

The Impact of Wind Energy on Hourly Load Following Requirements: An Hourly and Seasonal Analysis

Preprint

A. Krich and M. Milligan, Consultant
National Renewable Energy Laboratory

*To be presented at WINDPOWER 2005
Denver, Colorado
May 15-18, 2005*

Conference Paper
NREL/CP-500-38061
May 2005

NREL is operated by Midwest Research Institute • Battelle Contract No. DE-AC36-99-GO10337



NOTICE

The submitted manuscript has been offered by an employee of the Midwest Research Institute (MRI), a contractor of the US Government under Contract No. DE-AC36-99GO10337. Accordingly, the US Government and MRI retain a nonexclusive royalty-free license to publish or reproduce the published form of this contribution, or allow others to do so, for US Government purposes.

This report was prepared as an account of work sponsored by an agency of the United States government. Neither the United States government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States government or any agency thereof.

Available electronically at <http://www.osti.gov/bridge>

Available for a processing fee to U.S. Department of Energy and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: <mailto:reports@adonis.osti.gov>

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: <http://www.ntis.gov/ordering.htm>



Abigail Krich
Michael Milligan, Consultant
National Wind Technology Center
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401

Abstract

The impacts of wind energy on the power system grid can be decomposed into several time scales that include regulation, load following, and unit commitment. Techniques for evaluating the impacts on these time scales are still evolving, and as wind energy becomes a larger part of the electricity supply, valuable experience will be gained that will help refine these methods. Studies that estimated the impact of wind in the load following time scale found differing results and costs, ranging from near zero to approximately \$2.50/megawatt-hour (MWh). Part of the reason for these differences is the different interpretation of the impacts that would be allocated to this ancillary service. Because of the low correlation between changes in load and wind, long-term analyses of the load following impact of wind may find low impacts. During the daily load cycle, there is a tremendous variability in load following requirements in systems without wind. When significant levels of wind generation are added to the resource mix, relatively small changes in wind output can complicate the task of balancing the system during periods of large load swings. This paper analyzes the load following impacts of wind by segregating these critical time periods of the day and separating the analysis by season. The analysis compares wind generation at geographically dispersed sites to wind generation based primarily at a single site, and for a large penetration of wind (more than 20% wind capacity to peak load).

Load-Following Analysis

A 2000 study by Milligan and Factor [2] identified a number of scenarios for geographically distributing 1,600 megawatts (MW) of wind capacity among 12 locations in Iowa, optimized for either system reliability or economic benefit. A nameplate wind capacity of 1600 MW was chosen because this represented 9% of Iowa's predicted electrical load (energy) in 2015, and the state was considering a 10% Renewable Portfolio Standard (RPS) in this timeframe.

An hourly energy output was calculated for each of the wind farms in these scenarios, based on wind speed data and turbine power curves. The wind speeds were collected at a height of 50 m in 1997, as this year was very close to the long-term norm, and were scaled to match a 4-year average.

Matching hourly load data were then collected from the Mid-Continent Area Power Pool, representing the Iowa load. As the wind power fluctuates, the load also fluctuates, and the

two are not significantly correlated. During some hours the wind output and load will both increase or decrease, and at other hours they will move in opposite directions. At times when the load and wind fluctuations are moving in the same direction, they cancel each other out. It is thus not necessary to balance every fluctuation in wind output by ramping dispatchable generators to an equal and opposite extent. It is only necessary to balance out the difference between the load and wind fluctuations to achieve a total system balance.

In this study, the change in load from one hour to the next is considered the hourly ramp rate. Any fluctuations within the hour are ignored. As in [1], this study defines the hourly load following requirement as

$$R_t = L_t - L_{t-1} \quad (1)$$

Where L is the hourly load at hour t , and R is the load following requirement in the hour t . Once wind is added into the system, the load following requirements are defined as

$$R_{wt} = (L_t - W_t) - (L_{t-1} - W_{t-1}) \quad (2)$$

Where R_{wt} is the load following requirement in the hour t for the system with wind and W is the wind production at hour t , making the terms in parentheses the load net of wind in the respective hour.

In 2003, Milligan [1] used eight of the scenarios identified in the 2000 study to examine their load following impacts. Equations (1) and (2) were used to calculate R_t and R_{wt} for each hour of the year for each of these eight scenarios.

The load following effects were identified on an annual basis and compared between the different scenarios. The more geographically dispersed scenarios tended to have a lesser system impact than the ones with wind power based primarily at a single site.

Two of these scenarios are further examined in this study. Case A was chosen because it represented one of the most geographically dispersed of the eight cases and had one of the lowest impacts on load following demands. Case B was chosen because it represented the least geographically dispersed of the eight cases and had the highest impacts on load following demands. This gives an indication of a reasonable range for these impacts among well-sited wind farms.

Table 1 shows the geographic dispersion of the wind power in each of these cases, and Figure 1 shows the monthly average wind generation.

Table 1 - MW wind power at each site for Case A and B showing relative geographic dispersion

	Algona	Alta	Esther	Forest	Radcliffe	Sibley
Case A	200	400	500	50	100	350
Case B	0	1300	200	0	100	0

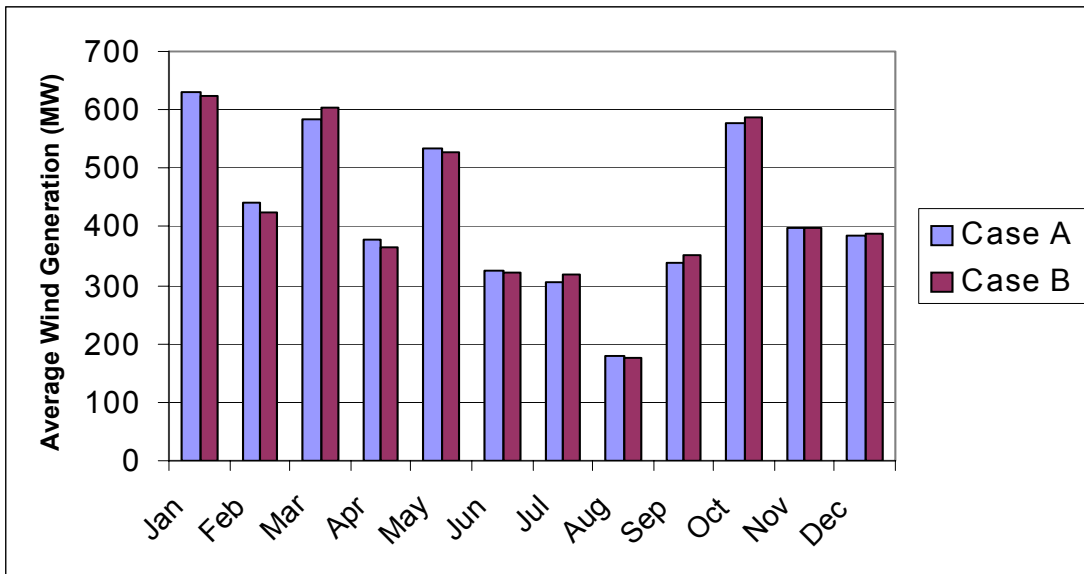


Figure 1 - Monthly wind generation

To get an idea of the impact of wind generation on load following requirements, [1] looked at the statistical distribution of the load following requirements over the entire year. Figure 2 and Figure 3 show the annual statistical distribution of hourly load following demands for the no-wind scenario (load only) and for the scenario of wind energy subtracted from the load (combined) for Cases A and B. Table 2 summarizes the differences, comparing the standard deviation of the load-only distribution, the standard deviation of the combined distribution, and the difference between the two cases. As compared with the no-wind scenario, Case A adds 20 MW, or 10.6%, to the standard deviation of load following demands, while Case B adds 32 MW, or 17.1%. Although these are noticeable increases to the load following variability, they are still only 1%-2% of the nameplate capacity of the wind farms.

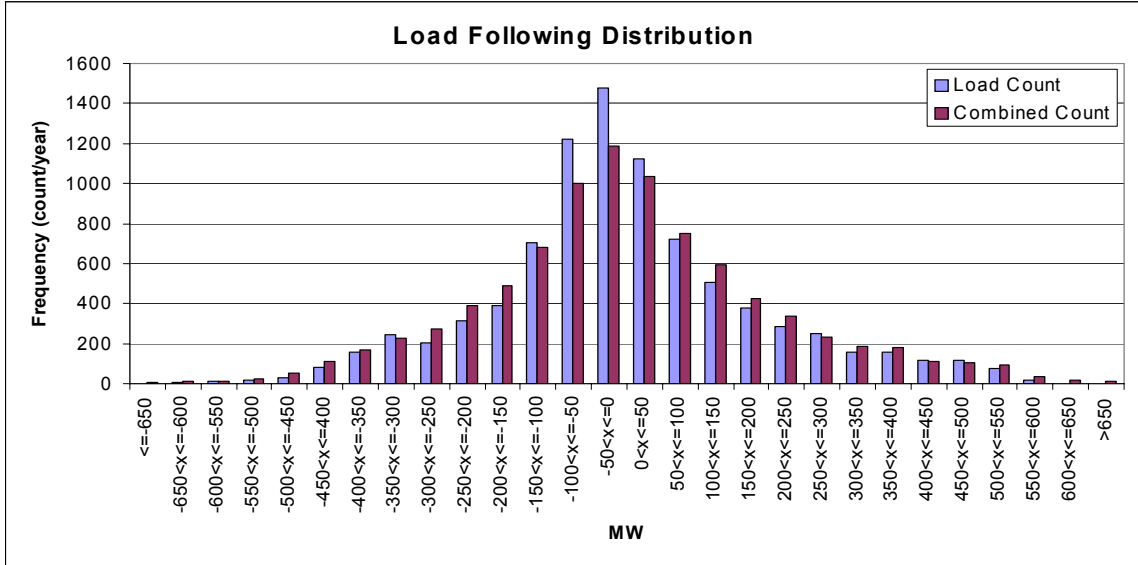


Figure 2 - Statistical distribution of load following requirements: Case A

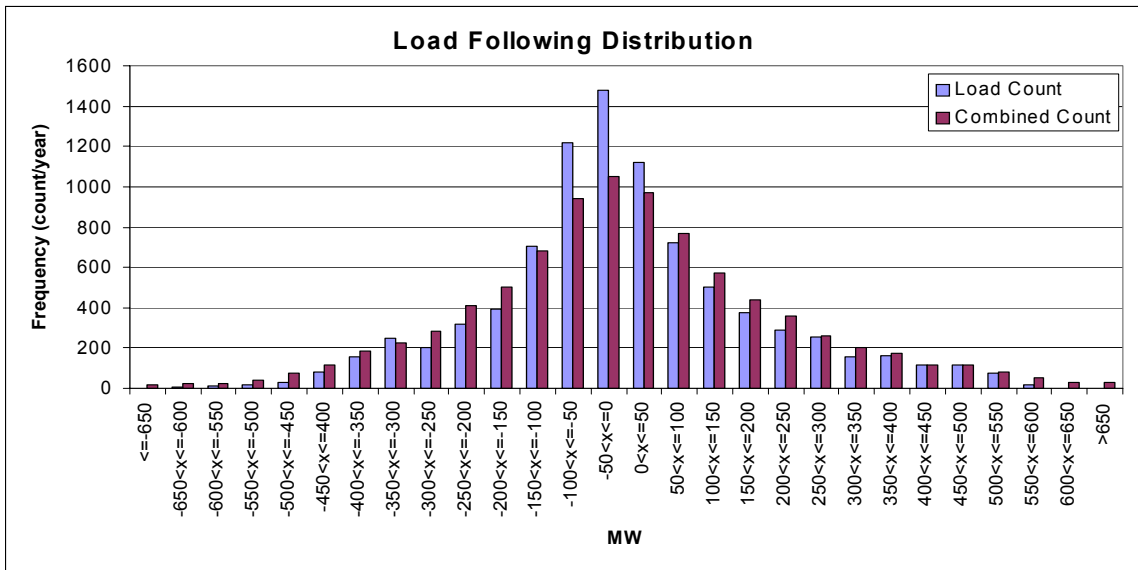


Figure 3 - Statistical distribution of load following requirements: Case B

Table 2 - Statistics of annual load following requirements

	Case A	Case B
St Dev Load Only	187.5	187.5
St Dev Load – Wind	205.5	219.5
Incremental Increase	20	32

Although looking at this data on an annual basis gives an indication of the average system impacts, it overlooks the trends of both the load and wind variations between seasons and across periods of the day. The Iowa electrical demand shows immense

systematic variation throughout the day and between seasons, while Iowa's wind variability, although sensitive to seasonal and diurnal differences, is not so systematic.

Figure 4 illustrates the impact of each of the two cases on load following requirements for the year. The upper panel of the graph shows Case B, the non-geographically disperse case, and the bottom panel shows the disperse generation Case A. The upper time series is the combined ramping requirements from load and wind, and the bottom series represents the load alone. Because the graphs show all hours of the year, it is difficult to discern the details. However, by examining the bands surrounding ± 500 MW, we can observe that wind does have an impact on the hourly load following requirements, and this effect is more pronounced in Case A than in Case B. We can also observe that the impact of 1,600 MW of wind in the 7,042-MW system does not increase the load following requirement anywhere near the rated capacity of the wind generation. However, this coarse analysis does not provide sufficient information about wind's effect on the system. For that we must break down the data set into meaningful time periods, which is the goal of this paper.

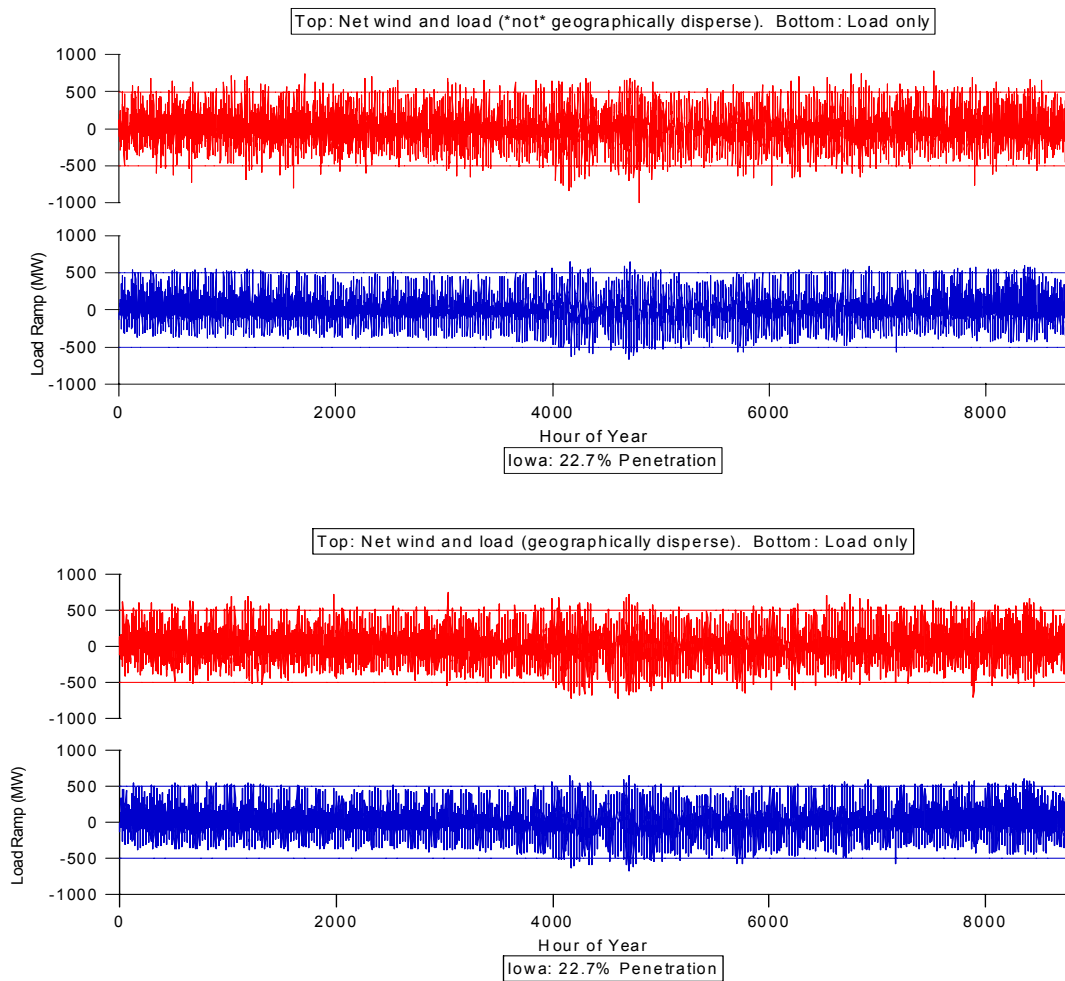


Figure 4 - Impact of 1,600 MW wind in the 7,042-MW Iowa (projected) system for the year

For the purposes of this study, the year was divided into seasons in which the monthly load profiles displayed a correlation of over 0.90. This resulted in five seasons and a minimum correlation of 0.96:

- Early spring – February and March
- Late spring – April and May
- Summer – June, July, and August
- Fall – September, October
- Winter – November, December, and January

Figure 5 shows the average daily load profiles for each of the five seasons designated in this study. The system load is highest in the summer and lowest in the late spring. The peak load of 7,042 MW occurs on July 25 in the hour ending at 5 pm, while the average at this time is only 5,371 MW. The late spring load is the lowest, with its peak of 4,863 MW occurring on April 9 in the hour ending at 9 am, while the average late spring peak of 4,264 MW falls in the hour ending at 11 am. The most pronounced difference in the load shape is during the evening period of 4 pm to 9 pm. In the fall, this period is rather flat, whereas the winter shows a sharp peak.

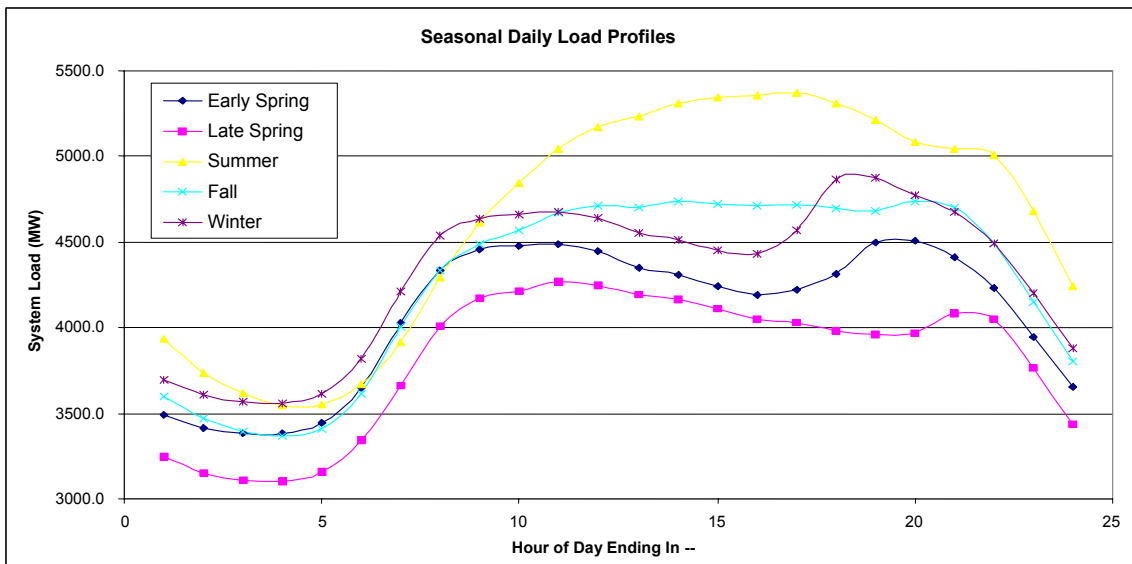


Figure 5 - Seasonal daily load profiles

In a summer-peaking region such as Iowa, which is most constrained during this season, 20 MW of increased variation due to wind will have a greater operating impact during the summer months than winter months. If the increased variation due to wind in summer were much higher than that of winter on a summer-peaking grid such as this one, the average annual impact may under-represent the true impact on the system during some times of the year and overestimate at other times.

Similarly, if the increased variation from wind were to occur mainly during the morning hours of 6 am to 8 am when the load following ability of the system is most constrained,

it would weigh more heavily on the system than if it were to fall mainly during the overnight lows from 2 am to 5 am when little ramping is needed. However, it is also possible (or even likely) that at high wind penetrations, high wind output at night could cause minimum loading problems if units run at minimum load.

This is actually the opposite of the Iowa data results. Figure 6 shows the statistical distribution of hourly load following demand for the load-only and combined scenarios in March and in August for Case A, while Figure 7 shows the same for Case B. Table 3 shows a summary of these distribution statistics. In both cases we can see that the variation of load following requirements is much greater in August than in March and that the increased variation due to the addition of wind is much greater in March than in August. The average hourly wind generation during the month of August is approximately 1/3 of the hourly wind generation in March, which contributes to wind's smaller impact on system variability during the summer.

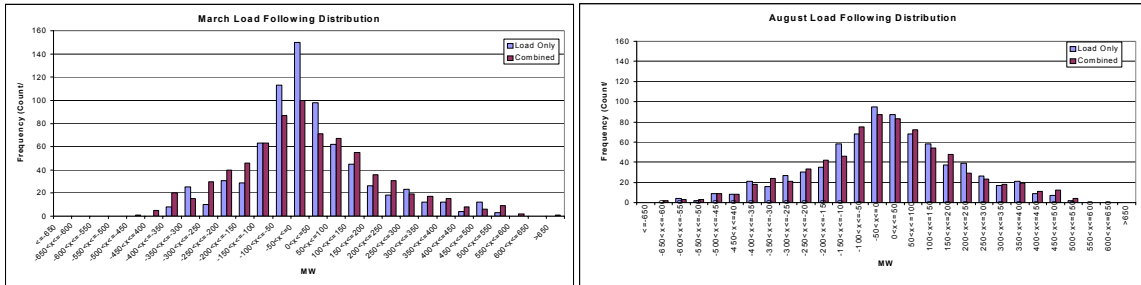


Figure 6 - March and August load following distributions for Case A

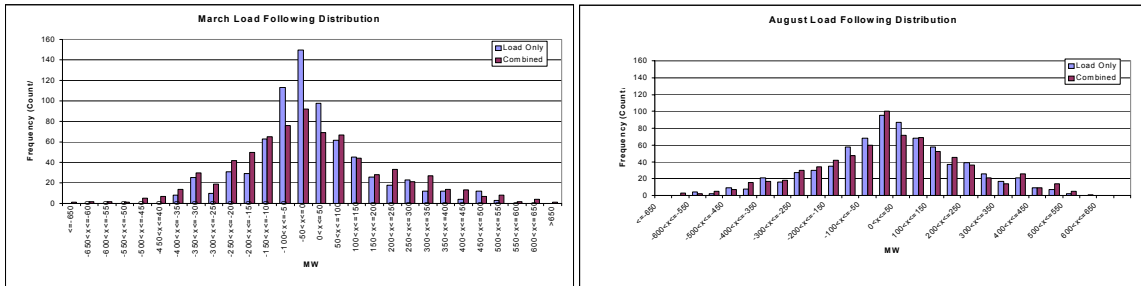


Figure 7 - March and August load following distributions for Case B

Table 3 – Statistics of load following requirement in March and August for Cases A and B

	Dispersed Case		Non-Dispersed Case	
	March	August	March	August
St Dev Load Only	166	204	166	204
St Dev Load – Wind	195	211	218	220
Incremental Increase	29	7	52	16

Figure 8 shows the statistical distribution of load following demand for the hours of 3 am to 4 am and 5 pm to 6pm for the load only and combined scenarios for Case A, and Figure 9 shows the same for Case B. Table 4 shows a summary of these distribution

statistics. In both cases we can see that the variation of load following requirements is much greater from 5 pm to 6 pm than from 3 am to 4 am and that the increased variation due to the addition of wind is much greater in the early morning hour than the evening hour.

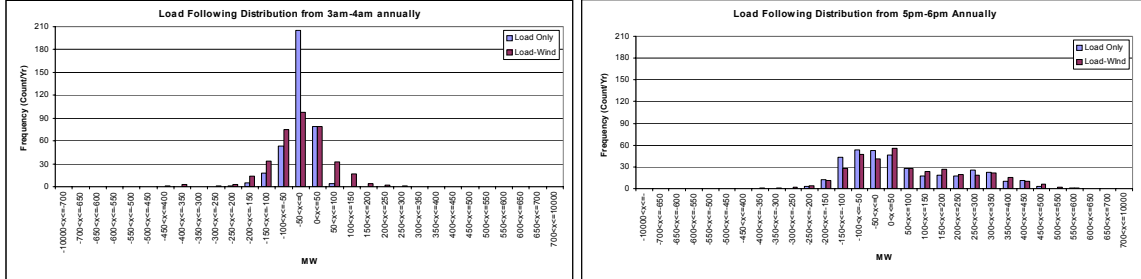


Figure 8 - Load following distributions for hour ending at 4 am and hour ending at 6 pm for Case A

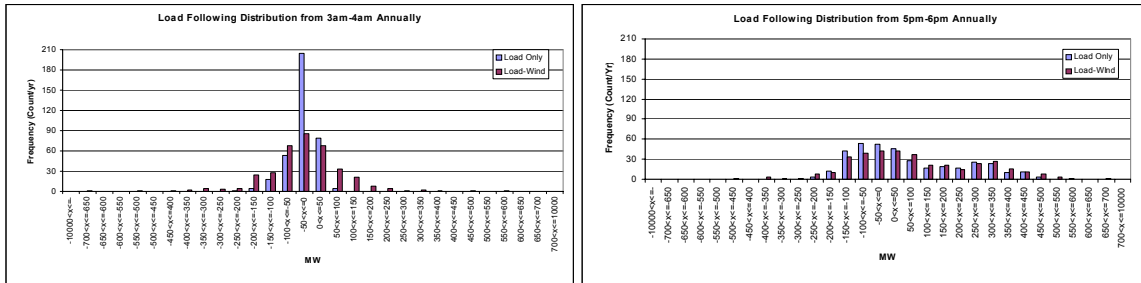


Figure 9 - Load following distributions for hour ending at 4 am and hour ending at 6 pm for Case B

Table 4 - Statistics of load following requirement in the hours ending at 4 am and 6 pm for Cases A and B

	Case A		Case B	
	3 am - 4 am	5 pm - 6 pm	3 am - 4 am	5 pm - 6 pm
St Dev Load Only	43	169	43	169
St Dev Load – Wind	87	177	122	193
Incremental Increase	44	8	79	24

Similar to the August distribution as compared with March, the distribution from 5 pm to 6 pm is shorter and wider than the distribution from 3 am to 4 am. However, the distribution from 5 pm to 6 pm differs from the August distribution in that a clear double peak is visible, a result of the changing sunset time throughout the year and the different load shapes noted in Figure 5. If the distribution from 5 pm to 6 pm is further broken down by seasons, as shown in Figure 10 for Case A and Figure 11 for Case B, it becomes clear why it is necessary to examine the load following impacts on both a time-of-day and a seasonal basis simultaneously. The variation of load following from 5 pm to 6 pm in the summer and in the winter is roughly half of what it is for this hour considered throughout the entire year. As shown in Table 5, the increase in variation due to the addition of wind is higher when this hour is broken down by season than when looked at throughout the year. This higher value more accurately reflects the variations managed by the grid operators. If the hour were looked at only on an annual basis, the impact of wind for this hour would be grossly underestimated.

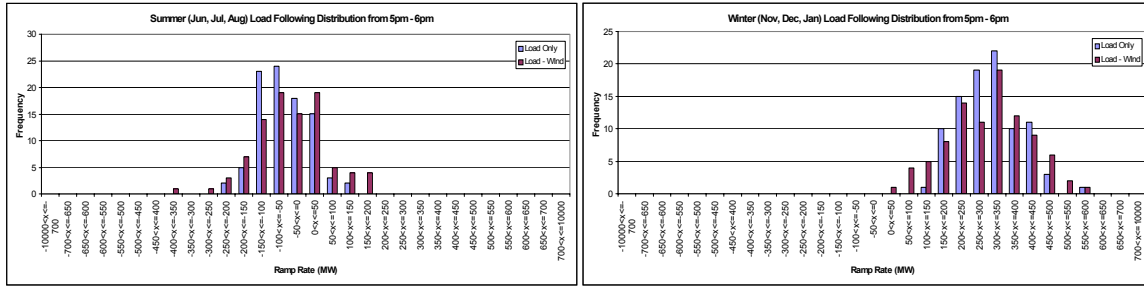


Figure 10 - Load following distributions for hour ending at 6 pm during the summer and winter for Case A

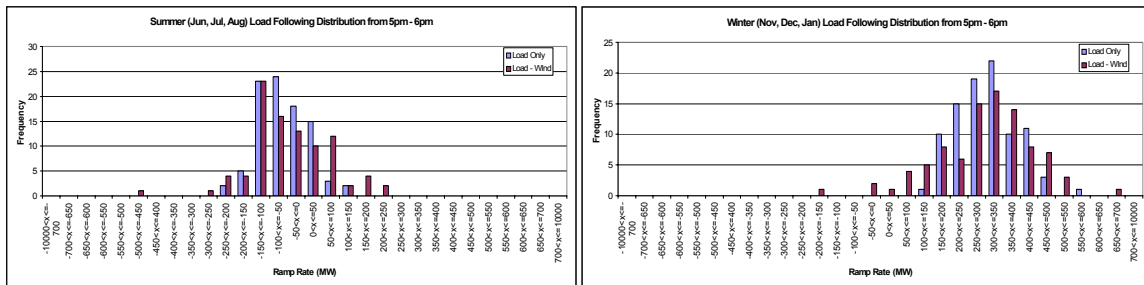


Figure 11 - Load following distributions for hour ending at 6 pm during the summer and winter for Case B

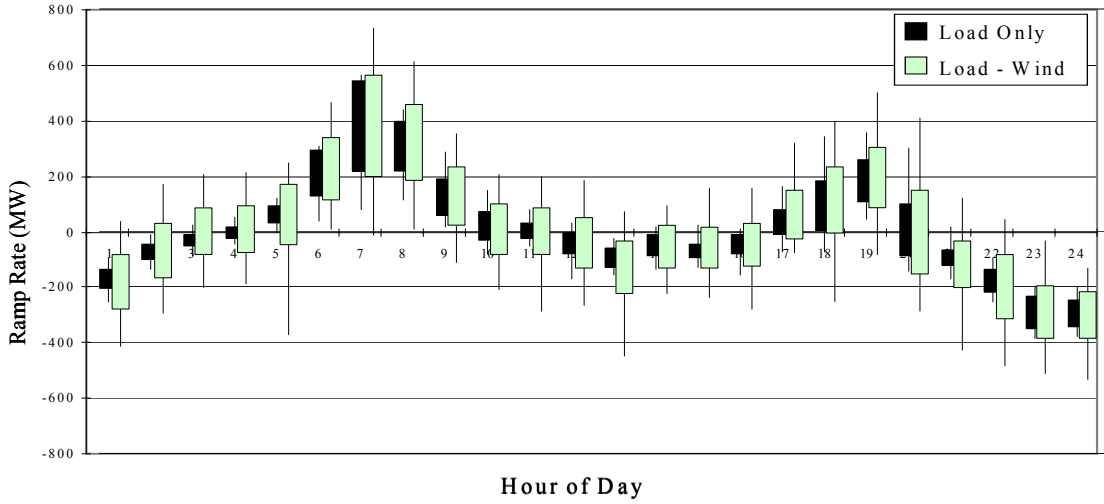
Table 5 - Statistics of load following requirement for hour ending at 6 pm in the summer and winter for Cases A and B

	Case A		Case B	
	Summer	Winter	Summer	Winter
St Dev Load Only	86	90	86	90
St Dev Load – Wind	104	118	139	126
Incremental Increase	18	28	53	36

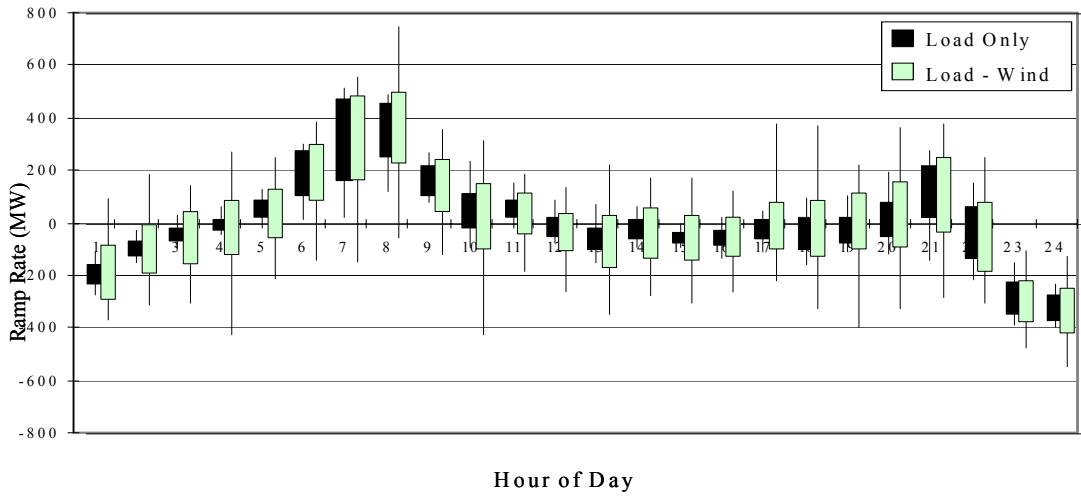
Table 5 shows another surprising result. Whereas in Case A the increased variation in winter is greater than in summer, the two are reversed in Case B. In all previous examples, the season or hour with the greater variation in the load-only scenario has consistently experienced less of a variation increase when wind is added. It is unclear why this reversal occurs between Cases A and B, although it is possible that it is related to the small difference in load following variation between the two seasons at this hour.

To further represent the variation from both time of day and seasonal differences simultaneously, Figure 12 shows the maximum, average plus a standard deviation, average minus a standard deviation, and minimum ramp rates by season for each hour of the day with and without wind for Case A. For all hours of all seasons, the standard deviation band is widened with the addition of wind, as is the range between the maximum and minimum hourly ramp rate. The same is true of Case B. This suggests that at no time can it be expected that the addition of wind power will decrease the variability in ramp rates needed from the conventional generators.

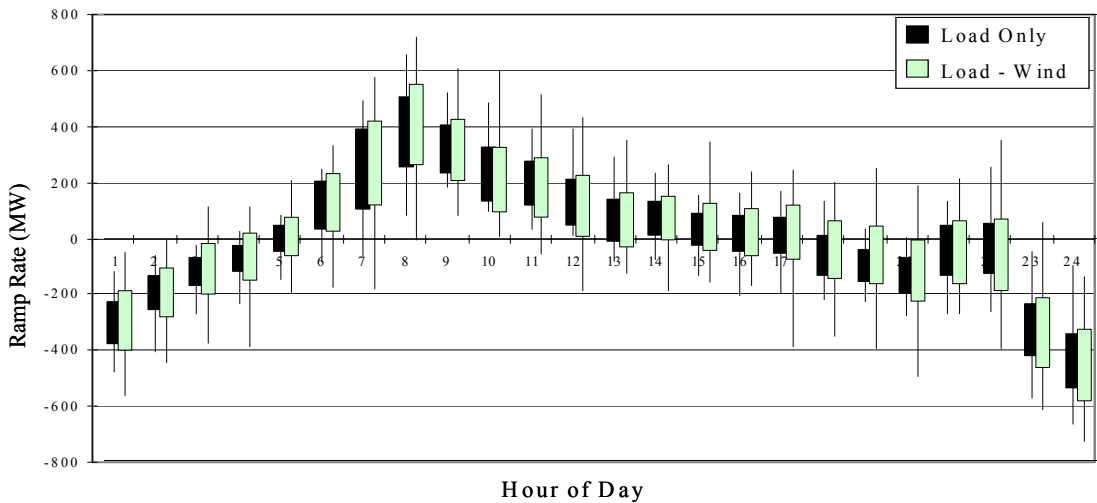
Early Spring Ramp Rates (Feb, Mar)



Late Spring Ramp Rates (Feb, Mar)



Summer Ramp Rates (Jun, Jul, Aug)



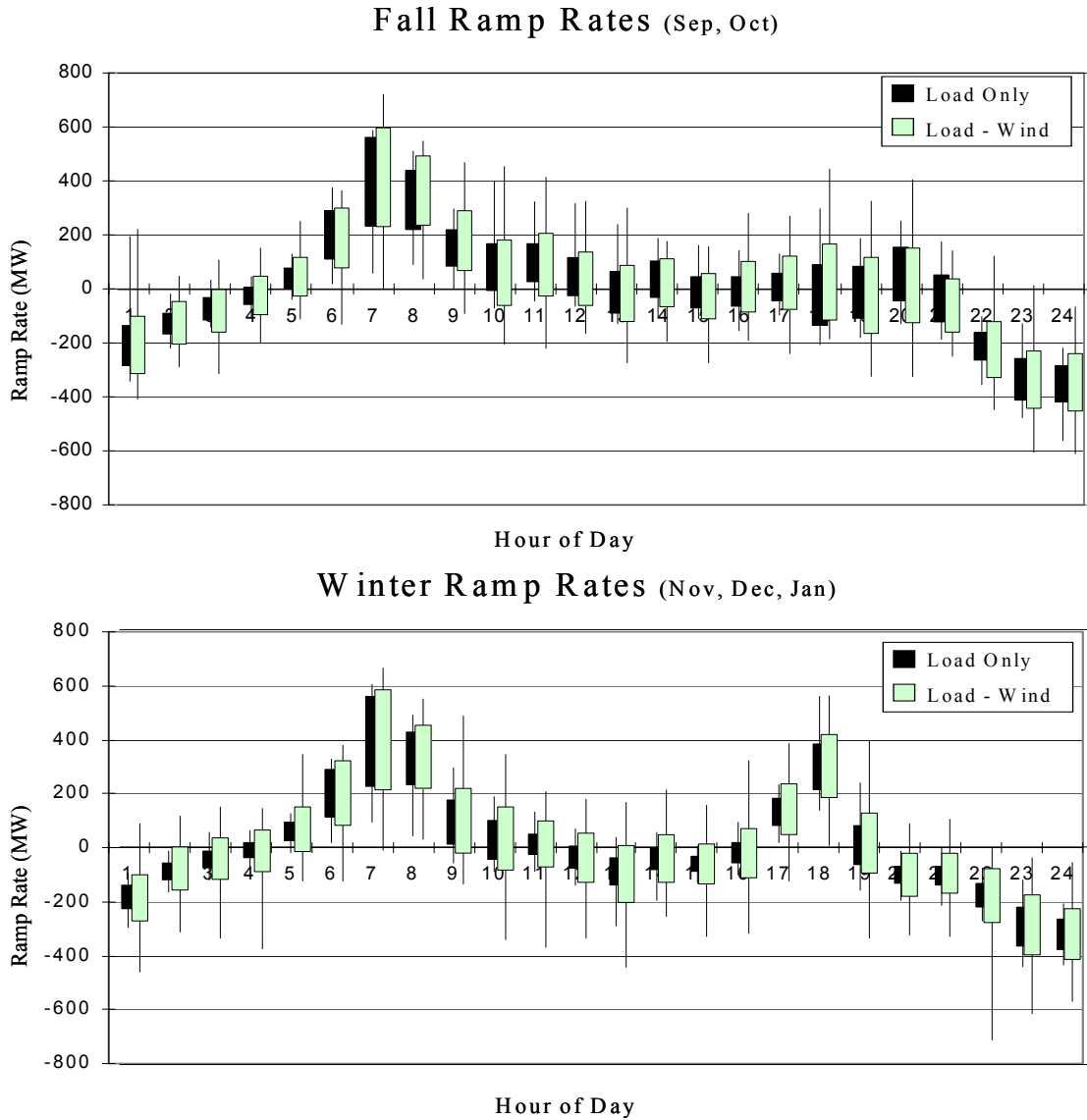


Figure 12 - Maximum, average plus a standard deviation, average minus a standard deviation, and minimum ramp rates for each hour of the day by season with and without wind for Case A. The thick band is the average +/- the standard deviation, the whiskers are the max and min.

Between the hours and seasons, the amount by which the standard deviation and range are increased and how the average ramping value shifts change. However, from these charts alone it is difficult to pinpoint the amount of the variability increase and any trends in how much and at what times it increases.

To assist in identification of these trends, the average and maximum increase in both standard deviation and range for each season are shown in Figure 13 and Figure 14. For Case A, there is a clear trend that appears in the standard deviation increase. The two spring seasons have a significantly higher incremental increase when wind is added when

compared with the other seasons. This pattern is still visible in Case B and the range increase.

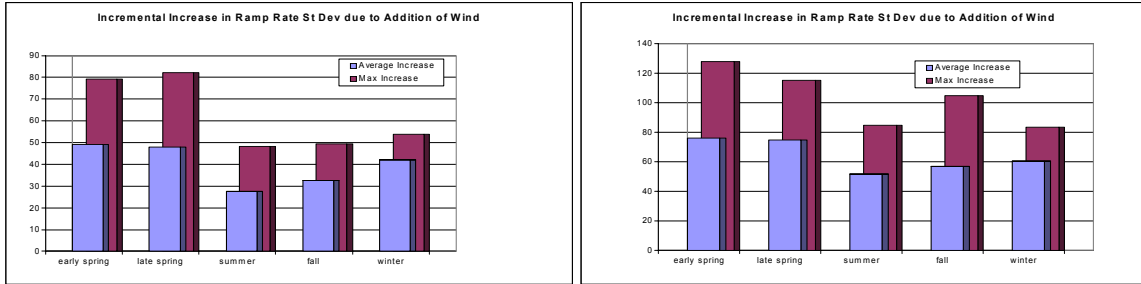


Figure 13 - Average and maximum incremental increase in load following standard deviation due to the addition of wind for each season for Case A and Case B

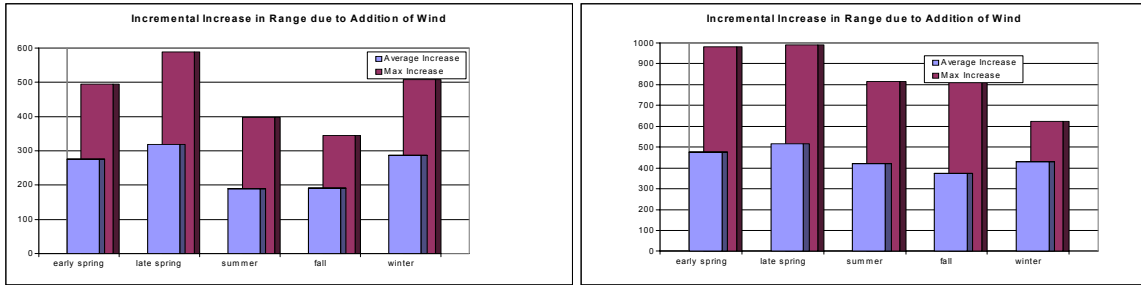


Figure 14 - Average and maximum incremental increase in load following range due to the addition of wind for each season for Case A and Case B

The incremental increase to the load following standard deviation and range are indicative of how much ramping variability can be attributed to wind. However, a more accurate allocation of variability to wind can be found by using a vector allocation method that was first developed by Kirby and Hirst [3] at Oak Ridge National Laboratory (ORNL). This method recognizes positive, negative, or zero correlation, in addition to being independent of the level of aggregation and the order in which each variable is introduced. The ORNL vector allocation of load following variability to wind can be calculated as

$$LFW = (\sigma_w^2 - \sigma_L^2 + \sigma_T^2) / (2\sigma_T) \quad (3)$$

Where LFW is the load following allocation to wind, σ_w is the standard deviation of the wind, σ_L is the standard deviation of the load, and σ_T is the total or combined standard deviation.

This metric was developed to allocation regulation to non-conformant loads, and it has been used extensively to allocate regulation impacts of load and wind. Because regulation is a capacity service, the allocation method splits the variability between two or more signals and makes no assumption regarding the correlation between the two signals. When high penetrations of wind are added to the generation supply, the operator will need to re-evaluate the level of load following reserves (LFR) necessary to keep the

system in balance. Techniques for estimating this impact on wind are not yet well defined. However, we believe that the use of the Oak Ridge allocation method can provide insight into wind’s impact on the system.

Figure 15 shows the load following allocation to wind through the ORNL vector allocation method for each season for Cases A and B. Although the allocation values are different from the incremental increases seen in Figure 13 and Figure 14, the same trend is seen. In both cases, the variation allocation to wind is greatest in the spring seasons.

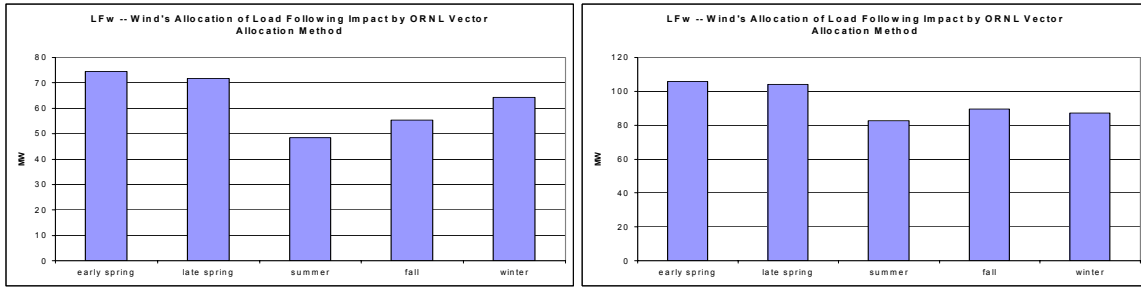
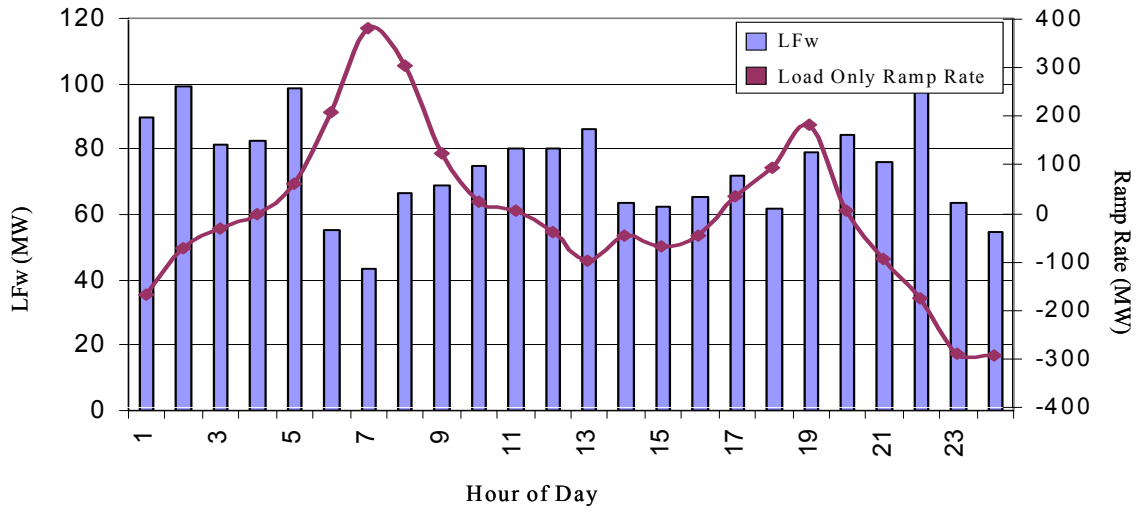


Figure 15 - LFw - Portion of load following impact allocated to wind by ORNL vector allocation method for each season for Case A and Case B

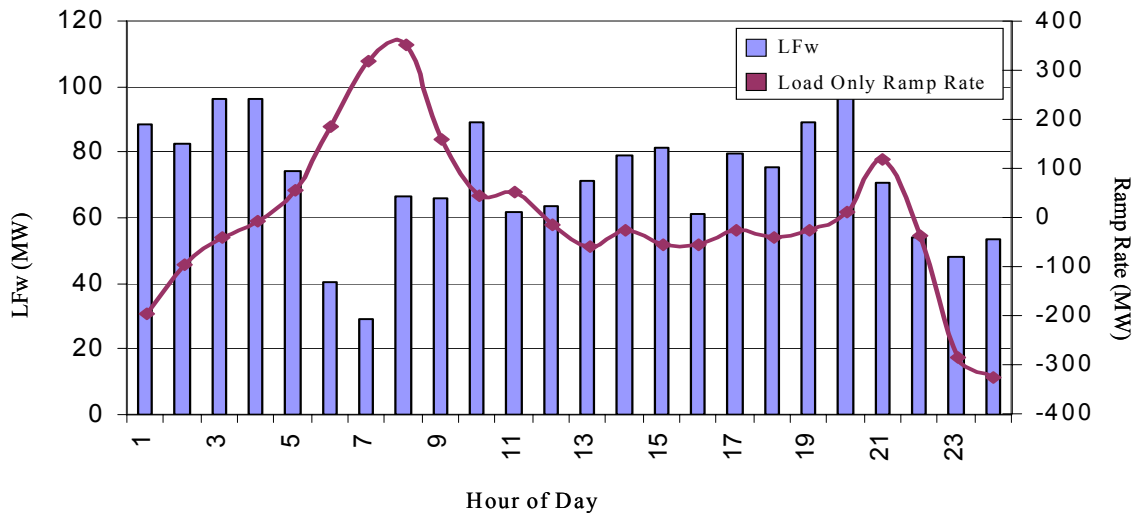
Figure 16 breaks the allocation down by hour of day for each of the seasons for Case A. Shown along with the allocation to wind is the ramp rate at each hour in the no-wind scenario. These charts depict a rough trend: for most periods when the load-only scenario ramps strongly, the allocation of variability to the wind is low.

Information such as this can be used along with wind and load forecasts to help system operators determine the level of LFR required on the system. The analysis presented here represents a perfect hindsight view of the load following impact of wind. In practice, system operators must ensure that sufficient flexible generation is available at all times. Ensuring sufficient generation is online when needed is determined in the unit-commitment time frame. This process can vary significantly across different regions, depending on established practice and market structure. In systems with significant amounts of wind generation, determining the required LFR will depend on load forecasts and wind forecasts and will be subject to some error. Statistical analyses of the historical behavior of the system, such as that presented here, can help establish bounds around hourly load following requirements. We expect that specific methods will undergo development and improvement as system operators obtain more experience with moderate to large wind penetrations. It is unlikely that a one-size-fits-all approach will work because of the differences in generation assets and capabilities.

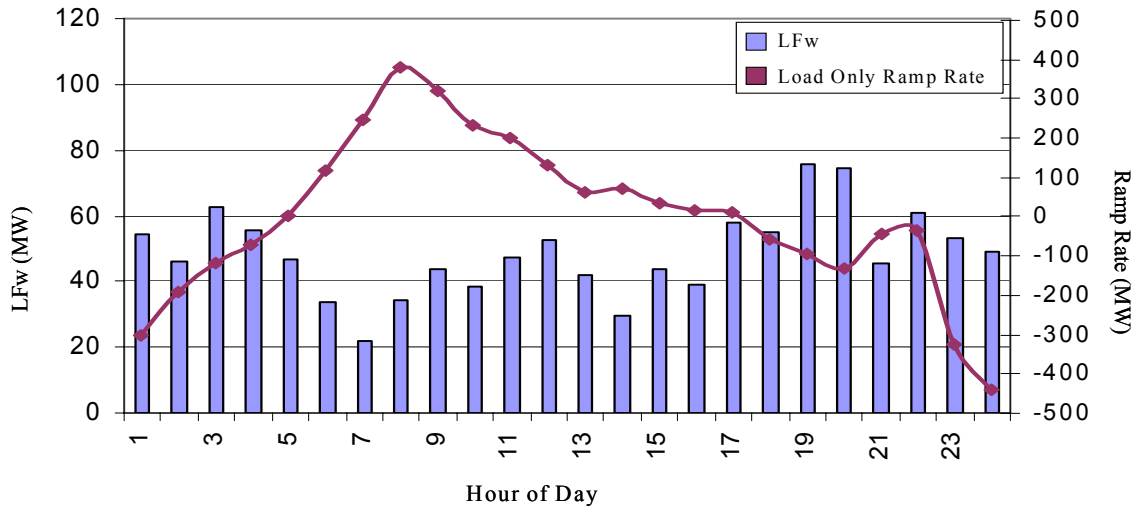
Early Spring Load Following Variability Allocation to Wind



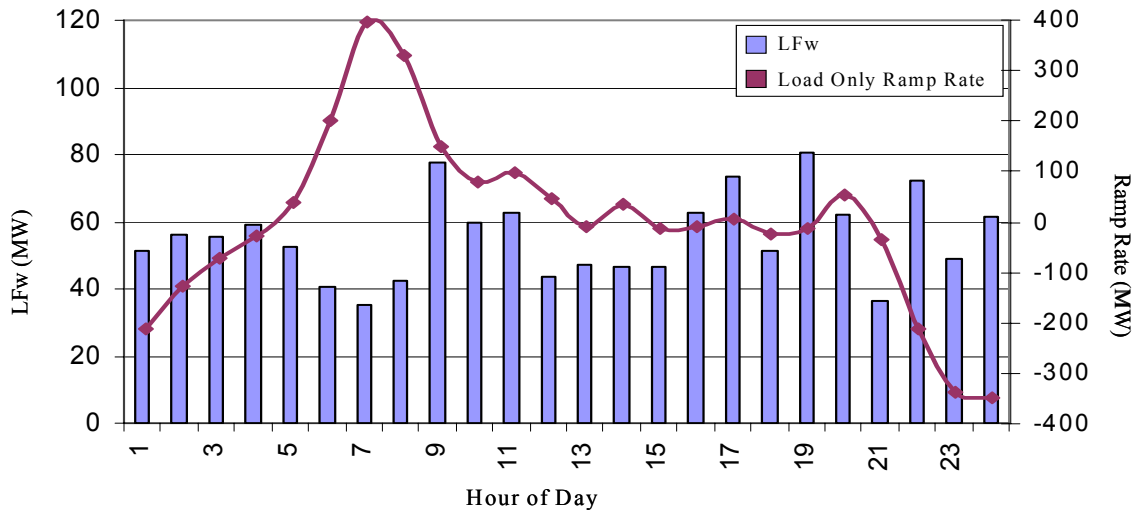
Late Spring Load Following Variability Allocation to Wind



Summer Load Following Variability Allocation to Wind



Fall Load Following Variability Allocation to Wind



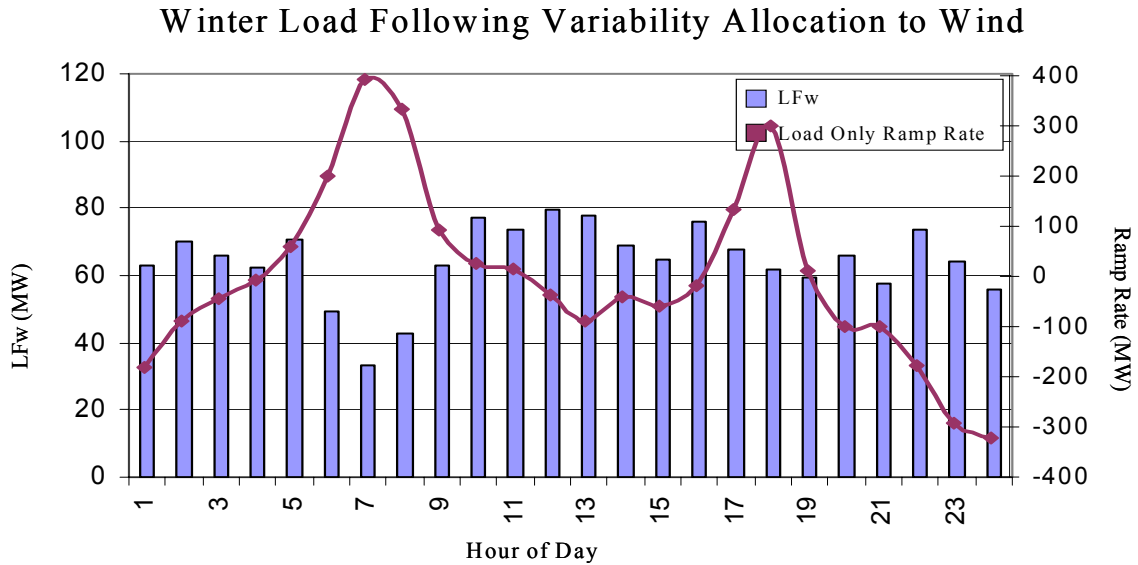


Figure 16 - Load following allocation to wind by ORNL vector allocation method by hour of the day for each season is shown in the bars correlated with the left scale. The load-only ramp rate is shown in the line correlated with the right scale

Conclusions

Large penetrations of wind energy can have a significant impact on system ramping requirements in the hourly time scale. This impact varies based on time of day and time of year, but at no time does this reach the rated capability of the wind generation. This impact can be calculated explicitly, and the allocation of the variability can be estimated. Analyses of actual system performance in systems with wind can help system operators plan for sufficient flexible generation during times it will be needed. The approach presented here provides a look at potential system requirements for hourly ramping. Although wind has an impact on load following requirements, these requirements during the critical morning ramp-up and evening ramp-down is driven largely by load. To put this in a more operational framework, wind and load forecasting must be considered, and the determination of required LFR will be subject to these and other uncertainties. Wind generation that is installed across a broad geographic area will have a smaller impact on ramp requirements than if all or most of the wind capacity is at a single location. These results may not be robust to other regions.

References

- [1] Milligan, M. Wind Power Plants and System Operation in the Hourly Time Domain. WINDPOWER 2003. 2003. Austin, Texas: American Wind Energy Association.

- [2] Milligan, M.R.; Factor, T. Optimizing the Geographic Distribution of Wind Plants in Iowa for Maximum Economic Benefit and Reliability. Wind Engineering. Vol 24, No 4, 2000; pp 271-290.

- [3] Kirby, B.; Hirst, E. Customer Specific Metrics for the Regulation and Load Following Ancillary Services. 2000. Oak Ridge National Laboratory: Oak Ridge, TN.

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

The public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to Department of Defense, Executive Services and Communications Directorate (0704-0188). Respondents should be aware that notwithstanding any other provision of law, no person shall be subject to any penalty for failing to comply with a collection of information if it does not display a currently valid OMB control number.

PLEASE DO NOT RETURN YOUR FORM TO THE ABOVE ORGANIZATION.

1. REPORT DATE (DD-MM-YYYY) May 2005		2. REPORT TYPE Conference Paper		3. DATES COVERED (From - To)	
4. TITLE AND SUBTITLE The Impact of Wind Energy on Hourly Load Following Requirements: An Hourly and Seasonal Analysis: Preprint				5a. CONTRACT NUMBER DE-AC36-99-GO10337	
				5b. GRANT NUMBER	
				5c. PROGRAM ELEMENT NUMBER	
6. AUTHOR(S) A. Krich and M. Milligan				5d. PROJECT NUMBER NREL/CP-500-38061	
				5e. TASK NUMBER WER5 5201	
				5f. WORK UNIT NUMBER	
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) National Renewable Energy Laboratory 1617 Cole Blvd. Golden, CO 80401-3393				8. PERFORMING ORGANIZATION REPORT NUMBER NREL/CP-500-38061	
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)				10. SPONSOR/MONITOR'S ACRONYM(S) NREL	
				11. SPONSORING/MONITORING AGENCY REPORT NUMBER	
12. DISTRIBUTION AVAILABILITY STATEMENT National Technical Information Service U.S. Department of Commerce 5285 Port Royal Road Springfield, VA 22161					
13. SUPPLEMENTARY NOTES					
14. ABSTRACT (Maximum 200 Words) The impacts of wind energy on the power system grid can be decomposed into several time scales that include regulation, load following, and unit commitment. Techniques for evaluating the impacts on these time scales are still evolving, and as wind energy becomes a larger part of the electricity supply, valuable experience will be gained that will help refine these methods. Studies that estimated the impact of wind in the load following time scale found differing results and costs, ranging from near zero to approximately \$2.50/megawatt-hour (MWh). Part of the reason for these differences is the different interpretation of the impacts that would be allocated to this ancillary service. Because of the low correlation between changes in load and wind, long-term analyses of the load following impact of wind may find low impacts. During the daily load cycle, there is a tremendous variability in load following requirements in systems without wind. When significant levels of wind generation are added to the resource mix, relatively small changes in wind output can complicate the task of balancing the system during periods of large load swings. This paper analyzes the load following impacts of wind by segregating these critical time periods of the day and separating the analysis by season. The analysis compares wind generation at geographically dispersed sites to wind generation based primarily at a single site, and for a large penetration of wind (more than 20% wind capacity to peak load).					
15. SUBJECT TERMS wind energy; wind plant; wind farm; capacity; grid; regulation; load following; unit commitment; hourly energy					
16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT UL	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
a. REPORT Unclassified	b. ABSTRACT Unclassified	c. THIS PAGE Unclassified			19b. TELEPHONE NUMBER (Include area code)

Standard Form 298 (Rev. 8/98)
Prescribed by ANSI Std. Z39.18