Summary of ISO New England Board and Committee Meetings

January 4, 2019 Participants Committee Meeting

Since the last update, the Markets Committee, the System Planning and Reliability Committee, the Audit and Finance Committee, the Compensation and Human Resources Committee, the Nominating and Governance Committee, and the Board of Directors each met on December 13 in Holyoke.

The Markets Committee received an update on winter energy security, including a review of market design objectives and the alternatives that had been considered as long-term fuel security solutions to address the risks facing the region. The Committee considered the timing for stakeholder review and discussion. Next, the Committee held a conversation on the risks within its purview, and reviewed its calendar for 2019. Finally, the Committee held an executive session to discuss corporate goals for 2019.

The System Planning and Reliability Committee was provided with an overview of activities and events that were a major focus during the late summer and fall of 2018, including qualifications for Forward Capacity Auction #13, the cluster study process to address the queue backlog in Maine, and ongoing FERC Order 1000 implementation. In addition, the Committee also previewed activities anticipated to be a major focus for the first quarter of 2019, including the development of the 2019 Regional System Plan. Next, the Committee reviewed a dashboard summary of ongoing projects, received an update on the system operations outlook for Winter 2018-2019, and reviewed the status of Regional System Plan projects. The Committee was also provided with an overview of enhancements to Operating Procedure No. 21 that relate to energy emergency forecasting and reporting. Finally, the Committee reviewed its calendar for 2019, and held an executive session to discuss corporate goals for 2019.

The Audit and Finance Committee discussed the results of the Northeast Power Coordinating Council's Critical Infrastructure Protection ("CIP") audit and the Company's cyber security work plan objectives for 2019. The Committee reviewed highlights of the work plan, which include upcoming projects related to identity and access management, participation in the GridEx V exercise, conducting a compromise assessment, and CIP controls enhancements. The Committee also reviewed its calendar for 2019. The Committee then met in executive session to review the corporate goals for 2019 and to assess achievement of 2018 corporate goals.

The Compensation and Human Resources Committee convened and reviewed the goal setting, assessment and compensation schedule for 2019. The Committee also reviewed its calendar for the upcoming year and received an update on employee benefits enrollment for 2019.

The Nominating and Governance Committee received a report on Joint Nominating Committee activities, and received a post-election update on the New England and federal political environments. Next, the Committee discussed ongoing director education, including possible site visits and potential speakers for future board meetings. Finally, the Committee reviewed its calendar for 2019.

The Board of Directors met to discuss winter energy security and to continue its discussion on risk management and strategic planning. The Board received an update on winter energy security and discussed interim and long-term solutions to address fuel security risks facing the region. The Board considered the various alternatives to address these risks, and considered the adequacy of the timeline for the design and analysis of key elements, integration of the complex interrelated market enhancements and stakeholder review and discussion of the proposed market changes. The Board discussed several other risk-related topics and the capacity markets in general. Finally, the Board received reports from the standing committees outlining highlights from their recent meetings.

NEPOOL Participants Committee Report

January 2019

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value over the period was $492M, down $111M from November 2018 and down $364M from December 2017
    - December natural gas prices over the period were 4% lower than November 2018 average values
    - Average RT Hub Locational Marginal Prices ($44.55/MWh) over the period were 19.7% lower than November averages
      - Average DA Hub LMP: $50.21/MWh
    - Average December 2018 natural gas prices and RT Hub LMPs over the period were down 38% and 44%, respectively, from December 2017 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98% during December, up from 97.6% during November*
    - The minimum value for the month was 92.6% on Sunday, Dec. 3**

Data are through December 27 (NCPC through December 26), 2018 unless otherwise noted.

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

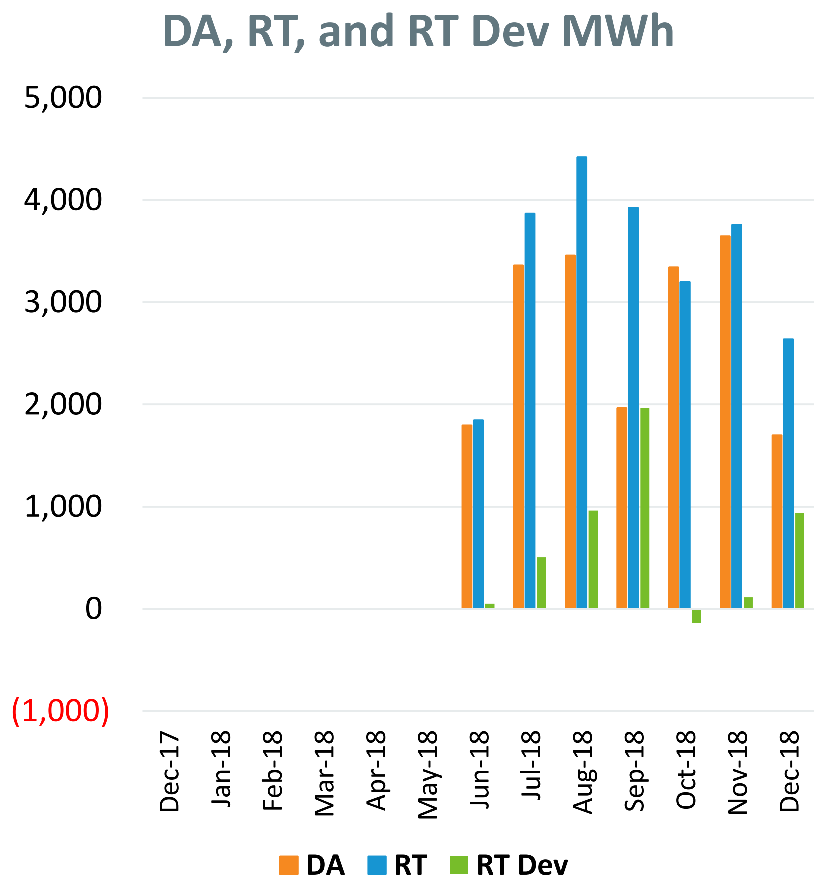
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**
****Daily values shown on slide 33**

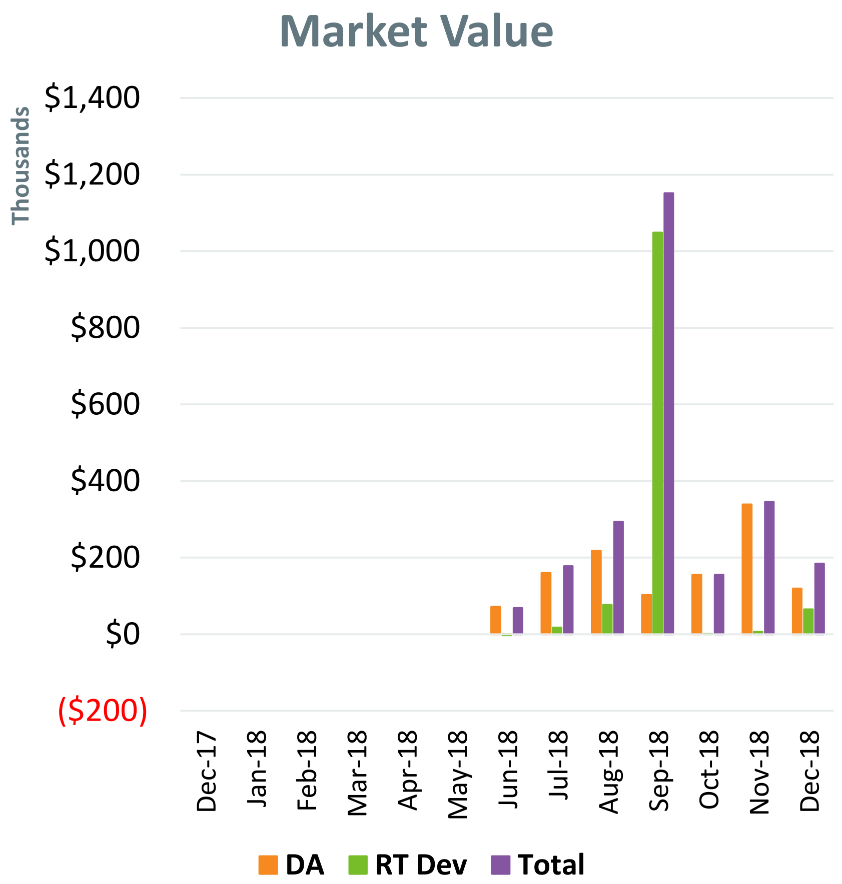
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - December NCPC payments totaled $3M over the period, down $1.6M from November 2018 and down $4M from December 2017
    - First Contingency* payments totaled $2.1M, down $1.8M from November
      - $2M paid to internal resources, down $1.6M from November
        - » $506K charged to DALO, $770K to RT Deviations, $794K to RTLO
      - $41K paid to resources at external locations, down $175K from November
        - » $38K charged to RT Deviations
    - Second Contingency payments totaled $0.9M, up $291K from November
  - NCPC payments over the period as percent of Energy Market value were 0.6%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $285K; Rapid Response Pricing (RRP) Opportunity Cost - $280K; Posturing - $41K; Generator Performance Auditing (GPA) - $188K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- The thirteenth Forward Capacity Auction will be held beginning February 4, and will include the first substitution auction running as part of the CASPR design
- There is a significant influx of new project proposals in the ISO's interconnection queue
  - There are now over 20,000 MW of resources in the interconnection queue

Forward Capacity Market (FCM) Highlights

- CCP 9 (2018-2019)
  - Late, new resources are being monitored closely
- CCP 10 (2019-2020)
  - ARA ICR & related values were filed with FERC on November 30 and we are awaiting an order
  - Third bilateral transaction window closed on December 7 and results to be posted by January 11
  - Third and final reconfiguration auction will be March 1-5 and results will be posted no later than March 19

ARA – Annual Reconfiguration Auction
CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

FCM Highlights, cont.

- CCP 11 (2020-2021)
  - Resources may no longer trade their Capacity Supply Obligation via bilateral transactions
  - Second reconfiguration auction will be August 1-5 and results to be posted by September 3
- CCP 12 (2021-2022)
  - First reconfiguration auction will be June 3-5

FCM Highlights, cont.

- CCP 13 (2022-2023)
  - Renewable technology resource election cap is approximately 481 MW.
  - Both the ICR & related values and informational FERC filings were made on November 6. FERC accepted the informational filing on December 19 and is expected to rule on the ICR & related values filing by January 18.
  - The primary auction will commence on February 4, 2019, and the ISO plans to administer the substitution auction immediately following the primary auction
  - Preparation activities include:
    - Resource Review: January 23
    - Mock Auction: January 28

- CCP 14 (2023-2024)
  - Preparations for qualification have begun
  - Upcoming training for existing capacity resources:
    - Qualification: January 10
    - Delist: January 24

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 12, 2019.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.6°F) Max: 65°F, Min: 20°F Precipitation: 2.72" – Above Normal Normal: 3.78" Snow: 0.10"	Hartford	Temperature: Above Normal (1.6°F) Max: 63°F, Min: 12°F Precipitation: 4.96" - Above Normal Normal: 3.44" Snow: 0.20"

Peak Load:	18,318 MW	December, 18, 2018	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

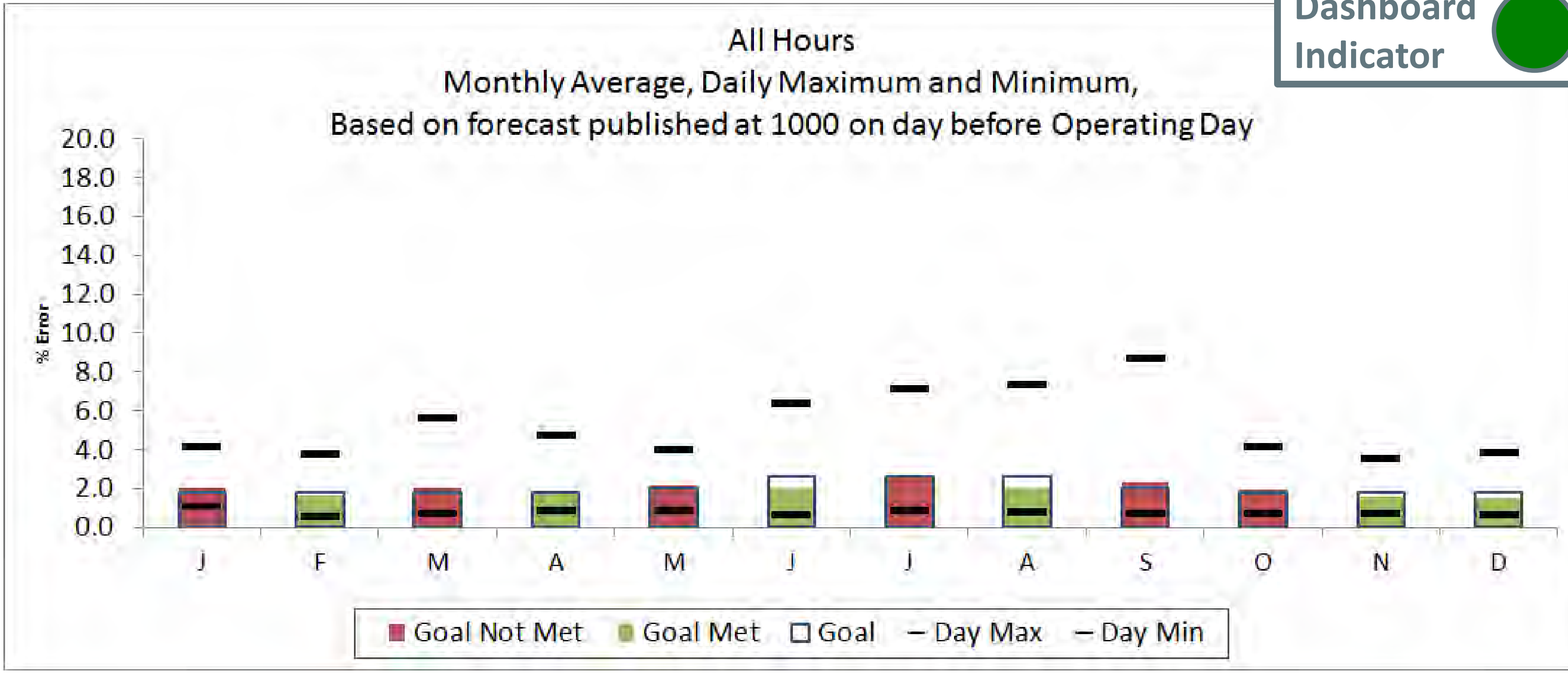
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
12/12/2018	NYISO	1000

2018 System Operations - Load Forecast Accuracy

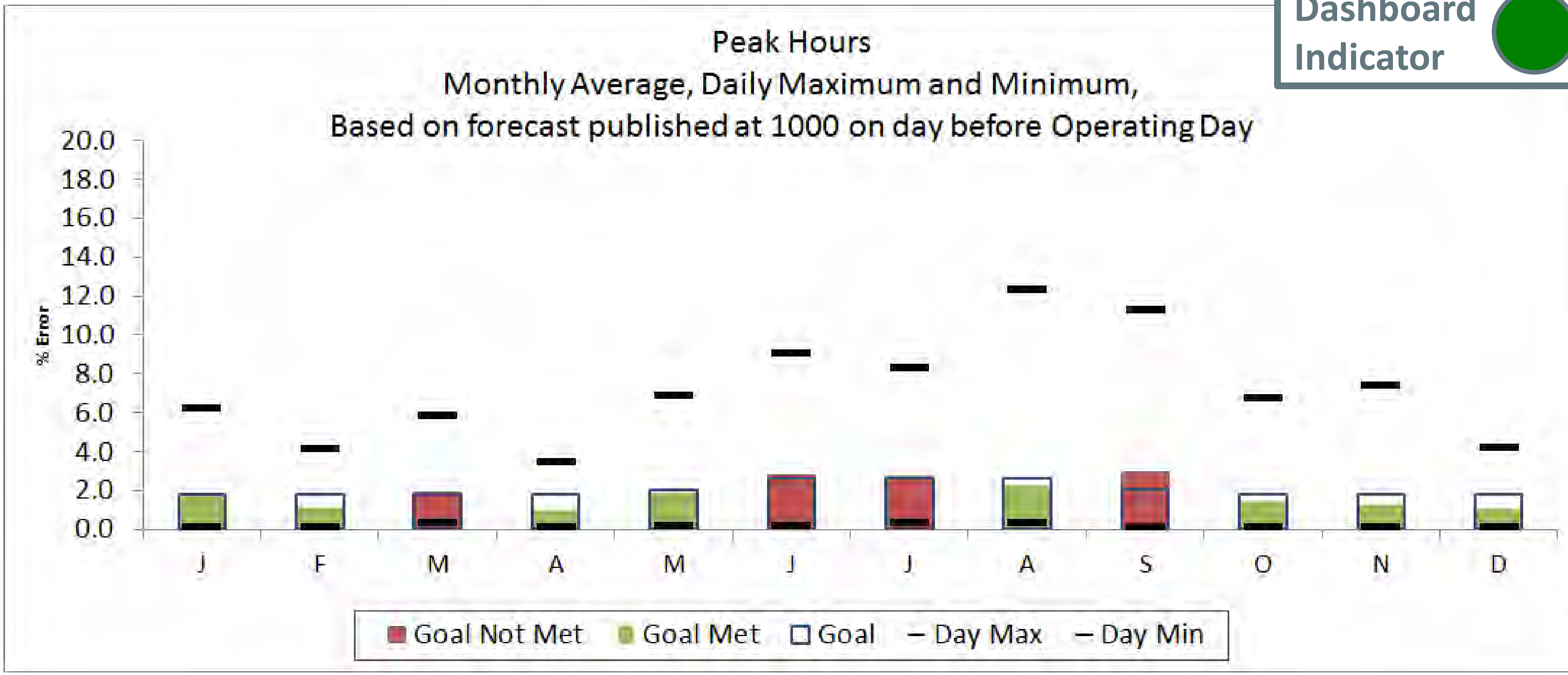
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	3.69	5.58	4.70	3.93	6.30	7.09	7.25	8.61	4.08	3.46	3.81	8.61
Day Min	1.02	0.53	0.63	0.82	0.83	0.59	0.81	0.76	0.67	0.68	0.65	0.57	0.53
MAPE	2.04	1.67	2.05	1.74	2.16	2.05	2.63	2.06	2.33	1.99	1.57	1.51	1.99
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

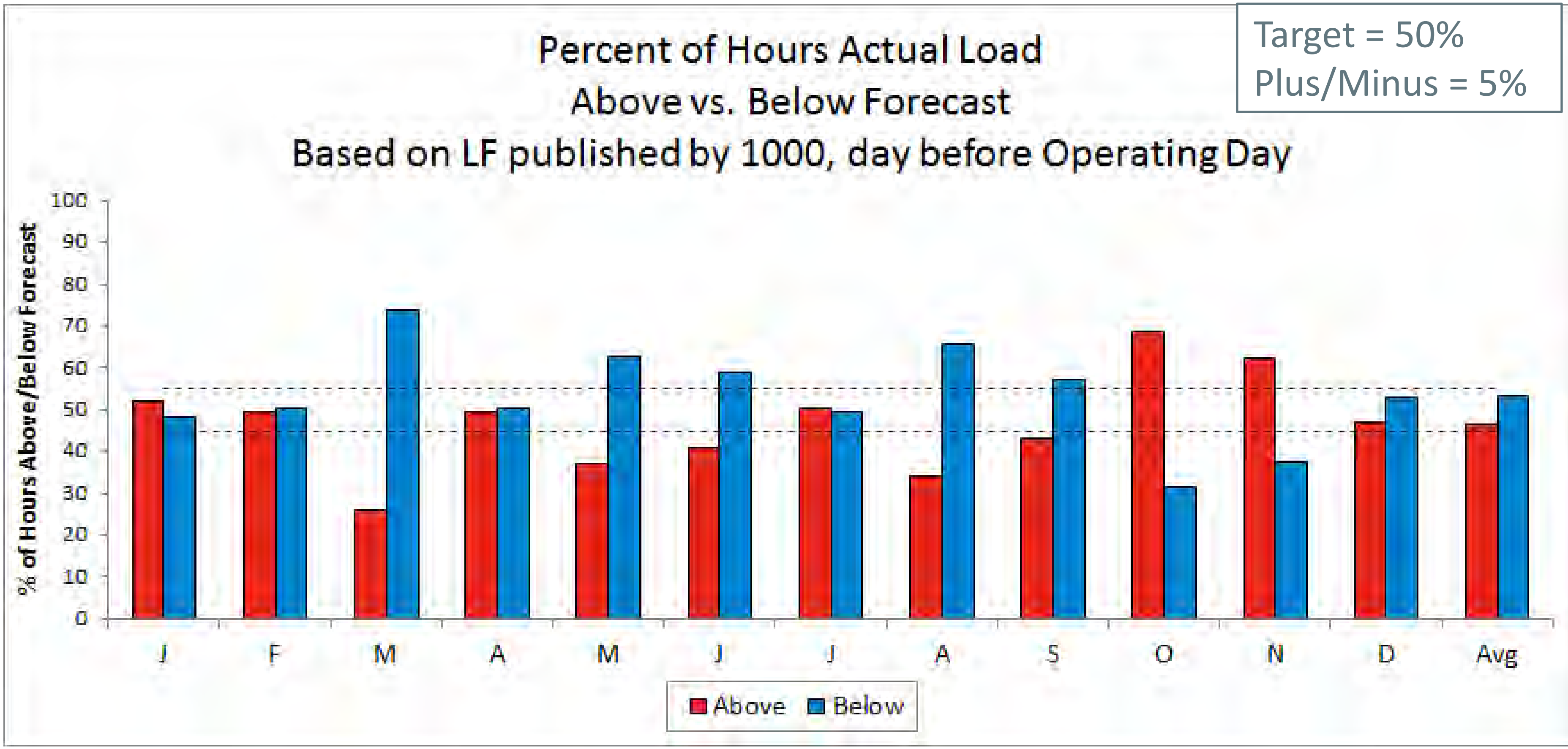
2018 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



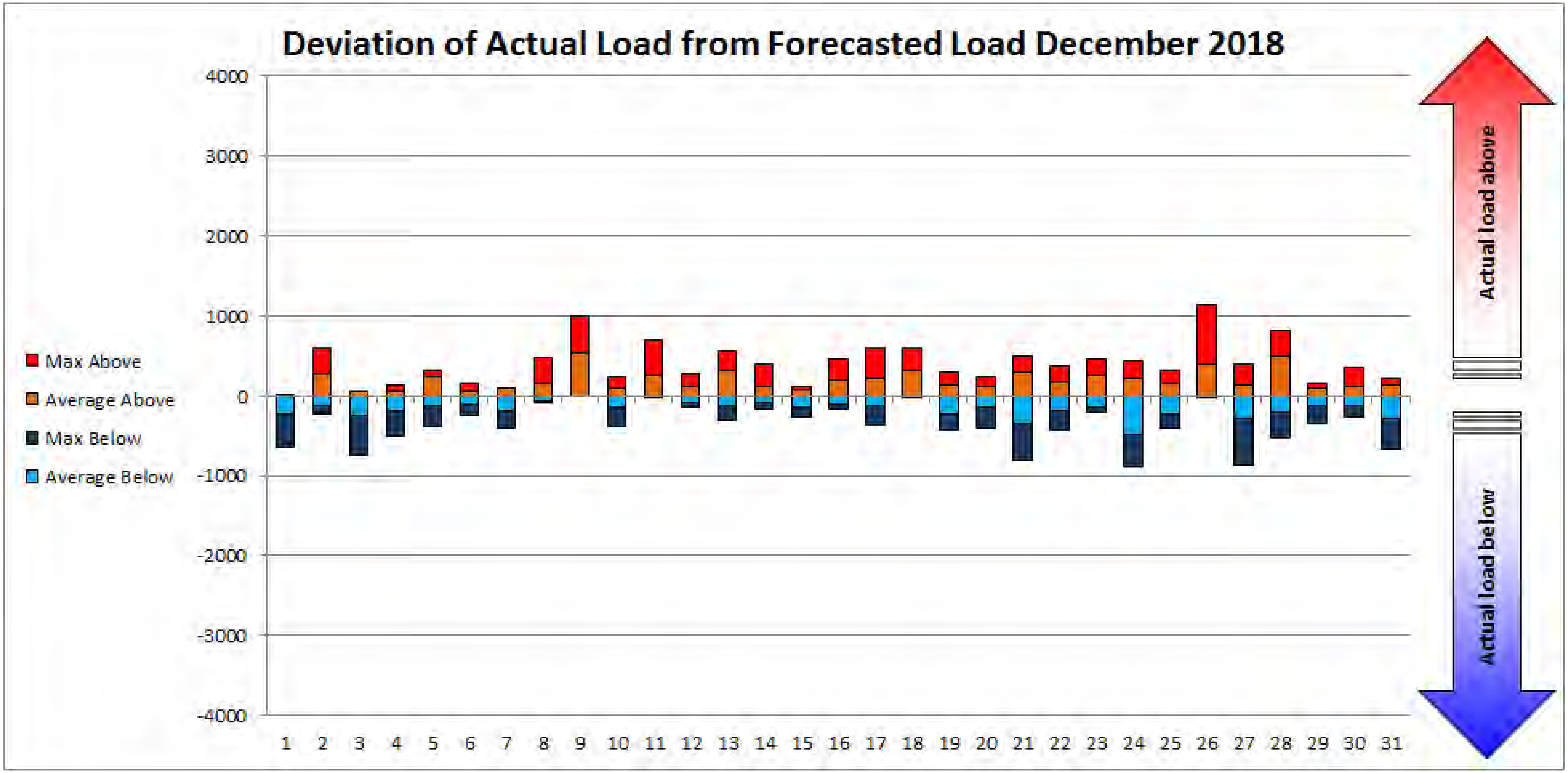
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.15	4.08	5.76	3.42	6.85	9.00	8.23	12.25	11.20	6.72	7.39	4.19	12.25
Day Min	0.04	0.03	0.25	0.04	0.13	0.13	0.25	0.25	0.06	0.09	0.05	0.03	0.03
MAPE	1.72	1.14	1.91	1.01	1.87	2.79	2.73	2.27	2.99	1.46	1.26	1.10	1.86
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

2018 System Operations - Load Forecast Accuracy cont.

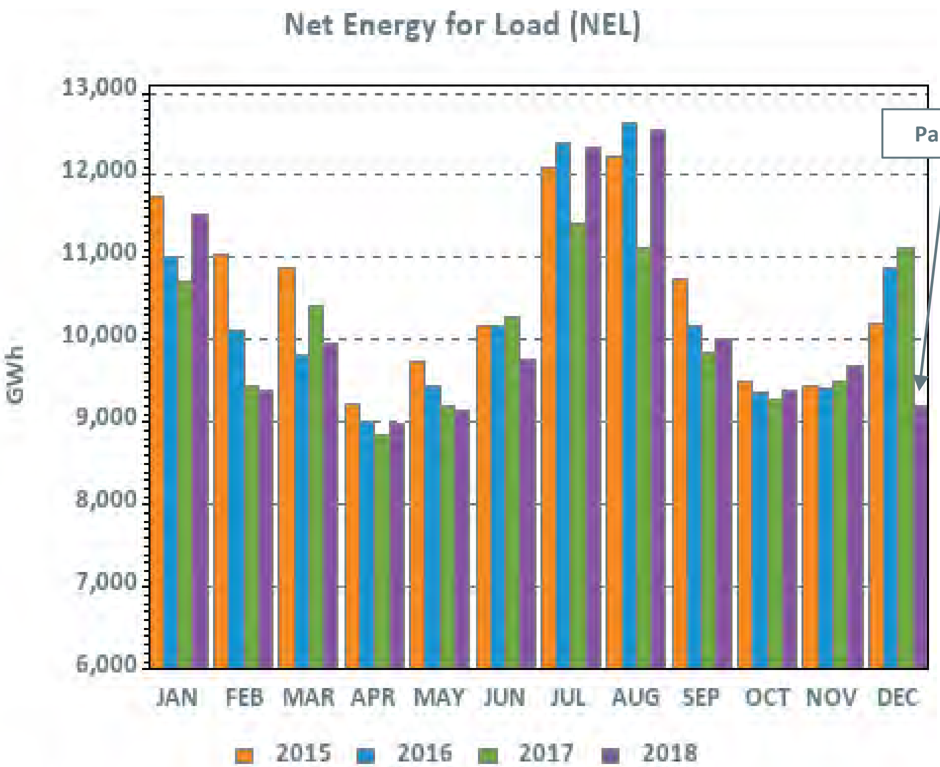


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	52	49.7	26.1	49.6	37.1	41	50.4	34.3	42.9	68.5	62.4	47	47
Below %	48	50.3	73.9	50.4	62.9	59	49.6	65.7	57.1	31.5	37.6	53	53
Avg Above	222.2	193.9	98.9	177.2	205.3	166	295.9	151.6	240.4	226.8	216.4	193.3	296
Avg Below	-242.2	-180.6	-278.3	-177.8	-222.8	-241.7	-351.0	-312.0	-235.8	-130.0	-130.2	-158.5	-351
Avg All	1	14	-192	1	-58	-72	-22	-168	-9	115	94	8	-25

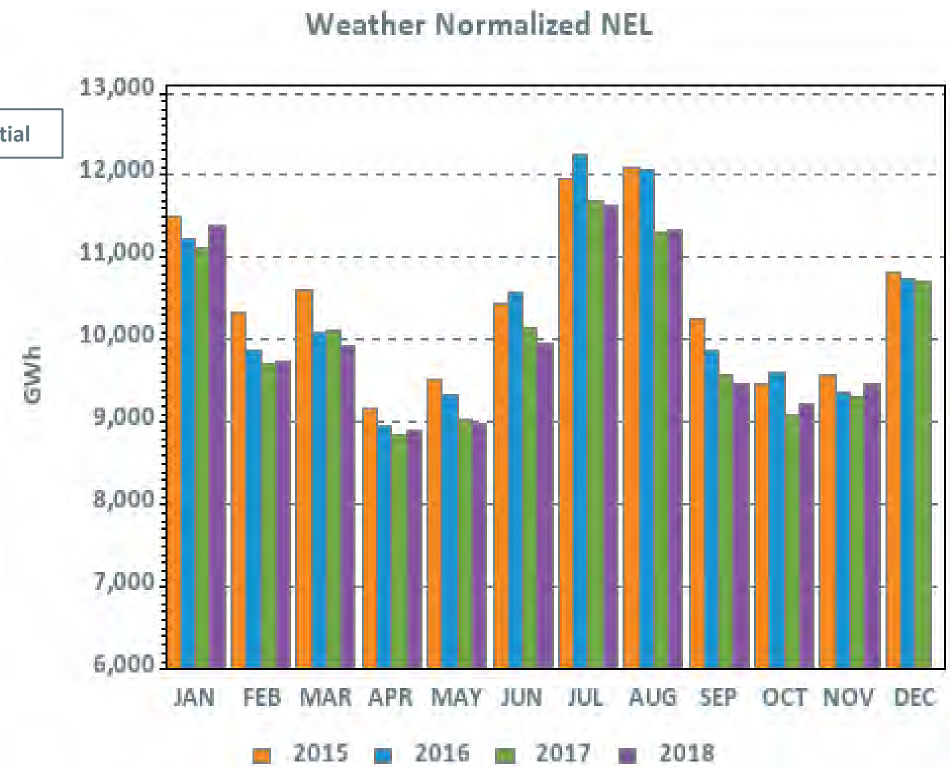
2018 System Operations - Load Forecast Accuracy cont.



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



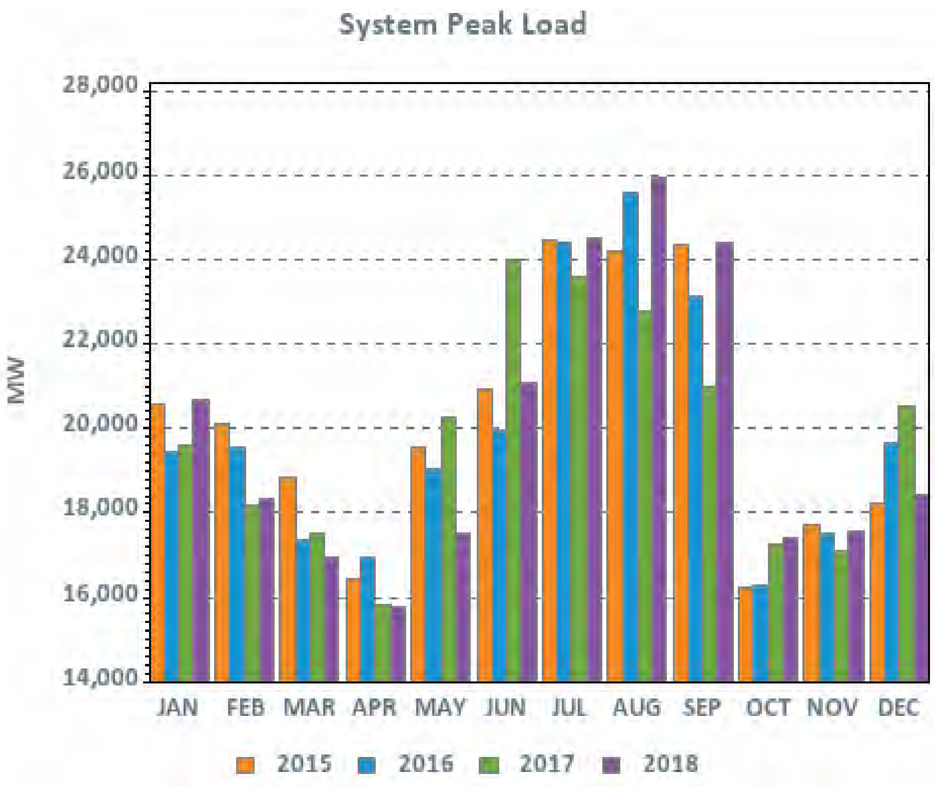
Ann Tot (TWh): 127.0 124.4 121.2 122.0



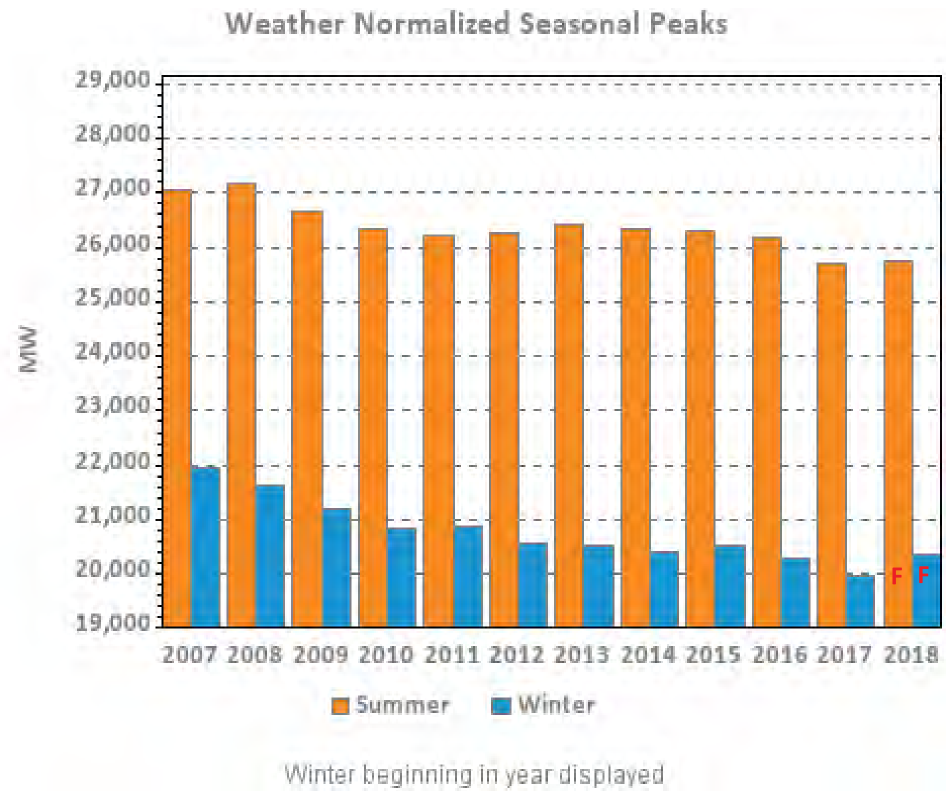
Ann Tot (TWh): 125.8 124.0 120.7 110.0

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



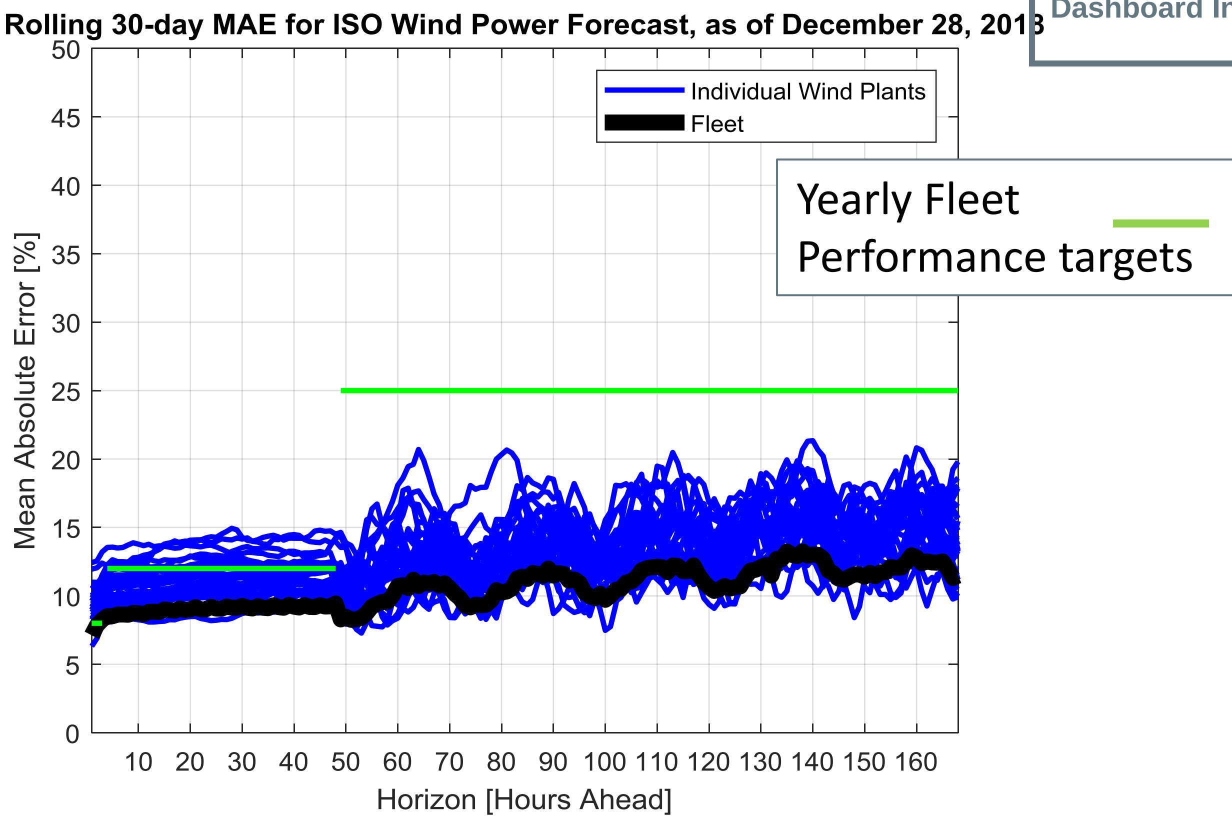
*Revenue quality metered value



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

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

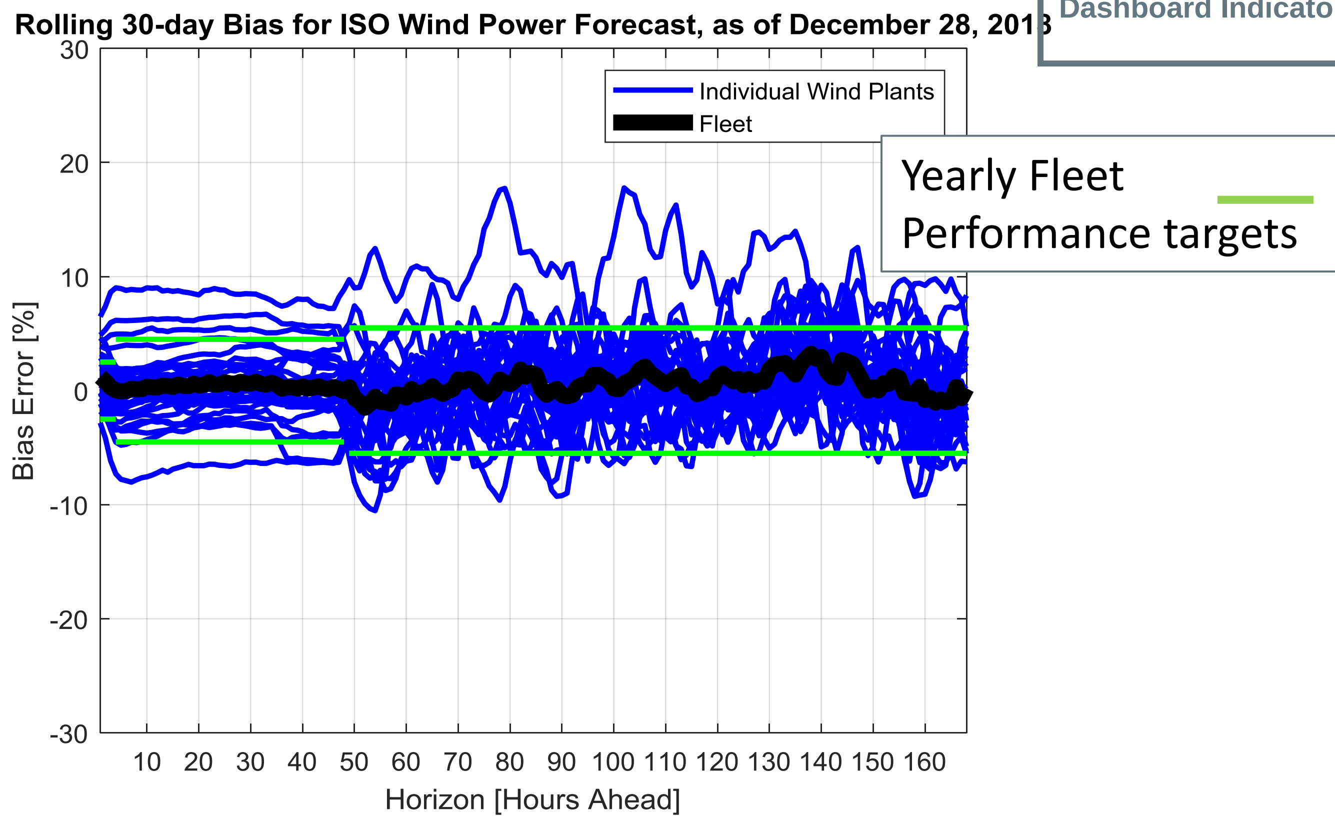
Dashboard Indicator



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

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

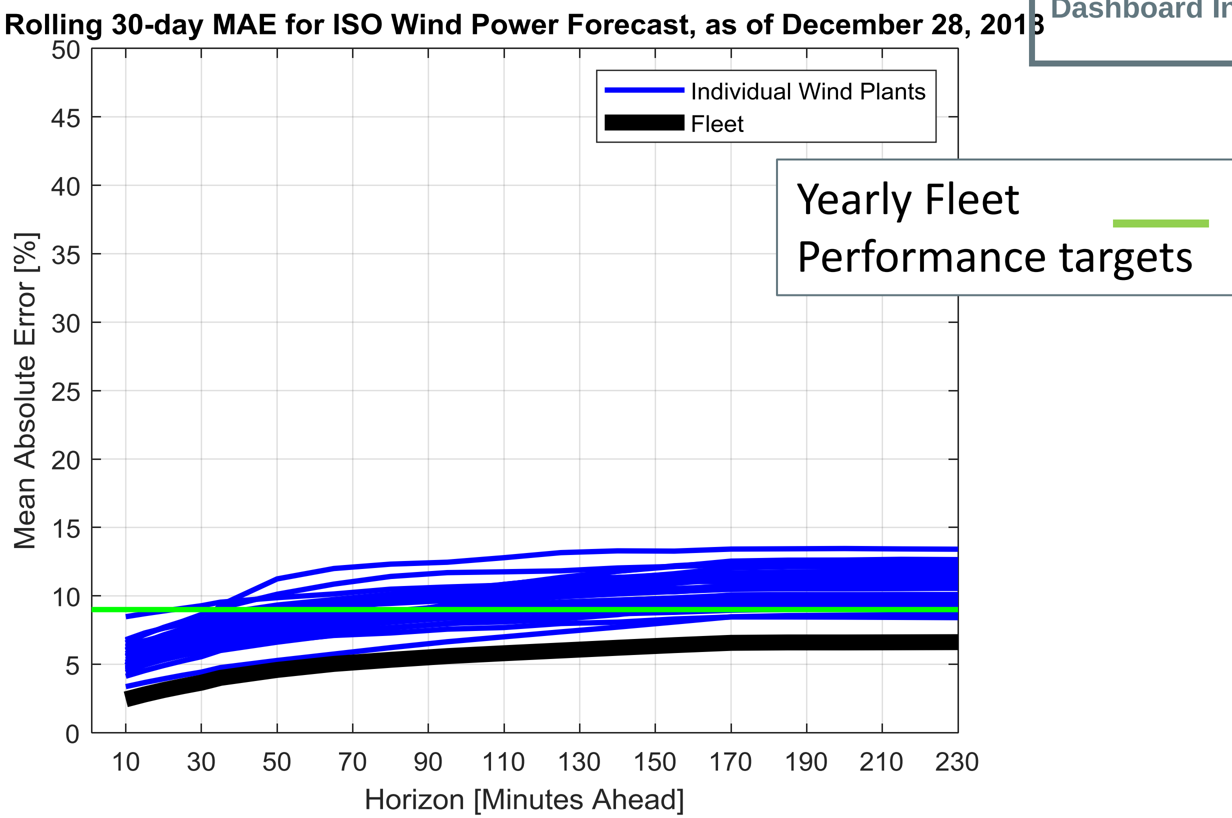
Dashboard Indicator



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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Wind Power Forecast Error Statistics: Short Term Forecast Bias

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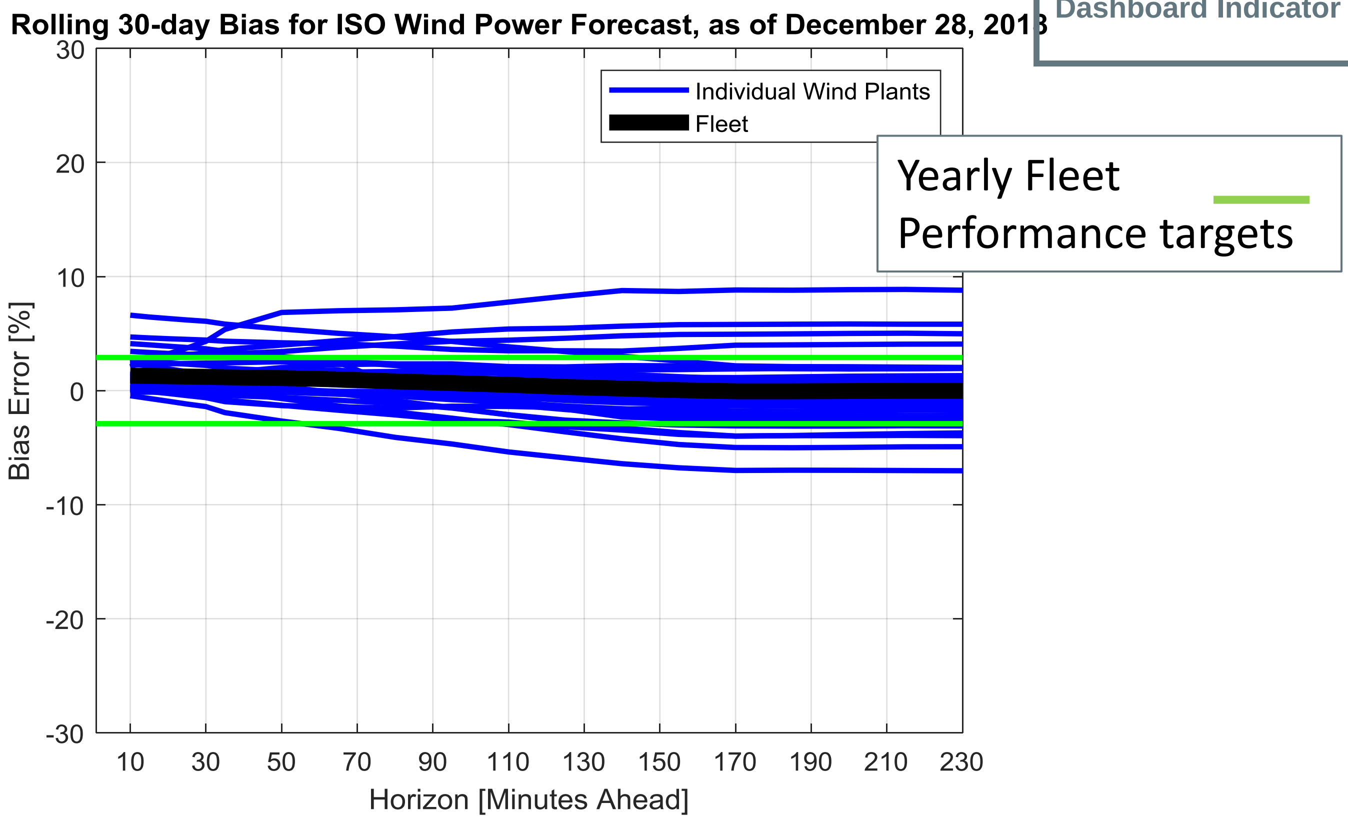

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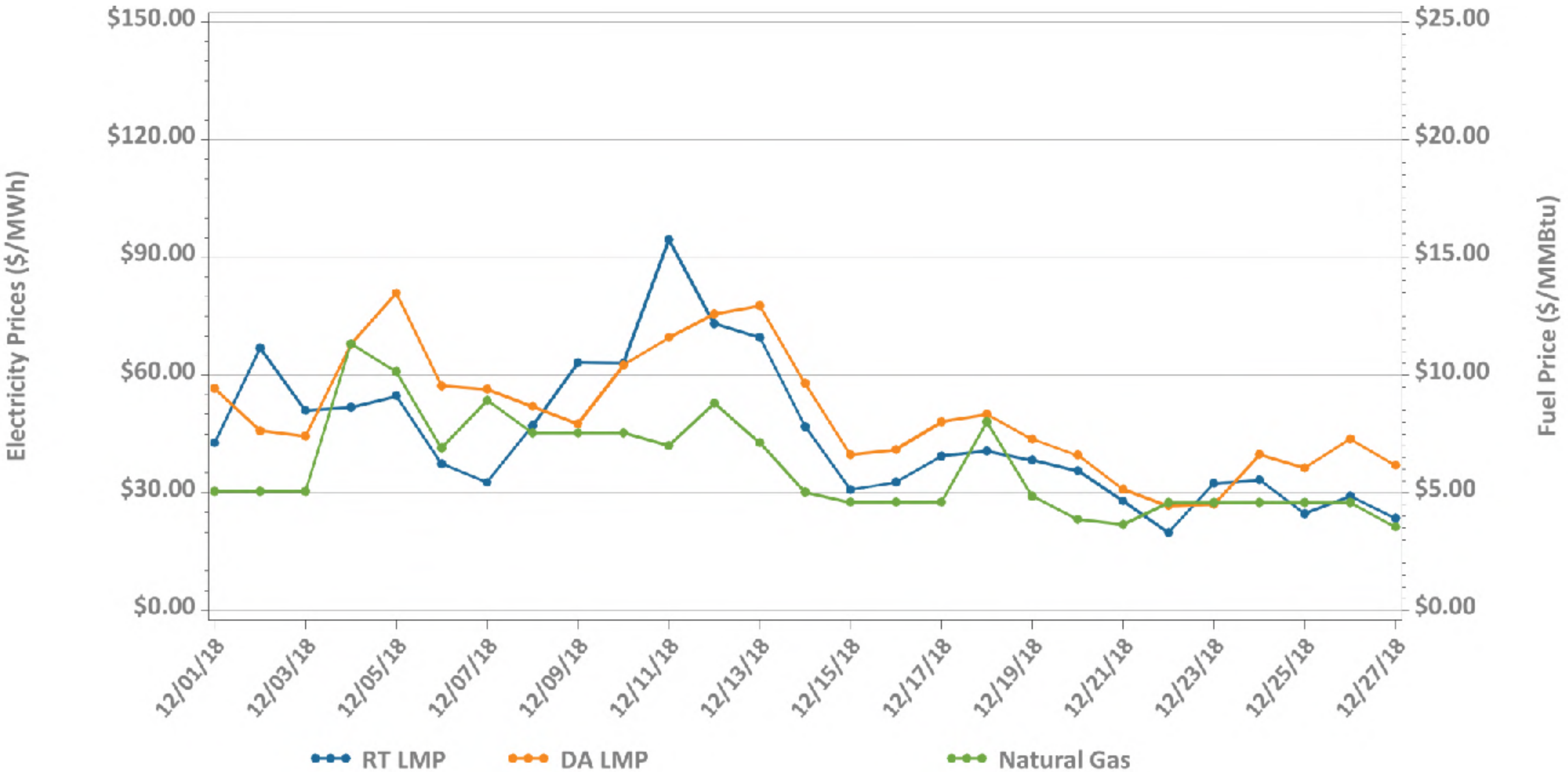
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: December 1-27, 2018

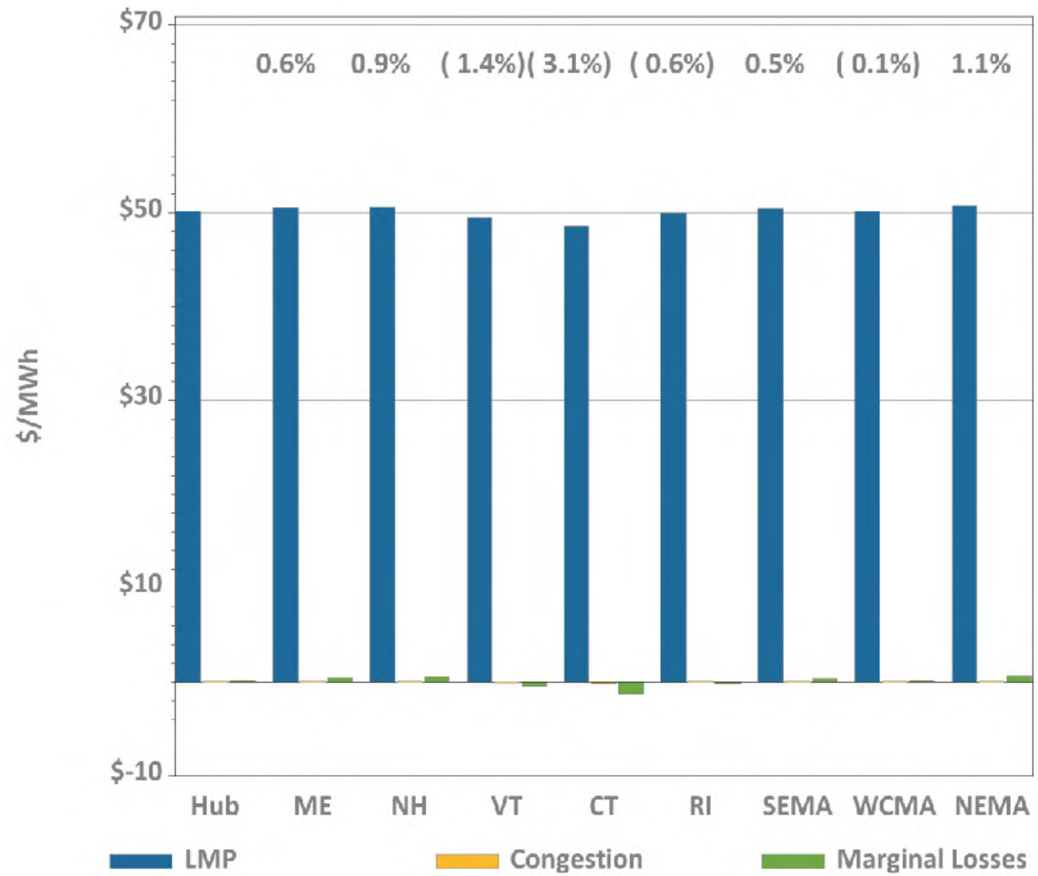


Underlying natural gas data furnished by:

ice Global markets in clear view

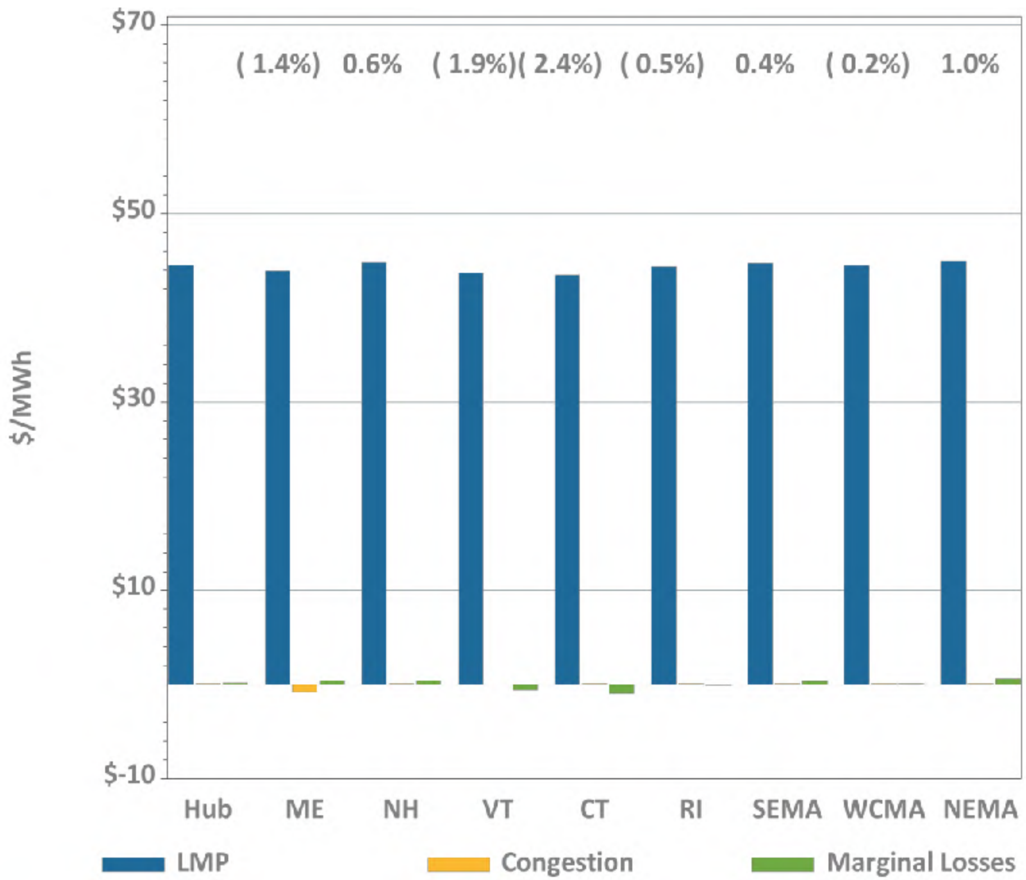
Average price difference over this period (DA-RT): $5.66
Average price difference over this period ABS(DA-RT): $11.15
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 25%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, December 2018



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

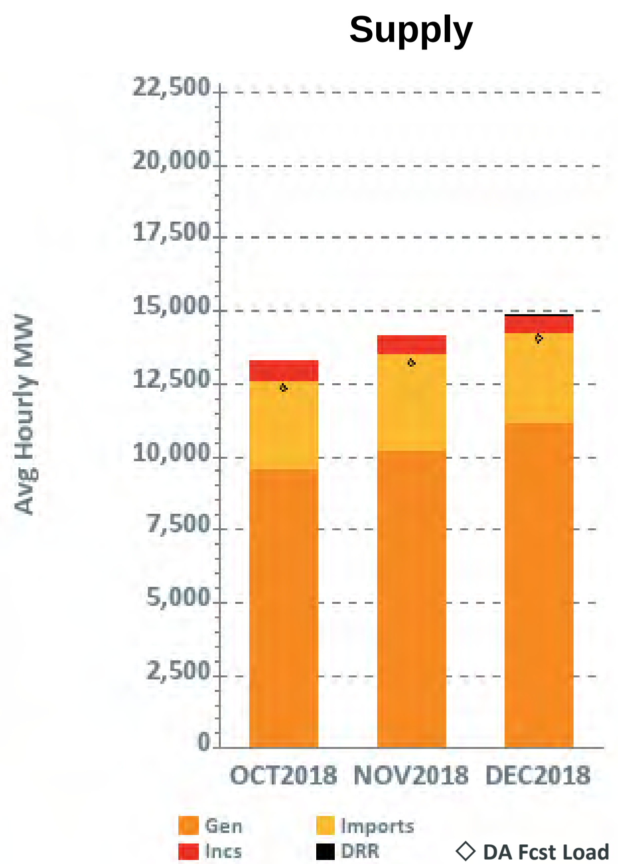
RT LMPs Average by Zone & Hub, December 2018

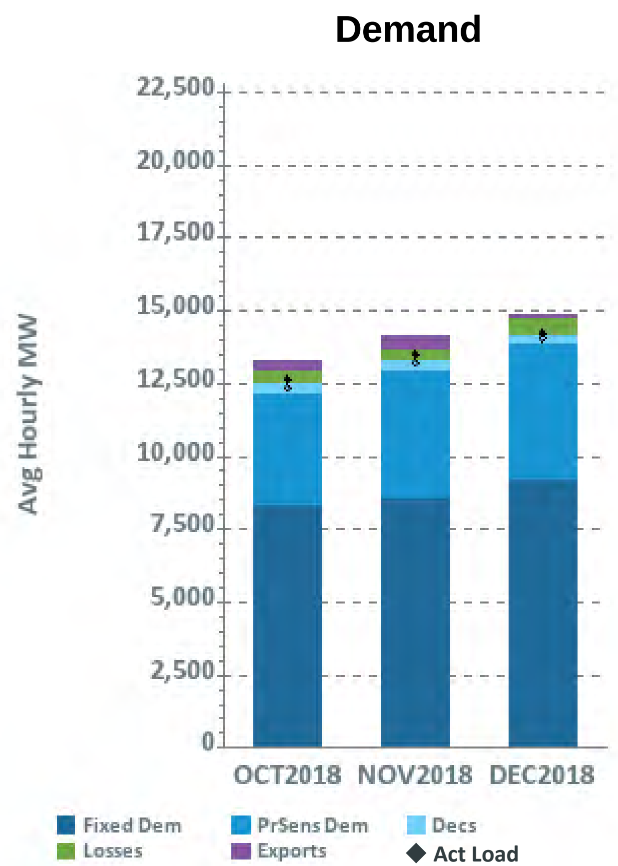


Definitions

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

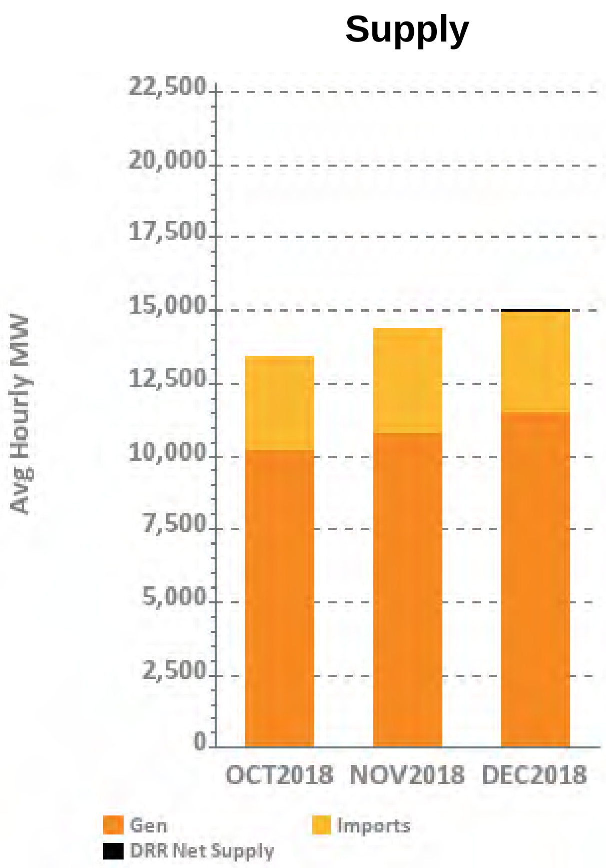


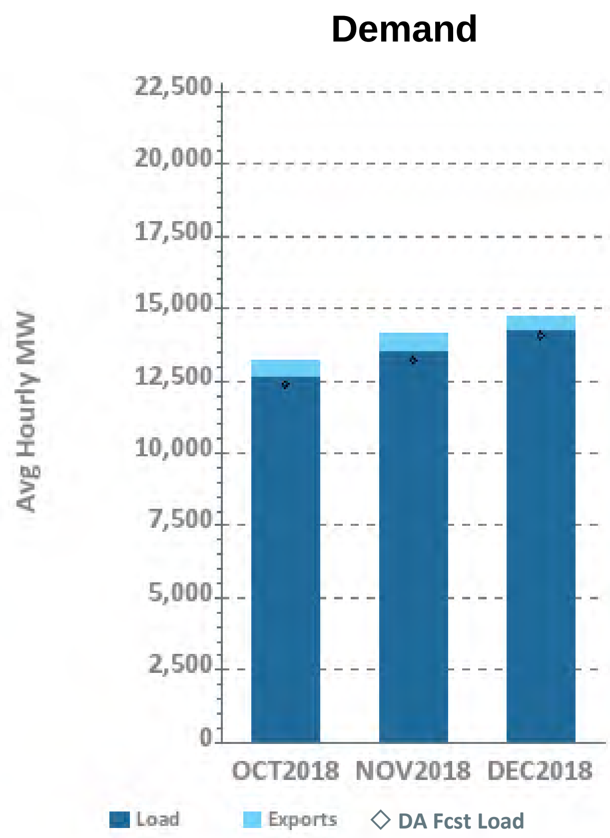


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

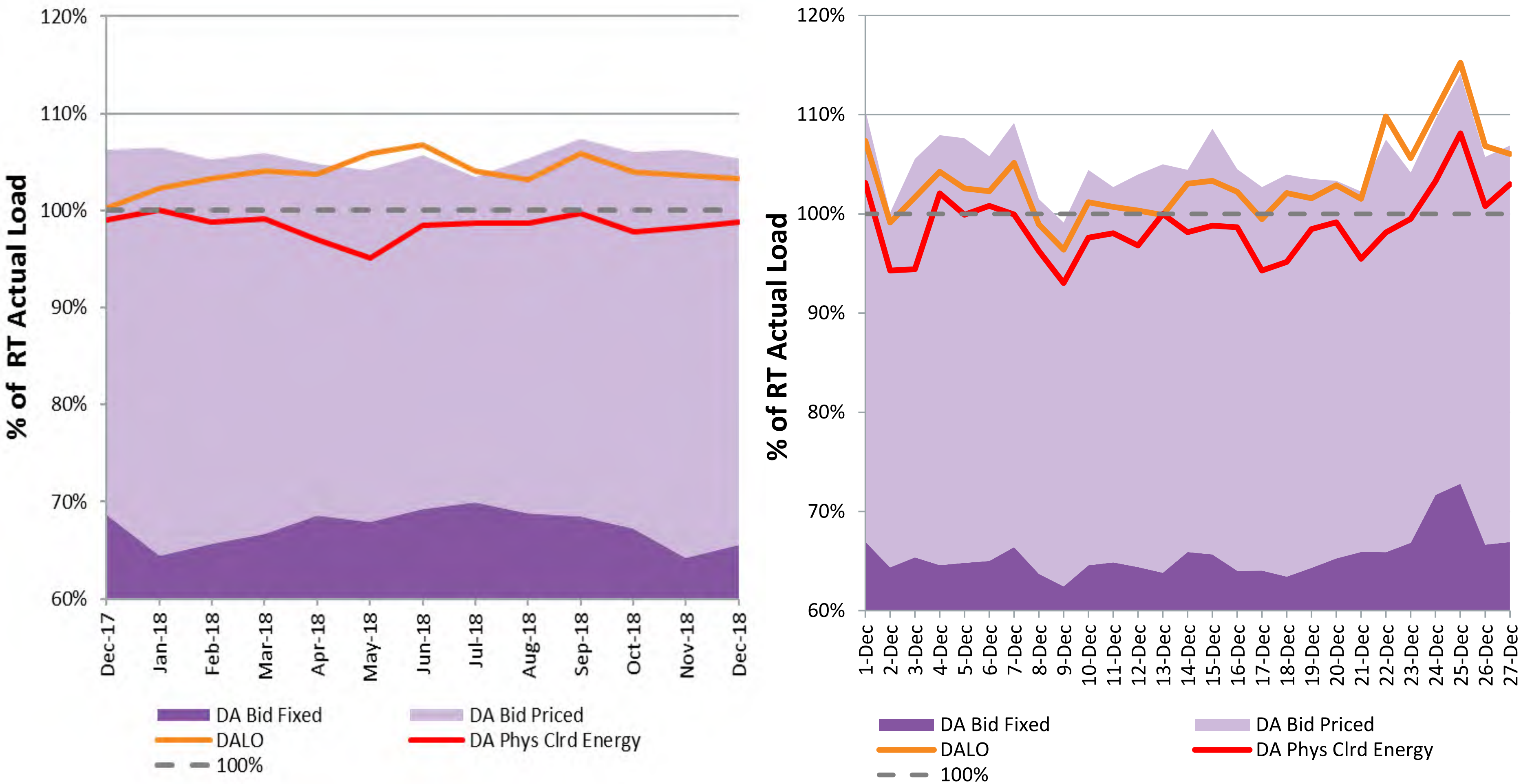
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



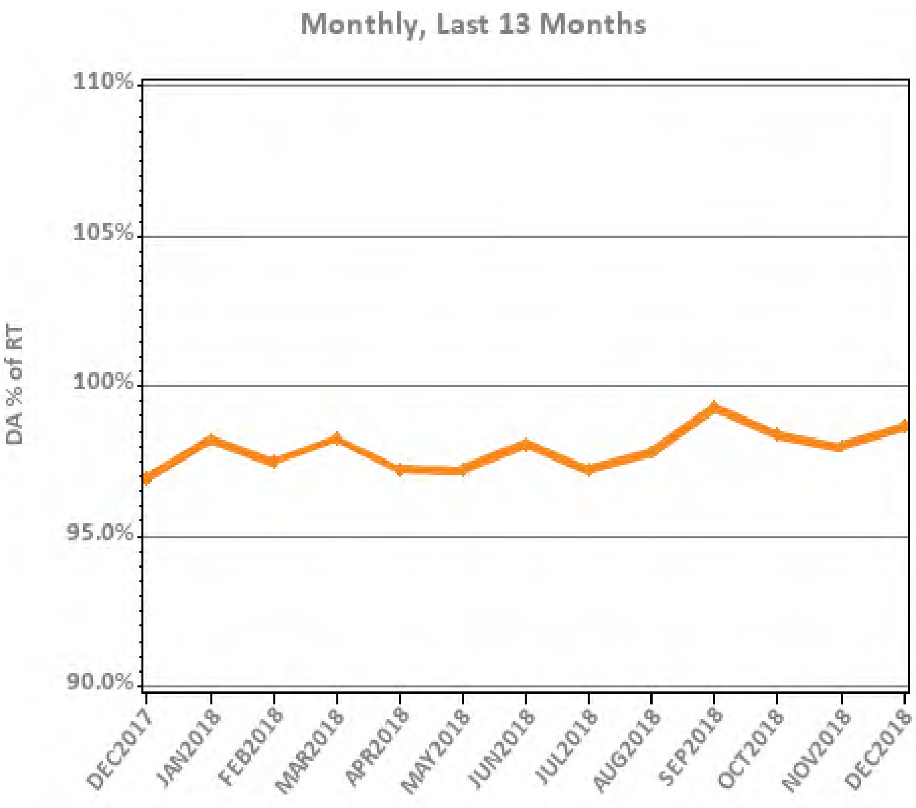


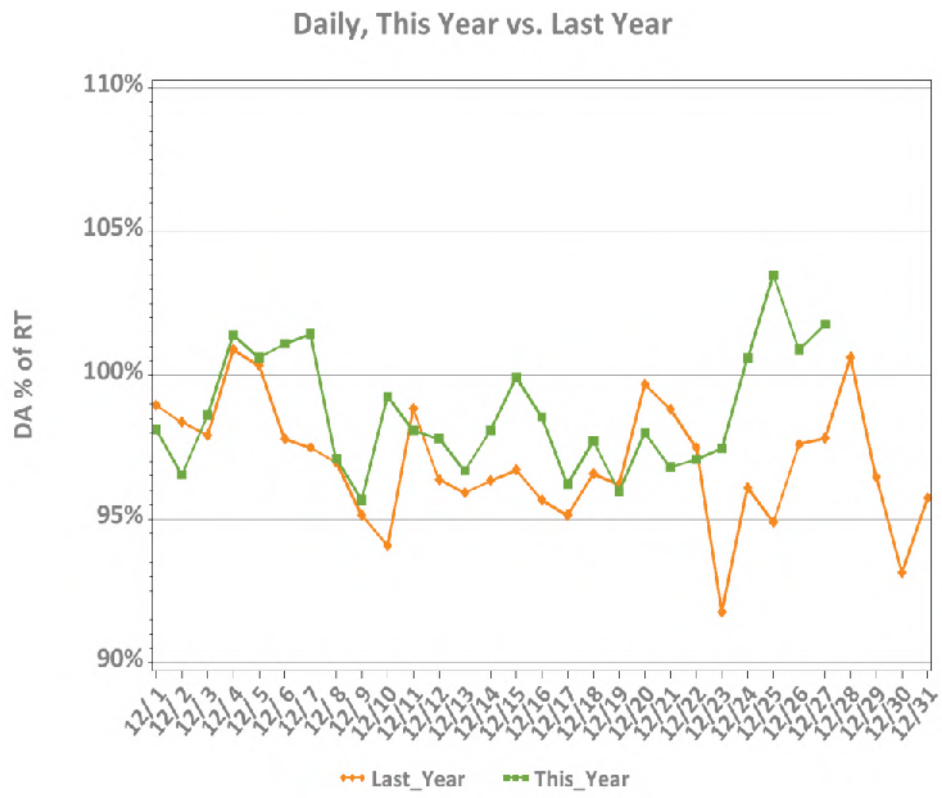
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)



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).

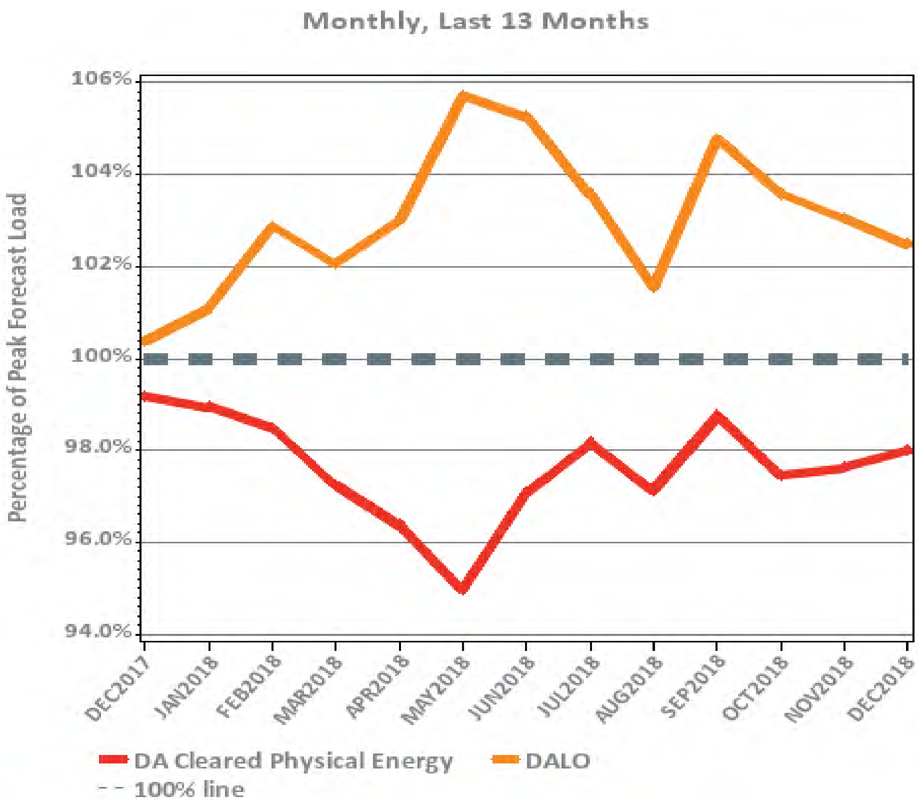
DA vs. RT Load Obligation: December, This Year vs. Last Year

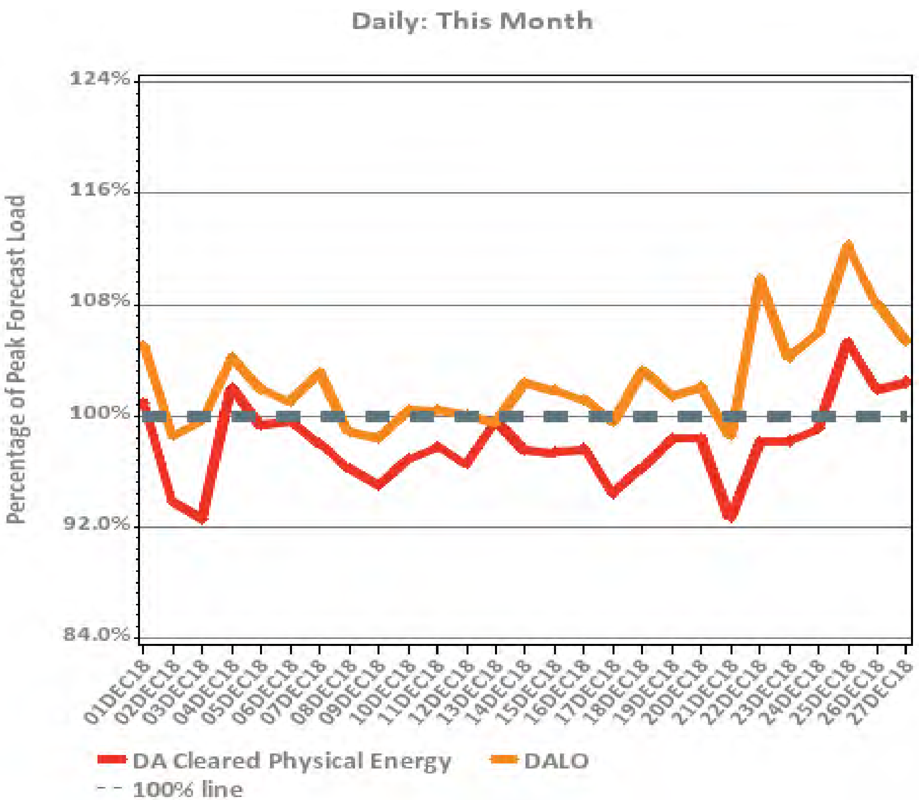




*Hourly average values

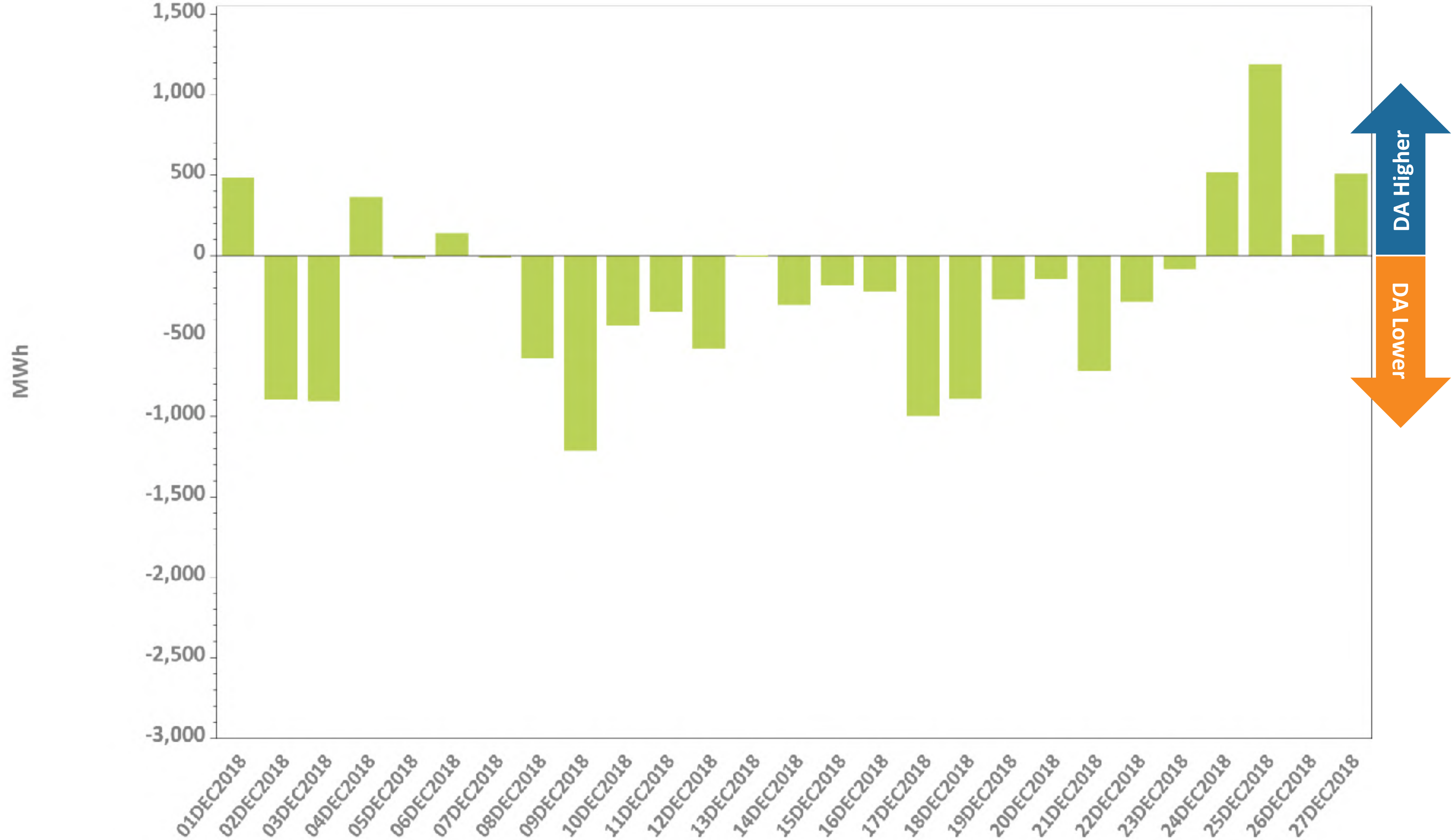
DA Volumes as % of Forecast in Peak Hour





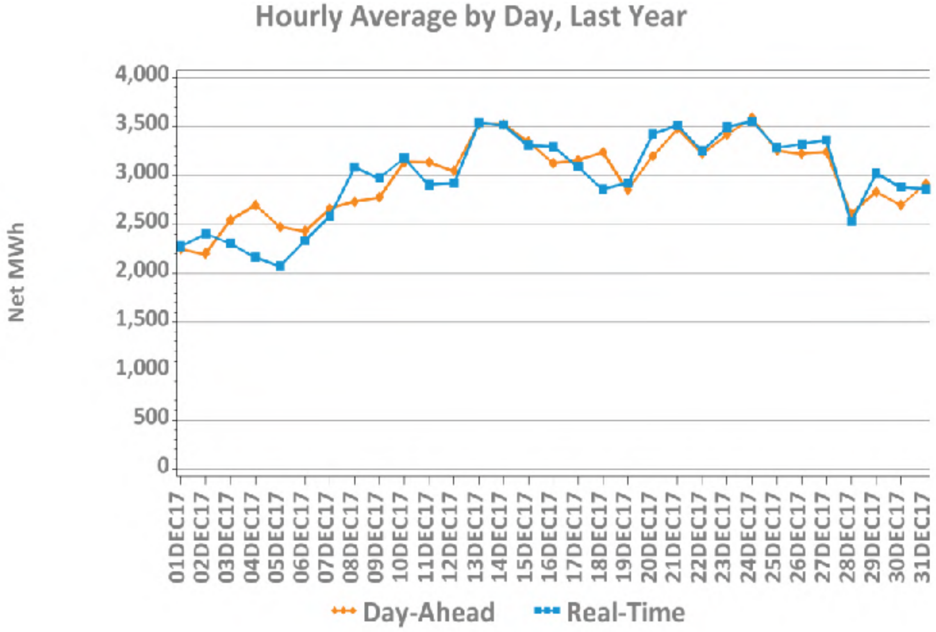
*There were no supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during December.

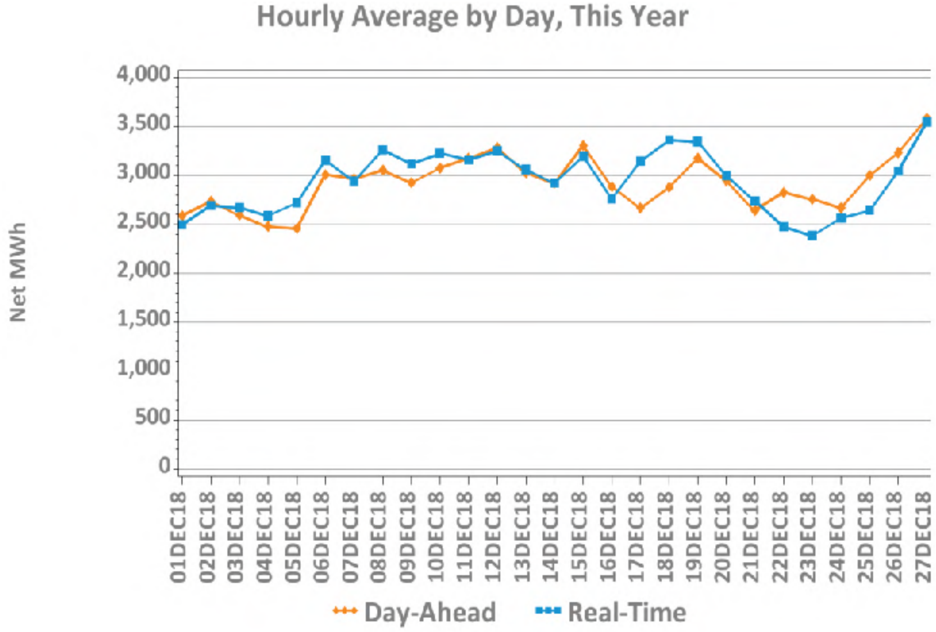
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

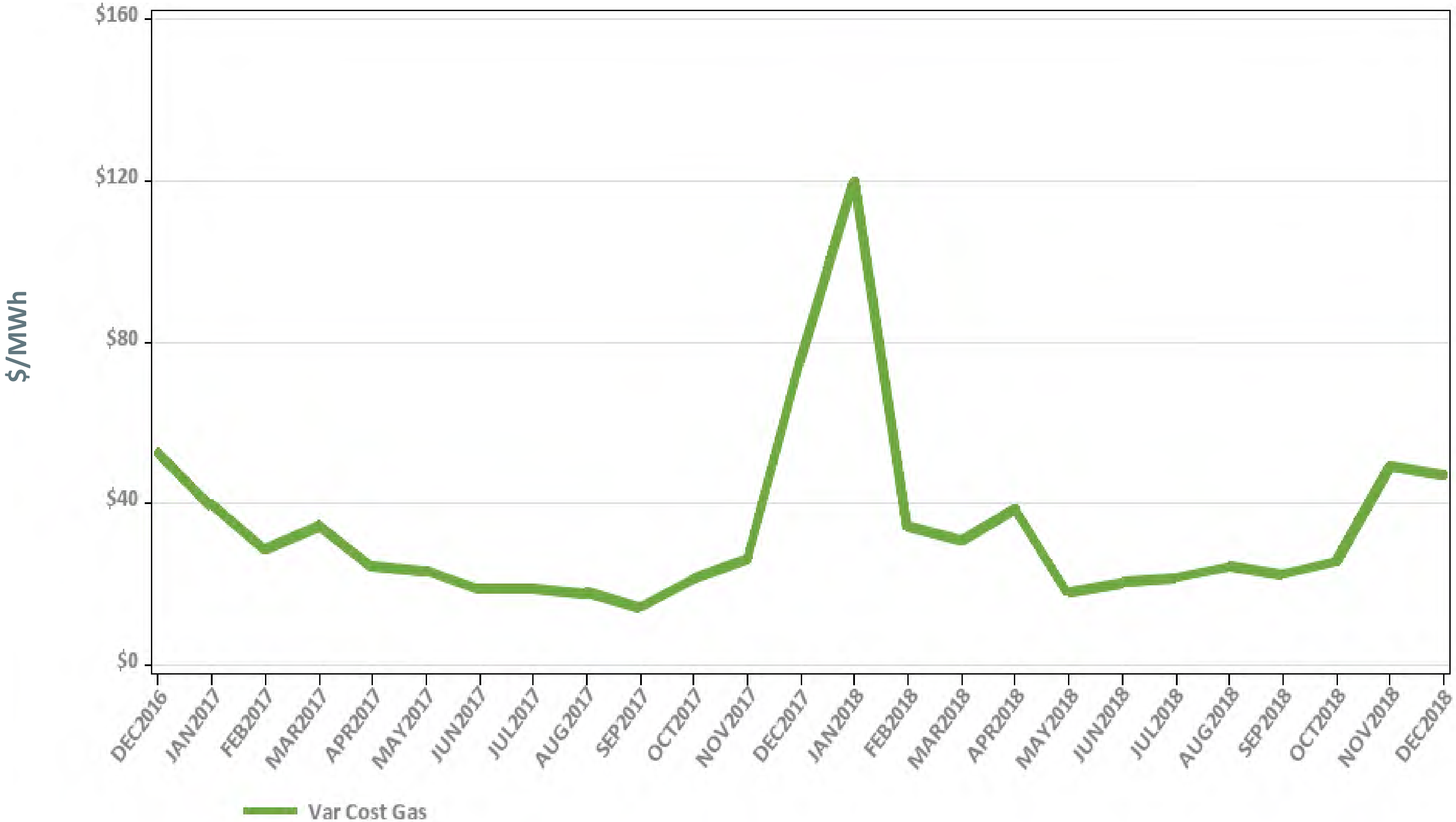
DA vs. RT Net Interchange December 2018 vs. December 2017





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

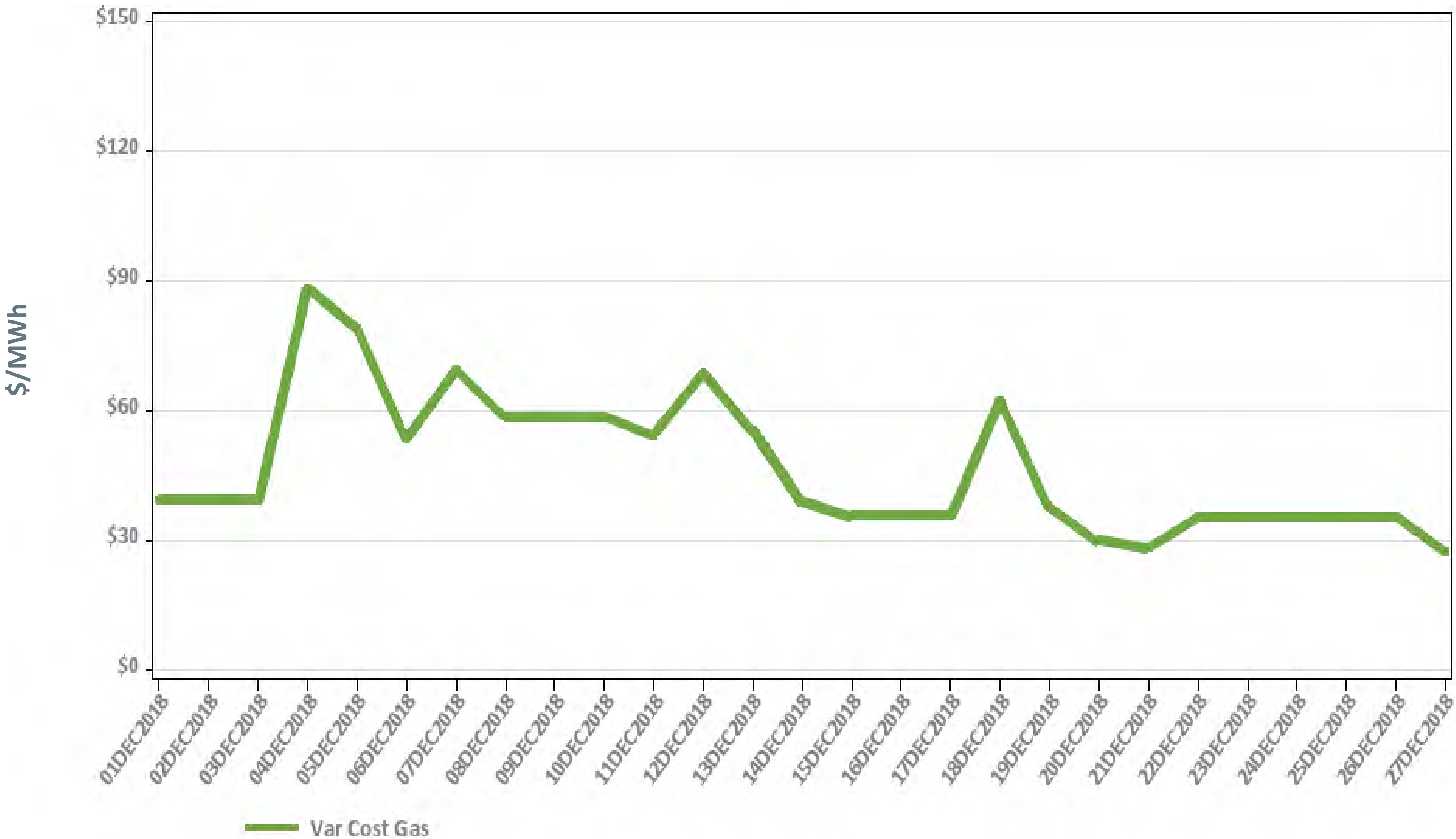


Underlying natural gas data furnished by:

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



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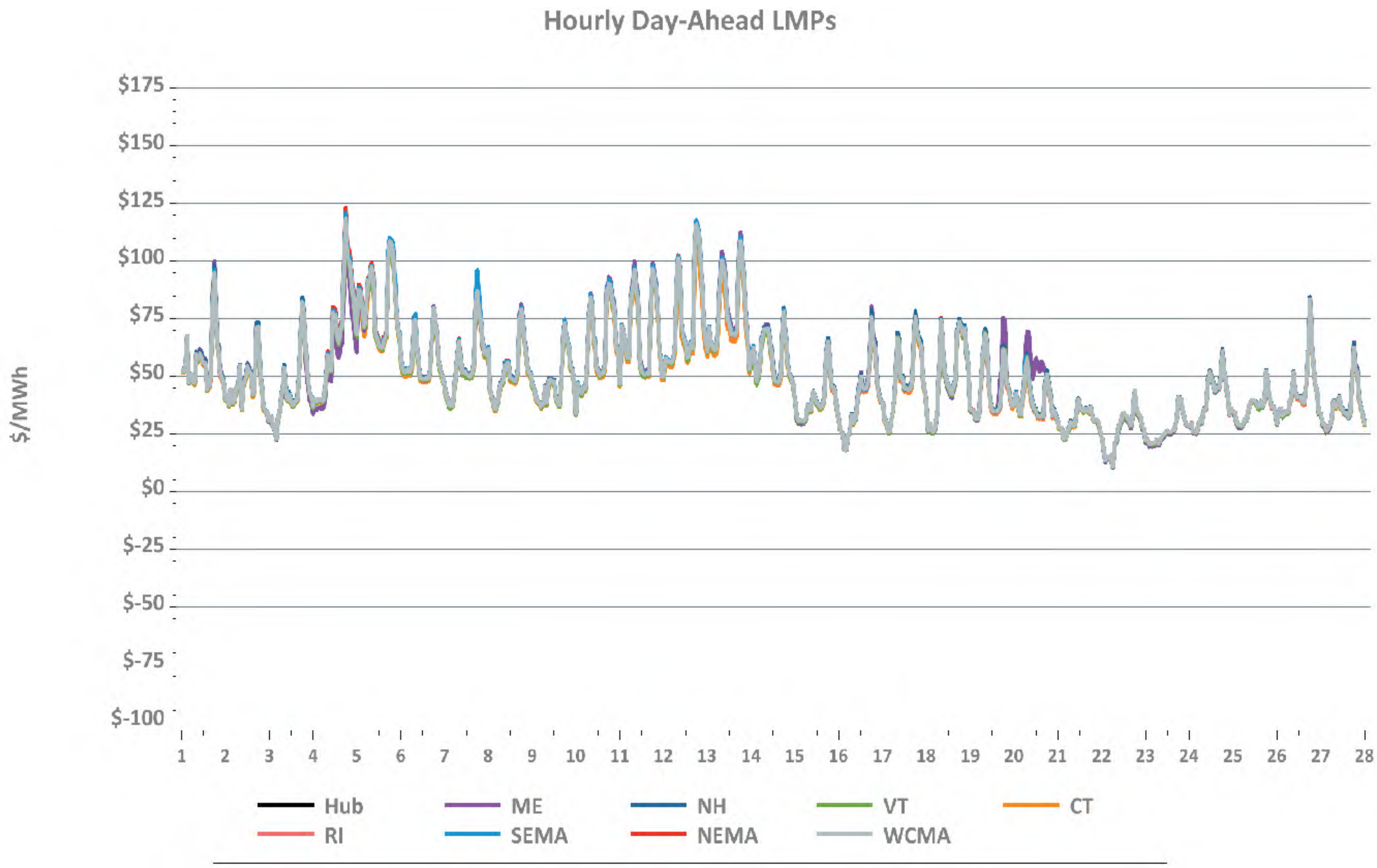
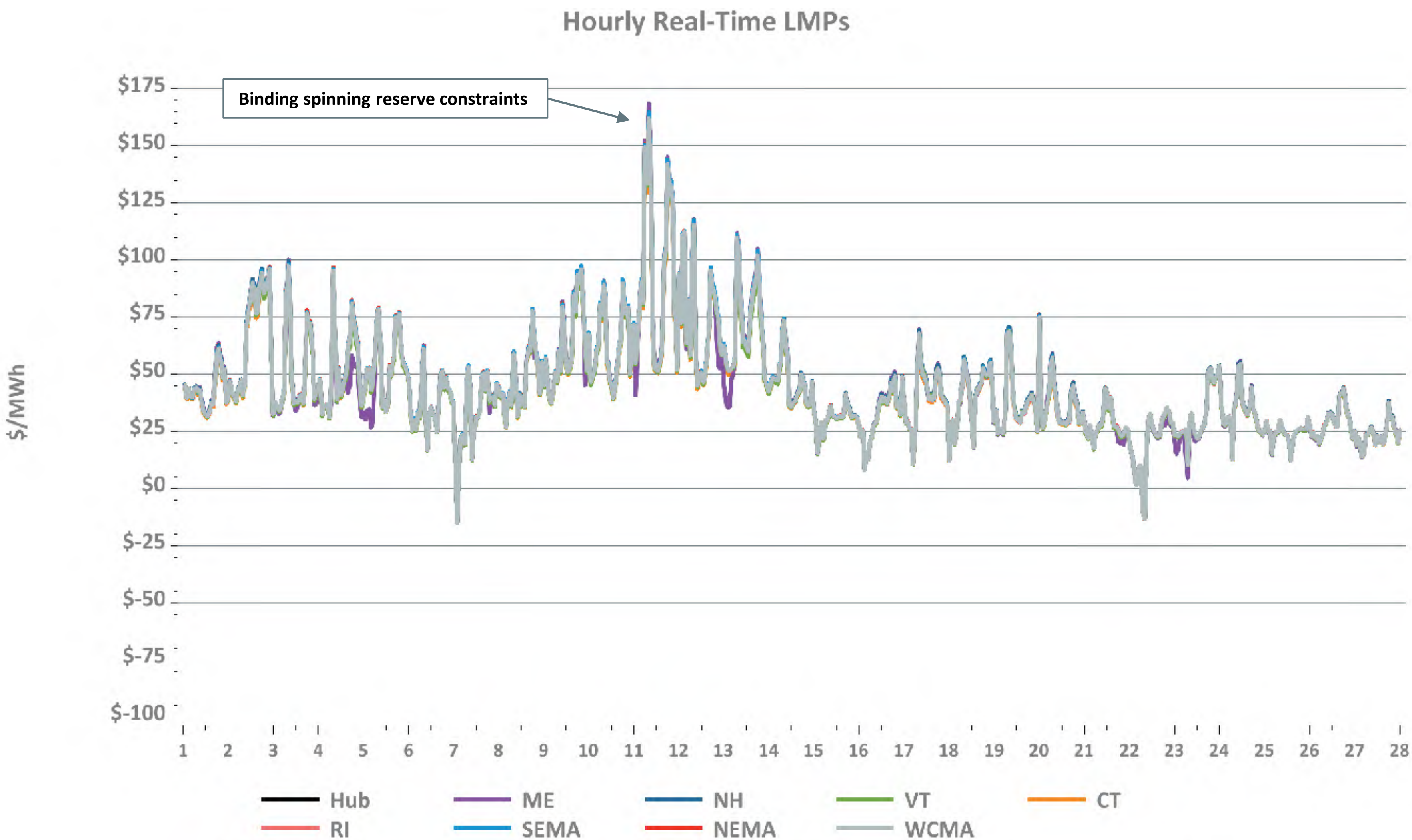
Hourly DA LMPs, December 1-27, 2018

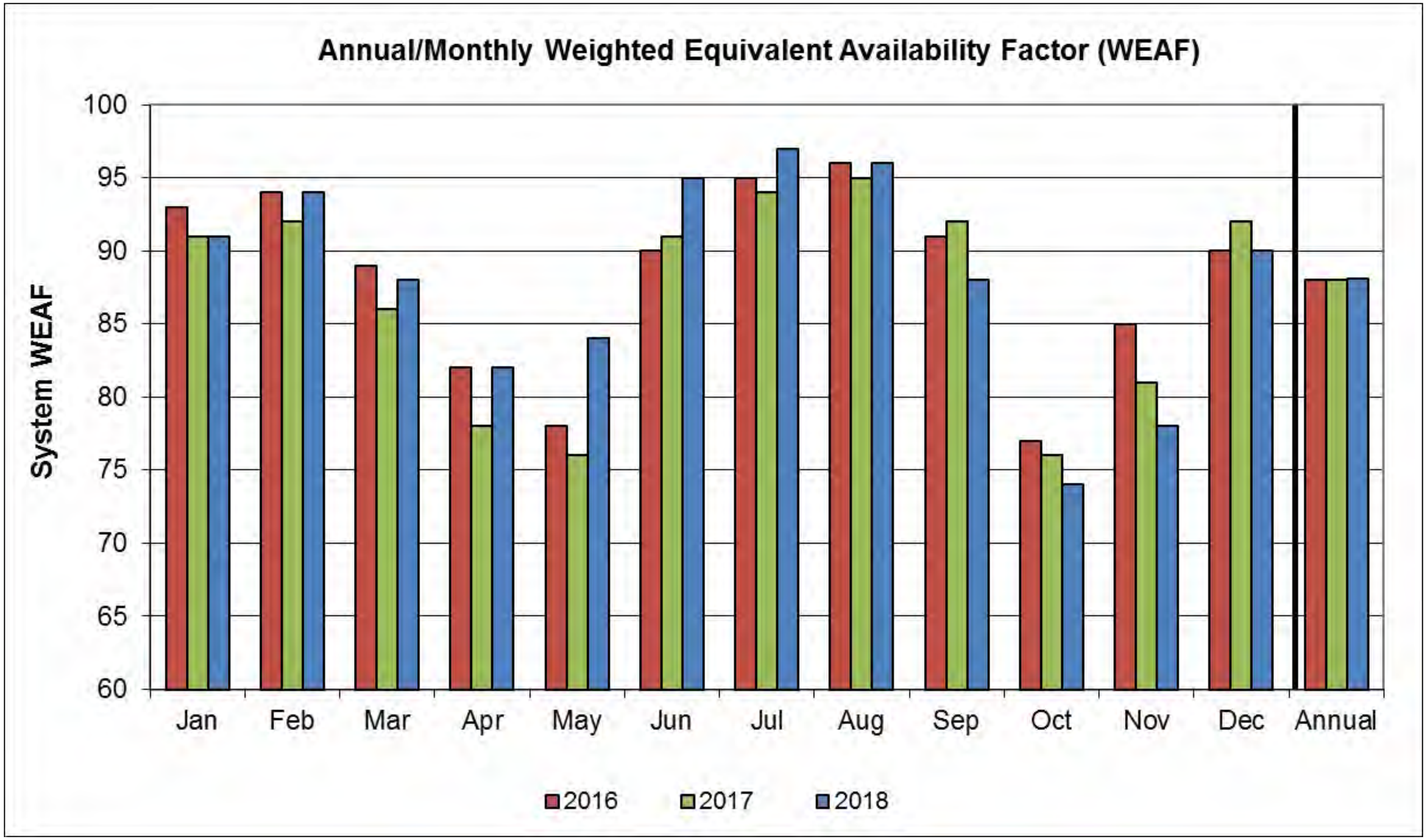


Hourly RT LMPs, December 1-27, 2018



- No Minimum Generation Emergencies were declared in December.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2018	91	94	88	82	84	95	97	96	88	74	78	90	88
2017	91	92	86	78	76	91	94	95	92	76	81	92	88
2016	93	94	89	82	78	90	95	96	91	77	85	90	88

Data as of 12/31/18

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	107.0	174.5	0.0	281.5
NH	16.9	91.1	0.0	108.0
VT	24.0	141.9	0.0	165.9
CT	86.7	68.4	432.3	587.4
RI	19.5	239.8	0.0	259.2
SEMA	18.1	390.9	0.0	409.0
WCMA	35.4	367.7	40.9	444.0
NEMA	39.0	683.8	0.0	722.8
Total	**346.5**	**2,158.0**	**473.2**	**2,977.8**

*** Active Demand Capacity Resources**

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

NEW GENERATION

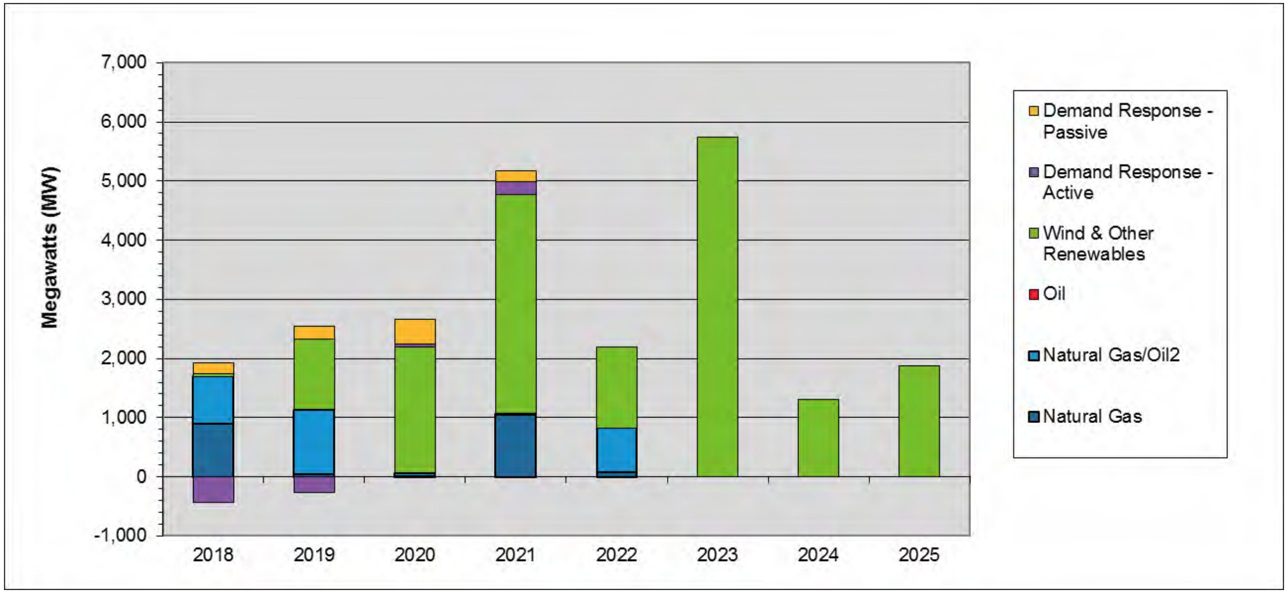
New Generation Update

Based on Queue as of 12/28/18

- 31 projects totaling 3,860 MW applied for interconnection study since the last update, with in-service dates of 2020 through 2025
- One project withdrew and two went commercial resulting in a net increase in new generation projects of 3,760 MW
- In total, 158 generation projects are currently being tracked by the ISO, totaling approximately 20,430 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2018	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total[1]
Demand Response - Passive	196	212	422	184	0	0	0	0	1,014	4.5
Demand Response - Active	-433	-270	42	204	0	0	0	0	-456	-2.0
Wind & Other Renewables	40	1,195	2,127	3,710	1,361	5,735	1,312	1,884	17,364	76.4
Oil	0	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	801	1,097	62	23	755	0	0	0	2,738	12.0
Natural Gas	896	43	6	1,045	73	0	0	0	2,063	9.1
Totals	**1,500**	**2,278**	**2,660**	**5,166**	**2,189**	**5,735**	**1,312**	**1,884**	**22,723**	**100.0**

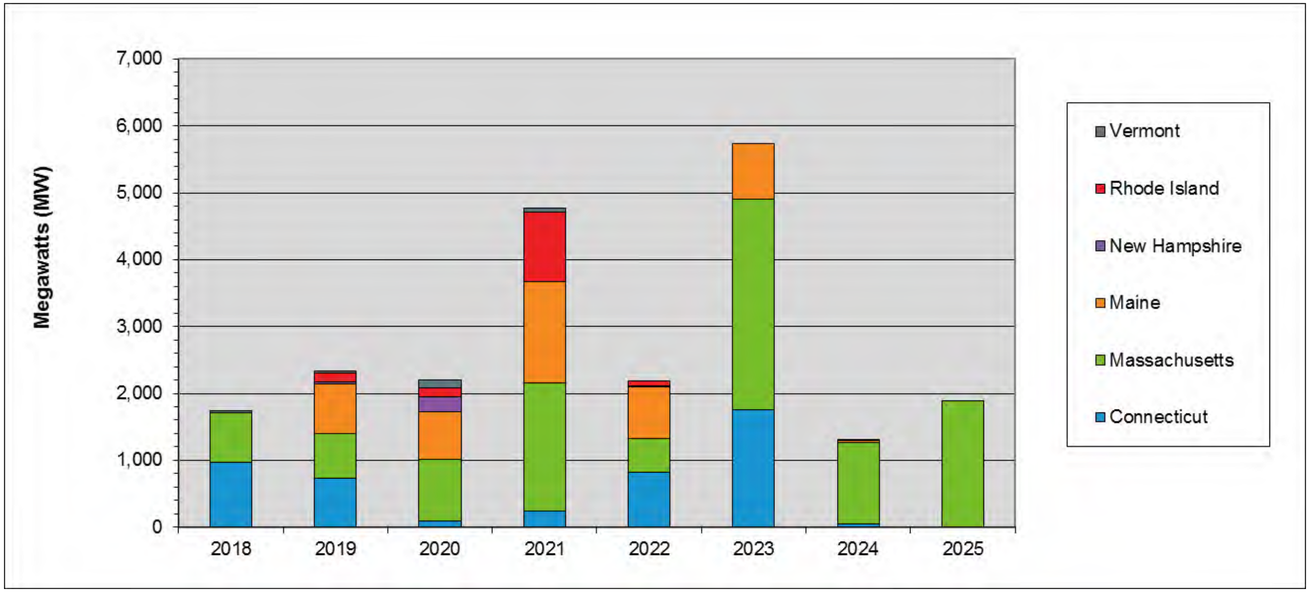
[1] Sum may not equal 100% due to rounding

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

- 2018 values include the 1,737 MW of generation that has gone commercial in 2018
- 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	2025	Total MW	% of Total[1]
Vermont	20	33	115	70	0	0	0	0	238	1.1
Rhode Island	0	128	133	1,030	73	0	0	0	1,364	6.2
New Hampshire	0	28	225	10	19	0	20	0	302	1.4
Maine	0	750	702	1,517	765	828	20	0	4,582	20.7
Massachusetts	746	662	926	1,913	514	3,147	1,232	1,884	11,024	49.7
Connecticut	971	734	94	238	818	1,760	40	0	4,655	21.0
Totals	**1,737**	**2,335**	**2,195**	**4,778**	**2,189**	**5,735**	**1,312**	**1,884**	**22,165**	**100.0**

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

- 2018 values include the 1,737 MW of generation that has gone commercial in 2018

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Fuel Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	2	39	0	0	2	39
Hydro	3	74	0	0	3	74
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,230	0	0	7	1,230
Natural Gas/Oil	8	1,937	2	541	6	1,396
Oil	0	0	0	0	0	0
Solar	93	2,654	0	0	93	2,654
Wind	32	13,306	1	30	31	13,276
Battery storage	13	1,188	0	0	13	1,188
Total	158	20,428	3	571	155	19,857

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	123	0	0	5	123
Intermediate	5	1,657	0	0	5	1,657
Peaker	116	5,342	2	541	114	4,801
Wind Turbine	32	13,306	1	30	31	13,276
Total	158	20,428	3	571	155	19,857

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/wood waste	2	39	1	37	0	0	1	2	0	0
Hydro	3	74	2	8	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	1,230	2	78	3	1,146	2	6	0	0
Natural Gas/Oil	8	1,937	0	0	2	511	6	1,426	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	93	2,654	0	0	0	0	93	2,654	0	0
Wind	32	13,306	0	0	0	0	0	0	32	13,306
Battery storage	13	1,188	0	0	0	0	13	1,188	0	0
Total	158	20,428	5	123	5	1,657	116	5,342	32	13,306

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

FORWARD CAPACITY MARKET

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	438.282	**-46.690**	407.62	-30.662
	Passive Demand	2,156.151	2,153.94	-2.211	2,150.196	-3.744	2,150.196	0	2,389.958	239.762	2,394.341	**4.380**	2,548.346	154.005
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**	**2,832.623**	**-42.310**	**2,955.966**	**123.343**
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	29,720.393	**-113.060**	29,700.519	-19.874
	Intermittent	891.616	864.924	-26.692	872.425	7.501	853.414	-19.011	870.558	17.144	855.947	**-14.611**	788.037	-67.91
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	**30,576.34**	**-127.660**	**30,488.556**	**-87.784**
Import Total		**1,449**	**1,449**	**0**	**1,449**	**0**	**1,449**	**0**	**1,449**	0	**1,599**	**150.000**	**1,568**	**-31.000**
*****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	**35,007.963**	**-19.970**	**35,012.522**	**4.559**
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**	**33,421**	**-462**	**33,421**	0	**33,247**	**-174**	**33,247**	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 Monthly 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	460.55	-4.165	459.928	-0.622				
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834	2,363.789	-0.16	2,527.244	163.46				
Demand Total		**2,746.156**	**2,734.01**	**-12.146**	**2,828.664**	**94.654**	**2,824.339**	**-4.325**	**2,987.172**	**162.83**				
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272	30,103.684	55.286	30,093.142	-10.54				
	Intermittent	850.143	893.189	43.046	904.311	11.122	831.251	-73.06	798.958	-32.293				
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**	**30,934.935**	**-17.774**	**30,892.1**	**-42.84**				
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**	**1,451**	**0**	**1,451**	**0**				
*****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**	**35,210.274**	**-22.099**	**35,330.272**	**120.00**				
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**	**33,407**	**-348**	**33,407**	**0**				

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

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*** 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	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	419.928	441.221	21.293				
	Passive Demand	2,791.02	2,835.354	44.334				
Demand Total		**3,210.95**	**3,276.575**	**65.625**				
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569				
	Intermittent	894.217	823.796	-70.421				
Generator Total		**31,389.02**	**30,888.03**	**-500.993**				
Import Total		**1,235.40**	**1,622.037**	**386.637**				
******Grand Total***		**35,835.37**	**35,786.64**	**-48.731**				
Net ICR (NICR)		**34,075**	**33,660**	**-415**				

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

** A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

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

Capacity Supply Obligation FCA 12

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445						
	Passive Demand	2,975.36						
Demand Total		**3,599.81**						
Generator	*Non-Intermittent*	29,130.75						
	Intermittent	880.317						
Generator Total		**30,011.07**						
Import Total		**1217**						
*****Grand Total**		**34,827.88**						
Net ICR (NICR)		**33,725**						

* 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 Monthly 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
2021-22	Active	480.941	143.504	624.445
	Passive	2604.793	370.568	2975.361
	Grand Total	3085.734	514.072	3599.806

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

What are Daily NCPC Payments?

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

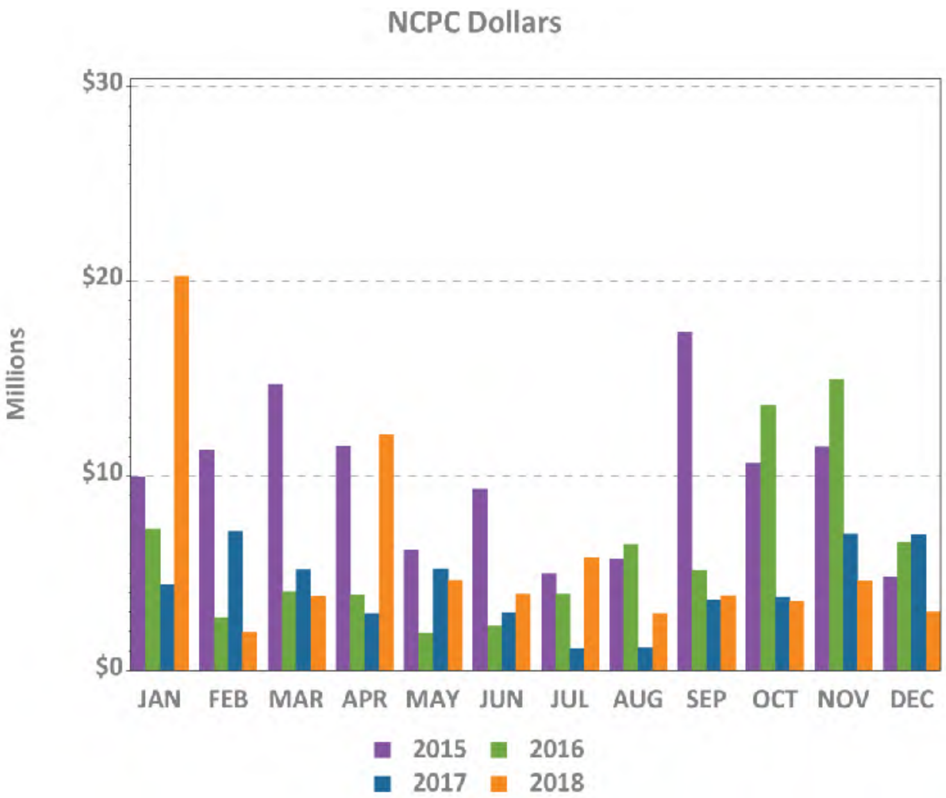
Definitions

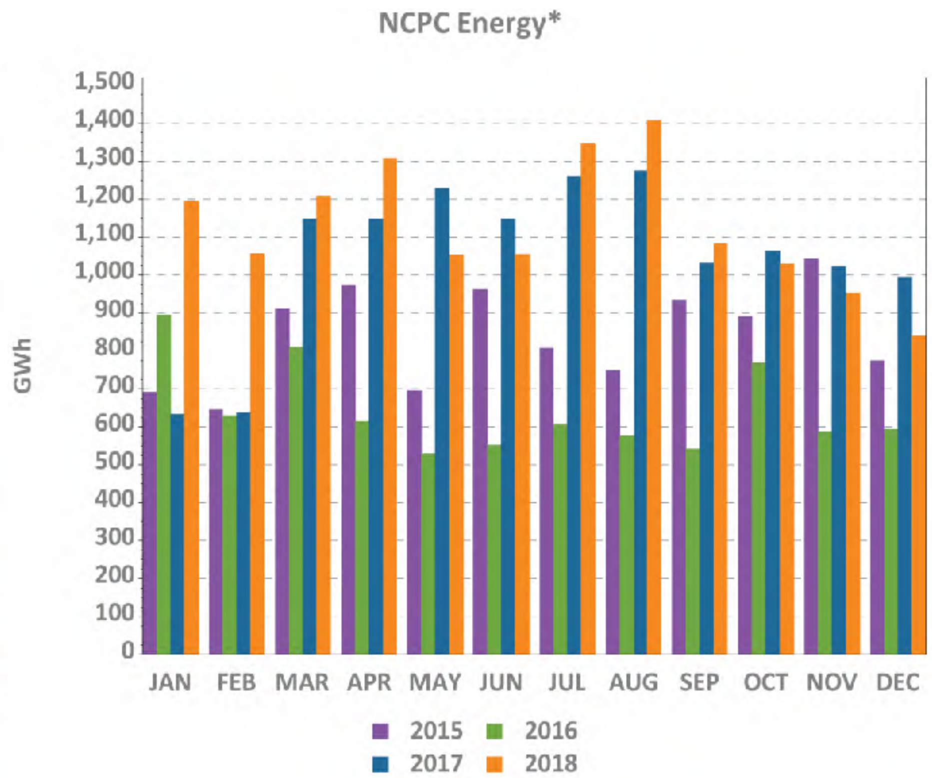
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

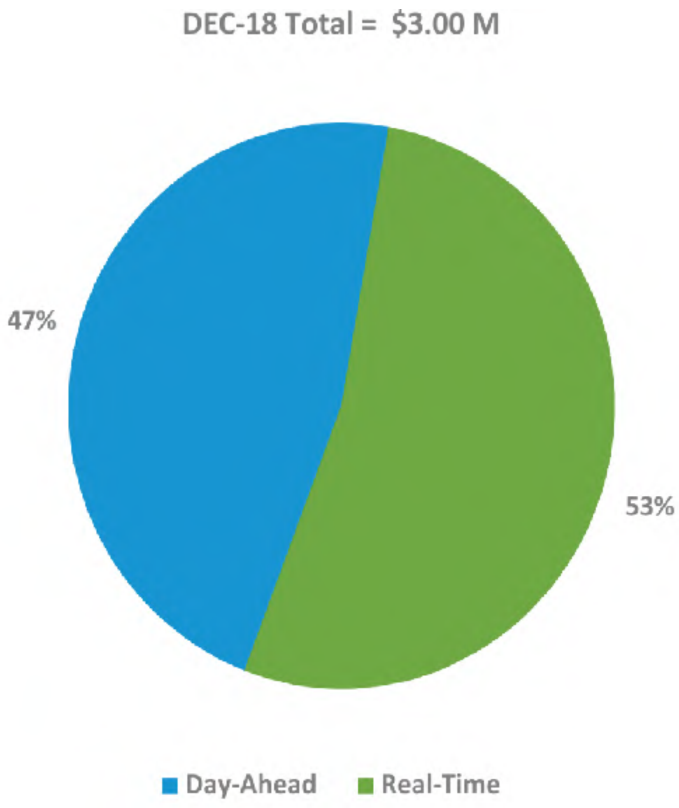
Year-Over-Year Total NCPC Dollars and Energy

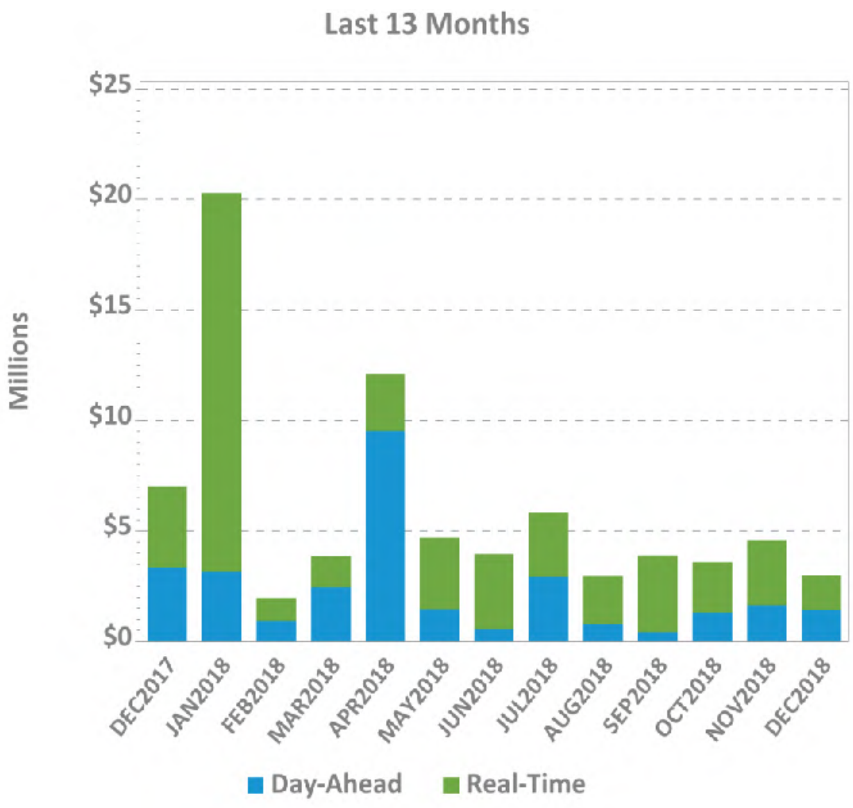




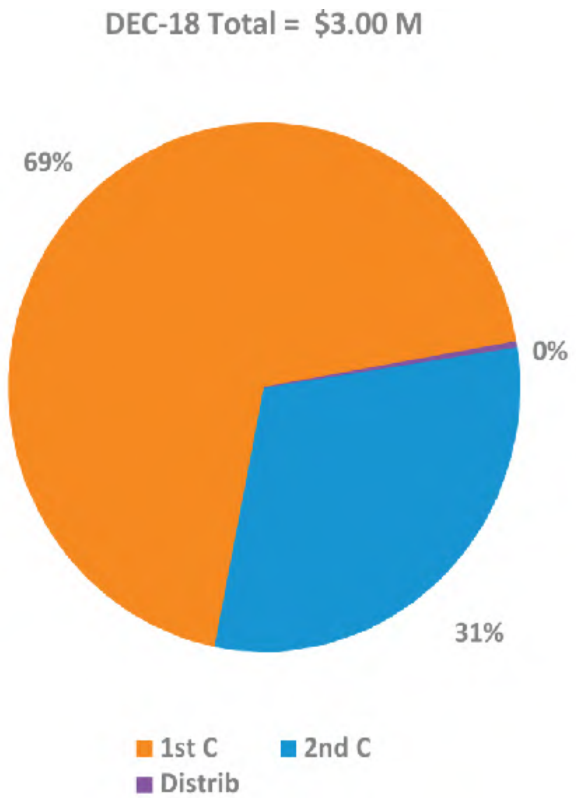
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

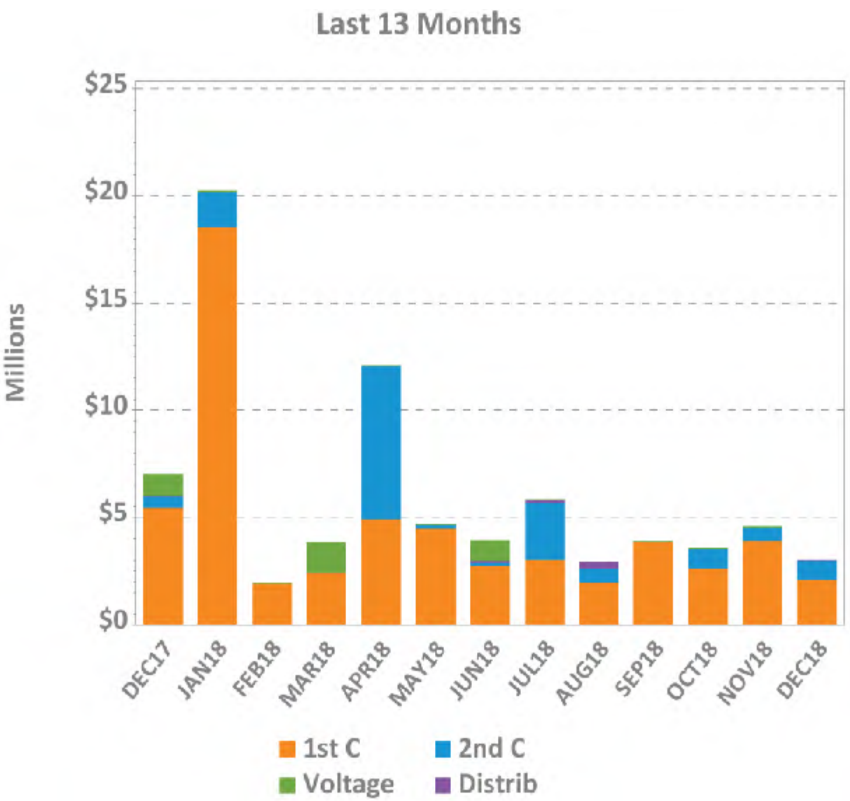
DA and RT NCPC Charges





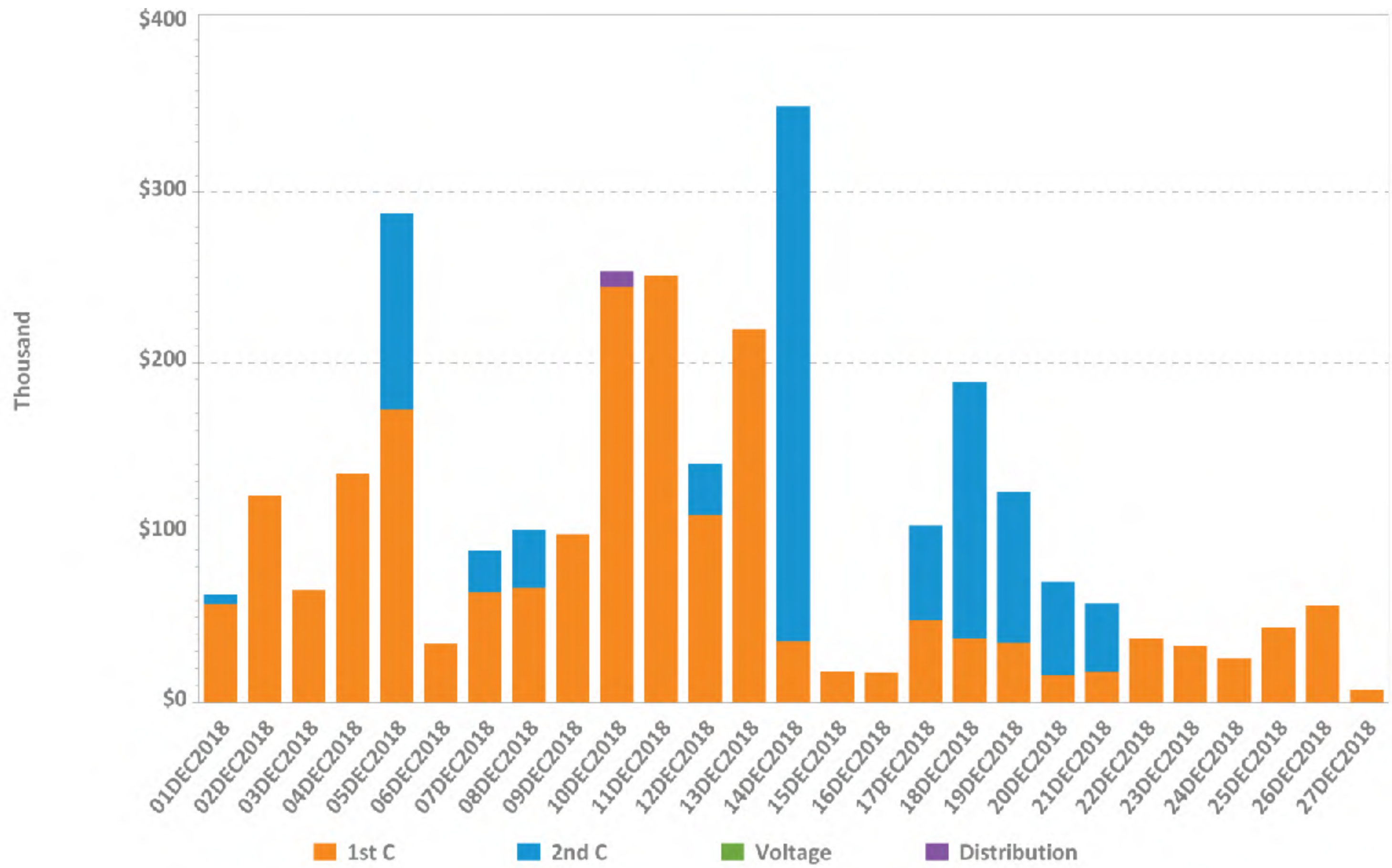
NCPC Charges by Type



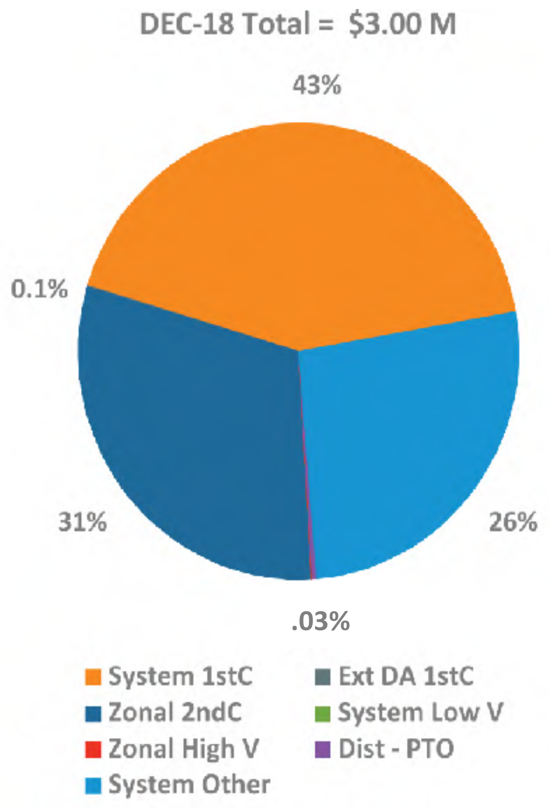


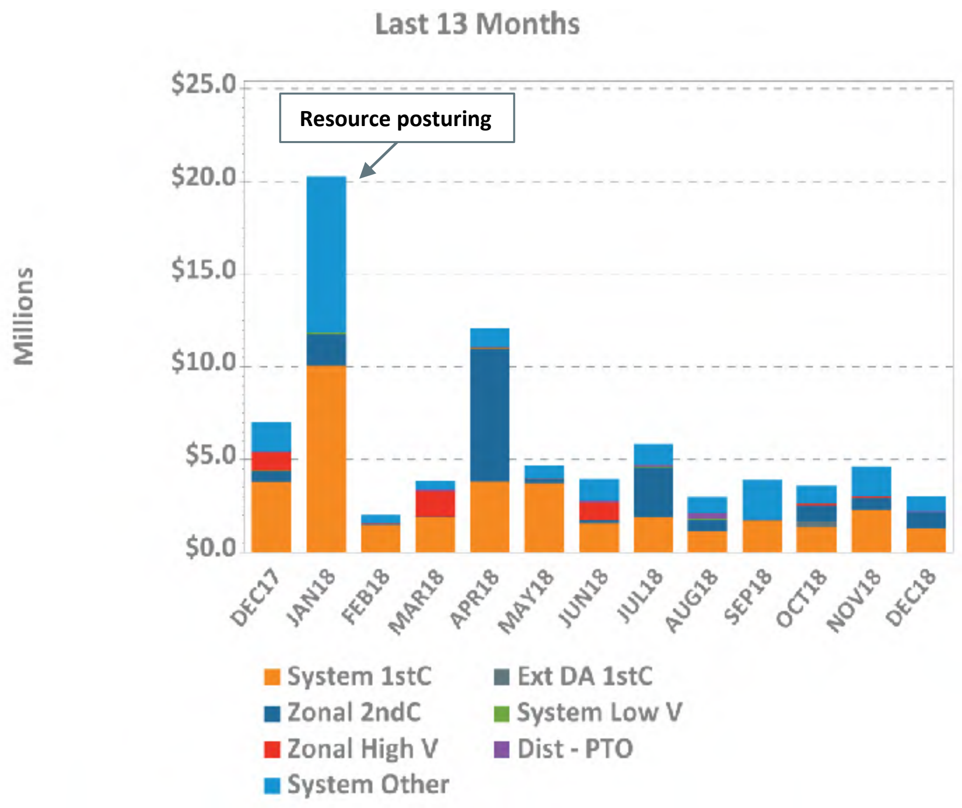
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



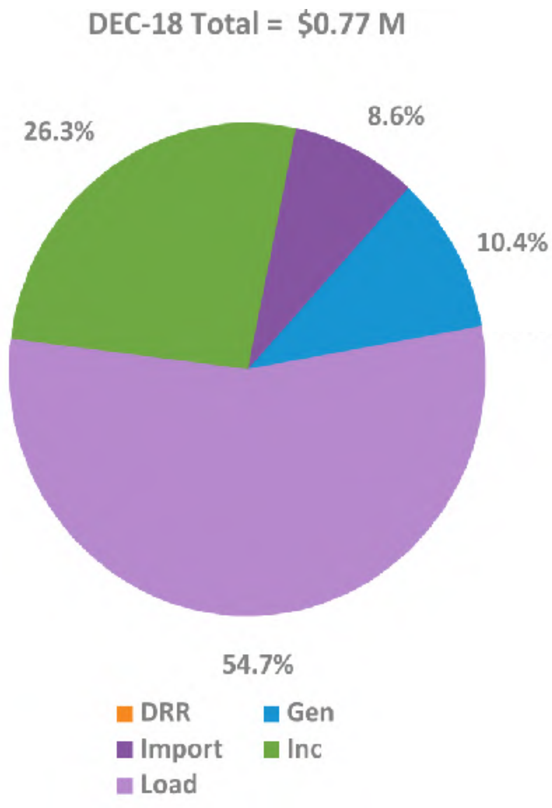
NCPC Charges by Allocation

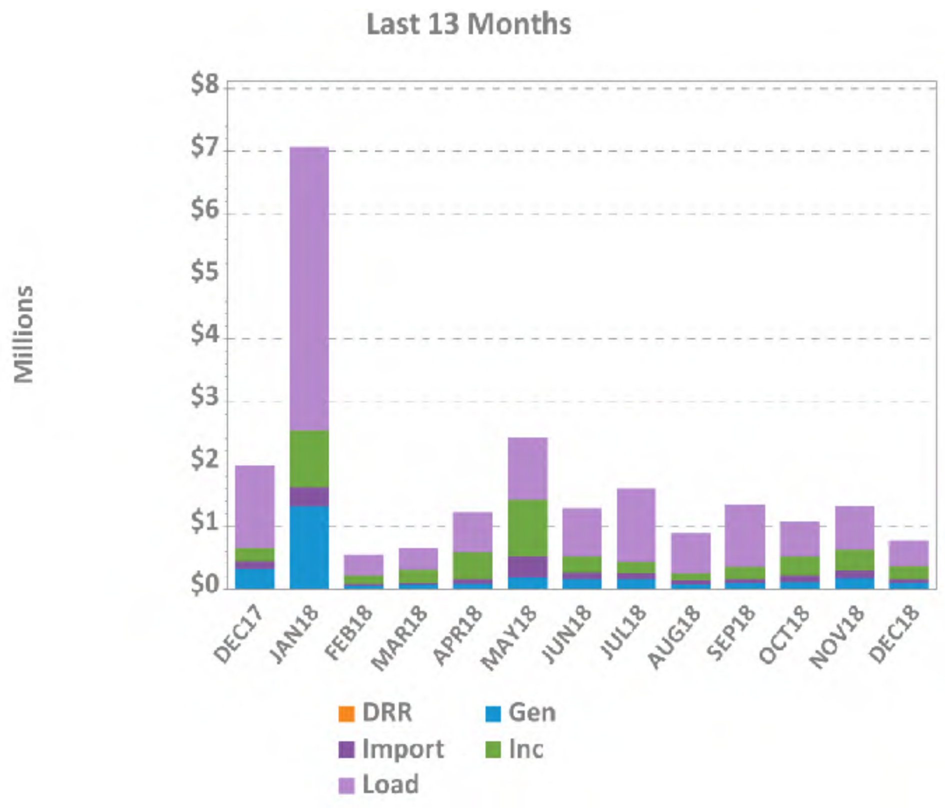




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

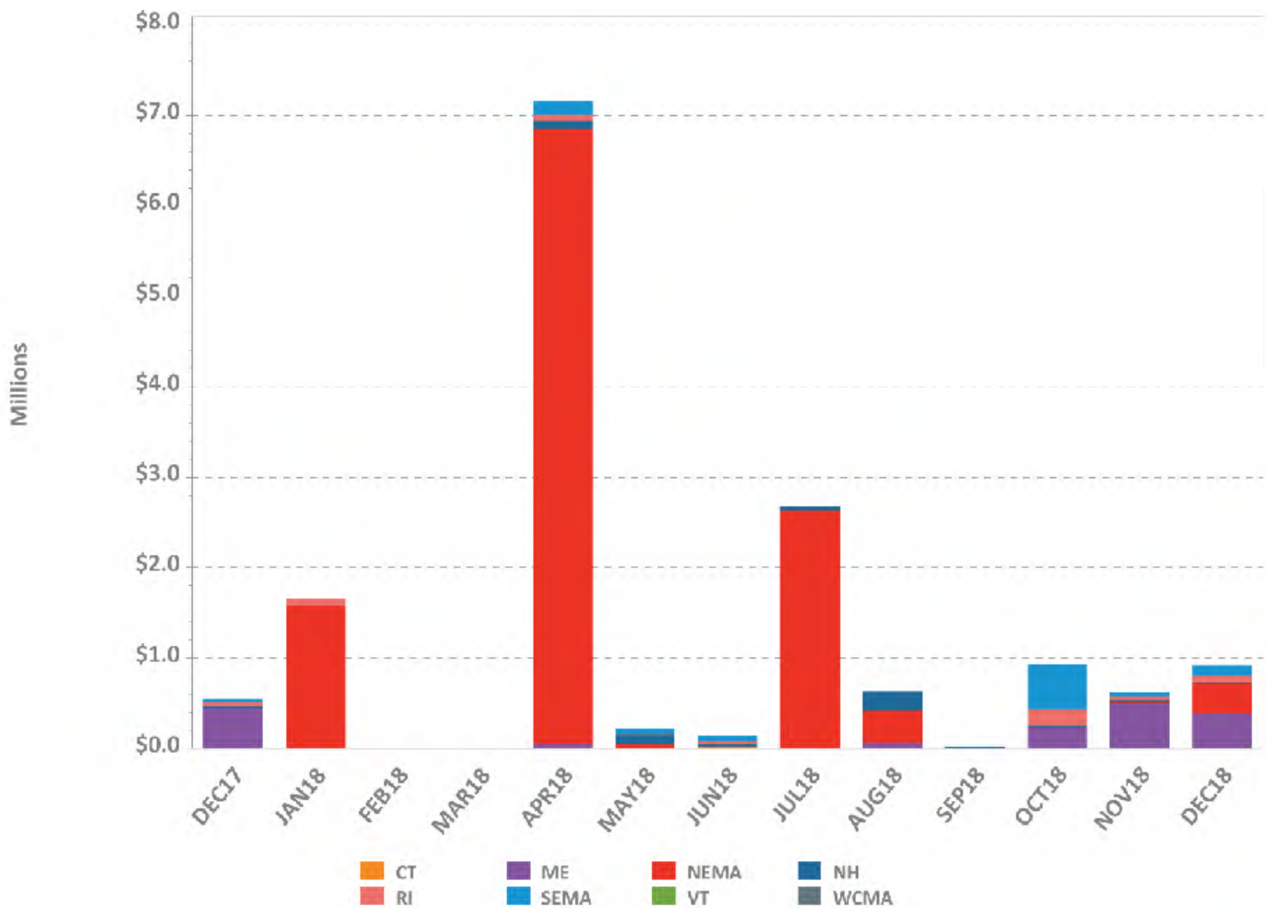
RT First Contingency Charges by Deviation Type





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

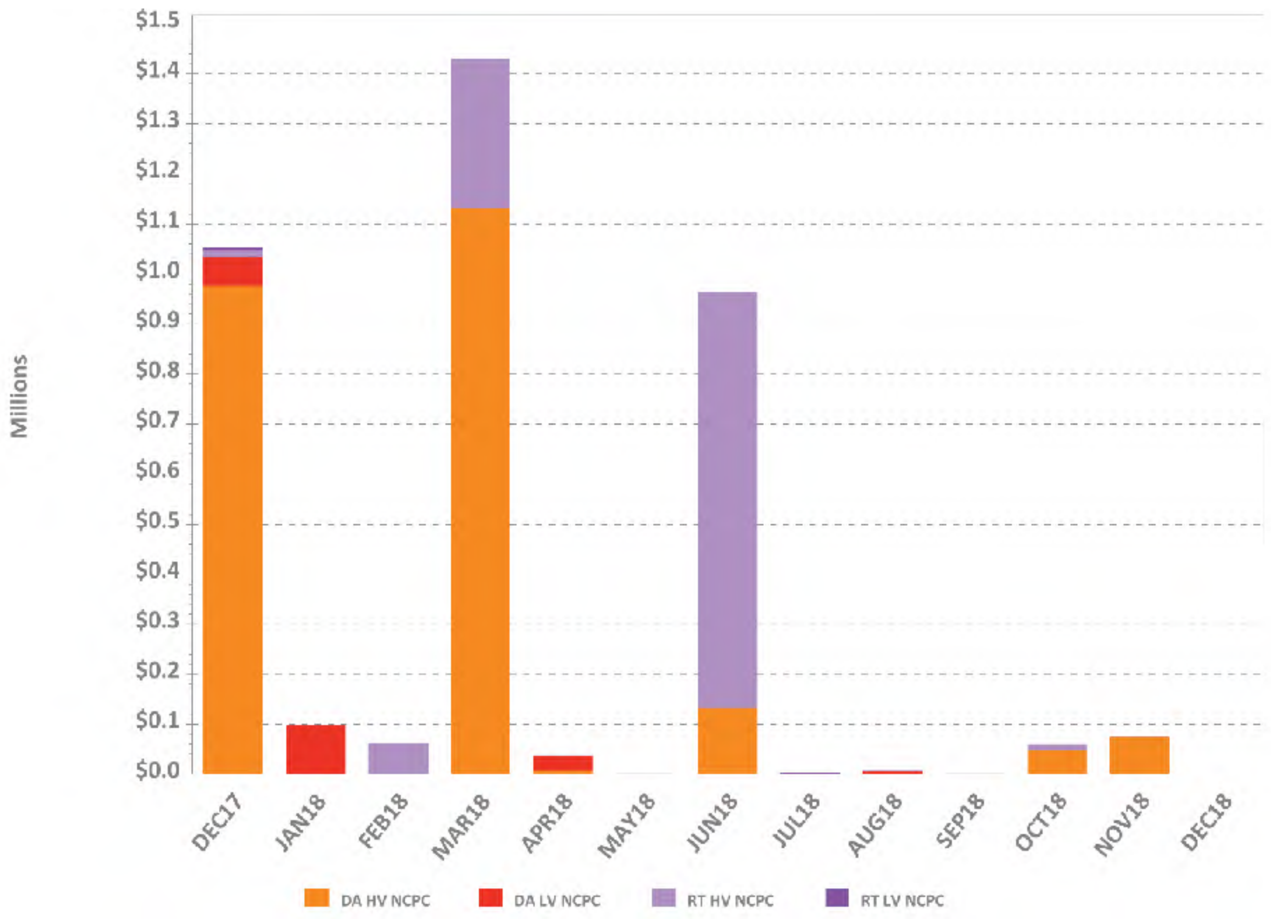
LSCPR Charges by Reliability Region



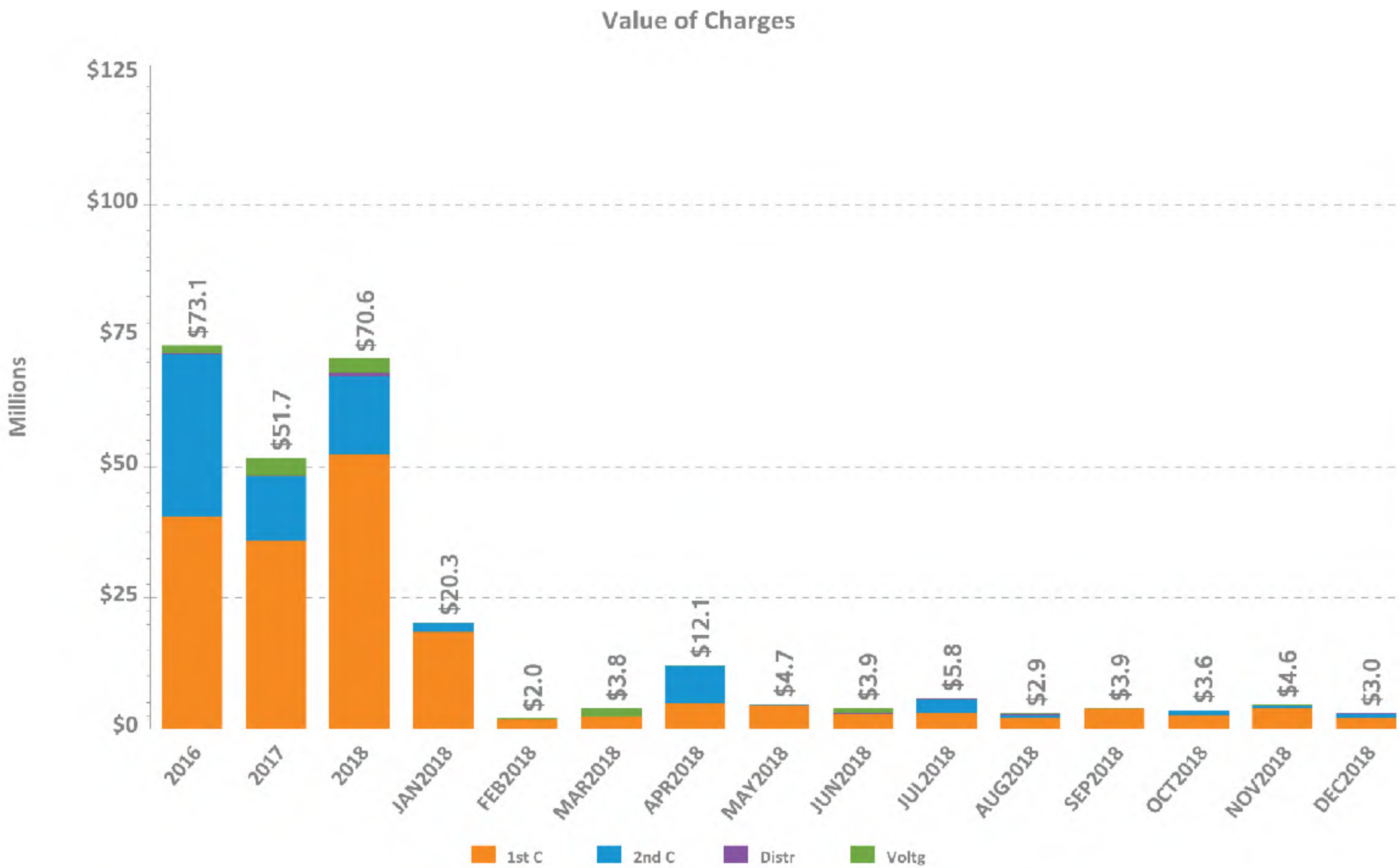
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

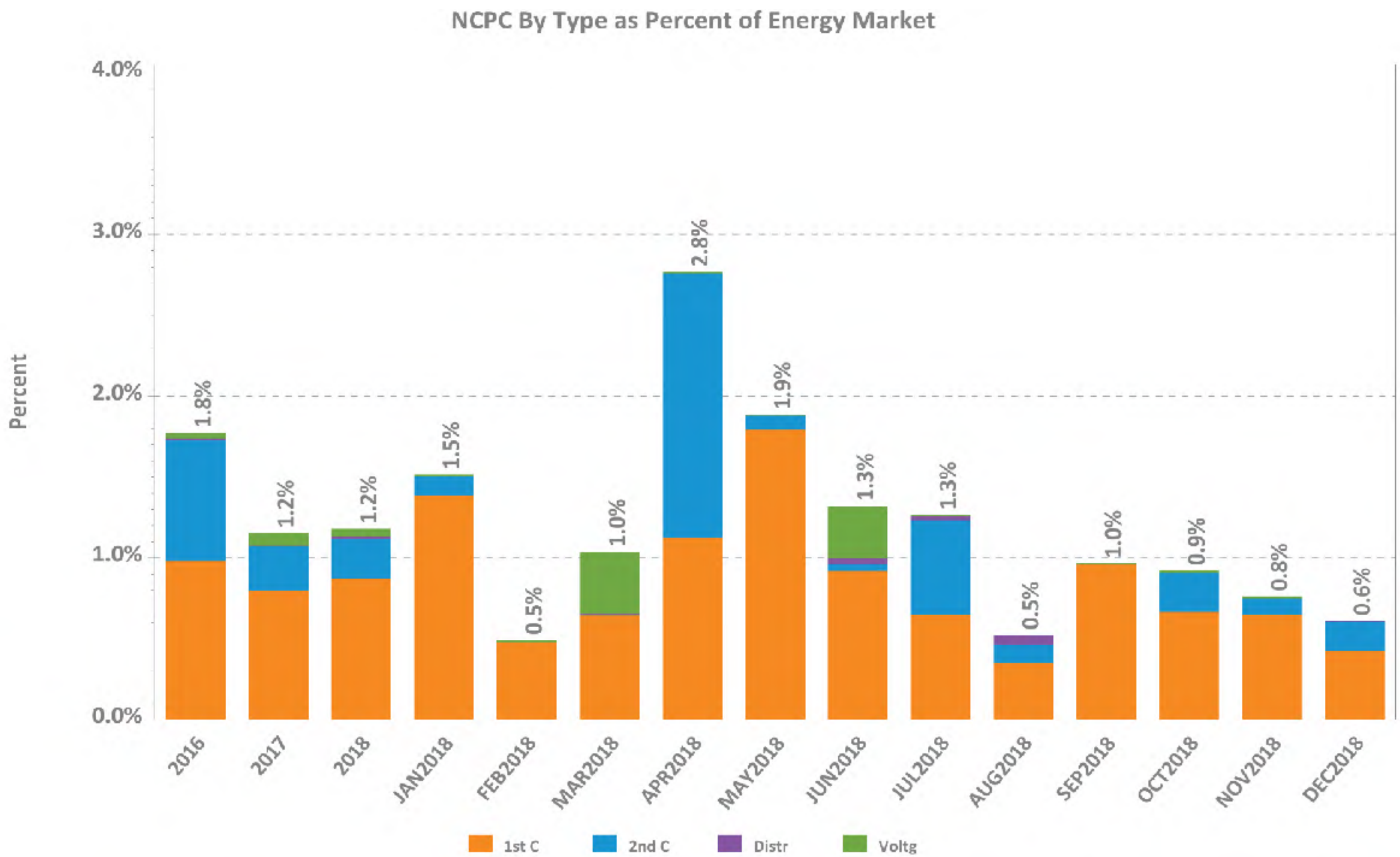
NCPC Charges for Voltage Support and High Voltage Control



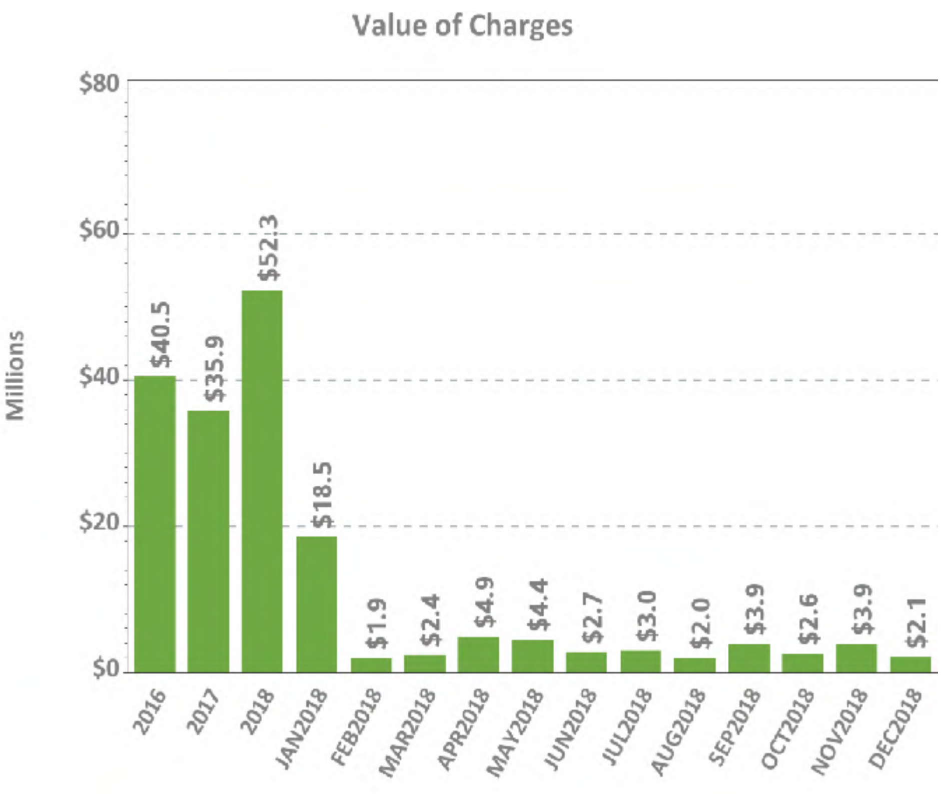
NCPC Charges by Type

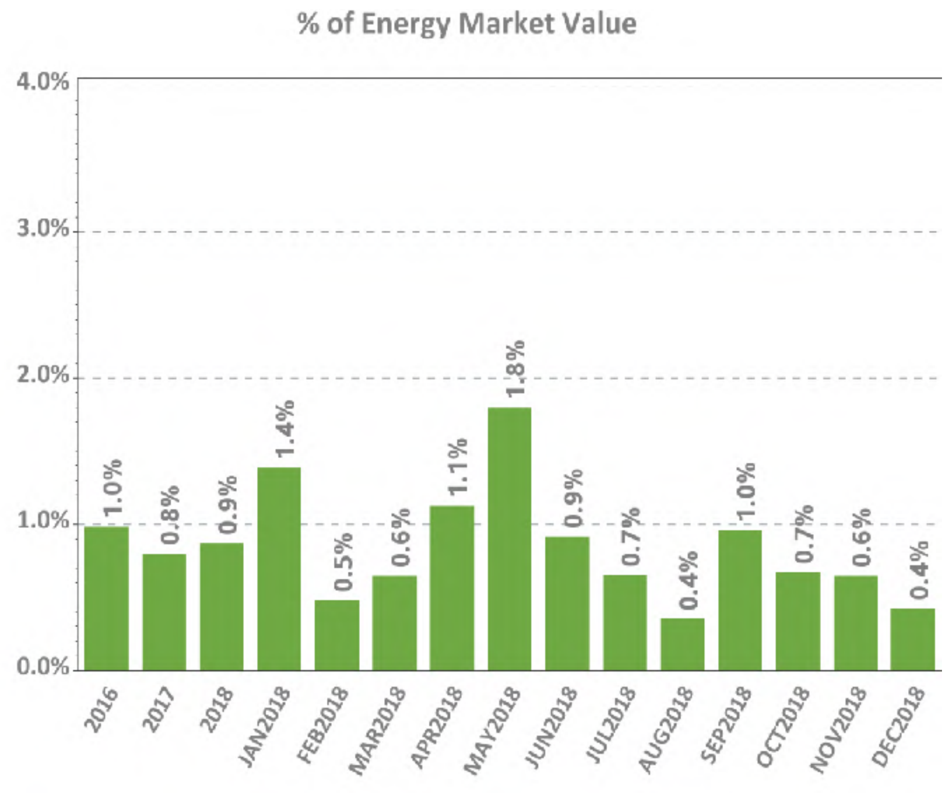


NCPC Charges as Percent of Energy Market



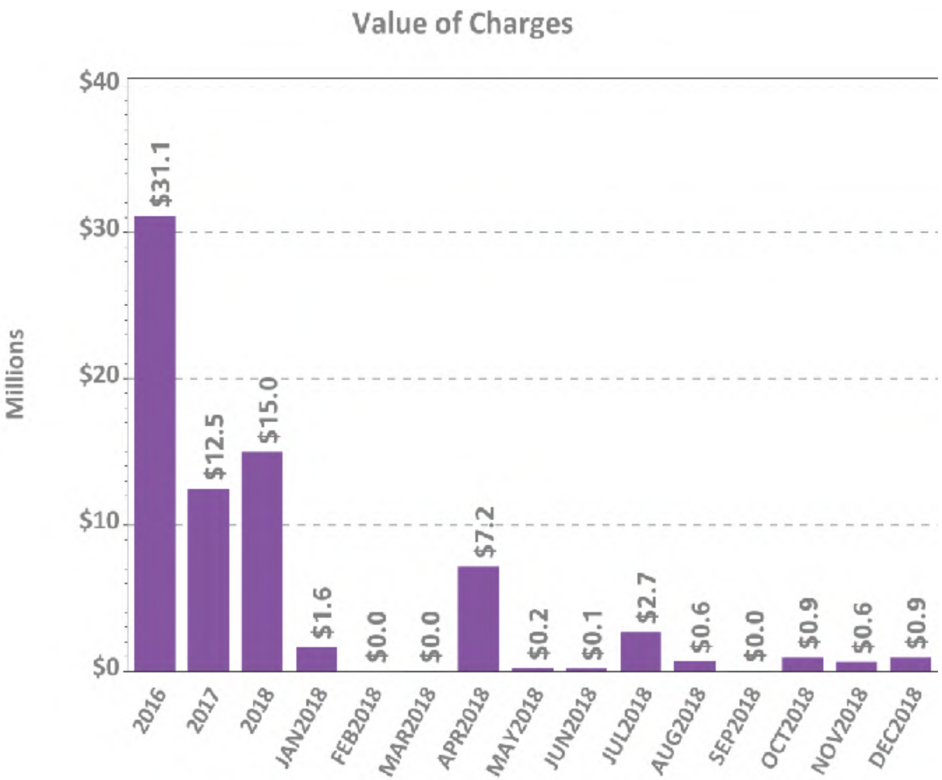
First Contingency NCPC Charges

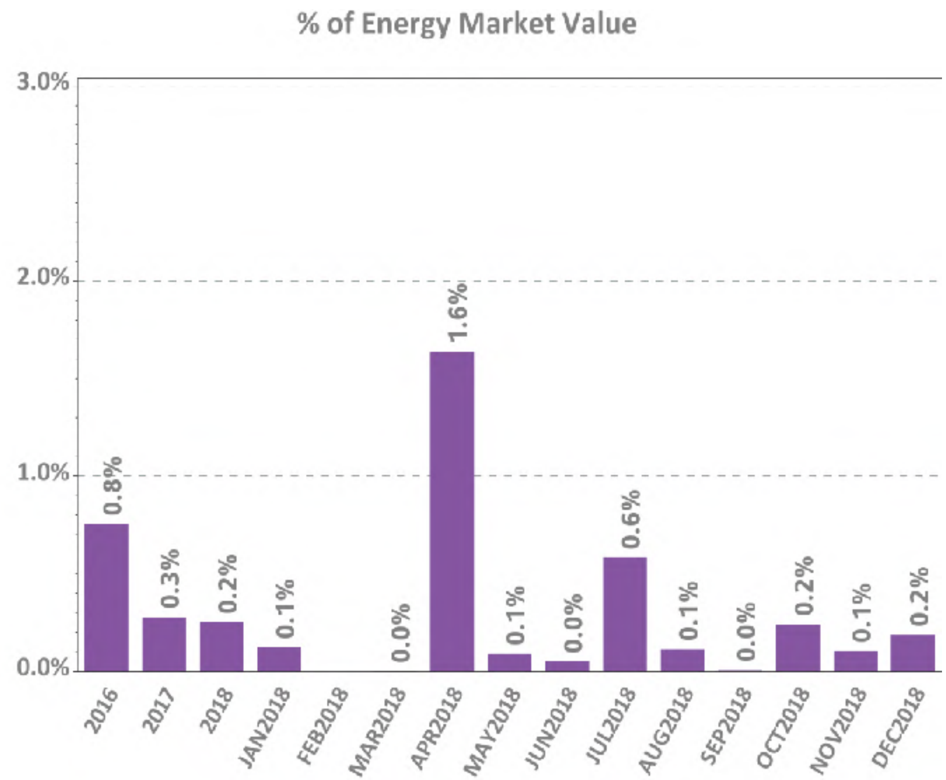




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

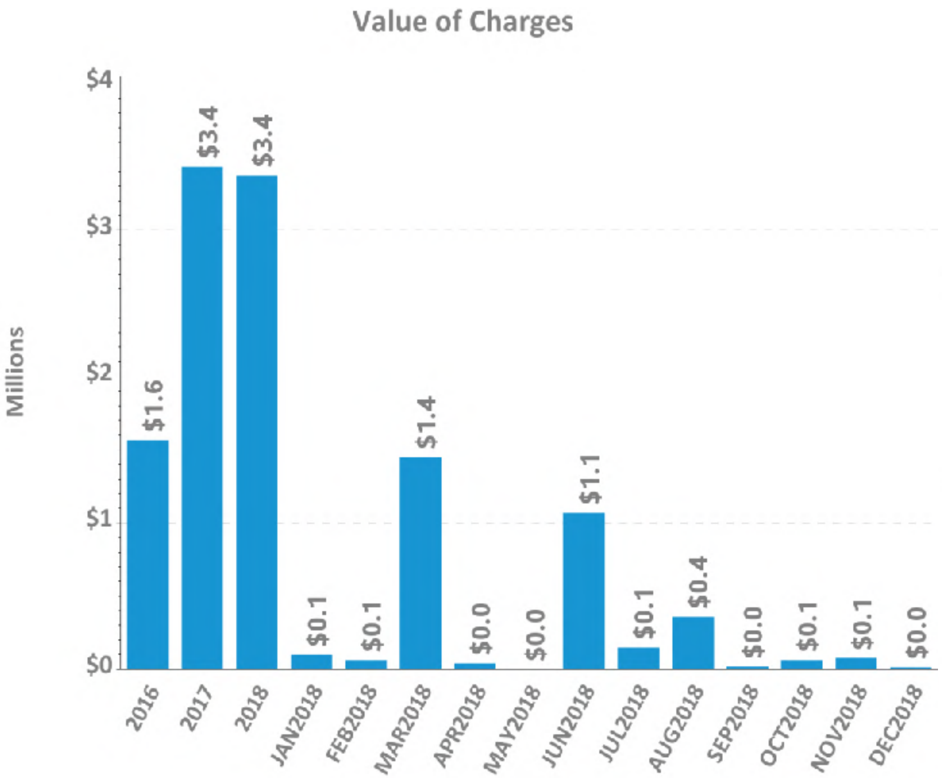
Second Contingency NCPC Charges

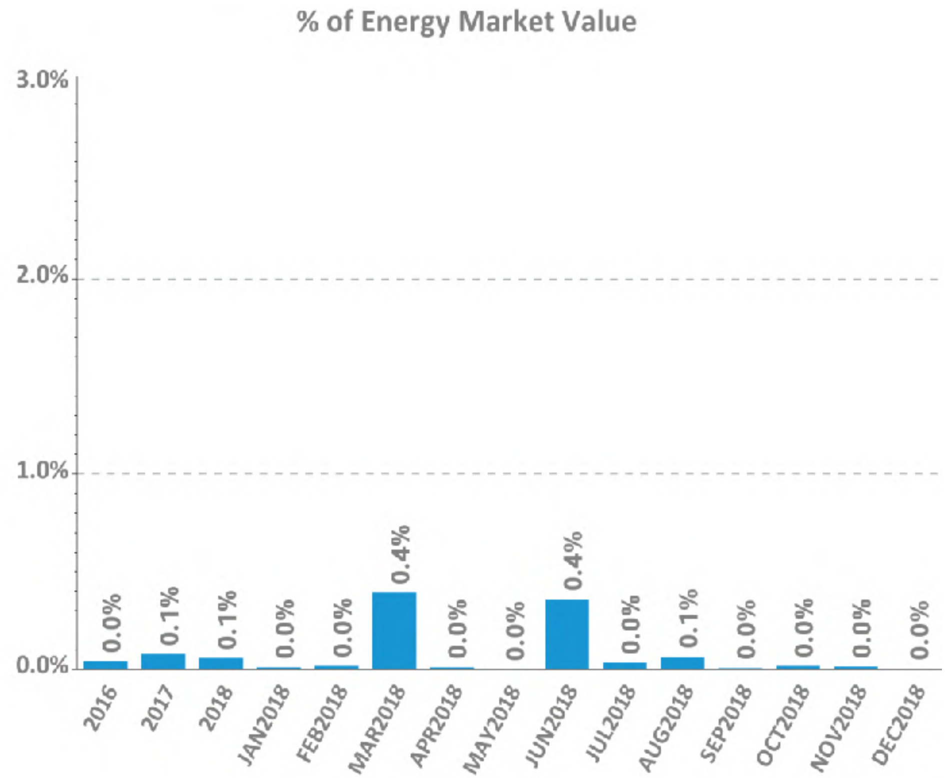




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

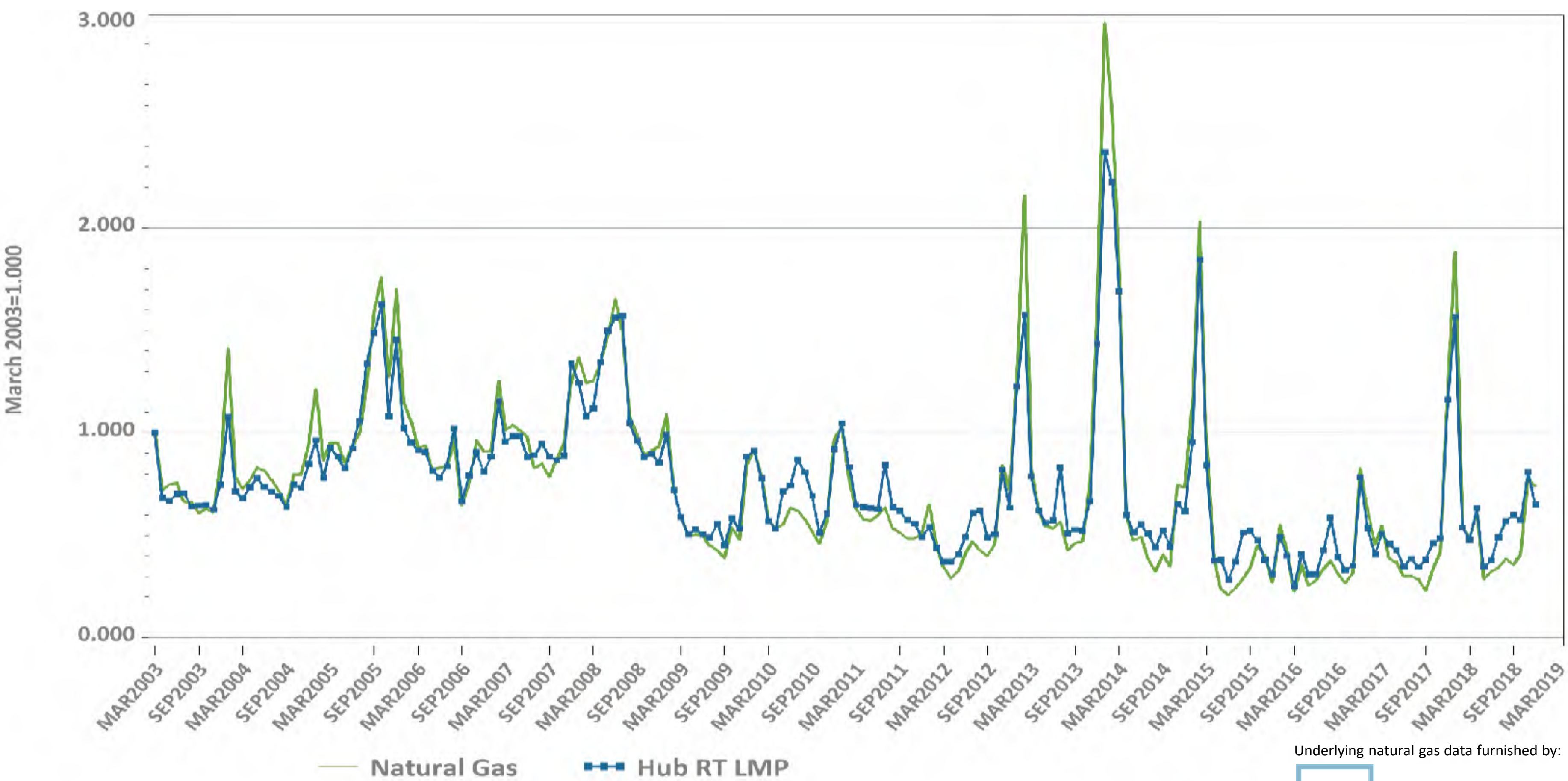
DA vs. RT LMPs ($/MWh)

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%

December-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$71.60	$69.59	$69.63	$71.06	$70.89	$71.15	$71.63	$71.33	$71.31
Real-Time	$80.61	$78.39	$74.27	$77.57	$77.93	$79.73	$80.44	$79.77	$79.89
RT Delta %	12.6%	12.7%	6.7%	9.2%	9.9%	12.1%	12.3%	11.8%	12.0%
December-18	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$50.77	$48.63	$50.50	$50.64	$49.52	$49.92	$50.47	$50.17	$50.21
Real-Time	$44.99	$43.46	$43.93	$44.82	$43.73	$44.33	$44.73	$44.49	$44.55
RT Delta %	-11.4%	-10.6%	-13.0%	-11.5%	-11.7%	-11.2%	-11.4%	-11.3%	-11.3%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-29.1%	-30.1%	-27.5%	-28.7%	-30.1%	-29.8%	-29.5%	-29.7%	-29.6%
Yr over Yr RT	-44.2%	-44.6%	-40.8%	-42.2%	-43.9%	-44.4%	-44.4%	-44.2%	-44.2%

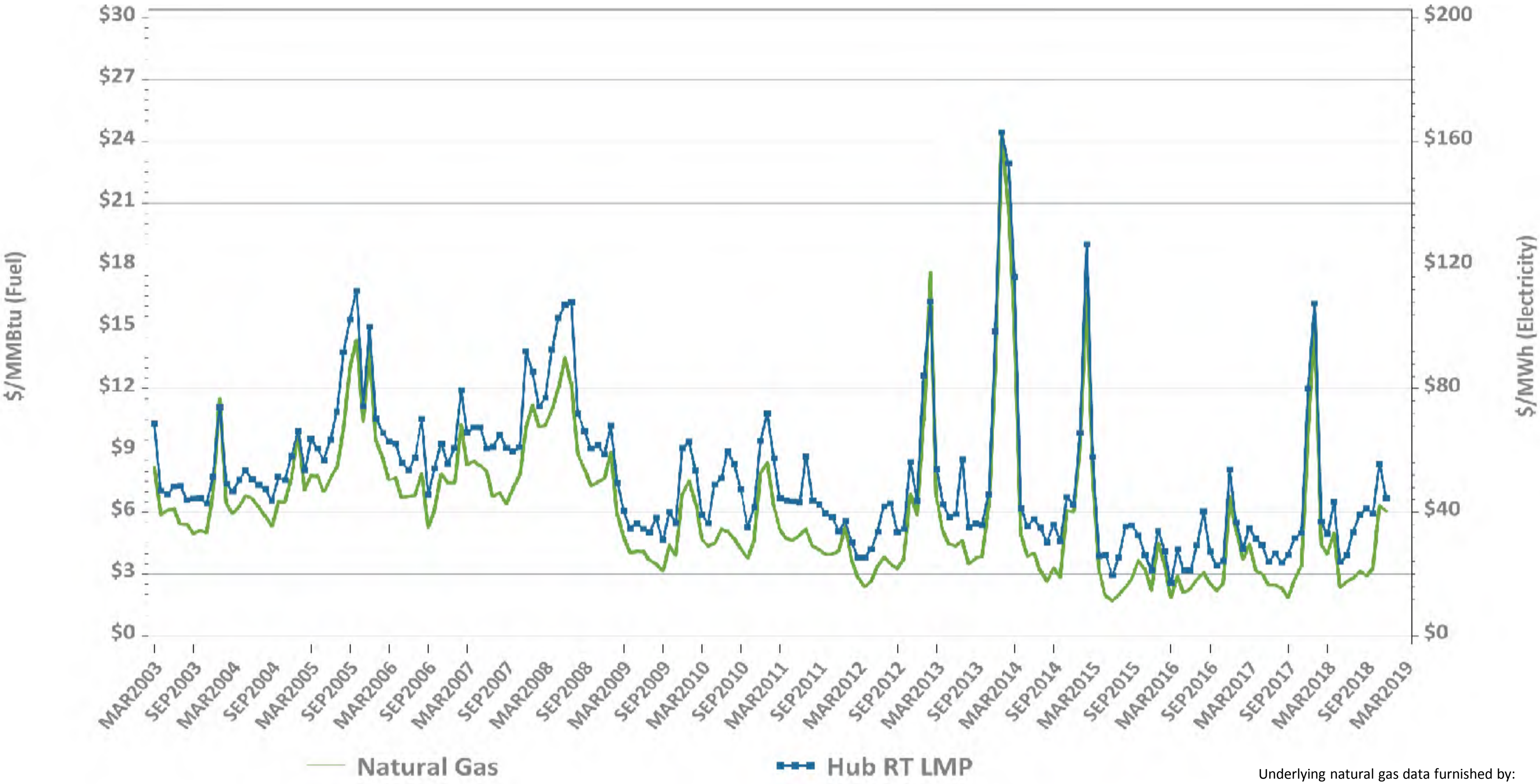
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

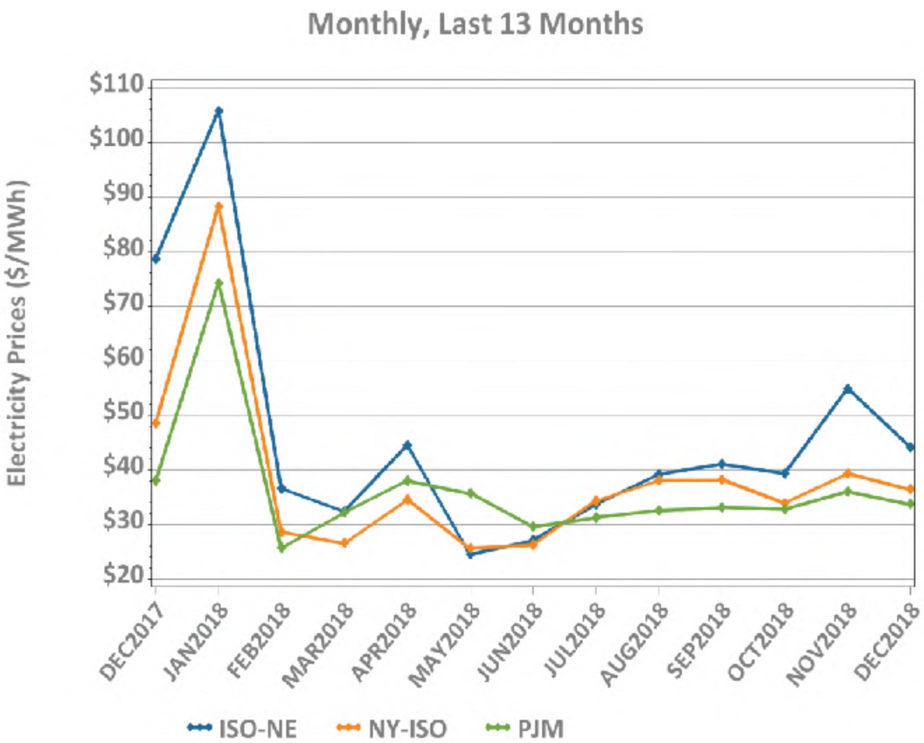
Monthly Average Fuel Price and RT Hub LMP



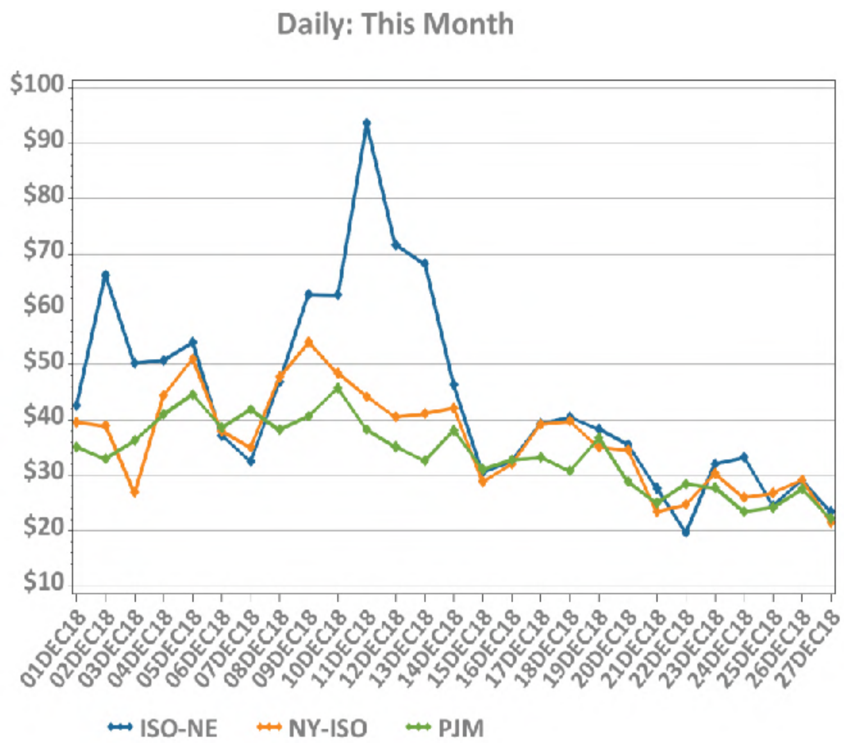
Underlying natural gas data furnished by:

ice Global markets in clear view

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

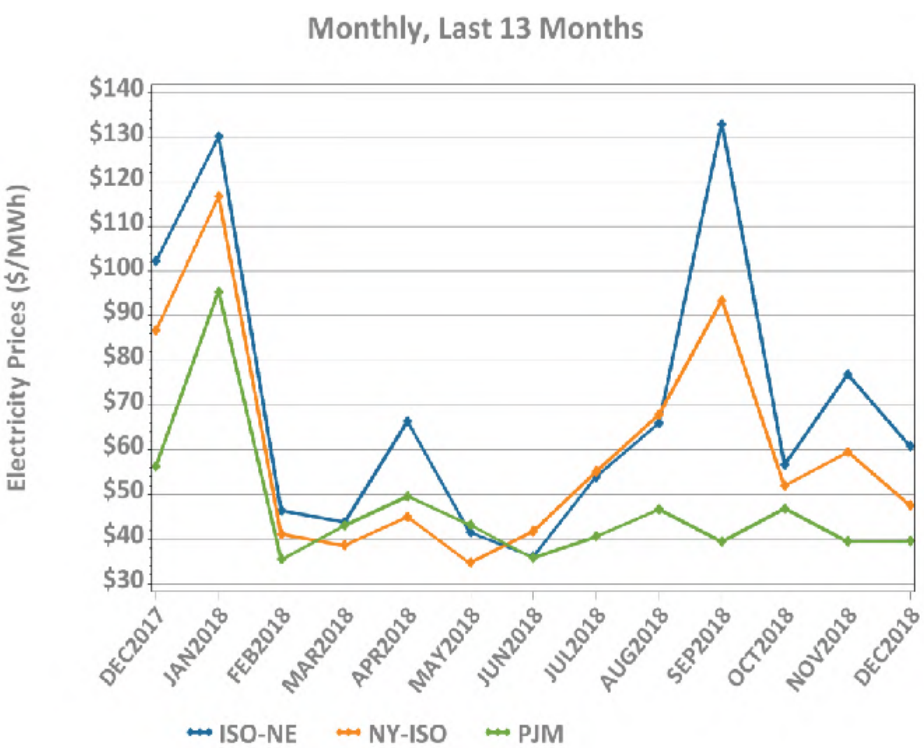


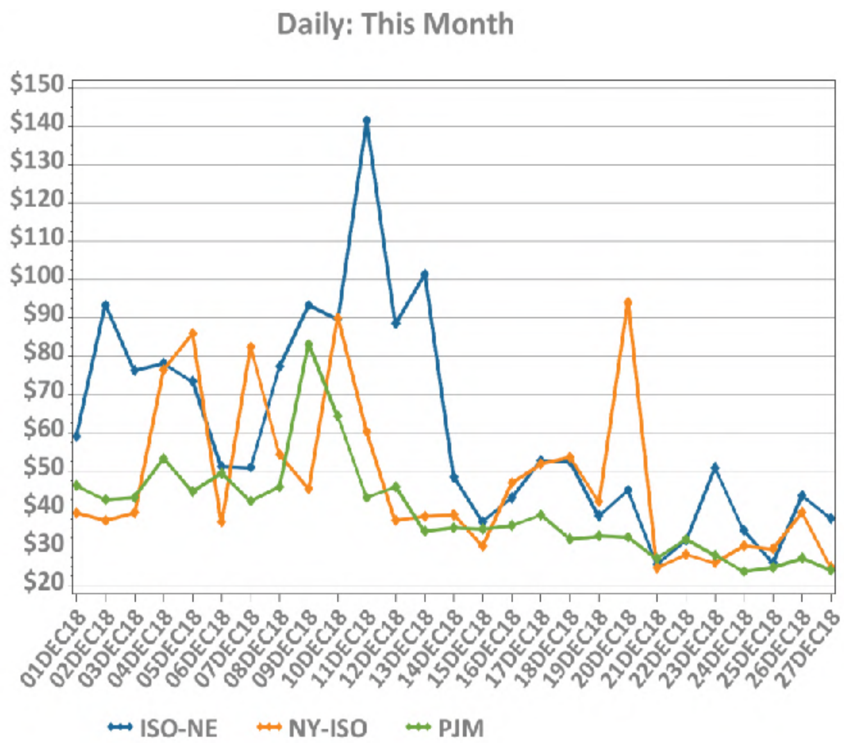
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





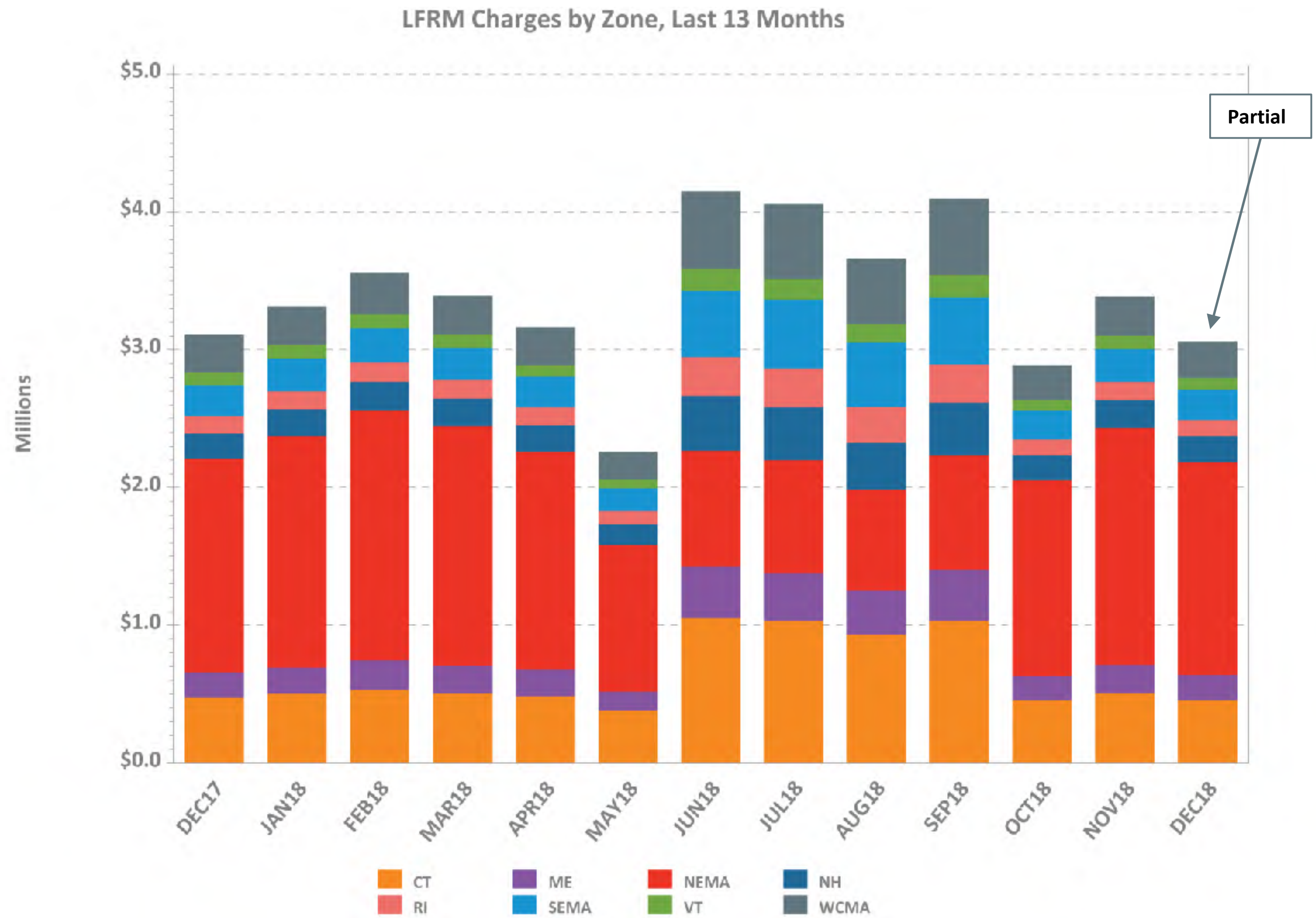
***Forecasted New England daily peak hours reflected**

Reserve Market Results – December 2018

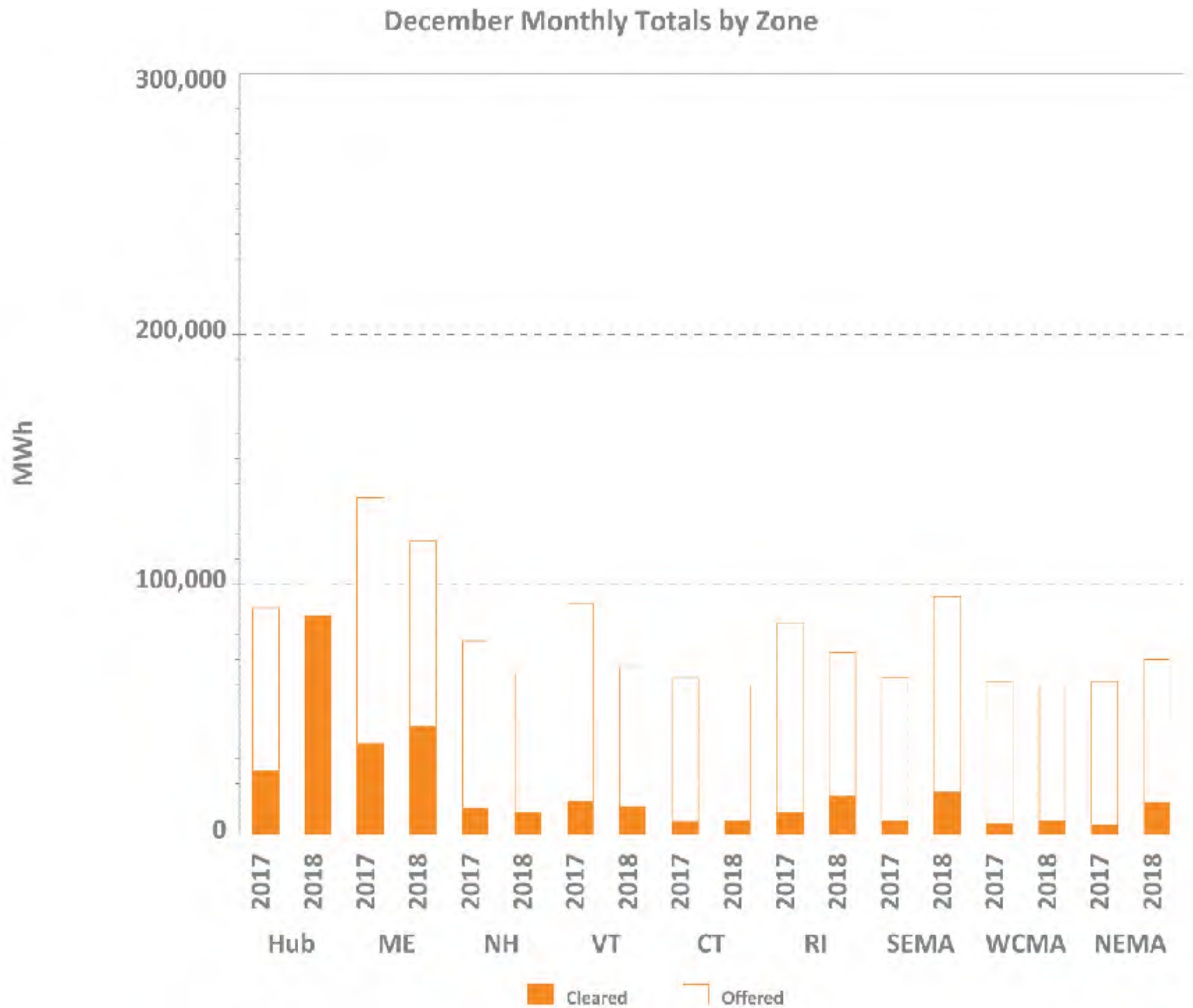
- Maximum potential Forward Reserve Market payments of $3.1M were reduced by credit reductions of $27K, failure-to-reserve penalties of $40K and no failure-to-activate penalties, resulting in a net payout of $3.1M or 98% of maximum
  - Rest of System: $0.98M/1.02M (96%)
  - Southwest Connecticut: $0.14M/0.14M (99%)
  - Connecticut: $0.26M/0.27M (96%)
  - NEMA: $1.7M/1.7M (99%)
- $983K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $983K in Real-Time Reserve payments
  - Rest of System: 182 hours, $623K
  - Southwest Connecticut: 182 hours, $176K
  - Connecticut: 182 hours, $152K
  - NEMA: 182 hours, $31K

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

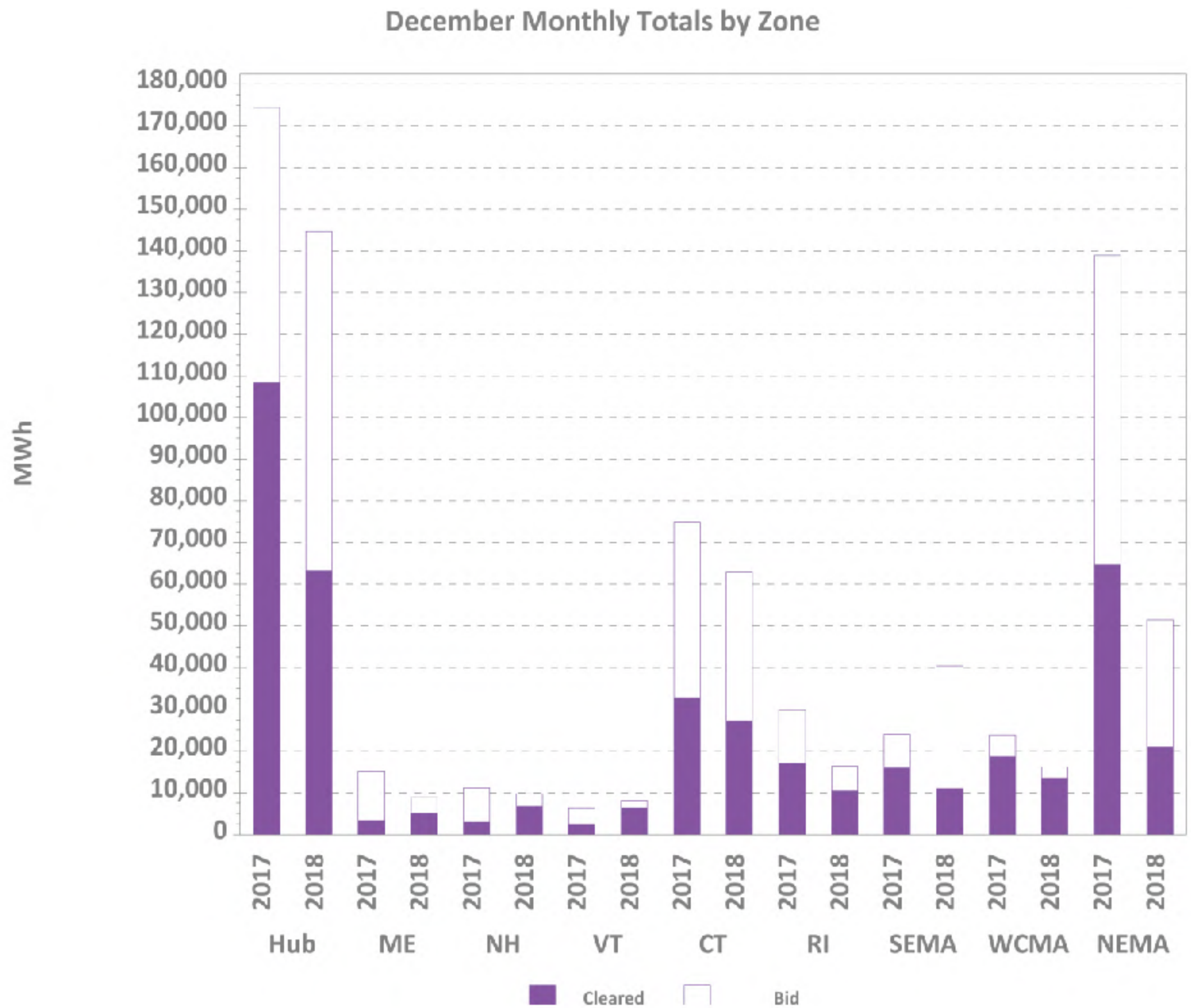
LFRM Charges to Load by Load Zone ($)



Zonal Increment Offers and Cleared Amounts



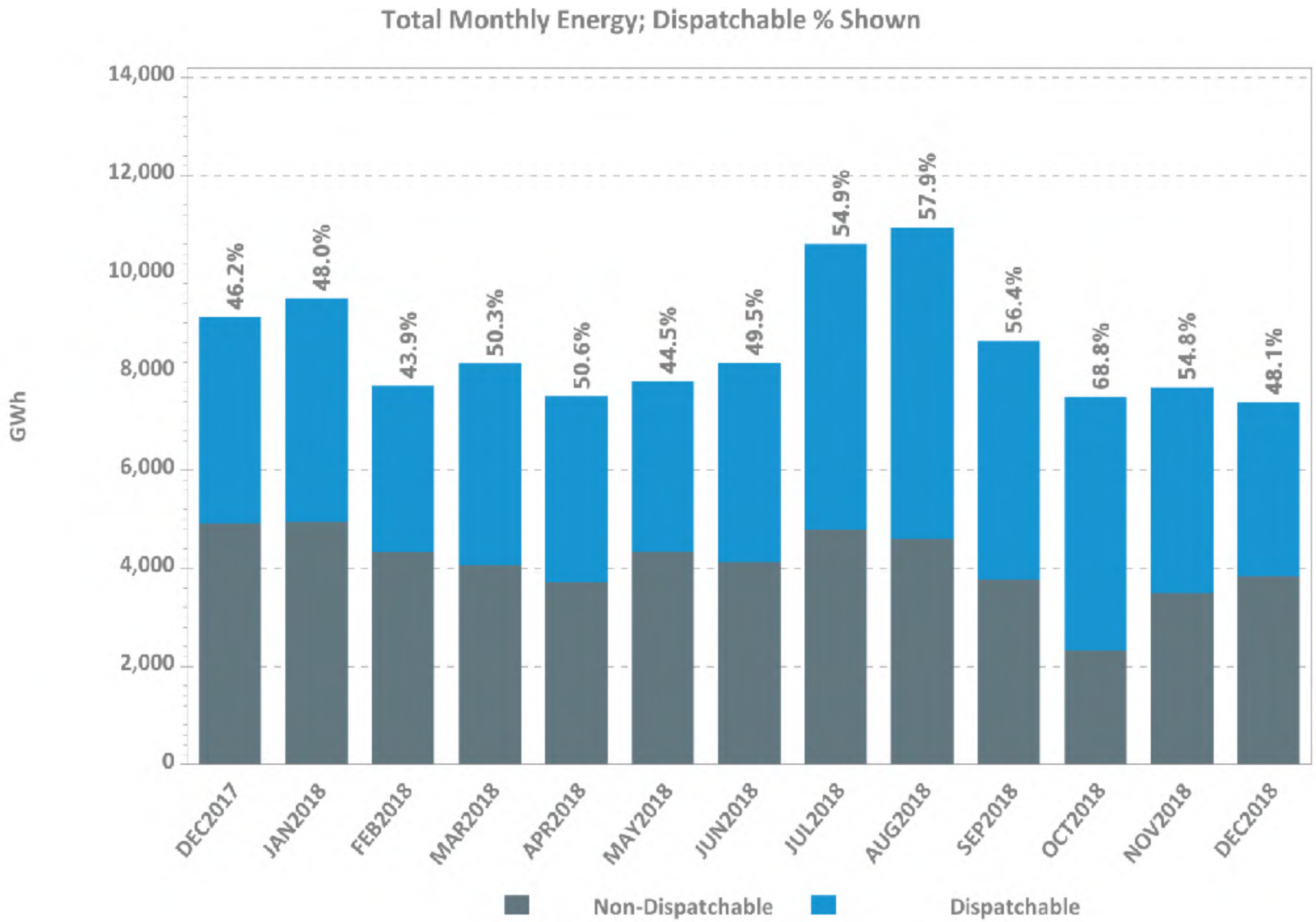
Zonal Decrement Bids and Cleared Amounts



Total Increment Offers and Decrement Bids

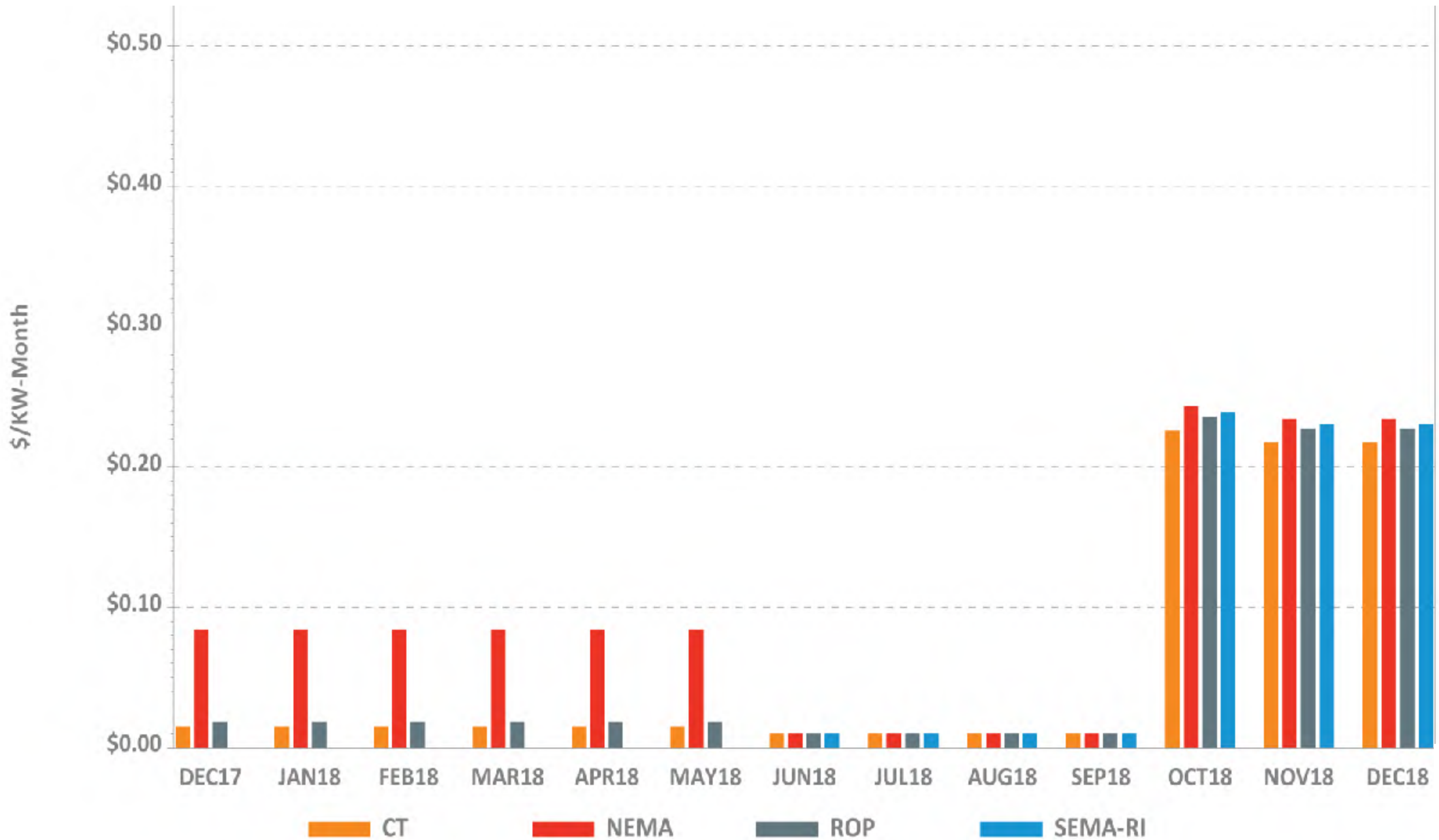
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

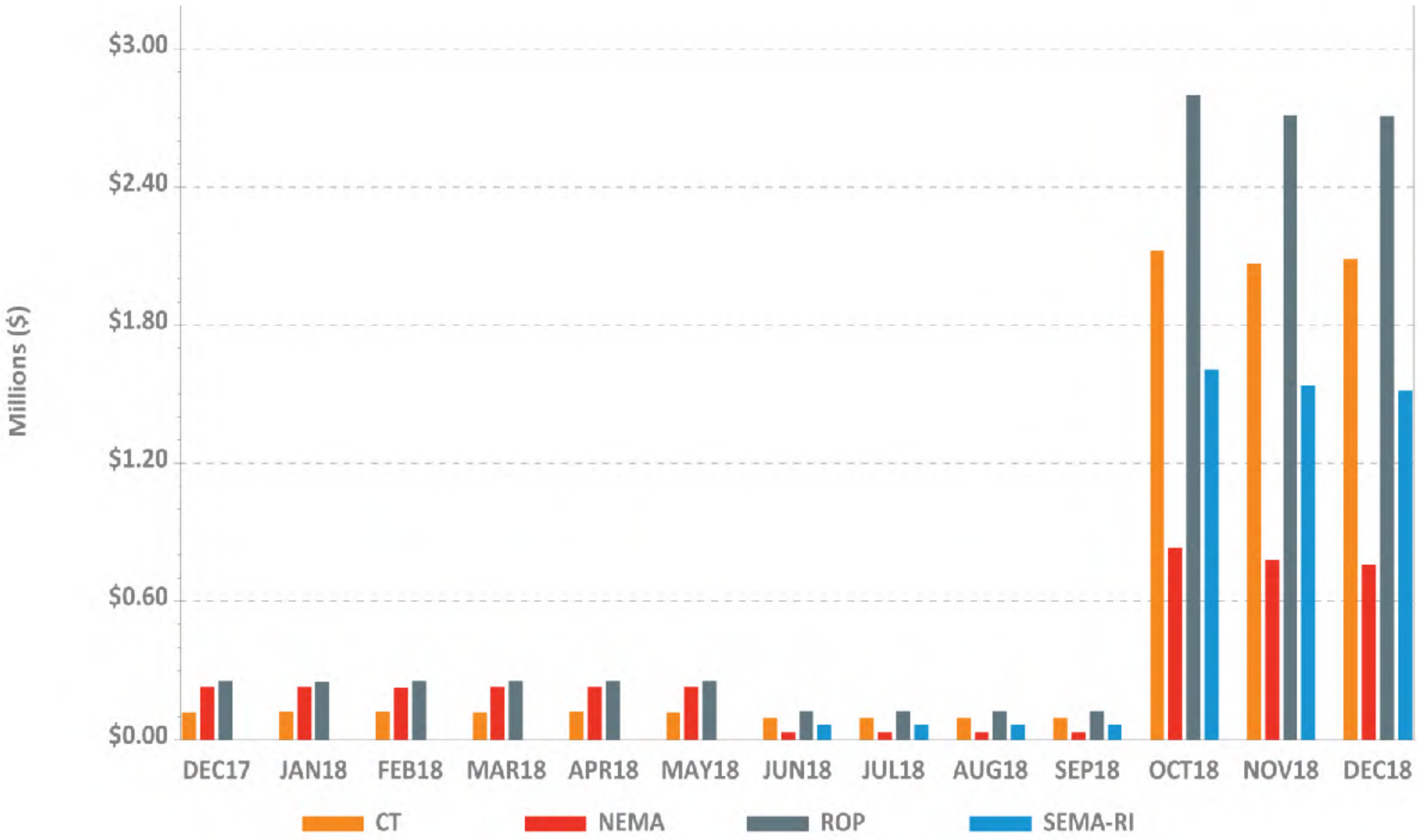
Rolling Average Peak Energy Rent (PER) by Capacity Zone



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: <u>Home > Markets > Other Markets Data > Forward Capacity Market > Reports</u> 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)

- January meeting has been canceled
- RSP19 scope of work will be discussed at the February meeting

* Agenda topics 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 2019 ten-year load forecast development process is underway
  - Staff continues to explore improvements to winter/summer peak and energy modeling
  - Staff is investigating ways to better capture expiring measures in the energy-efficiency forecast
  - Forecast to be finalized and posted as part of the CELT report by May 1
- Discussions with industry and counterparts at other ISOs/utilities continue regarding potential impacts of future emerging technologies/trends and methods of incorporating these into the forecast
- Upcoming forecast stakeholder meetings:
  - Distributed Generation Forecast Working Group – February 15
  - Load Forecasting Committee – February 11
  - Energy Efficiency Working Group – February 8

Interregional Planning

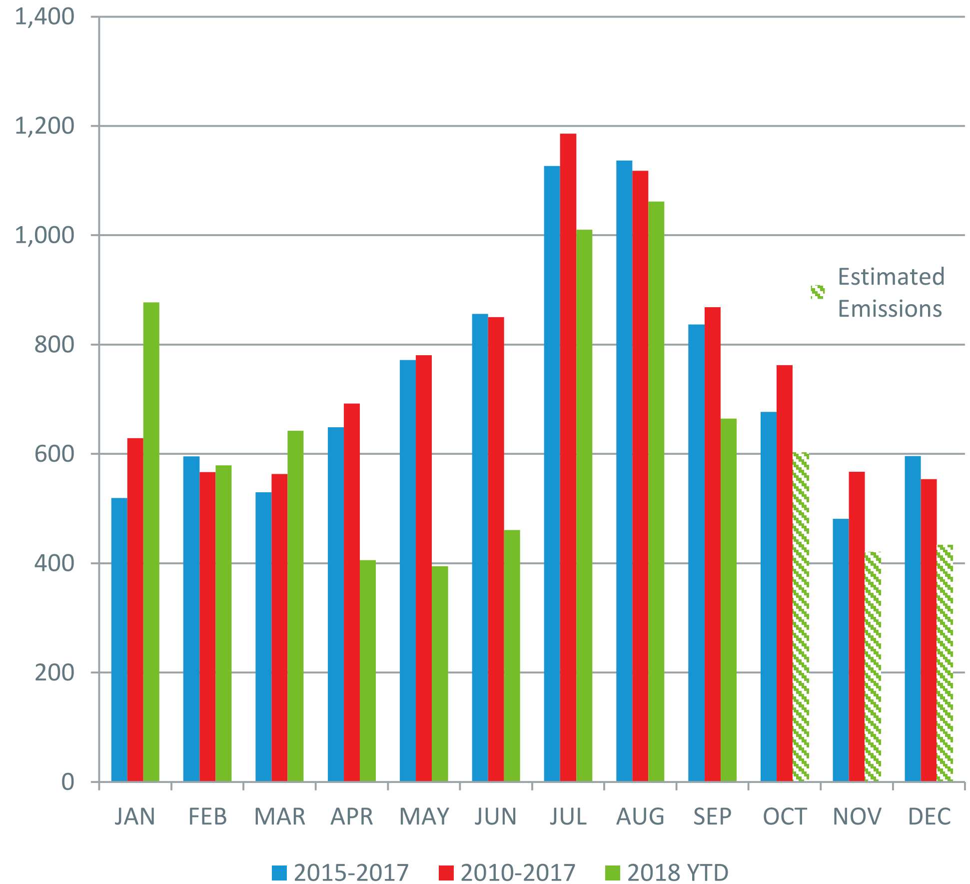
- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) WebEx was held on December 10
  - Discussions included updates on system needs that could have potential interregional solutions, projects with potential cross-border impacts, and next steps
  - Stakeholders are reminded that all IPSAC comments should be directed to PACMatters@iso-ne.com by COB January 4

Environmental Matters - MA CO_2 Generator Emissions Cap Update (310 CMR 7.74)

GWSA CO_2 Emissions Fall 2018 Cap Not Expected to Bind

- Year-to-date 2018 CO_2 emissions are estimated between 7.3 and 7.5 million metric tons (as of 12/27/18)
  - Annual emissions averaged between 8.77 and 9.13 million metric tons
  - 2018 cap is 9.15 million metric tons
- ~1.6 to 1.8 million metric tons estimated available for last two weeks of December
- December GWSA emissions average 550,000 to 600,000 metric tons
- >1.0 million metric tons surplus possible at year end

GWSA Monthly CO_2 Emissions (Thousand Metric Tons)



CMR - Code of Massachusetts Regulations
GWSA – Global Warming Solutions Act

RSP Project Stage Descriptions

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

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

Connecticut River Valley

Status as of 12/28/18

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	Nov-18	4
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 12/28/18

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-19	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 12/28/18

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 12/28/18

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 12/28/18

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	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 12/28/18

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 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Dec-19	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-19	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 12/28/18

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-19	3
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	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 12/28/18

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

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 12/28/18

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	Oct-18	4
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	4
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	4
Loop the 1570 line in and out the Pootatuck substation	Jul-18	4
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 12/28/18

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	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-19	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 12/28/18

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 12/28/18

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	Mar-18	4
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Jan-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 12/28/18

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 12/28/18

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	Mar-19	3
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-21	2*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Dec-18	4

* Substation portion of the project is a Present Stage status 3

Greater Boston Projects, cont.

Status as of 12/28/18

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	Sep-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Dec-19	3
Install third 115 kV line from West Walpole to Holbrook	Dec-19	3
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
Install a new 115 kV line from Sudbury to Hudson	Dec-20	2

Greater Boston Projects, cont.

Status as of 12/28/18

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	Dec-19	3
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	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	Dec-19	3
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-19	3

Greater Boston Projects, cont.

Status as of 12/28/18

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-20	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	3
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 12/28/18

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	Nov-18	4
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Oct-19	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 12/28/18

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 12/28/18

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 12/28/18

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	Jun-20	1

SEMA/RI Reliability Projects

Status as of 12/28/18

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Nov-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	2
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Jun-20	2
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	2
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	3

SEMA/RI Reliability Projects

Status as of 12/28/18

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Nov-19	2
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2

SEMA/RI Reliability Projects

Status as of 12/28/18

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

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

SEMA/RI Reliability Projects

Status as of 12/28/18

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

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

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

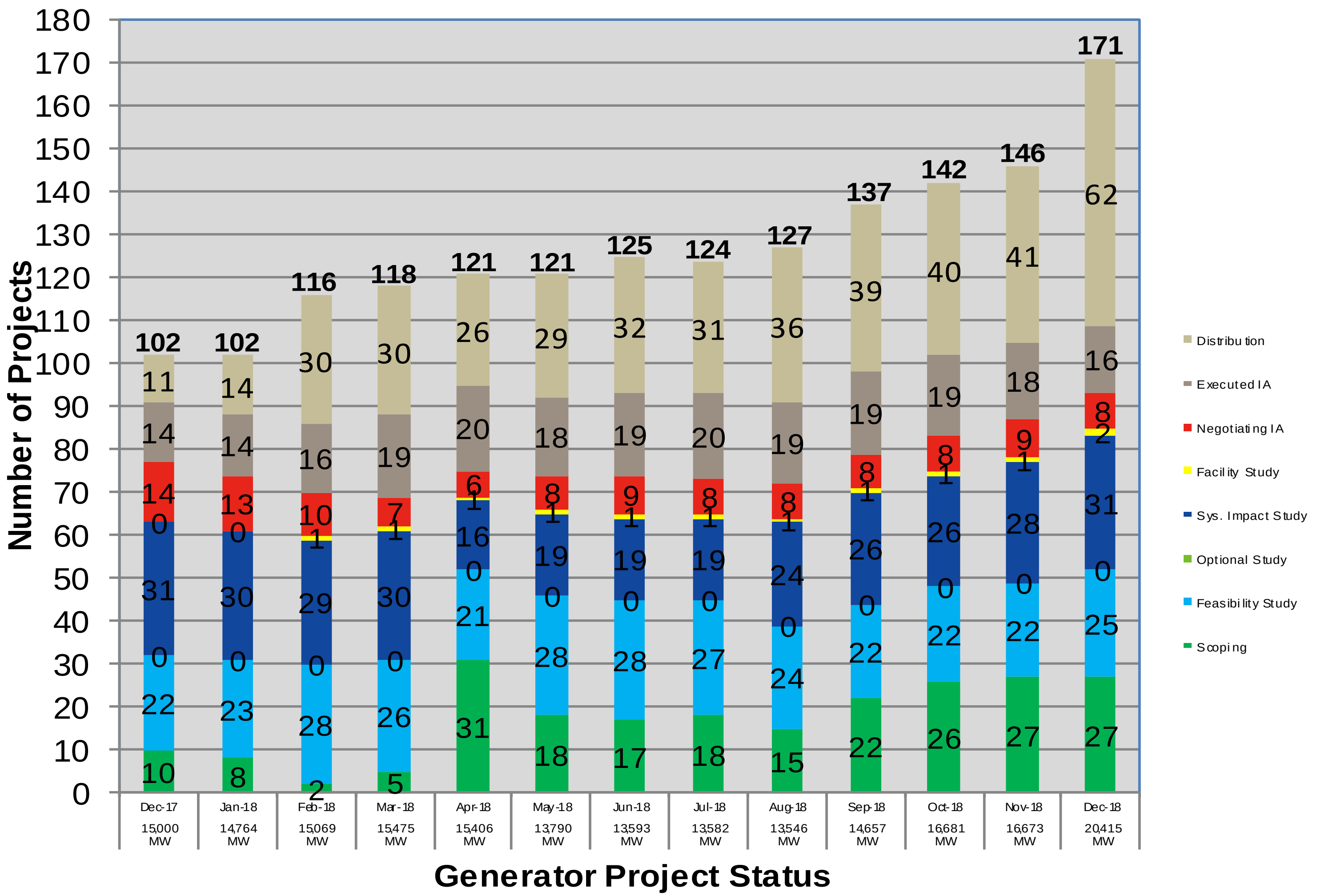
SEMA/RI Reliability Projects

Status as of 12/28/18

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

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

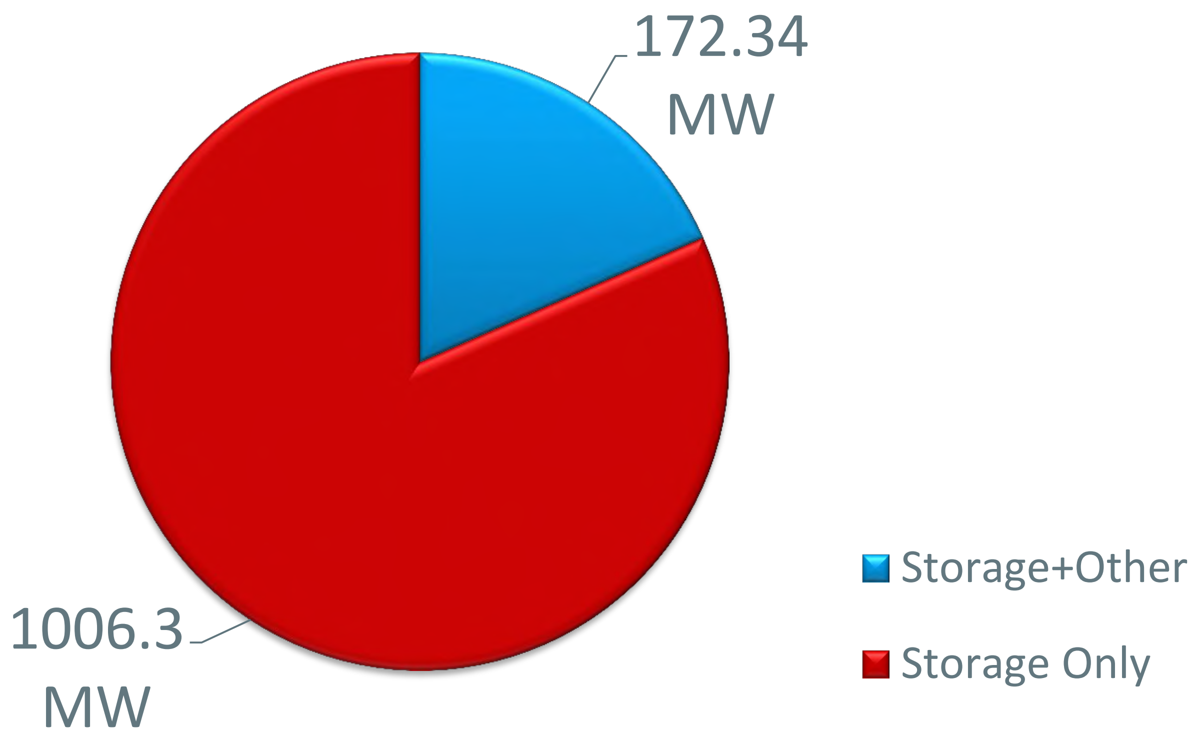
Status of Tariff Studies



Note: December 2018 based on partial data
As of December 2018, there are 5 ETU's in SIS, 2 in FS, 9 in Scoping, 2 Negotiating IA, and 1 with Executed IA
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of December 27, 2018)

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



At this time, all of the proposals are located in MA or ME

OPERABLE CAPACITY ANALYSIS

Winter 2018/19

Winter 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2019[2] CSO (MW)	Jan. - 2019[2] SCC (MW)
Operable Capacity MW [1]	30,991	33,187
Active Demand Capacity Resource (+) [5]	321	262
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	993	993
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	400	475
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,207	4,648
Net Capacity (NET OPCAP SUPPLY MW)	25,054	26,675
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,357	20,357
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,662	22,662
Operable Capacity Margin	2,392	4,013

[1]Operable Capacity is based on data as of **December 13, 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 **December 13, 2018**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 12, 2019.**

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

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

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

Winter 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Jan. - 2019[2] CSO (MW)	Jan. - 2019[2] SCC (MW)
Operable Capacity MW [1]	30,991	33,187
Active Demand Capacity Resource (+) [5]	321	262
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	993	993
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	400	475
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,674	5,165
Net Capacity (NET OPCAP SUPPLY MW)	24,587	26,158
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,057	21,057
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,362	23,362
Operable Capacity Margin	1,225	2,796

[1]Operable Capacity is based on data as of **December 13, 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 **December 13, 2018.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 12, 2019.**

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

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

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

Winter 2019 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 1, 2019 - 50/50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
1/5/2019	30991	321	993	156	290	0	2800	4085	25286	20357	2305	22662	2624
1/12/2019	**30991**	**321**	**993**	**156**	**400**	**0**	**2800**	**4207**	**25054**	**20357**	**2305**	**22662**	**2392**
1/19/2019	30991	321	993	156	422	5	2800	4009	25225	20357	2305	22662	2563
1/26/2019	31026	373	856	156	287	0	3100	3737	25287	20127	2305	22432	2855
2/2/2019	31026	373	856	156	629	0	3100	3737	24945	19850	2305	22155	2790
2/9/2019	31026	373	856	156	650	0	3100	3322	25339	19820	2305	22125	3214
2/16/2019	31026	373	856	156	624	0	3100	3045	25642	19549	2305	21854	**3788**
2/23/2019	31026	373	856	156	501	0	3100	2492	26318	18526	2305	20831	5487
3/2/2019	31026	373	856	156	1646	681	2200	1395	26489	18165	2305	20470	6019
3/9/2019	31026	373	856	156	1873	657	2200	1281	26400	17962	2305	20267	6133
3/16/2019	31026	373	856	156	667	689	2200	695	28160	17585	2305	19890	8270
3/23/2019	31026	373	856	156	1577	171	2200	798	27665	17000	2305	19305	8360

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Winter 2019 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

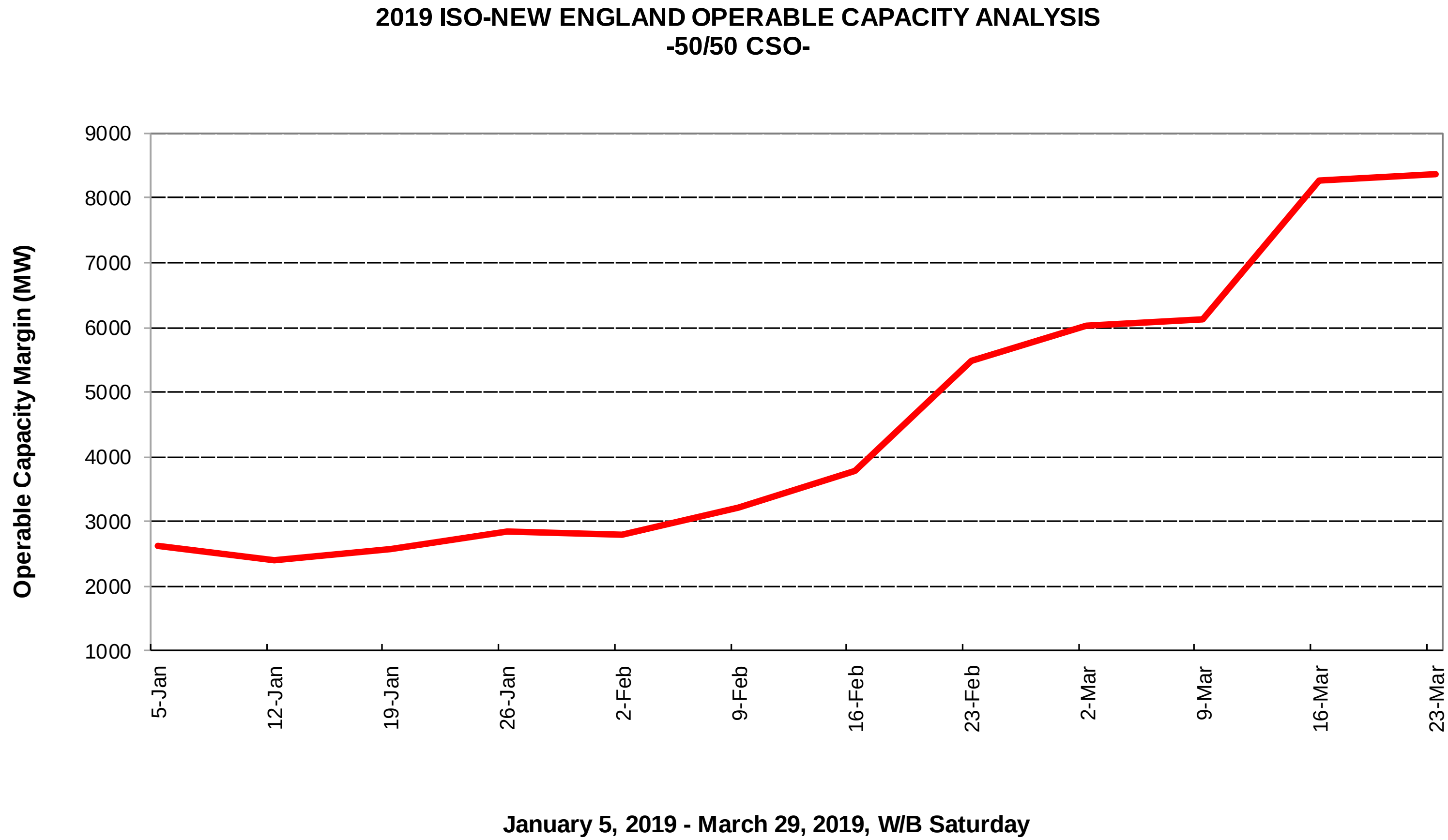
January 1, 2019 - 90/10 FORECAST using CSO

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

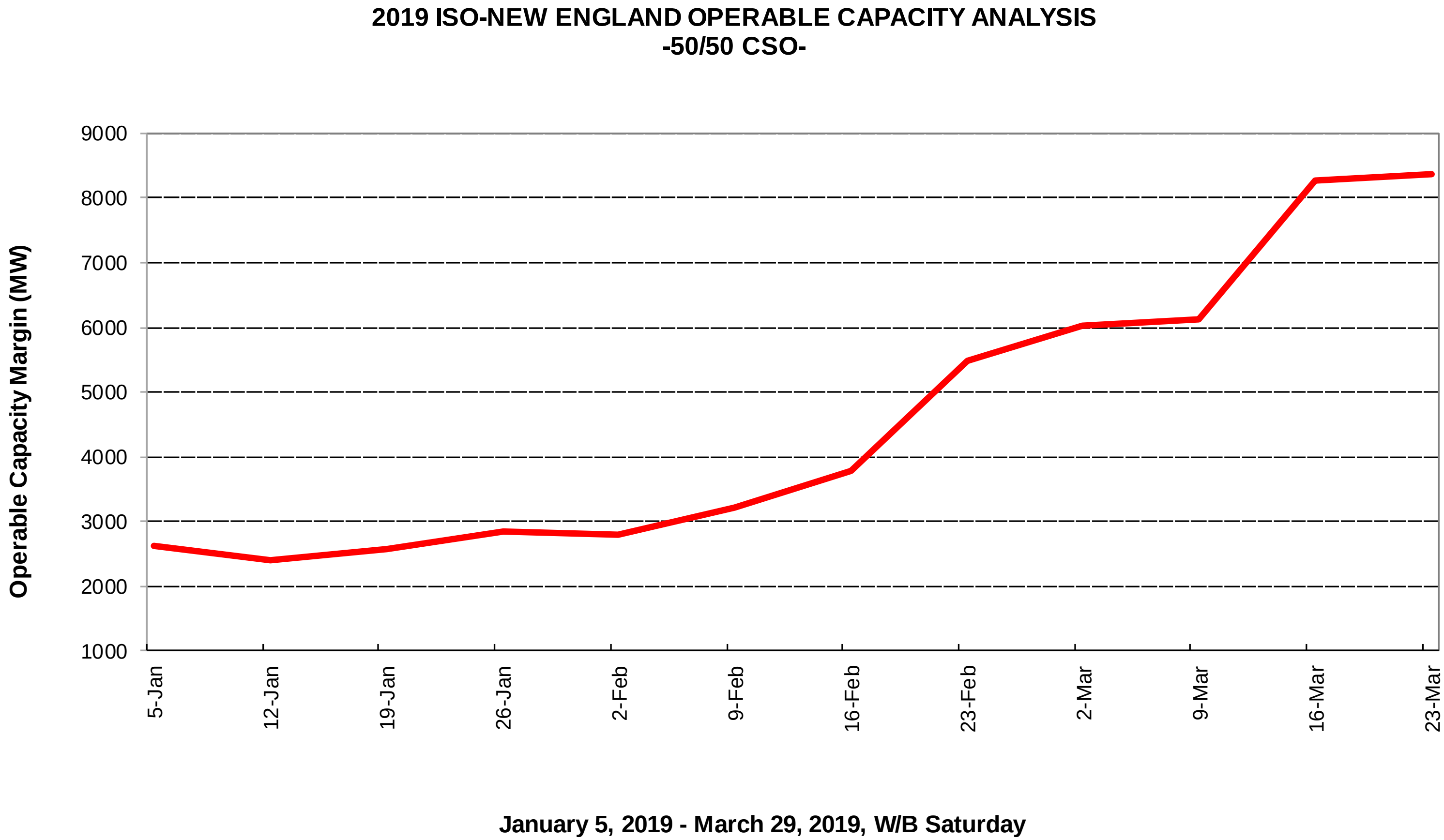
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
1/5/2019	30991	321	993	156	290	0	2800	4539	24832	21057	2305	23362	1470
1/12/2019	**30991**	**321**	**993**	**156**	**400**	**0**	**2800**	**4674**	**24587**	**21057**	**2305**	**23362**	**1225**
1/19/2019	30991	321	993	156	422	5	2800	4455	24779	21057	2305	23362	1417
1/26/2019	31026	373	856	156	287	0	3100	4153	24871	20819	2305	23124	1747
2/2/2019	31026	373	856	156	629	0	3100	4153	24529	20535	2305	22840	1689
2/9/2019	31026	373	856	156	650	0	3100	3691	24970	20504	2305	22809	2161
2/16/2019	31026	373	856	156	624	0	3100	3384	25303	20224	2305	22529	2774
2/23/2019	31026	373	856	156	501	0	3100	2768	26042	19170	2305	21475	4567
3/2/2019	31026	373	856	156	1646	681	2200	1626	26258	18798	2305	21103	5155
3/9/2019	31026	373	856	156	1873	657	2200	1496	26185	18589	2305	20894	5291
3/16/2019	31026	373	856	156	667	689	2200	849	28006	18200	2305	20505	7501
3/23/2019	31026	373	856	156	1577	171	2200	906	27557	17597	2305	19902	7655

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Winter 2019 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2019 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	132 [3]

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 26,458 MW system load based on the 2017 CELT Gross 50/50 Forecast minus PV and PDR and verified by the most recent voltage reduction test..
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	265 [3]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**2,542**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 26,458 MW system load based on the 2017 CELT Gross 50/50 Forecast minus PV and PDR and verified by the most recent voltage reduction test..
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of January 2, 2019

The following activity, as more fully described in the attached litigation report, has occurred since the report dated December 5, 2018 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

No Activity to Report

II. Rate, ICR, FCA, Cost Recovery Filings

	6	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER19-447)	Dec 20 Dec 17-20	NESCOE submits limited protest Eversource, National Grid, NRG intervene
	6	FCA13 Qualification Informational Filing (ER19-295)	Dec 19	FERC accepts informational filing
	7	ICR-Related Values and HQICCs – 2022-23 Capacity Commitment Period (ER19-291)	Dec 12 Dec 20	NEPGA submits supplemental protest; ISO-NE answers NESCOE, FirstLight and NEPGA protests NEPGA answers ISO-NE's Dec 12 answer; ISO-NE re-submits testimony to correct FCA13 Net CONE value ($8.156/kW-mo.)
	7	Correction to §IV.A Schedule 5 (Collection of NESCOE Budget) (ER19-140)	Dec 11	FERC accepts correction, eff. Jan 1, 2018
	7	2019 NESCOE Budget (ER19-110)	Dec 18	FERC accepts 2019 rate ($0.00711/kW of Monthly Network Load) to fund NESCOE's 2019 budget, eff. Jan 1, 2019
	8	2019 ISO-NE Administrative Costs and Capital Budgets (ER19-107)	Dec 18	FERC accepts recovery for 2019 ISO Budgets, eff. Jan 1, 2019
	9	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Dec 20	FERC conditionally accepts COS Agreement; Mystic compliance filing due Feb 18; initial and reply briefs on the ROE issue due Apr 19 and July 18, 2019, respectively
	11	MPD OATT 2018 Annual Info Filing Challenge (ER15-1429)	Dec 31	Maine Customer Group challenges Emera Maine's 2018 annual update of charges under the MPD OATT

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

*	12	Post-PRD Implementation Conforming and Clean-Up Changes (ER19-614)	Dec 20	ISO-NE and NEPOOL jointly file changes; comment date Jan 10, 2019
*	12	Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)	Dec 14 Dec 20-26	Vineyard Wind requests waiver of the pro-rata proration provisions in Section III.13.1.1.2.10 of the Tariff, and other affected provisions, such that Vineyard Wind may participate in as a RTR and any required proration will apply only to Vineyard Wind and any other similarly situated entities; comment date Jan 4, 2019 NEPOOL, National Grid, NESCOE intervene
	12	*Order 841* Compliance Filing (ER19-470)	Dec 10 Dec 14 Dec 7-18	Public Interest Organizations support extension of comment deadline FERC extends comment period to and including Feb 7, 2019 EPSA, LS Power, NESCOE, NRG intervene

	12	CASPR Conforming Changes (ER19-444)	Dec 14-21 Dec 21	Eversource, MA DPU, National Grid, NRG intervene NESCOE, RENEW, Vineyard Wind submit comments supporting the changes; NEPGA submits limited protest
	13	FCM Parameter Consolidation (ER19-335)	Dec 19	FERC accepts changes, eff. Jan 14, 2019
	13	New Capacity Resource Delayed Commercial Operation Changes (ER19-169)	Dec 20	FERC accepts changes, eff. Dec 24, 2018
	15	Fuel Security Retention Proposal (ER18-2364)	Jan 2	NEPGA, NRG, Vistra/Dynegy, PIOs request rehearing of *Fuel Security Retention Proposal Order*
	17	Economic Life Determination Revisions (ER18-1770)	Dec 10	NEPGA requests rehearing of Nov 9 *Economic Life Determination Revisions Order*

IV. OATT Amendments / TOAs / Coordination Agreements

	21	Interconnection Process Enhancement: Retiring Resources Treatment (ER19-449)	Dec 14-20	Eversource, National Grid, NRG intervene
	22	Blackstart Rate Update (ER19-251)	Dec 18	FERC accepts changes to Blackstart rate, Schedule 16, and the Tariff's centralized definitions section (I.2.2), eff. Jan 1, 2019
	22	Cluster Participation Deposit Refund Revisions (ER19-161)	Dec 13	FERC accepts CPD Refund Revisions, eff. Dec 23, 2018

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	22	Schedule 21-NEP: BIPCO LSA Amendments (ER19-707)	Dec 28	National Grid files amended TSA to reflect clarifying and ministerial changes; comment date Jan 18, 2019
*	22	Schedule 21-EM: Stored Solar J&WE LSA Extension (ER19-706)	Dec 28	Emera Maine and ISO-NE file Second Stored Solar LSA to extend discounted rate for an additional 2 years; comment date Jan 18, 2019
	23	Schedule 21-ES: Berkshire LSA (ER19-309)	Jan 2	FERC accepts LSA, eff. Jan 7, 2019
	23	Schedule 21-EM: Corrections to § 10.2 (ER19-64)	Dec 18	Emera Maine responds to Nov 30 deficiency letter; comment date Jan 8, 2019

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	25	Capital Projects Report - 2018 Q3 (ER19-113)	Dec 11	FERC accepts 2018 Q3 Report, eff. Oct 1, 2018
*	26	IMM Quarterly Markets Reports - 2018 Summer (ZZ18-4)	Dec 6	IMM files Summer 2018 Report

IX. Membership Filings

*	26	January 2019 Membership Filing (ER19-748)	Dec 31	***Memberships***: ADG Group; Dominion Bridgeport Fuel Cell LLC; ***Terminations***: Solea, NECCO, EmpireCo LP; comment date Jan 21

X. Misc. - ERO Rules, Filings; Reliability Standards

*	26	Revised Reliability Standard: TPL-001-5 (RM19-10)	Dec 7	NERC files TPL-001-5 for approval

XI. Misc. - of Regional Interest

*	27	203 Application: FirstLight Restructuring (EC19-44)	Jan 2	FirstLight Hydro and the FirstLight Project Companies requested FERC authorization for the FirstLight Restructuring; comment date Jan 23
*	27	203 Application: Emera / Revere Power (EC19-35)	Dec 14	Emera Project Cos. request authorization for transaction pursuant to which they will become wholly-owned subs of Revere Power (and Nautilus Power Related Persons); comment date Jan 4, 2019
*	27	203 Application: Dominion Bridgeport Fuel Cell (EC19-22)	Dec 20	FERC authorizes acquisition by FuelCell Energy Finance
	27	203 Application: Plymouth Rock/Engie (EC19-19)	Dec 14	FERC authorizes Engie's indirect acquisition of 100% of the equity interests in Plymouth Rock Energy, LLC
	28	203 Application: CPV Towantic/ Osaka Gas USA (EC19-16)	Dec 13 Dec 17	FERC authorizes Osaka Gas acquisition of 25% interest in CPV Towantic Osaka Gas notifies FERC that acquisition consummated on Dec 13
	28	203 App.: ECP/Fawkes Holdings (Wheelabrator) (EC19-14)	Dec 6	FERC authorizes sale of Wheelabrator to Fawkes Holdings (a Macquarie Related Person)
*	28	203 Application: Dominion Energy Manchester Street (EC19-3)	Dec 12 Dec 18	FERC authorizes Spade (Marco DM Holdings Related Person) acquisition of Manchester Street Manchester Street files notice that transaction consummated Dec 13
	28	203 Application: VTransco Acquisition of BED/Stowe Highgate Shares (EC18-137)	Dec 17	FERC authorizes VTransco acquisition of BED/Stowe Highgate shares
	29	203 Application: GenOn Reorganization (EC17-152)	Dec 14 Dec 20	GenOn Restructuring completed GenOn informs FERC that Restructuring was completed on Dec 14
	29	New England Ratepayers Assoc. Complaint (EL19-10)	Dec 17 Dec 20	NH OCA, NH Generator Group supplement comments filed on Dec 3; NH Legislators file comments NERA answers protests and comments
	29	PJM MOPR-Related Proceedings (EL18-178; ER18-1314; EL16-49)	Dec 6 Dec 20-21 Dec 21	PJM, Direct Energy/NextEra file limited answers to reply briefs; merchant generators submit Generator Letter Clean Energy Industries, UCS answer PJM's Dec 6 answer APPA, ELCON, LPPC, NRECA, and NRDC jointly answer Generator Letter
*	32	Related Facilities Agreement: NSTAR / Clear River Energy (ER19-639)	Dec 27	NSTAR files RFA to cover upgrades required for Clear River Energy project; comment date Jan 17, 2019
*	32	Related Facilities Agreement: CL&P / Clear River Energy (ER19-639)	Dec 27	CL&P files RFA to cover upgrades required for Clear River Energy project; comment date Jan 17, 2019
*	32	Related Facilities Agreement: CL&P / Cricket Valley (ER19-590)	Dec 18	CL&P files RFA to cover upgrades required for Clear River Energy project; comment date Jan 8, 2019
	32	NSTAR/MATEP Revised Distribution Service Agreement (ER19-431)	Dec 20	MATEP files comments urging approval of the Agreement
	33	NSTAR/HQ US MMWEC Use Rights Transfer Agreement (ER19-409)	Dec 13	MMWEC files statement of support, urging the FERC to approve the Agreement promptly

33	TSAs: First Amendments to EDC New England Clean Energy Connect TSAs (ER19-324 et al.)	Dec 26	CMP submits an amended eTariff record to reflect first amendments to EDC Agreements; comment date Jan 16, 2019
33	NSTAR/HQ US ENE Use Rights Transfer Agreement (ER19-146)	Dec 10	FERC accepts Agreement, eff. Nov. 20, 2018

XII. Misc. - Administrative & Rulemaking Proceedings

34	Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)	Dec 6	Harvard Electricity Law Institute submits comment suggesting Commissioner McNamee should recuse himself from these proceedings
		Dec 18	Clean Energy Advocates move for recusal of Commissioner McNamee
35	NOPR: Public Util. Trans. ADIT Rate Changes (RM19-5)	Dec 7	FERC issues notice extending comment deadline to Jan 22, 2019
36	NOPR: Amended FPA Section 203(a)(1)(B) (RM19-4)	Dec 20-31	AAI, APPA, EEI, Idaho Power, ITC, NRECA, Public Citizen, TAPS submit comments
36	NOPR: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)	Dec 20	FERC issues *Horizontal Market Power Analysis Refinements NOPR*; comment date 45 days after publication in the *Federal Register*

XIII. Natural Gas Proceedings

43	New England Pipeline Proceedings		
	• Atlantic Bridge Project (CP16-9)	Dec 26	FERC grants 2-year extension of time, to Jan 25, 2021, for completion of Project construction and availability for service
	• Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)	Dec 4-6	Halleran Landowners and Intervenors request rehearing of Nov 5 order granting a 2-year extension of time
		Dec 21	Constitution answers requests for rehearing; FERC issues tolling order affording it additional time to consider the requests for rehearing

XIV. State Proceedings & Federal Legislative Proceedings

* 46	Connecticut Zero-Carbon Resource Selections	Dec 28	Connecticut announces bids selected pursuant to Public Act 17-3

XV. Federal Courts

47	FCM Resource Retirement Reforms (17-1275)	Dec 28	Court remands the record to the FERC for a clarification of "what [the FERC] really means" in the context of its FCM Resource Retirement Reforms orders
47	Base ROE Complaints II & III (2012 & 2014) (15-1212)	Dec 28	DC Circuit issues order granting Intervenors' motion to dismiss, without prejudice to submission of another petition for review at the conclusion of the FERC proceedings

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: January 2, 2019

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through January 2, 2019. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **RTO Insider Press Policy Complaint (EL18-196)**

On August 31, RTO Insider LLC filed a Complaint pursuant to Section 206 of the Federal Power Act ("FPA") against NEPOOL requesting that the FERC either (i) find that NEPOOL's press policy "unlawful, unjust and unreasonable, unduly discriminatory and contrary to the public interest, and direct NEPOOL to cease and desist" from implementing its policy; or (ii) "if the [FERC] finds that NEPOOL can sustain such a ban as a "private" entity, [] direct that NEPOOL's special powers, privileges and subsidies be terminated and that an open stakeholder process be used by [ISO-NE]" ("Press Policy Complaint"). The Press Policy Complaint, which was also filed as a "protest" to NEPOOL's filing of the 132nd Agreement (*see* ER18-2208 in Section VIII below), broadens RTO Insider's efforts to "be in the room" and on terms it prefers.

NEPOOL answered the Complaint on September 20. NEPOOL cited numerous jurisdictional and procedural reasons why RTO Insider's claims fail and should be summarily rejected. NEPOOL also answered RTO Insider's arguments on the merits, should the FERC decide not to reject the Complaint summarily. Comments supporting the Complaint were submitted by the New Hampshire Office of Consumer Advocate ("NH OCA"), the Reporters Committee for Freedom of Press ("RCFP"), Bill Short, Public Interest Organizations ("PIOs"), and Public Citizen. Doc-less interventions only were submitted by Conservation Law Foundation ("CLF"), National Grid, NESCOE, New York Transmission Owners ("NYTOs"), the Sustainable FERC Project and Natural Resources Defense Council ("NRDC").

On October 5, NEPOOL answered elements of the NH OCA and PIOs' September 20 pleadings. Also on October 5, RTO Insider and PIOs answered NEPOOL's September 20 answer. On October 15, NEPOOL filed a limited response to the October 5 pleadings of RTO Insider and PIOs. The Complaint is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **PER Settlement Agreement Refund Report (EL16-120)**

On October 19, 2018, pursuant to the FERC's *September 20 Order*[2] in this proceeding, ISO-NE submitted a refund report addressing its recalculation of hourly PER values using the Adjusted PER Strike Price

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

for the September 30, 2016 through May 31, 2018 period. In its report, ISO-NE reported that there was one month (October 2017) during which the initial hourly PER determinations used for settlement were changed by applying the Adjusted PER Strike Price. Since PER Adjustments involve a 12-month rolling calculation methodology, the settlements for the months of November 2017 through October 2018 were impacted. For the months of November 2017 through February 2018, the recalculated PER Adjustments were handled through the data reconciliation process. Beginning with March 2018, PER Adjustments associated with the PER values for October 2017 were calculated using the Adjusted PER Strike Price and were included in initial monthly settlement statements. Amounts were identified in the report. Comments on the refund report, if any, were due on or before November 9; none were filed. The refund report is pending before the FERC. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19; ER18-2235)**

As previously reported, the Settling Parties[3] filed on August 17 in ER18-2235 a Joint Offer of Settlement (the "Settlement") to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015.[4] The Settlement proposes changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. If approved, the changes to Attachment F are to be effective mid-June, 2019, with the remaining changes to be effective January 1, 2020. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9 were supported by the Participants Committee at its July 24 meeting.

On September 6, ***NESCOE*** filed comments supporting the Settlement. Comments opposing the Settlement were filed by Municipal PTF Owners[5] and FERC Trial Staff. The ***Municipal PTF Owners*** ("Munis") assert that the Settlement worsens, rather than improves, the issues of "lack of transparency, clarity and specificity that led the Commission [to] find the existing Attachment F formula unjust and unreasonable", discriminates against load directly connected to PTF and exempted by Section II.12(c) of the ISO-NE Tariff from paying costs associated with service across non-PTF facilities, contravenes numerous settled rate principles without explanation or justification,[6] and imposes an unacceptable moratorium and burden on parties inclined to challenge Attachment F. ***FERC Trial Staff*** asserted that the Settlement, as filed, is not fair and reasonable nor is it in the public interest

[2] *New England Power Generators Assoc. v. ISO New England Inc.*, 164 FERC ¶ 61,190 (Sep. 20, 2018) ("*September 20 Order*") at P 21, Ordering Paragraph (C) (denying NESCOE's request for clarification and accepting the compliance filing submitted in ER18-1153).

[3] "Settling Parties" are identified as: CMP; CMEEC/CTMEEC; CT OCC; CT PURA; Emera Maine; Eversource (CL&P, PSNH, NSTAR); Fitchburg and Unitil; Green Mountain Power; Maine Electric Power Co.; ME OPA; MPUC, MA AG, MA AG, MA DPU, MMWEC, National Grid; NESCOE; NHEC; NH PUC; New Hampshire Transmission; RI DPUC; UI; VT DPS; VEC; VELCO; and Vermont Transco, LLC ("VTransco").

[4] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016) ("*RNS/LNS Rates and Rate Protocols Order*"). The *RNS/LNS Rates and Rate Protocols Order* found the ISO-NE Tariff unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS"). The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates". The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced. The FERC-established refund date is January 4, 2016.

[5] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[6] The elements of the Settlement that Municipal PTF Owners assert contravene settled rate principles include: provision for a fixed accrual for Post-Employment Benefits Other than Pension ("PBOPs"); continued TO use of net proceeds of debt, rather than gross proceeds of debt, in establishing capital structures under their proposed revenue requirement formula; inappropriate allocation of rental revenues from secondary uses of transmission facilities; the addition of miscellaneous intangible plant (Account 303), and depreciation and amortization of intangibles, to rate base; and the creation of a Regulatory Asset for an unspecified Massachusetts state tax rate change (without explanation).

"because it would result in unreasonable rates and contains fundamental defects",[7] and opposed the Settlement terms which would bind non-settling parties to the terms of the Settlement and establish a standard of review for changes to the Settlement. FERC Trial Staff suggested that these defects could be corrected in a comprehensive compliance filing, and requested that the FERC either (i) conditionally approve the Settlement subject to the submission of such a corrective compliance filing, or (ii) reject the Settlement in its entirety and set the entire matter for hearing.

Reply comments were submitted by NEPOOL, NESCOE and the MA AG. In its limited comments, ***NEPOOL*** noted that it supported the Interim Protocols and that it had no objection to the Settlement. ***NESCOE*** reiterated its support for the Settlement in its reply comments, urging the FERC to reject any arguments that consumer-interested parties "were not familiar with the issues relating to the Settlement or that they reached a settlement for any reason other than their view that it is in the best interests of consumers."[8] ***MA AG*** urged the FERC to approve the Settlement as submitted, despite the objections of FERC Trial Staff and Municipal PTF Owners, because it complies with the *RNS/LNS Rates and Rate Protocols Order* and represents a carefully negotiated resolution to numerous complex ratemaking and transparency issues.[9]

Settlement Judge Report. On November 5, Settlement Judge Dring submitted the contested settlement to the Commission. In his report, Judge Dring noted his "complete agreement with the statements that were filed in support of this settlement." He referred the Commission to the TOs' reply comments for the reasons why Trial Staff's and Municipal PTF Owners opposition are in error. On November 14, the Munis moved that the Commission expunge from the record in this proceeding the Settlement Judge's views on the merits of the settlement, arguing that the inclusion of those views exceeds the regulatory limits of the settlement judge's role. On November 29, FERC Trial Staff supported the Munis' motion, providing additional arguments as to how the settlement report exceeds the judge's authority and was otherwise deficient.

The Settlement continues to be pending before the Commission. Given this proceeding's procedural posture, Chief Judge Cintron terminated settlement judge procedures on November 15, subject to final action by the Commission. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[10] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion*

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[7] Included in the "fundamental defects" of the Settlement identified by FERC Trial Staff are that it: (1) enables the TOs to conduct extra-formulaic, ad hoc ratemaking for all externally-sourced inputs every year; (2) enables certain PTOs to over-recover certain plant costs; (3) enables certain PTOs to recover greater than 50% of Construction Work in Progress ("CWIP") in rate base (4) violates prior FERC orders about which customer groups can be made to pay incentive returns; (5) fails to appropriately calculate federal and state income taxes and, in particular, fails to account for excess Accumulated Deferred Income Taxes ("ADIT") created by the Tax Cuts and Jobs Act; (6) does not contain a fixed and stated ROE; and (7) does not contain a fixed and stated PBOPs expense.

[8] Reply Comments of the New England States Committee On Electricity, Docket Nos. ER18-2235 and EL16-19, at p. 2 (filed Sep. 28, 2018).

[9] Reply Comments of the Massachusetts Attorney General in Support of Settlement, Docket Nos. EL16-19 and ER18-2235 (filed Sep. 28, 2018).

[10] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarific.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

531-A).[11] However, the FERC's orders were challenged, and in *Emera Maine,*[12] the DC Circuit Court vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[13] and third (EL14-86)[14] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[15] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[16] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[17] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[18] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

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[11] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[12] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

[13] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% return on equity, and seeks a reduction of the Base ROE to 8.7%.

[14] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General ("MA AG"), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

[15] *Environment Northeast v. Bangor Hydro-Elec. Co. and Mass. Att'y Gen. v. Bangor Hydro-Elec. Co,* 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

[16] The 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders"*). *The Base ROE Complaint IV Orders*, as described in Section XV below, have been appealed to, and are pending before, the DC Circuit.

[17] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[18] *Id.* at P 2.; Finding of Fact (B).

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[19] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings. The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[20]

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based on the results of three models: the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Expected Earnings models. Within that composite zone, a smaller, "presumptively reasonable" zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[21] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[22] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively.

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[19] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

[20] *Id.* at 19.

[21] *Id.* at P 59.

[22] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG, and EMCOS.

On November 15, citing language in a MISO proceeding that provided the clarification they sought,[23] Customers withdrew their motion seeking clarification of the *Order Directing Briefs.* On November 16, CT PURA, EMCOS, MMWEC, and NHEC jointly asked the FERC to identify and, where not already in the record in these four proceedings, release the sources, data sets, and analyses underlying Figure 2 and Figure 3 in the *Order Directing Briefs* (at least one figure appeared to be based on proprietary information not available or included in the record). That request remains pending before the FERC.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER19-447)**

On November 30, 2018, ISO-NE and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2019-20 Capability Year to be held March 1, 2019, the second ARA for the 2020-21 Capability Year to be held August 1, 20189, and the first ARA for the 2021-22 Capability Year to be held June 3, 2019. The ICR-Related Values were supported by the Participants Committee at its November 2, 2018 meeting. A January 29, 2019 effective date was requested. Comments on this filing were due December 21, 2018. Because the ICR-Related Values for the ARAs contain the same change to the system reserve assumptions that NESCOE protested in the 2022-23 ICR-Related Values proceeding (*see* ER19-291 below), NESCOE submitted a limited protest in this proceeding, incorporating by reference and adopting its limited protest of the 2022-23 ICR-Related Values. Doc-less interventions were filed by Dominion, Eversource, Exelon National Grid, and NRG. This matter is pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA13 Qualification Informational Filing (ER19-295)**

On December 19, the FERC accepted ISO-NE's November 6, 2018 informational filing (the "FCA13 Informational Filing") for qualification in FCA13.[24] As previously reported, the Informational Filing contained ISO-NE's determinations that the same three Capacity Zones that were modelled for FCA12 will be modelled for FCA13 -- Southeastern New England ("SENE"), Northern New England ("NNE") and Rest of Pool. SENE will again be modeled as import-constrained; NNE will be modeled as export-constrained. The Informational Filing reported that there will be 34,925 MW of existing capacity in FCA13 competing with 8,716 MW of new capacity under a Net ICR of 33,750 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 3,223 MW of Static De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 14 demand bids, totaling 2,160 MW, and 86 supply offers, totaling 544 MW, to participate in the substitution auction. Unless the December 19 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[23] *See Assoc. of Bus. Advocating Tariff Equity, et al. v. Midcontinent Indep. Sys. Op.*, et al., 165 FERC ¶ 61,118, P 20 (Nov. 15, 2018) (clarifying that the *Order Directing Briefs* makes no final determinations, and that the briefs directed may address the justness and reasonableness of any aspect of the newly proposed methodologies).

[24] *ISO New England Inc.,* Docket No. ER19-295 (Dec. 19, 2018) (unpublished letter order).

- **ICR-Related Values and HQICCs – 2022-23 Capacity Commitment Period (ER19-291)**

On November 6, 2018, ISO-NE and NEPOOL filed an ICR, LSR for SENE, MCL for NNE, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2022-23 ICR-Related Values") for the 2022-23 Capacity Commitment Period ("CCP"). The values will be used in FCA13 to be held in February 2019. With a 2022-23 ICR of 34,719 MW (reflecting tie benefits of 2,000 MW) and HQICCs of 969 MW/mo., the net amount of capacity to be purchased in FCA13 to meet the ICR will be 33,750 MW. The LSR for the SENE Capacity Zone is 10,141. The MCL for the NNE Capacity Zone is 8,545 MW. The Participants Committee supported the 2022-23 ICR-Related Values (those without Clear River in the model) at its October 4, 2018 meeting.

Comments on this filing were due November 27. On November 16, NEPOOL filed comments that explained NEPOOL's processes and deliberations that preceded the November 6 filing and NEPOOL's support of the 2022-23 ICR-Related Values (those without Clear River modeled). Protests were filed by FirstLight, NEPGA and NESCOE. FirstLight and NEPGA conditioned their protests on the outcome of the FERC's December 3 *Fuel Security Proposal Order*. They assert that ISO-NE must "either be required to calculate the Region-Wide Capacity Requirement consistent with the resource performance upon which its region-wide fuel security reliability standard is based or properly recognize that ISO-NE is seeking to retain a Fuel Security RMR Resource for a winter energy demand outside of the Region-Wide Capacity Requirement." For its part, NESCOE's limited objection was to the increase in the level of modeled system reserves from 200 MW to 700 MW in ISO-NE's assumptions used to calculate the ICR-Related Values. NESCOE requested that the FERC direct ISO-NE to use the 200 MW value. Doc-less interventions were filed by Dominion, ENE, Exelon, LSPower, National Grid, and NRG.

Since the last Report, on December 12, NEPGA supplemented its protest (in light of the *Fuel Security Order*) to suggest that ISO-NE must "calculate the Region-Wide Security Requirement using the same imported energy and outage rate assumptions it proposes for its region-wide fuel security reliability standard, which would have the effect of increasing the Region-Wide Security Requirement to be compatible with the region-wide fuel security reliability standard." Also on December 12, ISO-NE answered the protests filed by NESCOE, FirstLight and NEPGA, each of which ISO-NE argued should be rejected. On December 20, NEPGA answered ISO-NE's December 12 answer and ISO-NE re-submitted the Sedlacek-Scibelli testimony to correct the FCA13 Net CONE value ($8.156/kW-mo.) identified in footnote 15. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Correction to §IV.A Schedule 5 (Collection of NESCOE Budget) (ER19-140)**

On December 11, 2018, the FERC accepted ISO-NE's correction to Tariff Section IV.A Schedule 5 (Collection of NESCOE Budget), effective for calendar year 2018, that updated the calendar year reference in the Schedule that was inadvertently not changed from 2017 to 2018 when the Schedule was updated last year in ER18-85 (NESCOE 2018 Budget Filing).[25] The correction filed in this proceeding ensures that the eTariff properly reflects the calendar year in the respective version of the ISO-NE Tariff. No other correction was needed or made. The correction was accepted effective January 1, 2018, as requested. Unless the December 11 letter order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2019 NESCOE Budget (ER19-110)**

On December 18, the FERC accepted the 2019 rate included in ISO-NE Tariff Section IV.A Schedule 5 to fund NESCOE's 2019 operations.[26] The 2019 Operating Expense Budget for NESCOE is $2,350,787. The amount to be recovered reflects true-ups from 2017 overcollections of $743,722. The NESCOE budget will result in a charge of $0.00711 per kilowatt ("kW") of Monthly Network Load. The 2019 NESCOE rate was accepted effective January 1, 2019. Unless the *NESCOE 2019 Rate Order* is challenged, this proceeding will be

[25] *ISO New England Inc.,* Docket No. ER19-140 (Dec. 11, 2018) (unpublished letter order).

[26] *ISO New England Inc.,* Docket No. ER19-110 (Dec. 18, 2018) (unpublished letter order) ("*NESCOE 2019 Rate Order*").

concluded. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2019 ISO-NE Administrative Costs and Capital Budgets (ER19-107)**

Also on December 18, the FERC accepted, effective January 1, 2019, ISO-NE's October 15 filing for recovery of its 2019 administrative costs (the "2019 Revenue Requirement") and submission of its 2019 calendar year capital budget ("2019 Capital Budget", and together with the 2019 Revenue Requirement, the "2019 ISO Budgets").[27] As previously reported, the 2019 ISO-NE Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. ISO-NE reported that the 2019 Revenue Requirement is $198 million, which decreases to $188.7 million after the over-collection for 2017 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2019 Core Operating Budget) comprise $168.9 million; depreciation and amortization of regulatory assets, $29.1 million; and a $9.3 million true-up from 2017 over-collections.

ISO-NE further reported that the 2019 Capital Budget, like the 2018 Capital Budget, is $28 million and is comprised of the following (with 2019 projected costs and target completion dates, if available, in parentheses):

Non-Project Capital Expenditures	($3.8 million)	Identity and Access Management Phase II (Dec 2019)	($600,000)
Energy Management Platform 3.2 Upgrade – Part II (Mar 2020)	($3 million)	Energy Storage Device Phase I (Mar 2019)	($500,000)
Energy Management Platform 3.2 Upgrade - Part I (Jun 2019)	($1.6 million)	New England External Transaction Tool (Sep 2019)	($500,000)
Other Emerging Work	($1.6 million)	IT Request System Project (June 2019)	($500,000)
nGem Software Development (Jun 2019)	($1.5 million)	Energy Storage Device Phase II (Mar 2020)	($500,000)
Winter Energy Security (Jul 2019)	($1.5 million)	Update TranSMART Architecture	($500,000)
Enterprise Application Integration Replacement (Dec 2019)	($1.5 million)	Capitalized Interest	($500,000)
2019 Issue Resolution -- Phase I (Jun 2019); Phase II (Dec 2019)	($1.5 million)	FCM Delayed Commercial Resource Treatment (Mar 2019)	($300,000)
Streamline Asset Registration Phase III (May 2020)	($1.2 million)	Annual Reconfiguration Transactions (Apr 2019)	($300,000)
IMM Data Analysis Phase II (Oct 2019)	($1.2 million)	BoPP FA Project (Oct 2019)	($300,000)
CIMNET Simultaneous Feasibility Test w/ Data Transfer Enhancements (Jun 2019)	($1 million)	Upgrade Security Application Framework (Mar 2019)	($200,000)
FCA 14 (Feb 2020)	($1 million)	FERC Form 1, 3-Q, 714	($200,000)
Energy Market Offer Caps (*Order 831*) (Oct 2019)	($1 million)	CASPR (Feb 2019)	($100,000)
Nested Constrained Capacity Zones (Feb 2020)	($800,000)	Massachusetts Green High Power Computing Center (Dec 2019)	($100,000)
Synchrophasor Initiatives – Next Generation (June 2019)	($600,000)	Baseline Telemetry System Improvements (Mar 2019)	($100,000)

[27] *ISO New England Inc.*, Docket No. ER18-107 (Dec. 18, 2018) (unpublished letter order) ("*2019 ISO-NE Budgets Order*").

Unless the *2019 ISO-NE Budgets Order* is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Mystic 8/9 Cost of Service Agreement (ER18-1639)**

On December 20, in a 2-1 decision (Commissioner Glick dissenting; Commissioner McIntyre not voting; Commissioner McNamee not participating), which followed an evidentiary proceeding and two rounds of briefing, the FERC conditionally accepted the Cost-of-Service Agreement ("COS Agreement")[28] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE.[29] The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. The *Mystic Order* directed Mystic to submit a compliance filing (intended to modify aspects of the COS Agreement that FERC rejected or directed be changed) on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in the case. Initial briefs on the ROE issue are due on or before April 19, 2019, and reply briefs are due on or before July 18, 2019.[30] Any requests for clarification and/or rehearing of the *Mystic Order* are due on or before January 22, 2019.

Mystic's Compliance Filing. Among others, changes and modifications are to include:

- ***Cost of Capital/Cost of Service***. The Mystic Order directs Mystic to (i) use its corporate parent's (Exelon's) capital structure for ratemaking purposes, not ExGen's;[31] and (ii) to recalculate the net original cost,[32] accumulated depreciation,[33] and excess deferred taxes and liability amounts[34] that were included in its initial cost of service presentation.
- ***Fuel Supply Charge***. The Mystic Order also directed Mystic to revise the COS Agreement by reducing Mystic's 100% proposed recovery of the costs of the Everett Facility to 91%, by adopting a sliding-scale incentive to induce Mystic make third-party gas sales, and by requiring a provision for maintaining a record of third-party sales for the purposes of verifying how revenues are credited. The FERC rejected Mystic's proposed $60 million recovery of its purchase price for the Everett Facility, noting that it was "unjust and unreasonable for Mystic to pass through Everett's gross plant-in-service value, whatever that value may be, given that ExGen purchased Everett to ensure that it could comply with ExGen's existing CSOs, and not for Everett to provide service to ISO-NE ratepayers during the term of th[e Mystic COS] Agreement." The FERC further disallowed any inclusion in rate base or cost-of-service any cost "unrelated to the operation of Mystic," and directed Mystic to identify and exclude such costs when calculating its Fuel Supply Charge.[35]

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[28] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Distrigas to third parties.

[29] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

[30] *Id.* at PP 31-34.

[31] *Id.* at PP 48-52.

[32] *Id.* at PP 63-65.

[33] *Id.* at PP 70-71.

[34] *Id.* at PP 73, 92.

[35] *Id.* at PP 148-152.

- ***True-Up Mechanism***. In the Mystic Order, the FERC (i) directed Mystic to modify the COS Agreement to require a demonstration that it would not be delaying projects until the term of the COS Agreement that it would otherwise have undertaken sooner with the purpose of recovering excessive costs from ratepayers;[36] (ii) clarified that the true-up mechanism would apply to all aspects of the COS Agreement, with the exception of those that are fixed or must be modified by filing an FPA section 205 filing (such as ROE);[37] and (iii) required Mystic to include revenues in the true-up process to ensure that the rate ultimately charged are just and reasonable, and that Mystic recover only its prudently incurred costs.[38]
- ***Clawback Provision***. The FERC also ordered Mystic to include a clawback provision in the COS Agreement that would require Mystic to refund with interest the costs of repairs and capital expenditures needed to continue operations during the term of the COS Agreement – in the event Mystic were to return to the market after the term of the COS Agreement or after an extension.[39]

July Mystic COS Agreement Order. Rehearing remains pending of the FERC's July order. As previously reported, the FERC issued an initial order regarding the COS Agreement, accepting the COS Agreement but suspending its effectiveness and setting it for accelerated hearings and settlement discussions.[40] The *Mystic COS Agreement Order* was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July Mystic COS Agreement Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. Constellation answered the NESCOE request for reconsideration On August 21. On September 10, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com); Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Sunita Paknikar (202-218-3904; spaknikar@daypitney.com).

- **VTransco Recovery of Highgate Ownership Share Acquistion Costs (ER18-1259)**

On June 28, VTransco requested clarification and/or rehearing of the FERC's May 29 order rejecting, without prejudice, VTransco's request for authorization to recover in transmission rates property transfer taxes, closing fees, and advisory fees related to its acquisition of ownership shares in the Highgate Transmission Facility.[41] In rejecting the request,[42] the FERC found that "VTransco has not made a showing … that these transaction-related costs have 'specific, measurable, and substantial benefits to ratepayers.' Accordingly, we reject VTransco's filing, without prejudice to it making a future filing that makes this showing."[43] The FERC also rejected "the pass-through of transaction-related costs to ratepayers in any

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[36] *Id.* at P 174.

[37] *Id.*

[38] *Id.* at P 179.

[39] *Id.* at PP 208-212.

[40] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

[41] *Vermont Transco, LLC*, 163 FERC ¶ 61,152 (May 29, 2018) ("*Highgate Acquisition Cost Recovery Order*").

[42] VTransco requested (and the MA AG challenged its request for) authorization to recover, under the regional formula rate, $639,780 in costs, including property transfer taxes, closing fees, and advisory fees, related to its acquisition recent of Highgate Transmission Facility ownership shares. VTransco stated that, absent FERC action, it would recover the expenses solely from Vermont customers (under its grandfathered 1991 Vermont Transmission Agreement ("VTA")). VTransco asserted that, because the costs are related to VTransco's acquisition of ownership shares in the Highgate Transmission Facility, a facility utilized solely to provide Regional Network Service, it is just and reasonable to allow VTransco to recover the Highgate Transaction costs through the ISO-NE Tariff formula rate, rather than through the VTA.

[43] *Id.* at P 16.

Commission-jurisdictional rate, without prejudice to VTransco submitting a request with the required showing of 'specific, measurable, and substantial benefits' to ratepayers."[44]

In its June 28 request for clarification and/or rehearing , VTransco asked the FERC (i) to clarify whether, in light of the *Highgate Acquisition Cost Recovery Order*'s disallowance of the requested rate treatment, VTransco was directed to recover the transaction costs from local service customers (since the FERC directed VTransco to book those costs to an account explicitly included in charges to local customers under the VTA); (ii) to clarify its approach with respect to VTransco's hold harmless commitment; and (iii) if taking a new policy approach, to grant rehearing and apply any new policy prospectively. The FERC issued a tolling order on July 30, 2018, affording it additional time to consider VTransco's request for rehearing, which remains pending. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **MPD OATT Annual Informational Filing (ER15-1429)**

On December 31, the Maine Customer Group[45] filed a formal challenge to Emera Maine's May 15, 2018 annual informational filing setting.[46] The formal challenge seeks certain cost reductions/exclusions to be effective June 1, 2018. Maine Customer Group states that the relief sought[47] has already been sought, unsuccessfully, directly from Emera Maine MPD through informal resolution procedures in accordance with the Protocols. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[48] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[49] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order. [50] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[51] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the

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[44] *Id.* at P 18.

[45] For purposes of this proceeding, "Maine Customer Group" is the MPUC, MOPA, Houlton water Co., and Van Buren Light & Power District, and Eastern Maine Electric Cooperative.

[46] The May 15 filing, submitted in accordance with the Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas ("Protocols"), set forth for the June 1, 2018 to May 31, 2019 rate year, the charges for transmission service under the MPD OATT ("MPD Charges"). *See* May 31, 2018 Litigation Report.

[47] The formal challenge seeks (i) exclusion of certain regulatory expenses allocated or directly assigned to the MPD transmission customers; (ii) exclusion of costs that would otherwise constitute a double-recovery for amortization of losses incurred as a result of a merger; (iii) correction of MPD-acknowledged errors in its Annual Update Filing; (iv) exclusion of certain costs for land associated with a project not in service; (v) exclusion from transmission rates certain costs for distribution equipment; (vi) exclude of costs improperly attributed to line 6901; and (vii) a flowback of excess ADIT resulting from the corporate tax reduction, and a requirement for Emera MPD to include a worksheet in its tariff to track excess/deficient ADIT.

[48] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

[49] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

[50] *Order Rejecting Filing* at P 1.

[51] *Id.* at P 36.

Order Rejecting Filing, which remains pending. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **Post-PRD Implementation Conforming and Clean-Up Changes (ER19-614)**

On December 20, ISO-NE and NEPOOL jointly filed changes to the Tariff to reflect the full implementation of Price-Responsive Demand ("PRD") and related clean-up changes ("Post-PRD Implementation Changes"). The Post-PRD Implementation Changes revised Tariff provisions related to: demand resource audits; the injection into the grid of electric power by demand resources; defined terms describing the measurement of facility load; Distributed Generation; and rules governing the aggregation of Demand Response Resources. A February 19, 2019 effective date was requested. Comments on this filing are due January 10, 2019. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)**

On December 14, Vineyard Wind petitioned the FERC for a waiver of the ISO-NE Tariff provisions necessary to allow it to participate in FCA13 as a Renewable Technology Resource ("RTR"). Vineyard Wind's request for RTR designation was earlier rejected by ISO-NE on the basis that the resources is to be located in federal waters. Under the CASPR Conforming Changes (*see* ER19-444 below), Vineyard Wind would not have been precluded from utilizing the RTR exemption. Consistent with the discussion in the November 30 filing, Vineyard Wind has asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR (following acceptance of the CASPR Conforming Changes) be limited for FCA13 to it and any other similarly situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment); there would be no impact on resources currently qualified to use the RTR exemption in FCA13. Comments on Vineyard Wind's request are due on or before January 4, 2019. Thus far, doc-less interventions were filed by NEPOOL, National Grid and NESCOE. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 841* Compliance Filing (ER19-470)**

On December 3, ISO-NE and NEPOOL jointly filed changes to Market Rule 1 and the OATT (and the PTO AC joined in the filing of the OATT revisions) in response to the requirements of *Order 841*.[52] For the majority of the revisions, ISO-NE requested a December 3, 2019 effective date; for a limited number of revisions, ISO-NE requested a January 1, 2024 effective date. The *Order 841* compliance changes were supported by the Participants Committee at its November 2 meeting. Following a request for a 45-day extension of time,[53] comments on this filing are now due February 7, 2019. Thus far, doc-less interventions have been filed by EPSA, ESA, AEE, LS Power, NESCOE, RENEW Northeast ("RENEW"). If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR Conforming Changes (ER19-444)**

On November 30, ISO-NE and NEPOOL jointly filed Tariff changes that to the Tariff that make enhancements and conforming changes to support the implementation of ISO-NE's Competitive Auctions with Sponsored Policy Resource ("CASPR") rules ("CASPR Conforming Changes"). The changes include clarifications

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[52] *See Electric Storage Participation in Mkts. Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*").

[53] The request for an extension of the previously notice December 24 comment deadline was requested by the Energy Storage Association ("ESA") and by a group comprised of Advanced Energy Economy ("AEE"), American Wind Energy Association ("AWEA"), Solar Energy Industries Association ("SEIA"), Solar RTO Coalition, and The Wind Coalition. The request was supported by the Acadia Center, NRDC, UCS, and the Sierra Club Environmental Law Program ("Public Interest Organizations").

to the core CASPR rules, the introduction of a "test price" mechanism that will apply to existing resources that are seeking to retire capacity through the substitution auction, market settlement, FCM Financial Assurance, resource adequacy parameter and planning study rule changes, and an ancillary clarification necessary to permit off-shore wind resources located in federal waters to qualify for use of the RTR Exemption. ISO-NE requested that the CASPR Conforming Changes become effective on January 29, 2019 (though some of the rule changes, e.g. changes to the qualification rules, will be used starting with the FCA14 qualification process). The CASPR Conforming Changes were supported by the Participants Committee at its November 2 meeting. Comments on this filing were due on or before December 24, 2018. Comments supporting the filing were filed by NESCOE, RENEW, and Vineyard Wind. NEPGA filed a limited protest, objecting to the aspect of the proposal whereby ISO-NE would file the IMM's rather than the Market Participant's Test Price for acceptance under FPA Section 205, and requested that the FERC order the Market Participant Test Price be filed for acceptance in any order accepting the CASPR Conforming Changes. Doc-less motions to intervene were filed by Calpine, Dominion, ENE, Eversource, Exelon, LS Power, MA DPU, National Grid, and NRG. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ICR and Related Values Assumptions Updates (ER19-343)**

On November 15, ISO-NE and NEPOOL jointly filed changes to the assumptions used in the calculation of the ICR and its Related Values. Specifically, the changes update assumptions used in the calculation of ICR, the Local Resource Adequacy Requirement ("LRA") (which is an input into the LSR, DCL, the Marginal Reliability Impact values, HQICCs (which are all probabilistically calculated), and the Transmission Security Analysis Requirement ("TSA") (which is deterministically calculated and an input into the LSR). A January 14, 2019 effective date was requested. The ICR and Related Values Assumptions Updates were supported by the Participants Committee at its October 4 meeting. Comments on this filing are due December 6, 2018; none were filed. Doc-less interventions were filed by Dominion, Eversource, FirstLight, National Grid, NESCOE, and NRG. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Parameter Consolidation (ER19-335)**

On December 19, the FERC accepted changes that establish a consolidated schedule for review and recalculation of a number of the parameters used in the FCM ("FCM Parameter Consolidation").[54] The parameters updated under the consolidated schedule are: the Cost of New Entry ("CONE"), Net CONE, Offer Review Trigger Prices ("ORTPs"), the Dynamic De-List Bid Threshold ("DDBT") and the Capacity Performance Payment Rate. The consolidated schedule will result in all of the parameters being updated for use in the FCA16 auction process, which generally begins in early 2021 and culminates in the Forward Capacity Auction to be held in February 2022. In order for the updated parameters to be ready for use in FCA16, ISO-NE expects that stakeholder review and filing of the updated parameters would occur in 2020. The FCM Parameter Consolidation changes were accepted effective as of January 14, 2019, as requested. Unless the December 19 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **New Capacity Resource Delayed Commercial Operation Changes (ER19-169)**

On December 20, 2018, the FERC accepted changes to the treatment of the delayed commercial operation of new capacity resources in the FCM jointly filed by ISO-NE and NEPOOL.[55] As previously reported, the two principal design changes were: (1) the removal of ISO-NE mandatory demand bids for new resources that are unable to satisfy all Critical Path Schedule milestones by the start of the Capacity Commitment Period;

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[54] *ISO New England and New England Power Pool Participants Comm.*, Docket No. ER19-335 (Dec. 19, 2018) (unpublished letter order).

[55] *ISO New England and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,266 (Dec. 20, 2018).

and (2) a new incentive structure that determines a monthly charge rate for new resources that have not fully demonstrated their Capacity Supply Obligation ("CSO"). The changes were accepted effective December 24, 2018, as requested. In accepting the changes, the FERC disagreed with PSEG's arguments that the proposed effective date violates the filed rate doctrine and rule against retroactive ratemaking, did not accept PSEG's further arguments asserting that the changes were not fully just and reasonable.[56] The FERC did not reach the arbitrage arguments articulated by the Northeastern Massachusetts Consumer-Owned Systems ("NEMACOS"),[57] finding the issue beyond the scope of the proceeding (though the order notes that the protested revisions "offer no additional arbitrage incentives beyond those already available to resources under the current Tariff."[58] Unless the December 20 order is challenged, with any challenges due on or before January 22, 2019, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Enhanced Storage Participation Changes (ER19-84)**

On October 10, ISO-NE and NEPOOL ("Filing Parties") jointly filed changes to the Tariff to enable emerging storage technologies to more fully participate in the New England markets (the "Storage Revisions"). The Storage Revisions allow emerging storage technologies to be dispatched in the Real-Time Energy Market in a manner that more fully recognizes their ability to transition continuously and rapidly between a charging state and a discharging state and that provides a means for their simultaneous participation in the energy, reserves, and regulation markets. The Filing Parties requested an April 1, 2019 effective date for the Storage Changes. Comments on the Storage Changes were due October 31. Doc-less interventions were filed by Calpine, Dominion, Eversource, FirstLight, National Grid, NextEra, NRG, and PSEG. ESA protested one element of the Storage Changes, specifically the proposal to automatically de-rate the amount of energy that a continuous storage facility can discharge into the energy market (the "automatic redeclaration" of Economic Maximum Limit and Maximum Consumption Limit). ESA asserted that the operational result of that approach "fails to account for the physical and operational characteristics of electric storage resources and imposes a market-inefficient choice on energy storage to forgo selling all of their stored energy rather than to conserve a significant fraction as operating reserves – for which they receive no compensation more often than not." On November 15, NEPOOL and ISO-NE answered the ESA protest. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- ***Order 844* Compliance Filing (ER18-2394)**

On November 29, the FERC accepted changes to Market Rule 1, the Information Policy and the centralized definitions section of the Tariff jointly filed by ISO-NE and NEPOOL in response to the monthly reporting requirements of FERC *Order 844*[59] ("*Order 844* Changes").[60] Each monthly report will be publically available on the ISO-NE website in machine-readable format. The Zonal Uplift Report will be reported 20 days after month's end, with daily Net Commitment Period Compensation ("NCPC") dollars by load zone and uplift category. The Resource-

[56] *Id.* at PP 24-26.

[57] "NEMACOS" are Belmont, Concord, Danvers, Georgetown, Groveland, Merrimac, Middleton, Reading, Rowley, and Wellesley.

[58] *Id.* at P 27.

[59] As reported in Section XII below, *Order 844* directed each RTO/ISO to establish in its tariff requirements to report, on a monthly basis: (1) total uplift payments for each transmission zone, broken out by day and uplift category (Zonal Uplift Report); (2) total uplift payments for each resource (Resource-Specific Uplift Report); and (3) for certain operator-initiated commitments after the Day-Ahead Energy Market, the size of the commitment, transmission zone, commitment reason, and commitment start time (Operator-Initiated Commitment Report). In addition to these reporting requirements, *Order 844* requires each RTO/ISO to include in its tariff the transmission constraint penalty factors ("TCPFs") used in its market software, as well as any circumstances under which those TCPFs can set locational marginal prices, and any process by which the TCPFs can be temporarily changed ("TCPF Requirements").

[60] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER18-2394 (Nov. 29, 2018) (unpublished letter order).

Specific Uplift Report will be reported 90 days after month's end, with total monthly NCPC dollars by resource. The Operator-Initiated Commitment Report will be reported 30 days after month's end, with the size, transmission zone, commitment reason, and commitment start time for the relevant commitments. Reference is made to the three reports in the Information Policy. With respect to the TCPF Requirements, a new defined term "Transmission Constraint Penalty Factor" was added to the Tariff's Centralized Definitions Section (§I.2.2) and the Tariff revised to reflect the ISO's current TCPF implementation. The *Order 844* Changes were accepted effective January 1, 2019, as requested. Unless the November 29 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Fuel Security Retention Proposal (ER18-2364)**

On December 3, the FERC accepted ISO-NE's Fuel Security Retention Proposal.[61] The Order accepted in all respects changes filed by ISO-NE on August 31, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue.

As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns".[62] ISO-NE proposed three sets of provisions to expand its authority on a short-term basis to enter into out-of-market arrangements in order to provide greater assurance of fuel security during winter months in New England (collectively, the "Fuel Security Retention Proposal").[63] ISO-NE stated that the interim provisions would sunset after FCA15, with a longer-term market solution to be filed by July 1, 2019, as directed in the *Mystic Waiver Order*. In addition, the ISO-NE transmittal letter described (i) the generally-applicable fuel security reliability review standard that will be used to determine whether a retiring generating resource is needed for fuel security reliability reasons; (ii) the proposed cost allocation methodology (Real-Time Load Obligation, though ISO-NE indicated an ability to implement NEPOOL's alternative allocation methodology if determined appropriate by the FERC); and (iii) the proposed treatment in the FCA of a retiring generator needed for fuel security reasons that elects to remain in service. The ISO-NE Fuel Security Changes were considered but not supported by the Participants Committee at its August 24 meeting. There was, however, super-majority support for (1) the Appendix L Proposal with some important adjustments to make that proposal more responsive to the FERC's guidance in the *Mystic Waiver Order* and other FERC precedent, and (2) the PP-10 Revisions, also with important adjustments (together, the "NEPOOL Alternative"). Comments on the Fuel Security Retention Proposal were due September 21.

On September 14, NEPOOL protested the filing and submitted the NEPOOL Alternative. Comments and protests were submitted numerous parties, including by Avangrid, Calpine, Cogentrix, Connecticut,[64] Constellation Mystic Power ("Constellation"), Dominion, ENECOS,[65] Environmental Defense Fund ("EDF"), Eversource, FirstLight,

[61] *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018) ("*Fuel Security Retention Proposal Order*").

[62] *Mystic Waiver Order* at P 55.

[63] The three sets of provisions include: (1) a trigger mechanism for authorizing ISO-NE action to retain capacity resources it determines are needed for fuel security reliability, as contained in a new Appendix L to Market Rule 1 (the "Appendix L Proposal"); (2) a new Section 13.2.5.2.5A of Market Rule 1 and revisions to Section III.13.2.5.2.5.1, to effectuate ISO-NE's proposed treatment of resources retained for fuel security in the FCA, the timing and integration of fuel security reliability reviews (including the ISO-NE's proposed application in the Substitution and Reconfiguration Auctions), and a proposal to allocate the costs associated with retaining units for fuel security (the "Section 13 Revisions"); and (iii) detailed reliability review implementation rules contained in revisions to ISO-NE Planning Procedure 10, Appendix I (the "PP-10 Revisions").

[64] For purposes of this proceeding, "Connecticut" is the Connecticut Dept. of Energy and Environ. Protection, Office of Consumer Counsel and Public Utilities Regulatory Authority.

[65] "ENECOS" in this proceeding are: Braintree, Concord, Georgetown, Hingham, Littleton, Middleborough, Middleton, Norwood, Pascoag, Reading, Taunton, Wellesley, and Westfield.

ISO-NE EMM, MA AG, MA DPU, MPUC, National Grid, NEPGA, NESCOE, NextEra, NH PUC, NRG, Participant Parties,[66] Verso, Vistra, American Petroleum Institute ("API"), APPA, EPSA, "Public Interest Organizations",[67] and RENEW Northeast ("RENEW"). Doc-less interventions only were filed by Brookfield, Calpine, CLF, ConEd, Energy New England ("ENE"), Exelon, IECG, Invenergy, MMWEC, NESCOE, NHEC, NRG, Repsol (out-of-time), Citizens Energy Corporation, Public Citizen, and NRECA. On October 1, Direct Energy submitted an answer highlighting their view that fuel security costs should be allocated to Regional Network Load. On October 2, NH PUC answered the MA DPU September 21 comments. The MA AG and MA DPU each answered NH PUC, on October 5 and 12, respectively. Answers were also filed by ISO-NE and Constellation (October 9); Answers to ISO-NE's October 9 answer were filed by FirstLight and NEPGA (October 17); NEPOOL (October 18); NextEra (October 22); NRG (October 23); and Vistra/Dynegy (October 24).

Dec 3 Fuel Security Retention Proposal Order. In accepting the ISO-NE Proposal, the FERC addressed, among others, the following topics:

- **The trigger and assumptions for the fuel security reliability review for retention of resources**: The FERC found the ISO-NE proposal to be reasonable,[68] but required ISO-NE at the end of each winter to "to submit an informational filing comparing the study assumptions and triggers from the modeling analysis to actual conditions experienced in the winter of 2018/19. The informational filing should also include a description of lessons learned, and explain if changes to study assumptions and triggers are necessary for future studies."[69]

- **Cost allocation**: The FERC found that cost allocation on a regional basis to Real-Time Load Obligation was just and reasonable and consistent with precedent regarding the past Winter Reliability Programs.[70]

- **Price treatment**: The FERC found that entering retained resources into the FCAs as price takers would be just and reasonable to ensure that they clear and are counted towards resource adequacy so that customers do not pay twice for the resource. The FERC said its determination on pricing is consistent with precedent in a 2017 NYISO order.[71]

- **Term of the interim fuel security provisions and Chapter 3**: The FERC found that it was appropriate to include FCAs 13, 14 and 15 in the term.[72] The FERC stated:

  > Given the limited amount of time between the July 1, 2019 filing deadline for the longer-term market solution, directed by the Commission, and the close of the FCA 15 retirement submission window in March 2020, we agree that the extension of the ability to retain resources through FCA 15 is a reasonable approach. We agree that it is necessary to implement a longer-term market solution as soon as possible, as discussed by commenters that request limiting the proposal to FCA 13 and 14. This interim solution is solely a stop-gap

[66] "Participant Parties" are: Direct Energy Business, NextEra Energy Marketing, the Associated Industries of Massachusetts ("AIM"), The Energy Consortium ("TEC"), and PowerOptions.

[67] "Public Interest Organizations" for purposes of this proceeding are: the Sustainable FERC Project, Acadia Center, Natural Resources Defense Council ("NRDC"), and the Sierra Club.

[68] *Fuel Security Retention Proposal Order* at PP 35-39.

[69] *Id.* at P 39.

[70] *Id.* at PP 53-56.

[71] *Id.* at PP 82-88. *See New York Indep. Sys. Operator, Inc.*, 161 FERC ¶ 61,189 (Nov 16, 2017) (NYISO order).

[72] *Fuel Security Retention Proposal Order* at PP 96-97.

> measure to address the fuel security challenges facing the region while ISO-NE develops its long-term market-based approach.[73]

Additionally, the FERC stated:

> Although the July 2 Order required ISO-NE to file its longer-term market solution no later than June 1, 2019, ISO-NE is free to file that solution earlier and we encourage it do so, if possible. In addition, we anticipate that the long-term market solution will obviate the need to continue to use the interim solution approved in this order. Accordingly, ISO-NE's filing must contain language that will remove from its tariff the short-term solution, if accepted.[74]

The FERC declined to provide guidance on what the long-term solution(s) should be.[75]

Challenges to the *Fuel Security Retention Proposal Order* were due on or before January 2, 2019 and were filed (and received prior to this Report being finalized) by NEPGA, NRG, Vistra/Dynegy Marketing & Trade, and PIOs. The requests for rehearing are pending, with FERC action required on or before February 1, 2019, or the requests will be deemed denied by operation of law. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Economic Life Determination Revisions (ER18-1770)**

Rehearing of the FERC's November 9 order,[76] accepting the revised Tariff language that changed the determination of economic life under Section III.13.1.2.3.2.1.2.C of the Tariff, is pending before the FERC. As previously reported, the Economic Life Revisions provide that the economic life of an Existing Capacity Resource is calculated as the evaluation period in which the net present value of the resource's expected future profit is maximized. The Economic Life Revisions were accepted effective as of August 10, 2018, as requested. In accepting the revisions, the FERC found that "it is just and reasonable to consider as part of the Economic Life calculation that a rational resource, in exercising competitive bidding behavior, would seek to exit the market, or retire, before it starts incurring consecutive losses."[77] The FERC found, contrary to NEPGA's assertions, that the "Economic Life Revisions do not represent a violation of the filed rate doctrine or constitute retroactive ratemaking."[78] Further, while the FERC was "mindful of the importance of not disrupting settled expectations based on existing market rules," the FERC concluded "that under these specific facts, the benefits of the proposed Economic Life Revisions outweigh potential disruptions to market participants' settled expectations and harm caused by reliance on the existing FCM rules."[79] On December 10, 2018, NEPGA requested rehearing of the *Economic Life Determination Revisions Order*. NEPGA's request for rehearing is pending, with FERC action required on or before January 9, 2019, or NEPGA's request will be deemed denied by operation of law. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[73] *Id.* at P 96.

[74] *Id.* at P 93.

[75] *Id.* at P 102.

[76] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*")

[77] *Economic Life Determination Revisions Order* at P 23.

[78] *Id.* at P 24.

[79] *Id.* at P 27.

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[80] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary. In addition, the FERC *sua sponte* extended the deadline in two Tariff provisions to enable Exelon to postpone its Mystic 8 and 9 retirement decision to and including January 4, 2019.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[81] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[82]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[83] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[84] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[85] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[86]

Requests for Rehearing and or Clarification. The following requests for rehearing and or clarification of the *Mystic Waiver Order* remain pending before the FERC:

- ♦ ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);

[80] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[81] *Id.* at P 47.

[82] *Id.* at P 48.

[83] *Id.* at P 55.

[84] *Id.* at PP 56-57.

[85] *Id.* at P 57.

[86] *Id.* at P 58.

- ***Connecticut Parties***[87] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[88] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);
- ***PIOs***[89] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and

[87] "Connecticut Parties" are the Conn. Pub. Utils. Regulatory Authority ("CT PURA") and the Conn. Dept. of Energy and Environ. Protection ("CT DEEP").

[88] The "EDCs" are the National Grid companies (Mass. Elec. Co., Nantucket Elec. Co., and Narragansett Elec. Co.) and Eversource Energy Service Co. (on behalf of its electric distribution companies – CL&P, NSTAR and PSNH).

[89] "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

On August 13, CT Parties opposed the NEPGA motion for clarification. On August 14, NEPOOL filed a limited response to Indicated New England EDCs, requesting that the FERC "reject the relief sought in [their motion] to the extent that relief would bypass or predetermine the outcome of the stakeholder process, without prejudice to [them] refiling their proposal, if appropriate, following its full consideration in the stakeholder process." Answers to the Indicated New England EDCs were also filed by the MA AG, NEPGA, NextEra, and CLF/NRDC/Sierra Club/Sustainable FERC Project. On August 29, the Indicated New England EDCs answered the August 14/16 answers. On August 27, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

On October 22, Calpine President and CEO, Thad Hill, filed a letter to provide additional context to the issues being addressed in the fuel security and Mystic proceedings.

Fuel Security Retention Proposal (ER18-2364). On December 3, the FERC accepted the changes to Market Rule 1 filed by ISO-NE in response to the *Mystic Waiver Order*. Those changes are reported on in ER18-2364 above.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting and ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[90] summarized in more detail in prior Reports, remains pending. Those requests were filed by (i) ***NextEra/NRG*** *(which* challenged the RTR Exemption Phase Out); (ii) ***ENECOS***[91] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[92] (which challenged the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenged the CASPR construct in its entirety and the CASPR Order's failure to define "investor confidence"). On April 24, ISO-NE answered Clean Energy Advocates' answer. On May 7, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CONE & ORTP Updates (ER17-795)**

Rehearing remains pending of the FERC's October 6, 2017 order accepting updated FCM CONE, Net CONE and ORTP values.[93] In accepting the changes, the FERC disagreed with the challenges to ISO-NE's choice of reference technology (gas-fired simple cycle combustion-turbine) and on-shore wind capacity factor (32%). The changes were accepted effective as of March 15, 2017, as requested. On November 6, NEPGA requested rehearing of the *CONE/ORTP Updates Order*. On December 4, 2017, the FERC issued a tolling order providing

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[90] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

[91] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

[92] "Clean Energy Advocates" are, collectively the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

[93] *ISO New England Inc.*, 161 FERC ¶ 61, 035 (Oct. 6, 2017)("*CONE/ORTP Updates Order*"), *reh'g requested*.

it additional time to consider NEPGA's request for rehearing of the *CONE/ORTP Updates Order*, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)**

Still pending before the FERC is ISO-NE's compliance filing in response to the FERC's August 8, 2016 remand order.[94] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and ISO-NE's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of whether the Bid Results were just and reasonable.[95] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." In February 13 comments, both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted. TransCanada requested that FERC establish a settlement proceeding where Market Participants could "exchange confidential information to determine what the rates should be" and refunds and "such other relief as may be warranted" provided. On February 28, ISO-NE answered the TransCanada and MA AG protests. On March 10, 2017, TransCanada answered ISO-NE's February 28 answer. This matter remains pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Interconnection Process Enhancement: Retiring Resources Treatment (ER19-449)**

On November 30, ISO-NE and NEPOOL jointly filed changes to Schedules 22, 23 and 25 of the OATT and Section III.13.1.1.2.3 of Market Rule 1 to enhance the manner in which capacity retirements are accounted for in certain interconnection studies performed for new resources seeking Capacity Network Resource Interconnection Service ("CNRIS") and Capacity Network Import Interconnection Service ("CNIIS") in order to participate in the FCM. These revisions also include a minor conforming change to the definition of Capacity Network Resource Capability ("CNR Capability") in Schedules 22 and 23 of the OATT. ISO-NE requested a January 29, 2019 effective date (which allows for implementation for FCA13). These revisions were addressed as part of the CASPR-Related Changes (*see* Section III above) and were supported by the Participants Committee at its November 2 meeting. Comments on this filing were due on or before December 21, 2018; none were filed. Doc-less interventions were filed by Eversource, Exelon, National Grid, and NRG. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[94] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[95] *2013/14 Winter Reliability Program Remand Order* at P 17.

- **Blackstart Rate Update (ER19-251)**

On December 18, the FERC accepted changes to Schedule 16 of the ISO-NE OATT[96] which (i) updated the rates for the payment of incremental capital and operating and maintenance ("O&M") costs for a generator to provide voluntary Blackstart Service (removing the NERC CIP Reliability Standard-related cost recovery provisions that blackstart owners are no longer subject to under the current Reliability Standard as a result of solely providing black start service); and (ii) included clean-up and conforming changes to the Tariff's consolidated definitions section (I.2.2). As previously reported, the update will result in an overall $0.9 million reduction in the costs of the Schedule 16 blackstart program. The changes were accepted effective as of January 1, 2019, as requested. Unless the December 18 letter order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Cluster Participation Deposit Refund Revisions (ER19-161)**

On December 13, the FERC accepted changes to the Clustering Provisions set forth in Schedules 22 (LGIA and LGIP), 23 (SGIA and SGIP) and 25 (Elective Transmission Upgrade ("ETU") Interconnection Procedures).[97] The changes permit the *ex post* return of a portion of the initial Cluster Participation Deposit ("CPD") in circumstances when a Cluster Enabling Transmission Upgrade ("CETU") is being replaced by an Internal Elective Transmission Upgrade ("Internal ETU") (together, the "CPD Refund Revisions"). The CPD Refund Revisions were accepted effective December 23, 2018, as requested. Unless the December 13 letter order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: BIPCO LSA Amendments (ER19-707)**

On December 28, National Grid filed clarifying and ministerial amendments to its local service agreement ("LSA") under Schedule 21-NEP with Block Island Power Company ("BIPCO") and ISO-NE. The changes included: (i) clarifications that BIPCO is responsible for telecommunications circuits; (ii) updates to the list of interconnection facilities and associated equipment; (iii) specification that BIPCO has elected to pay for the interconnection facilities via a Direct Assignment Facilities charge with no Contribution in Aid of Construction; (iv) identification of the transformer nameplate rating; (v) clarification as to the point of change in ownership (at the interconnection point); and (vi) other updates and corrections. A January 1, 2019 effective date was requested. Comments on this filing are due on or before January 18, 2019. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Stored Solar J&WE LSA Extension (ER19-706)**

On December 28, Emera Maine and ISO-NE filed an amended LSA ("Second Stored Solar LSA") by and among Emera Maine, Stored Solar J&WE, and ISO-NE for Local Non-Firm Point-to-Point Transmission Service under Schedule 21-EM of the ISO-NE OATT (the "Stored Solar LSA"). The Second Stored Solar LSA extends the discounted service rate accepted in February 2018 in Docket No. ER18-387. The term of the Second Stored Solar LSA is January 11, 2019 to December 31, 2020. A January 1, 2019 effective date was requested.

[96] *ISO New England and New England Power Pool*, Docket No. ER19-251 (Dec. 18, 2018) (unpublished letter order).

[97] *ISO New England Inc., et al.,* Docket No. ER19-161 (Dec. 13, 2018) (unpublished letter order).

Comments on the Second Stored Solar LSA are due on or before January 18, 2019. If there are any questions on these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-ES: Berkshire LSA (ER19-309)**

On January 2, 2019, the FERC accepted the Local Service Agreement ("LSA") among NSTAR, Berkshire Wind Power Cooperative Corporation ("Berkshire")[98] and ISO-NE.[99] The LSA provides for Firm and Non-Firm Local Point-To-Point Transmission Service for Berkshire's use of NSTAR (West)'s local facilities for "wheeling-out" power to the regional transmission system. The LSA was accepted effective as of January 7, 2019, as requested. Unless the January 2 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Corrections to § 10.2 (ER19-64)**

On November 30, the FERC issued a deficiency letter regarding Emera Maine's October 9 filed changes to Schedule 21-EM Section 10.2 (Emera Maine Penalties for Exceeding Non-Firm Capacity Reservation). In the October 9 filing, Emera Maine stated the changes were needed to correct errors in that section that date back to an October 11, 2007 *Order 890* compliance filing in which changes addressing unreserved use penalties were incorporated. Emera Maine hypothesized that the errors were the result of parallel changes to the section addressing penalties for unreserved use of *firm* transmission service being copied verbatim to the section addressing penalties for unreserved use of *non-firm* transmission service (without then changing references to firm to non-firm). In addition to changing references to firm to non-firm, Emera Maine also changed the basis upon which the penalty for exceeding non-firm reserved capacity for a greater than one-month period will be based.[100] Emera Maine requested a December 9, 2018 effective date for the changes.

Deficiency Letter. On November 30, the FERC issued a deficiency letter informing Emera Maine that its October 9 filing was deficient and that additional information is required in order to process the filing. Emera Maine was directed to file, on or before December 31, responses to a series of questions. Emera Maine's responses were filed on December 18, 2018. Comments on the December 18 deficiency letter response are due on or before January 8, 2019.

If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.)**

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[101] remains pending before the FERC. As previously reported, under the Settlement, permitted cost

[98] Berkshire is a non-profit entity created by 14 Mass. municipal utilities and MMWEC that owns and operates the 15 MW Berkshire Wind Power Project ("Berkshire Wind") located in Lanesboro, MA.

[99] *ISO New England Inc. and NSTAR Elec. Co.*, Docket No. ER19-309 (Jan 2, 2019) (unpublished letter order).

[100] The basis for the penalty changed from "a rate for *annual* Non-Firm Point-to-Point Transmission Service" to "a rate of *12 times the rate for monthly* Non-Firm Point-To-Point Transmission Service".

[101] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). The Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following an audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included

recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P-EM of the BHD OATT and $260,000 under the MPD OATT. Comments on the MPS Merger Cost Recovery Settlement were due on or before May 29, 2018; none were filed. On June 11, Settlement Judge Dring[102] certified the MPS Merger Cost Recovery Settlement to the FERC.[103] The MPS Merger Cost Recovery Settlement is pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **132nd Agreement (Press Membership Provisions) (ER18-2208)**

The 132nd Agreement remains pending before the FERC. As previously reported, NEPOOL filed changes to the NEPOOL Agreement (the "Amendments") implemented by the One Hundred Thirty-Second Agreement Amending New England Power Pool Agreement ("132nd Agreement") on August 13. The Amendments make clear that NEPOOL *membership* is not open to Press. Specifically, the Amendments prohibit Press from becoming a NEPOOL Participant or the designated representative of a Participant. A November 1, 2018 effective date was requested. The 132nd Agreement was approved in balloting following the Summer Meeting. Comments on this filing were due September 14.[104]

Early protests were submitted by Union of Concerned Scientists ("UCS"), the New England Professional Chapter of the Society of Professional Journalists ("NE SPJ"), Bill Short, and RTO Insider. In justifying their position that the Amendments should be rejected, UCS suggested that "Press participation in NEPOOL improves our collective problem-solving abilities, not reduces them." NE SPJ argued that "not allowing reporters access to public policy debates that will determine changes to the electricity markets … is doing a disservice to energy consumers." NEPOOL submitted a preliminary response to the UCS and NE SPJ protests on September 6. As its comments, RTO Insider submitted a copy of its Complaint (*see* EL18-196, Section I above). NEPOOL answered that submission on September 20. Bill Short filed a protest on September 11. On September 14, NHOCA, Public Interest Organizations,[105] Reporters Committee for Freedom of Press ("RCFP"), and Public Citizen filed protests. Those protests largely repeated arguments previously made and answered, but also sought to re-litigate whether New England arrangements satisfy the FERC's *Order 719* requirements, and premised their *Order 719* and other arguments and requests for relief on misunderstandings both of NEPOOL's position and of the applicable law. On October 1, NEPOOL responded to the NH OCA, Public Interest Organizations, and RCFP protests. On October 2, Public Citizen responded to NEPOOL's response. On October 5, RTO Insider answered NEPOOL's October 1 answer. Separate letters on

costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[102] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences: three in 2016 and two in 2017. In his most recent May 24, 2018 status report, Judge Dring indicated that the parties reached a settlement in principle, had filed a joint offer of settlement on May 8 ("MPS Merger Cost Recovery Settlement"), and recommended that settlement judge procedures be continued. The Settlement remains pending before the FERC and settlement judge procedures, for now, have not been terminated.

[103] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

[104] The FERC initially noticed a Sep. 4 comment date. Public Citizen requested a 30-day extension of that deadline. NEPOOL responded to that request asking that, in any action the FERC might take in response to Public Citizen's request, it preserve the opportunity for full consideration of any appropriate responses prior to any final determination. NEPOOL offered to defer the requested effective date for the Amendments as necessary. On Aug. 22, the FERC granted a 10-day extension of time, to Sep. 14, for comments.

[105] "Public Interest Organizations" are the Sustainable FERC Project, Conservation Law Foundation ("CLF"), Earthjustice, and Natural Resources Defense Council ("NRDC").

these matters were submitted by a group of U.S. Congressman and a group of Senators.[106] In addition, doc-less interventions were submitted by Avangrid, ConEd, Eversource, National Grid, and NESCOE.

Deficiency Letter. On October 31, the FERC issued a deficiency letter informing NEPOOL that its filing was deficient and that additional information was required in order to process the filing. NEPOOL was directed to file, and filed, responses to the FERC's questions on November 30. Comments, if any, on NEPOOL's responses were due December 21; none were filed. NEPOOL's response re-set the 60-day statutory clock for FERC action, which absent a further deficiency letter, will be January 30, 2019.

If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com), Dave Doot (860-275-0102; dtdoot@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

VIII. Regional Reports

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

FG&E's June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Regional Refund Reports (EL11-66)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[107] *and 531-B*[108] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Capital Projects Report - 2018 Q3 (ER19-113)**

On December 11, 2018, the FERC accepted, effective October 1, 2018, ISO-NE's October 15 Capital Projects Report and Unamortized Cost Schedule, which covered the third quarter ("Q3") of calendar year 2018 (the "Report").[109] Report highlights included the following new projects: (i) Streamline Asset Registration Phase III ($1.94 million); (ii) CASPR ($1.525million); (iii) Synchrophasor Initiatives – Next Generation ($968,900); (iv) Update Security Application Framework ($495,000); and (v) Lawson Lease Management ($125,800). The following three projects had significant changes: (i) CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements (2018 Budget decrease of $800,000); (ii) FERC Form 1, 3-Q and 714 (2018 Budget decrease of $456,700); and (iii) Identity

[106] The Congressmen included: Joseph P. Kennedy, III; Frank Pallone, Jr.; Bobby L. Rush; Fred Upton; Richard Neal; Peter Welch; Niki Tsongas; James P. McGovern; Katherine Clark; Seth Moulton; Michael Capuano; and David Cicilline. The Senators included: Richard Blumenthal, Sheldon Whitehouse; Jack Reed; Edward Markey; Elizabeth Warren; and Jeanne Shaheen. NEPOOL did not respond to either letter.

[107] *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[108] *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

[109] *ISO New England Inc.*, Docket No. ER19-113 (Dec. 11, 2018) (unpublished letter order).

and Access Management Phase II (2018 Budget increase of $857,000). Unless the December 11 order is challenged this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **IMM Quarterly Markets Reports – Summer 2018 (ZZ18-4)**

On December 6, the IMM filed with the FERC its Summer 2018 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Summer 2018 Report was discussed with the Markets Committee at its December 11-12 meeting.

IX. Membership Filings

- **January 2019 Membership Filing (ER19-748)**

On December 31, NEPOOL requested that the FERC accept (i) the memberships of ADG Group (Supplier Sector) and Dominion Bridgeport Fuel Cell LLC [Related Person to Dominion Energy Marketing (Generation Sector)]; and (ii) the termination of the Participant status of: Solea Energy (Supplier Sector), New England Confectionery Company and EmpireCo LP (each, Generation Sector Group Seat). Comments on this filing are due on or before January 21.

- **December 2018 Membership Filing (ER19-446)**

On November 30, NEPOOL requested that the FERC accept (i) the memberships of Alpha Gas & Electric (Supplier Sector); Eagle's View Partners (Supplier Sector); and Thordin ApS (Supplier Sector); (ii) the termination of the Participant status of: Food City & East Ave. Energy (End User Sector); and (iii) the name change of Enel X North America (f/k/a EnerNOC). This filing is pending before the FERC.

X. Misc. - ERO Rules, Filings; Reliability Standards

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Revised Reliability Standard: TPL-001-5 (RM19-10)**

On December 7, 2018, NERC filed for approval a revised Reliability Standard -- TPL-001-5 (Transmission System Planning Performance Requirements), and associated implementation plan, VRFs and VSLs (together, the "TPL-001 Changes"). NERC stated that the TPL-001 Changes improve upon the currently effective standard by enhancing Requirements for the study of Protection System single points of failure. Additionally, the TLP-001 Changes address two FERC directives from Order 786: (1) the TPL-001 Changes provide for a more complete consideration of factors for selecting which known outages will be included in Near-Term Transmission Planning Horizon studies, addressing the FERC's concern that the exclusion of known outages of less than six months in TPL-001-4 could result in outages of significant facilities not being studied; and (2) the TPL-001 Changes modify Requirements for Stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **New Reliability Standard: CIP-012-1 (RM18-20)**

On September 18, 2018, NERC filed for approval a new Reliability Standard -- CIP-012-1 (Cyber Security – Communications between Control Centers), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Control Center Cyber Security Communication Changes"). NERC stated that the changes modify the Critical Infrastructure Protection ("CIP") Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System ("BES") data communicated between BES Control Centers. CIP-012-1 requires Responsible Entities to develop a plan to mitigate the risks posed by unauthorized modification (integrity) and unauthorized disclosure (confidentiality) of Real-time Assessment and Real-time monitoring data. The plan must include the following three components: (1) identification of security protection used to meet the security objective; (2) identification of where the Responsible Entity applied the security protection; and (3) identification of the responsibilities of each Responsible Entity for applying the security protection. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

XI. Misc. - of Regional Interest

- **203 Application: FirstLight Restructuring (EC19-44)**

On January 2, 2019, FirstLight Hydro Generating Company (FirstLight Hydro) and the FirstLight Project Companies[110] requested FERC authorization for the disposition of jurisdictional facilities that will result from a proposed corporate restructuring involving the transfer of 100% of FirstLight Hydro's electric generating facilities and related assets ("Facilities") to the FirstLight Project Companies ("FirstLight Restructuring"). Following the FirstLight Restructuring, which the parties expect to be completed on or about March 31, 2019, the Facilities will be directly owned by the FirstLight Project Companies. Comments on this application are due on or before January 23, 2019.

- **203 Application: Emera / Revere Power (EC19-35)**

On December 14, Bridgeport Energy LLC ("Bridgeport"), Rumford Power Inc. ("Rumford"), Tiverton Power LLC ("Tiverton", and together with Bridgeport and Rumford, the "Project Companies"), and Revere Power, LLC ("Buyer" or "Revere"), requested FERC authorization for a proposed transaction that will result in the transfer of 100% of the indirect ownership interests in the Project Companies from Emera US Holdings Inc. ("Seller") to Revere. Following consummation of the transaction, the Project Companies will be wholly-owned, indirect subsidiaries of Revere, and Related Persons to Nautilus Power (Generation Sector) and its affiliates. Comments on this application are due on or before January 4, 2019.

- **203 Application: Dominion Bridgeport Fuel Cell, LLC (EC19-22)**

On December 20, the FERC authorized the acquisition of Dominion Bridgeport Fuel Cell, LLC, owner of a 15 MW fuel cell power plant in Bridgeport, CT and a new member as of January 1, 2019 (*see* ER19-784 in Section IX above) by FuelCell Energy Finance, LLC ("Fuel Cell"). Fuel Cell is a Related Person of DFC ERG CT, a member of the AR Sector.[111] Among other conditions, the December 20 order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **203 Application: Plymouth Rock/Engie (EC19-19)**

On December 14, the FERC authorized a transaction pursuant to which ENGIE Resources ("Engie") will indirectly acquire 100% of the equity interests in Plymouth Rock Energy, LLC ("Plymouth Rock").[112] Following the consummation of the transaction, Plymouth Rock and Engie will be Related Persons. Among other conditions, the *Plymouth Rock/Engie Order* required notice within 10 days of the acquisition's consummation, which has not yet been filed.

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[110] The "FirstLight Project Companies" are FirstLight CT Housatonic, FirstLight CT Hydro, FirstLight MA Hydro, and Northfield Mountain.

[111] *Dominion Bridgeport Fuel Cell, LLC*, Docket No. EC19-22 (Dec. 20, 2018).

[112] *Plymouth Rock Energy, LLC*, 165 FERC ¶ 62,164 (Dec. 14, 2018) ("*Plymouth Rock/Engie Order*").

- **203 Application: CPV Towantic/Osaka Gas USA (EC19-16)**

On December 13, the FERC authorized Osaka Gas USA's acquisition of a 25% direct equity ownership interest in CPV Towantic[113] and, on December 17, Osaka Gas notified the FERC that the acquisition was consummated that same day. Reporting on this proceeding has concluded.

- **203 Application: ECP/Fawkes Holdings (Wheelabrator) (EC19-14)**

On December 6, the FERC authorized the acquisition by Fawkes Holdings, LLC (a Related Person to Macquarie Energy) of all of the issued and outstanding shares of common stock of Wheelabrator Technologies Inc. ("Wheelabrator") currently held by the Energy Capital Partners companies ("ECP"). Following the consummation of the transaction, notice of which, as of the date of this Report, has not been filed, Wheelabrator will be a Macquarie Related Person and no longer a Calpine Related Person.

- **203 Application: Dominion Energy Manchester Street (EC19-3)**

On December 12, the FERC authorized the acquisition of Dominion Energy Manchester Street, Inc., owner of a 468 MW natural gas and oil combined-cycle power plant in Manchester, NH ("Manchester Street") by Spade Facilities II, LLC ("Spade"). Manchester Street was recently conditionally approved for membership by the Membership Subcommittee and, following the December 13 consummation of the transaction, is now a Related Person of Marco DM Holdings, LLC, a member of the Generation Sector.[114]

- **203 Application: VTransco Acquisition of BED/Stowe Highgate Share (EC18-137)**

On December 17, the FERC authorized the acquisition by VTransco of the Burlington and Stowe Electric Department ownership shares in the Highgate Transmission Facility.[115] VTransco stated that, after the close of the Transaction, VTransco will be the sole owner of the Highgate Transmission Facility. VTransco committed to hold transmission customers harmless and not to include transaction-related costs in its transmission revenue requirements for a period of five years following the acquisition. And should it ever seek to recover the transaction-related costs in rates, VTransco further committed to demonstrate off-setting benefits in a separate filing under section 205 of the FPA. The December 17 order directed VTransco to notify the FERC within 10 days of consummation of its acquisition, which as of the date of this Report has not yet occurred.

- **203 Application: Linde Energy Services (EC18-132)**

On September 14, the FERC authorized a transaction pursuant to which Linde AG will divest the parent of Linde Energy Services ("Linde"), Linde North America, Inc. to an unaffiliated third-party, now known as "Messer Industries GmbH" (the divestiture was expected to be a condition to FTC approval of the Linde AG/Praxair Inc. merger).[116] Among other conditions, the order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **203 Application: Wheelabrator Technologies (EC18-130)**

On September 19, the FERC authorized the disposition of up to 49% of the indirect ownership interests in Wheelabrator Technologies ("WTI") indirectly held public utility subsidiaries resulting from an initial public offering of up to approximately 49% of WTI's common stock. Among other conditions, the order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

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[113] *CPV Towantic, LLC and Osaka Gas USA Corp.*, 165 FERC ¶ 626,160 (Dec. 13, 2018).

[114] *Dominion Energy Fairless, LLC, et al.*, Docket No. EC19-3 (Dec. 12, 2018).

[115] *Vermont Transco LLC*, 165 FERC ¶ 62,176 (Dec. 17, 2018). The Highgate Transmission Facility is the United States portion of a line that extends from a site near Bedford Substation, in Québec, to a substation in Highgate, Vermont, crossing the International Boundary near Saint Armand, Québec, and Franklin, Vermont, and provides an interconnection between Hydro-Québec TransÉnergie and the transmission system in Vermont owned by VTransco.

[116] *Linde Energy Services, Inc.*, 164 FERC ¶62,147 (Sep. 14, 2018).

- **203 Application: GenOn Reorganization (EC17-152)**

On December 20, 2018, GenOn Holdings Inc. notified the FERC that the previously-approved[117] conversions of GenOn notes into common equity of, and corporate structure changes that resulted in, a "reorganized GenOn" that emerged as a result of GenOn's Chapter 11 restructuring (the "Restructuring") occurred on December 14, 2018. As a result of the Restructuring, Reorganized GenOn is no longer a subsidiary of, and GenOn Energy Management is no longer be a Related Person to, NRG. Reporting on this matter has concluded.

- **New England Ratepayers Association Complaint (EL19-10)**

As previously reported, the New England Ratepayers Association ("NERA") filed a complaint on November 2, 2018 seeking declaratory order finding that (i) New Hampshire Senate Bill 365 ("SB 365"),[118] which mandates a purchase price for wholesale sales by seven generators operating in NH, (i) is preempted by the Federal Power Act; (ii) SB 365 violates Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") (because SB 365 does not satisfy the requirement under PURPA and the FERC's implementing regulations[119] that rates set by the states for wholesale sales by QFs may not exceed the purchasing utilities' avoided costs; and (iii) NH is pre-empted from ordering purchases that are contrary to the FERC's order terminating PSNH's mandatory purchase obligation on a service territory-wide basis for QFs with a net capacity in excess of 20 MW. NERA asked the FERC to issue a ruling by February 1, 2019 (the date NH customers may first bear the costs of SB 365). Doc-less interventions were filed by Calpine, Eversource, National Grid, NRG, and the DC Office of People's Counsel. Comments supporting the Petition were filed by: NH OCA, the NH Generator Group,[120] EPSA, and a group of NH customers; a Protest was filed by the State of New Hampshire.[121] The New England Small Hydro Coalition filed comments that, while not taking a position on NERA's preemption argument, disagreed with the premise that underlies NERA's argument as to what constitutes an avoided cost rate in New Hampshire. Since the last report, NH OCA and the NH Generator Group amended/supplemented their December 3 comments. A group of NH Legislators that supported SB 365 filed comments on December 17 urging the FERC to deny the Petition. On December 20, NERA answered the protests and comments. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PJM MOPR-Related Proceedings (EL18-178; ER18-1314; EL16-49)**

On June 29, the FERC issued an order ("*PJM Order*")[122] regarding out-of-market support affecting the PJM capacity market.[123] Opening with the statement that "the integrity and effectiveness of the capacity

[117] *GenOn Energy Inc.*, 161 FERC ¶ 62,063 (Oct. 31, 2017).

[118] SB 365, 2018 N.H. Laws Ch. 379, An Act relative to the use of renewable generation to provide fuel diversity, codified at N.H. Rev. Stat. Chapter 362-H.

[119] 18 C.F.R. §§ 292.304(a); 292.101(b)(6) (2018).

[120] The NH Generator Group is comprised of the following entities: Bridgewater Power Company, L.P., DG Whitefield LLC, Pinetree Power – Tamworth LLC, Pinetree Power, Inc., Springfield Power, LLC, and Wheelabrator Concord Company, L.P.

[121] Although the State of New Hampshire requested and was eventually granted a two-week extension of time to file its comments, that extension was noticed on December 4, 2018, after the initial comment date and the submission of NH's comments.

[122] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018), *clarif. and/or reh'g requested*.

[123] The *PJM Order* addressed two separate, but related proceedings. The first, EL16-49, was initiated by a complaint originally filed by Calpine, joined by additional generation entities ("Calpine Complaint") on March 21, 2016, and later amended on January 9, 2017. The Calpine Complaint argued that PJM's MOPR was unjust and unreasonable because it did not address the impact of existing resources receiving out-of-market payments on the capacity market, and proposed interim tariff revisions that would extend the MOPR to a limited set of existing resources. The Calpine Complaint also requested the FERC to direct PJM to conduct a stakeholder process to develop and submit a long-term solution. The second proceeding was PJM's filing of its proposed revisions to its Tariff, pursuant to section 205 of the FPA in ER18-1314 ("PJM Filing"). The PJM Filing consisted of two alternate proposals designed to address the price impacts of state out-of-market support for certain resources. The first approach, preferred by PJM but not supported by its stakeholders, consisted of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). The second alternative approach, proposed in the event that the FERC determined that Capacity Repricing was

market administered by [PJM] have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources," the *PJM Order* determined that the PJM Tariff is currently unjust and unreasonable, rejected PJM's Section 205 Filing, granted in part Calpine's Complaint, and established a paper hearing to resolve the "price-suppressive" effects of out-of-market support for certain resources. Commissioners LaFleur and Glick both dissented, and Commissioner Powelson wrote a separate concurrence.

In the *PJM Order*, the FERC found "that it has become necessary to address the price suppressive impact of resources receiving out-of-market support." The FERC agreed with Calpine and PJM that changes to the PJM Tariff were required, but did not accept the changes proposed in the Calpine Complaint or the PJM Filing, finding that neither had been shown to be just and reasonable, and not unduly discriminatory or preferential. The majority stated that it was unable to determine, based on the record of either proceeding, the just and reasonable rate to replace the rate in PJM's Tariff. The *PJM Order* therefore found the PJM Tariff unjust and unreasonable, granted the Calpine Complaint, in part, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178), consolidating the record of the two earlier proceedings, and setting for paper hearing the issue of how to address a proposed alternative put forth in the *PJM Order*,[124] which would modify two existing aspects of the PJM Tariff, "or any other proposal that may be presented."

16 requests for clarification and/or rehearing of the *PJM Order* were filed on July 30. On August 29, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

Paper Hearing; Additional Briefing; PJM's Extended RCO Proposal. Following an August 22 notice of extension of time, interested parties were invited to submit their initial round of testimony, evidence, and/or argument by October 2, 2018. Initial briefs, comments and submissions were filed by over 50 parties. In its October 2 submission, PJM submitted a revised proposal, which includes an expanded MOPR coupled with a "Extended Resource Carve-Out" proposal ("Extended RCO"). The proposed MOPR would apply to all fuel and technology types and to both existing and new resources (a change from the original MOPR, which only applied to new gas-fired units). The Extended RCO would provide a means for states to support particular subsidized generation assets by removing them from certain aspects of the PJM capacity market and not subjecting them to MOPR in PJM's capacity market.

Reply testimony, evidence, and/or argument was due on or before November 6, 2018. Over 60 sets of reply briefs, evidence, etc. were filed. Since that time, a few parties submitted answers and additional comments. On December 6, PJM and Direct Energy/NextEra filed limited answers to reply briefs. In addition, a letter from a group of companies representing competitive new generation built in the PJM region since 2010 ("Generator Letter") urged the FERC to "to consider the broadest ramification of a fundamental change in the regulatory compact and the impact it would have on consumers, investors and even the fundamental American belief that markets drive better outcomes than government."[125] Answers to and comments on

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unjust and unreasonable, would have revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex").

[124] The proposed alternative approach would (i) modify PJM's MOPR such that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions; and (ii) in order to accommodate state policy decisions and allow resources that receive out-of-market support to remain online, establish an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support. Both aspects of the proposed replacement rate, along with a series of questions that need to be addressed, are more fully explained and raised in the *PJM Order*.

[125] Those companies included: Ares Power and Infrastructure Group, Caithness, Calpine, Carroll County and South Field Energy, CPV, J-POWER USA Development Co., Panda Power Funds, and Tenaska Energy.

PJM's answer were filed by "Clean Energy Industries"[126] and UCS. A response to the December 6 Generators Letter was filed by APPA, ELCON, LPPC, NRECA, and NRDC. These materials, together with all of the initial briefs and reply briefs, are pending before the FERC.

The FERC committed in the *PJM Order* to make every effort to issue an order establishing the just and reasonable replacement rate no later than January 4, 2019. The FERC also established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49. For further information on this proceeding, please contact Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Deepwater Wind PURPA Complaint (EL18-171)**

The June 7 complaint filed by Kathryn Leonard, an individual ratepayer and councilwoman for the City of Newport RI ("Complainant"), against the RI PUC, National Grid, and Deepwater Wind Block Island ("Deepwater Wind") remains ending before the FERC. The Complaint seeks, among other things, declaratory and injunctive relief barring the continued implementation of the Deepwater Wind Rhode Island PPA and prohibiting the RI PUC from "designating renewable power costs as 'distribution' costs in any way that prevents consumers from the benefits of purchasing power from competitive sources". Following a partially granted request for an extension of time by the RI PUC, answers to and comments on this Complaint were due on or before July 13. Answers were filed by Deepwater Wind, National Grid and the RI PUC. On July 23, Complainant objected separately to each of the answers. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PJM Clean MOPR Complaint (EL18-169)**

This proceeding, which could impact potentially impact New England's markets, remains pending. As previously reported, CPV Power Holdings, L.P. ("CPV"), Calpine Corporation ("Calpine"), and Eastern Generation, LLC ("Eastern Generation") (collectively, "PJM MOPR Complainants") filed a complaint on May 31, 2018 requesting that the FERC protect PJM's Reliability Pricing Model ("RPM") market from below-cost offers for resources receiving out-of-market subsidies by requiring PJM to adopt a "Clean MOPR" (i.e. a MOPR applicable to all subsidized resources and without categorical exemptions like those in PJM's MOPR-Ex proposal). PJM MOPR Complainants state that the Complaint offers the FERC a procedural vehicle to require adoption of the "Clean MOPR" that Complainants opine is not otherwise available in pending FERC proceedings (EL16-49 (PJM MOPR Complaint)[127] and ER18-1314 (PJM's pending MOPR changes)). They assert that the "Clean MOPR" is required to effectively address the impacts of state subsidy programs, and is consistent with the FERC's MOPR principles identified in the *CASPR Order*. Comments on the PJM Clean MOPR Complaint were due on or before June 20. PJM's answer, as well as comments and protests from over 25 parties were filed. Given its potential to impact New England, NEPOOL filed a doc-less motion to intervene. More than 30 other parties also intervened. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Sunita Paknikar (202-218-3904; spaknikar@daypitney.com).

- ***NYISO MOPR Proceeding (EL13-62)***

As in the PJM MOPR Proceeding, NEPOOL filed limited comments requesting that any FERC action or decision be limited narrowly to the facts and circumstances as presented, and that any changes ordered by

[126] "Clean Energy Industries" are AWEA, the Solar RTO Coalition, Solar Energy Industries Assoc., Advanced Energy Economy ("AEE"), the American Council on Renewable Energy ("ACORE"), and the Mid-Atlantic Renewable Energy Coalition ("MAREC").

[127] The "PJM MOPR Complaint" seeks a FERC order expanding the PJM MOPR in the Base Residual Auction for the 2019/2020 Delivery Year to prevent the artificial suppression of prices in the Reliability Pricing Model ("RPM") market by below-cost offers for existing resources whose continued operation is being subsidized by State-approved out-of-market payments. Complainants in the MOPR Complaint are Calpine, Dynegy, Eastern Generation, Homer City Generation, the NRG Companies, Carroll County Energy, C.P. Crane , the Essential Power PJM Companies, GDF SUEZ Energy Marketing NA, Oregon Clean Energy, and Panda Power Generation Infrastructure Fund.

the FERC not circumscribe the results of NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling. The NYISO MOPR Proceeding remains pending before the FERC.

If you have any questions concerning these proceedings, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Related Facilities Agreement: NSTAR / Clear River Energy (ER19-693)**

On December 27, NSTAR filed a Related Facilities Agreement ("RFA") between NSTAR and Clear River Energy LLC ("Clear River") for the purpose of providing the terms and conditions governing NSTAR's activities, and Clear River's associated cost responsibility, in completing the required upgrades on NSTAR's transmission line #3361 in connection with Clear River's LGIA with ISO-NE and National Grid.[128] A February 26, 2019 effective date was requested. Comments on this filing are due on or before January 17, 2019. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement: CL&P / Clear River (ER19-689)**

Also on December 27, CL&P filed a RFA with Clear River for the purpose of providing the terms and conditions governing CL&P's activities, and Clear River's associated cost responsibility, in completing the required upgrades to CL&P's s protection and control facilities in connection with Clear River's LGIA with ISO-NE and National Grid. A February 26, 2019 effective date was requested. Comments on this filing are also due on or before January 17, 2019. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement: CL&P / Cricket Valley (ER19-590)**

On December 18, CL&P filed a RFA with Cricket Valley Energy Center LLC ("Cricket Valley") governing the activities and associated cost responsibility for completing the required reconductoring of approximately five miles of 345 kV transmission line owned by CL&P (Line 398) from the NY-CT border – connecting to ConEd's 345 kV transmission line – to the CL&P Long Mountain Substation, and other associated upgrades described in the RFA ("Cricket Valley Reconducturing Project").[129] The Cricket Valley Reconducturing Project is required under the LGIA among Cricket Valley, NYISO and ConEd. A February 17, 2019 effective date was requested. Comments on this filing are due on or before January 8, 2019. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR/MATEP Revised Distribution Service Agreement (ER19-431)**

On November 29, NSTAR filed a revised Distribution Service Agreement ("Revised Distribution Agreement") for wholesale distribution service to MATEP LLC ("MATEP"). The Revised Distribution Agreement amends the Original Distribution Agreement (i) primarily by expanding the definition of the Brighton Tie Lines to include an incremental, fourth radial 13.8 kV circuit that will be used to enhance MATEP's ability to meet the needs of its own retail customers and to provide wholesale distribution service to MATEP for the purposes of continuing its power sales in the capacity and energy markets in New England, and (ii) by amending various terms and conditions to clarify and enhance those provisions stemming from the expansion of the definition of the Brighton Tie Lines. A January 30, 2019 effective date was requested. On December 20, MATEP filed comments urging FERC to approve the Revised Distribution Agreement. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[128] Clear River plans to construct an approximately 1,100 MW combined cycle generation project in Burrillville, Rhode Island that will be interconnected to the National Grid transmission system.

[129] Cricket Valley plans to construct an approximately 1,177 MW combined cycle generation project in Dover, New York that will be interconnected to the ConEd transmission system.

- **NSTAR/HQ US MMWEC Use Rights Transfer Agreement (ER19-409)**

On November 28, NSTAR filed an agreement by which it will transfer MMWEC's use rights over the Phase I/II HVDC facilities to HQUS (MMWEC itself does not have a mechanism to effectuate the transfer). A December 20, 2018 effective date was requested. On December 13, MMWEC filed a statement of support, requesting that the FERC approve the Agreement promptly. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **TSAs: First Amendments to EDC New England Clean Energy Connect TSAs (ER19-324 et al.)**

On November 9, CMP filed executed first amendments to 3 of its previously filed and accepted, cost-based transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of CMP's portion of a the NECEC Transmission Line. The amendments to the agreements with Eversource (NSTAR), National Grid and Unitil (the "EDC Agreements") make only two changes – (i) extension of the date that triggers an increase in monthly transmission service payments by the EDCs to CMP while Regulatory Approval for the Project is pending (from January 25, 2019 to June 25, 2019) and (ii) extension of the date by which any party to the EDC Agreements may terminate the EDC Agreement if Regulatory Approval is not received (from January 25, 2020 to June 25, 2020). Comments on the first amendments were due on or before November 30; none were filed. Doc-less interventions were filed by Eversource and National Grid. On December 26, as a result of discussions with FERC Staff, CMP submitted an amended eTariff record (not included with the November 9 filing) to reflect the amendments. Comments on the December 26 filing, if any, are due on or before January 16, 2019. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR/HQ US ENE Use Rights Transfer Agreement (ER19-146)**

On December 10, the FERC accepted the agreement by which NSTAR will transfer ENE's use rights over the Phase I/II HVDC facilities to HQUS (ENE itself does not have a mechanism to effectuate the transfer).[130] The Agreement was accepted effective November 20, 2018, as requested. Unless the December 10 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FERC Enforcement Action: Show Cause Order – Footprint Power (IN18-7)**

As previously reported, the FERC issued an order[131] on June 18, 2018 directing Footprint Power LLC and Footprint Power Salem Harbor Operations LLC (collectively, "Footprint") to show cause why they should not (i) be found to have violated the ISO-NE Tariff and FERC regulations by submitting what Enforcement Staff has concluded were false and misleading supply offers for, and by failing to report the fuel status and related operational status of, Salem Harbor Unit 4 in June and July of 2013; and as a result (ii) disgorge $2.05 million in CSO payments and be assessed a $4.2 million civil penalty. Enforcement Staff alleged that from June 26 through July 25, 2013, Footprint submitted supply offers that Unit 4 could not satisfy because Salem Harbor lacked usable fuel, and failed to report to ISO-NE that Salem Harbor's lack of usable fuel reduced Unit 4's output capabilities and availability as a capacity resource. In addition, Staff alleged that Footprint omitted material information from and/or misrepresented the fuel status of Salem Harbor and related operational status of Unit 4 in its communications with ISO-NE. On July 13, Footprint submitted a "Notice of De Novo Election", which requires the FERC to institute an action in the appropriate United States district court for a *de novo* review of the matter should the FERC assess civil penalties that Footprint fails to pay within 60 days. Following a FERC-granted extension of time to answer, Footprint filed its answer on August 2.

[130] *NSTAR Elec. Co.*, Docket No. ER19-146 (Dec. 10, 2018) (unpublished letter order).

[131] *Footprint Power LLC and Footprint Power Salem Harbor Ops. LLC*, 163 FERC ¶ 61,198 (June 18, 2018).

On September 19, OE Staff submitted its response to Footprint's August 2 answer. Finding merit in Footprint's defense relating to the start-up requirements of Salem Harbor Unit 4, Staff agreed with Footprint that its conduct during the June 27 through July 17, 2013 portion (the "Cold Start Period") of the "Relevant Period" (i.e., June and July 2013) did not violate the ISO-NE Tariff provisions and FERC regulations at issue,[132] re-evaluated its position and recommended that the FERC vacate the Order to Show Cause. On September 26, Footprint answered OE Staff's residual findings, and urged the Commission to promptly and definitively end this matter. This matter is again pending before the FERC.

- **FERC Enforcement Action: Order of Non-Public, Formal Investigation (IN15-10)**

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including its prohibition against electric energy market manipulation, that may have occurred in connection with, or related to, MISO's April 2015 Planning Resource Auction for the 2015/16 power year.

Unlike a staff NOV, a FERC order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that the FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. It does, however, give OE's Director, and employees designated by the Director, the authority to administer oaths and affirmations, subpoena witnesses, compel their attendance and testimony, take evidence, compel the filing of special reports and responses to interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)**

On January 8, 2018, the FERC initiated a new Grid Resilience in RTO/ISOs proceeding (AD18-7)[133] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[134] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, FRS requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain

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[132] Staff still believes that Footprint violated the ISO-NE Tariff and FERC regulations during the remaining portion of the Relevant Period, from July 18 to July 25, when Footprint submitted Day-Ahead Limited Energy Generator ("LEG") offers to which the Cold Start Period defense does not apply.

[133] *Grid Rel. and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

[134] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[135] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into 3 parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to 4 sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Since the last Report, reply comments were filed by APPA and American Municipal Power ("AMP") and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. Since the last Report, on December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[136] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that request is pending.

- **NOPR: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 15, 2018, the FERC issued a NOPR ("*ADIT NOPR*") proposing to require all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law").[137] Specifically, for transmission formula rates, the FERC is proposing (i) to require that public utilities deduct excess accumulated deferred income taxes ("ADIT") from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; (ii) to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually

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[135] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

[136] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

[137] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018).

track ADIT information; (iii) to require all public utilities with transmission stated rates to determine the amount of excess and deferred income tax caused by the 2017 Tax Law's reduction to the federal corporate income tax rate and return or recover this amount to or from customers. Comments on the *ADIT NOPR* are due on or before December 24, 2018.[138] On November 26, APPA, EEI and NRECA requested an additional 30 days (to January 22, 2019) to file comments in response to the *ADIT NOPR*. On December 7, the FERC issued a notice granting the November 26 motion, extending the deadline for comments on the ADIT NOPR to and including January 22, 2019.

- **NOPR: Amended FPA Section 203(a)(1)(B) (RM19-4)**

Also on November 15, 2018, the FERC issued a NOPR proposing to revise its regulations relating to mergers or consolidations by a public utility ("*Section 203(a)(1)(B) NOPR*").[139] Specifically, the FERC proposes to revise its regulations (i) to establish that a public utility must seek authorization under amended section 203(a)(1)(B) of the Federal Power Act to merge or consolidate, directly or indirectly, its facilities subject to the jurisdiction of the Commission, or any part thereof, with the facilities of any other person, or any part thereof, that are subject to the jurisdiction of the FERC *and have a value in excess of $10 million*, by any means whatsoever; and (ii) to establish a notification requirement for mergers or consolidations by a public utility if the facilities to be acquired have a value in excess of $1 million and such public utility is not required to secure FERC authorization under amended section 203(a)(1)(B). Comments on the *Section 203(a)(1)(B) NOPR* were due on or before December 31, 2018.[140] Comments were filed by American Antitrust Institute ("AAI"), APPA, EEI, Idaho Power Company, International Transmission Company, NRECA, Public Citizen, and Transmission Access Policy Group ("TAPS") The *Section 203(a)(1)(B) NOPR* is pending before the FERC.

- **NOPR: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)**

On December 20, 2018, the FERC issued a NOPR proposing to relieve market-based rate sellers of the obligation, when seeking to obtain or retain market-based rate authority in any RTO/ISO market with RTO/ISO-administered energy, ancillary services, and capacity markets subject to FERC-approved RTO/ISO monitoring and mitigation, to submit indicative screens ("*Horizontal Market Power Analysis Refinements NOPR*").[141] In RTOs and ISOs that lack an RTO/ISO-administered capacity market, market-based rate sellers would be relieved of the requirement to submit indicative screens if their market-based rate authority is limited to sales of energy and/or ancillary services. The FERC's regulations would continue to require RTO/ISO sellers to submit indicative screens for authorization to make capacity sales in any RTO/ISO markets that lack an RTO/ISO-administered capacity market subject to FERC-approved RTO/ISO monitoring and mitigation. The *NOPR* also proposes to eliminate the rebuttable presumption that FERC-approved RTO/ISO market monitoring and mitigation is sufficient to address any horizontal market power concerns regarding sales of capacity in RTOs/ISOs that do not have an RTO/ISO-administered capacity market. Comments on the *Horizontal Market Power Analysis Refinements NOPR* are due 45 days after publication in the *Federal Register*.[142]

- ***Order 849*: Pipeline Rates (RM18-11)**

Rehearing of *Order 849*[143] remains pending. As previously reported, in *Order 849*, the FERC adopted procedures through which the cost-based rates of natural gas pipelines are to be examined to determine which, if any, of those entities are collecting unjust and unreasonable rates in light of the 2017 Tax Law's reduction in the

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[138] The ADIT *NOPR* was published in the *Fed. Reg.* on Nov. 23, 2018 (Vol. 31, No. 226) pp. 59,331-59,343.

[139] *Implementation of Amended Section 203(a)(1)(B) of the Federal Power Act*, 165 FERC ¶ 61.091 (Nov. 15, 2018).

[140] The *Section 203(a)(1)(B) NOPR* was published in the *Fed. Reg.* on Nov. 29, 2018 (Vol. 31, No. 230) pp. 61,338-61,342.

[141] *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Trans. Org. and Indep. Sys. Op. Mkts.*, 165 FERC ¶ 61,091 (Dec. 20, 2018)

[142] The *Horizontal Market Power Analysis Refinements NOPR*, as of the date of this Report, has not yet been published in the *Fed. Reg*.

[143] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Fed. Income Tax Rate*, Order No. 849, 164 FERC ¶ 61,031 (July 18, 2018) ("*Order 849*").

corporate tax rate from 35% to 21% and the disallowance in the Tax Policy Statement (*see* PL17-1 below) of income tax allowances for MLP pipelines. With certain exceptions,[144] the procedures adopted are generally the same as the FERC proposed in its March 15, 2018 *Pipeline Rates NOPR*[145] and require interstate pipelines to (a) file a one-time report, FERC Form No. 501-G, that will provide financial information from the pipeline's 2017 FERC Form 2; and (b) voluntarily make a filing to address the changes to the pipeline's recovery of tax costs, or explain why no action is needed.[146] *Order 849* became effective September 13, 2018.[147]

Requests for rehearing of *Order 849* were filed by Enable Mississippi River Transmission and Enable Gas Transmission, Natural Gas Pipeline Company of America, and Process Gas Consumers Group and American Forest and Paper Association. On September 17, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending before the FERC.

- **DER Participation in RTO/ISOs (RM18-9)**

In *Order 841*[148] (*see* RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[149] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the April 10-11 technical conference in AD18-10,[150] were also to be filed in RM18-9. On June 26, over 50 parties submitted post-technical conference comments in this proceeding, including comments from ISO-NE, Calpine, Direct, Eversource, Icetec, NRG, Utility Services, EEI, EPRI, EPSA, NARUC, NRECA, and SEI. This matter is pending before the FERC.

- ***Order 845*: LGIA/LGIP Reforms (RM17-8)**

As previously reported, the FERC issued on April 19, 2018, its final rule,[151] *Order 845*, revising its *pro forma* Large Generator Interconnection Procedures ("LGIP") and *pro forma* LGIA to implement 10 specific

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[144] *Order 849* modifies the *Pipeline Rates NOPR's* proposed treatment of master limited partnership (MLP) pipelines and other pass-through entities in several respects, makes several changes to proposed FERC Form 501-G, and provides a guarantee that the FERC will not initiate a NGA section 5 rate investigation for a three-year moratorium period of an interstate pipeline that makes a limited NGA section 4 rate reduction filing that reduces its ROE to 12 percent or less.

[145] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Fed. Income Tax Rate*, 162 FERC ¶ 61,226 (Mar. 15, 2018) ("*Pipeline Rates NOPR*").

[146] Pipelines could respond in one of four ways: (1) A limited Natural Gas Act ("NGA") section 4 filing to reduce the pipeline's cost-based rates by the percentage reduction in its cost of service shown in its FERC Form No. 501-G; (2) A commitment to file either a prepackaged uncontested rate settlement or a general NGA section 4 rate case by December 31, 2018; (3) The filing of a statement explaining why no change in rates is required; or (4) The taking of no other action (other than the submittal of the one-time report). If the pipeline chooses options (3) or (4), the FERC will consider, after reviewing both the one-time report and the comments of others, whether to initiate a NGA Section 5 investigation.

[147] *Order 849* was published in the *Fed. Reg.* on July 30, 2018 (Vol. 83, No. 146) pp. 36,672-36,717.

[148] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), reh'g and/or *clarif. requested* ("*Order 841*").

[149] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[150] On April 10-11, 2018, the FERC held a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Technical conference materials are posted on the FERC's eLibrary. Interested persons were invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including on follow-up questions from FERC Staff related to the panels. Comments related to DER aggregation were to be filed in RM18-9; comments on the potential effects of DERs on the bulk power system, in AD18-10.

[151] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (Apr. 19, 2018) ("*Order 845*").

reforms designed to improve certainty for interconnection customers,[152] promote more informed interconnection decisions,[153] and enhance the interconnection process.[154] Based on the comments received on its December 15, 2016 NOPR[155] in this proceeding as well as other factors, *Order 845* declined to adopt four proposed reforms related to requiring periodic restudies, self-funding of network upgrades, the posting of congestion and curtailment information, and the modeling of electric storage resources. *Order 845* took no action on two additional issues raised in the NOPR -- cost caps for network upgrades and affected system coordination (which is being addressed in a separate proceeding). *Order 845* became effective July 23, 2018.

Requests for Rehearing. The Requests for rehearing and/or clarification of *Order 845* remain pending. Those requests were filed by APPA, Arizona Public Service Company, AWEA, California Utilities,[156] Duke, EEI, EON Climate & Renewables, MISO Transmission Owners, NYISO, SCE, and Southern Company Services. On June 6, ISO-NE answered AWEA's request for clarification. AWEA answered ISO-NE's answer on June 14. Answers to AWEA's answers were filed by Ameren on June 21 and the MISO Transmission Owners on June 29. On June 18, the FERC issued a tolling order affording it additional time to consider the requests for rehearing and/or clarification, which remain pending before the FERC.

Compliance Filing Deadline – Now 90 Days from the FERC's To-Be-Issued Order on Rehearing. *Order 845* initially required compliance filings to be filed on or before August 7, 2018. On May 17, the ISO/RTO Council ("IRC") requested a 70-day extension of time, to October 16, 2018, for the submission of compliance filings, which NEPOOL supported in comments submitted on May 23. On May 26, Southern Companies separately moved for a 90-day extension of time. On June 1, the FERC issued a notice extending the compliance date by 90 days for all, to November 5. EEI then asked for a further extension of time for transmission providers to submit their required compliance filings, 90 days following a FERC order on the pending rehearing requests. The American Wind Energy Association ("AWEA") opposed the EEI request. On October 3, the FERC issued a notice ("Oct 3 Extension Notice") granting EEI's request and indicating that compliance filings are now due within 90 days of the FERC's order addressing the pending requests for rehearing, which remain pending before the FERC. In light of the extension, ISO-NE has deferred final consideration of New England's proposed compliance changes pending the FERC's order on rehearing. On October 15, AWEA requested rehearing of the Oct 3 Extension Notice. On November 13, the FERC dismissed AWEA's request (i) because the Oct 3 Extension Notice is not procedurally subject to rehearing pursuant to Rule 713(a); (ii) the timing of compliance filings submissions is within the FERC's discretion; and (iii) the Oct 3 Extension Notice did not change or stay *Order 845*'s effective date (rather, it simply extends the date that compliance filings are due).

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[152] To improve certainty for interconnection customers, *Order 845* (1) removes the limitation that interconnection customers may only exercise the option to build a transmission provider's interconnection facilities and stand-alone network upgrades in instances when the transmission provider cannot meet the dates proposed by the interconnection customer; and (2) requires that transmission providers establish interconnection dispute resolution procedures that allow a disputing party to unilaterally seek non-binding dispute resolution.

[153] To promote more informed interconnection decisions, *Order 845* (1) requires transmission providers to outline and make public a method for determining contingent facilities; (2) requires transmission providers to list the specific study processes and assumptions for forming the network models used for interconnection studies; (3) revises the definition of "Generating Facility" to explicitly include electric storage resources; and (4) establishes reporting requirements for aggregate interconnection study performance.

[154] To enhance the interconnection process, *Order 845* (1) allows interconnection customers to request a level of interconnection service that is lower than their generating facility capacity; (2) requires transmission providers to allow for provisional interconnection agreements that provide for limited operation of a generating facility prior to completion of the full interconnection process; (3) requires transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection; and (4) requires transmission providers to set forth a procedure to allow transmission providers to assess and, if necessary, study an interconnection customer's technology changes without affecting the interconnection customer's queued position.

[155] *Reform of Generator Interconnection Procedures and Agreements*, 157 FERC ¶ 61,212 (Dec. 15, 2016) ("*LGIP/LGIA Reforms NOPR*"). The *LGIP/LGIA Reforms NOPR* was published in the *Fed. Reg.* on Jan. 13, 2017 (Vol. 82, No. 9) pp. 4,464-4,501.

[156] "California Utilities" are Pacific Gas and Elec. ("PG&E"), So. Cal. Edison ("SCE"), and San Diego Gas & Elec. ("SDG&E").

- ***Order 841*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

On February 15, the FERC issued *Order 841*, which requires each RTO/ISO to revise its tariff "to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets."[157] Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price. RTO/ISOs must file any necessary tariff changes on or before November 30, 2018 (270 days from *Order 841*'s publication in the Federal Register)[158] and implement those tariff provisions within one year of that compliance filing. New England's *Order 841* compliance filing changes will be considered by the Participants Committee at its November 2 meeting (Agenda Item #5). *Order 841* became effective June 4, 2018.

Order 841 did not adopt the *Storage NOPR's* proposed reforms related to DER aggregations. Instead, *Order 841* instituted a new rulemaking proceeding and technical conference (*see* RM18-9 above) to gather additional information to help the FERC determine what action to take with respect to DER aggregation. Requests for Clarification and/or Rehearing of *Order 841* were filed by CAISO, MISO, PJM, the AES Companies, AMP/APPA/NRECA, California Energy Storage Alliance, EEI, NARUC, PG&E, TAPS, and Xcel Energy Services. On April 13, 2018, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

Correcting Amendment. On November 16, the FERC issued a "correcting amendment" to restore regulatory text, adopted in *Orders 831/831-A*, that had been incorrectly replaced – rather than added to - in the regulatory text adopted in *Order 841*.[159] The text being restored was added as a new paragraph to 18 CFR § 35.28(g)(11).[160] Nothing in the *Correcting Amendment Order* was intended to alter any previous compliance requirements, effective dates established under *Orders 831/831-A* or *841*, nor any tariff changes previously accepted by the FERC in compliance with those orders. The *Correcting Amendment* became effective November 26, 2018.[161]

- **NOPR: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

The FERC's *Data Collection NOPR* remains pending. As previously reported, the FERC issued a July 21, 2016 NOPR, which superseded both its *Connected Entity NOPR* (RM15-23) and *Ownership NOPR* (RM16-3),

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[157] The participation model must: (1) ensure that a resource using the participation model is eligible to provide all capacity, energy and ancillary services that the resource is technically capable of providing in the markets; (2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price; (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and (4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.

[158] *Order 841* was published in the *Fed. Reg.* on Mar. 6, 2018 (Vol. 83, No. 44) pp. 9,580-9,633.

[159] *Offer Caps in Mkts. Operated by Regional Transmission Organizations and Indep. Sys. Operators, et al.*, 165 FERC ¶ 61,136 (Nov. 16, 2018) ("*Correcting Amendment Order*").

[160] (11) A resource's incremental energy offer must be capped at the higher of $1,000/MWh or that resource's cost-based incremental energy offer. For the purpose of calculating Locational Marginal Prices, Regional Transmission Organizations and Independent System Operators must cap cost-based incremental energy offers at $2,000/MWh. The actual or expected costs underlying a resource's cost-based incremental energy offer above $1,000/MWh must be verified before that offer can be used for purposes of calculating Locational Marginal Prices. If a resource submits an incremental energy offer above $1,000/MWh and the actual or expected costs underlying that offer cannot be verified before the market clearing process begins, that offer may not be used to calculate Locational Marginal Prices and the resource would be eligible for a make-whole payment if that resource is dispatched and the resource's actual costs are verified after-the-fact. A resource would also be eligible for a make-whole payment if it is dispatched and its verified cost-based incremental energy offer exceeds $2,000/MWh. All resources, regardless of type, are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh.

[161] The *Correcting Amendment* was published in the *Fed. Reg.* on Nov. 26, 2018 (Vol. 83, No. 227) p. 60,347.

proposing to collect certain data for analytics and surveillance purposes from market-based rate ("MBR") sellers and entities trading virtual products or holding FTRs and to change certain aspects of the substance and format of information submitted for MBR purposes.[162] The *Data Collection NOPR* presents substantial revisions from what the FERC proposed in the *Connected Entity NOPR*, and responds to the comments and concerns submitted by NEPOOL in that proceeding. Among other things, the changes proposed in the *Data NOPR* include: (i) a different set of filers; (ii) a reworked and substantially narrowed definition of Connected Entity; and (iii) a different submission process. With respect to the MBR program, the proposals include: (i) adopting certain changes to reduce and clarify the scope of ownership information that MBR sellers must provide; (ii) reducing the information required in asset appendices; and (iii) collecting currently-required MBR information and certain new information in a consolidated and streamlined manner. The FERC also proposes to eliminate MBR sellers' corporate organizational chart submission requirement adopted in *Order 816*. Comments on the *Data Collection NOPR* were due on or before September 19, 2016[163] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

- **NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)**

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[164] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[165] comments were due on or before July 25, 2018. Literally thousands of individual and mass mailed comments were filed. This matter remains pending before the FERC.

- **NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)**

On March 15, 2018, the FERC found that an impermissible double recovery results from granting a Master Limited Partnership pipeline ("MLP") both an income tax allowance and an ROE pursuant to the DCF methodology.[166] Accordingly, the FERC issued a revised policy statement that it will no longer permit an MLP to recover an income tax allowance in its cost of service. The finding follows an NOI[167] that sought comments regarding how to address any double recovery resulting from the FERC's income tax allowance and ROE policies in light of the D.C. Circuit's *United Airlines*[168] holding. The FERC indicated that it will address the application of *United Airlines* to non-MLP partnership forms as those issues arise in subsequent proceedings. The revised policy statement took effect on March 21, 2018. Requests for rehearing of the March 15 order were filed by the Dominion, Enable Mississippi River Transmission and Enable Gas Transmission, Enbridge and Spectra Energy Partners, EQT Midstream Partners, Kinder Morgan, Master Limited Partnership Association ("MLPA"), NGAA, SPPP,

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[162] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

[163] The *Data Collection NOPR* was published in the *Fed. Reg.* on Aug. 4, 2016 (Vol. 81, No. 150) pp. 51,726-51,772.

[164] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

[165] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

[166] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (Mar. 15, 2018), *order on reh'g*, 164 FERC ¶ 61,030 (July 18, 2018).

[167] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs,* 157 FERC ¶ 61,210 (Dec. 15, 2016).

[168] *United Airlines Inc. v. FERC*, 827 F.3d 122, 134, 136 (D.C. Cir. 2016) ("*United Airlines*") (holding that the FERC failed to demonstrate that there is no double recovery of taxes for a partnership pipeline as a result of the income tax allowance and ROE determined pursuant to the DCF methodology, and remanding the decisions to the FERC to develop a mechanism "for which the Commission can demonstrate that there is no double recovery" of partnership income tax costs). *Id.* at 137.

LP, Oil Pipe Lines, Plains Pipeline, Tallgrass Pipelines, and TransCanada. On July 18, the FERC issued its order on rehearing,[169] dismissing the requests for rehearing and clarification and providing guidance regarding the treatment of Accumulated Deferred Income Taxes ("ADIT") where the income tax allowance is eliminated from cost-of-service rates under the FERC's post-*United Airlines* policy. On August 17, the MLPA requested clarification and/or reconsideration of the *Order on Rehearing*, which is pending before the FERC. On September 4, R. Gordon Gooch answered MLPA's August 17 pleading. Petitions for review were filed in the D.C. Circuit by Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC, as well as by SFPP, L.P., in September 2018. Those appeals are pending in Case Nos. 18-1252, et al. in the D.C. Circuit.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[170] affirming Judge Cintron's August 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations ("Anti-Manipulation Rule") and NGA Section 4A.[171] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[172] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[173] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on

[169] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 164 FERC ¶ 61,030 (July 18, 2018) ("*Order on Rehearing*").

[170] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[171] *BP America Inc.,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[172] *BP Penalties Order* at P 3.

[173] *BP America Inc.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

September 12, 2016, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[174]

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[175] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[176]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

- **Staff Notices of Alleged Violations**

Rover. On July 13, 2017, the FERC issued a notice that Staff has preliminarily determined that, between February 2015 and September 2016, Rover Pipeline, LLC and Energy Transfer Partners, L.P. (collectively, "Rover") violated Section 7 of the Natural Gas Act by failing to fully and forthrightly disclose all relevant information to the FERC in Rover's application for a Certificate of Public Convenience and Necessity and attendant filings in Docket No. CP15-93. Staff alleges that Rover falsely promised it would avoid adverse effects to a historic resource that it was simultaneously working to purchase and destroy, and subsequently made several misstatements in its docketed responses to FERC questions about why it had purchased and demolished the resource.

Recall that Notices of Alleged Violations ("NoVs") are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing

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[174] *BP America Inc.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*")

[175] *Total Gas & Power North America, Inc.,* 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[176] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

Staff's conclusions regarding the subject's conduct.[177] NoVs are designed to increase the transparency of Staff's nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Atlantic Bridge Project (CP16-9)***
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
    - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
    - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.
    - Certificate of public convenience and necessity granted Jan. 25, 2017.[178]
    - Certain facilities,[179] providing 40,000 out of the project's total capacity of 132,705 dekatherms per day of incremental firm transportation service, placed into service on November 1, 2017.[180] Remaining Project capacity will be available when the remaining Project facilities are placed into service following Director of OEP authorization.
    - Algonquin files notice that construction of Salem Pike, Needham, Pine Hills and Plymouth meter and regulating stations began on April 2, 2018. Detailed information regarding construction activities can be found in the weekly construction reports filed in this docket.
    - On February 16, 2018, Algonquin filed with the DC Circuit Court of Appeals, pursuant to NGA Section 19(d)(2), a petition for review of the MA DEP's failure to issue, condition, or deny a minor-source air permit for Algonquin's proposed natural gas compressor station in the Town of Weymouth, MA by the July 31, 2016 deadline established by the FERC. Algonquin seeks an order establishing a deadline for the MA DEP to issue, condition, or deny the permit.
    - On May 31, the DC Circuit issued a *per curiam* order that holds this case in abeyance pending further order of the court.[181] The court based its order on the parties' representation that they have agreed on a schedule by which to resolve their dispute. The parties were directed to file status reports at 90-day intervals and to file motions to govern future proceedings within 30 days of respondents' final decision to issue, condition, or deny petitioner's permit application.

[177] *See Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh'g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

[178] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *order denying stay*, 160 FERC ¶ 61,015 (2017), *reh'g denied,* 161 FERC ¶ 61,255 (Dec. 13, 2017) ("*Atlantic Bridge Project Order*").

[179] The following facilities placed into service: Southeast Discharge Take-up and Relay (Fairfield County, CT); Modified Oxford Compressor Station (New Haven County, CT); Modified Chaplin Compressor Station (Windham County, CT); Modified Danbury (CT) Meter Station; and Modified Stony Point Compressor Station (Rockland County, NY).

[180] *Algonquin Gas Trans., LLC*, 158 FERC ¶ 61,061 (Oct. 27, 2017).

[181] *Algonquin Gas Trans. v. Mass. Dept. of Envtl. Protection*, Case No. 18-1045, DC Cir. (May 31, 2018).

    - The first status report was filed on August 24, and indicated that the case should continue to be held in abeyance. A second report was filed November 21. The next status report will be due in late February, 2019.
    - On December 26, 2018, the FERC granted Algonquin a two-year extension of time, to January 25, 2021, to complete the Project.[182] In requesting the extension, Algonquin attributed the need for additional time to permitting delays for the Weymouth Compressor Station and ongoing construction of the Horizontal Directional Drill of the Taconic Parkway in New York.

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
    - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
    - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
    - New 122-mile interstate pipeline.
    - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
    - Final EIS completed on Oct 24, 2014.
    - Certificates of public convenience and necessity granted Dec 2, 2014.
        - By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.
        - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).
    - On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.
        - On August 18, 2017, the 2nd Circuit denied Constitution's petition for review of the NY DEC decision, concluding that (1) the court lacked jurisdiction over the Constitution's claims to the extent that they challenged the timeliness of the decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.
        - Constitution filed a petition for a writ of certiorari of the 2nd Circuit's decision at the United States Supreme Court in January 2018 alleging, among other things, that the State's denial of the Clean Water Act permit exceeded the state's authority, and interfered with FERC's exclusive jurisdiction. On April 30, 2018, the Supreme Court denied Constitution's petition, thereby letting stand the 2nd Circuit's ruling.
    - On October 11, 2017, Constitution filed with the FERC a petition for declaratory order ("Petition") requesting that the FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time." (CP18-5)
        - On January 11, 2018, the FERC denied Constitution's Petition.[183] Although noting that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions, the FERC did not conclude that the practice violates the letter of the statute, found factually that Constitution gave

[182] *Algonquin Gas Trans., LLC*, Docket No. CP16-9 (Dec. 26, 2018) (unpublished letter order). Absent the extension, and pursuant to the Jan. 25, 2017 Certificate Order, the Project would otherwise have had to have been completed by Jan. 25, 2019.

[183] *Constitution Pipeline Co.*, 162 FERC ¶ 61,014 (Jan. 11, 2018), *reh'g requested*.

the NY DEC new deadlines, and found that the record did not show that the NY DEC in any instance failed to act on Constitution's application for more than the outer time limit of one year.[184]

  - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. FERC denied Constitution's request for rehearing of the January 2018 order.[185] On September 14, 2018, Constitution filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit.[186]

- On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
  - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order. The NY AG sought rehearing, and the Commission denied rehearing on November 22, 2016, noting again that the NY AG's complaint was still procedurally deficient.
- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown.
- On June 25, 2018, Constitution requested a further 2-year extension of the deadline to complete construction of its project, given the delays caused by the on-going fight over the water quality certification from the NYSDEC. Iroquois made a similar request on August 1, 2018. Constitution's request was opposed by several parties and Constitution answered some of the opposition pleadings. The FERC granted the requested two-year extension of time on November 5, 2018.[187]
- Rehearing of the November 5, 2018 order was requested by Halleran Landowners and a group of intervenors comprised of Catskill Mountainkeeper; Clean Air Council; Delaware-Otsego Audubon Society; Delaware Riverkeeper Network; Riverkeeper, Inc.; and Sierra Club ("Intervenors"). Constitution answered the requests for rehearing on December 21. The FERC issued a tolling order on December 21, affording it additional time to consider the requests for rehearing. This matter is pending before the FERC.

- **Non-New England Pipeline Proceedings**
  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:
  - **Northern Access Project (CP15-115)**
    - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On September 12, 2018 the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remains pending.

[184] *Id.* at P 23.

[185] *Constitution Pipeline Co., LLC*, 164 FERC ¶ 61,029 (2018) (September 2018 Waiver Rehearing Order).

[186] Constitution, Petition for Review in U.S. Court of Appeals for the D.C. Circuit, Docket No. CP18-5-000 (filed Sept. 14, 2018).

[187] *Constitution Pipeline Co.*, 165 FERC ¶ 61,081 (Nov. 5, 2018), *reh'g requested*.

- On August 6, the FERC dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[188] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[189] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
- As previously reported, the FERC issued an order, on Feb. 3, 2017, authorizing the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project").[190] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[191] Oral argument was held on November 16, 2017. The Court's decision is pending, and it remains to be seen how the Court will factor in the FERC's waiver determination in the *Northern Access Rehearing & Waiver Determination Order*.
- On November 26, 2018, the Applicants filed a request at FERC for a 3- year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request remains pending.

XIV. State Proceedings & Federal Legislative Proceedings

- **Connecticut Zero-Carbon Resource Selections**

On December 28, 2018, Connecticut announced that, pursuant to Public Act 17-3,[192] it had selected two nuclear power bids,[193] along with nine solar project bids (two of which were paired with energy storage)[194] and

[188] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*").

[189] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[190] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), reh'g denied 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[191] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[192] Public Act 17-3 required Connecticut to conduct an appraisal of nuclear power-generating facilities and solicit bids for zero-carbon electricity-generating resources.

[193] One bid was a 10-year bid from Millstone for roughly 50% of its output; the other, from Seabrook, for 1.9 million MWh beginning in 2022.

one offshore wind project (200 MW from Revolution Wind). Connecticut stated that over 100 renewable energy projects bid into this RFP, including numerous solar projects, land-based and offshore wind, and existing hydropower. Nearly all of Public Act 17-3's procurement authority was utilized. Assuming all of the selected projects successfully enter into contracts and are approved by CT PURA, Connecticut "will retain approximately 17% percent of total load for additional renewable procurement authority in future RFPs".

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCM Resource Retirement Reforms (17-1275)**
  Underlying FERC Proceedings: ER16-551[195]
  Petitioner: Exelon

On December 28, 2018, a mere five weeks after oral argument (held November 19, 2018), the DC Circuit Court of Appeals issued a decision remanding the record in this case to the FERC for a clarification of "what [the FERC] really means" in the context of its orders on the FCM Resource Retirement Reforms. Specifically, the FERC was directed to issue an order, not later than February 1, 2019, clarifying its position on the proper reading, process and legal standards associated with the Tariff changes that have ISO-NE file mitigated retirement bids for FERC review under § 205 of the FPA. In its appeal, Exelon continued its objection to the replacement of its De-List Bid for an IMM-mitigated De-List Bid in that FERC review under FPA § 205, which Exelon asserted "trample[s] on its § 205 rights". Writing for the Court, Senior Justice Williams observed that FERC counsel "seemed to contend [at oral argument] that the correct meaning of the challenged order was in conformity with the meaning that [Exelon] ascribed to the controlling statue. Because the parties' dispute may be illusory, we remand the record to the [FERC] to sort out what it really means." The Court emphasized that the decision *did not* resolve arguments briefed as to "whether a supplier's retirement bids are "rates" under [Section § 205 of the FPA], and therefore entitled to assessment by FERC under the "just and reasonable" criterion ... nor … whether Exelon can rightly be said to have consented to the new rules by virtue of having participated in the 2006 Forward Capacity Market Settlement."

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[196]
  Appellants: New England Transmission Owners

Also on December 28, the DC Circuit granted *per curiam* the October 3, 2018 motion to dismiss this case, "without prejudice to submission of another petition for review at the conclusion of the agency proceedings." As previously reported, the TOs filed a petition for review of the FERC's orders in the Base ROE II and III proceedings on July 13, 2015 ("Petition") and the Court a little more than one month later granted the TOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days (13 of which were filed). On October 3,

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[194] The selected solar projects include three in Connecticut (Montville Energy Center, Black Hill Point Energy Center (paired with energy storage) and Gravel Pit Solar), two in New Hampshire (Tilton Heights Energy Center and Steel Mill Solar) and four in Maine (Old Mill Solar, Keay Brook Energy Center, and GRE-3-ME-SACO (also paired with energy storage), and Kennebec PV Partners.

[195] *ISO New England Inc.,* 155 FERC ¶ 61,029 (Apr. 12, 2016) ("*Resource Retirement Reforms Order*"), *reh'g and clarif. denied*, 161 FERC ¶ 61,115 (Oct. 30, 2017) ("*FCM Resource Retirement Reforms Orders*").

[196] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

2018, Intervenors for Respondent[197] moved jointly to dismiss the Petition because the challenged orders were not final orders for purposes of appeal under the FPA. On October 15, the TOs filed a response in which they indicated that they do not oppose the Intervenors' request (presuming the Court determined that FERC's interpretation of the statutory constraints created by the 15-month refund period in its Order Denying Rehearing is not a final agency order under the FPA). Absent further challenge, this proceeding will be concluded.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[198] EL15-23[199]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[200] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course.

Other Federal Court Activity of Interest

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[201]
  Petitioners: NEPGA, Exelon

Pending before the DC Circuit is an appeal of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[202] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). In separate but related proceedings, the New Jersey Attorney General and several conservation groups have filed actions in federal district court in New Jersey seeking to limit PennEast's use of its NGA eminent domain authority.

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[197] "Intervenors for Respondent" are Belmont, Braintree, Concord, CT PURA, Georgetown, Groveland, Hingham, Littleton, MMWEC, Merrimac, Middleton, National Consumer Law Center; NHEC, Reading, Rowley, Taunton, and Wellesley.

[198] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[199] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[200] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

[201] *PennEa*st *Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[202] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

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