

NEPOOL Participants Committee Report May 2010

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Senior Vice President and Chief Operating Officer

Table of Contents

• Highlights	Page 3
• System Operations	Page 8
• Market Operations	Page 16
• Back-Up Detail	Page 25
– Load Response	Page 26
– New Generation	Page 29
– Reliability Costs	Page 37
• New Commitment Period Compensation (NCPC) Operating Costs	Page 38
• Reliability Agreement Summary	Page 67
– Regional System Plan (RSP)	Page 70
– Operable Capacity Analysis	Page 81
– Appendix	Page 91

Highlights

- **Day-Ahead (DA), Real-Time (RT) Prices and Transactions**
 - April natural gas prices over the period were 7.7% lower while oil prices were 6.2% higher than March 2010 average values
 - Average RT Hub Locational Marginal Prices (LMPs) over the period were down 6.7% from March 2010 averages

Underlying natural gas data furnished by:



Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)***
 - April payments total \$1.9M over the period, up \$608K from March
 - First Contingency payments total \$1.0M, down \$23K from March
 - \$513K paid to internal resources, down \$308K from March
 - \$70K charged to DALO, \$443K to RT Deviations
 - \$524K paid to resources at external locations, up \$285K from March
 - \$417K charged to DALO at external locations, \$107K to RT Deviation
 - Second Contingency payments total \$886K, up \$865K from the March total of \$21K
 - \$729K in CT, up \$729K from March due to generation and transmission outages
 - \$123K in NEMA, up \$123K
 - Voltage payments total \$0K, down \$256K from March
 - Distribution payments total \$25K, up \$21K from March
 - NCPC payments as percent of Energy Market value were 0.5%

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

Highlights (cont'd.)

- The Planning Advisory Committee (PAC) meeting scheduled for May 25 will discuss Environmental Issues and a draft scope of work of Economic Studies in response to the Stakeholder Requests received and discussed at the April 27 PAC meeting

Eastern Interconnection Planning Collaborative (EIPC)

- EIPC and DOE are still working to finalize agreement
- Effort to craft an Eastern Interconnection model for the analysis work has begun with EIPC members rolling up regional plans (2020 case)
 - Expect model to be complete by early May
 - Current plan is to issue a report on this in October
- Keystone held stakeholder meeting in St. Louis on April 22 and 23 regarding formation of Stakeholder Steering Committee (SSC)
 - No agreement reached on SSC make-up
 - Plan to continue discussion on webinar slated for 2 PM on May 7th
 - Need to reach agreement by mid-May

Highlights

- The lowest Spring Operable Capacity Margin is being calculated for the week beginning May 8th.
- The lowest Summer Operable Capacity Margin is being calculated for the week beginning June 5th.

System Operations

System Operations

<u>Weather Patterns:</u>	Boston	Temperature – Above Average Precipitation – Below Average	Hartford	Temperature – Above Average Precipitation – Below Average
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<u>Peak Load:</u>	16,259MW	April 7, 2010	21:00
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<u>Minimum Generation Emergencies :</u> None
<u>MLCC2:</u> 04/01- Real time contract curtailment due to low reserves.

<u>OP-4 :</u> None

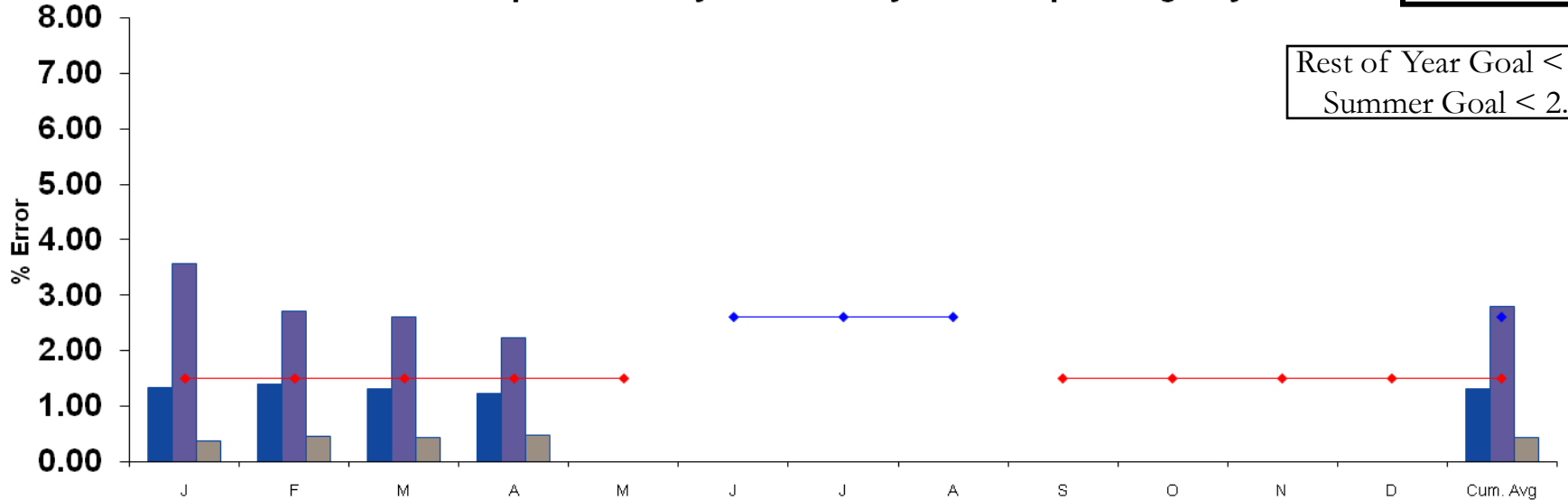
<u>NPCC Shared Activation of Reserve Events:</u>			
Apr 21	Loss of Darlington 4	IESO	850 MW
Apr 28	Loss of Chateauguay tie	NYISO	1495 MW

2010 System Operations - Load Forecast Accuracy

All Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published by 1000 on day before Operating Day

Dashboard Indicator 

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



■ Mo. Avg
 ■ Day Max
 ■ Day Min
 ◆ Summer Goal
 ◆ Rest of Year Goal

	J	F	M	A	M	J	J	A	S	O	N	D	Avg	
Mo Avg	1.33	1.39	1.31	1.23									1.31	Mo Avg
Day Max	3.57	2.72	2.62	2.24									2.79	Day Max
Day Min	0.37	0.45	0.43	0.48									0.43	Day Min
Summer Goal						2.60	2.60	2.60						
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50		
Current YTD ROY Avg.													1.43	

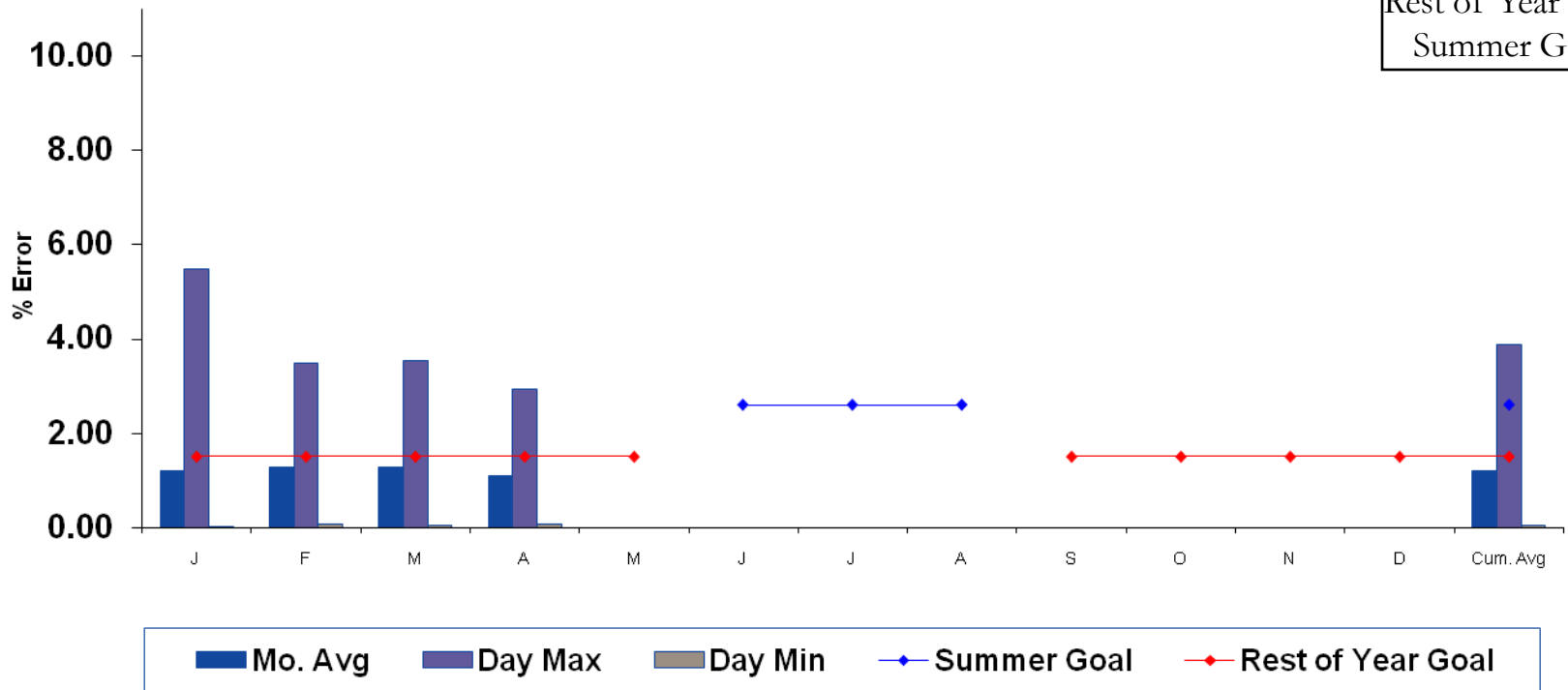
Contact: Steve Weaver														
Summer Goal = 2.6% Rest of Year Goal = 1.5%														
Summer consists of June, July and August-														

2010 System Operations - Load Forecast Accuracy cont.

Peak Hours
Monthly Average, Daily Maximum and Minimum
Based on forecast published by 1000 on day before Operating Day



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	1.20	1.28	1.28	1.21									1.21
Day Max	5.49	3.49	3.55	3.89									3.89
Day Min	0.03	0.07	0.05	0.05									0.05
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	
Current YTD ROY													

Contact: Steve Weaver

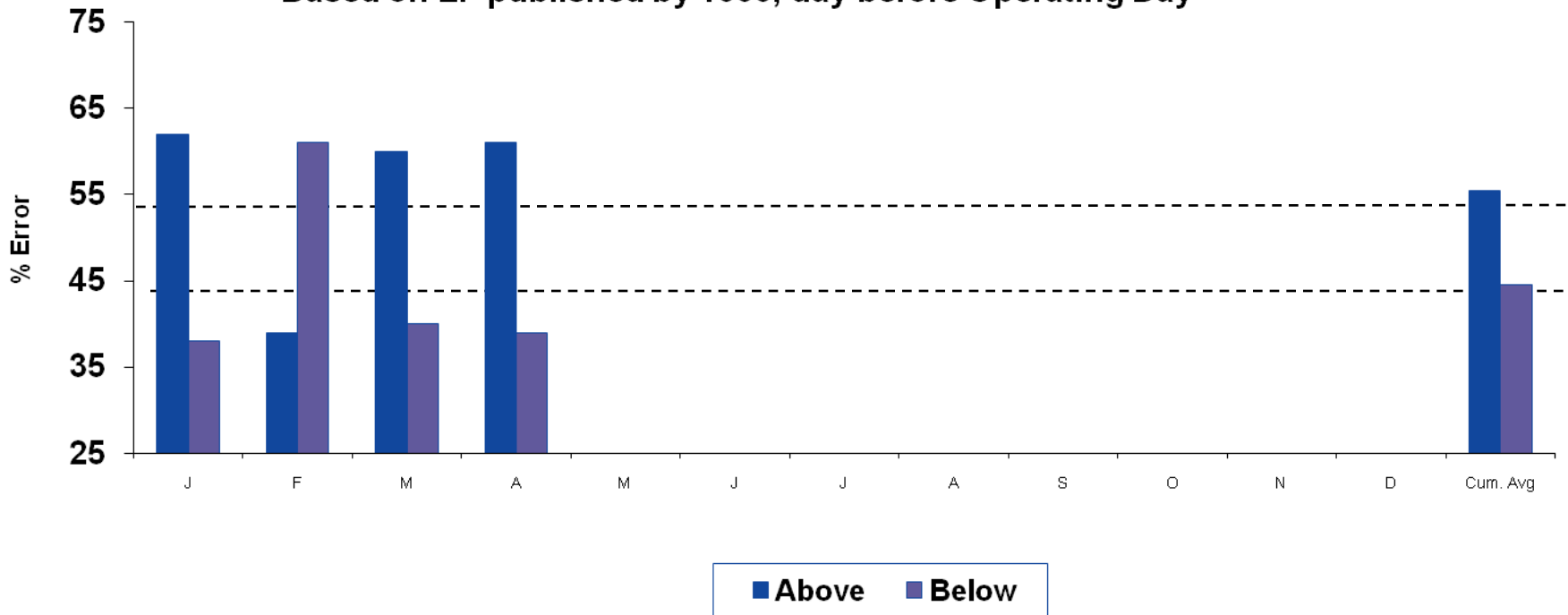
Summer Goal = 2.6% Rest of Year Goal = 1.5%

Summer consists of June, July and August.

2010 System Operations - Load Forecast Accuracy

**Percent of Hours Actual Load
Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day**

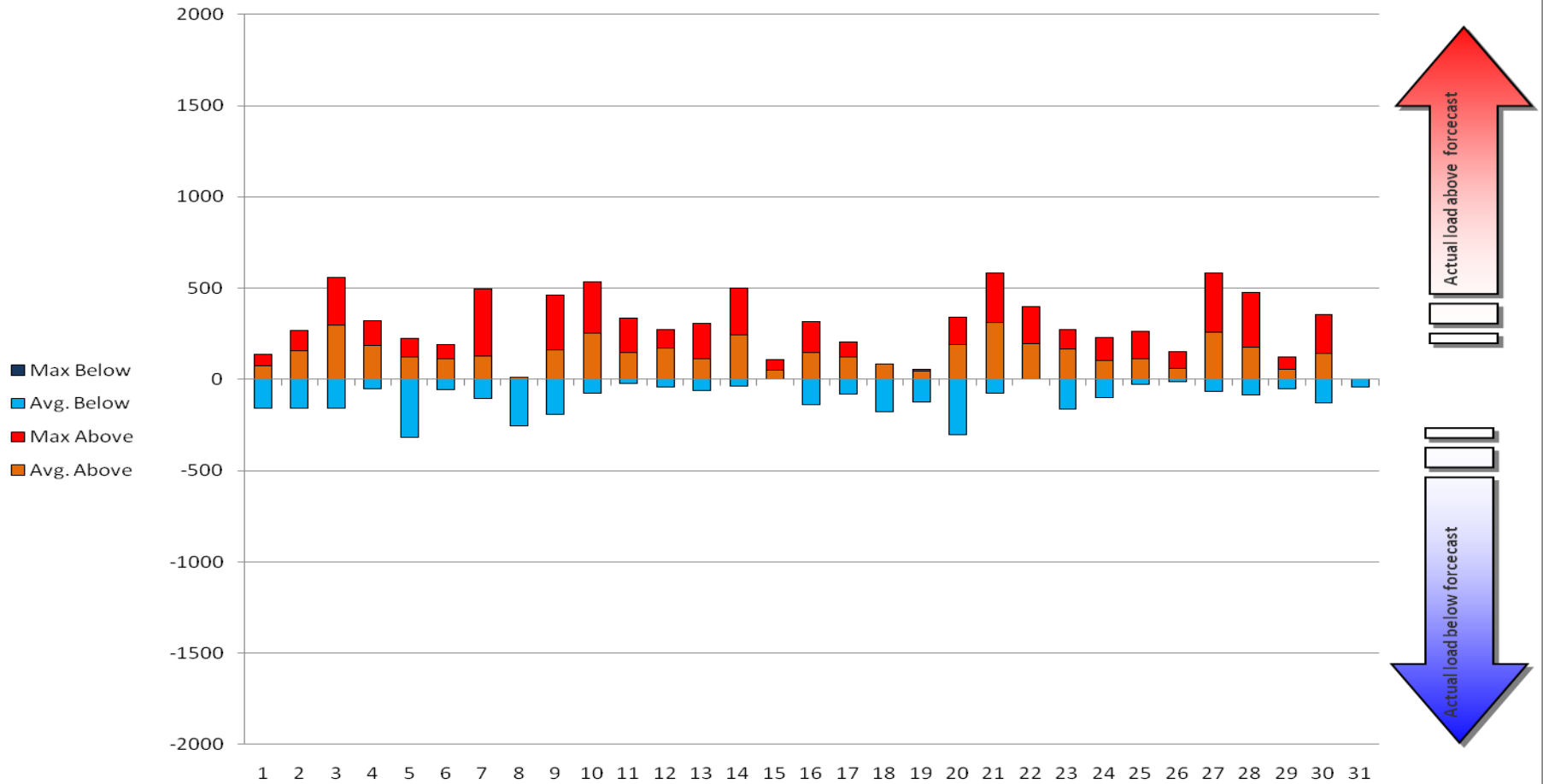
Target = 50%
Plus/Minus 5%



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	62.0	39.0	60.0	61.0									56.0
Below %	38.0	61.0	40.0	39.0									44.0
Avg Above	178.0	106.0	144.0	147.0									145.0
Avg Below	-112.0	-181.0	-118.0	-103.0									-127.0
Avg All	74.0	-69.0	38.0	45.0									24.0

Percent of hours during the month that the actual load was above versus below the forecast													
Sponsor:	Michael Taniwha												
Contact:	Steve Weaver												

Deviation of Actual Load from Forecasted Load April 2010

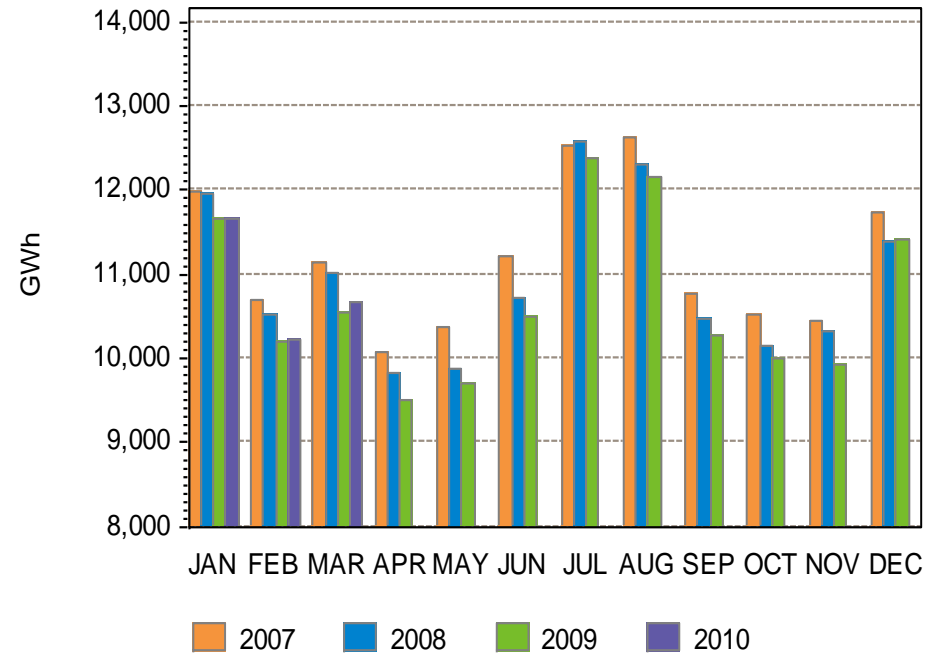
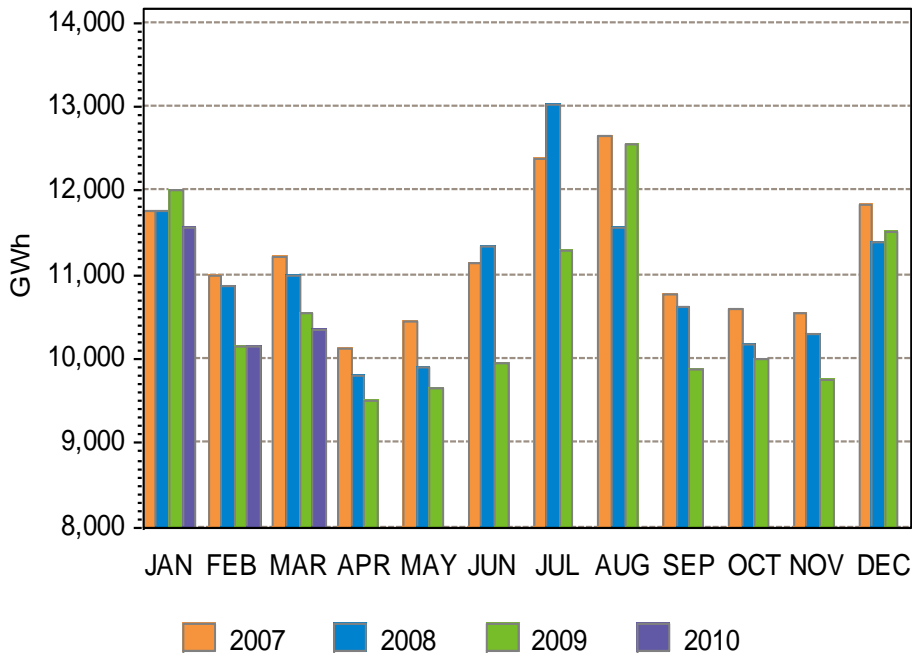


Sponsor	Mike Taniwha
Contact	Steve Weaver

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

Net Energy for Load (NEL)

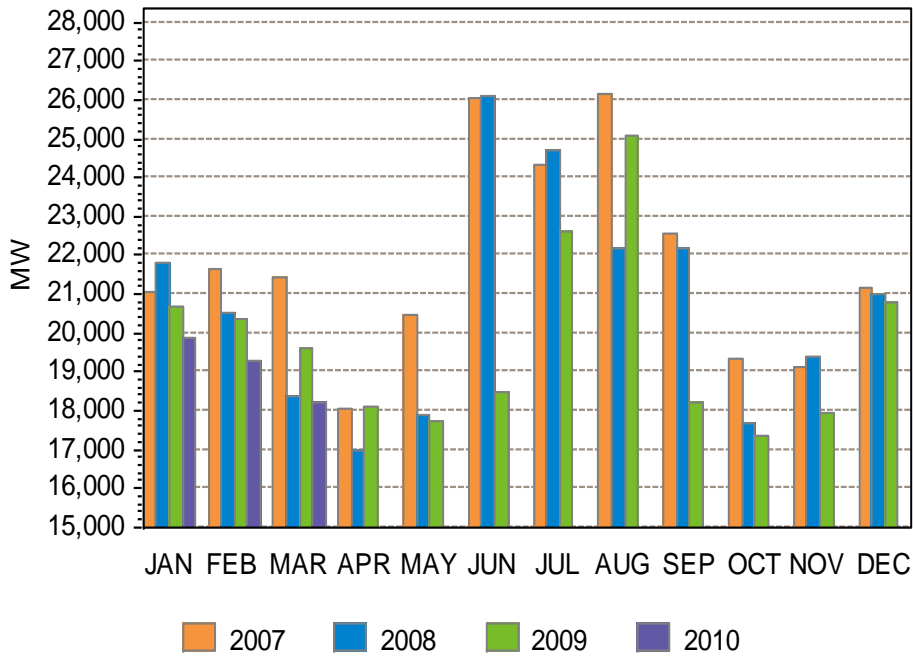
Weather Normalized NEL



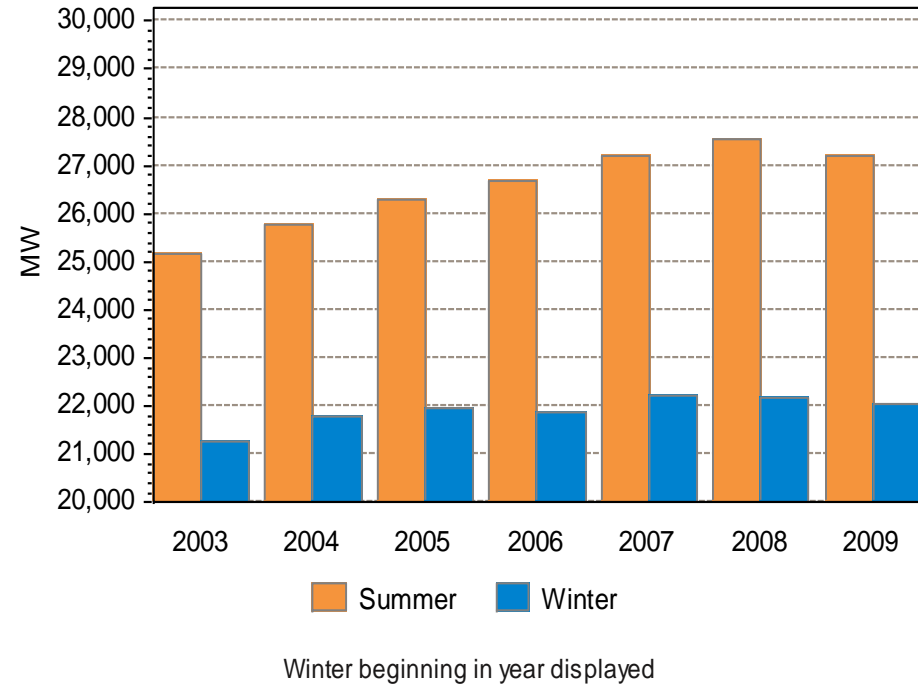
NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Reported on a one month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load

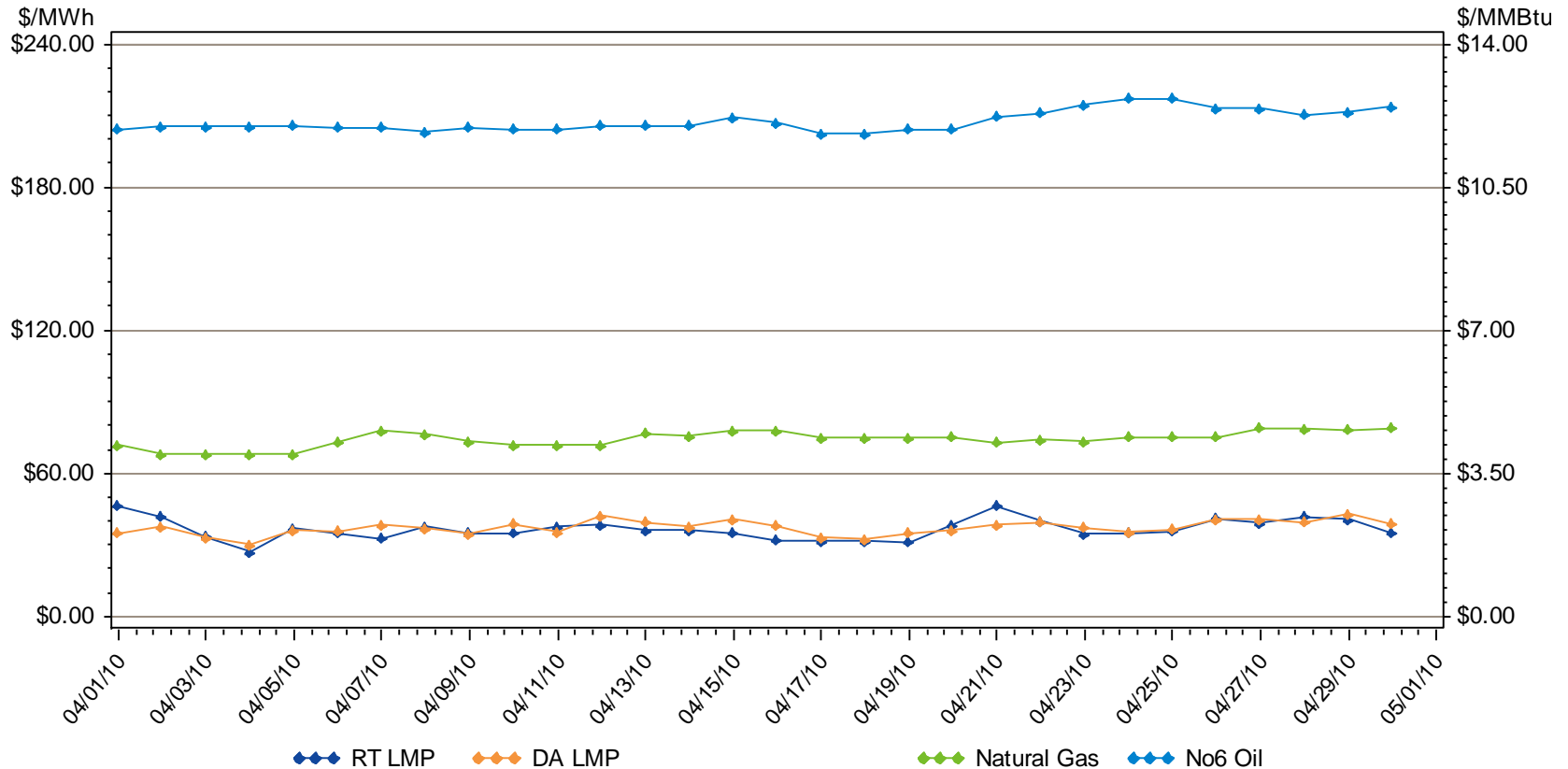


Weather Normalized Seasonal Peaks



Market Operations

DA and RT ISO-NE Hub Prices and Input Fuel Prices: April 1-30, 2010



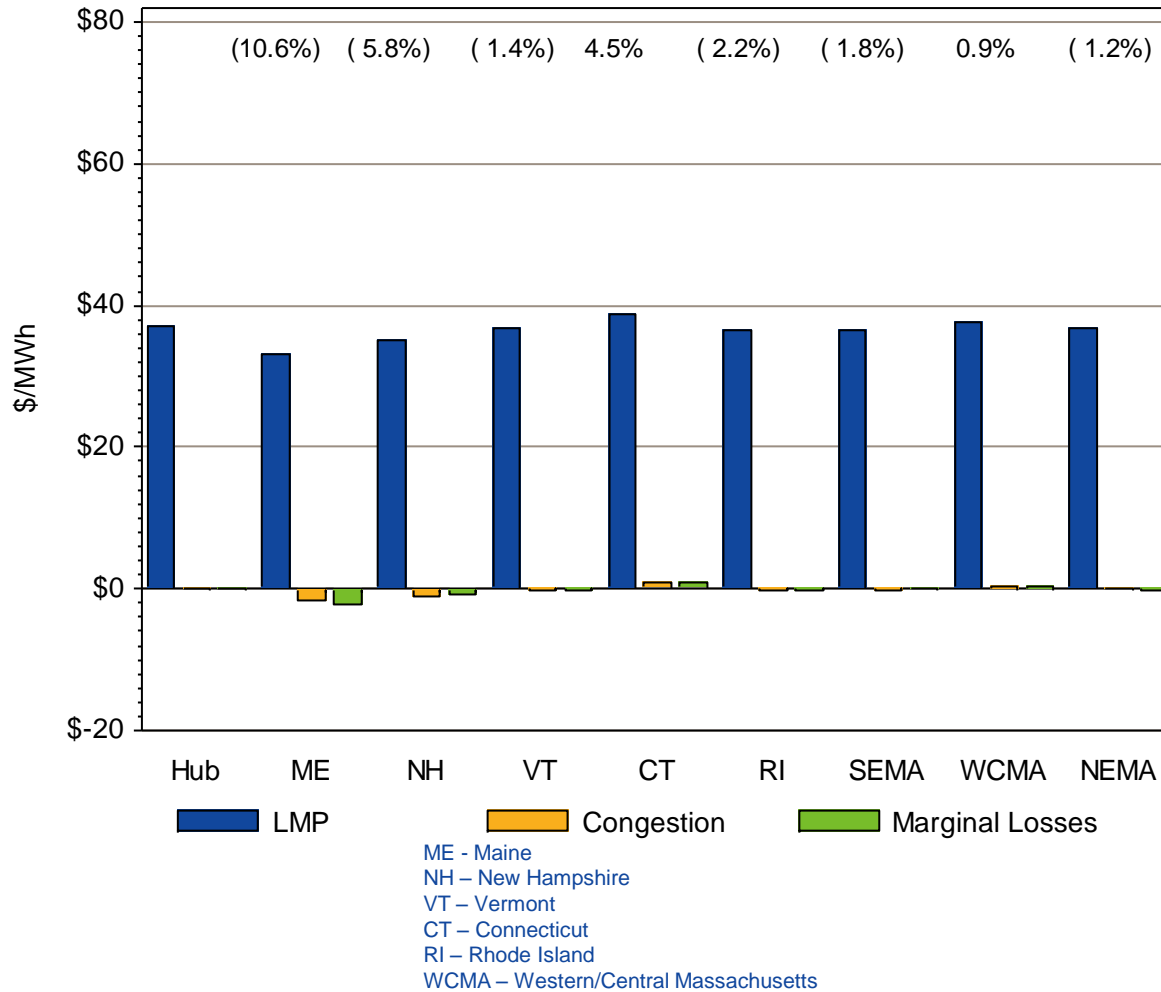
Underlying natural gas data furnished by:



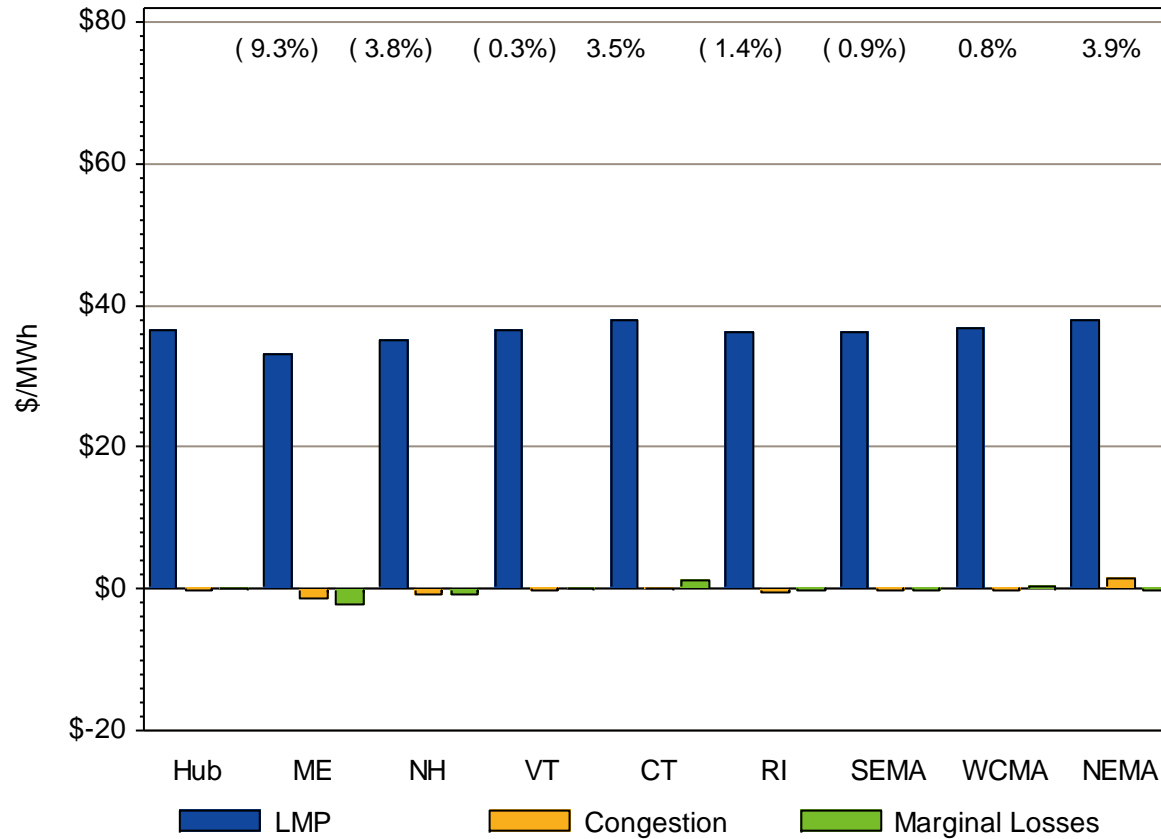
Average price difference over this period (DA-RT): \$0.61
 Average price difference over this period ABS(DA-RT): \$2.82
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 8%

Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOE's Energy Information Administration

DA LMPs Average by Zone & Hub – April 2010

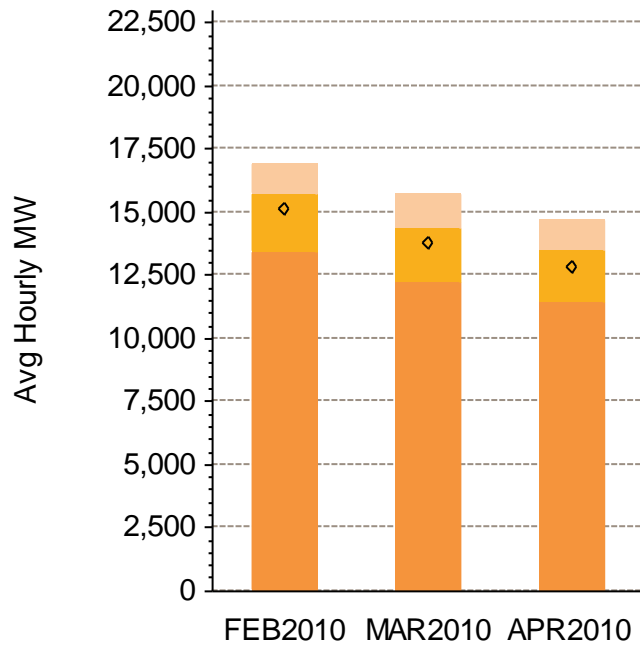


RT LMPs Average by Zone & Hub – April 2010



Components of Cleared DA Supply and Demand – Last Three Months

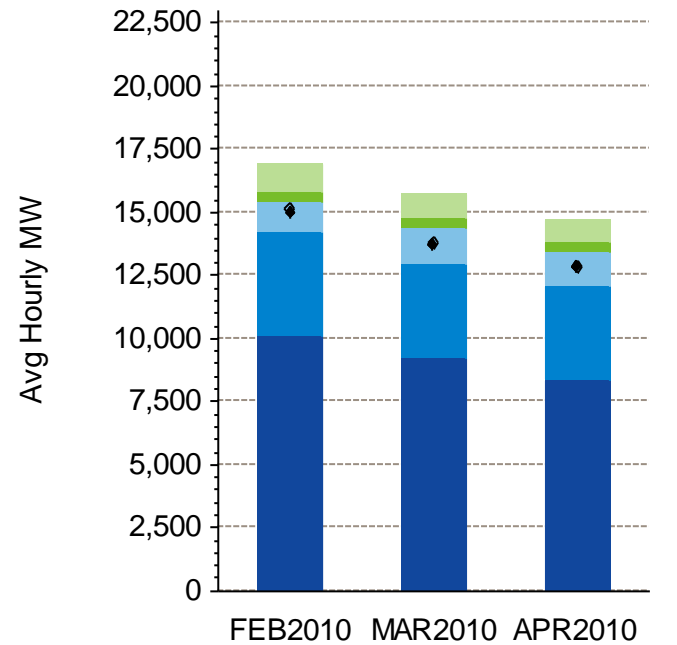
Supply



■ Gen ■ Incs
■ Imports ◇ DA Fcst Load

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

Demand

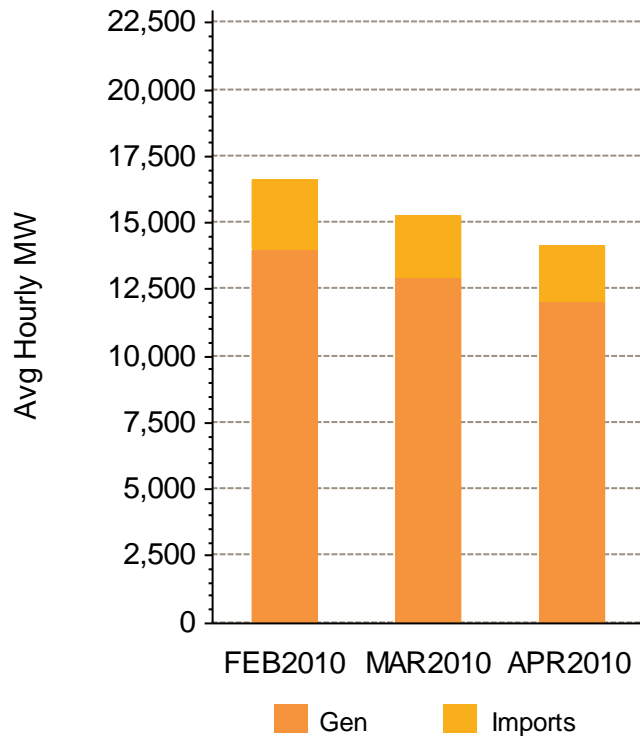


■ Fixed Dem ■ PrSens Dem ■ Decs
■ Losses ■ Exports ◇ Act Load

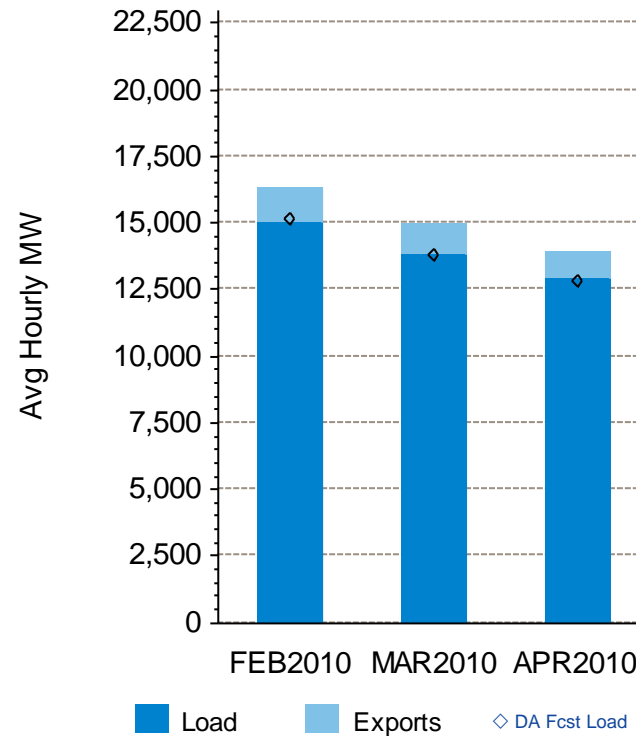
Fixed Dem – Fixed Demand
 PrSens Dem – Price Sensitive Demand
 Decs – Decrement Bids
 Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months

Supply

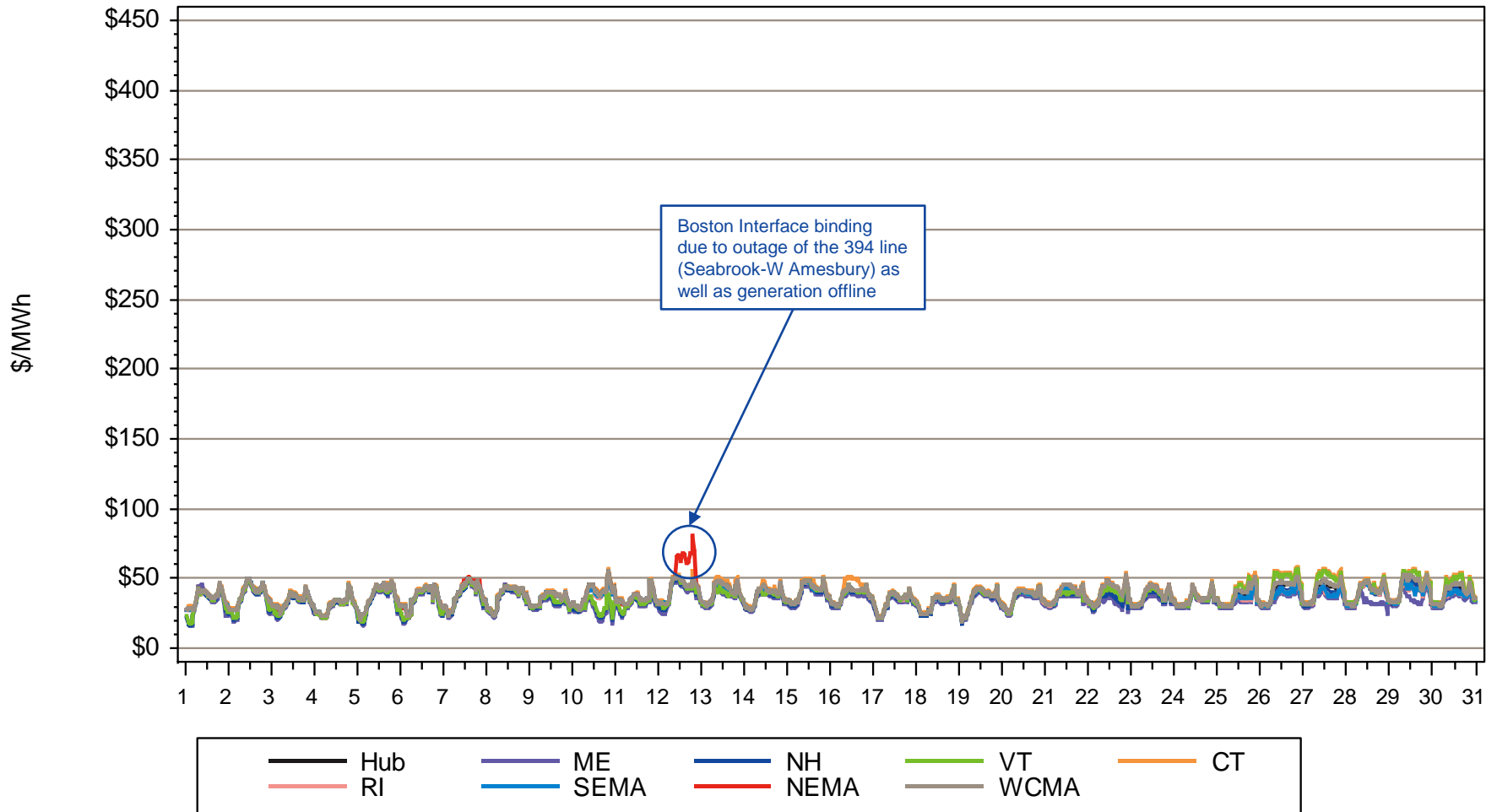


Demand



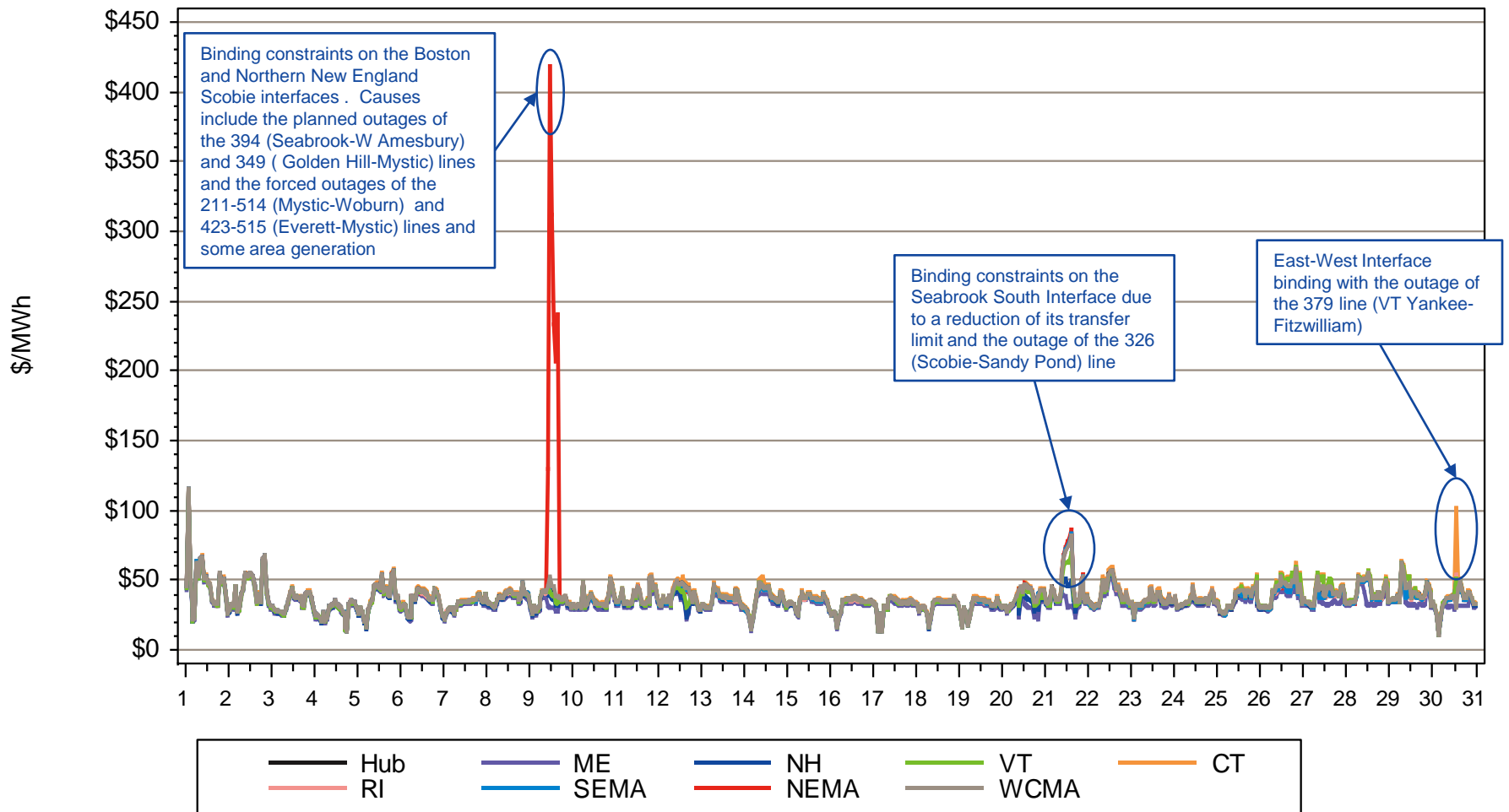
Hourly DA LMPs, April 1-30, 2010

Hourly Day-Ahead LMPs

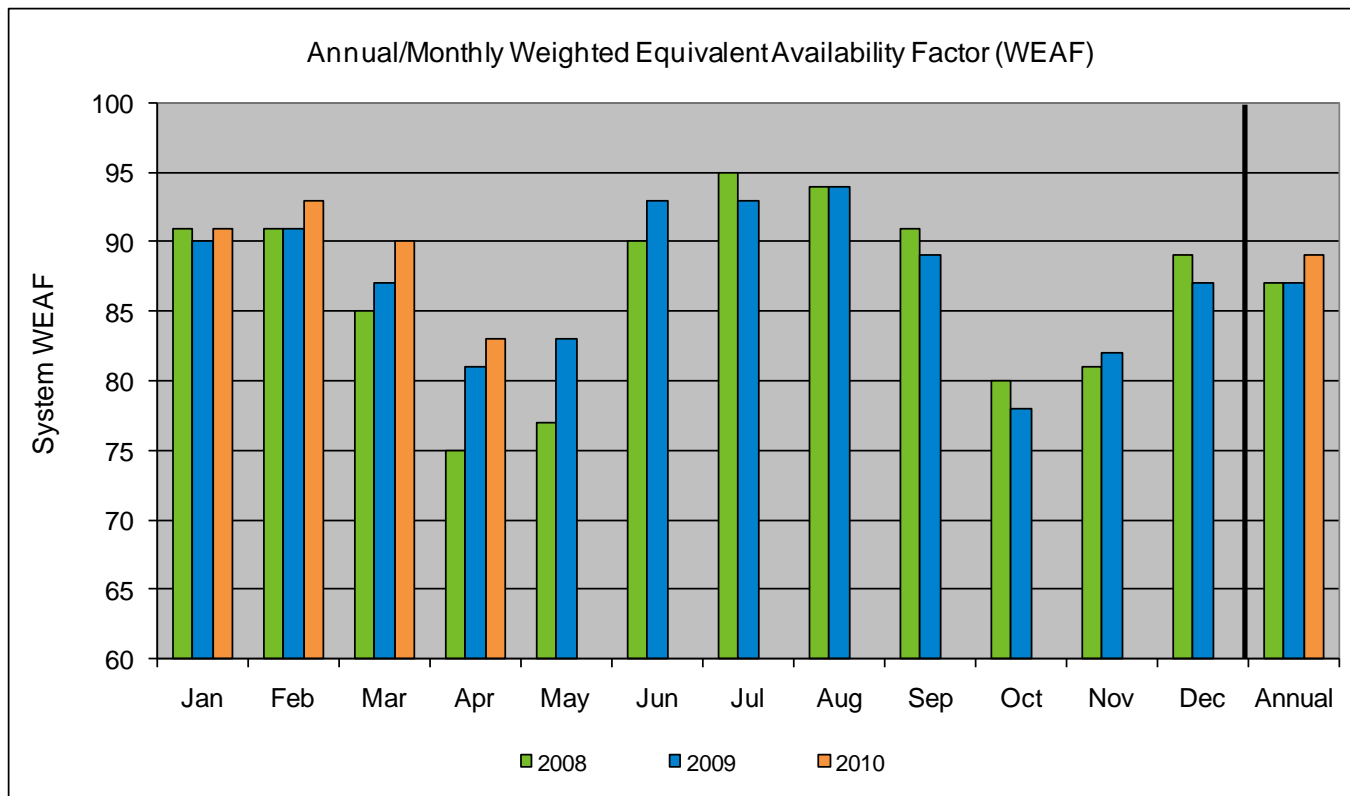


Hourly RT LMPs, April 1-30, 2010

Hourly Real-Time LMPs



System Unit Availability



Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	YTD	
91	93	90	83									89	2010
												87	2009
												87	2008
												90	2007

Back-up Detail

Load Response

Demand Response (as of April 30, 2010)

Ready To Respond*:			Approved**:	
Zone	Assets	Total MW	Assets	Total MW
CT	1,464	770.1	8	2.3
ME	132	521.3	2	0.5
NEMA	548	258.2	15	5.3
NH	203	102.6	4	2.0
RI	295	139.6	4	1.2
SEMA	396	135.7	12	5.5
VT	154	80.5	3	0.7
WCMA	525	267.0	15	11.9
Total	3,717	2,275.0	63	29.5

*Ready to Respond means the registration process is complete and the resource is eligible to participate in an Event

**Approved means the application for registration has been approved by ISO-NE

Demand Response (as of April 30, 2010)

Ready To Respond*:						Approved**:				
3,717 Assets 2,275.0 MW						63 Assets 29.5 MW				
Zone	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled
CT	1,464	2.4	747.3	20.4	0.0	8	0.0	0.9	1.5	0.0
SWCT***	726	0.1	367.8	1.2	0.0	5	0.0	0.5	0.5	0.0
ME	132	0.0	398.5	111.8	11.0	2	0.0	0.5	0.0	0.0
NEMA	548	20.6	223.4	14.2	0.0	15	0.1	2.9	2.4	0.0
NH	203	4.5	92.7	5.4	0.0	4	0.0	2.0	0.0	0.0
RI	295	13.4	114.1	12.1	0.0	4	0.2	1.0	0.0	0.0
SEMA	396	8.1	110.8	16.8	0.0	12	0.0	5.5	0.0	0.0
VT	154	1.8	72.4	0.5	5.9	3	0.0	0.7	0.0	0.0
WCMA	525	14.7	216.5	35.9	0.0	15	0.1	10.4	1.4	0.0
Total	3,717	65.4	1,975.8	217.0	16.9	63	0.4	23.9	5.2	0.0

* Ready to Respond means the registration process is complete and the resource is eligible to participate in an Event

** Approved means the application for registration has been approved by ISO-NE

*** SWCT assets are included in CT values and are not included in Total

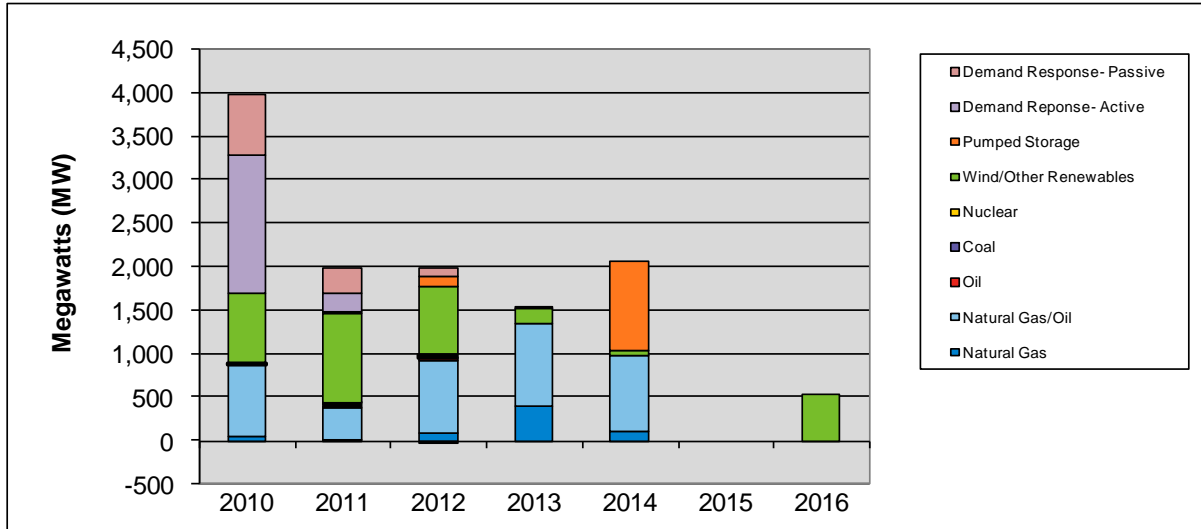
New Generation

New Generation Update

- One new generation project has applied for interconnection study since last month's update, representing a total of 20 MW
 - New project is a photovoltaic project (Hampden County, MA)
 - Projected in-service date is in 2012
- The capacity of two projects changed, resulting in a net increase in new generation projects of 14 MW
- In total, 87 generation projects are currently being tracked by the ISO, totaling approximately 9,200 MW*

* In the case where a project involves the retirement of a companion unit, only the net MW increase is reported

Actual and Projected Annual Capacity Additions By Supply Fuel Type and Demand Resource Type

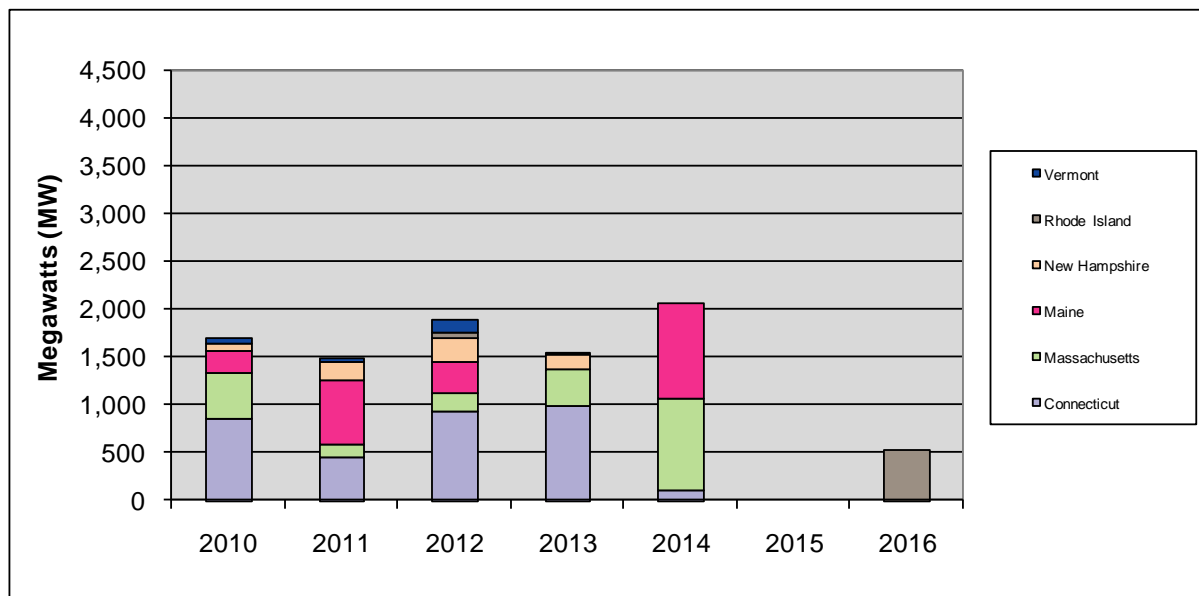


	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	0	0	0	0	1,073	8.9
Demand Response - Active	1,579	221	-6	0	0	0	0	1,794	14.8
Pumped Storage	0	25	111	25	1,025	0	0	1,186	9.8
Wind & Other Renewables	798	1,011	784	181	53	0	536	3,363	27.8
Nuclear	0	45	0	0	0	0	0	45	0.4
Coal	17	0	36	0	0	0	0	53	0.4
Oil	0	13	30	0	0	0	0	43	0.4
Natural Gas/Oil	838	372	844	934	877	0	0	3,865	32.0
Natural Gas	46	19	87	411	107	0	0	670	5.5
Totals	3,978	1,984	1,981	1,551	2,062	0	536	12,092	100.0

- 2010 values include the 26 MW of generation that has gone commercial in 2010
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources

Actual and Projected Annual Generator Capacity Additions

By State



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Vermont	61	25	129	0	0	0	0	215	2.3
Rhode Island	0	0	61	29	0	0	536	626	6.8
New Hampshire	76	201	249	152	0	0	0	678	7.3
Maine	217	673	320	0	1,000	0	0	2,210	24.0
Massachusetts	492	125	203	375	955	0	0	2,150	23.3
Connecticut	853	461	930	995	107	0	0	3,346	36.3
Totals	1,699	1,485	1,892	1,551	2,062	0	536	9,225	100.0

- 2010 values include the 26 MW of generation that has gone commercial in 2010

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	11	380	1	38	10	342
Coal	2	53	0	0	2	53
Hydro	9	1,219	0	24	9	1,195
Landfill Gas	2	36	0	0	2	36
Natural Gas	11	670	1	0	10	670
Natural Gas/Oil	15	3,865	5	1,161	10	2,704
Nuclear Uprates	2	45	0	0	2	45
Oil	2	43	0	0	2	43
Solar	1	20	0	0	1	20
Wind	32	2,868	4	180	28	2,688
Total	87	9,199	11	1,403	76	7,796

- 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	18	523	1	38	17	485
Intermediate	16	3,484	1	644	15	2,840
Peaker	21	2,324	5	541	16	1,783
Wind Turbine	32	2,868	4	180	28	2,688
Total	87	9,199	11	1,403	76	7,796

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

New Generation Projection By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	11	380	11	380	0	0	0	0	0	0
Coal	2	53	2	53	0	0	0	0	0	0
Hydro	9	1,219	0	0	5	32	4	1,187	0	0
Landfill Gas	2	36	2	36	0	0	0	0	0	0
Natural Gas	11	670	1	9	4	605	6	56	0	0
Natural Gas/Oil	15	3,865	0	0	7	2,847	8	1,018	0	0
Nuclear Uprates	2	45	2	45	0	0	0	0	0	0
Oil	2	43	0	0	0	0	2	43	0	0
Solar	1	20	0	0	0	0	1	20	0	0
Wind	32	2,868	0	0	0	0	0	0	32	2,868
Total	87	9,199	18	523	16	3,484	21	2,324	32	2,868

Capacity Supply Obligations (CSO) FCA 1

Resource Type	Resource Type	FCA 1	Proration		ARA 2		**Delisted MW Released		Annual Bilateral		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	1,850.074	1,818.402	-31.672	1,817.152	-1.250	1,817.152	0.000	1,515.593	-301.559	1,498.671	-16.922
	Passive Demand	703.488	689.729	-13.759	666.729	-23.000	666.729	0.000	654.078	-12.651	654.078	0.000
Demand Total		2,553.562	2,508.131	-45.431	2,483.881	-24.250	2,483.881	0.000	2,169.671	-314.210	2,152.749	-16.922
Generator Total		30,864.929	29,710.469	-1,154.460	29,814.719	104.250	29,646.719	-168.000	30,406.108	759.389	30,456.525	50.417
Import Total		933.583	898.542	-35.041	818.542	-80.000	818.542	0.000	373.363	-445.179	339.868	-33.495
ISO New England Participation		N/A	N/A	N/A	0.000	N/A	N/A	N/A	N/A	N/A	-242.442	N/A
Grand Total		34,352.074	33,117.142	1,234.932	33,117.142	0.000	32,949.142	-168.000	32,949.142	0.000	32,706.700	0.000

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

** Some Capacity that was previously held for reliability was released

Reliability Costs

Net Commitment Period Compensation (NCPC) Operating Costs

What are Daily NCPC Payments?

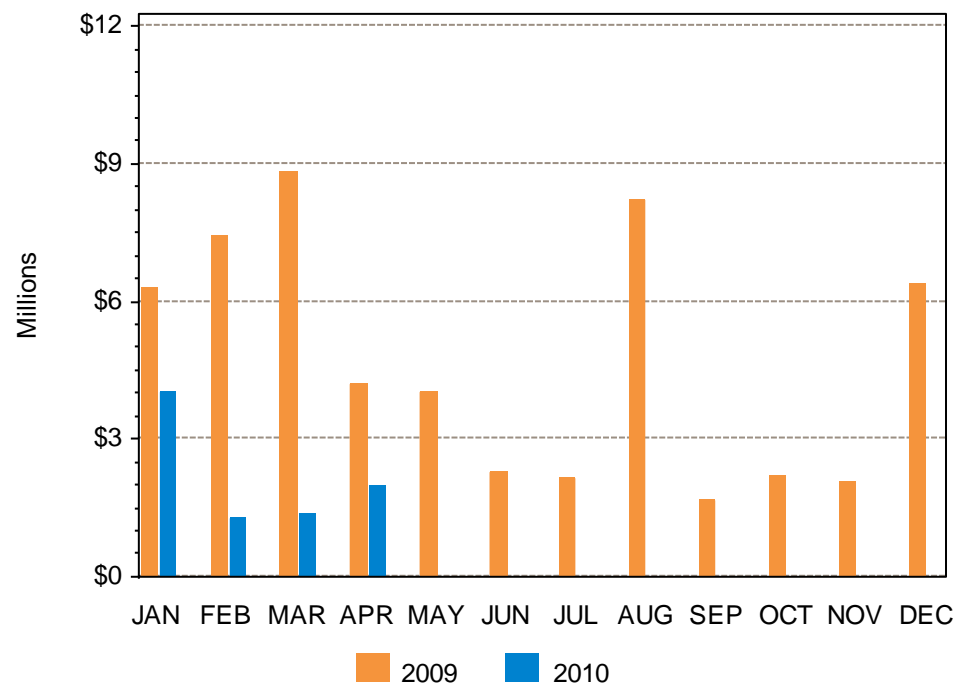
- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit 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

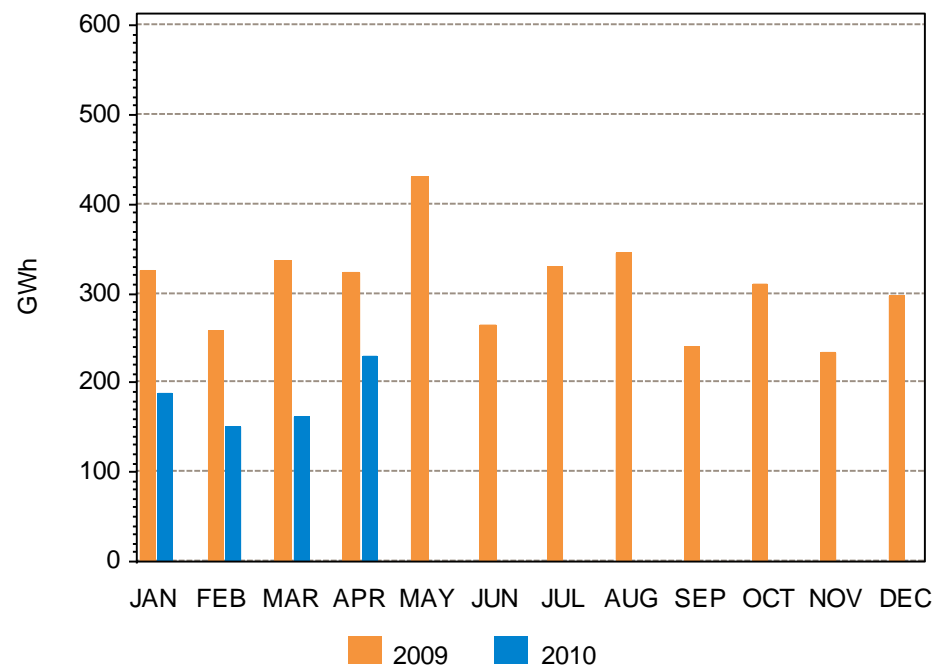
Voltage NCPC Payments	Reliability costs paid to resources operated by the ISO-NE to provide voltage control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are not providing 2 nd Contingency, Voltage, or Distribution requirements. These resources may have been providing first contingency coverage (system-wide or locally)
2nd Contingency NCPC Payments	Reliability costs paid to resources providing adequate capacity in constrained areas to respond to a local second contingency. They are committed based on 2 nd Contingency protocols
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

Year-Over-Year Total NCPC Dollars and Energy

Dollars



Energy

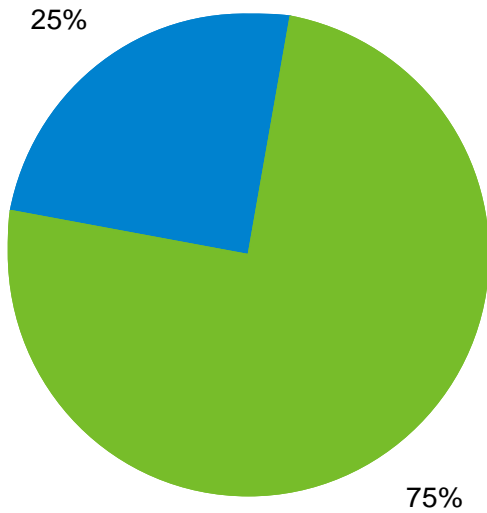


Note:

- 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.

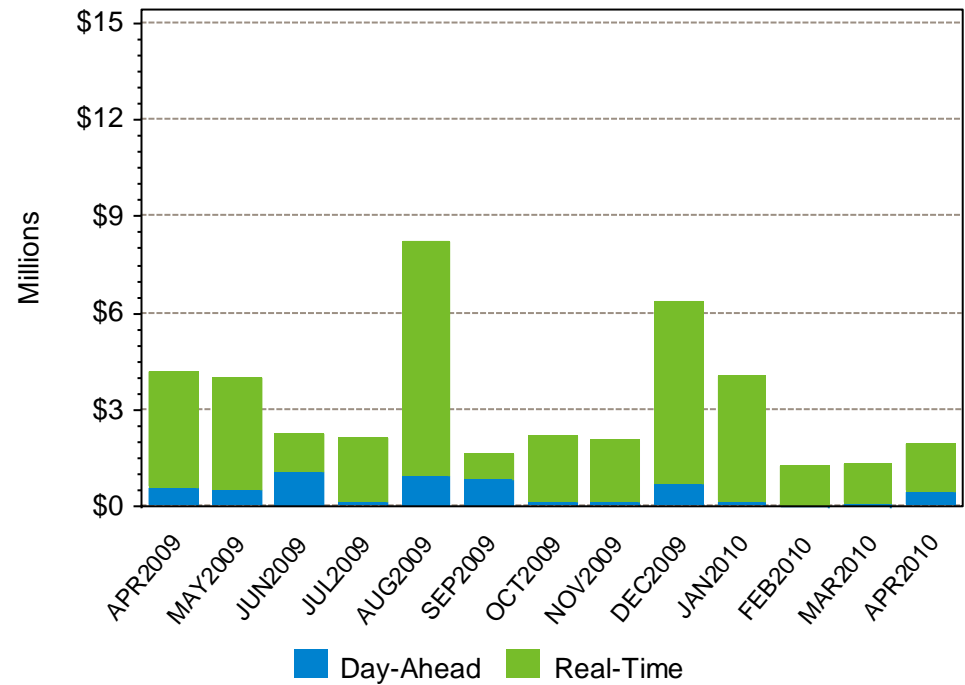
DA and RT NCPC Payments

APR-10 Total = \$1.95 M



■ Day-Ahead ■ Real-Time

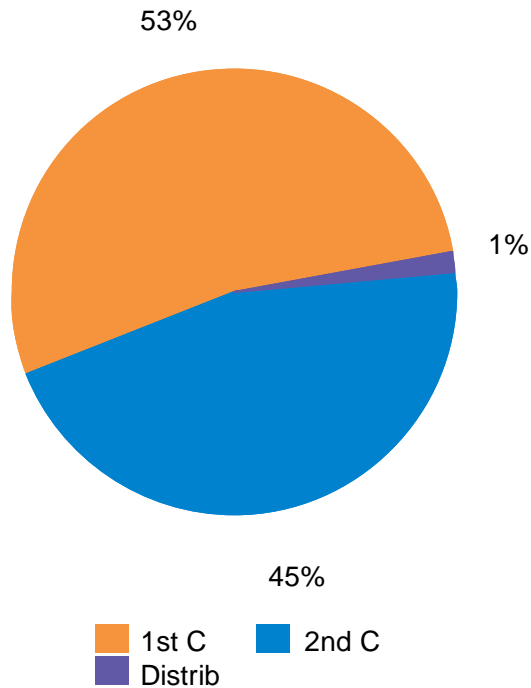
Last 13 Months



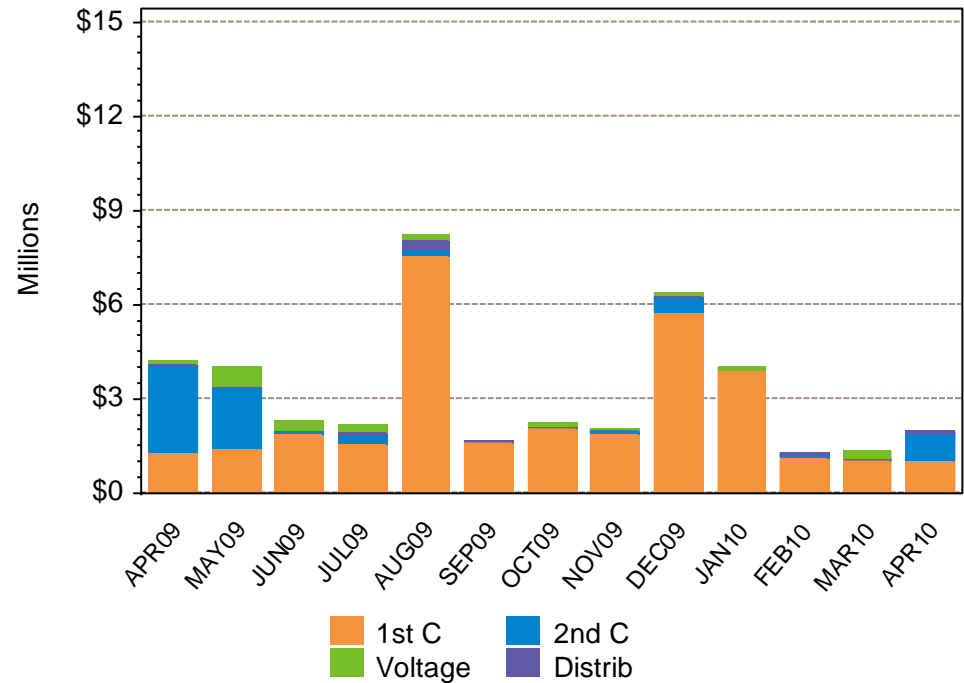
■ Day-Ahead ■ Real-Time

NCPC Payments by Type

APR-10 Total = \$1.95 M



Last 13 Months

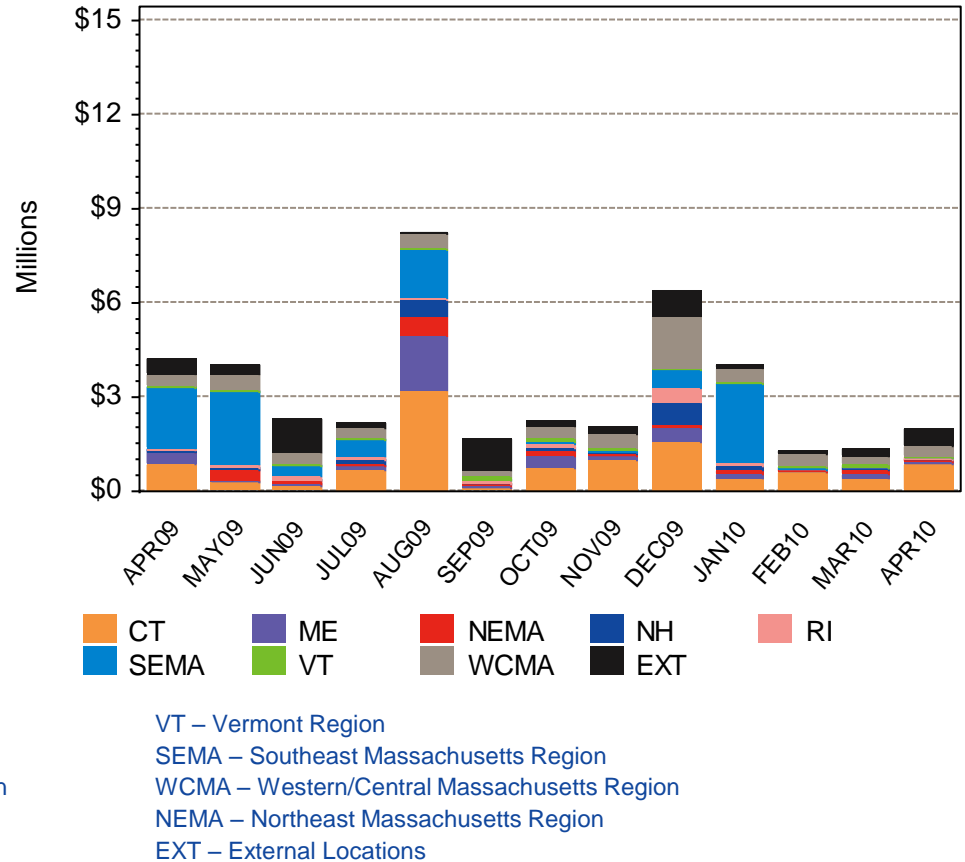
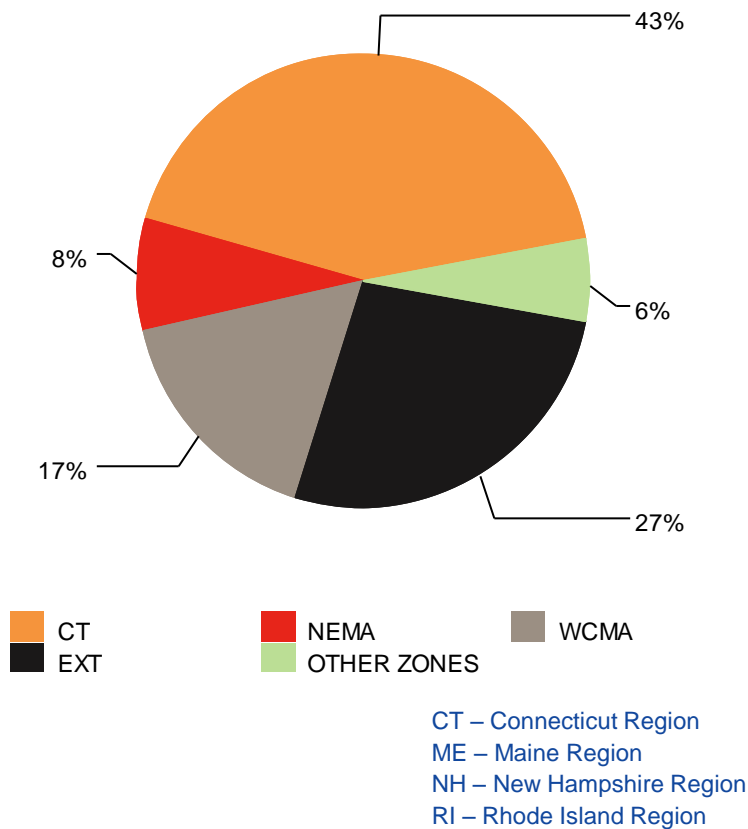


1st C – First Contingency
 2nd C – Second Contingency
 Distrib – Distribution
 Voltage – Voltage Support

NCPC Payments by Location

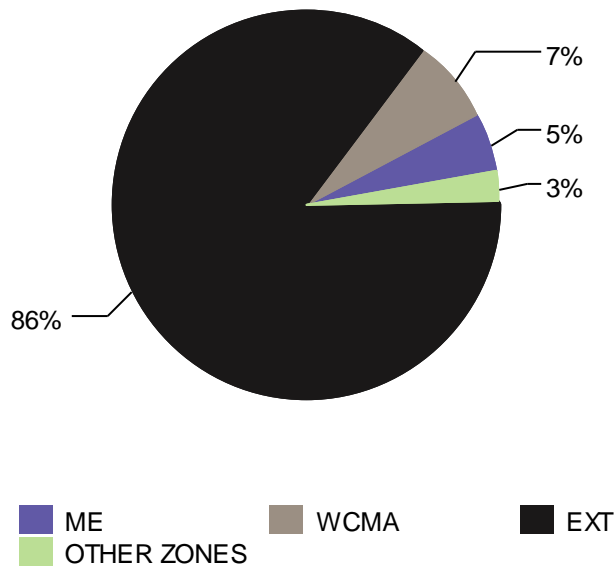
APR-10 Total = \$1.95 M

Last 13 Months

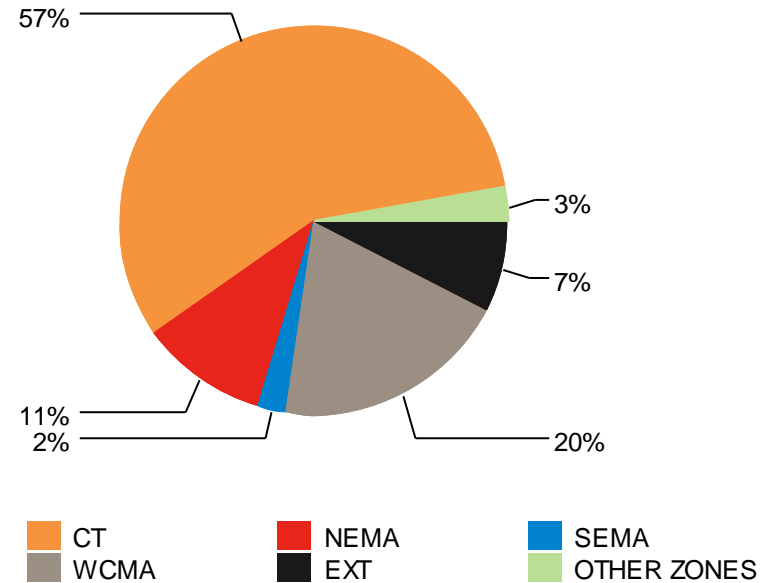


DA and RT NCPC Payments by Location

APR-10 Day-Ahead Total = \$0.49 M

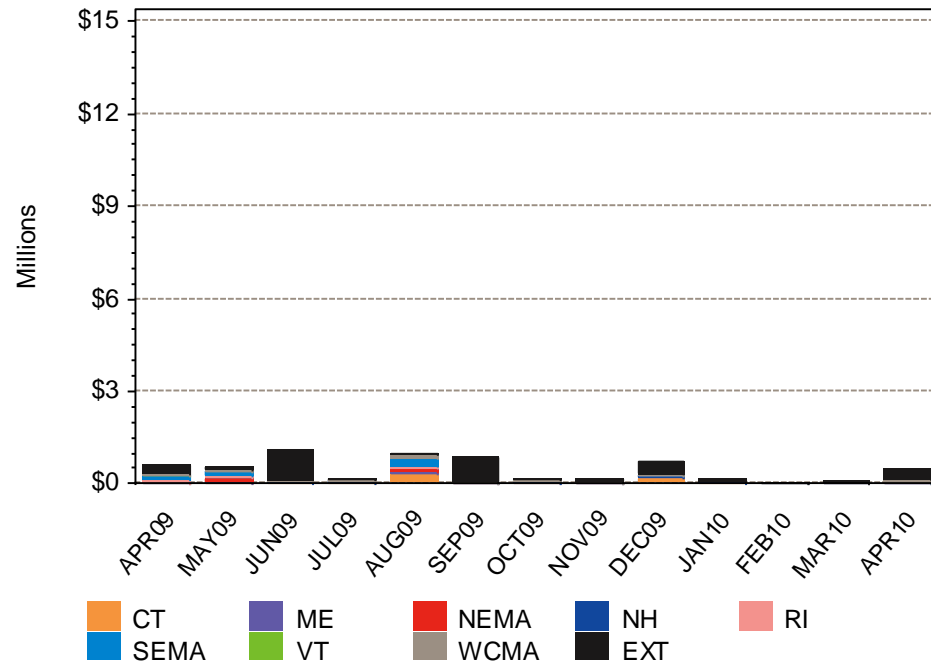


APR-10 Real-Time Total = \$1.46 M

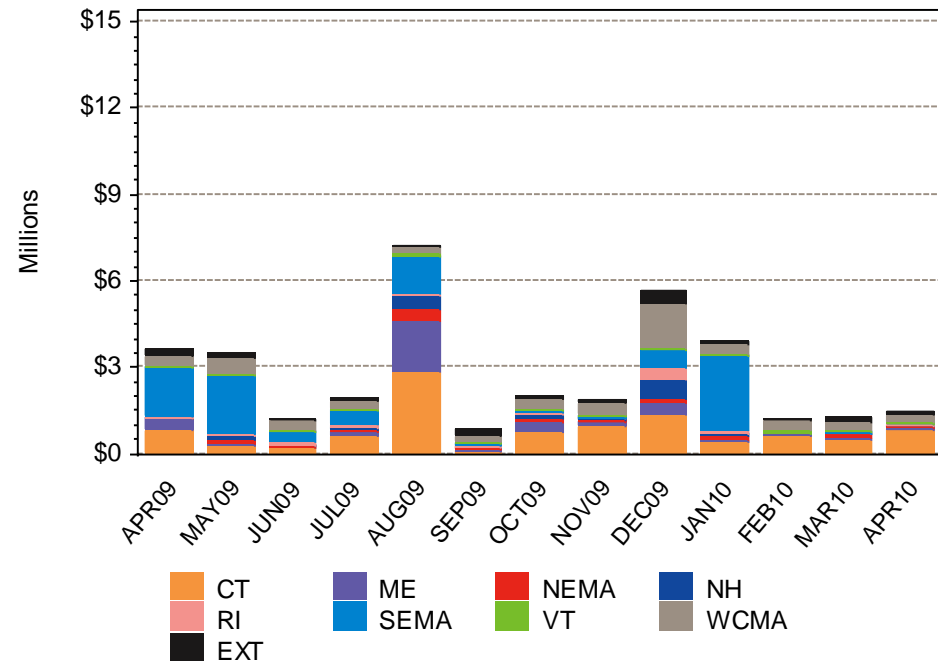


DA and RT NCPC Payments by Location, Last 13 Months

Day-Ahead, Last 13 Months

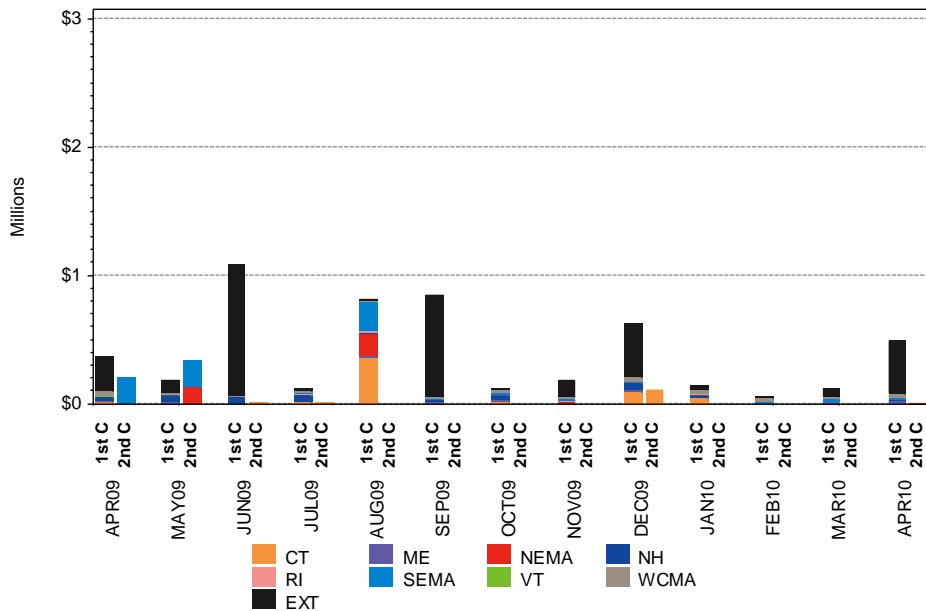


Real-Time, Last 13 Months

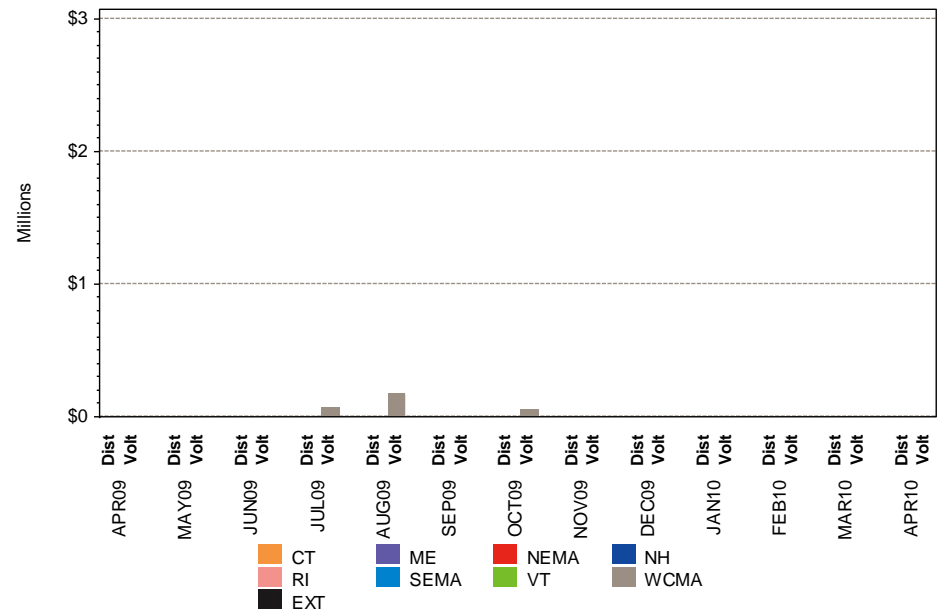


DA NCPC Payments by Type and Location

First and Second Contingency Payments

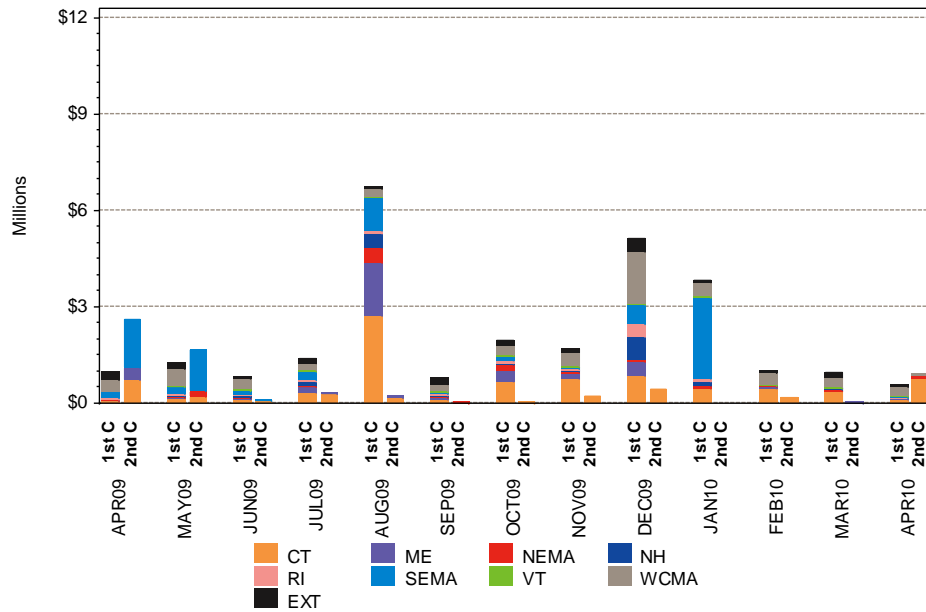


Voltage and Distribution Payments

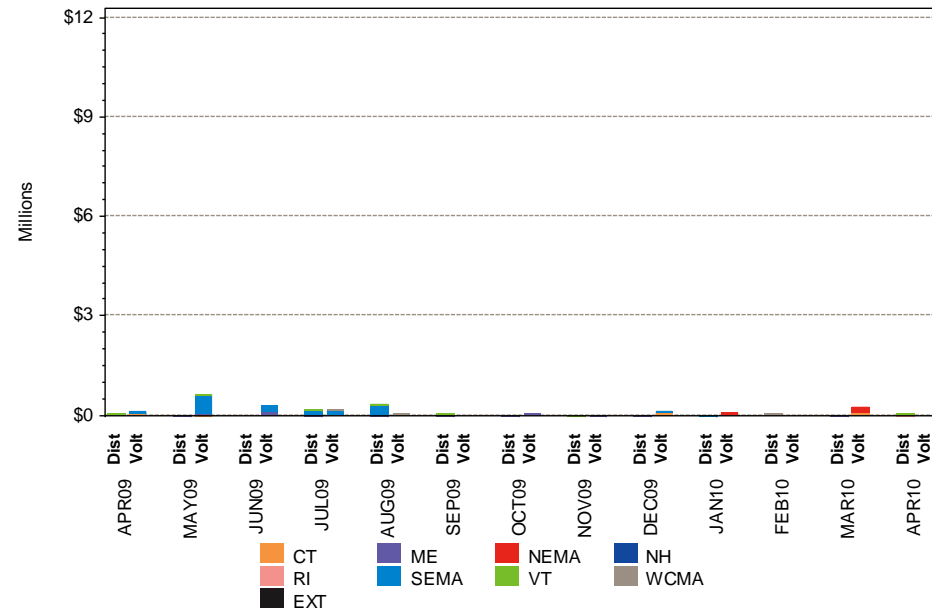


RT NCPC Payments by Type and Location

First and Second Contingency Payments

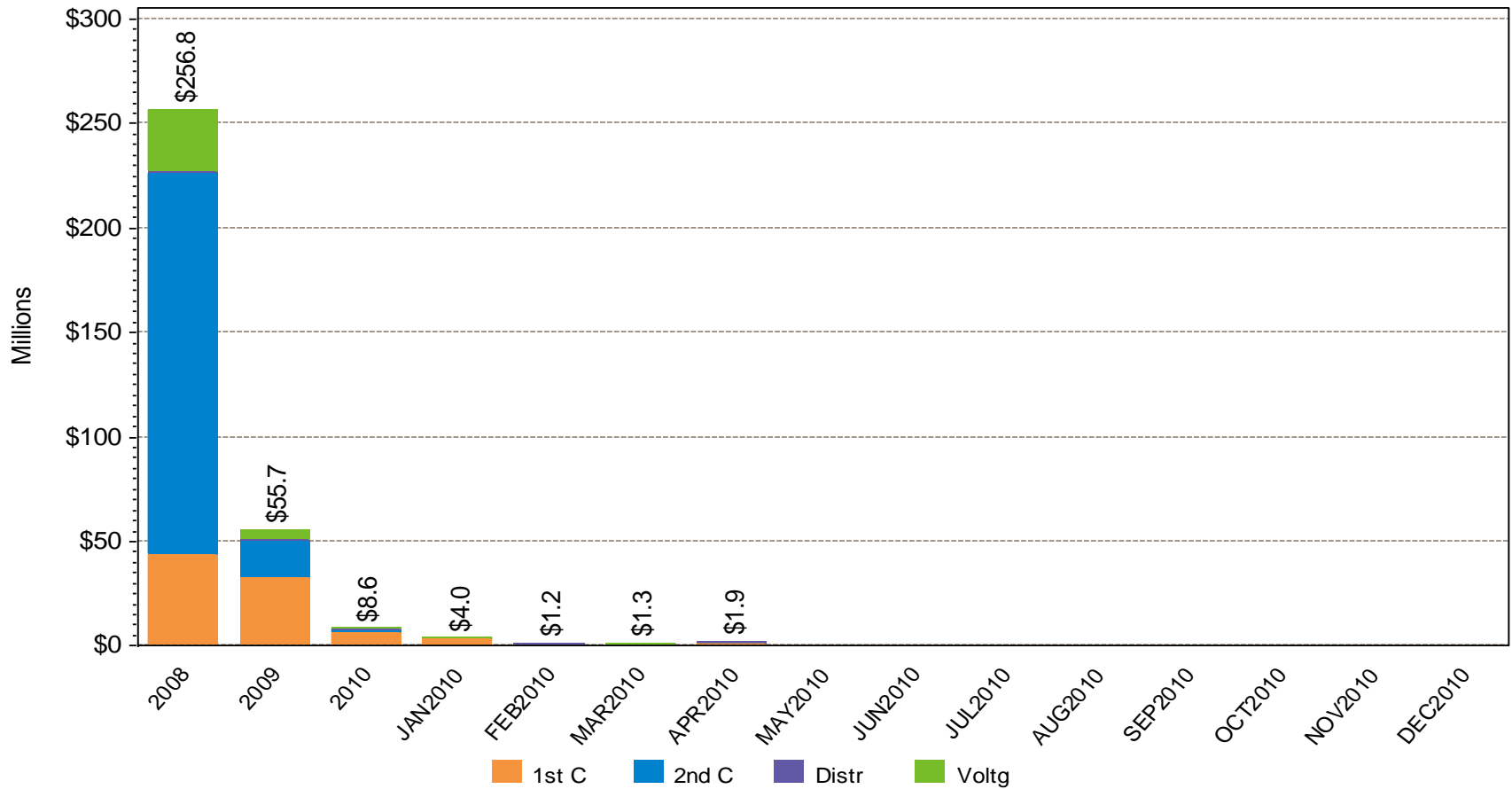


Voltage and Distribution Payments



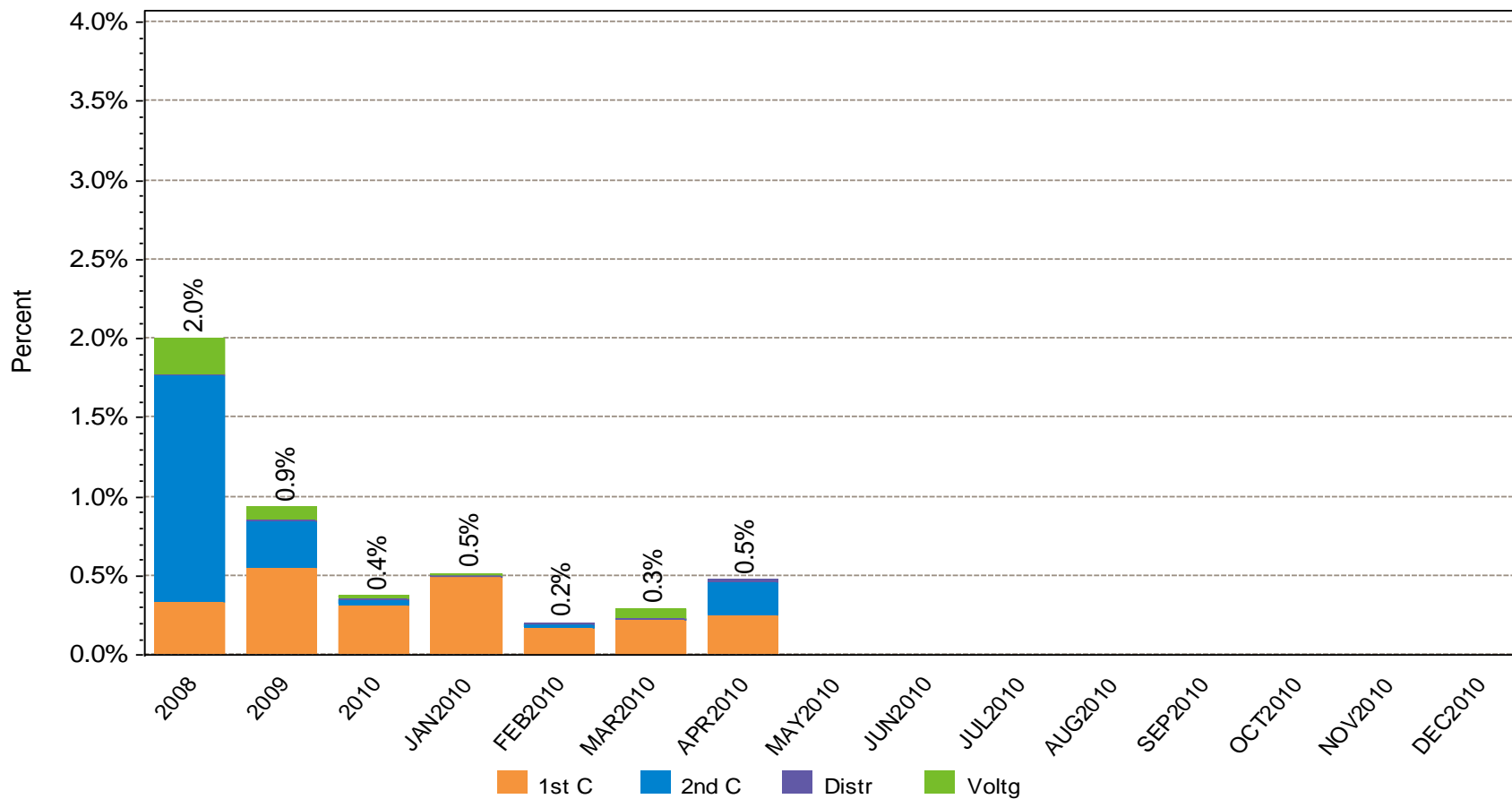
NCPC Payments by Type

Payments by Type of NCPC



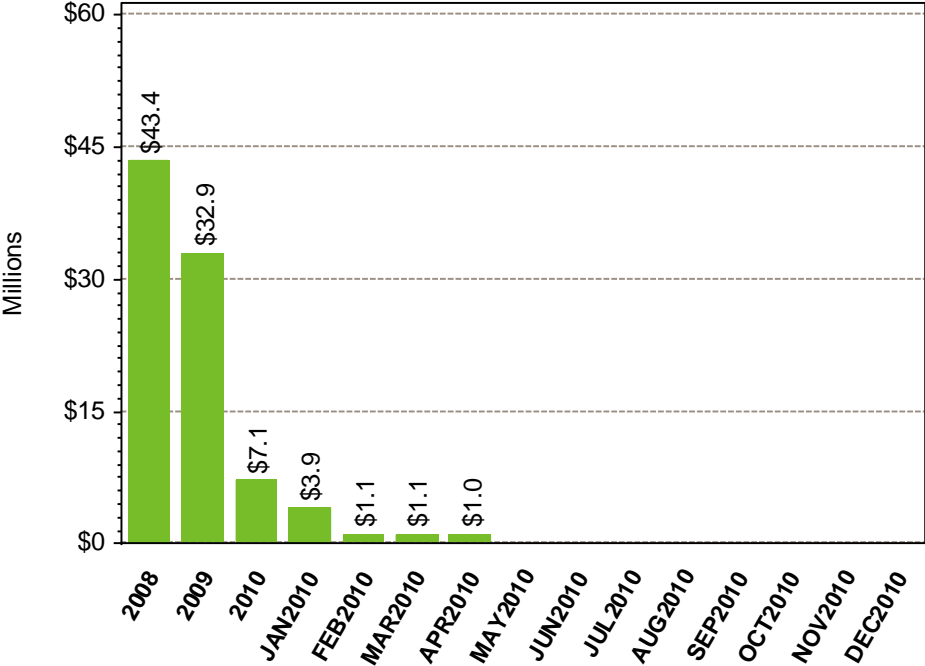
NCPC Payments by Percent of Energy Market

NCPC By Type as Percent of Energy Market

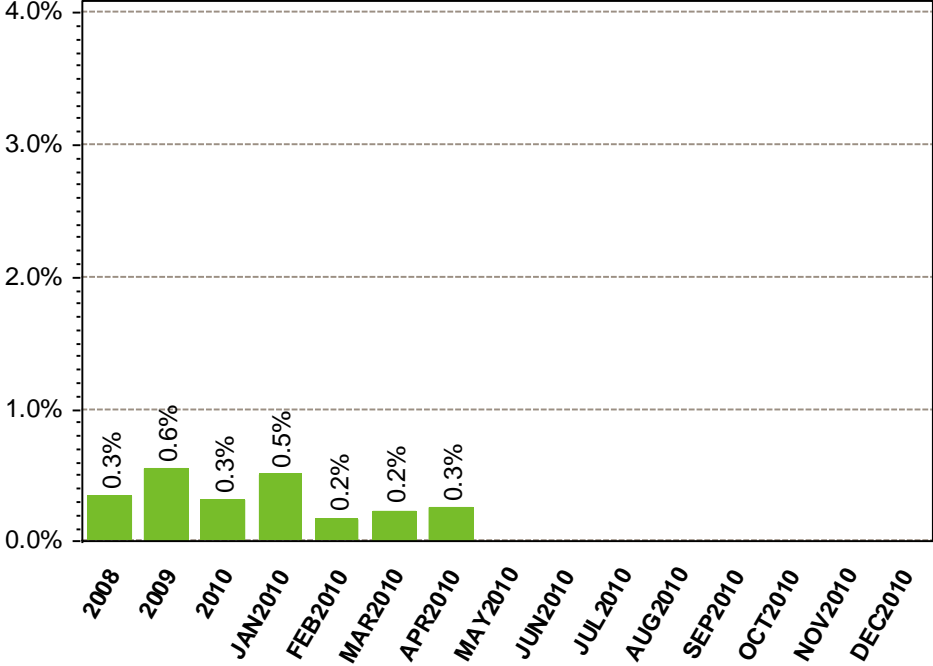


First Contingency NCPC Payments

Value of Payments



% of Energy Market Value

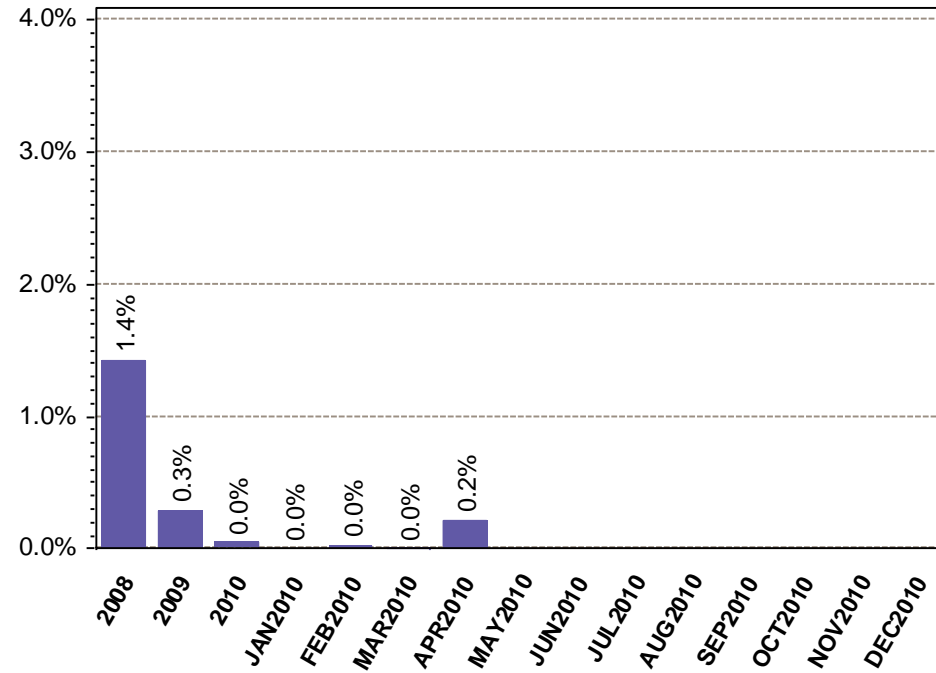
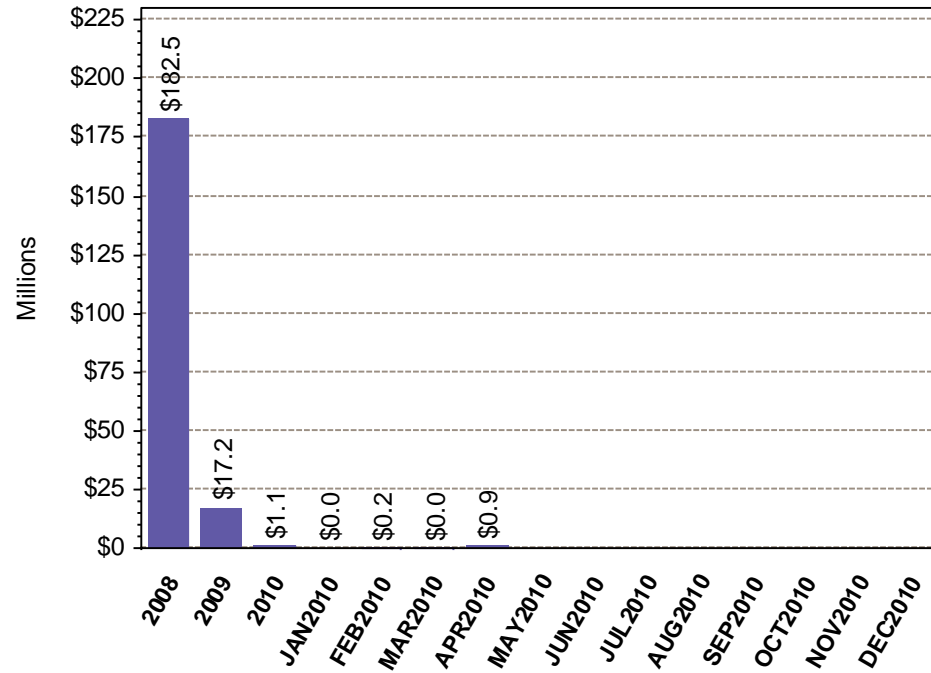


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Second Contingency NCPC Payments

Value of Payments

% of Energy Market Value

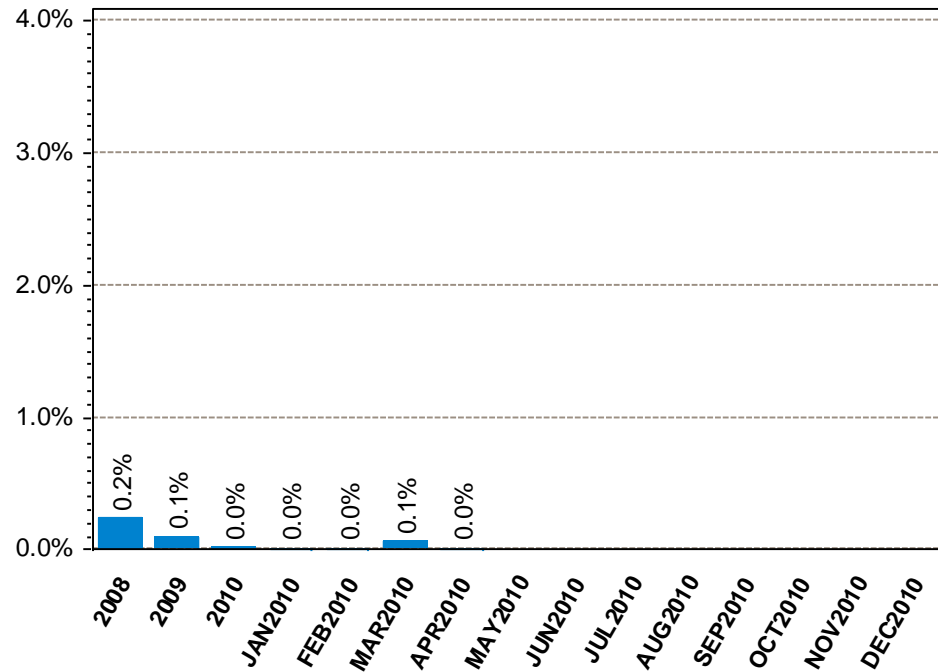
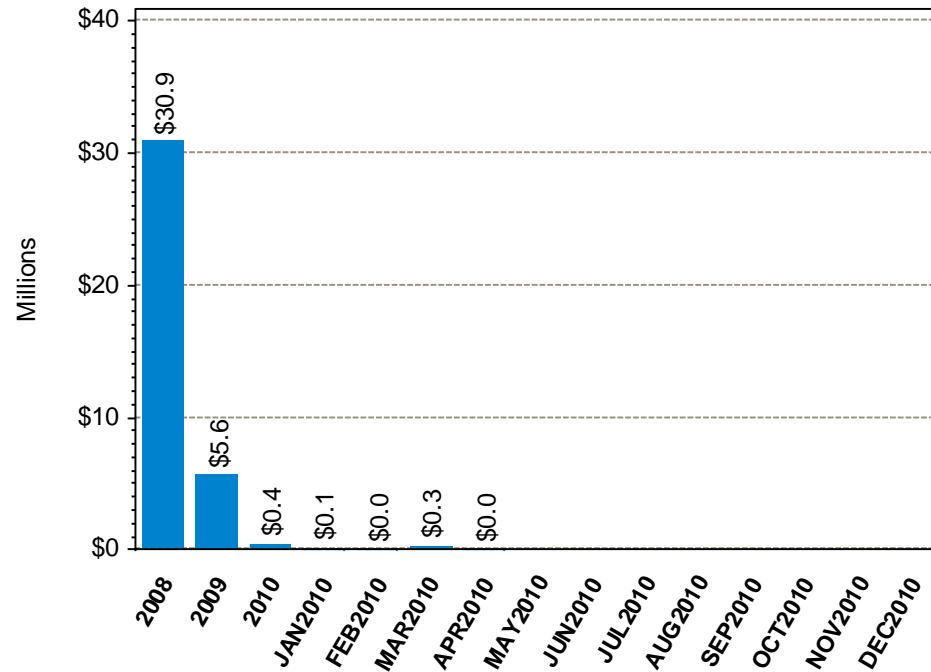


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Payments

Value of Payments

% of Energy Market Value



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 inc's and dec's
- Self-schedules
- DA vs. RT net interchange
- Delisted capacity

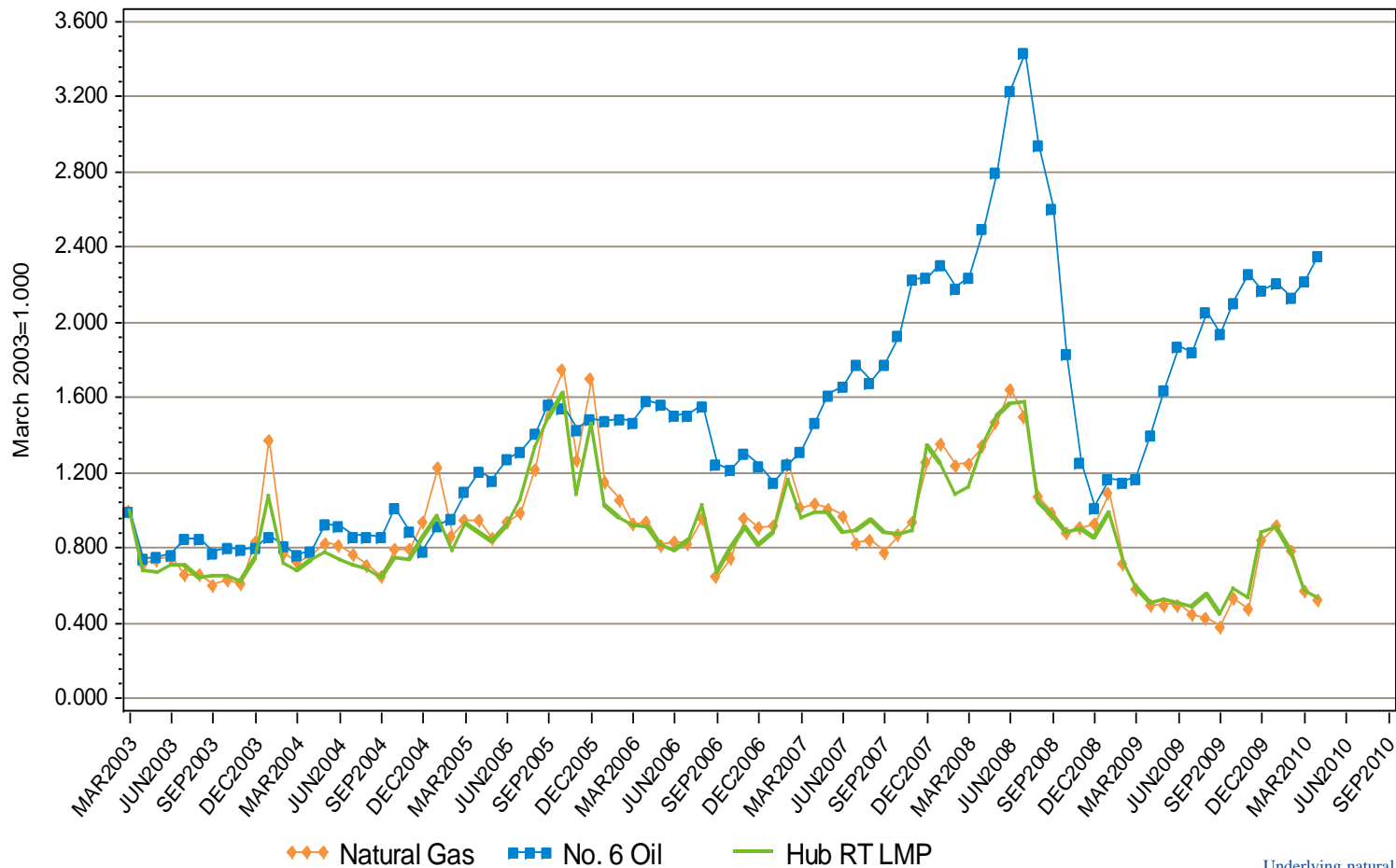
DA vs. RT LMPs (\$/MWh)

Arithmetic Average

Year 2008	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$79.85	\$84.85	\$76.13	\$79.22	\$81.07	\$79.33	\$82.73	\$81.31	\$80.64
Real-Time	\$80.49	\$83.56	\$75.60	\$79.52	\$81.17	\$79.62	\$81.56	\$81.41	\$80.75
RT Delta %	0.8%	-1.5%	-0.7%	0.4%	0.1%	0.4%	-1.4%	0.1%	0.1%
Year 2009	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$41.44	\$42.73	\$39.60	\$40.85	\$41.57	\$41.13	\$41.70	\$41.89	\$41.52
Real-Time	\$41.78	\$42.89	\$39.97	\$41.32	\$42.06	\$41.57	\$42.03	\$42.33	\$42.00
RT Delta %	0.8%	0.4%	1.0%	1.1%	1.2%	1.1%	0.8%	1.1%	1.1%

April-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$34.78	\$37.24	\$33.51	\$34.35	\$34.89	\$34.86	\$35.16	\$35.43	\$35.19
Real-Time	\$34.34	\$35.75	\$32.84	\$33.78	\$34.67	\$34.30	\$34.59	\$35.07	\$34.75
RT Delta %	-1.3%	-4.0%	-2.0%	-1.7%	-0.6%	-1.6%	-1.6%	-1.0%	-1.2%
April-10	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$36.75	\$38.85	\$33.24	\$35.01	\$36.67	\$36.35	\$36.50	\$37.53	\$37.19
Real-Time	\$38.01	\$37.85	\$33.18	\$35.20	\$36.46	\$36.08	\$36.26	\$36.87	\$36.57
RT Delta %	3.4%	-2.6%	-0.2%	0.5%	-0.6%	-0.8%	-0.7%	-1.8%	-1.7%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	5.7%	4.3%	-0.8%	1.9%	5.1%	4.3%	3.8%	5.9%	5.7%
Yr over Yr RT	10.7%	5.9%	1.0%	4.2%	5.2%	5.2%	4.8%	5.1%	5.2%

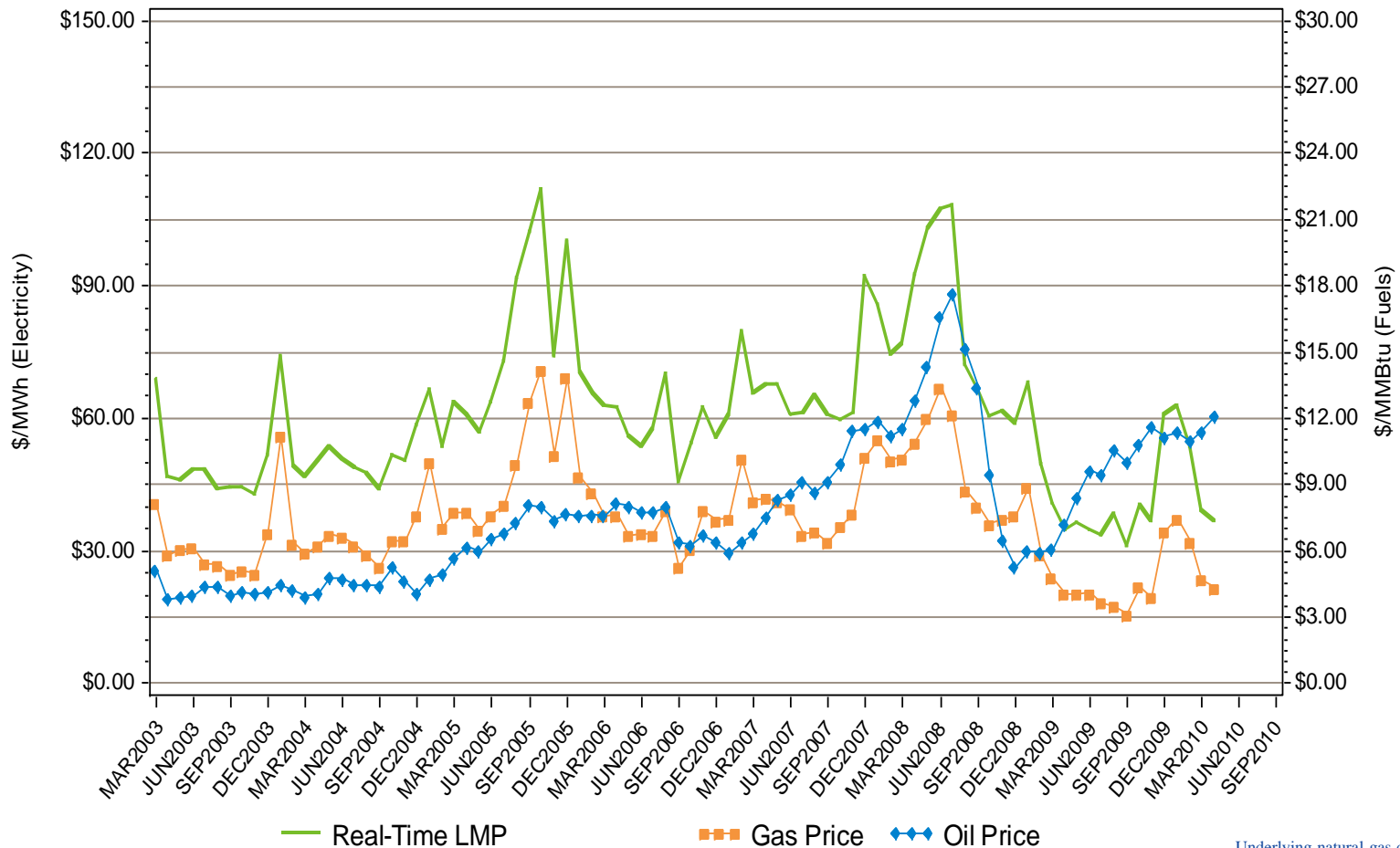
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:



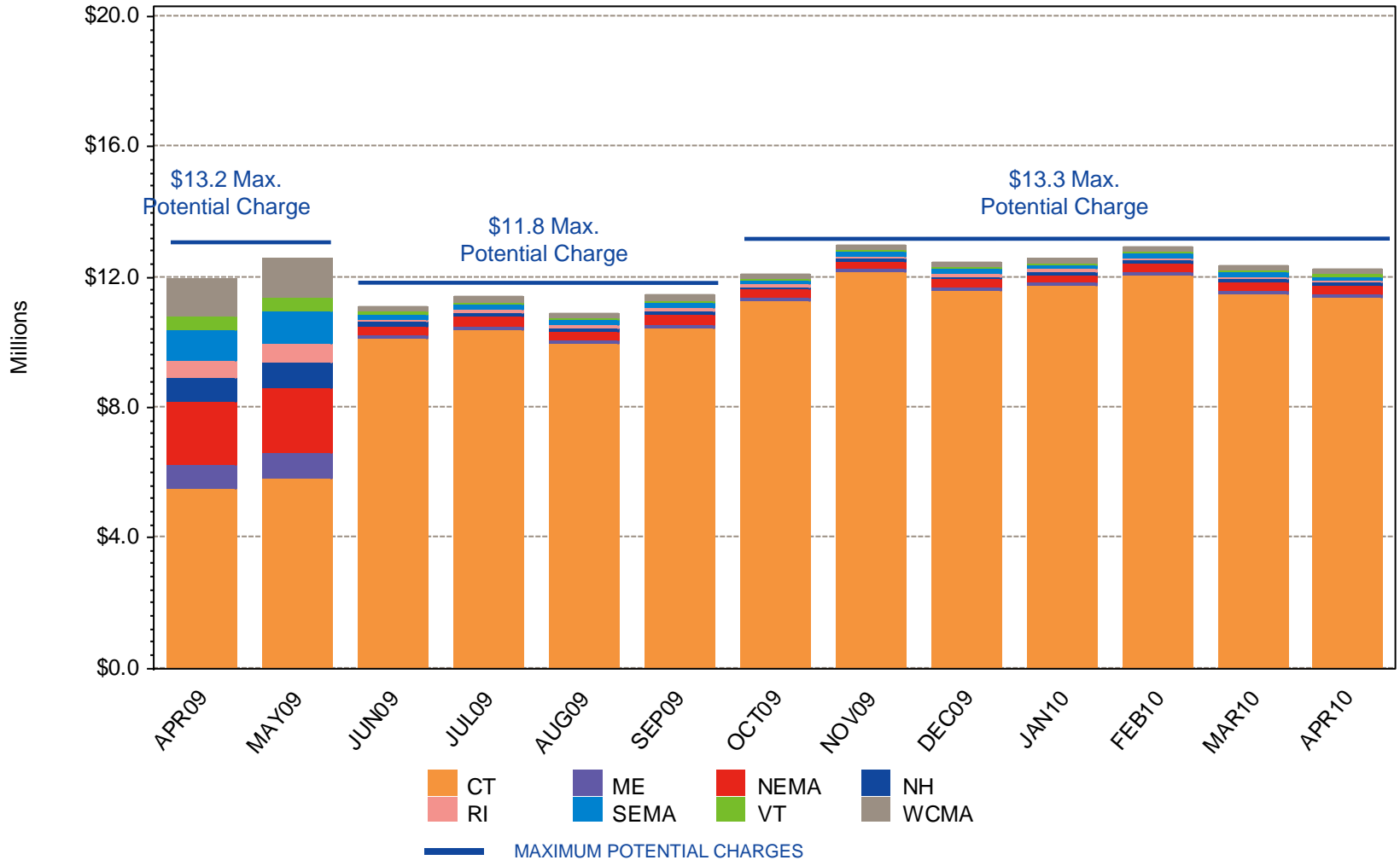
Reserve Market Results – April 2010

- Maximum potential Forward Reserve Market payments of \$13.3M were reduced by credit reductions of \$891K, failure-to-reserve penalties of \$162K and failure-to-activate penalties of \$0M, resulting in a net payout of \$12.2M or 92% of maximum
 - Rest of System: \$1.47M/\$1.68M (87%)
 - Southwest Connecticut: \$3.49M/\$4.22M (83%)
 - Connecticut: \$7.26M/\$7.37M (99%)
- \$1.1M total Real-Time credits were reduced by \$0K in Forward Reserve Energy Obligation Charges for a net of \$1.1M in Real-Time Reserve payments
 - Rest of System: 37 hours, \$741K
 - Southwest Connecticut: 37 hours, \$177K
 - Connecticut: 37 hours, \$107K
 - NEMA: 37 hours, \$121K
- The system reserve bias factor was used for Ten-Minute Spinning Reserve for approximately one hour on April 2

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

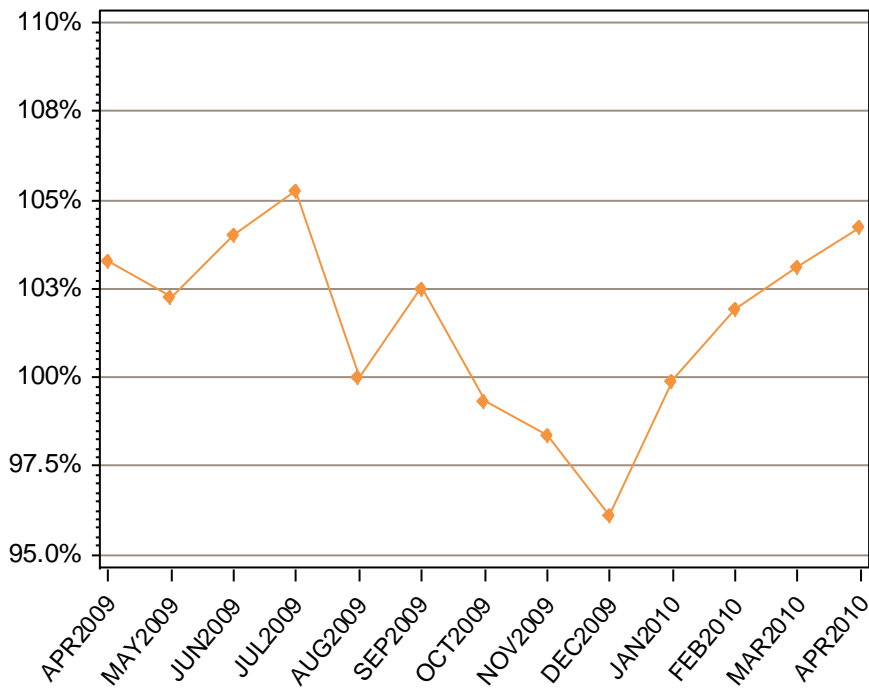
LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months

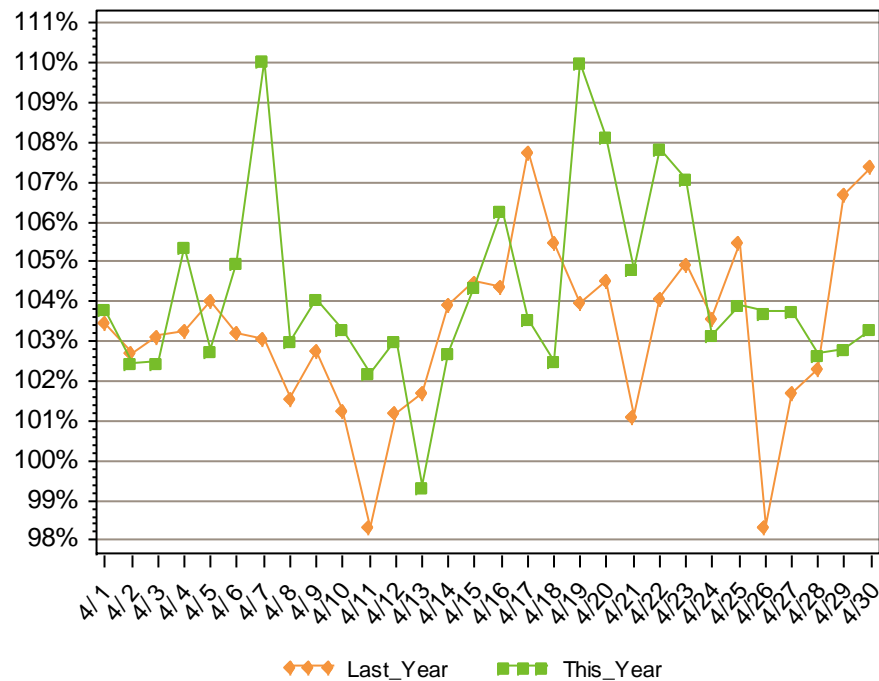


DA Load Obligation Percent of RT Load Obligation

Monthly, Last 13 Months

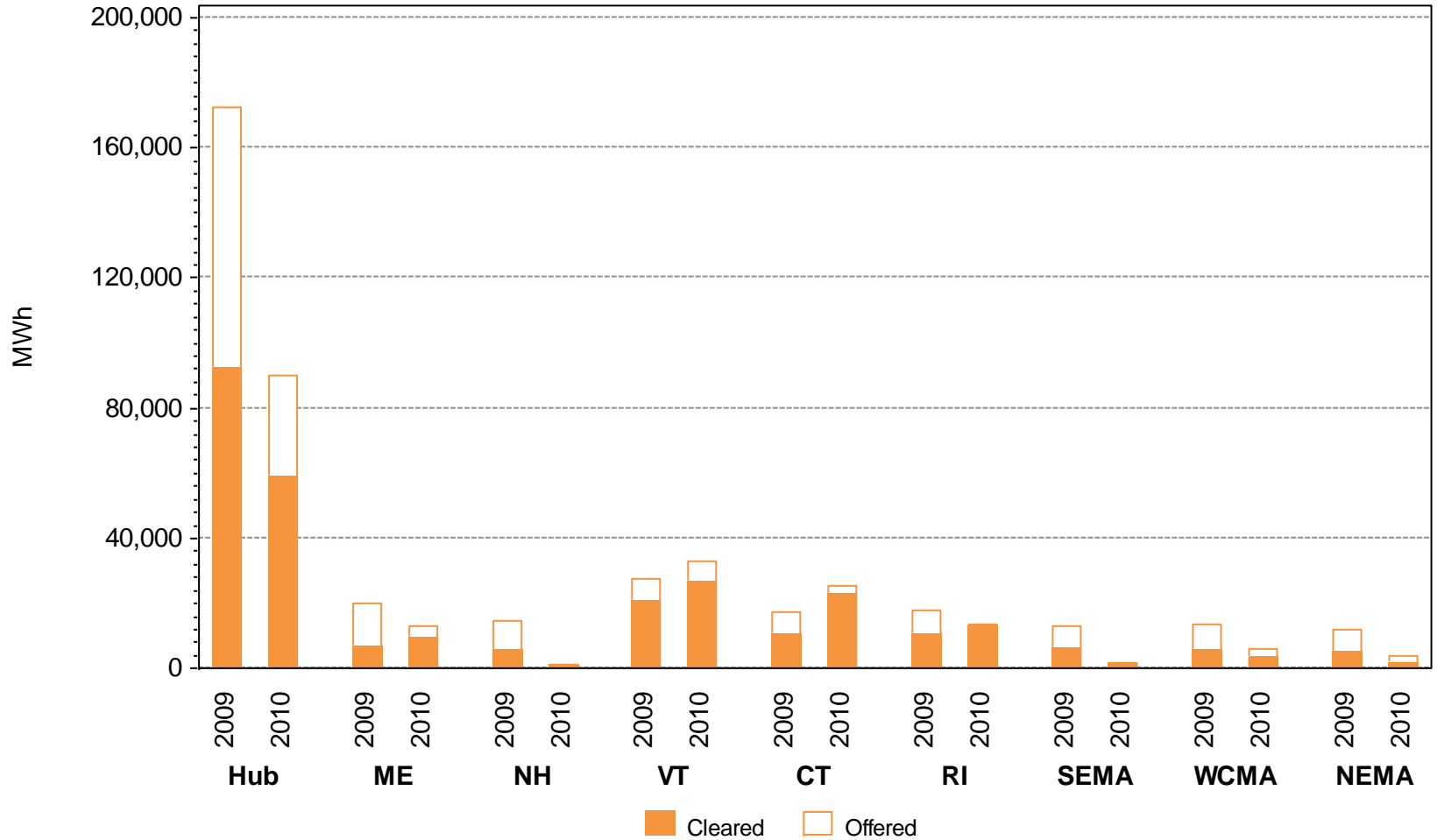


Daily, This Year vs. Last Year



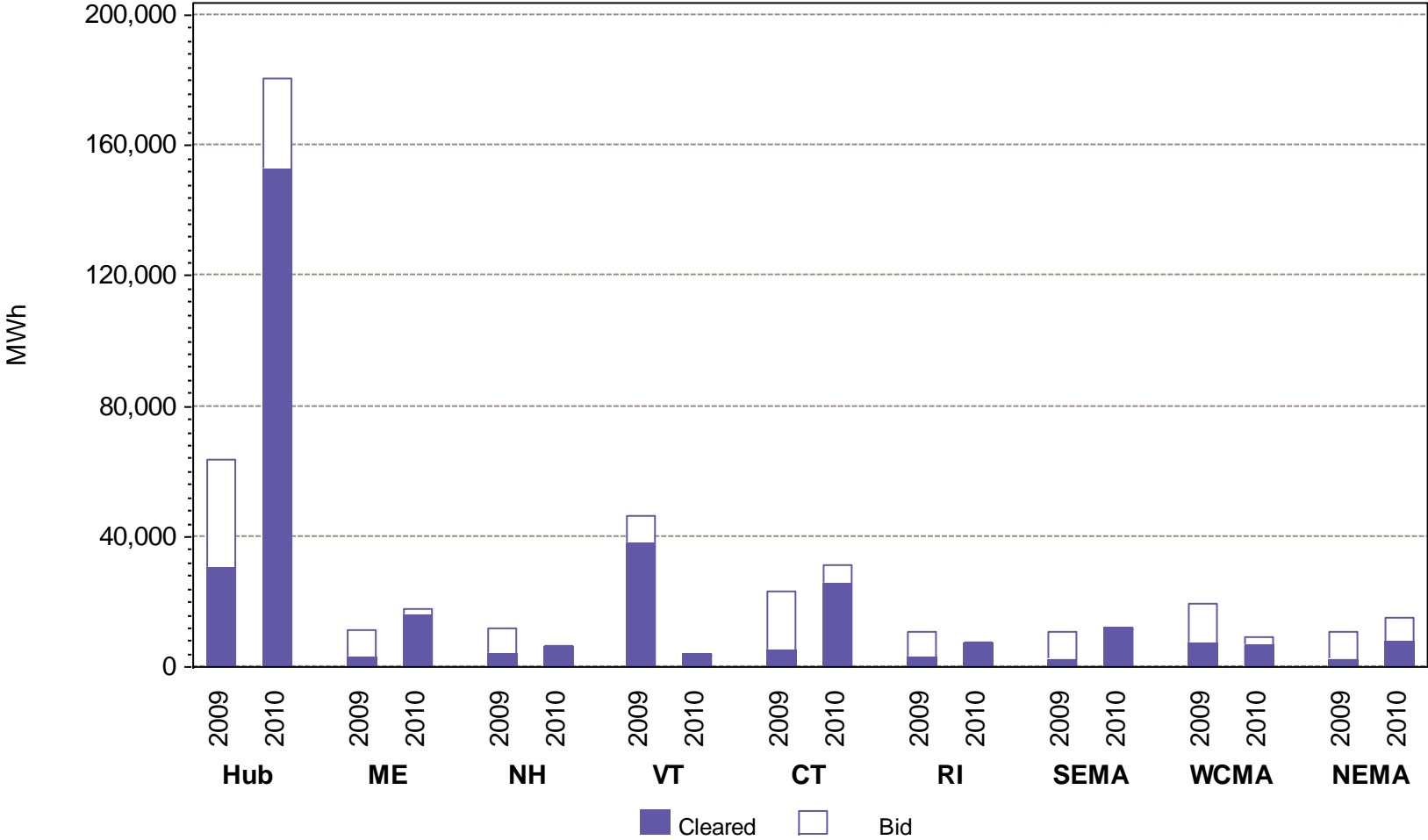
Zonal Increment Offers and Cleared Amounts

April Monthly Totals by Zone



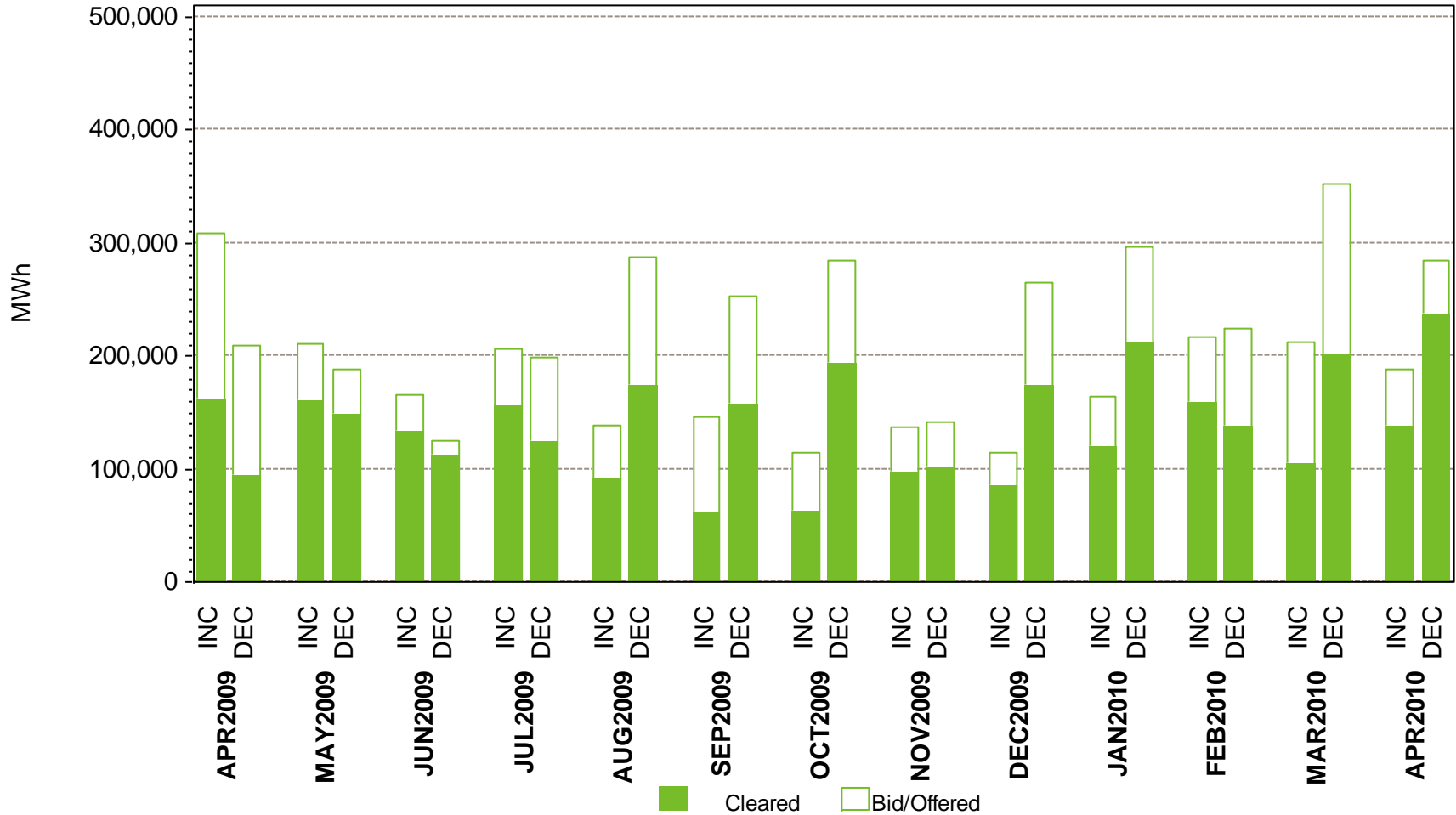
Zonal Decrement Bids and Cleared Amounts

April Monthly Totals by Zone



Total Increment Offers and Decrement Bids

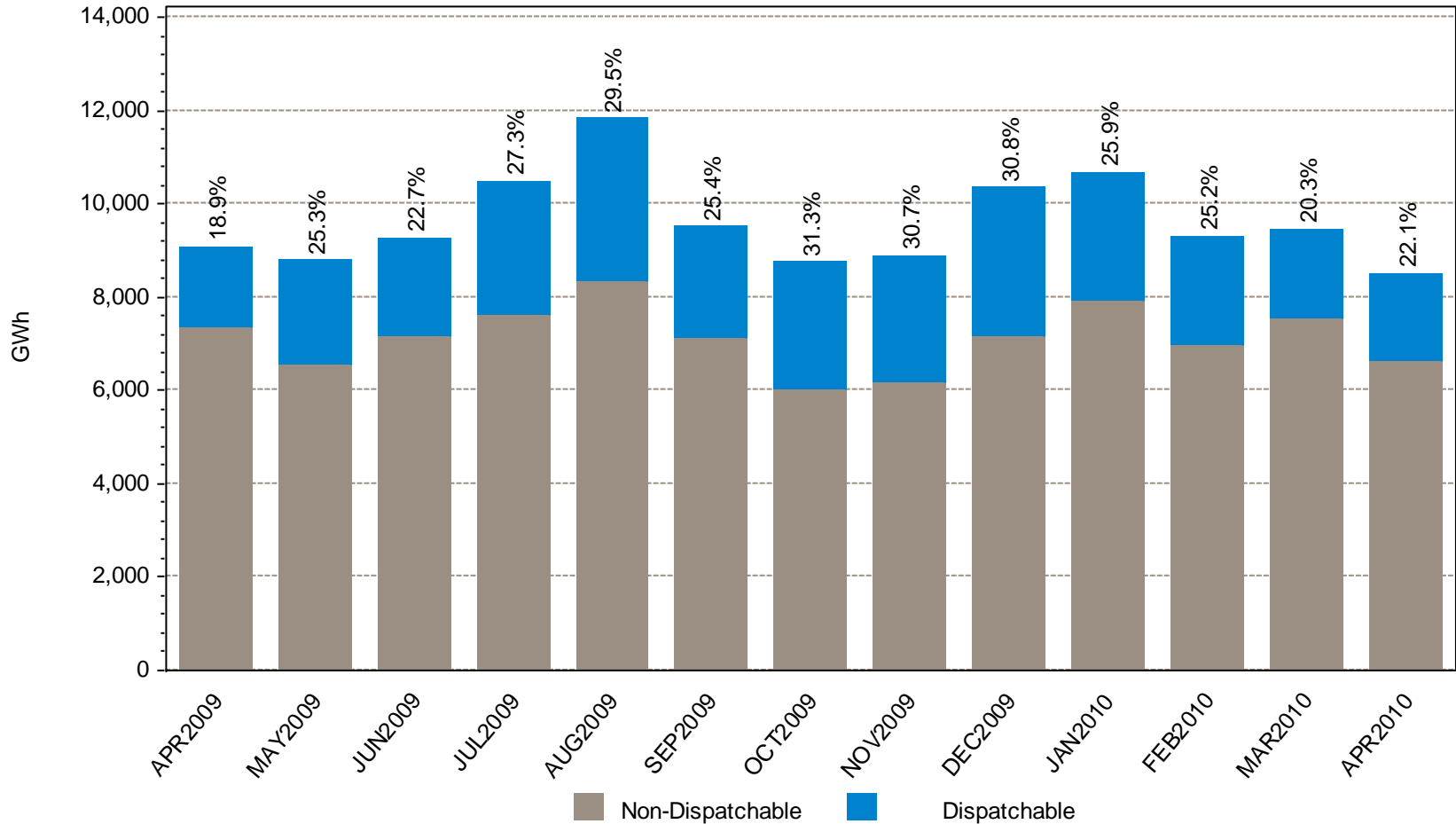
Zonal Level, Last 13 Months



Data excludes nodal offers and bids

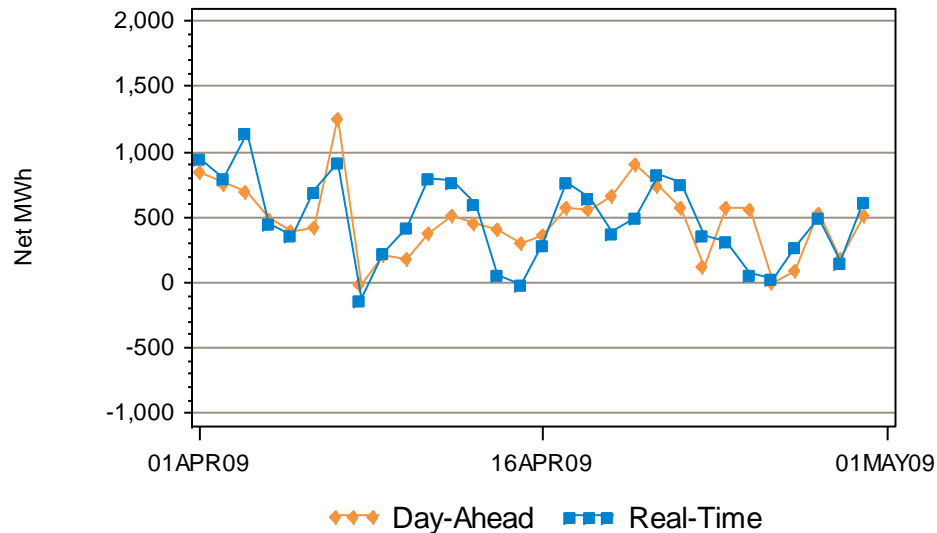
Dispatchable vs. Non-Dispatchable Generation

Total Monthly Energy; Dispatchable % Shown

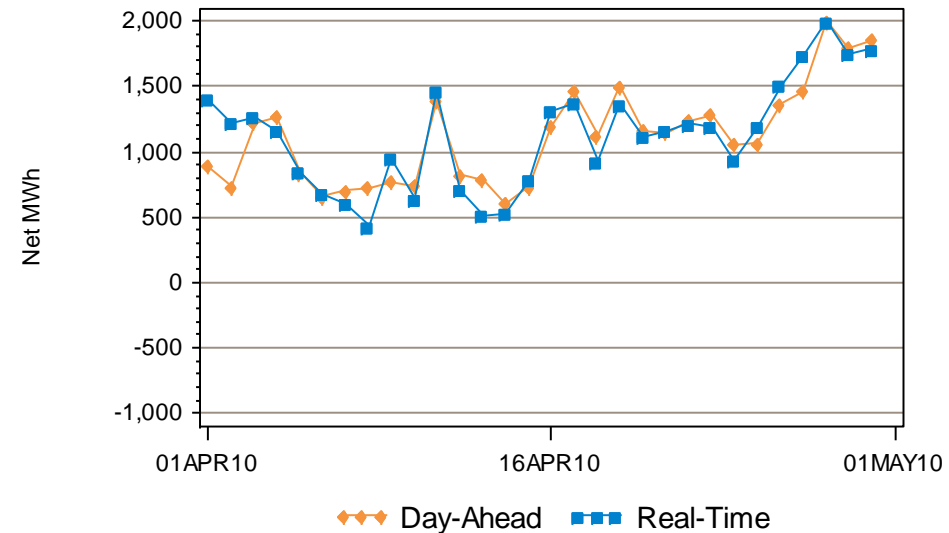


DA vs. RT Net Interchange April 2010 vs. April 2009

Hourly Average by Day, Last Year



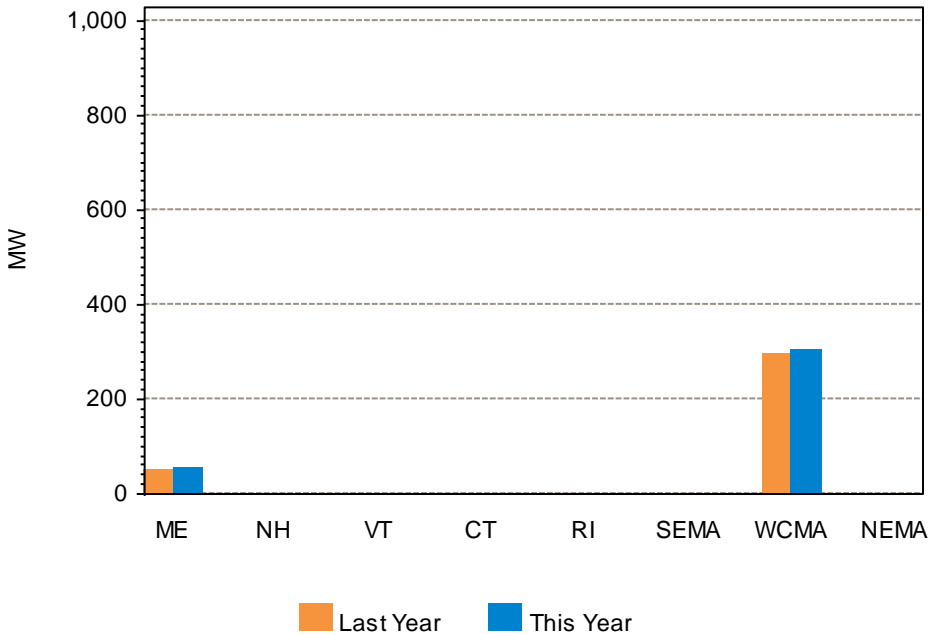
Hourly Average by Day, This Year



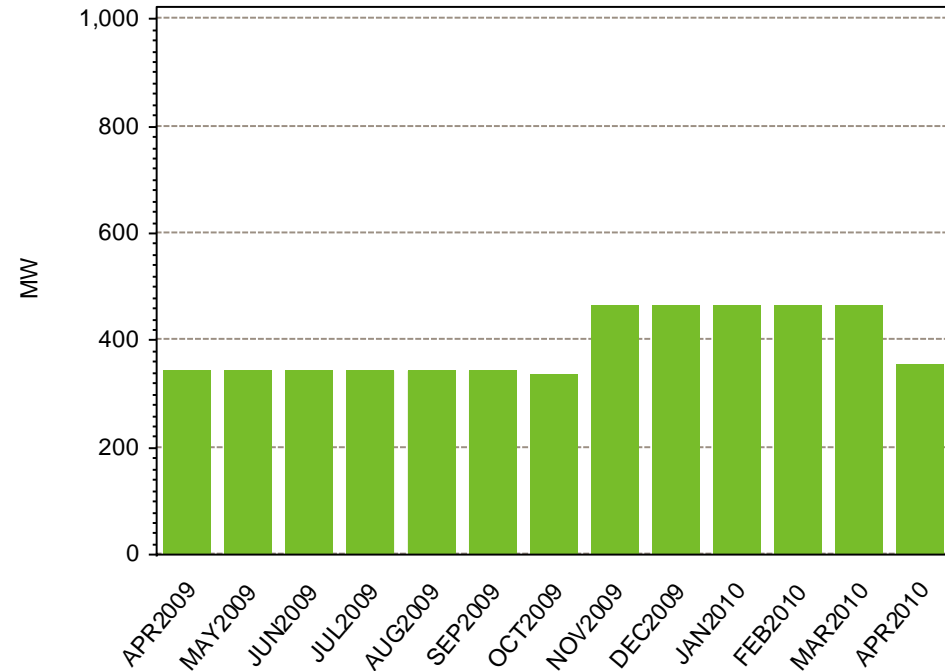
Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Delisted Capacity, April 2010

Delisted Capacity by Zone, This Year vs. Last Year



Total, Last 13 Months



During the Installed Capacity (ICAP) Transition Period, assets must de-list for the entire Commitment Period. The current Winter Commitment Period spans October 2009 through May 2010. The Summer Commitment Period will encompass June 2010 through September 2010.

Reliability Agreement Status Summary

Reliability Agreements

<u>Unit</u>	<u>Annual Fixed Cost⁽¹⁾</u>	<u>Summer MW*</u>	<u>\$/kw-month⁽¹⁾</u>	<u>Effective Date</u> "R" = Requested
Status: Effective with Final Federal Energy Regulatory Commission (FERC) Approval				
NRG Energy - Middletown 2-4, 10	\$49,611,273	770	\$5.37	01/01/06
NRG Energy - Montville 5, 6, 10 & 11	\$28,696,612	494	\$4.84	01/01/06
Berkshire Power	\$26,000,000	229	\$9.46	07/01/05
Con Edison - West Springfield 3	\$7,050,000	94	\$6.25	05/01/05
Pittsfield Generating - Altresco	\$13,000,000	141	\$7.68	12/01/05
Con Edison - West Springfield Gas Turbine GT-1 and GT-2	\$9,800,000	74	\$11.04	03/31/06
Public Service Enterprise Group (PSEG) - New Haven Harbor	\$37,492,000	448	\$6.97	11/18/04
PSEG - Bridgeport Harbor 2	\$14,008,000	130	\$8.98	11/18/04
NRG Energy - Norwalk Harbor 1, 2	\$32,000,000	330	\$8.08	06/19/07
Status: Terminated or Termination Pending				
NRG Energy - Devon 7 & 8 (10/1/04 & 6/7/04)	\$19,692,116	212 (retired)	\$7.74	08/01/02
Mirant Kendall Steam 1-3 & Jet 1 (5/1/07)	\$7,920,000	70	\$9.43	10/08/04
Exelon New - Boston 1 (11/16/06)	\$30,000,000	350 (deactivated)	\$7.14	01/01/02
NRG Energy - Devon 11-14 (1/1/07)	\$19,692,116	118	\$13.91	01/01/06
Boston Generating - Mystic 8 & 9 (1/1/07)	\$155,000,000	1373	\$9.41	01/01/06
PPL Corporation - Wallingford 2-5 (6/1/07)	\$22,000,000	167	\$10.98	02/01/03
Bridgeport Energy (6/1/07)	\$50,500,000	445	\$9.46	06/01/05
Dominion - Salem Harbor (last payment 7/07; obligation ended 10/08.)	\$3,375,000	741	\$0.38	07/22/05
Milford Power 1 & 2 (9/30/08)	\$72,500,000	521	\$11.60	11/03/04

⁽¹⁾Does not reflect the netting of Market Revenues, including transition payments, that are in excess of variable costs. Where FERC Settlements are pending, the settlement Annual Fixed Cost is shown.

*2009 Forecast Report of Capacity, Energy, Loads, and Transmission, or capacity at deactivation/retirement

<http://www.iso-ne.com/trans/celt/report/index.html>

No change from prior month

Requests for Reliability Determinations

<u>Unit</u>	<u>Summer MW*</u>	<u>Zone Location</u>	<u>Date Received</u>	<u>Date of Determination</u>
Status: Needed for System Reliability				
FPL Energy Yarmouth (aka Wyman) 1 & 2	103	ME	12/11/08	06/23/09
Status: Needed for System Reliability as of date of determination - Generator did not pursue a Reliability Agreement				
Con Edison - West Springfield 10	17	WCMA	08/19/05	02/23/06
Status: Not Needed for System Reliability as of Date of Determination				
FPL Energy - Yarmouth 4	603	ME	02/11/05	05/26/05
Indeck Enfield and Jonesboro	46	ME	11/15/05	12/28/05
Ridgewood and Blackstone Tupperware	3	RI	03/02/05	05/26/05
Lowell Cogeneration	28	WCMA	10/24/05	12/28/05
Millennium Power	326	WCMA	04/08/05	06/15/05
Taunton - Cleary	26	WCMA	05/11/05	12/28/05
Con Edison - Newington	505	NH	08/19/05	12/28/05
Con Edison - Doreen	16	WCMA	08/19/05	02/23/06
Lake Road 1-3	752	RI	09/23/05	12/28/05
Granite Ridge	660	NH	11/21/05	03/31/06
Calpine - Westbrook	510	ME	10/31/05	04/26/06
Braintree - Potter 2	75	SEMA	N/A	05/25/06
Boston Generating - Fore River	682	SEMA	N/A	05/25/06
Calpine - Rumford Power	245	ME	10/31/05	12/06/06
Con Edison - Woodland Road	16	WCMA	08/19/05	02/26/07
Lowell Power (1.3.9 granted, retired 7/1/08)	N/A	WCMA	03/21/05	05/17/05
Calpine - Androscoggin (1.3.9 granted, not deactivated)	127	ME	01/27/06	04/04/06
Mirant Kendall Steam 1-3, CT	209	NEMA	03/26/07	07/12/07
Boston Generating - Mystic 7	578	NEMA	11/12/08	05/19/09

*2009 Forecast Report of Capacity, Energy, Loads, and Transmission, or capacity at deactivation/retirement

No change from prior month

Regional System Plan (RSP)

Regional System Plan

- The May 25 PAC meeting will be “Environmental Day” and will include discussions of the following
 - Draft scope of work for 2010 Economic Studies in response to PAC discussions held on April 27
 - New England Wind Integration Study
 - Environmental Regulations
 - State Energy Efficiency Goals
- The New England East-West Solution (NEEWS) is scheduled for discussion at either the June 16 PAC meeting or the July 15 PAC meeting

Interregional Planning and Coordination

- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) WebEx meeting held April 30 to discuss the following
 - IPSAC Comments on the draft Northeast Coordinated System Plan 2009 (NCSP09) and Next Steps
 - IREMM Study of interregional production cost simulations
 - Interregional Transmission Cost Allocation between NYISO and PJM
 - ISO-NE is only an observer, would never circumvent the usual process for pursuing changes to the OATT, and has no plans for initiating interregional transmission cost allocation discussions with stakeholders at this time
- Environmental Advisory Group (EAG) teleconference scheduled for June 11

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 5/3/10

Project Benefit: Maintains system reliability for the North Shore area independent of Salem Harbor generation

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	Oct-10	2
Add King Street - W. Amesbury 115 kV line	Mar-11	2
Sandy Pond 345 kV Breakers	Jun-12	2
Reconductor Overhead portion of Mystic-Everett 115 kV line	Jun-12	2
Replace Salem-Railyard Cables	Oct-13	2

- Received Reliability Committee (RC) recommendation for I.3.9 approval on 3/27/08
- Final costs presented at 11/19/08 PAC meeting and at 12/18/08 RC meeting (for future vote)
- Transmission Cost Allocation (TCA) application presented at special stakeholder meeting on 1/29/09
- TCA recommended for approval by RC at March 2009 meeting

Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 5/3/10

Project Benefit: Improves system reliability for the Lower SEMA area independent of area generation

Upgrade	Expected In-service	Present Stage
Expand the Carver substation	Dec-12	1
Build new 345 kV line from Carver to new station near intersection with the #115 line	Dec-12	1
New station with 345-115 kV autotransformer and 3-breaker 115 kV ring bus	Dec-12	1
Build new 115 kV line from Canal to Barnstable	Dec-12	1
Upgrade the D21 line from Bell Rock to High Hill	Dec-12	1
342/322 DCT Separation	Dec-12	1

- ISO I.3.9 approval on 11/5/09
- Siting application scheduled to be filed late May 2010
- Full status update (needs, preferred solution, needs reassessment) given at 4/27/10 PAC

Maine Power Reliability Program (MPRP)

Status as of 5/3/10

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

Upgrade	Expected In-service	Present Stage
New 345 kV Line Construction (Orrington-Albion Road, Albion Road-Coopers Mills, Coopers Mills-Larrabee Road, Larrabee Road-Surowiec), (Surowiec-Raven Farm, South Gorham-Maguire Road, Maguire Road-Three Rivers)	2012	1
New 115 kV Line Construction (Orrington-Coopers Mills, Coopers Mills-Highland, Larrabee Road-Middle Street, Middle Street-Lewiston Lower, Larrabee Road-Livermore Falls, Livermore Falls-Rumford IP, Raven Farm-East Deering, East Deering-Cape, alter Section 212 to become Larrabee Road-Monmouth Substation and Monmouth Substation-Bowman Street, alter Section 86 to become Bucksport-Belfast and Belfast-Lincolntonville)	2012	1
Modify Spring Street substation to create a ring bus. Remove Browns Crossing substation. Reterminate lines at Maine Yankee substation. Loop Section 375 Buxton-Maine Yankee into Surowiec. Transfer existing 115 kV lines from Gulf Island to Larrabee Road substation.	2012	1
New 115 kV Capacitors (10 MVAR at Epping, 10 MVAR at Trenton). New 34.5 kV Capacitor (10.8 MVAR at Belfast)	2012	1
Separation of Double Circuit Towers (345 Kennebec River Crossing 375/377, 345 kV Maine Yankee 375/392, 115 kV Bucksport 65/205)	2012	1

- ISO I.3.9 approval on 7/31/08. ISO I.3.9 approval on 2/26/09 for project revisions
- TCA application presented at special stakeholder meeting on 1/29/09. RC vote on 5/19/09 to recommend approval failed with 64.36% in favor
- TCA determination letter sent on 1/29/10

Vermont Southern Loop Project

Status as of 5/3/10

Project Benefit: Improves Vermont and New England reliability by addressing the regional issues regarding the loss of the Coolidge – Vermont Yankee (340) 345 kV line

Upgrade	Expected In-service	Present Stage
Vermont Yankee – Newfane – Coolidge 345 kV line	Dec-10	3
Vernon 345/115 kV substation	Dec-10	3
Newfane 345/115 kV substation	Dec-10	3
Loop new 345 kV line into Newfane	Dec-10	3
Coolidge 345 kV substation expansion	Dec-10	3

- ISO I.3.9 approval on 10/1/08
- RC voted to recommend TCA approval to the ISO on 2/24/09
- Construction ahead of original schedule

New England East-West Solution (NEEWS)

Status as of 5/3/10

Plan Benefit: Improve New England reliability by increasing transfer limits of three critical interfaces and by eliminating future Springfield, MA and Rhode Island criteria violations

Sample Upgrade	Expected In-service	Present Stage
Interstate Reliability Project (IRP)	2013	1
Greater Springfield Reliability Project (GSRP)	2013	1
Central Connecticut East-West Reliability Project (CCRP)	2013	1
Rhode Island Reliability Project (RIRP)	2012	1

- Final “Needs” report posted (both redacted and secured versions)
- Final “Options” report posted (both redacted and secured versions)
- NEEWS preferred alternatives presented at 5/19/08 PAC meeting
- Received ISO I.3.9 approval 9/22/08
- Reaffirmed need for RIRP and GSRP at 6/17/09 PAC meeting
- Need for IRP and CCRP under study

Transmission Siting Update

- New England East-West Solution
 - ISO involvement in RI siting for RIRP complete
 - No determination yet
 - Siting application filed with MA and CT for Springfield portion in October 2008
 - Springfield – CT
 - CT Siting Council approved entire project except for the Manchester – Meekville Junction double-circuit separation portion (known as MMP)
 - NU to file supplemental testimony / studies on pros / cons of MMP versus MMP-V (separate the 395 3-terminal line into 2 separate lines)
 - Springfield – MA
 - Preliminary bench decision supports need but some routing issues remain

Transmission Siting Update, *cont.*

- Vermont Southern Loop Project
 - Project filed with Vermont Public Service Board in November 2007
 - Public Service Board approved on 2/11/09
- Maine Power Reliability Program
 - Project filed with the Maine Public Utility Commission on 7/1/08
 - Siting proceedings currently in progress
 - Hearings have been completed, but the possibility of future technical conferences and settlement discussions still exists
 - Briefs and reply briefs have been filed
 - Draft Examiner's Report was issued on 4/23/10

Operable Capacity Analysis

Spring 2010 Operable Capacity Analysis (MW)

	May-10* 50/50 Forecast (Reference Load)	May-10* 90/10 Forecast (Extreme Load)
Installed Resources (Based on the April Seasonal Claimed Capability (SCC) Report)	33,470	SAME
Net ICAP Purchases	(14)	SAME
New Generation	0	SAME
Net Resources***	33,456	SAME
Assumed Outages**	10,100	SAME
Generation at Risk Due to Gas Supply	0	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	19,970	21,572 (+1,602)
Reserve Requirement	1,800	SAME
Operable Capacity Required	21,770	23,372 (+1,602)
Operable Capacity Margin***	1,590	(20) (-1,610)

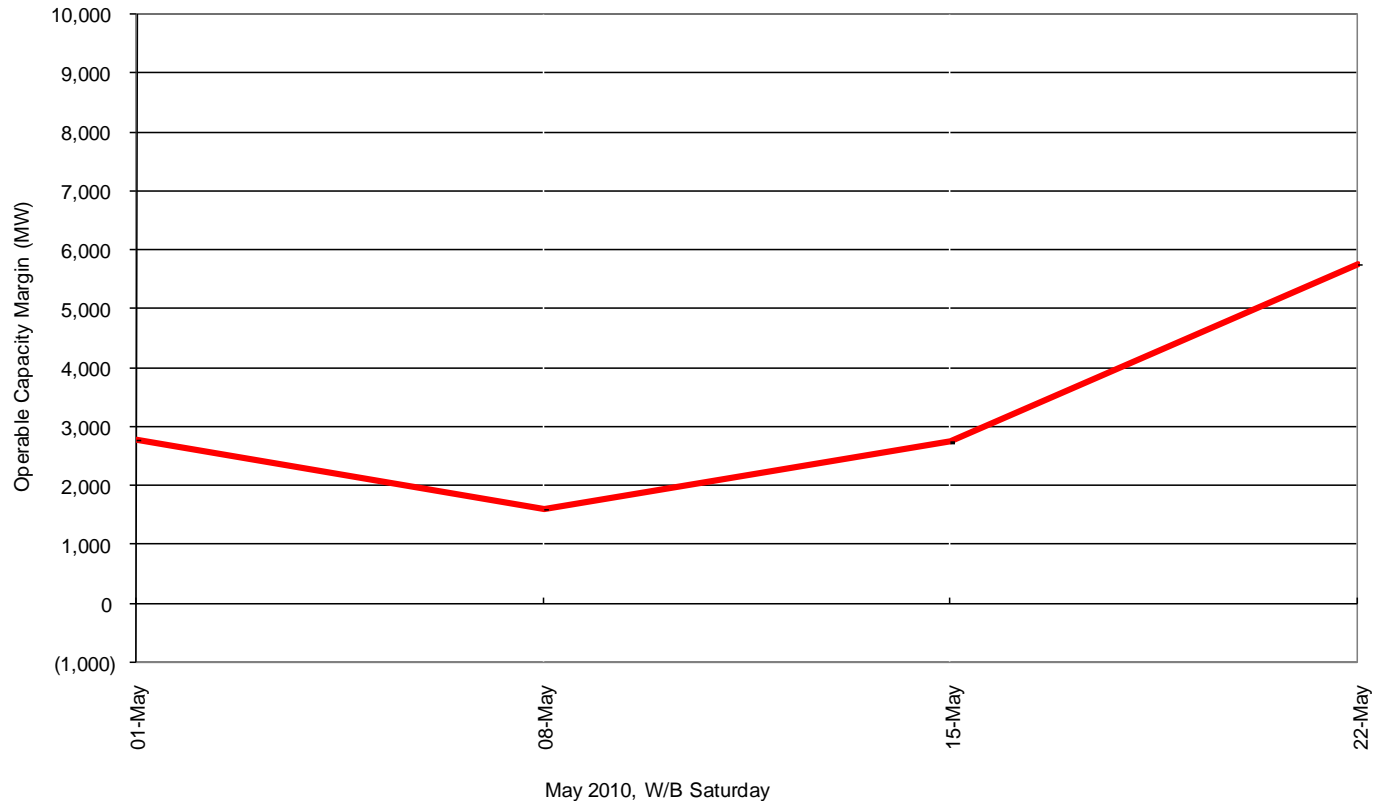
•Based on week with lowest Operable Capacity Margin, week beginning May 8th. Mystic 8 & 9 limited to 1,200 MW. Does not include Settlement Only Resources and Demand Response Resources

** Assumed Outages include 3,400 MW of Unplanned Outages, and 6,700 MW of Planned Outages

*** Rounded to the nearest ten

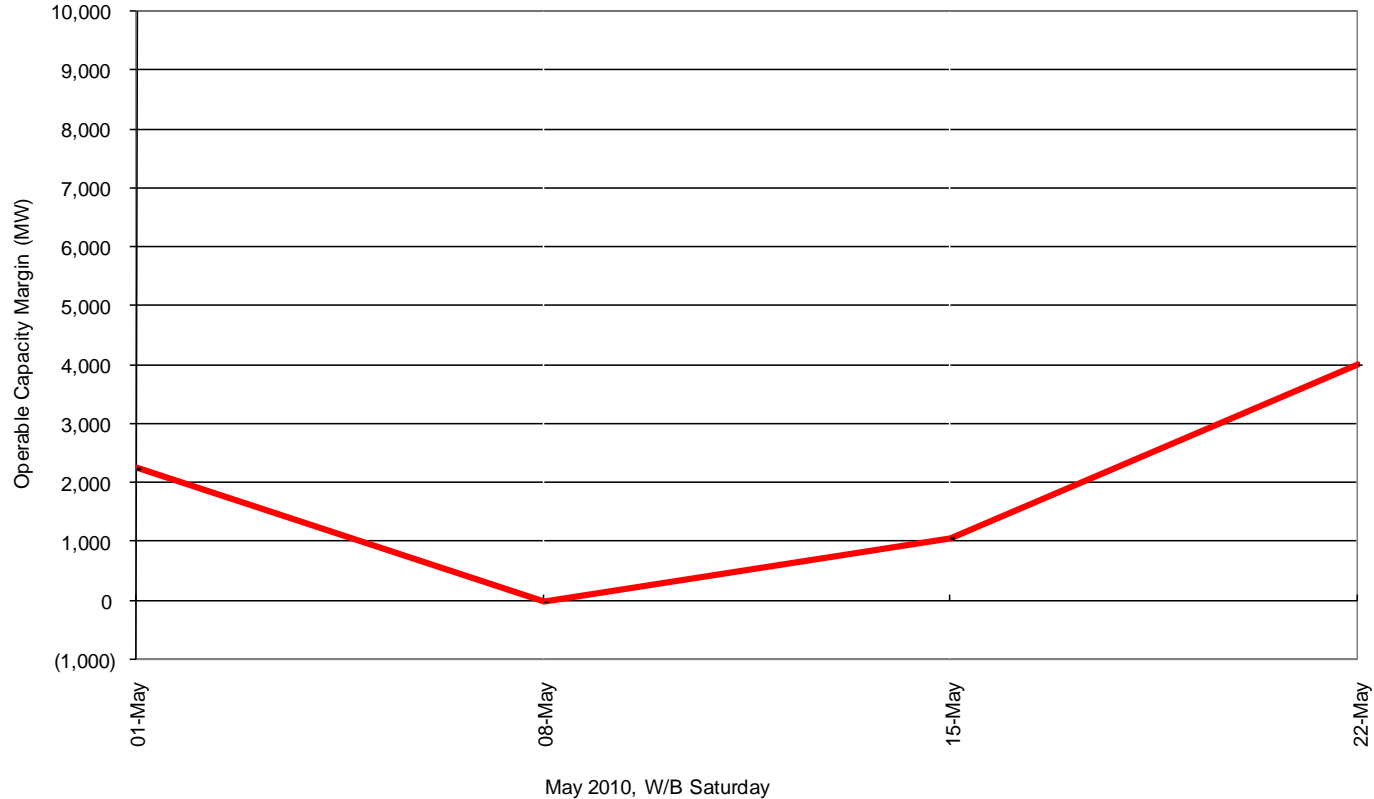
Spring 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

New England Operable Capacity Margins
WITH KNOWN EXTERNAL TRANSACTIONS - 50/50 FORECAST



Spring 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)

New England Operable Capacity Margins
WITH KNOWN EXTERNAL TRANSACTIONS - 90/10 FORECAST



Possible Relief Under OP4 (before 6/1/10)

OP 4 Action Number	Action Description	Amount Assumed Obtainable Under OP 4 (MW)
3	Interrupt 2-hour and Profile DR Resources*	234
6	Reduce 30-minute Operating Reserves	600
9	Interrupt 30-minute DR Resources*	823
11	Schedule Emergency Energy Transactions	1,000
12	Interrupt Additional DR Resources*	1,153
	Voltage Reduction requiring > 10 minutes	82
13	Voltage Reduction requiring < 10 minutes	366
15	Radio and TV Appeal	200
Total		4,458

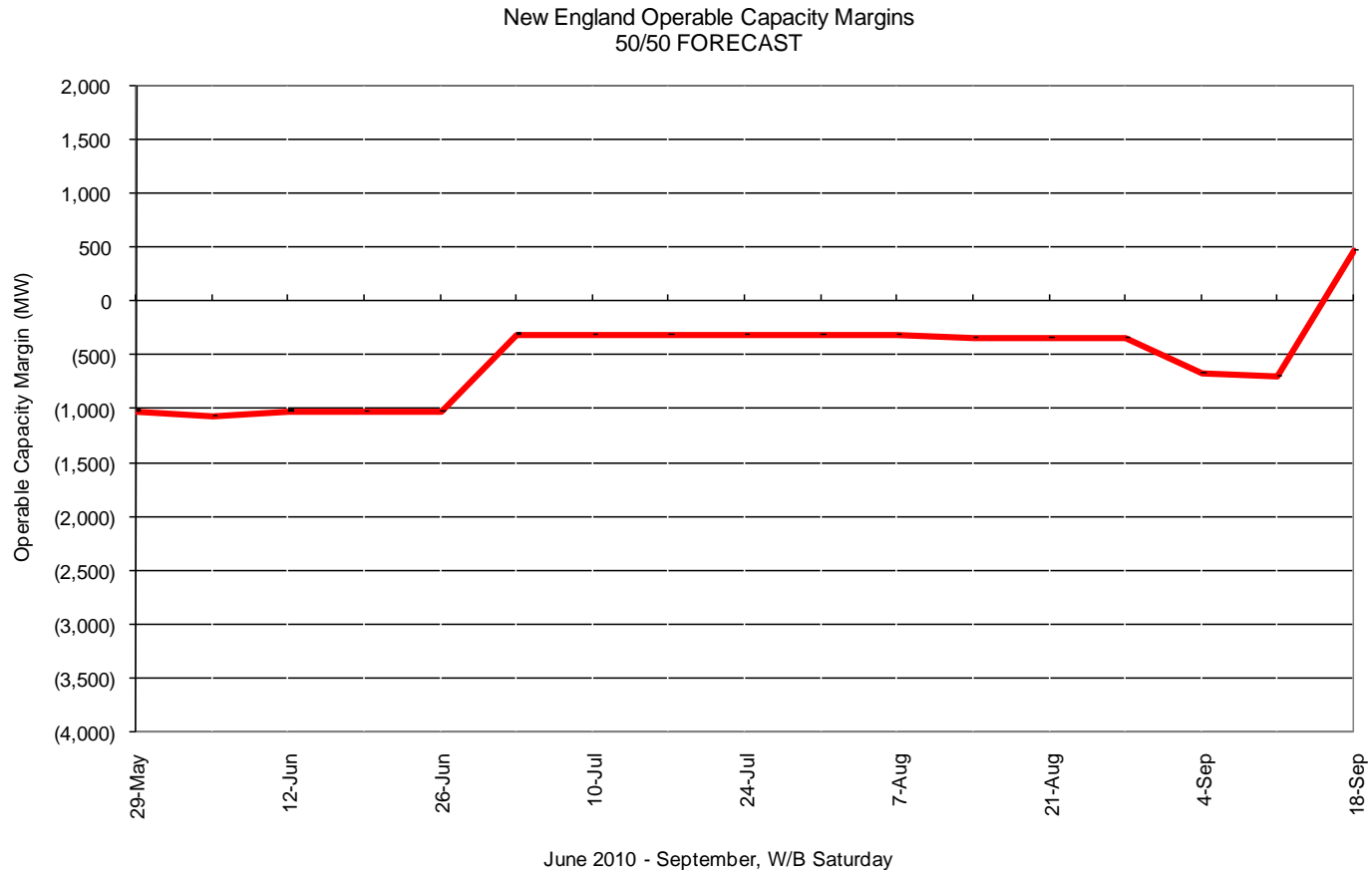
- Total Demand Response MW, including voluntary price response = 2,275 MW
- Demand Response based on data as of 4/30/2010
- OP-4 Actions based on a 28,048 MW system load

Summer 2010 Operable Capacity Analysis (MW)

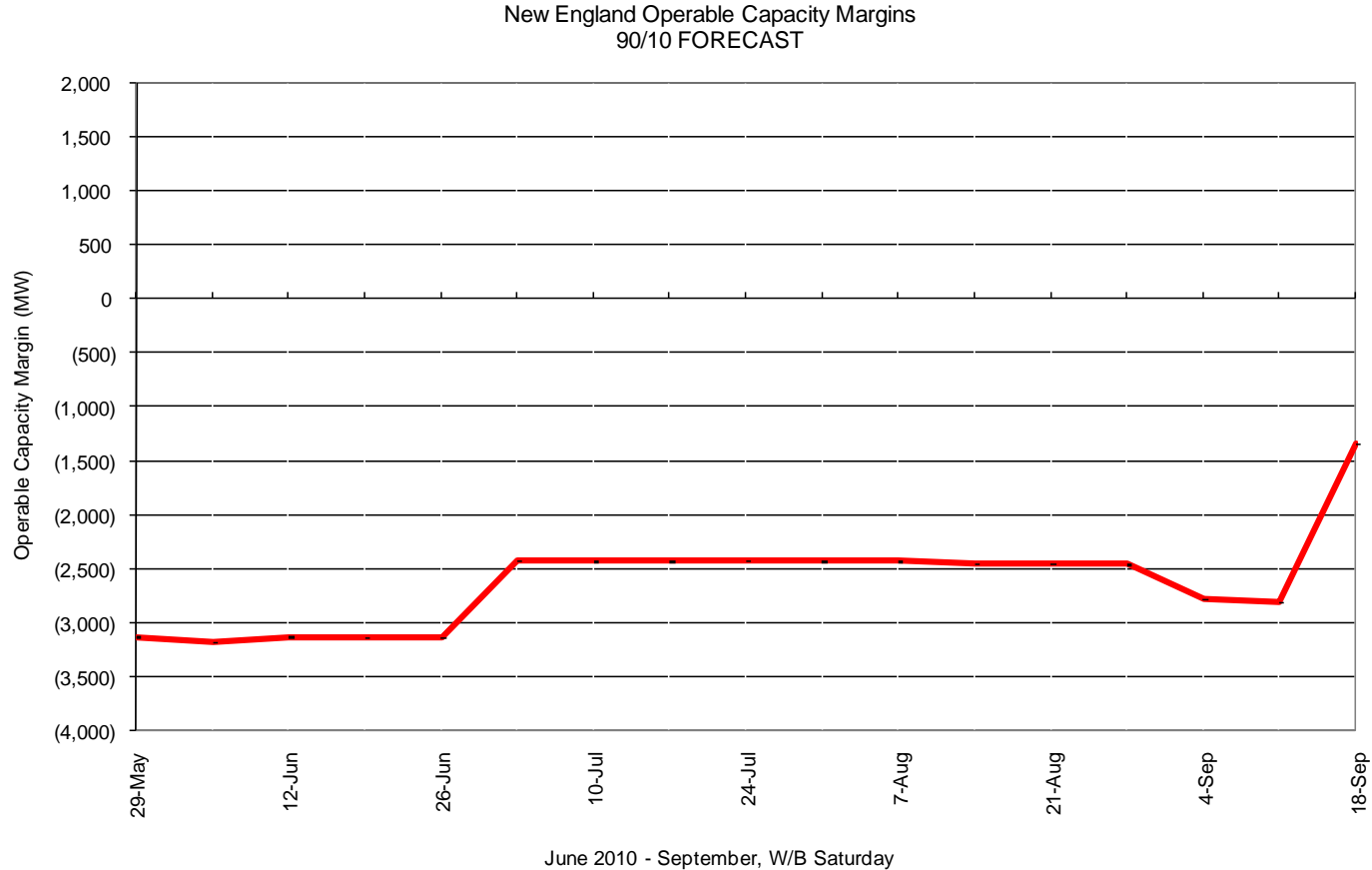
	June-10* 50/50 Forecast (Reference Load)	June-10* 90/10 Forecast (Extreme Load)
Available operable capacity	29,906	SAME
External Node Available capacity	339	SAME
Non Commercial Supply	0	SAME
Planned Outage MW	100	SAME
Allowance for Unplanned Outages	2,800	SAME
Generation at Risk Due to Gas Supply	0	SAME
Net Capacity	27,353	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	26,618	28,738 (+2,120)
Reserve Requirement	1,800	SAME
Operable Capacity Required	28,418	30,538 (+2,120)
Operable Capacity Margin	(1,063)	(3,185) (-2,122)

•Based on week with lowest Operable Capacity Margin, week beginning June 5th. Mystic 8 & 9 limited to 1,200 MW. Does not include Settlement Only Resources and Demand Response Resources.

Summer 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)



Summer 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)



Possible Relief Under OP4 (after 5/31/10) 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 Resources with a CSO 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
		600
2	Dispatch real time Demand Resources.	670 ²
3	Voluntary Load Curtailment of Market Participants' facilities.	40
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-Control-Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	130 ³
		520 ²
7	Request generating resources not subject to a Capacity Supply Obligation to voluntarily provide energy for reliability purposes	0
8	Voltage Reduction requiring < 10 minutes	270 ³
9	Voluntary Load Curtailment by Large Industrial and Commercial Customers. Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.	200 ¹
		5

Possible Relief Under OP4 (after 5/31/10) 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 Appeal	200
11	Request State Governors to Reinforce Power Warning Appeals.	100
Total		3,735

NOTES:

1. 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.
2. The MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software. Reserve Margin gross-ups is not included and derate is not applied.
3. The MW values are based on a 26,618 MW system load and the most recent voltage reduction test % achieved.

Appendix

Spring 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

May 3 , 2010 - WITH KNOWN EXTERNAL CONTRACTS - 50/50 FORECAST

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.

Week Beginning, Saturday															
Year	Month	Day	Installed Seasonal Claimed Capacity (SCC) [Note 1] <i>(MW)</i>	Net Interchange (NYPP, NB, HQ, Highgate) [Note 2] <i>(MW)</i>	New Generation [Note 3] <i>(MW)</i>	De-listed ICAP resources [Note 4] <i>(MW)</i>	Net Capacity [Note 5] <i>(MW)</i>	Peak Load Exposure [Note 6] <i>(MW)</i>	Operating Reserve Requirement [Note 7] <i>(MW)</i>	(Planned Outages) Total Known Maintenance <i>(MW)</i>	Allowance for Unplanned Outages [Note 8] <i>(MW)</i>	Generation at Risk Due to Gas Supply [Note 9] <i>(MW)</i>	Total Capacity <i>(MW)</i>	Operable Capacity Margin (+/-) <i>(MW)</i>	Extent of OP 4 Actions That May be Necessary (OP 4 Actions up to and including) [Note 10]
	May	1	33,467	(14)	0	290	33,456	16,687	1,800	8,800	3,400	0	21,256	2,770	
		8	33,467	(14)	0	290	33,456	19,970	1,800	6,700	3,400	0	23,356	1,590	
		15	33,467	(14)	0	290	33,456	20,924	1,800	4,600	3,400	0	25,456	2,730	
		22	33,467	(14)	0	290	33,456	21,811	1,800	700	3,400	0	29,356	5,750	

Notes: Please note that the information contained within the Capacity Analysis is a deterministic projection of system conditions which could materialize during any given week of the year

1. Installed Capability per the April 1, 2010 SCC report, Energy Management System units, with an adjustment for capability increases and decreases expected during the analysis period (SCC = Seasonal Claimed Capability). The Operable Capacity does not reflect possible transmission constraints within the ISO New England system.
2. Net Interchange is based on known capacity-backed (ICAP) contracts. This column combines monthly data, as it becomes available, with preliminary contract totals recorded in the 2009 Capacity, Energy, Loads, and Transmission - CELT Report.
3. New Generation information includes a) generation recently commercial but not yet reflected in the ISO New England SCC Report totals used in the Installed Capability Column, and b) future generation as assumed by ISO-NE System Planning Department. This value is rounded to the nearest hundred.
4. Delisted capacity is only known for the current month. Projections are based on known delisted capacity sales.
5. Net Capacity = (SCC) + (Interchange) + (New Generation) - (Delisted ICAP Sold) In this equation, values for SCC, Interchange and Delisted ICAP sold are rounded to the nearest ten (SCC = Seasonal Claimed Capability).
6. Peak Load Exposure per data included in the 2010 CELT Report with an adjustment for Other Demand Resources.
7. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
8. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
9. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
10. Relief from certain OP 4 Actions varies depending on system conditions.

Spring 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS May 3 , 2010 - WITH KNOWN EXTERNAL CONTRACTS - 90/10 FORECAST

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.

Week Beginning, Saturday															
Year	Month	Day	Installed Seasonal Claimed Capability (SCC) [Note 1] (MW)	Net Interchange (NYPP, NB, HQ, Highgate) [Note 2] (MW)	New Generation [Note 3] (MW)	De-listed ICAP resources [Note 4] (MW)	Net Capacity [Note 5] (MW)	Peak Load Exposure [Note 6] (MW)	Operating Reserve Requirement [Note 7] (MW)	(Planned Outages) Total Known Maintenance [Note 8] (MW)	Allowance for Unplanned Outages [Note 8] (MW)	Generation at Risk Due to Gas Supply [Note 9] (MW)	Total Capacity (MW)	Operable Capacity Margin (+/-) (MW)	Extent of OP 4 Actions That May be Necessary (OP 4 Actions up to and including) [Note 10]
	May	1	33,467	(14)	0	290	33,456	17,221	1,800	8,800	3,400	0	21,256	2,240	
		8	33,467	(14)	0	290	33,456	21,572	1,800	6,700	3,400	0	23,356	(20)	Action 2
		15	33,467	(14)	0	290	33,456	22,600	1,800	4,600	3,400	0	25,456	1,060	
		22	33,467	(14)	0	290	33,456	23,556	1,800	700	3,400	0	29,356	4,000	

Notes: Please note that the information contained within the Capacity Analysis is a deterministic projection of system conditions which could materialize during any given week of the year

1. Installed Capability per the April 1, 2010 SCC report, Energy Management System units, with an adjustment for capability increases and decreases expected during the analysis period (SCC = Seasonal Claimed Capability). The Operable Capability does not reflect possible transmission constraints within the ISO New England system.
2. Net Interchange is based on known capacity-backed (ICAP) contracts. This column combines monthly data, as it becomes available, with preliminary contract totals recorded in the 2009 Capacity, Energy, Loads, and Transmission - CELT Report.
3. New Generation information includes a) generation recently commercial but not yet reflected in the ISO New England SCC Report totals used in the Installed Capability Column, and b) future generation as assumed by ISO-NE System Planning Department. This value is rounded to the nearest hundred.
4. Delisted capacity is only known for the current month. Projections are based on known delisted capacity sales.
5. Net Capacity = (SCC) + (Interchange) + (New Generation) - (Delisted ICAP Sold) In this equation, values for SCC, Interchange and De-listed ICAP sold are rounded to the nearest ten (SCC = Seasonal Claimed Capability).
6. Peak Load Exposure per data included in the 2010 CELT Report with an adjustment for Other Demand Resources.
7. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
8. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
9. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
10. Relief from certain OP 4 Actions varies depending on system conditions.

Summer 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

May 3, 2010 - 50/50 FORECAST

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.

STUDY WEEK (Week Beginning, Saturday)	OPCAP SUPPLY							LOAD OBLIGATIONS			OPCAP MARGINS				
	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NON COMMERCIAL CAPACITY MW	PLANNED OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP 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 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN OP4
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	
05/29/2010	29,906	339	0	0	2,800	0	27,402	26,618	1,800	28,418	(1,016)	520	(496)	640	144
06/05/2010	29,906	339	0	100	2,800	0	27,353	26,618	1,800	28,418	(1,065)	520	(545)	640	95
06/12/2010	29,906	339	0	0	2,800	0	27,400	26,618	1,800	28,418	(1,018)	520	(498)	640	142
06/19/2010	29,906	339	0	100	2,800	0	27,391	26,618	1,800	28,418	(1,027)	520	(507)	640	133
06/26/2010	29,906	339	0	100	2,800	0	27,394	26,618	1,800	28,418	(1,024)	520	(504)	640	136
07/03/2010	29,906	339	0	0	2,100	0	28,112	26,618	1,800	28,418	(306)	520	214	640	854
07/10/2010	29,906	339	0	0	2,100	0	28,101	26,618	1,800	28,418	(317)	520	203	640	843
07/17/2010	29,906	339	0	0	2,100	0	28,101	26,618	1,800	28,418	(317)	520	203	640	843
07/24/2010	29,906	339	0	0	2,100	0	28,106	26,618	1,800	28,418	(312)	520	208	640	848
07/31/2010	29,906	339	0	0	2,100	0	28,102	26,618	1,800	28,418	(316)	520	204	640	844
08/07/2010	29,906	339	0	0	2,100	0	28,101	26,618	1,800	28,418	(317)	520	203	640	843
08/14/2010	29,906	339	0	100	2,100	0	28,080	26,618	1,800	28,418	(338)	520	182	640	822
08/21/2010	29,906	339	0	100	2,100	0	28,076	26,618	1,800	28,418	(342)	520	178	640	818
08/28/2010	29,906	339	0	100	2,100	0	28,074	26,618	1,800	28,418	(344)	520	176	640	816
09/04/2010	29,906	339	0	400	2,100	0	27,750	26,618	1,800	28,418	(668)	520	(148)	640	492
09/11/2010	29,906	339	0	400	2,100	0	27,717	26,618	1,800	28,418	(701)	520	(181)	640	459
09/18/2010	29,906	339	0	3,200	2,100	0	24,991	22,722	1,800	24,522	469	520	989	640	1,629

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011. Does not include Settlement Only Generators.
2. External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011
3. New resources that have not yet acquired a CSO but will become commercial in the future.
4. Allowance for Planned Outages includes planned outages scheduled greater than or equal to 15 days in advance.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
6. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
7. Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 - 6 = 7)
8. Peak Load Exposure per data included in the 2010 CELT Report.
9. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
10. Total Load Obligation per the formula (8 + 9 = 10)
11. Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
12. OP 4 Action 2 Real-time Demand Response not including reserve margin gross-ups and derate applied.
13. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
14. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes. Real Time Emergency Generation is capped at 600MW.
15. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (13 - 14 = 15). This does not include Emergency Energy Transactions (EETs).

Summer 2010 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

May 3, 2010 - 90/10 FORECAST

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.

STUDY WEEK (Week Beginning, Saturday)	OPCAP SUPPLY							LOAD OBLIGATIONS			OPCAP MARGINS				
	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NON COMMERCIAL CAPACITY MW	PLANNED OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP 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 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN OP4
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	
05/29/2010	29,906	339	0	0	2,800	0	27,402	28,738	1,800	30,538	(3,136)	520	(2,616)	640	(1,976)
06/05/2010	29,906	339	0	100	2,800	0	27,353	28,738	1,800	30,538	(3,185)	520	(2,665)	640	(2,025)
06/12/2010	29,906	339	0	0	2,800	0	27,400	28,738	1,800	30,538	(3,138)	520	(2,618)	640	(1,978)
06/19/2010	29,906	339	0	100	2,800	0	27,391	28,738	1,800	30,538	(3,147)	520	(2,627)	640	(1,987)
06/26/2010	29,906	339	0	100	2,800	0	27,394	28,738	1,800	30,538	(3,144)	520	(2,624)	640	(1,984)
07/03/2010	29,906	339	0	0	2,100	0	28,112	28,738	1,800	30,538	(2,426)	520	(1,906)	640	(1,266)
07/10/2010	29,906	339	0	0	2,100	0	28,101	28,738	1,800	30,538	(2,437)	520	(1,917)	640	(1,277)
07/17/2010	29,906	339	0	0	2,100	0	28,101	28,738	1,800	30,538	(2,437)	520	(1,917)	640	(1,277)
07/24/2010	29,906	339	0	0	2,100	0	28,106	28,738	1,800	30,538	(2,432)	520	(1,912)	640	(1,272)
07/31/2010	29,906	339	0	0	2,100	0	28,102	28,738	1,800	30,538	(2,436)	520	(1,916)	640	(1,276)
08/07/2010	29,906	339	0	0	2,100	0	28,101	28,738	1,800	30,538	(2,437)	520	(1,917)	640	(1,277)
08/14/2010	29,906	339	0	100	2,100	0	28,080	28,738	1,800	30,538	(2,458)	520	(1,938)	640	(1,298)
08/21/2010	29,906	339	0	100	2,100	0	28,076	28,738	1,800	30,538	(2,462)	520	(1,942)	640	(1,302)
08/28/2010	29,906	339	0	100	2,100	0	28,074	28,738	1,800	30,538	(2,464)	520	(1,944)	640	(1,304)
09/04/2010	29,906	339	0	400	2,100	0	27,750	28,738	1,800	30,538	(2,788)	520	(2,268)	640	(1,628)
09/11/2010	29,906	339	0	400	2,100	0	27,717	28,738	1,800	30,538	(2,821)	520	(2,301)	640	(1,661)
09/18/2010	29,906	339	0	3,200	2,100	0	24,991	24,538	1,800	26,338	(1,348)	520	(828)	640	(188)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011. Does not include Settlement Only Generators.
2. External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011
3. New resources that have not yet acquired a CSO but will become commercial in the future.
4. Allowance for Planned Outages includes planned outages scheduled greater than or equal to 15 days in advance.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
6. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
7. Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 - 6 = 7)
8. Peak Load Exposure per data included in the 2010 CELT Report.
9. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
10. Total Load Obligation per the formula (8 + 9 = 10)
11. Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
12. OP 4 Action 2 Real-time Demand Response not including reserve margin gross-ups and derate applied.
13. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
14. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes. Real Time Emergency Generation is capped at 600MW.
15. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (13 - 14 = 15). This does not include Emergency Energy Transactions (EETs).