APRIL 10, 2015 | BOSTON, MA

NEPOOL PARTICIPANTS COMMITTEE MEETING
04/10/15 MEETING, AGENDA ITEM #4

new england

# NEPOOL Participants Committee Report

*April 2015*

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

# Table of Contents


- Highlights Page 3
- System Operations Page 9
- Market Operations Page 20
- Back-Up Detail Page 37
  - Load Response Page 38
  - New Generation Page 40
  - Forward Capacity Market Page 47
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs Page 54
  - Regional System Plan (RSP) & Interregional Planning Page 85
  - Operable Capacity Analysis – Spring 2015 Page 115
  - Operable Capacity Analysis – Preliminary Summer 2015 Page 122
  - Operable Capacity Analysis – Appendix Page 129

# Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was $734M over the period, down $660M from February 2015 and down $584M from March 2014
  - March natural gas prices over the period were 53% lower than February 2015 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 54% lower than February 2015 averages
  - Average March 2015 natural gas prices and RT Hub LMPs over the period were down 48% and 50%, respectively, from March 2014 averages

- Average DA cleared physical energy in the peak hours as percent of forecasted load was 99.9% during March, up from 99.4% during February

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)*
  - March NCPC payments totaled $14.8M, up $3.5M from February and down $3.3M from March 2014
  - First Contingency payments totaled $9.5M, up $271K from February
    - $8.9M paid to internal resources, up $207K from February
      - $993K charged to DALO, $7.9M to RT Deviations
    - $522K paid to resources at external locations, up $65K from February
      - $483K charged to DALO at external locations, $39K to RT Deviations
  - Second Contingency payments totaled $4.9M, up $4.1M from the February total of $865K
  - Voltage payments were $448K, down $833K from February
  - NCPC payments over the period as percent of Energy Market value were 2.0%

# Highlights, cont.

- ISO received three economic study requests that will be discussed with the PAC on April 22
- ISO will be discussing the final PV forecast with the DGFWG on April 14
- FERC issued its final order on ISO's Order 1000 compliance filing on March 19. The new intraregional planning process will become effective on May 18, 2015, which is the same date for an additional compliance filing.

# Forward Capacity Market (FCM) Highlights

- CCP #4 (2013-2014)
  - Less than 10 MW of resources are non-commercial at this time. Discussions with the affected project sponsors have begun and will likely result in self-withdrawal.
- CCP #5 (2014-2015)
  - Approximately 60 MW of resources are non-commercial at this time but progress continues
- CCP #6 (2015-2016)
  - Entering the CCP, the Transmission Security Analysis margin for NEMA/Boston will be about 211 MW short
- CCP #7 (2016-2017)
  - Next bilateral transaction window is May 1-7
  - Second reconfiguration auction will be held August 3-5

CCP – Capacity Commitment Period

# FCM Highlights, cont.

- CCP #8 (2017-2018)
  - First bilateral transaction window is April 1-8
  - First reconfiguration auction will be held June 1-3
- CCP #9 (2018-2019)
  - First bilateral transaction window is April 2016
- CCP #10 (2019-2020)
  - Potential new capacity zones filed with FERC on April 6
  - Upcoming Deadlines
    - De-list bids are due by the Existing Resource Qualification Deadline of June 1
    - Non-Price Retirement window opens on June 1
    - New resource qualification packages are due June 16

# Highlights, cont.

- The lowest 50/50 Spring Operable Capacity Margin is projected for week beginning May 9, 2015.
- The lowest 90/10 Spring Operable Capacity Margin is projected for week beginning May 23, 2015.
- The lowest 50/50 and 90/10 Summer Operable Capacity Margin is projected for week beginning May 30, 2015.

# SYSTEM OPERATIONS

# System Operations

| | | | | |
|---|---|---|---|---|
| **Weather Patterns** | Boston | Temperature – Below normal (-6.6)<br>Max: 57, Min: 9<br>Precipitation 3.03" - Below Normal<br>Normal - 3.85"<br>Total Snowfall – 19.57" | Hartford | Temperature – Below normal ( -6.5)<br>Max: 57 , Min: 2<br>Precipitation 2.61" - Below Normal<br>Normal – 3.88"<br>Total Snowfall – 14.02" |

| | | | |
|---|---|---|---|
| **Peak Load:** | 18,863 MW | March 05, 2015 | 19:00 |

| | | |
|---|---|---|
| **MLCC2: None** | | |
| **OP-4 : None** | | |
| **NPCC Simultaneous Activation of Reserve Events**: | | |
| 3/10/15 | IESO | 525 MW |
| | | |
| | | |
| | | |
| | | |

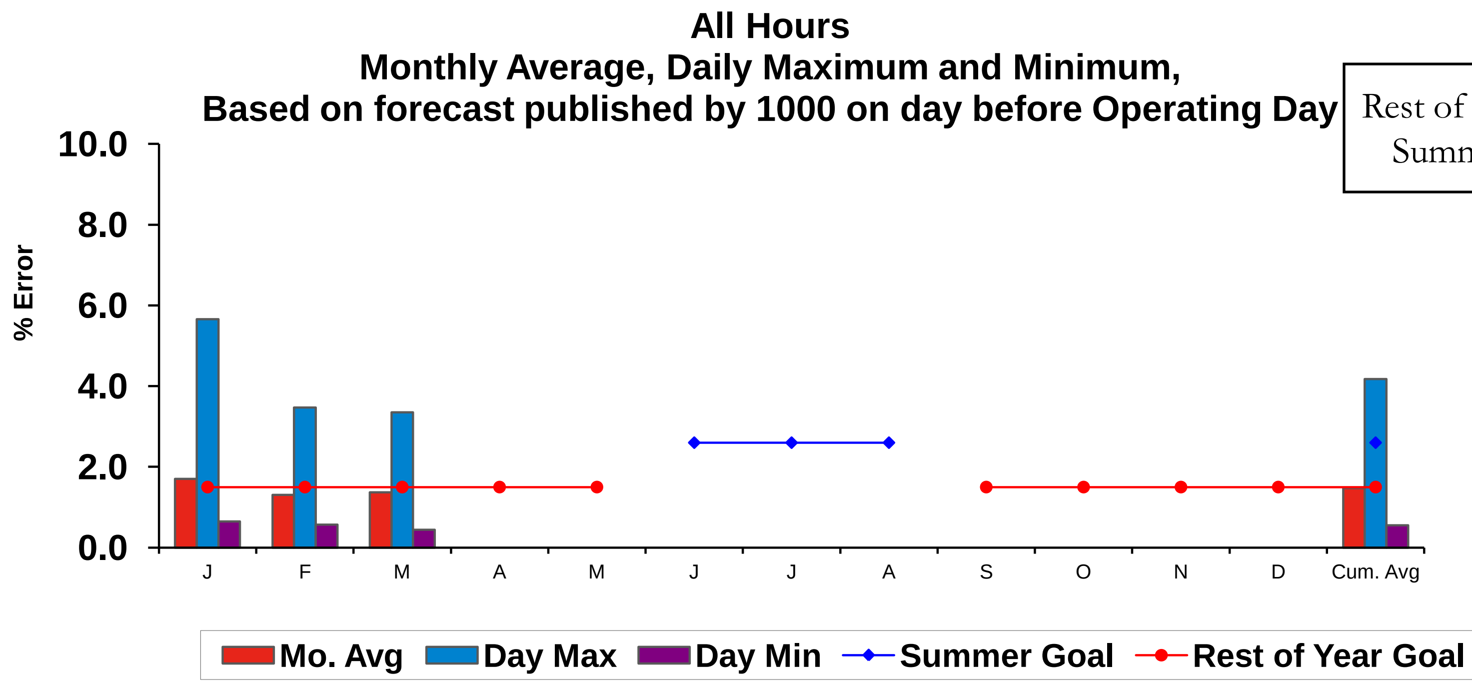
# System Operations, cont.

Minimum Generation Warnings & Events:

| | | |
|---|---|---|
| **Minimum Generation Warning** | **03/05/15** | **Start – 01:00, Expired – 19:00**<br>**Interchange Cuts Only** |
| **Minimum Generation Warning** | **03/10/15** | **Start – 23:00, Expired – 23:59**<br>**Interchange Cuts Only** |

# 2015 System Operations – Load Forecast Accuracy

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 | 1.70 | 1.31 | 1.37 | | | | | | | | | | 1.47 |
| Day Max | 5.66 | 3.47 | 3.35 | | | | | | | | | | 4.18 |
| Day Min | 0.65 | 0.57 | 0.44 | | | | | | | | | | 0.55 |
| 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 | 1.70 | 1.31 | 1.37 | | | | | | | | | | 1.47 |
| Summer Actual | | | | | | | | | | | | | |

Sponsor - John Norden
Contact – William Callan

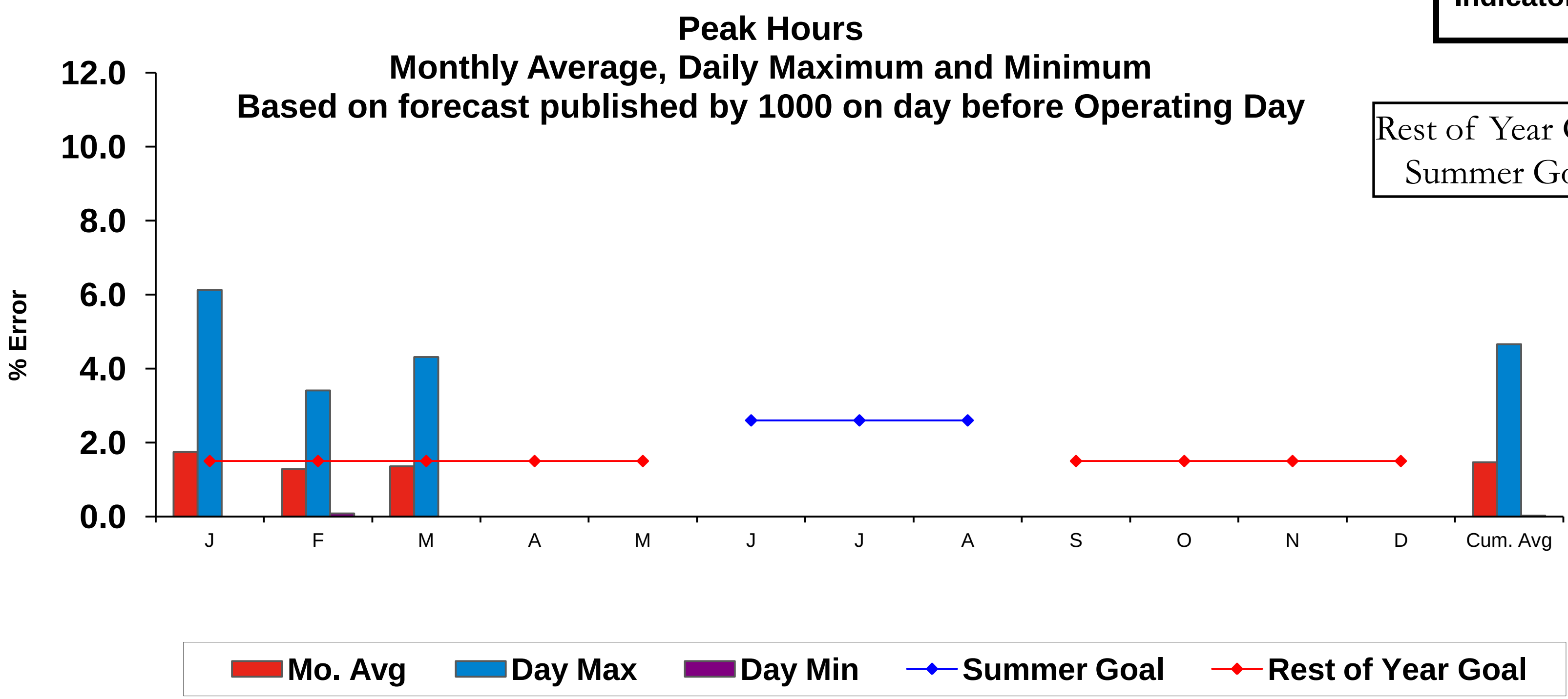
Summer Goal - 2.6%, Rest of Year Goal - 1.5%

Summer consists of June, July & August

# 2015 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator

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

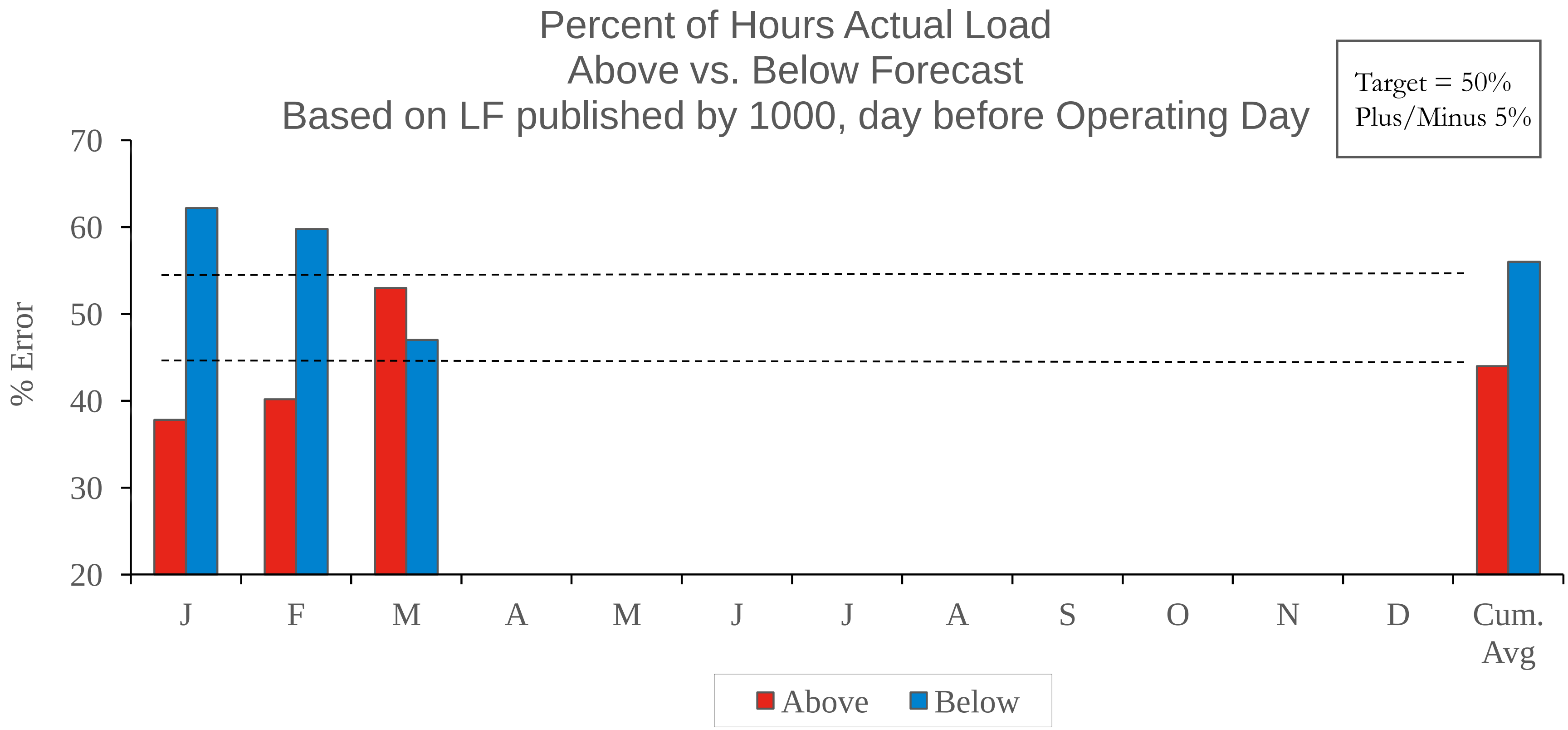



| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mo Avg | 1.75 | 1.28 | 1.36 | | | | | | | | | | 1.47 |
| Day Max | 6.13 | 3.41 | 4.31 | | | | | | | | | | 4.66 |
| Day Min | 0.00 | 0.08 | 0.00 | | | | | | | | | | 0.02 |
| Summer Goal | | | | | | 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 | 1.75 | 1.28 | 1.36 | | | | | | | | | | 1.47 |
| Summer Actual | | | | | | | | | | | | | |

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

Summer consists of June, July & August

# 2015 System Operations - Load Forecast Accuracy

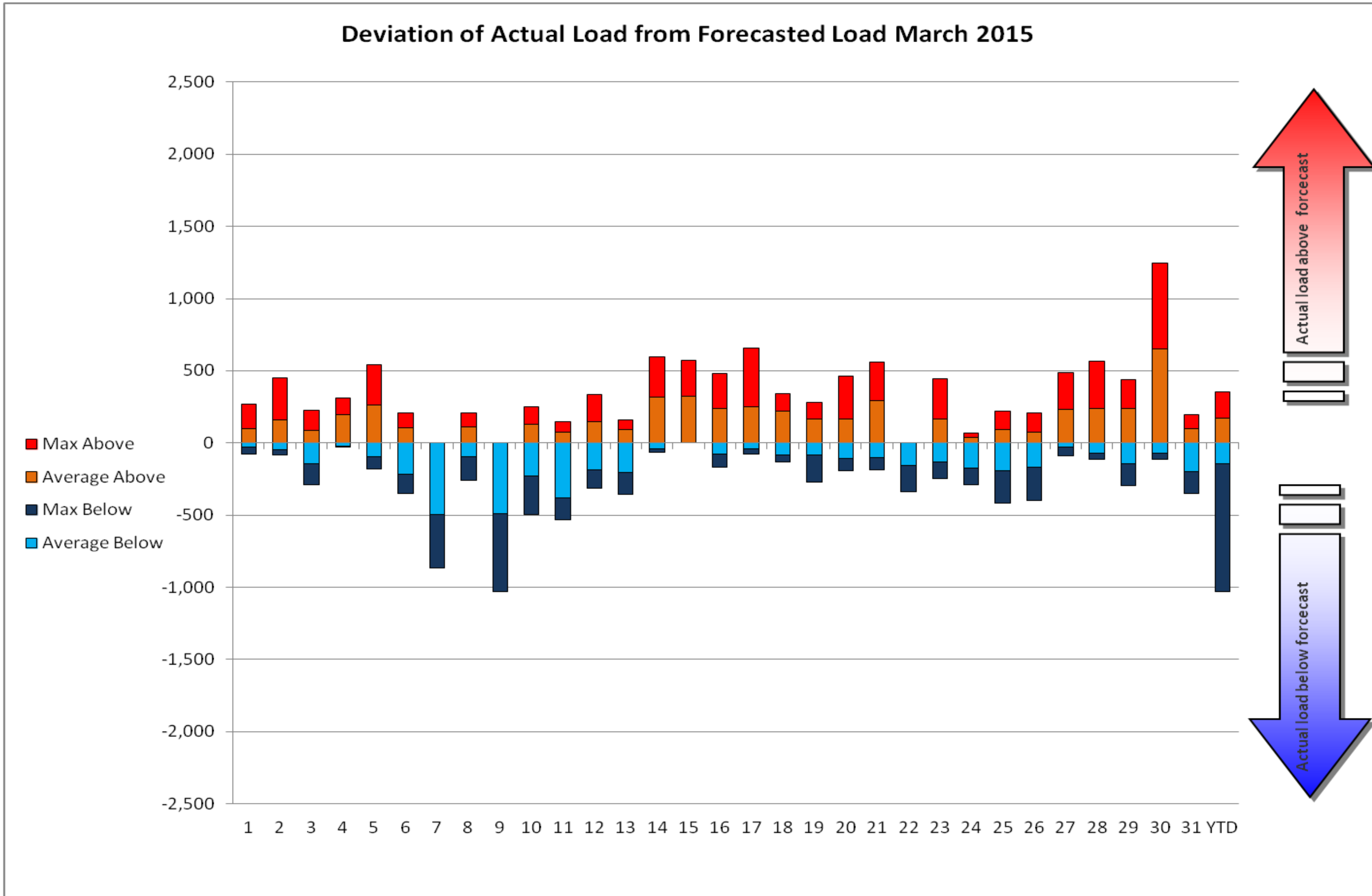



| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Above % | 37.8 | 40.2 | 52.8 | | | | | | | | | | 44 |
| Below % | 62.2 | 59.8 | 47.2 | | | | | | | | | | 56 |
| Avg Above | 143.0 | 147.0 | 170.0 | | | | | | | | | | 153 |
| Avg Below | -236.0 | -208.0 | -146.0 | | | | | | | | | | -196 |
| Avg All | -81.0 | -57.0 | 17.0 | | | | | | | | | | -40 |

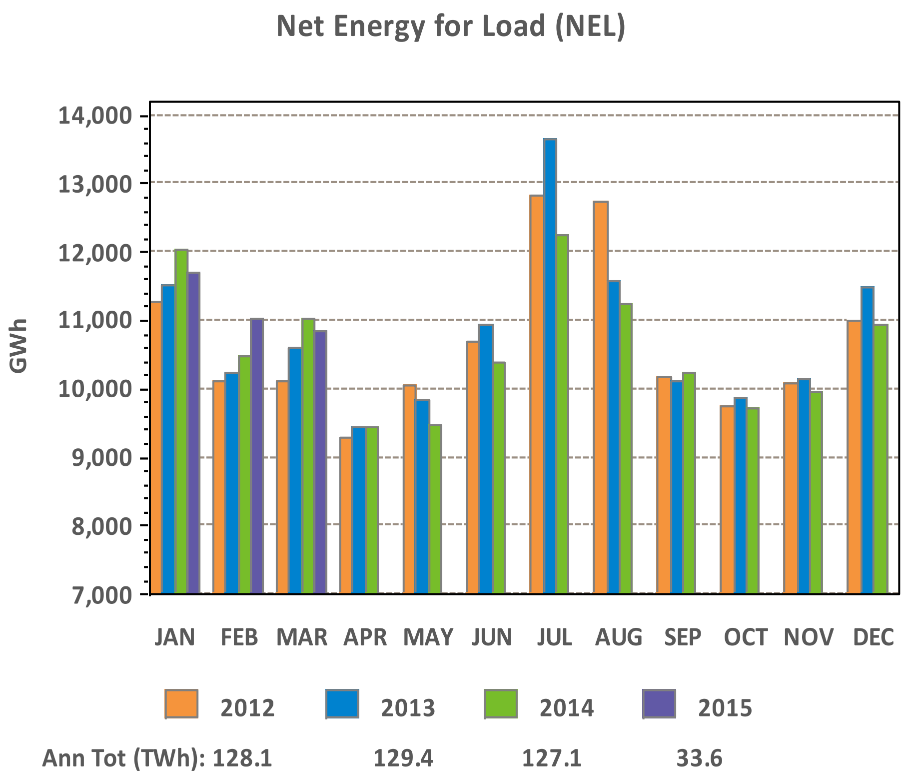
Percent of hours that the actual load was above versus below the forecast

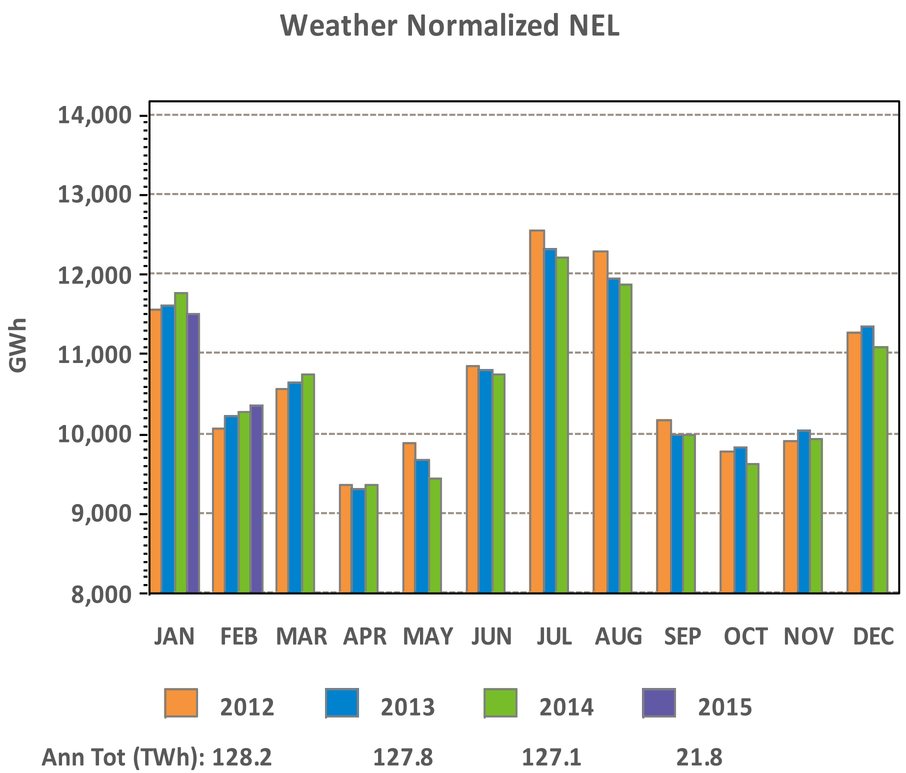
Sponsor –John Norden
Contact –William Callan

# 2015 System Operations - Load Forecast Accuracy



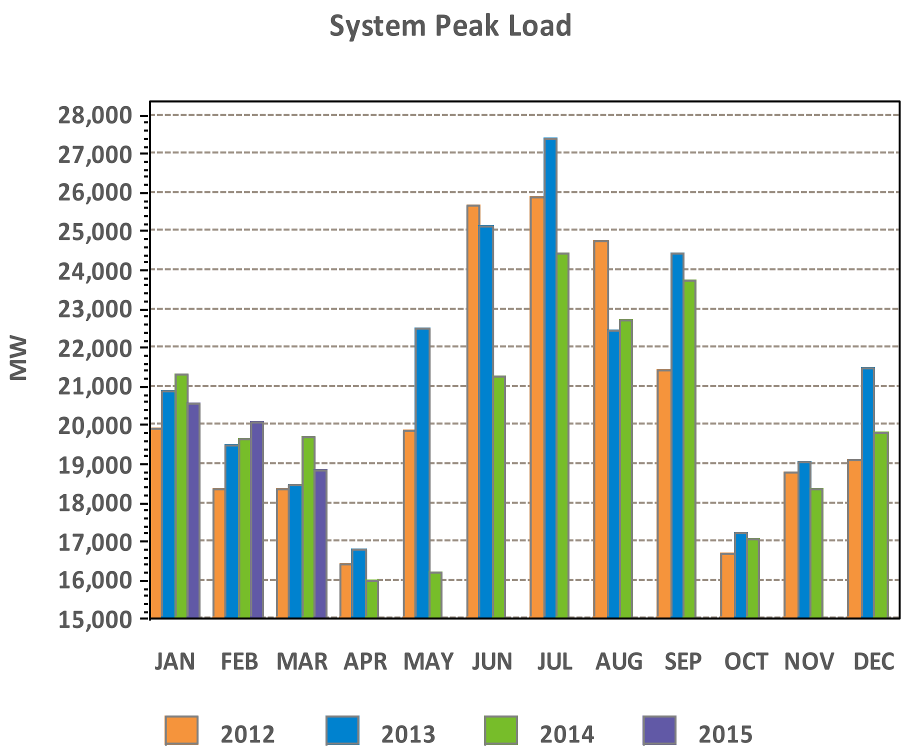
# Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

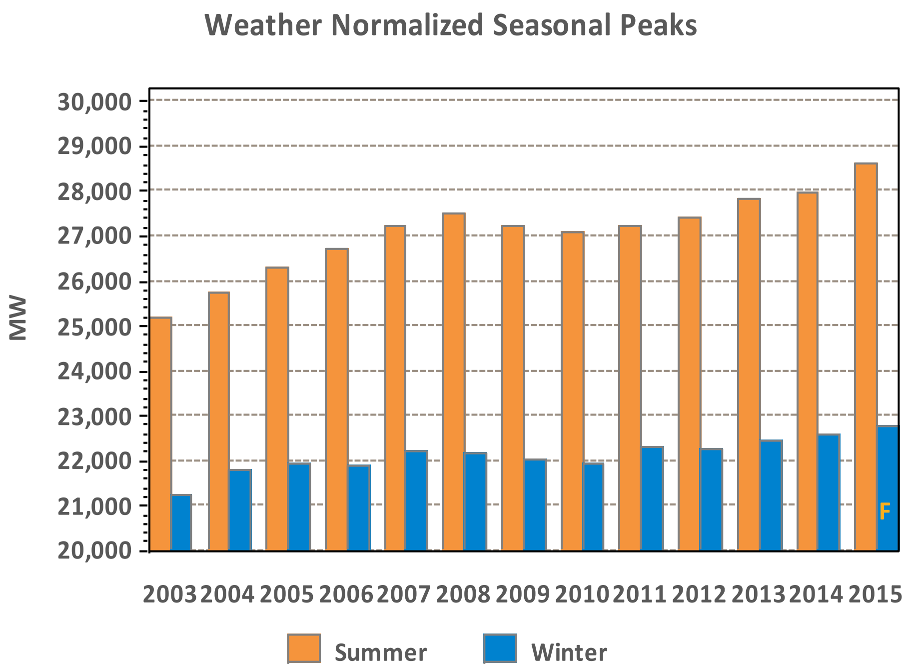



NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

# Monthly Peak Loads and Weather Normalized Seasonal Peak History



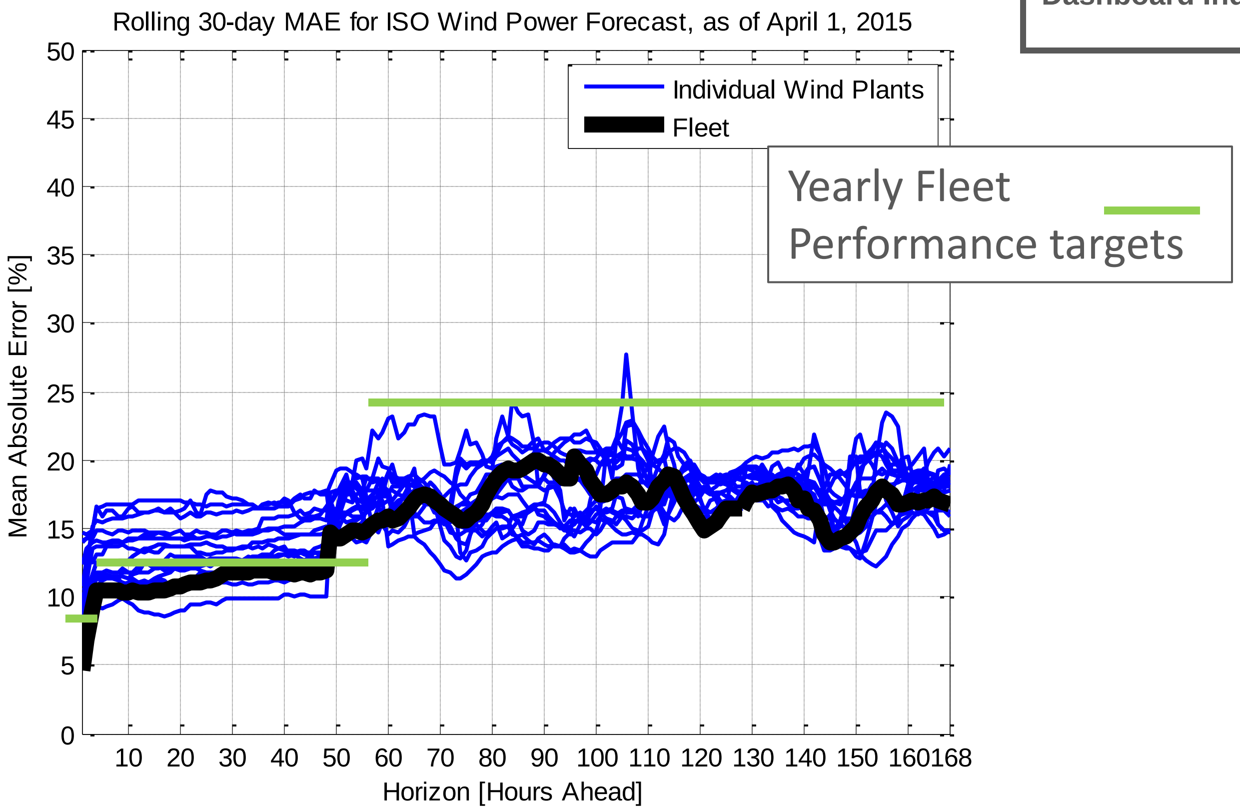




Winter beginning in year displayed

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

# Wind Power Forecast Error Statistics: MAE

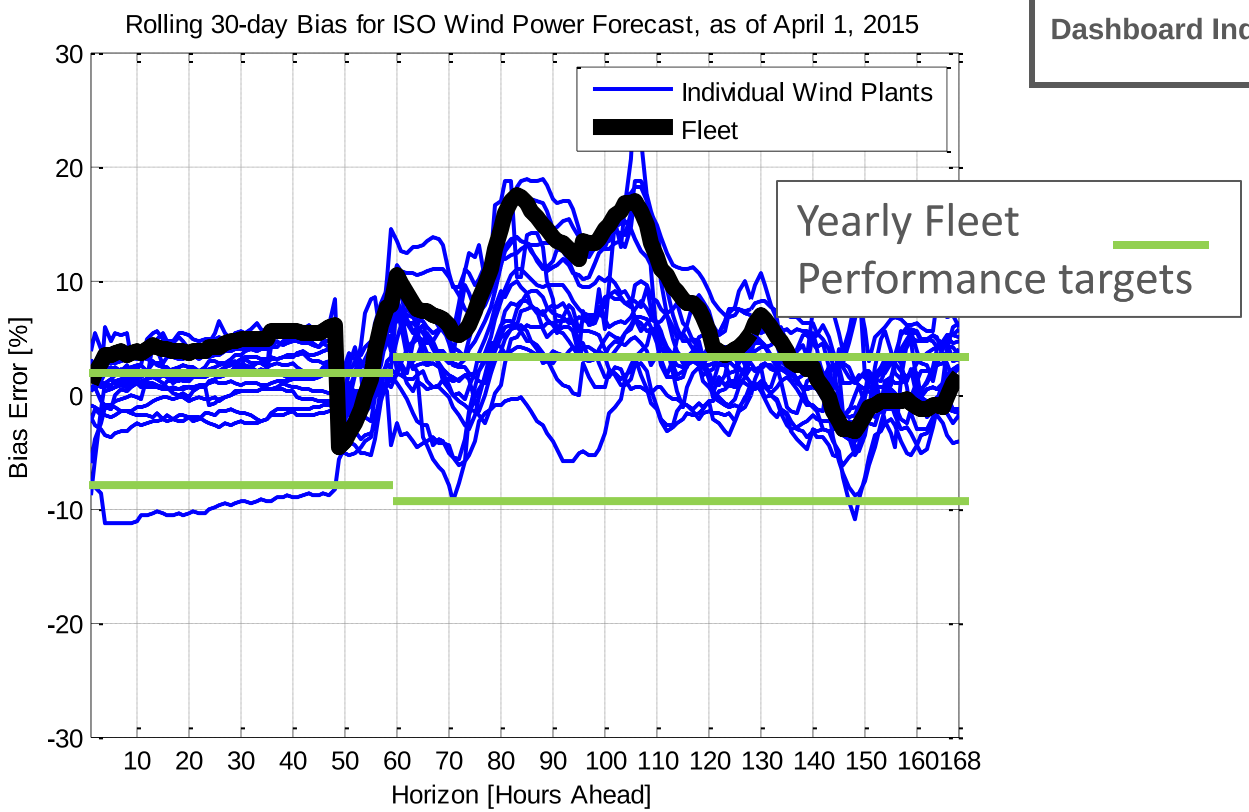
Dashboard Indicator




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

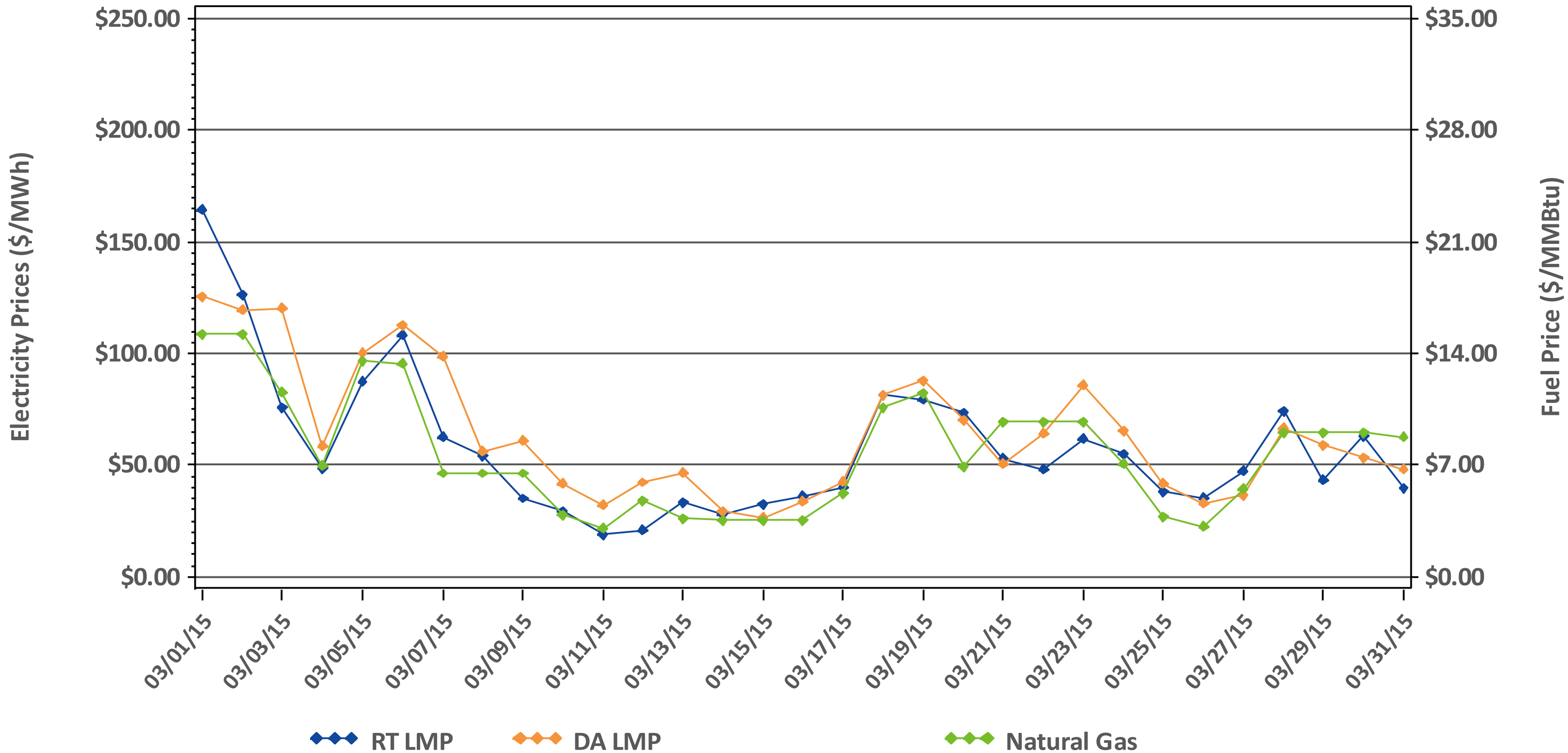
Dashboard Indicator




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 monthly values for March are near yearly performance targets specified in the forecast RFP. Some bias corrections applied in mid-March are not visible.

# MARKET OPERATIONS

# Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: March 1-31, 2015

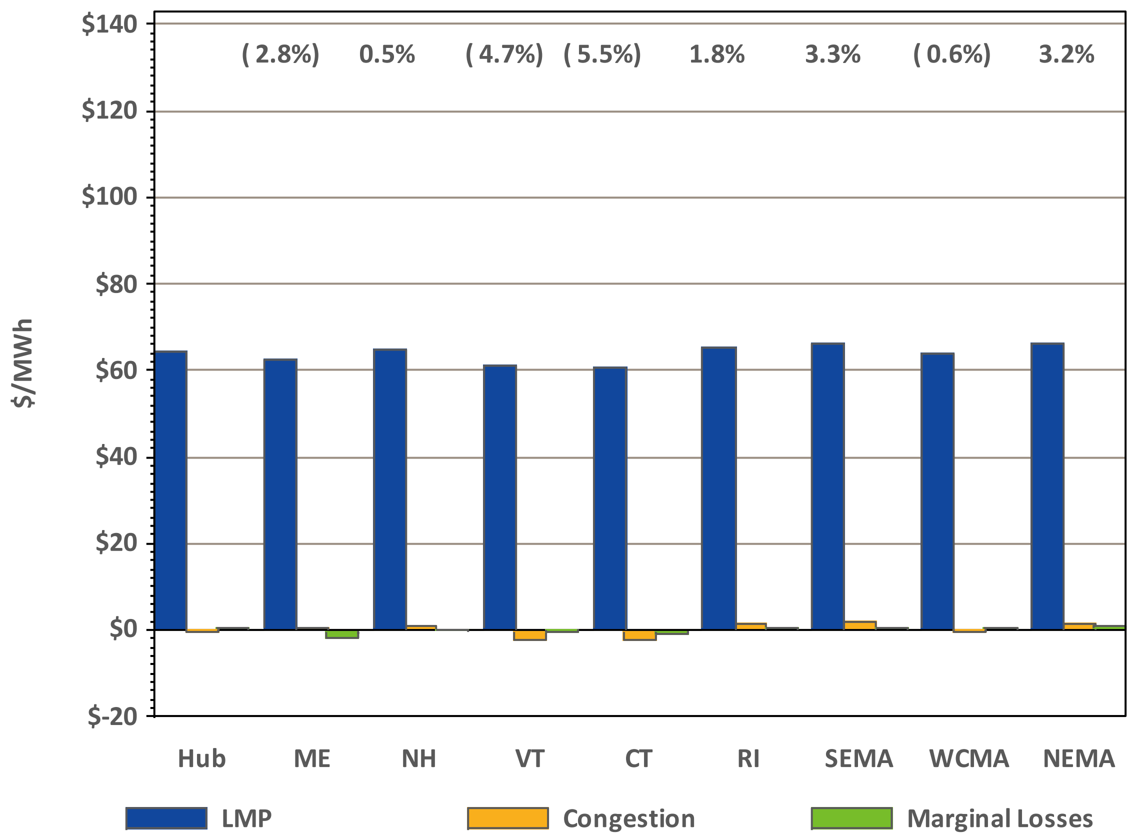



Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $6.31
Average price difference over this period ABS(DA-RT): $12.16
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 21%
Gas price is average of Massachusetts delivery points

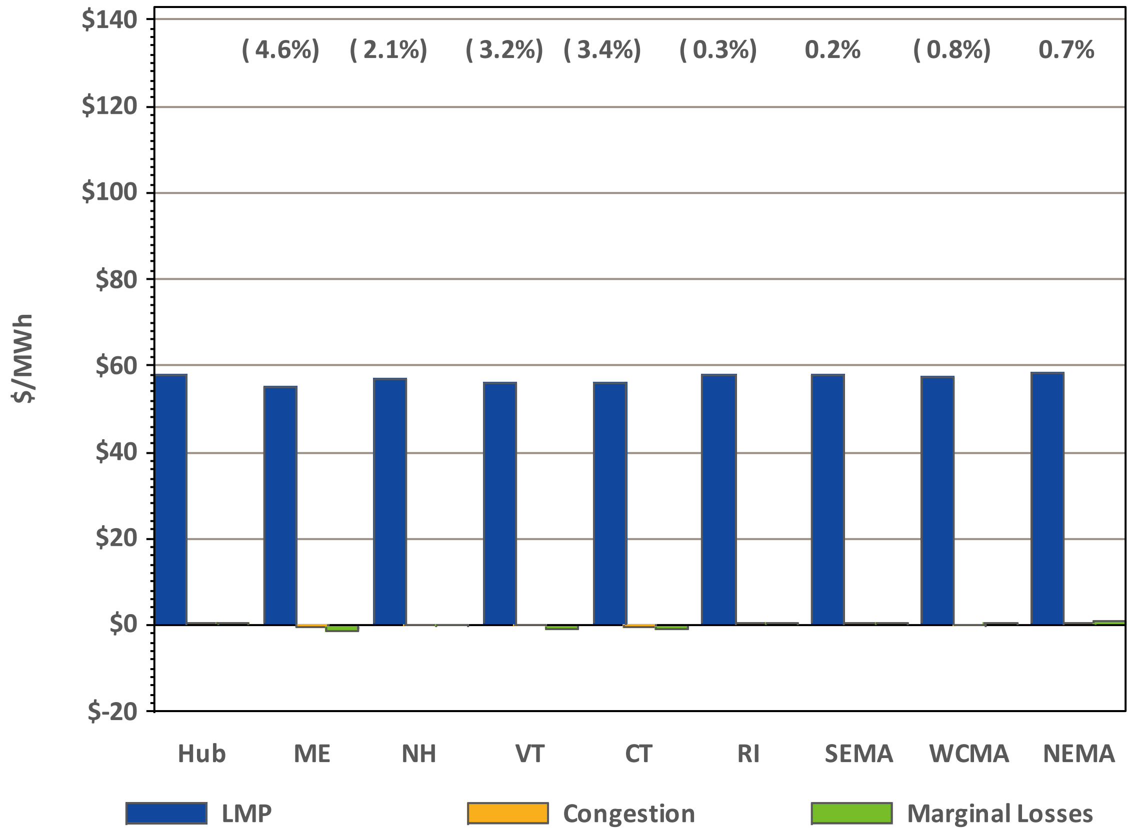
# DA LMPs Average by Zone & Hub, March 2015




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

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

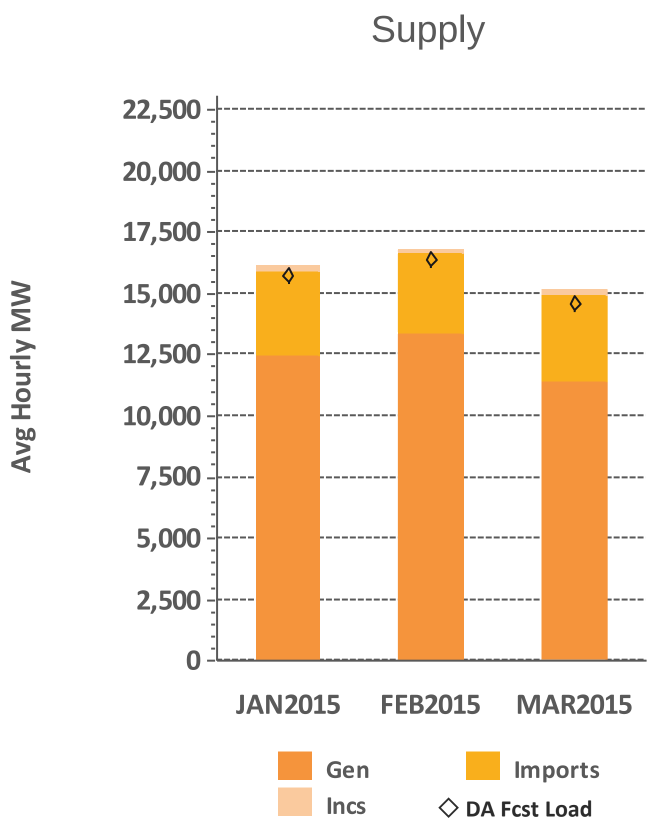
# RT LMPs Average by Zone & Hub, March 2015



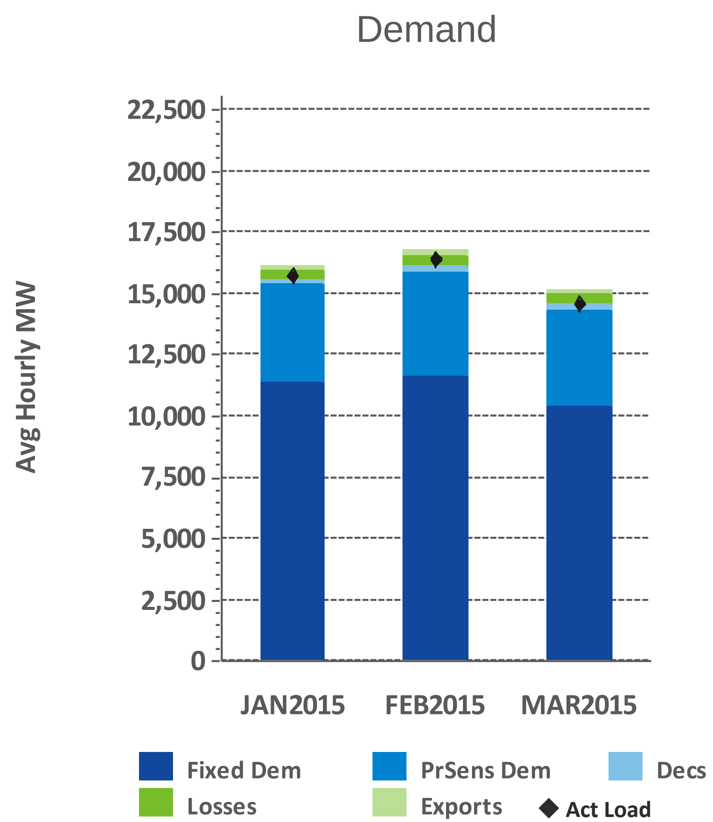
# Definitions

| 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

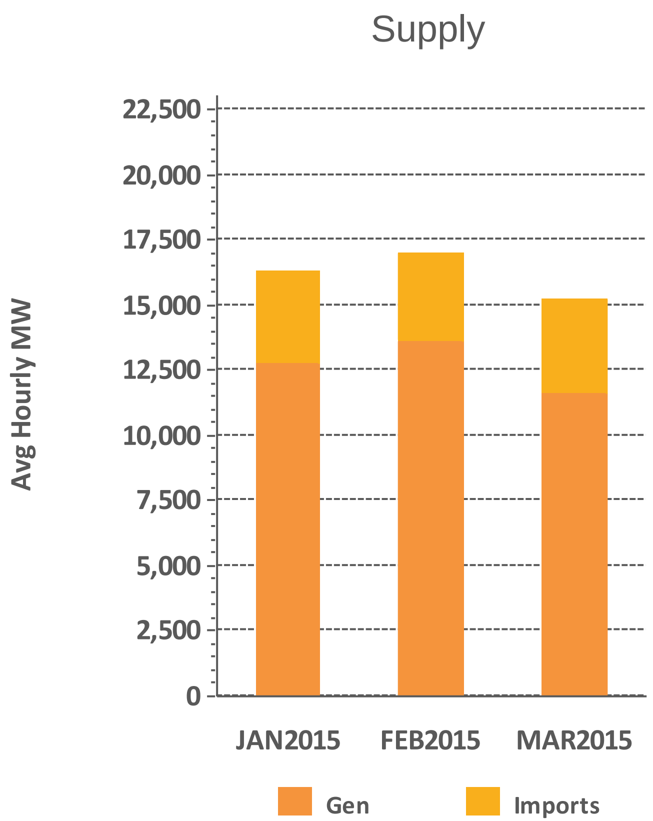


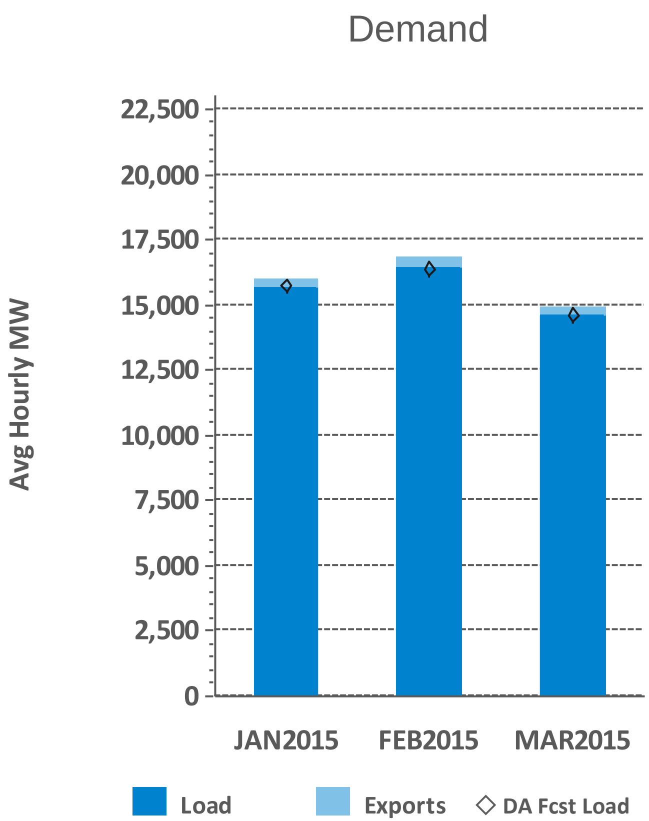

Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



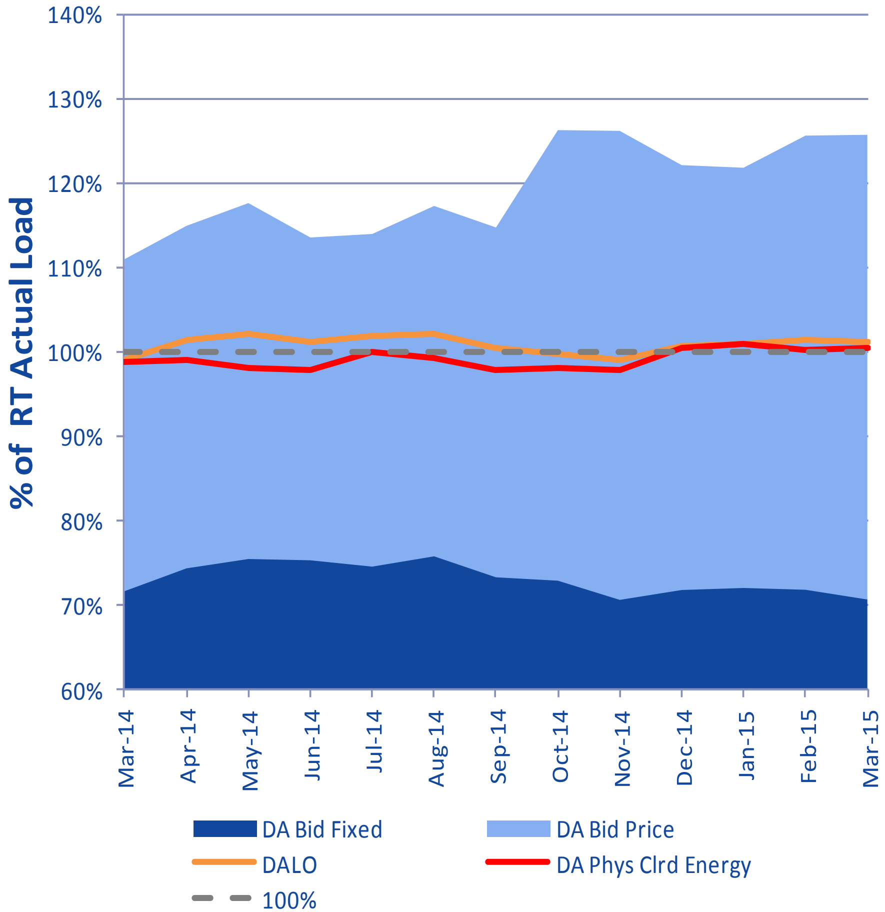

Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

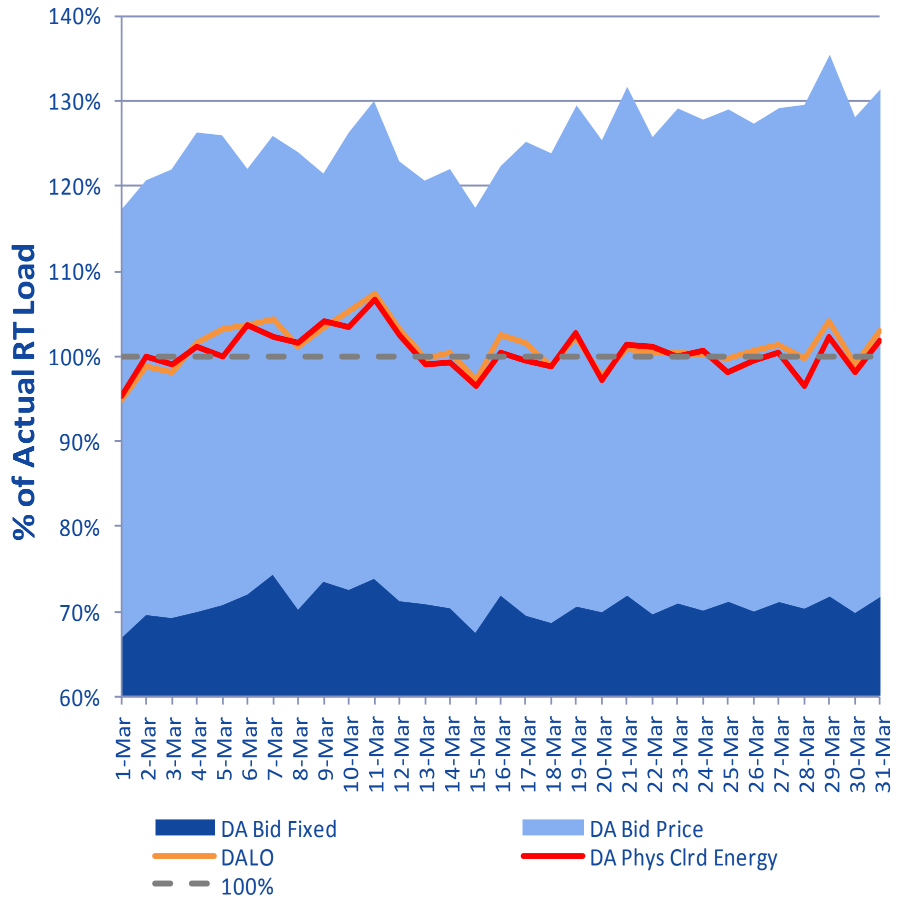
# Components of RT Supply and Demand – Last Three Months



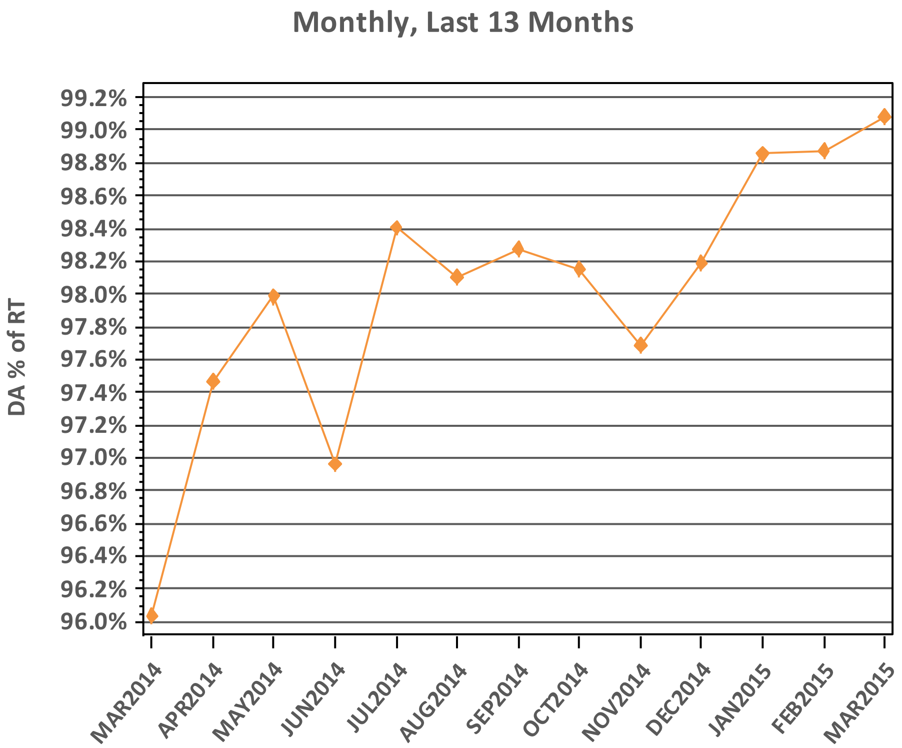
# DAM Volumes vs. RT Actual Load (at Peak Hour): Monthly and Daily

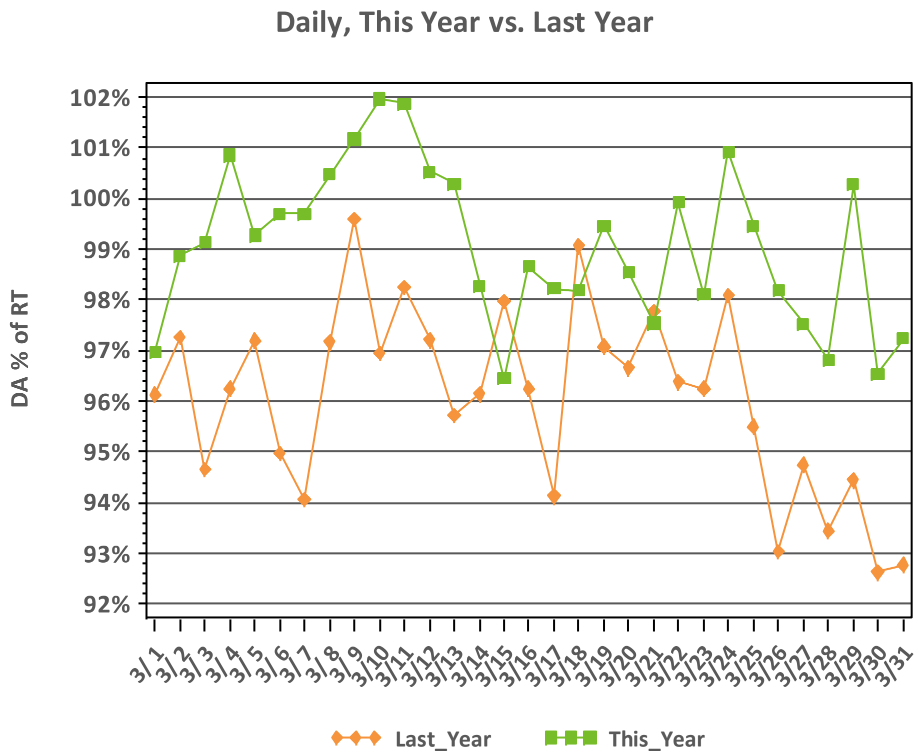



**Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.**

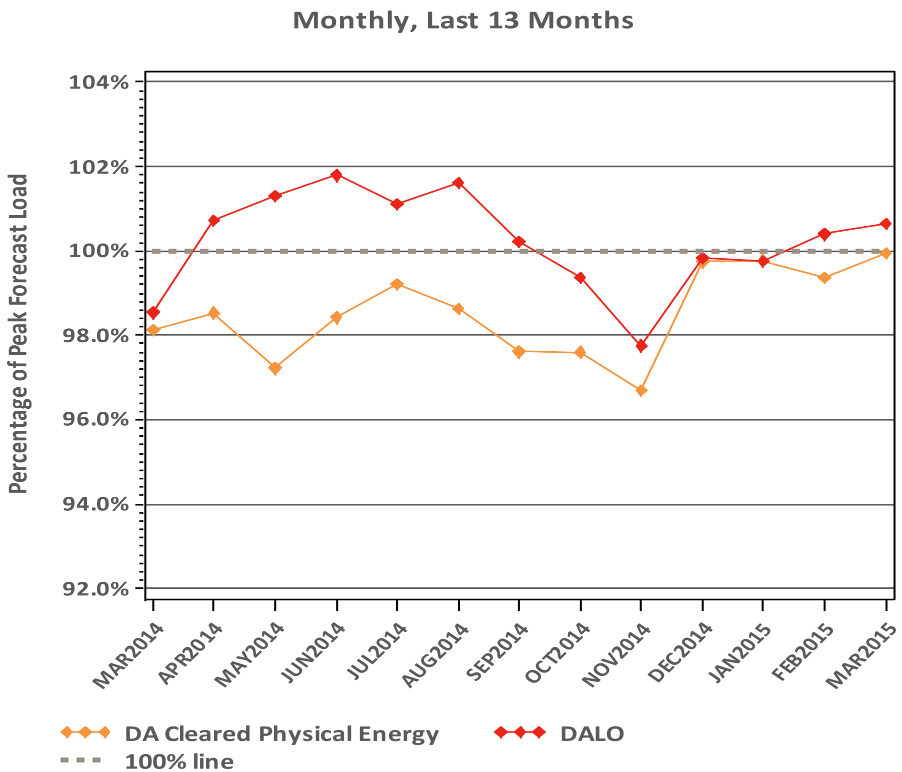
# DA vs. RT Load Obligation: March, This Year vs. Last Year

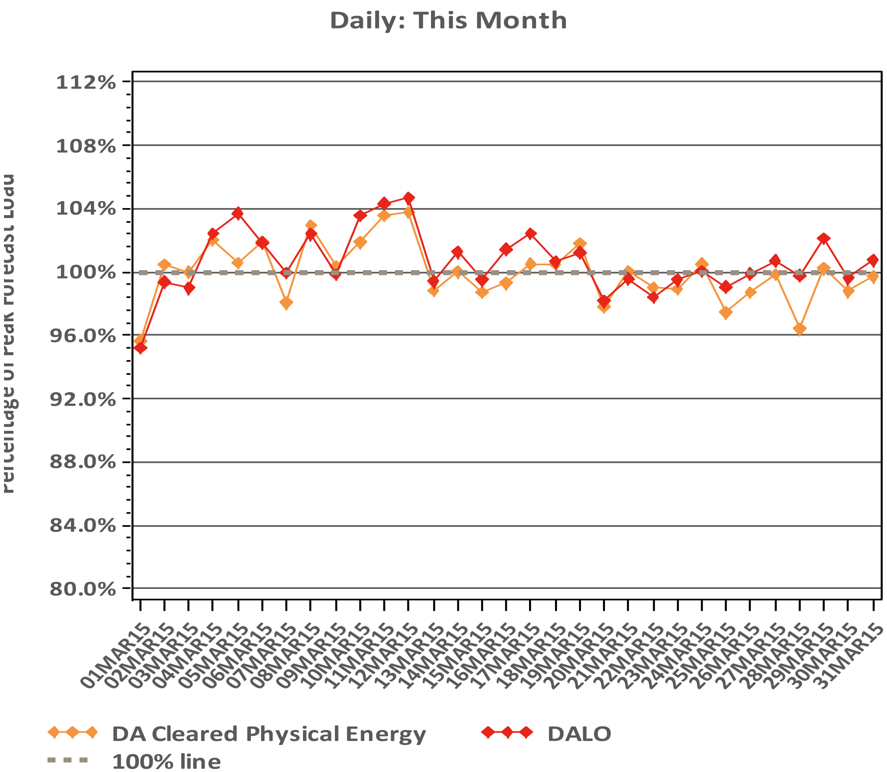



*Hourly average values

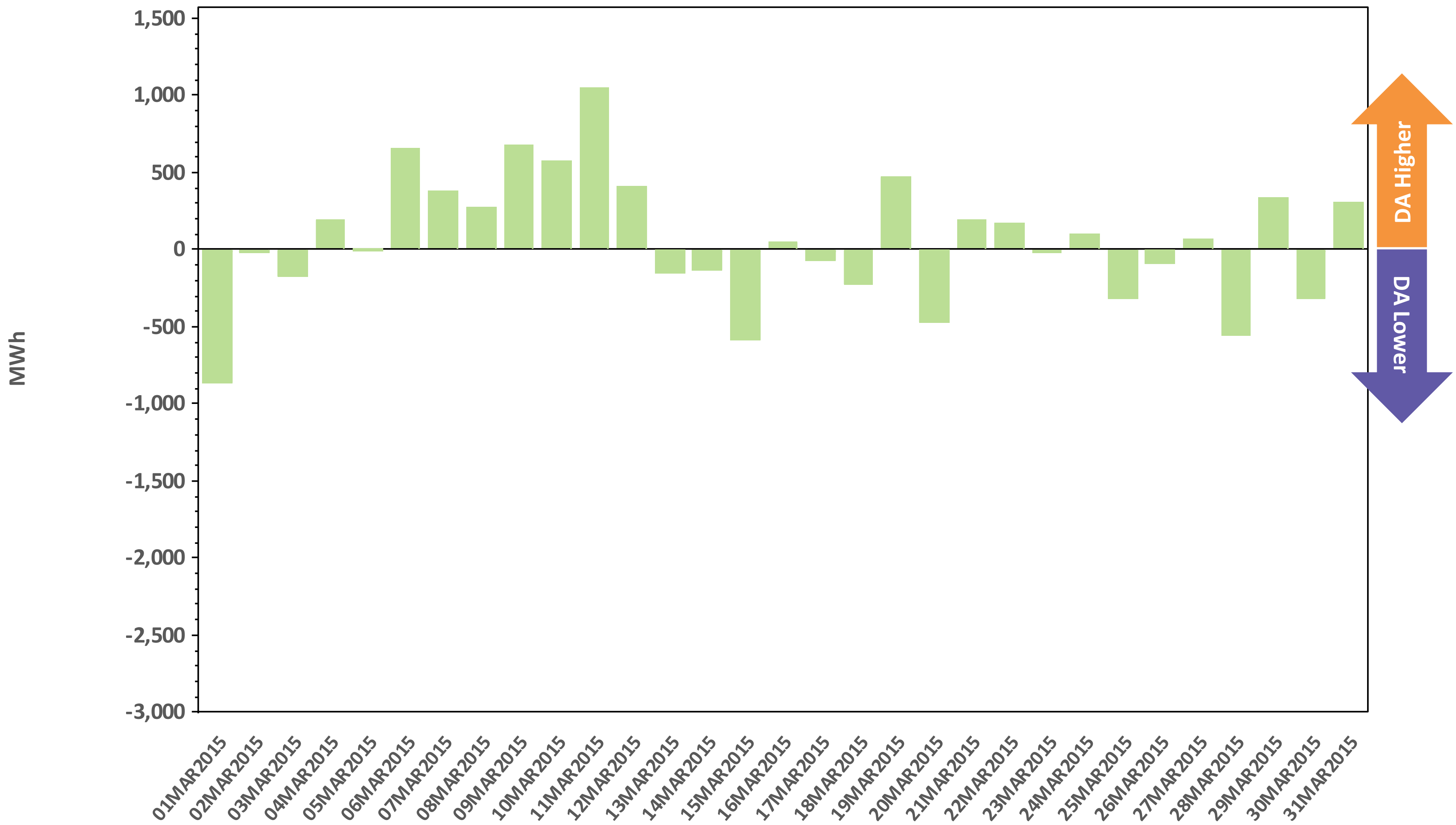
# DA Volumes as % of Forecast (Peak Hour)



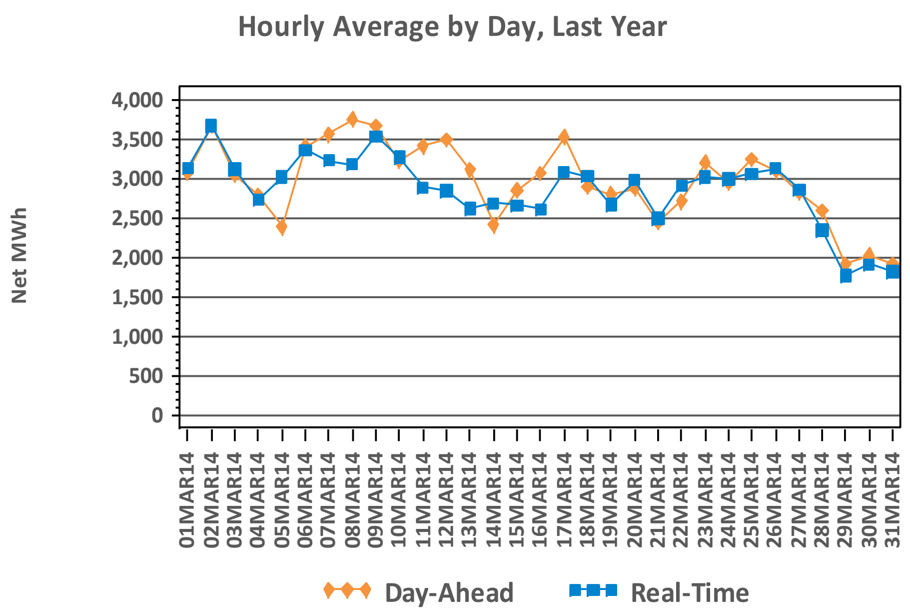

*Forecasted peak hour is reflected.

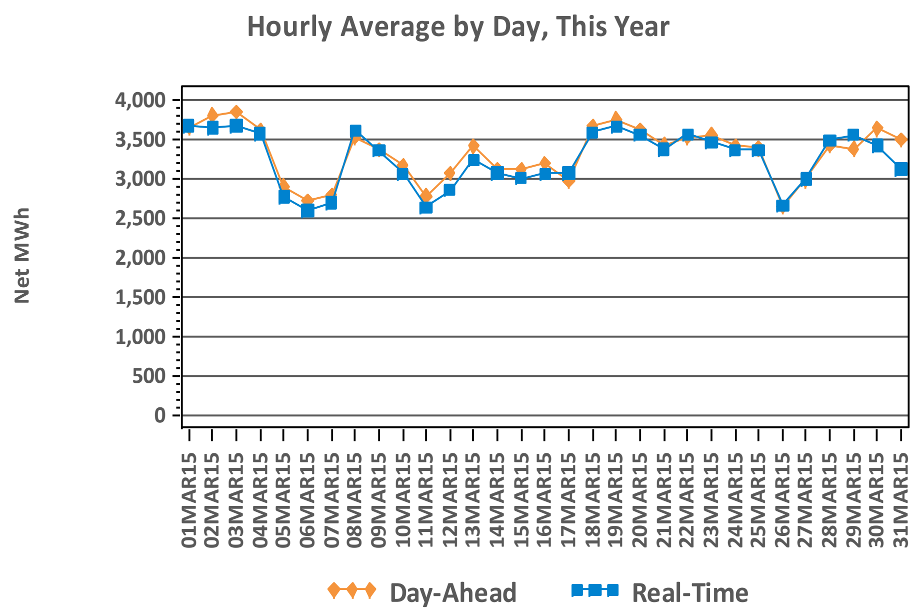
# DA Cleared Physical Energy Difference from RT System Load at Peak Hour




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

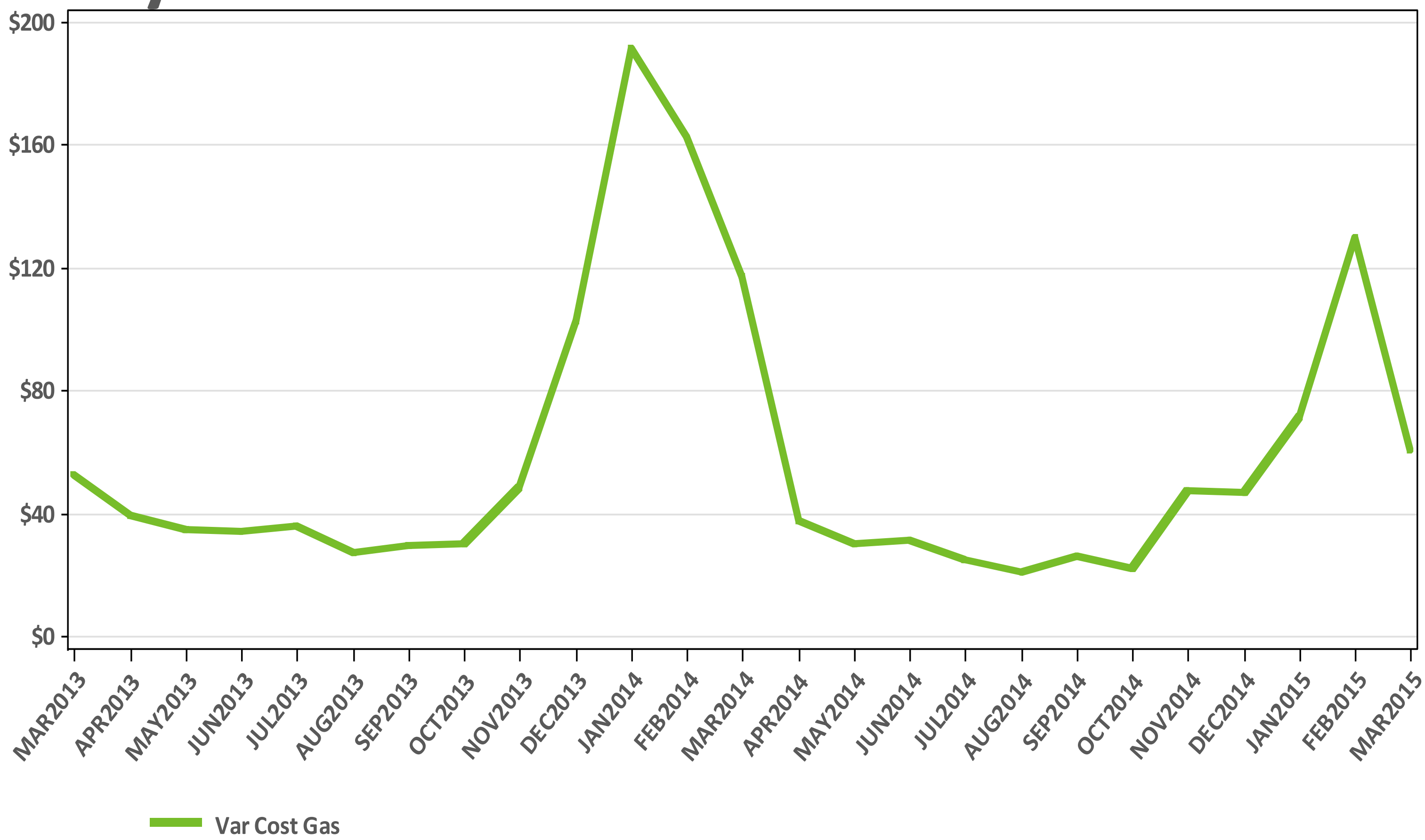
# DA vs. RT Net Interchange March 2015 vs. March 2014



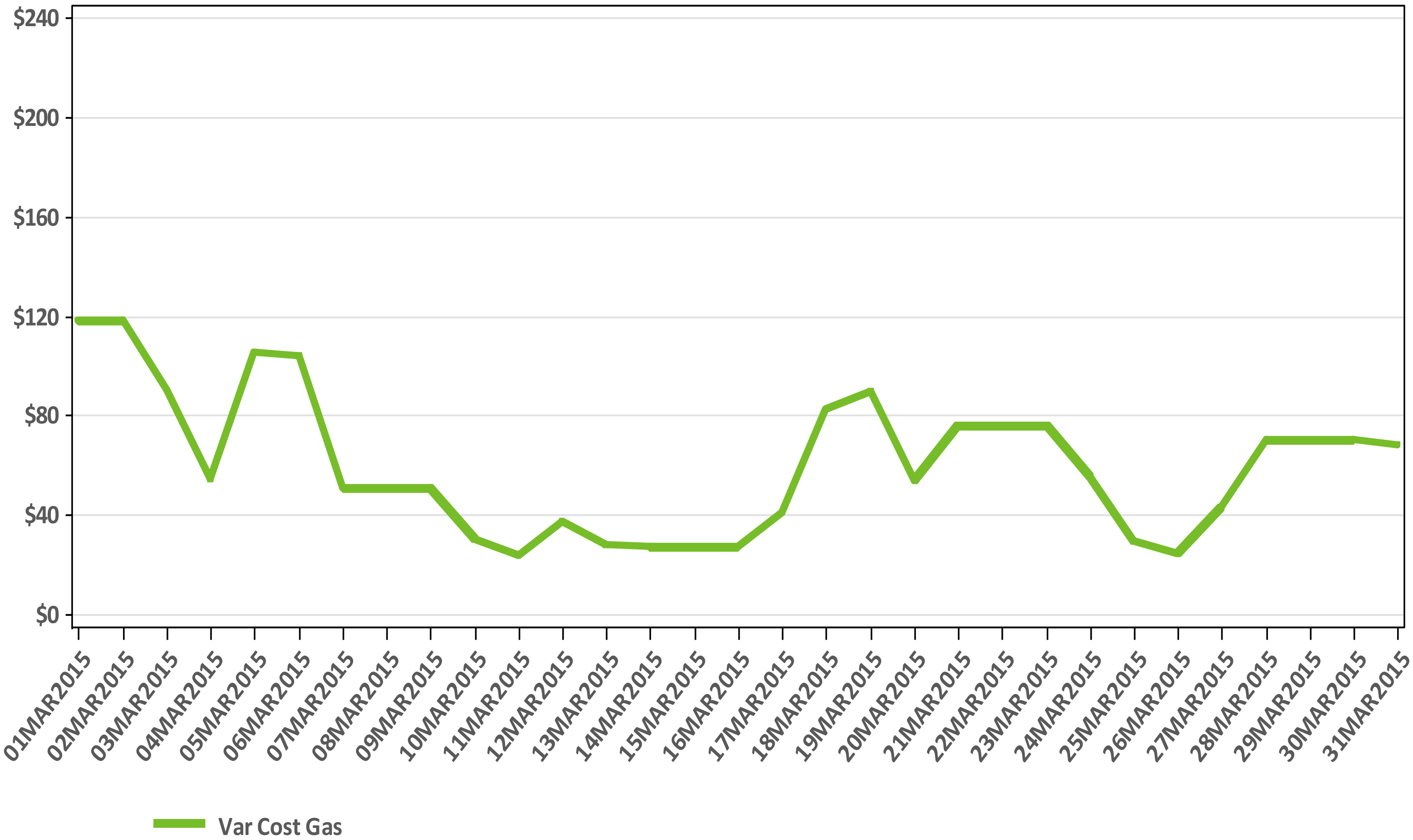

Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

# Variable Production Cost of Natural Gas: Monthly



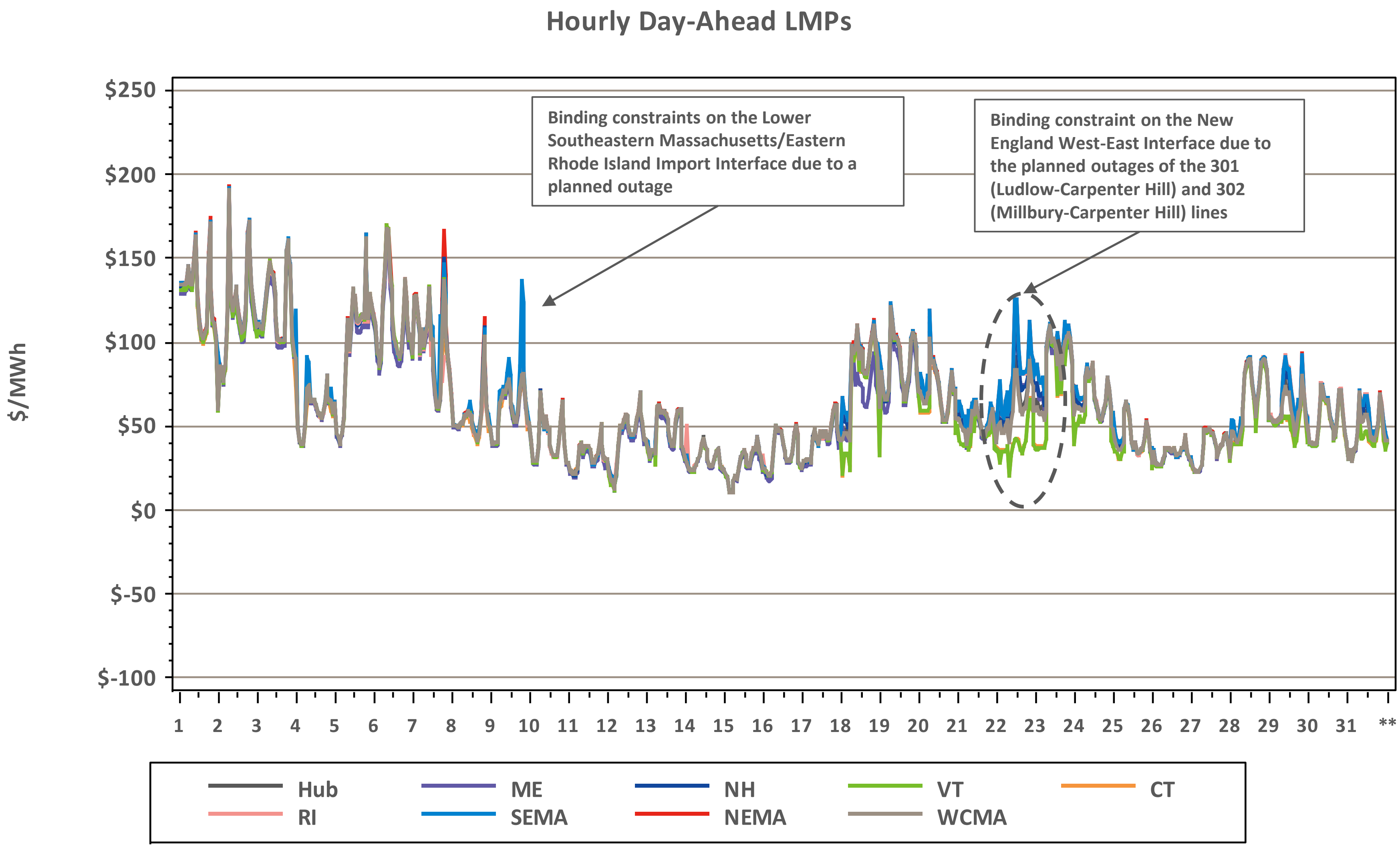

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

# Variable Production Cost of Natural Gas: Daily

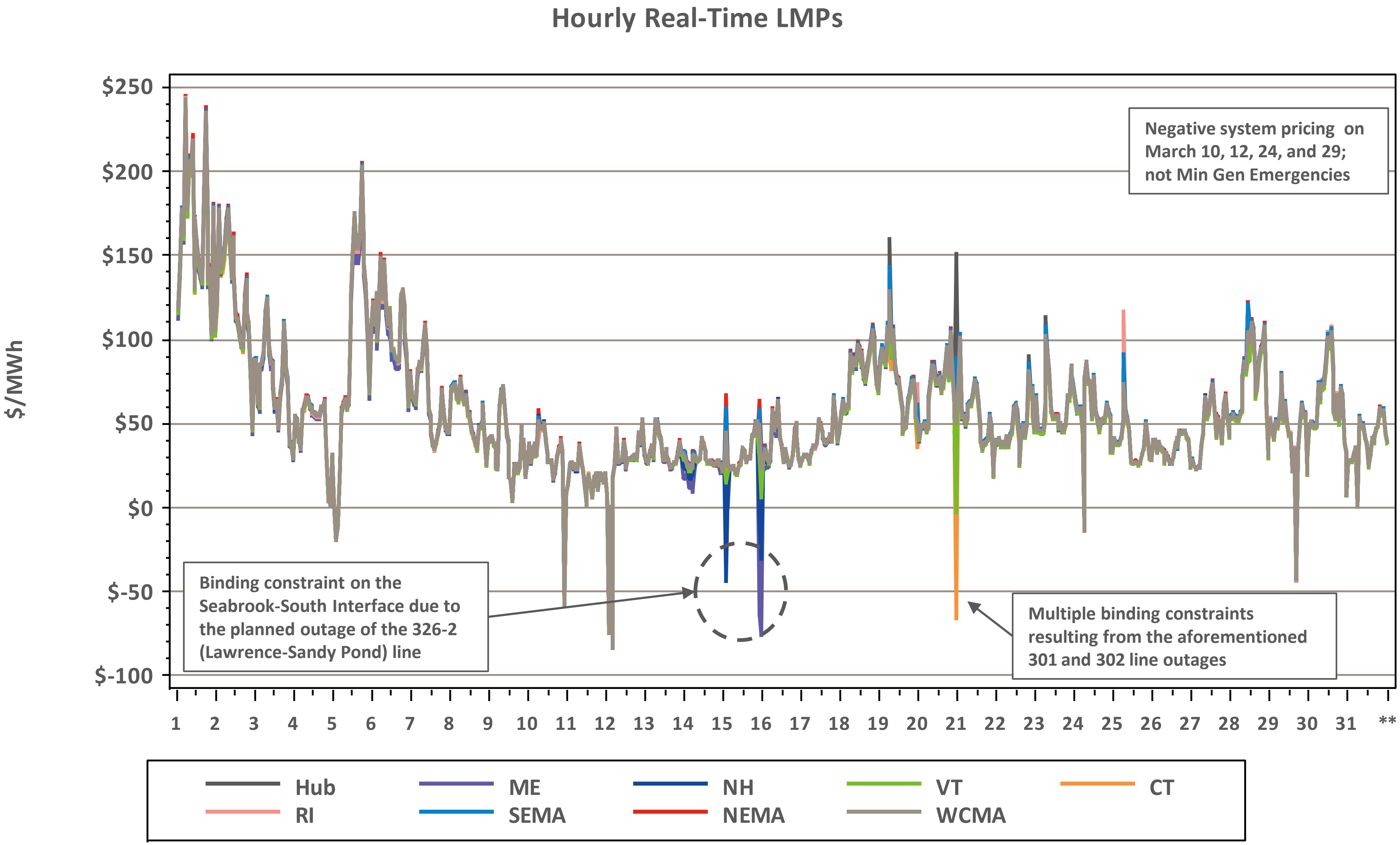



Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

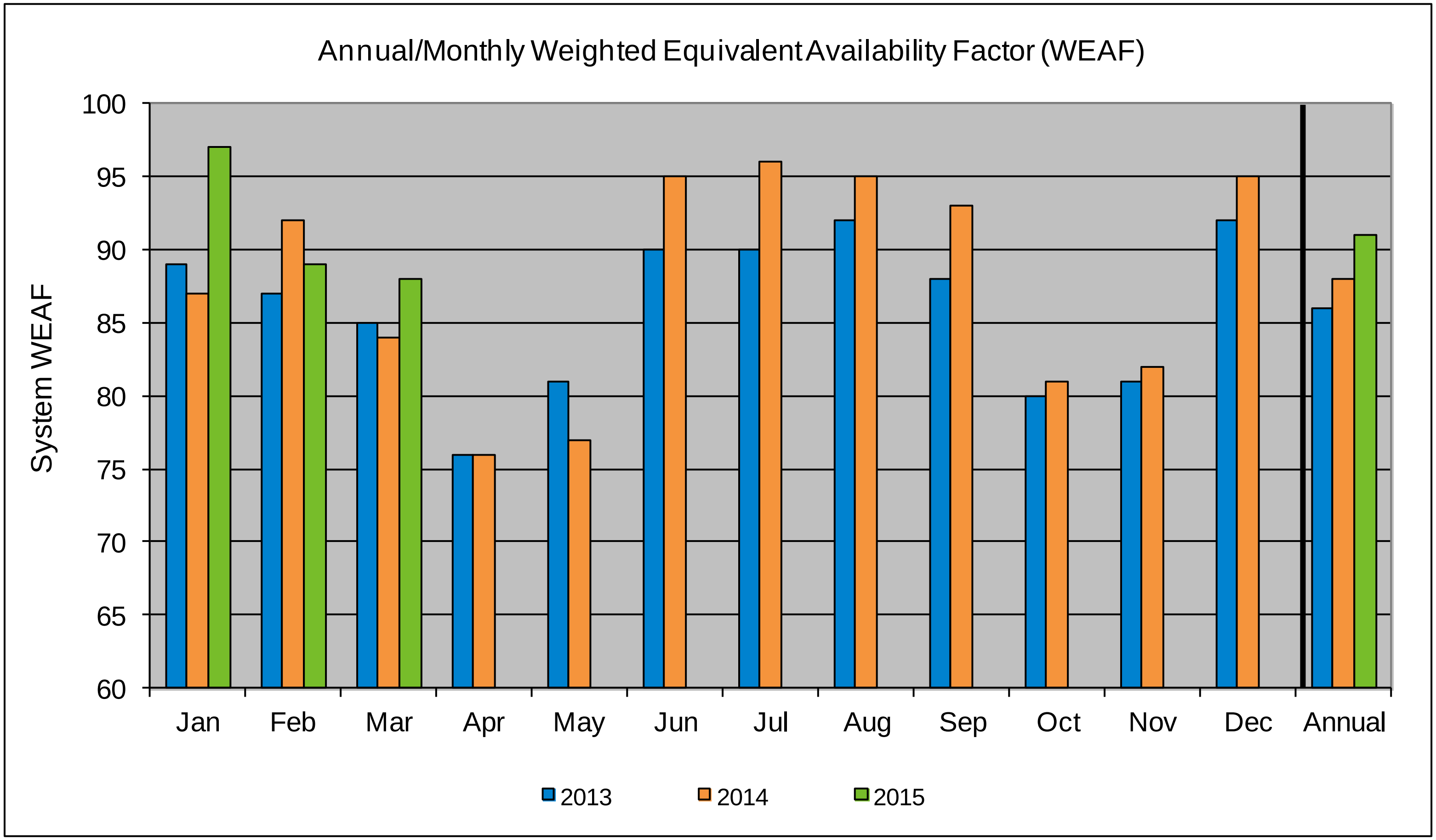
# Hourly DA LMPs, March 1-31, 2015



# Hourly RT LMPs, March 1-31, 2015



# System Unit Availability




| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2015** | 97 | 89 | 88 | | | | | | | | | | 91 |
| **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 4/6/15

# BACK-UP DETAIL

# LOAD RESPONSE

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

| Load Zone | RTDR* | RTEG** | On Peak | Seasonal Peak | Total |
|---|---|---|---|---|---|
| ME | 113.6 | 3.8 | 103.1 | 0.0 | 220.5 |
| NH | 8.2 | 14.3 | 69.9 | 0.0 | 92.4 |
| VT | 27.4 | 3.0 | 94.2 | 0.0 | 124.6 |
| CT | 84.6 | 73.1 | 77.5 | 312.3 | 547.4 |
| RI | 13.5 | 13.8 | 83.5 | 0.0 | 110.8 |
| SEMA | 11.1 | 9.5 | 157.7 | 0.0 | 178.3 |
| WCMA | 26.2 | 19.9 | 140.4 | 34.9 | 221.3 |
| NEMA | 34.2 | 3.5 | 307.5 | 0.0 | 345.1 |
| **Total** | **318.8** | **140.9** | **1,033.6** | **347.2** | **1,840.4** |

* 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

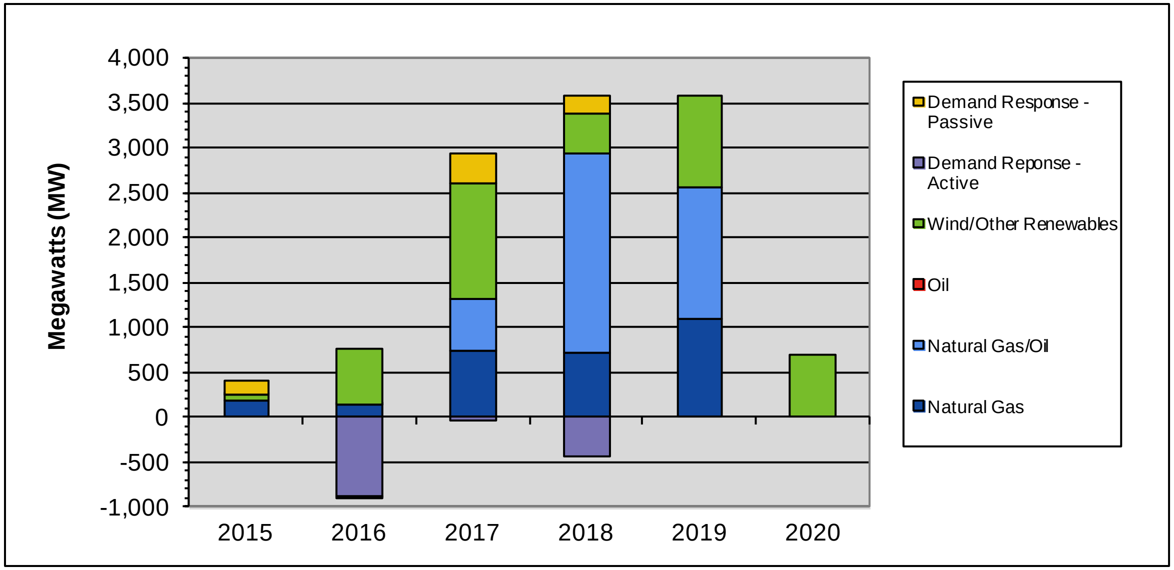
# New Generation Update

***Based on 3/1/15 Queue Update***

- Five new projects, with a total rating of 376 MW, have applied for interconnection study since the last update
  - The new projects consist of two new combustion turbines, one new wind facility, one upgrade to an existing hydro station, and one upgrade to an existing combined cycle plant. The expected in-service dates range from 2015 to 2019.
- One project went commercial and two projects withdrew from the Queue, resulting in a net increase in new generation projects of 83 MW
- In total, 79 generation projects are currently being tracked by the ISO, totaling approximately 11,300 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 | 6.3 |
| **Demand Response - Active** | 3 | -868 | -37 | -433 | 0 | 0 | -1,335 | -12.5 |
| **Wind & Other Renewables** | 77 | 620 | 1,309 | 458 | 1,029 | 698 | 4,191 | 39.3 |
| **Oil** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 |
| **Natural Gas/Oil[2]** | 0 | 10 | 567 | 2,208 | 1,469 | 0 | 4,254 | 39.9 |
| **Natural Gas** | 180 | 135 | 745 | 728 | 1,093 | 0 | 2,881 | 27.0 |
| **Totals** | **417** | **-115** | **2,914** | **3,157** | **3,591** | **698** | **10,661** | **100.0** |

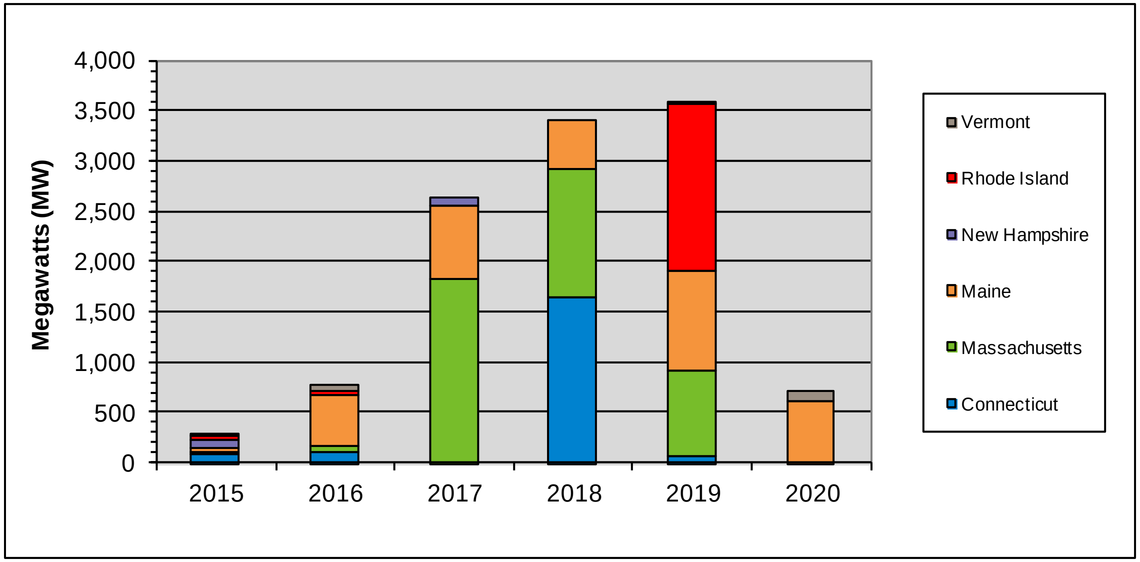
[1] Sum may not equal 100% due to rounding

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

- 2015 values include the 27 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 | 58 | 0 | 0 | 30 | 97 | 188 | 1.7 |
| **Rhode Island** | 27 | 51 | 0 | 0 | 1,661 | 0 | 1,739 | 15.4 |
| **New Hampshire** | 81 | 0 | 79 | 0 | 0 | 0 | 160 | 1.4 |
| **Maine** | 52 | 490 | 726 | 488 | 999 | 601 | 3,356 | 29.6 |
| **Massachusetts** | 10 | 65 | 1,816 | 1,267 | 838 | 0 | 3,996 | 35.3 |
| **Connecticut** | 84 | 101 | 0 | 1,639 | 63 | 0 | 1,887 | 16.7 |
| **Totals** | **257** | **765** | **2,621** | **3,394** | **3,591** | **698** | **11,326** | **100.0** |

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

- 2015 values include the 27 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 | 2 | 70 | 0 | 0 | 2 | 70 |
| Hydro | 6 | 38 | 0 | 0 | 6 | 38 |
| Landfill Gas | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas | 17 | 2,854 | 0 | 0 | 17 | 2,854 |
| Natural Gas/Oil | 17 | 4,254 | 0 | 0 | 17 | 4,254 |
| Oil | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 1 | 10 | 1 | 10 | 0 | 0 |
| Wind | 36 | 4,073 | 6 | 294 | 30 | 3,779 |
| Total | 79 | 11,299 | 7 | 304 | 72 | 10,995 |

- 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 | 133 | 0 | 0 | 3 | 133 |
| Intermediate | 26 | 5,465 | 0 | 0 | 26 | 5,465 |
| Peaker | 14 | 1,628 | 1 | 10 | 13 | 1,618 |
| Wind Turbine | 36 | 4,073 | 6 | 294 | 30 | 3,779 |
| Total | 79 | 11,299 | 7 | 304 | 72 | 10,995 |

- 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 | 2 | 70 | 2 | 70 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 6 | 38 | 0 | 0 | 5 | 13 | 1 | 25 | 0 | 0 |
| Landfill Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas | 17 | 2,854 | 1 | 63 | 13 | 2,700 | 3 | 91 | 0 | 0 |
| Natural Gas/Oil | 17 | 4,254 | 0 | 0 | 8 | 2,752 | 9 | 1,502 | 0 | 0 |
| Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 1 | 10 | 0 | 0 | 0 | 0 | 1 | 10 | 0 | 0 |
| Wind | 36 | 4,073 | 0 | 0 | 0 | 0 | 0 | 0 | 36 | 4,073 |
| Total | 79 | 11,299 | 3 | 133 | 26 | 5,465 | 14 | 1,628 | 36 | 4,073 |

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

# FORWARD CAPACITY MARKET

# Capacity Supply Obligation FCA 5

| Resource Type | Resource Type | FCA | 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 | 2,104.14 | 2,001.13 | -103.02 | 1,385.67 | -615.46 | 1,074.46 | -311.21 | 899.13 | -175.34 | 699.93 | -199.20 |
| | Passive Demand | 1,485.71 | 1,397.59 | -88.13 | 1,345.28 | -52.30 | 1,348.59 | 3.31 | 1,365.95 | 17.35 | 1,399.56 | 33.62 |
| Demand Total | | 3,589.85 | 3,398.71 | -191.14 | 2,730.95 | -667.76 | 2,423.05 | -307.90 | 2,265.07 | -157.98 | 2,099.49 | -165.58 |
| Generator | Non-Intermittent | 30,558.22 | 28,337.48 | -2,220.74 | 27,917.69 | -419.79 | 28,364.59 | 446.90 | 28,517.10 | 152.51 | 28,557.86 | 40.76 |
| | 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 | | 31,438.96 | 29,165.29 | -2,273.67 | 28,695.86 | -469.43 | 29,160.13 | 464.28 | 29,312.86 | 152.73 | 29,276.76 | -36.10 |
| Import Total | | 2,011.00 | 1,831.37 | -179.63 | 1,831.37 | 0.00 | 1,635.84 | -195.54 | 1,635.84 | 0.00 | 1,382.55 | -253.28 |
| ***Grand Total | | 37,039.81 | 34,395.37 | -2,644.44 | 33,258.18 | -1,137.19 | 33,219.02 | -39.16 | 33,213.77 | -5.25 | 32,758.81 | -454.96 |
| Net ICR (NICR) | | 33,200 | 33,200 | 0 | 33,200 | 0 | 32,209 | -991 | 32,209 | 0 | 32,588 | 379 |

* 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 | 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 | | | | | | | | |
| | *Passive Demand* | 1,631.335 | 1,519.740 | -111.595 | 1,519.311 | -0.43 | 1,543.793 | 24.482 | | | | | | | | |
| **Demand Total** | | **2,748.033** | **2,563.459** | **-184.574** | **2,463.581** | **-99.88** | **2,476.514** | **12.933** | | | | | | | | |
| Generator | *Non-Intermittent* | 30,704.578 | 28,146.837 | -2,557.741 | 28,127.044 | -19.79 | 28,523.002 | 395.958 | | | | | | | | |
| | *Intermittent* | 936.913 | 893.710 | -43.203 | 903.244 | 9.53 | 913.083 | 9.839 | | | | | | | | |
| **Generator Total** | | **31,641.491** | **29,040.547** | **-2,600.944** | **29,030.288** | **-10.26** | **29,436.085** | **405.797** | | | | | | | | |
| **Import Total** | | **1,830.000** | **1,606.862** | **-223.138** | **1,606.862** | **0.00** | **1,616.401** | **9.539** | | | | | | | | |
| *****Grand Total** | | **36,219.524** | **33,210.868** | **-3,008.656** | **33,100.731** | **-110.14** | **33,529.000** | **428.269** | | | | | | | | |
| **Net ICR (NICR)** | | **32,968** | **32,968** | **0** | 33,529 | 561 | 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 | | | | | | | | | | | | |
| | *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** | | | | | | | | | | | | |
| **Net ICR (NICR)** | | **33,855** | | | | | | | | | | | | |

* 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?

- "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

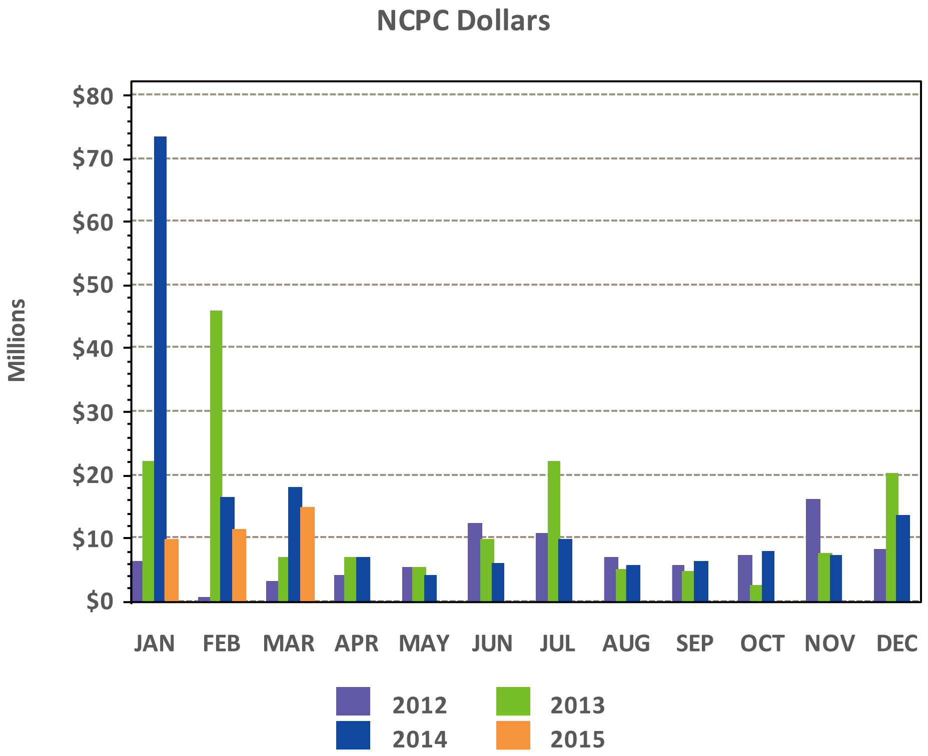
# Definitions

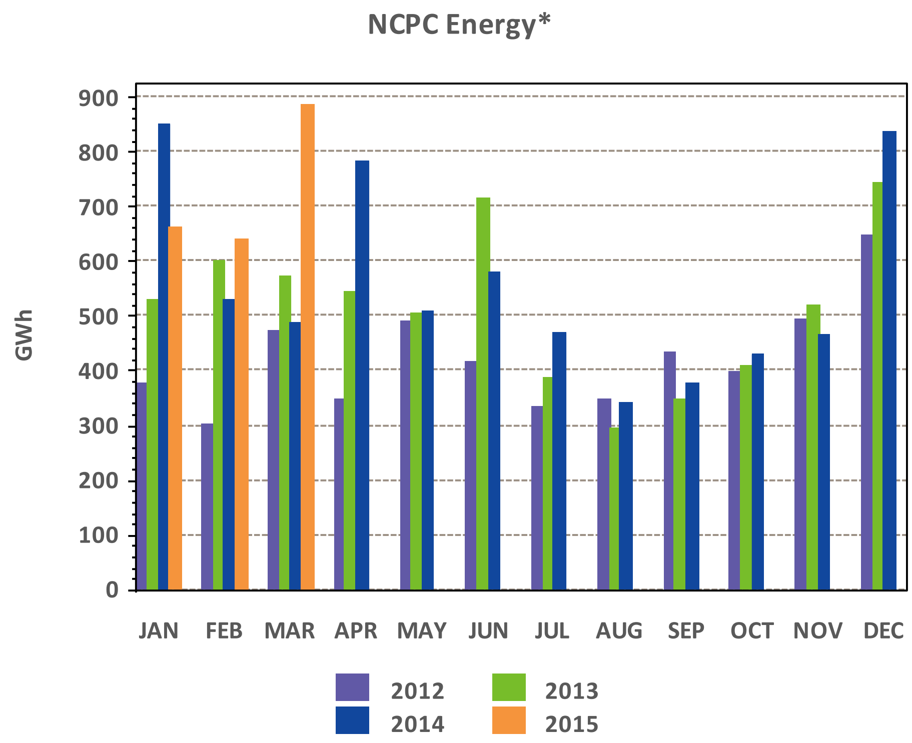
| | |
|---|---|
| 1st Contingency NCPC Payments | Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally |
| 2nd Contingency NCPC Payments | Reliability costs 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 1$^{st}$ Contingency | Market | DA 1$^{st}$ C (excluding at external nodes) is allocated to system DALO.<br>RT 1$^{st}$ C (at all locations) is allocated to System 'Daily Deviations'.<br>Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations) |
| External DA 1$^{st}$ Contingency | Market | DA 1$^{st}$ C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved |
| Zonal 2$^{nd}$ Contingency | Market | DA and RT 2$^{nd}$ 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 |

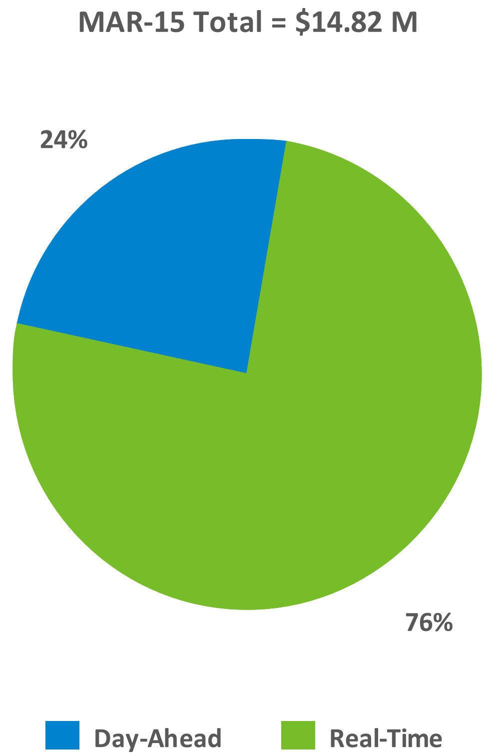
# Year-Over-Year Total NCPC Dollars and Energy

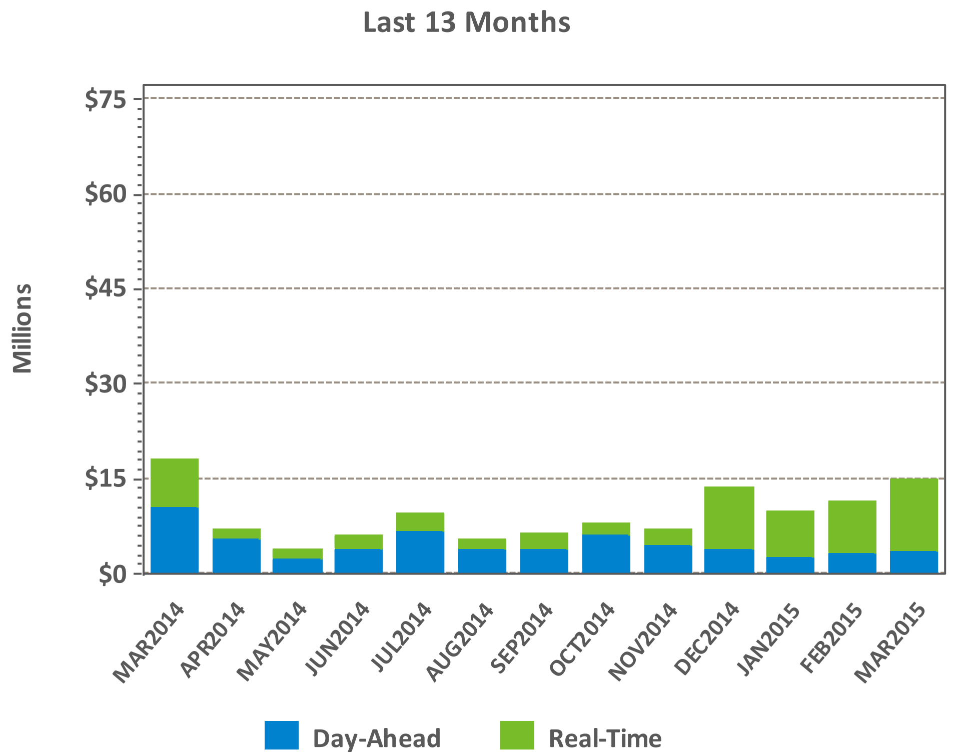


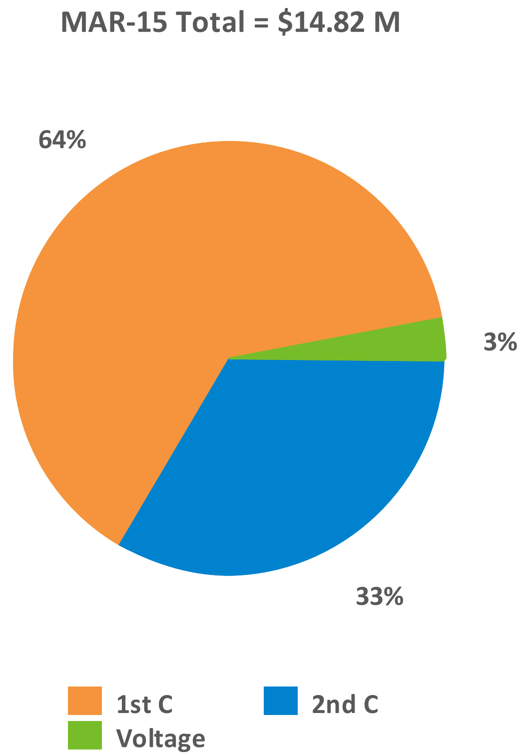

* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

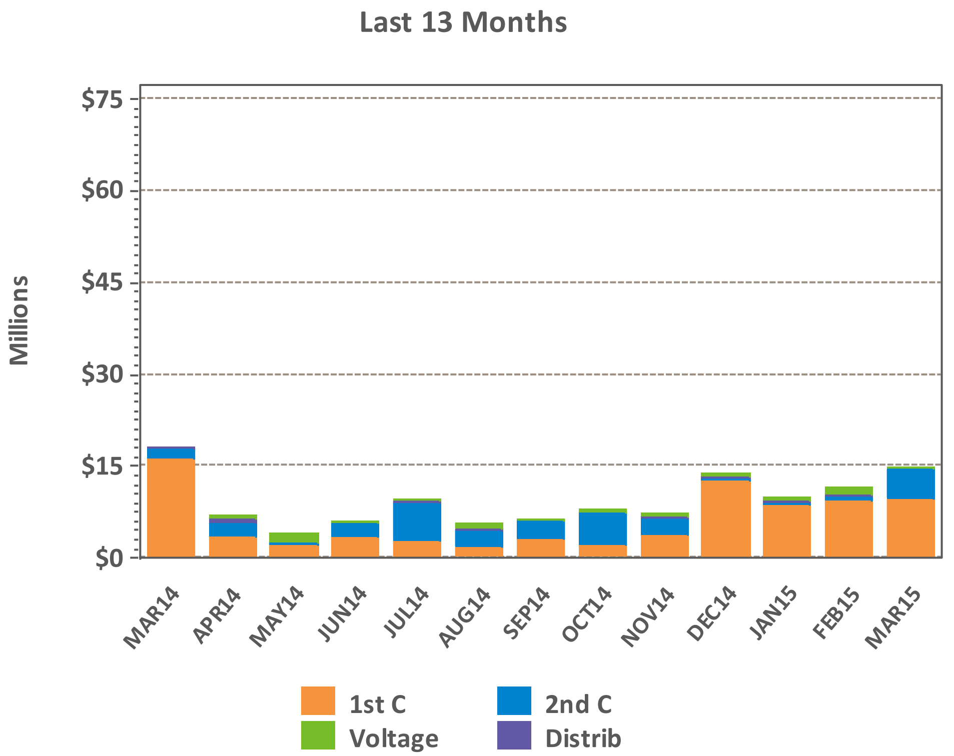
# DA and RT NCPC Charges



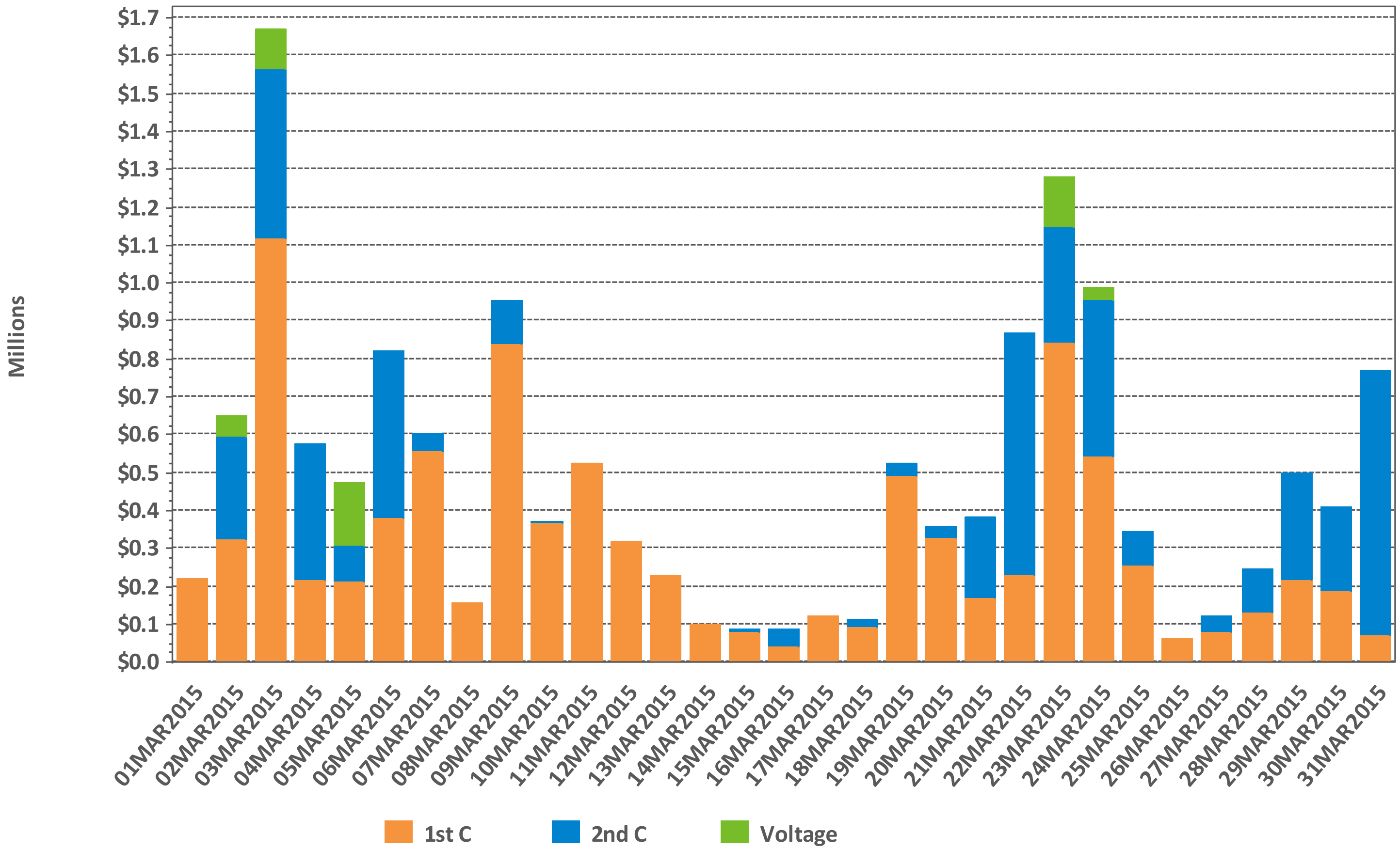
# NCPC Charges by Type



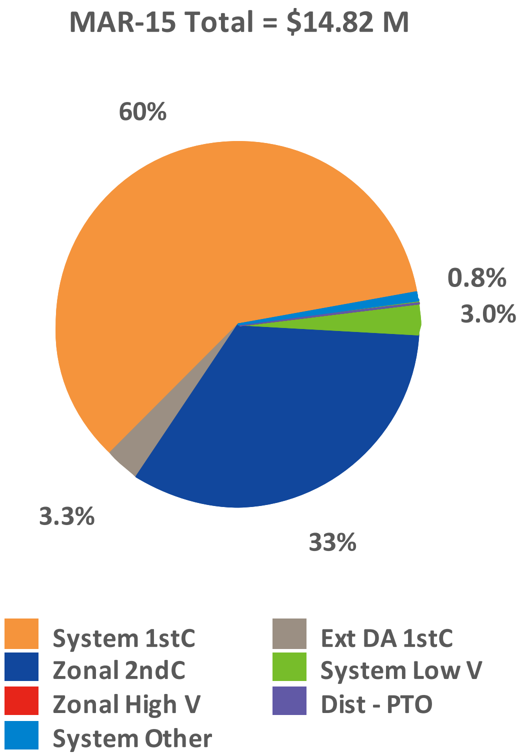



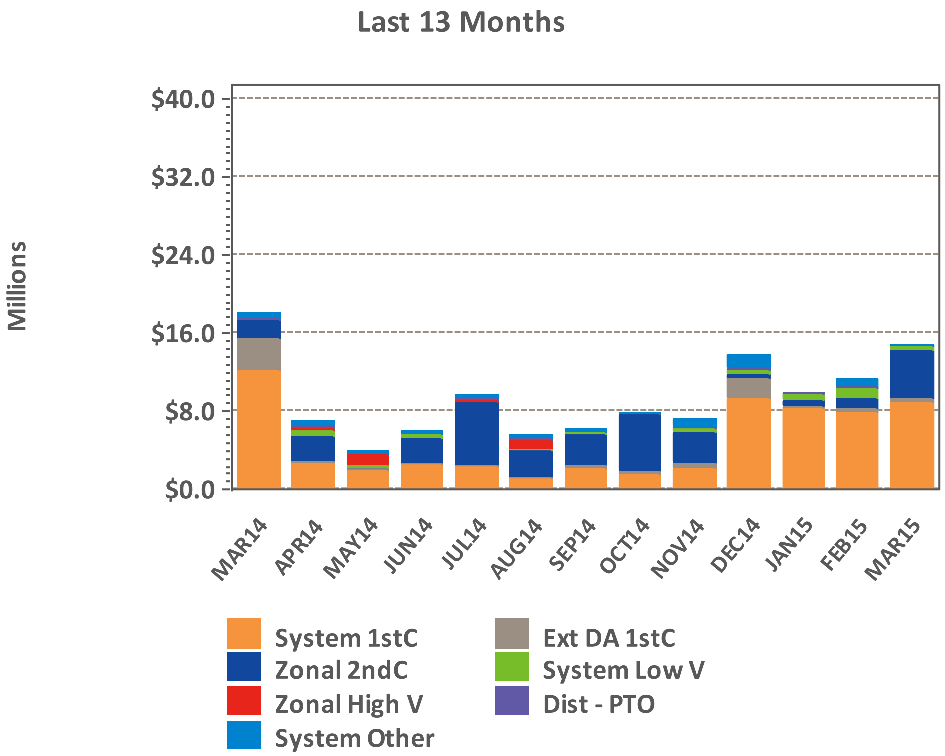

1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

# Daily NCPC Charges by Type

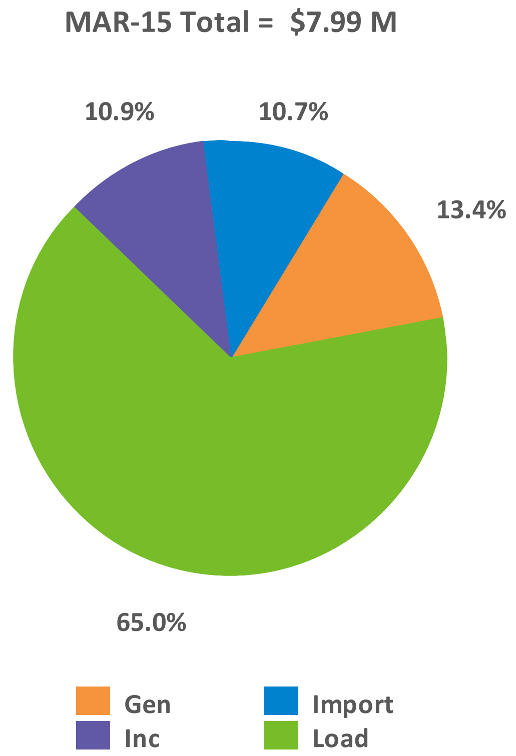


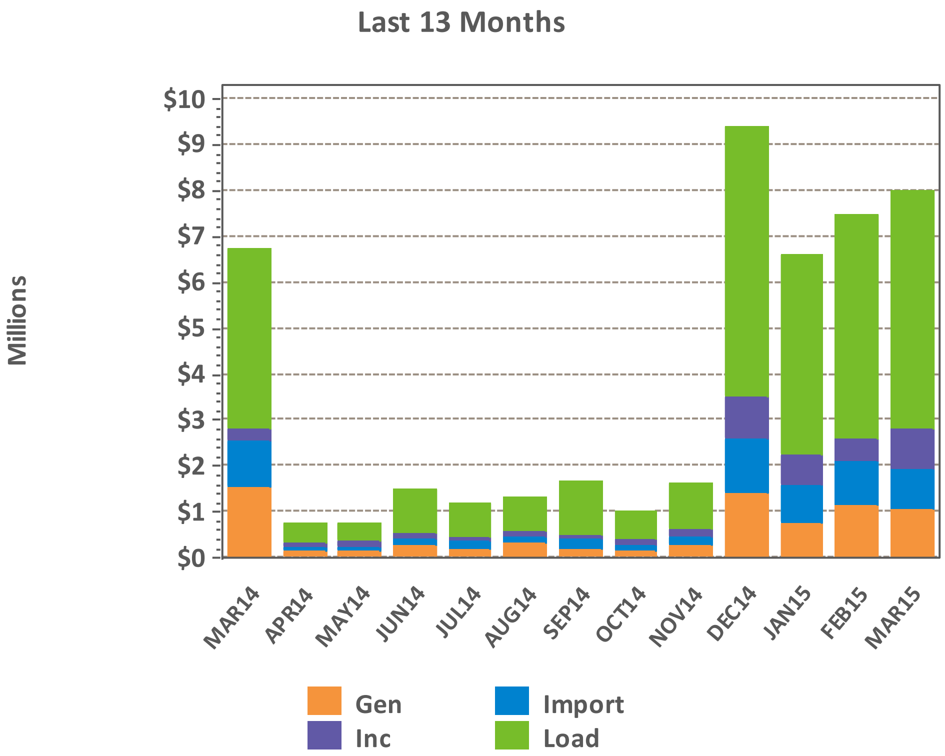
# NCPC Charges by Allocation



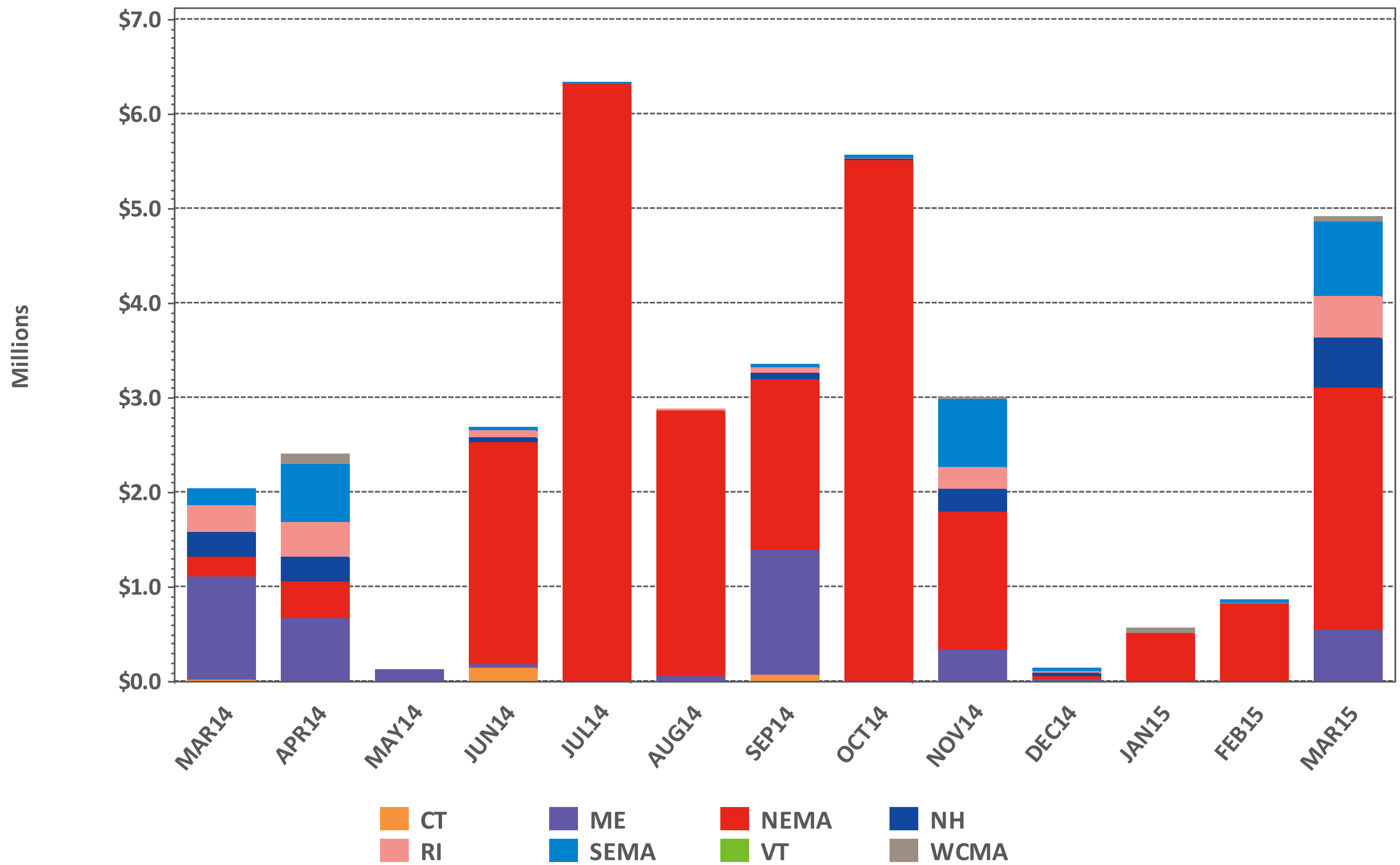
# RT First Contingency Charges by Deviation Type




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

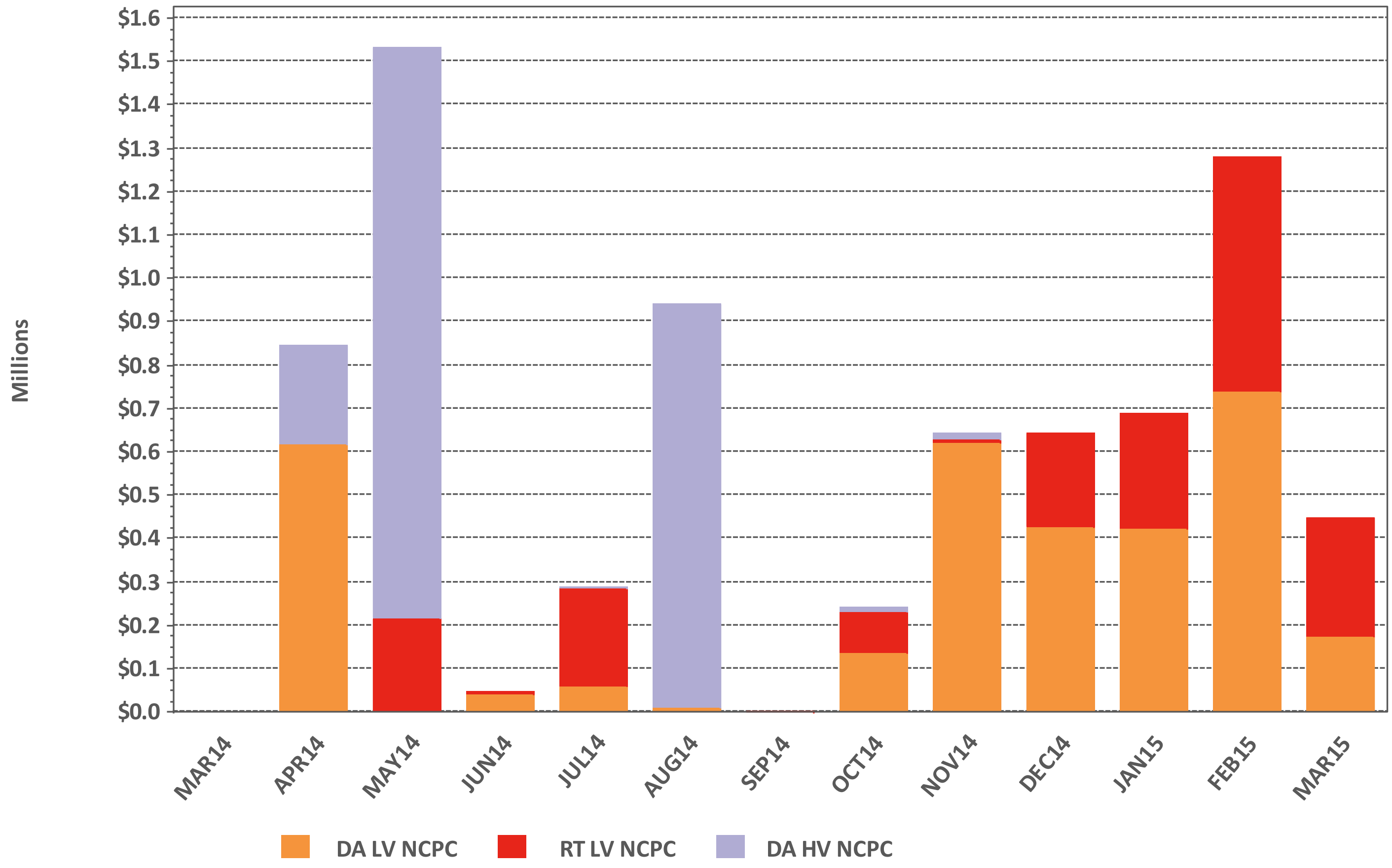
# LSCPR Charges by Zone



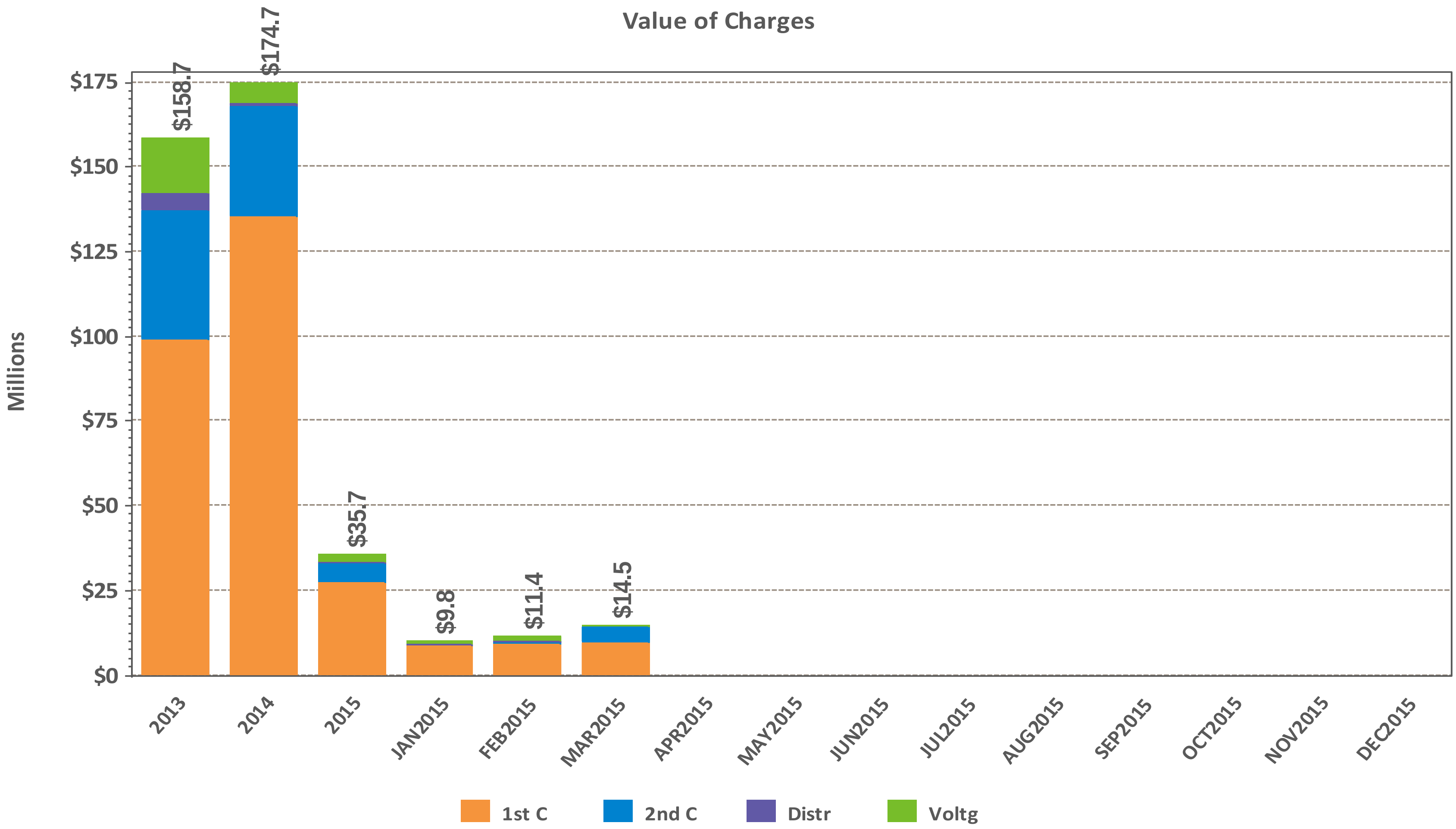

CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

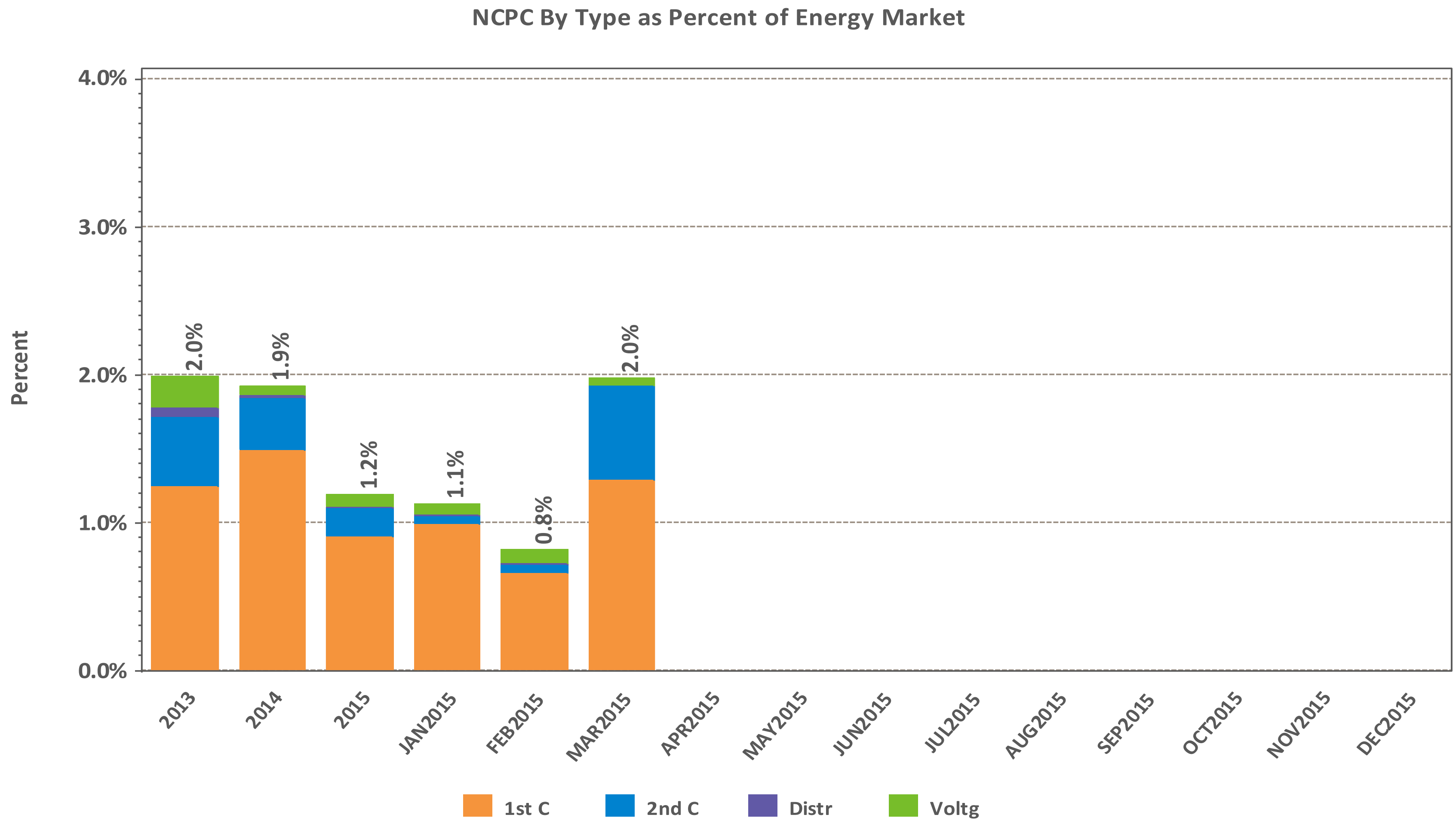
# NCPC Charges for Voltage Support and High Voltage Control



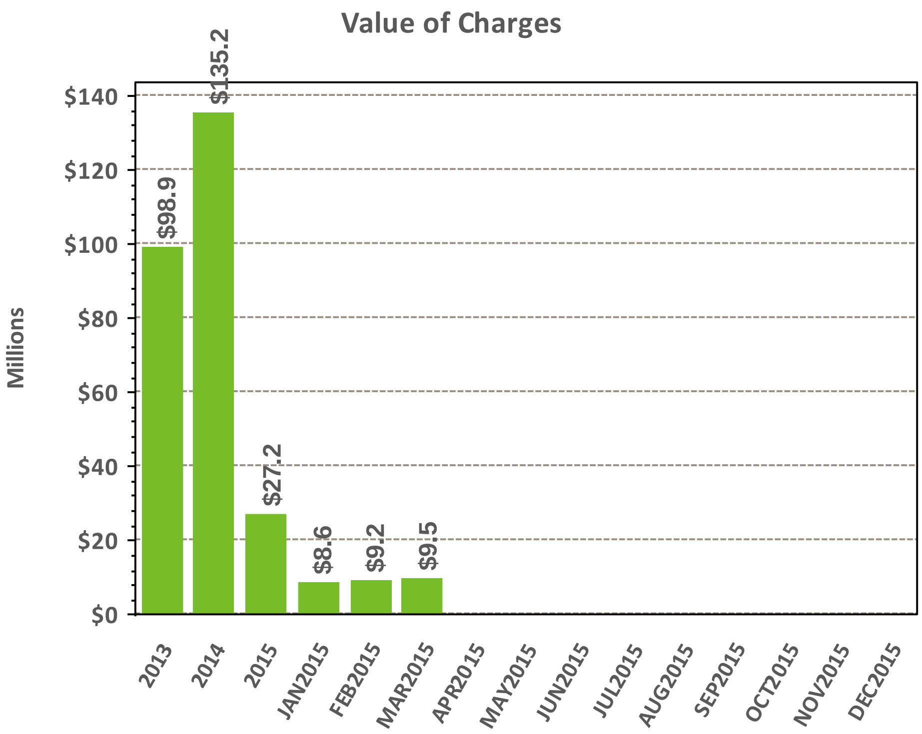
# NCPC Charges by Type

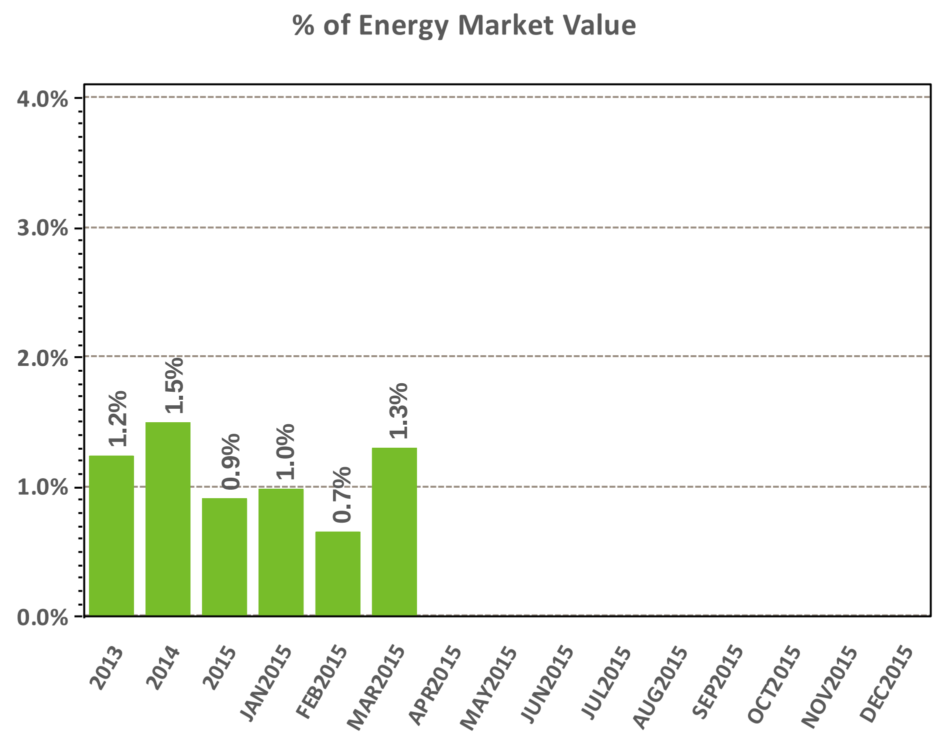


# NCPC Charges as Percent of Energy Market



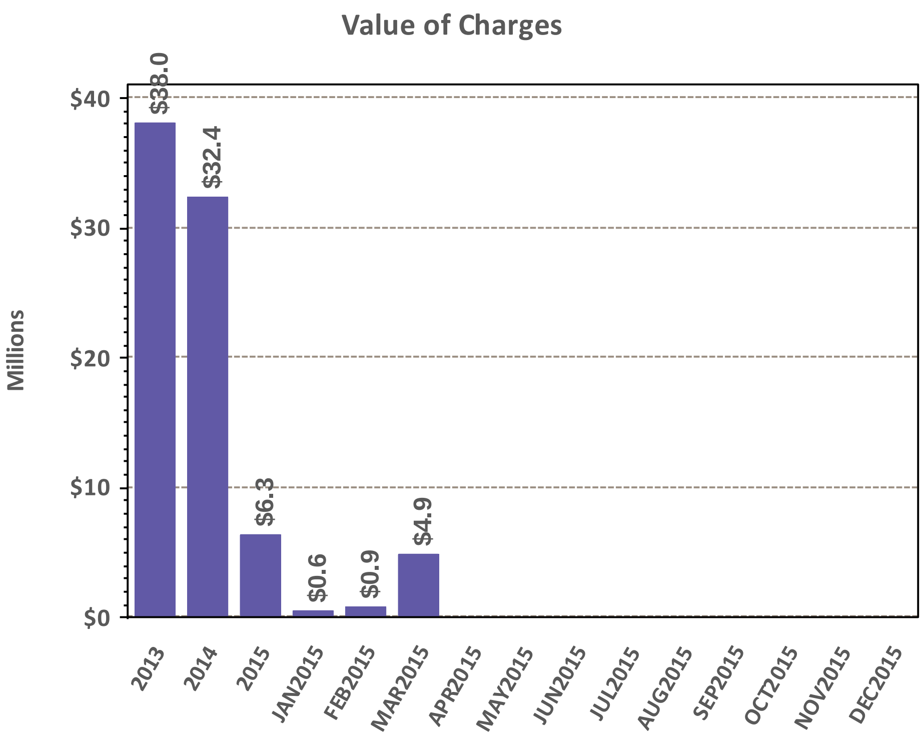
# First Contingency NCPC Charges

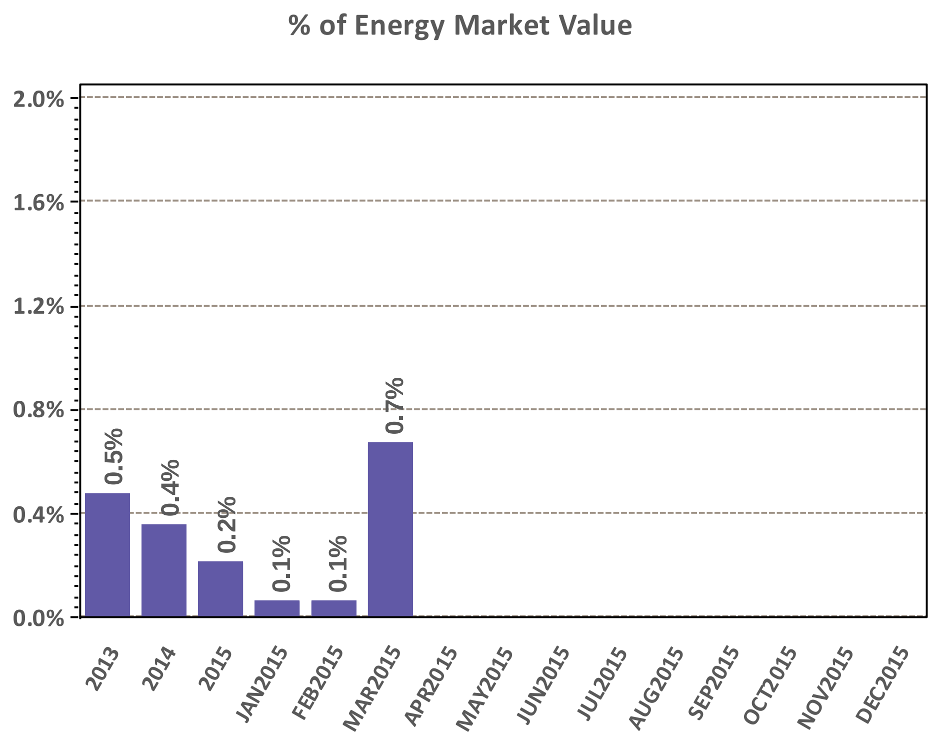



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

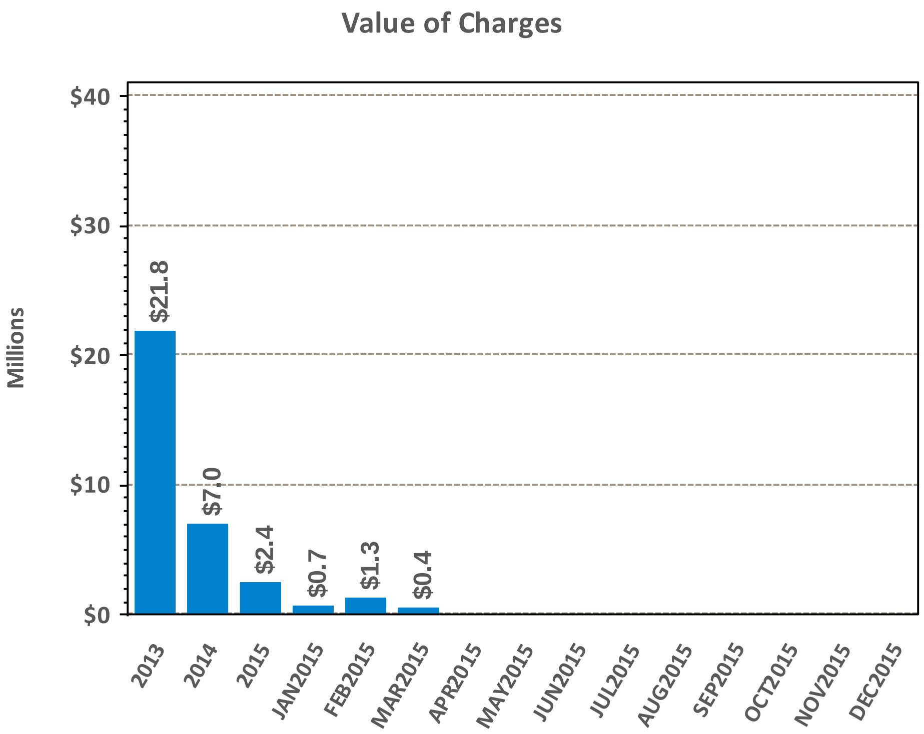
# Second Contingency NCPC Charges

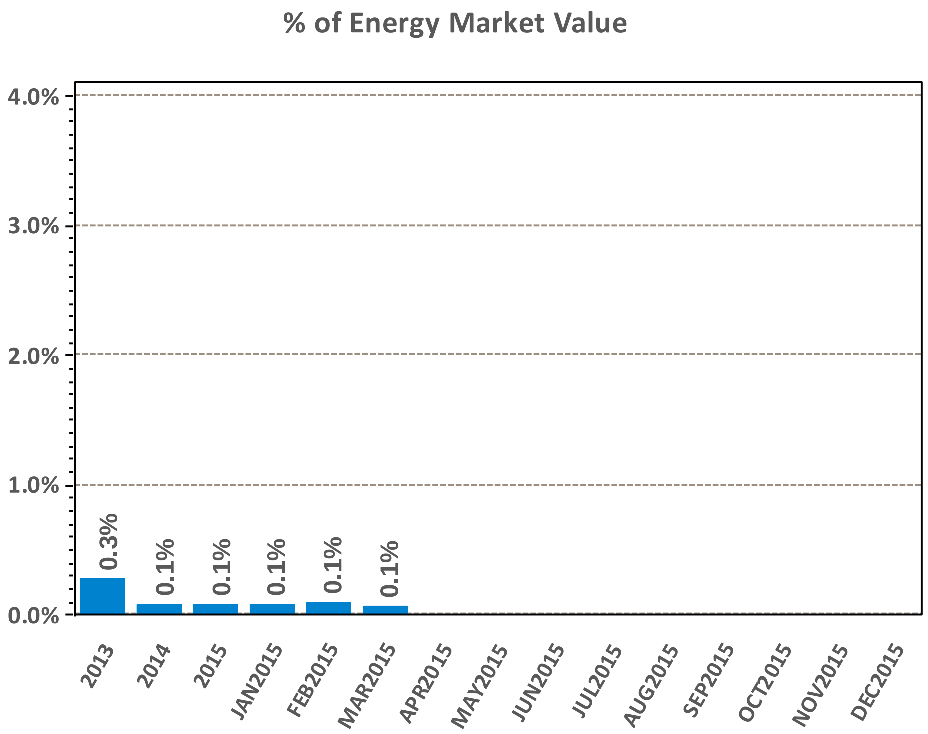



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

# 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

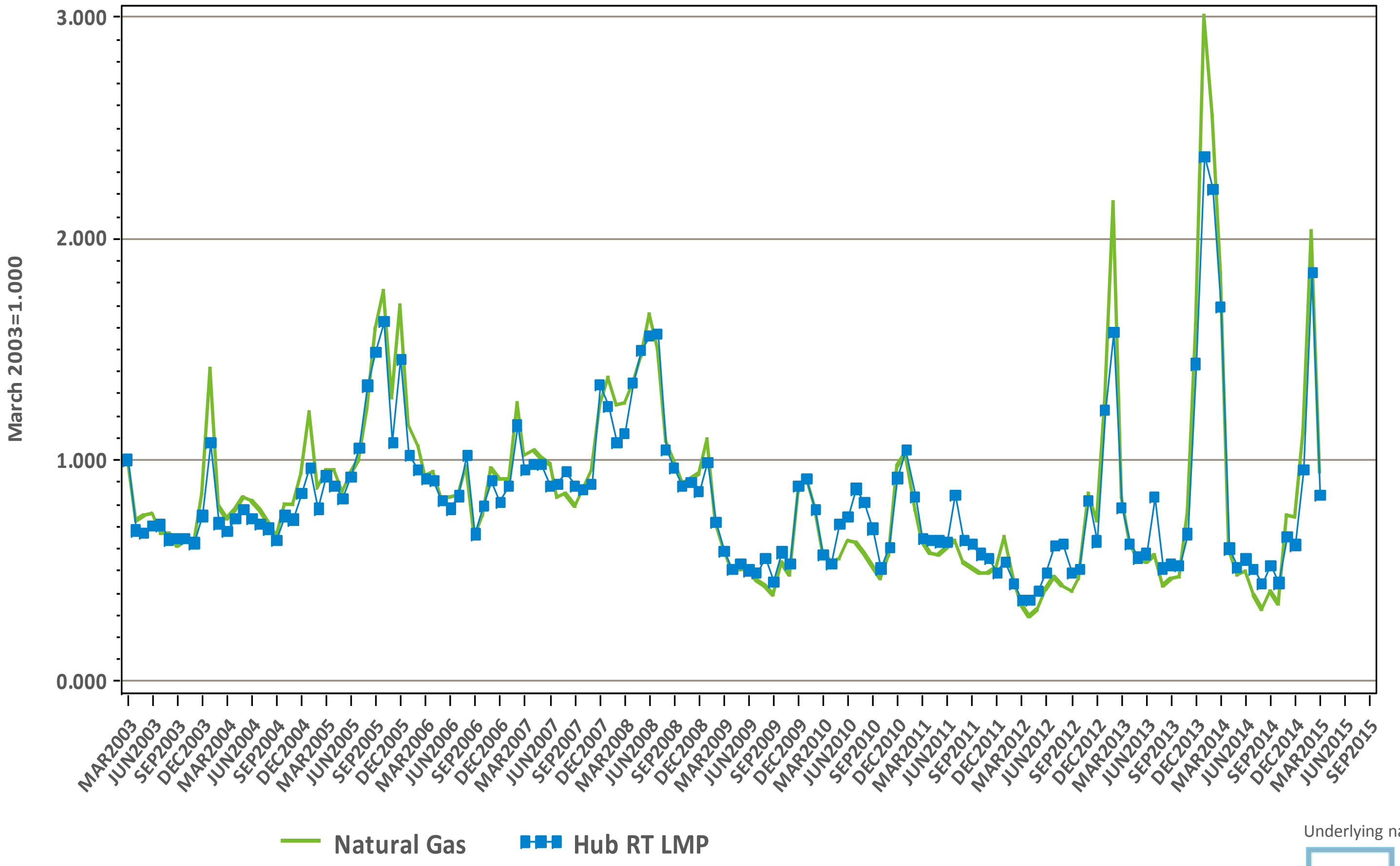
# DA vs. RT LMPs ($/MWh)

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% |

| March-14 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
|---|---|---|---|---|---|---|---|---|---|
| Day-Ahead | $111.77 | $109.23 | $107.34 | $109.75 | $109.34 | $112.49 | $112.27 | $111.12 | $111.16 |
| Real-Time | $116.87 | $114.46 | $110.06 | $113.20 | $112.47 | $116.65 | $117.15 | $116.10 | $116.12 |
| RT Delta % | 4.6% | 4.8% | 2.5% | 3.1% | 2.9% | 3.7% | 4.4% | 4.5% | 4.5% |
| March-15 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Day-Ahead | $66.28 | $60.69 | $62.47 | $64.56 | $61.24 | $65.38 | $66.36 | $63.87 | $64.25 |
| Real-Time | $58.34 | $55.98 | $55.24 | $56.71 | $56.08 | $57.73 | $58.02 | $57.48 | $57.93 |
| RT Delta % | -12.0% | -7.8% | -11.6% | -12.2% | -8.4% | -11.7% | -12.6% | -10.0% | -9.8% |
| Annual Diff. | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Yr over Yr DA | -40.7% | -44.4% | -41.8% | -41.2% | -44.0% | -41.9% | -40.9% | -42.5% | -42.2% |
| Yr over Yr RT | -50.1% | -51.1% | -49.8% | -49.9% | -50.1% | -50.5% | -50.5% | -50.5% | -50.1% |

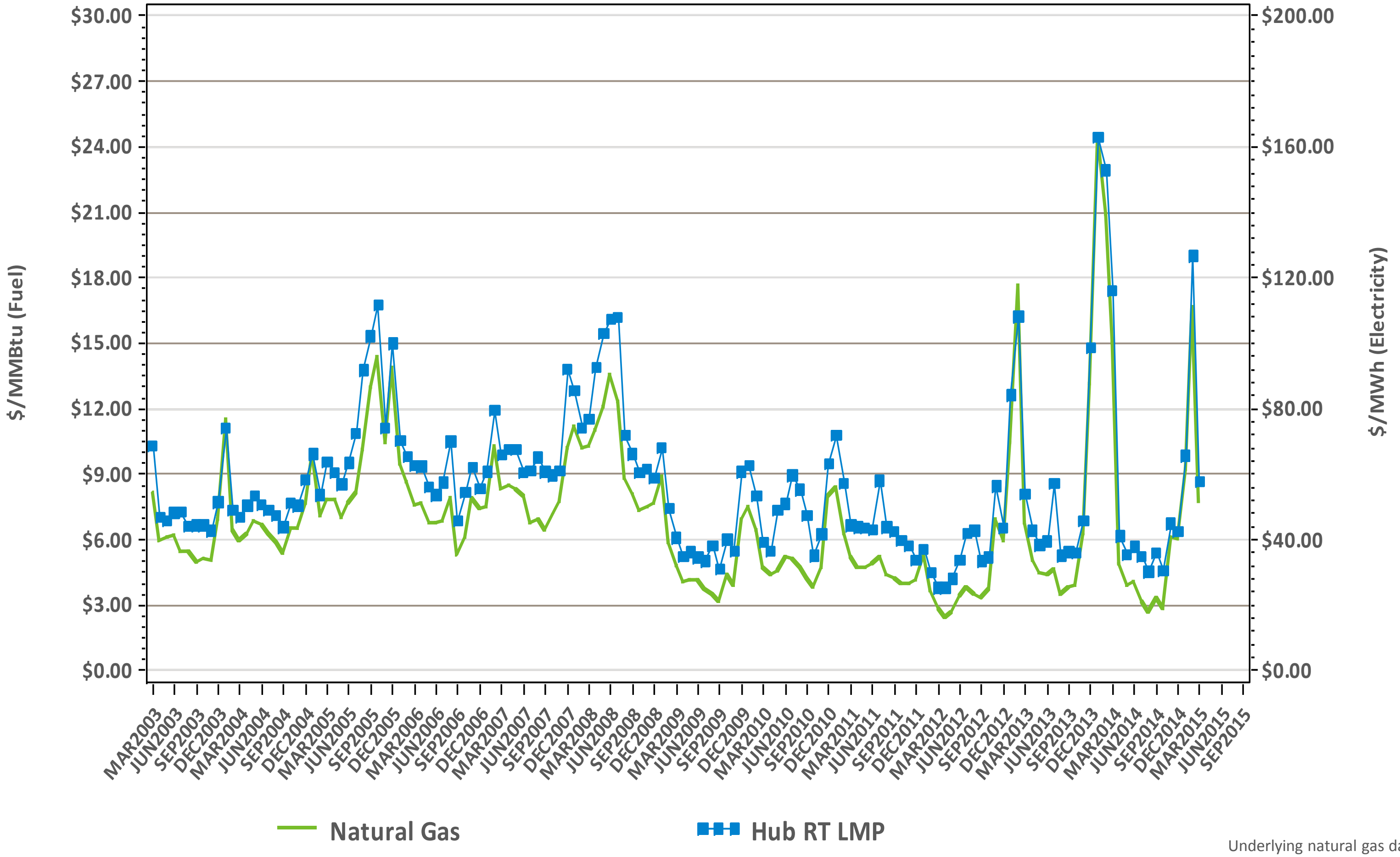
# Monthly Average Fuel Price and RT Hub LMP Indexes




Underlying natural gas data furnished by:

ICE Global markets in clear view

# Monthly Average Fuel Price and RT Hub LMP

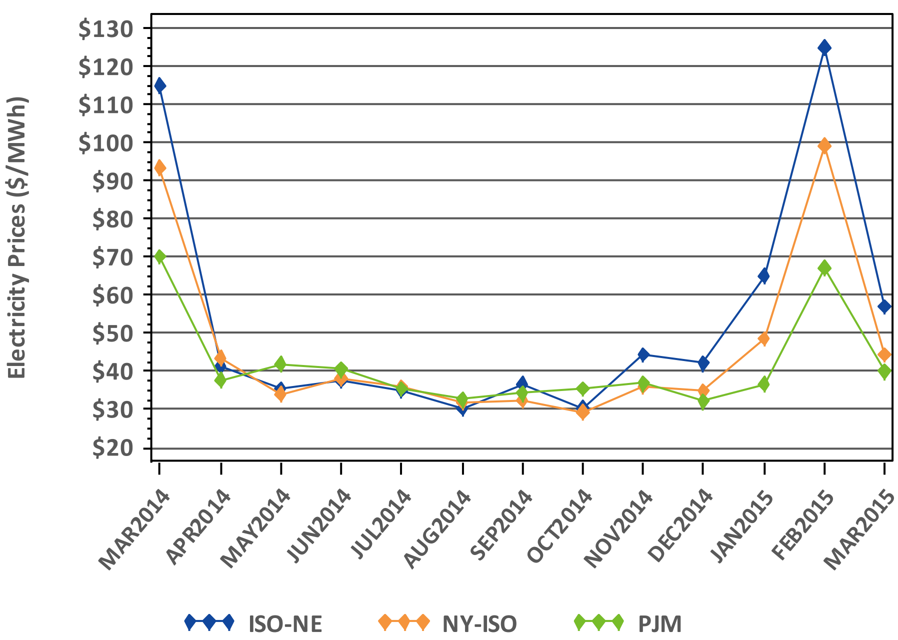



Underlying natural gas data furnished by:

ICE Global markets in clear view

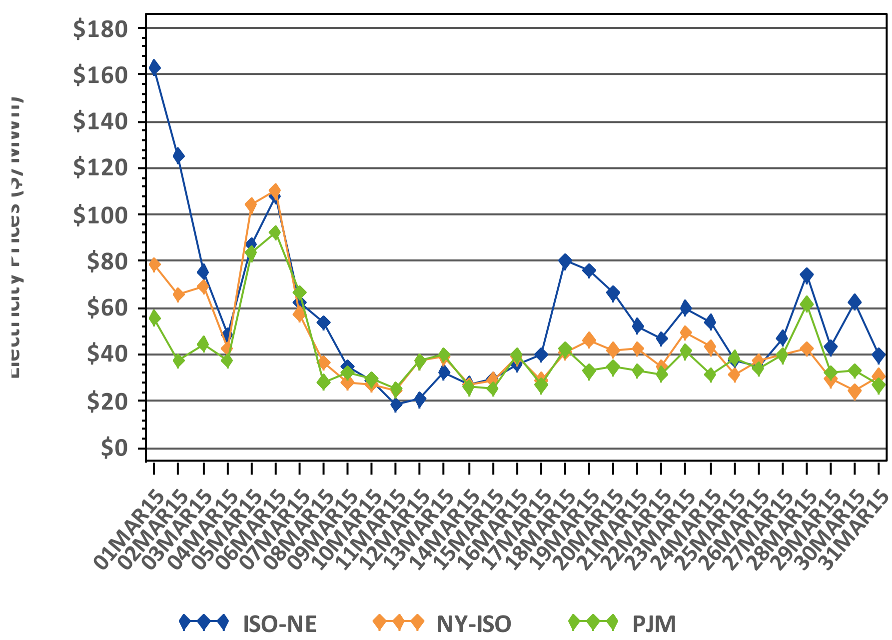
# New England, NY, and PJM Real Time Prices

Monthly, Last 13 Months



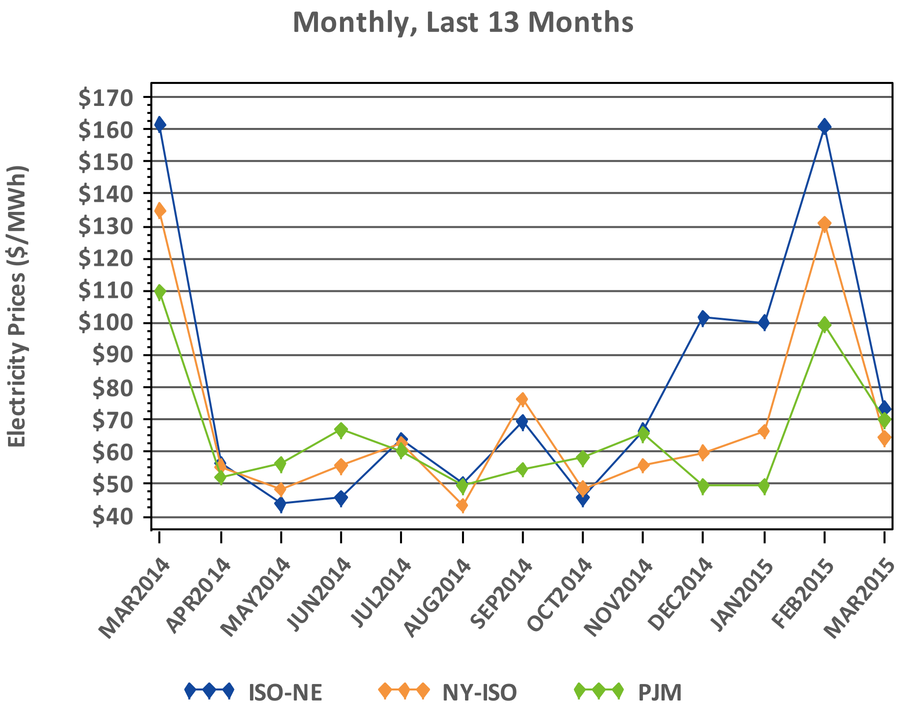

*Note: Hourly average prices are shown.

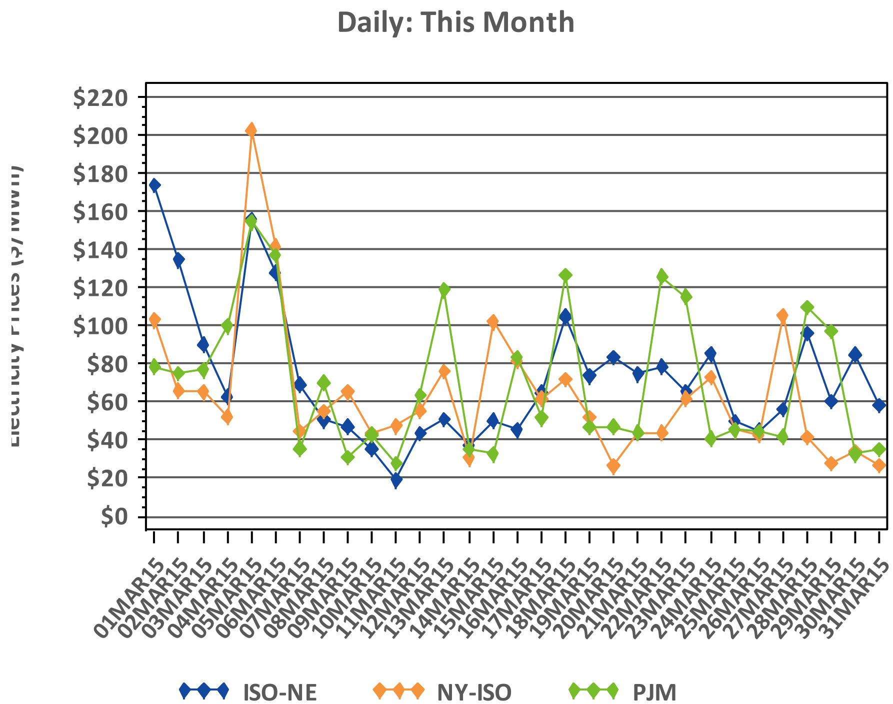
Daily: This Month




*Note: Hourly average prices are shown.

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



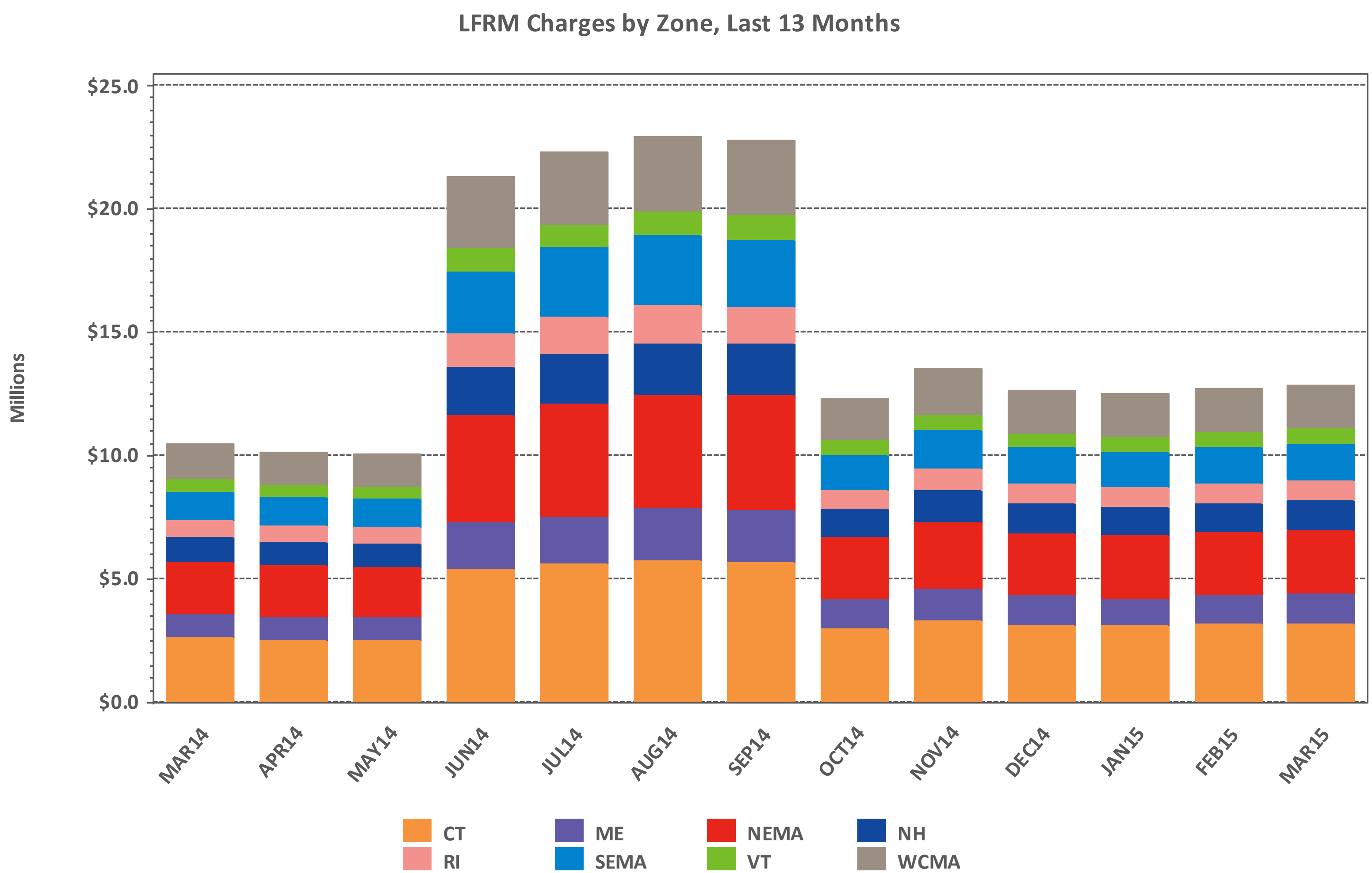

*Forecasted peak hour is reflected.

# Reserve Market Results – March 2015

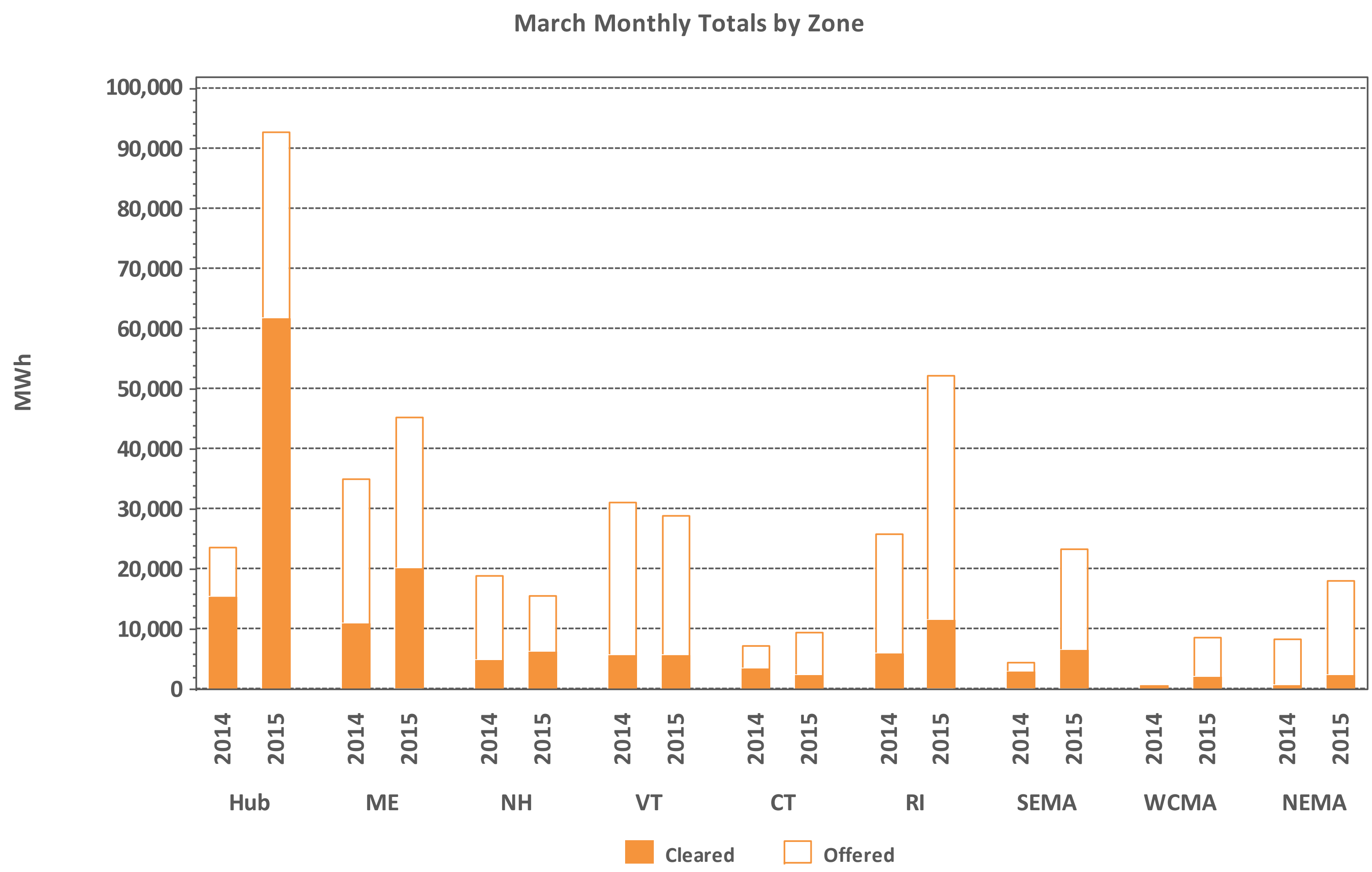
- Maximum potential Forward Reserve Market payments of \$13.8M were reduced by credit reductions of \$390K, failure-to-reserve penalties of \$584K and failure-to-activate penalties of \$0, resulting in a net payout of \$12.9M or 93% of maximum
  - Rest of System: \$7.34M/\$7.60M (97%)
  - Southwest Connecticut: \$0.92M/\$1.11M (83%)
  - Connecticut: \$4.60M/\$5.12M (90%)
- \$394K total Real-Time credits were reduced by \$0 in Forward Reserve Energy Obligation Charges for a net of \$394K in Real-Time Reserve payments
  - Rest of System: 124 hours, \$382K
  - Southwest Connecticut: 124 hours, \$8K
  - Connecticut: 124 hours, \$1K
  - NEMA: 124 hours, \$3K

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

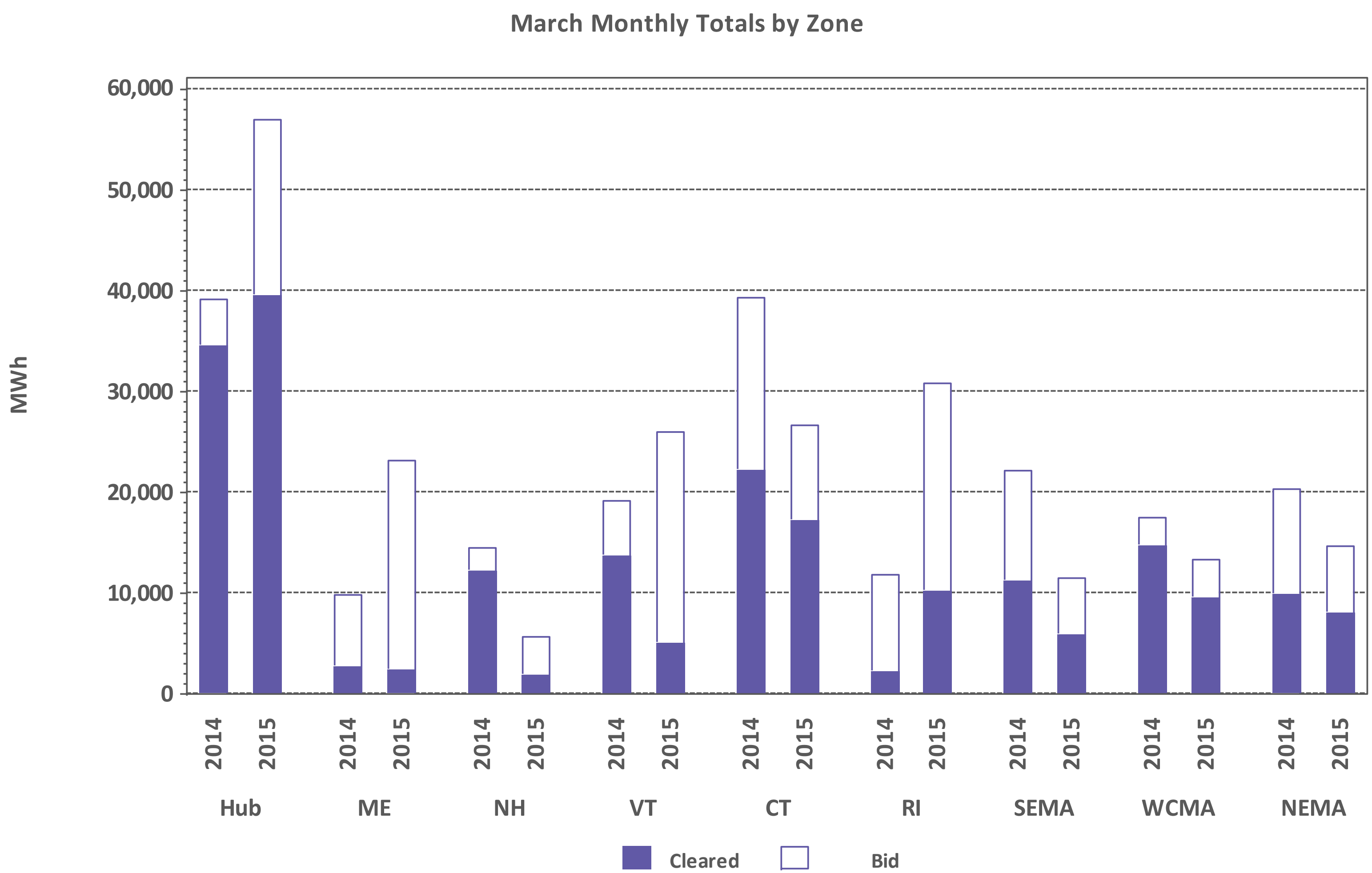
# LFRM Charges to Load by Load Zone ($)



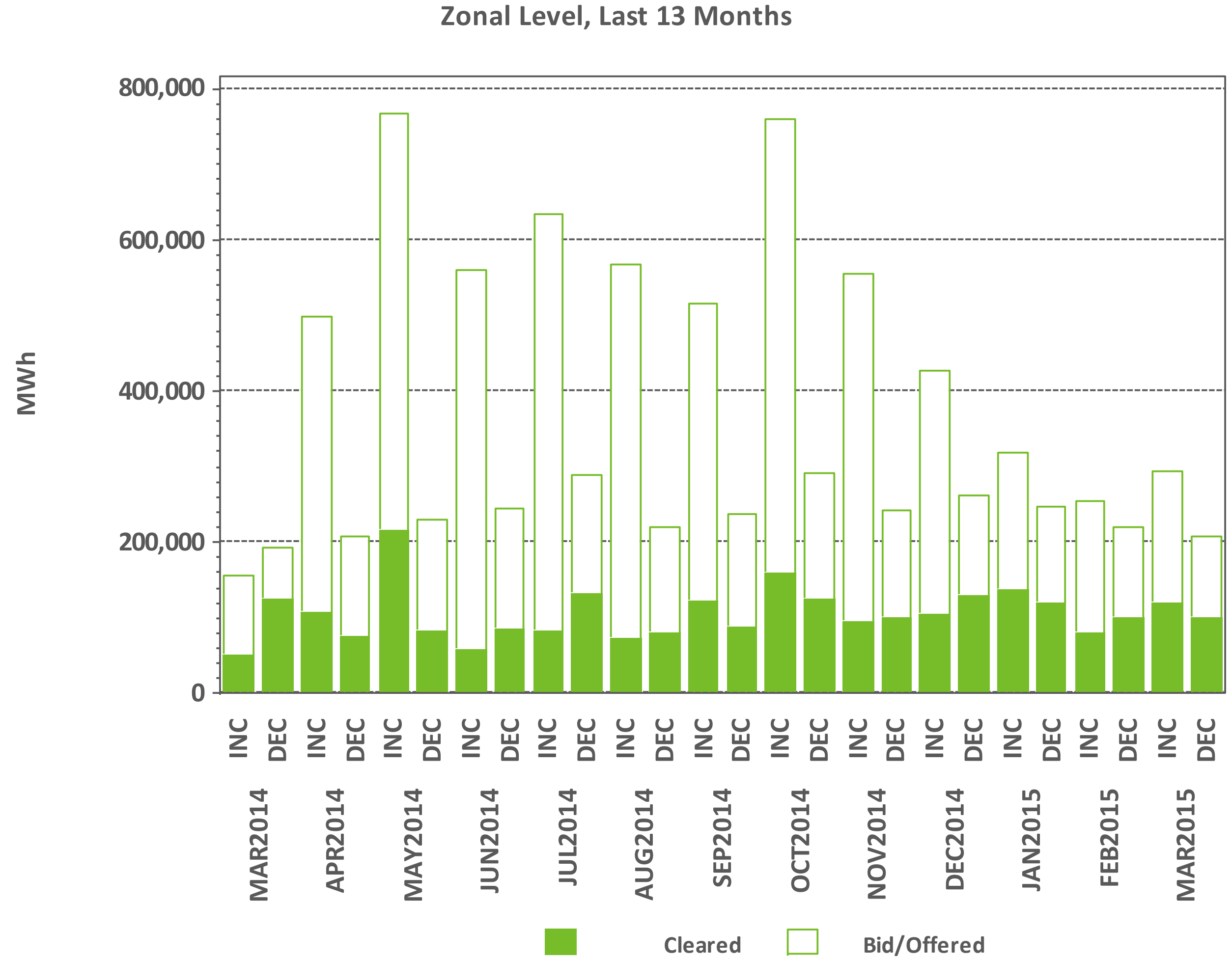
# Zonal Increment Offers and Cleared Amounts



# Zonal Decrement Bids and Cleared Amounts

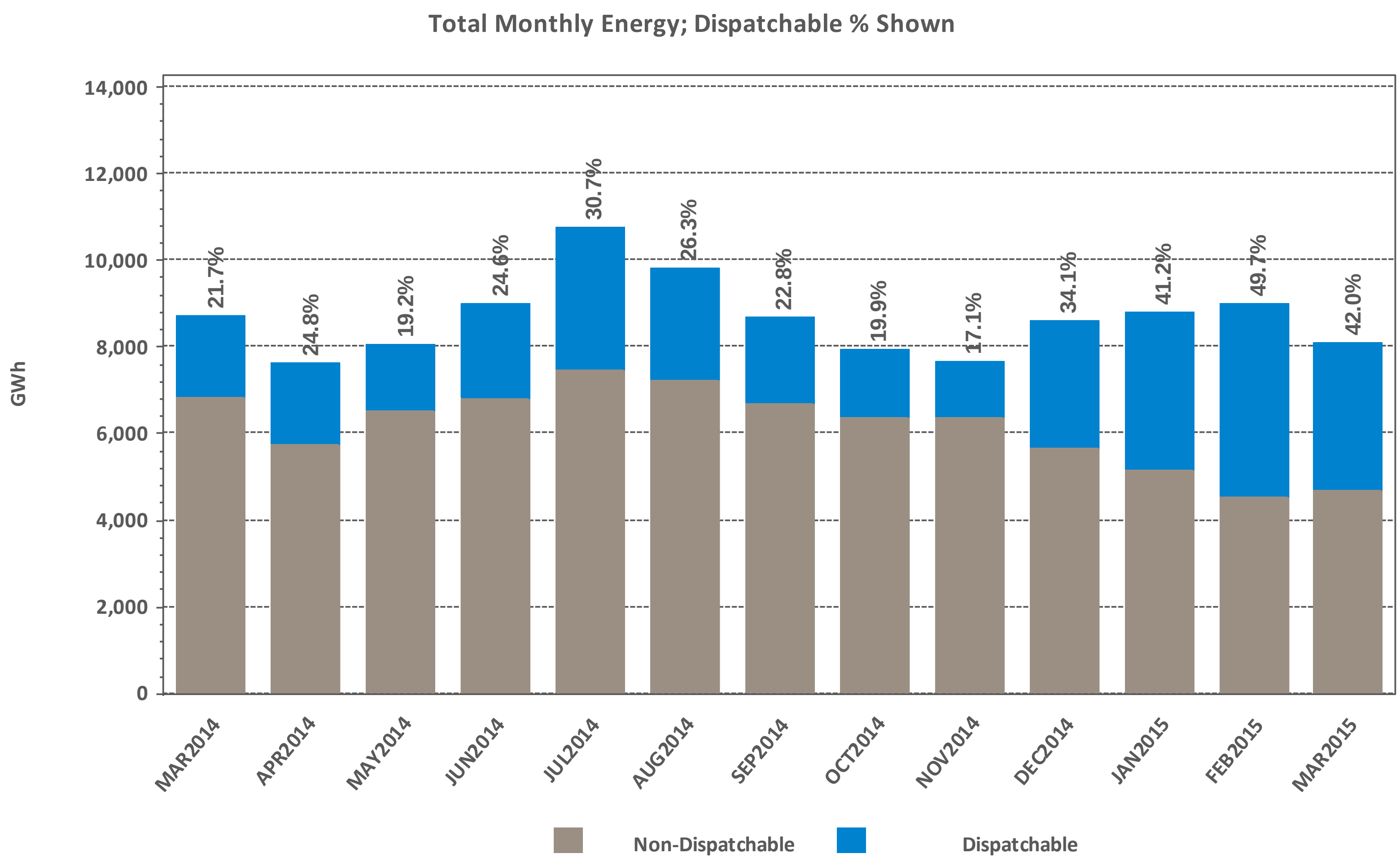


# Total Increment Offers and Decrement Bids



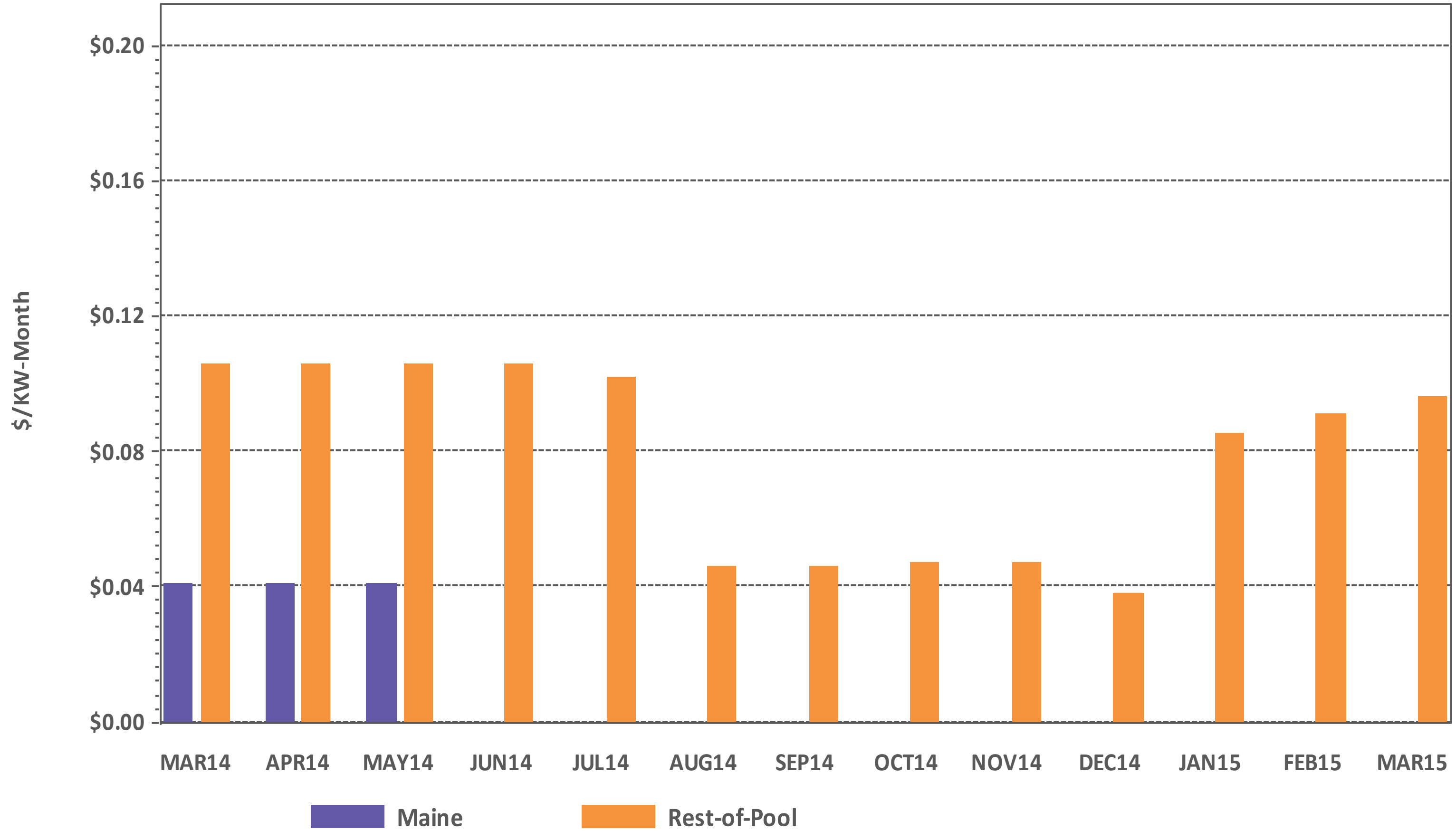

Data excludes nodal offers and bids

# 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).

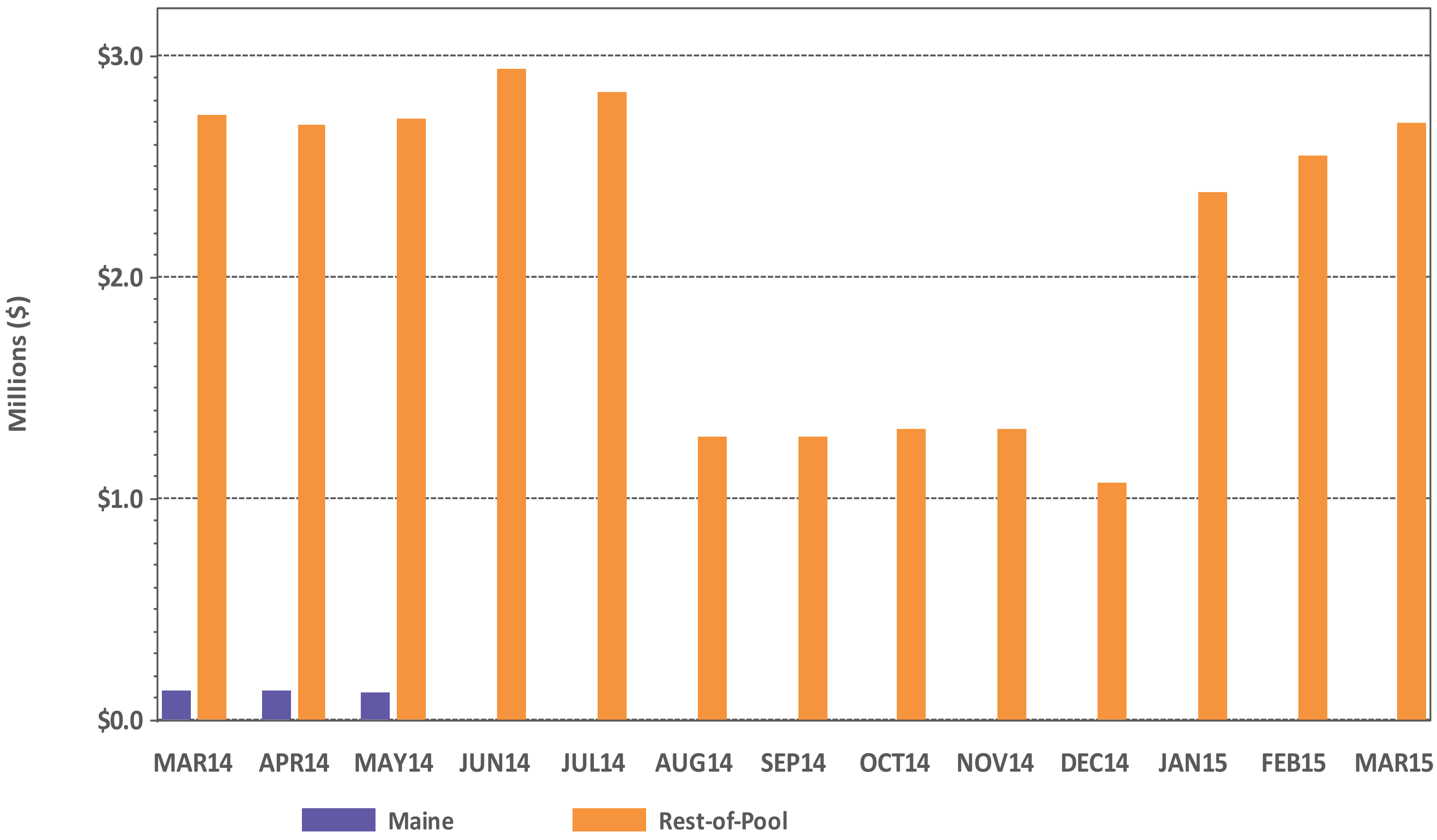
# Rolling Average Peak Energy Rent (PER)




**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) AND INTERREGIONAL PLANNING

# Planning Advisory Committee (PAC)

- The next PAC meeting is scheduled for April 22. Major agenda topics will include:
  - Post Winter 2014/15 Review
  - New England Gas Association Update
  - 2015 Economic Study Stakeholder Presentations
- Additional PAC meeting is slated for April 28. Major agenda topics will include:
  - ISO Discussion on Transmission Planning Methods and Assumptions
  - RSP15 Resource Adequacy Related Studies Scope of Work
  - RSP15 Load and Capacity Resource Overview

# Economic Study Requests

- Three economic study requests were submitted to the ISO and will be discussed with the PAC on April 22
- The ISO draft scope of work for economic studies is scheduled for discussion at the May PAC meeting

# Distributed Generation Forecast Working Group (DGFWG)

- DGFWG meeting is scheduled for April 14
  - Discussions will include stakeholder comments on the draft PV forecast, the final PV forecast, and the classification of the PV forecast into four types
- By the release of CELT 2015, the ISO plans on producing the final 2015 PV forecasts
  - Forecasts will show PV nameplate, estimated seasonal claimed capability, and energy production
  - Forecasts will be developed for the overall system, states, and RSP bubbles

# DGFWG, cont.

- ISO has classified PV resources by market participation type
  - FCM resources with capacity supply obligations
  - Settlement-only resources (energy market only)
  - Behind-the-meter resources that are already accounted for as part of the ISO load forecast
  - Remaining behind-the-meter resources
- ISO urges DG resources to participate in the FCM
- A portion of the behind-the-meter PV forecast has been identified as a part of the demand forecast that needs to be captured for purposes of Installed Capacity Requirement calculations
  - ISO will continue working with the PSPC and the RC to receive stakeholder input in preparation for FCA #10
- PV forecast will be used in new economic studies and new transmission planning studies
- 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

- FERC held technical conferences to consider the reliability implications of various compliance approaches to EPA's proposed June 2014 Clean Power Plan, regulating $CO_2$ emissions from existing generators
  – February 19, 2015 - National Overview (Washington, DC)
  – March 11, 2015 - Eastern Region (Washington, DC)
    - Steve Rourke and Bob Ethier participated indicating the following:
      – With RGGI, NEPOOL GIS tracking system and market rules to help with compliance, New England is already moving along on a clean energy path
      – Pay-for-Performance will ensure that existing generation retires from the market when it is no longer able to meet reliability needs and that new resources are actually able to meet those needs
      – ISO expects to work with the states to address reliability concerns
      – The IRC's proposed "reliability safety valve" is an important mechanism
      – Additional infrastructure will be necessary for natural gas generation and wind/hydro that will likely replace aging oil and coal resources

# 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 |

# NEEWS: Interstate Reliability Project

## *Status as of 4/6/15*

*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 | 3 |
| Card 345 kV Substation Expansion | Dec-15 | 3 |
| 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 |

# Maine Power Reliability Program (MPRP)

*Status as of 4/6/15*

*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 | Mar-15 | 4 |
| Construct New Section 3025 Coopers Mills to Larrabee Road | Apr-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 | 4 |
| Construct New Section 3022 Maguire Road to Eliot | Aug-14 | 4 |

* Scheduled to be in service April 13, 2015

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

# Maine Power Reliability Program, cont.

*Status as of 4/6/15*

*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 | Mar-15 | 4 |
| Construct New Section 243A Livermore Falls to Junction Section 243 | May-14 | 4 |
| Construct New Section 251 Livermore Falls to Larrabee Road | May-14 | 4 |
| Construct New Section 255 Larrabee Road to Middle Street | Mar-17 | 3 |
| Construct New Section 86A Tap to Belfast | Jul-14 | 4 |
| Construct New Section 256 Middle Street to Lewiston Lower | Mar-17 | 1 |

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

# Maine Power Reliability Program, cont.

*Status as of 4/6/15*

*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 | 4 |
| Rebuild Section 88 Coopers Mills to Augusta East Side | Feb-15 | 4 |
| Rebuild Section 89 Livermore Falls to Riley | May-14 | 4 |
| 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 |

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

# Maine Power Reliability Program, cont.

*Status as of 4/6/15*

*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 | Mar-15 | 4 |
| Install One 345/115 kV Autotransformer at Larrabee Road | Dec-12 | 4 |
| Install One 345/115 kV Autotransformer at Maguire Road | Apr-14 | 4 |
| Install One 345/115 kV Autotransformer at South Gorham | Nov-09 | 4 |

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

# New Hampshire/Vermont 10-Year Upgrades

*Status as of 4/6/15*

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

| Upgrade | Expected In-Service | Present Stage |
|---|---|---|
| Eagle Substation Add: 345/115 kV autotransformer | Dec-16 | 2 |
| 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-15 | 3 |
| New 115 kV overhead line, Scobie Pond-Huse Road | Dec-15 | 3 |
| New 115 kV overhead/submarine line, Madbury-Portsmouth | Dec-17 | 2 |
| New 115 kV overhead line, Scobie Pond-Chester | Dec-15 | 3 |
| New 115 kV overhead line, Coolidge-Ascutney | Dec-16 | 1 |

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

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

*Status as of 4/6/15*

*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 | 3 |
| 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 4/6/15*

*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 4/6/15*

*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-18 | 1 |
| 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 a 115 kV 37.8 MVAR capacitor bank | Dec-17 | 1 |
| Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation | Dec-16 | 1 |
| 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 | 1 |
| 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 | 1 |

* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut Projects, cont.*

*Status as of 4/6/15*

*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) | Dec-17 | 1 |
| Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443) | Dec-17 | 1 |
| Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor | Dec-18 | 1 |
| Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation | Dec-16 | 1 |
| Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation | Dec-17 | 1 |
| Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank | Dec-18 | 1 |
| Reconductor the 115 kV line between Newington and Newington Tap (1783) | Dec-18 | 1 |

* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut Projects, cont.*

*Status as of 4/6/15*

*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 | 1 |
| 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 | 1 |
| Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704) | Dec-18 | 1 |
| 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 | 1 |
| Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor | Dec-17 | 1 |
| Add a 345 kV breaker in series with breaker 5T at Southington | Dec-17 | 1 |

* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut Projects, cont.*

*Status as of 4/6/15*

*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 | 1 |
| Add a new 115 kV line from Frost Bridge to Campville | Dec-18 | 1 |
| 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 | 1 |
| Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1) | Dec-17 | 1 |
| Add a new 345/115 kV autotransformer at Barbour Hill substation | Dec-16 | 2 |
| Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation | Dec-16 | 2 |
| 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 4/6/15*

*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-17 | 1 |
| 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 | 1 |
| 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-17 | 1 |
| Loop the 1570 line in and out the Pootatuck substation | Dec-17 | 1 |
| Replace two 115 kV circuit breakers at the Freight substation | Dec-17 | 1 |

# Southwest Connecticut Projects, cont.

*Status as of 4/6/15*

*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-17 | 1 |
| Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887) | Dec-17 | 1 |
| Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR | Dec-17 | 1 |
| Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug) | Dec-17 | 1 |
| Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock) | Dec-17 | 1 |
| Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill | Dec-17 | 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 4/6/15*

*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-17 | 1 |
| Terminal equipment upgrade at the Newtown substation (1876) | Dec-17 | 1 |
| Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment | Dec-17 | 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 |

# Southwest Connecticut Projects, cont.

*Status as of 4/6/15*

*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 | Apr-16 | 2 |
| Upgrade the 115 kV bus at the Baird substation | Dec-17 | 1 |
| 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-16 | 2 |
| Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B) | May-18 | 1 |
| Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B) | Apr-19 | 1 |

# Southwest Connecticut Projects, cont.

*Status as of 4/6/15*

*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 | 1 |
| Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation | Dec-17 | 1 |
| Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers | Dec-17 | 1 |
| Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment | Dec-16 | 1 |
| Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B) | Dec-16 | 2 |
| Replace two 115 kV circuit breakers at Mill River | Dec-14 | 4 |

# Greater Boston Projects

*Status as of 4/6/15*

*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 | Dec-16 | 1 |
| Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury | Dec-16 | 1 |
| Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood | Jun-16 | 1 |
| Reconductor the F-158S 115 kV line from Maplewood to Everett | Jun-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 | 1 |
| Reconductor W-23W 69 kV line from Woodside to Northboro Road | Jun-16 | 1 |

# Greater Boston Projects, cont.

*Status as of 4/6/15*

*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 | Dec-15 | 1 |
| Separate Q-169 and F-158N DCT | Dec-15 | 1 |
| Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap | May-17 | 1 |
| 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 | 1 |
| 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 | 1 |
| Install a new 115 kV line from Sudbury to Hudson | Dec-18 | 1 |

# Greater Boston Projects, cont.

*Status as of 4/6/15*

*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 | 1 |
| Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations | Dec-15 | 1 |
| Install a new 115 kV 54 MVAR capacitor bank at Newton | Dec-16 | 1 |
| Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury | Dec-16 | 1 |
| 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-15 | 1 |
| 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 4/6/15*

*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 | 1 |

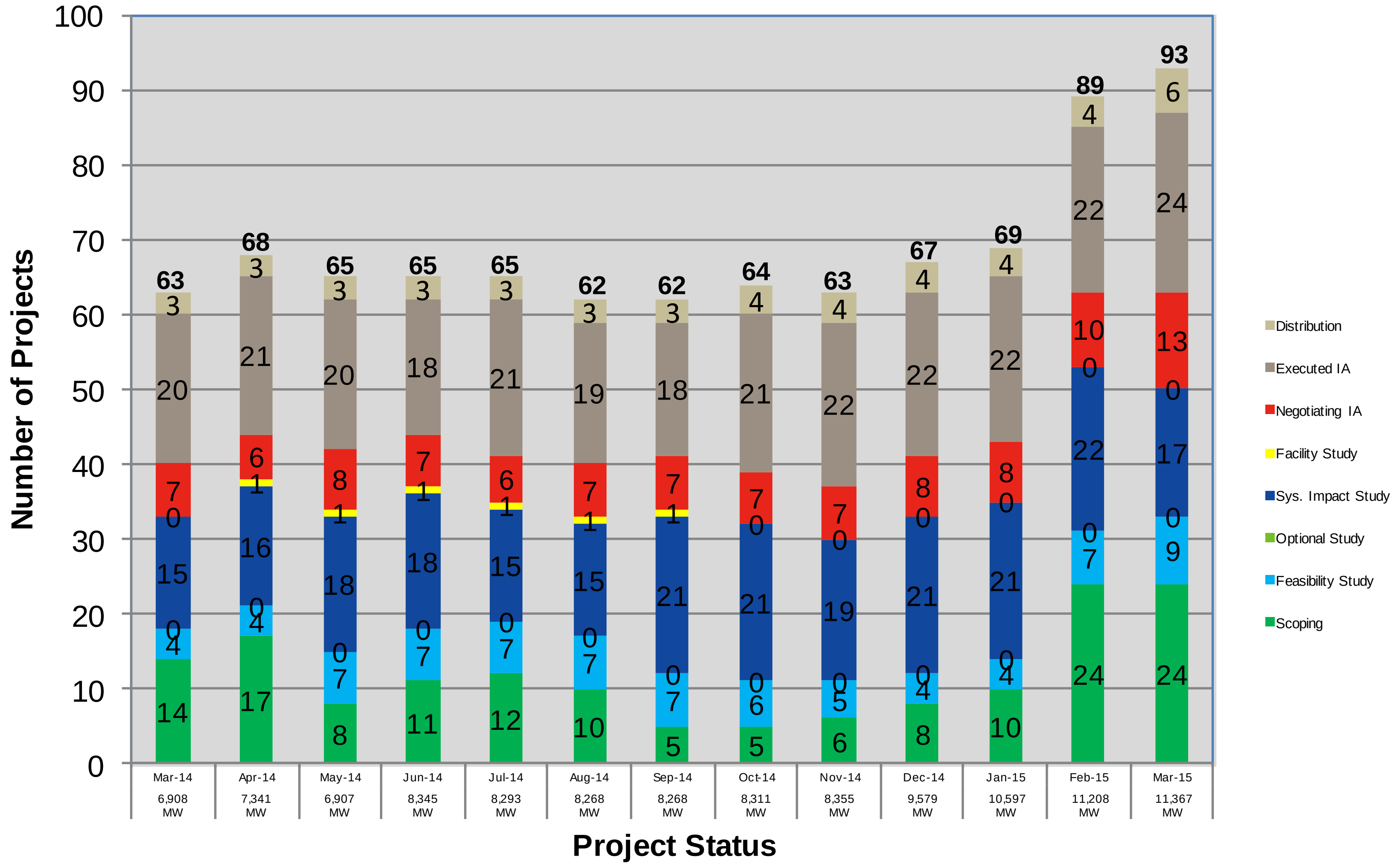
# Greater Boston Projects, cont.

*Status as of 4/6/15*

*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 | 1 |
| 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 | 1 |
| Install a 200 MVAR STATCOM at Coopers Mills | TBD | 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 | 1 |
| Install a 115 kV breaker in series with the 29 breaker at K Street | Dec-15 | 1 |

# Status of Tariff Studies

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# OPERABLE CAPACITY ANALYSIS

*Spring 2015*

# Spring 2015 Operable Capacity Analysis

| 50/50 Load Forecast (Reference) | May - 2015[2] CSO | May- 2015[2] SCC |
|---|---|---|
| Generator Operable Capacity MW [1] | 29,887 | 32,828 |
| OP CAP From OP-4 RTDR (+) | 468 | 468 |
| OP CAP From OP-4 RTEG (+) | 195 | 195 |
| Operable Capacity Generator with OP-4 DR and RTEG | 30,550 | 33,491 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 528 | 528 |
| Non Commercial Capacity (+) | 0 | 87 |
| Non Gas-fired Planned Outage MW (-) | 2,737 | 3,047 |
| Gas Generator Outages MW (-) | 823 | 988 |
| Allowance for Unplanned Outages (-) | 3,400 | 3,400 |
| Generation at Risk Due to Gas Supply (-) [4] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 24,118 | 26,671 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 19,945 | 19,945 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 22,320 | 22,320 |
| Operable Capacity Margin [3] | 1,798 | 4,351 |

[1] Generator Operable Capacity is based on data as of **March 25, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

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

[3] Includes OP4 actions associated with RTEG and RTDR

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

# Spring 2015 Operable Capacity Analysis

| 90/10 Load Forecast (Extreme) | May - 2015[2] CSO | May - 2015[2] SCC |
|---|---|---|
| Generator Operable Capacity MW [1] | 29,887 | 32,828 |
| OP CAP From OP-4 RTDR (+) | 468 | 468 |
| OP CAP From OP-4 RTEG (+) | 195 | 195 |
| Operable Capacity Generator with OP-4 DR and RTEG | 30,550 | 33,491 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 622 | 622 |
| Non Commercial Capacity (+) | 0 | 87 |
| Non Gas-fired Planned Outage MW (-) | 916 | 1,030 |
| Gas Generator Outages MW (-) | 778 | 862 |
| Allowance for Unplanned Outages (-) | 3,400 | 3,400 |
| Generation at Risk Due to Gas Supply (-) [4] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 26,078 | 28,908 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 23,802 | 23,802 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 26,177 | 26,177 |
| Operable Capacity Margin [3] | (99) | 2,731 |

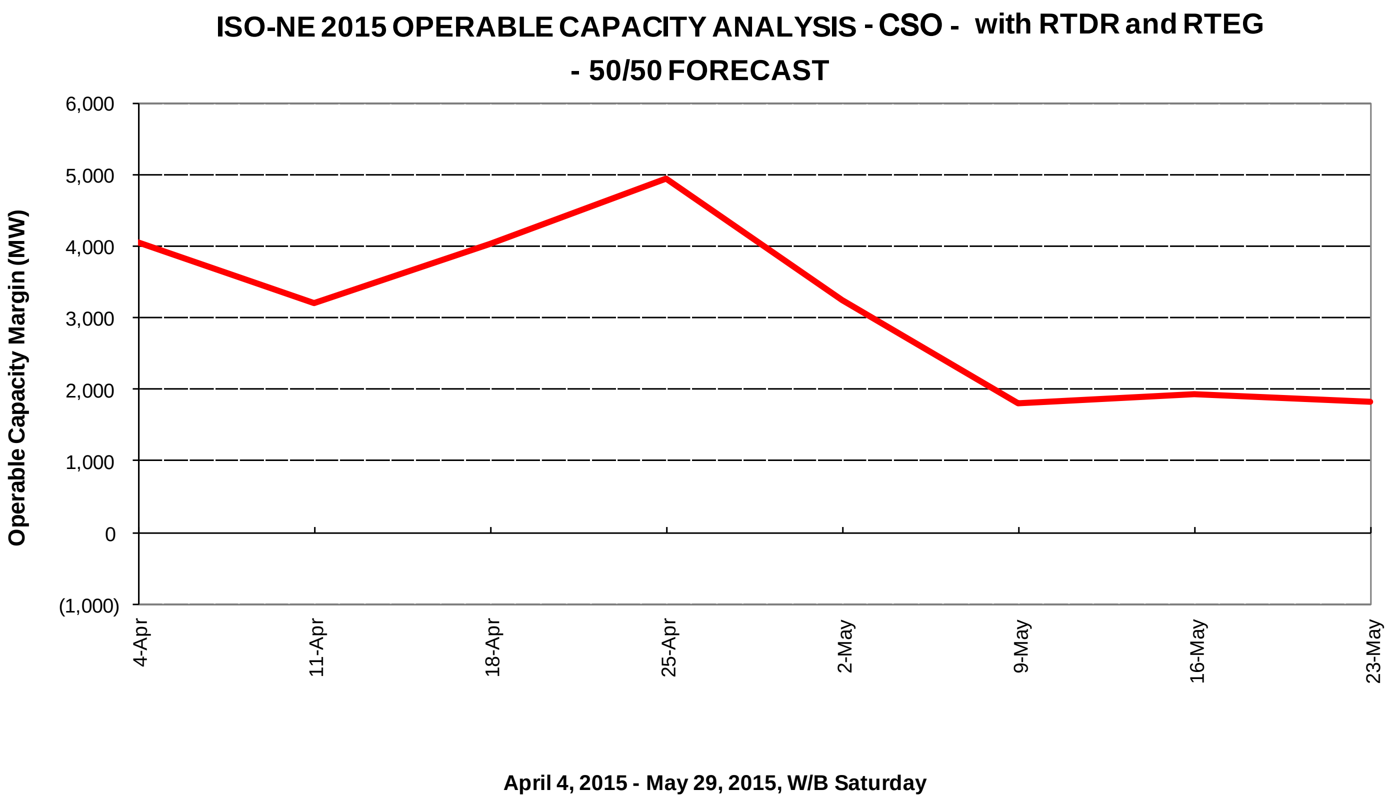
[1] Generator Operable Capacity is based on data as of **March 25, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Load based on preliminary 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **May 23, 2015**.

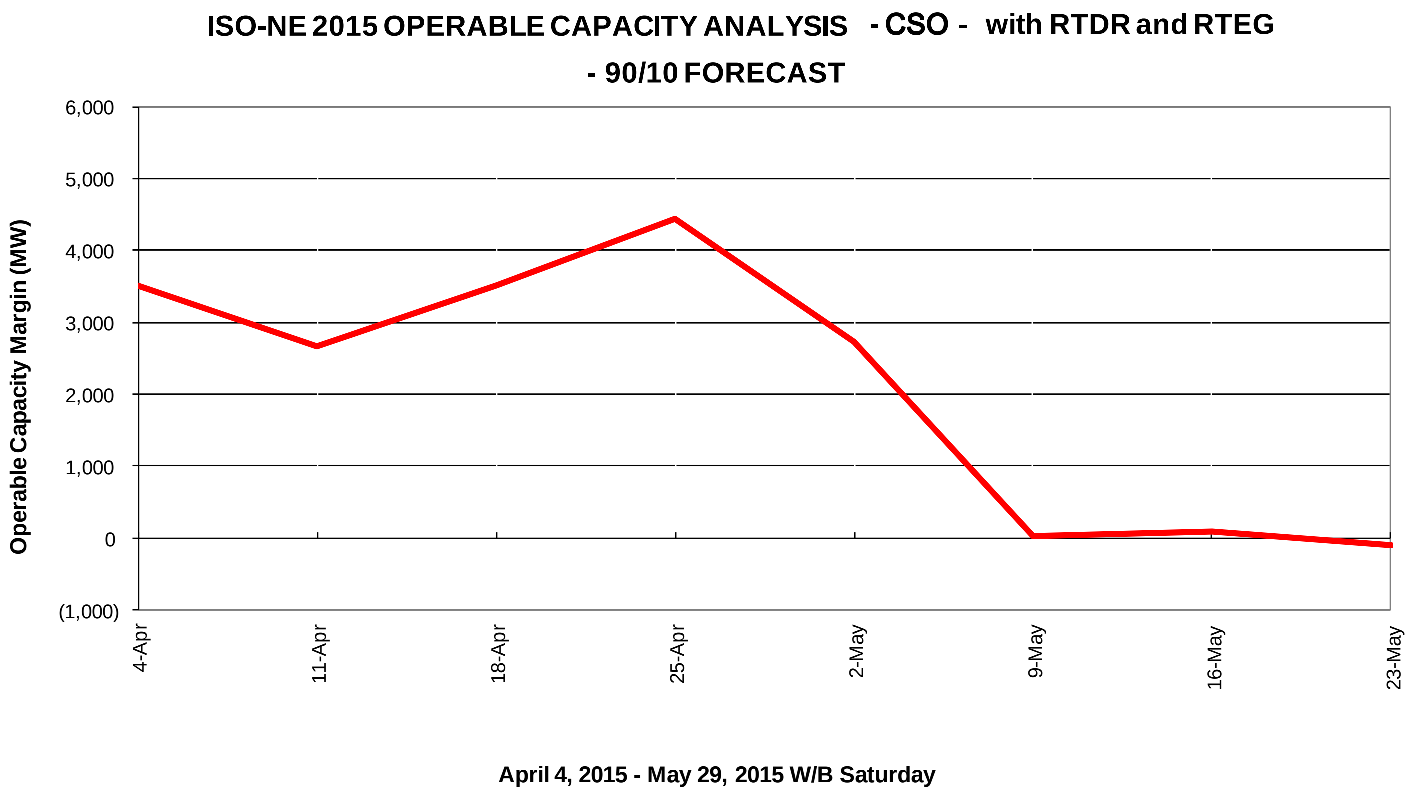
[3] Includes OP4 actions associated with RTEG and RTDR

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

# Spring 2015 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)



# Spring 2015 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)



# Spring 2015 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)

## ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

### April 10, 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 | EXTERNAL NODE AVAIL CAPACITY MW | NON COMMERCIAL CAPACITY MW | NON-GAS PLANNED OUTAGES CSO MW | GAS GENERATOR OUTAGES CSO MW | ALLOWANCE FOR UNPLANNED OUTAGES MW | GAS AT RISK MW | NET OPCAP SUPPLY MW | PEAK LOAD FORECAST MW | OPER RESERVE REQUIREMENT MW | NET LOAD OBLIGATION MW | OPCAP MARGIN MW | OPCAP FROM OP4 ACTIVE REAL-TIME DR MW | OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW | OPCAP FROM OP4 REAL-TIME EMER. GEN MW | OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
| 4/4/2015 | 30,057 | 660 | 0 | 3,045 | 1,691 | 2,700 | 0 | 23,281 | 17,313 | 2,375 | 19,688 | 3,593 | 319 | 3,912 | 141 | 4,053 |
| 4/11/2015 | 30,057 | 660 | 0 | 3,463 | 2,377 | 2,700 | 0 | 22,177 | 17,057 | 2,375 | 19,432 | 2,745 | 319 | 3,064 | 141 | 3,205 |
| 4/18/2015 | 30,057 | 266 | 0 | 3,893 | 1,243 | 2,700 | 0 | 22,487 | 16,539 | 2,375 | 18,914 | 3,573 | 319 | 3,892 | 141 | 4,033 |
| 4/25/2015 | 30,057 | 660 | 0 | 3,478 | 705 | 3,400 | 0 | 23,134 | 16,270 | 2,375 | 18,645 | 4,489 | 319 | 4,808 | 141 | 4,949 |
| 5/2/2015 | 29,887 | 622 | 0 | 4,879 | 1,034 | 3,400 | 0 | 21,196 | 16,243 | 2,375 | 18,618 | 2,578 | 468 | 3,046 | 195 | 3,241 |
| **5/9/2015** | **29,887** | **528** | **0** | **2,737** | **823** | **3,400** | **0** | **23,455** | **19,945** | **2,375** | **22,320** | **1,135** | **468** | **1,603** | **195** | **1,798** |
| 5/16/2015 | 29,887 | 622 | 0 | 1,399 | 1,118 | 3,400 | 0 | 24,592 | 20,942 | 2,375 | 23,317 | 1,275 | 468 | 1,743 | 195 | 1,938 |
| 5/23/2015 | 29,887 | 622 | 0 | 916 | 778 | 3,400 | 0 | 25,415 | 21,868 | 2,375 | 24,243 | 1,172 | 468 | 1,640 | 195 | 1,835 |

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 125% 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).

# Spring 2015 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)

## ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

### April 10, 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] |
| 4/4/2015 | 30,057 | 660 | 0 | 3,045 | 1,691 | 2,700 | 0 | 23,281 | 17,862 | 2,375 | 20,237 | 3,044 | 319 | 3,363 | 141 | 3,504 |
| 4/11/2015 | 30,057 | 660 | 0 | 3,463 | 2,377 | 2,700 | 0 | 22,177 | 17,599 | 2,375 | 19,974 | 2,203 | 319 | 2,522 | 141 | 2,663 |
| 4/18/2015 | 30,057 | 266 | 0 | 3,893 | 1,243 | 2,700 | 0 | 22,487 | 17,066 | 2,375 | 19,441 | 3,046 | 319 | 3,365 | 141 | 3,506 |
| 4/25/2015 | 30,057 | 660 | 0 | 3,478 | 705 | 3,400 | 0 | 23,134 | 16,789 | 2,375 | 19,164 | 3,970 | 319 | 4,289 | 141 | 4,430 |
| 5/2/2015 | 29,887 | 622 | 0 | 4,879 | 1,034 | 3,400 | 0 | 21,196 | 16,761 | 2,375 | 19,136 | 2,060 | 468 | 2,528 | 195 | 2,723 |
| 5/9/2015 | 29,887 | 528 | 0 | 2,737 | 823 | 3,400 | 0 | 23,455 | 21,721 | 2,375 | 24,096 | (641) | 468 | (173) | 195 | 22 |
| 5/16/2015 | 29,887 | 622 | 0 | 1,399 | 1,118 | 3,400 | 0 | 24,592 | 22,800 | 2,375 | 25,175 | (583) | 468 | (115) | 195 | 80 |
| **5/23/2015** | **29,887** | **622** | **0** | **916** | **778** | **3,400** | **0** | **25,415** | **23,802** | **2,375** | **26,177** | **(762)** | **468** | **(294)** | **195** | **(99)** |

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 125% 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).

# OPERABLE CAPACITY ANALYSIS

*Preliminary Summer 2015*

# Preliminary Summer 2015 Operable Capacity Analysis

| 50/50 Load Forecast (Reference) | June - 2015[2] CSO | June - 2015[2] SCC |
|---|---|---|
| Generator Operable Capacity MW [1] | 29,576 | 30,239 |
| OP CAP From OP-4 RTDR (+) | 446 | 446 |
| OP CAP From OP-4 RTEG (+) | 192 | 192 |
| Operable Capacity Generator with OP-4 DR and RTEG | 30,214 | 30,877 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 1,237 | 1,237 |
| Non Commercial Capacity (+) | 0 | 87 |
| Non Gas-fired Planned Outage MW (-) | 0 | 0 |
| Gas Generator Outages MW (-) | 0 | 0 |
| Allowance for Unplanned Outages (-) | 2,800 | 2,800 |
| Generation at Risk Due to Gas Supply (-) [4] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 28,651 | 29,401 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 26,710 | 26,710 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 29,085 | 29,085 |
| Operable Capacity Margin [3] | (434) | 316 |

[1] Generator Operable Capacity is based on data as of **March 25, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Load based on preliminary 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **May 30, 2015**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

# Preliminary Summer 2015 Operable Capacity Analysis

| 90/10 Load Forecast (Extreme) | June - 2015[2] CSO | June - 2015[2] SCC |
|---|---|---|
| Generator Operable Capacity MW [1] | 29,576 | 30,239 |
| OP CAP From OP-4 RTDR (+) | 446 | 446 |
| OP CAP From OP-4 RTEG (+) | 192 | 192 |
| Operable Capacity Generator with OP-4 DR and RTEG | 30,214 | 30,877 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 1,237 | 1,237 |
| Non Commercial Capacity (+) | 0 | 87 |
| Non Gas-fired Planned Outage MW (-) | 0 | 0 |
| Gas Generator Outages MW (-) | 0 | 0 |
| Allowance for Unplanned Outages (-) | 2,800 | 2,800 |
| Generation at Risk Due to Gas Supply (-) [4] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 28,651 | 29,401 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 29,060 | 29,060 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 31,435 | 31,435 |
| Operable Capacity Margin [3] | (2,784) | (2,034) |

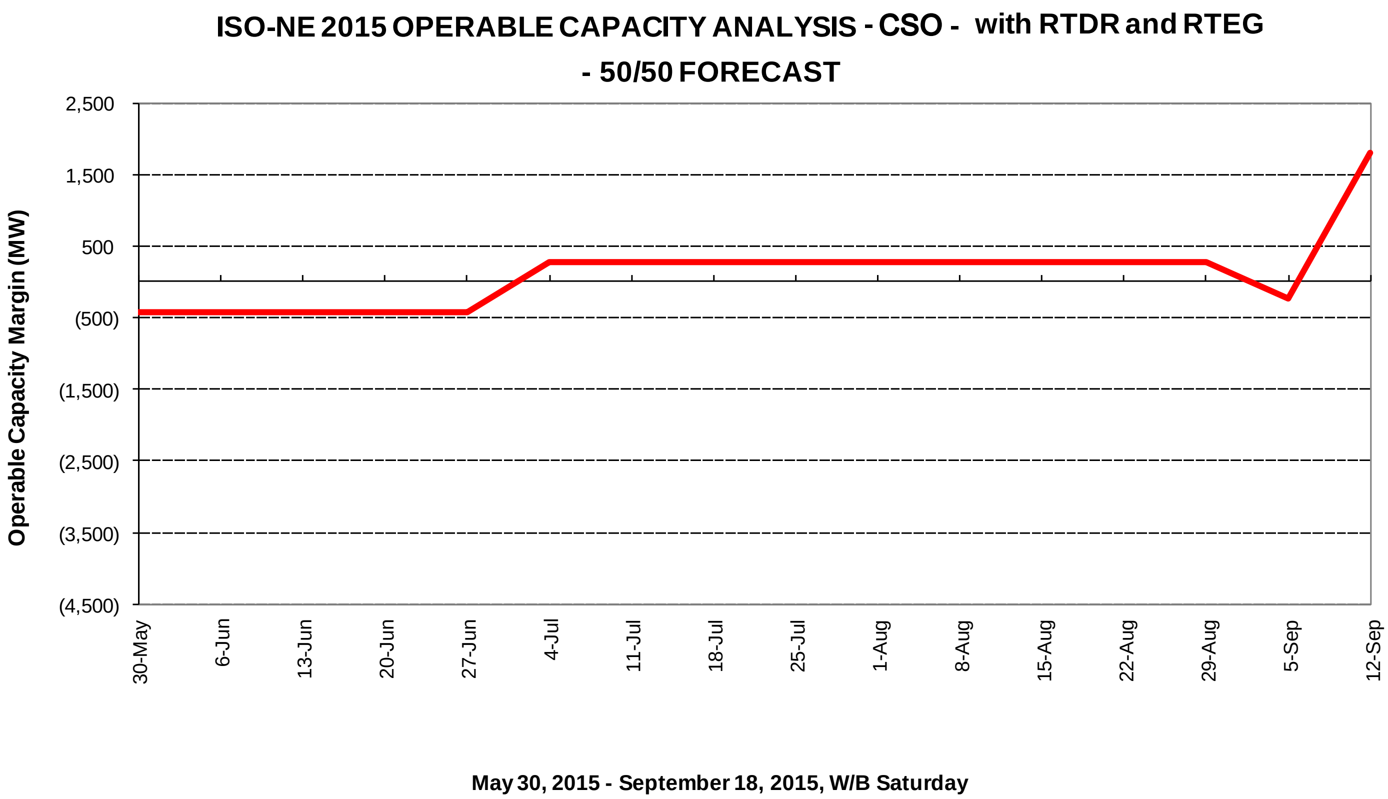
[1] Generator Operable Capacity is based on data as of **March 25, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Load based on preliminary 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **May 30, 2015**.

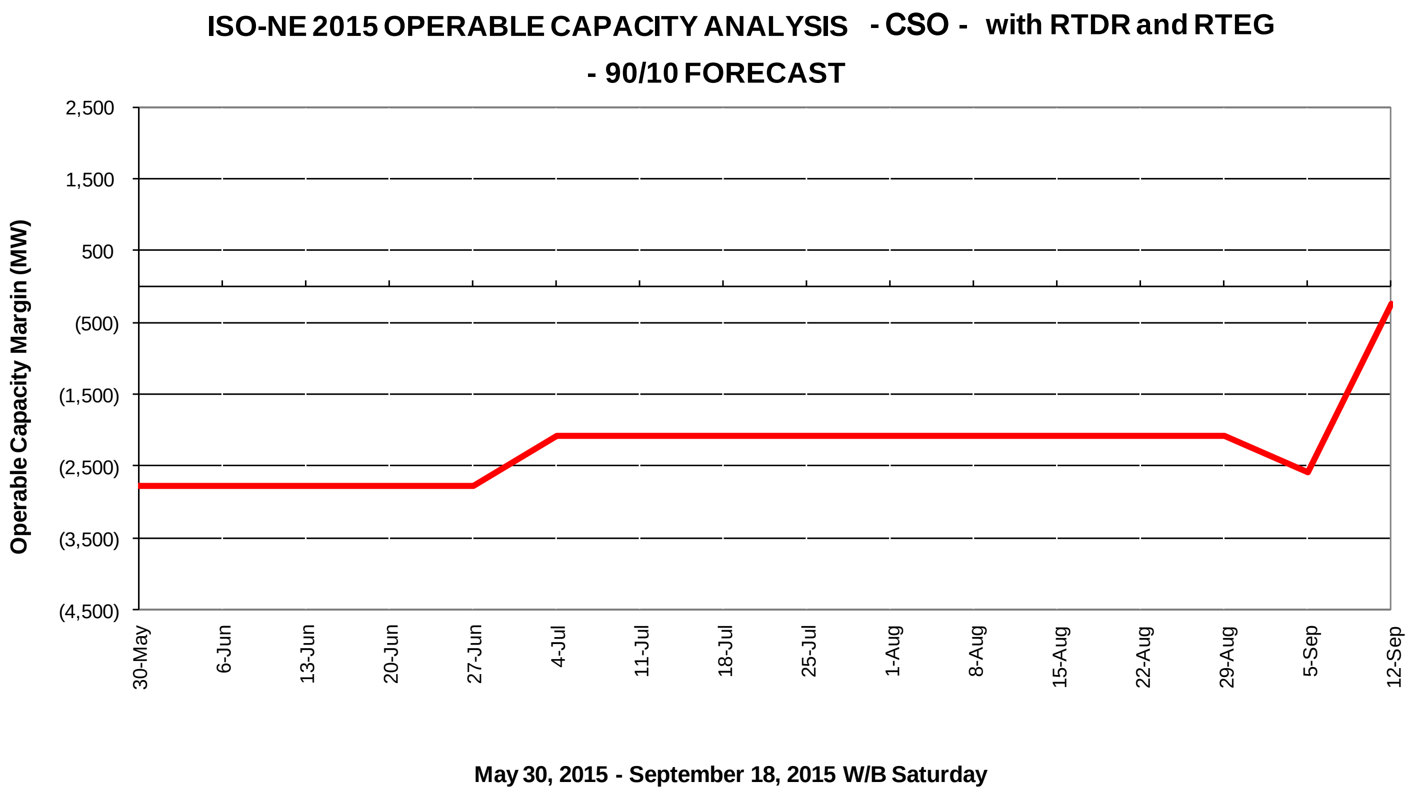
[3] Includes OP4 actions associated with RTEG and RTDR

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

# Preliminary Summer 2015 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)



# Preliminary Summer 2015 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)



# Preliminary Summer 2015 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)

## ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

### April 10, 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 | EXTERNAL NODE AVAIL CAPACITY MW | NON COMMERCIAL CAPACITY MW | NON-GAS PLANNED OUTAGES CSO MW | GAS GENERATOR OUTAGES CSO MW | ALLOWANCE FOR UNPLANNED OUTAGES MW | GAS AT RISK MW | NET OPCAP SUPPLY MW | PEAK LOAD FORECAST MW | OPER RESERVE REQUIREMENT MW | NET LOAD OBLIGATION MW | OPCAP MARGIN MW | OPCAP FROM OP4 ACTIVE REAL-TIME DR MW | OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW | OPCAP FROM OP4 REAL-TIME EMER. GEN MW | OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
| **5/30/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **26,710** | **2,375** | **29,085** | **(1,072)** | **446** | **(626)** | **192** | **(434)** |
| **6/6/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **26,710** | **2,375** | **29,085** | **(1,072)** | **446** | **(626)** | **192** | **(434)** |
| **6/13/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **26,710** | **2,375** | **29,085** | **(1,072)** | **446** | **(626)** | **192** | **(434)** |
| **6/20/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **26,710** | **2,375** | **29,085** | **(1,072)** | **446** | **(626)** | **192** | **(434)** |
| **6/27/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **26,710** | **2,375** | **29,085** | **(1,072)** | **446** | **(626)** | **192** | **(434)** |
| 7/4/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 7/11/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 7/18/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 7/25/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 8/1/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 8/8/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 8/15/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 8/22/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 26,710 | 2,375 | 29,085 | (372) | 446 | 74 | 192 | 266 |
| 8/29/2015 | 29,576 | 1,237 | 6 | 0 | 0 | 2,100 | 0 | 28,719 | 26,710 | 2,375 | 29,085 | (366) | 446 | 80 | 192 | 272 |
| 9/5/2015 | 29,576 | 1,237 | 6 | 12 | 493 | 2,100 | 0 | 28,214 | 26,710 | 2,375 | 29,085 | (871) | 446 | (425) | 192 | (233) |
| 9/12/2015 | 29,576 | 1,237 | 6 | 1,361 | 802 | 2,100 | 0 | 26,556 | 23,016 | 2,375 | 25,391 | 1,165 | 446 | 1,611 | 192 | 1,803 |

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 125% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

# Preliminary Summer 2015 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)

## ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

### April 10, 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 GENERATOR 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] |
| **5/30/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **29,060** | **2,375** | **31,435** | **(3,422)** | **446** | **(2,976)** | **192** | **(2,784)** |
| **6/6/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **29,060** | **2,375** | **31,435** | **(3,422)** | **446** | **(2,976)** | **192** | **(2,784)** |
| **6/13/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **29,060** | **2,375** | **31,435** | **(3,422)** | **446** | **(2,976)** | **192** | **(2,784)** |
| **6/20/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **29,060** | **2,375** | **31,435** | **(3,422)** | **446** | **(2,976)** | **192** | **(2,784)** |
| **6/27/2015** | **29,576** | **1,237** | **0** | **0** | **0** | **2,800** | **0** | **28,013** | **29,060** | **2,375** | **31,435** | **(3,422)** | **446** | **(2,976)** | **192** | **(2,784)** |
| 7/4/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 7/11/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 7/18/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 7/25/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 8/1/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 8/8/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 8/15/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 8/22/2015 | 29,576 | 1,237 | 0 | 0 | 0 | 2,100 | 0 | 28,713 | 29,060 | 2,375 | 31,435 | (2,722) | 446 | (2,276) | 192 | (2,084) |
| 8/29/2015 | 29,576 | 1,237 | 6 | 0 | 0 | 2,100 | 0 | 28,719 | 29,060 | 2,375 | 31,435 | (2,716) | 446 | (2,270) | 192 | (2,078) |
| 9/5/2015 | 29,576 | 1,237 | 6 | 12 | 493 | 2,100 | 0 | 28,214 | 29,060 | 2,375 | 31,435 | (3,221) | 446 | (2,775) | 192 | (2,583) |
| 9/12/2015 | 29,576 | 1,237 | 6 | 1,361 | 802 | 2,100 | 0 | 26,556 | 25,060 | 2,375 | 27,435 | (879) | 446 | (433) | 192 | (241) |

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 125% 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).

# OPERABLE CAPACITY ANALYSIS

*Appendix*

# Possible Relief Under OP4 based on OP4 Appendix A

| OP 4 Action Number | Page 1 of 2<br>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.<br>Begin to allow depletion of 30-minute reserve. | 0 [1]<br><br>600 |
| 2 | Dispatch real time Demand Resources. | **April 319** [3]<br>**May 468** [3]<br>**June – September 446** [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<br><br>Dispatch real time Emergency Generation | 133 [4]<br>**April 141** [3]<br>**May 195** [3]<br>**June – September 192** [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 March 25, 2015.
4. The MW values are based on a 26,658 MW system load and the most recent voltage reduction test % achieved.

# Possible Relief Under OP4 based on OP4 Appendix A

| OP 4 Action Number | Page 2 of 2<br>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 | 267 [4] |
| 9 | Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.<br><br>Voluntary Load Curtailment by Large Industrial and Commercial Customers. | 5<br><br>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 3,005 MW**<br>**May 3,208 MW**<br>**June – September 3,183 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 25, 2015.
4. The MW values are based on a 26,658 MW system load and the most recent voltage reduction test % achieved.