$5.00 - $9.99	$10.00 - $19.99	$20.00 - $49.99	$50.00 - $99.99	>= $100.00
FERP	95.8%	1.8%	0.0%	0.6%	0.6%	0.6%	0.6%

8.2 EIR Obligations

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



The following graph shows the hourly EIR Obligation MW 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
June 29-July 5, 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	95.8%	0.6%	0.6%	2.4%	0.6%	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
June 29-July 5, 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)
29Jun26	$0	$0	$0	$0	$0
30Jun26	$73,734	$1,058	-$1,062	-$4	$73,729
01Jul26	$0	$0	$0	$0	$0
02Jul26	$9,163,908	$62,637	-$77,595	-$14,958	$9,148,949
03Jul26	$0	$0	$0	$0	$0
04Jul26	$0	$0	$0	$0	$0
05Jul26	$15,903	$44	$0	$44	$15,947
Total	$9,253,544	$63,738	-$78,657	-$14,919	$9,238,626

Real-Time Reserve Market

9.1 Real-Time Reserve Payments

Real-Time Reserve Payment Summary by Reserve Zone
June 29-July 5, 2026

DAY	CT	NEMABSTN	ROS	SWCT	Total
29JUN26	$267.88	$87.23	$1,274.46	$195.77	$1,825.34
30JUN26	$30.60	$9.36	$115.24	$18.81	$174.01
01JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
02JUL26	$139,563.41	$51,647.69	$497,364.38	$167,951.30	$856,526.78
03JUL26	$80,243.20	$31,499.30	$329,678.00	$133,403.41	$574,823.91
04JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
05JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$220,105.09	$83,243.58	$828,432.08	$301,569.29	$1,433,350.04

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
June 29-July 5, 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	97.1%	2.9%	13.6%	30.5%	10.2%	11.9%	33.9%	0.0%	0.0%
TMNSR	97.4%	2.6%	7.5%	30.2%	11.3%	13.2%	37.7%	0.0%	0.0%
TMOR	97.6%	2.4%	8.2%	28.6%	8.2%	14.3%	40.8%	0.0%	0.0%

Real-Time Reserve Clearing Price Frequency, Local Reserve Zones
June 29-July 5, 2026

Local Reserve Zone	Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals
Connecticut	TMSR	97.1%	2.9%
	TMNSR	97.4%	2.6%
	TMOR	97.6%	2.4%
NEMA/Boston	TMSR	97.1%	2.9%
	TMNSR	97.4%	2.6%
	TMOR	97.6%	2.4%
Rest Of System	TMSR	97.1%	2.9%
	TMNSR	97.4%	2.6%
	TMOR	97.6%	2.4%
Southwest Connecticut	TMSR	97.1%	2.9%
	TMNSR	97.4%	2.6%
	TMOR	97.6%	2.4%

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
June 29-July 5, 2026

Local Day	Reserve Bias
June 29-July 5, 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 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]
June 29-July 5, 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
June 29-July 5, 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**
7/8/2026	Original	Initial posting.