Examining the Benefits of Optimal Spatial Diversification of Wind Capacity

By

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Abstract

This study examines the benefits of optimal spatial diversification of wind capacity as an option to reduce wind curtailment and, therefore, to increase the utilization of wind capacity. Wind generation concentrated at sites with the highest energy capture, once aggregated, does not utilize the installed wind capacity at the highest possible rate due to wind curtailment. Contrary to the expectations, wind generation at sites with lower energy capture but with wind generation patterns that minimize wind curtailment results in a higher utilization of installed wind capacity.

Such a configuration requires an optimization scheme to model power system flexibility and wind generation and to allocate capacity with the objective of maximizing the utilization of wind capacity, defined by the term "effective capacity factor", CF_E, (i.e. average system wide wind generation *less* curtailment, divided by installed capacity.)

In order to measure the benefits of optimal spatial configuration of wind capacity, a base-case configuration is defined which approximates the dominant trend in the wind industry. In the base-case configuration, capacity is allocated to sites in the order of their energy capture (capacity factor) until the capacity limit for the selected sites are reached. The improvement of CF_E in the optimal configuration over the base-case configuration is then used as a measure to quantify and illustrate the benefits of optimal spatial diversification.

The results of this study show that the CF_E of the installed wind capacity in the system improves by 2% to 4% in the optimally diversified configuration at low levels of wind penetration (10% to 20%) and subject to moderate to strict power system generation constraints. For medium levels of wind penetration (20% to 30%), there is no observed benefits since ramping complications fade away at higher levels of penetration. At high levels of penetration (25% to 40%), the minimum generation level constraint results in 5% to 10% CF_E improvement in the optimally diversified configuration.

Storage is modeled in the system, as an alternative method of comparing the optimal and base-case configurations. The storage capacity that would be saved by optimally diversifying the wind capacity is determined for different levels of wind capacity installations and subject to varying levels of power system flexibility. Power system generation flexibility is modeled by two key parameters of minimum generation level and ramping capability.

The benefits of optimal configuration over the business-as-usual base-case configuration are significant at low and high levels of wind penetration whereas the benefits are almost absent at medium levels of wind penetration. This is explained by the role that the key parameters of the generation fleet play at different levels of penetration.

Acknowledgements

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I. Introduction

The dominant trend in the development of large-scale wind power is to concentrate wind farms in regions with the highest energy capture. This is not surprising as developers are seeking the highest rates of return for their investments and are not directly responsible for costs incurred by the system as a result of increasing wind power penetration. The bulk of this cost is due to increased requirement for reserves such as fast response natural gas turbines and storage devices. However the increased overall cost poses itself as an obstacle on further development of wind power.

Since wind generation is intermittent and tends to be negatively correlated with the load, significant concentration of wind power can cause power system stability problems and increase the size of operational reserves. Hourly wind speeds tend to be highly correlated in fairly small geographic regions. As a consequence, the aggregated output from a large amount of capacity in a region with a consistent wind regime may exhibit large ramp rates and frequent periods of production at full capacity. This is particularly problematic when the system operator has to keep a minimum number of conventional units committed in anticipation of low wind generation and high system demand and there is no substantial hydropower or storage capacity to balance wind power fluctuations. As a result, wind production may need to be curtailed in order to avoid violating minimum generation levels and ramp rate constraints for other dispatchable generators on the grid.

Wind curtailment is the least costly way of handling over-generation and is currently practiced in California ISO and Texas but will likely emerge as a backup control option in the future when wind power penetration levels became much higher. As of year 2009 the highest penetration level of wind power in the US is for the Texas grid with roughly 8%. As more capacity is built, the frequency and the magnitude of wind curtailment are expected to increase.

Currently the wind power is traded through Power Purchase Agreements (PPA). “Power may be sold through a PPA to a local utility or electric cooperative, a more distant utility, or to a different wholesale or retail customer.”

“Many PPA agreements recognize that there will be times when either the purchaser, transmission owner or transmission authority (such as the Midwest Independent Transmission System Operator (MISO) or the Mid-Continent Area Power Pool (MAPP)) may curtail the production of wind energy at the facility because of constraints on the system, emergency or other reasons.”

“During negotiation of a PPA, the parties must decide who will bear the financial risk for losses that arise when the purchaser, transmission owner or transmission authority exercises its curtailment right. Many PPAs are structured as “take-or-pay” agreements, which means that the purchaser will pay the seller for wind energy actually delivered to the point of delivery and for “available capacity,” or energy that would have been delivered but for the curtailment.”

“The parties usually agree to calculate available capacity based on wind data available during the curtailment period and the power curve data for the wind turbines. The seller is often required to construct and maintain a meteorological tower capable of measuring and recording representative wind data 24 hours a day, and this data can be used to calculate the payment owed by the purchaser for the curtailed energy.” (Community Wind Development Handbook 2008)

The current structure of “take-or-pay” contracts which suits the low levels of wind penetration and infrequent needs for wind curtailment does not provide incentives for wind developers to build a spatially optimal configuration. However, as the curtailment would become more significant, these contracts are very likely negotiated differently in a way that the wind developers, and not the system operator, have to internalize the cost of curtailment. In this case, it would be in the wind developers’ best interests to build capacity in much the same way as the optimization model of this study predicts.

This study illustrates from a system perspective the benefits of spatial diversification of wind capacity. The optimal diversification of wind capacity, explained later at more detail, is characterized by capacity being allocated to sites with relatively lower energy capture but with wind patterns that apparently result in less wind curtailment. This study shows that under moderate to strict power system generation constraints, the optimal wind capacity configurations can significantly improve the utilization of wind generation assets. Optimality is measured by the effective capacity factor, CF_E (i.e. average system wide wind generation *less* curtailment, divided by installed capacity).

In order to demonstrate the benefits of spatial diversification to sites with lower wind resource, a base-case configuration procedure is defined in which wind capacity is being allocated to sites in the order of their capacity factors, the highest capacity factor sites get allocated first, until the maximum allowed capacity for each site is reached. The base-case $\mathrm{CF_E}$ values are obtained as wind power penetration increases for different sets of minimum generation level and ramping constraints.

By comparing the base-case and the optimal configurations of wind capacity, subject to the physical constraints of the power system generation, this study draws attention to issues that may arise in the course of the development of large-scale wind power. Although the wind speed and the load data is based on a specific geographic region which is the Lower Peninsula of Michigan, it is expected that the results can be general enough to be applied to other regions with significant wind development plans in the coming decades.

As of the date of writing this thesis, there is an ongoing investigation to find new ways of quantifying and illustrating the benefits of optimal, spatially diverse configuration of wind capacity compared to the business-as-usual, base case configuration. Introducing storage in the model was one way to compare the optimal and base-case configurations. As it will be explained later at a greater detail, storage is added to the base-case configuration to achieve the same rate of wind capacity utilization as in the optimal case for increments of installed wind capacity.

1.1 Review of the Related Recent Studies

The concept of spatial distribution of wind capacity was first seriously examined as a measure to improve the effective load carrying capacity (ELCC) of the wind generation assets in a series of articles in late 1990s. Since the penetration of wind electricity was not significantly large in any centralized power system a decade ago, early studies focused more on reliability assessment of wind generation assets rather than power system generation constraint issues, such as minimum operating point and ramping capability of conventional units that have arisen quite recently.

Milligan et al. 1998 analyzed the value of geographically diverse wind capacity on the reliability of the aggregate wind generation. An optimization algorithm was designed to select from six sites based on their hourly wind speed time series. These sites were chosen form a larger set to represent the diversity of wind regime in Minnesota. The objective functions were taken as two different reliability measures, loss of load expectation (LOLE) and energy not served (ENS) which were minimized by repeated selections of 25MW clusters from these sites until a certain wind capacity is optimally allocated. The study concluded that although the correlation of wind speed with load does play a role in how much each site contributes to the optimal configuration, "a wind site that provides more energy is likely to contribute more to system reliability than a site with less energy."Therefore the capacity factor, a widely accepted indicator of the wind resource quality, plays a more pronounced role in reliability of wind generation than correlation with load. However, Milligan et al. 1999 which extended their analysis in Milligan et al. 1998 to account for inter-annual variations by considering three consecutive years of hourly wind speed data failed to establish any concrete relation between capacity factor (wind resource quality), load correlation of the sites and their contribution to the optimal mix. These two related studies, nonetheless, argued that spatial diversification of wind generation is a way to enhance reliability of wind generation. This conclusion was, however, not based on any comparison between the optimal configuration which apparently is spatially diverse and the configuration in which the capacity is concentrated in a single site.

As it will be shown later in the methodology section, an optimization algorithms very similar to these two studies have been used.

More recent studies have considered wind surplus and over-generation issues besides reliability assessment of wind generation and as the penetration of wind is rapidly increasing, wind curtailment and power system generation constraints are coming to the forefront of wind integration research. Short et al. 2003 was among the earliest studies that modeled the increasing trend in wind surplus and reduced capacity value of wind up until 2050. Their study was based on WinDS, a computer model of expansion of generation and transmission capacity in the US and uses a linear optimization program to minimize the cost of providing power. The objective function was subject to several constraints including wind resource availability in each region, access to existing transmission lines, load constraint and reserve constraints. The study did not go into the details of the model but tried to capture all major aspects of wind generation including reliability. The wind surplus was calculated with no consideration of the minimum generation levels and ramping capabilities of the conventional plants and for that reason is rather crude.

The study argued that increased penetration of wind in the US electric sector can substantially increase the reserve requirement. This would make the capacity value of wind drop drastically. It hinted, with no further illustration, that low correlation of wind sites, as a result of spatial diversity, can slow the increasing pace of operational reserves.

A more developed and realistic attitude toward power system generation constraints needed an understanding of the impact of wind on the dispatch of conventional generators and their ramping capabilities. Ummels et al. 2007 modeled a European power system with substantial penetration of combined heat and power (CHP) generation and Milligan et al. 2008 studied the ramping requirement of balancing areas in Minnesota. They have contributed to an understanding of the system constraints that result in wind curtailment.

In (Ummels et al. 2007) impact of wind power variability is assessed, through simulation, for different wind power penetration levels. The concepts of upward and downward regulation and minimum load generation issues are clearly defined and the study concludes that for the Dutch power system, ramping constraint issues are absent but wind curtailment for increased wind power penetration occurs mainly due to the minimum generation levels imposed by significant CHP penetration. Although, there is no mention of the role of spatial diversification of wind capacity to mitigate the operational issues, one could expect with some prior knowledge of the Dutch wind installations, a highly diversified combination of off-shore and on-shore wind generation would help reduce wind variability and ramping requirement of the system.

Ramping requirements, however, may pose serious challenges to wind power integration in the presence of the isolated operation of balancing areas. As Milligan et al. 2008 demonstrated consolidation of balancing areas or sharing of balancing obligation would reduce the ramping requirement of the system. The study argued however that “In some cases, wind actually increases the correlation between balancing areas, and in other cases, this correlation decreases with the addition of wind.”

This stresses the significance of power system planning for optimally diversified configuration of wind capacity, developing wind capacity at regions which their wind patterns are correlated in a way that once aggregated would reduce the ramping and reserve requirement of wind generation.

Milligan et al. 2008 based itself on “Minnesota 20% Wind Integration Report” in assuming that the State of Minnesota operates as a single balancing area with no interaction with the MISO energy market. In this study similarly a single consolidated balancing area for the Lower Peninsula of the state of Michigan is assumed.

Few system operators in the US have so far experienced substantial penetration of wind power. The reports published in the past three years on the actual issues faced by the system operators such as over-generation and extreme ramping events provided the essential concepts for a simplified, though realistic enough modeling of the power system.

Wind curtailment is becoming the chief method of dealing with system stability in over-generation periods. “Intermittency Analysis Project Final Report” (California Energy Commission 2007) mentioned wind curtailment and enhanced flexibility of the conventional generation assets as solutions for high wind periods coupled with light loads. “California ISO Integration of Renewable Resources Report” (September 2007) is particularly valuable as it was the first report based on a real power system that explored the operational aspects of wind generation and anticipated the exacerbation of over-generation issues for higher wind power penetration levels. This study concluded that curtailment of up to 500MW of wind capacity for up to 100 hours is quite expected for 20% RPS target in California.

As reliability assessment of wind assets is driven to the background by more pressing and relatively recently emerged over-generation and ramping issues, new studies are focusing on the operational aspects of large scale wind power, wind curtailment and storage. However, so far, no work has been done comparing the spatial diversification and concentration of wind generation in terms of over-generation and extreme ramping events in conventional grids. With the accelerating rate of wind turbine installations, optimal allocation of the new capacity to sites which may not necessarily have the highest energy capture (i.e. capacity factor), could achieve substantially higher rates of wind capacity utilization compared to the highly concentrated configurations at sites with the highest wind speed averages.

1.2 Research Question

The dominant trend in the wind industry is toward developing wind capacity at regions with the highest energy capture (i.e. capacity factor) first. Once no longer it is economically feasible to develop more capacity, mainly due to land area constraints and associated expenses, sites with lower energy capture are developed.

There are indications, based on the existing literature, that this trend is not optimal from a system perspective. In other words, it could be less costly to diversify the wind capacity development before reaching the capacity limits in sites with the highest energy capture.

There are several intuitive reasons to initially justify this outlook. First, wind speed shows spatial patterns of correlation that decline as distance increases. This means less variation in the aggregate output of diversified wind capacity. Second, sites exhibit relatively consistent yearly patterns of correlation with the load. Although these patterns are subject to inter-annual variations, it can be cautiously stated that each region has intrinsic features that render it a unique wind pattern over a sufficiently long period of time. The practical implication of this as it will be shown in the result section is that subject to physical constraints of the power system some sites are at a more advantageous position that others with a higher energy capture in terms of utilization the installed capacity.

Therefore, the research question of this study can be most appropriately formulated as below:

“What is the potential for spatial diversification to improve the utilization of wind assets by avoiding wind curtailment?” This has to be investigated along at least three dimensions: (1) as the level of wind penetration increases, (2) under different levels of power system flexibility defined by minimum generation level and ramping capability and finally (3) subject to different land area (capacity) constraints which limit the wind capacity that can be developed in each region.

Spatial diversification is not considered in this study as a random process but is governed by an optimization process which seeks to increase the utilization rate of installed capacity. In contrast to this spatially diverse optimal configuration which hereafter is referred to as the optimal configuration, a base case configuration is defined which represents the current trend in the wind industry in which sites with the highest energy capture are developed first.

1.3 Thesis Outline

This thesis is organized into three major sections (section 2, 3 and 4) each with some subsections.

Section 2 explains in detail, the data used in this study, its processing, and modeling of wind generation and its complexities and power system conventional generation.

Section 2.2, "Modeling of Wind Complexities", starts with explaining the method of scaling-up of 10m wind speed data and continues with horizontal scaling of wind speed point measurements to obtain slightly varied time series capturing variation within each region. Section 2.2 concludes with the discussion of land area availability or what would be referred to later in the thesis as capacity constraint.

Section 2.3, "Power System (Conventional) Generation Modeling", presents a simplified model of the generation fleet which is characterized by two key parameters: (1) Minimum Generation Level (*MGL*) and (2) Ramping Capability

Section 2.4, "Wind Curtailment and the Optimization Process", explains the concept of wind surplus and curtailment and the optimization process. Section 2 concludes with the introduction of the storage and how it has been modeled in this study.

Section 3, "Results Analysis", discusses the results of the two sets of experiments subject to different levels of power system flexibility and capacity constraint.

Section 4, "Conclusions and Future Study", sums up the observations in section 3 and ends with "Future Work" which presents an outline for further investigation of the results and ways to improve the model.

It should be stressed here, that this is an ongoing research and this thesis is by no means the culmination of the research on this subject. The final results are expected to be sent for publication as a journal paper in fall 2009.

II. Methodology

2.1 Data Types and Processing

In this study, two major types of data have been acquired and processed.

- Hourly Load Data
- 10m Wind Speed Data

Michigan has recently passed an RPS and significant growth in wind capacity is expected in Michigan's Lower Peninsula. Therefore, the State of Michigan's Lower Peninsula served by MISO is chosen for this study but hopefully the results can be generalized to all power systems which are planning for substantial penetration of wind power.

Hourly load data is obtained for Consumers Energy and Detroit Edison companies for the 5 year period of 2000-2004 (FERC 2009). An earlier forecast of load growth by the Michigan Capacity Need Forum (2006) has been recently revised due to the declining economic conditions. Therefore the growth in the load has not been modeled in this study. In fact the growth is highly uncertain at this point, but likely to be low in the coming years. The data from these two companies are simply added to represent the hourly load data for the consolidated balancing area serving the lower peninsula of Michigan.

For wind speed data, 10m anemometer measurements from National Climatic Data Center (NCDC) are primarily used (NCDC 2009). NCDC has over 180 actively recording meteorological stations throughout the state of Michigan. They record environmental attributes such as temperature, humidity, wind speed and direction. NCDC is the only publicly available source of wind speed data in Michigan with a roughly even distribution of measuring stations across the state.

NCDC data in its original format was not useful for this study. The goal was to obtain neat hourly wind speed data for 2000 through 2004 at 80m above ground level (AGL).

There were many missing data set points (i.e. no wind speed measurement for some hours) and the wind speed measurements, in the original format presented by NCDC, are averaged over a 5 minute period at a varied frequency of one to three measurements per hour. The first step was to average multiple measurements within an hour to obtain single hourly measurement and it was assumed that the resulting average can approximate the actual hourly average in a sufficiently accurate way for this study. This can be justified by the fact that wind speed measurements within an hour, particularly when averaged over a 5 minute period, are highly correlated. Therefore, averaging intra-hourly measurements can yield a close approximation of the hourly average.

Then the missing hours and days were replaced by the adjacent periods. The missing data that had to be replaced varied from 1% to 10% of the 5 year period for different stations. A large portion of the missing data is in the form of single missing hours that can be replaced by averaging the adjacent hours. Since wind speed tends to have a high temporal correlation (i.e. correlation between adjacent hours) such missing hours can be replaced without affecting the quality of the data.

Figure 2.1 shows NCDC meteorological stations and their spatial distribution in the Lower Peninsula of Michigan. Those stations for which wind speed data for the five year period of 2000-2004 were available are highlighted.

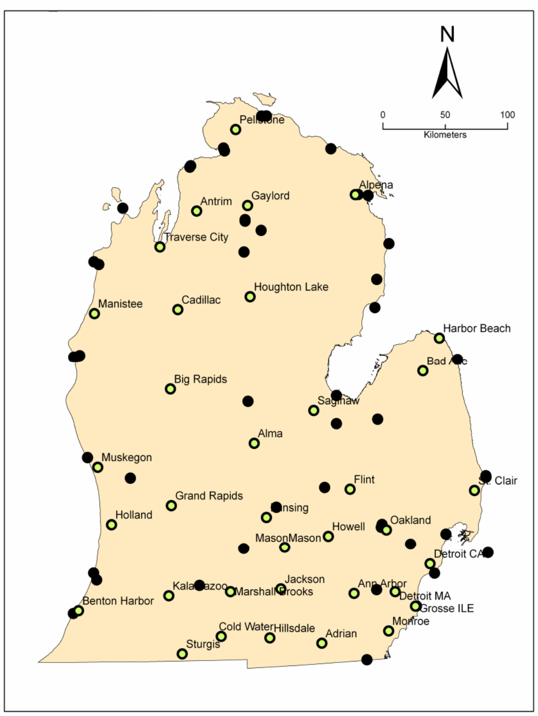


Figure 2.1: NCDC Meteorological Stations in Michigan's Lower Peninsula

2.2 Modeling of Wind Complexities

There were intermediate steps before wind speed data at 80m AGL (typical hub height for >1MW wind turbines) was compiled and the final site selection could be implemented accordingly. Numerous studies have scaled up the 10m anemometer data using wind speed power law and a constant shear coefficient. For example (Lewis 2007) has used this method to scale up NCDC 10m data to the hub height. This study explores the applicability of locational marginal price (LMP) for wind power siting. As it will be discussed shortly, this method can result in an inaccurate approximation of the actual wind speed at the hub height.

Once wind speed data at the hub height (80m) is obtained, then the question arises over the extent to which measurements at a single location can represent wind speed variation in a geographic region that can accommodate up to several gigawatts of wind capacity.

These two issues as they have been dealt with in this study are discussed in the next two sections.

2.2.1 Vertical Scaling of Wind Speed

Wind at distances close to earth surface is subject to wind shear phenomenon which causes variation in wind speed and direction over vertical distances. Wind shear causes 10m data to be less than 80m. This is usually corrected by applying the power law to 10m wind speed data using a constant shear coefficient α as in (2.1). V_{h1} and V_{h2} are wind speed magnitudes at heights h_1 and h_2 respectively.

(2.1)
$$V_{h_2} = V_{h_1}\left(\frac{h_2}{h_1}\right)^{\alpha}$$

However wind shear varies diurnally, seasonally and by location. In order to capture the seasonal and diurnal variation, a comparison between tall tower and 10m hourly measurements of the same locations is required.

No tall tower data for which there is a corresponding 10m data is available in Michigan. Therefore three sites in Minnesota (figure 2.2) were selected that are relatively well distanced. Minnesota is part of the Great Lakes region which also includes Michigan. Moreover, the extracted patterns of diurnal and seasonal shear exhibit characteristics similar to other regions including central plains in the US (Schwartz et al. 2006) and it was assumed that they are general enough to apply to Michigan. This is however not ideal and once similar data in Michigan became available they should be used for more accurate shear patterns.

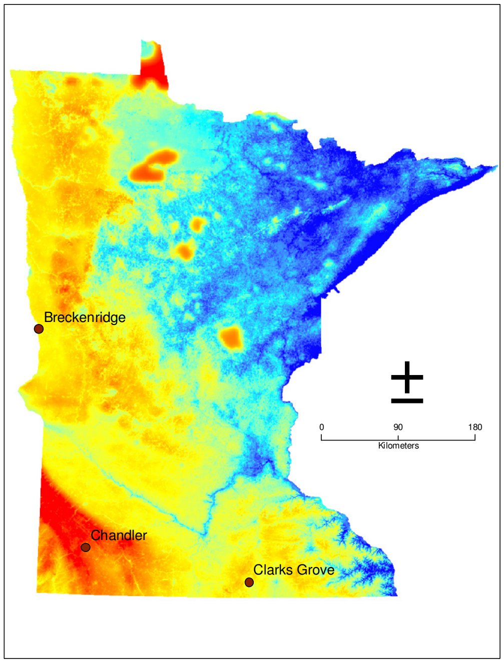


Figure 2.2: The Map of three sites in Minnesota which had 10m/70m hourly wind speed measurements.
(The data was used to obtain the season-hourly shear coefficients.)
Background color spectrum (red-blue) is included to show wind resource quality (red color represent the highest wind speed average and blue the lowest wind speed average.)

Since 10m wind speed averages are very much influenced by highly variable factors such as topography, vegetation and other terrain features, these averages are not reliable indicators of the wind resource quality (i.e. energy capture) at 80m. The midpoints of the range for wind speed average at 80m provided by 3TIER assessment model (3TIER 2009) were used for this purpose. 3TIER is one of several wind resource assessment companies that produces high spatial resolution wind speed data from mesoscale climate models. Figure 2.3 shows the upper and lower bounds of wind speed average at 80m for Harbor Beach in the Thumb area as given in the 3TIER assessment model.

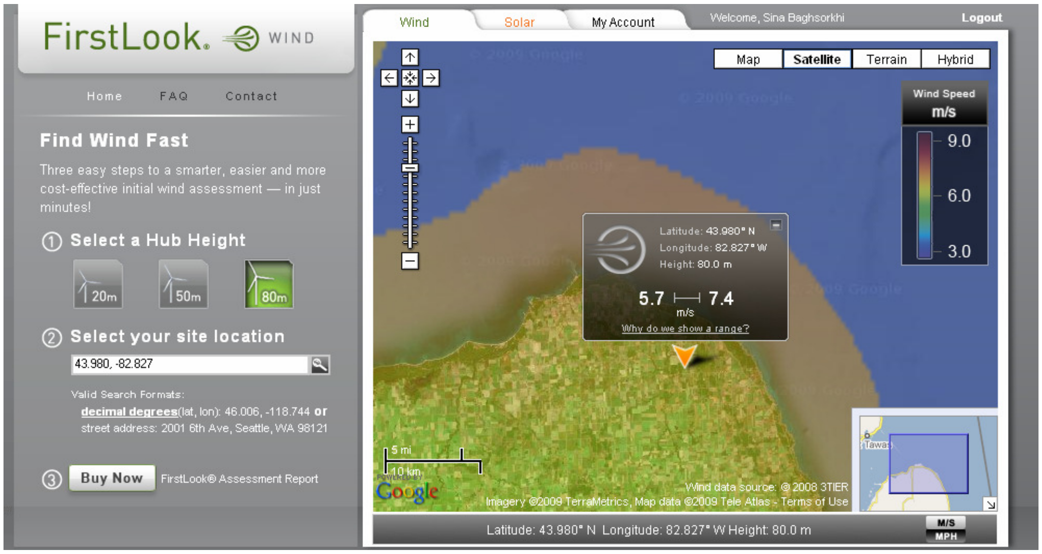


Figure 2.3: 3TIER assessment model's interactive window (showing the range of 80m wind speed average for a point in the Thumb area close to Harbor Beach)

The season-hourly shear coefficients (figure 2.4) are based on the wind speed data from the three sites in Minnesota and were multiplied by a constant factor (k) to produce an hourly wind speed time series with its average matching the average obtained from the 3TIER model. (2.2)

(2.2) $$V_{80\mathrm{m}} = V_{10\mathrm{m}} \left(\frac{80}{10} \right)^{k\alpha_{\mathrm{season,\ hr}}}$$

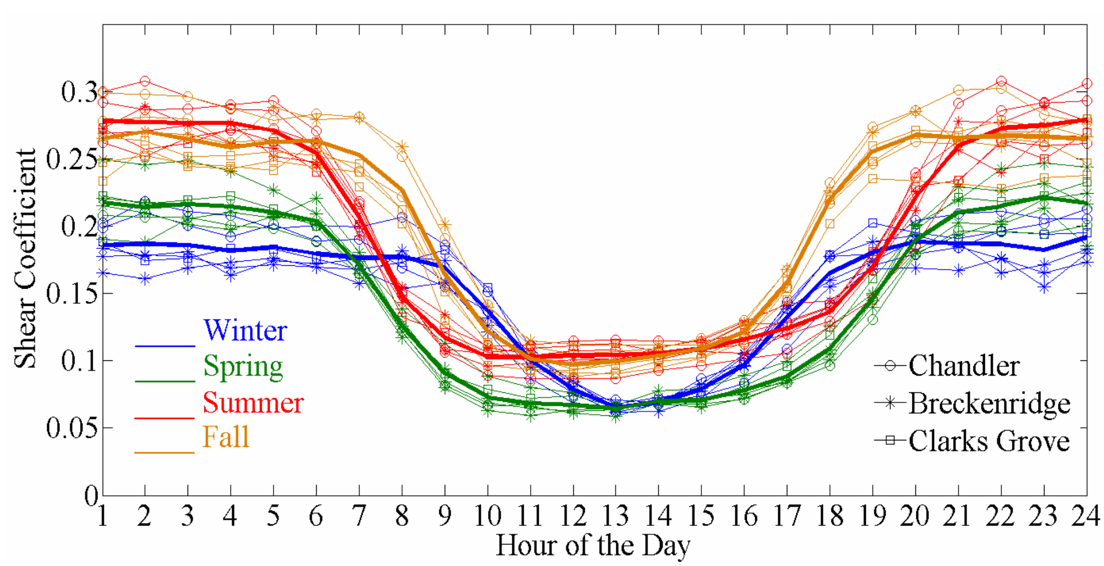


Figure 2.4: Season-hourly Shear Coefficients

2.2.2 Horizontal Scaling of Wind Speed and Conversion to Power

The hub height wind speed was converted to power using the power curve of the GE 1.5MW XLE wind turbine (Figure 2.5). The pitch-controlled turbine, contrary to the older stall controlled technology, allows the turbine to keep the output at the rated capacity at high wind speeds. This technology enables the curtailment of wind by the virtue of the pitch mechanism (often referred to blade- feathering).

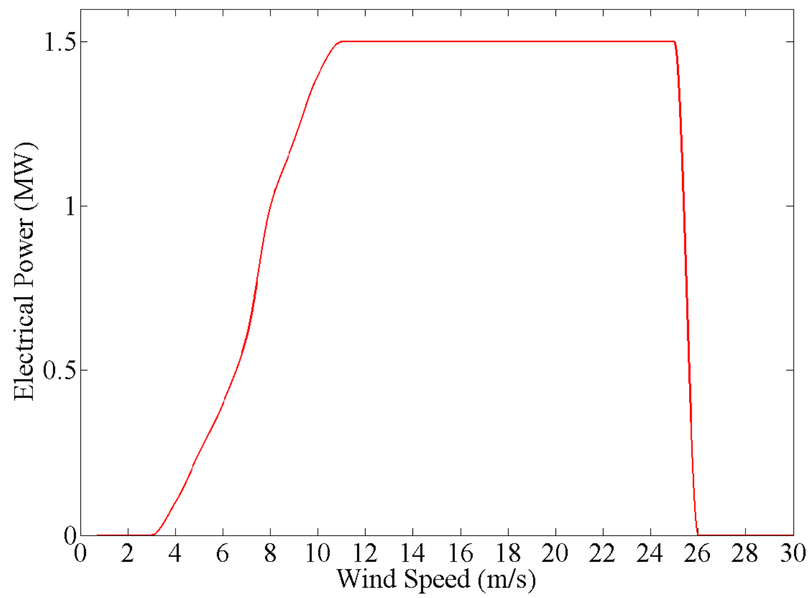


Figure 2.5: Power curve of GE 1.5MW XLE pitch controlled wind turbine (Source: GE Energy 1.5MW Turbine Brochure)

The original wind power time series may be a good approximation for the hourly output of turbines that are relatively close to the wind speed measurement point. However, spatial variation in wind speed will cause the correlation in power production between any two turbines to decline as a function of the distance between them.

As the distance between wind turbines increases, there may be more lagged correlation depending on the wind regime, mesoscale atmospheric patterns and geography. Since an understanding of this complex phenomenon was beyond the scope of this study, a simplified notion of time lag between wind speeds at different locations was adopted to model this complexity. Wave properties were assumed for wind in such a way that any disturbance occurring at time t at location A would be felt at time t+δt at location B which lies in the direction of the propagation of wind with a distance of *s* from A. It was then assumed that the time lag δt after which point B experiences the same disturbance as in point A is directly proportional to *s*, the distance between points A and B and inversely proportional to propagation speed along the AB line.

This time delay is modeled by the weighted averaging of wind speed at the current hour (t), an hour ahead (t+1) and an hour ago (t-1) (2.3). V_t^{c-} is a new wind speed time series, created by the weighted averaging of the wind speed at each hour in the original time series with its previous hour. V_t^{c+} is created by weighted averaging of wind speed at each hour in the original time series with its next hour. P_t^c is the averaged power time series of the new wind speed time series.

$$V_t^{c^-} = c V_{t-1} + (1 - c)V_t \qquad (2.3)$$
$$V_t^{c^+} = (1 - c)V_t + c V_{t+1}$$

$$P_t^c = \frac{P(V_t^{c^-}) + P(V_t^{c^+})}{2} \qquad (2.4)$$

c, the parameter governing the weighted average, can be tuned to adjust the correlation between sites. This method does not change the average of the time series nor does it significantly influence the variance of the output and therefore the resulting wind power time series does not significantly vary either. As an example the wind speed time series corresponding to c=0.50 has a standard deviation of roughly 96% (averaged for 25 sites) of the original time series standard deviation. For the power time series resulting from (2.4) this figure is 97%.

A similar approach was taken by Persuad et al. 2003 based on the wind front movement in a region. However, it should be acknowledged that fronts are not moving in vacuum and therefore their propagation comes close to the flow of incompressible fluids. This means that disturbances in reality propagate at a much faster rate and the likely causes of correlation between distanced wind turbines are more complex than can be explained by front propagation alone. This however, is an attempt to approximate reality as best as the limited knowledge in the literature permits.

Figure 2.6 shows wind speed correlation, linearly interpolated, as a function of distance and is based on wind speed data vertically scaled to 80m for five adjacent sites in Michigan relative to one reference site (figure 2.7).

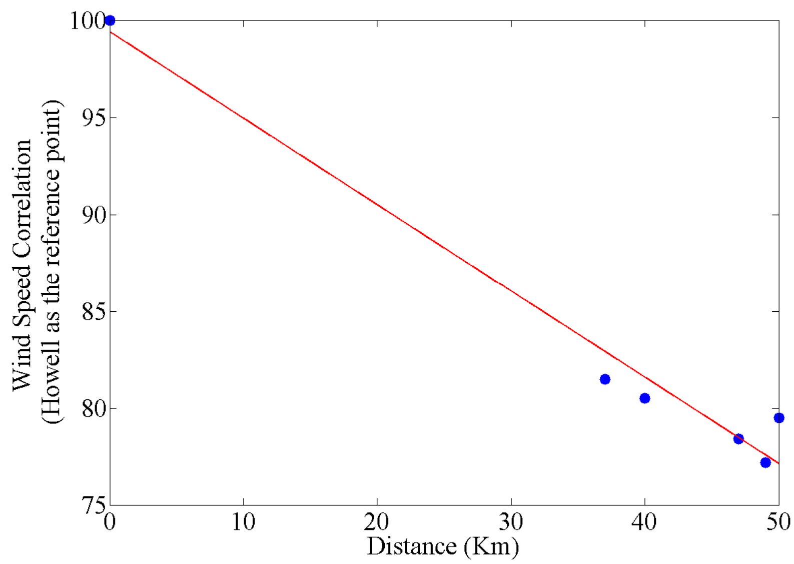


Figure 2.6: Wind speed correlation as a function of distance

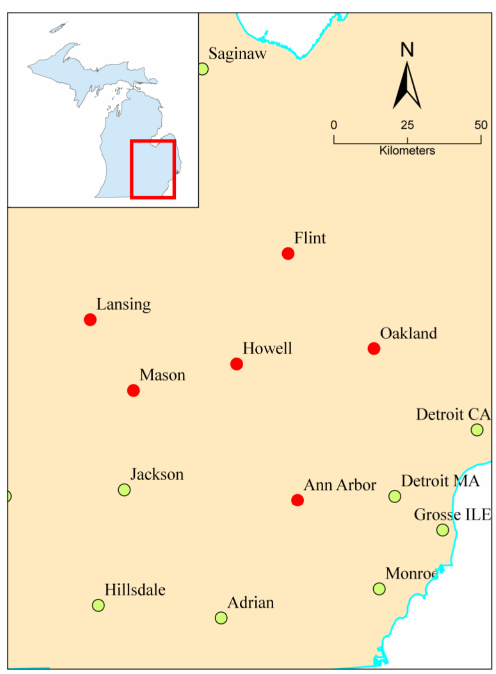


Figure 2.7: Sites used to obtain the rate of change in wind speed correlation with distance (Howell as the reference point)

Based on this correlation figure and with the assumption that 4 GW of wind capacity is installed within a 20km distance of the original point measurement (NCDC site), the minimum correlation would be roughly 0.90 and this is achieved by increasing c to 0.50 in (2.3).

So for the first 100MW cluster c is set to 0, which yields the original power time series. The second 100MW has a power time series that is obtained by setting c to 0.02 in (2.3) and (2.4). As clusters of capacity are installed c increases separately at each site until it reaches 0.50 and the new power time series are obtained via (2.3) and (2.4).

Figure 2.8 compares the normalized wind power of a cluster of turbines corresponding to c=0.50 to that of the original wind power time series.

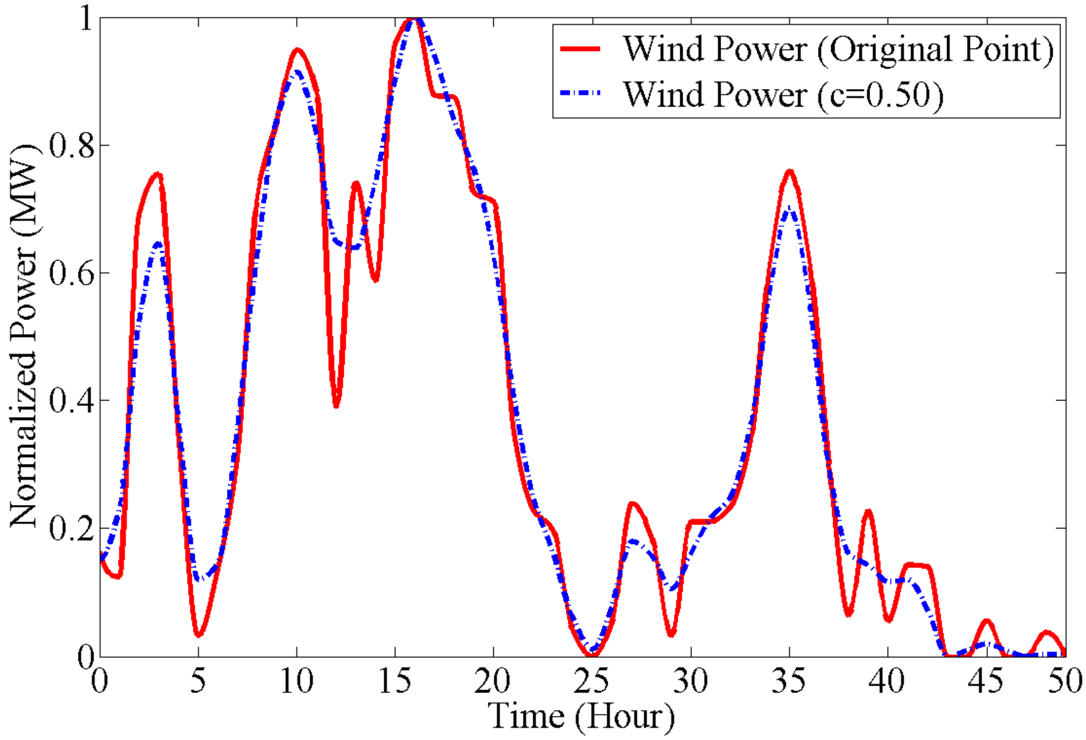


Figure 2.8: Weighted averaged power time series versus the power time series of the original point

2.2.3 Final Selection of Sites

Once the vertical scaling of 10m wind speed to 80m wind speed was done and speed was converted to power using the GE 1.5MW XLE power curve, sites with extremely low energy capture were omitted for the sake of computational time. These sites were deemed unlikely to contribute at all to the optimal configuration. The threshold for capacity factor was set as 0.33 and sites with lower capacity factor were omitted. Table 2.1 provides a list of selected sites with their corresponding capacity factors. Figure 2.9 shows the map of selected sites.

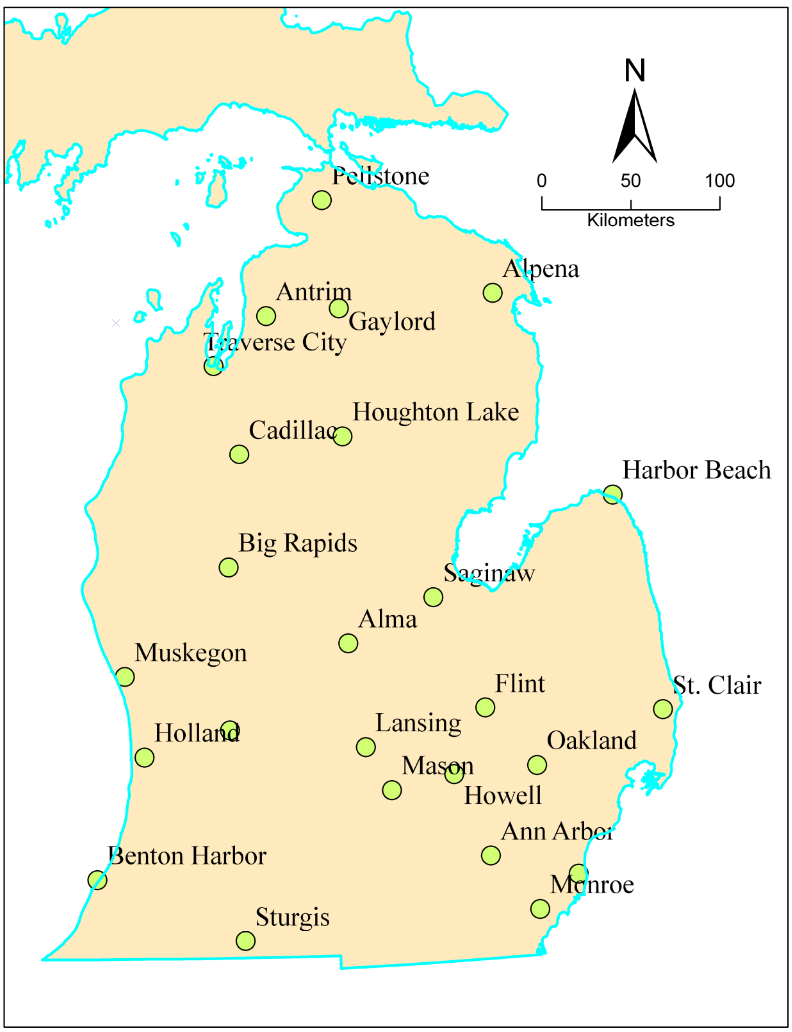


Figure 2.9: A map of selected sites in the Lower Peninsula of Michigan

Site Name	Site Index	80 m Wind Speed Average (m/s)	Capacity Factor
Pellston	1	6.8	0.4356
Benton Harbor	2	6.8	0.4264
Harbor Beach	3	6.6	0.4045
Traverse City	4	6.5	0.4025
Cadillac	5	6.5	0.4014
Muskegon	6	6.3	0.3958
Holland	7	6.5	0.3928
Gaylord	8	6.2	0.3728
Antrim	9	6.1	0.3699
Monroe	10	6.1	0.3646
Big Rapids	11	6.0	0.3645
Alma	12	6.1	0.3643
Hillsdale	13	6.0	0.3571
St Clair	14	5.9	0.3538
Flint	15	6.0	0.3525
Grosse	16	6.0	0.3524
Howell	17	6.0	0.351
Lansing	18	5.9	0.3503
Oakland	19	6.0	0.3503
Grand Rapids	20	6.0	0.3495
Sturgis	21	5.9	0.3463
Mason	22	5.8	0.3444
Saginaw	23	6.0	0.3419
Ann Arbor	24	5.8	0.3348
Alpena	25	5.6	0.3338

Table 2.1: A list of selected sites with their corresponding wind speed averages and capacity factors

2.2.4 Land Area (Capacity) Constraint

A recent report prepared for Michigan Wind Energy Resource Zone Board (June 2009) studied the availability of land for wind capacity development in Michigan. It has used geospatial techniques to establish a wide range of exclusion criteria including all types of land cover/use that might be in conflict with wind turbine installations and has identified four regions, one in the Thumb area and the remaining three along the western side of the state as having the highest energy capture in Michigan.

The report stated that with all land use/cover conflicts excluded, there can be 2GW to 4 GW of capacity in the Thumb region and close to 1 GW of capacity for each of the three regions. This is however restricted to certain areas within each region and as a result would be a conservative estimate of the capacity that can be developed at each region.

Therefore, in this study it was assumed that each of the 25 sites can accommodate either up to 2 GW, as the small capacity constraint or up to 4GW, as the large capacity constraint. The capacity constraint is, in fact, a parameter introduced to capture the impact of land availability on the spatial diversification of wind resources. This will be further explained in the results section.

2.3 Modeling of Power System (Conventional) Generation

In order to have a better understanding of the impact of wind fluctuation on thermal plants operation, knowledge of the mechanical operation of these plants and steam cycles, in general, are indispensible. Changing the output of steam plants which constitute coal (with the exception of IGCC plants) and nuclear plants, often referred to as "load cycling", can be very detrimental to the plant's lifetime and the boiler in particular (Lefton et al. 2006). Frequent cycling can render a steam plant inoperative within the first decade of its life. Therefore, the plant operator has to balance the need for dynamic response of the plant with the structural durability of its components.

Furthermore there is a time delay between the commitment of a plant and the point when it reaches its rated output. If the plant starts cold (i.e. having been offline for 48hr to 120hr) this transition can be longer and more costly. This becomes more pressing at substantial penetration of wind and forms the basis of the minimum generation constraint that will be discussed in this section.

In this study, a simplified model of power system generation has been used. It was too detailed and therefore unnecessary, for the purpose of this study, to consider the operational flexibility of the individual plants. As a matter of fact, it is desirable to have a reduced form model that allows rapid simulation and has transparent, easily interpreted assumptions.

Had it been necessary to model different types of plants (e.g. coal, nuclear, combined cycle, natural gas) in terms of minimum generation output and ramping capability, it would have required a close study of the hourly power output of the individual plants in Michigan. These data are compiled by a private company (Platts) and are not publicly available.

Instead of dealing with individual plants flexibility, this study models the aggregate output of the generation fleet by considering two key parameters of the system.

(1) Minimum Generation Level

(2) Ramping Capability

These two parameters, as it will be explained next, approximate the aggregate response of the conventional generation without getting into the details of the characteristics of distinct types of plants and also the export/import issue.

2.3.1 Minimum Generation Level

Minimum generation level (*MGL*) is defined in the model as the level below which the conventional units, considered in aggregate, cannot be dispatched. A study by Denholm and Margolis observe that "data from the PJM system for 2003 indicates that the wholesale price of electricity fell to levels well below the cost of fuel on a number of occasions, with the price even going negative during several hours of the year (PJM 2005). These events occurred near the normal minimum load of roughly 36% of peak load for that year, but appear to happen at levels of demand as high as 40% of peak load. This would imply a flexibility factor of about 60–65% for the PJM system." (Denholm et al. 2007)

A different approach than that of Denholm and Margolis was taken in this study. *MGL* has to be a function of the total committed plants and unit commitment varies day by day. This disparity is even more pronounced across seasons. Figure 2.10 shows load variation in typical high demand

and low demand days from the dataset. There are undoubtedly more units committed during a high demand day than a low demand day. Also units are dispatched closer to their nominal capacity in high demand days. *MGL* should be modeled in a way to reflect these complexities. Furthermore to avoid modeling market pricing complexities, *MGL* was defined as a percentage of the daily minimum load and parameterized by β (2.5).

$$MGL_i = \beta \min(Load_{t \in D_i}) \qquad 0 \le \beta \le 1.00$$
$$D_i = \text{hours in the } i^{\text{th}} \text{ day of the dataset} \tag{2.5}$$

β is a parameter that can be varied to adjust the size of *MGL*. Typically in power systems with substantial penetration of hydropower, such as the Nordic grid (with 60% of electricity served by hydropower) β can be very small. In power systems with substantial penetration of inflexible nuclear power, β is expected to be closer to the upper bound. For Michigan which its electricity fuel mix is roughly 70% coal, 20% nuclear and 10% natural gas β is expected to be in the middle of the range.

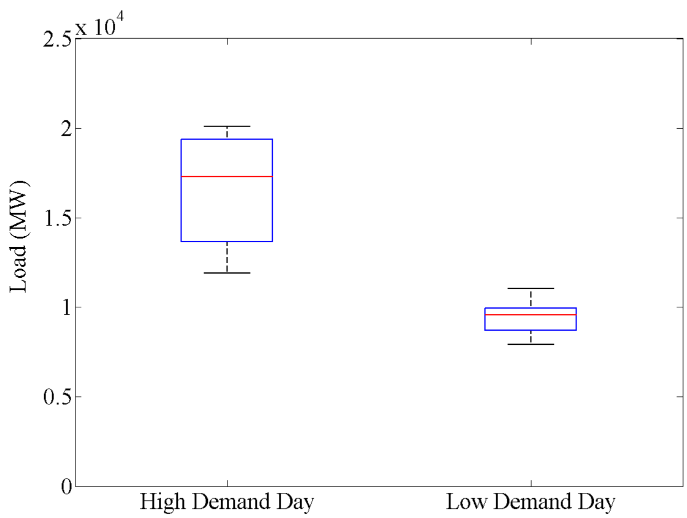


Figure 2.10: Load variation in typical high and low demand days.
(The red bars mark the median and the black bars mark the upper and lower bound of the load)

2.3.2 Ramping Capability

The second parameter of the power system generation was defined as its hourly upward and downward ramping capability. Downward ramping constraint is an expression of the energy spillage or the thermal stress that operator of a flexible generation unit is unwilling to exceed, aggregated at the power system level. The upward ramping constraint is an expression of the limited availability of the spinning reserves and the response time of the auxiliary generation units to fluctuation in load and wind.

The ramping capability of a system is determined by the number of online units with load following capability. It is intuitive to assume that more units with load following capability are committed on high demand days than on low demand days. Therefore, the ramping capability of a system is assumed as varying on a daily basis. The model in this study assumed that ramping capability of the conventional generation fleet is a constant times the maximum upward and downward load ramping at each day (2.6).

K=1 corresponds to the smallest (i.e. the most binding) ramping constraint which means wind energy is only integrated into the system to the extent that it does not cause the ramping of the modified load (load less wind less *MGL*) to exceed the maximum upward and downward ramping of load observed each day. In the experiments, *K*=2 corresponds to the largest (i.e. the least binding) ramping constraint.

$$\begin{aligned} &UPRC_i = K \max\left(Load_{t+1\in D_i} - Load_{t\in D_i}\right) \\ &DNRC_i = K \max\left(Load_{t-1\in D_i} - Load_{t\in D_i}\right) \\ &D_i = \text{hours in the } i^{\text{th}} \text{ day of the dataset} \\ &K \geq 1 \end{aligned} \qquad (2.6)$$

2.4 Curtailment and the Optimization Process

Wind generation is curtailed to (1) provide enhanced system security at times of over-generation by keeping conventional generators online and avoid costs associated with de-committing conventional generators for short periods of time, (2) limit the ramp rates of the conventional generation fleet either to avoid exceeding the physical limits of the generation capacity or to maintain system efficiency and (3) avoid transmission congestion following network faults and other system failures.

The focus of this study is on the impact of generation system flexibility on wind curtailment and therefore, the complexities of transmission system effects were not considered. Furthermore, the bulk of wind curtailment, particularly at higher penetration levels is expected to occur due to insufficient flexibility of the generation fleet and not the transmission congestion (Milligan et al. 2008).

The first two conditions are expected to be mitigated by spatial diversification of wind capacity to regions that exhibit a consistently higher correlation with the load whereas transmission congestion seems to be an obstacle for spatial diversification of the capacity.

The power system model defined with *MGL* and ramping capability as parameters governing the flexibility of the generation fleet acts as a constraint shaping the optimal spatial configuration of wind capacity.

The the optimization program allocates clusters of 100MW to maximize the objective function. The objective function is the utilization of the aggregate wind capacity expressed in the Effective Capacity Factor (CF_E) (2.7). CF_E is the total of wind generation less wind curtailment divided by the installed capacity. Over the course of the optimization violation of the *MGL* and ramping constraints results in wind curtailment and therefore reduces the CF_E. In (2.7), X_i is the installed capacity at site i and W_i is the normalized hourly output at site i.

Ideally optimization process should allocate every single turbine but since this would have dramatically increased the computational time without adding much precision to the final results, cluster size of 100MW was chosen to be allocated at each step.

The wind penetration is increased to 50% and the optimization results including wind surplus, CF_E, the capacity allocation for each site are recorded. Capacity constraint, as discussed earlier, allows two values of 2GW for small capacity constraint and 4GW for large capacity constraint.

$$CF_E(X_1, X_2, ..., X_n) = \frac{\frac{1}{T}\sum_{t=1}^{T}[(X_1W_{1,t} + X_2W_{2,t} + ... + X_nW_{n,t}) - S_t - URS_t - DRS_t]}{(X_1 + X_2 + ... + X_n) \times T} \tag{2.7}$$

Since this study also considers the energy storage (to be introduced in the next subsection), hereafter wind curtailment is substituted with a general term of wind surplus which can be either discarded as in the case of curtailment (e.g. blade feathering) or stored.

Wind Surplus in this model has three components, surplus due to violation of (1) the minimum generation level, (2) the upward ramping constraint and (3) the downward ramping constraint. These three components are denoted by terms *S*, *URS* and *DRS* respectively.

S, wind surplus due to violation of *MGL*, is computed by subtracting wind generation plus *MGL* from the load whenever these two terms combined exceeds the load (2.8). Whenever the load exceeds the wind generation plus *MGL*, an intermediary term, *DEF*, stores the deficit (2.9). This deficit is met by flexible generation and helps determine the ramping surplus. The absolute rate of change in *DEF* should not exceed the upward and downward ramping capabilities of the system which are determined on a daily basis.

(2.8) $$S_t = Max(MGL_i + X_1W_{1,t} + X_2W_{2,t} + \ldots + X_nW_{n,t} - L_t, 0)$$

(2.9) $$DEF_t = Load - [MGL_i + (X_1W_{1,t} + X_2W_{2,t} + \ldots + X_nW_{n,t}) - S_t]$$

It is assumed that wind forecast for a definite number of hours ahead is available for each site. This is necessary for computation of wind surplus due to violation of the upward ramping constraint. *URS* is computed by adjusting (increasing) the *DEF* in the upcoming hours so that the rate of change in *DEF* is kept below the upward ramping capability. For example if the rate of change of *DEF* from the current hour to two hours ahead exceeds twice the ramping capability, then wind is curtailed at the current hour to increase DEF_t to such a level that the rate of change ($DEF_{t+2} - DEF_t$) would be below $2 \times UPRC_i$ (2.10). In the model and with the existing dataset, the required hours ahead that should be checked (i.e. *m* in (2.10)) did not exceed two.

(2.10) $$URS_i = Max(DEF_{t+1} - DEF_t - UPRC_i, \ldots, DEF_{t+r} - DEF_t - r \times UPRC_i, 0) \quad r = 1, 2, \ldots, m$$

Once the necessary adjustment in *DEF* at the current hour was made to account for wind surplus due to upward ramping capability of flexible generation (2.11), the downward ramping constraint is checked to see if *DEF* needs further increase. DEF_t is compared to DEF_{t-1} to determine *DRS*, wind surplus due to the violation of the downward ramping constraint (2.12).

(2.11) $$DEF_t' = Load - [MGL_i + (X_1 W_{1,t} + X_2 W_{2,t} + \ldots + X_n W_{n,t}) - S_t - URS_i]$$
$$DEF' \text{:Adjusted } DEF \text{ to account for Upward Ramping Surplus}$$

(2.12) $$DRS_t = Max(DEF_{t-1}' - DEF_t' - DNRC_{t \in D_i}, 0)$$

2.5 Energy Storage

Storage is often referred to as a source of power system flexibility with an emerging application to wind power integration. However some studies have dismissed storage as too costly an option to be feasible in the coming decades. "Unfortunately the high cost of storage systems limits the situation in which they are useful. … business case for constructing high capacity, long duration energy storage solely to solve wind integration issues has been limited to very remote or island systems." (Douglas 2006)

Despite the gloomy picture for the energy storage option in near future, more recent studies argue that storage could lower the cost of electricity and therefore would be an integral part of future power systems with high penetration of wind power (Sullivan 2008).

This study considers storage coupled with the non-optimal base case configuration to measure the benefits of spatial diversification of wind capacity and enable the comparison between the base-case and optimal configurations.

No specific technology is assumed for the storage system. However, it was assumed to have an 81% (0.9 × 0.9) round trip efficiency which is typical of most battery technologies. In other words, 10% of the total wind surplus that charges the storage system is lost. Similarly 10% of the already stored energy is lost during discharging to the grid (2.13). The power to energy ratio is assumed to be 1 which means that the storage system can discharge and charge fully within an hour, the smallest time frame considered in this study. In (2.13), DEF_t is the deficit after *Srpls*, total surplus due to the violations of ramping constraint and *MGL*, have been taken into account. ST_t is the stored energy at time t and *CS* is the total energy capacity of the storage system.

(2.13) $$ST_t = \min(ST_{t-1} + 0.9 Srpls_t,\ CS) \text{ for } Srpls_t > 0$$
$$ST_t = ST_{t-1} - \min(ST_{t-1}, \frac{DEF_t}{0.9}) \text{ for } Srpls_t = 0$$

2.6 Simplifying Assumptions in the Model

Similar to any other model that tries to simplify the reality but often fails to include some subtle, though important, aspects of the objective world, our model is limited in some aspects too.

The first major simplifying assumption of the model is the absence of imports and exports to neighboring regions. No balancing area, unless it serves an isolated island, totally relies on its generation resources to serve the load. In fact it is quite common to schedule, usually 24 hours in advance electricity imports and exports. For a balancing area with high penetration of wind power, this requires an accurate forecast of wind.

The second simplifying assumption relates to unit commitment and dispatch in the model. In the presence of a perfectly accurate wind forecast, one may argue that units can be committed and dispatched so as to integrate a considerable portion of what would otherwise end up as wind surplus. Not to dispute this fact, it has to be understood that wind power still has some residual stochasticity and that there is always some error in the forecast. The more concentrated the wind installations are, the greater the error of forecast would be. In any case, the values of β can be adjusted for a conservative approximation of the behavior of the generation fleet.

III. Results Analysis

In order to assess the potential benefits of optimal spatial diversification of wind capacity, two sets of experiments were designed.

1. Observing the differences between the optimal and base case configurations subject to varying degrees of power system constraints (*MGL* and ramping constraints) as a function of wind power penetration.

2. Measuring the amount of storage required in the base-case configuration to achieve the same level of CF_E as in the optimal configurations, subject to varying degrees of power system constraints (*MGL* and ramping constraints), and as a function of installed wind capacity.

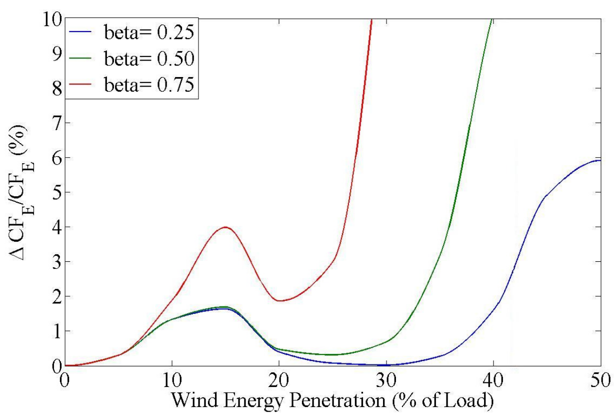
In the first set of experiments, the wind penetration level is changing and therefore the corresponding capacity in the optimal configuration is, expectedly, lower than the capacity in the base-case configuration. And this explains the improvement in the CF_E in the optimal case (i.e. less capacity installed for the same level of wind energy integrated into the system).

In the second set of experiments, the same quantities of wind capacity with 1GW increments are installed (1) under the base-case scenario and (2) optimally. At each level of wind capacity development, improvement in CF_E in the optimal configuration (more wind energy integrated to the system for the same level of wind capacity) is obtained. The required storage capacity that would result in the same CF_E improvement in the base-case configuration is then observed as a function of installed capacity.

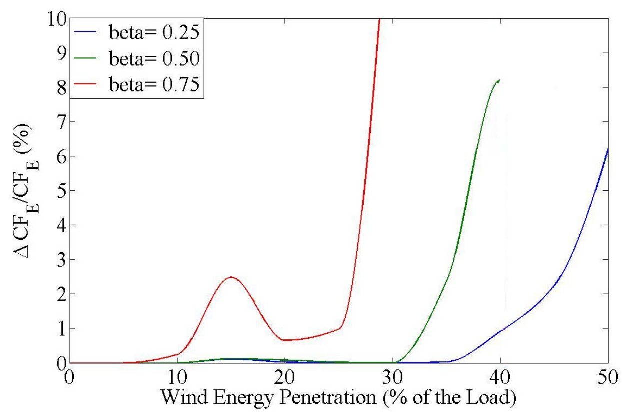
The idea behind the second set of experiments, introducing storage, is to understand how much need for storage can be avoided by optimal spatial diversification of wind capacity. As mentioned earlier storage is a highly costly option for enhancing power system flexibility. Nonetheless, there is little doubt that it is going to be utilized in future power systems to mitigate wind power intermittency issues.

3.1 Low Penetration of Wind Power and the Impact of Ramping Constraint

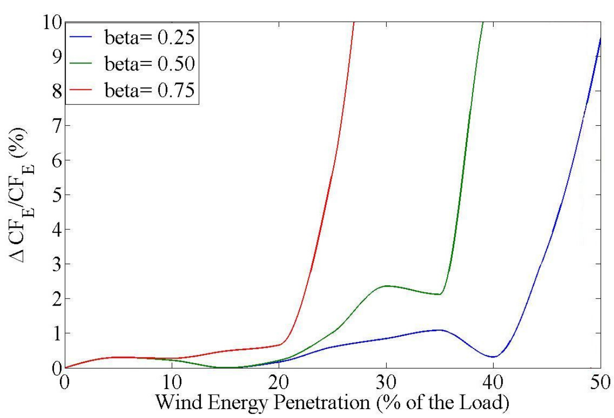
In both sets of experiments, small ramping constraint (i.e. K=1 in (2.6)) resulted in an unexpected CF_E improvement in the optimal configuration. For the first set of experiments in which the changes are observed as a function of wind penetration, this improvement, defined as $\Delta CF_E/(CF_{E\text{-}Base\ Case})$ reaches its peak at around 15% of wind penetration and declines thereafter. The CF_E improvement at 15% penetration is varying between 2% to 4% depending on the *MGL* for high capacity constraint (4GW)(figure 3.1 (a) and (b)).



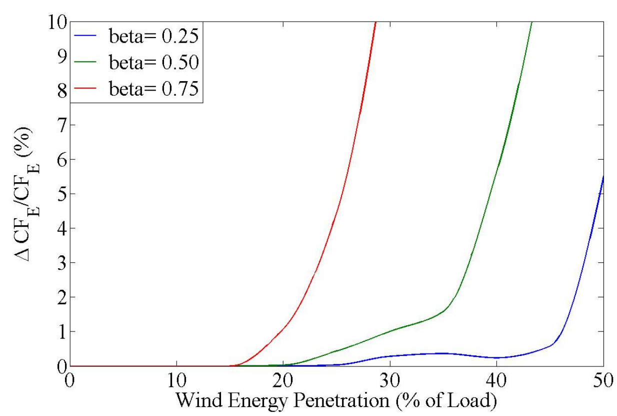
(a) Capacity Constraint = 4GW , K=1



(b) Capacity Constraint = 4GW , K=2



(c) Capacity Constraint = 2GW , K=1



(d) Capacity Constraint = 2GW , K=2

Figure 3.1: The improvement of CF_E in the optimal configuration

For the small capacity constraint (2GW) although this pattern still exists, it is far less pronounced (figure 11 (c) and (d)) and occurs at lower penetration levels of 5% to 10%. At small capacity constraint, spatial diversity is forced upon the base-case. In other words, more sites are selected solely because the capacity for development at each site is more limited than the high capacity constraint configurations. This forced spatial diversity mitigates the ramping constraint complications. Therefore the peak in CF_E improvement occurs at lower levels of penetration and is less pronounced for configurations corresponding to the small capacity constraint.

It is noteworthy that at low levels of wind penetration (under 20%) subject to the small ramping constraint (i.e. K=1 in (2.6)), the percentage of wind surplus due to violation of the ramping constraint varies from 100% to 90% for β= 0.25 and β=0.50. This figure drops to 40% at 15% penetration for β=0.75. For the large ramping constraint (i.e. K=2 in (2.6)) these figures are in the range of 0% to 5%. Altogether, the ramping capability of the system significantly influences the benefits of the optimal configurations over the base-case configurations at low levels of wind penetration.

The raw values of CF_E for small and large capacity and ramping constraints are demonstrated in figure 3.2.

The second set of experiments which involves adding storage capacity in the base case configuration to reach the same level of CF_E as in the optimal configuration also resulted in similar but slightly different patterns.

Figure 3.3 shows the changes in the ratio of required storage capacity to installed capacity of wind for 1GW increments of installed wind capacity. β, a parameter governing the minimum generation level (MGL), is set to 0.25. This value of β corresponds to a relatively flexible power system typically, although not necessarily, with substantial penetration of hydropower as in the case of the Nordic grid.

In the first 5 GW of installed capacity, the ratio is significantly higher for the configurations that are subject to the small ramping constraint (i.e. K=1 in (2.6)) than those which have a larger ramping constraint (i.e. K=2 in (2.6)). This pattern is observed independent of the capacity constraint, although it is more pronounced in the large capacity constraint (4GW).

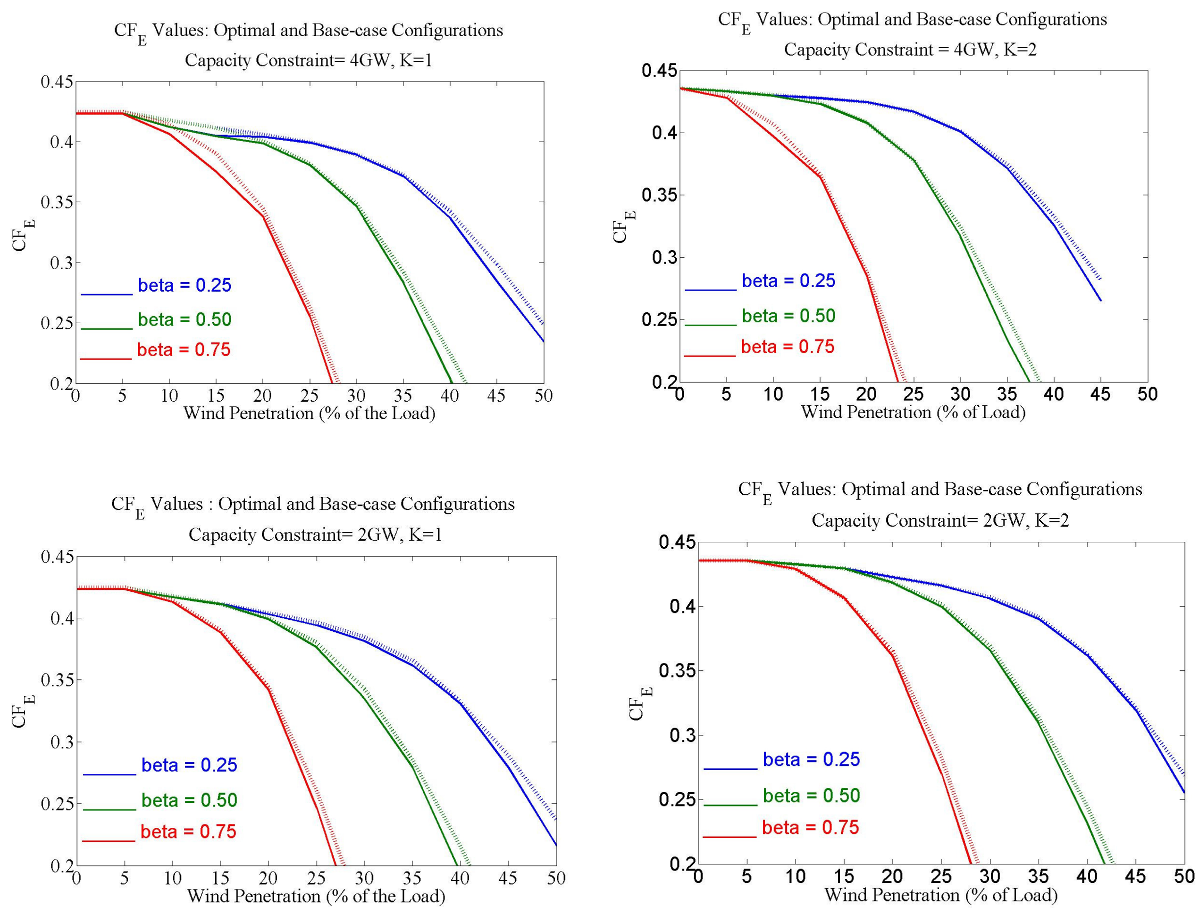


Figure 3.2: The CF_E values for optimal (dotted line) and base-case (solid line) configurations

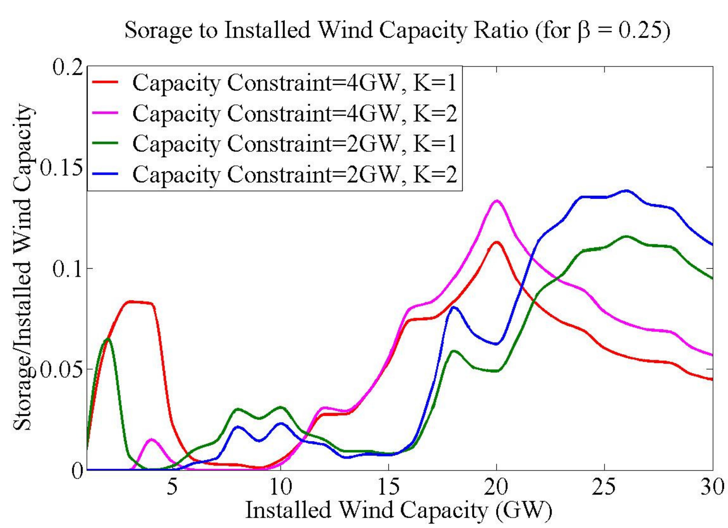


Figure 3.3: Required storage to installed wind capacity ration for β= 0.25

3.2 Medium Penetration of Wind Power, the receding impact of ramping and the emerging significance of Minimum Generation Level

As the penetration of wind increases past 15%, the ramping constraint does not influence the CF_E in the base-case and the optimal configurations as strongly as before.

At medium levels of wind penetration (20% to 30%) subject to small ramping constraint (i.e. K=1 in (2.6)), the percentage of wind surplus due to violation of ramping constraint gets smaller and is in the range of 50% to 5% for β= 0.50 and β=0.75. This figure varies from 90% to 75% for β= 0.25. This is because at such a low *MGL*, wind surplus due to over-generation is still relatively infrequent.

With still considerable wind surplus resulting from violation of the ramping constraint, the patterns seen at low wind penetration are no longer present at medium penetration of wind power. This can be explained by the fact that a certain level of diversification of wind capacity has already taken place at medium levels of penetration. In figure 11, the improvement in CF_E almost drops to zero for β=0.25 and β =0.50 (in the *MGL* constraint) between 20% and 30% penetration and undergoes a sharp decline for β=0.75 at around 20% penetration.

In fact, at such medium levels of penetration, installed capacity in the optimal and base case allocations are not significantly different in terms of sites that have been allocated and the allocated capacity to each site.

However, the duration of the transition phase of the development, characterized by very small improvement of CF_E in the optimal configuration, is influenced by β. For β=0.75 which characterizes a relatively inflexible power system generation (in terms of *MGL*), this transition is shorter and at 25% penetration onwards a sharp increase in the improvement of CF_E in the optimal case is observed.

At lower values of β, this transition starts at 20% penetration and lasts up to 30 to 40% penetration.

The second set of experiments involving storage, exhibit the same patterns with some variations. In figure 3.2 the installed capacity range of 5GW to 15GW (for β =0.25) is characterized by a decline in the ratio of the required storage to the installed wind capacity. For the configurations subject to the small capacity constraint (2GW), there is a local peak in the storage ratio at around 10GW. As it will be discussed later, this is due to the particular set of sites used in this study.

It must be noted that the wind surplus at low wind capacity installation (penetration) is mainly caused by violation of ramping constraints whereas in medium levels of wind capacity installation (penetration) and particularly for higher values of β parameter, this shifts gradually to violation of the minimum generation level.

However, ramping capability of the system (parameterized by K in (2.6)) manifests itself in the transition phase by the higher ratio of required storage to installed wind capacity for the large ramping constraint (i.e. K=2 in (2.6)). This was the reverse at low levels of installed capacity because the ramping constraint violation was almost the sole cause of wind surplus and therefore the large ramping constraint resulted in relatively very small ratios of storage capacity to installed wind capacity.

One potential explanation for the observed lower ratios of storage to installed wind capacity for configurations that are subject to the small ramping constraint (i.e. K=1 in (2.6)) at medium levels of wind capacity development is the higher utilization of storage capacity. While only a small fraction of the total wind surplus is due to violation of ramping constraints at higher levels of installed wind capacity, the storage capacity is more available to absorb that portion of the surplus. This is because violations of the ramping and the *MGL* constraints tend not to coincide in this model. Figure 3.4 shows a typical temporal pattern of surplus due to the violation of the ramping and the *MGL* constraints as a function of the hours of a three day period.

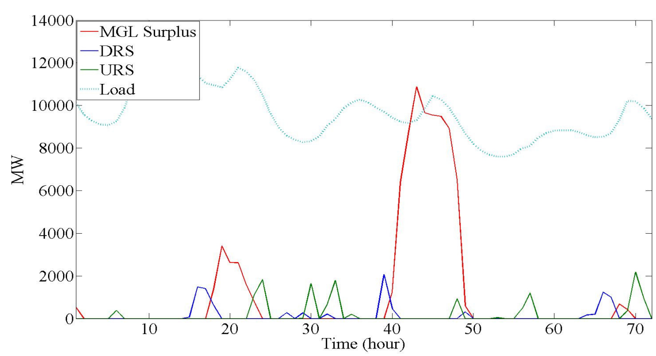


Figure 3.4: typical patterns of surplus due to the violations of the ramping and the *MGL* constraints

3.3 High penetration of Wind Power and the role of Minimum Generation Level

Violation of the *MGL* becomes almost the sole cause of wind surplus at high levels of wind penetration. The percentage of surplus due to violation of ramping constraint at very high penetration levels and subject to the small ramping constraint (i.e. K=1 in (2.6)) varies between 1% to 4% of the total wind surplus depending on the value of β and the level of penetration.

As it is seen in figures 3.1, higher values of β parameter correspond to higher slope values of the improvement of CF_E (in percent).

This is somewhat different in the second set of experiments involving storage and wind capacity (as opposed wind penetration). As in figure 3.3, the ratio of required storage to installed wind capacity increases sharply at higher levels of installed capacity, however, it declines after reaching its peaks at 20GW and 25 GW for large (4GW) and small (2GW) capacity constraints respectively.

This can be explained by the fact that some sites with modest energy captures (i.e. not extremely high capacity factors) contribute significantly to the optimal configuration whereas sites with higher capacity factor contribute less. When the base-case configuration fully develops highest capacity factor sites and starts building capacity at these medium capacity factor sites it gets closer to the optimal configuration. As a result, the storage to installed wind capacity ratio drops as these sites are being developed.

Table 3.1 shows the contribution of individual sites in the optimal and base-case configurations having 30GW of installed wind capacity for β=0.25, capacity constraint of 4GW and small ramping constraint (i.e. K=1 in (2.6)).

Subject to the above constraints, the optimal configuration does not allocate the full capacity allowed by the capacity constraint (4GW) to site 3, 4 and 5 but fully develops sites 6 and 8 which have substantially lower energy capture. As the base case configuration, having exhausted the top capacity factor sites, starts developing sites 6, 7 and 8 consecutively, the CF_E of the base case configuration gets closer to that of the optimal configuration. As a result, the ratio of the required storage to installed wind capacity drops as soon as the base case starts developing those sites.

Depending on the wind regime of the individual sites and their contribution to the optimal configuration, the benefits of optimal spatial diversification, measured against the spatially less diverse, business-as-usual scenario may experience ups and downs over the course of wind power development in a region.

However, it might be tentatively suggested that at high levels of wind capacity installations, the storage capacity is utilized more efficiently and therefore the drop in the ratio of the required storage to installed wind capacity is partly due to this higher utilization of the storage capacity.

More investigation of the result is required to explain these complexities and illuminate the actual processes at work that cause such unexpected drops in the ratio of the required storage to installed wind capacity at high levels of installed wind capacity.

Site Index	Capacity Factor	Optimal Configuration Installed Capacity (GW)	Base-case Configuration Installed Capacity (GW)
1	0.4356	4000	4000
2	0.4264	4000	4000
3	0.4045	2600	4000
4	0.4025	1700	4000
5	0.4014	500	4000
6	0.3958	4000	4000
7	0.3928	3100	4000
8	0.3728	4000	2000
9	0.3699	0	0
10	0.3646	0	0
11	0.3645	0	0
12	0.3643	0	0
13	0.3571	0	0
14	0.3538	0	0
15	0.3525	300	0
16	0.3524	4000	0
17	0.351	0	0
18	0.3503	0	0
19	0.3503	1400	0
20	0.3495	200	0
21	0.3463	0	0
22	0.3444	0	0
23	0.3419	200	0
24	0.3348	0	0
25	0.3338	0	0

Table 3.1: Optimal and base-case allocation of 30GW for β=0.25, K=1 and large capacity constraint (4GW)

IV. Conclusions and Future Study

4.1 Conclusions

So far, a close analysis of the results of these two sets of experiments, one measuring the improvement in CF_E from base-case to optimal configurations as a function of wind penetration and the second measuring the ratio of the required storage to the installed wind capacity as function of installed wind capacity, has demonstrated tangible benefits of the optimal spatial diversification of wind capacity at low and high levels of wind power penetration (installed capacity).

The ramping capability of the system determines the extent over which a system would benefit from optimal spatial diversification of wind capacity at low wind penetrations (installed capacity). This is a significant finding with immediate practical implications for systems planning to expand the wind capacity. As it has been the case in many regions including the Lower Peninsula of Michigan, most wind development plans, some approved by MISO and would be installed within the next couple of years, are in the thumb area. This area apparently has the highest energy capture in Michigan (not considering the offshore resources) and is closer to major load centers in South East Michigan than potential sites on the western coast of Michigan.

However, concentration of large wind capacity subject to specific wind patterns of the Thumb area would undoubtedly cause extreme fluctuation of the aggregate wind output. Under such circumstances, the operational reserve capacity of the system should be dramatically increased or otherwise wind curtailment would be inevitable. This is at least what the result of this study shows.

Based on the specific set of sites used for this study, simultaneous development of wind capacity at sites other than the single highest capacity factor site can substantially mitigate the wind curtailment due to the ramping constraints at low levels of wind penetration. The wind generation at these other sites usually has a low correlation with the wind generation at the highest capacity factor site.

As further wind penetration targets are reached with more sites being developed, the ramping complications recedes to the background. At medium levels of wind capacity development, certain degree of spatial diversification is achieved even with the business-as-usual scenario of prioritizing the sites according to their energy capture, what was referred to in this thesis as the base-case configuration. In other words, certain degree of spatial diversity is forced upon the base-case configuration by the limited availability of land at each site.

At substantially higher levels of wind penetration, say 25% to 30%, the minimum generation level, characterizing another aspect of the inflexibility of the generation fleet comes to the forefront causing substantial wind curtailment. Under such a condition, the optimal diversification of wind capacity results in higher utilization of wind capacity (i.e. more wind energy integrated with less installed wind capacity).

As with the case of storage capacity used to save costs associated with developing a greater number of sites, there are still uncertainties involving how to accurately interpret the results. However, this is clear that power systems with limited ramping capabilities require a relatively high capacity of storage to offset the benefits of spatial diversification at low levels of installed wind capacity. It is still an open question how the ratio of storage to wind capacity changes at high levels of installed wind capacity. This question is complex since the results, discussed earlier, are for the specific set of sites used in this study and the understanding of how the storage capacity would be utilized at high levels of installed wind capacity is limited.

Moreover, there is a need for further analysis of the data. It has to be examined if the results would exhibit similar patterns for shorter periods of time, say a year. Also, it would be helpful to do a sensitivity analysis for the parameters in the model. The bottom-line is to establish certainty about the observed patterns and to verify that these patterns exist independent of subtleties in the model and the specific set of data used in this study. Only once these uncertainties are addressed, the results can be generalized to other power systems planning large-scale integration of wind power.

These conclusions, far from being final, foretell a fundamental change in how the wind power would be traded in the market as the wind penetration increases. The way “take-and-pay” contracts currently work has to be overhauled to force wind developers to internalize the cost of wind curtailment. This would encourage wind developers to choose sites that are not necessarily of the highest nominal energy capture but have wind generation patterns that result in higher utilization of the installed capacity.

In the meantime, Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) who are typically responsible for the control, planning and development of power system ancillary devices and transmission assets have a crucial role to play in this process. This includes building the required transmission capacity prior to the full development of the spatial configuration.

Only through fundamental reorganization of the electricity market and the long-term planning of the power system infrastructure, the huge resources that go into the development of large-scale wind capacity can be most efficiently utilized.

4.2 Future Study

A more specific and quantitative method of determination of the impact of ramping constraint at both low and high levels of wind penetration is still required to concretely establish the relation of wind curtailment to the ramping and *MGL* constraints.

The role of storage has to be investigated at a greater detail to more accurately interpret the patterns observed in the ratio of storage to installed wind capacity in figure 3.3.

Moreover the role that the specific set of sites has played needs to be studied more concretely. One way to illuminate how closely the results depend on this specific set of sites is to eliminate some sites on a random basis and to observe how all these patterns, discussed in section 3, would change. This procedure is in progress and soon it would become clear to what extent these results can be generalized to other power systems and to what extent these are just the outcome of the specific set of data and possibly modeling approach that have been used in this study.

These two sets of experiments were designed to measure the benefits of optimal spatial diversification of wind resources over the dominant trend in the wind industry. There could be more ingenious ways to objectify these benefits and this is an area for further work too.

With the load and the wind speed data (at the hub height) being available, this study can be easily extended to other aspects of wind integration studies, including reliability assessment. It would be interesting to examine how close the optimal configurations in this study would be to the optimal configuration that maximizes the capacity value of wind.

Finally, it would be interesting to extend the examination of the benefits of optimal diversification into power system economics. Such a study has to quantify the economic value of wind and measure the extra cost of building the required infrastructure in a larger number of sites as in the case of the optimally diversified configuration. Furthermore, this study should account for the changes in power system's reserve and transmission capacity for the optimal and the base-case configurations. This analysis would also require a more detailed unit commitment and dispatch which can be constructed using MISO bidding data (of individual generators) which is publicly available. This economic analysis would be an essential part of a comprehensive cost-benefit analysis of the optimal spatial diversification versus the business-as-usual concentration of wind capacity.

This thesis is part of an ongoing research that ultimately leads to a journal publication in fall 2009.

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