NEPOOL Participants Committee Report

June 2015 Markets & Operations Data – Not a Full Report

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

- Highlights Page 3
- System Operations Page 6
- Market Operations Page 9
- Back-Up Detail Page 25
  - Load Response Page 26
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs Page 28

Highlights

- Average natural gas prices ($<1.90/MMBtu), DA LMPs ($21.16/MWh), RT LMPs ($19.61/MWh) all were the lowest since SMD
- June Energy Market Value was ($246M), the lowest since SMD

Underlying natural gas data furnished by:

ICE Global markets in clear view

Highlights, cont.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was $246M over the period, down $29M from May 2015 and down $186M from June 2014
  - June natural gas prices over the period were 11.6% lower than May 2015 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 25% lower than May 2015 averages
  - Average June 2015 natural gas prices and RT Hub LMPs over the period were down 57% and 48%, respectively, from June 2014 averages
- Average DA cleared physical energy in the peak hours as percent of forecasted load was 97.9% during June, down from 98.7% during May

Underlying natural gas data furnished by:

ICE Global markets in clear view

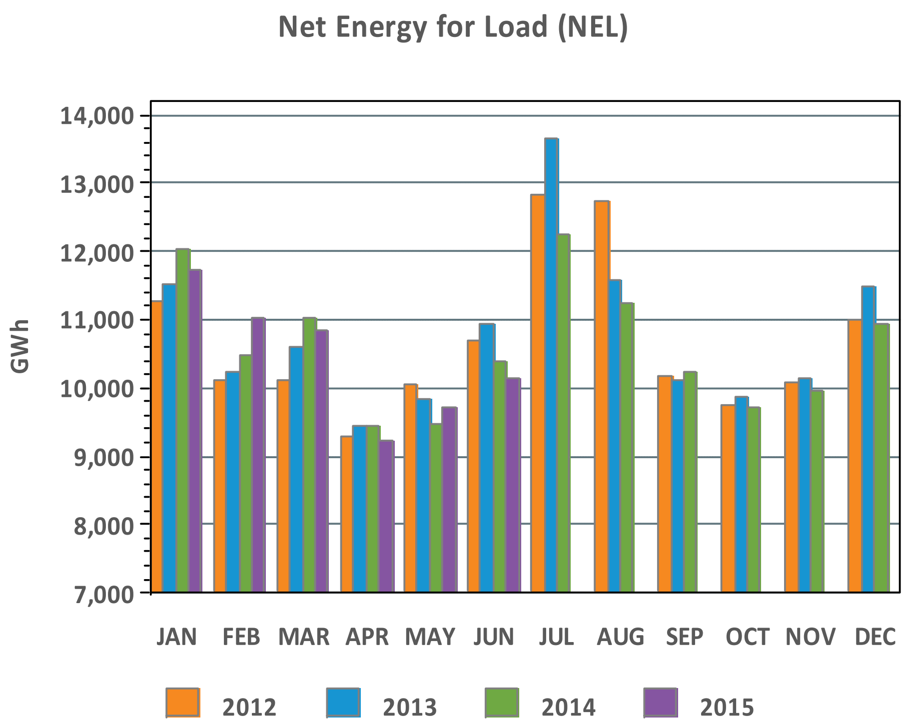
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Highlights, cont.

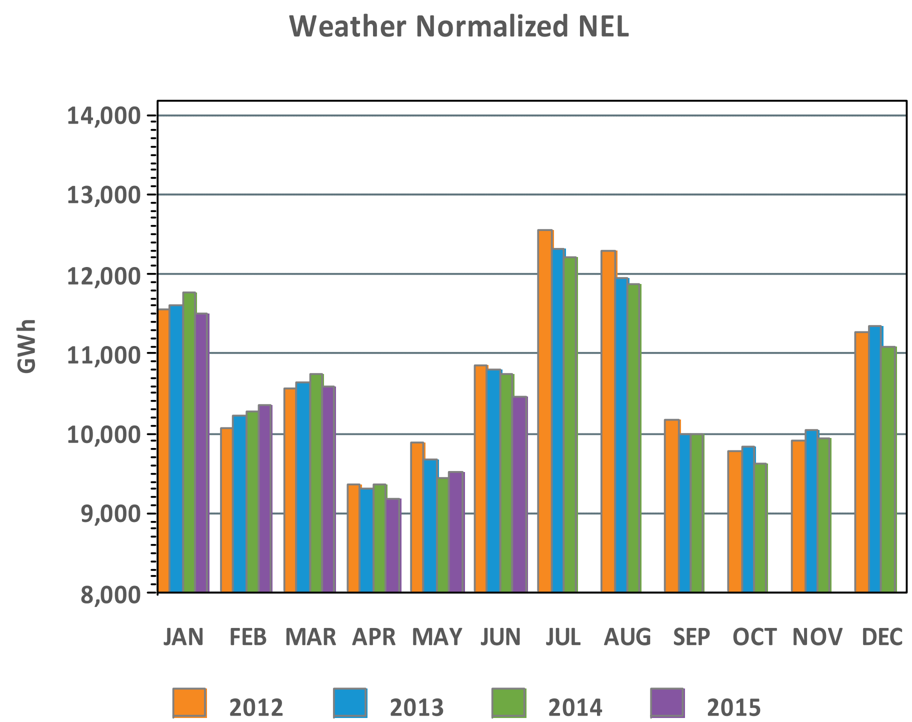
- Daily Net Commitment Period Compensation (NCPC)
  - June NCPC payments totaled $9.4M, up $3.1M from May and up $3.5M from June 2014
  - First Contingency payments totaled $4.7M, up $312K from May
    - $4.4M paid to internal resources, up $145K from May
      - $466K charged to DALO, $4.0M to RT Deviations
    - $219K paid to resources at external locations, up $168K from May
  - Second Contingency payments totaled $4.6M, up $2.6M from the May total of $2.0M
    - Driven by NEMA reliability commitments
    - A reallocation of $1.8M of these charges to NEMA network load is scheduled
  - Voltage payments were $193K, up $193K from May
  - NCPC payments over the period as percent of Energy Market value were 3.8%

SYSTEM OPERATIONS

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



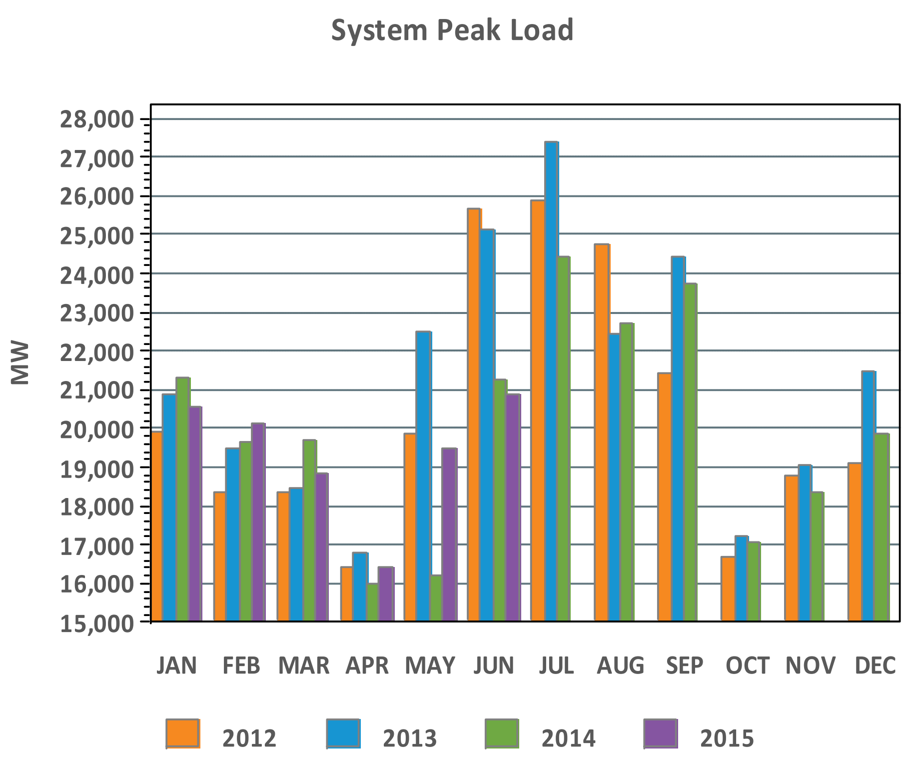
Ann Tot (TWh): 128.1 129.4 127.2 62.7

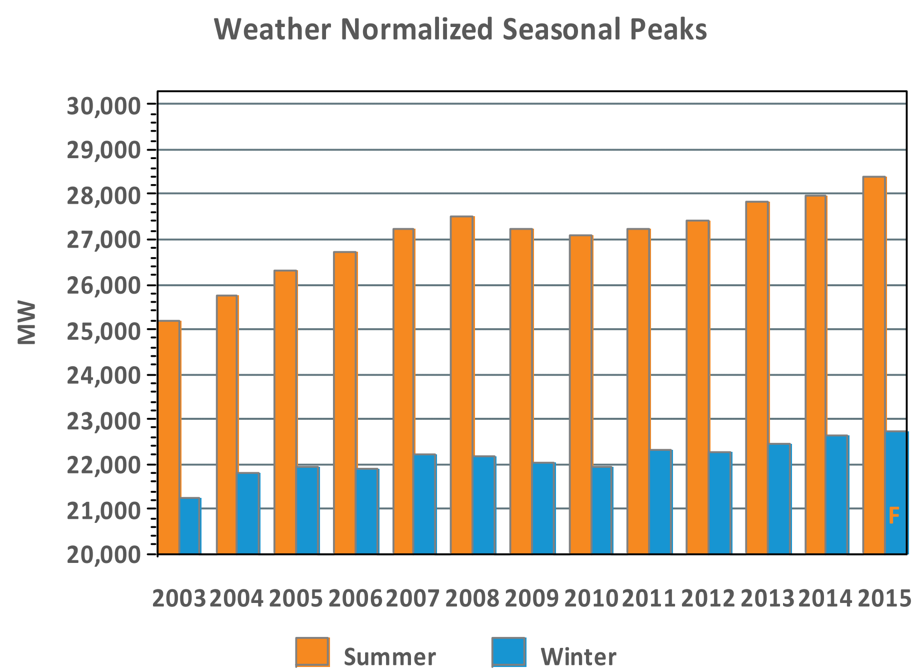


Ann Tot (TWh): 128.2 127.8 127.1 61.6

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



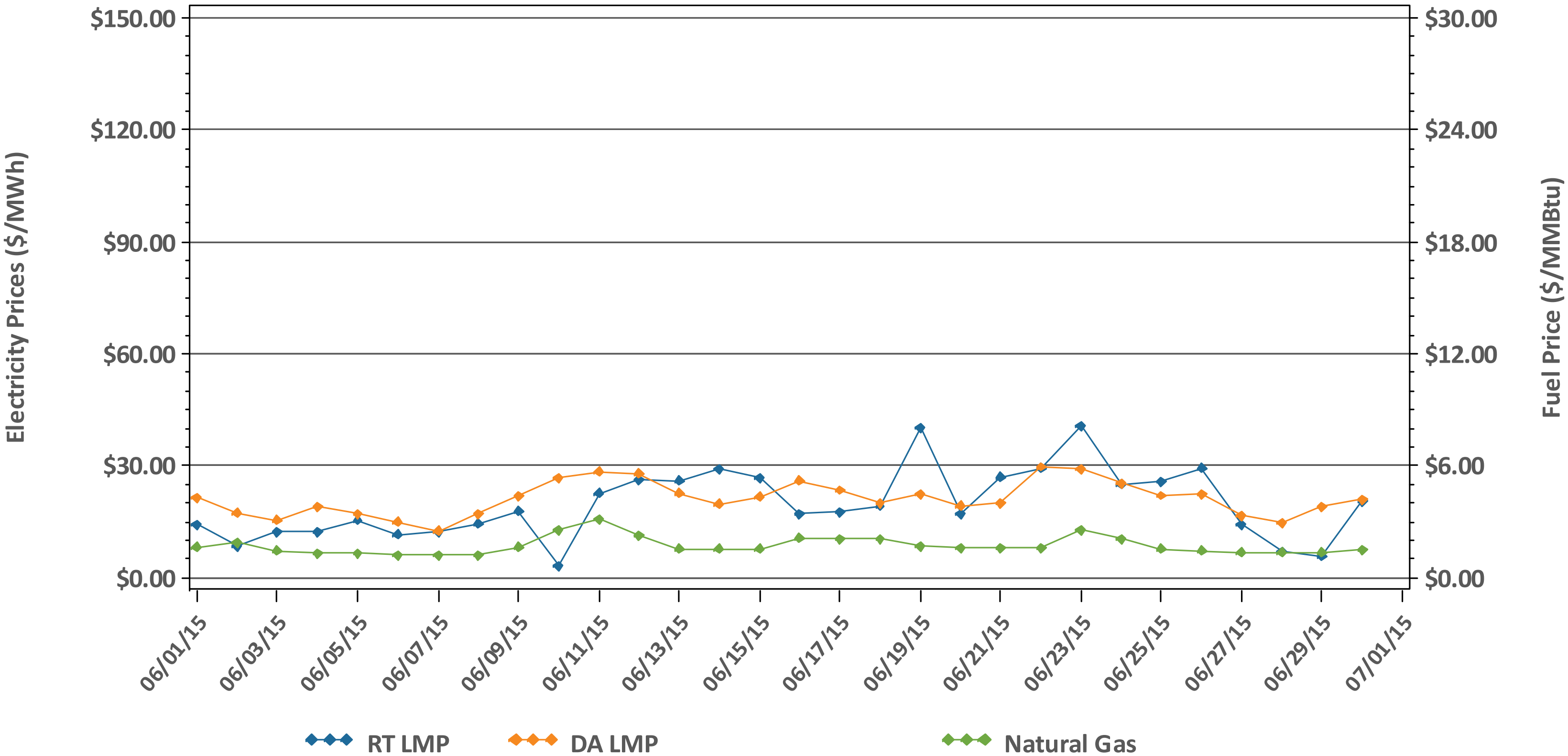


Winter beginning in year displayed

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

MARKET OPERATIONS

Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: June 1-30, 2015

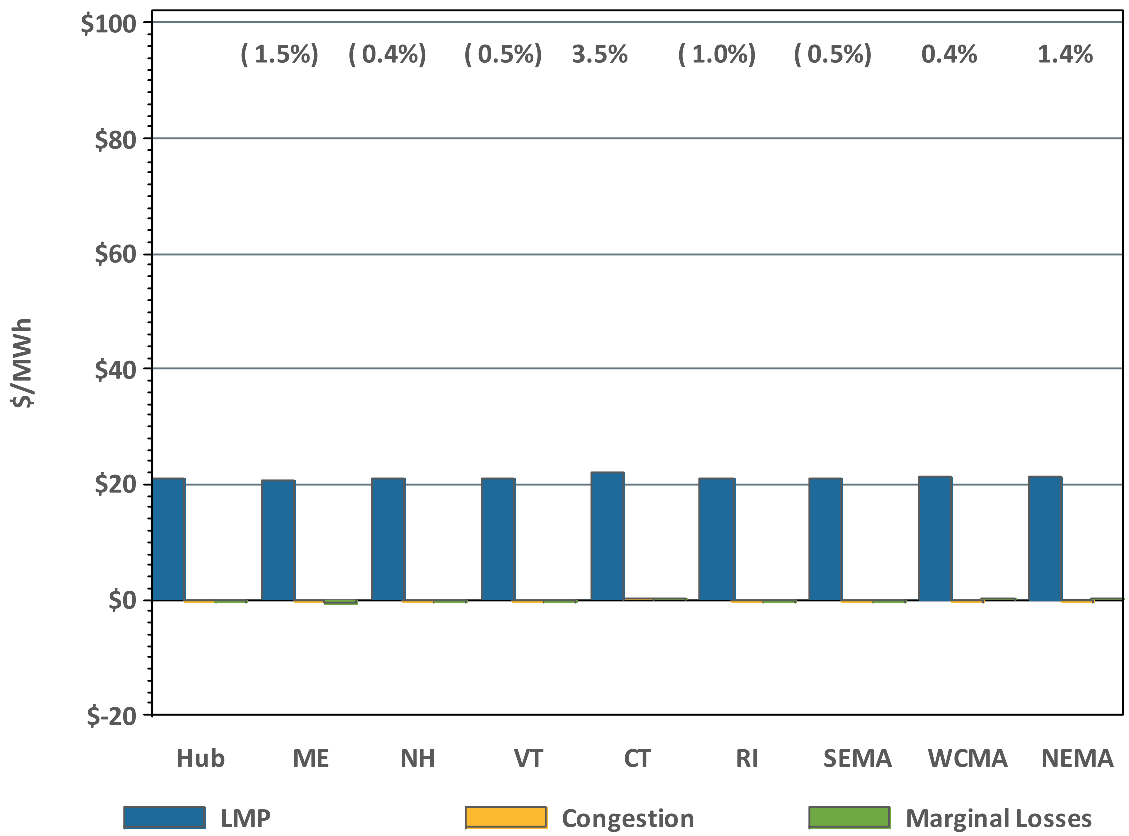


Underlying natural gas data furnished by:

ICE Global markets in clear view

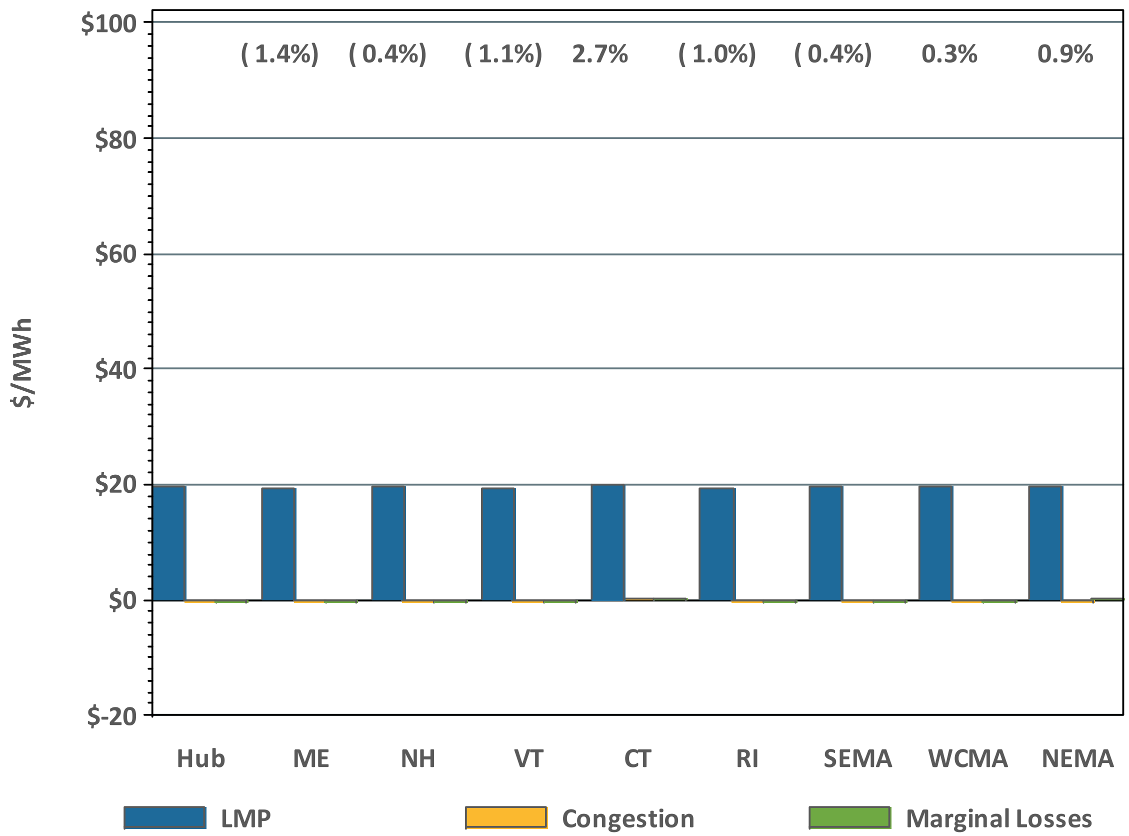
Average price difference over this period (DA-RT): $1.55
Average price difference over this period ABS(DA-RT): $5.84
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 30%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, June 2015



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

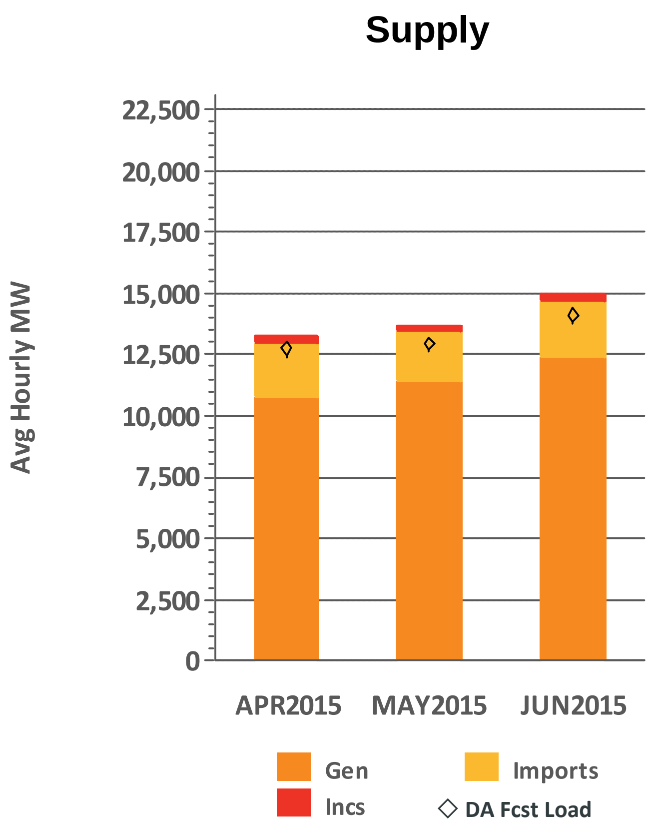
RT LMPs Average by Zone & Hub, June 2015



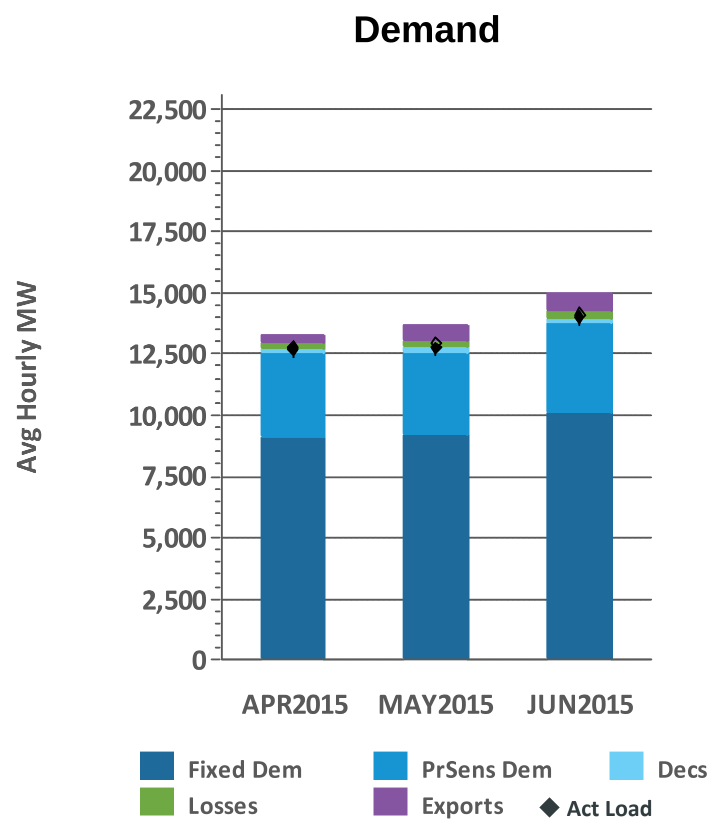
Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

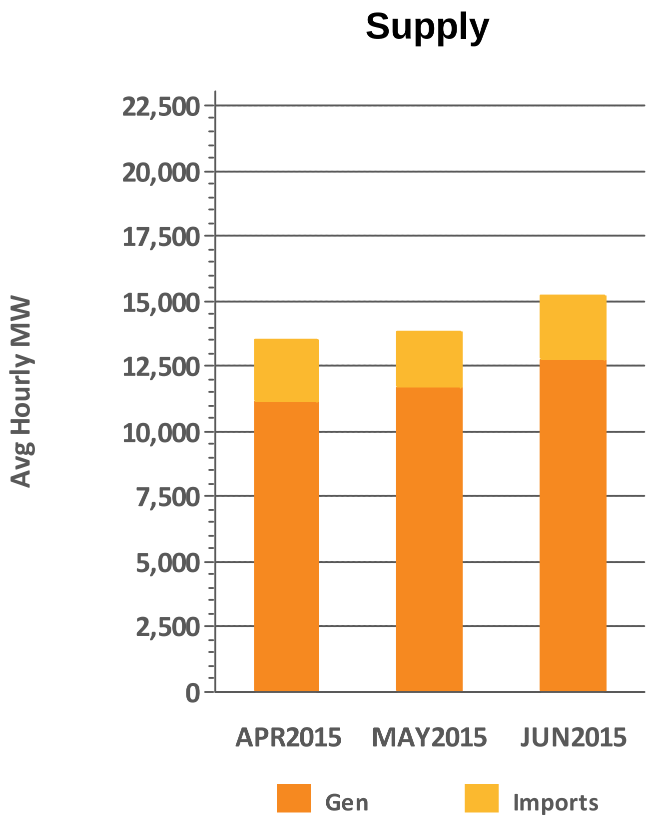


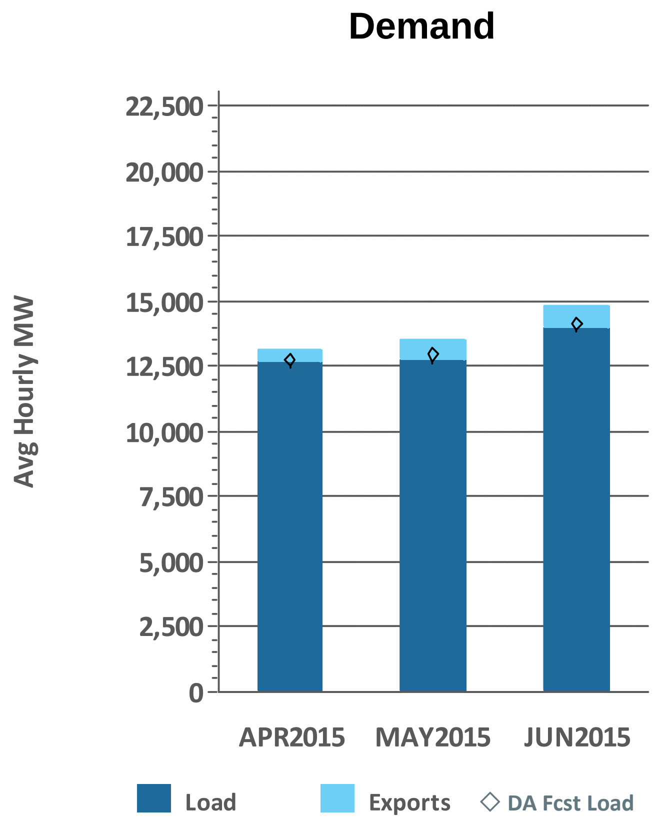
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



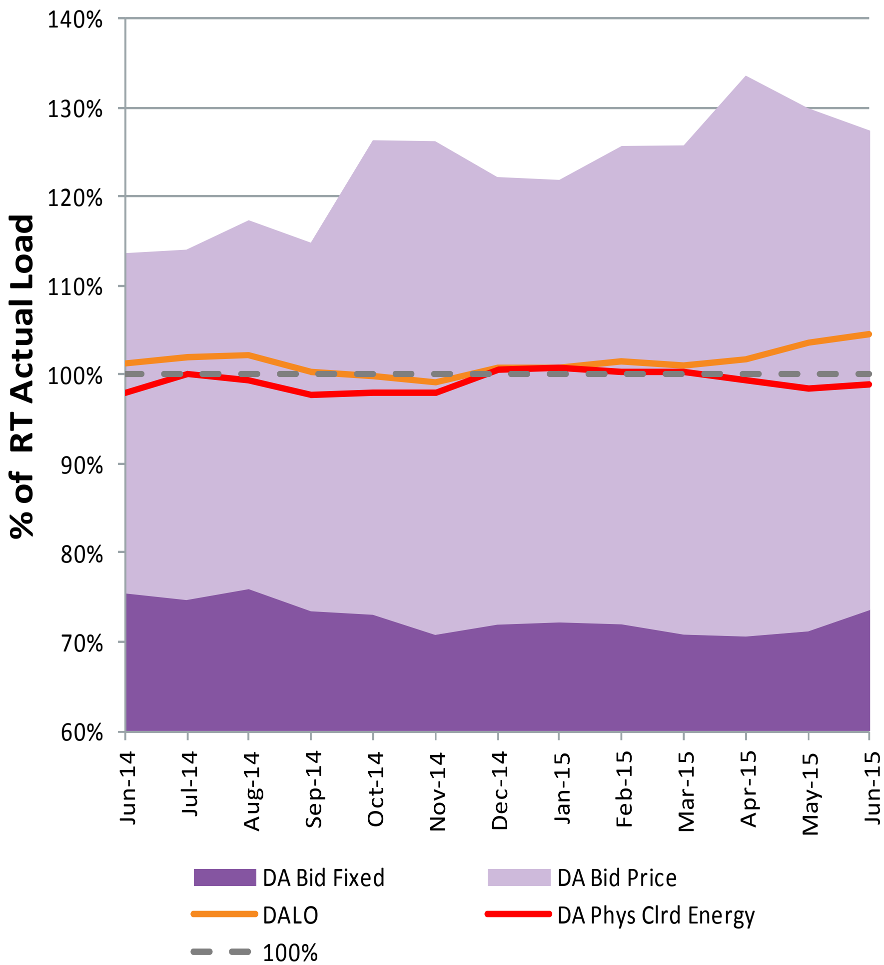
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

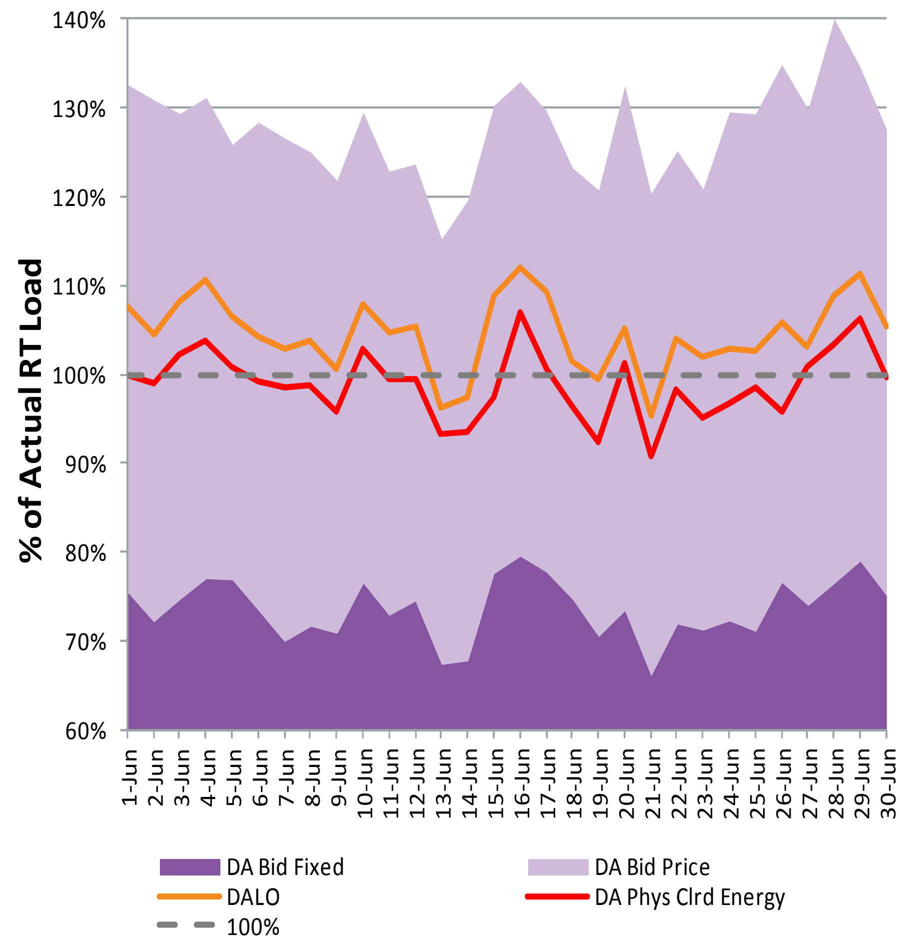
Components of RT Supply and Demand – Last Three Months





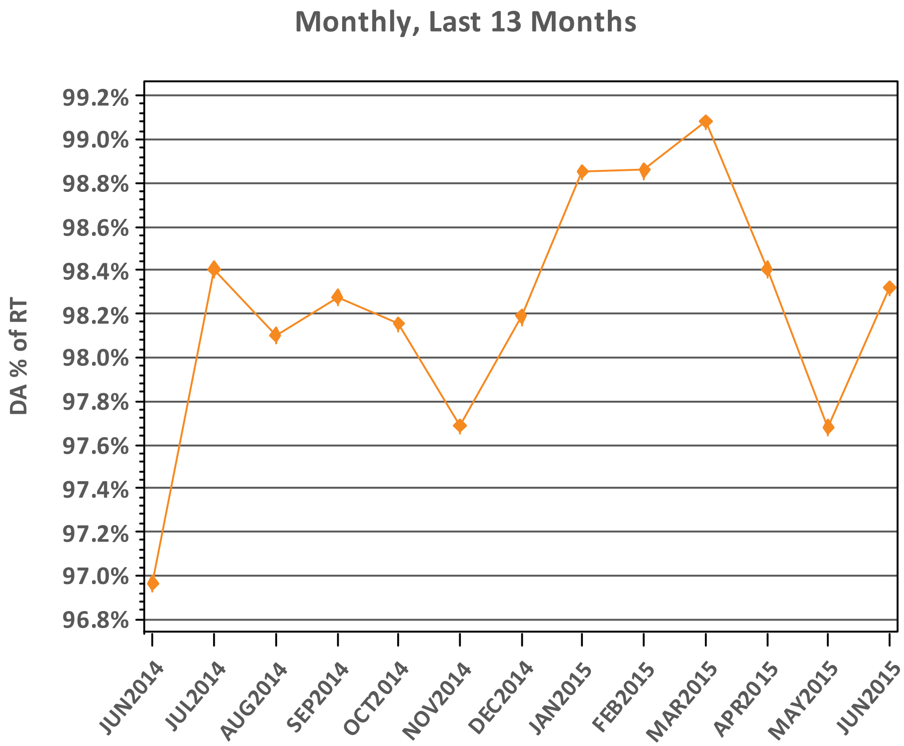
DAM Volumes vs. RT Actual Load (Peak Hour): Monthly and Daily

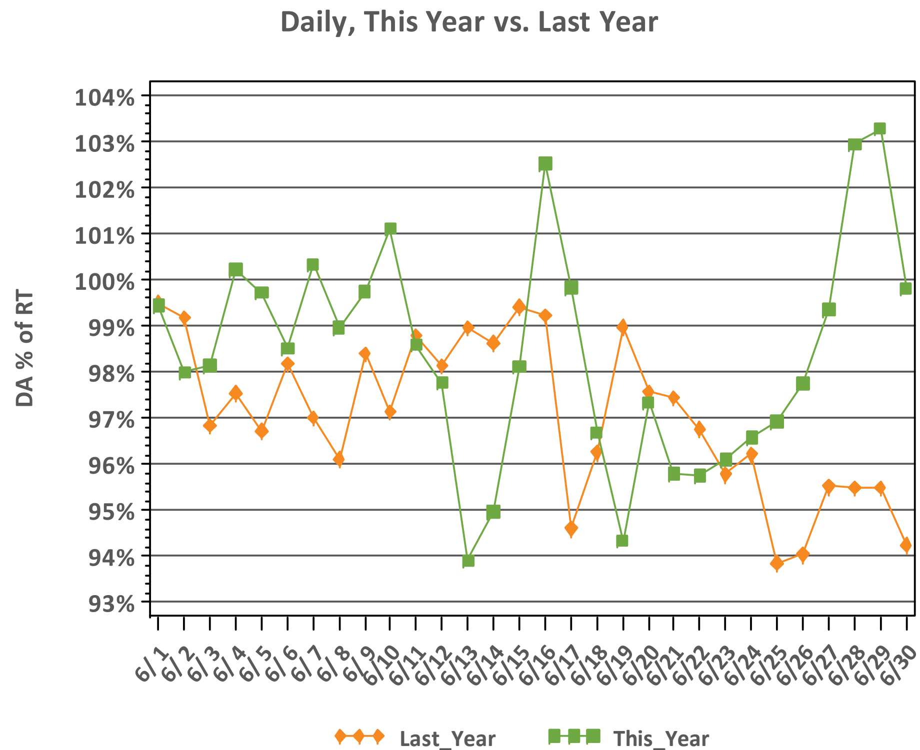




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

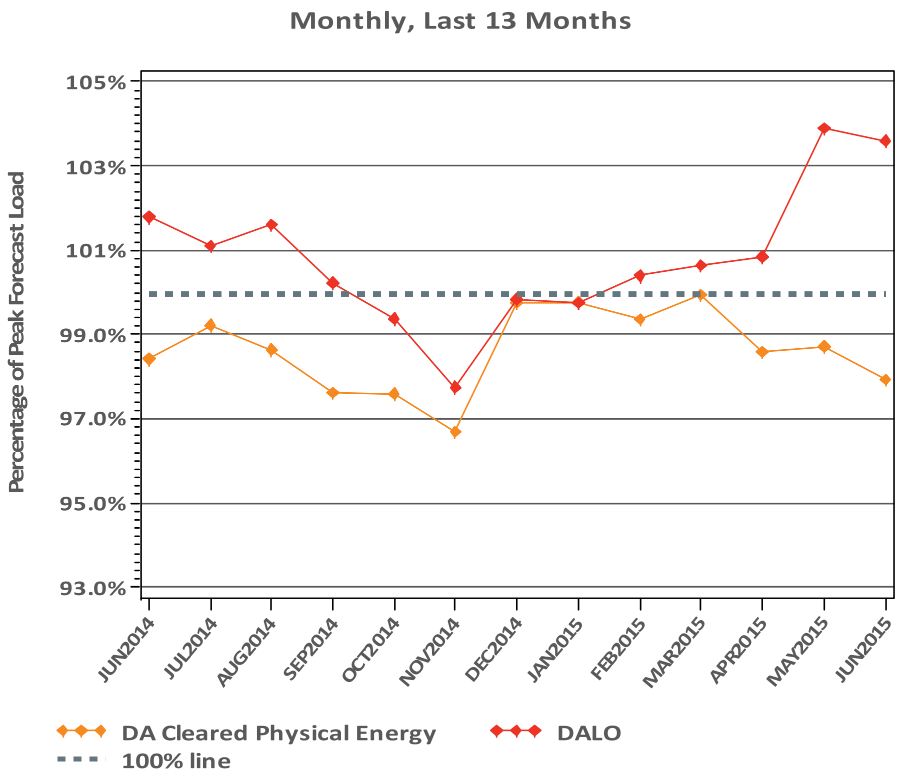
DA vs. RT Load Obligation: June, This Year vs. Last Year

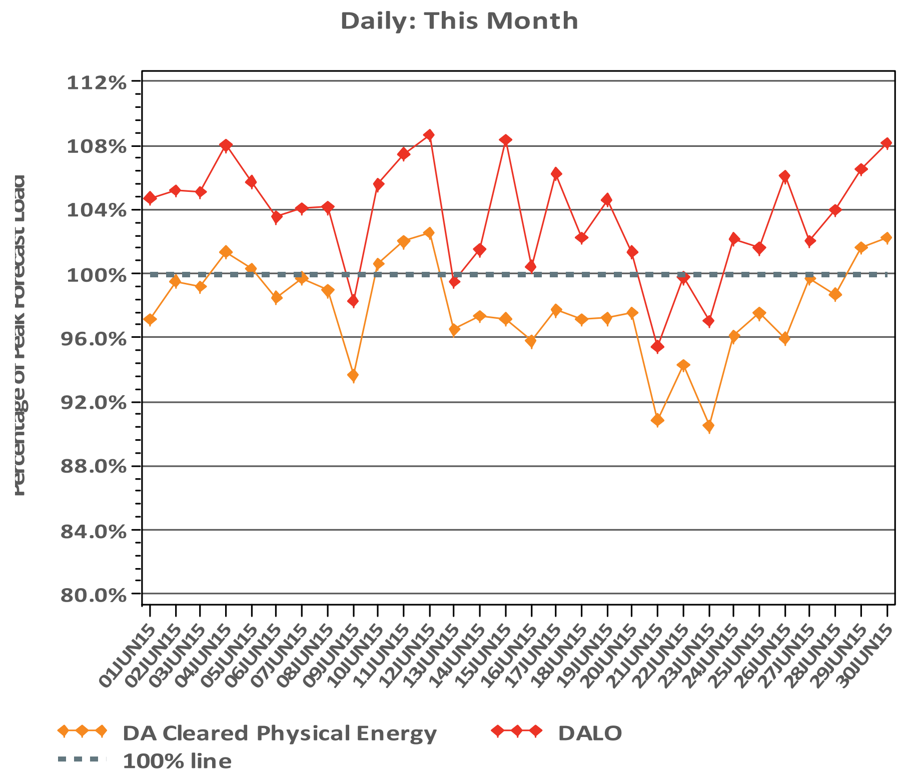




*Hourly average values

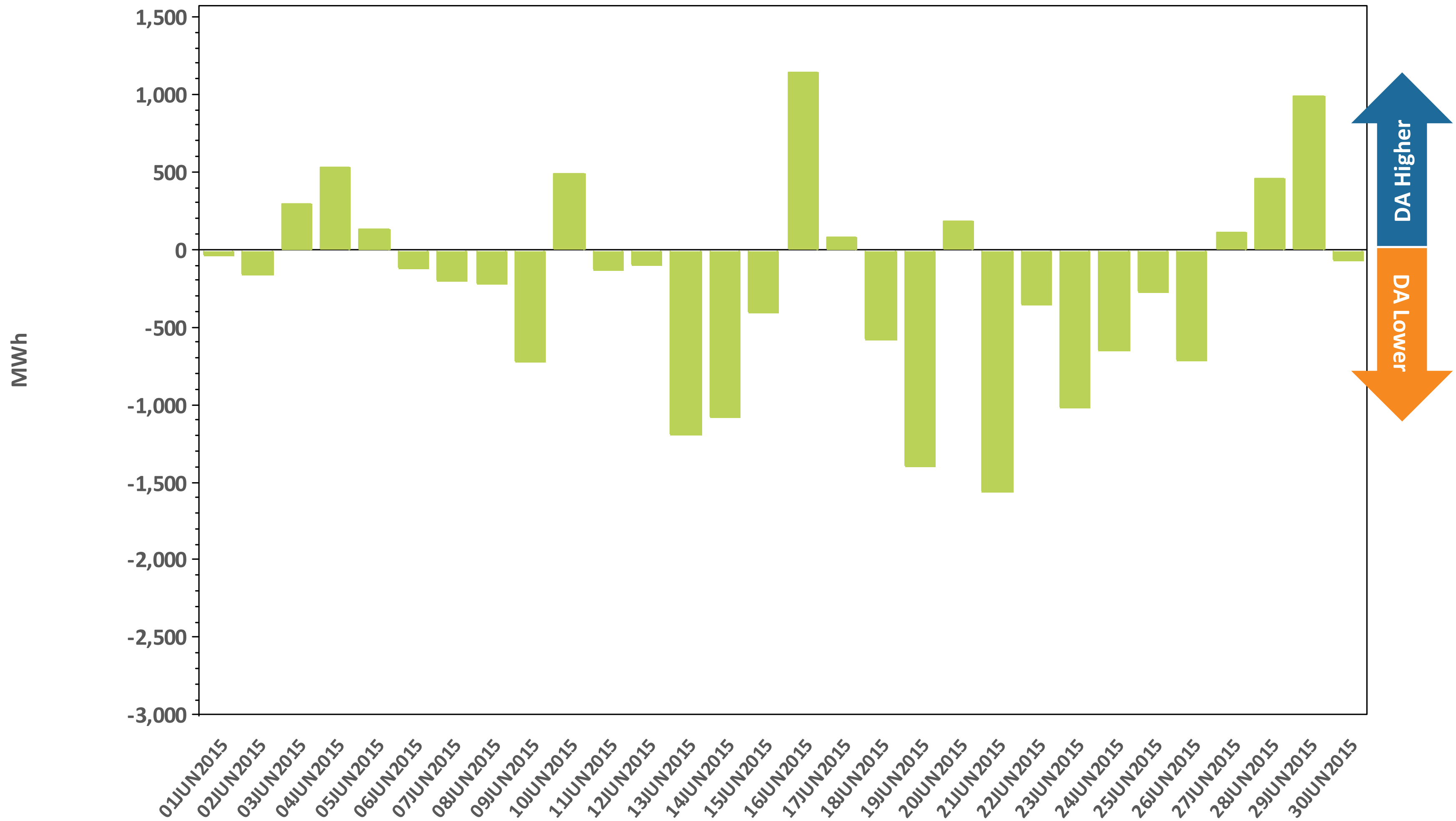
DA Volumes as % of Forecast (Peak Hour)





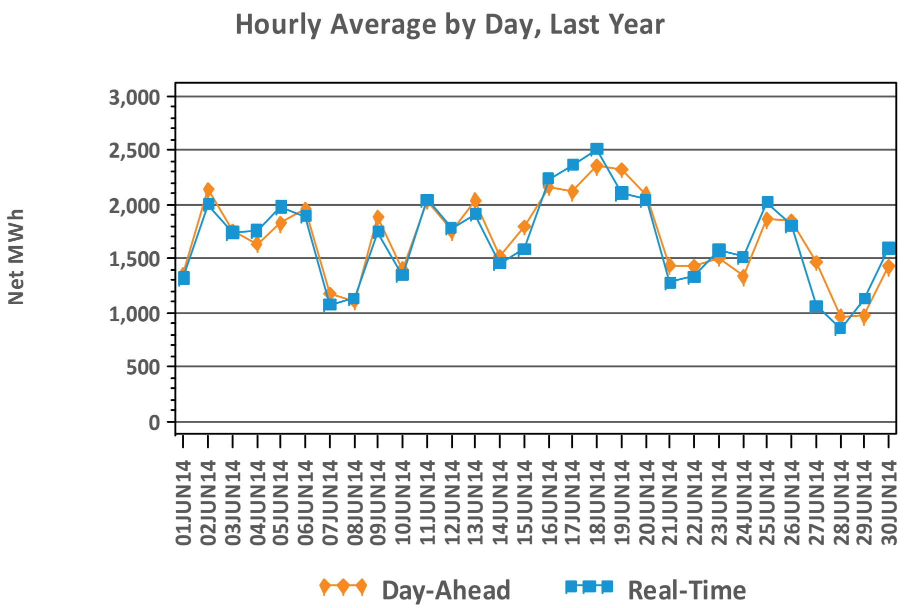
*Forecasted peak hour is reflected.

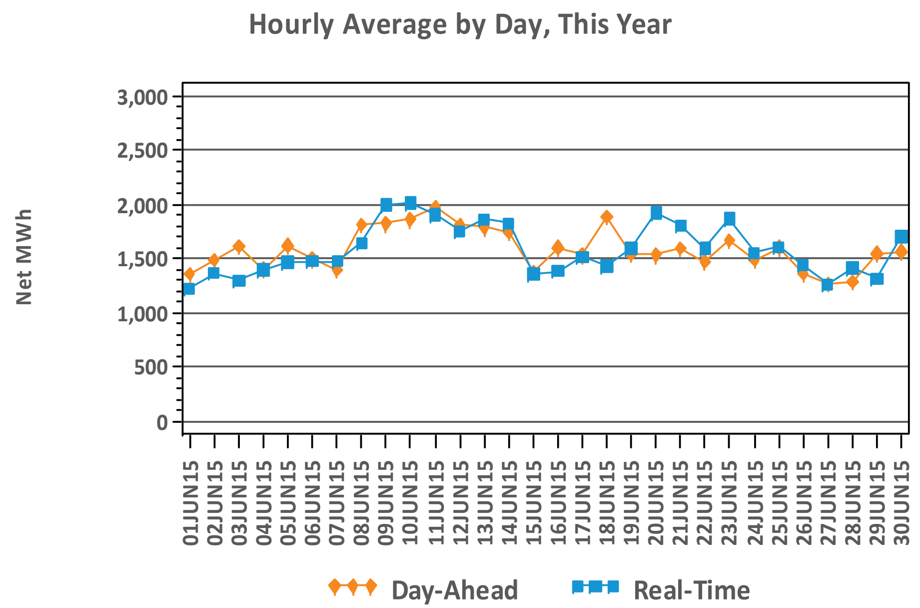
DA Cleared Physical Energy Difference from RT System Load at Peak Hour



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

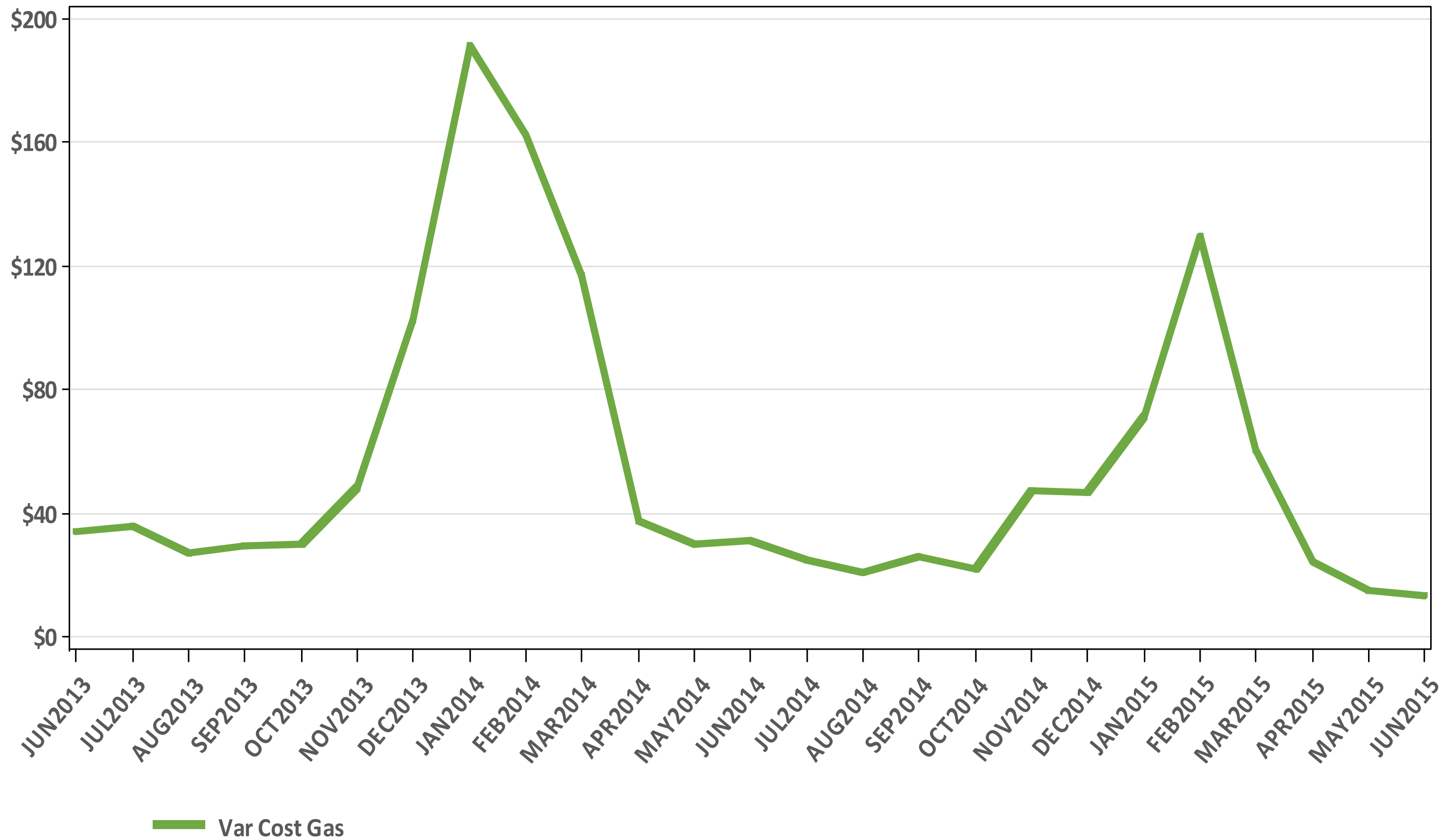
DA vs. RT Net Interchange June 2015 vs. June 2014





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

Variable Production Cost of Natural Gas: Monthly

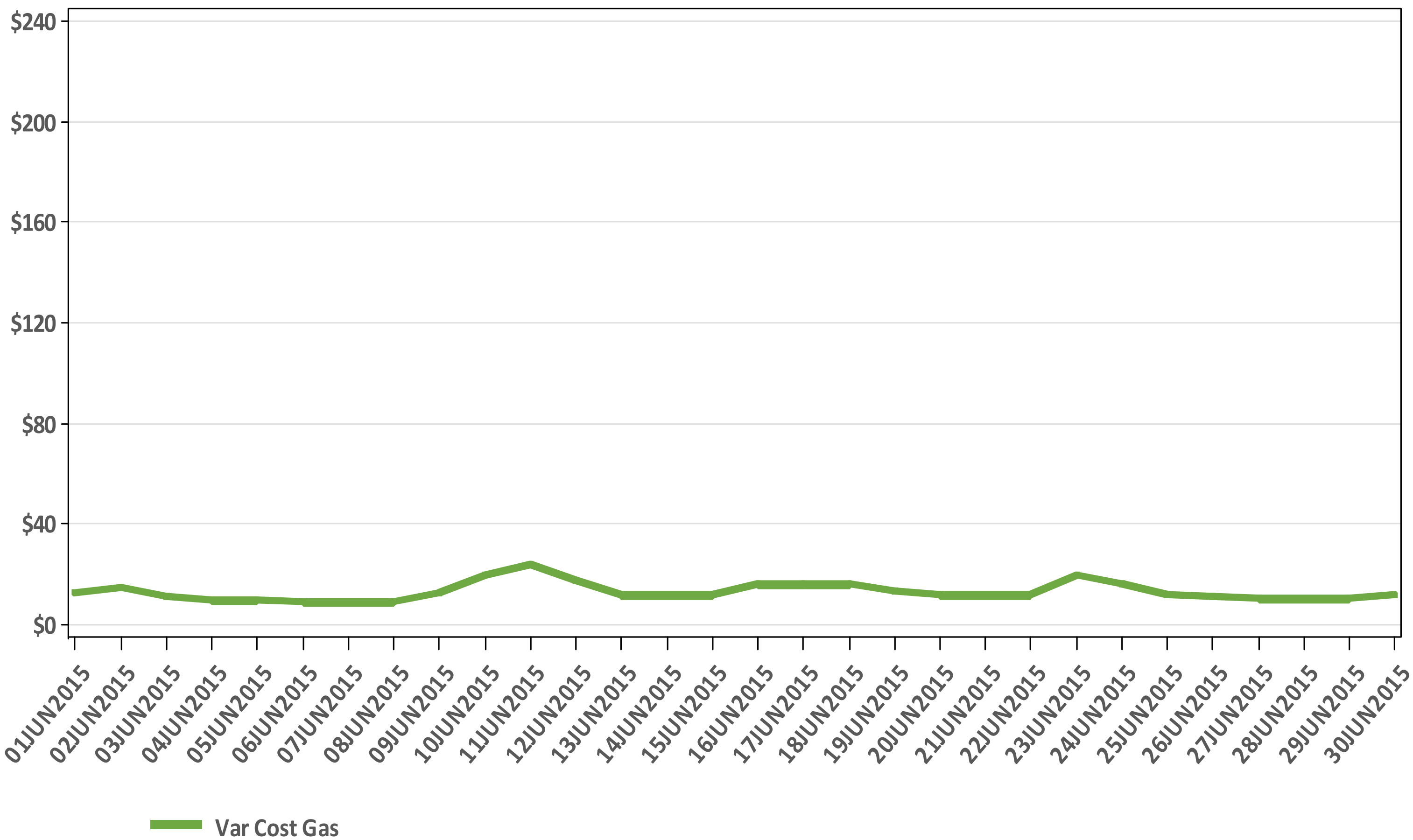


Underlying natural gas data furnished by:

ice Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

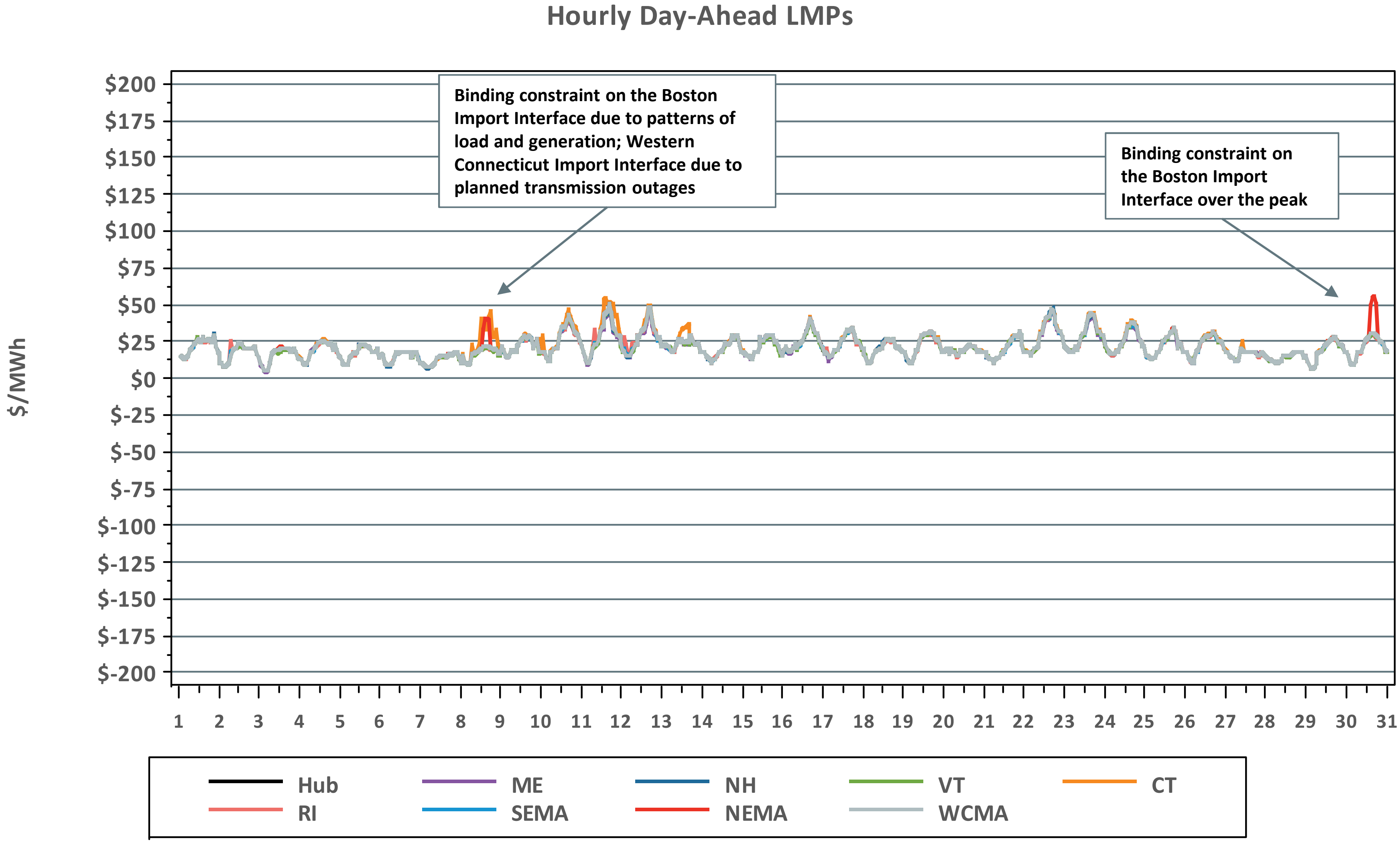


Underlying natural gas data furnished by:

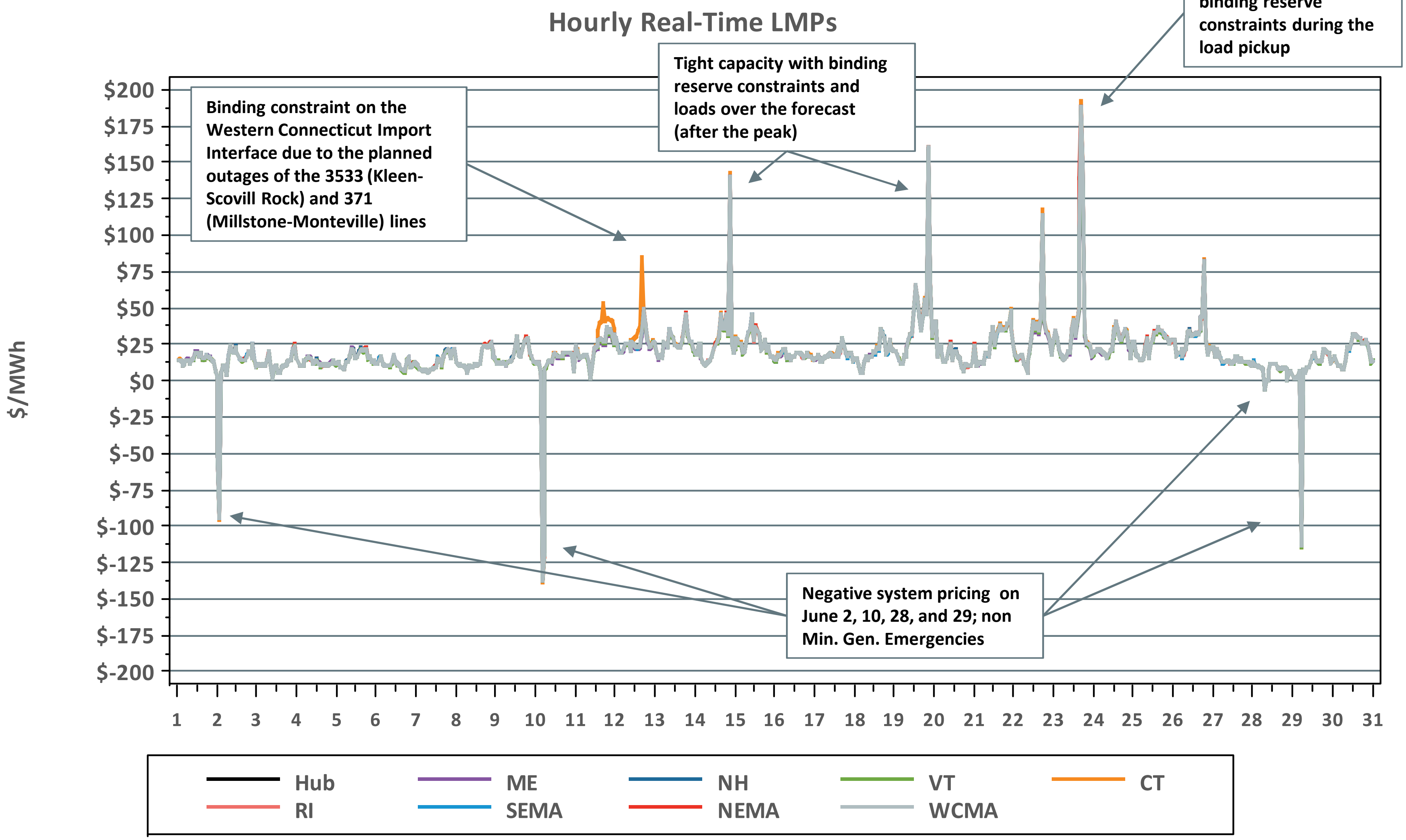
ICE Global markets in clear view

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

Hourly DA LMPs, June 1-30, 2015



Hourly RT LMPs, June 1-30, 2015



BACK-UP DETAIL

LOAD RESPONSE

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

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	116.4	5.1	120.1	0.0	241.7
NH	9.1	15.1	75.3	0.0	99.5
VT	29.2	3.7	104.9	0.0	137.8
CT	77.8	109.2	74.4	310.7	572.0
RI	10.3	13.0	158.7	0.0	181.9
SEMA	10.2	10.8	206.0	0.0	227.0
WCMA	28.1	20.5	206.9	46.2	301.7
NEMA	43.9	7.5	375.0	0.0	426.4
Total	**325.1**	**184.9**	**1,321.3**	**356.9**	**2,188.1**

* 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.

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

What are Daily NCPC Payments?

- Payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area

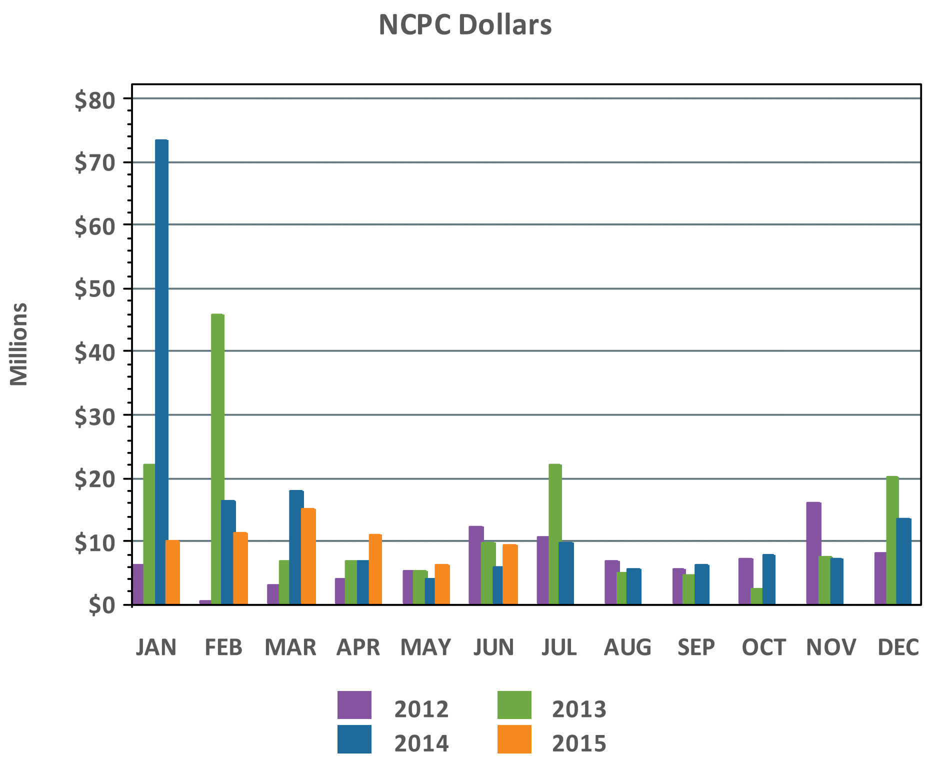
Definitions

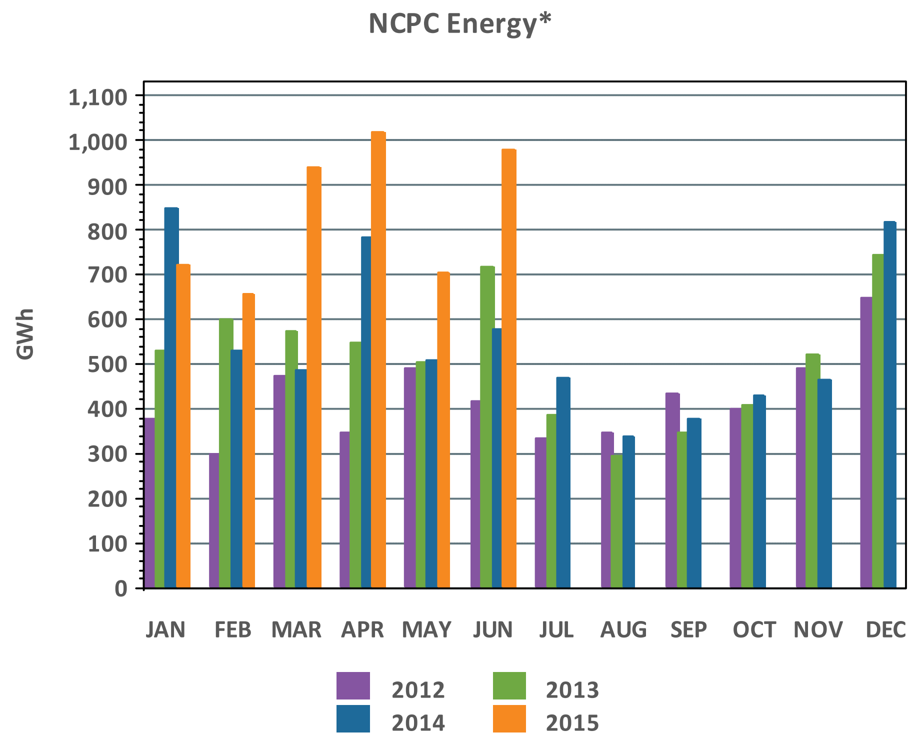
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

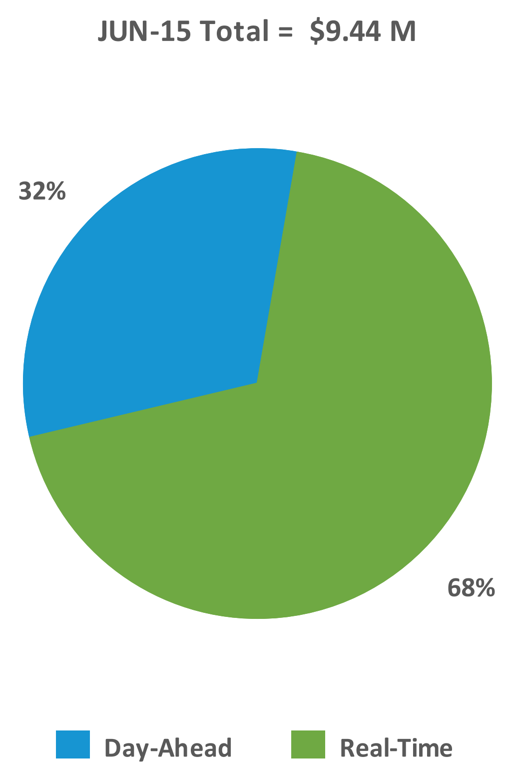
Year-Over-Year Total NCPC Dollars and Energy

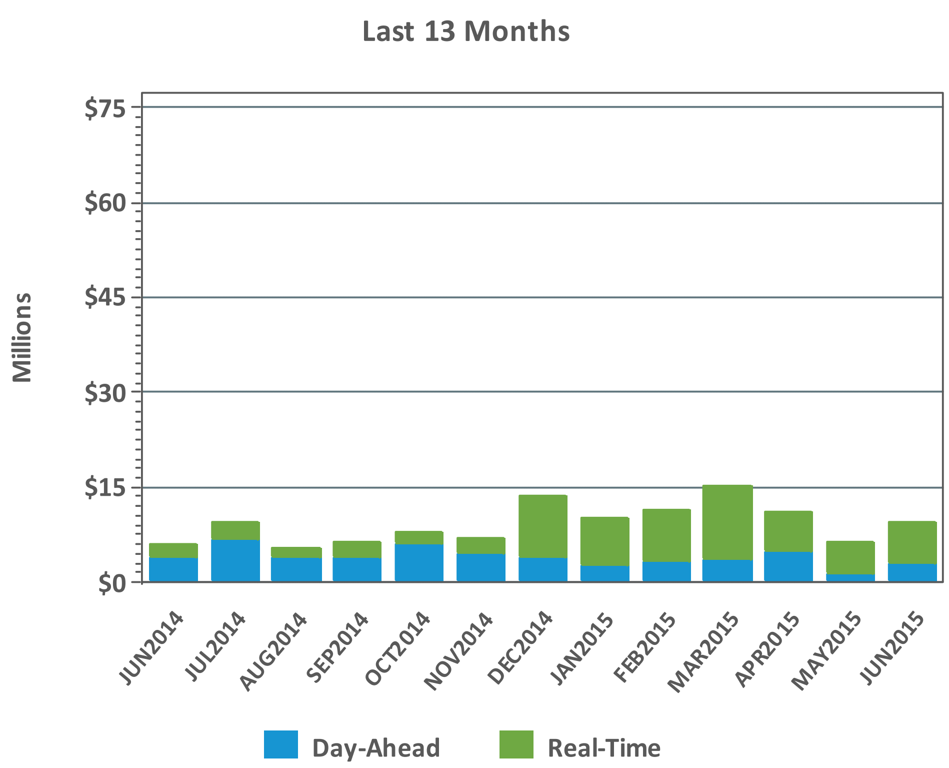




* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

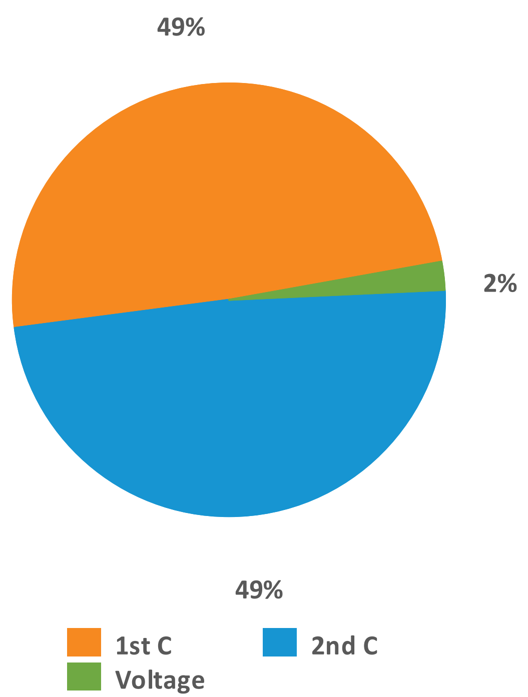
DA and RT NCPC Charges



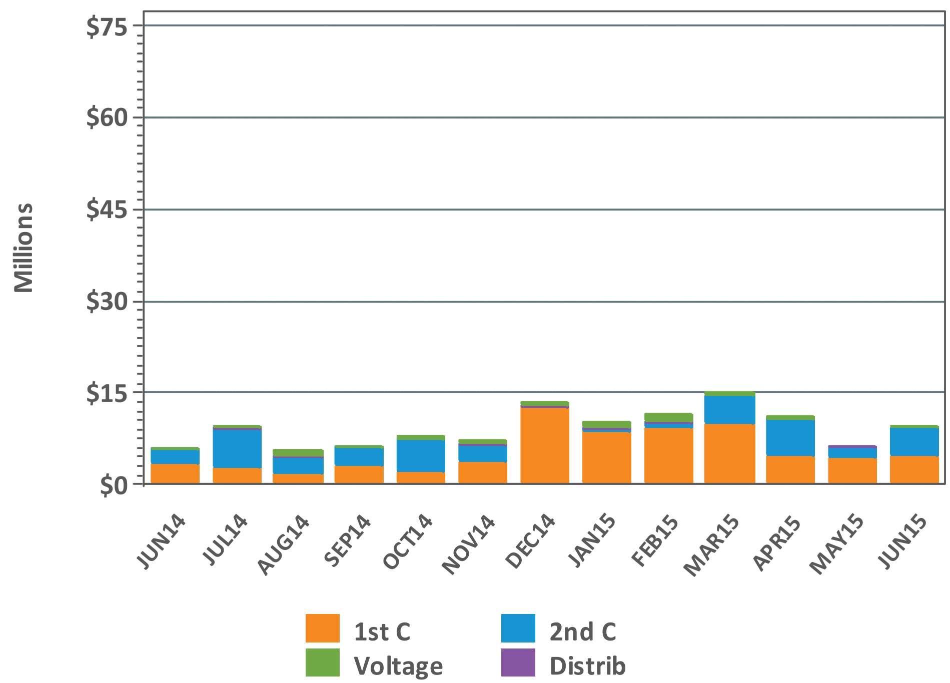


NCPC Charges by Type

JUN-15 Total = $9.44 M

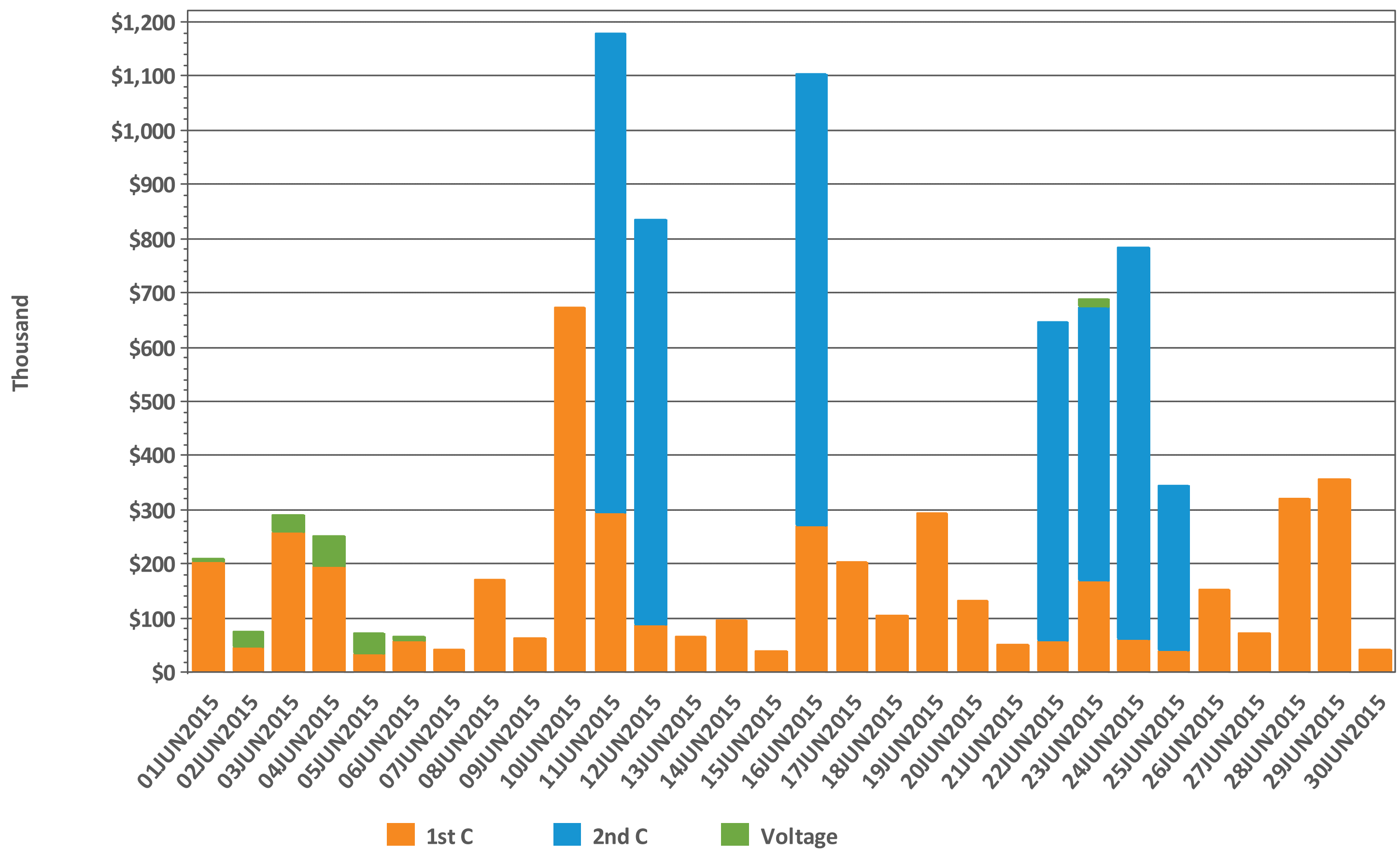


Last 13 Months

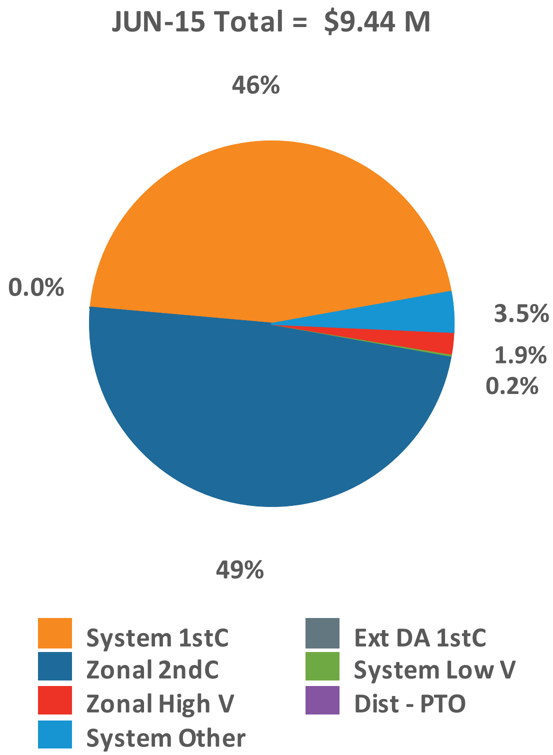


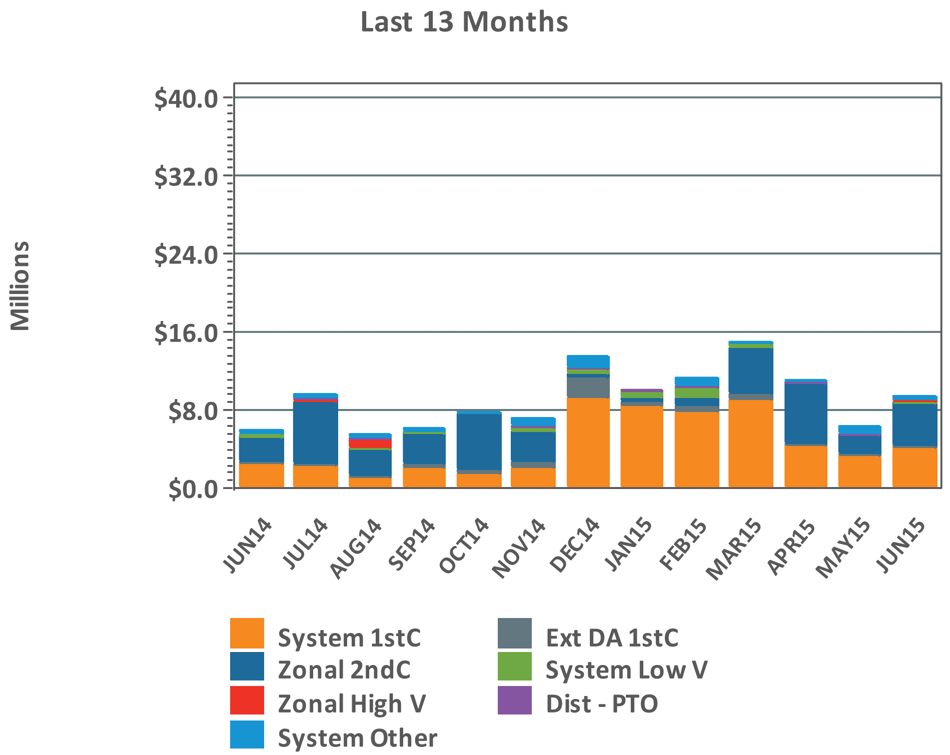
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

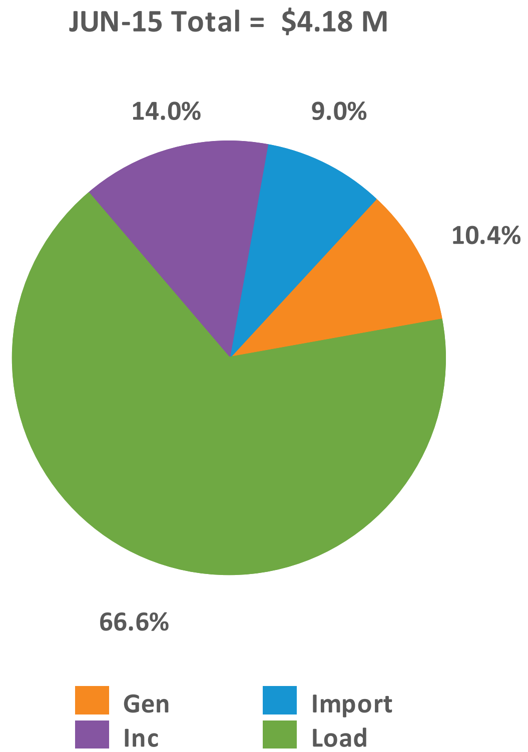


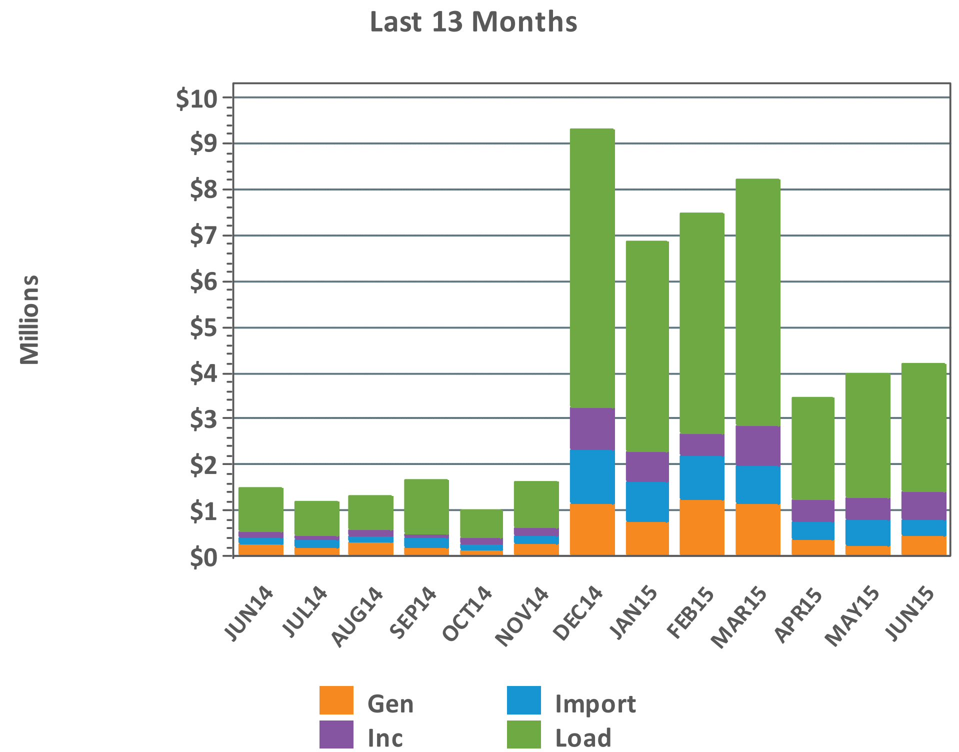
NCPC Charges by Allocation





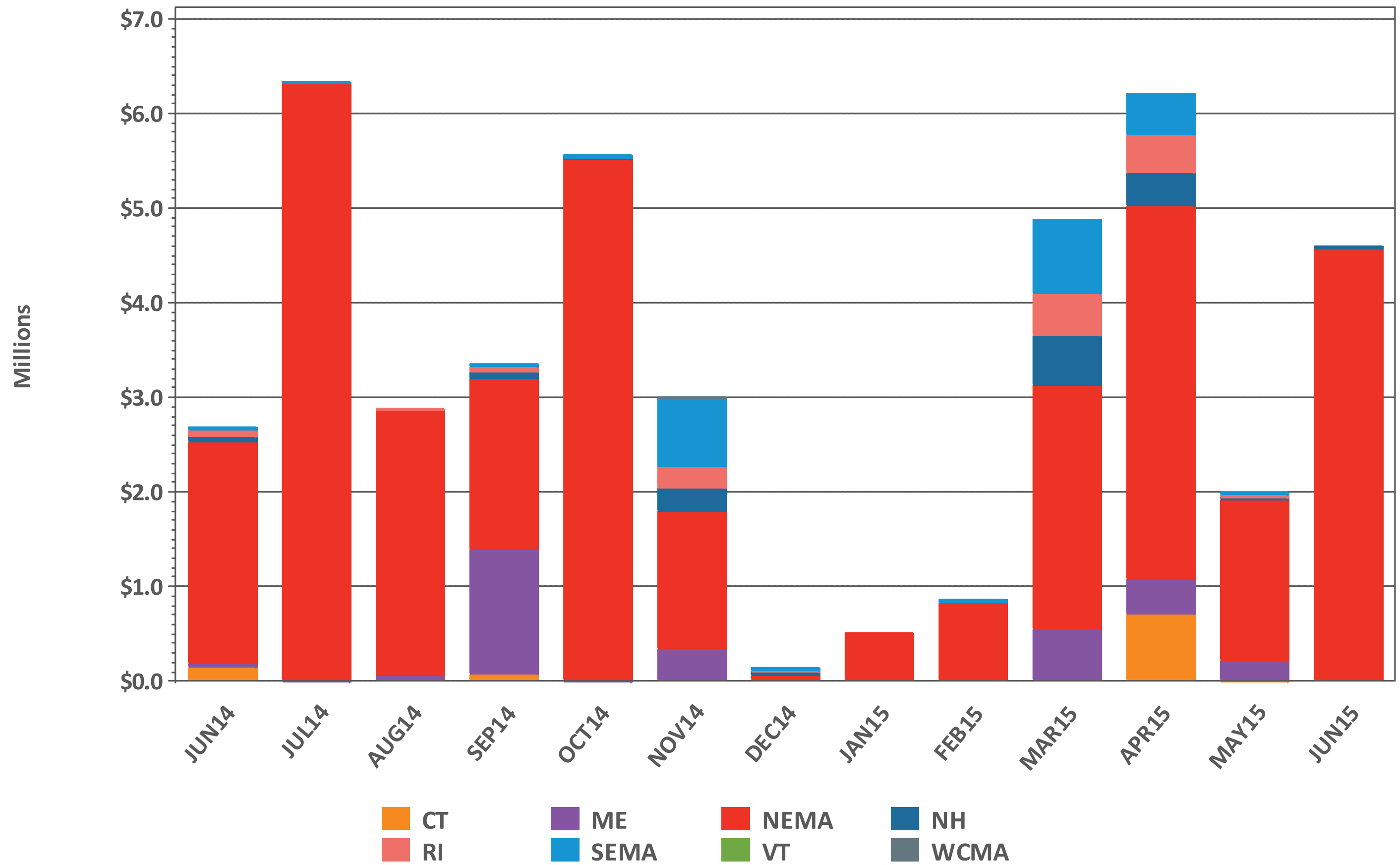
RT First Contingency Charges by Deviation Type





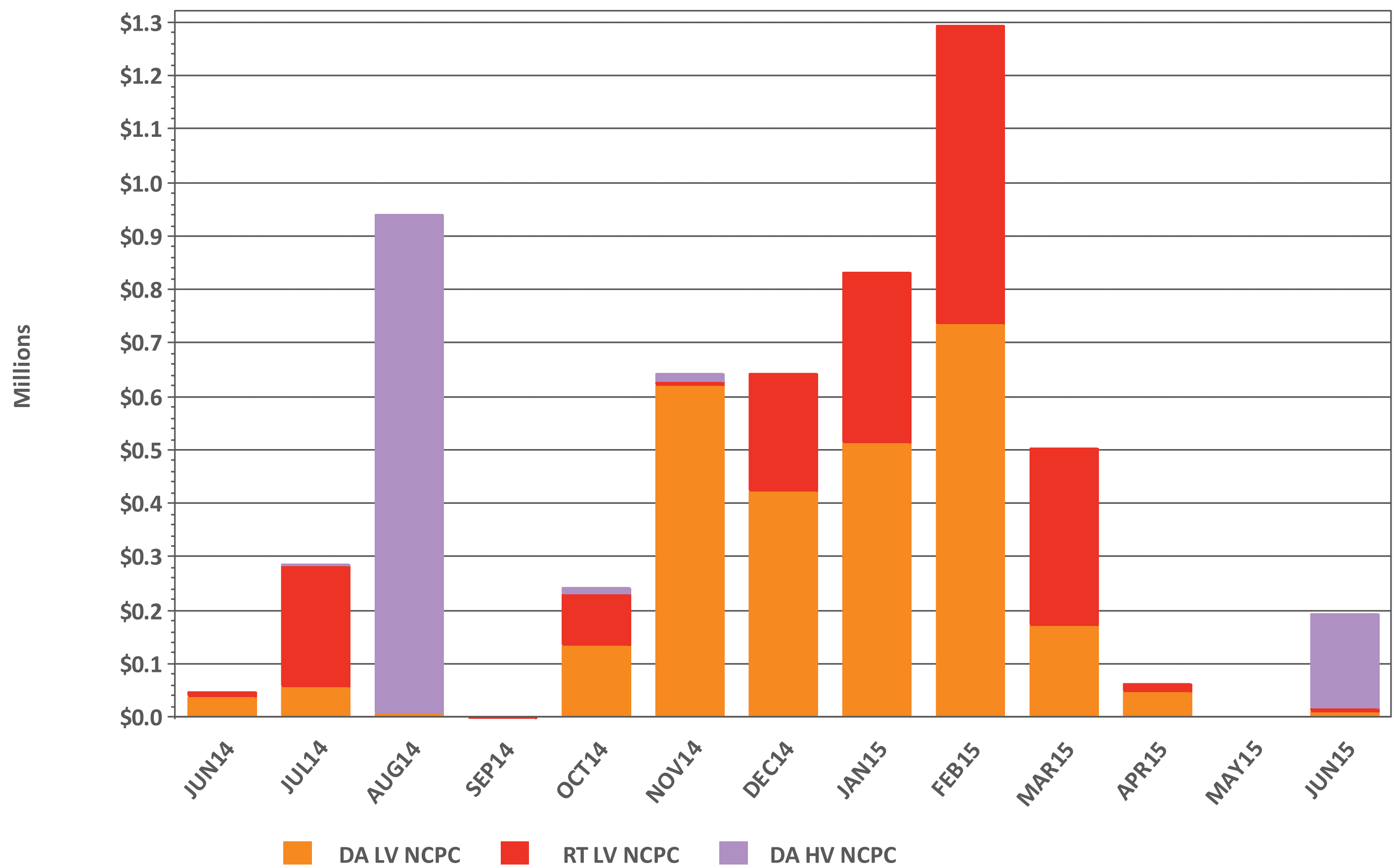
Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations

LSCPR Charges by Zone

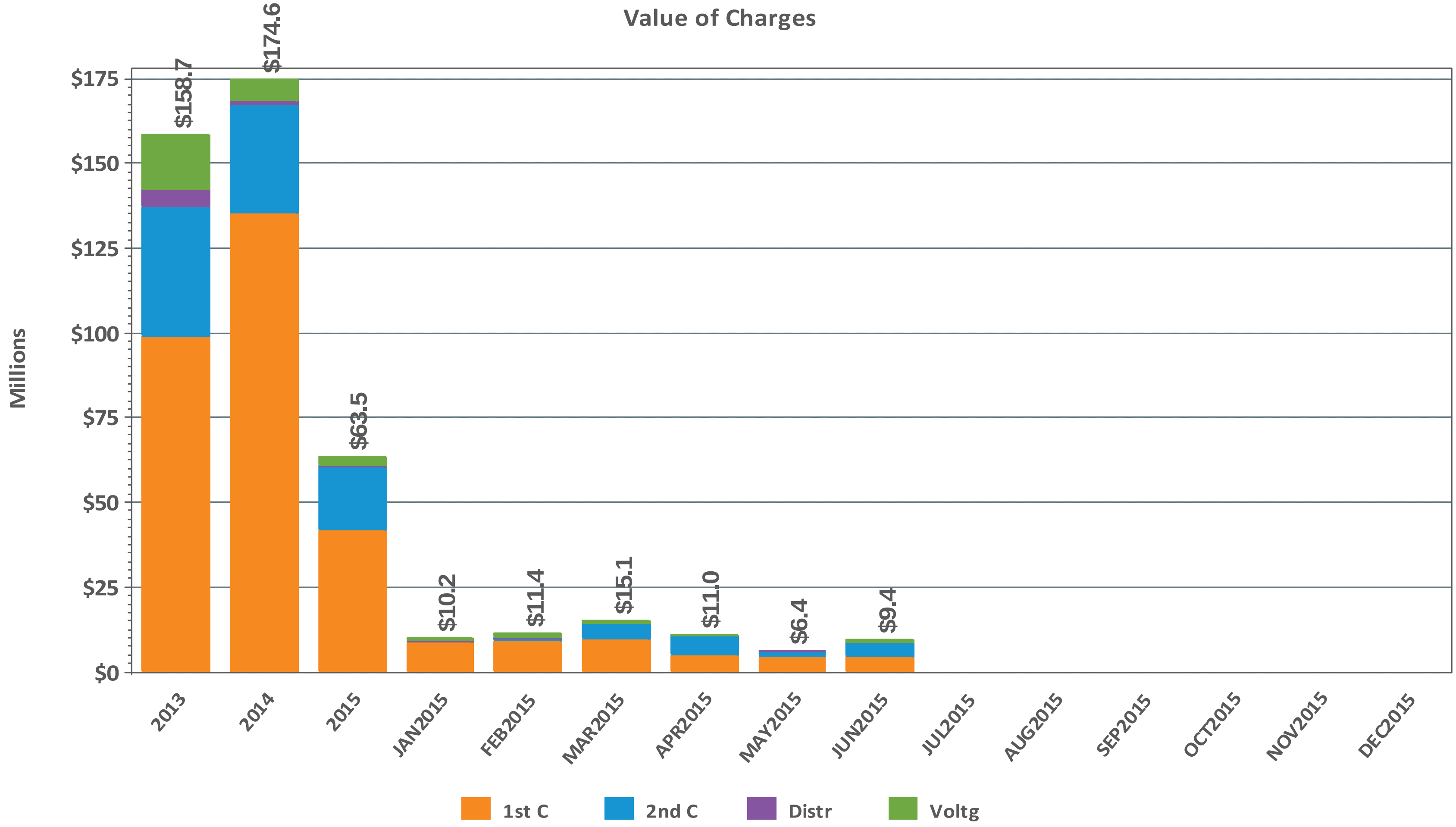


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

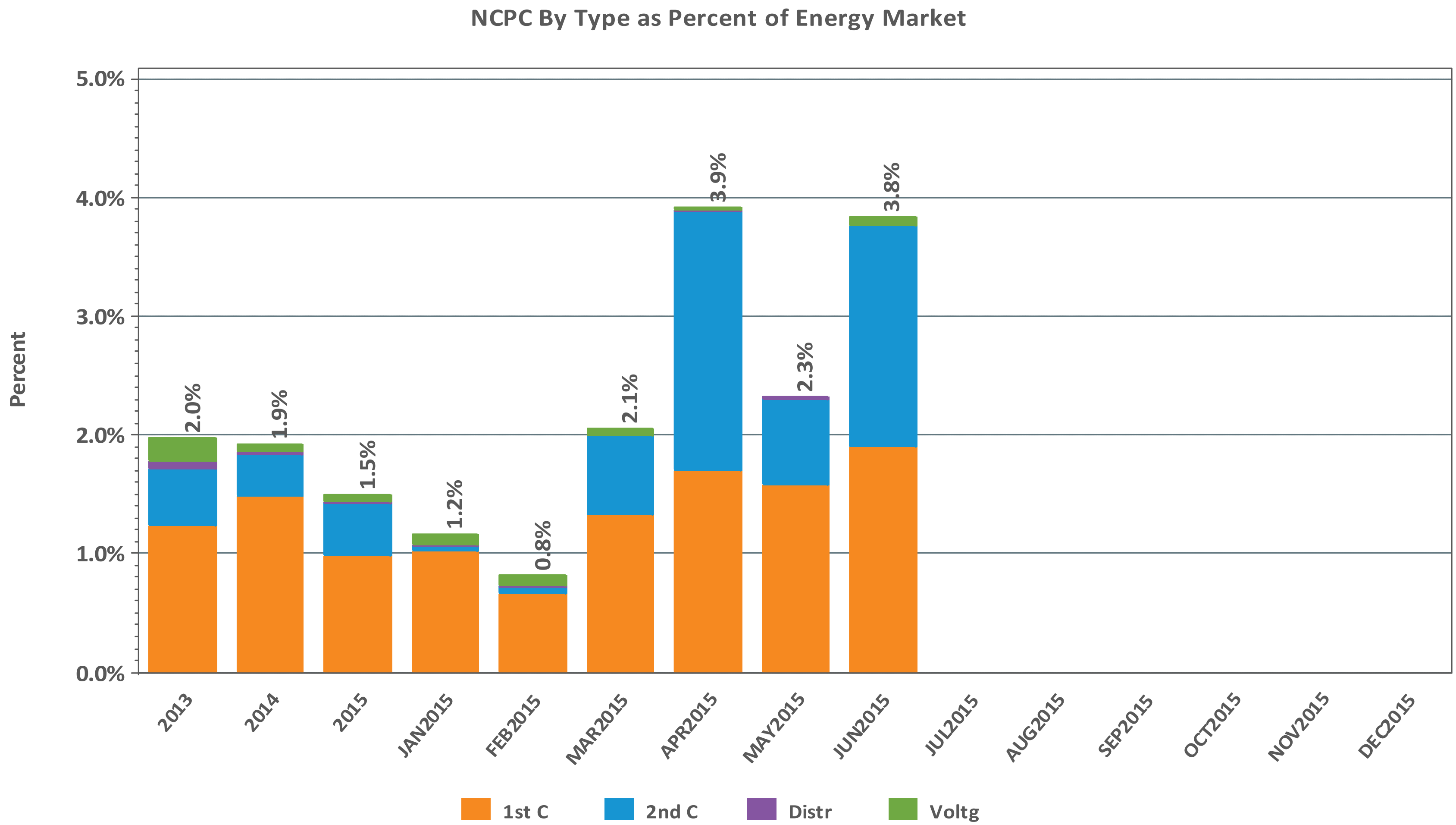
NCPC Charges for Voltage Support and High Voltage Control



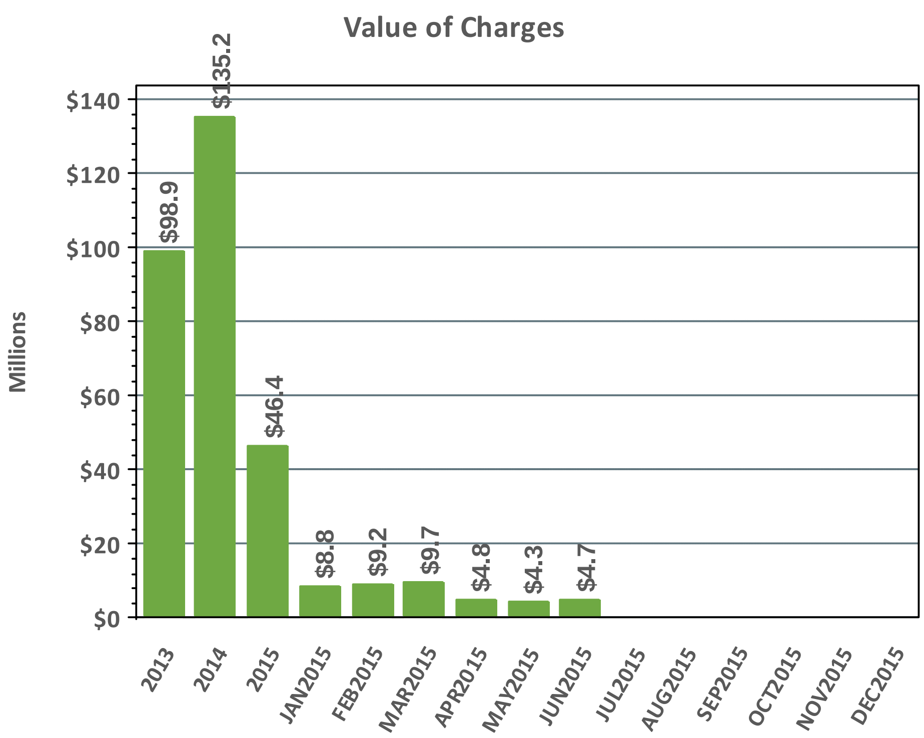
NCPC Charges by Type

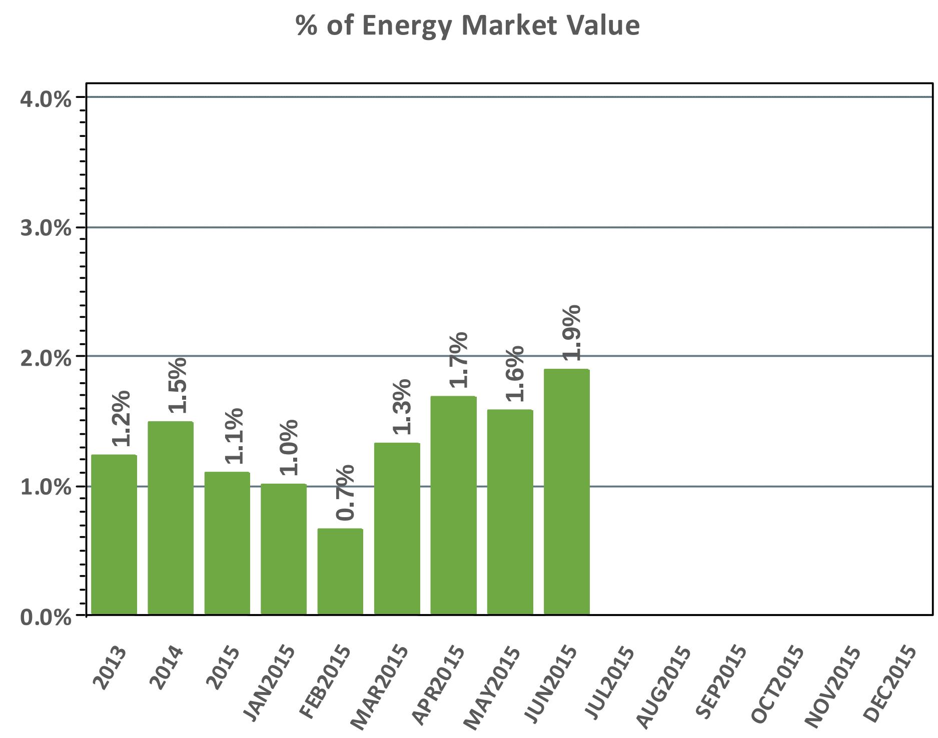


NCPC Charges as Percent of Energy Market



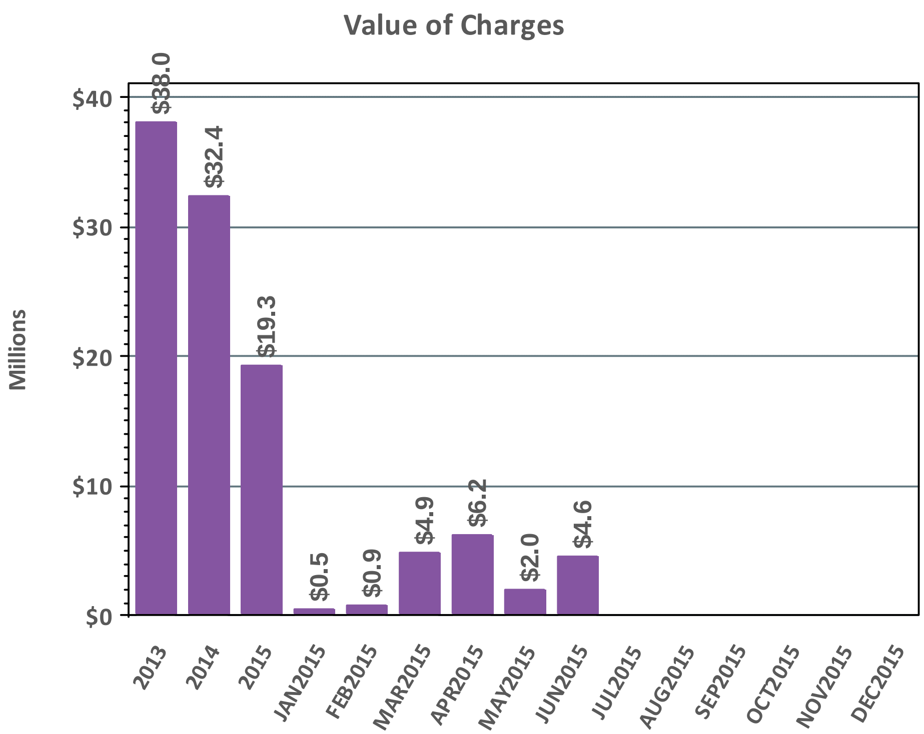
First Contingency NCPC Charges

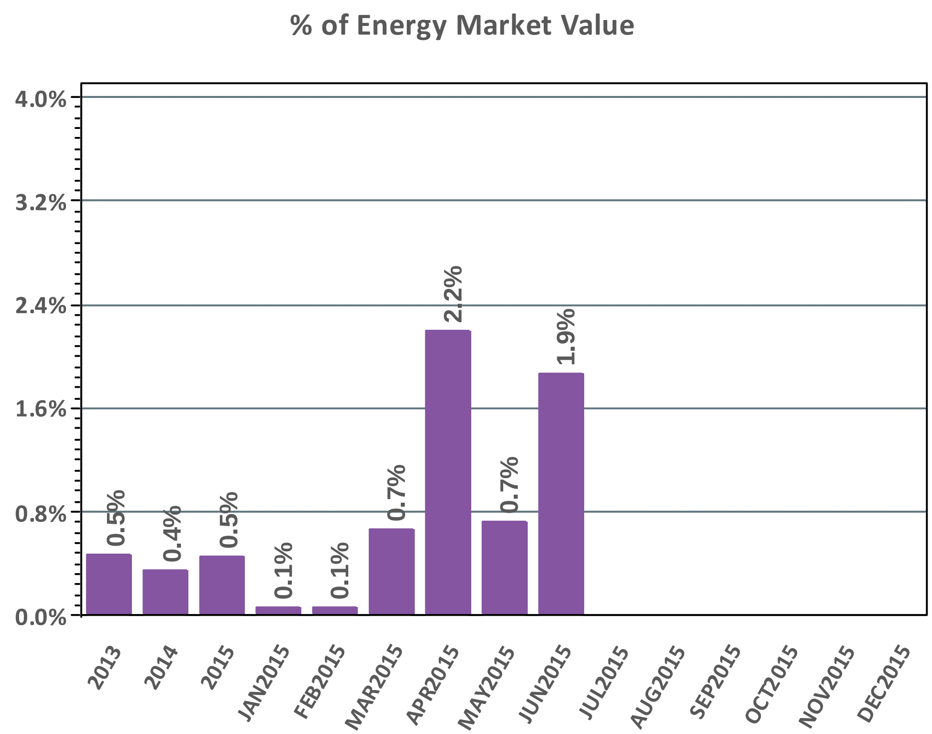




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

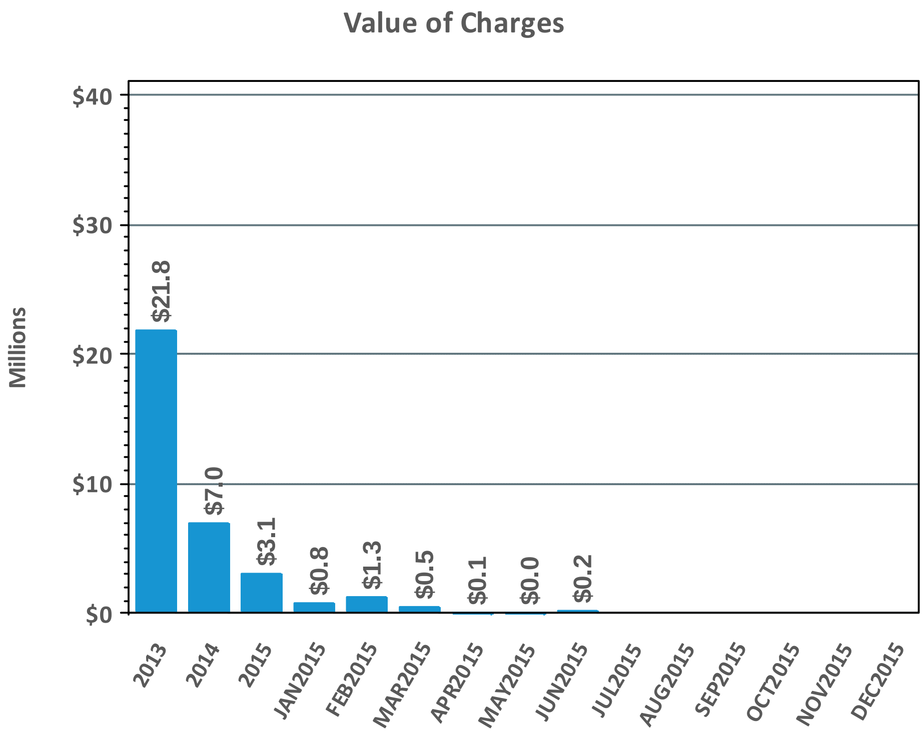
Second Contingency NCPC Charges

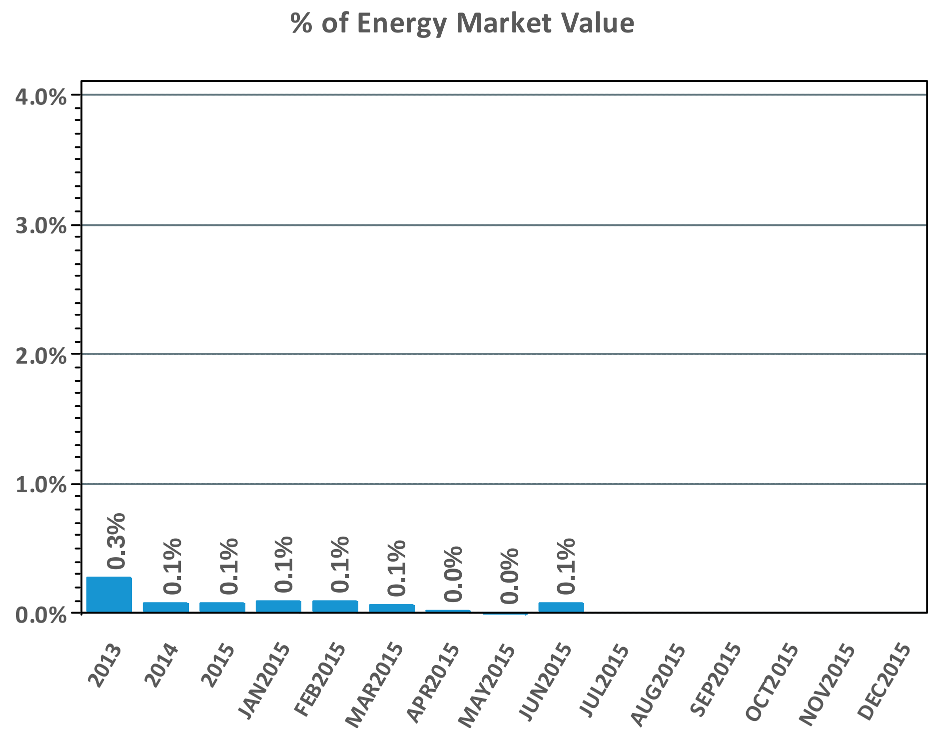




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

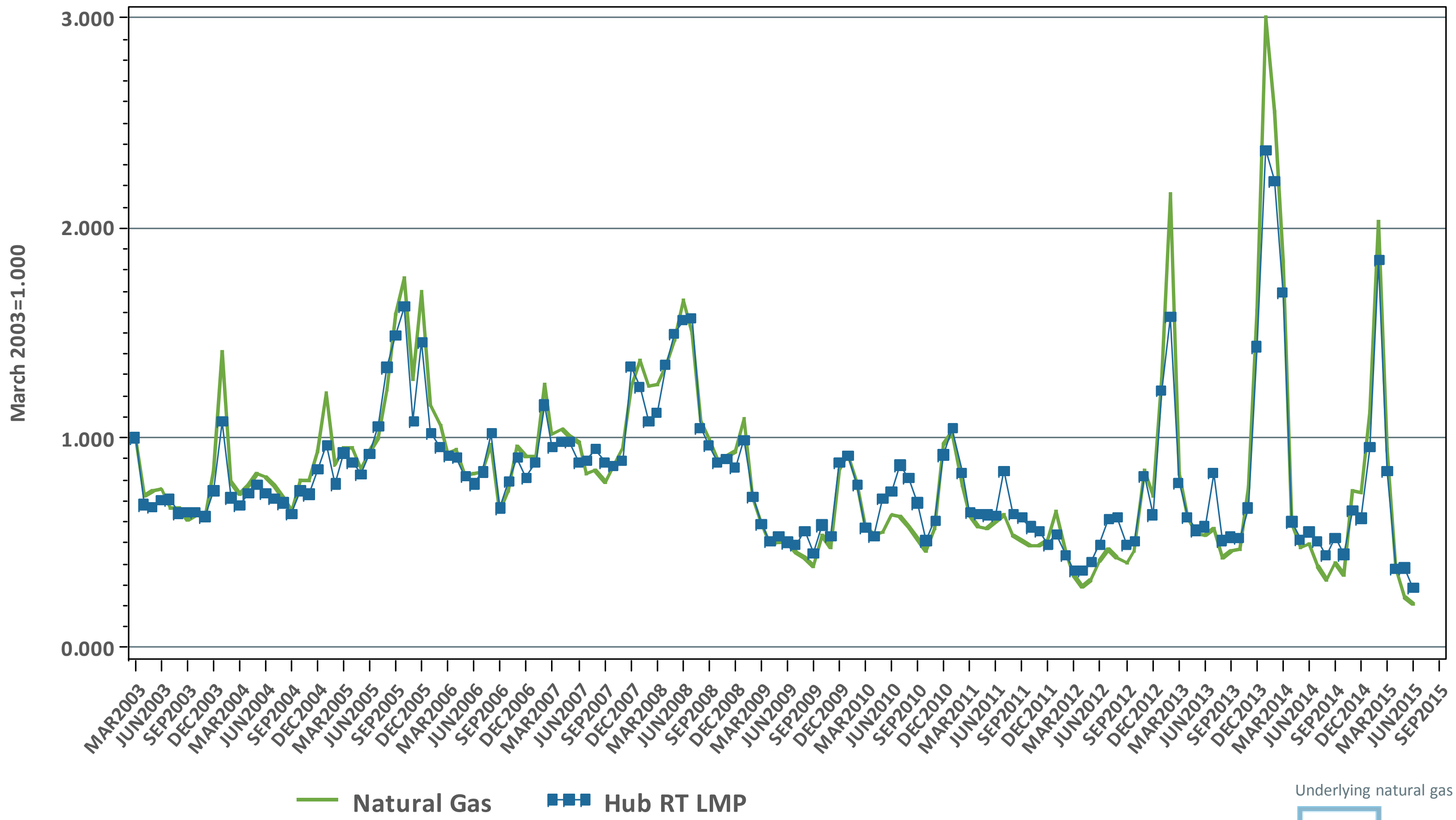
DA vs. RT LMPs ($/MWh)

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%

June-14	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$38.30	$38.12	$36.46	$37.75	$37.56	$37.76	$37.79	$38.03	$37.92
Real-Time	$38.24	$37.92	$36.52	$37.61	$37.24	$37.82	$37.89	$37.94	$37.92
RT Delta %	-0.2%	-0.5%	0.2%	-0.4%	-0.9%	0.1%	0.2%	-0.2%	0.0%
June-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$21.46	$21.89	$20.83	$21.08	$21.04	$20.95	$21.05	$21.25	$21.16
Real-Time	$19.79	$20.13	$19.34	$19.53	$19.39	$19.41	$19.53	$19.66	$19.61
RT Delta %	-7.8%	-8.1%	-7.2%	-7.3%	-7.9%	-7.4%	-7.2%	-7.5%	-7.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-44.0%	-42.6%	-42.9%	-44.2%	-44.0%	-44.5%	-44.3%	-44.1%	-44.2%
Yr over Yr RT	-48.2%	-46.9%	-47.1%	-48.1%	-47.9%	-48.7%	-48.5%	-48.2%	-48.3%

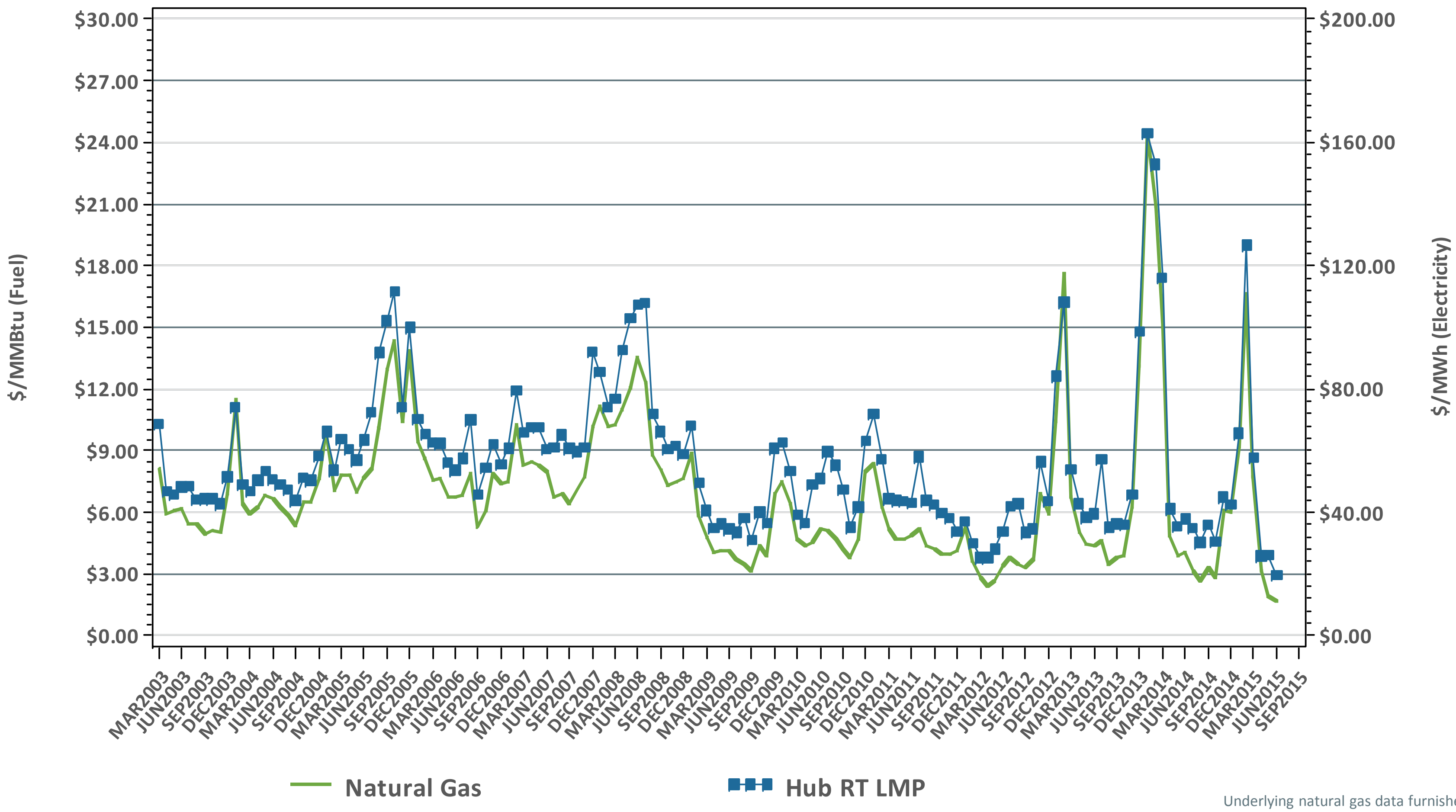
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

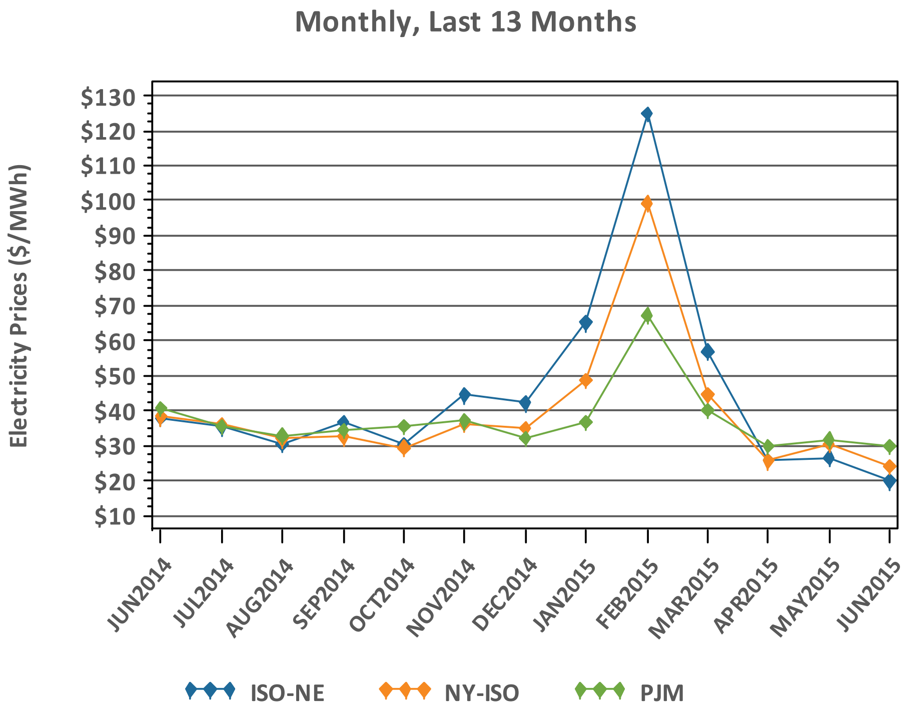
ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

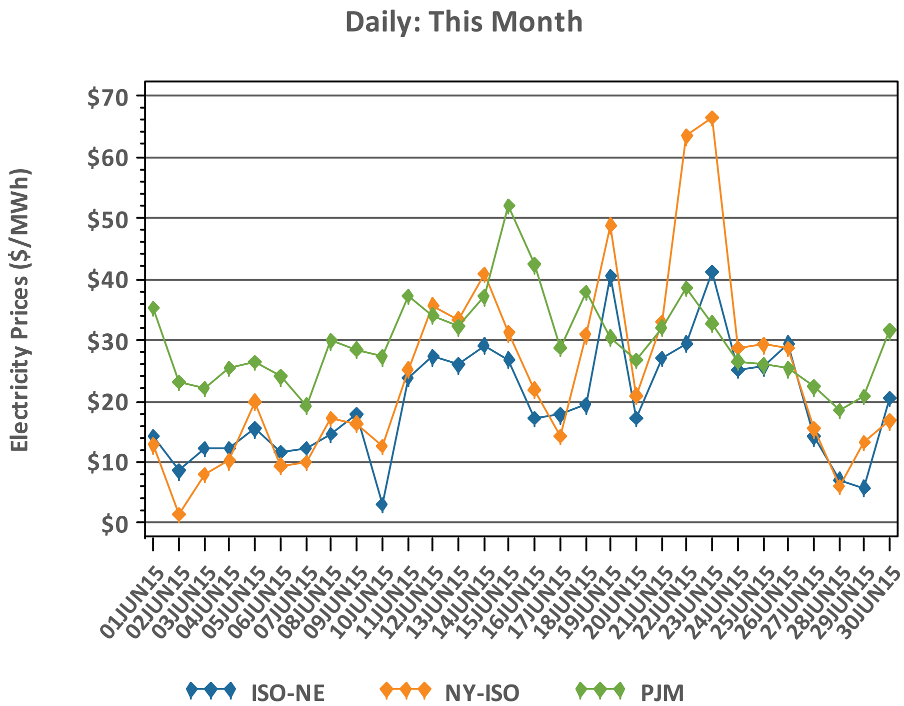


Underlying natural gas data furnished by:

New England, NY, and PJM Real Time Prices

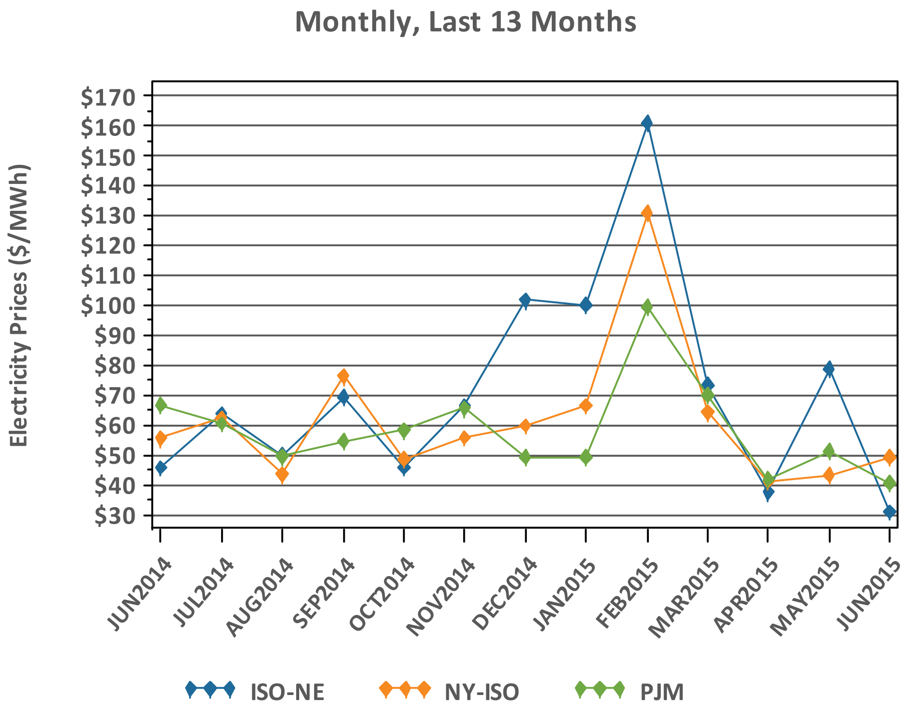


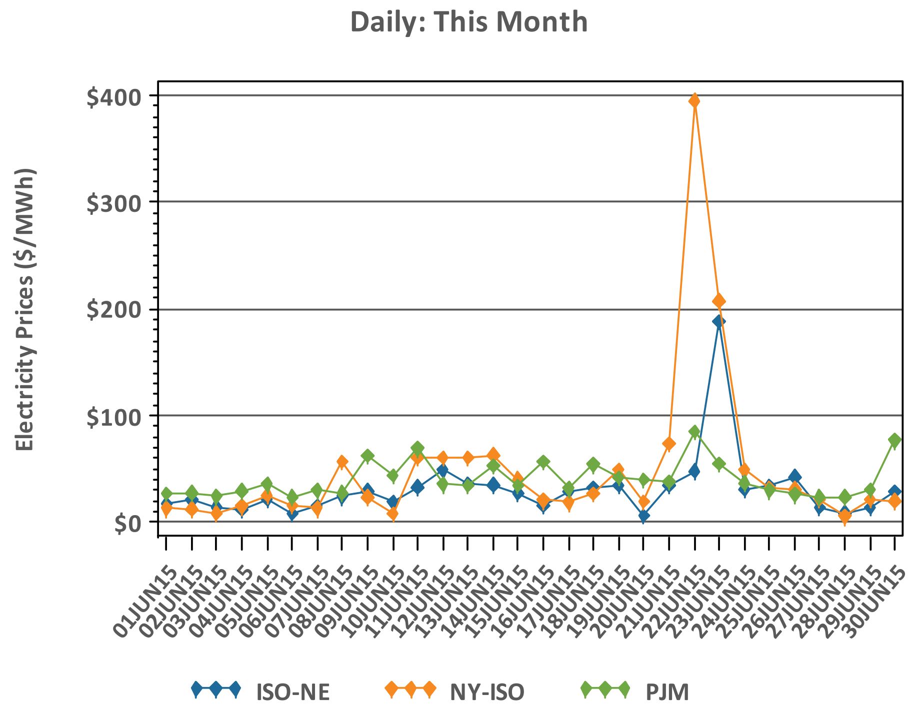
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





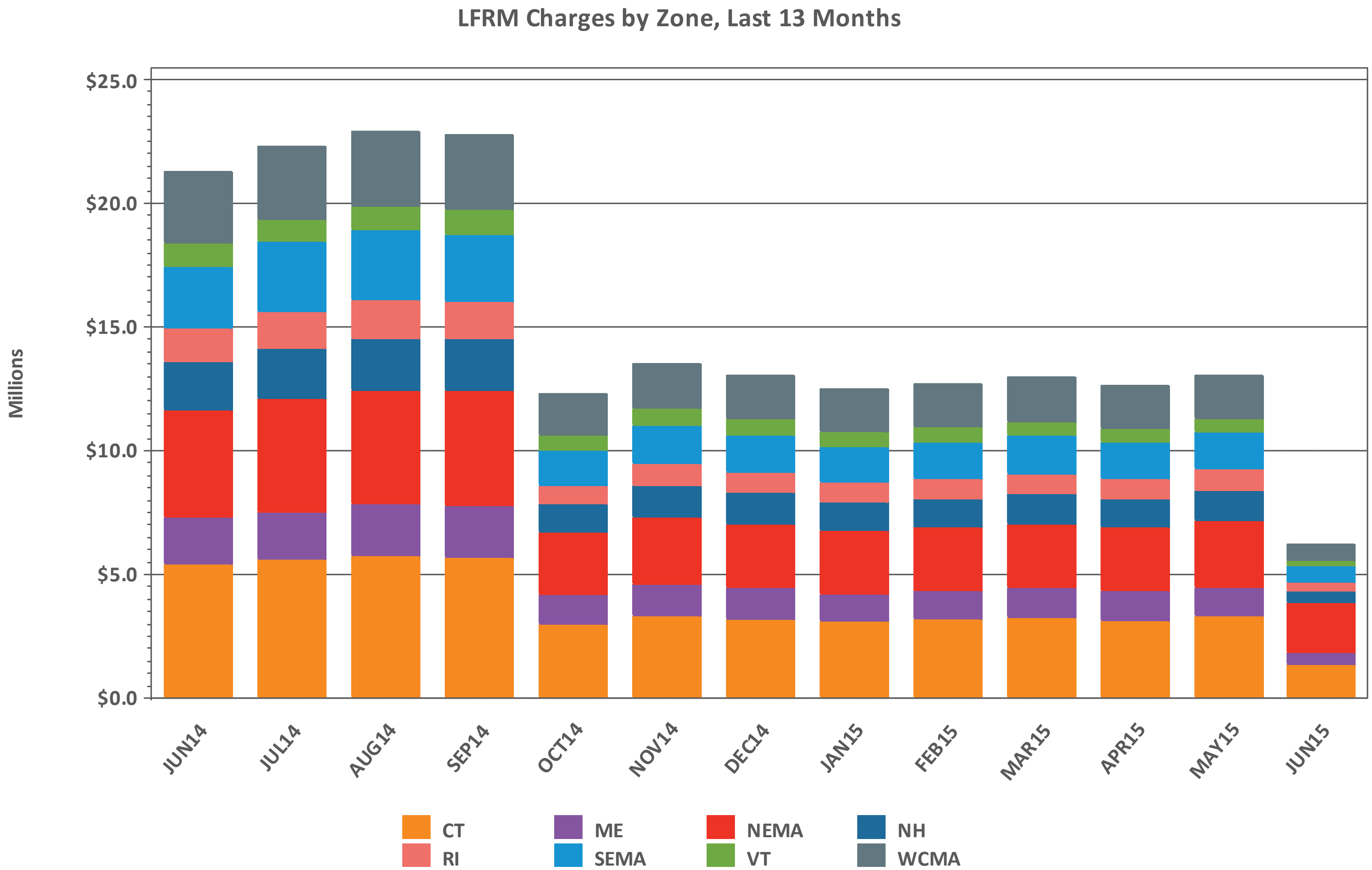
*Forecasted New England peak hour is reflected.

Reserve Market Results – June 2015

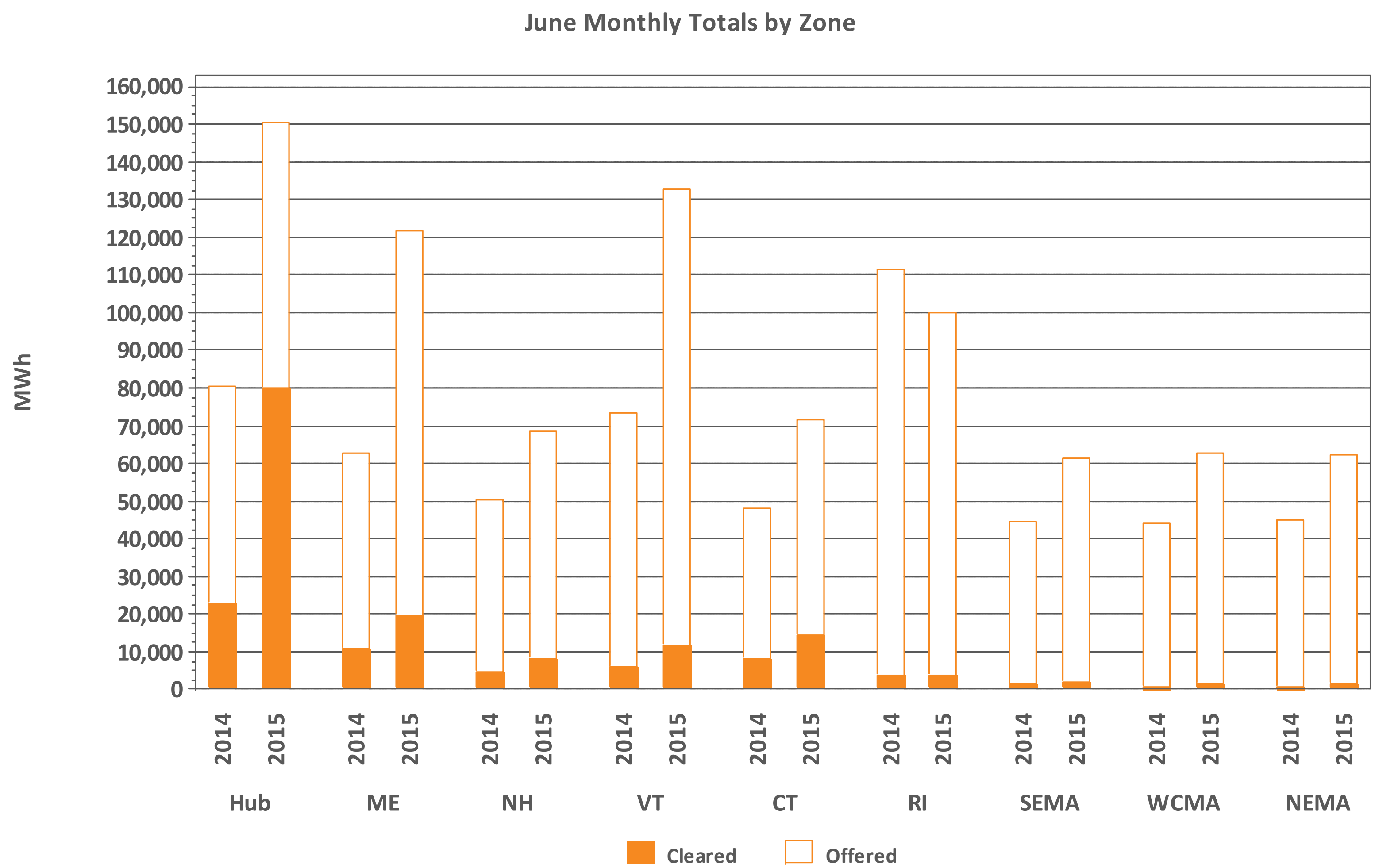
- Maximum potential Forward Reserve Market payments of $6.5M were reduced by credit reductions of $85K, failure-to-reserve penalties of $136K and failure-to-activate penalties of $0, resulting in a net payout of $6.2M or 97% of maximum
  - Rest of System: $2.44M/$2.55M (96%)
  - Southwest Connecticut: $0.45M/$0.46M (99%)
  - Connecticut: $1.59M/$1.60M (99%)
  - NEMA: $1.76M/$1.85M (95%)
- $1.6M total Real-Time credits were reduced by $636K in Forward Reserve Energy Obligation Charges for a net of $958K in Real-Time Reserve payments
  - Rest of System: 81 hours, $580K
  - Southwest Connecticut: 81 hours, $231K
  - Connecticut: 81 hours, $68K
  - NEMA: 81 hours, $80K

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

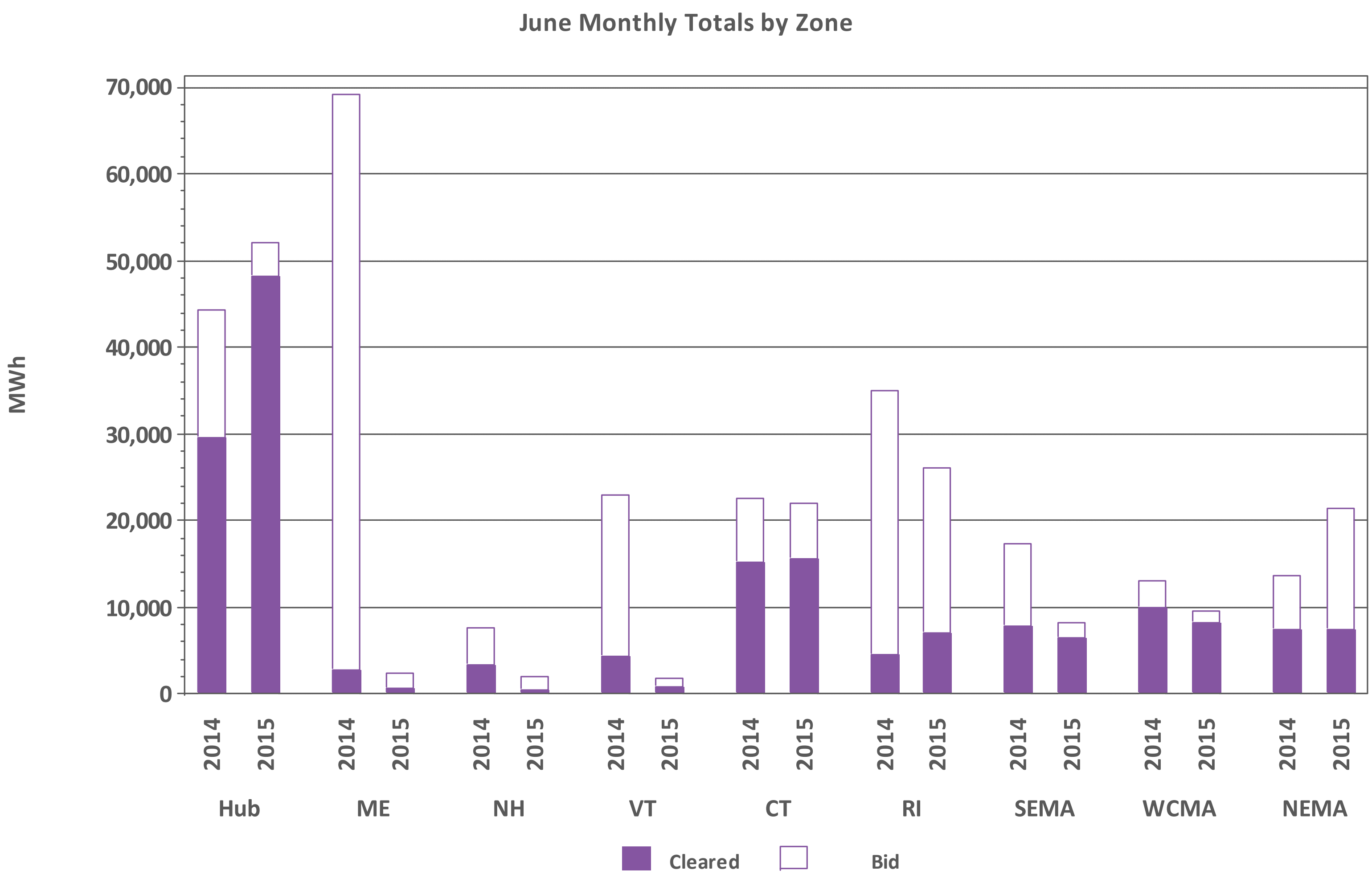
LFRM Charges to Load by Load Zone ($)



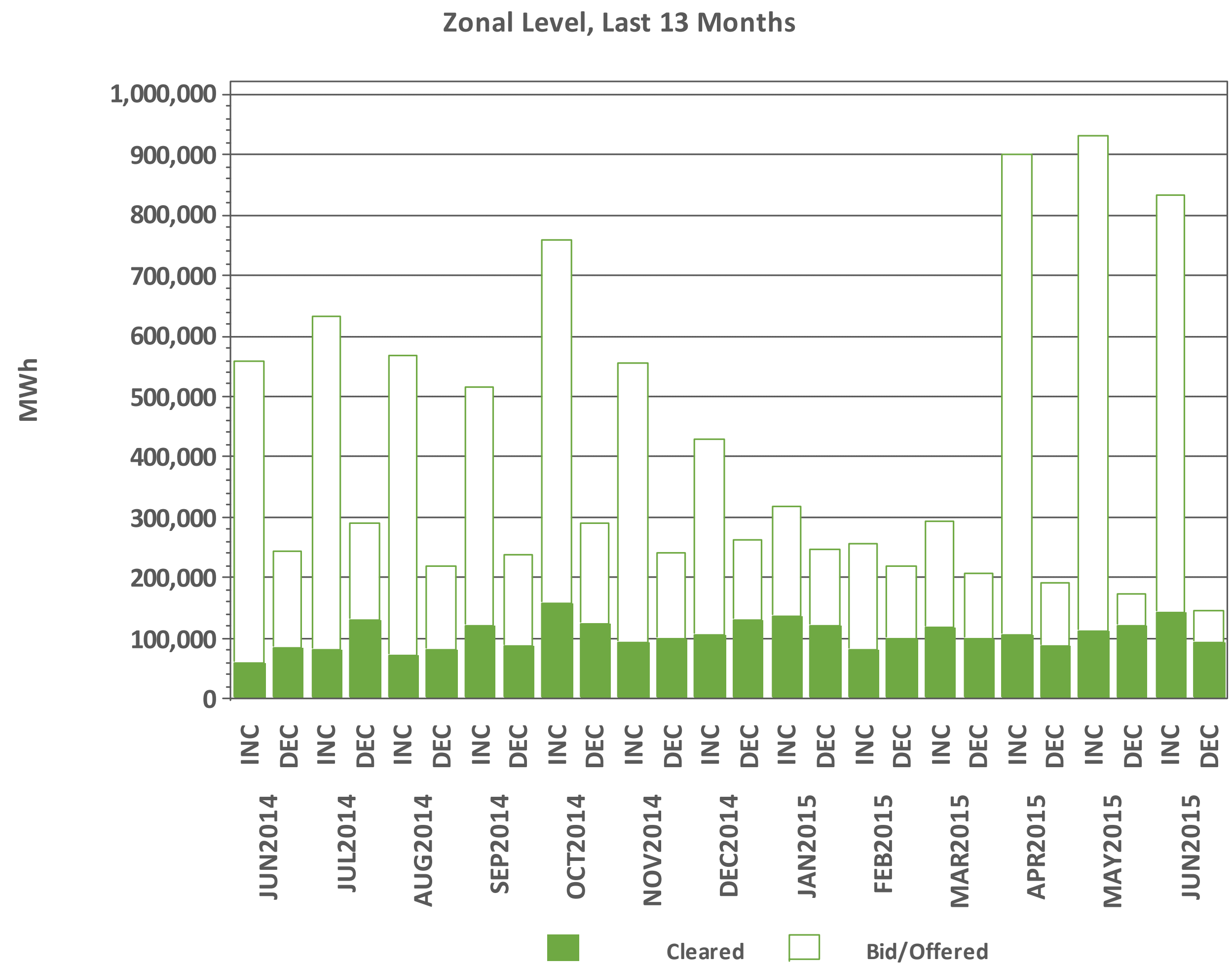
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

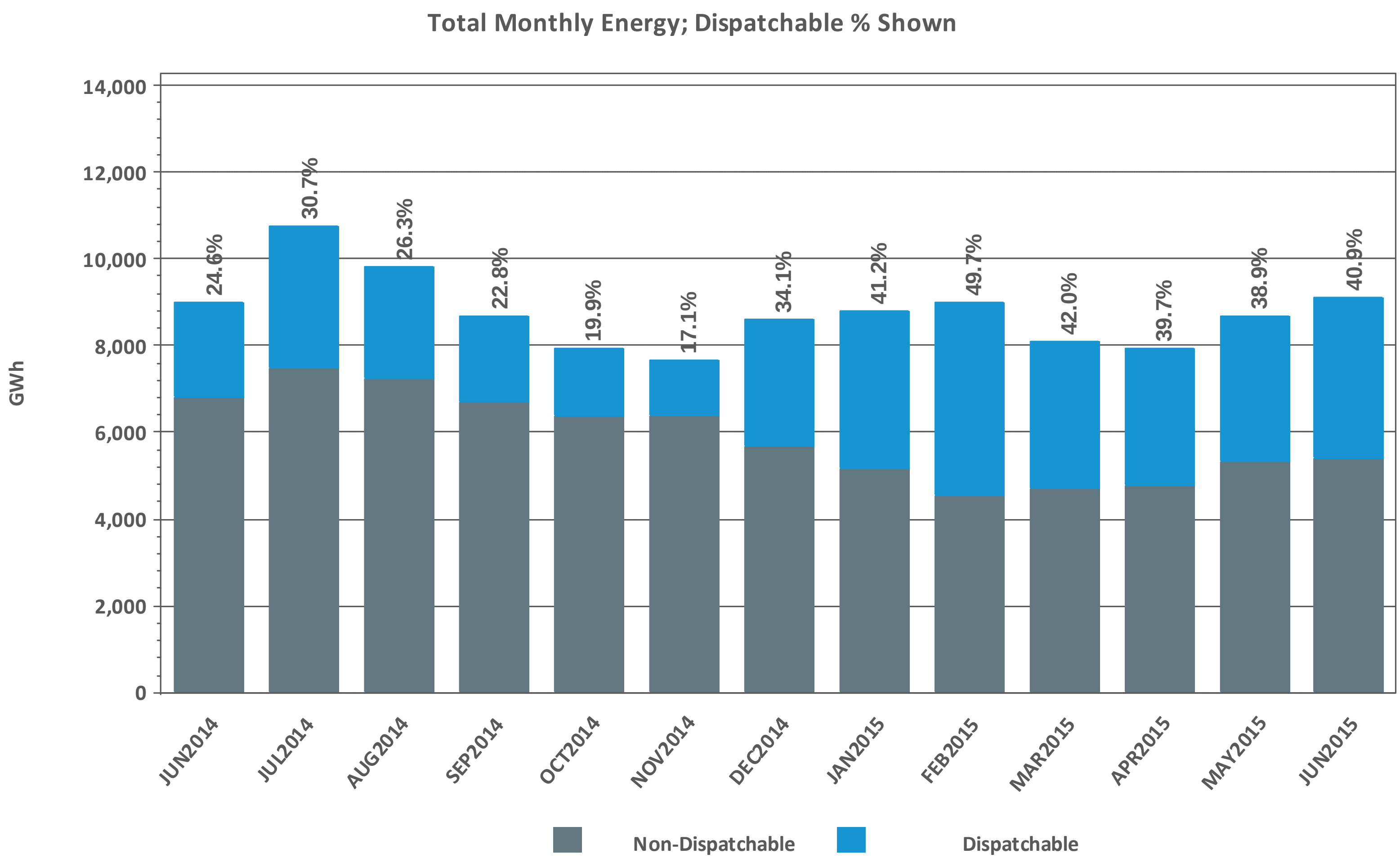


Total Increment Offers and Decrement Bids



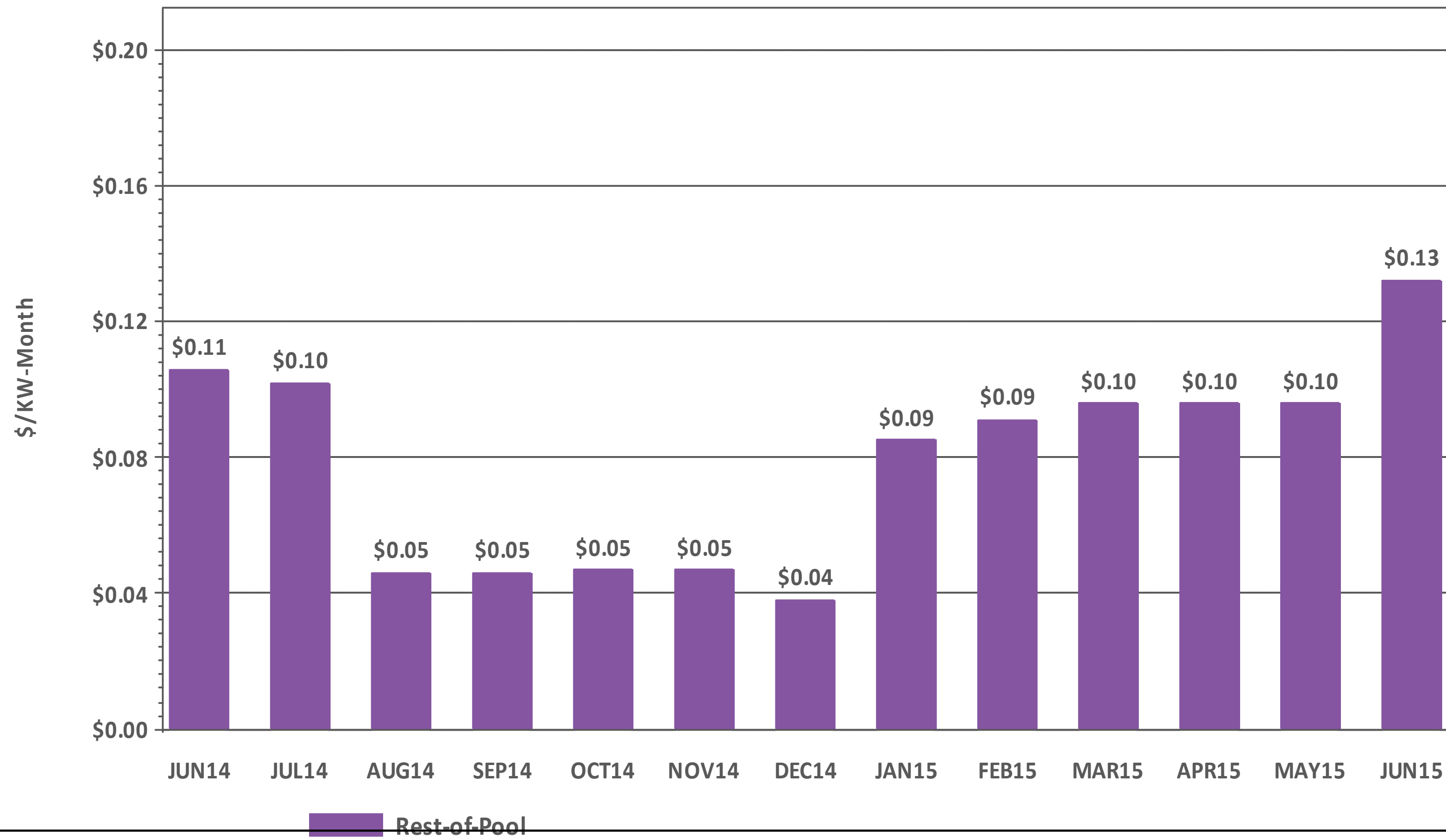
Data excludes nodal offers and bids

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).

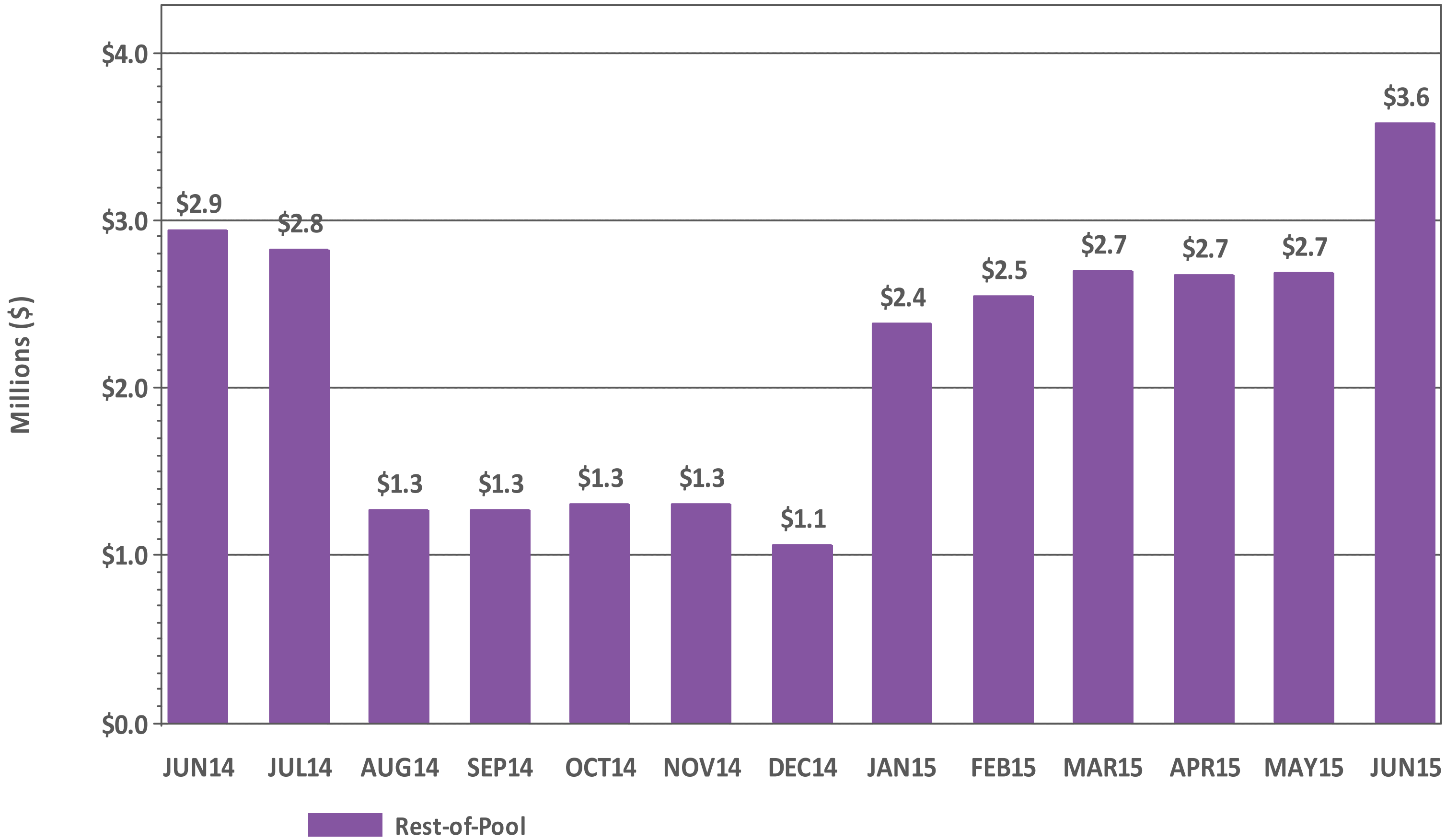
Rolling Average Peak Energy Rent (PER)



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.