Capacity Performance Action Items

August 18, 2014

Action Items are identified in these slides according to the number in the posted spreadsheet list recorded at the 8/12/14 stakeholder meeting

Action Item #1
Were the coal units that were off on January 7 back on for the winter storm?

Here is the breakdown for the coal units that were on forced outage on 1/7/14 1900 that returned to service for at least 6 hours in January.

NOTE THAT THE PIE CHART FROM THE CAPACITY PRESENTATION (SLIDE 6) SHOWS 13,700 MW of coal due to rounding.

Coal on Forced Outage on 1/7/14 19:00	13768	209
Units Returned from FO on 1/7/14 1900	**Sum of MW**	**Count of Return to Service**
N	789	32
Y	12979	177

Action Item #2

ID	Requester	Action Item	Response	PJM Assignment
2	Mike Borgati	For the gas interruption outages, what percent were called outside of their DA awards?	Placeholder – to be provided	

Action Item #3
Please add percentage on slide 6 for January 24 and 28

- 40200 MW/.22 (Forced Outage Rate on 1/7/14 @ 1900) = Approximately 183,000 MW of capacity
  - Jan 24 FO = 29,100/183,000 = 15.9%
  - Jan 28 FO = 23,800/183,000 = 13.0%

Action Item # 4

- On January 7th, 2014 1900 HRs
  - 3,865 MW of forced outages were due to units with announced retirement dates

Action Item # 5 and 7

- On January 7th, 2014 1900 HRs
  - 40,170 MW of capacity was on forced outage
  - 30 MW of non-capacity was on forced outage

Note there was 2,060 MW attributed to ambient air - proportioned by Capacity and Non-Capacity forced outages on 1/7/14 @ 1900

On 1/7/14 @ 1900
38,111 Capacity on FO
29 MW Non-Capacity on FO
38,111 + 29 = 38,140 which doesn't equal 40,200.

The remaining 2,060 MW was attributed to "Ambient Air" tickets - proportioned
Capacity FO w/ Ambient Air Distribution = 38,111 + 2060 * (38,111/38,140) = 40,170 MW
Non-Capacity FO w/ Ambient Air Distribution = 29 + 2060 * (29/38,140) = 30 MW

Action Item # 6

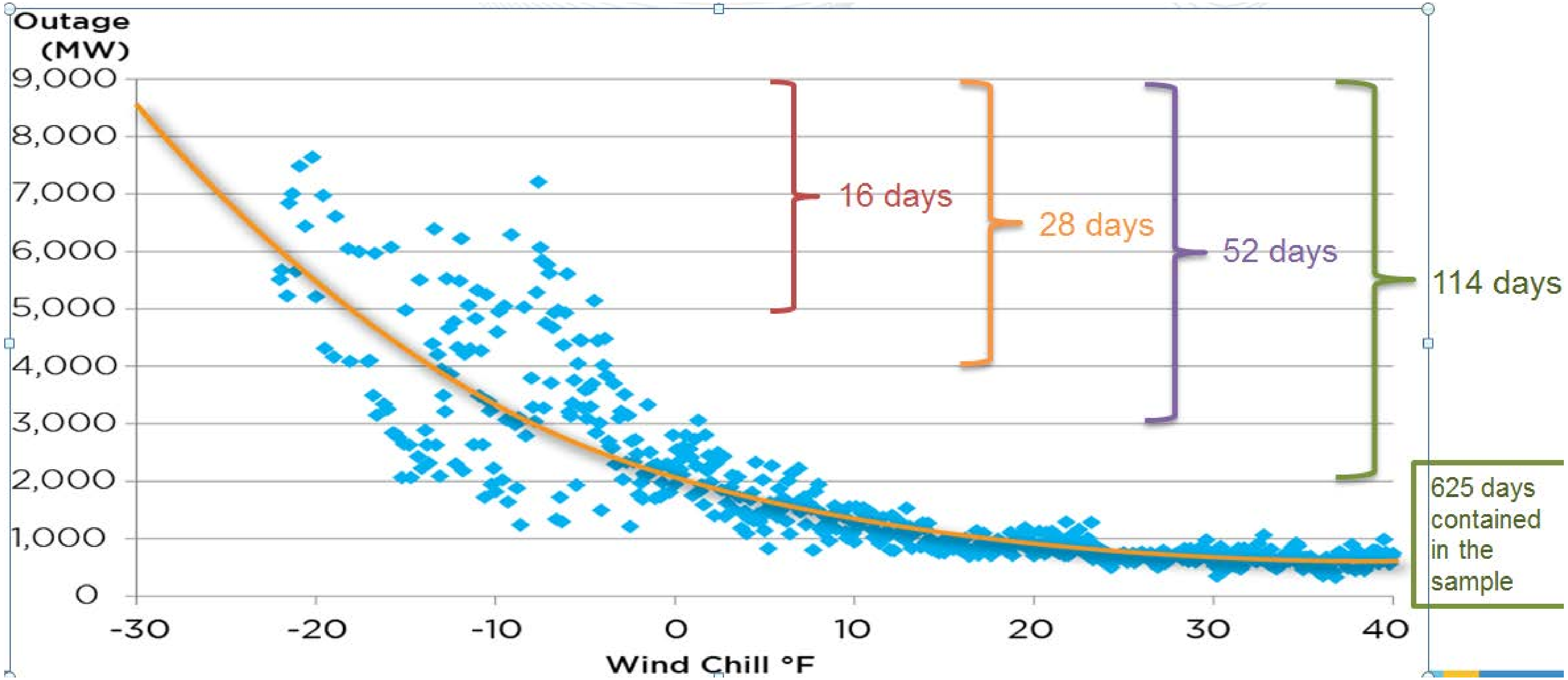
- On January 7th, 2014 1900 HRs
- For confidentiality purposes, TO zones were grouped into East, Central, South, West regions. The % Forced Outage by region was calculated as follows
  - % of TO Generation on Forced Outage = Total FO MW in TO Zone/Total MW in TO Zone
  - Each TO Zone was grouped into a region. The % of TO Generation on Forced Outage for each TO Zone in each region was averaged together to get the Average Percentage of Forced Outage Generation by Region.

Action Item #6
Was generator location important to outage numbers? For instance, a particular LDA or behind a certain LDC?

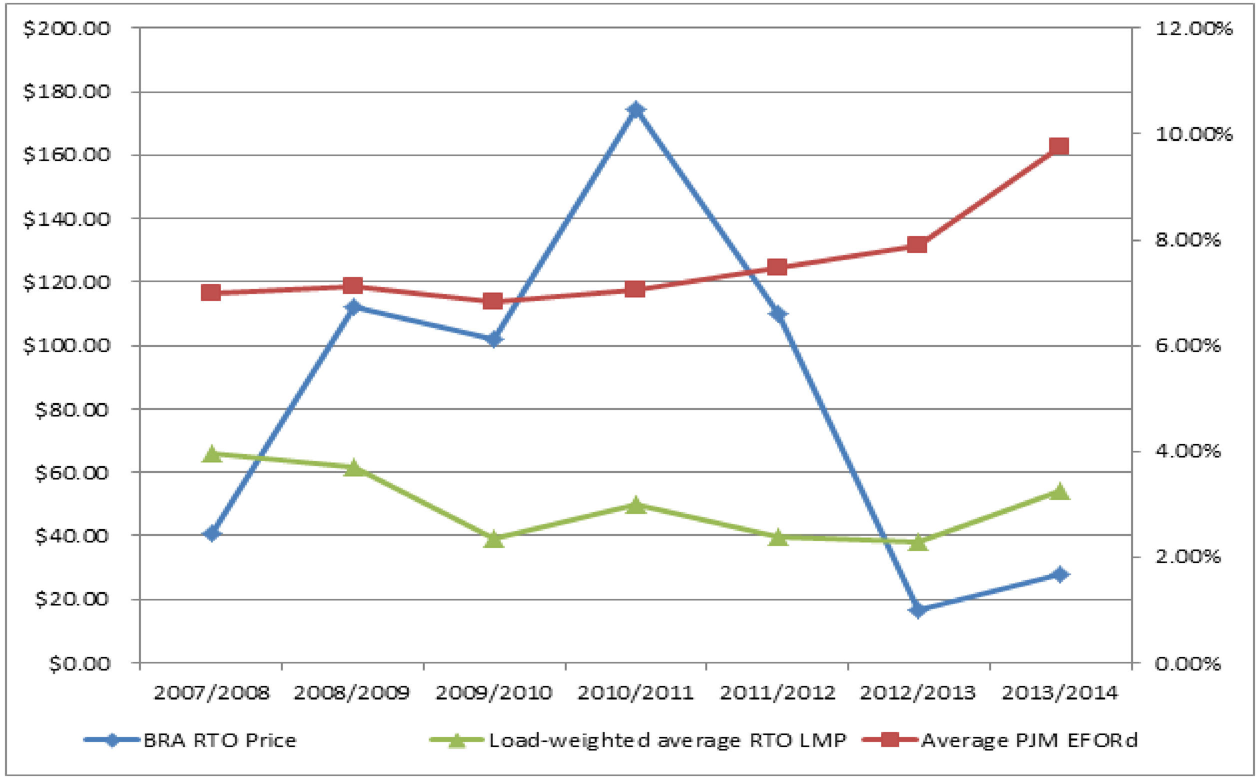
Forced Outage Rate – January 7, 2014 HE 1900 by zone (some aggregation)

Geographic Region	Average Percentage of Generation on Forced Outage by Region
East: AE, DPL, JC, ME, PE, PL, PS	25%
Central: DUQU, FE-S, PN	24%
South: BC, DOM, PEP	16%
West: AEP, COMED, DAY, DEOK, EKPC, FE-W	22%

Is the wind chill and outage graph showing bad performance on just a few days? Can you show the cluster of days?



Are outages higher in years with lower capacity prices? Is there correlation between EFORd and the prices?



Please elaborate on the analysis demonstrating that January was a 1 in 10 event.

Weather conditions on January 7

PJM collected the lowest annual wind-adjusted temperature from each of the last 40 years and computed the population's mean and standard deviation. Assuming a normal distribution, the January 7 weather conditions were consistent with a "1 in 10" probability of occurrence.

Weather conditions in the month of January

PJM collected data on January heating degree days from each of the last 40 years and computed the population’s mean and standard deviation. Assuming a normal distribution, the January 2014 weather conditions were consistent with a "1 in 10" probability of occurrence.

Action Item #18

PJM RTO Winter Weather Parameter

Parameters for Normal Distribution		
Parameter	Symbol	Estimate
Mean	Mu	3.195424
Std Dev	Sigma	7.384563

Quantiles for Normal Distribution		
	Quantile	
Percent	Observed	Estimated
1.0	-14.02880	-13.98364
5.0	-11.86382	-8.95110
10.0	-10.49825	-6.26827
25.0	0.18790	-1.78539
50.0	4.50196	3.19542
75.0	7.85306	8.17624
90.0	11.77305	12.65912
95.0	14.60135	15.34195
99.0	15.00132	20.37449

Jan 7, 2014:
-4.1 WWP

PJM RTO January Heating Degree Days

Parameters for Normal Distribution		
Parameter	Symbol	Estimate
Mean	Mu	918.4244
Std Dev	Sigma	154.11

Quantiles for Normal Distribution		
	Quantile	
Percent	Observed	Estimated
1.0	626.113	559.911
5.0	683.482	664.936
10.0	727.871	720.924
25.0	795.856	814.479
50.0	914.079	918.424
75.0	1053.347	1022.370
90.0	1093.201	1115.924
95.0	1110.086	1171.913
99.0	1312.047	1276.938

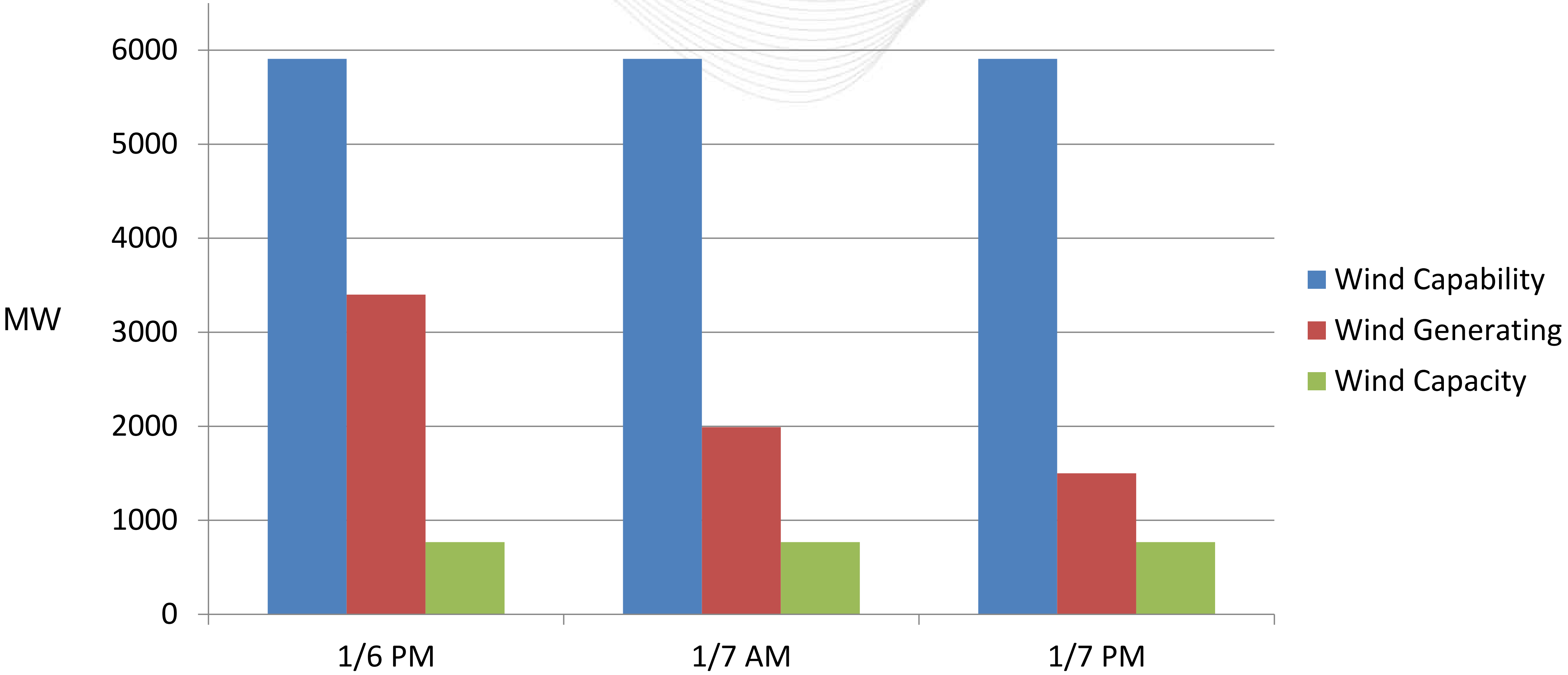
January 2014:
1,084 HDD

Remove the weather-outages units from the cumulative prob table so they are not double counted

The cumulative probability tables were built with GADS data from the period 2008 – 2012. It does not include performance data from this past January.

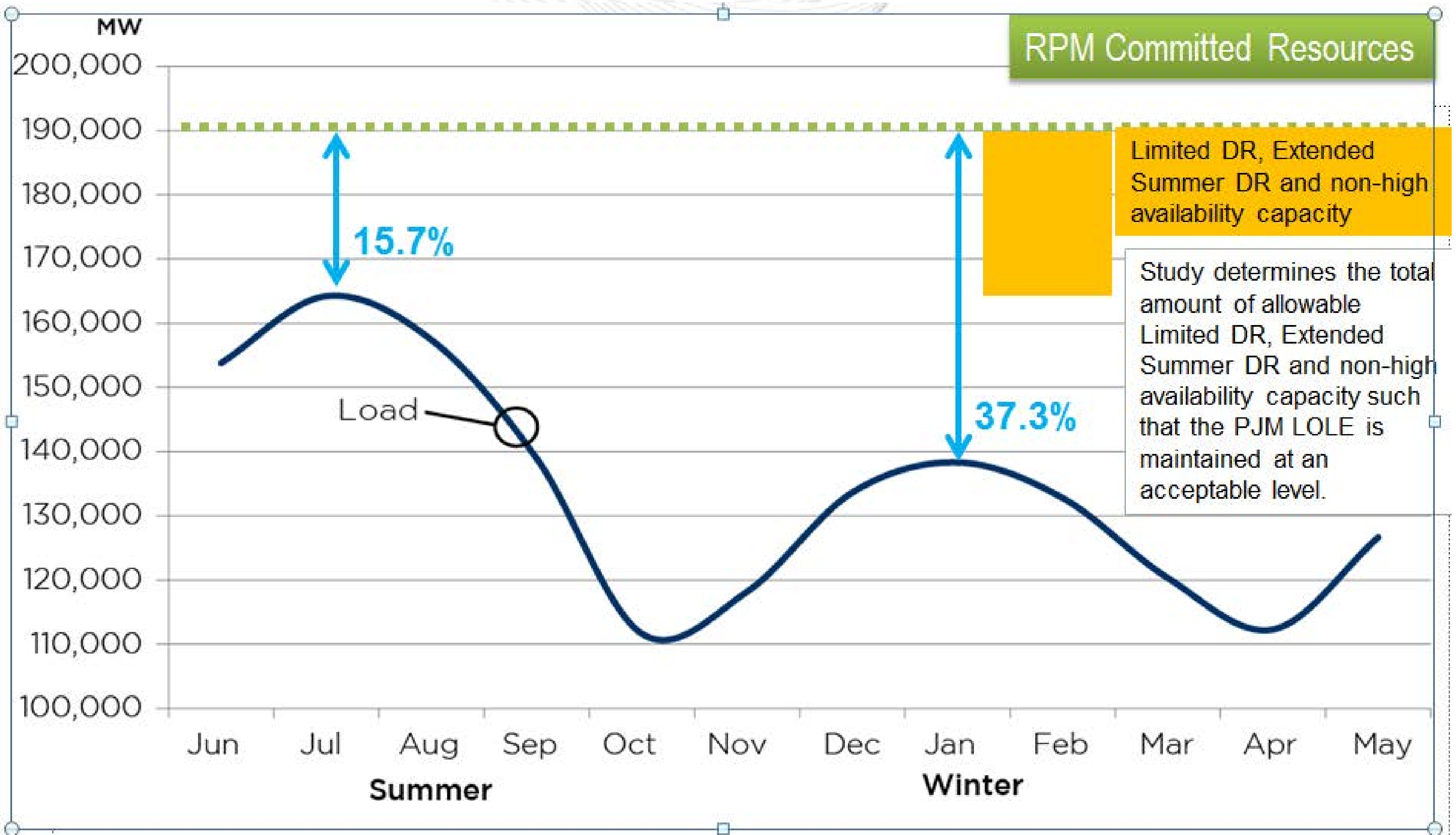
During the period 2008-2012, gas curtailments were not prevalent and events similar to January 7, 2014 were non-existent. Therefore, removing the weather-outages units from the cumulative prob table will not alter the mean and standard deviation in the unavailability distribution of the remaining fleet nor the results of the LOLP study.

Action Item # 21:
How did wind perform in the winter?



Action Item #23

Please further explain the 15.7% and the 37.3% reserve margin graph.



Please detail what resources were included for 2015 and 2016 comparison on slide 9.

Please share the differences in capacity between winter 2015 and 2016. What are your CIR assumptions.

Winter 2014/15

Total ICAP: 183,220 MW (174,250 Internal Committed + 4,228 External Committed + 4,472 Internal Uncommitted)

Winter 2015/16

Total ICAP: 174,760 MW (169,354 Internal Committed + 4,790 External Committed + 616 Internal Uncommitted)

Action Item # 26

- Approximately 22,070 MW is dual fuel capable
- Information from GADS

How much generation from the queue is ultimately built on a MW-basis and a generator-basis by primary mover (fuel-type)?

- Statistics are based on queues that have 90% of the proposed new generation projects either in-service or withdrawn (note: while PJM is currently in the AA1 queue, the latest queue that meets this criterion was the U1-queue which closed 4/30/08 and thus the data excludes the current gas boom)
- Only includes requests for new facilities (no uprates)
- Capacity MWs are based on what was studied and included in the final ISA

Action Item #29

	Natural Gas	Wind	All Fuels
Number of Projects	302	168	613
Proposed MWs	121,678.4	2,904.1	147,135.2
MWs Completed	12,761.6	790.7	16,026.0
% of MWs Complete	10.5%	27.2%	10.9%
Number of Projects Complete	49	44	147
% of Projects Complete	16.2%	26.2%	24.0%

If a planned generator cleared in a BRA, how much of the queue is that?

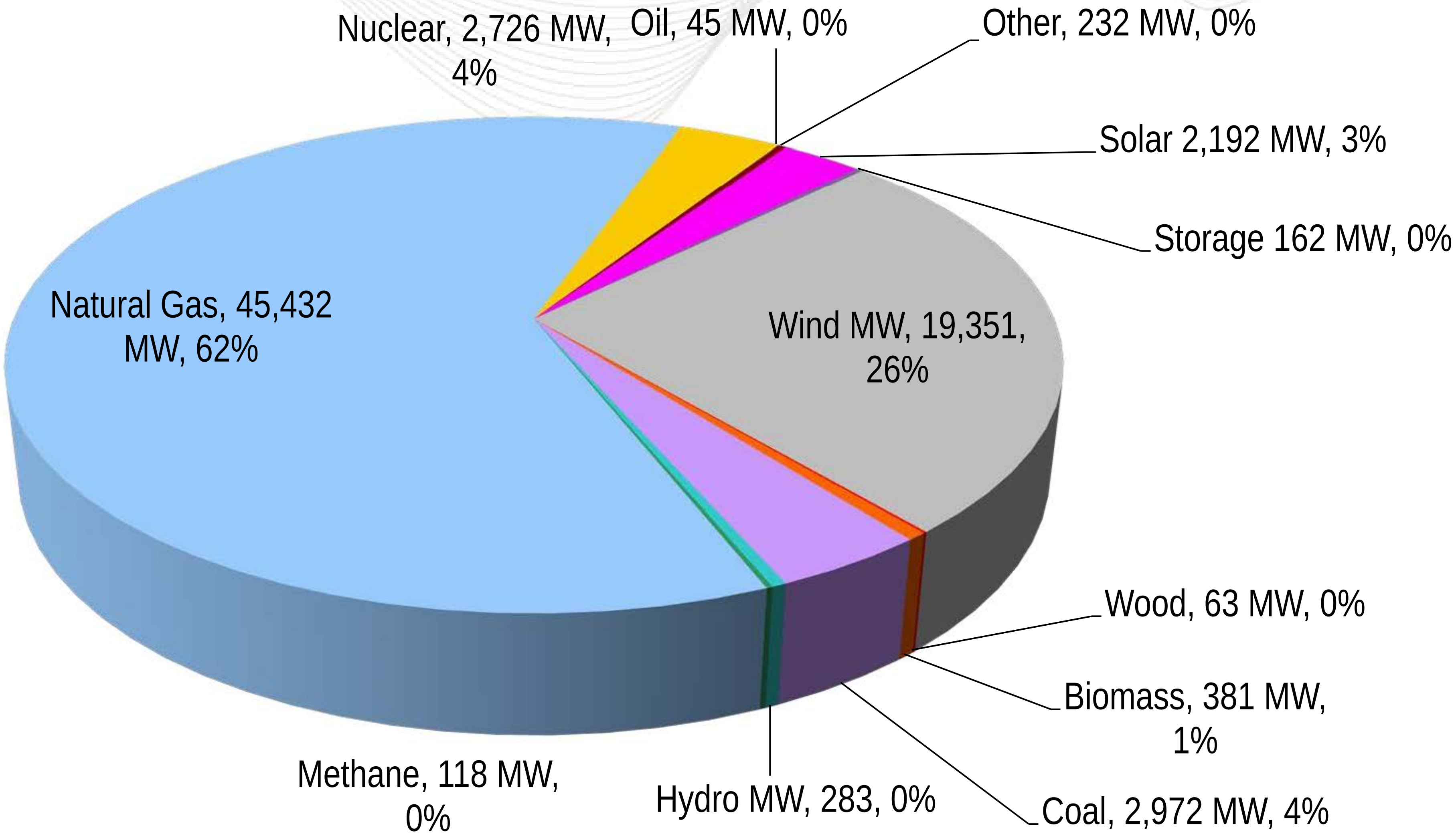
UCAP

DY	New Generation	Generation Uprates	Total
17/18	5927.4	339.3	6266.7
16/17	4281.6	1181.3	5462.9
15/16	4898.9	447.4	5346.3

ICAP

DY	New Generation	Generation Uprates	Total
17/18	6457.6	515.7	6973.3
16/17	4410.3	1238.0	5648.3
15/16	N/A	N/A	N/A

Action Item #30



As of 03/2013

Action Item #34: Peak Hour Period Availability (PHPA)

Capacity Performance Meeting

August 18, 2014

Peak Hour Period Availability Assessment

- Provides a means to assess whether committed generation resources are available at expected levels during critical peak periods
  - Credits or charges generation resource providers to the extent that they exceed or fall short of that expected availability.

Peak-Hour Periods

- PJM measures generation availability performance during peak load periods.
- The peak hour periods are defined based on summer and winter operating periods when high demand conditions are likely to occur.
- Defined Peak-Hour Periods:
  - Summer: June through August, hours ending 15:00 LPT through hour ending 19:00 LPT, on non-holiday weekdays
  - Winter: January and February, hours ending 8:00 LPT through 9:00 LPT and hours ending 19:00 LPT through 20:00 LPT, on non-holiday weekdays.
- Total number of hours is approximately 500 hours (can vary from year to year)

Calculate & Compare for each unit:

Target Unforced Capacity (TCAP)

Based on EFORd-5

vs.

Peak Period Capacity (PCAP)

Based on EFORp

Equivalent Demand Forced Outage Rate (EFORd-5)

- EFORd-5 determined based on 5 years of outage data through September 30 prior to the Delivery Year.
- Index similar to EFORd except that it is determined using 5 years instead of one year of outage data.
- Index calculated using GADs data.
- If unit does not have full 5 years of history, EFORd-5 will be calculated using class average EFORd and the available history.
- Class average EFORd will be used for a new generating unit.
- EFORd-5 is used to calculate Target Unforced Capacity.

Target Unforced Capacity (TCAP) is calculated for each unit committed to either RPM or FRR and is equal to:

Total Unit ICAP Commitment Amount * 1 – EFORd-5

TCAP is the “target” used to measure the peak period availability of capacity from the generator in the Delivery Year. It may be different from the Delivery Year UCAP value.

Equivalent Peak Period Forced Outage Rate (EFORp)

- EFORp determined using following sets of hours from the defined peak periods:
  - Forced outage hours when needed (outage hours exclude Outside Management Control (OMC) events)
  - Forced partial outage hours when needed (outage hours exclude OMC events)
  - Service hours
- “Outage hours when needed” determined by PJM by identifying hours during which the real-time LMP would have exceeded the cost-based offer for the unit or PJM would have (absent the outage) called the unit for operating reserves, taking into account the unit’s operating constraints.

Considerations for Single-Fueled, Natural Gas Units

- For a single-fueled, natural gas-fired unit, forced outages during the winter peak-hour period will not be used in determining the unit's EFORp if the resource provider can demonstrate that such failure was due to non-availability of gas to supply the unit as a results of events that were Outside Management Control (OMC).

- Lack of fuel in the cases where the operator of the unit is not in control of contracts, supply lines, or delivery of fuels is considered an OMC event.

Equivalent Peak Period Forced Outage Rate (EFORp)

$$\text{EFORp} = \left(\text{Forced Outage Hours When Needed} + \text{Equivalent Forced Partial Outage Hours When Needed} \right) / \left(\text{Service Hours} + \text{Forced Outage Hours When Needed} \right)$$

If service hours < 50 hours during the peak period, the EFORp will be set to the lesser of the calculated EFORp or the calculated EFORd (based on outage data that covers the entire Delivery Year).

Peak Period Capacity Available (PCAP) =

Total Unit ICAP Commitment Amount * 1 - EFORp

The Delivery Year PCAP of a unit is compared with the TCAP established prior to Delivery Year to determine a Peak Period Capacity Shortfall.

Peak-Hour Period Capacity Shortfall =

TCAP − PCAP

- A positive number indicates a shortfall
- A negative number indicates an excess

- Limited to 50% of Total Unit ICAP Commitment Amount * (1- Effective EFORd)
- If 50% limitation is triggered in a Delivery Year, the limit will increase to 75% the following Delivery Year.
- If 75% limitation is triggered in a Delivery Year, the limit will increase to 100% in the following Delivery Year.
- The 50% limit will be reinstated after 3 years of good performance.

Estimates of unit's EFORp and Peak Period Capacity Shortfall to be provided in December of Delivery Year.

Net Peak-Hour Period Capacity Shortfalls

- For each Resource Provider, the net of their Peak-Hour Period Capacity Shortfalls in an LDA are determined.
- The netting of Peak-Hour Period Capacity Shortfalls in an LDA is performed across committed units within a single account in eRPM.
- There is no netting of shortfalls across multiple accounts in eRPM.

Peak-Hour Period Availability is determined on a unit-specific basis; however shortfalls are netted across committed units in an eRPM account.

Adjusted Net Peak-Hour Period Capacity Shortfalls

- Excess available generation capacity in a party's account that satisfied the capacity resource obligations (satisfied DA Energy Market offer requirement and summer/winter testing requirement) may be used to reduce a Net Peak-Hour Period Capacity Shortfall in an LDA.
  - It may not be used to create a negative or more negative Net PHP Capacity Shortfall in an LDA (representing overperformance).
- This Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA is separated into shortfall due to RPM commitments and shortfall due to FRR commitments.
- The Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA is applied to each day in the DY.
- Resource Providers with a positive Adjusted Net Peak Period Capacity Shortfall in an LDA will be assessed a Peak-Hour Period Availability Charge retroactively for each day in the DY.
- Providers with a negative Adjusted Net Peak Period Capacity Shortfall in an LDA may share in the allocation of PHPA Charges.

Daily Peak-Hour Period Availability Charge =

Daily Peak-Hour Period Availability Charge Rate * Adjusted Net Peak Period Capacity Shortfall in LDA

- Different rate for shortfalls in LDA due to RPM commitments versus shortfalls in LDA due to FRR Commitments

- Charges are assessed daily and billed retroactively for the entire Delivery Year in the August bill (issued in September) after the conclusion of the Delivery Year.

Charge Rates for Shortfalls

- Rate Applied to Net Peak Period Capacity Shortfalls for RPM Commitments in an LDA is equal to the Provider's Weighted Average Resource Clearing Price in an LDA ($/MW-day).
  - Provider's Weighted Average Resource Clearing Price (WARCP) in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by a party's cleared and makewhole MWs in the LDA.
    - Cleared MWs acquired or transferred through a Unit Specific Transaction for cleared capacity are accounted for in the calculation of Provider's WARCP.
    - Cleared MWs or Makewhole MWs in the LDA for wind, solar, DR or EE Resources are not considered in the calculation of Provider's WARCP.
  - If Provider's WARCP is $0/MW-day, a PJM WARCP in an LDA will be used.
    - PJM WARCP is determined by calculating the weighted average resource clearing prices in the LDA across all RPM Auctions, weighted by the total cleared and make-whole MWs in the LDA.

- Rate Applied to Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in an LDA is equal to the weighted average of resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

Allocation of Peak-Hour Period Availability Charges

- Charges for RPM Resource Commitments are allocated to over-performing Resource Providers that have a negative Adjusted Net Peak Period Capacity Shortfalls for RPM Commitments in LDA.
- Charges for FRR Capacity Plan Commitments are allocated to over-performing Resource Providers that have a negative Adjusted Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in LDA.
- Amount allocated to over-performing Resource Provider is capped at their Adjusted Net Peak Period Capacity Shortfall in the LDA times the Daily Peak-Hour Period Availability Charge Rate.

Allocation of Peak-Hour Period Availability Charges

- Any remaining balance of Charges is allocated to LSEs in LDA who were assessed a Locational Reliability Charge and FRR Alternative LSEs in LDA that over performed (i.e., FRR LSEs with negative Net Peak Period Capacity Shortfalls).
- Allocations to LSEs are performed on a pro-rata basis based on the LSE's daily unforced capacity obligations.
- Charges and Credits are assessed daily and billed retroactively for the entire Delivery Year by the August bill (issued in September) after the conclusion of the Delivery Year.

See the DY's RPM Peak Hour Period Availability Calculator posted on RPM Auction User Information web page to estimate charges and credits.

- Load Comparisons for January 7, 2014:
  - Actual vs PJM Load Forecast

Peak	Actual Load	PJM Load Forecast	Delta
Morning	137,998	140,551	2,553
Evening	140,510	139,552	988

  - Actual vs DA Market Load (as bid by Market Participants)

Peak	Actual Load	DA Market Load	Delta
Morning	137,998	134,588	3,410
Evening	140,510	135,387	5,123

Slide 9 – What did PJM project with regard to wind resources and its performance for 2015 and 2016?

PJM assumed wind generators performed at their average capacity credit rating of 13% of nameplate.

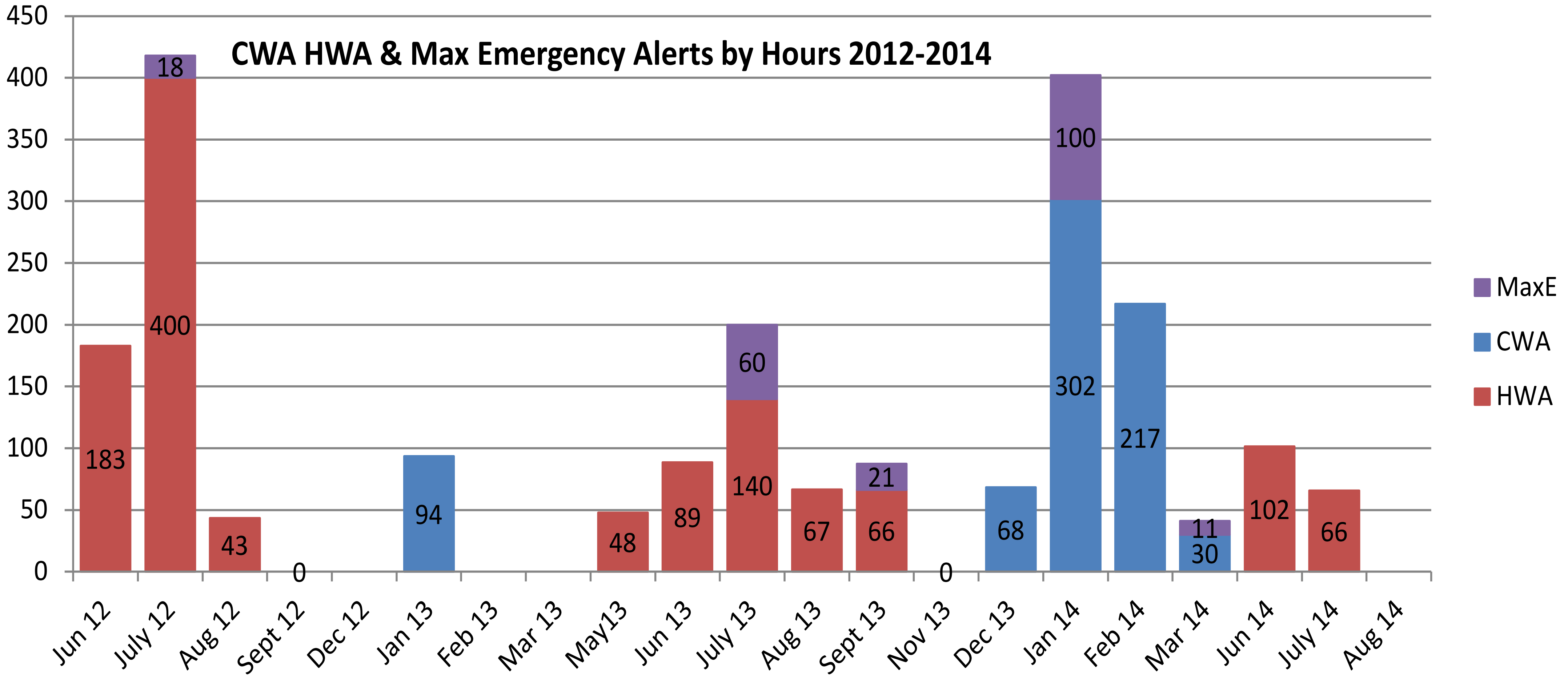
Slide 10 – Please indicate how the GADS-filed unit ratings for the winter months posted by generators are reflected in the 190,000 MW IRM line.

On average, PJM unit winter ratings are about 1% higher than summer ratings. So the ICAP in the winter season would be about 192,000 MW.

Action Item #49

	Days			Hours		
	HWA	CWA	MaxE	HWA	CWA	MaxE
Jun 12	8			183		
July 12	18		1	400		18
Aug 12	2			43		
Sept 12			1			
Dec 12						
Jan 13		4			94	
Feb 13						
Mar 13						
May13	2			48		
Jun 13	4			89		
July 13	6		3	140		60
Aug 13	3			67		
Sept 13	3		1	66		21
Nov 13			1			
Dec 13		3			68	
Jan 14		13	5		302	100
Feb 14		10			217	
Mar 14		2	1		30	11
Jun 14	3			60		
July 14	3			66		
Aug 14						
TOTAL:	**52**	**32**	**13**	**1162**	**711**	**210**

Action Item #49



Action Item #49