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The Canadian Wind Energy Association (CanWEA) is pleased to make available “*An Analysis of the Impacts of Large-Scale Wind Generation on the Ontario Electricity System*”.

This analysis set out to answer the following questions:

- How well correlated are the seasonal and daily variations of wind with load in Ontario?
- To what degree will the addition of wind to the Ontario grid increase the variability of loads that must be met by non-wind generating sources?
- How much difference does geographic diversity in the production of wind make?

The analysis reached the following conclusions:

- Overall, wind is relatively well matched with winter loads but is less well matched with summer loads. Applying simple techniques, an estimate of the overall capacity value of wind on the Ontario system would be about 37-40% of rated capacity, and it would range from about 47% in the winter to 19% in the summer.
- The addition of wind would increase net load variability by much less than the variability of the wind itself. It is estimated that the addition of 2,000 MW of wind would increase the 1-hour load following requirement by 37 MW on an annual basis, or 56 MW in summer. On a 3-hour time frame, the increase in load-following requirement would be 93 MW on an annual basis, or 146 MW in summer. The largest increase in net load over a 3-hour period would be 200 MW.
- The combination of output from 17 geographically dispersed sites in Ontario is estimated to be about 60-70% less variable, on a 10 minute or 1 hour time frame, than the output from a single site.

This analysis represents an important step forward in enhancing our understanding of the potential impacts of significantly enhanced wind energy generation on the Ontario electrical grid. It clearly suggests that the addition of 2,000 MW of new wind energy capacity in Ontario is manageable.

Potential areas for further research and analysis include:

- The analysis of winds and loads in future years. The present study assessed just one year of data, and did not account for future load growth or expected changes in peak load patterns.
- The use of more sophisticated grid models to assess the impacts of wind on plant scheduling and dispatch, operating costs, load-following, voltage stability, transmission flows, and other factors.
- The potential role of wind forecasting in mitigating the impacts of wind on the Ontario electricity system.

CanWEA would like to thank the following organizations for making this analysis possible:

- Superior Wind Energy commissioned and managed the work.
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- AWS TrueWind for undertaking and completing the study.

Additional copies of the document can be downloaded at www.canwea.ca.



An Analysis of the Impacts of Large-Scale Wind Generation on the Ontario Electricity System

Prepared For:

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Association
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1. Introduction

This report presents the results of an analysis commissioned by Superior Wind Energy, Inc, to study the potential impacts of wind energy production on the electricity system in Ontario, using wind and load data for one year from May 2003 to April 2004. Six wind energy developers provided wind data from a total of 17 potential wind energy project sites for the study. These data were converted to estimates of turbine output every 10 minutes throughout the year using a generic wind turbine power curve at an assumed hub height of 80 m. The Ontario Independent Electricity System Operator (IESO) provided a corresponding set of 10-minute system load data. The objective of the study was to examine the coincidence of wind plant output and loads in different time periods, and to assess the overall impact of the addition of a large amount of wind energy on the variability of the net load.

2. Data Analysis

AWS Truewind acquired data from six wind developers for 17 sites in Ontario. The purpose of casting such a wide net was to obtain a representative picture of the geographic diversity of wind projects likely to be built in the province. A minimum of one year of validated 10-minute wind speed (at a minimum of two levels) and temperature data were requested for each site. Data from 20 sites were received, but three sites were rejected from the study (one because of an incorrect time interval, another because of an incorrect time interval and several data gaps, and the third because the annual wind speed was so low in comparison to the other sites that we believed a project would probably not be developed there).

The one-year period from May 2003 to April 2004 was chosen for the study because it had the most complete data record from the largest number of sites. All but three of the 17 sites had data encompassing the entire year. The remaining sites covered at least 10 months and, we concluded that it would suffice to reconstruct the missing periods using data from other sites.

Although all of the data provided by the developers were validated in advance, we applied a cursory validation routine to verify the data quality. Time series of the daily mean wind speeds from each monitoring level were graphed and these were used to identify any discontinuities between levels. When questionable observations were detected, the 10-minute data from the period were scrutinized and rejected if necessary. All missing or invalid data were subsequently reconstructed using a hierarchical approach explained below.

The wind speed data from each monitoring site were collected at several different heights, typically at several levels below the 80 m hub height used in this analysis. If observed 80 m data were not available, the top-level data were extrapolated to hub height using the site-specific observed wind shear exponent. To account for differences between

daytime and nighttime wind shear, a diurnally varying exponent was calculated and applied at each site.

Once 80 m wind speed distributions were created for each site, gaps of less than 6 hours were filled by interpolating between the nearest valid data records before and after the gaps. For gaps longer than 6 hours, this method could lead to significant errors in both mean speed and the variability of speed, so we chose to fill the gaps using data from nearby sites. A linear regression was first established from concurrent valid data records at both sites, and then the speeds from the replacement site were applied to the equation to fill the gaps. Missing temperature records were reconstructed using a similar approach. The reconstruction resulted in data records containing 52,704 valid 10-minute data records for each monitoring site.

Using the temperature data from each site, and its elevation, the air density was computed for each 10-minute record. The amount of energy produced by a wind turbine for a given wind speed is directly proportional to air density.

The wind speed and air density for each record were then applied to a generic wind turbine power curve, which estimates turbine output as a function of wind speed. Power curves for three large commercial models designed for moderate wind climates – the GE 1.5sle (1.5 MW), Vestas V-82 (1.65 MW), and Gamesa G-87 (2 MW) – were averaged to create this curve. The effective nameplate capacity of the composite turbine is 1.72 MW. To account for air density, the wind speed was scaled by the cube of the ratio of the actual air density to the nominal value for which the power curve was specified. To account for losses, the wind speeds were discounted by 5% before being entered into the power curve, and the turbine output was reduced by a further 2%.¹ The total loss ranged from about 10 to 12%.

The next step was to scale the wind production to the full plant rated capacity. Based on information we received from the developers and the IESO wind project queue, we assigned each of the 17 sites a rated capacity between 50 and 250 MW. The total capacity at all sites is 2,000 MW.

The wind energy production values were then compared with the corresponding provincial energy load data provided by the IESO for the entire analysis period. This dataset was inspected for completeness and no invalid values were detected. However, the data were affected by the blackout that occurred in much of the Midwest and Northeast of the United States as well as Ontario on 14 August 2003. For the period from August 14 to August 20, the IESO was unable to provide accurate 10-minute demand data. This period was excluded from the analysis of the coincidence and variability of wind and load. Although peak loads sometimes occur in August, the blackout period was short enough that we do not believe it substantially affected our results.

¹ The wind speed reduction is intended to mimic the effect of wake and array losses as well as blade soiling, icing, and individual turbine downtime. It is not meant to be an exact representation of these losses, however. The 2% output reduction is intended to represent typical electrical losses.

3. Results and Discussion

The analysis set out to address several key questions.

- First, how well correlated are the seasonal and daily variations of wind with load in Ontario? This question is relevant in determining the value of wind energy on the Ontario system. To the extent that wind production tends to be high when loads are also high (i.e., the two are positively correlated), wind will have more value to the system both as capacity and energy.
- Second, to what degree will the addition of wind to the Ontario grid increase the variability of loads that must be met by non-wind generating sources (net load)? The variability, particularly over short time scales such as 10 minutes or 1 hour, is related to the amount of load-following capability the system must have to provide reliable power at all times.
- Third, how much difference does geographic diversity make? It is well known that the combined output of geographically dispersed projects is less variable than a single project, but by how much depends on the wind climate, the distance between projects, the relevant time horizon, and other factors.

In the following sections we attempt to answer these questions by analyzing the data in a number of different ways.

3.1. Characteristics of Ontario Wind Projects

Ontario boasts a moderate wind resource that is concentrated around the northern and eastern shores of the Great Lakes. According to the data we obtained, wind speeds at prospective wind project sites in the province range from under 7 m/s to just over 8 m/s, with an average of 7.3 m/s, when projected to a hub height of 80 m. The corresponding net capacity factor (the average annual output divided by the maximum output at rated capacity) ranges from just over 25% to over 40%. In Figure 1, the relationship between mean wind speed and net capacity factor is plotted.

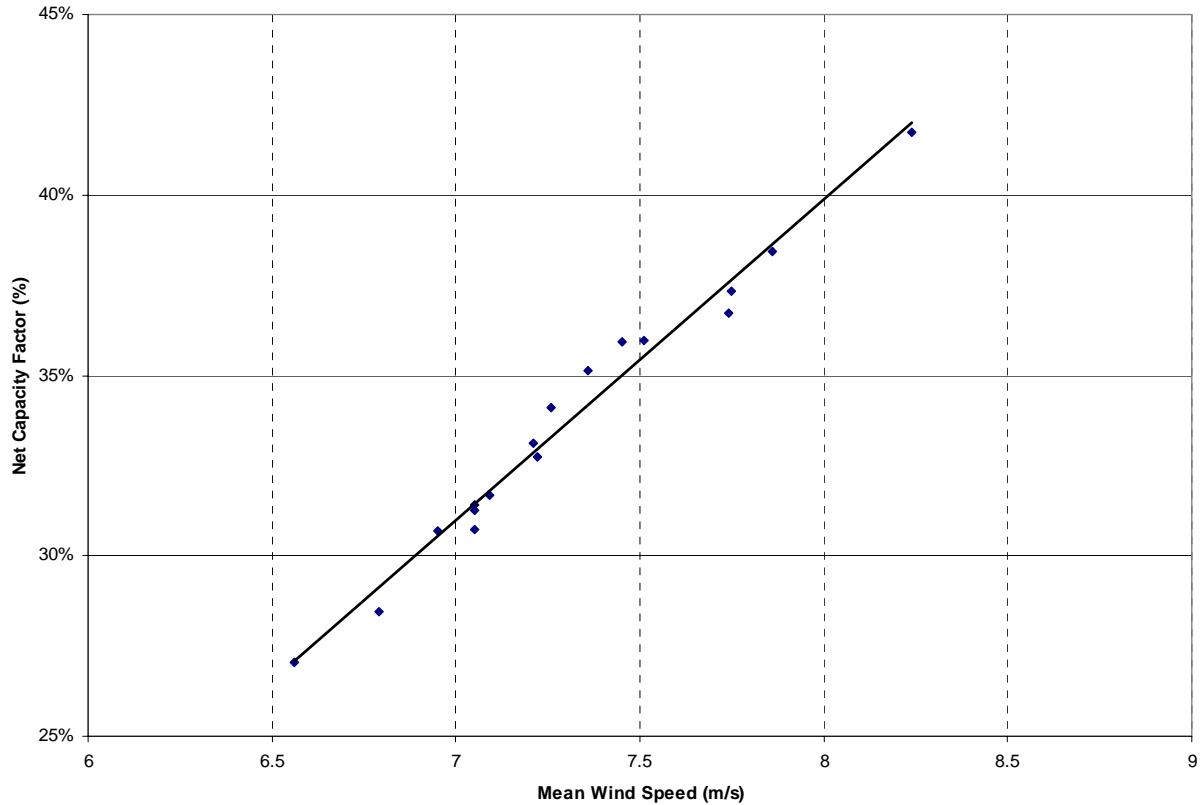


Figure 1. Relationship between net capacity factor (%) and mean wind speed (m/s) at wind project sites in Ontario. Points do not fall exactly on a line because of variations in the distribution of speeds around the mean at each site, and also because of variations in air density.

Table 1 below lists the sites in each transmission zone and their rated capacities. To protect proprietary information, the exact site locations are not given, nor are the mean wind speeds and net plant capacity factor.

Table 1. Transmission zone, site ID, and assumed project size (MW).

Zone	ID	Project Size (MW)
Bruce	B-1	50
Bruce	B-2	50
Bruce	B-3	50
Bruce	B-4	100
East	E-1	150
East	E-2	50
Northeast	NE-1	200
Northeast	NE-2	100
Northeast	NE-3	100
Northwest	NW-2	200
Southwest	SW-1	150
Southwest	SW-2	100
Southwest	SW-3	100
Southwest	SW-4	50
Southwest	SW-5	250
Southwest	SW-6	100
West	W-1	200
Total		2000

3.2. Seasonal Wind and Load Patterns

Figure 2 contains a plot of the monthly average predicted wind output and load for the entire province. Both wind and load are plotted in megawatts, but against different axes. To convert the wind output in megawatts to capacity factor, divide by 2000.

The annual load pattern is bimodal with the maximum value occurring in January (~20,000 MW) and a secondary maximum observed in July.² This is not surprising because energy demand is driven in part by environmental conditions. With Ontario's cold winters and short winter days, there is relatively high demand for heating and lighting in that season. In the summer, unusually hot days result in relatively high power demand for air conditioning.

Wind energy production also peaks in the winter, because of the high frequency of winter storms passing through the region. This suggests that wind may have relatively high value on the Ontario system in this season. The swing between winter and summer is proportionately larger for wind than for load, however, and thus, wind probably has less value for meeting summer loads.

² The reported loads for August 2003 are depressed because of the August 14 blackout and ensuing demand and generation interruptions. Without these disruptions, August loads would have averaged about 1000 MW higher.

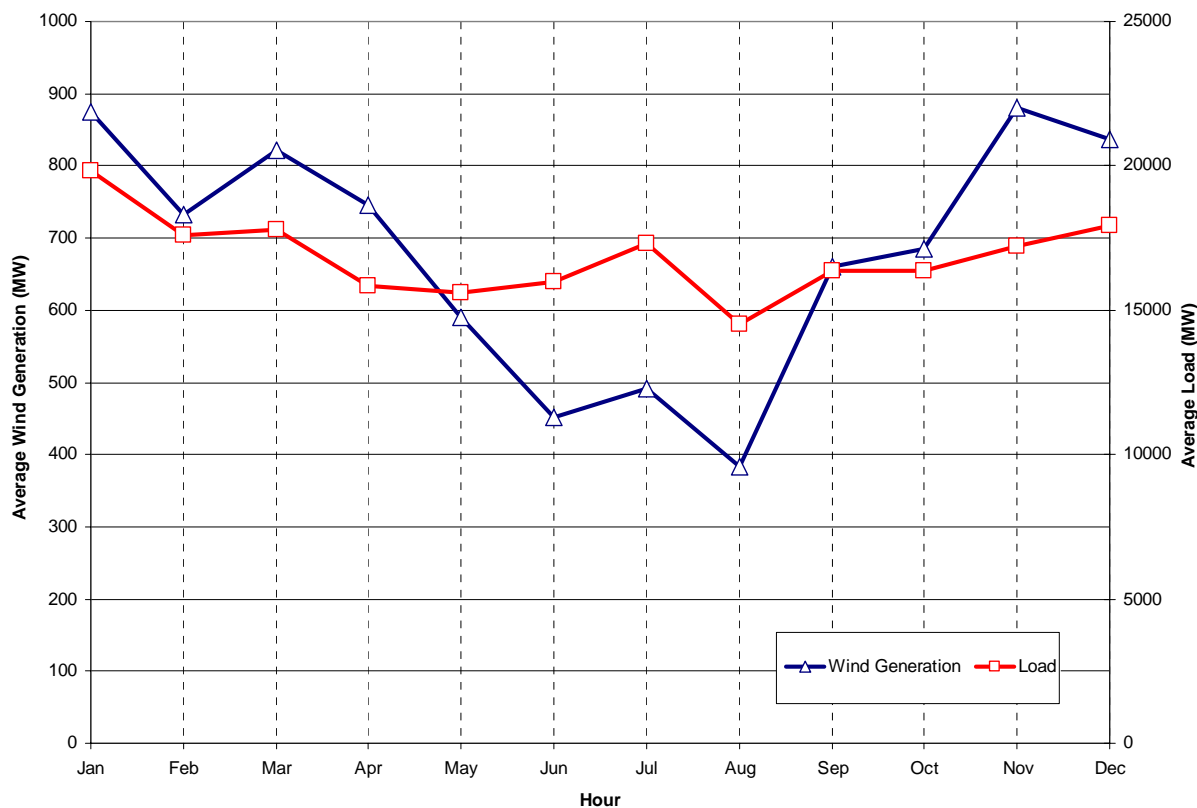


Figure 2. Mean monthly wind energy production (blue line) and mean monthly load (red line) for May 2003 – April 2004. The wind energy production assumes 2000 MW of wind plant capacity divided among 17 sites in the province. The apparent drop in demand in August is in part because of the blackout of August 14 and its ensuing demand data impacts.

3.3. Daily Wind and Load Patterns

Figure 3 compares the wind generation and load on a daily basis, averaged over the year. The load tends to peak between 8 am and 8 pm, the time when people are awake and using the most power for lighting, heating, and cooling, and when businesses and factories are in operation. The wind generation, however, tends to peak at night, between 8 pm and 6 am. This pattern, which is common in wind energy, reflects the fact that at night, as the earth's surface cools, the planetary boundary layer (the part of the atmosphere in direct contact with the surface and affected by surface conditions) becomes shallow and its turbulence subsides. This development allows strong winds aloft to come much closer to the surface than they can during the day.

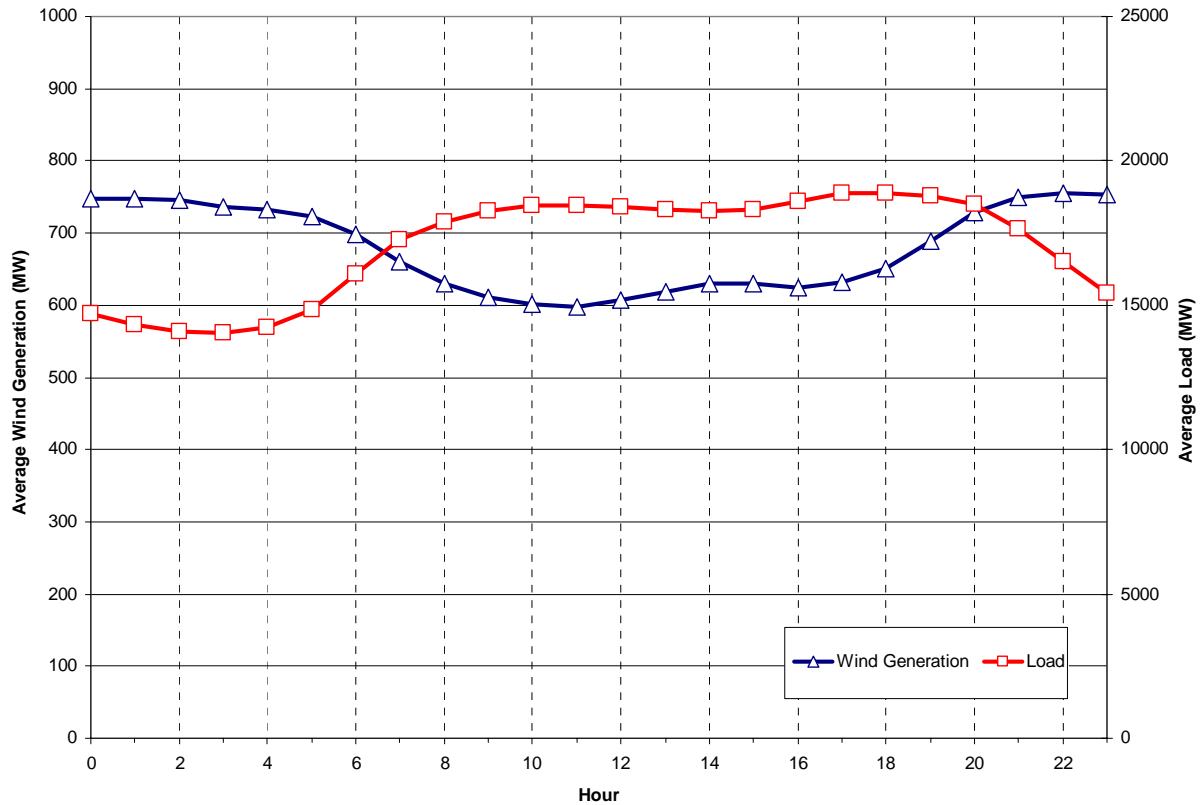
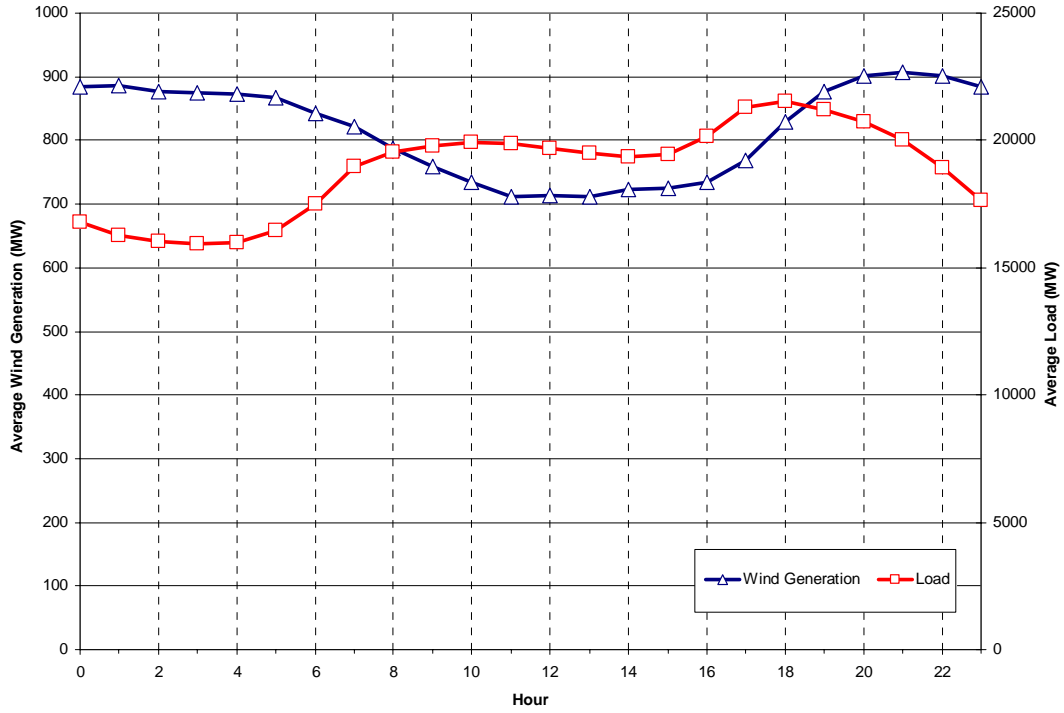


Figure 3. Mean wind energy production (blue line) and mean load (red line) at different times of day for May 2003 – April 2004. The wind energy production assumes 2000 MW of wind plant capacity divided among 17 sites.

It is instructive also to compare the diurnal patterns in the winter and summer seasons separately (Figure 4). On a daily basis, it appears that wind output is better matched with load in winter (top) than in summer (bottom). It is significant that the late afternoon rise in winter load – which occurs with the switching on of lights and home heating as the sun sets and people return home from work – corresponds quite well with the late afternoon/early evening rise in wind output. In the summer, in contrast, not only is wind generation lower throughout the day, but the loads reach a peak earlier in the day, when the wind is usually near minimum. (There is a slight secondary peak in wind generation at around 2 pm, however. This peak may correspond to lake breezes created by the heating of the land on warm, sunny days.)

WINTER



SUMMER

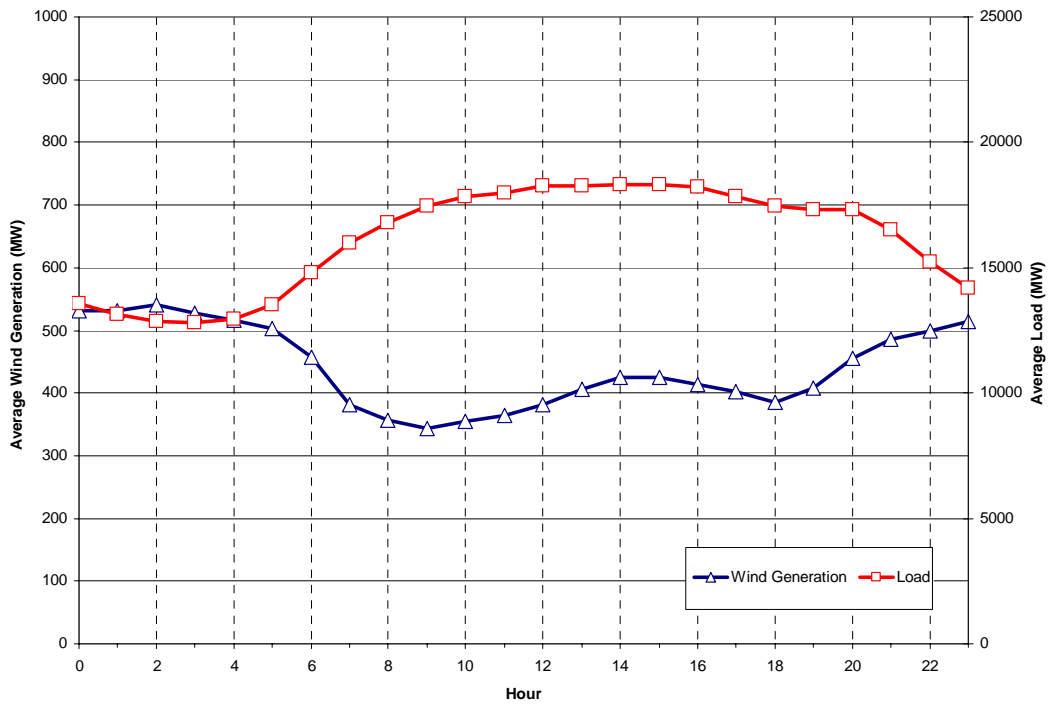


Figure 4. Mean hourly average wind energy generation and mean load in winter (top) and summer (bottom). The wind energy production assumes 2000 MW of wind plant capacity divided among 17 sites.

3.4. Capacity Value

The preceding charts provide a general sense of the correlation between wind and load on the Ontario electric system. It is possible to go one step further to estimate the capacity value of wind. The capacity value is defined as the equivalent amount of conventional generating capacity that could be replaced by wind without affecting the ability of the system to deliver power reliably, as measured by a statistic such as the loss of load probability (LOLP) or loss of load expectation (LOLE). It is not within the scope of this study to conduct a full reliability analysis. Research has shown, however, that a few simple statistics can provide a rough estimate of the capacity value.³

The capacity value depends most importantly on the ability of a generating plant to deliver power during times of peak load. One method of estimating the capacity value of wind is therefore to calculate the average output during peak load periods. We have done this for two seasons, winter and summer, and with two methods, as shown in Table 2. In one method, the mean wind output (expressed as capacity factor) is calculated for the top 5% of 10-minute loads in each season; in the other, the mean output is calculated for the top 10 days.⁴

Table 2. Estimated Capacity Value of Wind for Different Seasons and with Different Methods

Season	Method	Mean CF
Winter	Top 5%	46.1%
	Top 10 Days	47.4%
Summer	Top 5%	18.7%
	Top 10 Days	18.9%
Annual	Top 5%	37.5%
	Top 10 Days	40.9%

The results are consistent between the two methods. In the winter, the wind output during peak hours was quite high, about 46-47%, whereas in summer it was comparatively low, about 19%. On an annual basis, the dominance of winter load peaks means that the average output in the peak load hours is closer to the winter norm than to the summer

³ “The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations,” Report to New York State Energy Research and Development Authority, by GE Energy Consulting, March 4 2004 (http://www.nyserda.org/publications/wind_integration_report.pdf).

⁴ The top 5% of 10-minute loads were selected by sorting all 10-minute records in order of decreasing load and selecting the 2628 periods (out of 52760) with the highest loads. The top 10 days were selected the same way, after calculating the total load (not peak load) for each day of the year.

norm. Based on these calculations, the overall capacity value of wind on the Ontario electric system appears to be around 37-40%.

It should be noted that these estimates are sensitive to a number of assumptions. One assumption is that the May 2003 – April 2004 period was typical for both wind and load. While the wind data suggest that this period was, in fact, fairly representative of meteorological conditions in the province, we do not know if the same is true of loads. In addition, although the wind and load data taken separately may be typical, the coincidence between them, especially on peak load days, may not be. In other studies, a wide variation has been observed in the capacity value of wind depending on the year used in the analysis. Thus, we strongly recommend that this analysis be repeated for other years, using simulated wind data if necessary.

3.5. Variability

Another important aspect of the impact of wind energy on the Ontario electricity system is variability, which is defined in this context as unpredicted changes in wind generation over time. Variability is most important over relatively short time scales – from minutes to hours – since it is over that time frame that generating units must be held in reserve and dispatched at short notice to meet changing net load. A concern of grid operators is that the addition of large amounts of wind energy on their system will substantially increase the variability of the net load, and therefore increase the required load-following capability. The net load is defined as the actual load minus any wind generation added to the system, and is the load that must be met by non-wind generating units.

Once again, although it is beyond the scope of this study to conduct a thorough review of the impact of wind on load-following requirements, a few simple statistics are instructive. One guideline often followed in electricity system planning is that the load-following requirement is equal to **three times the standard deviation** of step changes in load from one time period to the next. Assuming a normal distribution of step changes, this measure captures 99.7% of the load swings. For this study, we looked at step changes in wind, load, and net load (load minus wind) over three time frames: 10 minutes, 1 hour, and 3 hours. Table 3 summarizes the results.

Table 3. Three times the standard deviation of wind and load changes, by season and time shift, in MW.

Time Period	Wind	Load	Net Load (Load-Wind)	Change
Annual				
10 minutes	135	436	459	22
1 hour	299	2087	2125	37
3 hours	569	5429	5523	93
Winter				
10 minutes	139	446	467	21
1 hour	306	2201	2222	21
3 hours	605	5643	5686	43

Summer				
10 minutes	121	453	473	20
1 hour	264	2148	2204	56
3 hours	473	5751	5897	146

Each of the first three data columns gives three times the standard deviation of the step changes for that parameter – wind, load, or net load – for the given time period. The last column is the change in variability of the net load compared to the load without wind. It therefore measures the impact of wind on the net load-following requirement.

It is important to note that the change in variability is much smaller than the variability of the wind alone. The reason is that fluctuations in wind and load are for the most part uncorrelated. Indeed, the standard deviation of load minus wind can be roughly estimated, especially in winter, by taking the square root of the sum of the squares of the separate wind and load standard deviations. In summer, wind and load fluctuations on the 1 and 3 hour time frames are somewhat negatively correlated, resulting in a greater increase in variability than in other seasons. This is a reflection of the summer pattern already noted, in which wind tends to drop in the morning when the load increases, and wind tends to rise at night when the load drops. Despite this negative wind-load correlation, the increase in the load-following requirement in summer remains much smaller than would be inferred from the wind variability alone. The largest increase, 146 MW, represents a 2.6% increase over the load-following requirement without wind.

A different way to assess the load-following requirement is to consider the worst-case changes in net load. Since large, abrupt increases in net load pose a greater problem for the system than decreases – because reserve capacity must be ramped-up quickly – we looked at the largest negative swings in wind and positive swings in load and net load. They are shown in Table 4.

*Table 4. Largest swings in wind, load, and net load that would result in a ramp-up of non-wind generation.**

Time Period	Wind	Load	Net Load (Load-Wind)	Change
10 minutes	-344	1931	1942	11
1 hour	-578	2646	2849	202
3 hours	-874	5338	5532	194

*Calculated by taking the difference between 10-minute records separated by 10 minutes, 1 hour, or 3 hours.

It is not appropriate to consider the seasons separately, since the largest swings may – and do – occur at different times depending on whether it is the wind, load, or net load that is being considered. In the period analyzed in this study, the largest decreases in wind occurred in the fall and spring. The largest 10-minute increase in load occurred in the fall; whereas the largest 1-hour and 3-hour increases occurred in winter and summer,

respectively. The largest 1-hour and 3-hour increases in net load both occurred in the summer, however. This appears to confirm that the tendency of the wind to drop in the morning when the load rises places the greatest stress on non-wind generators in summer.

By this measure, the increase in required load-following reserve in the 1-hour and 3-hour time frames is about 200 MW. It should be emphasized that the largest swings in net load occur quite rarely. From May 2003 to April 2004, there is only one day – the early morning of June 24, 2003 – when the net load over a 3-hour period is greater than the largest increase without wind. The wind and load changes from 5 am to 9 am on this day are shown in Figure 5.

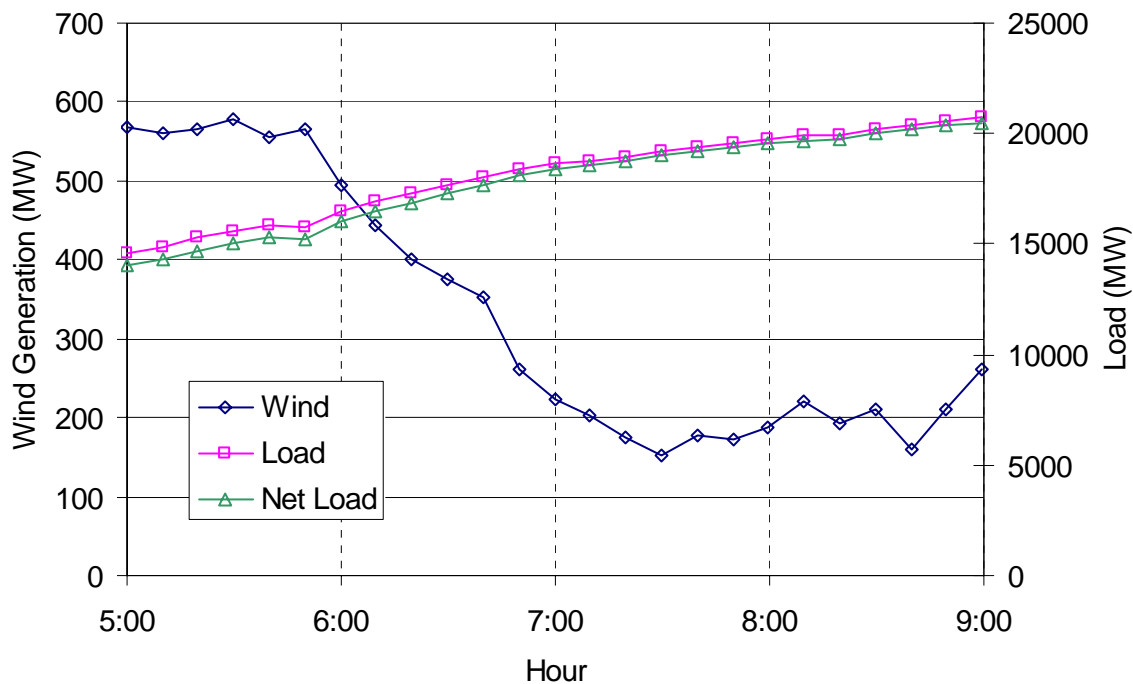
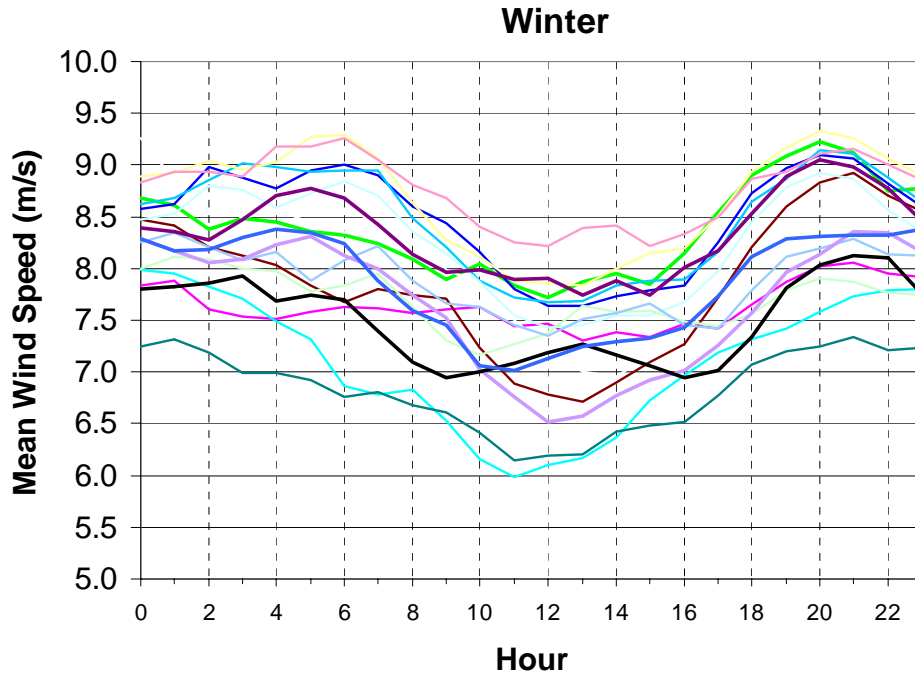


Figure 5. Wind, load, and net load on the morning of June 24, 2003. This period is the only one in which the 3-hour swing in net load exceeded the largest 3-hour swing without wind.

3.6. Geographic Diversity

The last element of this study consists of an analysis of the geographic diversity of wind generation in Ontario and the effect of this diversity on the overall impact of wind generation. Figure 6 shows the daily wind speed profiles for each of the sites in winter and summer. While the general patterns described earlier are evident, there is a wide variation in the details. Some sites have a narrower range of daily variation than others; some peak earlier or later than others. In the summer, in particular, some sites show a noticeable secondary mid-afternoon peak, which may be associated with a lake breeze.

These various profiles imply that some sites will have somewhat more value to the system than others for the same average energy output.



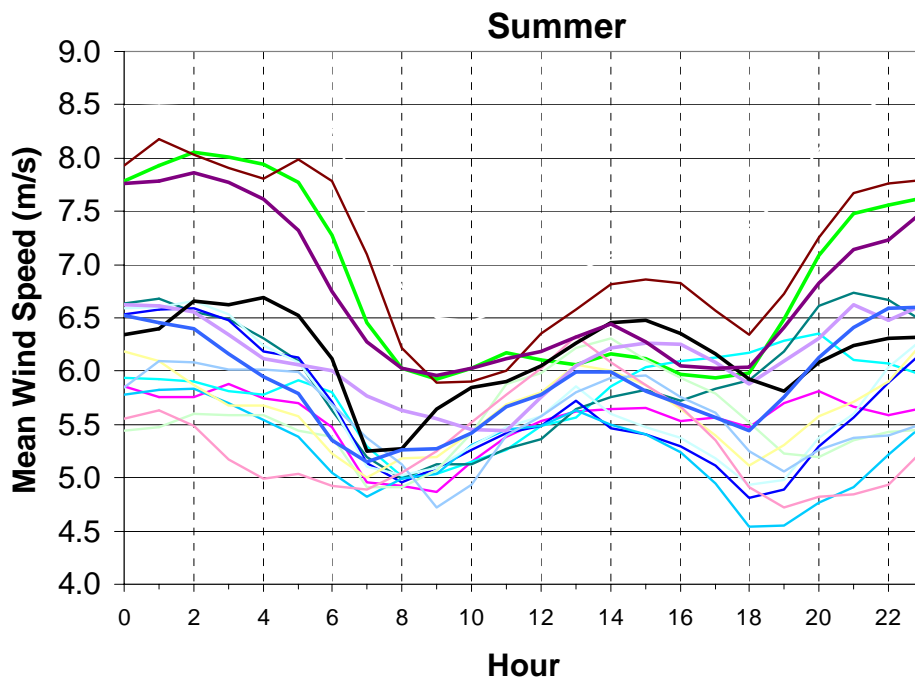


Figure 6. Winter (top) and summer (bottom) daily wind speed profiles for the 17 sites.

Another important aspect of geographic diversity is its role in mitigating wind fluctuations. Because the fluctuations in wind speed on a time scale of minutes to hours tend to be uncorrelated between project sites, by combining the output of several projects, the overall variability is reduced compared to obtaining the same output from a single, large project. We found, in fact, that the combined output of the 17 sites would have about 60-70% less variable than a single site, when measured as a proportion of the total rated capacity for time frames of 10 minutes to 3 hours. Thus, it is in the IESO's interest to encourage the development of wind projects at geographically dispersed sites. The "diversity benefit" of combining the output of the wind projects is illustrated in Figure 7.

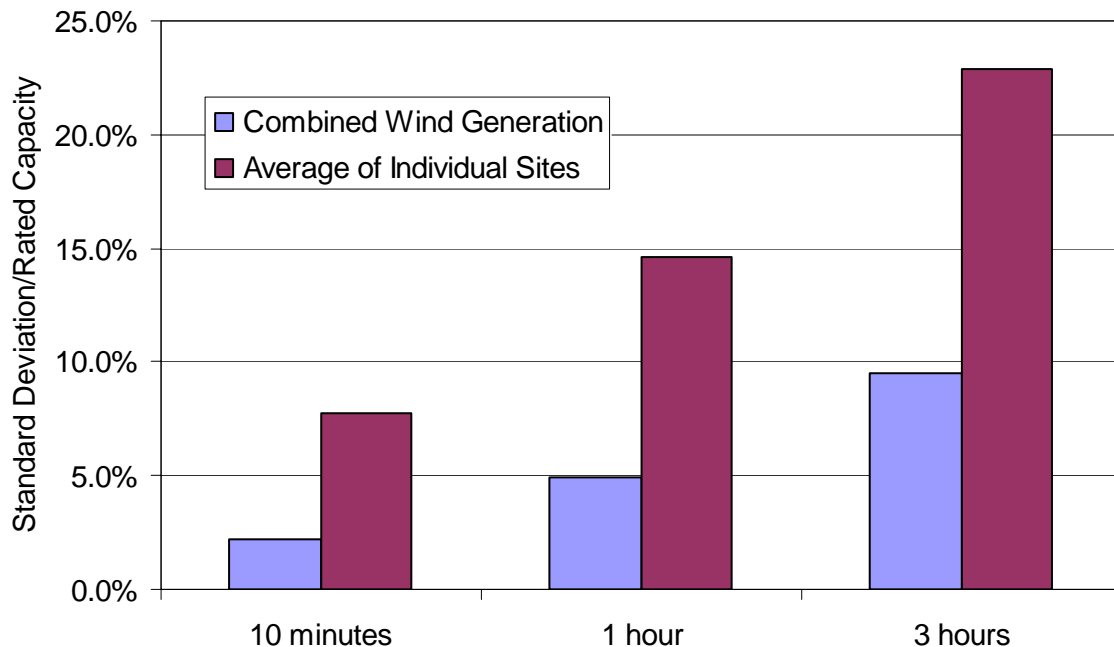


Figure 7. The relative variability of wind output, as measured by the standard deviation of step changes divided by the rated capacity, for individual projects taken separately and for all projects combined.

4. Conclusions

This study has addressed several questions about the impact of wind energy on the Ontario grid. Using concurrent wind and load data for May 2003 – April 2004, and assuming the development of 2000 MW of wind capacity at 17 sites around the province, we assessed the correlation of wind and load on both a seasonal and daily basis. We found that wind overall is relatively well matched with winter loads, but less well matched with summer loads. Applying simple techniques, we concluded that the overall capacity value of wind on the Ontario system would be about 37-40% of rated capacity, and that it would range from about 47% in winter to 19% in summer.

We also assessed how the addition of 2000 MW of wind generation would affect the overall variability of net loads on the Ontario system. By calculating the standard deviation of the change in wind, load, and load minus wind for periods ranging from 10 minutes to 3 hours, we concluded that the addition of wind would increase net load variability by much less than the variability of the wind itself. The reason for this is that wind and load are for the most part uncorrelated.

By applying the simple rule that the load-following requirement equals three times the standard deviation of net load on a 1-hour time frame, we conclude that the addition of 2000 MW of wind would increase load-following requirement by 37 MW on an annual basis, or 56 MW in summer. On a 3-hour time frame, the increase in load-following

requirement would be 93 MW on an annual basis, or 146 MW in summer. Furthermore, the largest increase in net load over a 3-hour period would be 5532 MW with the wind generation compared to 5338 MW without the wind generation – a 200 MW increase. The increase in net load variability is greater in summer than in winter because of a tendency for loads to increase and winds to drop, and vice-versa, at the same time.

Finally, we briefly assessed the benefits of geographic diversity. After noting a rather wide variation in the daily wind patterns at different sites, we found that the combination of output from all 17 sites is about 60-70% less variable, on a 10-minute or 1-hour time frame, than the output from a single site. Since the diversity benefit increases with greater distance between projects, it is in the IESO's interest to encourage the development of wind in different areas of the province.