NEPOOL Participants Committee Report

March 2021

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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: January 2020 Energy Market value totaled $488M
  - February 2021 Energy market value over the period was $716M, up $228M from January and up $483M from February 2020
  - February 2021 natural gas prices over the period were 92% higher than January average values
    - Average RT Hub Locational Marginal Prices ($77.42/MWh) were 77% higher than January averages
      - DA Hub: $80.15/MWh
    - Average February 2021 natural gas prices and RT Hub LMPs were up 320% and 281%, respectively, from February 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.2% during February, up from 98.4% during January*
    - The minimum value for the month was 94.4% on Monday, February 1st

Data through February 24th

Underlying natural gas data furnished by: ICE Global markets in clear view

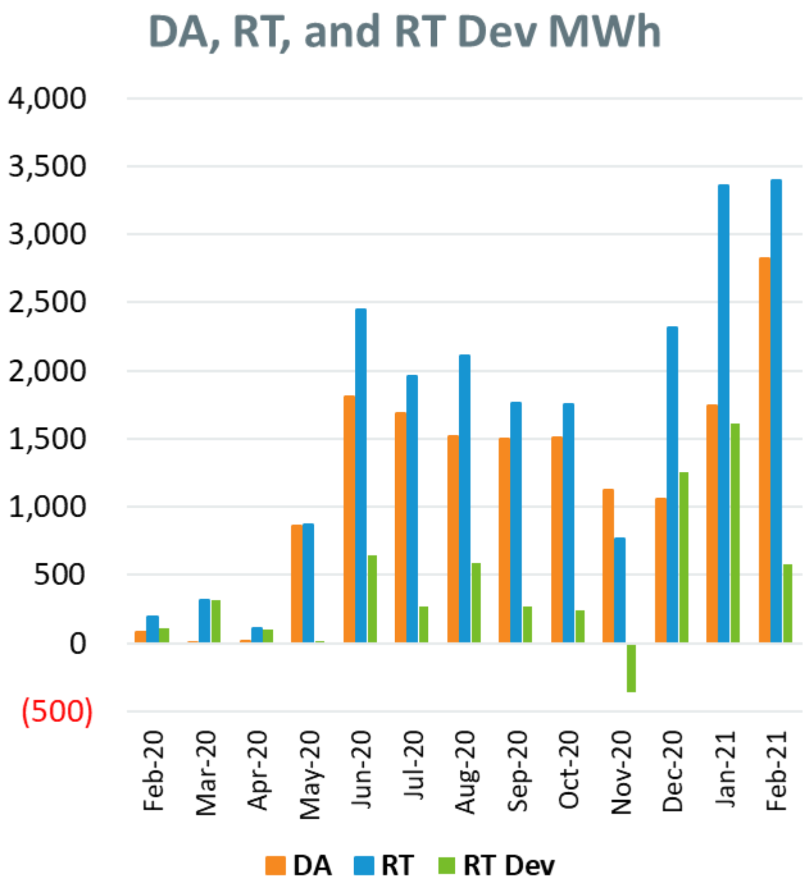
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

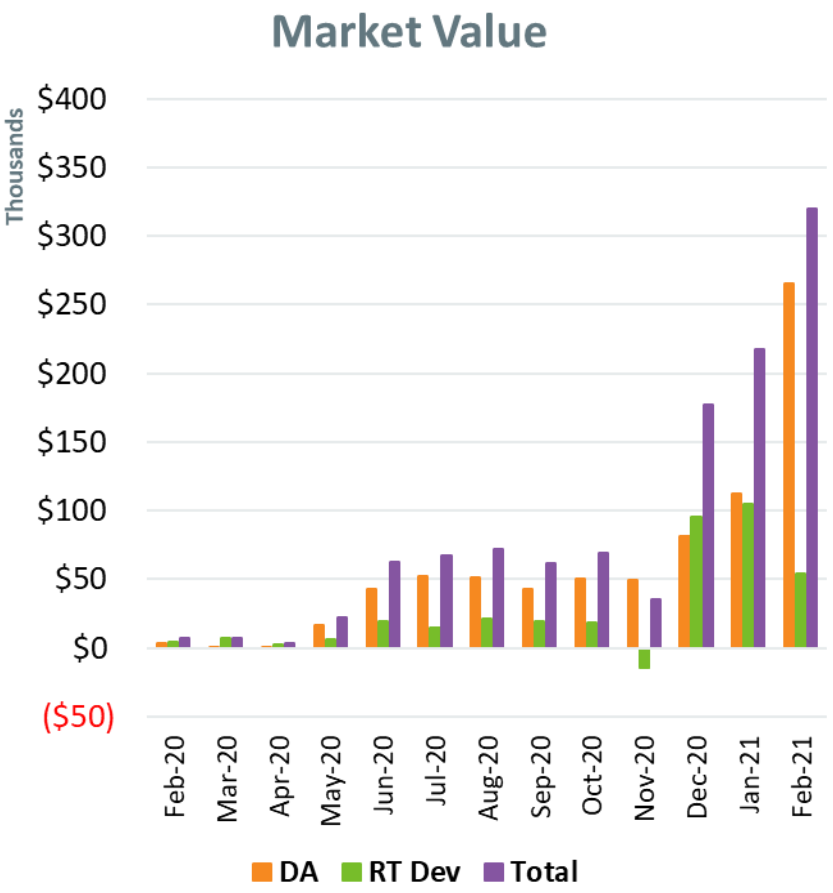
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - February NCPC payments totaled $2.3M over the period, down $1.2M from January and up $1.3M from February 2020
    - First Contingency payments totaled $1.9M, down $0.2M from January
      - $1.9M paid to internal resources, up $0.1M from January
        - » $596K charged to DALO, $655K to RT Deviations, $649K to RTLO*
      - $16K paid to resources at external locations, down $275K from January
        - » Charged to RT Deviations
    - Second Contingency payments totaled $0.1M, down $1.1M from January
    - Distribution payments totaled $259K, up $134K from January
    - Voltage payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.3%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $272K; Rapid Response Pricing (RRP) Opportunity Cost - $323K; Posturing - $31K; Generator Performance Auditing (GPA) - $23K**

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.

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) will be held on March 1-3, and results will be posted no later than March 31
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) will be held on August 2-4, and results will be posted no later than September 1
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 1
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 1, 2020
    - Approved projects were shared with the RC at their January meeting
  - Capacity zone development discussions began at the November 19, 2020 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - FCA 16 dynamic delist bid threshold price to be determined, then posted to the ISO-NE website in early March upon FERC approval of the new methodology

Highlights

- FCA 15 was completed on February 8, and results were filed with the FERC on February 26
- Draft 2019 Electric Generator Air Emissions Report results were presented to the Environmental Advisory Group on February 19
- 2021 first quarter CO_2 emissions are trending higher than first quarter emissions from previous years
- Efforts to finalize the Future Grid Reliability Study (FGRS) Phase 1 study assumptions continue
- 2021 Economic Study requests are due April 1
- 2021 load forecast nearing completion and will be published as part of the CELT report on April 30
- Transmission Planning for the Clean-Energy Transition study results are expected in Q2

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- The 2021 load forecast development process continues
  - Upcoming meetings include: Energy-Efficiency Forecast Working Group (3/19), Load Forecast Committee (3/26), and Distributed Generation Forecast Working Group (3/22)
  - Changes to reconstitution used in the gross load forecast have required fundamental changes to be developed and implemented into the 2021 energy-efficiency forecast
  - In the March/April timeframe, PAC and RC will discuss the preliminary ten-year forecast
  - Publication of the final ten-year forecast will be in the CELT report, which will be posted on April 30

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
  - 2021 Annual QTPS Certification
    - All 25 QTPSs submitted completed Annual QTPS Certification forms to the ISO prior to the close of the Certification Window on January 31
    - The ISO has determined that all 25 QTPSs continue to meet the Attachment K requirements and has notified them accordingly
- The Boston 2028 RFP lessons-learned process, with respect to competitive transmission solutions, was discussed at the 12/16/20 PAC meeting, and initial ISO responses were discussed at the 2/17/21 PAC meeting
  - Further discussion will continue at future 2021 PAC meetings

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning March 6, 2021.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 8, 2021.

Summary of the Texas Extreme Cold Weather Event

- During the week beginning on Sunday February 14, the ERCOT Interconnection experienced severe weather and extreme low temperatures that led to supply and demand imbalance
- ERCOT system operators ordered firm customer load shedding beginning in the early morning hours of Monday February 15 to prevent an ERCOT wide blackout
- Resources of every technology type had difficulty with startup and operations; Resource losses were caused by multiple reasons including fuel supply disruption, fuel quality, infrastructure freeze ups, icing, snow cover, and other issues
  - 52,277 MW out of 107,514 MW total installed capacity was forced out or unavailable
- Continued load shedding was required for multiple days in order to maintain a supply and demand balance; The magnitude of the load that had to be disconnected made it difficult to rotate feeders
  - At its peak, ~20,000 MW of load was shed
- ERCOT presented to its Board in an urgent meeting last week, and that presentation was circulated to stakeholders as part of this Participants Committee meeting
- SPP and MISO also experienced emergency conditions during this time frame which required firm customer load shedding but these events were not as extreme as those experienced in ERCOT
  - SPP directed the interruption of service twice: once for approximately 50 minutes on the morning of Feb. 15, and again for a little more than three hours on the morning of Feb. 16.
  - MISO also shed load during the event but exact dates and quantities are not available
- Several investigations are under way including a joint FERC/NERC inquiry and the State of Texas inquiries

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (0.9°F) Max: 50°F, Min: 11°F Precipitation: 3.05" – Below Normal Normal: 3.25" Snow: 15.03"	Hartford	Temperature: Below Normal (1.2°F) Max: 48°F, Min: 7°F Precipitation: 3.35" - Above Normal Normal: 2.89" Snow: 20.80"

Peak Load:	18,034 MW	02/01/2021	18:00 (ending)

Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
None			

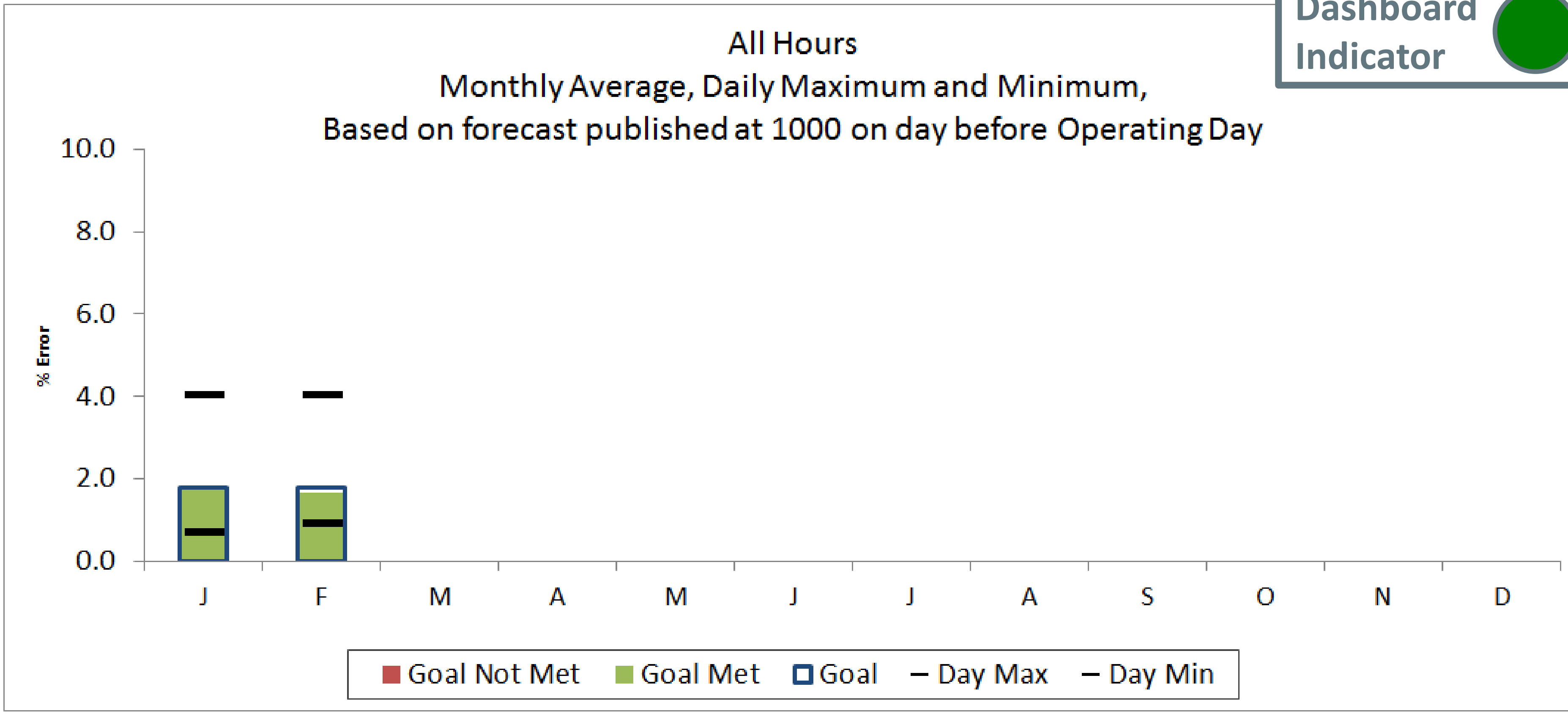
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
None		

2021 System Operations - Load Forecast Accuracy

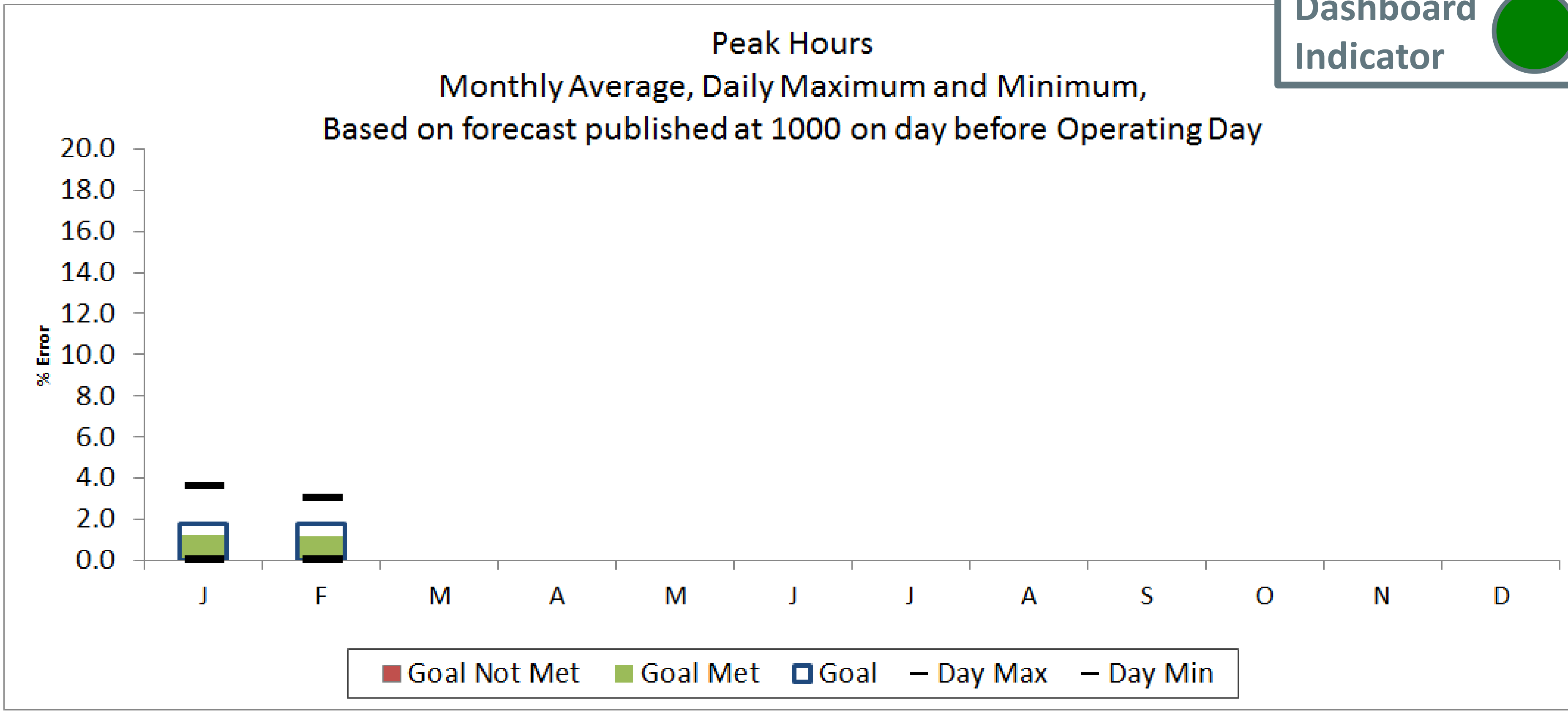
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03											4.04
Day Min	0.70	0.92											0.70
MAPE	1.72	1.66											1.69
Goal	1.80	1.80											

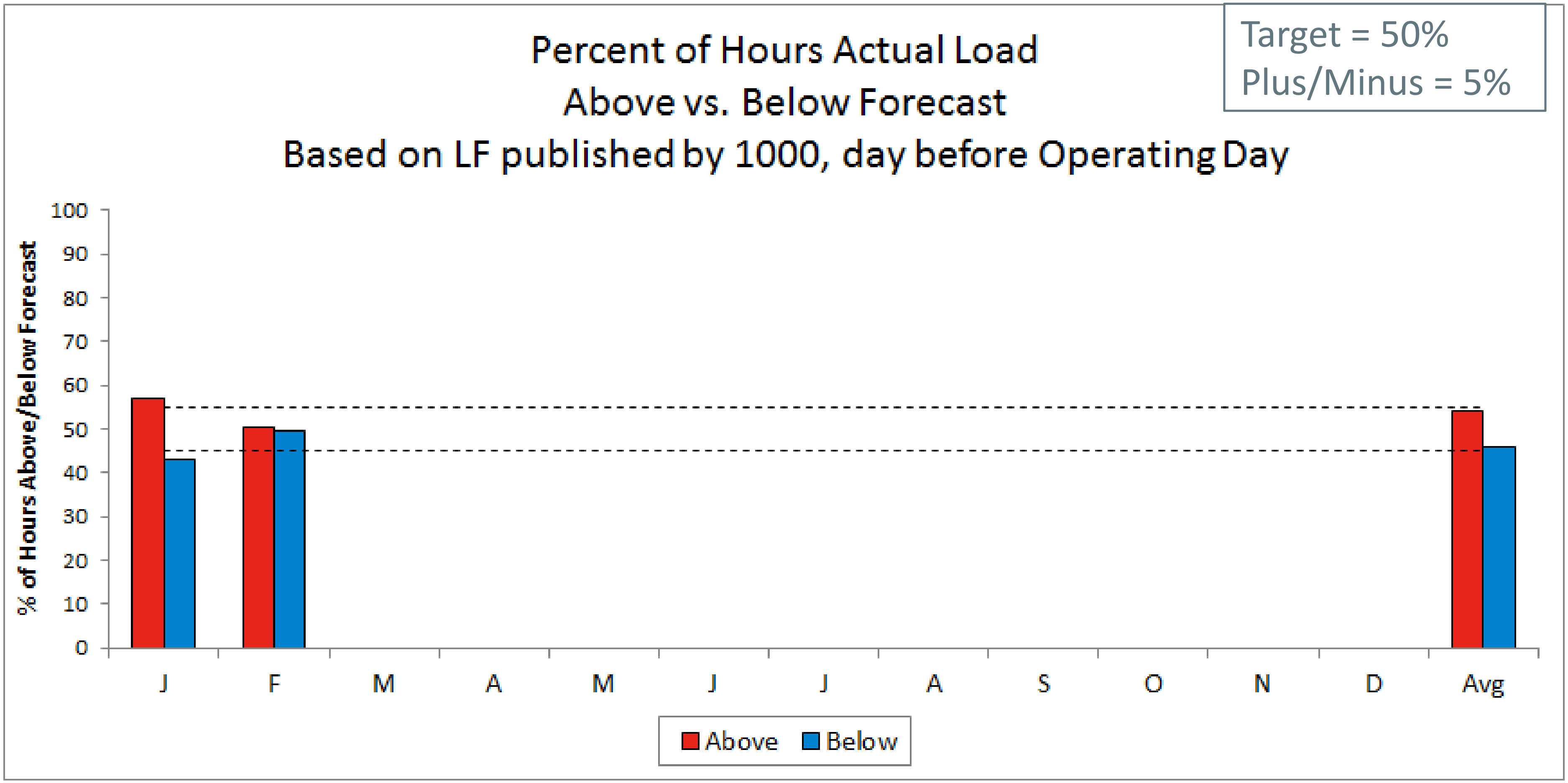
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



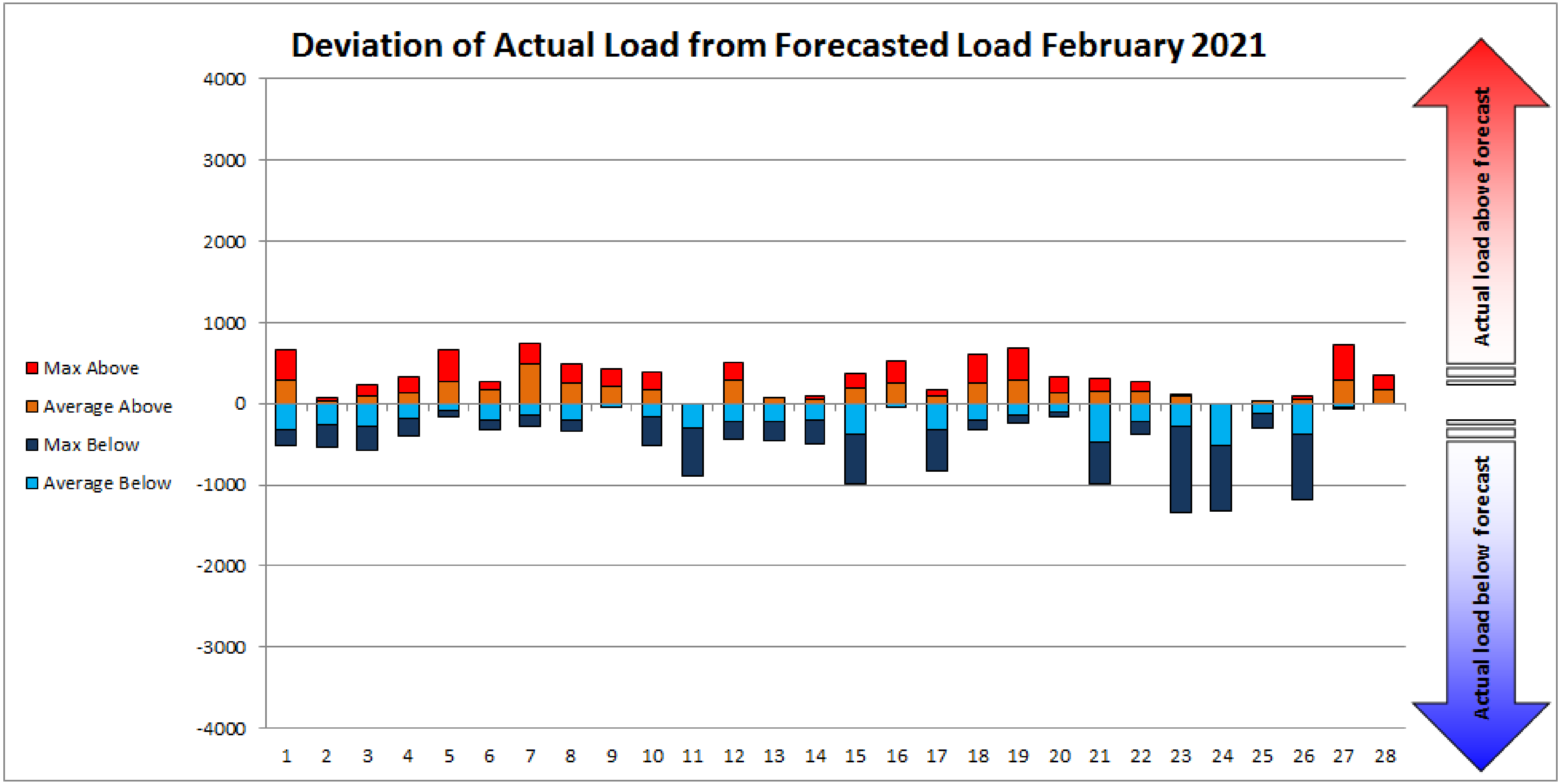
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03											3.61
Day Min	0.02	0.06											0.02
MAPE	1.26	1.18											1.22
Goal	1.80	1.80											

2021 System Operations - Load Forecast Accuracy cont.

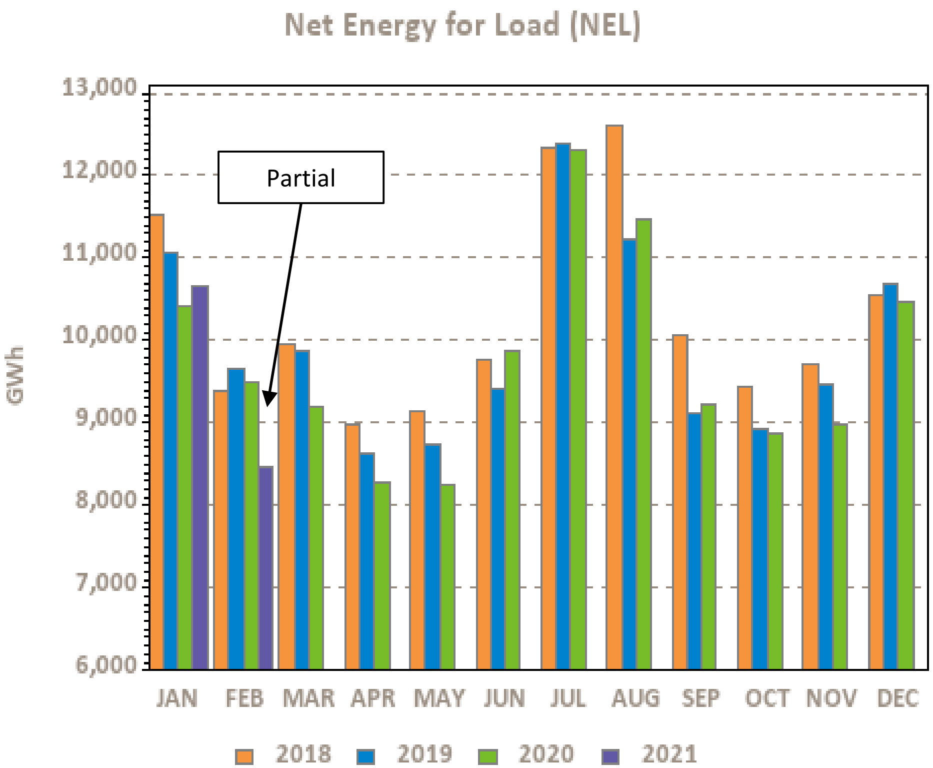


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4											54
Below %	42.9	49.6											46
Avg Above	209.5	166.7											210
Avg Below	-147.6	-216.4											-216
Avg All	60	-25											20

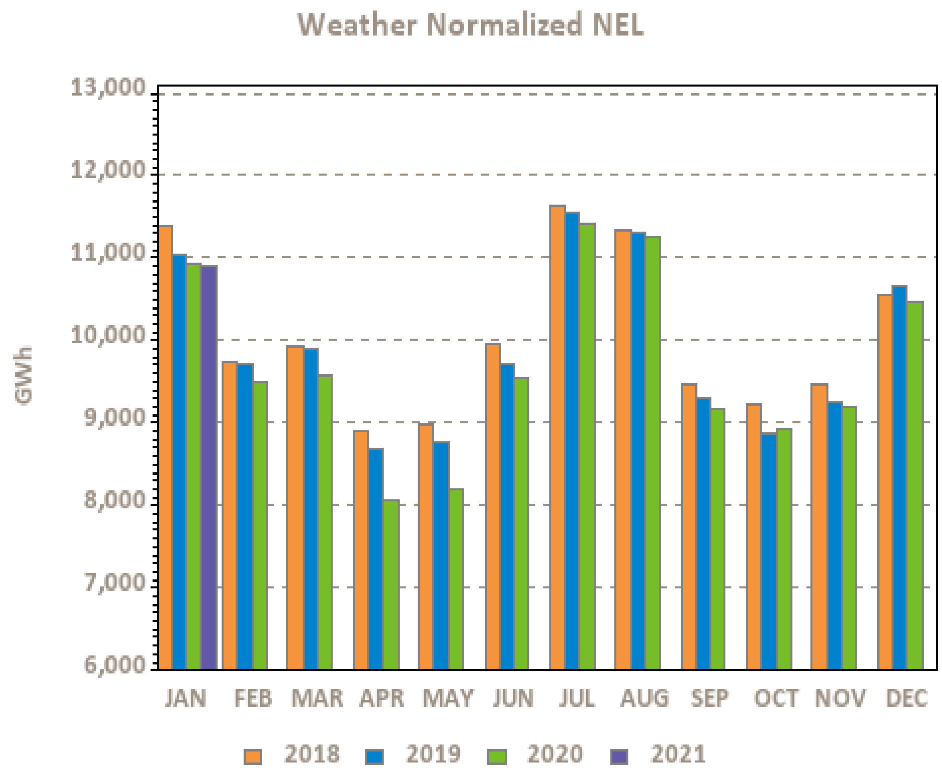
2021 System Operations - Load Forecast Accuracy cont.



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



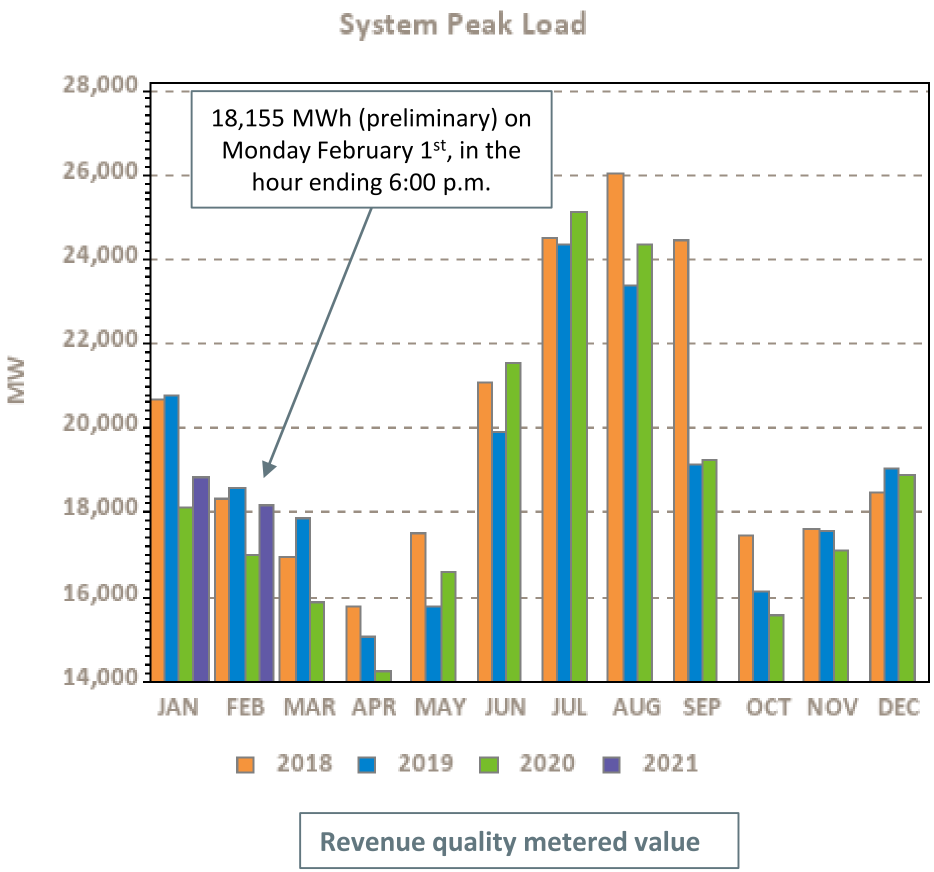
Ann Tot (TWh): 123.5 119.2 116.9 19.1

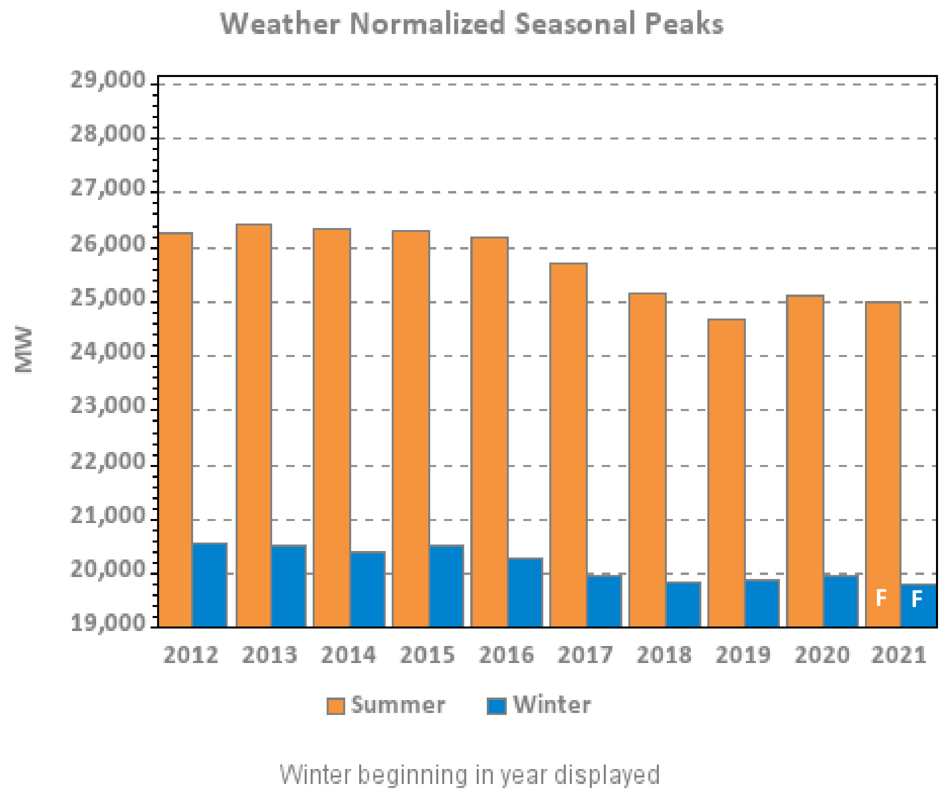


Ann Tot (TWh): 120.6 118.8 116.3 10.9

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 may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

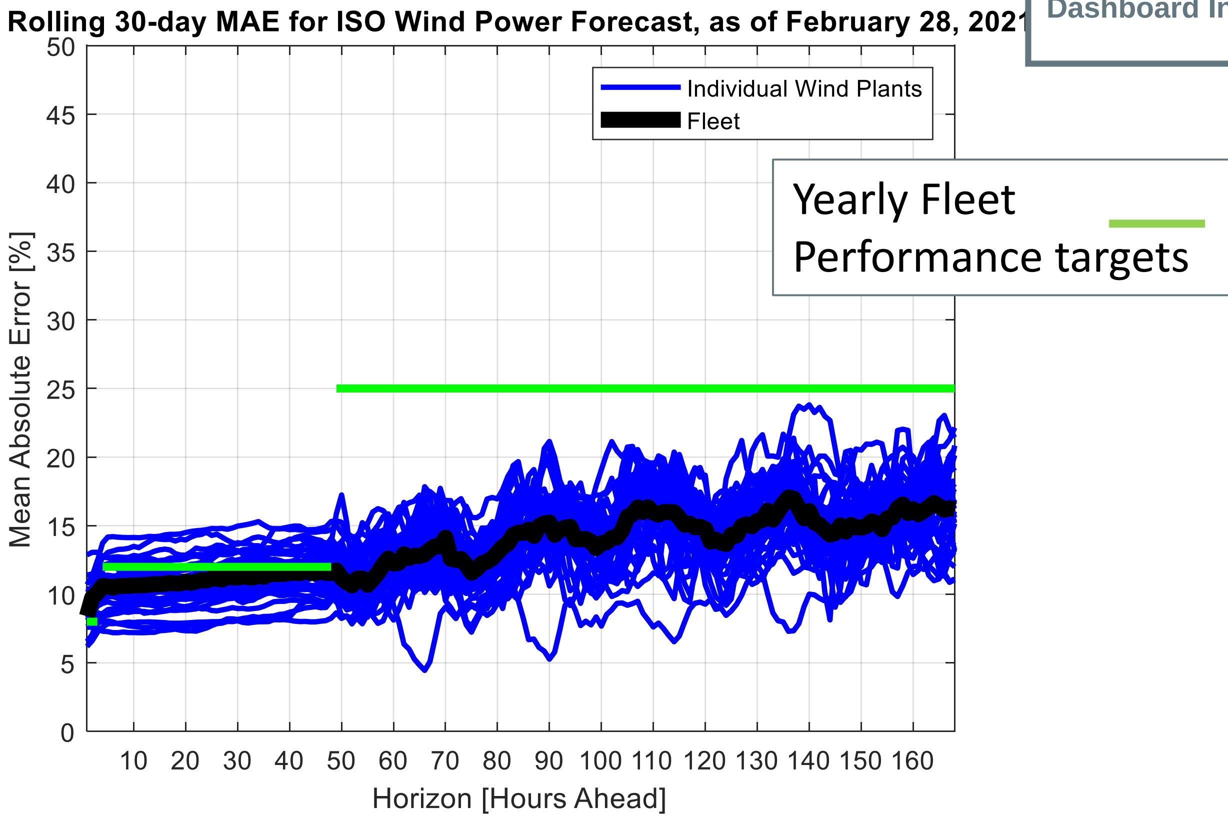




F – designates forecasted values, which are updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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

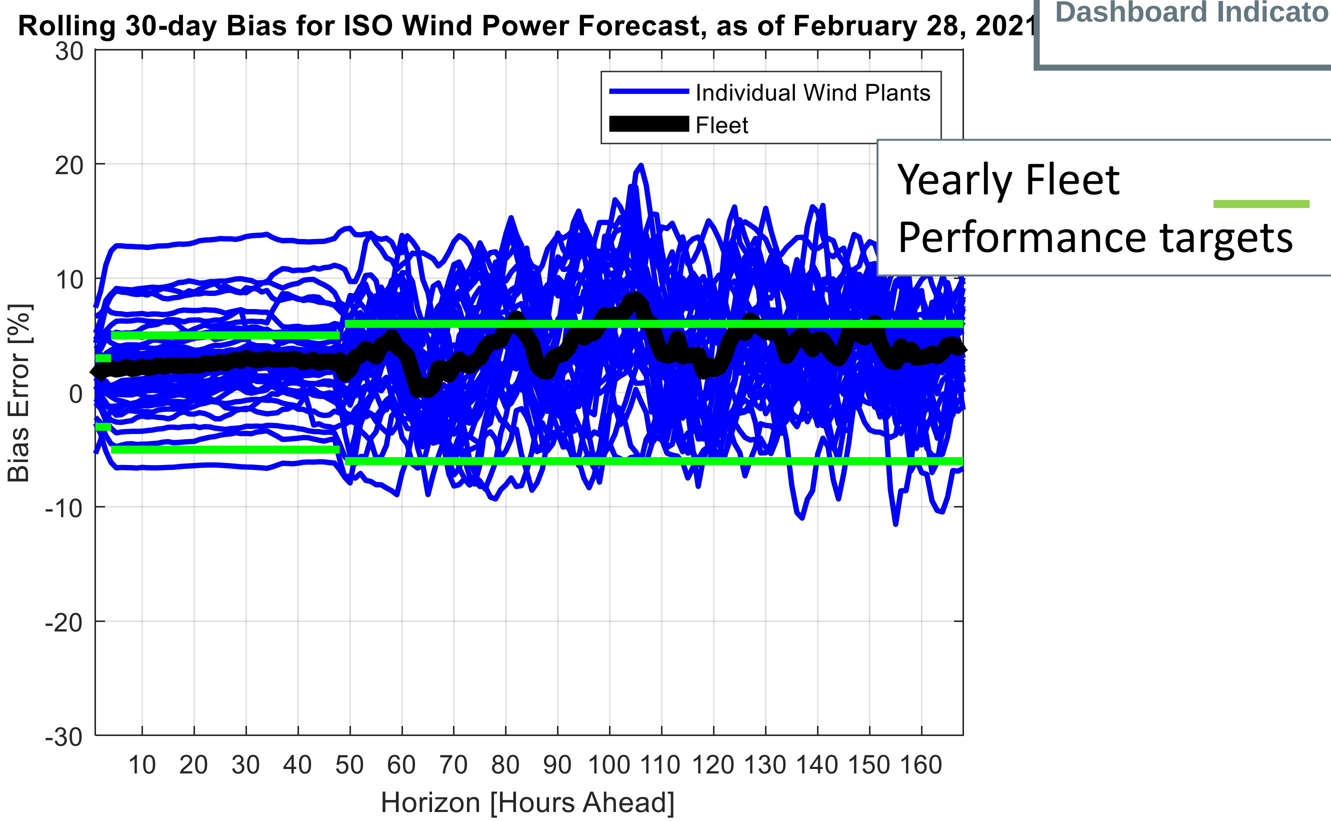
Dashboard Indicator



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 ISO-NE/DNV-GL 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

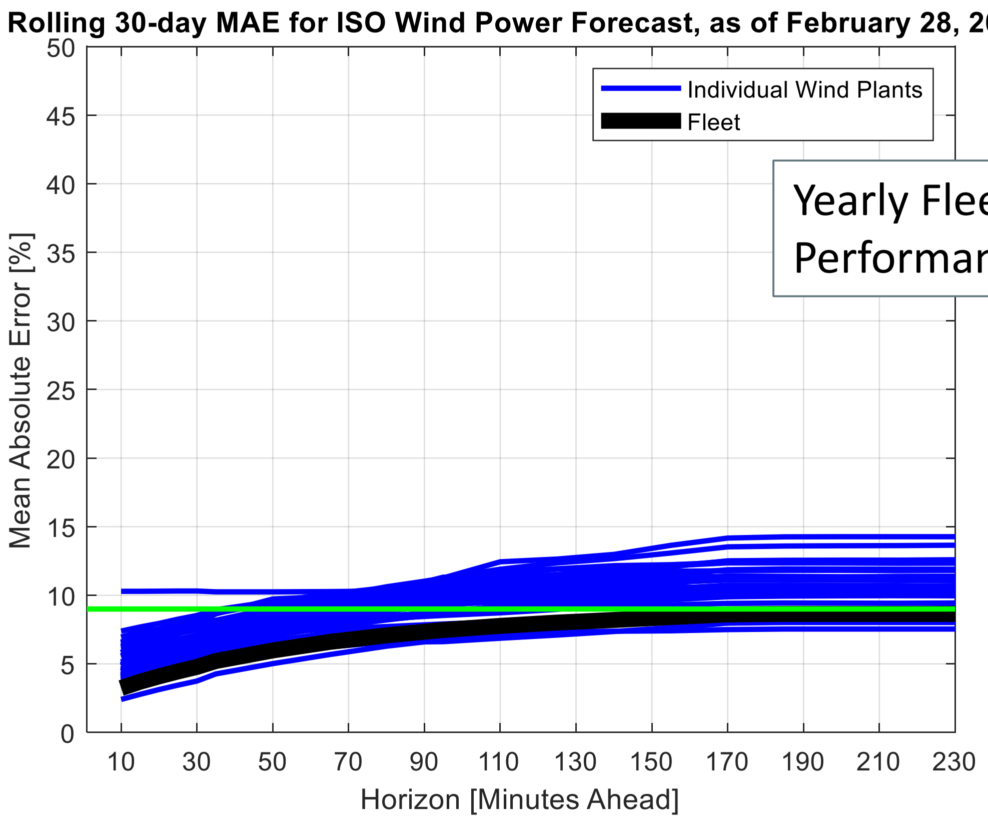
Dashboard Indicator



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-GL forecast compares well with industry standards, and monthly Bias is mostly within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

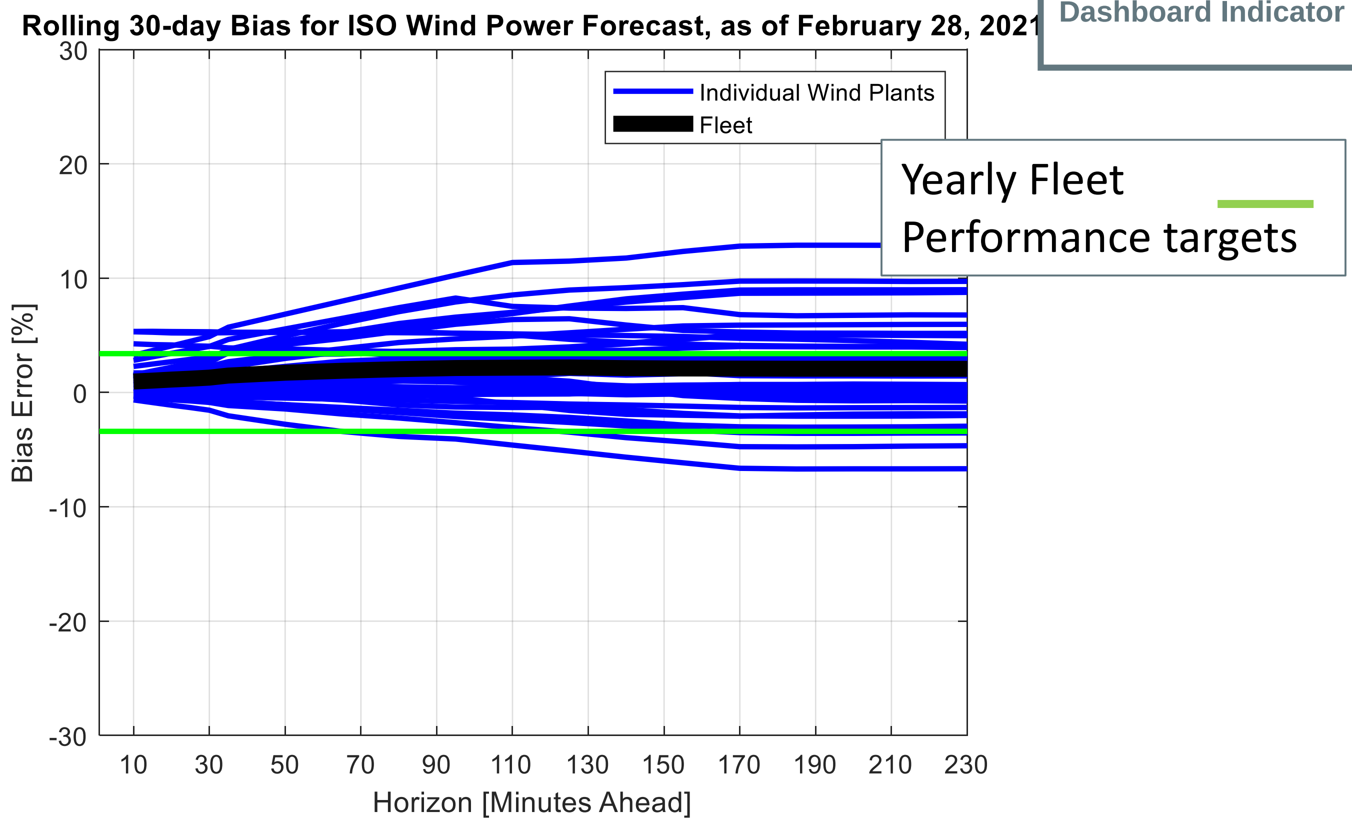


Yearly Fleet Performance targets

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-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

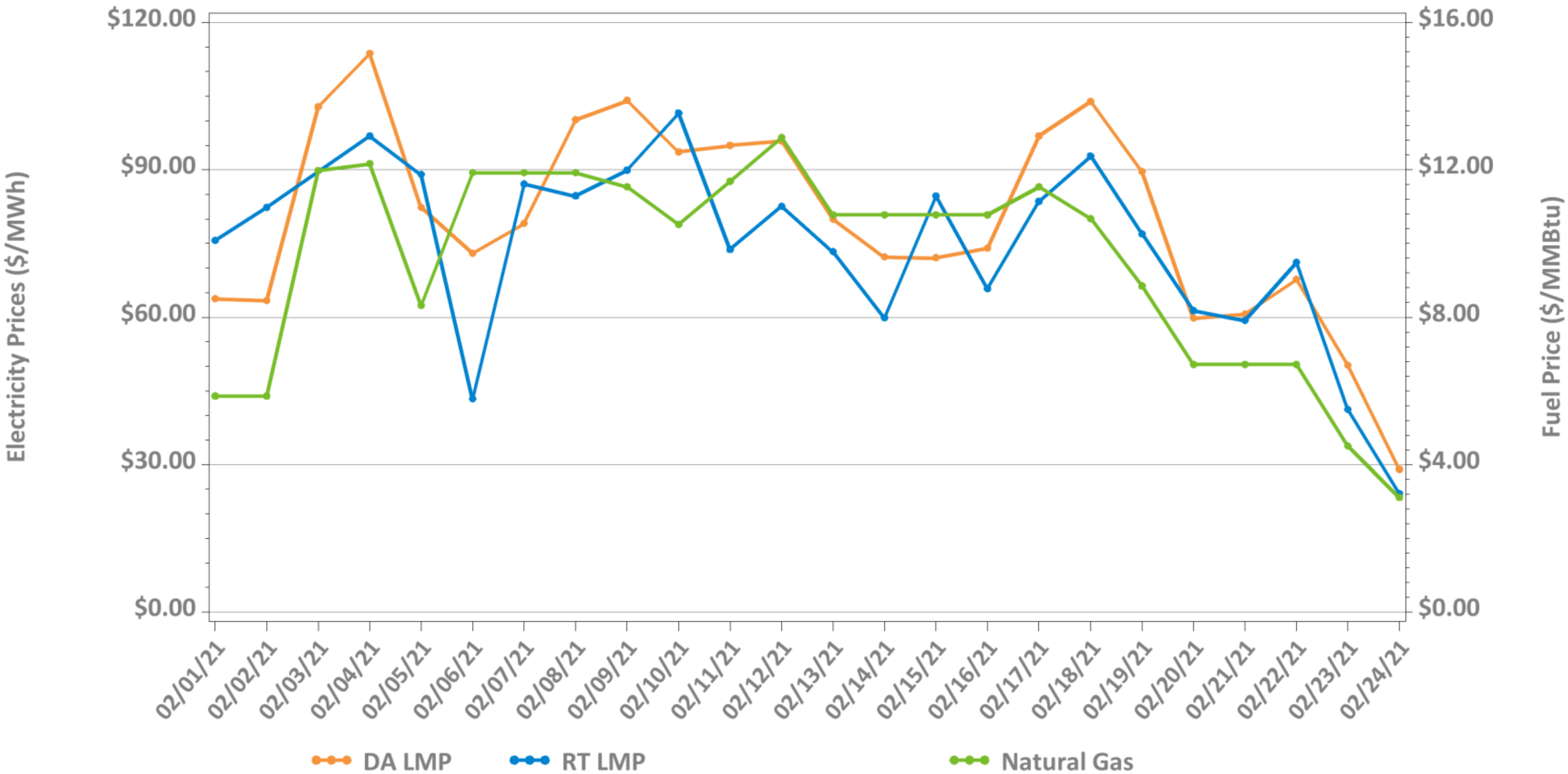
Dashboard Indicator



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-GL 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: February 1-24, 2021



Underlying natural gas data furnished by:

ICE Global markets in clear view

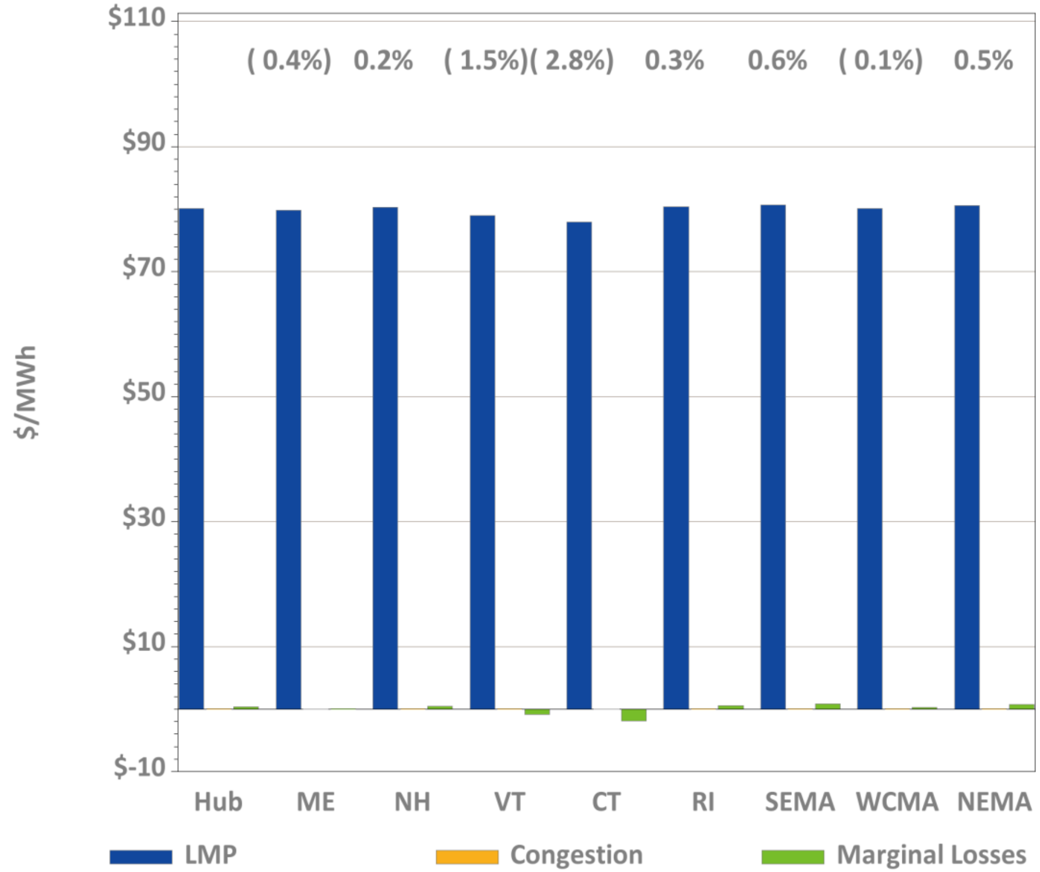
Average price difference over this period (DA-RT): $2.72

Average price difference over this period ABS(DA-RT): $13.13

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 17%

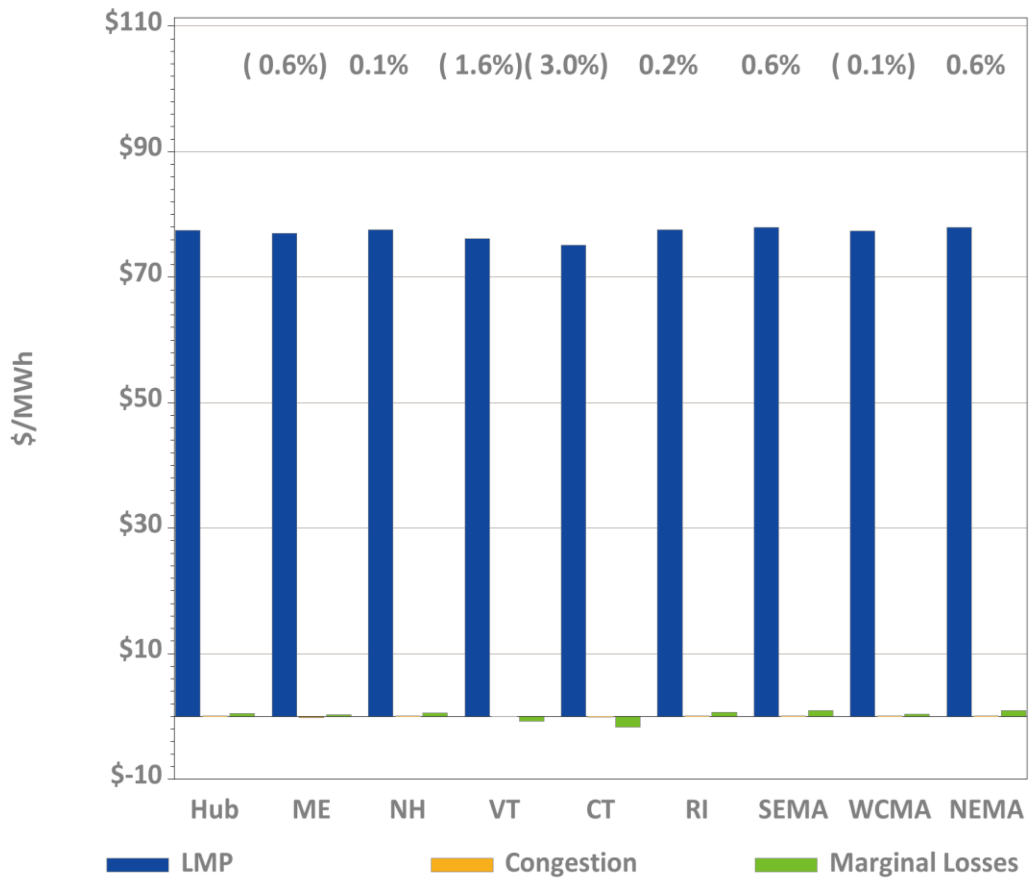
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, February 2021



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

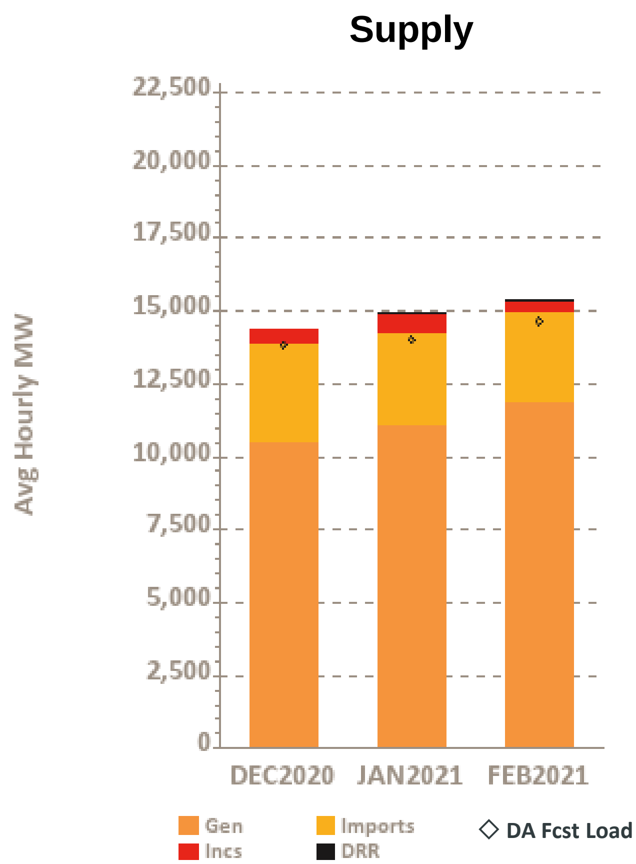
RT LMPs Average by Zone & Hub, February 2021

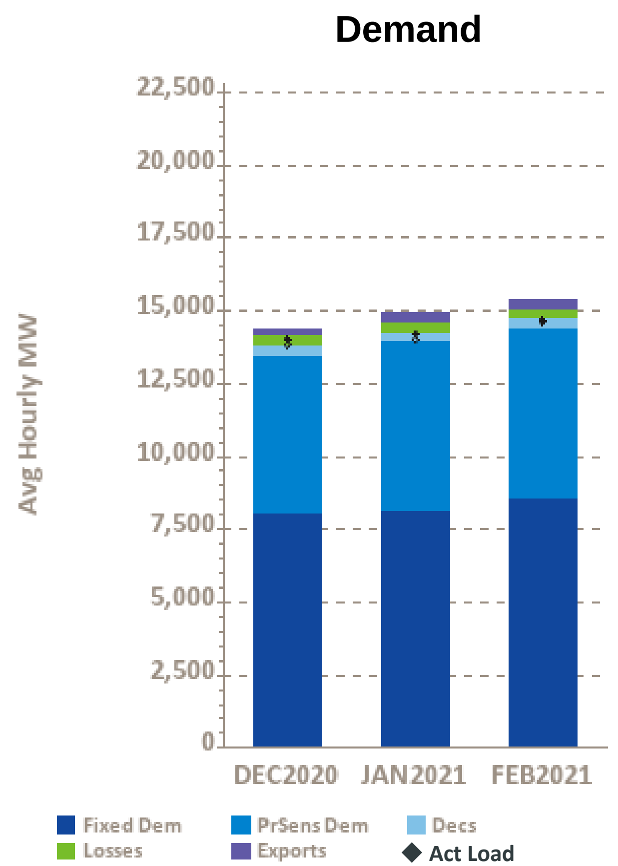


Definitions

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

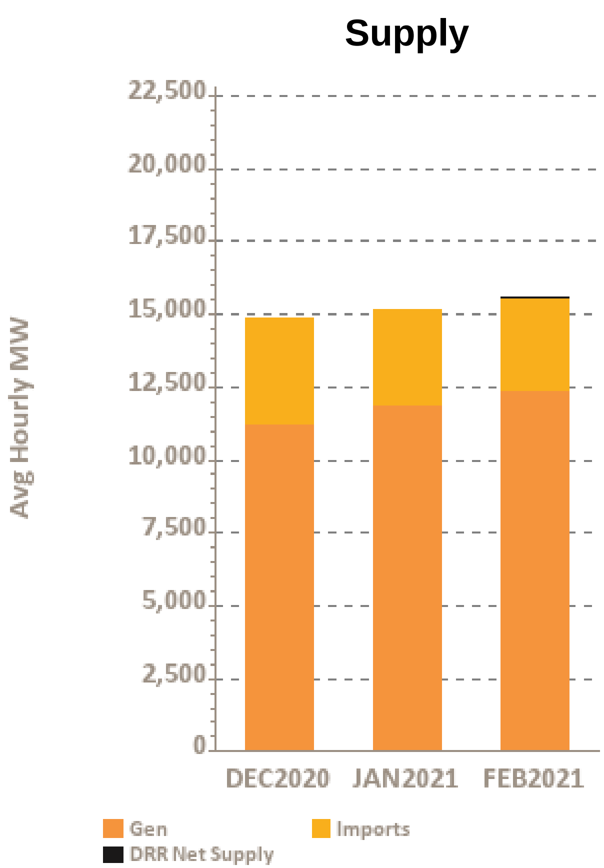


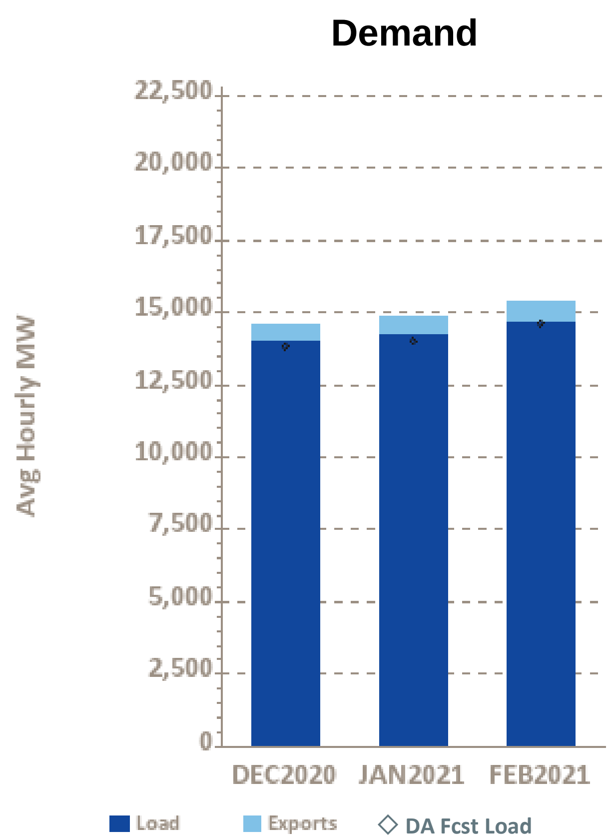


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

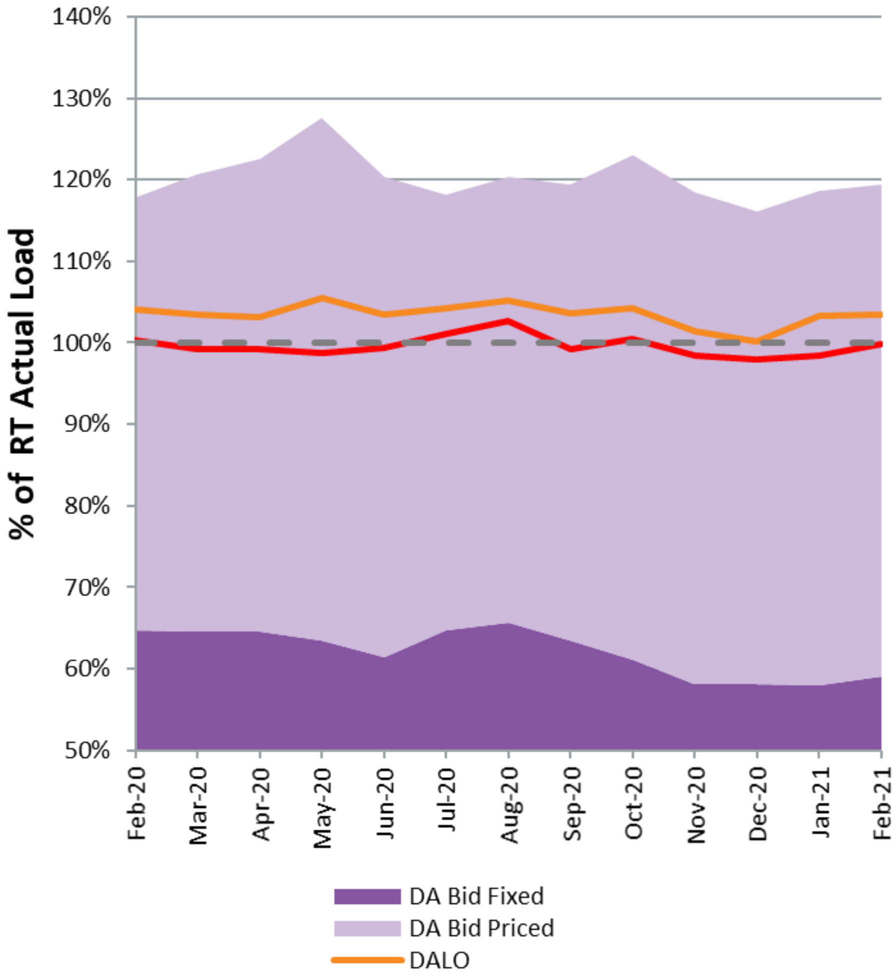
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

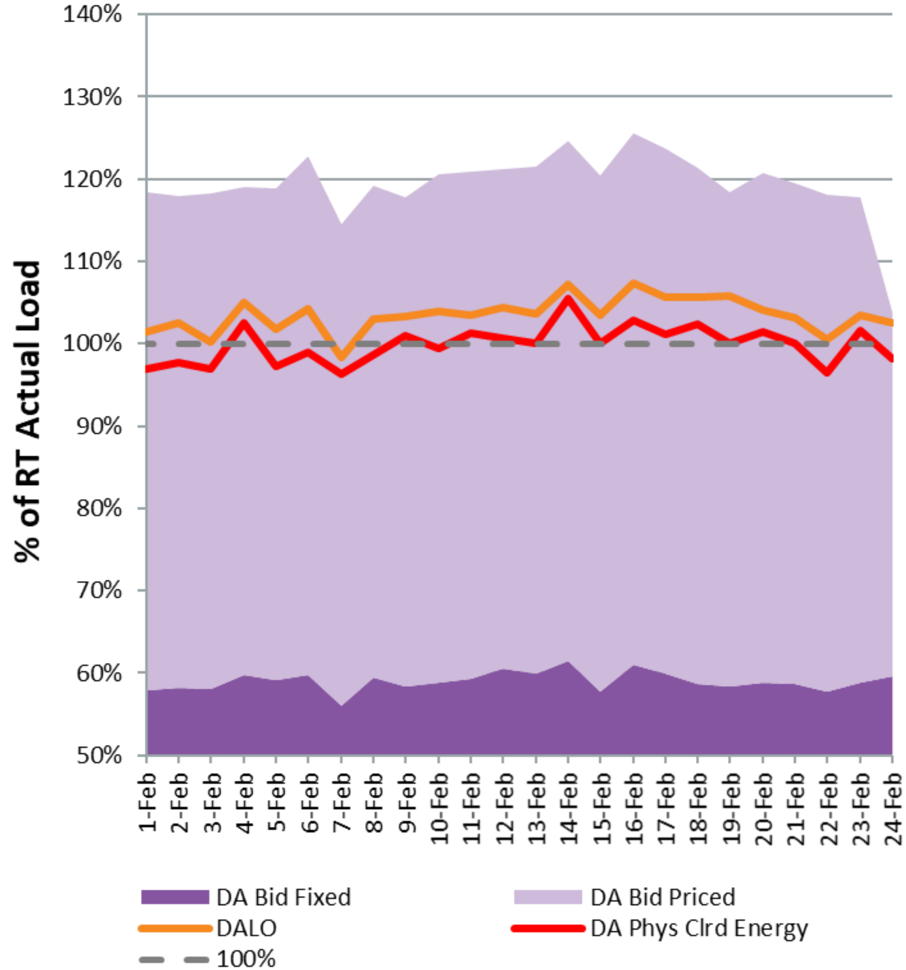
Components of RT Supply and Demand – Last Three Months





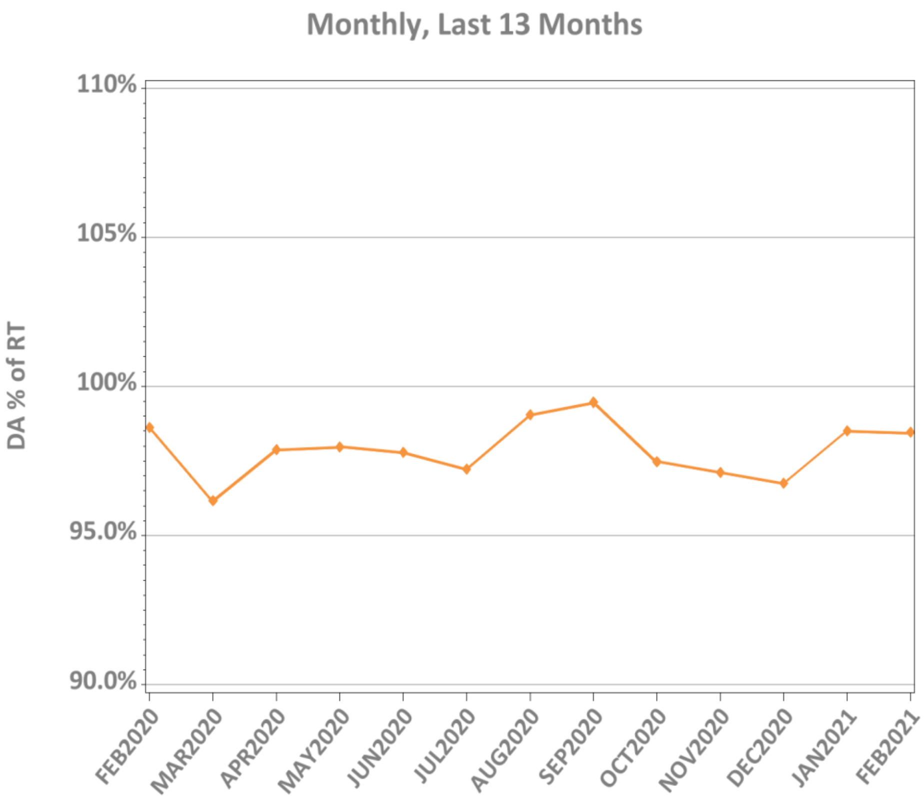
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

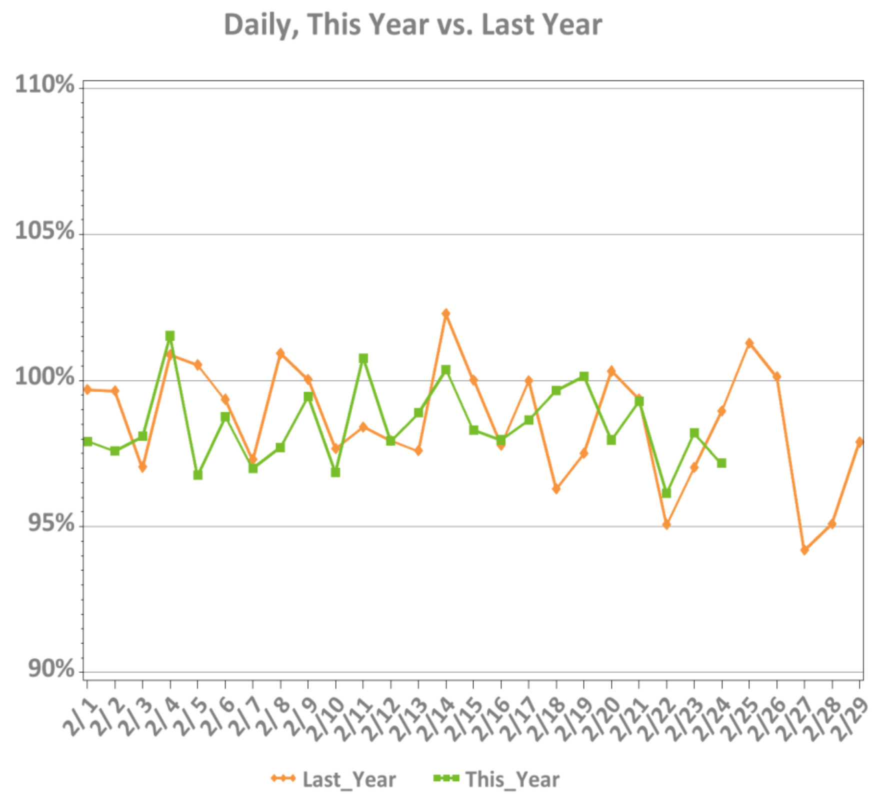




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

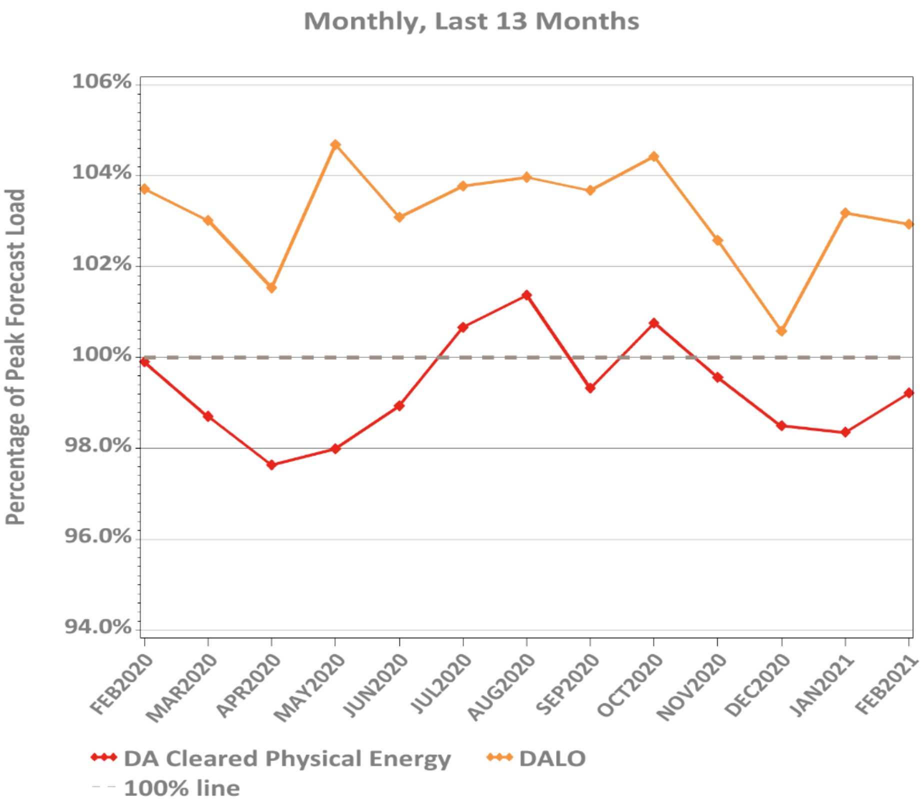
DA vs. RT Load Obligation: February, This Year vs. Last Year

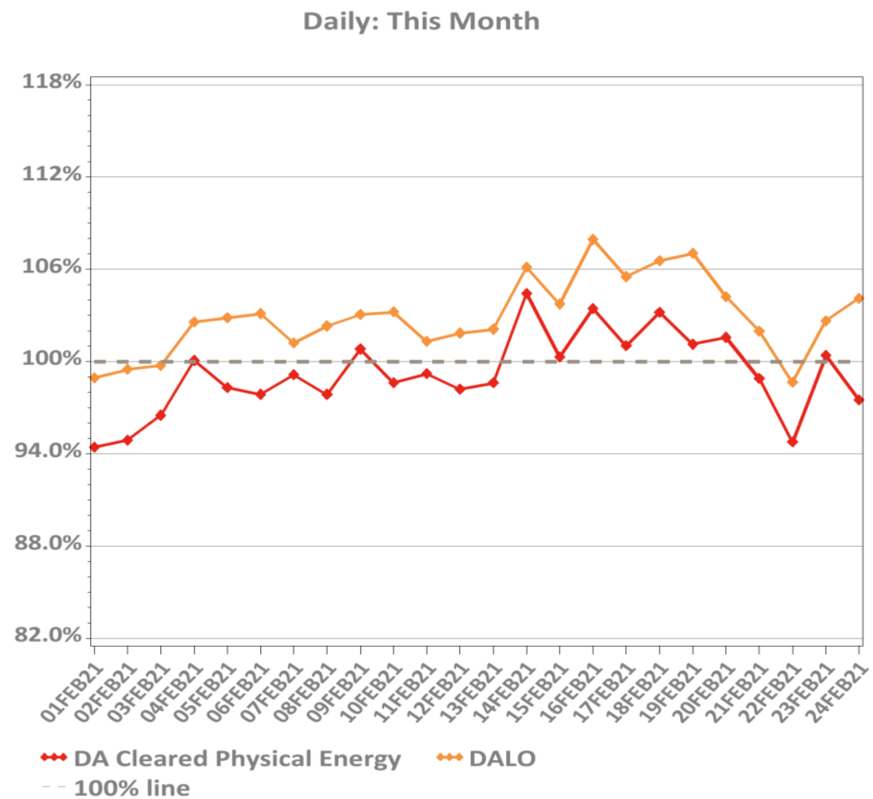




*Hourly average values

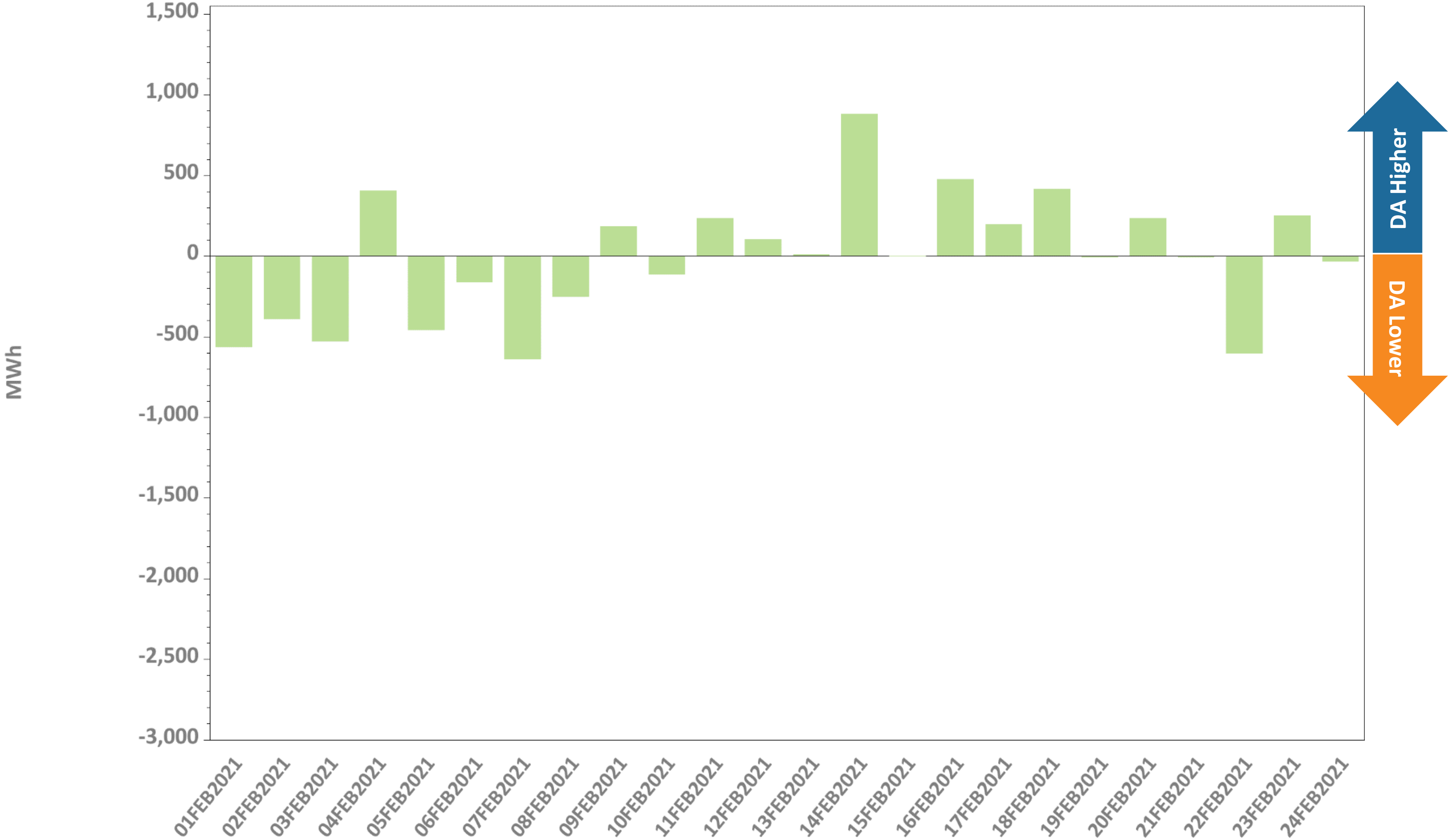
DA Volumes as % of Forecast in Peak Hour





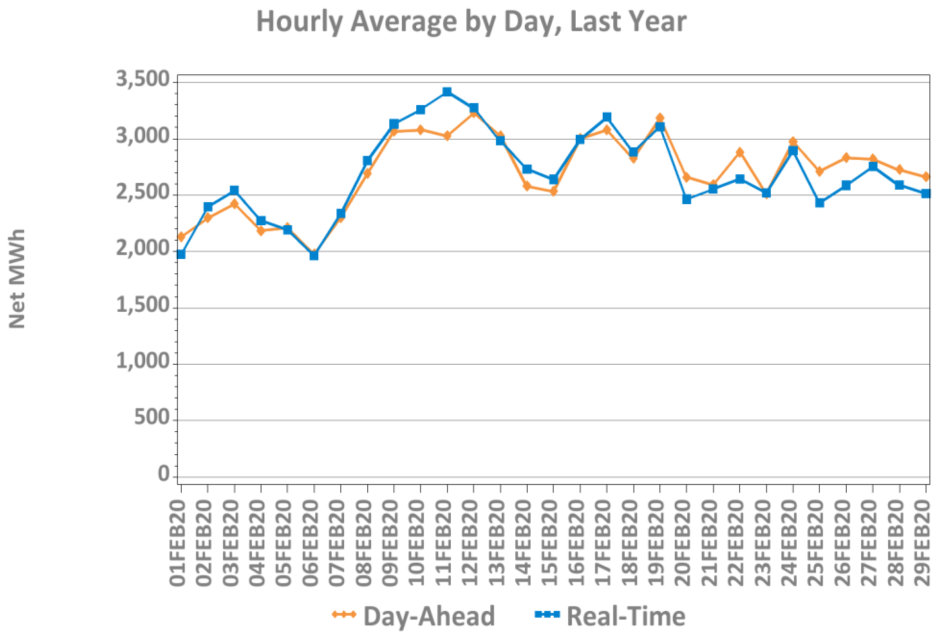
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during February.

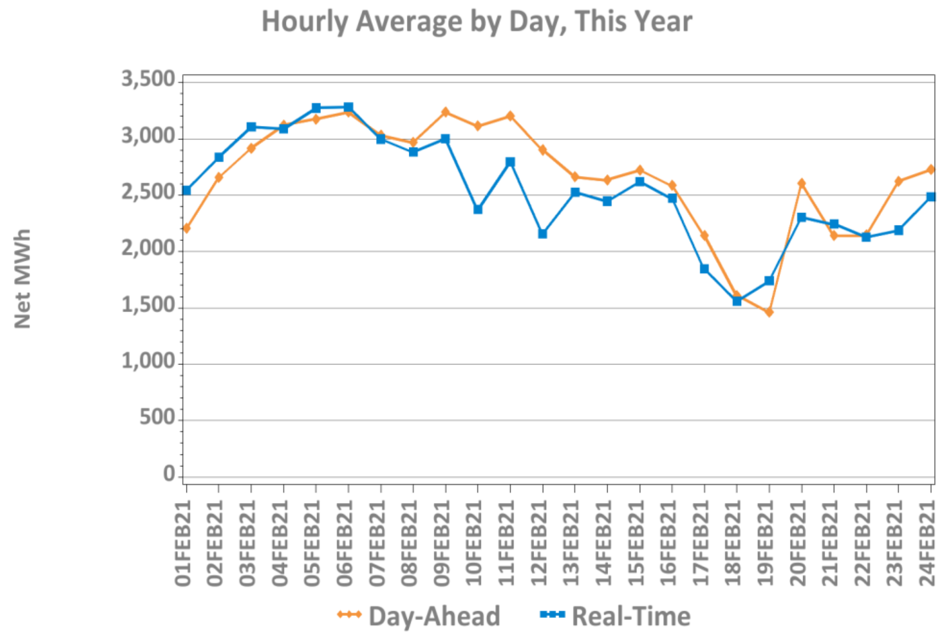
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

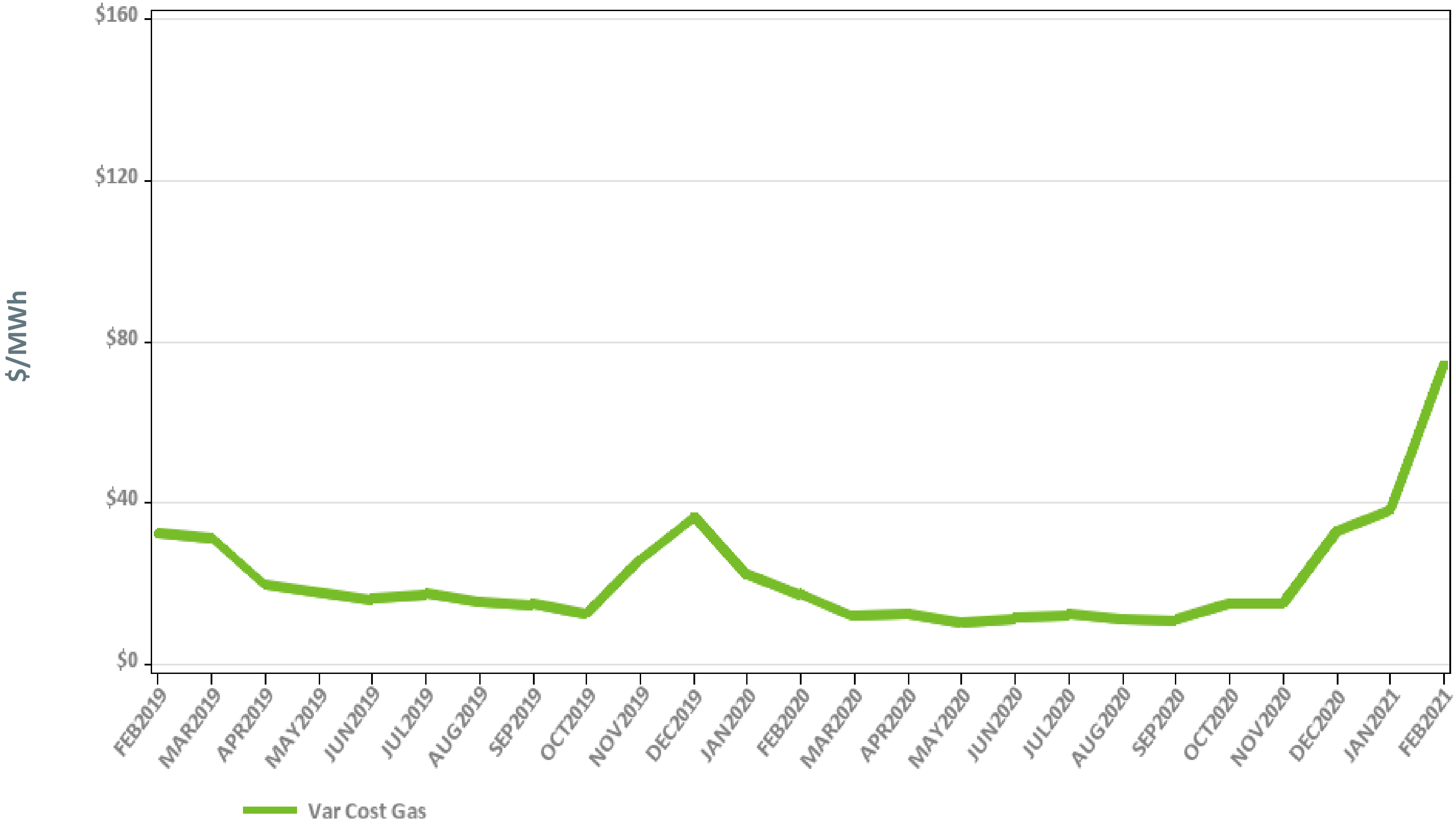
DA vs. RT Net Interchange
February 2020 vs. February 2021





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

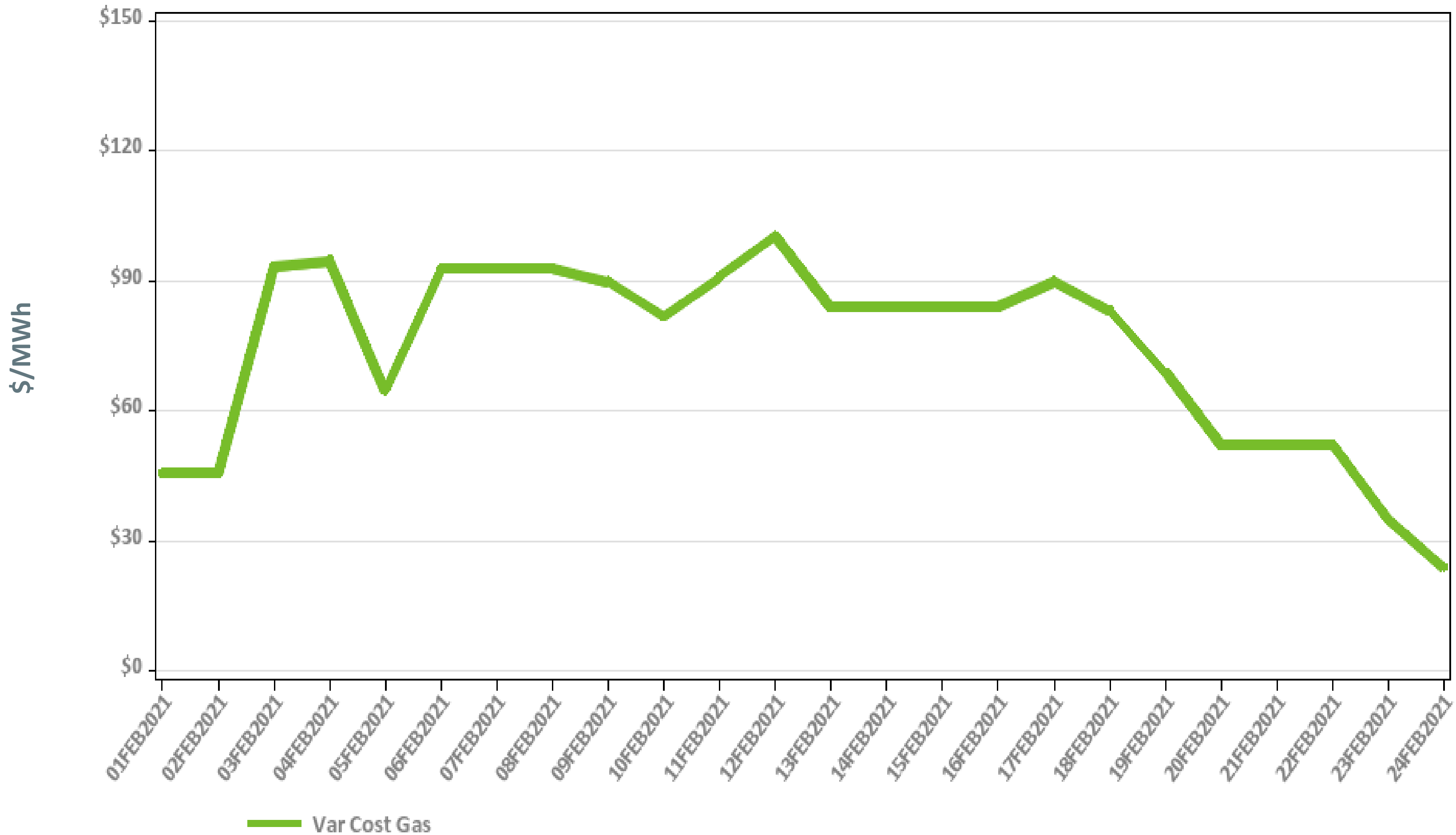
Variable Production Cost of Natural Gas: Monthly



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

Underlying natural gas data furnished by: ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

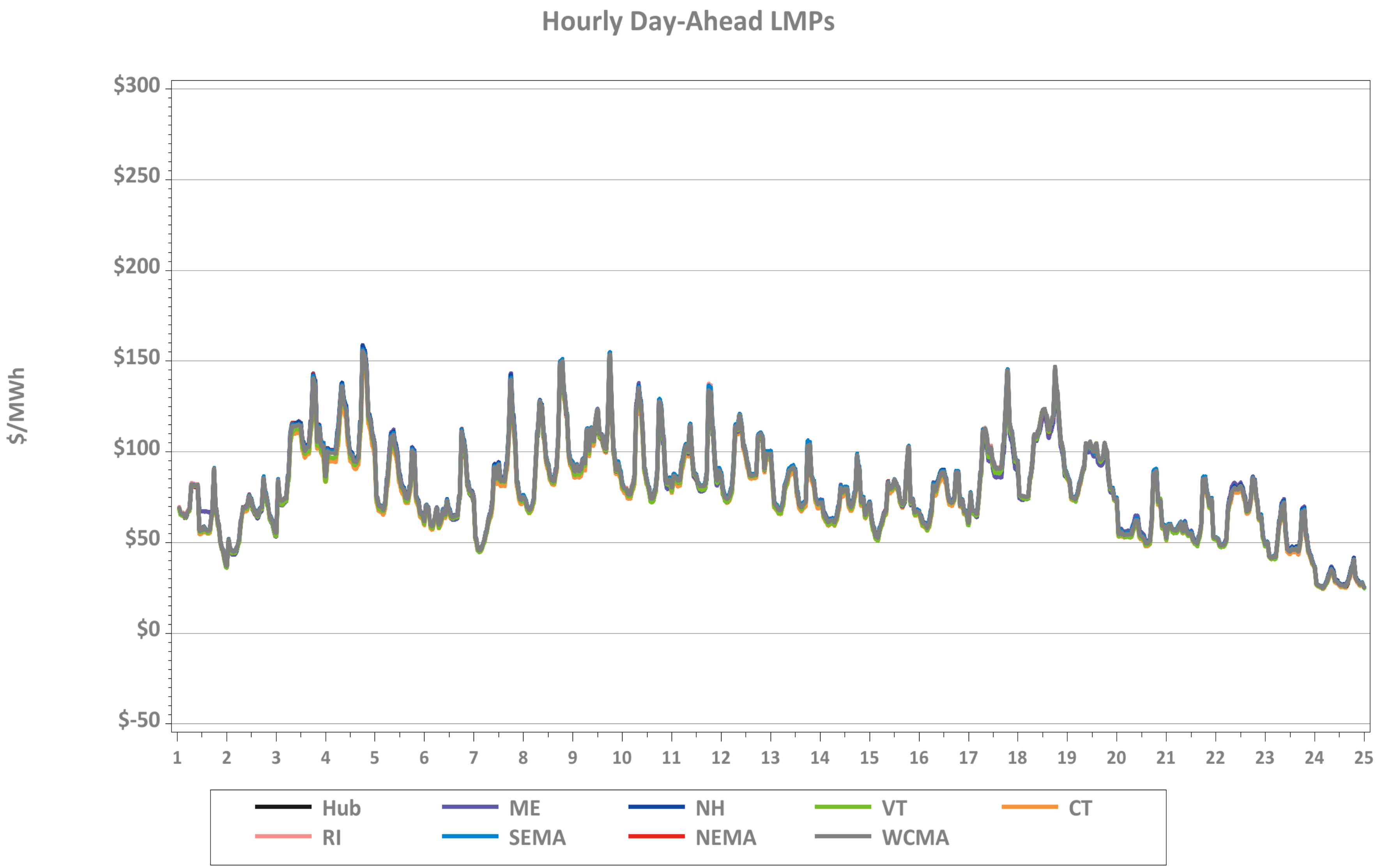


Underlying natural gas data furnished by:

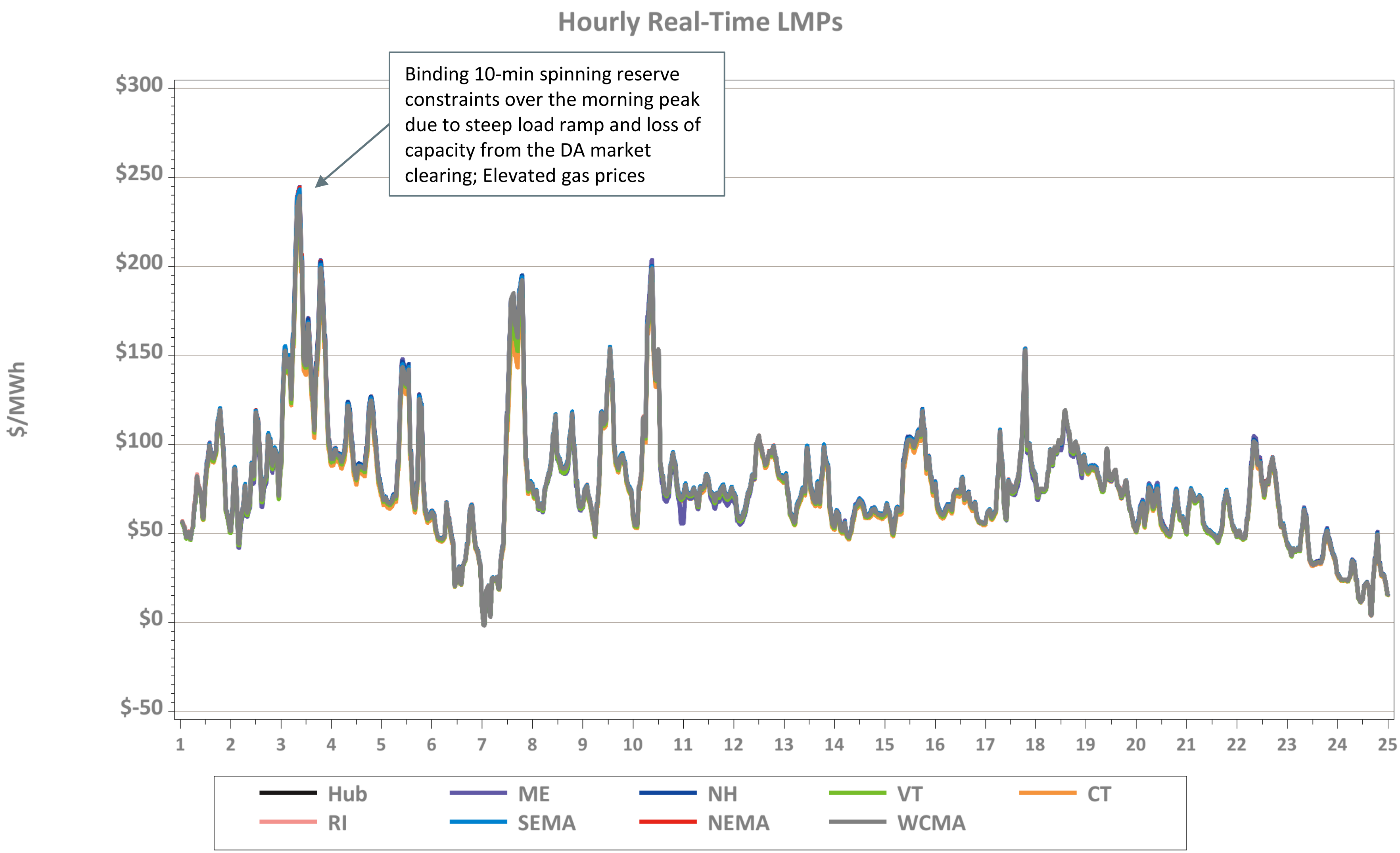
ice Global markets in clear view

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

Hourly DA LMPs, February 1-24, 2021

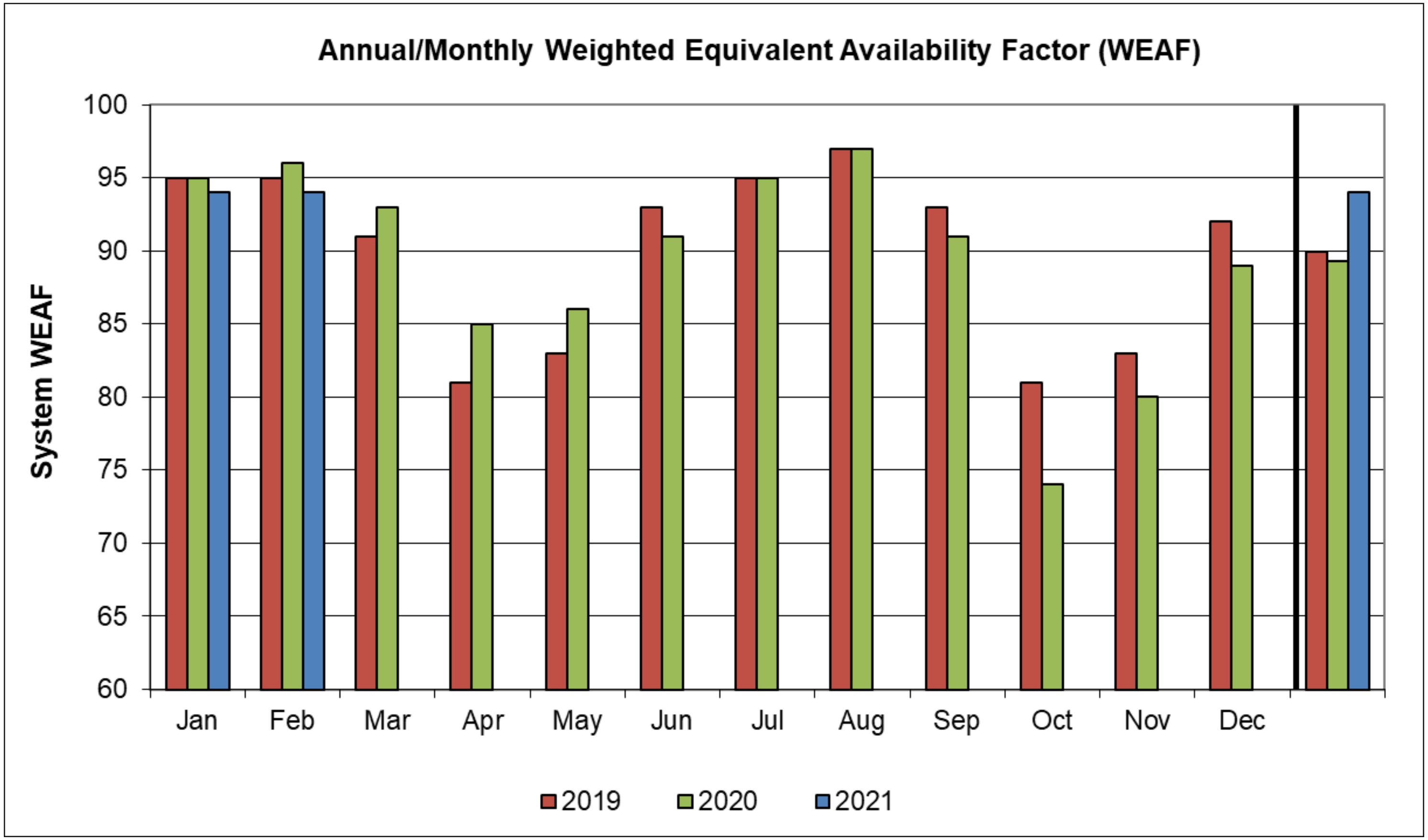


Hourly RT LMPs, February 1-24, 2021



- No Minimum Generation Emergencies were declared during February.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94	94											94
2020	95	96	93	85	86	91	95	97	91	74	80	89	89
2019	95	95	91	81	83	93	95	97	93	81	83	92	90

Data as of 2/24/2021

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for March 2021

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	79.2	142.0	0.0	221.2
NH	35.0	131.3	0.0	166.2
VT	34.4	133.0	0.0	167.4
CT	107.8	100.8	571.4	780.0
RI	33.9	268.4	0.0	302.3
SEMA	40.1	415.2	0.0	455.3
WCMA	70.7	443.5	26.0	540.2
NEMA	58.3	764.7	0.0	822.9
Total	**459.4**	**2,398.8**	**597.4**	**3,455.6**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

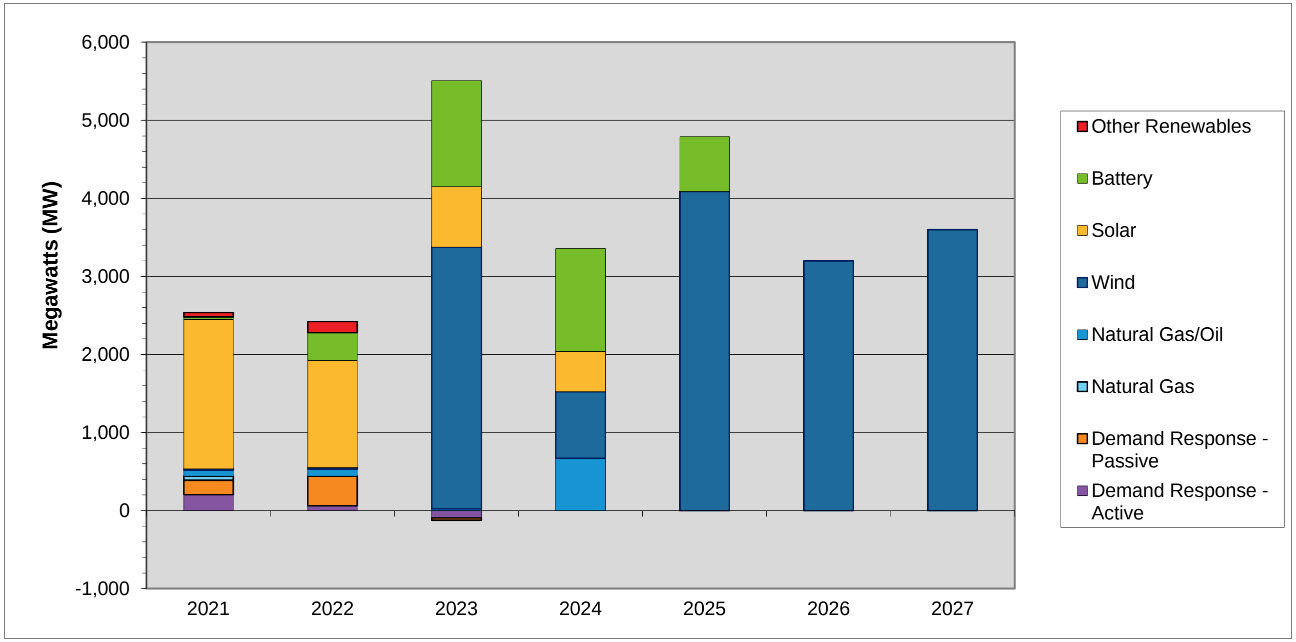
New Generation Update

Based on Queue as of 2/26/21

- Seven new projects totaling 493 MW applied for interconnection study since the last update
  - They consist of seven new PV projects, with in-service dates ranging from 2022 to 2024
- No projects went commercial or were withdrawn, but the capacity of two existing projects was reduced, resulting in a net increase in new generation projects of 373 MW
- In total, 265 generation projects are currently being tracked by the ISO, totaling approximately 24,600 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



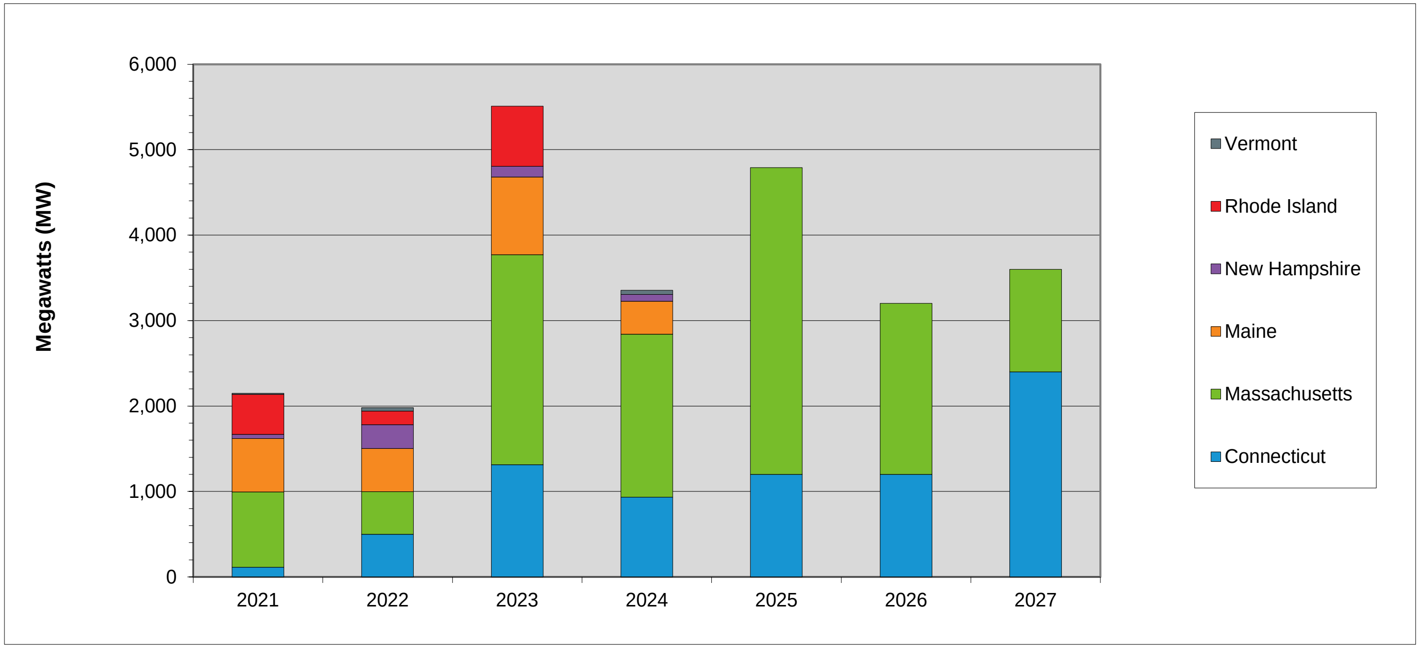
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	56	142	0	0	0	0	0	198	0.8
Battery	34	358	1,359	1,316	704	0	0	3,771	14.9
Solar[2]	1,912	1,371	772	516	0	0	0	4,571	18.1
Wind	19	20	3,355	852	4,087	3,200	3,600	15,133	59.8
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	3.4
Natural Gas	53	0	0	0	0	0	0	53	0.2
Demand Response - Passive	184	380	-28	0	0	0	0	536	2.1
Demand Response - Active	204	62	-94	0	0	0	0	172	0.7
Totals	2,538	2,422	5,387	3,356	4,791	3,200	3,600	25,294	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

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.4
Rhode Island	466	160	704	0	0	0	0	1,330	5.4
New Hampshire	50	276	126	80	0	0	0	532	2.2
Maine	625	506	907	387	0	0	0	2,425	9.9
Massachusetts	881	500	2,460	1,907	3,591	2,000	1,200	12,539	51.0
Connecticut	113	498	1,312	932	1,200	1,200	2,400	7,655	31.1
Totals	**2,150**	**1,980**	**5,509**	**3,356**	**4,791**	**3,200**	**3,600**	**24,586**	**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	1	8	1	8	0	0
Battery Storage	21	3,771	0	0	21	3,771
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	5	53	0	0	5	53
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	201	4,571	11	164	190	4,407
Wind	22	15,133	1	15	21	15,118
Total	265	24,586	17	282	248	24,304

- 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
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	132	3	23	5	109
Intermediate	9	822	1	14	8	808
Peaker	226	8,499	12	230	214	8,269
Wind Turbine	22	15,133	1	15	21	15,118
Total	265	24,586	17	282	248	24,304

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	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	1	8	1	8	0	0	0	0	0	0
Battery Storage	21	3,771	0	0	0	0	21	3,771	0	0
Fuel Cell	4	54	4	54	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	5	53	0	0	4	47	1	6	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	201	4,571	0	0	0	0	201	4,571	0	0
Wind	22	15,133	0	0	0	0	0	0	22	15,133
Total	265	24,586	8	132	9	822	226	8,499	22	15,133

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 11

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*	419.928	441.221	21.293	594.551	153.33	584.35	-10.201
Demand	*Passive Demand*	2,791.02	2,835.354	44.334	2,883.767	48.413	2,964.695	80.928
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**	**3,549.045**	**70.727**
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661	2,9678.995	-480.896
Generator	*Intermittent*	894.217	823.796	-70.421	809.571	-14.225	689.524	-120.047
Generator Total		**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**	**30,368.519**	**-600.943**
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**	**1,124.6**	**-485.244**
Grand Total*		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**	**35,042.164**	**-1015.46**
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**	**32,205**	**-1,315**

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 12

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*	624.445	659.137	34.692	603.776	-55.361		
	Passive Demand	2,975.36	3,045.073	69.713	31,23.232	78.159		
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**37,27.008**	**22.798**		
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159		
	Intermittent	880.317	806.609	-73.708	660.932	-145.677		
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**		
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**		
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**		
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,320**	**-230**		

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 13

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*	685.554	683.116	-2.438				
	Passive Demand	3,354.69	3,407.507	52.817				
Demand Total		**4,040.244**	**4,090.623**	**50.38**				
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157				
	Intermittent	1,024.792	901.672	-123.12				
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**				
Import Total		**1,187.69**	**1,292.41**	**104.72**				
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**				
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**				

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

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						
	Passive Demand	3,327.071						
Demand Total		**3,919.114**						
Generator	*Non-Intermittent*	27,816.902						
	Intermittent	1,160.916						
Generator Total		**28,977.818**						
Import Total		**1,058.72**						
Grand Total*		**33,955.652**						
Net ICR (NICR)		**32,490**						

* 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 bilaterals and reconfiguration auction 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 2015-2020 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						
	Passive Demand		3,212.865						
Demand Total			**3,890.538**						
Generator		*Non-Intermittent*	28,154.203						
		Intermittent	1,089.265						
Generator Total			**29,243.468**						
Import Total			**1,487.059**						
Grand Total*			**34,621.065**						
Net ICR (NICR)			**33,270**						

* 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 bilaterals and reconfiguration auction 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 2015-2020 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**

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

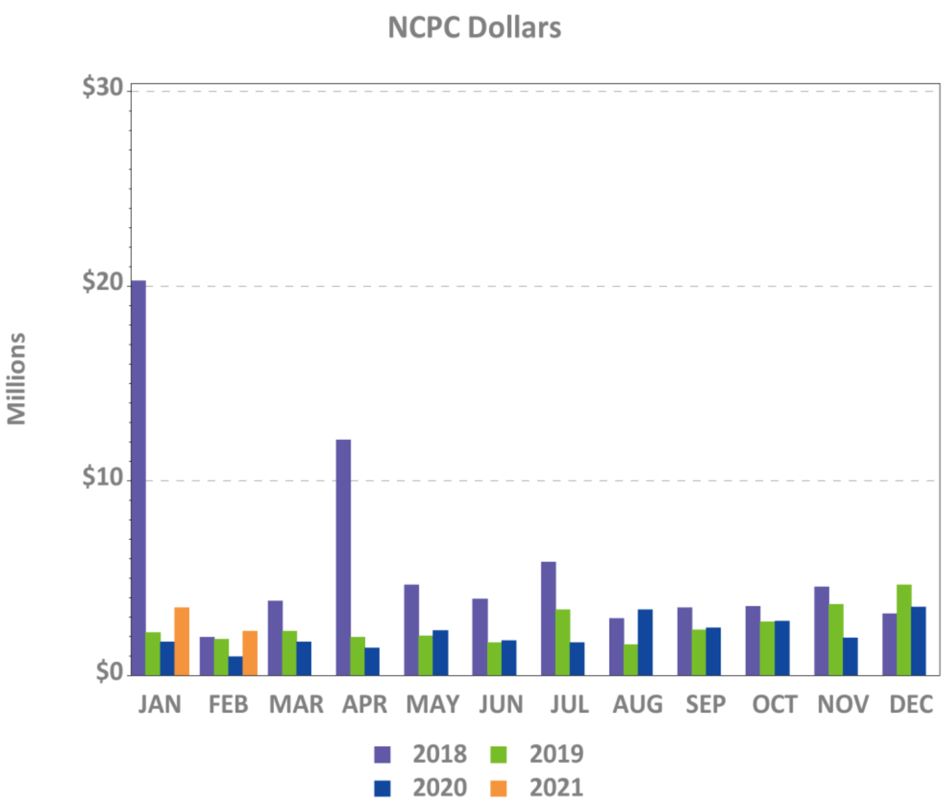
Definitions

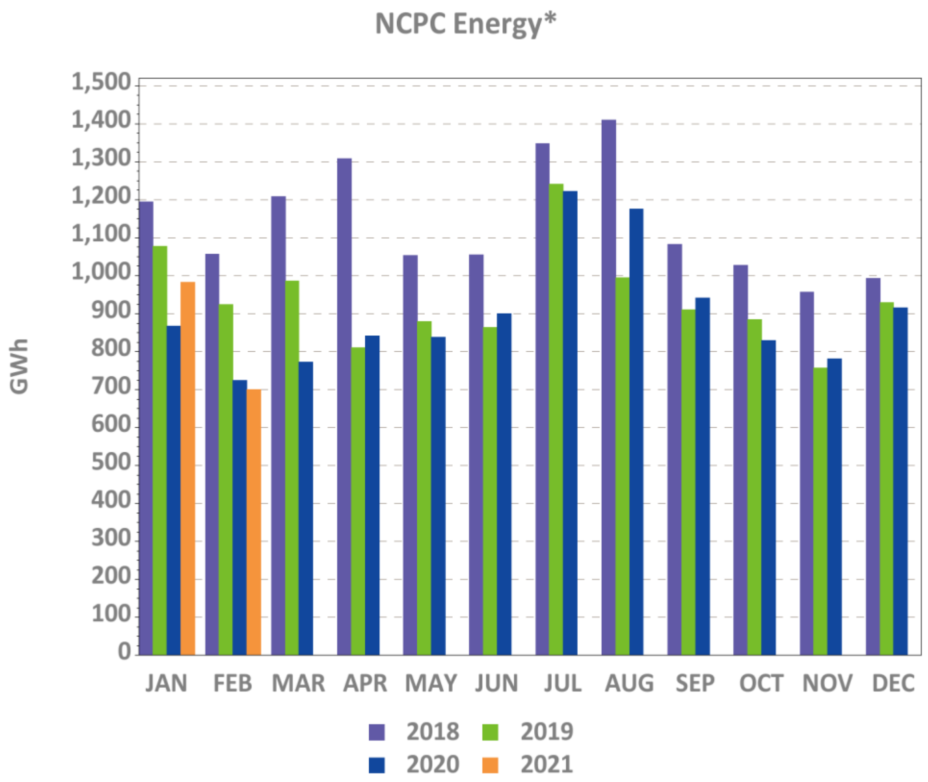
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd 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 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st 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 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd 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).

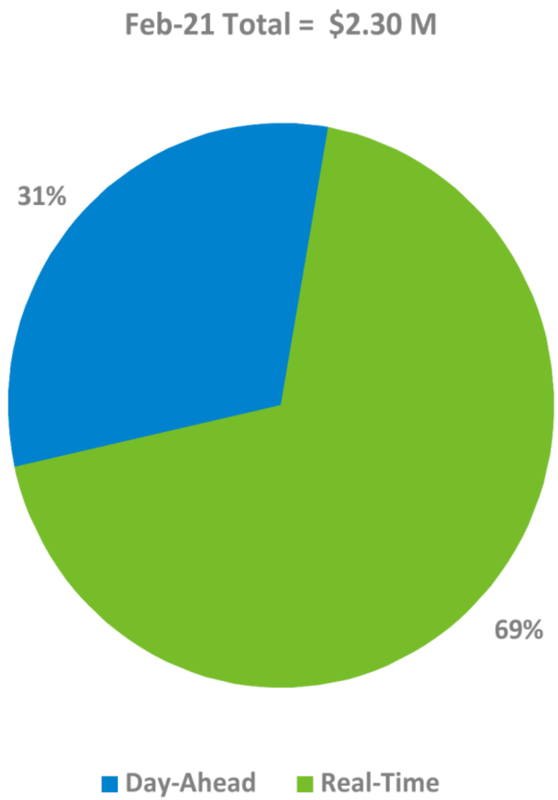
Year-Over-Year Total NCPC Dollars and Energy



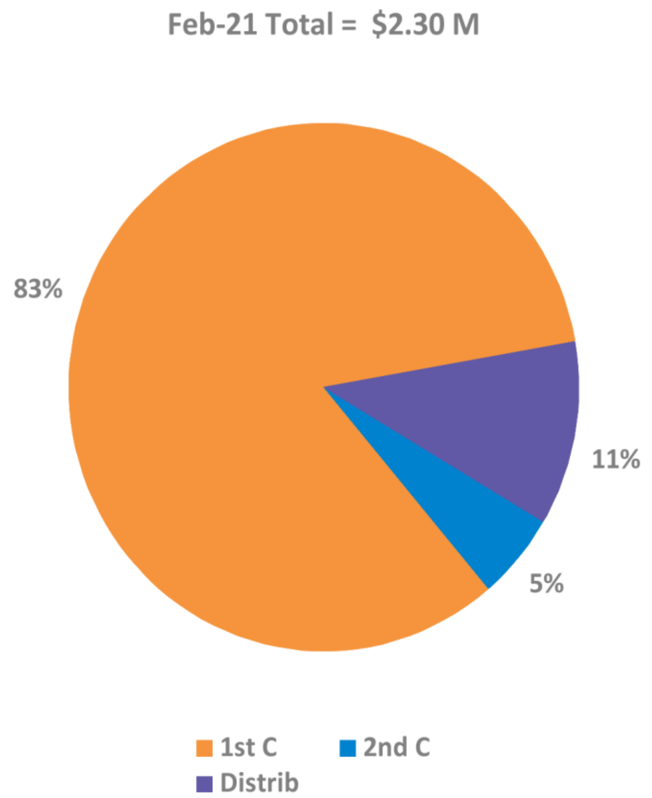


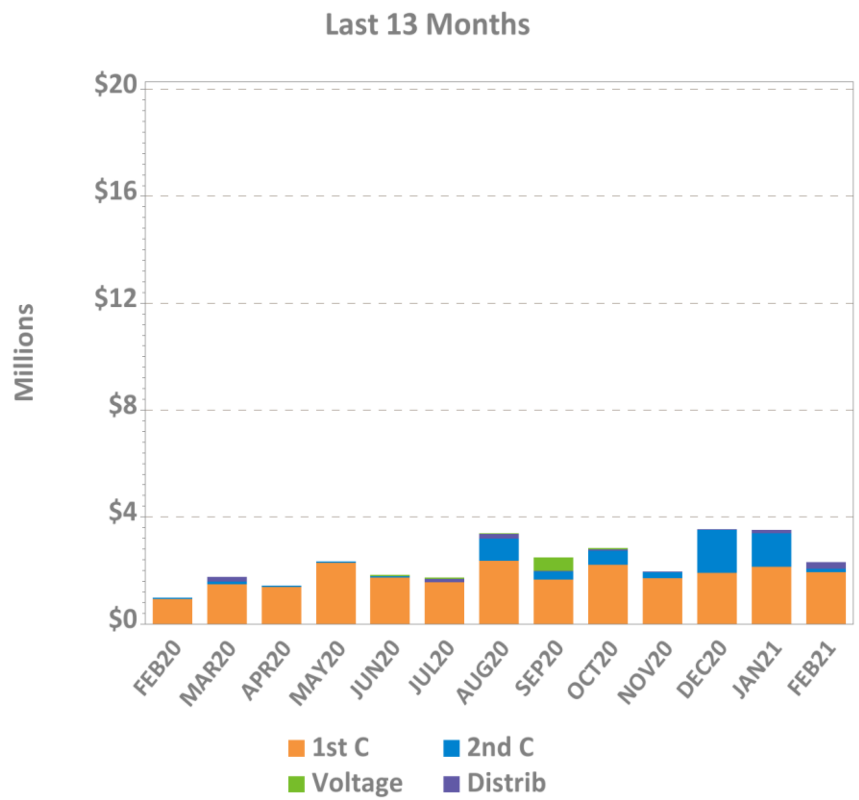
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



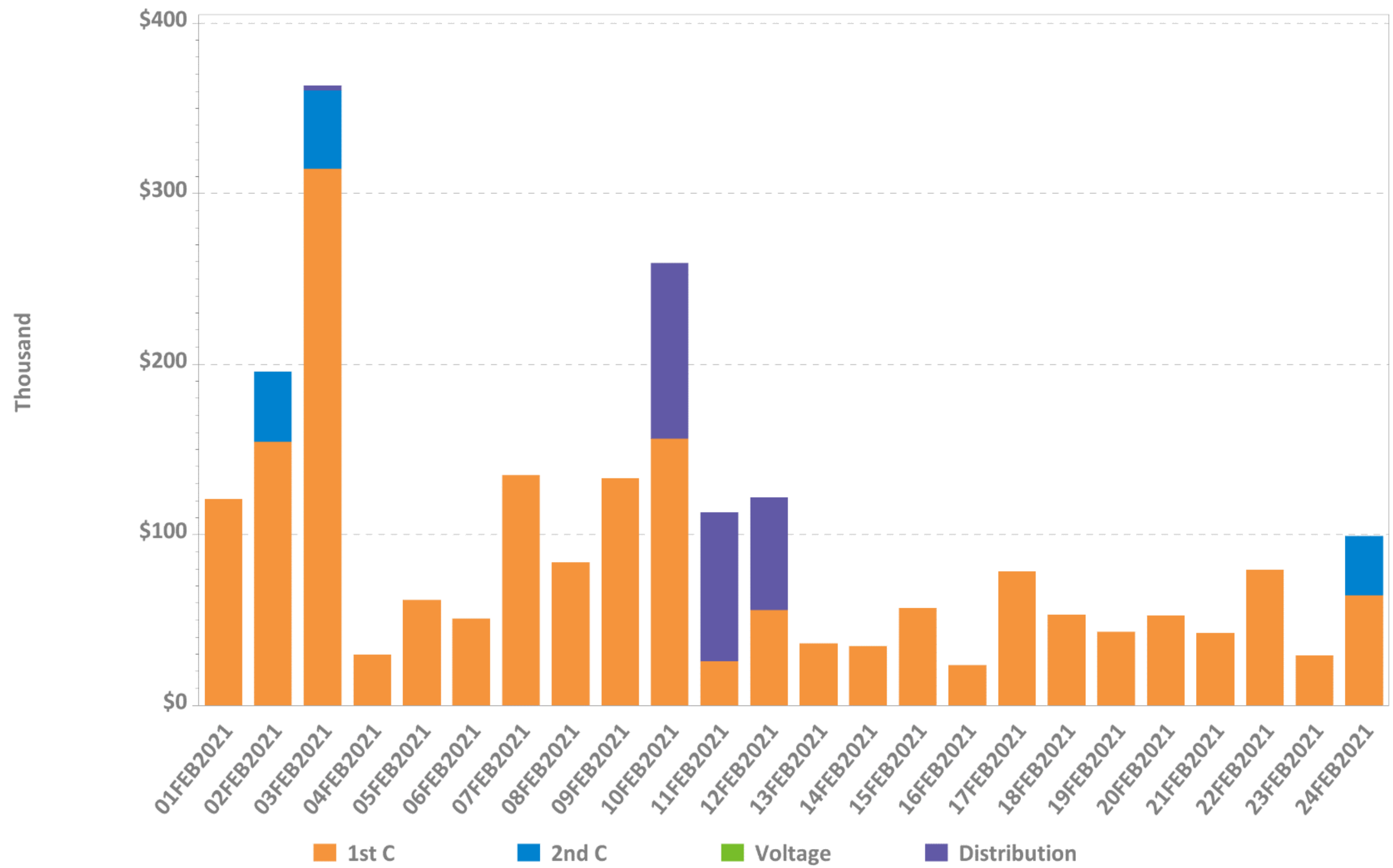
NCPC Charges by Type



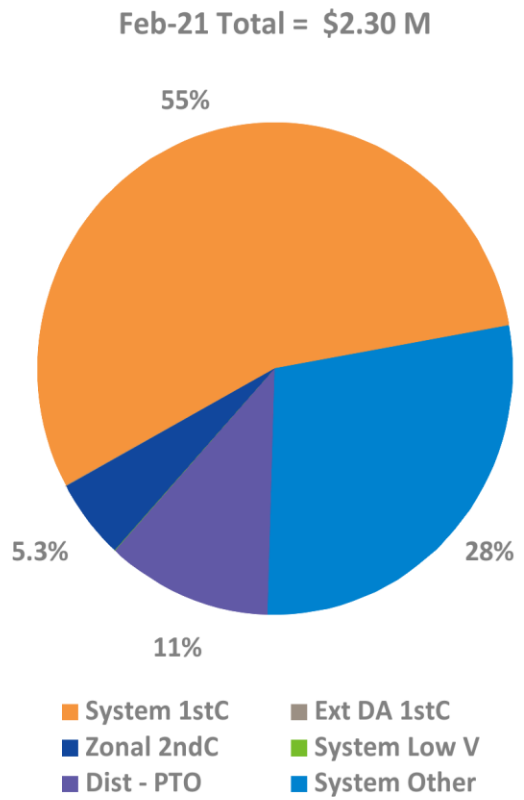


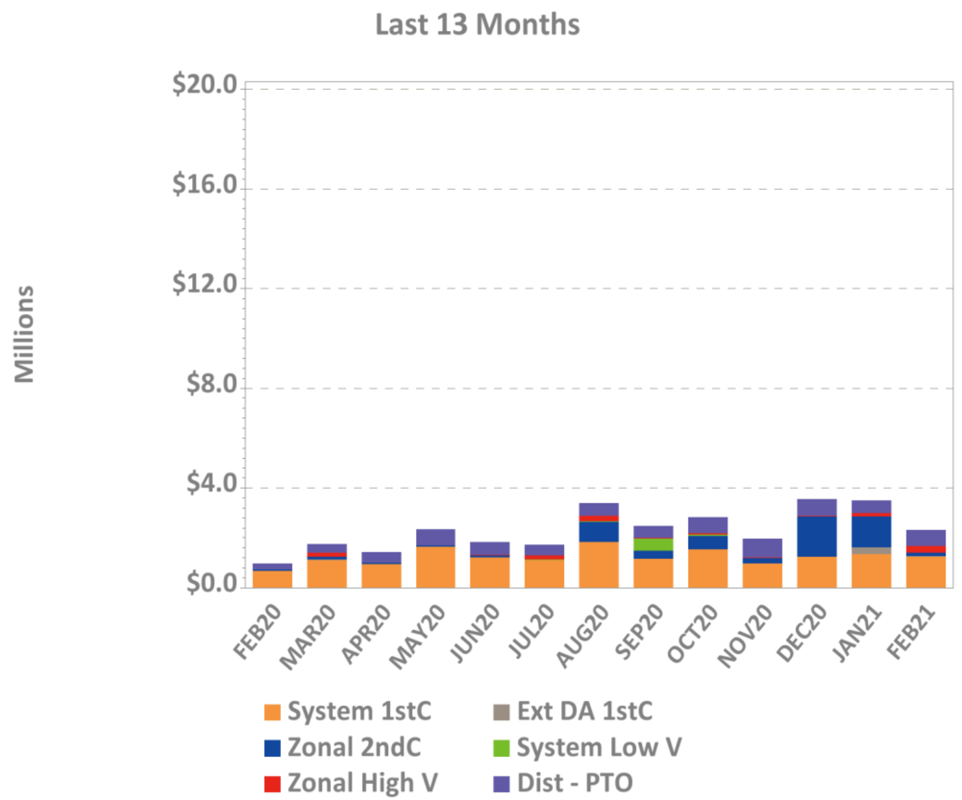
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



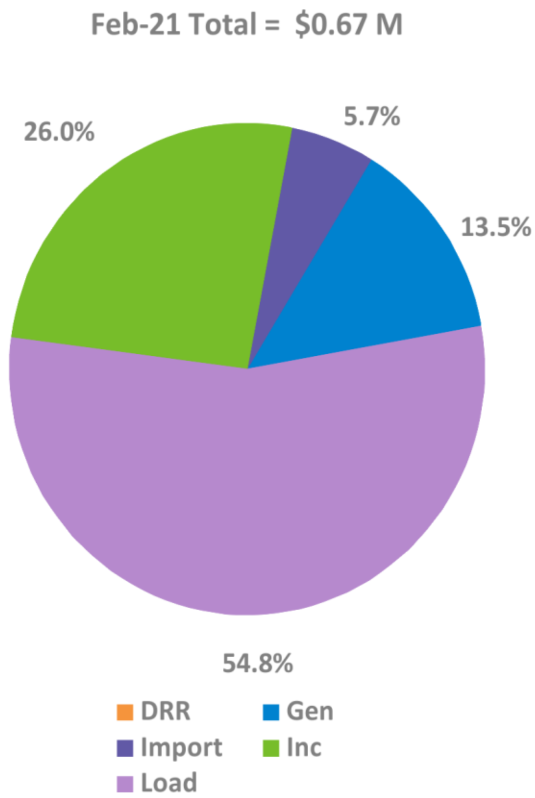
NCPC Charges by Allocation

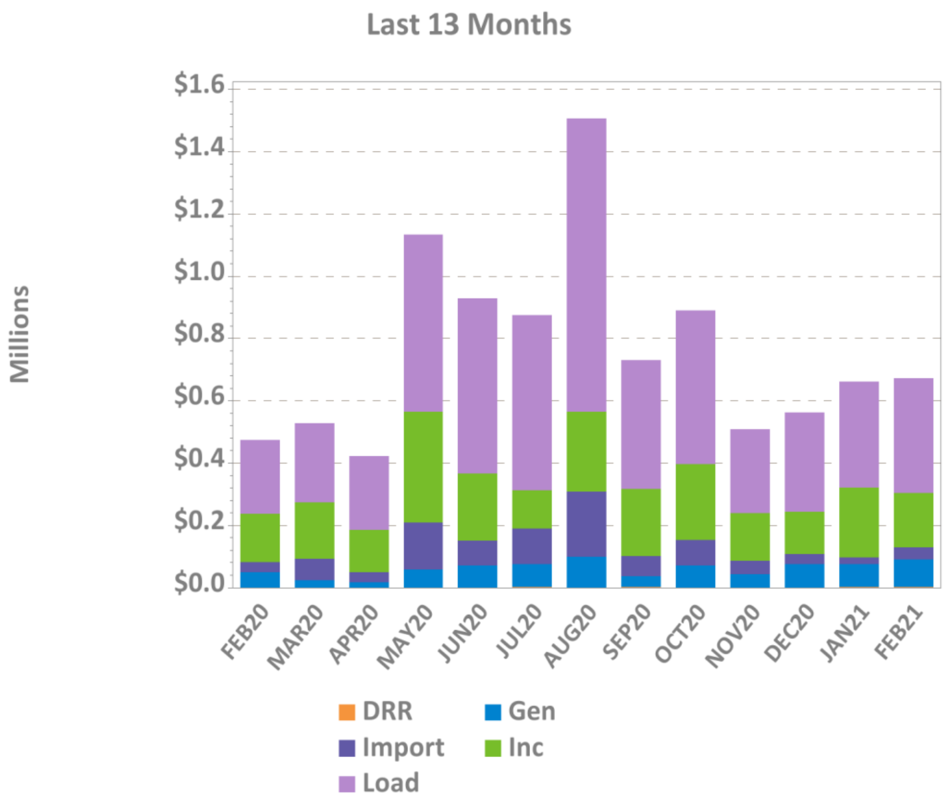




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

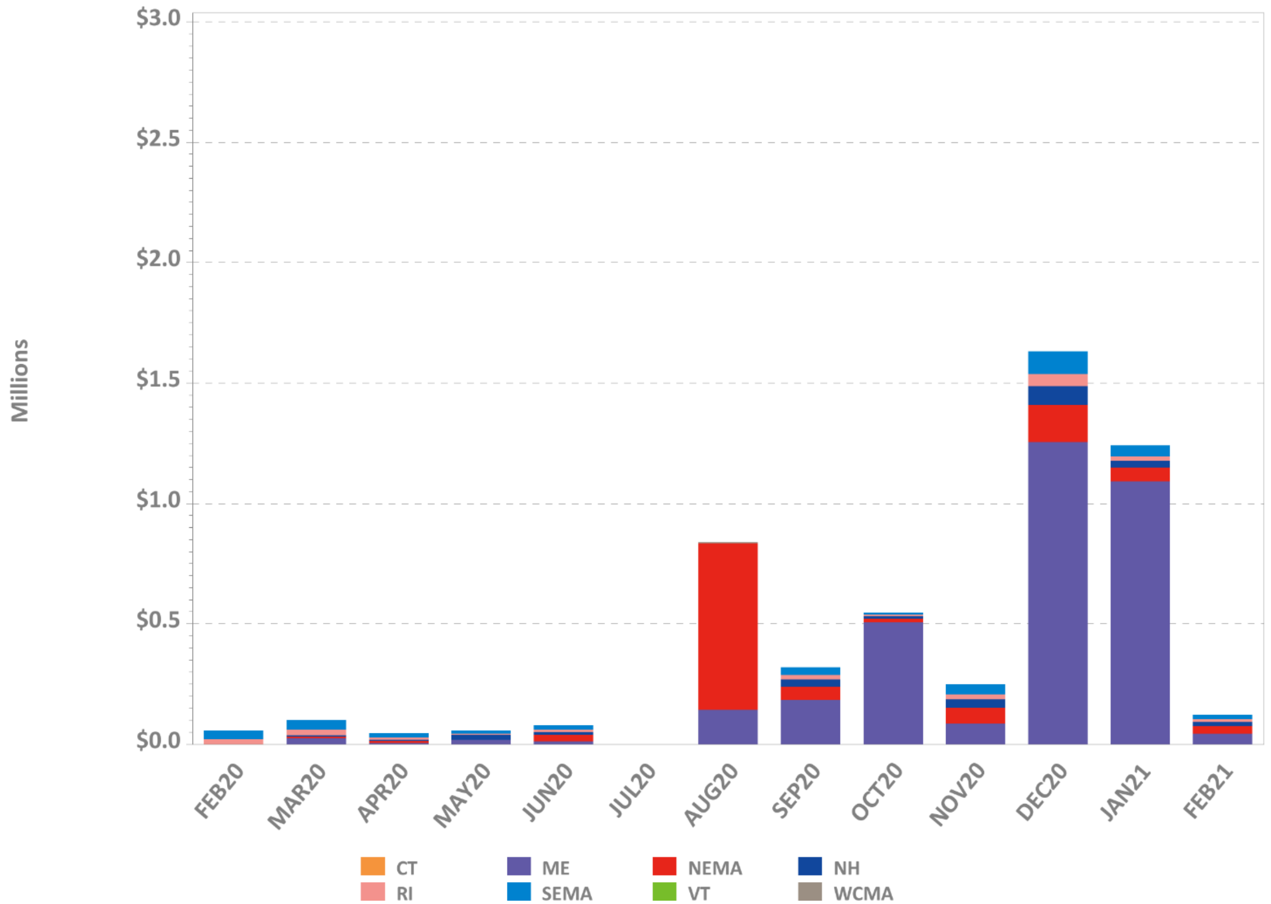
RT First Contingency Charges by Deviation Type





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

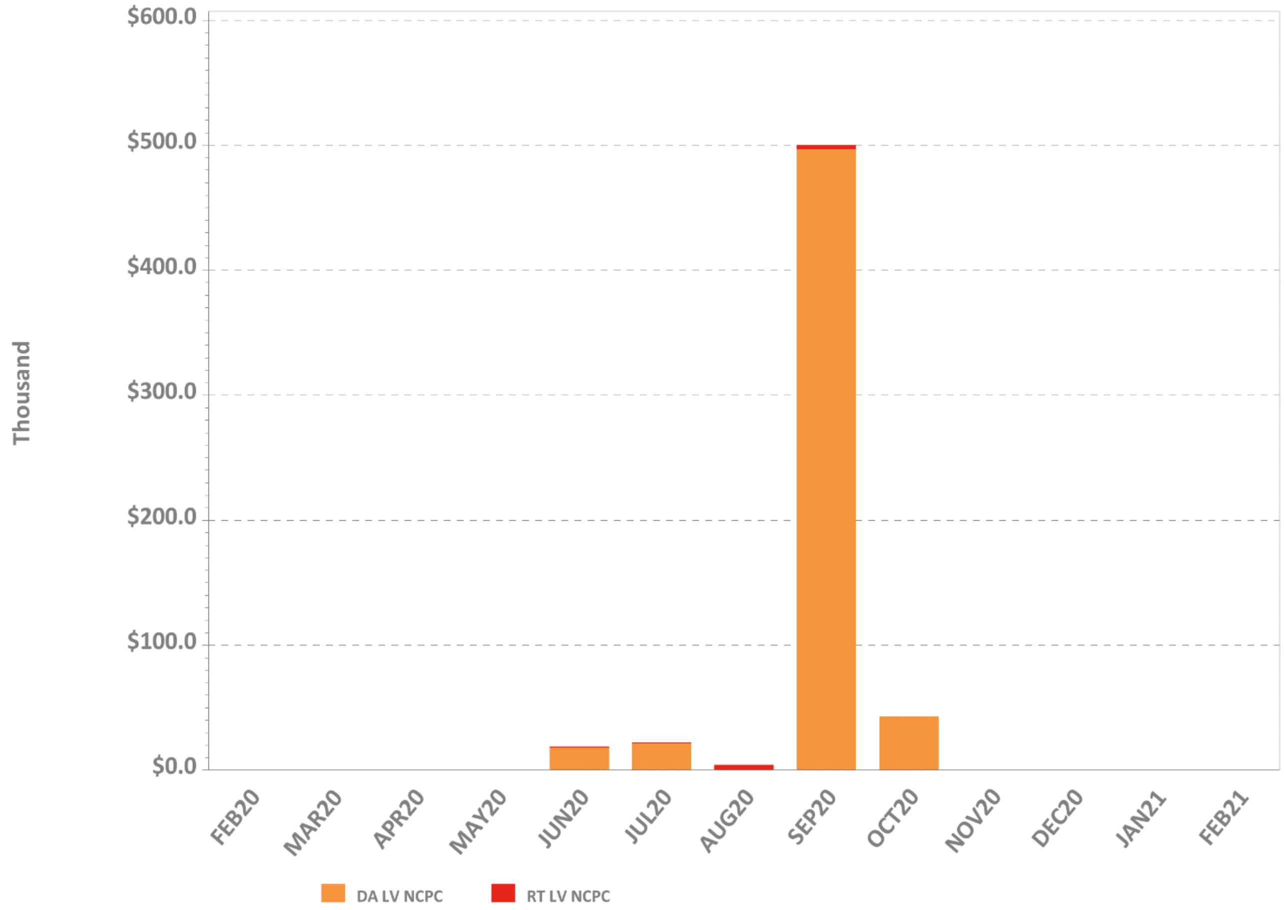
LSCPR Charges by Reliability Region



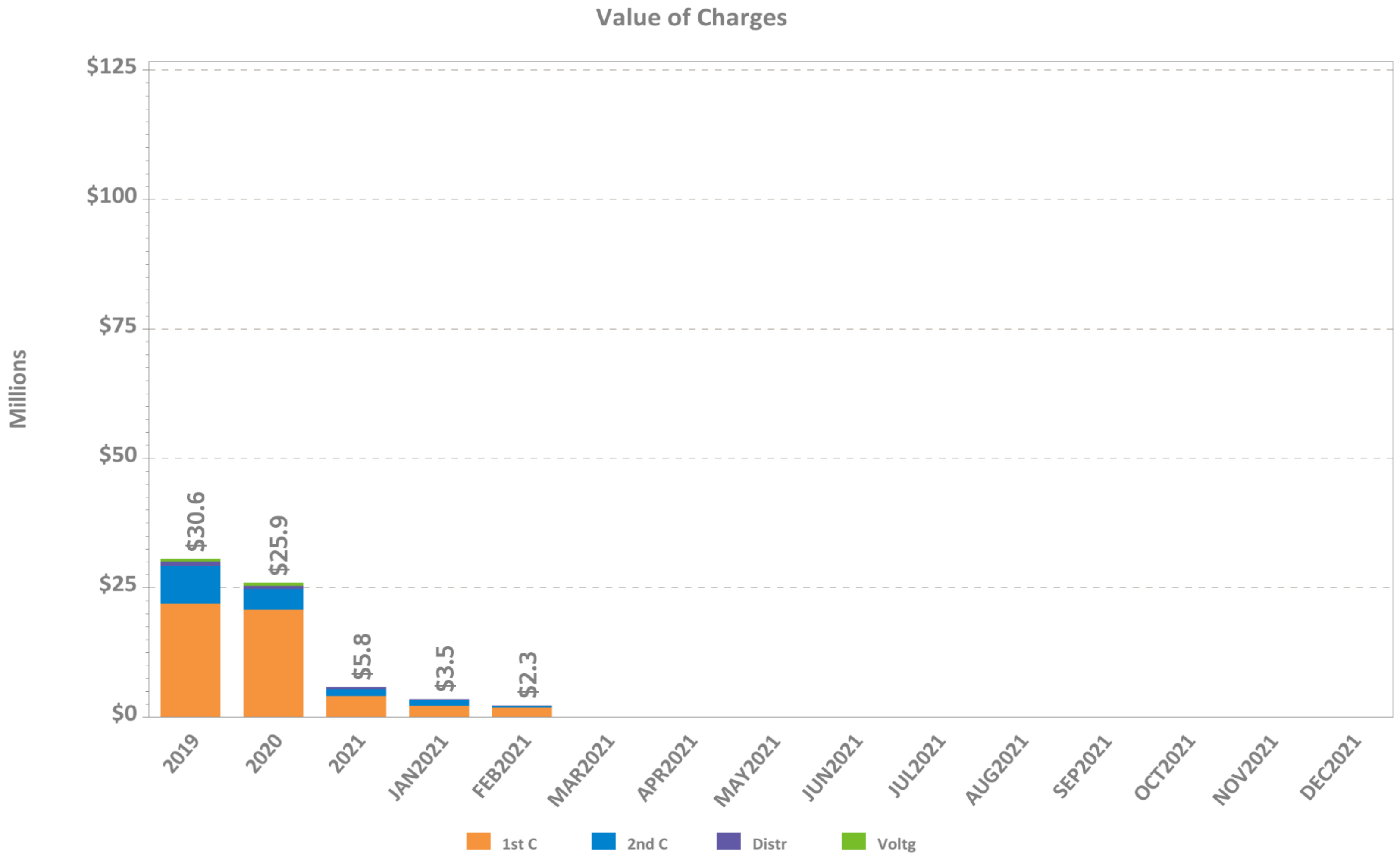
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

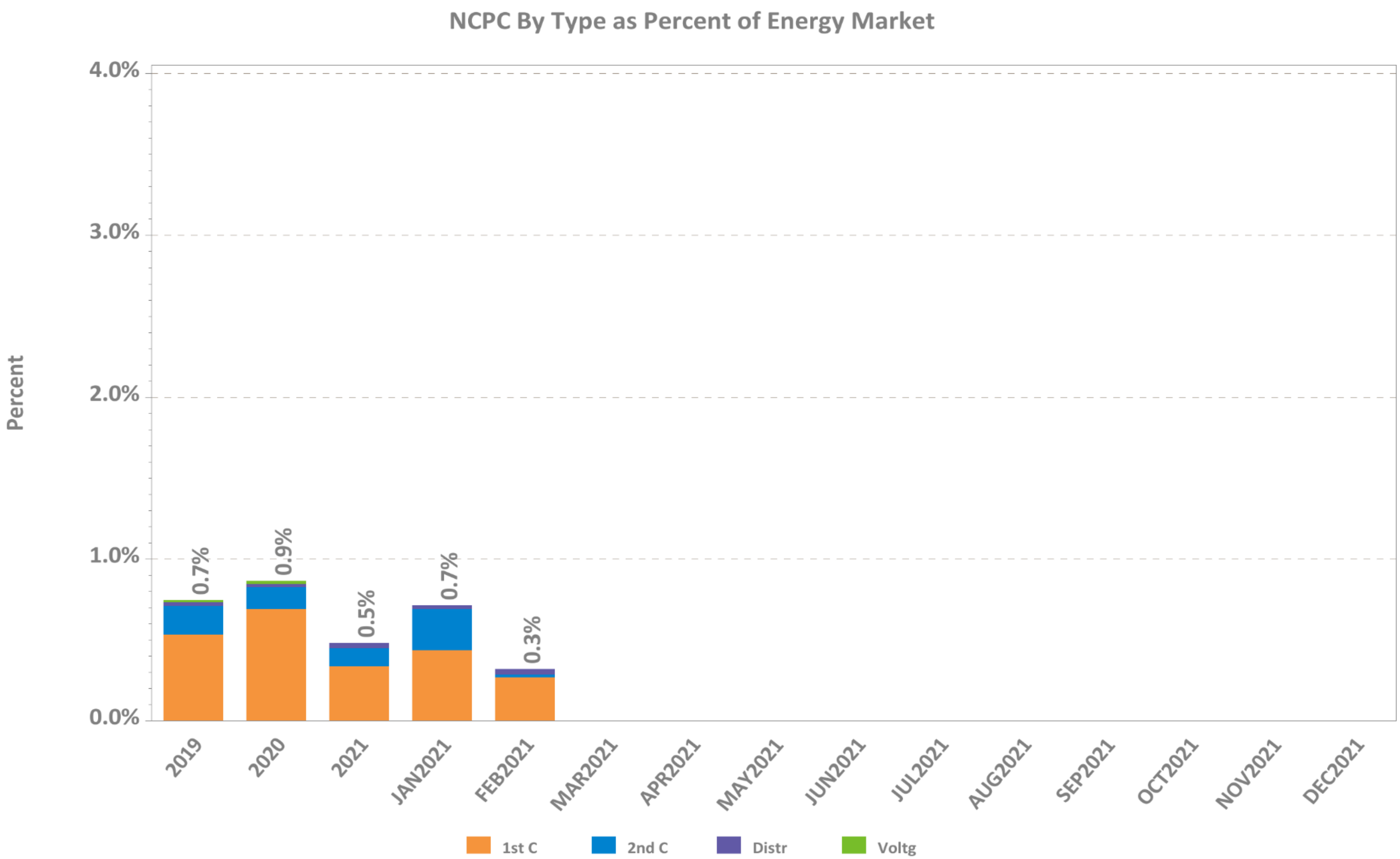
NCPC Charges for Voltage Support and High Voltage Control



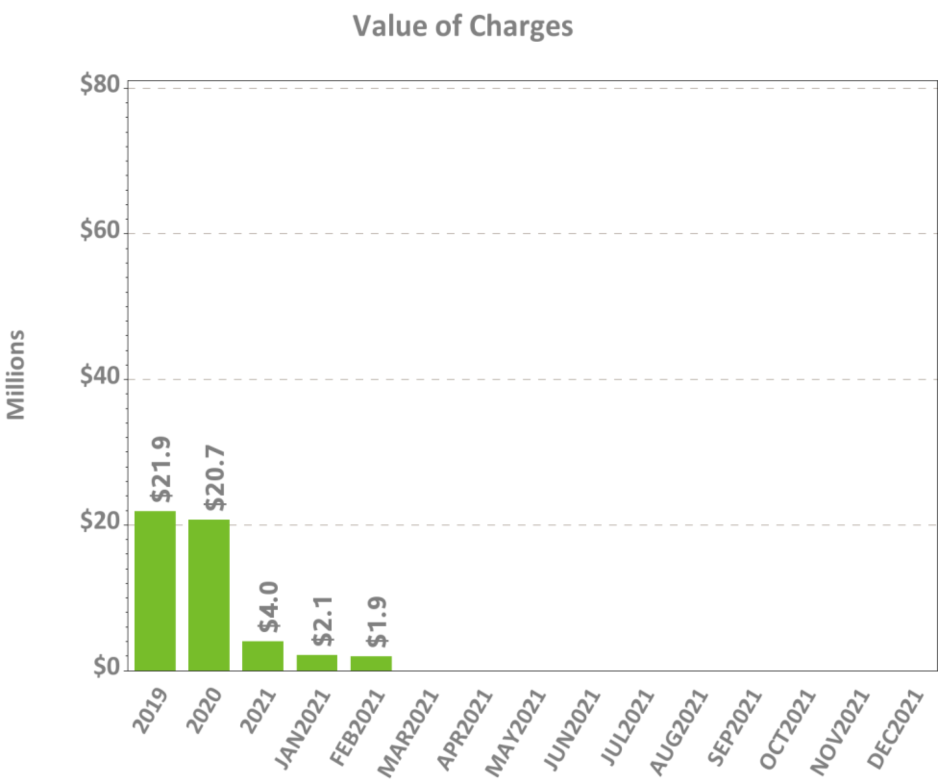
NCPC Charges by Type

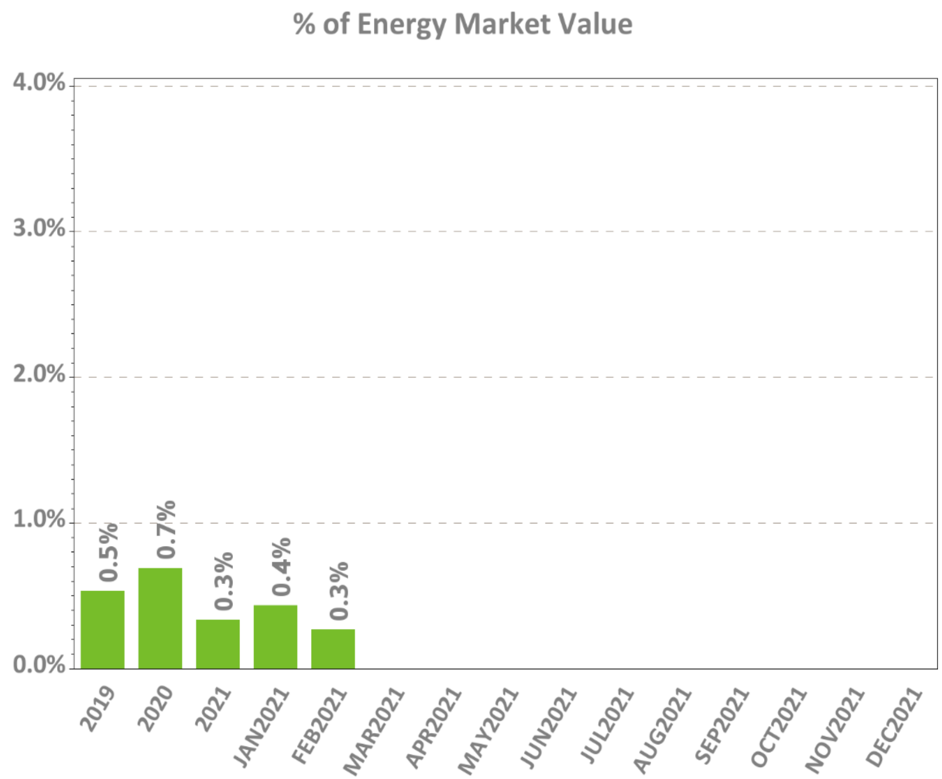


NCPC Charges as Percent of Energy Market



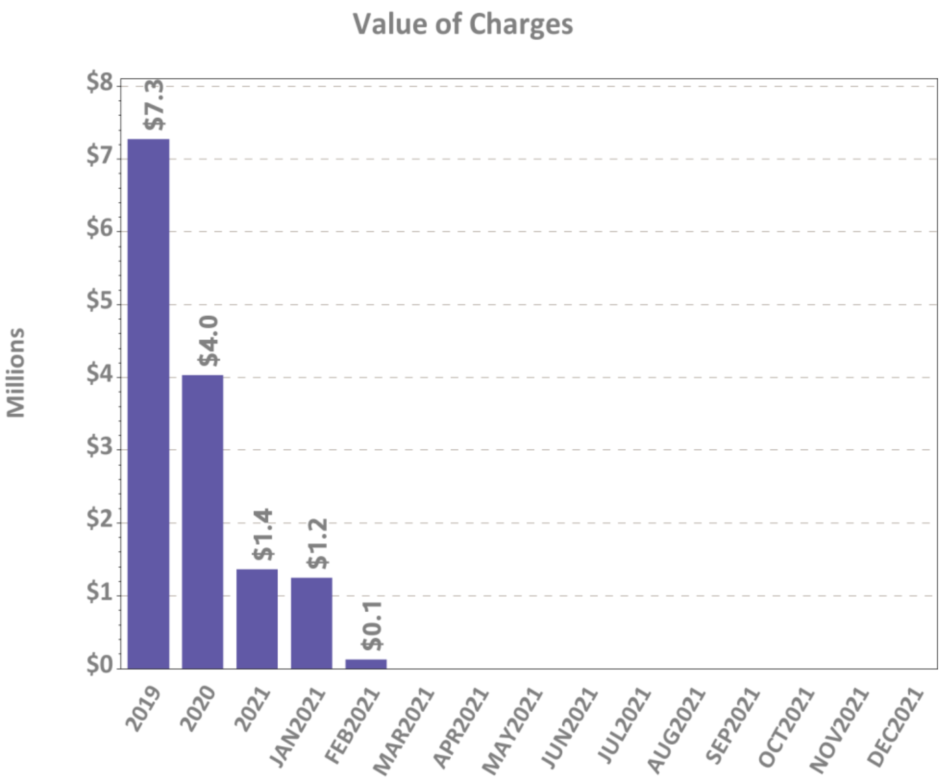
First Contingency NCPC Charges

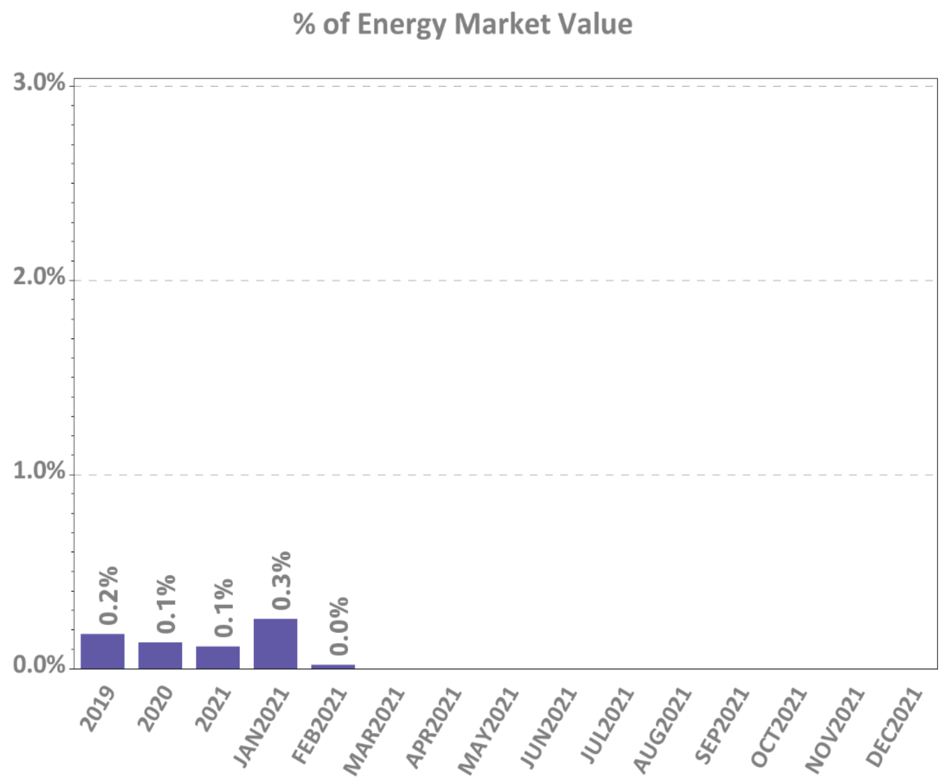




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

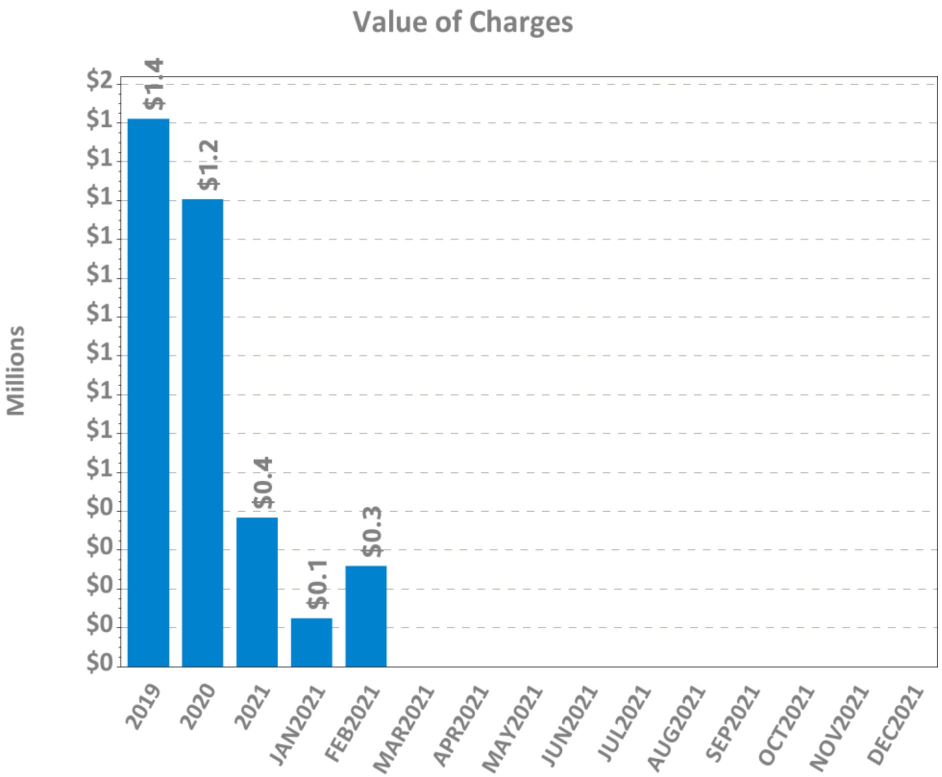
Second Contingency NCPC Charges

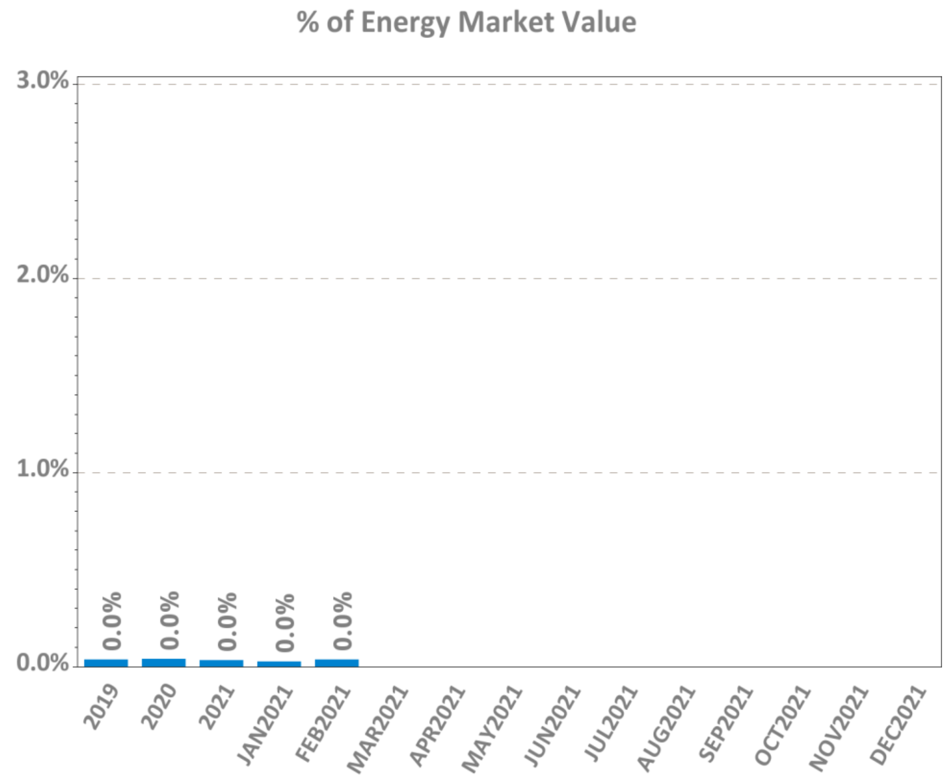




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

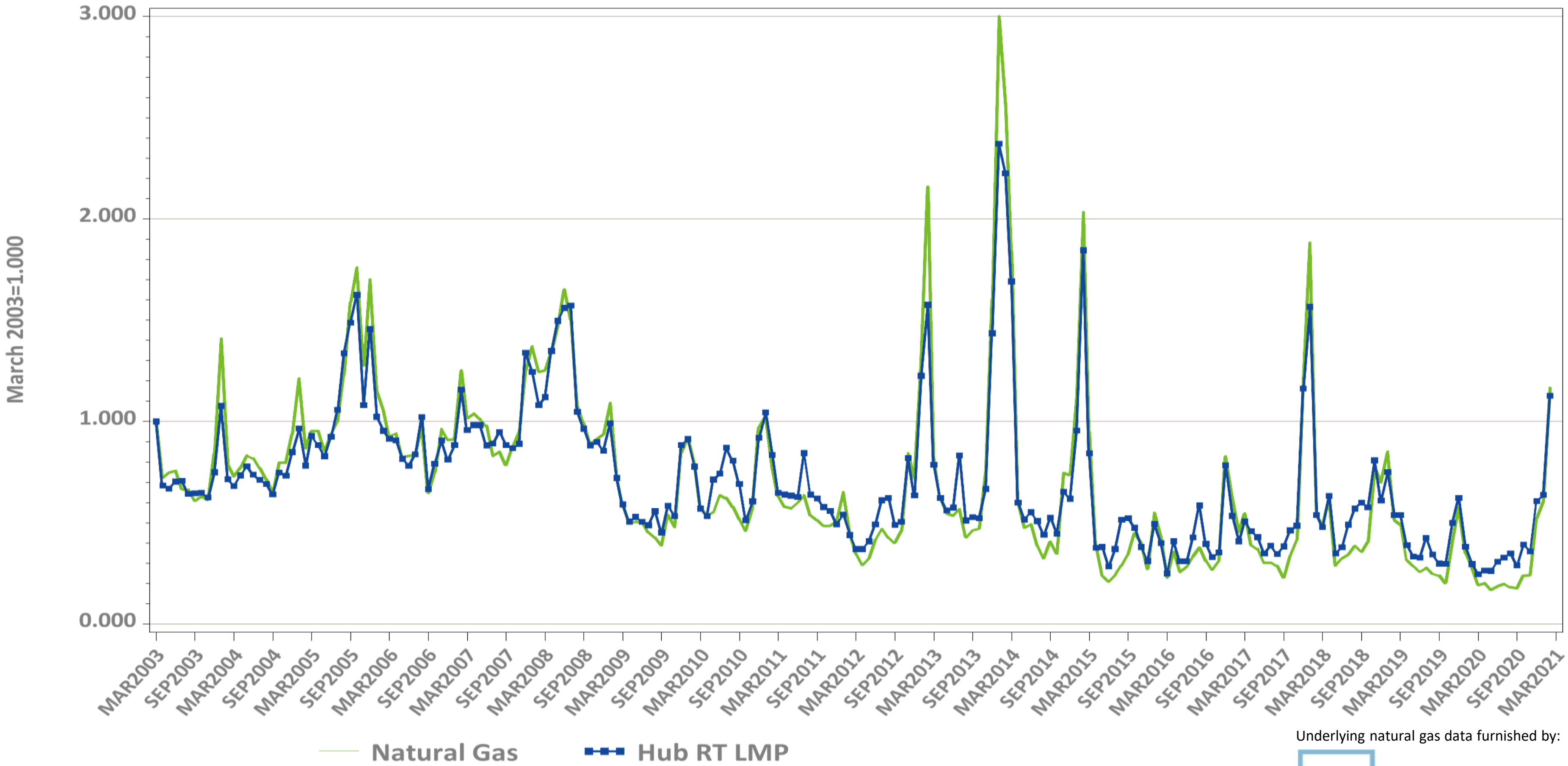
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%
Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%

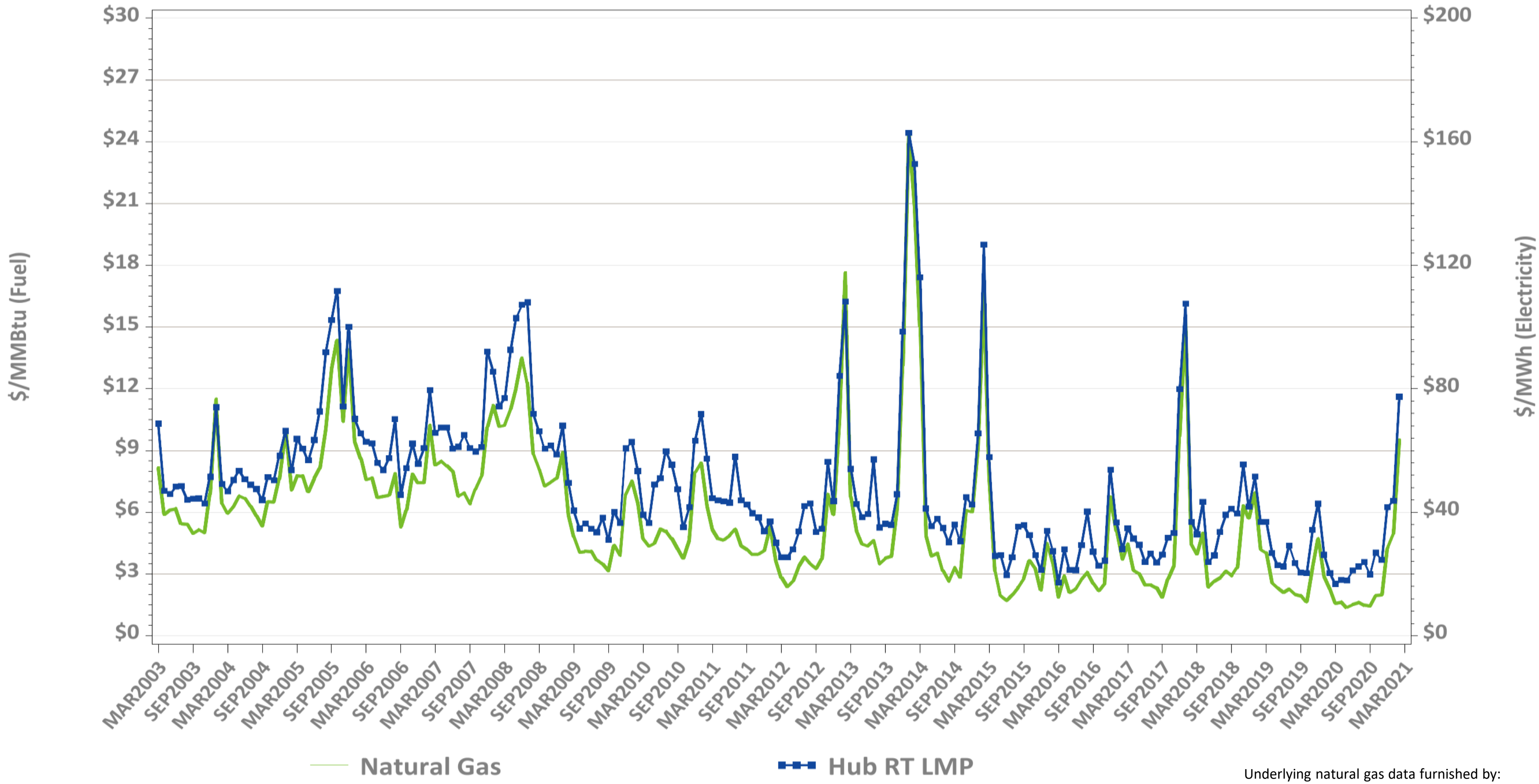
February-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.31	$22.34	$23.14	$23.27	$22.64	$23.01	$23.26	$23.04	$23.06
Real-Time	$20.53	$19.80	$20.34	$20.53	$19.98	$20.29	$20.50	$20.29	$20.32
RT Delta %	-11.9%	-11.4%	-12.1%	-11.8%	-11.8%	-11.8%	-11.9%	-11.9%	-11.9%
February-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$80.53	$77.91	$79.83	$80.29	$78.93	$80.42	$80.64	$80.10	$80.15
Real-Time	$77.90	$75.11	$76.97	$77.53	$76.18	$77.60	$77.91	$77.35	$77.42
RT Delta %	-3.3%	-3.6%	-3.6%	-3.4%	-3.5%	-3.5%	-3.4%	-3.4%	-3.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	245.5%	248.7%	245.0%	245.0%	248.6%	249.5%	246.7%	247.7%	247.6%
Yr over Yr RT	279.4%	279.4%	278.4%	277.6%	281.3%	282.4%	280.1%	281.2%	281.1%

Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by: ice Global markets in clear view

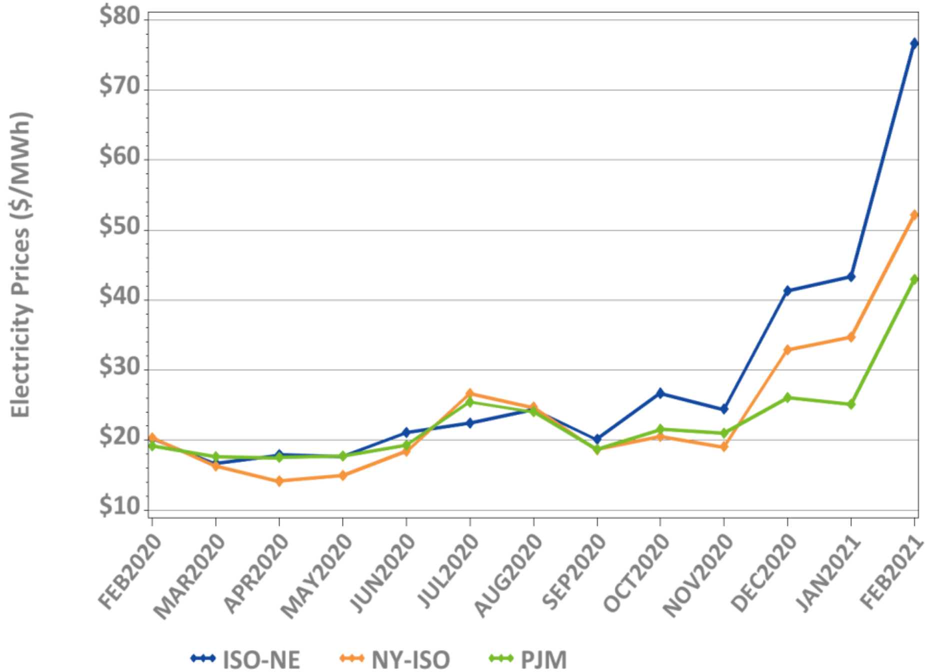
Monthly Average Fuel Price and RT Hub LMP



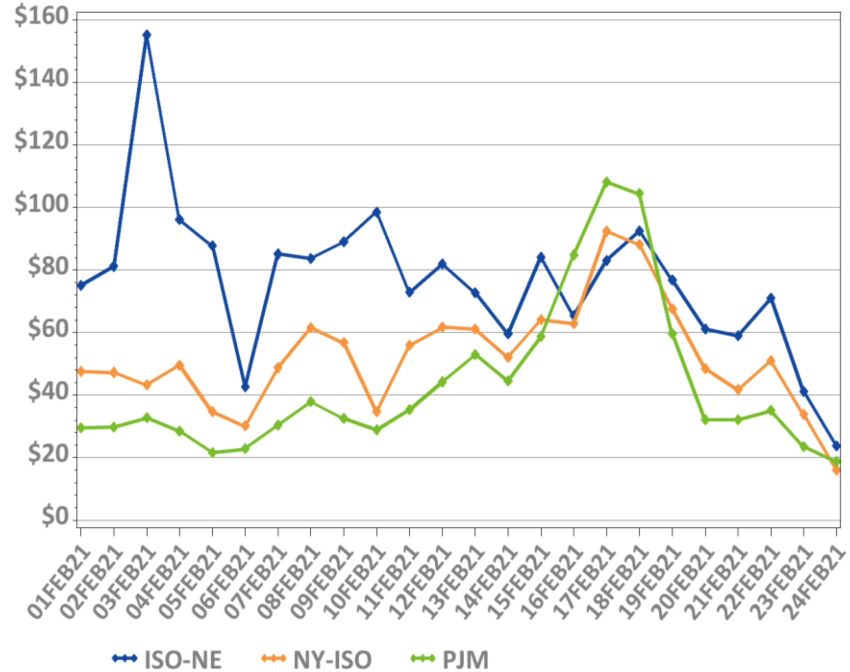
Underlying natural gas data furnished by:

ice Global markets in clear view

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

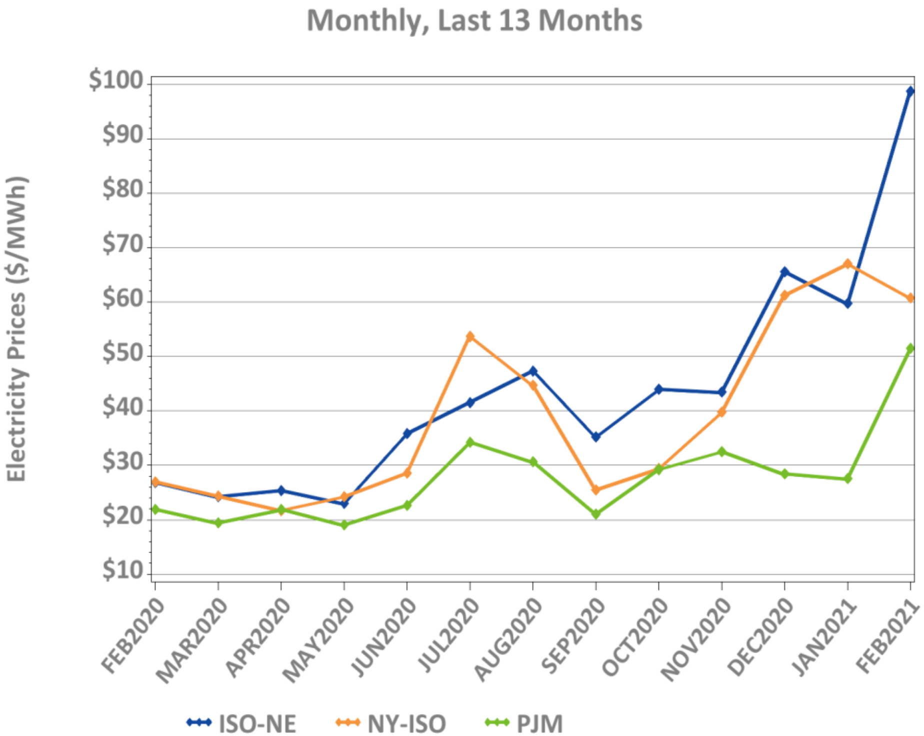


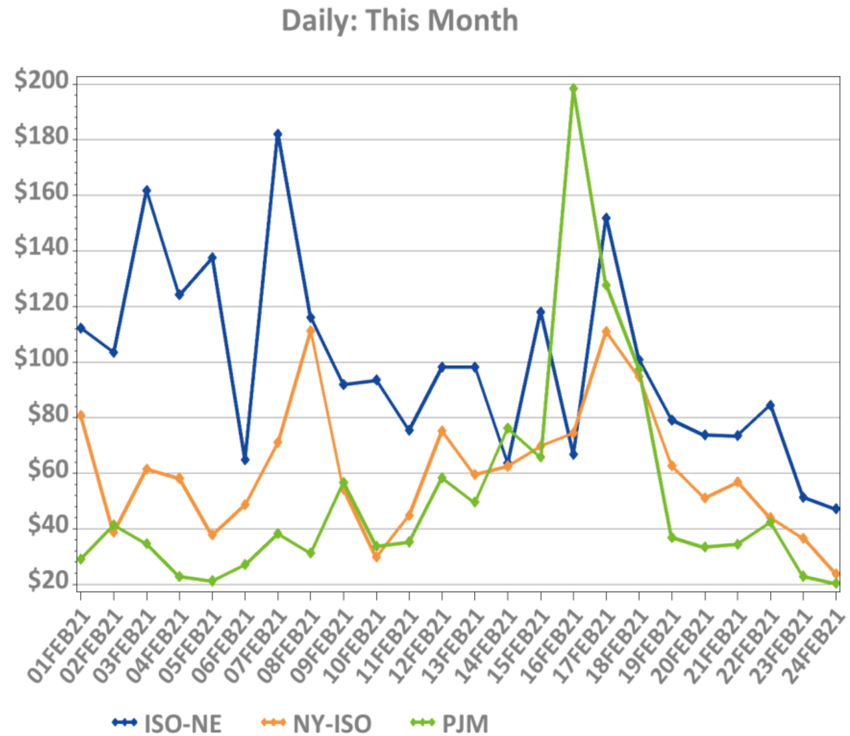
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





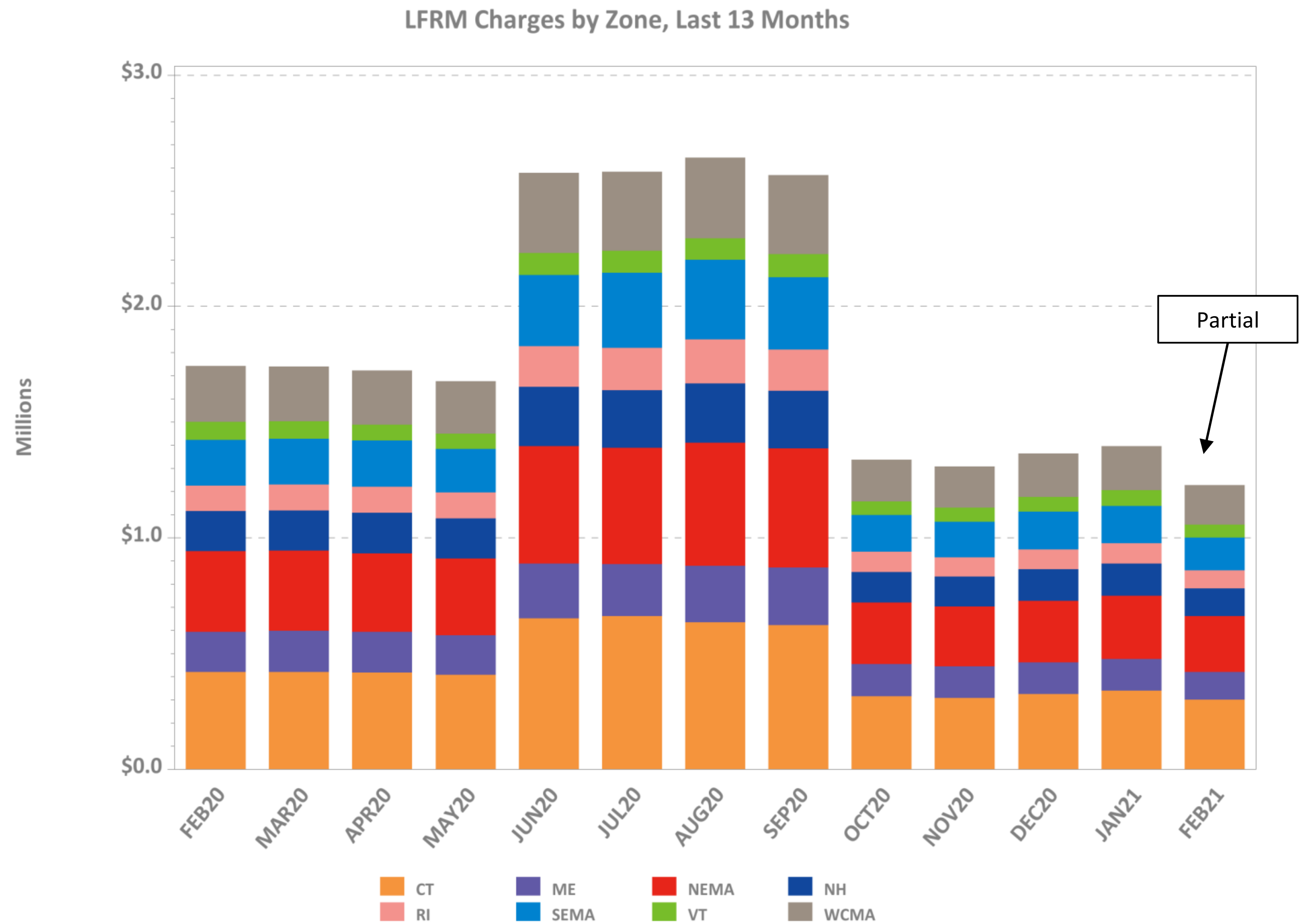
***Forecasted New England daily peak hours reflected**

Reserve Market Results – February 2021

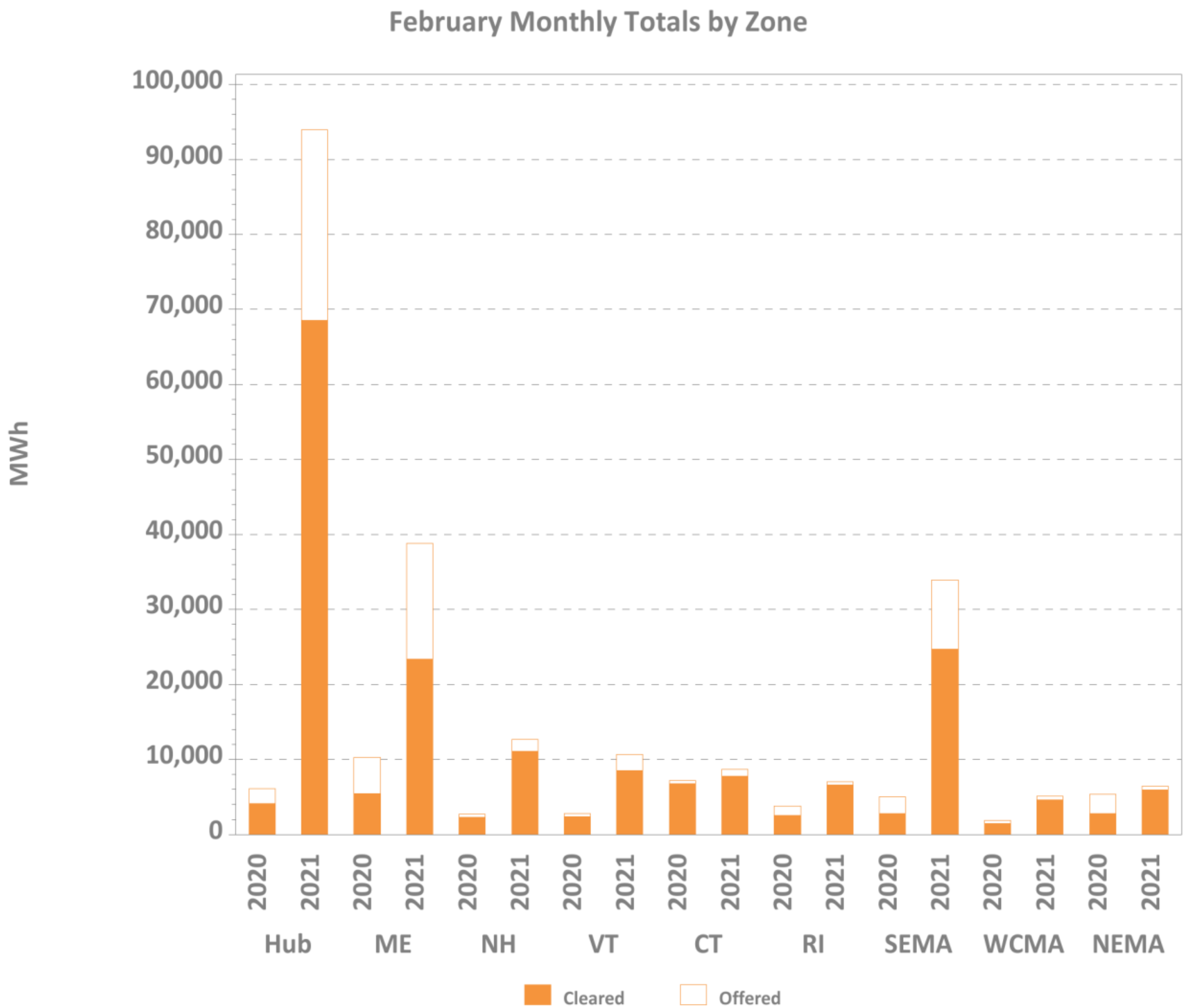
- Maximum potential Forward Reserve Market payments of $1.3M were reduced by credit reductions of $22K, failure-to-reserve penalties of $33K, and no failure-to-activate penalties, resulting in a net payout of $1.2M or 96% of maximum
  - Rest of System: $0.94M/1M (95%)
  - Southwest Connecticut: $0.04M/0.04M (100%)
  - Connecticut: $0.25M/0.25M (99%)
- $506K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $506K in Real-Time Reserve payments
  - Rest of System: 154 hours, $351K
  - Southwest Connecticut: 154 hours, $90K
  - Connecticut: 154 hours, $17K
  - NEMA: 154 hours, $48K

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.

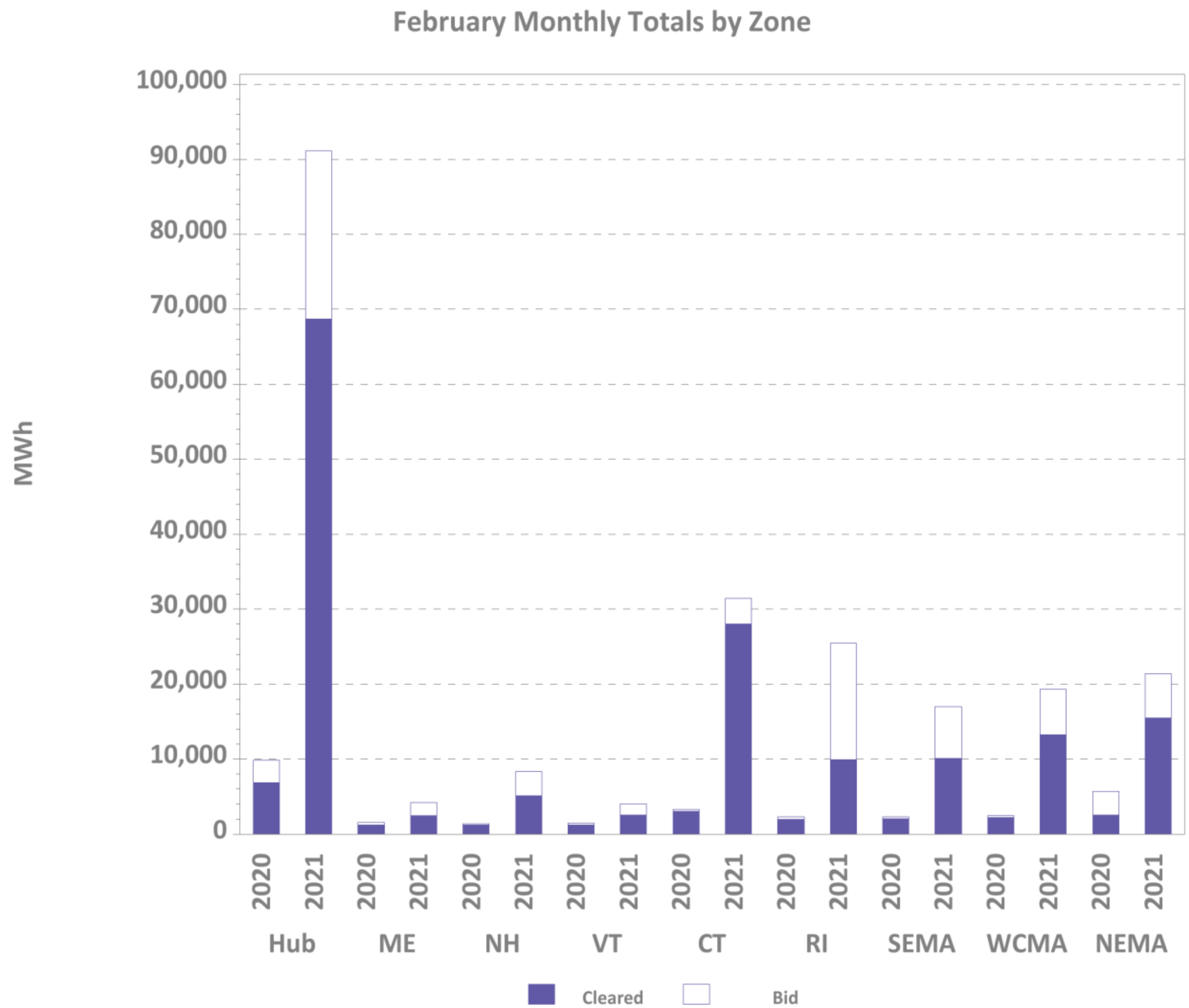
LFRM Charges to Load by Load Zone ($)



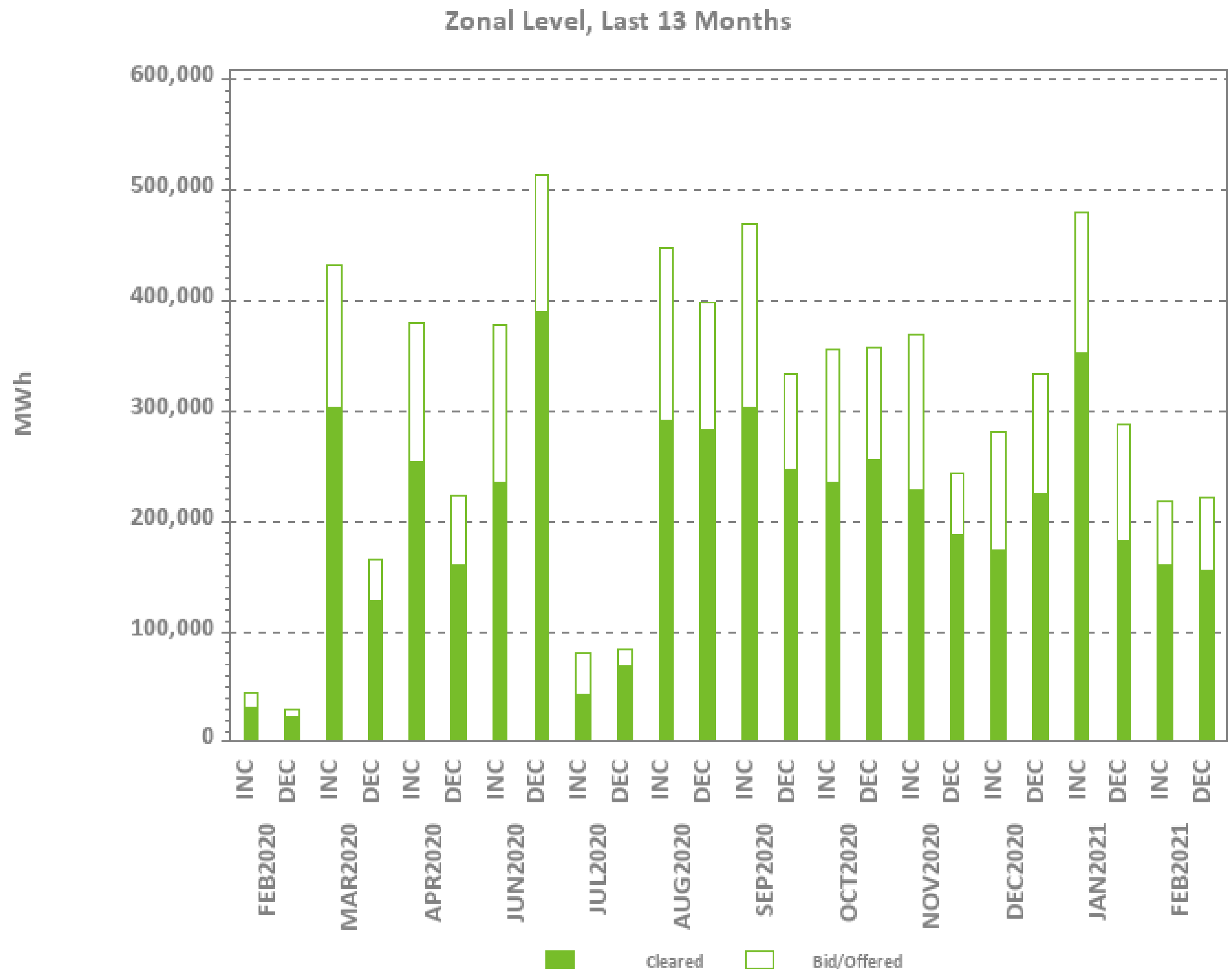
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

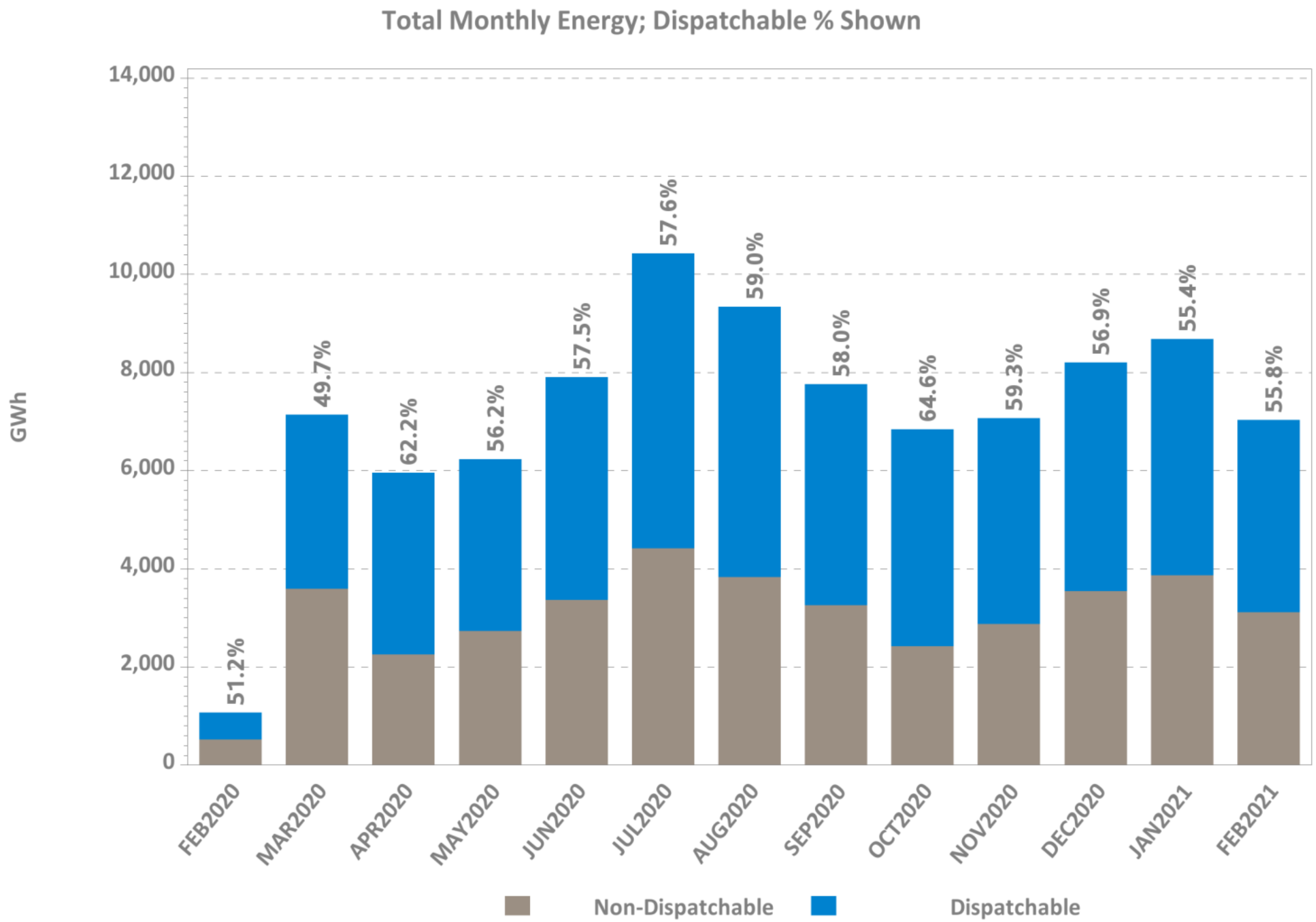


Total Increment Offers and Decrement Bids



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)

- 2021 is an RSP publication year (RSP21)
- Goal is to improve value and usability of the RSP report
  - The ISO received valuable stakeholder feedback as part of the spring 2020 survey
- Target is for RSP21 to be 50% shorter in length than RSP19
  - Static information found in the RSP to be moved to the ISO-NE website
  - Dynamic information found in the RSP to be included in the report but at a high level
- ISO will improve the reporting of information related to the New England regional system planning process with:
  - Better utilization of the ISO-NE website
  - More frequent reporting
  - Tables/graphics in a format that is easily downloadable
- RSP21 Public Meeting date is set for October 6
  - Venue and format have yet to be decided

Planning Advisory Committee (PAC)

- March 17 PAC Meeting Agenda Topics*
  - Lower Maine 2030 Needs Assessment Results
  - FCA 16 Zonal Boundary Determinations
  - RSP21 Process Kick-off
  - Western and Central Massachusetts (WCMA) 2029 Solutions Study Scope of Work
  - Cape Cod Resource Integration Study Preliminary Results
  - Storage in Transmission Planning Studies
  - Draft 2021 CELT Load Forecast Update
  - NPCC Directory #1 Asset Condition Update - Phase 3-5
  - Regional System Plan Transmission Projects and Asset Condition March 2021 Update
  - New Hampshire 115 kV Laminate Structure Replacements

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

Transmission Planning for the Clean-Energy Transition

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Study work is in progress, with results expected in Q2

Economic Studies

- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Additional sensitivities may be addressed as part of the Future Grid Reliability Study
    - Ancillary Services simulations will not be performed
    - Report to be completed by June 1
- 2021 Economic Study requests are due April 1
  - Submitted in accordance with Attachment K, Section 4.1(b) of the Tariff
  - Memo to PAC was issued on February 10 outlining the process and related deadlines

Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - The ISO is working on model development by reviewing assumptions with NEPOOL
  - Production Cost Simulations to commence in the April timeframe and initial results expected in early summer
  - Phase 1 work will be submitted as a 2021 Economic Study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined
  - Studies likely to be performed by a consultant

2019 Electric Generator Air Emissions Report

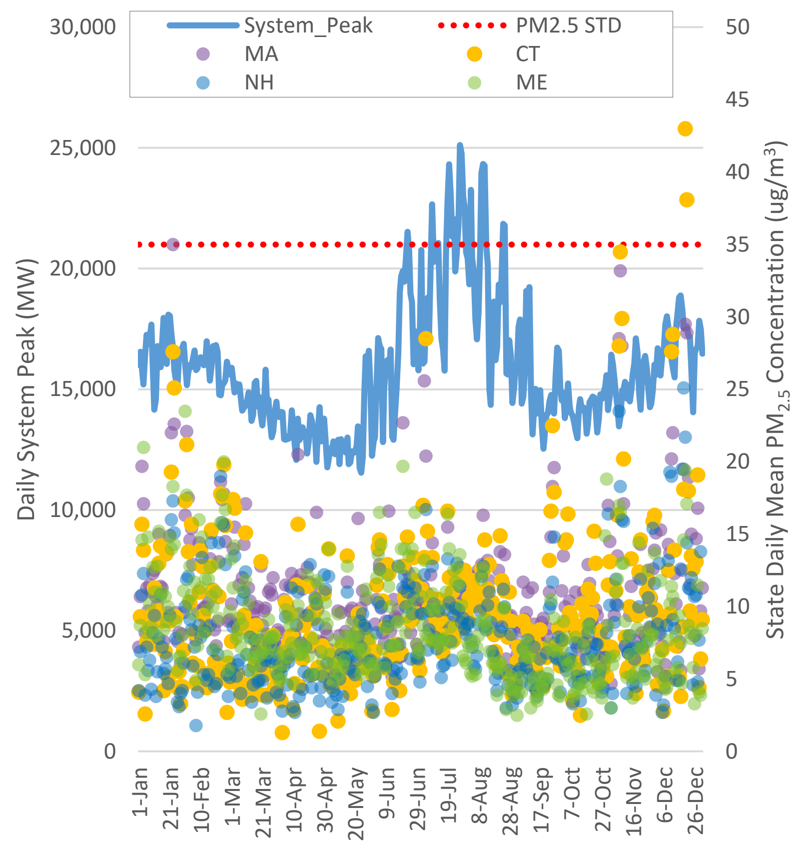
- Report in draft form
  - The annual ISO New England *Electric Generator Air Emissions Report* provides a comprehensive analysis of New England electric generator air emissions (NO_X, SO_2, and CO_2) and a review of relevant system conditions
- Draft Report includes:
  - New England Native Generation System Emissions
    - Total (ktons)
    - Rates (lbs/MWh)
  - New England Locational Marginal Unit Marginal Emissions
    - Both unweighted and load-weighted analyses
    - Rates (lbs/MWh)
  - Does not include import emissions
- Results were presented to the Environmental Advisory Group on February 19
- Final Report to be posted in March
  - An updated Emissions Report, that includes import emissions, to be posted in the May timeframe

Environmental Matters – Reset on Federal Environmental Priorities; Focus on Particles

EPA Shifting Staff & Priorities in Response to Executive Orders

- EPA asked to update fine particle ($PM_{2.5}$) and other ambient air standards (O_3, NO_2), challenged as too weak
  - More stringent standards could require limiting emissions and constraining operations at fossil generators
- Chart shows 2020 daily system peak generation (MW) (left axis) vs. maximum $PM_{2.5}$ daily outdoor concentrations for some New England States (right axis)
  - All New England monitoring sites currently 12-20 micrograms per cubic meter (ug/m^3)
  - Current 24-hour standard 35 ug/m^3 (dotted red line) (right axis)
  - Health researchers recommend lowering 24-hour standard to 15-25 ug/m^3, adding monitors near power plants and other industrial sources

States Ask EPA to Reconsider 2020 Fine Particle Standard, Lower Limit



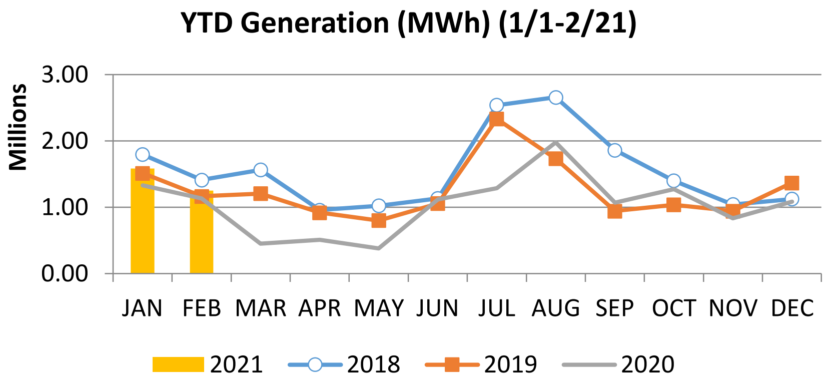
$PM_{2.5}$, fine particulate; O_3, ground-level ozone; NO_2, nitrogen dioxide. All emitted during combustion of fossil fuels by engines, boilers and turbines.

MA, CT, RI and VT joined other states petitioning EPA to withdraw 12/18/20 $PM_{2.5}$ standard, in light of health research showing harm at lower concentrations

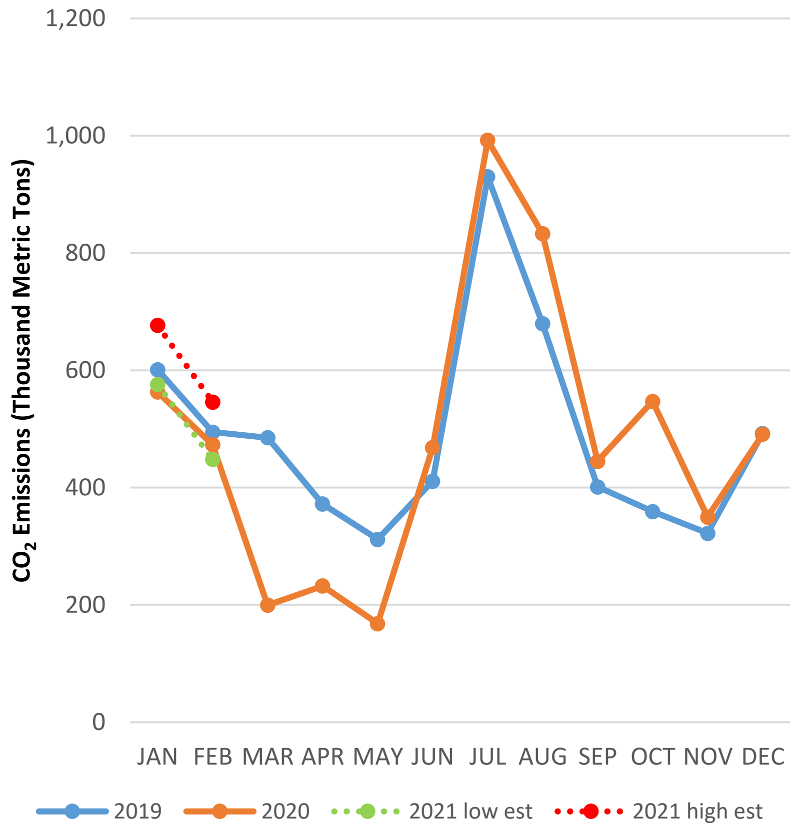
Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 Emissions Trending Higher Than Past 1st Quarters

- YTD 2021 estimated CO_2 emissions range between 1.0 and 1.2 MMT
  - 2021 cap is 8.23 MMT
- March 11, 2021: Next GWSA auction will offer 1.6 million allowances (20% of 2021 cap)
- December 16, 2020: GWSA auction clearing price was $7.25 per metric ton



2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



MMT – Million Metric Tons

GWSA - Global Warming Solutions Act

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.

Southwest Connecticut (SWCT) Projects

Status as of 2/19/2021

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Mar-16	4
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Oct-18	4
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	4
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	4
Loop the 1570 line in and out the Pootatuck substation	Jul-18	4
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 2/19/2021

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Nov-20	4
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 2/19/2021

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-16	4
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-19	4
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	4

Southwest Connecticut Projects, cont.

Status as of 2/19/2021

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	Mar-18	4
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Feb-21	4

Southwest Connecticut Projects, cont.

Status as of 2/19/2021

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Remove the Sackett phase shifter	Mar-17	4
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	4
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	4
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	4
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	4
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
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*	May-22	3*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
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 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
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
Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-21	3*
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	May-21	3

*Mystic to Chelsea line portion of the project is a present stage 4 as of October 2020.

Greater Boston Projects, cont.

Status as of 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	May-22	3
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
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 2/19/2021

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

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

SEMA/RI Reliability Projects

Status as of 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
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
Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
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
Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
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 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
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	Jun-23	2
Extend the Line 114 from the Dartmouth town line (Eversource-NGRID border) to Bell Rock substation	Dec-23	2
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 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
Retire the Barnstable SPS	Dec-21	3
Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-23	1
Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	3
Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
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 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
Reconductor the J16S line	Jun-22	2
Replace the Kent County 345/115 kV transformer	Mar-22	2
West Medway 345 kV circuit breaker upgrades	Dec-21	3
Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 2/19/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Reconductor the L190-4 and L190-5 line sections	Dec-26	1
Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
Upgrade Card 115 kV to BPS standards	Mar-23	2
Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-21	1

Eastern CT Reliability Projects, cont.

Status as of 2/19/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

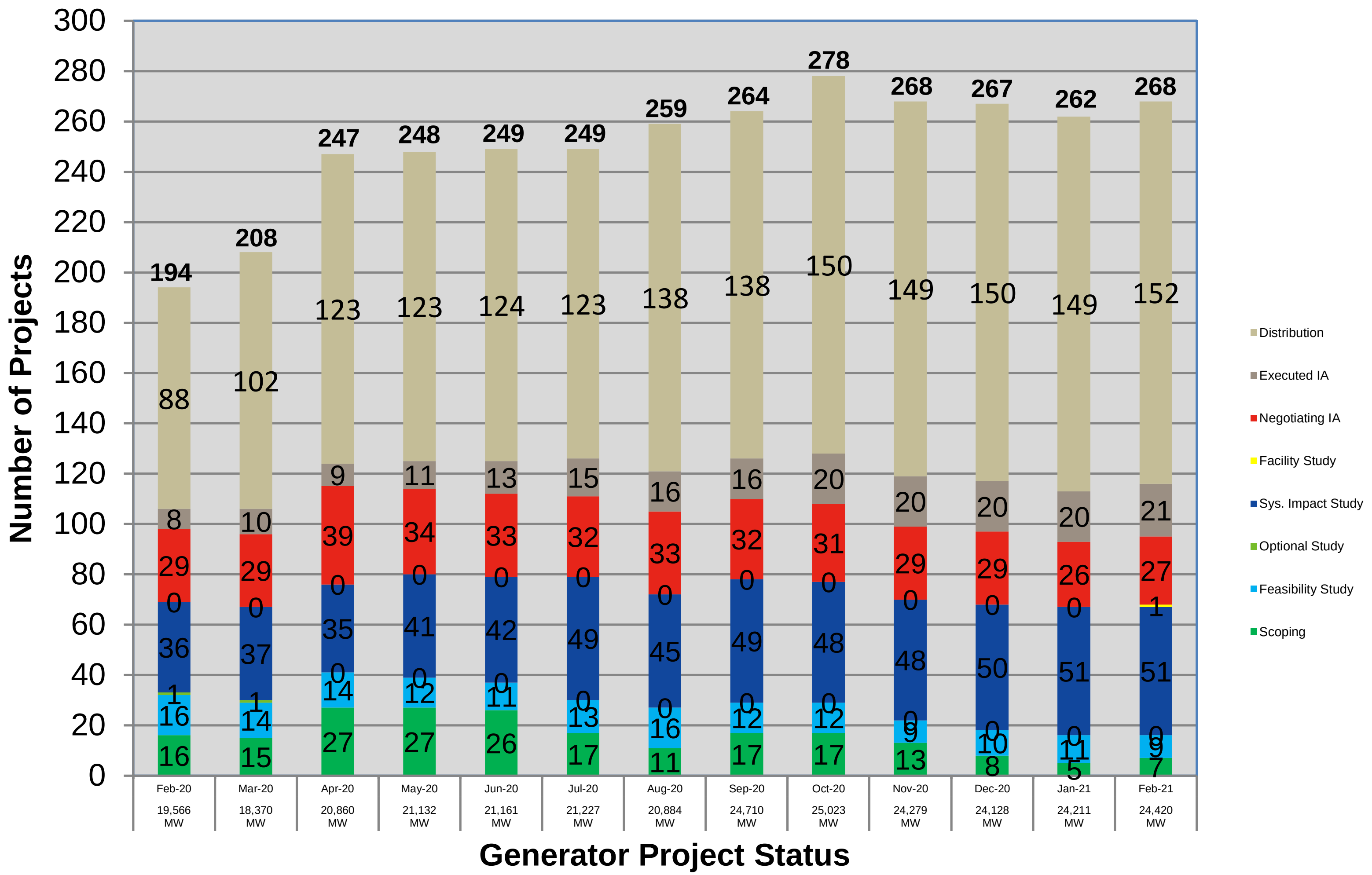
Eastern CT Reliability Projects, cont.

Status as of 2/19/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Install one 345 kV series breaker with the Montville 1T	June-22	2
Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	1
Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	1
Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

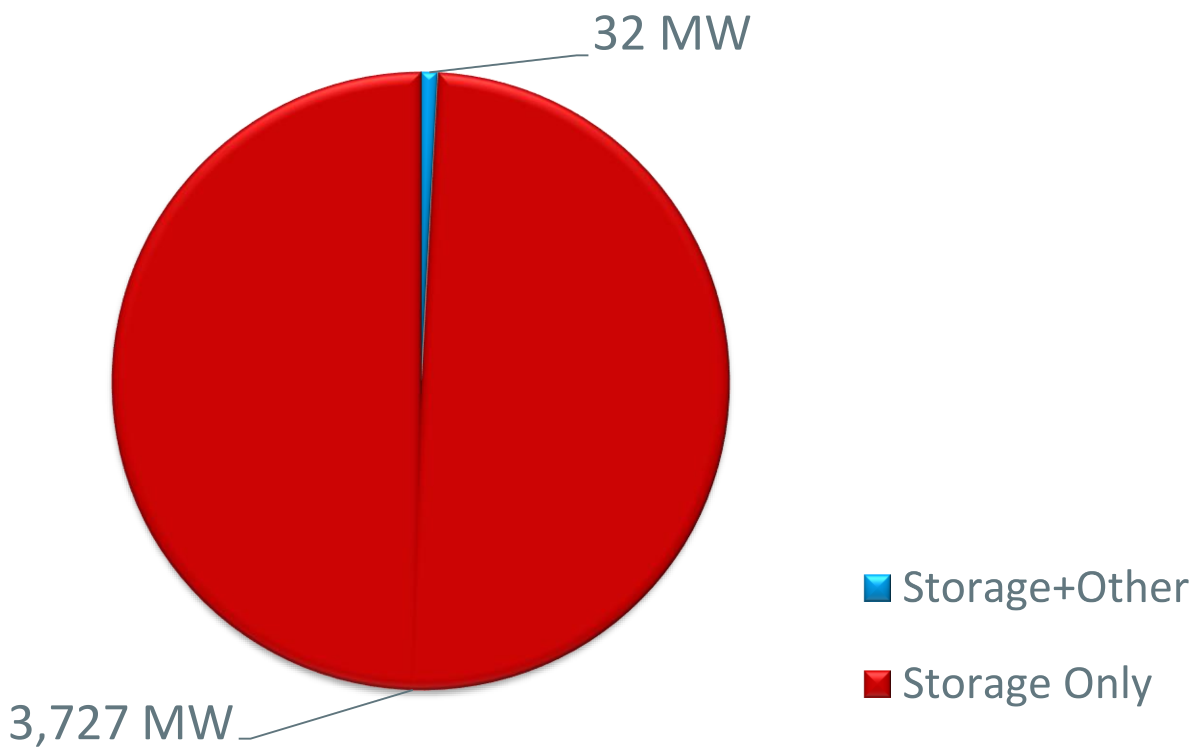
Status of Tariff Studies



Note: February 2021 is based on partial data.
As of February 2021, there are 0 ETU's in Scoping, 0 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of February 24, 2021)

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



OPERABLE CAPACITY ANALYSIS

Winter 2021 Analysis

Winter 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	March - 2021[2] CSO (MW)	March - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,428	33,752
Active Demand Capacity Resource (+) [5]	425	410
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,119	1,119
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,216	2,400
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	1,245	1,422
Net Capacity (NET OPCAP SUPPLY MW)	26,318	29,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,941	17,941
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,246	20,246
Operable Capacity Margin	6,072	9,020

[1]Operable Capacity is based on data as of **February 23, 2021** 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 **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 6, 2021.**

[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.

Winter 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	March - 2021[2] CSO (MW)	March - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,428	33,752
Active Demand Capacity Resource (+) [5]	425	410
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,119	1,119
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,216	2,400
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	2,179	2,489
Net Capacity (NET OPCAP SUPPLY MW)	25,384	28,199
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,520	18,520
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,825	20,825
Operable Capacity Margin	4,559	7,374

[1] Operable Capacity is based on data as of **February 23, 2021** 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 **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 6, 2021.**

[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.

Winter 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 50-50 FORECAST using CSO

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 during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/6/2021	**30428**	**425**	**1119**	**7**	**2216**	**0**	**2200**	**1245**	**26318**	**17941**	**2305**	**20246**	**6072**
3/13/2021	30428	425	1119	7	1850	250	2200	373	27306	17736	2305	20041	7265
3/20/2021	30428	425	1119	7	1874	1560	2200	0	26345	17352	2305	19657	6688
3/27/2021	30460	509	1025	7	790	244	2700	0	28267	16759	2305	19064	9203

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active 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 Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Winter 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 90-10 FORECAST using CSO

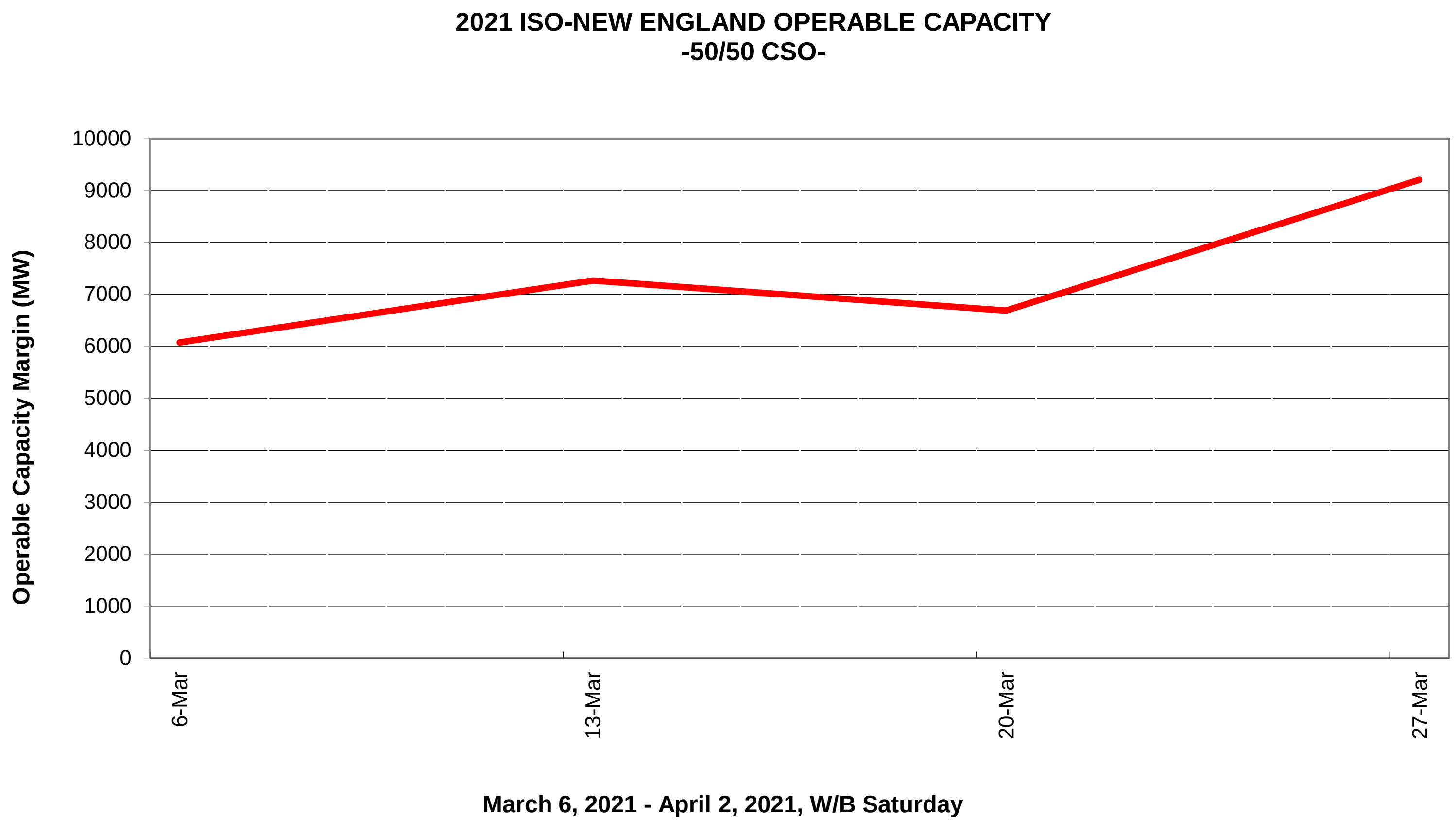
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
3/6/2021	**30428**	**425**	**1119**	**7**	**2216**	**0**	**2200**	**2179**	**25384**	**18520**	**2305**	**20825**	**4559**
3/13/2021	30428	425	1119	7	1850	250	2200	1307	26372	18309	2305	20614	5758
3/20/2021	30428	425	1119	7	1874	1560	2200	0	26345	17915	2305	20220	6125
3/27/2021	30460	509	1025	7	790	244	2700	379	27888	17305	2305	19610	8278

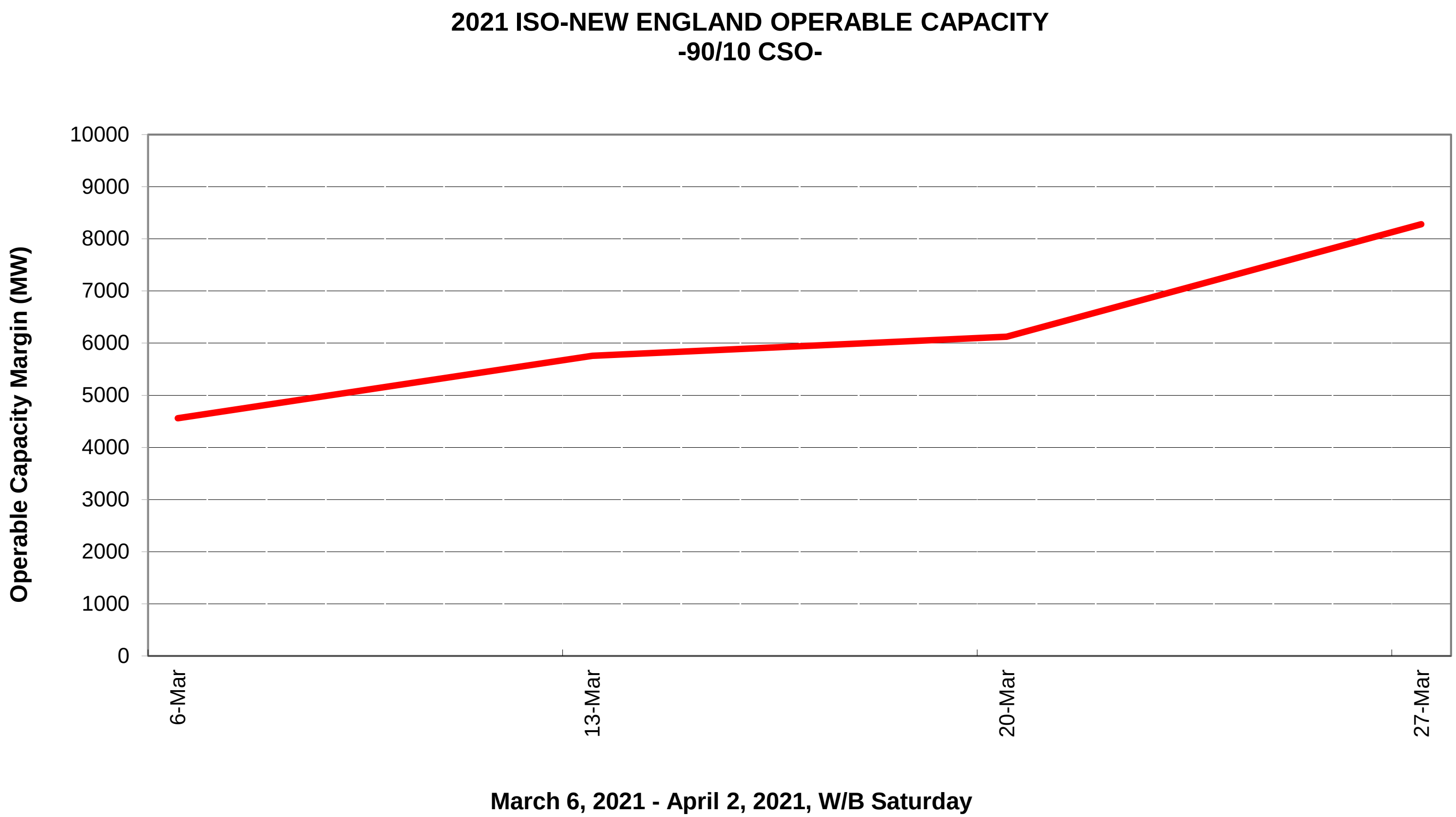
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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

Winter 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Spring 2021 Analysis

Spring 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,448	33,752
Active Demand Capacity Resource (+) [5]	536	437
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,745	3,026
Gas Generator Outages MW (-)	2,433	2,705
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,438	26,090
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,118	18,118
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,423	20,423
Operable Capacity Margin	3,015	5,667

[1] Operable Capacity is based on data as of **February 23, 2021** 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 **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 2021.**

[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.

Spring 2021 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**May - 2021[2] CSO (MW)**	**May - 2021[2] SCC (MW)**
Operable Capacity MW [1]	30,448	33,752
Active Demand Capacity Resource (+) [5]	536	437
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,745	3,026
Gas Generator Outages MW (-)	2,433	2,705
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,438	26,090
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,612	19,612
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,917	21,917
Operable Capacity Margin	1,521	4,173

[1]Operable Capacity is based on data as of **February 23, 2021** 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 **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 2021.**

[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.

Spring 2021 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 50-50 FORECAST using CSO

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 during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
4/3/2021	30460	509	1025	7	3929	1641	2700	0	23731	16134	2305	18439	5292
4/10/2021	30460	509	1025	7	5506	1850	2700	0	21945	15870	2305	18175	3770
4/17/2021	30460	509	1025	7	5481	1342	2700	0	22478	15335	2305	17640	4838
4/24/2021	30460	509	1025	7	3245	1770	2700	0	24286	15057	2305	17362	6924
5/1/2021	30448	536	1025	7	3096	1983	3400	0	23537	15029	2305	17334	6203
5/8/2021	**30448**	**536**	**1025**	**7**	**2745**	**2433**	**3400**	**0**	**23438**	**18118**	**2305**	**20423**	**3015**
5/15/2021	30448	536	1025	7	1460	1812	3400	0	25344	19152	2305	21457	3887
5/22/2021	30448	536	1025	7	1273	1213	3400	0	26130	20113	2305	22418	3712

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active 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 Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Spring 2021 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 90-10 FORECAST using CSO

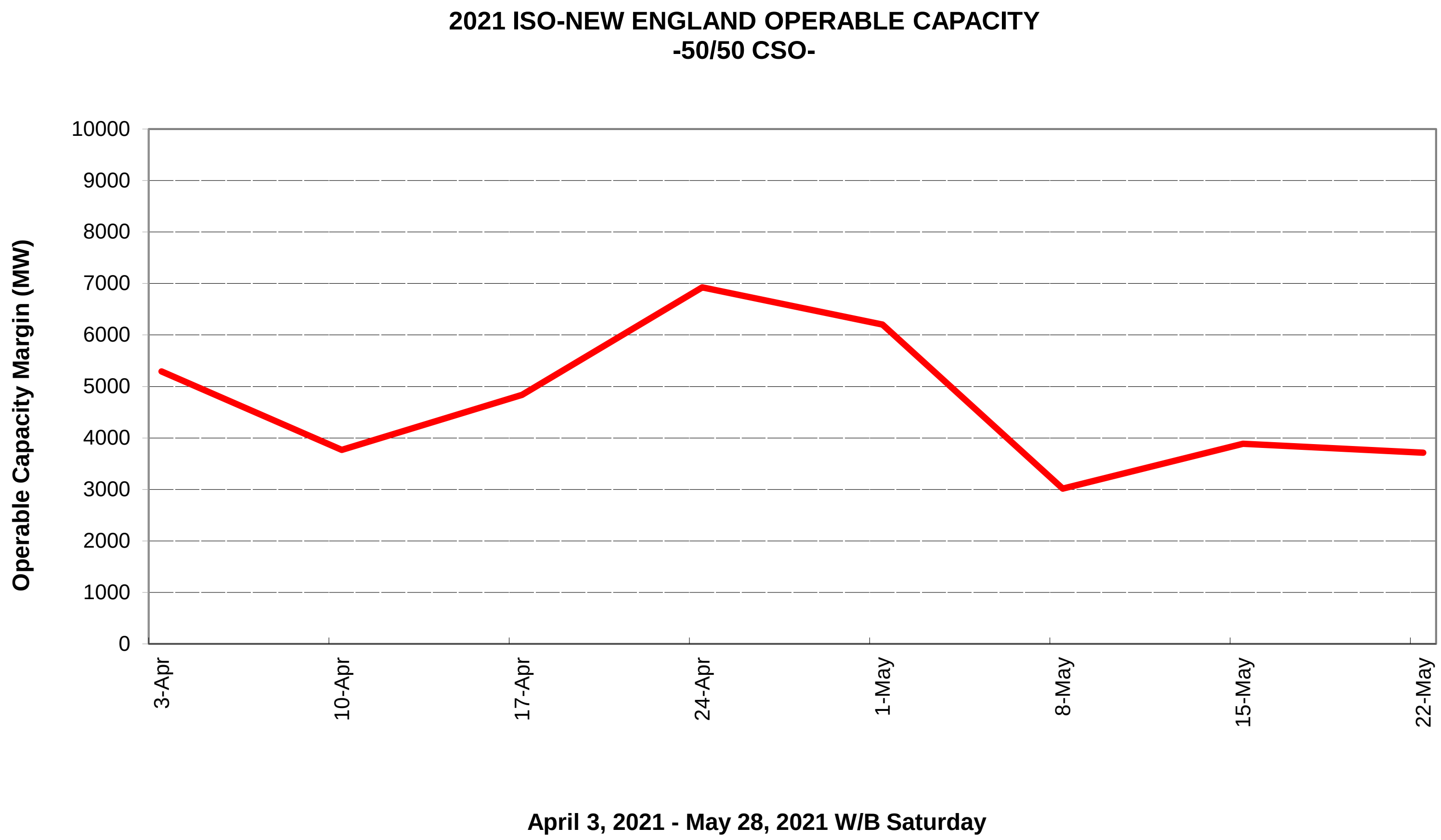
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
4/3/2021	30460	509	1025	7	3929	1641	2700	0	23731	16667	2305	18972	4759
4/10/2021	30460	509	1025	7	5506	1850	2700	0	21945	16395	2305	18700	3245
4/17/2021	30460	509	1025	7	5481	1342	2700	0	22478	15846	2305	18151	4327
4/24/2021	30460	509	1025	7	3245	1770	2700	0	24286	15560	2305	17865	6421
5/1/2021	30448	536	1025	7	3096	1983	3400	0	23537	15531	2305	17836	5701
5/8/2021	**30448**	**536**	**1025**	**7**	**2745**	**2433**	**3400**	**0**	**23438**	**19612**	**2305**	**21917**	**1521**
5/15/2021	30448	536	1025	7	1460	1812	3400	0	25344	20716	2305	23021	2323
5/22/2021	30448	536	1025	7	1273	1213	3400	0	26130	21741	2305	24046	2084

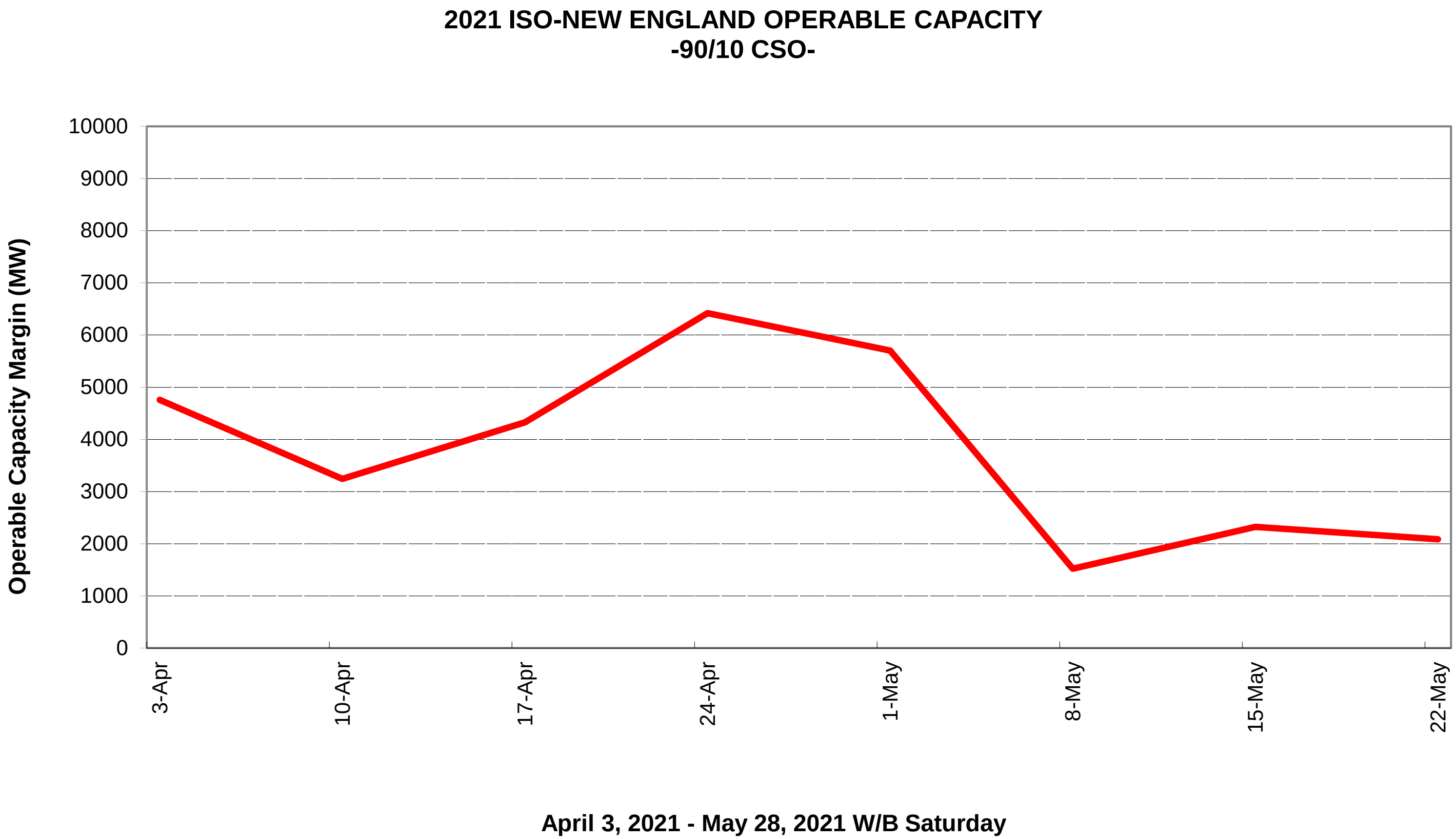
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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

Spring 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Spring 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



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

Overview of the ISO New England Board Search Process

March 2021

Overview: Our Search Process in Partnership with the ISO New England JNC

Assess needs

Board Analysis & Needs Assessment

- Diligence ISO New England's strategy over the next 3-5 years
- Conduct Board Composition Analysis exercise to assess current state of Board composition and identify key needs on the horizon. As needed annually, update and refine Board Composition Matrix and align with input from the Board
- Conduct Board Needs Assessment with **Joint Nominating Committee (JNC)** annually in advance of the full search process

Director profiles and timeline

- Based on Board Composition Analysis and needs assessment, with ongoing contributions from the **JNC** as it convenes, identify priority "candidate archetypes" for directors
- Determine ideal timing for upcoming director recruitment, based on ISO New England's strategic needs and board member term limit timeline and board leadership succession imperatives
- Refine and finalize Candidate Archetypes and update position specification for current board cycle

Identify candidates

Candidate Slate Development

- For each Candidate Archetype, we then seek to identify a diverse slate of potential candidates
- We also welcome suggestions from the JNC/NEPOOL and will evaluate each recommendation regardless of the source
- We interview and vet each candidate that we intend to present to the **JNC**. We soft reference all candidates, and conduct formal references whenever possible
- A range of materials summarizing our candidate slate is presented to the **JNC**, including full resumes

JNC Assessment of Candidate(s)

- Meet with the **JNC** to identify ~6-8 top candidates per director search
- Once the **JNC** interviews candidates (typically over 2 rounds of interviews), RRA facilitates a feedback debrief to help the committee select the nominees

Final Diligence

- Complete extensive formal referencing and background check(s)
- If the **JNC** has any concerns that specific stakeholder groups may have concerns about a candidate, we work with the **JNC** to establish a process for vetting around these issues
- Respond to any diligence requests that the prospective nominees have i regards to better understanding the board's fit for their objectives

Appoint and repeat

Appoint Director

- Nomination process then continues to unfold in alignment with ISO New England process guidelines from bylaws
- Appoint successful candidate(s) to ISO New England's board

Repeat

- RRA develops and tracks an Evergreen Pipeline between search cycles, maintain a current perspective on potential candidates for future recruitment. RRA engages with these potential candidates to gauge interest and conduct preliminary vetting for future process with the **JNC**

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Key Deliverables

Board Composition Matrix

- This document is an analysis of the current Board's composition and serves as a baseline for identifying current/future potential experience gaps and underrepresentation of experience on the Board based on the requirements of the bylaws and the board's view of its most pressing experiential requirements.
- The Board Composition Matrix was created at the outset of RRA's 3-Year engagement with ISO New England. A review of the Board Composition Analysis is undertaken annually as needed when directors leave/join the board. Inputs include:
  - **Director Interview:** discuss each director's professional history and current board leadership roles as well as their personal plans over the next 3–5 years (to identify potential departures outside of term limits).
  - **Definition Review:** Review the skills and experience definitions for accuracy and completeness and revise as needed
  - **RRA Analysis:** RRA analyzes the directors' skills and experiences and aligned them with the board composition matrix
  - **Director Self Assessment:** RRA then reviews with each director his/her column in the matrix and revised as needed based on new information provided to clarify competencies

Board Needs Assessment:

- The Board Needs Assessment is conducted annually and will inform the current year's director search Position Specification. Inputs include:
  - Meeting with members of the JNC to discuss the key experiential priorities for the current year's search
  - Shaping these discussions into the Candidate Archetypes document and the updated Position Specification. Both of these documents are reviewed and iterated the with the JNC until they are approved

Candidate Slate

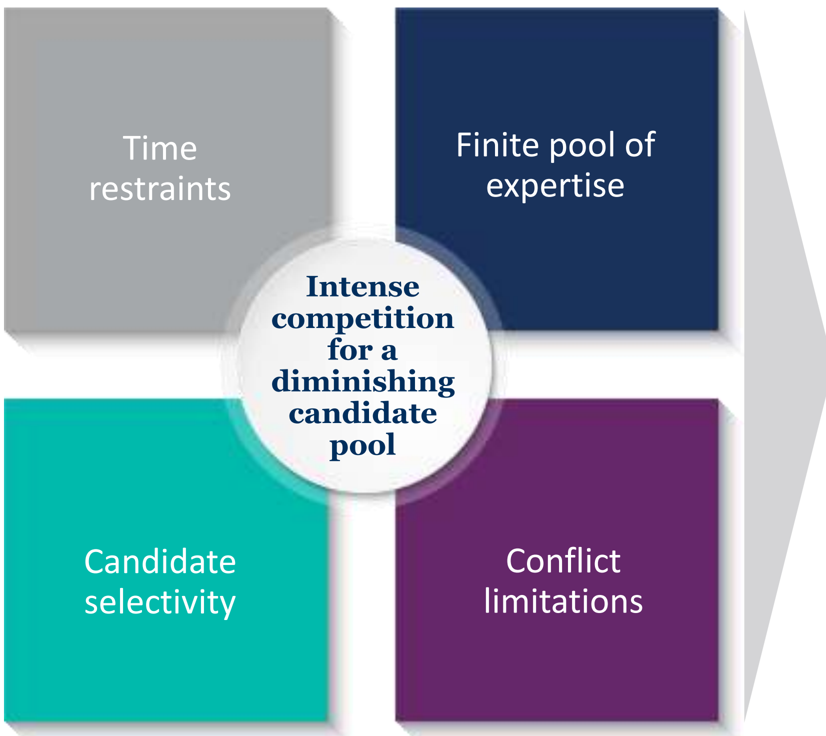
- The list of vetted and engaged board candidates for each search cycle

Evergreen Pipeline

- An ongoing list of potential board candidate profiles that is refreshed for new names and maintained as candidate availability/ changes over time (year over year) with future board refreshment in mind

Evergreen Process: A Proactive Approach for Staying Ahead of Board Recruitment Needs

Typical challenges with board recruitment



Our approach to mitigate these:

- An “evergreen” process that **proactively identifies and vets candidates** in advance of their availability
- Take into account both **planned director departures and their resultant committee leadership succession implications,** as well as a structured review of **future strategy driven experiential composition needs**
- **Continual re-evaluation of the Board’s composition**

Benefits

- Balance board director longevity with the **active inclusion of new thinking** on **ISO New England’s** Board
- Begin to cultivate interest from candidates **months or years in advance of availability**; *particularly helpful when targeting highly desirable candidates that bring specialized skillsets to the Board*
- Support **long term board leadership succession needs**
- Allow RRA to explore a **richer pool of candidates** who may not be immediately available and/or broaden the network to include individuals at the forefront of advances perhaps in an unrelated industry.

2021 ISO New England Board Search: Candidate Archetypes

Transmission Expertise	▪ Technical expertise in transmission planning and operations remains a key area of interest. The JNC noted the need to "recognize a balance" with traditional Board executive oversight skills and having adequate technical appreciation to fully grasp core initiatives.
Markets Expertise	▪ Most JNC members indicated the need for expertise in energy markets. This could arise from the candidate's direct experience in managing assets or a trading function engaged in wholesale power or other energy markets, or from engagement in market design analysis.
Diversity	▪ The JNC unanimously highlighted the need for candidates who bring racial, gender, or ethnic diversity to the board. Such candidates would bring diversity of thought as well as important representation of the breadth of stakeholders and, ultimately, customers that ISO New England serves. There is understanding from JNC members that in order to ensure a robust slate of "board ready" diverse candidates, efforts may need to be made to look outside of the energy industry.
Energy Transition Expertise	▪ Several JNC members outlined a need for the expertise relative to the technologies and business models associated with the clean energy transition and an understanding of the associated policies and regulatory mandates.
Customer Advocate	▪ Some JNC members stated that adding an individual who has experience advocating on behalf of consumer interest is a needed point of view on the Board. This person should bring an informed view on costs considerations for customers, ideally with insight specific to utilities in New England. Such candidates would be able to effectively apply their expertise to ensure a Board-level perspective on ISO-NE's mandates of reliability and end-user value.

ISO New England Board Composition Requirements
Guiding principles across each search cycle

Sections 9 and 13 of the Participants Agreement set forth requirements for Board composition

- At least **three of the directors** shall have prior relevant experience in the **electric industry**.
- Beyond this, a **cross-section of desirable skills** and experiences is then outlined: " . . .such as, for purposes of illustration but not by way of mandate or limitation, experience in Commission electric regulatory affairs, energy industry management, corporate finance, bulk power systems, human resource administration, power pool operations, public policy, distributed generation or demand response technologies, renewable energy, consumer advocacy, environmental affairs, business management and information technologies."
- In addition, to ensure sensitivity to regional concerns, strong preference is given to identifying **candidates from New England**

These requirements are then overlaid with the ISO New England Board's need to have the **necessary expertise** to populate the following six committees of the Board:

System Planning and Reliability (SPARC)	Markets
Audit and Finance	Human Resources and Compensation
IT and Cyber	Nominating and Governance

2021-2022 Upcoming Retirements & Areas of Expertise
A snapshot view of the current composition of the board

Director (by retirement date)	(1) Electric Industry/ Transmission Experience	(2) Markets Expertise Financial Markets (F) Energy Markets (E)	(3) Top Corporate Officer Experience At least one CEO; as noted	(4) Public Service, Regulatory Experience (FERC, States)	(5) Audit Committee Financial Expert	(6) IT/Cyber Security Expertise
Kathleen Abernathy '21			X	X		
Phil Shapiro '21		X (F)	X	X	X	
Barney Rush '22	X	X (F,E)	X		X	
Vickie VanZandt '22	X		X			X
Roberto Denis '23	X		X			
Brook Colangelo '26			X			X
Mike Curran '27		X (F,E)	X (CEO)		X	X
Cheryl LaFleur '28	X	X (E)	X (CEO)	X		X
Mark Vannoy '29	X		X	X		
Gordon van Welie	X	X (E)	X (CEO)			X

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Independence Guidelines
We vet all candidates for potential conflicts of interest

The ISO New England Code of Conduct sets for a range of conflict guidelines for qualifying as an Independent Director. These include:

FERC Interlock

- FERC authorization is required for any officer or director of a public utility (including ISO-NE) seeking to simultaneously hold a position as officer or director of:
  - Another public utility
  - Any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of the public utility
  - Any company supplying electrical equipment to the public utility of that officer or director

Restriction on Securities Ownership

- No director, spouse or minor child of a director may own, control or hold with the power to vote securities of a publicly-traded market participant or affiliate
  - There is a three-part test in Section 2.1 of the Code to exclude the securities of participants with a de minimis relationship to the ISO
  - Also excluded: publicly available mutual funds, other collective funds or widely held pension funds that do not concentrate in investments in market participants
  - New directors must divest any securities deemed to be a conflict within six months

No Association with Market Participants/Affiliates

- Directors may not be "associated" with a market participant or affiliate through:
  - Employment by the director or his or her spouse as an officer, director, partner or employee of a market participant or affiliate
  - Receipt of benefits from a market participant or affiliate (other than customary retirement benefits)
  - Having a material ongoing relationship with a market participant or affiliate

Beyond These Parameters, We Assess for "Board Readiness"

We assess all potential candidates based upon our insights into high-performing board behaviors

Foundational Director Behaviors

Behaviors that are the basics for director success

Prepared & Engaged	Comes prepared, is fully present at meetings, and seeks to add value
Current & Open	Stays abreast of industry and company developments; is open to new ideas, processes and ways to solve problems
Builds Trust & Respect	Is able to build and earn the trust and respect of fellow directors
External Stakeholder Savvy	Understands external stakeholder perspectives as well as how to think about maximizing shareholder returns

Differentiating Behaviors

Behaviors that differentiate the best, most effective directors

Source: Russell Reynolds Global Board Culture Survey 2019, n = 750 corporate directors.

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Position Specification

ISO New England Inc.

Board Director

For NEPOOL Use Only

Our Client

ISO New England Inc. (ISO-NE) is a Regional Transmission Organization (RTO) and 501C3, serving the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. In 1997, the Federal Energy Regulatory Commission (FERC) approved ISO-NE's creation as an independent system operator (ISO) in response to federal legislation passed in the early 1990s that called for industry restructuring by creating non-discriminatory access to transmission systems and removing obstacles to wholesale electricity competition. ISO-NE was established to ensure the reliability of New England's bulk electric power system and to establish and operate the region's competitive wholesale electricity markets, which were launched in 1999.

ISO-NE's stated mission is to protect the health of New England's economy and the well-being of its people, by ensuring the constant availability of electricity today and for future generations. To achieve this, ISO-NE has three critical roles and responsibilities in New England: (Operations) keeping electricity supply and demand in balance 24/7, (Design) designing, running, and overseeing the region's wholesale electricity marketplace and (Planning) ensuring that the power system meets New England's needs over the next 10 years.

ISO-NE currently oversees a power system of 350 generating units, approximately 9,000 miles of high-voltage transmission lines that serves the six-state region, and transmission interconnections to the neighboring power systems of New York, Quebec, and New Brunswick. New England's wholesale electricity markets currently include day-ahead and real-time energy markets, a forward market for capacity, and ancillary services. In 2020, the ISO settled approximately $7.9 billion of market transactions in the wholesale electricity marketplace the ISO administers.

ISO New England is regulated by the FERC, which defines the authority, responsibilities, and services provided by ISO New England and approves the rules that guide the company. In 2003, FERC approved ISO New England's change in regulatory designation from an ISO to an RTO, giving ISO-NE authority over the development of transmission needed for system reliability and oversight of wholesale market rules and changes.

ISO New England meets the wholesale electricity demands of the 7.2 million commercial and retail electricity customers by fulfilling three primary responsibilities:

- Minute-to-minute reliable operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines.
- Development, oversight, and fair administration of New England's wholesale electricity marketplace, through which wholesale power is bought, sold, and traded. These competitive markets provide positive economic and environmental outcomes for consumers and improve the ability of the power system to efficiently meet consumer demand.
- Management of a comprehensive bulk power system planning process that addresses New England's power system reliability needs into the future. If market responses are not adequate to meet the identified needs, the ISO, in its role as RTO, must identify appropriate transmission infrastructure solutions that are essential for maintaining power system reliability.

FERC-approved rules for ISO New England can be found in the *ISO New England Inc. Transmission, Markets, and Services Tariff* (the ISO Tariff): https://www.iso-ne.com/participate/rules-procedures/tariff.

While ISO New England plays a critical role in the wholesale electricity markets, it is a not-for-profit organization. The ISO Tariff outlines the FERC-approved revenues the company collects for its services and sets out the cost recovery and allocation mechanisms for transmission and ancillary services in the region.

As ISO-NE enters its twenty-fourth year as an organization in 2021, it continues to operate the region's bulk electric power system and administer the region's wholesale electricity markets. Current industry challenges that ISO New England is working on with stakeholders include a Future Grid Initiative, intended to support the region's transition to clean energy through the integration of state-supported renewable resources into the regional power system and the evolution and repositioning of the region's wholesale electricity markets, which include the development of additional market products and services.

The Role

Two of ISO New England's current Directors will be rolling off the Board due to term limitations in Q3 2021 and the organization is seeking to find their successors. The newly elected Directors will be appointed to serve three-year terms that will commence in October 2021. The candidates will then be eligible for re-election for a total of two additional three-year terms, provided that there is no conflict with the Board's guidelines around the mandatory retirement age (see detail in guidelines section below).

The successful candidates will join eight other Directors, seven of whom are outside Directors, with responsibility for overseeing the financial performance, ethical standards, and managerial assets of the organization. With backgrounds including utilities, finance, regulation, communications, and academia, members of the Board play a critical role in ISO New England governance, bringing objectivity, insight, and advice and ensuring that the company is addressing issues of timely importance. Currently, the utility industry, as a whole, is undergoing a period of unprecedented transformation driven by a range of factors including a fast-evolving technology landscape, near record low commodity prices, the integration of an ever-increasing supply of renewable generation, disparate regulatory regimes, extensive consolidation, and an aging workforce. Thus, the ISO New England Board is facing an especially challenging period for defining a strategy for the organization that meets the wide range of needs and perspectives of its stakeholders. While exciting, this challenge also compels the Board to seek candidates with the highest caliber of strategic and analytical capabilities to help the company navigate through this uncharted territory.

The Board maintains an active and demanding schedule, and participation in all Board meetings is expected. The Board also engages with stakeholders and state public utility commissions throughout the year and set meetings with these groups are a part of the Board's annual agenda. The successful candidates should be prepared to completely engage in and contribute to the Board's activities. The by-laws for the Board require that three Board members serve on each committee and, typically, Board members serve on an average of three committees per Director. The standing committees for the Board are: the Nominating and Governance Committee, the Compensation and Human Resources Committee, the Audit and Finance Committee, the Markets Committee, the System Planning and Reliability

Committee, and the Information Technology and Cyber Security Committee. Additionally, special committees can be convened, and directors also participate in the Joint Nomination Committee that selects new Board members. The current schedule of Board meetings is outlined below.

2021 Board and Committee Meetings.

DATE	MEETING
January 20 -21	Board & Committee Meetings: A&F, Comp & HR, Markets, Nom & Gov, SPARC **Location:** Virtual
February 9	Comp & HR **Location:** Teleconference
February 18	Board & Committee Meeting: A&F, Nom & Gov **Location:** Virtual
March 17 -18	Board & Committee Meetings w/ NECPUC: A&F, Markets, Nom & Gov, SPARC, Special Committee on IT & Cyber Security **Location**: Virtual
May 20	Audit & Finance, Markets, Nom & Gov **Location**: Virtual
June 23	Board, Committee Meetings & NEPOOL Summer Meeting (June 22-24): Comp & HR, Markets, Nom & Gov, SPARC, Special Committee on IT & Cyber Security **Location:** Manchester Village, VT
August 19	Committee Meeting: A&F, Markets **Location**: Holyoke, MA or Teleconference
September 22 – 23	Board & Committee Meeting: A&F, Comp & HR, Markets, Nom & Gov, SPARC, Special Committee on IT & Cyber Security **Location:** Exact Location TBD *(Board retirement dinner evening of TBD)*
October 6	RSP Public Meeting **Location:** TBD
November 1 – 3	Board & Committee Meetings (includes NECPUC on the 2nd): A&F, Comp & HR, Markets, Nom & Gov, SPARC, Joint Board/NEPOOL Sector Meetings on the 3rd **Location:** Boston, MA
May 23 – 26	NECPUC Symposium (voluntary attendance) **Location:** Newport, RI
May 26	IRC Joint Board Conference **Location:** Virtual

Full details on the Board's structure and governance can be obtained by reviewing the Board's by-laws, which can be found here:

https://www.iso-ne.com/static-assets/documents/aboutiso/corp_gov/bylaws/bylaws_of_ISO_NE.pdf

Russell Reynolds Associates will also provide a copy of the by-laws upon request.

Candidate Profile

The by-laws governing the board of ISO New England require that it be composed of exceptional leaders from a spectrum of backgrounds that include technical knowledge of electric power and natural gas operations, but also commercial market operations, trading and risk management, IT, finance, and regulatory experience. Given the forthcoming waive of retirements that the board faces, the Joint Nominating Committee is taking a broad view on the expertise and experience that they desire to see in this year's candidate slate. Of particular interest to the Joint Nominating Committee are candidates with a depth of expertise in markets, ideally with energy industry experience specific to wholesale market operations; candidates who have a depth of experience in utility operations, particularly bulk power transmission planning and operations; and candidates who have played a leadership role in navigating the policies and technologies that are bringing about the transformation within the energy sector.

Diversity and richness of professional and functional expertise is of paramount importance in qualifying potential new Directors. However, the impending Board member retirements will lead to a loss of institutional knowledge and governance expertise that will amplify the need to identify candidates who bring an understanding of board operations shaped by experience serving on corporate or relevant industry boards. Candidates will ideally bring a strong customer-oriented perspective to the Board and have professional or personal ties to the New England region, though this regional connection is not a mandate for the current search process.

In terms of the personal qualifications that ISO New England seeks, candidates must have unquestionable personal ethics and integrity combined with a positive reputation within their respective industry. Candidates' experience should come from well-managed and accountable companies/organizations known for excellence in operating performance. To be a culture fit for the Board, candidates should be team-oriented, engaged and inquisitive, and must be capable of presenting diverse points of view in a constructive manner. Intellectual curiosity and a mission-driven orientation will also be essential traits for ensuring effective engagement in the highly complex and technical work that this board performs. Further, candidates should be adept at bringing out the best in their peers to promote a consensus-driven decision-making process. The new Director should be able to challenge the thinking on the Board and provide differentiated perspectives and insights but do so in a constructive and impactful way. The ISO New England Board interacts extensively with stakeholders, so Directors must display a sincere desire to work effectively within the stakeholder engagement construct.

Given the time commitment required by the ISO New England Board, Directors may find that it is difficult to fulfill their obligations to more than two additional outside boards. Further, an extensive range of conflict guidelines also limits Directors in their pursuit of outside board and employment opportunities within the energy, and to some extent financial, sectors and beyond, so thoughtful consideration of the restrictions and rules detailed in the section below are needed in determining whether the ISO New England board is a fit for prospective candidates' professional objectives.

Board Member Restrictions and Affiliation Rules

This individual will be an independent Director free of any conflicts and interlocks, as defined by FERC's "Interlock Rule" and the ISO-NE Code of Conduct, respectively.

- Interlock rule: FERC prohibits any Director of a public utility (like ISO-NE) from also holding a position as an officer or Director of another public utility or a supplier of electrical equipment to that public utility, bank, trust company, banking association, or firm authorized by law to underwrite or participate in marketing of securities of a public utility, unless FERC approves the "interlock."

  As Board members know from experience, FERC seems unwilling to waive the Interlock Rule. Accordingly, the candidate should treat this as an absolute prohibition. A similar provision in the ISO-NE Code of Conduct prohibits a Director from concurrently serving as an officer, Director, partner, or employee of a market participant or affiliate.

- ISO NE Code of Conduct ISO New England's Code of Conduct contains the following provisions relevant to the search:

  - **Relationships with Market Participants and Affiliates:** A Director cannot serve as an executive officer or Director of a market participant or affiliate. Additionally, a Director cannot receive continuing benefits (other than customary retirement-related benefits) from a market participant or affiliate.

  - **Financial Interests:** A Director or his or her spouse and minor children cannot own, control, or hold power-to-vote securities of a market participant or affiliate.

  - **Spouse's Employment:** The Code of Conduct prohibits a Director's spouse from serving as an officer, Director, or employee of a market participant or affiliate, unless the Audit and Finance Committee of the Board of Directors approves a waiver.

  - **Material ongoing business or professional relationships:** A Director may not have an ongoing relationship with a market participant or affiliate or an employee of the same. The Audit and Finance Committee of the Board of Directors determines what constitutes such relationships.

  - **Bylaws' Age Limitation:** ISO-NE's bylaws state that no person shall be eligible for election or reelection unless such person is age 70 or less at the time of election or reelection.

The ISO-NE list of market participants and affiliates will be provided by Russell Reynolds to candidates, for their review of potential conflicts, along with detailed conflict guidelines.

Search Process

The ISO elects its Board members through a nominating process that involves representatives from the ISO New England Board of Directors, the New England Power Pool (NEPOOL), and the New England Conference of Public Utilities Commissioners who compose the Joint Nominating Committee (JNC). Candidates also receive the endorsement of the NEPOOL Participants Committee. For the current search process, two rounds of interviews are expected before finalist candidates are nominated for endorsement by NEPOOL. Once NEPOOL has voted for the endorsement, the candidate would begin serving as a Director in the October 2021 Board meeting.

Compensation

The compensation schedule outlined for the ISO New England's Board of Directors is as follows:

Annual compensation, paid in quarterly instalments

Annual Retainer	$70,000
Chairman of the Board	$25,000
Committee Chairpersons	$10,000
Board Vice Chair	$5,000

Meeting fees (including teleconferences, if joining via teleconference fee is half), paid after each meeting

Board Meeting Fees	$2,000 per meeting day
Committee Meeting Fees	$1,500 per meeting day
Joint Meetings with NEPOOL and NECPUC	$1,500 per meeting day
Joint Nominating Committee Meetings	$1,500 per meeting day
Telephonic Attendance Meeting Fees	50% of the usual meeting fee
Special Meetings Special Meetings at the request of the CEO or Board	$1,500 per meeting day
Special Director Assignments Any special project or assignment at the request of the CEO and Board	$250 per hour

Contact

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M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: February 25, 2021

RE: Updating Offer Review Trigger Prices (ORTP) Values for FCA16

At the March 4, 2021 Participants Committee teleconference meeting, you will be asked to consider the Markets Committee's recommendation to amend NEPOOL's previously-adopted proposal relating to ORTPs, which are to be used in the sixteenth Forward Capacity Auction (FCA16). In addition, you will be asked to consider the ISO's modified set of ORTPs and related Tariff revisions. This memorandum summarizes the relevant background information, explains the voting process, and includes a form of resolution.

In addition, included with this memorandum are the following Attachments:

- Attachment A: The February 24 Markets Committee-recommended set of Tariff redlines.
- Attachment B: The ISO-proposed Tariff redlines for its modified ORTP proposal.
- Attachment C: The Markets Committee's February 24 Notice of Actions.
- Attachment D: The ISO/IMM's background materials.

PROCEDURAL BACKGROUND

Following an extended stakeholder process, on December 3, 2020, the Participants Committee considered and approved, by a 71.84% Vote in favor, a set of ORTP values and related Tariff revisions (among other parameters)[1] to be used in the Forward Capacity Market (FCM) beginning with FCA16. The NEPOOL-approved ORTP revisions differed from those the ISO favored. At the request of the ISO, NEPOOL also considered and voted the ISO-favored ORTP provisions and FCM parameters, which failed with an 18.33% Vote in favor. As a result, a jump ball[2] was established with a NEPOOL-supported alternative to the ISO's proposed set of Tariff revisions.

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[1] The additional parameters approved by NEPOOL, which included updates the Cost of New Entry (CONE), Net CONE, and Performance Payment Rate (PPR), were the same parameters favored by the ISO.

[2] In a jump ball proceeding, the ISO and NEPOOL submit both proposals to FERC on equal legal footing. *See* Participants Agreement § 11.1.5. The FERC determines which proposal is "just and reasonable and preferable." *See id.*

DEVELOPMENTS SINCE THE DECEMBER 3 PARTICIPANTS COMMITTEE VOTE

On December 11, 2020, the New England Power Generators Association filed a complaint challenging the ISO's proposed Net CONE calculation for FCA16.[3] Consequently, the ISO (in consultation with NEPOOL Counsel) decided to bifurcate its FCM parameter values filing. As noted in the ISO's December 31, 2020 transmittal letter, the ISO sought a FERC decision on those FCM parameters on which ISO and NEPOOL did not depart (i.e., CONE, Net CONE, and PPR values) in time for the FCA16 qualification process, which begins in March 2021.[4] Explaining that FERC approval of the ORTP values could wait until later in the FCA16 qualification process, the ISO committed to file the two alternative NEPOOL and ISO ORTP proposals in a subsequent jump ball filing.[5]

On December 27, 2020, the federal Consolidated Appropriations Act, 2021 (the Act) was signed into law. Among other things, this Act extended the beginning of construction deadline for the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) for certain renewable resources. Because of this material change in circumstances, the ISO, working with its consultants (Concentric Energy Advisors, Inc. and Mott MacDonald), assessed the impact of the Act and, as explained further below, revised its previously-considered set of ORTP values and related Tariff revisions.

Because the ISO bifurcated its FCM parameters filings, the jump ball proceeding will be limited to the issues where NEPOOL and the ISO disagreed—the ORTPs and related Appendix A revisions. For the sake of clarity herein, the previously adopted NEPOOL alternative will be referred to as the "Dec. 3 NEPOOL ORTP Proposal."

MARKETS COMMITTEE CONSIDERATION

At the February 9–10, 2021 Markets Committee meeting, the ISO presented its initial proposed Tariff revisions resulting from the material change in circumstances caused by the Act. The ISO explained that, because the ITC eligibility was revised for offshore wind and solar technologies, its consultants re-calculated ORTPs for those technology types. The ISO further explained that, because the PTC only applied to onshore wind projects that already had a $0.000/kW-month ORTP, no change to that ORTP was proposed. The ISO also concluded that the tax law changes under the Act warranted Tariff revisions to include a new ORTP value for Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery, as well as additional Tariff revisions regarding the weighted average approach to calculate ORTPs for multiple technology types.

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[3] Complaint and Request for Fast-Track Process of the New England Power Generators Association, Inc., Docket No. EL21-26 (filed Dec. 11, 2020).

[4] ISO New England Inc., Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787, at 3 (filed Dec. 31, 2020).

[5] *Id.* at 41.

Thus, the ISO proposed the following changes to its previously-favored package of ORTPs and related Tariff provisions (together, the ISO's Revised ORTP Proposal):

- Two new ORTP values in Appendix A:
  - Photovoltaic Solar: $0.000/kW-month
  - Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery: $6.964/kW-month
- Adding Tariff language to Sections III.A.21.1.1 and III.A.21.2(c) stating that the weighted average calculation would only be used when an ORTP for the combination of technology types is not specified in the Tariff
- Proposing new Tariff language to specify the ITC percentages that would be used during the FCAs 17 and 18 ORTP adjustment for Photovoltaic Solar and Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery

At its February 24, 2021 meeting, the Markets Committee first considered whether, in light of the Act and proposed modifications to the ISO-favored ORTPs and related Tariff revisions, the Dec. 3 NEPOOL ORPT Proposal should also be changed. With a 71.67% Vote in favor, that Committee voted to recommend that the Participants Committee approve three changes (discussed below) to the Dec. 3 NEPOOL ORTP Proposal. In addition, at the request of the ISO, the Markets Committee also considered whether to recommend NEPOOL Participants Committee support for the ISO's Revised ORTP Proposal. That resolution failed with no Participant voting in support.

1. *Union of Concerned Scientists (UCS) (on behalf of RENEW Northeast) Amendment #1: Incorporate the Current ITC values into FCA16 ORTPs*[6]

The first amendment offered at the Markets Committee proposed to ensure that the ITC eligibility for solar and offshore wind projects (i.e., **26** percent and **30** percent, respectively) were reflected in the Dec. 3 NEPOOL ORTP Proposal. The latter technology type's ORTP remained unchanged because the Dec. 3 NEPOOL ORTP Proposal included an ORTP of $0.000/kW-month. The former technology type's ORTP, however, changed. Thus, UCS Amendment #1 modified the Dec. 3 NEPOOL ORTP Proposal by striking out the Photovoltaic Solar ORTP of $1.861/kW-month and inserting a $0.000/kW-month value (which is the same value as the ISO's modified ORTP proposal[7]). This motion to amend the Dec. 3 NEPOOL ORTP Proposal passed at the Markets Committee with a 73.81% Vote in favor.

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[6] To review UCS's presentation, please click here.

[7] Although the ISO and the Markets Committee propose the same ORTP for solar resources, the Markets Committee-supported value includes an assumption of a longer economic life, an assumption that was approved by the Participants Committee when it approved the Dec. 3 NEPOOL ORTP Proposal. The ISO's new solar ORTP assumes a 20-year economic life.

2. *UCS Amendment #2: Reflecting the Solar ITC Phase Down Values in ORTP Annual Adjustments for FCAs 17 and 18*[8]

The Markets Committee next considered UCS's second amendment, which sought to add Tariff language to the Dec. 3 NEPOOL ORTP Proposal's requirement for the ISO, during the ORTP adjustments for FCAs 17 and 18, to update the PTC and ITC inputs of the capital budgeting model to reflect the most current tax law. UCS's amendment proposed additional Tariff language intended to ensure that the capital budgeting model for the photovoltaic solar resource would include 26% ITC for FCA17, 22% for FCA18, and 10% thereafter. This motion passed with a 73.71% Markets Committee Vote in favor.

3. *Advanced Energy Economy, Borrego Solar Systems, Enel X, ENGIE North America, and RENEW Northeast's Amendments to Section III.A.21.1.1*[9]

The third and final amendment to the Dec. 3 NEPOOL ORTP Proposal considered by the Markets Committee, which was jointly proposed by a number of Participants, was offered to ensure that new capacity resources composed of assets having different technology types received an ORTP based on the weighted average of the ORTPs of the asset technology types that composed the capacity resource. Specifically, co-located assets of multiple technology types registering as a single resource would receive an ORTP equal to the weighted average of the ORTPs applicable to the assets comprising the resource. For co-located assets of multiple technology types registering as separate FCM resources, the ORTPs assigned would be the applicable ORTP to the underlying technology type. To effectuate the joint amendment's purpose, Tariff language was proposed to Section III.A.21.1.1. Relatedly, the joint amendment also struck out the Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery Demand Capacity Resource ORTP from the Dec. 3 NEPOOL ORTP Proposal. The proponents argued that the ORTP for this demand capacity resource was inconsistent with the existing Tariff language. This third amendment passed with a Markets Committee a 75.31% Vote in favor.

With Markets Committee support for three amendments to the Dec. 3 NEPOOL ORTP Proposal, the Markets Committee then considered and, with a 71.667% Vote in favor, voted to recommend that the Participants Committee support the modified package of ORTP provisions.[10] Thus, the Participants Committee will consider whether to change its prior support for the Dec. 3 NEPOOL ORTP Proposal in favor of the modified package recommended by the Markets Committee, which is referred to herein as the "MC-recommended Modified NEPOOL ORTP Proposal."

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[8] UCS's presentation explaining its amendment can be reviewed here.

[9] The presentation fully describing the joint amendment can be accessed here.

[10] The individual Sector votes at the Markets Committee were as follows: *Generation* – 4.77% in favor, 11.93% opposed, 0 abstentions; *Transmission* – 16.7% in favor, 0% opposed, 0 abstentions; *Supplier* – 5.01% in favor, 11.69% opposed, 5 abstentions; *Publicly Owned Entity* – 16.7% in favor, 0% opposed, 0 abstentions; *Alternative Resources* – 11.79% in favor, 4.71% opposed, 0 abstentions; and *End User* – 16.7% in favor, 0% opposed, 1 abstention.

At the request of the ISO, the Markets Committee also voted on the ISO's Revised ORTP Proposal. That Proposal received a 0% Vote in favor; thus, it was not recommended by the Markets Committee.[11]

For the sake of convenience, the following table provides the Markets Committee-recommended ORTPs, as well as the ISO's updated ORTPs.

Revised ORTPs Since the December 3 NPC Vote (New ORTPs Highlighted in Green)		
Generating Capacity Resources		
Technology Type	**ISO-NE's ORTP ($/kW-month)**	**Markets Committee-Supported ORTP ($/kW-month)**
Simple Cycle Combustion Turbine	$5.366	$5.366
Combined Cycle Gas Turbine	$9.819	$9.819
On-Shore Wind	$0.000	$0.000
Off-Shore Wind	N/A[12]	$0.000
Energy Storage Device – Lithium Ion Battery	$2.923	$2.612
Photovoltaic Solar	$0.000	$0.000[13]
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$6.964	N/A
Demand Capacity Resources		
Technology Type	**ISO-NE's ORTP ($/kW-month)**	**Markets Committee-Supported ORTP ($/kW-month)**
Load Management (Commercial / Industrial)	$0.761	
Previously Installed Distributed Generation	$0.761	
New Distributed Generation	Based on generation technology type	
On-Peak Solar	$5.425	
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$7.376	N/A
Energy Efficiency	$0.000	

[11] The individual Sector votes at the Markets Committee were as follows: *Generation* – 0% in favor, 16.7% opposed, 1 abstention; *Transmission* – 0% in favor, 16.7% opposed, 3 abstentions; *Supplier* – 0% in favor, 16.7% opposed, 8 abstentions; *Publicly Owned Entity* – 0% in favor, 16.7% opposed, 0 abstentions; *Alternative Resources* – 0% in favor, 16.5% opposed, 0 abstentions; and *End User* – 0% in favor, 16.7% opposed, 2 abstentions.

[12] Although the ISO inputted a 30% ITC into the capital budgeting model when evaluating the Act's impact on offshore wind resources, that technology type's ORTP under the ISO's calculation was still above the FCA starting price. As a result, the ISO did not include an offshore wind-specific ORTP in its proposed updated Tariff revisions.

[13] *See supra* note 7 and accompanying text.

THE PARTICIPANTS COMMITTEE VOTING PROCESS

Following its standard process, the starting point at the March 4 Participants Committee meeting will be to consider whether to support the MC-recommended Modified NEPOOL ORTP Proposal instead of the previously-approved Dec. 3 NEPOOL ORTP Proposal. The following form of resolution may be used to initiate Participants Committee consideration:

> RESOLVED, that the Participants Committee supports amending its previously-approved Offer Review Trigger Prices and related Tariff revisions as recommended by the Markets Committee at its February 24, 2021 meeting, and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

If the MC-recommended Modified NEPOOL ORTP Proposal is not further amended and that Proposal receives a 60% or greater Vote in favor, then the Modified NEPOOL ORTP Proposal will be the Participants Committee-approved alternative to the ISO's Revised ORTP Proposal. If the motion to support the MC-recommended Modified NEPOOL ORTP Proposal fails to pass, then the Dec. 3 NEPOOL ORTP Proposal will remain as NEPOOL's-approved alternative to the ISO's Proposal.

Following the Participants Committee's standard process, any member or alternate may offer an amendment to the MC-recommended Modified NEPOOL ORTP Proposal.[14] Any amendments, including an amended package, will need to receive at least a 60% Vote in favor to be supported. Participants need to be aware that, under the intended voting process, if the Participants Committee first amends the MC-recommended Modified NEPOOL ORTP Proposal at its March 4 meeting but then fails to support the amended MC-recommended Modified NEPOOL ORTP Proposal, then NEPOOL will not have an approved alternative and as your counsel we will no longer be in a position to advocate for a NEPOOL alternative to the ISO's Revised ORTP Proposal (including the Dec. 3 NEPOOL ORTP Proposal). In the event the MC-recommended Modified NEPOOL ORTP Proposal is amended and that amended proposal also receives a 60% or greater Vote in favor, then the jump ball will reflect that amended proposal.

Consistent with ISO's rights under the Participants Agreement, we expect that the ISO will request a separate vote on the ISO's Revised ORTP Proposal following Committee action on the MC-recommended Modified NEPOOL ORTP Proposal.

Given the unique and unprecedented circumstances before us, we offer Figure 1 to provide further clarity to the Participants Committee members and alternates on the contemplated voting process for the March 4 meeting on a modified alternative NEPOOL ORTP proposal.

[14] At this time, we have not been advised of any such proposed amendments.

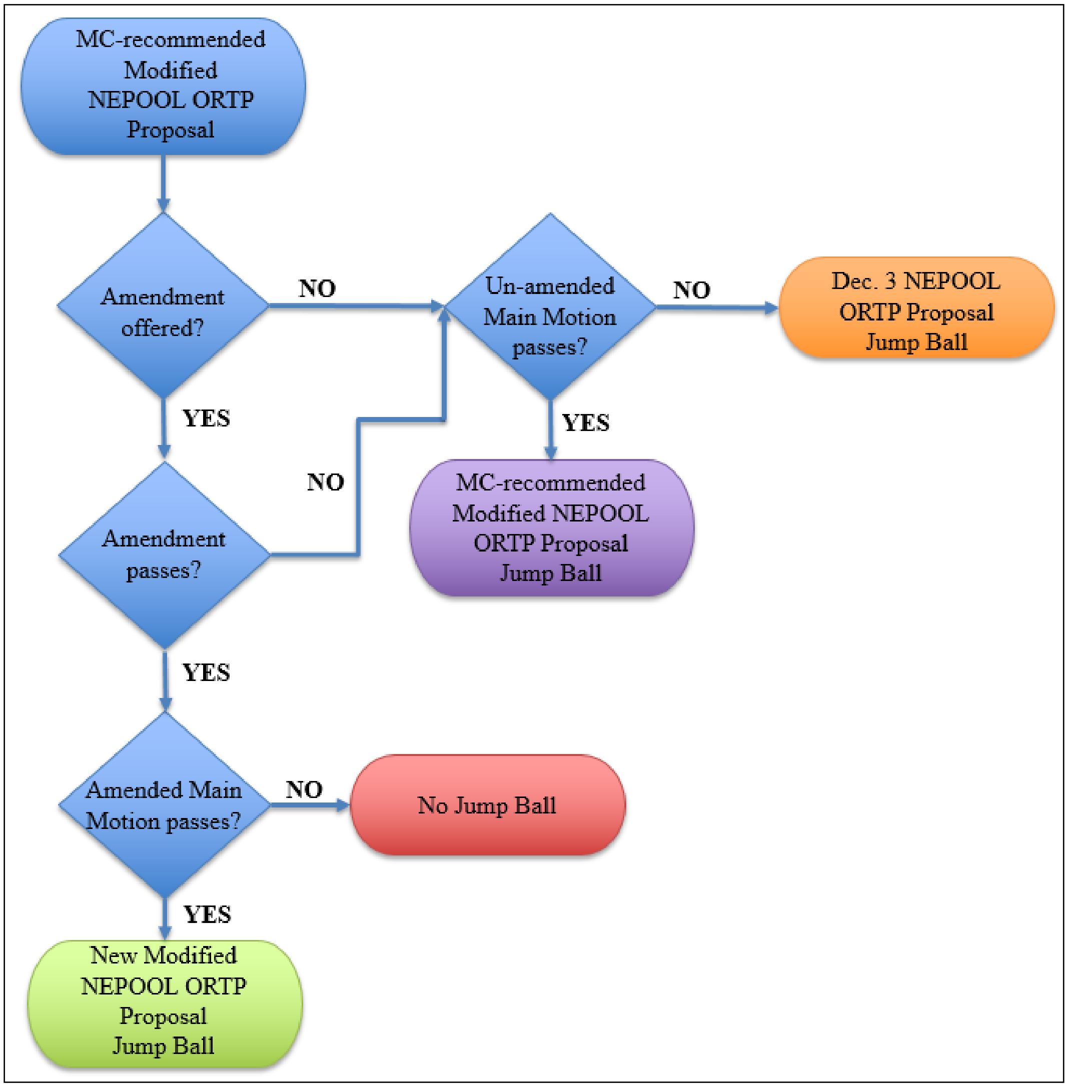

Figure 1: NPC Voting Process

If anyone wishes to offer amendments for Participants Committee consideration, please provide those amendments to NEPOOL Counsel (slombardi@daypitney.com and rgarza@daypitney.com) as soon as possible so that we can circulate them in time for member review and consideration before the meeting.

memo

To: NEPOOL Participants Committee

From: Mark Karl, Vice President Market Development and Settlements

Date: March 2, 2021

Subject: ISO Revisions to the Offer Review Trigger Price for Co-located Resources for FCA 16 (CCP 2025-2026)

Over the course of the February 2021 Markets Committee (MC) meetings, ISO New England heard the concerns raised by stakeholders regarding the vetting of the various inputs and assumptions used in developing the Offer Review Trigger Price (ORTP) for the Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery ("co-located ORTP").

Although the ISO previously reviewed the development of these ORTP values with stakeholders, we understand that the ISO's proposal may benefit from additional time to evaluate and discuss the methodology and assumptions employed. Therefore, the newly proposed co-located ORTPs (in both the Generating Capacity Resource and Demand Capacity Resource categories[1]) for FCA 16 will not be included in the ORTP values filed by ISO New England.

The revised Tariff language for the NEPOOL Participants Committee will reflect the removal of these ORTP values. Accordingly, the language proposed by the ISO in February clarifying that a weighted average ORTP value will not be applied when an ORTP is available for specific combinations of technology types has been removed, as it is now moot.

[1] The Generating Capacity Resource and Demand Capacity Resource ORTPs share some similar inputs and assumptions and, therefore, it is reasonable that the same concerns raised in regards to the Generating Capacity Resource ORTP would also impact the Demand Capacity Resource ORTP.

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