NEPOOL Participants Committee Report

December 2015

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 was $245M over the period, down $130M from October 2015 and down $254M from November 2014
  - November natural gas prices over the period were 7.4% lower than October 2015 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 16.5% lower than October 2015 averages
  - Average November 2015 natural gas prices and RT Hub LMPs over the period were down 45% and 39%, respectively, from November 2014 averages
- Average DA cleared physical energy in the peak hours as percent of forecasted load was 98.3% during November, down from 100% during October

All data through November 24 (RT NCPC through November 22) except where 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

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November NCPC payments totaled $10.0M, down $711K from October and up $2.9M from November 2014
    - November NCPC payments attributable to the RT evaluation of non fast-start unit that cleared DA totaled $5.0M
  - First Contingency payments totaled $4.6M, down $574K from October
    - $4.3M paid to internal resources, up $706K from October
      - $813K charged to DALO, $3.5M to RT Deviations
    - $311K paid to resources at external locations, down $1.3M from October
      - $214K charged to DALO at external locations, $97K to RT Deviations
  - Second Contingency payments totaled $4.1M, down $1.0M from the October total of $5.1M
  - Voltage payments were $1.3M, up $904K from October
  - NCPC payments over the period as percent of Energy Market value were 4.1%

Highlights, cont.

- ISO Board of Directors approved the 2015 Regional System Plan on November 5
- Changes to the RSP process are being proposed such that the next RSP would be issued in 2017
- FERC filings made on November 10 regarding qualification of resources and regional/zonal requirements for the tenth Forward Capacity Auction
- 2015 economic planning studies are underway. All three study requests focus on the impacts of wind integration. Study updates to be presented at the December 14 Planning Advisory Committee (PAC) meeting
- Technical session on the generation queue and overlapping impact test analysis to be presented at the December 15 PAC meeting
- Results of the reliability review for the Pilgrim Non-Price Retirement Request to be presented at the December 16 Reliability Committee meeting

Forward Capacity Market (FCM) Highlights

- CCP #4 (2013-2014)
  - Less than 4 MW of resources are non-commercial at this time
- CCP #5 (2014-2015)
  - Less than 17 MW of resources are non-commercial at this time
- CCP #6 (2015-2016)
  - Less than 123 MW of resources are non-commercial at this time
- CCP #7 (2016-2017)
  - Updated Installed Capacity Requirement (ICR) will be filed with FERC no later than December 1, 2015
  - Third bilateral transaction window will be December 1-7, 2015
  - Third reconfiguration auction will be March 1-3, 2016
    - Based on results of the second reconfiguration auction, entering the CCP, the Transmission Security Analysis margin for NEMA/Boston will be about 356 MW short. ISO Operations is working with the Local Control Centers to address this deficiency.

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #8 (2017-2018)
  - Updated ICR will be filed with FERC no later than December 1, 2015
  - Second bilateral transaction window will be May 2-6, 2016
  - Second reconfiguration auction will be August 1-3, 2016
- CCP #9 (2018-2019)
  - Updated ICR will be filed with FERC no later than December 1, 2015
  - First bilateral transaction window will be April 1-7, 2016
  - First reconfiguration auction will be June 1-3, 2016

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #10 (2019-2020)
  - Non-price retirement window closed on October 12. A total of approximately 728 MW of retirements were received including a full retirement request of 677 MW from Pilgrim
    - Only Pilgrim is yet to be reviewed for reliability. Results to be presented to the RC at their December 16 meeting.
  - Approximately 62 MW of generation and demand resources will receive the Renewable Technology Exemption
  - Both the Qualification and Requirements (ICR and Local Sourcing Requirement) FERC Filings were made on November 10
  - Forward Capacity Auction to commence on February 8, 2016
- CCP #11 (2021-2022)
  - Preparations are underway for existing and new resource qualification training which will incorporate timeline changes and new rules (associated with the Retirement Reforms Project and subject to FERC approval)

FERC Order 1000

- ISO, PJM, and NYISO are developing joint interregional planning procedures
- IPSAC meeting has been scheduled for December 14 to discuss interregional needs and other issues

Highlights, cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margin is projected for week beginning January 9, 2016

2015/16 Winter Reliability Program (Unchanged from last month; Updated data will be published during the week of December 7)

- **Oil Program**
  - By the Oct. 1 deadline, 81 Units submitted intent to provide 4.464 million barrels
  - Based upon assets participating in program total eligible oil is anticipated to be 2.965 million barrels
  - Total oil program cost exposure is anticipated to be $38.25M (@$12.90/barrel)
- **LNG Program**
  - By the Oct. 1 deadline, 8 Units submitted intent to provide at least 1.42 million MMBTU Based upon asset submissions, and capping submissions to permissible asset thresholds total eligible LNG is 1.278 million MMBTU
  - Total LNG program cost exposure is anticipated to be $2.75M (@$2.15/MMBTU)
- **DR Program**
  - By the Oct. 1 deadline, 7 Assets submitted (6 accepted by ISO) an intent to provide at least 26.5 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $132K

Winter Reliability Program Update

- Dual Fuel Commissioning Program
  - Participation:
    - 6 Units submitted intent to commission Dual Fuel Capability
      - 4 units for 2014/15 (1,039 MW)
      - 2 units for 2015/16 (735 MW)
    - Total additional winter seasonal claimed capability represented: 1,774 MW
  - Dual Fuel Commissioning Activity and related NCPC:
    - Units commissioned (as of Nov. 30): 5 successful, 1 outstanding
    - Total NCPC Commissioning Cap: $5.7M
      - 2014/15: $3.56M
      - 2015/16: $2.19M
    - NCPC incurred (as of Nov. 22): $1.1M*
    - Remaining Commissioning Cap for 2015/16: $0.8M

***Subject to increase as NCPC data over the last 8 days of November is finalized**

CTS Background

- CTS will improve the market efficiency of external transactions between the NY and NE regions
- CTS Goals and Benefits:
  - **Reduces Latency**
    - Tie scheduling interval will be every 15 minutes
    - Shared clearing process will finalize a schedule approximately 20 minutes ahead of the interval start
  - **Minimize non-economic clearing**
    - ISOs will use a shared clearing process using forecasted price and system data from both ISOs
    - Participants provide a single transaction at a minimum price spread they are willing to accept
- Note that under certain reserve deficiency conditions (for example; shortage of ten minute operating reserves), each Control Area will take the necessary actions to protect reliability

CTS Project Status

- Generator Control Application (GCA), which features a look-ahead commitment model, was implemented on November 9
  - This application was a pre-requisite for CTS implementation
- CTS will be implemented effective December 15th
- FERC notice of December 15th effective date was filed on December 2nd
- Extensive joint testing with NYISO successfully completed
- Access to NYISO's Joint Energy Scheduling System (JESS) for bidding opened to ISO-NE stakeholders on December 2nd
- ISO will monitor the performance of the CTS function and report its observations to stakeholders in Q1 2016

NERC GRIDEX III

- On November 18 and 19, ISO New England and many New England Utilities participated in GridEx III, a North American wide electrical grid exercise that was designed for electric utilities to exercise their response to simulated coordinated cyber and physical security threats and incidents
- GridEx III was purely an exercise and the simulated scenarios did not impact actual bulk power system or wholesale market operations.
- ISO New England conducted the entire exercise using the Training Simulator at its Backup Control Center

NERC GRIDEX III, cont.

- ISO New England and many New England Utilities were full participants in GridEx III
  - As full participants, exercise scenarios were developed specifically for New England's bulk power system and required a resource-intensive response by ISO New England and the New England Utilities that participated
- The GridEx exercise simulated physical and cyber-attacks on a number of bulk electric system facilities across New England and played out a number of aggressive and impactful scenarios disrupting both the flow of data and physical damage to the New England power grid
- It provided an excellent opportunity for New England to test its ability to respond to attacks on the grid

NERC GRIDEX III, cont.

- We are in the process of evaluating the exercise response across the ISO, New England Utilities, NPCC and NERC
- ISO and participating utilities followed established operating and security procedures to maintain reliable grid operations during the two full days of simulated grid attacks
- As we evaluate our (and regional) response, we expect to find many opportunities for improvement, which will further strengthen our ability to respond to these events in the future
- We expect that NERC will publish a full report on this exercise in Q2 2016

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature –Above Normal (+3.1°) Max: 76.0°, Min: 28.0° Precipitation 2.07” – Below Normal Normal 3.98”	Hartford	Temperature – Above Normal (+3.7°) Max: 76.0°, Min: 19.0° Precipitation 2.20” - Below Normal Normal 4.06”

Peak Load:	17,410 MW	November 23, 2015	18:00 (ending)

M/LCC 2: 11/2/2015	Transmission Constraints	Declared: 12:15 Cancelled: 21:00
OP 4 : None		
NPCC Simultaneous Activation of Reserve Events:		
Date	Area	MW
11/12/2015	PJM	1,280
11/13/2015	IESO	850

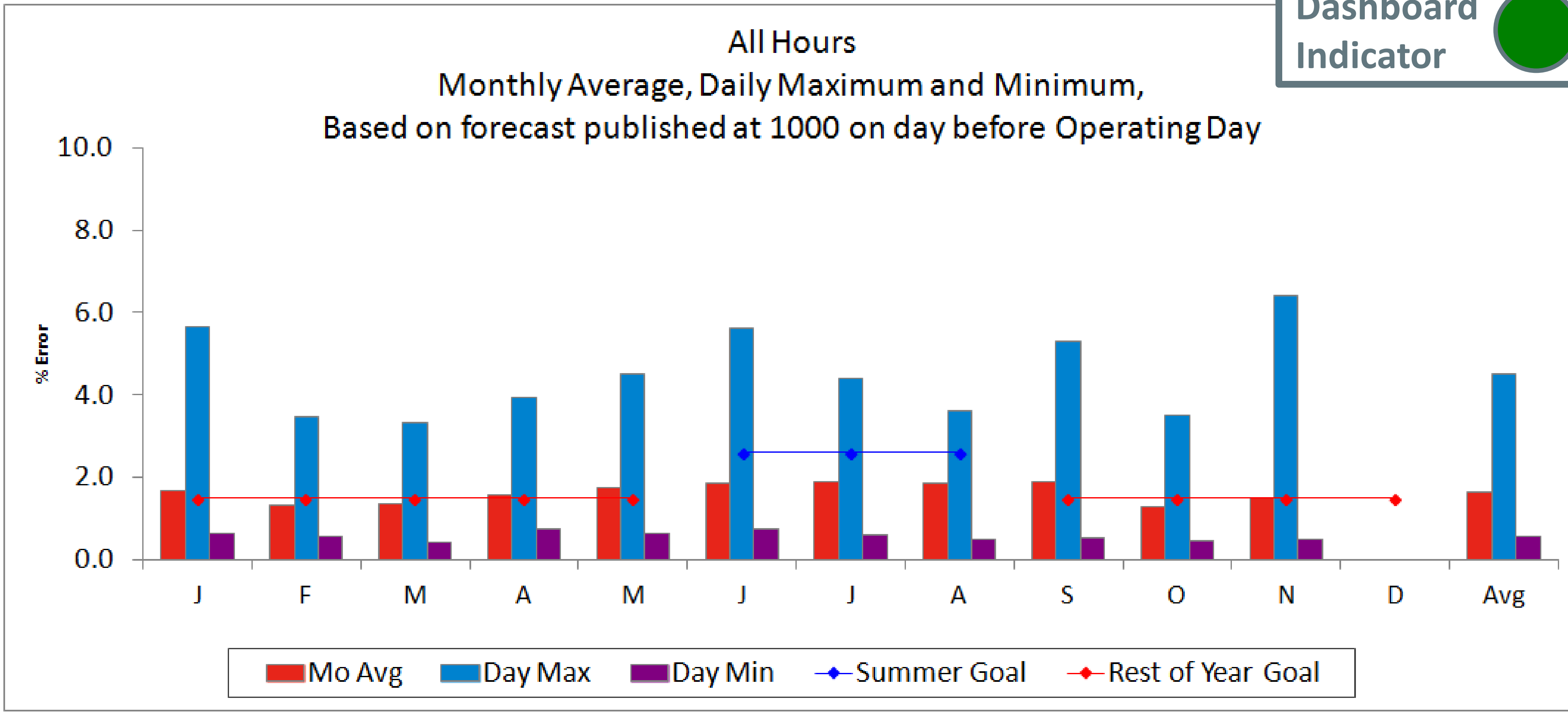
System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	11/22/15, 23:00 – 11/23/15 06:00	No Actions Necessary

2015 System Operations - Load Forecast Accuracy

Dashboard Indicator

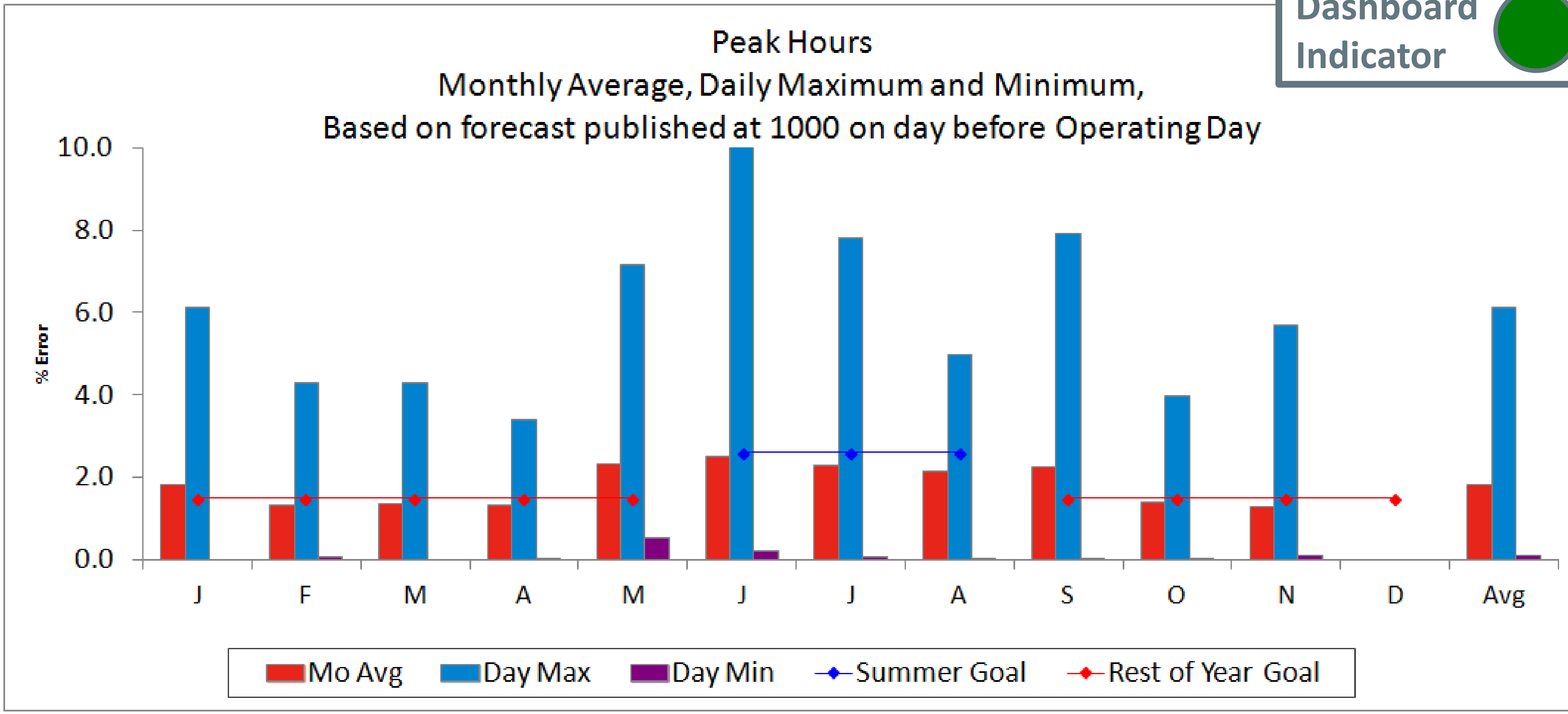


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.70	1.31	1.37	1.59	1.76	1.88	1.91	1.88	1.90	1.30	1.49		1.65
Day Max	5.66	3.47	3.35	3.93	4.53	5.64	4.41	3.63	5.31	3.51	6.40		4.53
Day Min	0.65	0.57	0.44	0.74	0.63	0.75	0.60	0.51	0.53	0.47	0.50		0.58
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.70	1.31	1.37	1.59	1.76				1.90	1.30	1.49		1.55
Summer Actual						1.88	1.91	1.88					1.89

Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2015 System Operations - Load Forecast Accuracy cont.

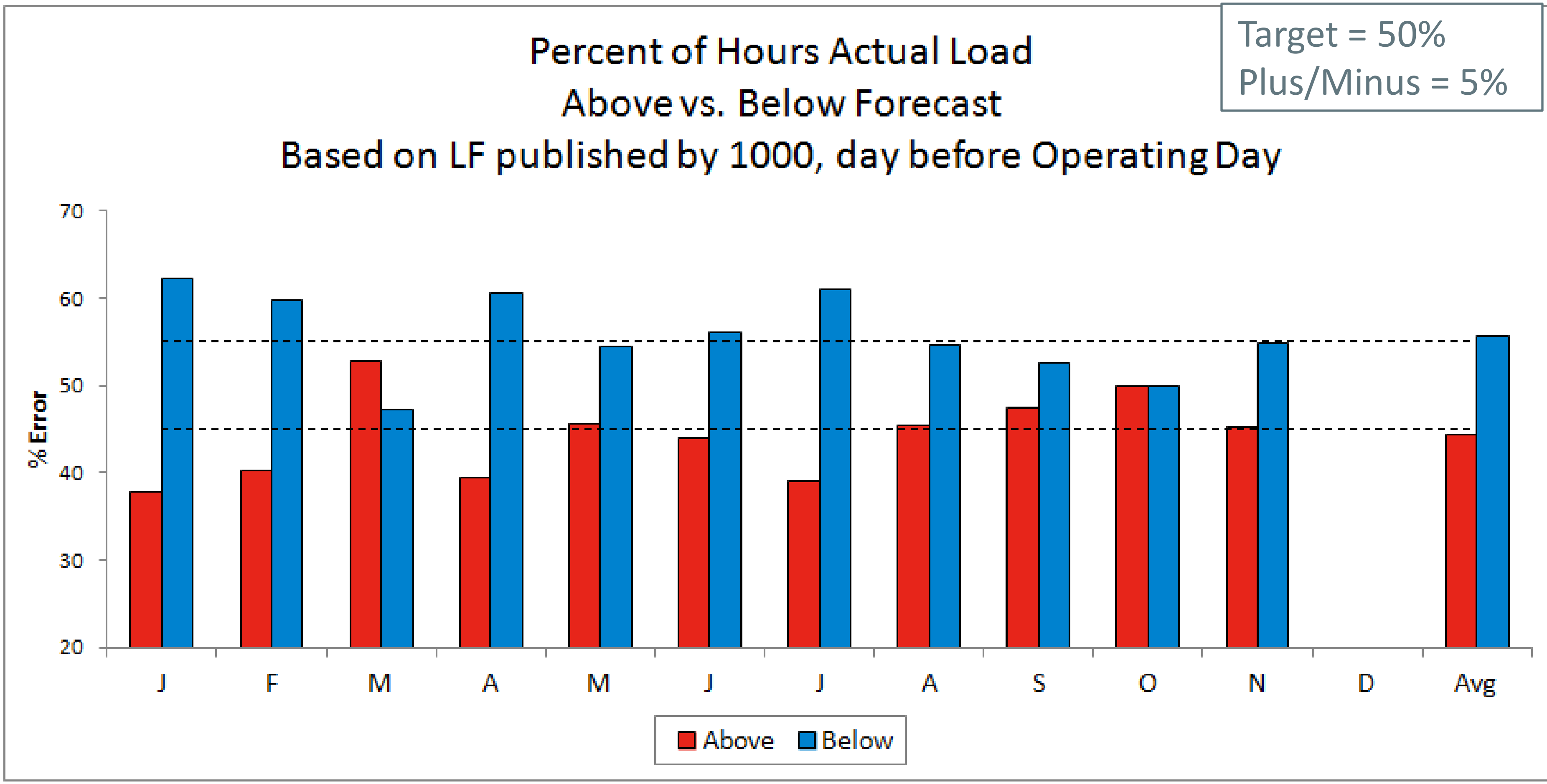
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.84	1.32	1.36	1.32	2.34	2.52	2.28	2.16	2.26	1.38	1.30		1.83
Day Max	6.13	4.31	4.31	3.40	7.15	11.57	7.80	4.97	7.91	3.96	5.68		6.11
Day Min	0.00	0.08	0.00	0.03	0.53	0.22	0.06	0.01	0.03	0.03	0.09		0.10
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.84	1.32	1.36	1.32	2.34				2.26	1.38	1.30		1.64
Summer Actual						2.52	2.28	2.16					2.32

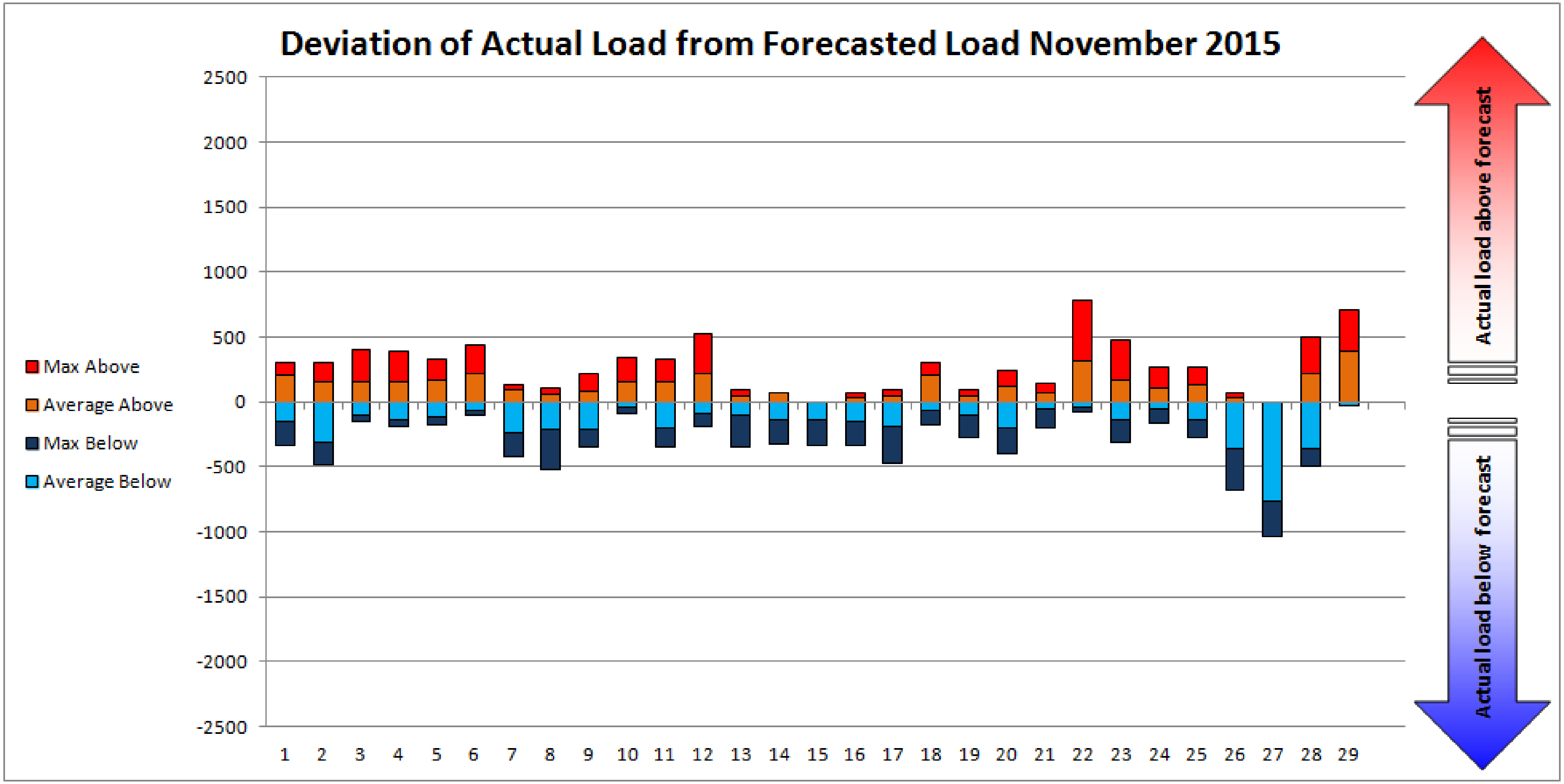
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2015 System Operations - Load Forecast Accuracy cont.

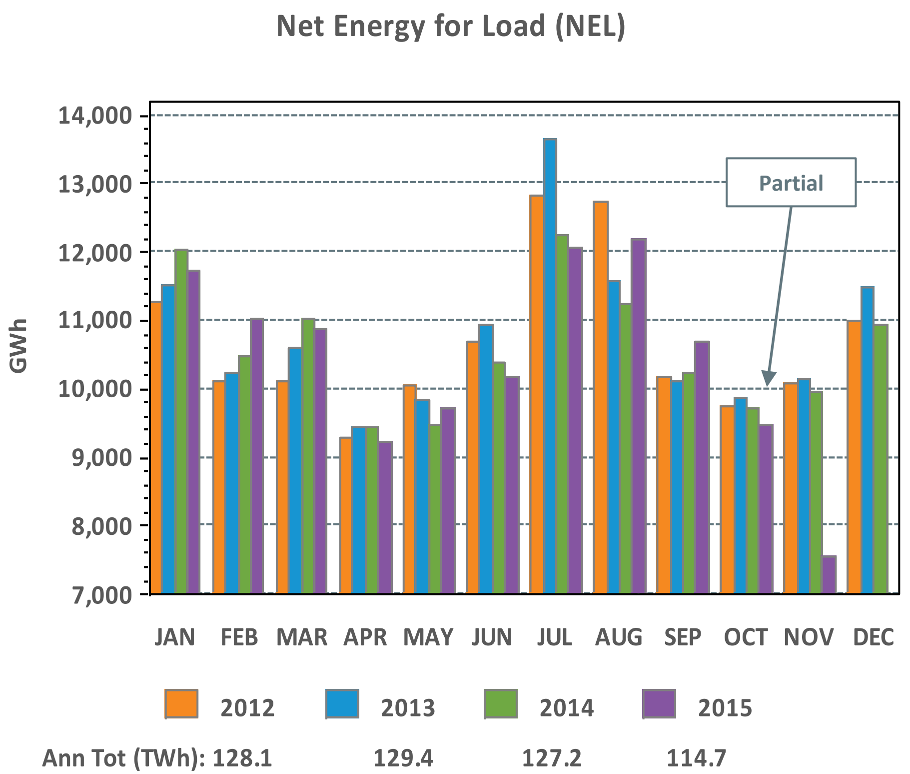


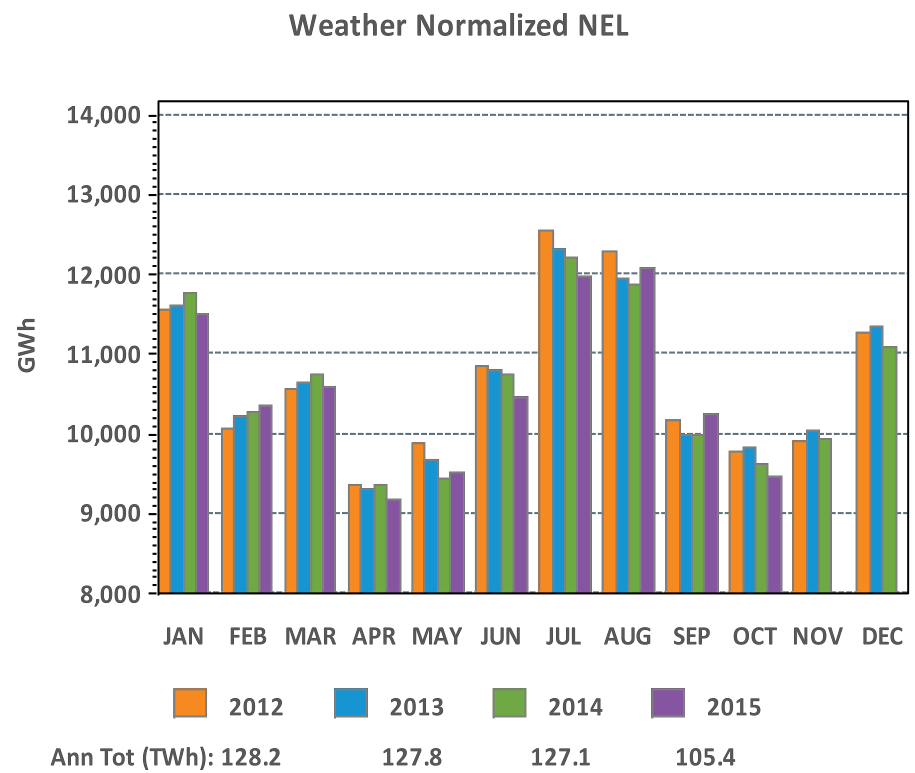
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	37.8	40.2	52.8	39.4	45.6	43.9	39	45.4	47.5	50	45.2		44
Below %	62.2	59.8	47.2	60.6	54.4	56.1	61	54.6	52.5	50	54.8		56
Avg Above	143.4	147	169.7	130.2	215.1	158.9	185.3	201	230.6	127.4	128.1		167
Avg Below	-235.8	-208.2	-146.1	-179.5	-157.4	-212.7	-247.3	-243.8	-192.7	-120.0	-163.7		-191
Avg All	-81	-57	17	-49	34	-55	-70	-39	41	4	-38		-26

2015 System Operations - Load Forecast Accuracy cont.



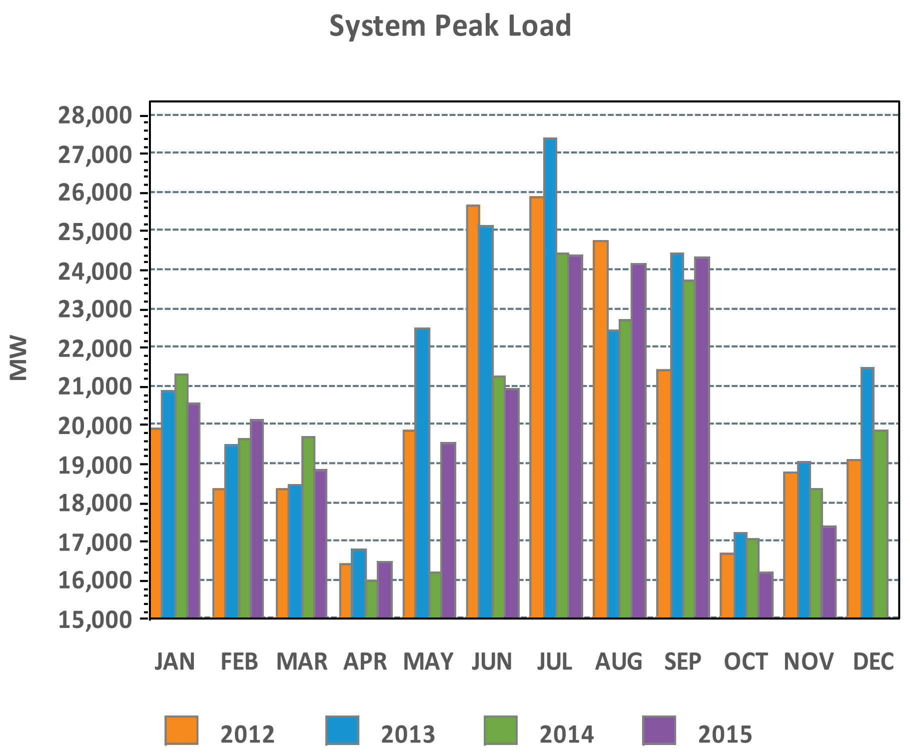
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

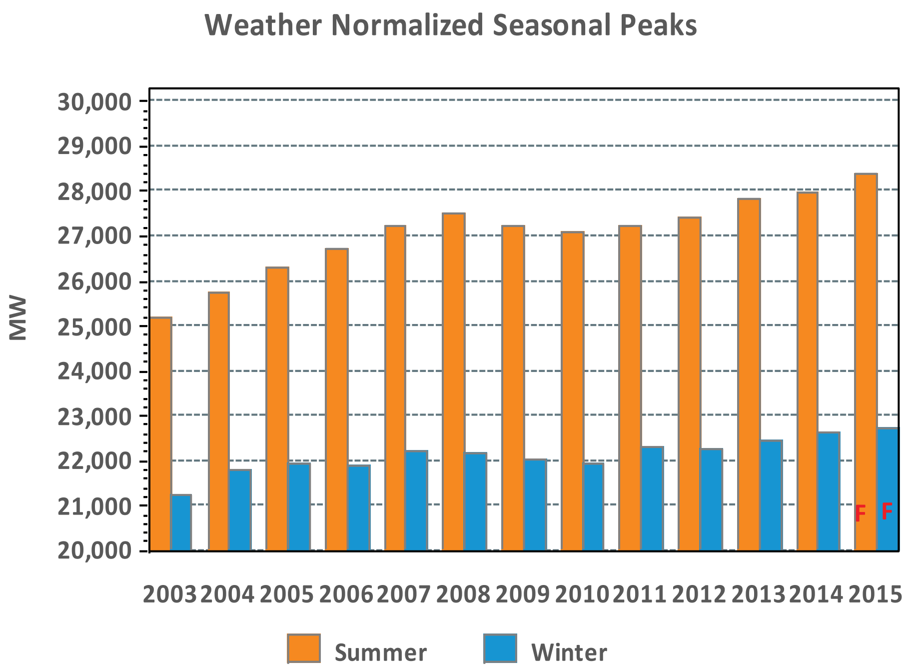




NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



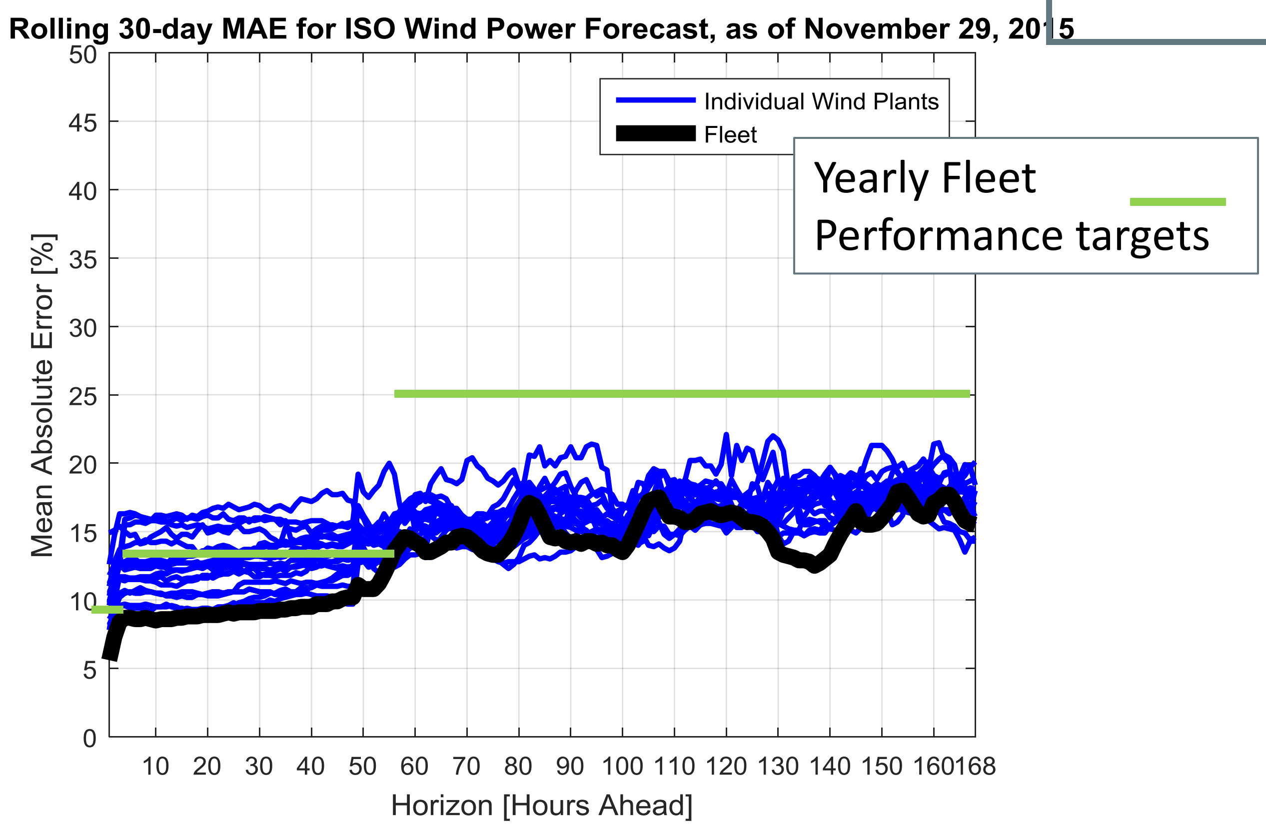


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents “gross forecast”

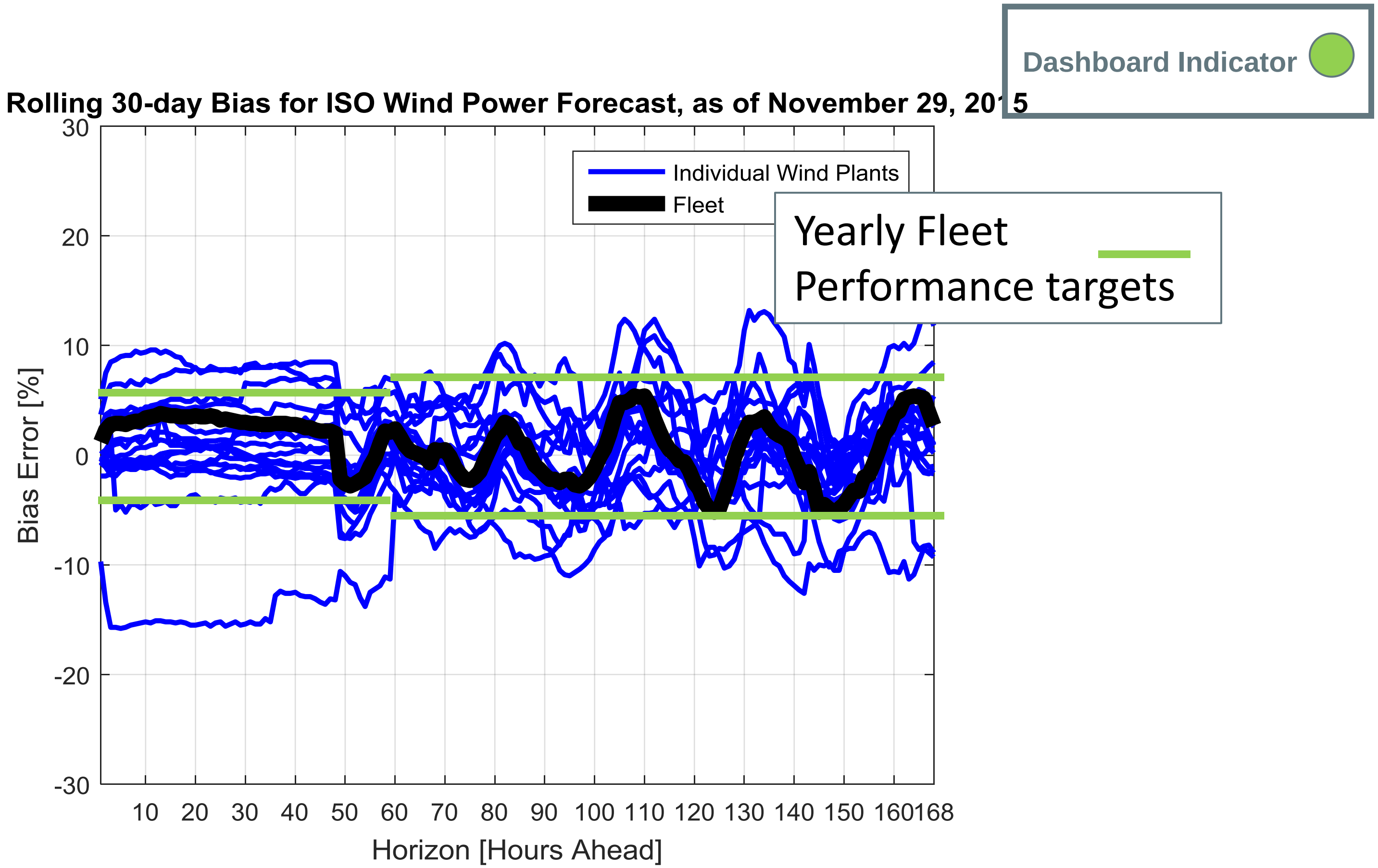
Wind Power Forecast Error Statistics: MAE

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/GH forecast is very good compared to industry standards, and MAE continues to be well within the yearly performance targets specified in the forecast RFP.

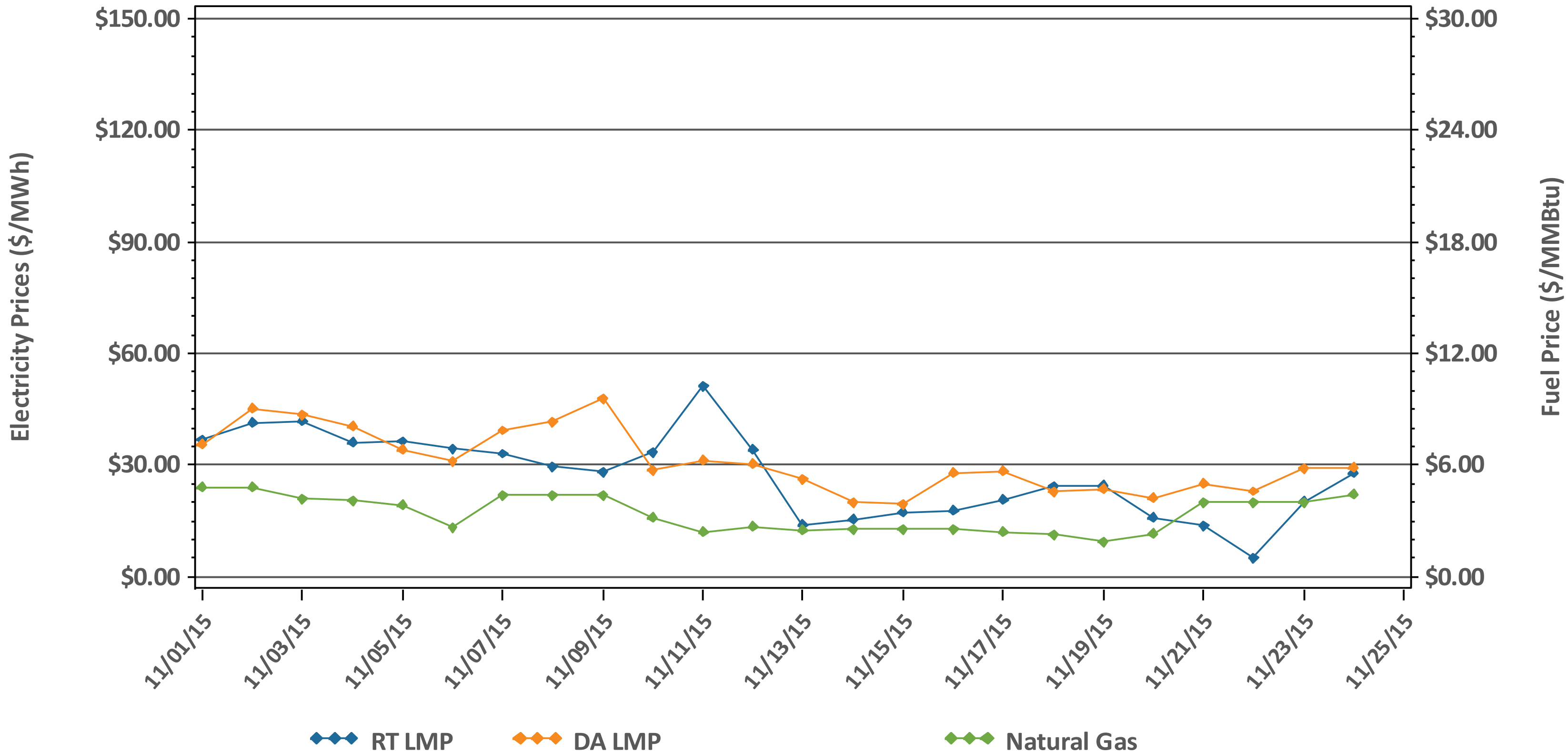
Wind Power Forecast Error Statistics: Bias



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and October's monthly values are mostly within yearly performance targets specified in the forecast RFP.

MARKET OPERATIONS

Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: November 1-24, 2015

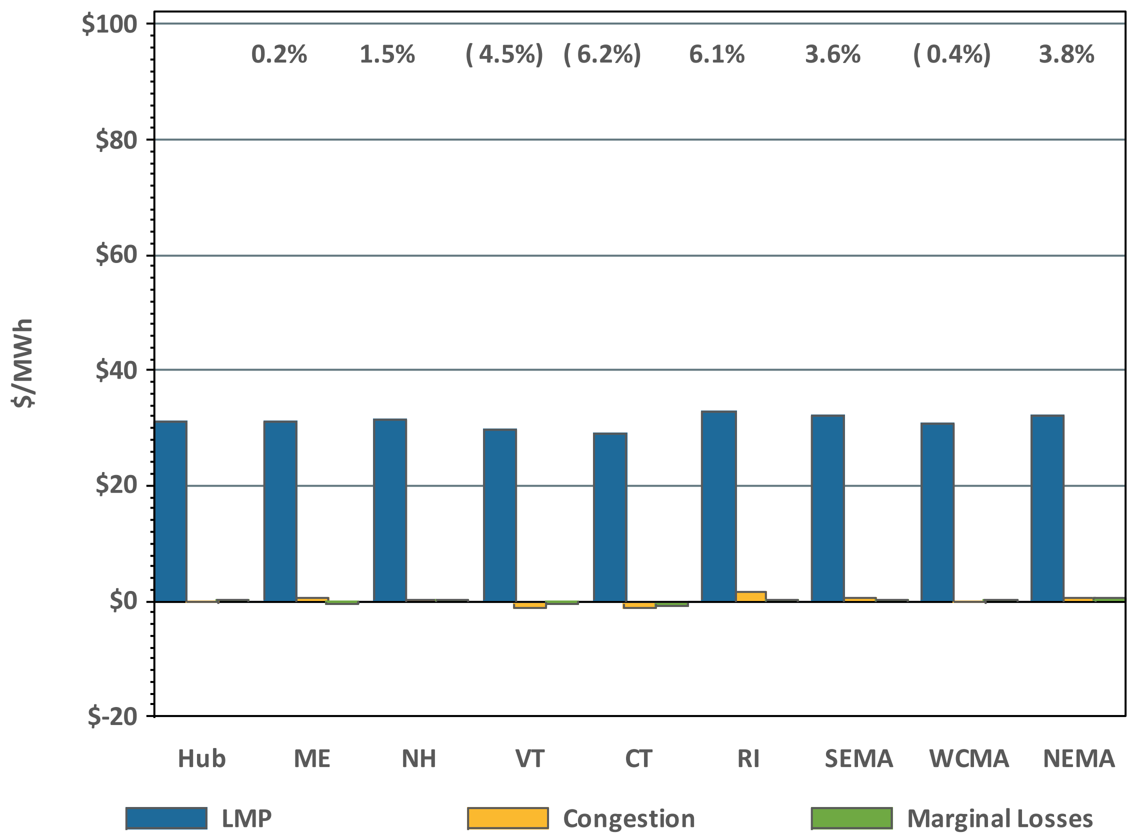


Underlying natural gas data furnished by:

ICE Global markets in clear view

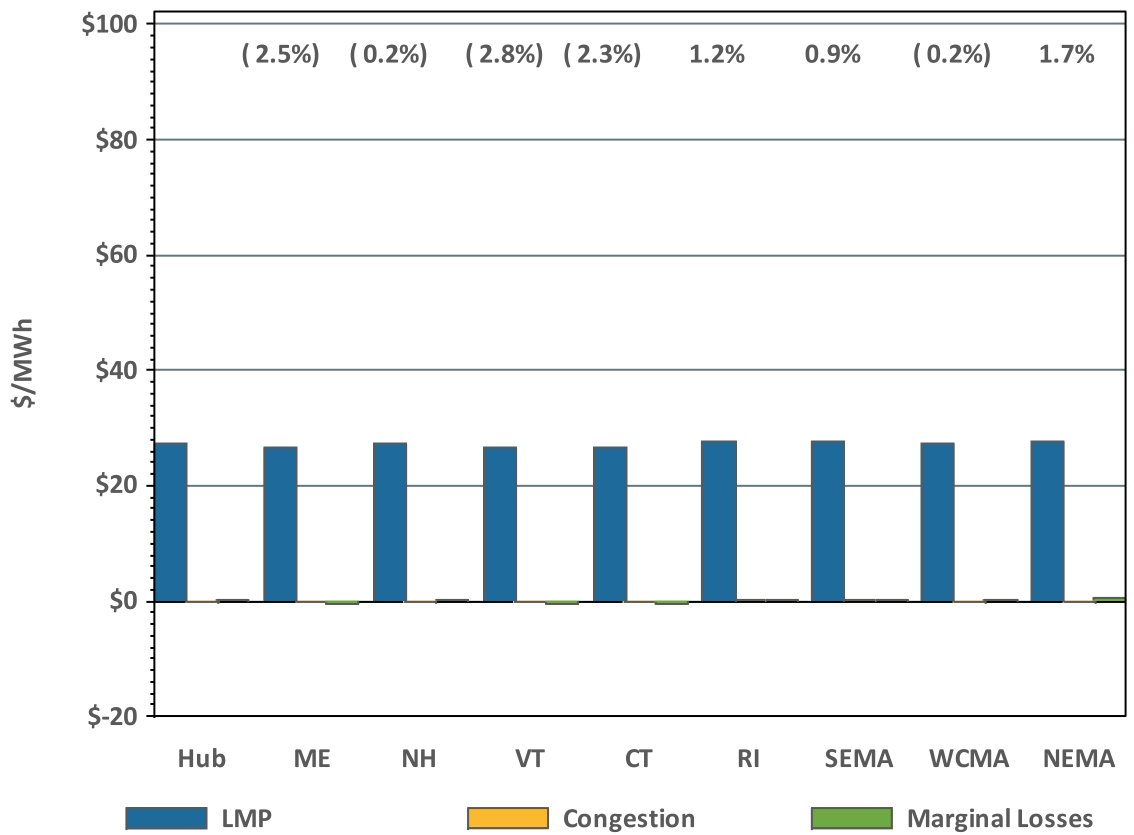
Average price difference over this period (DA-RT): $3.82
Average price difference over this period ABS(DA-RT): $6.98
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 26%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2015



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

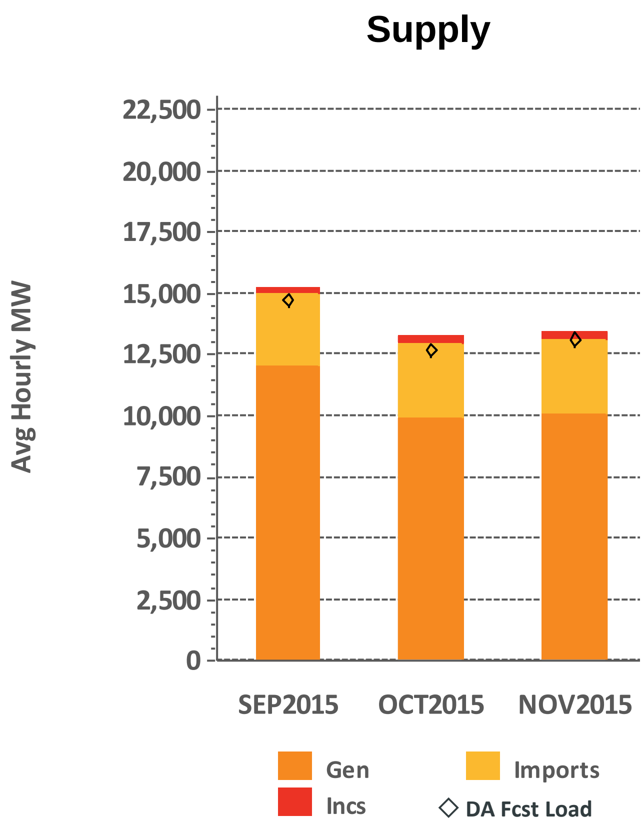
RT LMPs Average by Zone & Hub, November 2015



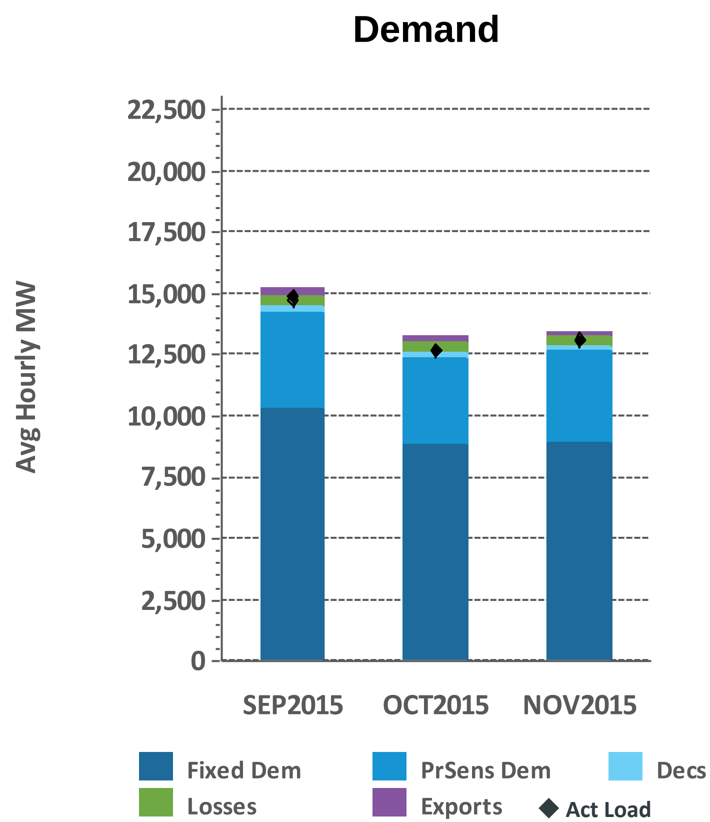
Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including pump load), exports, and virtual purchases (excluding bulk 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

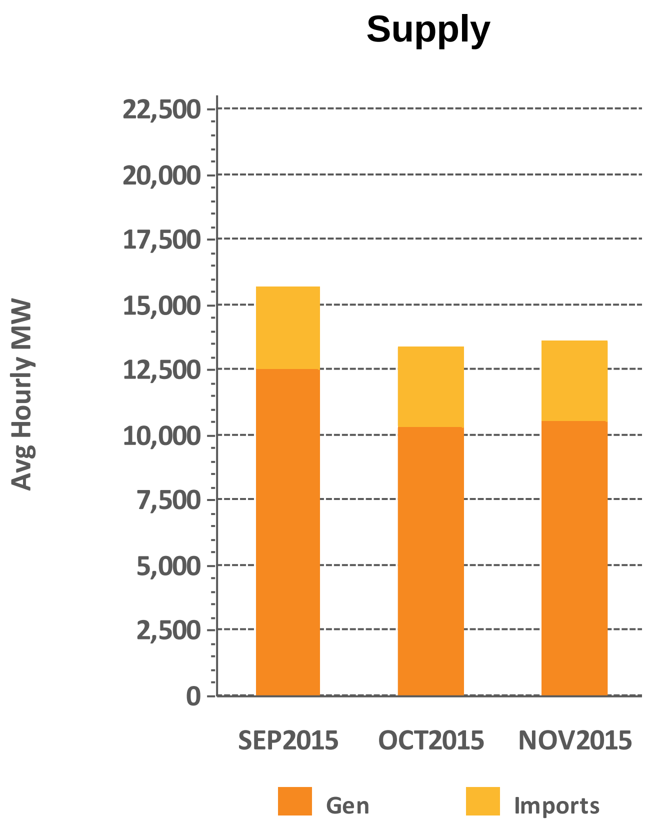


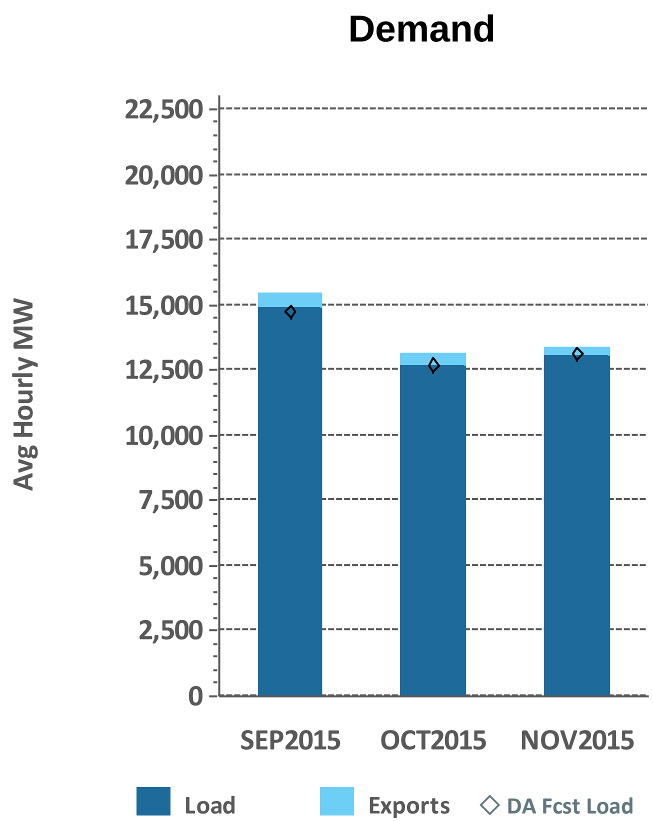
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



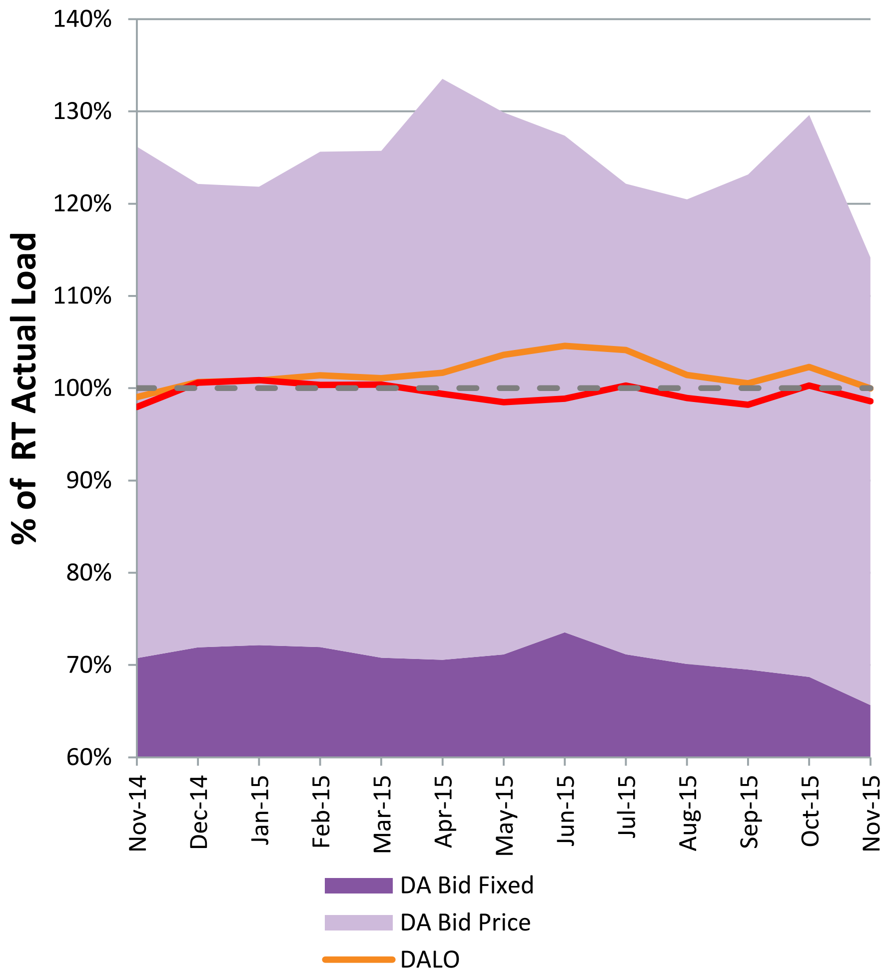
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

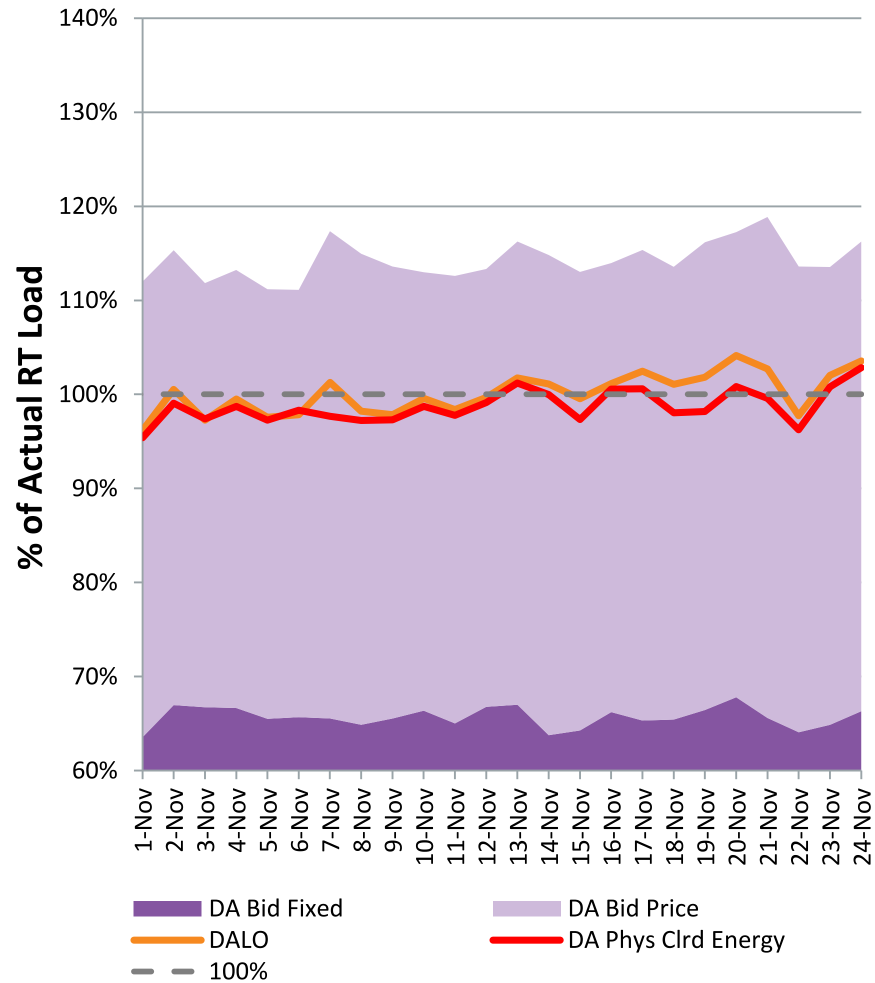
Components of RT Supply and Demand – Last Three Months





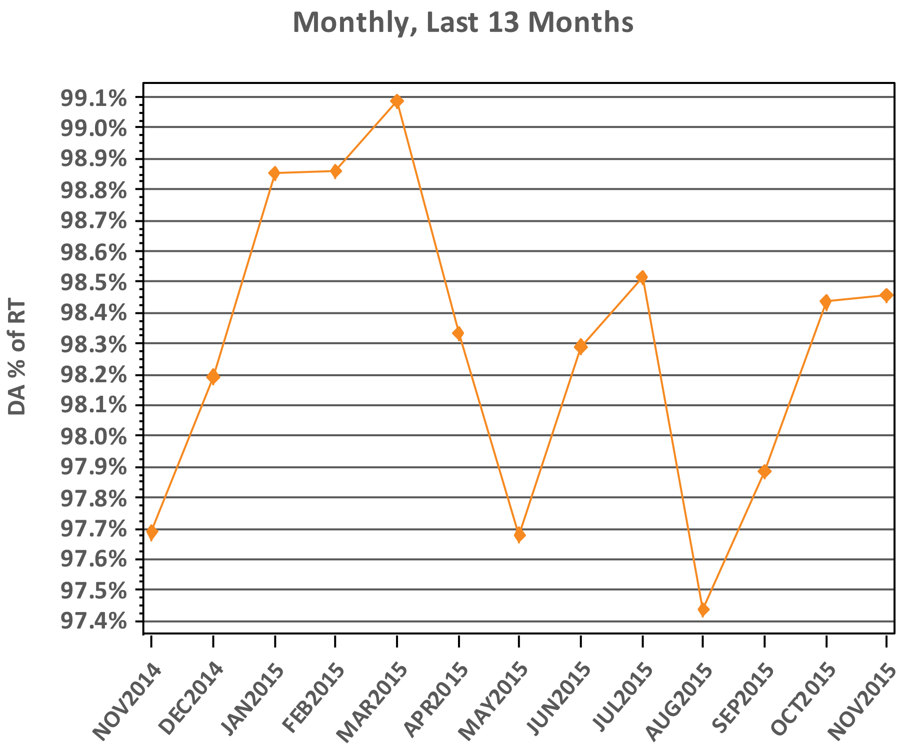
DAM Volumes vs. RT Actual Load (Peak Hour): Monthly and Daily

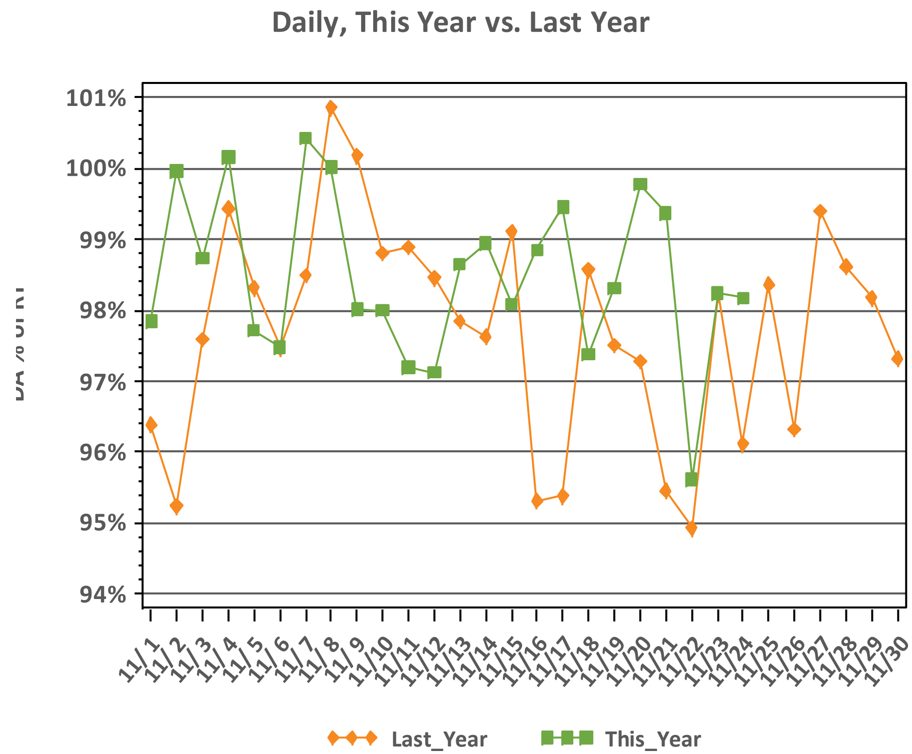




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

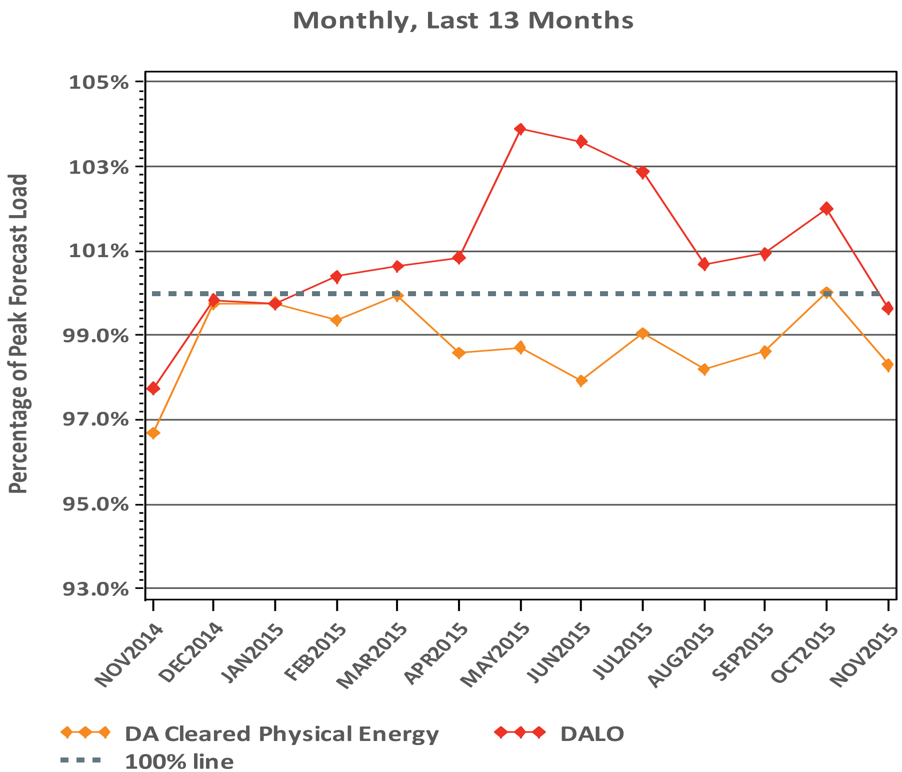
DA vs. RT Load Obligation: November, This Year vs. Last Year

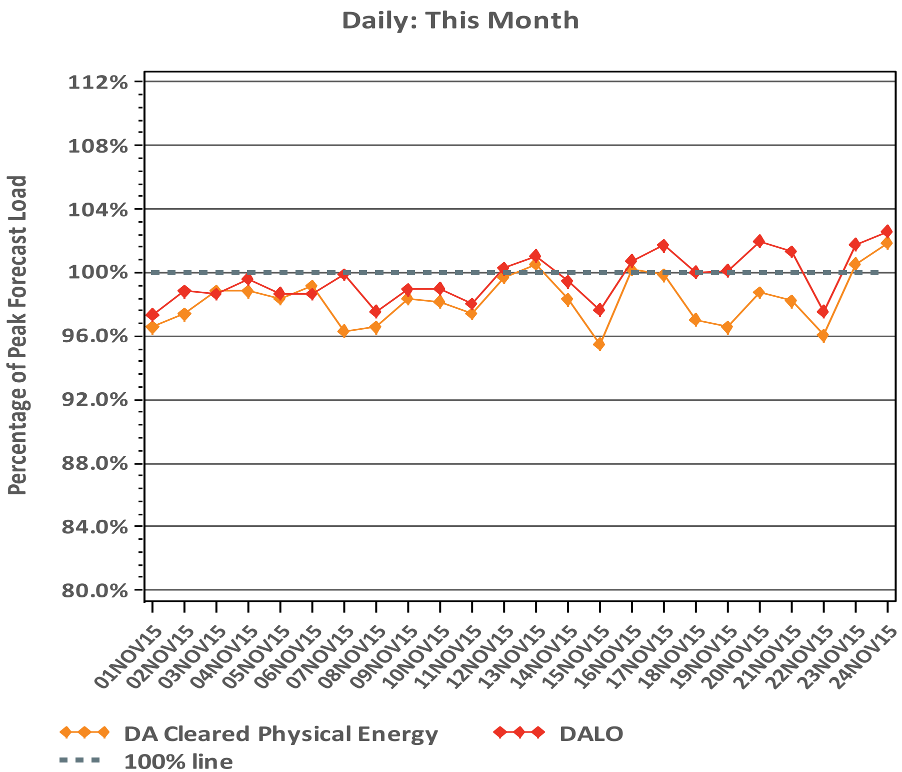




*Hourly average values

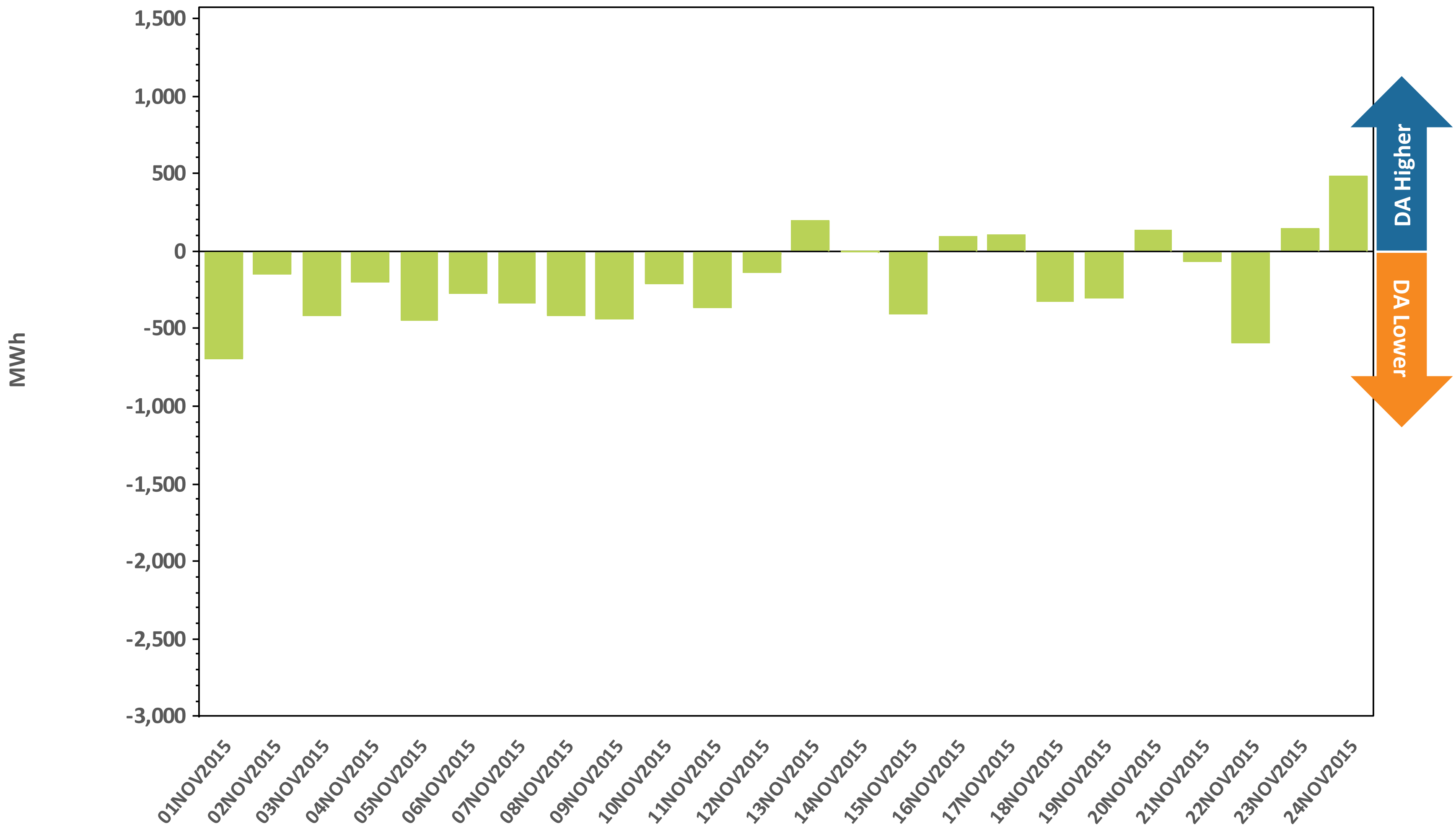
DA Volumes as % of Forecast (Peak Hour)





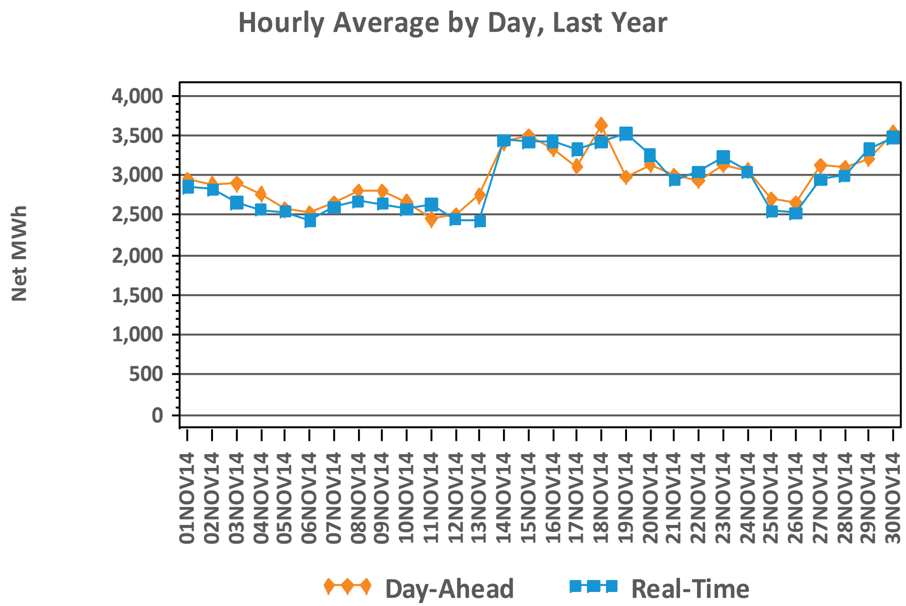
*Forecasted peak hour is reflected.

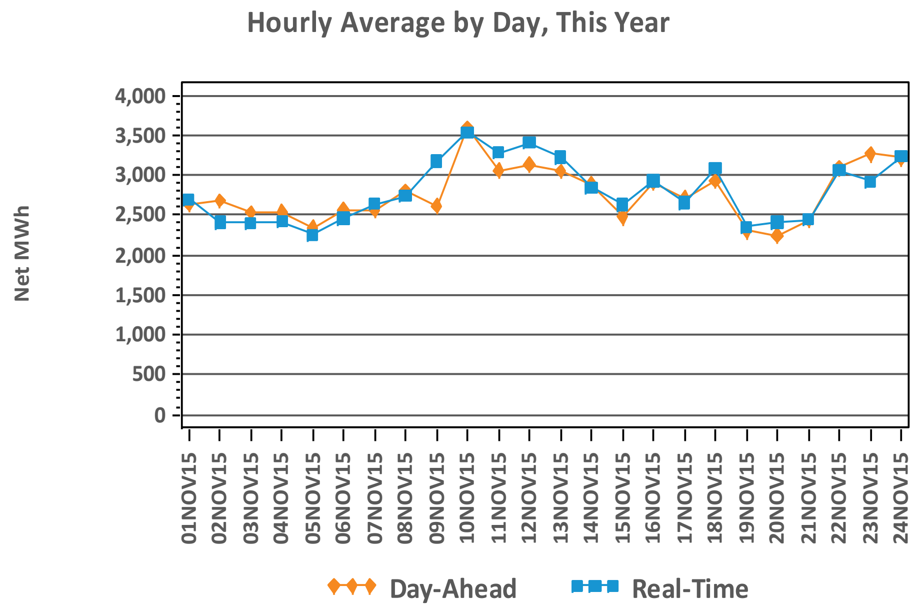
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

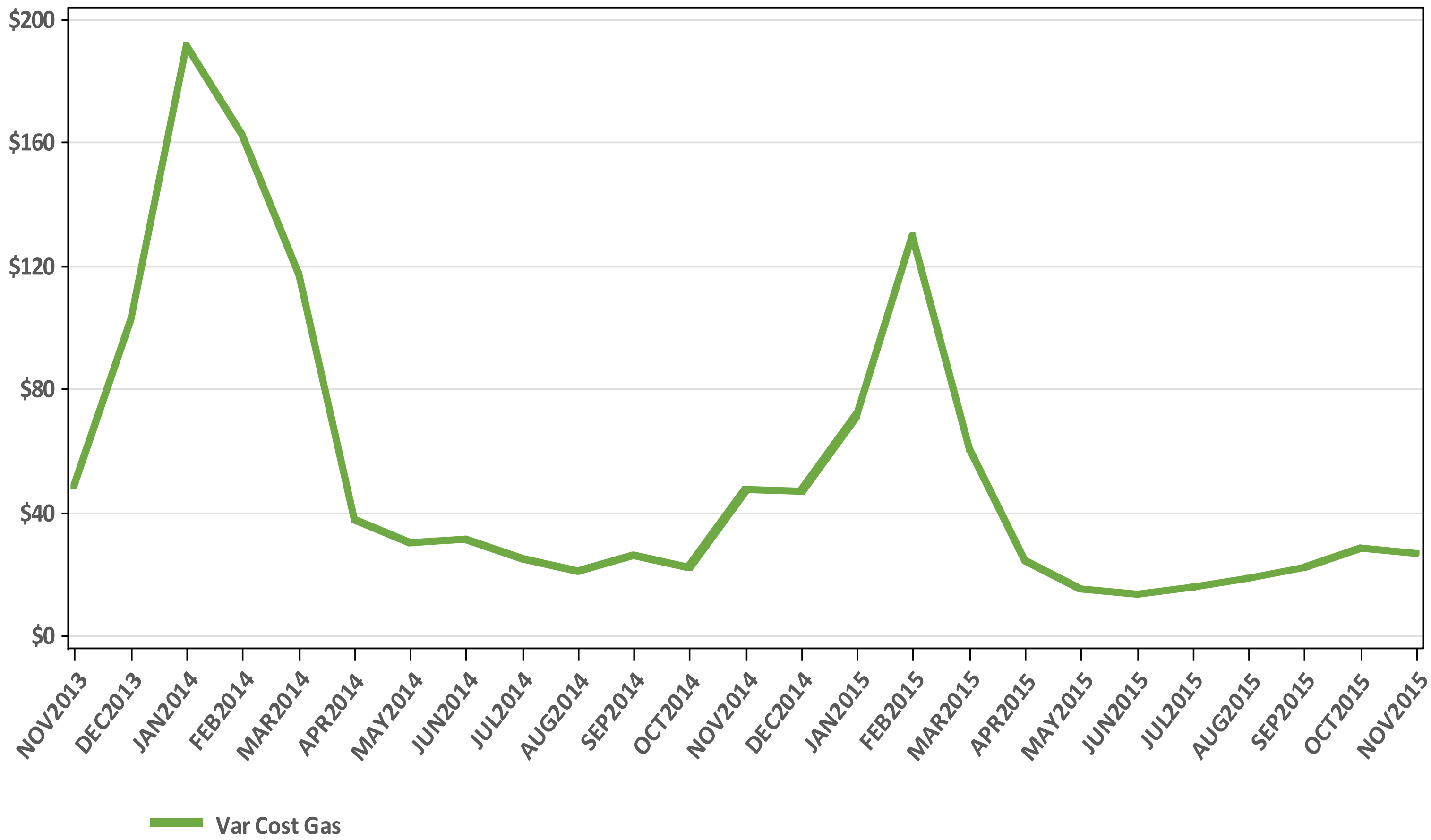
DA vs. RT Net Interchange November 2015 vs. November 2014





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

Variable Production Cost of Natural Gas: Monthly

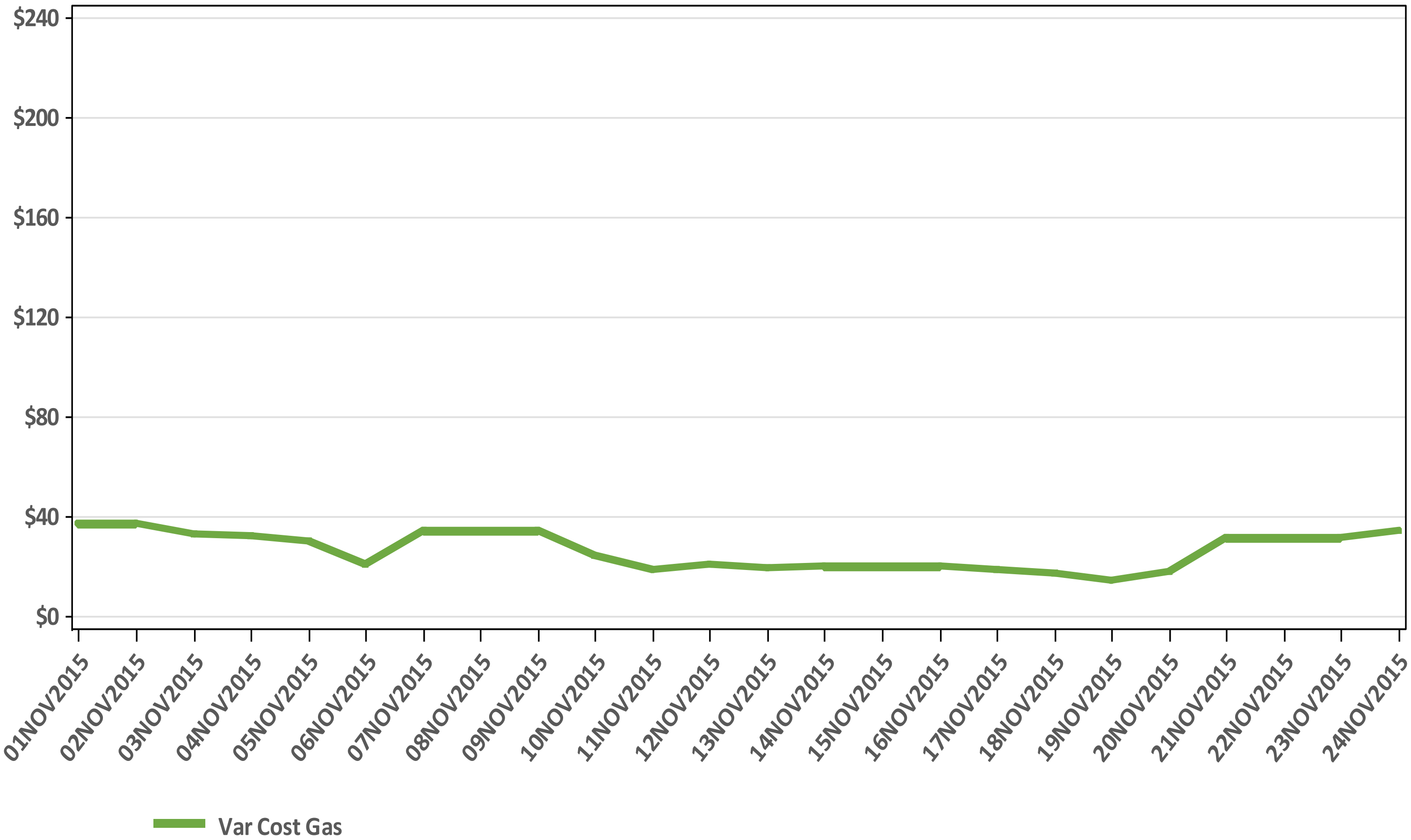


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

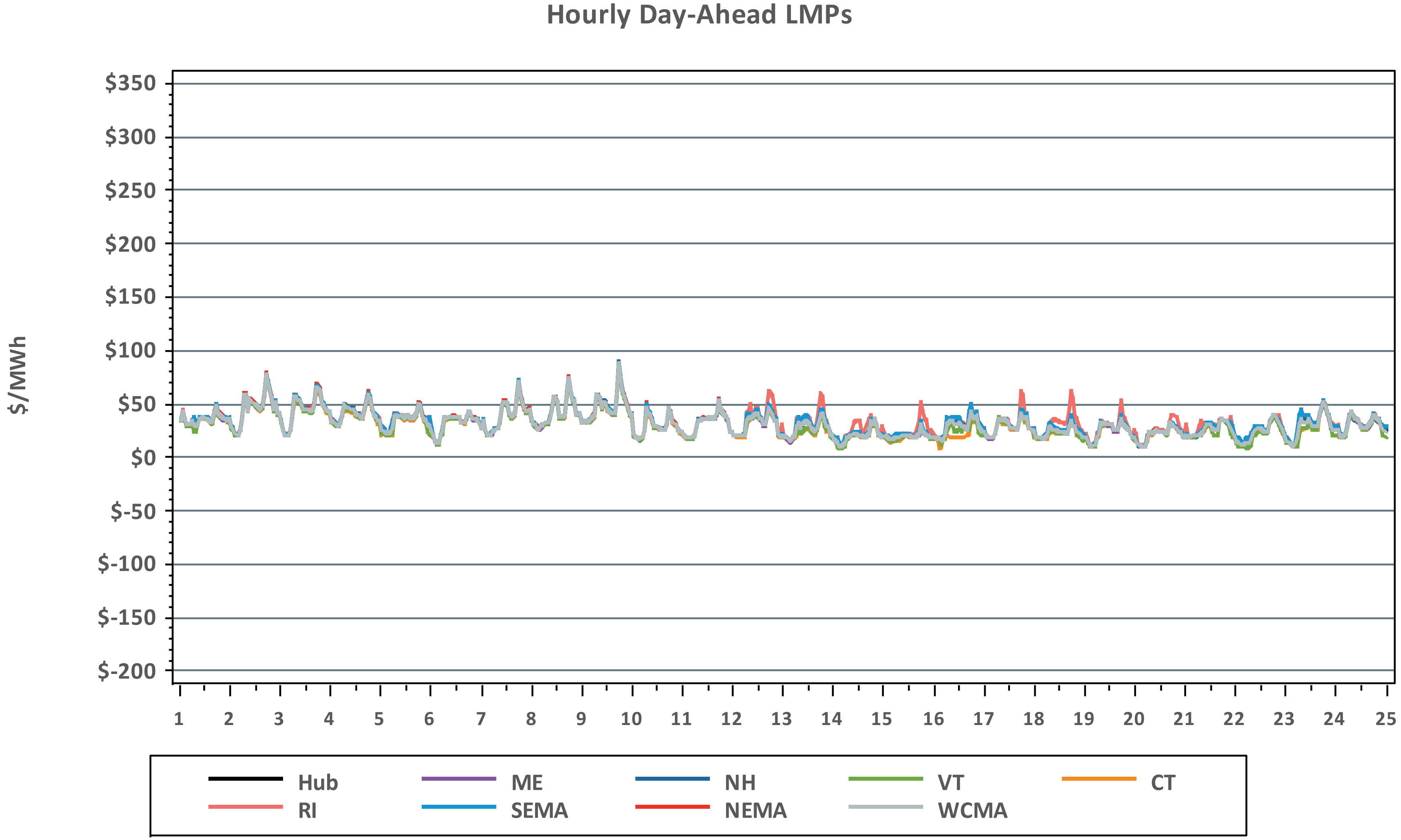


Underlying natural gas data furnished by:

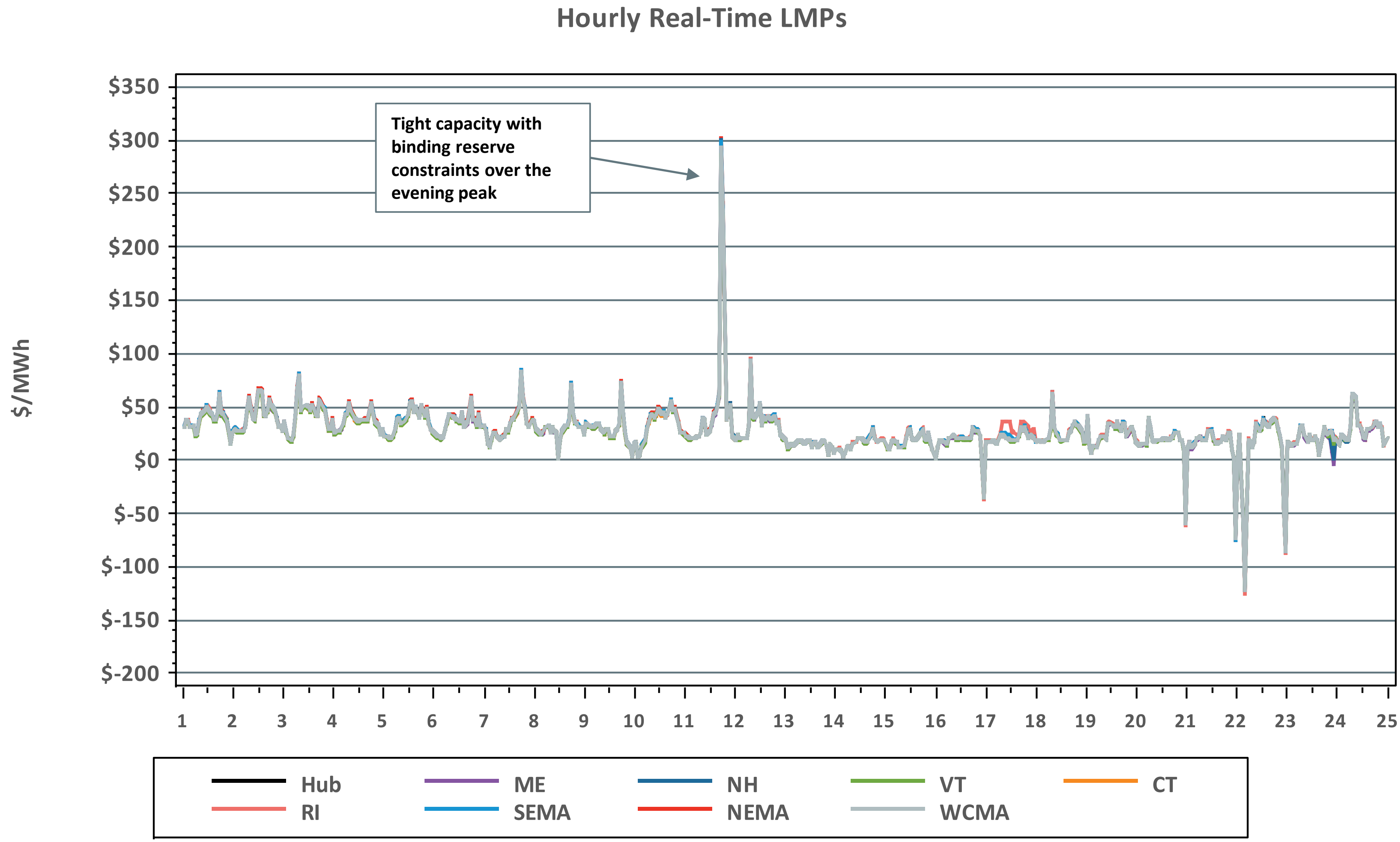
ICE Global markets in clear view

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

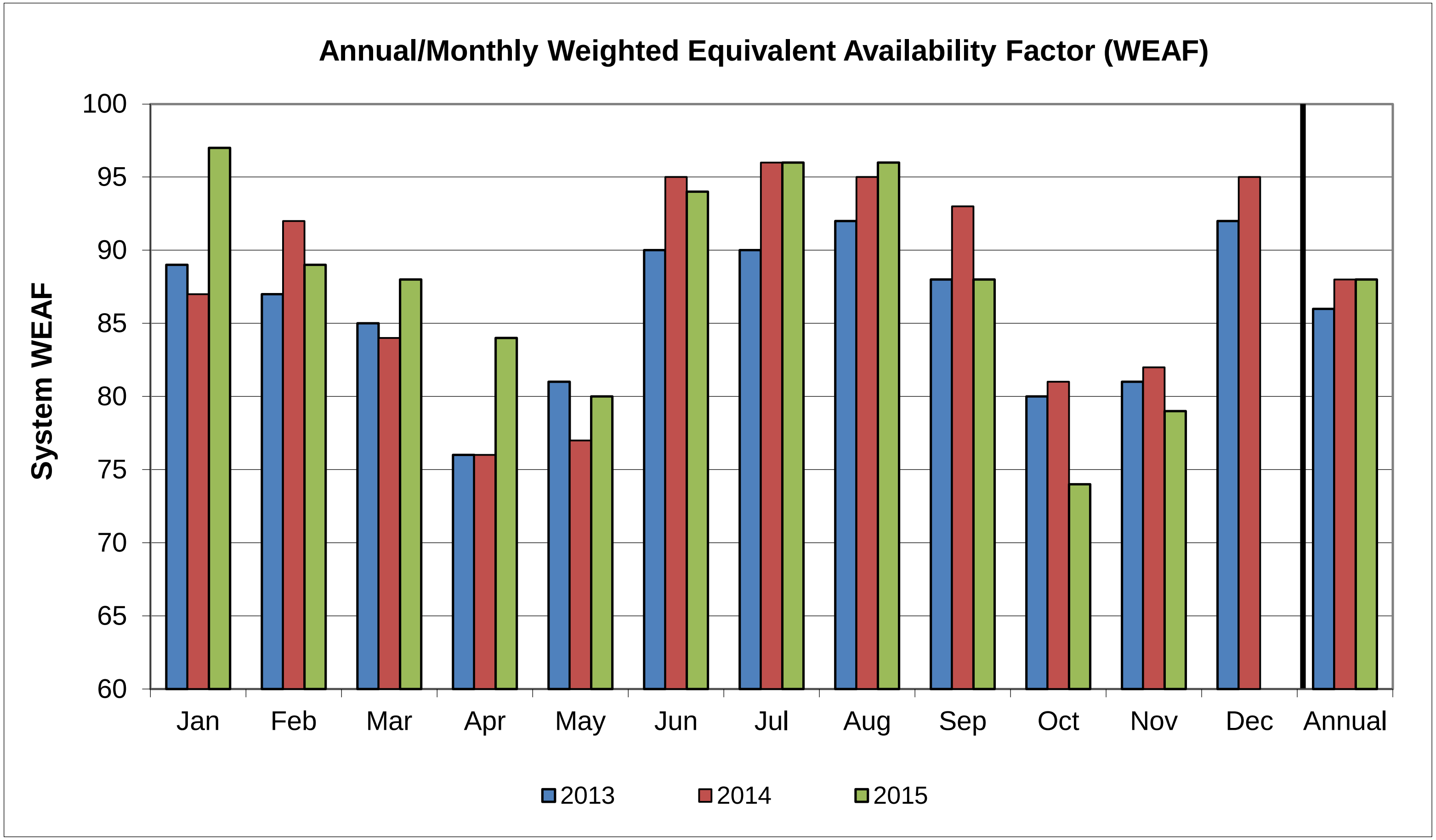
Hourly DA LMPs, November 1-24, 2015



Hourly RT LMPs, November 1-24, 2015



System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2015	97	89	88	84	79	94	96	96	88	74	79		88
2014	87	92	84	76	77	95	96	95	93	81	82	95	88
2013	89	87	85	76	81	90	90	92	88	80	81	92	86
2012	93	92	88	75	83	93	95	95	91	76	80	89	88

Data as of 11/30/15

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for December 2015

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	114.3	3.4	117.7	0.0	235.4
NH	5.2	9.8	75.3	0.0	90.3
VT	31.5	3.1	104.9	0.0	139.5
CT	66.5	80.3	71.5	310.7	529.0
RI	10.3	11.7	160.0	0.0	181.9
SEMA	5.4	8.7	202.5	0.0	216.6
WCMA	21.0	19.5	207.0	46.2	293.7
NEMA	29.4	5.6	374.0	0.0	408.9
Total	283.5	142.1	1,312.7	356.9	2,095.2

* Real Time Demand Response

** Real Time Emergency Generation

NOTE: CSO values include T&D loss factor (8%) and, as applicable, a reserve margin gross-up of either 14.3% or 16.1%, respectively, for portions of resources that selected a multi-year obligation in the FCA 1 or FCA 2. Otherwise, reserve margin gross-ups were discontinued with FCA 3.

NEW GENERATION

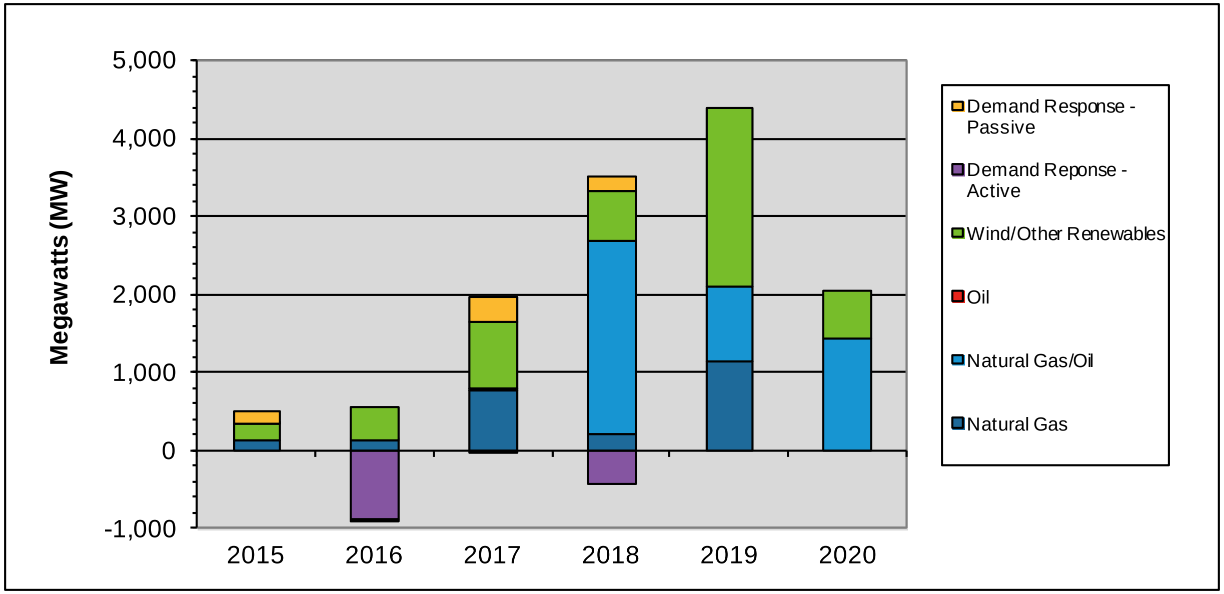
New Generation Update

Based on Queue as of 11/30/15

- Eight new projects, with a total rating of 1,369 MW, have applied for interconnection study since the last update
  - The new projects consist of three new wind plants, three new battery storage facilities that are associated with planned and existing generating plants, one new photovoltaic plant, and one new combined cycle plant that also has battery storage. The expected in-service dates range from 2016 to 2020.
- One project went commercial, resulting in a net increase in new generation projects of 1,341 MW
- In total, 85 generation projects are currently being tracked by the ISO, totaling approximately 12,000 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



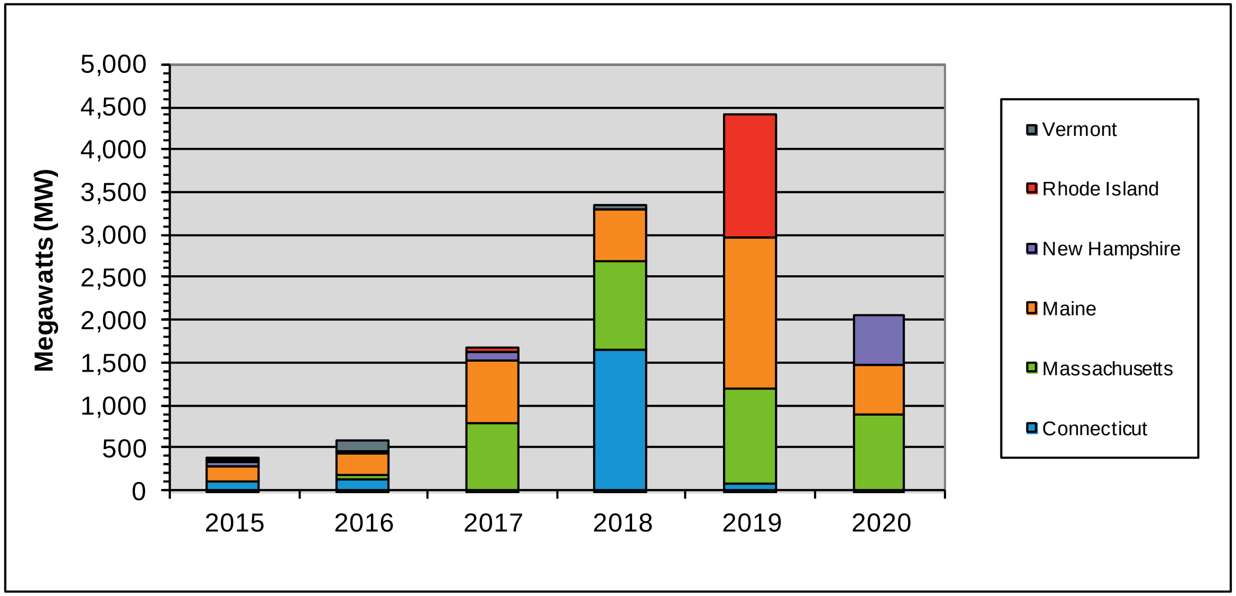
	2015	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Demand Response - Passive	157	-12	330	196	0	0	670	5.7
Demand Response - Active	3	-868	-37	-433	0	0	-1,335	-11.4
Wind & Other Renewables	204	437	854	644	2,298	601	5,038	43.2
Oil	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	0	10	14	2,475	947	1,440	4,886	41.9
Natural Gas	139	123	786	210	1,149	0	2,407	20.6
Totals	**503**	**-310**	**1,947**	**3,092**	**4,394**	**2,041**	**11,666**	**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**

- 2015 values include the 314 MW of generation that has gone commercial in 2015
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions
By State



	2015	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Vermont	3	117	0	30	0	0	150	1.2
Rhode Island	27	22	29	0	1,430	0	1,508	12.2
New Hampshire	40	15	120	0	0	570	745	6.0
Maine	179	255	739	607	1,781	601	4,162	33.8
Massachusetts	10	40	766	1,061	1,120	870	3,867	31.4
Connecticut	84	121	0	1,631	63	0	1,899	15.4
Totals	**343**	**570**	**1,654**	**3,329**	**4,394**	**2,041**	**12,331**	**100.0**

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

- 2015 values include the 314 MW of generation that has gone commercial in 2015

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	37	0	0	1	37
Hydro	4	33	0	0	4	33
Landfill Gas	1	2	0	0	1	2
Natural Gas	14	2,331	0	0	14	2,331
Natural Gas/Oil	17	4,886	0	0	17	4,886
Oil	0	0	0	0	0	0
Solar	10	370	6	105	4	265
Wind	35	4,290	6	329	29	3,961
Battery Storage	3	68	0	0	3	68
Total	85	12,017	12	434	73	11,583

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

New Generation Projection
By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	3	102	0	0	3	102
Intermediate	23	5,936	0	0	23	5,936
Peaker	24	1,689	6	105	18	1,584
Wind Turbine	35	4,290	6	329	29	3,961
Total	85	12,017	12	434	73	11,583

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

New Generation Projection
By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	37	1	37	0	0	0	0	0	0
Hydro	4	33	0	0	3	8	1	25	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	14	2,331	1	63	10	2,070	3	198	0	0
Natural Gas/Oil	17	4,886	0	0	10	3,858	7	1,028	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	10	370	0	0	0	0	10	370	0	0
Wind	35	4,290	0	0	0	0	0	0	35	4,290
Battery Storage	3	68	0	0	0	0	3	68	0	0
Total	85	12,017	3	102	23	5,936	24	1,689	35	4,290

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		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	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56	789.366	-53.425	638.393	-150.973
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1,700.586	184.08	1,694.766	-5.82	1,687.458	-7.308
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624	**2,601.851**	**-191.67**	**2,543.377**	**-58.47**	**2,484.132**	**-59.245**	**2,325.851**	-158.281
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28,727.16	284.73	28,881.019	153.859	**28,971.511**	90.492
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48	777.924	-42.819	**754.101**	-23.823
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914	**29,271.643**	**99.95**	**29,547.9**	**276.26**	**29,658.943**	**111.043**	**29,725.612**	66.669
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290	**1,616.821**	**-25.00**	**1,399.037**	**-217.78**	**1,337.037**	**-62**	**1,337.037**	0
*****Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000	**33,490.315**	**-116.72**	**33,490.32**	**0.00**	**33,480.112**	**-10.208**	**33,388.5**	-91.612
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	33,114	**-342**	**33,114**	**0.00**	**33,391**	**277**	**33,391**	**0**

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

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

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

Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		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	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549	781.206	-151.52	671.28	-109.926				
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1,544.276	0.48	1,544.119	-0.157				
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**	2,325.482	-151.03	2,215.399	-110.083				
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958	28,307.339	-215.66	28,791.131	483.792				
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46	824.833	-13.793				
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**	29,145.965	-290.12	29,615.964	469.999				
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**	1,576.401	-40.00	1,576.401	0				
***Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**	33,047.848	-481.15	33,407.764	359.916				
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0	33,529	0.00	33,529	0				

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

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

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

Capacity Supply Obligation FCA 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,080.079	887.493	-192.59	896.202	8.709								
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211								
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,852.865**	6.498								
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,667.121	143.325								
	Intermittent	876.925	898.955	22.03	921.922	22.967								
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**								
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**								
*****Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,817.438**	**311.286**								
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	**0**								

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

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

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

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												
	Passive Demand	2,156.151												
Demand Total		**2,803.411**												
Generator	*Non-Intermittent*	29,550.564												
	Intermittent	891.616												
Generator Total		**30,442.18**												
Import Total		**1,449**												
***Grand Total		**34,694.591**												
Net ICR (NICR)		**34,189**												

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

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** 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**

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

What are Daily NCPC Payments?

- Payments made to resources whose hourly 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 over the course of 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

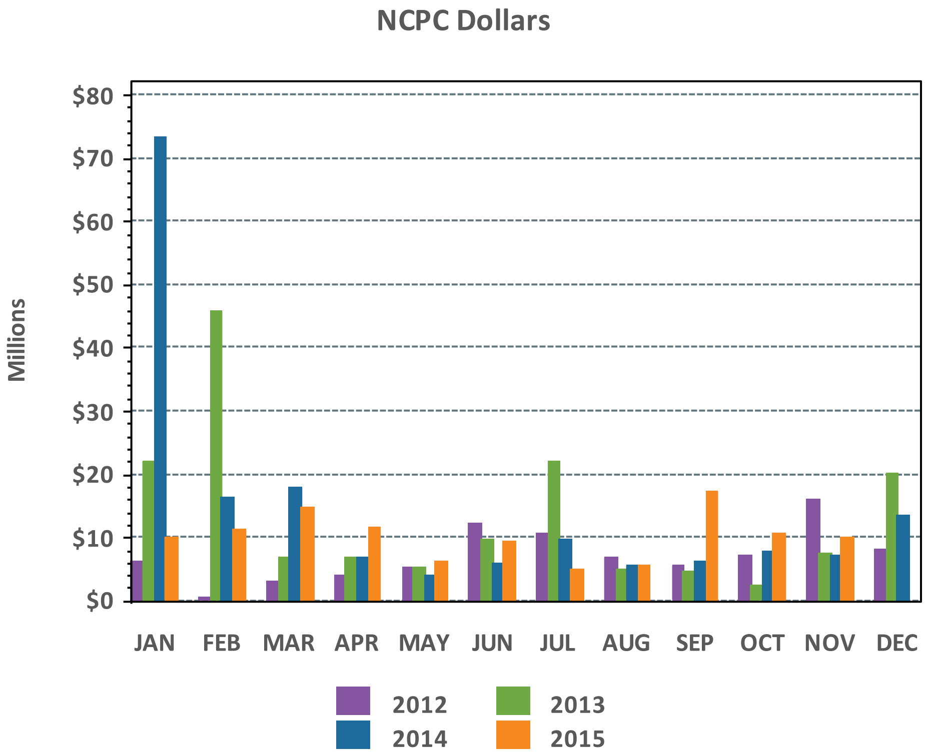
Definitions

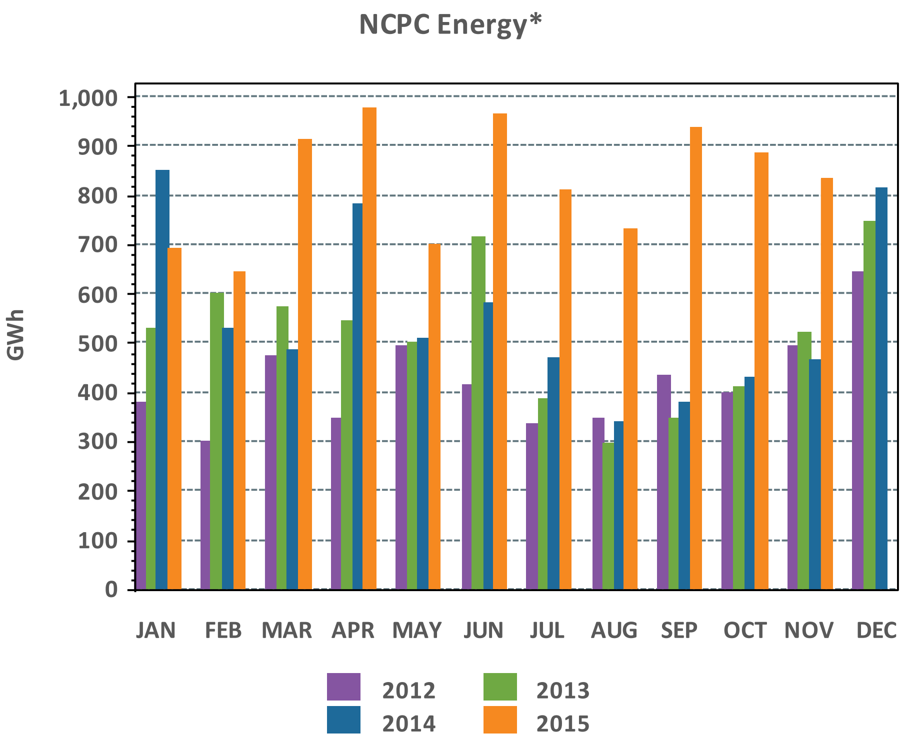
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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
Delisted Units	Resources within the control area that have requested to be classified as a non-installed capacity (ICAP) resource, and as such, are not required to offer their capacity into the DA Energy Market
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, Min Generation Emergency, and Generator and DARD NCPC

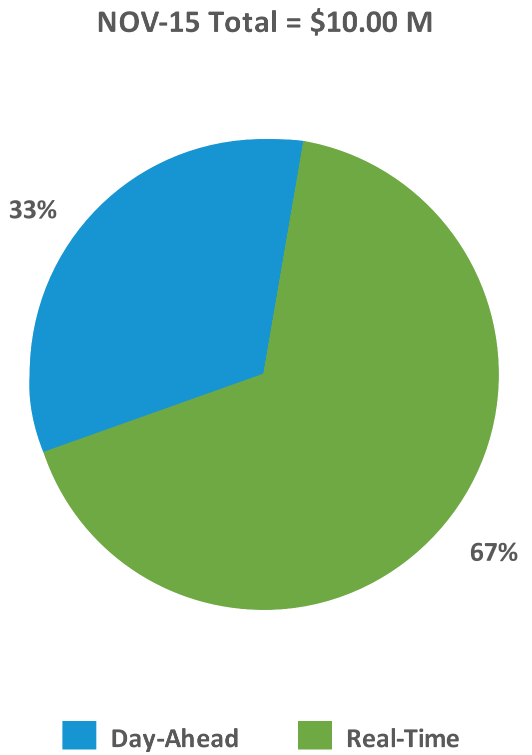
Year-Over-Year Total NCPC Dollars and Energy

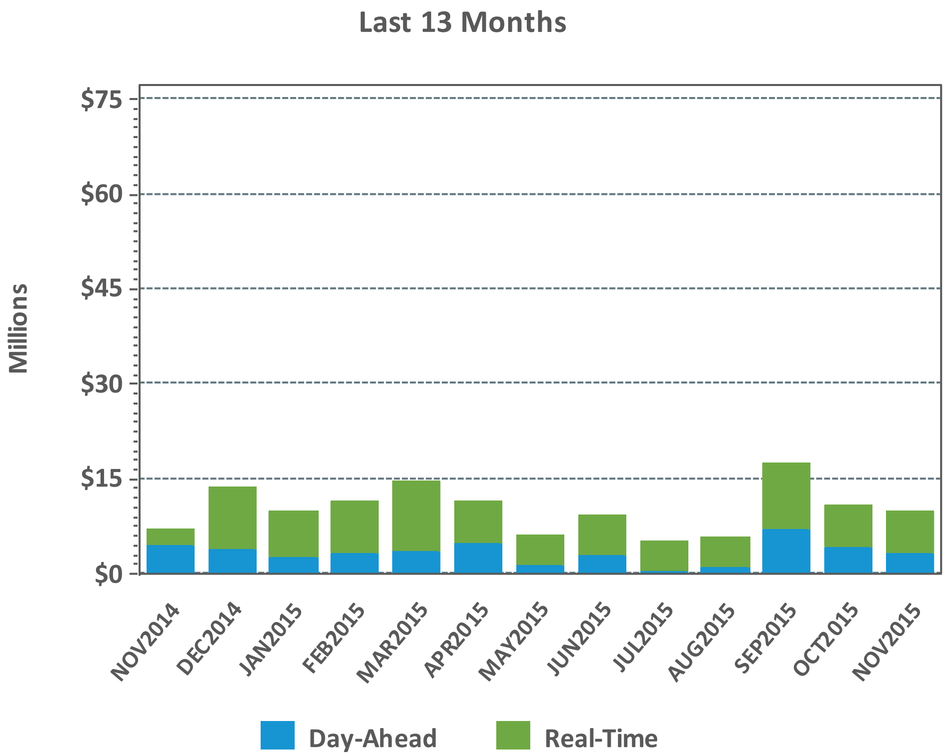




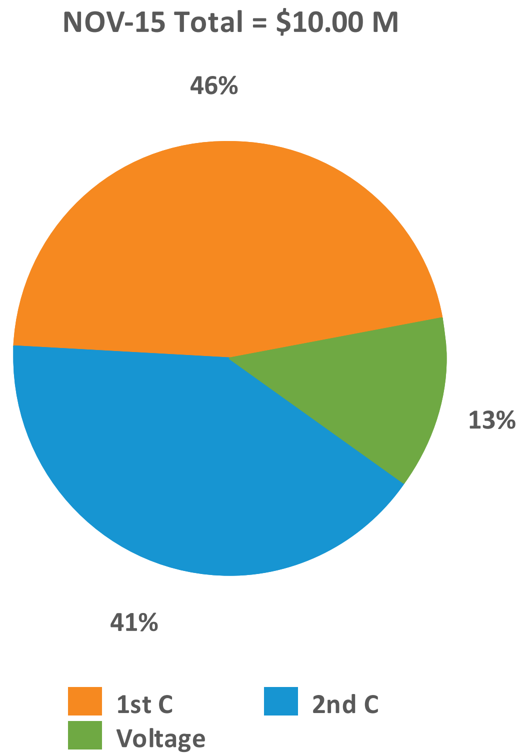
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

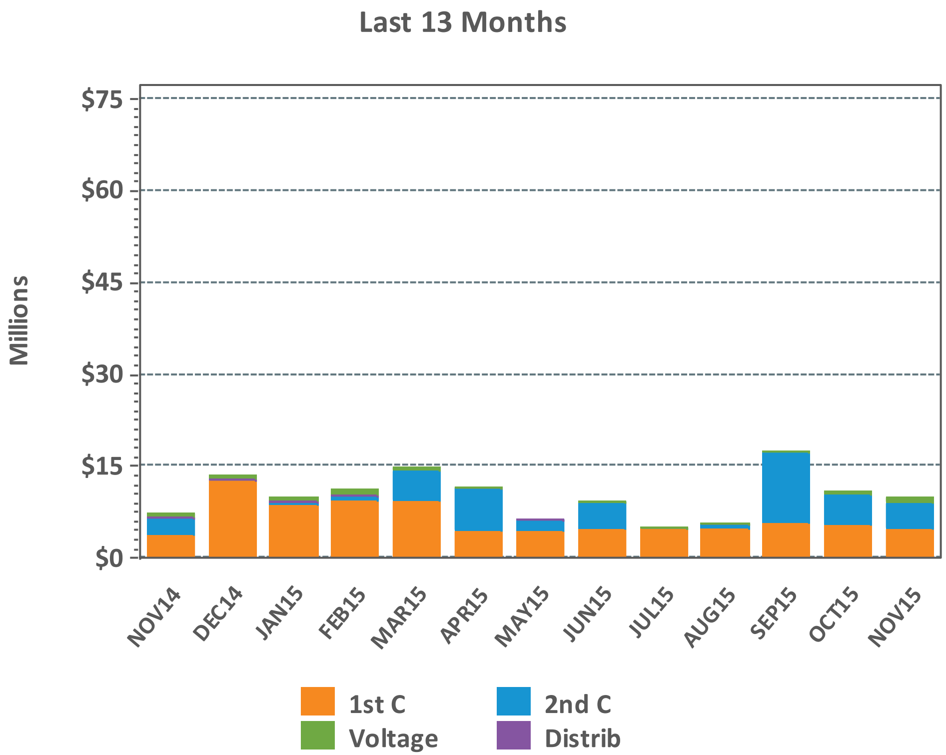
DA and RT NCPC Charges





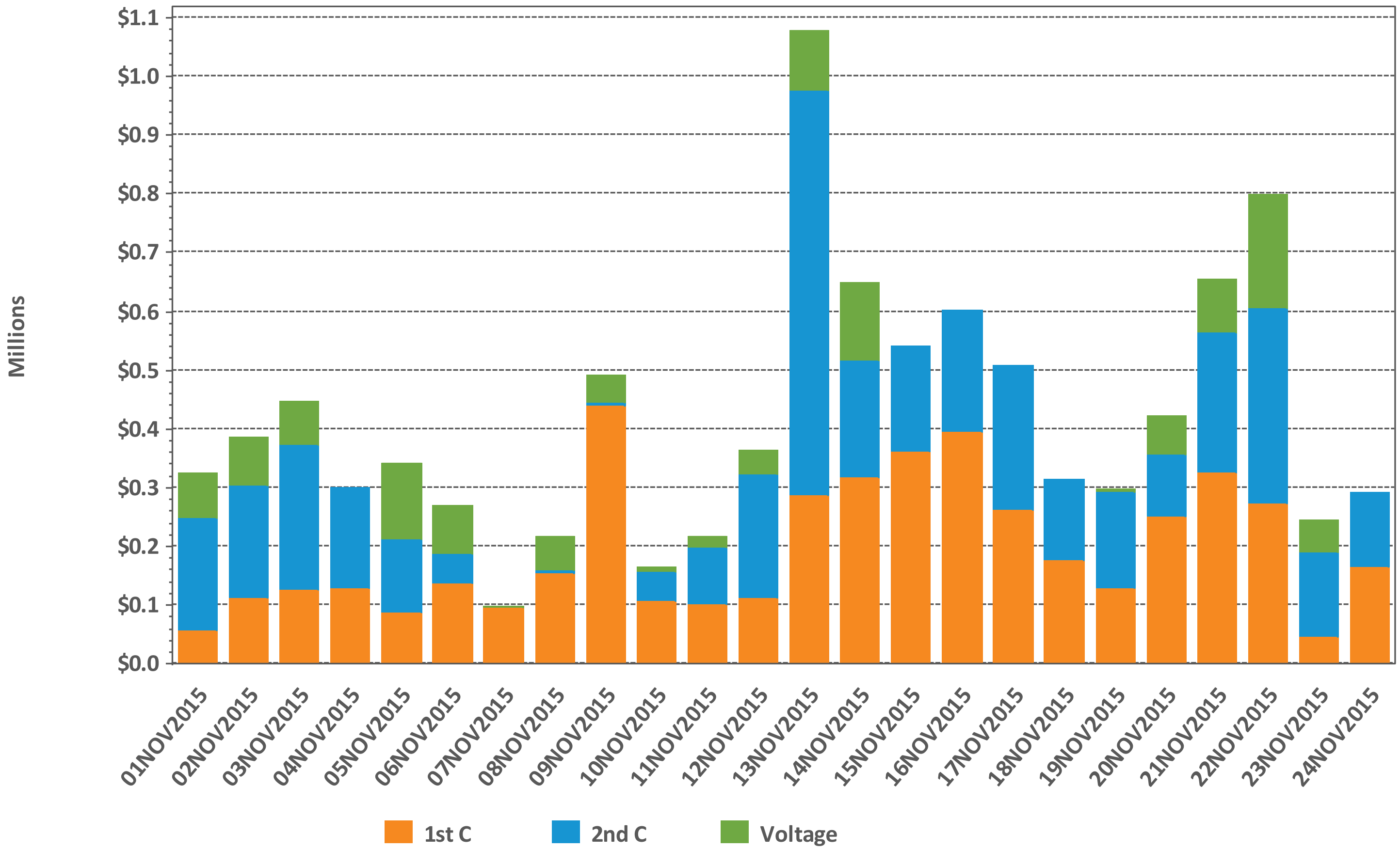
NCPC Charges by Type



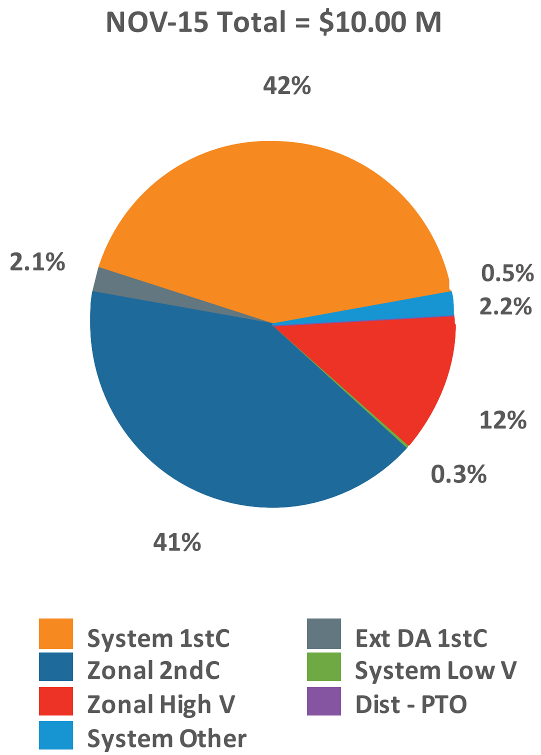


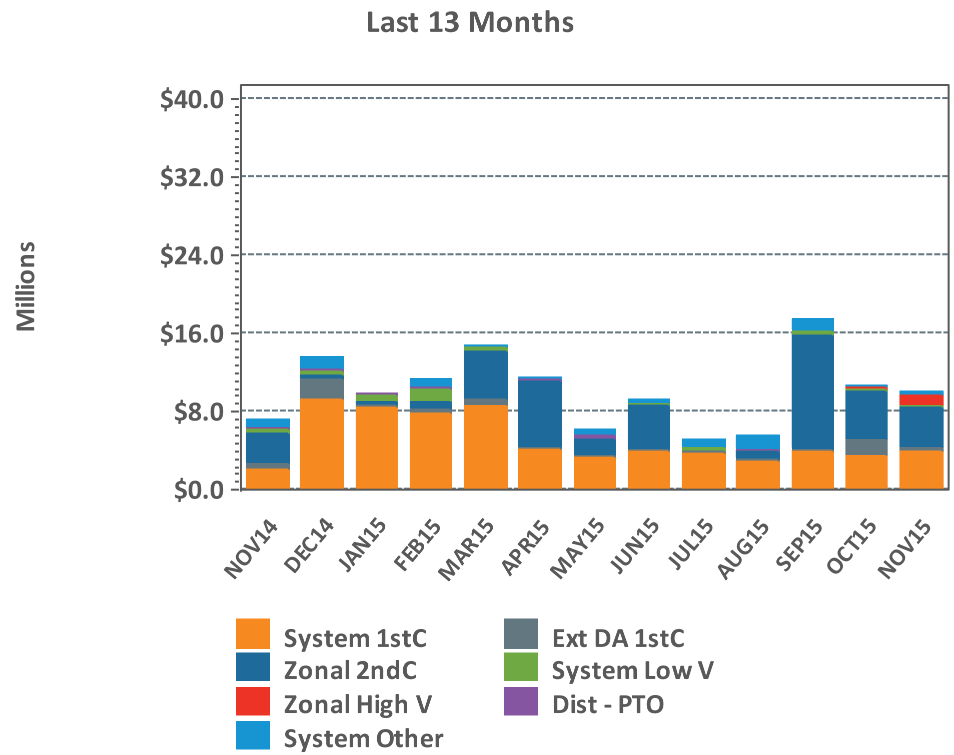
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



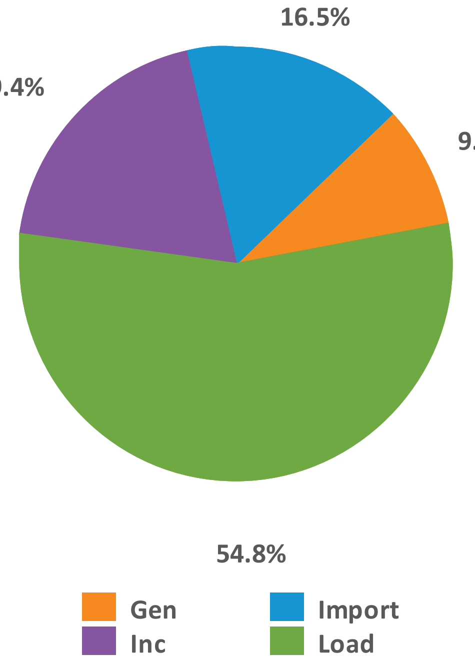
NCPC Charges by Allocation



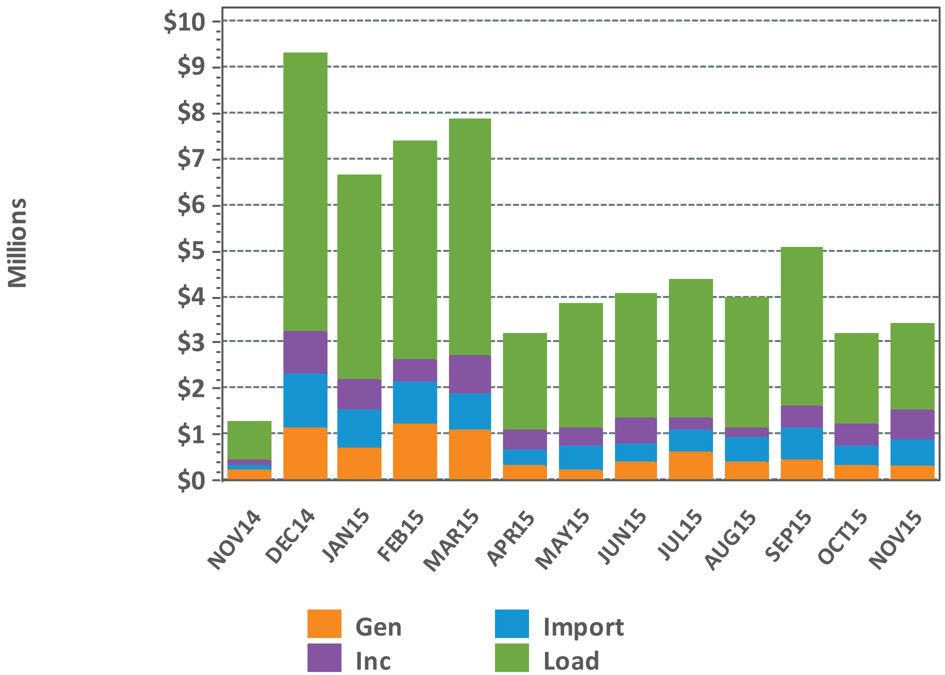


RT First Contingency Charges by Deviation Type

NOV-15 Total = $3.42 M

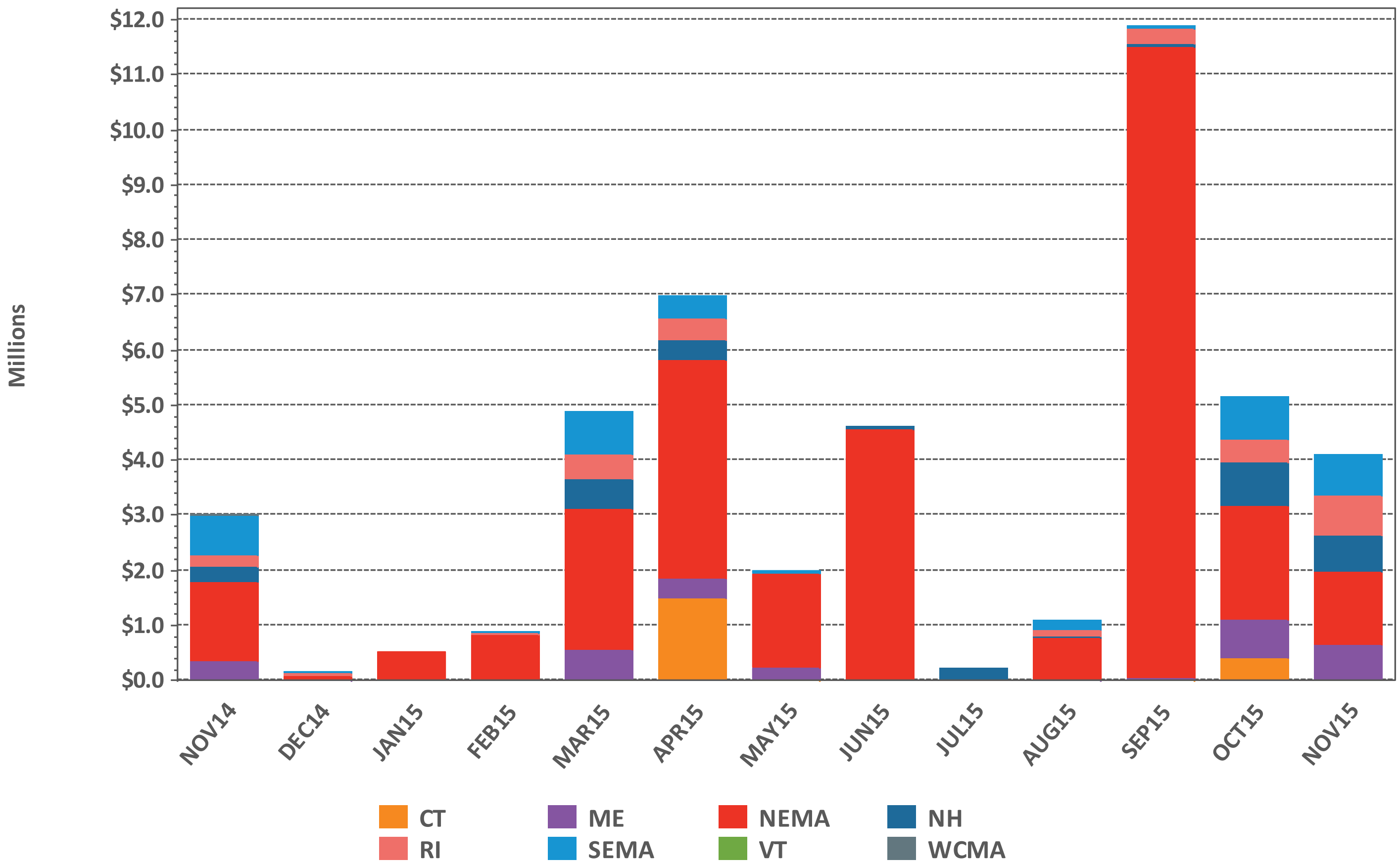


Last 13 Months



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

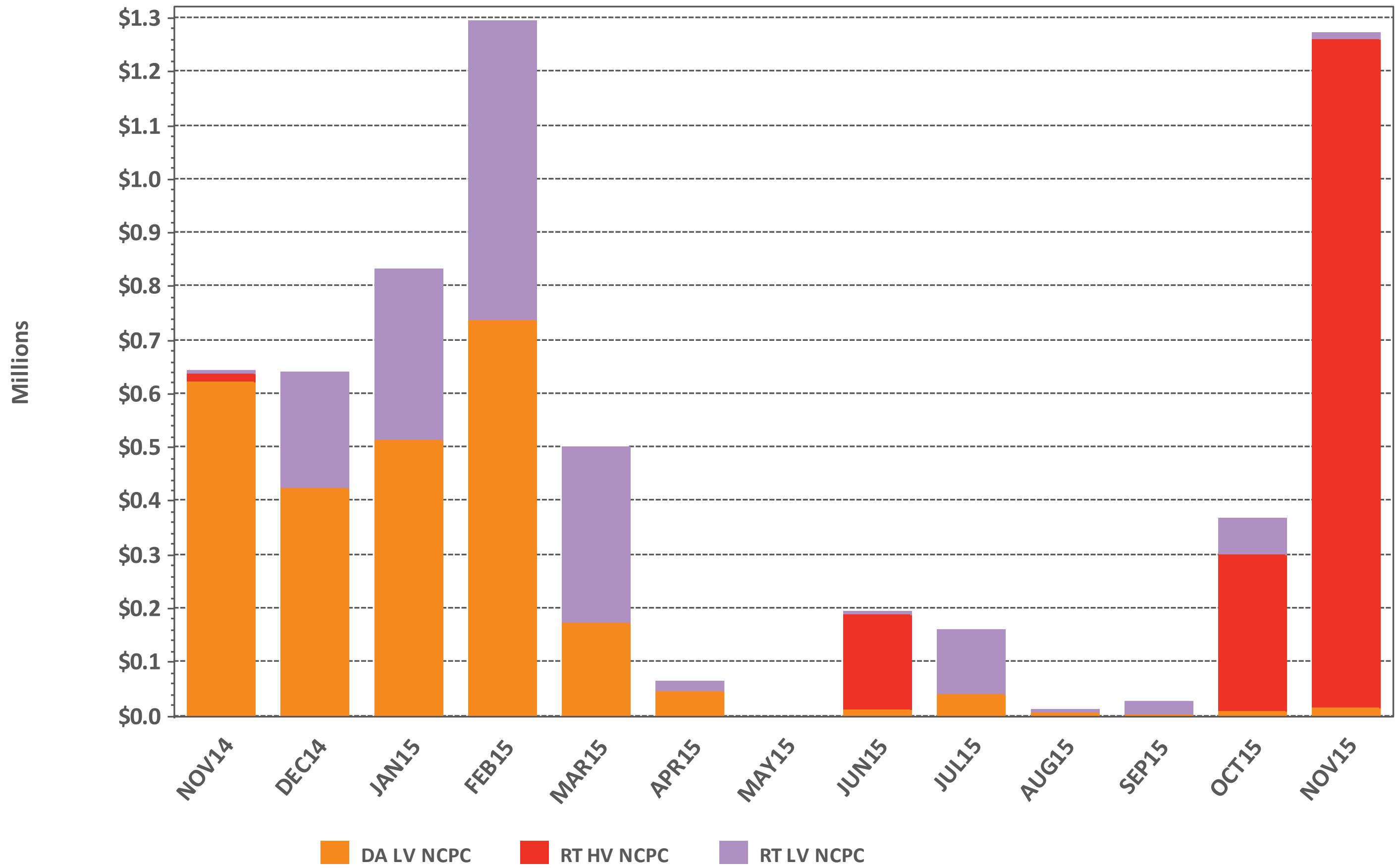
LSCPR Charges by Zone



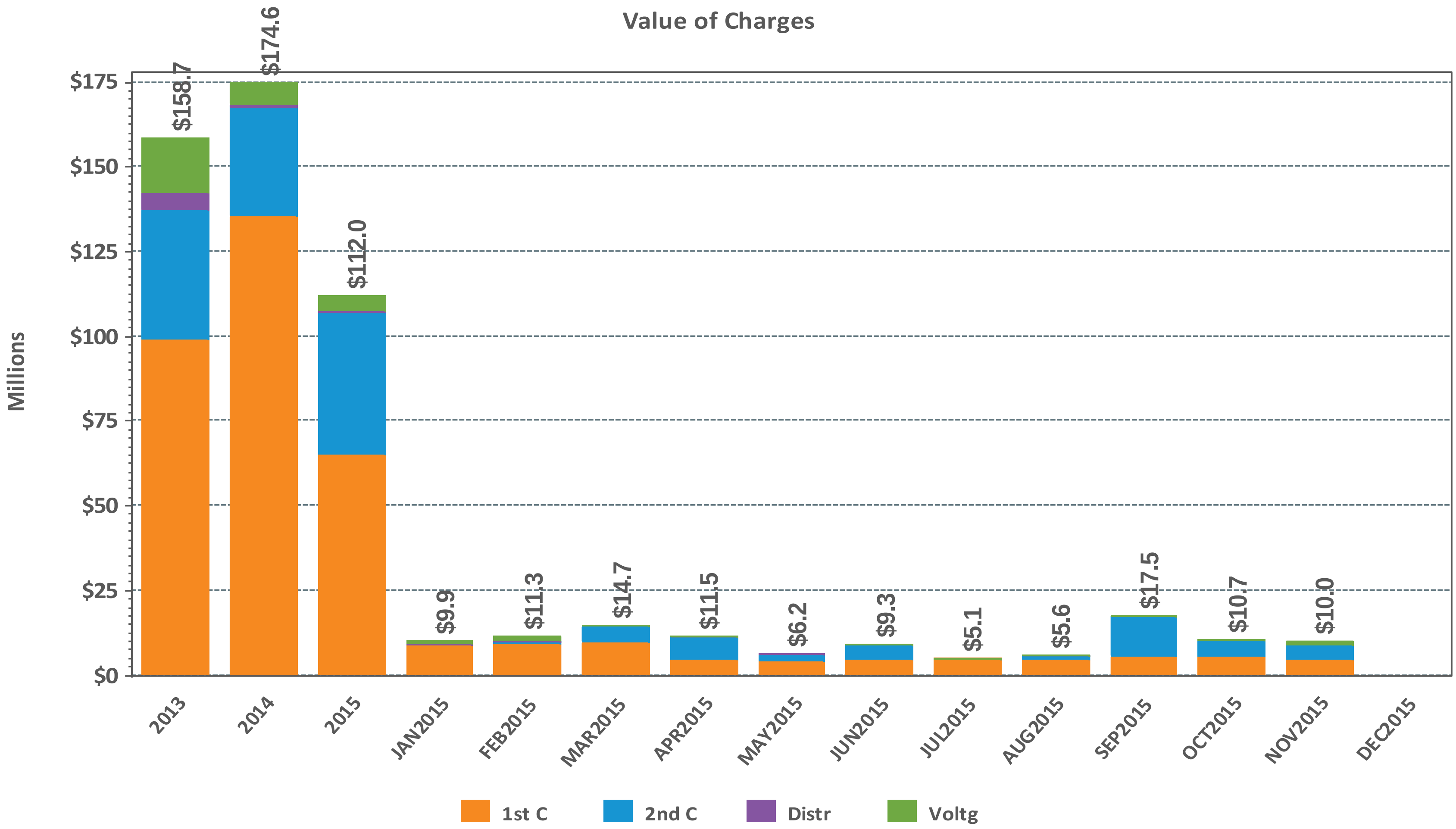
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

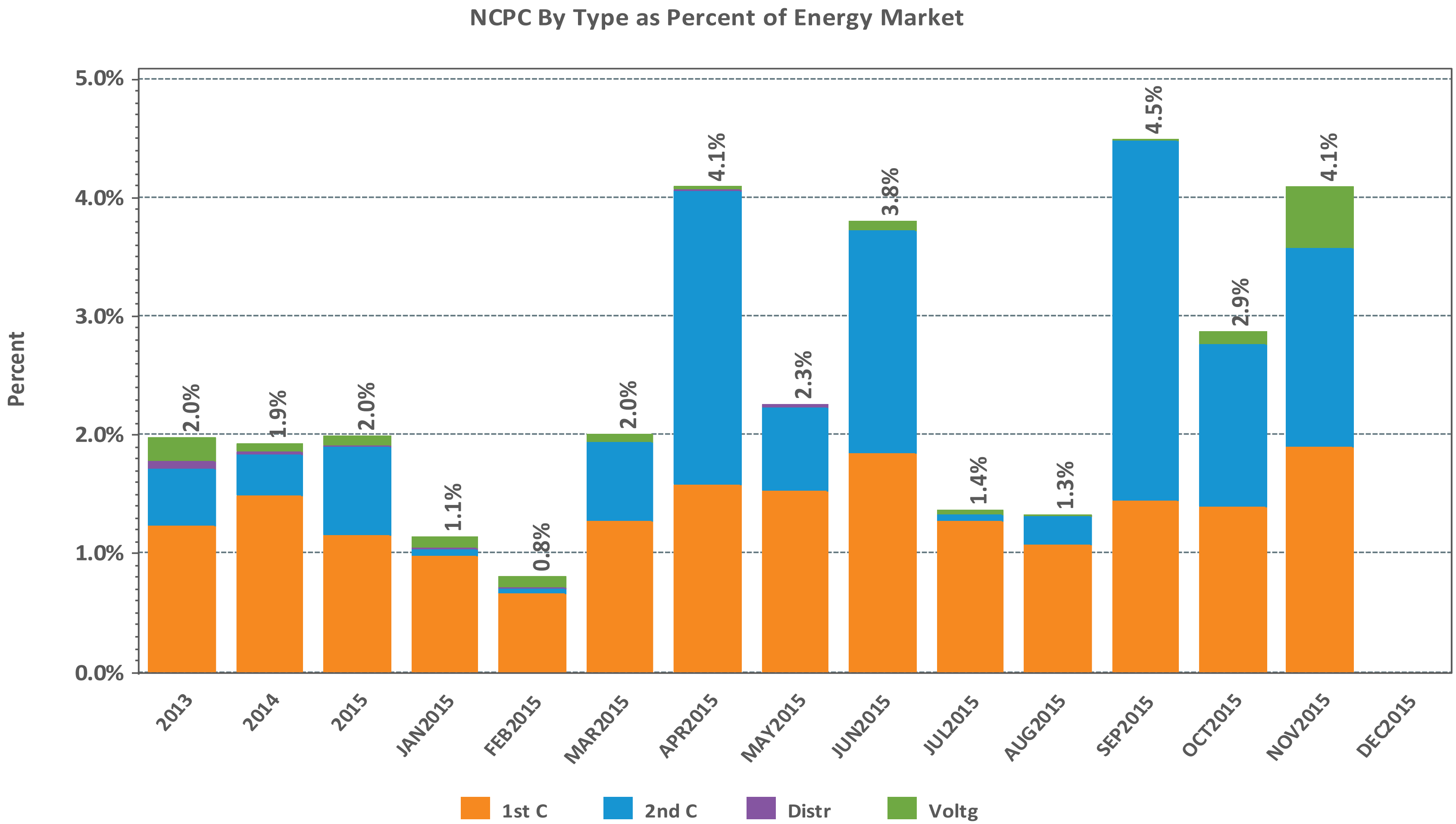
NCPC Charges for Voltage Support and High Voltage Control



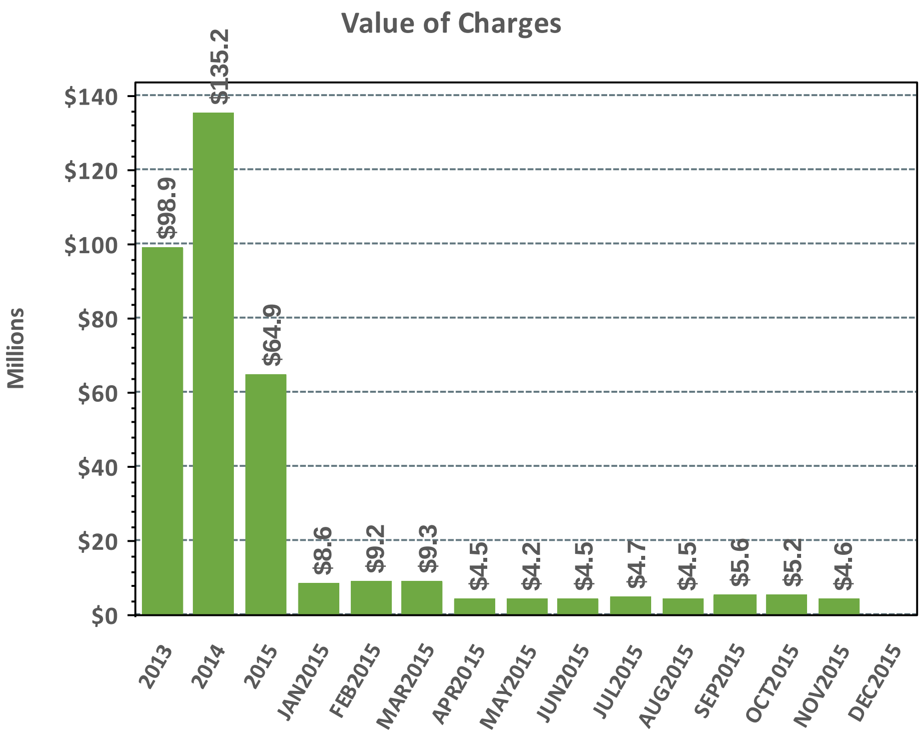
NCPC Charges by Type

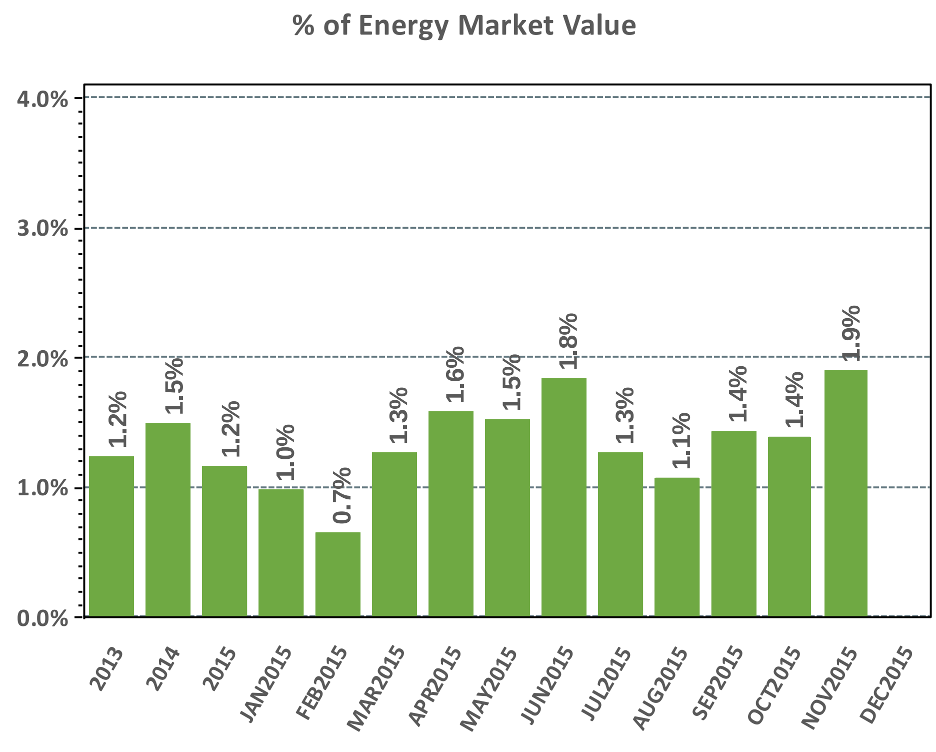


NCPC Charges as Percent of Energy Market



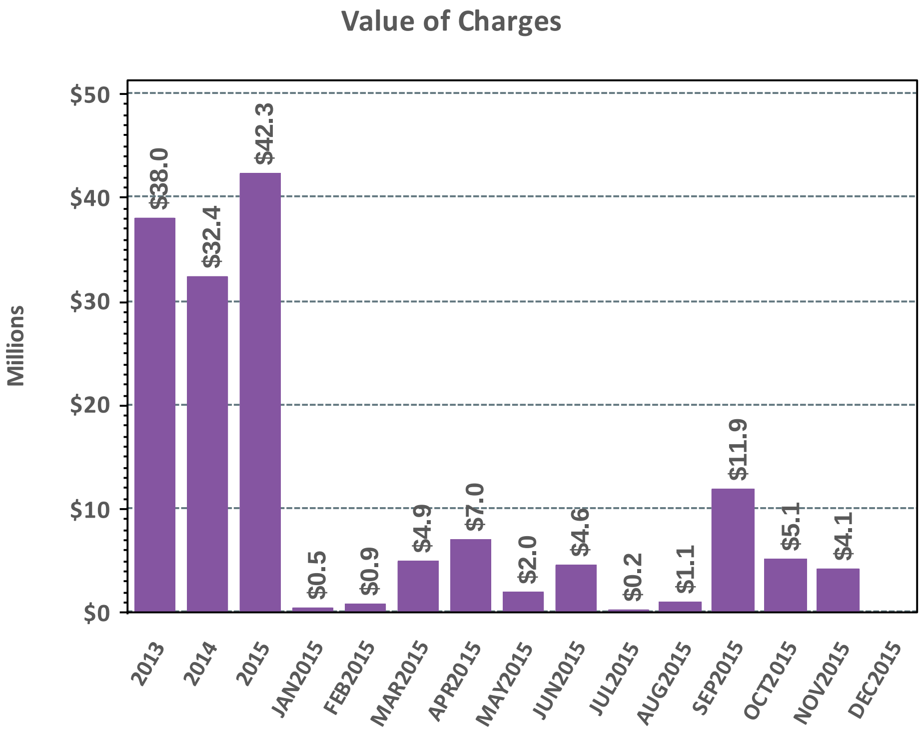
First Contingency NCPC Charges

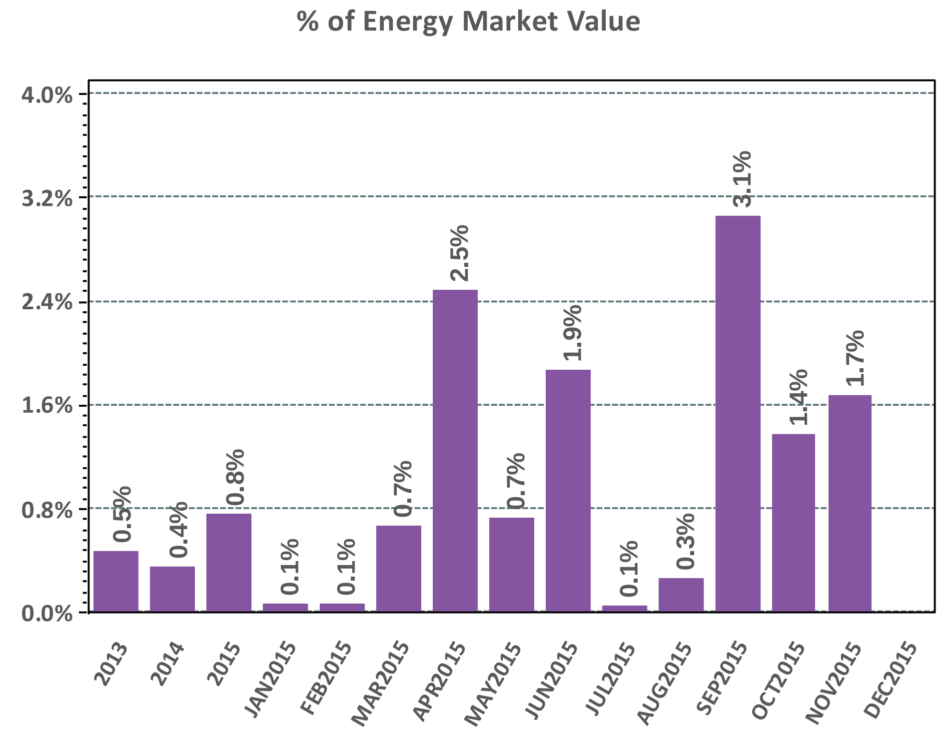




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

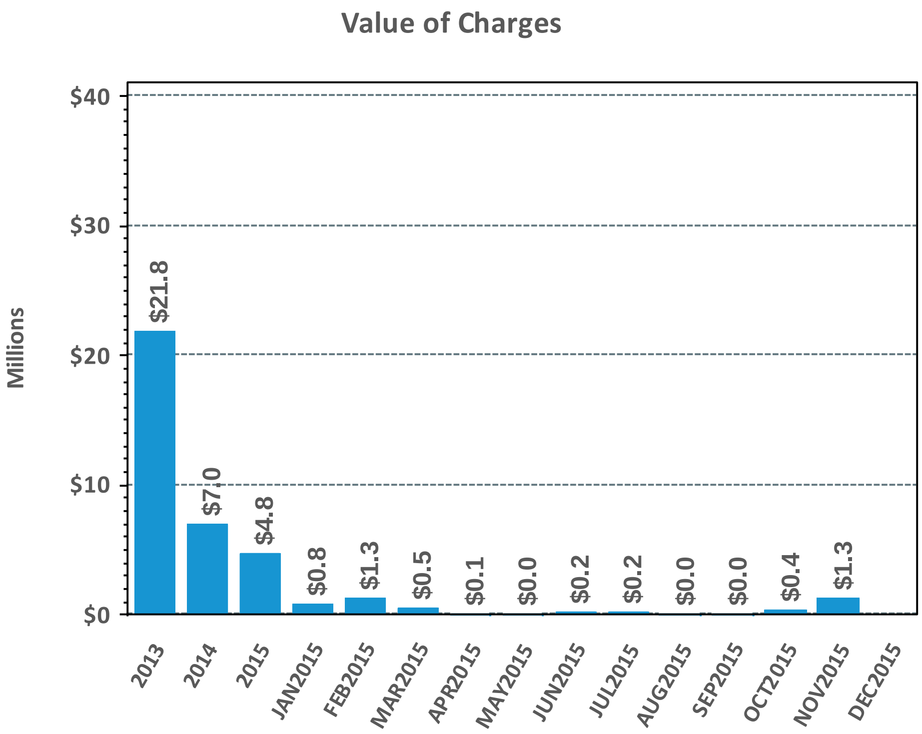
Second Contingency NCPC Charges

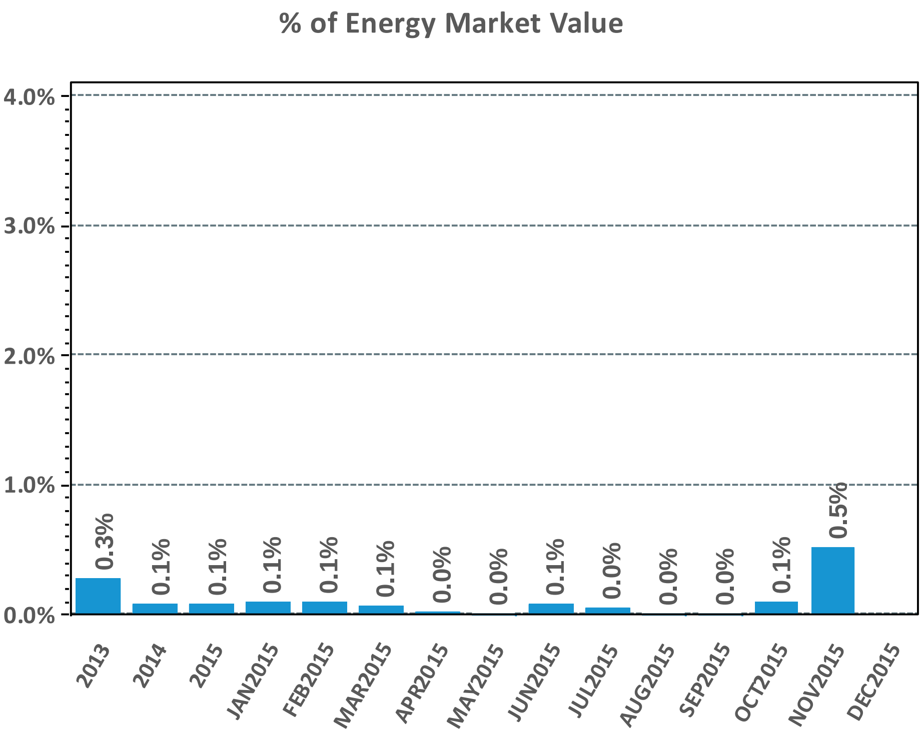




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

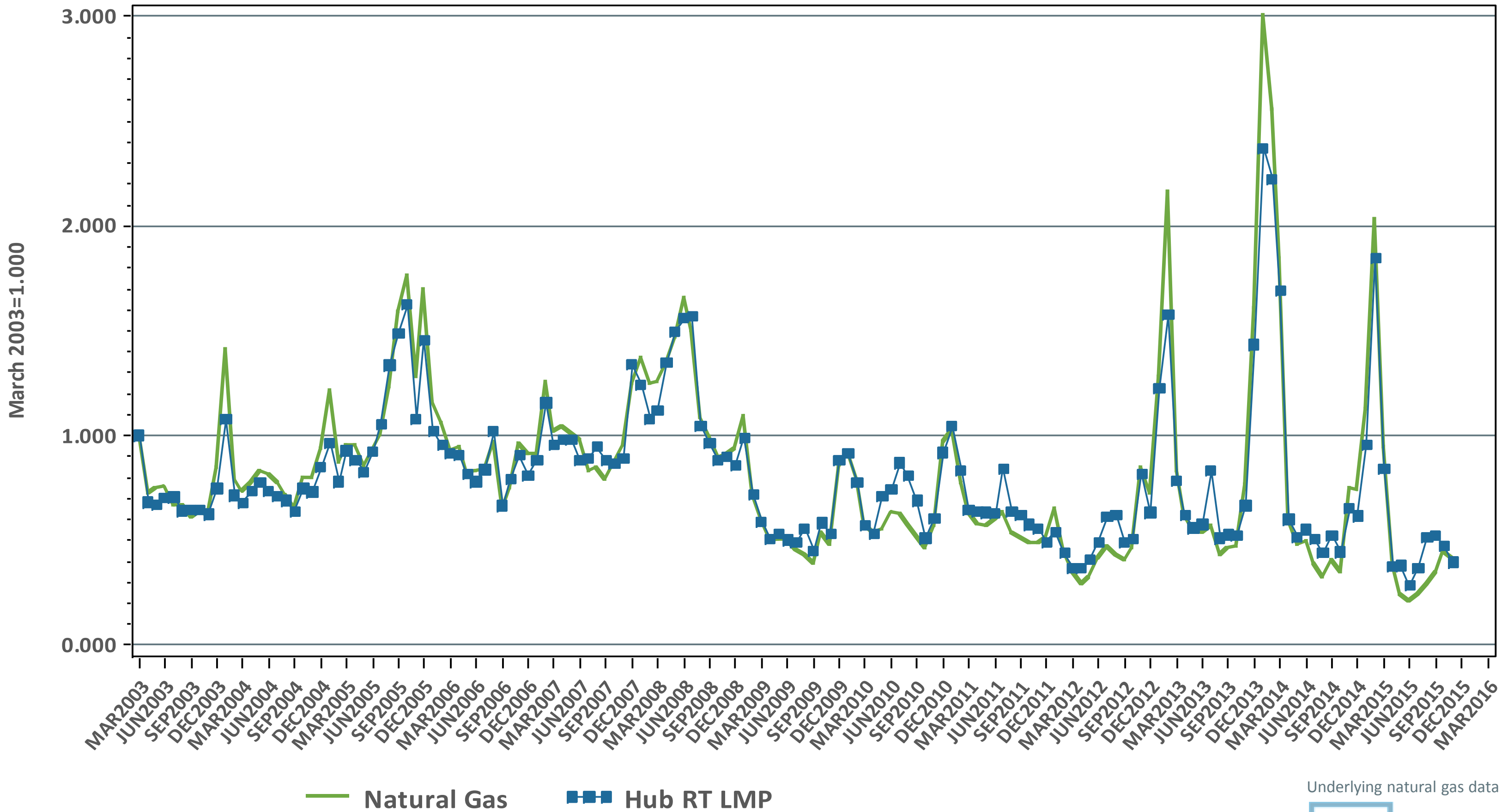
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2013	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$56.90	$55.43	$54.48	$55.98	$55.36	$57.80	$57.02	$56.38	$56.43
Real-Time	$56.32	$55.90	$53.23	$55.15	$55.08	$56.10	$56.43	$56.12	$56.06
RT Delta %	-1.0%	0.8%	-2.3%	-1.5%	-0.5%	-2.9%	-1.0%	-0.5%	-0.7%
Year 2014	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$64.98	$64.10	$61.95	$64.12	$63.82	$64.98	$64.71	$64.66	$64.57
Real-Time	$64.03	$63.11	$59.04	$61.48	$61.60	$63.34	$63.45	$63.29	$63.32
RT Delta %	-1.5%	-1.5%	-4.7%	-4.1%	-3.5%	-2.5%	-2.0%	-2.1%	-1.9%

November-14	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$48.39	$47.10	$46.24	$47.52	$46.26	$47.92	$48.17	$47.72	$47.72
Real-Time	$45.26	$44.67	$42.59	$43.42	$43.12	$44.80	$44.94	$44.83	$44.88
RT Delta %	-6.5%	-5.2%	-7.9%	-8.6%	-6.8%	-6.5%	-6.7%	-6.1%	-6.0%
November-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$32.28	$29.27	$31.17	$31.57	$29.77	$32.97	$32.22	$31.01	$31.14
Real-Time	$27.73	$26.67	$26.61	$27.23	$26.54	$27.60	$27.50	$27.22	$27.27
RT Delta %	-14.1%	-8.9%	-14.6%	-13.8%	-10.8%	-16.3%	-14.6%	-12.2%	-12.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-33.3%	-37.9%	-32.6%	-33.6%	-35.6%	-31.2%	-33.1%	-35.0%	-34.8%
Yr over Yr RT	-38.7%	-40.3%	-37.5%	-37.3%	-38.4%	-38.4%	-38.8%	-39.3%	-39.2%

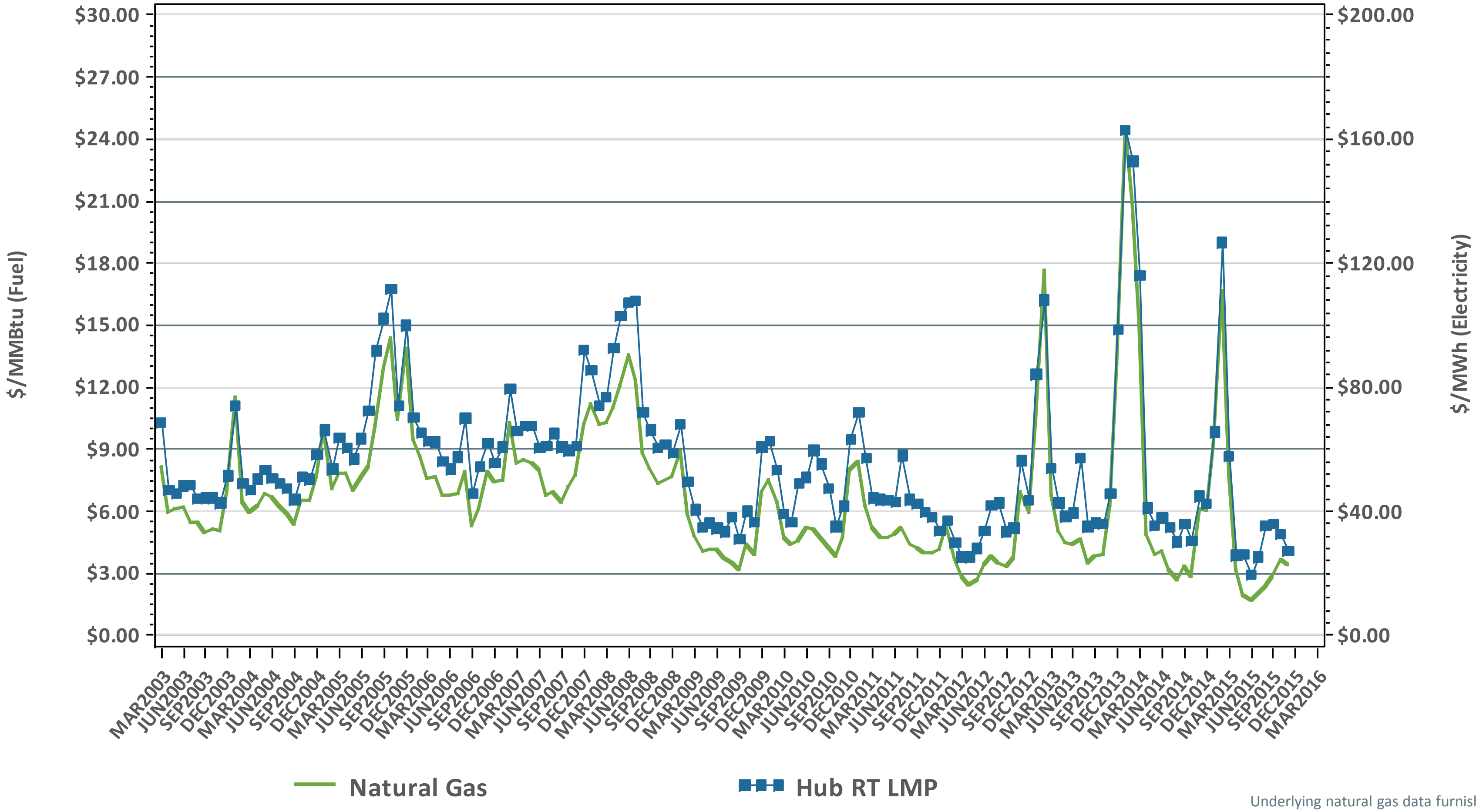
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

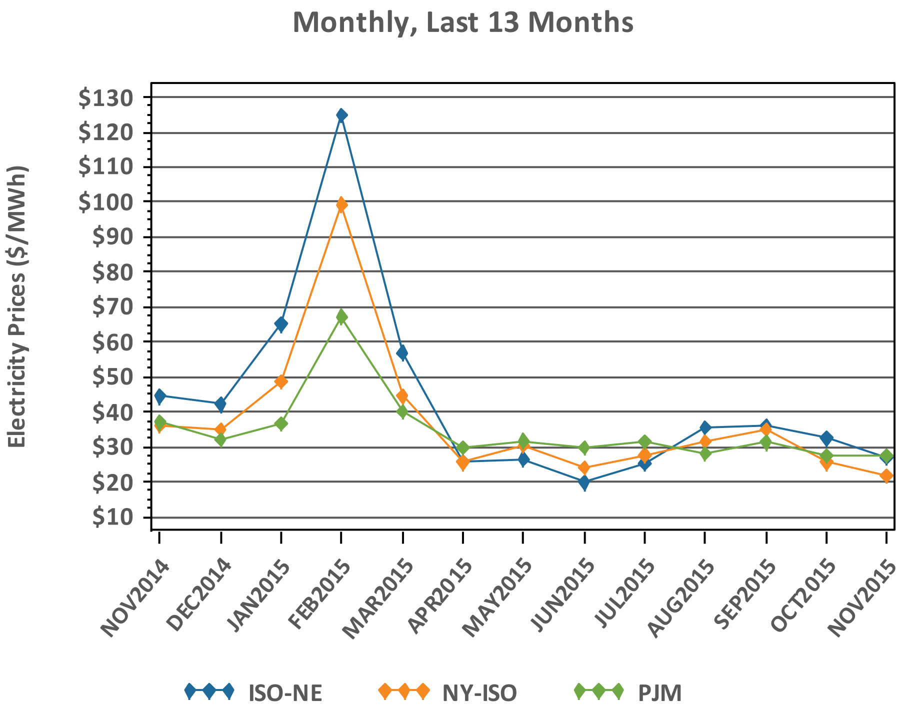
Monthly Average Fuel Price and RT Hub LMP



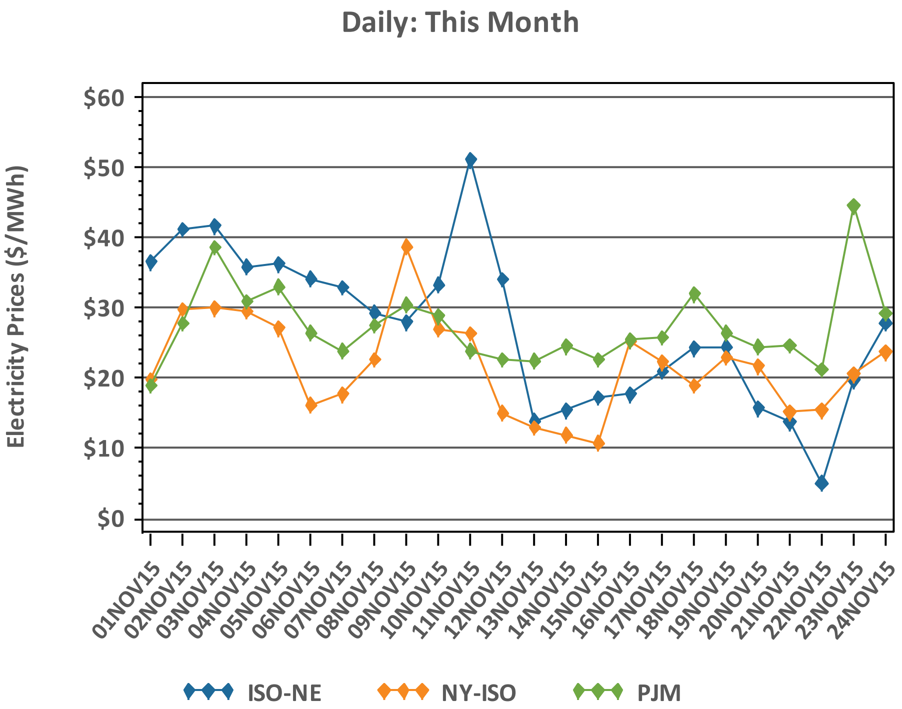
Underlying natural gas data furnished by:

ICE Global markets in clear view

New England, NY, and PJM Real Time Prices

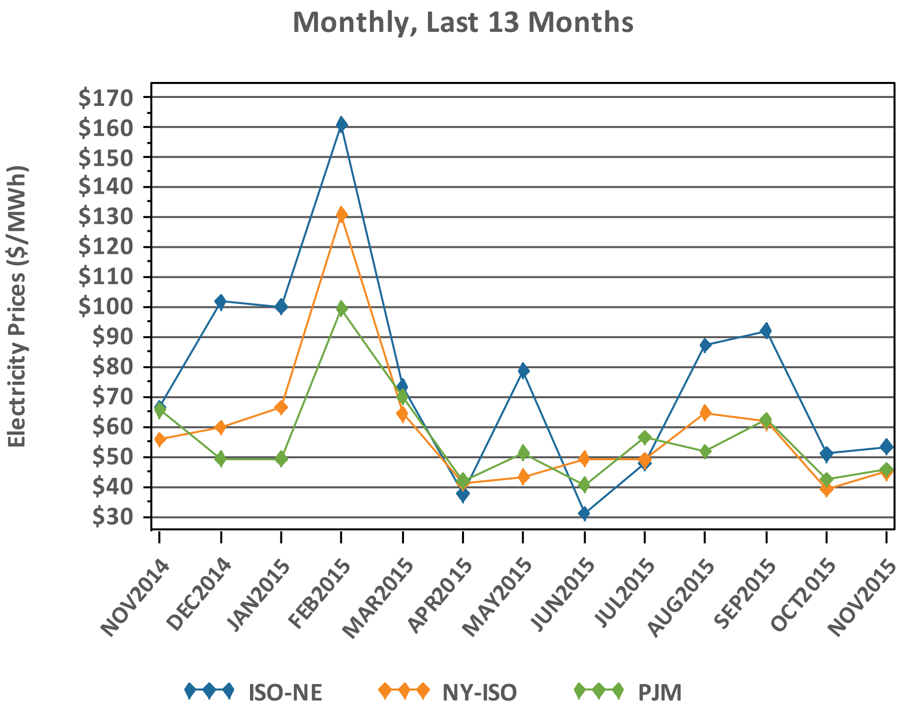


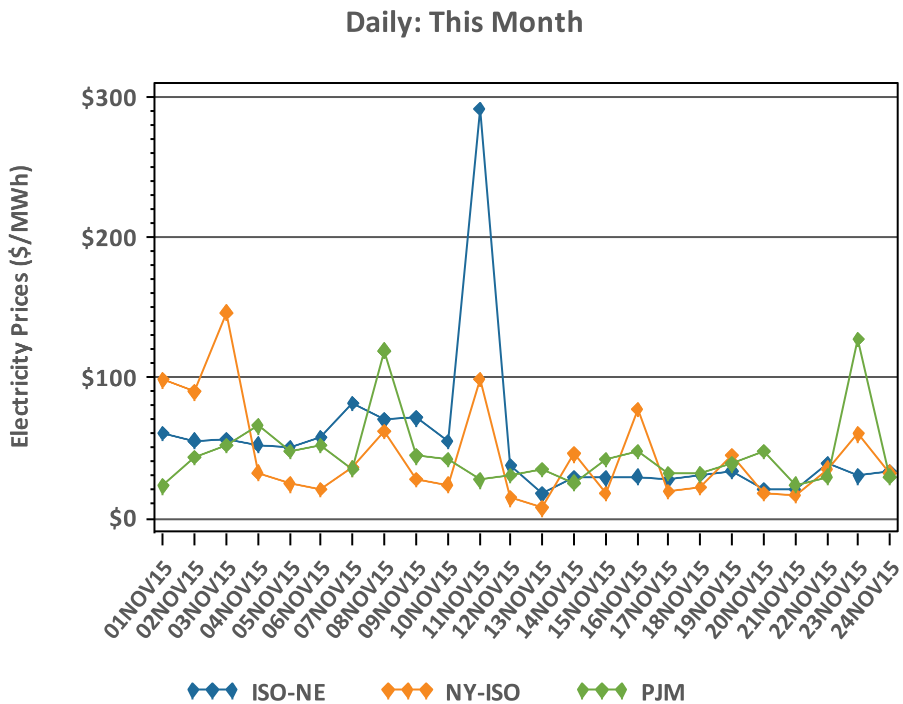
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Real Time Prices (Peak Hour)





*Forecasted New England peak hour is reflected.

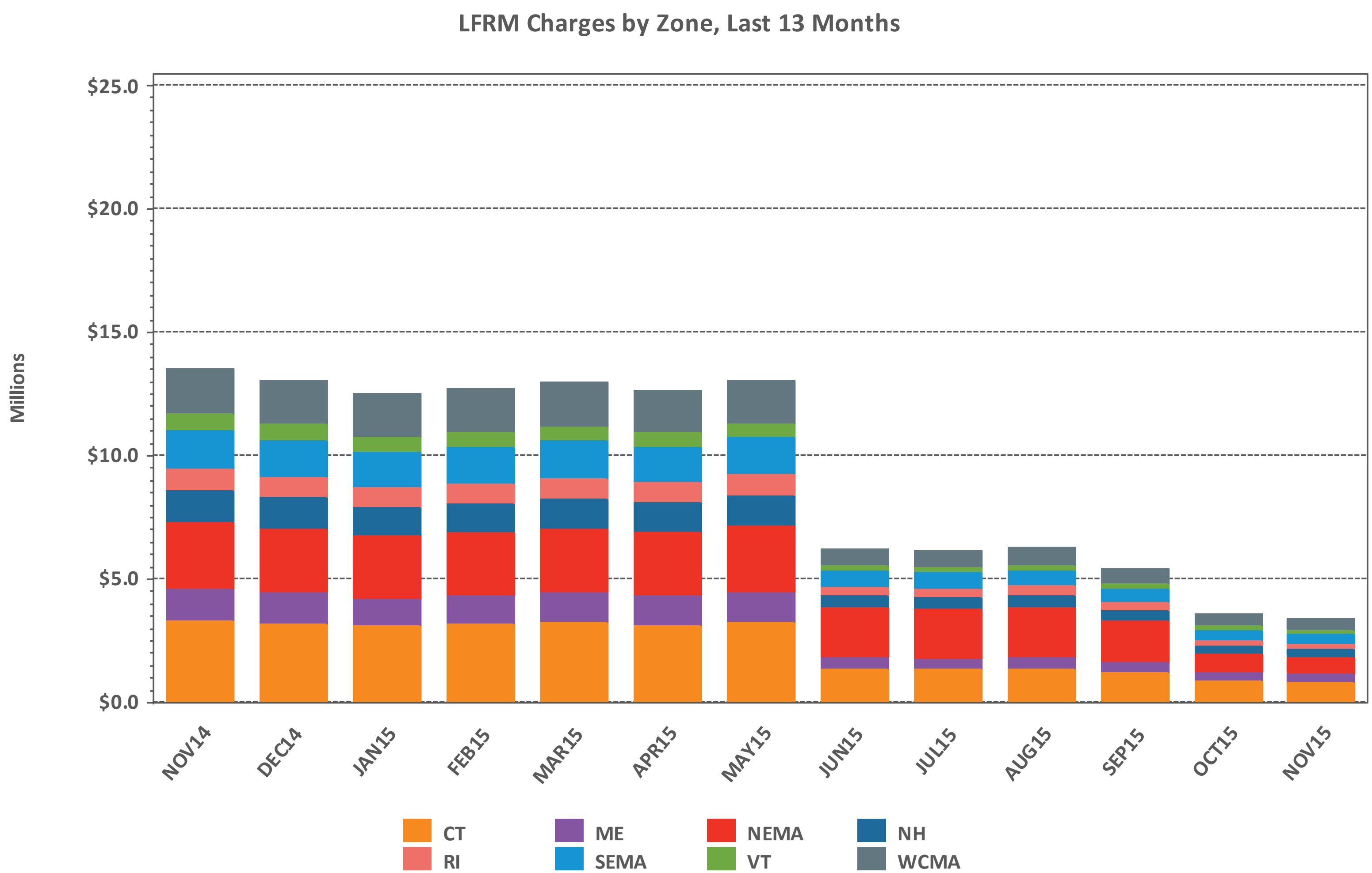
Reserve Market Results – November 2015

- Maximum potential Forward Reserve Market payments of $3.5M were reduced by credit reductions of $65K, failure-to-reserve penalties of $103K and failure-to-activate penalties of $2K, resulting in a net payout of $3.4M or 95% of maximum
  - Rest of System: $1.62M/$1.73M (94%)
  - Southwest Connecticut: $0.28M/$0.31M (89%)
  - Connecticut: $1.46M/$1.49M (98%)

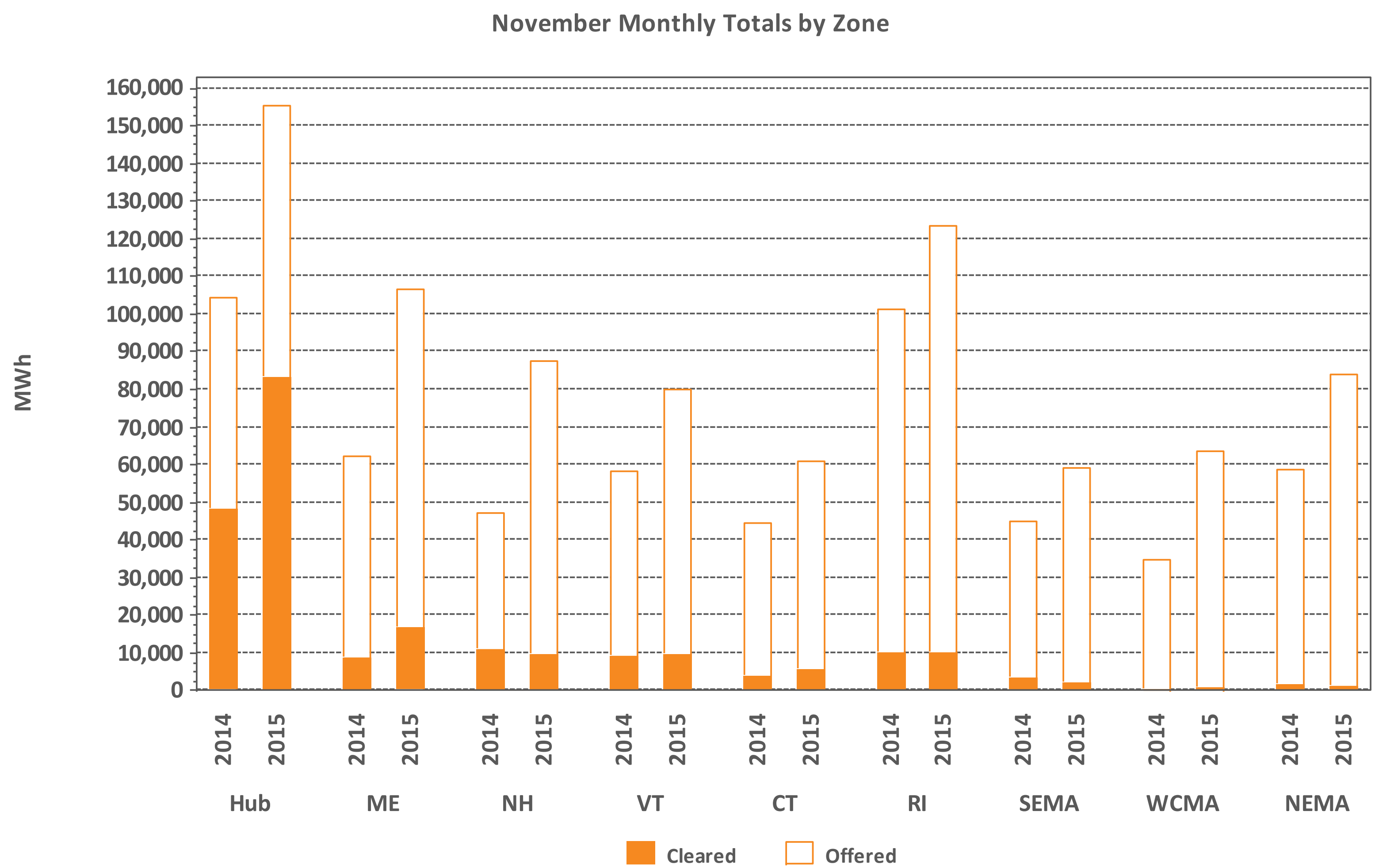
- $580K total Real-Time credits were reduced by $269K in Forward Reserve Energy Obligation Charges for a net of $310K in Real-Time Reserve payments
  - Rest of System: 28 hours, $188K
  - Southwest Connecticut: 28 hours, $137K
  - Connecticut: 28 hours, -$41K
  - NEMA: 28 hours, $26K

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

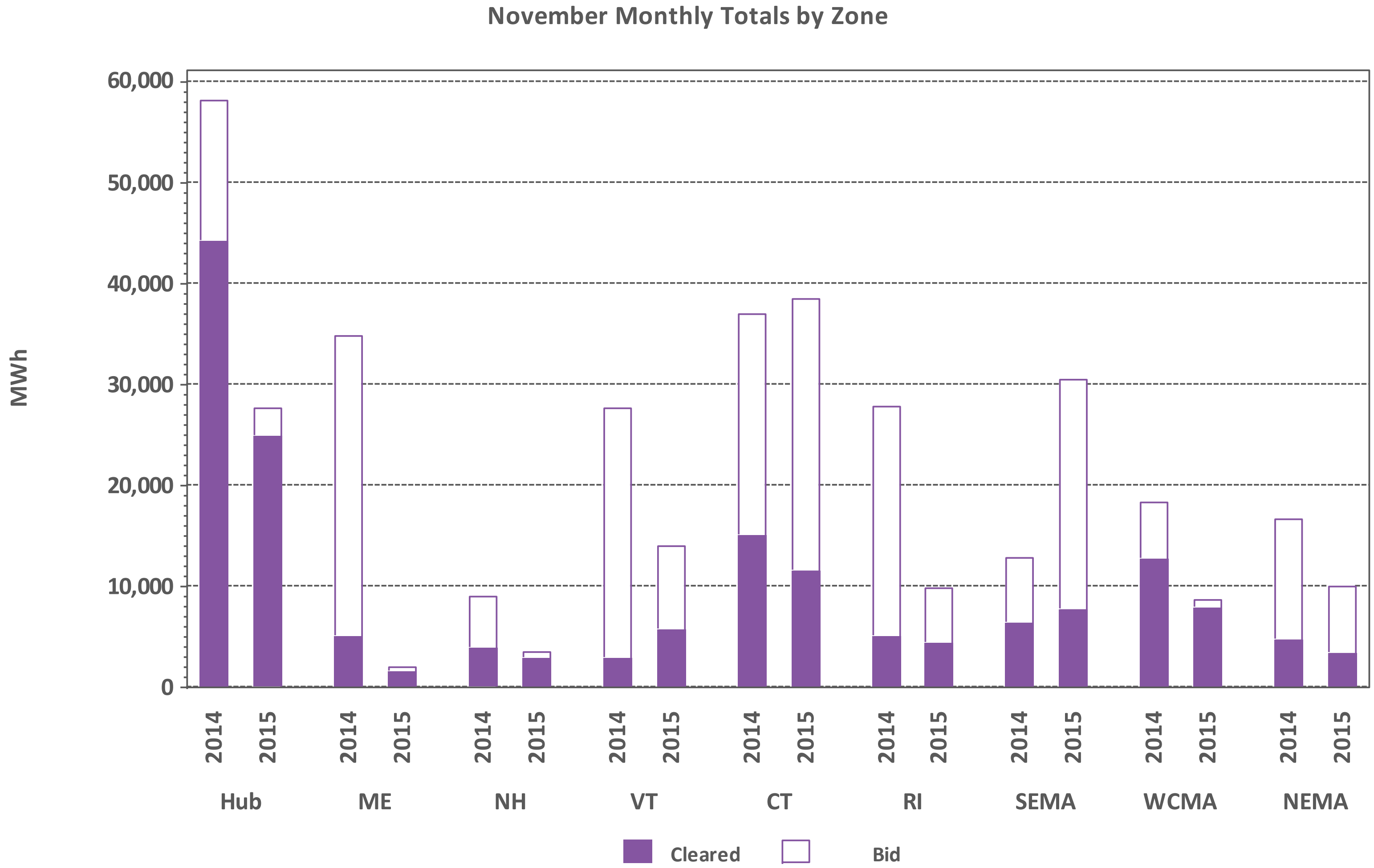
LFRM Charges to Load by Load Zone ($)



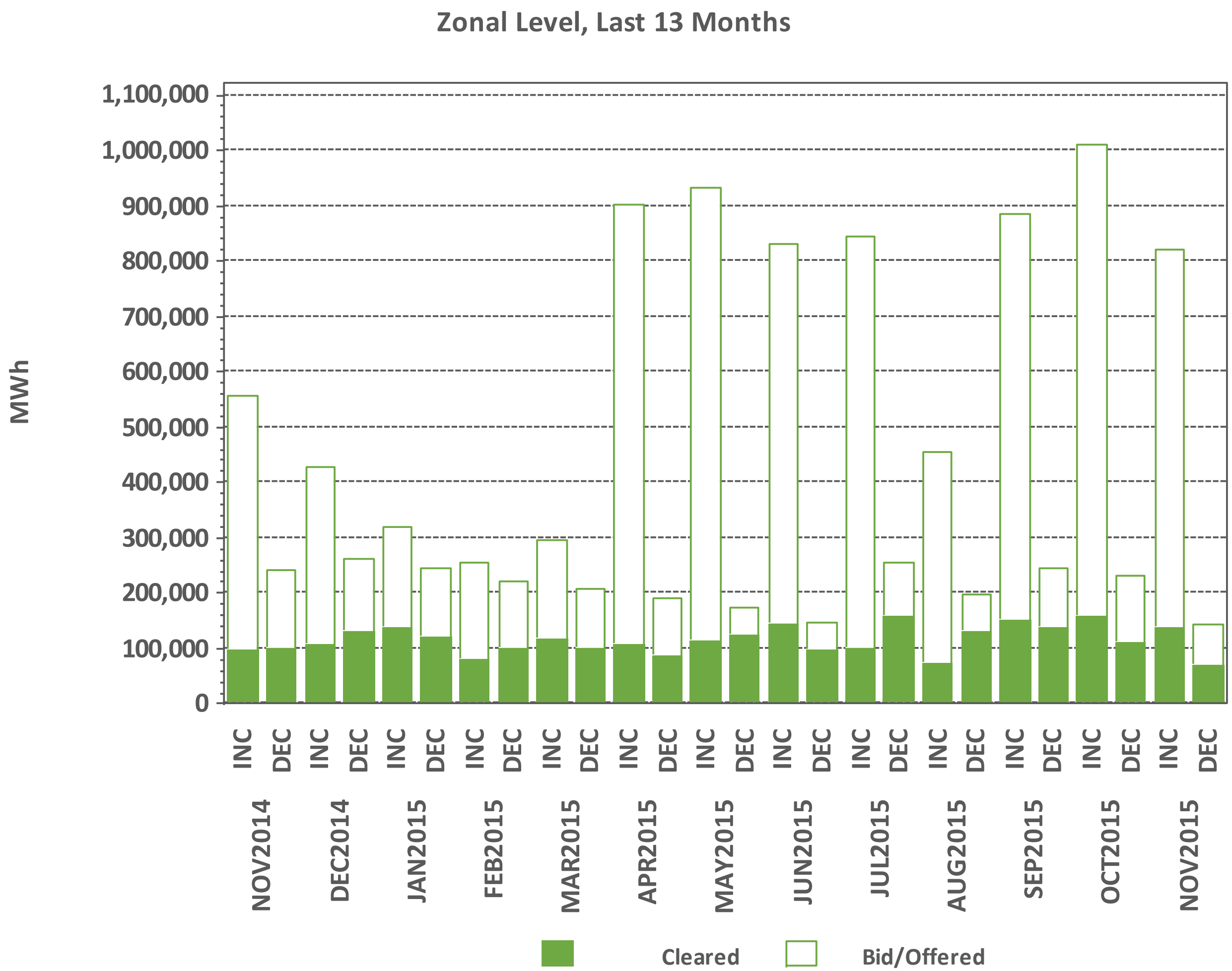
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

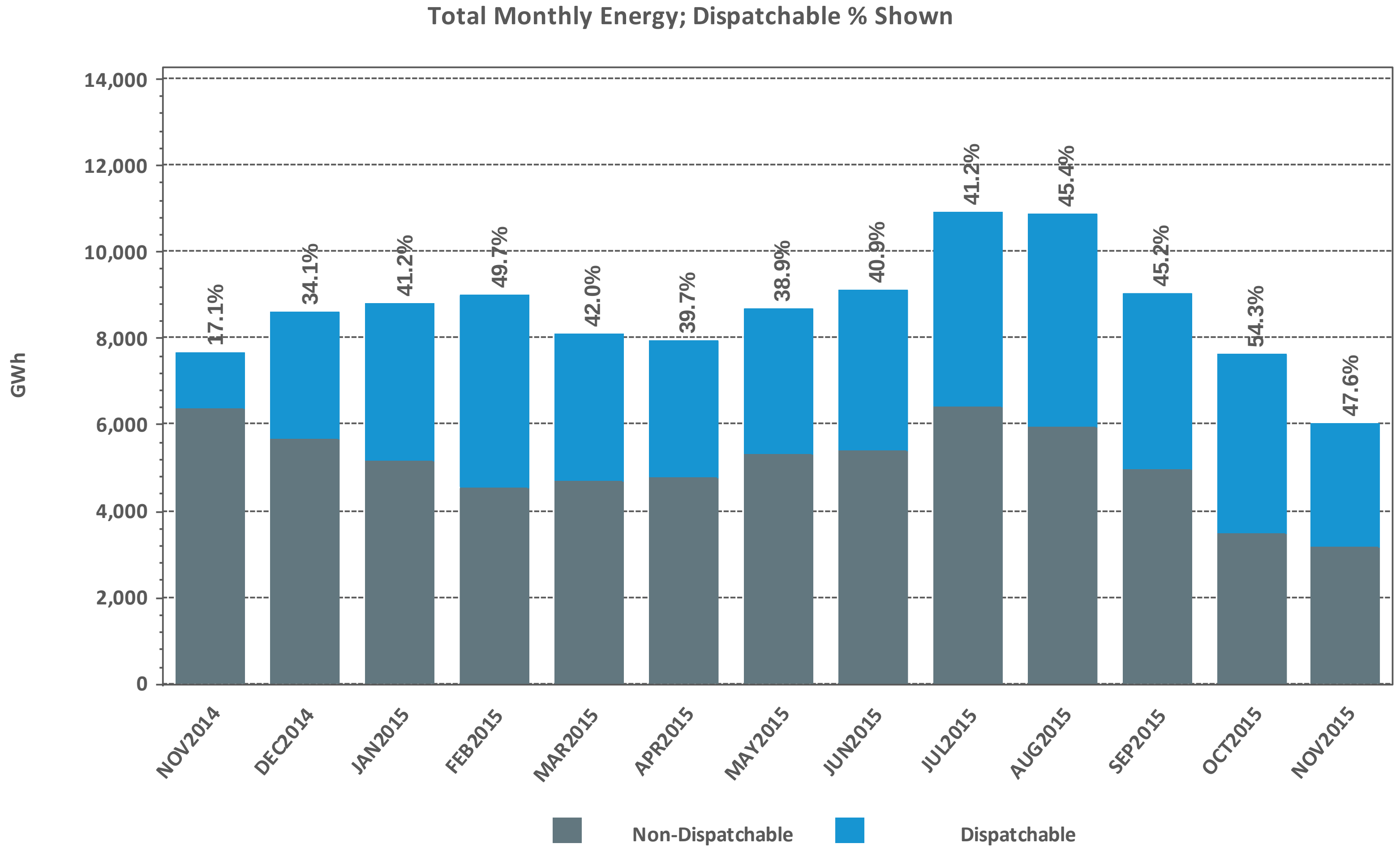


Total Increment Offers and Decrement Bids



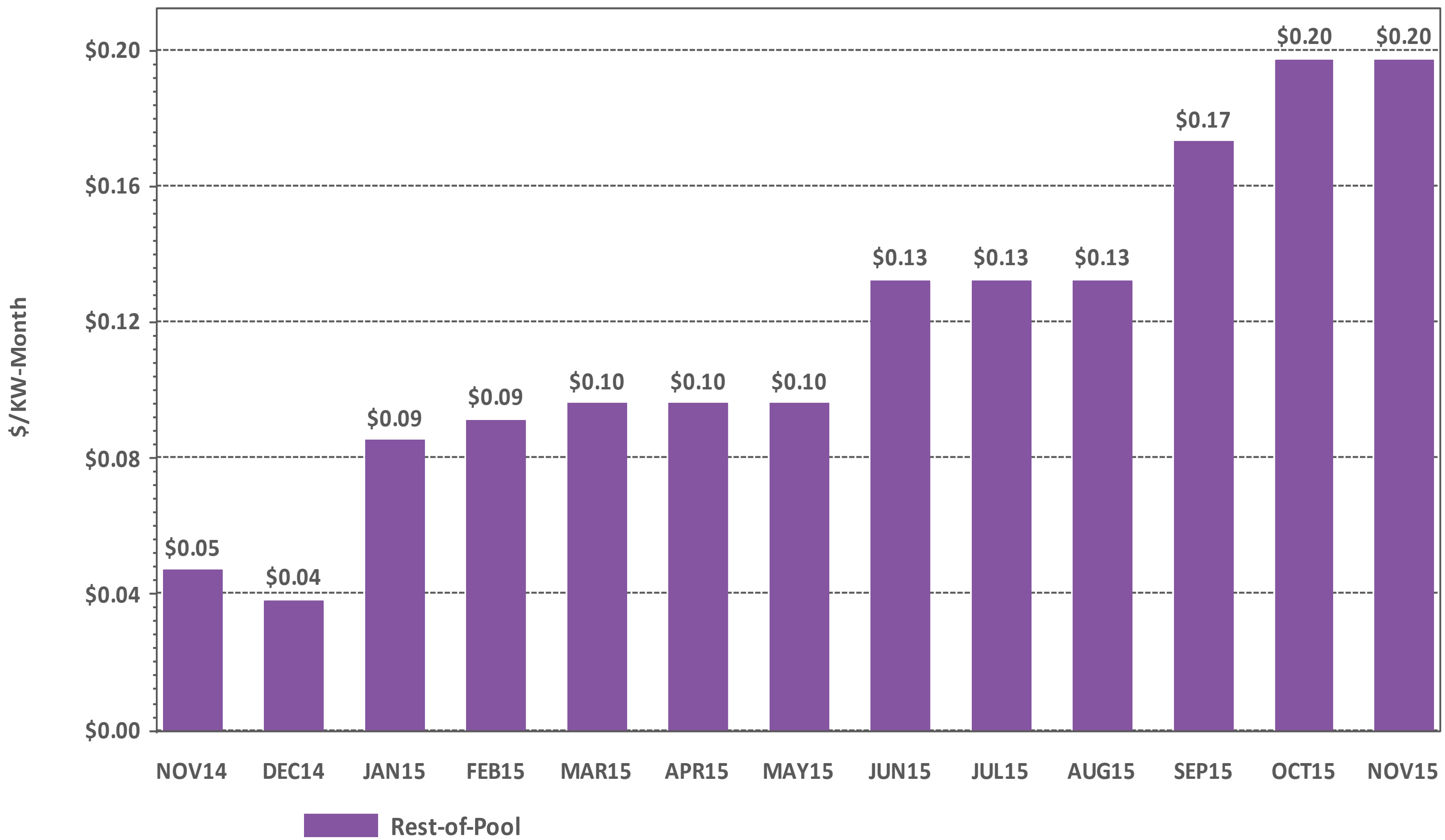
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

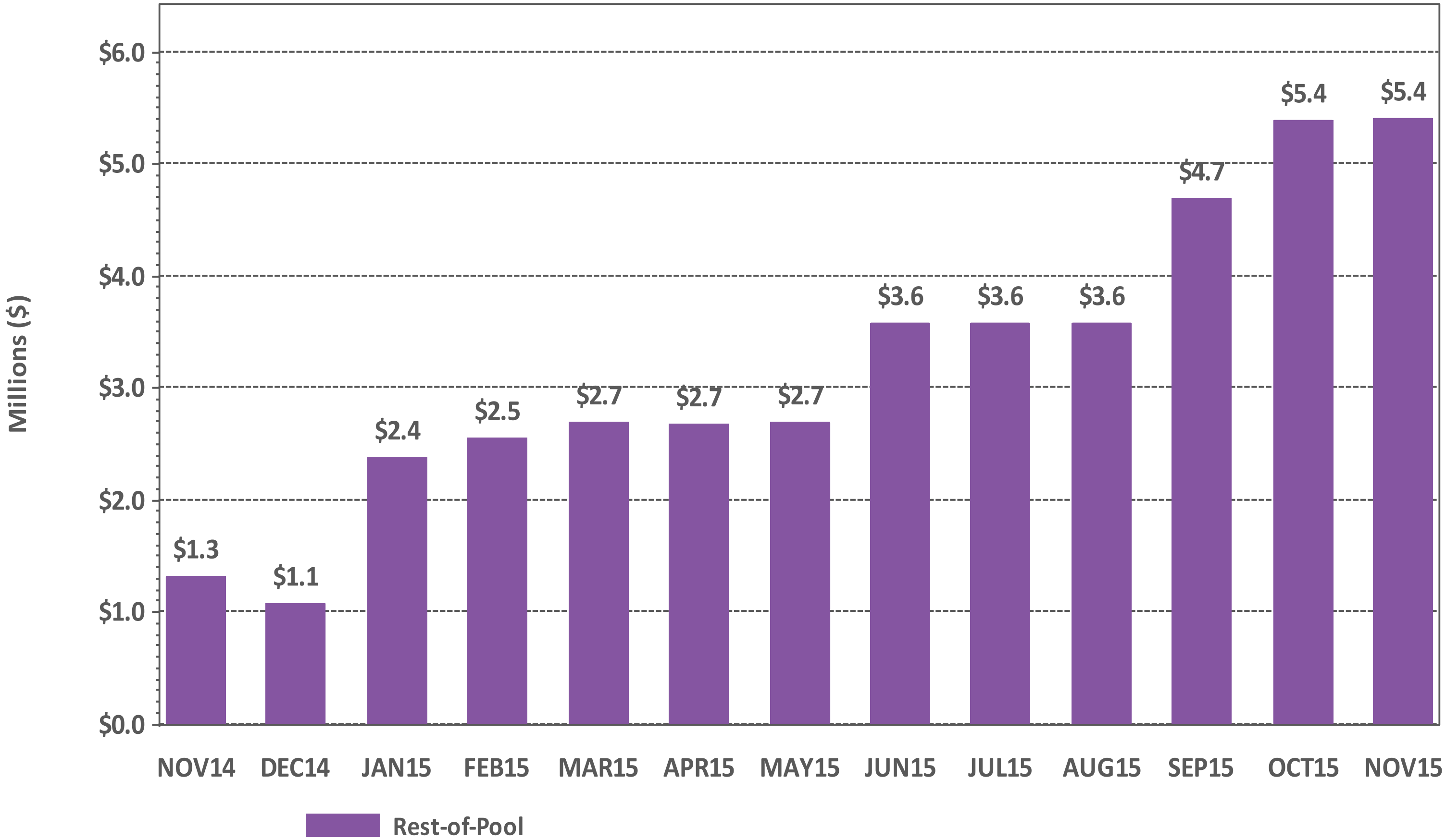
Rolling Average Peak Energy Rent (PER)



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

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

PER Adjustments



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

REGIONAL SYSTEM PLAN (RSP)

RSP15 and the RSP Process

- ISO Board of Directors approved RSP15 on November 5
  - The ISO appreciates all the stakeholder effort and input that made this report possible
- On October 27, the TC discussed proposed changes to the OATT, including Attachment K, in response to stakeholder requests
  - Issue RSP no less than once every three years
  - It is the ISO's intent to issue the next RSP in 2017, pending further input from stakeholders, and to issue RSP every other year
  - Change the timing of the RSP page turn, public meeting, and issuance from specific months to more generic requirements would better coordinate with stakeholder schedules, ISO workloads, and the processes of neighboring systems
  - Follow-up discussion with the TC will be scheduled and a vote is anticipated 4th quarter

Planning Advisory Committee (PAC)

- December PAC Meeting Agendas (tentative)
  - December 14
    - Offshore SEMA Wind Economic Study Update
    - Maine Wind Economic Study Update
    - Keene Road Economic Study Update
    - Transmission Planning Assumptions
  - December 15
    - Technical Session – FCM Overlapping Impact Analysis and the Queue

Distributed Generation Forecast Working Group (DGFWG)

- DGFWG meeting is scheduled for December 8 to discuss updates to state DG policies, recent DG survey results, and next steps
- ISO is surveying utilities on a monthly basis for total PV capacity by service territory in support of operational load forecasting activities
- ISO will continue to work with DGFWG stakeholders to improve data collection processes
- ISO is working with DG resources seeking participation in the FCM
- ISO is working with the transmission owners, distribution owners, the states, and IEEE to resolve interconnection issues
- ISO will continue participation in DOE projects that support operational and planning forecasts of PV

Environmental Matters

- Environmental Advisory Group teleconference held November 3 discussed the following:
  - Draft results of the 2014 New England Electric Generator Air Emissions Report
  - Mercury & Air Toxics Standard legal review
  - 2015 Ozone Standard and impacts on southern New England
  - EPA final Clean Power Plan and possible regional compliance strategies
  - Other environmental matters

Economic Studies

- ISO is conducting three 2015 economic studies of wind integration scenarios
  - Study of the Keene Road Area
  - Study utilizing the Strategic Transmission Analysis results
  - Study of offshore wind expansion
- Studies have been given priority by the ISO
  - Draft results for the Keene Road Area will be discussed with the PAC on December 15
  - Discussions of other draft results are planned for PAC by early 2016
  - Final reports completed after consultation with the PAC
- Studies will compare the performance of the future system with additional representative future system improvements
  - Studies will not include detailed transmission planning analysis including system impact study results
- ISO may form special economic study working groups that will supplement PAC discussions via conference calls
  - PAC presentations will be structured to discuss the general PAC economic study issues upfront
  - More technical discussions will be reviewed with PAC members as the last meeting agenda item

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

Connecticut River Valley

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	Oct-17	1
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	Oct-17	1
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	Oct-17	1
Chelsea Station - Rebuild to a three-breaker ring bus	Oct-17	1

Note: The above listing focuses on major transmission line construction and rebuilding.

NEEWS: Interstate Reliability Project

Status as of 11/24/15

Plan Benefit: Improves New England reliability by increasing transfer limits of three critical interfaces

Upgrade	Expected In-Service	Present Stage
Build New 345 kV Line 3271 Card - Lake Road	Dec-15	4
Card 345 kV Substation Expansion	Dec-15	4
Lake Road 345 kV Substation Expansion	Dec-15	3
Build New 345 kV Line 341 Lake Road to CT/RI Border	Dec-15	3
Build New 345 kV Line 341 CT/RI Border to West Farnum	Dec-15	3
West Farnum 345 kV Substation Additions (New Line Terminations)	Dec-15	3
New Sherman Road 345 kV Substation	Dec-15	3
West Farnum 115 kV Substation Upgrades	Sep-14	4
Reconductor 345 kV Line 328 West Farnum to Sherman Road	Dec-15	3
Riverside Substation Relay Upgrades	Sep-14	4
Woonsocket Substation Relay Upgrades	Sep-14	4
Hartford Avenue Substation Relay Upgrades	Sep-14	4
Build New 345 kV Line 366 West Farnum to MA/RI Border	Dec-15	3
Build New 345 kV Line 366 MA/RI Border to Millbury 3	Dec-15	3
Millbury 3 Substation Expansion	Dec-15	3
Carpenter Hill Substation Relay Upgrades	Dec-15	3

New Hampshire/Vermont 10-Year Upgrades

Status as of 11/24/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	3
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	Dec-16	2
New 115 kV overhead line, Scobie Pond-Huse Road	Nov-15	4*
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-17	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	3

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 11/24/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Dec-16	3
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	Apr-15	4*
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 11/24/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Mar-15	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

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 11/24/15

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 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	Dec-16	3
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-17	1
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	Dec-17	2
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-16	3
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	Dec-17	2
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Dec-17	2
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-17	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut (GHCC) Projects, cont.*

Status as of 11/24/15

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 In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-16	2
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	2
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-18	2
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut (GHCC) Projects, cont.*

Status as of 11/24/15

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 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	2
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	2
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	2
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	2
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 11/24/15

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 In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-17	2
Add a new 115 kV line from Frost Bridge to Campville	Dec-18	2
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-18	2
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-17	2
Add a new 345/115 kV autotransformer at Barbour Hill substation	Jan-16	3
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Jan-16	3
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-16	2

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 11/24/15

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 In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Dec-16	2
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-17	1
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	2
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-17	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-17	1
Loop the 1990 line in and out the Bunker Hill substation	Dec-17	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Dec-18	1
Loop the 1570 line in and out the Pootatuck substation	Dec-18	1
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	3

Southwest Connecticut Projects, cont.

Status as of 11/24/15

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 In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	1
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-18	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-18	1
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-18	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-18	1
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-17	1

Southwest Connecticut Projects, cont.

Status as of 11/24/15

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 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	Dec-17	1
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-16	2
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	Dec-16	1
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	1
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	1

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 11/24/15

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 In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	3
Upgrade the 115 kV bus at the Baird substation	Dec-17	2
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	3
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	2
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-19	1

Southwest Connecticut Projects, cont.

Status as of 11/24/15

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 In-Service	Present Stage
Remove the Sackett phase shifter	Dec-17	1
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-17	2
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-17	2
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-18	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Dec-16	2
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Dec-16	3
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	1
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Dec-17	1
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	1
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	1
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	3
Reconductor the F-158S 115 kV line from Maplewood to Everett	Dec-16	1
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	Dec-18	1
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	3
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-16	1

Greater Boston Projects, cont.

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Separate X-24 and E-157W DCT	May-17	1
Separate Q-169 and F-158N DCT	Dec-15	3
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	2
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	May-17	1
Install third 115 kV line from West Walpole to Holbrook	Dec-16	1
Install new 345 kV breaker in series with the 104 breaker at Stoughton	Dec-16	2
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-15	3
Install a new 115 kV line from Sudbury to Hudson	Dec-18	1

Greater Boston Projects, cont.

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-17	1
Install a 345 kV breaker in series with breaker 104 at Woburn	Dec-16	1
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	May-16	2
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Dec-15	3
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	2
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	Dec-16	2
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Dec-16	1
Install a 115 kV breaker on the West bus at K Street	Dec-16	2
Install 115 kV cable from Mystic to Chelsea	Dec-17	1
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-17	1

Greater Boston Projects, cont.

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-17	1
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station	Dec-16	1
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-17	1
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-17	2

Greater Boston Projects, cont.

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Jun-16	2
Upgrade Edgar 115 kV station to BPS standards	Dec-20	1
Upgrade Dover 115 kV station to BPS standards	Dec-20	1
Upgrade East Cambridge 115 kV station to BPS standards	Dec-19	1
Upgrade West Methuen 115 kV station to BPS standards	Jun-18	1
Upgrade Medway 115 kV station to BPS standards	Dec-19	2
Install a 200 MVAR STATCOM at Coopers Mills	Dec-18	1
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	1
Install a 345 kV 160 MVAR shunt reactor at K Street	May-18	1
Install a 115 kV breaker in series with the 5 breaker at Framingham	Jun-17	2
Install a 115 kV breaker in series with the 29 breaker at K Street	Dec-16	2

Pittsfield/Greenfield Projects

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Sep-16	2
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Dec-16	2
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Dec-16	3
Build a new 115 kV three-breaker switching station (Erving) ring bus	Dec-16	3
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Dec-16	3
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	3

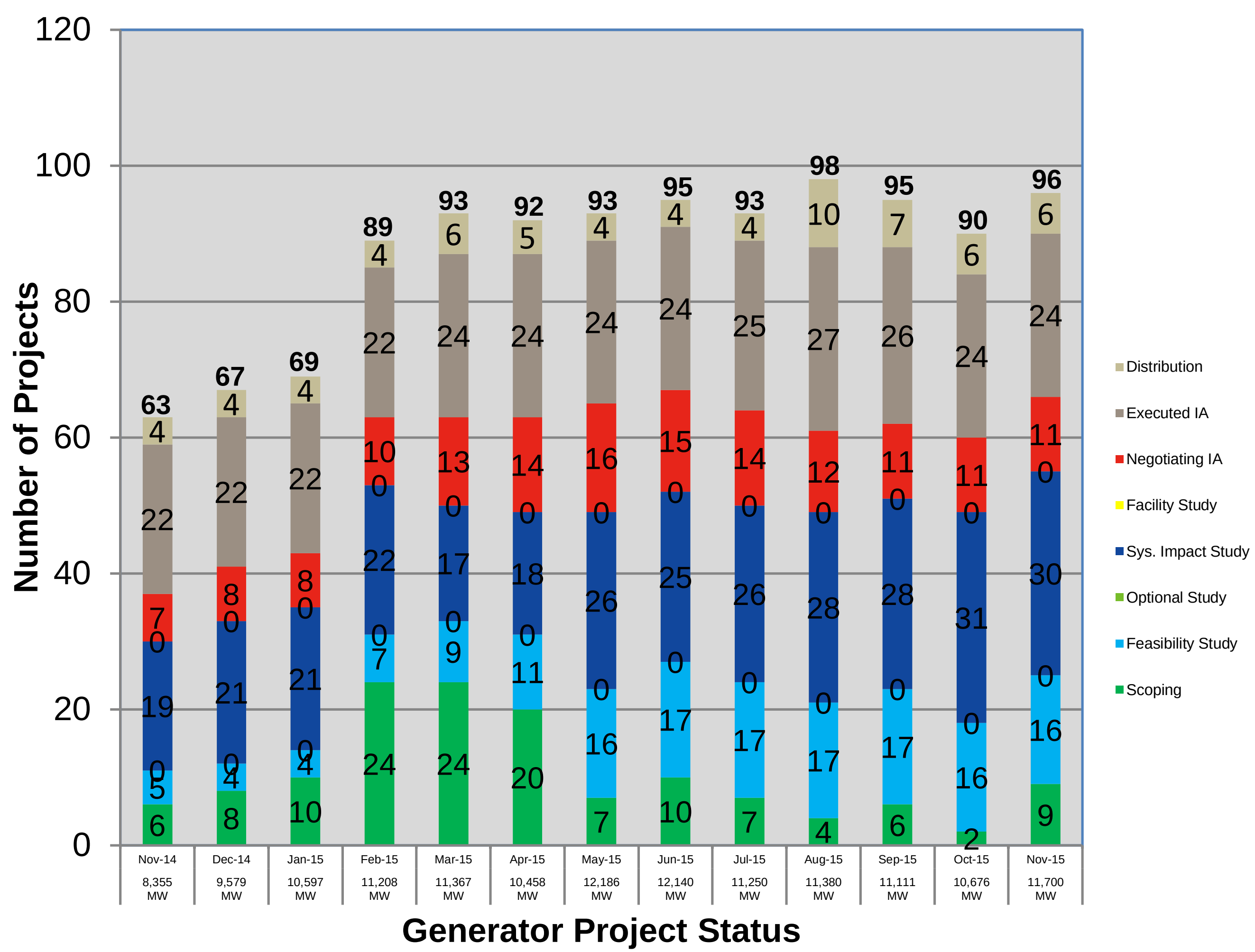
Pittsfield/Greenfield Projects, cont.

Status as of 11/24/15

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

Upgrade	Expected 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	3
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	Oct-16	2
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

Status of Tariff Studies



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

Note: As of November 2015, there are 7 ETU's in SIS and 2 in scoping

Note: November 2015 based on data as of November 23

OPERABLE CAPACITY ANALYSIS

Winter 2015-16 Analysis

Winter 2015-16 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January - 2016[2] CSO	January - 2016[2] SCC
Generator Operable Capacity MW [1]	29,897	32,814
OP CAP From OP-4 RTDR (+)	413	413
OP CAP From OP-4 RTEG (+)	174	174
Operable Capacity Generator with OP-4 DR and RTEG	30,484	33,401
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,226	1,226
Non Commercial Capacity (+)	35	35
Non Gas-fired Planned Outage MW (-)	686	729
Gas Generator Outages MW (-)	0	34
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	3,828	4,220
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,431	26,879
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,077	21,077
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,382	23,382
Operable Capacity Margin [3]	1,049	3,497

[1] Generator Operable Capacity is based on data as of **November 10, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **November 10, 2015**

[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **January 9, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

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

Winter 2015-16 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January- 2016[2] CSO	January - 2016[2] SCC
Generator Operable Capacity MW [1]	29,897	32,814
OP CAP From OP-4 RTDR (+)	413	413
OP CAP From OP-4 RTEG (+)	174	174
Operable Capacity Generator with OP-4 DR and RTEG	30,484	33,401
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,226	1,226
Non Commercial Capacity (+)	35	35
Non Gas-fired Planned Outage MW (-)	686	729
Gas Generator Outages MW (-)	0	34
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	4,534	5,004
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,725	26,095
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,737	21,737
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,042	24,042
Operable Capacity Margin [3]	(317)	2,053

[1] Generator Operable Capacity is based on data as of **November 10, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **November 10, 2015**

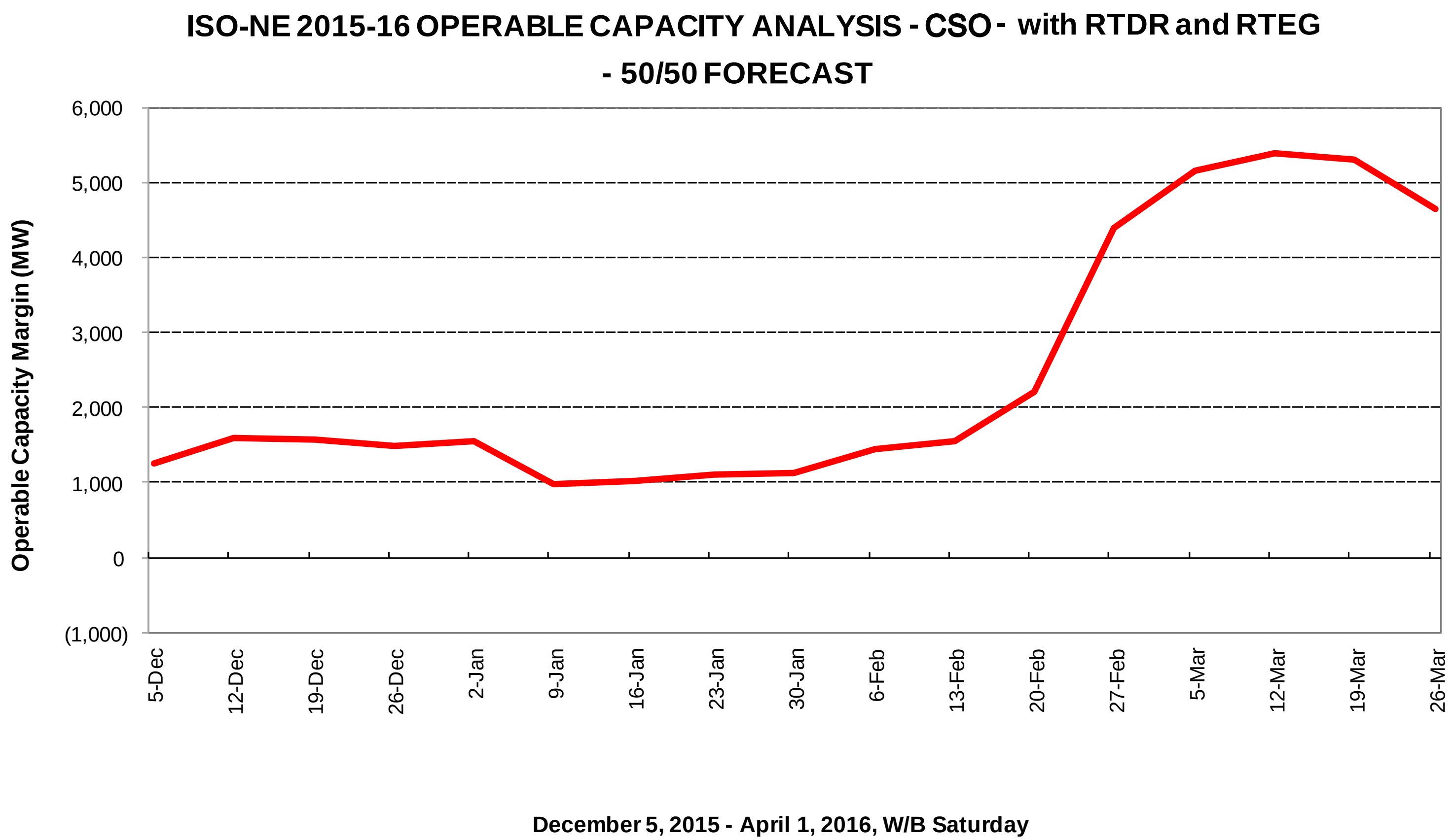
[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **January 9, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

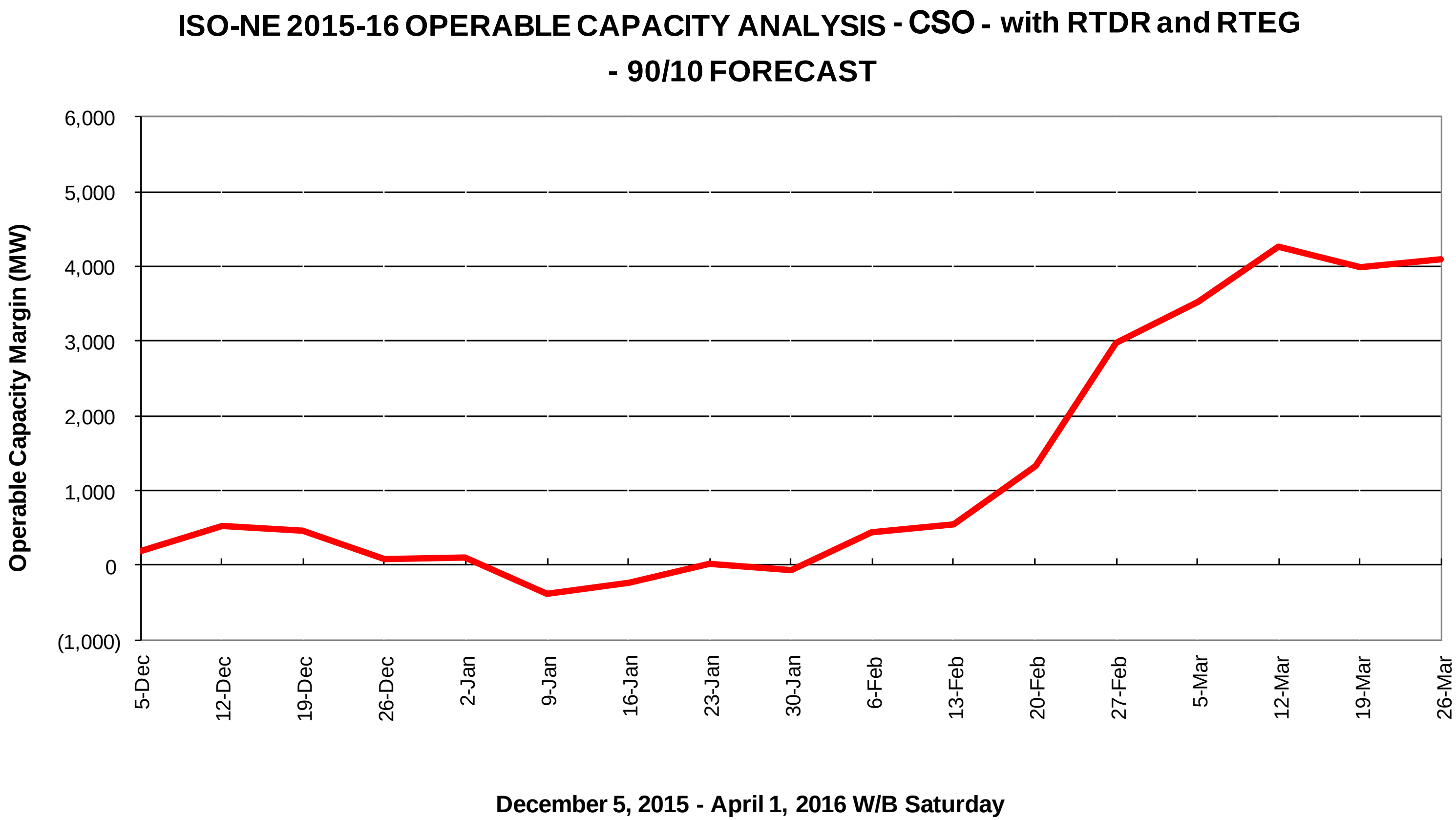
[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

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

Winter 2015-16 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Winter 2015-16 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



Winter 2015-16 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2015-16 OPERABLE CAPACITY ANALYSIS

December 4, 2015 - 50/50 FORECAST using CSO values with RTDR and RTEG

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
12/5/2015	30,428	867	30	1,537	1,250	3,200	2,188	23,150	19,951	2,305	22,256	894	284	1,178	142	1,320
12/12/2015	30,428	867	30	849	900	3,200	2,581	23,795	20,247	2,305	22,552	1,243	284	1,527	142	1,669
12/19/2015	30,428	867	30	831	654	3,200	2,870	23,770	20,258	2,305	22,563	1,207	284	1,491	142	1,633
12/26/2015	30,428	867	35	712	161	3,200	3,494	23,763	20,322	2,305	22,627	1,136	284	1,420	142	1,562
1/2/2016	29,897	1,226	35	685	0	2,800	3,741	23,932	20,602	2,305	22,907	1,025	413	1,438	174	1,612
1/9/2016	**29,897**	**1,226**	**35**	**686**	**0**	**2,800**	**3,828**	**23,844**	**21,077**	**2,305**	**23,382**	**462**	**413**	**875**	**174**	**1,049**
1/16/2016	29,897	1,226	35	643	0	2,800	3,828	23,887	21,077	2,305	23,382	505	413	918	174	1,092
1/23/2016	29,897	1,226	35	610	0	2,800	3,785	23,963	21,077	2,305	23,382	581	413	994	174	1,168
1/30/2016	29,897	1,226	35	642	0	3,100	3,655	23,761	20,850	2,305	23,155	606	413	1,019	174	1,193
2/6/2016	29,897	1,226	35	685	0	3,100	3,568	23,805	20,577	2,305	22,882	923	413	1,336	174	1,510
2/13/2016	29,897	1,226	35	700	0	3,100	3,481	23,877	20,547	2,305	22,852	1,025	413	1,438	174	1,612
2/20/2016	29,897	1,226	35	381	0	3,100	3,394	24,283	20,279	2,305	22,584	1,699	413	2,112	174	2,286
2/27/2016	29,897	1,226	37	794	0	2,200	2,715	25,451	19,269	2,305	21,574	3,877	413	4,290	174	4,464
3/5/2016	29,897	1,226	37	850	1,147	2,200	1,115	25,848	18,912	2,305	21,217	4,631	413	5,044	174	5,218
3/12/2016	29,897	1,226	37	1,271	1,324	2,200	486	25,879	18,712	2,305	21,017	4,862	413	5,275	174	5,449
3/19/2016	29,897	1,226	37	2,618	917	2,200	0	25,425	18,339	2,305	20,644	4,781	413	5,194	174	5,368
3/26/2016	29,897	1,226	37	3,024	1,239	2,700	0	24,197	17,762	2,305	20,067	4,130	413	4,543	174	4,717

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2015 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Winter 2015-16 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)

ISO-NE 2015-16 OPERABLE CAPACITY ANALYSIS

December 4, 2015 - 90/10 FORECAST using CSO values with RTDR and RTEG

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
12/5/2015	30,428	867	30	1,537	1,250	3,200	2,627	22,711	20,579	2,305	22,884	(173)	284	111	142	253
12/12/2015	30,428	867	30	849	900	3,200	3,022	23,354	20,883	2,305	23,188	166	284	450	142	592
12/19/2015	30,428	967	30	831	654	3,200	3,427	23,313	20,895	2,305	23,200	113	284	397	142	539
12/26/2015	30,428	867	35	712	161	3,200	4,260	22,997	20,960	2,305	23,265	(268)	284	16	142	158
1/2/2016	29,897	1,226	35	685	0	2,800	4,534	23,139	21,248	2,305	23,553	(414)	413	(1)	174	173
1/9/2016	**29,897**	**1,226**	**35**	**686**	**0**	**2,800**	**4,534**	**23,138**	**21,737**	**2,305**	**24,042**	**(904)**	**413**	**(491)**	**174**	**(317)**
1/16/2016	29,897	1,226	35	643	0	2,800	4,421	23,294	21,737	2,305	24,042	(748)	413	(335)	174	(161)
1/23/2016	29,897	1,226	35	610	0	2,800	4,194	23,554	21,737	2,305	24,042	(488)	413	(75)	174	99
1/30/2016	29,897	1,226	35	642	0	3,100	4,194	23,222	21,503	2,305	23,808	(586)	413	(173)	174	1
2/6/2016	29,897	1,226	35	685	0	3,100	3,922	23,451	21,222	2,305	23,527	(76)	413	337	174	511
2/13/2016	29,897	1,226	35	700	0	3,100	3,832	23,526	21,192	2,305	23,497	29	413	442	174	616
2/20/2016	29,897	1,226	35	381	0	3,100	3,652	24,025	20,916	2,305	23,221	804	413	1,217	174	1,391
2/27/2016	29,897	1,226	37	794	0	2,200	3,517	24,649	19,877	2,305	22,182	2,467	413	2,880	174	3,054
3/5/2016	29,897	1,226	37	850	1,147	2,200	2,135	24,828	19,509	2,305	21,814	3,014	413	3,427	174	3,601
3/12/2016	29,897	1,226	37	1,271	1,324	2,200	1,021	25,344	19,303	2,305	21,608	3,736	413	4,149	174	4,323
3/19/2016	29,897	1,226	37	2,618	917	2,200	725	24,700	18,920	2,305	21,225	3,475	413	3,888	174	4,062
3/26/2016	29,897	1,226	37	3,024	1,239	2,700	0	24,197	18,325	2,305	20,630	3,567	413	3,980	174	4,154

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2015 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16) This does not include Emergency Energy Transactions (EETs).

OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4:Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	**December 284[3]** **January - March 413[3]**
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	135 [4] **December 142[3]** **January - March 174 [3]**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of November 10, 2015.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.

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	Voltage Reduction requiring 10 minutes or less	269 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**December 2,975 MW** **January - March 3,136 MW**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of November 10, 2015.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.