

# NEPOOL Participants Committee Report

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*September 2019*



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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



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# Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value was \$321M, down \$93M from July 2019 and down \$240M from August 2018
    - August natural gas prices were 11% lower than July 2019 average values
    - Average RT Hub Locational Marginal Prices (\$23.58/MWh) were 19% lower than July 2019 averages
      - Avg. DA Hub LMP: \$25.69/MWh
    - Average August 2019 natural gas prices and RT Hub LMPs were down 36% and 40%, respectively, from August 2018 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 101.3% during August, up from 99.9% during July\*
    - Highest monthly average since Standard Market Design implementation
    - The minimum value for the month was 93.4% on Tuesday, August 13<sup>th</sup>

Full month of August 2019 data is reflected throughout the report.

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

Underlying natural gas data furnished by:



# Highlights, cont.

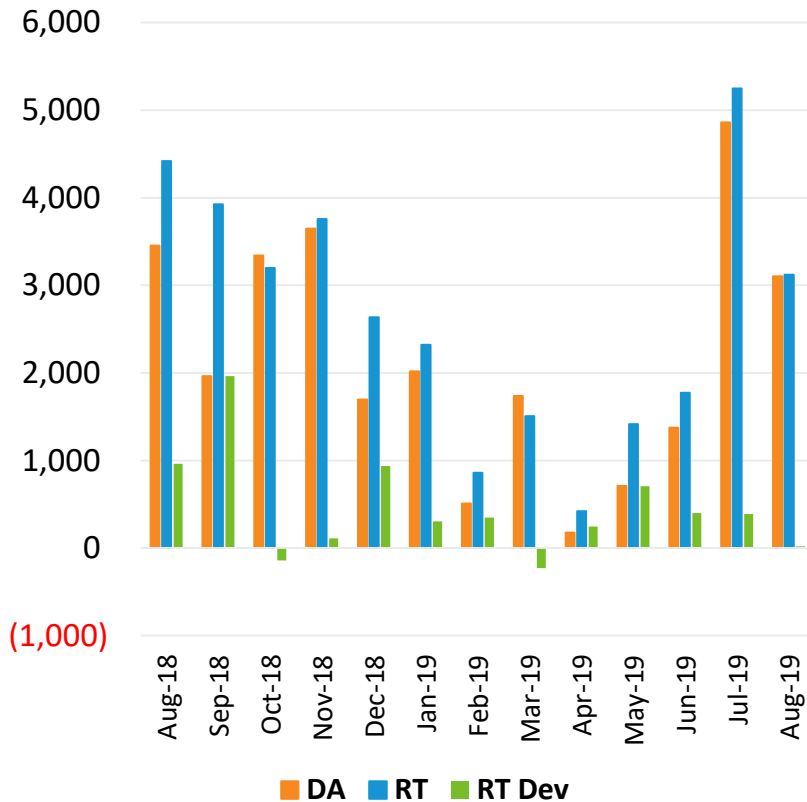
- Daily Net Commitment Period Compensation (NCPC)
  - August NCPC payments totaled \$1.6M, down \$2.1M from July 2019 and down \$1.3M from August 2018
    - First Contingency\* payments totaled \$1.1M, down \$0.5M from July
      - \$1.1M paid to internal resources, down \$0.4M from July
        - » \$218K charged to DALO, \$474K to RT Deviations, \$394K to RTLO
      - \$7K paid to resources at external locations, down \$9K from July
        - » Charged to RT Deviations
    - Second Contingency payments totaled \$357K, down \$1.6M from July
    - Distribution payments totaled \$149K, down \$42K from July
  - NCPC payments over the period as percent of Energy Market value were 0.5%

\* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - \$158K; Rapid Response Pricing (RRP) Opportunity Cost - \$223K; Posturing - \$13K; Generator Performance Auditing (GPA) - \$0



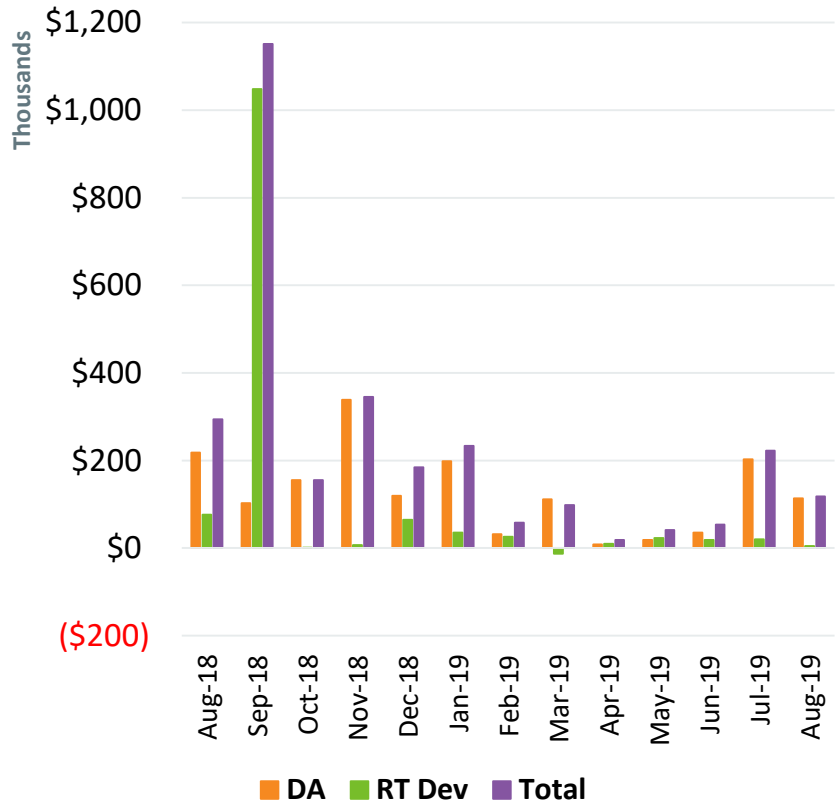
# Price Responsive Demand (PRD) Energy Market Activity by Month

## DA, RT, and RT Dev MWh



(1,000)

## Market Value



(\$200)

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



# Highlights

- The RSP19 public meeting will be held on September 12, from 11:30am until 4:00pm, at The Westin Copley Place in Boston, MA
- ISO continues to meet with the TC and RC on proposed enhancements to the competitive transmission solicitation process in the OATT to support an October filing
- FCA 14 qualification activities are nearing completion
  - New Capacity Resource Qualification Determinations to be disseminated by September 27
  - FERC filings pertaining to ICR and qualification will be made on November 5



# Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Second reconfiguration auction will be August 1-5, and results were posted on September 3
- CCP 12 (2021-2022)
  - Second reconfiguration auction will be August 3-5, 2020 and results to be posted by September 2, 2020
- CCP 13 (2022-2023)
  - Auction results were filed with FERC on February 28 and FERC has yet to rule
  - First reconfiguration auction will be June 1-3, 2020 and results to be posted by July 1, 2020

# FCM Highlights, cont.

- CCP 14 (2023-2024)
  - New Capacity Resource Qualification is ongoing
    - On target to release QDNs on September 27
    - Renewable Technology Resource Exemption: approximately 336 MW
  - Existing Capacity Resource Qualification is complete
  - This will be the first FCA where nested capacity zones will be modeled
    - Tariff changes were filed with FERC and an order is expected by October 1
    - Capacity Zones to be modeled include: Rest of Pool, Southeastern New England, Northern New England, and Maine (nested zone within Northern New England)
  - ICR & related values development discussions are ongoing with the PSPC and RC
- Both the ICR and Informational (qualification) FERC filings will be made on November 5

FCA – Forward Capacity Auction  
ICR – Installed Capacity Requirement  
PSPC – Power Supply Power Committee

RC – Reliability Committee  
QDN – Qualification Notification Determination

ISO-NE PUBLIC



# FERC Order 1000

- Intraregional Planning

- Qualified Transmission Project Sponsor (QTPS)
  - 21 companies have achieved QTPS status
  - One company is currently moving through the QTPS application process
- Based on the results of the Boston Needs Assessment to date, the ISO plans to release its first request for proposal (RFP) for a competitively developed transmission solution in late 2019 or early 2020
- Ongoing discussions to support an October 2019 Tariff filing at the following Committees
  - NEPOOL Transmission Committee; NEPOOL Reliability Committee; Participating Transmission Owners Administrative Committee
- Draft RFP templates have been provided to the PAC



# Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance. Consideration is being given to:
  - Shifts in technology/measure mix are anticipated
  - Trend of coupling of behind-the-meter (BTM) photovoltaics (PV) with BTM energy storage to shift assumed performance characteristics of BTM PV
- The 2020 load forecast process has begun and the ISO would like to highlight the following dates
  - Energy-Efficiency Forecast Working Group WebEx will be held on September 13
  - Load Forecast Committee meeting will be held on September 27
  - Distributed Generation Forecast Working Group meeting will be held on October 2



# Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 2, 2019.
- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning January 11, 2020.



# SYSTEM OPERATIONS



# System Operations

<u>Weather Patterns</u>	Boston	Temperature: Above Normal (2.0°F) Max: 95°F, Min: 57°F Precipitation: 3.48" – Above Normal Normal: 3.35"	Hartford	Temperature: Above Normal (0.9°F) Max: 95°F, Min: 47°F Precipitation: 3.30" – Above Normal Normal: 3.93"
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<u>Peak Load:</u>	22,901 MW	Aug 19, 2019	16:00 (ending)
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## Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
None for August			



# System Operations

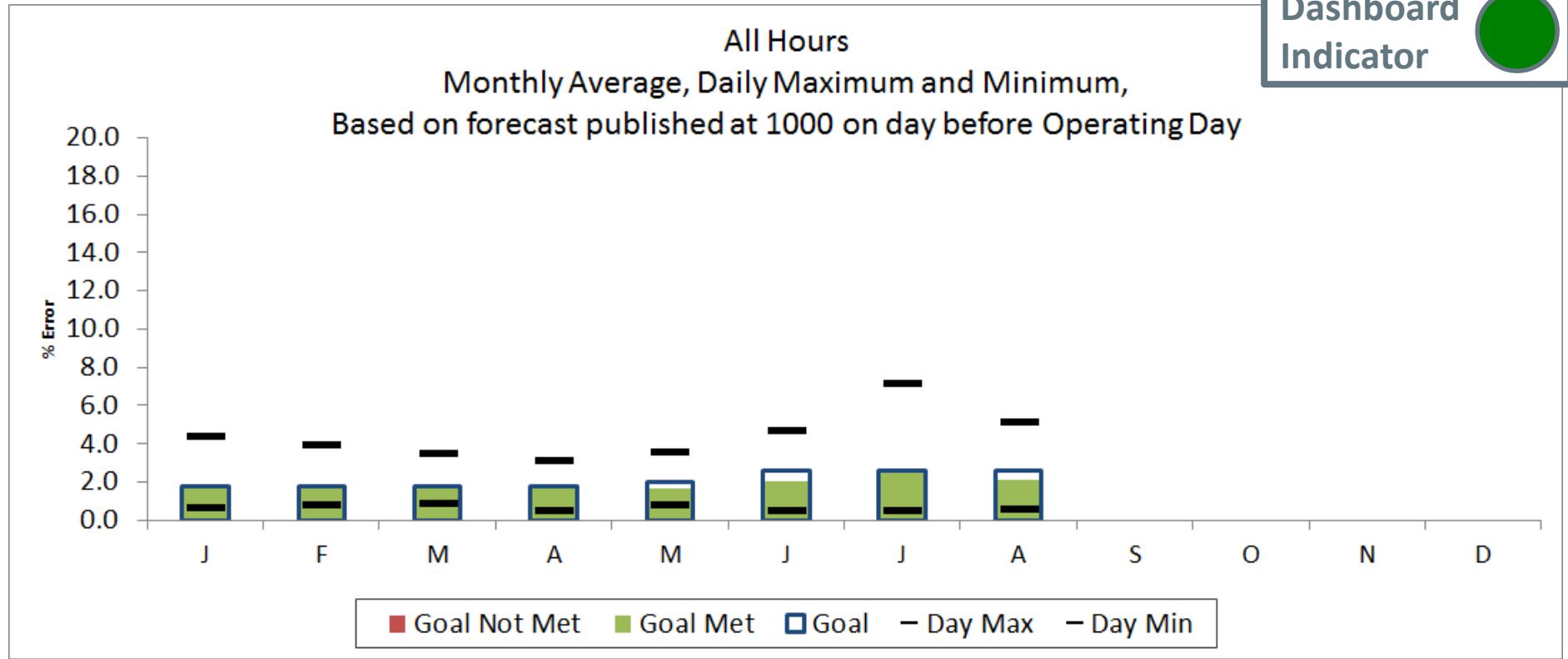
## NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
None for August		



# 2019 System Operations - Load Forecast Accuracy

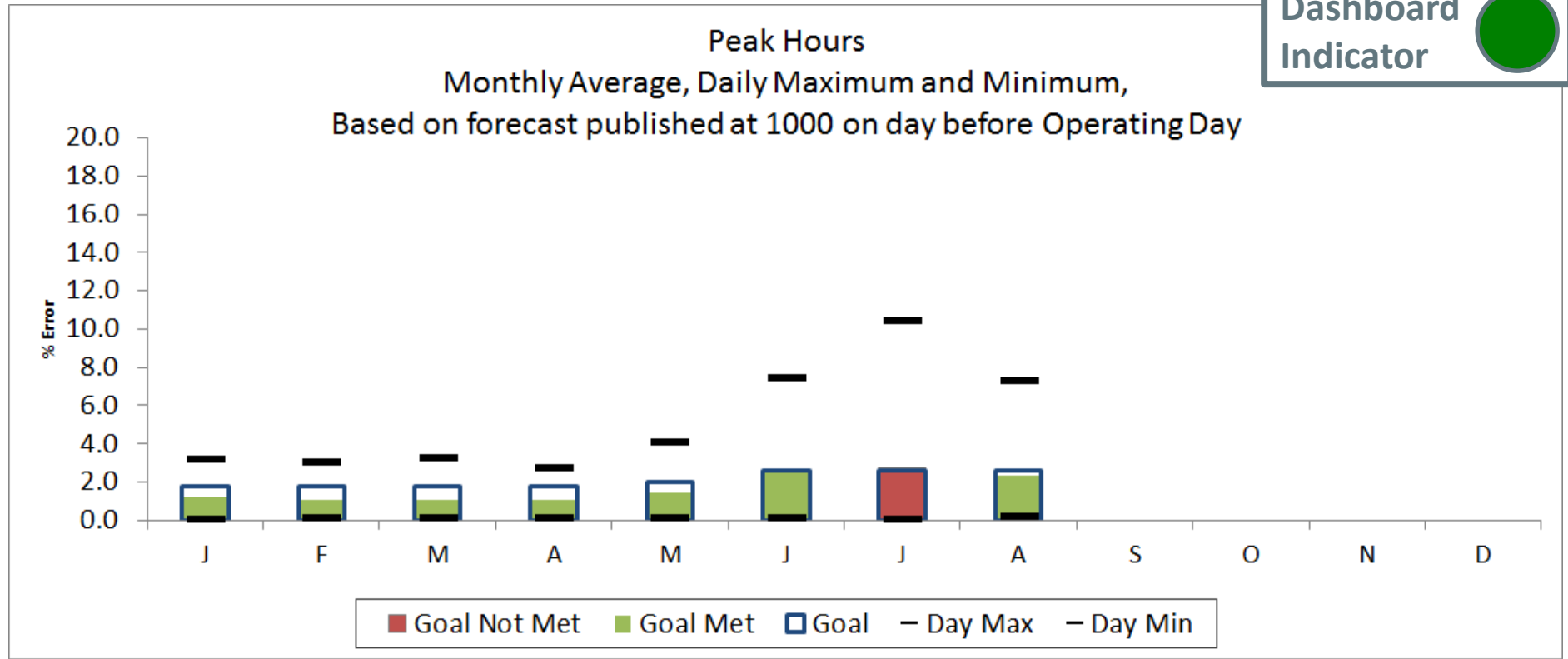
Dashboard  
Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.36	3.87	3.47	3.11	3.53	4.68	7.14	5.10					7.14
Day Min	0.60	0.77	0.81	0.49	0.79	0.49	0.44	0.57					0.44
MAPE	1.76	1.68	1.72	1.79	1.64	2.01	2.46	2.12					1.90
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

# 2019 System Operations - Load Forecast Accuracy cont.

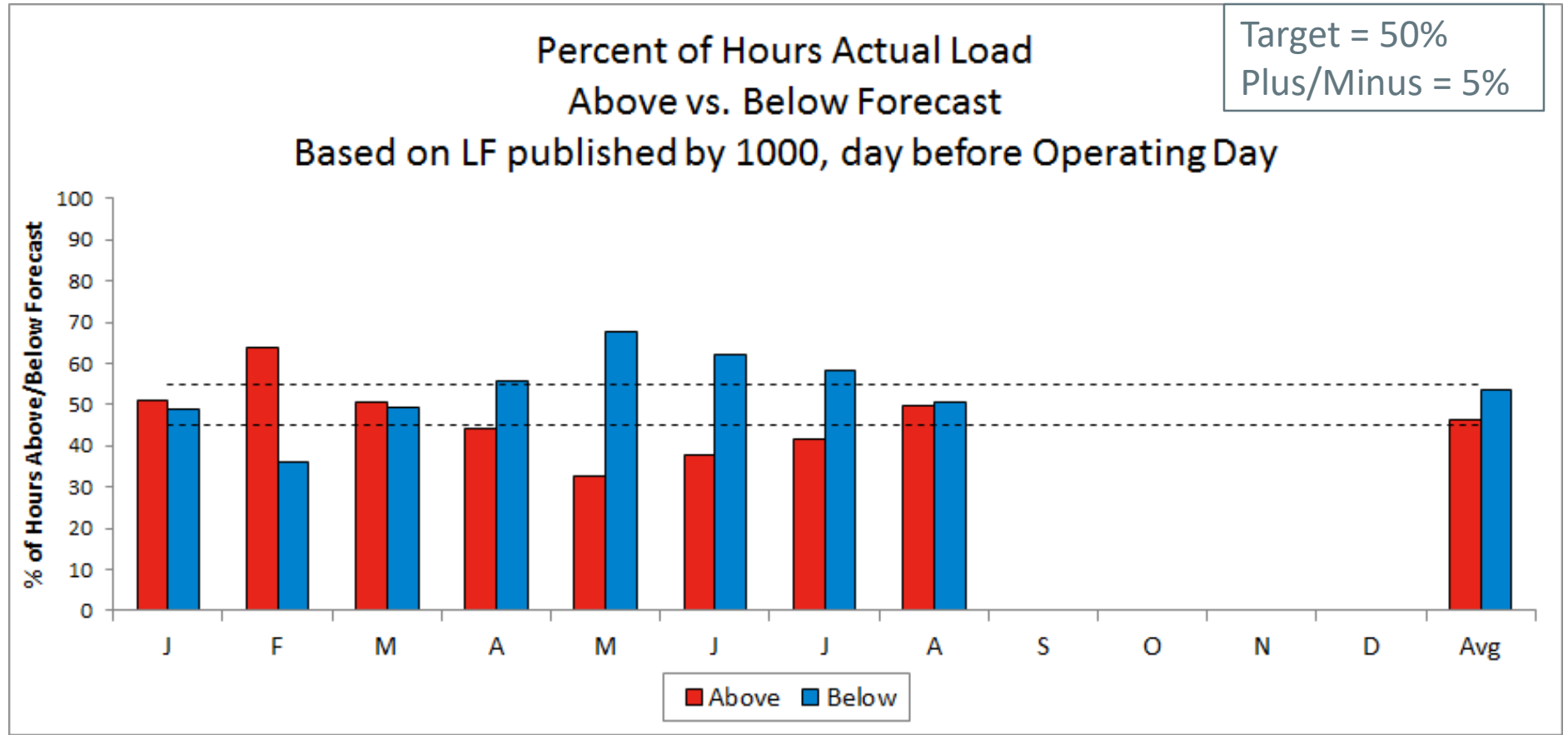
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.17	3.03	3.23	2.71	4.08	7.39	10.38	7.27					10.38
Day Min	0.02	0.06	0.06	0.12	0.07	0.07	0.01	0.16					0.01
MAPE	1.22	1.04	1.06	1.04	1.45	2.53	2.72	2.37					1.69
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

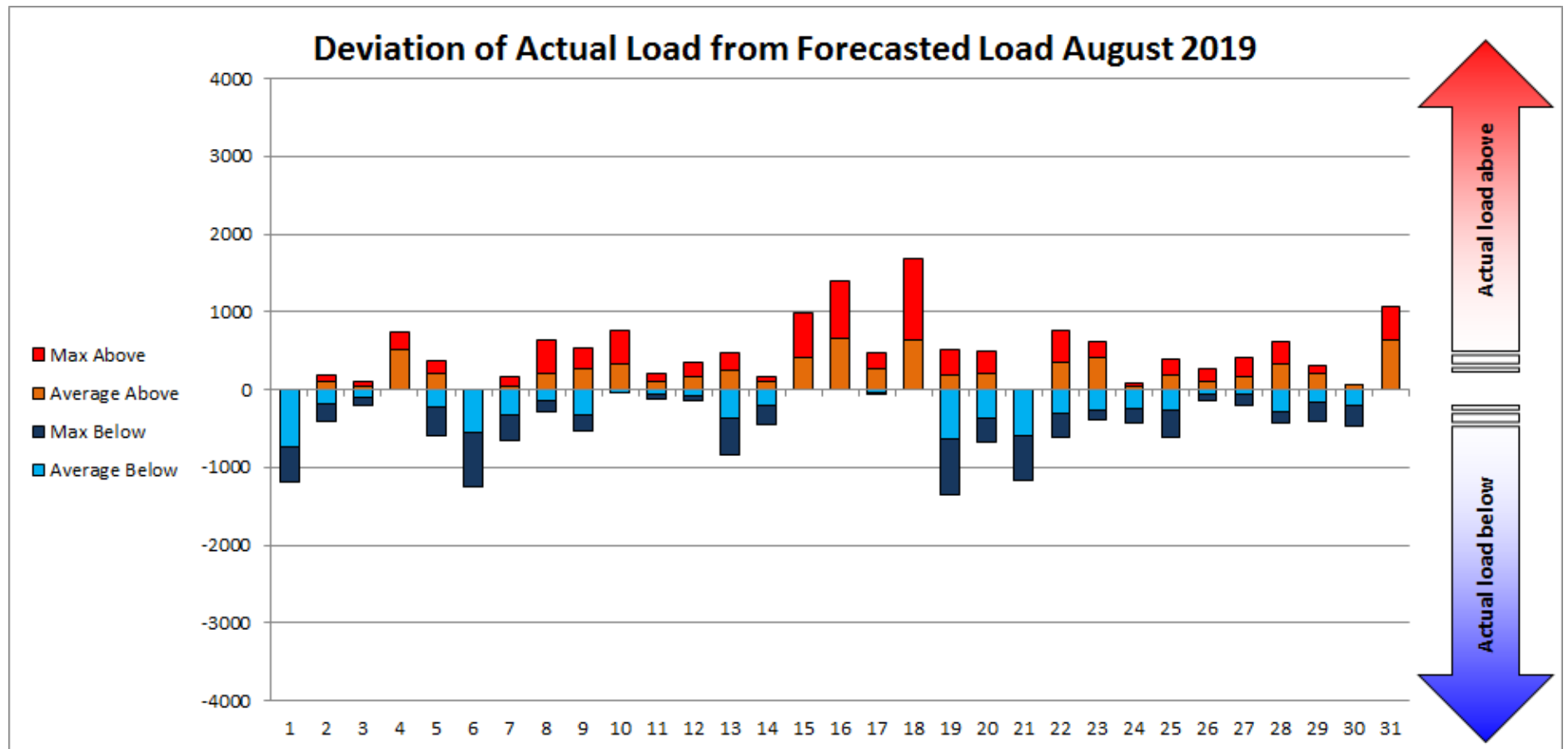


# 2019 System Operations - Load Forecast Accuracy cont.



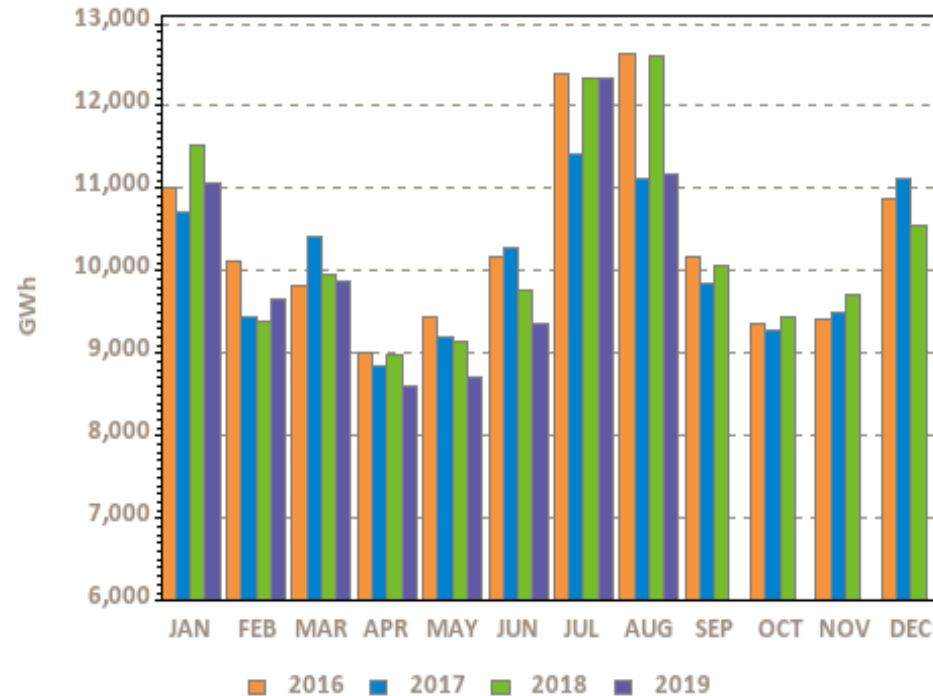
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	51.1	64	50.5	44.2	32.5	37.9	41.7	49.6					46
Below %	48.9	36	49.5	55.8	67.5	62.1	58.3	50.4					54
Avg Above	211.7	224.2	162.1	184.1	126.1	144.9	268.3	230.9					268
Avg Below	-183.0	-174.3	-192.4	-161.7	-179.6	-225.1	-350.1	-220.1					-350
Avg All	30	88	-12	1	-79	-80	-108	8					-20

# 2019 System Operations - Load Forecast Accuracy cont.



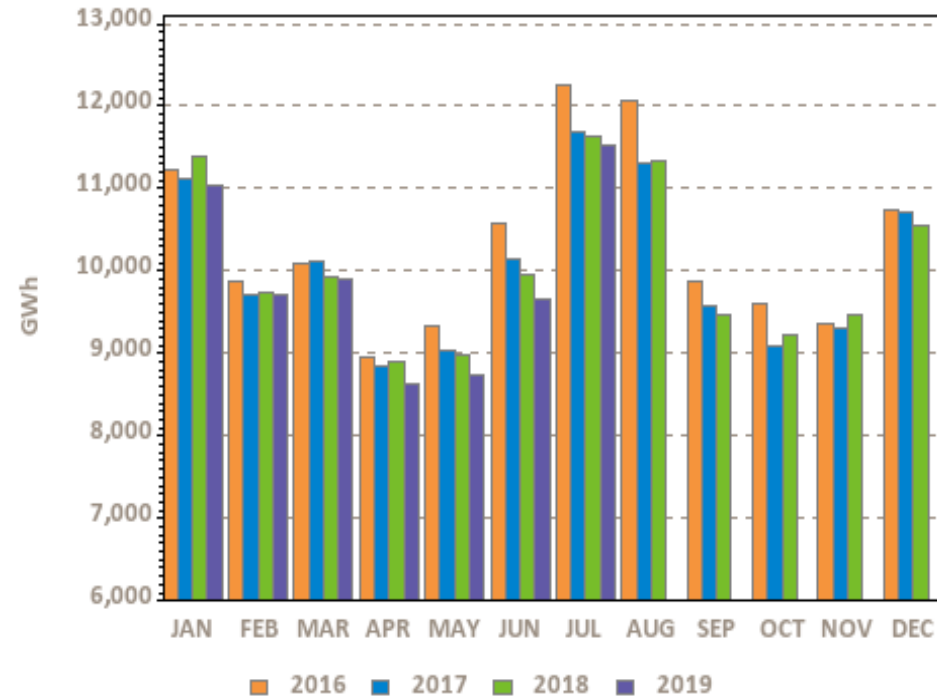
# Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)



Ann Tot (TWh): 124.4 121.2 123.3 80.2

Weather Normalized NEL

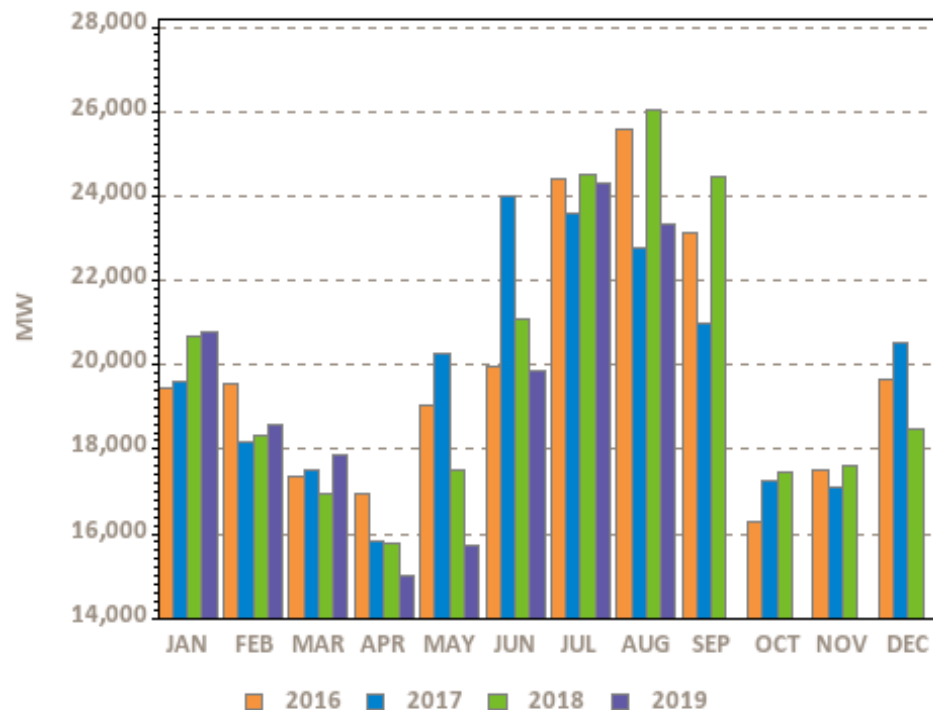


Ann Tot (TWh): 124.0 120.7 120.6 69.2

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.

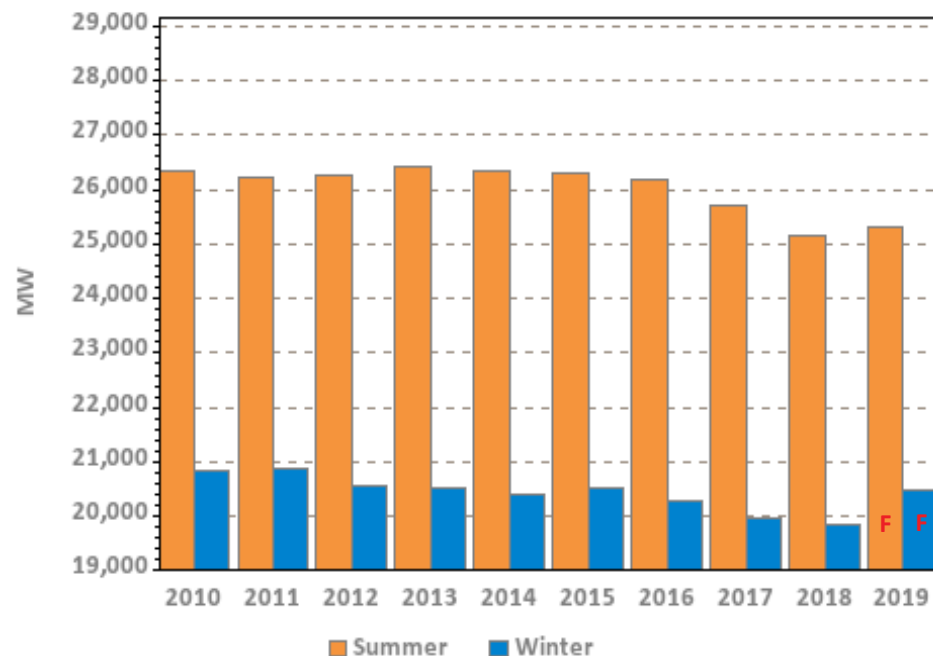
# Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load



\*Revenue quality metered value

Weather Normalized Seasonal Peaks



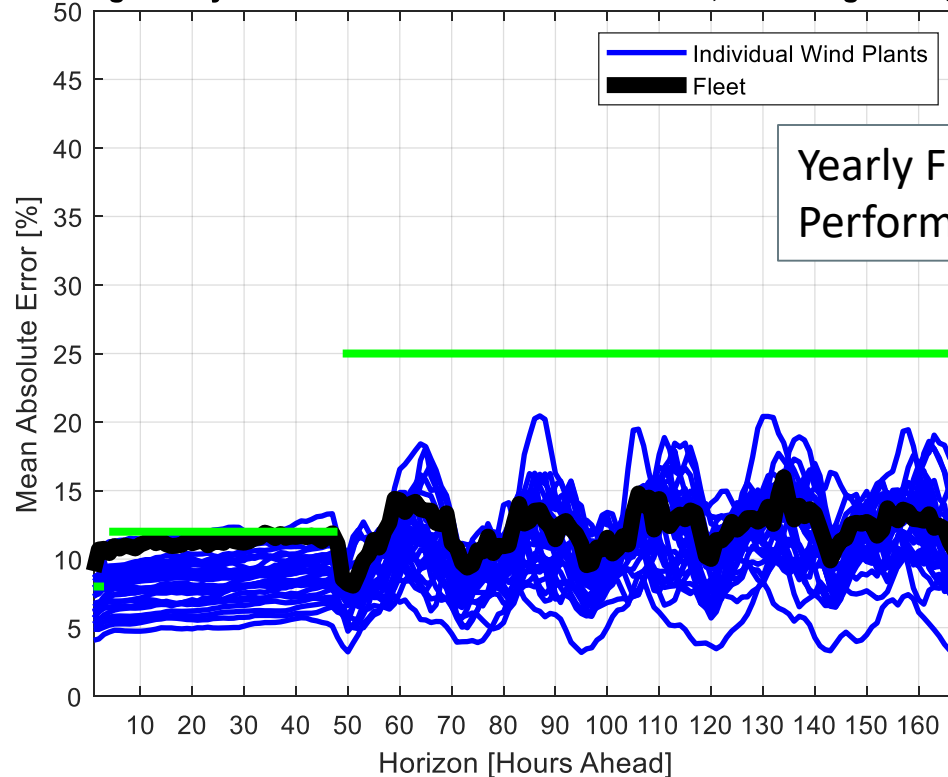
Winter beginning in year displayed

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

Rolling 30-day MAE for ISO Wind Power Forecast, as of August 31, 2019

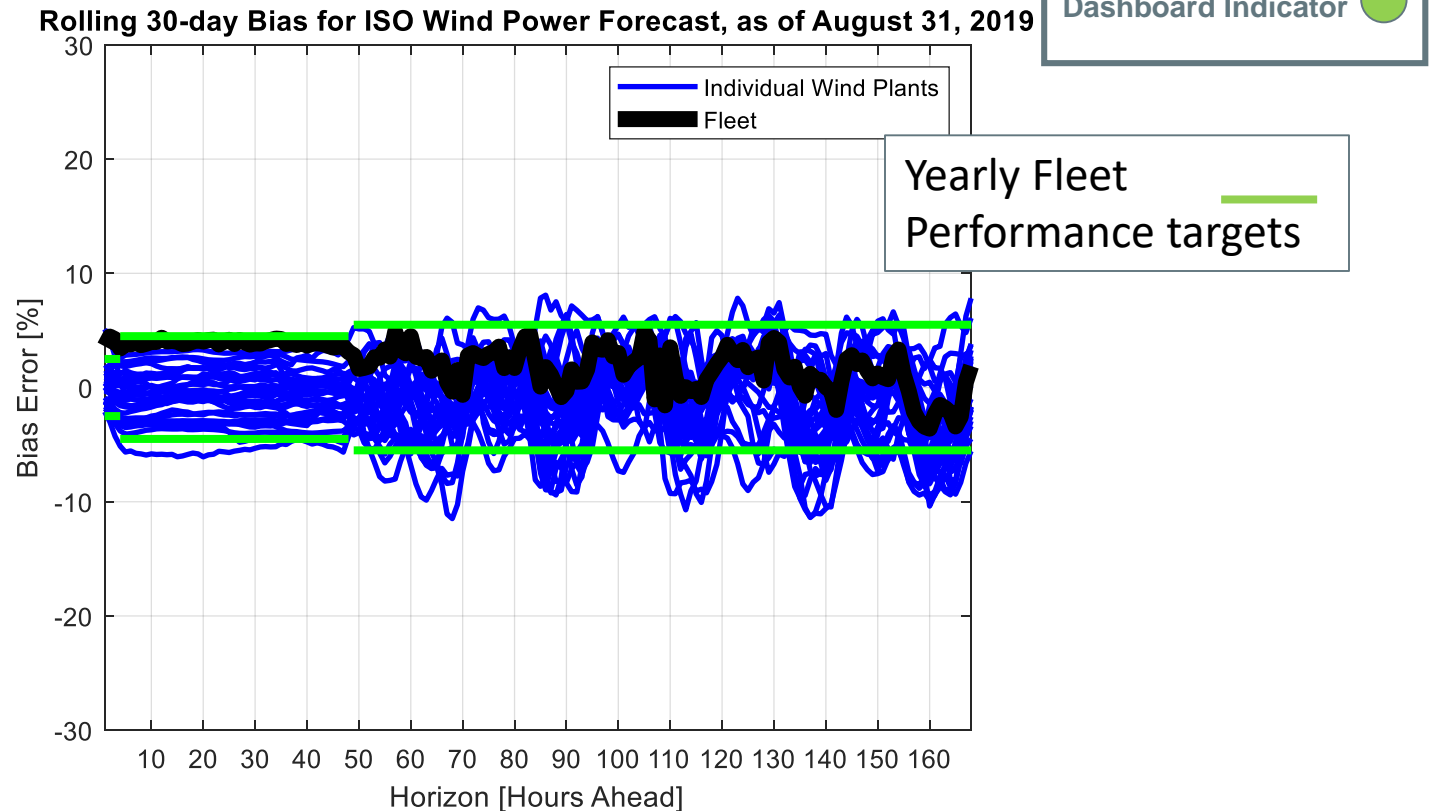


Dashboard Indicator



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.

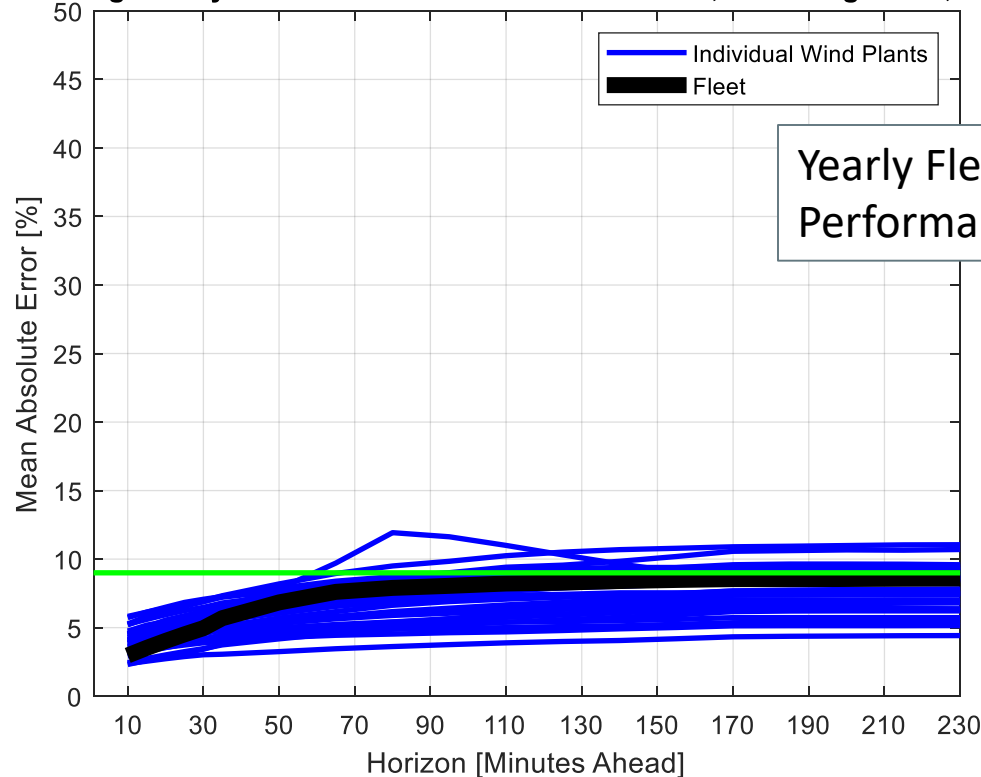
# Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias



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 targets.

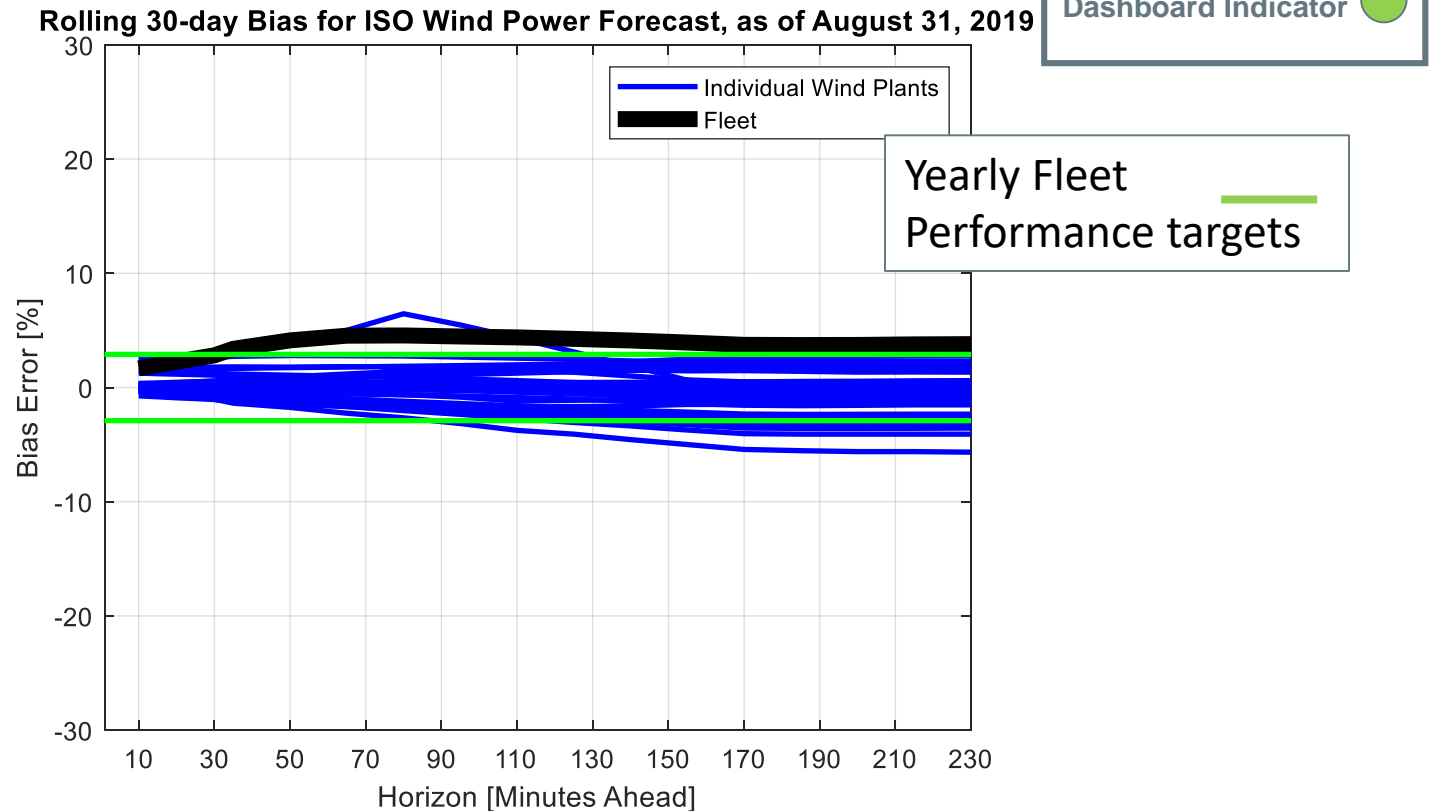
# Wind Power Forecast Error Statistics: Short Term Forecast MAE

Rolling 30-day MAE for ISO Wind Power Forecast, as of August 31, 2019



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



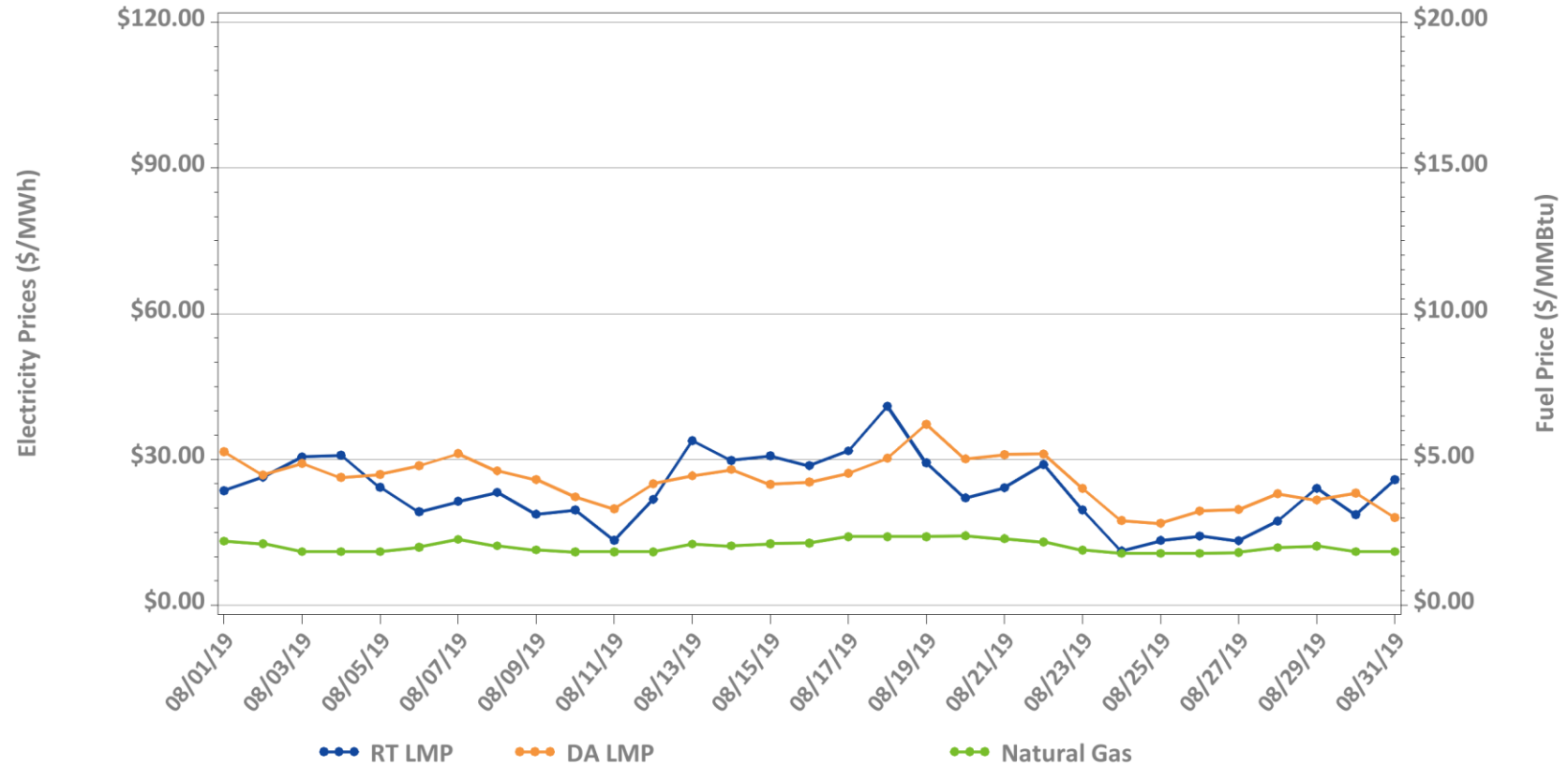
Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards,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



# MARKET OPERATIONS



# Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: August 1-31, 2019

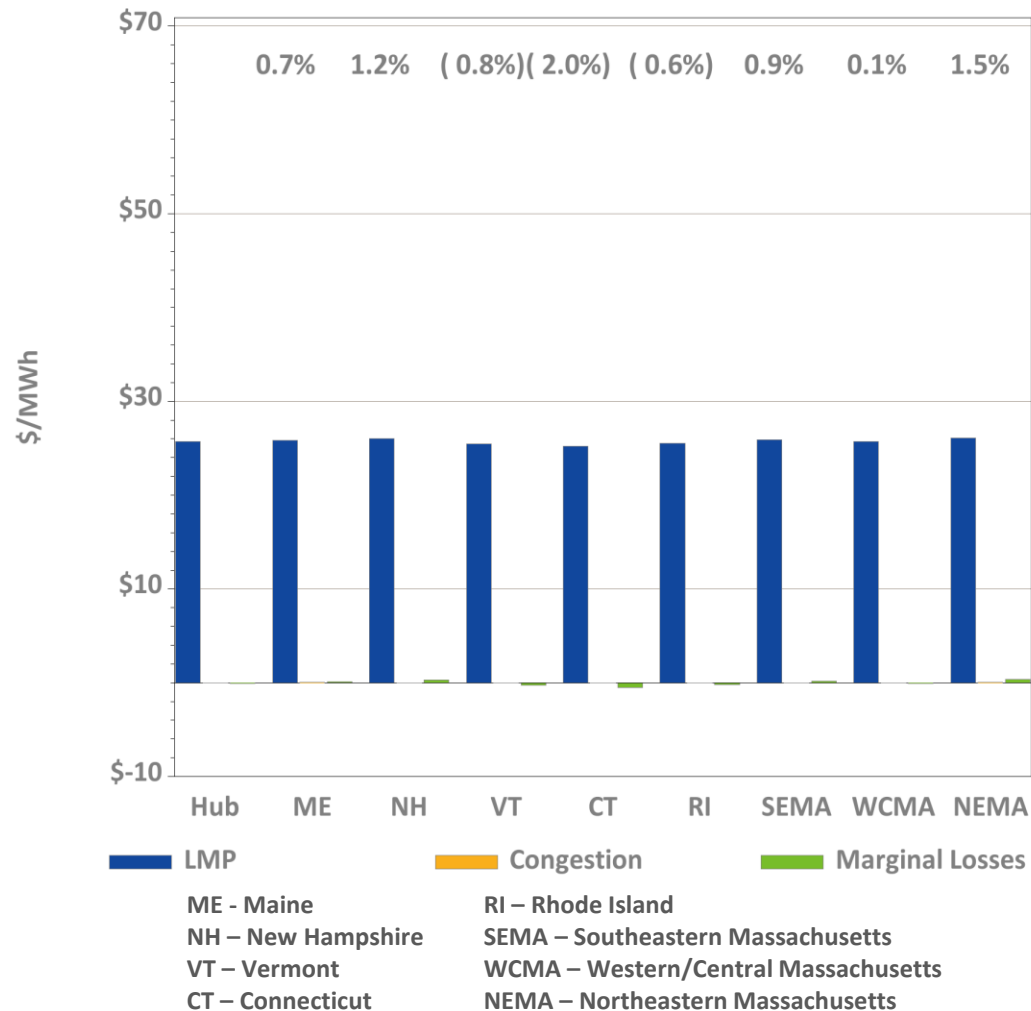


Underlying natural gas data furnished by:

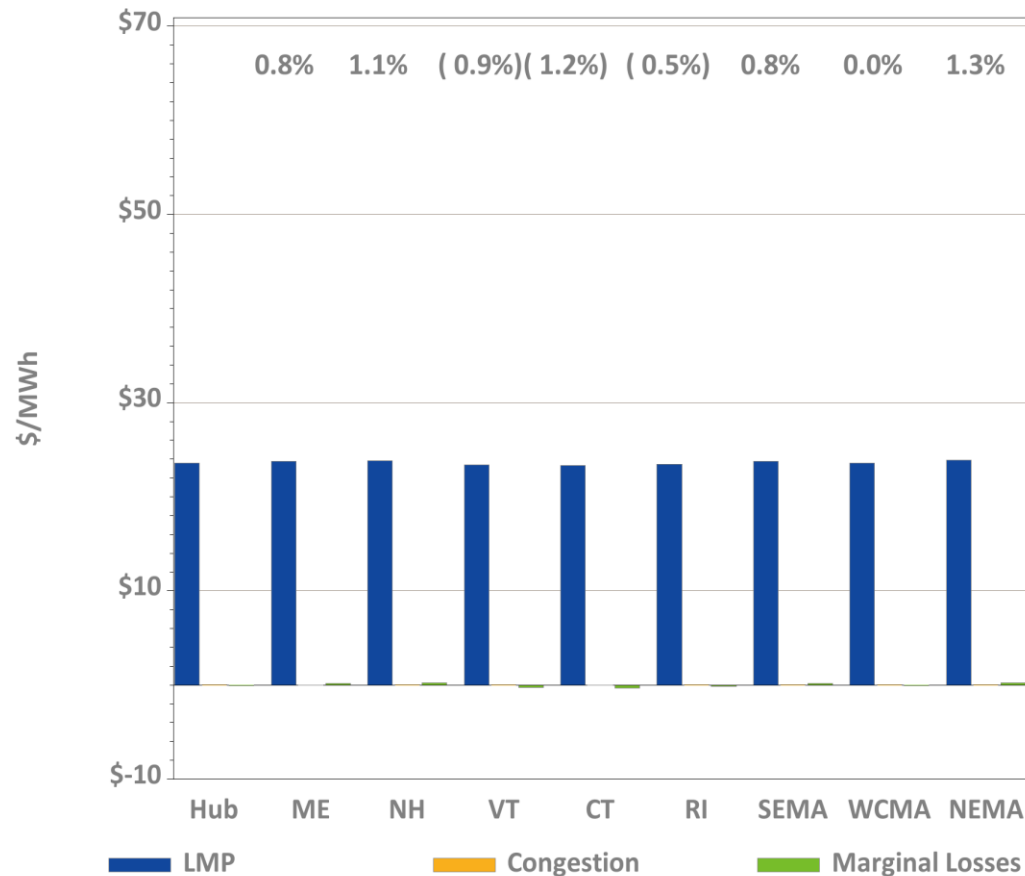


Average price difference over this period (DA-RT): \$2.11  
 Average price difference over this period ABS(DA-RT): \$5.32  
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 23%  
 Gas price is average of Massachusetts delivery points

# DA LMPs Average by Zone & Hub, August 2019



# RT LMPs Average by Zone & Hub, August 2019

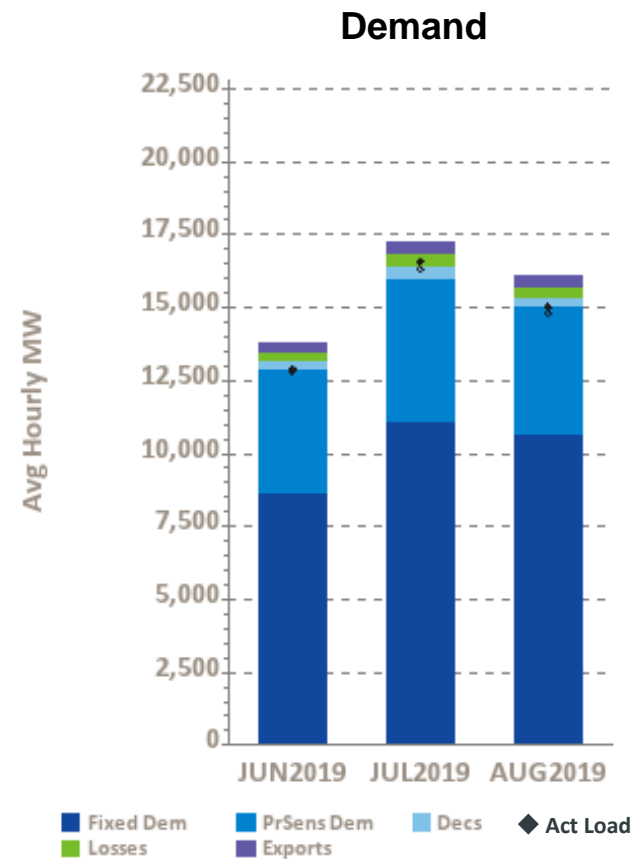
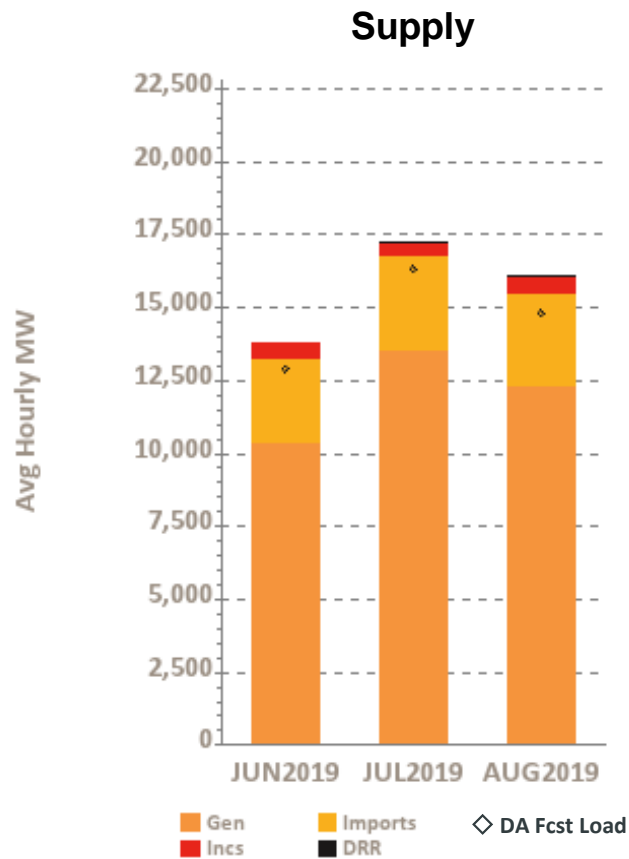


# Definitions

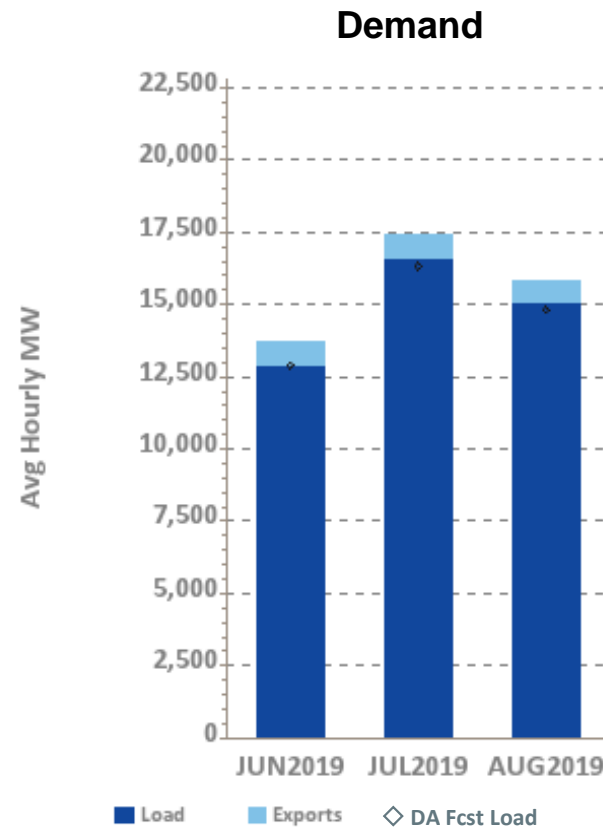
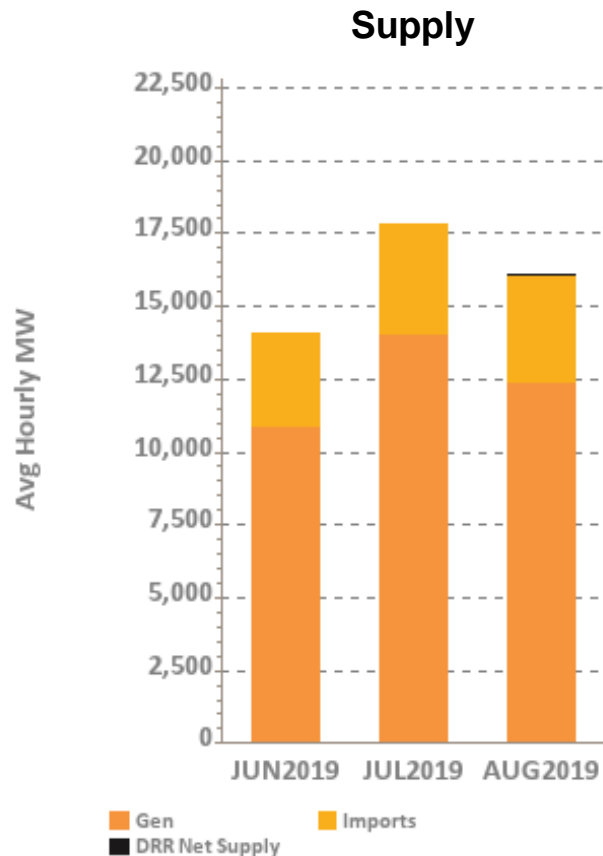
Day-Ahead Concept	Definition
Day-Ahead Load Obligation ( <b>DALO</b> )	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net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

# Components of Cleared DA Supply and Demand

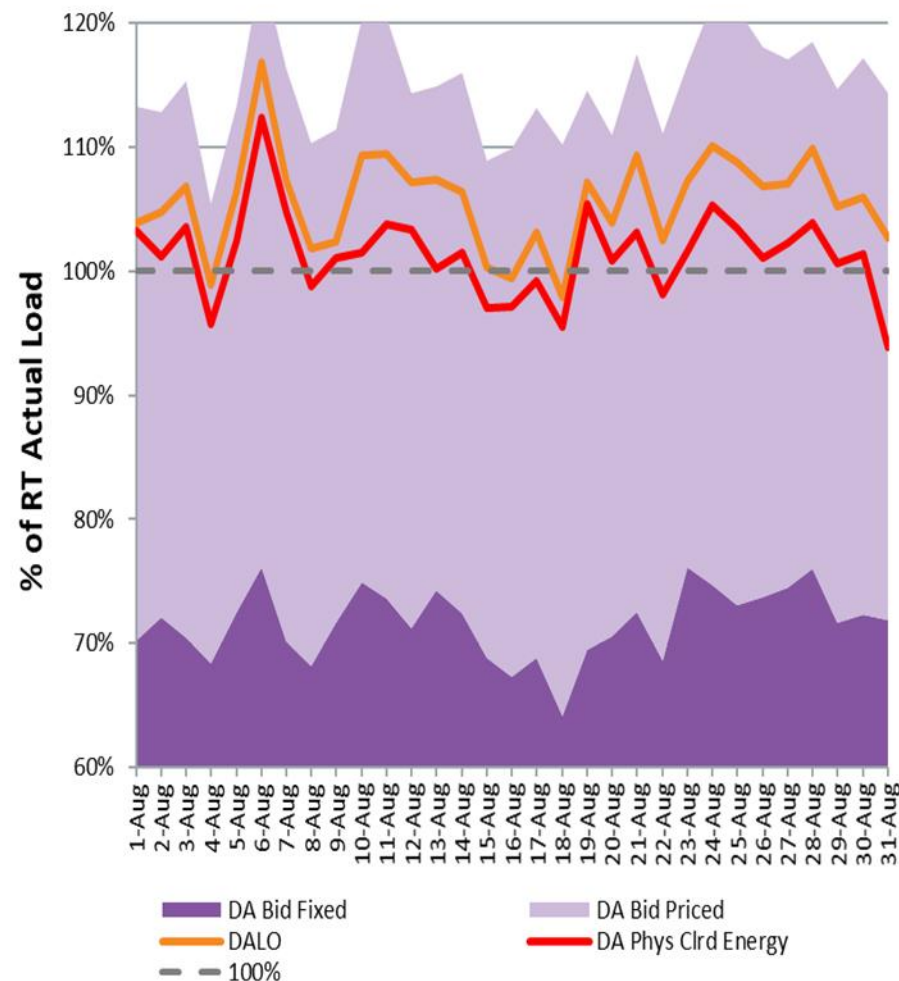
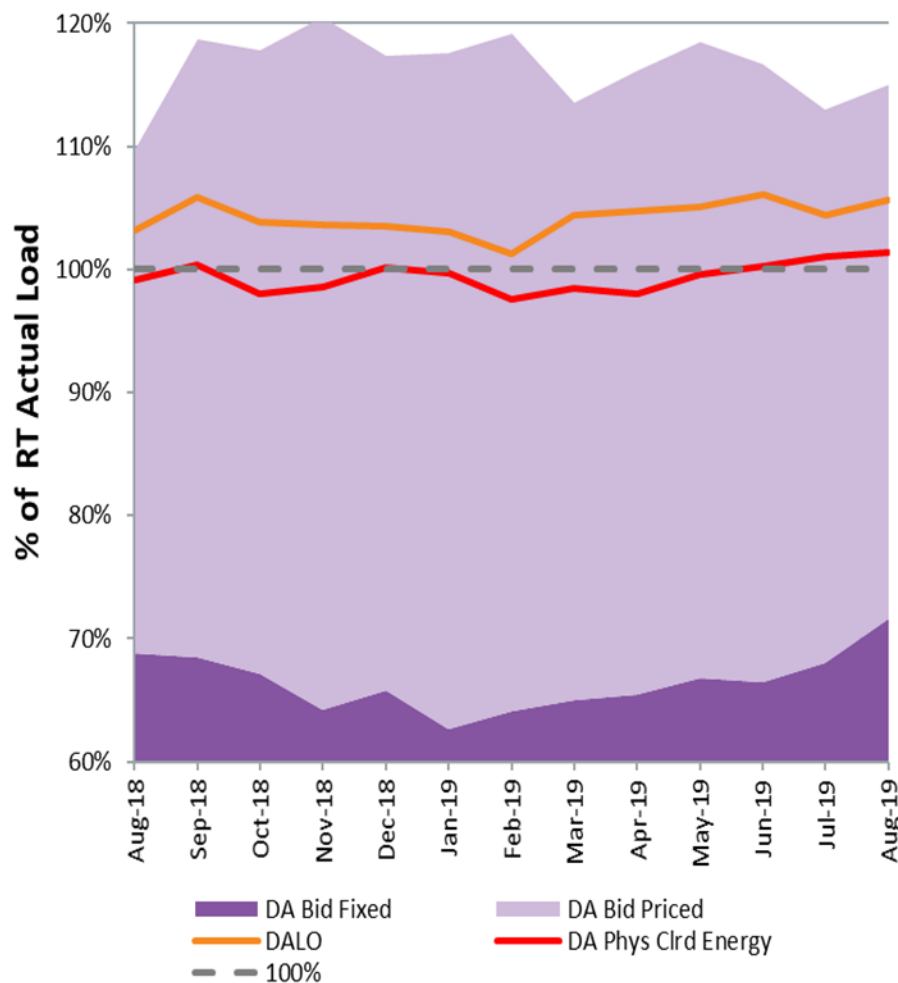
## – Last Three Months



# Components of RT Supply and Demand – Last Three Months



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

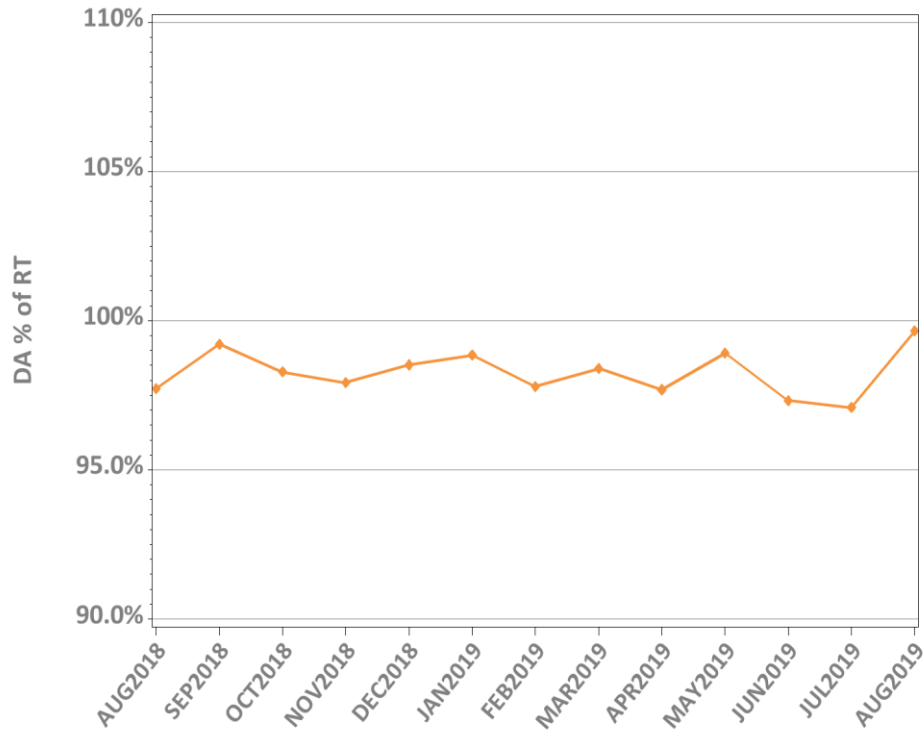


Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

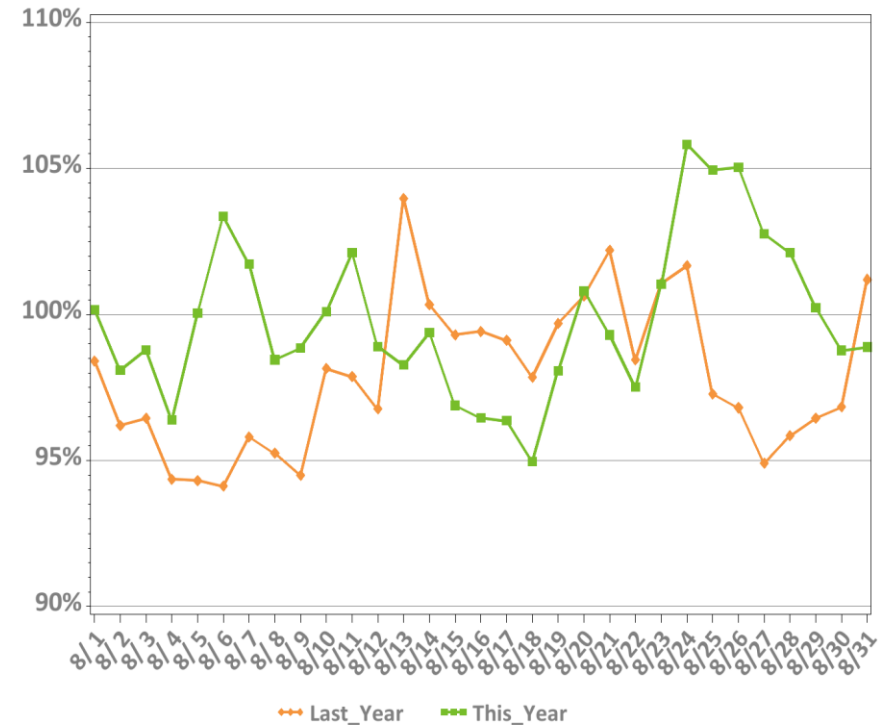


# DA vs. RT Load Obligation: August, This Year vs. Last Year

Monthly, Last 13 Months



Daily, This Year vs. Last Year

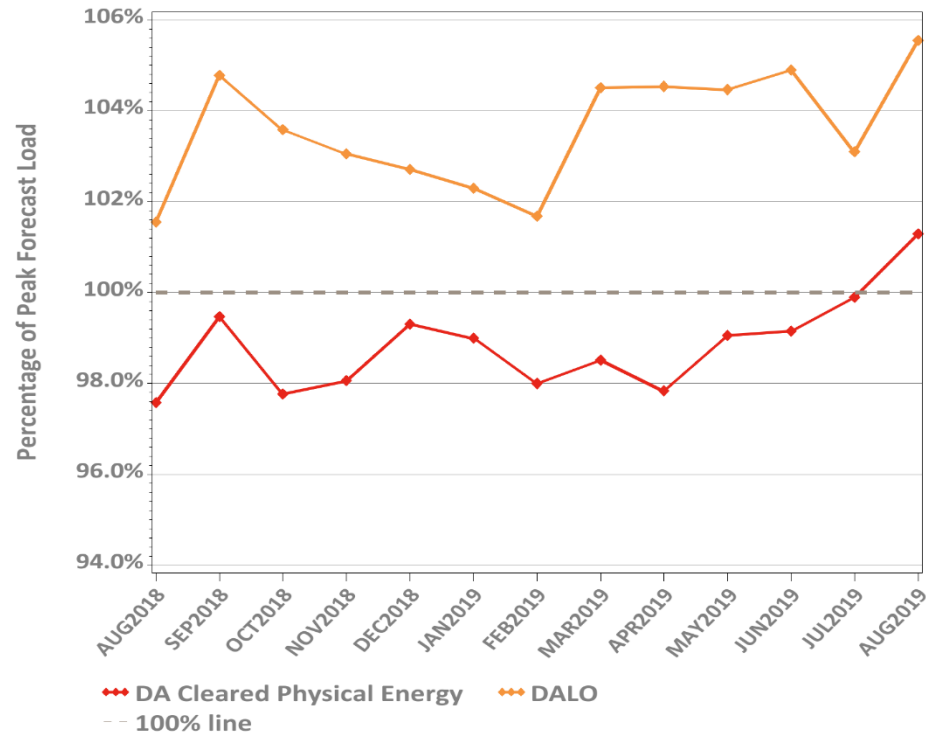


\*Hourly average values

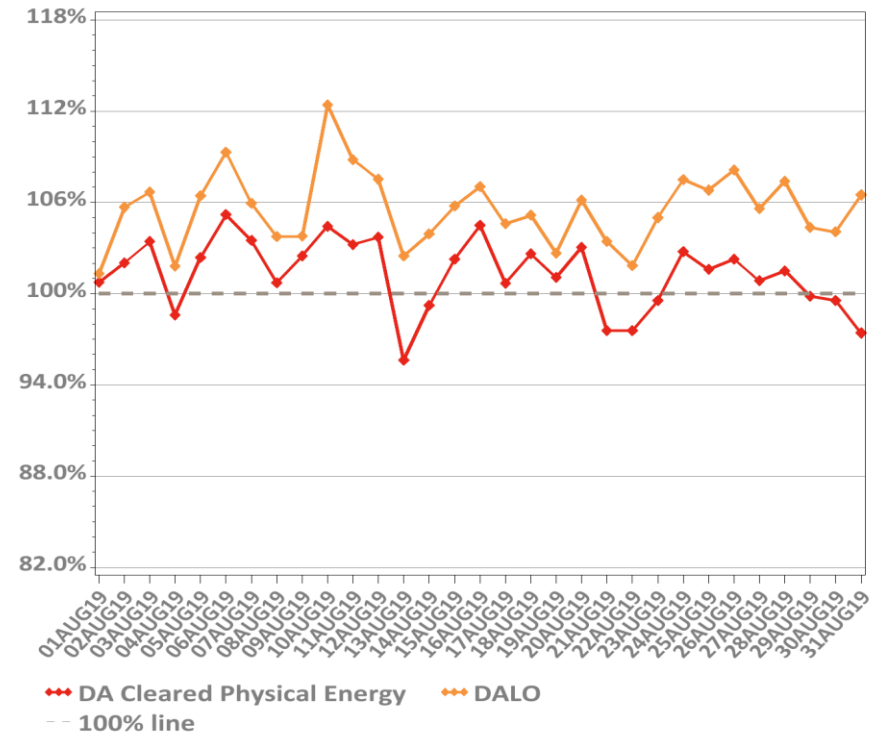


# DA Volumes as % of Forecast in Peak Hour

Monthly, Last 13 Months

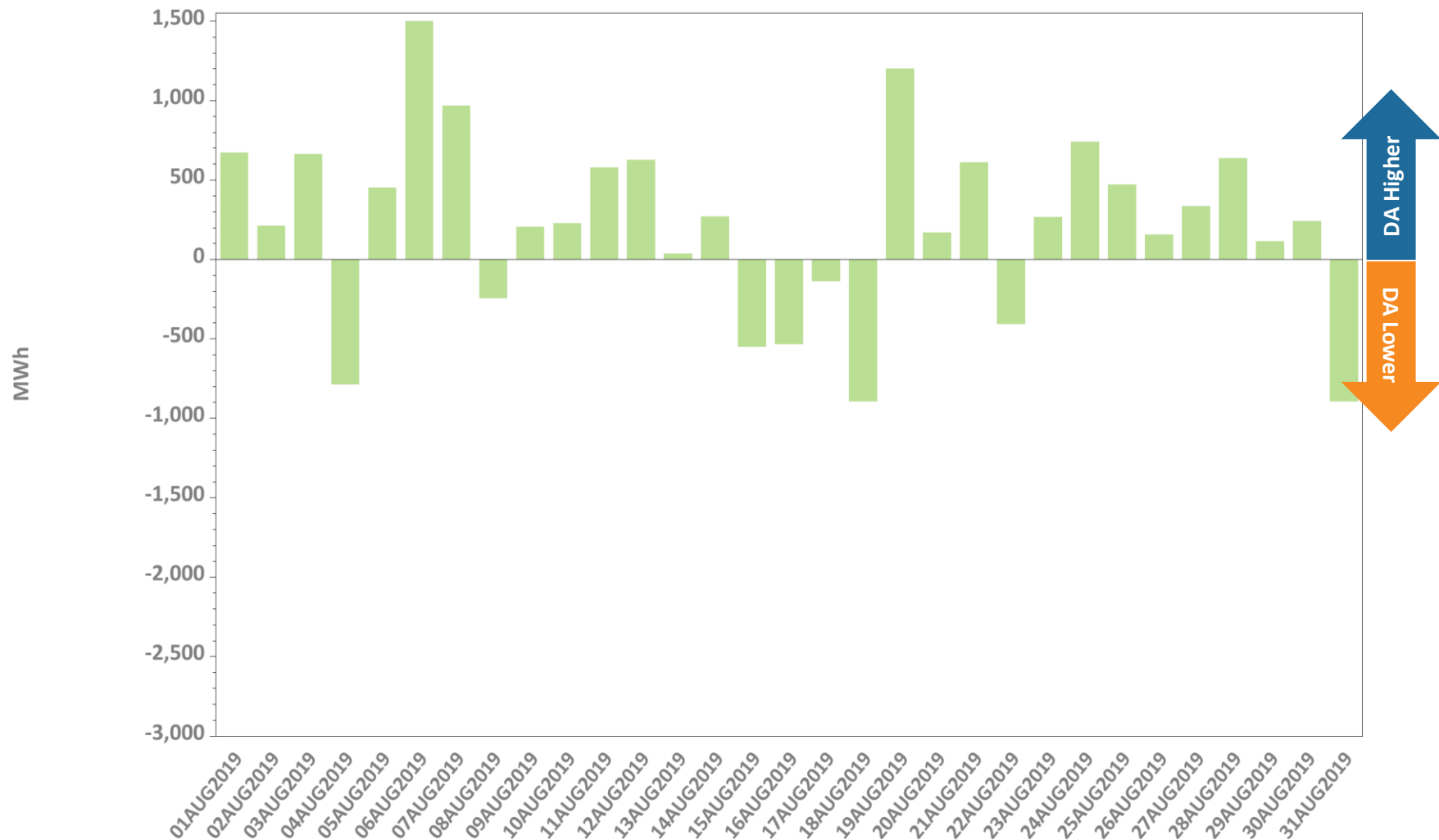


Daily: This Month



\* There were no supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during August. There was one commitment post-RAA during August.

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



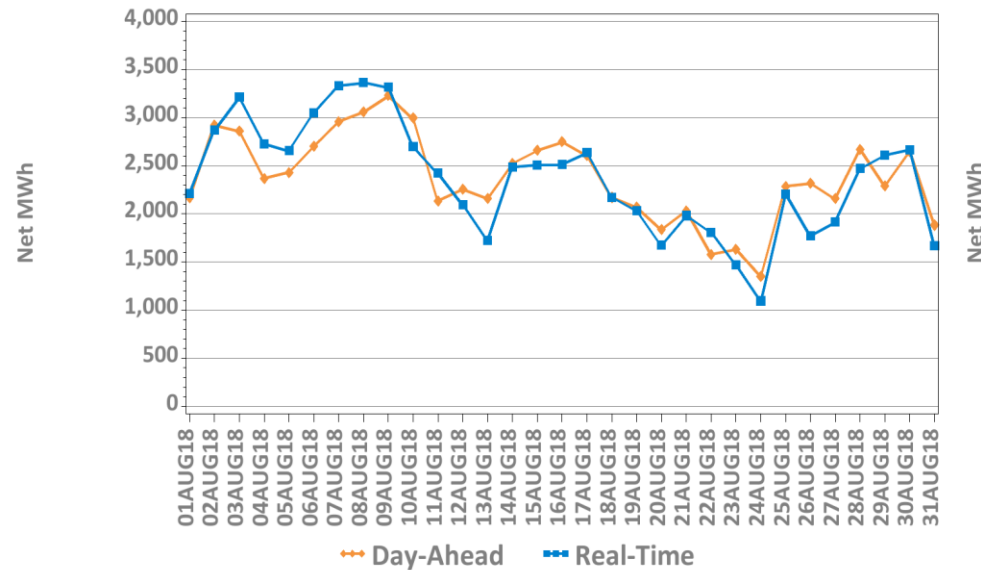
\*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.



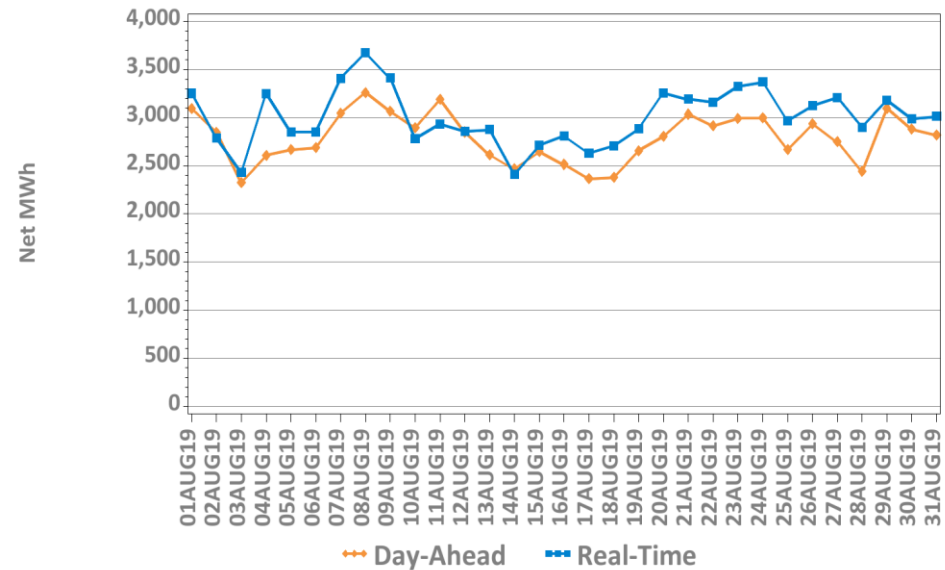
# DA vs. RT Net Interchange

## August 2019 vs. August 2018

Hourly Average by Day, Last Year

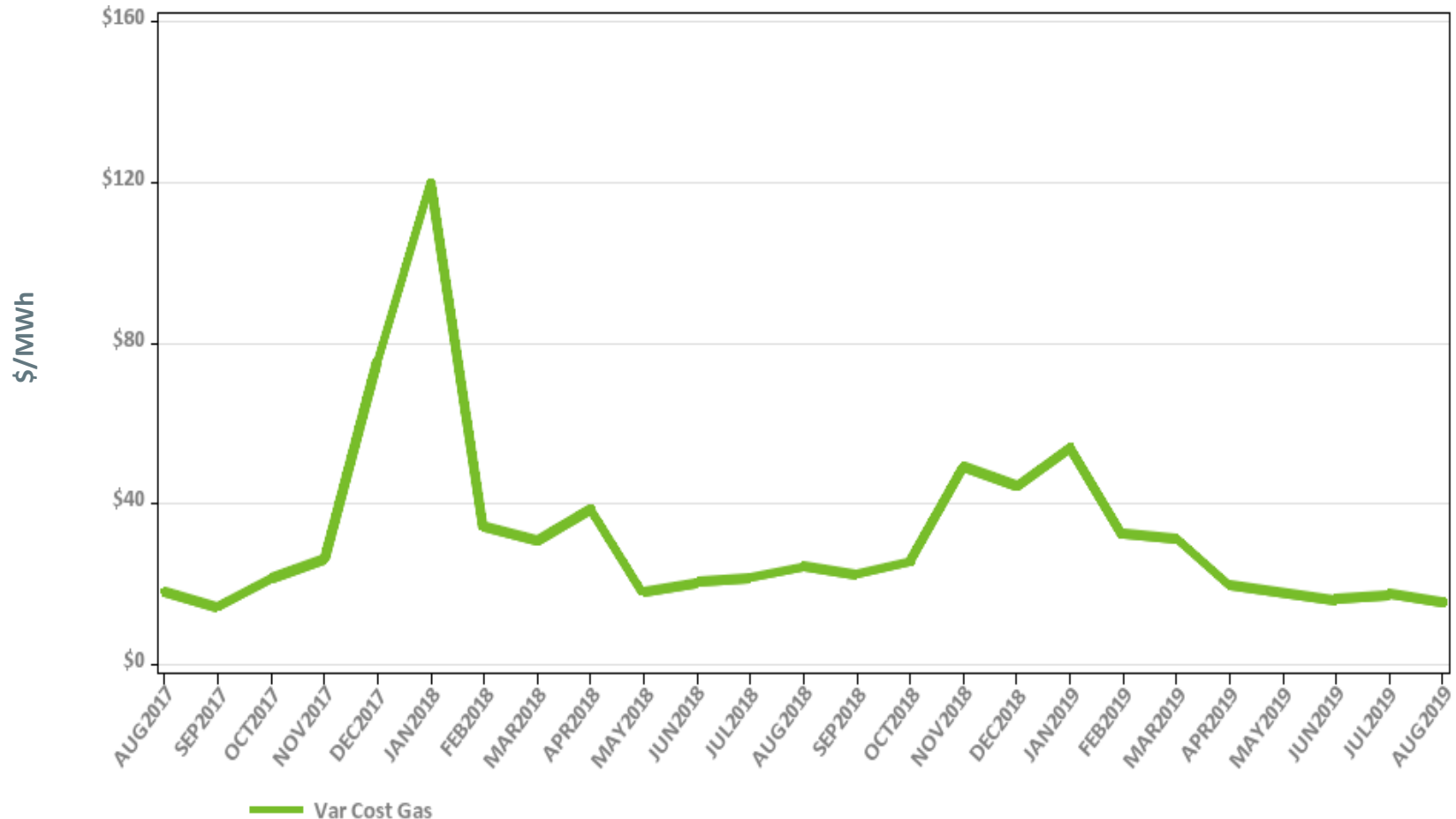


Hourly Average by Day, This Year



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

# Variable Production Cost of Natural Gas: Monthly

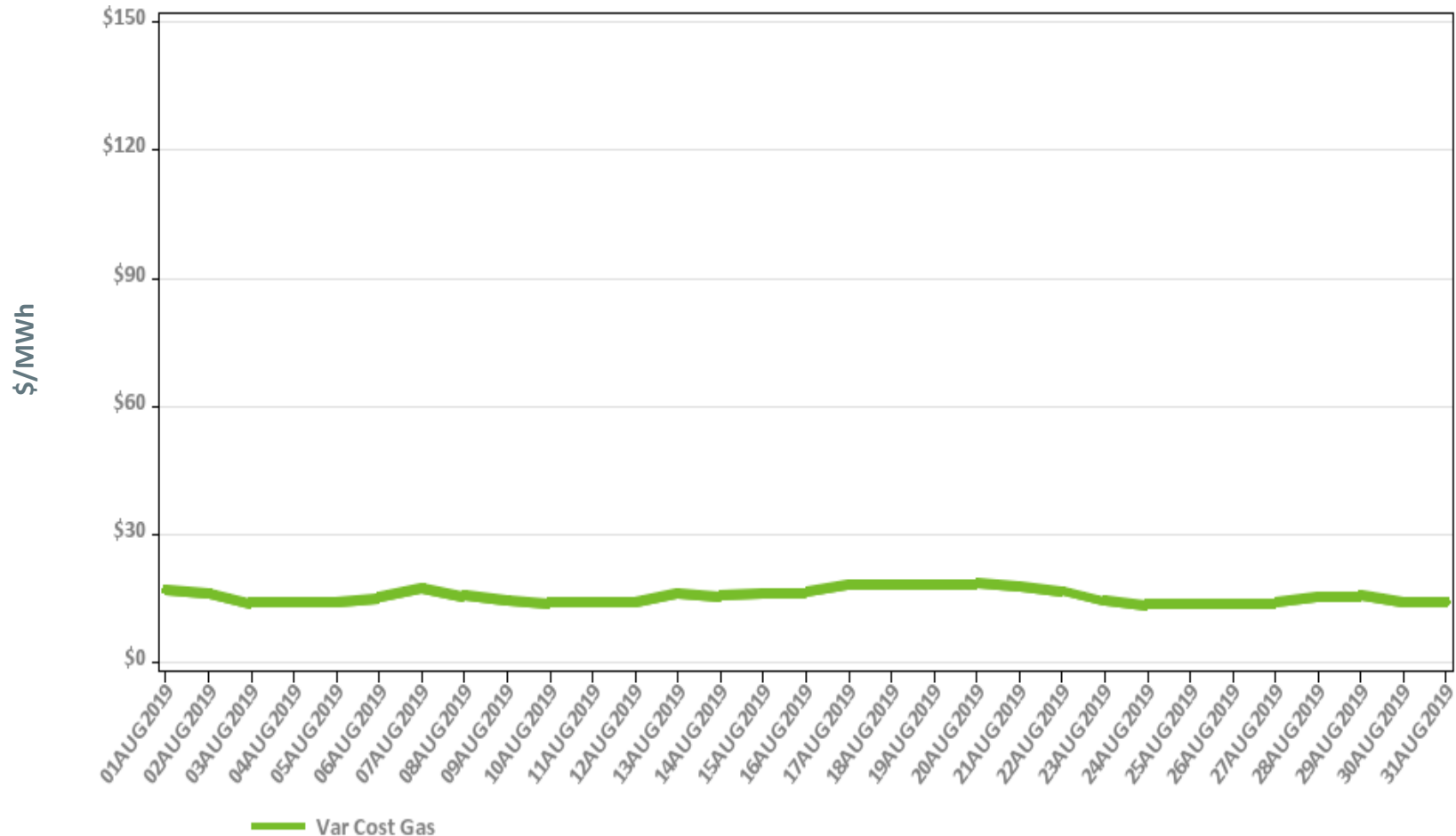


**Note:** Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



# Variable Production Cost of Natural Gas: Daily



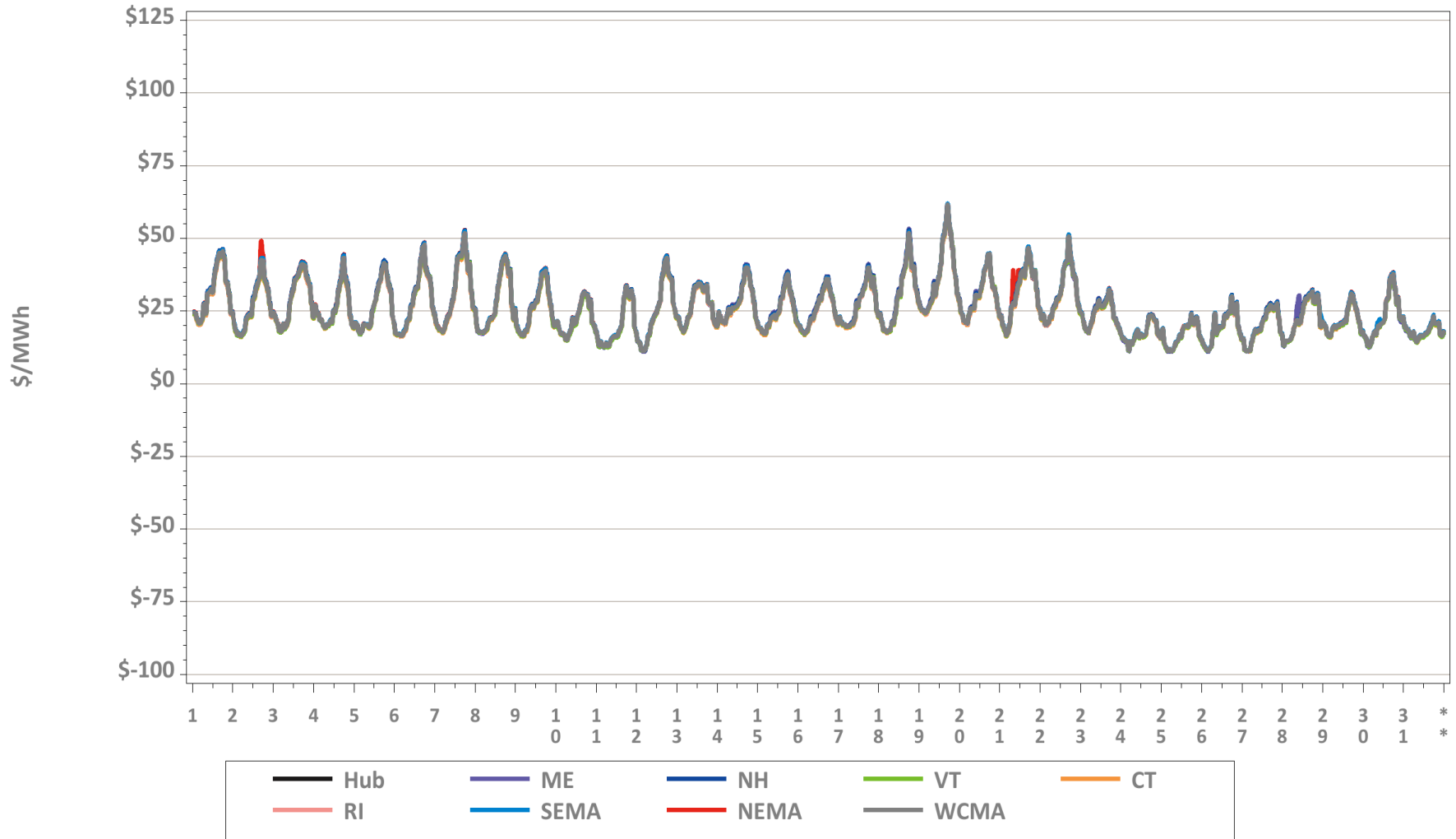
**Note:** Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



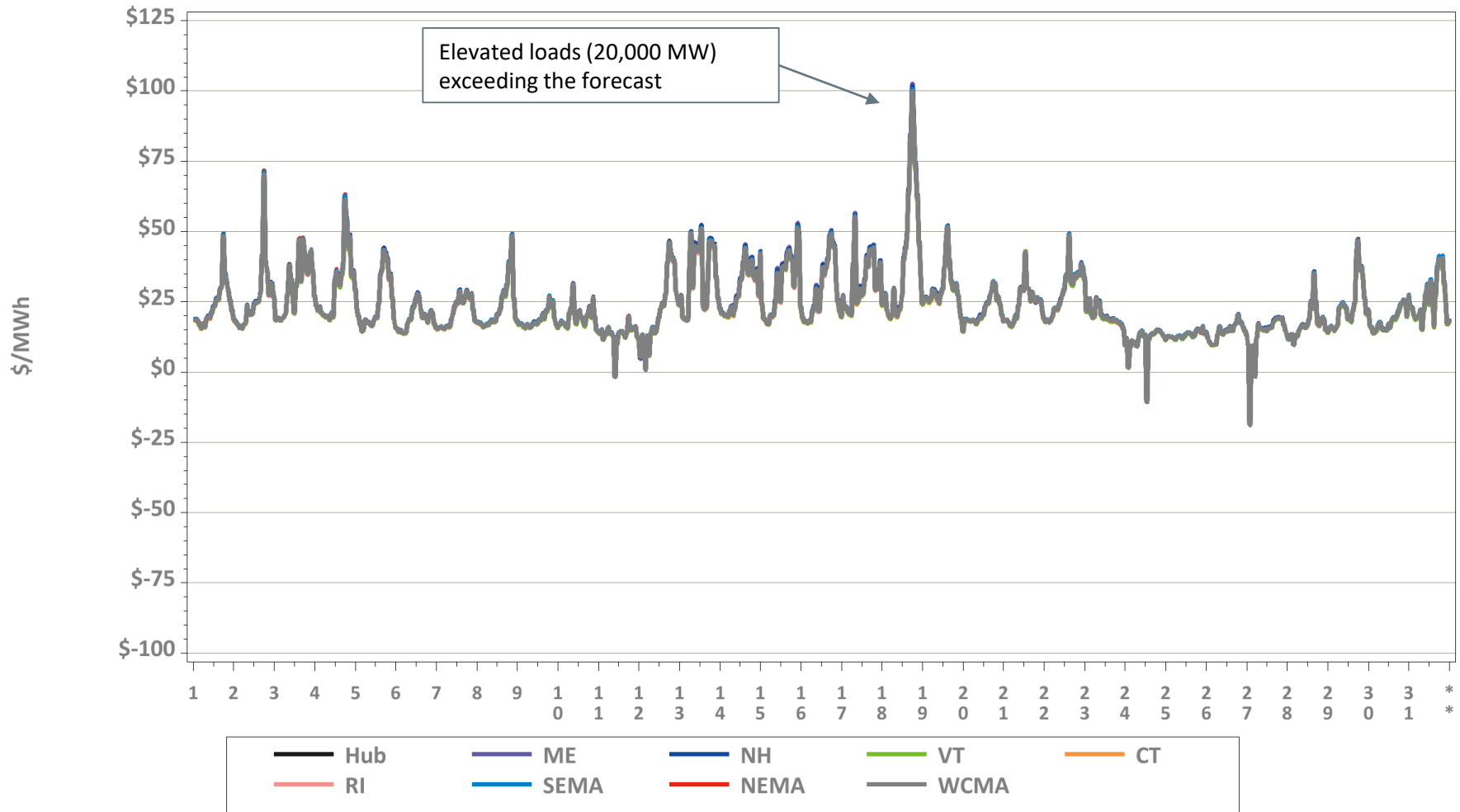
# Hourly DA LMPs, August 1-31, 2019

Hourly Day-Ahead LMPs



# Hourly RT LMPs, August 1-31, 2019

Hourly Real-Time LMPs

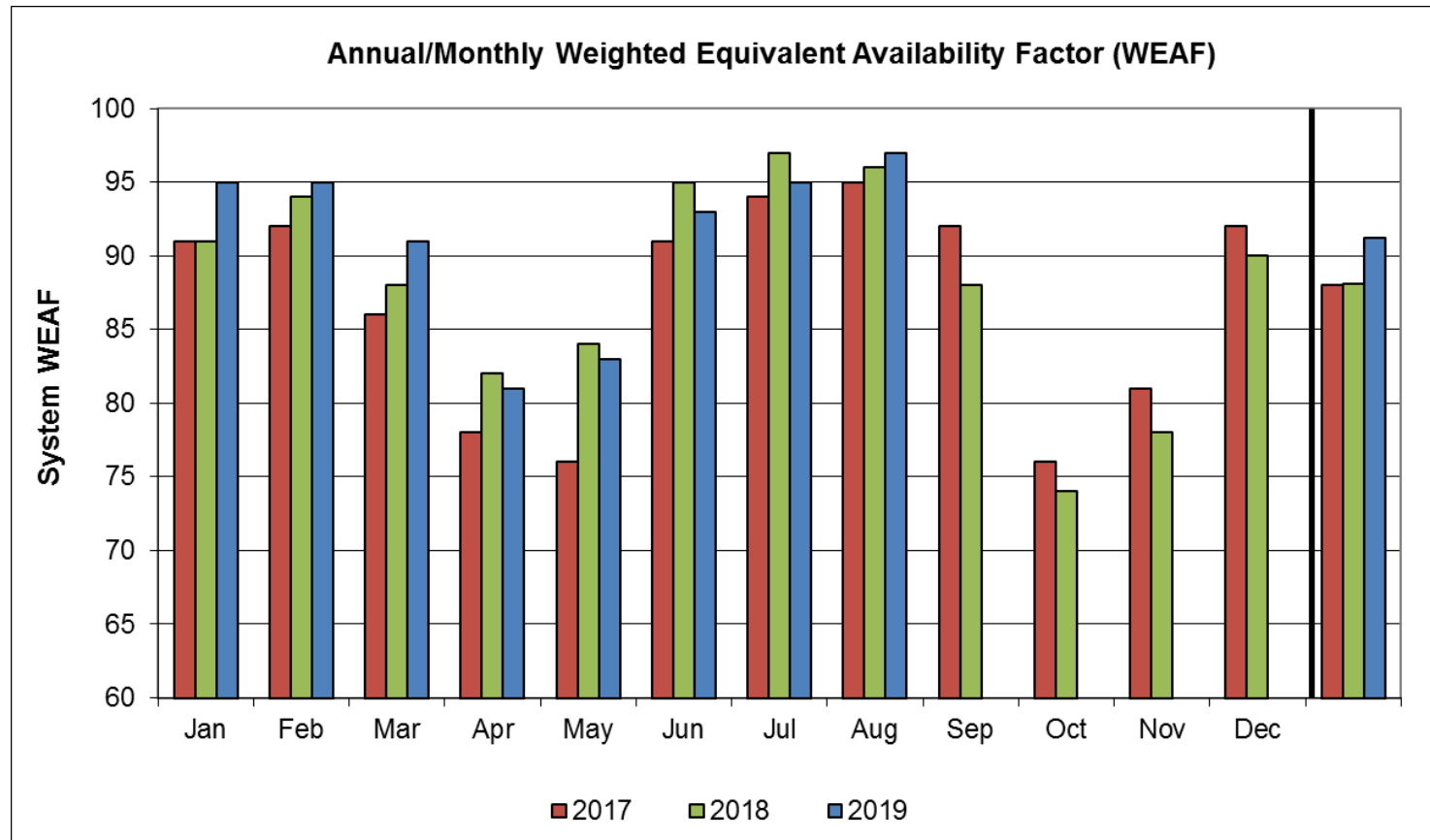


- No Minimum Generation Emergencies were declared during August.





# System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2019	95	95	91	81	83	93	95	97					91
2018	91	94	88	82	84	95	97	96	88	74	78	90	88
2017	91	92	86	78	76	91	94	95	92	76	81	92	88

Data as of 9/3/19



# BACK-UP DETAIL



# DEMAND RESPONSE



# Capacity Supply Obligation (CSO) MW by Demand Resource Type for September 2019

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	102.6	185.7	0.0	288.3
NH	34.1	107.8	0.0	142.0
VT	25.2	120.0	0.0	145.1
CT	104.8	119.0	457.9	681.7
RI	24.0	230.3	0.0	254.3
SEMA	30.2	407.4	0.0	437.6
WCMA	62.3	412.0	49.6	523.9
NEMA	52.4	668.7	0.0	721.1
<b>Total</b>	<b>435.6</b>	<b>2,250.9</b>	<b>507.5</b>	<b>3,194.0</b>

\* Active Demand Capacity Resources

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

# NEW GENERATION



# New Generation Update

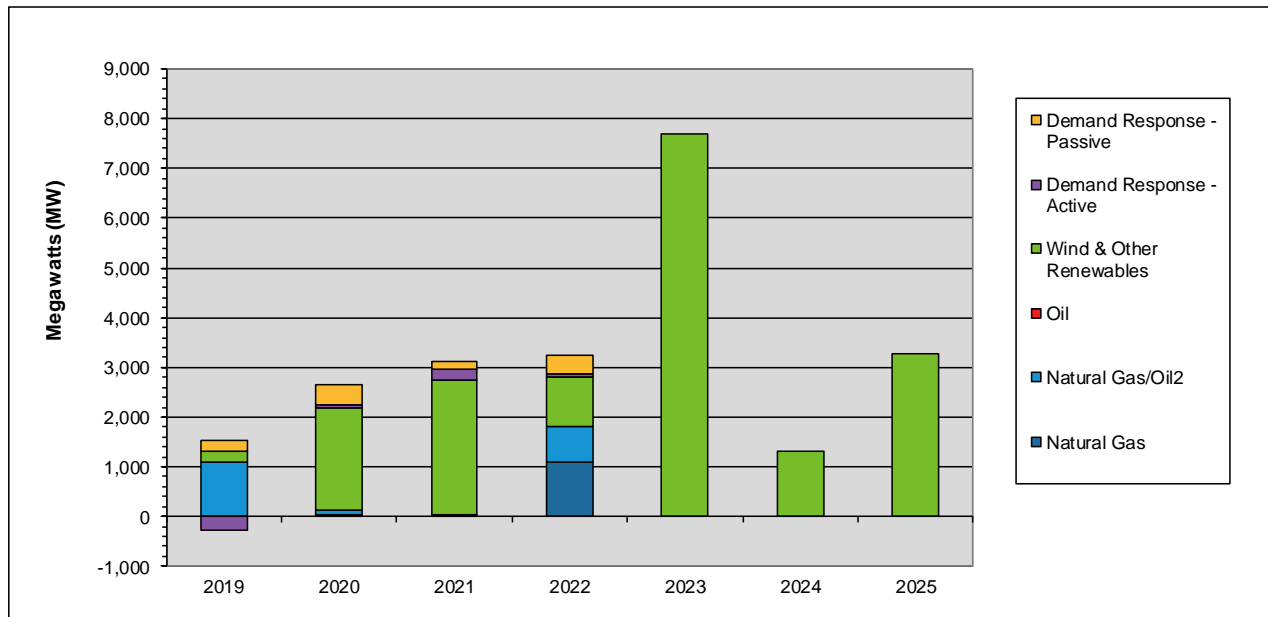
## *Based on Queue as of 9/9/19*

- 23 projects totaling 1,273 MW applied for interconnection study since the last update
  - They consist of 11 new solar projects, nine battery projects, two wind projects, and one fuel cell project, with in-service dates ranging from 2020 to 2025
- 14 projects withdrew and none went commercial, resulting in a net increase in new generation projects of 253 MW
- In total, 184 generation projects are currently being tracked by the ISO, totaling approximately 20,200 MW



# Actual and Projected Annual Capacity Additions

## *By Supply Fuel Type and Demand Resource Type*



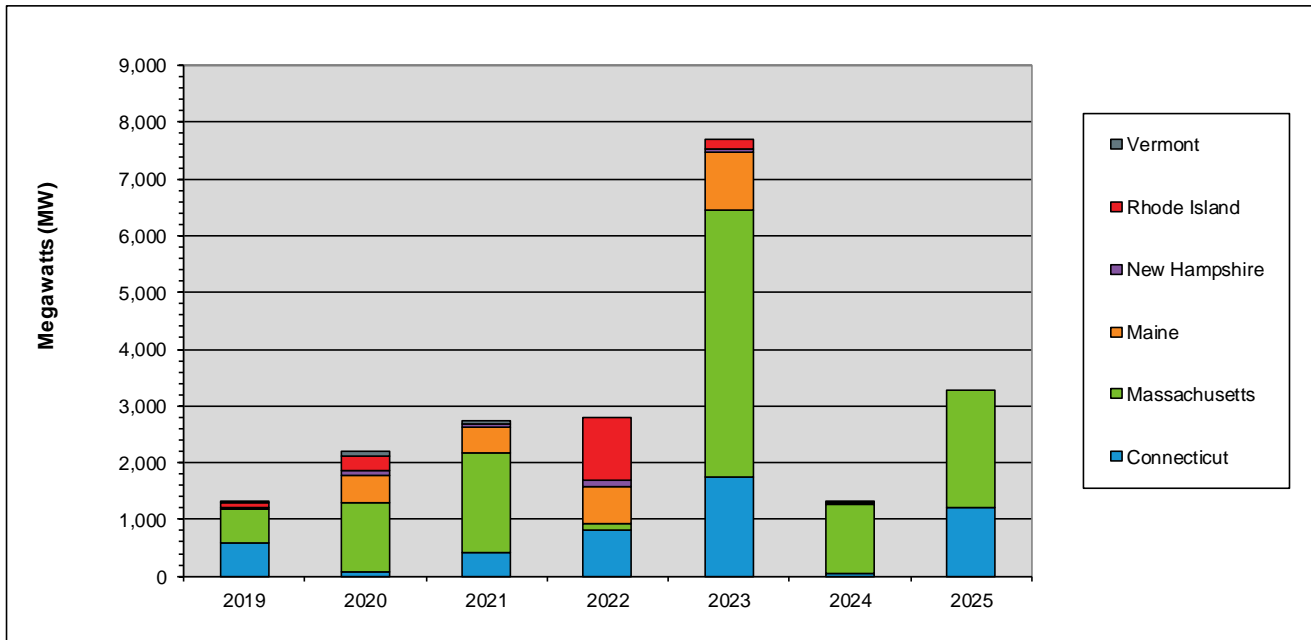
	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total <sup>1</sup>
Demand Response - Passive	212	422	184	380	0	0	0	1,199	5.3
Demand Response - Active	-270	42	204	62	0	0	0	39	0.2
Wind & Other Renewables	216	2,066	2,719	978	7,697	1,312	3,276	18,264	80.9
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil <sup>2</sup>	1,097	76	0	711	0	0	0	1,884	8.4
Natural Gas	0	49	25	1,103	0	0	0	1,177	5.2
<b>Totals</b>	<b>1,256</b>	<b>2,656</b>	<b>3,132</b>	<b>3,234</b>	<b>7,697</b>	<b>1,312</b>	<b>3,276</b>	<b>22,563</b>	<b>100.0</b>

<sup>1</sup> Sum may not equal 100% due to rounding

<sup>2</sup> 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 since 2010-11

# Actual and Projected Annual Generator Capacity Additions By State



	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total <sup>1</sup>
Vermont	33	75	70	0	0	0	0	178	0.8
Rhode Island	74	258	0	1,103	180	0	0	1,615	7.6
New Hampshire	28	90	55	105	50	20	0	348	1.6
Maine	0	481	447	660	1,003	20	0	2,611	12.2
Massachusetts	597	1,212	1,770	116	4,704	1,232	2,076	11,707	54.9
Connecticut	581	75	402	808	1,760	40	1,200	4,866	22.8
Totals	1,313	2,191	2,744	2,792	7,697	1,312	3,276	21,325	100.0

<sup>1</sup> Sum may not equal 100% due to rounding



# New Generation Projection

## *By Fuel Type*

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	1	37	0	0	1	37
Hydro	2	71	0	0	2	71
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,240	0	0	7	1,240
Natural Gas/Oil	6	832	0	0	6	832
Oil	0	0	0	0	0	0
Solar	120	3,191	2	51	118	3,140
Wind	25	12,770	2	33	23	12,737
Battery storage	23	2,065	0	0	23	2,065
Total	184	20,206	4	84	180	20,122

- 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*

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	130	0	0	5	130
Intermediate	3	1,146	0	0	3	1,146
Peaker	151	6,160	2	51	149	6,109
Wind Turbine	25	12,770	2	33	23	12,737
Total	184	20,206	4	84	180	20,122

- 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*

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	1	37	1	37	0	0	0	0	0	0
Hydro	2	71	1	5	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	1,240	3	88	3	1,146	1	6	0	0
Natural Gas/Oil	6	832	0	0	0	0	6	832	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	120	3,191	0	0	0	0	120	3,191	0	0
Wind	25	12,770	0	0	0	0	0	0	25	12,770
Battery storage	23	2,065	0	0	0	0	23	2,065	0	0
Total	184	20,206	5	130	3	1,146	151	6,160	25	12,770

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

# FORWARD CAPACITY MARKET



# Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	377.525	367.227	-10.298	464.715	97.488	460.55	-4.165	459.928	-0.622	457.966	-1.962	493.5	35.534
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834	2,363.789	-0.16	2,527.244	163.46	2,529.014	1.77	2594.08	65.066
Demand Total		2,746.156	2,734.01	-12.146	2,828.664	94.654	2,824.339	-4.325	2,987.172	162.83	2,986.98	-0.192	3,087.58	100.6
Generator	Non-Intermittent	30,520.433	30,462.67	-57.763	30,048.398	-414.272	30,103.684	55.286	30,093.142	-10.54	30,081.64	-11.502	30,146.76	65.115
	Intermittent	850.143	893.189	43.046	904.311	11.122	831.251	-73.06	798.958	-32.293	800.387	1.429	733.668	-66.719
Generator Total		31,370.576	31,355.86	-14.716	30,952.709	-403.151	30,934.935	-17.774	30,892.1	-42.84	30,882.027	-10.073	30,880.42	-1.604
Import Total		1,449.8	1,449.8	0	1,451	1.2	1,451	0	1,451	0	1,459	8	1,428	-31
**Grand Total		35,566.532	35,539.668	-26.864	35,232.373	-307.295	35,210.274	-22.099	35,330.272	120.00	35,328.007	-2.265	35,396	67.996
Net ICR (NICR)		34,151	33,755	-396	33,755	0	33,407	-348	33,407	0	33,390	-17	33,390	0

\* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

\*\* 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 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				
	Passive Demand	2,791.02	2,835.354	44.334				
Demand Total		3,210.95	3,276.575	65.625				
Generator	Non-Intermittent	30,494.80	30,064.23	-430.569				
	Intermittent	894.217	823.796	-70.421				
Generator Total		31,389.02	30,888.03	-500.993				
Import Total		1,235.40	1,622.037	386.637				
**Grand Total		35,835.37	35,786.64	-48.731				
Net ICR (NICR)		34,075	33,660	-415				

\* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

\*\* 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				
	Passive Demand	2,975.36	3,045.073	69.713				
Demand Total		3,599.81	3,704.21	104.4				
Generator	Non-Intermittent	29,130.75	29,244.404	113.654				
	Intermittent	880.317	806.609	-73.708				
Generator Total		30,011.07	30,051.013	39.943				
Import Total		1,217	1,305.487	88.487				
**Grand Total		34,827.88	35,060.710	232.83				
Net ICR (NICR)		33,725	33,550	-175				

\* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

\*\* 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						
	Passive Demand	3,354.69						
Demand Total		4,040.244						
Generator	Non-Intermittent	28,586.498						
	Intermittent	1,024.792						
Generator Total		2,961.29						
Import Total		1,187.69						
**Grand Total		34,839.224						
Net ICR (NICR)		33,750						

\* Real-time Emergency Generators (RTEG) CSO not capped at 600,000 MW

\*\* 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
2010-11	Active	1,246.40	603.675	1,850.07
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1,768.39	184.99	1,953.38
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1,726.55	98.227	1,824.78
	Passive	861.602	211.261	1,072.86
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1,794.20	257.341	2,051.54
	Passive	1,040.11	257.793	1,297.91
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2,062.20	41.945	2,104.14
	Passive	1,264.64	221.072	1,485.71
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1,935.41	66.104	2,001.51
	Passive	1,395.89	247.449	1,643.33
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1,116.47	0.23	1,116.70
	Passive	1,386.56	244.775	1,631.34
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1,066.59	13.486	1,080.08
	Passive	1,619.15	341.37	1,960.52
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1,870.55	285.602	2,156.15
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2375.422	370.734	2746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2571.361	639.586	3210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3085.734	514.072	3599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3386.703	653.541	4040.244

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



# What are Daily NCPC Payments?

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



# Definitions

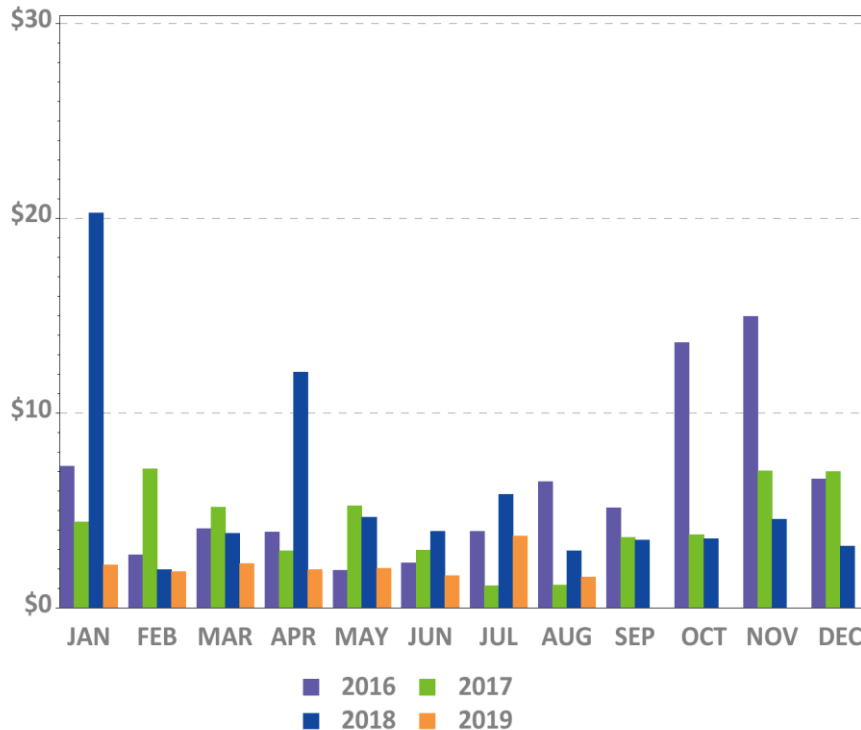
1 <sup>st</sup> Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2 <sup>nd</sup> Contingency NCPC Payments	Reliability costs paid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

# Charge Allocation Key

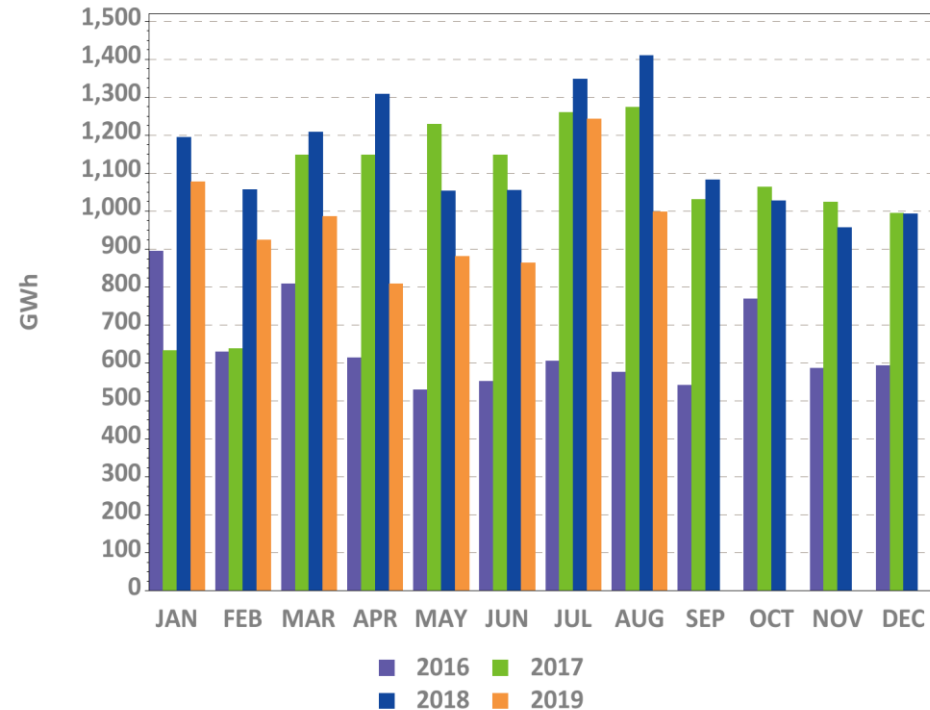
Allocation Category	Market / OATT	Allocation
System 1 <sup>st</sup> Contingency	Market	DA 1 <sup>st</sup> C (excluding at external nodes) is allocated to system DALO. RT 1 <sup>st</sup> C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load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

# Year-Over-Year Total NCPC Dollars and Energy

NCPC Dollars



NCPC Energy\*

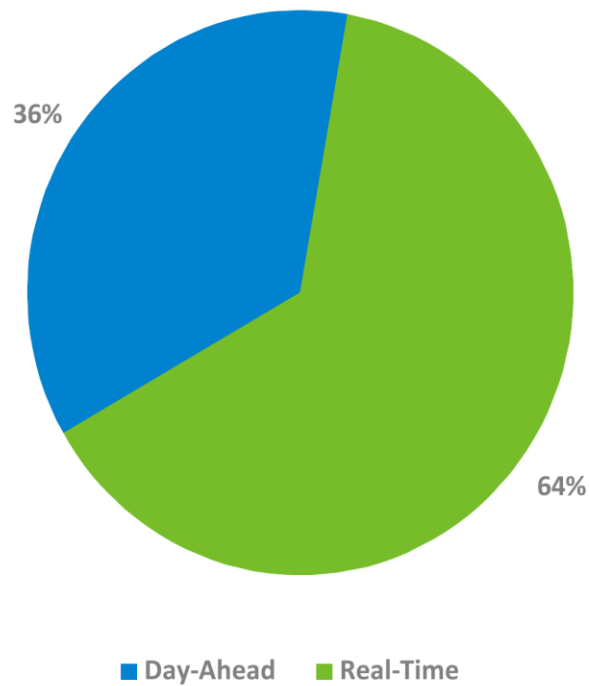


\* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

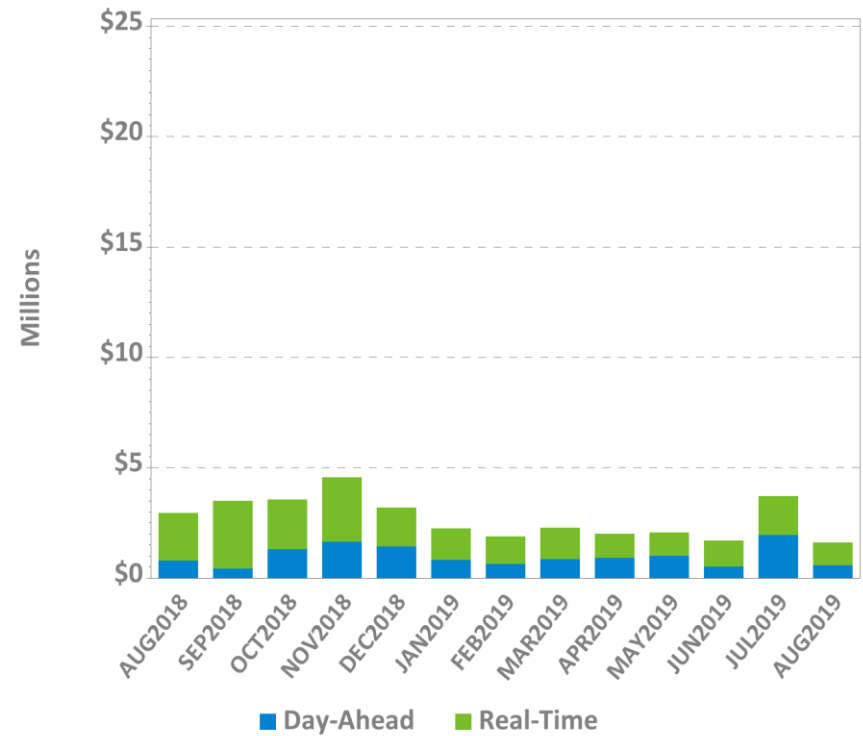


# DA and RT NCPC Charges

Aug-19 Total = \$1.59 M

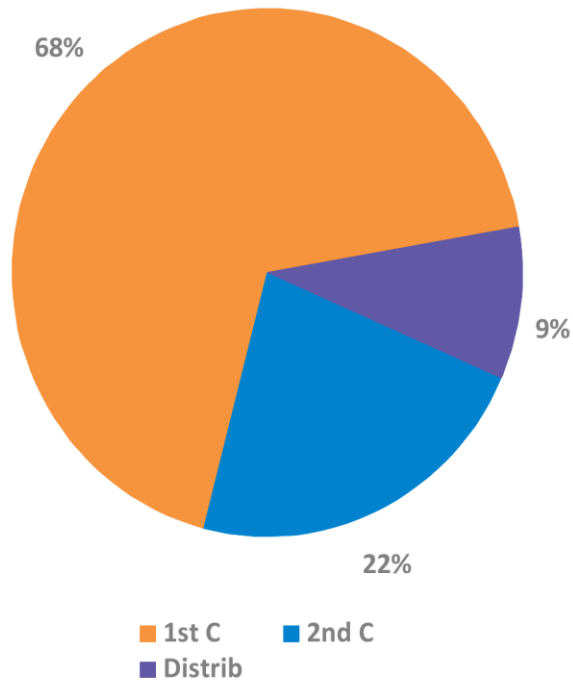


Last 13 Months

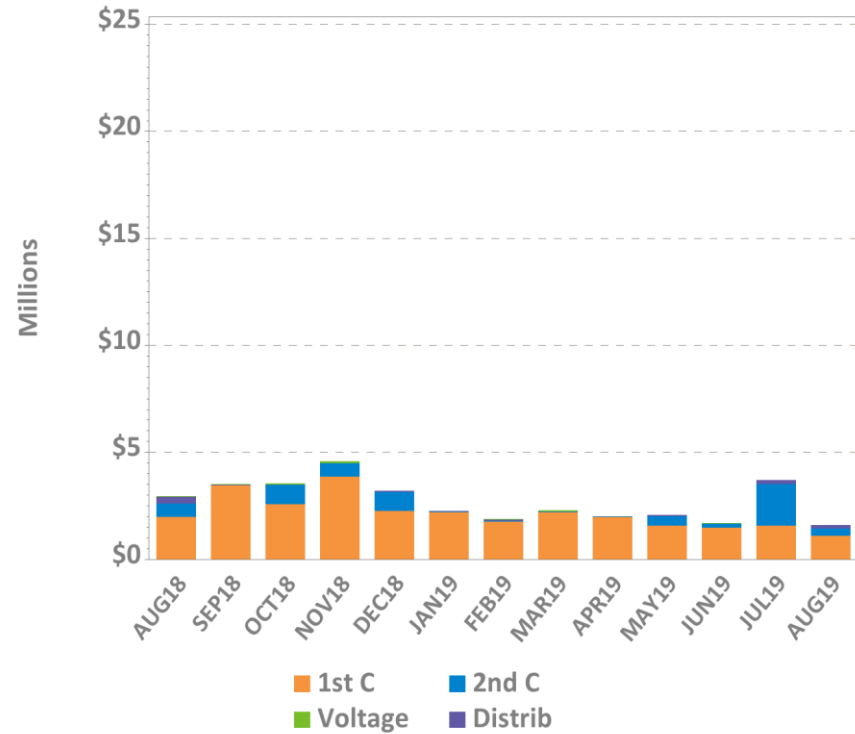


# NCPC Charges by Type

Aug-19 Total = \$1.59 M



Last 13 Months

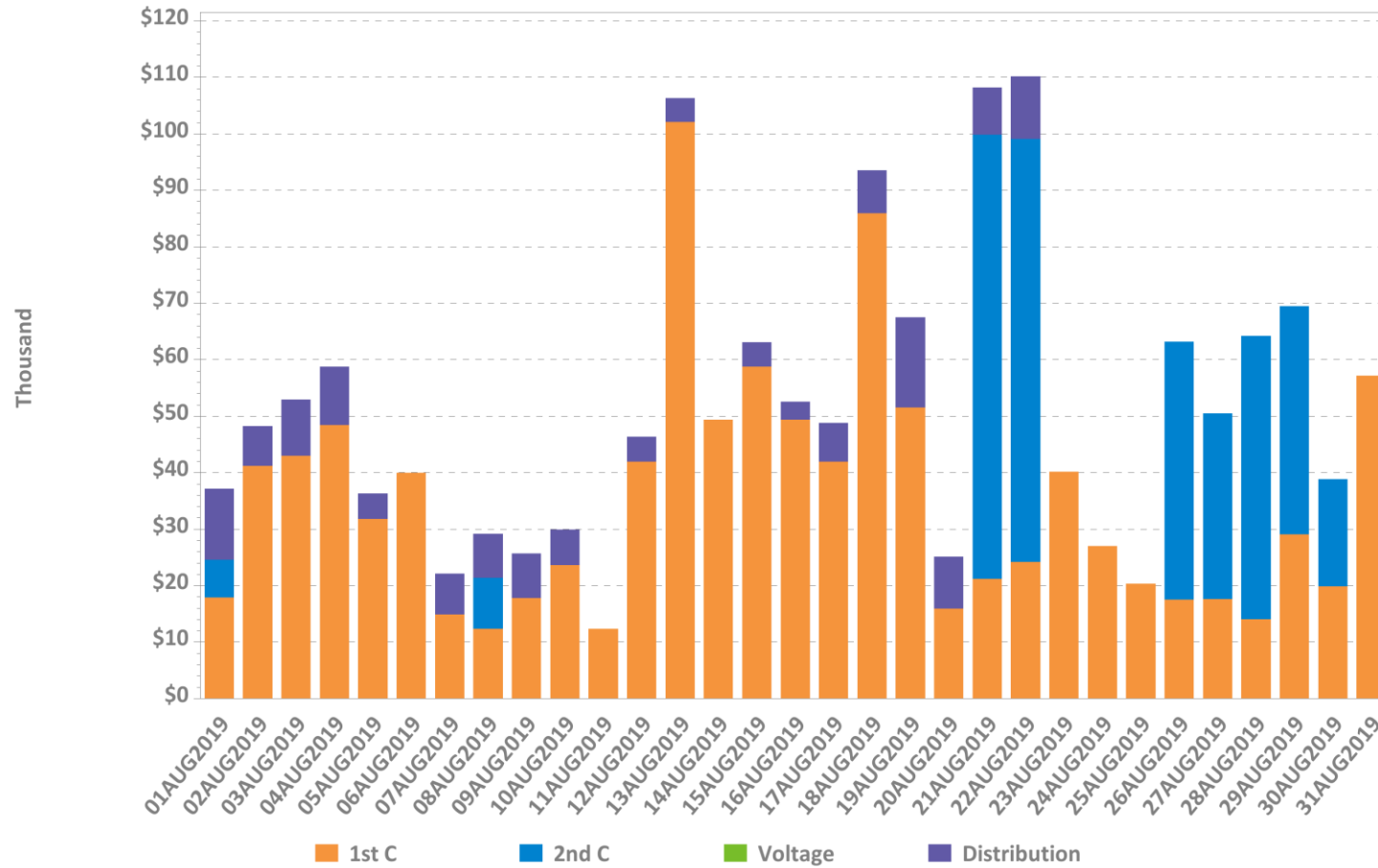


1<sup>st</sup> C – First Contingency  
2<sup>nd</sup> C – Second Contingency  
Distrib – Distribution  
Voltage – Voltage

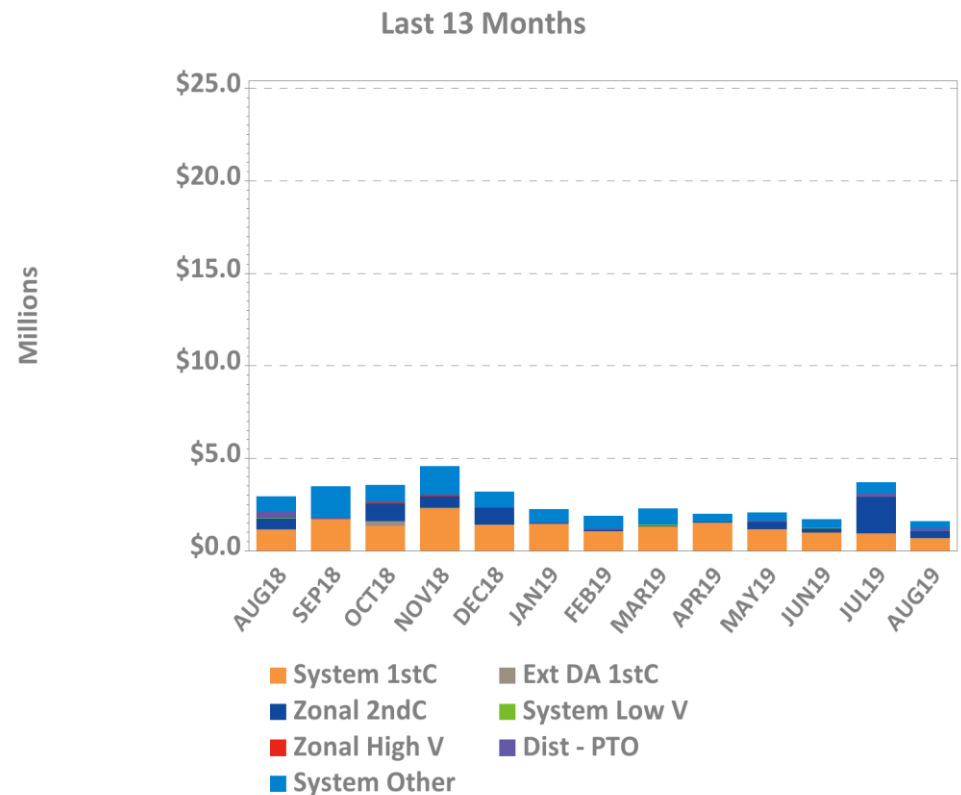
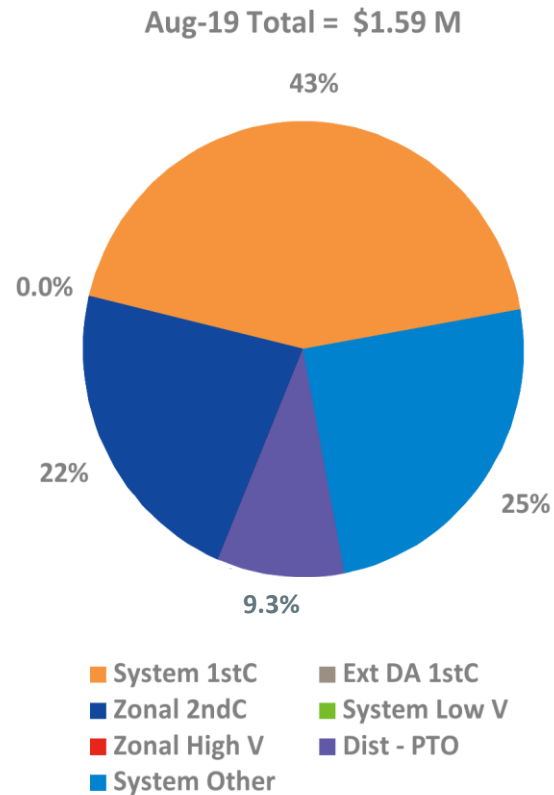




# Daily NCPC Charges by Type

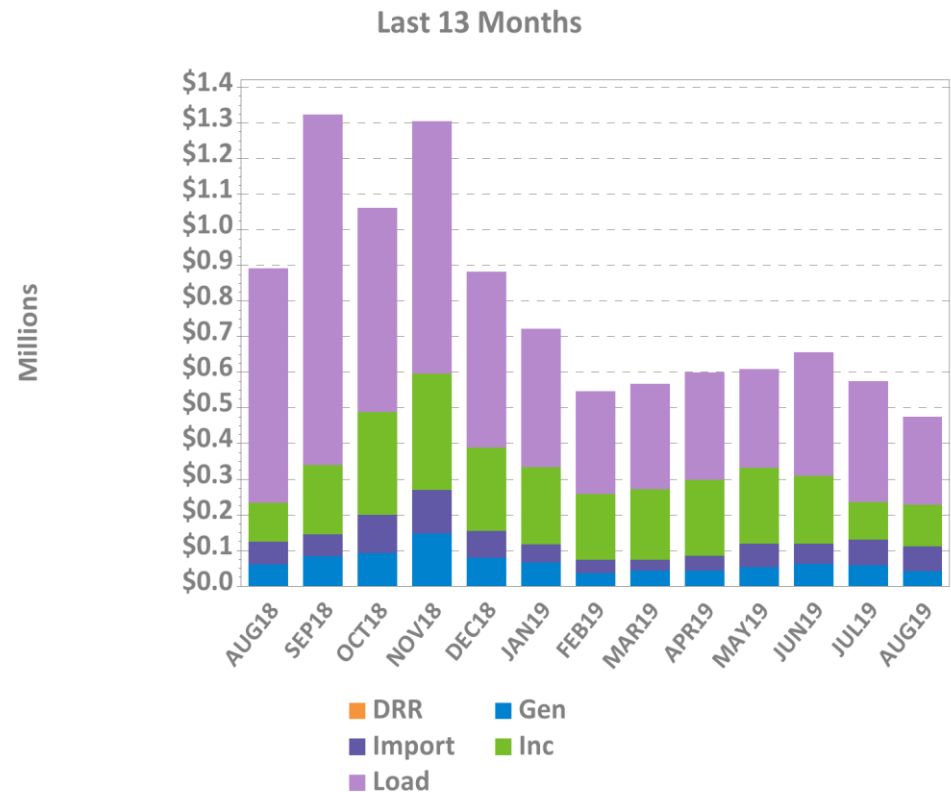
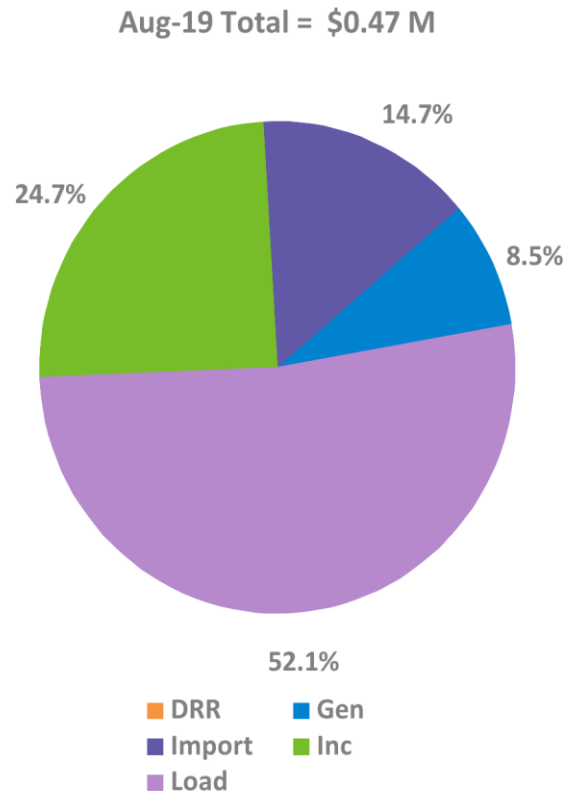


# NCPC Charges by Allocation



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

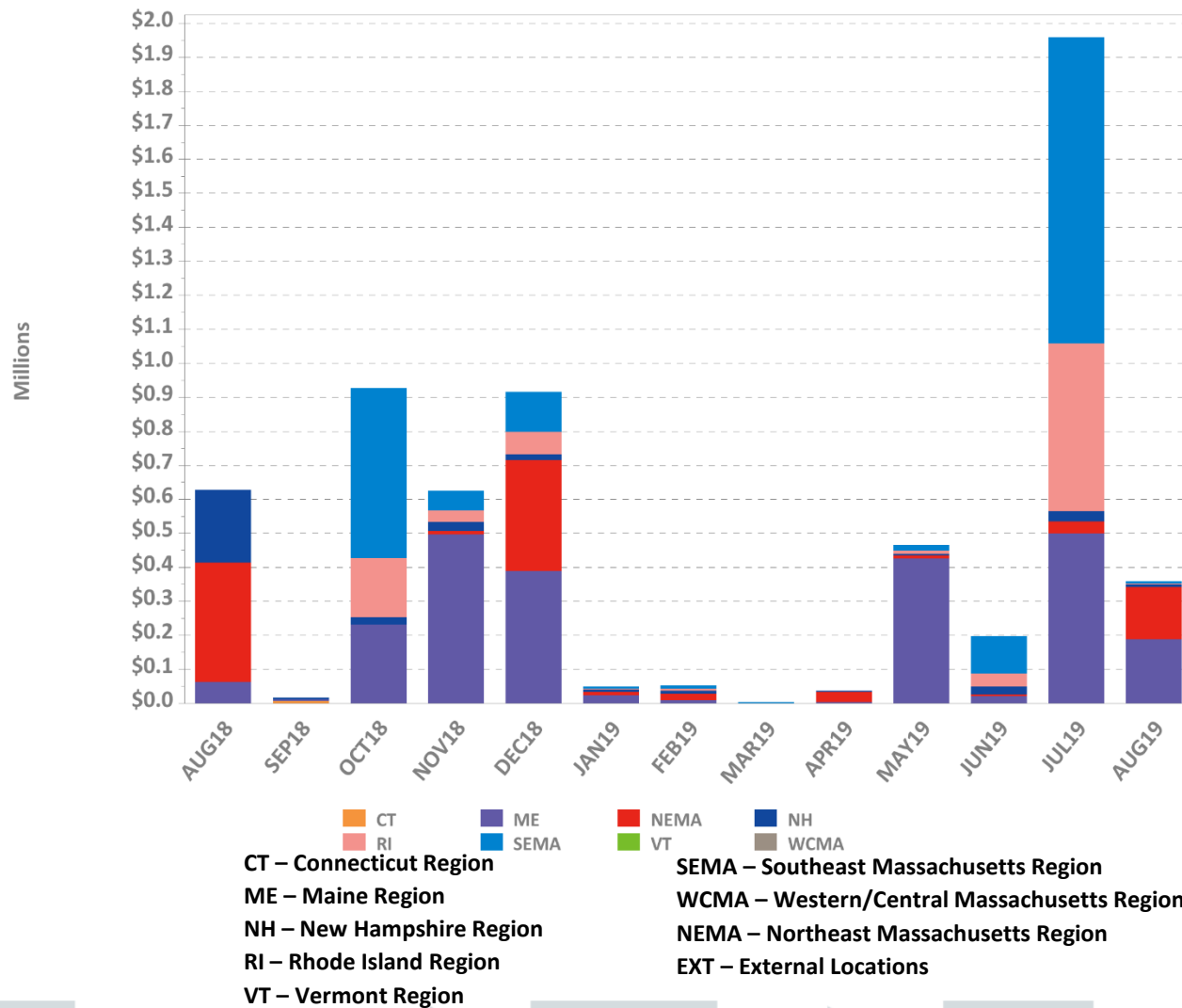
Inc – Increment Offer deviations

Import – Import deviations

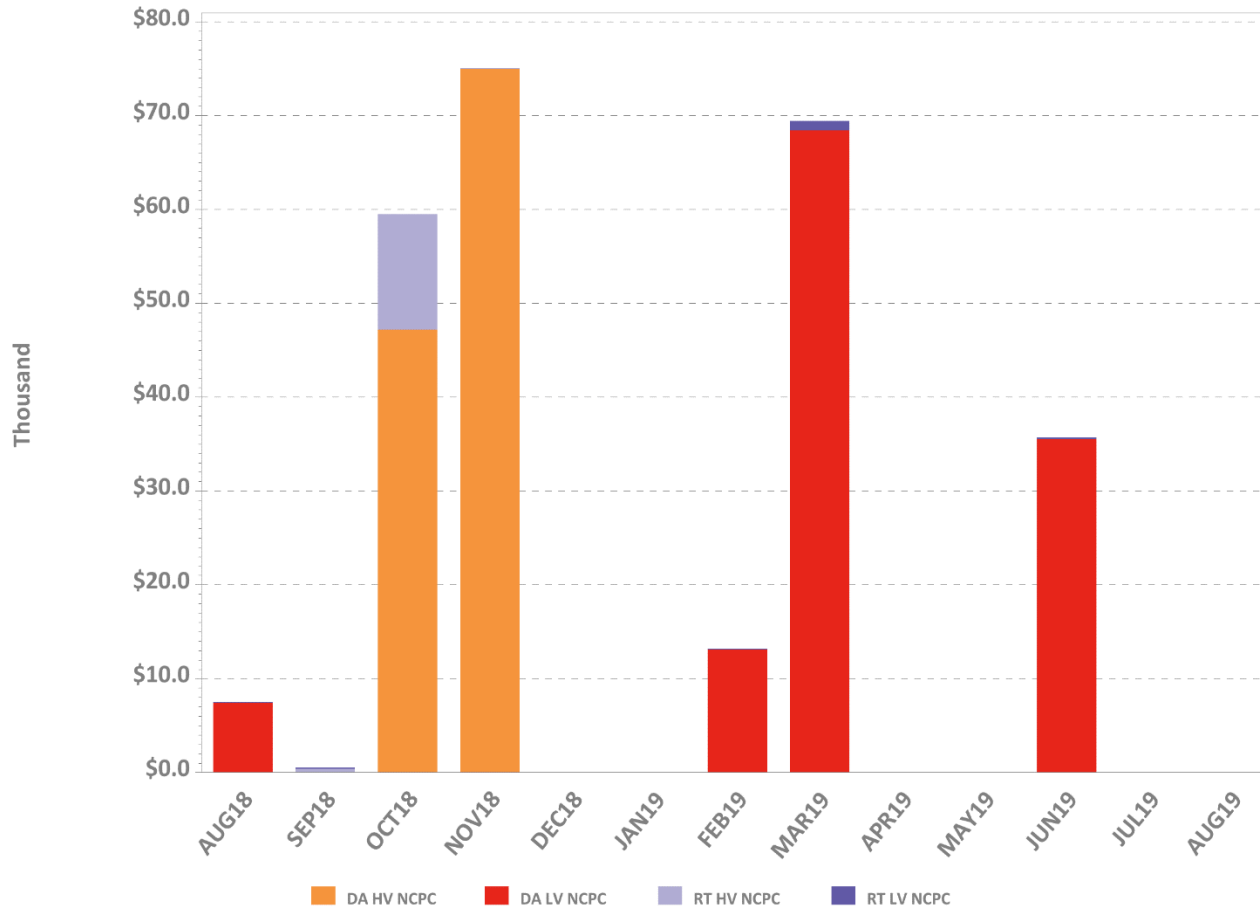
Load – Load obligation deviations



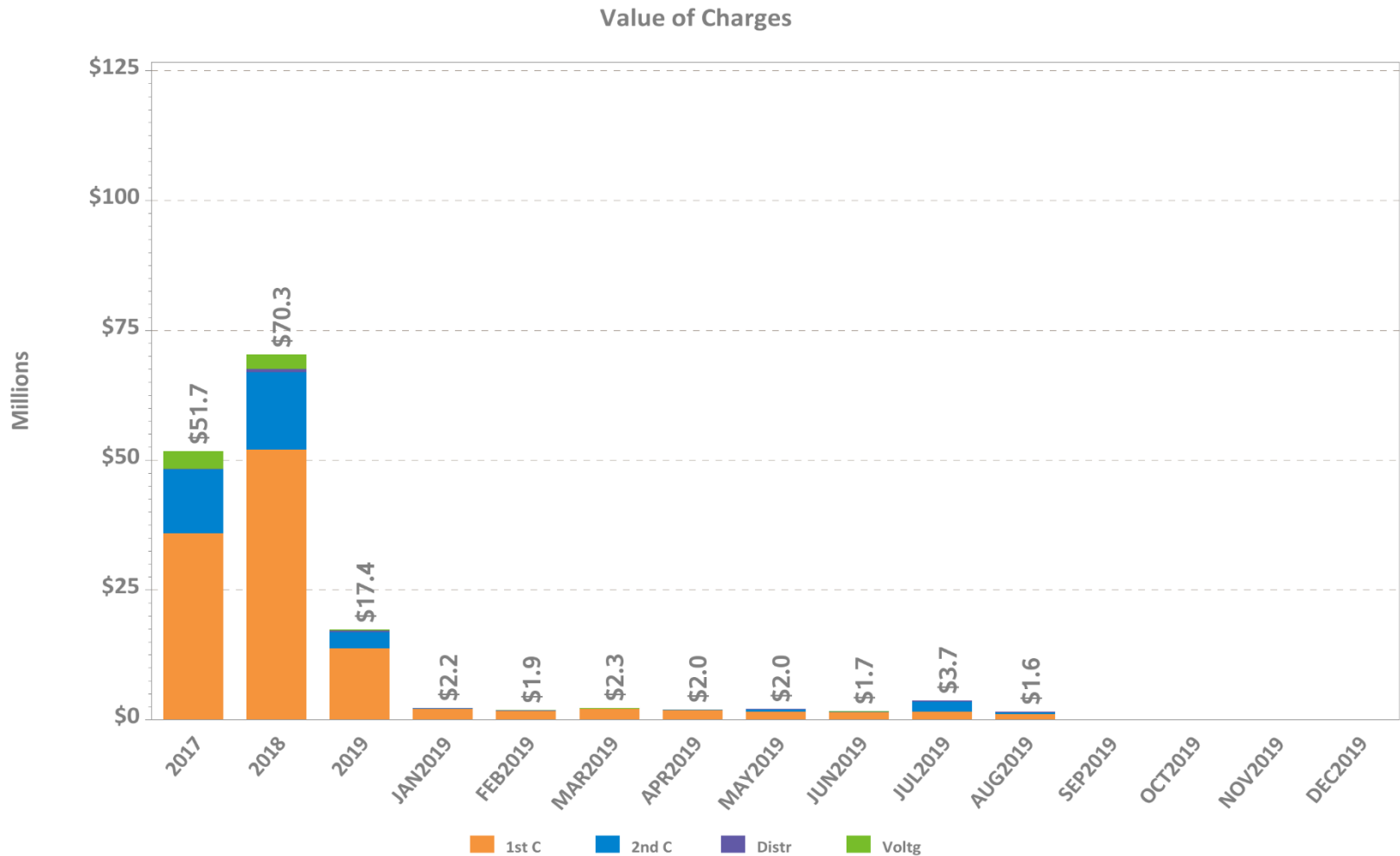
# LSCPR Charges by Reliability Region



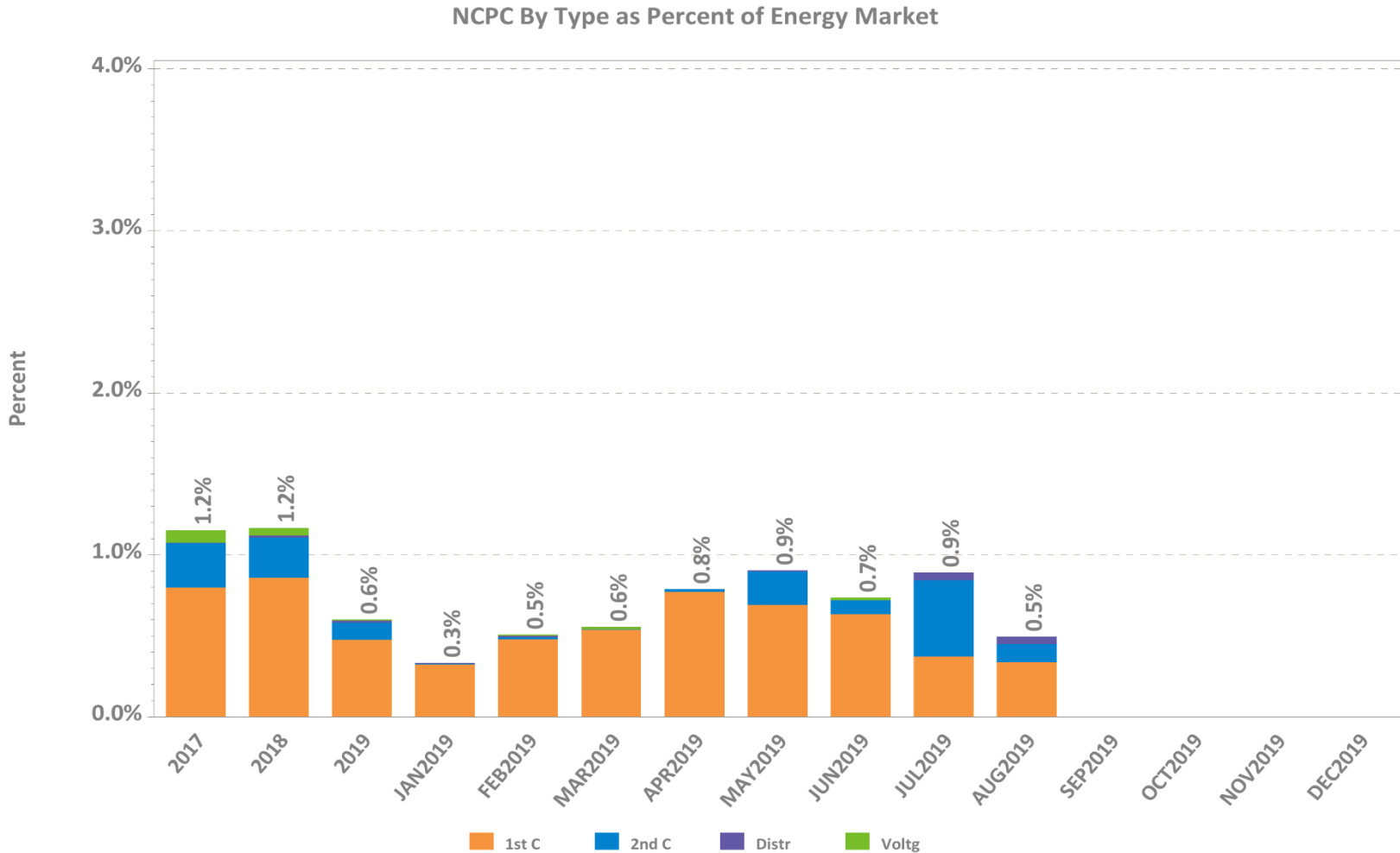
# NCPC Charges for Voltage Support and High Voltage Control



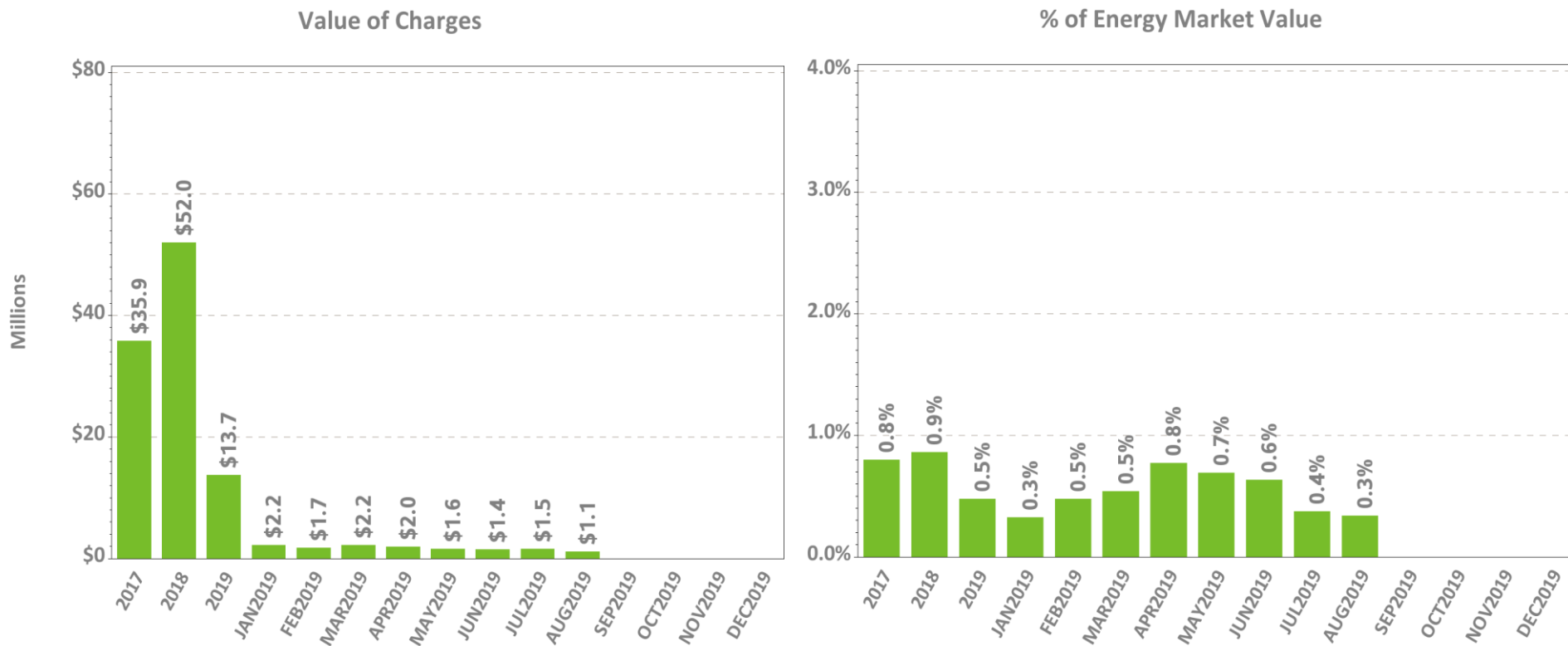
# NCPC Charges by Type



# NCPC Charges as Percent of Energy Market



# First Contingency NCPC Charges

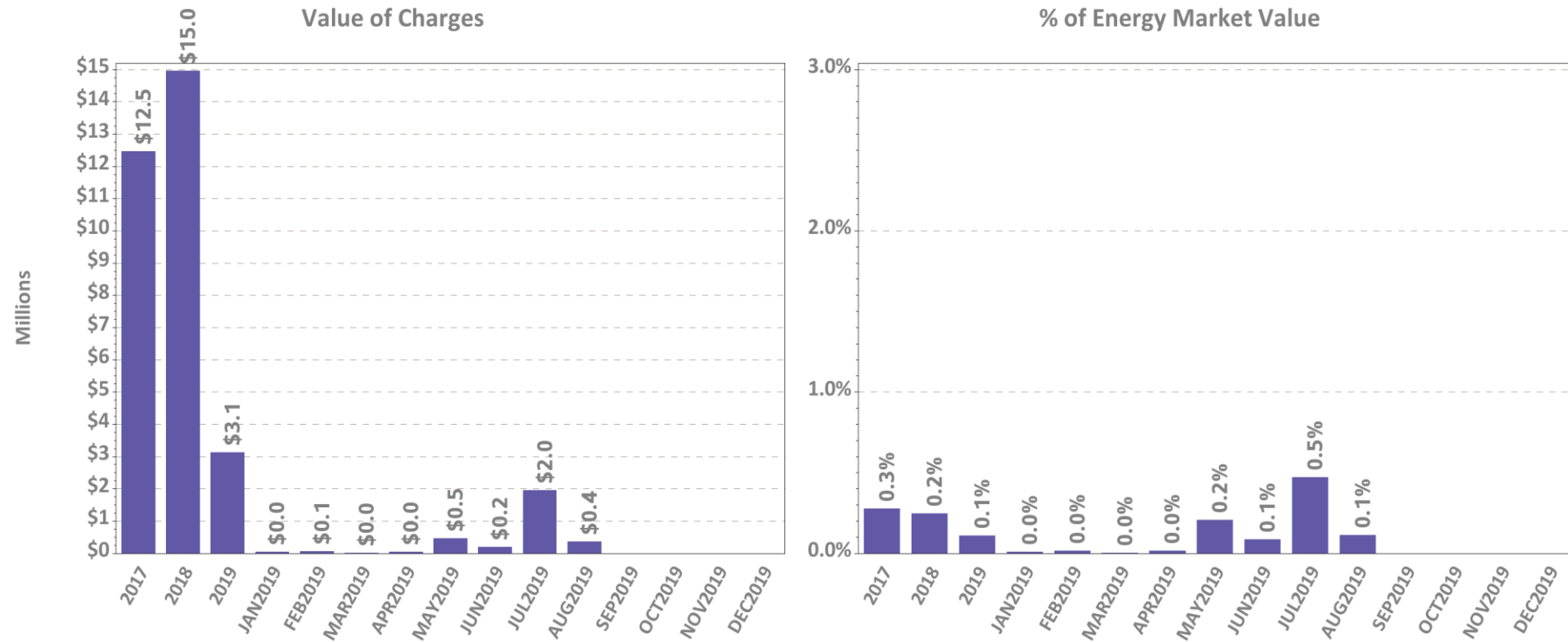


**Note:** Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market





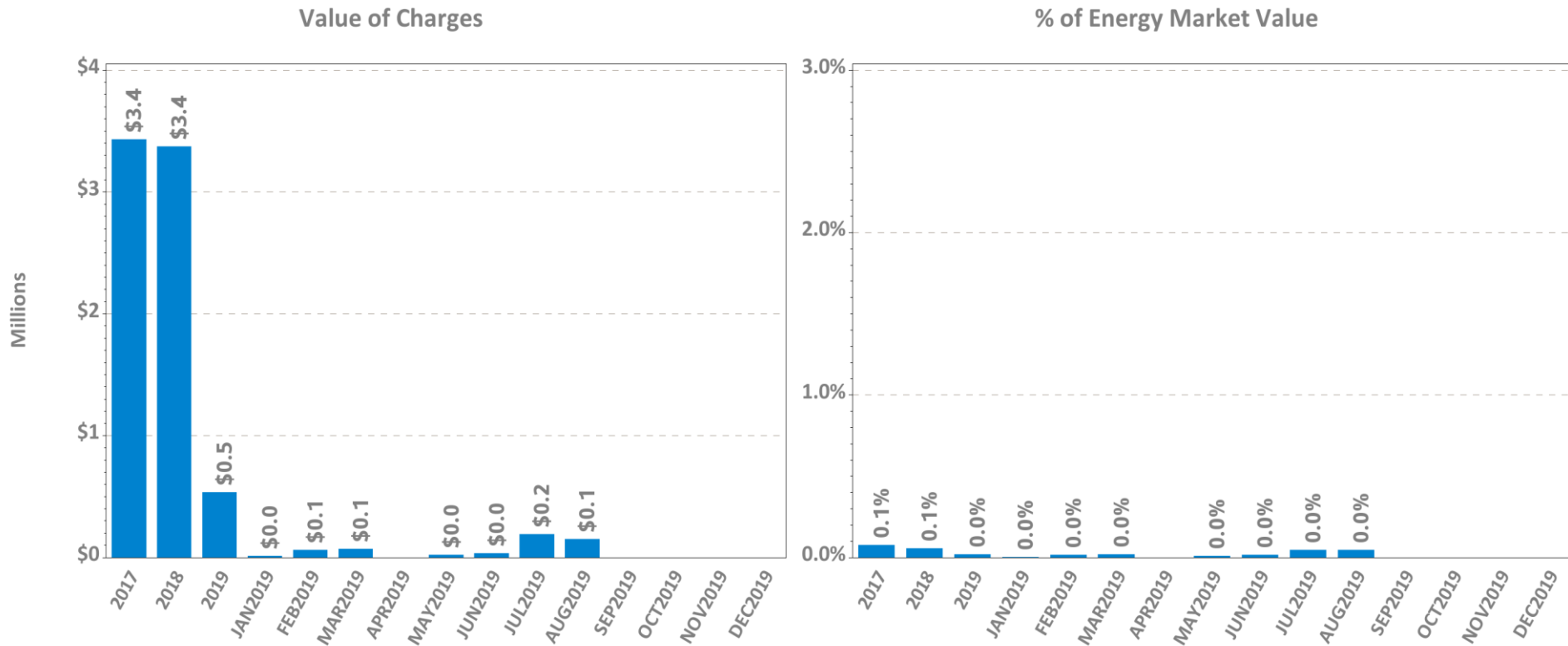
# Second Contingency NCPC Charges



**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



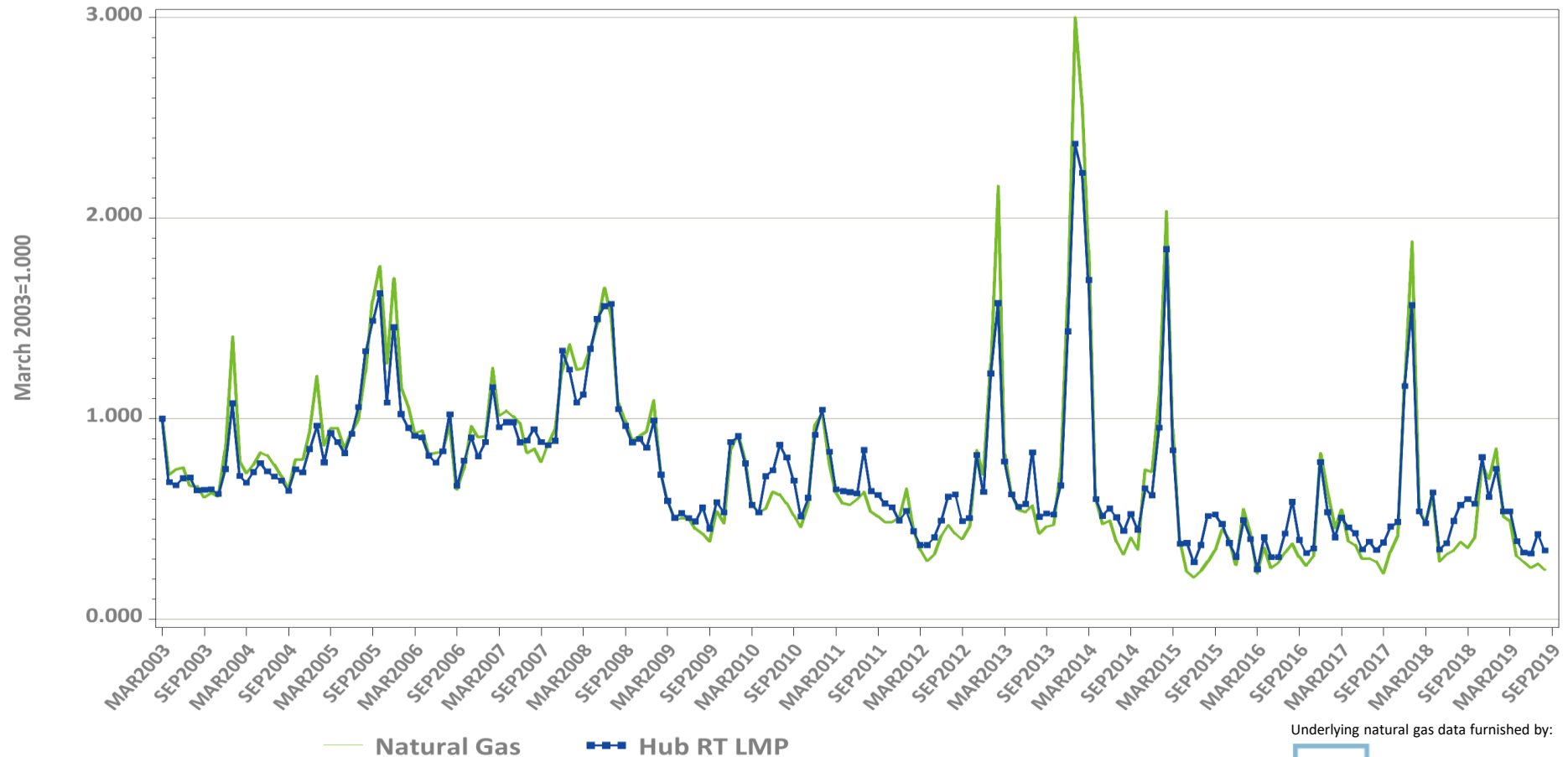
# DA vs. RT LMPs (\$/MWh)

## Arithmetic Average

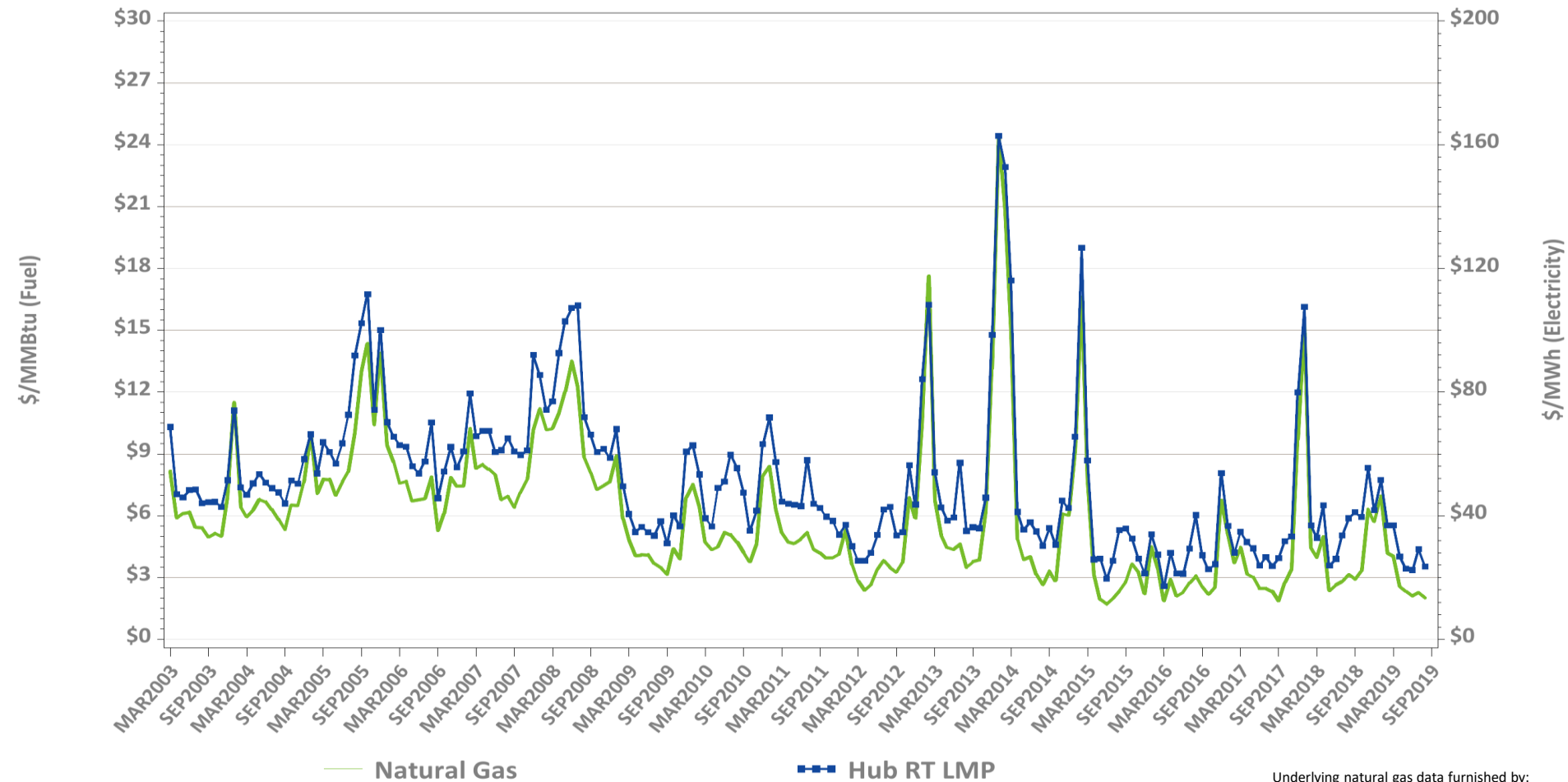
Year 2017	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$33.46	\$33.35	\$32.50	\$33.13	\$33.05	\$33.13	\$33.27	\$33.43	\$33.35
Real-Time	\$34.76	\$33.93	\$31.39	\$32.78	\$33.02	\$33.78	\$33.98	\$33.97	\$33.94
RT Delta %	3.9%	1.7%	-3.4%	-1.0%	-0.1%	2.0%	2.1%	1.6%	1.7%
Year 2018	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$44.45	\$43.60	\$42.63	\$44.04	\$43.71	\$44.11	\$44.62	\$44.19	\$44.13
Real-Time	\$43.87	\$43.13	\$41.03	\$43.17	\$42.83	\$43.37	\$43.68	\$43.58	\$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%

August-18	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$39.42	\$38.65	\$38.69	\$39.34	\$39.22	\$39.20	\$39.66	\$39.20	\$39.16
Real-Time	\$39.42	\$38.95	\$38.57	\$39.37	\$39.02	\$39.04	\$39.36	\$39.22	\$39.18
RT Delta %	0.0%	0.8%	-0.3%	0.1%	-0.5%	-0.4%	-0.8%	0.1%	0.1%
August-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$26.09	\$25.19	\$25.86	\$26.00	\$25.48	\$25.54	\$25.93	\$25.72	\$25.69
Real-Time	\$23.89	\$23.30	\$23.77	\$23.85	\$23.37	\$23.47	\$23.77	\$23.59	\$23.58
RT Delta %	-8.4%	-7.5%	-8.1%	-8.3%	-8.3%	-8.1%	-8.3%	-8.3%	-8.2%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-33.8%	-34.8%	-33.2%	-33.9%	-35.0%	-34.8%	-34.6%	-34.4%	-34.4%
Yr over Yr RT	-39.4%	-40.2%	-38.4%	-39.4%	-40.1%	-39.9%	-39.6%	-39.9%	-39.8%

# Monthly Average Fuel Price and RT Hub LMP Indexes



# Monthly Average Fuel Price and RT Hub LMP

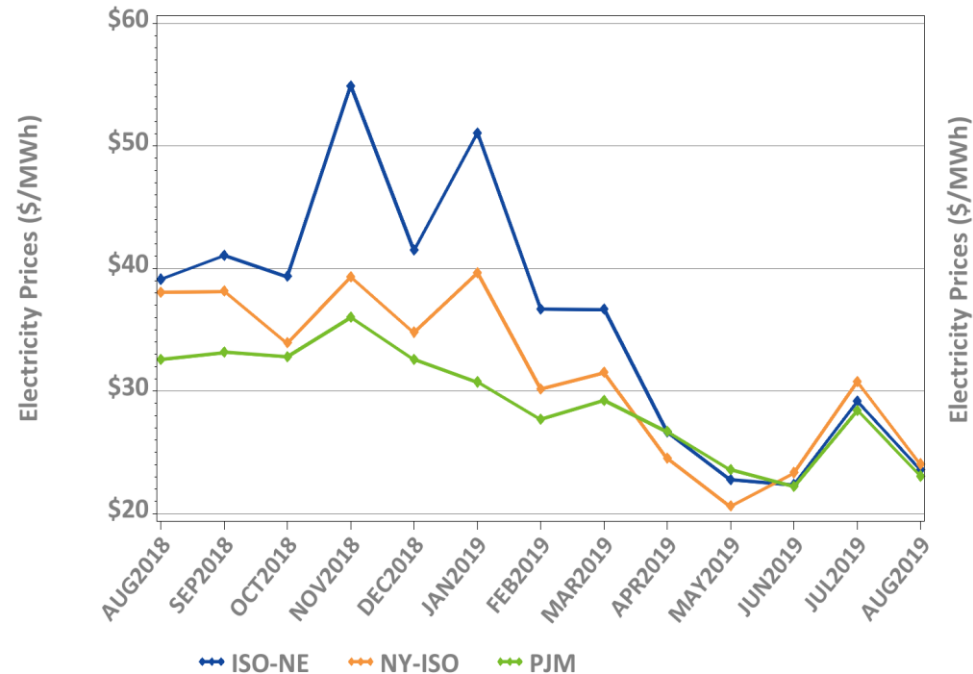


Underlying natural gas data furnished by:



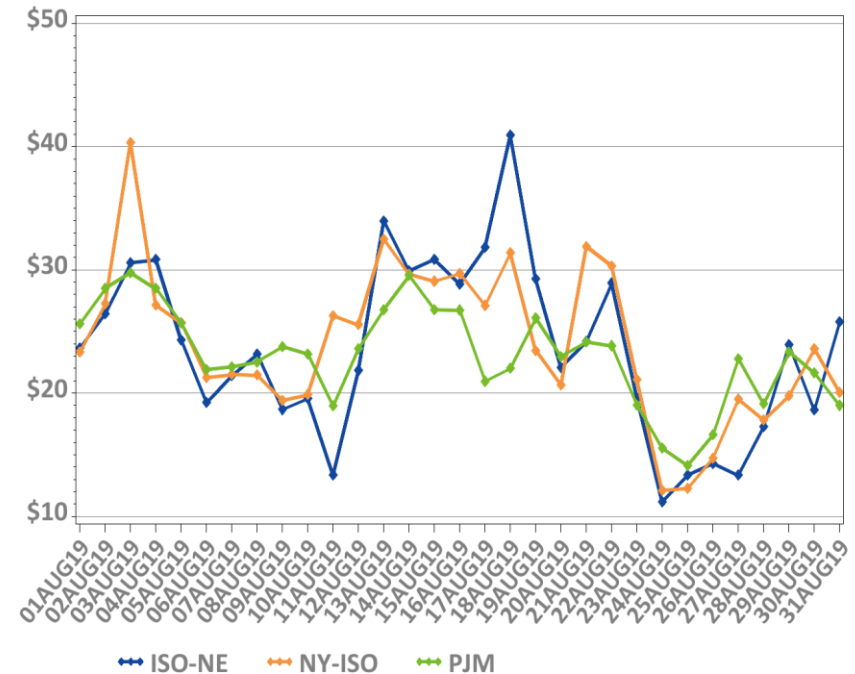
# New England, NY, and PJM Hourly Average Real Time Prices by Month

Monthly, Last 13 Months



\*Note: Hourly average prices are shown.

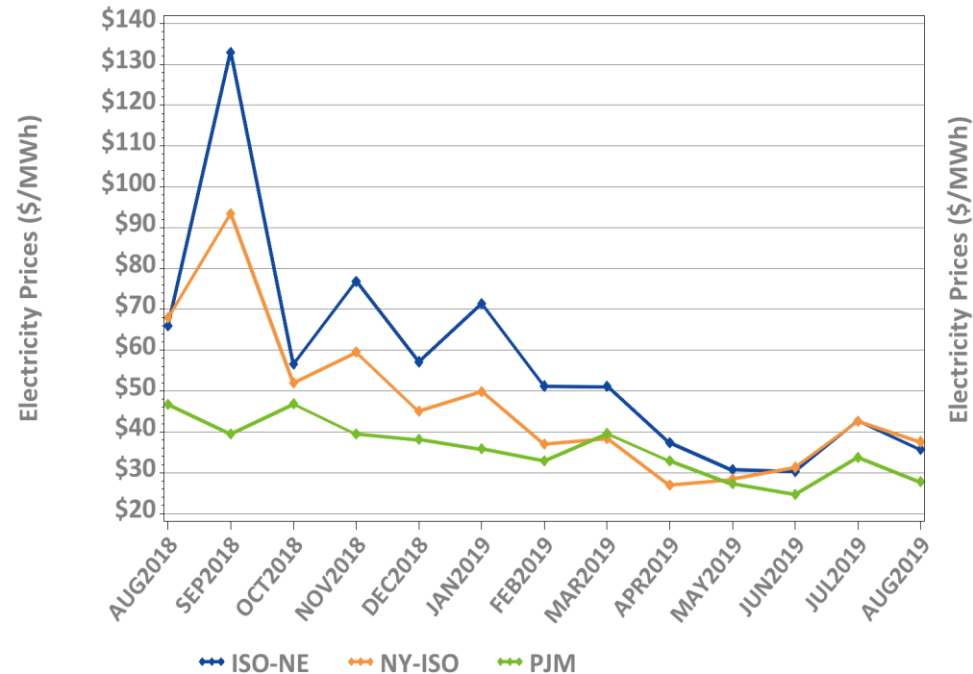
Daily: This Month



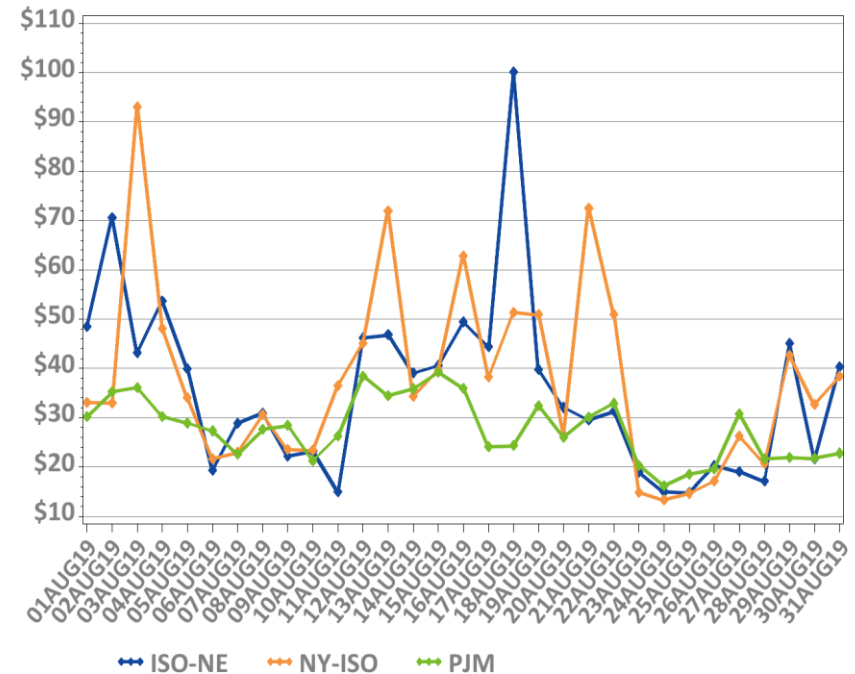
\*Note: Hourly average prices are shown.

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

Monthly, Last 13 Months



Daily: This Month



\*Forecasted New England daily peak hours reflected





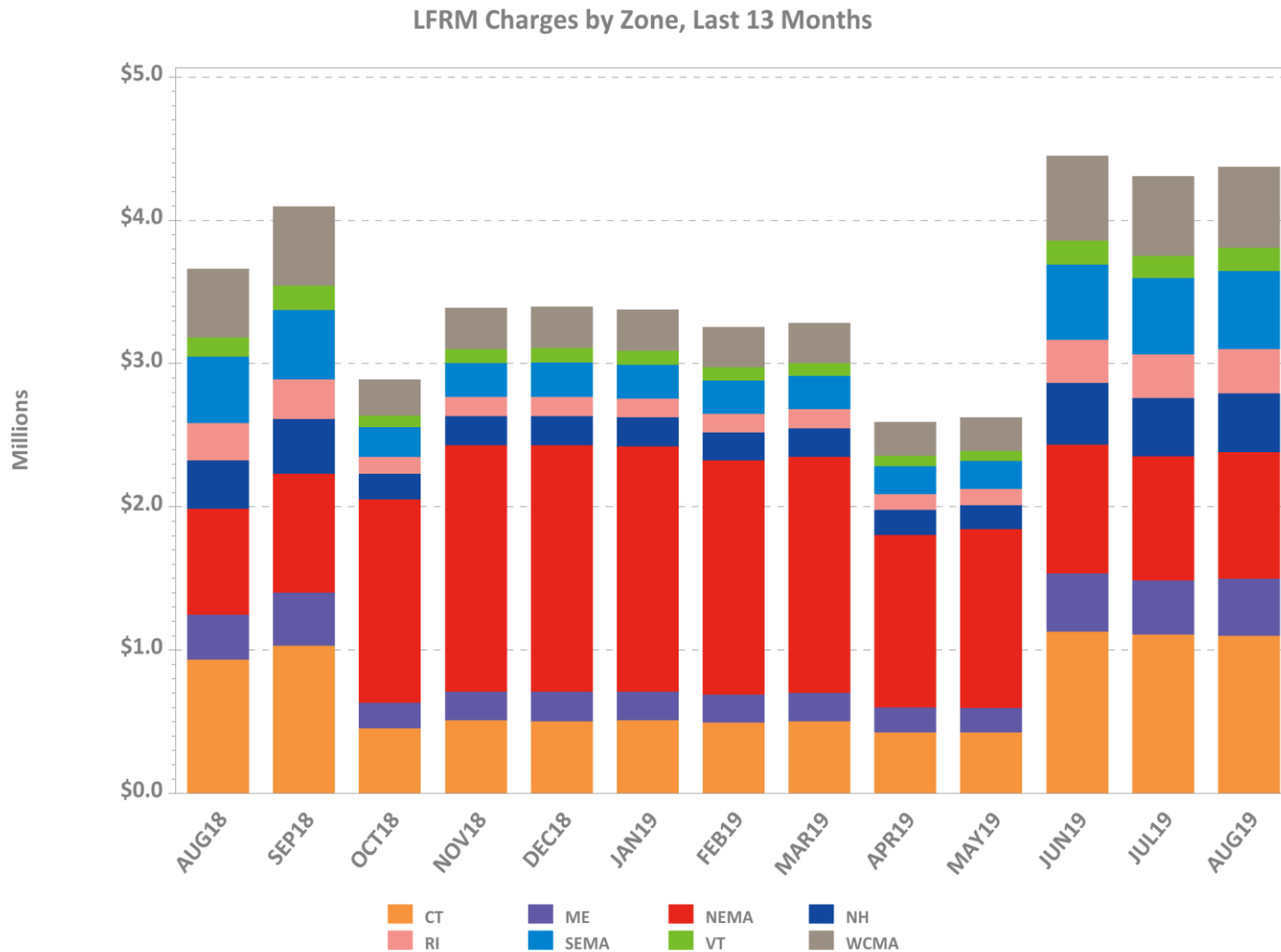
# Reserve Market Results – August 2019

- Maximum potential Forward Reserve Market payments of \$4.5M were reduced by credit reductions of \$71K, failure-to-reserve penalties of \$106K and no failure-to-activate penalties, resulting in a net payout of \$4.4M or 96% of maximum
  - Rest of System: \$3.28M/3.38M (97%)
  - Southwest Connecticut: \$0.31M/0.36M (86%)
  - Connecticut: \$0.79M/0.8M (98%)
- \$861K total Real-Time credits were reduced by \$2K in Forward Reserve Energy Obligation Charges for a net of \$859K in Real-Time Reserve payments
  - Rest of System: 231 hours, \$675K
  - Southwest Connecticut: 231 hours, \$70K
  - Connecticut: 231 hours, \$76K
  - NEMA: 231 hours, \$38K

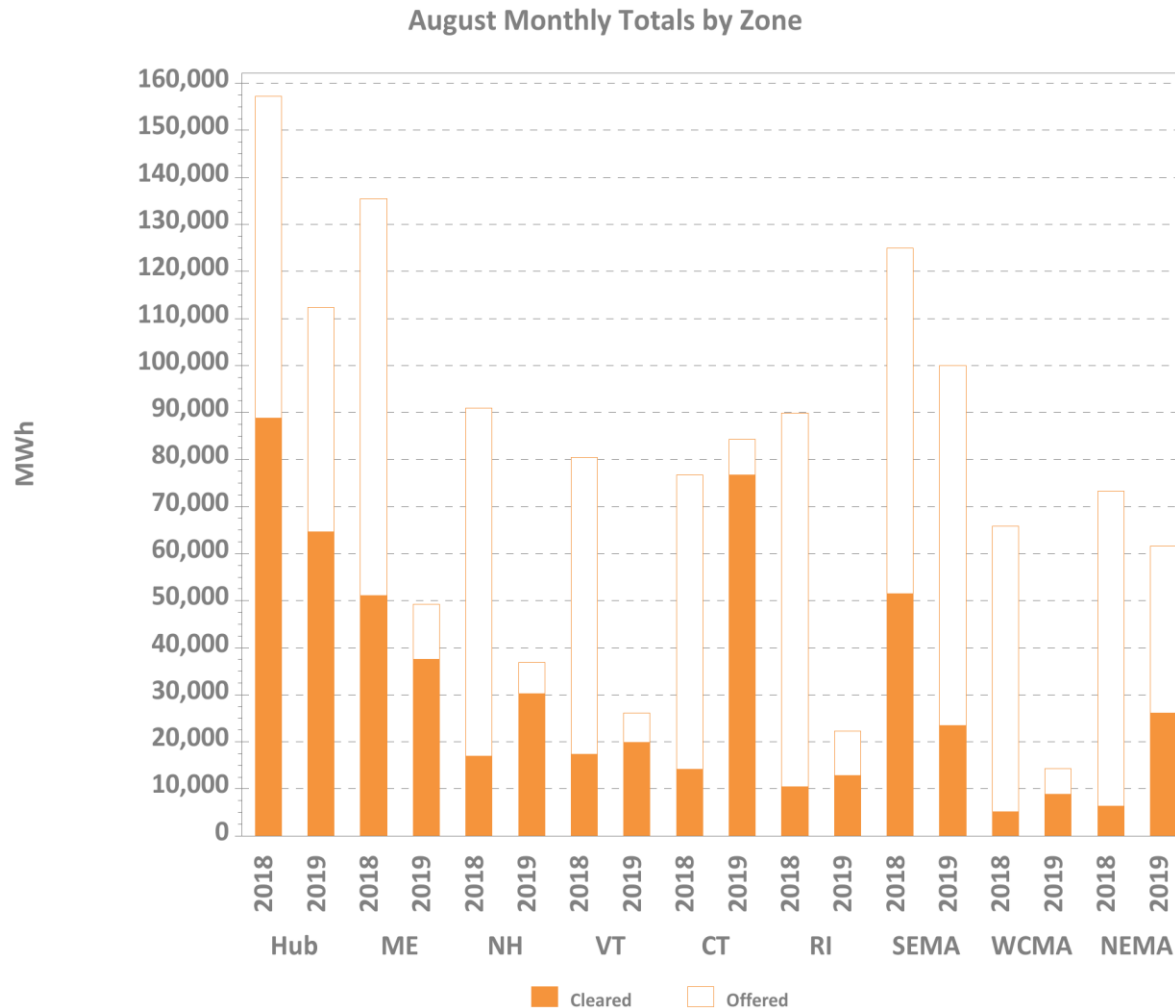
\* “Failure to reserve” results in both credit reductions and penalties in the Locational Forward Reserve Market.



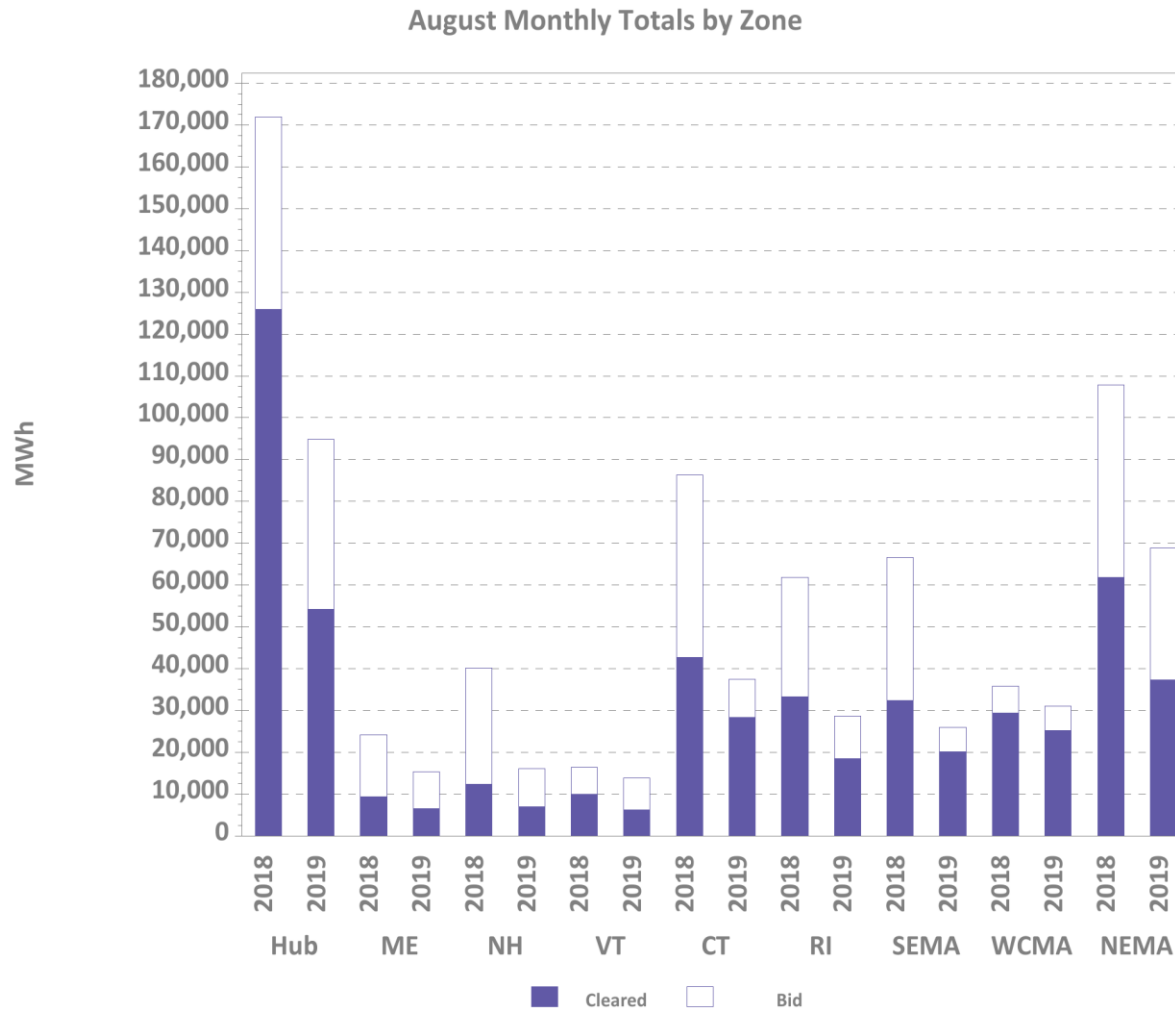
# LFRM Charges to Load by Load Zone (\$)



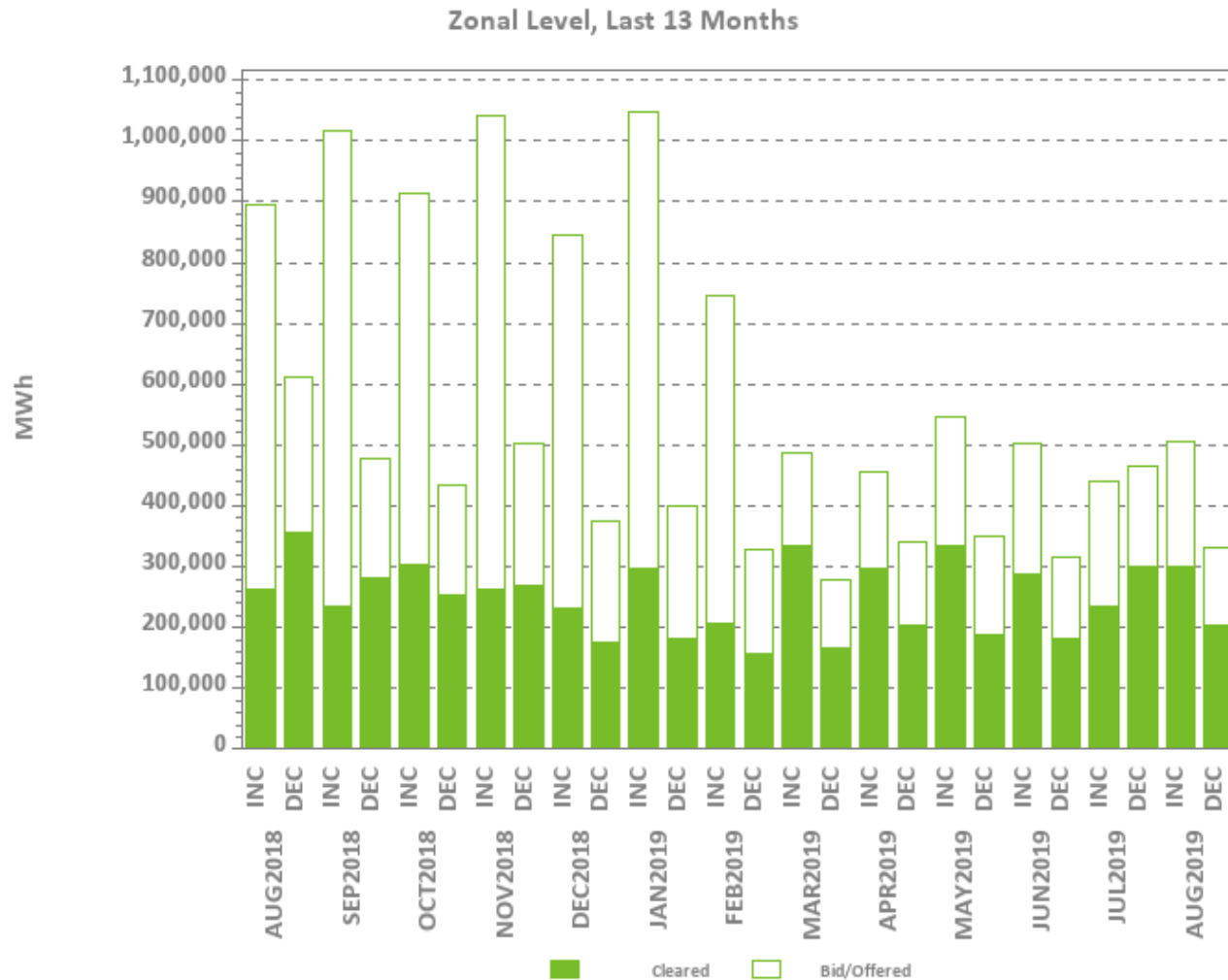
# Zonal Increment Offers and Cleared Amounts



# Zonal Decrement Bids and Cleared Amounts

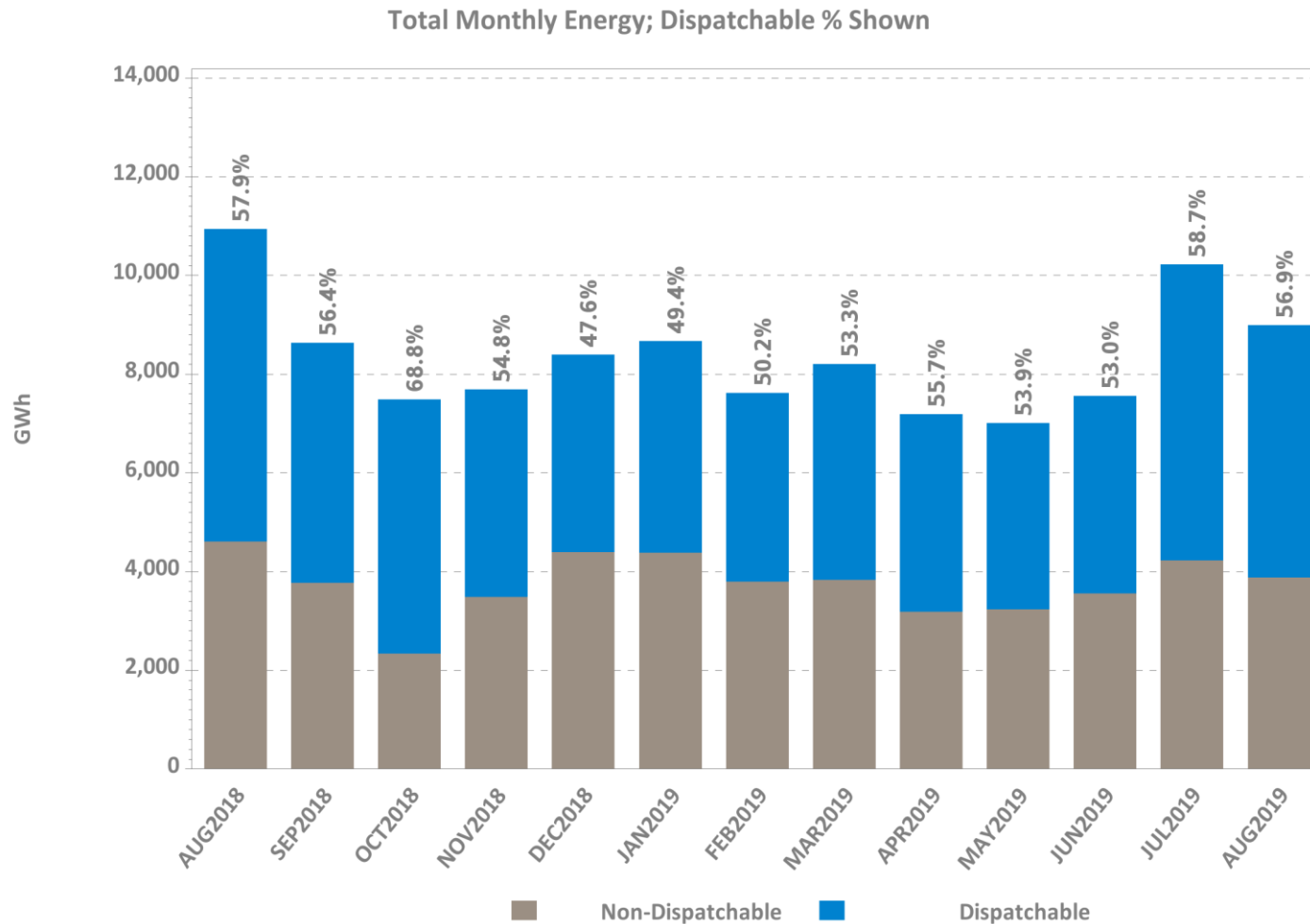


# Total Increment Offers and Decrement Bids



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)



# 2019 Regional System Plan

- The RSP19 public meeting will be held on September 12, from 11:15am until 4:00pm, at The Westin Copley Place in Boston, MA
  - Materials were posted August 29, including the draft RSP19 report





# Agenda: 2019 Regional System Plan Meeting

*September 12; The Westin Copley Place, Boston, MA*

- 11:15 a.m. Check in at the Registration Desk
- 11:45 a.m. Lunch
- 12:45 p.m. Welcoming remarks
- 1:00 p.m. **Keynote: Damir Novosel**, President and Founder of Quanta Technology
- 1:30 p.m. ISO New England report on ***2019 Regional System Plan*** and Q&A
- 2:15 p.m. Break
- 2:30 p.m. **Panel: Transition to the Grid of the Future:  
Adapting to Disruptive Technologies**
- 4:00 p.m. Closing remarks and adjourn

# Panel Discussion

- Moderator
  - **Brook Colangelo**, ISO New England, Board of Directors
- Panelists
  - **Marshall Van Alstyne**, Boston University and Fellow at MIT's Initiative on the Digital Economy
  - **Katherine Prewitt**, Eversource Energy
  - **Mark O'Malley**, National Renewable Energy Laboratory
  - **Damir Novosel**, Quanta Technology

# Planning Advisory Committee (PAC)

- September 26 PAC Meeting Agenda Topics\*
  - Boston 2028 Preliminary Preferred Solution
  - Boston 2028 Needs Assessment Addendum
  - Boston 2028 Needs Assessment Update
  - ECT 2029 Needs Assessment Results
  - Update to the Transmission Planning Technical Guide - Short Circuit
  - Eastern Interconnection Planning Collaborative Update

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



# Economic Studies

- Three economic study requests were introduced at the April 25 PAC meeting
  - Study requests were submitted by Anbaric, NESCOE, and RENEW Northeast
- Detailed assumptions for each study request were discussed at the August 8 PAC meeting
- The ISO will attempt to complete all analyses for all three requests by Q2 of 2020
  - Preliminary results expected by Q4 of 2019



# Environmental Matters – MA CO<sub>2</sub> Generator Emissions Cap Update (310 CMR 7.74)

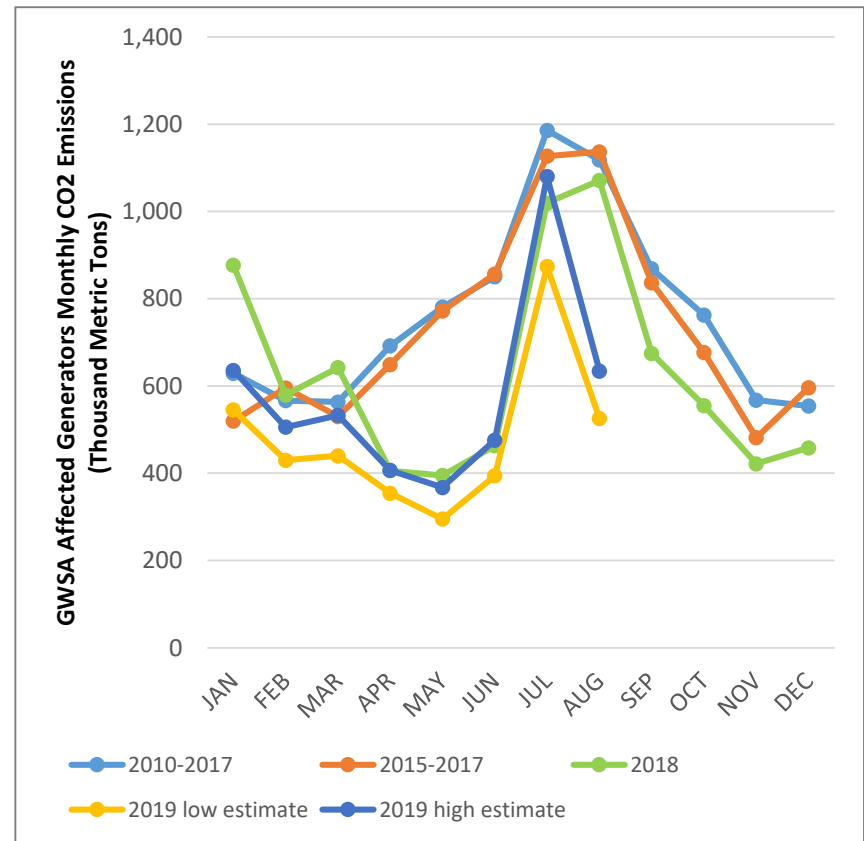
*Massachusetts Global Warming Solutions Act (GWSA)*

## Estimated 2019 Monthly Emissions Trend Lower under GWSA CO<sub>2</sub> Cap

- 2019 cap set at 8.73 million metric tons (MMT)
  - 2018 emissions: 7.56 MMT
- Estimated 2019 monthly emissions range (metric tons):
  - Jan 2019: 545,228 – 635,949
  - Feb 2019: 429,523 – 505,696
  - Mar 2019: 345,470 – 473,633
  - Apr 2019: 224,138 – 257,386
  - May 2019: 264,374 – 329,763
  - Jun 2019: 336,584 – 407,926
  - Jul 2019: 616,343 – 747,649
  - Aug 2019: 525,494 – 634,284\*
  - **YTD 2019: 3.8 MMT – 4.6 MMT**

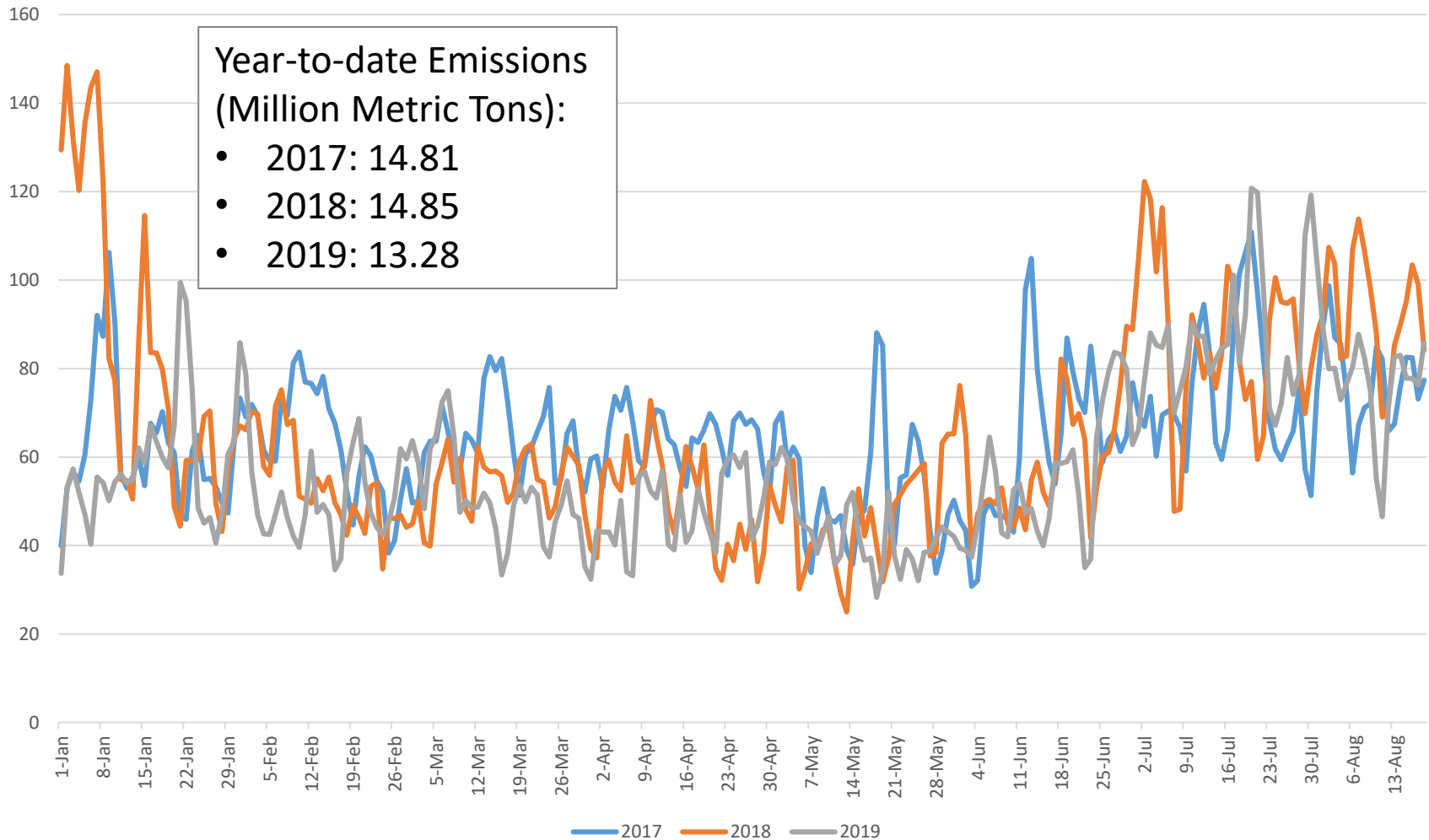
\* August 2019 estimated emissions through 8/23/19

## GWSA Monthly CO<sub>2</sub> Emissions (Thousand Metric Tons)



July 2019 estimated emissions through 8/23/19

# System Daily Estimated CO<sub>2</sub> Emissions 2017-2019 YTD (Thousand Metric Tons)



\* YTD estimated emissions through 8/18 of each year

# 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.



# New Hampshire/Vermont 10-Year Upgrades

*Status as of 8/27/19*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

Upgrade	Expected/ Actual In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	May-20	3
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4





# New Hampshire/Vermont 10-Year Upgrades, cont.

*Status as of 8/27/19*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

Upgrade	Expected/ Actual In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Dec-14	4
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4



# New Hampshire/Vermont 10-Year Upgrades, cont.

*Status as of 8/27/19*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Dec-14	4
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4



# Greater Hartford and Central Connecticut (GHCC) Projects\*

*Status as of 8/27/19*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Jun-18	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

\* Replaces the NEEWS Central Connecticut Reliability Project



# Greater Hartford and Central Connecticut Projects, cont.\*

*Status as of 8/27/19*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Jun-20	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Jun-20	3

\* Replaces the NEEWS Central Connecticut Reliability Project



# Greater Hartford and Central Connecticut Projects, cont.\*

*Status as of 8/27/19*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	4
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Jun-20	3
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	4
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

\* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut Projects, cont.\*

*Status as of 8/27/19*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

Upgrade	Expected/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-18	4
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Jun-18	4
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

\* Replaces the NEEWS Central Connecticut Reliability Project



# Southwest Connecticut (SWCT) Projects

*Status as of 8/27/19*

*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 8/27/19*

*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)	Jun-20	2
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 8/27/19*

*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	3
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	3



# Southwest Connecticut Projects, cont.

*Status as of 8/27/19*

*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)	Sep-20	2



# Southwest Connecticut Projects, cont.

*Status as of 8/27/19*

*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 8/27/19*

*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-21	2*
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 8/27/19*

*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	Dec-19	3
Install third 115 kV line from West Walpole to Holbrook	Dec-19	3
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-20	2



# Greater Boston Projects, cont.

*Status as of 8/27/19*

*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	3
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	Jan-20	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	Dec-19	3

# Greater Boston Projects, cont.

*Status as of 8/27/19*

*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	Dec-20	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 position	Dec-16	4



# Greater Boston Projects, cont.

*Status as of 8/27/19*

*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	Nov-19	3
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





# Pittsfield/Greenfield Projects

*Status as of 8/27/19*

*Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts*

Upgrade	Expected/ Actual In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Mar-17	4
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Nov-17	4
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	4
Build a new 115 kV three-breaker switching station (Erving) ring bus	Mar-17	4
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Jun-17	4
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4



# Pittsfield/Greenfield Projects, cont.

*Status as of 8/27/19*

*Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts*

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	4
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Mar-17	4
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4



# Pittsfield/Greenfield Projects, cont.

*Status as of 8/27/19*

*Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts*

Upgrade	Expected/ Actual In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Jun-20	3



# SEMA/RI Reliability Projects

*Status as of 8/27/19*

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Nov-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Jun-20	3
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	3
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	3

# SEMA/RI Reliability Projects, cont.

*Status as of 8/27/19*

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Nov-20	2
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2
1720	Separate the N12/M13 DCT and re-conductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2

# SEMA/RI Reliability Projects, cont.

*Status as of 8/27/19*

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-21	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Nov-20	1
1727	Retire the Barnstable SPS	Dec-21	1
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-21	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-21	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-21	1

# SEMA/RI Reliability Projects, cont.

*Status as of 8/27/19*

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	1
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-21	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Dec-21	1
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Dec-21	3

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

# SEMA/RI Reliability Projects, cont.

*Status as of 8/27/19*

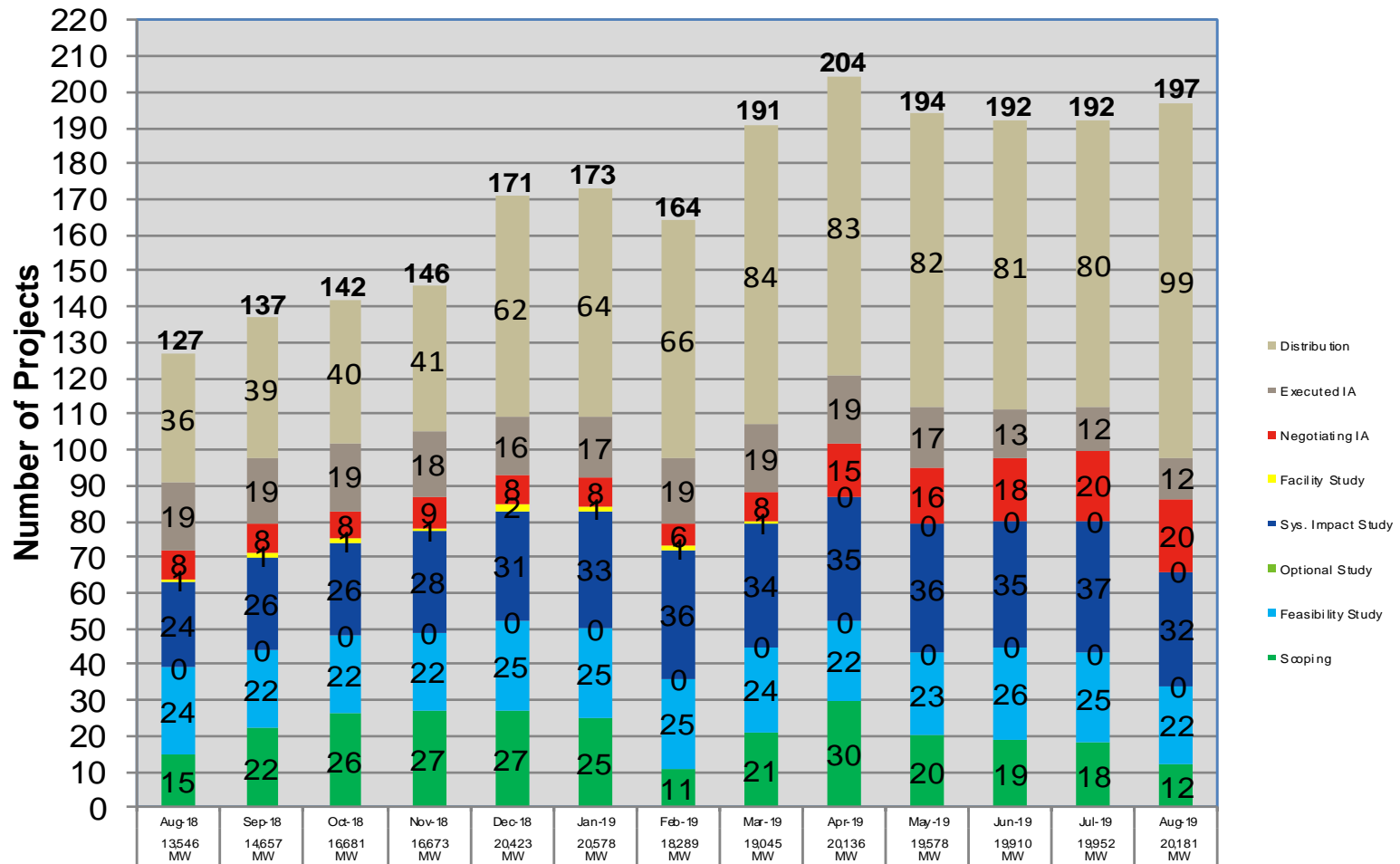
*Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area*

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Dec-20	2
1724	Replace the Kent County 345/115 kV transformer	Nov-20	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	2
1790	Medway 115 kV circuit breaker replacements	Dec-21	2





# Status of Tariff Studies

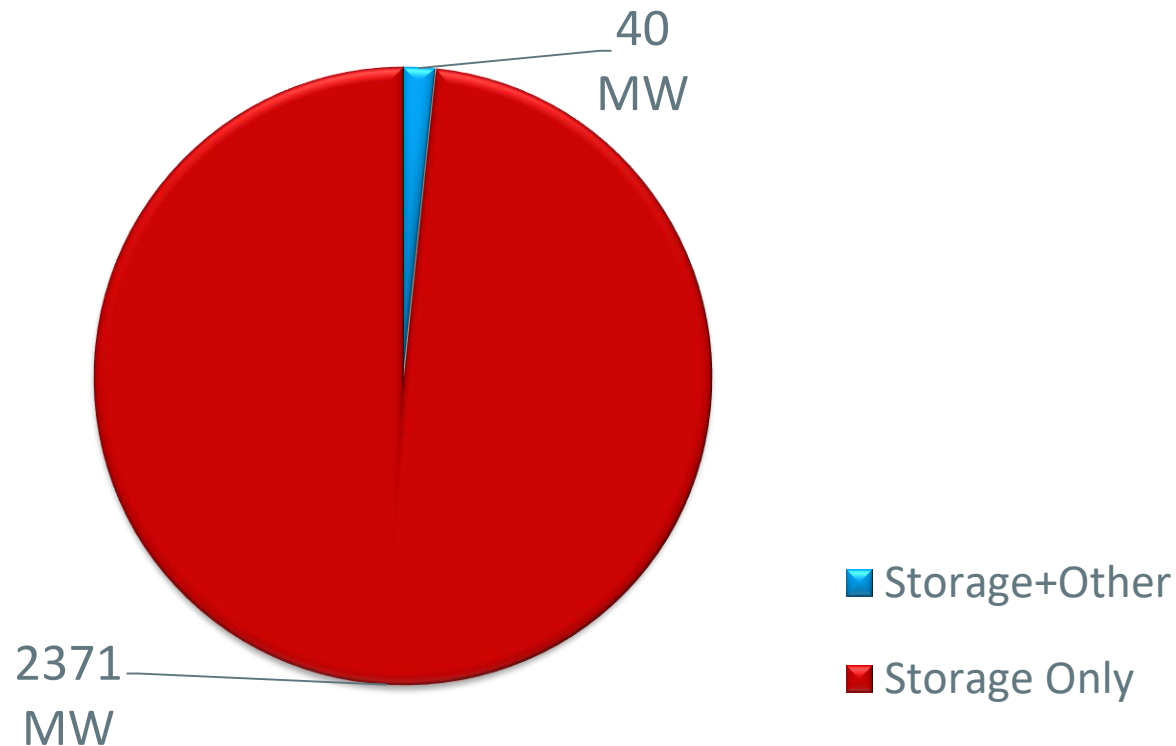


As of August 2019, there are 6 ETU's in Scoping, 5 in FS, 3 in SIS, 0 in FAC, 1 Negotiating IA, and 1 with Executed IA

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

# What is in the Queue (as of September 1, 2019)

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



# OPERABLE CAPACITY ANALYSIS

*Fall 2019 Analysis*

# Fall 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	November - 2019 <sup>2</sup> CSO (MW)	November - 2019 <sup>2</sup> SCC (MW)
Operable Capacity MW <sup>1</sup>	31,344	33,594
Active Demand Capacity Resource (+) <sup>5</sup>	455	439
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	4,062	4,154
Gas Generator Outages MW (-)	2,890	3,182
Allowance for Unplanned Outages (-) <sup>4</sup>	3,600	3,600
Generation at Risk Due to Gas Supply (-) <sup>3</sup>	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,192	24,042
Peak Load Forecast MW (adjusted for Other Demand Resources) <sup>2</sup>	16,912	16,912
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,217	19,217
Operable Capacity Margin	2,975	4,825

<sup>1</sup>Operable Capacity is based on data as of **August 28, 2019** 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 **August 28, 2019**.

<sup>2</sup> Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 2, 2019**.

<sup>3</sup> Total of (Gas at Risk MW) – (Gas Gen Outages MW).

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

<sup>5</sup> 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.

# Fall 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	November - 2019 <sup>2</sup> CSO (MW)	November - 2019 <sup>2</sup> SCC (MW)
Operable Capacity MW <sup>1</sup>	31,344	33,594
Active Demand Capacity Resource (+) <sup>5</sup>	455	439
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	4,062	4,154
Gas Generator Outages MW (-)	2,890	3,182
Allowance for Unplanned Outages (-) <sup>4</sup>	3,600	3,600
Generation at Risk Due to Gas Supply (-) <sup>3</sup>	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,192	24,042
Peak Load Forecast MW (adjusted for Other Demand Resources) <sup>2</sup>	17,503	17,503
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,808	19,808
Operable Capacity Margin	2,384	4,234

<sup>1</sup>Operable Capacity is based on data as of **August 28, 2019** 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 **August 28, 2019**.

<sup>2</sup> Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 2, 2019**.

<sup>3</sup> Total of (Gas at Risk MW) – (Gas Gen Outages MW).

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

<sup>5</sup> 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.

# Fall 2019 Operable Capacity Analysis

## 50/50 Forecast (Reference)

### ISO-NE OPERABLE CAPACITY ANALYSIS

September 1, 2019 - 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, and 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]
9/14/2019	30611	403	1304	28	2468	456	2100	0	27322	21176	2305	23481	3841
9/21/2019	30611	403	1304	28	3718	0	2100	0	26528	21080	2305	23385	3143
9/28/2019	31694	389	473	28	5838	234	2800	0	23712	15204	2305	17509	6203
10/5/2019	31694	389	473	28	4970	1540	2800	0	23274	15241	2305	17546	5728
10/12/2019	31694	389	573	28	3531	1512	2800	0	24841	16200	2305	18505	6336
10/19/2019	31694	389	473	28	3021	1568	2800	0	25195	16577	2305	18882	6313
10/26/2019	31344	455	917	28	3524	437	3600	0	25183	16792	2305	19097	6086
11/2/2019	31344	455	917	28	4062	2890	3600	0	22192	16912	2305	19217	2975
11/9/2019	31344	455	917	28	3819	2460	3600	0	22865	17269	2305	19574	3291
11/16/2019	31344	455	917	28	3185	1169	3600	251	24539	18034	2305	20339	4200
11/23/2019	31344	455	917	28	1097	1169	3600	964	25914	18780	2305	21085	4829

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 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 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  $(9 - 12 = 13)$

# Fall 2019 Operable Capacity Analysis

## 90/10 Forecast (Extreme)

### ISO-NE OPERABLE CAPACITY ANALYSIS

September 1, 2019 - 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, and 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]
9/14/2019	30611	403	1304	28	2468	456	2100	0	27322	22794	2305	25099	2223
9/21/2019	30611	403	1304	28	3718	0	2100	0	26528	22692	2305	24997	1531
9/28/2019	31694	389	473	28	5838	234	2800	0	23712	15745	2305	18050	5662
10/5/2019	31694	389	473	28	4970	1540	2800	0	23274	15783	2305	18088	5186
10/12/2019	31694	389	573	28	3531	1512	2800	0	24841	16770	2305	19075	5766
10/19/2019	31694	389	473	28	3021	1568	2800	0	25195	17159	2305	19464	5731
10/26/2019	31344	455	917	28	3524	437	3600	0	25183	17380	2305	19685	5498
11/2/2019	31344	455	917	28	4062	2890	3600	0	22192	17503	2305	19808	2384
11/9/2019	31344	455	917	28	3819	2460	3600	0	22865	17871	2305	20176	2689
11/16/2019	31344	455	917	28	3185	1169	3600	409	24381	18659	2305	20964	3417
11/23/2019	31344	455	917	28	1097	1169	3600	1201	25677	19428	2305	21733	3944

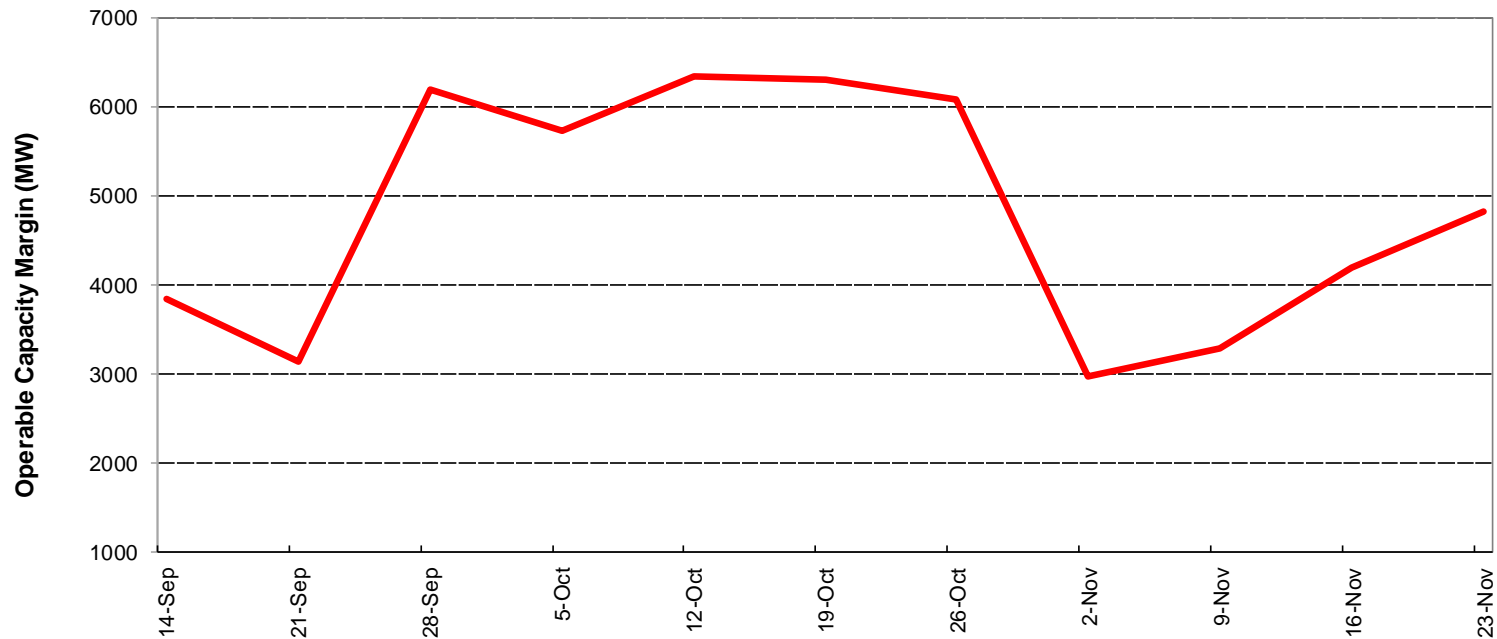
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,212 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

# Fall 2019 Operable Capacity Analysis

## 50/50 Forecast (Reference)

2019 ISO-NEW ENGLAND OPERABLE CAPACITY  
-50/50 CSO-



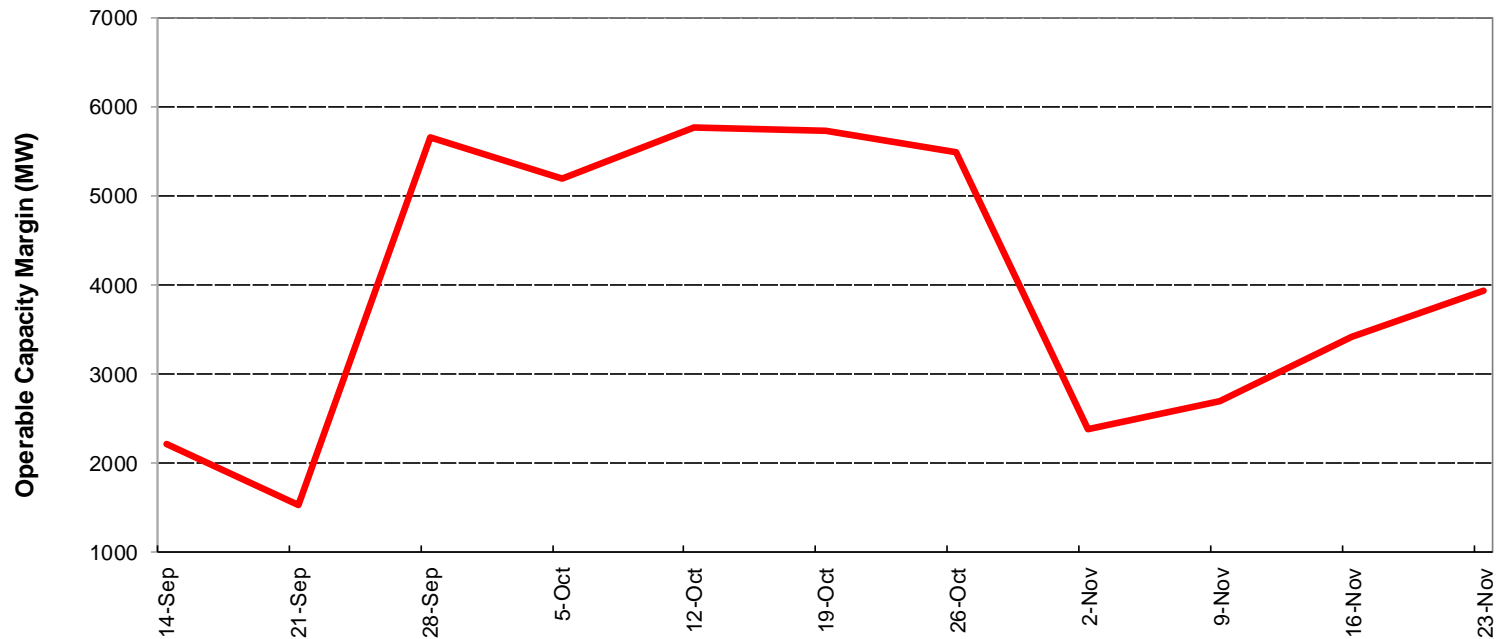
September 14, 2019 - November 29, 2019, W/B Saturday



# Fall 2019 Operable Capacity Analysis

## 90/10 Forecast (Extreme)

2019 ISO-NEW ENGLAND OPERABLE CAPACITY  
-90/10 CSO-



September 14, 2019 - November 29, 2019, W/B Saturday

# OPERABLE CAPACITY ANALYSIS

*Preliminary Winter 2019/20 Analysis*

# Preliminary Winter 2019/20 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January - 2019 <sup>2</sup> CSO (MW)	January - 2019 <sup>2</sup> SCC (MW)
Operable Capacity MW <sup>1</sup>	31,344	33,594
Active Demand Capacity Resource (+) <sup>5</sup>	458	328
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	482	499
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) <sup>4</sup>	2,800	2,800
Generation at Risk Due to Gas Supply (-) <sup>3</sup>	4,207	4,648
Net Capacity (NET OPCAP SUPPLY MW)	25,258	26,920
Peak Load Forecast MW (adjusted for Other Demand Resources) <sup>2</sup>	20,476	20,476
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,781	22,781
Operable Capacity Margin	2,477	4,139

<sup>1</sup>Operable Capacity is based on data as of **August 28, 2019** 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 **August 28, 2019**.

<sup>2</sup> Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 11, 2020**.

<sup>3</sup> Total of (Gas at Risk MW) – (Gas Gen Outages MW).

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

<sup>5</sup> 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.

# Preliminary Winter 2019/20 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January - 2019 <sup>2</sup> CSO (MW)	January - 2019 <sup>2</sup> SCC (MW)
Operable Capacity MW <sup>1</sup>	31,344	33,594
Active Demand Capacity Resource (+) <sup>5</sup>	458	328
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	482	499
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) <sup>4</sup>	2,800	2,800
Generation at Risk Due to Gas Supply (-) <sup>3</sup>	4,674	5,168
Net Capacity (NET OPCAP SUPPLY MW)	24,791	26,400
Peak Load Forecast MW (adjusted for Other Demand Resources) <sup>2</sup>	21,173	21,173
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,478	23,478
Operable Capacity Margin	1,313	2,922

<sup>1</sup>Operable Capacity is based on data as of **August 28, 2019** 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 **August 28, 2019**.

<sup>2</sup> Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 11, 2020**.

<sup>3</sup> Total of (Gas at Risk MW) – (Gas Gen Outages MW).

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

<sup>5</sup> 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.

# Preliminary Winter 2019/20 Operable Capacity Analysis

## 50/50 Forecast (Reference)

### ISO-NE OPERABLE CAPACITY ANALYSIS

September 1, 2019 - 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, and 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]
11/30/2019	31344	458	917	28	959	333	3200	2325	25930	19232	2305	21537	4393
12/7/2019	31344	458	917	28	920	333	3200	2786	25508	19532	2305	21837	3671
12/14/2019	31344	458	917	28	875	0	3200	3301	25371	19543	2305	21848	3523
12/21/2019	31344	458	917	28	330	0	3200	3621	25596	19608	2305	21913	3683
12/28/2019	31344	458	917	28	330	0	3200	3967	25250	19993	2305	22298	2952
1/4/2020	31344	458	917	28	329	279	2800	3806	25533	20476	2305	22781	2752
1/11/2020	31344	458	917	28	482	0	2800	4207	25258	20476	2305	22781	2477
1/18/2020	31344	458	917	28	482	0	2800	4014	25451	20476	2305	22781	2670
1/25/2020	31344	458	917	28	482	0	2800	3737	25728	20245	2305	22550	3178
2/1/2020	31344	458	917	28	545	0	3100	3737	25365	19967	2305	22272	3093
2/8/2020	31344	458	917	28	545	0	3100	3322	25780	19937	2305	22242	3538
2/15/2020	31344	458	917	28	498	0	3100	3045	26104	19664	2305	21969	4135
2/22/2020	31344	458	917	28	405	0	3100	2492	26750	18636	2305	20941	5809
2/29/2020	31344	458	917	28	1188	267	2200	1809	27283	18273	2305	20578	6705
3/7/2020	31344	458	917	28	1219	279	2200	1659	27390	18069	2305	20374	7016
3/14/2020	31344	458	917	28	1219	647	2200	737	27944	17690	2305	19995	7949
3/21/2020	31344	458	917	28	1823	650	2200	319	27755	17102	2305	19407	8348

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 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 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  $(9 - 12 = 13)$

# Preliminary Winter 2019/20 Operable Capacity Analysis

## 90/10 Forecast (Extreme)

### ISO-NE OPERABLE CAPACITY ANALYSIS

September 1, 2019 - 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, and 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]
11/30/2019	31344	458	917	28	959	333	3200	2620	25635	19886	2305	22191	3444
12/7/2019	31344	458	917	28	920	333	3200	3132	25162	20194	2305	22499	2663
12/14/2019	31344	458	917	28	875	0	3200	3668	25004	20206	2305	22511	2493
12/21/2019	31344	458	917	28	330	0	3200	4023	25194	20273	2305	22578	2616
12/28/2019	31344	458	917	28	330	0	3200	4408	24809	20674	2305	22979	1830
1/4/2020	31344	458	917	28	329	279	2800	4260	25079	21173	2305	23478	1601
1/11/2020	31344	458	917	28	482	0	2800	4674	24791	21173	2305	23478	1313
1/18/2020	31344	458	917	28	482	0	2800	4460	25005	21173	2305	23478	1527
1/25/2020	31344	458	917	28	482	0	2800	4153	25312	20934	2305	23239	2073
2/1/2020	31344	458	917	28	545	0	3100	4153	24949	20648	2305	22953	1996
2/8/2020	31344	458	917	28	545	0	3100	3691	25411	20617	2305	22922	2489
2/15/2020	31344	458	917	28	498	0	3100	3384	25765	20336	2305	22641	3124
2/22/2020	31344	458	917	28	405	0	3100	2768	26474	19277	2305	21582	4892
2/29/2020	31344	458	917	28	1188	267	2200	2040	27052	18903	2305	21208	5844
3/7/2020	31344	458	917	28	1219	279	2200	1874	27175	18693	2305	20998	6177
3/14/2020	31344	458	917	28	1219	647	2200	891	27790	18302	2305	20607	7183
3/21/2020	31344	458	917	28	1823	650	2200	427	27647	17697	2305	20002	7645

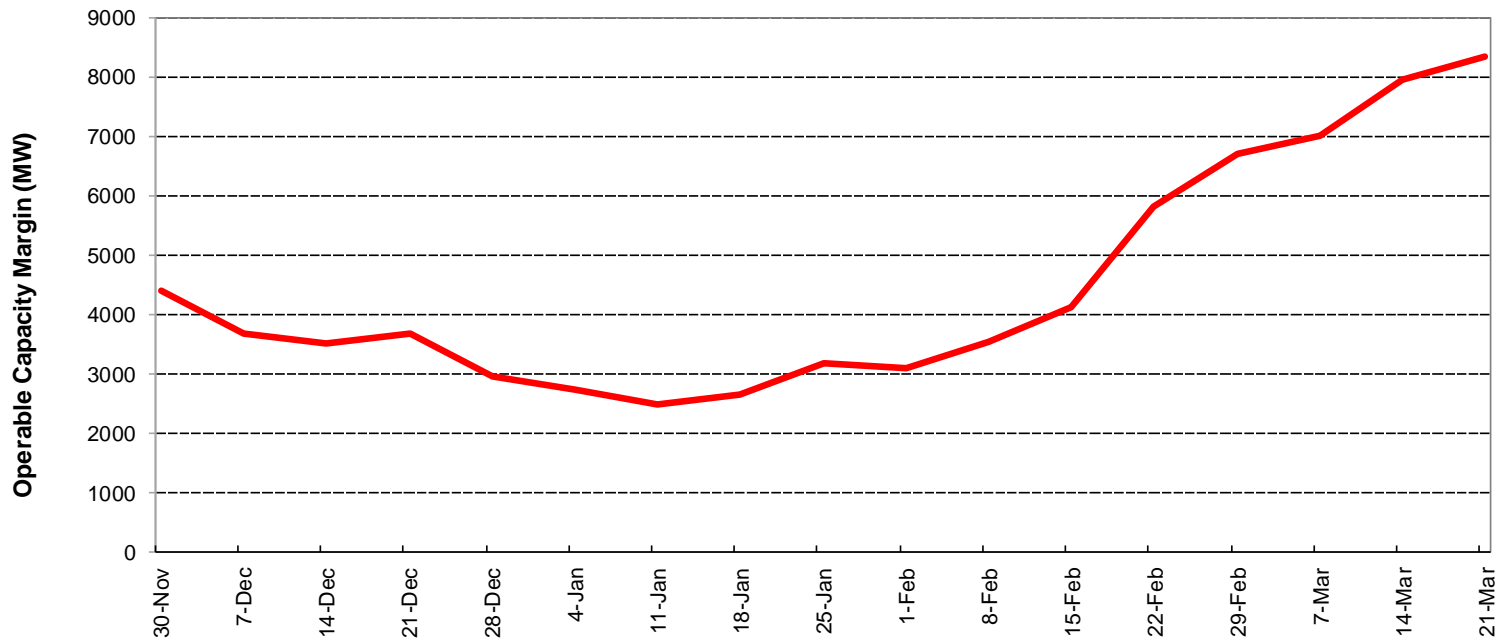
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,212 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

# Preliminary Winter 2019/20 Operable Capacity Analysis

## 50/50 Forecast (Reference)

2019 ISO-NEW ENGLAND OPERABLE CAPACITY  
-50/50 CSO-

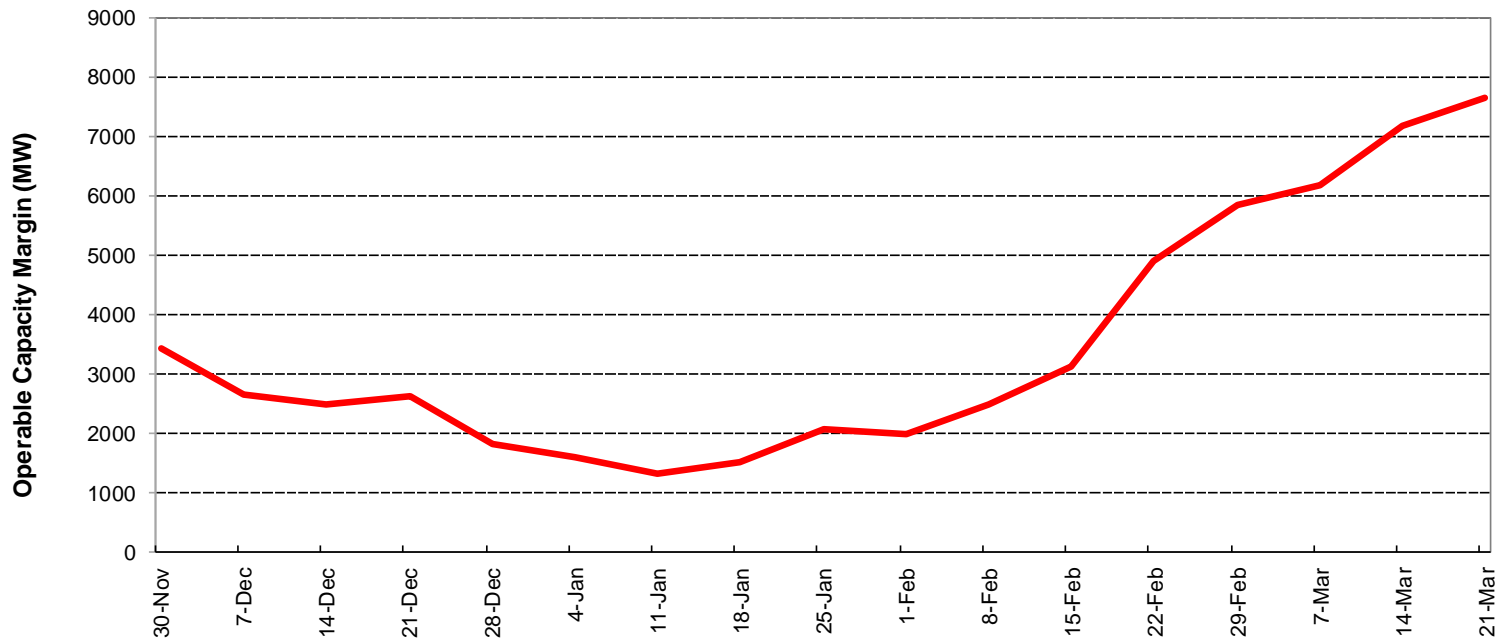


November 30, 2019- March 27, 2020, W/B Saturday

# Preliminary Winter 2019/20 Operable Capacity Analysis

## 90/10 Forecast (Extreme)

2019 ISO-NEW ENGLAND OPERABLE CAPACITY  
-90/10 CSO-



November 30, 2019- March 27, 2020, W/B Saturday



# 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 <sup>1</sup>  600
2	Declare Energy Emergency Alert (EEA) Level 1 <sup>4</sup>	0
3	Voluntary Load Curtailment of Market Participants’ facilities.	40 <sup>2</sup>
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 <sup>3</sup>

## 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 voluntarily provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 <sup>3</sup>
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 <sup>2</sup>
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 <sup>2</sup>
11	Request State Governors to Reinforce Power Warning Appeals.	100 <sup>2</sup>
Total		<b>2,520</b>

## 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