NEPOOL PARTICIPANTS COMMITTEE
02/02/18 MEEITNG, AGENDA ITEM #4

NEPOOL Participants Committee Report

February 2018

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value over the period was $1.1B, up $285M from December 2017 and up $684M from January 2017
  - January natural gas prices over the period were 77% higher than December 2017 average values
  - Average RT Hub Locational Marginal Prices ($119.14/MWh) over the period were 49% higher than December averages
    - DA Hub LMP averaged $118.29/MWh
  - Average January 2018 natural gas prices and RT Hub LMPs over the period were up 237% and 225%, respectively, from January 2017 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.9% during January, down slightly from 99.2% during December*

Data are through January 24, 2018 (NCPC through Jan. 23) unless otherwise noted.

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

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

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - January NCPC payments totaled $19.6M over the period, up $12.6M from December and up $15.2M from January 2017
    - First Contingency* payments totaled $17.9M, up $12.5M from December
      - $17.8M paid to internal resources, up $12.5M from December
        - » $2.8M charged to DALO, $6.8M to RT Deviations, $8.3M to RTLO
      - $58K paid to resources at external locations, down $48K from December
        - » $58K to RT Deviations
    - Second Contingency payments totaled $1.6M, up $1.1M from December
      - Virtually all charged to NEMA for protection on January 5
    - Voltage payments totaled $98K, down $954K from December
    - Distribution payments totaled zero, down $2K from December
  - NCPC payments over the period as percent of Energy Market value were 1.7%

*** NCPC types reflected in the First Contingency Amount: Posturing - $7.2M; Dispatch Lost Opportunity Cost (DLOC) - $590K; Rapid Response Pricing (RRP) Opportunity Cost - $429K; Generator Performance Auditing (GPA) - $55K;**

Highlights, cont.

- 2017 Economic Study draft results are scheduled for discussion at the February 14 Planning Advisory Committee meeting
- The twelfth Forward Capacity Auction (FCA #12) for the May 2021 – June 2022 Capacity Commitment Period is scheduled to begin on Monday, February 5
- The 2018 long-term forecast cycle is underway
  - The Load Forecast Committee, Energy-Efficiency Forecast Working Group, and Distributed Generation Forecast Working Group all have meetings scheduled in February

Forward Capacity Market (FCM) Highlights

- CCP #8 (2017-2018)
  - Monthly activities continue
  - New, non-commercial resources are attempting to cover in the monthly activities
- CCP #9 (2018-2019)
  - Third bilateral transaction window closed on December 8, 2017 and results were posted on January 12, 2018
  - Third reconfiguration auction will be March 1-5, 2018, and results to be posted by March 19, 2018
- CCP #10 (2019-2020)
  - Second bilateral transaction window will be May 2-4, 2018
  - Second reconfiguration auction will be August 1-3, 2018

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #11 (2020-2021)
  - First bilateral transaction window will be April 4-6, 2018
  - First reconfiguration auction will be June 1-5, 2018
- CCP #12 (2021-2022)
  - FERC Informational Filing was made on November 7, 2017 and was accepted by FERC on January 19, 2018
  - ICR & related values were filed with FERC on November 7, 2017 and accepted by FERC on December 18, 2017
  - Auction will commence on February 5, 2018
  - The Renewable Technology Resource election cap is approximately 514 MW

FCM Highlights, cont.

- CCP #13 (2022-2023)
  - Topology certification complete and results were presented to the RC on January 17, 2018
  - Preliminary capacity zones were discussed at the PAC in November and final capacity zones to be decided in April, after priced retirement and permanent delist bids are received
  - Upcoming Training
    - New Capacity Offer Price Development for Cost Workbooks: February 15
    - Show of Interest for Prospective New Capacity Resources: February 27
    - New Capacity Qualification Package Submittal: May 1
  - Enhancements to the FCM Participation Guide to reflect recent changes for price-responsive demand and CASPR are underway

CASPR – Competitive Auctions with Sponsored Policy Resources

FERC Order 1000

- Intraregional Planning
  - Several parties have submitted information to be considered as Qualified Transmission Project Sponsors (QTPS's), and 20 companies have been approved

Highlights, cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margin Week is projected for week beginning January 27, 2018.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margin Week is projected for week beginning May 5, 2018.

2017/18 Winter Reliability Program As of December 1, 2017

- **Oil Program**
  - As of December 1st, participation from 86 units for a total of 3.868 million barrels of oil
  - 2.867 million barrels of the total inventory on December 1 are eligible for compensation per the winter program rules
  - Total oil program cost exposure is expected to be $29.62M (@$10.33/barrel)
- **LNG Program**
  - As of December 1st, no participation
- **DR Program**
  - As of December 1st, participation from 3 assets providing 7.5 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $23.2K

2017/18 Winter Program Usage as of January 1, 2017

- Winter Program Oil Inventory Changes:
  - Dec 2017: 548,410 BBLs
- Winter Program DR Events:
  - Dec 2017: none
- Please note that January Data is not available until the week of Feb 5 and will be sent to Participants as soon as it is compiled

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal 0.4°F Max: 61°F, Min: -2°F Precipitation: 4.77" – Above Normal Normal: 3.04" Snow: 15.4"	Hartford	Temperature: Below Normal 1.3°F Max: 60, Min: -9 Precipitation: 3.83" - Above Normal Normal: 2.91" Snow: 13.2"

Peak Load:	20,631 MW	Jan 5, 2018	18:00 (ending)

MLCC2:	**Reason:** Extreme weather followed by extreme cold temperatures	**Declared:** Jan 3, 2018 16:00 **Cancelled:** Jan 9, 2018 12:00
OP-4 : None		
NPCC Simultaneous Activation of Reserve Events:		
Date	Area	MW
Jan 1	PJM	700
Jan 3	PJM	1000
Jan 4	ISO NE	680
Jan 7	NYISO	600
Jan 7	IESO	600
Jan 25	ISO NE	700

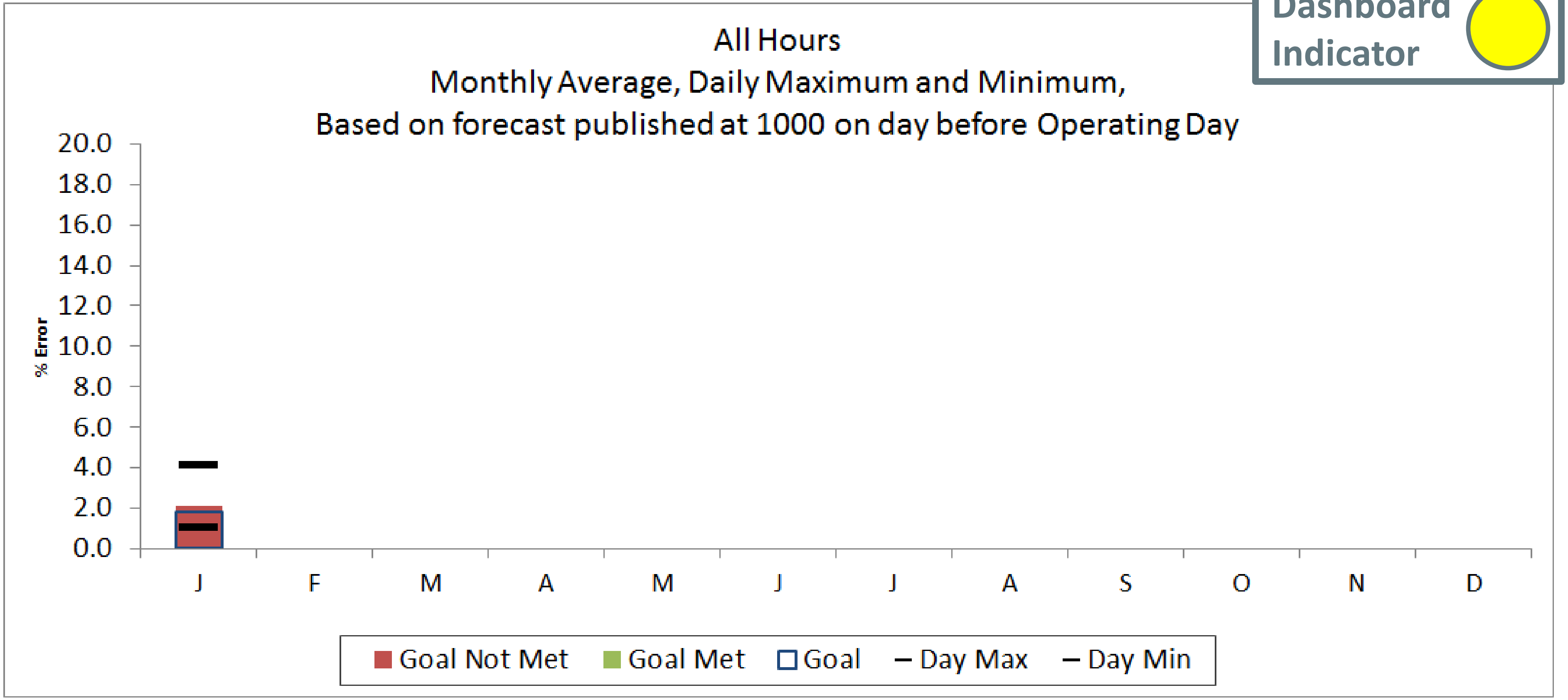
System Operations, cont.

Minimum Generation Warnings & Events:

None		

2018 System Operations - Load Forecast Accuracy

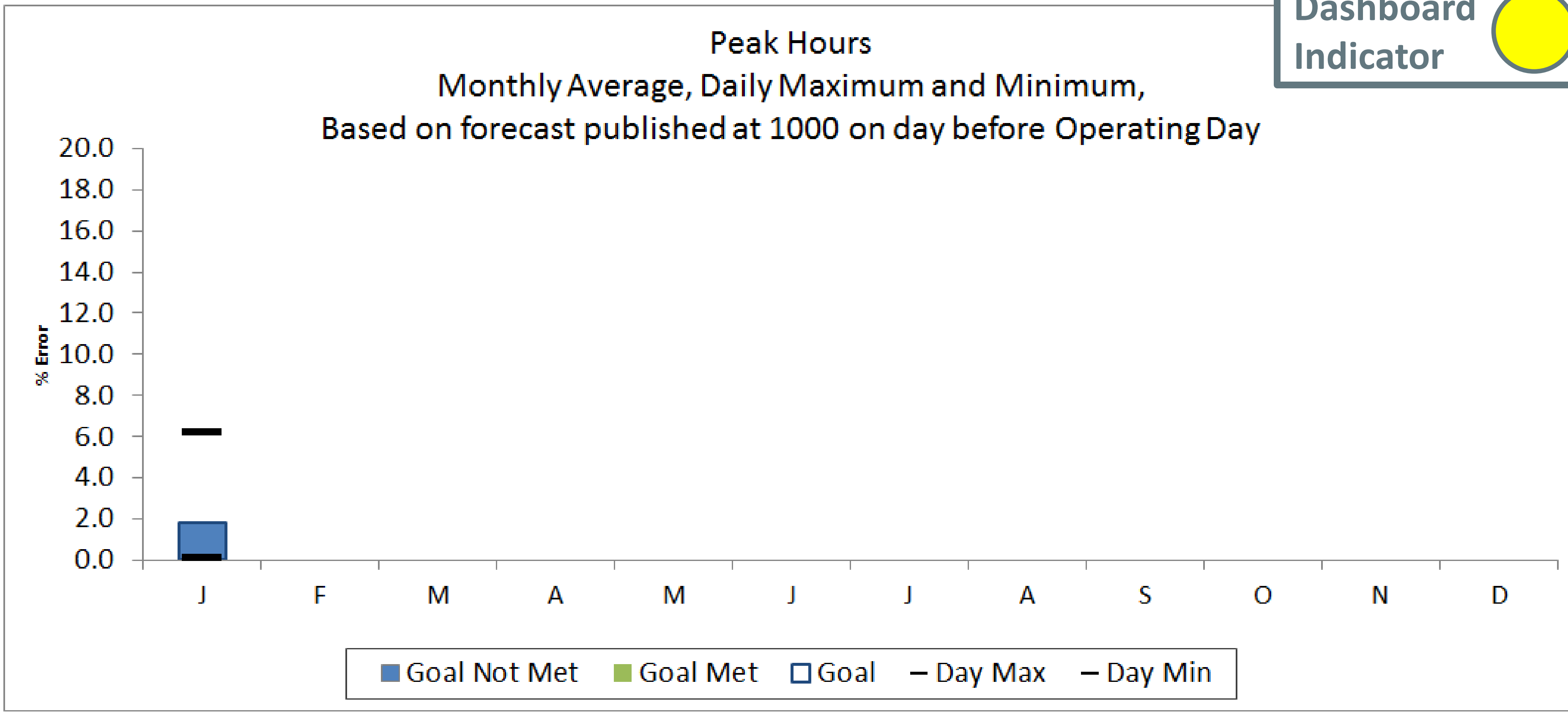
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05												4.05
Day Min	1.02												1.02
MAPE	2.08												2.08
Goal	1.80												

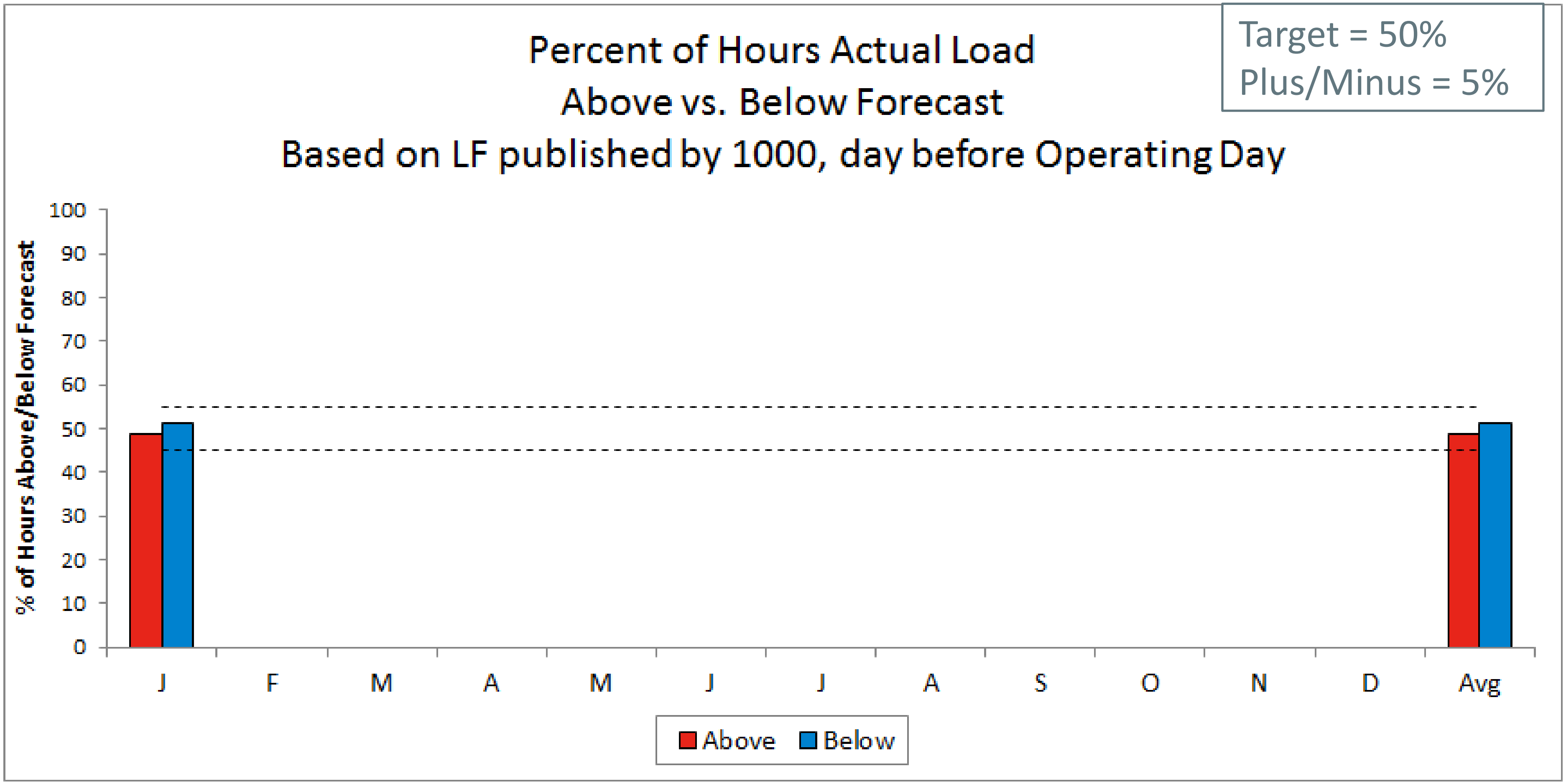
2018 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



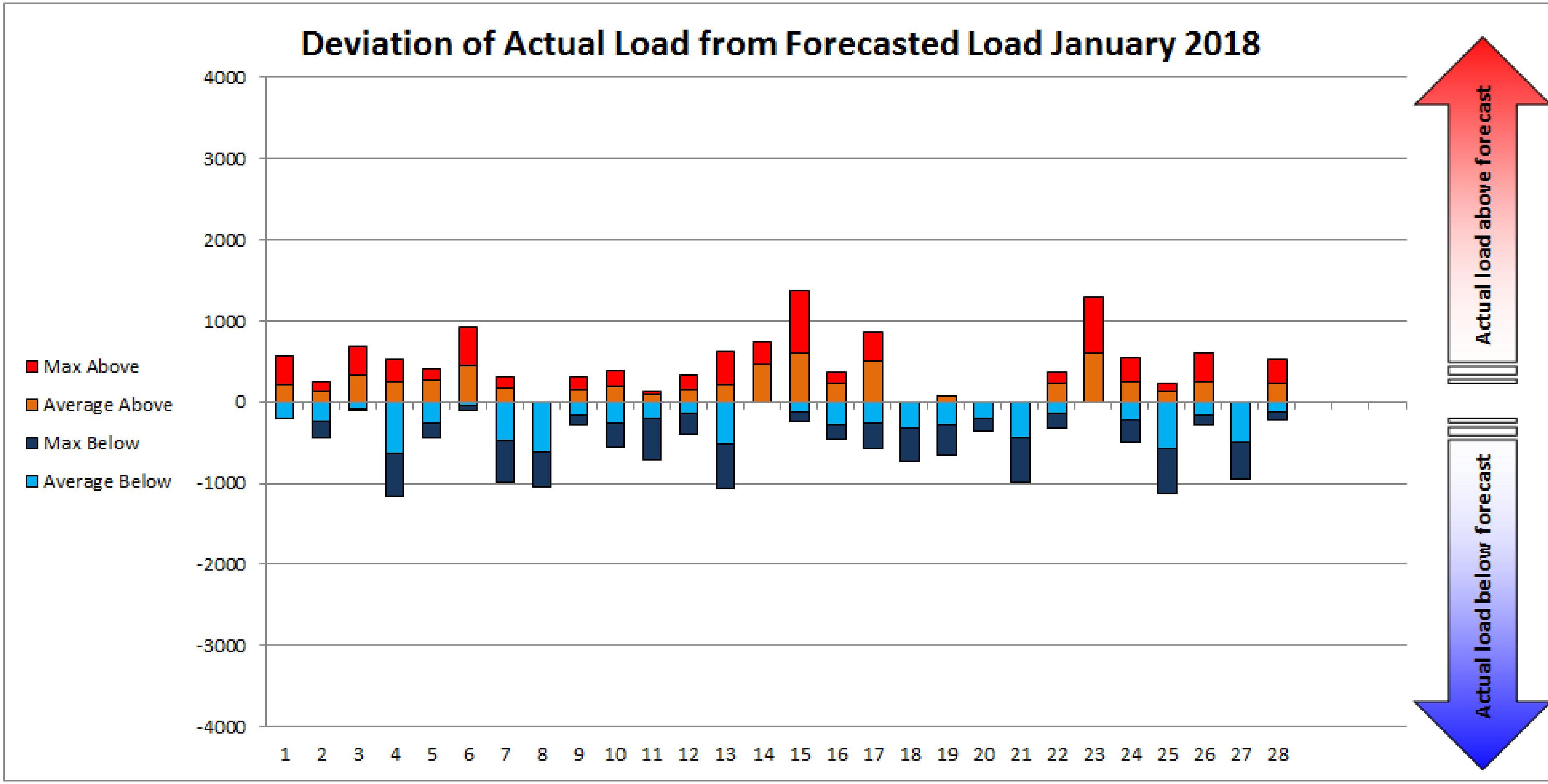
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.15												6.15
Day Min	0.04												0.04
MAPE	1.82												1.82
Goal	1.80												

2018 System Operations - Load Forecast Accuracy cont.

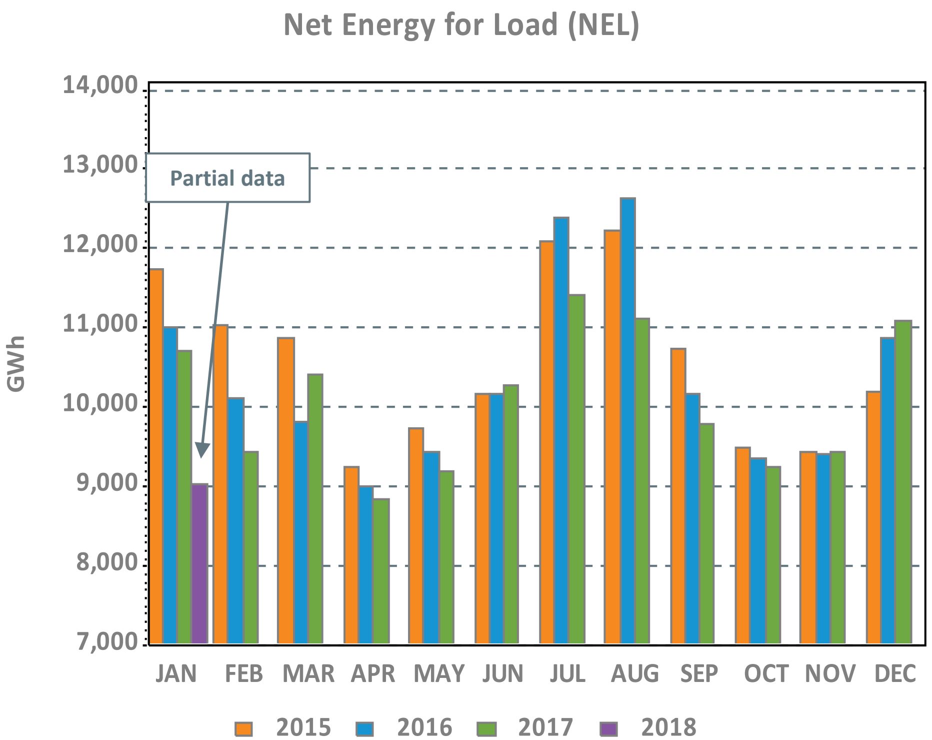


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	48.7												49
Below %	51.3												51
Avg Above	197.1												197
Avg Below	-242.3												-242
Avg All	-24												-24

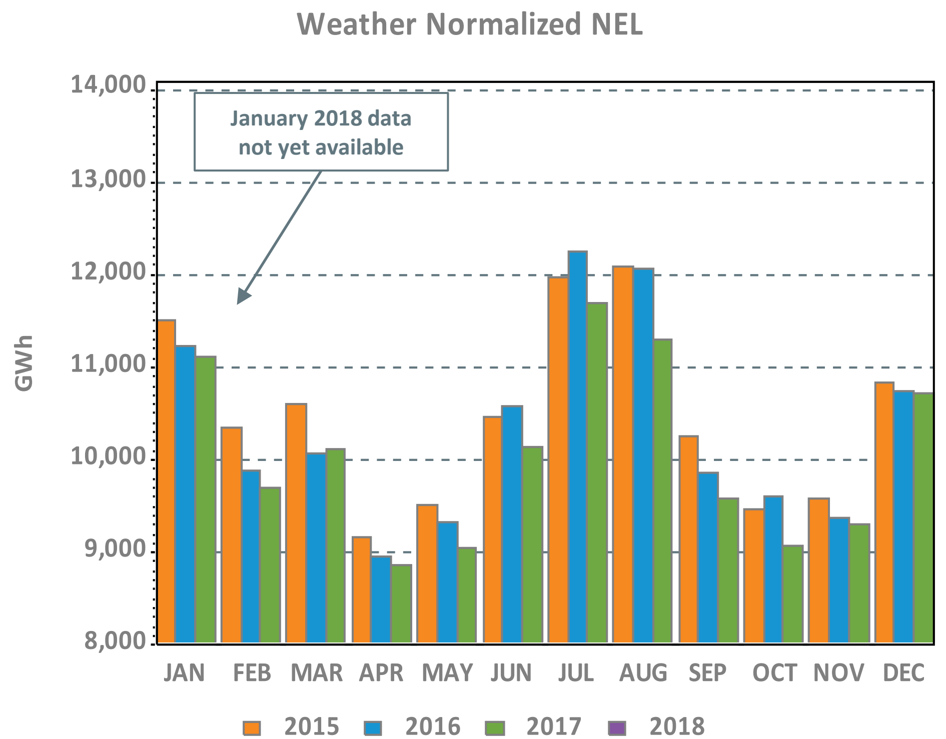
2018 System Operations - Load Forecast Accuracy cont.



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



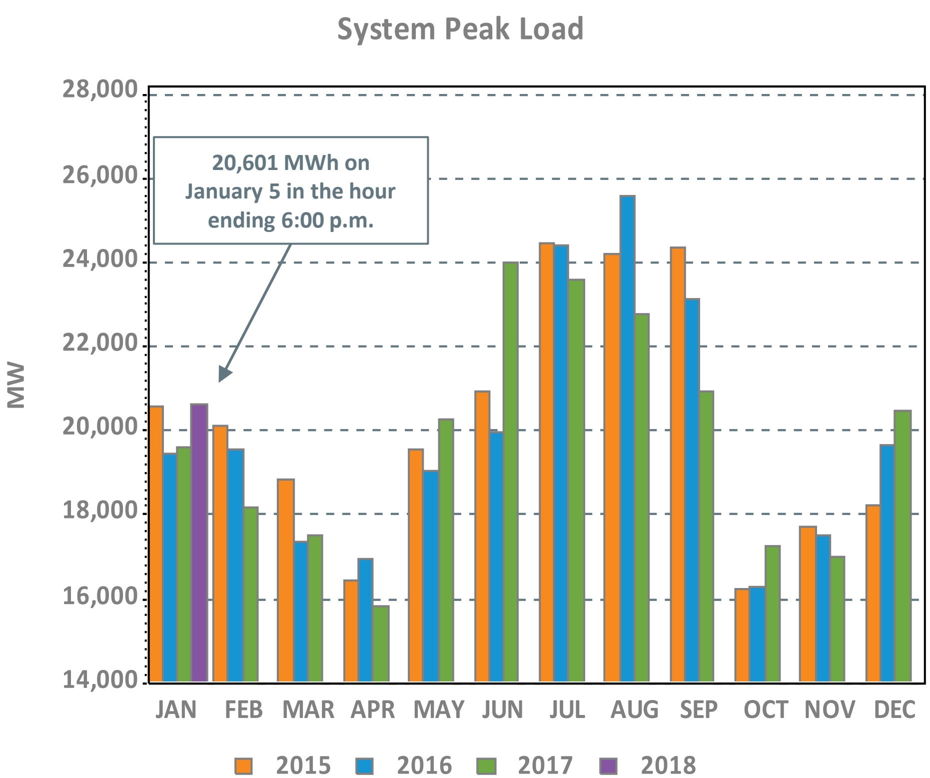
Ann Tot (TWh): 127.0 124.4 121.1 9.0



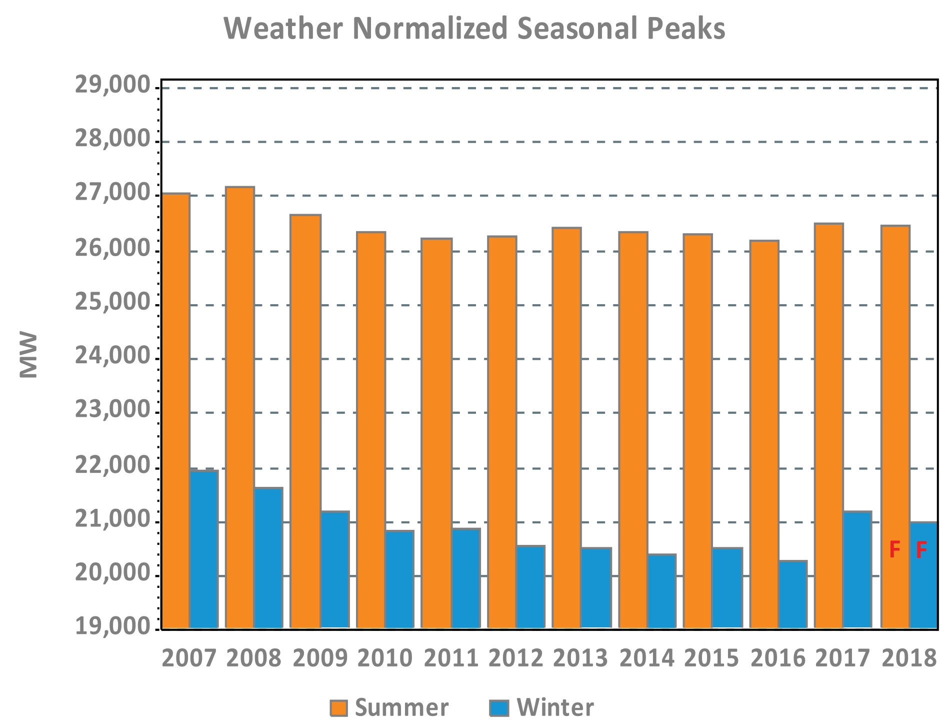
Ann Tot (TWh): 125.8 124.0 120.7 Pending

NEPOOL NEL is the total net 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



*Revenue quality metered value

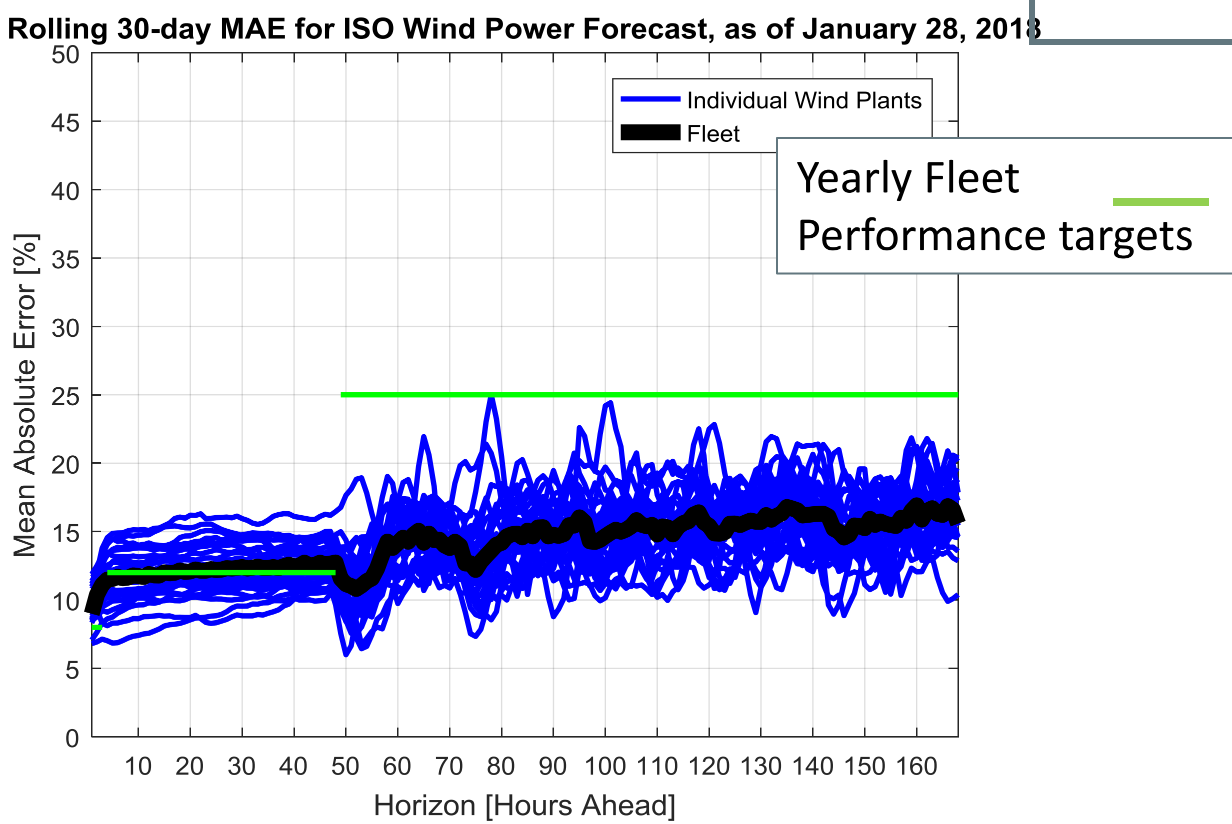


Winter beginning in year displayed

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

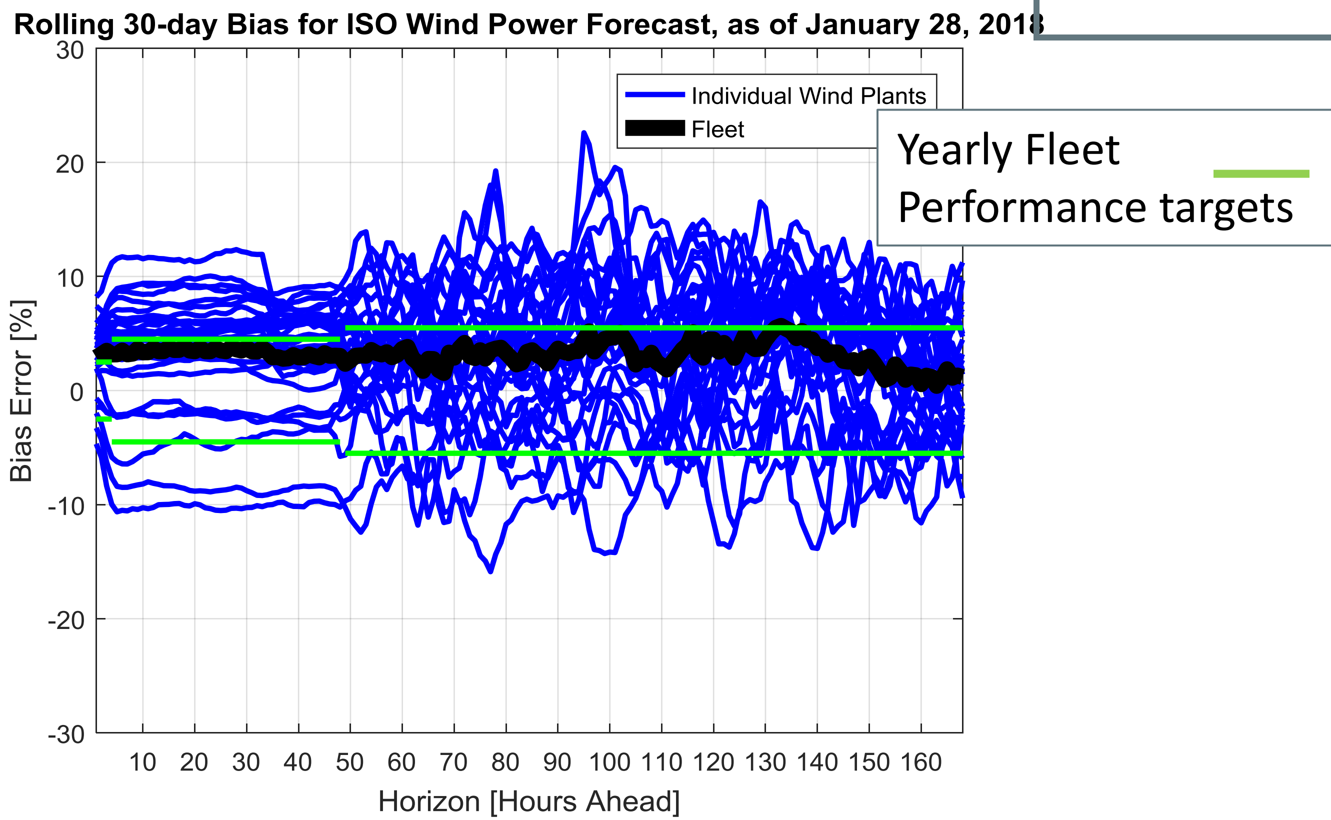
Dashboard Indicator



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 mostly well-within the yearly performance targets.

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

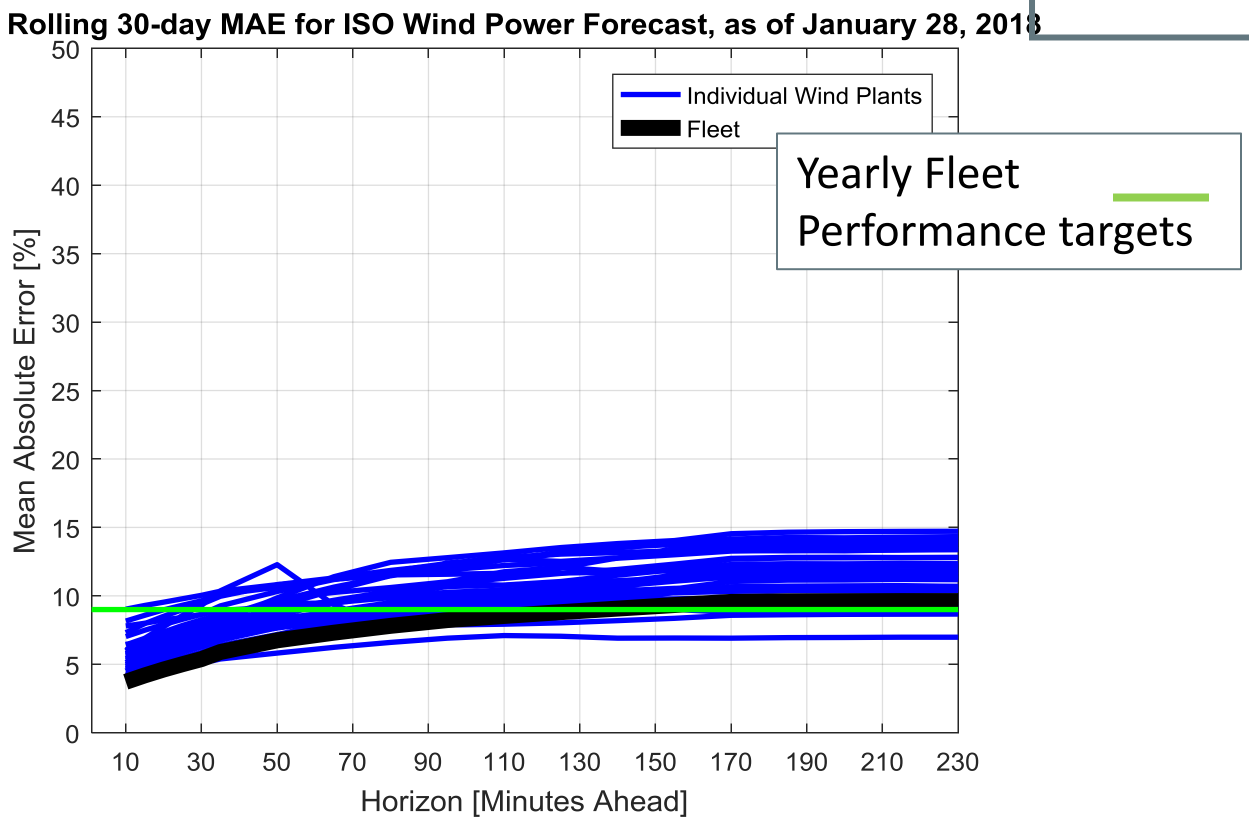
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator



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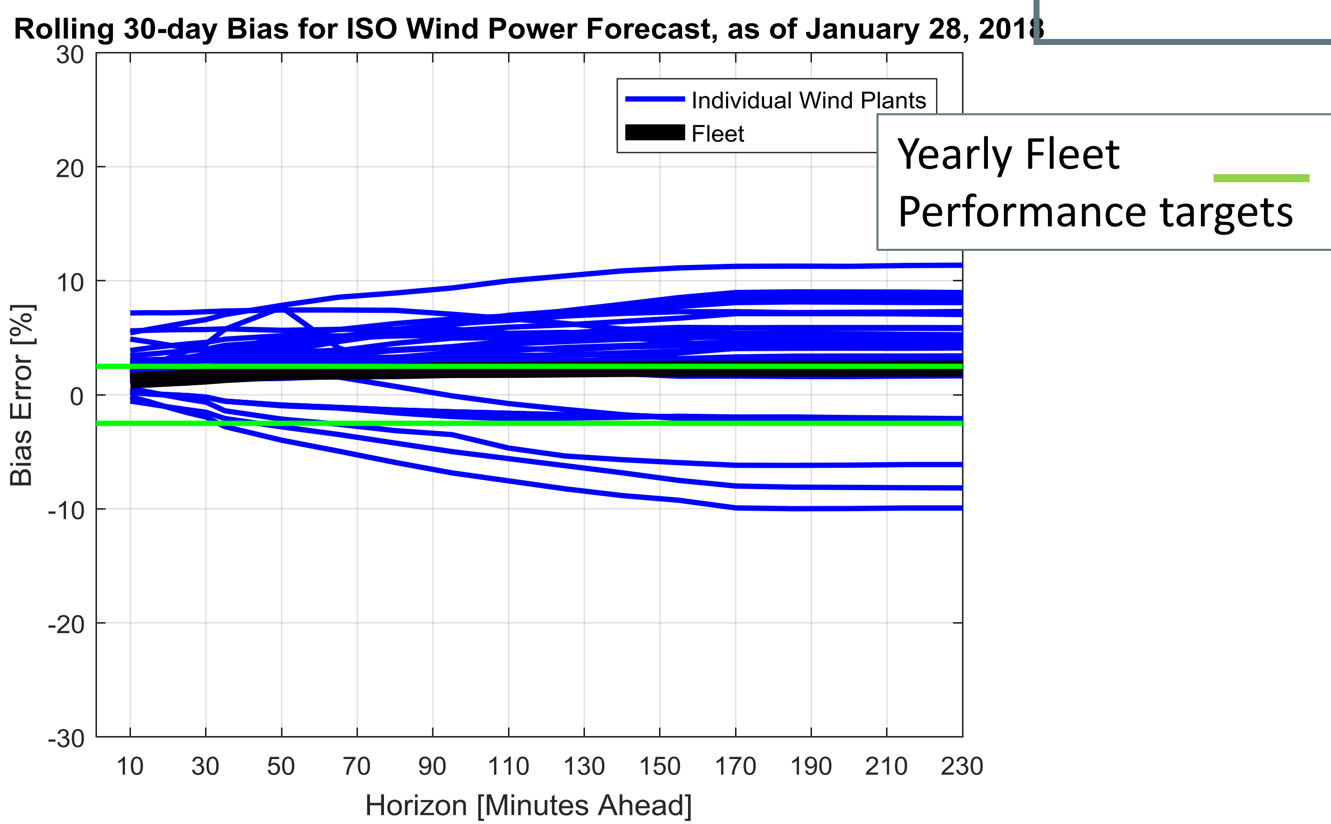

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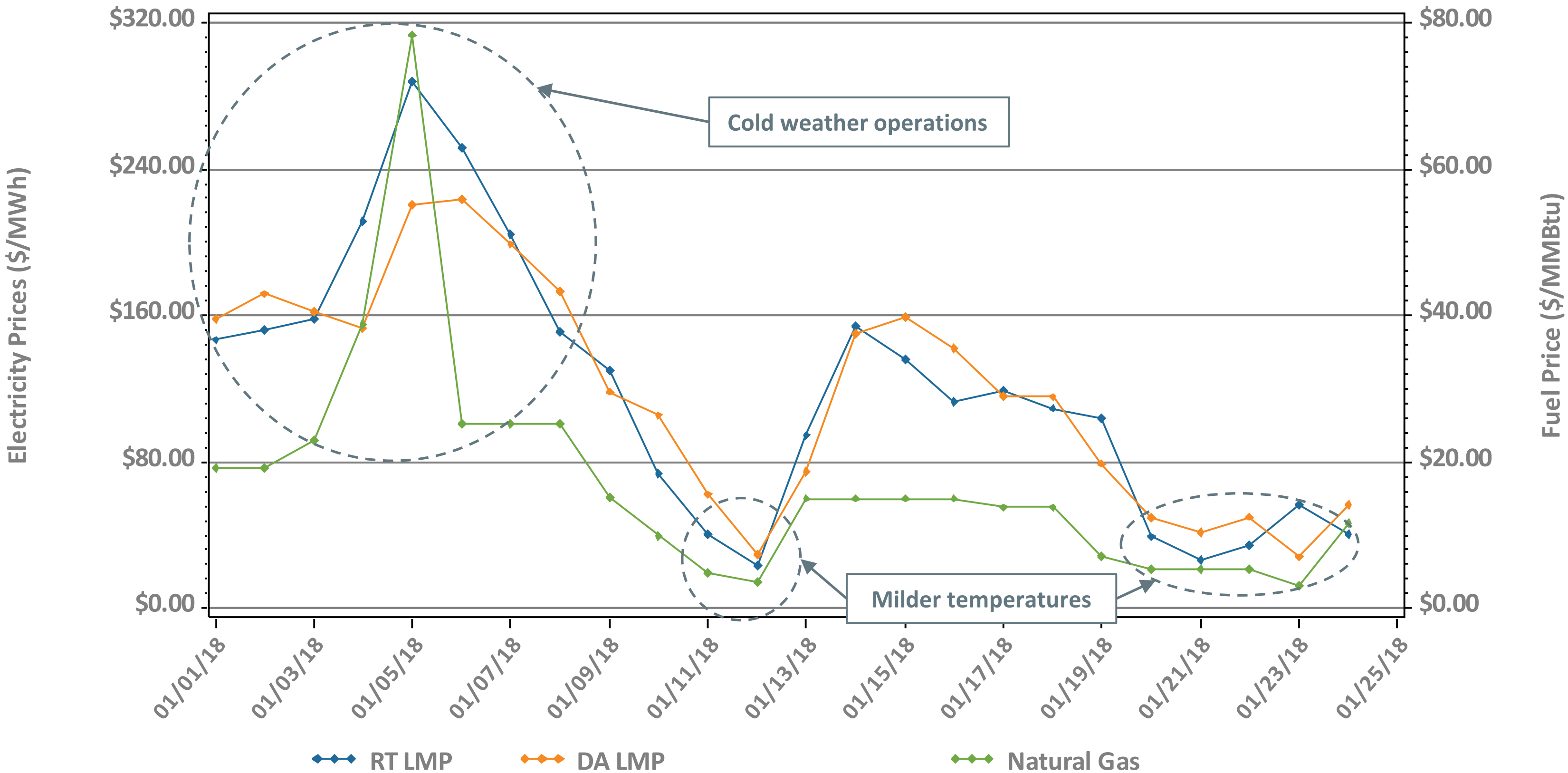
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: January 1-24, 2018



Underlying natural gas data furnished by:

ICE Global markets in clear view

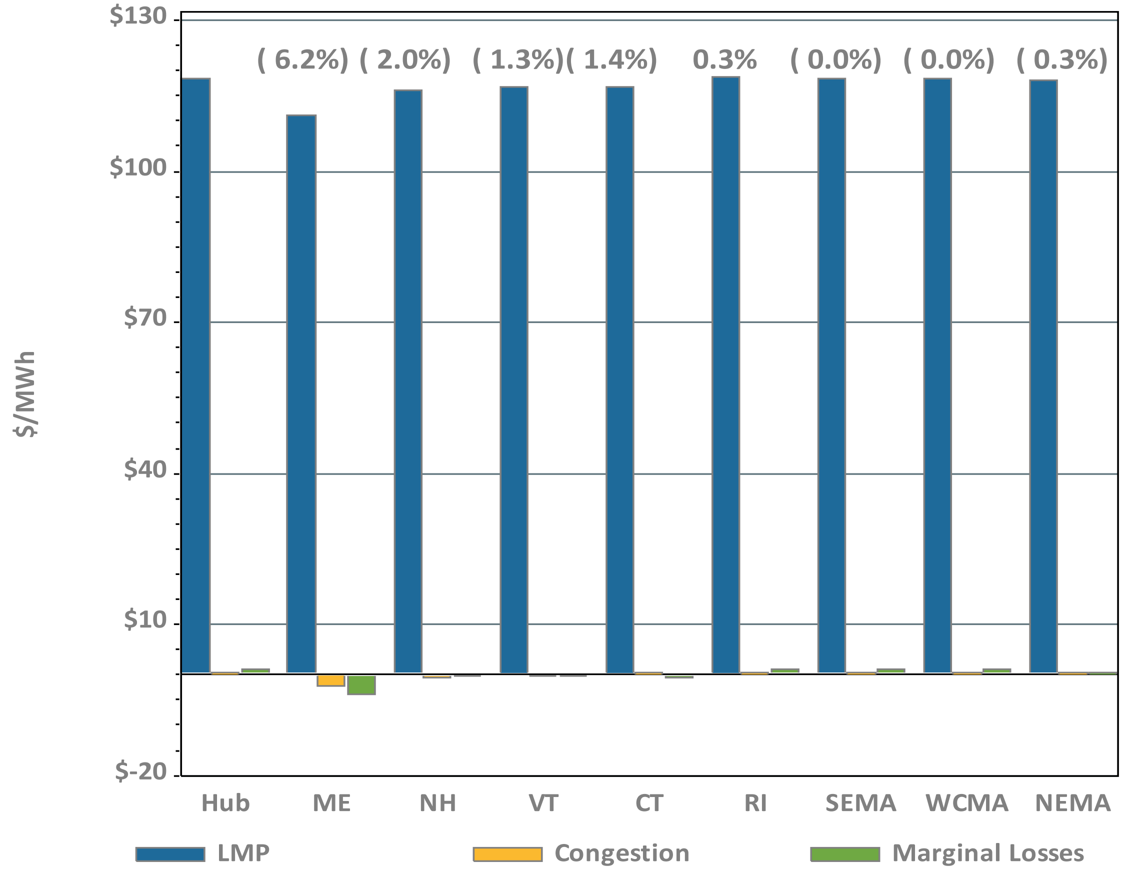
Average price difference over this period (DA-RT): $-0.85

Average price difference over this period ABS(DA-RT): $20.15

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

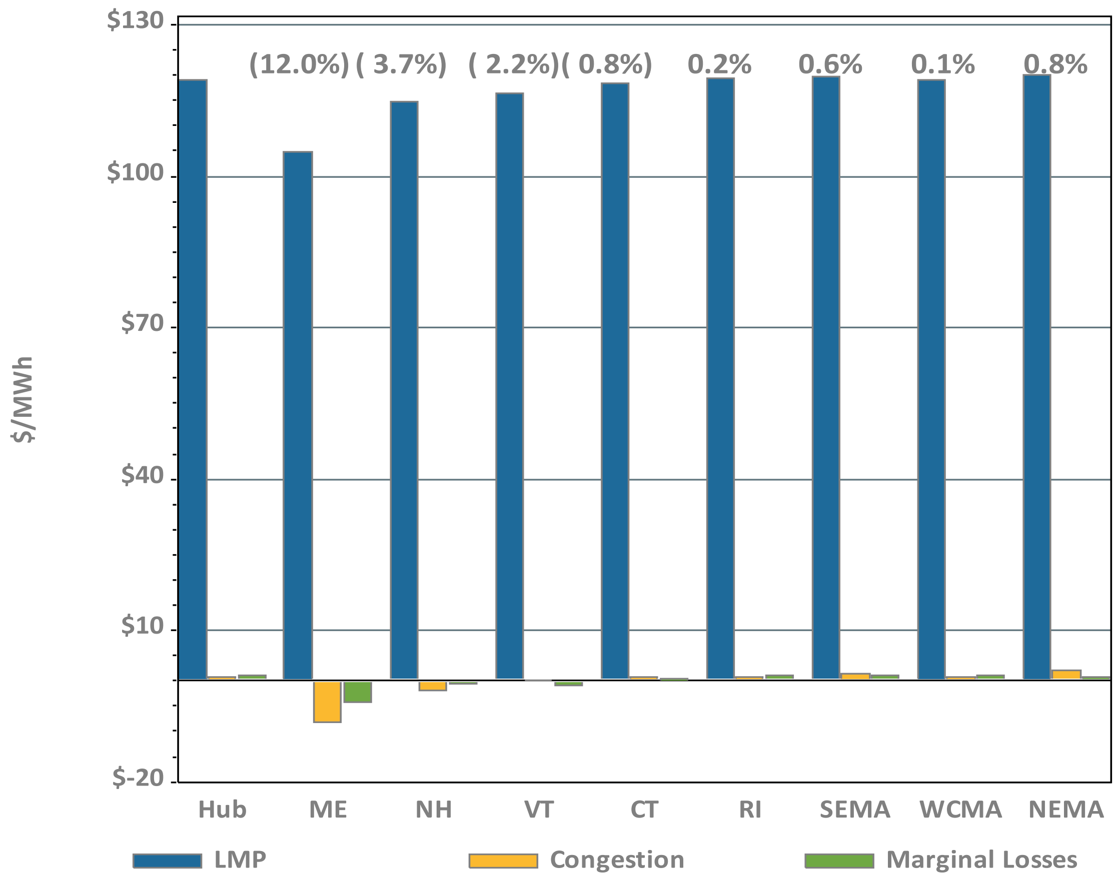
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, January 2018



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

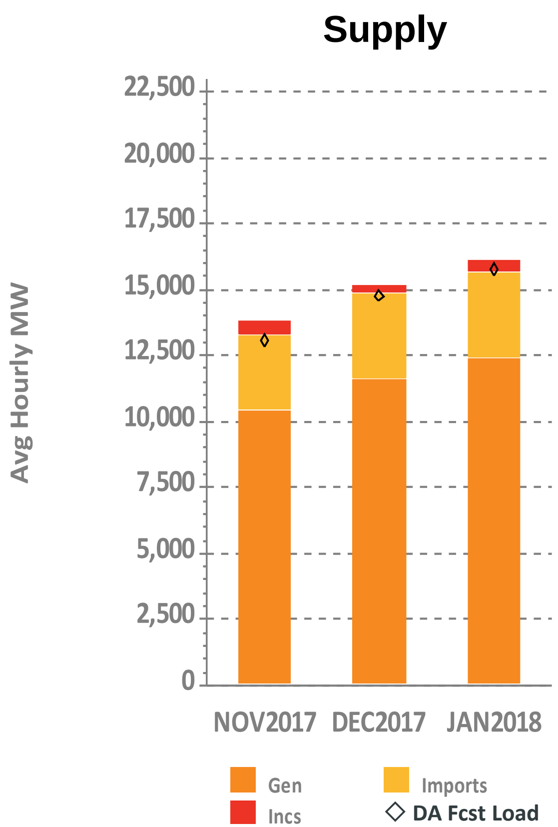
RT LMPs Average by Zone & Hub, January 2018



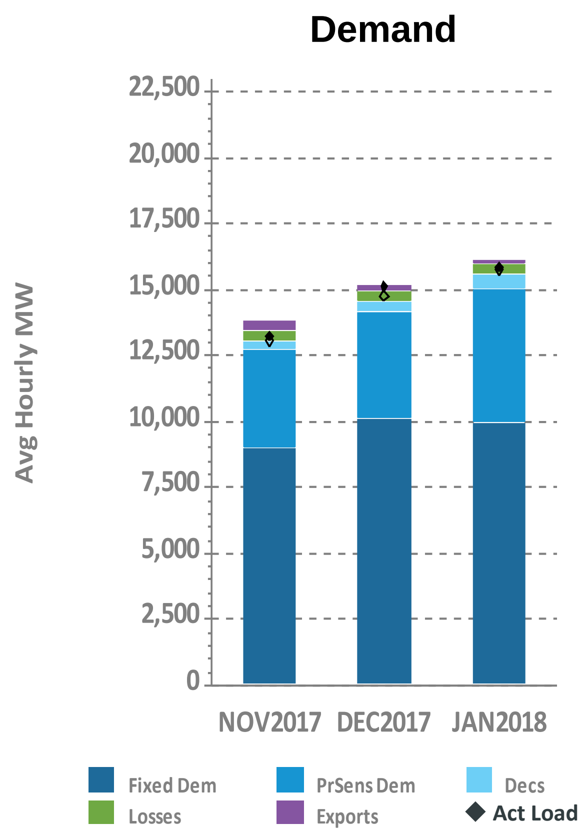
Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

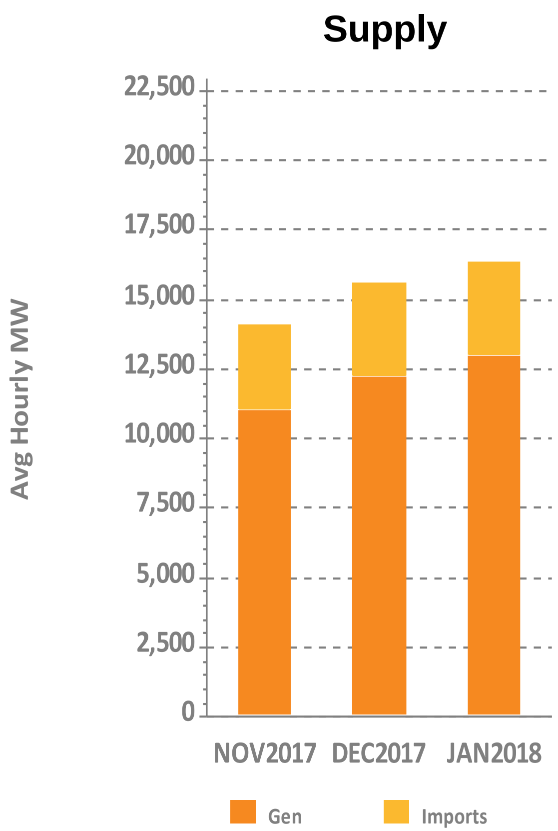


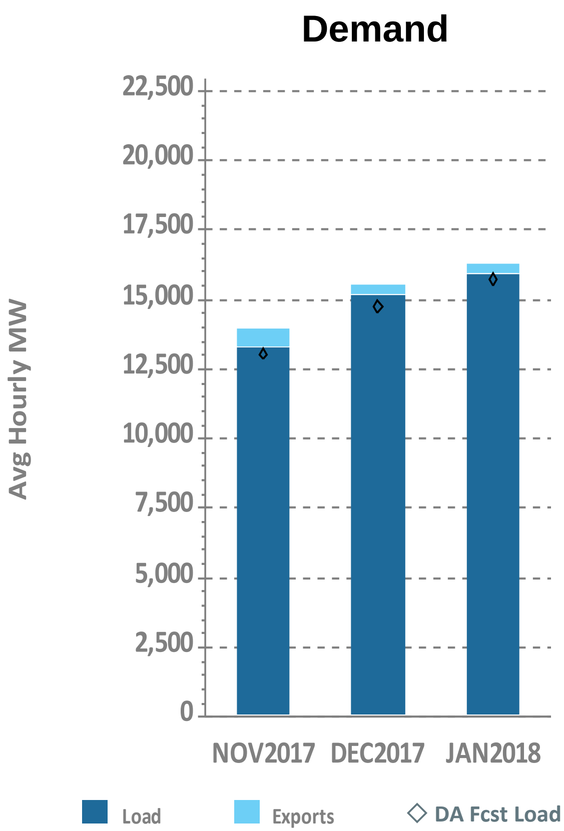
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



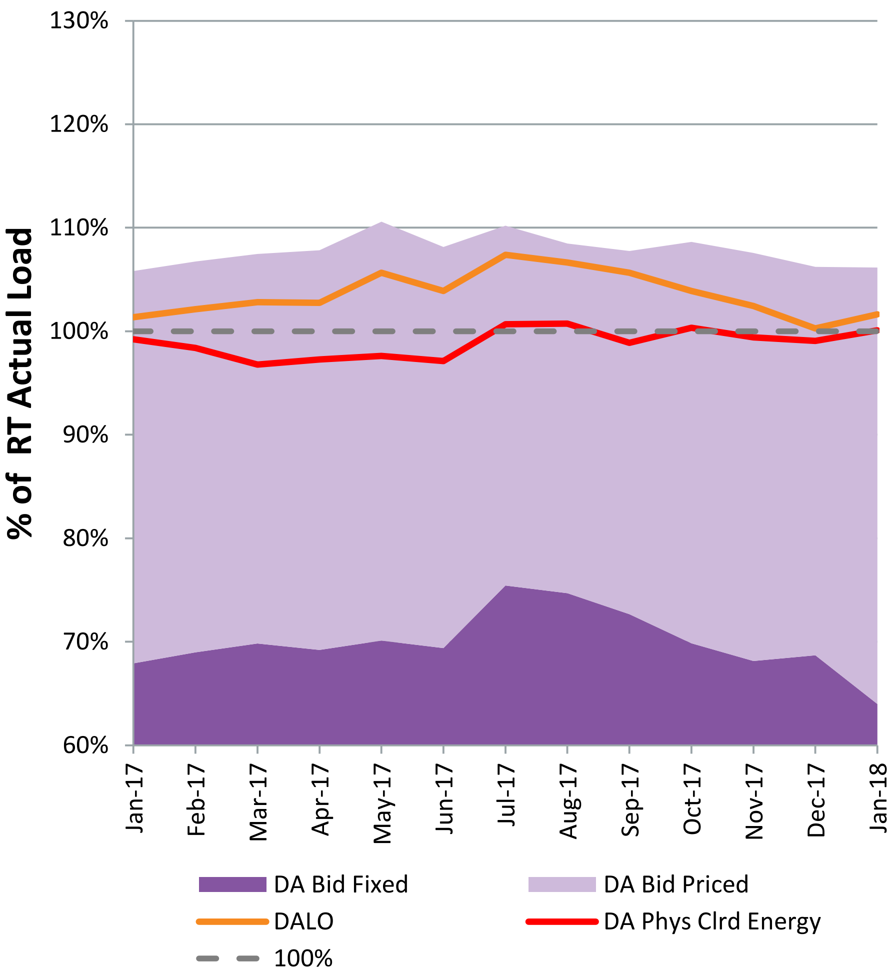
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

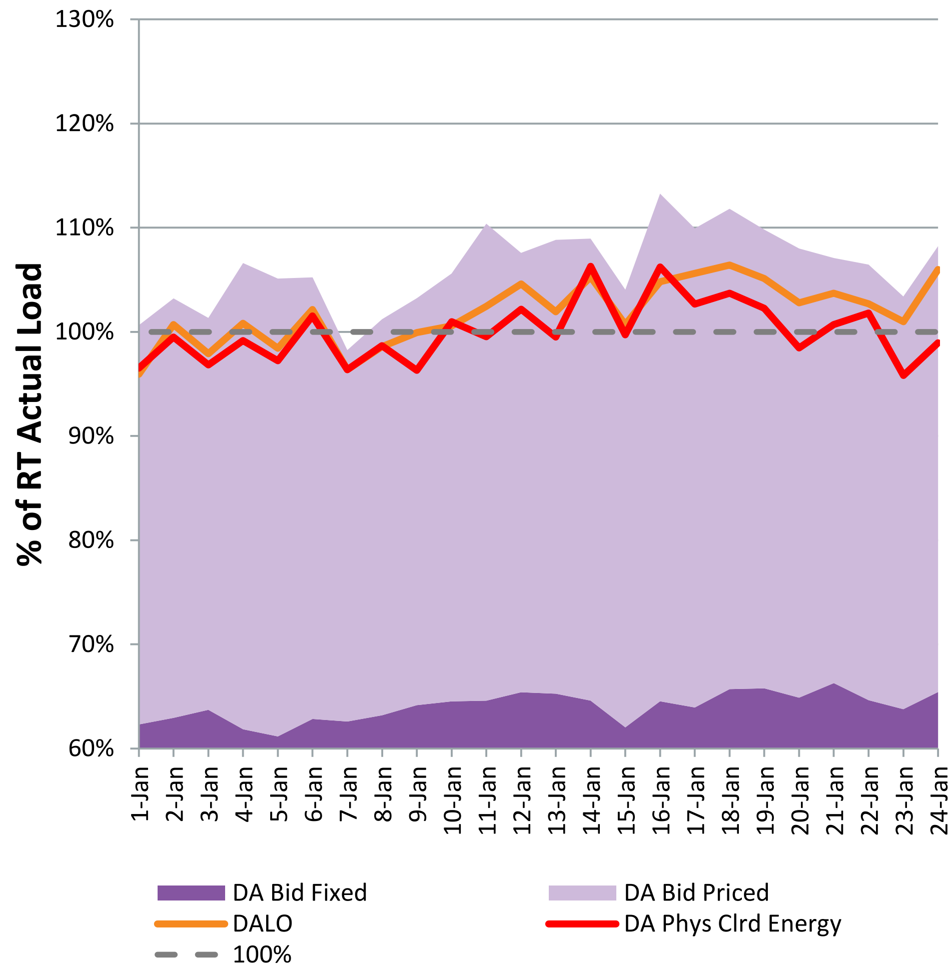
Components of RT Supply and Demand – Last Three Months





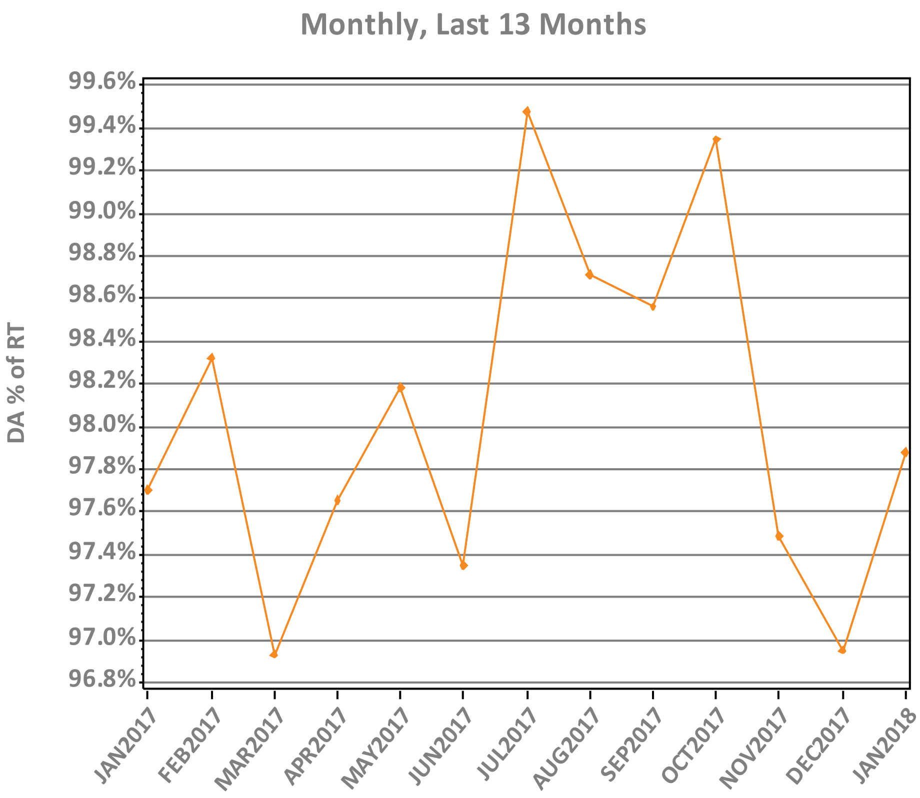
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

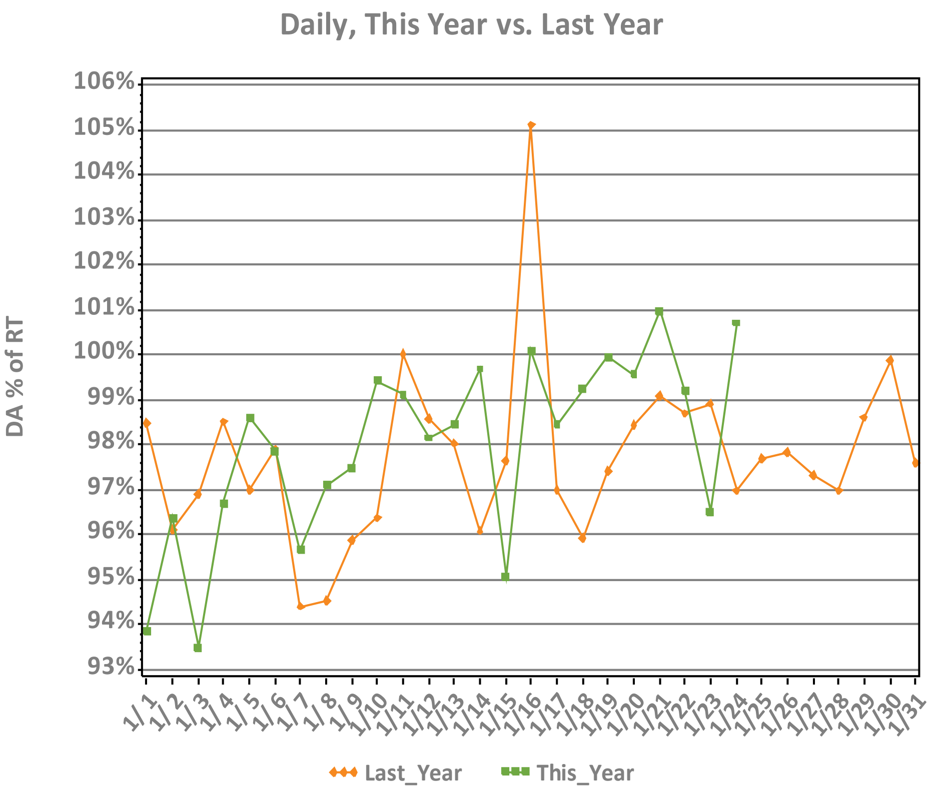




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

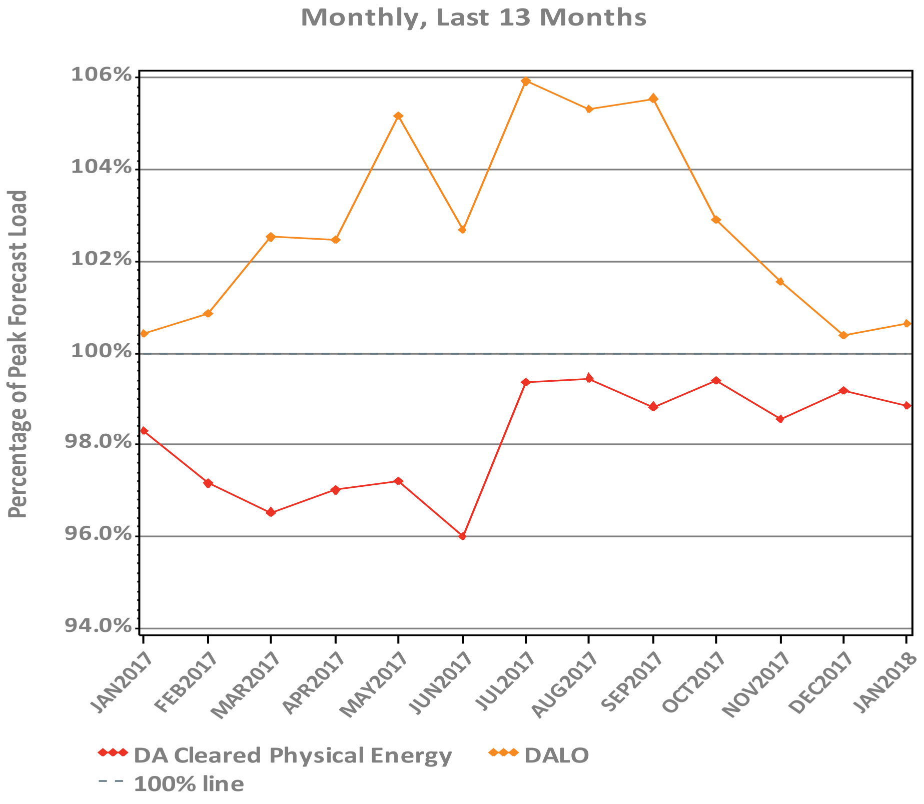
DA vs. RT Load Obligation: January, This Year vs. Last Year

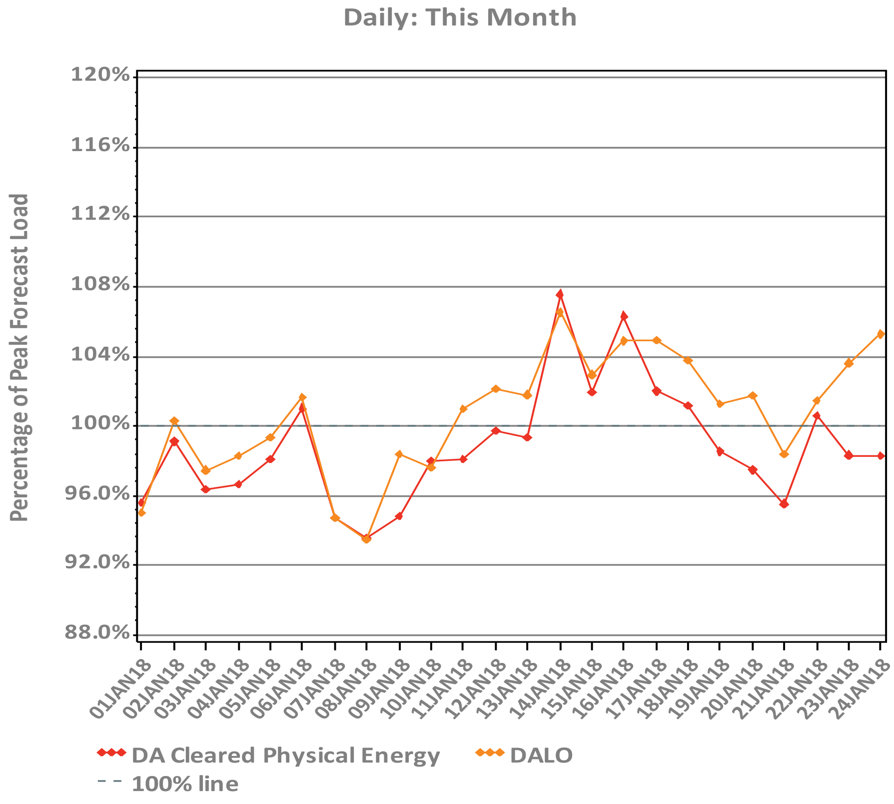




*Hourly average values

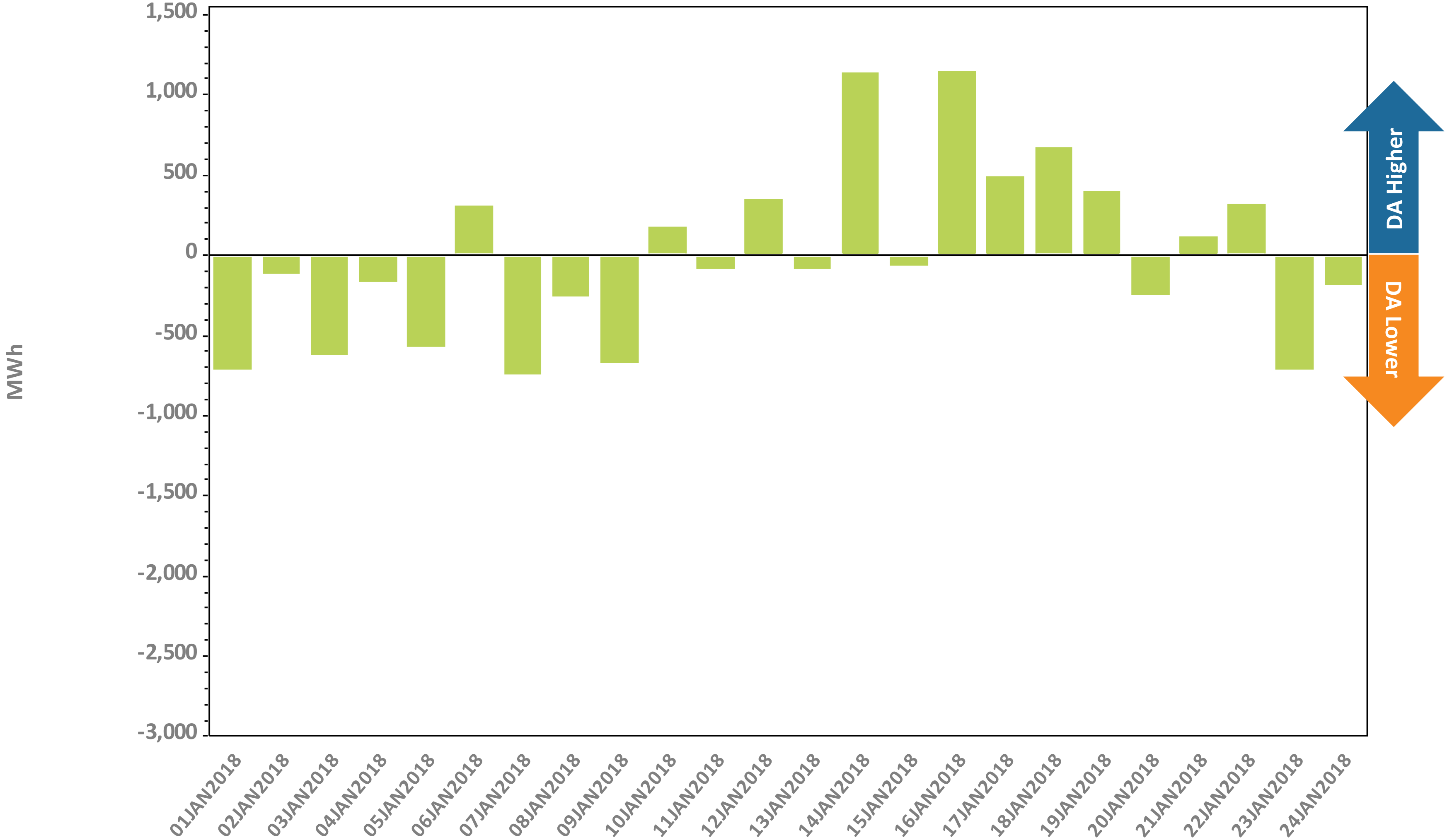
DA Volumes as % of Forecast in Peak Hour





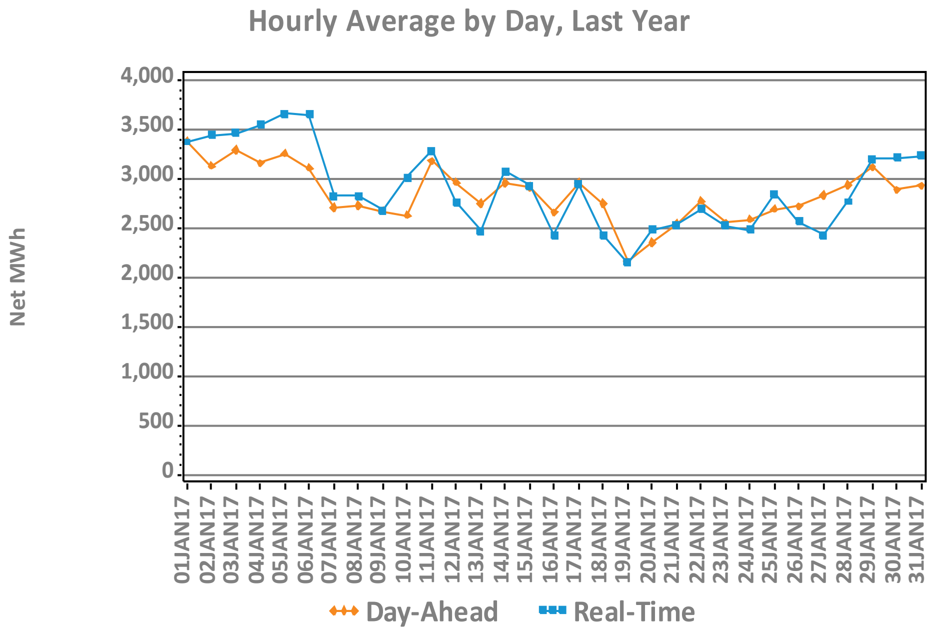
***There were two supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) on January 1 and 7.**

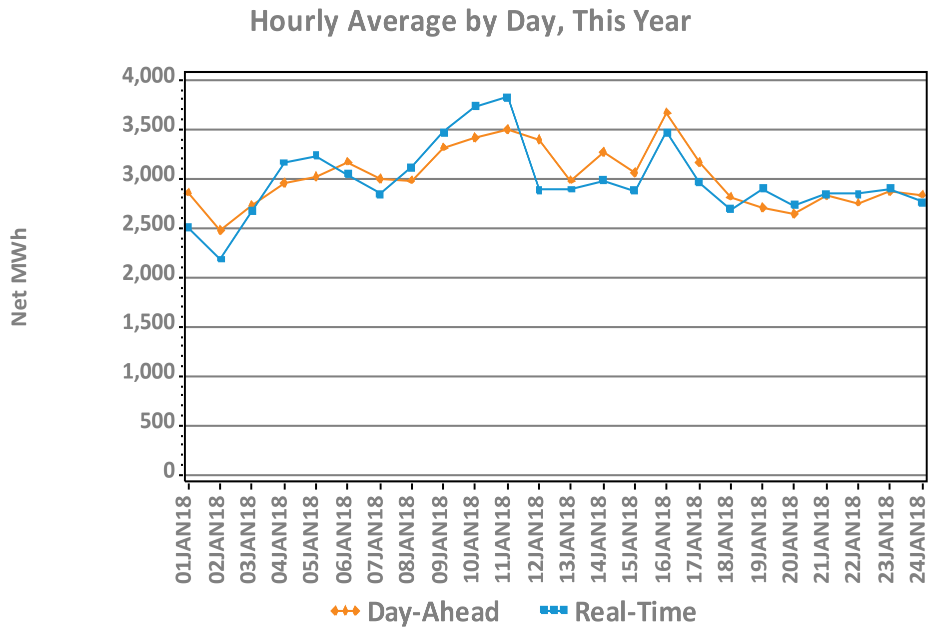
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

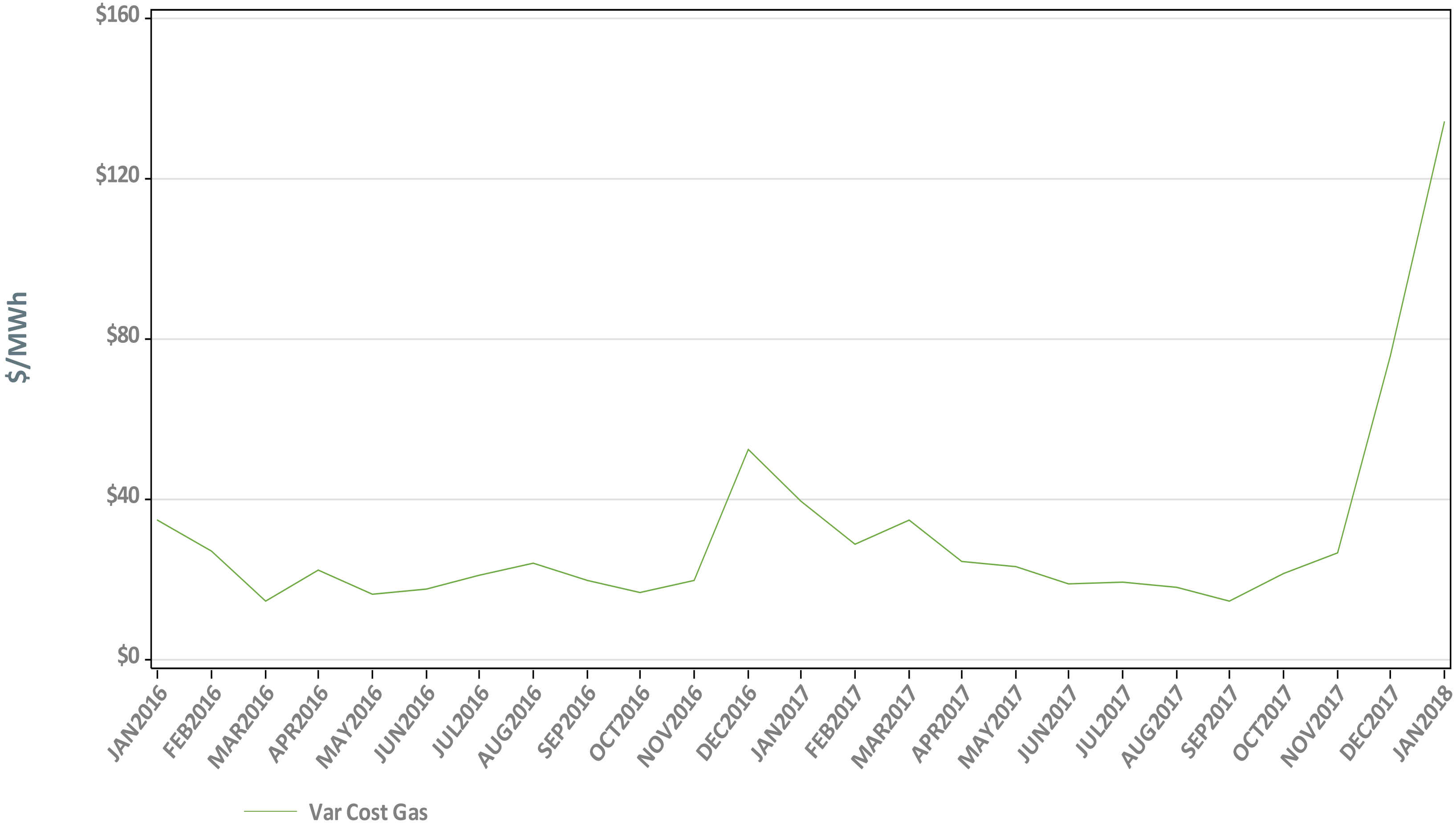
DA vs. RT Net Interchange January 2018 vs. January 2017





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

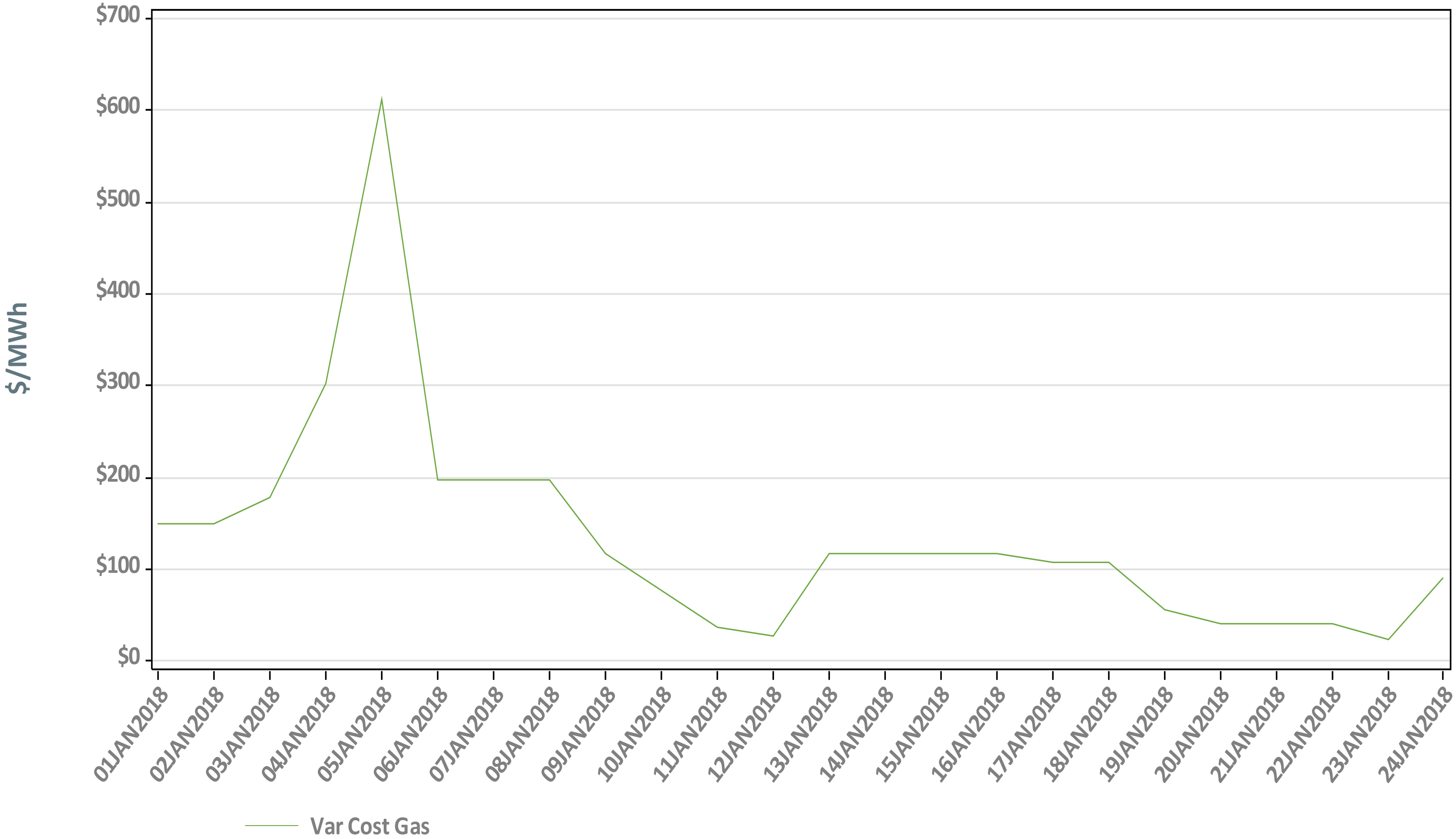
Variable Production Cost of Natural Gas: Monthly



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

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

Variable Production Cost of Natural Gas: Daily

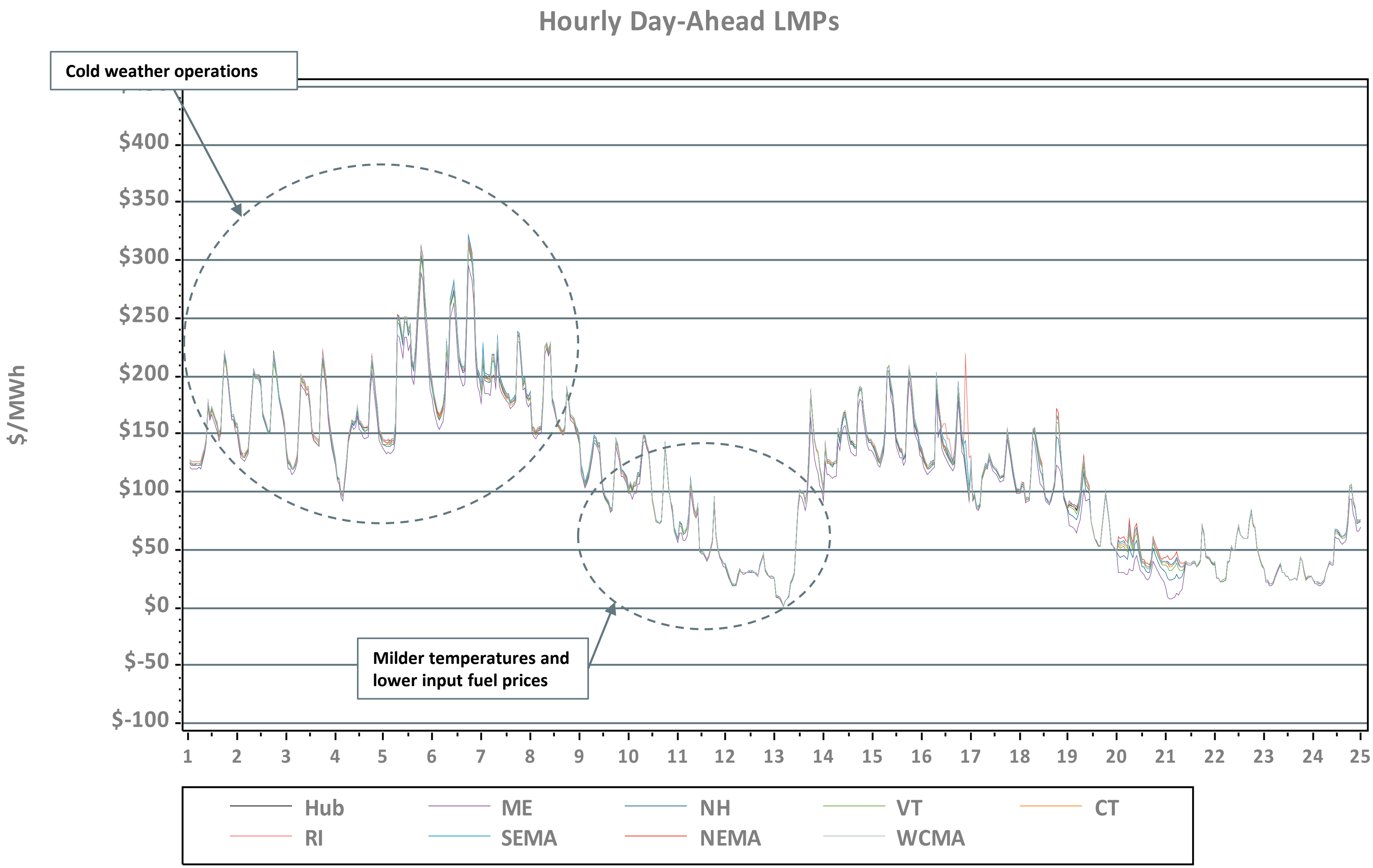


Underlying natural gas data furnished by:

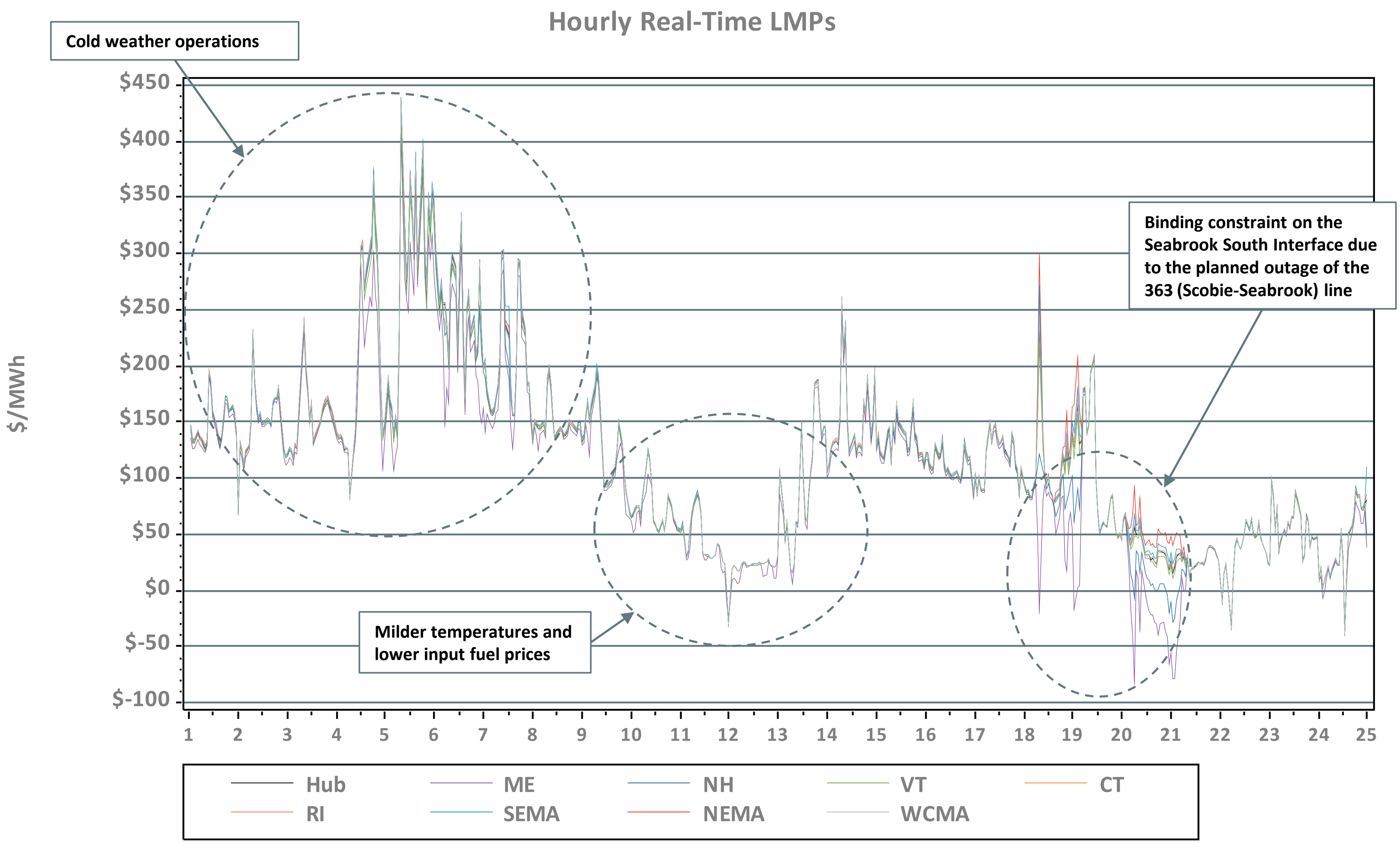
ICE Global markets in clear view

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

Hourly DA LMPs, January 1-24, 2018

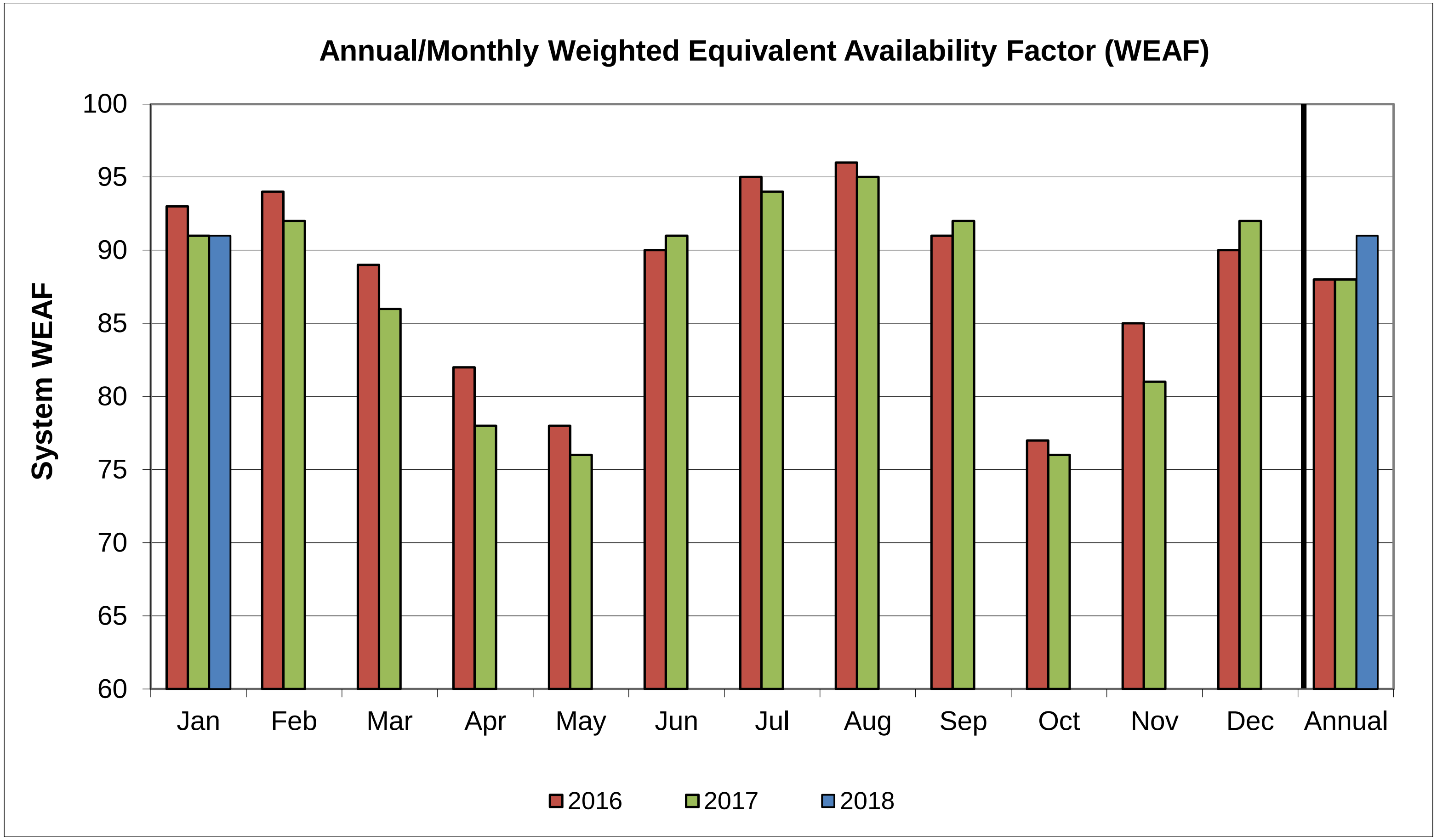


Hourly RT LMPs, January 1-24, 2018



* No Minimum Generation Emergencies were declared in January.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2018	91												91
2017	91	92	86	78	76	91	94	95	92	76	81	92	88
2016	93	94	89	82	78	90	95	96	91	77	85	90	88

Data as of 1/29/18

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for February 2018

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	109.0	0.0	162.4	0.0	271.4
NH	13.1	0.0	87.8	0.0	100.8
VT	27.1	0.0	132.6	0.0	159.7
CT	88.3	1.1	59.8	444.0	593.2
RI	14.5	0.0	213.4	0.0	227.9
SEMA	25.0	0.0	320.9	0.0	346.0
WCMA	36.9	0.0	295.8	49.0	381.7
NEMA	39.1	-0.2[1]	596.5	0.0	635.4
Total	**353.1**	**0.8**	**1,869.2**	**493.0**	**2,716.1**

*** Real Time Demand Response**
**** Real Time Emergency Generation**
[1] Negative CSO resulting from reconfiguration auction activity
NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

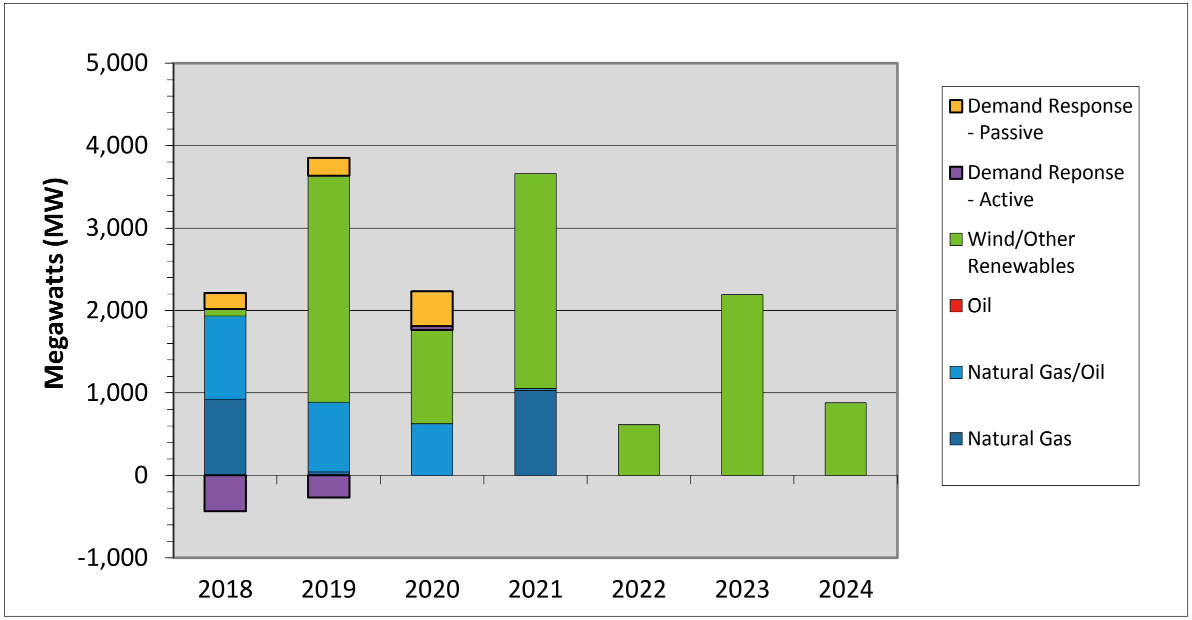
New Generation Update

Based on Queue as of 1/29/18

- Three new projects, with a total rating of 25 MW, have applied for interconnection study since the last update
  - The projects consist of new photovoltaic plants with expected in-service dates in 2018 and 2019
- Three projects withdrew from the queue and no projects went commercial, resulting in a net decrease in new generation projects of 246 MW
- In total, 93 generation projects are currently being tracked by the ISO, totaling approximately 14,800 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Demand Response - Passive	196	212	422	0	0	0	0	830	5.6
Demand Response - Active	-433	-270	42	0	0	0	0	-660	-4.4
Wind & Other Renewables	82	2,751	1,141	2,607	613	2,193	880	10,267	68.7
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,009	844	625	23	0	0	0	2,501	16.7
Natural Gas	926	43	0	1,030	0	0	0	1,999	13.4
Totals	**1,780**	**3,581**	**2,231**	**3,660**	**613**	**2,193**	**880**	**14,937**	**100.0**

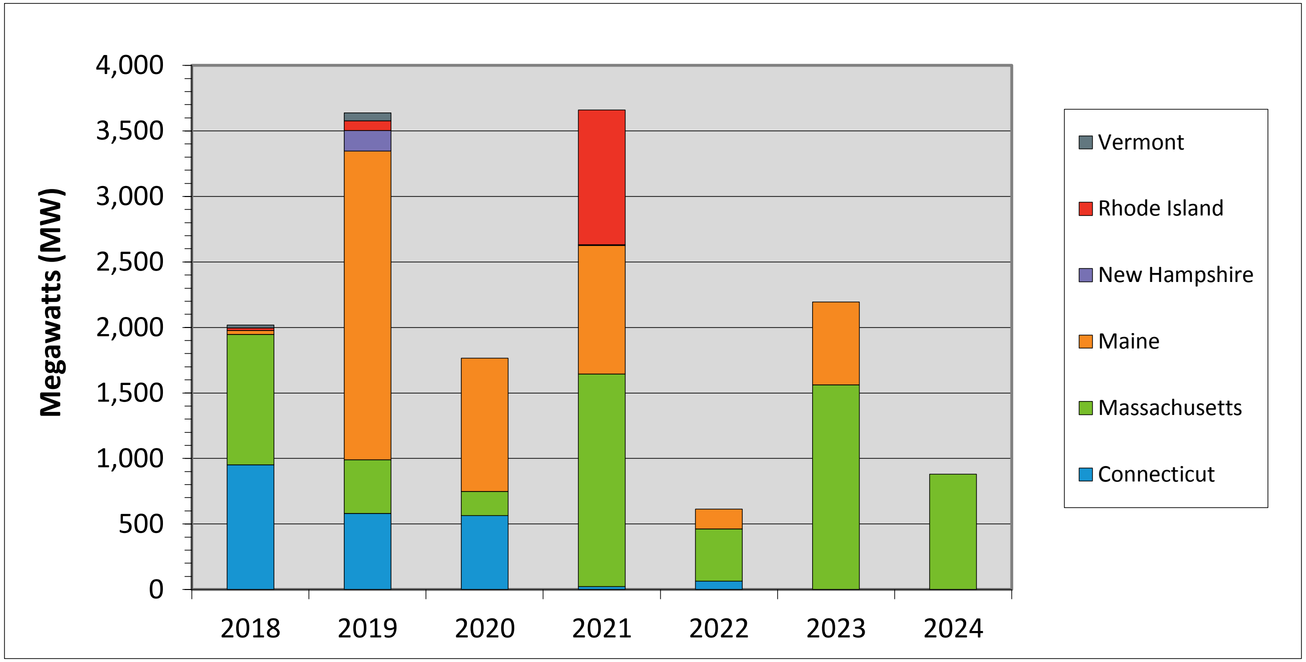
[1] Sum may not equal 100% due to rounding

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Vermont	20	60	0	0	0	0	0	80	0.5
Rhode Island	21	74	0	1,030	0	0	0	1,125	7.6
New Hampshire	0	158	0	5	0	0	0	163	1.1
Maine	30	2,356	1,018	982	150	630	0	5,166	35.0
Massachusetts	995	411	185	1,620	400	1,563	880	6,054	41.0
Connecticut	951	579	563	23	63	0	0	2,179	14.8
Totals	**2,017**	**3,638**	**1,766**	**3,660**	**613**	**2,193**	**880**	**14,767**	**100.0**

[1] **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	3	99	0	0	3	99
Landfill Gas	0	0	0	0	0	0
Natural Gas	8	2,062	2	816	6	1,246
Natural Gas/Oil	8	2,501	2	1,009	6	1,492
Oil	0	0	0	0	0	0
Solar	33	1,116	0	0	33	1,116
Wind	33	8,400	0	0	33	8,400
Battery Storage	7	552	0	0	7	552
Total	93	14,767	4	1,825	89	12,942

- 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	3	105	0	0	3	105
Intermediate	11	3,802	2	1,517	9	2,285
Peaker	46	2,460	2	308	44	2,152
Wind Turbine	33	8,400	0	0	33	8,400
Total	93	14,767	4	1,825	89	12,942

- 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	3	99	1	5	1	28	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	8	2,062	1	63	6	1,899	1	100	0	0
Natural Gas/Oil	8	2,501	0	0	4	1,875	4	626	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	33	1,116	0	0	0	0	33	1,116	0	0
Wind	33	8,400	0	0	0	0	0	0	33	8,400
Battery Storage	7	552	0	0	0	0	7	552	0	0
Total	93	14,767	3	105	11	3,802	46	2,460	33	8,400

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 8

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*	1,080.079	887.493	-192.59	891.604	4.111	772.352	-119.252	601.852	-170.5	400.487	-201.365	381.941	-18.546
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211	2025.383	68.72	2,036.906	11.523	2,112.758	75.852	2,308.73	195.972
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,848.267**	**1.9**	**2,797.735**	**-50.532**	**2,638.758**	**-158.977**	**2,513.245**	**-125.513**	2,690.671	177.426
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,666.87	143.074	28,658.35	-8.52	28,863.752	205.402	28,888.84	25.092	28,833.605	-55.235
	Intermittent	876.925	898.955	22.03	922.173	23.218	918.782	-3.391	920.037	1.255	916.51	-3.527	823.162	-93.348
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**	**29,577.132**	**-11.911**	**29,783.789**	**206.657**	**29,805.35**	**21.565**	29,656.767	-148.583
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**	**1,375.53**	**0**	**1314.43**	**-61.1**	**1,394.43**	**80**	1,345.998	-48.432
*****Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,812.84**	**306.688**	**33,750.397**	**-62.443**	**33,736.977**	**-13.417**	**33,713.03**	**-23.948**	33,693.436	-19.594
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	**0**	**33,442**	**-619**	**33,442**	**0**	**33,138**	**-304**	33,138	**0**

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

** 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 Month Capacity Supply Obligation Changes report on the ISO New England website.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column. The Grand Total for FCA 8 does not reflect a Supplemental Information filing in March of 2014.

Capacity Supply Obligation FCA 9

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*	647.26	596.701	-50.559	553.857	-42.844	525.843	-28.014	484.972	-40.871				
	Passive Demand	2,156.151	2,153.94	-2.211	2,150.196	-3.744	2,150.196	0	2,389.958	239.762				
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**	**2,676.039**	**-28.014**	**2,874.93**	198.891				
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65	29,803.997	20.166	29,833.445	29.448				
	Intermittent	891.616	864.924	-26.692	872.425	7.501	853.414	-19.011	870.558	17.144				
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**	**30,657.41**	**1.155**	**30,704.003**	46.593				
Import Total		**1,449**	**1,449**	**0**	**1,449**	**0**	**1,449**	**0**	**1,449**	0				
***Grand Total**		**34,694.591**	**34,622.746**	**-71.845**	**34,809.309**	**186.563**	**34,782.45**	**-26.859**	**35,027.933**	245.483				
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**	**33,421**	**-462**	**33,421**	0				

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

** 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 Month Capacity Supply Obligation Changes report on the ISO New England website.

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

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								
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834								
Demand Total		**2,746.156**	**2734.01**	**-12.146**	**2,828.664**	**94.654**								
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272								
	Intermittent	850.143	893.189	43.046	904.311	11.122								
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**								
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**								
*****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**								
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**								

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

** 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 Month Capacity Supply Obligation Changes report on the ISO New England website.

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

Capacity Supply Obligation FCA 11

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*	419.928												
	Passive Demand	2,791.019												
Demand Total		**3,210.947**												
Generator	*Non-Intermittent*	30,494.8												
	Intermittent	894.217												
Generator Total		**31,389.02**												
Import Total		**1,235.4**												
***Grand Total**		**35,835.368**												
Net ICR (NICR)		**34,075**												

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

** 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 Month Capacity Supply Obligation Changes report on the ISO New England website.

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1246.399	603.675	1850.074
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1768.392	184.99	1953.382
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1726.548	98.227	1824.775
	Passive	861.602	211.261	1072.863
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1794.195	257.341	2051.536
	Passive	1040.113	257.793	1297.906
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2062.196	41.945	2104.141
	Passive	1264.641	221.072	1485.713
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1935.406	66.104	2001.51
	Passive	1395.885	247.449	1643.334
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1116.468	0.23	1116.698
	Passive	1386.56	244.775	1631.335
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1066.593	13.486	1080.079
	Passive	1619.147	341.37	1960.517
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1870.549	285.602	2156.151
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2018.201	350.43	2368.631
	Grand Total	2375.422	370.734	2746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2236.727	554.292	2791.019
	Grand Total	2571.361	639.586	3210.947

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

What are Daily NCPC Payments?

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

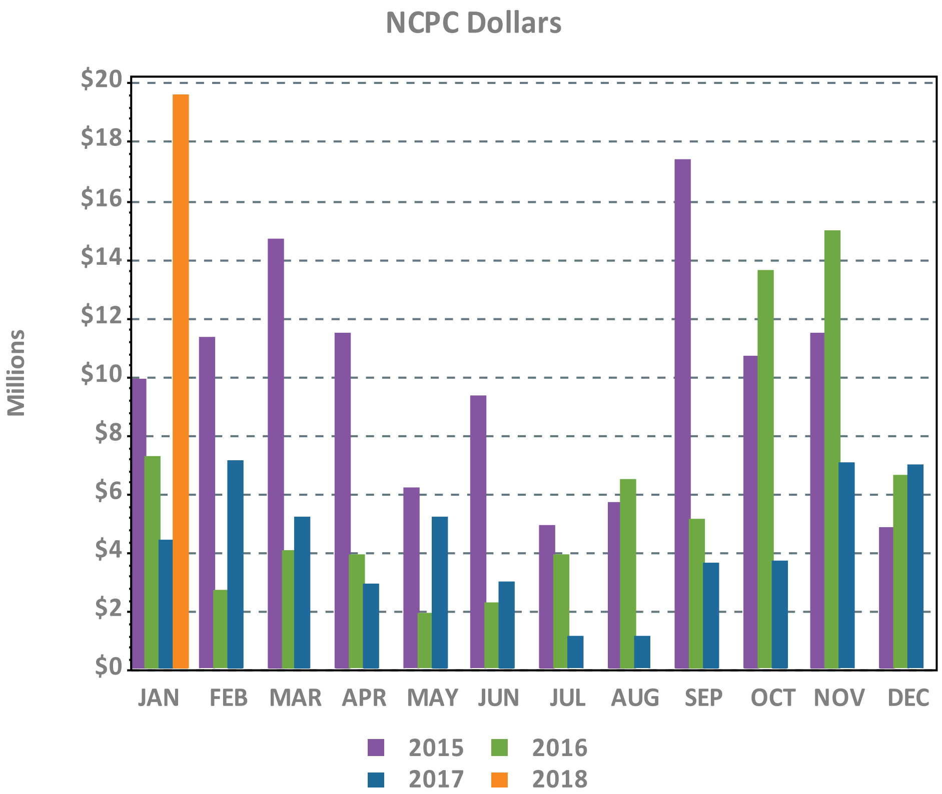
Definitions

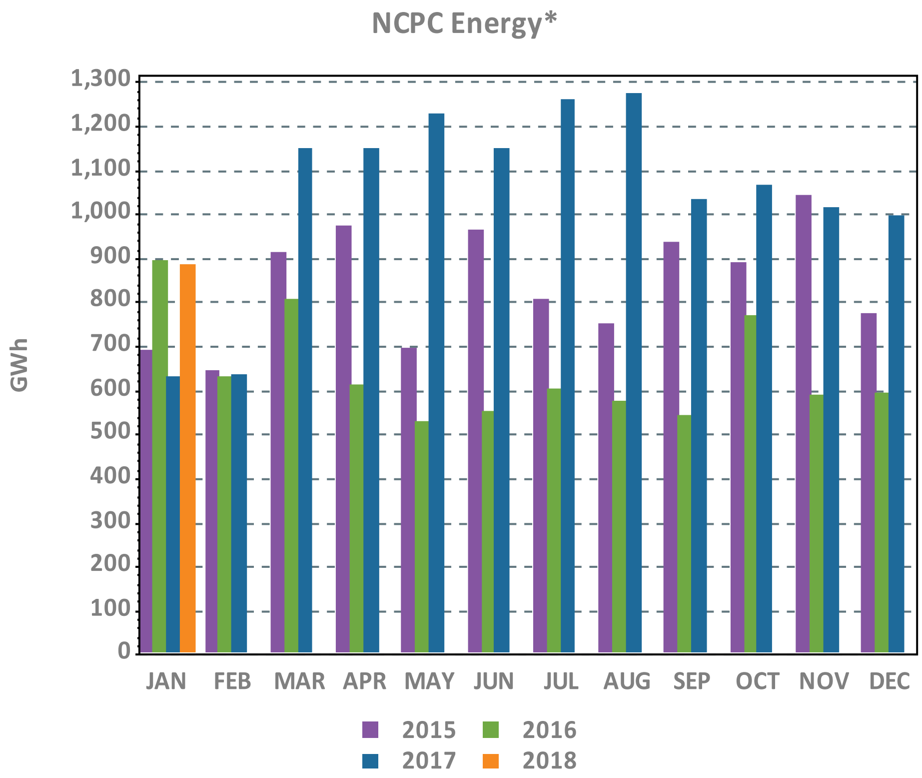
1^{st} Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2^{nd} Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

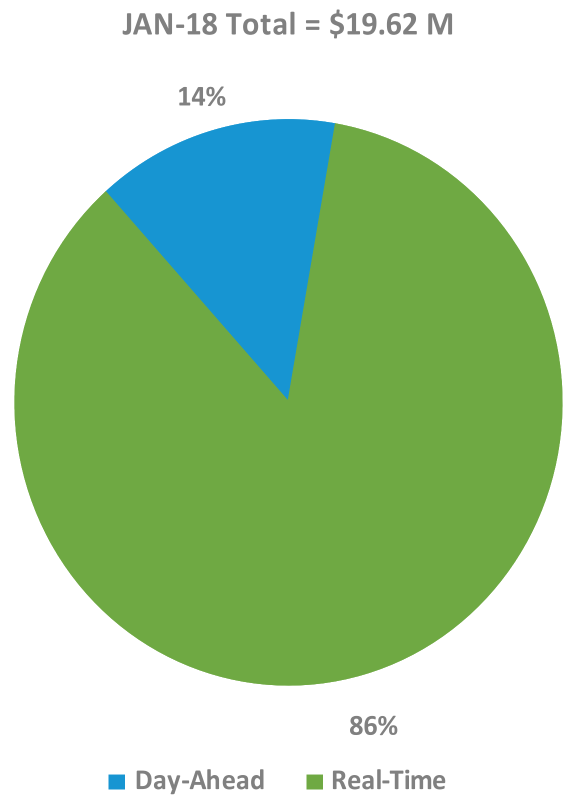
Year-Over-Year Total NCPC Dollars and Energy

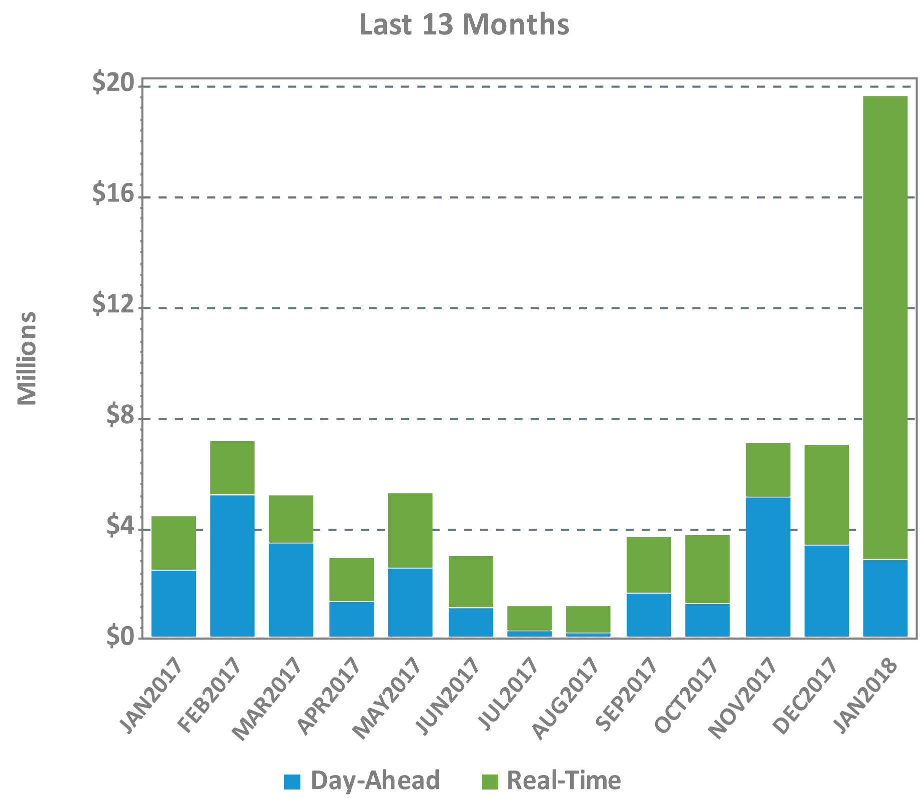




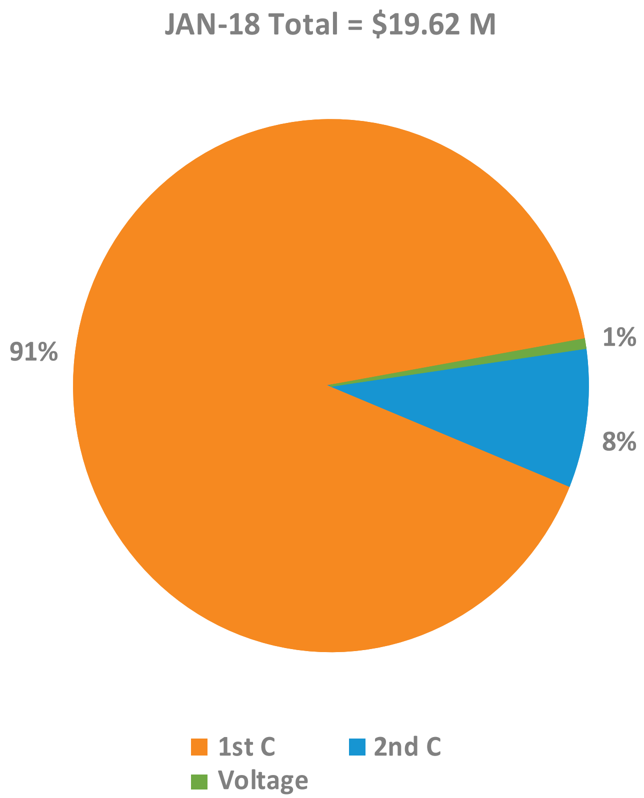
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

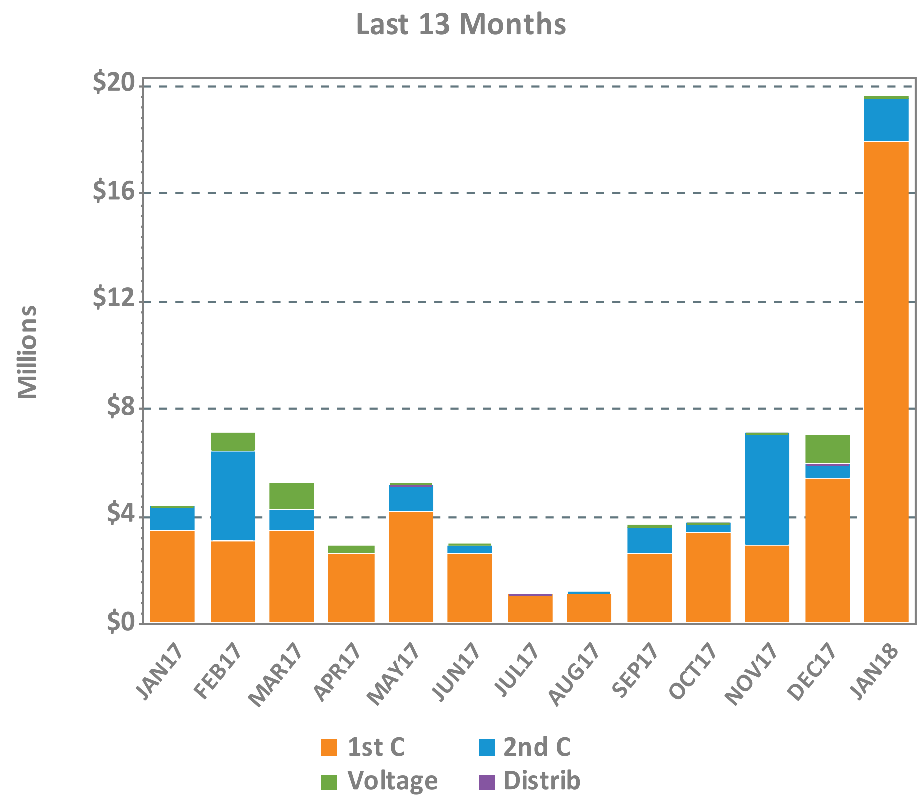
DA and RT NCPC Charges





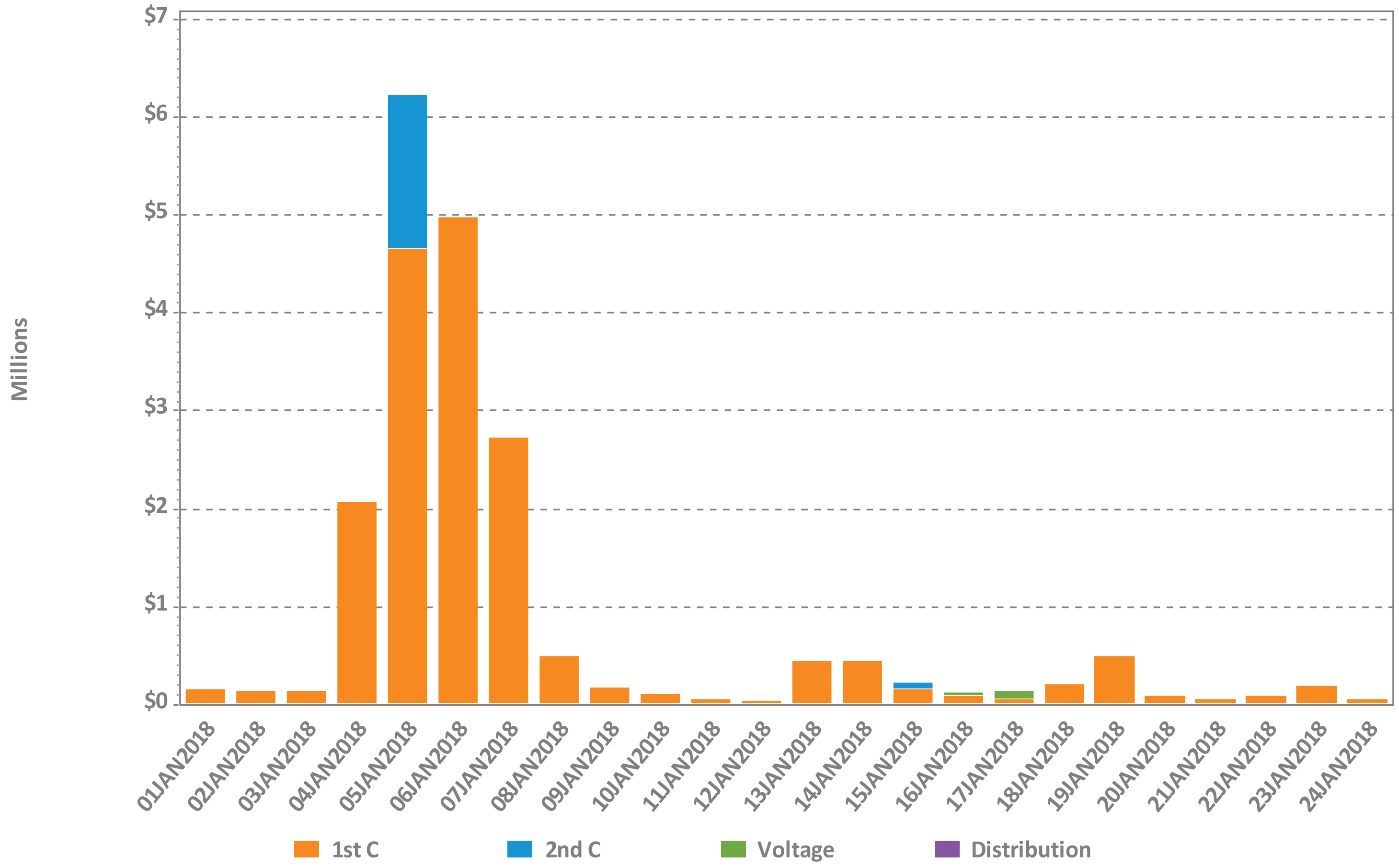
NCPC Charges by Type



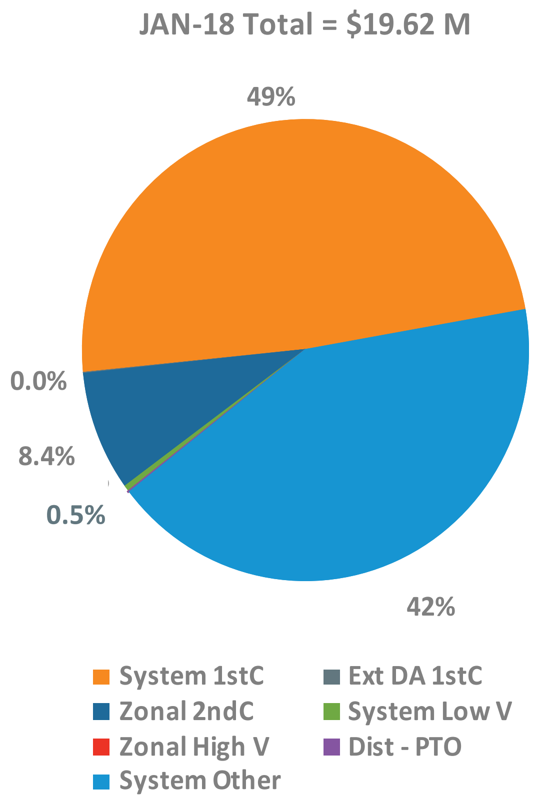


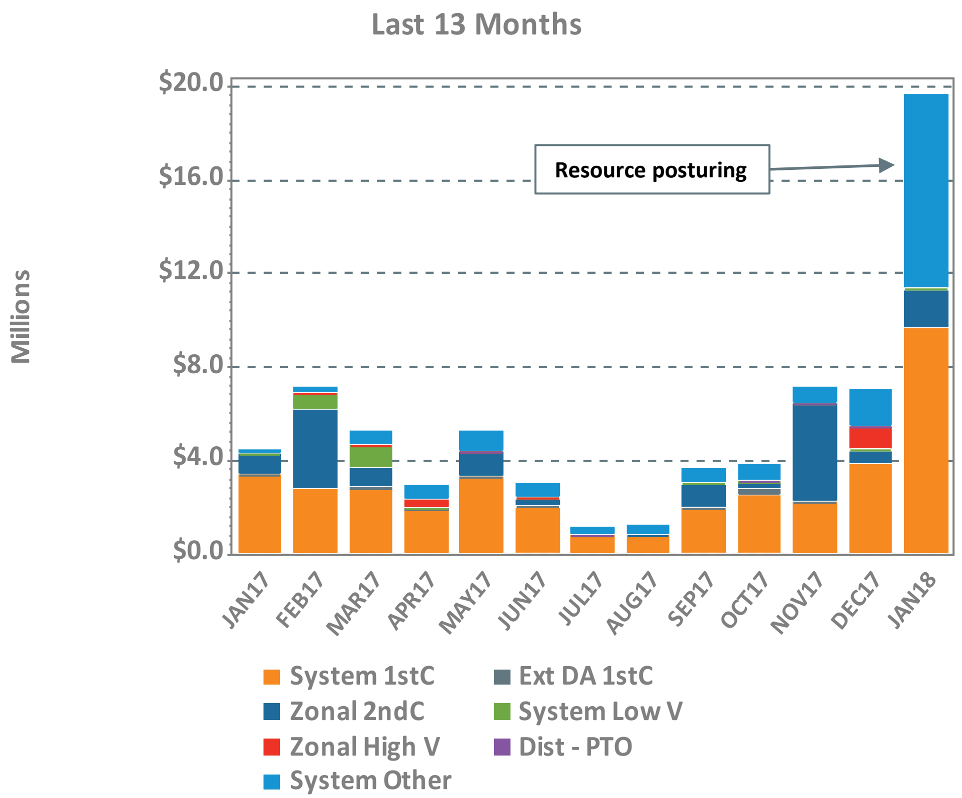
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



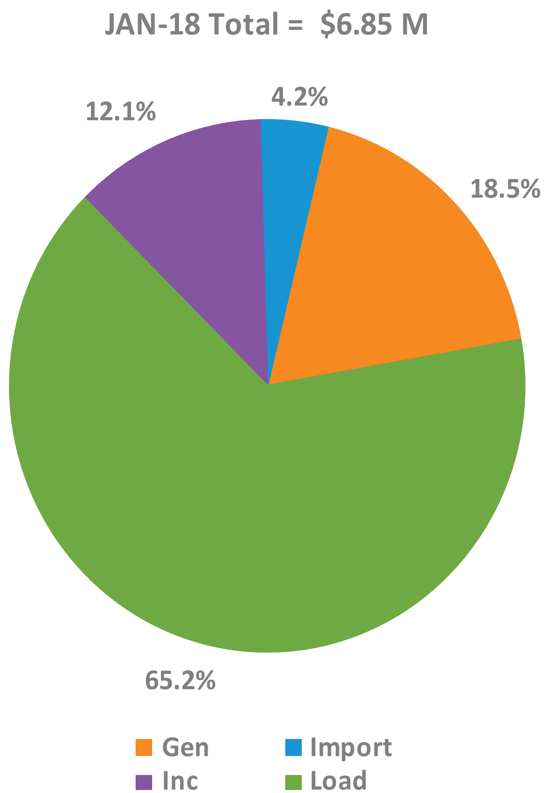
NCPC Charges by Allocation

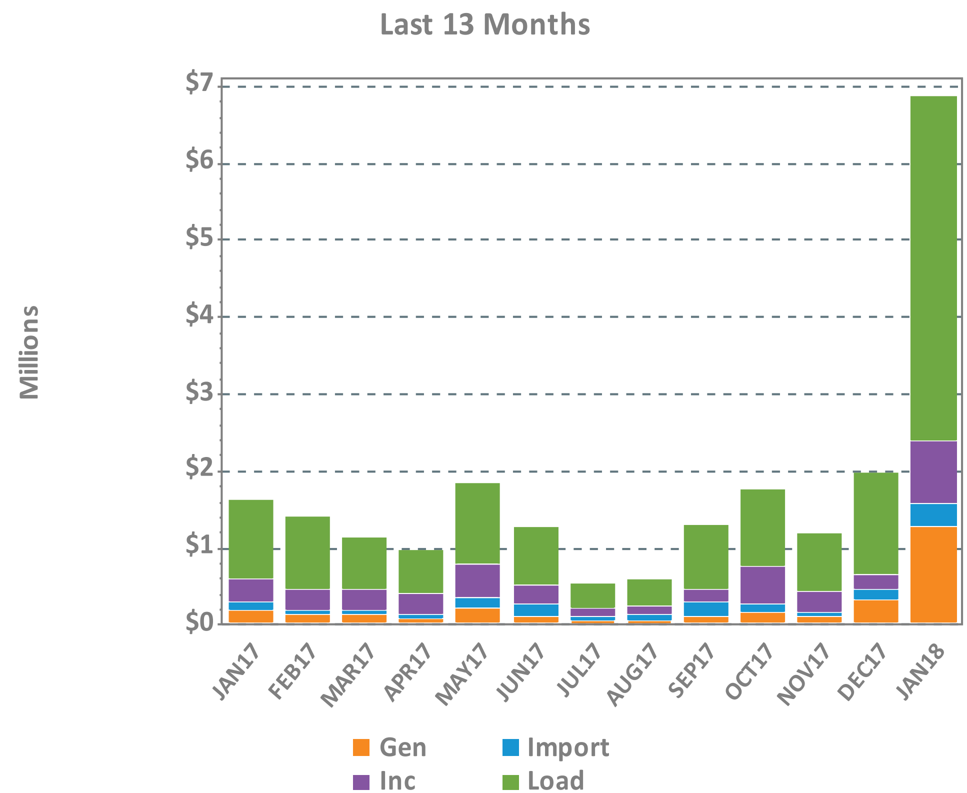




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

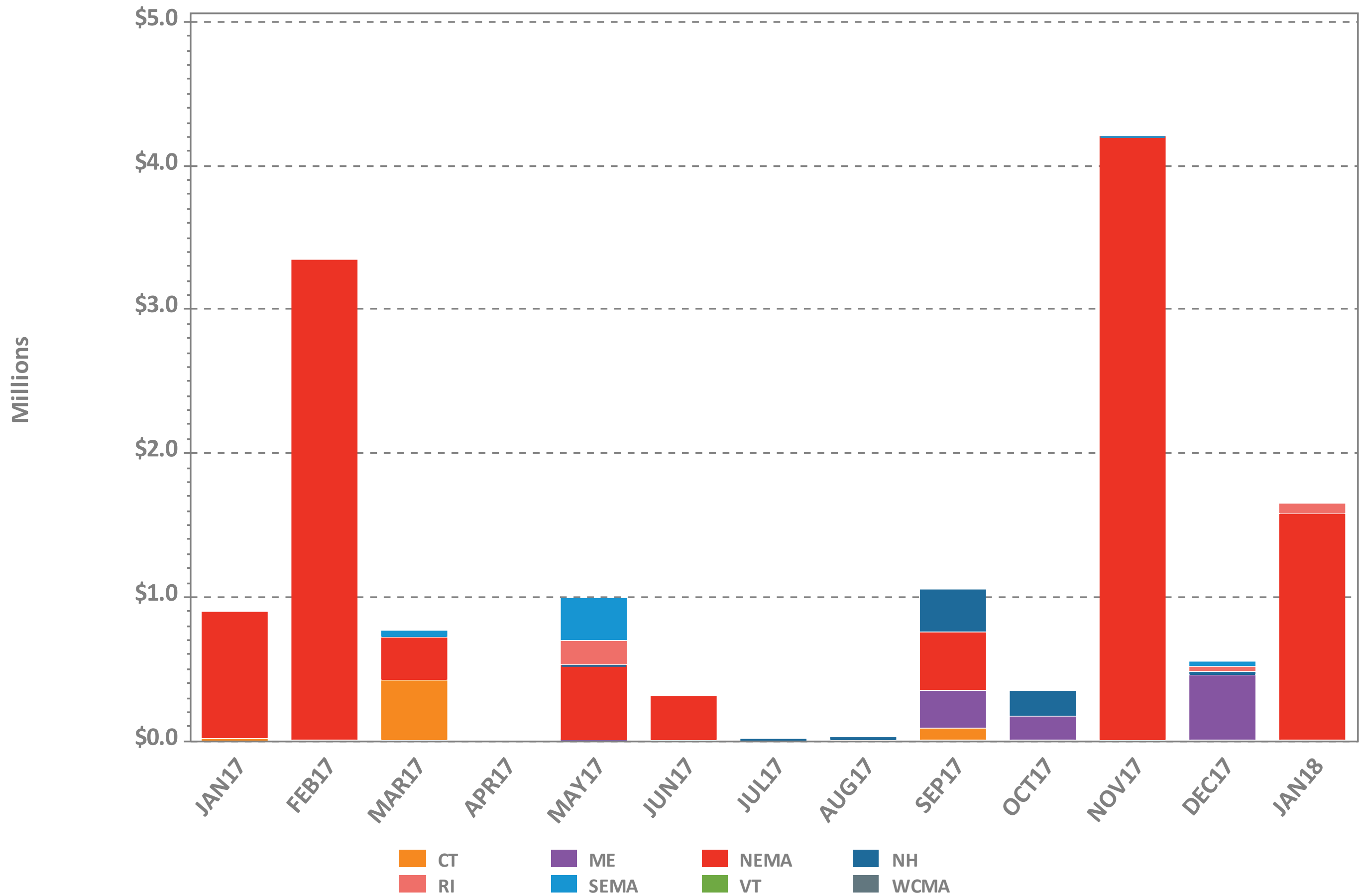
RT First Contingency Charges by Deviation Type





Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

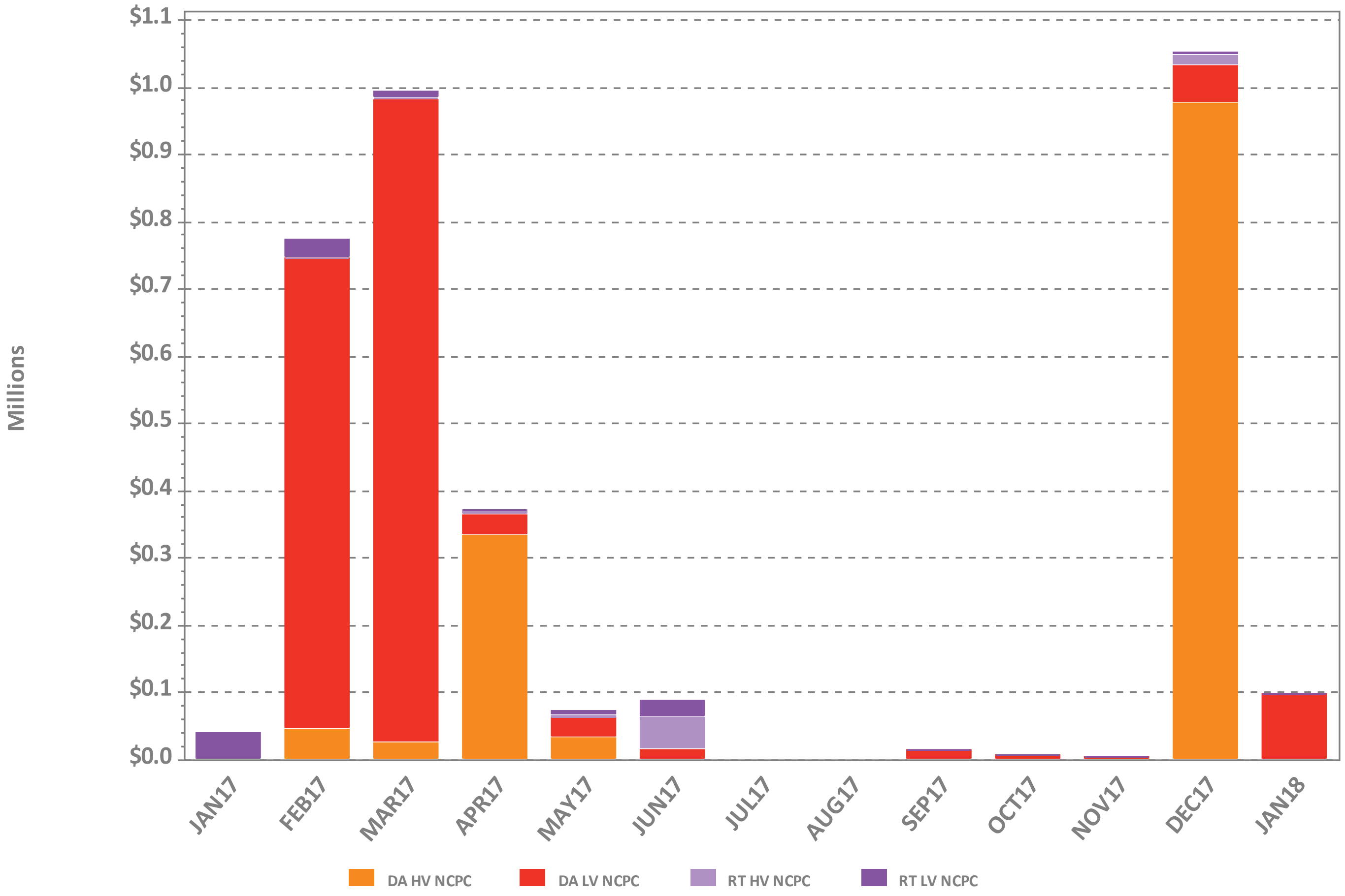
LSCPR Charges by Reliability Region



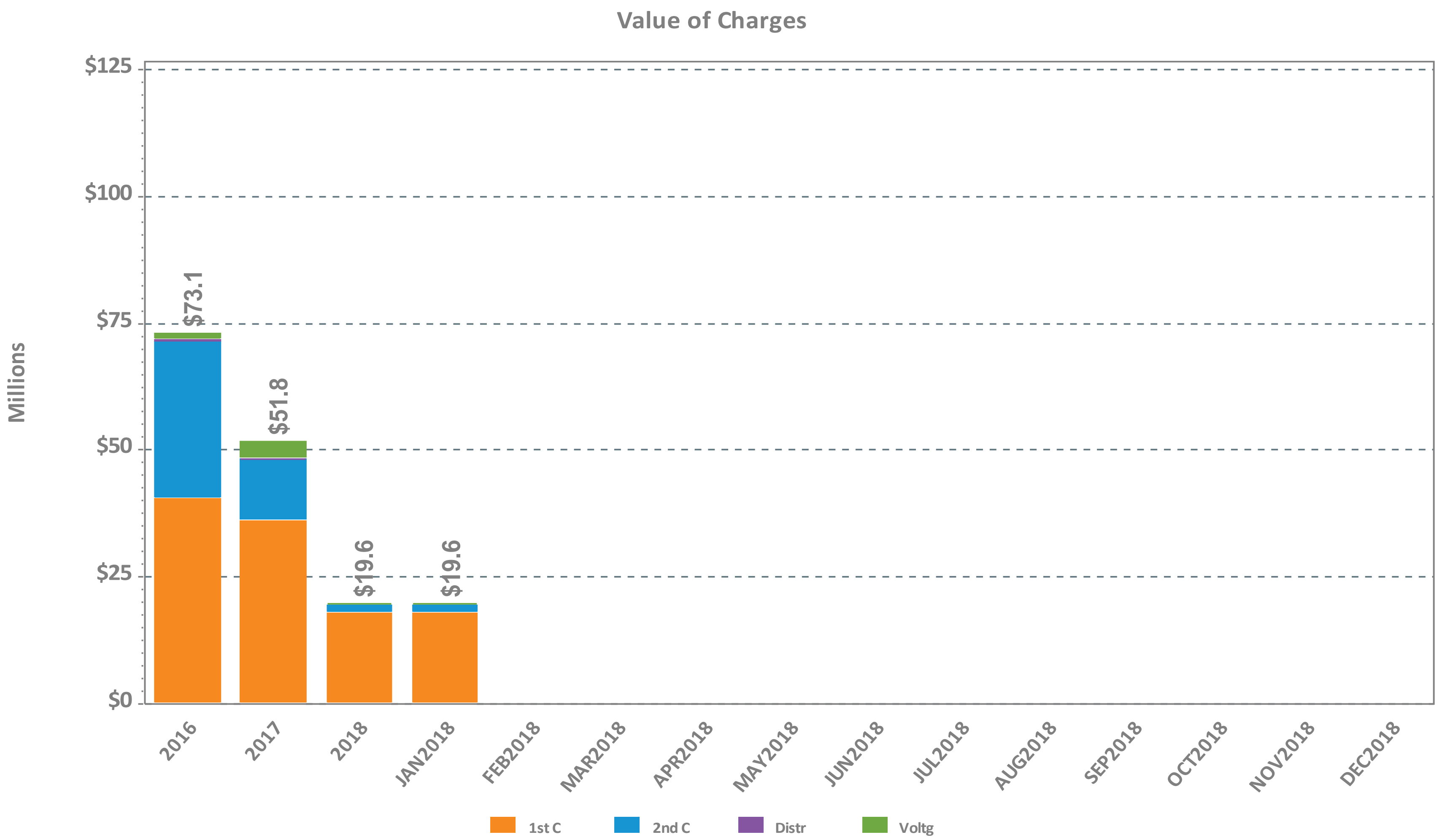
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

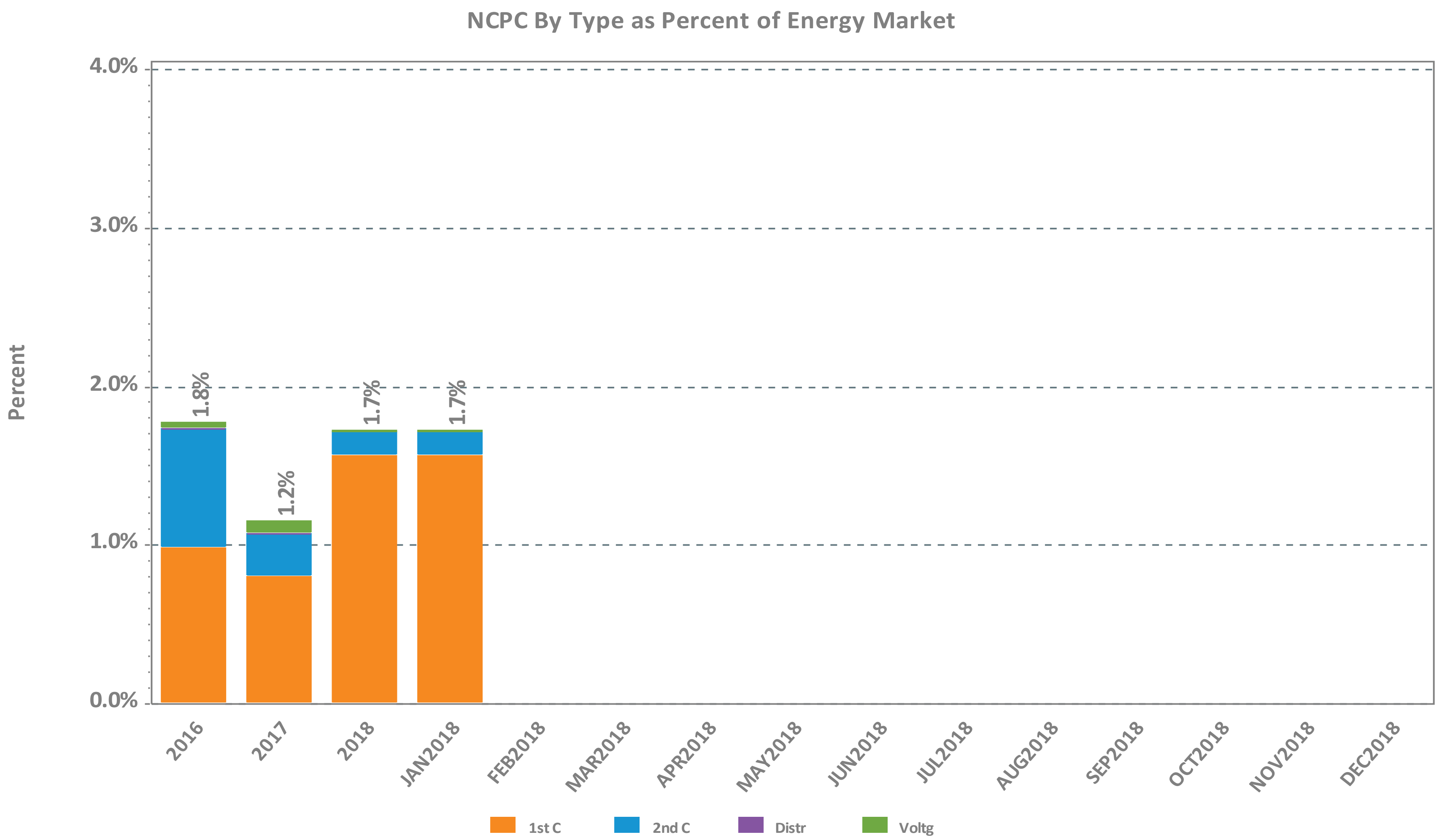
NCPC Charges for Voltage Support and High Voltage Control



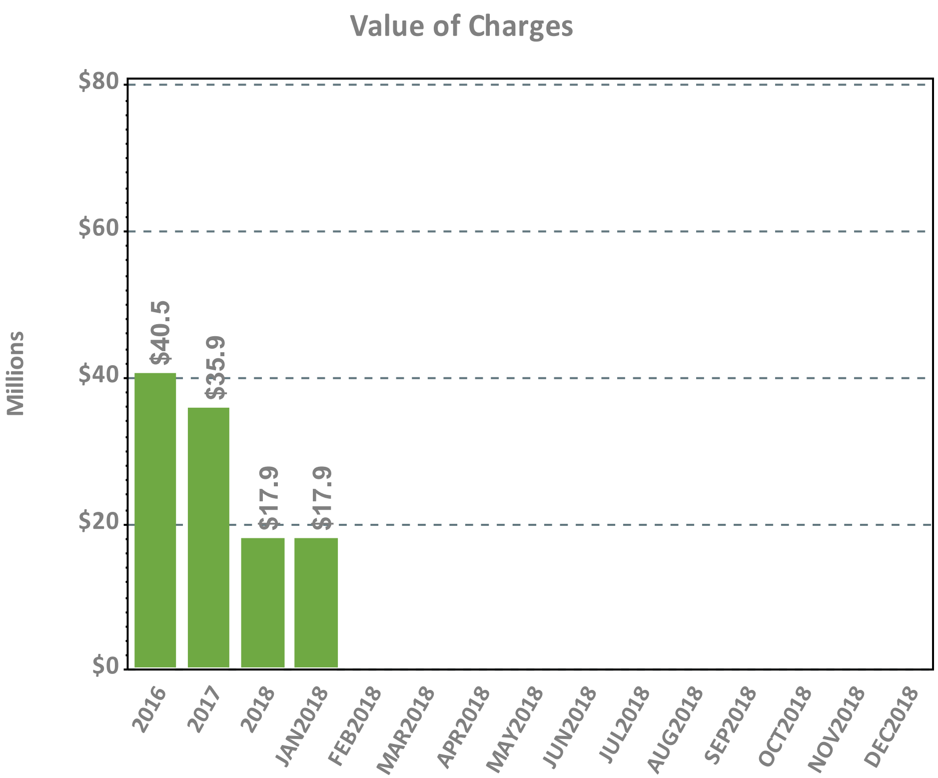
NCPC Charges by Type

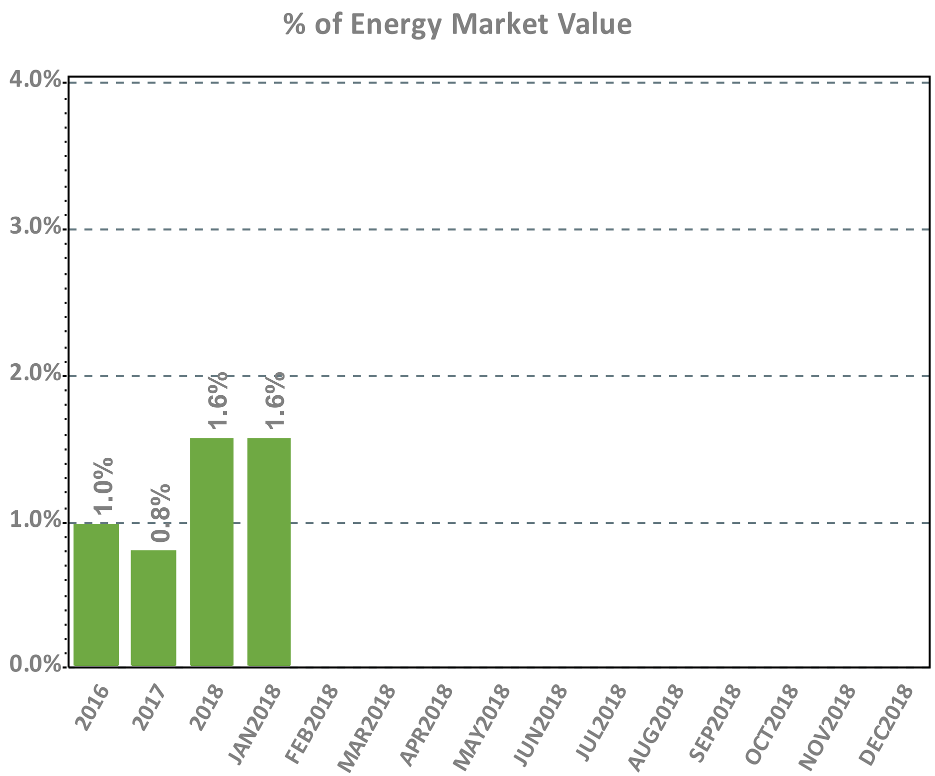


NCPC Charges as Percent of Energy Market



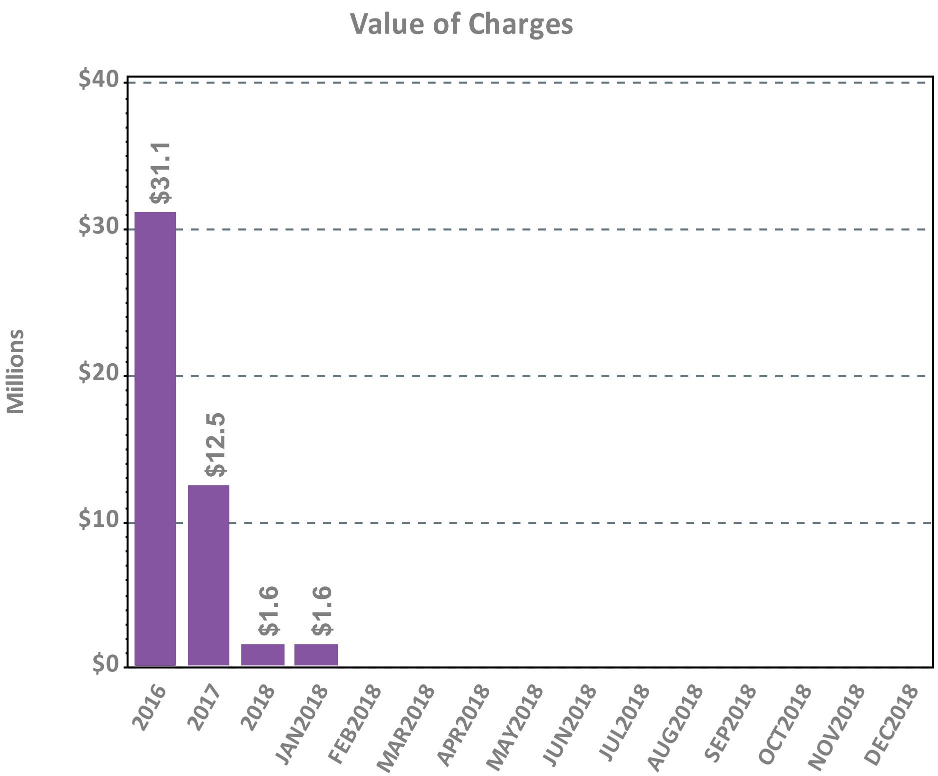
First Contingency NCPC Charges

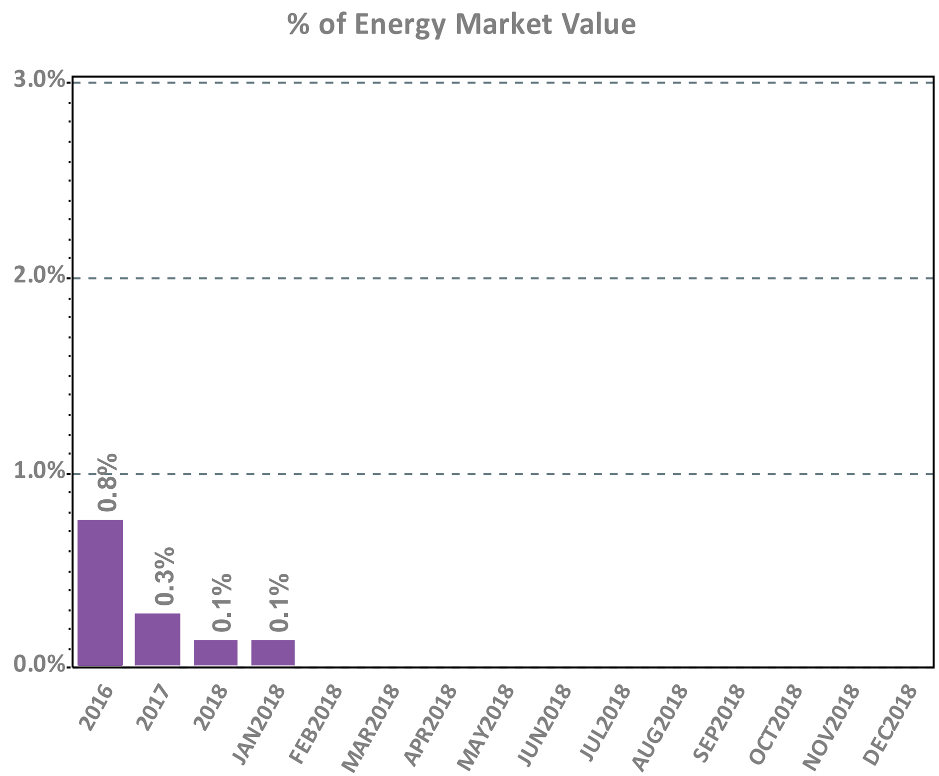




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

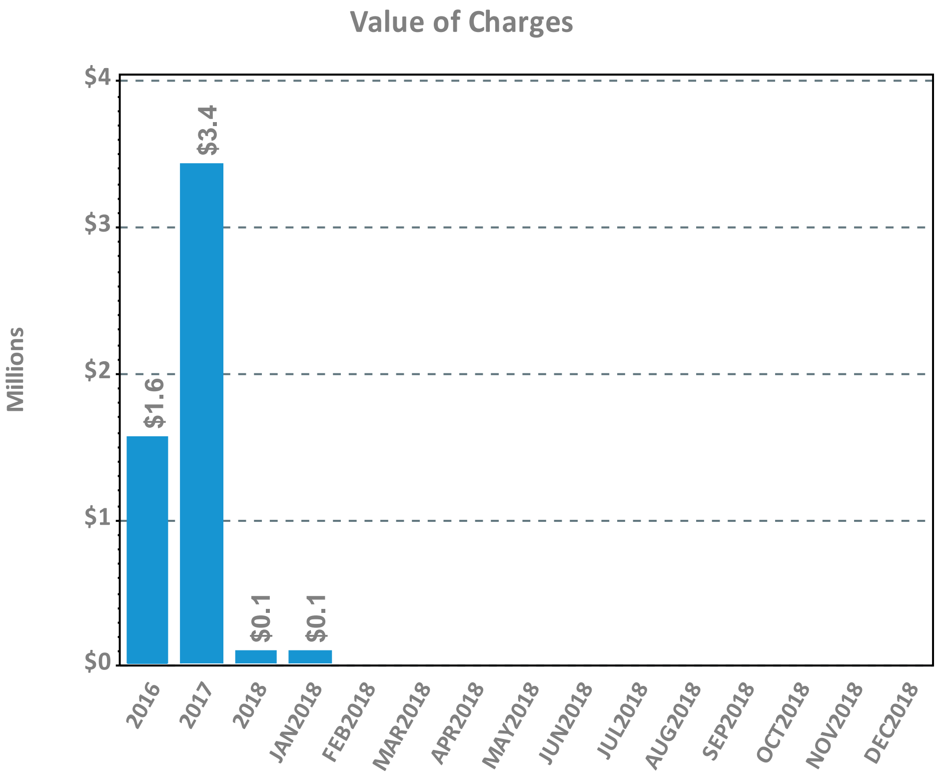
Second Contingency NCPC Charges

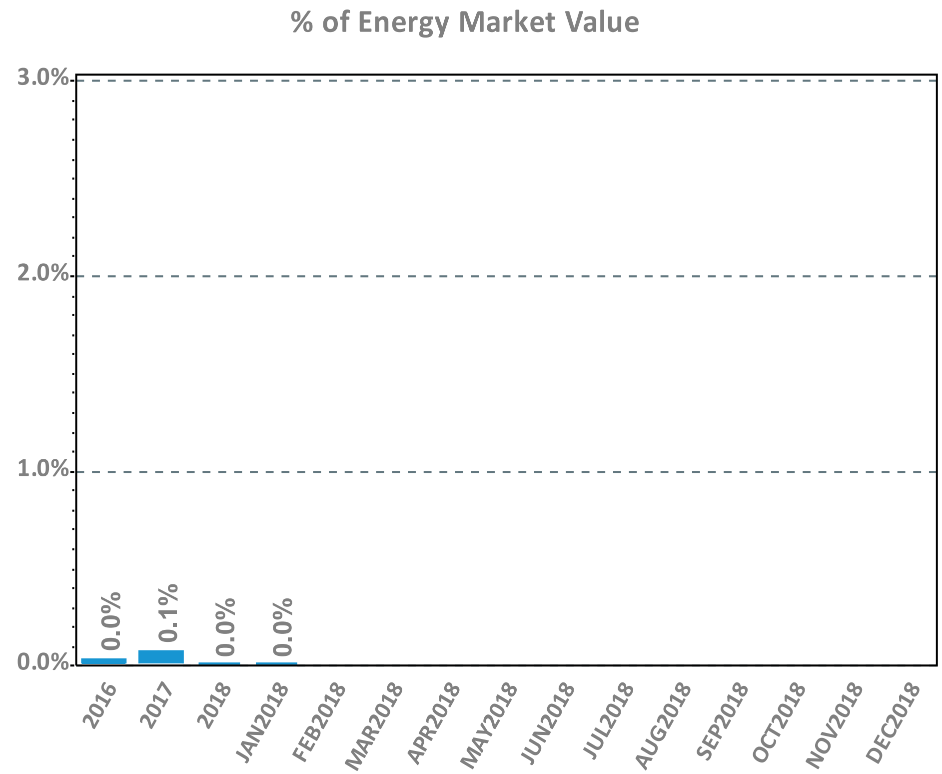




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

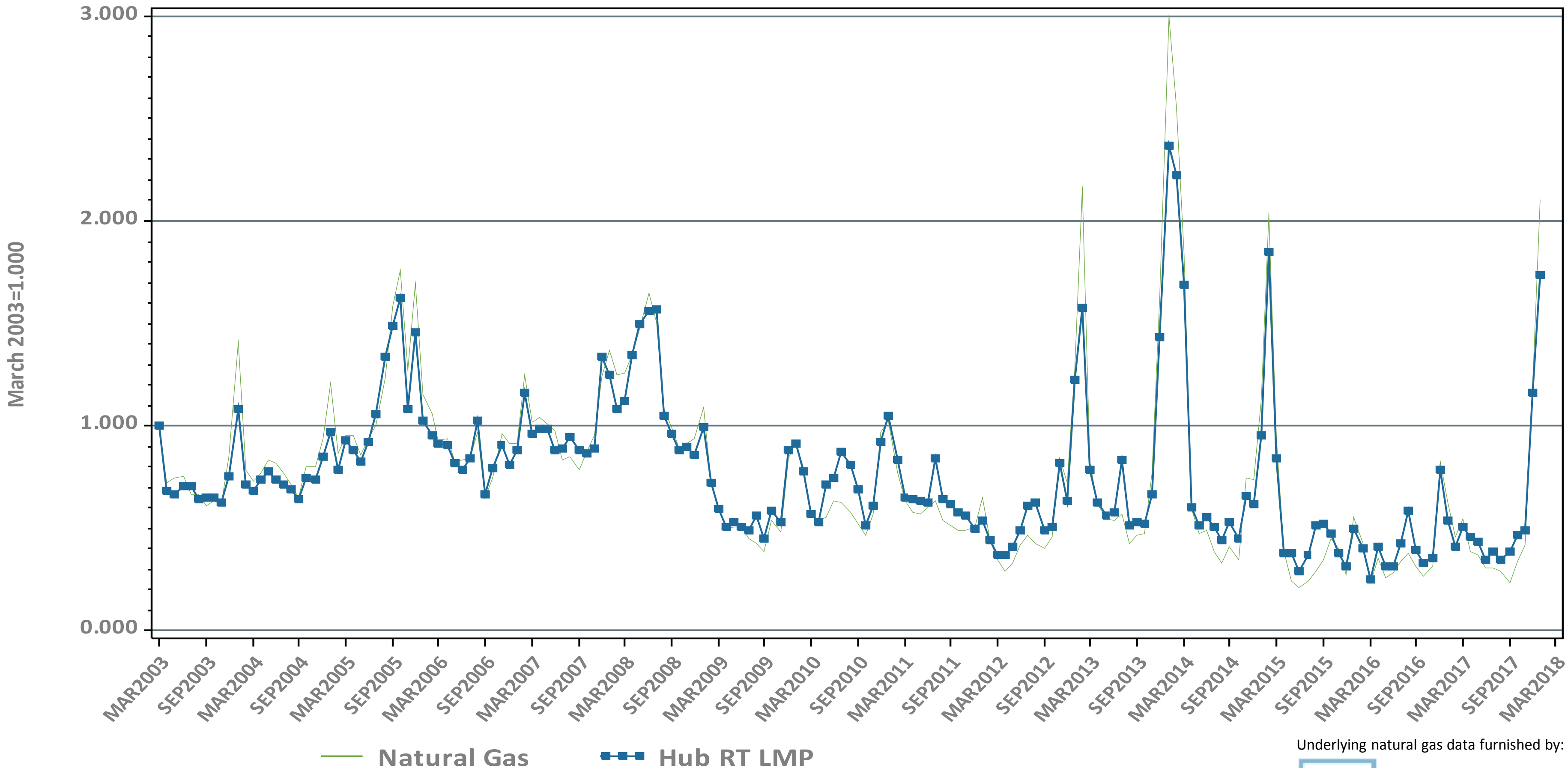
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2016	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.66	$29.77	$29.07	$29.64	$29.66	$29.66	$29.88	$29.85	$29.78
Real-Time	$29.74	$29.00	$27.81	$28.60	$28.49	$28.87	$29.01	$28.98	$28.94
RT Delta %	-3.0%	-2.6%	-4.3%	-3.5%	-3.9%	-2.7%	-2.9%	-2.9%	-2.8%
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%

January-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$40.22	$40.04	$39.49	$40.09	$39.73	$40.14	$40.17	$40.35	$40.30
Real-Time	$36.99	$36.44	$35.51	$36.37	$35.89	$36.52	$36.57	$36.67	$36.66
RT Delta %	-8.0%	-9.0%	-10.1%	-9.3%	-9.7%	-9.0%	-9.0%	-9.1%	-9.0%
January-18	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$117.99	$116.60	$110.95	$115.98	$116.75	$118.68	$118.27	$118.29	$118.29
Real-Time	$120.15	$118.24	$104.86	$114.68	$116.57	$119.43	$119.82	$119.22	$119.14
RT Delta %	1.8%	1.4%	-5.5%	-1.1%	-0.2%	0.6%	1.3%	0.8%	0.7%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	193.4%	191.2%	180.9%	189.3%	193.9%	195.6%	194.4%	193.2%	193.5%
Yr over Yr RT	224.8%	224.4%	195.3%	215.3%	224.8%	227.0%	227.7%	225.1%	225.0%

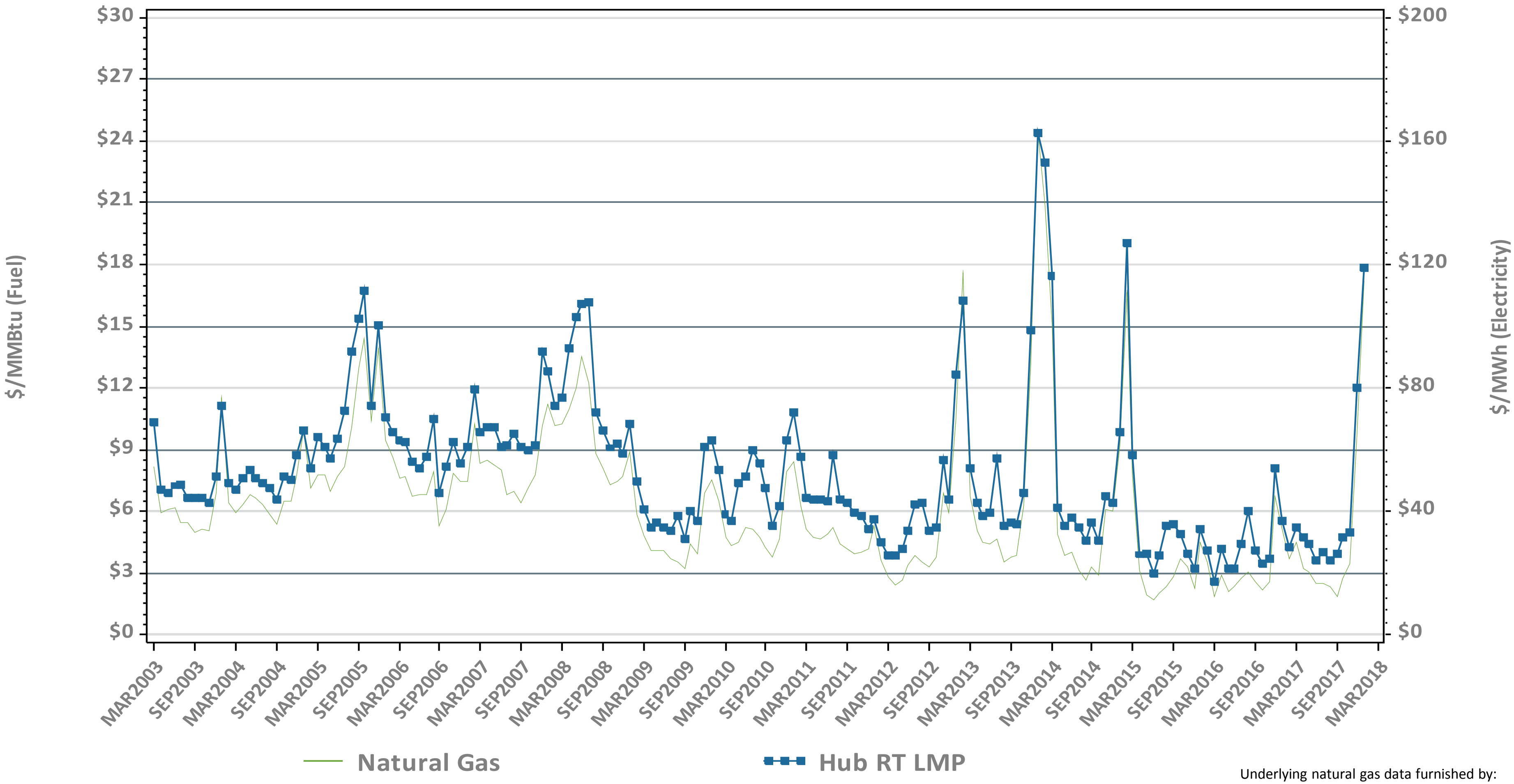
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

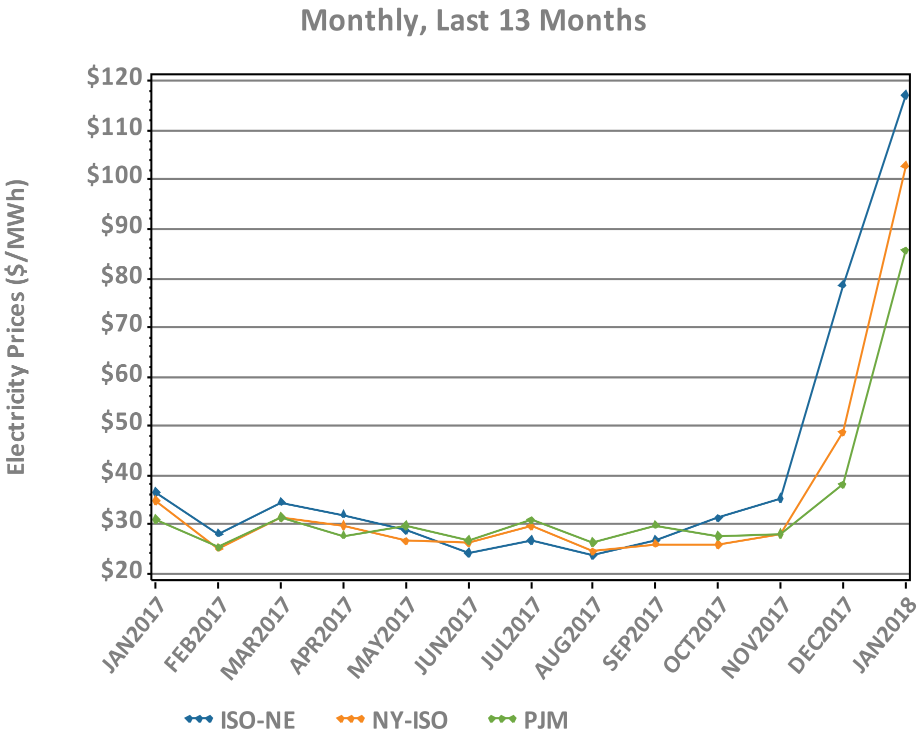
Monthly Average Fuel Price and RT Hub LMP



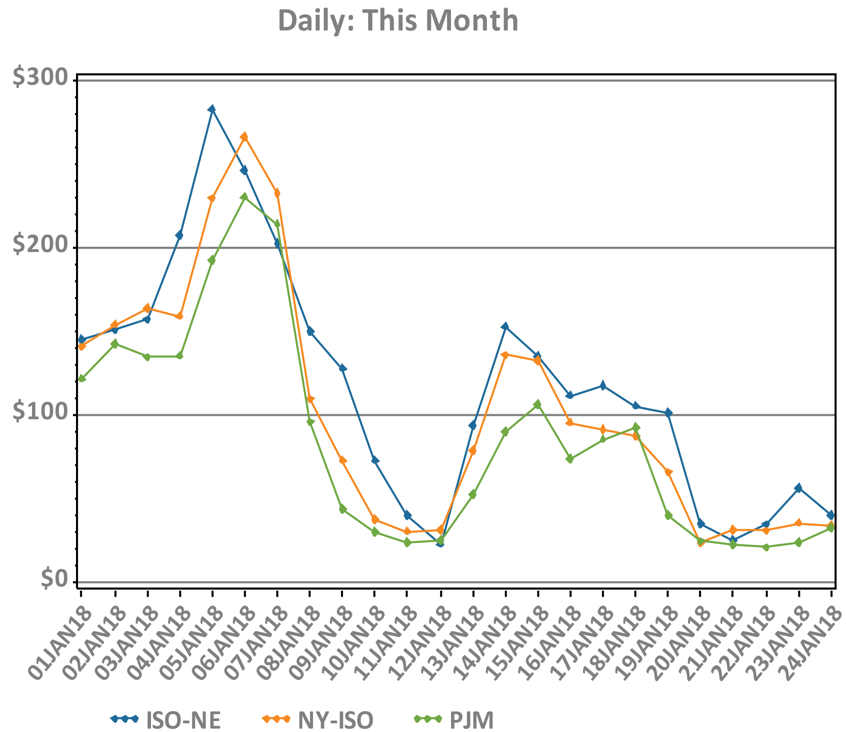
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

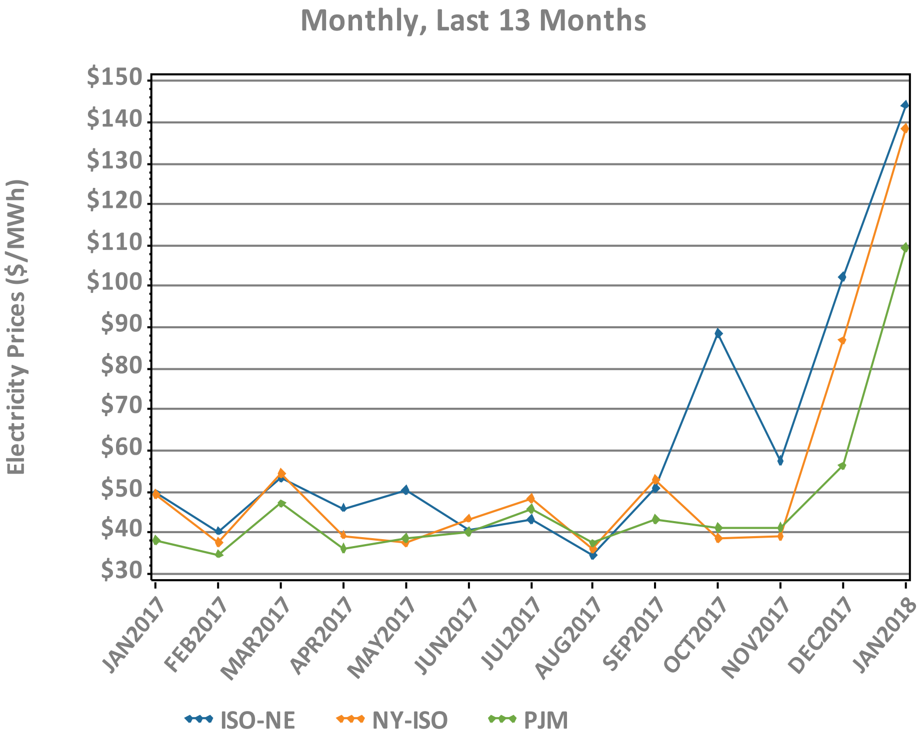


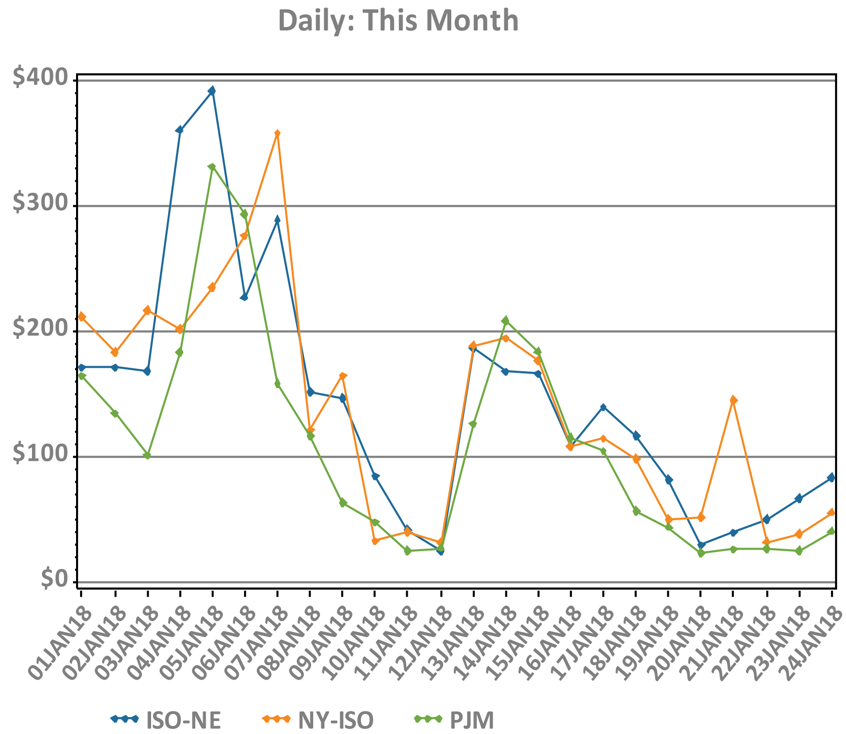
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





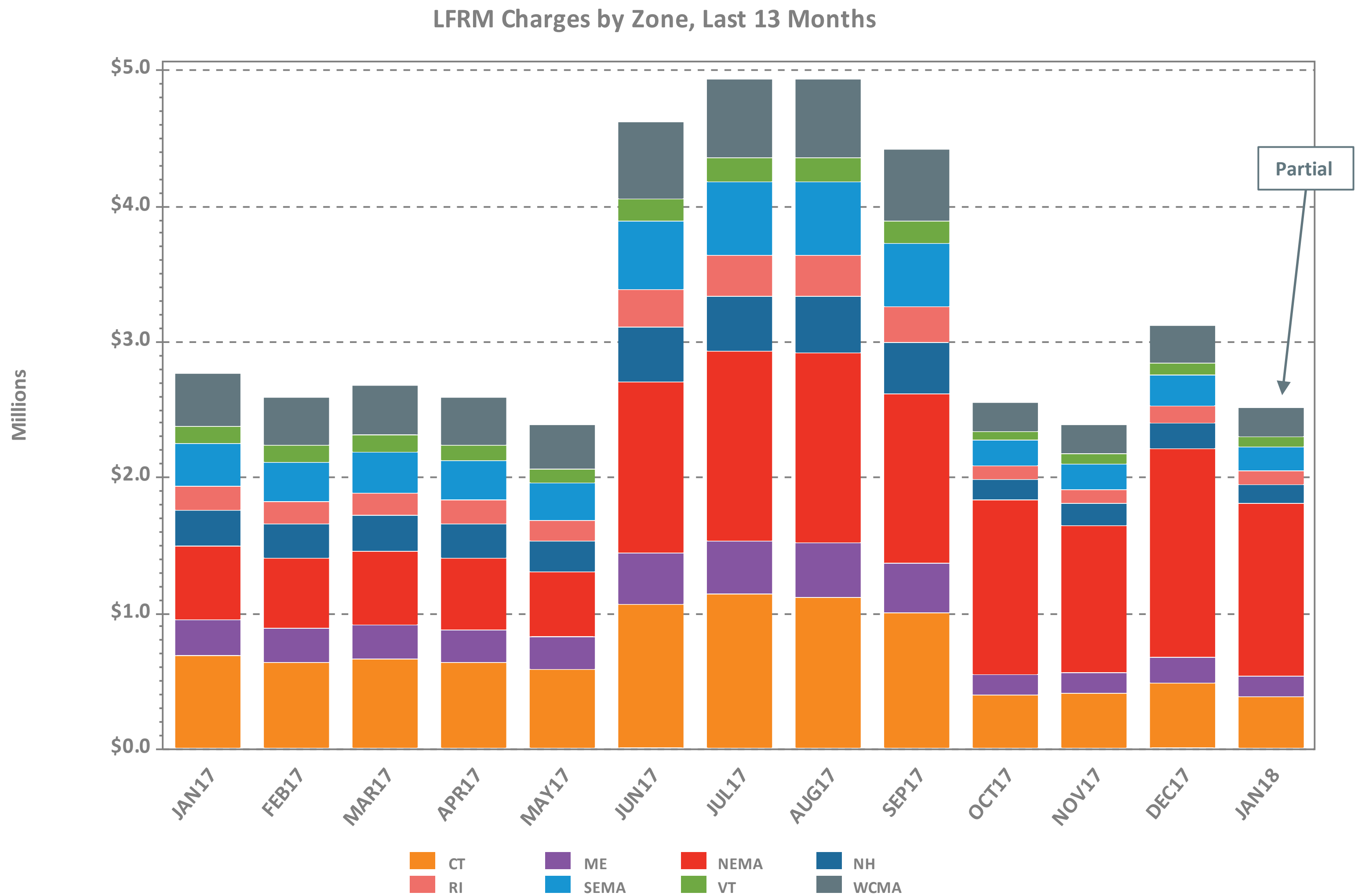
***Forecasted New England daily peak hours reflected**

Reserve Market Results – January 2018

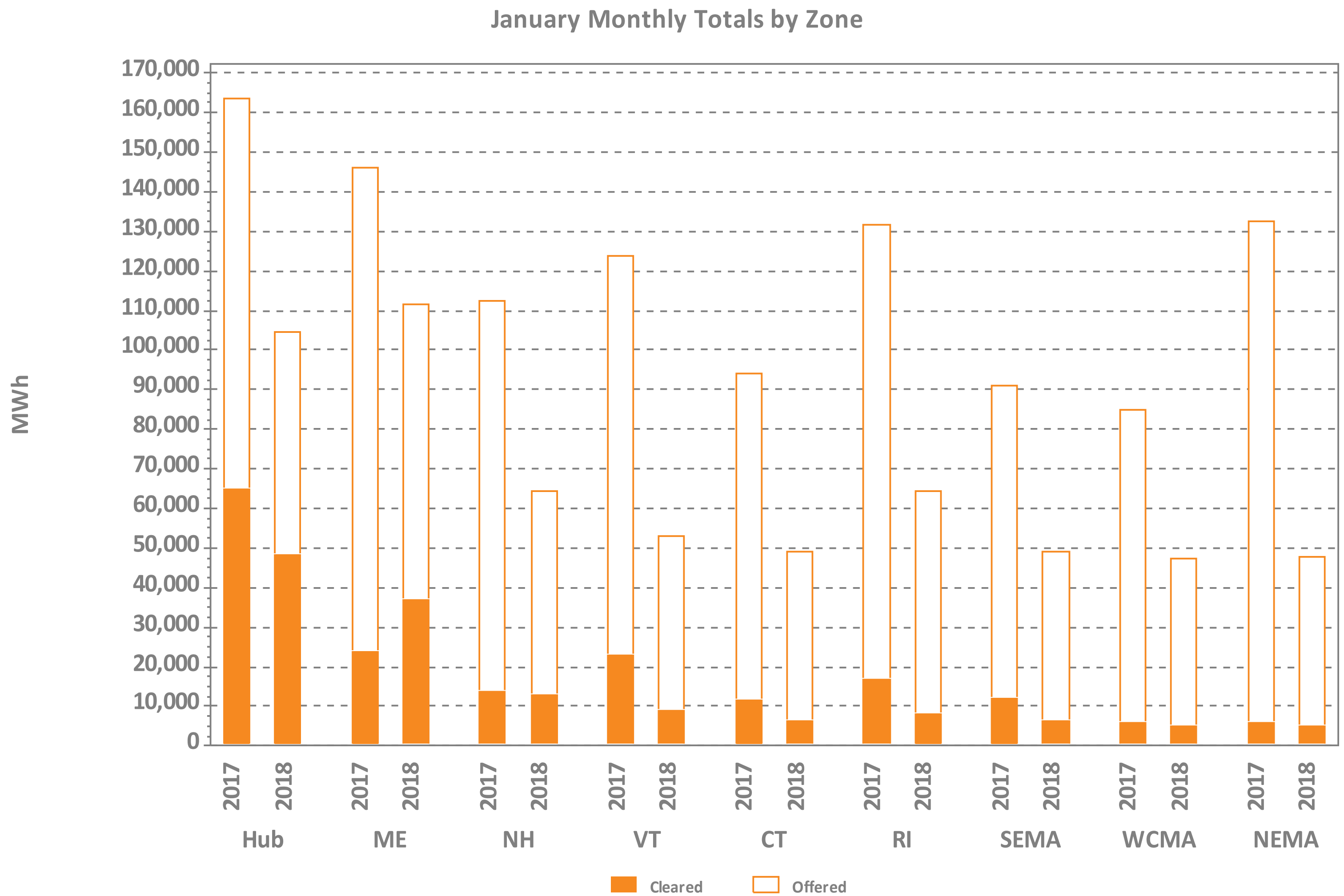
- Maximum potential Forward Reserve Market payments of $2.8M were reduced by credit reductions of $107K, failure-to-reserve penalties of $161K and no failure-to-activate penalties, resulting in a net payout of $2.5M or 90% of maximum
  - Rest of System: $0.84M/0.97M (87%)
  - Southwest Connecticut: $0.08M/0.12M (69%)
  - Connecticut: $0.41M/0.42M (96%)
  - NEMA: $1.2M/1.3M (93%)
- $1.0M total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $1.0M in Real-Time Reserve payments
  - Rest of System: 132 hours, $705K
  - Southwest Connecticut: 132 hours, $106K
  - Connecticut: 132 hours, $86K
  - NEMA: 132 hours, $120K

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

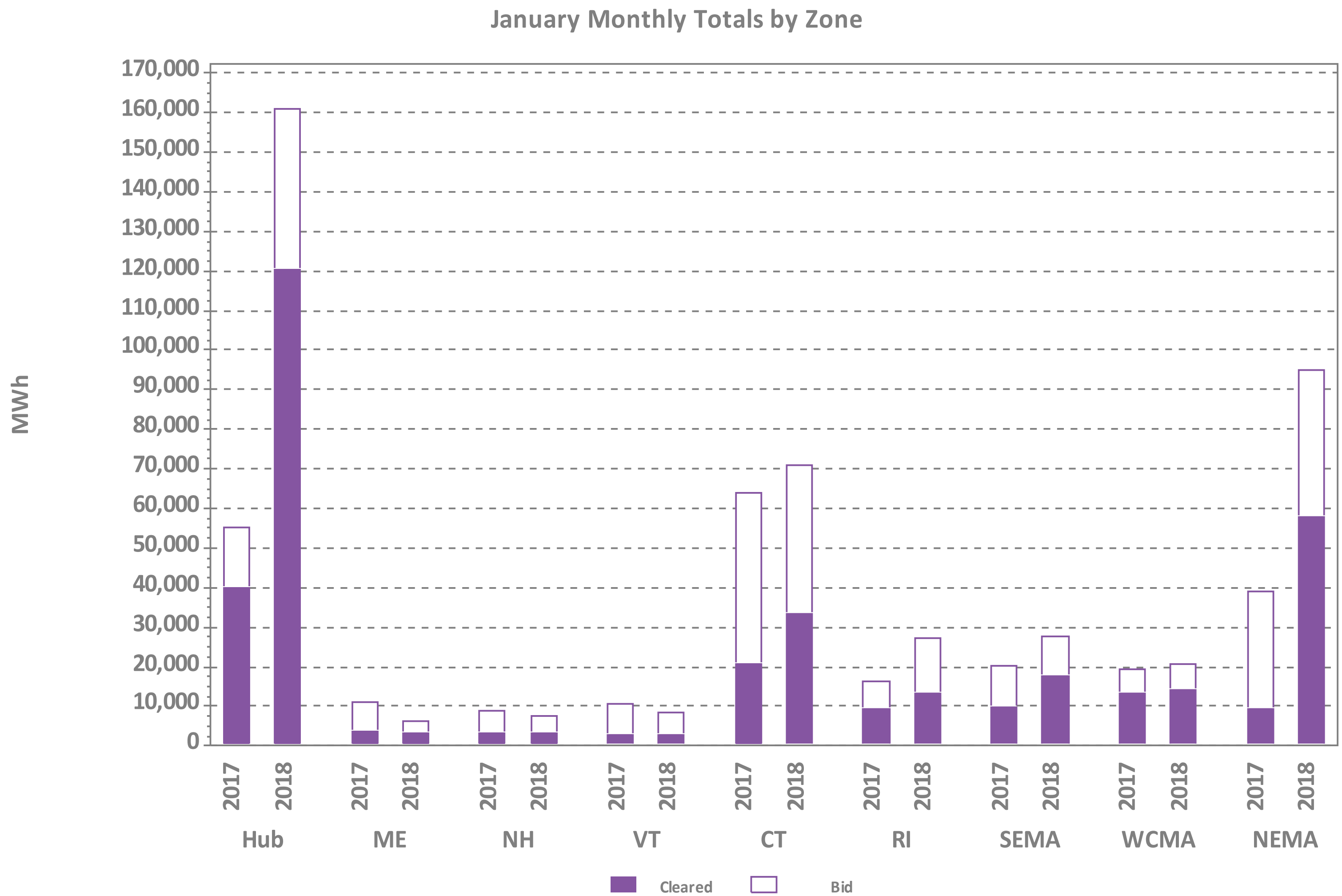
LFRM Charges to Load by Load Zone ($)



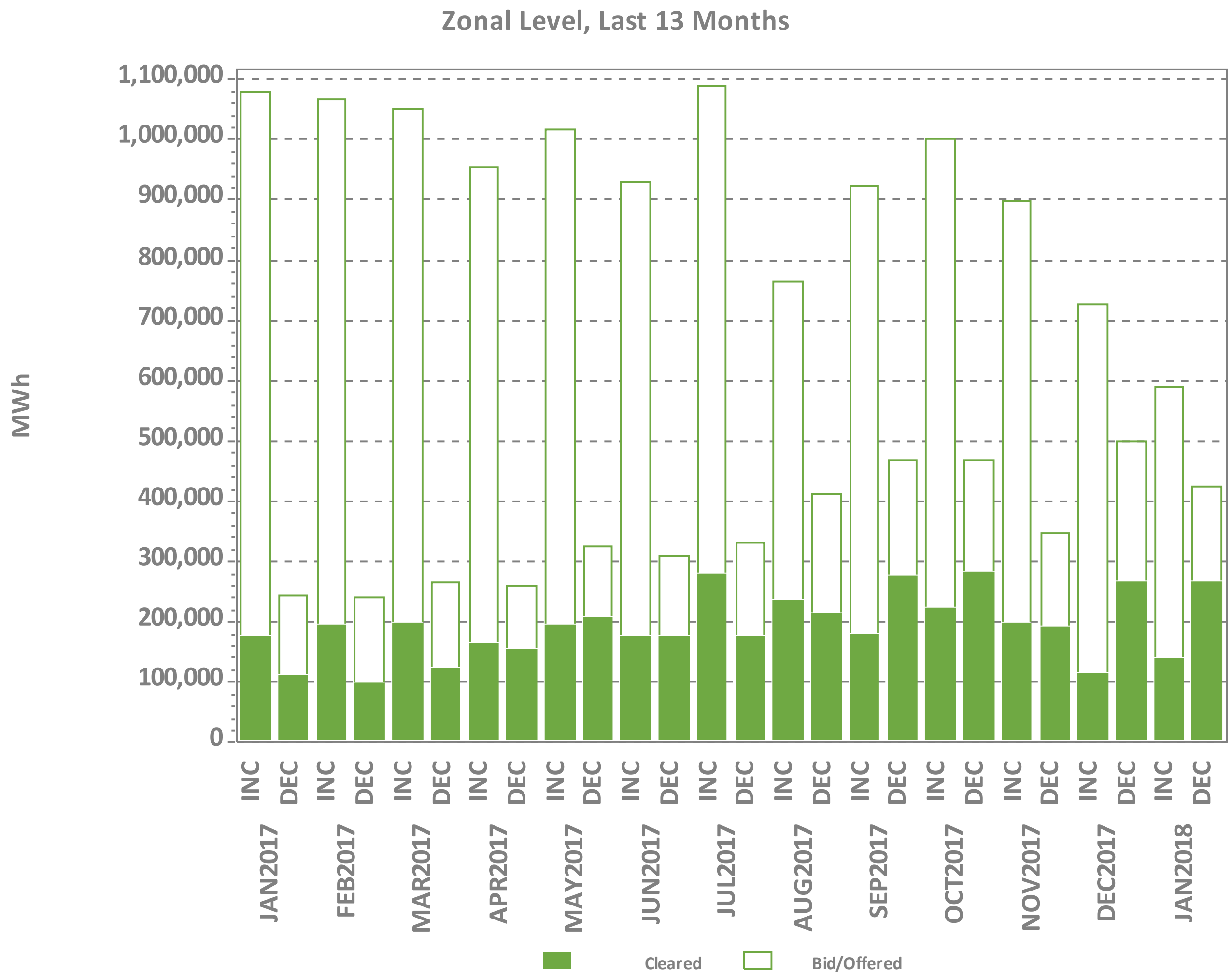
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

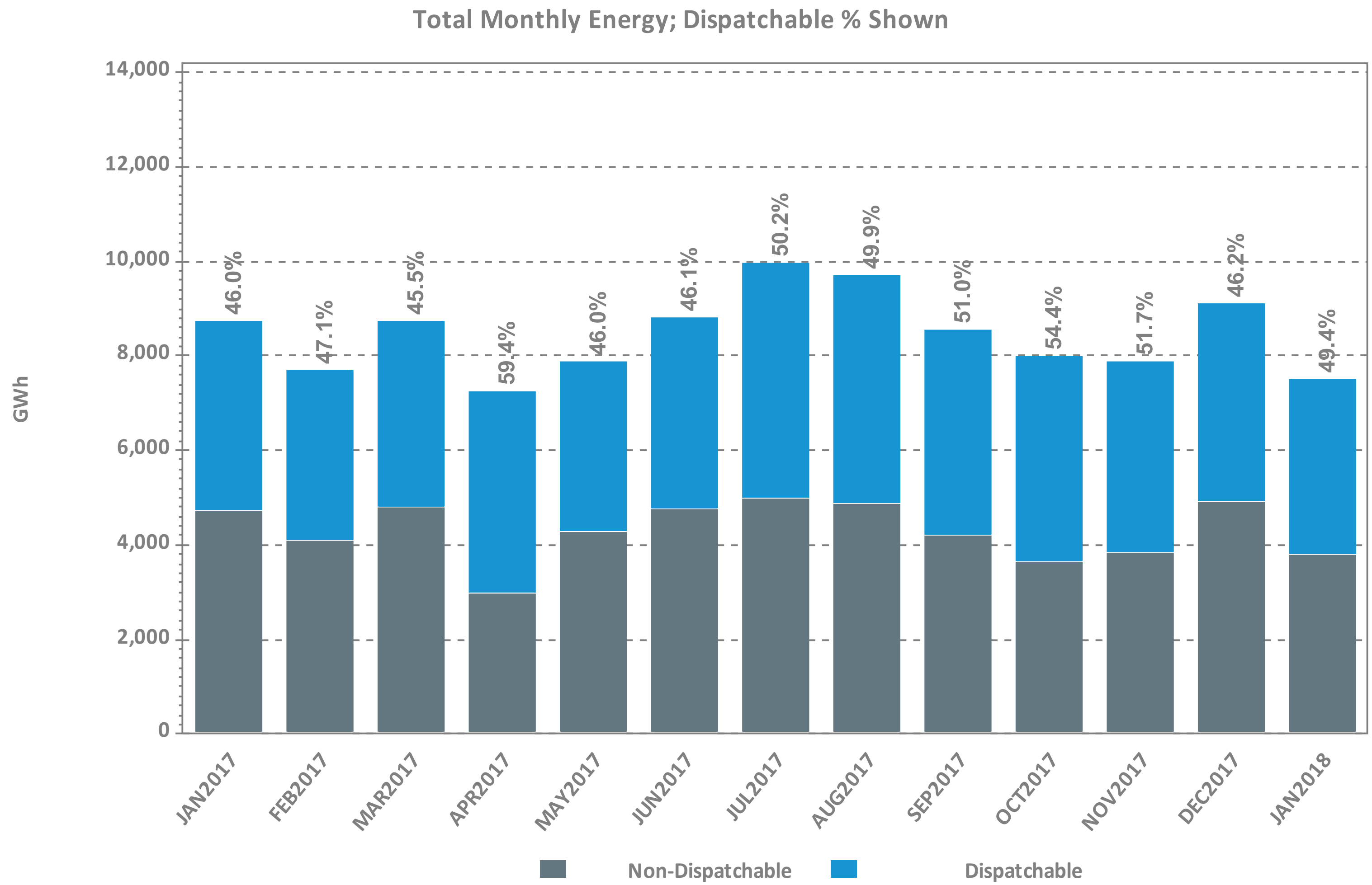


Total Increment Offers and Decrement Bids



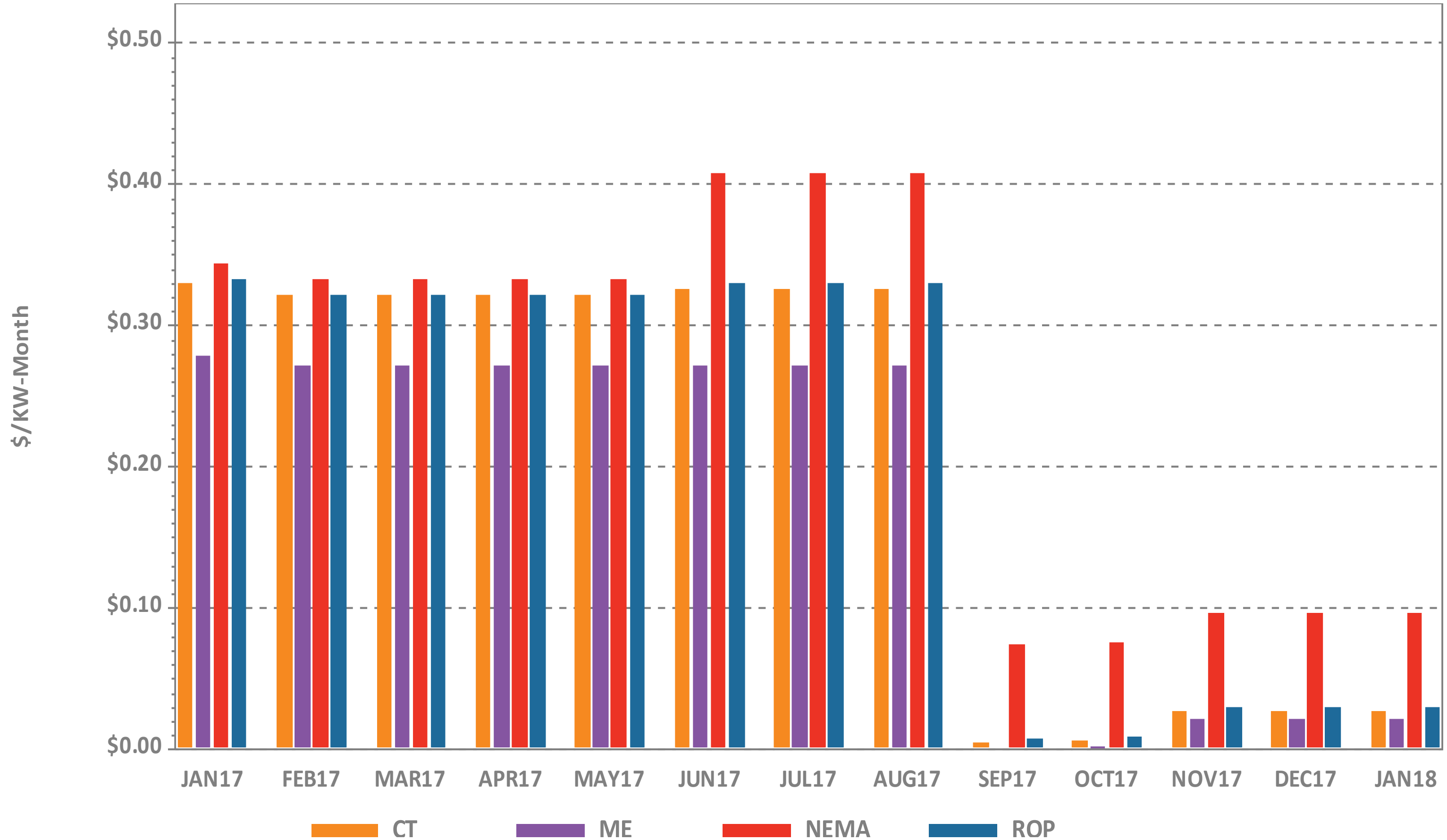
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

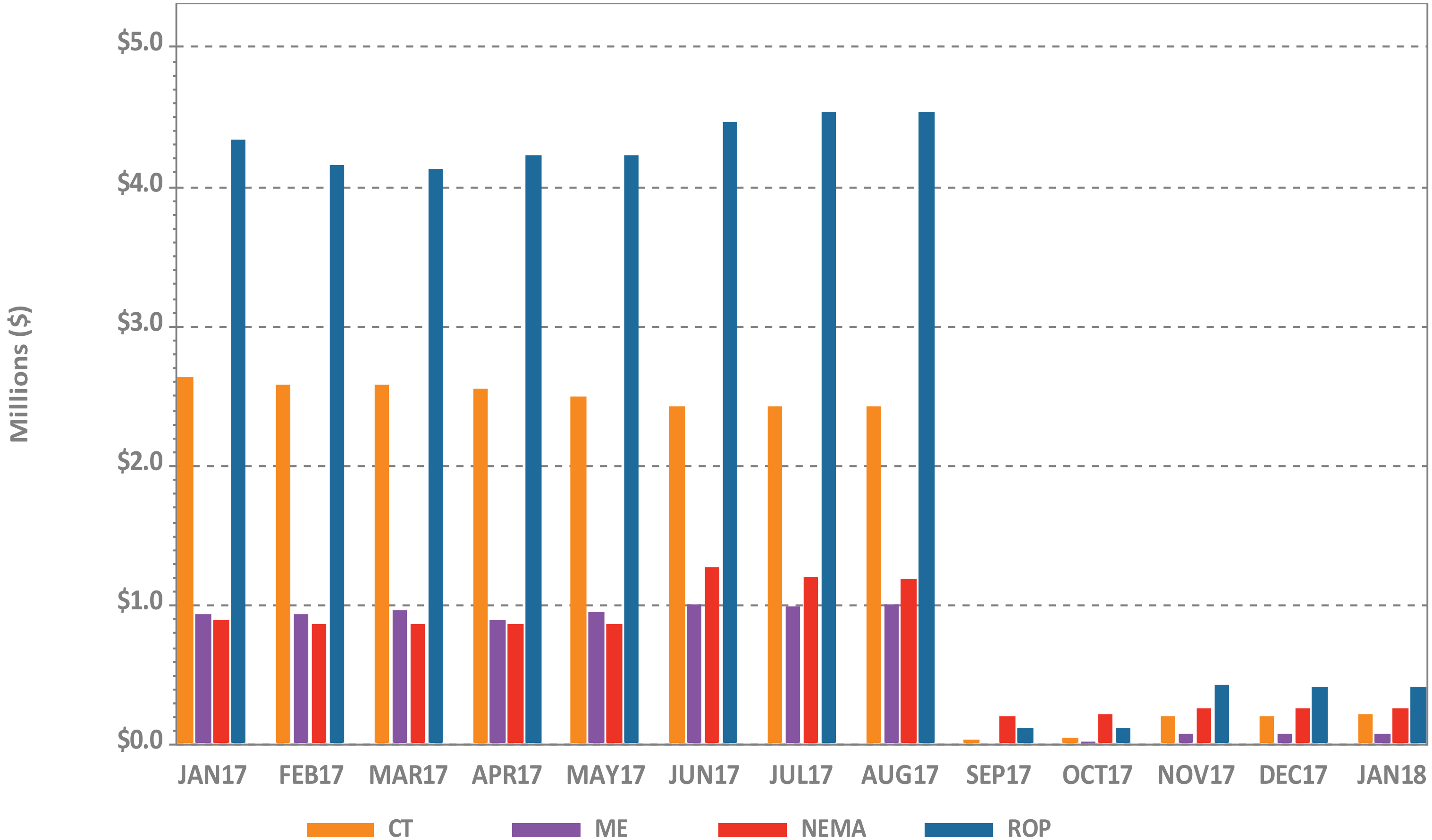
Rolling Average Peak Energy Rent (PER)



Rolling Average PER is currently calculated as a rolling twelve month average of individual monthly PER values for the twelve months preceding the obligation month.

Individual monthly PER values are published to the ISO web site here: Home > Markets > Other Markets Data > Forward Capacity Market > Reports and are subject to resettlement.

PER Adjustments



PER Adjustments are reductions to Forward Capacity Market monthly payments resulting from the rolling average PER.

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- February 14 PAC Meeting Agenda Topics*
  - 2017 Economic Study Draft Results
  - Western and Central MA 2027 Needs Assessment Scope of Work - Revision 1

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

Load, Energy Efficiency, and Photovoltaic Forecast

- The forecast development process for 2018 has commenced, and the draft forecasts will be presented to PAC in March
  - Load Forecast
    - Next Load Forecast Committee meeting will be held on 2/7/18
    - Project to enhance information available on our website to be completed by Q1 2018
  - Energy-Efficiency (EE) Forecast
    - Next EE Forecast Working Group meeting is scheduled for 2/16/18
  - Photovoltaic (PV) Forecast
    - Distributed Generation Forecast Working Group meeting will be held on 2/12/18

Interregional Planning

- The Northeast Coordinated System Plan 2017 (NCSP17) is under development consistent with the scope of work discussed at the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) held on 12/11/17
  - Plans call for posting the draft report for stakeholder comment in the March timeframe

Environmental Matters

- The ISO tracks environmental regulatory developments affecting new and existing generators and transmission infrastructure
  - Environmental Advisory Group will meet on 1/30/18 to discuss various regional environmental developments
  - No comments were received on the 2016 system emissions report, and the final report will be posted shortly
  - EPA accepting comments until 2/28/18 on options for achieving greenhouse gas reductions at existing power plants
    - Also adding more public hearings on proposed Clean Power Plan repeal
  - On 1/23/18, Massachusetts DEP acknowledged questions from stakeholders about the availability of Massachusetts Global Warming Solutions Act generator emission cap allowances and concerns about:
    - Market conditions, allowance supply and price formation during the calendar year
    - Solutions that may include allowing early allowance trading, extending "emergency deferred compliance" option to emergencies that occur throughout the calendar year instead of just the year-end
  - On 1/26/18, Regional Greenhouse Gas Initiative (RGGI) states held a webinar on design issues involved with Virginia joining RGGI

2017 Economic Study

- The 2017 Study will examine three cases with the same basic assumptions that were used in the 2016 Study Scenario 3, but with the retirement of 2,100 MW of nuclear generation and changes in the resource mix to reflect differing amounts of energy efficiency, onshore wind, and offshore wind
  - 2017 Economic Study draft results are scheduled for discussion at the 2/14/18 PAC meeting
  - 2017 Economic Study scope of work and assumptions were discussed with the PAC on 5/25/17

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.

Connecticut River Valley

Status as of 1/26/18

Project Benefit: Addresses system needs in the Connecticut River Corridor in Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	Aug-17	4
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	Aug-18	3
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	Dec-16	4
Chelsea Station - Rebuild to a three-breaker ring bus	Jan-18	4

New Hampshire/Vermont 10-Year Upgrades

Status as of 1/26/18

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	Dec-18	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 1/26/18

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 1/26/18

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 1/26/18

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	3
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 1/26/18

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 new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	3
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)	Dec-18	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 1/26/18

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)	Dec-18	2
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	3
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-18	3
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 1/26/18

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	3
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	Dec-18	3
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 1/26/18

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	Dec-18	3
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	3
Loop the 1570 line in and out the Pootatuck substation	Jul-18	3
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 1/26/18

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	Sep-18	3
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Oct-18	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	3
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	3
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Oct-18	3
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Apr-18	3

Southwest Connecticut Projects, cont.

Status as of 1/26/18

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)	Jun-19	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Jun-19	2

Southwest Connecticut Projects, cont.

Status as of 1/26/18

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	May-18	3
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)	Apr-19	3
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 1/26/18

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 1/26/18

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	Dec-18	2
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-19	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-18	2

Greater Boston Projects, cont.

Status as of 1/26/18

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	Jun-18	2
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-19	3
Install third 115 kV line from West Walpole to Holbrook	Sep-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-19	1

Greater Boston Projects, cont.

Status as of 1/26/18

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	May-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	Dec-18	3
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-19	2
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	May-19	2

Greater Boston Projects, cont.

Status as of 1/26/18

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-18	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	Jun-18	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-18	3
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 1/26/18

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	Dec-18	3
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-18	2
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 1/26/18

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 1/26/18

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

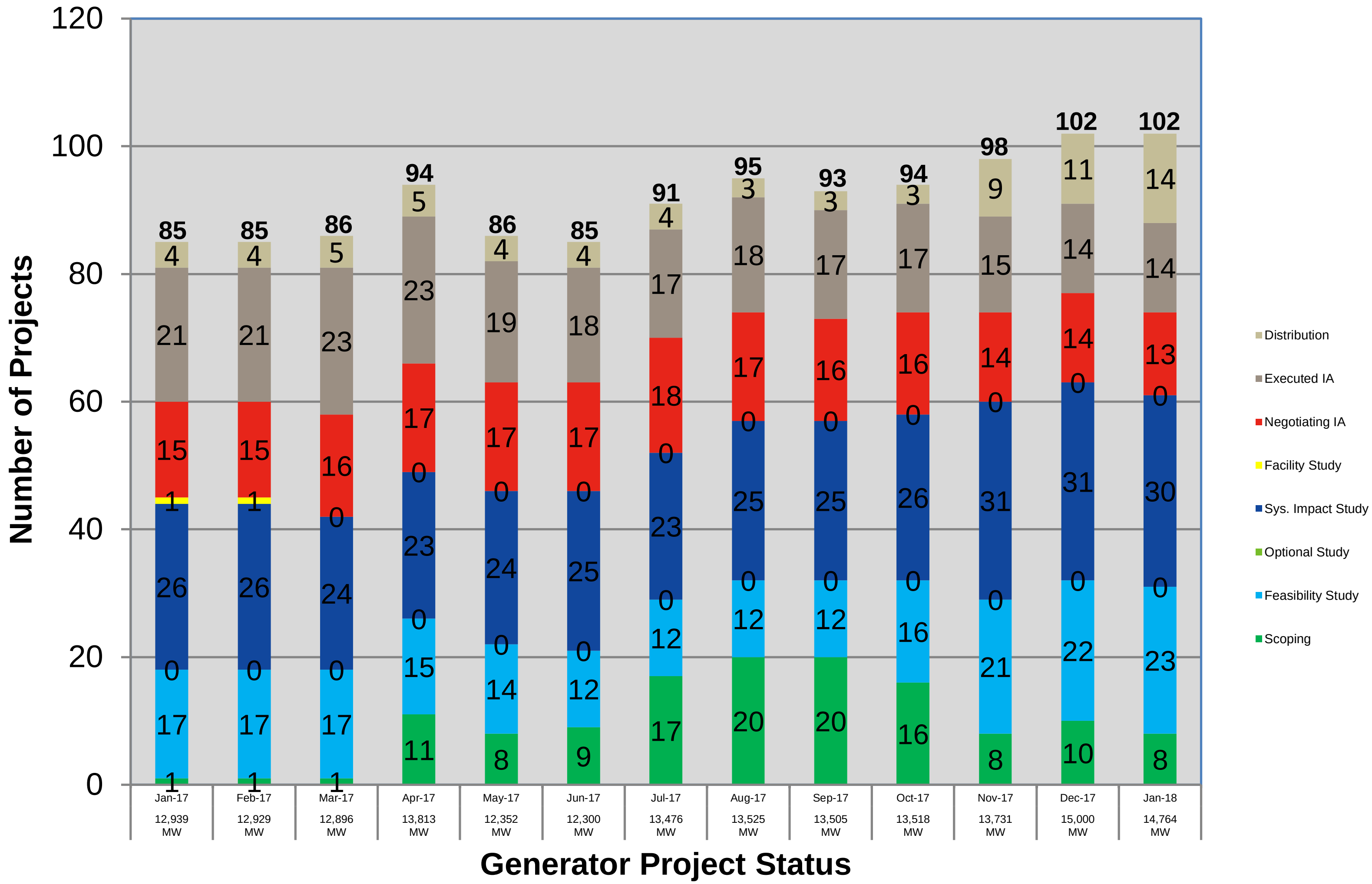
Pittsfield/Greenfield Projects, cont.

Status as of 1/26/18

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	Dec-19	1

Status of Tariff Studies



Note: January 2018 based on partial data

Note: As of January 2018, there are 12 ETU's in SIS, 4 in FS, 1 in Scoping, 1 in FAC, and 4 in Neg. IA

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OPERABLE CAPACITY ANALYSIS

Winter 2017/18

Winter 2018 Operable Capacity Analysis

50/50 Load Forecast (Reference)	February - 2018[2] CSO	February - 2018[2] SCC
Operable Capacity MW [1]	29,797	31,314
OP CAP From OP-4 RTDR (+)	387	387
OP CAP From OP-4 RTEG (+)	1	1
Operable Capacity with OP-4 DR and RTEG	30,185	31,702
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	940	940
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	367	416
Gas Generator Outages MW (-)	674	0
Allowance for Unplanned Outages (-) [5]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [4]	3,063	4,130
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,921	24,996
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,966	20,966
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,271	23,271
Operable Capacity Margin [3]	650	1,725

[1]Operable Capacity is based on data as of **January 16, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **January 16, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 27, 2018**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

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

Winter 2018 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	February - 2018[2] CSO	February - 2018[2] SCC
Operable Capacity MW [1]	29,797	31,314
OP CAP From OP-4 RTDR (+)	387	387
OP CAP From OP-4 RTEG (+)	1	1
Operable Capacity with OP-4 DR and RTEG	30,185	31,702
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	940	940
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	367	416
Gas Generator Outages MW (-)	674	0
Allowance for Unplanned Outages (-) [5]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [4]	3,479	4,589
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,505	24,537
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,658	21,658
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,963	23,963
Operable Capacity Margin [3]	-458	574

[1] Operable Capacity is based on data as of **January 16, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **January 16, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 27, 2018**

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

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

Winter 2018 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

February 2, 2018 - 50/50 FORECAST using CSO values with RTDR and RTEG

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	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	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
1/27/2018	**29,797**	**940**	**0**	**367**	**674**	**3,100**	**3,063**	**23,533**	**20,966**	**2,305**	**23,271**	**262**	**387**	**649**	**1**	**650**
2/3/2018	29,797	940	0	475	545	3,100	3,192	23,425	20,690	2,305	22,995	430	387	817	1	818
2/10/2018	29,797	940	0	155	545	3,100	2,777	24,160	20,660	2,305	22,965	1,195	387	1,582	1	1,583
2/17/2018	29,797	940	0	858	545	3,100	2,500	23,734	20,388	2,305	22,693	1,041	387	1,428	1	1,429
2/24/2018	29,797	940	0	1,668	545	3,100	1,947	23,477	19,366	2,305	21,671	1,806	387	2,193	1	2,194
3/3/2018	29,797	1,202	0	1,616	674	2,200	1,402	25,107	19,004	2,305	21,309	3,798	387	4,185	1	4,186
3/10/2018	29,797	1,202	0	2,002	674	2,200	1,264	24,859	18,802	2,305	21,107	3,752	387	4,139	1	4,140
3/17/2018	29,797	1,202	0	2,718	674	2,200	710	24,697	18,424	2,305	20,729	3,968	387	4,355	1	4,356
3/24/2018	29,797	1,202	0	3,783	674	2,200	295	24,047	17,839	2,305	20,144	3,903	387	4,290	1	4,291
3/31/2018	29,776	1,302	0	4,434	1,923	2,700	0	22,021	17,071	2,305	19,376	2,645	380	3,025	2	3,027

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2017 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 26,482 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV) http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Winter 2018 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

February 2, 2018 - 90/10 FORECAST using CSO values with RTDR and RTEG

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	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR 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	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
1/27/2018	**29,797**	**940**	**0**	**367**	**674**	**3,100**	**3,479**	**23,117**	**21,658**	**2,305**	**23,963**	**(846)**	**387**	**(459)**	**1**	**(458)**
2/3/2018	29,797	940	0	475	545	3,100	3,608	23,009	21,373	2,305	23,678	(669)	387	(282)	1	(281)
2/10/2018	29,797	940	0	155	545	3,100	3,146	23,791	21,342	2,305	23,647	144	387	531	1	532
2/17/2018	29,797	940	0	858	545	3,100	2,839	23,395	21,062	2,305	23,367	28	387	415	1	416
2/24/2018	29,797	940	0	1,668	545	3,100	2,223	23,201	20,009	2,305	22,314	887	387	1,274	1	1,275
3/3/2018	29,797	1,202	0	1,616	674	2,200	1,633	24,876	19,636	2,305	21,941	2,935	387	3,322	1	3,323
3/10/2018	29,797	1,202	0	2,002	674	2,200	1,479	24,644	19,428	2,305	21,733	2,911	387	3,298	1	3,299
3/17/2018	29,797	1,202	0	2,718	674	2,200	864	24,543	19,038	2,305	21,343	3,200	387	3,587	1	3,588
3/24/2018	29,797	1,202	0	3,783	674	2,200	403	23,939	18,436	2,305	20,741	3,198	387	3,585	1	3,586
3/31/2018	29,776	1,302	0	4,434	1,923	2,700	0	22,021	17,652	2,305	19,957	2,064	380	2,444	2	2,446

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2017 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 26,482 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV) http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
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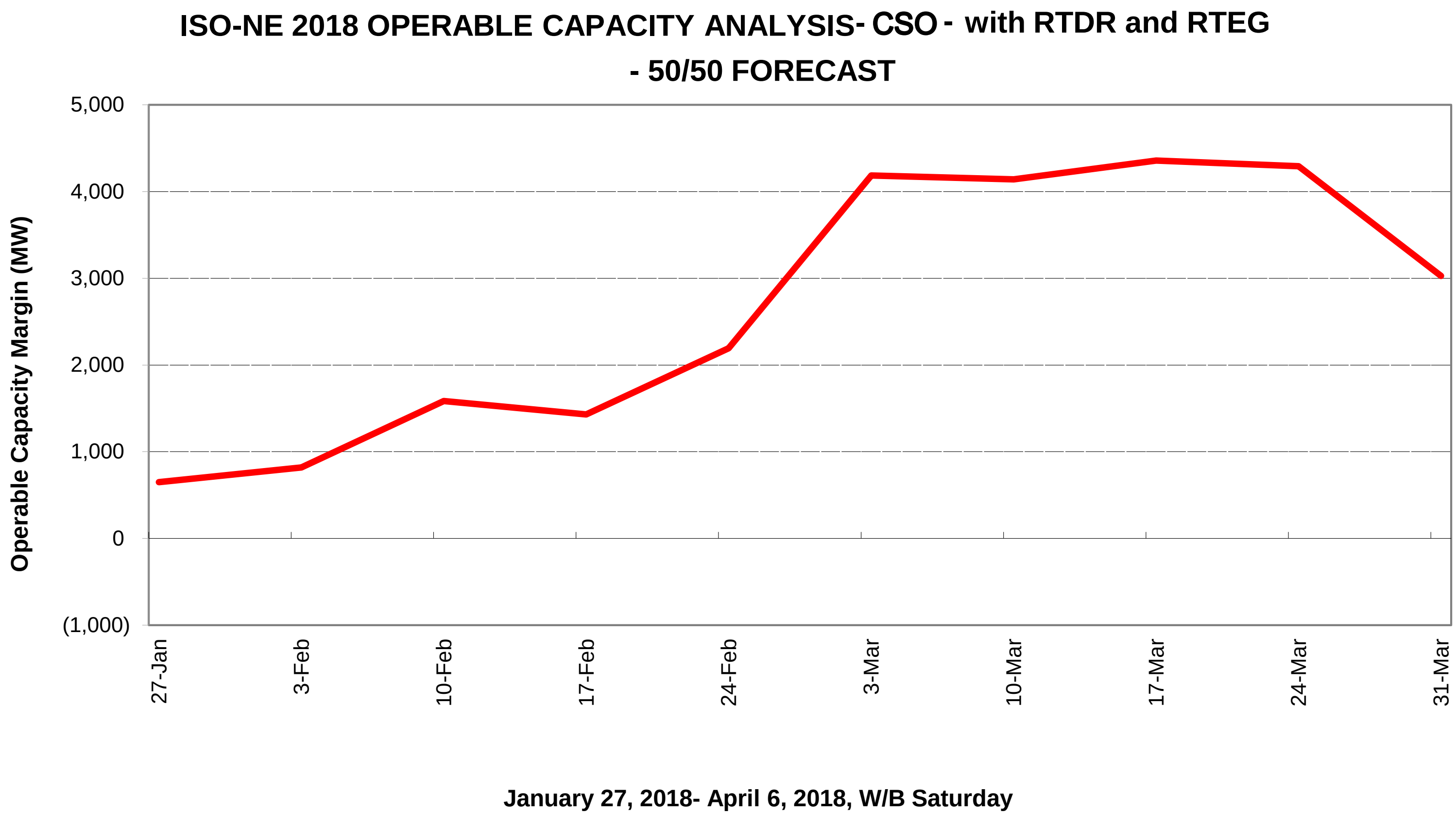
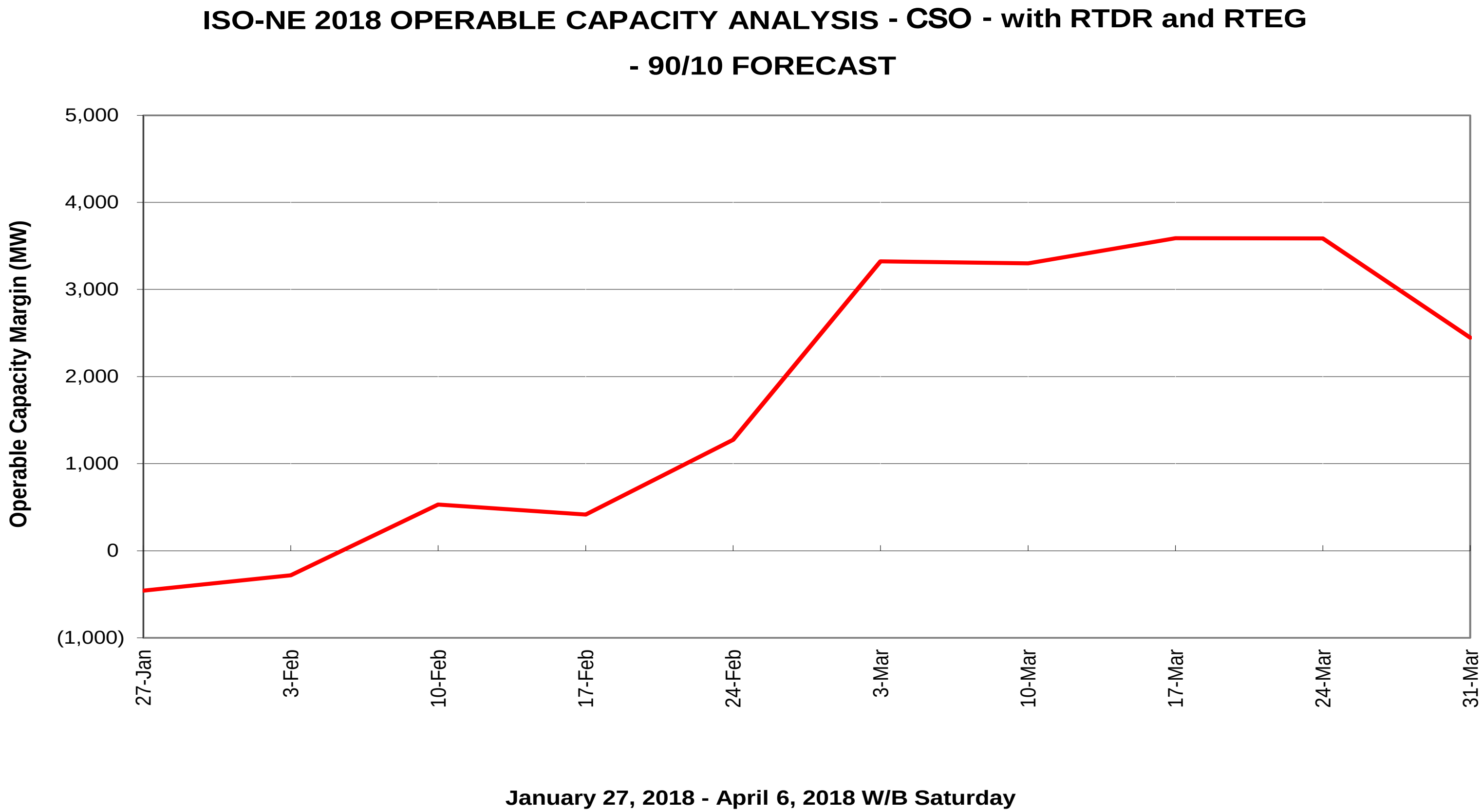
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Winter 2018 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Winter 2018 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Spring 2018

Preliminary Spring 2018 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2018[2] CSO	May - 2018[2] SCC
Operable Capacity MW [1]	29,776	31,314
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	30,158	31,696
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,202	1,202
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,976	3,387
Gas Generator Outages MW (-)	2,252	1,793
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	22,732	24,318
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,473	19,473
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,778	21,778
Operable Capacity Margin [3]	954	2,540

[1]Operable Capacity is based on data as of **January 16, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **January 16, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 5, 2018.**

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

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

Preliminary Spring 2018 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2018[2] CSO	May - 2018[2] SCC
Operable Capacity MW [1]	29,776	31,314
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	30,158	31,696
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,202	1,202
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,976	3,387
Gas Generator Outages MW (-)	2,252	1,793
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	22,732	24,318
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,301	21,301
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,606	23,606
Operable Capacity Margin [3]	-874	712

[1]Operable Capacity is based on data as of **January 16, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **January 16, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 5, 2018**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

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

Preliminary Spring 2018 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

February 2, 2018 - 50/50 FORECAST using CSO values with RTDR and RTEG

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	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	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
4/7/2018	29,776	1,302	0	4,290	1,830	2,700	0	22,258	16,811	2,305	19,116	3,142	380	3,522	2	3,524
4/14/2018	29,776	1,202	0	5,062	1,686	2,700	0	21,530	16,283	2,305	18,588	2,942	380	3,322	2	3,324
4/21/2018	29,776	1,202	0	4,512	1,461	2,700	0	22,305	16,009	2,305	18,314	3,991	380	4,371	2	4,373
4/28/2018	29,776	1,202	0	4,301	1,191	3,400	0	22,086	15,291	2,305	17,596	4,490	380	4,870	2	4,872
5/5/2018	**29,776**	**1,202**	**0**	**2,976**	**2,252**	**3,400**	**0**	**22,350**	**19,473**	**2,305**	**21,778**	**572**	**380**	**952**	**2**	**954**
5/12/2018	29,776	1,202	0	1,923	2,238	3,400	0	23,417	20,507	2,305	22,812	605	380	985	2	987
5/19/2018	29,776	1,091	0	1,877	951	3,400	0	24,639	21,467	2,305	23,772	867	380	1,247	2	1,249
5/26/2018	29,776	1,202	0	908	698	3,400	0	25,972	22,521	2,305	24,826	1,146	380	1,526	2	1,528

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2017 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 26,482 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV) http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Preliminary Spring 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

February 2, 2018 - 90/10 FORECAST using CSO values with RTDR and RTEG

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	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	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
4/7/2018	29,776	1,302	0	4,290	1,830	2,700	0	22,258	17,384	2,305	19,689	2,569	380	2,949	2	2,951
4/14/2018	29,776	1,202	0	5,062	1,686	2,700	0	21,530	16,841	2,305	19,146	2,384	380	2,764	2	2,766
4/21/2018	29,776	1,202	0	4,512	1,461	2,700	0	22,305	16,558	2,305	18,863	3,442	380	3,822	2	3,824
4/28/2018	29,776	1,202	0	4,301	1,191	3,400	0	22,086	15,839	2,305	18,144	3,942	380	4,322	2	4,324
5/5/2018	**29,776**	**1,202**	**0**	**2,976**	**2,252**	**3,400**	**0**	**22,350**	**21,301**	**2,305**	**23,606**	**(1,256)**	**380**	**(876)**	**2**	**(874)**
5/12/2018	29,776	1,202	0	1,923	2,238	3,400	0	23,417	22,420	2,305	24,725	(1,308)	380	(928)	2	(926)
5/19/2018	29,776	1,091	0	1,877	951	3,400	0	24,639	23,459	2,305	25,764	(1,125)	380	(745)	2	(743)
5/26/2018	29,776	1,202	0	908	698	3,400	0	25,972	24,600	2,305	26,905	(933)	380	(553)	2	(551)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2017 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 26,482 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV) http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
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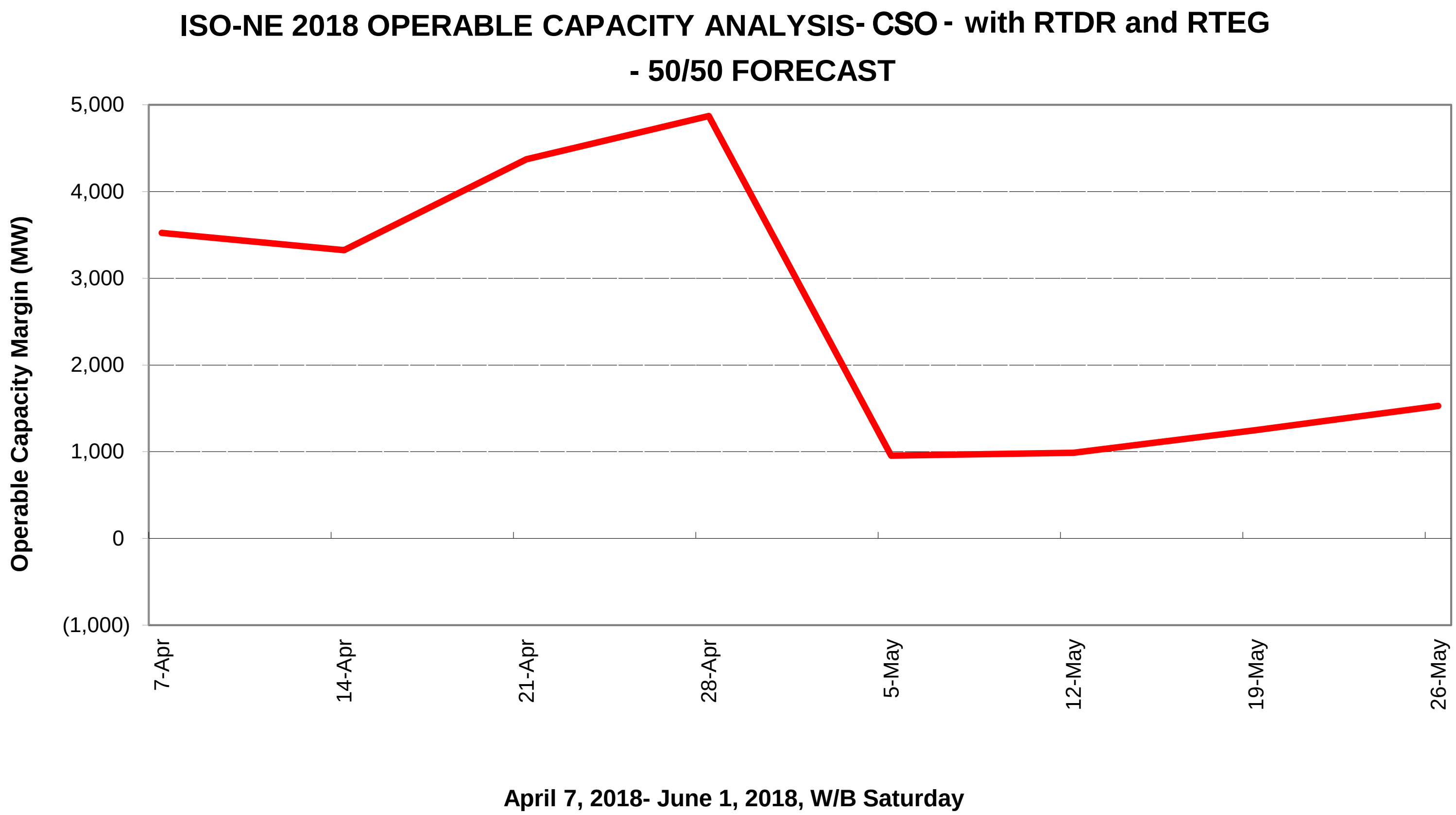
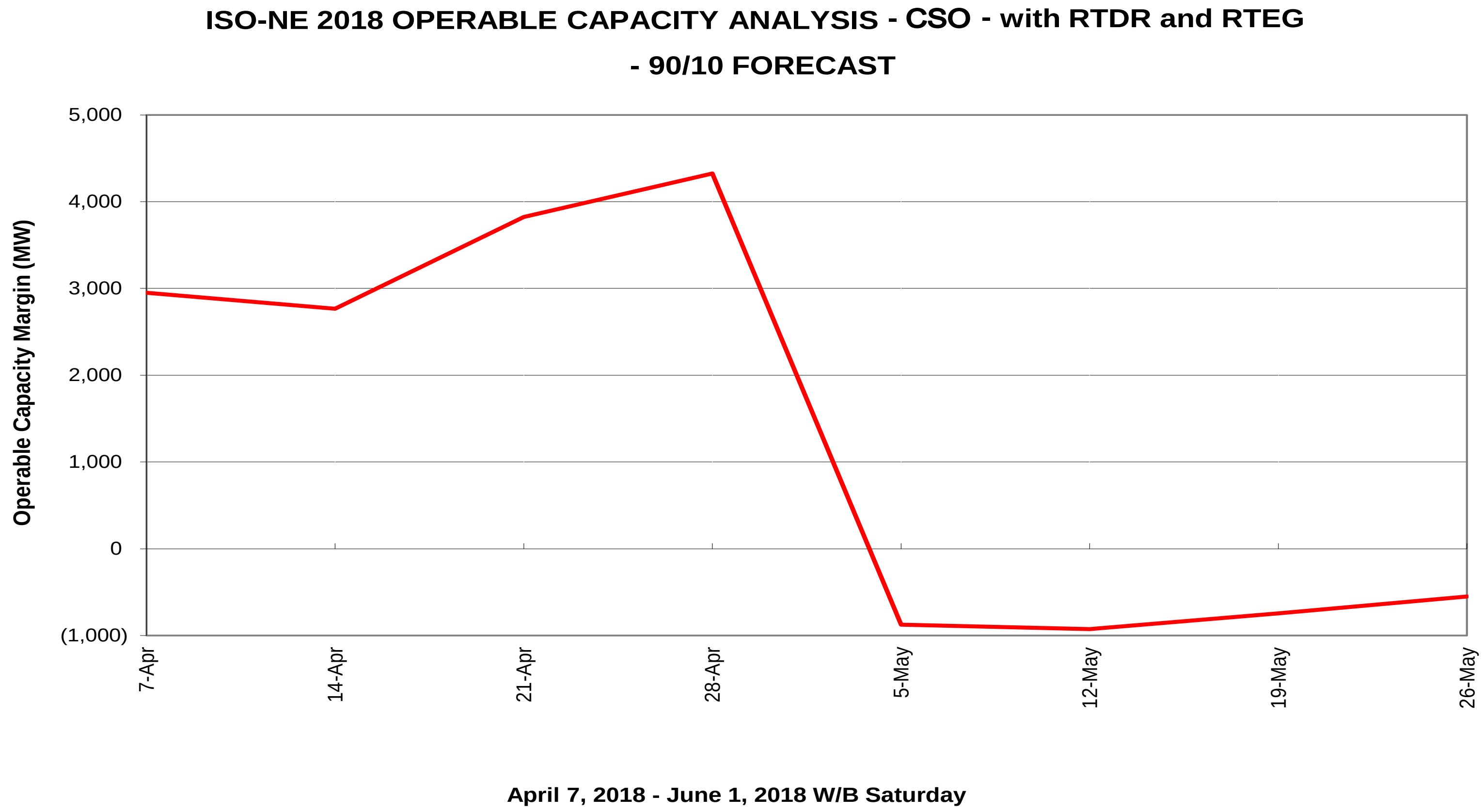
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Spring 2018 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Spring 2018 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify “Settlement Only” generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	**February - March 387** [3] **April - May 380** [3]
3	Voluntary Load Curtailment of Market Participants’ facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	133 [4] **February - March 1** [3] **April - May 2** [3]

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of January 16, 2018.
4. The MW values are based on a 26,482 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A, cont.

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	265 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**February - March 2,931 [3]** **April - May 2,925 [3]**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of January 16, 2018.
4. The MW values are based on a 26,482 MW system load and the most recent voltage reduction test % achieved.