BONNEVILLE POWER ADMINISTRATION

Regulation, Load Following and Generation/Load Imbalance

Calculations Based on 1487 MW to 6670 MW of Installed Wind Generation

Presented by the
Wind Integration Team

Pre-decisional. For discussion purposes only.

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

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Overview:

Bonneville Power Administration created the cross-agency Wind Integration Team (WIT) soon after settling the 2009 Wind Integration Rate Case (WI-09). The primary goal of the WIT is to find how we can reliably and cost-effectively integrate the amount of wind generation that is planned in the BPA Balancing Authority Area (BAA). The manager and members of WIT agreed that the first order of business for WIT was to find the best methodology for calculating in-hour balancing requirements needed for wind generation (includes regulation, load following and generation imbalance) both internally and through a public process. Once the methodology had been determined, it was used to calculate the amount of capacity needed from now through CY 2012. The numbers thus calculated will be used as the basis for the wind integration portion of the 2010-2011 rate case (only the numbers calculated for FY 2010 and FY 2011).

This document details the methods used for scaling in planned wind projects and how the forecasts for those projects was estimated. It also details the load data, how that differs from real-time area load calculations and how the area load forecast was generated from stored data. Once the data is explained, the remainder of the document gives the results of the studies for wind and load and details next steps.

Scaling in Planned Wind*:*

In order to calculate the balancing requirements for planned wind generation, BPA used data from the MesoScale model created by 3TIER, a Seattle-based wind forecasting company. We had 3TIER take the MesoScale model and produce the most common delays between different wind generators in BPA's BAA. Once 3TIER completed this, BPA used the results to calculate the different leads and lags for planned wind from existing wind. BPA attempted to use more than one existing wind farm for each planned wind installation. All downloaded wind data was scrubbed for missing data. Appendix A details the assumed leads and lags for planned wind. It also shows the leads and lags for some already-installed wind that was used to insure the data set has all the wind generation data.

Once the leads and lags were determined, BPA used the capacity of the installed and planned wind farms in conjunction with the leads and lags to determine the estimated output of the planned wind farms. When more than one existing wind farm was used to scale in a planned farm, the existing farms were split equally in determining the output of the planned farm. The planned wind farm capacity over the existing wind farm capacity was used as the primary multiplier for calculating the planned wind farm's output. The output of the installed wind farm was moved to the correct time frame (moved back or forward in the database by the time lead or lag) then multiplied by the primary multiplier. If more than one existing wind farm was used for the planned farm, the product was then multiplied by the percentage that the existing wind farm was given.

For example, if a planned 100 MW wind farm (A) had a 20 minute lead before an existing 200 MW wind farm (B) and a 10 minute lag after an existing 50 MW wind farm

(C) and both B and C were equally indicative of the output of A, A would have the following estimated generation for any minute:

$$A = (100/200)*(B^{+20minutes})*0.5 + (100/50)*(C^{-10minutes})*0.5$$

The calculations were performed for all planned wind generation through CY 2012, therefore includes a few wind farms planned for FY 2013. These numbers are the basis for the wind portion of the calculations performed to estimate the balancing required. This table outlines the number of existing wind generation sites as well as the planned sites in future years.

Fiscal Year (FY) achieved	Installed Wind (MW)	Total Plants
2008	1425	14
2009	2105	21
2010	3155	30
2011	4330	40
2012	5570	48
2013	6670	53

Load Estimates:

The area load used in the calculations is slightly different than the area load seen on the BPA external Operations web site. The area load on the operations page is simply the total generation in the BPA BAA minus the total of all interchanges (transfers to/from adjacent BAAs). Since the pump load is not part of the load forecast, it was subtracted from the area load prior to loading it into the calculations. The reasons the pump load is not part of the load forecast are that it is scheduled at precise times, there is no weather variation that affects it (same MW draw whether it is 30 degrees or 100 degrees) and its power is directly fed by Grand Coulee so does not affect the rest of the controlled hydro system.

To determine the load amount that corresponds with each wind penetration level, load growth factors were determined and applied. For the FY 2007 load the actual scrubbed PI data was used for October 2006 through September 2007, and then the first nine months were repeated for October 2007 through June 2008. For FY 2008, we needed to account for Clark PUD coming back into the BAA. Since Clark is about 9% of the BAA load, and assuming a 1% growth factor, the data from October 2006 through November 2007 was scaled up by 10%. The data from December 2007 through June 2008 was the actual scrubbed PI data for that period. For the FY 2009 load, a load growth of 1% was assumed. For the remaining years, the load growth was determined from total BAA load as forecasted by the BPA load forecasting group. The time series was scrubbed for missing data. The following were the multipliers used:

FY09_Load	FY 2008 * 1.010 Load Growth
FY10_Load	FY 2009 * 1.022 Load Growth
FY11_Load	FY 2010 * 1.020 Load Growth
FY12_Load	FY 2011 * 1.004 Load Growth
FY13_Load	FY2012 * 1.017 Load Growth

The load forecast was downloaded from historical storage (rotary accounts). In order to change the stored system load forecast to an area load forecast, the total of the transfer customer schedules (another rotary account) was subtracted from the system load forecast. The transfer customers are located in other BAAs and are therefore not included in the area load.

Estimating Future Wind Forecasts

Background

All generating resources within the BPA BAA provide hourly estimates of their expected generation level to BPA Transmission Services. This allows for a matching of generation within the BA to the loads that are served both within and outside the BA. The hourly schedules are agreed to going into the hour so that interchange levels and control totals are consistent between adjacent BAs. These interchange levels and control totals do not change when a generator deviates from their schedule. Those generation resources acquired by the BA to maintain within-hour balance instead offset any errors between what a generator was expected to do and what they actually do.

In the case of the BPA BA, the within-hour balancing is provided by the hydroelectric resources of the Federal Columbia River Power System (FCRPS) managed by BPA Power Services. Providing balancing services from these resources affects the hydraulic operation of those facilities. In order to provide power to overcome a generator underperforming, water must move through the turbines of a facility, and that water is no longer available for other uses. The converse is true for generator over-performance where water is physically stored. Capacity, both hydraulic capacity in the form of reservoir space and turbine capacity, must be withheld from other uses to allow enough room for this kind of service.

Forecast Methodology

It is understood that forecasting expected generation from wind resources is difficult. It relies on a fuel source that is uncertain and output is very sensitive to that uncertainty. It is very important to represent that uncertainty to estimate the reserves required to provide imbalance service.

The goal is to develop a simple model that replicates the forecast accuracy that has been observed in the BPA BAA. Most forecasts measure accuracy by their mean absolute error (MAE) and root-mean squared error (RMSE) statistics. Often these statistics are expressed in terms of percent of a facility's capacity to allow comparison between facilities of different sizes. Replicating the MAE and RMSE within 1% of plant capacity was deemed to be a representative replication of the forecast.

Fourteen wind generation facilities in the BPA BAA were used in this analysis using data from August 1, 2007 to August 1, 2008. Examination of hour-ahead wind generator forecasts against observed generation levels shows the forecasts consistently lagging the observations. An example is illustrated in Figure A. For this reason, this effort focused on simple persistence models to find a suitable representation of observed forecast behavior. By this, it is meant that a previous hour's actual generation level will be used as the prediction for a future hour.

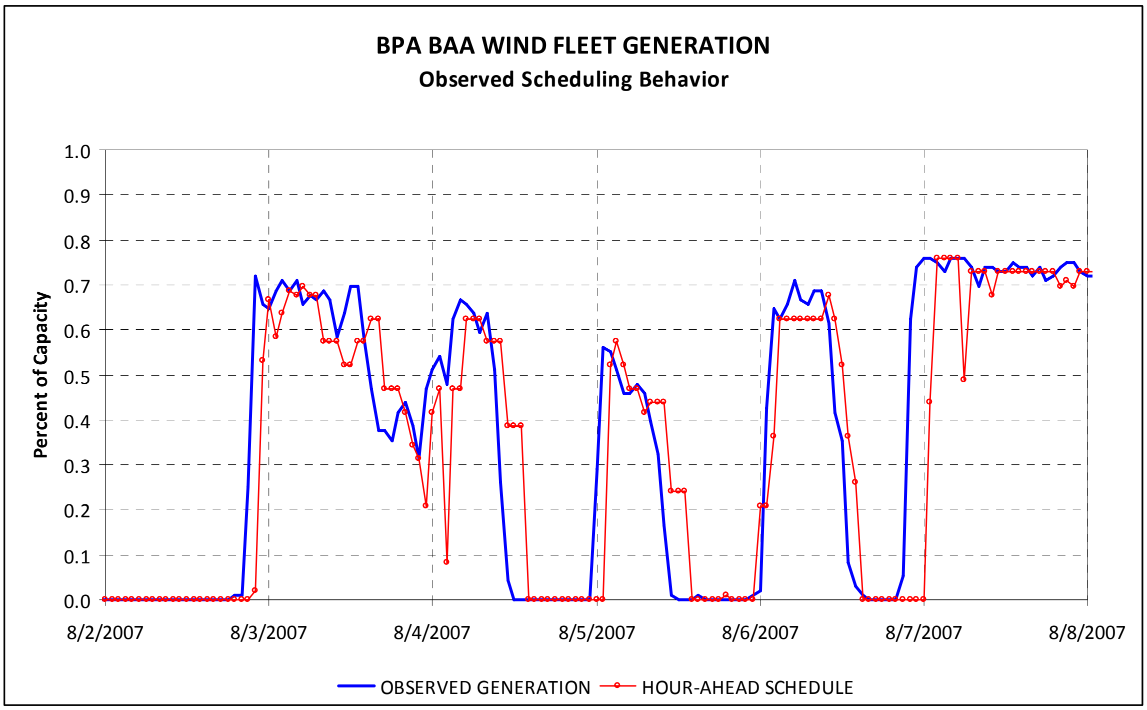


Figure A – Hour-ahead schedules generation show a lag behind the observations.

Results

It was found that a 2-hour lagged persistence model either matched or was an improvement over observed MAE and RMSE for 11 of the 14 projects used in this analysis. Figures B and C summarize this. Data points above the 1:1 Line represent those points where the modeled forecast produced a smaller error value that observed.

Conclusion

The 2-hour lag persistence model replicated the MAE and RMSE accuracy statistics within 1% of plant capacity for 11 of the 14 projects used in this analysis. It is recommended that all projected wind generation be modeled using a 2-hour lag.

MAE and RMSE Graphs:

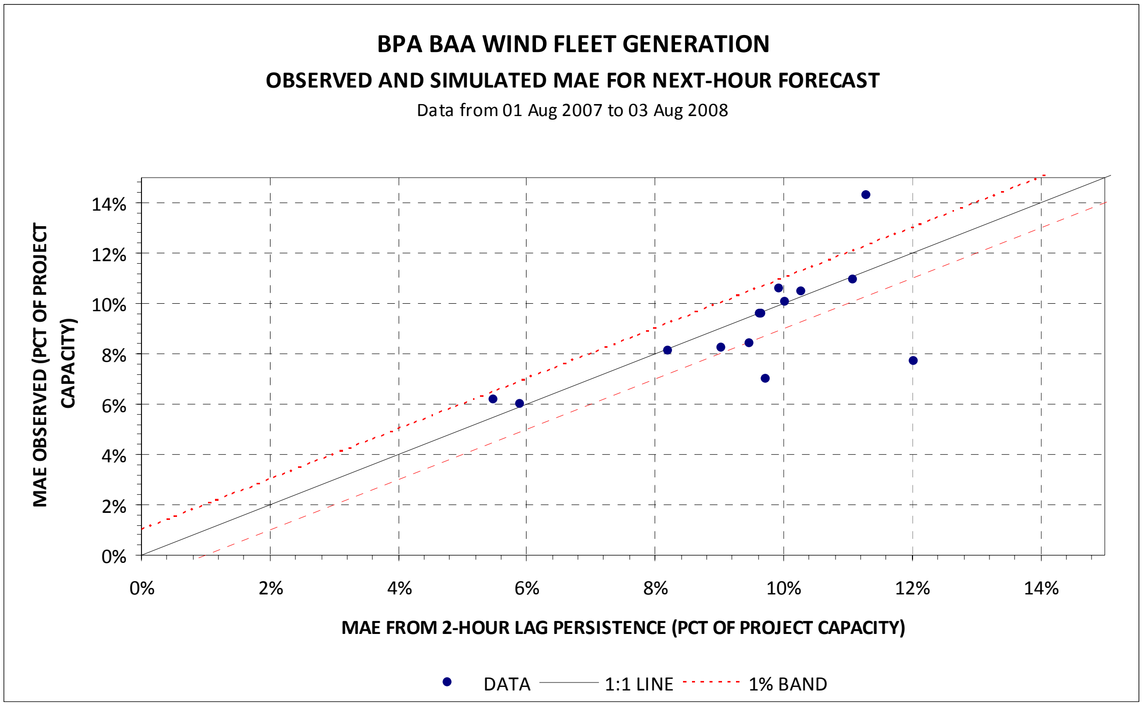


Figure B – MAE results from the 2-hour lag persistence forecast.

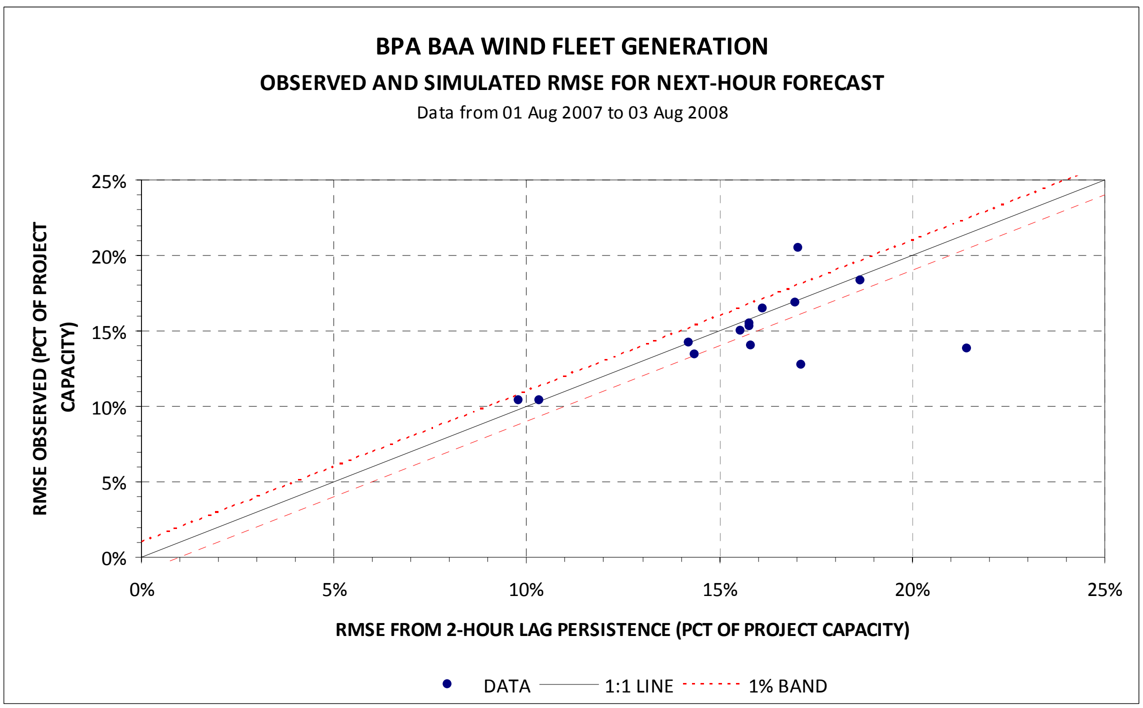


Figure C – RMSE results from the 2-hour lag persistence forecast.

In-Hour Balancing and Capacity Requirements Methodology

BPA decided during the WI-09 Rate Case proceedings and settlement that there was a need for a lot of communication between BPA and interested parties when choosing the methodology to be used for calculating the impact on BPA of the wind generation that is to be integrated in BPA's BAA. To this end, there have been conferences, conference calls, email communications and one-on-one visits with multiple parties to insure that we received as much input as possible prior to deciding on the methodology to be used by the Wind Integration Team for on-going studies as well as the studies to be used in the FY 2010-11 rate case.

Differences from WI-09 Rate Case Methodology

The base methodology being used at this point is very different from the methodology used for WI-09 rate case. During that rate case BPA attempted to find the balancing requirements without regard to schedule since the rate case was not planned to include capacity requirements for generation imbalance. Therefore, the averaging consisted of rolling averages without regard to clock hour. Also, since BPA was not looking at GI or schedules and since all of BPA's balancing in-hour is performed by generation on regulation, the timeframe consisted of hourly averages which were then compared with actual data every minute. The new methodology does take the clock hour into account as well as estimates and forecasts for each hour.

Another major difference between WI-09 rate case and current methodology is the calculations for WI-09 did not take into account the varying pattern of wind versus load. There were two calculations performed for WI-09, requirements for load then requirements for load net wind (total load minus total wind). The difference between these two was considered to be the amount of balancing required of the BPA system due to wind. With the current methodology both load and wind contributions to BPA balancing requirements are calculated at all times. This insures that neither wind nor load takes an inordinate amount of the total balancing requirements needed.

Finally, during the WI-09 rate case BPA was limited by spreadsheet size so used only four months of historic data to determine the requirements for FY 2009. With the current methodology, BPA has 21 months of historic data that is being used to calculate in-hour balancing requirements. This gives much greater detail for the studies, will allow WIT to look at seasonal differences and provides a much more robust dataset.

Base Methodology

In order to calculate in-hour balancing and capacity requirements, the following dataset was needed: actual area load, area load forecast, total actual wind generation and total wind generation forecast, which were downloaded or calculated as previously described. With this data, BPA calculated the load net wind actual (area load minus total wind generation every minute) and load net wind schedule (area load forecast minus total wind generation forecast).

For each of the total wind, total load and load net wind time series, a “perfect” schedule is determined based on the clock hourly average of each time series. Minutes 10 through 49 of each hour are set to the hourly average, and minute 50 through minute 9 of the next hour are ramped in on a straight-line basis between the hourly averages.

For the same time series, a ten minute average is created. The actual data, ten minute averages, ‘perfect’ schedules and the schedules submitted (or estimated for future years) form the basis for the requirements calculations

The total reserve requirement has been separated into three components - regulation (reg), following (fol), and imbalance (imb). The regulation component is defined as the minute-by-minute variations around the 10-minute clock average of the wind generation, load or load net wind. The following component is defined as the difference minute-by-minute between the ten (10) minute clock average of the wind generation, load or load net wind and the associated perfect schedule. The imbalance component is defined as the change in the following component requirement by using forecasted schedules instead of perfect schedules. There are three graphs depicting this in appendix C, load only, wind only and load net wind.

For each of these components BPA calculated both an inc and dec requirement. With each iteration of the study, 0.25% of the upper and lower values were discarded, thereby leaving 99.5% of the values for calculating the capacity requirements of the BPA BAA. This agrees with BPA’s historic method of using three standard deviations to calculate requirements: three standard deviations leaves 99.7% of values so BPA is not accounting for another 0.2% of movement. BPA has performed very well on all balancing standards (NERC and WECC) and therefore is allowing 0.2% more ‘slop’ on the system from this point forward.

Wind and Load Contribution to Total Capacity Requirement

In order to find the amount that wind and load contribute to the total requirement, BPA needed to find a method that was statistically valid and insured that the sum of the parts always equaled the total (e.g. wind reg up + load reg up = total reg up). In order to do this in a statistically accurate manner, BPA employed incremental standard deviation. This shows for a one MW increase in wind regulation standard deviation, how many MW increase in the load net wind regulation standard deviation occurs. Likewise, for a one MW increase in load regulation standard deviation, this will show the MW increase in the load net wind regulation standard deviation. Therefore, for any MW increase or decrease in regulation for wind or load, the total regulation increase can be determined by using the appropriate incremental standard deviation. This is discussed in detail in Appendix B.

Time Series of studies

The timeline used for calculating the requirements is hour of day for the full data set. This translates to 24 values for each of the different capacity requirements (wind regulation inc, wind following inc, etc.) The 0.25% of the upper and lower values were discarded for each hour, and then the total requirement was calculated based on the maximum value for the 24 hour series. Calculating the needed capacity by time of day produces the capacity values that we will need to hold to meet our balancing requirements 99.5% of the time. This is denoted in the table and graph in the results section.

Results

The regulation and load following numbers for wind are showing as less than calculated during the WI-09 rate case proceedings. As has been demonstrated by some interested parties, although we attempted to keep all GI out of those studies, some inevitably crept in since we were completely ignoring all schedules and forecasts. The preliminary results based on the maximum of hourly requirement (shown in appendix D) for the total reserve requirement for different levels of wind integration are:

		Regulation		Following (PS)		Following (ES)		Following (D)	
FY	**Wind(MW)**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
08	**1425**	124.3	-140.4	313.4	-366.6	928.2	-1,143.3	614.8	-776.7
09	**2105**	126.8	-143.1	334.8	-381.5	1,130.0	-1,426.5	795.2	-1,044.9
10	**3155**	134.4	-151.1	380.1	-409.6	1,483.6	-2,013.5	1,103.5	-1,603.9
11	**4330**	143.8	-158.4	419.2	-448.3	1,794.9	-2,370.5	1,375.7	-1,922.2
12	**5570**	148.9	-162.8	465.7	-486.3	2,237.2	-2,884.8	1,771.5	-2,398.5
13	**6670**	149.8	-166.9	470.2	-479.7	2,157.1	-2,772.5	1,686.9	-2,292.7

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (2 hour persistence for wind; scaled historical estimates for load)
- D – the delta, i.e. the increase in following due to imbalance (ES – PS)

Although regulation, following, and imbalance requirements are evaluated for the projected wind fleet out to the year 2013, this does not make any assumption whether resources currently available to the BPA BA will or will not be capable of providing for those requirements.

In appendix D, the hour of day values are tabulated for each of the requirements for both wind and load from 2008 through 2013. These will be the basis for calculating requirements as we go forward in order to delineate between heavy and light load hours or even going as far as calculating the normal balancing requirements by time of day for any wind penetration level.

It can be seen in appendix D that the total load requirement actually diminishes as we go further into the future. Although this is not intuitive since the total load does increase as time goes on, this is the nature of the BPA BAA system due to the dramatic increase in installed wind. The wind requirements are disproportionately small when the installed capacity is below 3000 MW, but due to its variability and poor forecasts, the requirements for wind overtake the requirements for load once the installed capacity reaches the 3000 MW mark, approximately one-half the amount of our average load. Note that the majority of the decrease in the total requirements for load and total increase in the total requirement for wind comes from the GI component.

The following two graphs depict an estimate of the wind and load requirements, respectively, based on proportional maximum values. For example, the regulation inc for wind for FY 08 was calculated by taking the maximum regulation inc for wind for all hours in the FY 08 table, dividing that by itself plus the maximum regulation inc for load for all hours in the FY 08 table and multiplying the resulting fraction by the total regulation inc requirement as denoted in the table on the previous page.

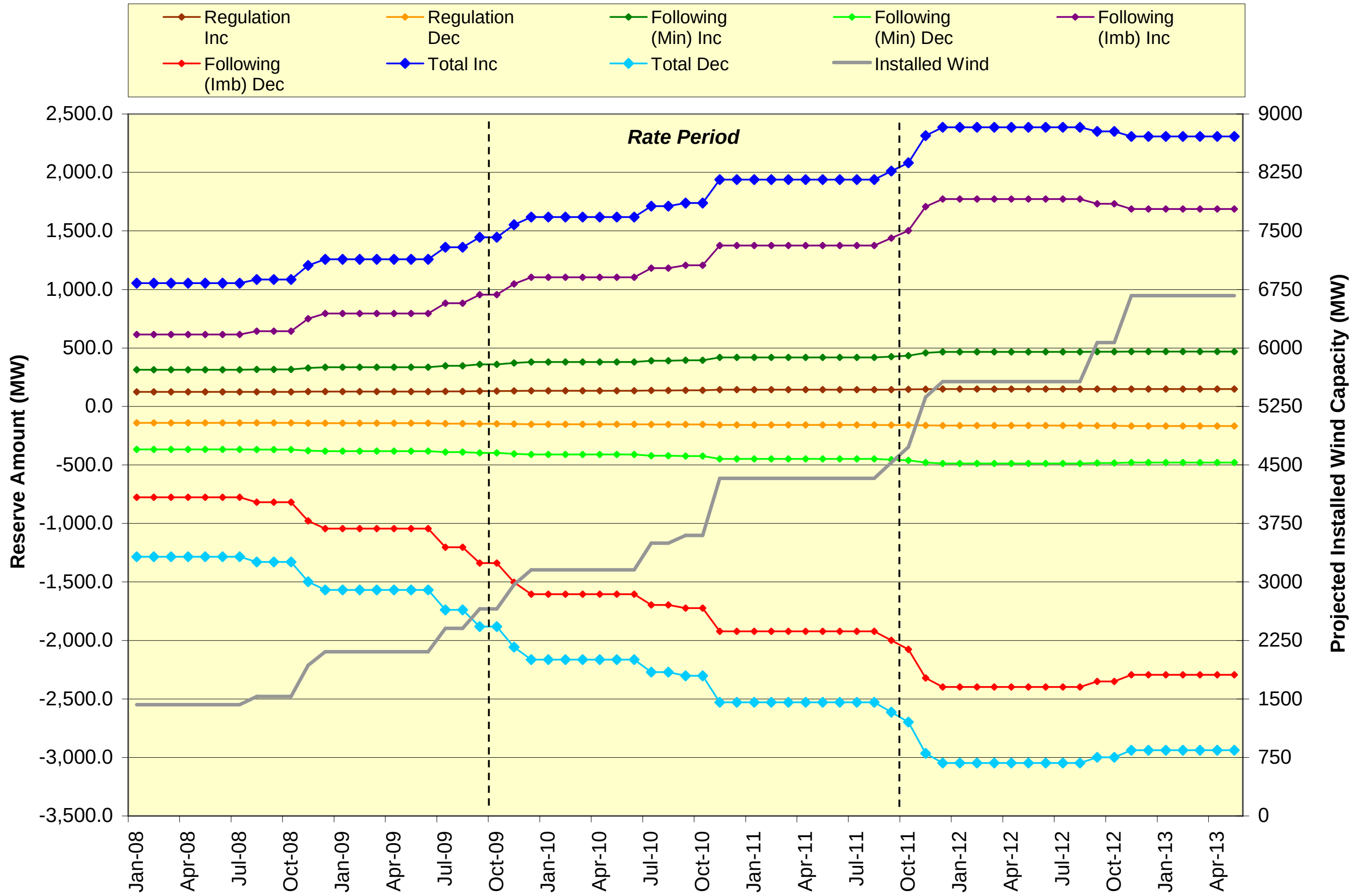
		Regulation		Following (PS)		Following (ES)		Following (D)	
FY	Wind(MW)	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec
08	1425	10.0	-10.2	56.1	-58.0	276.7	-301.7	211.4	-238.3
09	2105	13.8	-14.5	83.3	-90.1	508.4	-620.3	415.7	-526.3
10	3155	27.3	-27.5	139.5	-146.1	834.6	-1258.1	694.7	-1126.4
11	4330	40.3	-40.2	178.5	-186.7	1187.7	-1651.7	1014.4	-1485.5
12	5570	51.0	-53.8	225.9	-228.4	1671.4	-2223.2	1466.8	-2023.3
13	6670	53.1	-54.1	224.1	-224.0	1571.7	-2100.5	1362.6	-1908.2

		Regulation		Following (PS)		Following (ES)		Following (D)	
FY	Wind(MW)	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec
08	1425	114.3	-130.2	257.3	-308.6	651.5	-841.6	403.4	-538.4
09	2105	113.0	-128.6	251.5	-291.4	621.6	-806.2	379.5	-518.6
10	3155	107.1	-123.6	240.6	-263.5	649.0	-755.4	408.8	-477.5
11	4330	103.5	-118.2	240.7	-261.6	607.2	-718.8	361.3	-436.7
12	5570	97.9	-109.0	239.8	-257.9	565.8	-661.6	304.7	-375.2
13	6670	96.7	-112.8	246.1	-255.7	585.4	-672.0	324.3	-384.5

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (2 hour persistence for wind; scaled historical estimates for load)
- D – the delta, i.e. the increase in following due to imbalance (ES – PS)

BONNEVILLE POWER ADMINISTRATION

Total Reserve Requirement through 2013



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Appendix A: Scaling in Wind

Wind site locations PROJECT NAME (based on info from S. Enyeart 4/30/2008, revised 7/15/2008)	**MW**	**Full Service Date**	**Scale**
Vansycle Wind Project	25	1998	
Stateline Wind Project (Nine Mile substation)	90	2000	
Condon Wind Project	50	2000	
Klondike Phase I	24	2000	
Nine Canyon 1	18	2001	
Klondike Phase II	76	2005	
Blue Sky/Hopkins Ridge	150	2005	
Big Horn Wind Project (Spring Creek Substation)	200	8/2006	
Leaning Juniper Phase 1 (Jones Canyon Substation)	100	10/2006	
White Creek Wind (Rock Creek Substation)	200	10/2007	100 10 bef Big Horn, 100 20 bef Big Horn
Klondike III part 1 and 2 (John Day 230kV Substation)	225	10/2007	20 after Klondike 1 and Klondike 2
Biglow Canyon Wind Phase 1 (John Day 230kV Substation)	126	12/2007	10 bef Leaning Juniper
Nine Canyon 1A	45	2/2008	Same as Nine Canyon
Goodnoe Hills (Rock Creek Substation)	96	2/2008	30 bef Big Horn
Total as of 12/2007:	**1425**		

Wind site locations PROJECT NAME (based on info from S. Enyeart 4/30/2008, revised 7/15/2008)	**MW**	**Full Service Date**	**Scale**
2008 Projects			
Nine Canyon II Addition	32	8/2008	5 after 9 canyon
Klondike III part 3 (John Day 230kV Substation)	75	8/2008	10 after Klondike III
	100	11/2008	5 after LJ1 and 30 before Biglow Canyon
	200	11/2008	30 after Klondike III and 5 before LJ1
	100	11/2008	30 before LJ1
	100	12/2008	40 before LJ1 and 10 before Goodnoe
	73	12/2008	50 after KN1 and 2 and 40 after Biglow
Additions 2008:	**680**		
Potential Total as of 12/2008:	**2105**		
2009 Projects			
	50	7/2009	5 before B H1
	150	7/2009	1 after biglow 1 and 10 before goodnoe
	100	7/2009	40 before LJ1
	150	9/2009	10 before goodno and 20 before white creek
	100	9/2009	30 before LJ1 and 10 before KN1/2
	100	11/2009	30 after KN1/2, 40 after KN3, 5 before LJ1
	60	11/2009	20 before Hopkins and 45 after 9 cany
	150	11/2009	10 after white creek and 40 after KN1/2
	190	12/2009	30 before LJ1 and 10 before Biglow
Additions 2009:	**1050**		
Potential Total as of 12/2009:	**3155**		

Wind site locations PROJECT NAME (based on info from S. Enyeart 4/30/2008, revised 7/15/2008)	**MW**	**Full Service Date**	**Scale**
2010 Projects			
	110	7/2010	50 before Wild Horse
	125	7/2010	10 before Biglow and 30 before LJ1
	50	7/2010	10 before Biglow and 30 before LJ1
	77	7/2010	60 after KN1/2, 20 after LJ1, 40 after Biglow
	100	9/2010	10 after Goodnoe, 5 after White Creek, 90 before 9 canyon
	150	11/2010	5 after BH1 and 20 after Goodnoe
	110	11/2010	60 after 9 cany and 90 after KN3
	53	11/2010	10 after goodnoe
	100	11/2010	10 after white creek and 40 after KN1/2
	300	11/2010	90 after Wild horse (total estimate)
Additions 2010:	**1175**		
Total by 2010:	**4330**		

Wind site locations PROJECT NAME (based on info from S. Enyeart 4/30/2008, revised 7/15/2008)	**MW**	**Full Service Date**	**Scale**
2011 Projects			
	200	9/2011	40 after KN1/2 and 3, 40 before Vancycle (mainly kn123, small amount Van)
	200	10/2011	25 after LJ1, 50 after KN1/2
	80	11/2011	40 before KN1/2 and 3, 40 before Biglow
	60	11/2011	40 before LJ1, 20 before Biglow
	100	11/2001	10 before Wild Horse
	200	11/2011	50 after KN1/2 and 3 (30%) and 40 after Big horn (70%)
	200	11/2011	60 after Stateline
	200	12/2011	30 after Big Horn, 30 before Hopkins Ridge
Additions 2011:	**1240**		
Total by 2011:	**5570**		
2012 Projects			
	200	9/2012	60 after Stateline
	300	9/2012	40 before LJ1, 20 before KN1/2 and 3
	200	11/2012	40 before LJ1, 10 before KN 1/2 and 3
	200	11/2012	30 before Hopkins Ridge and 30 after Bighorn
	200	11/2012	50 after KN1/2 and 3 (30%) and 40 after Big horn (70%)
Additions 2012:	**1100**		
Total by 2012:	**6670**		

Appendix B: Allocating Total Reserve Requirement Among Causes

Goal

The goal of this paper is to provide a quantitatively robust method for allocating a control area's balancing requirement among the relevant elements causing the requirement. By accounting for the correlations among factors, one may calculate the component balancing requirement such that the individual components sum to the diversified total requirement. Proceeding further, one may take the concept of the Gaussian Copula to make the calculation relevant for non-normal distributions.

Application in these analyses

The remainder of this appendix describes in detail the incremental standard deviation method, these two equations describe are how it was applied to our data:

Load allocation = (Load net Wind percentile) * [(Load St Dev) ^ 2 + Cov(Load, Wind)] / (Load net Wind St Dev) ^ 2
Wind allocation = (Load net Wind percentile) * [(Wind St Dev) ^ 2 + Cov(Load, Wind)] / (Load net Wind St Dev) ^ 2

A Simple Example

To begin the discussion, an example in terms of standard normal distributions is examined. Consider two normal distributions, both with mean = 0.0 and standard deviation = 1.0. The joint standard deviation considering correlation is calculated by:

$$s_p = [\mathbf{sRs}^T]^{1/2}$$

where:

s_p is the total standard deviation of the combined distributions,

s is a row vector, $\{s_1, s_2, . . . s_n\}$, of size n containing standard deviation values of the variables contained in the total portfolio (in this example the values are 1.0 and 1.0),

R is the correlation matrix of size n x n relating each of the portfolio variables to one another,

$\mathbf{s}^T$ is a column vector, $\{s_1, s_2, . . . s_n\}$, of size n of standard deviation values of the variables contained in the total portfolio (again, in this example the values are 1.0 and 1.0).

Here it is observable that the correlation matrix is the key element in calculating the standard deviation of the total portfolio. Continuing with the example and given the above equation, the 95th percentile, or a z-value of 1.64, for the combined distribution under varying correlation scenarios is as follows:

Correl	**P95 a**	**P95 b**	**P95 a + b**
1.00	1.64	1.64	3.29
0.90	1.64	1.64	3.21
0.80	1.64	1.64	3.12
0.70	1.64	1.64	3.03
0.60	1.64	1.64	2.94
0.50	1.64	1.64	2.85
0.40	1.64	1.64	2.75
0.30	1.64	1.64	2.65
0.20	1.64	1.64	2.55
0.10	1.64	1.64	2.44
0.00	1.64	1.64	2.33

Observe that under the correlation value of 1.00 the 95th percentile values are directly additive, but under all other circumstances the percentiles are not directly additive.

The question now is how to make the above percentiles additive. Calculating the incremental standard deviation values allows for the direct addition of the percentile values:

$$\mathbf{s}_{\text{Inc}} = \mathbf{Rs}^T / s_p$$

where;

$\mathbf{s}_{\text{Inc}}$ is a vector, $\{s_{\text{Inc }1}, s_{\text{Inc }2}, \ldots s_{\text{Inc }n}\}$, of size n of incremental standard deviation values.

The incremental standard deviation calculates percent contribution of any individual component to the total portfolio standard deviation. For each given correlation value, the incremental standard deviation values are as follows:

Correl	s_{inc} **a**	s_{inc} **b**
1.00	1.00	1.00
0.90	0.97	0.97
0.80	0.95	0.95
0.70	0.92	0.92
0.60	0.89	0.89
0.50	0.87	0.87

0.40	0.84	0.84
0.30	0.81	0.81
0.20	0.77	0.77
0.10	0.74	0.74
0.00	0.71	0.71

Observing the above table of incremental standard deviation values reveals why under the case of a 1.00 correlation the standard deviation values, and hence percentile values, are directly additive: each component is contributing 100% of its variation to the aggregate standard deviation. Note that the percent contribution of a and b to the total in the table above is the same under all correlation values because in this example a and b both have the same standard deviation values. If the standard deviation values differed, the incremental standard deviations would not be equal for both a and b. It may be worth noting that the sum of $\mathbf{s}_{\mathrm{Inc}}$ does not necessarily equal 1.0.

From the incremental standard deviation values contained in the above table, the marginal standard deviation values are calculated resulting in 95th percentile values that also are now directly additive:

Correl	**P95 a**	**P95 b**	**P95 a + b**
1.00	1.64	1.64	3.29
0.90	1.60	1.60	3.21
0.80	1.56	1.56	3.12
0.70	1.52	1.52	3.03
0.60	1.47	1.47	2.94
0.50	1.42	1.42	2.85
0.40	1.38	1.38	2.75
0.30	1.33	1.33	2.65
0.20	1.27	1.27	2.55
0.10	1.22	1.22	2.44
0.00	1.16	1.16	2.33

Again, in the above example, the proportion is equal for both distributions because each distribution has the same standard deviation. Had differing standard deviation values been chosen, the proportioning would be different.

Applying to Non-Normal Distributions: Borrowing From Gaussian Copula

The preceding machinations may be applied to non-normal distributions to make the percentile values directly additive by borrowing a concept from the Gaussian Copula method of correlating distributions. In general terms, a Gaussian Copula is a method of correlating n variables in terms of n standard normal distributions. This results in a matrix of size i x n of correlated z-values. Since calculating the cumulative distribution function for all z-values results in n uniform distributions with values u_i, 0.0>= u_i, <= 1.0, correlated cumulative probabilities may be selected from any empirical or other known distribution type. The process for the Gaussian Copula is given by:

$\mathbf{P}$ = CDF[$\mathbf{CZ}$],

where;

$\mathbf{P}$ is a i x n matrix of correlated values $0.0 >= u_i, <= 1.0$ for each n,

CDF is the cumulative distribution function for a standard normal distribution,

$\mathbf{C}$ is a matrix of Cholesky factors given correlation matrix $\mathbf{R}$,

where;

$\mathbf{C} = \mathbf{LD}^{1/2}$,

where $\mathbf{L}$ and $\mathbf{D}$ are the lower diagonal and the diagonal of matrix $\mathbf{R}$.

$\mathbf{Z}$ is a i x n matrix of independent, identically distributed, standard normal random variables

This notion of processing in terms of standard normal distributions and transforming from standard normal probability values to those of the distributions in question is what allows for the component decomposition of the aggregate balancing requirement; despite the balancing distribution being non-normal. In the specific application used for the purposes of allocating a control area's balancing requirement among the relevant elements, the above notion is performed partly in reverse.

The Application to Allocating the Balancing Requirement (Error Signal)

Recalling that the goal is to provide a quantitatively robust method for allocating the control area balancing requirement among the relevant elements causing the requirement, the aforementioned calculations and notions are now applied to the specific case of allocating the control area balancing requirement between two causal elements; Element 1 (E2) and Element 2 (E2).

Given that the desire is to allocate the balancing requirement between E1 and E2, total calculated balancing is:

$\mathbf{B}_T = \mathbf{B}_{E1} + \mathbf{B}_{E2}$

where;

$\mathbf{B}_T$ is a vector of length n of calculated total balancing requirements,

$\mathbf{B}_{E1}$ is a vector of length n of calculated balancing requirements for Element 1 only,

$\mathbf{B}_{E2}$ is a vector of length n of calculated balancing requirements for Element 2 only,

The first step toward being able to sum the percentiles is to translate the $P_{99.5}[\mathbf{B}_T]$ value into a normal distribution z-value:

$$z\mathbf{B}_T = (P_{99.5}[\mathbf{B}_T] - \text{Mean}[\mathbf{B}_T]) / s[\mathbf{B}_T]$$

Having translated the desired $P_{99.5}[\mathbf{B}_T]$ off of the empirical distribution, $\mathbf{B}_T$, into terms of a normal distribution, calculating the incremental standard deviation values for E1 and E2 may begin. From the earlier discussion, the component standard deviation is given by:

$$\mathbf{s}_{\text{Inc}} = \mathbf{R}\mathbf{s}^T / s_p$$

applying to the specific problem at hand:

$\mathbf{R}$ is the correlation matrix of $\mathbf{B}_{E1}$ and $\mathbf{B}_{E2}$,

$\mathbf{s}^T$ is a column vector of standard deviation values for $\mathbf{B}_{E1}$ and $\mathbf{B}_{E2}$,

s_p is the standard deviation of $\mathbf{B}_T$,

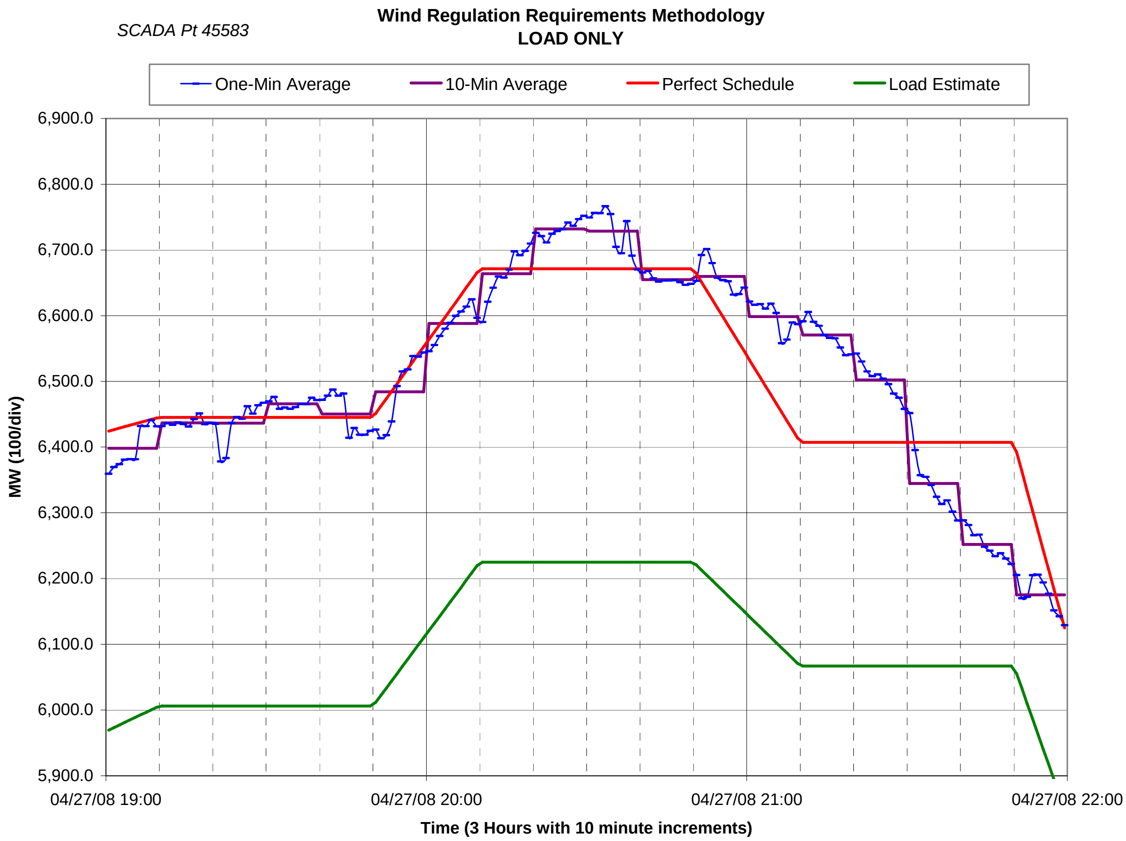
and finally,

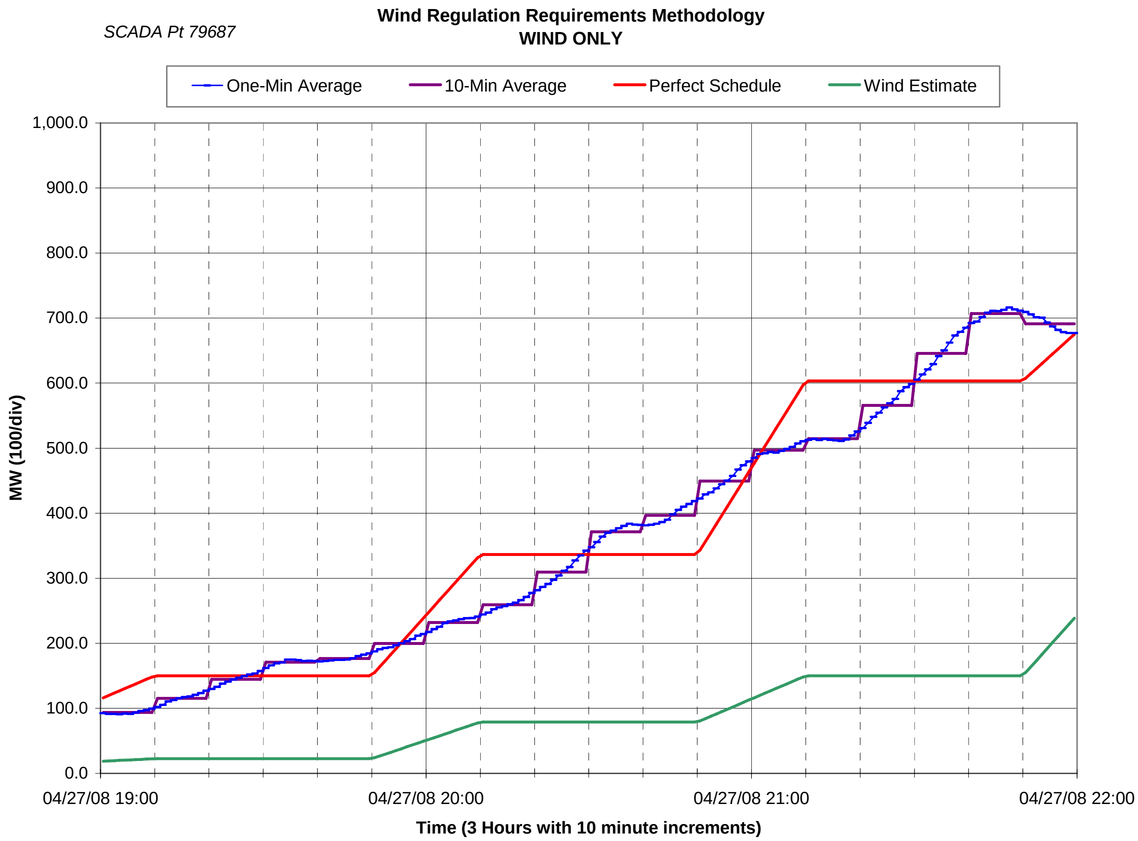
$\mathbf{s}_{\text{Inc}}$ is a vector containing the component contribution of $\mathbf{B}_{E1}$ and $\mathbf{B}_{E2}$ to $\mathbf{B}_{T}$,.

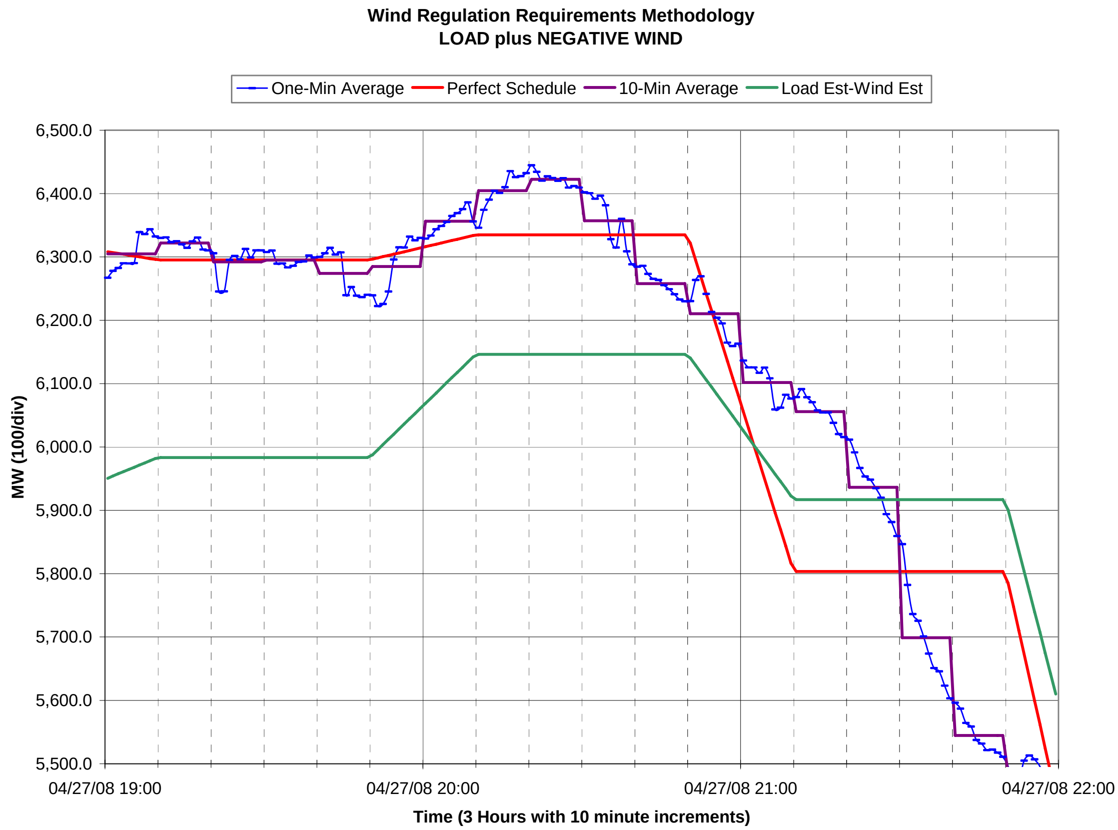
Calculating the amount that $\mathbf{B}_{E1}$ and $\mathbf{B}_{E2}$ contribute to $\mathbf{B}_T$ at a given percentile, the 99.5th in this case, is given by:

$$\begin{aligned} P_{99.5}[\mathbf{B}_T] = {} & z\mathbf{B}_T * \mathbf{s}\{\mathbf{B}_{E1}\} * \mathbf{s}_{\text{Inc}}\{\mathbf{B}_{E1}\} + \text{Mean}[\mathbf{B}_{E1}] + \\ & z\mathbf{B}_T * \mathbf{s}\{\mathbf{B}_{E2}\} * \mathbf{s}_{\text{Inc}}\{\mathbf{B}_{E2}\} + \text{Mean}[\mathbf{B}_{E2}] \end{aligned}$$

Appendix C: Graphic depiction of requirements methodology




SCADA Pt 79687
Wind Regulation Requirements Methodology
WIND ONLY
One-Min Average
10-Min Average
Perfect Schedule
Wind Estimate
1,000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
MW (100/div)
04/27/08 19:00
04/27/08 20:00
04/27/08 21:00
04/27/08 22:00
Time (3 Hours with 10 minute increments)


Wind Regulation Requirements Methodology
LOAD plus NEGATIVE WIND
One-Min Average
Perfect Schedule
10-Min Average
Load Est-Wind Est
6,500.0
6,400.0
6,300.0
6,200.0
6,100.0
6,000.0
5,900.0
5,800.0
5,700.0
5,600.0
5,500.0
MW (100/div)
04/27/08 19:00
04/27/08 20:00
04/27/08 21:00
04/27/08 22:00
Time (3 Hours with 10 minute increments)

Appendix D: Reserve requirements by hour of day

	Regulation FY08 (1425MW Wind)					
	Total		Load		Wind	
Hour	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
1	76.0	-77.3	68.4	-69.7	7.6	-7.7
2	73.2	-73.7	62.8	-63.2	10.4	-10.5
3	65.5	-68.3	59.0	-61.6	6.5	-6.7
4	66.6	-70.2	60.5	-63.8	6.1	-6.4
5	82.4	-83.4	75.9	-76.9	6.4	-6.5
6	104.4	-111.1	99.6	-106.0	4.8	-5.1
7	124.3	-140.4	118.6	-134.1	5.6	-6.3
8	94.0	-100.3	88.3	-94.3	5.7	-6.1
9	87.5	-93.3	81.2	-86.6	6.3	-6.7
10	84.8	-84.0	79.1	-78.3	5.7	-5.7
11	89.7	-101.1	84.0	-94.7	5.7	-6.4
12	91.9	-95.3	86.7	-89.9	5.2	-5.4
13	83.8	-87.7	76.2	-79.7	7.6	-8.0
14	80.9	-88.9	73.6	-80.9	7.2	-7.9
15	80.1	-89.5	73.0	-81.5	7.1	-8.0
16	100.8	-87.8	92.9	-80.9	7.9	-6.9
17	91.2	-96.7	83.7	-88.7	7.5	-7.9
18	86.0	-89.3	77.9	-80.9	8.1	-8.4
19	77.2	-80.4	68.2	-71.1	9.0	-9.4
20	78.0	-81.9	69.8	-73.3	8.2	-8.6
21	81.2	-86.4	74.2	-79.0	6.9	-7.4
22	101.7	-107.2	96.8	-102.0	5.0	-5.2
23	108.3	-105.1	103.0	-100.0	5.3	-5.2
24	89.2	-92.0	83.6	-86.2	5.7	-5.8

	Regulation FY09 (2105MW Wind)					
	Total		Load		Wind	
Hour	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
1	79.6	-80.7	67.9	-68.8	11.7	-11.8
2	75.6	-78.7	61.2	-63.7	14.4	-15.0
3	71.1	-71.1	60.5	-60.5	10.6	-10.6
4	71.1	-74.0	61.5	-64.1	9.6	-9.9
5	85.8	-88.0	76.0	-78.0	9.7	-10.0
6	107.7	-114.8	100.2	-106.8	7.5	-8.0
7	126.8	-143.1	118.2	-133.4	8.6	-9.7
8	96.8	-104.2	87.8	-94.6	9.0	-9.7
9	90.8	-96.5	81.3	-86.4	9.5	-10.1
10	87.5	-86.4	78.3	-77.3	9.2	-9.1
11	92.0	-105.8	82.9	-95.3	9.1	-10.4
12	95.1	-98.3	86.5	-89.4	8.6	-8.9
13	85.1	-91.5	74.0	-79.5	11.1	-12.0
14	82.5	-90.9	72.3	-79.6	10.2	-11.3
15	85.2	-92.0	74.1	-80.1	11.0	-11.9
16	103.2	-91.5	91.3	-80.9	12.0	-10.6
17	93.0	-99.2	81.9	-87.4	11.1	-11.8
18	90.0	-92.6	77.7	-79.9	12.3	-12.6
19	80.1	-86.0	66.2	-71.0	13.9	-15.0
20	82.6	-87.3	69.5	-73.5	13.1	-13.9
21	83.6	-90.5	72.7	-78.7	10.9	-11.7
22	104.1	-111.2	96.5	-103.1	7.7	-8.2
23	111.4	-109.5	103.5	-101.7	7.9	-7.8
24	93.0	-93.9	84.3	-85.1	8.7	-8.8

	Regulation FY10 (3155MW Wind)					
	Total		Load		Wind	
Hour	Inc	Dec	Inc	Dec	Inc	Dec
1	89.0	-91.4	65.9	-67.6	23.2	-23.8
2	95.0	-93.3	64.8	-63.6	30.3	-29.7
3	79.1	-80.1	58.7	-59.4	20.5	-20.7
4	81.9	-81.6	62.5	-62.2	19.5	-19.4
5	95.0	-95.8	76.7	-77.3	18.4	-18.5
6	115.4	-123.8	101.4	-108.8	14.0	-15.0
7	134.4	-151.1	118.9	-133.8	15.5	-17.4
8	104.0	-112.0	87.1	-93.8	16.9	-18.2
9	99.6	-101.6	81.6	-83.2	18.0	-18.3
10	94.5	-93.0	76.6	-75.4	17.9	-17.6
11	100.5	-110.2	83.1	-91.1	17.4	-19.1
12	101.8	-106.4	85.1	-88.9	16.7	-17.5
13	96.6	-103.9	74.4	-80.1	22.2	-23.9
14	89.7	-97.7	70.7	-77.0	19.0	-20.7
15	97.2	-107.5	75.3	-83.3	21.9	-24.2
16	108.6	-103.0	86.6	-82.2	21.9	-20.8
17	103.8	-108.3	82.0	-85.6	21.7	-22.7
18	98.7	-101.8	75.2	-77.6	23.5	-24.2
19	92.7	-96.7	66.0	-68.7	26.8	-27.9
20	96.2	-98.4	70.0	-71.6	26.2	-26.8
21	93.1	-99.8	70.8	-75.9	22.3	-23.9
22	113.4	-116.2	96.9	-99.4	16.4	-16.8
23	122.4	-121.3	105.8	-104.8	16.6	-16.5
24	99.2	-101.1	81.6	-83.1	17.7	-18.0

	Regulation FY11 (4330MW Wind)					
	Total		Load		Wind	
Hour	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
1	98.9	-100.2	65.2	-66.1	33.7	-34.1
2	107.4	-103.3	60.5	-58.1	47.0	-45.1
3	88.7	-90.0	58.1	-59.0	30.6	-31.1
4	92.6	-92.2	63.1	-62.9	29.4	-29.3
5	102.3	-105.1	75.8	-77.9	26.5	-27.3
6	124.7	-132.7	103.9	-110.5	20.8	-22.2
7	143.8	-158.4	120.7	-132.9	23.1	-25.5
8	111.2	-117.7	86.9	-92.0	24.3	-25.7
9	107.2	-108.4	80.8	-81.7	26.4	-26.7
10	102.2	-101.1	76.4	-75.6	25.8	-25.6
11	109.3	-117.3	83.9	-90.0	25.4	-27.3
12	111.0	-116.4	86.1	-90.3	24.9	-26.1
13	105.6	-113.0	73.5	-78.6	32.1	-34.4
14	100.3	-108.3	71.6	-77.3	28.7	-31.0
15	107.2	-117.9	75.2	-82.7	32.0	-35.2
16	114.6	-111.7	83.7	-81.7	30.8	-30.1
17	112.4	-117.9	80.4	-84.4	31.9	-33.5
18	110.5	-111.7	74.8	-75.6	35.8	-36.1
19	103.9	-107.3	65.2	-67.4	38.7	-40.0
20	106.7	-107.4	68.8	-69.3	37.9	-38.1
21	105.6	-107.8	71.7	-73.2	33.9	-34.6
22	122.7	-126.4	97.1	-100.1	25.6	-26.4
23	130.3	-131.0	105.4	-105.9	25.0	-25.1
24	109.7	-110.4	82.5	-83.0	27.2	-27.4

Regulation FY12 (5570MW Wind)

	Total		Load		Wind	
Hour	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
1	109.3	-108.9	63.2	-63.0	46.1	-45.9
2	114.9	-118.9	52.9	-54.8	62.0	-64.2
3	97.2	-98.1	56.3	-56.8	40.9	-41.3
4	102.2	-99.7	62.2	-60.6	40.0	-39.1
5	113.1	-113.6	76.4	-76.7	36.7	-36.9
6	133.4	-139.7	104.1	-109.0	29.2	-30.6
7	148.9	-162.8	119.0	-130.1	29.9	-32.7
8	118.3	-125.3	86.8	-92.0	31.5	-33.4
9	113.4	-113.2	78.3	-78.2	35.1	-35.0
10	111.1	-108.9	75.0	-73.5	36.1	-35.4
11	116.6	-121.8	81.4	-85.0	35.2	-36.8
12	117.3	-125.9	82.9	-89.0	34.4	-36.9
13	115.1	-123.8	71.6	-77.0	43.5	-46.8
14	110.0	-116.2	69.7	-73.7	40.3	-42.5
15	123.0	-127.3	76.0	-78.7	47.0	-48.7
16	125.2	-120.2	82.6	-79.4	42.5	-40.9
17	118.2	-125.8	75.4	-80.2	42.8	-45.6
18	119.1	-123.3	71.1	-73.6	48.1	-49.7
19	116.9	-118.8	63.4	-64.4	53.5	-54.4
20	116.1	-115.7	66.1	-65.9	50.0	-49.9
21	116.0	-117.5	70.4	-71.3	45.6	-46.2
22	132.9	-134.4	97.0	-98.0	35.9	-36.3
23	143.3	-142.8	106.6	-106.2	36.7	-36.6
24	119.7	-119.8	80.9	-81.0	38.8	-38.8

	Regulation FY13 (6670MW Wind)					
	Total		Load		Wind	
Hour	Inc	Dec	Inc	Dec	Inc	Dec
1	109.6	-116.0	63.0	-66.6	46.6	-49.3
2	124.7	-121.3	58.7	-57.1	65.9	-64.2
3	102.6	-99.9	59.1	-57.6	43.4	-42.3
4	103.8	-101.4	63.1	-61.7	40.6	-39.7
5	112.6	-116.1	76.1	-78.4	36.6	-37.7
6	135.9	-142.5	106.6	-111.8	29.3	-30.7
7	149.8	-166.9	119.9	-133.6	29.9	-33.3
8	121.7	-129.0	88.1	-93.4	33.6	-35.6
9	116.8	-117.1	79.8	-80.1	37.0	-37.1
10	111.6	-110.4	75.3	-74.5	36.3	-35.9
11	120.2	-126.7	84.2	-88.7	36.0	-37.9
12	120.9	-128.9	86.1	-91.8	34.8	-37.1
13	119.1	-125.7	73.1	-77.2	46.0	-48.5
14	112.4	-118.8	70.9	-74.9	41.5	-43.9
15	120.4	-127.4	75.8	-80.2	44.7	-47.3
16	128.2	-125.3	84.3	-82.4	43.9	-42.9
17	122.5	-126.0	78.9	-81.2	43.6	-44.8
18	124.3	-123.7	73.7	-73.4	50.6	-50.4
19	119.7	-120.9	64.8	-65.5	54.9	-55.4
20	121.2	-121.6	68.0	-68.3	53.2	-53.4
21	120.6	-121.0	71.0	-71.3	49.6	-49.7
22	140.5	-137.2	101.2	-98.9	39.2	-38.3
23	145.2	-142.3	108.2	-105.9	37.1	-36.3
24	123.8	-122.6	83.5	-82.6	40.4	-39.9

	Following FY08 (1425MW Wind)											
	Total				Load				Wind			
Hour	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)
1	161.7	-171.5	775.7	-686.0	112.6	-119.4	479.6	-427.0	49.1	-52.1	296.0	-258.9
2	121.1	-137.4	928.2	-740.0	65.7	-74.6	550.2	-436.3	55.3	-62.8	378.1	-303.8
3	119.1	-125.4	789.4	-694.4	62.0	-65.2	483.1	-422.7	57.2	-60.2	306.5	-271.9
4	113.6	-141.6	683.3	-699.8	72.5	-90.4	445.9	-456.2	41.1	-51.2	238.1	-244.2
5	208.6	-219.0	628.8	-788.1	179.3	-188.3	459.4	-567.6	29.2	-30.7	169.9	-221.2
6	313.4	-334.5	699.7	-1,087.1	295.7	-315.5	584.4	-878.1	17.8	-19.0	115.5	-209.4
7	294.8	-366.6	802.4	-1,032.6	274.7	-341.5	663.5	-851.7	20.1	-25.0	138.8	-180.8
8	200.7	-212.1	848.6	-1,102.8	169.4	-179.0	649.8	-839.5	31.3	-33.1	198.6	-263.1
9	179.1	-193.3	717.2	-912.8	149.2	-161.1	548.2	-694.5	29.9	-32.2	169.0	-218.2
10	163.1	-168.0	849.7	-850.0	130.5	-134.5	640.4	-641.0	32.6	-33.5	209.3	-209.1
11	154.6	-162.5	720.7	-807.5	124.8	-131.2	557.5	-624.1	29.8	-31.3	163.3	-183.4
12	156.1	-172.2	716.0	-803.8	121.0	-133.5	569.9	-639.7	35.1	-38.7	146.1	-163.9
13	156.9	-160.5	772.3	-801.9	103.6	-106.0	605.7	-629.3	53.3	-54.5	166.6	-172.6
14	149.1	-143.6	876.9	-961.7	107.6	-103.6	723.3	-795.7	41.5	-40.0	153.5	-165.9
15	165.7	-165.0	884.7	-914.8	101.3	-100.9	717.1	-743.1	64.4	-64.1	167.5	-171.7
16	146.4	-175.7	749.2	-958.2	99.2	-119.1	580.5	-743.9	47.2	-56.7	168.3	-213.9
17	272.2	-278.8	823.3	-955.7	242.1	-248.0	685.2	-792.1	30.1	-30.8	138.0	-163.3
18	223.9	-248.7	695.2	-957.0	185.4	-205.9	547.0	-749.4	38.5	-42.8	148.7	-208.4
19	177.0	-176.7	613.3	-1,001.7	120.5	-120.3	438.9	-722.3	56.5	-56.4	174.9	-280.3
20	194.5	-192.0	762.6	-1,143.3	144.8	-142.9	530.3	-788.5	49.7	-49.1	232.7	-355.5
21	176.7	-184.9	774.8	-1,059.5	141.1	-147.6	544.2	-737.1	35.7	-37.3	231.6	-323.9
22	234.0	-245.1	821.3	-942.9	213.6	-223.7	622.0	-709.0	20.4	-21.4	199.9	-234.6
23	262.3	-271.4	726.2	-820.2	242.0	-250.4	545.1	-609.1	20.3	-21.0	181.1	-211.2
24	233.1	-234.1	697.4	-751.2	208.7	-209.6	495.1	-528.6	24.4	-24.5	202.5	-222.9

Note: PS – perfect schedule
ES – estimated schedule

	Following FY09 (2105MW Wind)											
	Total				Load				Wind			
Hour	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)
1	192.3	-205.2	935.7	-941.9	109.0	-116.3	392.6	-397.4	83.3	-88.9	543.5	-544.9
2	147.9	-172.2	1,130.0	-924.9	61.3	-71.4	461.7	-378.2	86.6	-100.8	668.7	-547.0
3	158.6	-152.8	909.1	-860.8	58.3	-56.2	388.5	-367.6	100.3	-96.7	521.0	-493.5
4	139.6	-165.3	941.9	-875.2	70.8	-83.9	441.7	-412.0	68.8	-81.5	501.7	-464.5
5	229.8	-238.7	838.1	-881.3	180.4	-187.5	477.4	-501.2	49.3	-51.2	362.2	-381.7
6	334.8	-350.3	884.9	-1,092.7	302.9	-316.9	615.8	-739.2	32.0	-33.5	269.7	-354.3
7	315.9	-381.5	1,005.6	-1,297.2	282.2	-340.8	694.2	-887.8	33.7	-40.7	310.8	-408.6
8	222.4	-231.7	1,059.2	-1,352.3	169.3	-176.4	646.6	-815.5	53.1	-55.3	411.3	-535.0
9	197.5	-211.2	887.3	-985.1	145.9	-156.0	533.9	-591.3	51.6	-55.2	353.0	-393.3
10	191.5	-190.1	926.3	-1,038.8	132.0	-131.0	547.1	-610.4	59.5	-59.1	379.1	-428.2
11	180.3	-185.6	845.2	-1,017.2	125.4	-129.1	515.5	-616.9	54.9	-56.5	329.7	-400.3
12	186.3	-205.8	817.3	-1,022.0	120.4	-133.0	508.4	-634.8	65.9	-72.8	308.8	-387.0
13	185.2	-196.6	932.4	-1,053.5	102.1	-108.4	556.3	-629.3	83.0	-88.1	376.0	-424.2
14	169.8	-170.4	946.9	-984.3	103.1	-103.4	618.1	-642.9	66.7	-67.0	328.7	-341.3
15	193.0	-202.9	959.7	-1,047.5	92.8	-97.5	624.3	-683.1	100.2	-105.3	335.1	-364.1
16	180.1	-212.6	909.7	-1,063.3	96.2	-113.5	535.0	-625.2	83.9	-99.0	373.6	-436.9
17	280.0	-287.7	860.5	-1,087.6	228.3	-234.6	573.4	-710.2	51.7	-53.1	286.5	-376.7
18	244.0	-268.8	772.7	-1,060.0	178.0	-196.1	471.0	-634.6	66.0	-72.7	302.9	-427.2
19	198.9	-204.8	750.6	-1,163.8	109.2	-112.4	391.6	-603.3	89.7	-92.3	360.1	-562.4
20	224.5	-212.1	900.7	-1,426.5	138.5	-130.9	454.2	-697.8	86.0	-81.3	447.2	-729.9
21	195.9	-217.4	973.0	-1,187.6	135.0	-149.8	490.4	-593.5	60.9	-67.6	484.3	-596.1
22	268.1	-274.9	996.3	-1,073.5	229.2	-235.0	584.5	-624.7	38.9	-39.9	412.7	-449.8
23	294.2	-290.3	854.7	-1,055.2	260.0	-256.6	513.4	-602.3	34.2	-33.7	341.4	-453.0
24	257.8	-257.1	828.9	-1,133.7	215.6	-215.0	450.5	-575.7	42.2	-42.1	379.2	-559.3

Note: PS – perfect schedule
ES – estimated schedule

	Following FY10 (3155MW Wind)											
	Total				**Load**				**Wind**			
Hour	**Inc (PS)**	**Dec (PS)**	**Inc (ES)**	**Dec (ES)**	**Inc (PS)**	**Dec (PS)**	**Inc (ES)**	**Dec (ES)**	**Inc (PS)**	**Dec (PS)**	**Inc (ES)**	**Dec (ES)**
1	253.3	-276.5	1,301.6	-1,364.0	95.3	-104.0	313.4	-330.3	158.0	-172.5	989.3	-1,034.9
2	204.5	-225.5	1,401.1	-1,357.2	51.7	-57.0	331.6	-321.8	152.8	-168.5	1,070.2	-1,036.1
3	213.5	-211.5	1,199.6	-1,181.1	46.4	-46.0	301.2	-296.5	167.0	-165.5	899.0	-885.3
4	193.0	-209.7	1,342.5	-1,349.9	64.8	-70.4	379.6	-382.6	128.2	-139.3	965.6	-970.0
5	282.3	-287.2	1,282.7	-1,222.2	184.3	-187.5	482.8	-466.6	98.0	-99.7	803.1	-758.8
6	380.1	-387.5	1,234.7	-1,254.3	316.2	-322.4	629.4	-640.0	63.9	-65.2	606.9	-615.9
7	363.0	-409.6	1,388.3	-1,720.9	299.2	-337.7	709.8	-862.8	63.8	-71.9	676.6	-855.7
8	276.4	-268.0	1,288.0	-1,734.3	170.1	-165.0	543.4	-706.0	106.3	-103.1	741.3	-1,023.5
9	248.1	-261.4	1,247.1	-1,263.0	144.1	-151.8	495.9	-504.5	104.0	-109.6	750.0	-757.2
10	238.5	-232.9	1,209.6	-1,453.8	124.3	-121.4	479.1	-567.4	114.2	-111.5	730.2	-885.9
11	225.6	-227.4	1,169.6	-1,402.4	120.1	-121.1	488.8	-580.0	105.4	-106.3	680.9	-822.5
12	249.3	-269.0	1,008.7	-1,406.2	119.5	-128.9	427.9	-590.8	129.8	-140.1	580.6	-815.1
13	253.7	-269.8	1,140.2	-1,510.7	96.3	-102.4	437.4	-579.9	157.4	-167.4	702.7	-930.8
14	227.7	-209.9	1,483.6	-1,258.4	99.1	-91.4	639.0	-542.1	128.5	-118.5	844.2	-716.0
15	268.7	-271.2	1,090.6	-1,385.1	85.4	-86.1	471.0	-608.8	183.3	-185.0	618.9	-775.4
16	243.1	-291.2	1,131.9	-1,596.7	86.8	-103.9	413.9	-584.3	156.3	-187.2	716.0	-1,009.2
17	314.4	-326.2	1,097.3	-1,563.2	211.1	-219.1	486.8	-654.7	103.3	-107.2	609.4	-906.7
18	294.7	-304.4	1,048.9	-1,516.0	165.1	-170.5	412.4	-567.8	129.6	-133.9	638.7	-951.8
19	265.9	-258.1	1,033.0	-1,708.2	101.1	-98.1	328.5	-528.0	164.8	-160.0	706.3	-1,183.5
20	281.7	-260.4	1,167.7	-2,013.5	121.0	-111.8	362.8	-590.4	160.7	-148.6	805.7	-1,424.8
21	272.3	-272.9	1,247.1	-1,638.8	134.9	-135.2	398.6	-504.7	137.4	-137.7	850.4	-1,136.8
22	347.8	-337.6	1,253.0	-1,526.6	250.0	-242.7	514.8	-590.5	97.8	-94.9	739.0	-937.2
23	372.0	-381.8	1,179.7	-1,563.7	287.9	-295.4	499.3	-604.9	84.1	-86.3	680.4	-959.0
24	320.9	-312.9	1,239.4	-1,756.4	224.2	-218.6	436.6	-552.5	96.8	-94.3	804.5	-1,206.6

Note: PS – perfect schedule
ES – estimated schedule

	Following FY11 (4330MW Wind)											
	Total				Load				Wind			
Hour	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)
1	287.6	-314.6	1,590.0	-1,699.1	84.6	-92.5	268.4	-287.9	203.0	-222.1	1,322.9	-1,412.6
2	248.6	-274.7	1,661.7	-1,718.7	46.6	-51.5	268.5	-278.2	202.0	-223.2	1,394.1	-1,441.3
3	261.5	-255.6	1,518.4	-1,509.5	41.1	-40.2	262.8	-261.3	220.3	-215.4	1,256.5	-1,249.1
4	245.0	-251.2	1,794.9	-1,565.2	62.6	-64.2	357.2	-313.9	182.4	-187.0	1,441.4	-1,254.4
5	309.0	-319.9	1,594.7	-1,547.3	175.2	-181.4	440.0	-434.2	133.8	-138.5	1,159.2	-1,117.5
6	407.5	-424.1	1,508.9	-1,550.1	314.3	-327.2	602.8	-622.1	93.1	-96.9	908.6	-930.5
7	407.2	-448.3	1,715.5	-1,857.8	311.9	-343.4	693.8	-754.9	95.3	-104.9	1,018.6	-1,099.7
8	322.9	-309.5	1,576.4	-1,881.6	173.1	-165.9	502.2	-578.7	149.8	-143.6	1,068.9	-1,296.3
9	288.4	-287.7	1,567.5	-1,514.2	140.5	-140.1	461.2	-447.6	148.0	-147.6	1,104.4	-1,064.8
10	288.6	-279.2	1,349.8	-1,757.3	125.5	-121.4	404.5	-510.0	163.2	-157.8	944.8	-1,246.6
11	260.9	-266.7	1,308.8	-1,735.4	115.0	-117.5	414.8	-537.7	145.9	-149.1	894.0	-1,197.7
12	285.1	-301.8	1,224.4	-1,771.1	114.2	-120.9	390.7	-553.5	170.9	-180.9	833.3	-1,217.2
13	296.0	-313.4	1,346.7	-1,833.2	89.6	-94.8	376.6	-510.0	206.5	-218.6	970.0	-1,323.1
14	289.3	-272.3	1,717.6	-1,589.4	99.0	-93.1	547.4	-506.6	190.4	-179.1	1,169.8	-1,082.4
15	308.9	-314.2	1,248.3	-1,786.6	75.8	-77.1	390.4	-570.2	233.1	-237.1	856.9	-1,214.9
16	284.3	-341.1	1,286.4	-1,965.5	80.1	-96.1	329.4	-500.2	204.3	-245.0	954.4	-1,461.0
17	362.3	-358.2	1,235.2	-1,915.5	210.5	-208.1	416.9	-576.2	151.8	-150.0	817.0	-1,336.8
18	336.0	-348.2	1,238.3	-1,861.5	152.6	-158.2	351.8	-492.2	183.4	-190.0	889.2	-1,373.9
19	310.4	-302.9	1,252.0	-2,218.4	93.1	-90.8	278.3	-467.7	217.3	-212.1	975.8	-1,755.0
20	322.2	-307.2	1,377.5	-2,370.5	110.1	-105.0	308.4	-492.8	212.1	-202.2	1,070.0	-1,879.6
21	314.7	-328.8	1,441.6	-1,938.4	124.5	-130.1	340.2	-438.2	190.2	-198.7	1,103.5	-1,503.2
22	388.0	-393.9	1,567.0	-1,933.9	240.1	-243.8	483.3	-561.4	147.8	-150.1	1,084.7	-1,373.8
23	419.2	-419.7	1,401.1	-2,050.3	291.1	-291.5	468.1	-585.4	128.1	-128.2	933.1	-1,465.1
24	358.8	-352.6	1,574.3	-2,167.6	221.9	-218.1	414.7	-506.0	136.9	-134.5	1,161.6	-1,664.7

Note: PS – perfect schedule
ES – estimated schedule

	Following FY12 (5570MW Wind)											
	Total				Load				Wind			
Hour	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)	Inc (PS)	Dec (PS)	Inc (ES)	Dec (ES)
1	342.7	-371.1	1,883.4	-2,082.4	79.4	-85.9	230.4	-253.7	263.4	-285.2	1,654.3	-1,830.1
2	286.3	-313.4	1,916.7	-2,062.5	40.3	-44.1	219.6	-236.4	246.0	-269.3	1,697.9	-1,826.9
3	304.6	-318.3	1,894.6	-1,779.3	36.2	-37.8	232.4	-218.1	268.4	-280.5	1,663.3	-1,562.2
4	278.3	-280.7	2,237.2	-1,726.5	55.8	-56.3	321.2	-252.2	222.4	-224.4	1,920.2	-1,477.4
5	360.1	-376.0	1,906.1	-1,996.4	177.0	-184.8	403.0	-421.7	183.1	-191.2	1,508.4	-1,580.3
6	460.1	-452.8	1,838.9	-1,874.3	326.2	-321.0	584.0	-586.8	134.0	-131.8	1,258.2	-1,290.9
7	437.5	-471.7	2,025.2	-2,130.5	312.1	-336.5	646.8	-686.2	125.4	-135.2	1,374.3	-1,440.0
8	356.6	-330.6	1,850.7	-2,221.7	171.4	-158.9	454.9	-517.7	185.2	-171.7	1,389.0	-1,695.3
9	318.1	-320.8	1,804.1	-1,907.4	130.9	-132.1	396.3	-415.4	187.2	-188.8	1,405.3	-1,489.4
10	327.3	-327.3	1,634.5	-2,120.6	116.4	-116.4	355.0	-443.7	210.9	-210.9	1,278.9	-1,676.1
11	304.2	-308.6	1,457.3	-2,178.7	109.5	-111.0	342.7	-489.3	194.8	-197.5	1,114.6	-1,689.4
12	334.0	-344.0	1,493.4	-2,203.1	109.3	-112.5	341.3	-484.6	224.7	-231.4	1,151.8	-1,718.1
13	345.8	-352.0	1,666.2	-2,304.6	84.8	-86.4	322.7	-438.1	260.9	-265.6	1,343.4	-1,866.4
14	330.2	-317.2	1,961.8	-1,948.9	92.2	-88.6	444.9	-441.3	237.9	-228.6	1,516.4	-1,507.1
15	376.7	-365.1	1,742.9	-2,185.8	69.3	-67.2	376.7	-476.8	307.4	-298.0	1,364.9	-1,707.2
16	329.7	-371.0	1,577.9	-2,464.0	73.9	-83.2	271.7	-414.9	255.8	-287.8	1,303.0	-2,043.7
17	394.4	-388.6	1,455.3	-2,376.2	192.3	-189.5	351.4	-487.5	202.1	-199.2	1,102.3	-1,885.7
18	381.6	-374.4	1,489.8	-2,361.4	138.9	-136.3	297.1	-419.9	242.8	-238.2	1,195.9	-1,947.1
19	364.1	-374.3	1,568.5	-2,679.7	83.0	-85.3	238.4	-382.9	281.1	-289.0	1,332.5	-2,301.4
20	373.9	-356.1	1,692.5	-2,884.8	102.4	-97.5	270.3	-419.4	271.5	-258.5	1,423.3	-2,467.4
21	368.9	-376.2	1,739.9	-2,390.3	118.3	-120.6	302.3	-390.9	250.6	-255.5	1,440.0	-2,002.7
22	424.7	-450.9	1,811.9	-2,388.1	228.8	-243.0	426.3	-518.8	195.8	-208.0	1,386.7	-1,870.8
23	465.7	-486.3	1,636.0	-2,587.9	285.3	-297.9	429.5	-556.9	180.4	-188.4	1,206.6	-2,031.2
24	410.0	-408.0	1,845.9	-2,820.2	218.6	-217.5	376.2	-482.4	191.4	-190.5	1,471.7	-2,341.2

Note: PS – perfect schedule
ES – estimated schedule

BONNEVILLE POWER ADMINISTRATION

	Following FY13 (6670MW Wind)											
	Total				**Load**				**Wind**			
Hour	**Inc (PS)**	**Dec (PS)**	**Inc (ES)**	**Dec (ES)**	**Inc (PS)**	**Dec (PS)**	**Inc (ES)**	**Dec (ES)**	**Inc (PS)**	**Dec (PS)**	**Inc (ES)**	**Dec (ES)**
1	341.9	-367.5	1,955.1	-2,067.2	77.2	-82.9	243.0	-257.7	264.8	-284.6	1,713.6	-1,811.1
2	288.2	-318.6	1,985.3	-2,077.4	40.6	-44.9	232.8	-244.0	247.6	-273.7	1,753.4	-1,834.2
3	312.9	-317.8	1,908.0	-1,758.4	38.5	-39.1	244.1	-224.8	274.4	-278.7	1,665.0	-1,534.5
4	290.2	-283.9	2,157.1	-1,800.4	58.7	-57.4	321.0	-270.5	231.5	-226.5	1,840.0	-1,533.1
5	369.1	-378.1	2,001.1	-1,935.2	182.2	-186.7	431.9	-424.8	186.9	-191.5	1,574.8	-1,515.7
6	459.9	-468.4	1,822.7	-1,833.5	327.5	-333.5	597.3	-603.8	132.4	-134.9	1,228.5	-1,232.9
7	446.6	-479.7	2,039.8	-2,022.1	319.5	-343.2	677.7	-690.0	127.1	-136.5	1,358.1	-1,328.3
8	384.5	-363.8	1,875.2	-2,288.9	176.4	-166.8	468.9	-544.6	208.2	-196.9	1,399.7	-1,735.7
9	349.3	-344.7	1,824.2	-1,887.4	139.9	-138.0	411.8	-422.5	209.4	-206.6	1,409.9	-1,462.4
10	321.1	-308.9	1,622.4	-2,140.2	113.1	-108.8	362.3	-459.5	208.0	-200.1	1,259.4	-1,679.7
11	306.1	-302.4	1,533.1	-2,129.6	110.4	-109.1	372.5	-499.3	195.7	-193.3	1,160.6	-1,630.3
12	343.3	-364.4	1,463.5	-2,077.3	112.0	-118.9	356.3	-492.4	231.2	-245.5	1,106.9	-1,584.5
13	362.6	-388.8	1,618.9	-2,242.8	86.4	-92.6	328.2	-449.5	276.3	-296.2	1,290.6	-1,793.2
14	333.1	-329.2	2,067.0	-1,912.3	90.2	-89.1	472.9	-438.6	243.0	-240.1	1,593.6	-1,473.3
15	370.9	-373.9	1,718.3	-2,106.5	72.7	-73.3	399.7	-493.8	298.2	-300.6	1,317.3	-1,611.0
16	332.4	-379.8	1,582.2	-2,384.6	73.4	-83.8	293.2	-436.4	259.0	-296.0	1,285.8	-1,943.0
17	410.7	-399.7	1,439.4	-2,276.3	204.6	-199.1	372.8	-505.9	206.1	-200.6	1,065.1	-1,767.6
18	376.1	-410.6	1,469.5	-2,334.1	134.9	-147.3	304.5	-445.7	241.2	-263.4	1,168.1	-1,893.9
19	360.6	-374.6	1,541.8	-2,587.3	84.1	-87.4	244.7	-388.2	276.5	-287.2	1,299.5	-2,203.6
20	389.2	-371.3	1,653.1	-2,772.5	106.4	-101.5	273.0	-417.9	282.8	-269.8	1,381.2	-2,356.6
21	393.5	-399.1	1,747.3	-2,419.1	123.0	-124.7	309.2	-402.6	270.5	-274.4	1,440.4	-2,020.0
22	462.3	-468.6	1,848.1	-2,386.2	244.9	-248.3	449.4	-531.1	217.4	-220.3	1,400.1	-1,856.9
23	470.2	-477.7	1,686.8	-2,606.8	290.5	-295.1	444.7	-565.0	179.7	-182.6	1,242.2	-2,041.9
24	404.3	-398.6	1,861.0	-2,737.6	213.8	-210.8	381.1	-479.5	190.5	-187.8	1,481.9	-2,261.5

Note: PS – perfect schedule
ES – estimated schedule