NEPOOL PARTICIPANTS COMMITTEE
04/04/14 MEETING, AGENDA ITEM #5

NEPOOL Participants Committee Report

April 2014

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - March natural gas prices over the period were 19.3% lower, while oil prices were 0.3% lower than February 2014 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 17.6% lower than February 2014 averages
  - Average March 2014 natural gas prices and RT Hub LMPs were up 149% and 133%, respectively, from March 2013 averages
- Average daily (peak hour) DA cleared physical energy as percent of forecasted load was 98.6% in March and 98.4% in February

All data through March 26, unless otherwise noted.

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

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

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)*
  - March payments totaled $16.8M, up $673K from February
  - First Contingency payments totaled $15.0M, up $322K from February
    - $11.6M paid to internal resources, down $241k from February
      - $5.5M charged to DALO, $6.1M to RT Deviations
    - $3.4M paid to resources at external locations, up $563K from February
      - $3.4M charged to DALO at external locations, $15K to RT Deviations
  - Second Contingency payments totaled $1.8M, up $344K from the February total of $1.5M
  - Voltage payments were $0, unchanged from February
  - Distribution payments totaled $9K, up $6K from February
  - NCPC payments over the period as percent of Energy Market value were 1.3%

*Total includes NCPC payments to eligible resources at external locations.

Highlights, cont.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margin is projected for week beginning May 17th.
- The lowest 50/50 and 90/10 Summer Operable Capacity Margin is projected for weeks beginning May 31st, June 7th, June 14th.

Highlights, cont.

- The final interim photovoltaic forecast will be discussed with the Distributed Generation Forecast Working Group on April 2
- The draft Northeast Coordinated System Plan was discussed with the Inter-Area Planning Stakeholder Advisory Committee on March 28. Final stakeholder comments are due by April 8.
- Economic Study requests are due to ISO by April 1
- Work continues on identifying capacity zones for the ninth Forward Capacity Auction (FCA #9)
- Initial meeting of the Variable Resource Working Group is scheduled for April 17 in Springfield, MA

Highlights, cont.
Forward Capacity Market Update

- CCP #5
  - Annual Reconfiguration Auction #3 (ARA-3) was held March 3-5 and results were posted on March 19
- CCP #6 (2015-2016)
  - ARA-2 Bilateral Period to open on May 1 and close on May 7
- CCP #7 (2016-2017)
  - ARA-1 Bilateral Period to open on April 1 and close on April 7
- CCP #8 (2017-2018)
  - A supplemental filing was made on March 25 indicating that Groton Wind received a capacity supply obligation in accordance with the tariff
- CCP #9 (2018-2019)
  - On January 31, the ISO submitted tariff changes related to the modeling of capacity zones. FERC has yet to approve those changes.
  - Discussions with the PAC continue regarding zones to be modeled for FCA #9. Final list of zones to be determined by the April/May time frame.
  - Show of Interest window closed on March 4

CCP – Capacity Commitment Period

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature – Below Average (-6.3) Max - 60, Min - 11 Precipitation 3.55” (Liquid) Below Average Normal 3.85” Snowfall = 1.30”	Hartford	Temperature – Below Average (-7.8) Max - 59, Min - 0 Precipitation 3.77” (Liquid) – Below Average Normal = 3.88” Snowfall = 1.92”

Peak Load:	19,700 MW	March 3, 2014	19:00

MLCC2:			
3/4/2014	12:30 – 20:00	All of New England	Capacity
OP-4 : **None**			

NPCC Simultaneous Activation of Reserve Events:

03/01/14	PJM	800MW
03/03/14	ISO-NE	557MW
03/04/14	NYISO	1290MW
03/10/14	NYISO	1290MW
03/14/14	IESO	800MW

System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	**03/09/14**	**Start - 04:00, Expired - 08:00** **Interchange Cuts Only**
Minimum Generation Warning	**03/09/14**	**Start - 15:00, Expired - 18:00** **Interchange Cuts Only**
Minimum Generation Warning	**03/10/14**	**Start -04:00, Expired - 07:00** **Interchange Cuts & SS Denied**
Minimum Generation Warning	**03/10/14 – 03/11/14**	**Start - 23:00, Expired - 07:00** **Interchange Cuts Only**
Minimum Generation Warning	**03/11/14**	**Start - 15:00, Expired - 18:00** **SS Denied Only**
Minimum Generation Warning	**03/11/14**	**Start - 23:00, Expired - 23:59** **No Actions Taken**
Minimum Generation Warning	**03/12/14**	**Start - 00:01, Expired - 08:00** **Interchange Cuts & SS Denied**
Minimum Generation Warning	**03/12/14**	**Start - 09:00, Expired - 17:00** **No Actions Taken**
Minimum Generation Warning	**03/12/14 – 03/13/14**	**Start - 21:00, Expired - 07:00** **Interchange Cuts & SS Denied**
Minimum Generation Warning	**03/15/14**	**Start - 14:00, Expired - 19:00** **Interchange Cuts Only**
Minimum Generation Event	**03/15/14**	**Start - 07:16, Expired - 19:00** **Interchange Cuts Only**

System Operations

Minimum Generation Warnings & Events: Continued

Minimum Generation Warning	**03/15/14 – 03/16/14**	**Start - 23:00, Expired - 09:00** **Interchange Cuts & SS Denied**
Minimum Generation Event	**03/16/14**	**Start – 00:01, Expired - 04:00** **Interchange Cuts Only**
Minimum Generation Event	**03/16/14**	**Start – 07:05, Expired - 09:00** **No Actions Taken**
Minimum Generation Warning	**03/16/14**	**Start - 16:00, Expired - 20:00** **SS Denied Only**
Minimum Generation Warning	**03/19/14 – 03/20/14**	**Start - 22:00, Expired - 06:00** **Interchange Cuts Only**
Minimum Generation Warning	**03/20/14 – 03/21/14**	**Start - 23:00, Expired - 06:00** **Interchange Cuts & SS Denied**
Minimum Generation Warning	**03/21/14**	**Start - 23:00, Expired - 23:59** **Interchange Cuts Only**
Minimum Generation Warning	**03/22/14**	**Start – 00:01, Expired - 07:00** **Interchange Cuts & SS Denied**
Minimum Generation Warning	**03/22/14**	**Start – 18:00, Expired – 19:00** **No Actions Taken**
Minimum Generation Warning	**03/22/14 – 03/23/14**	**Start – 22:00, Expired – 10:00** **Interchange Cuts Only**
Minimum Generation Event	**03/23/14**	**Start – 00:01, Expired – 08:30** **Interchange Cuts Only**

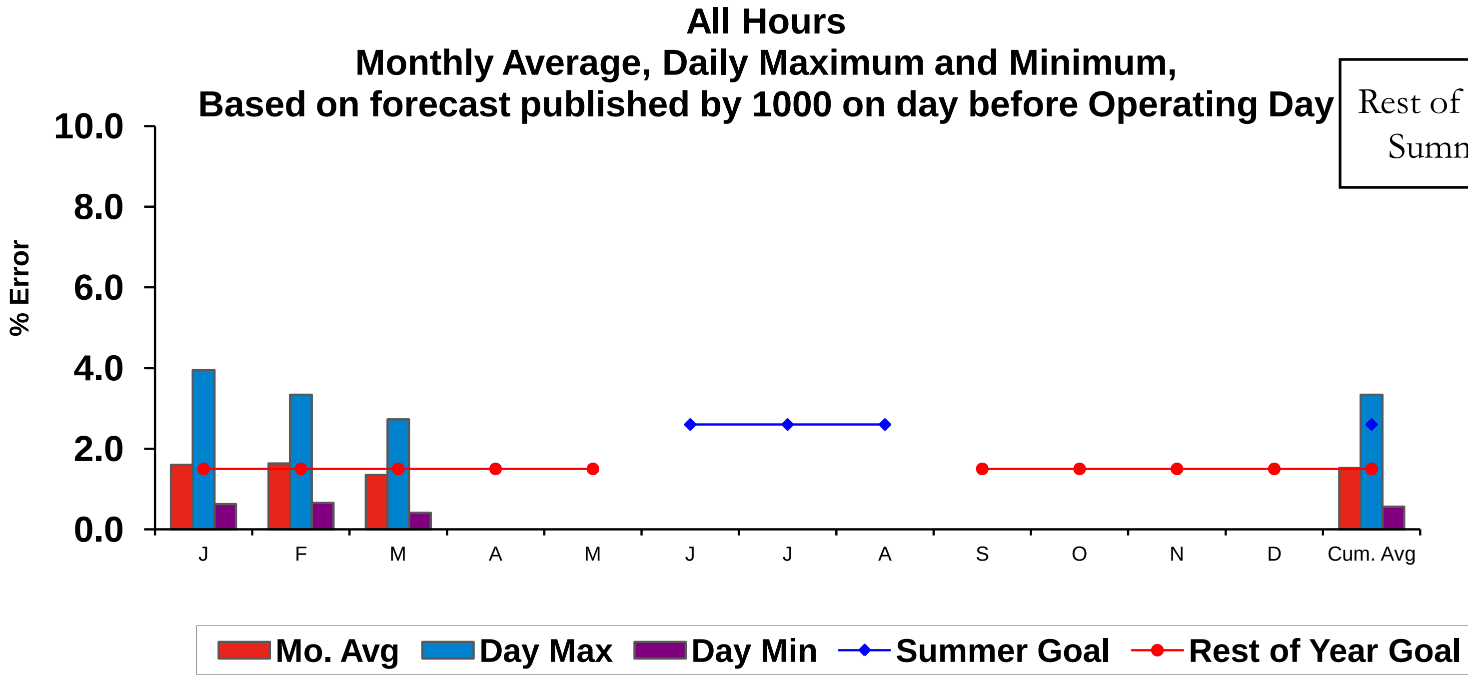
System Operations

Minimum Generation Warnings & Events: Continued

Minimum Generation Warning	**03/24/14**	**Start – 00:01, Expired - 06:00** **No Actions Taken**
Minimum Generation Warning	**03/29/14**	**Start – 01:00, Expired - 06:00** **No Actions Taken**
Minimum Generation Warning	**03/29/14 – 03/30/14**	**Start – 23:00, Expired - 10:00** **Interchange Cuts & SS Denied**
Minimum Generation Warning	**03/30/14 – 03/31/14**	**Start – 23 ;00, Expired - 06:00** **Interchange Cuts & SS Denied**

2014 System Operations – Load Forecast Accuracy

Dashboard Indicator



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.60	1.63	1.35										1.52
Day Max	3.95	3.34	2.73										3.34
Day Min	0.63	0.66	0.41										0.56
Summer Goal						2.6	2.6	2.6					
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	1.60	1.63	1.35										1.52
Summer Actual													

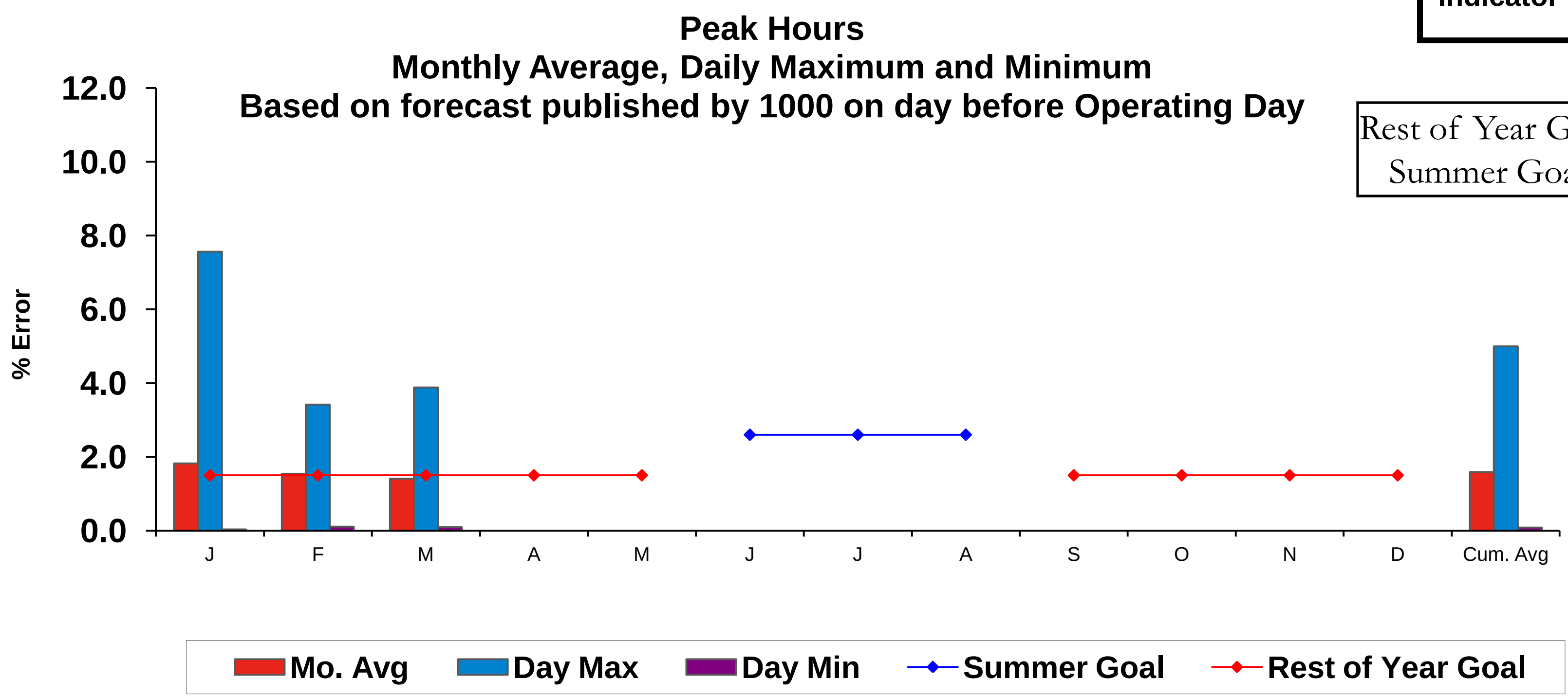
Summer Goal - 2.6%, Rest of Year Goal - 1.5%

Summer consists of June, July & August

2014 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator

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

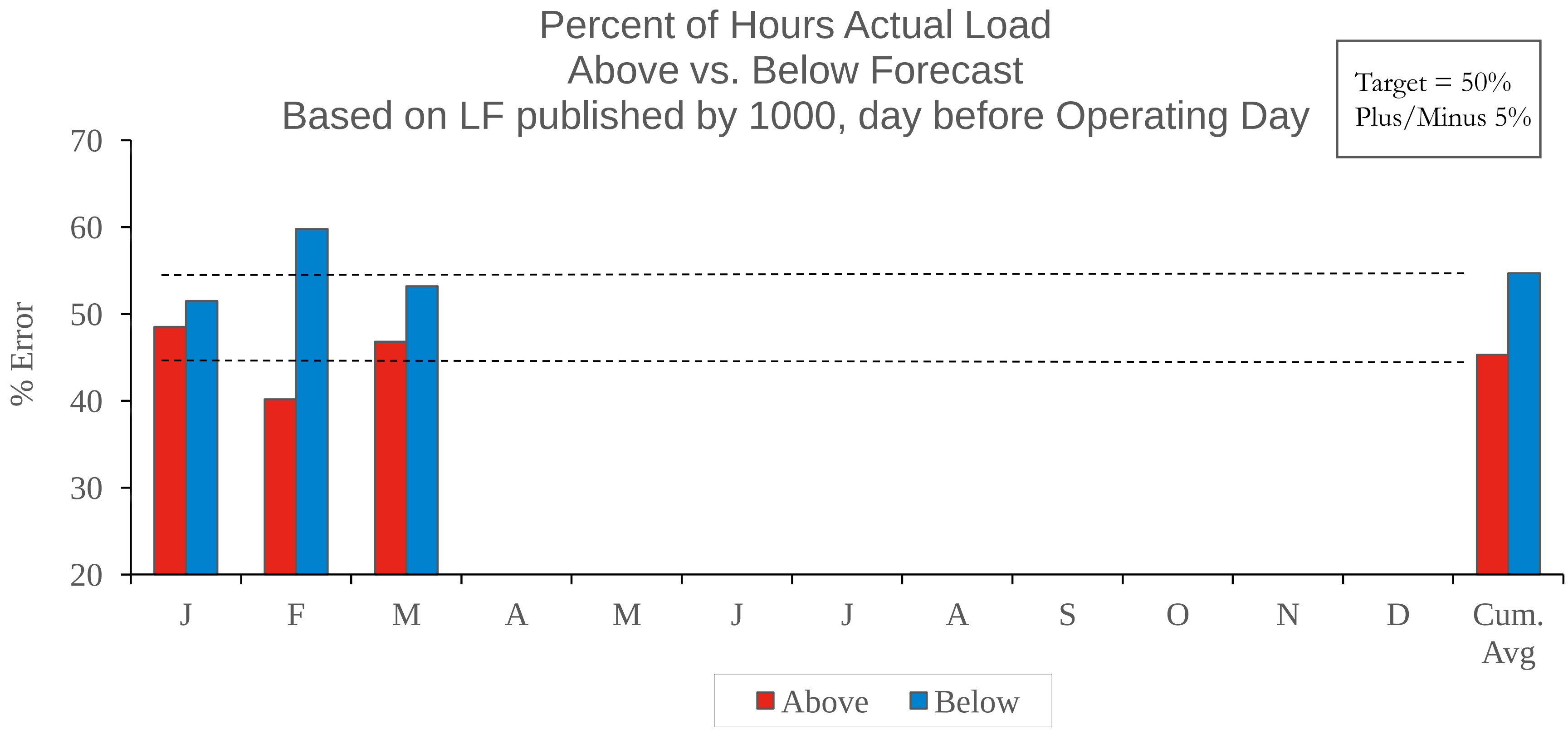


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.82	1.54	1.41										1.59
Day Max	7.56	3.42	3.88										5.00
Day Min	0.03	0.11	0.09										0.08
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of year Actual	1.82	1.54	1.41										1.59
Summer Actual													

Summer Goal - 2.6%, Rest of Year Goal - 1.5%

Summer consists of June, July & August

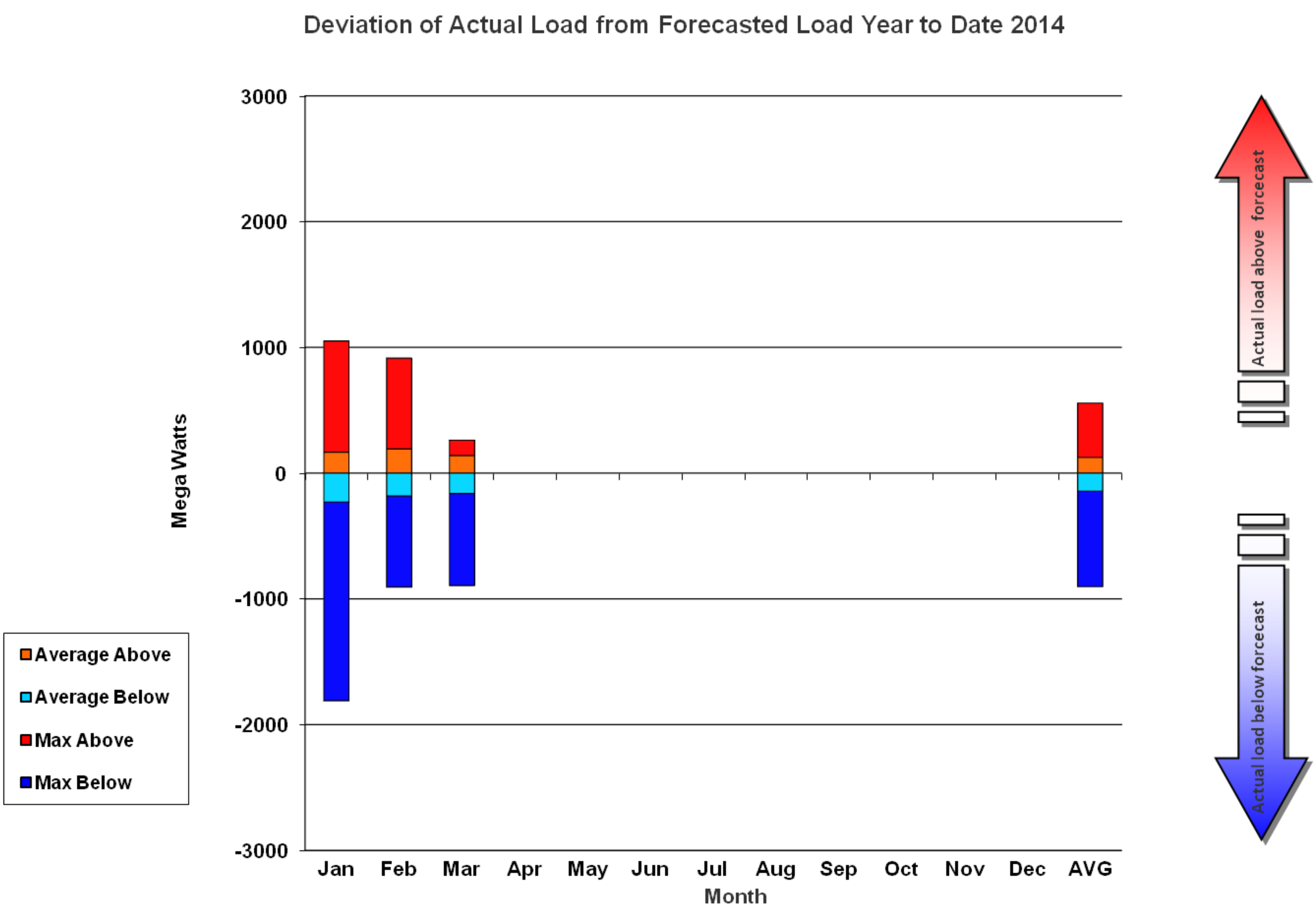
2014 System Operations - Load Forecast Accuracy



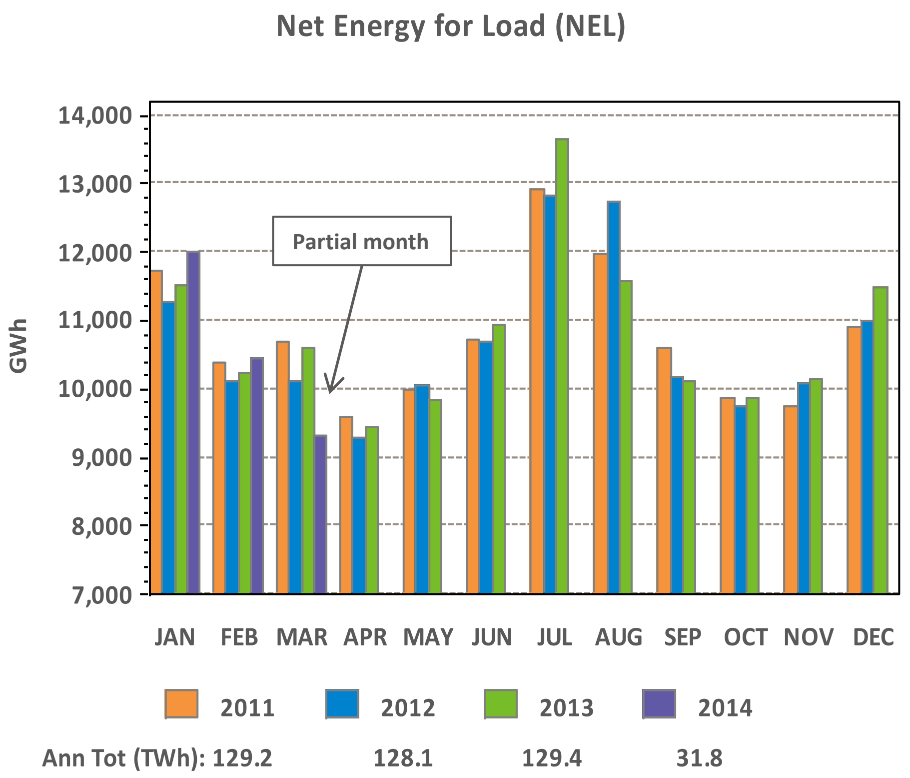
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	48.5	40.2	46.8										45.3
Below %	51.5	59.8	53.2										54.7
Avg Above	167.0	192.0	139.0										165.1
Avg Below	-230.0	-181.0	-161.0										-191.0
Avg All	-52.0	-21.0	-27.0										-33.7

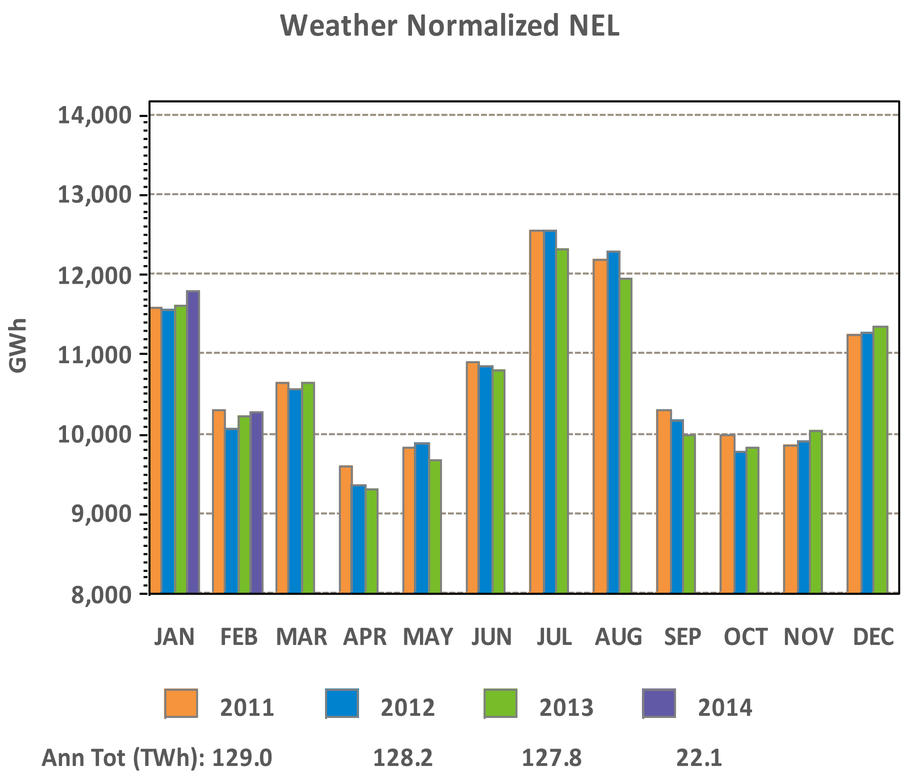
Percent of hours that the actual load was above versus below the forecast

2014 System Operations - Load Forecast Accuracy



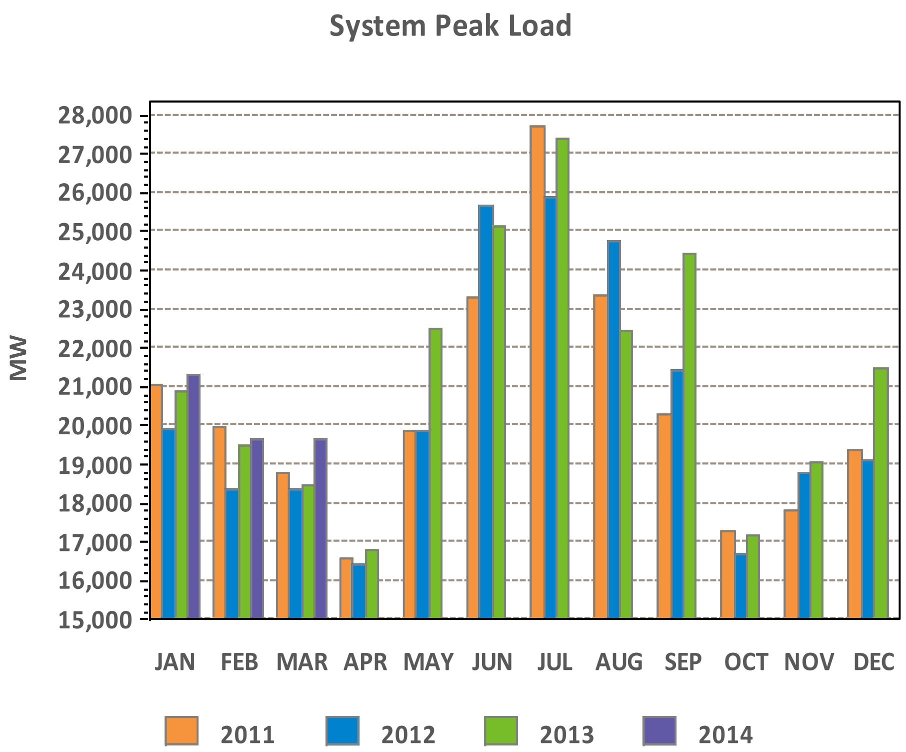
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

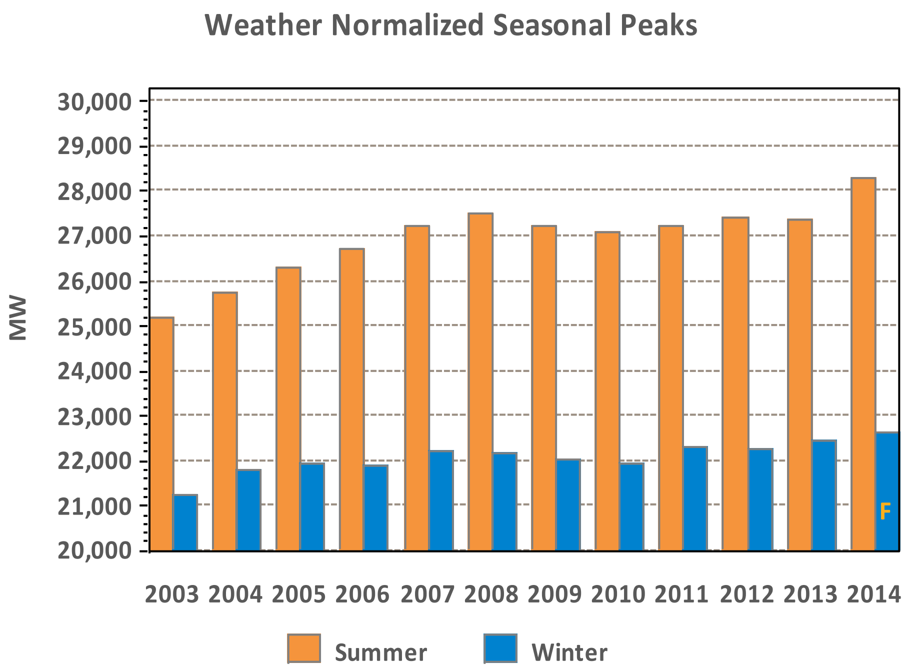




NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

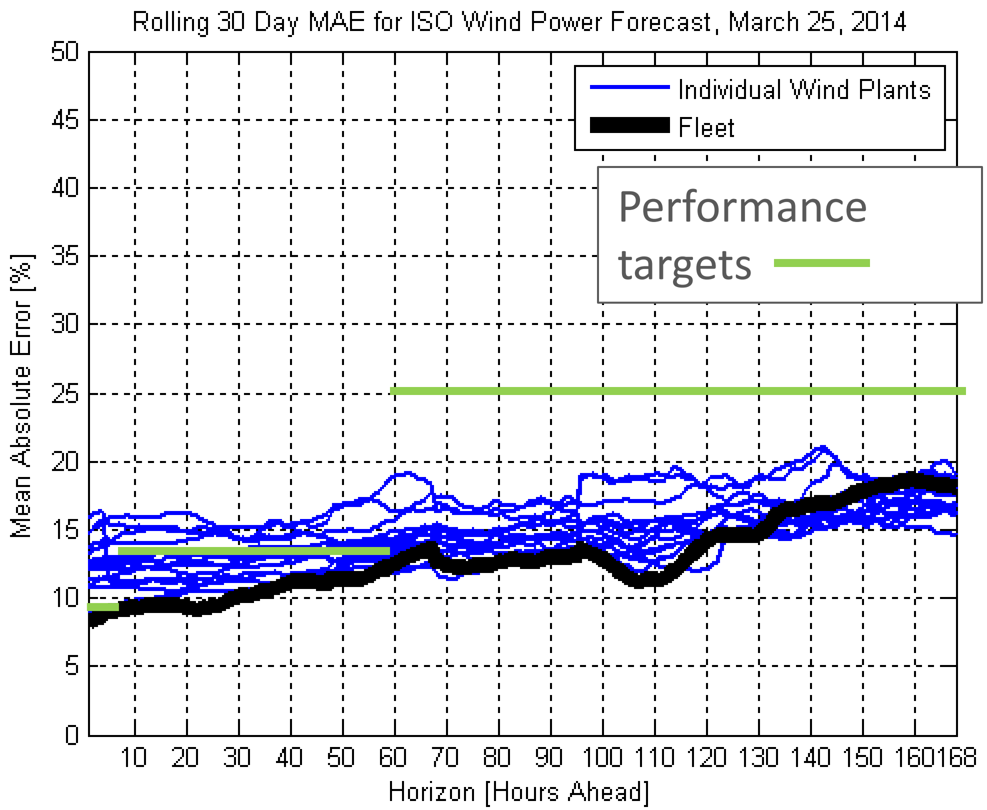




Winter beginning in year displayed

*** F – designates forecasted values, which are updated in April/May of the following year.**

Wind Power Forecast Error Statistics: Mean Absolute Error (MAE)

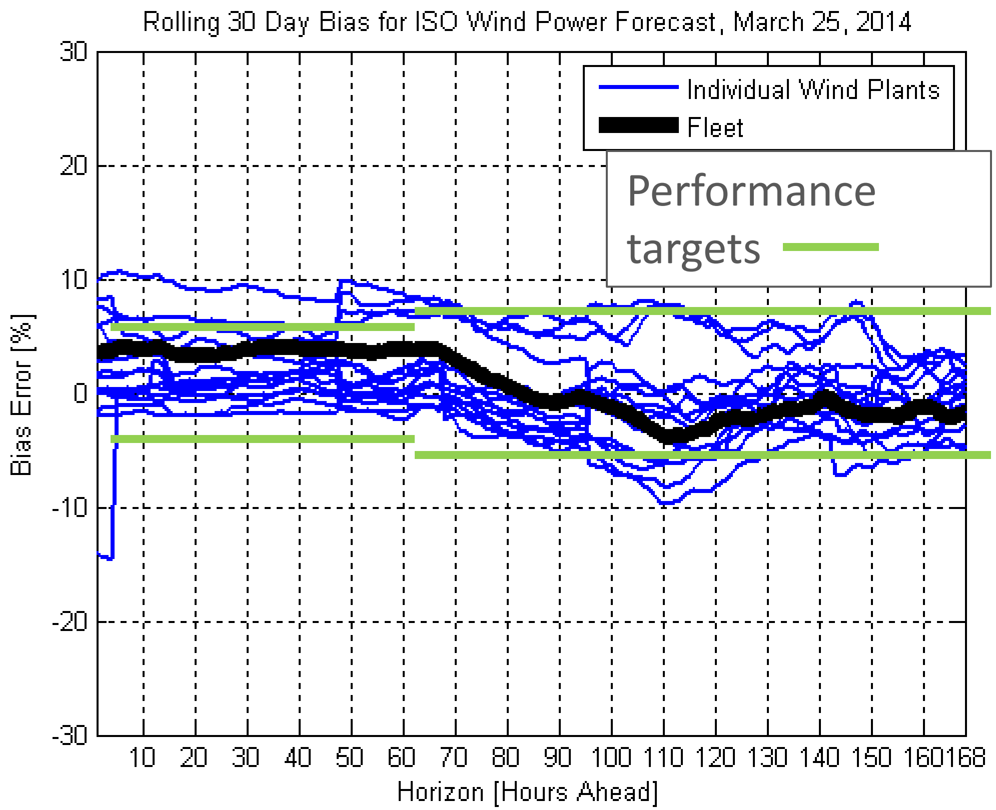


Dashboard Indicator

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 is within the yearly performance targets specified in the forecast RFP.

Wind Power Forecast Error Statistics: Bias

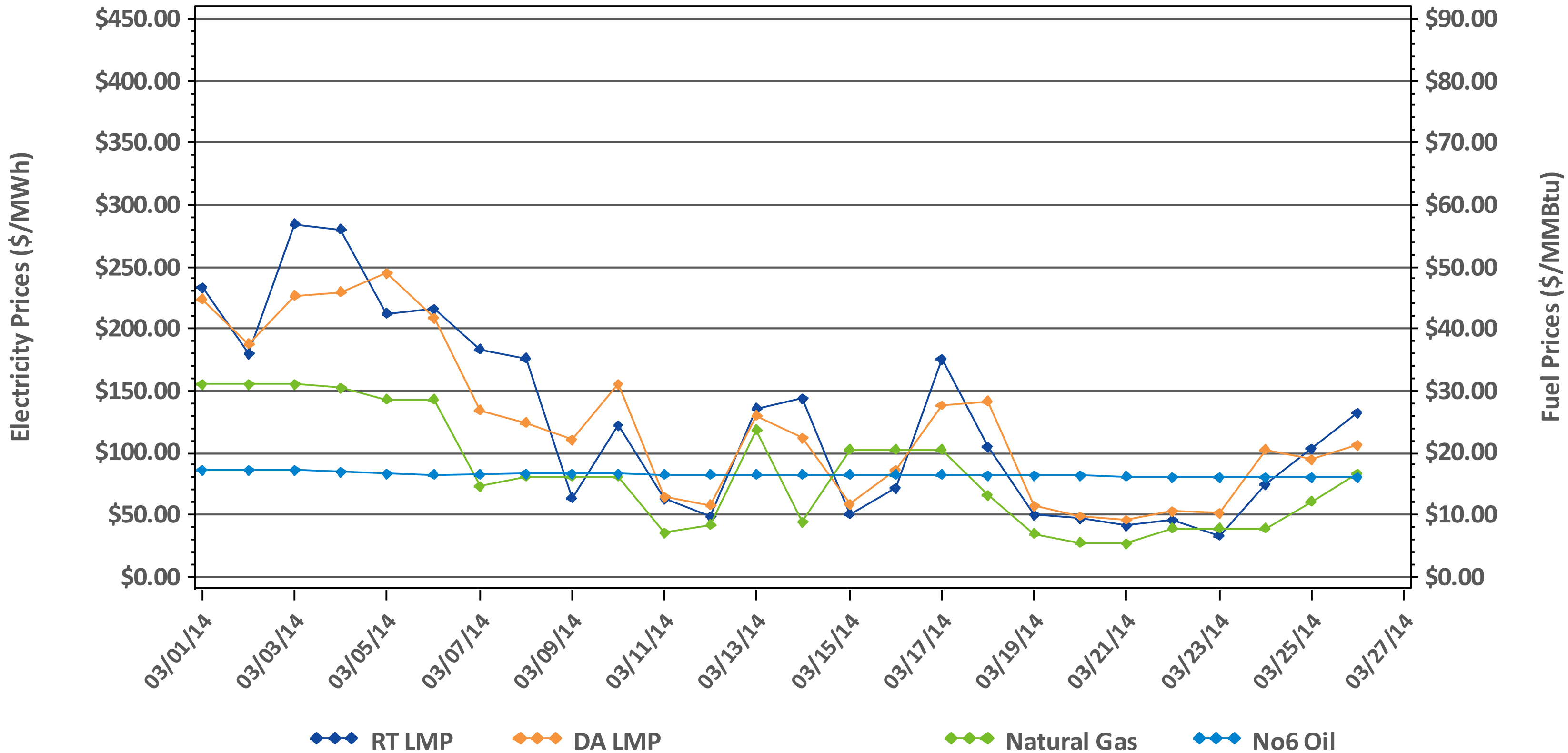
Dashboard Indicator



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

MARKET OPERATIONS

Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: March 1-26, 2014

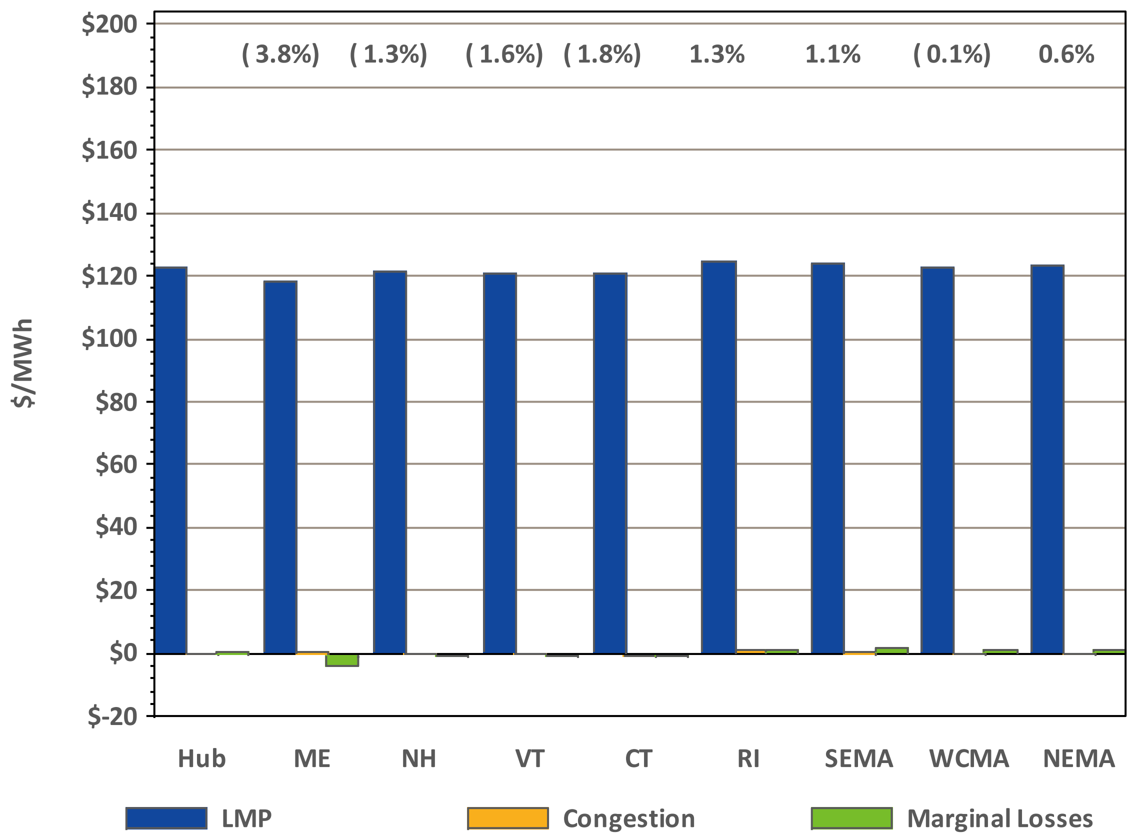


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $-3.00
Average price difference over this period ABS(DA-RT): $22.72
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 18%
Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOEs Energy Information Administration

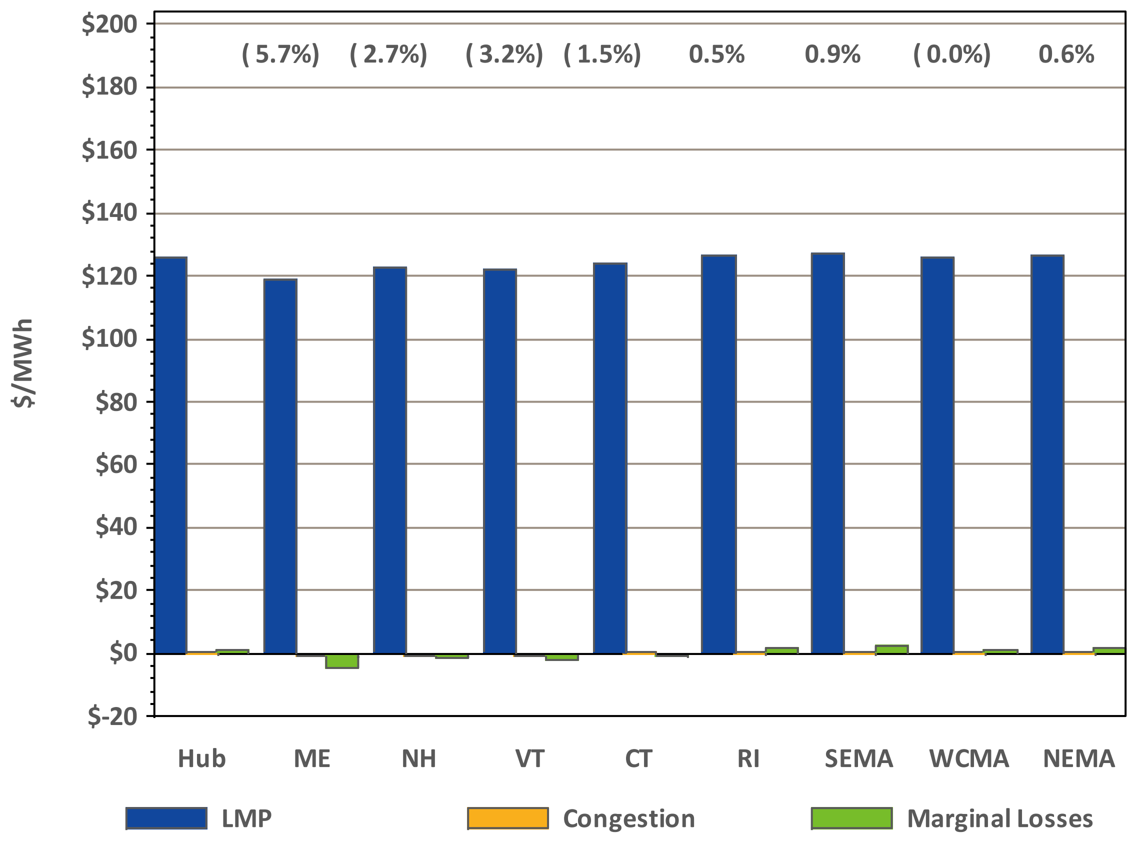
DA LMPs Average by Zone & Hub, March 2014



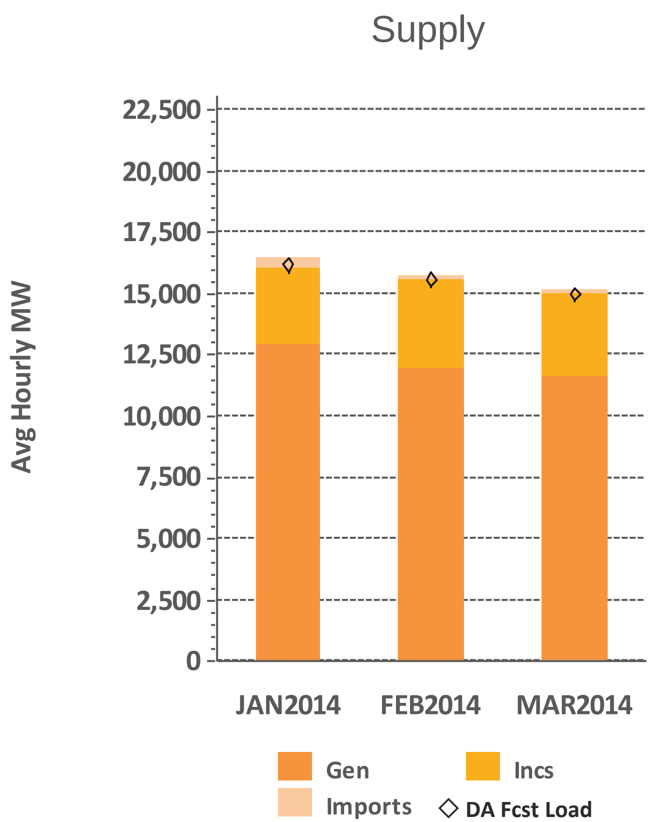
ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut

RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

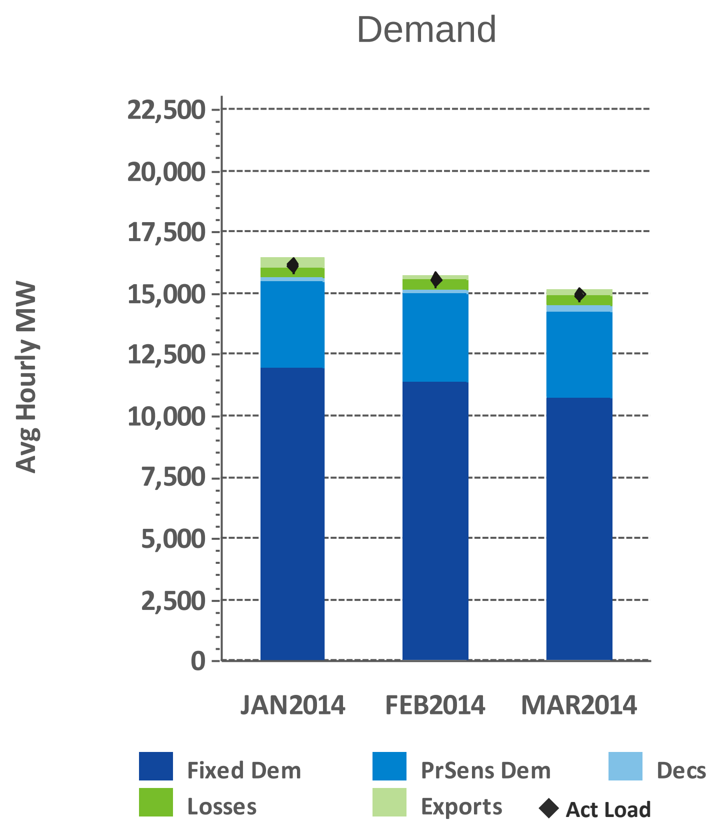
RT LMPs Average by Zone & Hub, March 2014



Components of Cleared DA Supply and Demand – Last Three Months

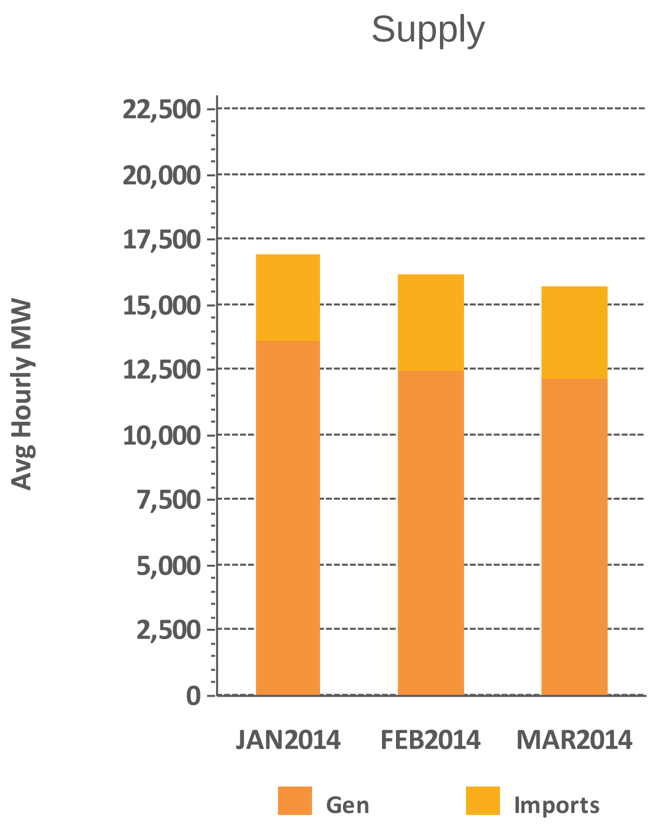


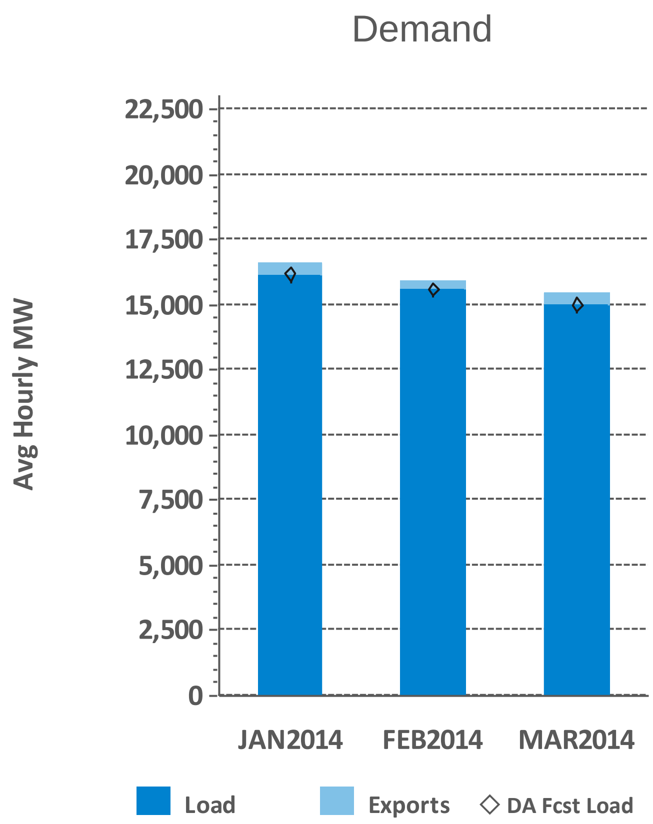
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



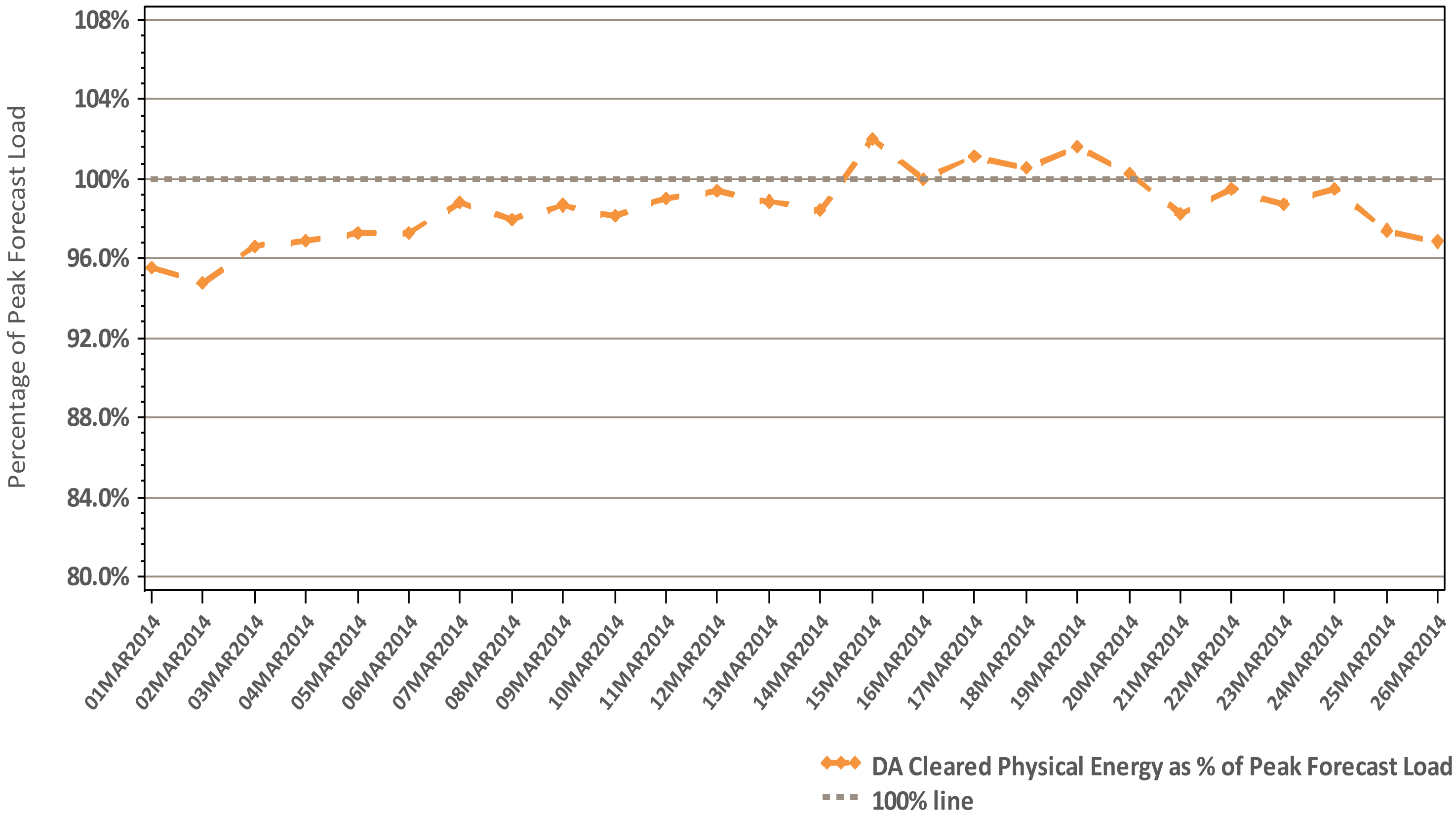
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months





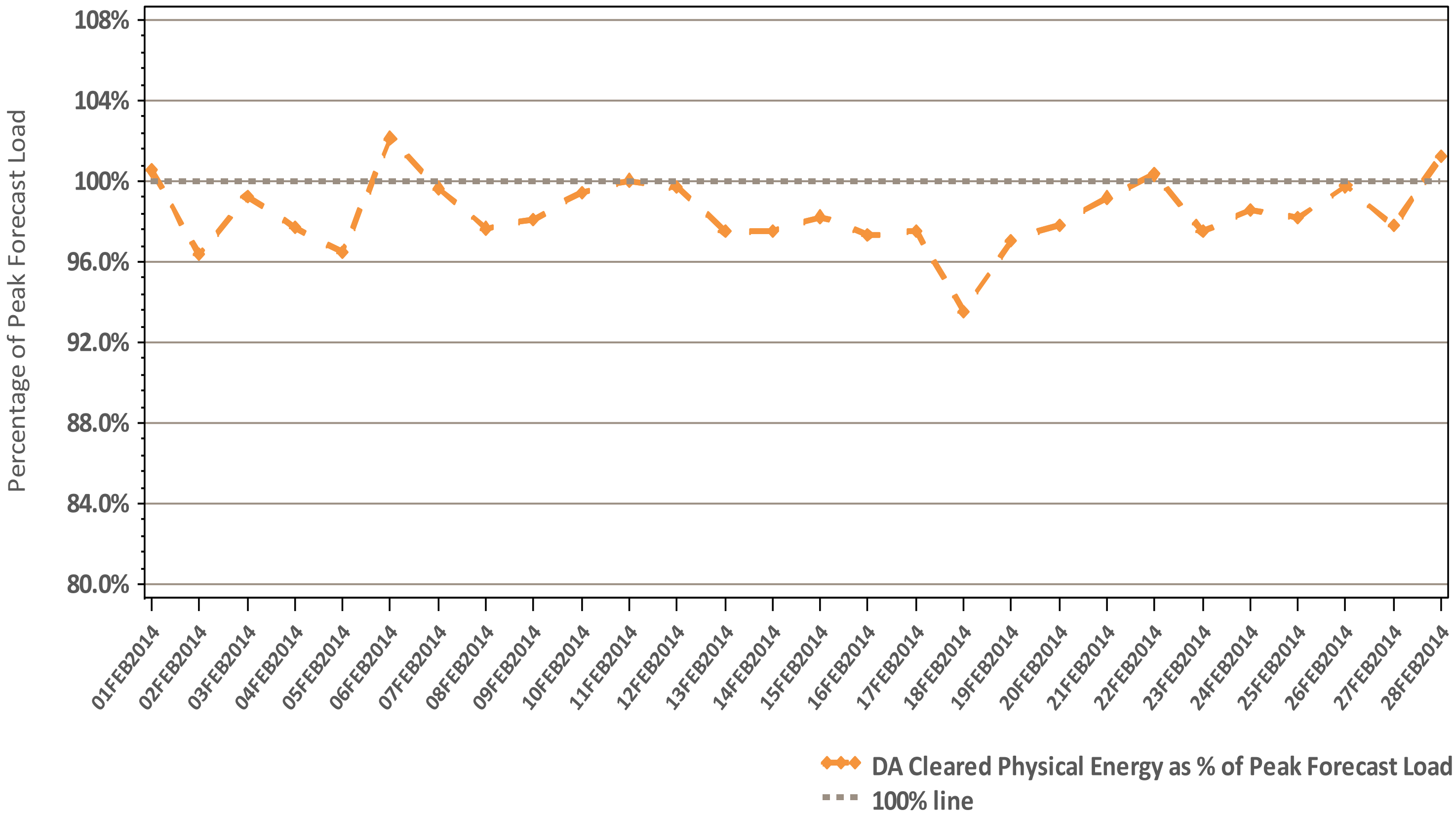
DA Cleared Physical Energy as Percent of Forecast (peak hour): March 2014



Note: Percentages were derived for the peak hour of each day.

DA Cleared Physical Energy is the physical supply (Gen + Net Imports) cleared in the DA Market
--Analysis reflects the peak forecasted hour--

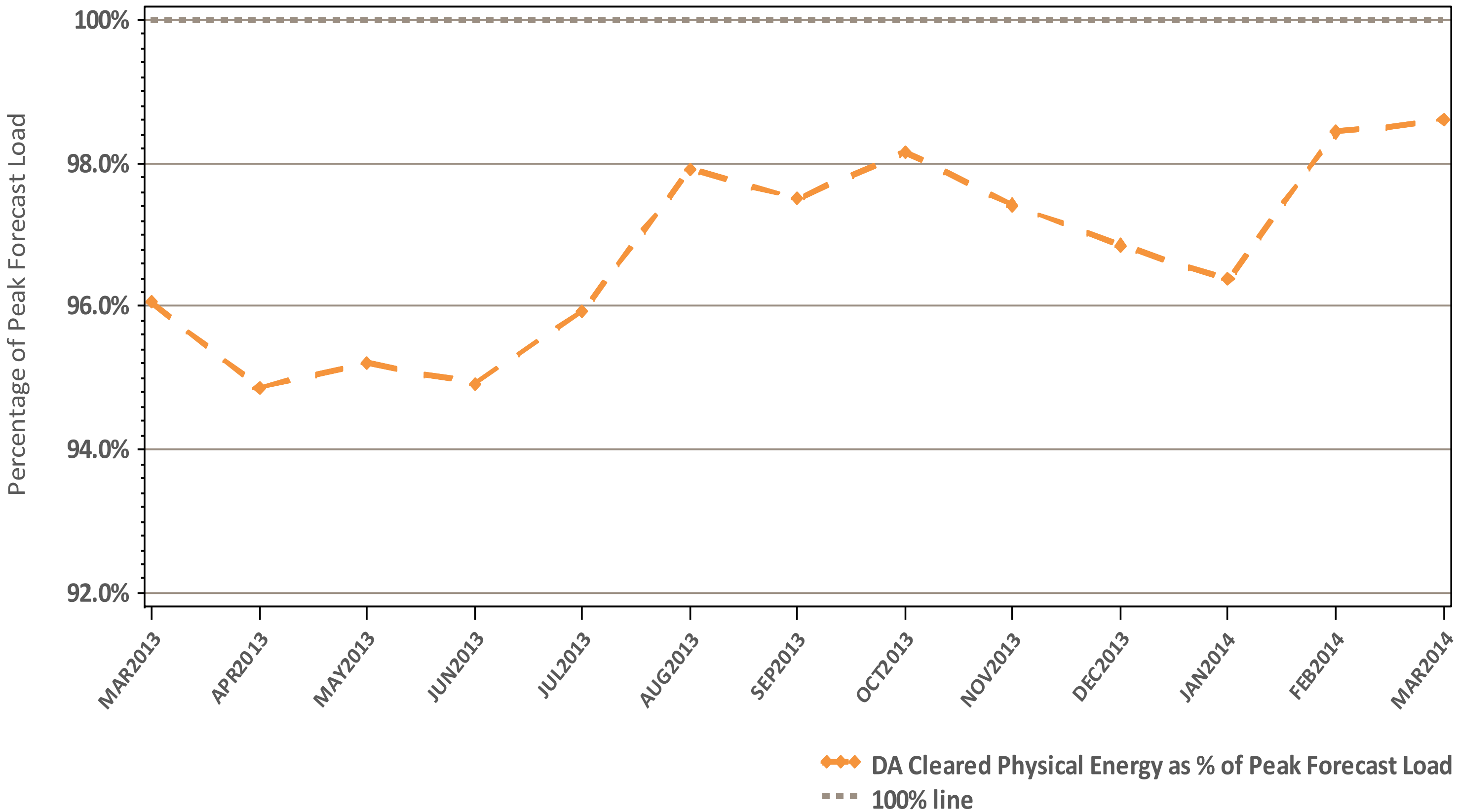
DA Cleared Physical Energy as Percent of Forecast (peak hour): February 2014



Note: Percentages were derived for the peak hour of each day.

DA Cleared Physical Energy is the physical supply (Gen + Net Imports) cleared in the DA Market
--Analysis reflects the peak forecasted hour--

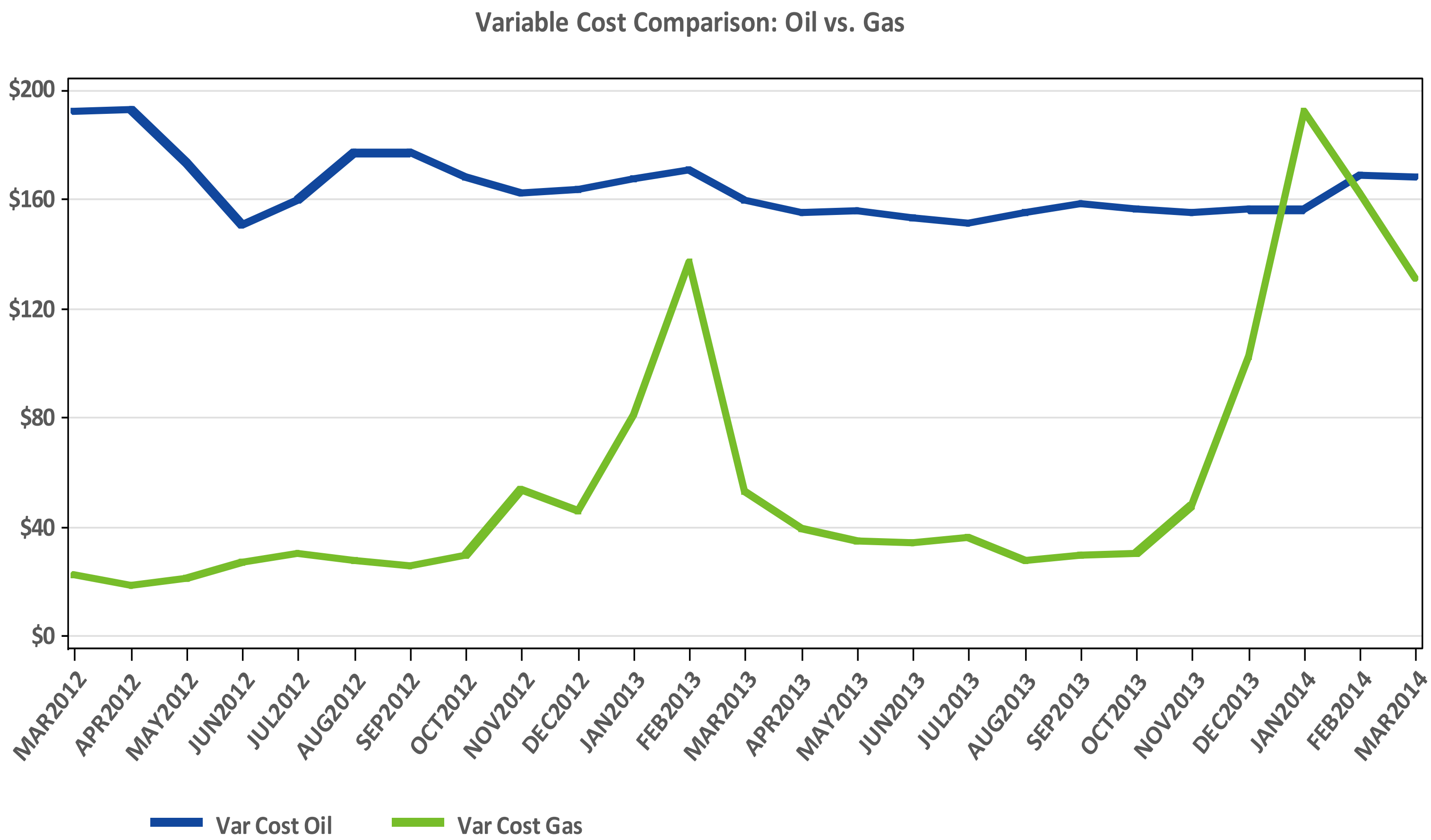
DA Cleared Physical Energy as Percent of Forecast (peak hour): Last 13 Months



Note: Percentages were derived for the peak hour of each day, then averaged over the month.

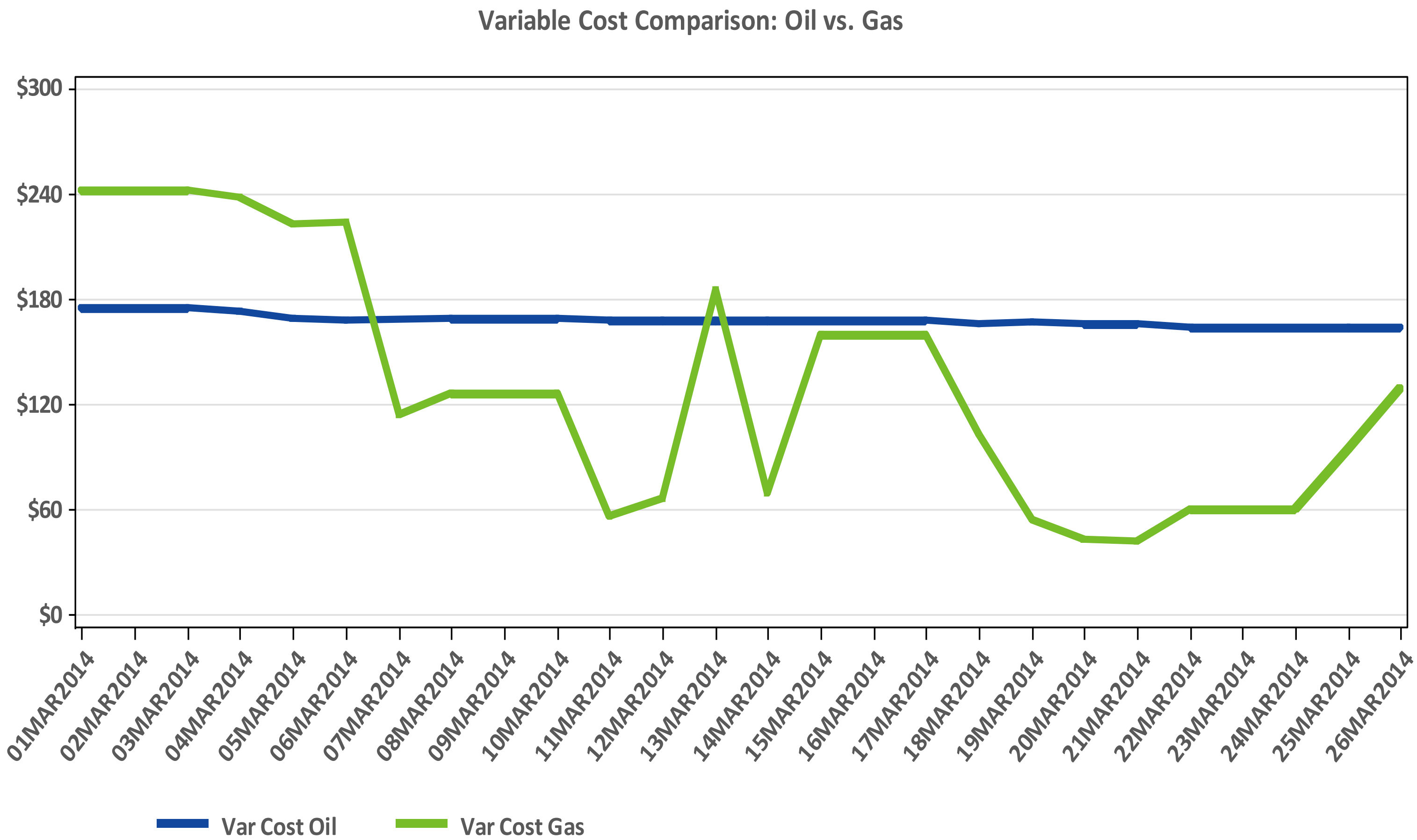
DA Cleared Physical Energy is the physical supply (Gen + Net Imports) cleared in the DA Market
--Analysis reflects the peak forecasted hour--

Variable Production Cost of Fuels: Monthly



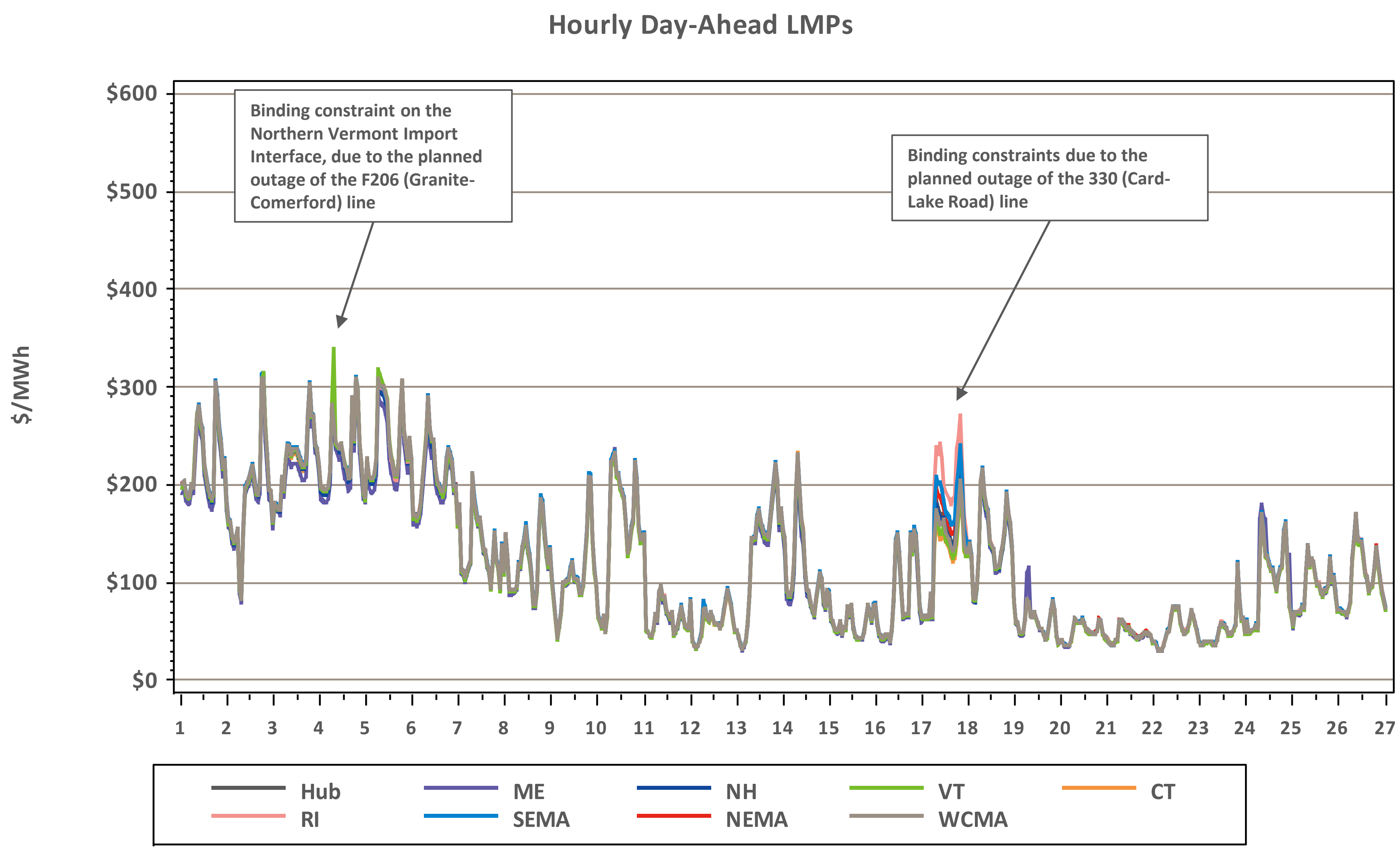
Note: Assumes proxy heat rates of 10,100,000 Btu/MWh for oil and 7,800,000 Btu/MWh for gas units.

Variable Production Cost of Fuels: Daily

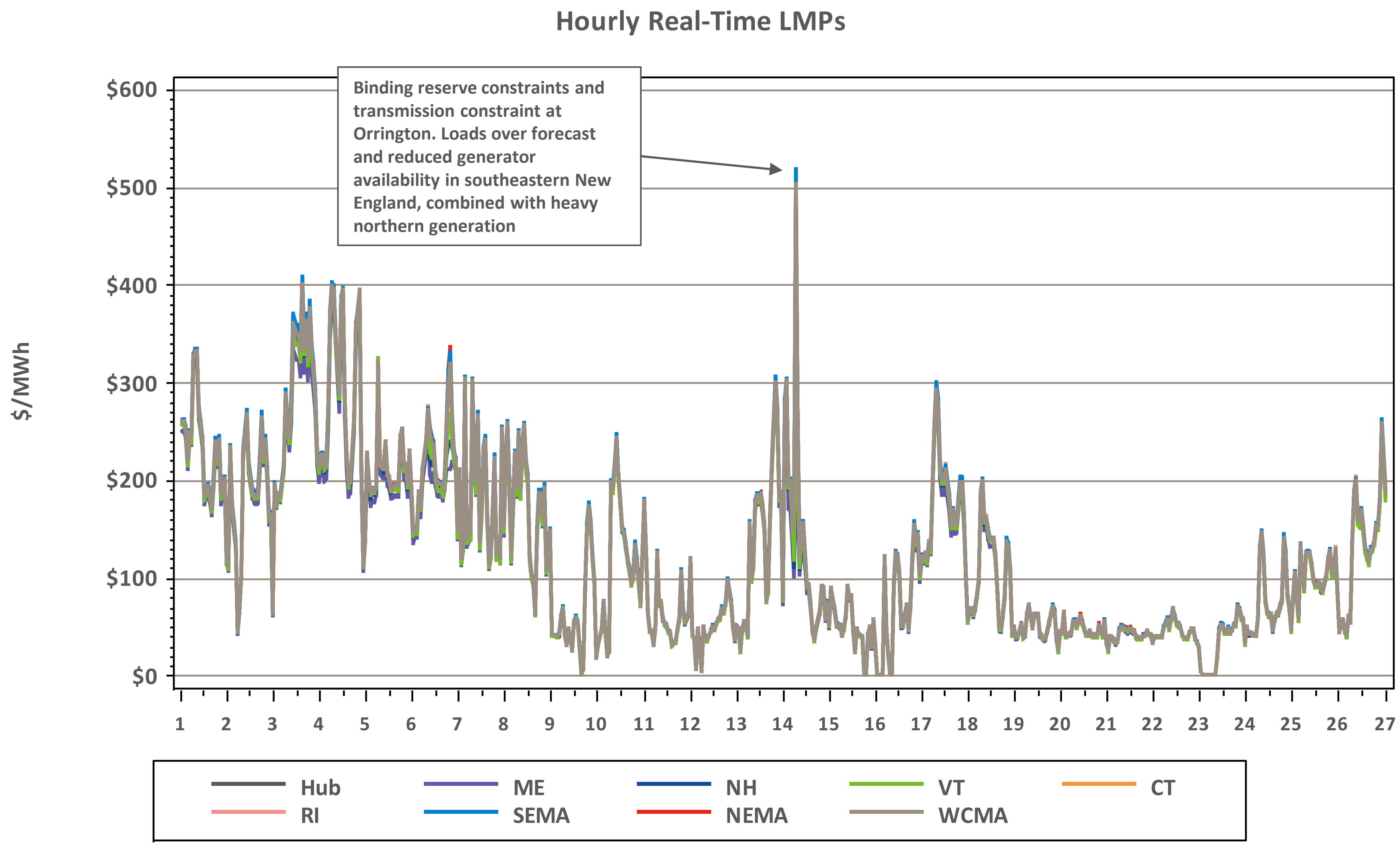


Note: Assumes proxy heat rates of 10,100,000 Btu/MWh for oil and 7,800,000 Btu/MWh for gas units.

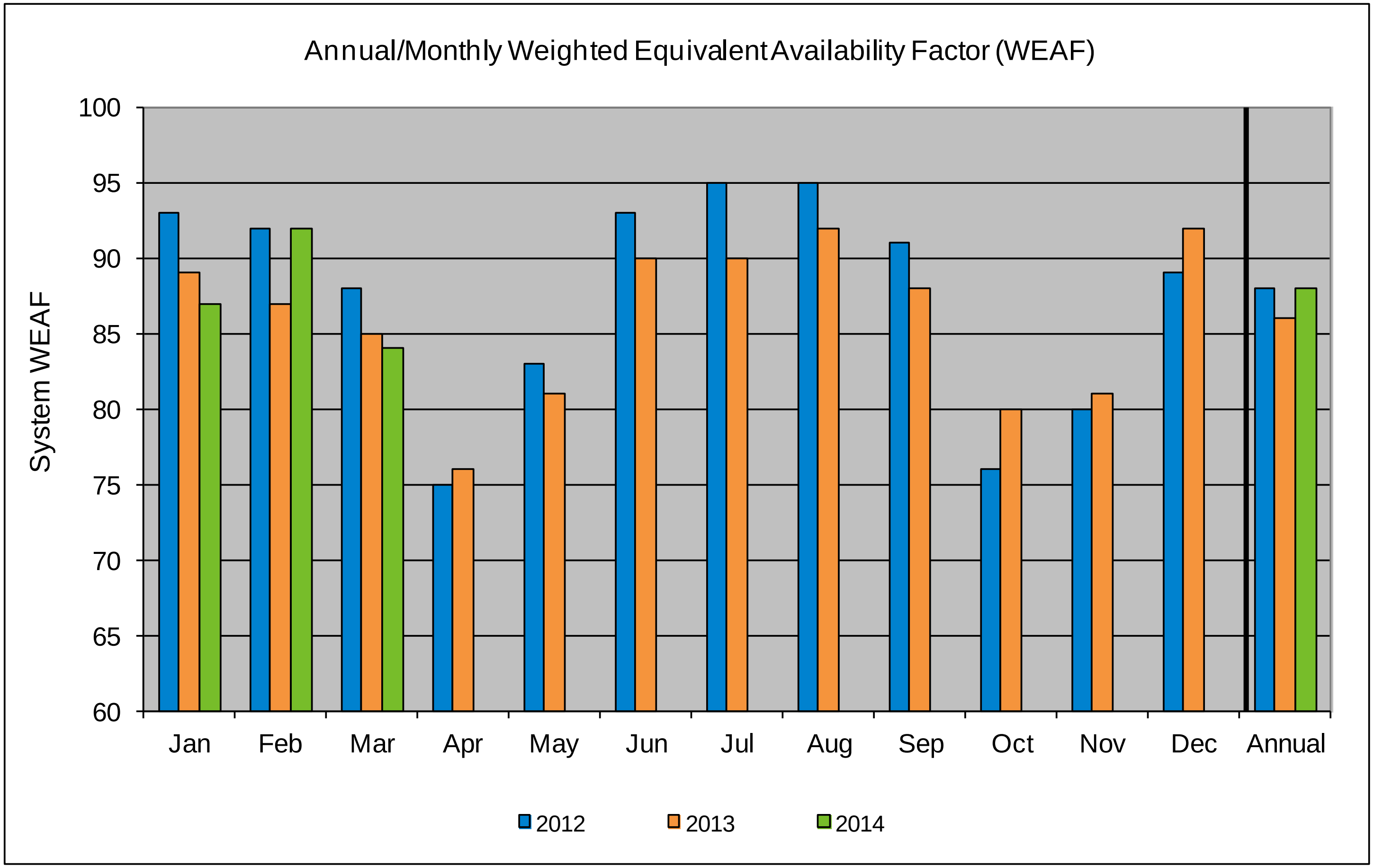
Hourly DA LMPs, March 1-26, 2014



Hourly RT LMPs, March 1-26, 2014



System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2014	87	92	84										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
2011	92	89	83	74	76	95	96	95	90	73	83	89	86

Data as of 3/31/14

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for April 2014

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	138.64	8.03	86.83	0.00	233.50
NH	4.13	13.51	64.72	0.00	82.37
VT	24.50	2.46	86.79	0.00	113.75
CT	86.63	74.82	80.92	299.33	541.69
RI	12.86	9.54	75.61	0.00	98.01
SEMA	9.59	11.34	111.51	0.00	132.44
WCMA	21.43	22.45	102.67	28.69	175.25
NEMA	16.23	21.17	204.55	0.00	241.94
Total	**314.01**	**163.32**	**813.60**	**328.02**	**1,618.96**

* 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

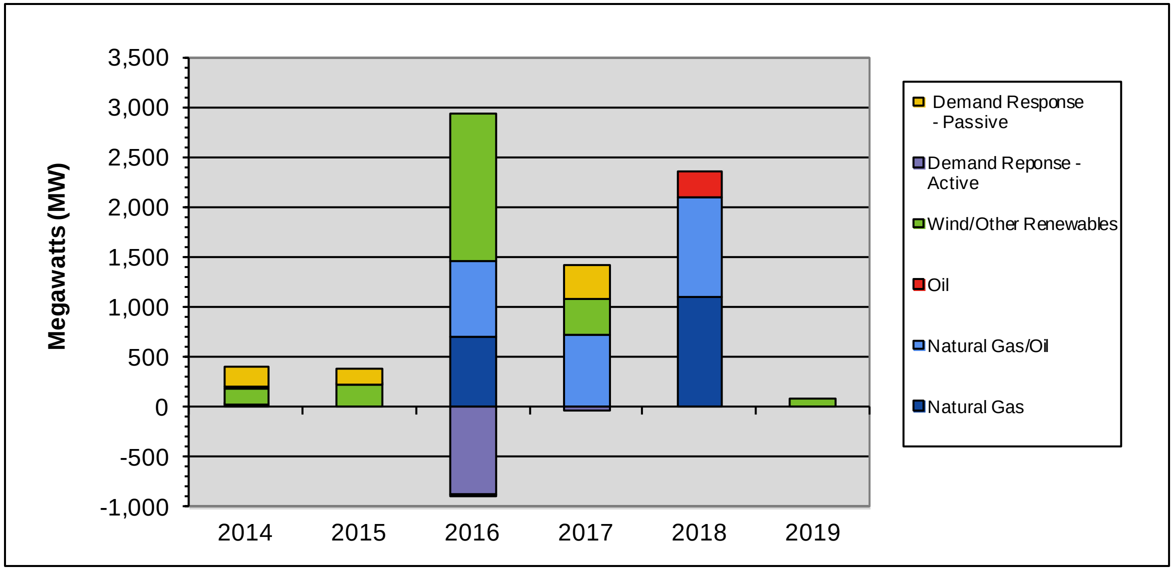
New Generation Update

Based on 4/1/14 Queue Update

- Seven new projects, with a total rating of 928 MW, have applied for interconnection study since the last update
  - The new projects consist of three combustion turbines, a wind project, a fuel cell, and two combined cycle facilities with expected in-service dates ranging from 2018 to 2019
- One project withdrew from the Queue, resulting in a net increase in new generation projects of 854 MW
- In total, 56 generation projects are currently being tracked by the ISO, totaling 6,900 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2014	2015	2016	2017	2018	2019	Total MW	% of Total[1]
Demand Response - Passive	188	157	-12	330	0	0	663	9.9
Demand Response - Active	19	3	-868	-37	0	0	-883	-13.2
Wind & Other Renewables	166	236	1,479	360	0	85	2,326	34.7
Oil	0	0	0	0	245	0	245	3.7
Natural Gas/Oil[2]	8	0	745	736	1,008	0	2,497	37.3
Natural Gas	21	0	716	0	1,110	0	1,847	27.6
Totals	**402**	**396**	**2,060**	**1,389**	**2,363**	**85**	**6,695**	**100.0**

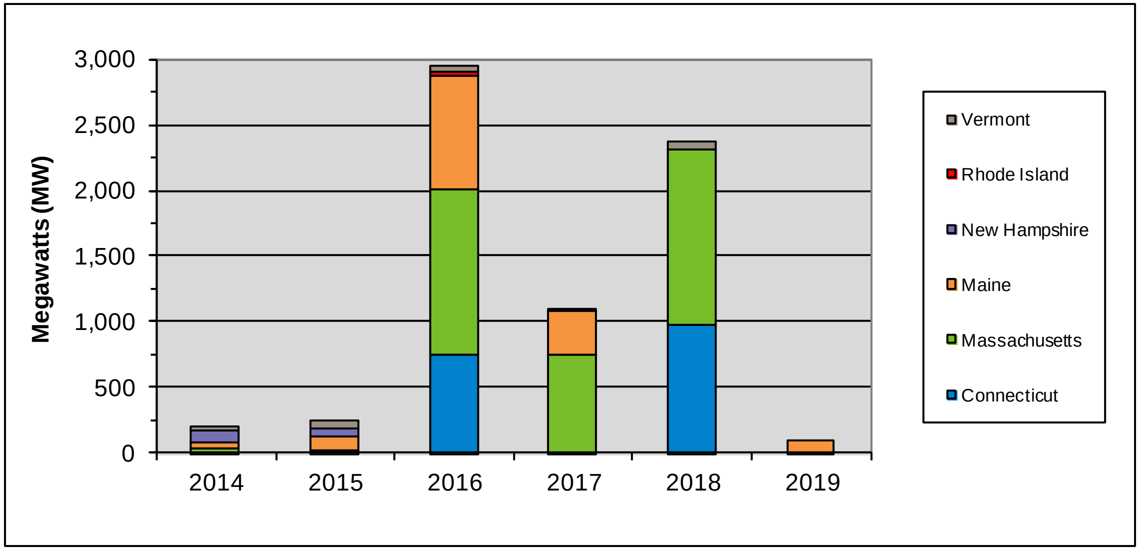
[1] **Sum may not equal 100% due to rounding**

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

- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2014	2015	2016	2017	2018	2019	Total MW	% of Total[1]
Vermont	30	60	33	20	48	0	191	2.8
Rhode Island	0	0	29	0	0	0	29	0.4
New Hampshire	89	65	0	0	0	0	154	2.2
Maine	52	93	868	340	0	85	1,438	20.8
Massachusetts	24	18	1,265	736	1,346	0	3,389	49.0
Connecticut	0	0	745	0	969	0	1,714	24.8
Totals	**195**	**236**	**2,940**	**1,096**	**2,363**	**85**	**6,915**	**100.0**

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

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	3	138	1	68	2	70
Hydro	5	62	0	0	5	62
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,847	0	0	7	1,847
Natural Gas/Oil	11	2,497	0	0	11	2,497
Oil	1	245	0	0	1	245
Solar	3	16	2	10	1	6
Wind	26	2,110	4	77	22	2,033
Total	56	6,915	7	155	49	6,760

- 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	4	144	1	68	3	76
Intermediate	13	3,180	0	0	13	3,180
Peaker	13	1,481	2	10	11	1,471
Wind Turbine	26	2,110	4	77	22	2,033
Total	56	6,915	7	155	49	6,760

- 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	3	138	3	138	0	0	0	0	0	0
Hydro	5	62	0	0	4	12	1	50	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	1,847	1	6	3	1,255	3	586	0	0
Natural Gas/Oil	11	2,497	0	0	6	1,913	5	584	0	0
Oil	1	245	0	0	0	0	1	245	0	0
Solar	3	16	0	0	0	0	3	16	0	0
Wind	26	2,110	0	0	0	0	0	0	26	2,110
Total	56	6,915	4	144	13	3,180	13	1,481	26	2,110

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 4

Resource Type	Resource Type	FCA 4	Proration		Annual Bilateral Period 1 for ARA 2		ARA 2		Annual Bilateral Period 2 for ARA 2		Annual Bilateral 3 Period		ARA 3	
		*CSO	CSO	**Change	ARA 2	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*	2,051.536	1,860.060	-191.476	1,681.032	-179.028	1,482.357	-198.675	1,367.357	-115.000	1,021.146	-346.211	700.637	-320.509
	Passive Demand	1,297.906	1,154.626	-143.280	1,135.705	-18.921	1,163.465	27.760	1,163.465	0.000	1,123.515	-39.950	1,149.743	26.228
Demand Total		**3,349.442**	**3,014.686**	**-334.756**	**2,816.737**	**-197.949**	**2,645.822**	**-170.915**	**2,530.822**	**-115.000**	**2,144.661**	**-386.161**	**1,850.380**	-294.281
Generator	*Non-Intermittent*	31,161.623	27,655.394	-3,506.229	27,839.130	183.736	28,386.625	547.495	27,890.197	-496.428	28,354.572	464.375	28,812.896	458.324
	Intermittent	1,085.540	979.072	-106.468	972.075	-6.997	857.886	-114.189	865.064	7.178	841.517	-23.547	784.778	-56.739
Generator Total		**32,247.163**	**28,634.466**	**-3,612.697**	**28,811.205**	**176.739**	**29,244.511**	**433.306**	**28,755.261**	**-489.250**	**29,196.089**	**440.828**	**29,597.674**	401.585
Import Total		**1,992.600**	**1,726.449**	**-266.151**	**1,726.449**	**0.000**	**1,396.258**	**-330.191**	**1,396.258**	**0.000**	**1,296.258**	**-100.000**	**1,182.869**	-113.389
*****Grand Total**		**37,589.205**	**33,375.601**	**-4,213.604**	**33,354.391**	**-21.210**	**33,286.591**	**-67.800**	**32,682.341**	**-604.250**	**32,637.008**	**-45.333**	**32,630.923**	-6.085

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

** Change columns contains 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 5

Resource Type	Resource Type	FCA 4	Proration		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	ARA 2	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,104.141	2,001.126	-103.015	1,385.670	-615.456	1,074.461	-311.21	899.125	-175.336	699.930	-199.195
	Passive Demand	1,485.713	1,397.586	-88.127	1,345.283	-52.303	1,348.593	3.31	1,365.947	17.354	1399.564	33.617
Demand Total		**3,589.854**	**3,398.712**	**-191.142**	**2,730.953**	**-667.759**	**2,423.054**	**-307.90**	**2,265.072**	**-157.982**	**2099.494**	-165.578
Generator	*Non-Intermittent*	30,558.220	28,337.481	-2,220.739	27,917.690	-419.791	28,364.588	446.90	28,517.097	152.509	28557.855	40.758
	Intermittent	880.737	827.804	-52.933	778.165	-49.639	795.545	17.38	795.767	0.222	718.908	-76.859
Generator Total		**31,438.957**	**29,165.285**	**-2,273.672**	**28,695.855**	**-469.430**	**29,160.133**	464.28	**29,312.864**	**152.731**	**29276.763**	-36.101
Import Total		**2,011.001**	**1,831.372**	**-179.629**	**1,831.372**	**0.000**	**1,635.835**	-195.54	**1,635.835**	**0.000**	**1382.551**	-253.284
***Grand Total**		**37,039.812**	**34,395.369**	**-2,644.443**	**33,258.180**	**-1,137.189**	**33,219.022**	-39.16	**33,213.771**	**-5.251**	**32758.808**	-454.963

* 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 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								
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000								
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624								
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709								
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205								
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914								
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290								
***Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000								

* 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												
	Passive Demand	1,631.335	1,519.740	-111.595												
Demand Total		**2,748.033**	**2,563.459**	-184.574												
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741												
	Intermittent	936.913	893.710	-43.203												
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**												
Import Total		**1,830.000**	**1,606.862**	**-223.138**												
***Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**												

* 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												
	Passive Demand	1,960.517												
Demand Total		**3,040.596**												
Generator	*Non-Intermittent*	28,547.813												
	Intermittent	876.925												
Generator Total		**29,424.738**												
Import Total		**1,237.034**												
*****Grand Total**		**33,702.368**												

* 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.

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

What are Daily NCPC Payments?

- “Make-whole” 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

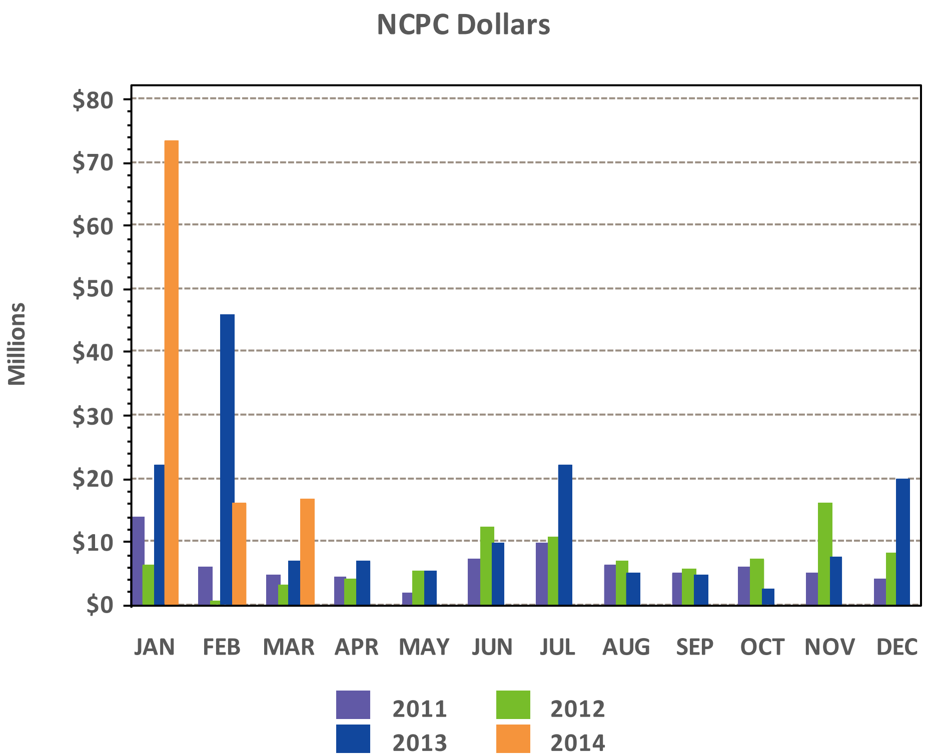
Definitions

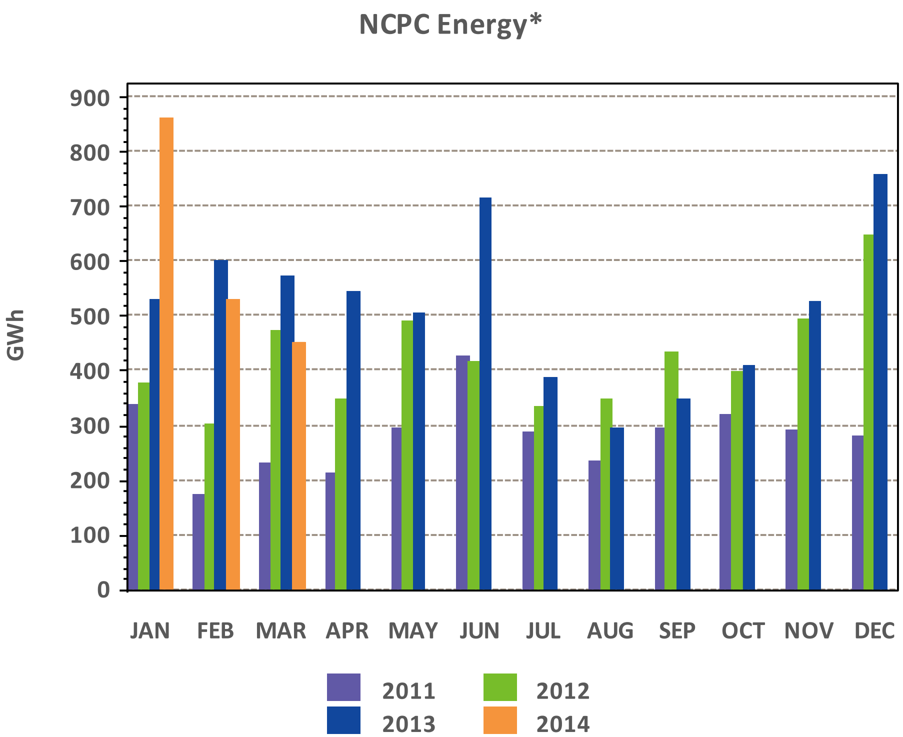
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally.
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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

Year-Over-Year Total NCPC Dollars and Energy

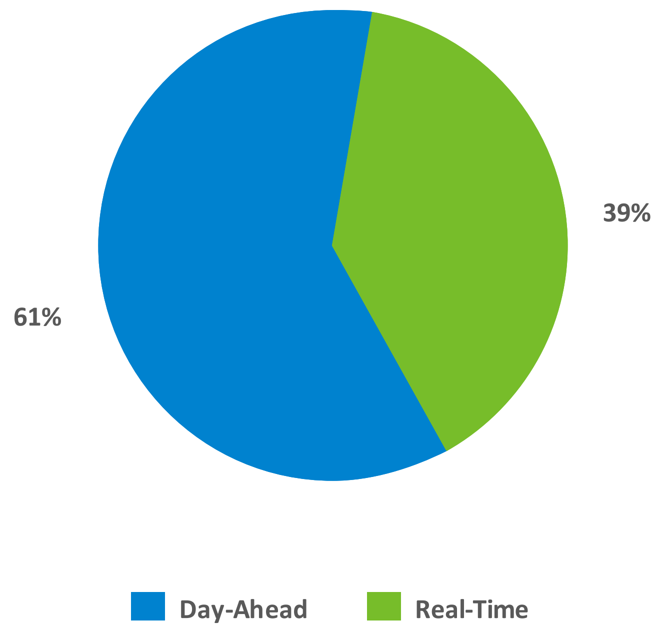




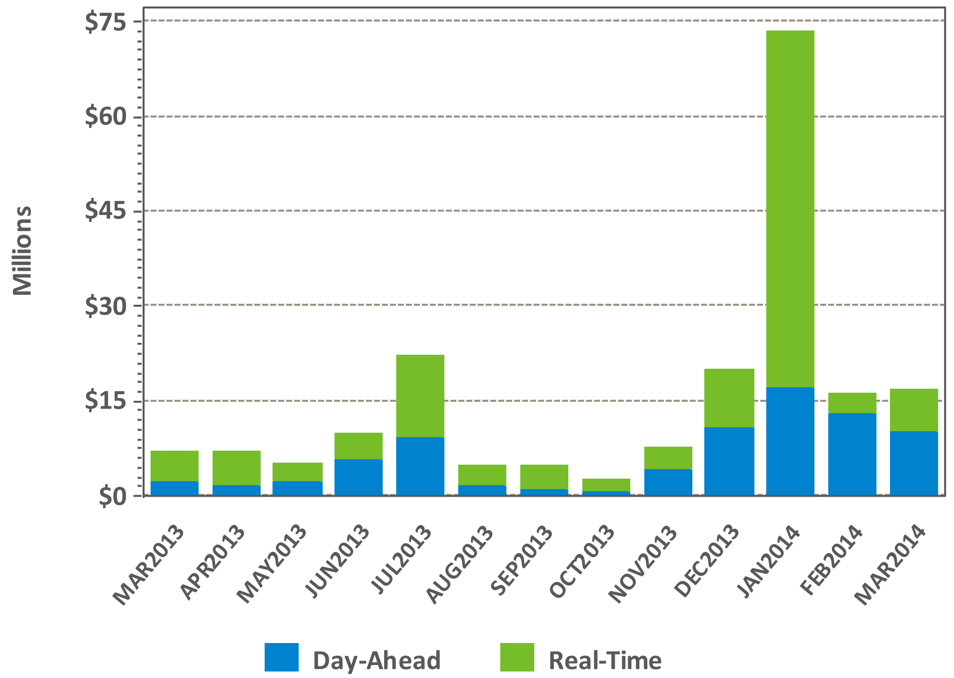
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

DA and RT NCPC Charges

MAR-14 Total = $16.81 M

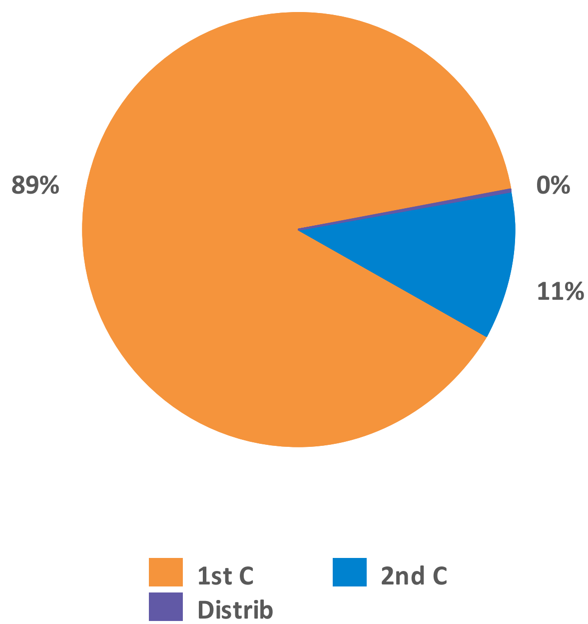


Last 13 Months

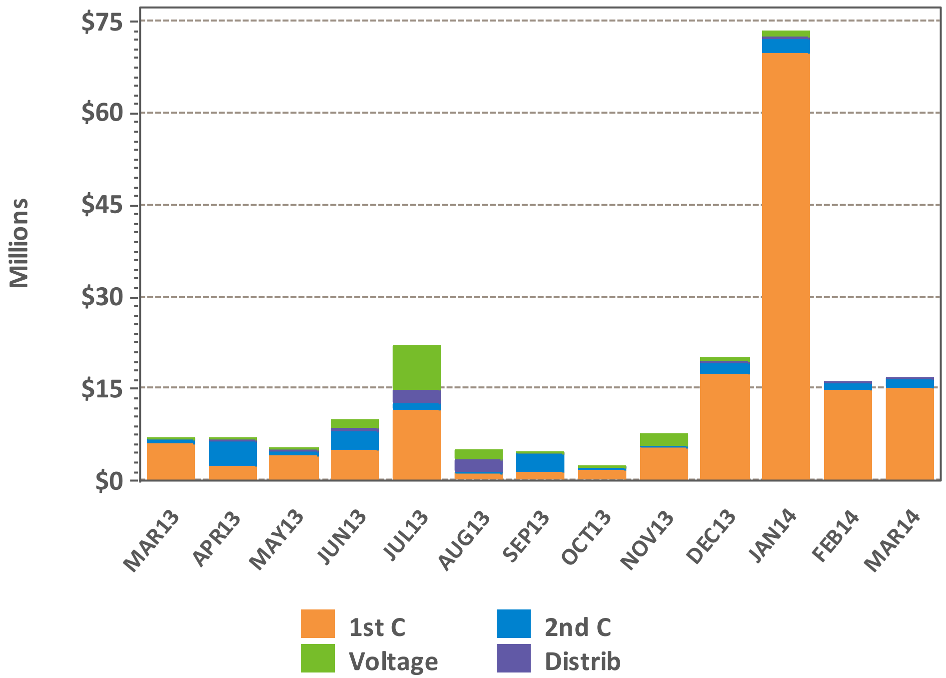


NCPC Charges by Type

MAR-14 Total = $16.81 M

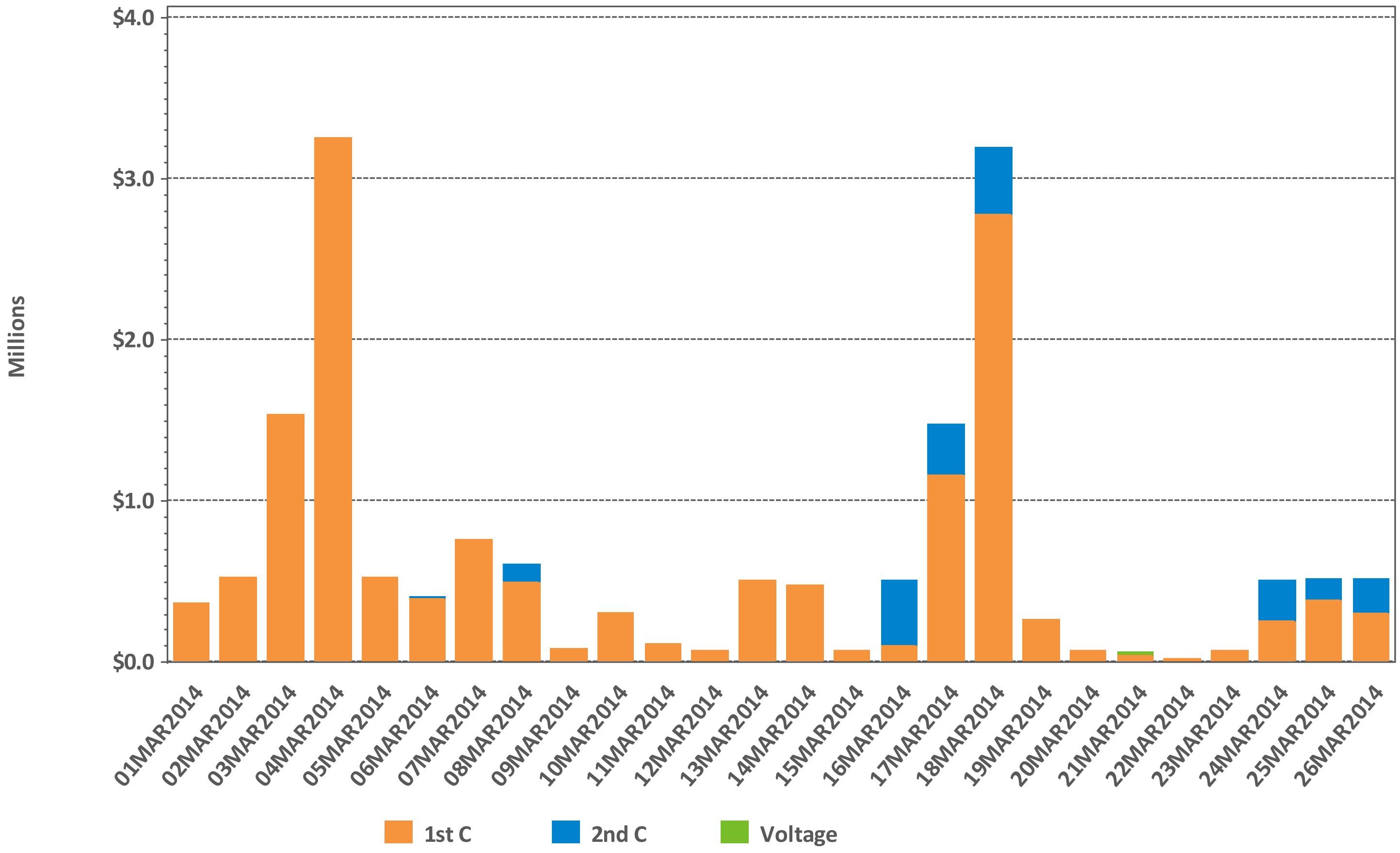


Last 13 Months



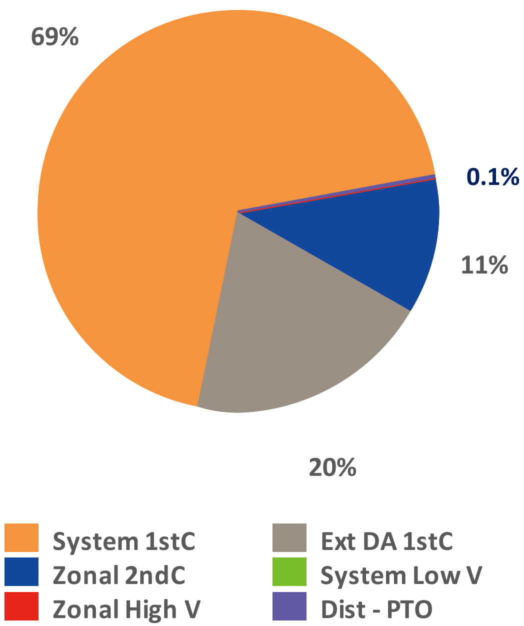
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

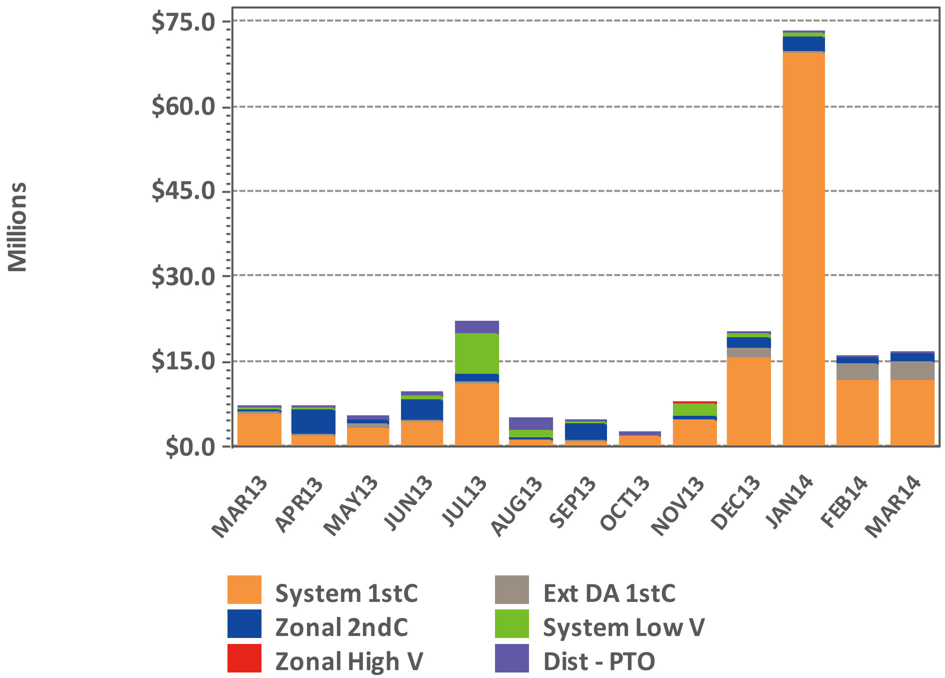


NCPC Charges by Allocation

MAR-14 Total = $16.81 M

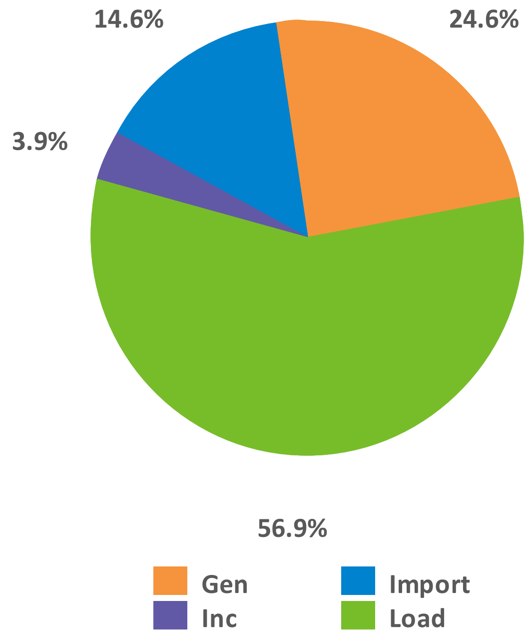


Last 13 Months

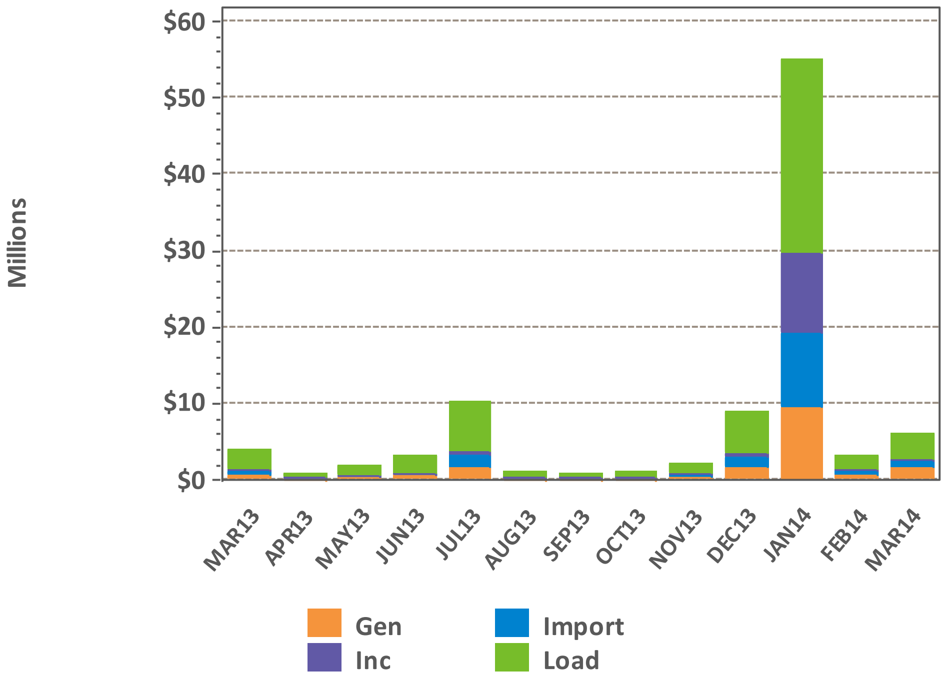


RT First Contingency Charges by Deviation Type

MAR-14 Total = $6.07 M

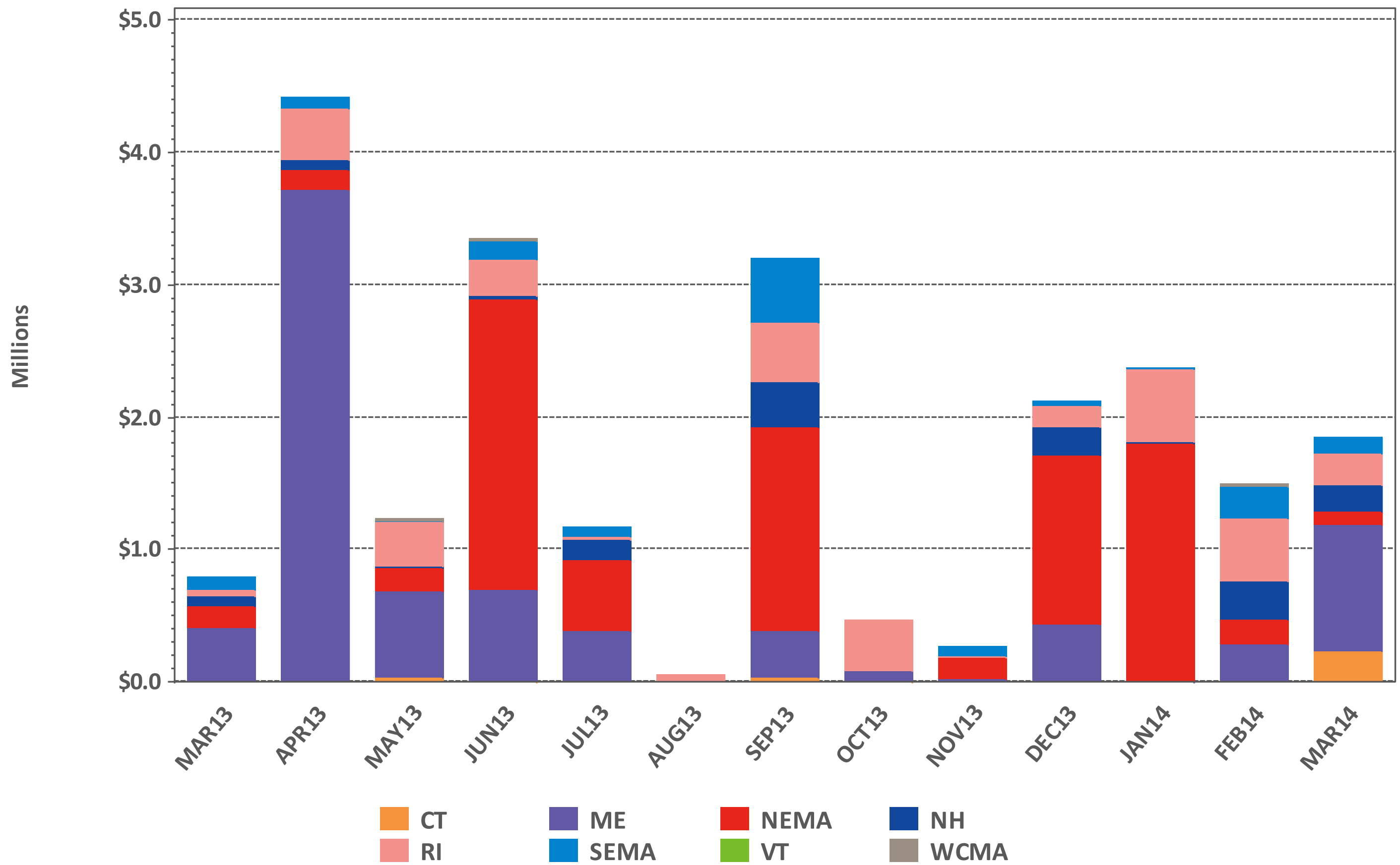


Last 13 Months



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

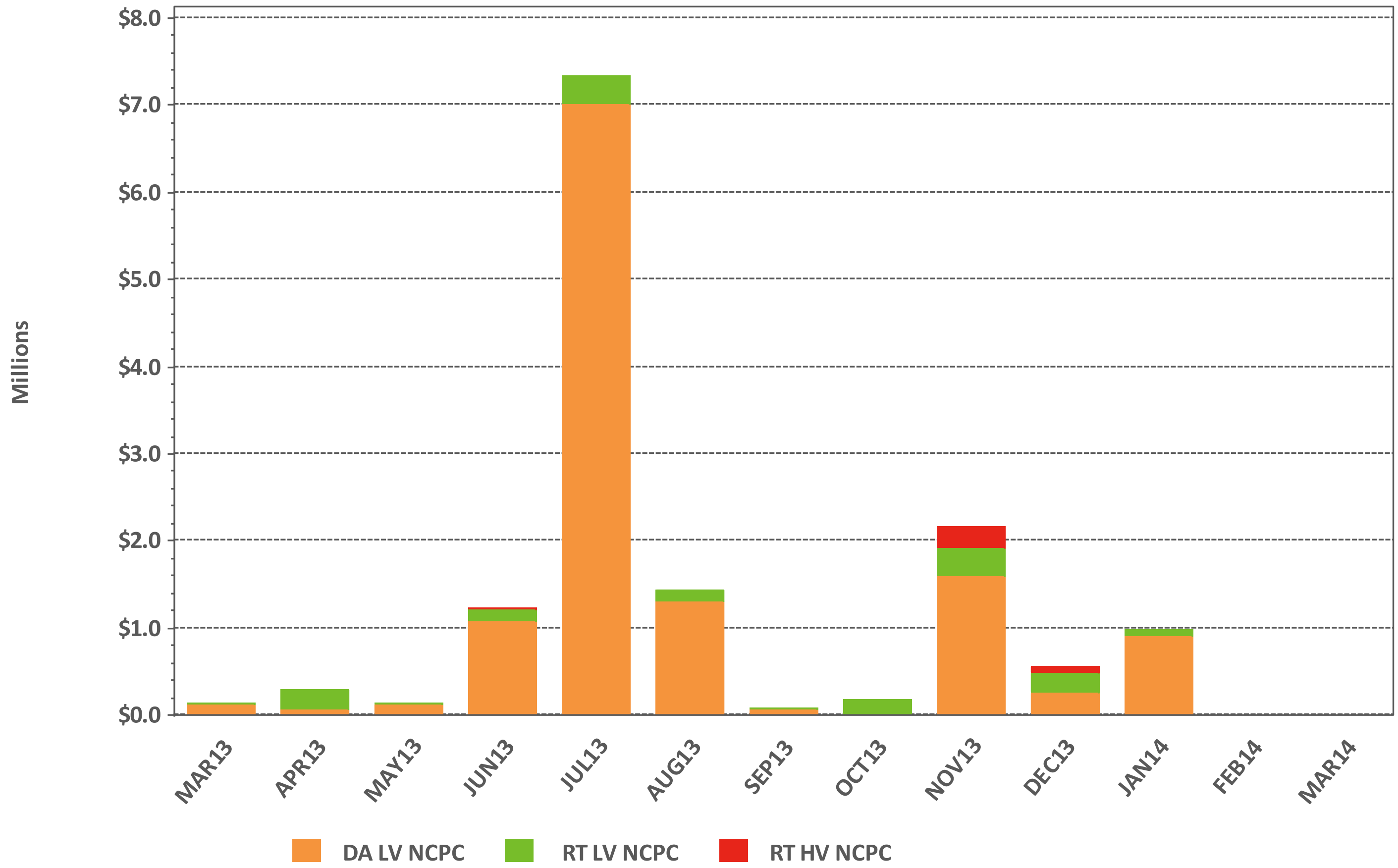
LSCPR Charges by Zone



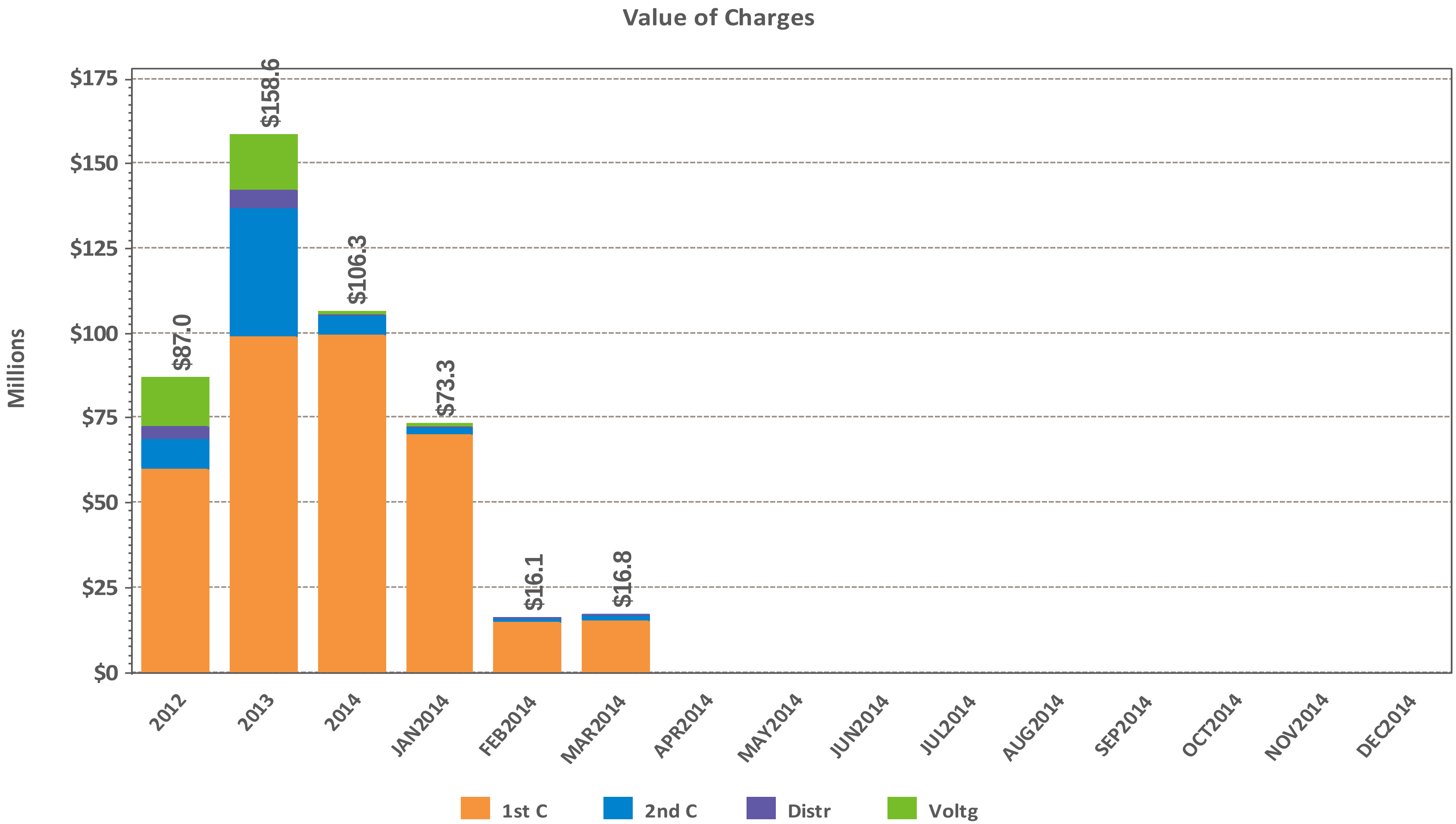
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

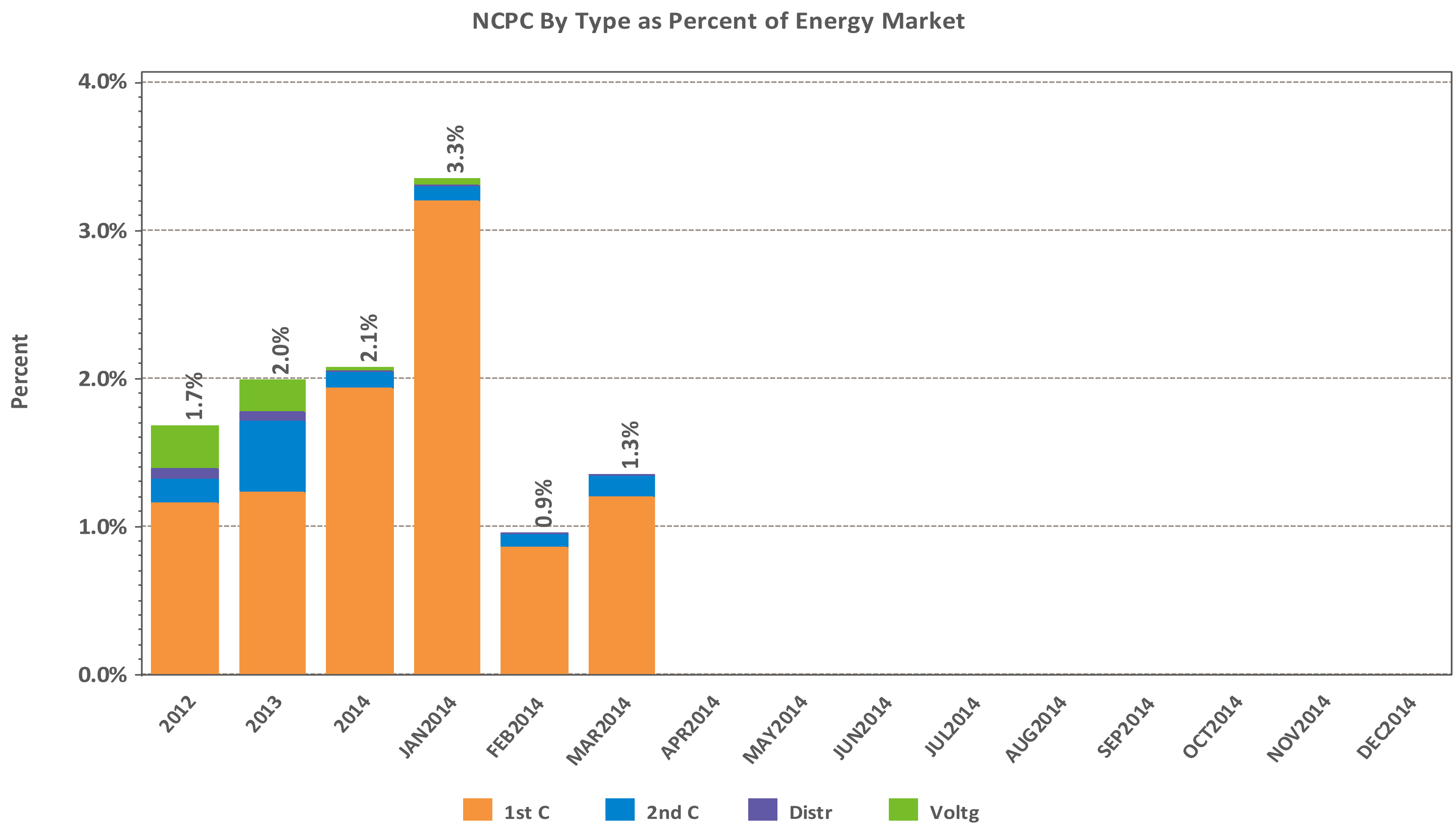
NCPC Charges for Voltage Support and High Voltage Control



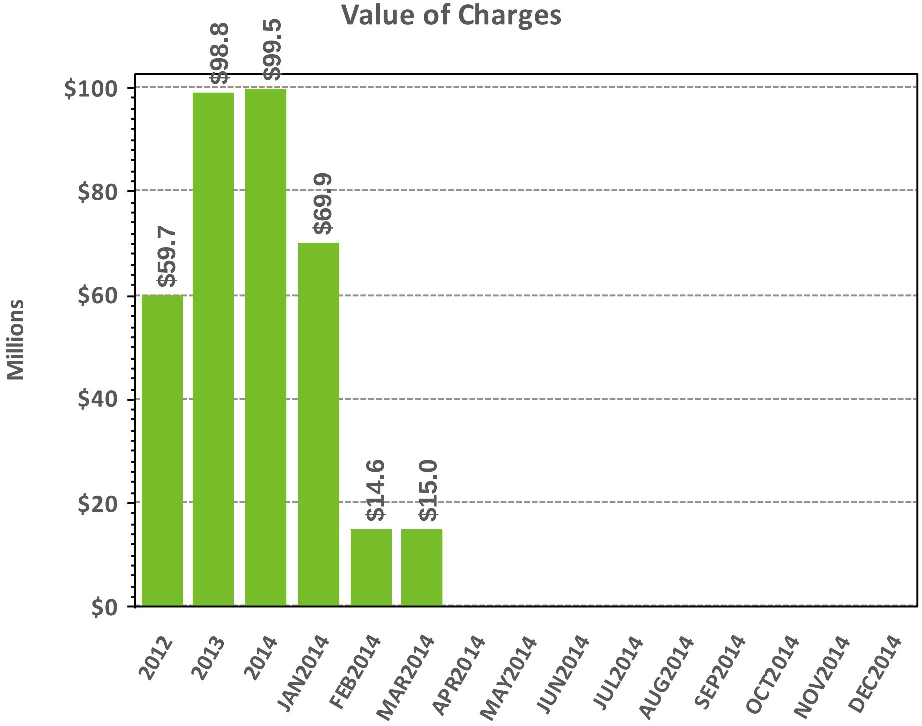
NCPC Charges by Type

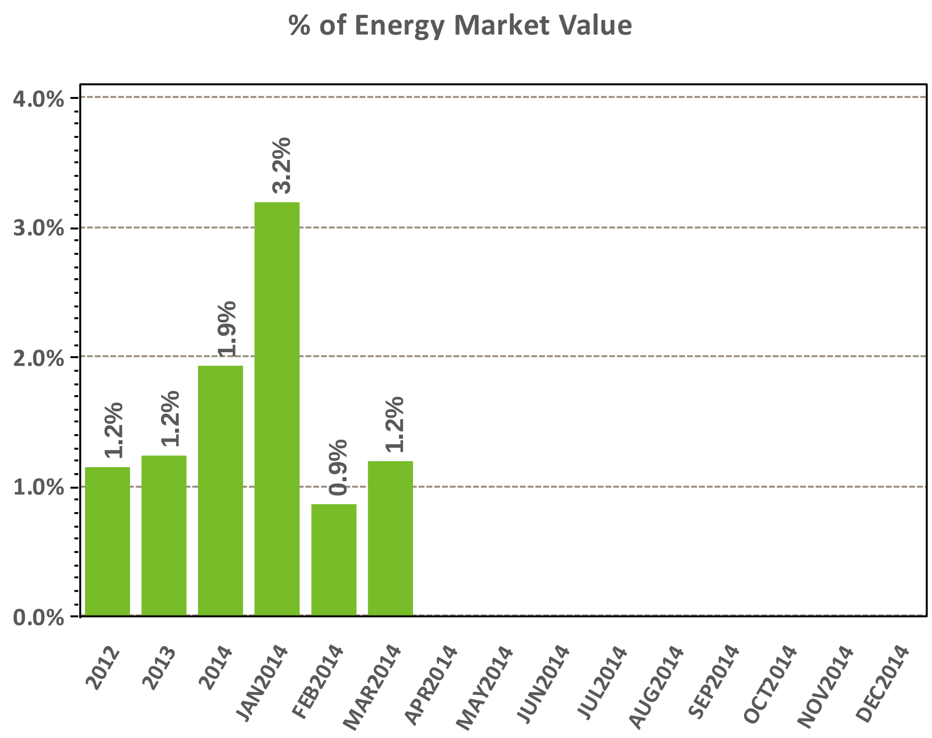


NCPC Charges as Percent of Energy Market



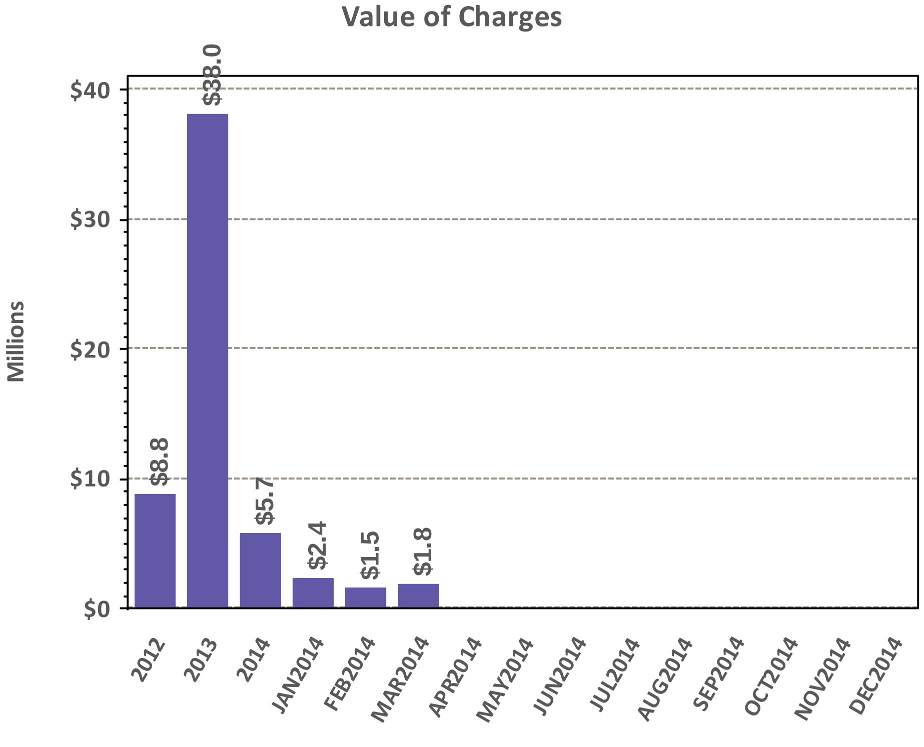
First Contingency NCPC Charges

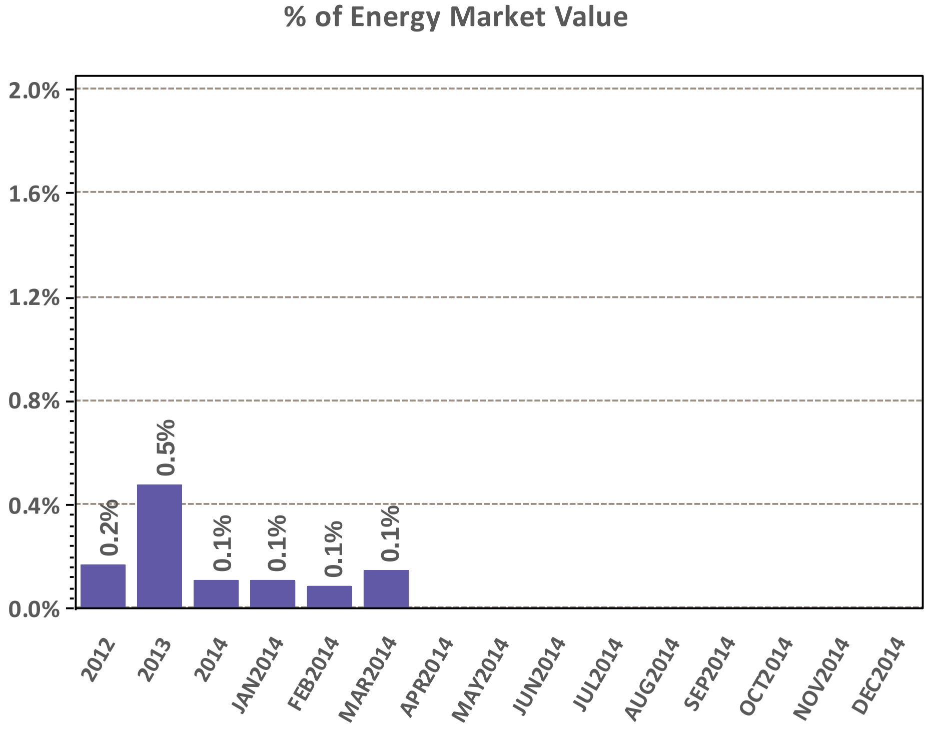




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

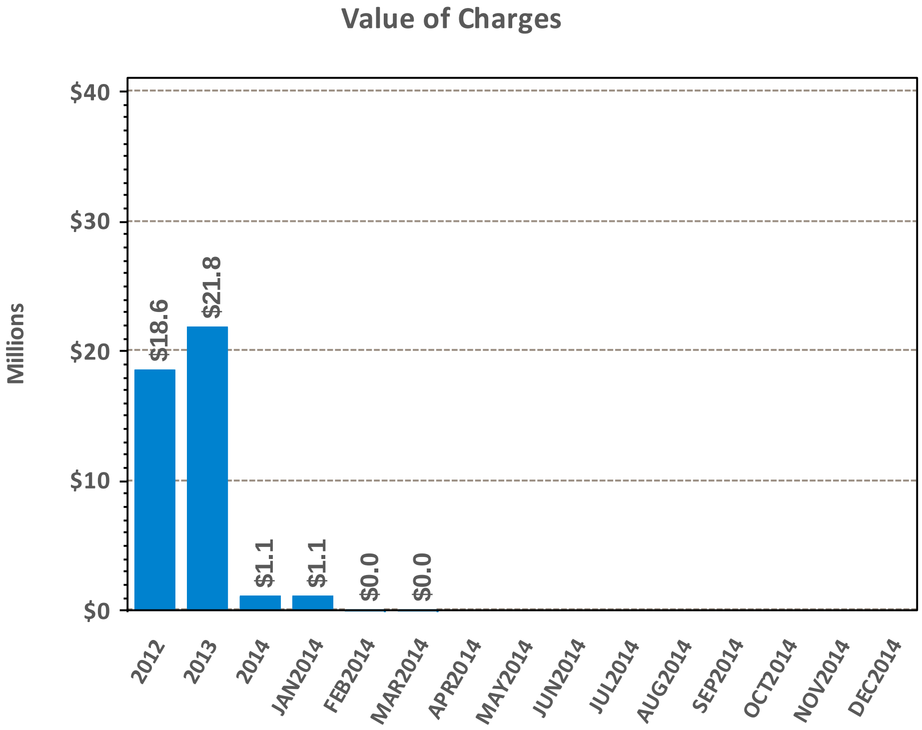
Second Contingency NCPC Charges

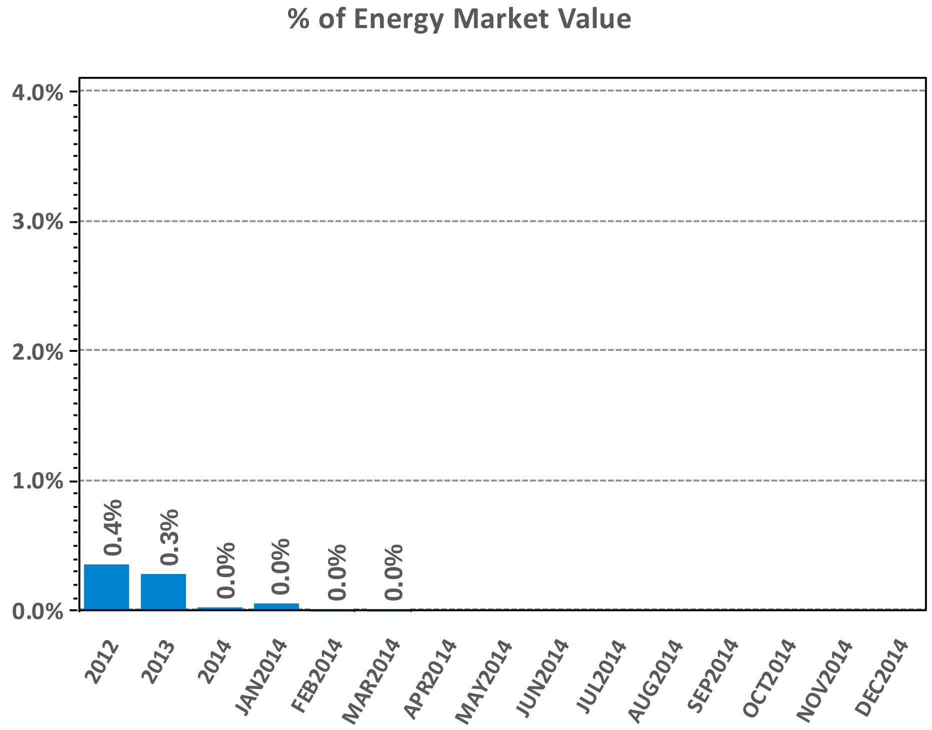




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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:

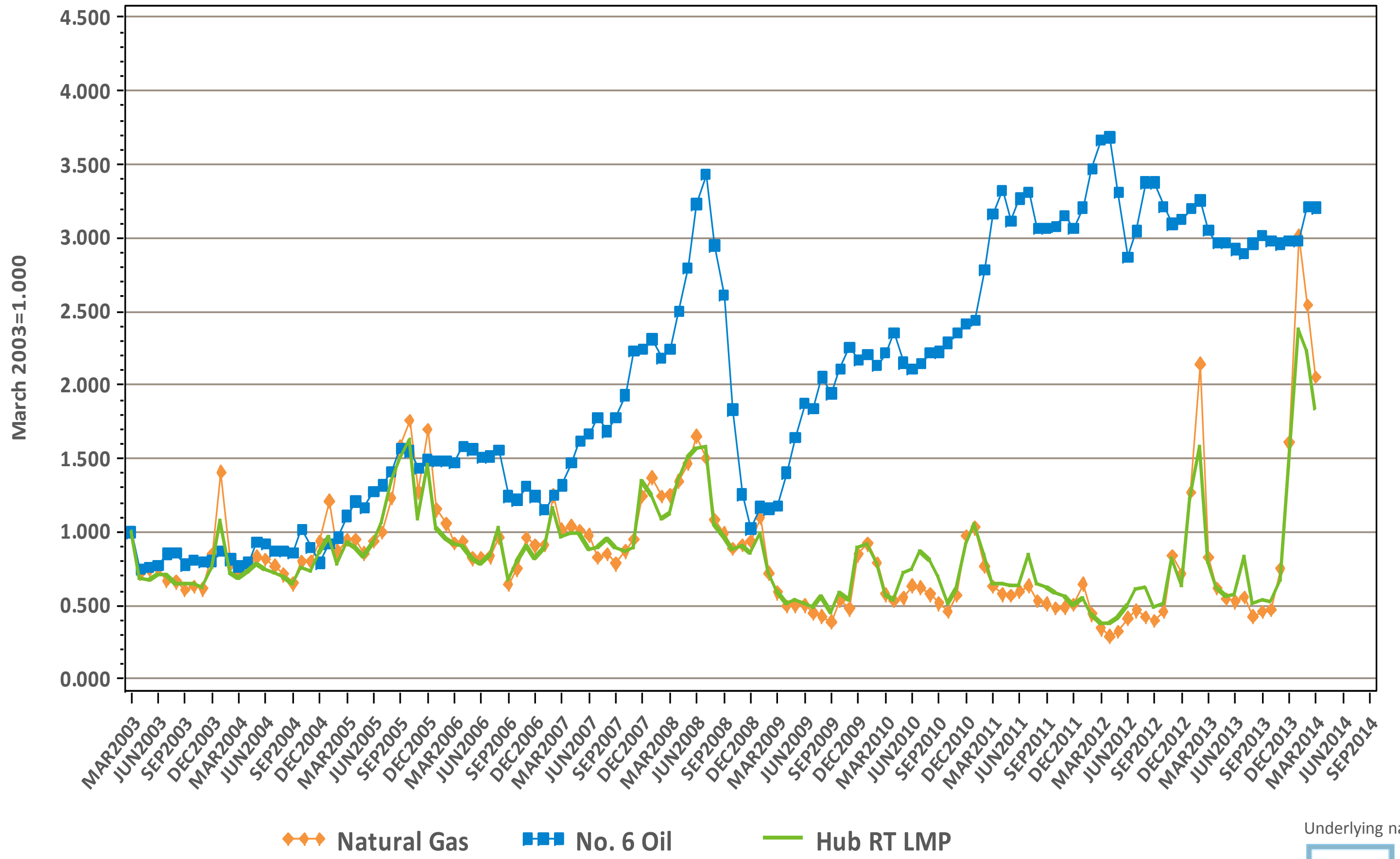
- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

DA vs. RT LMPs ($/MWh)

Year 2012	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$36.48	$37.09	$36.20	$36.24	$36.57	$36.56	$36.44	$37.29	$36.43
Real-Time	$36.22	$36.95	$35.25	$36.00	$36.22	$35.96	$36.22	$36.97	$36.17
RT Delta %	-0.7%	-0.4%	-2.6%	-0.7%	-0.9%	-1.7%	-0.6%	-0.8%	-0.7%
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%

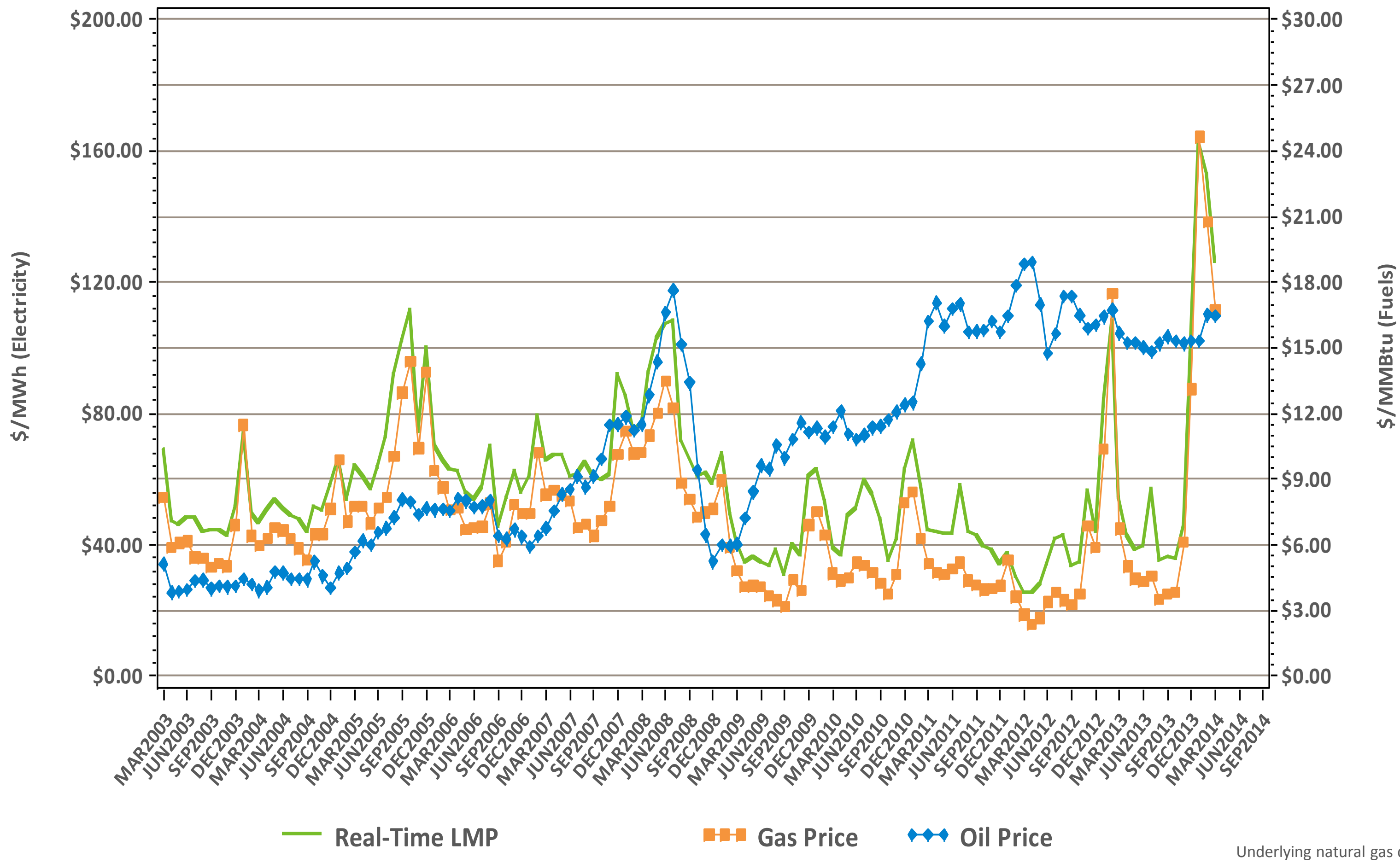
March-13	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$53.06	$52.70	$50.93	$52.74	$52.55	$53.31	$53.29	$53.22	$53.09
Real-Time	$54.14	$53.81	$51.96	$53.41	$53.31	$54.08	$54.32	$54.04	$54.01
RT Delta %	2.0%	2.1%	2.0%	1.3%	1.5%	1.5%	1.9%	1.5%	1.7%
March-14	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$123.53	$120.61	$118.23	$121.19	$120.81	$124.46	$124.14	$122.76	$122.84
Real-Time	$126.69	$124.05	$118.76	$122.49	$121.85	$126.58	$127.09	$125.87	$125.91
RT Delta %	2.6%	2.9%	0.5%	1.1%	0.9%	1.7%	2.4%	2.5%	2.5%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	132.8%	128.9%	132.1%	129.8%	129.9%	133.5%	133.0%	130.7%	131.4%
Yr over Yr RT	134.0%	130.5%	128.6%	129.3%	128.6%	134.0%	134.0%	132.9%	133.1%

Monthly Average Fuel Price and RT Hub LMP Indexes



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

Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:

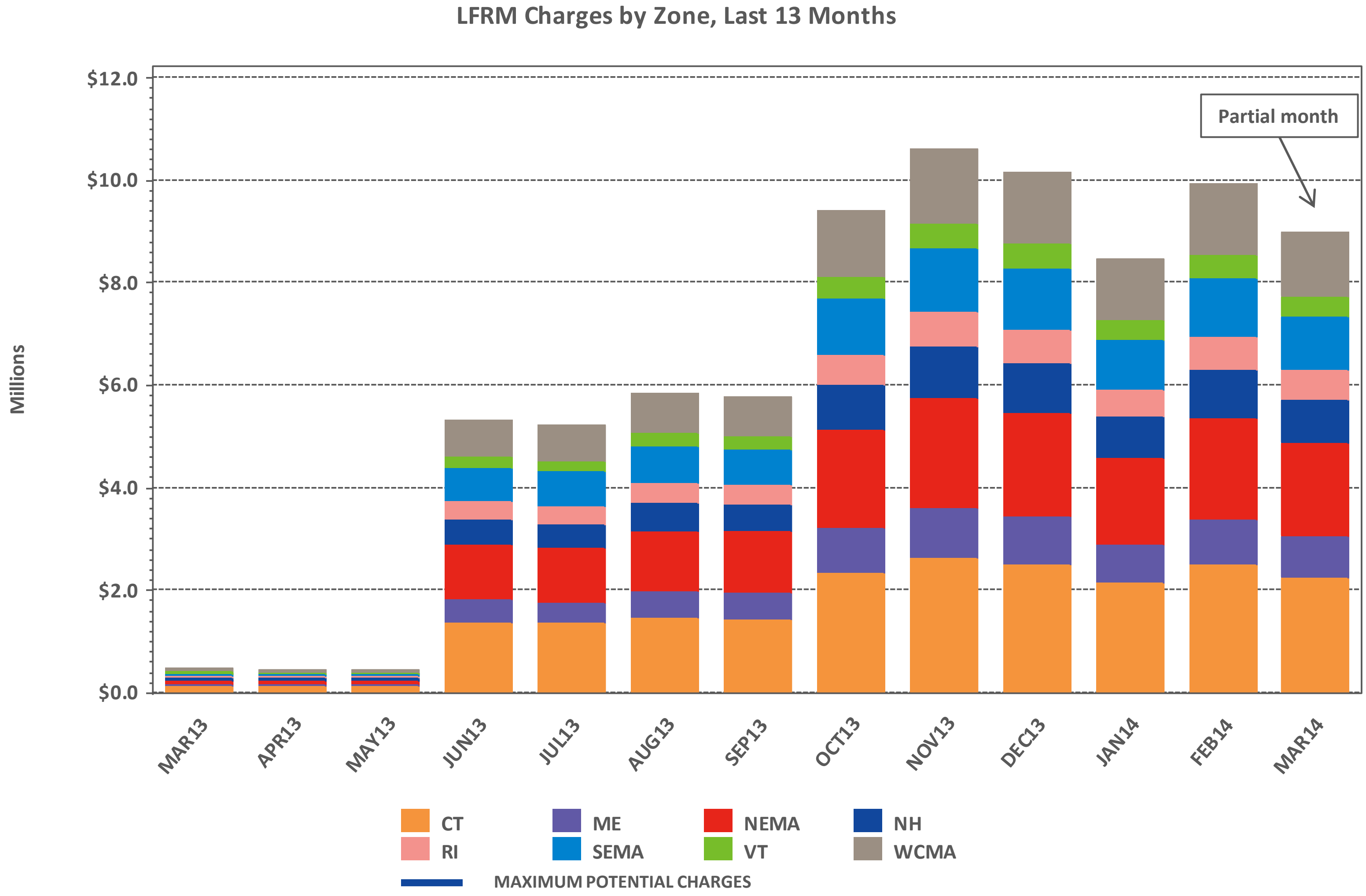
ICE Global markets in clear view

Reserve Market Results – March 2014

- Maximum potential Forward Reserve Market payments of $9.8M were reduced by credit reductions of $336K, failure-to-reserve penalties of $508K and failure-to-activate penalties of $0M, resulting in a net payout of $9.0M or 91% of maximum
  - Rest of System: $5.35M/$5.94M (90%)
  - Southwest Connecticut: $0.54M/$0.56M (95%)
  - Connecticut: $3.11M/$3.34M (93%)
- $2.8M total Real-Time credits were reduced by $98K in Forward Reserve Energy Obligation Charges for a net of $2.7M in Real-Time Reserve payments
  - Rest of System: 49 hours, $1.7M
  - Southwest Connecticut: 49 hours, $501K
  - Connecticut: 49 hours, $366K
  - NEMA: 49 hours, $106K

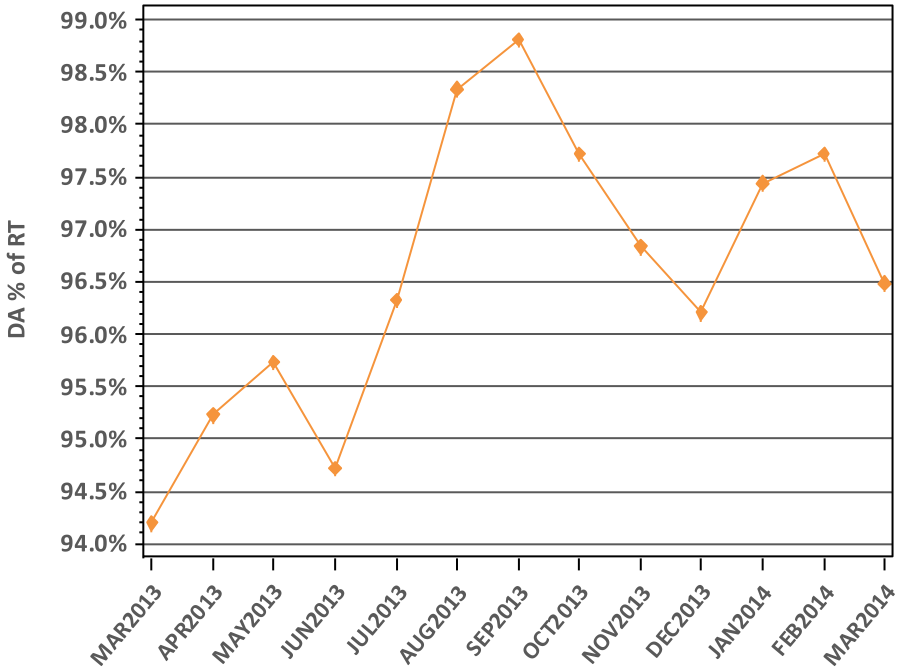
* "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market.

LFRM Charges to Load by Load Zone ($)

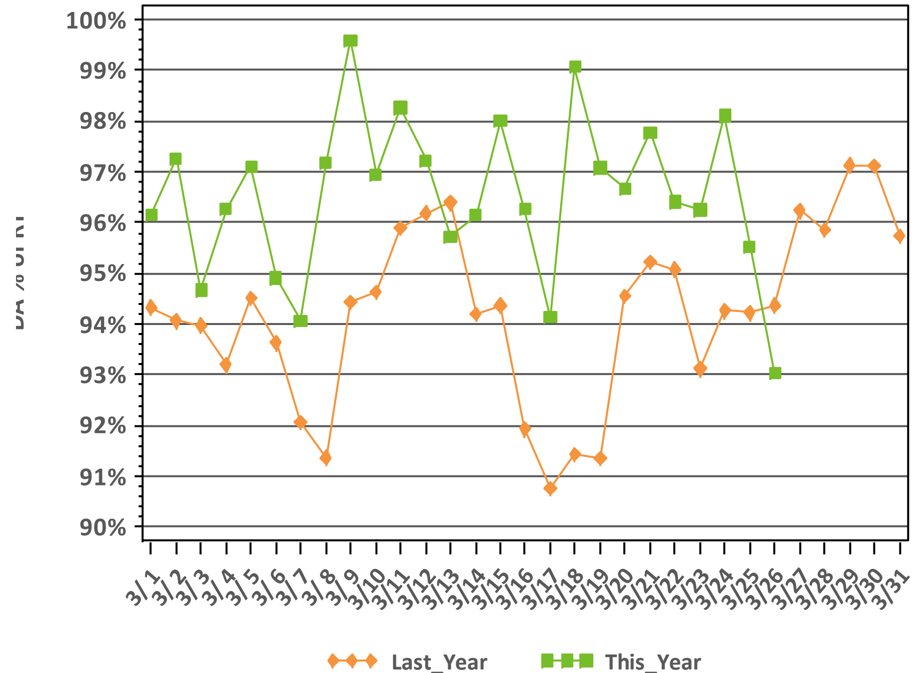


DA vs. RT Load Obligation: March, This Year vs. Last Year

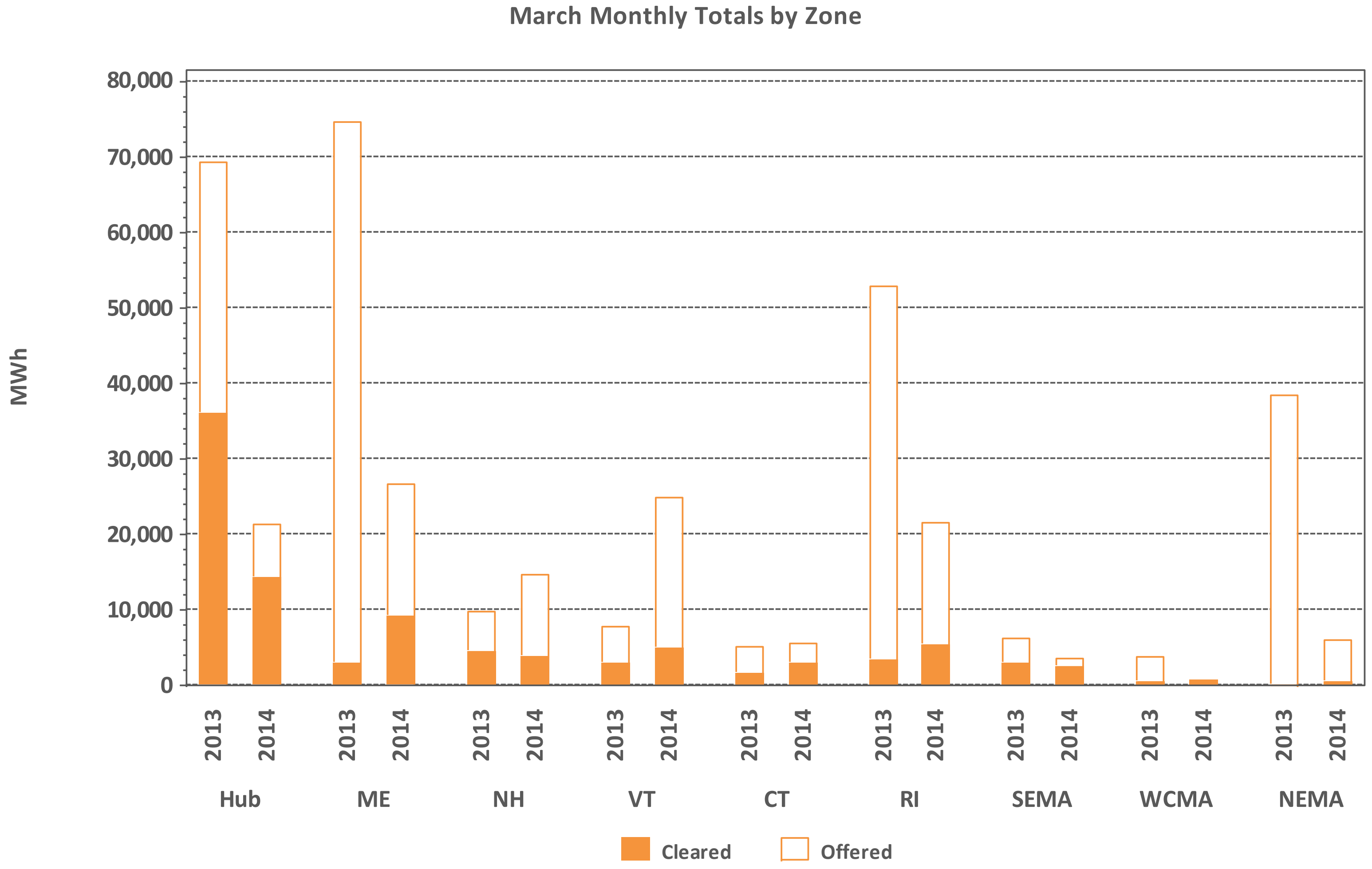
Monthly, Last 13 Months



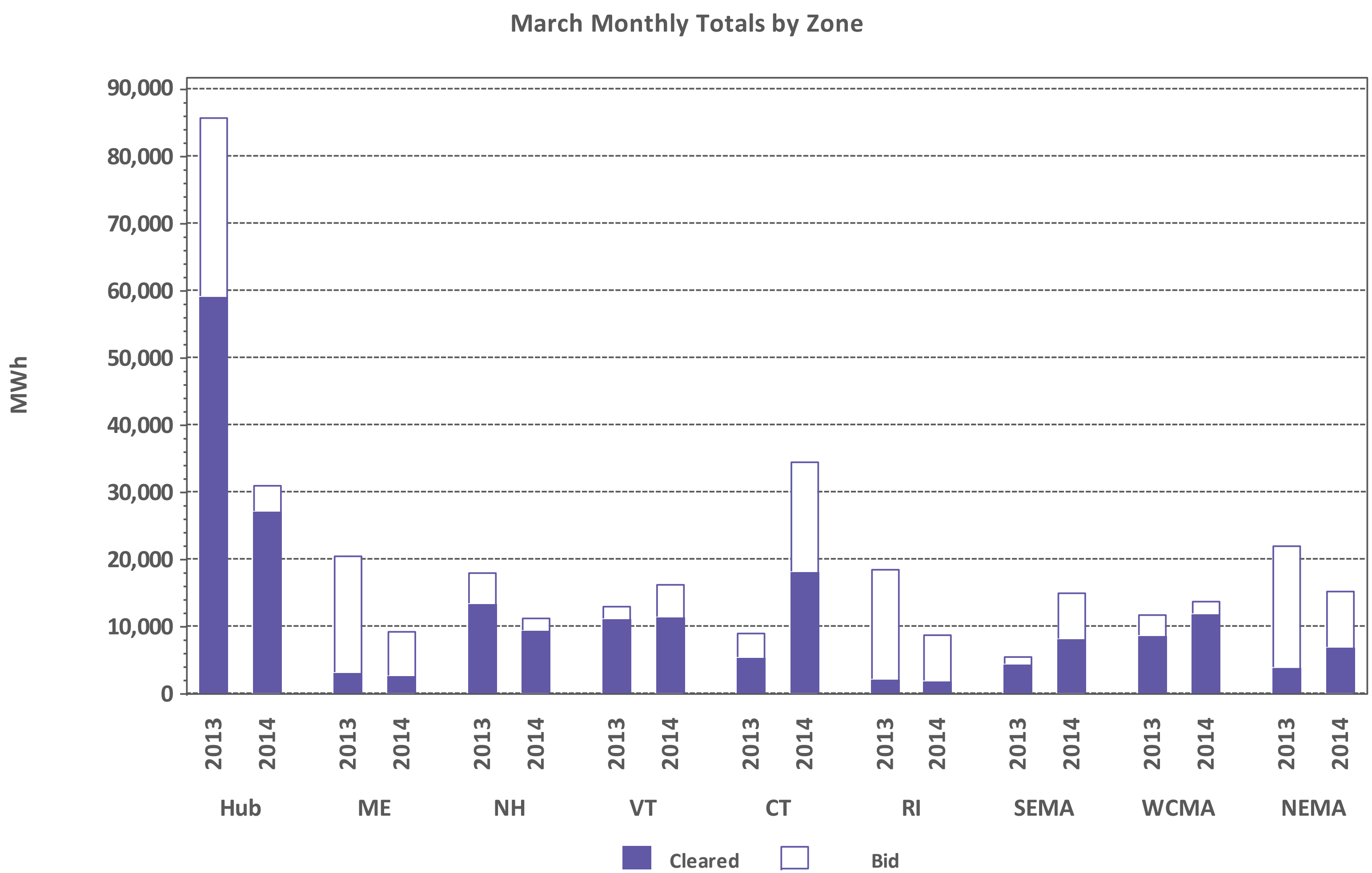
Daily, This Year vs. Last Year



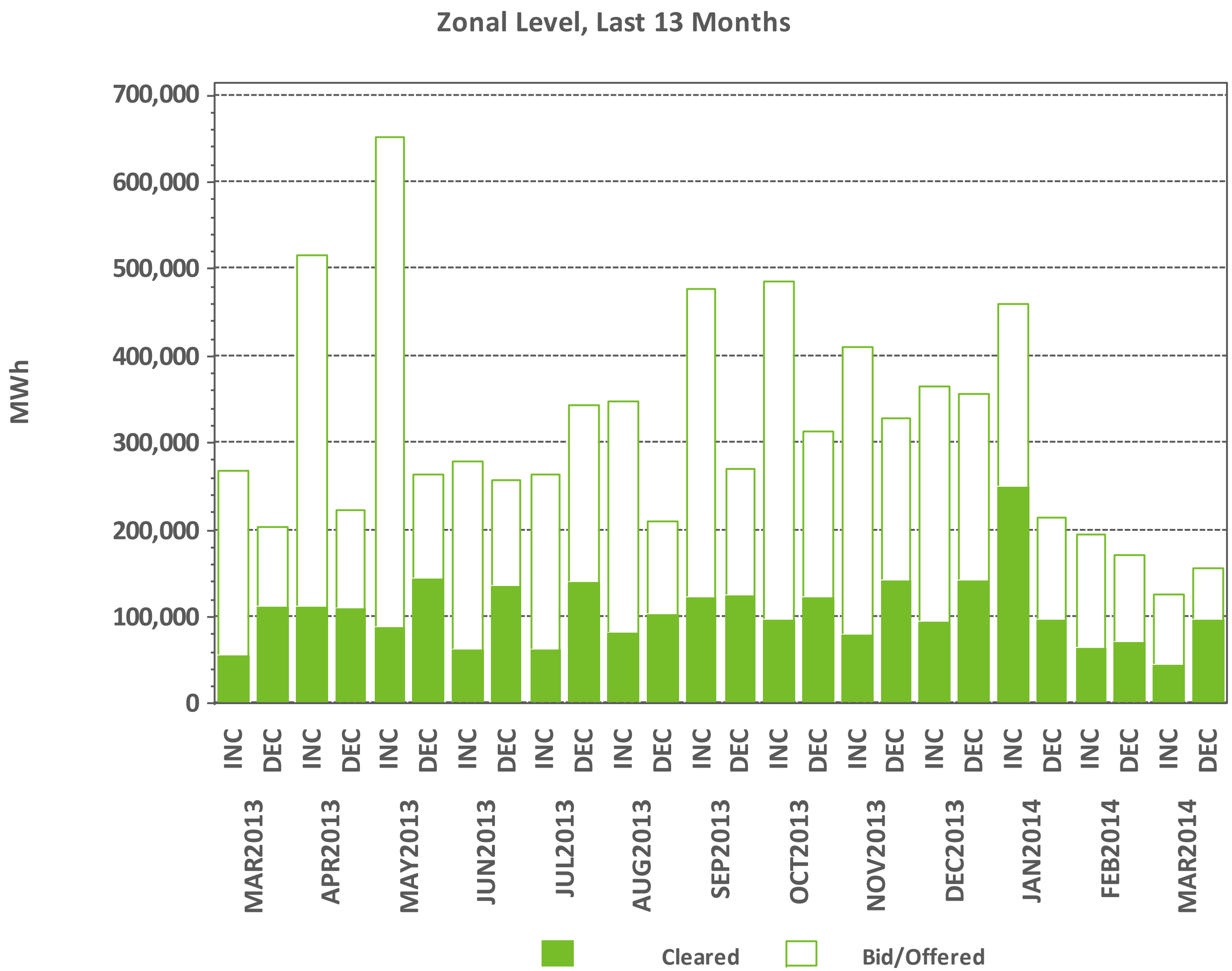
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

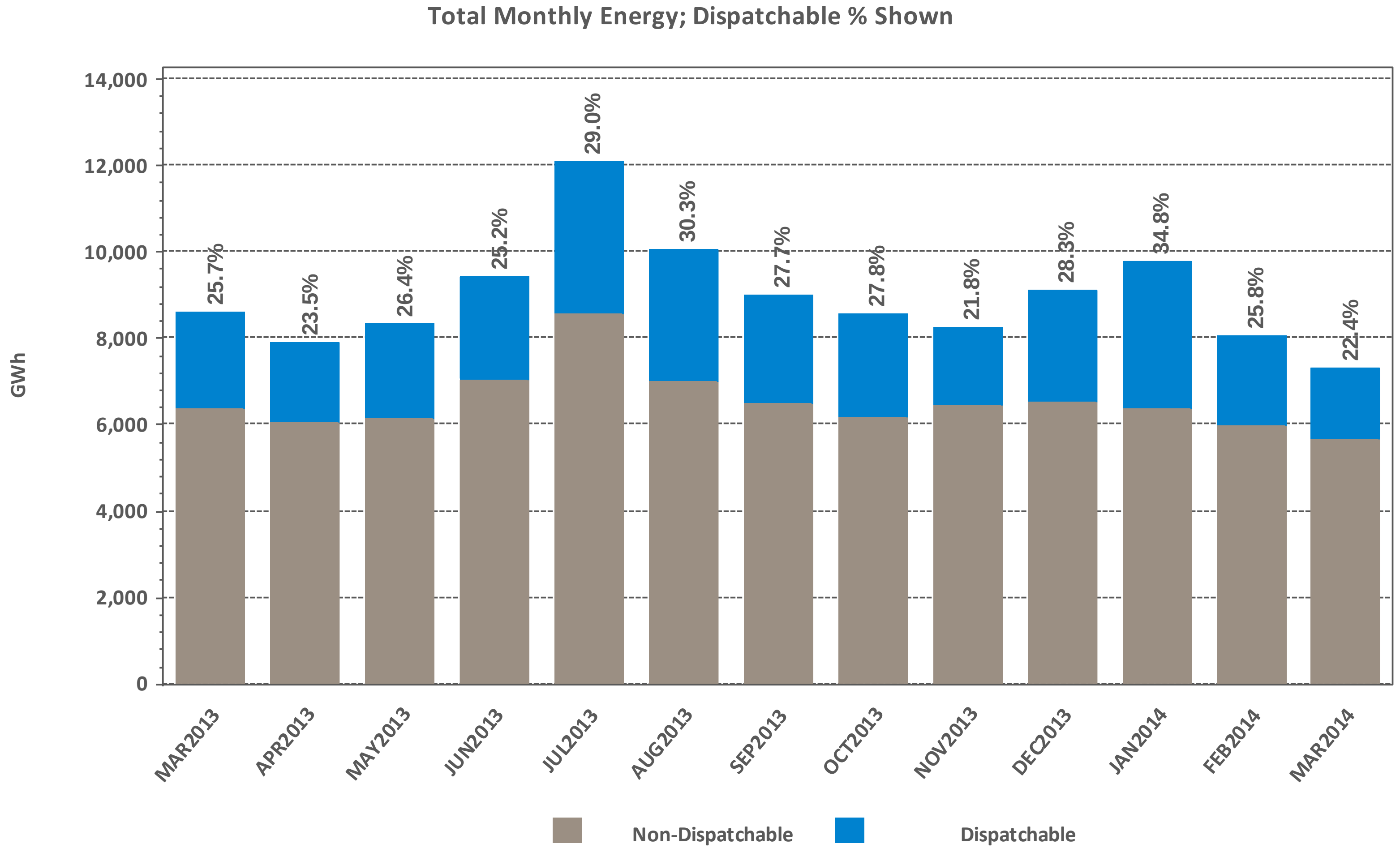


Total Increment Offers and Decrement Bids

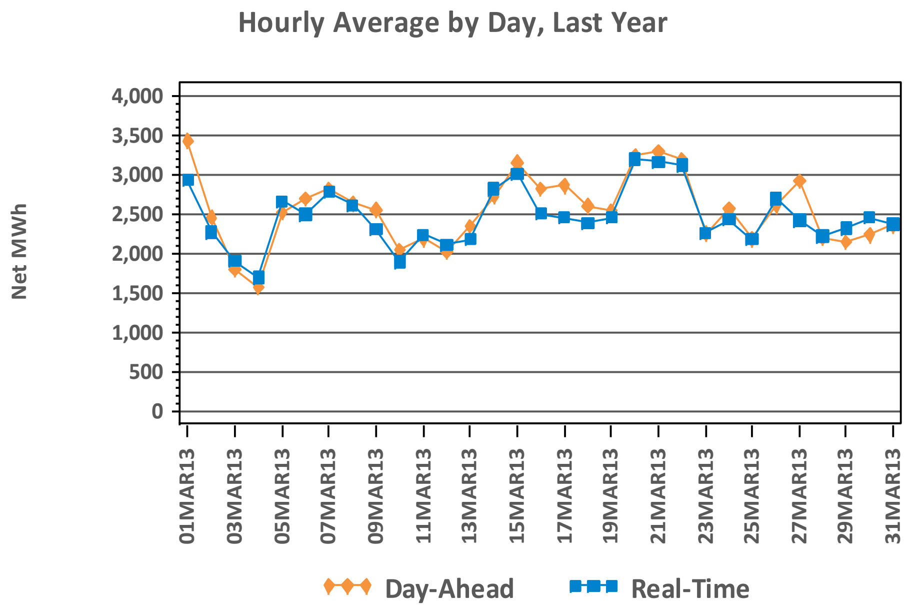


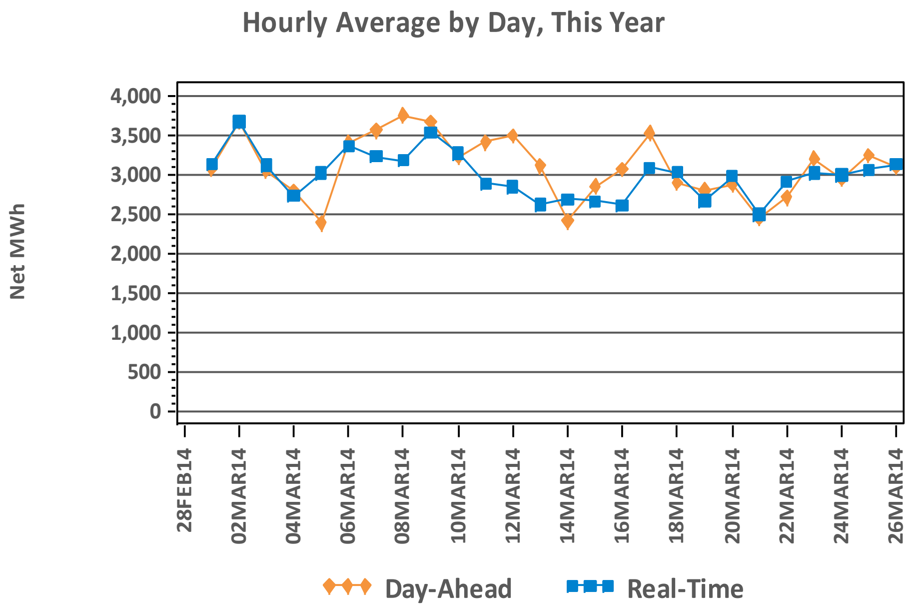
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



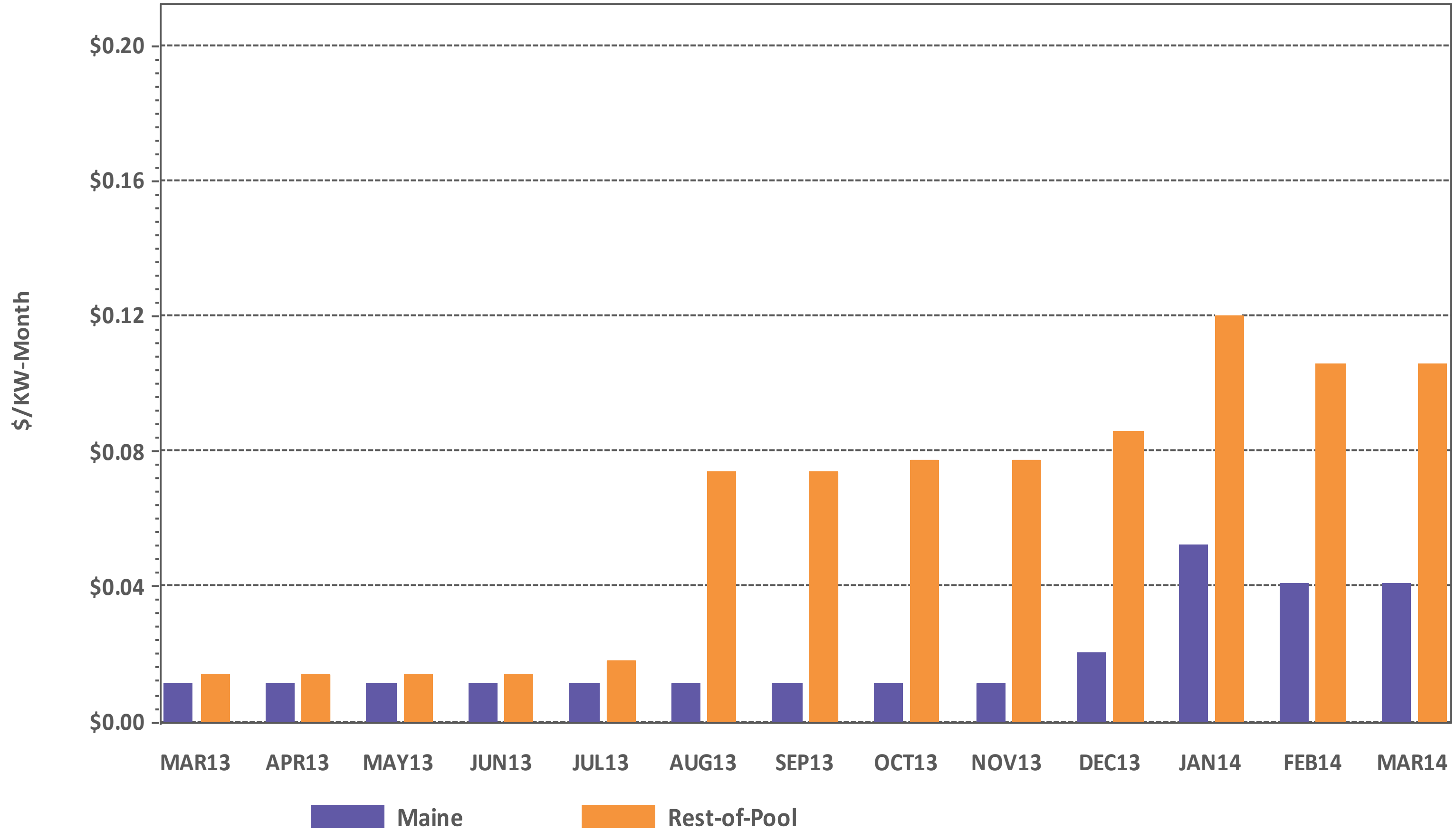
DA vs. RT Net Interchange
March 2014 vs. March 2013





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

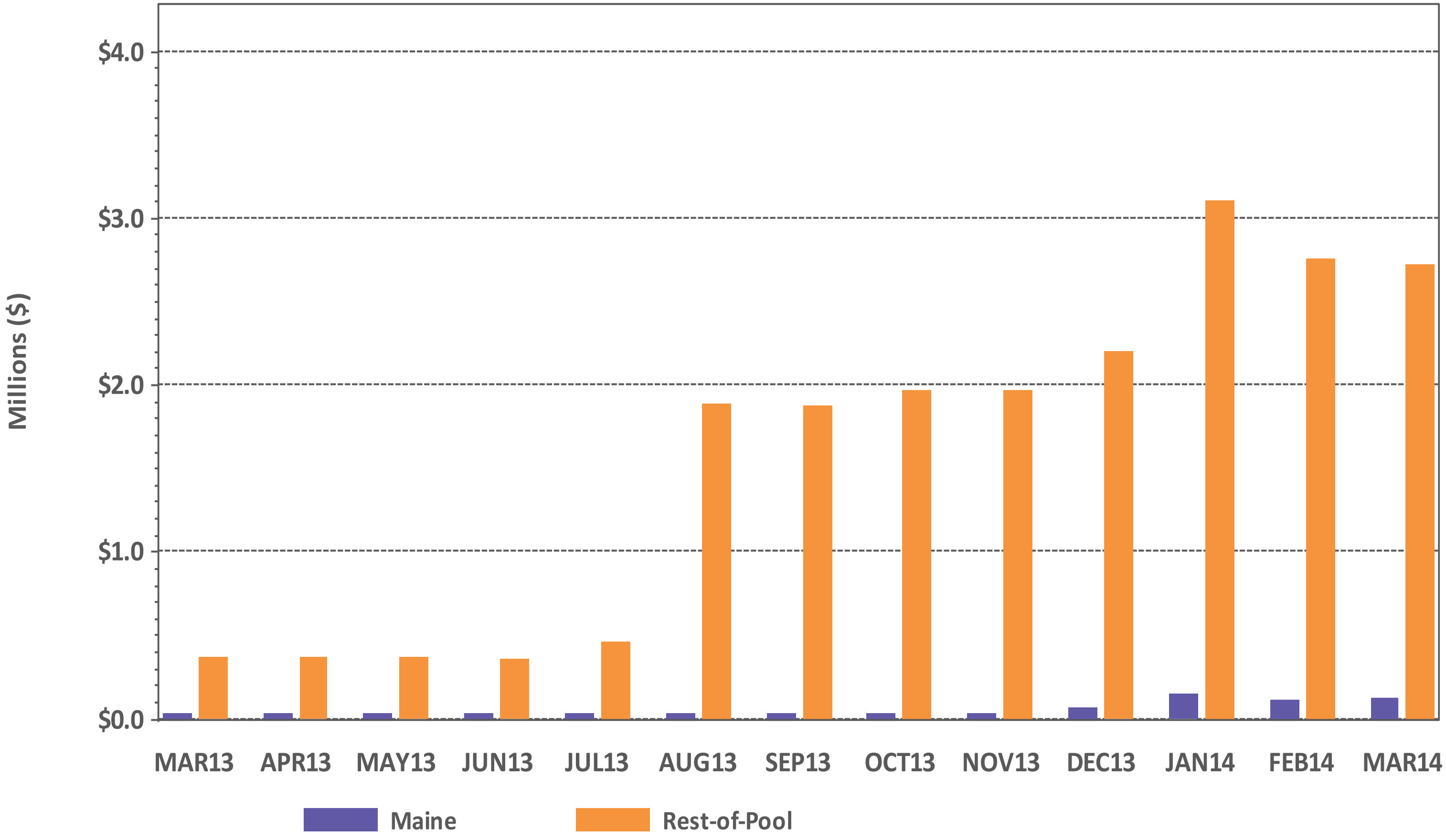
Rolling Average Peak Energy Rent (PER)



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) AND INTERREGIONAL PLANNING

Planning Advisory Committee (PAC)

- Economic Study requests are due to ISO by April 1
  - The ISO will advise all requestors of all received requests and the time allotted for each presentation by April 3
  - Presentation materials are due to the ISO by April 9
- April 29 PAC Agenda Topics
  - EIPC Gas/Electric Interface Study Update
  - SEMA Load Pocket Nodal Market Resource Alternative Analysis Update
  - 2014 ICF Benchmarking Study
  - 2014-2023 Regional State Energy and Peak Forecast Update
  - RSP14 Resource Adequacy Related Studies Scope of Work
  - RSP14 Load and Capacity Resource Overview
  - 2013 Economic Study Update
  - Stakeholder Proposals for 2014 Economic Studies

Distributed Generation Forecast Working Group (DGFWG)

- The Final Interim PV Forecast, DG location and modeling issues, status of interconnection issues and ISO plans for use of the DG forecast, DG in FCM, and next steps will be discussed at the April 2 meeting
  - ISO is reflecting information received from the distribution owners for additional information
  - The Final Interim PV Forecast is being refined with only minor changes and will appear as part of the CELT 2014
- Follow-up discussions will be held at DGFWG meetings and the PAC will be kept advised of DGFWG activities with the goal of developing an overall DG forecast for CELT 2015
- ISO is working with the transmission owners, distribution owners, and the states to resolve interconnection issues
- ISO will utilize its normal transparent process that allows all stakeholders to provide input on the use of the DG forecast
  - Uses of the DG forecast will be vetted through PAC and NEPOOL committees as necessary

Inter-Area Planning Stakeholder Advisory Committee (IPSAC) and Environmental Advisory Group (EAG)

- An IPSAC webinar was held on March 28 to discuss the draft Northeast Coordinated System Plan
  - See http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2014/mar282014/index.html
  - Final stakeholder comments are due April 8
- On a March 26 conference call, state air quality regulators requested ISO-NE, NYISO and PJM assist in developing an emissions methodology that allows quantification of avoided emissions due to energy efficiency and renewable energy production
  - The next call will be scheduled in April to discuss the states’ request in more detail

Variable Resource Working Group (VRWG)

- The VRWG is a NEPOOL advisory stakeholder group that will provide a forum for the exchange of information and ideas on issues affecting participation by variable resources in New England
- The VRWG will hold its initial meeting on April 17 at the Sheraton Springfield Monarch Place Hotel in Springfield, MA
- Materials will be posted at http://www.iso-ne.com/committees/comm_wkgrps/othr/index.html

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

North Shore Upgrades – Salem Harbor Non-Price Retirement

Status as of 3/31/14

Project Benefits: Allows for the Non-Price Retirement of the Salem Harbor Plant

Upgrade	Expected In-service	Present Stage
Reconductor Y-151 Tewksbury Jct. - West Methuen 115 kV	Feb-14	4
Reconductor B-154N King St. - South Danvers 115 kV	Feb-13	4
Reconductor C-155N King St. - South Danvers 115 kV	Feb-13	4
Reconductor S-145 Tewksbury - North Reading 115 kV	Aug-13	4
Reconductor T-146 Tewksbury - North Reading 115 kV	Aug-13	4

Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 3/31/14

Project Benefit: Improves system reliability for the Lower SEMA area

Upgrade	Expected In-service	Present Stage
Expand the Carver Substation	Jun-13	4
Build New 345 kV Line from Carver to Vicinity of Bourne Substation and connect to Line 120. Expand Bourne with one breaker position.	Jun-13	4*
Construct New 115 kV Substation with 345-115 kV Autotransformer and Loop Line 115 into the new substation	Dec-13	4
Upgrade the 115 kV Bell Rock to High Hill D21 Line	May-13	4
Separate the 345 kV (342 / 322) Double Circuit Tower Lines	Jun-13	4

Project approved by MA EFSB on 4/27/12

* The work is in service in a temporary configuration. The final in-service configuration will be completed May 2014.

NEEWS: Interstate Reliability Project

Status as of 3/31/14

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	3
Card 345 kV Substation Expansion	Dec-15	3
Lake Road 345 kV Substation Expansion	Dec-15	2
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	1
West Farnum 345 kV Substation Additions (New Line Terminations)	Dec-15	1
New Sherman Road 345 kV Substation	Dec-15	1
West Farnum 115 kV Substation Upgrades	Sep-14	3
Reconductor 345 kV Line 328 West Farnum to Sherman Road	Dec-15	1
Riverside Substation Relay Upgrades	Sep-14	3
Woonsocket Substation Relay Upgrades	Sep-14	3
Hartford Avenue Substation Relay Upgrades	Sep-14	3
Build New 345 kV Line 366 West Farnum to MA/RI Border	Dec-15	1
Build New 345 kV Line 366 MA/RI Border to Millbury 3	Dec-15	1
Millbury 3 Substation Expansion	Dec-15	2
Carpenter Hill Substation Relay Upgrades	Dec-15	2

NEEWS: Central Connecticut Reliability Project

Status as of 3/31/14

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

Upgrade	Expected In-service	Present Stage
Central Connecticut Reliability Project (CCRP)*	Jun-17	1

* Combined with Greater Hartford Central Connecticut Study

Maine Power Reliability Program (MPRP)

Status as of 3/31/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

New 345 kV Lines	Expected In-Service	Present Stage
Construct New Section 3023 Orrington to Albion Road	May-13	4
Construct New Section 3024 Albion Road to Coopers Mills	Jan-15	3
Construct New Section 3025 Coopers Mills to Larrabee Road	Mar-15	3
Construct New Section 3026 Larrabee Road to Surowiec	Dec-12	4
Construct New Section 3020 Surowiec to Raven Farm	Nov-13	4
Construct New Section 3021 South Gorham to Maguire Road	Apr-14	3
Construct New Section 3022 Maguire Road to Eliot	Jun-14	3

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

Maine Power Reliability Program, *cont.*

Status as of 3/31/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

New 115 kV Lines	Expected In-Service	Present Stage
Construct New Section 254 Orrington to Coopers Mills	Feb-15	3
Construct New Section 243A Livermore Falls to Junction Section 243	May-14	3
Construct New Section 251 Livermore Falls to Larrabee Road	May-14	3
Construct New Section 255 Larrabee Road to Middle Street	Apr-15	3
Construct New Section 86A Tap to Belfast	Jul-14	3
Construct New Section 256 Middle Street to Lewiston Lower	April-15	1

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

Maine Power Reliability Program, *cont.*

Status as of 3/31/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

115 kV Lines Rebuilds	Expected In-Service	Present Stage
Rebuild Section 60 Coopers Mills to Bowman Street	Feb-15	3
Rebuild Section 88 Coopers Mills to Augusta East Side	Feb-15	3
Rebuild Section 89 Livermore Falls to Riley	May-14	3
Rebuild Section 229 Riley to Rumford IP	May-13	4
Rebuild Section 212 Monmouth to Larrabee Road	Feb-13	4
Rebuild Section 269 Bowman Street to Monmouth	May-12	4
Rebuild Section 238 Louden to Maguire Road	Feb-12	4
Rebuild Section 250 Maguire Road to Three Rivers	Dec-13	4

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

Maine Power Reliability Program, *cont.*

Status as of 3/31/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

345/115 kV Autotransformers	Expected In-Service	Present Stage
Install One 345/115 kV Autotransformer at Albion Road	Apr-13	4
Install One 345/115 kV Autotransformer at Coopers Mills	Jan-15	3
Install One 345/115 kV Autotransformer at Larrabee Road	Dec-12	4
Install One 345/115 kV Autotransformer at Maguire Road	Apr-14	3
Install One 345/115 kV Autotransformer at South Gorham	Nov-09	4

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

Transmission Siting Update

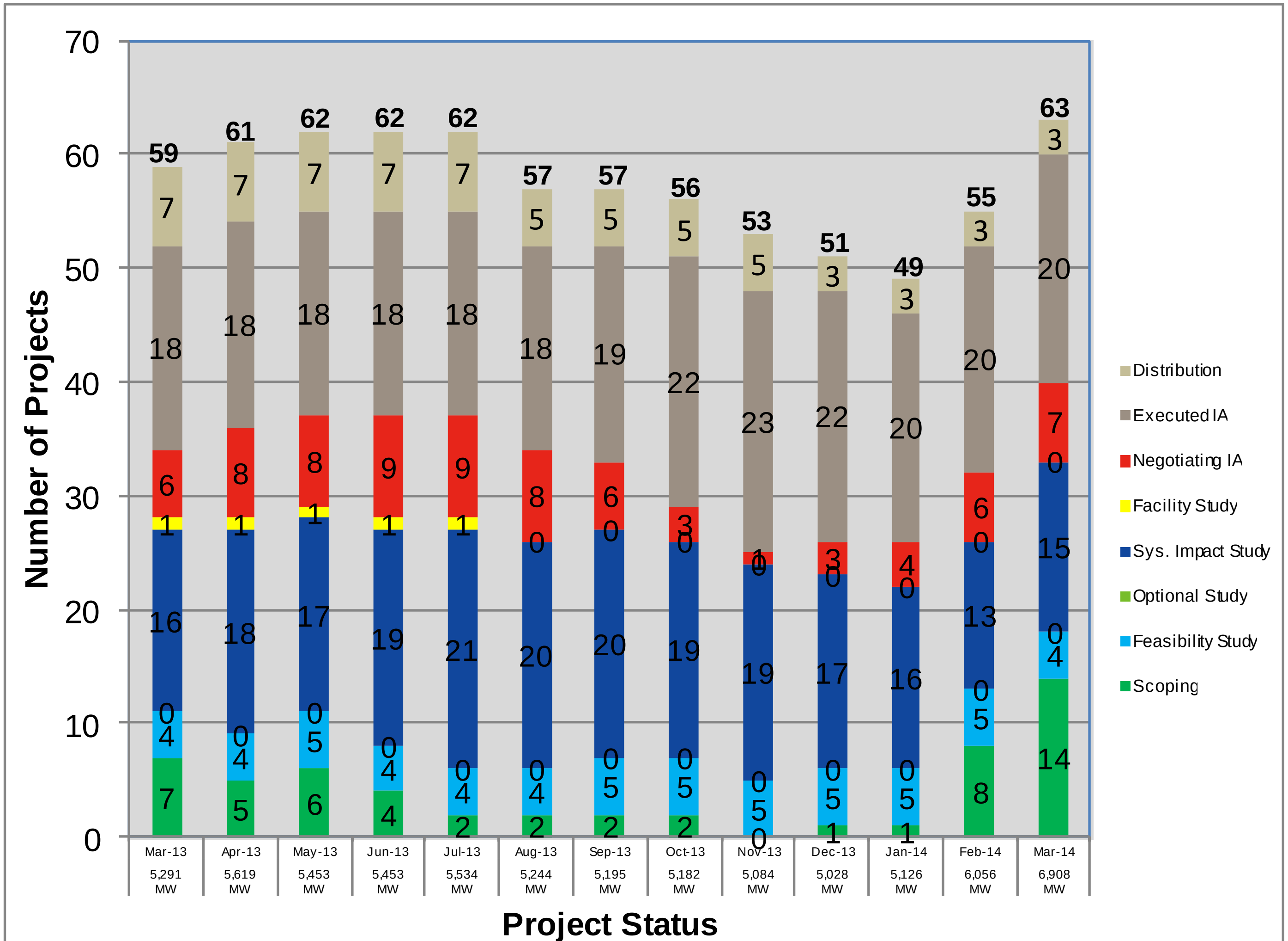
- NEEWS
  - Rhode Island Reliability Project
    - Project completed
  - Greater Springfield Reliability Project
    - Project completed
  - Interstate Reliability Project
    - National Grid siting application was filed in MA on 6/21/12
    - National Grid siting application was filed in RI on 7/19/12
    - CL&P's siting hearings in CT were completed on 8/30/12
    - Received siting approval from CT on 1/2/13. The RI Energy Facilities Siting Board approved the project on 6/14/13. MA EFSB directed the drafting of a Tentative Decision approving the project on 1/30/14
- MPRP
  - Project filed with the Maine Public Utility Commission on 7/1/08
  - Maine PUC approved most of the project on 6/10/10
  - Hearings are complete - written order received on Lewiston Loop

NSTAR Cable Rating Changes – Boston Area

- In April 2013, NSTAR presented updates to the cable ratings to the PAC[1]
- The changes were driven by the following:
  - Moving ratings to a consistent time period for emergency ratings – 12 hours for summer LTE and 4 hours for winter LTE
  - Multiple rating sets to reflect status of forced cooling systems and/or status of adjacent transmission cables
  - A total of (35) 115 kV cables and (10) 345 kV cables had their ratings change
- As of March 2014, NSTAR has submitted a portion of the summer cable ratings to ISO-NE for inclusion in the NX-9 database
  - These are anticipated to go into effect spring 2014
- In the coming months, NSTAR will also be providing updated winter ratings for these cables
  - These would have an anticipated effective date of November 1, 2014

[1] https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/apr242013/a10_nstar_greater_boston_cable_ratings.pdf

Status of Tariff Studies



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

OPERABLE CAPACITY ANALYSIS

Spring 2014

Spring 2014 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May -2014 [2] CSO	May -2014 [2] SCC
Generator Operable Capacity MW [1]	29,627	34,022
OP CAP From OP-4 RTDR (+)	418	418
OP CAP From OP-4 RTEG (+)	234	234
Operable Capacity Generator with OP-4 DR and RTEG	30,279	34,674
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,083	1,083
Non Commercial Capacity (+)	68	68
Non Gas-fired Planned Outage MW (-)	2,267	2,386
Allowance for Unplanned Outages (-)	3,400	3,400
Gas Generator Outages MW (-)	2,020	2,126
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23, 743	27,913
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,216	21,216
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,591	23,591
Operable Capacity Margin [3]	152	4,322

[1] Generator Operable Capacity is based on data as of March 18th, 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning May 17th, 2014

[3] Includes OP4 actions associated with RTEG and RTDR

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

Spring 2014 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May -2014[2] CSO	May -2014[2] SCC
Generator Operable Capacity MW [1]	29,627	34,022
OP CAP From OP-4 RTDR (+)	418	418
OP CAP From OP-4 RTEG (+)	234	234
Operable Capacity Generator with OP-4 DR and RTEG	30,279	34,674
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,083	1,083
Non Commercial Capacity (+)	68	68
Non Gas-fired Planned Outage MW (-)	2,267	2,386
Allowance for Unplanned Outages (-)	3,400	3,400
Gas Generator Outages MW (-)	2,020	2,126
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23, 743	27,913
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	23,058	23,058
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	25,433	25,433
Operable Capacity Margin [3]	(1690)	2,480

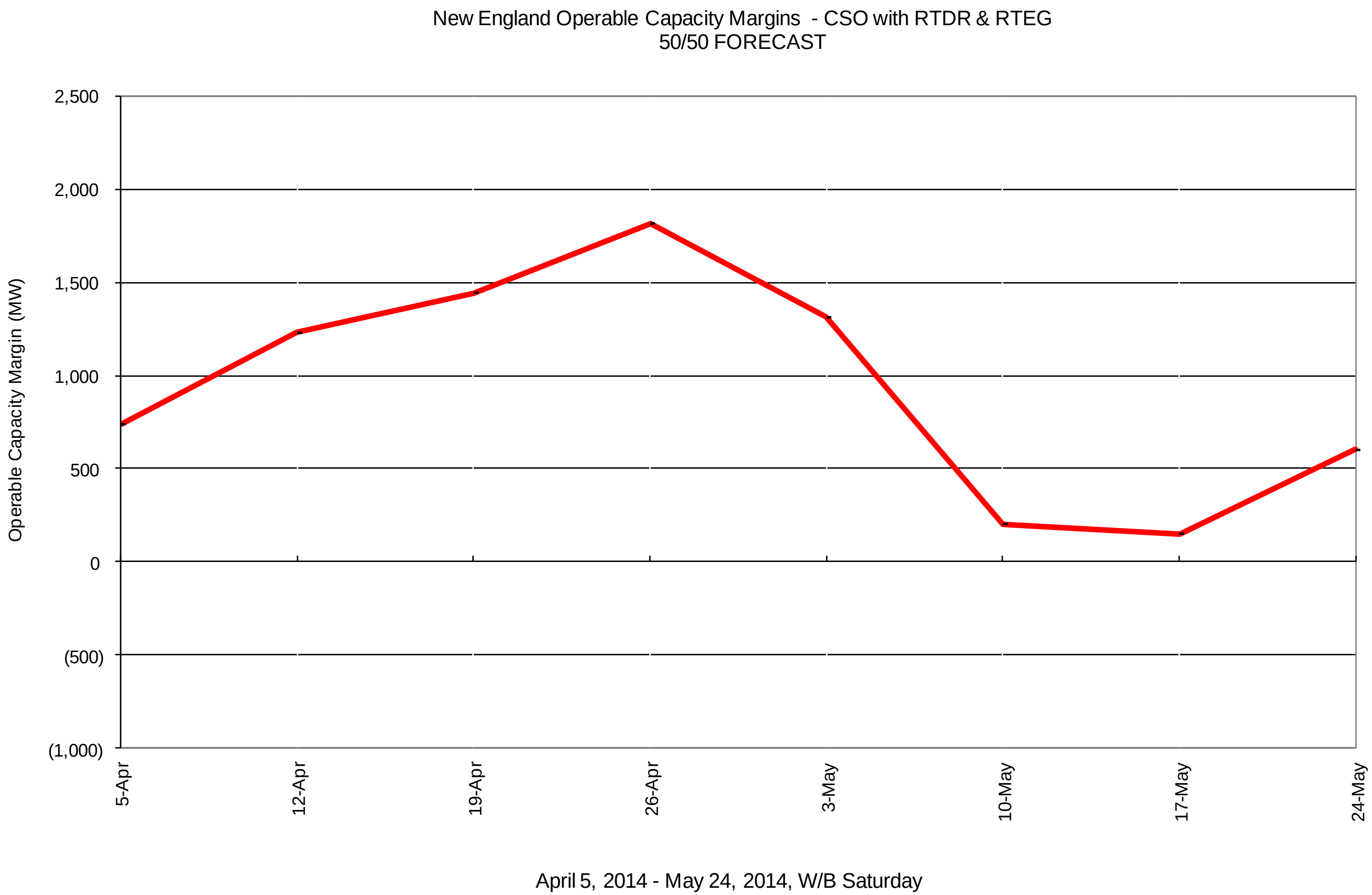
[1] Generator Operable Capacity is based on data as of March 18th , 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning May 17th, 2014.

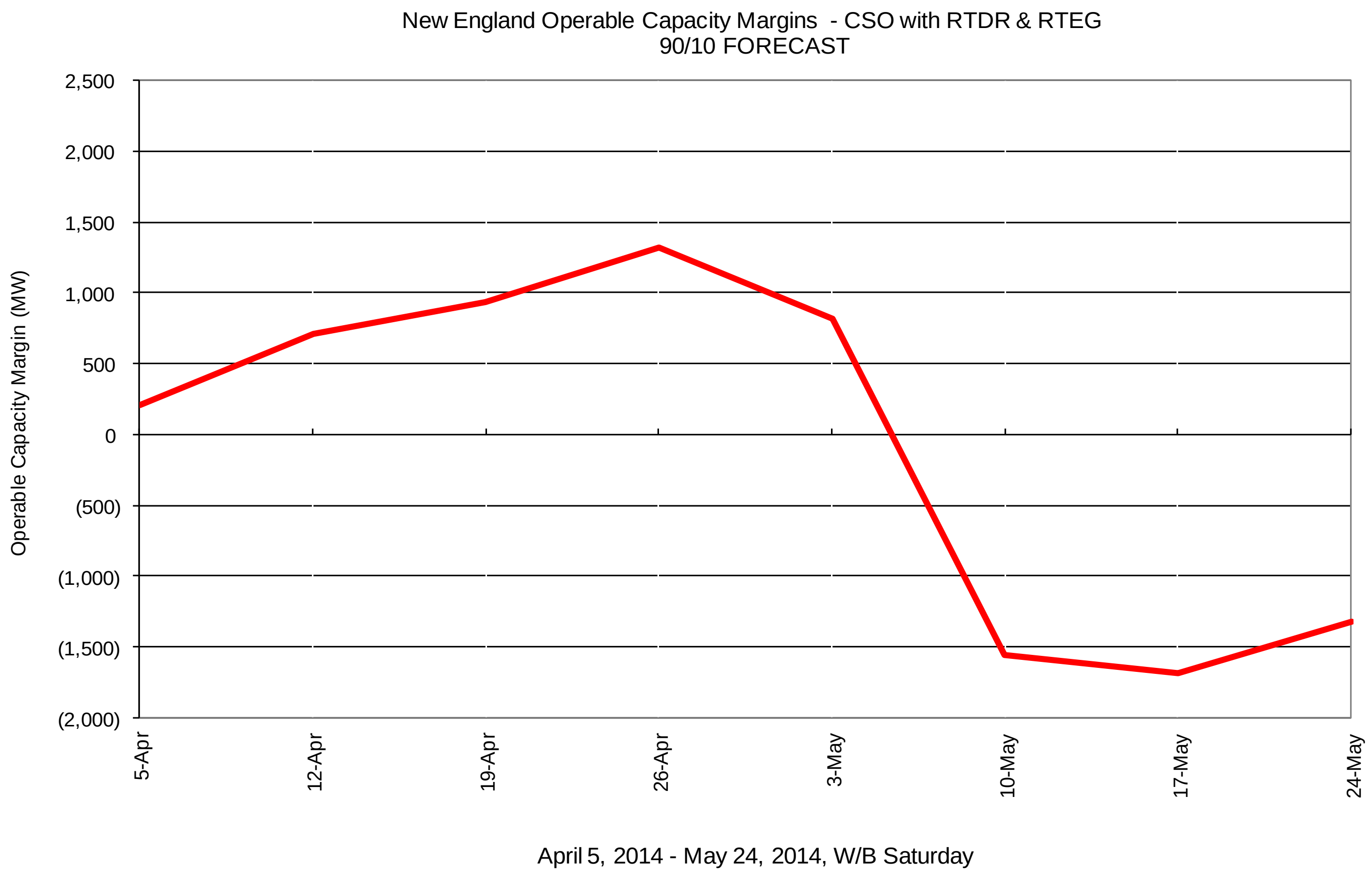
[3] Includes OP4 actions associated with RTEG and RTDR

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

Spring 2014 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)



Spring 2014 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)



Spring 2014 Operable Capacity Analysis(MW)
50/50 Forecast (Reference)

ISO-NE 2014 OPERABLE CAPACITY ANALYSIS

April 4, 2014 - 50/50- FORECAST - 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.

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
4/5/2014	30,121	757	68	6,048	2,700	2,038	0	20,160	17,524	2,375	19,899	261	314	575	163	738
4/12/2014	30,121	757	68	5,567	2,700	2,281	0	20,398	17,271	2,375	19,646	752	314	1,066	163	1,229
4/19/2014	30,121	757	68	5,995	2,700	2,152	0	20,099	16,757	2,375	19,132	967	314	1,281	163	1,444
4/26/2014	29,627	1,083	68	5,242	3,400	2,108	0	20,028	16,490	2,375	18,865	1,163	418	1,581	234	1,815
5/3/2014	29,627	1,183	68	5,776	3,400	2,205	0	19,497	16,463	2,375	18,838	659	418	1,077	234	1,311
5/10/2014	29,627	889	68	3,164	3,400	1,871	0	22,149	20,223	2,375	22,598	(449)	418	(31)	234	203
5/17/2014	**29,627**	**1,083**	**68**	**2,267**	**3,400**	**2,020**	**0**	**23,091**	**21,216**	**2,375**	**23,591**	**(500)**	**418**	**(82)**	**234**	**152**
5/24/2014	29,627	1,083	68	1,750	3,400	1,166	0	24,462	22,138	2,375	24,513	(51)	418	367	234	601

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 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. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
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 2013 CELT Report and adjusted for Passive Demand Resources.
10. Operating Reserve Requirement based on 125% 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).

Spring 2014 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)

ISO-NE 2014 OPERABLE CAPACITY ANALYSIS

April 4, 2014 - 90/10- FORECAST - 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.

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
4/5/2014	30,121	757	68	6,048	2,700	2,038	0	20,160	18,053	2,375	20,428	(268)	314	46	163	209
4/12/2014	30,121	757	68	5,567	2,700	2,281	0	20,398	17,792	2,375	20,167	231	314	545	163	708
4/19/2014	30,121	757	68	5,995	2,700	2,152	0	20,099	17,263	2,375	19,638	461	314	775	163	938
4/26/2014	29,627	1,083	68	5,242	3,400	2,108	0	20,028	16,989	2,375	19,364	664	418	1,082	234	1,316
5/3/2014	29,627	1,183	68	5,776	3,400	2,205	0	19,497	16,961	2,375	19,336	161	418	579	234	813
5/10/2014	29,627	889	68	3,164	3,400	1,871	0	22,149	21,983	2,375	24,358	(2,209)	418	(1,791)	234	(1,557)
5/17/2014	**29,627**	**1,083**	**68**	**2,267**	**3,400**	**2,020**	**0**	**23,091**	**23,058**	**2,375**	**25,433**	**(2,342)**	**418**	**(1,924)**	**234**	**(1,690)**
5/24/2014	29,627	1,083	68	1,750	3,400	1,166	0	24,462	24,056	2,375	26,431	(1,969)	418	(1,551)	234	(1,317)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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3. New resources 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. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
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 2013 CELT Report and adjusted for Passive Demand Resources.
10. Operating Reserve Requirement based on 125% 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

Summer 2014

Summer 2014 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2014[2] CSO	June -2014[2] SCC
Generator Operable Capacity MW [1]	29,136	30,829
OP CAP From OP-4 RTDR (+)	489	489
OP CAP From OP-4 RTEG (+)	211	211
Operable Capacity Generator with OP-4 DR and RTEG	29,836	31,529
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,283	1,283
Non Commercial Capacity (+)	68	68
Non Gas-fired Planned Outage MW (-)	352	371
Allowance for Unplanned Outages (-)	2,800	2,800
Gas Generator Outages MW (-)	0	0
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	28,035	29,709
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,929	26,929
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,304	29,304
Operable Capacity Margin [3]	(1269)	405

[1] Generator Operable Capacity is based on data as of March 18th , 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, weeks beginning May 31st, June 7th June 14th , 2014.

[3] Includes OP4 actions associated with RTEG and RTDR

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

Summer 2014 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	June- 2014[2] CSO	June - 2014[2] SCC
Generator Operable Capacity MW [1]	29,136	30,829
OP CAP From OP-4 RTDR (+)	489	489
OP CAP From OP-4 RTEG (+)	211	211
Operable Capacity Generator with OP-4 DR and RTEG	29,836	31,529
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,283	1,283
Non Commercial Capacity (+)	68	68
Non Gas-fired Planned Outage MW (-)	352	371
Allowance for Unplanned Outages (-)	2,800	2,800
Gas Generator Outages MW (-)	0	0
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	28,035	29,709
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	29,259	29,259
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	31,634	31,634
Operable Capacity Margin [3]	(3,599)	(1,925)

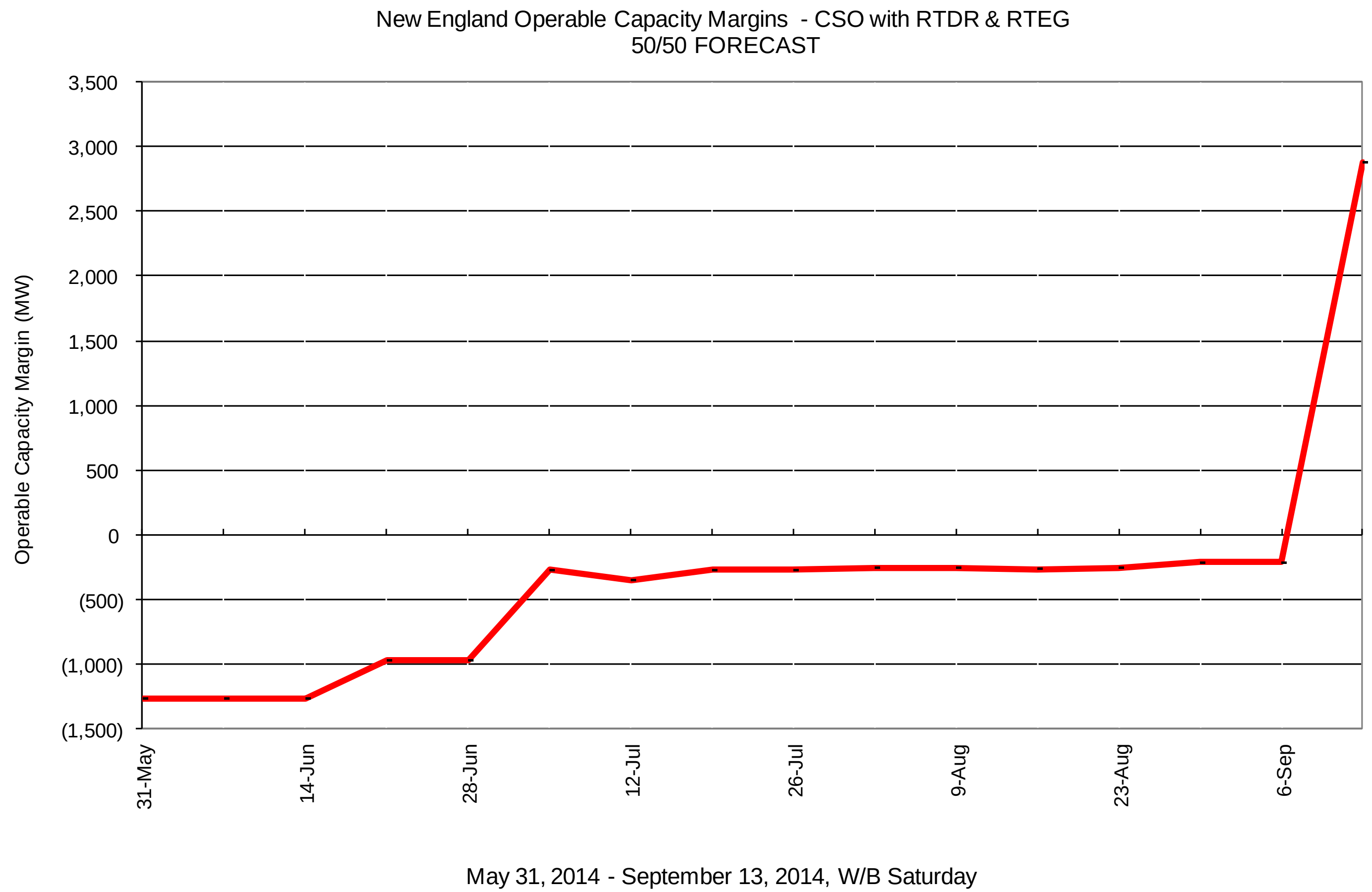
[1] Generator Operable Capacity is based on data as of March 18th , 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, weeks beginning May 31st, June 7th June 14th , 2014

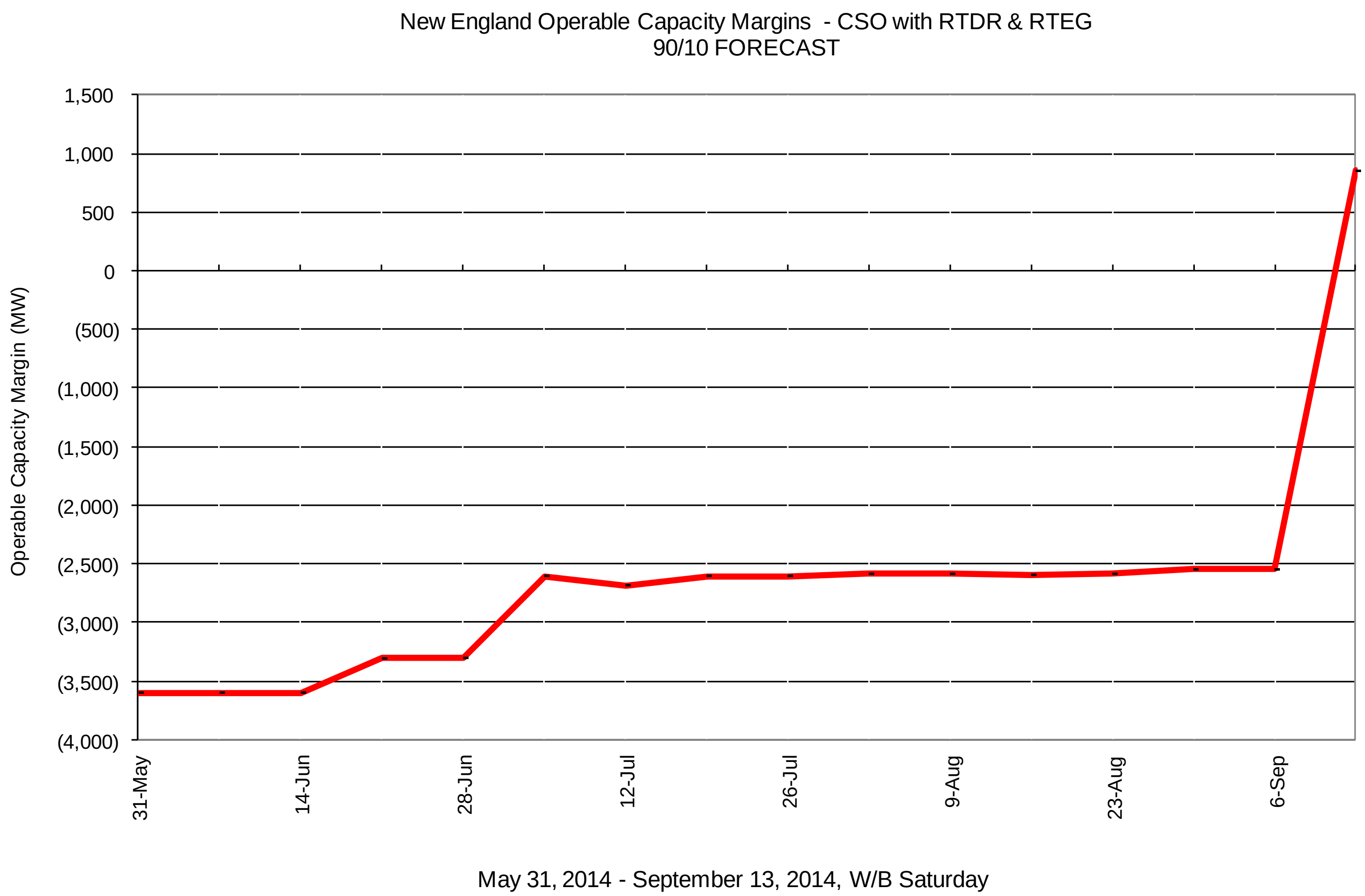
[3] Includes OP4 actions associated with RTEG and RTDR

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

Summer 2014 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)



Summer 2014 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)



Summer 2014 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)

ISO-NE 2014 OPERABLE CAPACITY ANALYSIS

April 4, 2014 - 50/50- FORECAST - 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.

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO 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]
5/31/2014	**29,136**	**1,283**	**68**	**352**	**2,800**	**0**	**0**	**27,335**	**26,929**	**2,375**	**29,304**	**(1,969)**	**489**	**(1,480)**	**211**	**(1,269)**
6/7/2014	**29,136**	**1,283**	**68**	**352**	**2,800**	**0**	**0**	**27,335**	**26,929**	**2,375**	**29,304**	**(1,969)**	**489**	**(1,480)**	**211**	**(1,269)**
6/14/2014	**29,136**	**1,283**	**68**	**352**	**2,800**	**0**	**0**	**27,335**	**26,929**	**2,375**	**29,304**	**(1,969)**	**489**	**(1,480)**	**211**	**(1,269)**
6/21/2014	29,136	1,283	68	58	2,800	0	0	27,629	26,929	2,375	29,304	(1,675)	489	(1,186)	211	(975)
6/28/2014	29,136	1,283	68	57	2,800	0	0	27,630	26,929	2,375	29,304	(1,674)	489	(1,185)	211	(974)
7/5/2014	29,136	1,283	68	57	2,100	0	0	28,330	26,929	2,375	29,304	(974)	489	(485)	211	(274)
7/12/2014	29,136	1,283	68	134	2,100	0	0	28,253	26,929	2,375	29,304	(1,051)	489	(562)	211	(351)
7/19/2014	29,136	1,283	68	57	2,100	0	0	28,330	26,929	2,375	29,304	(974)	489	(485)	211	(274)
7/26/2014	29,136	1,283	68	57	2,100	0	0	28,330	26,929	2,375	29,304	(974)	489	(485)	211	(274)
8/2/2014	29,136	1,283	68	40	2,100	0	0	28,347	26,929	2,375	29,304	(957)	489	(468)	211	(257)
8/9/2014	29,136	1,283	68	40	2,100	0	0	28,347	26,929	2,375	29,304	(957)	489	(468)	211	(257)
8/16/2014	29,136	1,283	68	48	2,100	0	0	28,339	26,929	2,375	29,304	(965)	489	(476)	211	(265)
8/23/2014	29,136	1,283	68	40	2,100	0	0	28,347	26,929	2,375	29,304	(957)	489	(468)	211	(257)
8/30/2014	29,136	1,283	68	0	2,100	0	0	28,387	26,929	2,375	29,304	(917)	489	(428)	211	(217)
9/6/2014	29,136	1,283	68	0	2,100	0	0	28,387	26,929	2,375	29,304	(917)	489	(428)	211	(217)
9/13/2014	29,136	1,283	68	157	2,100	428	0	27,802	23,248	2,375	25,623	2,179	489	2,668	211	2,879

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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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. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
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 2013 CELT Report and adjusted for Passive Demand Resources.
10. Operating Reserve Requirement based on 125% 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).

Summer 2014 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)

ISO-NE 2014 OPERABLE CAPACITY ANALYSIS

April 4, 2014 - 90/10- FORECAST - 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.

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO 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]
5/31/2014	**29,136**	**1,283**	**68**	**352**	**2,800**	**0**	**0**	**27,335**	**29,259**	**2,375**	**31,634**	**(4,299)**	**489**	**(3,810)**	**211**	**(3,599)**
6/7/2014	**29,136**	**1,283**	**68**	**352**	**2,800**	**0**	**0**	**27,335**	**29,259**	**2,375**	**31,634**	**(4,299)**	**489**	**(3,810)**	**211**	**(3,599)**
6/14/2014	**29,136**	**1,283**	**68**	**352**	**2,800**	**0**	**0**	**27,335**	**29,259**	**2,375**	**31,634**	**(4,299)**	**489**	**(3,810)**	**211**	**(3,599)**
6/21/2014	29,136	1,283	68	58	2,800	0	0	27,629	29,259	2,375	31,634	(4,005)	489	(3,516)	211	(3,305)
6/28/2014	29,136	1,283	68	57	2,800	0	0	27,630	29,259	2,375	31,634	(4,004)	489	(3,515)	211	(3,304)
7/5/2014	29,136	1,283	68	57	2,100	0	0	28,330	29,259	2,375	31,634	(3,304)	489	(2,815)	211	(2,604)
7/12/2014	29,136	1,283	68	134	2,100	0	0	28,253	29,259	2,375	31,634	(3,381)	489	(2,892)	211	(2,681)
7/19/2014	29,136	1,283	68	57	2,100	0	0	28,330	29,259	2,375	31,634	(3,304)	489	(2,815)	211	(2,604)
7/26/2014	29,136	1,283	68	57	2,100	0	0	28,330	29,259	2,375	31,634	(3,304)	489	(2,815)	211	(2,604)
8/2/2014	29,136	1,283	68	40	2,100	0	0	28,347	29,259	2,375	31,634	(3,287)	489	(2,798)	211	(2,587)
8/9/2014	29,136	1,283	68	40	2,100	0	0	28,347	29,259	2,375	31,634	(3,287)	489	(2,798)	211	(2,587)
8/16/2014	29,136	1,283	68	48	2,100	0	0	28,339	29,259	2,375	31,634	(3,295)	489	(2,806)	211	(2,595)
8/23/2014	29,136	1,283	68	40	2,100	0	0	28,347	29,259	2,375	31,634	(3,287)	489	(2,798)	211	(2,587)
8/30/2014	29,136	1,283	68	0	2,100	0	0	28,387	29,259	2,375	31,634	(3,247)	489	(2,758)	211	(2,547)
9/6/2014	29,136	1,283	68	0	2,100	0	0	28,387	29,259	2,375	31,634	(3,247)	489	(2,758)	211	(2,547)
9/13/2014	29,136	1,283	68	157	2,100	428	0	27,802	25,275	2,375	27,650	152	489	641	211	852

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8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
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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)
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OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4 based on 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.	April = 314 [3] May = 418 [3] June-September =489 [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	134 [4] April = 163 [3] May = 234 [3] June-September = 211 [3]
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
8	Voltage Reduction requiring 10 minutes or less	267 [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		April = 3,023 MW May = 3,198 MW June-September = 3,246 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 March 18th , 2014.
4. The MW values are based on a 26,690 MW system load and the most recent voltage reduction test % achieved.