SEPTEMBER 12, 2018

September 3 OP-4 Event and Capacity Scarcity Condition

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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Capacity Scarcity Condition Monday, September 3, 2018

- Two primary factors led to the implementation of OP 4 event
  - Significant generation outages and reductions totaling ~1650 MW occurred during the dispatch day
  - Higher than forecasted temperatures and dew points with largest departures in the afternoon resulted in significant load forecast deviations
- 30-minute Reserve Constraint Penalty Factor violated for the following 5 minute intervals: 15:40 – 18:15
  - $1,000/MWh Reserve Constraint Penalty Factor
- 10-minute Reserve Constraint Penalty Factor violated for the following 5 minute intervals: 17:00 – 17:10 and 17:35 – 18:00
  - $1,500/MWh Reserve Constraint Penalty Factor
- System conditions required implementation of M/LCC 2 and OP 4
  - M/LCC 2: 15:15 – 21:00
  - OP 4, Actions 1,2: 15:30 – 20:00
  - OP 4, Actions 3-5: 16:00 – 21:00

Generation Outages and Reduction

- During the course of the operating day the system experienced ~1650 MW of significant generation outages and reductions
- The largest loss, totaling ~1050 MWs, occurred between 15:00 and 15:30
- In addition, there were ~250 MWs of small reductions across many generators
- The total reductions were ~1900 MWs

Additional Commitments

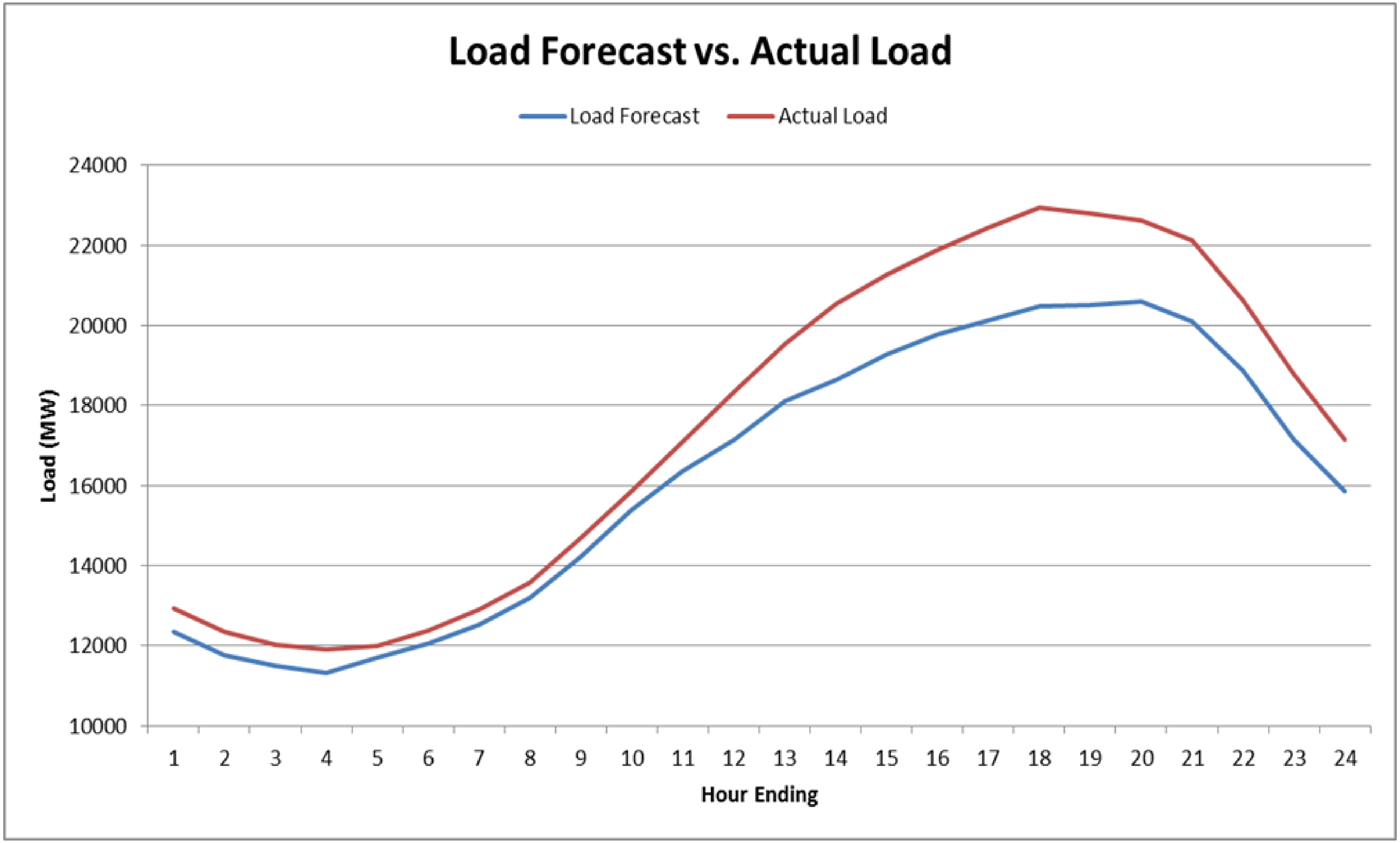
- Prior to the significant outage of a resource between 15:00 and 15:30, the ISO committed ~600 MW of capacity resources
- Subsequent to the large outage, the ISO committed all remaining resources totaling ~45 MWs with short enough notification and start times that they could assist in meeting the evening peak

Load Forecast Deviations and Weather

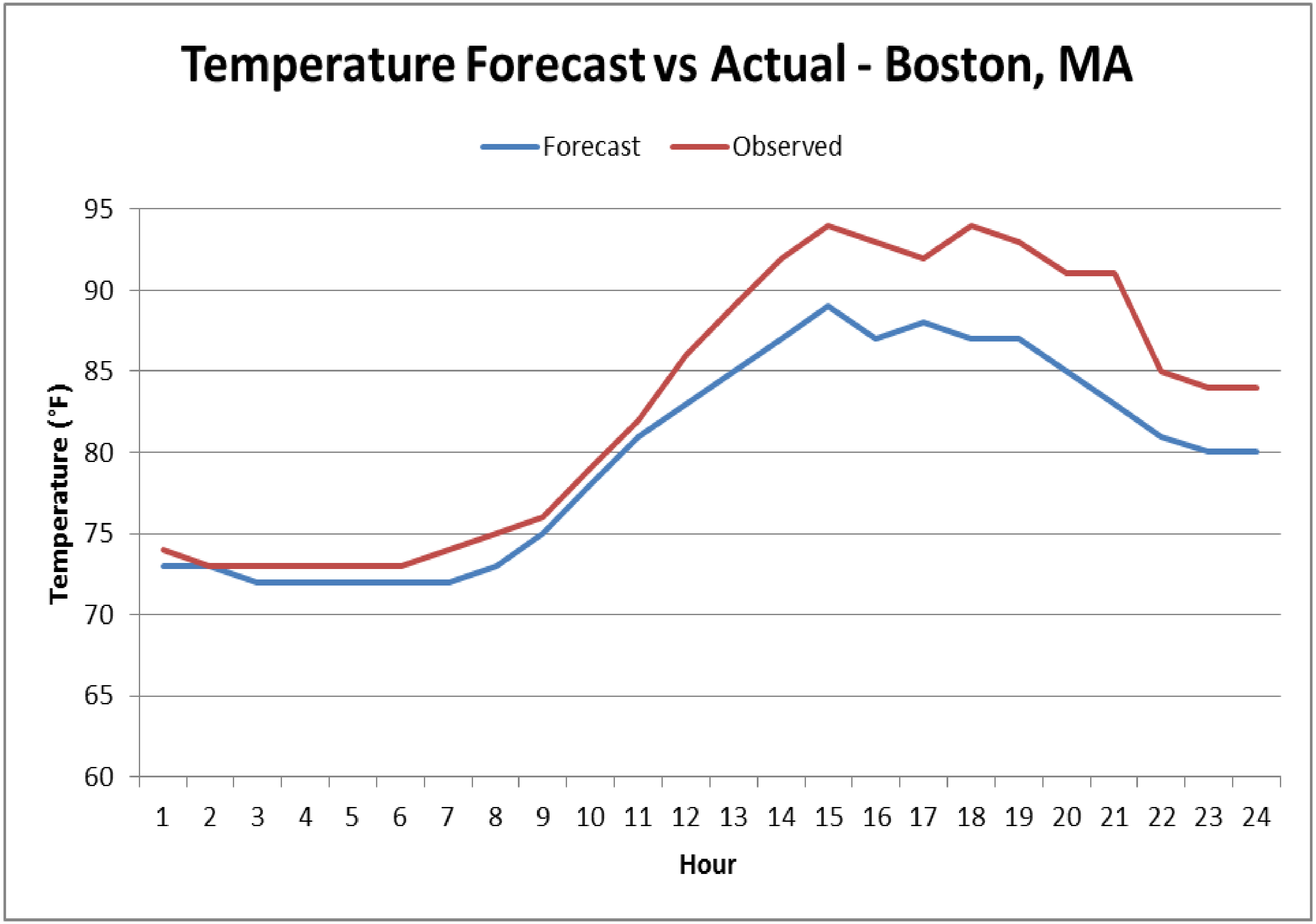
- The ISO load forecast for the peak hour on 9/3 was 20,590 MWs
- Actual peak load served on 9/3 was 22,956 MWs*
- The ISO load forecast accuracy is primarily determined by the accuracy of weather forecasts
- On 9/3, the actual weather was hotter and more humid than forecast
  - As the weather became hotter and more humid than forecast, the load started to deviate accordingly
- The following slides detail the temperature, dew point and Temperature Humidity Index (THI) deviations from the forecast for Boston and Hartford
  - THI is a measure of the degree of discomfort experienced by an individual in warm weather

*Reconstituted Load with Active DR was 23,174 MW; Not Revenue Quality Metered Data

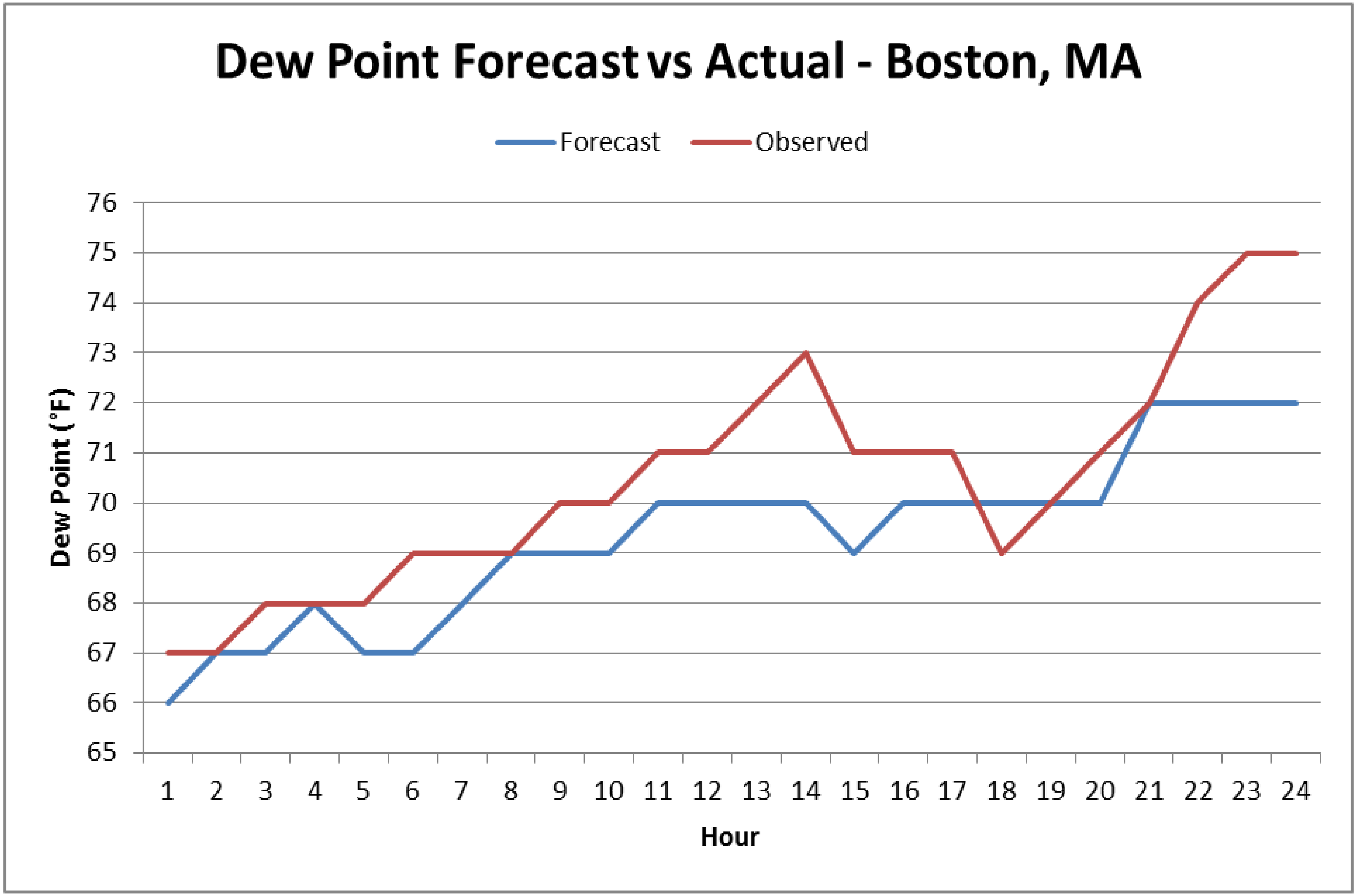
System Load – Actual versus Forecast



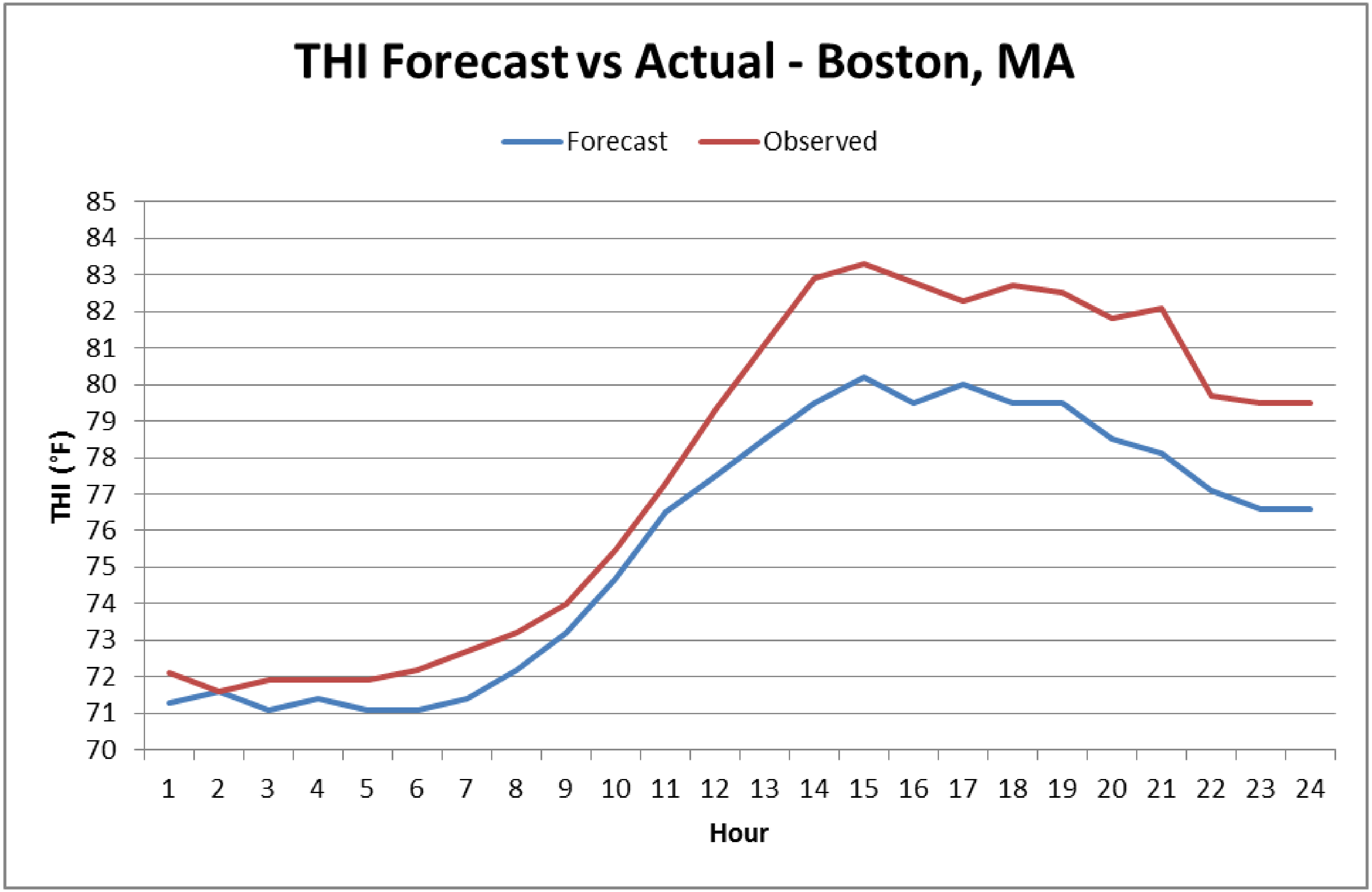
Boston Temperature – Actual versus Forecast



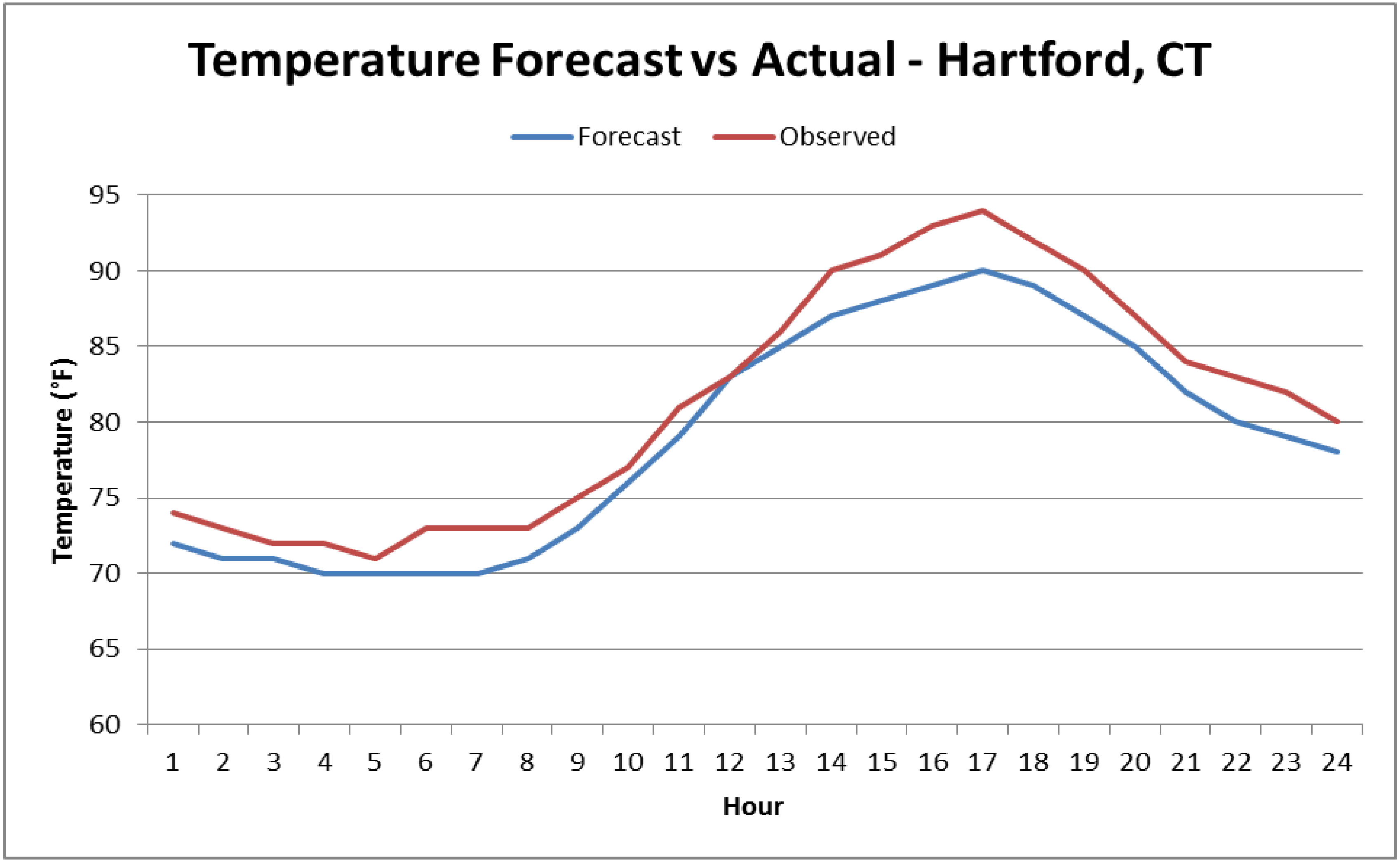
Boston Dew Point– Actual versus Forecast



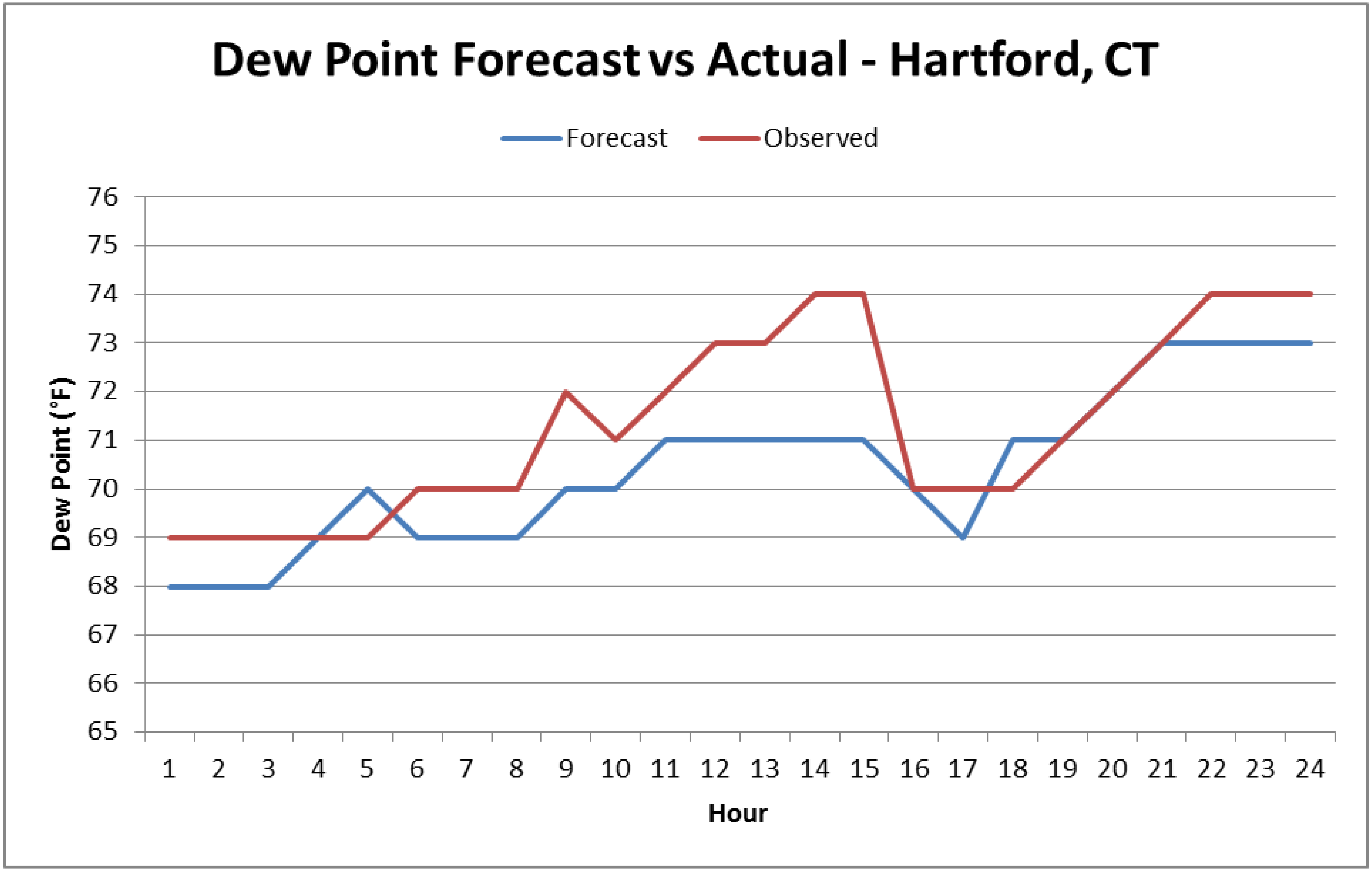
Boston THI – Actual versus Forecast



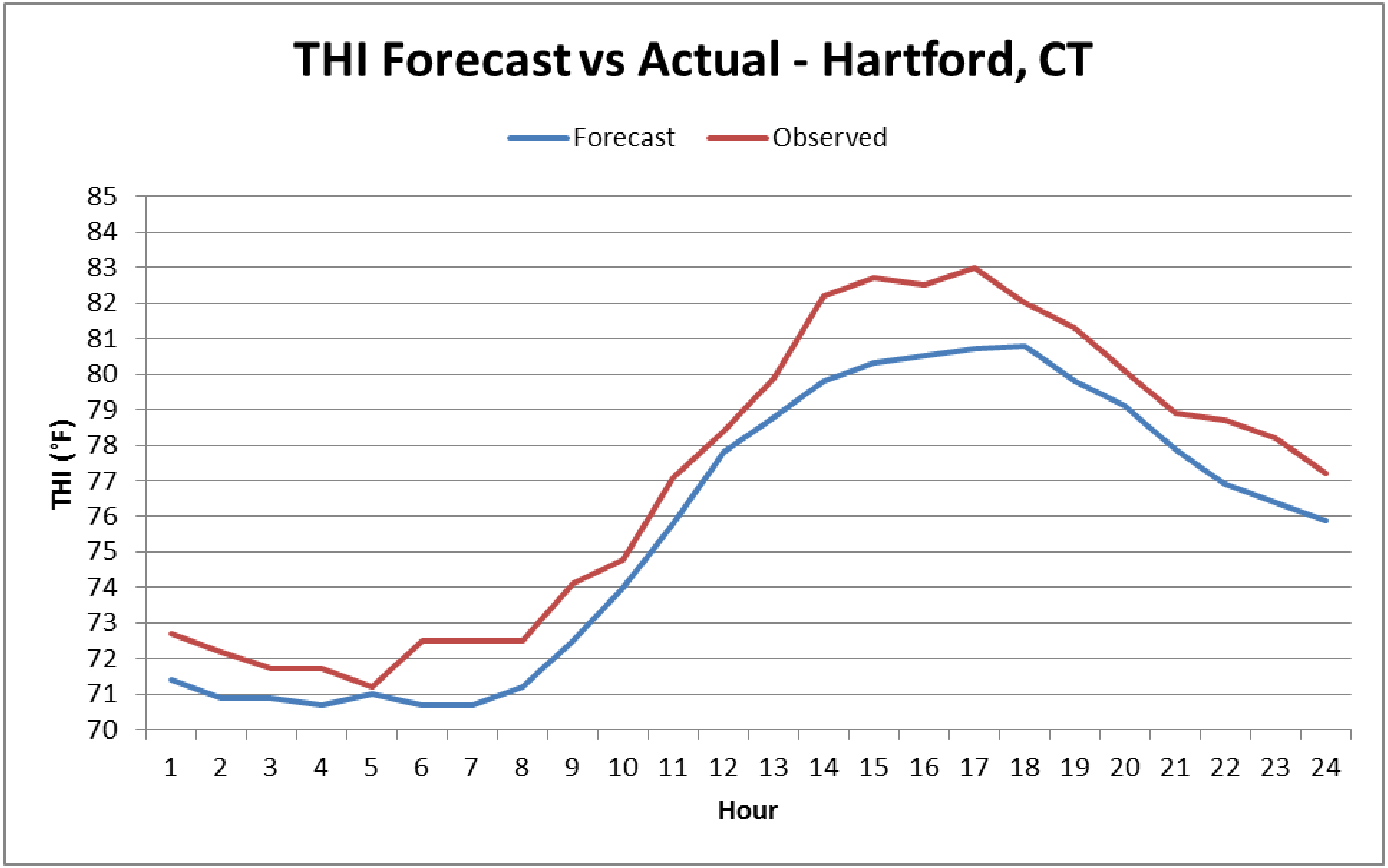
Hartford Temperature – Actual versus Forecast



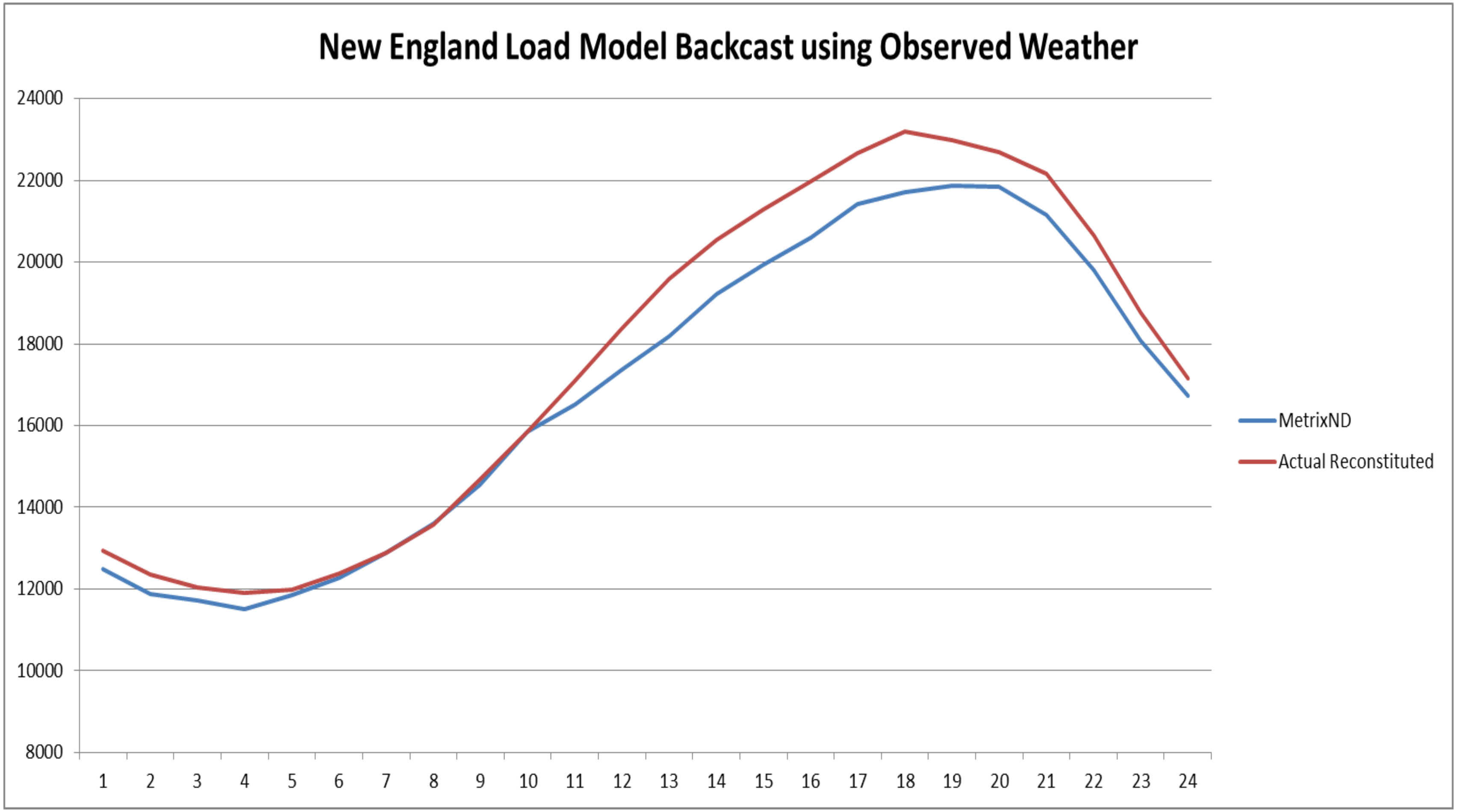
Hartford Dew Point – Actual versus Forecast



Hartford THI – Actual versus Forecast



Backcasting Actual Weather in Load Forecast Model would have resulted in a Load Forecast of ~22,000 MWs versus ~20,600 MWs



Top 10 Labor Day Loads and Actual Weather

Year	2018	2014	2015	2011	2013	2007	1999	2008	2012	2005
HE01	12944	13639	12204	13415	13955	11271	11660	11621	11831	11706
HE02	12360	12958	11545	12684	13313	10765	11116	11021	11233	11076
HE03	12030	12555	11122	12213	12866	10426	10814	10637	10861	10675
HE04	11895	12357	10907	11931	12672	10278	10651	10430	10651	10499
HE05	11986	12325	10895	11903	12703	10314	10663	10440	10663	10462
HE06	12377	12579	11143	12171	13027	10597	10958	10665	10973	10673
HE07	12888	13033	11461	12495	13460	10867	11430	10923	11294	10934
HE08	13584	13783	12157	13336	14028	11753	12273	11730	11972	11730
HE09	14680	15089	13270	14699	15058	13080	13528	13033	13085	12975
HE10	15859	16570	14494	16155	16302	14332	14820	14235	14208	14211
HE11	17095	17890	15677	17352	17348	15245	15692	15064	14990	14986
HE12	18379	18898	16759	18259	18013	15837	16245	15485	15421	15369
HE13	19583	19552	17723	18871	18330	16221	16430	15685	15727	15537
HE14	20559	19928	18566	19101	18493	16463	16431	15761	15890	15518
HE15	21298	20101	19350	19070	18391	16678	16435	15851	16009	15501
HE16	21980	20386	19993	19007	18340	16956	16533	16024	16122	15585
HE17	22647	20787	20610	18978	18519	17307	16789	16352	16322	15855
HE18	23174	21083	20923	18964	18728	17542	16967	16581	16479	16076
HE19	22971	20818	20649	18784	18648	17429	16882	16430	16340	15984
HE20	22688	20771	20755	19131	18965	17918	17352	16727	16665	16454
HE21	22151	20557	20373	18907	18753	18229	17420	16905	16601	16521
HE22	20655	19100	18922	17668	17581	17116	16355	15749	15470	15354
HE23	18779	17231	17082	16008	15972	15389	14759	14101	13959	13636
HE24	17159	15604	15494	14433	14529	13917	13309	12628	12633	12224
Peak	23174	21083	20923	19131	18965	18229	17420	16905	16665	16521
Hartford High	94	89	90	82	78	86	79	84	78	77
Hartflord Low	71	70	61	67	70	57	71	53	57	55
% Sun	50	38	75	25	13	88	13	88	38	88
Avg Dewpoint	73	68	63	67	71	58	61	55	57	52
Boston High	94	84	93	86	79	87	84	84	71	69
Boston Low	73	72	66	69	69	60	67	64	60	59
% Sun	50	38	75	25	0	88	25	100	38	88
Avg Dewpoint	72	70	62	67	70	57	62	42	59	53
Estimated PV (peak hour)	415	126	175	no data	no data	no data	no data	no data	no data	no data

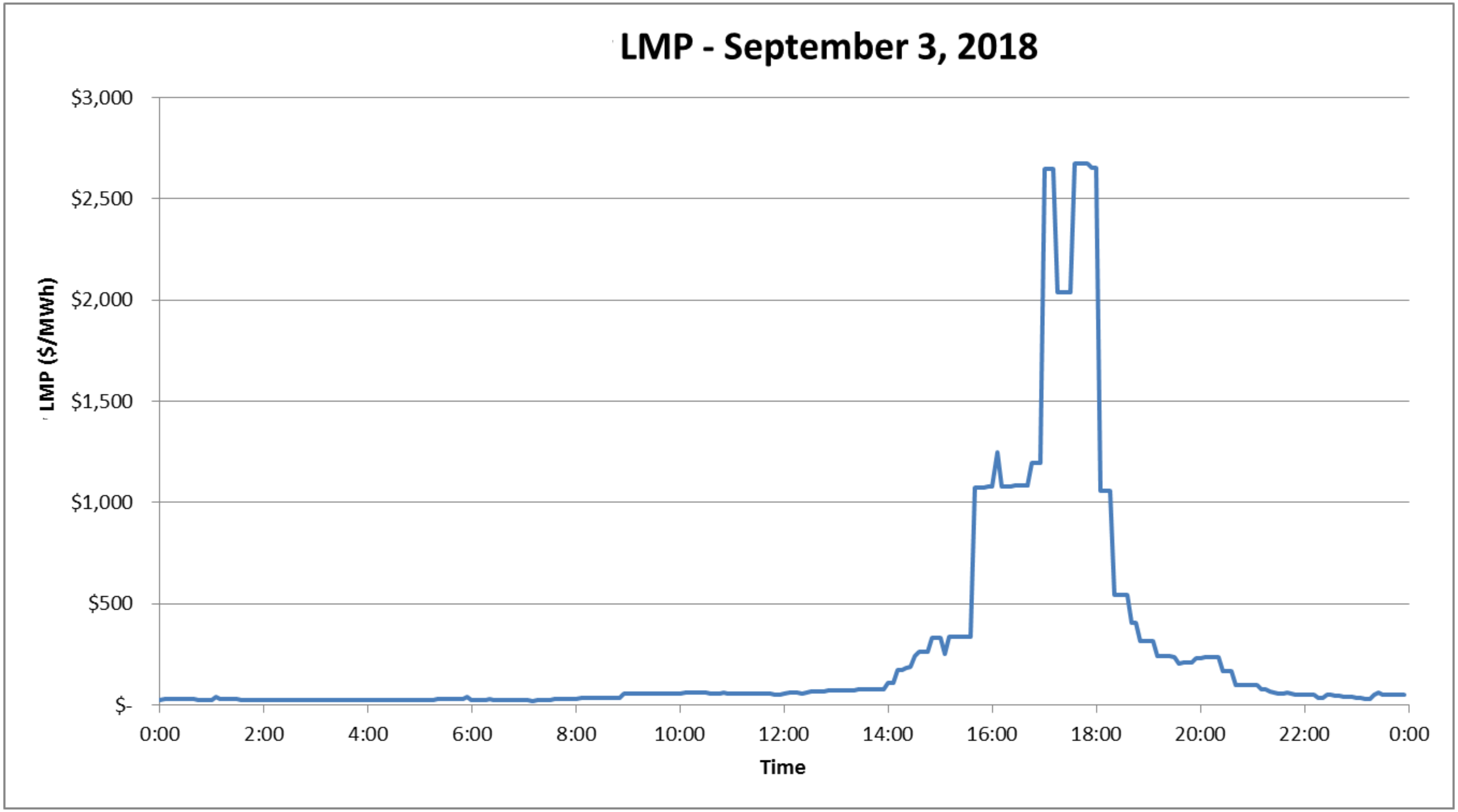
Operable Capacity Analysis during the OP 4 Event (HE 17)

Capacity Supply Obligation (CSO)	+	30,239
Capacity Additions > CSO	+	582
Outages and Reductions	–	3,649
Generation Unavailable Due to Start Time	–	6,470
NYISO Purchases	+	1,400
NBSO Purchases	+	797
HQ Purchases	+	1,158
Total Available Capacity	=	24,057
New England Load		22,667
Operating Reserve Requirement		2,108
Net Capability Required		24,775
Capacity Margin	Total Available - Required	-718

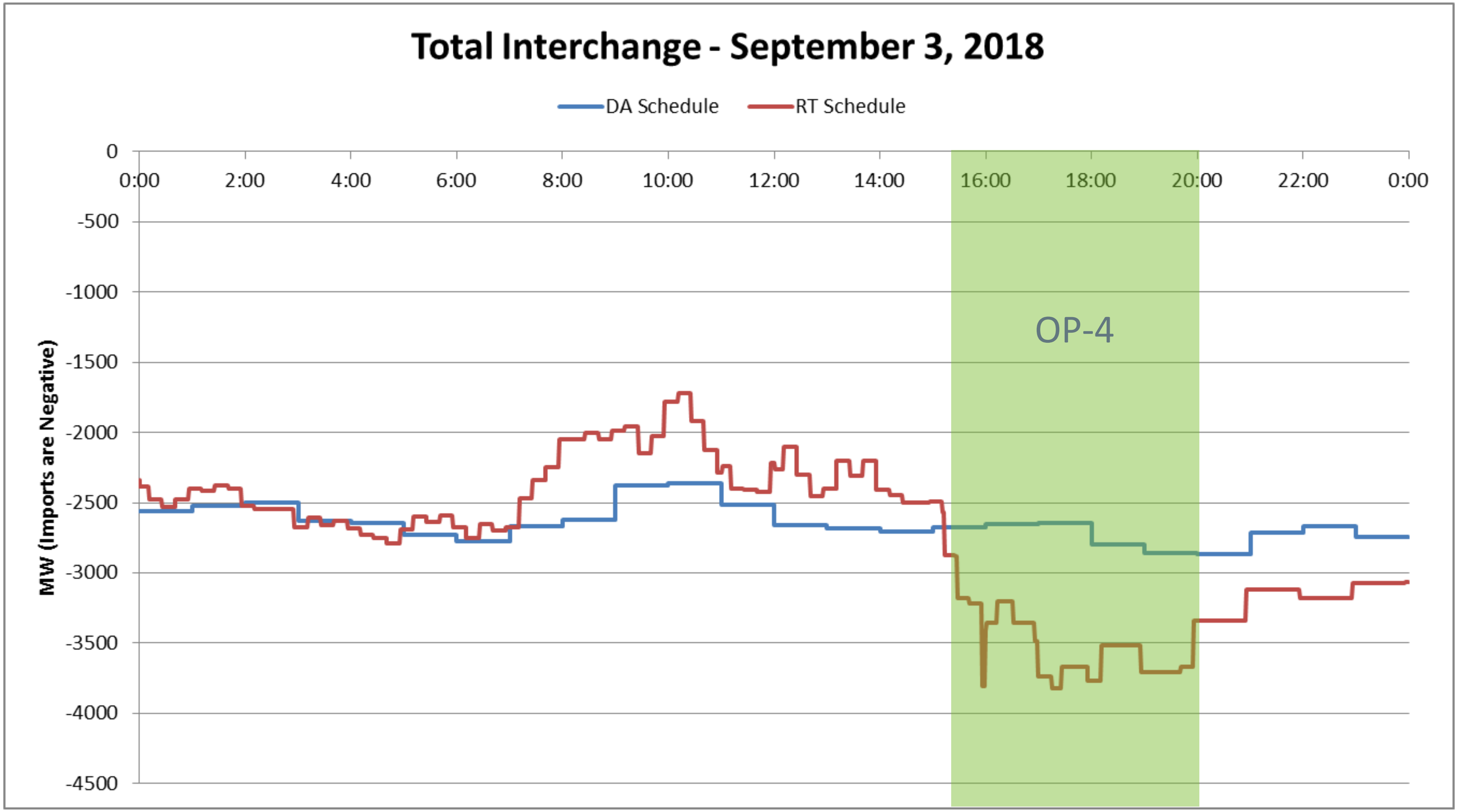
Capacity Scarcity Condition Details

September 3, 2018 Capacity Scarcity Condition Event Summary		
5 Minute Intervals	Constraint #1	Constraint #2
15:40 - 16:55 (16 intervals)	System 30 Min RCPF - VIOLATED	System 10 Min RCPF - Binding
17:00 - 17:10 (3 intervals)	System 30 Min RCPF - VIOLATED	System 10 Min RCPF - VIOLATED
17:15 - 17:30 (4 intervals)	System 30 Min RCPF - VIOLATED	System 10 Min RCPF - Binding
17:35 - 18:00 (6 intervals)	System 30 Min RCPF - VIOLATED	System 10 Min RCPF - VIOLATED
18:05 - 18:15 (3 intervals)	System 30 Min RCPF - VIOLATED	

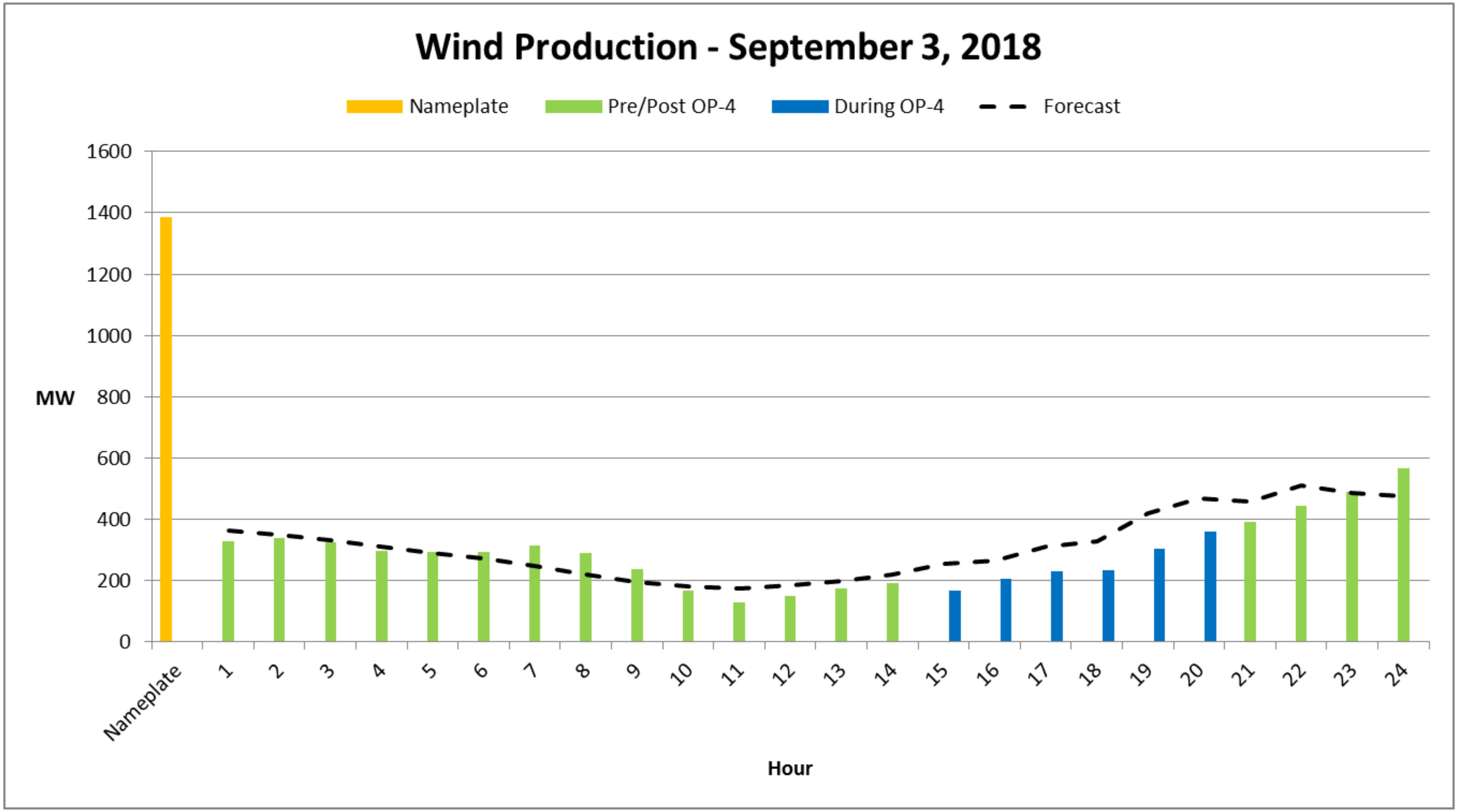
Real Time Pricing – Hub LMPs



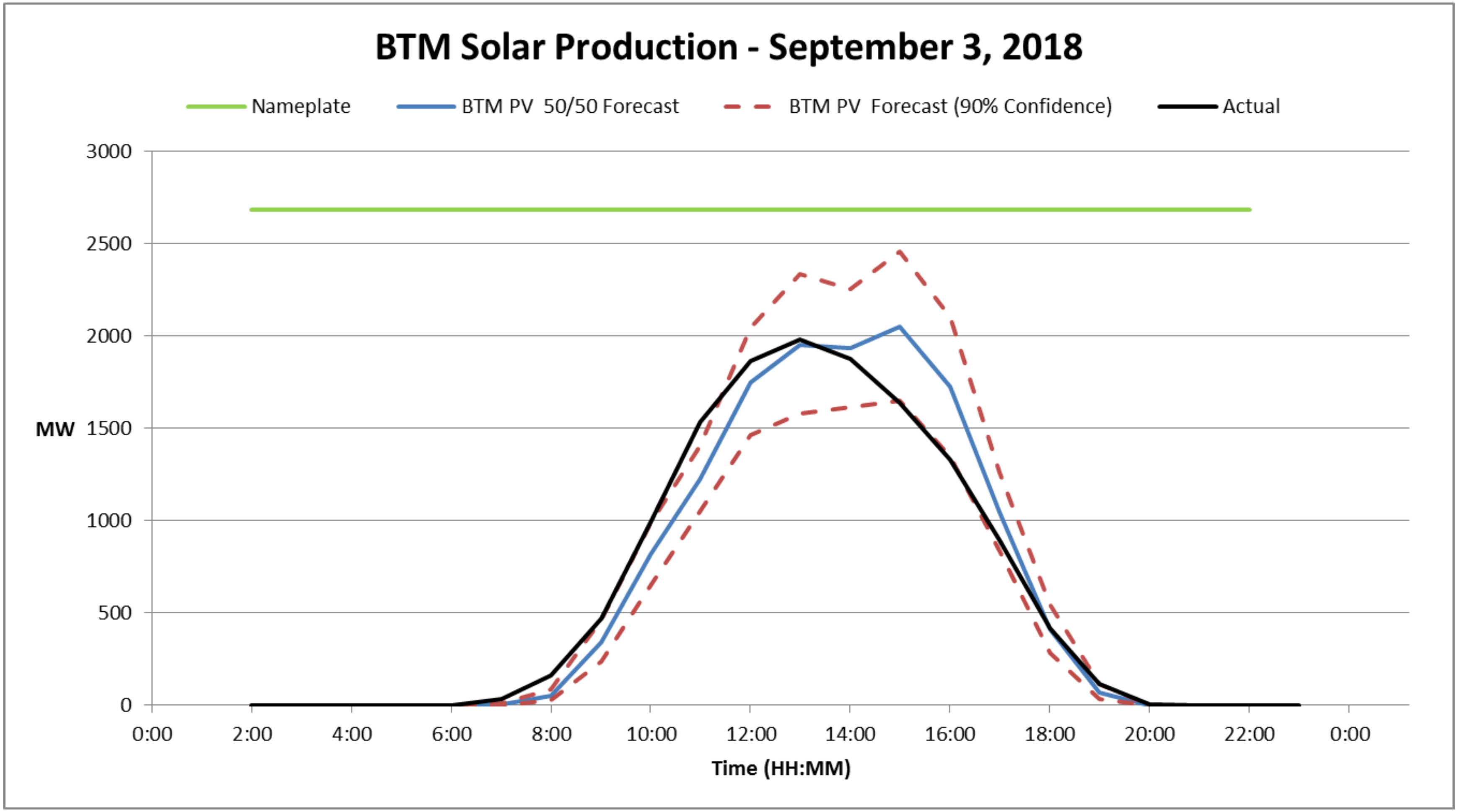
Interchange – Aggregate



Wind Output – Forecast versus Actual



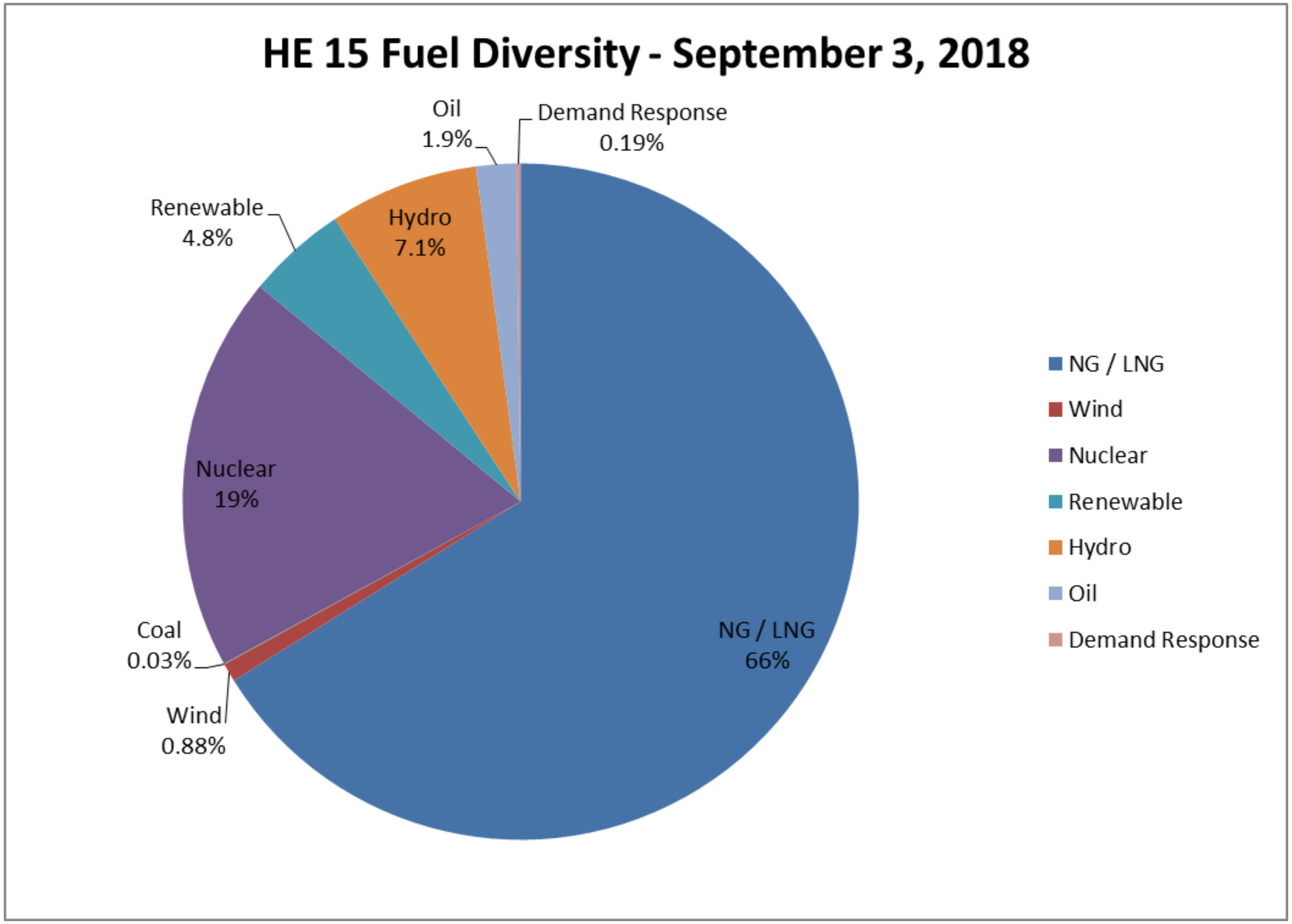
Solar Output – Forecast versus Actual



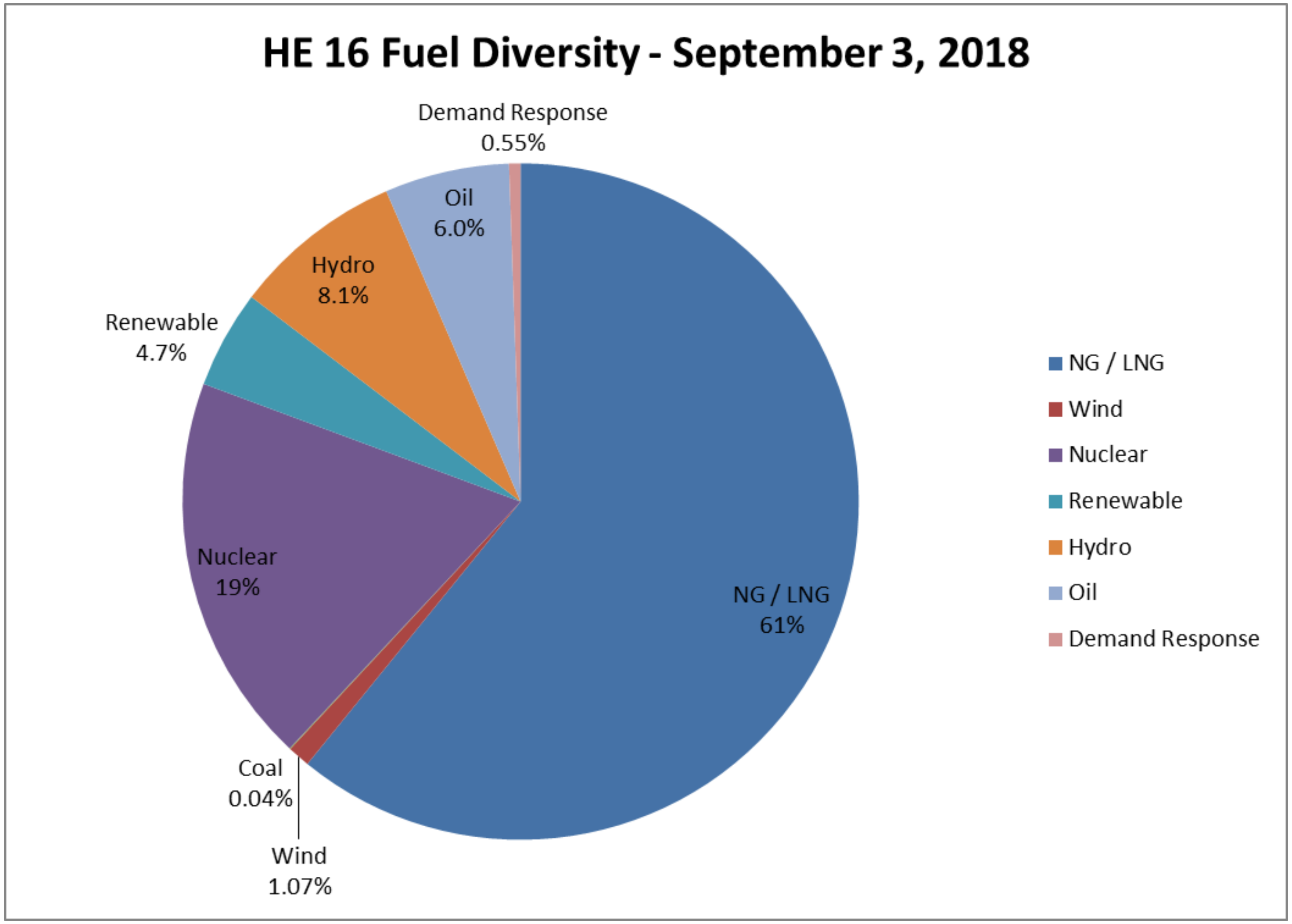
Emergency Purchases (Preliminary)

- New Brunswick Power System Operator:
  - 16:20-17:14; 150 MW
  - 17:14-18:00; 229 MW
- New York Independent System Operator:
  - 17:00-17:30; 251 MW
  - 17:30-18:00; 100 MW

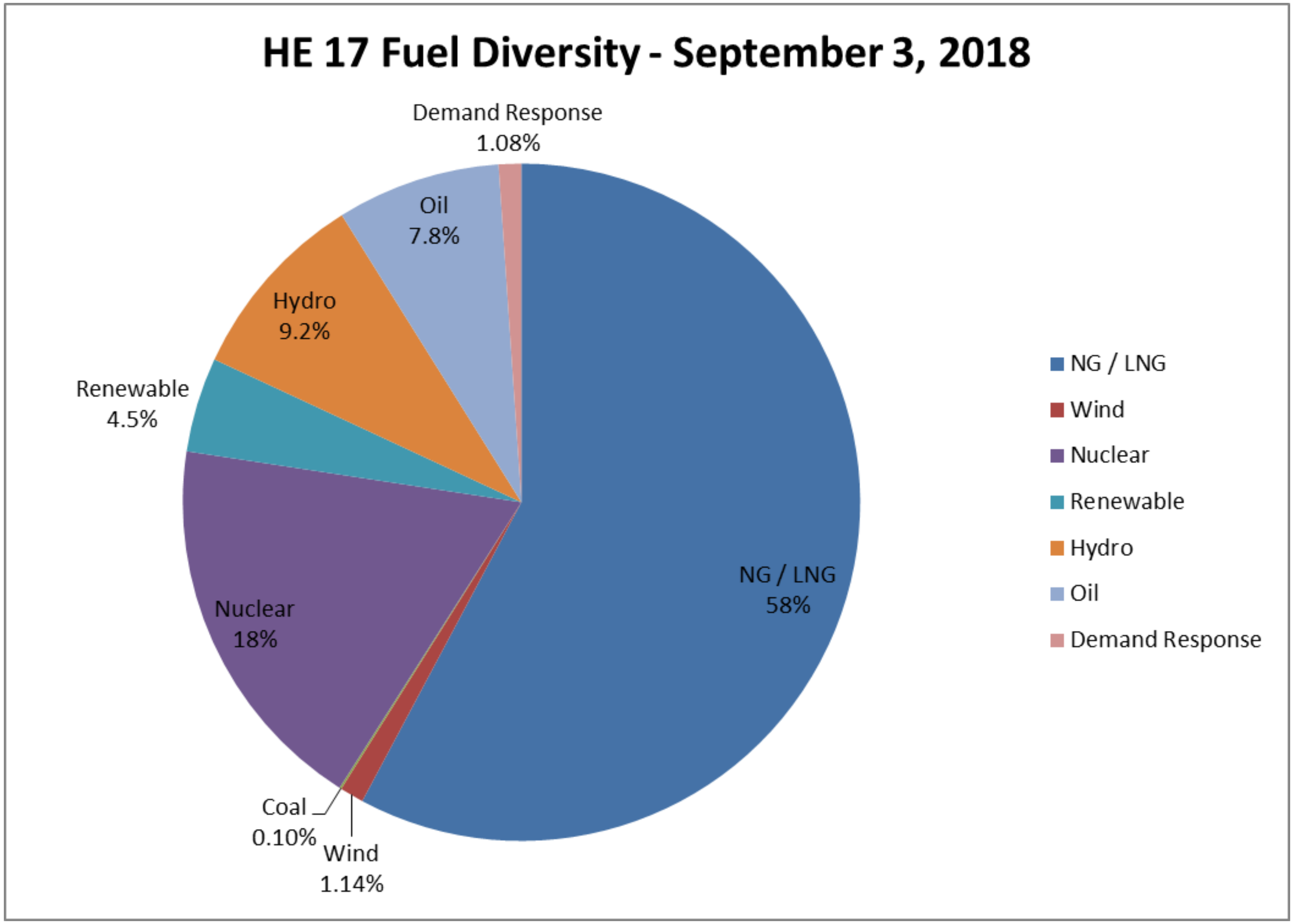
Fuel Diversity – September 3, 2018 HE 15



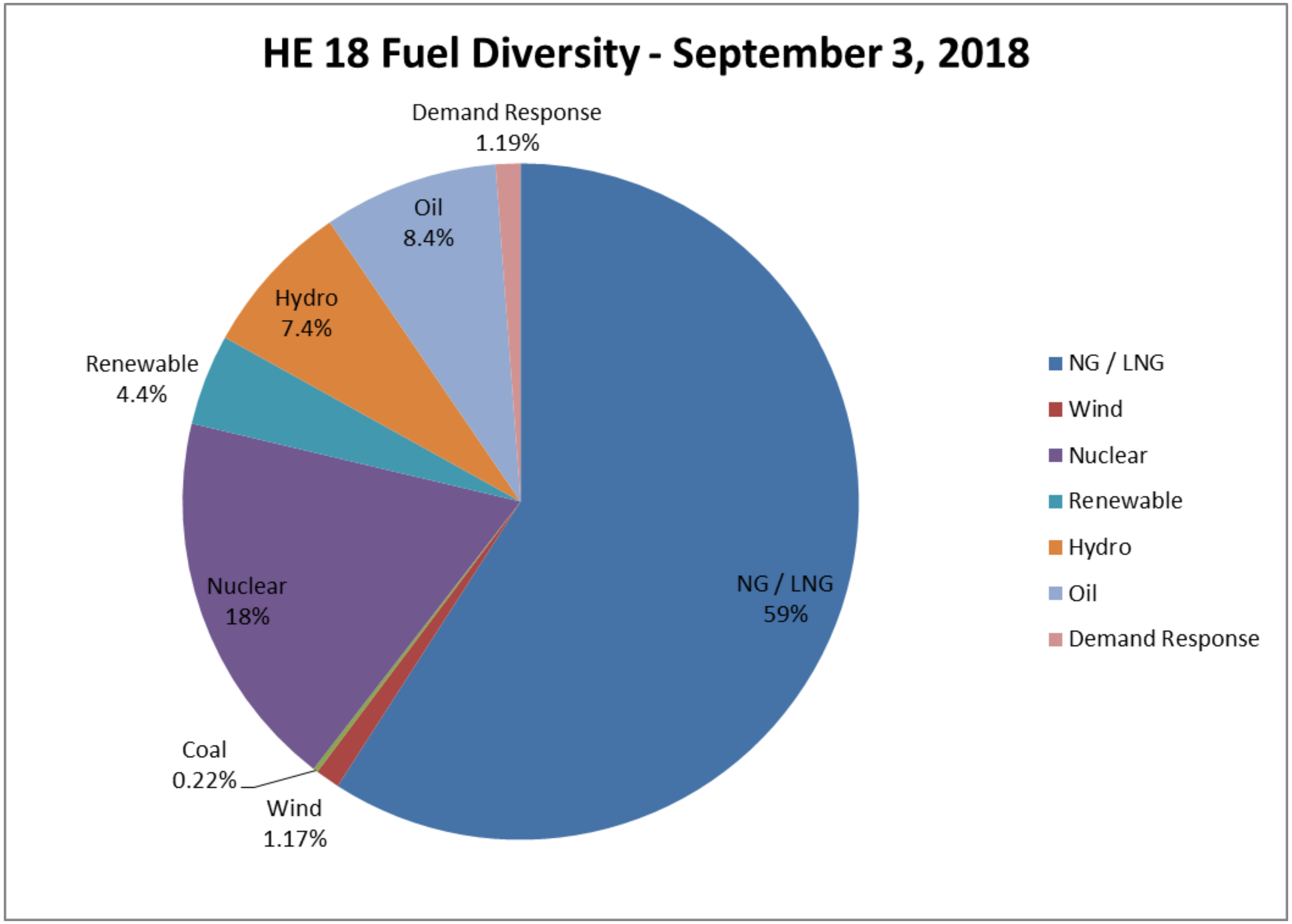
Fuel Diversity – September 3, 2018 HE 16



Fuel Diversity – September 3, 2018 HE 17



Fuel Diversity – September 3, 2018 HE 18



DA and RT Energy Market LMPs and NCPC Costs

- DA Hub Hourly LMPs ranged from $21.34/MWh to $60.85/MWh and averaged $38.65/MWh
- RT Hub LMPs ranged from $19.79/MWh to $2,677.05/MWh
  - Average of all intervals: $262.61/MWh
- Daily NCPC totaled $1.9M

Preliminary Pay-for-Performance Summary

Payment Classification	Credit/(Charge)
FCM Resources – Credits	$36.1M
FCM Resources – Charges	($37.0M)
Subtotal: FCM Resources – Net	($0.9M)
Other Import Transactions – Credits	$7.3M
Other Assets – Credits	$1.5M
Subtotal: Other	$8.8M
Total	**$7.8M**

- Preliminary balancing ratio averaged 0.72[1]
- Performance payment credits exceed the charges for this CSC by $7.8M.
- This imbalance is due to the FERC-mandated exclusion of Energy Efficiency resources from Performance Payments when the CSC occurs in off-peak hours.[2] Imbalance will be collected pro-rata from all CSO, including Energy Efficiency, to balance the settlement.[3]

1. *Average for the 32 five-minute intervals of CSC*
2. *FERC order dated May 30, 2014 at P 73.*
3. *Per Market Rule 1, Section 13.7.2.4 (i)*

Peak Energy Rent (PER) Projections

- There were non-zero PER values for 4 hours during the day
  - RT LMP exceeded strike price
- Labor Day PER will be included in the monthly PER adjustment for 8 months, October 2018 – May 2019
  - PER is retired effective June 1, 2019
- Estimate $7 Million per month PER adjustment, for a total of $56 Million
  - Generators, Imports, Active Demand are subject to PER
  - Self supply and Passive Demand excluded

Questions