Weekly Market Summary

July 13-19, 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: July 13-19, 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	$65.01	$54.03	20.3%	$85.00	-23.5%
*Real-Time Energy Market; All Hours	$41.88	$57.99	-27.8%	$72.48	-42.2%
*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)	22,433	22,218	1.0%	24,368	-7.9%
DA Load Obligation (All Zones)	-2,771,742	-2,581,091	7.4%	-2,919,590	-5.1%
RT Load Obligation (All Zones)	-2,602,954	-2,523,177	3.2%	-2,902,525	-10.3%
DA Cleared Exports (All Interfaces)	-113,627	-75,599	50.3%	-87,037	30.5%
RT Scheduled Exports (All Interfaces)	-272,636	-189,200	44.1%	-144,928	88.1%

Weekly Supply Statistics	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Input Fuel Price (Natural Gas, $/MMBtu)	$2.70	$2.94	-8.2%	$4.88	-44.6%
Mass Average Input Fuel Price (Natural Gas, $/MMBtu)	$2.63	$2.78	-5.4%	$6.45	-59.2%
Metered Generation (MWh)	2,427,041	2,319,025	4.7%	2,694,702	-9.9%
Generation Obligation (MWh)	2,934,366	2,766,715	6.1%	3,097,636	-5.3%
RT Demand Reduction Obligation (MWh)	12	7	77.8%	382	-96.9%
Self-Scheduled Generation (MWh)	948,260	930,626	1.9%	1,060,719	-10.6%
DA Cleared Imports (MWh - All Interfaces)	477,181	421,098	13.3%	369,087	29.3%
RT Scheduled Imports (MWh - All Interfaces)	507,326	447,691	13.3%	402,934	25.9%

Market Payments	This Week	Last Week	% Chg vs. Prior Week	Last Year	% Chg vs. Prior Year
Day-Ahead and Real-Time Energy Market Payments ($)	$210,447,397	$153,753,554	36.9%	$306,544,967	-31.3%
Day-Ahead Ancillary Services Market Payments ($)	$7,021,033	$199,307	Large	$10,317,872	-32.0%
Real-Time Reserve Market Payments ($)	$1,386	$524,459	-99.7%	$87,126	-98.4%

Underlying natural gas data furnished by:

Weekly Market Summary

Day-Ahead Price Separation

- From Monday-Tuesday, July 13-14, depressed pricing in the Maine (ME) Load Zone was caused by a binding constraint on the Orrington South Interface due to several equipment outages. The equipment was restored on July 14.
- On Wednesday, July 15, depressed pricing in the ME Load Zone was caused by binding constraints on the Orrington South Interface and Maine-New Hampshire Interface due to patterns of load and generation.
- From Thursday through Sunday, July 16-19, 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

- From Tuesday-Wednesday, and Saturday, July 14-15 and 18, 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 Thursday and Friday, July 16-17, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine-New Hampshire Interface and the Keene Road Export Interface due to patterns of load and generation.
- On Sunday, July 19, depressed pricing in the ME Load Zone was caused by binding constraints on the Maine-New Hampshire Interface and Keene Road Export Interface due to the planned outage of the 3001 (Keene Road - Keswick) line and patterns of load and generation. The 3001 line is expected to be restored on July 30.

Real-Time Price Corrections

- None.

Year-to-Date Peak Load Statistics*

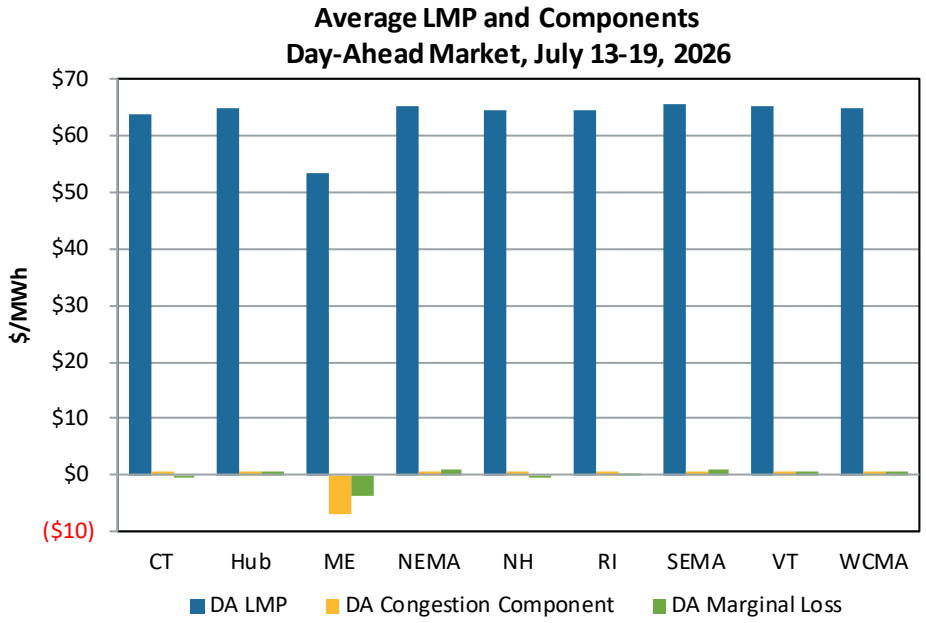
- FCM Peak Load (preliminary, subject to change) is 25,303 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2. At this hour, the Capacity Zone-level FCM peak loads were 3,231 MW in Northern New England, 2,034 MW in Maine, and 20,038 MW in Rest-of-Pool.
- Revenue Quality System Peak Load (initial) is 25,832 MW and occurred in the hour ending 7:00 P.M. on Thursday, July 2.
- Telemetered System Peak Load is 22,258 MW and occurred in the hour ending 7:00 P.M. on Friday, June 12.

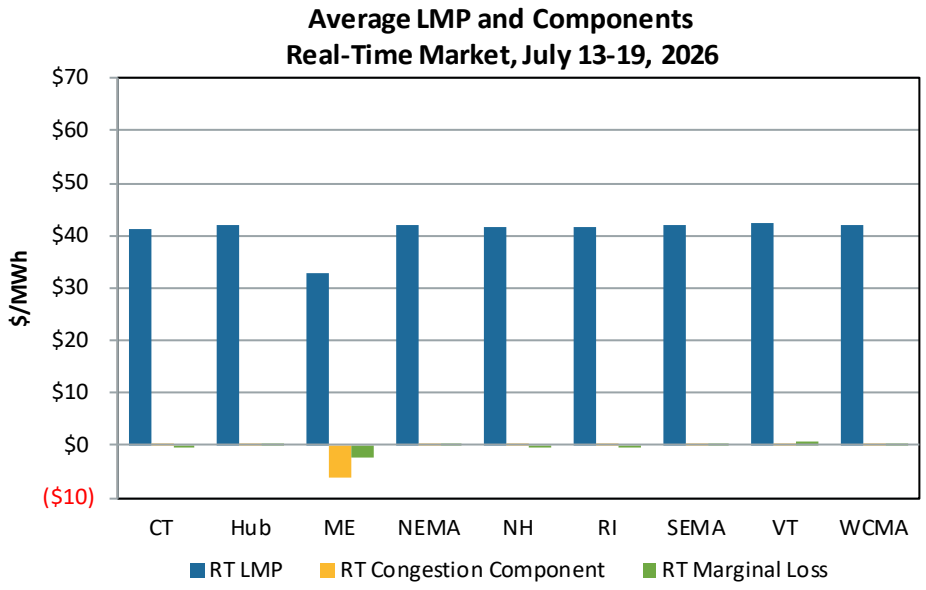
*Due to the difference in calculation methodologies, these values can occur on different days and hours.

Pricing

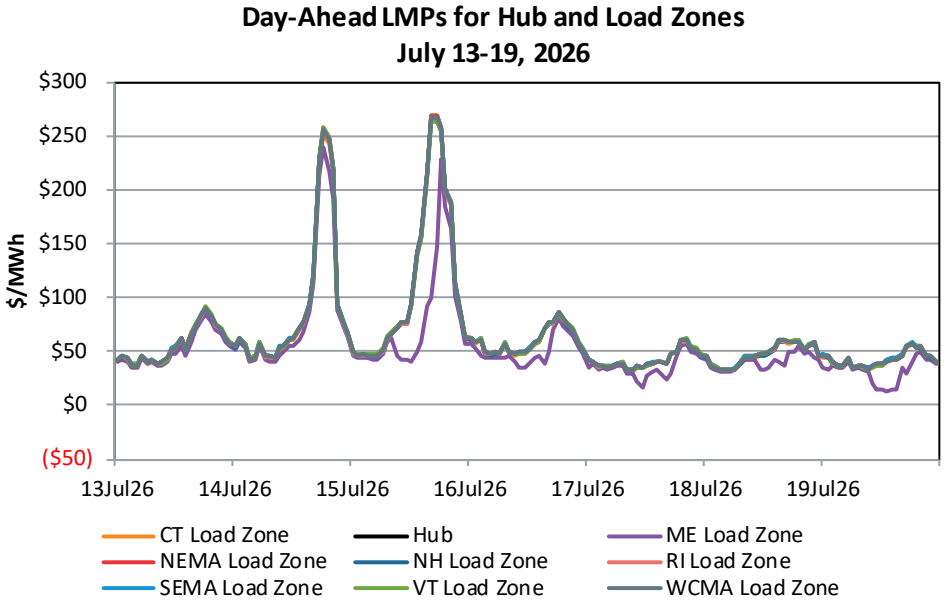
2.1 Pricing

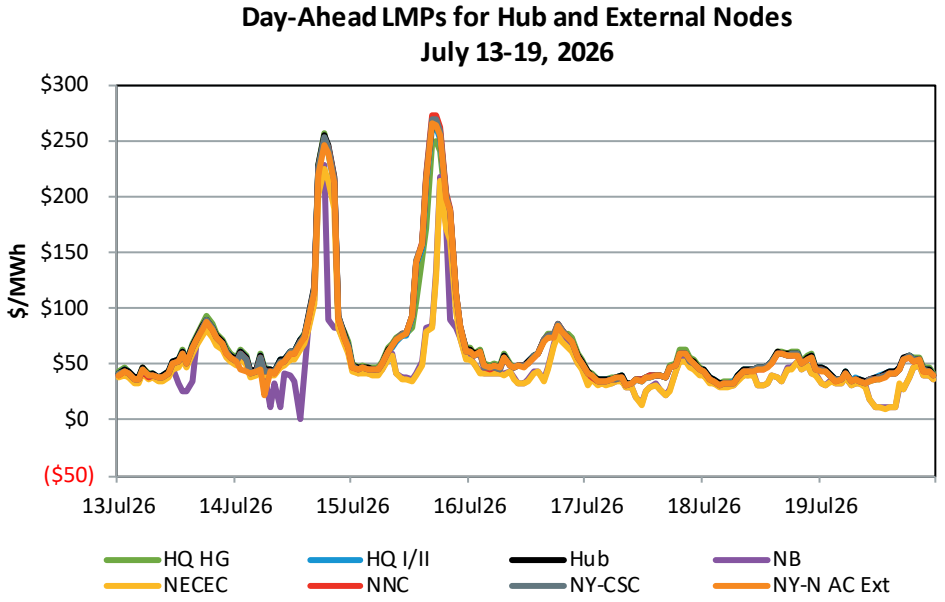
The two graphs below show the weekly average of LMPs, congestion, and marginal loss components at the Hub and Load Zones for both the Day-Ahead and Real-Time Energy Markets.



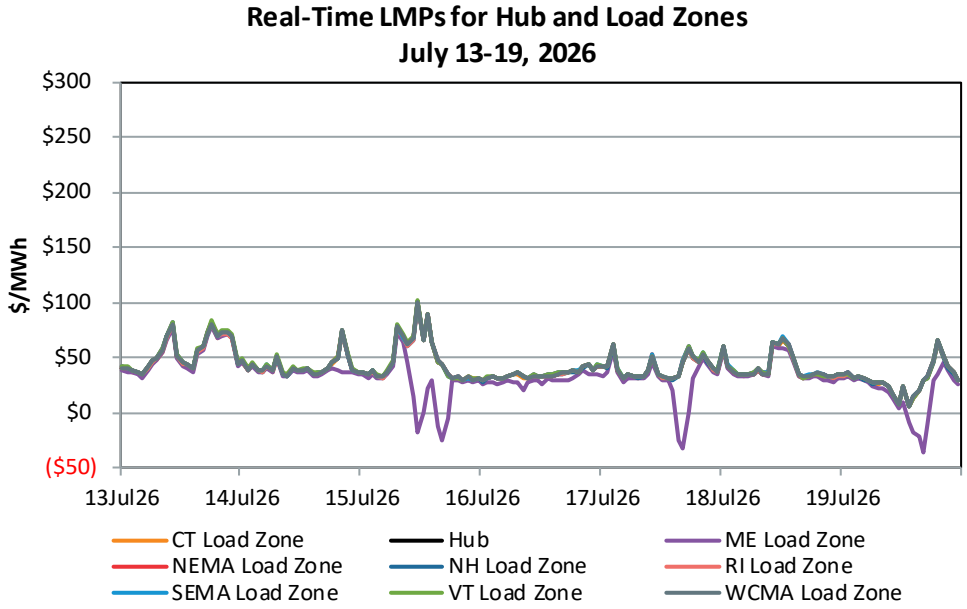


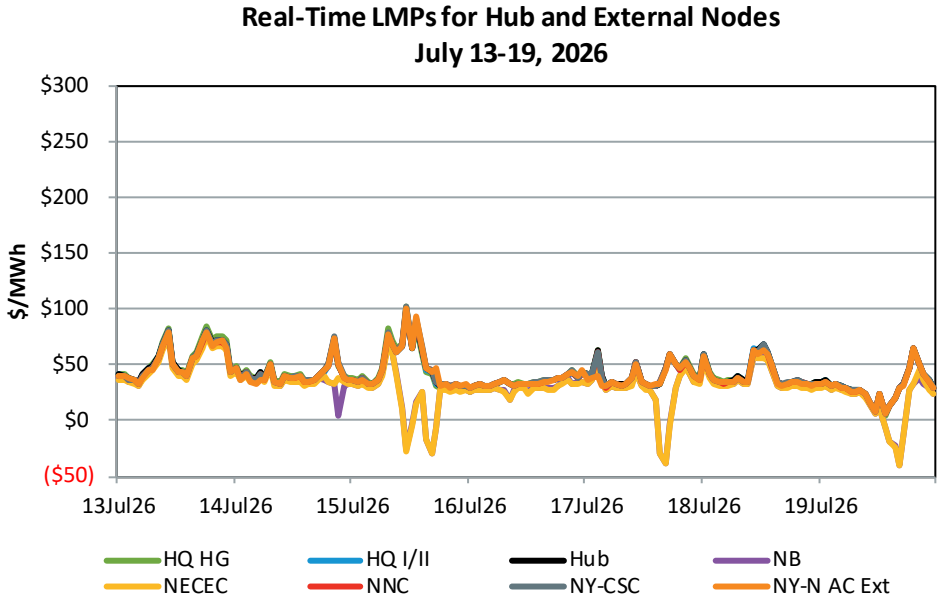
The following two graphs show hourly Day-Ahead LMPs for the Hub, the eight Load Zones, and the seven external nodes. In cases where there is little or no price separation, the lines for multiple locations may be indistinguishable from each other.





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, July 13-19, 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	$65.01	$41.88	$32.60	$5.35	$266.82	$99.63	100%	100%	64%	47.05	14.55	31%
ME	$53.31	$32.74	$13.18	$-35.69	$240.21	$79.34	82%	78%	61%	37.07	18.89	51%
NH	$64.50	$41.52	$32.30	$5.24	$264.06	$98.60	99%	99%	64%	46.86	14.58	31%
VT	$65.29	$42.27	$32.72	$5.27	$263.38	$101.39	100%	101%	65%	46.87	14.89	32%
CT	$63.93	$41.30	$31.79	$5.31	$268.28	$99.99	98%	99%	65%	47.16	14.42	31%
RI	$64.71	$41.56	$32.48	$5.35	$266.71	$98.82	100%	99%	64%	46.99	14.40	31%
SEMA	$65.47	$42.16	$32.91	$5.41	$267.92	$99.80	101%	101%	64%	47.06	14.61	31%
WCMA	$65.09	$41.94	$32.60	$5.35	$267.88	$100.09	100%	100%	64%	47.22	14.59	31%
NEMA	$65.44	$42.12	$32.85	$5.39	$268.25	$99.82	101%	101%	64%	47.33	14.67	31%
NB Ext	$47.62	$31.50	$0.35	$-39.48	$228.64	$79.48	73%	75%	66%	31.30	19.45	62%
NY-N AC Ext	$63.19	$41.11	$22.00	$5.30	$265.98	$100.37	97%	98%	65%	46.66	14.43	31%
HQ Ext	$64.36	$41.64	$32.47	$5.38	$262.01	$97.94	99%	99%	65%	46.09	14.38	31%
HG Ext	$64.47	$42.17	$32.79	$5.27	$257.46	$101.95	99%	101%	65%	43.99	15.01	34%
CSC Ext	$64.25	$41.85	$31.84	$5.36	$269.70	$101.59	99%	100%	65%	47.48	14.69	31%
NNC Ext	$63.98	$41.39	$31.68	$5.35	$273.21	$100.73	98%	99%	65%	47.73	14.44	30%
NECEC Ext	$50.20	$30.91	$10.45	$-39.64	$226.01	$75.18	77%	74%	62%	35.31	18.92	54%

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

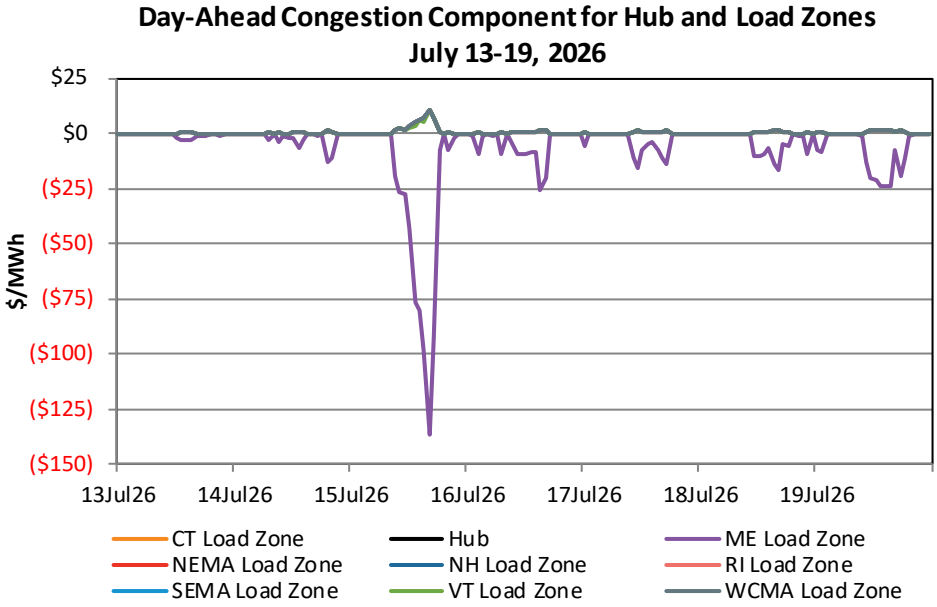
5-Minute LMP Summary (RT Only)
July 13-19, 2026

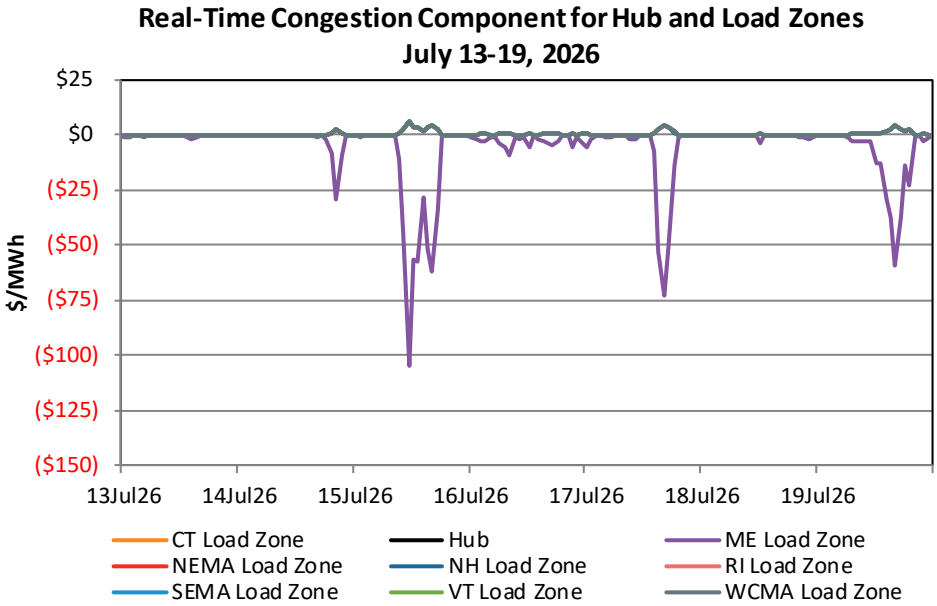
Hub/Zone	Max RT LMP ($/MWh)	Min RT LMP ($/MWh)	RT Std Dev	RT as % of Hub
Hub	$142.09	-$31.15	$16.47	100%
ME	$133.76	-$45.50	$20.37	47%
NH	$142.00	-$30.64	$16.48	99%
VT	$147.73	-$30.73	$16.83	101%
CT	$141.07	-$30.94	$16.31	99%
RI	$140.10	-$31.06	$16.31	99%
SEMA	$141.67	-$31.50	$16.55	101%
WCMA	$142.64	-$31.17	$16.52	100%
NEMA	$142.56	-$31.40	$16.60	101%

5-Minute Energy Component of LMP
July 13-19, 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	0.8%	1.1%	65.3%	27.0%	4.7%	1.1%	0.0%	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.





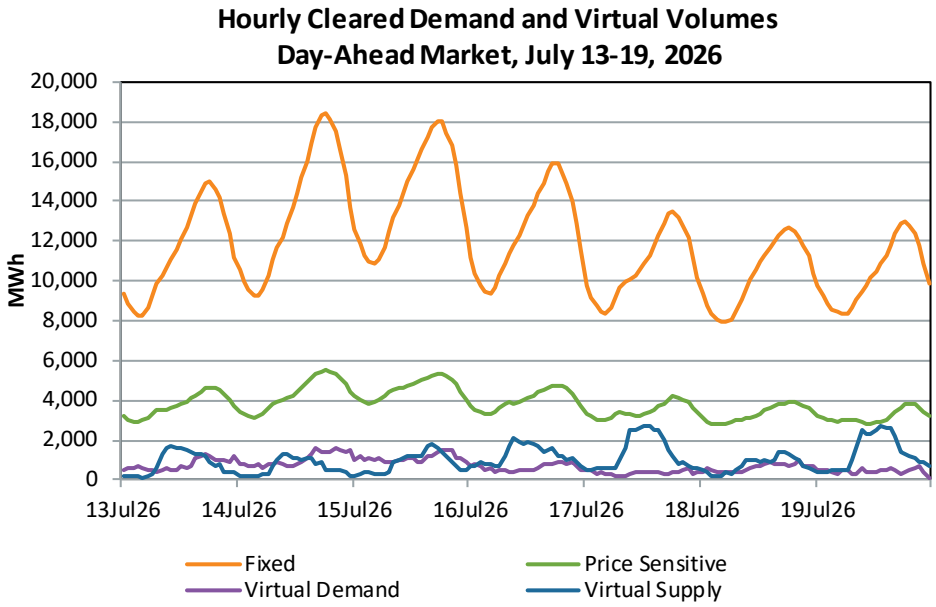
Energy Market Demand

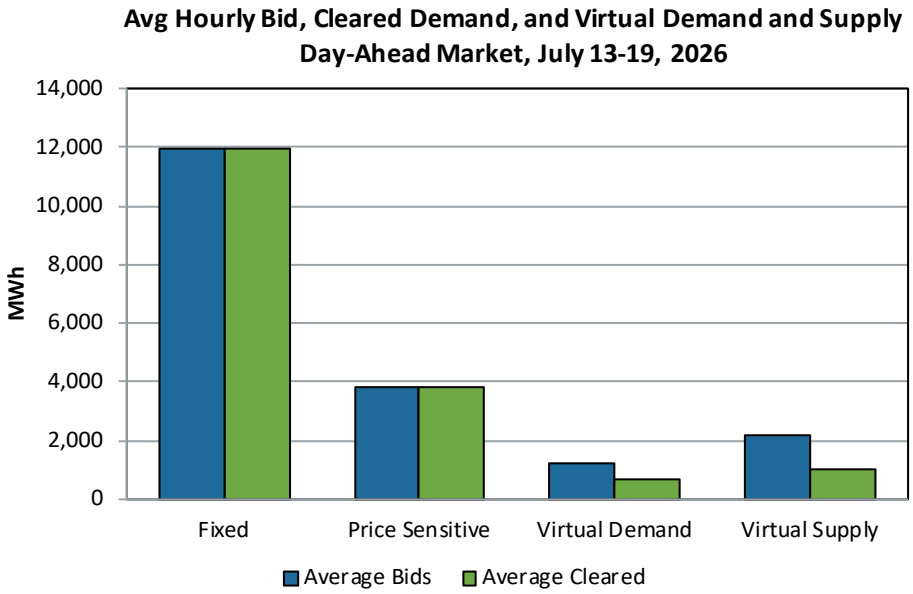
3.1 Day-Ahead Demand

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	23,440	14,302	63.9%	26,481	-11.5%
ME	208,206	200,759	3.7%	222,881	-6.6%
NH	261,661	249,486	4.9%	274,784	-4.8%
VT	92,104	91,163	1.0%	103,269	-10.8%
CT	646,657	587,101	10.1%	689,601	-6.2%
RI	194,313	185,069	5.0%	205,399	-5.4%
SEMA	342,961	319,098	7.5%	370,450	-7.4%
WCMA	359,066	341,532	5.1%	378,675	-5.2%
NEMA	567,848	527,576	7.6%	595,159	-4.6%
NB Ext	270	7,767	-96.5%	154	75.3%
NY-N AC Ext	72,813	46,502	56.6%	35,412	105.6%
HQ Ext	21,477	0	N/A	140	Large
HG Ext	26,680	10,851	145.9%	21,812	22.3%
CSC Ext	29,581	30,351	-2.5%	50,276	-41.2%
NNC Ext	6,791	7,776	-12.7%	2,492	172.5%
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)

July 13-19, 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	13JUL26	0	0	4,746	3,260	0	0	4,188	2,606	4,188
Hub	14JUL26	0	0	7,823	6,437	0	0	5,235	1,476	5,235
Hub	15JUL26	0	0	8,609	8,007	0	0	6,056	3,171	6,056
Hub	16JUL26	0	0	2,757	10,114	0	0	2,208	3,355	2,208
Hub	17JUL26	0	0	2,661	11,558	0	0	2,211	5,808	2,211
Hub	18JUL26	0	0	3,997	4,819	0	0	1,125	3,742	1,125
Hub	19JUL26	0	0	4,878	5,721	0	0	2,417	5,257	2,417
ME	13JUL26	22,189	7,052	1,460	9,686	22,189	7,052	855	5,409	30,095
ME	14JUL26	25,476	8,472	2,589	12,977	25,476	8,472	1,192	5,232	35,140
ME	15JUL26	25,633	8,400	1,867	11,994	25,633	8,400	1,070	5,809	35,102
ME	16JUL26	22,796	7,345	1,649	15,543	22,796	7,345	618	9,575	30,759
ME	17JUL26	20,144	6,379	1,689	21,043	20,144	6,379	1,114	11,408	27,637
ME	18JUL26	19,499	6,270	1,544	11,781	19,499	6,270	1,362	6,126	27,131
ME	19JUL26	19,409	6,282	1,840	25,381	19,409	6,282	1,489	13,586	27,180
NH	13JUL26	31,992	5,193	789	1,939	31,992	5,193	379	1,469	37,565
NH	14JUL26	37,534	5,834	1,842	1,793	37,534	5,834	958	1,157	44,326
NH	15JUL26	37,681	5,988	1,678	2,319	37,681	5,988	954	1,571	44,623
NH	16JUL26	33,209	5,446	689	4,270	33,209	5,446	356	2,204	39,010
NH	17JUL26	28,683	4,910	847	3,831	28,683	4,910	371	2,092	33,963
NH	18JUL26	27,527	4,720	871	2,415	27,527	4,720	715	1,086	32,961
NH	19JUL26	27,165	4,349	767	3,457	27,165	4,349	308	1,977	31,821
VT	13JUL26	1,192	12,200	1,205	1,762	1,192	12,200	413	1,039	13,805
VT	14JUL26	1,211	13,821	2,097	1,754	1,211	13,821	1,027	935	16,059
VT	15JUL26	1,148	13,493	1,889	2,166	1,148	13,493	781	1,263	15,421
VT	16JUL26	1,054	11,970	1,253	2,429	1,054	11,970	608	1,714	13,632
VT	17JUL26	1,349	9,790	940	2,632	1,349	9,790	360	1,800	11,498
VT	18JUL26	1,451	11,154	1,456	1,842	1,451	11,154	975	1,060	13,580
VT	19JUL26	1,427	9,197	1,088	2,563	1,427	9,197	434	2,047	11,058
CT	13JUL26	67,222	21,089	4,460	2,597	67,222	21,089	3,114	1,913	91,424
CT	14JUL26	80,285	24,757	3,688	2,587	80,285	24,757	2,670	1,663	107,712
CT	15JUL26	84,844	27,810	2,034	2,361	84,844	27,810	1,376	1,686	114,029
CT	16JUL26	73,431	24,205	2,292	3,790	73,431	24,205	1,713	2,558	99,348
CT	17JUL26	62,649	21,165	2,191	4,640	62,649	21,165	1,677	2,231	85,491
CT	18JUL26	57,714	18,734	2,514	2,254	57,714	18,734	2,034	824	78,482
CT	19JUL26	57,964	17,852	2,755	3,670	57,964	17,852	2,544	1,799	78,360
RI	13JUL26	20,727	4,860	2,290	2,043	20,727	4,860	1,002	1,246	26,589
RI	14JUL26	23,286	5,910	4,152	2,081	23,286	5,910	2,072	1,138	31,268

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	15JUL26	26,659	6,488	3,263	2,609	26,659	6,488	2,525	1,782	35,672
RI	16JUL26	23,187	5,403	834	5,271	23,187	5,403	411	2,373	29,001
RI	17JUL26	19,976	4,659	582	5,168	19,976	4,659	216	2,137	24,851
RI	18JUL26	19,305	4,406	1,049	2,171	19,305	4,406	570	1,036	24,281
RI	19JUL26	20,154	4,527	545	2,463	20,154	4,527	416	1,393	25,097
SEMA	13JUL26	34,747	10,773	1,504	2,520	34,747	10,773	537	2,032	46,057
SEMA	14JUL26	41,806	12,700	1,623	1,753	41,806	12,700	621	1,236	55,127
SEMA	15JUL26	46,146	14,691	1,219	1,621	46,146	14,691	409	1,280	61,245
SEMA	16JUL26	38,664	12,460	960	3,379	38,664	12,460	588	2,587	51,713
SEMA	17JUL26	33,322	10,181	845	3,931	33,322	10,181	383	2,469	43,886
SEMA	18JUL26	32,320	9,837	614	2,416	32,320	9,837	419	1,539	42,577
SEMA	19JUL26	33,407	9,951	652	2,913	33,407	9,951	331	2,449	43,688
WCMA	13JUL26	38,136	11,435	1,815	1,706	38,136	11,435	1,022	1,440	50,594
WCMA	14JUL26	45,994	12,626	2,191	1,618	45,994	12,626	1,292	1,156	59,912
WCMA	15JUL26	48,049	12,634	1,321	6,201	48,049	12,634	792	2,234	61,475
WCMA	16JUL26	42,336	11,504	1,021	3,437	42,336	11,504	703	2,186	54,543
WCMA	17JUL26	35,279	10,343	1,107	3,502	35,279	10,343	750	1,849	46,372
WCMA	18JUL26	34,298	9,578	1,068	2,023	34,298	9,578	971	974	44,846
WCMA	19JUL26	33,739	9,255	1,115	2,953	33,739	9,255	936	1,774	43,930
NEMA	13JUL26	60,381	17,531	1,227	2,166	60,381	17,531	468	1,613	78,380
NEMA	14JUL26	72,218	19,824	2,166	1,763	72,218	19,824	941	1,303	92,982
NEMA	15JUL26	75,175	20,804	1,186	1,791	75,175	20,804	518	1,402	96,497
NEMA	16JUL26	66,912	18,316	610	4,459	66,912	18,316	349	2,764	85,576
NEMA	17JUL26	56,746	16,281	760	3,997	56,746	16,281	439	2,132	73,466
NEMA	18JUL26	55,507	15,180	506	3,239	55,507	15,180	420	909	71,107
NEMA	19JUL26	55,579	15,456	405	3,290	55,579	15,456	307	1,871	71,341

3.2 Real-Time Demand

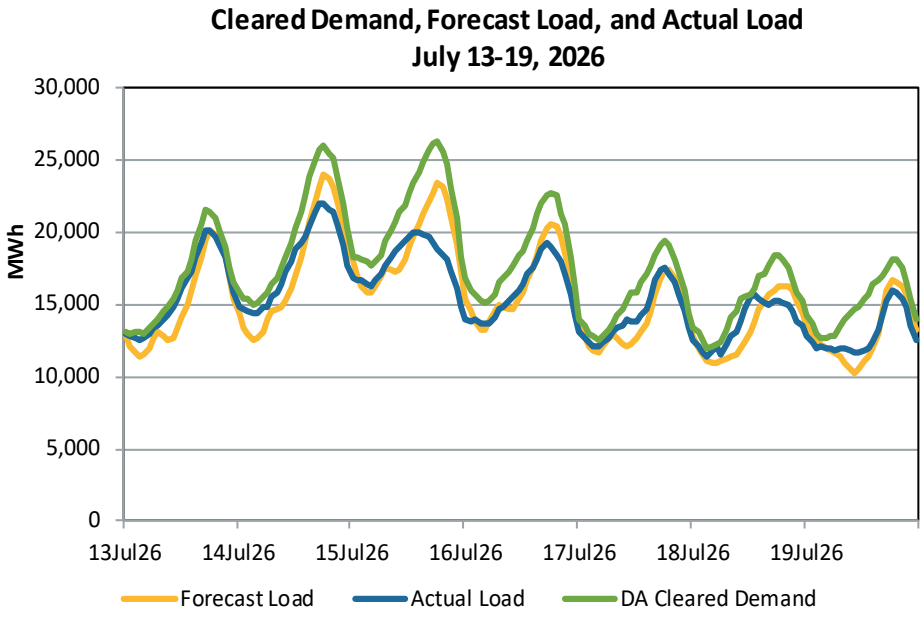
The following table displays the Real-Time Load Obligation at each Load Zone and external nodes for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
ME	211,841	213,691	-0.9%	229,618	-7.7%
NH	247,448	248,441	-0.4%	278,923	-11.3%
VT	90,454	87,026	3.9%	100,729	-10.2%
CT	612,464	581,994	5.2%	688,303	-11.0%
RI	179,943	173,318	3.8%	202,090	-11.0%
SEMA	330,098	317,389	4.0%	368,589	-10.4%
WCMA	339,468	330,460	2.7%	383,579	-11.5%
NEMA	532,002	518,978	2.5%	601,161	-11.5%
NB Ext	4,022	3,126	28.7%	3,211	25.3%
NY-N AC Ext	200,638	134,309	49.4%	86,109	133.0%
HQ Ext	15,748	1	Large	0	N/A
HG Ext	3	1	200.0%	0	N/A
CSC Ext	38,035	39,702	-4.2%	50,879	-25.2%
NNC Ext	14,190	12,061	17.7%	4,729	200.1%
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
13JUL26	19	20,506	$80.99	$79.34	$82.10	$83.17	$79.62	$80.63	$81.75	$81.10	$82.23
14JUL26	19	22,433	$44.98	$40.30	$44.97	$45.76	$44.70	$44.86	$45.24	$45.08	$45.44
15JUL26	14	20,401	$89.25	$22.40	$88.15	$89.05	$89.92	$88.80	$89.43	$89.52	$89.32
16JUL26	18	19,569	$36.67	$28.91	$36.18	$36.54	$36.45	$36.50	$37.15	$36.66	$37.00
17JUL26	19	17,951	$50.40	$31.86	$49.72	$50.89	$50.14	$50.12	$50.92	$50.46	$50.66
18JUL26	14	16,076	$61.14	$57.08	$60.37	$60.94	$60.03	$60.16	$61.65	$61.22	$61.50
19JUL26	19	16,348	$47.16	$28.96	$46.32	$46.91	$46.62	$46.91	$47.78	$47.15	$47.32

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.



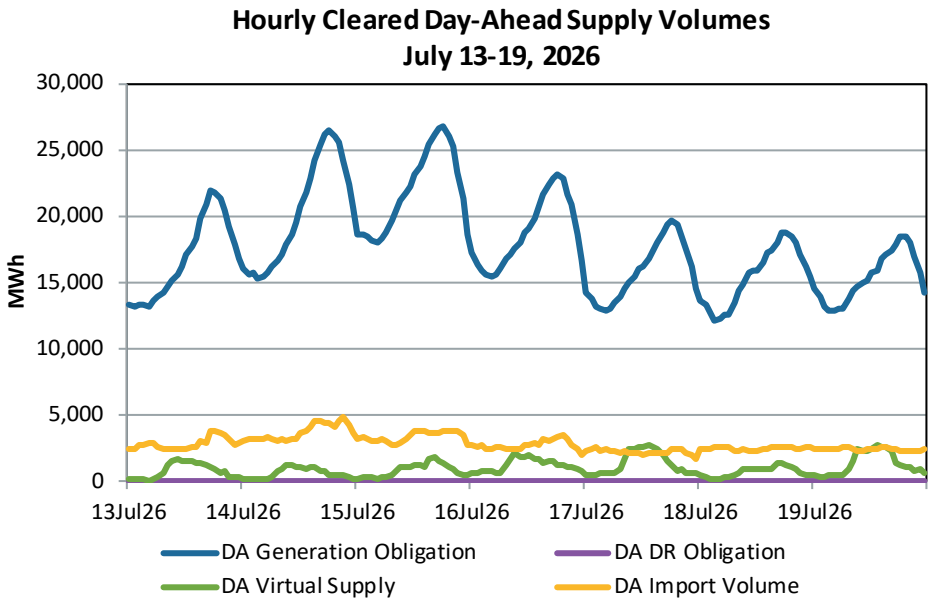
The table below compares the total quantities (MWh) of Day-Ahead Load Obligation with the Real-Time Load Obligation for each Load Zone (including nodal locations within each Load Zone) for the week. Day-Ahead Load Obligation is composed of Day-Ahead cleared demand bids and cleared Decrement bids. Real-Time 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	213,099	213,847	-748	99.7%
NH	264,270	247,979	16,291	106.6%
VT	95,053	90,454	4,598	105.1%
CT	654,912	612,535	42,377	106.9%
RI	196,758	179,944	16,814	109.3%
SEMA	344,297	332,482	11,815	103.6%
WCMA	410,561	393,593	16,968	104.3%
NEMA	569,353	532,119	37,234	107.0%

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	17,781	16,273	9.3%	18,285	-2.8%
DA Demand Reduction Obligation	0	0	0.0%	5	-100.0%
DA Cleared Increments	1,016	795	27.8%	988	2.8%
DA Imports	2,840	2,507	13.3%	2,197	29.3%

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	39,622	8,626	359.3%	35,883	10.4%
NY-N AC Ext	167,843	181,713	-7.6%	152,942	9.7%
HQ Ext	46,699	27,293	71.1%	135,346	-65.5%
HG Ext	30,472	13,198	130.9%	37,819	-19.4%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	2,999	1,920	56.2%	6,808	-55.9%
NECEC Ext	189,546	188,349	0.6%	N/A	N/A

4.2 Real-Time Supply

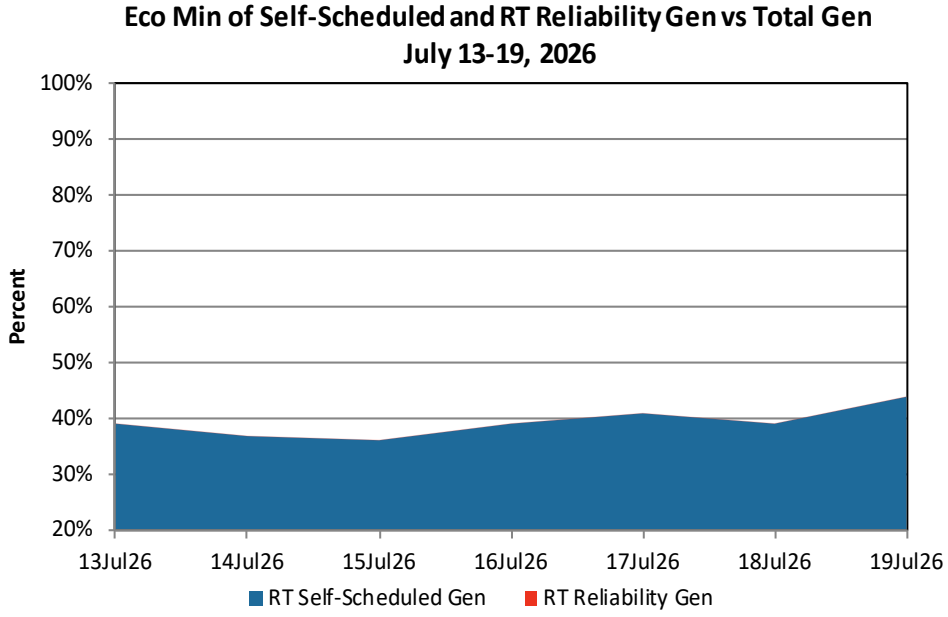
The following table provides daily and weekly totals, in megawatt-hours (MWh), of the amount of electricity produced by classified fuel type during the week. The data provided are for the full system, including "settlement only" resources that do not offer their output into the wholesale markets. The 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	13Jul26	14Jul26	15Jul26	16Jul26	17Jul26	18Jul26	19Jul26	Total
Batteries	726	753	522	652	676	312	389	4,030
Hydro	17,431	18,644	20,202	15,123	13,837	11,275	11,960	108,472
Landfill Gas	944	893	851	876	935	957	956	6,412
Methane	30	36	40	33	41	43	46	269
Natural Gas	198,811	225,948	247,513	201,057	169,768	168,632	132,415	1,344,144
Nuclear	79,939	79,880	79,860	79,889	79,930	79,934	79,976	559,408
Oil	23	2,170	4,029	364	259	12	0	6,857
Other	2,637	2,383	1,115	2,985	3,007	1,292	2,875	16,294
PRD	0	4	0	0	0	8	0	12
Refuse	7,138	7,294	7,202	7,159	8,016	8,094	7,870	52,773
Solar	22,425	16,722	12,420	21,365	23,700	8,994	23,105	128,731
Wind	11,723	25,554	28,777	25,627	17,733	20,919	31,099	161,432
Wood	4,870	4,884	4,761	5,321	6,221	5,879	6,286	38,222
Total	346,697	385,165	407,292	360,451	324,123	306,351	296,977	2,427,056

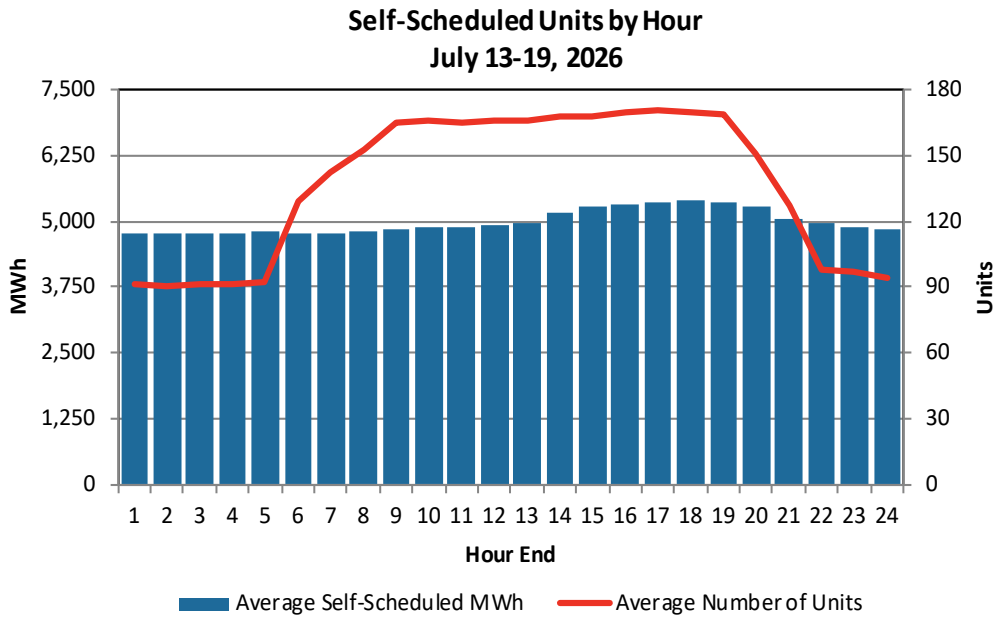
Online generators that are at their Economic Minimum output level are not eligible to set the clearing price. Real-Time Self-Scheduled Generation shown below reflects output by self-scheduled generation and by (non-dispatchable) Settlement Only Resources (SORs). Real-Time Reliability Generation represents 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
13Jul26	134,999	0	346,696
14Jul26	141,918	0	385,166
15Jul26	146,571	0	407,291
16Jul26	140,203	0	360,451
17Jul26	133,249	0	324,122
18Jul26	119,685	0	306,351
19Jul26	131,635	0	296,975

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



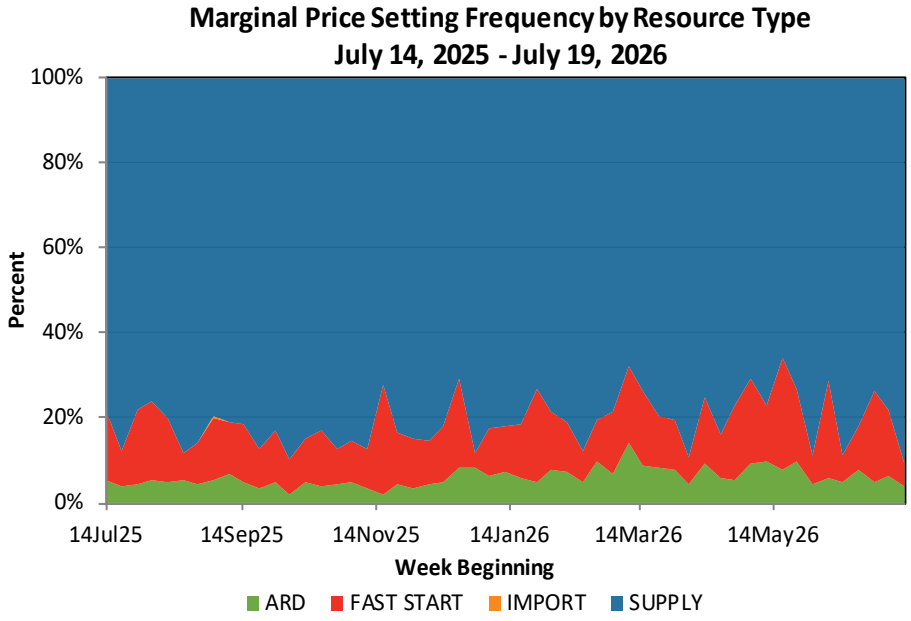
The following graph shows the average number of self-scheduled generating units and MWh for each hour of the last week.



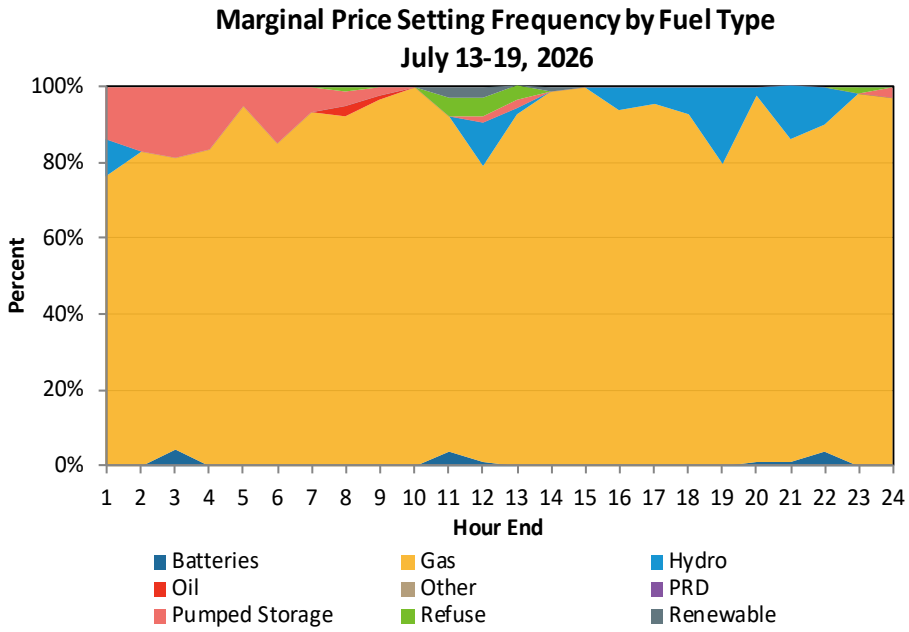
The following table provides the total Real-Time Imports by Interface for this week, last week, the same week a year ago, and the percentage change for each.

Location	This Week (MWh)	Last Week (MWh)	% Chg vs. Prior Week	Last Year (MWh)	% Chg vs. Prior Year
NB Ext	33,359	8,174	308.1%	31,024	7.5%
NY-N AC Ext	240,097	220,709	8.8%	210,602	14.0%
HQ Ext	33,820	21,456	57.6%	134,244	-74.8%
HG Ext	7,234	4,001	80.8%	16,797	-56.9%
CSC Ext	0	0	N/A	0	N/A
NNC Ext	3,270	5,002	-34.6%	10,267	-68.2%
NECEC Ext	189,546	188,349	0.6%	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 37% 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

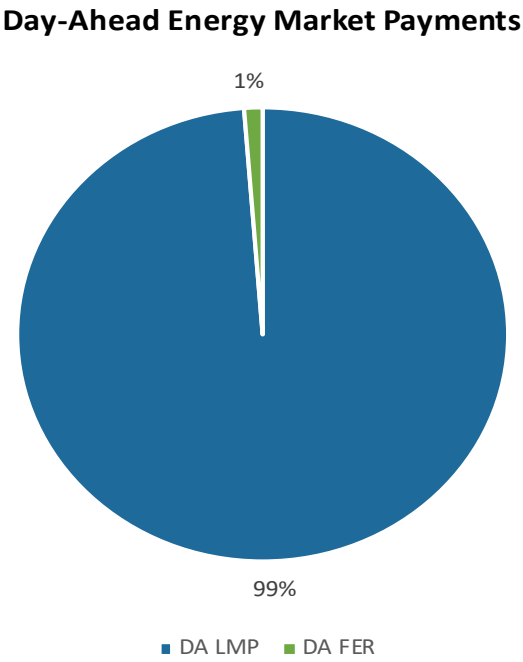
6.1 Energy Market Payments

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.

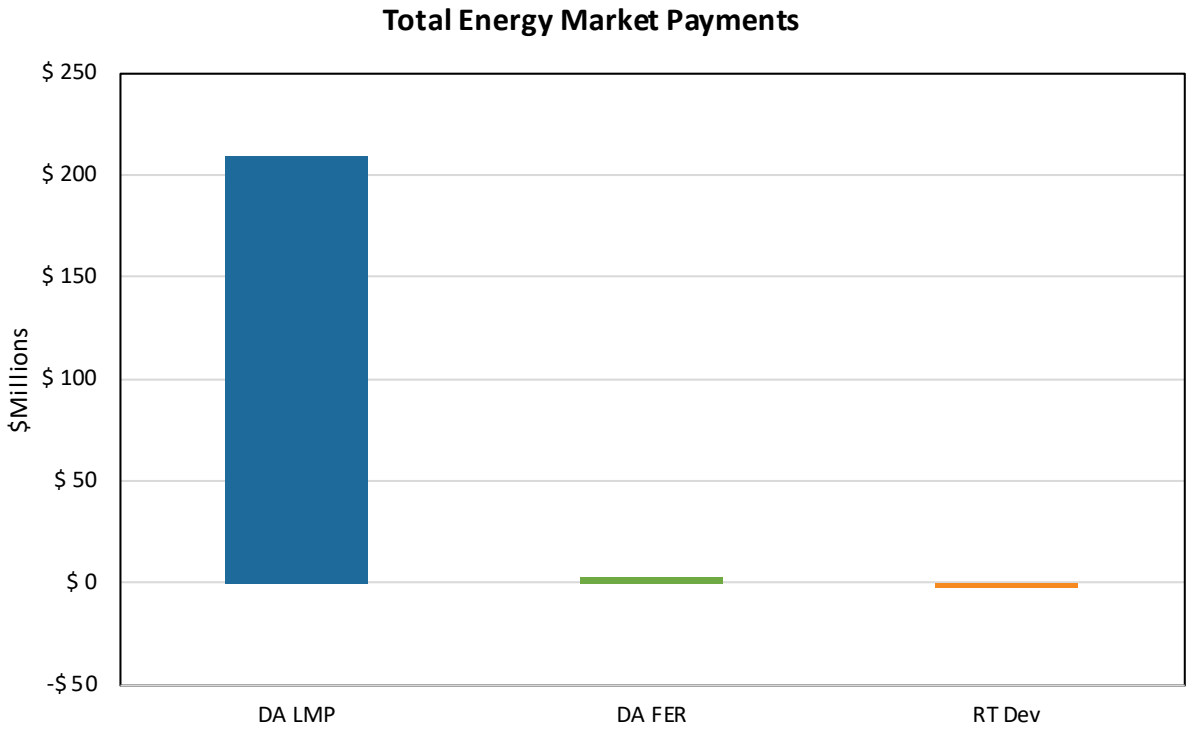
Energy Market Payment Summary
July 13-19, 2026

DA LMP Payments (A)	DA FER Payments (B)	RT Dev Payments (C)	Energy Market Payment (D=A+B+C)
$209,632,372	$2,573,964	-$1,758,939	$210,447,397

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



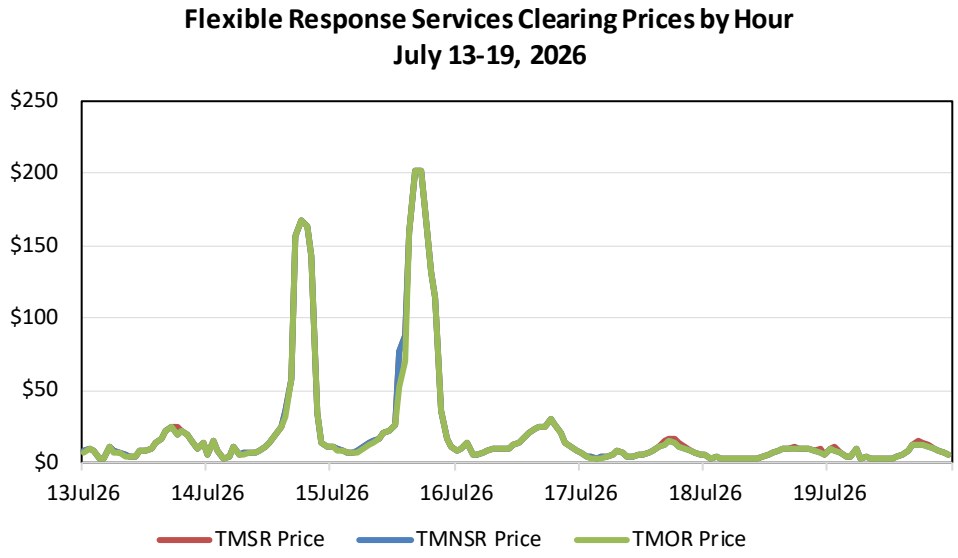
The chart below shows the magnitude of each component's contribution to the total Energy Market payment.



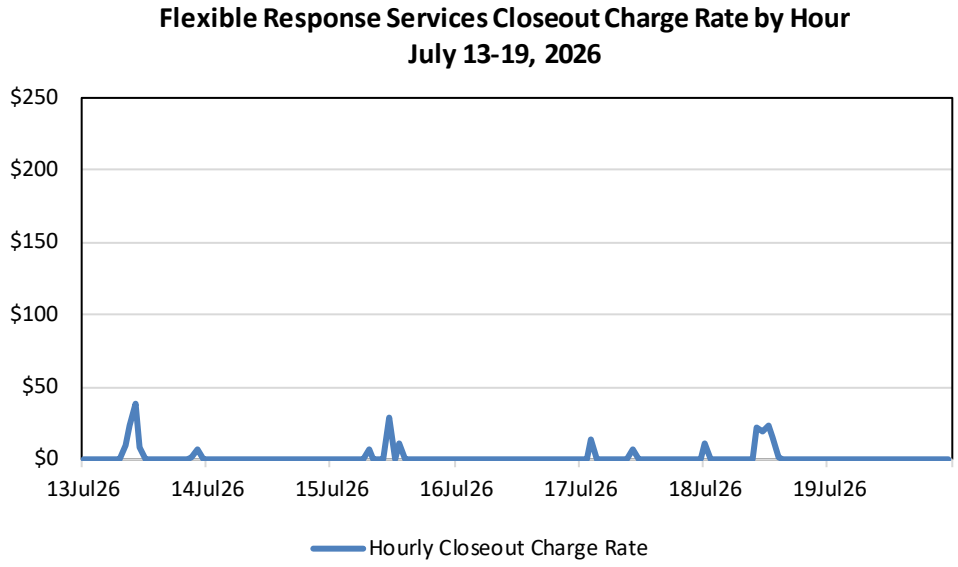
Flexible Response Services (FRS)

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.



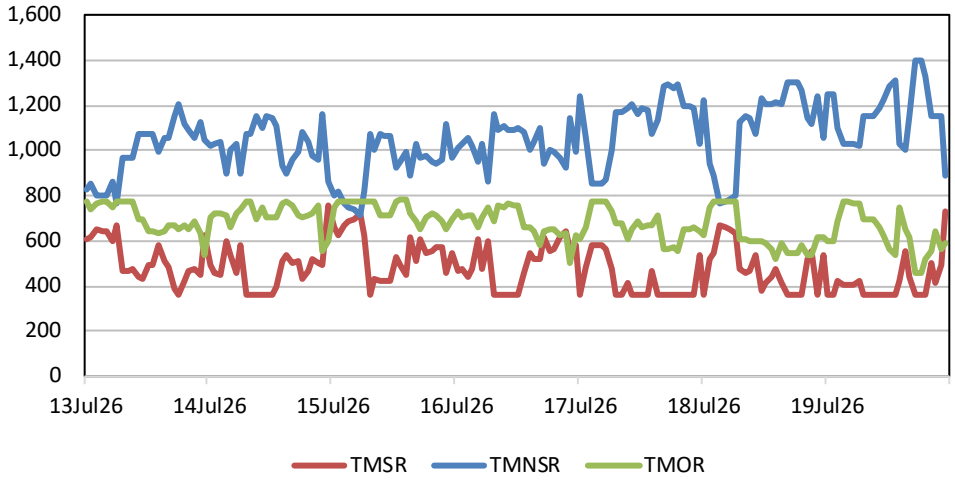
Percentage of Hours with Closeout Charge Rates
July 13-19, 2026

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	89.9%	1.2%	3.0%	2.4%	3.6%	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
July 13-19, 2026



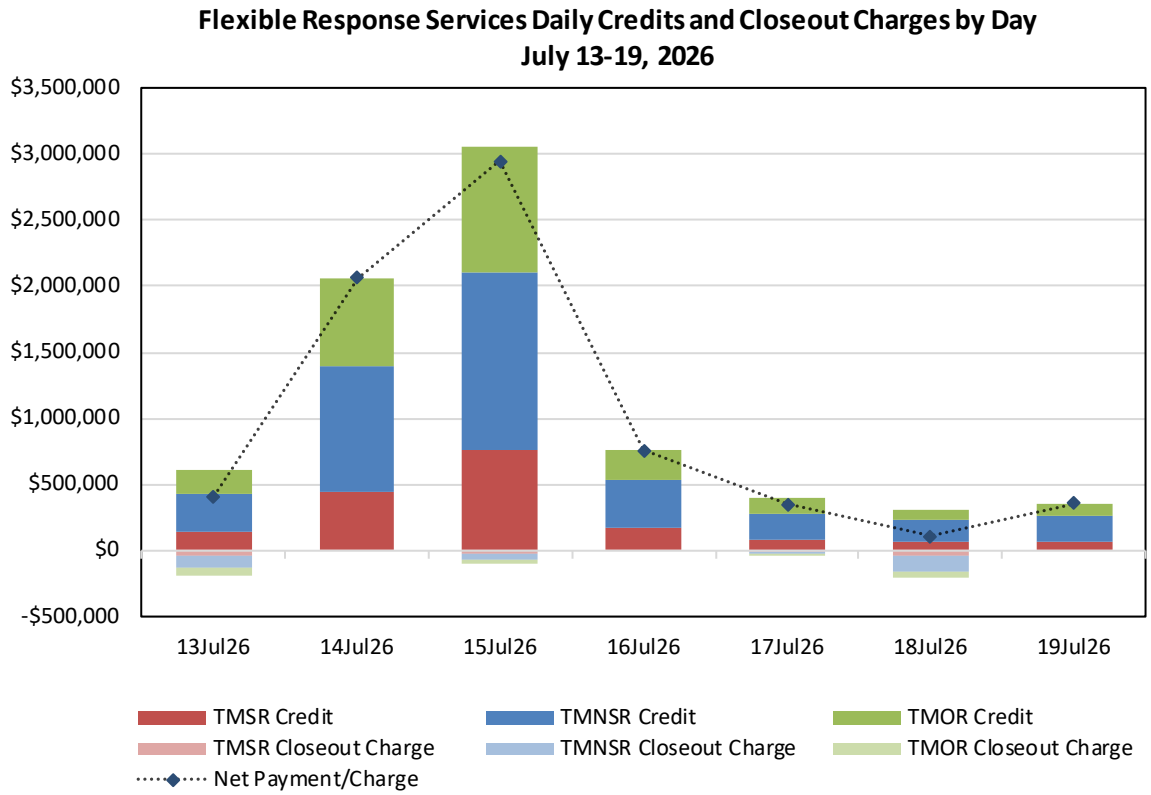
7.3 FRS Payments

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
July 13-19, 2026

Product Type	FRS Payments (A)	FRS Closeout Charges (B)	FRS Net Payments/Charges (C=A+B)
TMSR	$1,731,250	-$111,747	$1,619,504
TMNSR	$3,486,030	-$271,673	$3,214,357
TMOR	$2,322,927	-$168,787	$2,154,140
Total	$7,540,208	-$552,207	$6,988,001

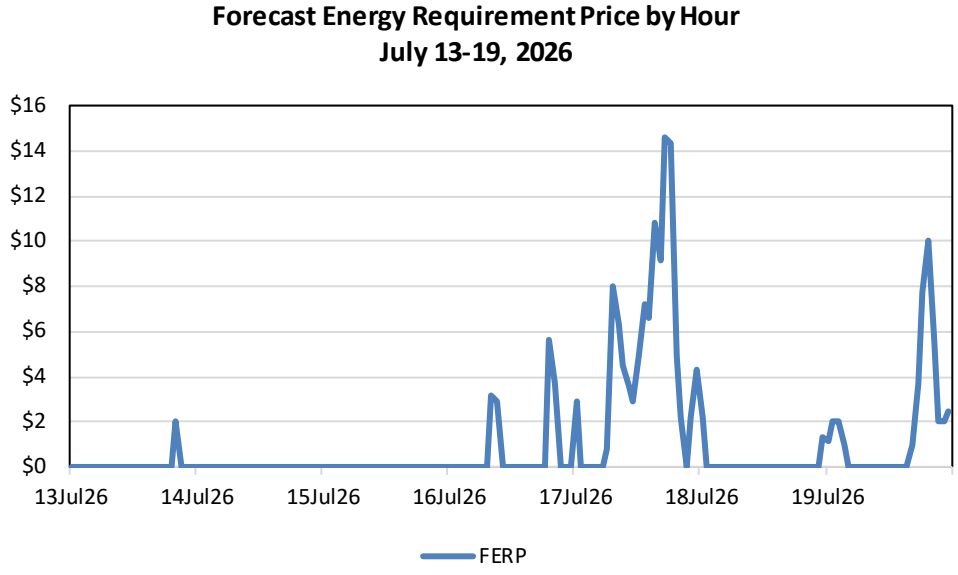
The following graph shows the daily Credit and Closeout charges by FRS product type:



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)
July 13-19, 2026

13Jul26	14Jul26	15Jul26	16Jul26	17Jul26	18Jul26	19Jul26	Weekly Average
$0.08	$0.00	$0.00	$0.64	$4.60	$0.14	$1.70	$1.02

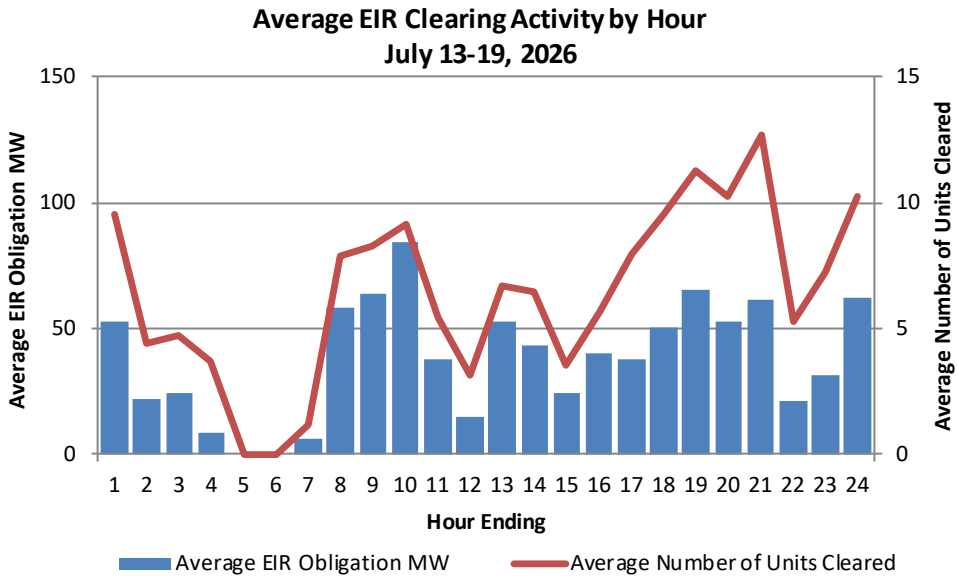
The following table shows the distribution of the hourly FERP during the reporting week.

Hourly Forecast Energy Requirement Price Distribution
July 13-19, 2026

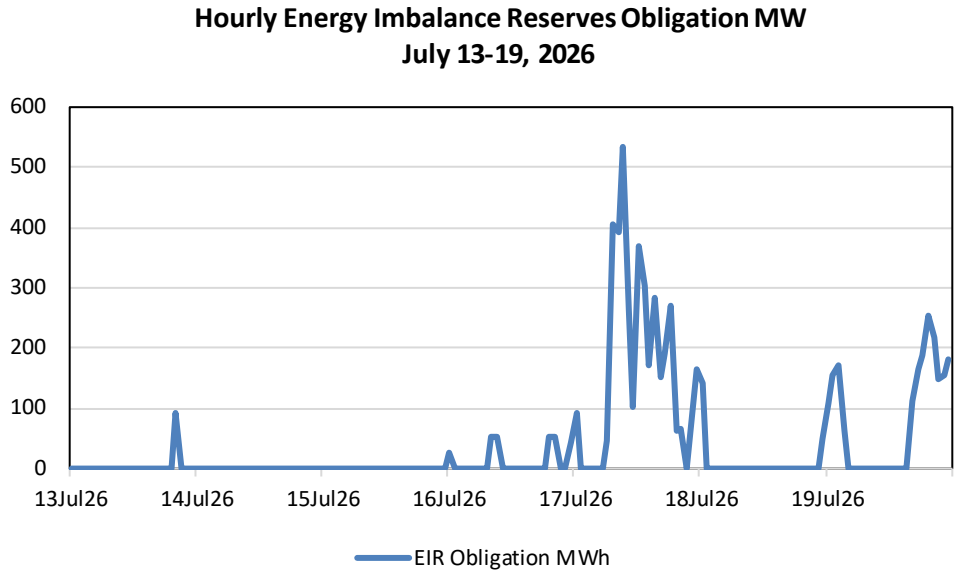
Frequency Tabulation	$0.00	$0.01 - $4.99	$5.00 - $9.99	$10.00 - $19.99	$20.00 - $49.99	$50.00 - $99.99	>= $100.00
FERP	78.0%	14.9%	4.8%	2.4%	0.0%	0.0%	0.0%

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
July 13-19, 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	76.8%	1.8%	6.5%	9.5%	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
July 13-19, 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)
13Jul26	$37,831	$186	$0	$186	$38,018
14Jul26	$0	$0	$0	$0	$0
15Jul26	$0	$0	$0	$0	$0
16Jul26	$275,740	$837	$0	$837	$276,578
17Jul26	$1,595,291	$27,300	-$1,907	$25,394	$1,620,684
18Jul26	$45,841	$377	-$1,595	-$1,218	$44,623
19Jul26	$619,261	$7,833	$0	$7,833	$627,093
Total	$2,573,964	$36,534	-$3,502	$33,032	$2,606,996

Real-Time Reserve Market

9.1 Real-Time Reserve Payments

Real-Time Reserve Payment Summary by Reserve Zone
July 13-19, 2026

DAY	CT	NEMABSTN	ROS	SWCT	Total
13JUL26	$18.33	$25.29	$137.30	$15.28	$196.20
14JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
15JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
16JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
17JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
18JUL26	$76.74	$67.58	$978.37	$66.73	$1,189.42
19JUL26	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$95.07	$92.87	$1,115.67	$82.01	$1,385.62

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
July 13-19, 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	99.5%	0.5%	100.0%	0.0%	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
July 13-19, 2026

Local Reserve Zone	Product	Zero-Priced 5-Minute Intervals	Non-Zero 5-Minute Intervals
Connecticut	TMSR	99.5%	0.5%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
NEMA/Boston	TMSR	99.5%	0.5%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Rest Of System	TMSR	99.5%	0.5%
	TMNSR	100.0%	0.0%
	TMOR	100.0%	0.0%
Southwest Connecticut	TMSR	99.5%	0.5%
	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
July 13-19, 2026

Local Day	Reserve Bias
July 13-19, 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]
July 13-19, 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
July 13-19, 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**
7/22/2026	Original	Initial posting.