

NEPOOL Participants Committee Report September 2010

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Senior Vice President and Chief Operating Officer

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Highlights

- **Day-Ahead (DA), Real-Time (RT) Prices and Transactions**

- August natural gas prices over the period were 7.1% lower while oil prices were 3.3% higher than July 2010 average values
- Average RT Hub Locational Marginal Prices (LMPs) over the period were down 7.2% from July 2010 averages

Underlying natural gas data furnished by:



Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)***
 - August payments total \$11.7M over the period, down \$7.7M from July
 - First Contingency payments total \$10.2M, down \$6.1M from July
 - \$9.1M paid to internal resources, down \$6.8M from July
 - \$961K charged to DA Load Obligations (DALO), \$8.1M to RT Deviations
 - \$1.2M paid to resources at external locations, up \$724K from July
 - \$1.1M charged to DALO at external locations, \$59K to RT Deviations
 - Second Contingency payments total \$92K, up \$57K from the July total of \$35K
 - Voltage payments total \$936K, down \$1.4M from July
 - Distribution payments total \$415K, down \$347K from July
 - NCPC payments as percent of Energy Market value were 1.7%

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

Highlights (cont'd.)

- The Regional System Plan (RSP) Public Meeting will be held on September 16 and will feature two panel sessions
- A number of Planning Advisory Committee (PAC) meetings are scheduled for this fall covering multiple topics of interest. Discussion on Non Transmission Alternatives planned for RSP 11 is scheduled for October and the New England Wind Integration Study is scheduled for November

Eastern Interconnection Planning Collaborative (EIPC)

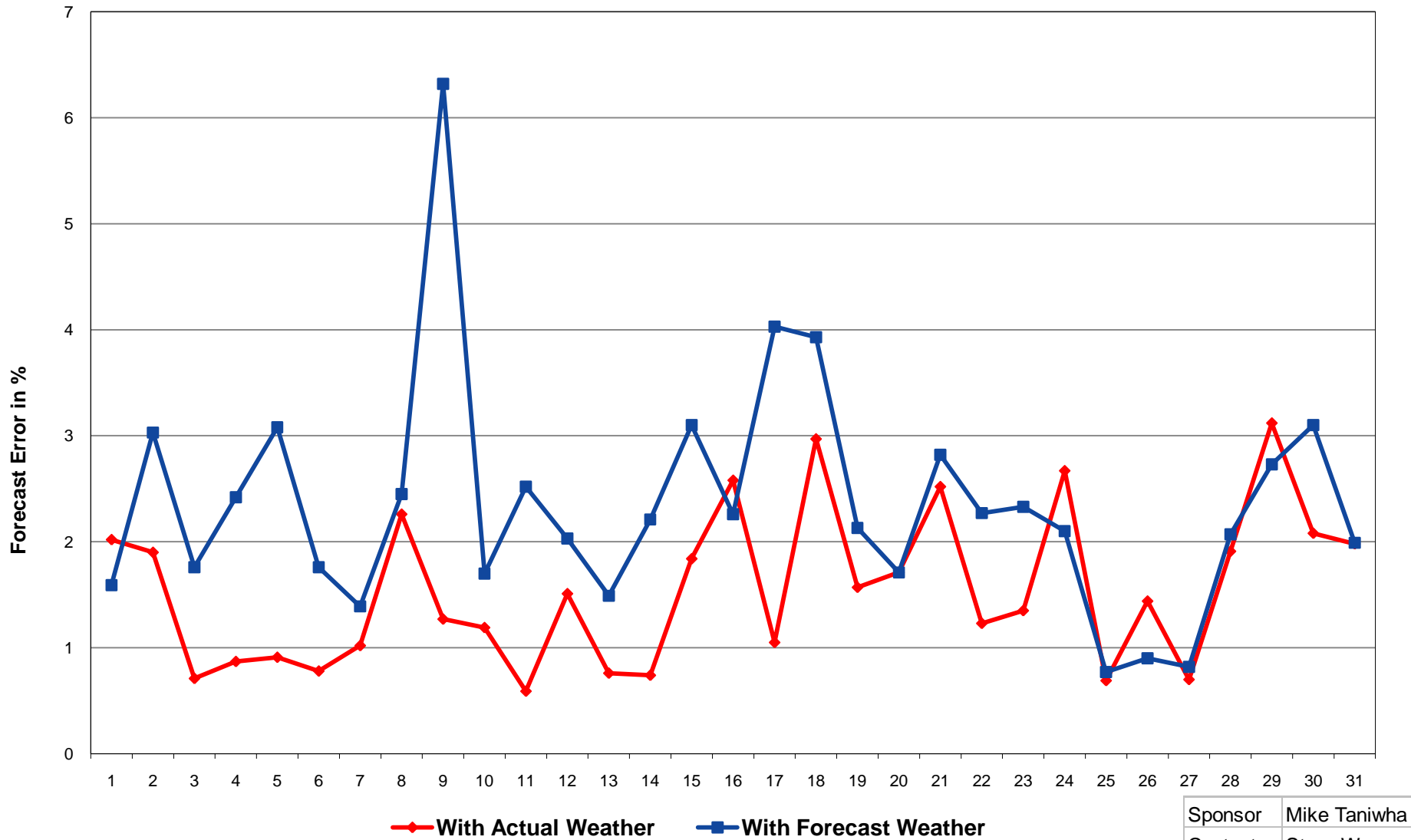
- Stakeholder Steering Committee has formed working groups to support their efforts
 - Modeling Working Group
 - Roll-up Working Group
 - Scenario Planning Working Group
 - Governance Task Force
- Several New England representatives have volunteered for the working groups
- Initial efforts are to establish ground rules and confirm objectives
- An EIPC representative will attend each working group meeting
- Information on the working groups, including high-level meeting notes, will be posted at www.eipconline.com

Highlights (cont'd.)

- August ended and Sept. started with another heat wave
 - Monthly Peak Load of 25,885 MW on August 31
 - All-time September Peak Load of 26,098 MW on Sept 2
- A large generation trip occurred on Thursday, Sept 2 @ 13:09 PM
 - LMP's were over \$1000 for 20 minutes
 - Experienced difficulty recovering from the large contingency and Area Control Error deviation given the high loads and insufficient system flexibility on that day
 - Interface with New York was already loaded and the ISO could not fully use the 'Shared Activation of Reserves' procedure
 - The ISO is conducting a detailed analysis of this event and will report back at a future NEPOOL RC/PC meeting

Daily Average Load Forecast Percent Error - August 2010

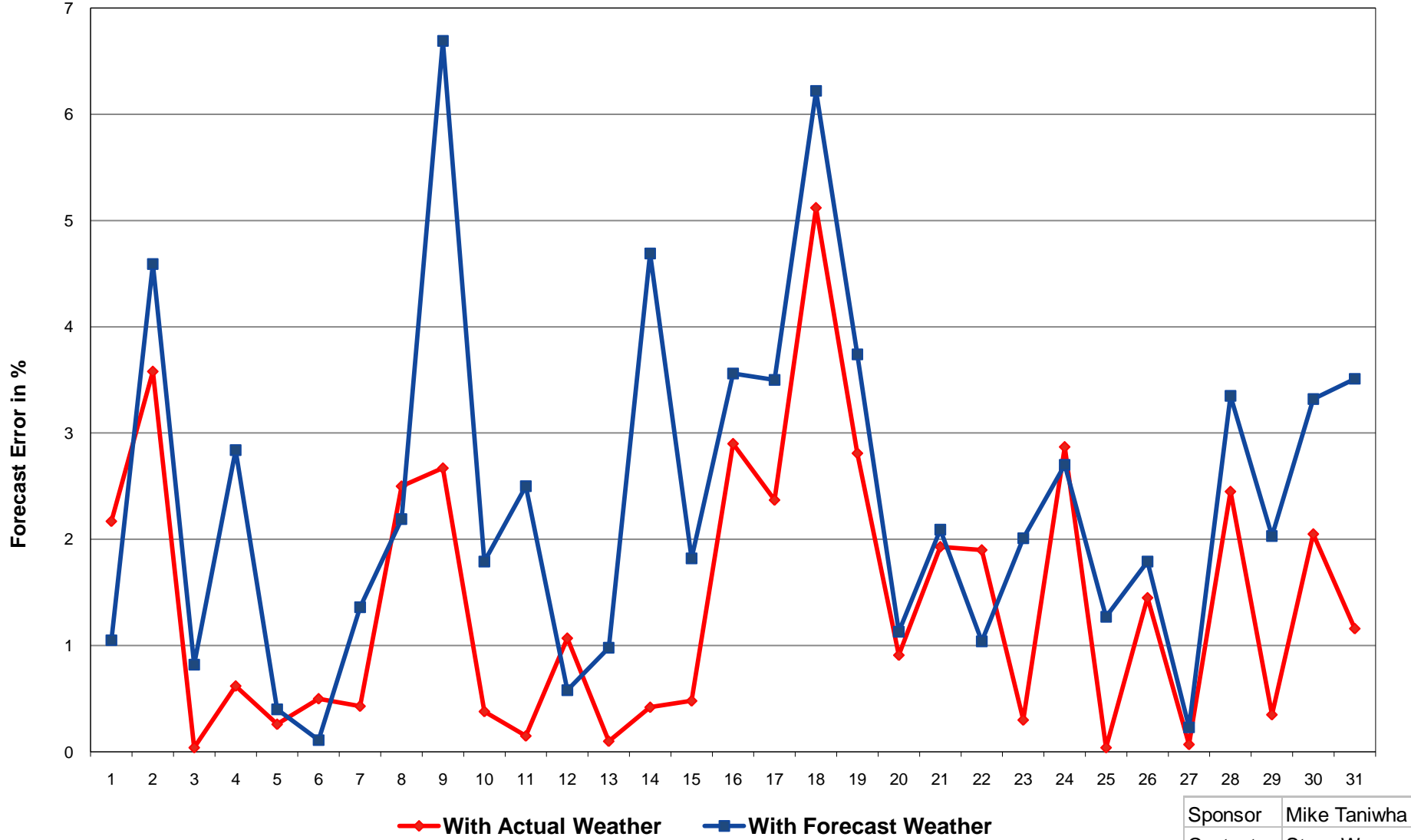
Monthly Average Error was 2.4% with Forecast Weather and 1.5% with Actual Weather



Sponsor	Mike Taniwha
Contact	Steve Weaver

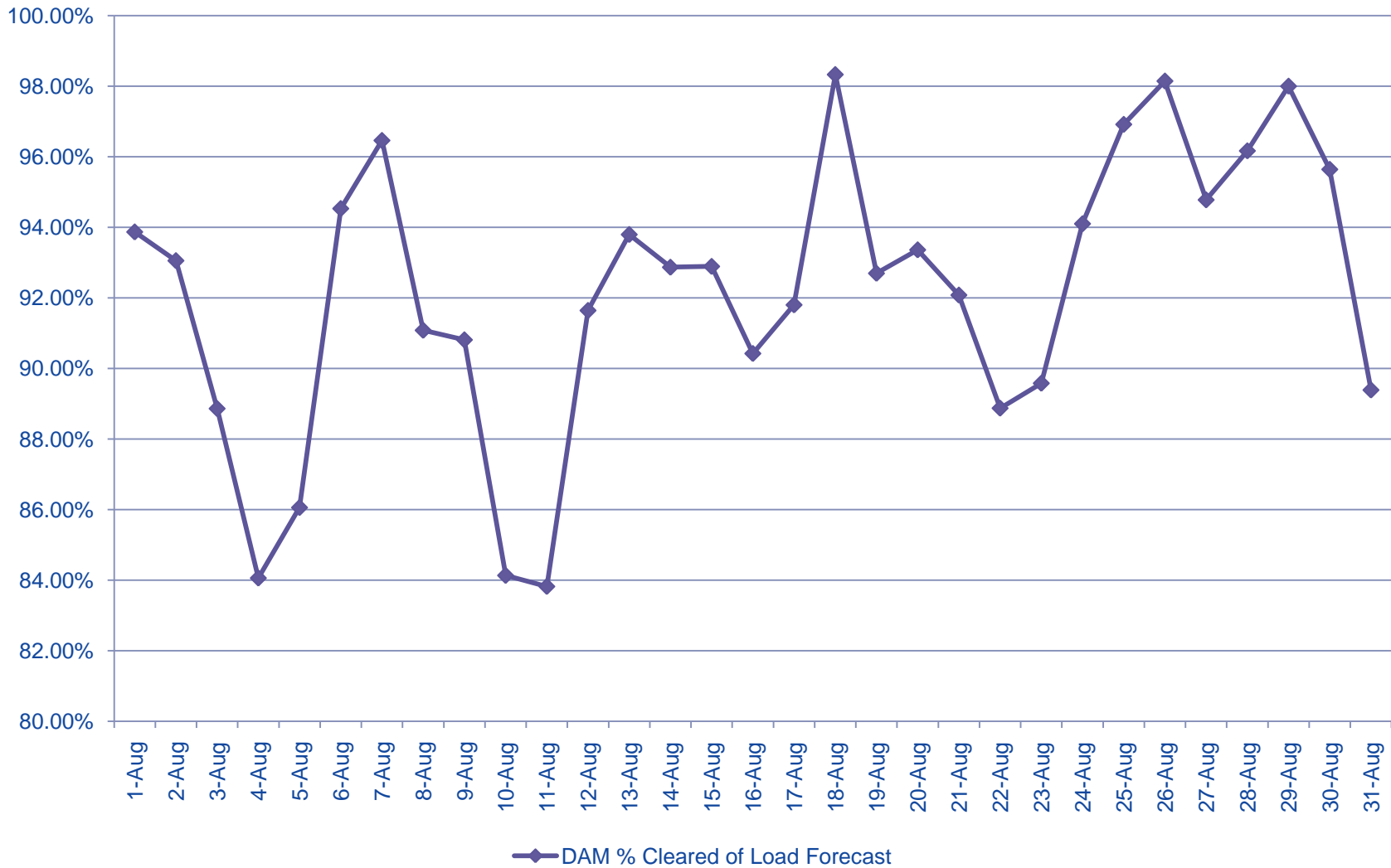
Load Forecast Percent Error at Hour of Daily Peak - August 2010

Monthly Average Error was 2.4% with Forecast Weather and 1.4% with Actual Weather



Sponsor	Mike Taniwha
Contact	Steve Weaver

August 2010 - Percent of Day Ahead Forecasted Peak that Cleared in the Day Ahead Market



System Operations

System Operations

<u>Weather Patterns:</u>	Boston	Temperature – Average Precipitation – Above Average	Hartford	Temperature – Much above Avg* Precipitation – Below Average * (6 degrees above normal)
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<u>Peak Load:</u>	25,885MW	August 31, 2010	17:00
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Minimum Generation Emergencies : Aug 19, Aug 24, Aug 29

M/LCC2:
08/09 - Due to a Capacity Deficiency, 08/31 – Due to a Capacity Deficiency

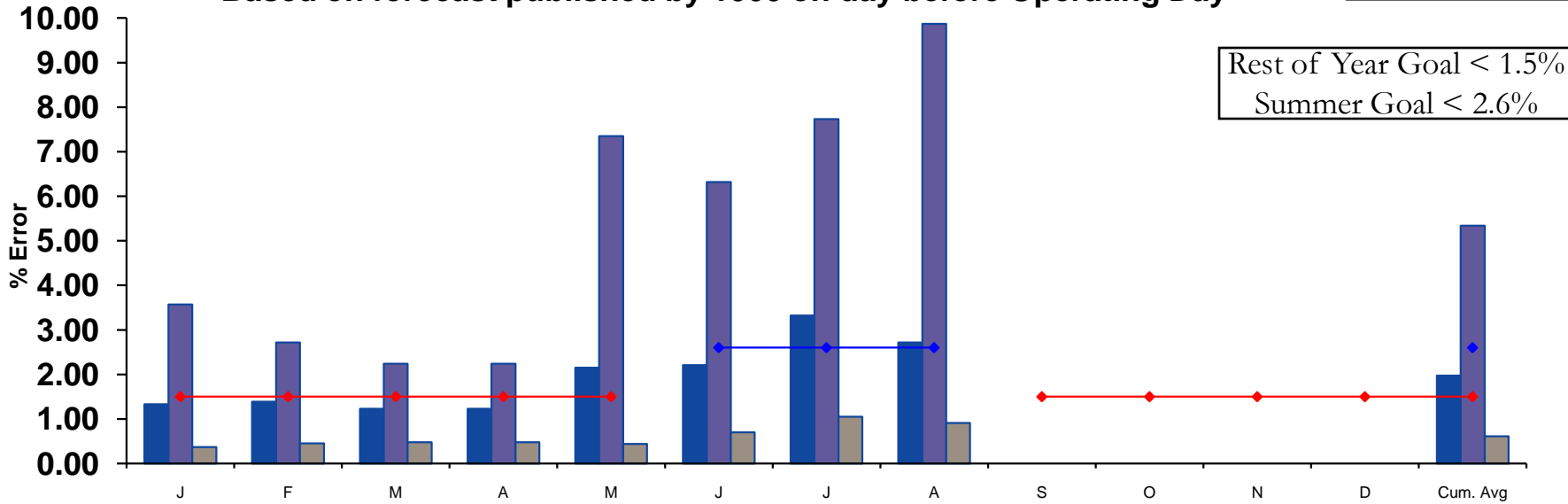
OP-4 :
08/09- Due to a Capacity Deficiency, Loads were 2200 MW over the forecasted curve on peak.
Implemented Action 1 only.

NPCC Shared Activation of Reserve Events:

August 05	ISO-NE	550MW
August 08	IESO	800MW
August 11	PJM	1296MW

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



■ 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	2.15	2.21	3.32	2.72					1.97	Mo Avg
Day Max	3.57	2.72	2.62	2.24	7.35	6.32	7.73	9.87					5.34	Day Max
Day Min	0.37	0.45	0.43	0.48	0.44	0.70	1.05	0.91					0.61	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.													1.49	
Summer Average													2.75	

Contact: Steve Weaver

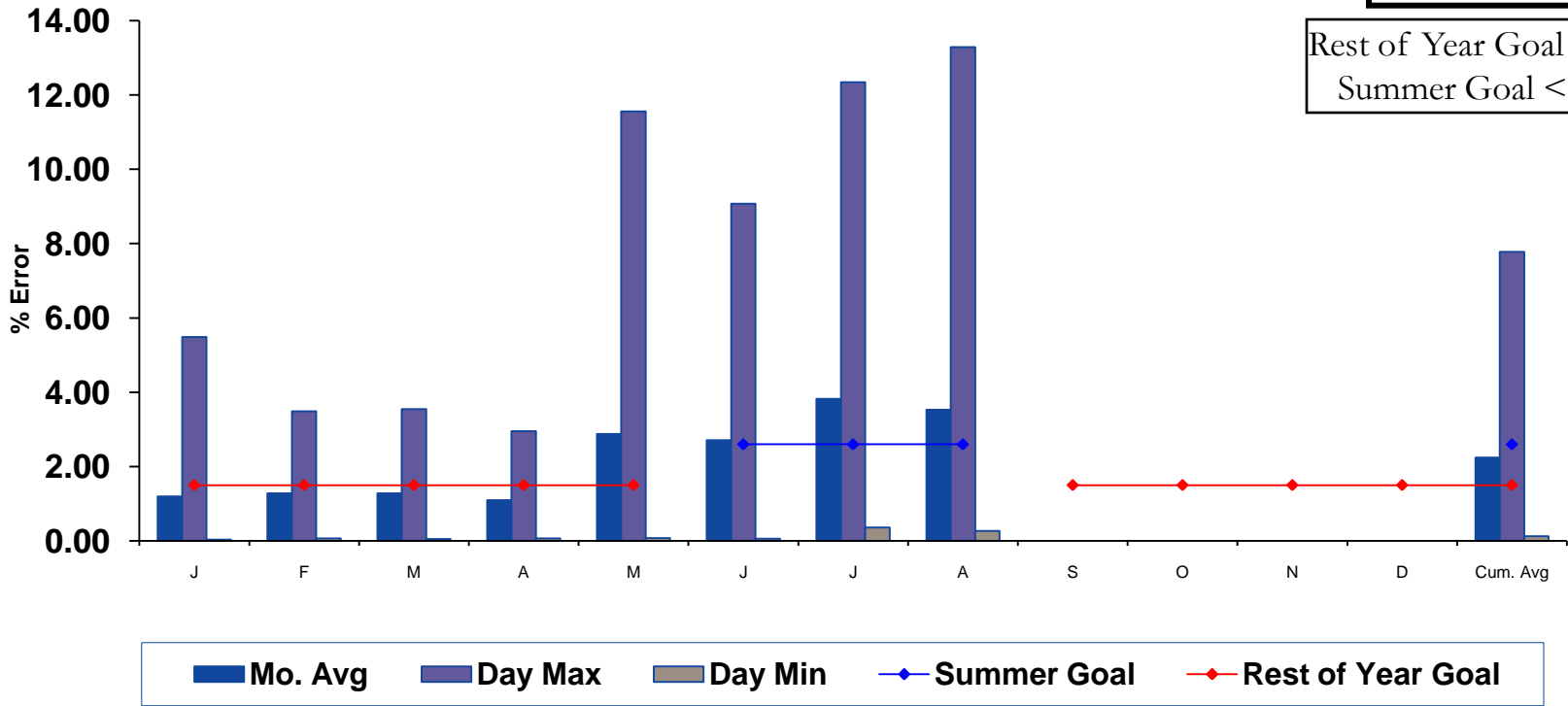
Summer Goal = 2.6% Rest of Year(ROY) Goal = 1.5%
 Summer consists of June, July and August-

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

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	1.20	1.28	1.28	1.10	2.88	2.71	3.82	3.53					2.24
Day Max	5.49	3.49	3.55	2.95	11.56	9.07	12.34	13.29					7.78
Day Min	0.03	0.07	0.05	0.07	0.08	0.06	0.36	0.27					0.13
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													1.55
Summer Average													3.35

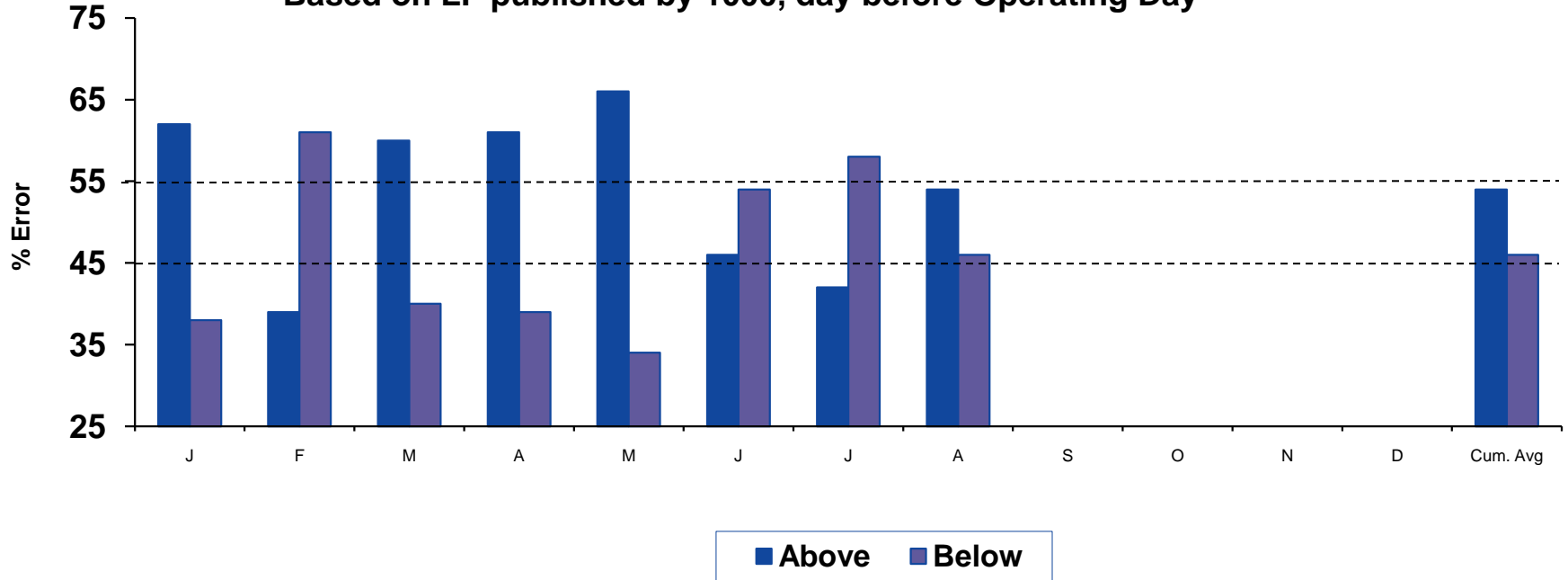
Contact: Steve Weaver

Summer Goal = 2.6%	Rest of Year(ROY) Goal = 1.5%
Summer consists of June, July and August.	

2010 System Operations - Load Forecast Accuracy

Target = 50%
Plus/Minus 5%

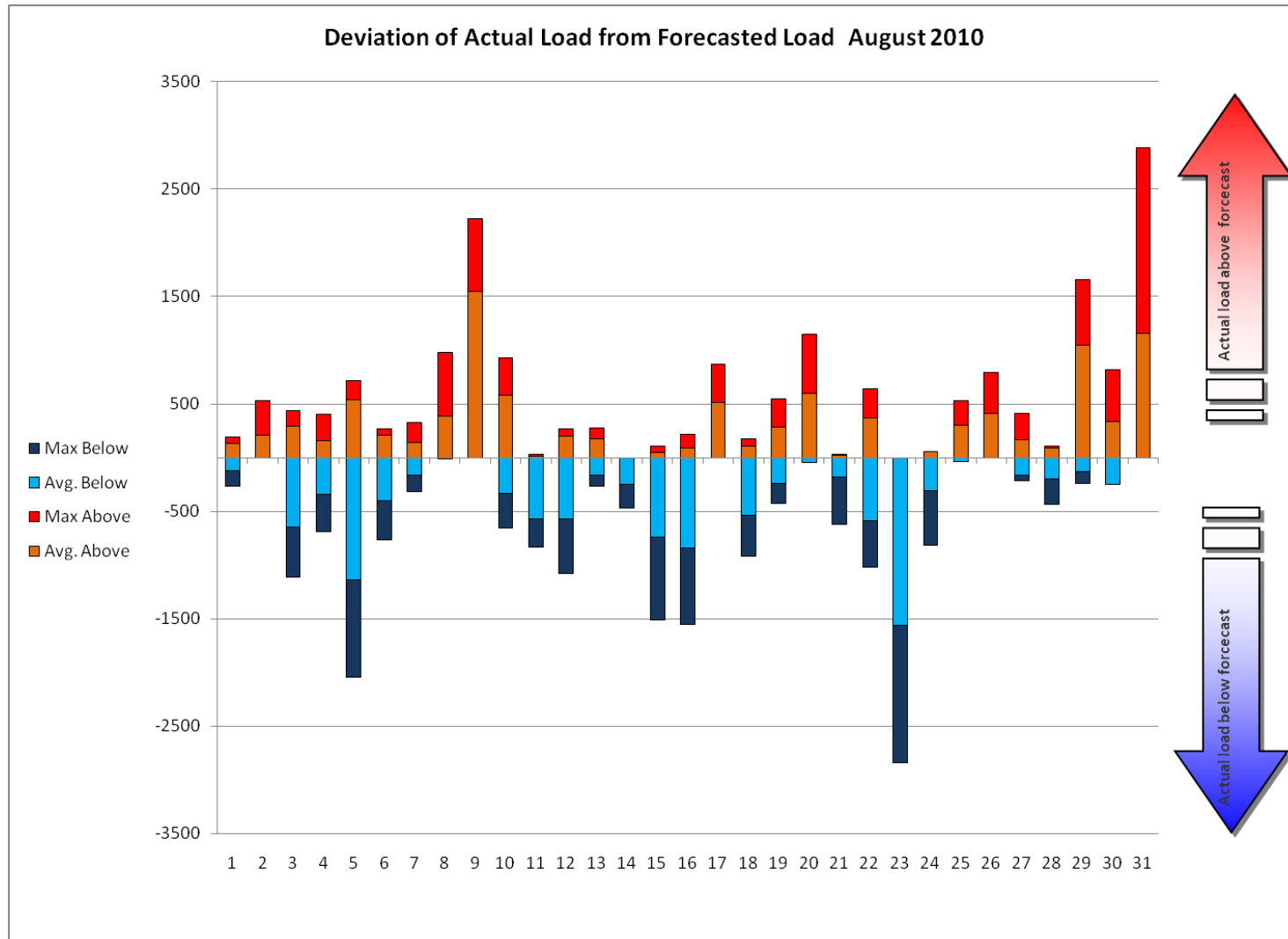
Percent of Hours Actual Load Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	62.0	39.0	60.0	61.0	66.0	46.0	42.0	54.0					54.0
Below %	38.0	61.0	40.0	39.0	34.0	54.0	58.0	46.0					46.0
Avg Above	178.0	106.0	144.0	147.0	258.0	198	327	329.0					171.0
Avg Below	-112.0	-181.0	-118.0	-103.0	-155.0	-314	-533	-340.0					-189.0
Avg All	74.0	-69.0	38.0	45.0	107.0	-91.0	-166.0	8.0					-7.0

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

2010 System Operations - Load Forecast Accuracy

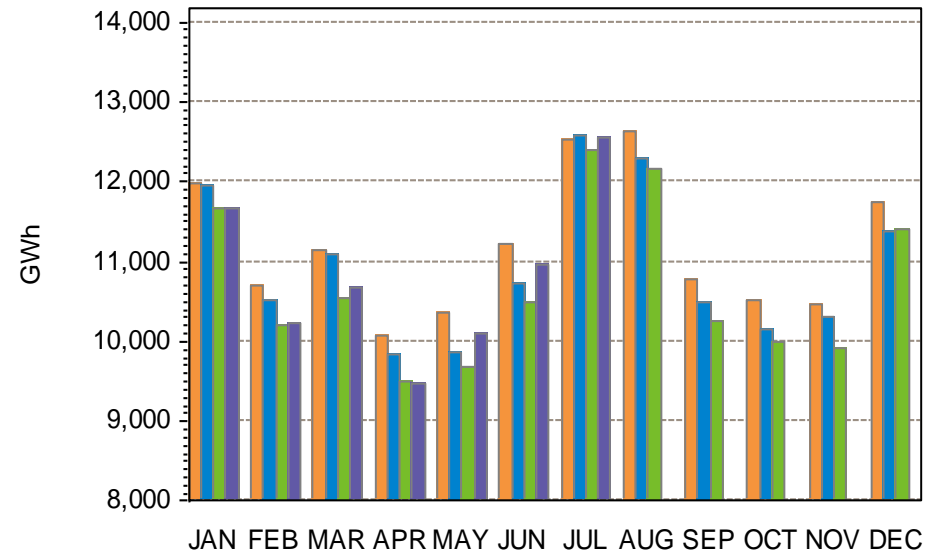
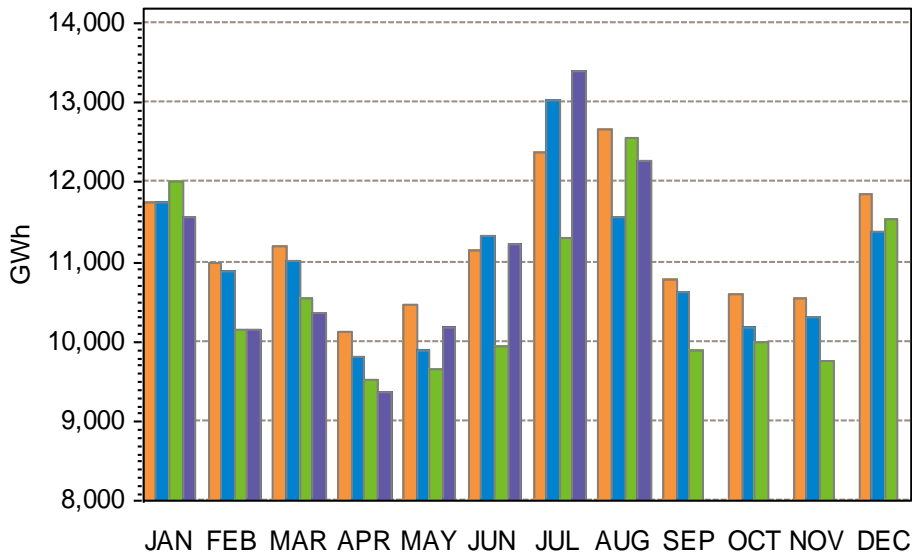


Sponsor	Mike Taniwha
Contact	Steve Weaver

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

Net Energy for Load (NEL)

Weather Normalized NEL



■ 2007 ■ 2008 ■ 2009 ■ 2010

Ann Tot (TWh): 134E3 132E3 127E3 88473

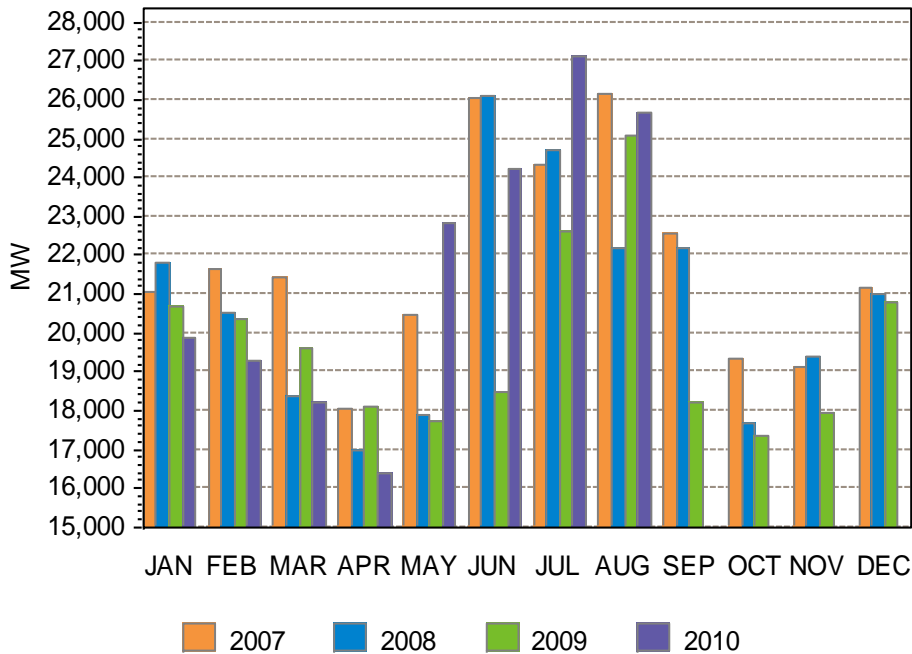
■ 2007 ■ 2008 ■ 2009 ■ 2010

Ann Tot (TWh): 134.2 131.2 128.3 75.7

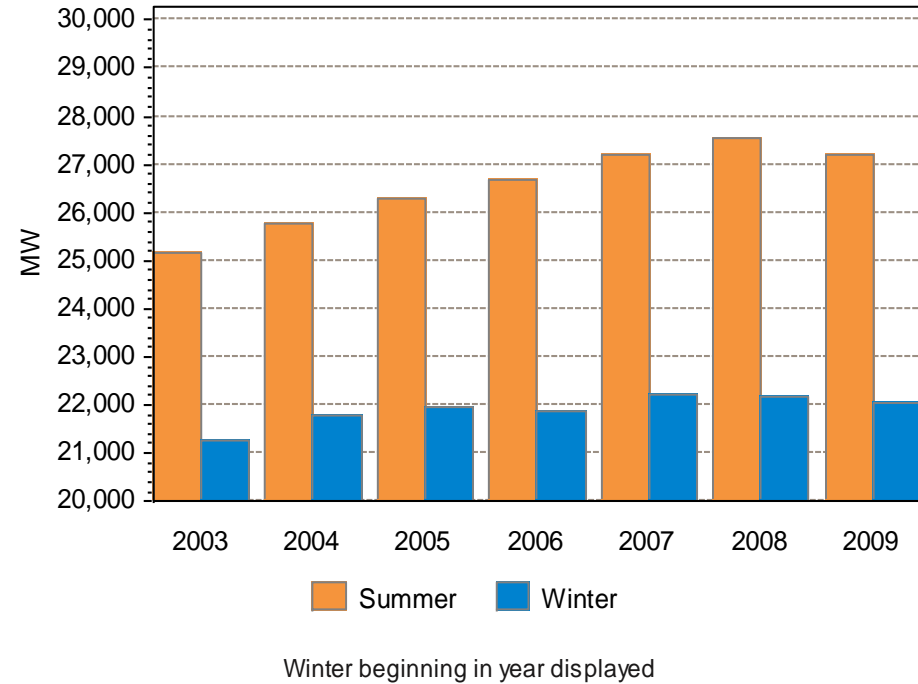
NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as:
 Generation – pumping load + net interchange.
 Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load

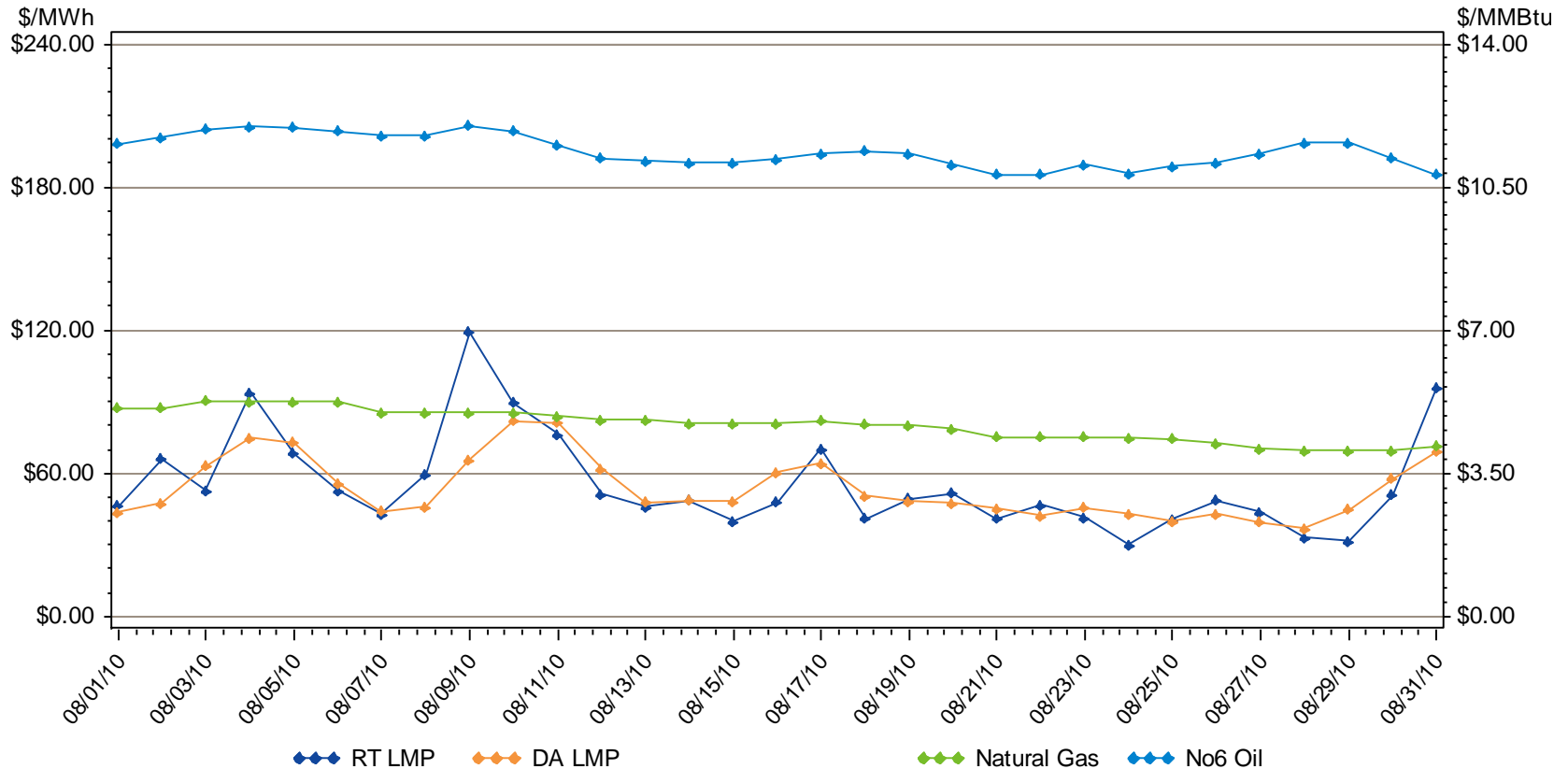


Weather Normalized Seasonal Peaks



Market Operations

DA and RT ISO-NE Hub Prices and Input Fuel Prices: August 1-31, 2010



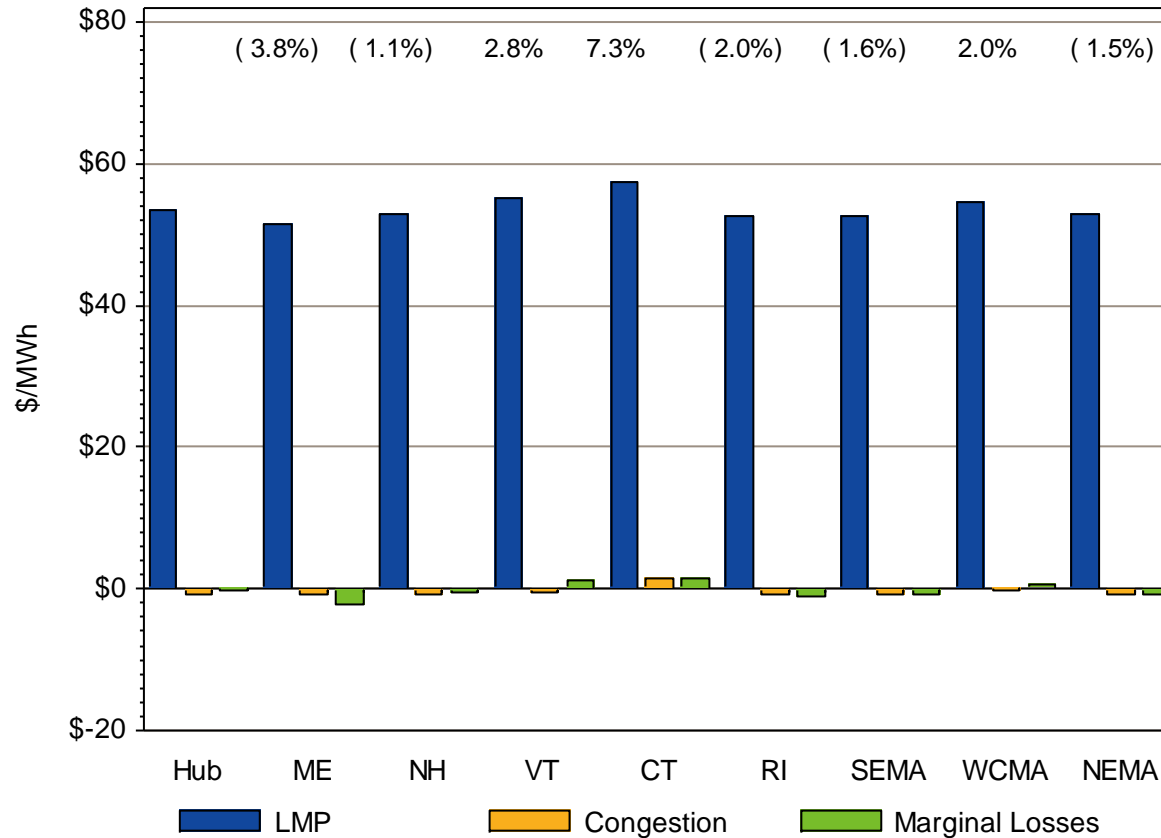
Underlying natural gas data furnished by:



Average price difference over this period (DA-RT): \$-1.85
 Average price difference over this period ABS(DA-RT): \$9.04
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%

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

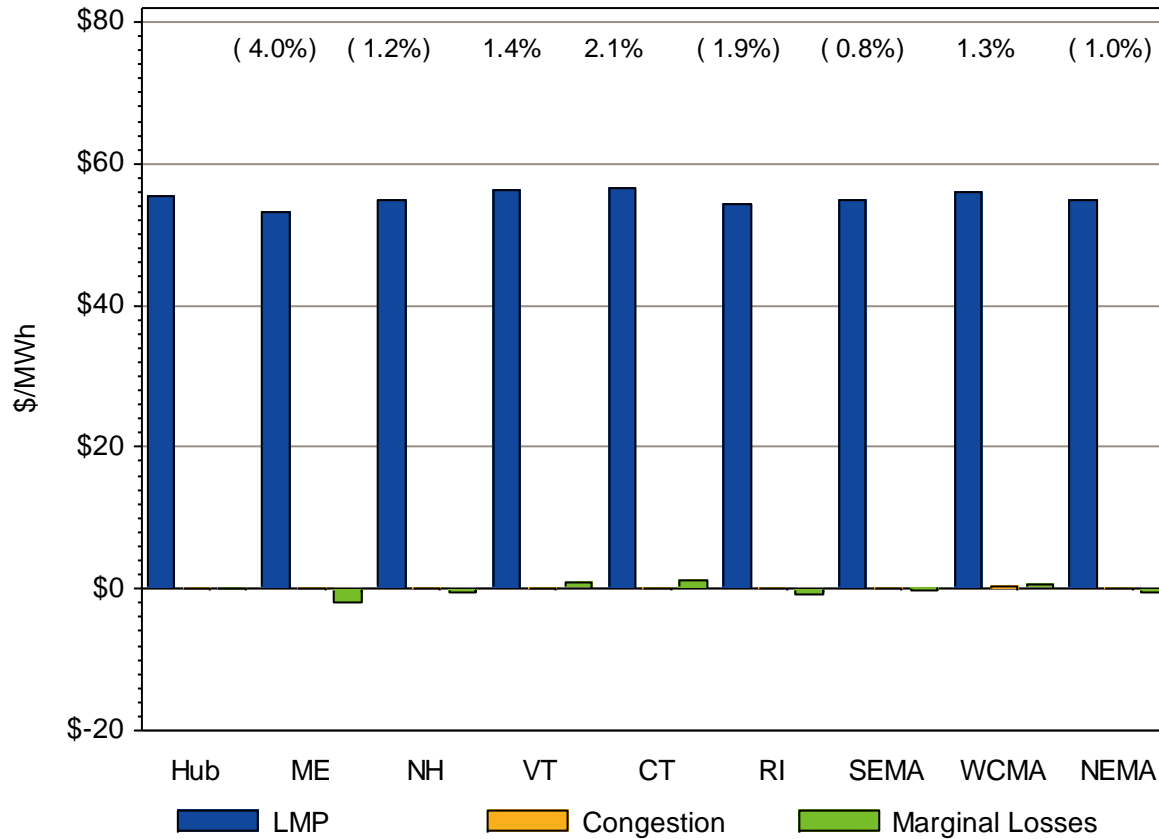
DA LMPs Average by Zone & Hub – August 2010



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

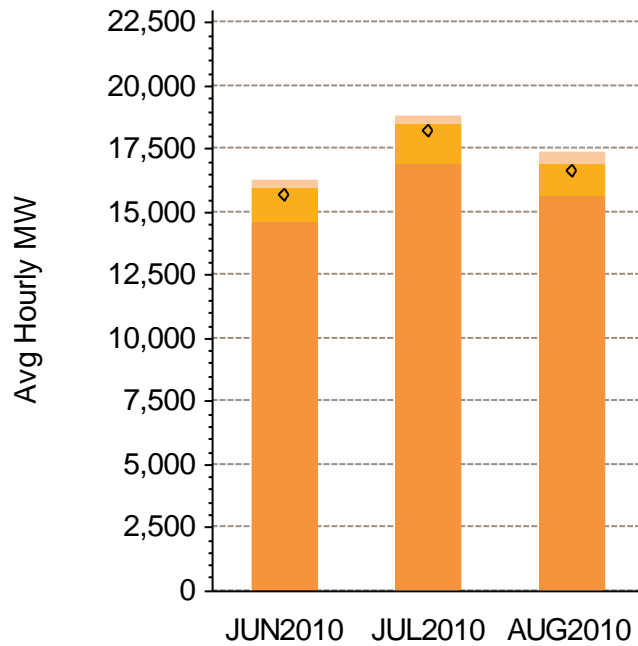
RI - Rhode Island
 SEMA - Southeastern Massachusetts
 WCMA - Western/Central Massachusetts
 NEMA - Northeastern Massachusetts

RT LMPs Average by Zone & Hub – August 2010



Components of Cleared DA Supply and Demand – Last Three Months

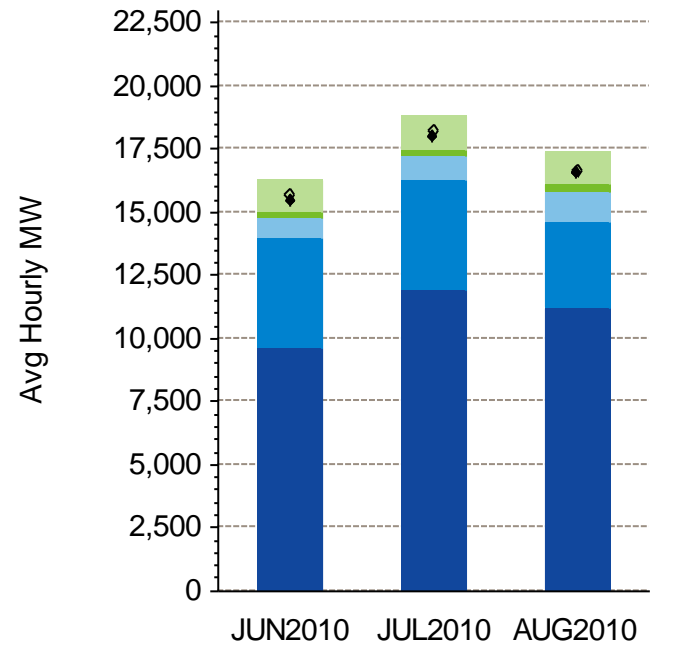
Supply



■ Gen ■ Incs
■ Imports ◆ DA Fcst Load

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

Demand

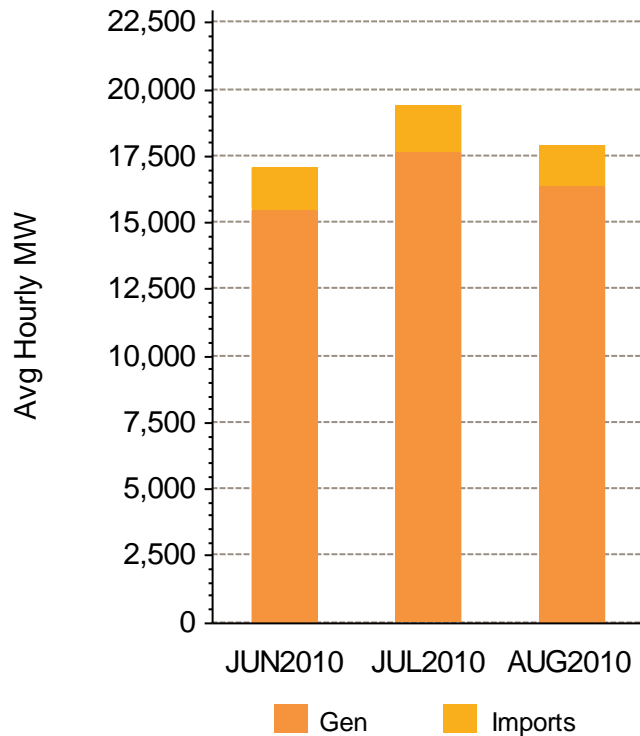


■ Fixed Dem ■ PrSens Dem ■ Decs
■ Losses ■ Exports ◆ Act Load

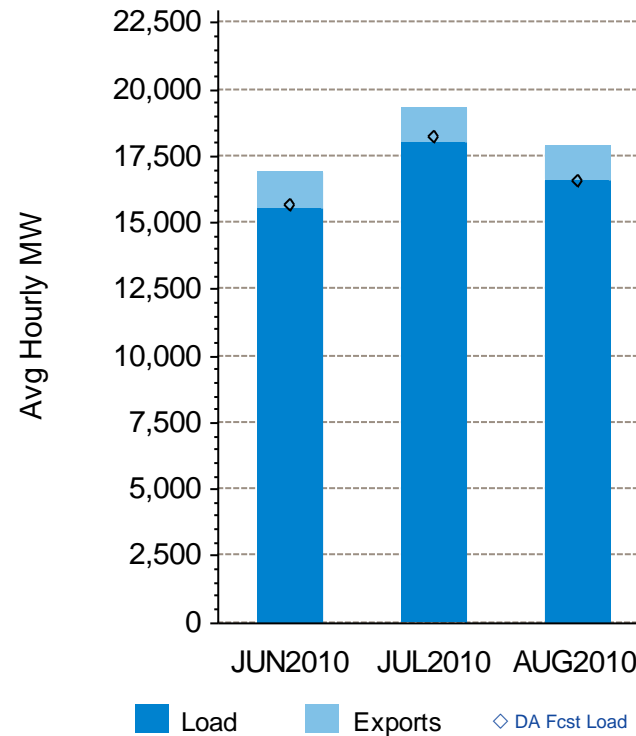
Fixed Dem – Fixed Demand
 PrSens Dem – Price Sensitive Demand
 Decs – Decrement Bids
 Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months

Supply

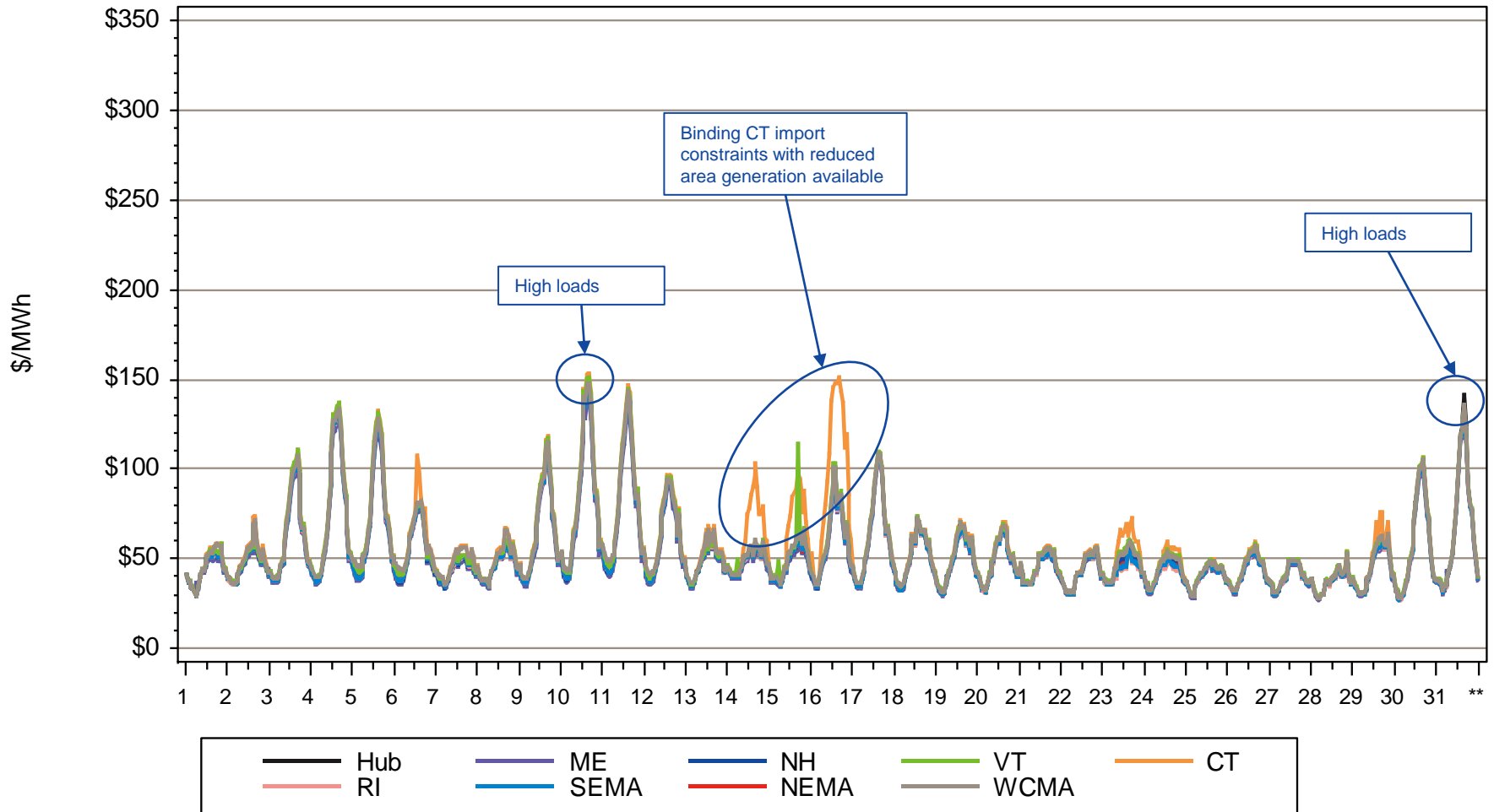


Demand



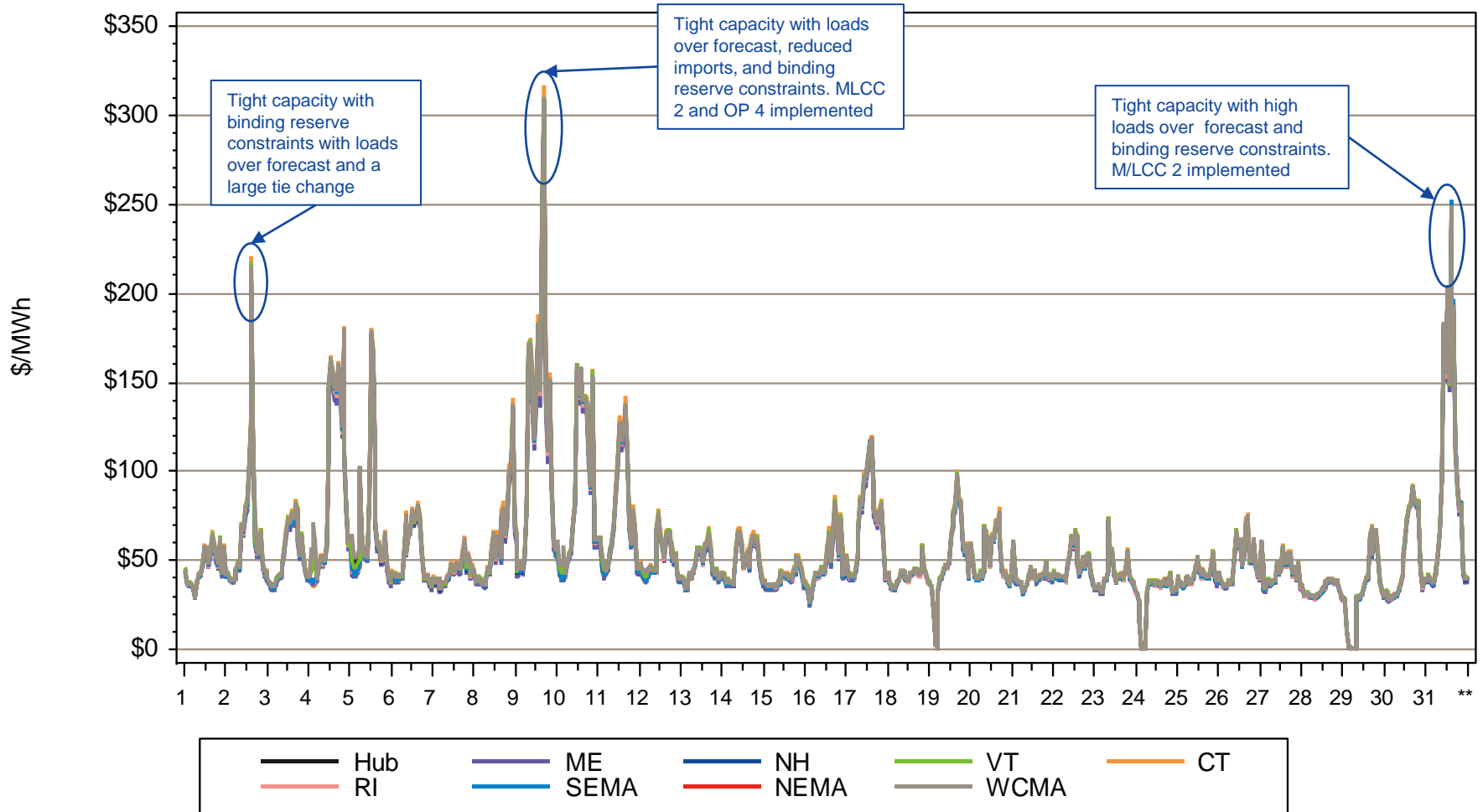
Hourly DA LMPs, August 1-31, 2010

Hourly Day-Ahead LMPs

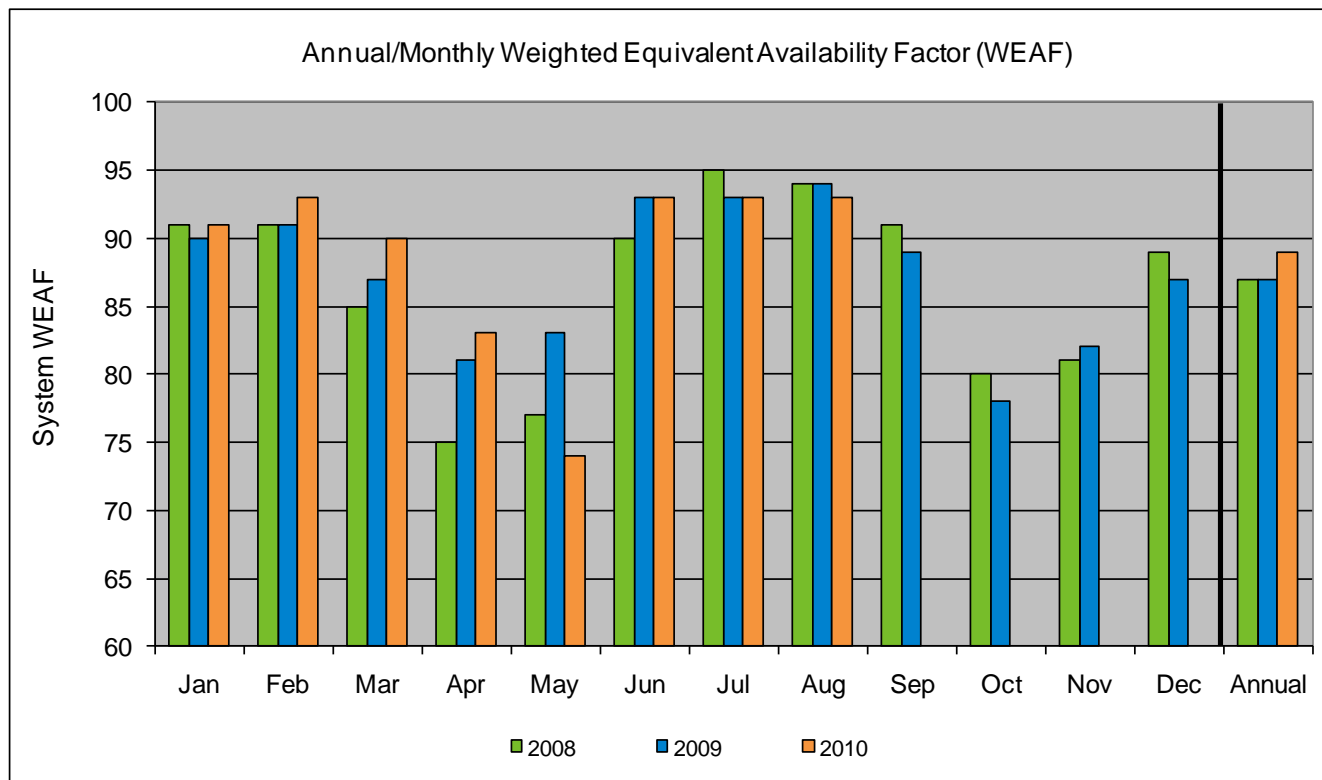


Hourly RT LMPs, August 1-31, 2010

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	74	93	93	93					89	2010
												87	2009
												87	2008
												90	2007

Back-up Detail

Load Response

Net Capacity Supply Obligation (CSO) MW by Demand Resource Type for August 2010

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	161.35	17.33	19.83	0.00	198.51
NH	28.68	21.57	32.42	0.00	82.67
VT	23.71	12.97	41.74	0.00	78.42
CT	223.04	249.85	56.81	108.53	638.24
RI	27.26	38.98	34.46	0.00	100.71
SEMA	42.83	35.64	62.10	0.00	140.57
WCMA	81.28	55.21	56.60	9.48	202.55
NEMA	69.17	61.47	97.67	0.00	228.31
Total	669.41	522.39	406.24	118.01	1,716.05

* Real-Time Demand Response

** Real-Time Demand Response with Emergency Generation

NOTE: Net CSO values include T&D loss factor (8%) and reserve margin gross-up (14.3%)

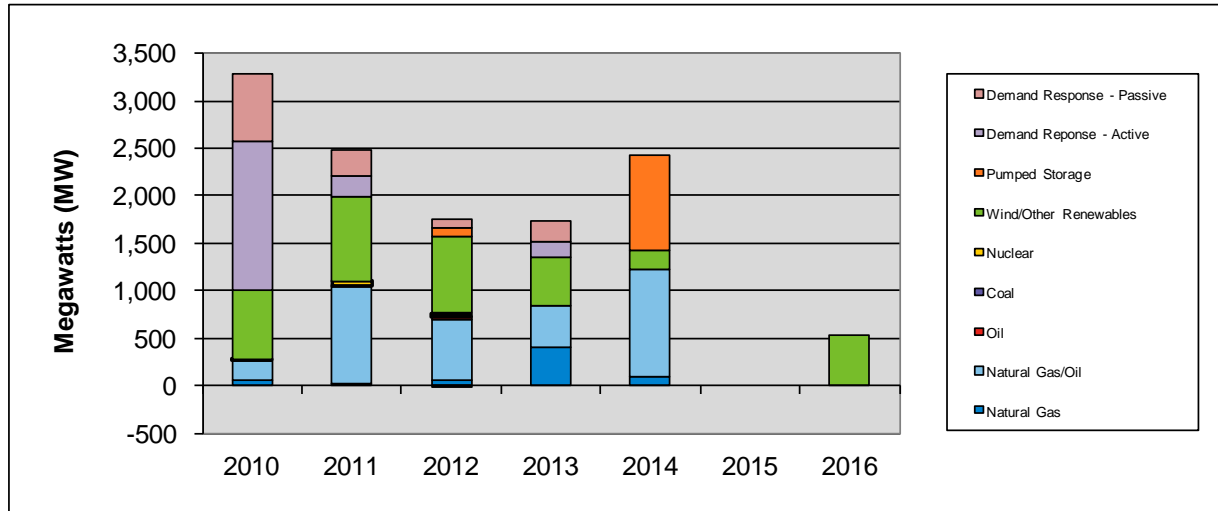
New Generation

New Generation Update

- No new generation projects have applied for interconnection study since the last update
- One project went commercial and two projects withdrew from the queue, resulting in a net decrease in new generation projects of 93 MW
- In total, 83 generation projects are currently being tracked by the ISO, totaling approximately 8,700 MW*

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

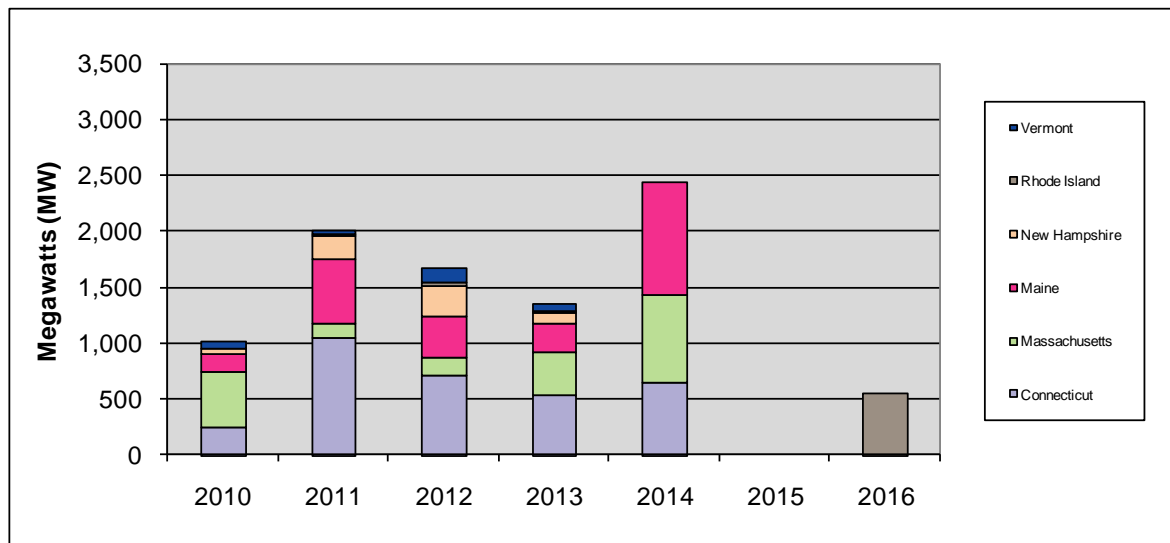
Actual and Projected Annual Capacity Additions By Supply Fuel Type and Demand Resource Type



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	225	0	0	0	1,298	10.6
Demand Response - Active	1,579	221	-6	169	0	0	0	1,963	16.0
Pumped Storage	0	0	86	0	1,000	0	0	1,086	8.9
Wind & Other Renewables	718	888	813	494	188	0	536	3,637	29.7
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	218	1,018	640	444	1,131	0	0	3,451	28.2
Natural Gas	54	31	60	411	107	0	0	663	5.4
Totals	3,286	2,494	1,754	1,743	2,426	0	536	12,239	100.0

- 2010 values include the 293 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	64	0	0	0	279	3.1
Rhode Island	0	12	34	29	0	0	536	611	6.8
New Hampshire	51	218	267	94	0	0	0	630	7.0
Maine	162	569	377	251	1,000	0	0	2,359	26.3
Massachusetts	492	128	158	380	791	0	0	1,949	21.7
Connecticut	241	1,043	700	531	635	0	0	3,150	35.1
Totals	1,007	1,995	1,665	1,349	2,426	0	536	8,978	100.0

- 2010 values include the 293 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	14	462	1	38	13	424
Coal	1	36	0	0	1	36
Hydro	7	1,215	0	24	7	1,191
Landfill Gas	1	34	0	0	1	34
Natural Gas	9	632	0	0	9	632
Natural Gas/Oil	13	3,233	3	943	10	2,290
Nuclear Uprates	2	45	0	0	2	45
Oil	2	43	0	0	2	43
Solar	0	0	0	0	0	0
Wind	34	2,985	4	180	30	2,805
Total	83	8,685	8	1,185	75	7,500

- 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	19	586	1	38	18	548
Intermediate	16	3,256	1	644	15	2,612
Peaker	14	1,858	2	323	12	1,535
Wind Turbine	34	2,985	4	180	30	2,805
Total	83	8,685	8	1,185	75	7,500

- 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	14	462	14	462	0	0	0	0	0	0
Coal	1	36	1	36	0	0	0	0	0	0
Hydro	7	1,215	0	0	4	29	3	1,186	0	0
Landfill Gas	1	34	1	34	0	0	0	0	0	0
Natural Gas	9	632	1	9	4	590	4	33	0	0
Natural Gas/Oil	13	3,233	0	0	8	2,637	5	596	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	0	0	0	0	0	0	0	0	0	0
Wind	34	2,985	0	0	0	0	0	0	34	2,985
Total	83	8,685	19	586	16	3,256	14	1,858	34	2,985

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?

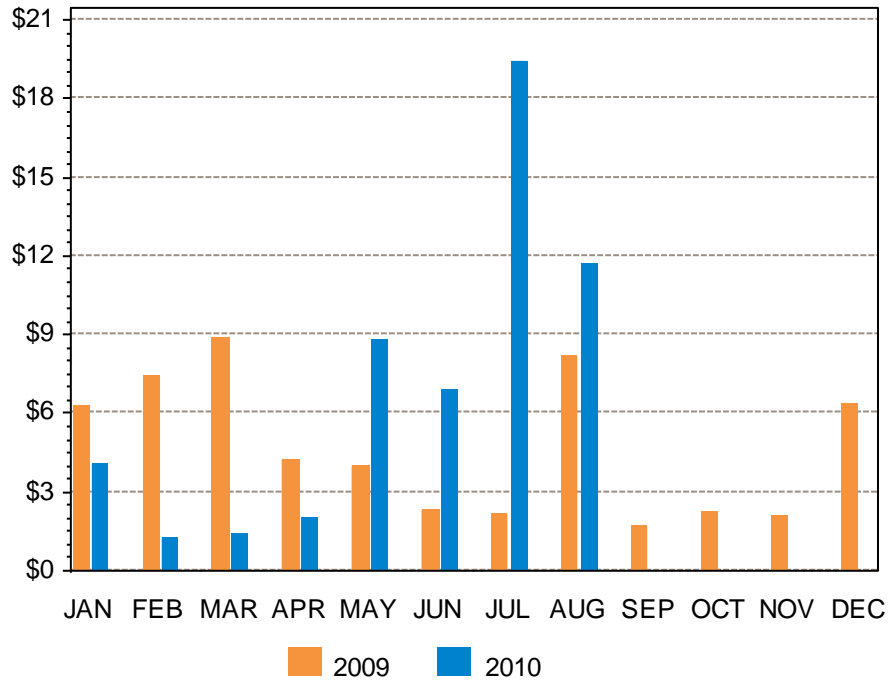
- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit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

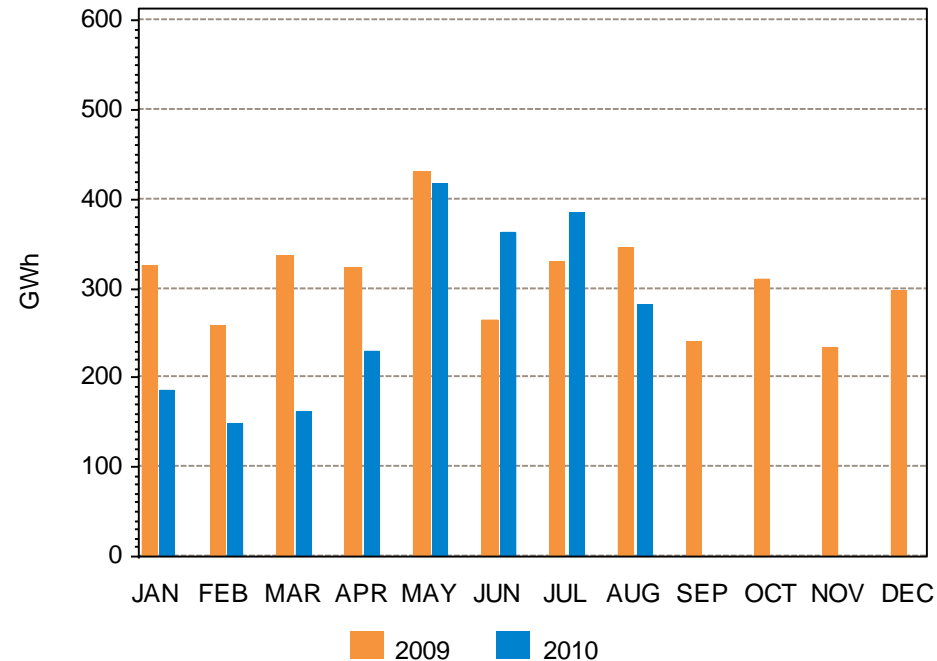
Voltage NCPC Payments	Reliability costs paid to resources operated by the ISO-NE to provide voltage control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (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

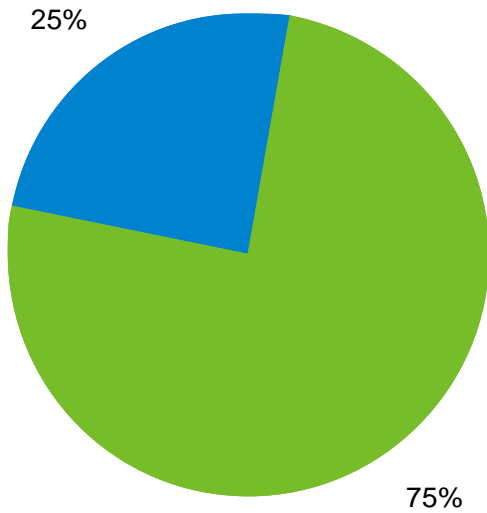


Note:

- 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.

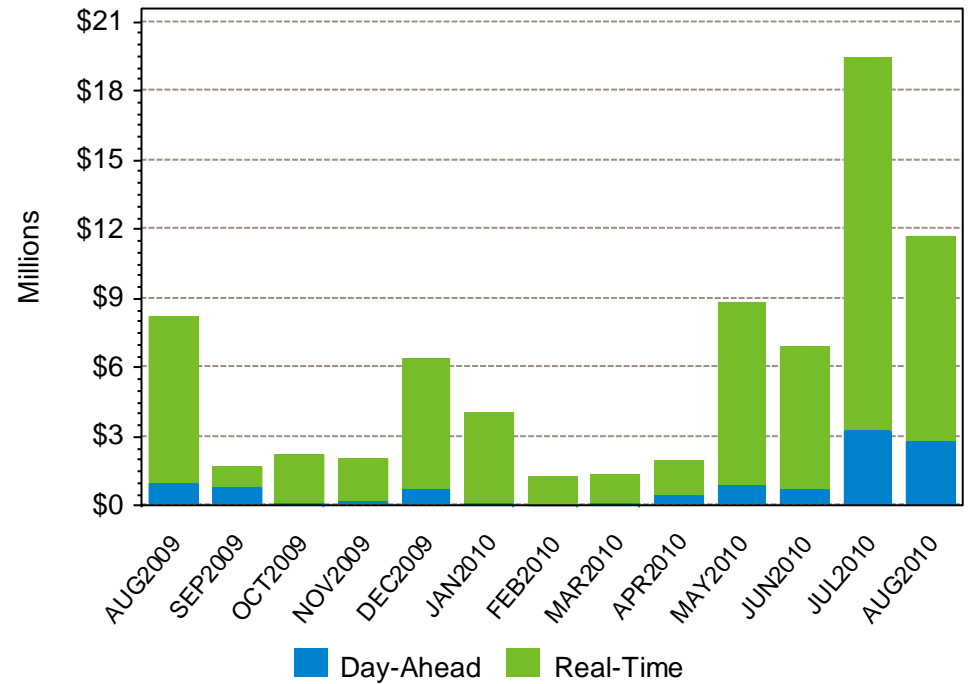
DA and RT NCPC Payments

AUG-10 Total = 11.66 M



■ Day-Ahead ■ Real-Time

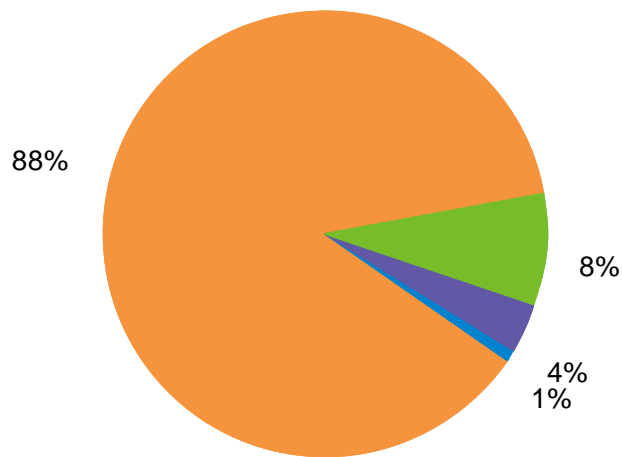
Last 13 Months



■ Day-Ahead ■ Real-Time

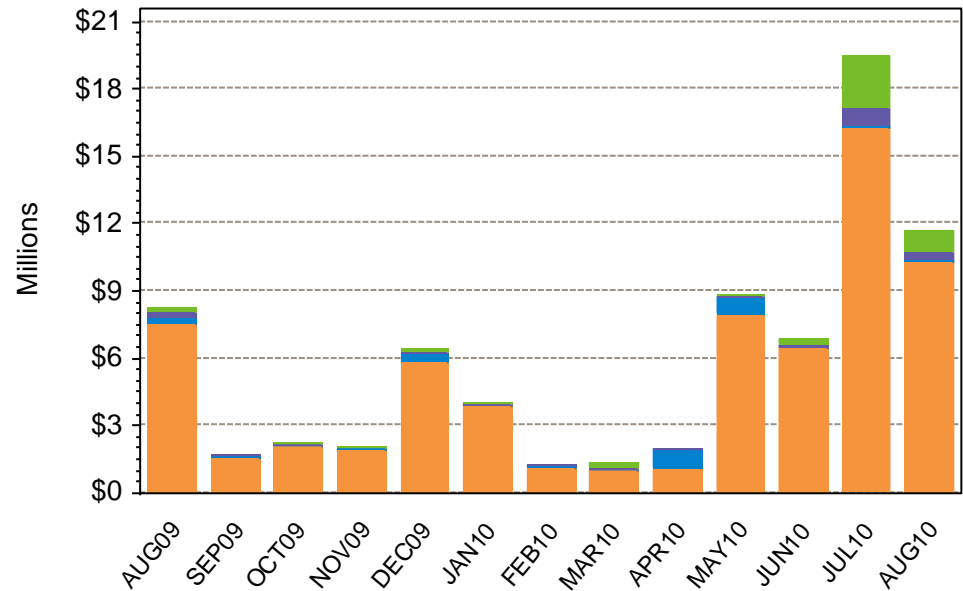
NCPC Payments by Type

AUG-10 Total = 11.66 M



■ 1st C ■ 2nd C
■ Distrib ■ Voltage

Last 13 Months

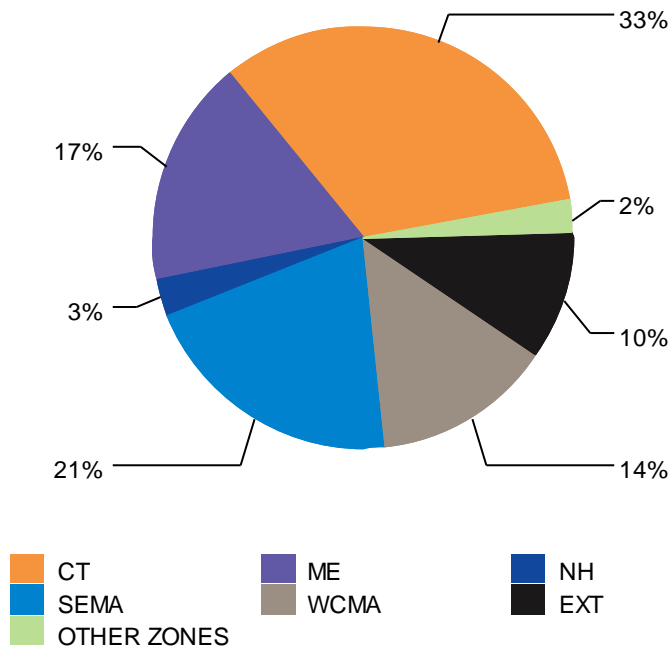


■ 1st C ■ 2nd C
■ Voltage ■ Distrib

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

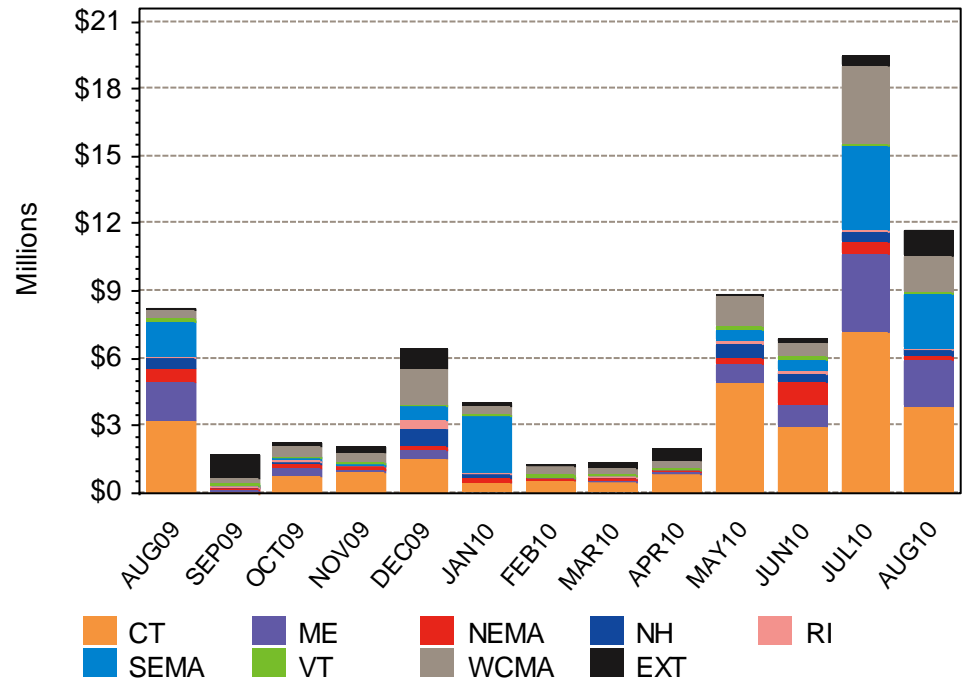
NCPC Payments by Location

AUG-10 Total = 11.66 M



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

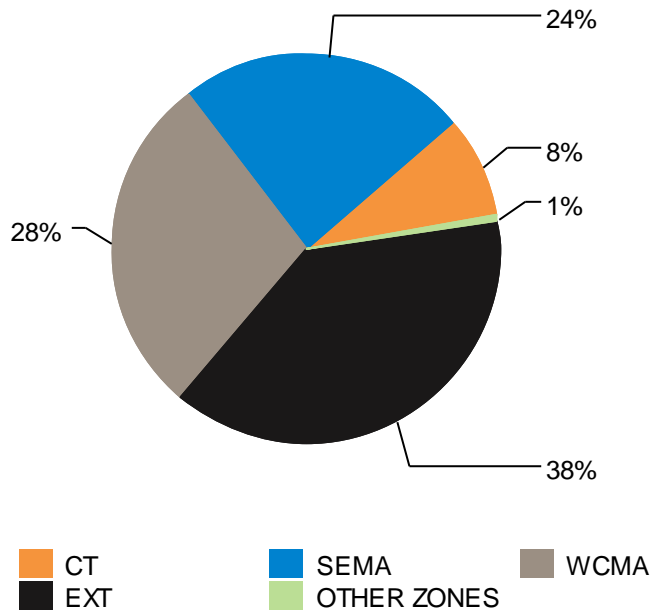
Last 13 Months



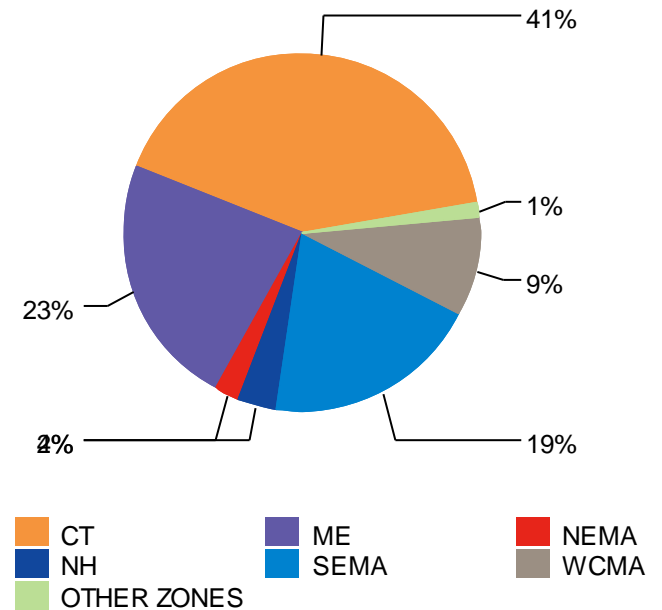
VT – Vermont Region
 SEMA – Southeast Massachusetts Region
 WCMA – Western/Central Massachusetts Region
 NEMA – Northeast Massachusetts Region
 EXT – External Locations

DA and RT NCPC Payments by Location

AUG-10 Day-Ahead Total = \$2.86 M

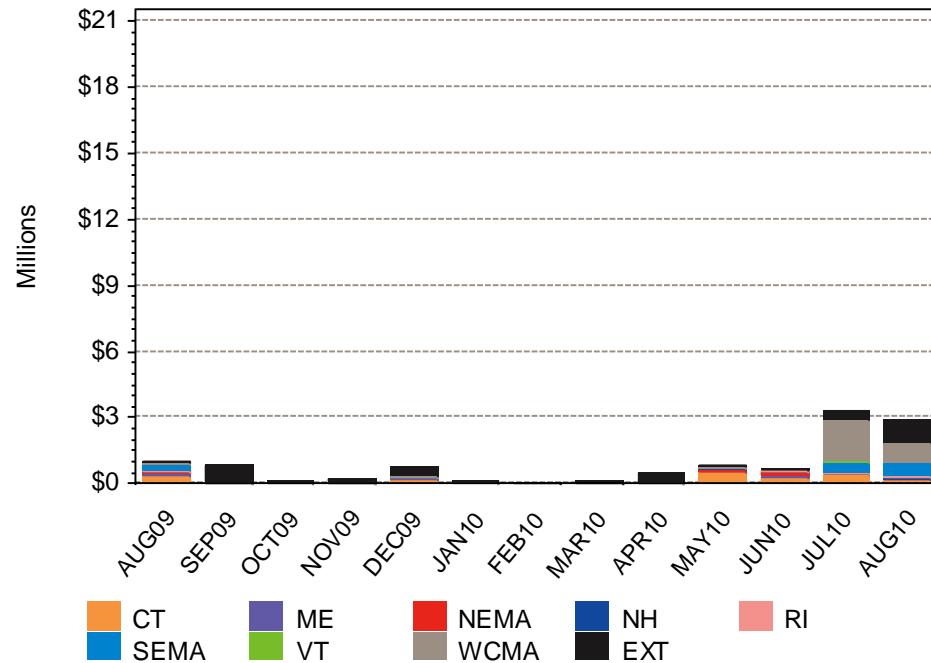


AUG-10 Real-Time Total = \$8.80 M

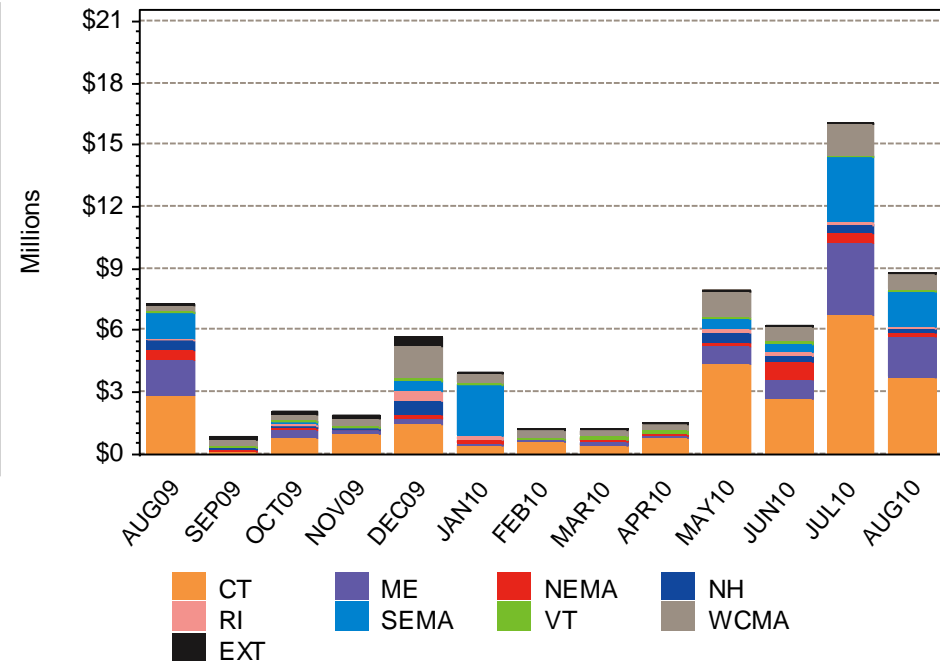


DA and RT NCPC Payments by Location, Last 13 Months

Day-Ahead, Last 13 Months

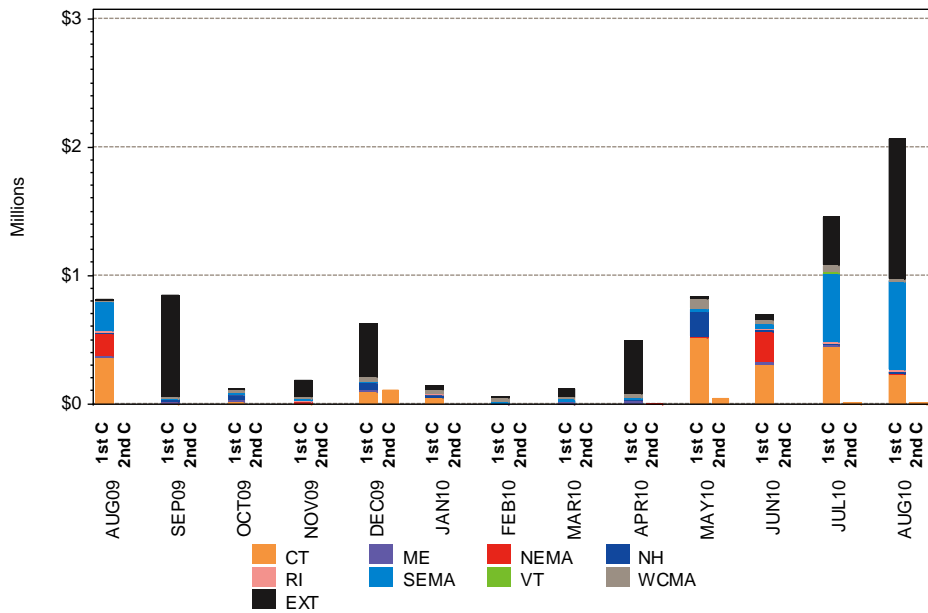


Real-Time, Last 13 Months

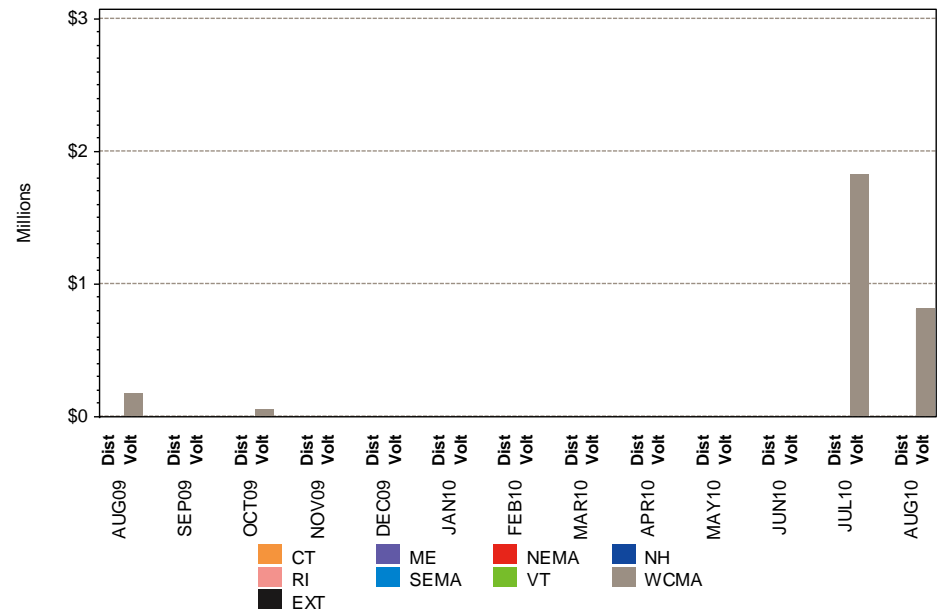


DA NCPC Payments by Type and Location

First and Second Contingency Payments

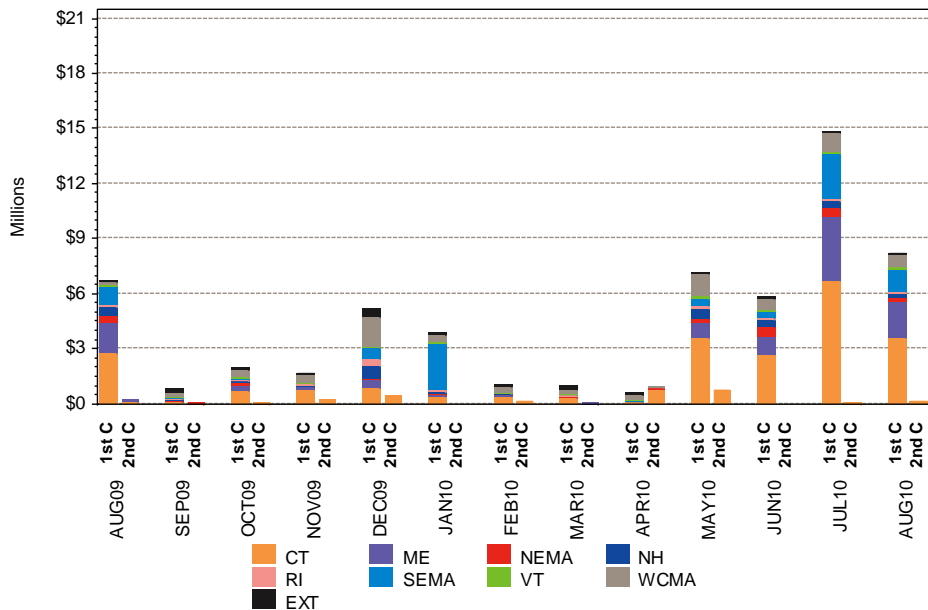


Voltage and Distribution Payments

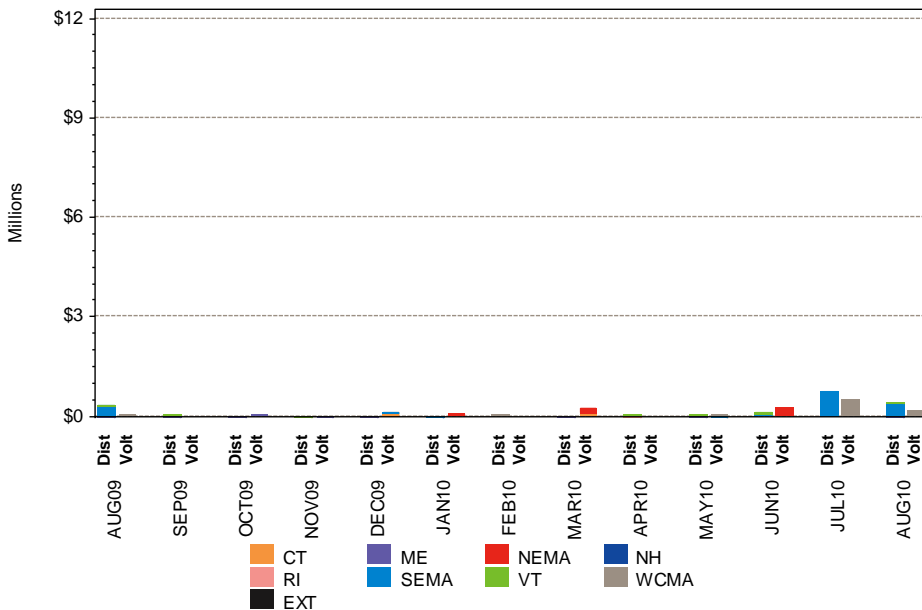


RT NCPC Payments by Type and Location

First and Second Contingency Payments

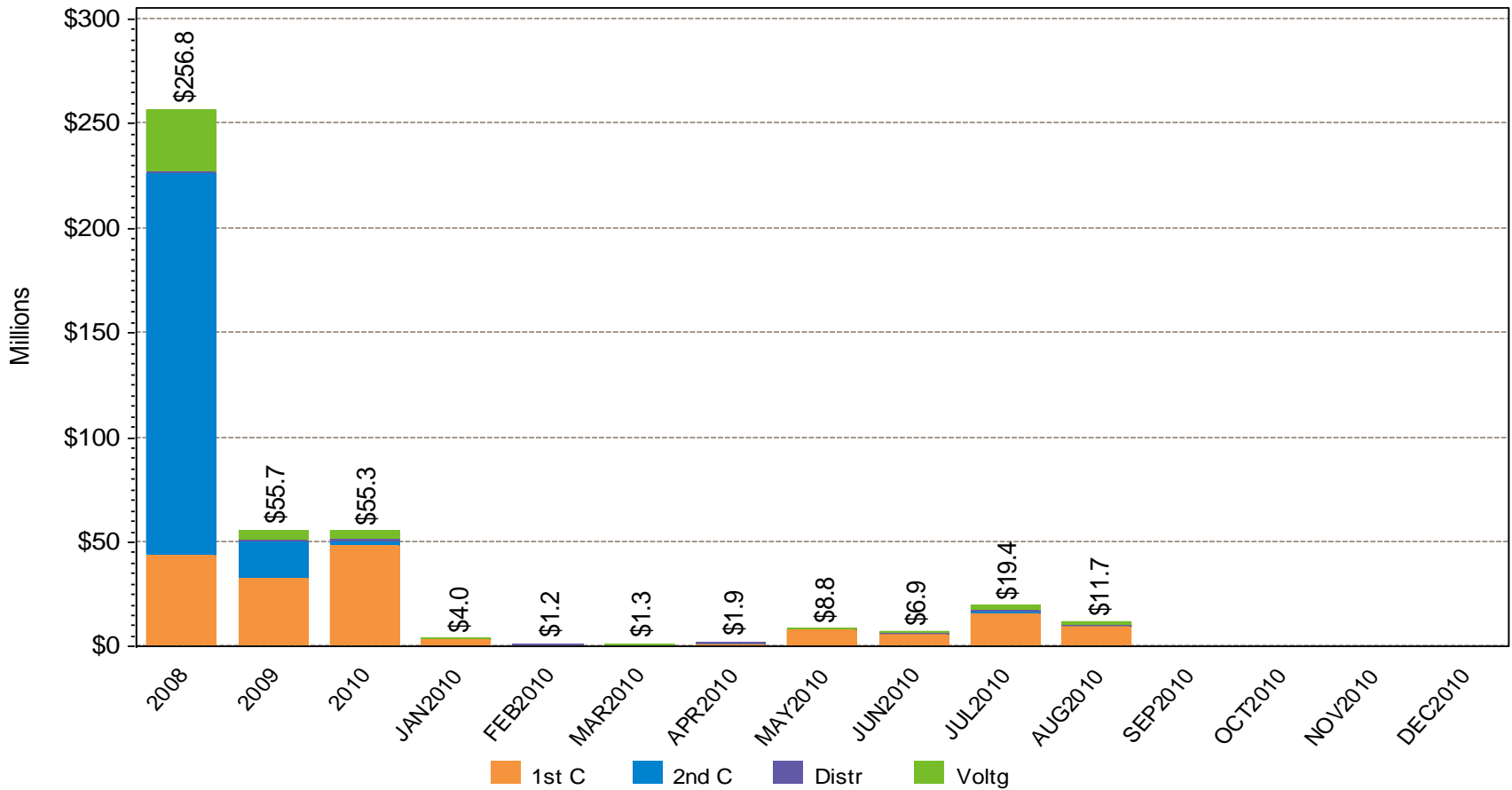


Voltage and Distribution Payments



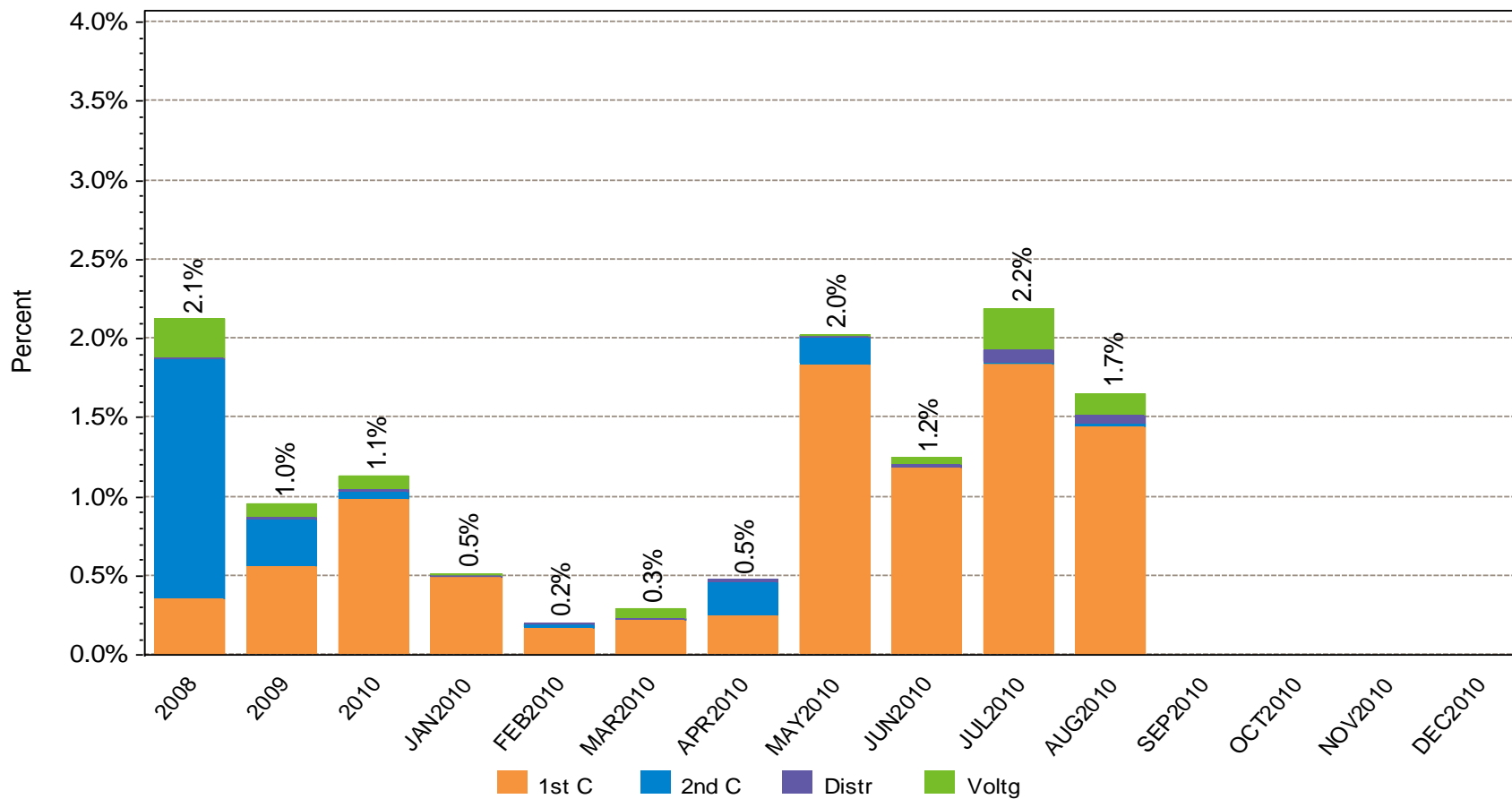
NCPC Payments by Type

Payments by Type of NCPC



NCPC Payments by Percent of Energy Market

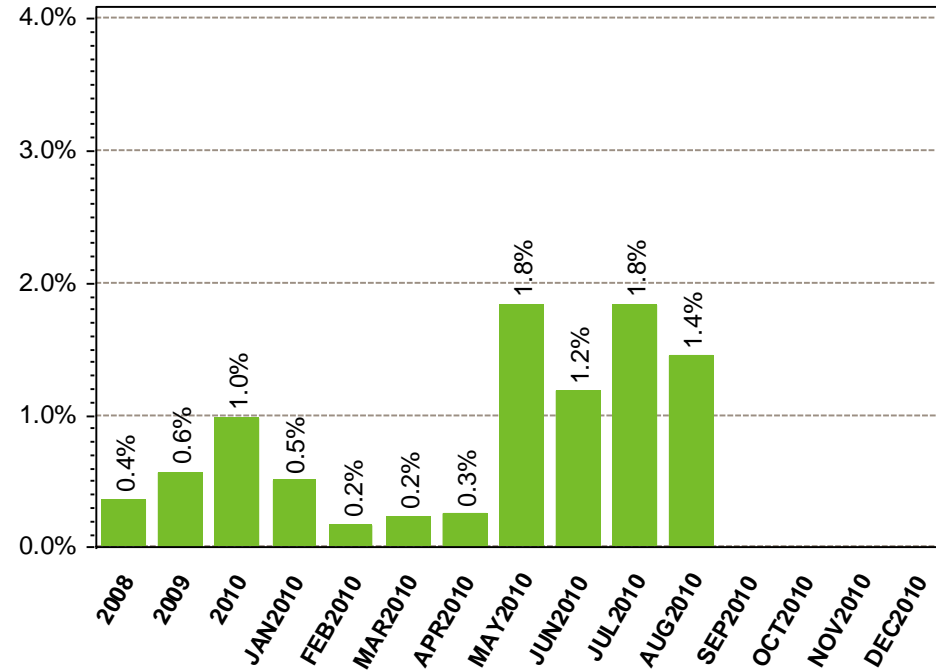
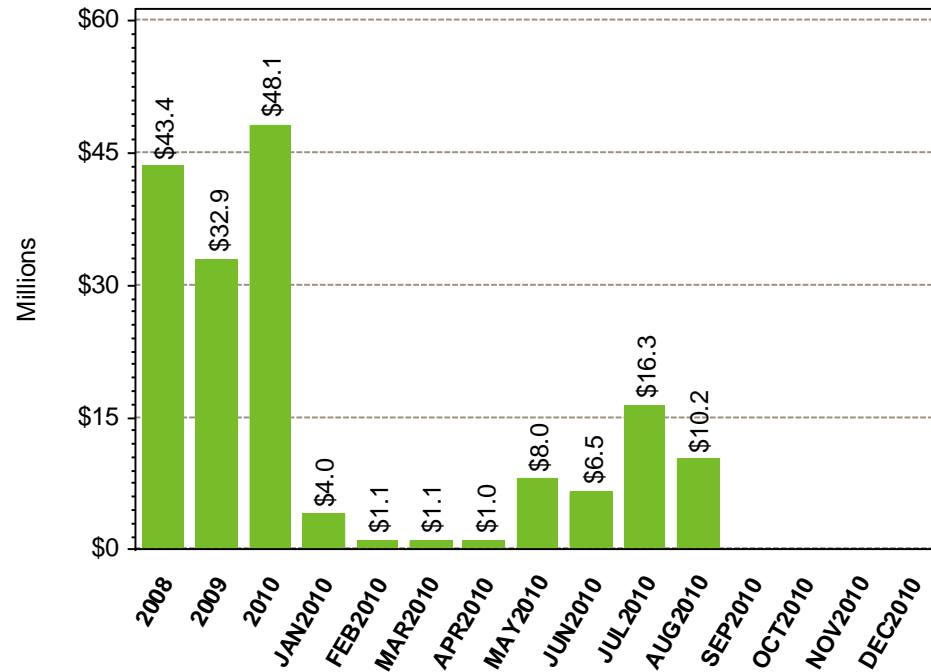
NCPC By Type as Percent of Energy Market



First Contingency NCPC Payments

Value of Payments

% of Energy Market Value

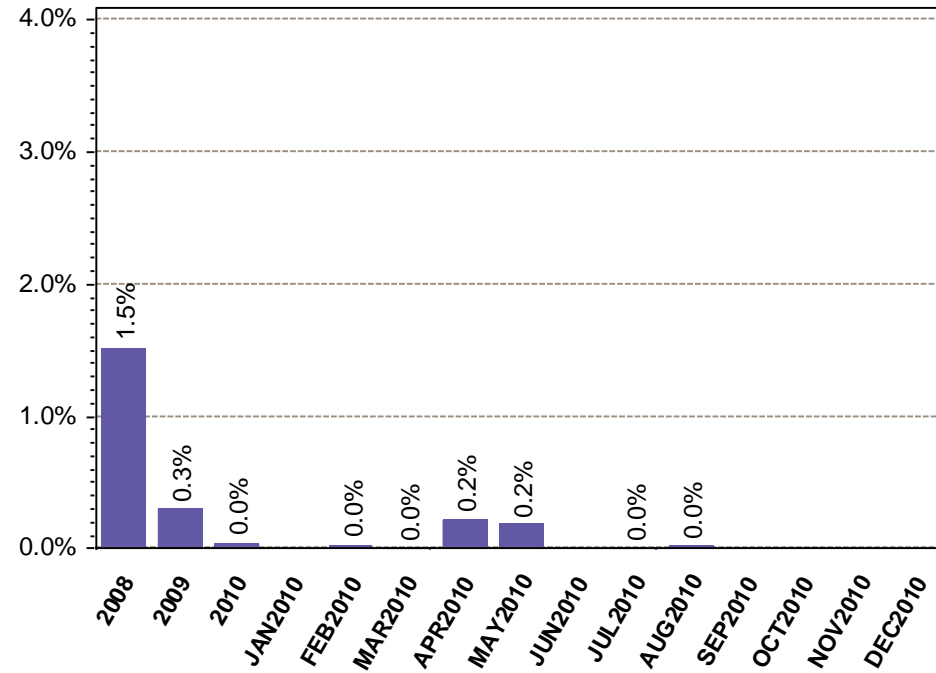
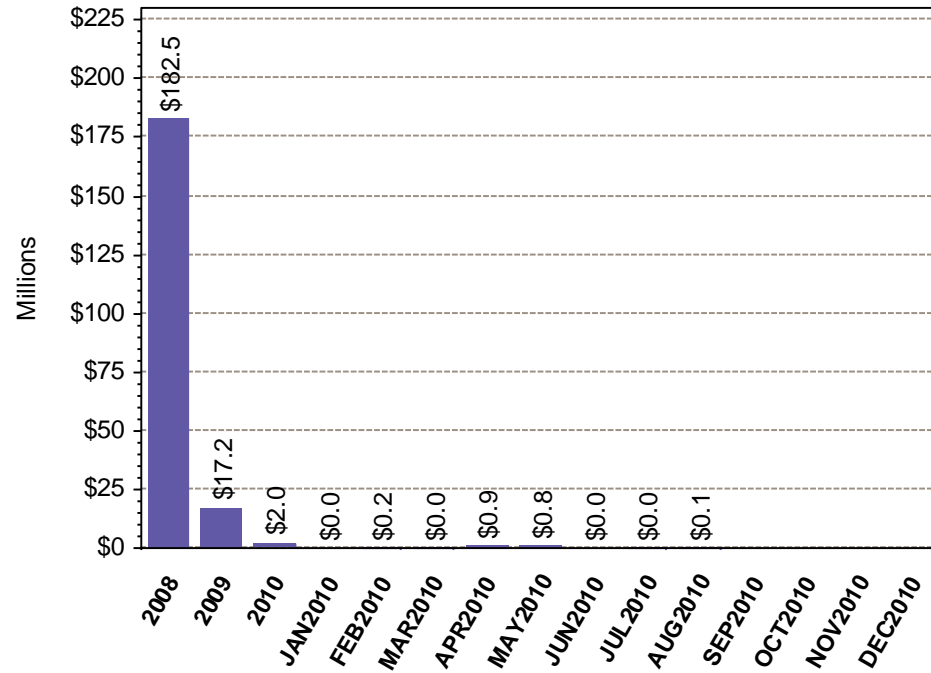


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Second Contingency NCPC Payments

Value of Payments

% of Energy Market Value

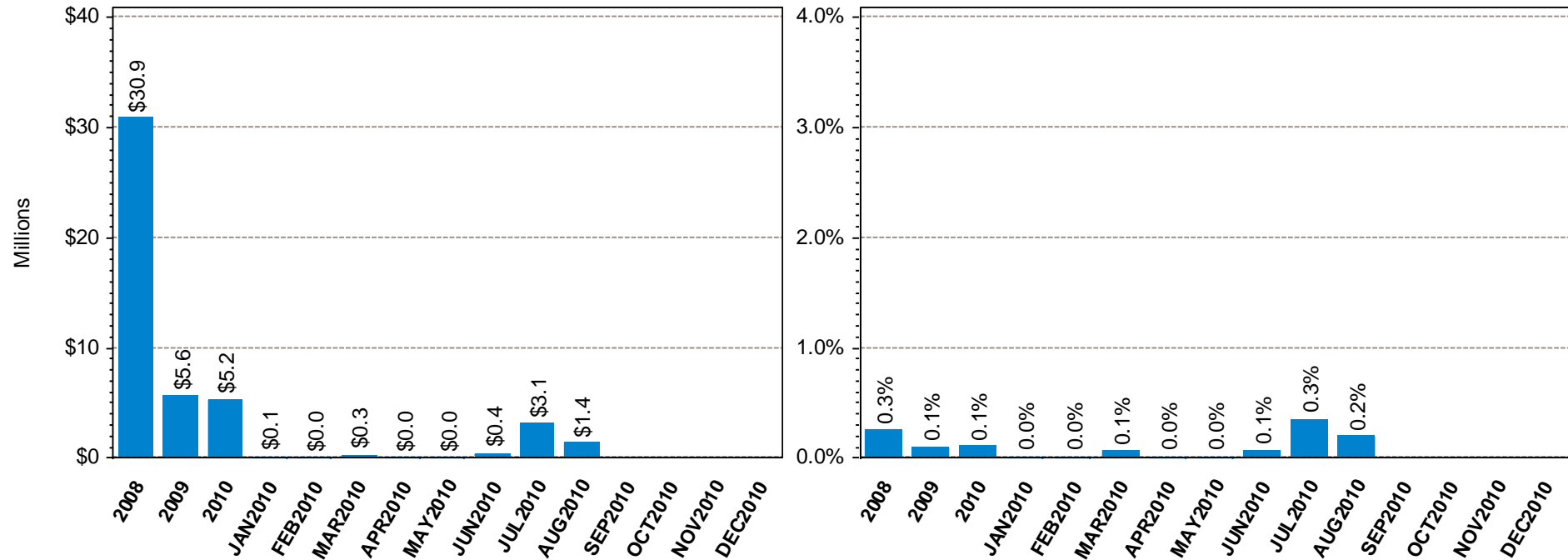


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

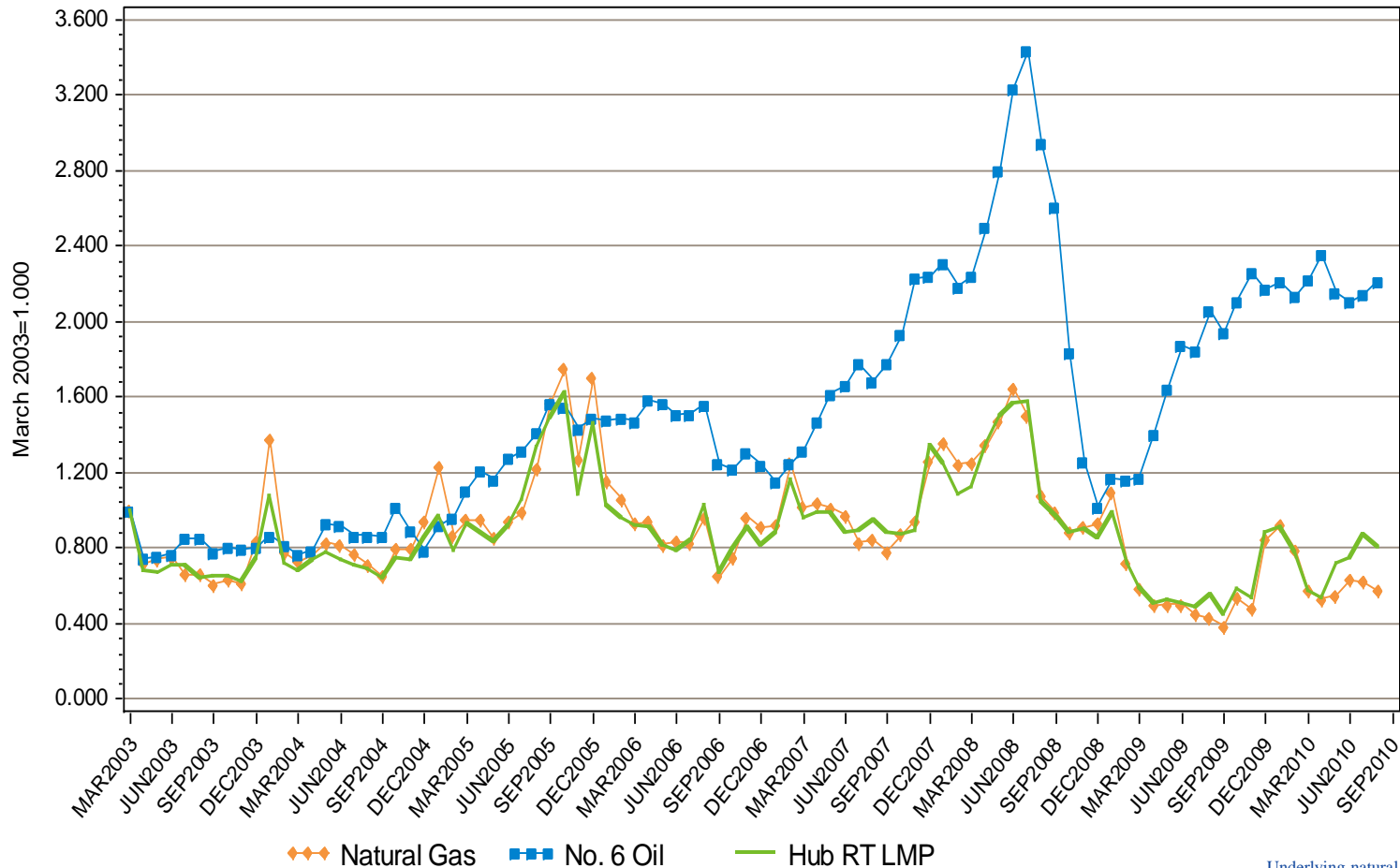
DA vs. RT LMPs (\$/MWh)

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%

August-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$35.02	\$36.58	\$33.49	\$34.86	\$35.58	\$34.89	\$35.26	\$35.48	\$35.23
Real-Time	\$38.12	\$39.23	\$36.11	\$37.97	\$38.78	\$37.78	\$38.25	\$38.53	\$38.25
RT Delta %	8.8%	7.2%	7.8%	8.9%	9.0%	8.3%	8.5%	8.6%	8.6%
August-10	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$52.77	\$57.46	\$51.51	\$52.94	\$55.05	\$52.47	\$52.69	\$54.63	\$53.55
Real-Time	\$54.85	\$56.55	\$53.20	\$54.75	\$56.15	\$54.37	\$54.96	\$56.10	\$55.40
RT Delta %	4.0%	-1.6%	3.3%	3.4%	2.0%	3.6%	4.3%	2.7%	3.5%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	50.7%	57.1%	53.8%	51.9%	54.7%	50.4%	49.4%	53.9%	52.0%
Yr over Yr RT	43.9%	44.2%	47.3%	44.2%	44.8%	43.9%	43.7%	45.6%	44.8%

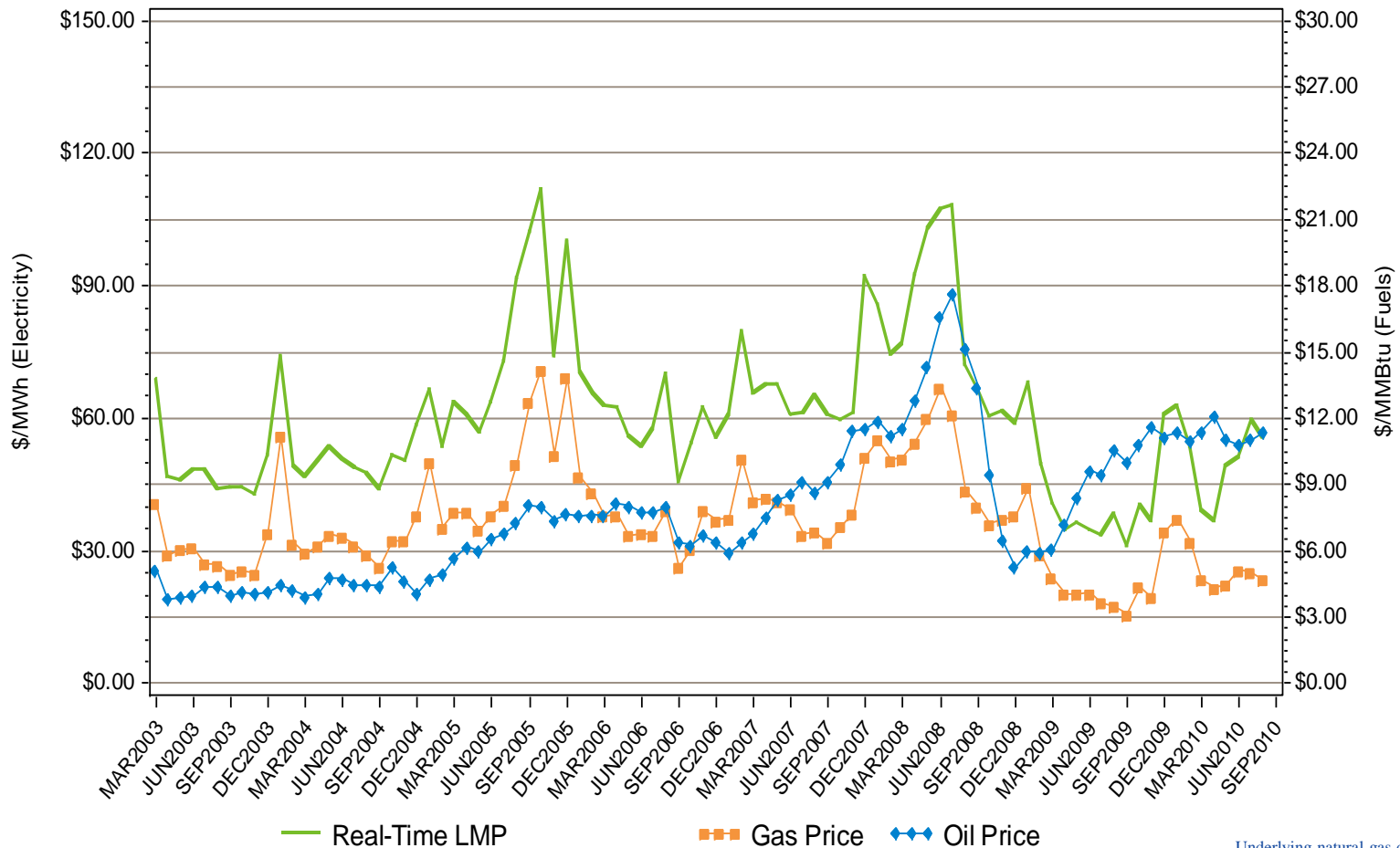
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:



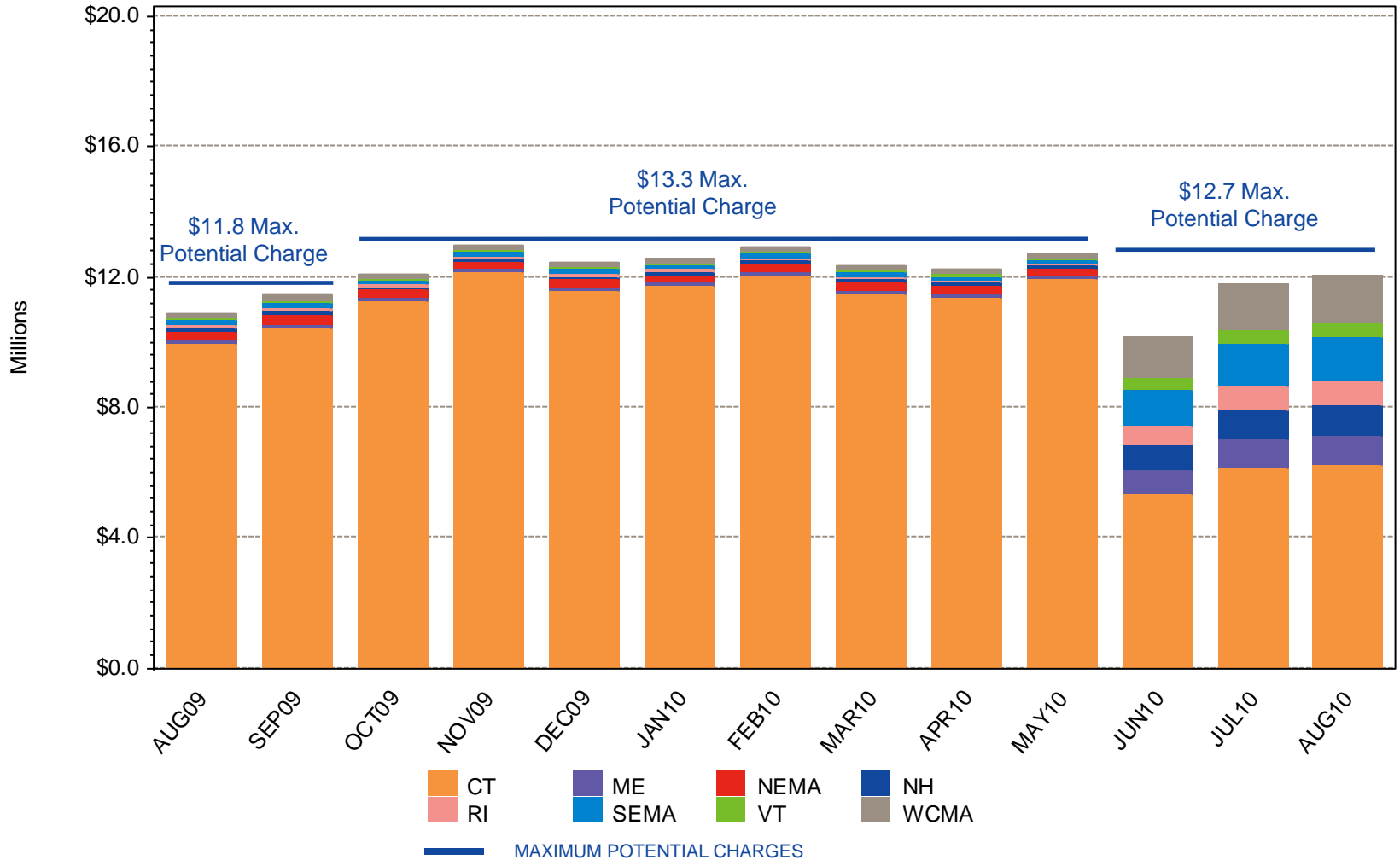
Reserve Market Results – August 2010

- Maximum potential Forward Reserve Market payments of \$12.7M were reduced by credit reductions of \$253K, failure-to-reserve penalties of \$380K and failure-to-activate penalties of \$2K, resulting in a net payout of \$12.0M or 95% of maximum
 - Rest of System: \$1.09M/\$1.16M (94%)
 - Southwest Connecticut: \$3.52M/\$3.78M (93%)
 - Connecticut: \$7.43M/\$7.73M (96%)
 - NEMA: n/a
- \$1.4M total Real-Time credits were reduced by \$443K in Forward Reserve Energy Obligation Charges for a net of \$964K in Real-Time Reserve payments
 - Rest of System: 80 hours, \$636K
 - Southwest Connecticut: 80 hours, \$208K
 - Connecticut: 80 hours, \$66K
 - NEMA: 80 hours, \$55K
- The system reserve bias factor was used on three days (August 2, 30, and 31) during this period

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

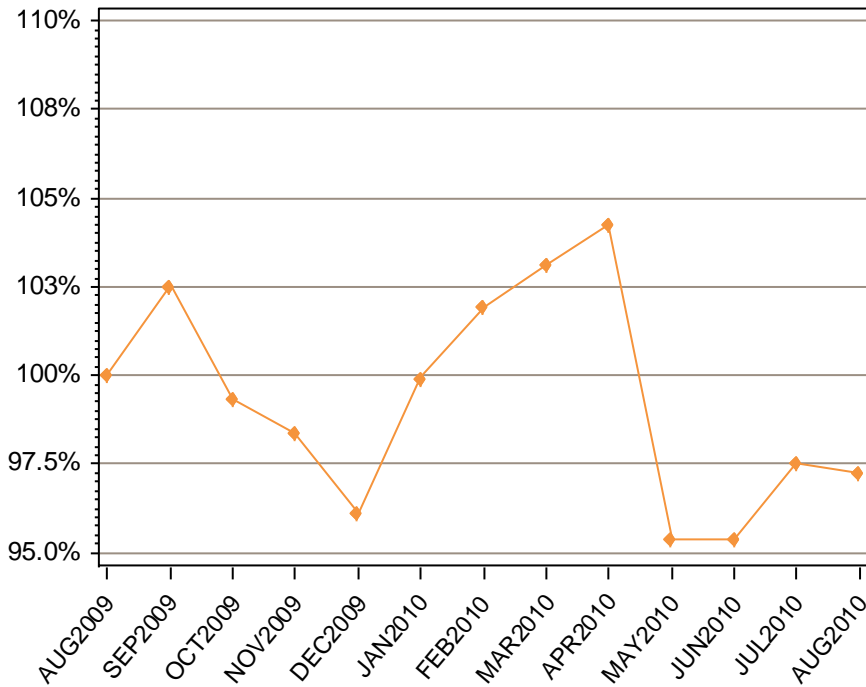
LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months

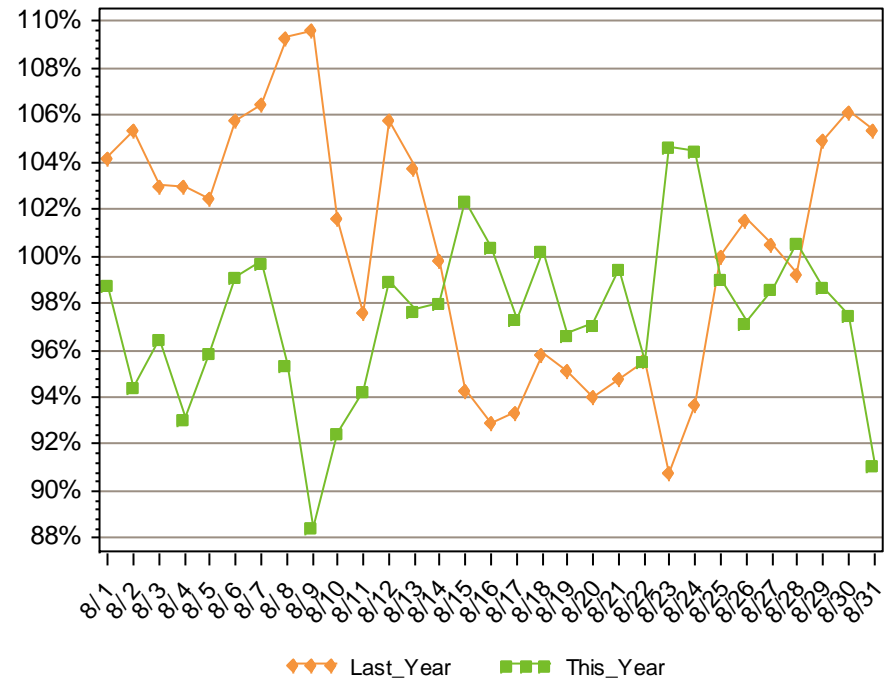


DA Load Obligation Percent of RT Load Obligation

Monthly, Last 13 Months

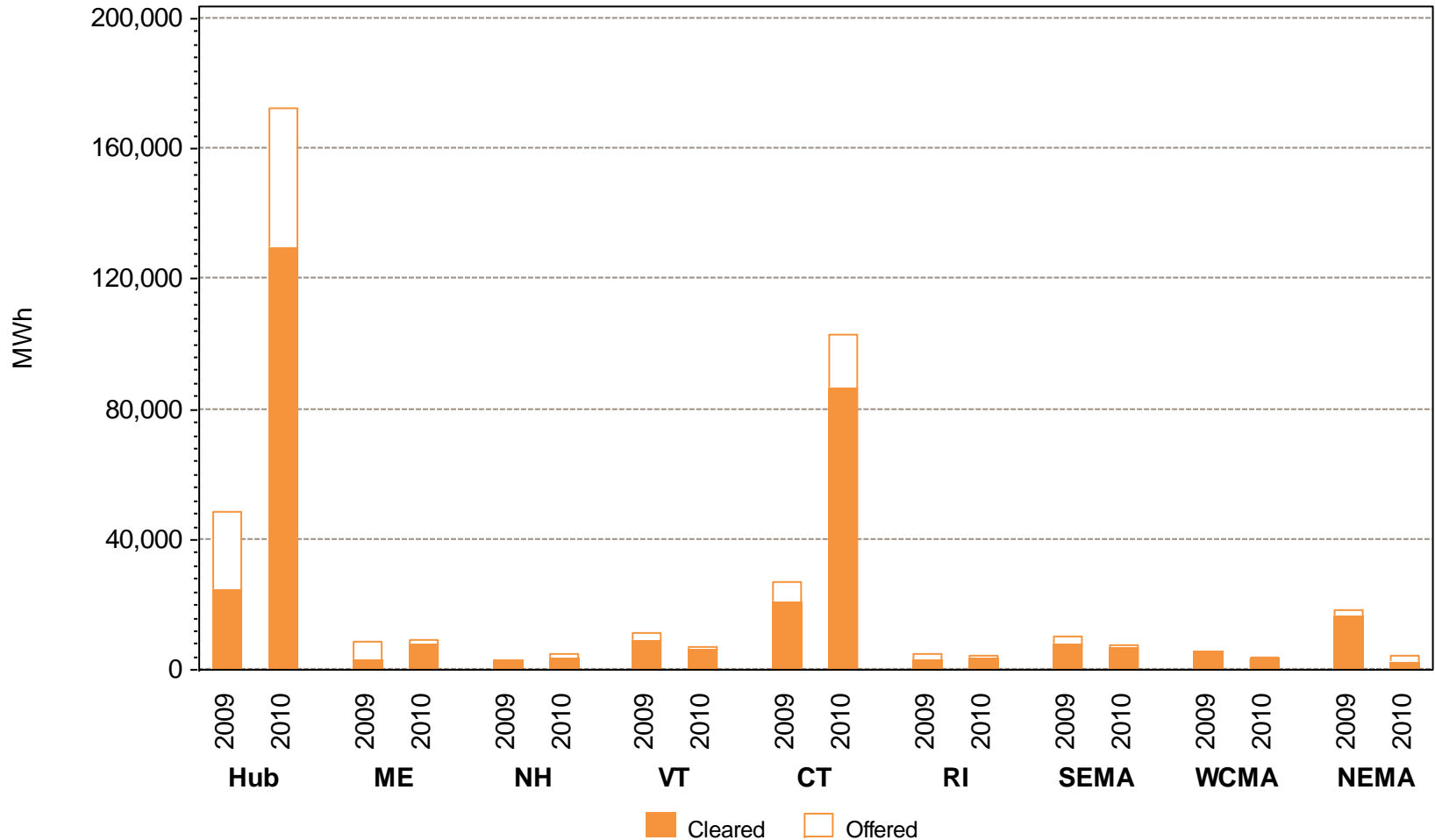


Daily, This Year vs. Last Year



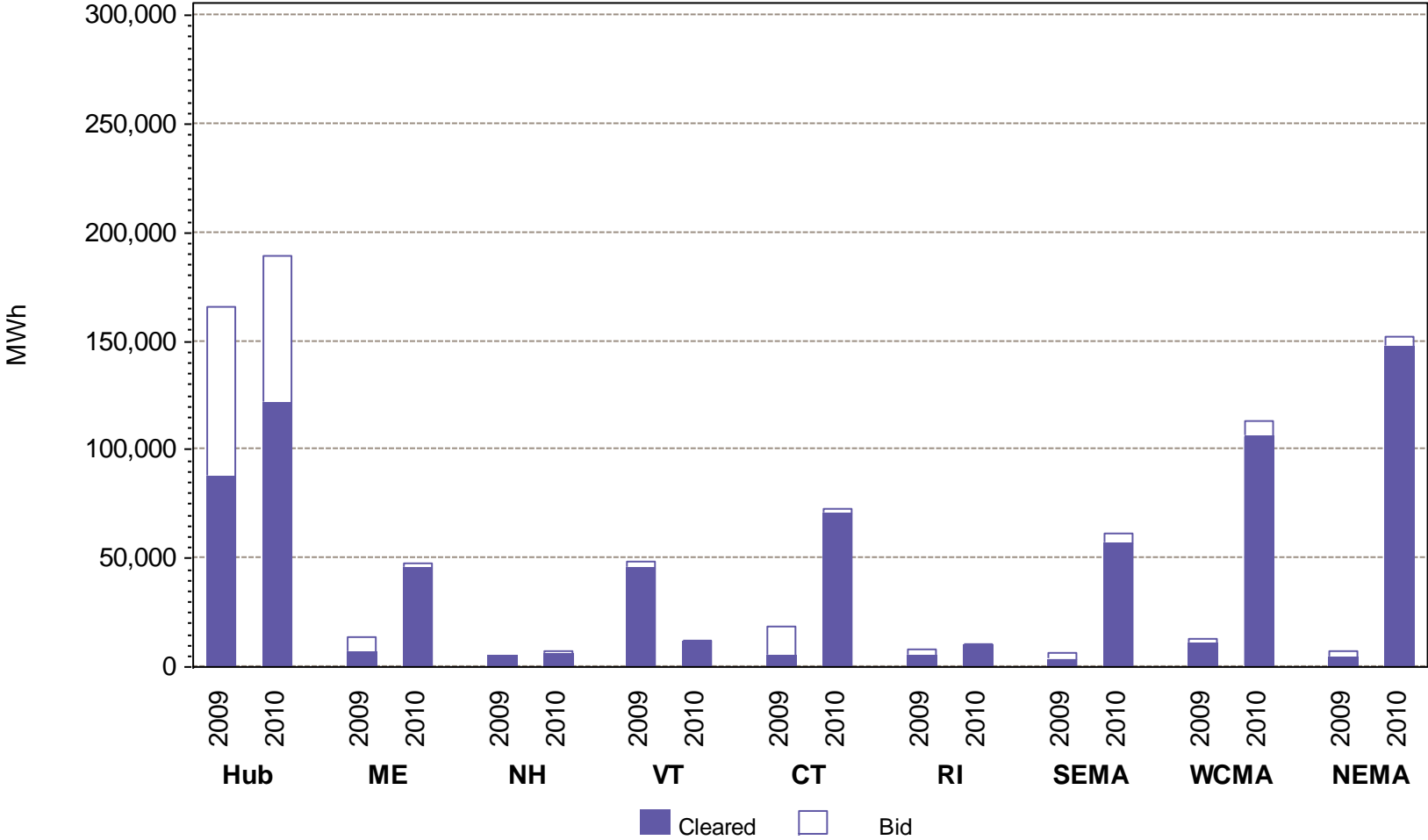
Zonal Increment Offers and Cleared Amounts

August Monthly Totals by Zone



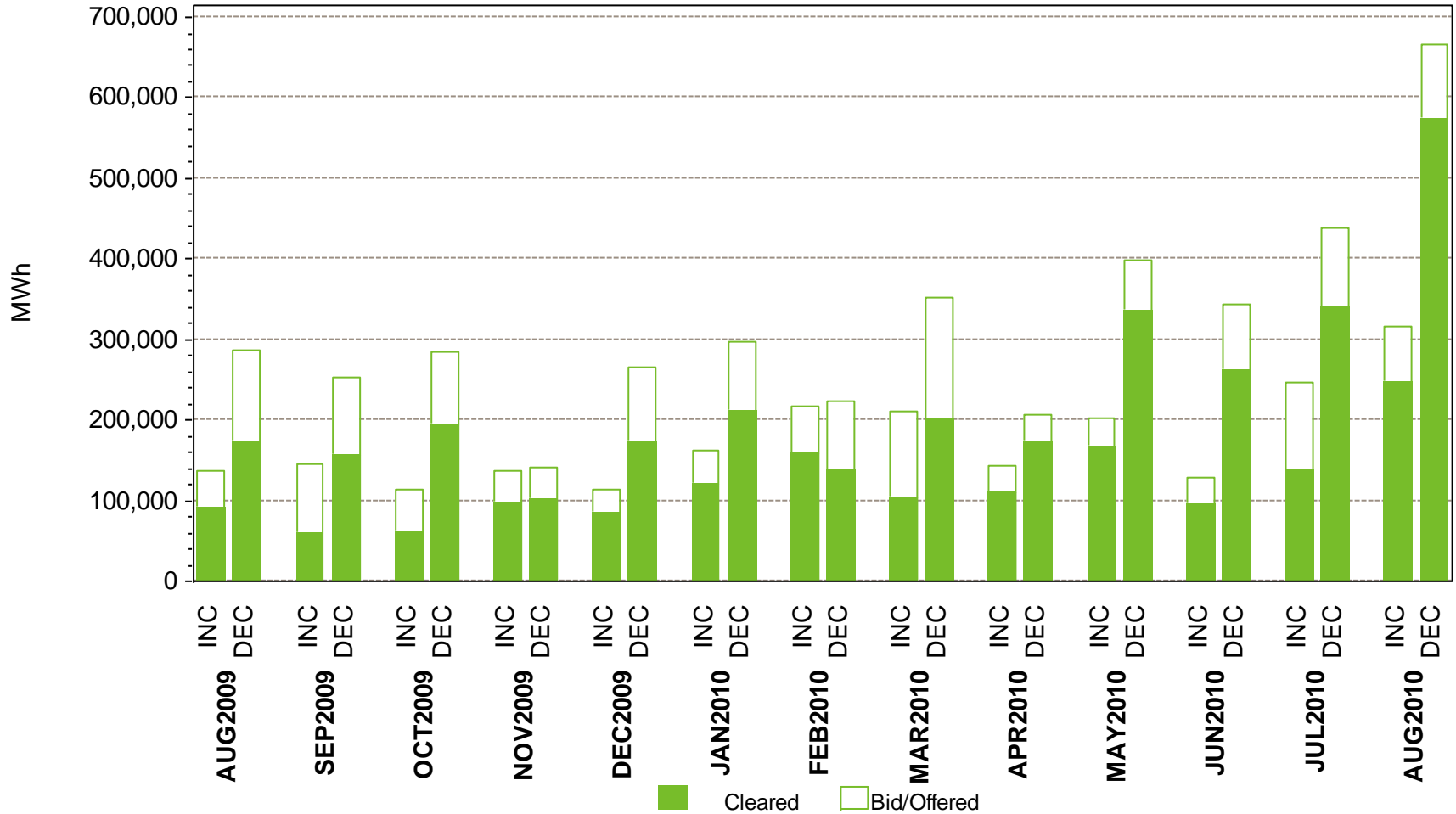
Zonal Decrement Bids and Cleared Amounts

August Monthly Totals by Zone



Total Increment Offers and Decrement Bids

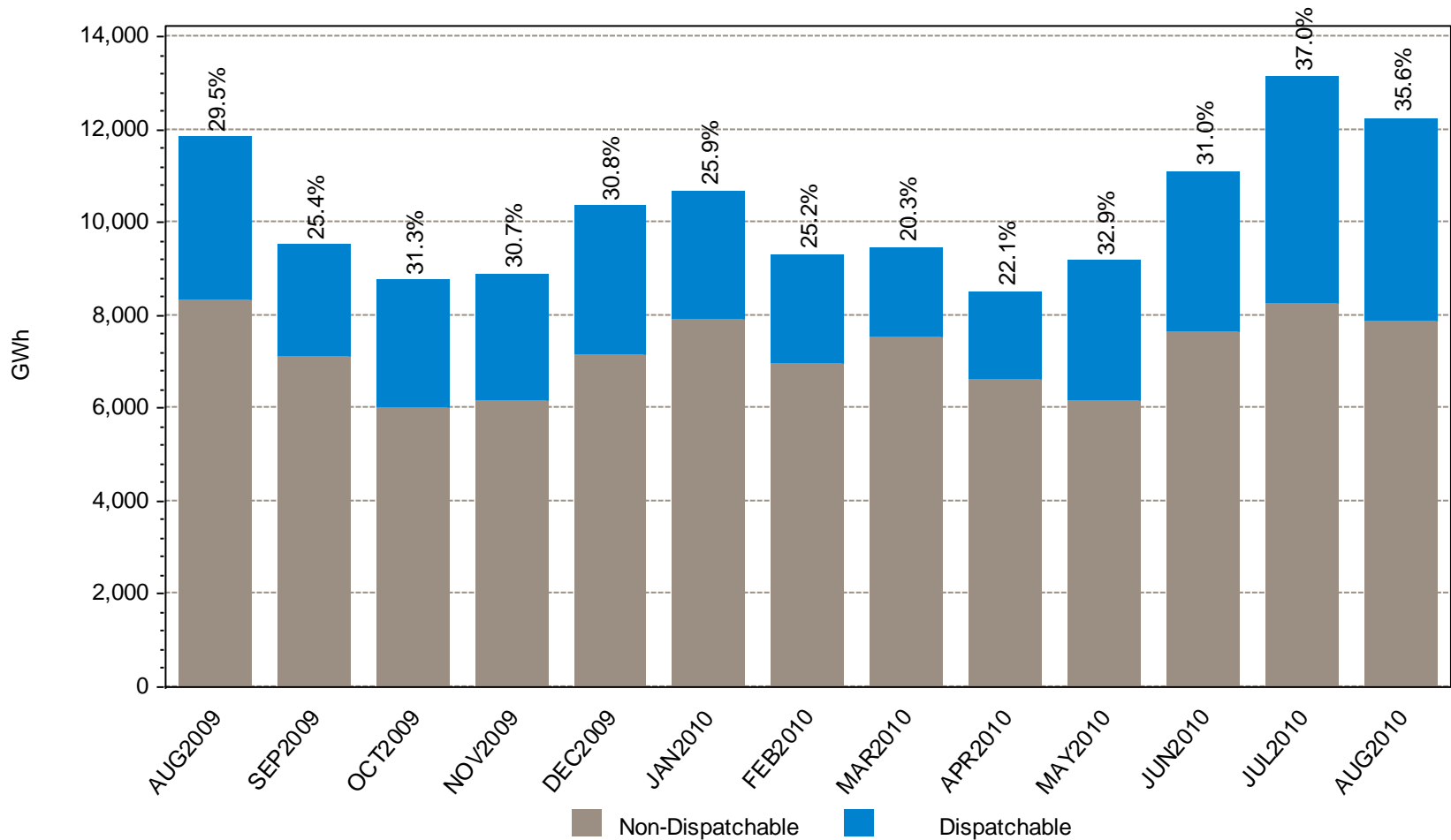
Zonal Level, Last 13 Months



Data excludes nodal offers and bids

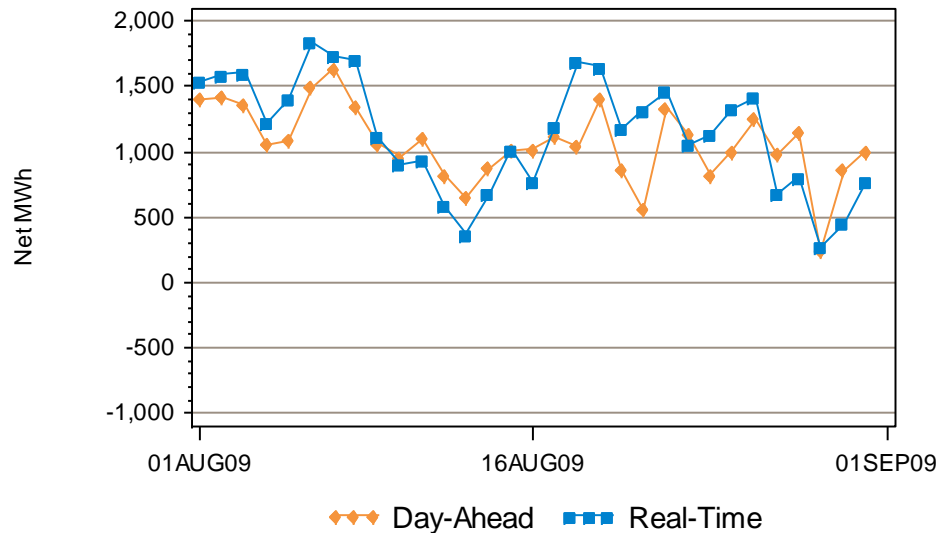
Dispatchable vs. Non-Dispatchable Generation

Total Monthly Energy; Dispatchable % Shown

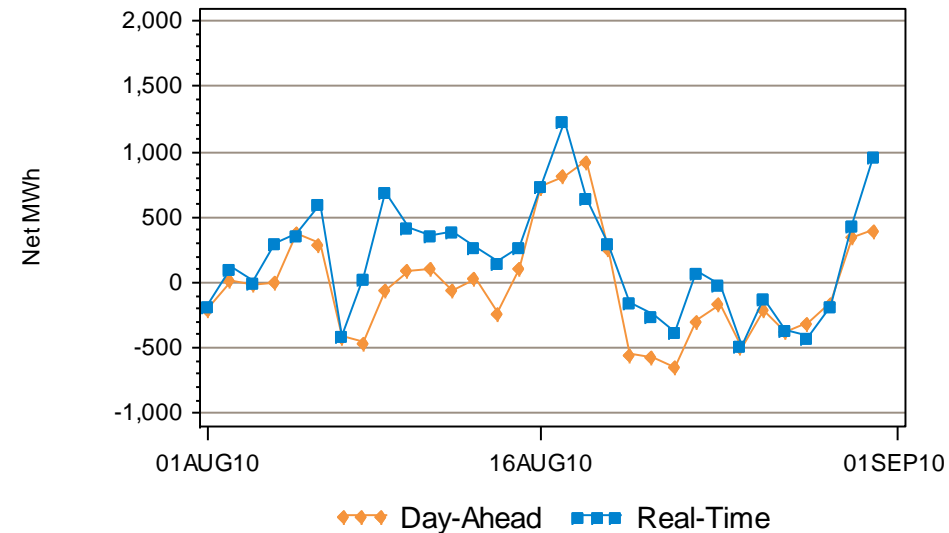


DA vs. RT Net Interchange August 2010 vs. August 2009

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

Regional System Plan (RSP)

RSP10 Report Schedule and Process

- August 12 – Written substantive comments on the draft RSP10 were discussed with the Planning Advisory Committee (PAC) and will be reflected in the Public Meeting version
 - All final comments are subject to review by ISO staff, including the Technical Editor
 - Status of the NEEWS project
 - Additional emphasis on the region’s ability to meet its Renewable Portfolio Standard goals
 - Clarifying comments, primarily on environmental issues, wind and solar unit integration issues, and transmission projects
 - Update the new initiatives included in Section 12.3.2 and include them in the Executive Summary
- The Public Meeting Version of RSP10 will be posted September 8
 - Please submit questions **by noon on September 14**
 - Communicate to ISO through pacmatters@iso-ne.com

RSP10 Public Meeting: September 16

Preliminary Agenda

9:30 a.m. – 9:40 a.m.	Welcome
9:40 a.m. – 10:30 a.m.	Presentation of the 2010 RSP and stakeholder discussion (priority will be given to written questions received in advance of the public meeting)
10:30 a.m. – 10:45 a.m.	Break
10:45 a.m. – 12:00 p.m.	Panel #1: State Planning Initiatives and Non-Transmission Alternatives
12:15 p.m. – 1:00 p.m.	Lunch
1:15 p.m. – 1:45 p.m.	Keynote Address: Patricia A. Hoffman, Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy
1:45 p.m. – 3:15 p.m.	Panel #2: Drivers of the Future Grid
3:15 p.m. – 3:30 p.m.	Concluding Comments

PAC Meeting Schedule and Tentative Agendas

- **September 21** – Update on interregional production cost studies, Maine Power Reliability Program, Northern Maine System Performance, SWCT Needs, UI PTF improvements, and Transmission Owner PAC meetings to present Local System Plans for UI, NU, VT, and NGRID
- **October 21** – Tentative agenda includes the RSP Project List, transmission studies, and an introduction to non-transmission analysis planned for RSP11
- **November 16** – Wind day and discussion of state Energy Efficiency programs

Interregional Planning and Coordination

- Inter-Area Planning Stakeholder Advisory Committee WebEx is tentatively scheduled for October 6 to discuss interregional production cost studies
- Comments on the FERC system planning NOPR are due by September 29
- Environmental Advisory Group meetings are planned for October 8 and December 17

Eastern Interconnection Planning Collaborative (EIPC)

- Stakeholder Steering Committee has formed working groups to support their efforts
 - Roll-up Working Group
 - Modeling Working Group
 - Scenario Planning Working Group
 - Governance Task Force
- Several New England representatives have volunteered for the working groups
- Initial efforts are to establish ground rules and confirm objectives
- EIPC representative will attend each working group meeting
- Information on the working groups, including high-level meeting notes, will be posted at www.eipconline.com

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 9/7/10

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 9/7/10

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 Service Road substation near intersection with the #115 line	Dec-12	1
New Service Road substation 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 summer 2010
- Full status update (needs, preferred solution, needs reassessment) given at 4/27/10 PAC
- Draft solutions report posted 6/21/10; final needs report posted 6/21/10

Maine Power Reliability Program (MPRP)

Status as of 9/7/10

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
- Maine PUC issued an order approving most of the projection on 6/10/10

Vermont Southern Loop Project

Status as of 9/7/10

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 9/7/10

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
- IRP discussion held at 8/12/10 PAC meeting. ISO findings show continued need for IRP
- Need for CCRP under study

Transmission Siting Update

- New England East-West Solution
 - ISO involvement in RI siting for RIRP complete
 - RI PUC issued draft approval
 - Siting application filed with MA and CT for Springfield portion in October 2008
 - Springfield – CT
 - CT Siting Council approved entire project with the Manchester – Meekville Junction Variation (separate the 395 3-terminal line into 2 separate lines)
 - Springfield – MA
 - Preliminary bench decision supports need but some routing/EMF 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
 - Maine PUC approved most of the project on 6/10/10
 - Hearings continue on some portions of the project (Lewiston Loop, Three Rivers, Surowiec-Raven Farm)
 - Proposed Plan Applications and TCAs need to be revised to reflect the new version of the project

Operable Capacity Analysis

Fall 2010-Spring 2011 Operable Capacity Analysis (MW)

	September-10 ² 50/50 Forecast (Reference Load)	September-10 ² 90/10 Forecast (Extreme Load)
Generator Capacity Supply Obligation ¹	30,041	SAME
External Node Available capacity	342	SAME
Non Commercial Supply	0	SAME
Planned and other known outage MW ³	1,500	SAME
Allowance for Unplanned Outages	2,100	SAME
Generation at Risk Due to Gas Supply	0	SAME
Net Capacity ⁴	26,780	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 ⁴	(1,640)	(3,760) (-2,120)

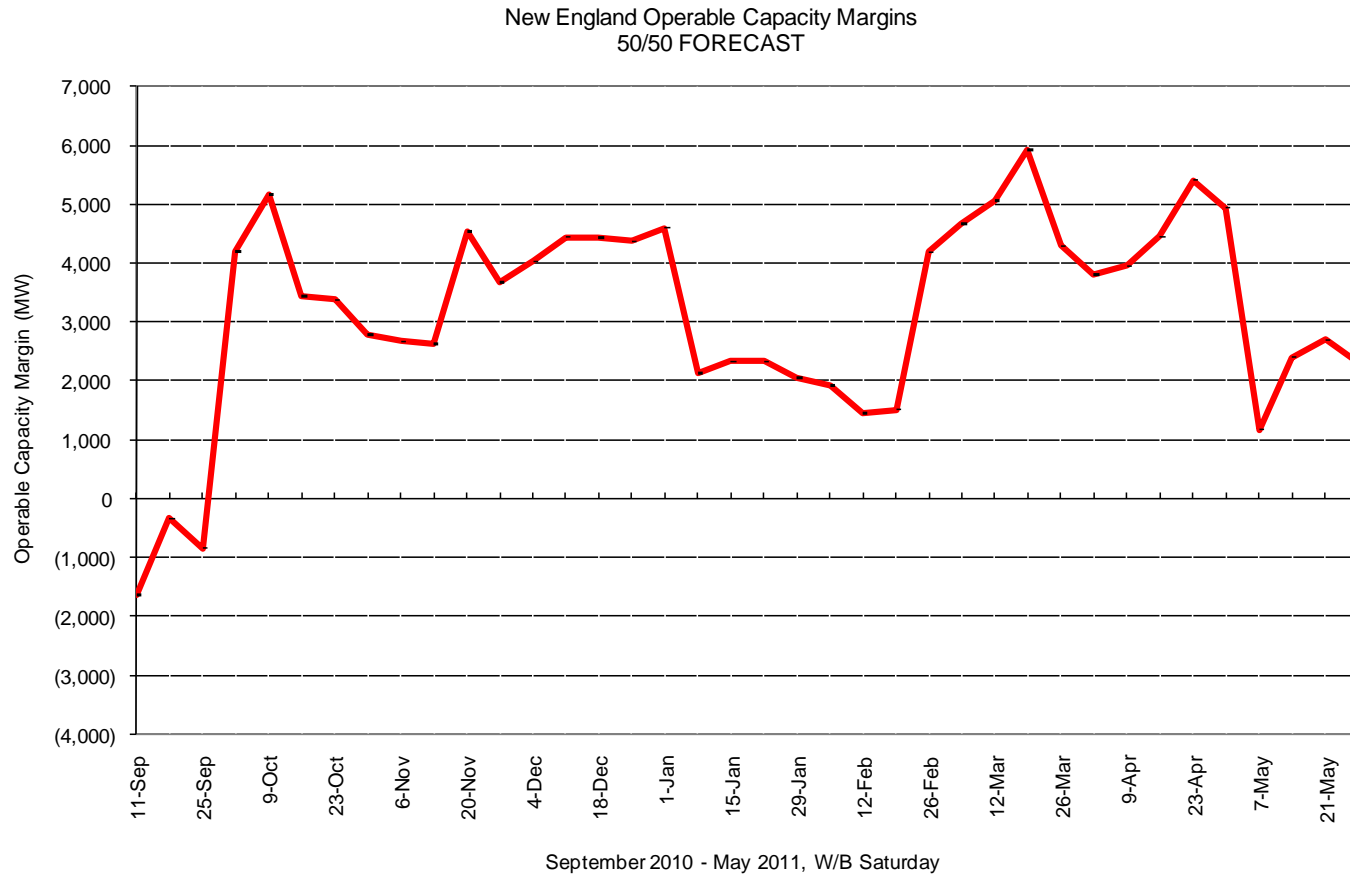
¹ Generator Capacity Supply Obligation is based on data as of September 1, 2010 and does not include Capacity Supply Obligations associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

² Based on week with lowest Operable Capacity Margin, week beginning September 11th.

³ Rounded to the nearest hundred.

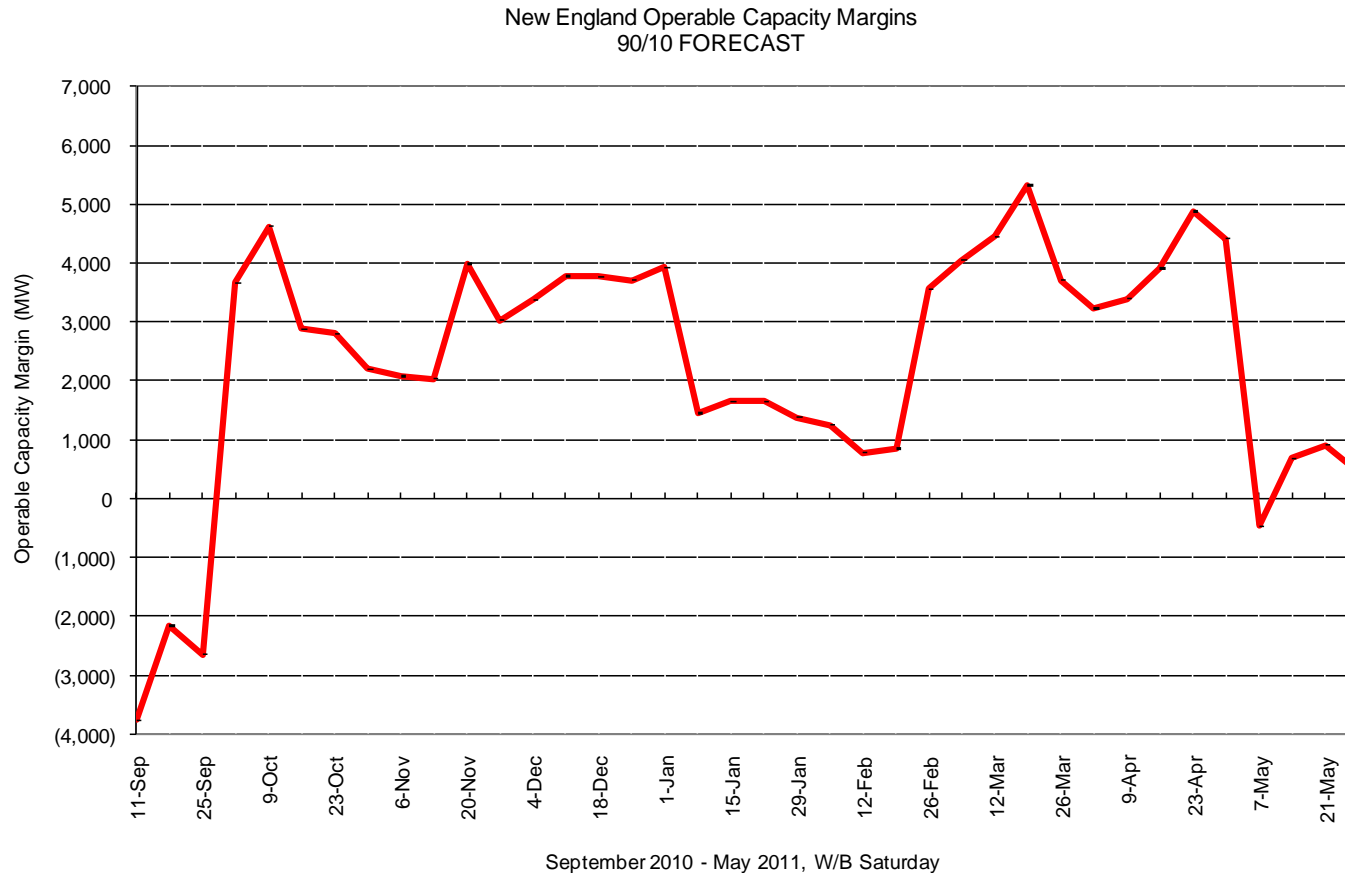
⁴ Rounded to the nearest ten

Fall 2010-Spring 2011 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)



Note: Based on data as of September 1, 2010. Does not include Settlement Only Generators and Active Demand Response.

Fall 2010-Spring 2011 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)



Note: Based on data as of September 1, 2010. Does not include Settlement Only Generators and Active Demand Response.

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 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 ¹ 600 ²
2	Dispatch real time Demand Resources.	670 ³
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 ⁴ 520 ³
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 ⁴
9	Voluntary Load Curtailment by Large Industrial and Commercial Customers. Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.	200 ² 5

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 Appeal	200
11	Request State Governors to Reinforce Power Warning Appeals.	100
Total		3,735

Based on results of the April Bilateral and Reconfiguration auctions for June CSO

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. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
4. The MW values are based on a 26,618 MW system load and the most recent voltage reduction test % achieved.

Appendix

Fall 2010-Spring 2011 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

September 7, 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	KNOWN OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP MW	EXPORT LTD AVAIL OPCAP MW(with no outages <15 days	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMEN T MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR	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]	
09/11/2010	30,041	342	0	1,500	2,100	0	28,516	26,780	26,618	1,800	28,418	(1,640)	670	(970)	520	(450)
09/18/2010	30,041	342	0	4,100	2,100	0	25,986	24,180	22,722	1,800	24,522	(340)	670	330	520	850
09/25/2010	30,291	300	0	4,200	2,800	0	26,135	23,590	22,632	1,800	24,432	(840)	670	(170)	520	350
10/02/2010	30,291	300	0	5,000	2,800	0	25,263	22,790	16,793	1,800	18,593	4,200	670	4,870	520	5,390
10/09/2010	30,291	300	0	4,000	2,800	0	26,333	23,790	16,829	1,800	18,629	5,160	670	5,830	520	6,350
10/16/2010	30,291	300	0	4,800	2,800	0	25,517	22,990	17,748	1,800	19,548	3,440	670	4,110	520	4,630
10/23/2010	30,291	300	0	4,500	2,800	0	25,804	23,290	18,110	1,800	19,910	3,380	670	4,050	520	400
10/30/2010	30,196	300	0	4,000	3,600	0	26,245	22,900	18,315	1,800	20,115	2,780	670	3,450	520	400
11/06/2010	30,196	300	0	4,000	3,600	0	26,194	22,900	18,430	1,800	20,230	2,670	670	3,340	520	400
11/13/2010	30,196	300	0	3,700	3,600	0	26,527	23,200	18,772	1,800	20,572	2,630	670	3,300	520	400
11/20/2010	30,196	300	0	3,000	3,600	0	27,225	23,900	17,555	1,800	19,355	4,540	670	5,210	520	400
11/27/2010	30,196	300	0	1,200	3,600	0	29,032	25,700	20,234	1,800	22,034	3,670	670	4,340	520	400
12/04/2010	30,394	368	0	1,300	3,200	0	29,119	26,260	20,433	1,800	22,233	4,030	670	4,700	520	400
12/11/2010	30,394	368	0	600	3,200	0	29,757	26,960	20,720	1,800	22,520	4,440	670	5,110	520	400
12/18/2010	30,394	368	0	600	3,200	0	29,789	26,960	20,731	1,800	22,531	4,430	670	5,100	520	400
12/25/2010	30,394	368	0	600	3,200	0	29,795	26,960	20,793	1,800	22,593	4,370	670	5,040	520	400
01/01/2011	30,394	368	0	500	2,800	0	29,848	27,460	21,064	1,800	22,864	4,600	670	5,270	520	400
01/08/2011	30,394	368	0	500	2,800	2,000	29,848	25,460	21,526	1,800	23,326	2,130	670	2,800	520	400
01/15/2011	30,394	368	0	300	2,800	2,000	30,125	25,660	21,526	1,800	23,326	2,330	670	3,000	520	400
01/22/2011	30,394	368	0	300	2,800	2,000	30,123	25,660	21,526	1,800	23,326	2,330	670	3,000	520	400
01/29/2011	30,394	368	0	500	3,100	2,000	29,853	25,160	21,305	1,800	23,105	2,050	670	2,720	520	400
02/05/2011	30,394	368	0	900	3,100	2,000	29,484	24,760	21,040	1,800	22,840	1,920	670	2,590	520	400
02/12/2011	30,394	368	0	1,400	3,100	2,000	28,995	24,260	21,011	1,800	22,811	1,450	670	2,120	520	400
02/19/2011	30,394	368	0	1,600	3,100	2,000	28,841	24,060	20,751	1,800	22,551	1,510	670	2,180	520	400
02/26/2011	30,394	368	0	1,900	3,100	0	28,481	25,760	19,770	1,800	21,570	4,190	670	4,860	520	400
03/05/2011	30,394	300	0	2,600	2,200	0	27,822	25,890	19,424	1,800	21,224	4,670	670	5,340	520	400
03/12/2011	30,394	300	0	2,400	2,200	0	28,024	26,090	19,229	1,800	21,029	5,060	670	5,730	520	400
03/19/2011	30,394	300	0	1,900	2,200	0	28,477	26,590	18,867	1,800	20,667	5,920	670	6,590	520	400
03/26/2011	30,196	300	0	3,400	2,700	0	26,823	24,400	18,306	1,800	20,106	4,290	670	4,960	520	400
04/02/2011	30,196	300	0	4,400	2,700	0	25,778	23,400	17,803	1,800	19,603	3,800	670	4,470	520	400
04/09/2011	30,196	300	0	4,500	2,700	0	25,698	23,300	17,553	1,800	19,353	3,950	670	4,620	520	400
04/16/2011	30,196	300	0	4,500	2,700	0	25,704	23,300	17,047	1,800	18,847	4,450	670	5,120	520	400
04/23/2011	30,196	300	0	3,800	2,700	0	26,359	24,000	16,785	1,800	18,585	5,410	670	6,080	520	400
04/30/2011	30,196	300	0	3,600	3,400	0	26,579	23,500	16,758	1,800	18,558	4,940	670	5,610	520	400
05/07/2011	30,196	300	0	3,800	3,400	0	26,407	23,300	20,325	1,800	22,125	1,170	670	1,840	520	400
05/14/2011	30,196	300	0	1,600	3,400	0	28,622	25,500	21,296	1,800	23,096	2,400	670	3,070	520	400
05/21/2011	30,196	300	0	400	3,400	0	29,771	26,700	22,198	1,800	23,998	2,700	670	3,370	520	400
05/28/2011	30,196	300	0	0	3,400	0	30,184	27,100	22,976	1,800	24,776	2,320	670	2,990	520	400

- Available OPCAP MW based on resource Capacity Supply Obligations, CSO, from Forward Capacity Tracking System, FCTS. Does not include Settlement Only Generators. (separate LTOCM run without any generator outages, tab Case Output-System Results-EXPORT LTD AVAIL OPCAP MW)
- External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO. (LTOCM application Case Output-System Results-EXTERNAL NODE AVAIL OPCAP MW)
- New resources that have not yet acquired a CSO but will become commercial in the future.
- Planned Outages includes outages scheduled greater than or equal to 15 days in advance.
- 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. (LTOCM application Case Output-System Results-UNPLANNED OUTAGES MW)
- Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions. (LTOCM application Case Output-System Results-GEN RISK DUE TO GAS SUP MW)
- Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 + 6 = 7)
- Peak Load Exposure per data included in the 2010 CELT Report. (LTOCM application-Case Output-System Results-LOAD FORECAST MW)
- Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency. (LTOCM application Case Output-System Results-OPER RESERVE REQUIREMENT MW)
- Total Load Obligation per the formula (8 + 9 = 10)
- Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
- OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are included.
- OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
- 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.
- 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).

Fall 2010-Spring 2011 Operable Capacity Analysis (MW)

90/10 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

September 7, 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	KNOWN OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP MW	EXPORT LTD AVAIL OPCAP MW(with no outages <15 days	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT T 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
09/11/2010	30,041	342	0	1,500	2,100	0	28,516	26,780	28,738	1,800	30,538	(3,780)	670	(3,090)	520	(2,570)
09/18/2010	30,041	342	0	4,100	2,100	0	25,986	24,180	24,538	1,800	26,338	(2,160)	670	(1,490)	520	(970)
09/25/2010	30,291	300	0	4,200	2,800	0	26,135	23,590	24,441	1,800	26,241	(2,650)	670	(1,980)	520	(1,460)
10/02/2010	30,291	300	0	5,000	2,800	0	25,263	22,790	17,328	1,800	19,128	3,660	670	4,330	520	4,850
10/09/2010	30,291	300	0	4,000	2,800	0	26,333	23,790	17,365	1,800	19,165	4,620	670	5,290	520	5,810
10/16/2010	30,291	300	0	4,800	2,800	0	25,517	22,990	18,312	1,800	20,112	2,880	670	3,550	520	4,070
10/23/2010	30,291	300	0	4,500	2,800	0	25,804	23,290	18,685	1,800	20,485	2,800	670	3,470	520	400
10/30/2010	30,196	300	0	4,000	3,600	0	26,245	22,900	18,897	1,800	20,697	2,200	670	2,870	520	400
11/06/2010	30,196	300	0	4,000	3,600	0	26,194	22,900	19,015	1,800	20,815	2,080	670	2,750	520	400
11/13/2010	30,196	300	0	3,700	3,600	0	26,527	23,200	19,368	1,800	21,168	2,030	670	2,700	520	400
11/20/2010	30,196	300	0	3,000	3,600	0	27,225	23,900	18,112	1,800	19,912	3,990	670	4,660	520	400
11/27/2010	30,196	300	0	1,200	3,600	0	29,032	25,700	20,874	1,800	22,674	3,030	670	3,700	520	400
12/04/2010	30,394	368	0	1,300	3,200	0	29,119	26,260	21,079	1,800	22,879	3,380	670	4,050	520	400
12/11/2010	30,394	368	0	600	3,200	0	29,757	26,960	21,375	1,800	23,175	3,780	670	4,450	520	400
12/18/2010	30,394	368	0	600	3,200	0	29,789	26,960	21,386	1,800	23,186	3,770	670	4,440	520	400
12/25/2010	30,394	368	0	600	3,200	0	29,795	26,960	21,450	1,800	23,250	3,710	670	4,380	520	400
01/01/2011	30,394	368	0	500	2,800	0	29,848	27,460	21,730	1,800	23,530	3,930	670	4,600	520	400
01/08/2011	30,394	368	0	500	2,800	2,000	29,848	25,460	22,206	1,800	24,006	1,450	670	2,120	520	400
01/15/2011	30,394	368	0	300	2,800	2,000	30,125	25,660	22,206	1,800	24,006	1,650	670	2,320	520	400
01/22/2011	30,394	368	0	300	2,800	2,000	30,123	25,660	22,206	1,800	24,006	1,650	670	2,320	520	400
01/29/2011	30,394	368	0	500	3,100	2,000	29,853	25,160	21,978	1,800	23,778	1,380	670	2,050	520	400
02/05/2011	30,394	368	0	900	3,100	2,000	29,484	24,760	21,705	1,800	23,505	1,250	670	1,920	520	400
02/12/2011	30,394	368	0	1,400	3,100	2,000	28,995	24,260	21,676	1,800	23,476	780	670	1,450	520	400
02/19/2011	30,394	368	0	1,600	3,100	2,000	28,841	24,060	21,407	1,800	23,207	850	670	1,520	520	400
02/26/2011	30,394	368	0	1,900	3,100	0	28,481	25,760	20,396	1,800	22,196	3,560	670	4,230	520	400
03/05/2011	30,394	300	0	2,600	2,200	0	27,822	25,890	20,039	1,800	21,839	4,050	670	4,720	520	400
03/12/2011	30,394	300	0	2,400	2,200	0	28,024	26,090	19,838	1,800	21,638	4,450	670	5,120	520	400
03/19/2011	30,394	300	0	1,900	2,200	0	28,477	26,590	19,465	1,800	21,265	5,320	670	5,990	520	400
03/26/2011	30,196	300	0	3,400	2,700	0	26,823	24,400	18,887	1,800	20,687	3,710	670	4,380	520	400
04/02/2011	30,196	300	0	4,400	2,700	0	25,778	23,400	18,368	1,800	20,168	3,230	670	3,900	520	400
04/09/2011	30,196	300	0	4,500	2,700	0	25,698	23,300	18,111	1,800	19,911	3,390	670	4,060	520	400
04/16/2011	30,196	300	0	4,500	2,700	0	25,704	23,300	17,590	1,800	19,390	3,910	670	4,580	520	400
04/23/2011	30,196	300	0	3,800	2,700	0	26,359	24,000	17,319	1,800	19,119	4,880	670	5,550	520	400
04/30/2011	30,196	300	0	3,600	3,400	0	26,579	23,500	17,292	1,800	19,092	4,410	670	5,080	520	400
05/07/2011	30,196	300	0	3,800	3,400	0	26,407	23,300	21,968	1,800	23,768	(470)	670	200	520	400
05/14/2011	30,196	300	0	1,600	3,400	0	28,622	25,500	23,016	1,800	24,816	680	670	1,350	520	400
05/21/2011	30,196	300	0	400	3,400	0	29,771	26,700	23,988	1,800	25,788	910	670	1,580	520	400
05/28/2011	30,196	300	0	0	3,400	0	30,184	27,100	24,844	1,800	26,644	460	670	1,130	520	400

- Available OPCAP MW based on resource Capacity Supply Obligations, CSO, from Forward Capacity Tracking System, FCTS. Does not include Settlement Only Generators. (separate LTOCM run without any generator outages, tab Case Output-System Results-column LZ EXPORT LTD AVAIL OPCAP MW)
- External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO. (LTOCM application Case Output-System Results-EXTERNAL NODE AVAIL OPCAP MW)
- New resources that have not yet acquired a CSO but will become commercial in the future.
- Planned Outages includes outages scheduled greater than or equal to 15 days in advance.
- 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. (LTOCM application Case Output-System Results-UNPLANNED OUTAGES MW)
- Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions. (LTOCM application Case Output-System Results-GEN RISK DUE TO GAS SUP MW)
- Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 - 6 = 7)
- Peak Load Exposure per data included in the 2010 CELT Report. (LTOCM application-Case Output-System Results-LOAD FORECAST MW)
- Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency. (LTOCM application Case Output-System Results-OPER RESERVE REQUIREMENT MW)
- Total Load Obligation per the formula (8 + 9 = 10)
- Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
- OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
- 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.
- 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 (EET).

NEPOOL PARTICIPANTS COMMITTEE
9/17/10 MEETING, AGENDA ITEM #4A

2010 Second Quarter Quarterly Markets Report

Marc D. Montalvo
Director, Assessment & Investigation
Internal Market Monitoring
September 17, 2010

Overview of Quarterly Markets Report

- The Quarterly Markets Report reviews energy market competitiveness and contains summary information regarding overall market performance and outcomes
- The IMM studies specific market events, changes in market conditions and possible trends and reports on them each quarter
- Issues for further study and recommendations are presented
- The Quarterly Markets Report is posted at

http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/index.html

Highlights

	2nd Quarter 2010	1st Quarter 2010	2nd Quarter 2009
Real-Time Load (GWh)	30,764	32,065	29,137
Weather Normalized Real-Time Load (GWh)	30,573	32,557	29,712
Peak Real-Time Load (MW)	24,239	19,901	18,468
Average Day-Ahead Hub LMP (\$/MWh)	43.27	50.45	35.52
Average Real-Time Hub LMP (\$/MWh)	45.55	51.71	35.24
Average Natural Gas Price (\$/MMBtu)	4.66	6.19	4.10
Average #6 Oil Price 1% sulfur (\$/MMBtu)	11.46	11.39	8.43
Total NCPC (\$ millions)	17.4	6.6	10.1

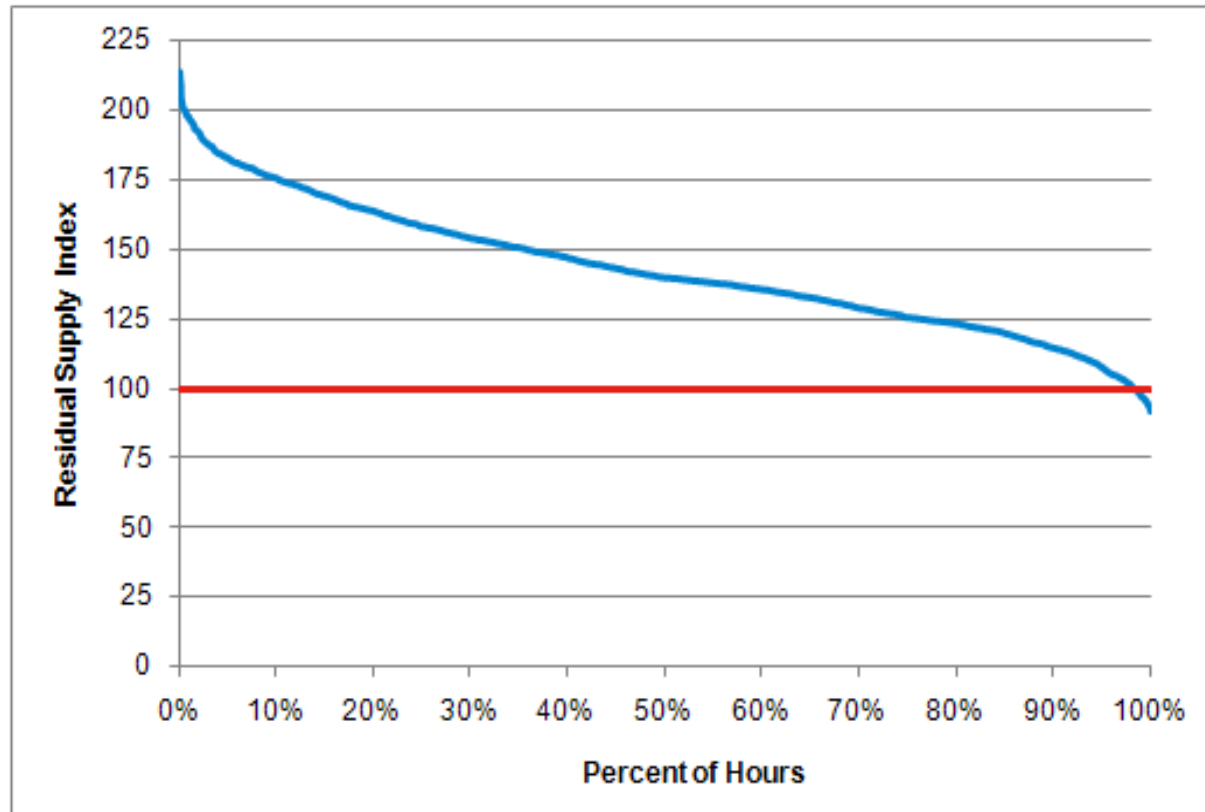
Issues and Recommendations

- The IMM recommends that the ISO consider revising the market rules so that virtual transactions are not allocated real-time NCPC charges.
- The IMM recommends that the ISO consider modifying the market rule to allow the FRM threshold price to be calculated daily using a daily fuel price index.
- The IMM is assessing the market rules and incentives for demand response resources to follow dispatch instructions and may recommend design changes in the future.
- The IMM is reviewing the definition of shortage event and triggers and may recommend design changes in the future.

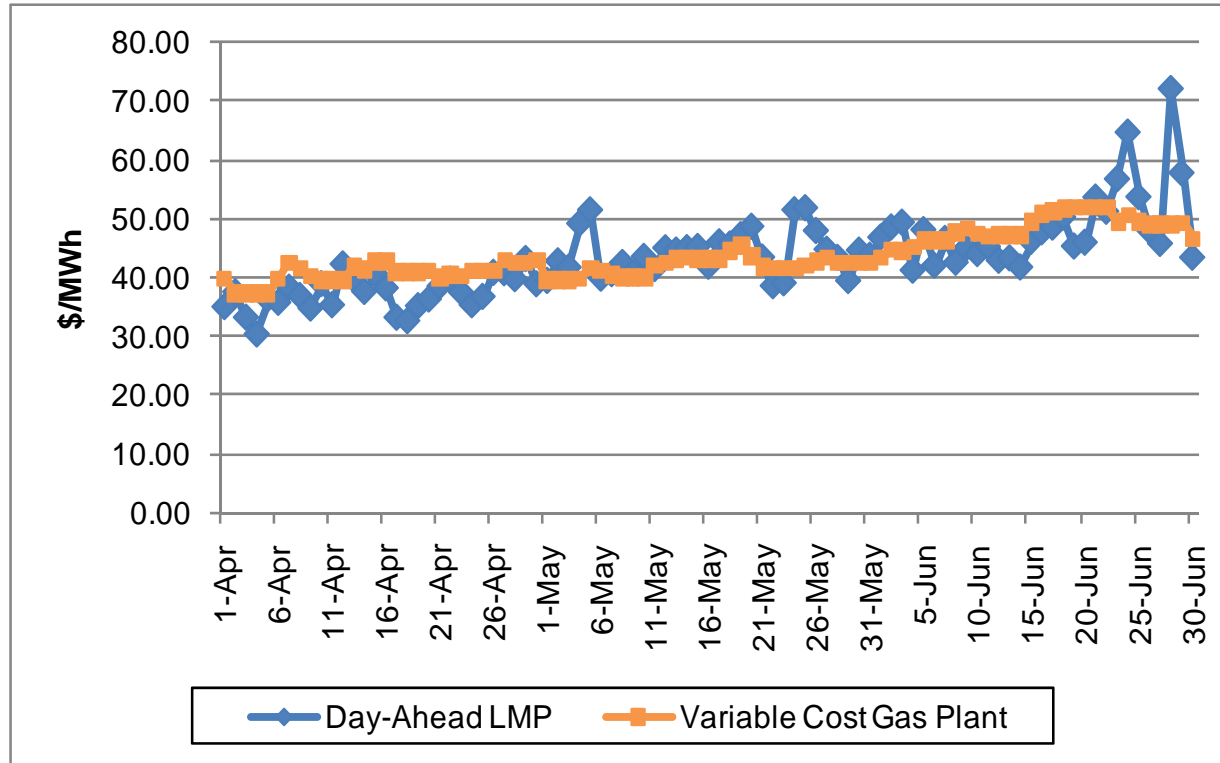
Competitiveness of the Energy Market

- The price outcomes of the ISO administered energy market are consistent with those expected of a competitive market
- The energy market is generally unconcentrated and structurally competitive
- Energy prices by and large reflect supplier short-run marginal costs
- When needed, mitigation rules provide adequate behavioral remedies

Systemwide Residual Supplier Index



Average Day-Ahead Hub Price vs. Running Cost of the Typical Gas Plant



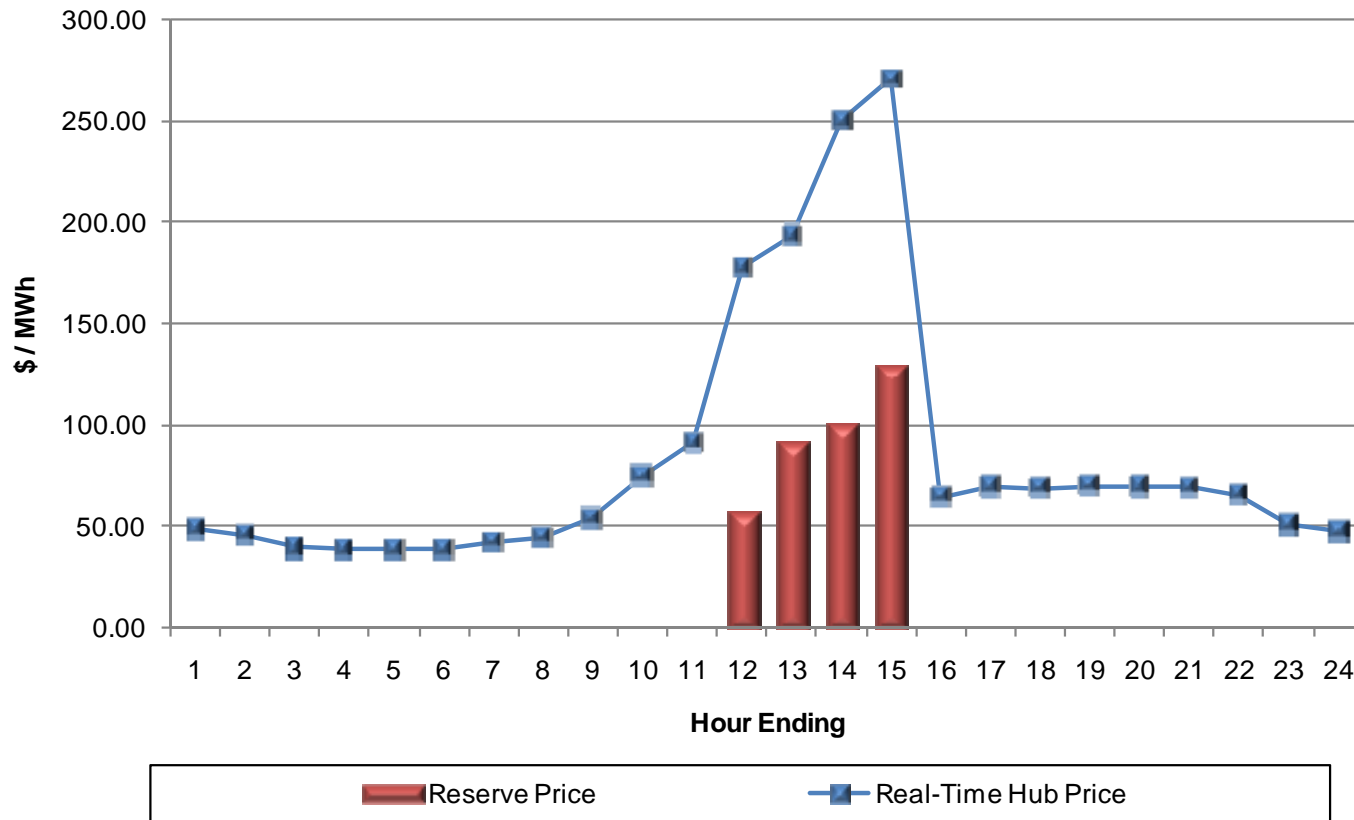
Underlying natural gas data furnished by:



Market Performance on June 24, 2010

- Market performed well; participants acted competitively.
- Higher than expected temperatures and 1,800 MW of generator trips and reductions across the day resulted in capacity shortages.
- ISO invoked Operating Procedure #4, Actions During a Capacity Deficiency.
- Thirty minute operating reserve constraint bound for four hours.
- Ten minute reserve constraint violated for one five minute dispatch interval.
- Manual market interventions by the operators limited to actions required to manage constraints not included in the dispatch algorithm.

Hourly Integrated Real-Time Prices, June 24, 2010

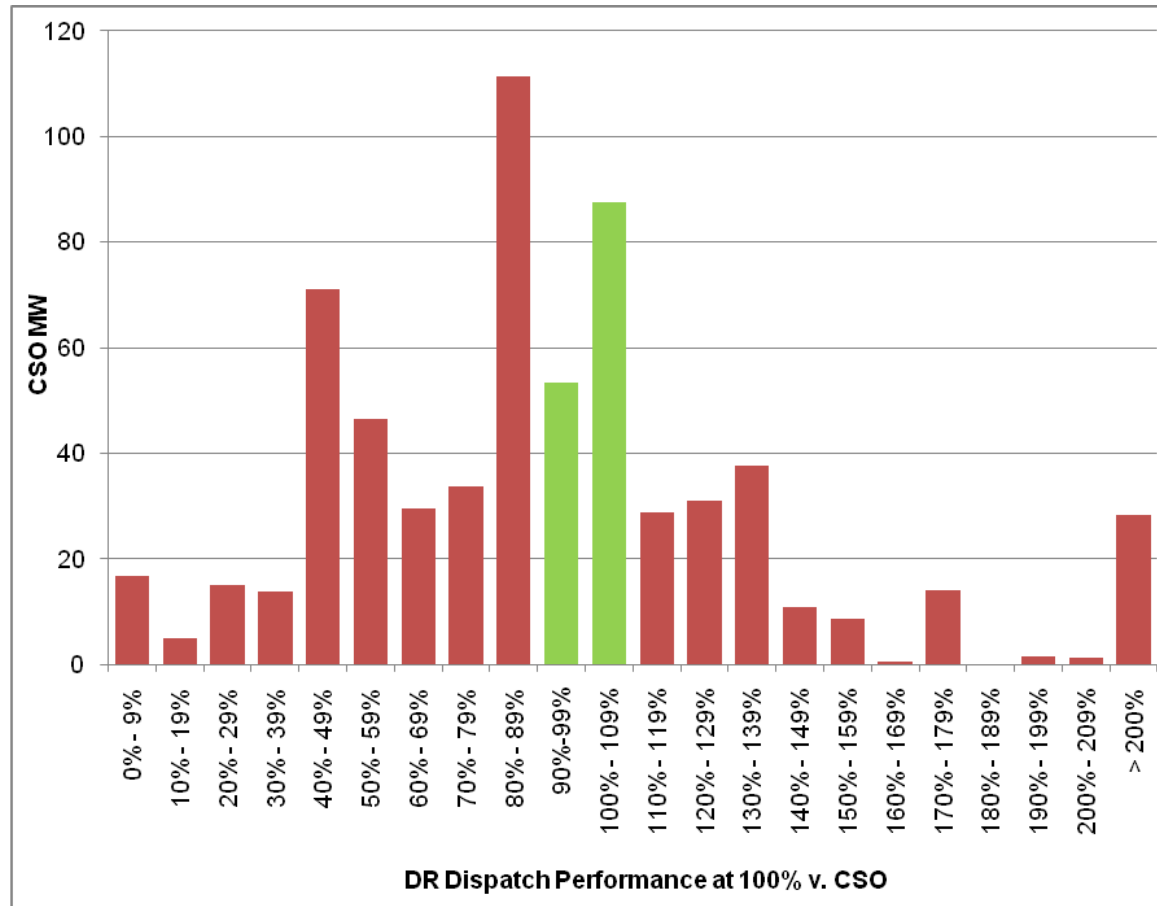


Demand Resource Performance On June 24, 2010

- ISO dispatched 669 MW of demand response resources, 653 MW of responded.
- The IMM observed that the majority of the dispatched demand response resources either underperformed (reduced less than their Capacity Supply Obligation(CSO)) or over-performed (reduced more than their Capacity Supply Obligation). (See slide 12)
- This appears to be the result of several factors:
 - possible incentive problems in the day-ahead load response program (DALRP),
 - a desire or need by some demand response providers to use the event to audit new assets, and
 - the FCM provisions that allow overperforming demand response resources to receive an allocation of the penalties paid by underperforming resources.

Demand Resource Performance (cont'd)

DR reduction as a % of CSO during OP4 Event, June 24, 2010

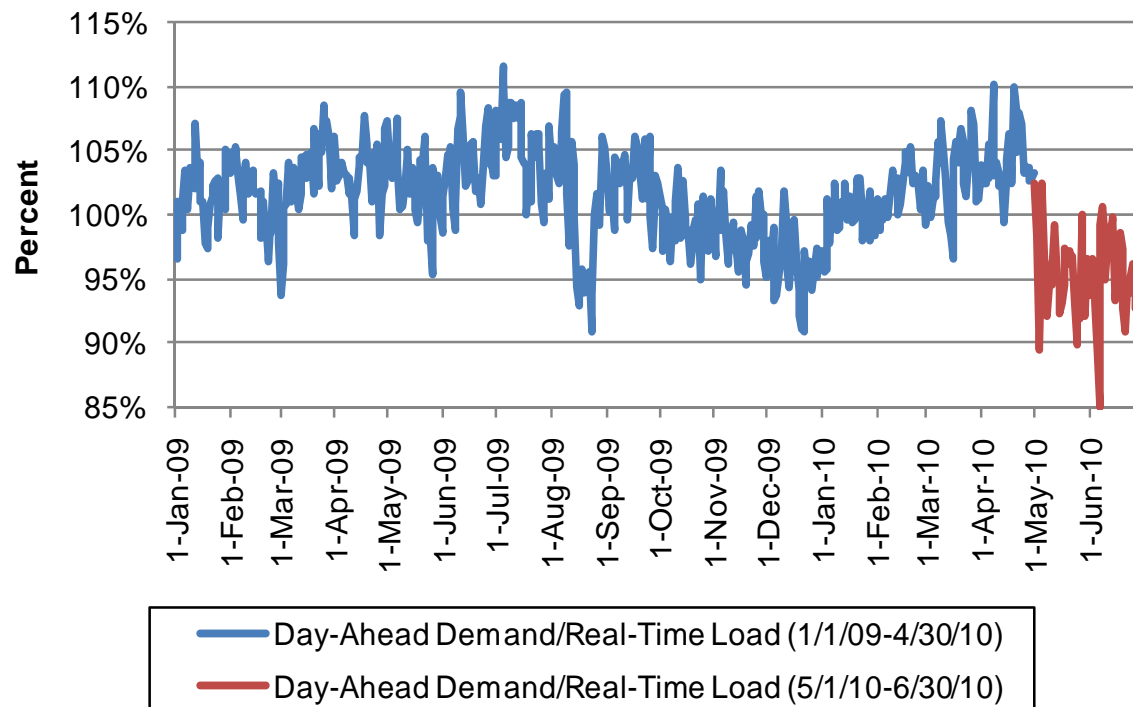


FCM Shortage Event Definition

- A shortage event begins after the ten-minute non-spinning reserve constraint has been violated for thirty contiguous minutes.
- The events of June 24 did not trigger a shortage event.
- On June 24, 2010, the ten-minute non-spinning reserve constraint was violated for one five-minute dispatch interval.
- The shortage event definition requires an extraordinary system condition and tying a shortage events to such extreme conditions may not meet the intent of the overall FCM performance penalty structure.
- The IMM will conduct additional analysis of this design feature and may recommend design changes in the future.

Review of Reductions in the Percentage of Demand Clearing in the Day-Ahead Market

- The graph below shows Day-Ahead demand clearing as a percent of Real-Time load from January 2009 through June 2010.
- Since early May, the percentage of demand clearing in the Day-Ahead Market has declined several points.

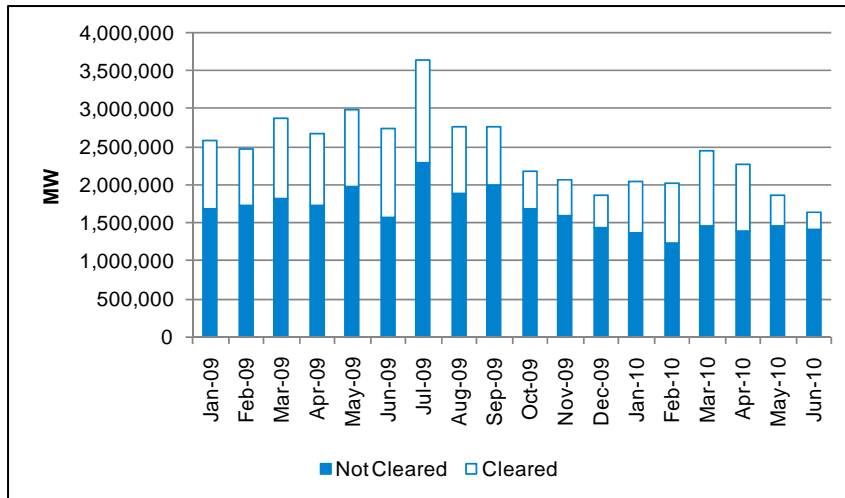


Review of Reductions in the Percentage of Demand Clearing in the Day Ahead Market

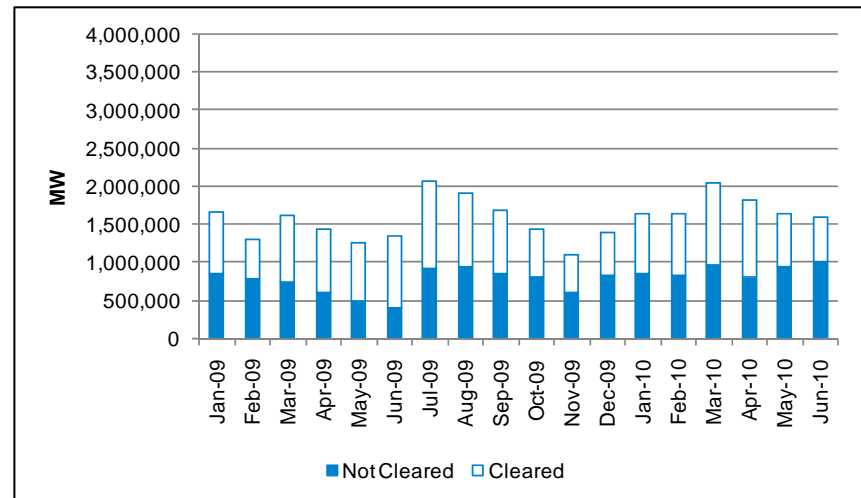
- Decline does not seem to be the result of anticompetitive behavior
 - No observed withholding of supply
 - No discernable change in bidding strategies of physical demand
- Decline likely the result of
 - Lackluster volumes of virtual demand bids submitted and cleared.
 - A sharp reduction in the volume of virtual supply offers submitted and cleared.
 - Beginning in May, a contraction of supply due to long term outages which shifted the supply curve to the left.

Virtual Transaction Volumes

Virtual Offers



Virtual Demand



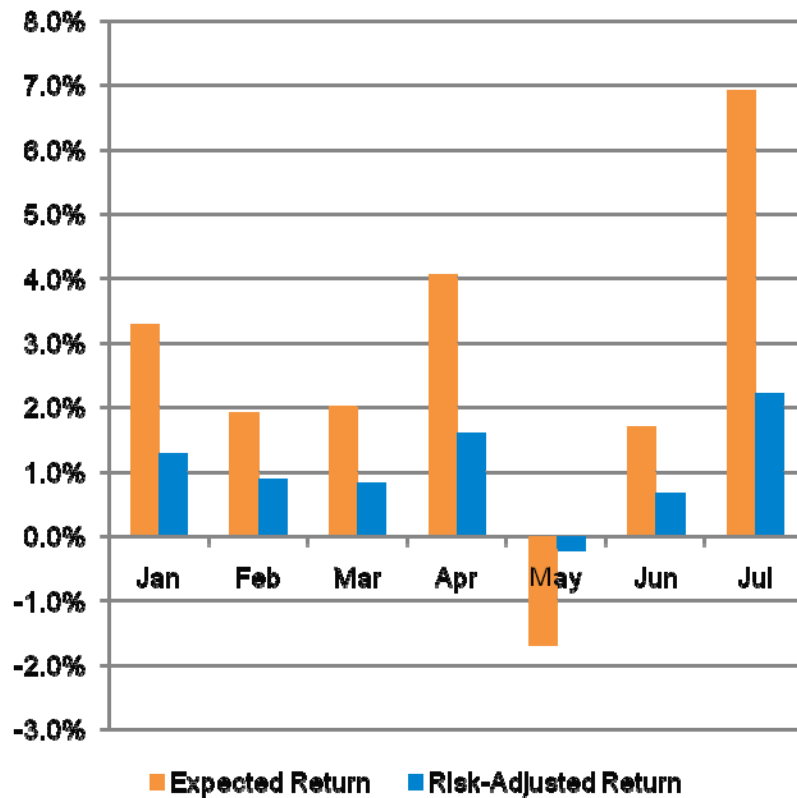
Observations on Virtual Transactions

- Over the last year the volume of submitted and cleared virtual supply offers has decreased and the volume of virtual demand bids has stayed flat, despite real time prices exceeding day ahead prices.
- This behavior is broadly consistent with the following:
 - Changes in the day-ahead/real-time price relationship have reduced the opportunities for virtual supply in the day-ahead market.
 - The risk associated with taking virtual bidding positions given the volatility of real time prices.
 - The high transaction costs associated with taking these positions.

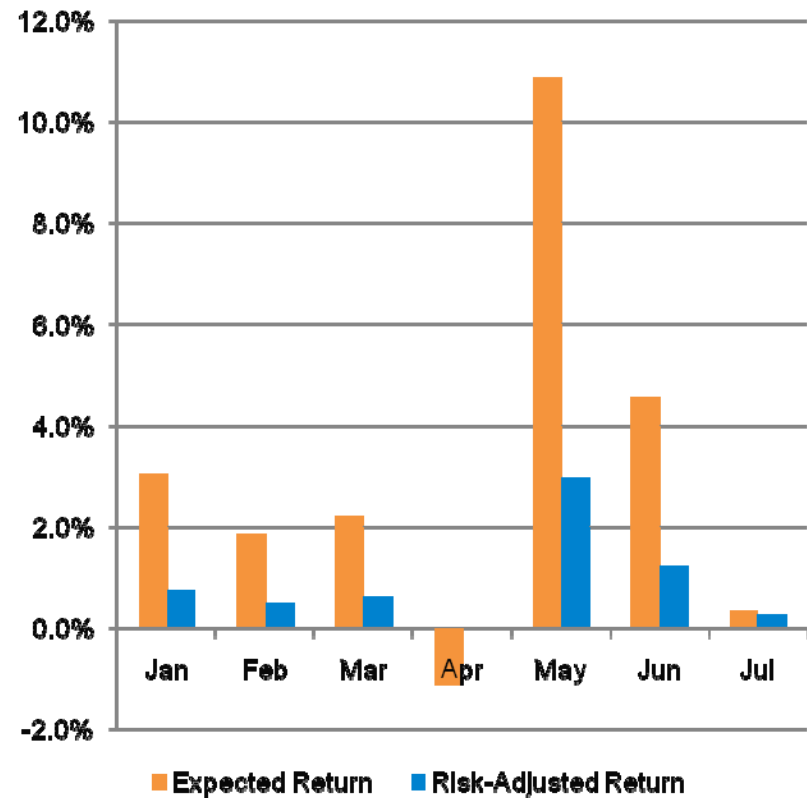
Returns on Virtual Transaction Positions

Analysis of returns on a 1MW position cleared in every hour assuming that the sample distribution equals the true distribution

Virtual Offers



Virtual Bids



Observations on Virtual Transactions (Cont)

- The total amount of NCPC charged to virtual transactions over the last six months has been remarkably high relative to the overall profitability of the positions taken.
 - In the first 6 months of 2010, the profitability of virtual positions totaled \$8.4 million.
 - The total allocation of NCPC charges to these positions totaled \$6.4 million.
- The IMM recommends that the ISO consider revising the market rules so that virtual transactions are not allocated real-time NCPC charges.

Review of the Interaction of Load Forecast Error and Price Spikes

- Occasionally we have seen large differences between the load forecast used to make supplemental commitments and actual loads. On some of these days, price spikes have occurred in the real-time market.
- IMM prepared an analysis to determine if there was a systematic problem with the ISO load forecast and to determine if supply withholding contributed to the price spikes.
- The IMM has found that:
 - The load forecasts has little bias;
 - The majority of the load forecast error can be explained by weather forecast error; and
 - Price spikes experienced on days with large load forecast error are the result of the interaction of supply and demand in the presence of stochastic shocks, (e.g. loss of a resource or transmission line) not the consequence of withholding.

Questions?



To: NEPOOL Budget & Finance Subcommittee and Participants Committee

From: Bob Ludlow and Cheryl Arnold

Date: September 14, 2010

Subject: Projected 2011 Revenue Requirement for ISO New England Administrative Cost
Tariff Schedules

To help our Participants prepare their 2011 budgets and consistent with information provided in previous years, this memo includes a preliminary indication of ISO-NE's 2011 costs. Specifically, the memo includes (1) the estimated 2011 Revenue Requirement, including the true-ups for previous years, and a comparison to the 2010 Revenue Requirement (see Exhibit 1 below), and (2) the 2011 Revenue Requirement by activity (see Exhibit 2, which is attached). The cost assignment and allocation mechanisms that were utilized in the Draft 2011 Tariff schedules were established as part of the settlement that has been in effect for the last nine years.

Because of true-ups, the overall Revenue Requirement has decreased by \$3.0 million year-over-year, from \$137.2M for 2010 to \$134.2M for 2011. Prior to true-ups, the 2011 Revenue Requirement reflects an overall increase of 7.8%. By Tariff Schedule, the increases are: Schedule 1, 11%; Schedule 2, 8%; and Schedule 3, 5%. The increase is due in part to economic and external factors, including interest rates, salary adjustments, health insurance cost increases and depreciation expense, as well as the cost to maintain the increased work committed to in previous years, including compliance, computer services, demand resource integration and Forward Capacity Market (FCM). In addition, the increase is attributable to enhanced services included in this "measured growth" budget. These services include transmission planning, FCM, price responsive demand, studies and application development and user interface improvements.

Draft Exhibit 1				
ISO New England Revenue Requirement By Tariff Schedule 2011 Estimated Amount vs. 2010 ACT Filed Amount				
	Sch 1	Sch 2	Sch 3	Total
2011 Revenue Requirement Before Prior Year True Ups	\$ 33,845,121	\$ 62,046,284	\$ 47,540,110	\$ 143,431,515
2009 Final True Up	(1,580,949)	1,155,734	(2,077,700)	(2,502,914)
2010 Estimated True Up	(1,333,445)	(2,147,842)	(3,271,390)	(6,752,677)
Total 2011 Estimated Revenue Requirement By Tariff Schedule	30,930,727	61,054,175	42,191,020	134,175,923
Total 2010 Revenue Requirement as filed in 2010 ACT filing	33,697,623	54,415,081	49,040,932	137,153,636
\$ Increase/(Decrease) from 2010 to 2011	\$ (2,766,896)	\$ 6,639,094	\$ (6,849,912)	\$ (2,977,713)
% Increase/(Decrease) from 2010 to 2011	(8.2%)	12.2%	(14.0%)	(2.2%)

As indicated in Exhibit 1, Tariff Schedule 1 has decreased by approximately \$2.8M, or 8.2%. The decrease in the Schedule 1 revenue requirement is due to true-ups for prior years. In the fourth quarter of 2009 and continuing into 2010, Schedule 1 Tariff collections have been higher than the filed amounts as a result of the higher network load values that have been seen across the load-related Tariff schedules. Also contributing was lower-than-projected spending across a number of areas and line items in the last four months of 2009 plus currently forecasted lower spending for 2010. This lower spending is primarily savings on depreciation expense due to the timing of project go-live dates (which impacts all three Tariff schedules) and an estimate that the \$1 million Board of Directors contingency will not be utilized.

Excluding the net impact of prior year true-ups, Schedule 1 costs increased by \$3.4M. This increase is attributable to:

- increased depreciation costs of \$0.9M for projects that impact all three Tariff schedules (e.g., Business Continuity Plan Infrastructure Enhancements Phase I, Web Enhancements, and Credit and Billing Enhancements) and projects that pertain mostly to Schedule 1 (the Facilities Outage Scheduling System Phase II and Outage Coordination Economic Analysis Tool Phases I and II)
- an increase in Short-Term Transmission Outage Application work
- 2011 Measured Growth costs for Transmission Planning/Non-Transmission Alternatives
- 2011 Measured Growth activities impact all Tariff schedules, including Schedule 1 (Information Delivery, Cost Impact Analysis, User Interface Improvements, and Studies and Application Development)
- economic and external factors and the cost of maintaining services added in the past few years, including compliance and business continuity

Tariff Schedule 2 has increased by \$6.6M, or 12.2%. Included is:

- \$1.8M increase for true-ups, as a result of higher-than-projected Schedule 2 energy volume (offset by lower-than-projected transaction unit activity related to Virtual Energy and Financial Transmission Rights and lower-than-projected spending)
- increased depreciation costs of \$0.5M for projects that impact all three Tariff schedules (see above) and projects that pertain mostly to Schedule 2 (Demand Resource Integration and Customer Asset Management System II projects)
- an increase in activity for Market Monitoring, Business Process Improvement and Market Analysis work in the Market Operations area
- IT Applications Development non-internal capital development work
- economic and external factors and the cost of maintaining services added in the past few years, including compliance, demand resource integration and business continuity

Tariff Schedule 3 has decreased by approximately \$6.8M, or 14.0%, due to true-ups for prior years. The true-ups reflect higher-than-projected collections across the load-related Tariff schedules (see above) and increased Schedule 3 export-related Tariff revenues, combined with lower-than-projected spending (also discussed above).

Memo Regarding Proposed 2011 Revenue Requirement

September 13, 2010

Page 3

Excluding the net impact of prior year true-ups, Schedule 3 costs increased \$2.3M. Included is:

- an increase in depreciation costs of \$0.5M for projects that impact all three Tariff schedules (see above) and projects that pertain mostly to Schedule 3 (FCM Phase III, FCM Enhancements, Operational Enhancements, and Auditing and Testing projects)
- an increase in FCM support activity
- an increase in NPCC/NERC Dues
- an increase in Eastern Interconnection Planning Collaborative and Smart Grid related work (i.e., the portions not funded by the Department of Energy grant)
- measured growth activities that impact all Tariff schedules (see above)
- economic and external factors and costs attributable to services added in the past few years, including compliance and business continuity

Attached you will find **Exhibit 2**, which is a draft of the 2011 revenue requirement by activity. This exhibit will be part of the Administrative Cost Tariff filing.

The ISO 2011 Revenue Requirement will be reviewed and voted on at the September 17, 2010 NPC meeting. Should you have any questions regarding the information provided in this memo, do not hesitate to contact us.

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Administration-CEO						
2	12651	Adm/Finance/HR - Indirect Administrative Support	Total Dir Labor	\$ 6,861,713	\$ 1,478,563	\$ 3,551,012	\$ 1,832,138
3	12652	Adm/Finance/HR - NEPOOL Committee Support	Total Dir Labor	5,353	1,153	2,770	1,429
4	12654	Adm/Finance/HR - National Committee Support	Total Dir Labor	7,302	1,573	3,779	1,950
5		Total		6,874,367	1,481,290	3,557,561	1,835,516
6							
7	Finance						
8	11601	Payroll Administration	Total Dir Labor	167,668	36,129	86,770	44,769
9	11701	Accounts Payable	Total Dir Labor	116,100	25,017	60,083	31,000
10	11702	Procurement	Total Dir Labor	186,453	40,177	96,492	49,785
11	11901	Billing for Transmission and Energy Settlements	Total Dir Labor	67,517	14,549	34,941	18,028
12	12001	Iso Tariff Design	Total Dir Labor	359,539	77,474	186,065	96,000
13	12002	Credit Administration	Total Dir Labor	3,156	680	1,633	843
14	12005	Credit Administration	Total Dir Labor	485,973	104,718	251,496	129,759
15	12010	Zone/BU/CCC Support	Total Dir Labor	4,926	1,062	2,549	1,315
16	12012	Forward Capacity Market Production	Alloc-Fixed	250,000	-	-	250,000
17	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	416,550	89,758	215,569	111,222
18	12201	Treasury and Cash Management	Total Dir Labor	2,842,666	612,538	1,471,111	759,017
19	12301	Activity Accounting and Reporting	Total Dir Labor	9,083	1,957	4,700	2,425
20	25554	Generation Information System	Alloc-Fixed	4,552	2,048	2,048	455
21	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	64,178	8,991	36,299	18,888
22	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	803,609	167,713	419,323	216,573
23	92006	Depreciation Expense 2006 Assets	Alloc-Fixed	1,352,553	309,464	658,423	384,666
24	92007	Depreciation Expense 2007 Assets	Alloc-Fixed	1,352,822	241,479	224,433	886,910
25	92008	Depreciation Expense 2008 Assets	Alloc-Fixed	5,810,900	1,158,693	2,297,049	2,355,158
26	92009	Depreciation Expense 2009 Assets	Alloc-Fixed	7,816,147	1,590,586	2,454,270	3,771,291
27	92010	Depreciation Expense 2010 Assets	Alloc-Fixed	7,114,468	1,406,530	2,386,193	3,321,745
28	92011	Depreciation Expense 2011 Assets	Alloc-Fixed	1,622,596	297,422	804,483	520,691
29	99995	NPCC/NERC Dues	Alloc-Fixed	4,557,098	-	-	4,557,098
30	99996	Operating Contingency	Total Dir Labor	800,000	172,384	414,009	213,607
31	99996	Operating Contingency	Total Dir Labor	1,000,000	215,480	517,511	267,009
32	99998	Payroll & Other Accruals	Total Dir Labor	7,347,185	1,583,173	3,802,249	1,961,763
33		Total		44,555,738	8,158,023	16,427,700	19,970,015
34							
35	Building Services						
36	12664	Building Maintenance	Total Dir Labor	2,755,019	593,652	1,425,753	735,614
37	12668	Building Maintenance - Offsite Temporary Offices	Total Dir Labor	54,562	11,757	28,236	14,568
38		Total		2,809,581	605,409	1,453,989	750,183
39							
40	Enterprise Risk Management						
41	21301	ERM - QC & BP Anal & Coordination	Alloc-Fixed	141,126	46,995	46,995	47,136
42	22701	ERM -Enterprise Risk Mgmt - Admn	Alloc-Fixed	64,048	21,328	21,328	21,392
43	22702	ERM -Enterprise Risk Mgmt - Initia	Alloc-Fixed	90,263	30,058	30,058	30,148
44	22703	ERM-Bus Cont Pl Prog Admin & Support	Alloc-Fixed	26,391	8,788	8,788	8,814
45	22704	ERM - Record Retention Services	Alloc-Fixed	33,386	11,118	11,118	11,151
46	22705	ERM - Corporate Scorecard	Alloc-Fixed	109,555	36,482	36,482	36,592
47	22706	ERM - Document Management Services	Alloc-Fixed	4,387	1,755	1,316	1,316
48	23001	CP - COS, RMR, and PUSH	Alloc-Fixed	1,206	-	603	603
49	23002	CP - Strategic and Business Planning	Alloc-Fixed	36,397	12,120	12,120	12,157
50	23003	CP - Safety / Security / Facilities	Total Dir Labor	32,516	7,007	16,827	8,682
51	25006	ERM - Business Process Maintenance	Alloc-Fixed	83,182	37,432	37,432	8,318
52	25011	Corrective Action/Preventive Action	Alloc-Fixed	4,552	1,516	1,516	1,520
53	25008	QMS - Quality Management System	Alloc-Fixed	317,187	105,623	105,623	105,940
54		Total		944,196	320,221	330,206	293,770
55							
56	Human Resources						
57	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	45,527	9,810	23,561	12,156
58	12701	Recruiting/Interviewing	Total Dir Labor	681,557	146,862	352,713	181,982
59	12801	Employee Relations	Total Dir Labor	7,506	1,617	3,884	2,004
60	12901	Benefit Administration	Total Dir Labor	1,058,782	228,147	547,931	282,704
61	12951	Compensation	Total Dir Labor	264,536	57,002	136,900	70,633
62	12961	HR - General	Total Dir Labor	511,920	110,309	264,924	136,687
63	12962	HR - Training	Total Dir Labor	806,324	173,747	417,282	215,296
64	13301	Labor Relations	Total Dir Labor	48,175	10,381	24,931	12,863
65		Total		3,424,328	737,875	1,772,127	914,326

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No. (a)	Description (b)		Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		Legal Department					
2	8301	GC - Federal Regulatory	Total Dir Labor	40,595	8,747	21,008	10,839
3	12423	GC - Financial Assurance Policy (FAP)	Total Dir Labor	222,083	47,855	114,931	59,298
4	12425	GC - e-Tariff Filings on Behalf of Third Parties	Total Dir Labor	72,000	15,515	37,261	19,225
5	12502	Board of Directors	Total Dir Labor	143,882	31,004	74,461	38,418
6	12504	ISO Tariff Litigation	Total Dir Labor	112,595	24,262	58,269	30,064
7	12505	Administration of OATT	Alloc-Fixed	309,571	309,571	-	-
8	12508	Energy Markets/Compliants/Rule Changes	Alloc-Fixed	20,297	-	20,297	-
9	12509	Market Monitoring and Sanctions	Alloc-Fixed	40,595	-	20,297	20,297
10	12513	Miscellaneous Labor Matters	Total Dir Labor	150,001	32,322	77,627	40,052
11	12514	NEPOOL Participants Committee	Total Dir Labor	77,392	16,677	40,051	20,664
12	12517	Administrative and Clerical Support	Total Dir Labor	273,587	58,953	141,584	73,050
13	12520	Market Monitoring Rules/Regulations	Alloc-Fixed	243,570	-	97,428	146,142
14	12521	Billing Disputes	Total Dir Labor	24,001	5,172	12,421	6,408
15	12523	NEPOOL Information Policy	Total Dir Labor	20,297	4,374	10,504	5,420
16	12542	Transmission Upgrades CT	Alloc-Fixed	59,999	-	42,000	18,000
17	12543	Independent Market Advisor	Alloc-Fixed	800,000	-	560,000	240,000
18	12544	FERC Proceedings	Total Dir Labor	144,362	31,107	74,709	38,546
19	12555	GC - Transmission Upgrades - VT	Total Dir Labor	5,999	1,293	3,104	1,602
20	12559	General Corporate	Total Dir Labor	1,006,986	216,986	521,126	268,874
21	12562	Transmission Upgrades VT (WBAM)	Alloc-Fixed	12,000	-	8,400	3,600
22	12563	Regulatory Matters	Total Dir Labor	119,999	25,857	62,101	32,041
23	12565	GC - Conn Regulatory Matters - (WBAM)	Total Dir Labor	42,447	9,146	21,967	11,334
24	12569	NOPR / Rulemaking Comments	Total Dir Labor	215,999	46,544	111,782	57,674
25	12570	Operations	Total Dir Labor	47,999	10,343	24,840	12,816
26	12571	ISO Reporting	Total Dir Labor	12,000	2,586	6,210	3,204
27	12572	GC - BSAI - 205 General Proceedings	Total Dir Labor	119,999	25,857	62,101	32,041
28	12573	206 General Proceedings	Total Dir Labor	108,001	23,272	55,892	28,837
29	12574	Market Rule 1 Proceedings	Total Dir Labor	468,000	100,845	242,195	124,960
30	12575	Transmission Cost Allocation	Alloc-Fixed	196,001	-	137,200	58,800
31	12579	GC - SH - Market Rule 1 Proceedings	Total Dir Labor	215,999	46,544	111,782	57,674
32	12583	GC - SH - LICAP Appeal	Alloc-Fixed	17,999	-	-	17,999
33	12584	Installed Capacity Requirements	Alloc-Fixed	84,000	-	-	84,000
34	12587	Capacity Market Development	Alloc-Fixed	628,209	-	-	628,209
35	12588	Web Content Management	Total Dir Labor	350,334	75,490	181,302	93,542
36	12594	Maine Transmission Siting	Alloc-Fixed	59,999	-	42,000	18,000
37	12663	Public Information	Total Dir Labor	1,155,115	248,904	597,785	308,426
38	12556	GC - Patents	Total Dir Labor	5,999	1,293	3,104	1,602
39	12592	GC - State Proceedings	Alloc-Fixed	24,001	-	12,000	12,000
40	12598	GC - ERO	Alloc-Fixed	30,000	12,000	12,000	6,000
41	12669	Government Affairs	Total Dir Labor	1,595,258	343,746	825,563	425,948
42		Total		9,277,172	1,776,263	4,445,304	3,055,606
43							
44		Internal Audit					
45	15001	Audit - Indirect Mgmt Duties	Total Dir Labor	28,675	6,179	14,840	7,656
46	15002	Audit- Personnel Management	Total Dir Labor	11,412	2,459	5,906	3,047
47	15003	Audit- Budget & Forecasting	Total Dir Labor	11,412	2,459	5,906	3,047
48	15005	Audit - Audit & Finance Committee	Total Dir Labor	17,119	3,689	8,859	4,571
49	15007	Audit- Annual Audit Work Plan	Total Dir Labor	22,825	4,918	11,812	6,094
50	15008	Audit-Training	Total Dir Labor	65,400	14,092	33,845	17,462
51	15021	Audit- Performance Measurements	Total Dir Labor	28,531	6,148	14,765	7,618
52	15022	Audit- Vendor Contracts	Total Dir Labor	13,620	2,935	7,048	3,637
53	15023	Audit- Wire Transfers	Total Dir Labor	9,988	2,152	5,169	2,667
54	15026	Audit - Financial Assurance	Total Dir Labor	36,836	7,938	19,063	9,836
55	15031	Audit - Financial Assurance	Total Dir Labor	19,584	4,220	10,135	5,229
56	15040	Audit-Operations	Total Dir Labor	238,238	51,336	123,291	63,612
57	15058	Audit - Asset Registration	Total Dir Labor	5,706	1,230	2,953	1,524
58	15090	Audit - Training	Total Dir Labor	5,450	1,174	2,820	1,455
59	15161	External Audit- Pension Audit	Total Dir Labor	55,219	11,899	28,576	14,744
60	15162	Ext Audit- Financial Audit	Total Dir Labor	81,280	17,514	42,063	21,702
61	15166	Ext Audit -Pricing Module Certification	Alloc-Fixed	76,200	-	76,200	-
62	15085	Audit - Information Technology	Total Dir Labor	34,237	7,378	17,718	9,142
63	15110	External Audit - Operations	Total Dir Labor	22,825	4,918	11,812	6,094
64	15177	Ext Audit - Satellite / SCADA Internet Vulnerability Assessment	Total Dir Labor	17,780	3,831	9,201	4,747
65	15186	Ext Audit - SAS 70 Direct Support	Total Dir Labor	11,412	2,459	5,906	3,047
66	15190	Int Audit Special Projects	Total Dir Labor	28,664	6,177	14,834	7,654
67	15191	IA Special Projects - Audit Universe - Auto Audit Implementation	Total Dir Labor	2,724	587	1,410	727
68	15192	IA Special Projects - Data Mining - Audit Command Language Imp	Total Dir Labor	3,632	783	1,880	970
69	25702	External Audit - SAS 70	Alloc-Fixed	408,934	-	408,934	-
70	28581	External Firm Stimulus Funds - Project Mock Audit	Total Dir Labor	25,400	5,473	13,145	6,782
71		Total		1,283,106	171,947	898,093	213,066

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		COO-Adm					
2	19001	COO - NEPOOL Committee Support	Total OPS Labor	5,329	1,428	2,555	1,345
3	19003	COO - National Committee Support	Total OPS Labor	21,315	5,713	10,221	5,381
4	19004	Employee Development	Total OPS Labor	6,050	1,621	2,901	1,527
5	19005	COO - Indirect Supervision/Clerical Support	Total OPS Labor	1,301,867	348,920	624,290	328,656
6	19007	COO - Operational Excellence	Total OPS Labor	500,000	134,008	239,767	126,225
7	19009	COO - Renewable Resource Integration	Alloc-Fixed	272,663	-	-	272,663
8		Total		2,107,224	491,690	879,735	735,798
9							
10							
11		System Operations - Administration					
12	14405	System Ops Mgt & Adm - Indirect Supervision/Clerical Support	SOA Labor	559,426	193,226	259,685	106,515
13	14408	System Ops Mgt & Adm - National Committee Support	SOA Labor	11,127	3,843	5,165	2,119
14	14409	System Ops Mgt & Adm - Employee Development	SOA Labor	45,000	15,544	20,888	8,568
15		Total		615,553	212,613	285,738	117,201
16							
17		Operations					
18	14001	Ops - Generation Dispatch	Alloc-Fixed	2,487,437	-	2,089,447	397,990
19	14002	Ops - Transmission Operations	Alloc-Fixed	1,649,429	1,319,543	82,471	247,414
20	14304	Ops - Advanced Scheduling and Forecasting	Alloc-Fixed	822,093	41,105	649,453	131,535
21	14402	Ops - Operations Training	Alloc-Fixed	1,803,866	721,546	721,546	360,773
22	14413	Ops - Operations Support Training & Development	Alloc-Fixed	822,093	328,837	328,837	164,419
23	14562	Ops - Regional Committee Support	OPS Labor	21,070	5,890	11,665	3,514
24	14563	Ops - National Committee Support	OPS Labor	12,440	3,478	6,887	2,075
25	14564	Ops - Indirect Supervision/Clerical Support	OPS Labor	822,093	229,829	455,141	137,122
26	14702	TPC - Procedure Documentation	Alloc-Fixed	473,337	189,335	189,335	94,667
27		Total		8,913,856	2,839,563	4,534,783	1,539,510
28							
29		Reliability and Operations Services					
30	14703	TPC - NEPOOL Committee Support	OS Labor	350,866	194,895	67,831	88,140
31	14704	TPC - Regional Committee Support	OS Labor	24,949	13,858	4,823	6,287
32	14706	TPC - Indirect Supervision/Clerical Support	OS Labor	34,766	19,311	6,721	8,733
33	14711	ISO TMS Tariff-Section 2 - (OATT) and Agreements Support	Alloc-Fixed	233,657	77,808	77,808	78,042
34	14715	EIPC - Non DOE Funded/Unallowable	Alloc-Fixed	235,490	-	-	235,490
35	14716	EIPC - Initiate Project	Alloc-Fixed	99,403	-	-	99,403
36		Total		979,131	305,873	157,183	516,076
37							
38		Reliability and Operations Compliance					
39	14801	ROC - Compliance Monitoring	Alloc-Fixed	634,509	253,804	253,804	126,902
40	14802	ROC - NEPOOL Committee Support	OS Labor	2,196	1,098	-	1,098
41	14803	ROC - Regional Committee Support	OS Labor	91,636	45,818	-	45,818
42	14805	ROC - Indirect Supervision/Clerical Support	OS Labor	1,411	784	273	354
43	14806	ROC - Employee Development	OS Labor	6,799	3,777	1,314	1,708
44	14808	ROC - Change Management	Alloc-Fixed	50,588	22,764	5,059	22,764
45	14809	ROC - Tariff Compliance	Alloc-Fixed	121,843	36,553	73,106	12,184
46	14810	ROC - NERC Self Certifications	Alloc-Fixed	25,219	21,436	-	3,783
47	14804	ROC - National Committee Support	OS Labor	51,428	25,714	-	25,714
48		Total		985,628	411,747	333,555	240,326
49							
50		Operations Support Services					
51	14301	TSO - Contract Administration and Scheduling	Alloc-Fixed	(60,000)	(6,000)	(42,000)	(12,000)
52	14451	TSO - NEPOOL Committee Support	TSO Labor	14,390	4,659	6,880	2,852
53	14452	TSO - Regional Committee Support	TSO Labor	47,251	15,297	22,590	9,364
54	14453	TSO - National Committee Support	TSO Labor	20,720	6,708	9,906	4,106
55	14454	TSO - Indirect Supervision/Clerical Support	TSO Labor	804,056	260,307	384,408	159,341
56	14455	TSO - Employee Development	TSO Labor	148,022	47,921	70,767	29,334
57	14462	OSS - General Systems Operations Support	TSO Labor	553,212	179,099	264,483	109,631
58	14464	OSS - Econ Anal Equip Out (TOA)	Alloc-Fixed	118,334	118,334	-	-
59	14466	OSS - Monthly Forward Capacity Market (FCM)	Alloc-Fixed	384,586	-	-	384,586
60	18361	OSS - Transmission Studies, Operations, OASIS Support	Alloc-Fixed	2,336,156	1,868,925	116,808	350,423
61	18381	OSS - Transmission Outage Appl - Short Term	Alloc-Fixed	1,680,345	1,344,276	84,017	252,052
62	18382	OSS - Trans Out Ap Lg Term	Alloc-Fixed	207,085	-	-	207,085
63		Total		6,254,158	3,839,526	917,858	1,496,774

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No. (a)	Description (b)		Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		Market Operations - Adm					
2	19101	MO - NEPOOL Committee Support	MOA Labor	3,092	-	2,164	927
3	19103	MO - National Committee Support	MOA Labor	3,092	-	2,164	927
4	19104	MO - Indirect Supervision/Clerical Support	MOA Labor	1,010,312	-	707,219	303,094
5	19105	Employee Development	MOA Labor	15,971	-	11,180	4,791
6	19118	Cost of Poor Quality - COPQ	Alloc-Fixed	49,465	16,487	16,487	16,482
7	19119	Corporate Scorecard Metrics	Alloc-Fixed	6,183	2,061	2,061	2,061
8	19120	CEII Requests	Total Dir Labor	24,733	5,330	12,799	6,604
9	19121	Membership/Participant Support	Alloc-Fixed	24,733	-	12,366	12,366
10	19112	Settlements - Customer Service	MOA Labor	140,498	-	98,348	42,149
11		Total		1,278,078	23,877	864,788	389,412
12							
13		Market Monitoring					
14	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	1,895,567	-	1,326,897	568,670
15	16103	Administration Supervision and Clerical Support	Alloc-Fixed	101,676	-	71,173	30,503
16	16111	Employee Development	MMM Labor	375,483	-	262,838	112,645
17	16117	Manuals & Procedures	MMM Labor	2,311	-	1,618	693
18	16121	FCM Market Monitoring	Alloc-Fixed	337,025	-	-	337,025
19		Total		2,712,062	-	1,662,526	1,049,536
20							
21		Hourly Market Operations					
22	21901	Day Ahead Market Administration	Alloc-Fixed	296,760	-	296,760	-
23	21902	Real Time Price Verification	Alloc-Fixed	296,760	-	296,760	-
24	21903	FTR/ARR Administration	Alloc-Fixed	118,685	59,342	59,342	-
25	21907	MA - Indirect Supervision/Clerical Support	MA Labor	85,189	-	82,498	2,690
26	21908	Employee Development	MA Labor	86,263	-	83,539	2,724
27	21913	MA-Data Collection/Report Writing	Alloc-Fixed	42,394	-	42,394	-
28	21914	QUA Administration	Alloc-Fixed	89,014	44,507	44,507	-
29	21915	FTR/Auction Administration	MA Labor	308,580	-	308,580	-
30	21916	Forward Reserve Market - Administration	Alloc-Fixed	20,770	-	-	20,770
31	21917	Real Time Price Finalization	Alloc-Fixed	84,789	-	84,789	-
32		Total		1,429,204	103,849	1,299,170	26,184
33							
34		Market Analysis & Settlements					
35	1701	Billing Statements - Energy	Alloc-Fixed	74,580	-	74,580	-
36	1702	Billing Statements - Transmission	Alloc-Fixed	45,168	45,168	-	-
37	1713	Billing Statements - ISO Tariff	Total Dir Labor	23,460	5,055	12,141	6,264
38	1714	Billable Tariff Re-billings	Alloc-Fixed	2,451	2,451	-	-
39	2036	MAS - Market Analysis - Projects	Alloc-Fixed	117,298	-	117,298	-
40	2037	MAS - Bill Job Aid	Alloc-Fixed	7,003	1,050	4,202	1,751
41	2038	MAS - Standard MAS	Alloc-Fixed	23,460	-	14,076	9,384
42	2039	MAS - BITT and Business Tools	Alloc-Fixed	51,471	7,721	30,883	12,868
43	2041	MAS - Production Support - Hourly Markets	Alloc-Fixed	46,919	-	42,227	4,692
44	2042	MAS - Production Support - Monthly Markets	Alloc-Fixed	49,370	14,811	4,937	29,622
45	2043	MAS - Release Checkout and Support	Alloc-Fixed	2,451	368	1,471	613
46	2044	MAS - EQR Reporting	Alloc-Fixed	2,451	368	1,471	613
47	2047	MAS - Score Card	Alloc-Fixed	31,513	4,661	15,350	11,502
48	2048	MAS - FCM	Alloc-Fixed	140,757	-	-	140,757
49	2049	MAS - Product Testing	Alloc-Fixed	14,006	-	11,205	2,801
50	2050	MAS - Business Acceptance Testing	Alloc-Fixed	2,451	-	1,961	490
51	2051	MAS - Legal Support	Alloc-Fixed	23,460	-	11,730	11,730
52	2052	MAS - FERC Data Request	Alloc-Fixed	23,460	-	11,730	11,730
53	2053	MAS - Tariff Change Coordination (TCC)	Total Dir Labor	11,905	2,565	6,161	3,179
54	2005	Settlements - Customer Service	STLM Labor	67,284	9,950	32,777	24,558
55	2007	Settlements - Admin support - NEPOOL Committees	STLM Labor	31,513	4,660	15,351	11,502
56	2008	Settlements - Admin support (ISO)	STLM Labor	105,393	15,586	51,341	38,467
57	2009	Settlements - Indirect Supervision/Clerical Support	STLM Labor	539,219	79,740	262,674	196,806
58	2010	Settlements - Employee Development	STLM Labor	191,770	28,359	93,418	69,993
59	2013	Settlements - FTR Administration	Alloc-Fixed	11,905	-	11,905	-
60	2014	Billing Statements - NCPD	Alloc-Fixed	110,295	-	55,147	55,147
61	2015	Settlements Projects	STLM Labor	199,231	29,462	97,053	72,716
62	2020	Settlements-Billing Disputes	Total Dir Labor	18,908	4,074	9,785	5,049
63	2021	Settlements-Analysis & Reporting	Total Dir Labor	105,393	22,710	54,542	28,141
64	2022	Settlements-Demand Response	Alloc-Fixed	23,460	-	-	23,460
65	2023	Settlements-Fixed RMR	Alloc-Fixed	2,451	-	-	2,451
66	2024	Settlements - ASM Regulation	Alloc-Fixed	11,905	-	-	11,905
67	2025	Settlements - ASM Locational Forward Reserve	Alloc-Fixed	58,474	-	-	58,474
68	2026	Settlements-Batch Processing	Total Dir Labor	42,367	9,129	21,925	11,312
69	2031	Settlements - Business Streamlining	STLM Labor	119,399	17,657	58,163	43,578
70	2032	Settlements - Billing	STLM Labor	21,009	3,107	10,234	7,668
71	2033	Settlements - Market Analysis	Alloc-Fixed	32,913	-	32,913	-
72	2034	Settlements - COPQ	Alloc-Fixed	210,786	31,618	84,314	94,854
73		Total		2,597,304	340,270	1,252,962	1,004,072

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No. (a)	Description (b)		Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		Market Services					
2	16001	Participant/membership support	Alloc-Fixed	305,335	-	152,668	152,668
3	16006	Call Support (HEAT)	Alloc-Fixed	1,454,819	378,253	960,180	116,385
4	16403	MSS NEPOOL Market Committee	MS Labor	33,006	-	29,706	3,301
5	16404	MSS NEPOOL Committee Support	MS Labor	33,006	-	29,706	3,301
6	16408	Miscellaneous and Administrative Activities	MS Labor	166,098	-	149,489	16,610
7	16401	MSS NEPOOL Reliability Committee	MS Labor	33,006	-	29,706	3,301
8	16413	MSS - Market Rules	MS Labor	6,994	-	6,295	699
9	16419	Asset Registration Implemented	Alloc-Fixed	55,955	-	55,955	-
10	16420	Asset Registration Review	Alloc-Fixed	27,977	-	27,977	-
11	16421	C10/C30 Audits	Alloc-Fixed	55,955	-	47,002	8,953
12	16422	Claimed Capability Audits	Alloc-Fixed	55,955	-	55,955	-
13	16423	COPQ/Rework - Cost of Poor Quality	Total Dir Labor	13,989	3,015	7,239	3,735
14	16424	Demand Resource Audits	Alloc-Fixed	95,584	-	95,584	-
15	16425	DR Registration Implemented	Alloc-Fixed	139,886	-	139,886	-
16	16426	DR Registration Review	Alloc-Fixed	139,886	-	139,886	-
17	16427	MSS Analysis and Reporting	Alloc-Fixed	13,989	-	12,590	1,399
18	16428	MSS Business Analysis - Issues Management	Alloc-Fixed	13,989	-	12,590	1,399
19	16429	MSS Business Analysis - Process Improvement	Alloc-Fixed	254,039	-	228,635	25,404
20	16430	MSS Business Analysis - Committee Monitoring	Alloc-Fixed	13,989	-	12,590	1,399
21	16432	New Generation Coordination and Registration	Alloc-Fixed	55,955	-	55,955	-
22	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	27,977	6,029	14,478	7,470
23	16414	MSS Direct Customer Contact	MS Labor	154,611	-	139,150	15,461
24		Total		3,152,000	387,296	2,403,220	361,484
25							
26		Market Training and Reliability Contracts					
27	21504	Employee Development	Alloc-Fixed	28,612	-	14,306	14,306
28	16021	Training development	Alloc-Fixed	417,523	-	208,762	208,762
29		Total		446,135	-	223,068	223,068
30							
31		Resource Adequacy					
32	18101	LF - Develop Load Forecast	Alloc-Fixed	299,937	59,987	59,987	179,962
33	18121	SP - Operations Forecast Support	Alloc-Fixed	127,849	25,570	25,570	76,709
34	18131	LF - Other Load Forecasting Activities	Alloc-Fixed	95,887	19,177	19,177	57,532
35	14313	PSR - National Committee Support	PSR Labor	3,136	341	158	2,637
36	14315	PSR - Employee Development	PSR Labor	141,827	15,411	7,157	119,259
37	17403	TCA Application Review	Alloc-Fixed	159,811	-	-	159,811
38	17507	FCA - Auctions & Filings	Alloc-Fixed	845,459	-	-	845,459
39	17508	FCA - Annual Reconfiguration Auction Support/Reliability Review	Alloc-Fixed	127,849	-	-	127,849
40	17101	PSR Analysis	Alloc-Fixed	287,660	-	201,362	86,298
41	17131	PSR - Calculate Objective Capability	Alloc-Fixed	508,572	-	-	508,572
42	17231	PSR Regulatory Filings	Alloc-Fixed	127,849	-	-	127,849
43	17251	PSR-Regional Bulk Power System Assessment	Alloc-Fixed	191,774	95,887	95,887	-
44	17331	PSR NEPOOL Committee Support	PSR Labor	172,510	18,745	8,706	145,059
45	17361	PSR Regional Committee Support	PSR Labor	135,688	14,744	6,847	114,097
46	17401	PSR Indirect Supervisory Activities	PSR Labor	127,849	13,892	6,452	107,505
47	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	194,502	-	-	194,502
48	17503	FCA - New Resource Qualification Support	Alloc-Fixed	239,241	-	-	239,241
49	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	127,849	-	-	127,849
50		Total		3,915,250	263,754	431,304	3,220,192
51							
52		System Planning					
53	18148	SP - NEPOOL Committee Support	Alloc-Fixed	1,303	-	1,303	-
54	18150	SP - Regional Transmission Expansion Plan	Alloc-Fixed	522,708	392,031	130,677	-
55	18401	SP - Regional Activities	Alloc-Fixed	437,178	437,178	-	-
56	18521	SP - Employee Development	SP Labor	36,866	9,152	6,536	21,178
57	18531	SP - Indirect Supervision/Clerical Support	SP Labor	211,595	52,531	37,513	121,551
58	18532	SP - New England Governors' Study Request	Alloc-Fixed	49,500	49,500	-	-
59		Total		1,259,149	940,392	176,029	142,728
60							
61		Transmission Planning					
62	18201	TR - Transmission System Assessment	Alloc-Fixed	2,135,566	2,135,566	-	-
63	18261	TR - Transmission Tariff Information Requirements	Alloc-Fixed	54,433	54,433	-	-
64	18301	TR - NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	88,170	88,170	-	-
65	18333	TR - General SIS/FS	Alloc-Fixed	481,572	481,572	-	-
66	18334	TR - Indirect Supervision/Clerical Support	TP Labor	443,439	443,439	-	-
67	18335	TR - Regulatory Activities - NPCC	TP Labor	92,517	92,517	-	-
68	18336	TR - National Activities	TP Labor	250,000	250,000	-	-
69	18337	TR - Regulatory Activities	TP Labor	106,520	106,520	-	-
70	18338	TR - Employee Development	TP Labor	77,529	77,529	-	-
71	18341	TR - NERC Compliance	TP Labor	89,199	89,199	-	-
72		Total		3,818,947	3,818,947	-	-

Line No.	Activity Code		Allocation Factor (1) (c)	Self-Funding Tariff			
	No. (a)	Description (b)		Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		Program Management					
2	801	Program Management - Administration	Total Dir Labor	394,546	85,017	204,182	105,347
3	1661	ISO Program Management	Alloc-Fixed	319,793	-	223,855	95,938
4	25739	Backup Control Center - Test	Alloc-Fixed	25,344	11,405	11,405	2,534
5	25783	Forward Capacity Market	Alloc-Fixed	344,838	-	-	344,838
6	25795	Long Term Transmission Rights (LTTR)	Alloc-Fixed	5,934	-	5,934	-
7	25002	PMO Support	Alloc-Fixed	117,298	35,189	41,054	41,054
8	25822	System Restoration and Blackstart Resource Resource Mgmt	Total Dir Labor	4,552	4,552	-	-
9	25825	Tariff Management Software	Total Dir Labor	3,660	789	1,894	977
10	25834	FOSS Phase 2	Alloc-Fixed	23,460	23,460	-	-
11	25835	FCM Phase III	Alloc-Fixed	669,269	-	-	669,269
12	25839	Baseline Telemetry System BLTS	Alloc-Fixed	46,919	18,768	14,076	14,076
13	25842	Credit & Billing Enhancements	Alloc-Fixed	24,160	-	12,080	12,080
14	25829	Demand Resource Integration	Alloc-Fixed	561,959	-	561,959	-
15	25849	Allowable Smart Grid SIDU	Alloc-Fixed	153,846	23,077	23,077	107,692
16	25850	Unallowable Smart Grid SIDU	Alloc-Fixed	260,038	39,006	39,006	182,027
17	25868	Information Delivery OE	Total Dir Labor	150,000	32,322	77,627	40,051
18		Total		3,105,614	273,583	1,216,148	1,615,884
19							
20		Business Architecture and Technology					
21	21201	Business Architecture and Technology	Total Dir Labor	1,623,751	349,886	840,309	433,556
22	21203	BAT - Employee Development	Total Dir Labor	21,850	4,708	11,308	5,834
23		Total		1,645,602	354,595	851,617	439,390
24							
25		Market Development Administration					
26	21001	Markets Development	Total Dir Labor	1,744,451	375,895	902,772	465,784
27	21003	MD - Employee Development	Total Dir Labor	46,032	9,919	23,822	12,291
28	16201	Market Rules and Procedures	Alloc-Fixed	13,531	-	5,412	8,118
29	16607	National Committee Support	MD Labor	642,682	3,851	342,869	295,962
30		Total		2,446,696	389,665	1,274,876	782,155
31							
32		Market Design					
33	22601	MDes-Direct Supervision&Clerical	Total Dir Labor	71,006	15,300	36,747	18,959
34	22602	MDes-Committee Meetings	Total Dir Labor	23,669	5,100	12,249	6,320
35	22607	Mdes - NEPOOL Markets Committee Administration	Alloc-Fixed	150,035	15,003	67,516	67,516
36	22603	MDes-Employee Development	Total Dir Labor	23,669	5,100	12,249	6,320
37	22606	Mdes-Existing Market Analysis/Support	Total Dir Labor	167,181	36,024	86,518	44,639
38	22608	Mdes - Market Rules	Alloc-Fixed	23,669	2,367	10,651	10,651
39		Total		459,228	78,895	225,929	154,404
40							
41		Demand Resource Strategy					
42	22401	Demand Response	Total Dir Labor	581,434	125,287	300,898	155,248
43	22402	DR-Regulatory Committees and Working Groups	Total Dir Labor	6,373	1,373	3,298	1,702
44	22404	RFP Linkages	Total Dir Labor	607,426	130,888	314,350	162,188
45	22406	DR-Fillings/Reports	Total Dir Labor	44,966	9,689	23,271	12,006
46		Total		1,240,199	267,238	641,817	331,144
47							
48		IT Management					
49	6517	Employee Development - Hardware/Software	Total Dir Labor	578,343	124,621	299,299	154,423
50	6519	Indirect Supervision and Clerical Support	Total Dir Labor	2,163,447	466,180	1,119,608	577,659
51	6552	IT - Security	Total Dir Labor	121,209	26,118	62,727	32,364
52	6556	IT - Budget Preparation, Tracking & Forecast	Total Dir Labor	222,622	47,971	115,209	59,442
53	6557	IT - Information Technology Committee	Total Dir Labor	66,629	14,357	34,481	17,791
54	22512	IT CW/QA - Daily Code Reconciliation	Alloc-Fixed	24,736	8,410	8,163	8,163
55	22513	IT NPCC - Product Build	Alloc-Fixed	5,262	-	-	5,262
56	22514	IT NPCC - Service/Maintenance	Alloc-Fixed	(20,126)	-	-	(20,126)
57	22515	IT - General Counsel Support Data Retrieval	Alloc-Fixed	8,234	1,774	4,261	2,199
58	22501	IT CW/QA - Change Management Support	Alloc-Fixed	408,318	183,743	183,743	40,832
59		Total		3,578,673	873,175	1,827,491	878,007
60							
61		IT System/Network & Desktop					
62	6510	Desktop Support - Hardware	Total Dir Labor	253,429	54,609	131,152	67,668
63	6511	Desktop Support - Software	Total Dir Labor	264,010	56,889	136,628	70,493
64	6512	Host Computer - Hardware	Alloc-Fixed	411,187	-	308,390	102,797
65	6513	Host Computer - Software	Alloc-Fixed	952,649	-	714,487	238,162
66	6514	Networking - Hardware	Total Dir Labor	258,543	55,711	133,799	69,034
67	6516	Communications	Total Dir Labor	1,546,606	333,263	800,386	412,957
68	6550	IT - Data Communications Support	Total Dir Labor	269,644	58,103	139,544	71,997
69	6602	Help Desk Support	Total Dir Labor	128,091	27,601	66,289	34,202
70	6615	IT - Host Computer Monitoring	Alloc-Fixed	566,214	-	283,107	283,107
71	6616	IT - Desktop Support	Total Dir Labor	729,213	157,131	377,376	194,706
72	6617	IT - System Administration - Unix	Total Dir Labor	554,343	119,450	286,879	148,014
73	6618	IT - System Administration - Windows	Total Dir Labor	508,902	109,658	263,362	135,881
74	6619	IT - Systems Support Misc	Total Dir Labor	45,657	9,838	23,628	12,191
75	6620	IT - Systems Support - Security	Total Dir Labor	22,592	4,868	11,692	6,032
76	6621	IT - Network Support	Total Dir Labor	388,013	83,609	200,801	103,603
77	6622	IT - Network/Systems Compliance 2009 Initiative	Total Dir Labor	202,803	43,657	104,849	54,097
78		Total		7,101,697	1,114,388	3,982,369	2,004,941

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No. (a)	Description (b)		Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		IT Cyber Security					
2	6539	IT Policy/Procedures Program	Total Dir Labor	63,449	13,672	32,835	16,941
3	6540	IT Security Compliance and Reporting	Total Dir Labor	910,071	196,102	470,972	242,997
4	6540A	IT Controls Assessment	Total Dir Labor	39,629	8,539	20,509	10,581
5	6540B	IT Virus/Malware Reporting and Response	Total Dir Labor	4,440	957	2,298	1,185
6	6540D	IT Intrusion Monitoring and Response	Total Dir Labor	146,514	31,571	75,822	39,120
7	6540E	IT System Compliance Enhancement	Total Dir Labor	186,225	40,128	96,374	49,724
8	6541	IT Security SW Tools Program	Total Dir Labor	40,567	8,741	20,994	10,832
9	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	81,410	17,542	42,131	21,737
10	6544	Infragrad (FBI)	Total Dir Labor	56,484	12,171	29,231	15,082
11	6546	IT Internal Audit Support	Total Dir Labor	24,736	5,330	12,801	6,605
12	6547	IT - Security Training	Total Dir Labor	9,309	2,006	4,817	2,485
13	6548	CIP Compliance & Monitoring	Total Dir Labor	187,340	40,368	96,951	50,021
14		Total		1,750,174	377,128	905,734	467,312
15							
16		IT Enterprise Applications Support					
17	6571	DBA Support - MOPS	Total Dir Labor	2,034,907	438,482	1,053,087	543,338
18	6591	Data Architect - MOPS	Total Dir Labor	75,315	16,229	38,976	20,110
19	6594	IT Data Analyst	Total Dir Labor	75,315	16,229	38,976	20,110
20	6595	IT WEB Application Support	Total Dir Labor	405,915	87,467	210,066	108,383
21	6702	IT WEB Support	Total Dir Labor	142,768	30,764	73,884	38,120
22	21805	IT Markets Software Support - TSO	Total Dir Labor	290,778	62,657	150,481	77,640
23	21806	IT Markets Software Support - Enterprise	Total Dir Labor	606,580	130,706	313,912	161,962
24	21706	IT Markets Software Development - Enterprise	Alloc-Fixed	37,658	8,114	19,488	10,055
25	21813	FSIT - Service Management Support	Alloc-Fixed	37,658	-	30,126	7,532
26	9704	NEPOOL OASIS Administration	Alloc-Fixed	72,862	72,862	-	-
27	21801	IT Markets Software Support - Settlements	Alloc-Fixed	331,447	-	265,158	66,289
28	21803	IT Markets Software Support - Finance	Alloc-Fixed	381,171	-	304,937	76,234
29	21804	IT Markets Software Support - Mitigation	Alloc-Fixed	282,203	-	225,762	56,441
30	21802	IT Markets Software Support - Publishing	Alloc-Fixed	225,945	-	180,756	45,189
31	21807	IT Markets Software Support - Planning	Alloc-Fixed	288,105	-	230,484	57,621
32	21808	IT CM/QA - Training Delivery to NON-IT	Alloc-Fixed	109,910	-	87,928	21,982
33	21809	IT CM/QA - Tools	Alloc-Fixed	316,847	-	253,478	63,369
34	21810	IT Issue Resolution	Alloc-Fixed	37,658	-	30,126	7,532
35	21811	FSIT - Single Sign On Support	Alloc-Fixed	137,708	-	110,167	27,542
36	21812	FSIT - GADS Support	Alloc-Fixed	37,658	-	30,126	7,532
37	21814	IT - Manual Database Edit	Total Dir Labor	75,315	16,229	38,976	20,110
38		Total		6,003,722	879,739	3,686,894	1,437,090
39							
40		IT Energy Management Systems					
41	21600	EMS - Indirect Supervision and Administration	Total Dir Labor	175,553	37,828	90,851	46,874
42	21601	EMS - Power System Modeling	Total Dir Labor	380,408	81,970	196,865	101,572
43	21603	EMS - Applications Support	Total Dir Labor	514,044	110,766	266,024	137,254
44	21604	EMS/DTS Support	Alloc-Fixed	893,497	714,797	178,699	-
45	21605	EMS - DAM Support	Alloc-Fixed	463,940	92,788	278,364	92,788
46	21606	EMS - Real-time Market Support	Alloc-Fixed	1,302,873	260,575	781,724	260,575
47	21607	EMS - Forecast Support	Alloc-Fixed	124,614	24,923	74,769	24,923
48	21608	EMS - FTR Support	Alloc-Fixed	67,523	-	67,523	-
49		Total		3,922,452	1,323,648	1,934,818	663,986
50							
51		IT Enterprise Applications Development					
52	21701	IT Settlement Application Support	Alloc-Fixed	98,881	-	19,776	79,105
53	21702	IT Corporate Application Support	Alloc-Fixed	98,881	-	19,776	79,105
54	21703	IT WEB & TSO Application Support	Alloc-Fixed	98,881	-	19,776	79,105
55	21707	Application Analysis and Conceptual Design	Alloc-Fixed	148,321	-	118,657	29,664
56	21708	Application Design Evaluation and Selection	Alloc-Fixed	98,881	-	79,105	19,776
57	21709	Technology Evaluation and Selection	Alloc-Fixed	98,881	-	79,105	19,776
58	21710	ESD - Indirect Supervision and Administration	Alloc-Fixed	148,321	-	118,657	29,664
59	21711	EWB and CAPA Analysis	Alloc-Fixed	148,321	-	118,657	29,664
60	6518	Employee Development - Software	Total Dir Labor	73,134	15,760	37,847	19,527
61		Total		1,012,502	15,760	611,356	385,366
62							
63		IT Power System Modeling Management					
64	21650	PSMM- Indirect Supervision and Administration	Total Dir Labor	157,574	33,957	81,544	42,072
65	21651	PSMM- Power System Modeling	Alloc-Fixed	552,926	221,170	221,170	110,585
66	21652	PSMM- System Application Support	Alloc-Fixed	233,826	93,530	93,530	46,765
67	21653	PSMM-TTSE Support	Alloc-Fixed	172,156	137,725	34,431	-
68	21654	PSMM- NX9 Administration	Alloc-Fixed	102,895	41,158	41,158	20,579
69	21655	PSMM- ICCP Support	Alloc-Fixed	204,975	81,990	81,990	40,995
70	21656	PSMM- Transmission Project Management	Alloc-Fixed	51,390	41,112	10,278	-
71		Total		1,475,742	650,643	564,102	260,997
72							
73		IT Software Systems Testing					
74	21752	SST-Web Support	Alloc-Fixed	2,265	793	793	680
75	21753	SST-TSO Support	Alloc-Fixed	12,433	622	622	11,190
76	21754	SST-Settlement Support	Alloc-Fixed	2,202	771	771	661
77	21756	SST-EMS Support	Alloc-Fixed	4,279	1,498	1,498	1,284
78	21757	SST-Market Support	Alloc-Fixed	31,461	11,011	11,011	9,438
79	21760	SST-Infrastructure Support	Alloc-Fixed	4,405	1,542	1,542	1,321
80		Total		57,045	16,236	16,236	24,574
81							
82		Total ISO		\$ 143,431,515	\$ 33,845,121	\$ 62,046,284	\$ 47,540,110

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: September 14, 2010

RE: Boston Generating LLC Chapter 11 Bankruptcy Proceedings (10-14419 (SCC))
Financial Assurance Update

On August 18, 2010, Boston Generating LLC (“Boston Gen”) filed a voluntary petition under Chapter 11 of the US Bankruptcy Code. We have been asked to provide the NEPOOL Participants with information regarding any exposure that that bankruptcy creates for NEPOOL. We are providing this information pursuant to Section 2.3 of the ISO Information Policy.

According to the ISO, Boston Gen had not provided any additional financial assurance at the time of its bankruptcy filing and does not currently have any additional financial assurance posted with the ISO. Boston Gen is generally a net payee within the Pool and therefore is generally not required to provide additional financial assurance under the ISO New England Financial Assurance Policy. Boston Gen defaulted on a payment obligation to the ISO of less than \$1,000 for charges that accrued before the filing of its bankruptcy petition. The ISO is planning to exercise its right under the ISO Billing Policy to use amounts due to Boston Gen for pre-petition activities to set off that amount due.

The ISO is monitoring the situation and is prepared to take additional steps under the Financial Assurance and Billing Policies to the extent those actions are required. In addition, the ISO is looking into possible exposure that the Pool may have for amounts due from Boston Gen relating to potential settlements for pre-petition charges as a result of pending FERC proceedings.¹

¹ Developments regarding the bankruptcy filing, as well the pending request by Boston Gen for authorization, in part, to sell its five generating facilities, are and will be summarized in the Litigation Report.