AUGUST 2, 2013 | MANCHESTER, NH

NEPOOL PARTICIPANTS COMMITTEE
8/2/13 MEETING, AGENDA ITEM #4

NEPOOL Participants Committee Report

August 2013

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - July natural gas prices over the period were 7.6% higher while oil prices were 1.7% lower than June 2013 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 66% higher than June 2013 averages
- Average July 2013 natural gas prices and RT Hub LMPs, respectively, were up 25% and 57%, respectively, from July 2012 averages.

***All data through July 24 unless noted.**

Underlying natural gas data furnished by:

ice Global markets in clear view

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - July payments over the period totaled $20.7M, up $10.9M from June
  - First Contingency payments totaled $11.1M, up $6.2M from June
    - $11.1M paid to internal resources, up $6.3M from June
      - $1.2M charged to DALO, $9.9M to RT Deviations
    - $25K paid to resources at external locations, down $43K from June
      - $15K charged to DALO at external locations, $10K to RT Deviations
  - Second Contingency payments totaled $1.2M, down $2.1M from the June total of $3.3M
      - Protection for Eastern load zones on seven days resulted in payments of $1.2M, most of which resulted on July 16-18 during the heat wave
  - Voltage payments totaled $6.9M, up $5.6M from June
  - Distribution payments totaled $1.5M, up $1.2M from June
  - NCPC payments over the period as percent of Energy Market value were 2.9%

Highlights, cont.

- The lowest 50/50 and 90/10 Summer Operable Capacity Margin is being calculated for the week beginning September 7th.
- The lowest 50/50 and 90/10 Fall Operable Capacity Margin is being calculated for the week beginning September 21st.

Highlights, cont.

- Manual 20 changes regarding external capacity transactions did not gain approval by the MC at their July meeting. The ISO will be seeking a vote at the August NPC
- ISO made a FERC compliance filing on July 30 indicating a schedule to target FCA #9 for changes related to the development of capacity zones
- RSP13 draft has been distributed to stakeholders for comment and will be reviewed at the August 13 PAC meeting

JULY 3, 2013 DCS EVENT

Highlights

- Forest fires in James Bay area of Quebec in vicinity of 735 kV transmission right-of-way
- Multiple transmission line trips coupled with losses of generation, load and exports
  - Four transmission lines tripped
  - Approximately 2,900 MW of Quebec generation rejected Special Protection Scheme
  - Approximately 3,500 MW of Quebec load tripped
  - Approximately 3,370 MW of exports to NYISO, ISO-NE, NBSO, and IESO tripped
- New England lost ~1,750 MW of imports from HQ
- New England recovered from the source loss in under 11 minutes
- No SOL or IROL violations in New England

Highlights, cont.

- Eastern Interconnection was able to sustain the loss of HQ Imports
  - System load was decreasing
  - Imports from HQ tripped over the course of several minutes
  - Length of disturbance allowed governor response and some level of AGC to mitigate the impact on Eastern Interconnection
  - Frequency decreased to a minimum value of 59.91

- TransÉnergie is working with NERC/NPCC to perform an event analysis

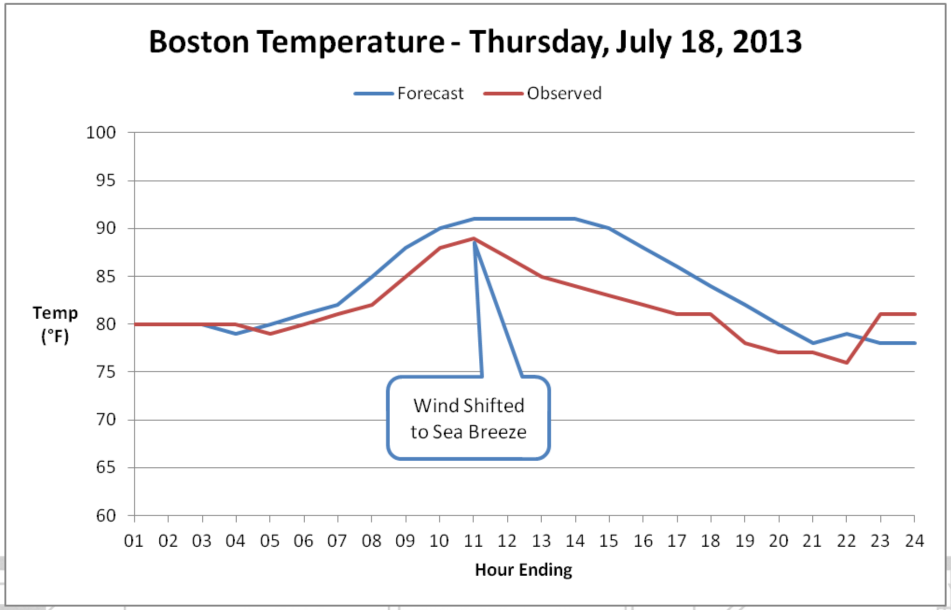
WEEK OF JULY 14-20, 2013 OPERATIONS

Preparations for the Week

- All transmission work and generation outages and reductions that could be postponed or cancelled were completed prior to heat wave
- ISO New England Operations Staff had preparatory meetings with the following entities prior to and during the heat wave:
  - NYISO, HQ, NBSO, IESO, PJM and MISO Reliability Coordinators
  - Master Local Control Centers
  - Gas Pipeline Operators
- Implemented M/LCC #2 at 1045 on Monday, 7/15/13
- Forecasted tight operating reserves throughout the week

Preparations for the Week, cont.

- Weather deviations from forecast impacted load forecast accuracy. This was particularly the case on Thursday when the temperatures dropped significantly along the coast due to an afternoon sea breeze
  - Actual average temperatures were lower than forecast by an average of 1.1°F during peak hours throughout the week.
  - Boston temperatures on Thursday during peak hours were lower than forecast by an average of 3.4°F with a dew point below forecast by an average of 1.4°F
  - Friday saw the closest correlation between the weather and load forecast with very high temperatures and dew points throughout New England



Capacity Deficiency Event Summary

- Operating Procedure #4 “Action During a Capacity Deficiency” (OP-4) implemented on July 19 due to generator reductions and transmission constraints.

Action(s)	Implemented	Cancelled
M/LCC #2	7/15 (10:45)	7/20 (21:00)
OP#4 Action 1	12:00	20:30
OP#4 Action 2*	13:00	20:30
OP#4 Action 3*	14:20	18:00
OP#4 Action 5*	15:00	18:00

(*) = Actions of OP#4 that were not implemented in Maine due to transmission constraints

Capacity Deficiency Event Summary, cont.

- On Friday forecasted an operating reserve deficiency of 449 MW based on the load forecast of 27,850
- Peak hour generator reductions and outages totaled 4,611 MW
- Peak hour (Hour Ending 17) imports were as follows:

Interface	Actual	Interface	Actual
NYN	629 Import	NB	800 Import
NNC	38 Export	Phase 2	1400 Import
CSC	330 Export	HG	218 Import

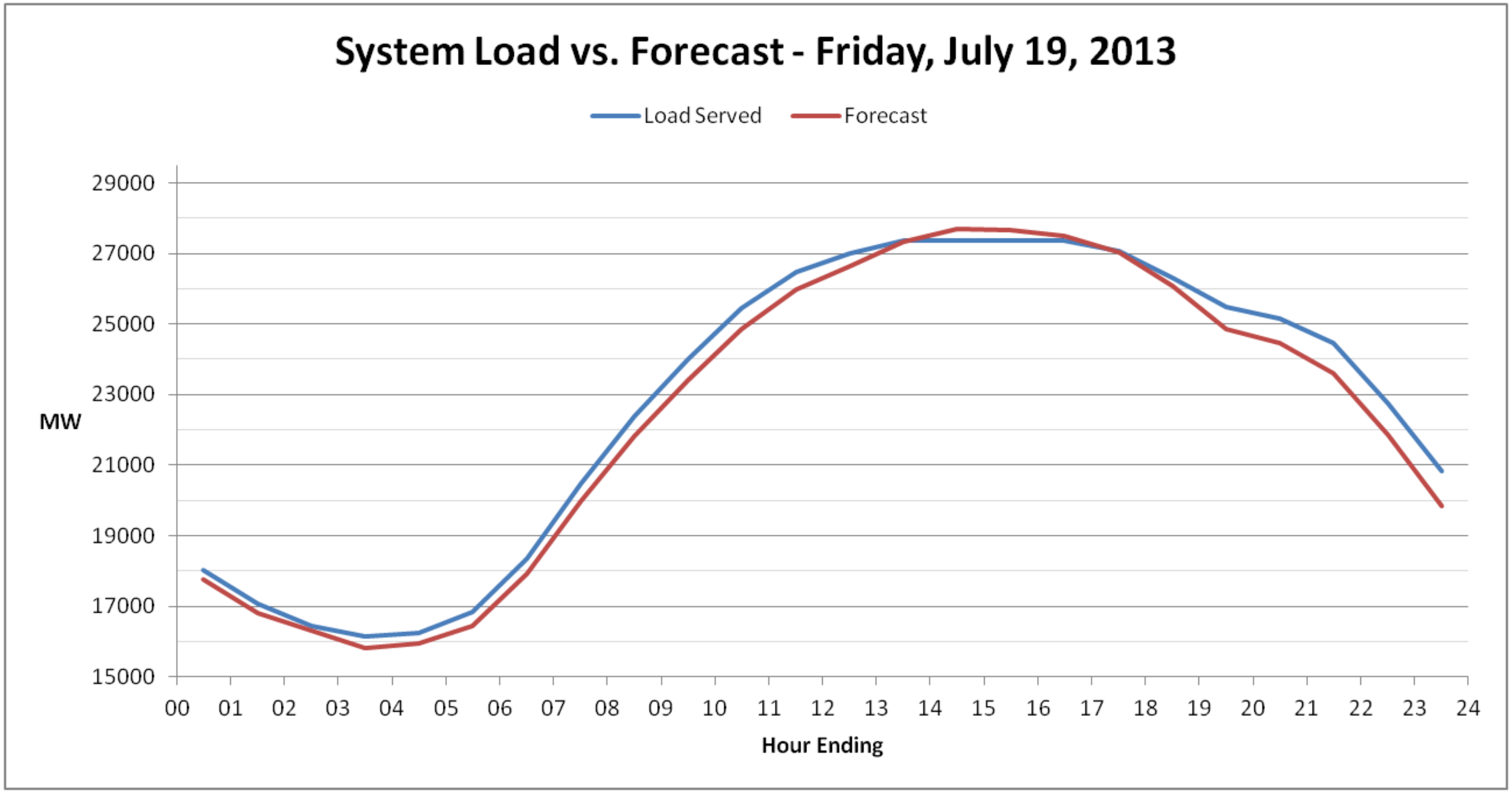
Capacity Deficiency Event Summary, cont.

- Forecasted temperature in Hartford and Boston was 99°F.
  - Sixth consecutive day with temperatures climbing above 90 degrees in New England
- Actual temperatures in Boston were as forecasted. Temperature in Hartford was slightly lower.
- Expected schedule of net deliveries for the peak hour were 1,718 MW. The actual scheduled net deliveries were 2,677 MW

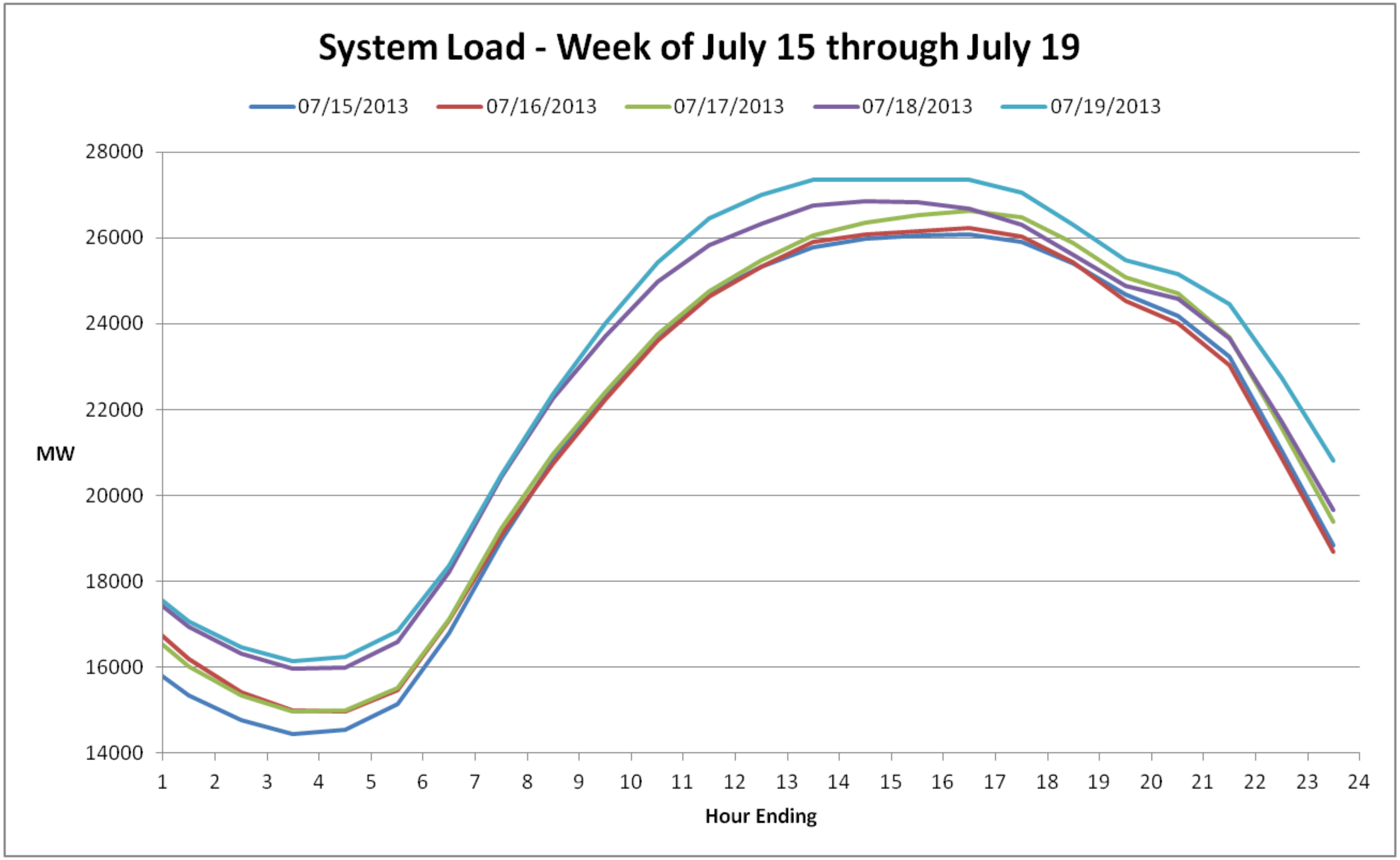
Capacity Deficiency Event Summary, cont.

- Just prior to noon, operating reserves became deficient
  - OP#4 Action 1 was declared at 12:00 allowing for the depletion of 30 minute reserves and notification to all resources to be prepared to provide capacity up to Capacity Supply Obligation
  - At 13:00, Action 2 was declared (excluding Maine) dispatched all Real Time Demand Resources (193 MW)
  - At 14:20, Action 3 of OP#4 was declared requesting Market Participants to conserve energy
  - At 15:00, Action 5 of OP#4 was declared in order to maintain ten minute operating reserves. 200 MW of Participant Emergency Energy Transactions were purchased in Hour Ending 16.

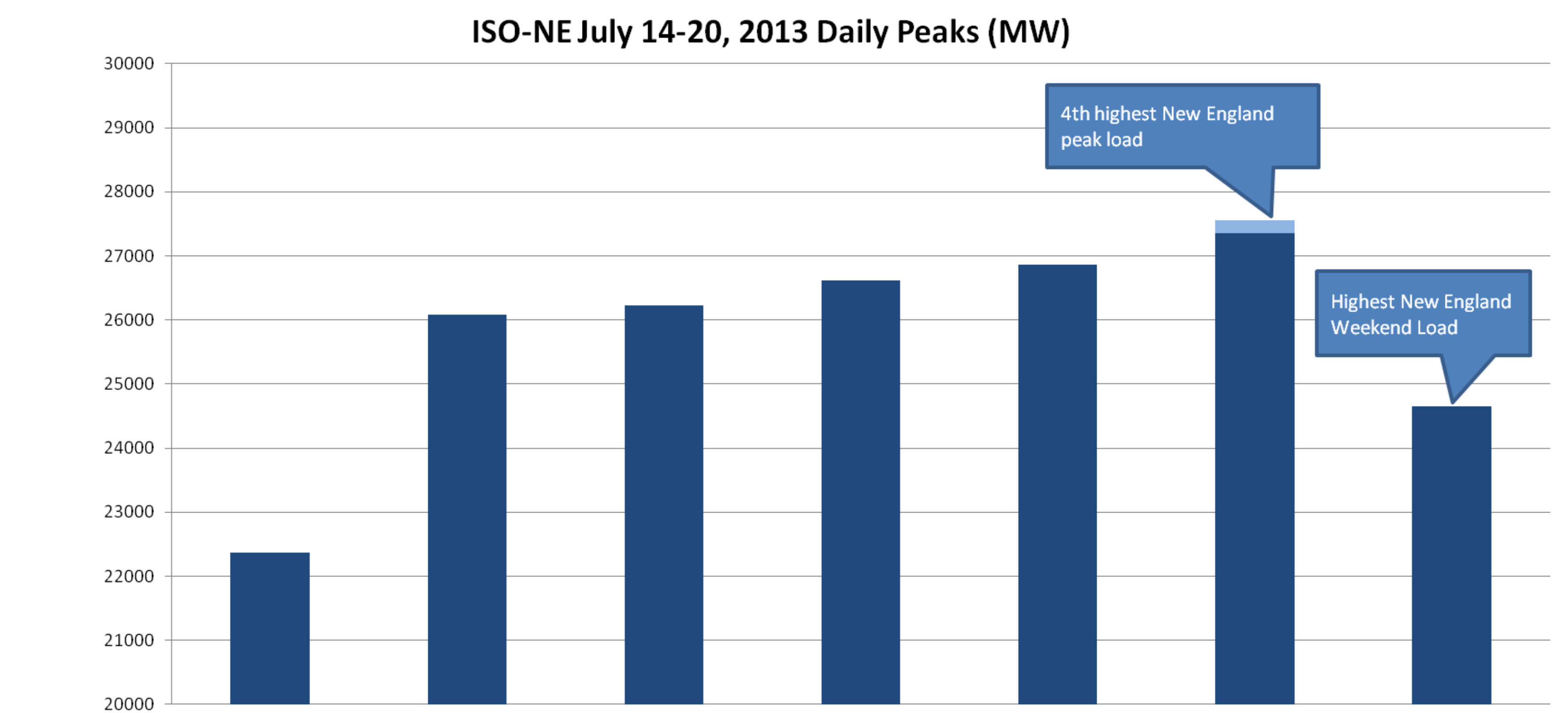
System Load vs. Forecast on July 19



System Load – Week of July 15 through July 19

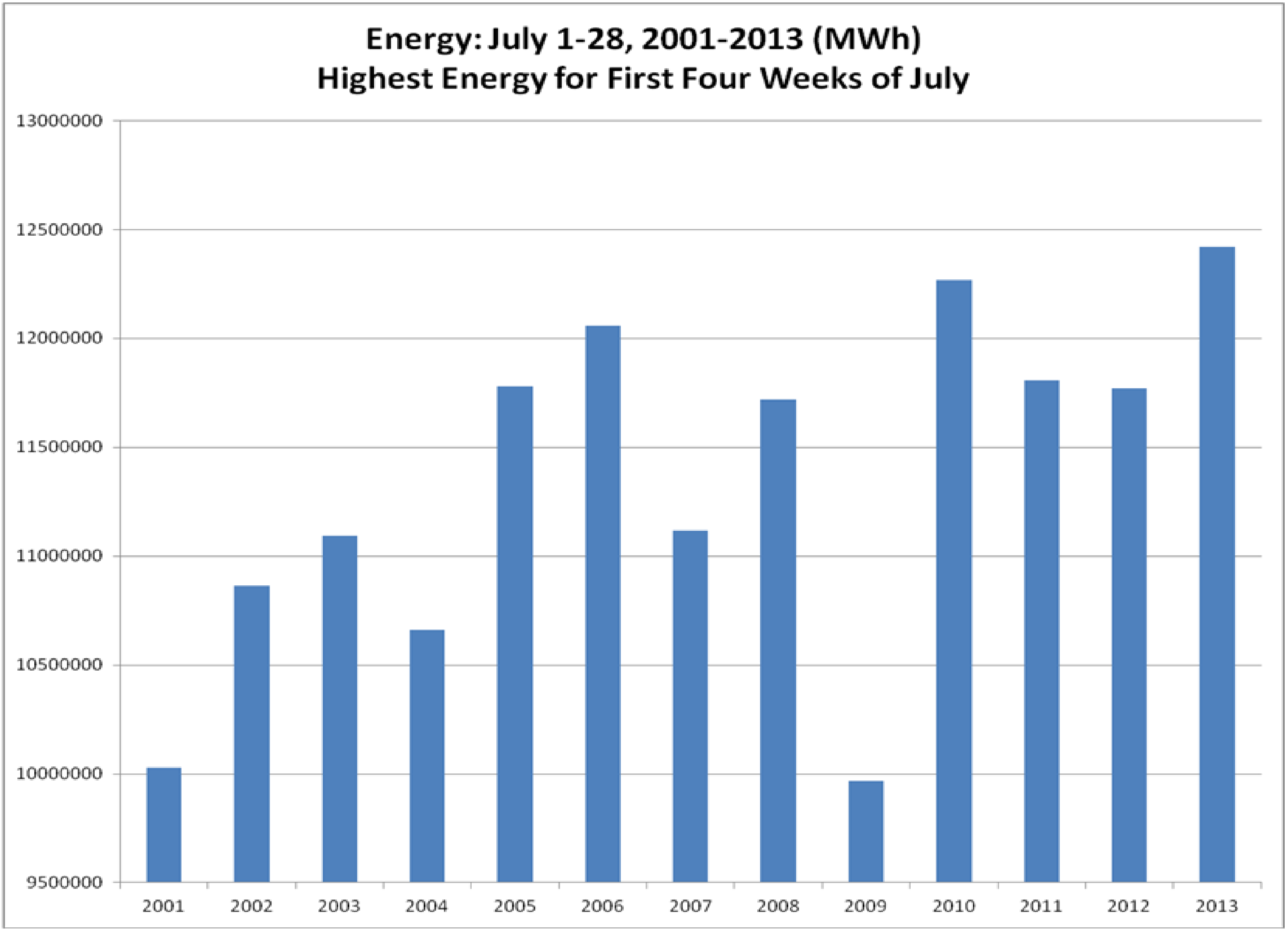


Daily Peak Load – Week of July 14



	07/14/2013 (Sun)	07/15/2013 (Mon)	07/16/2013 (Tue)	07/17/2013 (Wed)	07/18/2013 (Thu)	07/19/2013 (Fri)	07/20/2013 (Sat)
Demand Resources						194	
Actual	22374	26089	26225	26623	26867	27359	24648

Total Energy Consumed in July since 2001



Summary of Demand Response Dispatch

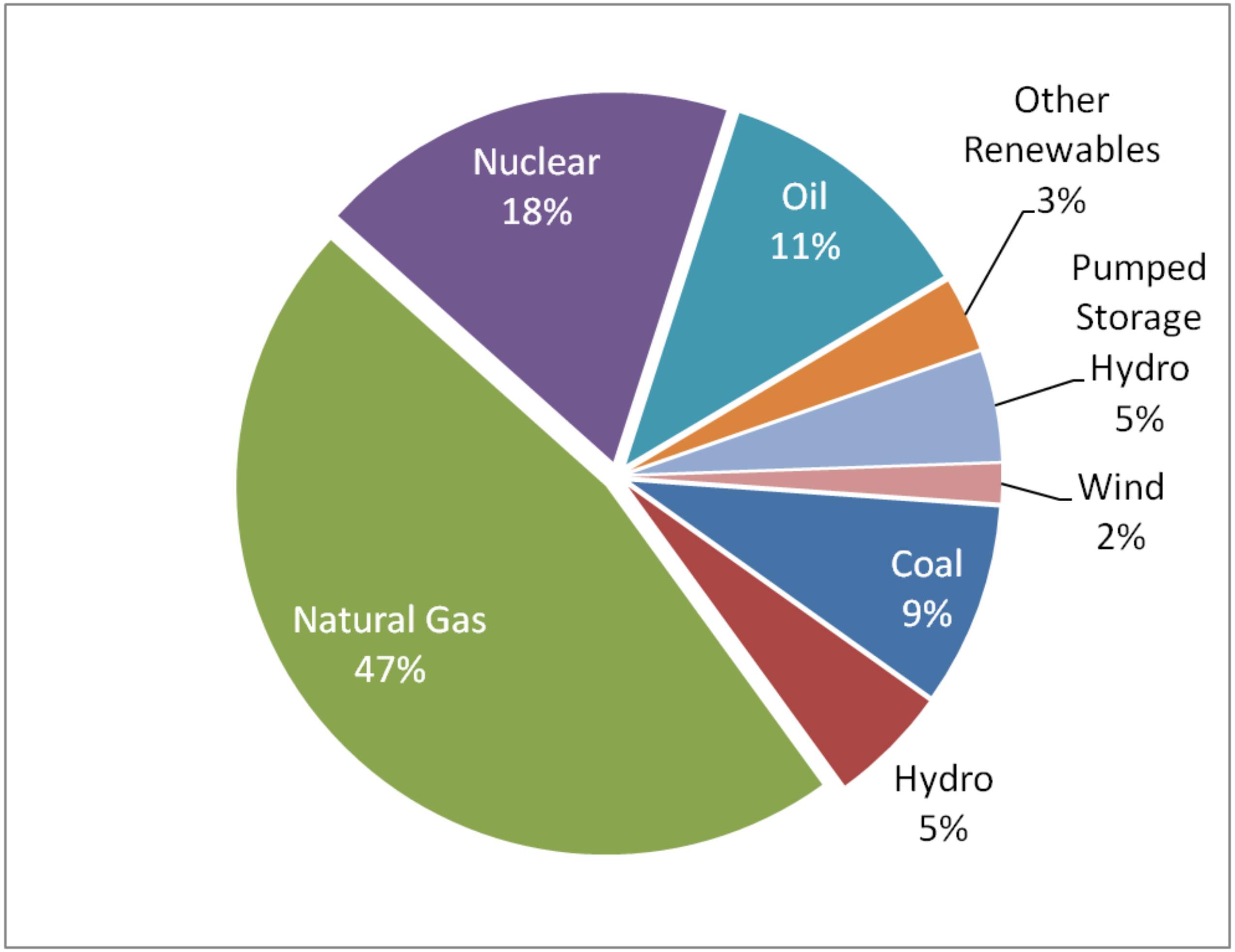
- 193 MW Dispatched at 13:05 (performance measurement starts at 13:35)
- Demand Response dispatch cancelled at 20:35

Duration of the July 19th, 2013 Real Time Event (Local Time)		MW Dispatched (NET CSO)	Performance during 100% Dispatch Period (MW)	Percent Avg. Performance vs. Net CSO
Start Time	End Time			
13:35	20:35	193	184	95%

Demand Response Performance

Load Zone	Net CSO (MW)	Performance (MW)	Percent of Initial Performance to Net CSO
CT	87.1	81.2	93.2%
NEMA	25.4	26.0	102.5%
NH	3.6	9.8	276.9%
RI	19.4	8.2	42.3%
SEMA	10.1	9.6	94.9%
VT	23.0	29.3	127.1%
WCMA	24.7	19.7	79.7%
Total	193.3	183.8	95.1%

Generation by fuel type at peak



Peak Energy Rent (PER) Impacts on July 19

July 19, 2013 Preliminary Results

- Peak Energy Rent conditions occurred during 5 hours on July 19, 2013 (hours ending 13:00 through 17:00) in the Rest-Of-Pool Capacity Zone ***only***
- The strike price for the day (for comparison to Hub LMPs) was \$558.37/MWh (Actual Real-Time Hub LMPs ranged from \$585-\$869/MWh)
- The PER hours during July are estimated to produce a ~\$1.9M reduction to CSO payments during the August 2013 delivery month (billed in September)

Observations

- Transmission Constraints from North to South locked in Northern Generation from getting to load centers
  - In past years, transfers from New Brunswick to New England have been low due to Point Lepreau outage and this is no longer the case
- 6th hot day in a row (>90° F)
  - Generator reductions due to ambient air temperature and environmental issues
- No transmission system facilities failures
- Adequate reactive resources to maintain transmission system voltages
- System Operators at the ISO, LCCs, External Areas, Generating Designated Entities and Demand Designated Entities performed well and in a collaborative and coordinated fashion to maintain reliability of the system

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature – Above Average (+2.0) Max 99, Min 60 Precipitation 3.39” (Liquid) Average Normal 2.86”,	Hartford	Temperature – Average (+3.0) Max 97, Min 58 Precipitation 4.18” (Liquid) – Average Normal = 3.43

Peak Load:	27, 377 MW *	July 19,2013	17:00

M/LCC2: 07/03/2013, 17:00 – 20:00, Due to a New England capacity deficiency - H.Q. Major Transmission event
M/LCC2: 07/04/2013, 12:55 – 20:00, Due to a New England capacity deficiency - Loss of 1 pole of Phase 2
M/LCC2: 07/10/2013 14:30 – 20:00, Due to A New England capacity deficiency with congestion in Maine
M/LCC2: 07/15/2013, 10:45 through 7/20/2013 21:00, Due to extended hot weather and forecasted New England capacity deficiencies
OP4: Action 1 07/19/2013 12:00 - 20:30 Implemented Power Caution
OP4: Action 2 07/19/2013 13:15 – 20:30 Demand response activated all of New England except Maine -194 MW
OP4: Action 3 07/19/2013 14:20 - 18:00 Request Voluntary Load Curtailment of Market Participants in NE
OP4: Action 5 07/19/2013 15:00 - 18:00 Called for EET’s
* Does not include preliminary estimate 194 MW of RTDR dispatch.

System Operations

NPCC Simultaneous Activation of Reserve Events:		
07/03/2013	NYISO	1018 MW
07/03/2013	ISO-NE	1500 MW
07/04/2013	ISO-NE	622 MW
07/14/2013	IESO	850 MW
07/15/2013	PJM	2800 MW
07/16/2013	IESO	850 MW
07/17/2013	NYISO	674 MW
07/18/2013	ISONE	516 MW
07/19/2013	IESO	800 MW
07/22/2103	IESO	500 MW

System Operations

Minimum Generation Warning	07/01/13	Start-22:00, Expired-23:39 Interchange Cuts Only
Minimum Generation Warning	07/02/13	Start-02:00, Expired-07:00 No Actions
Minimum Generation Warning	07/02/13 – 07/03/13	Start-23:00, Expired-07:00 Interchange cuts & SS Denied
Minimum Generation Event	07/03/13	Start- 00:01, Expired-05:00 Interchange cuts & SS Denied
Minimum Generation Warning	07/10/13	Start- 03:00, Expired-07:00 Interchange cuts only
Minimum Generation Warning	07/12/13	Start-03:00, Expired-07:00 Interchange cuts only
Minimum Generation Warning	07/13/13	Start-00:01, Expired-09:00 Interchange Cuts & SS denied
Minimum Generation Event	07/13/13	Start-08:00Expired-09:00 Interchange Cuts & SS denied
Minimum Generation Warning	07/14/13	Start-00:01, Expired 09:00 Interchange Cuts only

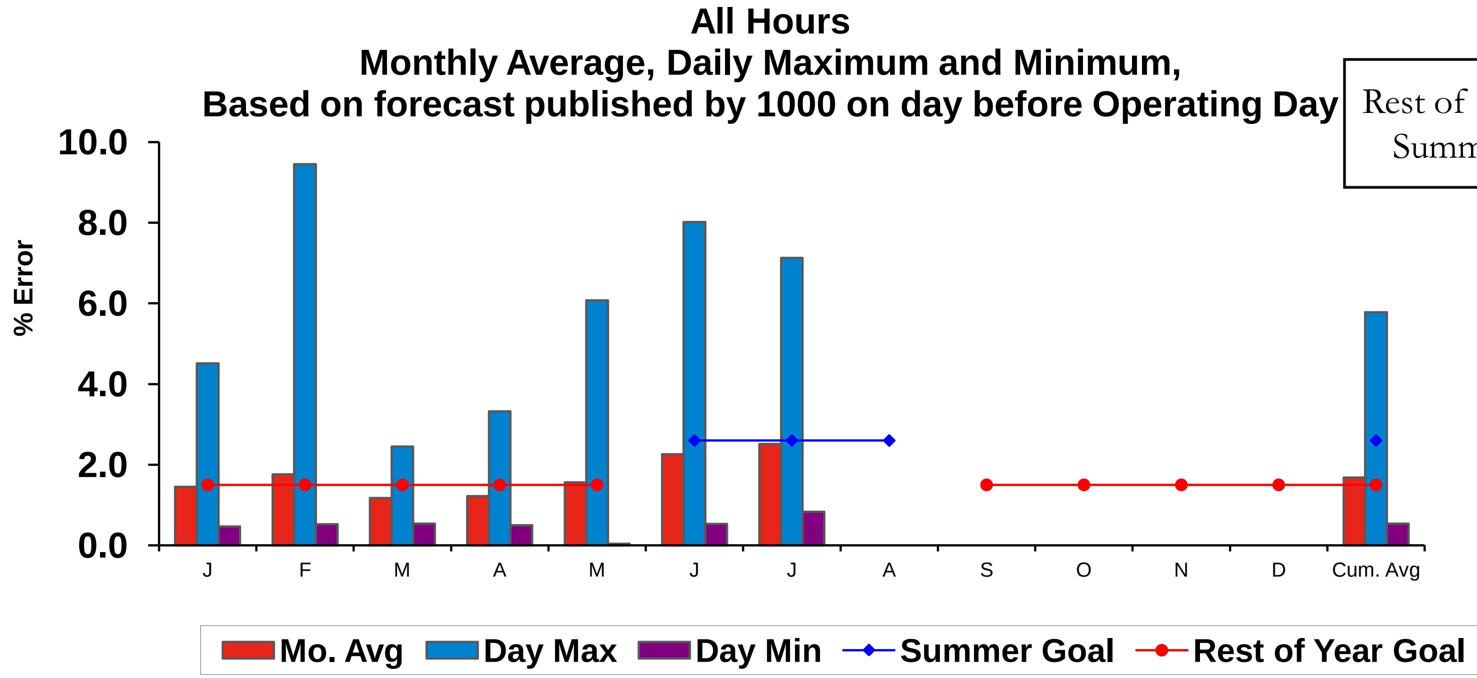
System Operations

Minimum Generation Warning	07/17/13	Start-05:00 Expired-07:00 Interchange Cuts Only
Minimum Generation Warning	07/25/13	Start-02:00, Expired 06:00 Interchange Cuts Only
Minimum Generation Warning	07/25/13	Start-02:00, Expired 06:00 Interchange Cuts Only
Minimum Generation Warning	07/25/13	Start-12:30, Expired 22:59 Interchange Cuts & SS Denied
Minimum Generation Warning	07/26/13	Start-00:01, Expired 07:00 Interchange Cuts Only
Minimum Generation Warning	07/26/13	Start-23:00, Expired 23:59 Interchange Cuts Only
Minimum Generation Warning	07/27/13	Start-00:01, Expired 09:00 Interchange Cuts & SS Denied
Minimum Generation Event	07/27/13	Start-05:00, Expired 08:00 Interchange Cuts & SS Denied
Minimum Generation Warning	07/28/13	Start-08:00, Expired 10:00 Interchange Cuts & SS Denied

2013 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	1.45	1.64	1.17	1.22	1.56	2.26	2.51						1.68
Day Max	4.51	9.45	2.45	3.32	6.07	8.02	7.13						5.78
Day Min	0.46	0.52	0.54	0.50	0.40	0.53	0.83						0.54
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	1.43	1.76	1.17	1.21	1.56								1.40
Summer Actual						2.26	2.51						2.38

Sponsor - John Norden

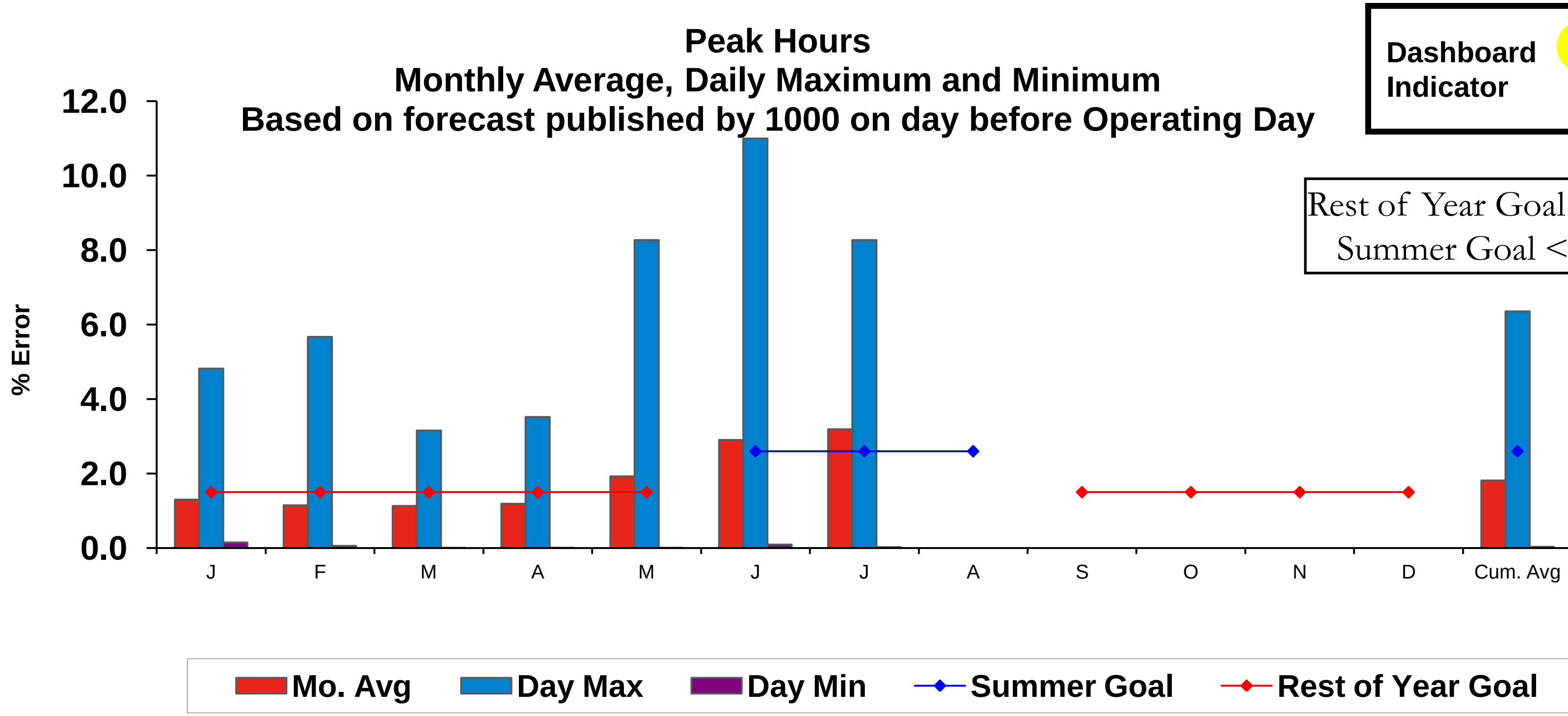
Contact – William Callan

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

Summer consists of June, July & August

2013 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	1.30	1.15	1.13	1.19	1.92	2.90	3.19						1.81
Day Max	4.82	5.67	3.16	3.52	8.27	11.00	8.27						6.36
Day Min	0.02	0.06	0.01	0.01	0.01	0.09	0.02						0.03
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	1.26	1.23	1.13	1.19	1.40								1.34
Summer Actual						2.9	3.19						3.04

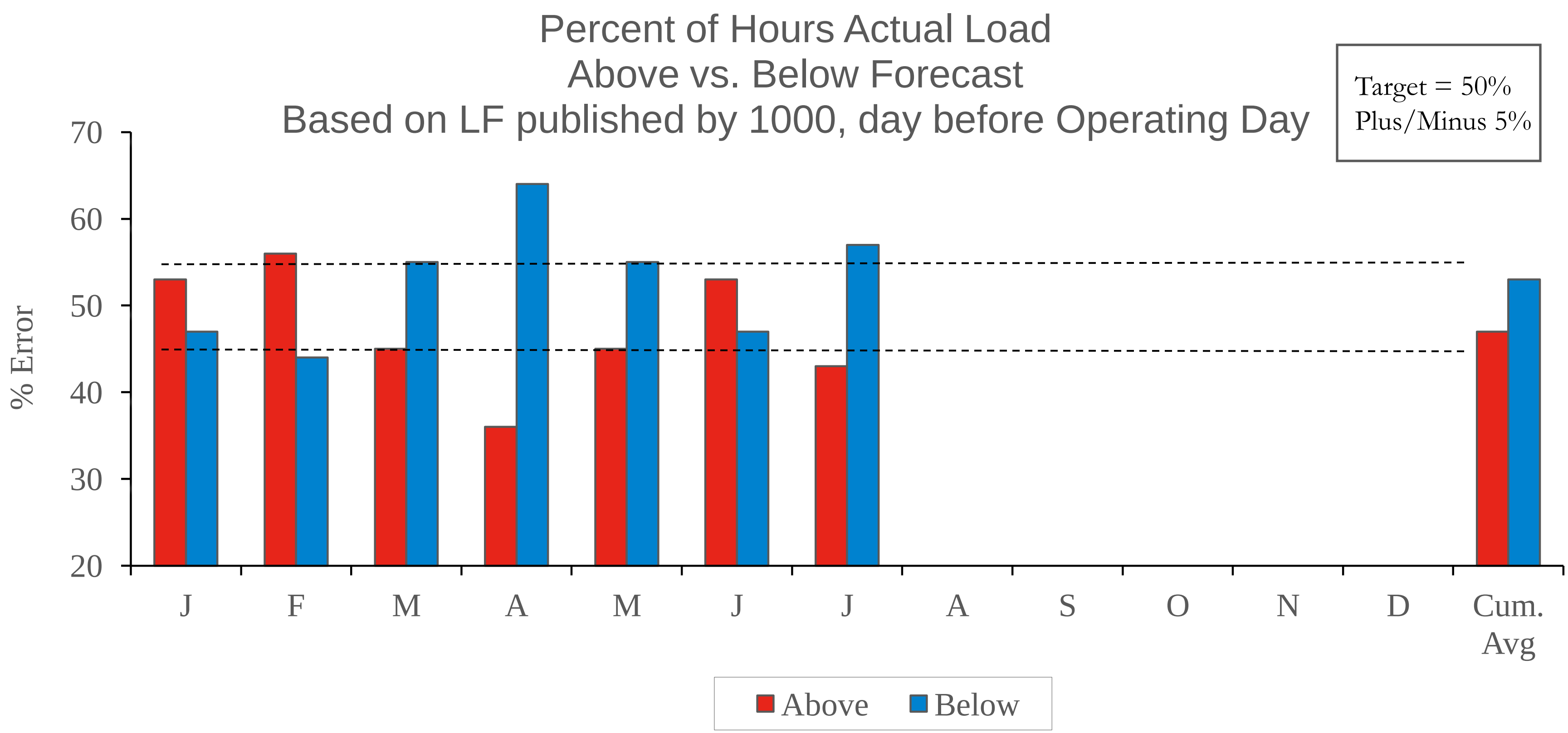
Sponsor - John Norden

Contact - William Callan

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

Summer consists of June, July & August

2013 System Operations - Load Forecast Accuracy

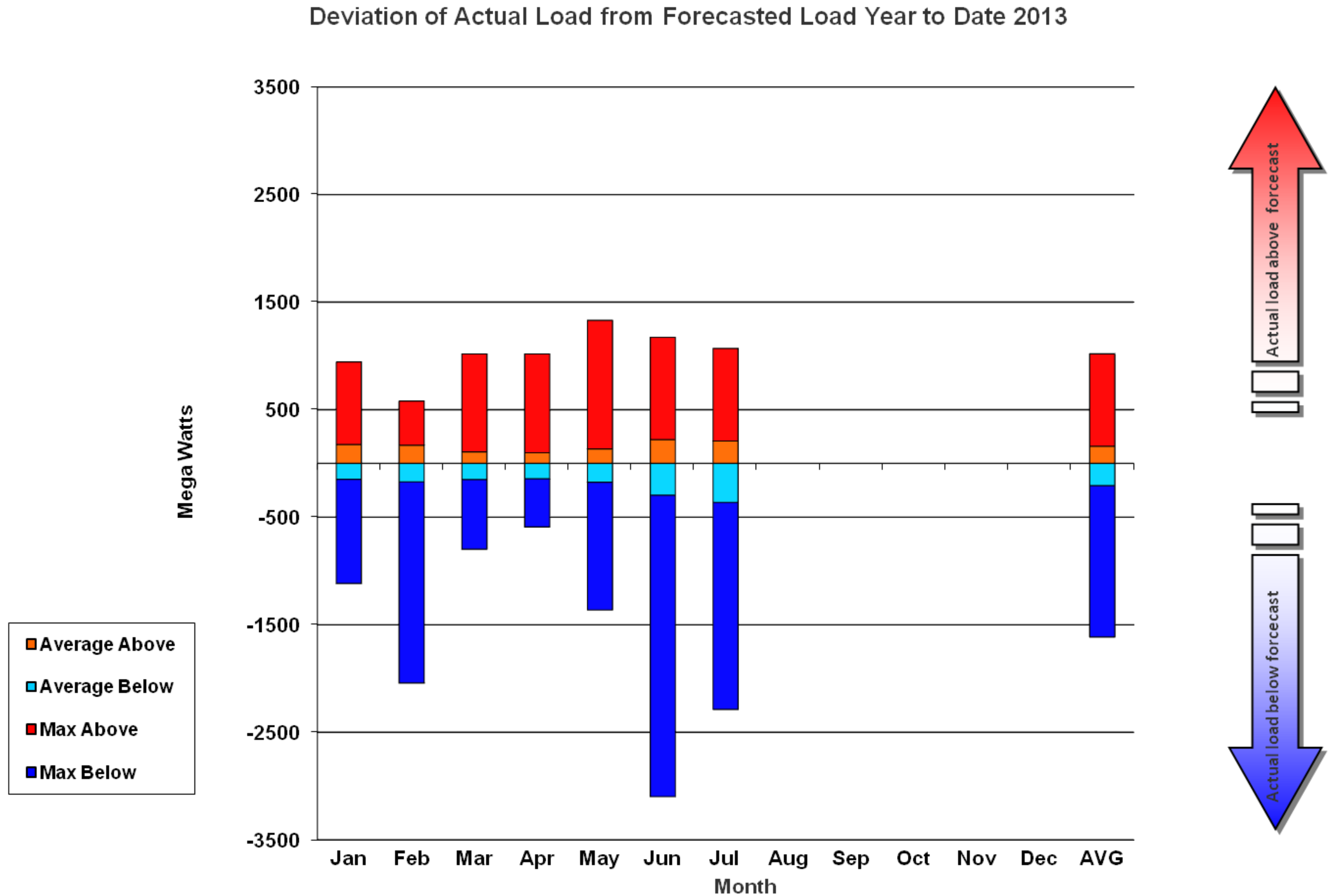


J	F	M	A	M	J	J	A	S	O	N	D	Avg
53.0	56.0	45.0	36.0	45.0	53.0	43.0						47.0
47.0	44.0	55.0	64.0	55.0	47.0	57.0						53.0
176.0	169.0	107.0	100.0	134.0	222	202						158.0
-147.0	-171.0	-150.0	-132.0	-174.0	-296	-362						-204.0
21.0	-6.0	-30.0	-40.0	-39.0	-59.0	-143.0						-42.7

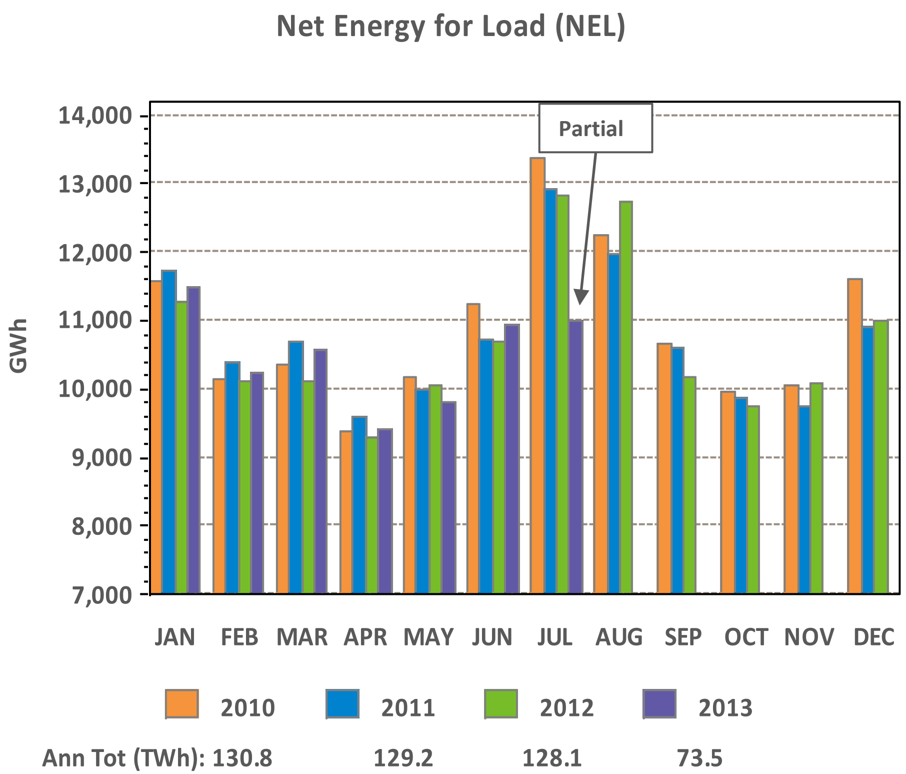
Percent of hours that the actual load was above versus below the forecast

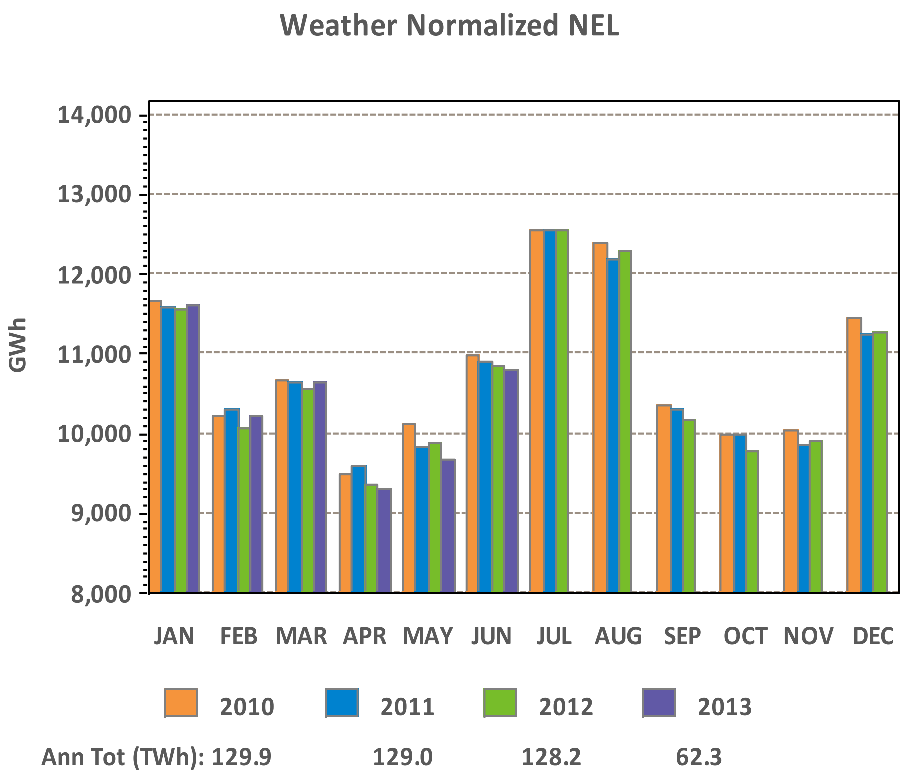
Sponsor – John Norden
Contact – William Callan

2013 System Operations - Load Forecast Accuracy



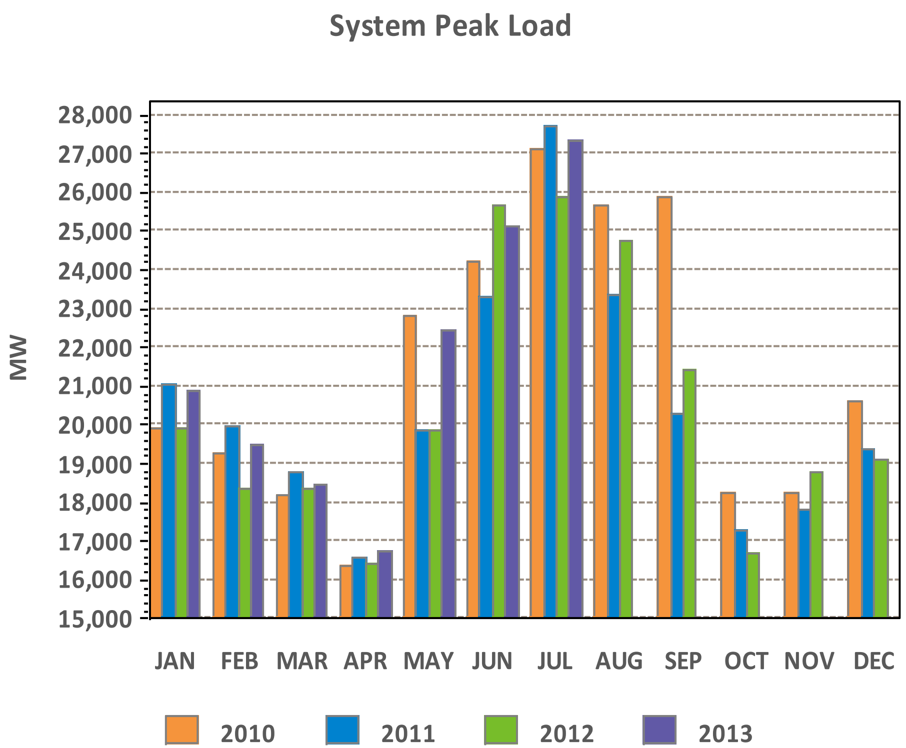
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

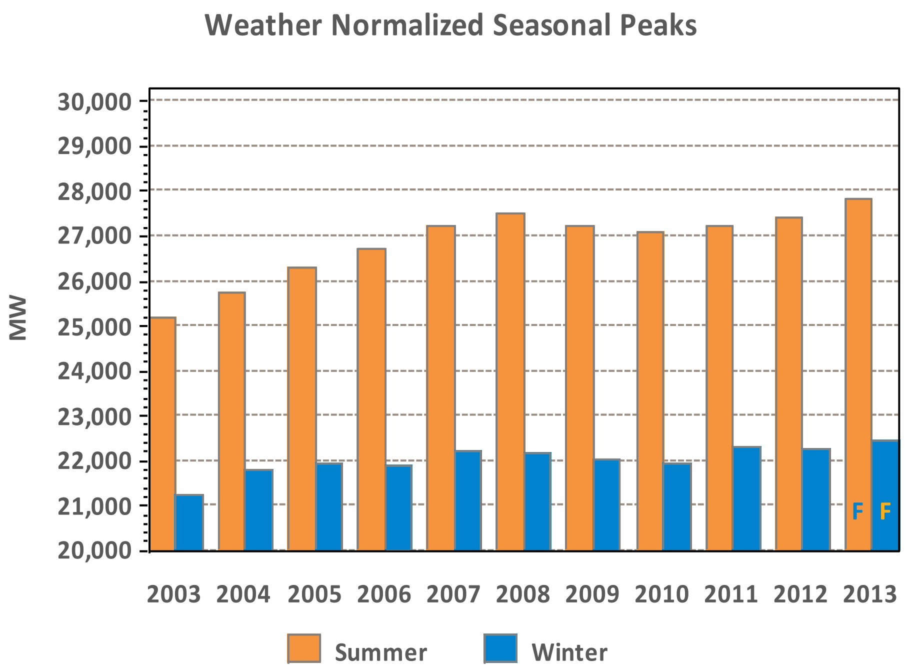




NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



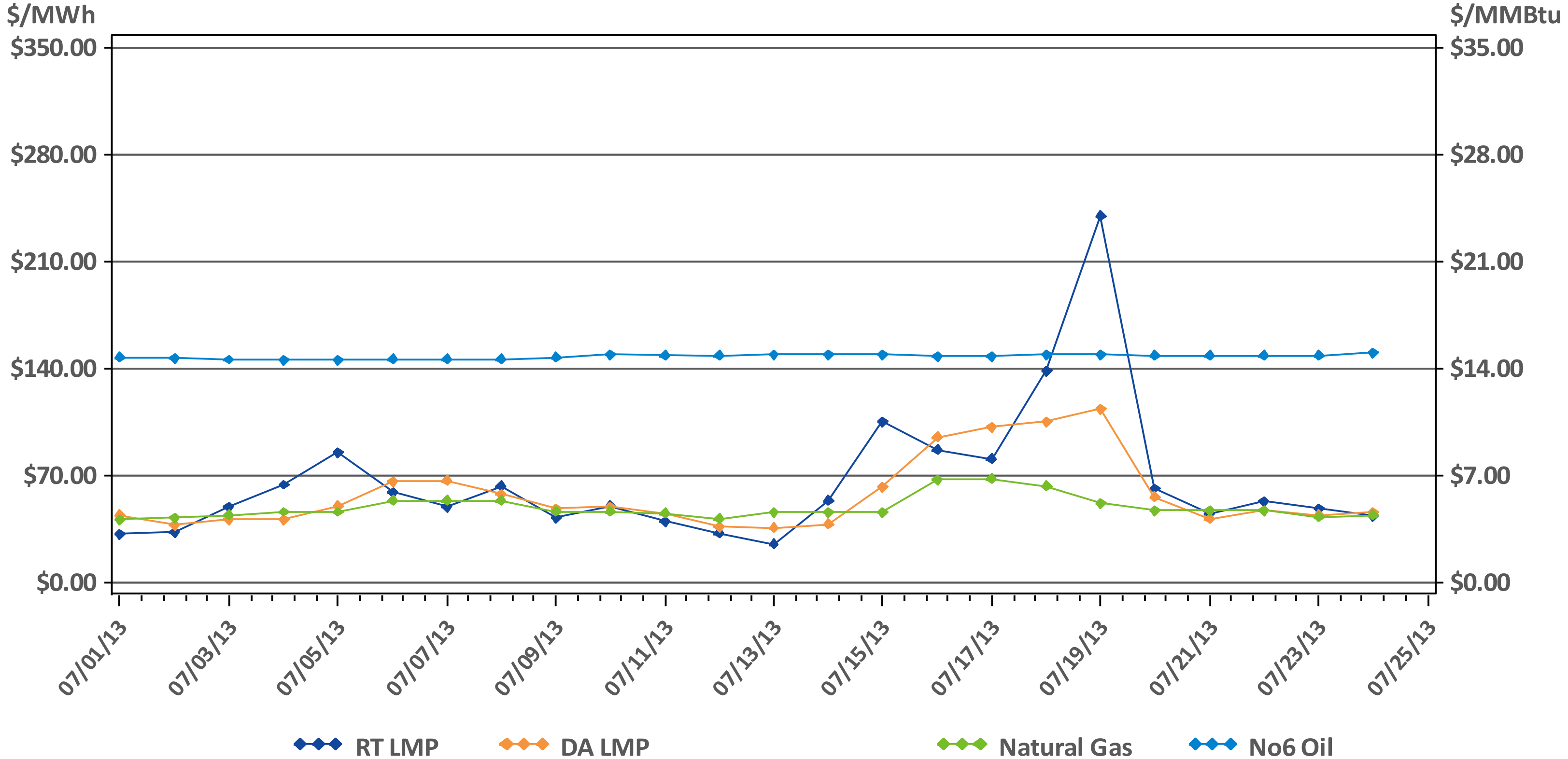


Winter beginning in year displayed

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

MARKET OPERATIONS

DA and RT ISO-NE Hub Prices and Input Fuel Prices: July 1-24, 2013

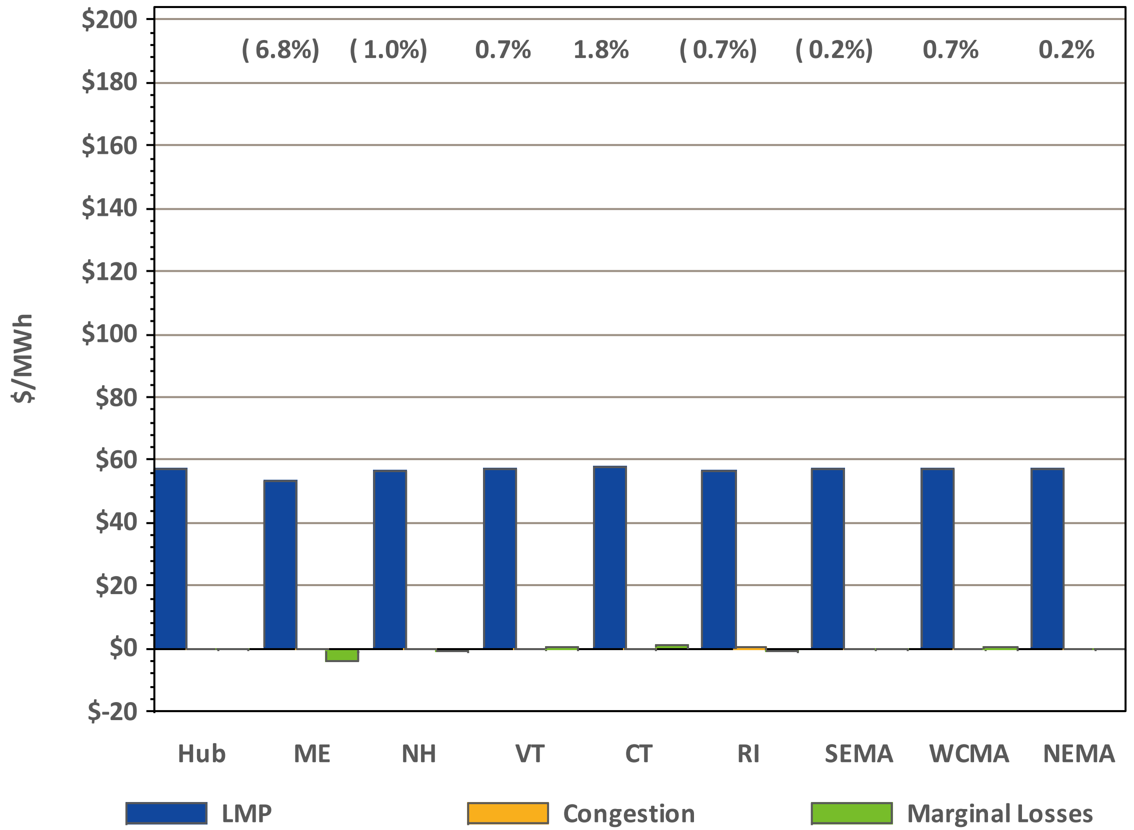


Underlying natural gas data furnished by:

ICE Global markets in clear view

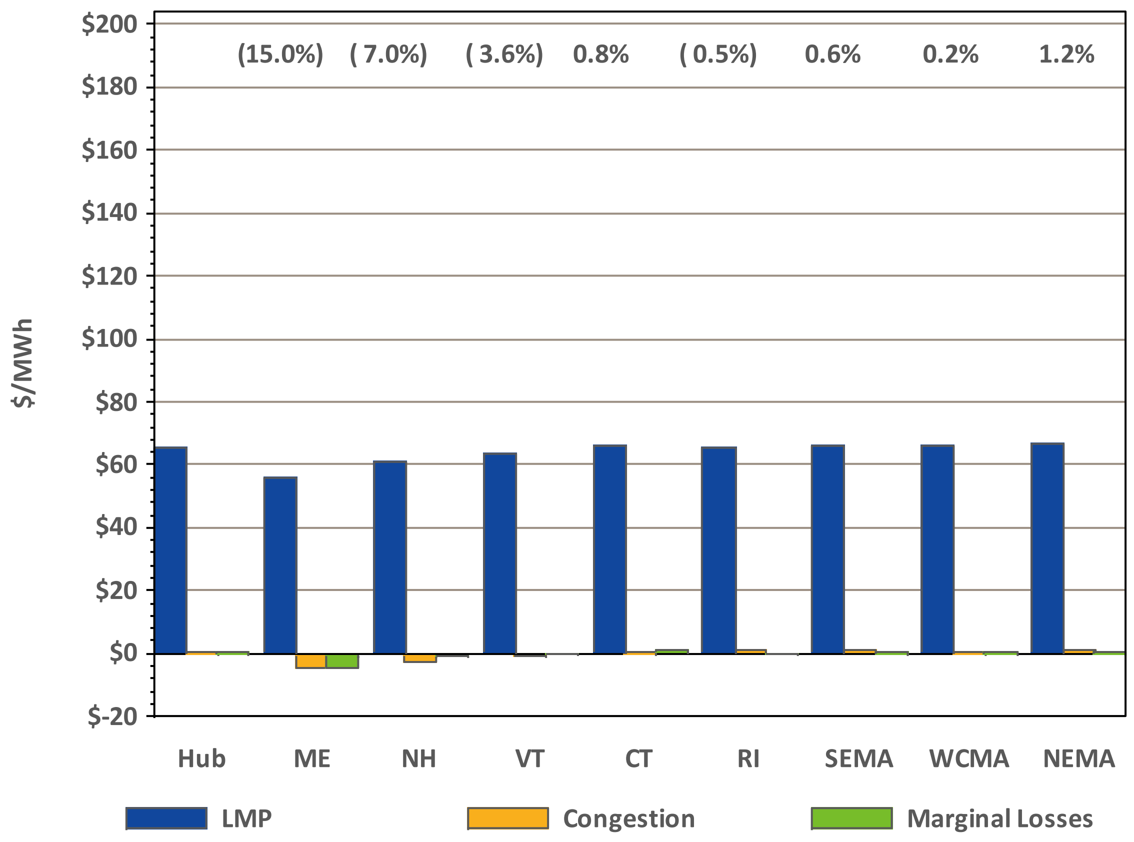
Average price difference over this period (DA-RT): $-8.75
Average price difference over this period ABS(DA-RT): $16.98
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 26%
Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOEs Energy Information Administration

DA LMPs Average by Zone & Hub, July 2013

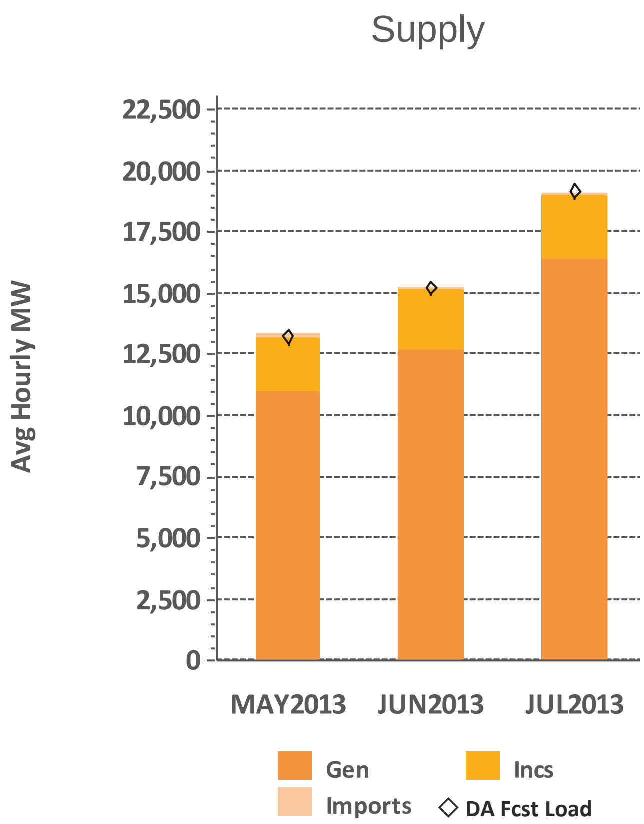


ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

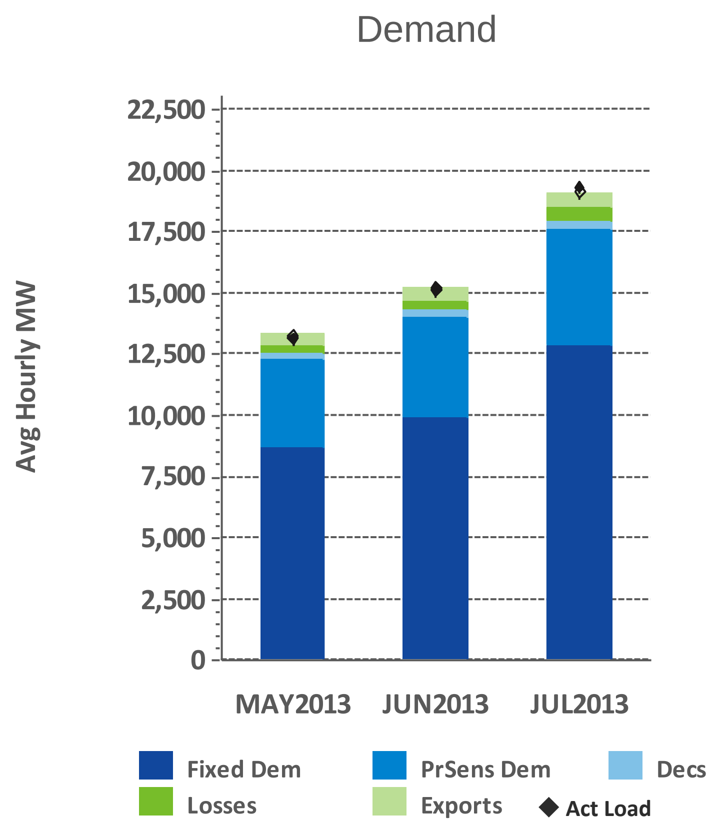
RT LMPs Average by Zone & Hub, July 2013



Components of Cleared DA Supply and Demand – Last Three Months

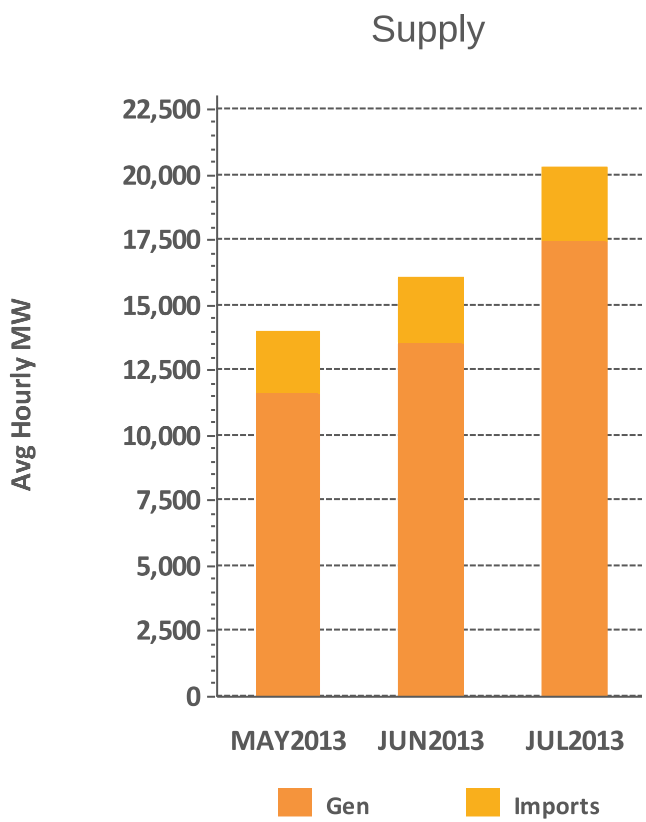


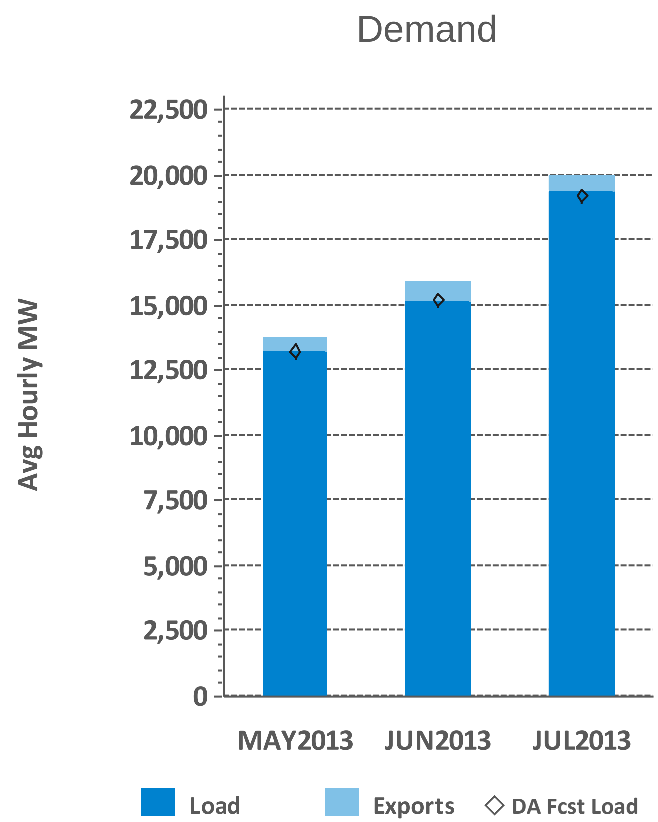
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



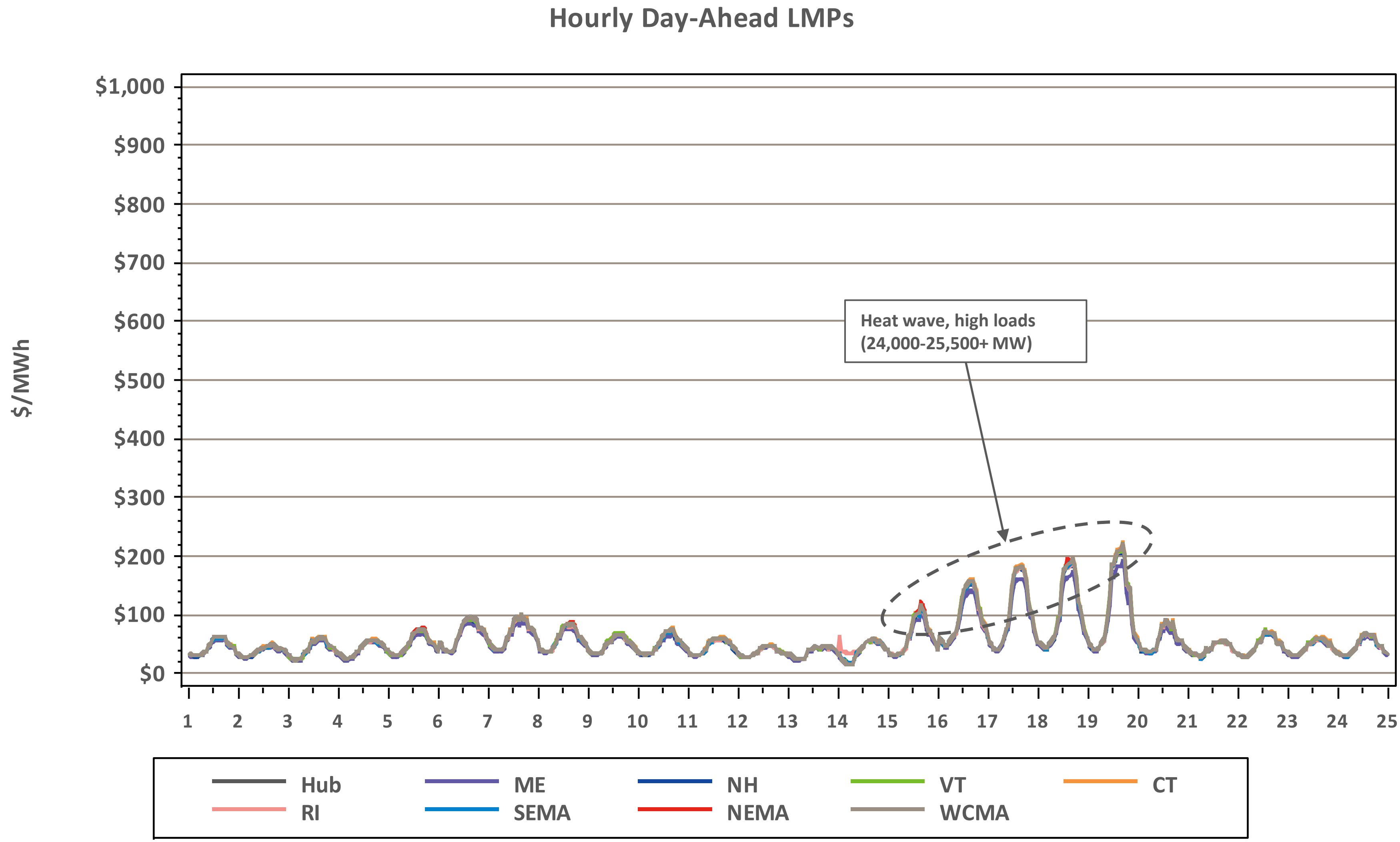
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months

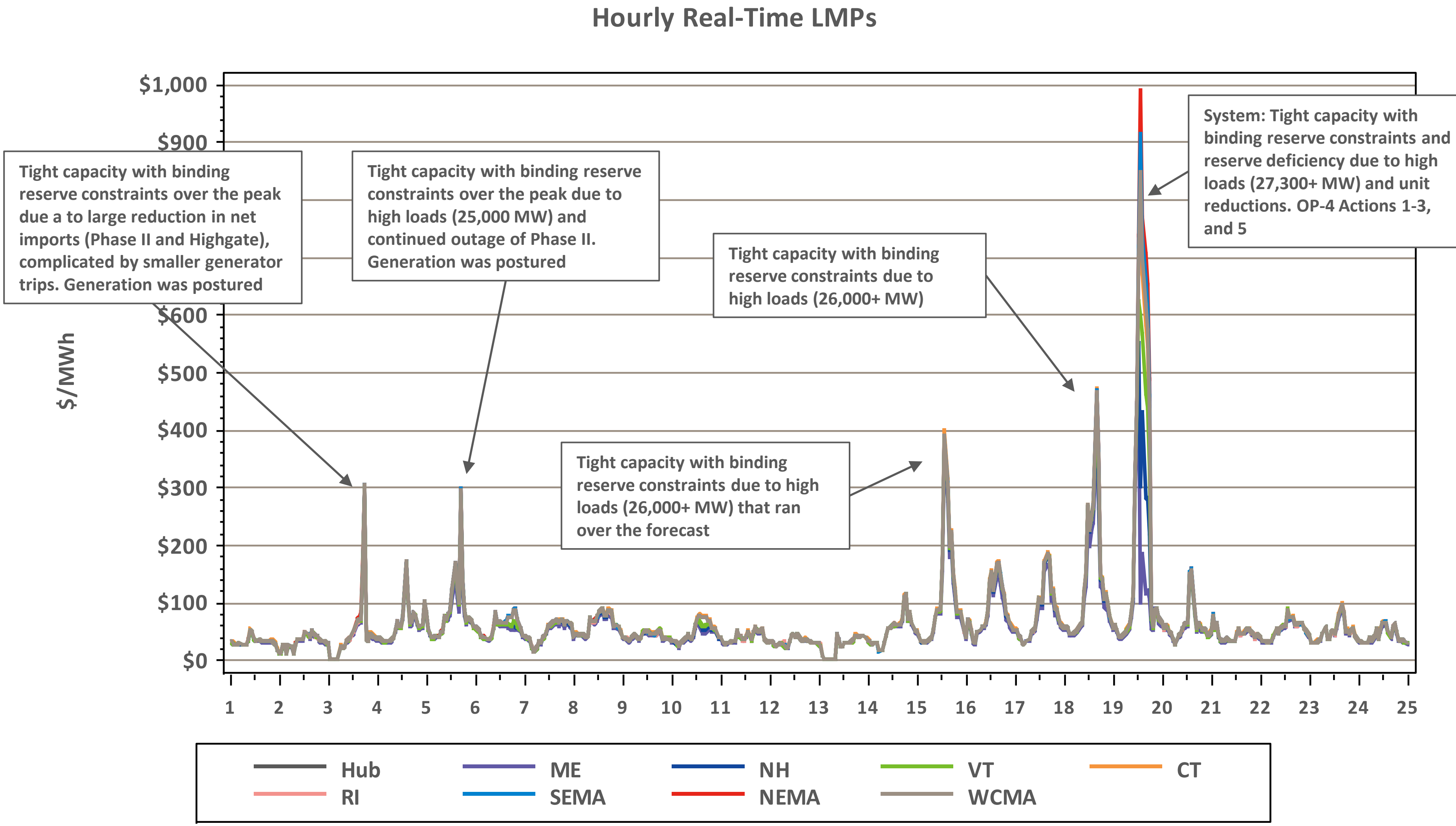




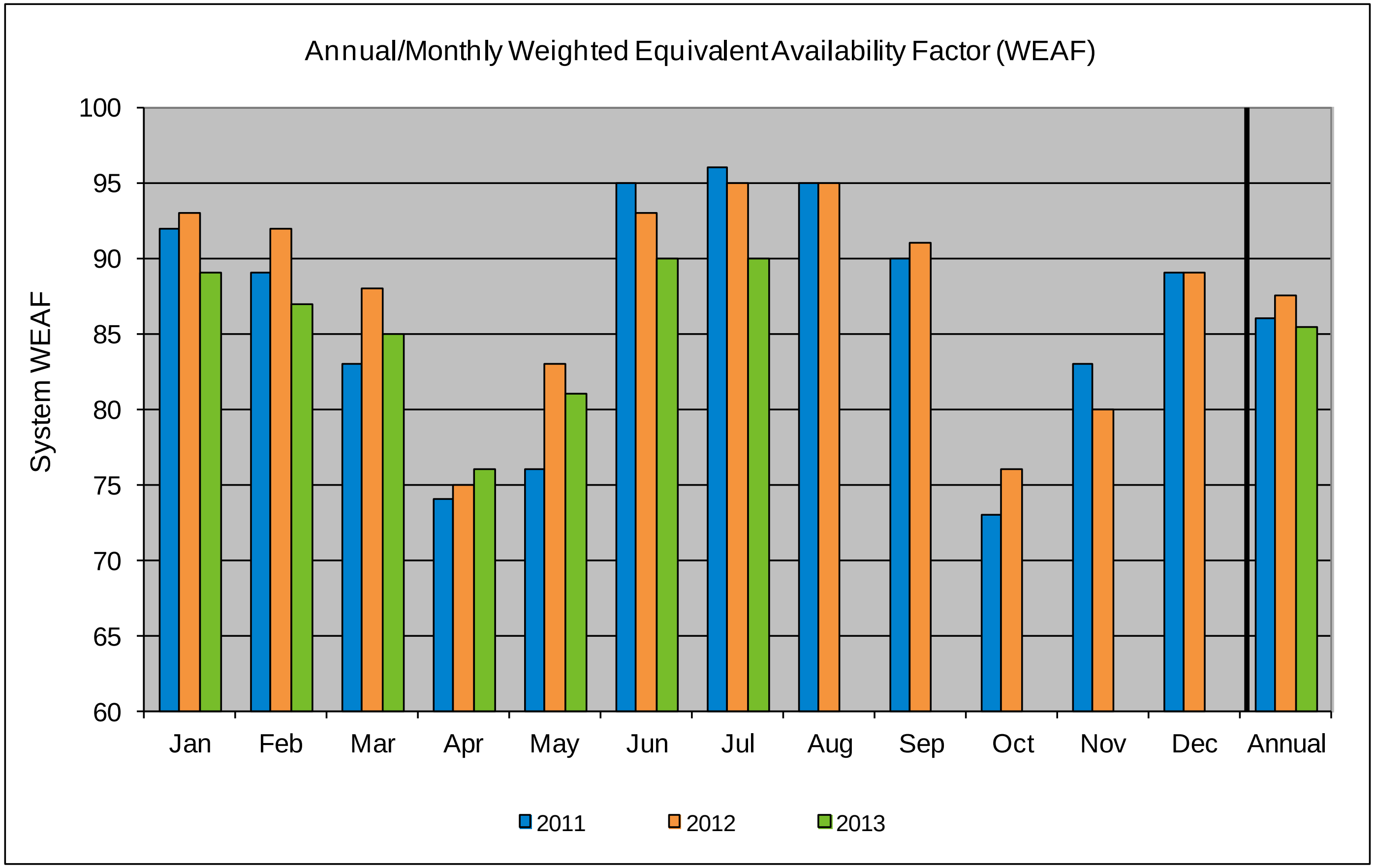
Hourly DA LMPs, July 1-24, 2013



Hourly RT LMPs, July 1-24, 2013



System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2013	89	87	85	76	81	90	90						85
2012	93	92	88	75	83	93	95	95	91	76	80	89	88
2011	92	89	83	74	76	95	96	95	90	73	83	89	86
2010	91	93	90	83	74	93	93	93	86	77	81	91	87

Data as of 7/26/13

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for August 2013

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	134.63	8.55	87.09	0.00	230.26
NH	3.84	11.70	64.72	0.00	80.26
VT	24.84	2.12	87.34	0.00	114.30
CT	104.85	77.04	76.91	299.33	558.13
RI	23.32	9.39	77.77	0.00	110.48
SEMA	12.33	10.74	111.97	0.00	135.04
WCMA	26.45	22.56	102.99	28.69	180.69
NEMA	21.83	21.33	206.10	0.00	249.27
Total	**352.08**	**163.43**	**814.89**	**328.02**	**1,658.43**

* 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

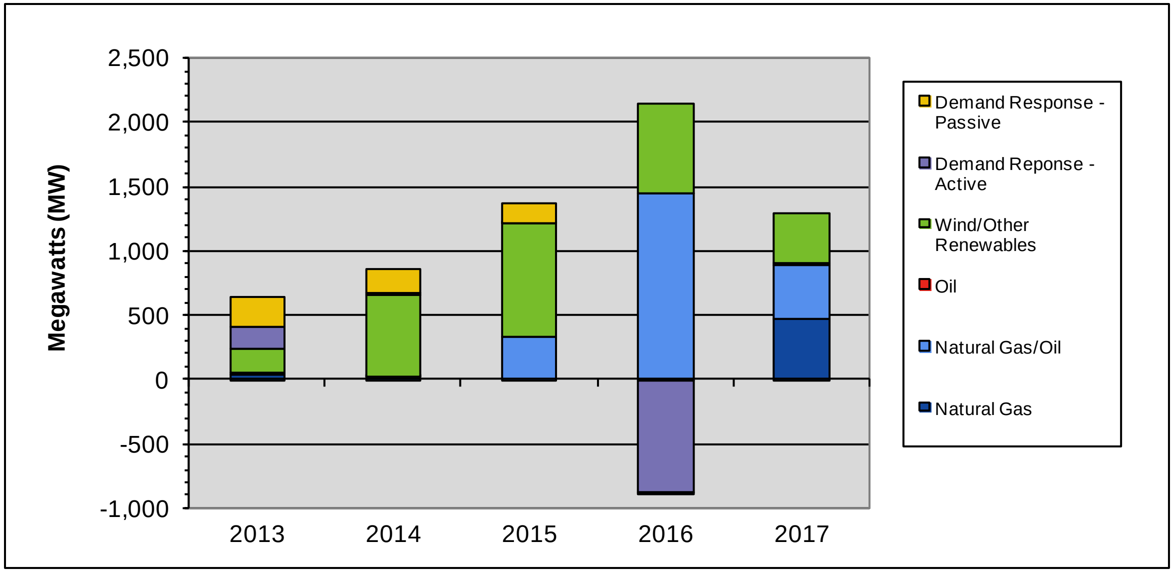
New Generation Update

Based on 7/24/13 Interim Queue Update

- One new project, with a capacity of 99 MW, has applied for interconnection study since the last update
  - The new project is a wind facility, with an expected in-service date of 2016
- One project withdrew from the Queue, resulting in a net increase in new generation projects of 81 MW
- In total, 58 generation projects are currently being tracked by the ISO, totaling 5,500 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



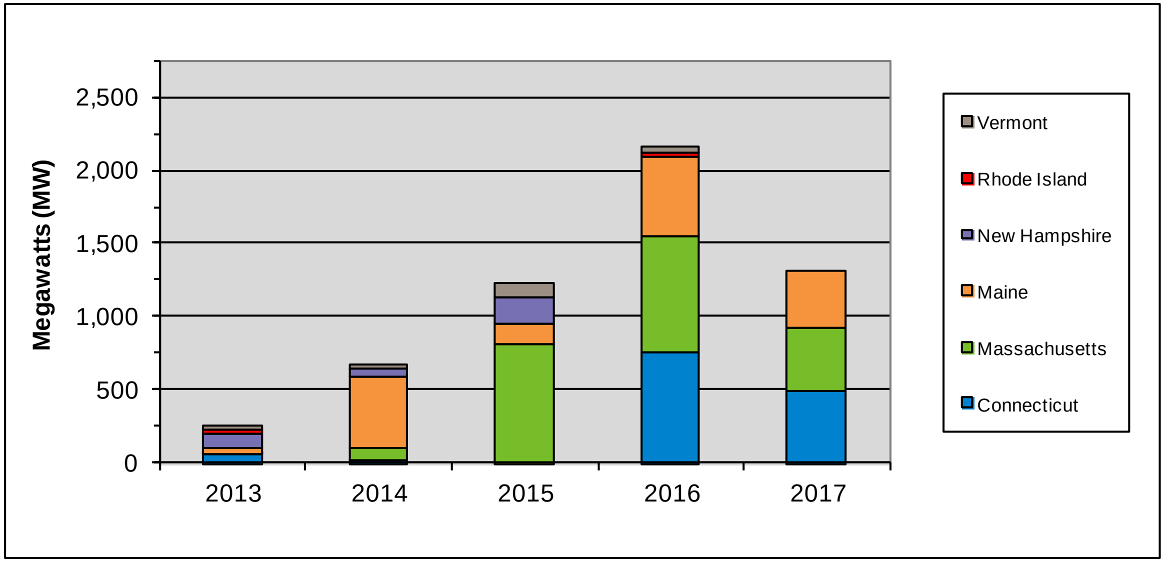
	2013	2014	2015	2016	2017	Total MW	% of Total*
Demand Response - Passive	225	188	157	-12	0	558	10.2
Demand Response - Active	169	19	3	-868	0	-677	-12.4
Wind & Other Renewables	195	632	888	693	391	2,799	51.2
Oil	0	0	0	0	14	14	0.3
Natural Gas/Oil	11	8	332	1,461	416	2,228	40.8
Natural Gas	40	20	0	0	482	542	9.9
Totals	**640**	**867**	**1,380**	**1,274**	**1,303**	**5,464**	**100.0**

*** Sum may not equal 100% due to rounding**

- 2013 values include the 46 MW of generation that has gone commercial in 2013
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2013	2014	2015	2016	2017	Total MW	% of Total*
Vermont	30	20	98	33	0	181	3.2
Rhode Island	28	0	0	29	0	57	1.0
New Hampshire	97	59	171	0	0	327	5.9
Maine	33	494	152	544	391	1,614	28.9
Massachusetts	11	72	799	803	430	2,115	37.9
Connecticut	47	15	0	745	482	1,289	23.1
Totals	**246**	**660**	**1,220**	**2,154**	**1,303**	**5,583**	**100.0**

*** Sum may not equal 100% due to rounding**

- 2013 values include the 46 MW of generation that has gone commercial in 2013

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	5	214	2	106	3	108
Hydro	5	68	0	0	5	68
Landfill Gas	0	0	0	0	0	0
Natural Gas	5	532	1	9	4	523
Natural Gas/Oil	7	2,228	0	0	7	2,228
Oil	1	14	0	0	1	14
Solar	3	16	2	10	1	6
Wind	32	2,465	3	38	29	2,427
Total	58	5,537	8	163	50	5,374

- 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	7	238	3	115	4	123
Intermediate	11	2,327	0	0	11	2,327
Peaker	8	507	2	10	6	497
Wind Turbine	32	2,465	3	38	29	2,427
Total	58	5,537	8	163	50	5,374

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	5	214	5	214	0	0	0	0	0	0
Hydro	5	68	0	0	4	18	1	50	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	5	532	2	24	3	508	0	0	0	0
Natural Gas/Oil	7	2,228	0	0	4	1,801	3	427	0	0
Oil	1	14	0	0	0	0	1	14	0	0
Solar	3	16	0	0	0	0	3	16	0	0
Wind	32	2,465	0	0	0	0	0	0	32	2,465
Total	58	5,537	7	238	11	2,327	8	507	32	2,465

FORWARD CAPACITY MARKET

Forward Capacity Market Update

- CCP #8 (2017-2018)
  - Capacity Zones
    - Next stakeholder meeting scheduled for 8/19
    - ISO made a FERC compliance filing on July 30 indicating a schedule to target FCA #9 for changes related to the development of capacity zones
  - New import qualification continues
    - The ISO will be meeting with NYISO again in August
    - Two question sets have been sent to Participants thus far. A second teleconference with Participants is scheduled for late July
  - Non-price retirement (NPR) window opened 6/3 and closes 10/6
  - New Resource Qualification continues to be on target with QDN's to be released on 9/27

Capacity Supply Obligation FCA 4

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

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

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

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

Capacity Supply Obligation FCA 5

Resource Type	Resource Type	FCA 4	Proration		Annual Bilateral Period 1 for ARA 2		ARA 2		Annual Bilateral Period 2 for ARA 2		Annual Bilateral 3 Period		ARA 3	
		*CSO	CSO	**Change	ARA 2	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,104.141	2,001.126	-103.015	1,385.670	-615.456								
	Passive Demand	1,485.713	1,397.586	-88.127	1,345.283	-52.303								
Demand Total		**3,589.854**	**3,398.712**	**-191.142**	**2,730.953**	**-667.759**								
Generator	*Non-Intermittent*	30,558.220	28,337.481	-2,220.739	27,917.690	-419.791								
	Intermittent	880.737	827.804	-52.933	778.165	-49.639								
Generator Total		**31,438.957**	**29,165.285**	**-2,273.672**	**28,695.855**	**-469.430**								
Import Total		**2,011.001**	**1,831.372**	**-179.629**	**1,831.372**	**0.000**								
***Grand Total**		**37,039.812**	**34,395.369**	**-2,644.443**	**33,258.180**	**-1,137.189**								

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

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

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

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral Period 1 for ARA 1		ARA 1		Annual Bilateral Period 1 for ARA 2		ARA 2		Annual Bilateral Period 2 for ARA 2		Annual Bilateral 3 Period	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624								
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000								
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624								
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709								
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205								
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914								
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290								
***Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000								

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

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

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

Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral Period 1 for ARA 1		ARA 1		Annual Bilateral Period 1 for ARA 2		ARA 2		Annual Bilateral Period 2 for ARA 2		Annual Bilateral 3 Period	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979												
	Passive Demand	1,631.335	1,519.740	-111.595												
Demand Total		**2,748.033**	**2,563.459**	-184.574												
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741												
	Intermittent	936.913	893.710	-43.203												
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**												
Import Total		**1,830.000**	**1,606.862**	**-223.138**												
*****Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**												

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

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

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

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

What are Daily NCPC Payments?

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

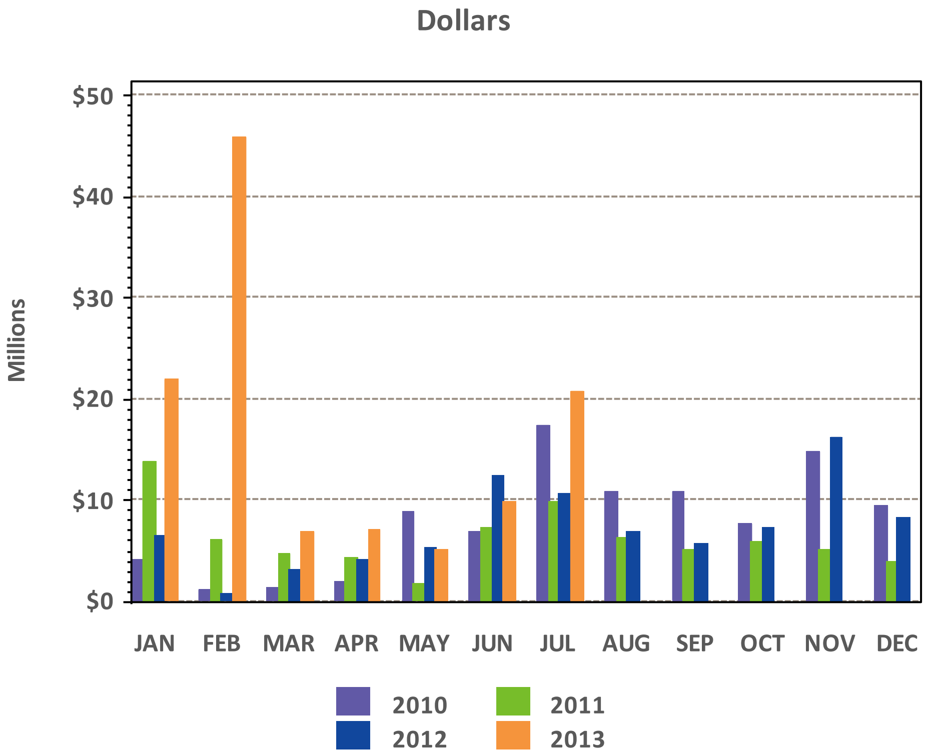
Definitions

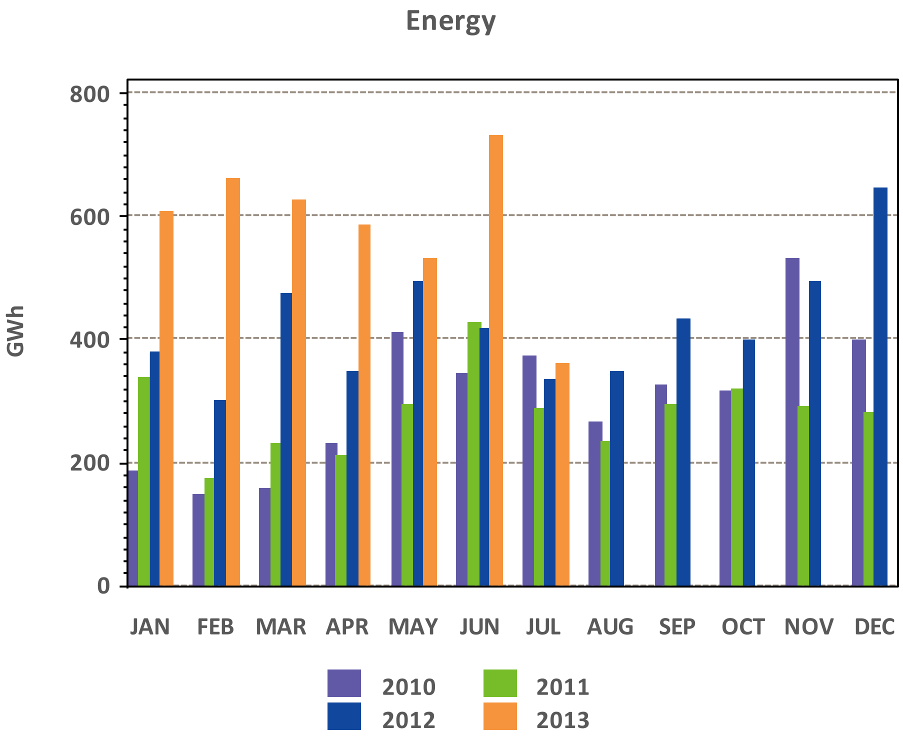
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally.
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

Year-Over-Year Total NCPC Dollars and Energy

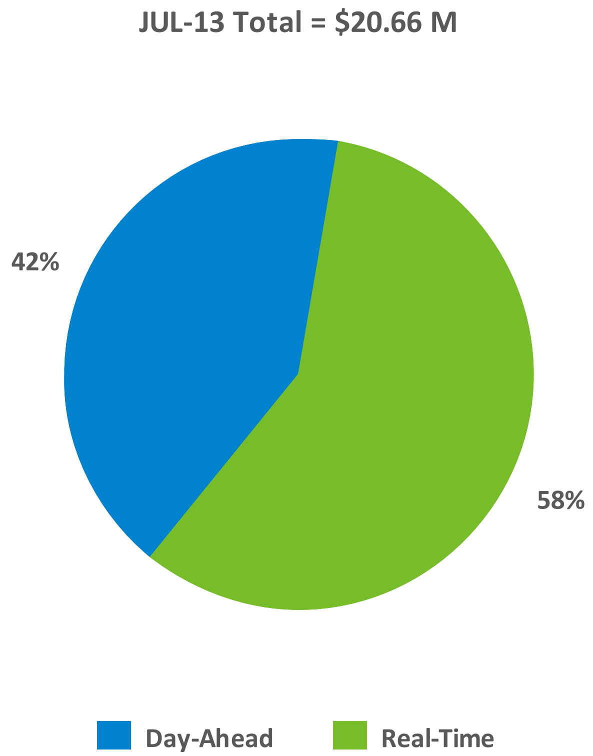


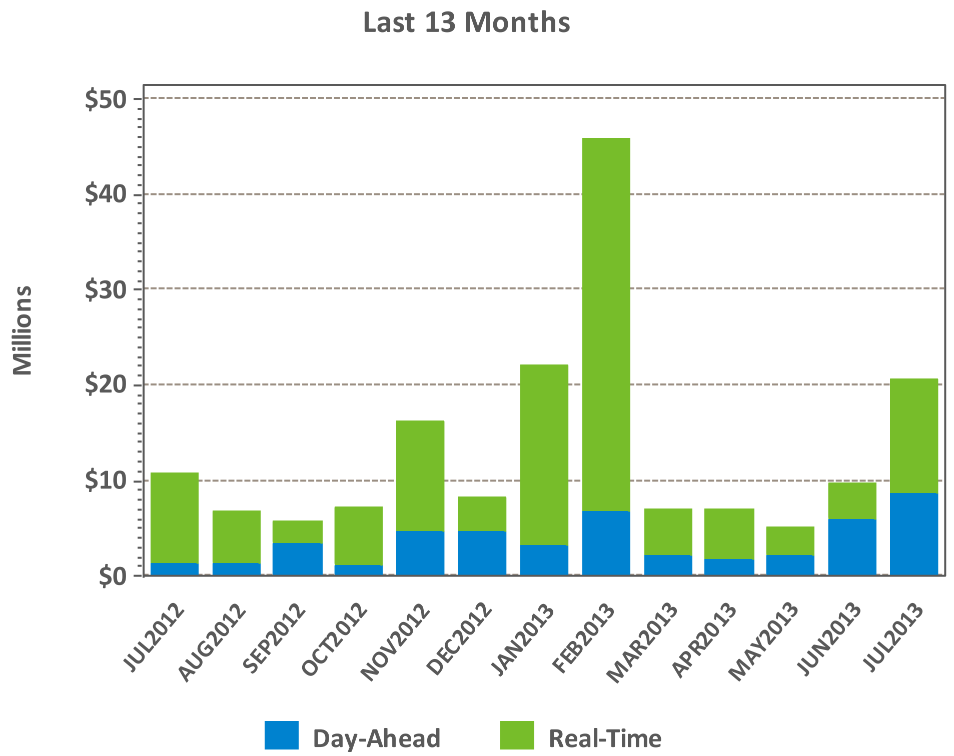


Note:

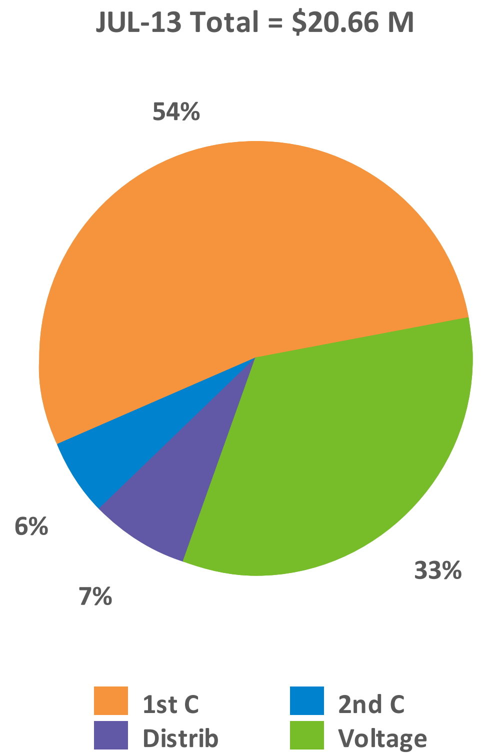
- Overall Reliability Cost MWh includes out of merit DA and RT 1st Contingency, 2nd Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

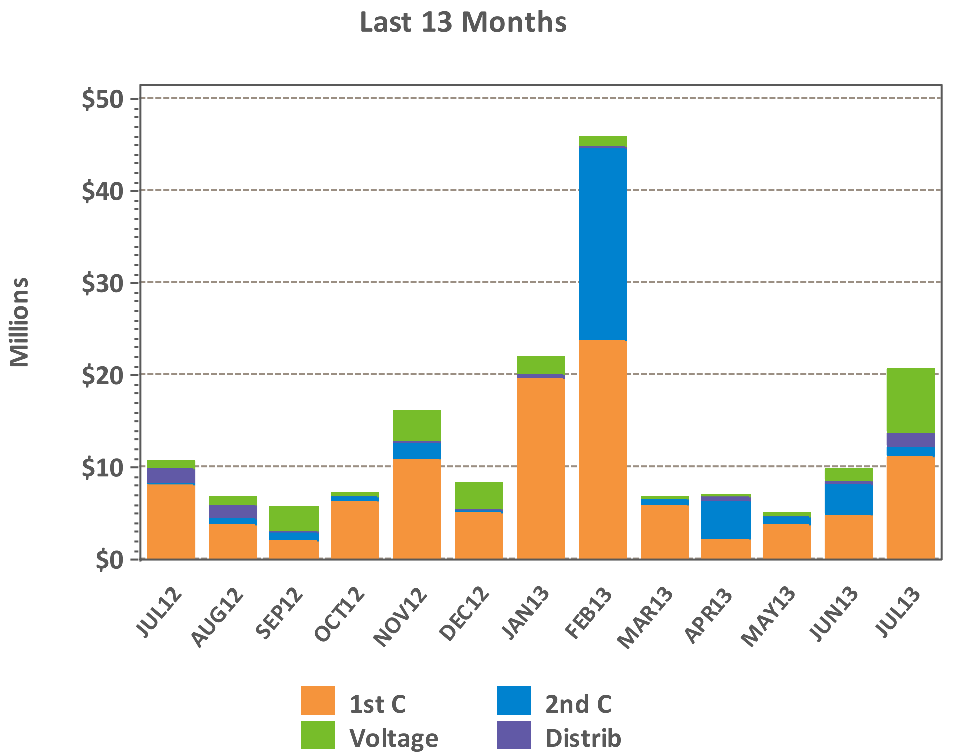
DA and RT NCPC Charges





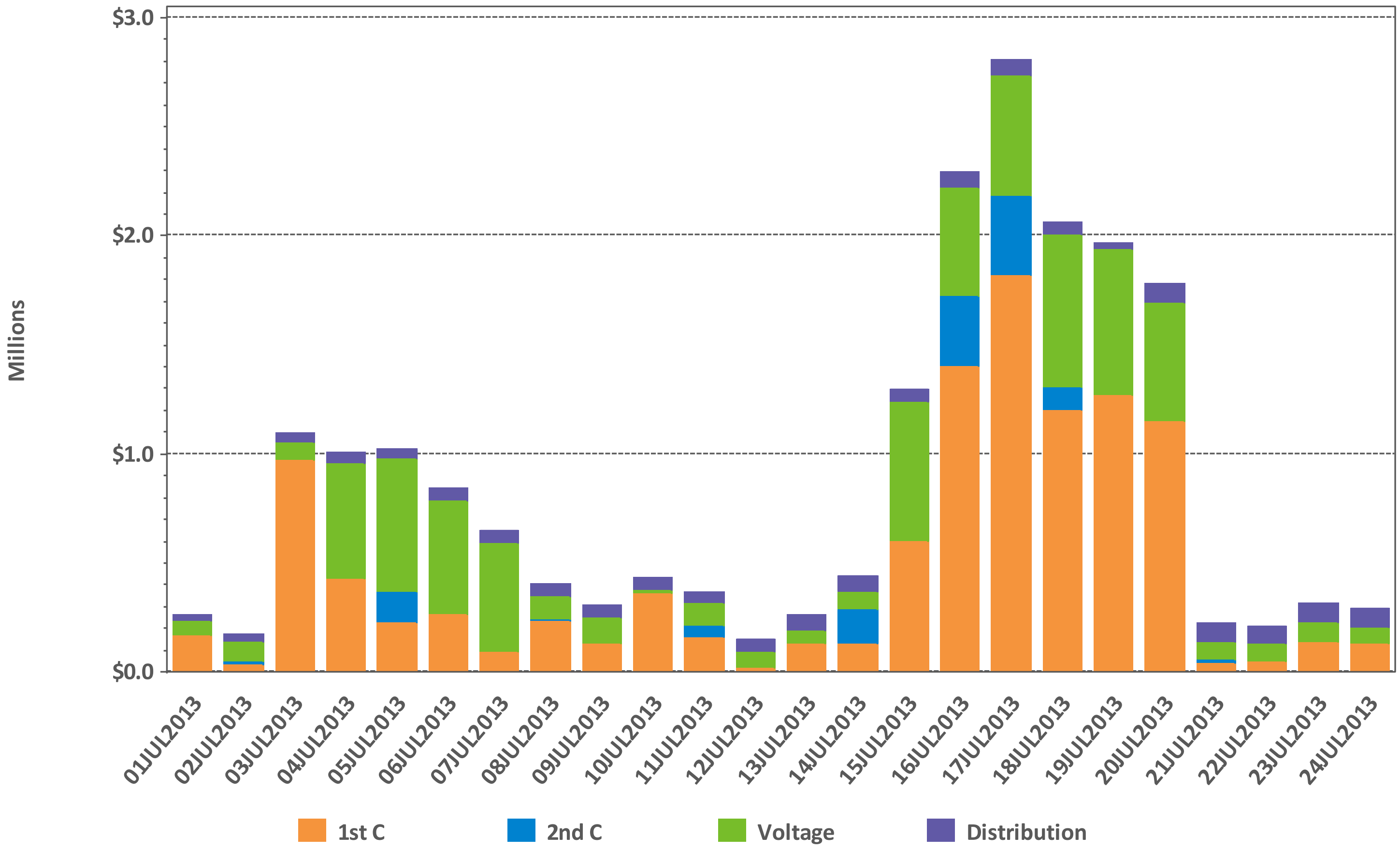
NCPC Charges by Type



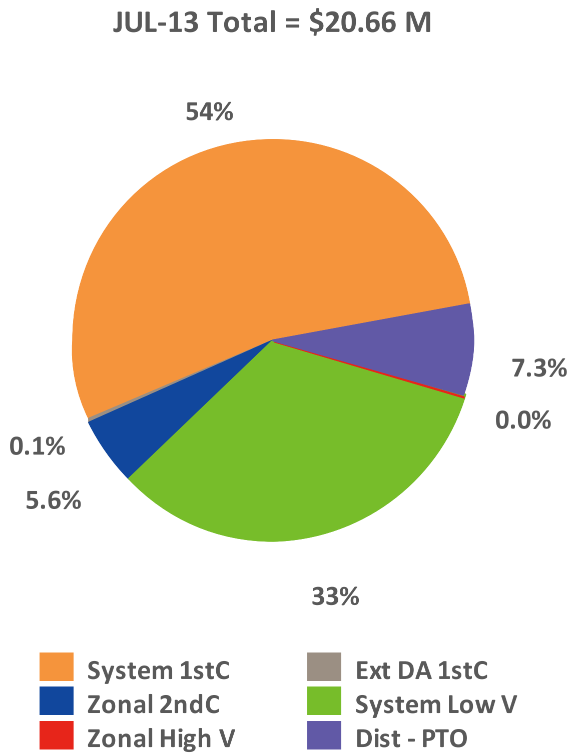


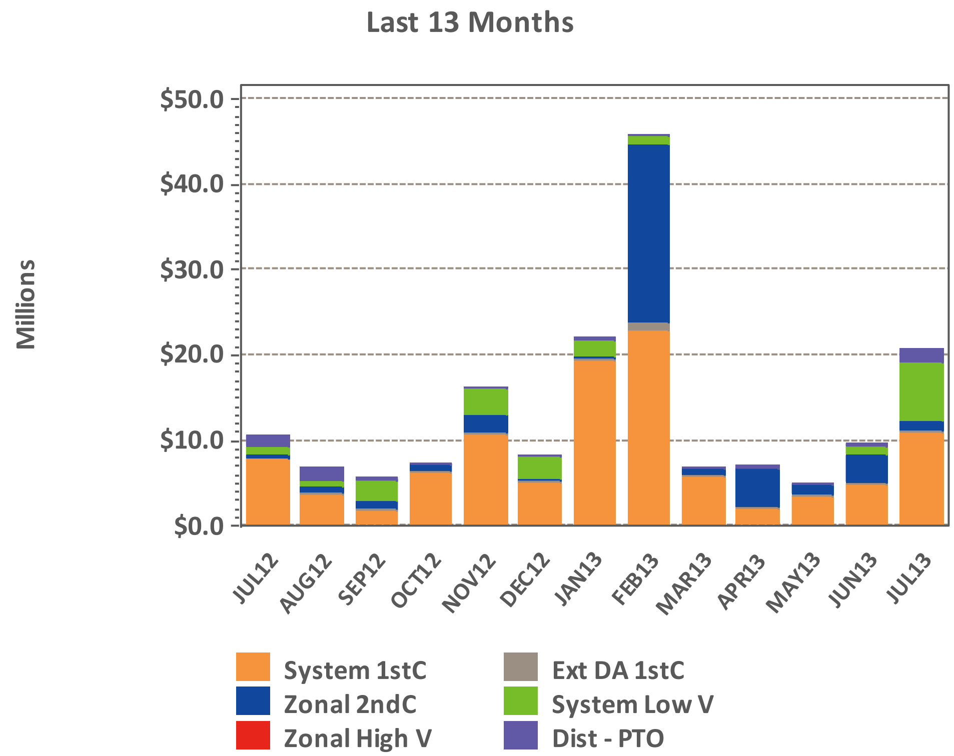
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

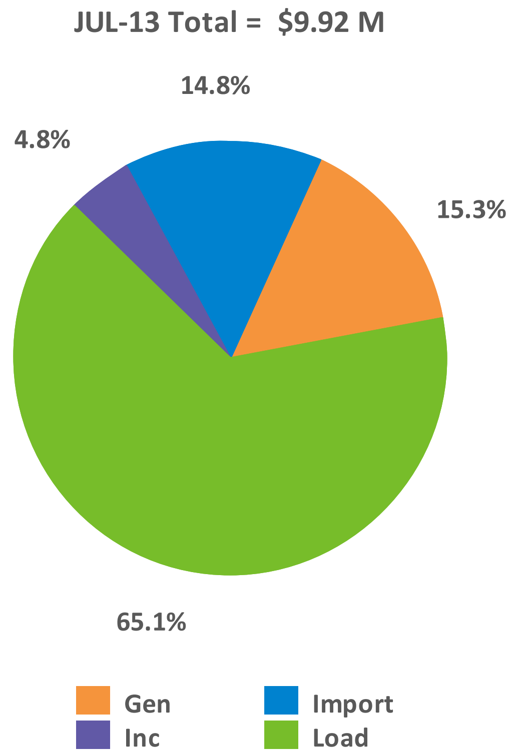


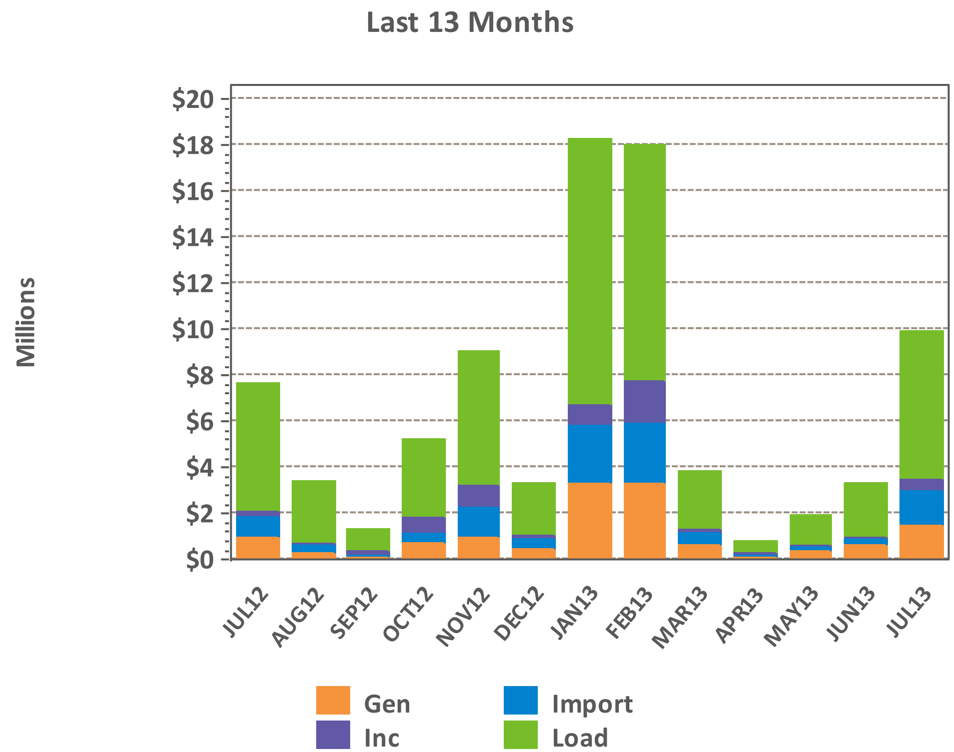
NCPC Charges by Allocation





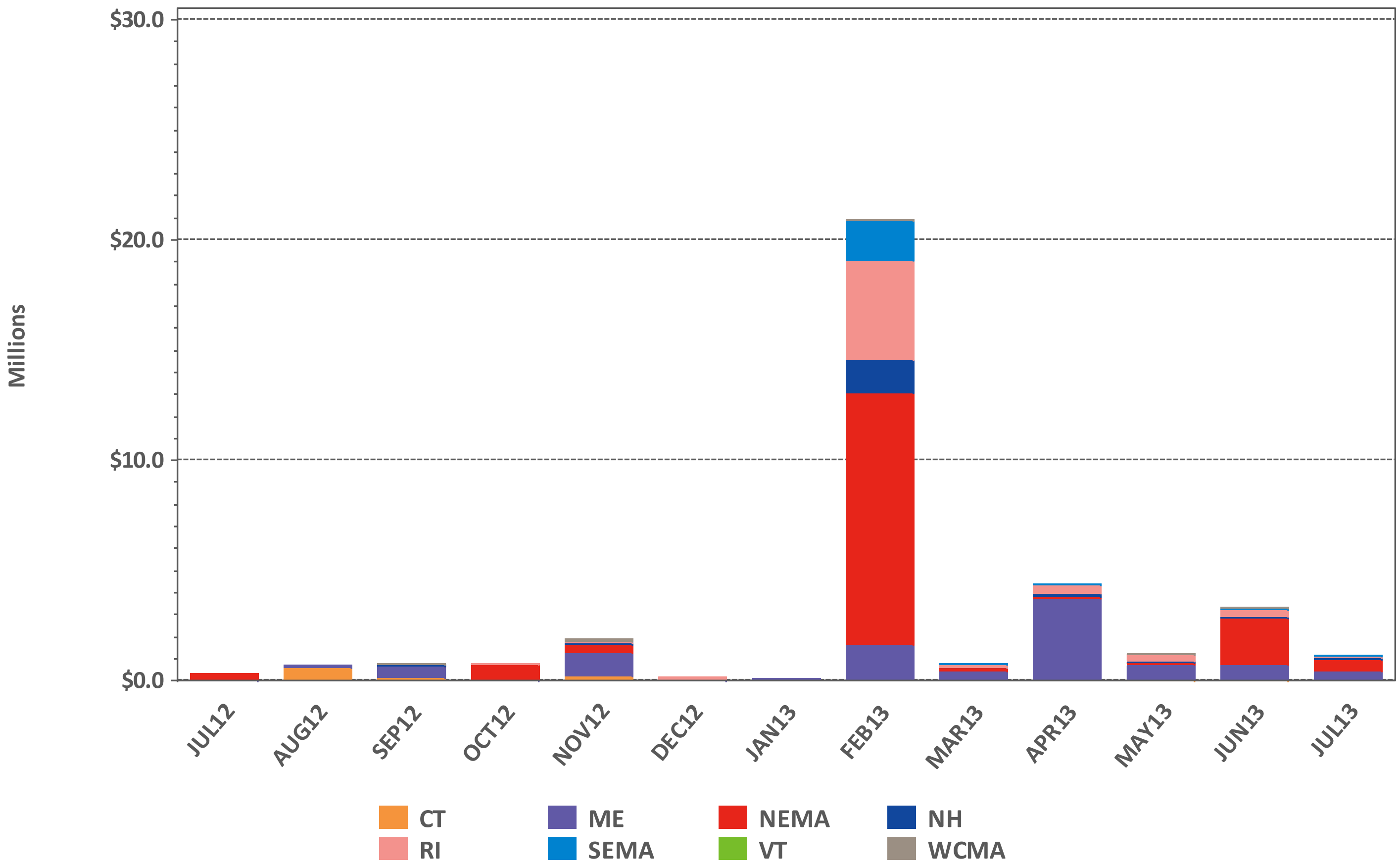
RT First Contingency Charges by Deviation Type





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

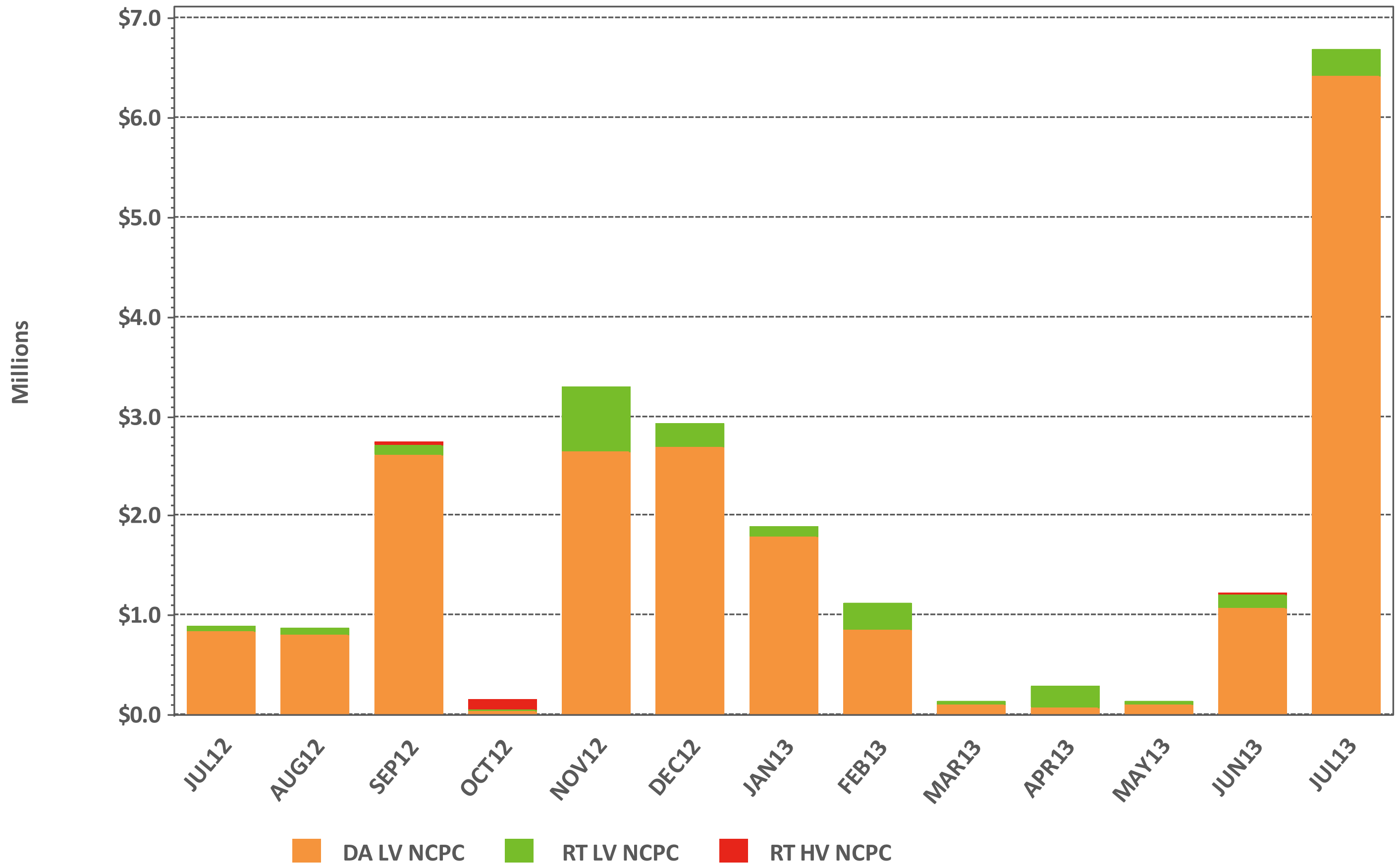
LSCPR Charges by Zone



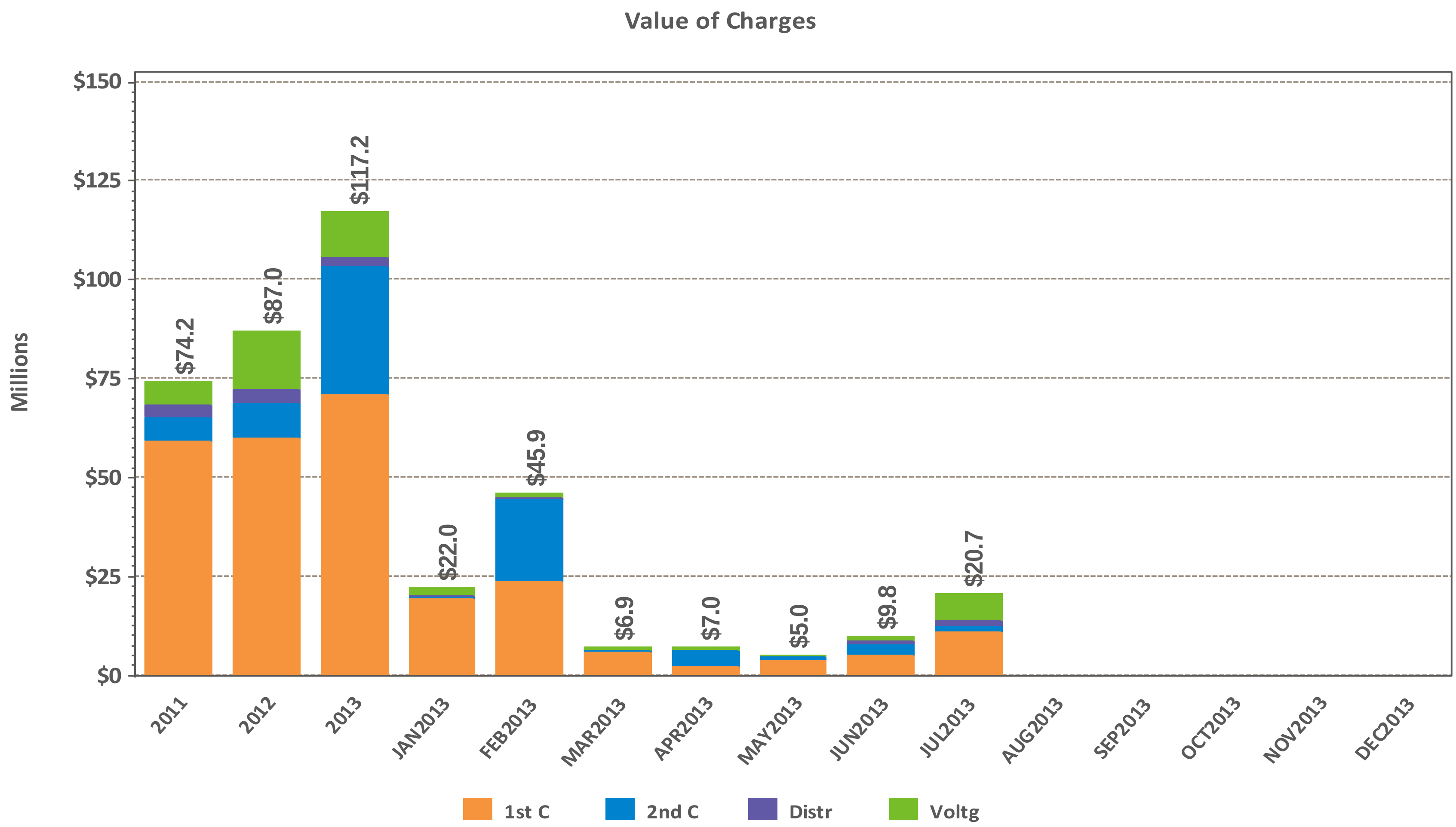
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

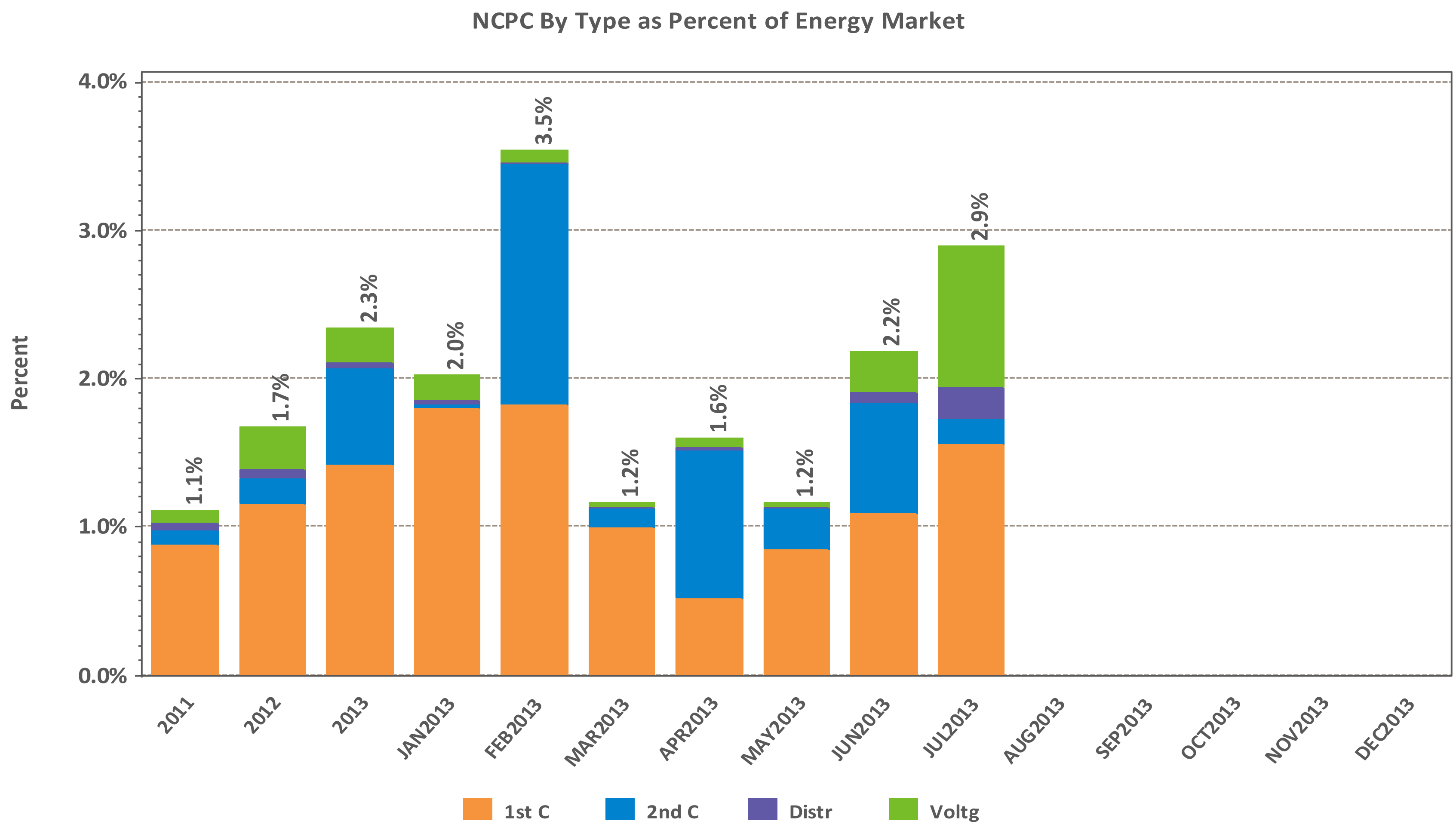
NCPC Charges for Voltage Support and High Voltage Control



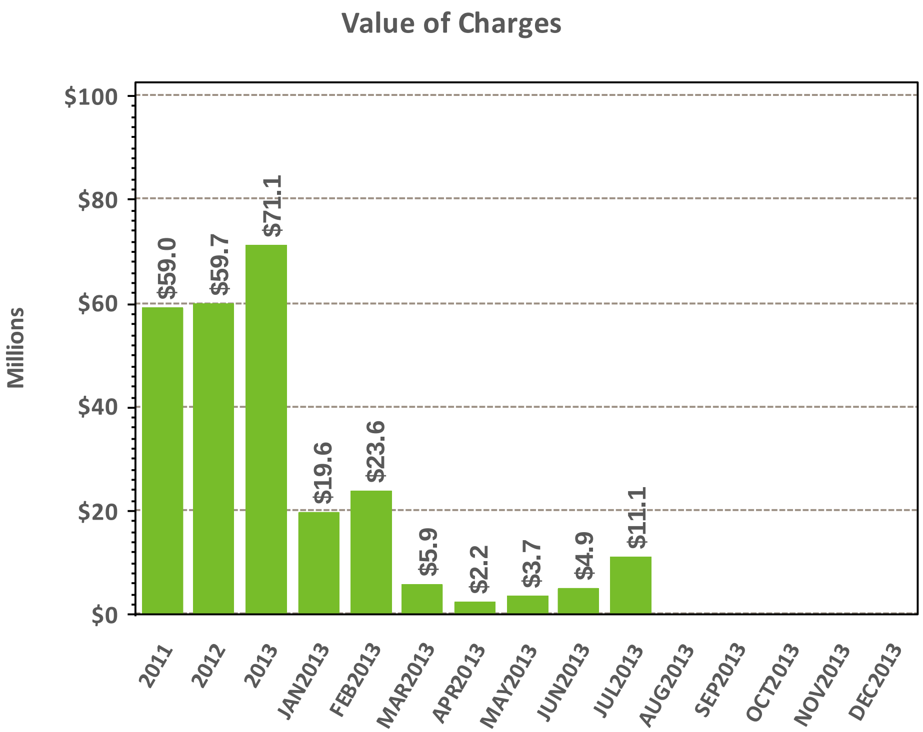
NCPC Charges by Type

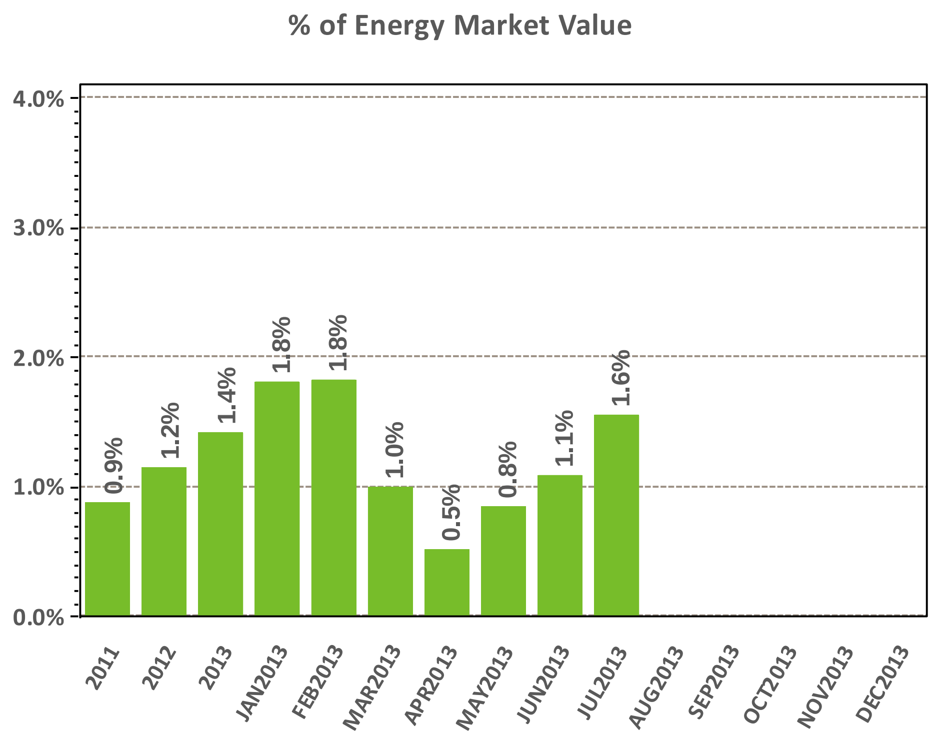


NCPC Charges as Percent of Energy Market



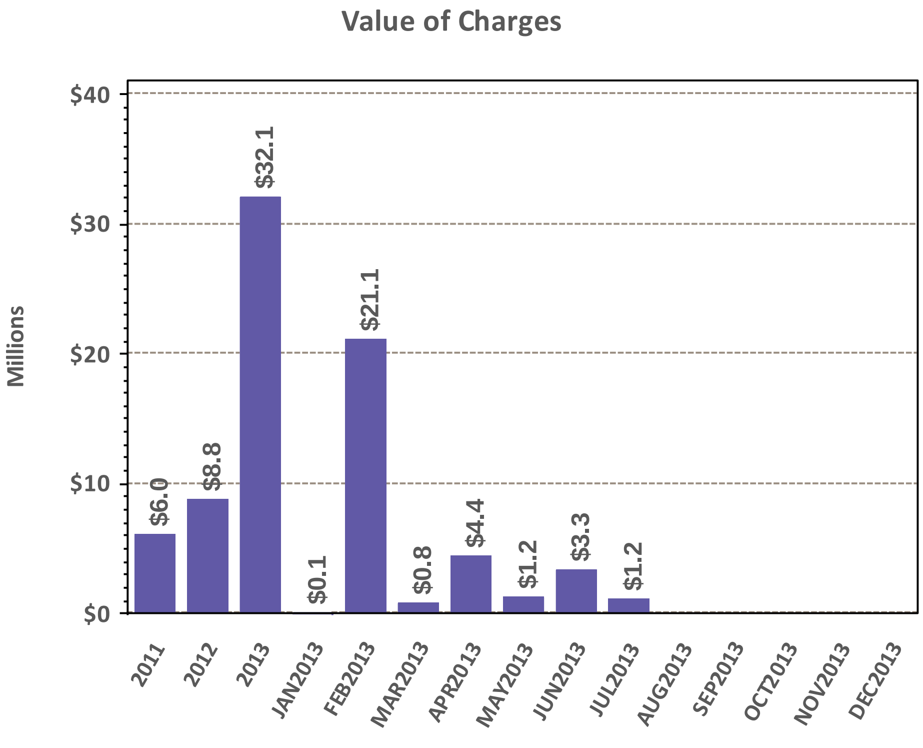
First Contingency NCPC Charges

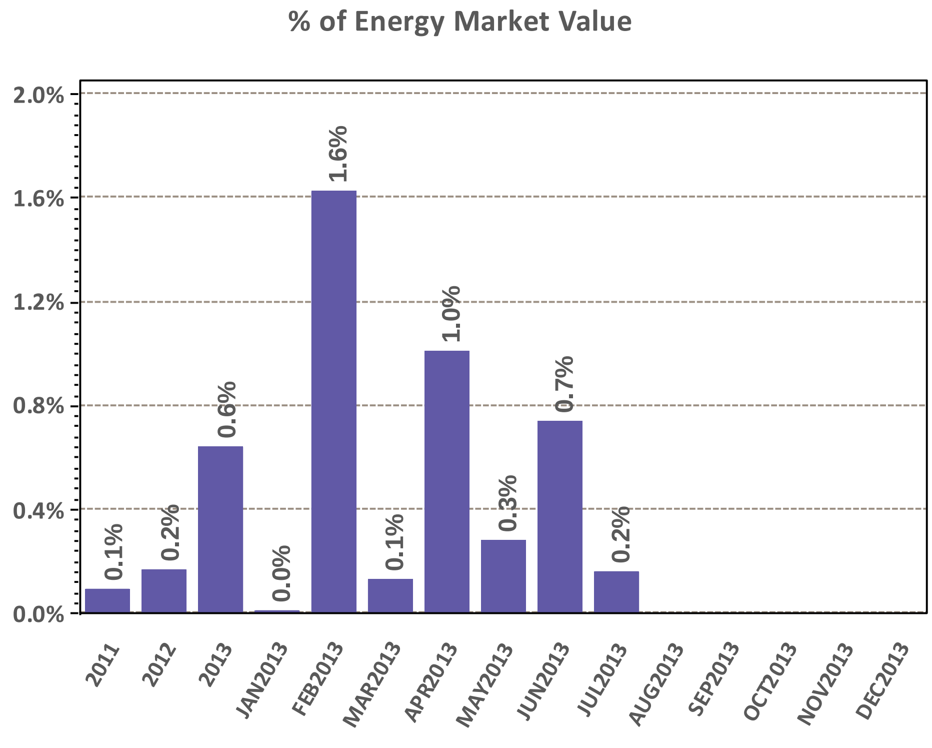




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

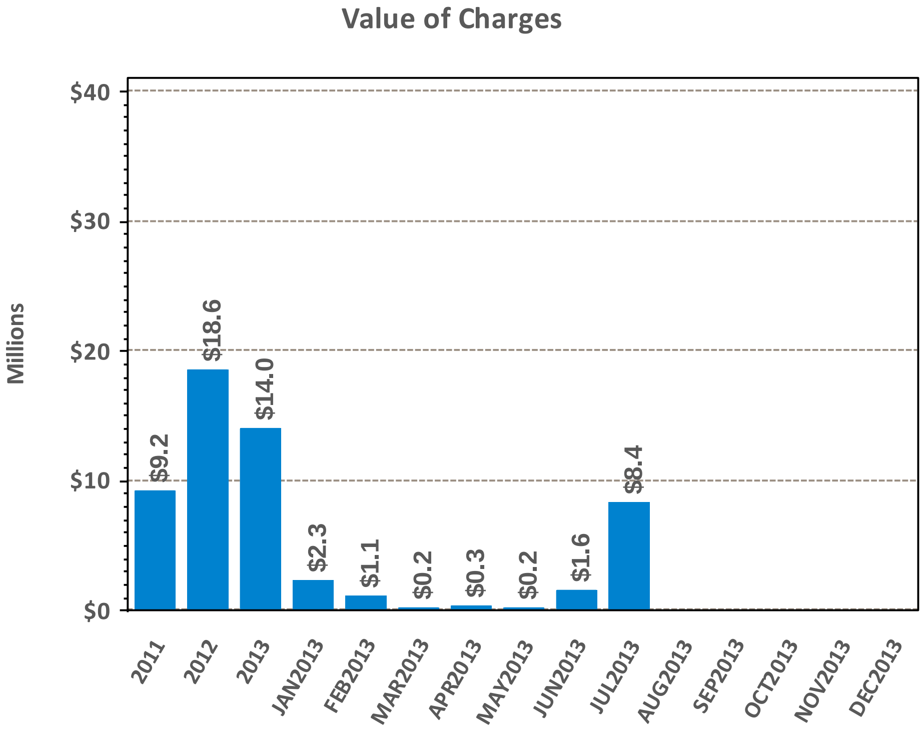
Second Contingency NCPC Charges

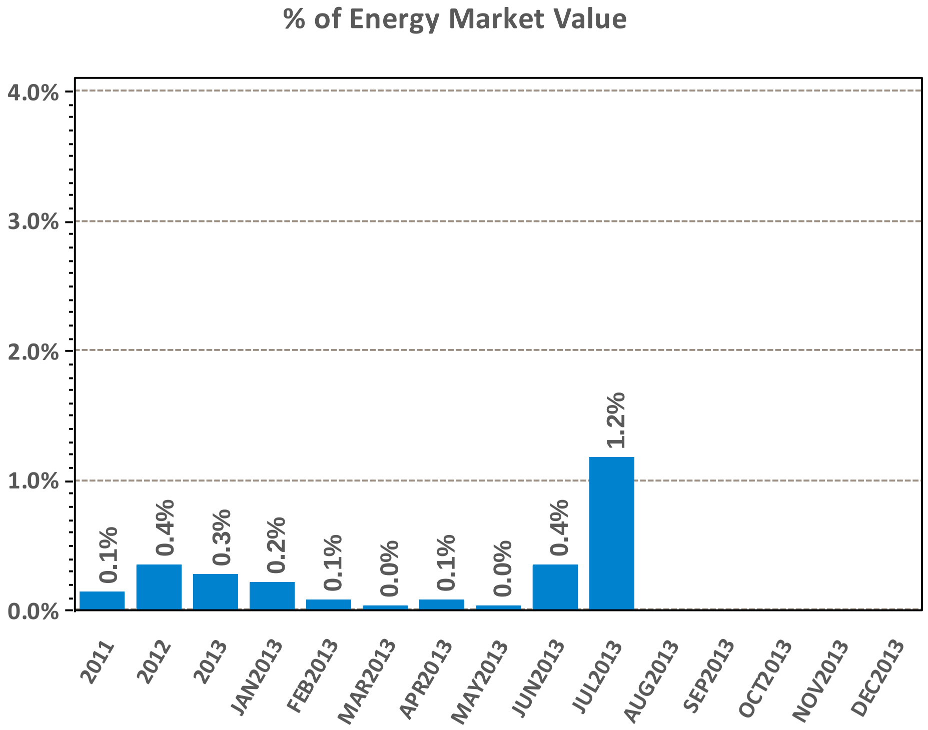




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

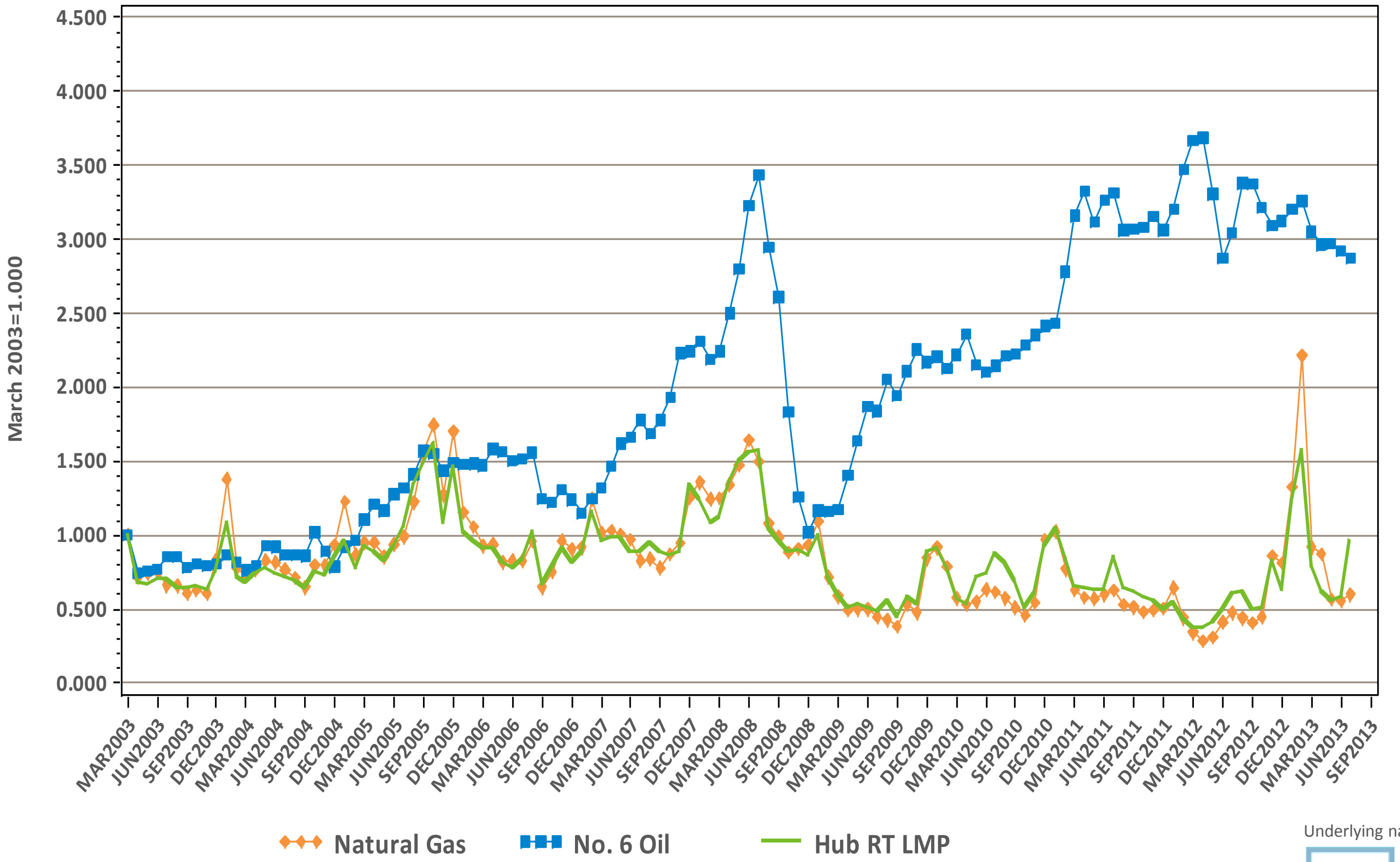
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2011	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.14	$47.47	$45.58	$45.94	$46.67	$45.78	$46.19	$46.92	$46.38
Real-Time	$46.57	$47.95	$44.95	$46.07	$46.57	$46.14	$46.58	$47.23	$46.68
RT Delta %	0.9%	1.0%	-1.4%	0.3%	-0.2%	0.8%	0.9%	0.7%	0.6%
Year 2012	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$36.48	$37.09	$36.20	$36.24	$36.57	$36.56	$36.44	$37.29	$36.43
Real-Time	$36.22	$36.95	$35.25	$36.00	$36.22	$35.96	$36.22	$36.97	$36.17
RT Delta %	-0.7%	-0.4%	-2.6%	-0.7%	-0.9%	-1.7%	-0.6%	-0.8%	-0.7%

July-12	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$41.72	$43.80	$40.63	$41.57	$42.34	$41.59	$41.73	$43.22	$41.88
Real-Time	$41.87	$43.43	$40.69	$41.78	$42.48	$41.57	$41.93	$43.26	$41.94
RT Delta %	0.4%	-0.9%	0.2%	0.5%	0.3%	0.0%	0.5%	0.1%	0.2%
July-13	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$57.03	$57.99	$53.09	$56.39	$57.35	$56.56	$56.84	$57.36	$56.94
Real-Time	$66.49	$66.20	$55.84	$61.07	$63.36	$65.36	$66.11	$65.80	$65.70
RT Delta %	16.6%	14.2%	5.2%	8.3%	10.5%	15.6%	16.3%	14.7%	15.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	36.7%	32.4%	30.7%	35.6%	35.4%	36.0%	36.2%	32.7%	36.0%
Yr over Yr RT	58.8%	52.4%	37.2%	46.2%	49.2%	57.2%	57.7%	52.1%	56.6%

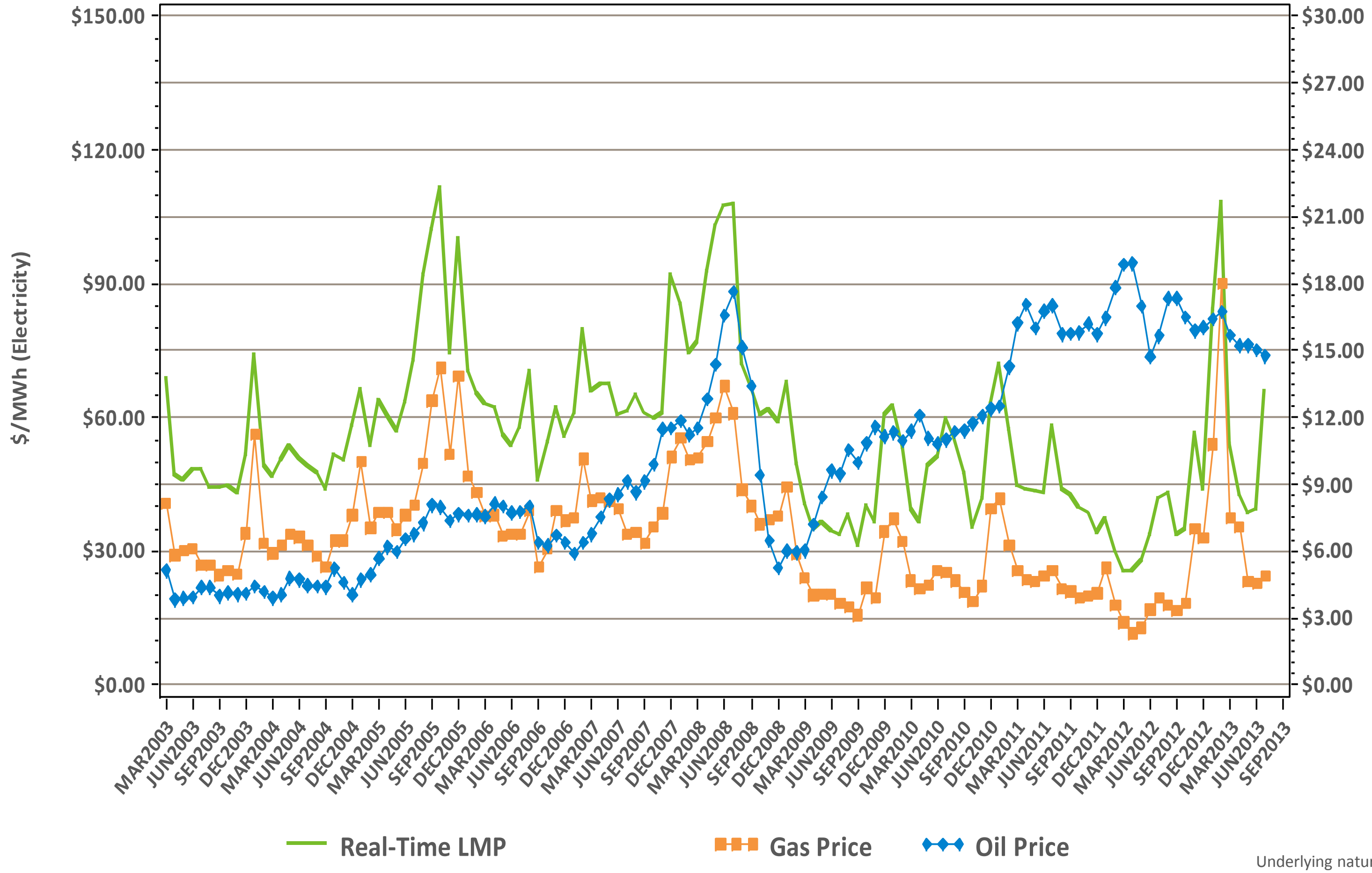
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:

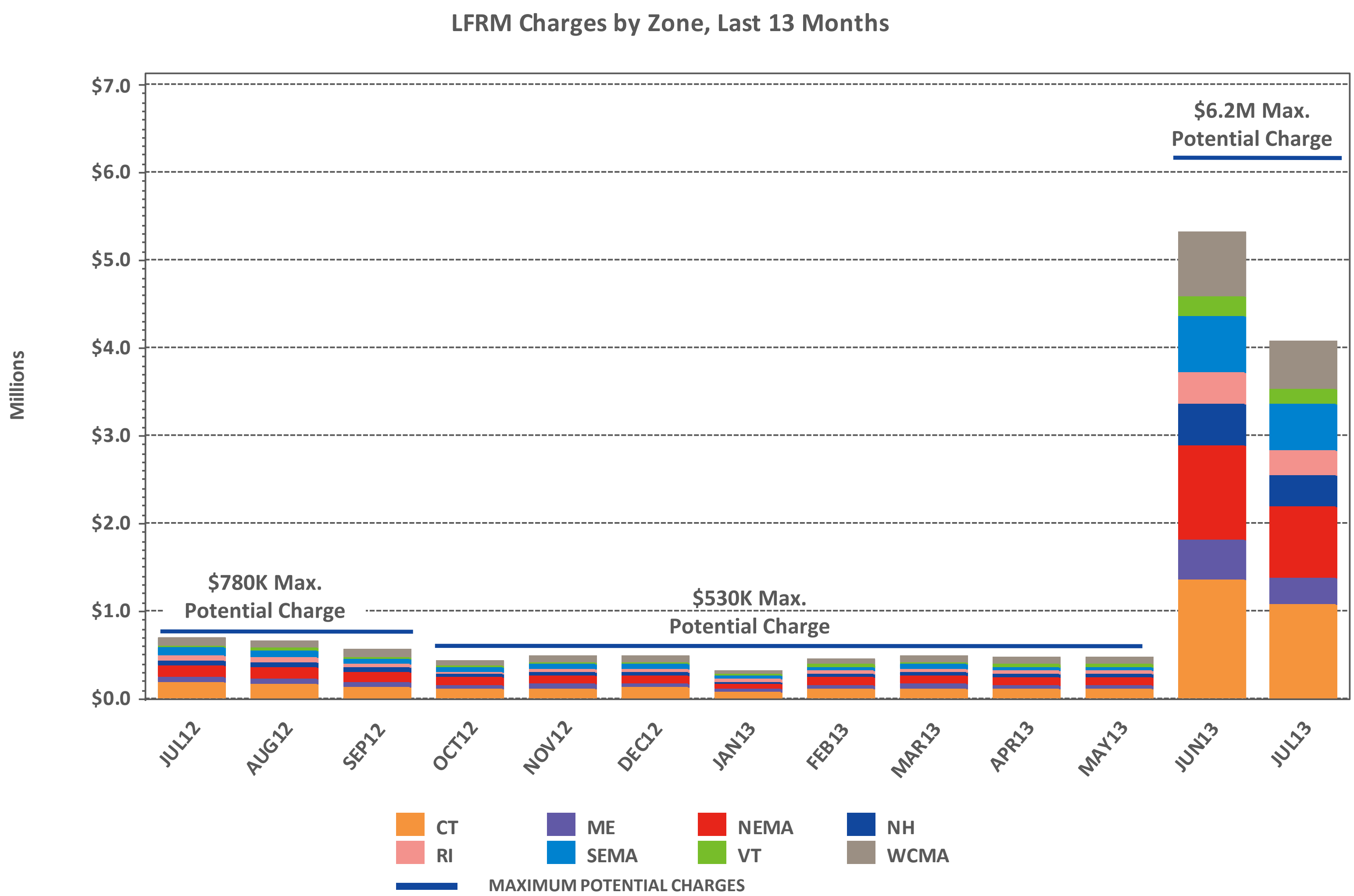
ICE Global markets in clear view

Reserve Market Results – July 2013

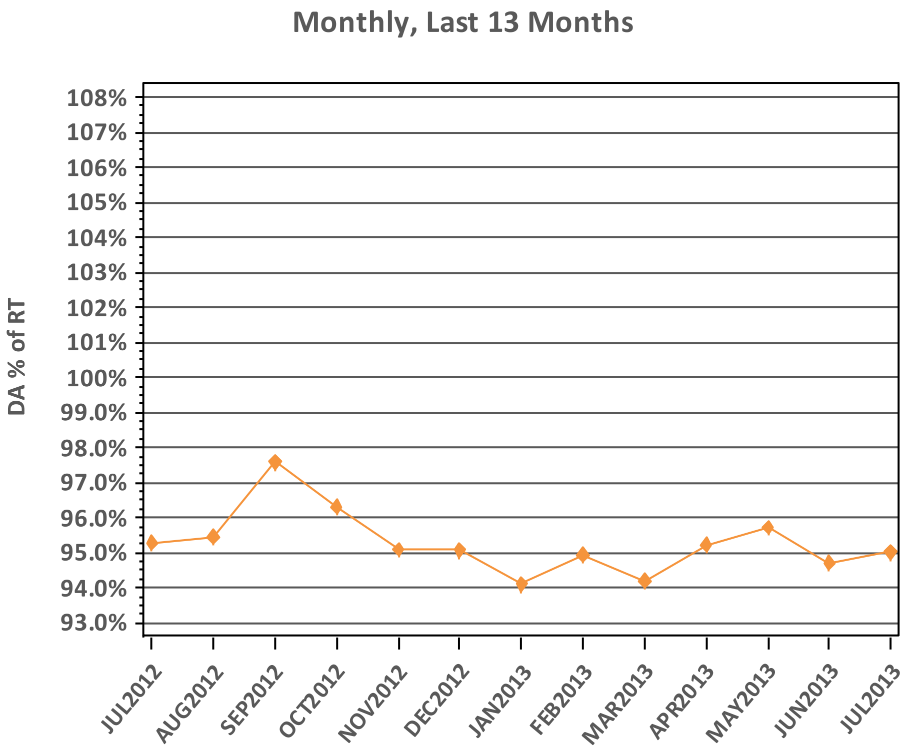
- Maximum potential Forward Reserve Market payments of $4.8M were reduced by credit reductions of $275K, failure-to-reserve penalties of $412K and failure-to-activate penalties of $34K, resulting in a net payout of $4.1M or 85% of maximum
  - Rest of System: $2.2M/$2.6M (85%)
  - Southwest Connecticut: $173K/$456K (38%)
  - Connecticut: $1.7M/$1.8M (97%)
  - NEMA: N/A
- $16.5M total Real-Time credits were reduced by $5.2M in Forward Reserve Energy Obligation Charges for a net of $11.3M in Real-Time Reserve payments
  - Rest of System: 199 hours, $5.9M
  - Southwest Connecticut: 199 hours, $2.7M
  - Connecticut: 199 hours, $2.0M
  - NEMA: 199 hours, $661K

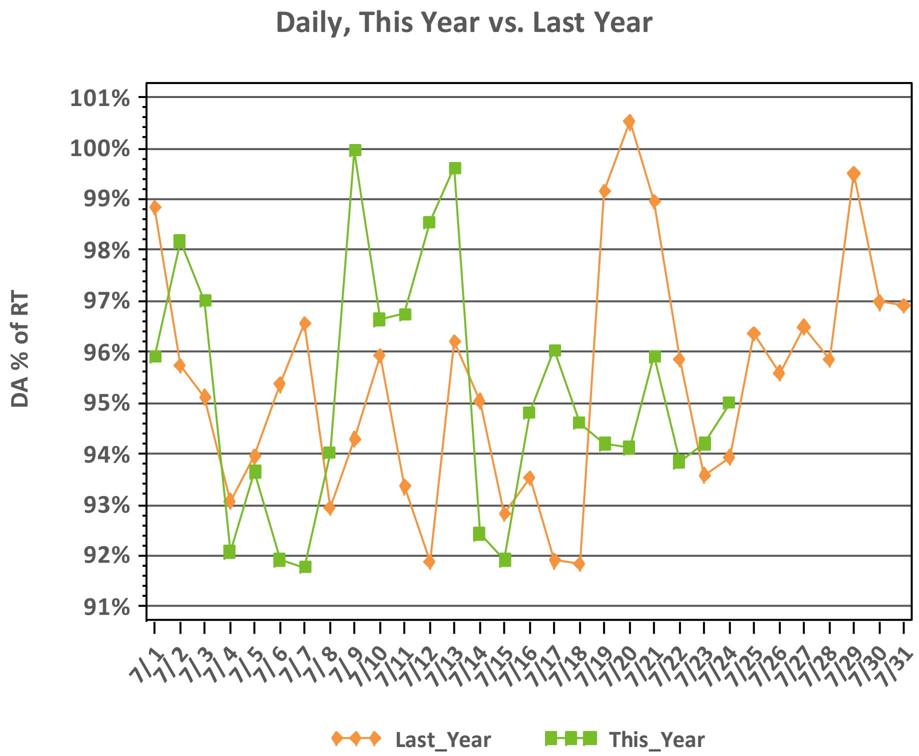
*** "Failure to reserve" results in both reductions in credits and penalties in the Locational Forward Reserve Market.**

LFRM Charges to Load by Load Zone ($)

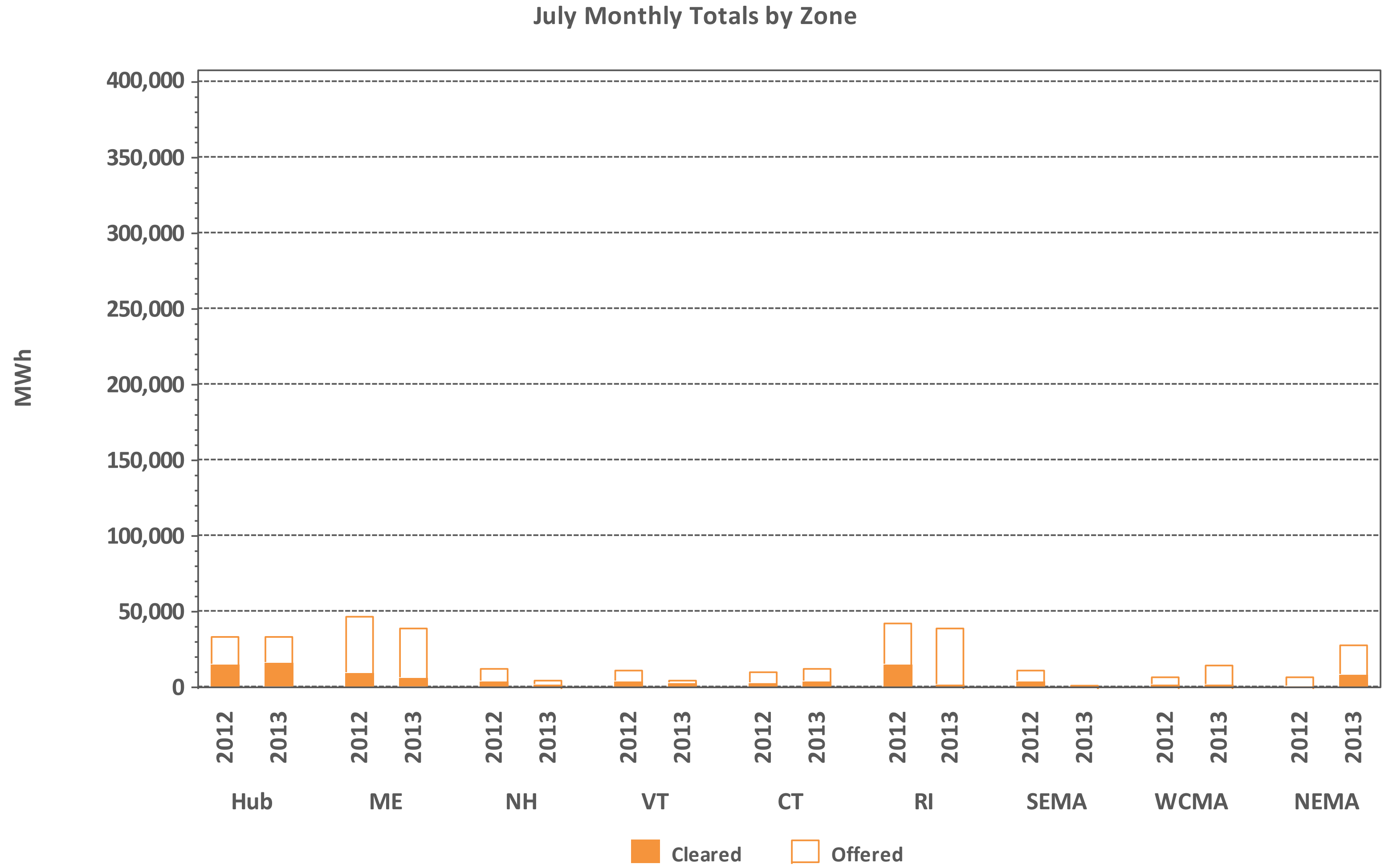


DA vs. RT Load Obligation: July, This Year vs. Last Year

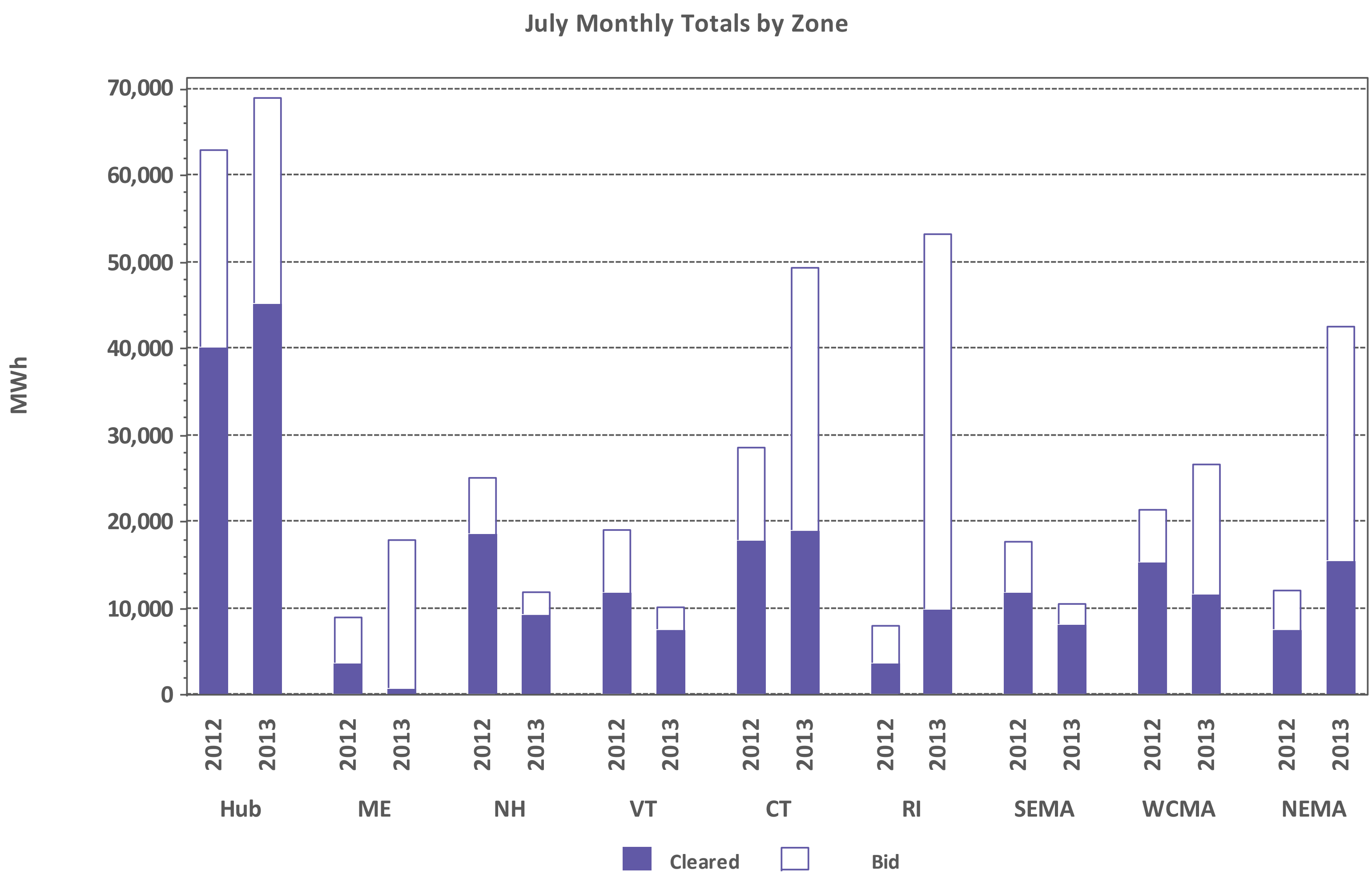




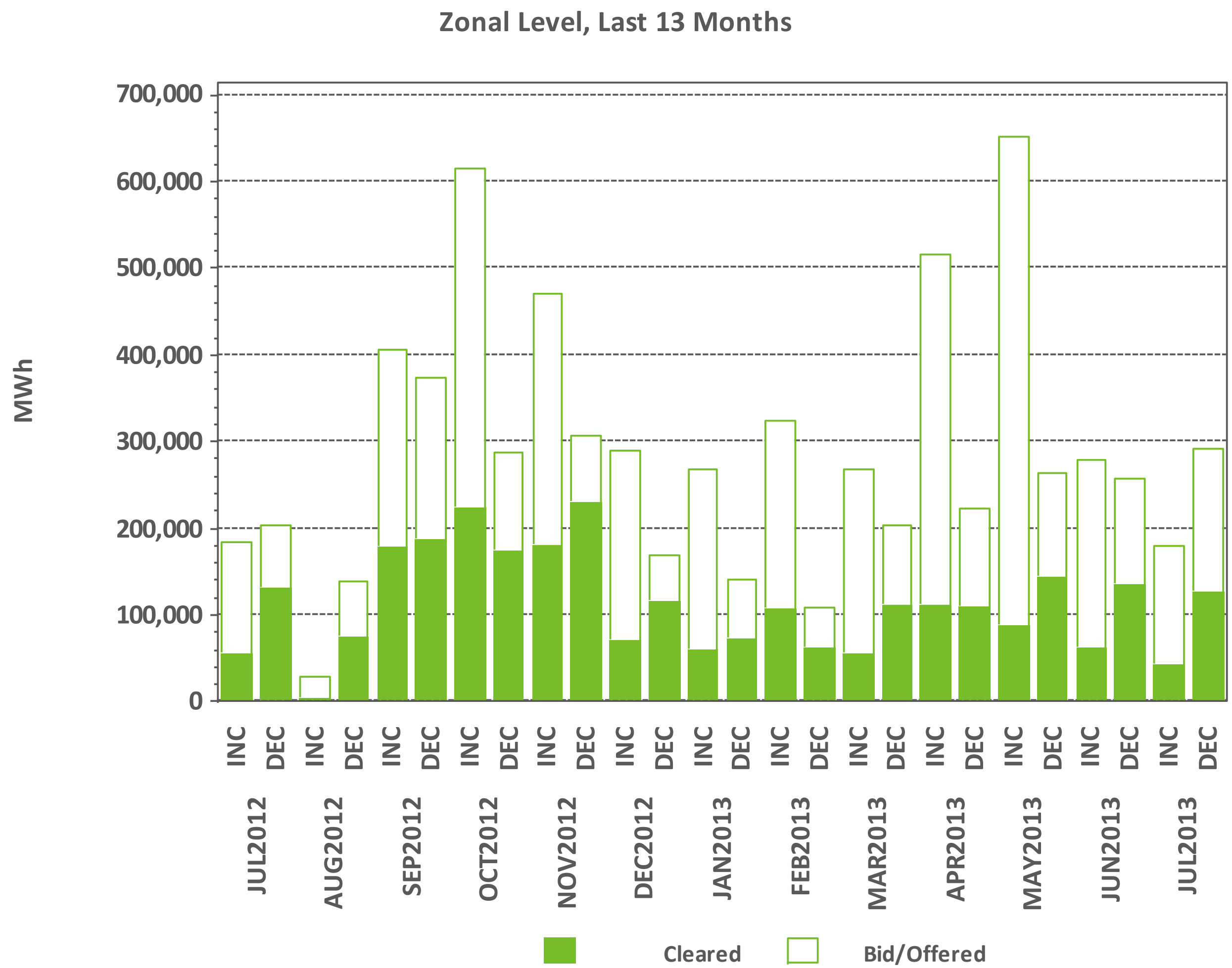
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

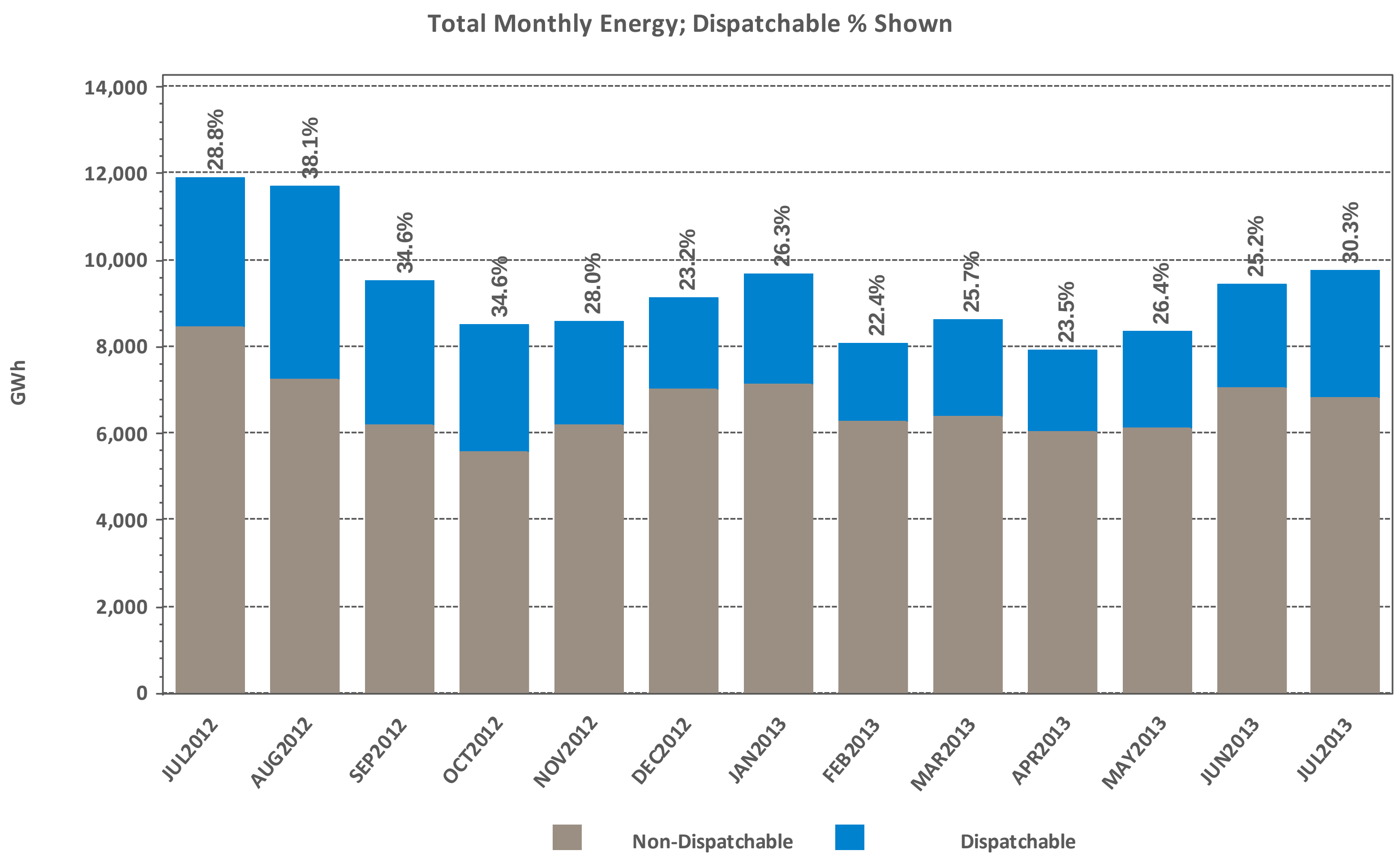


Total Increment Offers and Decrement Bids

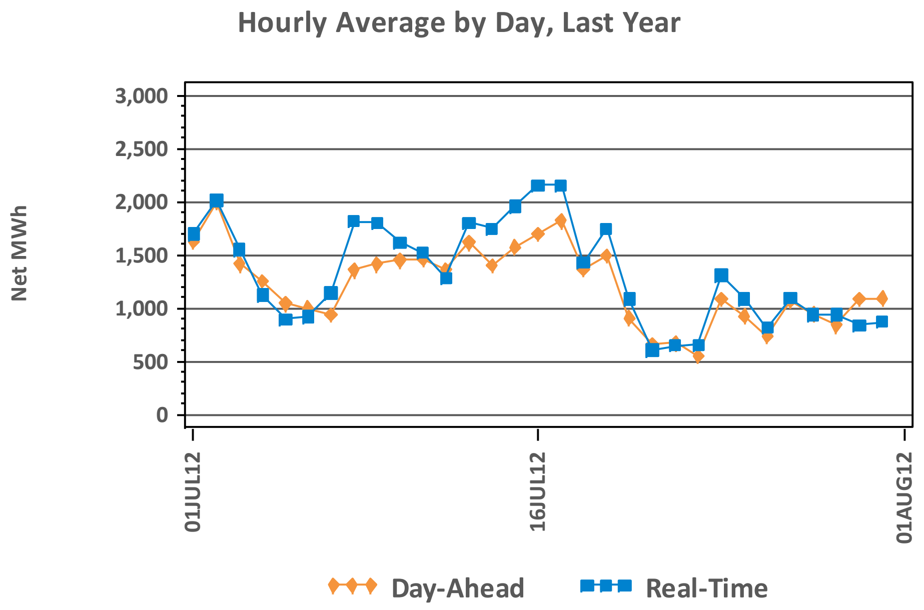


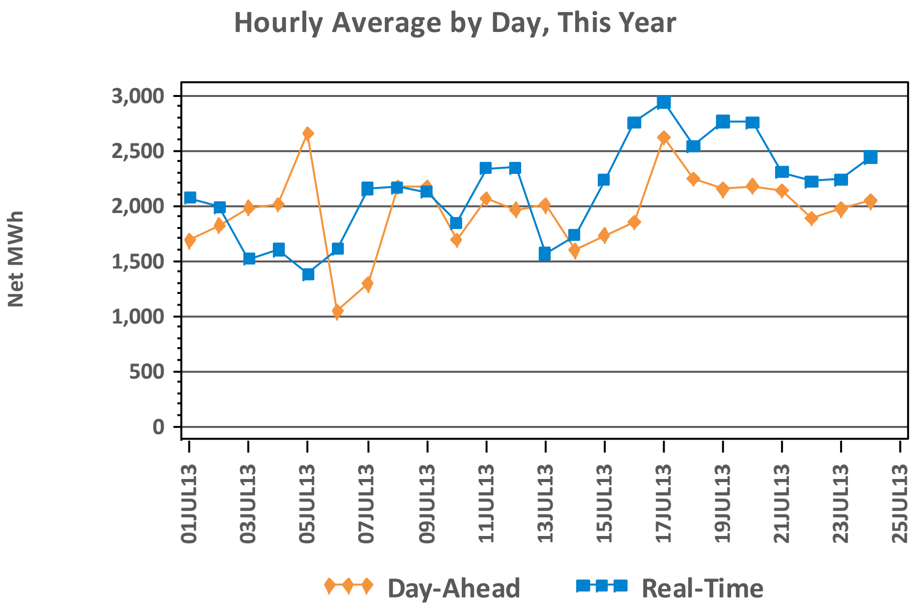
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



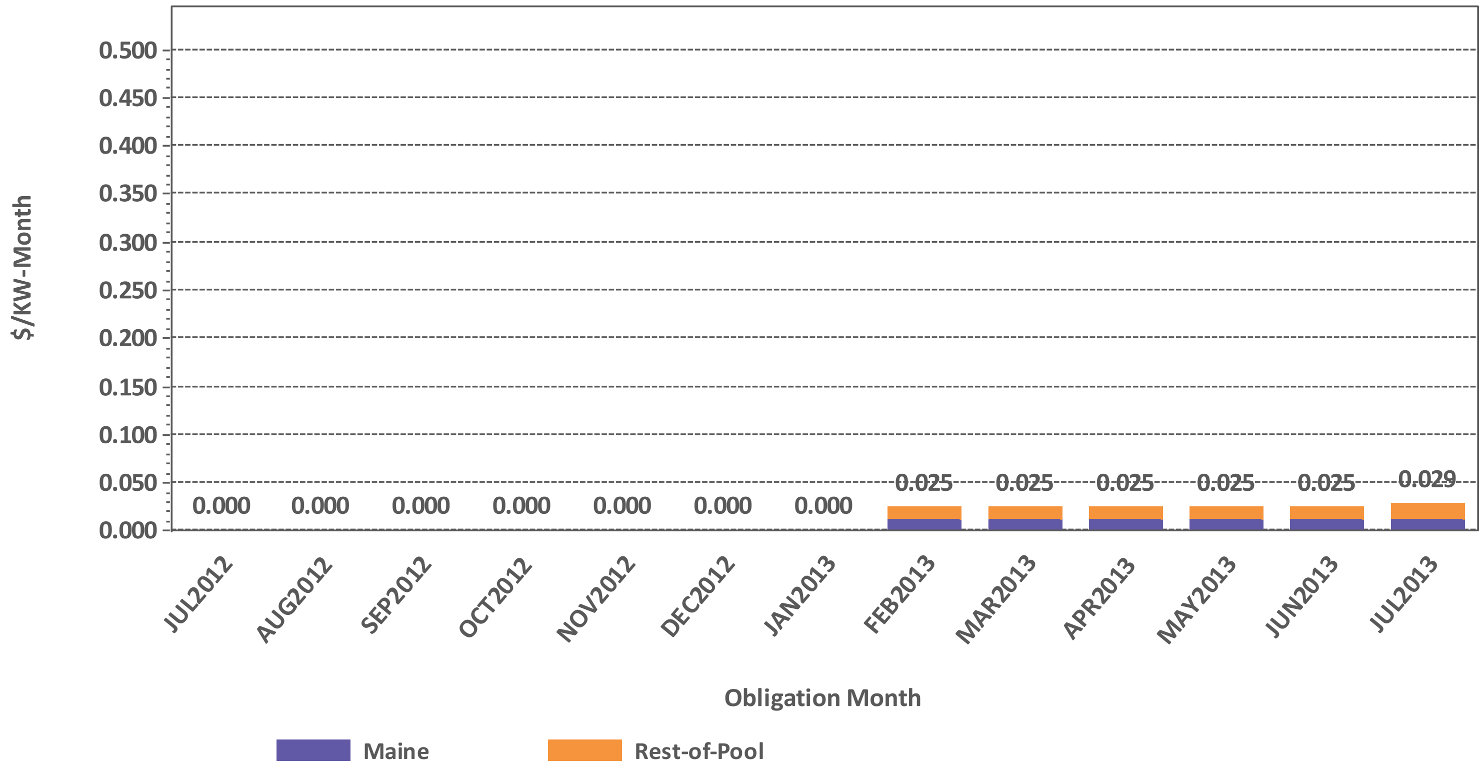
DA vs. RT Net Interchange
July 2013 vs. July 2012





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

Rolling Average Peak Energy Rent (PER)



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

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

REGIONAL SYSTEM PLAN (RSP) AND INTERREGIONAL PLANNING

Planning Advisory Committee

- RSP13 draft has been distributed to stakeholders for comment and will be reviewed at the August 13 PAC meeting
- August 13 Tentative Agenda:
  - Regional System Plan Page Turn
  - NESCOE Presentation on Use of Probabilistic Analysis in System Planning Base Case Development
  - Follow-up Discussion on EIPC non-Grant Work

RSP Project Stage Descriptions

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

North Shore Upgrades – Merrimack Valley

Status as of 7/25/13

Project Benefit: Maintains system reliability for the North Shore area

Upgrade	Expected In-service	Present Stage
Wakefield Junction/Merrimack Valley		
115 kV Overhead Reconductor (G133E)	Feb-08	4
Reconductor Wakefield Junction - Golden Hills Tap 115 kV	Sep-08	4
30 MVAR 115 kV Capacitor at Revere	Oct-08	4
Wakefield Junction Substation	Nov-09	4
Loop 345 kV and 115 kV Lines into Wakefield Substation	Nov-09	4
Retirement of Golden Hills Substation	Apr-10	4
Add Parallel 115 kV Cable in Mystic-Everett Line	Dec-12	4
Add King Street - W. Amesbury 115 kV Line	Apr-11	4
Reconductor Overhead Portion of Mystic-Everett 115 kV Line	May-13	4

North Shore Upgrades – Salem Harbor Non-Price Retirement

Status as of 7/25/13

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

Upgrade	Expected In-service	Present Stage
Reconductor Y-151 Tewksbury Jct. - West Methuen 115 kV	Dec-13	2
Reconductor B-154N King St. - South Danvers 115 kV	Feb-13	4
Reconductor C-155N King St. - South Danvers 115 kV	Feb-13	4
Reconductor S-145 Tewksbury - North Reading 115 kV	Aug-13	2
Reconductor T-146 Tewksbury - North Reading 115 kV	Aug-13	2

Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 7/25/13

Project Benefit: Improves system reliability for the Lower SEMA area

Upgrade	Expected In-service	Present Stage
Expand the Carver Substation	Jun-13	4
Build New 345 kV Line from Carver to Vicinity of Bourne Substation and connect to Line 120. Expand Bourne with one breaker position.	Jun-13	4*
Construct New 115 kV Substation with 345-115 kV Autotransformer and Loop Line 115 into the new substation	Dec-13	3
Upgrade the 115 kV Bell Rock to High Hill D21 Line	May-13	4
Separate the 345 kV (342 / 322) Double Circuit Tower Lines	Jun-13	4

Project approved by MA EFSB on 4/27/12

* The work is in service in a temporary configuration. The final in-service configuration will be completed by December 2013.

NEEWS: Greater Springfield Reliability Project

Status as of 7/25/13

Plan Benefit: Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

Upgrade	Expected In-service	Present Stage
Construct New 345 kV Ludlow - Agawam Line	Dec-13	4
Construct New 345 kV Agawam - North Bloomfield Line	Dec-13	4
Expand Existing 115 kV Agawam Station & Construct New 345 kV Yard	Dec-13	4
Expand 345 kV North Bloomfield Station	Dec-13	4
Expand & Reconfigure 345 kV Ludlow Station	Dec-13	4
Rebuild 115 kV Agawam - Piper Line	Dec-13	4
Rebuild 115 kV Agawam - Chicopee Line	Dec-13	4
Construct New 115 kV Cadwell Switching Station	Dec-13	4
Reconductor 115 kV Ludlow - Orchard Line	Dec-13	4
Rebuild 115 kV Orchard - Cadwell Line	Dec-13	4
Rebuild 115 kV Ludlow - Cadwell Line	Dec-13	4

NEEWS: Greater Springfield Reliability Project, *cont.*

Status as of 7/25/13

Plan Benefit: Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

Upgrade	Expected In-service	Present Stage
Build New 115 kV Fairmont Switching Station	Dec-13	3
Rebuild 115 kV Fairmont - Piper Line	Dec-13	3
Rebuild 115 kV Fairmont - Chicopee Line	Dec-13	3
Rebuild 115 kV Fairmont - Cadwell Line	Dec-13	3
Rebuild 115 kV Fairmont - Shawinigan Line	Dec-13	3
Rebuild 115 kV Ludlow - Shawinigan Line	Dec-13	4
Reconfigure 115 kV South Agawam Switching Station	Dec-13	4
Reconfigure 115 kV Southwick - South Agawam Line	Dec-13	4
Rebuild Two 115 kV South Agawam - Agawam Lines	Dec-13	4
Terminate Two 115 kV East Springfield - Cadwell Lines	Dec-13	3

NEEWS: Manchester – Meekville Project

Status as of 7/25/13

Plan Benefit: Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

Upgrade	Expected In-service	Present Stage
Build New 345 kV Manchester to Meekville Junction Line	Dec-12	4
Separate 3-Terminal 345 kV 395 Line at Meekville Junction	Dec-12	4
Reterminate 345 kV North Bloomfield Line to Manchester Substation	Dec-13	4

NEEWS: Rhode Island

Status as of 7/25/13

Plan Benefit: Improves reliability by eliminating Rhode Island criteria violations

Upgrade	Expected In-service	Present Stage
Construct New West Farnum - Kent County 345 kV Line	May-13	4
Install 3rd Kent County 345-115 kV Autotransformer	Sep-11	4
Kent County Substation Upgrades	May-12	4
Reconductor Kent County - Drumrock 115 kV Line	Jul-11	4
Reconductor Short Segments of West Farnum - Hartford Avenue - Drumrock 115 kV Lines	Mar-13	4

NEEWS: Interstate & Central Connecticut

Status as of 7/25/13

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

Upgrade	Expected In-service	Present Stage
Interstate Reliability Project (Interstate)	Dec-15	1
Central Connecticut Reliability Project (CCRP)*	Jun-17	1

* Combined with Greater Hartford Central Connecticut Study

Maine Power Reliability Program (MPRP)

Status as of 7/25/13

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

New 345 kV Lines	Expected In-Service	Present Stage
Construct New Section 3023 Orrington to Albion Road	May-13	4
Construct New Section 3024 Albion Road to Coopers Mills	Jan-15	2
Construct New Section 3025 Coopers Mills to Larrabee Road	Mar-15	3
Construct New Section 3026 Larrabee Road to Surowiec	Dec-12	4
Construct New Section 3020 Surowiec to Raven Farm	Nov-13	3
Construct New Section 3021 South Gorham to Maguire Road	Jun-14	3
Construct New Section 3022 Maguire Road to Eliot	Jun-14	2

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

Maine Power Reliability Program, *cont.*

Status as of 7/25/13

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

New 115 kV Lines	Expected In-Service	Present Stage
Construct New Section 254 Orrington to Coopers Mills	Feb-15	3
Construct New Section 243A Livermore Falls to Junction Section 243	May-14	3
Construct New Section 251 Livermore Falls to Larrabee Road	Apr-14	3
Construct New Section 255 Larrabee Road to Middle Street	Apr-15	2
Construct New Section 86A Tap to Belfast	July-14	2
Construct New Section 256 Middle Street to Lewiston Lower	April-15	1

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

Maine Power Reliability Program, *cont.*

Status as of 7/25/13

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric 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 66 Detroit to Wyman Hydro	May-11	4
Rebuild Section 67 Detroit to Albion Road	May-13	4
Rebuild Section 203 Detroit to Bucksport	Apr-12	4
Rebuild Section 257 (formerly 67) Coopers Mills to Albion Road	May-13	4
Rebuild Section 258 (formerly 84) Coopers Mills to Albion Road	Aug-13	3
Rebuild Section 166 Surowiec to Spring Street	Nov-11	4
Rebuild Section 167 Surowiec to Moshers	Nov-11	4

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

Maine Power Reliability Program, *cont.*

Status as of 7/25/13

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

115 kV Lines Rebuilds (continued)	Expected In-Service	Present Stage
Rebuild Section 60 Coopers Mills to Bowman Street	Feb-15	3
Rebuild Section 88 Coopers Mills to Augusta East Side	Feb-15	3
Rebuild Section 89 Livermore Falls to Riley	Mar-14	2
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	2

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

Maine Power Reliability Program, *cont.*

Status as of 7/25/13

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

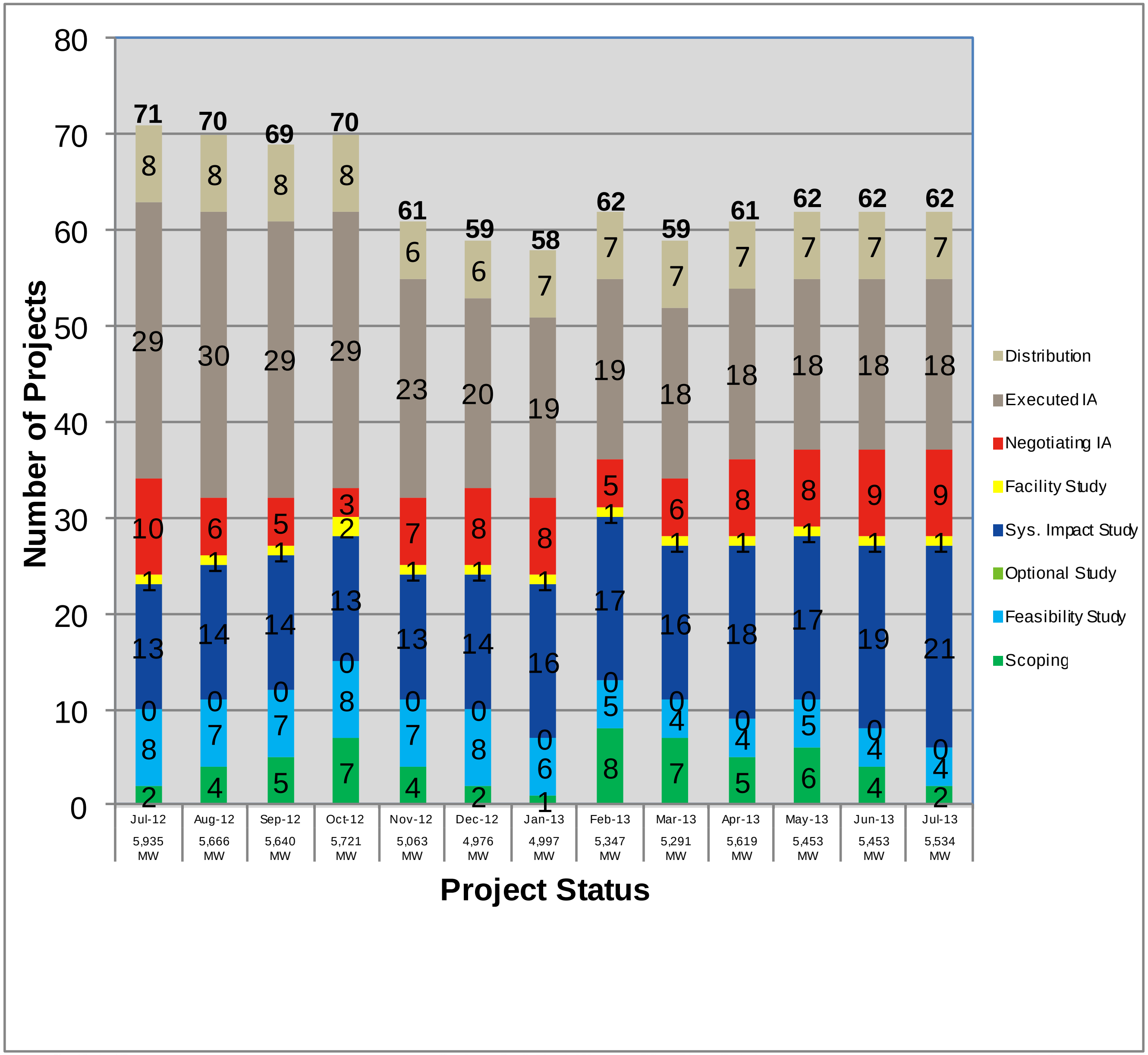
345/115 kV Autotransformers	Expected In-Service	Present Stage
Install One 345/115 kV Autotransformer at Albion Road	Apr-13	4
Install One 345/115 kV Autotransformer at Coopers Mills	Jan-15	2
Install One 345/115 kV Autotransformer at Larrabee Road	Dec-12	4
Install One 345/115 kV Autotransformer at Maguire Road	Jun-14	3
Install One 345/115 kV Autotransformer at South Gorham	Nov-09	4

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

Transmission Siting Update

- NEEWS
  - Rhode Island Reliability Project
    - Received siting approval from Rhode Island authorities
  - Greater Springfield Reliability Project
    - Received siting approval from both Connecticut and Massachusetts authorities
  - Interstate Reliability Project
    - National Grid siting application was filed in MA on 6/21/12
    - National Grid siting application was filed in RI on 7/19/12
    - CL&P's siting hearings in CT were completed on 8/30/12
    - Received siting approval from CT on 1/2/13. The RI PUC made a recommendation to the RI EFSB on 4/8/13 to approve the project. Siting hearings in MA are scheduled to begin in August
- MPRP
  - Project filed with the Maine Public Utility Commission on 7/1/08
  - Maine PUC approved most of the project on 6/10/10
  - Hearings are complete - awaiting written order on Lewiston Loop
  - TCAs are being revised to reflect the new version of the project

Status of Tariff Studies



OPERABLE CAPACITY ANALYSIS

Summer 2013

Summer 2013 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September-2013 [2] CSO	September-2013 [2] SCC
Generator Operable Capacity MW [1]	29,458	31,192
OP CAP From OP-4 RTDR (+)	429	429
OP CAP From OP-4 RTEG (+)	234	234
Operable Capacity Generator with OP-4 DR and RTEG	30,121	31,855
External Node Available Capacity – CSO Only (+)	1,183	1,183
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	1,393	1,466
Allowance for Unplanned Outages (-)	2,100	2,100
Gas Generator Outages MW (-)	232	244
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	27,579	29,228
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,690	26,690
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,065	29,065
Operable Capacity Margin [3]	(1,486)	163

[1] Generator Operable Capacity is based on data as of July 23rd , 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, weeks beginning September 7th 2013

[3] Includes OP4 actions associated with RTEG and RTDR

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

Summer 2013 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	September-2013 [2] CSO	September-2013 [2] SCC
Generator Operable Capacity MW [1]	29,458	31,192
OP CAP From OP-4 RTDR (+)	429	429
OP CAP From OP-4 RTEG (+)	234	234
Operable Capacity Generator with OP-4 DR and RTEG	30,121	31,855
External Node Available Capacity – CSO Only (+)	1,183	1,183
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	1,393	1,466
Allowance for Unplanned Outages (-)	2,100	2,100
Gas Generator Outages MW (-)	232	244
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	27,579	29,228
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	28,985	28,985
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	31,360	31,360
Operable Capacity Margin [3]	(3,781)	(2,132)

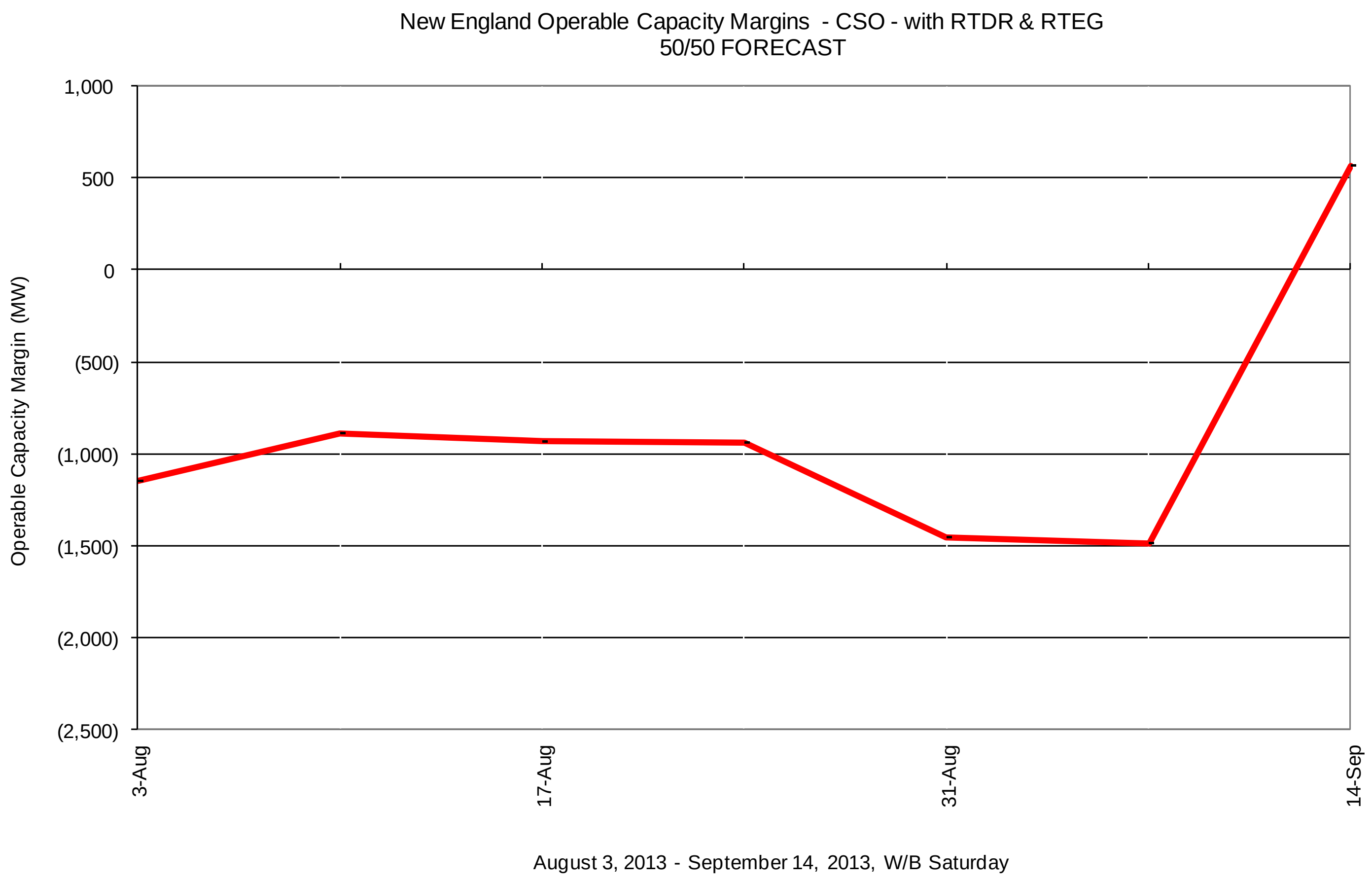
[1] Generator Operable Capacity is based on data as of July 23rd, 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning September 7th, 2013

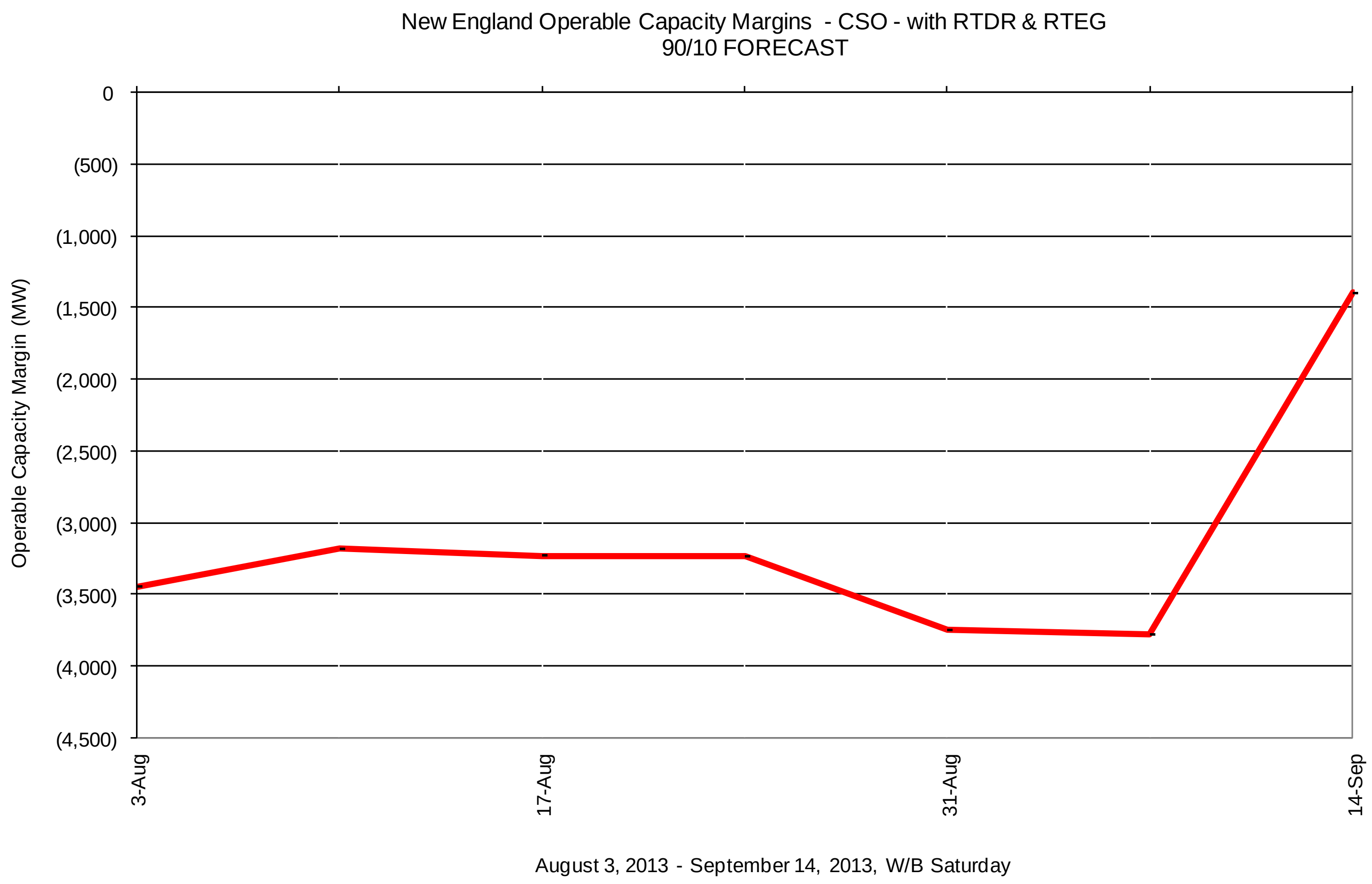
[3] Includes OP4 actions associated with RTEG and RTDR

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

Summer 2013 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)



Summer 2013 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)



Summer 2013 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)

ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

July 29, 2013 - 50/50- FORECAST - CSO

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

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
08/03/2013	29,748	1,039	0	1,286	2,100	0	0	27,401	26,690	2,375	29,065	(1,664)	352	(1,312)	163	(1,149)
08/10/2013	29,748	1,039	0	1,026	2,100	0	0	27,661	26,690	2,375	29,065	(1,404)	352	(1,052)	163	(889)
08/17/2013	29,748	1,039	0	1,070	2,100	0	0	27,617	26,690	2,375	29,065	(1,448)	352	(1,096)	163	(933)
08/24/2013	29,748	1,039	0	1,076	2,100	0	0	27,611	26,690	2,375	29,065	(1,454)	352	(1,102)	163	(939)
08/31/2013	29,458	1,183	0	1,361	2,100	232	0	26,948	26,690	2,375	29,065	(2,117)	429	(1,688)	234	(1,454)
09/07/2013	**29,458**	**1,183**	**0**	**1,393**	**2,100**	**232**	**0**	**26,916**	**26,690**	**2,375**	**29,065**	**(2,149)**	**429**	**(1,720)**	**234**	**(1,486)**
09/14/2013	29,458	803	0	2,284	2,100	896	0	24,981	22,701	2,375	25,076	(95)	429	334	234	568

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 external Capacity Supply Obligations, CSO .
3. New resources that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast per data included in the 2013 CELT Report adjusted for Other Demand Resources.
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16);
This does not include Emergency Energy Transactions (EETs).

Summer 2013 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)

ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

July 29, 2013 - 90/10- FORECAST - CSO

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

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
08/03/2013	29,748	1,039	0	1,286	2,100	0	0	27,401	28,985	2,375	31,360	(3,959)	352	(3,607)	163	(3,444)
08/10/2013	29,748	1,039	0	1,026	2,100	0	0	27,661	28,985	2,375	31,360	(3,699)	352	(3,347)	163	(3,184)
08/17/2013	29,748	1,039	0	1,070	2,100	0	0	27,617	28,985	2,375	31,360	(3,743)	352	(3,391)	163	(3,228)
08/24/2013	29,748	1,039	0	1,076	2,100	0	0	27,611	28,985	2,375	31,360	(3,749)	352	(3,397)	163	(3,234)
08/31/2013	29,458	1,183	0	1,361	2,100	232	0	26,948	28,985	2,375	31,360	(4,412)	429	(3,983)	234	(3,749)
09/07/2013	**29,458**	**1,183**	**0**	**1,393**	**2,100**	**232**	**0**	**26,916**	**28,985**	**2,375**	**31,360**	**(4,444)**	**429**	**(4,015)**	**234**	**(3,781)**
09/14/2013	29,458	803	0	2,284	2,100	896	0	24,981	24,667	2,375	27,042	(2,061)	429	(1,632)	234	(1,398)

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 external Capacity Supply Obligations, CSO .
3. New resources that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast per data included in the 2013 CELT Report adjusted for Other Demand Resources.
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16);
This does not include Emergency Energy Transactions (EETs).

OPERABLE CAPACITY ANALYSIS

Fall 2013

Fall 2013 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September-2013 [2] CSO	September-2013 [2] SCC
Generator Operable Capacity MW [1]	29,458	31,192
OP CAP From OP-4 RTDR (+)	429	429
OP CAP From OP-4 RTEG (+)	234	234
Operable Capacity Generator with OP-4 DR and RTEG	30,121	31,855
External Node Available Capacity – CSO Only (+)	1,183	1,183
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	3,340	3,516
Allowance for Unplanned Outages (-)	2,100	2,100
Gas Generator Outages MW (-)	751	791
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	25,113	26,631
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,609	22,609
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,984	24,984
Operable Capacity Margin [3]	129	1,647

[1] Generator Operable Capacity is based on data as of July 23, 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, weeks beginning September 21th 2013

[3] Includes OP4 actions associated with RTEG and RTDR

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

Fall 2013 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	September-2013 [2] CSO	September-2013 [2] SCC
Generator Operable Capacity MW [1]	29,458	31,192
OP CAP From OP-4 RTDR (+)	429	429
OP CAP From OP-4 RTEG (+)	234	234
Operable Capacity Generator with OP-4 DR and RTEG	30,121	31,855
External Node Available Capacity – CSO Only (+)	1,183	1,183
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	3,340	3,516
Allowance for Unplanned Outages (-)	2,100	2,100
Gas Generator Outages MW (-)	751	791
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	25,113	26,631
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,567	24,567
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,942	26,942
Operable Capacity Margin [3]	(1,829)	(311)

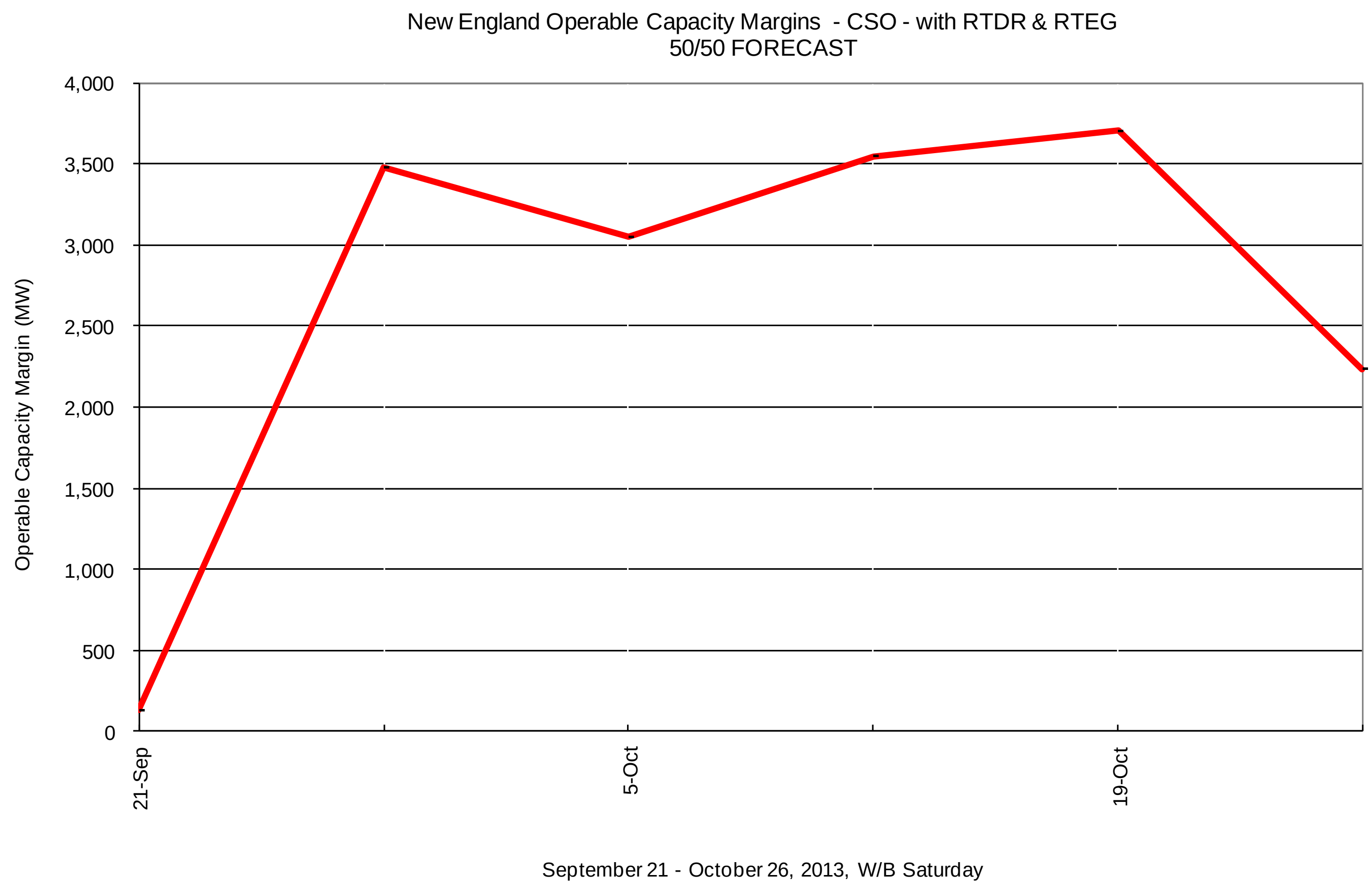
[1] Generator Operable Capacity is based on data as of July 23rd, 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning September 21st , 2013

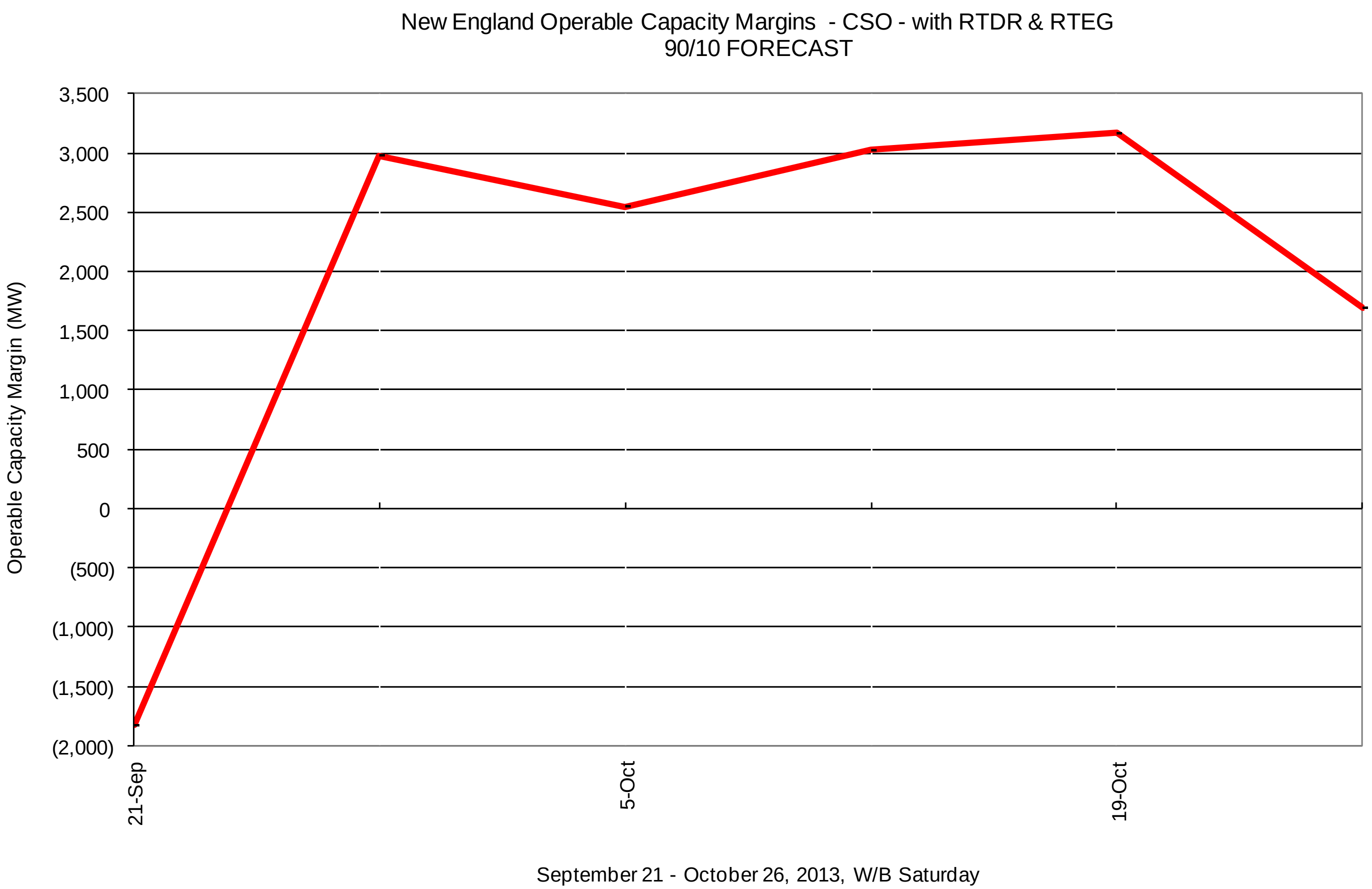
[3] Includes OP4 actions associated with RTEG and RTDR

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

Fall 2013 Operable Capacity Analysis(MW)
50/50 Forecast (Reference)



Fall 2013 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)



Fall 2013 Operable Capacity Analysis(MW)
50/50 Forecast (Reference)

ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

July 29, 2013 - 50/50- FORECAST - CSO

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STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
09/21/2013	**29,458**	**1,183**	**0**	**3,340**	**2,100**	**751**	**0**	**24,450**	**22,609**	**2,375**	**24,984**	**(534)**	**429**	**(105)**	**234**	**129**
09/28/2013	29,560	1,183	38	3,944	2,800	2,386	0	21,651	16,499	2,375	18,874	2,777	467	3,244	234	3,478
10/05/2013	29,560	1,183	38	5,022	2,800	1,702	0	21,257	16,534	2,375	18,909	2,348	467	2,815	234	3,049
10/12/2013	29,560	1,183	38	3,235	2,800	2,055	0	22,691	17,468	2,375	19,843	2,848	467	3,315	234	3,549
10/19/2013	29,560	1,183	38	2,627	2,800	2,142	0	23,212	17,836	2,375	20,211	3,001	467	3,468	234	3,702
10/26/2013	29,560	989	114	2,732	3,600	2,375	0	21,956	18,045	2,375	20,420	1,536	467	2,003	234	2,237

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Fall 2013 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)

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July 29, 2013 - 90/10- FORECAST - CSO

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09/28/2013	29,560	1,183	38	3,944	2,800	2,386	0	21,651	16,998	2,375	19,373	2,278	467	2,745	234	2,979
10/05/2013	29,560	1,183	38	5,022	2,800	1,702	0	21,257	17,035	2,375	19,410	1,847	467	2,314	234	2,548
10/12/2013	29,560	1,183	38	3,235	2,800	2,055	0	22,691	17,995	2,375	20,370	2,321	467	2,788	234	3,022
10/19/2013	29,560	1,183	38	2,627	2,800	2,142	0	23,212	18,373	2,375	20,748	2,464	467	2,931	234	3,165
10/26/2013	29,560	989	114	2,732	3,600	2,375	0	21,956	18,588	2,375	20,963	993	467	1,460	234	1,694

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OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0[1] 600
2	Dispatch real time Demand Resources.	600 [3]
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	130 [4] 400 [3]
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	260 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
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		3,535

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software.
4. The MW values are based on a 26,462 MW system load and the most recent voltage reduction test % achieved.