



NEPOOL Participants Committee Report

July 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



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Regular Operations Report - Highlights



Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
 - Update: May 2023 Energy Market value totaled \$232M
 - June 2023 Energy market value was \$342M, up \$110M from May 2023 and down \$399M from June 2022
 - June natural gas prices over the period were 65% higher than May average values
 - Average RT Hub Locational Marginal Prices (\$35.16/MWh) over the period were 52% higher than May averages
 - Avg. DA Hub: \$33.52/MWh
 - Average June 2023 natural gas prices and RT Hub LMPs over the period were down 64% and 51%, respectively, from June 2022 averages
 - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98% during June, down from 98.5% during May*
 - The minimum value for the month was 93.8% on Saturday, June 3rd

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Underlying natural gas data furnished by:



ISO-NE PUBLIC

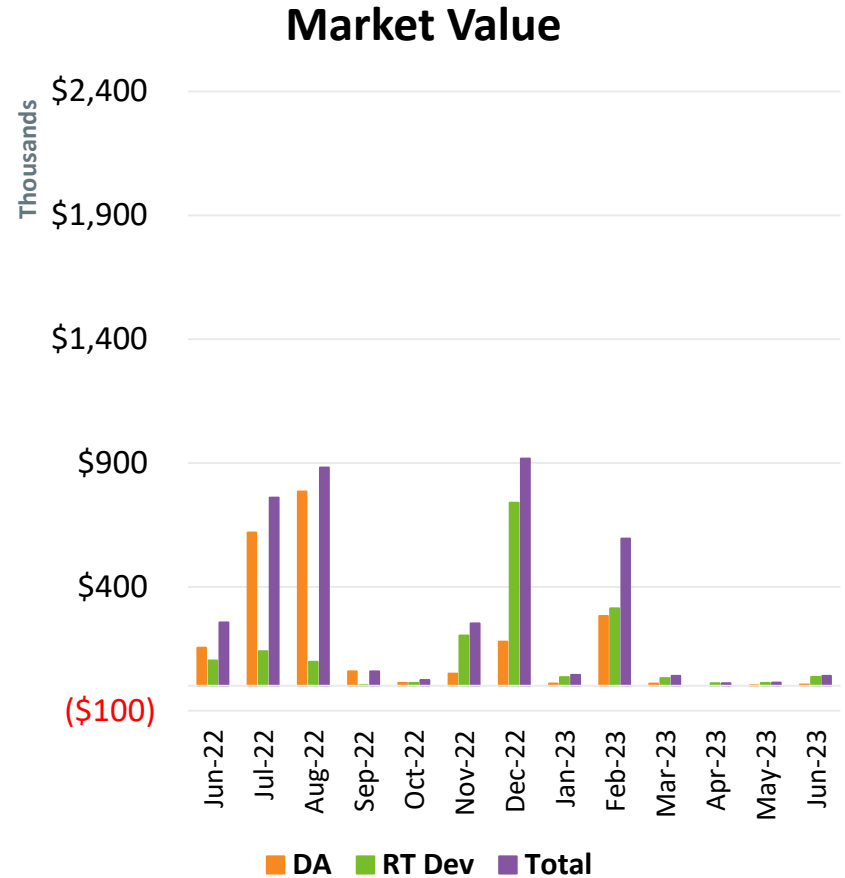
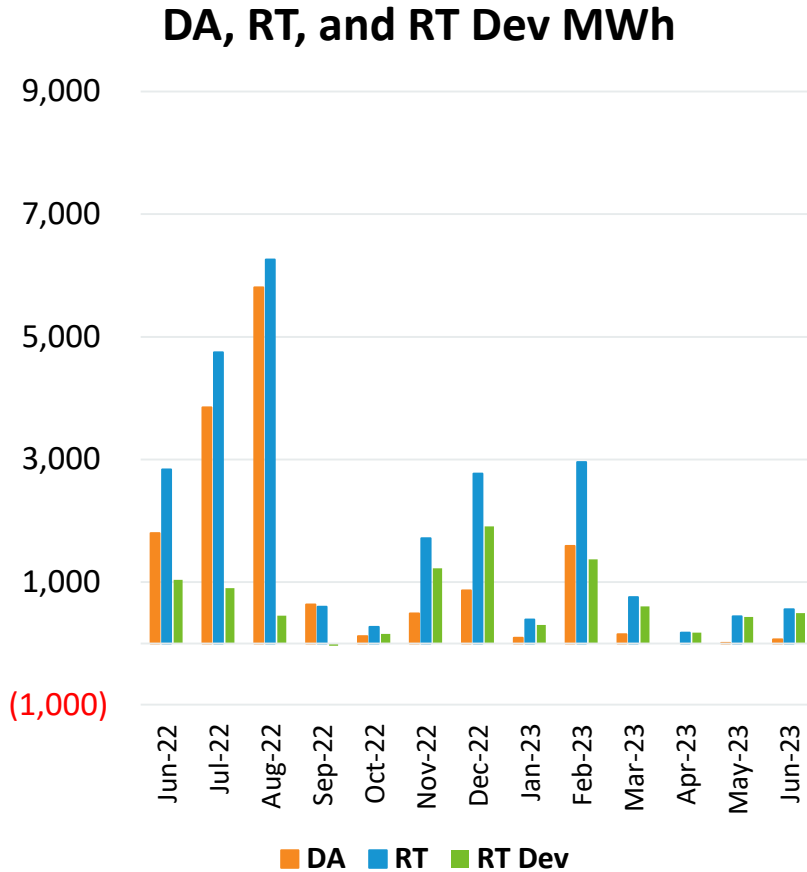
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
 - June 2023 NCPC payments totaled \$1.8M over the period, up \$0.5M from May 2023 and down \$1.2M from June 2022
 - First Contingency payments totaled \$1.7M, up \$0.5M from May
 - \$1.6M paid to internal resources, up \$0.5M from May
 - » \$103K charged to DALO, \$800K to RT Deviations, \$737K to RTLO*
 - \$96K paid to resources at external locations, down \$44K from May
 - » Charged to RT Deviations
 - Second Contingency payments totaled \$20K
 - Distribution payments were \$4K
 - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - \$410K; Rapid Response Pricing (RRP) Opportunity Cost - \$327K; Posturing - \$0K; Generator Performance Auditing (GPA) - \$0K**



Price Responsive Demand (PRD) Energy Market Activity by Month



Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.



Highlights

- The RSP Executive Summary draft has been reviewed by the Board, and the full document is now being assembled
- The 2024 load forecast cycle will begin in Q4 2023
- Qualified Transmission Project Sponsor (QTPS)
 - 25 companies have achieved QTPS status



Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
 - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 15 (2024-2025)
 - Second annual reconfiguration auction (ARA2) will be held on August 1-3, and results will be posted no later than August 31
- CCP 16 (2025-2026)
 - First annual reconfiguration auction (ARA1) was held on June 1-5, and results were posted on July 3
- CCP 17 (2026-2027)
 - Auction results were filed with FERC on March 21 and the filing is pending
 - ISO requested an effective date of July 19

FCM Highlights, cont.

- CCP 18 (2027-2028)
 - Capacity zone development discussions began at the December 13, 2022 PAC meeting, with follow-up discussions at the March 14 RC and March 16 PAC meetings
 - All subsequent reconfiguration auctions model the same zones as the FCA
 - ISO posted existing capacity values on March 30
 - ISO posted the Retirement and Permanent Delist Bid summary on April 12
 - Show of Interest Submission Window closed on May 8
 - ISO held a PSPC meeting on June 21 and discussed the assumptions for ICR and related values and tie benefits studies for FCA 18
 - The results of the tie benefits study are expected to be presented at the July 26 PSPC meeting



SYSTEM OPERATIONS



System Operations

<u>Weather Patterns</u>	Boston	Temperature: Below Normal (2.1°F) Max: 84°F, Min: 47°F Precipitation: 3.44" – Below Normal Normal: 3.89"	Hartford	Temperature: Below Normal (0.9°F) Max: 94°F, Min: 46°F Precipitation: 1.27" - Below Normal Normal: 4.28"
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<u>Peak Load:</u>	18,202 MW	June 26, 2023	18:00 (ending)
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Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
NONE			



System Operations

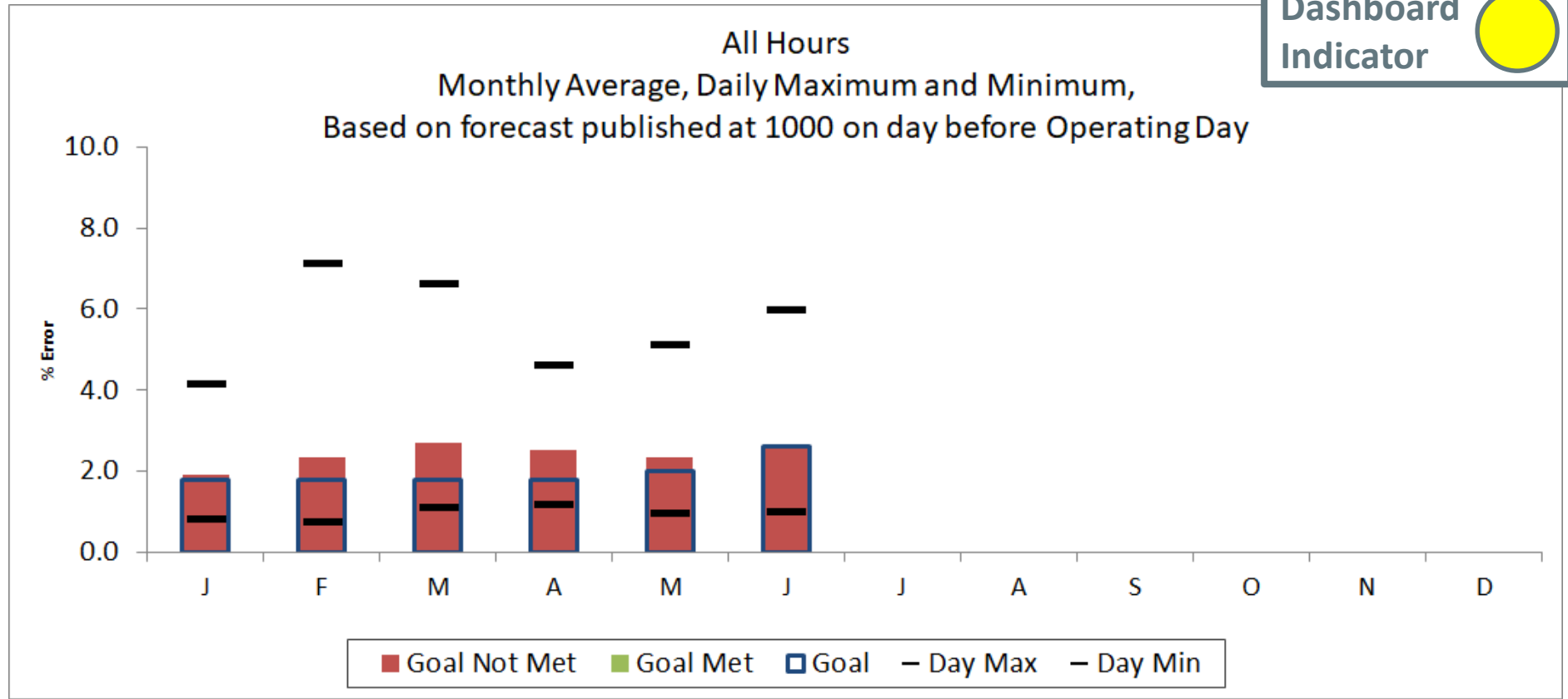
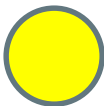
NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
6/24/2023	ISO-NE	950
6/26/2023	ISO-NE	1550



2023 System Operations - Load Forecast Accuracy

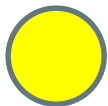
Dashboard
Indicator



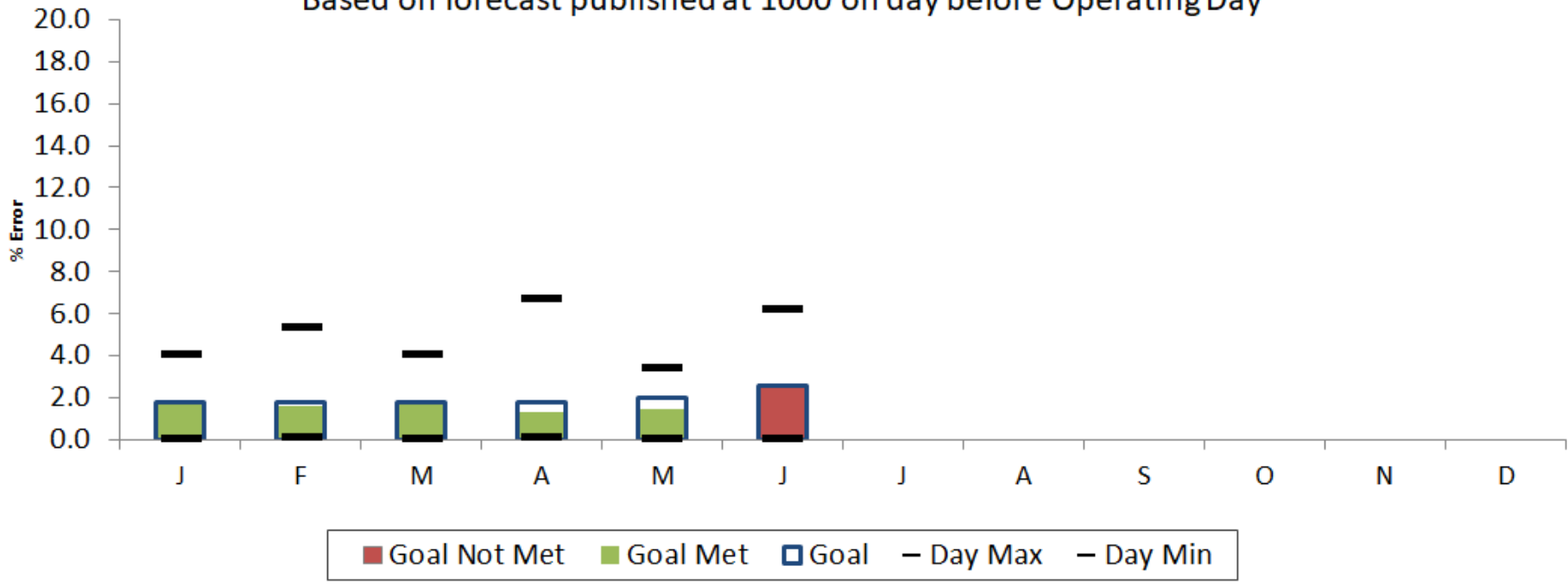
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14	7.12	6.59	4.61	5.10	5.97							7.12
Day Min	0.80	0.74	1.08	1.17	0.96	0.97							0.74
MAPE	1.91	2.34	2.70	2.52	2.36	2.63							2.41
Goal	1.80	1.80	1.80	1.80	2.00	2.60							

2023 System Operations - Load Forecast Accuracy cont.

Dashboard
Indicator

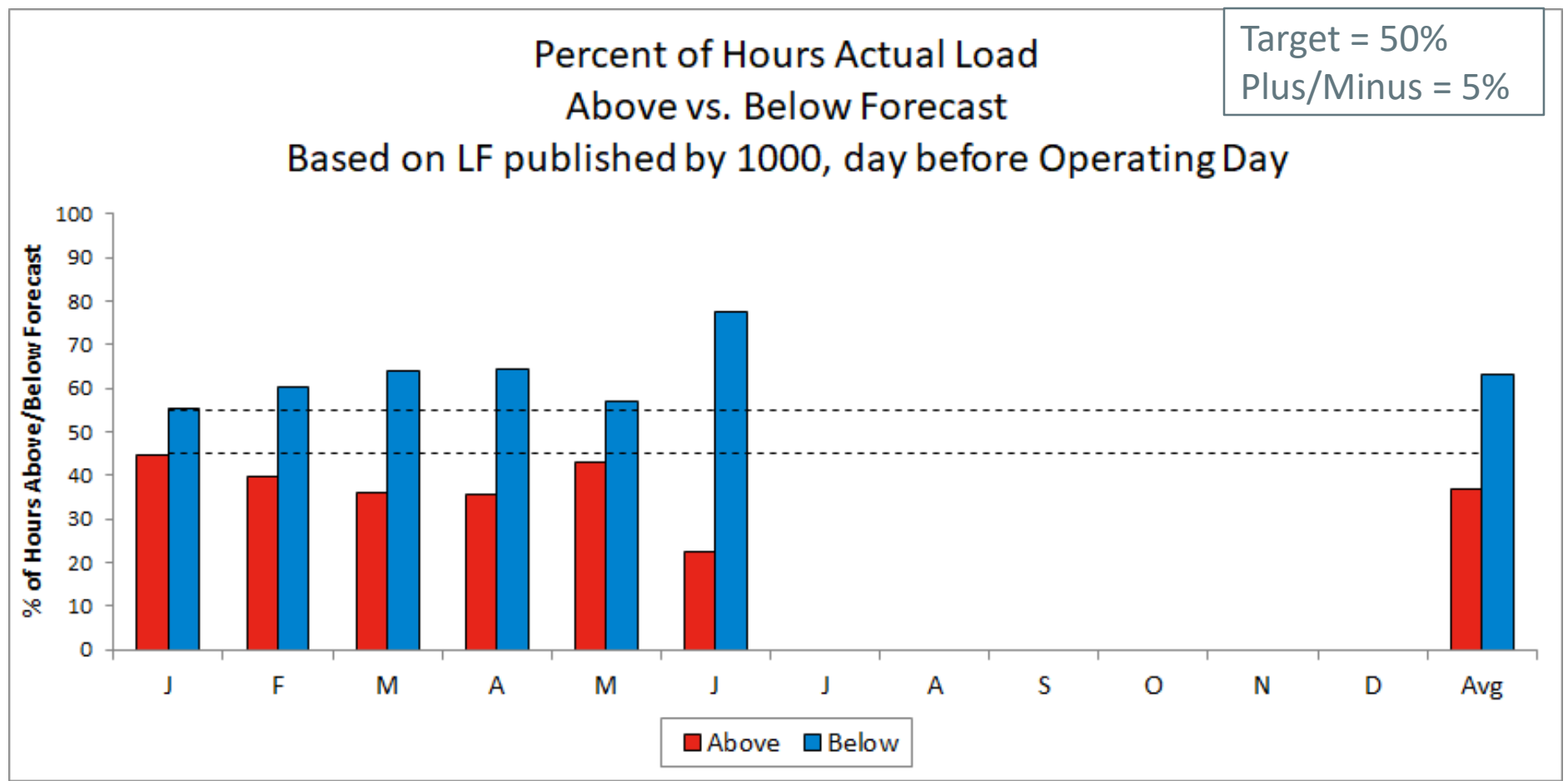


Peak Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published at 1000 on day before Operating Day



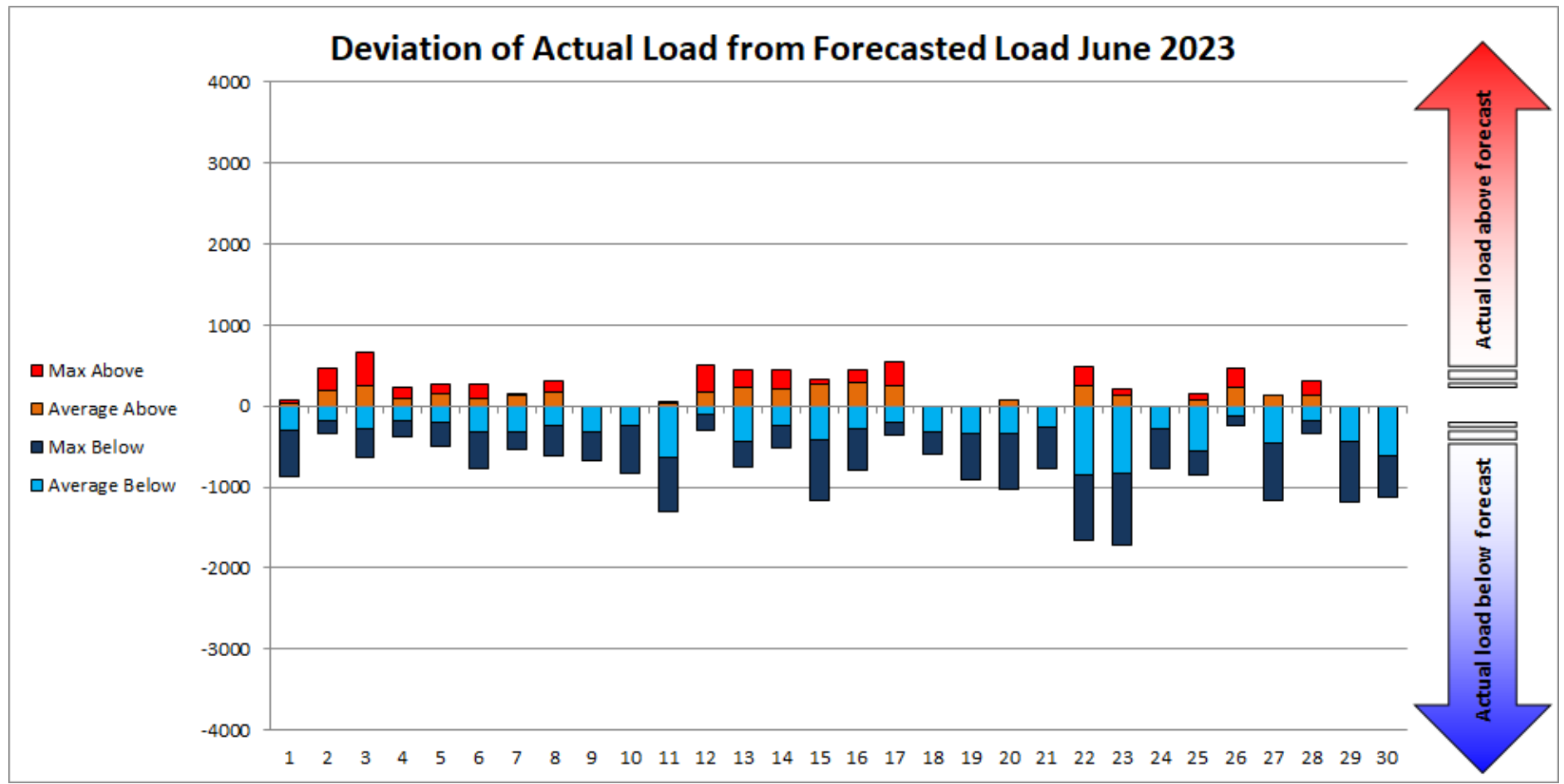
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21							6.68
Day Min	0.01	0.08	0.06	0.11	0.03	0.04							0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65							1.75
Goal	1.80	1.80	1.80	1.80	2.00	2.60							

2023 System Operations - Load Forecast Accuracy cont.

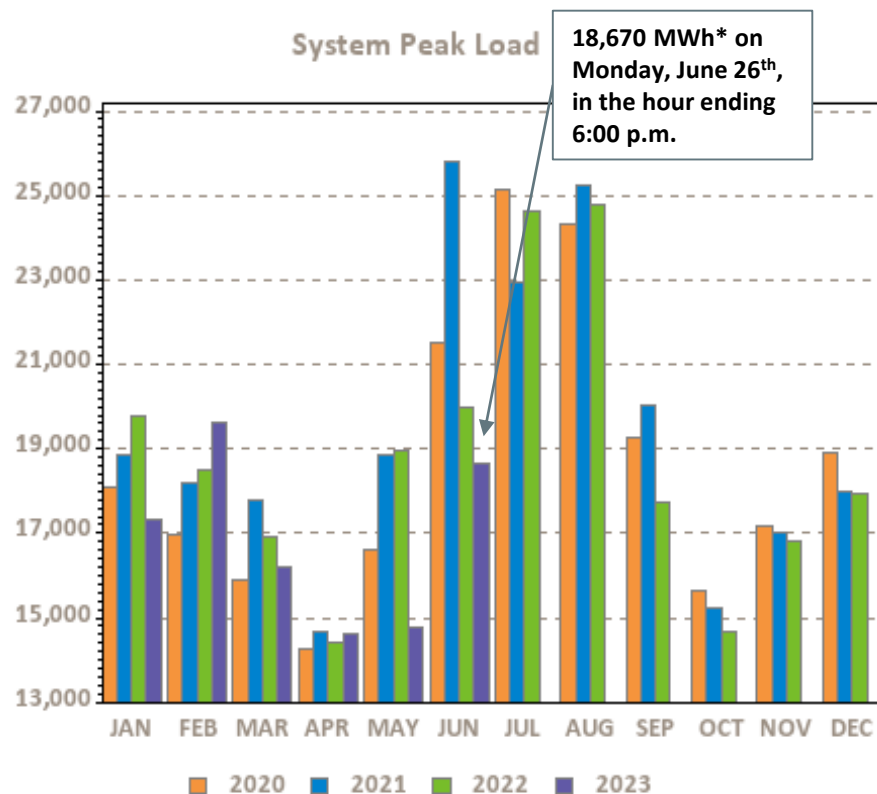


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6							37
Below %	55.4	60.3	63.8	64.3	57	77.4							63
Avg Above	235.7	228	172.9	194.5	183.5	120							236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3							-350
Avg All	-10	-28	-142	-74	-17	-236							-85

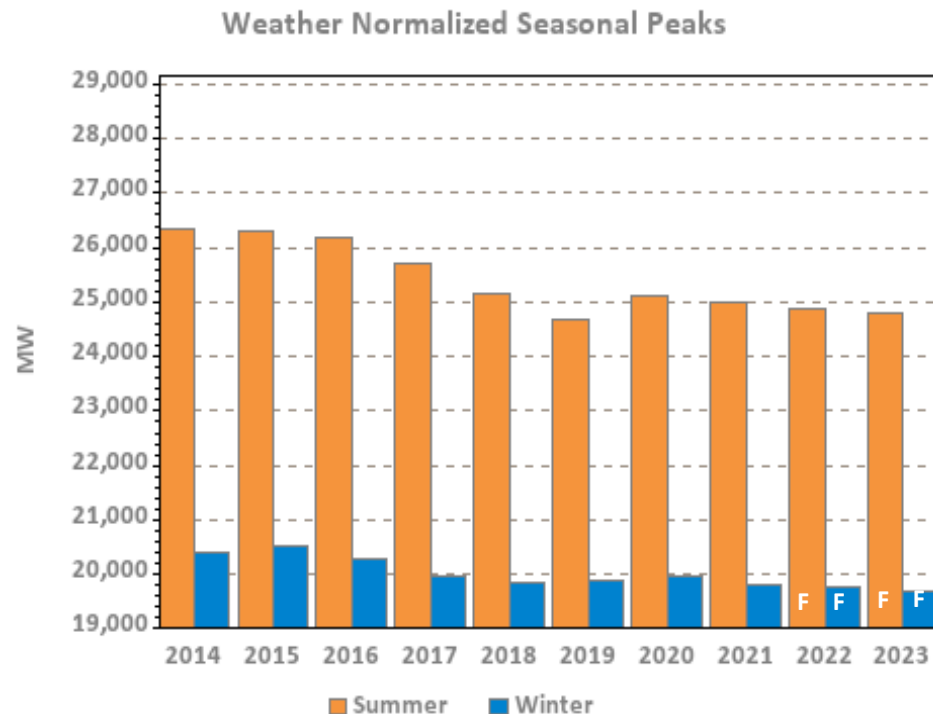
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value



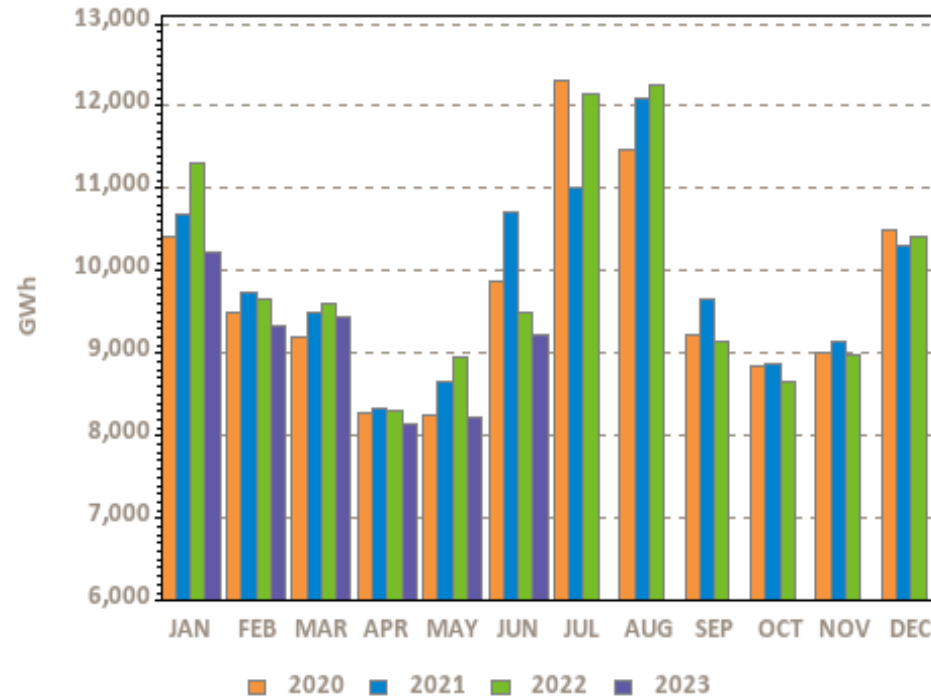
Winter beginning in year displayed

F – designates forecasted values, which are typically updated in April/May of the following year; represents “net forecast” (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)



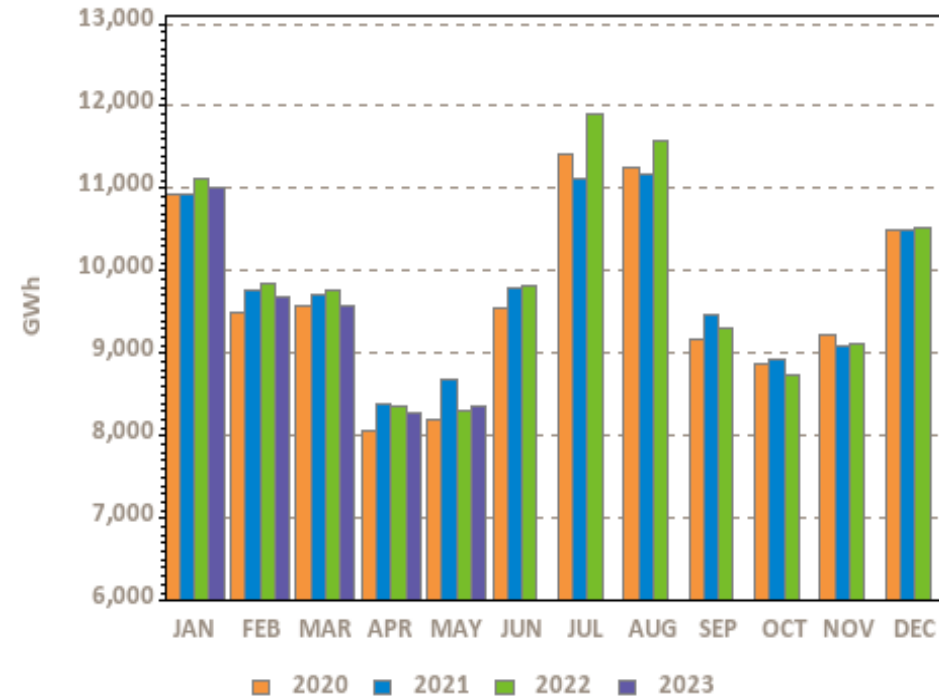
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)



Ann Tot (TWh): 116.9 118.8 118.9 54.6

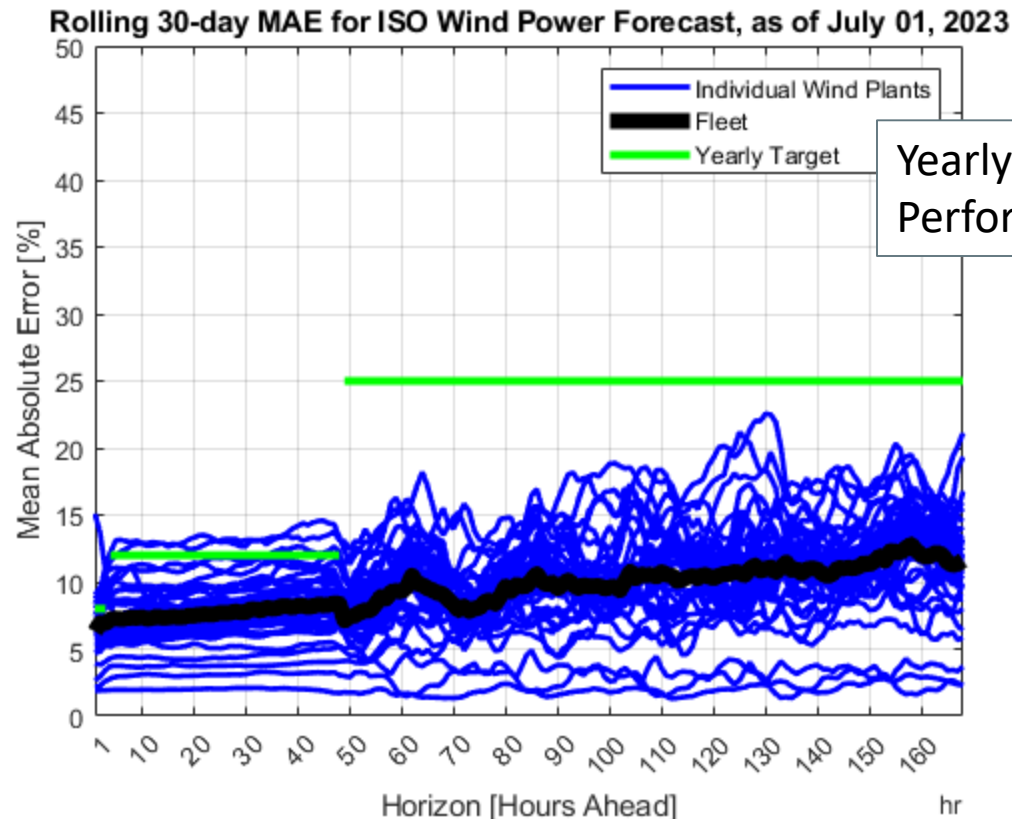
Weather Normalized NEL



Ann Tot (TWh): 116.3 117.6 118.4 46.9

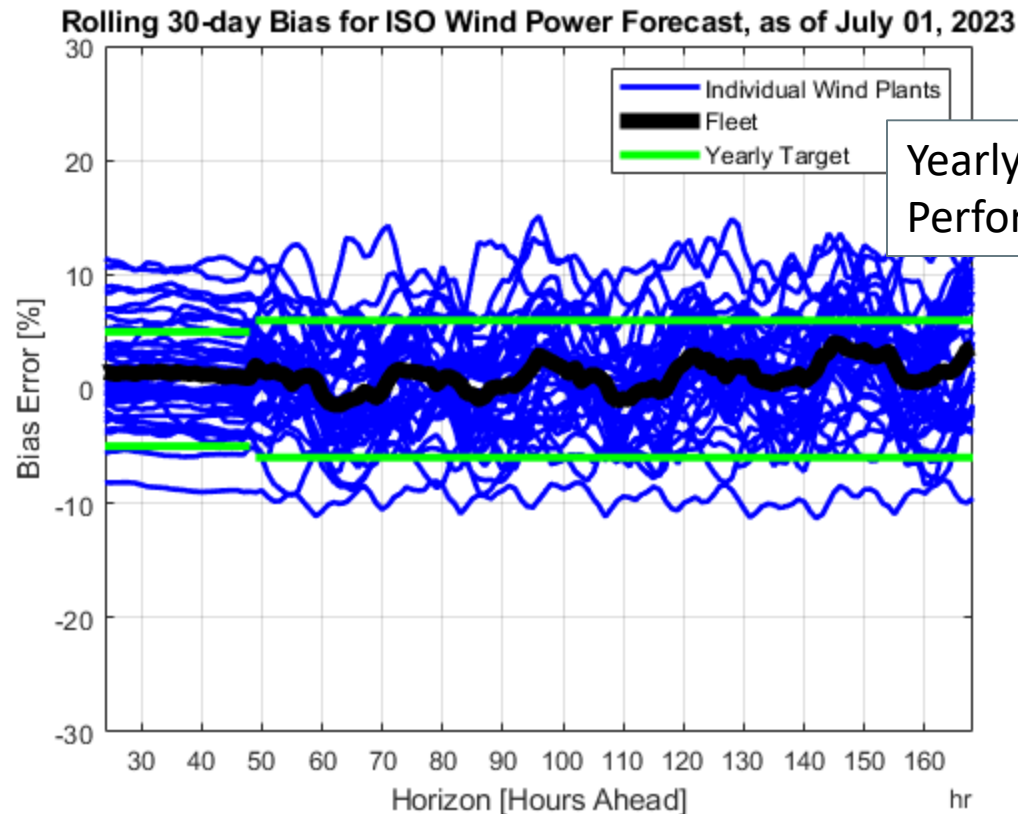
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported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

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias



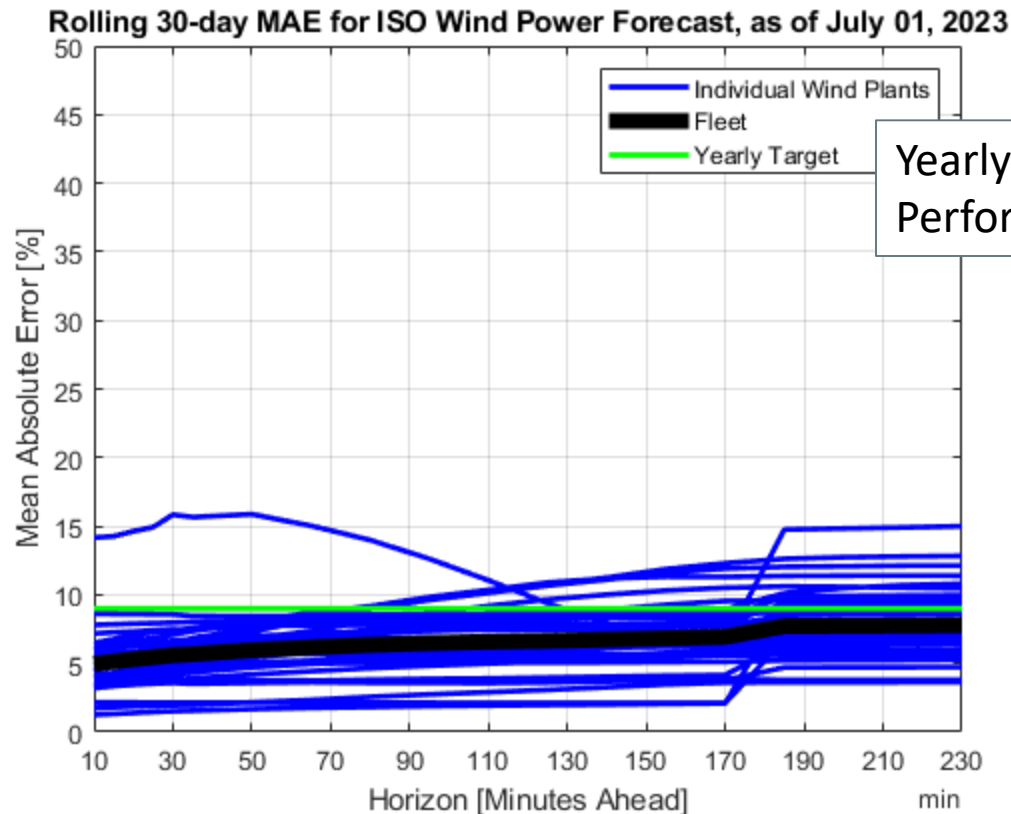
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics:

Short Term Forecast MAE

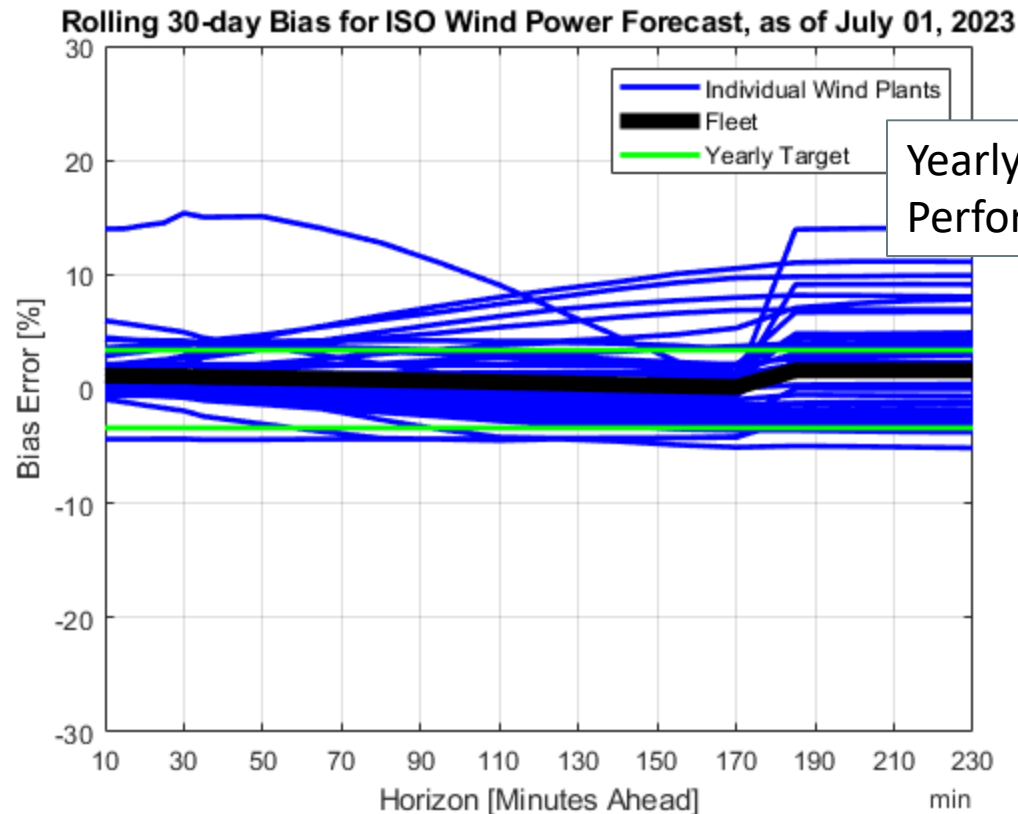


Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the forecast compares well with industry standards, and monthly MAE is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias



Dashboard Indicator

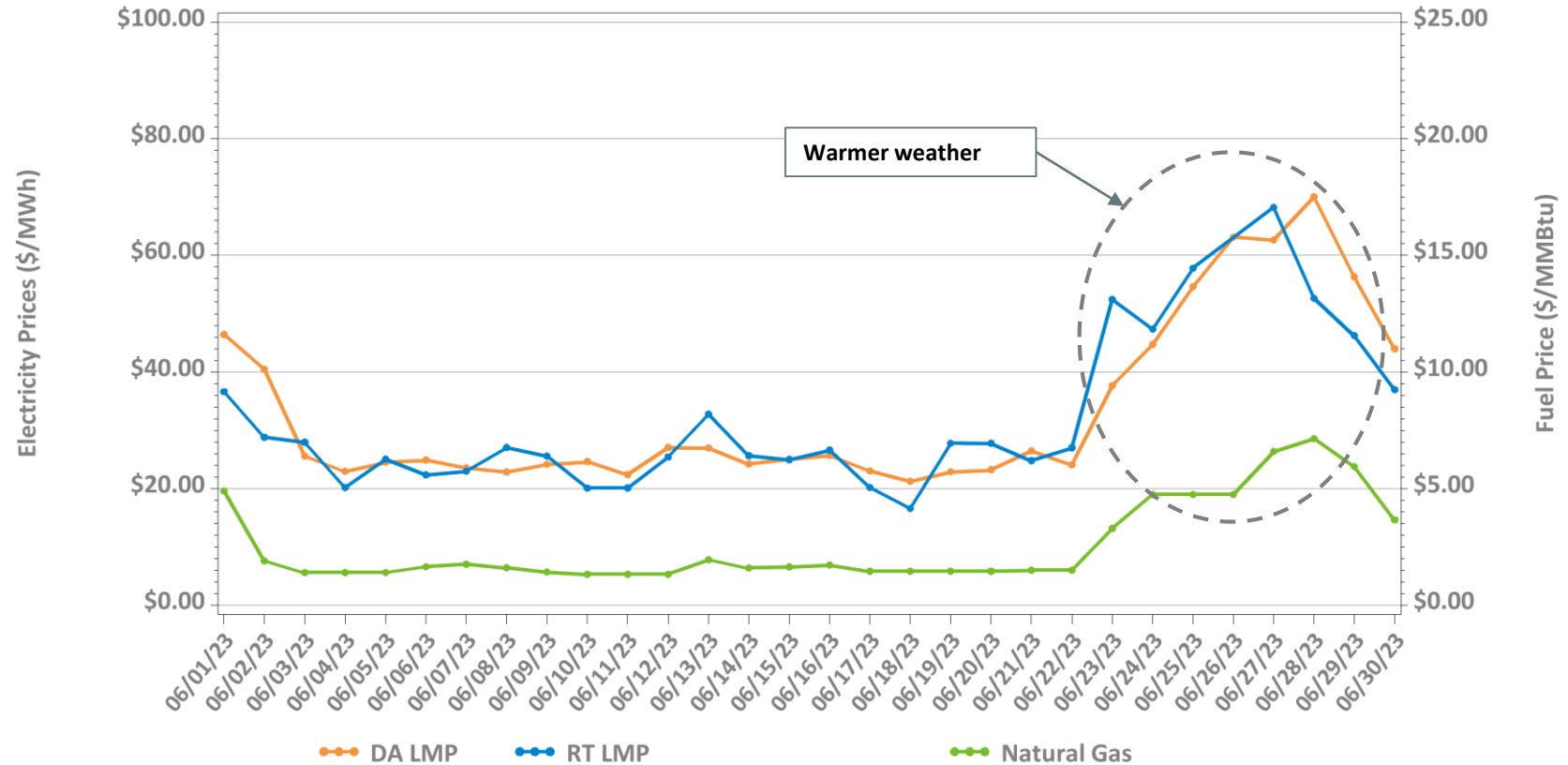


Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and monthly Bias is within yearly performance.

MARKET OPERATIONS



Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: June 1-30, 2023

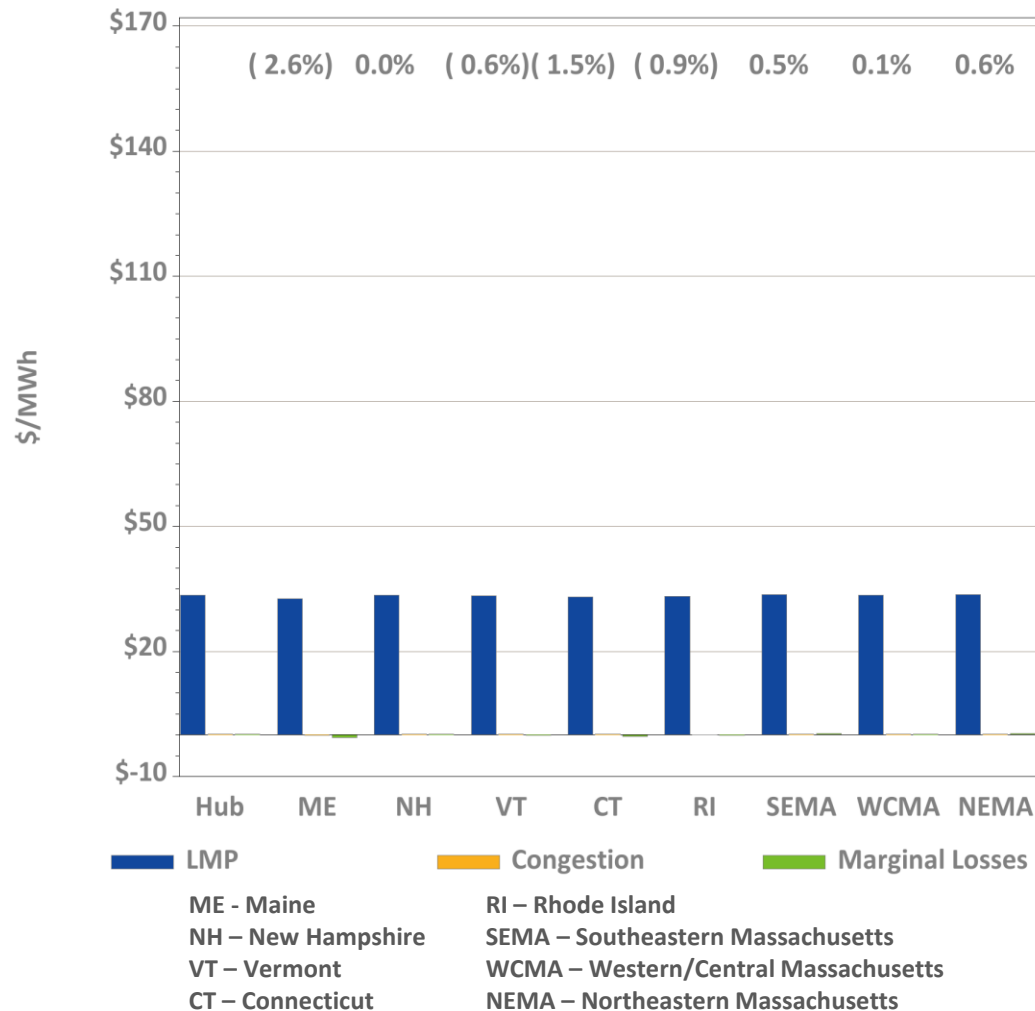


Underlying natural gas data furnished by:

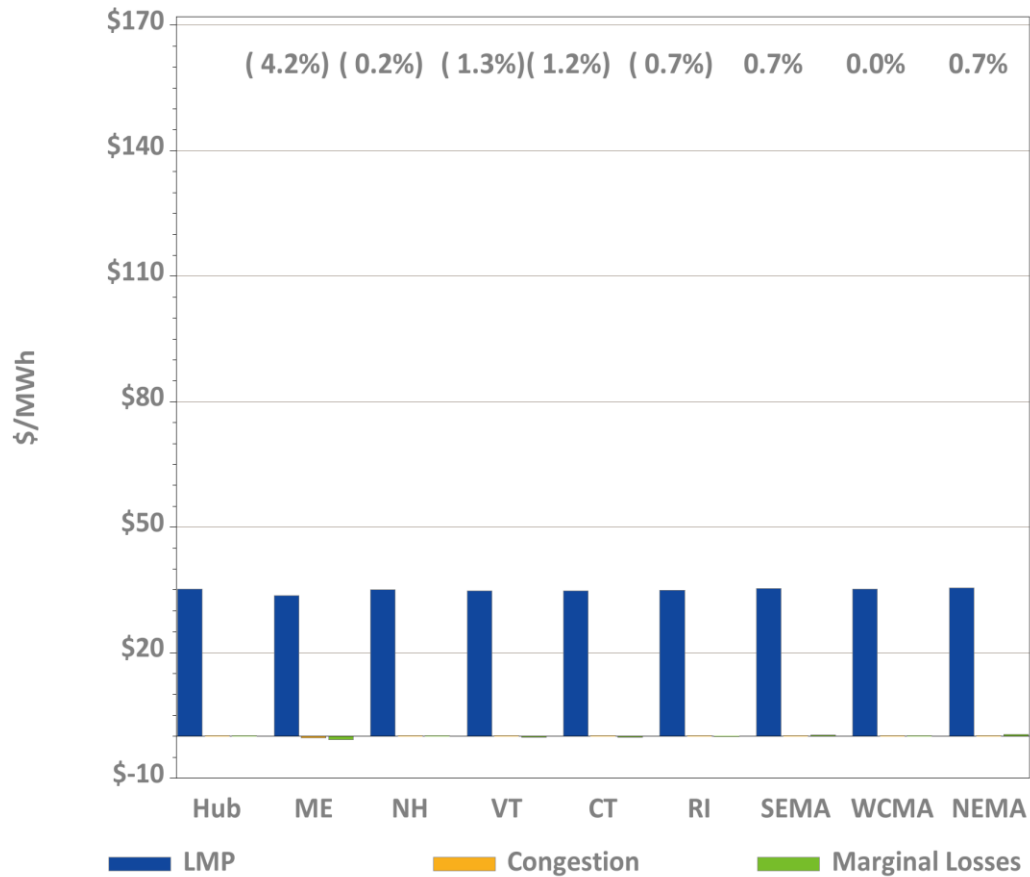


Average price difference over this period (DA-RT): \$-1.64
 Average price difference over this period ABS(DA-RT): \$6.94
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 20%
 Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, June 2023



RT LMPs Average by Zone & Hub, June 2023

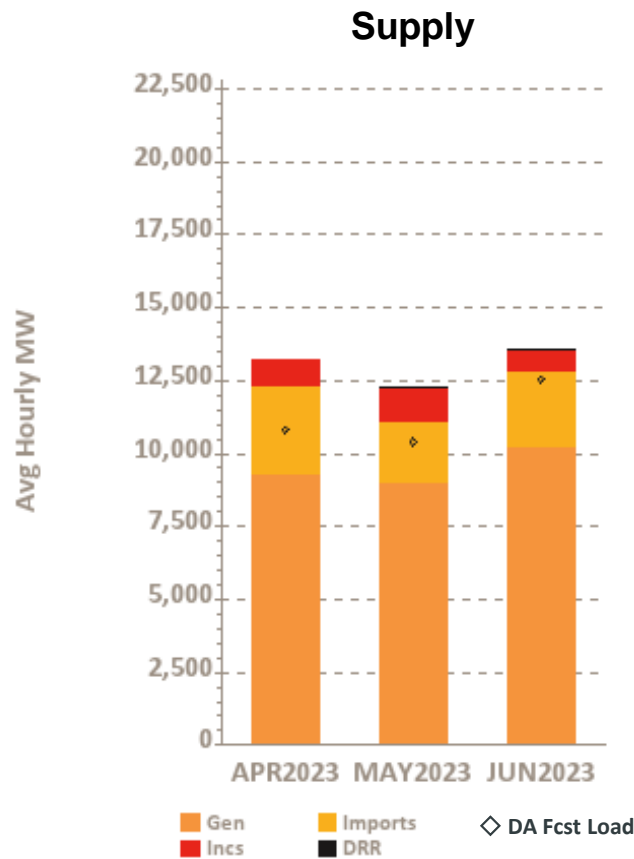


Definitions

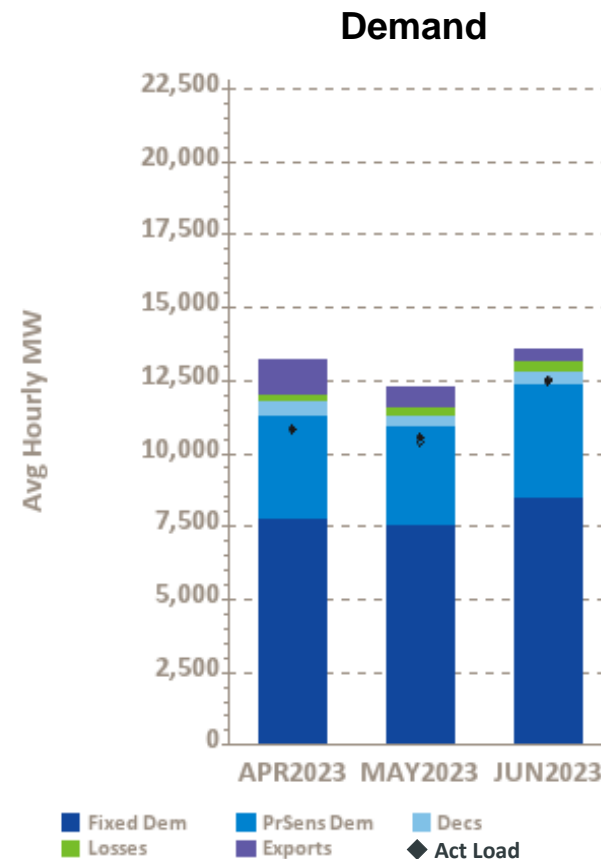
Day-Ahead Concept	Definition
Day-Ahead Load Obligation (DALO)	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand

– Last Three Months



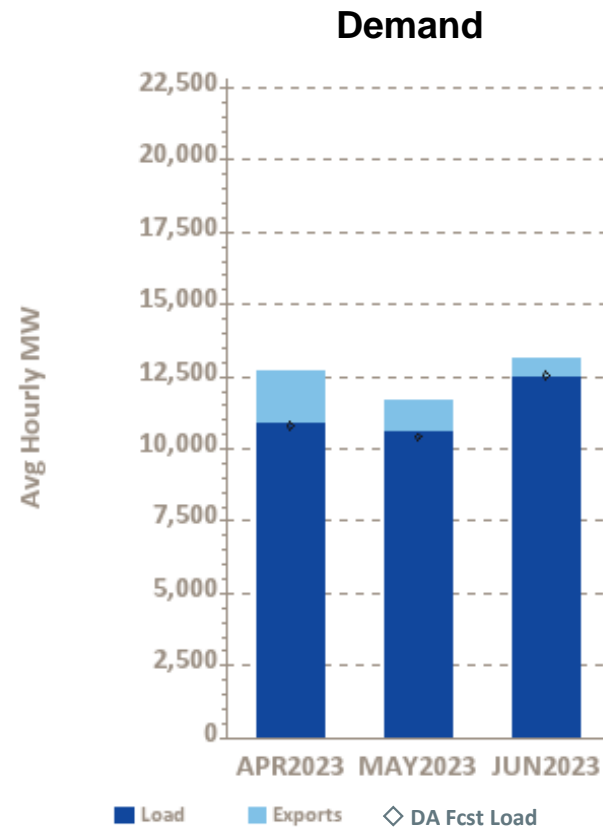
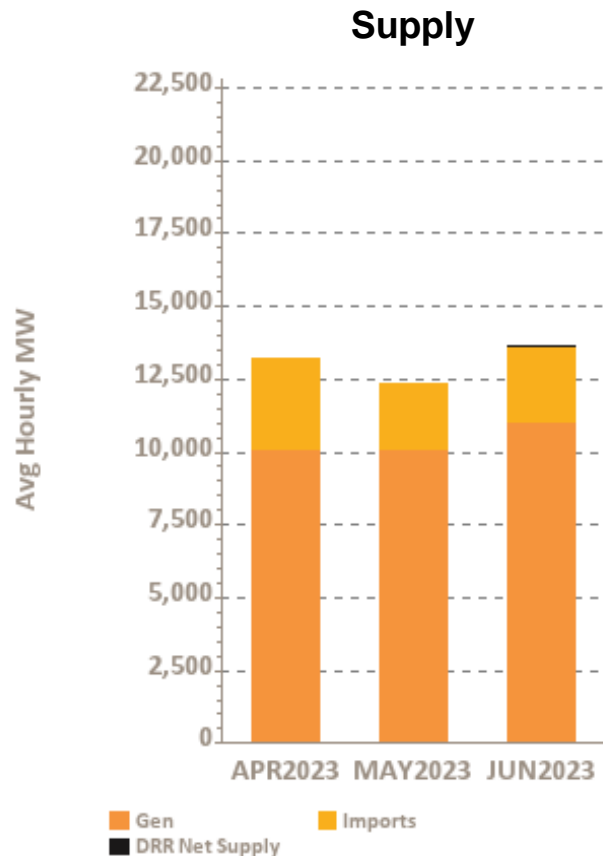
Gen – Generation
 Incs – Increment Offers
 DA Fcst Load – Day-Ahead Forecast Load
 DRR – Demand Response Resource



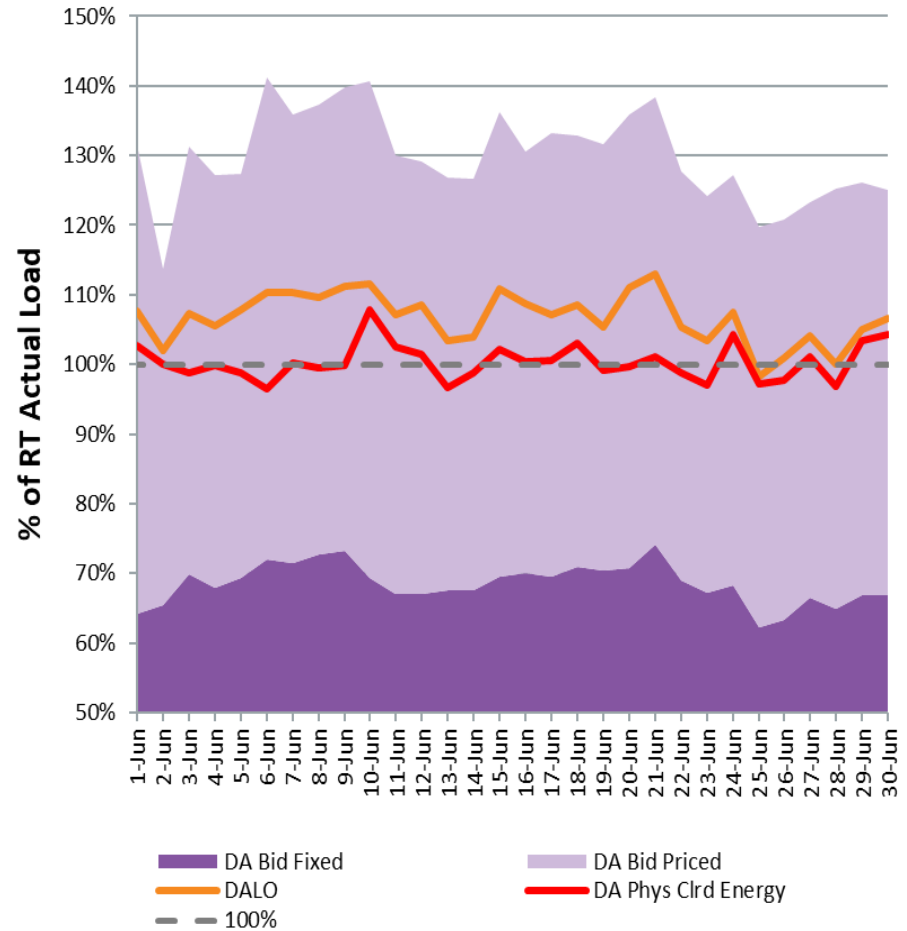
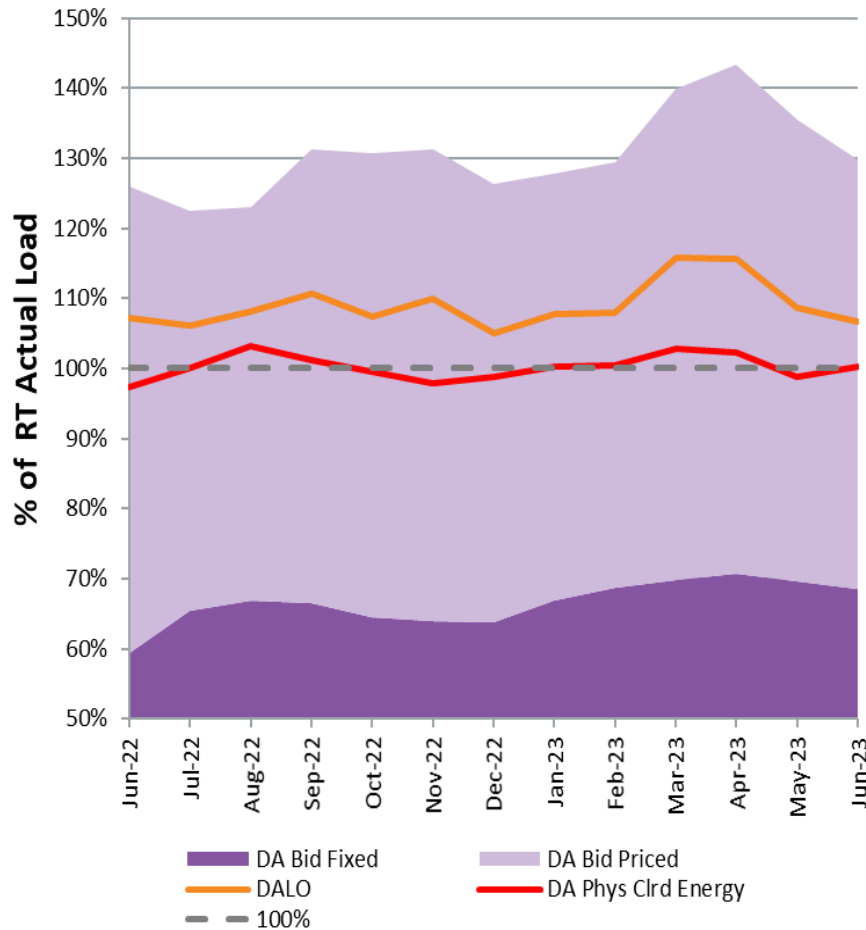
Fixed Dem – Fixed Demand
 PrSens Dem – Price Sensitive Demand
 Decs – Decrement Bids
 Act Load – Actual Load



Components of RT Supply and Demand – Last Three Months



DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

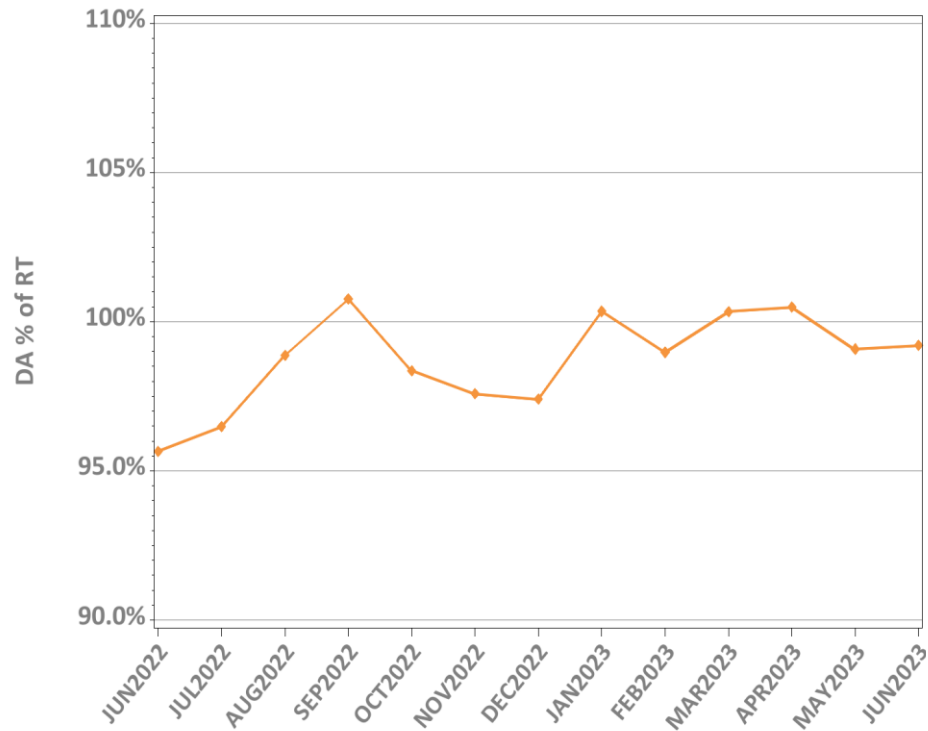


Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

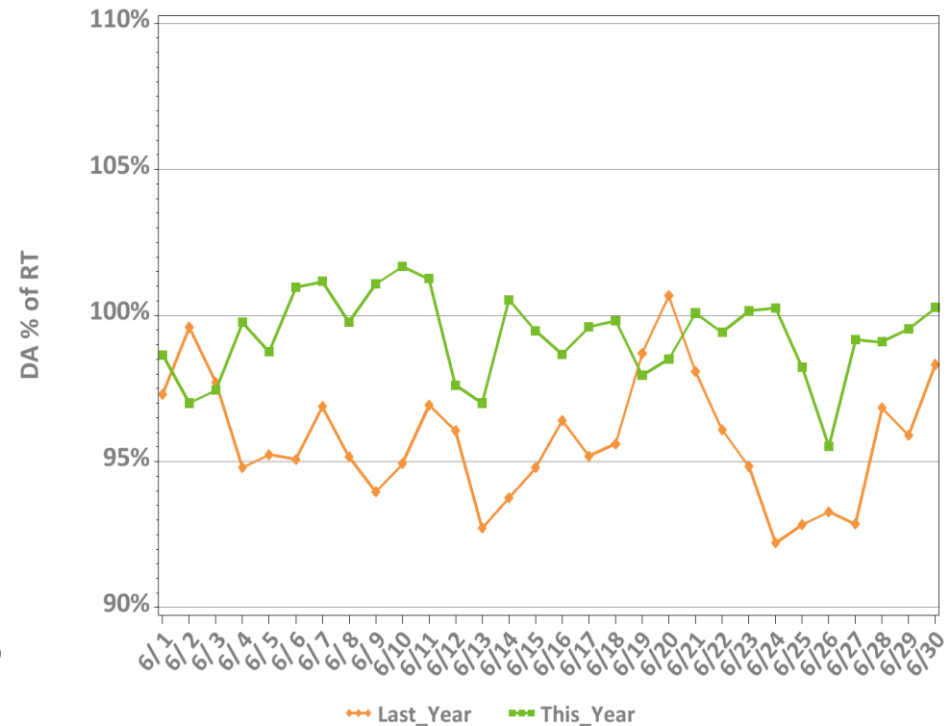


DA vs. RT Load Obligation: June, This Year vs. Last Year

Monthly, Last 13 Months



Daily, This Year vs. Last Year

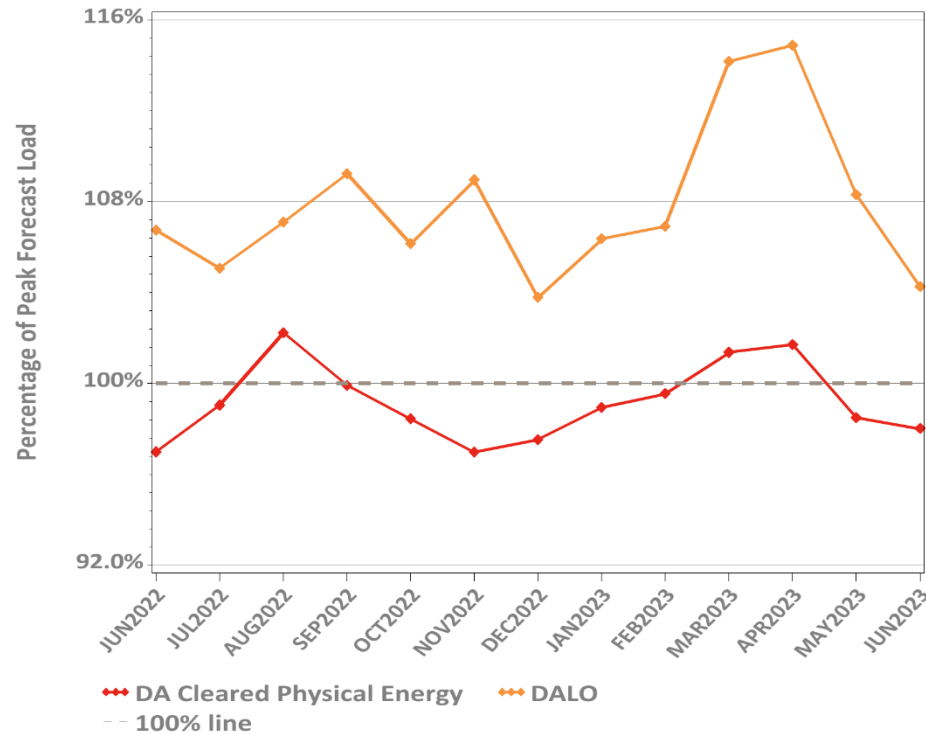


*Hourly average values

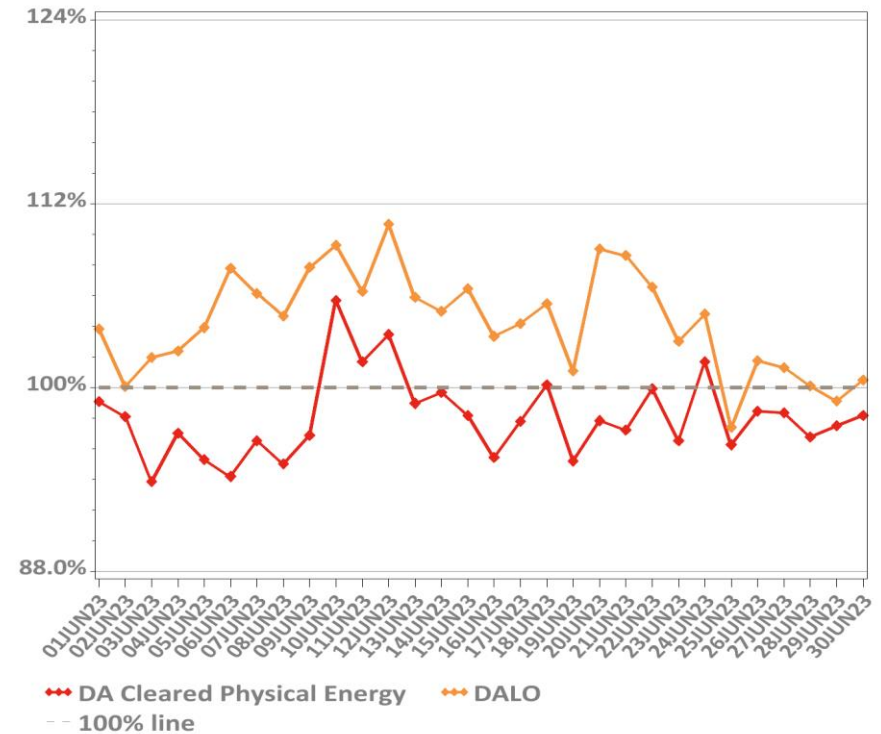


DA Volumes as % of Forecast in Peak Hour

Monthly, Last 13 Months

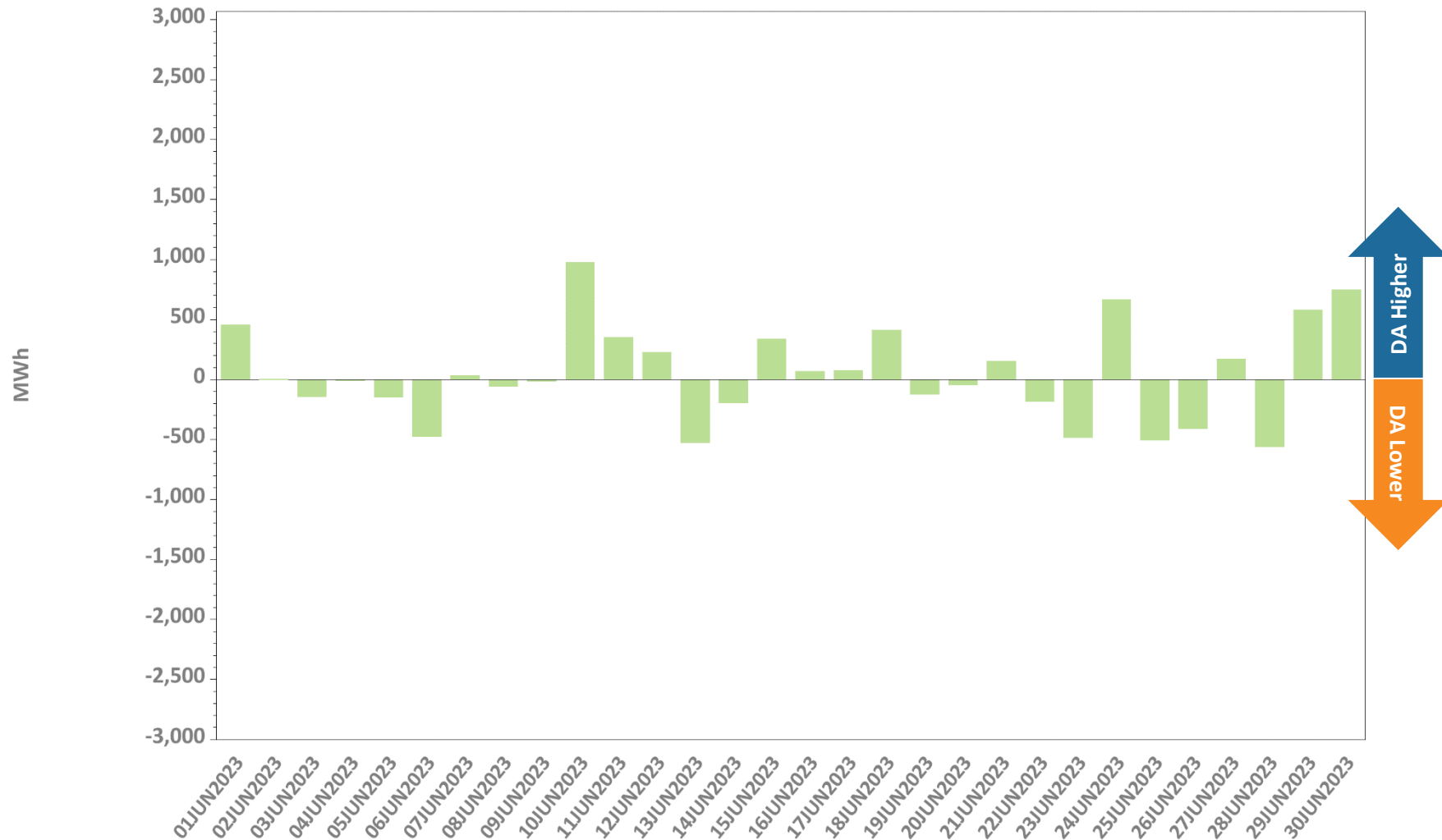


Daily: This Month



Note: There were **no** system-level manual supplemental commitments for capacity required **during the Reserve Adequacy Assessment (RAA)** period during the month.

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



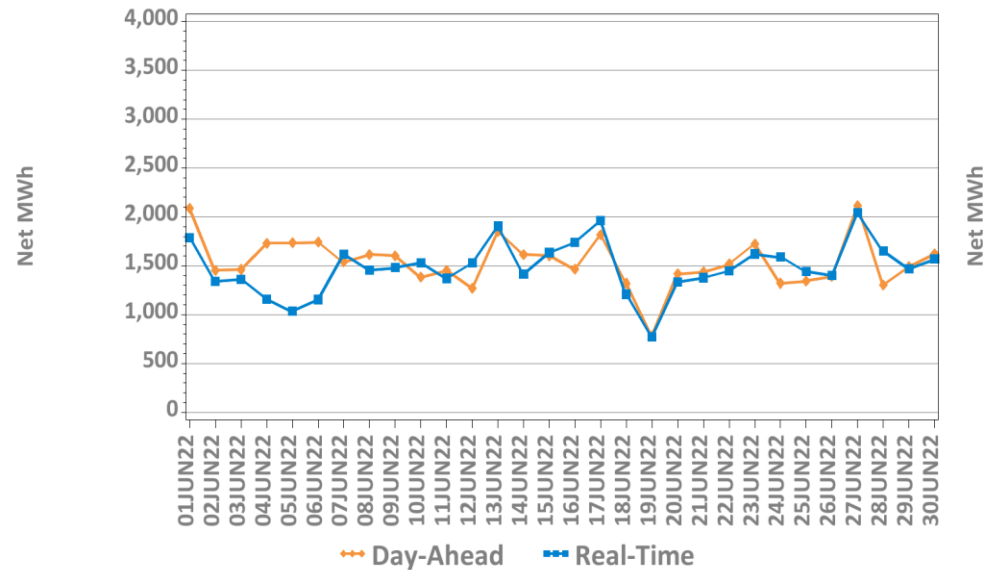
*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.



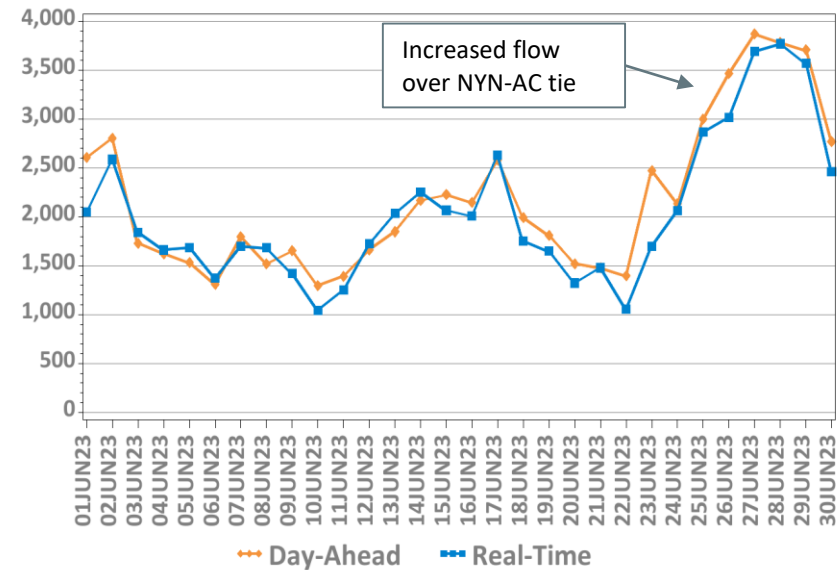
DA vs. RT Net Interchange

June 2023 vs. June 2022

Hourly Average by Day, Last Year



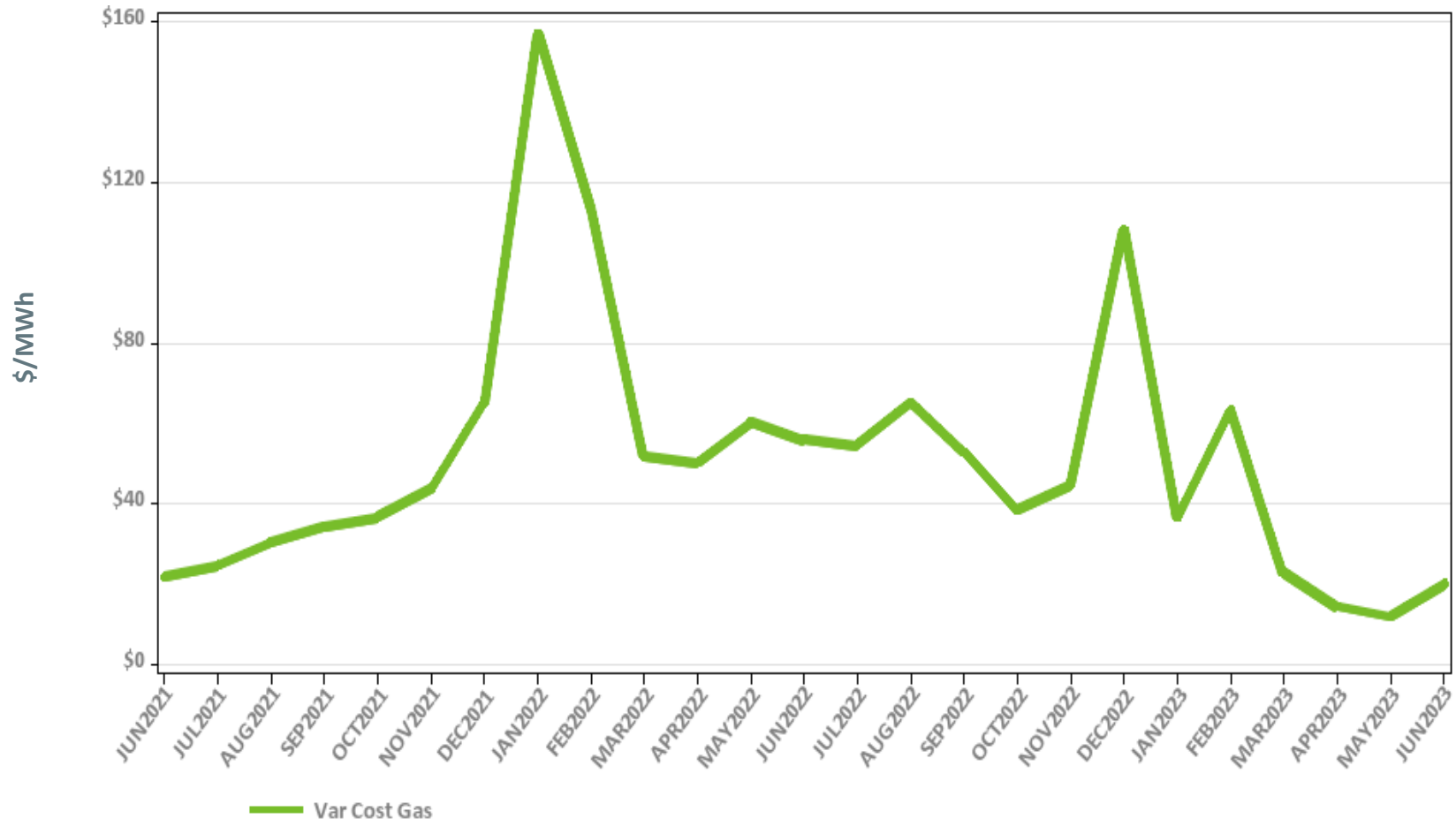
Hourly Average by Day, This Year



Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports



Variable Production Cost of Natural Gas: Monthly

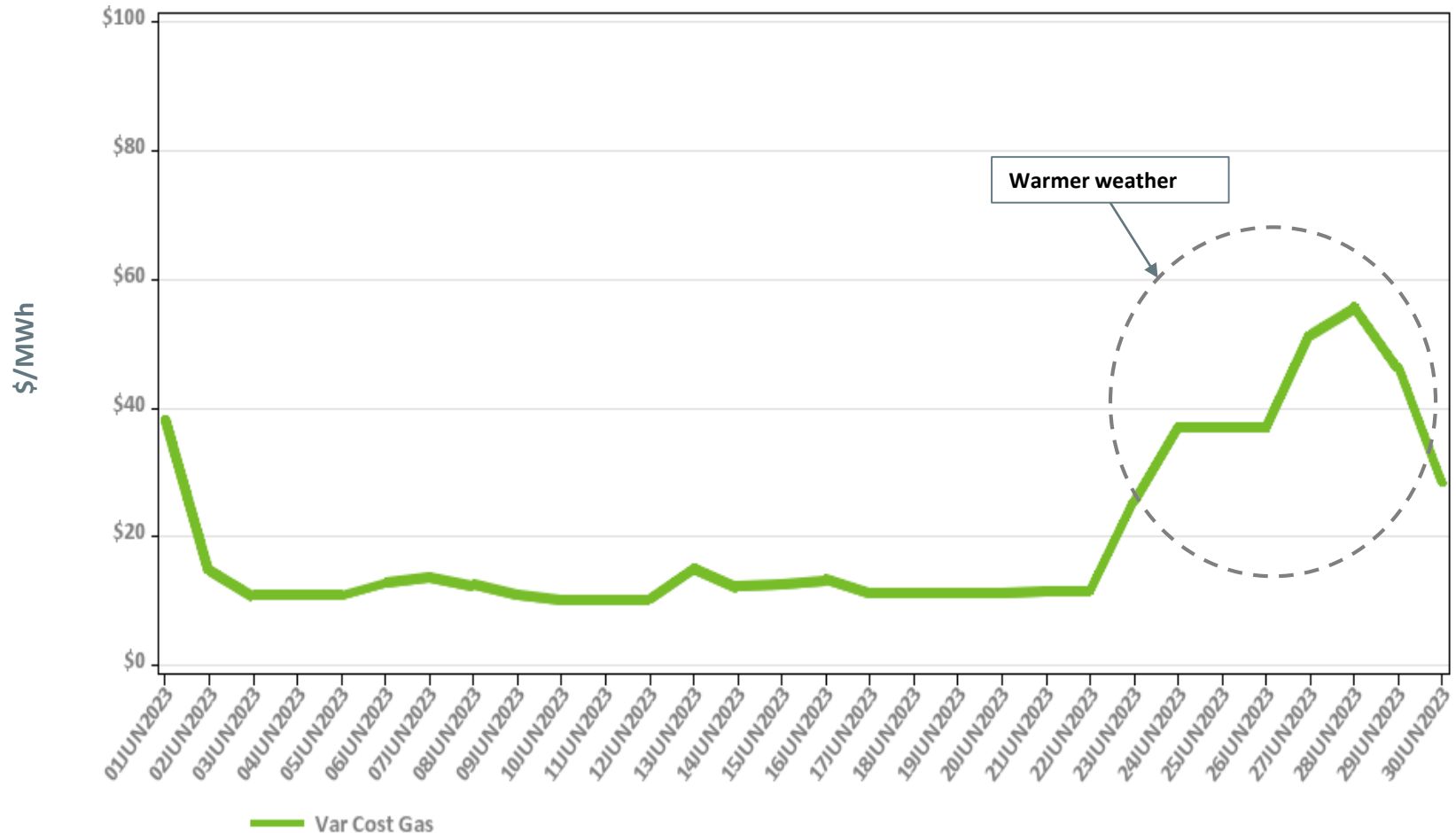


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



Variable Production Cost of Natural Gas: Daily



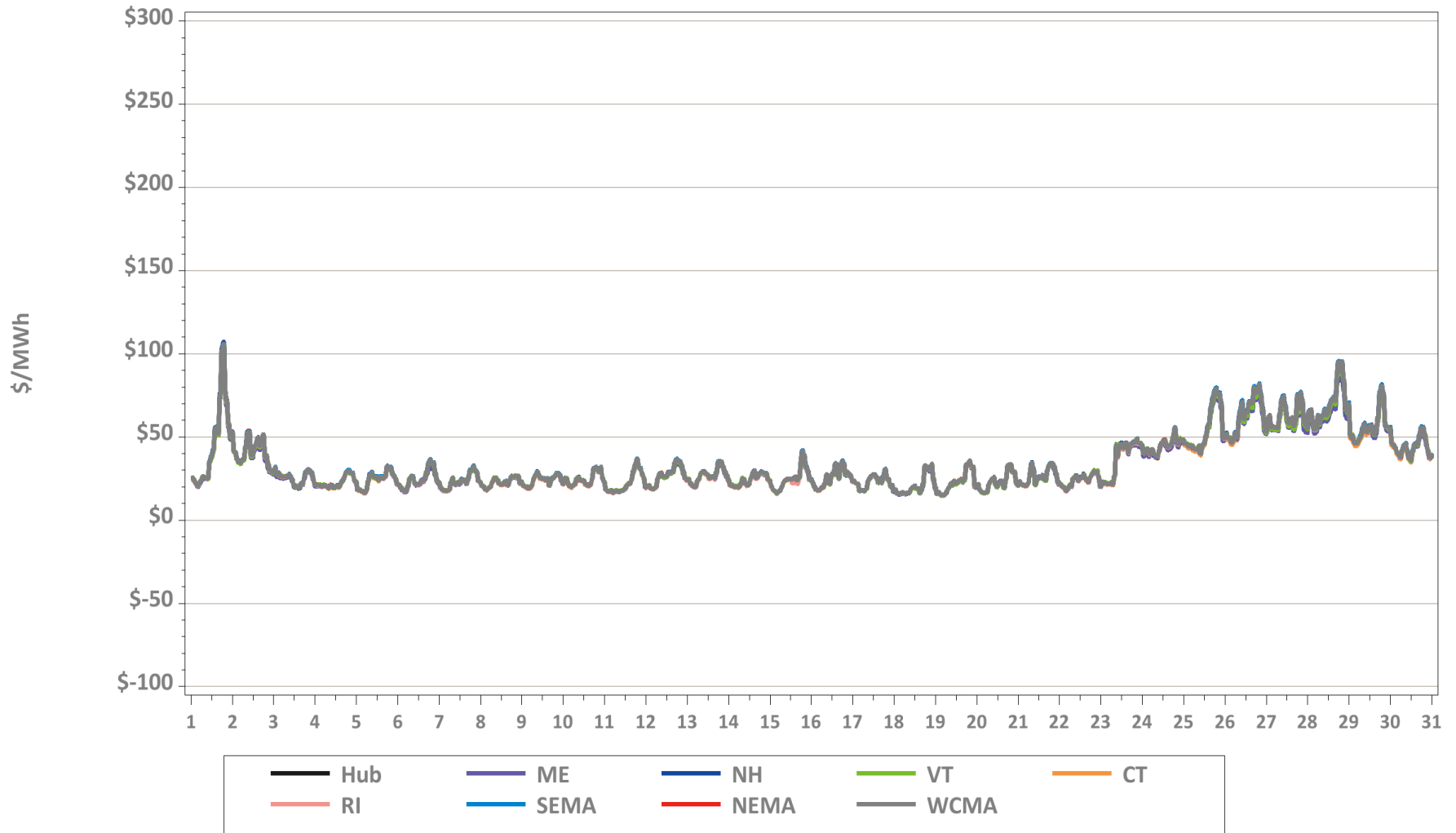
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



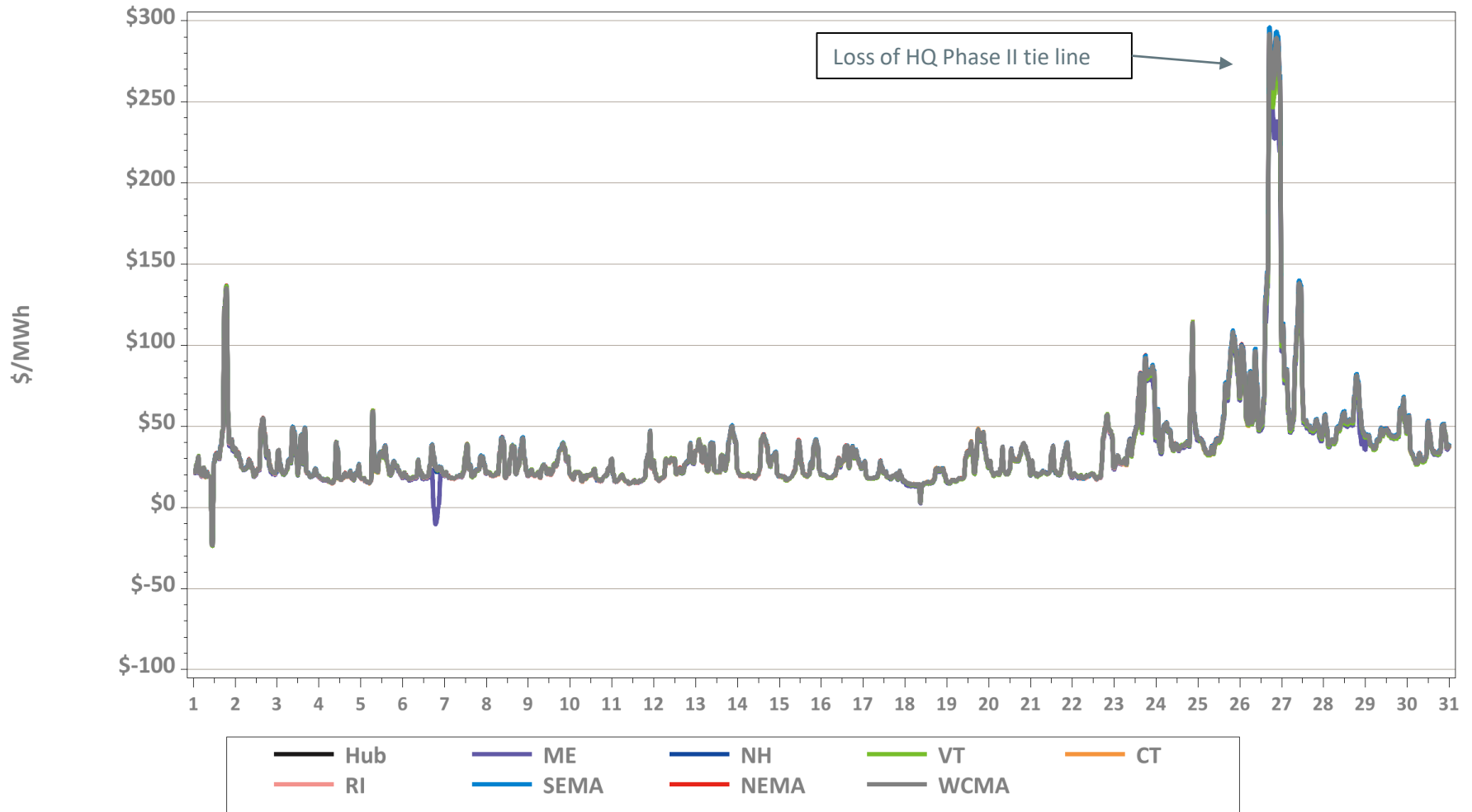
Hourly DA LMPs, June 1-30, 2023

Hourly Day-Ahead LMPs



Hourly RT LMPs, June 1-30, 2023

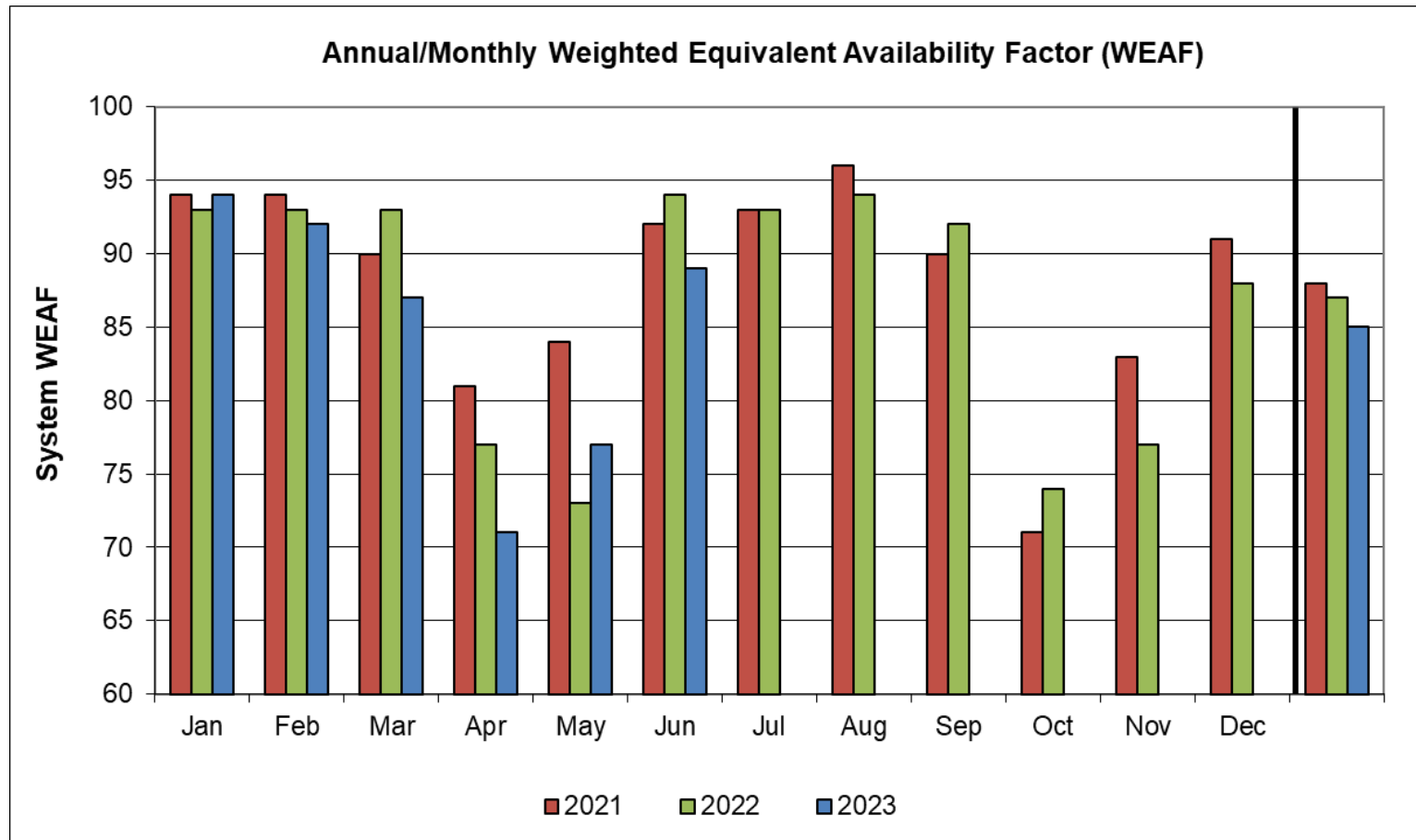
Hourly Real-Time LMPs



* BTM (Behind the meter)



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92	87	71	77	89							85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87
2021	94	94	90	81	84	92	93	96	90	71	83	91	88

Data as of 6/26/2023

BACK-UP DETAIL



DEMAND RESPONSE



Capacity Supply Obligation (CSO) MW by Demand Resource Type for July 2023

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	48.7	200.2	0.0	248.9
NH	35.4	156.1	0.0	191.5
VT	38.9	123.0	0.0	161.9
CT	118.4	170.9	598.6	887.9
RI	24.1	318.9	0.0	343.1
SEMA	31.1	470.4	0.0	501.5
WCMA	74.3	520.4	26.6	621.3
NEMA	68.8	775.2	0.0	844.0
Total	439.8	2,735.1	625.3	3,800.2

* Active Demand Capacity Resources

NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION



New Generation Update

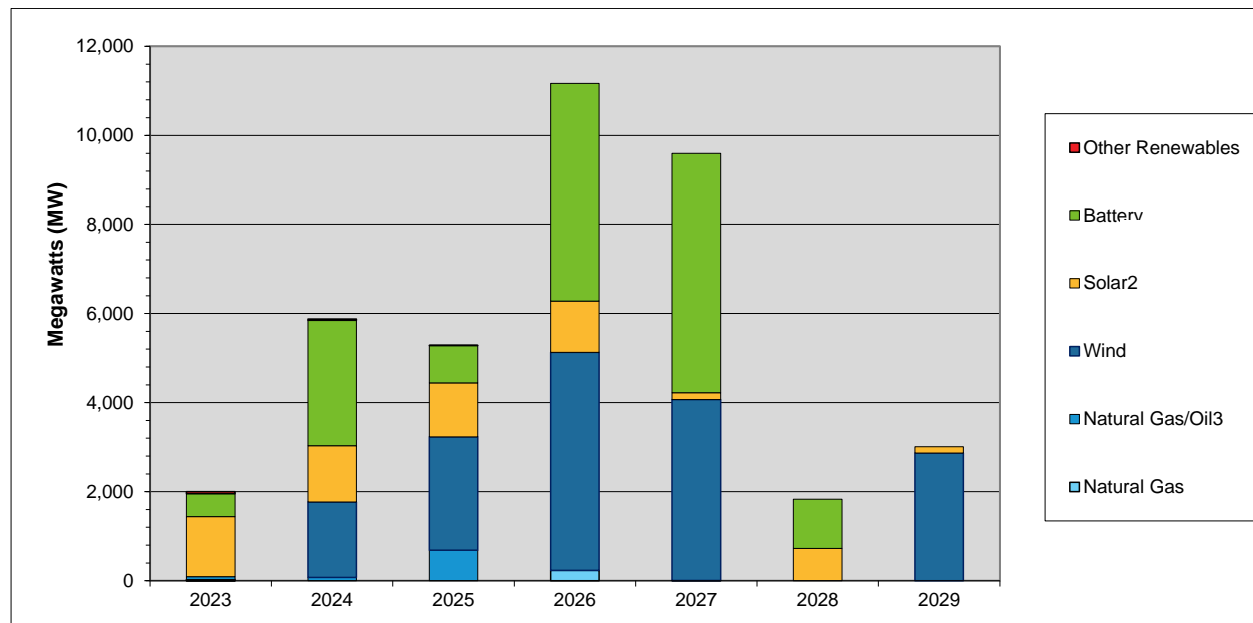
Based on Queue as of 6/30/23

- Eighteen projects totaling 1,904 MW were added to the interconnection queue since the last update
 - Eleven battery projects, six solar paired with battery projects and one fuel cell project with in-service dates of 2024 to 2027
- In total, 376 generation projects are currently being tracked by the ISO, totaling approximately 39,642 MW



Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



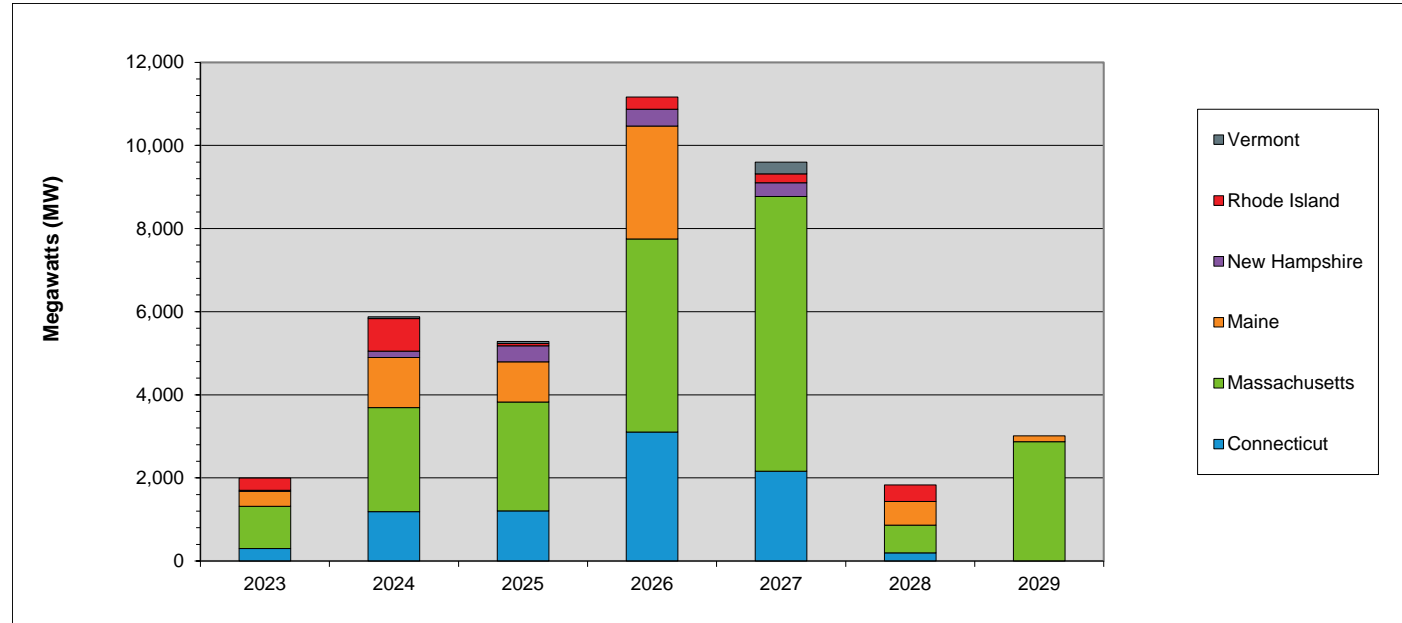
	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total ¹
Other Renewables	47	30	2	0	0	0	0	79	0.2
Battery	514	2,815	839	4,888	5,377	1,104	0	15,537	40.1
Solar ²	1,349	1,265	1,208	1,153	154	725	139	5,993	15.5
Wind	0	1,693	2,545	4,893	4,064	0	2,870	16,065	41.4
Natural Gas/Oil ³	62	73	688	0	0	0	0	823	2.1
Natural Gas	26	0	0	233	4	0	0	263	0.7
Totals	1,998	5,876	5,282	11,167	9,599	1,829	3,009	38,760	100.0

¹ Sum may not equal 100% due to rounding

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

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

Actual and Projected Annual Generator Capacity Additions By State



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total ¹
Vermont	0	40	50	0	285	0	0	375	1.0
Rhode Island	298	787	54	295	211	400	0	2,045	5.3
New Hampshire	25	154	388	402	328	0	0	1,297	3.3
Maine	360	1,203	964	2,723	0	567	139	5,956	15.4
Massachusetts	1,015	2,504	2,620	4,646	6,612	664	2,870	20,931	54.0
Connecticut	300	1,188	1,206	3,101	2,163	198	0	8,156	21.0
Totals	1,998	5,876	5,282	11,167	9,599	1,829	3,009	38,760	100.0

¹ Sum may not equal 100% due to rounding

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	107	15,537	1	15	106	15,522
Fuel Cell	4	46	0	0	4	46
Hydro	2	33	1	5	1	28
Natural Gas	5	263	0	0	5	263
Natural Gas/Oil	4	823	1	62	3	761
Nuclear	0	0	0	0	0	0
Solar	227	5,993	16	361	211	5,632
Wind	27	16,947	1	800	26	16,147
Total	376	39,642	20	1,243	356	38,399

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	92	1	5	7	87
Intermediate	3	761	0	0	3	761
Peaker	338	21,842	18	438	320	21,404
Wind Turbine	27	16,947	1	800	26	16,147
Total	376	39,642	20	1,243	356	38,399

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	107	15,537	0	0	0	0	107	15,537	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	2	33	2	33	0	0	0	0	0	0
Natural Gas	5	263	2	13	0	0	3	250	0	0
Natural Gas/Oil	4	823	0	0	3	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	227	5,993	0	0	0	0	227	5,993	0	0
Wind	27	16,947	0	0	0	0	0	0	27	16,947
Total	376	39,642	8	92	3	761	338	21,842	27	16,947

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

FORWARD CAPACITY MARKET



Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	592.043	688.07	96.027	659.671	-28.399	564.371	-95.3
	Passive Demand	3,327.071	3,327.932	0.861	3,315.207	-12.725	3,253.179	-62.028
Demand Total		3,919.114	4,016.002	96.888	3,974.878	-41.124	3,817.550	-157.328
Generator	Non-Intermittent	27,816.902	28,275.143	458.241	27,697.714	-577.429	27,684.252	-13.462
	Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504	893.444	-32.498
Generator Total		28,977.818	29,403.589	425.771	28,623.656	-779.933	28,577.696	-45.96
Import Total		1,058.72	1,058.72	0	1,029.800	-28.92	958.380	-71.42
Grand Total*		33,955.652	34,478.311	522.661	33,628.334	-849.977	33,353.626	-274.708
Net ICR (NICR)		32,490	32,980	490	31,480	-1,500	31,690	210

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	677.673	673.401	-4.272				
	Passive Demand	3,212.865	3,211.403	-1.462				
Demand Total		3,890.538	3,884.804	-5.734				
Generator	Non-Intermittent	28,154.203	27,714.778	-439.425				
	Intermittent	1,089.265	1,073.794	-15.471				
Generator Total		29,243.468	28,788.572	-454.896				
Import Total		1,487.059	1297.132	-189.927				
Grand Total*		34,621.065	33,970.508	-650.557				
Net ICR (NICR)		33,270	31,775	-1,495				

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond and reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	765.35						
	Passive Demand	2,557.256						
Demand Total		3,322.606						
Generator	Non-Intermittent	26,805.003						
	Intermittent	1,178.933						
Generator Total		27,983.936						
Import Total		1,503.842						
Grand Total*		32,810.384						
Net ICR (NICR)		31,645						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	622.854						
	Passive Demand	2,316.815						
Demand Total		2,939.669						
Generator	Non-Intermittent	26,507.420						
	Intermittent	1,356.084						
Generator Total		27,863.504						
Import Total		566.998						
Grand Total*		31,370.171						
Net ICR (NICR)		30,305						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2,375.422	370.734	2,746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2,571.361	639.586	3,210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3,596.056	323.058	3,919.114
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	3,720.217	170.321	3,890.538
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	3,092.648	229.958	3,322.606

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS



What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule



Definitions

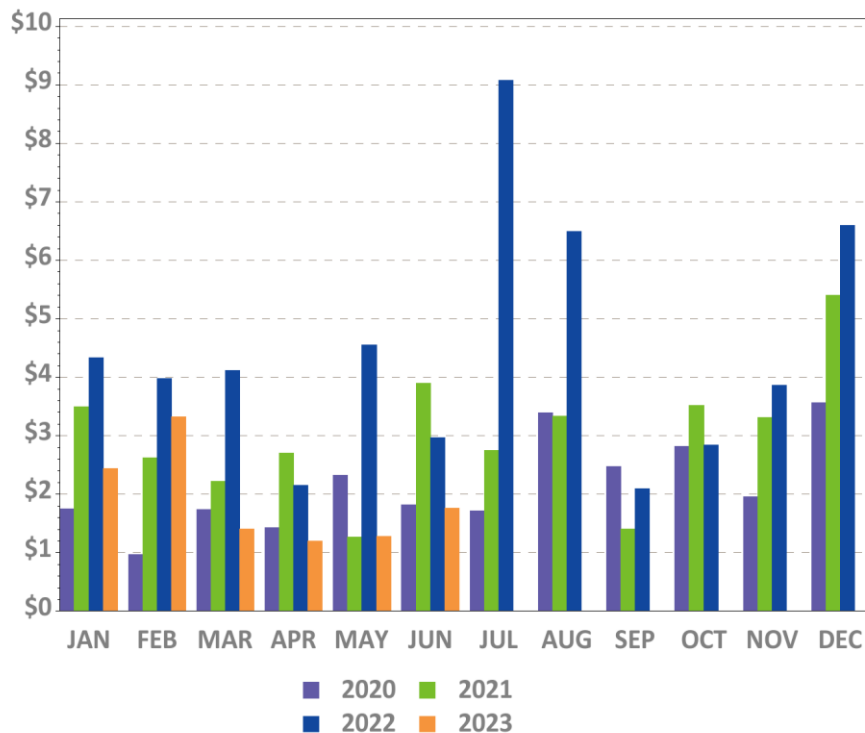
1 st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2 nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2 nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
OATT	Open Access Transmission Tariff

Charge Allocation Key

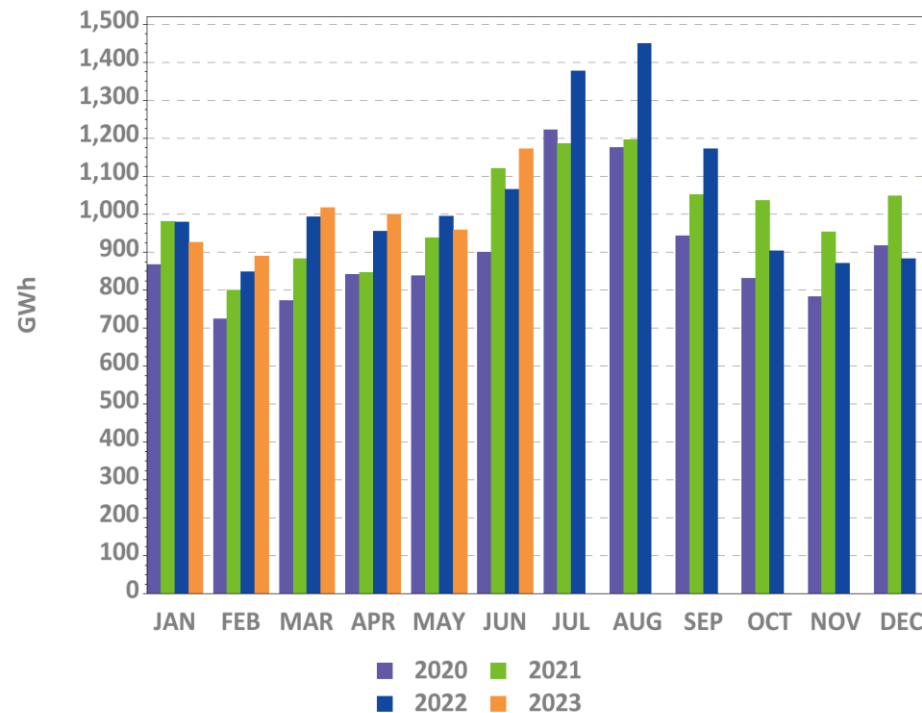
Allocation Category	Market / OATT	Allocation
System 1 st Contingency	Market	DA 1 st C (excluding at external nodes) is allocated to system DALO. RT 1 st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1 st Contingency	Market	DA 1 st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2 nd Contingency	Market	DA and RT 2 nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

Year-Over-Year Total NCPC Dollars and Energy

NCPC Dollars



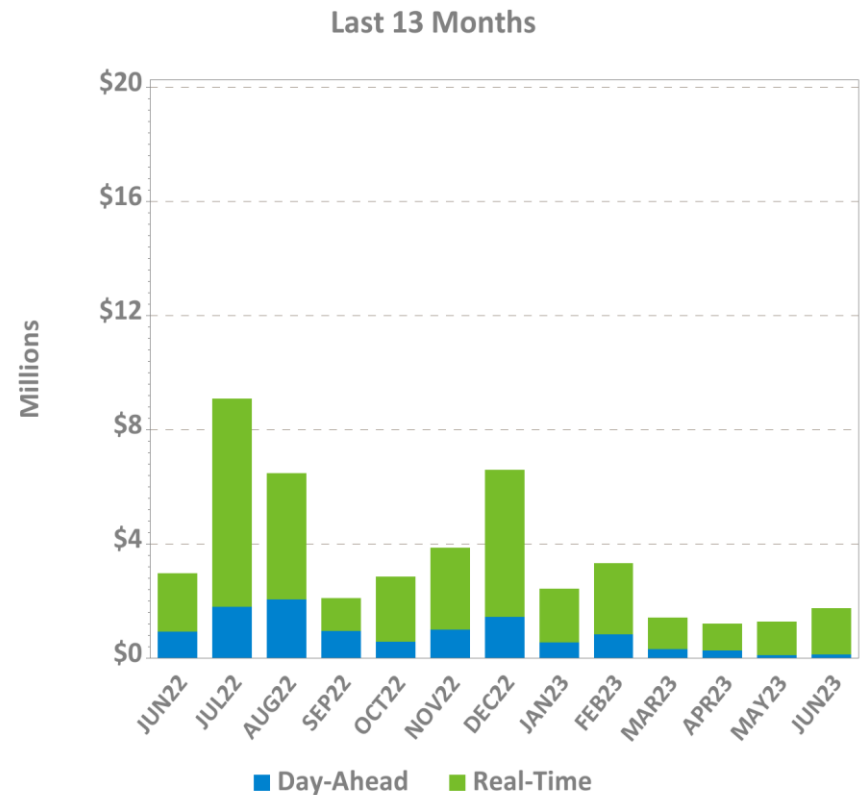
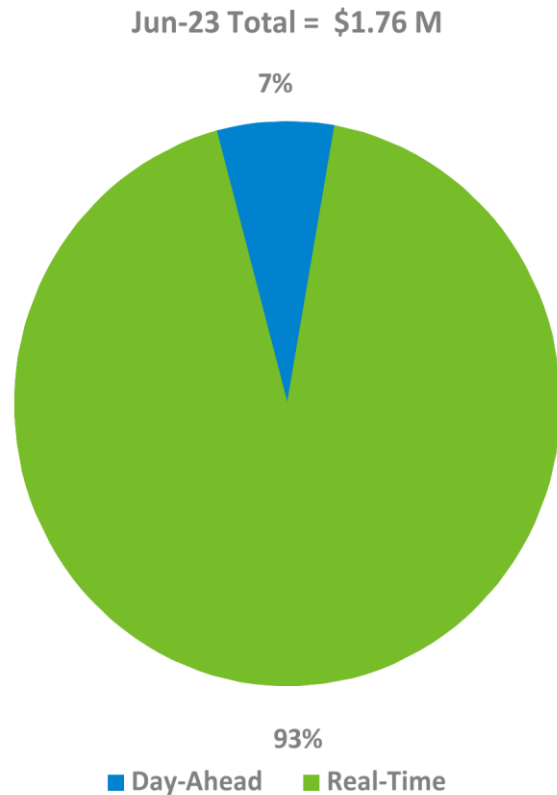
NCPC Energy*



* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

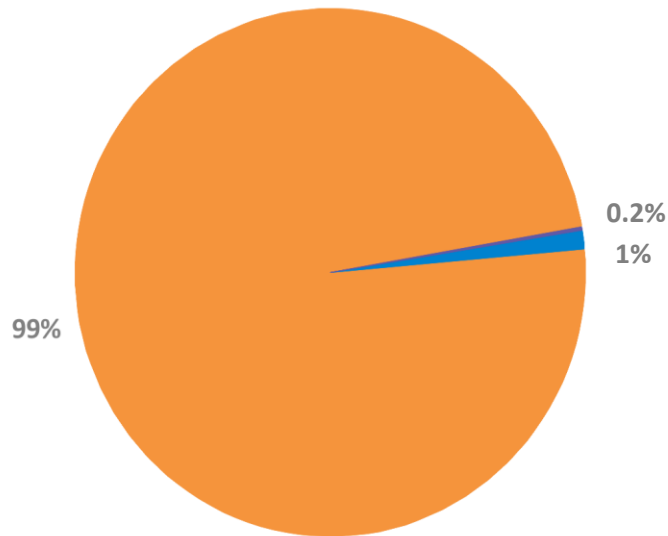


DA and RT NCPC Charges



NCPC Charges by Type

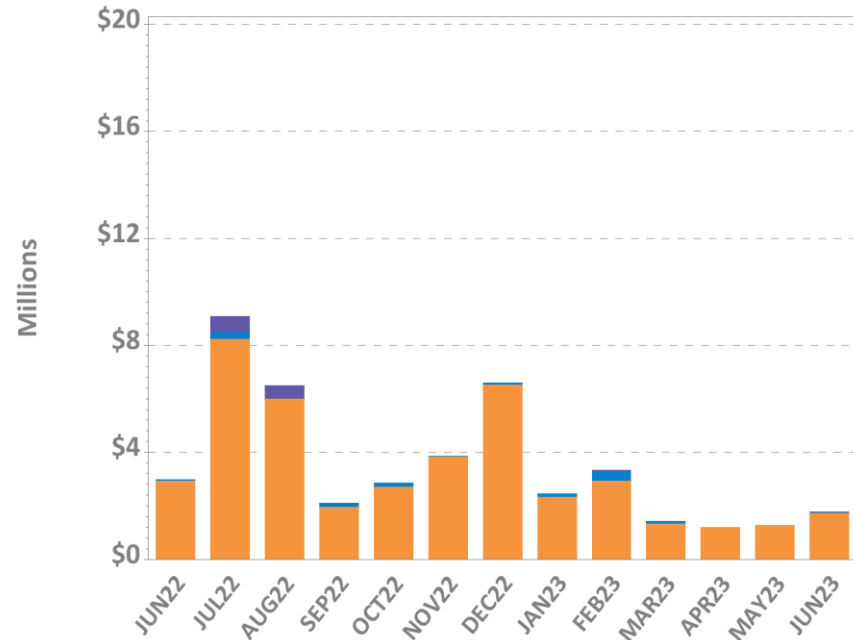
Jun-23 Total = \$1.76 M



1st C 2nd C
Distrib

1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

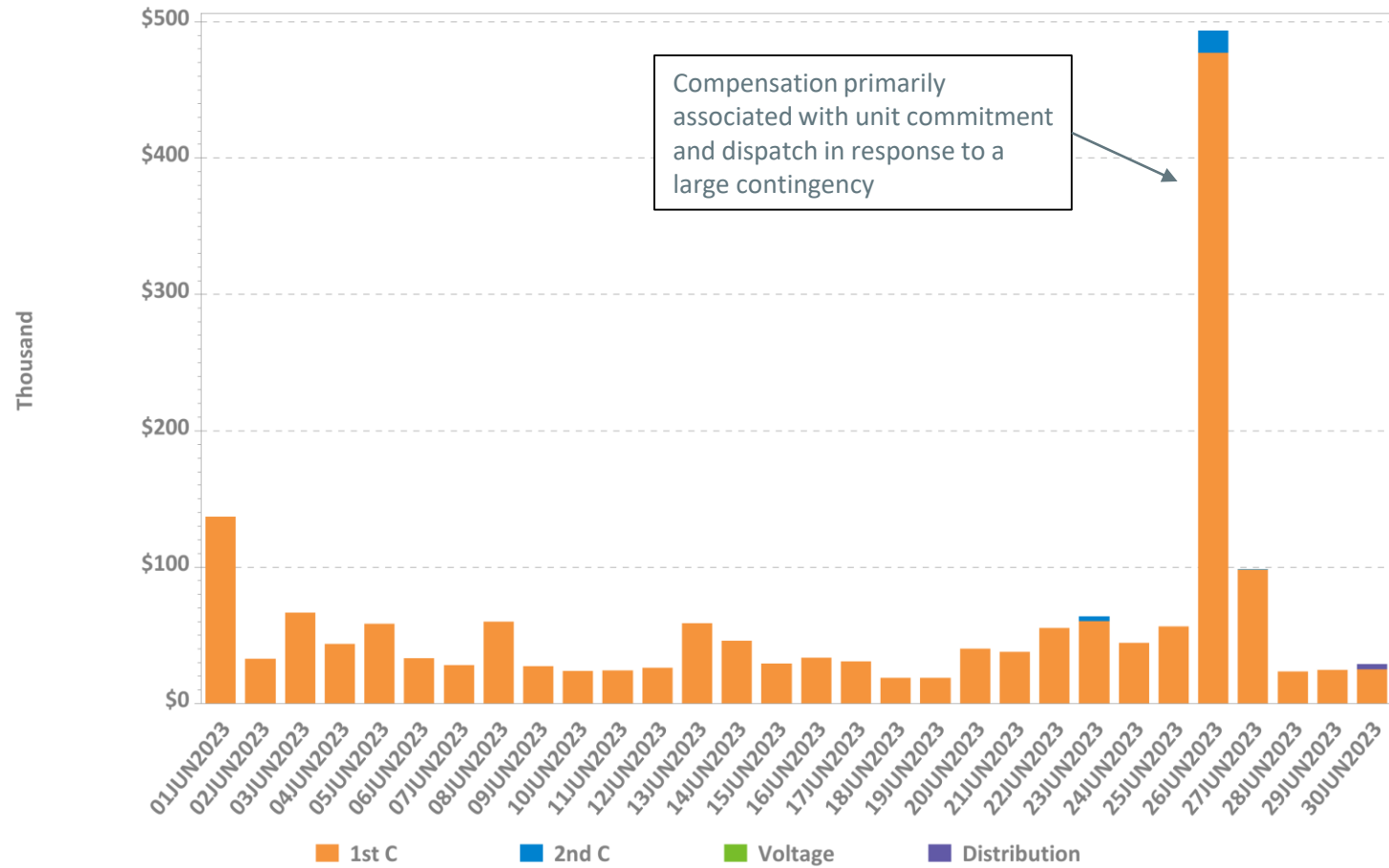
Last 13 Months



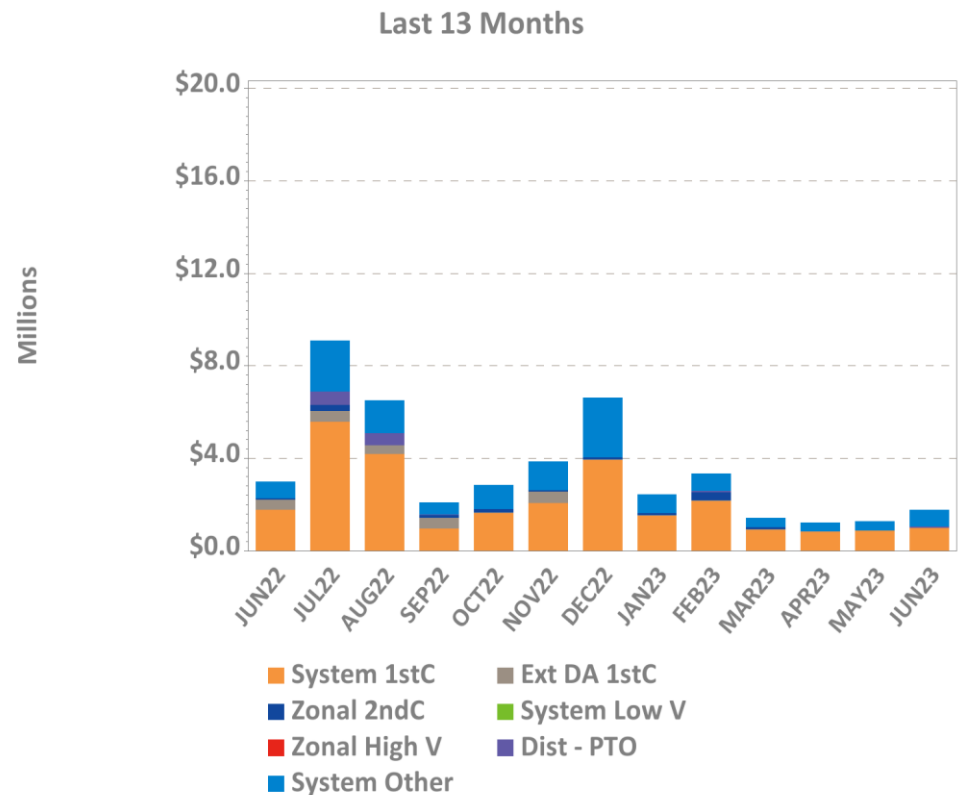
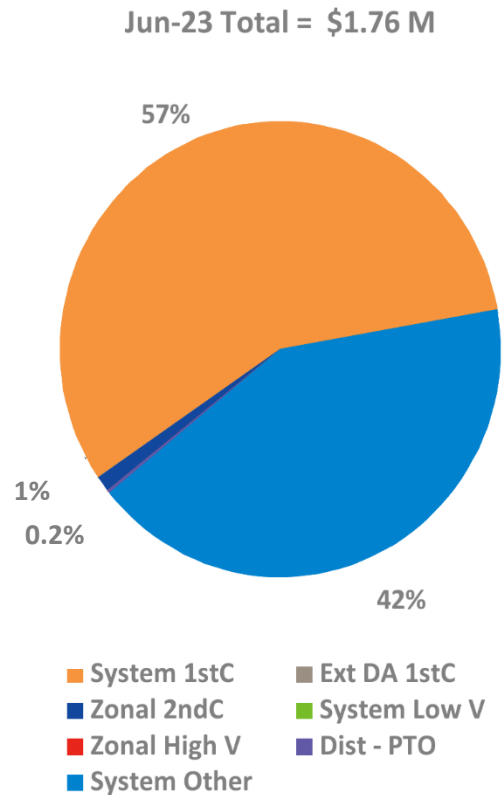
1st C 2nd C
Voltage Distrib



Daily NCPC Charges by Type

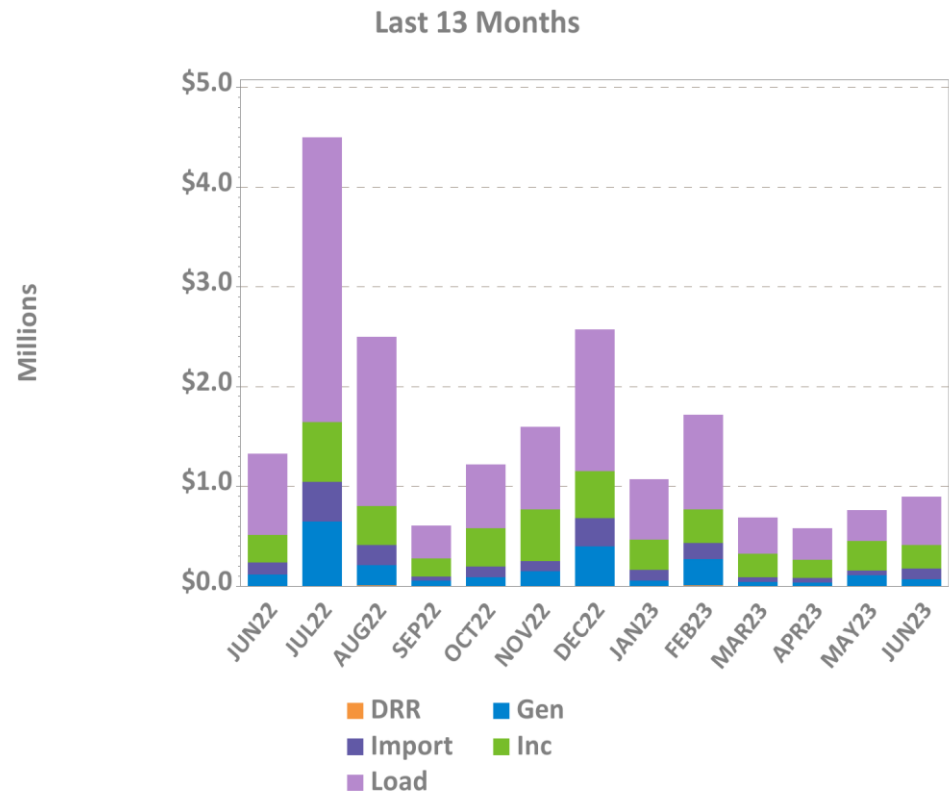
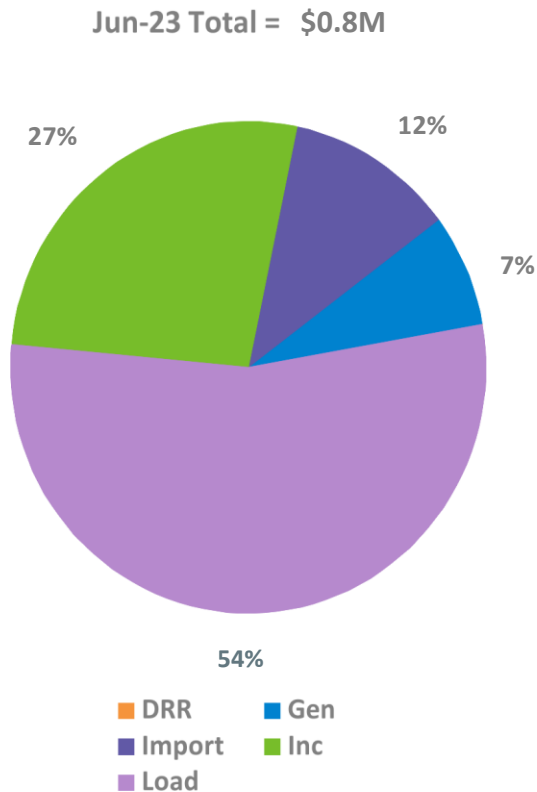


NCPC Charges by Allocation



Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

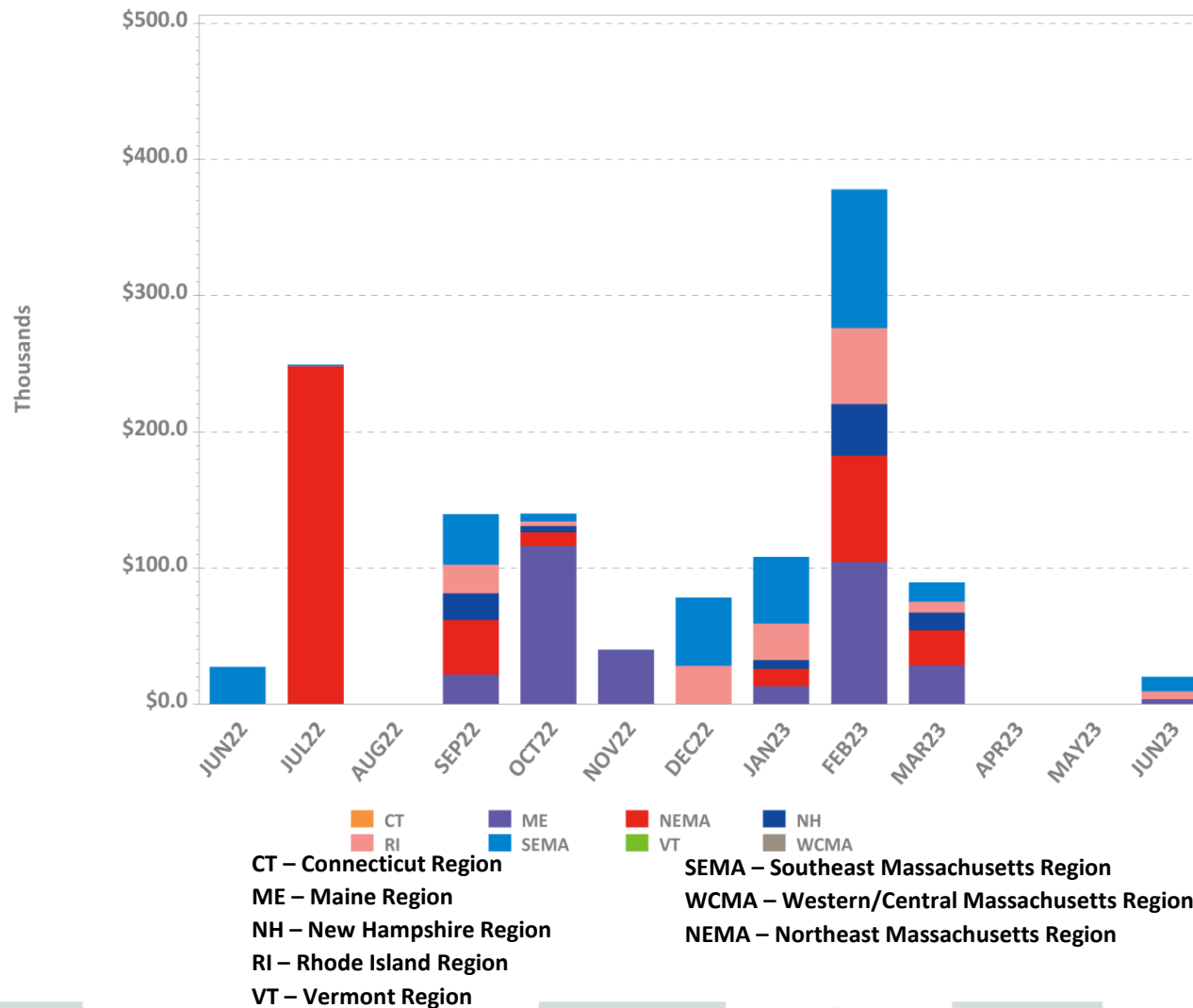
RT First Contingency Charges by Deviation Type



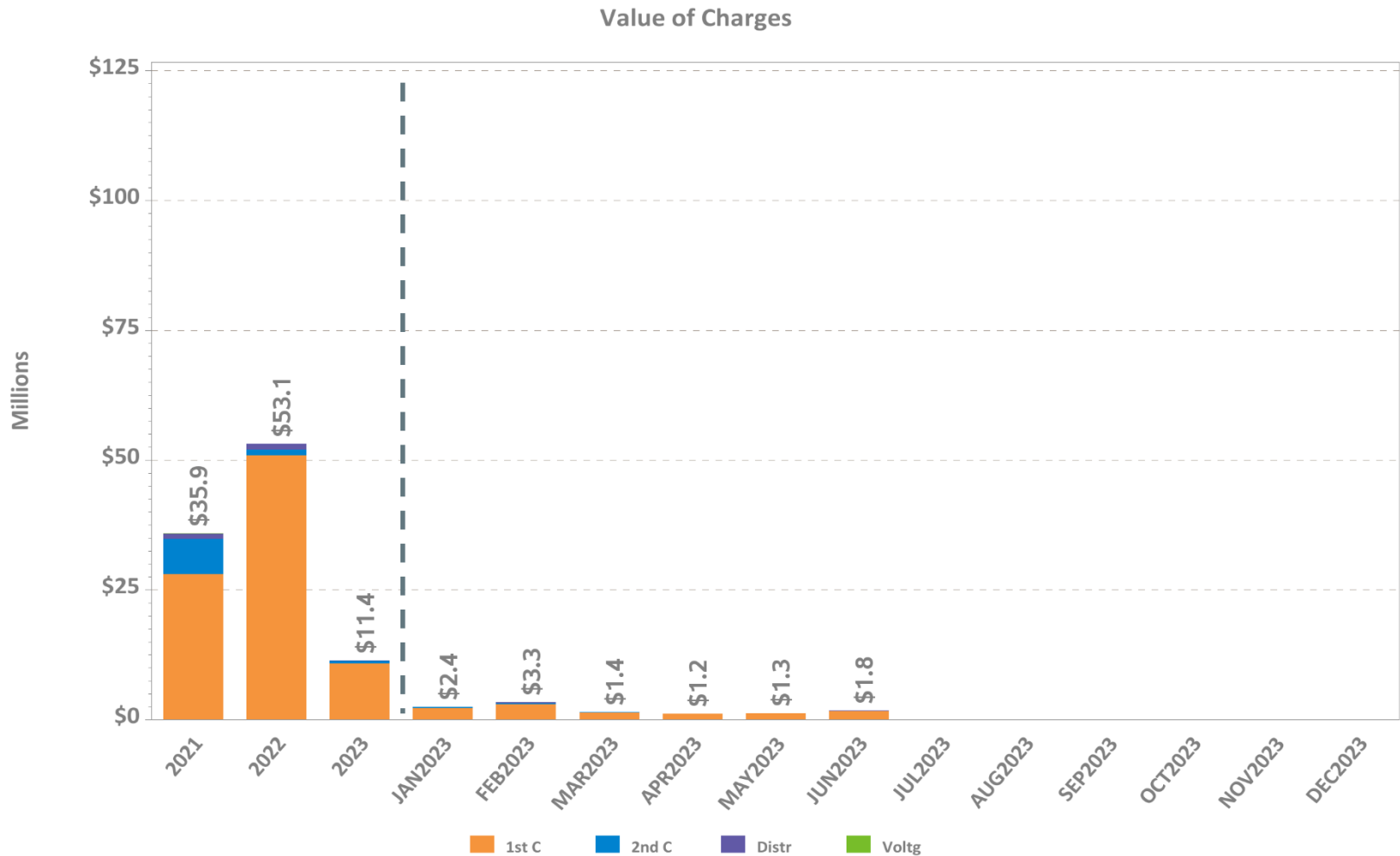
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations



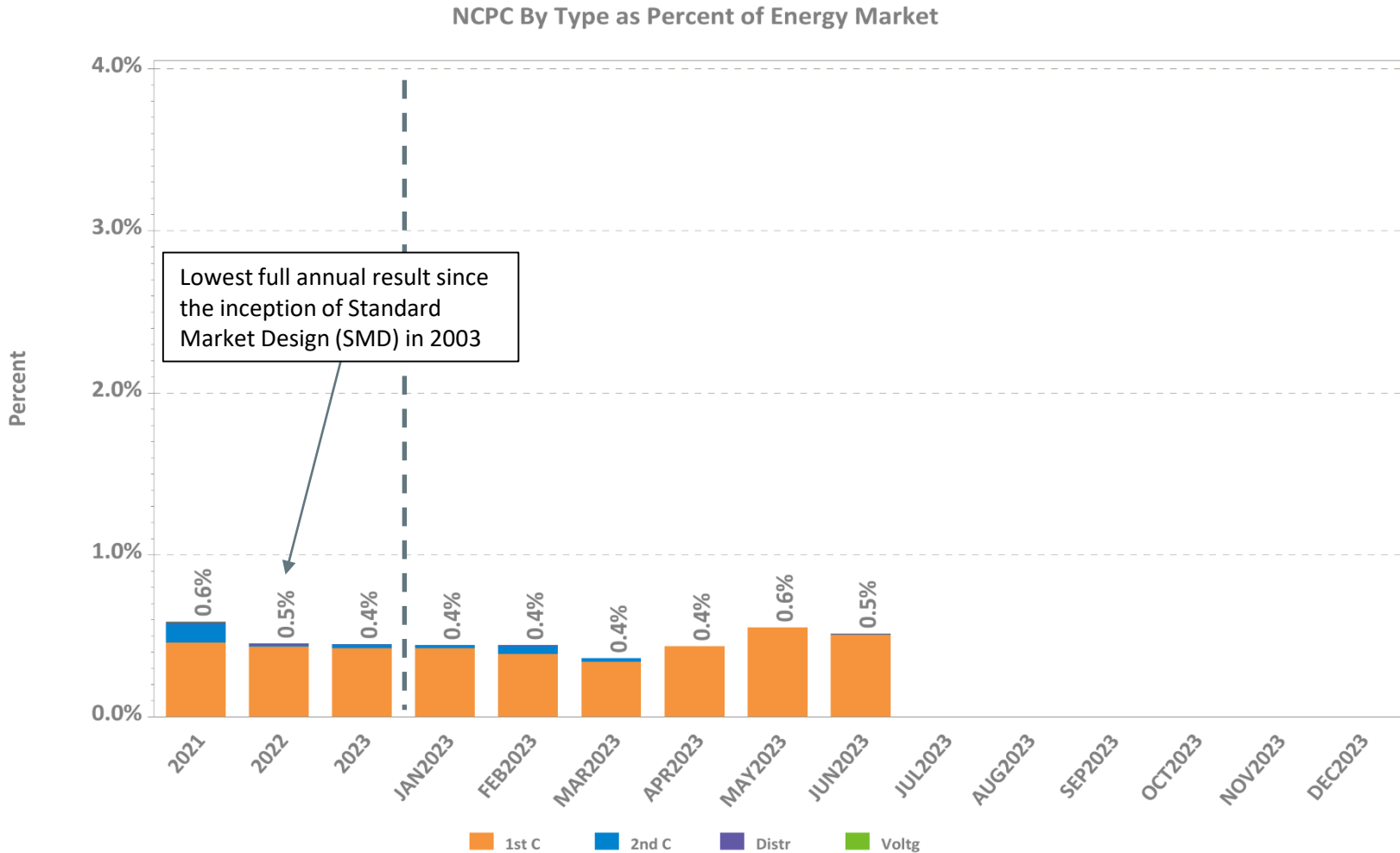
LSCPR Charges by Reliability Region



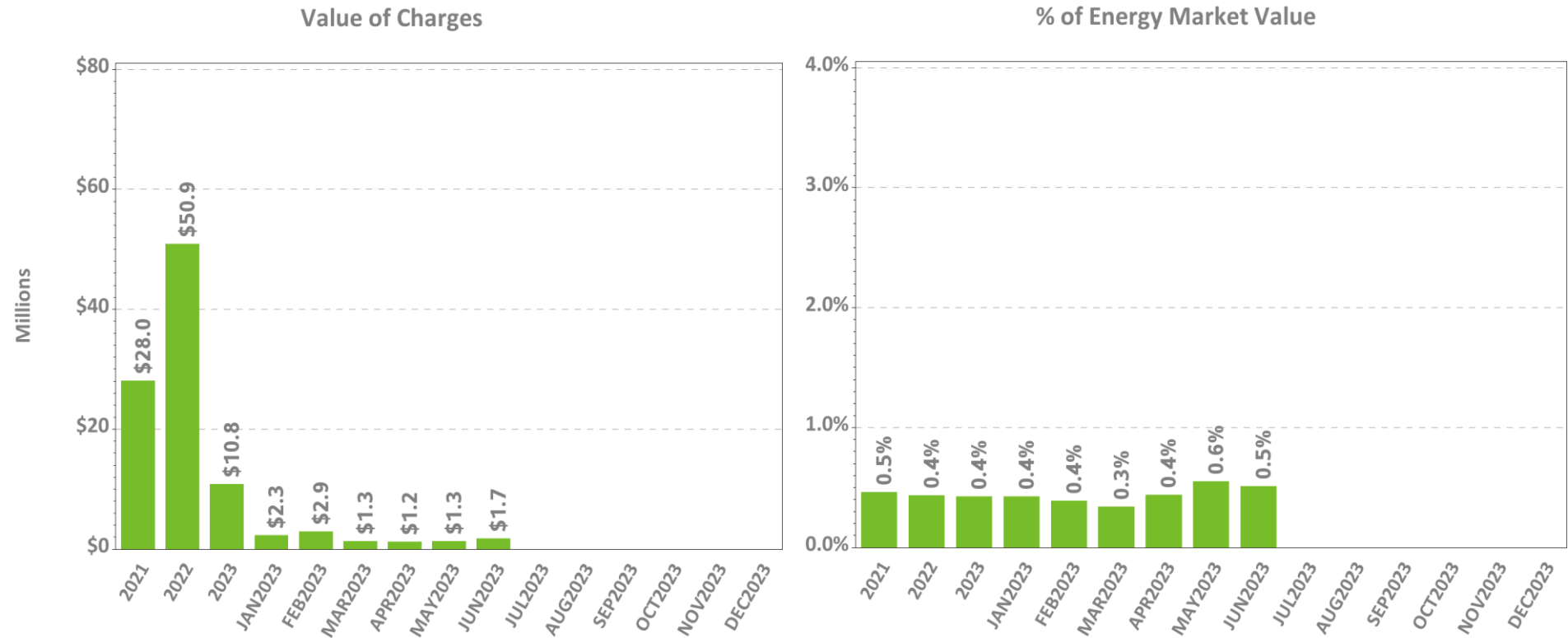
NCPC Charges by Type



NCPC Charges as Percent of Energy Market



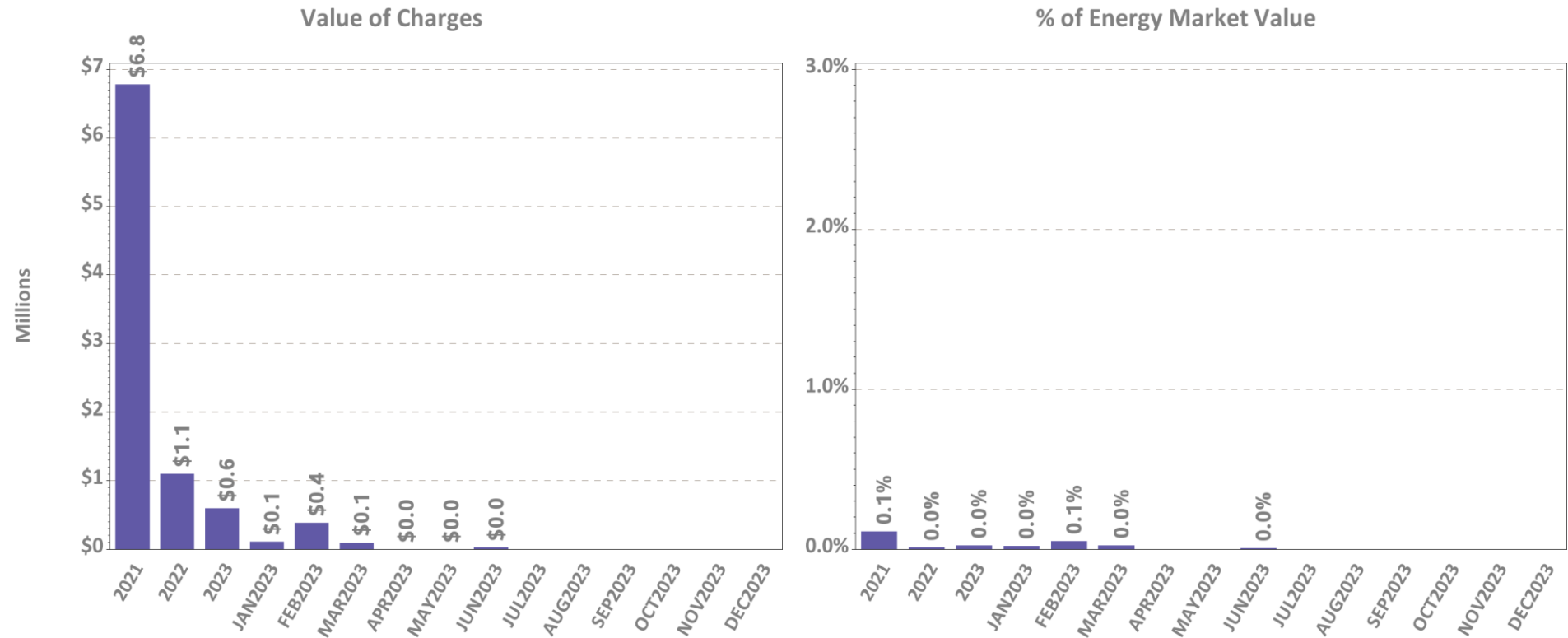
First Contingency NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market



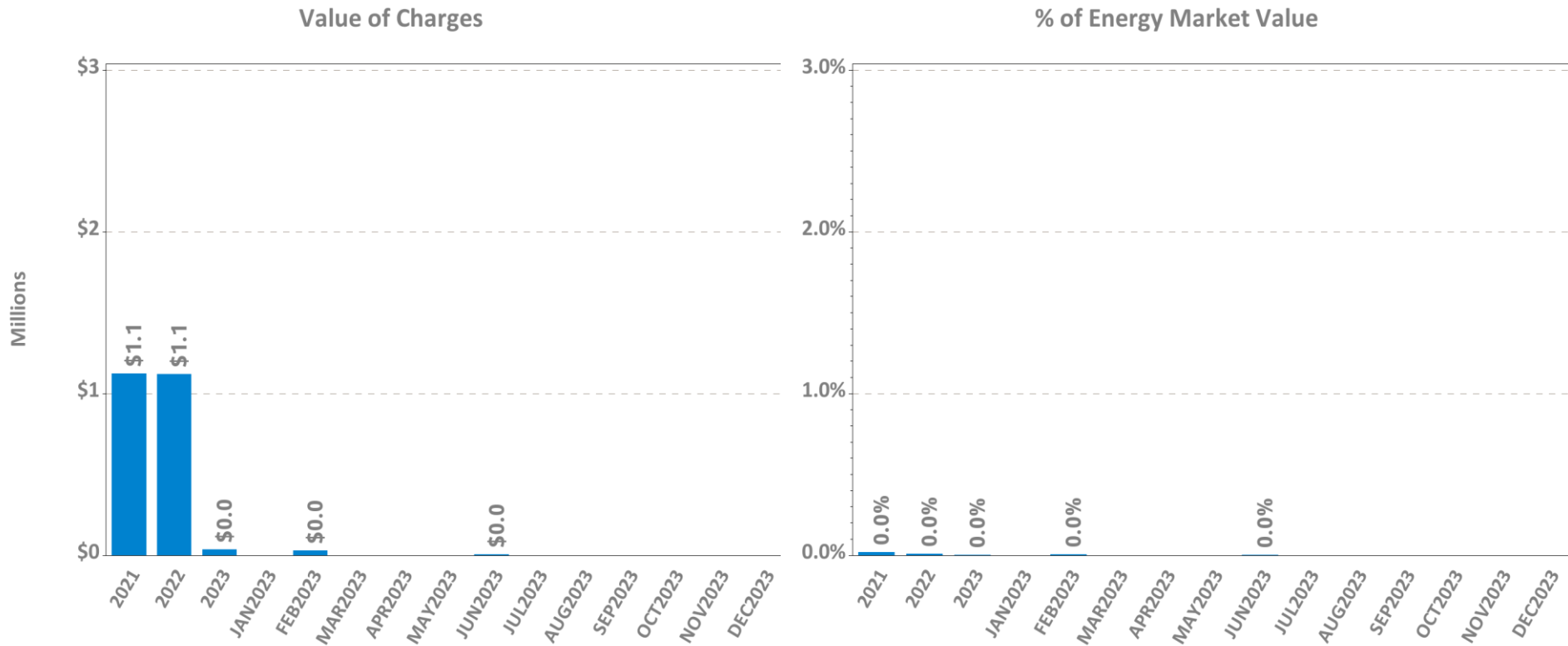
Second Contingency NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market



Voltage and Distribution NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market



DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange



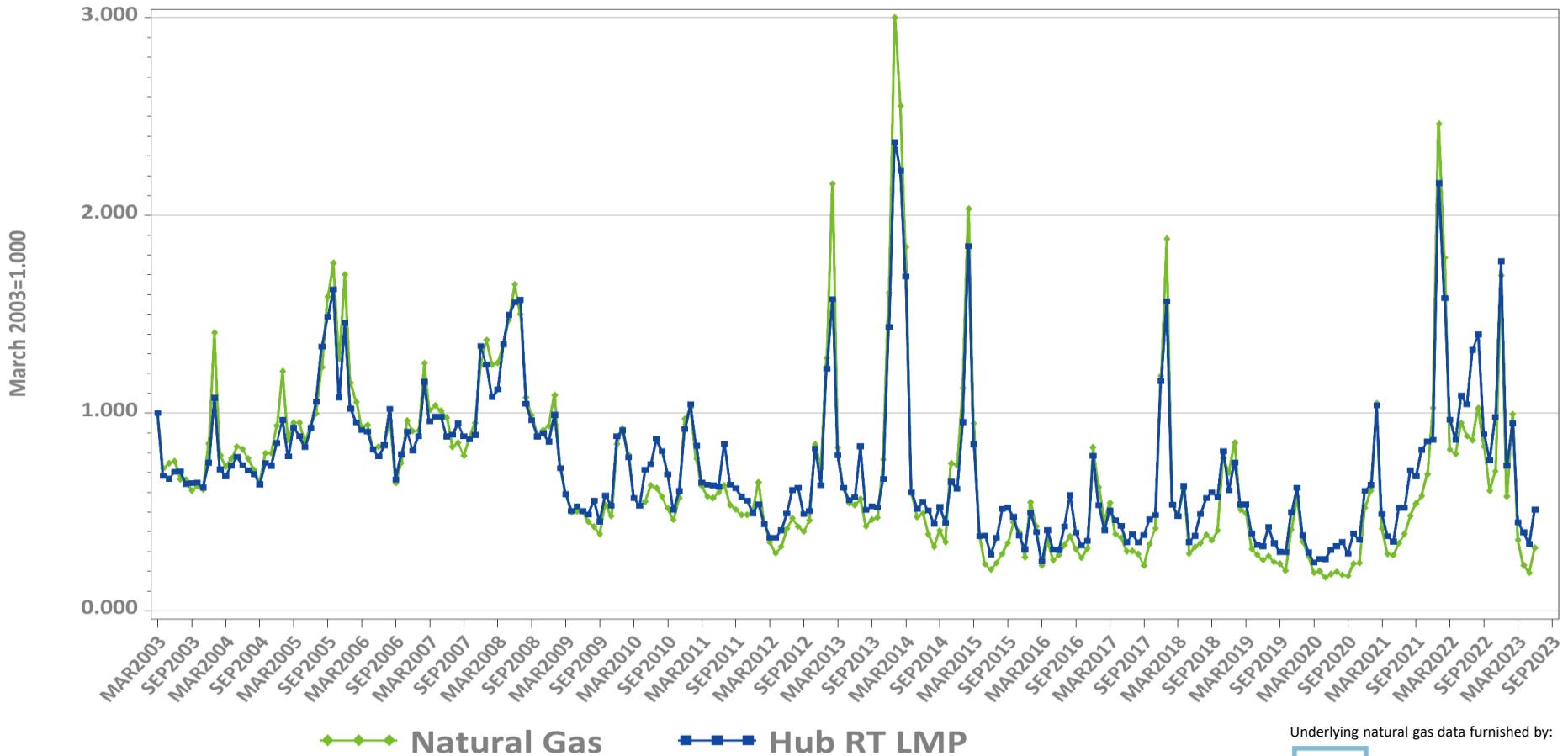
DA vs. RT LMPs (\$/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$46.54	\$44.60	\$45.52	\$46.27	\$45.05	\$45.88	\$46.38	\$45.91	\$45.92
Real-Time	\$45.25	\$43.97	\$44.28	\$45.10	\$44.15	\$44.61	\$45.09	\$44.85	\$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%
Year 2022	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$86.07	\$84.05	\$84.15	\$85.73	\$84.46	\$85.35	\$86.01	\$85.66	\$85.55
Real-Time	\$85.42	\$83.83	\$83.06	\$85.07	\$83.67	\$84.71	\$85.37	\$85.00	\$84.92
RT Delta %	-0.8%	-0.3%	-1.3%	-0.8%	-0.9%	-0.7%	-0.7%	-0.8%	-0.7%

June-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$69.15	\$67.48	\$68.32	\$69.08	\$67.80	\$68.11	\$68.71	\$68.58	\$68.43
Real-Time	\$72.50	\$71.03	\$71.49	\$72.31	\$70.82	\$71.43	\$72.04	\$71.86	\$71.71
RT Delta %	4.8%	5.3%	4.6%	4.7%	4.5%	4.9%	4.8%	4.8%	4.8%
June-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$33.71	\$33.01	\$32.64	\$33.53	\$33.31	\$33.21	\$33.70	\$33.56	\$33.52
Real-Time	\$35.42	\$34.74	\$33.69	\$35.07	\$34.70	\$34.90	\$35.40	\$35.17	\$35.16
RT Delta %	5.1%	5.2%	3.2%	4.6%	4.2%	5.1%	5.1%	4.8%	4.9%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-51.3%	-51.1%	-52.2%	-51.5%	-50.9%	-51.2%	-51.0%	-51.1%	-51.0%
Yr over Yr RT	-51.1%	-51.1%	-52.9%	-51.5%	-51.0%	-51.1%	-50.9%	-51.1%	-51.0%

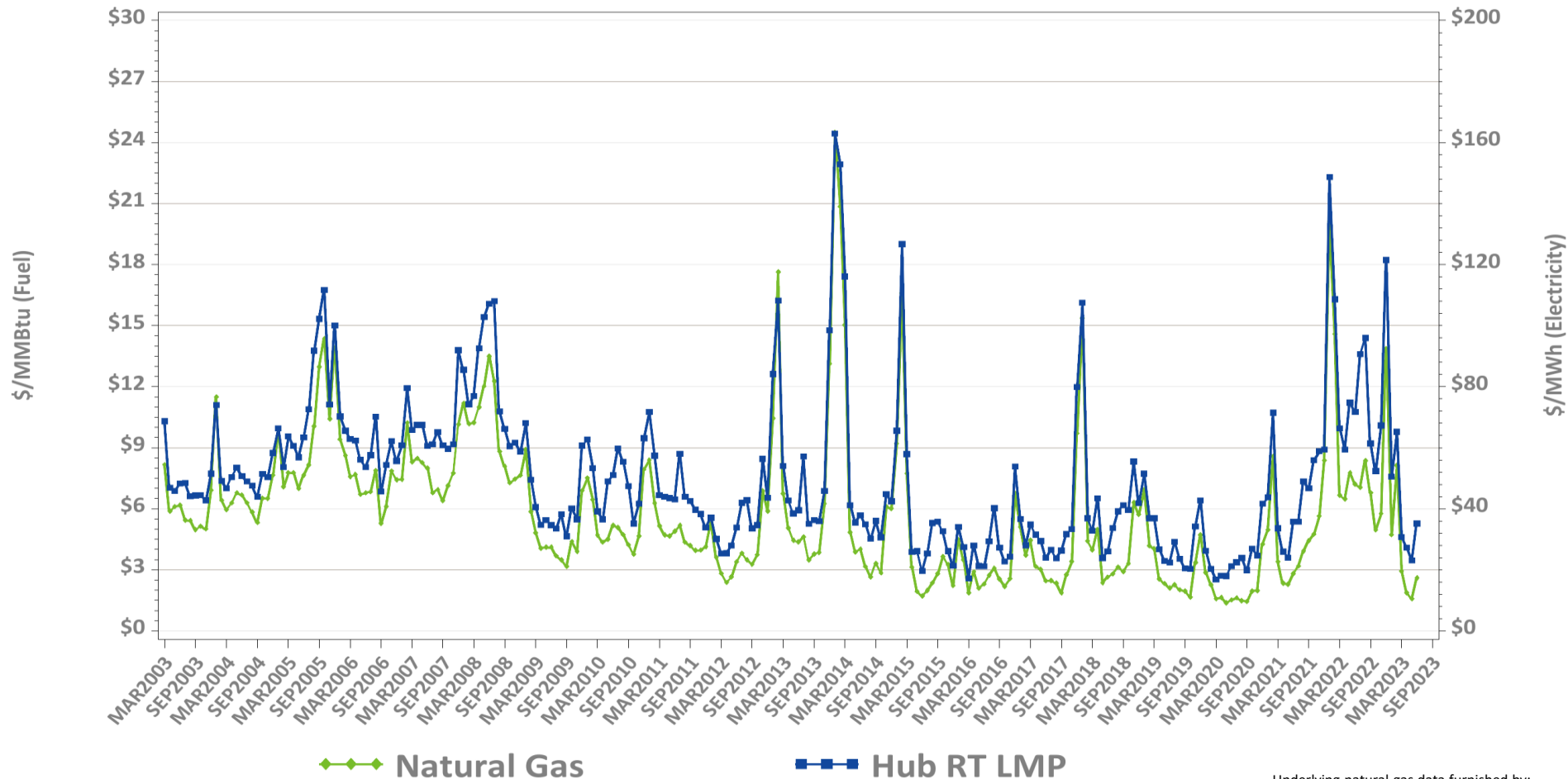
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



Monthly Average Fuel Price and RT Hub LMP

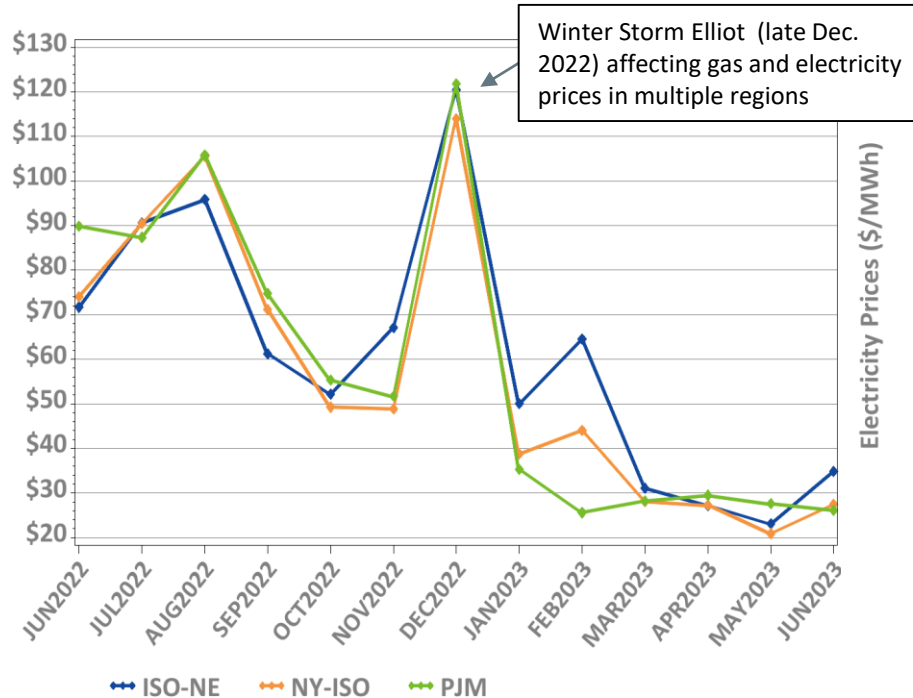


Underlying natural gas data furnished by:



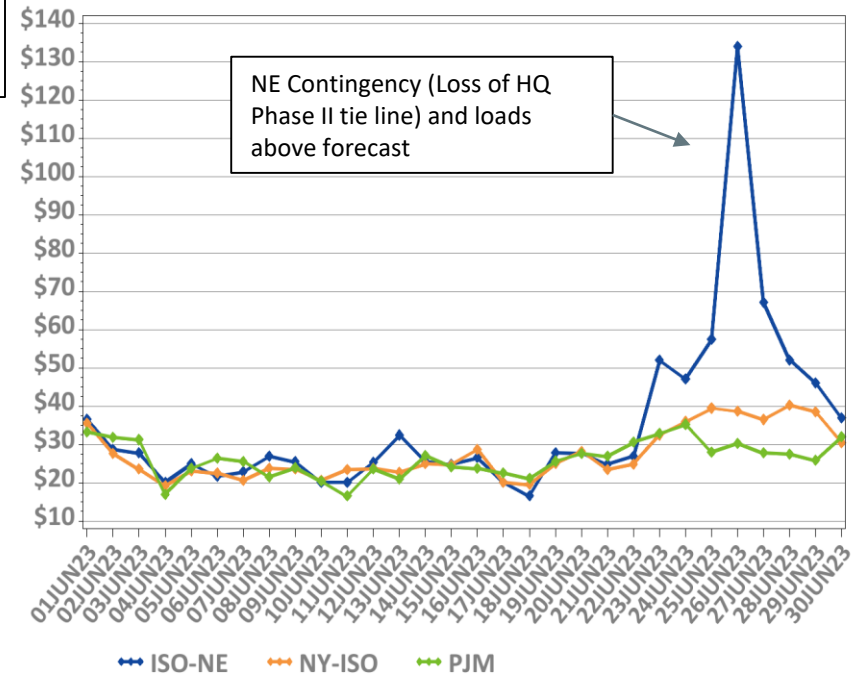
New England, NY, and PJM Hourly Average Real Time Prices by Month

Monthly, Last 13 Months



*Note: Hourly average prices are shown.

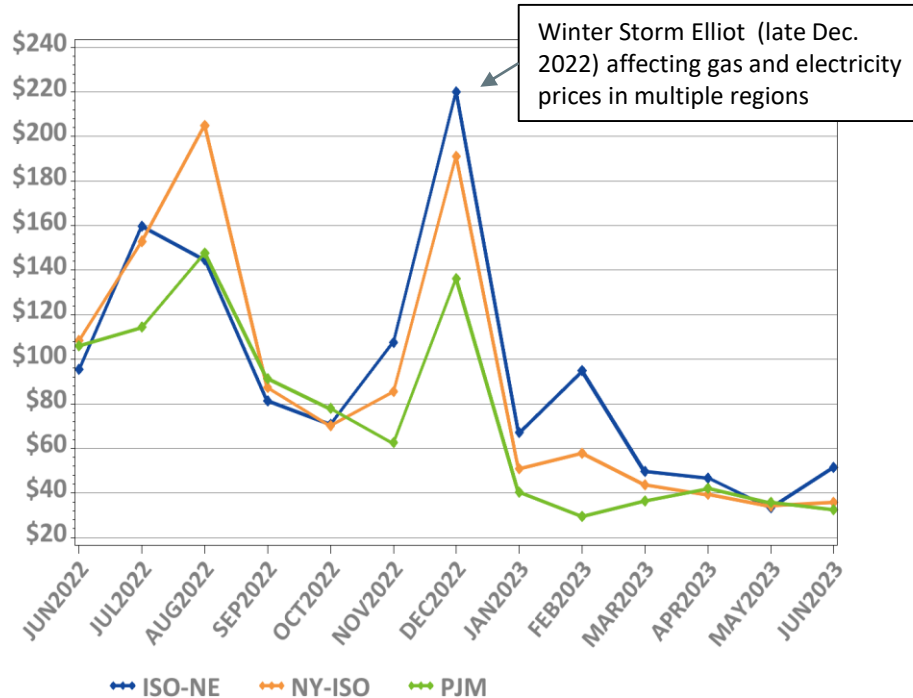
Daily: This Month



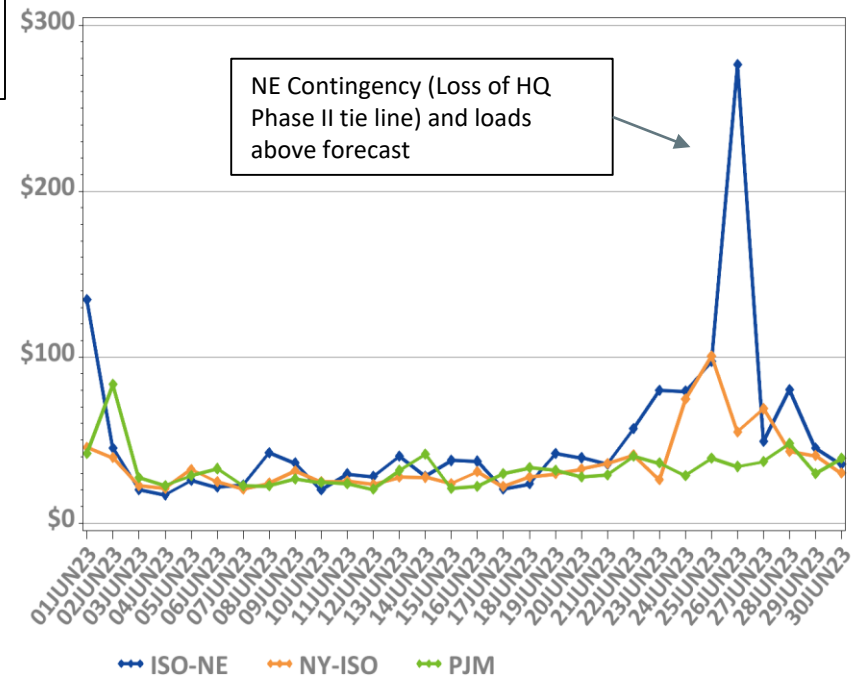
*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices

Monthly, Last 13 Months



Daily: This Month



*Forecasted New England daily peak hours reflected

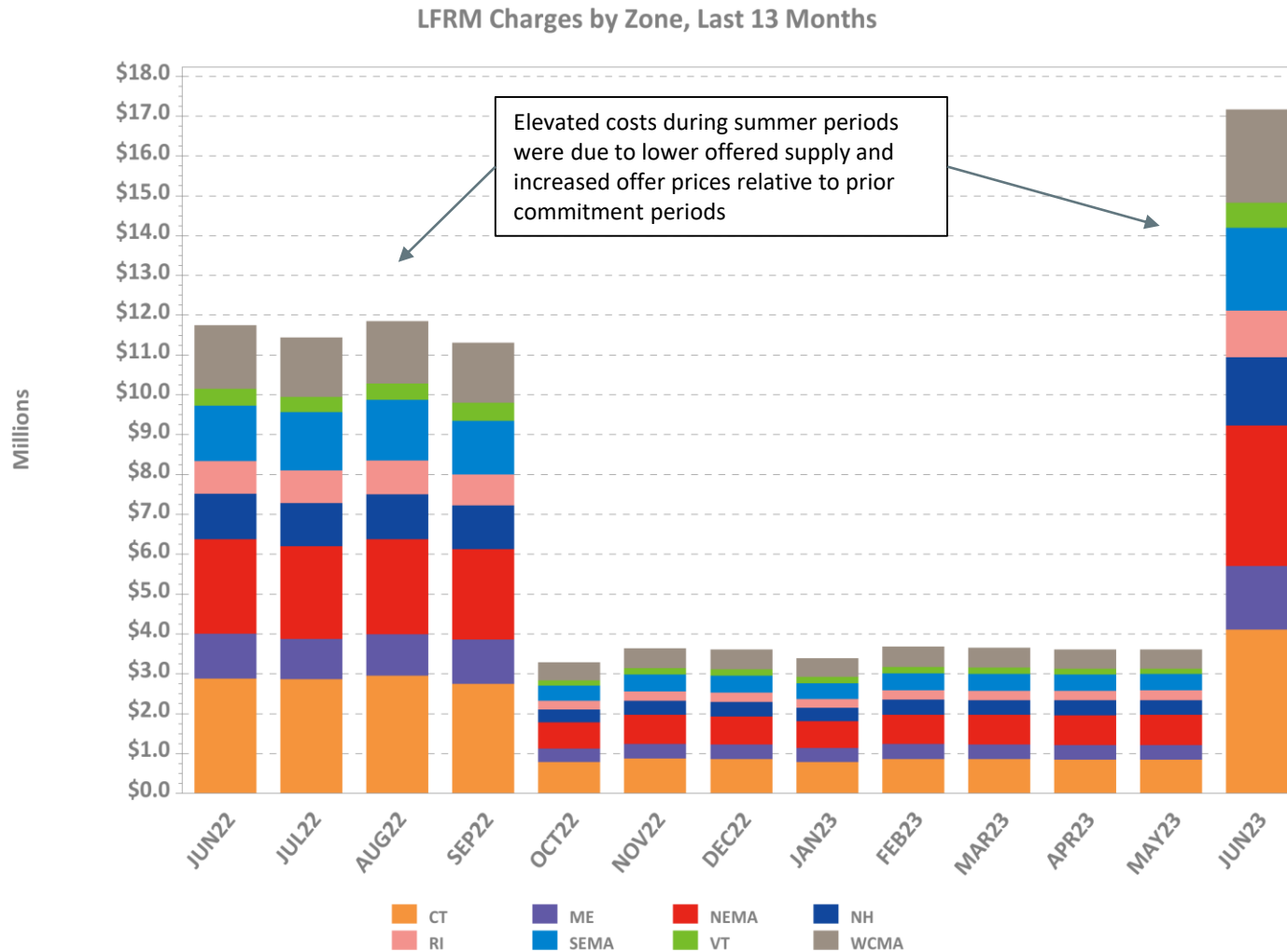
Reserve Market Results – June 2023

- Maximum potential Forward Reserve Market payments of \$18.9M were reduced by credit reductions of \$702K, failure-to-reserve penalties of \$1.05M and failure-to-activate penalties of \$1K, resulting in a net payout of \$17.2M or 91% of maximum
 - Rest of System: \$13.92M/15.51M (90%)
 - Southwest Connecticut: \$0.49M/0.49M (99%)
 - Connecticut: \$2.63M/2.79M (94%)
 - NEMA: \$0.1M/0.1M (100%)
- \$257K total Real-Time credits were reduced by \$51K in Forward Reserve Energy Obligation Charges for a net of \$206K in Real-Time Reserve payments
 - Rest of System: 180 hours, \$145K
 - Southwest Connecticut: 180 hours, \$32K
 - Connecticut: 180 hours, \$17K
 - NEMA: 180 hours, \$13K

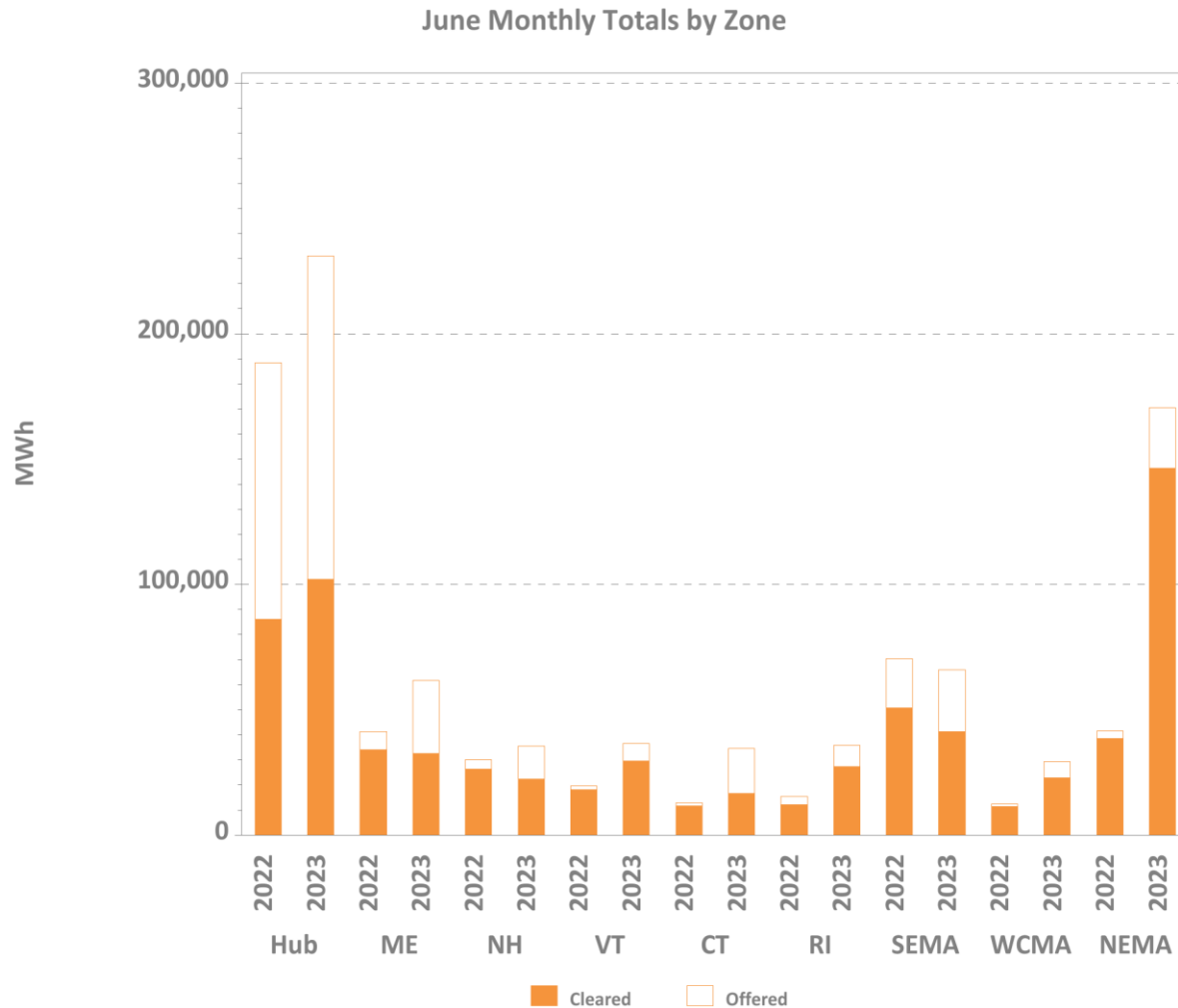
Note: “Failure to reserve” results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.



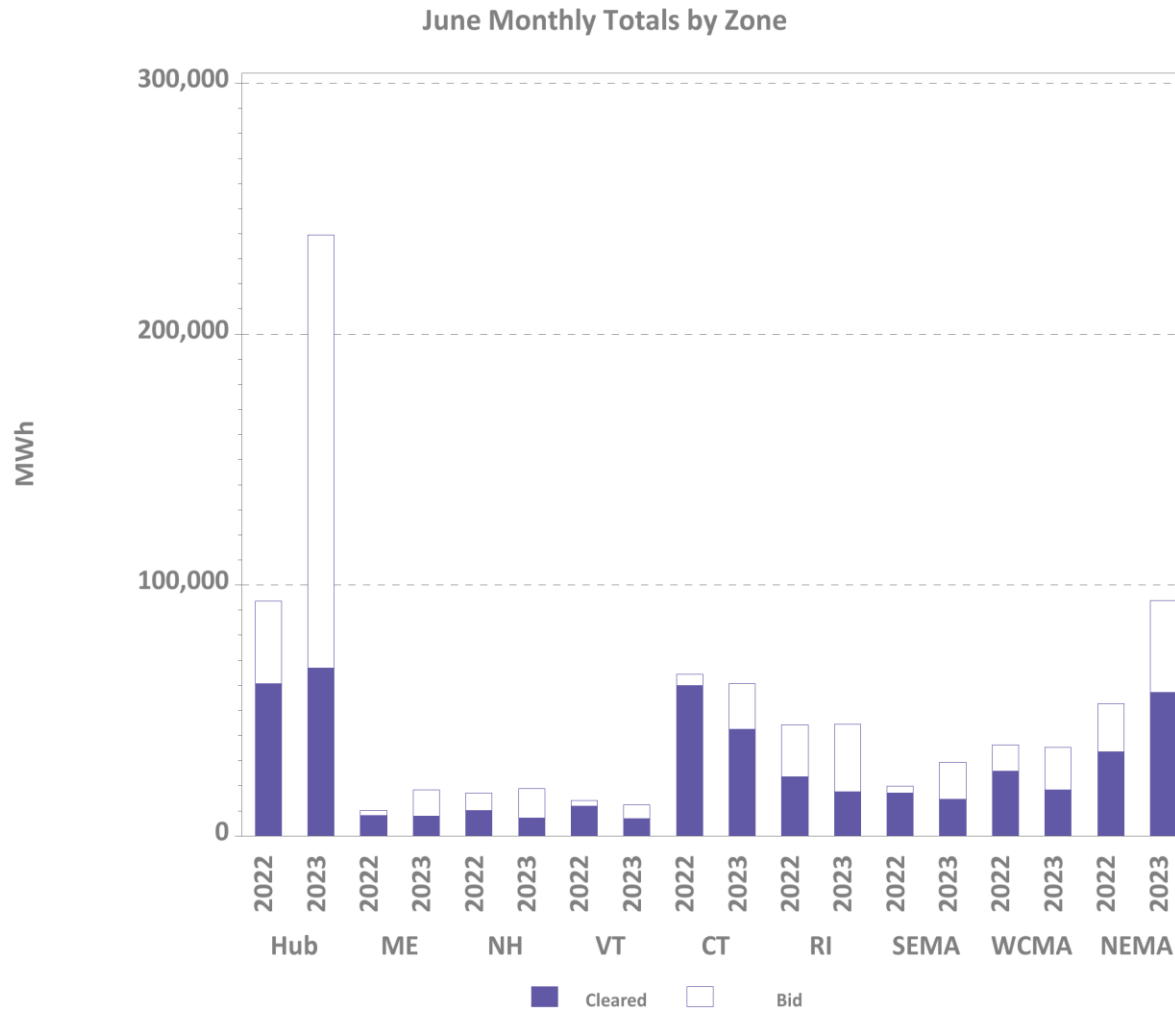
LFRM Charges to Load by Load Zone (\$)



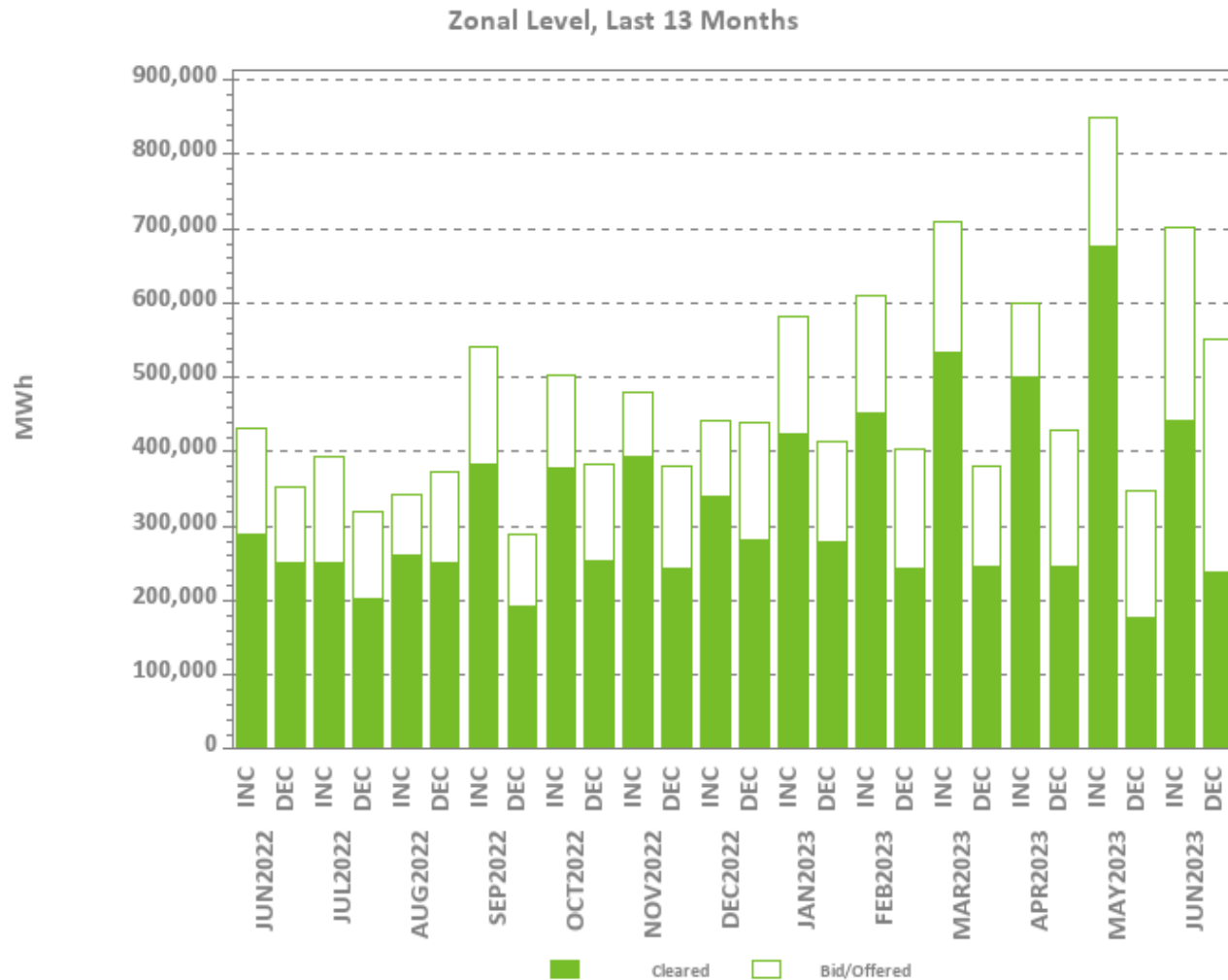
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

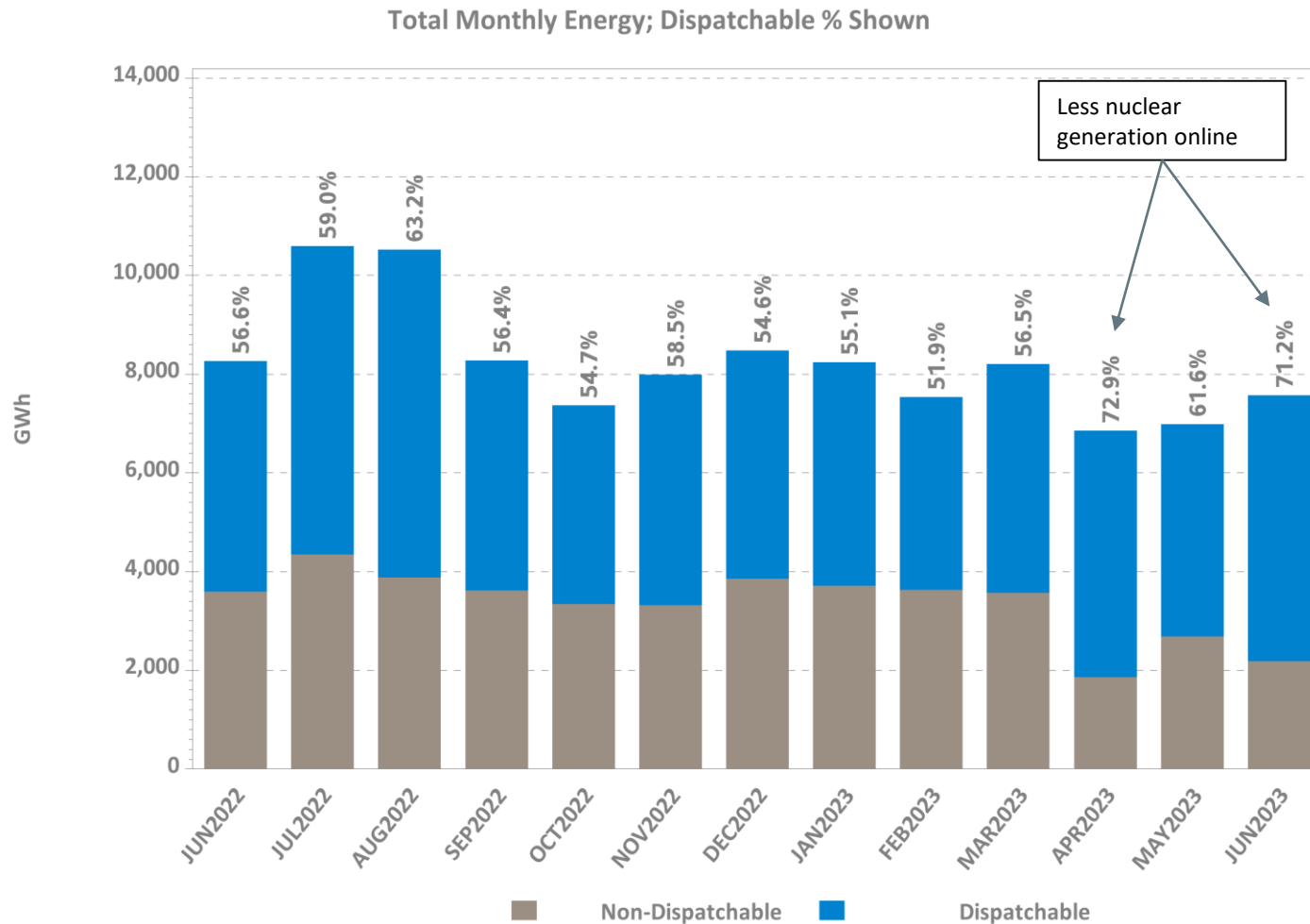


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



* Dispatchable MWh here are defined to be all generation output that is not self-committed ('must run') by the customer.



REGIONAL SYSTEM PLAN (RSP)



Regional System Plan (RSP)

- 2023 is an RSP publication year
- 2023-24 RSP will continue the streamlining efforts started with the 2021 RSP
- 2023-24 RSP will focus on being an overview narrative about ISO's system planning and the outlook for the New England grid
- 2023-24 RSP Public Meeting date is set for November 1 and will be held concurrently with the ISO Open Board Meeting
- The Executive Summary draft has been reviewed by the Board, and the full document is now being assembled



Planning Advisory Committee (PAC)

- July 25 PAC Meeting Agenda Topics*
 - Asset Condition Projects
 - Connecticut Structure Replacement & OPGW Installations (Eversource)
 - Derby Junction to Ansonia Corridor Transmission Rebuild Update (Avangrid)
 - Northboro Road Substation Breaker Replacements (National Grid)
 - V5/U6 & S8 ACR (National Grid)
 - 2050 Transmission Study: Transmission Development Roadmaps
 - Economic Planning for the Clean Energy Transition (EPCET) Fuel Constraints Model
 - Energy Storage in Transmission Planning Studies: Updated Assumptions
 - Requirements for Modeling Resources with Contracts in Needs Assessments

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

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Consultant to perform cost estimates has been selected – Electrical Consultants Inc. (ECI)
- ECI is working on developing cost estimates for potential transmission additions
- Development of transmission solutions will continue throughout the first half of 2023
- Additional discussion on solution development occurred at the 4/20/23 PAC meeting



Economic Studies

- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
 - New effort is to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
 - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, assumptions and results from the Benchmark and Market Efficiency Need scenarios, an overview of the capacity expansion model and how it will be used in the Policy scenario. The ISO presented the first round of Policy scenario assumptions in April 2023 and presented preliminary results in June 2023. More results will be presented in July and August.
 - FGRS Phase 2 is now the Stakeholder-Requested Scenario in EPCET



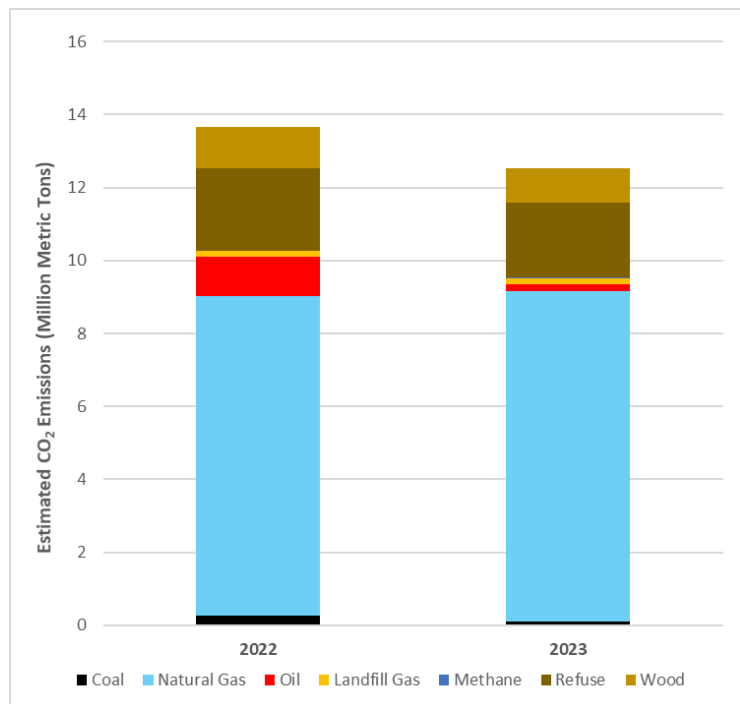
Future Grid Reliability Study (FGRS)

- Phase 1
 - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
 - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
 - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard
 - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability “gaps” that remain will be identified
 - High-level outline was presented at the April PAC



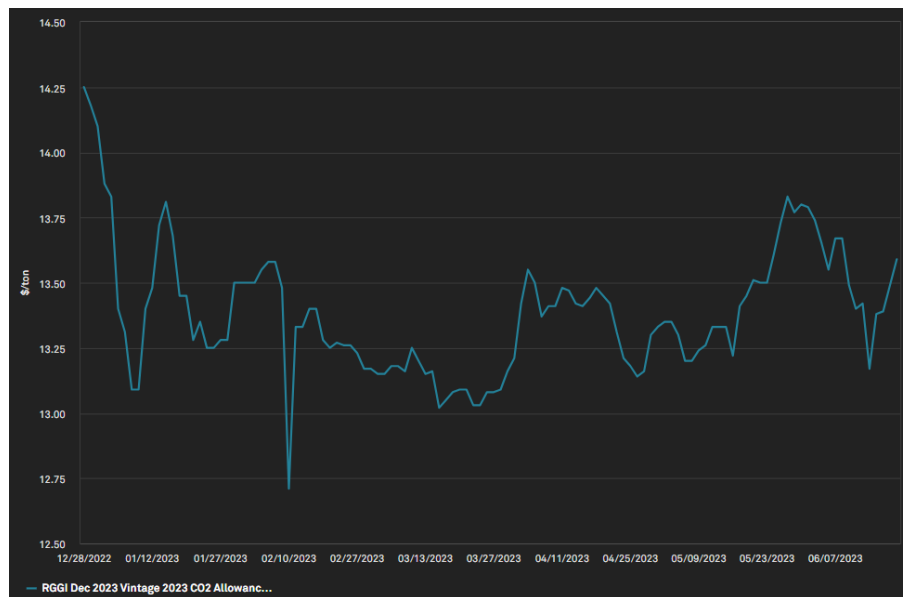
New England Power System Carbon Emissions

2022 vs. 2023 New England Power System Estimated Carbon Dioxide (CO₂) Emissions



Data as of 06/18/2023

RGGI Allowance Prices



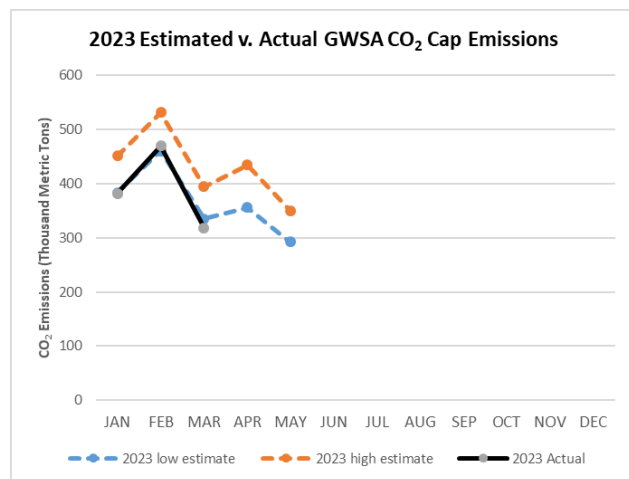
- 06/22/23: RGGI allowance spot price - \$13.59
- 06/07/23 60th RGGI auction cleared at \$12.73 per ton
 - 22,026,639 CO₂ allowances sold
 - 11,245,778 Cost Containment Reserve (CCR) allowances available
 - CCR trigger price is \$14.88 per ton in 2023; therefore, no CCR allowances were sold

RGGI – Regional Greenhouse Gas Initiative

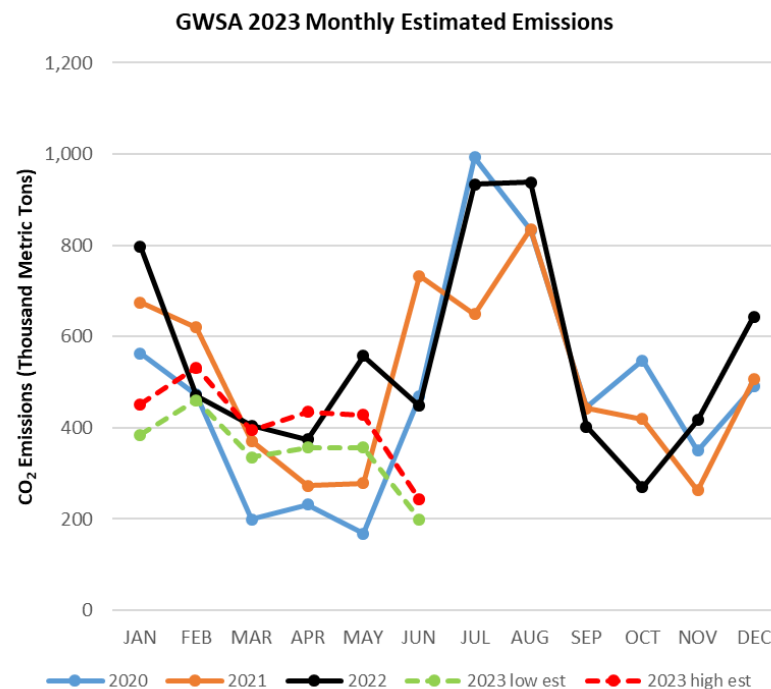
Massachusetts CO₂ Generator Emissions Cap

2023 Estimated Emissions Under CO₂ Cap

- As of 06/20/23, June 2023 estimated GWSA CO₂ emissions range between **198,815** and **243,229** metric tons
 - Year-to-date 2023 estimated emissions range between **27%** and **32%** of the 2023 cap of 7.84 MMT
- According to the [EPA CAMPD](#), the 1st Quarter GWSA CO₂ emissions were **1.17** MMT
 - 15%** of the 2023 cap of 7.84 MMT
 - The actual 1st Quarter emissions were 1% lower than the 2023 low estimate and 18% lower than the 2023 high estimate



2020-2023 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act

MMT – Million Metric Tons

Sources: ISO-NE (estimated emissions); EPA (actual emissions)

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

Note: The listings in this section focus on major transmission line construction and rebuilding.



Greater Boston Projects

Status as of 6/26/2023

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	Dec-23	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 6/26/2023

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Mar-25	3

Greater Boston Projects, cont.

Status as of 6/26/2023

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Mar-21	4

Greater Boston Projects, cont.

Status as of 6/26/2023

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-23	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4



Greater Boston Projects, cont.

Status as of 6/26/2023

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1520	Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
1643	Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
1341, 1645	Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
1646	Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
1647	Install a 115 kV breaker in series with the 5 breaker at Framingham	Mar-17	4
1554	Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	4
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	4
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Mar-26	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	3
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-23	3
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-23	3
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	1



SEMA/RI Reliability Projects, cont.

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-25	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal

** Cancelled per ISO-NE PAC presentation on August 27, 2020



SEMA/RI Reliability Projects, cont.

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	May 22	4
1724	Replace the Kent County 345/115 kV transformer	Mar-22	4
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4



Eastern CT Reliability Projects

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	3
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Dec-22	4
1851	Upgrade Card 115 kV to BPS standards	Dec-22	4
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Feb-23	4
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	4



Eastern CT Reliability Projects, cont.

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	3
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Feb-23	4
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Feb-23	4
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Sept-22	4
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Feb-23	4
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	Nov-21	4
1862	Install a +55/-29 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-23	3
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Mar-22	4
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington)	Feb-23	4
1904	Convert 69 kV equipment at Buddington to 115 kV to facilitate the conversion of the 400-2 line to 115 kV	Dec-23	3



Boston Area Optimized Solution Projects

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Dec-21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Apr-22	4
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Jun-23	4



New Hampshire Solution Projects

Status as of 6/26/2023

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Dec-23	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Dec-23	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Mar-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	3



Upper Maine Solution Projects

Status as of 6/26/2023

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line	Dec-24	3
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Jun-24	3



Upper Maine Solution Projects, cont.

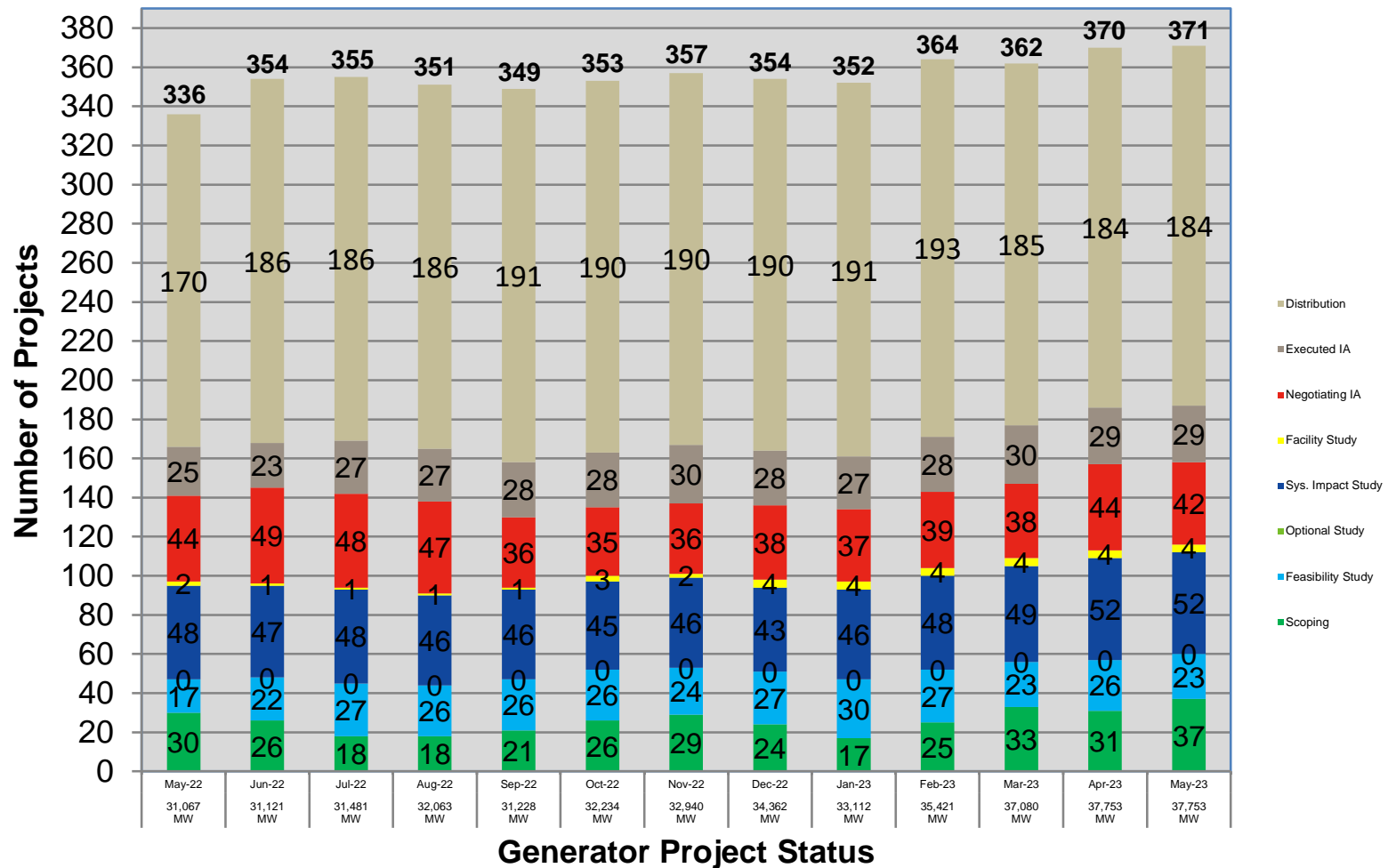
Status as of 6/26/2023

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	3
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	2
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	2



Status of Tariff Studies as of June 1, 2023



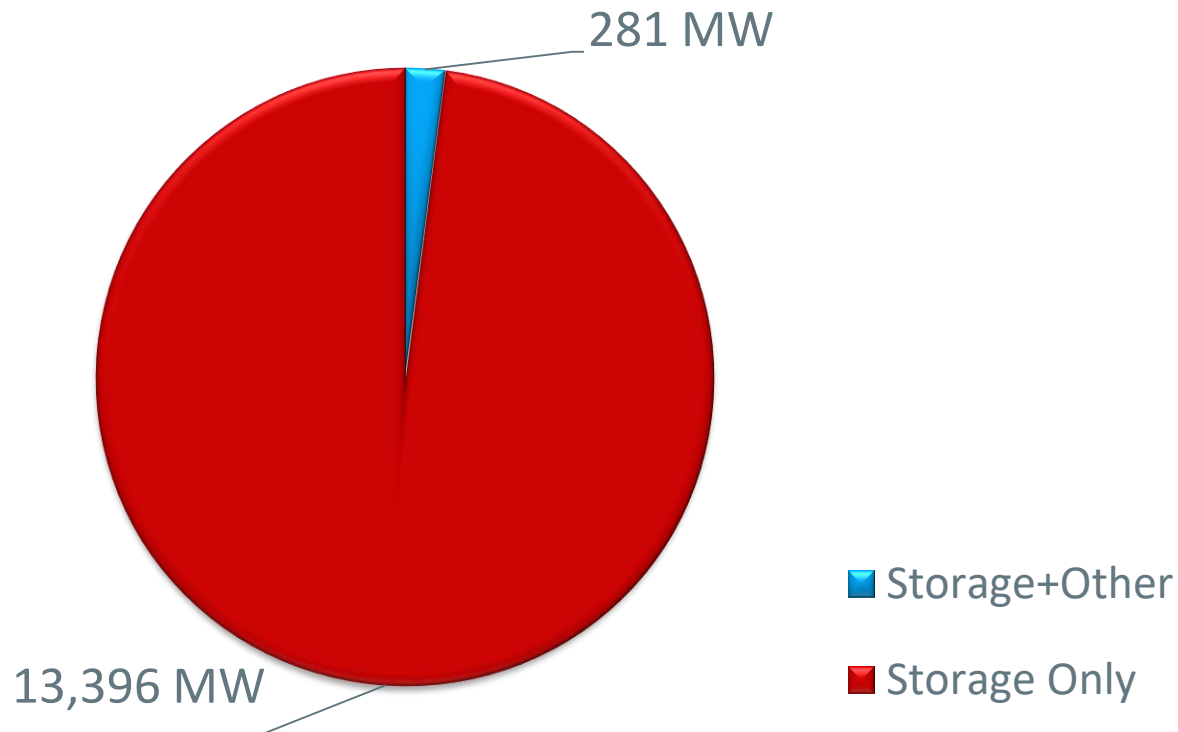
10 ETUs in Scoping, 7 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 2 Negotiating IA, and 3 with Executed IA

Transmission Service Requests needing study: 1 in Scoping and 3 in SIS

<https://irtt.iso-ne.com/external.aspx>

What is in the Queue (as of June 1, 2023)

Storage Projects are proposed as stand-alone storage or as co-located with wind or solar projects



OPERABLE CAPACITY ANALYSIS

Summer 2023

Highlights

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning September 9, 2023.



OPERABLE CAPACITY ANALYSIS

Summer 2023 Analysis



Summer 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September - 2023 ² CSO (MW)	September - 2023 ² SCC (MW)
Operable Capacity MW ¹	28,022	28,906
Active Demand Capacity Resource (+) ⁵	518	402
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	179	179
Non Gas-fired Planned Outage MW (-)	614	634
Gas Generator Outages MW (-)	261	394
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,702	27,317
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	24,605	24,605
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,910	26,910
Operable Capacity Margin	-208	407

¹Operable Capacity is based on data as of **June 27, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **June 27, 2023**.

² Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 9, 2023**.

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

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

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

Summer 2023 Operable Capacity Analysis

90/10 Load Forecast	September - 2023 ² CSO (MW)	September - 2023 ² SCC (MW)
Operable Capacity MW ¹	28,022	28,906
Active Demand Capacity Resource (+) ⁵	518	402
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	179	179
Non Gas-fired Planned Outage MW (-)	614	634
Gas Generator Outages MW (-)	261	394
Allowance for Unplanned Outages (-) ⁴	2,100	2,100
Generation at Risk Due to Gas Supply (-) ³	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,702	27,317
Peak Load Forecast MW(adjusted for Other Demand Resources) ²	26,421	26,421
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,726	28,726
Operable Capacity Margin	-2,024	-1,409

¹Operable Capacity is based on data as of **June 27, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **June 27, 2023**.

² Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 9, 2023**.

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

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

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

Summer 2023 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

June 27, 2023 - 50-50 FORECAST using CSO MW

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

Report created: 6/27/2023

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas- Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50- 50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50- 50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
7/15/2023	28014	405	1020	15	164	0	2100	0	27190	24605	2305	26910	280	N	Summer 2023
7/22/2023	28014	405	1020	15	173	0	2100	0	27181	24605	2305	26910	271	N	Summer 2023
7/29/2023	28022	518	958	179	490	0	2100	0	27087	24605	2305	26910	177	N	Summer 2023
8/5/2023	28022	518	958	179	485	0	2100	0	27092	24605	2305	26910	182	N	Summer 2023
8/12/2023	28022	518	958	179	477	0	2100	0	27100	24605	2305	26910	190	N	Summer 2023
8/19/2023	28022	518	958	179	363	0	2100	0	27214	24605	2305	26910	304	N	Summer 2023
8/26/2023	28022	518	958	179	365	0	2100	0	27212	24605	2305	26910	302	N	Summer 2023
9/2/2023	28022	518	958	179	446	0	2100	0	27131	24605	2305	26910	221	N	Summer 2023
9/9/2023	28022	518	958	179	614	261	2100	0	26702	24605	2305	26910	-208	Y	Summer 2023

Column Definitions

- CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
- External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
- Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
- CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
- CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
- Unplanned Outage Allowance MW:** Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
- CSO Generation at Risk Due to Gas Supply MW:** Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
- CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
- Peak Load Forecast MW:** Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
- Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
- CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
- CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- Operable Capacity Season Label:** Applicable season and year.
- Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Summer 2023 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

June 27, 2023 - 90/10 FORECAST using CSO MW

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

Report created: 6/27/2023

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas- Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90- 10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90- 10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
7/15/2023	28014	405	1020	15	164	0	2100	0	27190	26421	2305	28726	-1536	N	Summer 2023
7/22/2023	28014	405	1020	15	173	0	2100	0	27181	26421	2305	28726	-1545	N	Summer 2023
7/29/2023	28022	518	958	179	490	0	2100	0	27087	26421	2305	28726	-1639	N	Summer 2023
8/5/2023	28022	518	958	179	485	0	2100	0	27092	26421	2305	28726	-1634	N	Summer 2023
8/12/2023	28022	518	958	179	477	0	2100	0	27100	26421	2305	28726	-1626	N	Summer 2023
8/19/2023	28022	518	958	179	363	0	2100	0	27214	26421	2305	28726	-1512	N	Summer 2023
8/26/2023	28022	518	958	179	365	0	2100	0	27212	26421	2305	28726	-1514	N	Summer 2023
9/2/2023	28022	518	958	179	446	0	2100	0	27131	26421	2305	28726	-1595	N	Summer 2023
9/9/2023	28022	518	958	179	614	261	2100	0	26702	26421	2305	28726	-2024	Y	Summer 2023

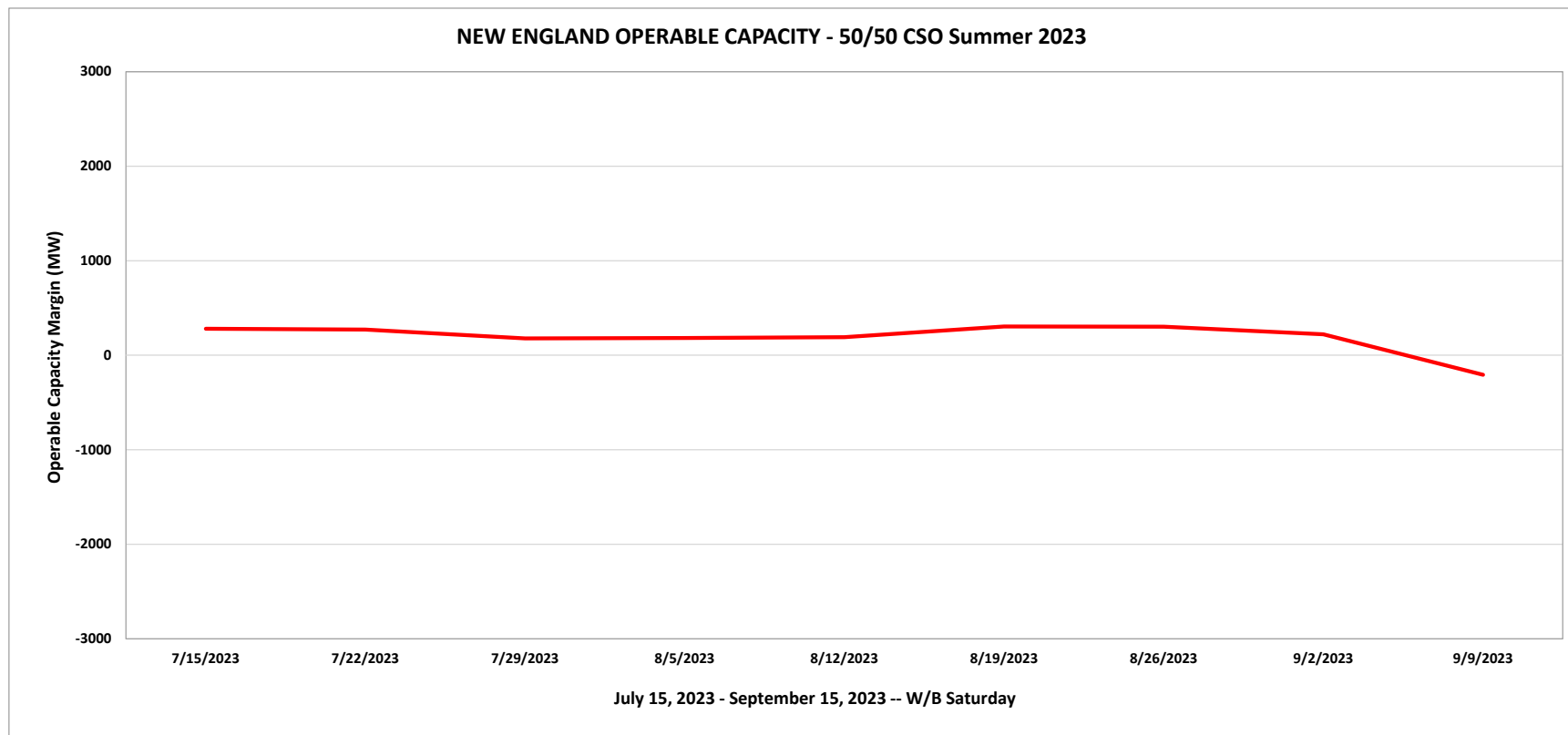
Column Definitions

- 1. CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
- 2. CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
- 3. External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
- 4. Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
- 5. CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
- 6. CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
- 7. Unplanned Outage Allowance MW:** Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
- 8. CSO Generation at Risk Due to Gas Supply Mw:** Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
- 9. CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
- 10. Peak Load Forecast MW:** Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
- 11. Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
- 12. CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
- 13. CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
- 14. Operable Capacity Season Label:** Applicable season and year.
- 15. Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

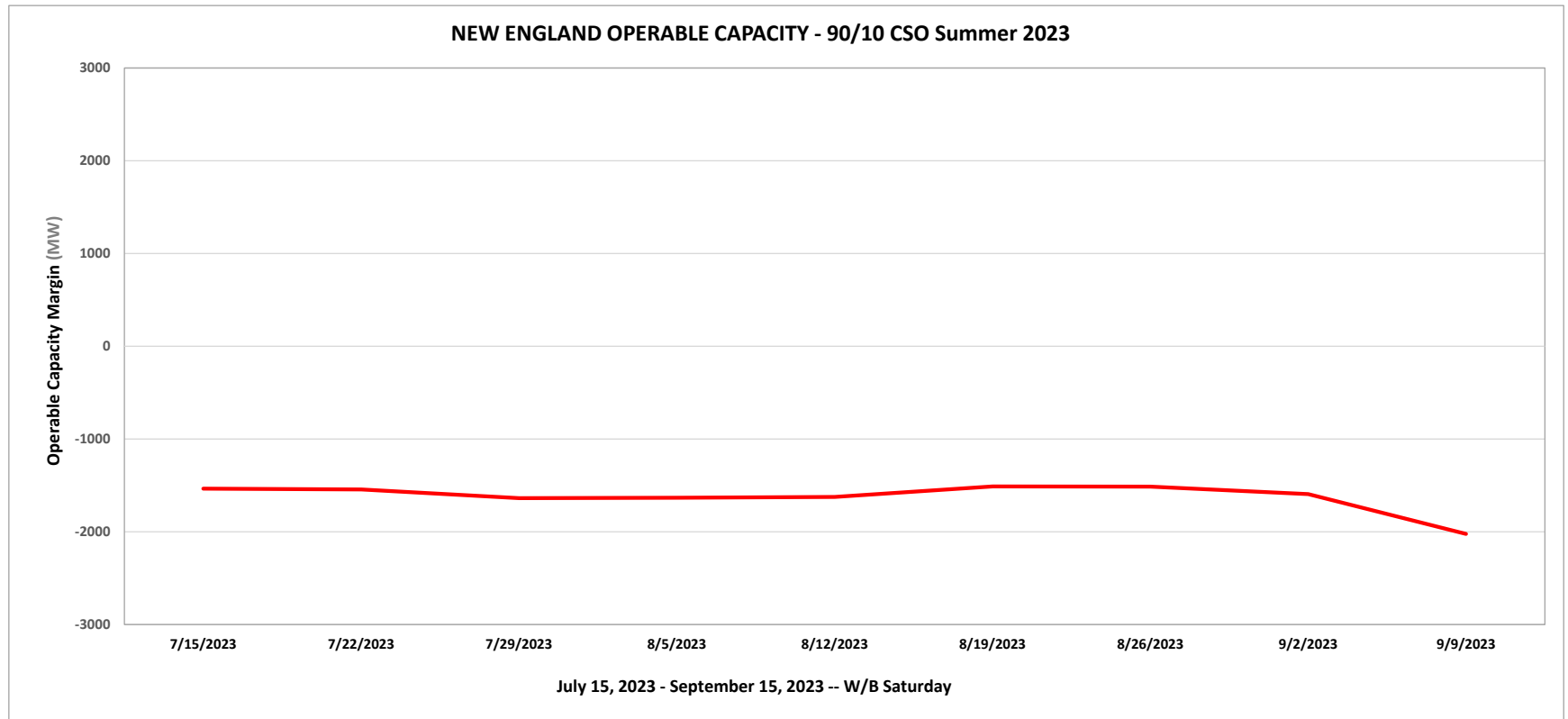
Summer 2023 Operable Capacity Analysis

50/50 Forecast (Reference)



Summer 2023 Operable Capacity Analysis

90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify “Settlement Only” generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 ¹ 600
2	Declare Energy Emergency Alert (EEA) Level 1 ⁴	0
3	Voluntary Load Curtailment of Market Participants’ facilities.	40 ²
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	125 ³

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 ³
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 ²
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 ²
11	Request State Governors to Reinforce Power Warning Appeals.	100 ²
Total		2,520

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations