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Utility-scale Wind Power: Impacts of Increased Penetration

Lawrence Pitt, G. Cornelis van Kooten, Murray Love and Ned Djilali

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REPA Research Group
Department of Economics
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PO Box 1700 STN CSC
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UTILITY-SCALE WIND POWER: IMPACTS OF INCREASED PENETRATION

Lawrence Pitt, G. Cornelis van Kooten, Murray Love and Ned Djilali

Institute for Integrated Energy Systems (IESVic)
University of Victoria
Victoria BC, CANADA

ABSTRACT

Intermittent renewable energy sources such as wind, solar, run-of-river hydro, tidal streams and wave fluxes present interesting challenges when exploited in the production of electricity, which is then integrated into existing and future grids. We focus on wind energy systems because they have an emerging presence, with new installed capacity approaching 8 GW annually. We survey many studies and compile estimates of regulation, load following and unit commitment impacts on utility generating assets with increasing wind penetration. Reliability (system reserve), observed capacity factors and the effective capacity (ability to displace existing generation assets) of wind energy systems are discussed. A simple energy balance model and some results from utility-scale simulations illustrate the existence of a law of diminishing returns with respect to increasing wind penetration when measured by wind's effective capacity, fuel displacement or CO_2 abatement. A role for energy storage is clearly identified. Finally, the scale of wind energy systems is shown to be large for significant energy production and preliminary evidence is reviewed showing that extraction of energy from the atmospheric boundary layer by such systems, when penetration levels are significant, may have potential environmental impacts.

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INTRODUCTION

With upwards of 8 GW of nameplate wind turbine capacity being installed annually world wide, this form of electricity production deserves careful scrutiny. This paper presents results from a review of potential impacts introduced when wind generation becomes part of the generating portfolio of large utility systems. Power generation from wind has economic impacts for utilities due to the intermittent nature and spatial distribution of the wind resource (DeCarolis and Keith 2004). Furthermore, integration of significant percentages of fluctuating wind power into existing and future utility grid systems present unique challenges for the remaining generation mix to balance electricity supply and demand and to maintain reliability.

Prior to actual utility experience or serious attempts to model real utility-scale penetration of wind power, much speculation existed about the potential impacts of wind power. A perception exists that the variability and uncontrollability of wind make it unsuitable for widespread use as a large scale generating technology or that it would require MW for MW backup if it were used. On the other hand, perception is also widespread that wind power can be readily incorporated into existing grid systems with penetration levels of up to 20% or more without additional measures (Irish WEA 2000, EWEA 2003). Both perceptions turn out to be incorrect, as the results of recent work and experience will show.

First we examine two distinct metrics for wind energy systems – effective capacity (or capacity credit) and capacity factor. Then we discuss some of the systemic impacts of wind energy systems, especially those seen from the point of view of the conventional, non-wind generating plant. The role wind power can play in reducing CO_2 from power generation is also examined. We end with some mention of climate/meteorological impacts of wind power.

EFFECTIVE CAPACITY OF WIND FARMS

The effective capacity value of wind farms has been debated for many years and there is still no definitive definition or metric (Milligan 2004). The effective capacity is a measure of the generator's contribution to system reliability and is tied to meeting peak loads during some specified period. The best guide seems to be observation of actual wind farm output, but this type of data is rarely published and difficult to come by. The difficulty of establishing an effective capacity value for wind energy systems is rooted in the variable nature of the wind resource. The capacity factor, on the other hand, is well defined and is the integral of the instantaneous power normalized by the integral of the nameplate capacity over the same period. It is best viewed as a measure of energy (MWh) production and its value is strongly influenced by the variable nature of the wind resource.

One simple approach to determine wind's effective capacity value is to estimate how much conventional capacity can be displaced by wind generation. Logic suggests that wind plants do not displace conventional plants megawatt for megawatt, since wind plants rarely produce energy at their rated output. Nor would they displace capacity equivalent to the wind plant's average capacity factor (up to ~35%), since the wind plant may experience several periods of near-zero output, in which case conventional generation equal in capacity to the wind plant's average output will be required.

An hourly load curve was obtained using load data for the ERCOT (Texas) electric system for the year 2000 (Casazza and Delea 2003). Wind speed data from SAMPSON datasets scaled to a hub height of 100m was used together with a transfer function representative of a GE 1.5 MW wind turbine to determine wind power production from a variety of sites in Texas.

A net load (demand minus wind production) was created and this was the load seen by the conventional generators. The conventional generators of ERCOT are idealized as a set of identical two-state (on/off) machines with a capacity of 500 MW each with a uniform reliability of 85%. That is, each generator, at any hour, will have a probability of 0.85 that it is in operation. For each hour's net load, a series of these generators would be "stacked" until the load curve was satisfied. If some generators were out of service in a given hour, the model would keep adding generators – keeping track of all capacity, whether operational or not – until the demand was met.

Having determined the range of capacity required to meet the original system demand, wind was put back into the generating mix, once again creating a net load curve for the other generators to follow, but this time in the context of the two-state reliability model, with 85% reliable 500 MW generators. The reliability model was run several times for each level of wind penetration to develop a picture of the conventional capacity requirements at each level. The average peak capacity requirement for each penetration level was then subtracted from the average no-wind peak capacity requirement.

The results, shown in Figure 1, are from a very simple model. The coarseness of a two-state 500 MW generator does not reflect the true responses of system generators. Second, these results only span a one-year time series of load data. Capacity values are sensitive to the correlation between peak load occurrence and the statistics of the system generators.

Nevertheless the main feature observed, the saturation of displaced generation capacity with increasing wind penetration, is notable. At low wind penetrations, wind does in fact reduce conventional capacity require-ments, but this effect declines as wind capacity increases.

Even when wind's capacity is equal to the peak system load of about 60 GW, it only displaces about 9 GW of conventional capacity, due to infrequent but unavoidable periods in which wind output is minimal. This saturation of capacity displacement is similar to that found in two recent studies of wind penetration into the UK and Irish systems (ILEX 2002, ESB 2004), as well as in our own modeling (Liu, van Kooten and Pitt 2005).

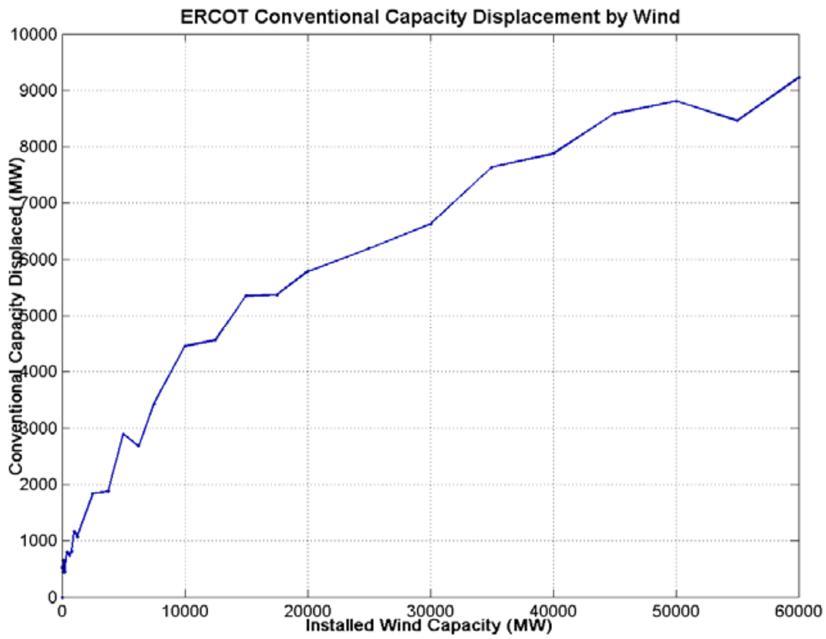


Figure 1: Conventional capacity displaced by wind

In a recent study (California Energy Commission 2003) examining the integration costs of California's proposed Renewable Portfolio Standards, a much more detailed analysis of *effective capacity credit* has been made. Using actual utility load data, forecast errors, wind farm output, area control errors (ACE), system frequency and many other factors, most at a resolution of one minute, a more rigorous effective load carrying capacity was determined for a variety of renewable generators. The goal is to develop capacity credit payment standards for potential projects and to assist system planners.

The study estimated that three wind farm aggregates, Altamont, San Gorgonio and Tehachpi, which collectively represent 75% of California's deployed wind capacity, had relative capacity credits of 26.0%, 23.9% and 22.0% respectively. This is not to be confused with a measured capacity factor – a value determined by integrating over a one-year period – which is in the range of 30% - 33% for these sites

In one of several large system operator studies of wind penetration now underway, the first phase of a study for the New York ISO (NYSERDA 2004) reports reliability estimates for 101 potential wind sites based on loss of load expectation when system loads exceed 90% of system peak load. Effective capacity ranged from 3% to 12% of nameplate wind capacity for the onshore sites and 23% for a prime site off Long Island.

No determination of effective capacity values was found from the European experience. However Holttinen (2003) estimated correlation coefficients for wind resources and loads across the NORDEL system. When looked at over a two-year period (2000 and 2001) wind and loads were very weakly correlated (0.16 – 0.3). The correlation for the critical peak load months of December, January and February was found generally to be negative (-0.11). Further, Holttinen (2003) reports a strong negative (-0.7) correlation between wind and temperature in Finland. Since peak load is temperature sensitive in Finland, the effective capacity value of wind would likely be very low. These results indicate that the effective capacity values determined by the aforementioned California study are not generally applicable to other circumstances and reflect the site-specific nature of the wind resource. Also it would appear prudent to have long time series data for wind-load correlation and effective capacity determinations.

OBSERVED CAPACITY FACTORS OF LARGE-SCALE WIND DEPLOYMENT

Capacity factor for wind energy systems is primarily a measure of energy production since experience suggests that wind plants have a high degree of availability (~98%). It is the resource availability that determines the energy production and hence the capacity factor for wind farms, and the value widely quoted is in the range of 30% to 35%. The form of 'fuel interruption' due to the variability of the wind is typically not a factor for thermal generators such as coal, gas or nuclear where the capacity factor is determined by the combination of planned (for maintenance) and forced (due to faults) shutdowns.

Production data from wind farms are not widely available. However, the OECD countries do report aggregate production information that is collected by the International Energy Agency (IEA 2004). Fig. 2 is a compilation of capacity factors for wind power production in each of the 26 countries of the OECD for 2001 and 2002. These capacity factor values will be biased to a lower value from the actual value since the method of reporting does not correct for any new capacity added in the calendar year. This means that, for example, if 100 MW of new capacity is brought on line in December with only one month (or less) of production, the capacity factor assumes the new capacity was available for the full calendar year.

The observed capacity factor values in Fig. 2 for wind power are quite striking. First, the deployment of 21.75 GW of wind power represents a robust sample of wind sites and recent turbine technology. The production from all this wind capacity amounted to 35.06 TWh and that corresponds to an observed capacity factor of 18%. This is almost half the ‘standard’ value quoted by almost every source; especially those describing wind power’s potential. The poorest production rate of 13% is from the largest single-country wind power plant, Germany.

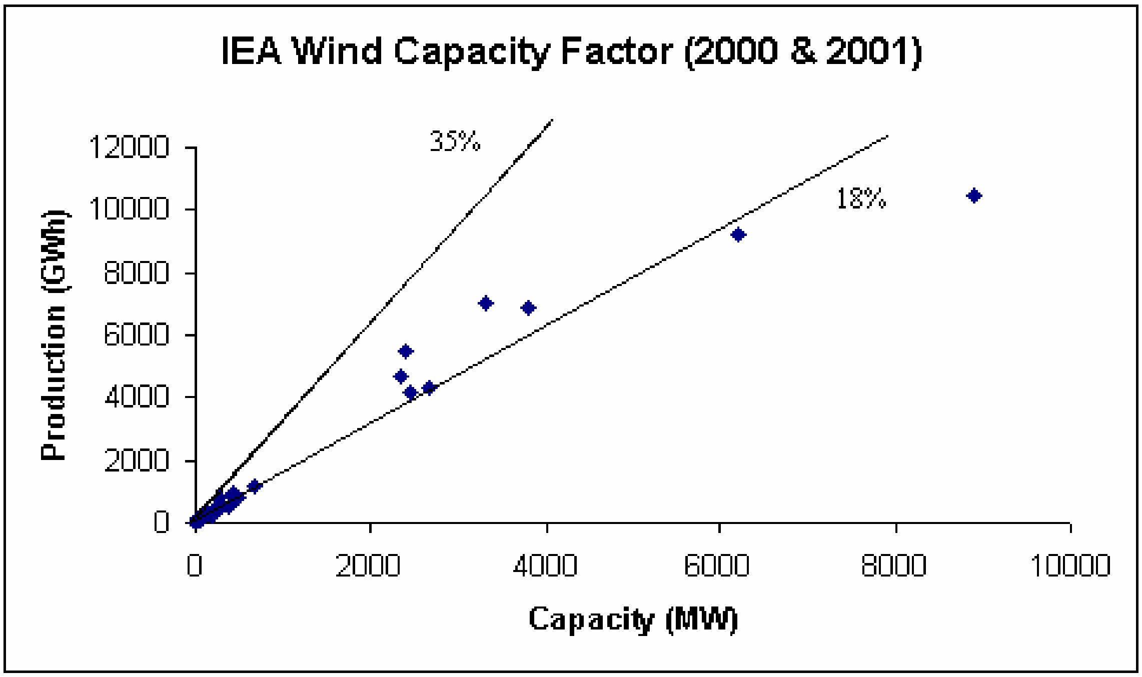


Fig. 2 IEA Wind Capacity Factors

The other countries with large wind capacity (Denmark, Spain and the United States) together average 21%. Very few capacity factors exceed 30% and they represent less than 0.5% of the installed capacity based. This suggests that the ‘standard’ capacity factor value of 30% to 35% is representative of the best sites, and they may be few in number. Once large-scale deployment of wind power infrastructure takes place, less optimum wind resources are sampled, resulting in the lower than expected capacity factor of 18%. The implication of the low value is quite profound for the economics of wind as well as the scale of impact – nearly twice as much wind capacity may be required to achieve the estimated production targets that government incentive policies and wind power planners have previously projected.

Actual production figures for two wind farms in Canada, recently made available by the Quebec Energy Board (Régie de l'énergie Quebec 2004) show further evidence of the challenge of developing wind power. Five years of production data for the 76 MW Cap Chat and 57 MW Matane wind farms, both located on the Gaspésie peninsula show that, once initial system faults are corrected, the best years of production result in average capacity values of 18%, although it was only 16.5% for the past 12 months. These sites were projected to have production levels resulting in estimated capacity factors exceeding 30%. The operator of these wind farms, Axor, is reported to be losing money due to much lower production than expected.

The dominant location for wind power infrastructure is presently on-shore or interior plains and the results presented here suggest that a rubric of ~20% capacity factor is more appropriate for this type of deployment. The limitation of land based wind power is recognized as there is growing interest in exploiting offshore environments because of presumed better wind resources resulting in improved capacity factors, anticipated to be in the 40% range. Of course this will come at the expense of more costly installations and intrusion of massive energy infrastructure into a potentially sensitive marine environment. Offshore wind is in the early stages of development. For example, the Danish 180 MW Horns Rev installation has taken six years to commission, including re-powering all 80 turbines due to saltwater intrusion. The controversial Cape Wind project in Nantucket sound has recently received a positive environmental assessment from the US Army Corps of Engineers. However, we await sufficient observations of actual offshore wind farm performance before drawing general conclusions regarding their production potential.

SYSTEMIC IMPACTS OF WIND ENERGY SYSTEMS

In this section we illustrate the variable nature of wind energy systems as seen by the entire power generation system. We employ the assumption that the rest of the system responds to the net load (i.e., actual load minus wind). This assumption is used widely in wind integration analyses and represents the way wind generated electricity is incorporated by utilities. At present there is little, if any, system control of wind farms. In Europe, wind generated electricity is referred to as 'bound production' and must be accommodated when available by the utility operator.

A second feature of the observed deployment of wind energy systems is the effect of geographic dispersion. Wind farms are located in a variety of locations and the wind resources are generally less correlated over distances of 200 km (Holttien 2003). This makes the aggregate output of geographically dispersed wind farms less volatile than if an equivalent wind plant was located in one place.

To evaluate the output from a large aggregate of wind farms, in terms of hour-to-hour volatility, the ERCOT system load was used as before. The output from the total wind plant is subtracted from the system load, resulting in a net load curve, which the rest of the system is forced to follow in order to maintain system stability. Figure 3 illustrates this for the ERCOT system with 10 GW of installed wind capacity. Not only is the net load curve far less predictable and smooth than the original load curve, it also spans a far larger range.

One way of measuring the changes in the required ramping rates of the other generators is to look at the distribution of the hourly changes in the load curve with varying levels of wind compared to that of the original no-wind curve. Two such distributions are shown in Figure 4. The top distribution is for a single wind plant located in Amarillo, Texas, while the bottom is for the six-location combined plant. Both distributions show the no-wind distribution for comparison (thick line). In the absence of large amounts of wind, the distribution of the hourly load differential has a high, narrow peak at zero and a standard deviation of 1.53 GW, with almost no hourly ramps greater than 5 GW.

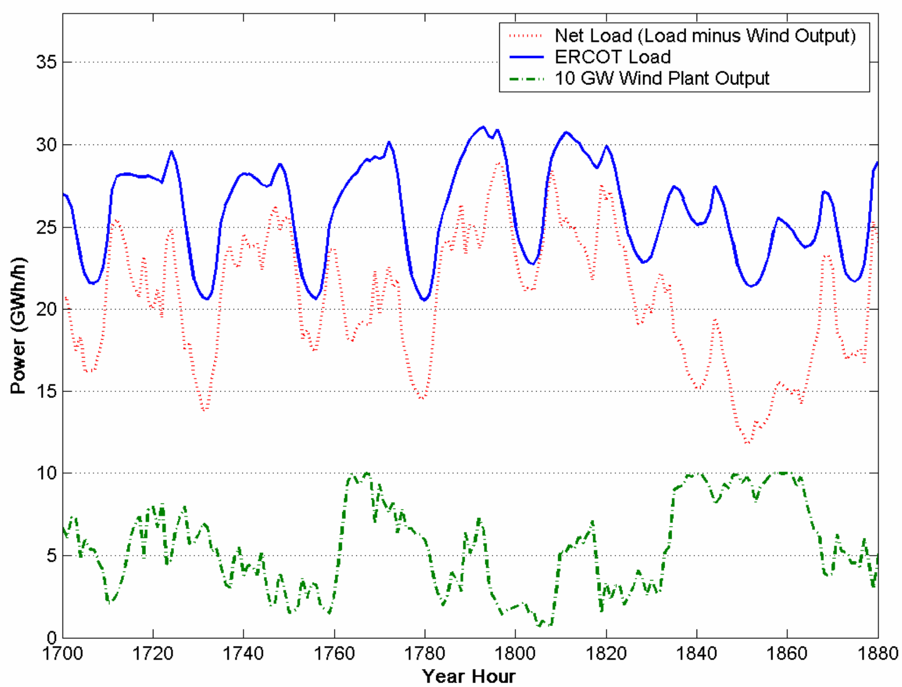
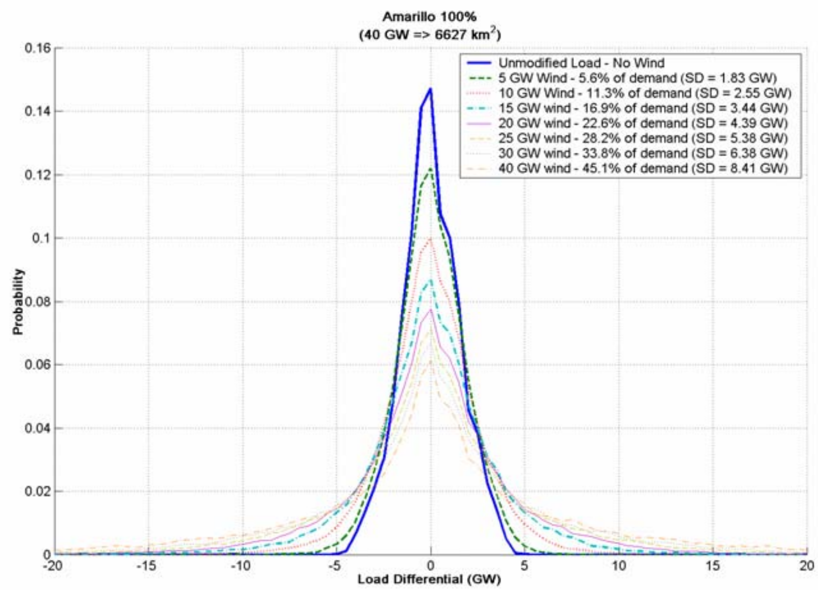


Fig 3. ERCOT (Texas) Load, Net Load and 10 GW Wind plant output



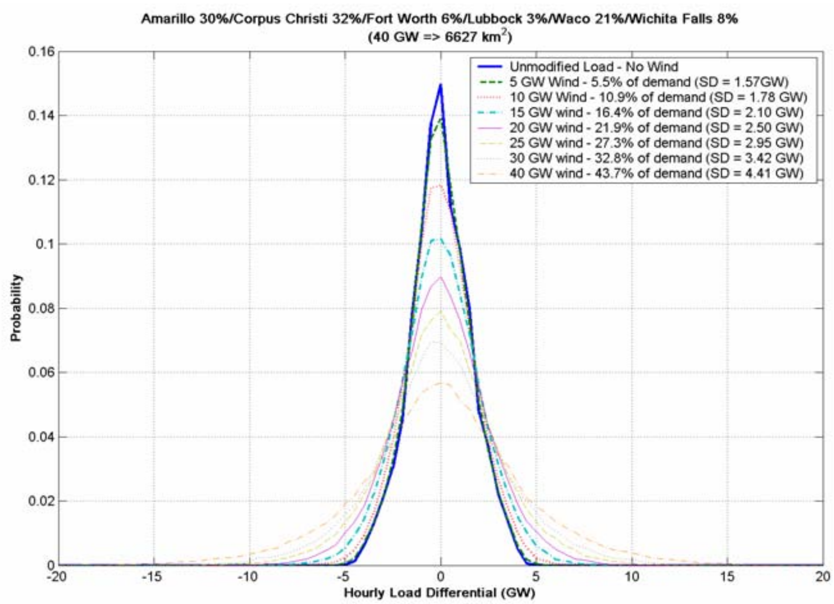


Figure 4: Top: single wind farm; Bottom: Same capacity dispersed across six sites

The shape of the differential distribution changes once substantial amounts of wind generation are incorporated into the net load curve. As wind penetration increases, the distribution becomes lower and flatter, indicating a greater number of large ramps. With 20 GW of installed wind capacity supplying 21%-23% of the annual ERCOT electricity consumption, the standard deviation of the load differential has risen to 4.39 GW introduced by the single Amarillo wind plant, and 2.35 GW for the distributed wind plant. Hence the geographic dispersion of wind farms helps reduce the ramping rates and consequent systemic impact of wind power.

Power system operation has to be considered one of the largest just-in-time systems where generation of electricity is balanced by system losses and loads. It is most helpful to look at how this happens over a range of timescales, from minutes to days, which is exactly the breakdown that system operators have adopted through many years of experience. System operators refer to *regulation* as balancing generation and loads on minute-by-minute timescales, *load following* as typically balancing hourly or sub-hourly demands, and *unit commitment* as balancing on a day- and/or week-ahead timescale. *System planning* looks ahead from four to 20 years and beyond.

Time series data needed to perform effective modeling of utility scale penetration of wind is lacking, at least in the public domain. The load time series data available is averaged hourly net system load (ERCOT data is the example we chose). As the regulation and load following behaviour of a system is determined on a sub-hourly time scale, impacts on these time scales have been integrated out of the data sample. More seriously, several key parameters needed accurately to characterize the conventional generation plant, such as start up costs, minimum loads and ramping rates, are difficult to ascertain because of their proprietary nature.

Several utility scale wind impact studies have been undertaken recently and are an indication of the pending deployment of significant wind energy systems (Parsons et al 2004, CEC 2003, MISO 2004). A summary of results is shown in Table 1. Comparison of the results is challenging due to the variety of utility generation mixes and study methodologies; however, the increasing number of studies across such a diverse group of utility circumstances is valuable because some general and robust conclusions can be drawn.

All the studies reviewed employ a common basic methodology: available wind speed data are converted to electrical output power via a representative wind turbine power curve and the results scaled up to some nameplate capacity to represent a particular wind farm. The number of wind farms required depends on the penetration level to be modeled. As before, the total wind output is subtracted from total load to produce a net load for the existing generation mix to follow. Typical time resolution is one hour, although some studies have higher time resolution wind and load data available. It is important to realize that this net load approach has the effect of yielding perfect wind forecasting and is good for an upper bound impact assessment. Some studies attempt to introduce some type of wind forecast error to add, in an uncorrelated fashion, to a set of load forecast errors. Then the proprietary utility-owned computer-simulation codes are run to determine reliability and dispatch. This is where the simulations differ in detail as some are trying to model market-based structures (the majority) versus an integrated structure, such as the Bonneville Power Authority (BPA). Nevertheless, they have a common approach: one code 'solves' for reliability to determine the capacity required for each hour (unit commitment time frame) and then the dispatch code is run to determine the hourly load following requirements and, if high resolution time series data are used, faster time scale regulation requirements are estimated. The codes are then run without wind present and differences are attributed as costs for incorporating wind.

Table 1. Summary of Ancilliary Costs of Wind

Study	Wind Penetration (%) (Normalized to peak load)	Total Ancilliary Cost ($/MWh of wind)
UWIG/Xcel	3.3	1.85
Pacificorp	20	5.50
BPA	7	1.47 – 2.27
We Energies I	4	1.90
We Energies II	29	2.92
Great River I	4.3	3.19
Great river II	16.6	4.53
California ISO (Phase I)	4	TBD
MISO	15	4.60

Some common trends appear from these system impact studies. First, even at very low penetration levels, wind power is detectable as a system cost. Surprisingly, wind power's ancillary costs remain modest per megawatt hour of wind production up to penetration levels of 20%. A key factor is spatial dispersion of wind farms and the resulting 'smoothing' of wind plant output. The wind forecast error is a major factor in load following and unit commitment timeframes, and how it combines with other system uncertainties such as load forecast errors is crucial for estimating system impacts.

A few caveats need to be mentioned as well. First, due to the back casting nature of the datasets, most studies do not have correlated (same year) wind and load data so major weather effects will not be modeled. Second, transmission constraints are not modeled. This second issue is the more important of the two.

The last two entries in Table 1, the California ISO study and the Minnesota ISO study, are distinct from the others. The CaISO (CEC 2003) study is part of a major detailed effort to ascertain how to apportion the ancillary costs and capacity credits for existing wind plants and the study is based on several years of actual wind farm output. Load following and unit commitment costs are to be determined in later phases.

The MISO study is interesting for several reasons. First, it is an extension of the first table entry and looks at integrating 1500 MW of wind into a likely 2010 system scenario. Second, it employs a meteorological model to simulate the wind flow regime with grid resolution ranging from 45 km to 5 km, and uses three year wind speed data sets with 10 minute resolution. High-resolution (one second) wind turbine output data were available. Simulated wind farm output could be compared to actual data to assess mean errors and improve the modeling effort before scaling up to the 1500 MW dispersed wind plant. Various wind-forecasting algorithms were employed. Load data sets spanned the same years as the wind data. No transmission constraints were used as in all previous work.

The MISO study probably offers one of the most detailed estimates of ancillary regulation costs as does the CaISO study. It clearly demonstrates the benefit of geographic dispersion of the wind plant and the uncorrelated nature of the resulting short time scale fluctuations from wind farms with respect to load fluctuations resulting in low regulation cost impact.

The bulk of the integration costs of 1500 MW of wind in the MISO study are, like the majority of previous studies, due to the costs at the hourly level and from forecast errors. These costs are still relatively modest and suggest that they scale with wind penetration by a factor of less than one. Also these costs could be improved through reduction of wind forecast errors as well as investigating more optimum strategies for short term balancing. Hence, the ancillary costs reported here are conservative.

Two other recent studies are of value. Hirst and Hilde (2004) model a high penetration level (up to 2000 MW of wind into a 5000 MW peak load unidentified utility) and attempt to estimate the net payments (hourly energy payment minus ancillary costs) to the wind producers. Sample utility hourly load data were used, comprising sample weeks from different seasons – spring, summer and winter – and wind data scaled up and dispersed in a representative way. The utility's proprietary dispatching software was used to simulate a wholesale market involving day-ahead unit commitment and a real time hourly load balancing, as well as a regulation market.

This is the first study to attempt such an estimate. At small wind penetration, wind payments are similar to marginal costs, but they fall with increasing penetration for several reasons: (1) As wind kWhs displace conventional kWhs, the conventional generation is pushed to lower marginal cost regions of the supply curve. (2) Increased wind increases the ancillary costs, which decreases the net payment. Hirst and Hilde (2004) claim that the similarity between their average and marginal cost estimates suggest they are on the right track, although they offer caution regarding the simulation results for the high-end penetration levels (greater than 20%). Nonetheless, the results are very interesting and suggest that wind farm developers, in addition to seeking areas with excellent wind resources, also seek markets with high cost electricity given the often quoted figure of ~$40/MWh for wind production.

IMPACT OF WIND PENETRATION ON THERMAL GENERATING PLANT

Previous studies examined system impacts of wind penetration from the reliability (effective capacity) or ancillary costs points of view. While informative, they do not address more detailed impact questions such as fuel displacement and emissions. Further, wind's impact on the operating points of conventional, predominantly thermal plants has not been revealed by these approaches. The first comprehensive attempt to estimate conventional plant impacts due to wind penetration was undertaken by the Irish system operation ESB National Grid (2004). This study has produced some possibly groundbreaking results that suggest serious negative impacts of wind power at large scales.

The near-term scenario uses the existing Irish generating system portfolio of coal, hydro, fuel oil, peat and gas. The *long-term scenario* upgrades the coal plant through desulphurization (10% output de-rating), maintains the hydro plant and proposes a flexible combination of CCGT and OCGT for the remainder (including new plant to service load growth). Wind resource information is of a high quality and existing Irish wind farm data are used extensively to inform the up-scaling of wind plants for the simulations. Capacity factors of up-scaled wind plants average 34%. Wind forecasting is assumed to be highly accurate to reflect the wind industry claims that improved forecasting techniques are emerging rapidly.

The Irish ESB National Grid (2004) study reports significant impacts on the thermal generating plant, such as reduced capacity factors of both base load and load following plants and large increases in the frequency of plant starts and stops. The significant reduction of base load and load following capacity factors have cost implications (cost of production recovered over fewer megawatt hours); the increase in start up and ramping requirements have cost and maintenance implications. The consequence of this latter impact is unknown but could be quite significant. For example, more planned (for maintenance) and unplanned (due to failures) due to the thermal plant being driven much harder will further reduce thermal plant capacity factors leaving fewer production hours available and driving costs up. Also the further reduction of thermal plant capacity factors due to this effect would require additional capital plant to be constructed to meet reliability requirements. More work is required to better quantify these nonlinear (negative) cost impacts of wind.

The primary motivation of wind power is the potential for CO_2 mitigation from the displacement of thermally generated megawatt hours by wind-generated megawatt hours. There is an implicit expectation, most prevalent in policy thinking, that wind displacement of thermal generation results in a linear displacement of CO_2. Hence, for example, if wind energy replaces 1 Kwh of energy from coal, CO_2 emissions would be reduced by the full amount of the emissions that would otherwise have been emitted by burning coal.

The Irish ESB National Grid study provides a serious assessment of this potential. Using their data, a system-wide CO_2-emission rate was calculated for each scenario: 5000 MW scenario, 0.625 tCO_2/MWh; 6500 MW scenario, 0.521 tCO_2/MWh. These figures were used to estimate the potential CO_2 reduction resulting from a given amount of wind production and compared to the actual reduction yielded by the full simulation.

Using data provided by this report (ESB 2004), the thermal fuel consumption rate was determined for the various wind penetration ratios simulated, with the results displayed in Figures 5 and 6.

For the 5000 MW Peak Load System, which represents the current Irish system, generating the remaining load using wind first improves thermal system efficiency, simply because the most inefficient thermal plant is displaced by wind power. However, this improvement begins to be offset, at around 7-8% wind penetration, by the increasing number of thermal plant start/stops and ramping rates. Beyond 10% penetration, the thermal plant fuel efficiency degrades.

The simulation results for the 6500 MW Peak Load System are most significant. It has been recognized for sometime that base-load generating coal plants, with their associated large thermal inertia, would not be responsive enough for working in tandem with a wind generating plant (Leonard and Muller 2002). The 5000 MW Peak Load result in Figure 5 bears this out, as does the recent work examining wind penetration into the Estonian system (Liik et al 2003). The latter work is perhaps an example of an extreme case of old coal fired generation with large thermal inertia. Their simulations indicate that wind penetration of 5–10% can begin to drive the thermal system into states of very high fuel consumption, negating gains made from the relatively minor addition of wind power into this unique system.

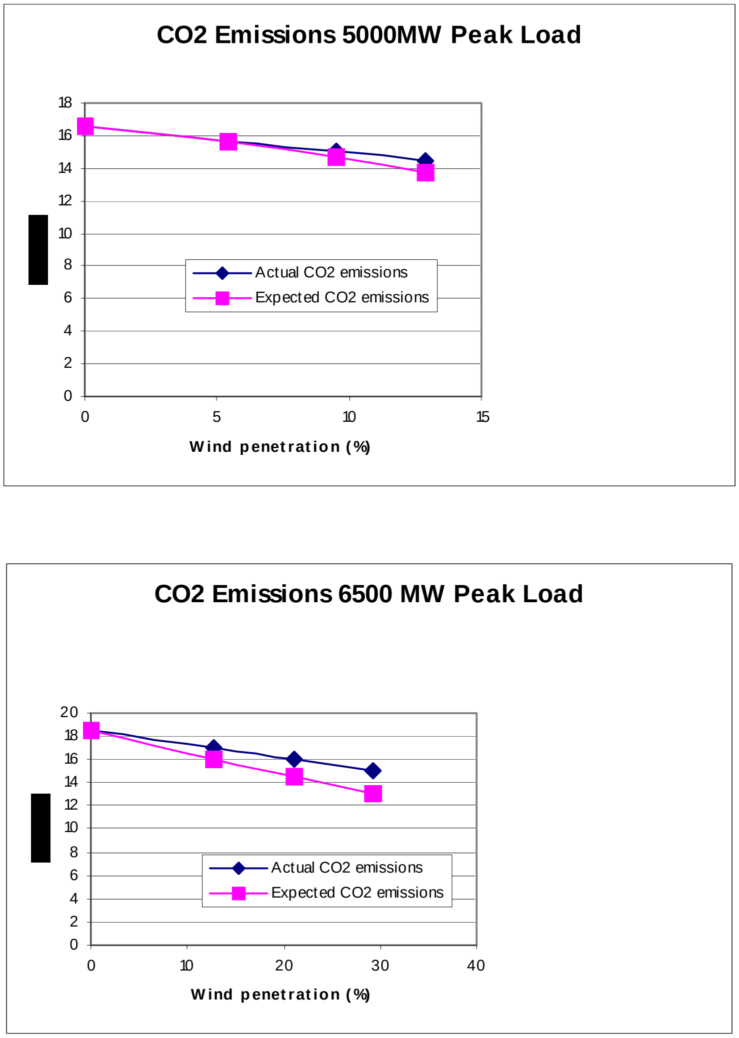


Fig 5. Expected and actual (simulated) CO_2 emissions from Irish ESB National Study (2004)

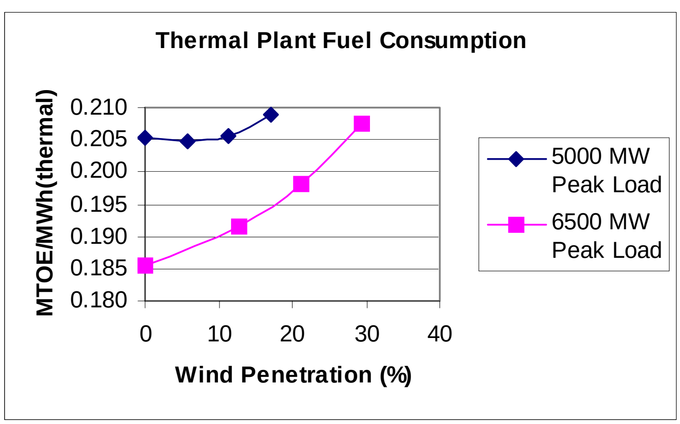


Fig 6. Thermal plant fuel consumption derived from ESB National Grid study

However, it has also been suggested that, in most utility systems, thermal plants evolve as wind power is deployed over several decades (DeCarolis and Keith 2004). More responsive gas turbine plants are anticipated to be more compatible with the fluctuating wind plant output and will be the generating technology of choice to meet new demand as well as to replace retired coal-fired generation. We examine this potential using the Irish study.

The 6500 MW Peak Load System simulation is one of the first attempts to model this evolution towards predominantly gas dominated thermal plant. However, the negative impact on thermal fuel efficiency (Figure 6), as wind power penetrates this system, may be surprising to some. As all the thermal plant is modeled as efficient gas generation plant, there is no inefficient plant to displace as wind begins to penetrate, as in the previous 5000 MW Peak System case. Consequently the fuel efficiency is impacted immediately as wind begins to penetrate. The thermal fuel efficiency of the gas-dominated plant is reduced to the levels of the old generating mix with wind penetration levels of less than 30%. Extrapolating these results to a wind penetration level of 50%, a level envisioned as necessary for deep cuts in green house gas emission, a fuel reduction of only 33.8% would be realized. Again diminishing returns emerge, this time in terms of the realizable fuel saving and consequent CO_2 reduction potential of wind power, even with the more responsive gas-dominated generating plant.

Cost estimates for electricity production with significant wind penetration was the main purpose of the Irish ESB National Grid study. Meaningful cost estimates through simulations of the existing Irish system were not feasible as there was a lack of knowledge of sunk costs of existing plant, some of it over 40 years old. Hence, they based their cost estimates on the 6500 MW gas-dominated system, which is considered new. Recovery of capital and variable costs was over 15 years. The bid prices for all generation were obtained from an analysis of recent production and were used in their proprietary scheduling code along with capital costs.

The costs obtained for the Irish system (Table 2) study indicate two main points: 1) that the ancillary costs (regulation, load following) surveyed in Table 1 are dwarfed by the increased fuel costs and reduced effective capacity factors of the thermal plant as wind is introduced; 2) the mitigation costs are high compared to oft quoted figures such as US$50/t. This report concludes that the Irish government should consider other options for CO_2 mitigation.

Table 2. Cost of Wind in 6500 MW Scenario

Wind Penetration (%)	Increase per MWh of wind (∈/MWh)	CO2 Mitigation Cost (∈/t)
12.8	43.3	140
21.1	41.3	128
29.3	41.8	126

Although the cost estimates obtained by the Irish study are high they should be considered *lower* bound estimates. There are three main reasons for this. First, the wind plant is assumed to have capacity factors averaging better than 34%. While this may be valid for off-shore plant, as reported earlier, when large deployments of wind plant are sampled, observed capacity factors seem to be lower than expected. Hence the capacity factors used here for wind plant are potentially optimistic. Second, no allowance was made to ascertain the additional maintenance cost due to the thermal plant operating with increased start/stop and ramp rates. This may require additional capital plant to be on line to offset any increase in planned maintenance or fault shutdowns due to this impact. Third, the increased variability of the thermal plant operation will lead to higher demand fluctuations for natural gas. Potentially more gas will be purchased on the spot market and less from long term contract. The cost impact of this could be quite significant.

Overall, the impact of wind penetration on the presumed-to-be-wind-friendly thermal gas plant is dramatic. It is akin to the impact on fuel economy of vehicles when switching from highway driving to city driving. With vehicles, a hybrid configuration employing an energy storage element is needed to offset the impact of fluctuating driving cycles. So it would appear with wind energy systems and complementary thermal generating plant. An element of storage would seem to be necessary to capture the benefit (fuel displacement) to minimize undue stress on the thermal plant.

DENMARK AS A CASE STUDY

The negative impact of wind on thermal generating plants, as reviewed above, would be expected to be manifest in real systems. For example, Denmark wind power production in 2000 was 3.37 TWh, a penetration level of over 16% and growing to levels nearing 21% in 2003. The balance of production was from central coal fired plants (54%) and district-level CHP plants (30%). This wind penetration level, the highest of any single utility system, is used by many as evidence that wind power can be easily (and rapidly) integrated into any system with little impact. In fact, the existence of this level of wind penetration without noticeable impacts would seem to contradict the results of the Irish ESB National Grid Study.

Closer examination of the Danish system reveals a very different picture, however. Both wind power and CHP production are priority or bound production in Denmark. As such, the system operator, Eltra, has to take this bound production and balance demand with the remaining dispatchable generation capacity. The dispatchable generation is coal-fired thermal plant and is dominated by the non-dispatchable capacity by a wide margin. It would seem surprising that this generating mix would be able to balance supply and demand, given the limited available capacity and flexibility of the dispatchable thermal plant.

The wind penetration level in Eltra's system of 16% or higher is misleading because in reality, Eltra's system is imbedded within a much larger NORDEL transnational system via interconnections to the Nordic countries of Sweden, and Norway. There are also major connections to Germany. These interconnections mean that Eltra's 16 – 21% wind production is more like a penetration ration of 1-2% when viewed by the whole NORDEL system. Hence Denmark's Nordic neighbours as well as Germany act as large sinks for wind production that exceeds demand. Using data published from the Eltra website, we see a strong correlation between wind production and electricity exports (Figure 7). This suggests how the Eltra system handles wind production: exporting to a much larger, predominantly hydroelectric based system and it results in additional costs.

METEOROLOGICAL/CLIMATE IMPACTS OF LARGE-SCALE WIND POWER

Some of the first investigations of meteorological impacts of large-scale wind farms emerged this year, all employing meso-scale modeling codes where the presence of wind turbines was modeled by increased surface roughness scale. The reduction of wind speed, due to this 'roughness', leads to a downward momentum flux that compensates for the momentum loss of the bottom layer.

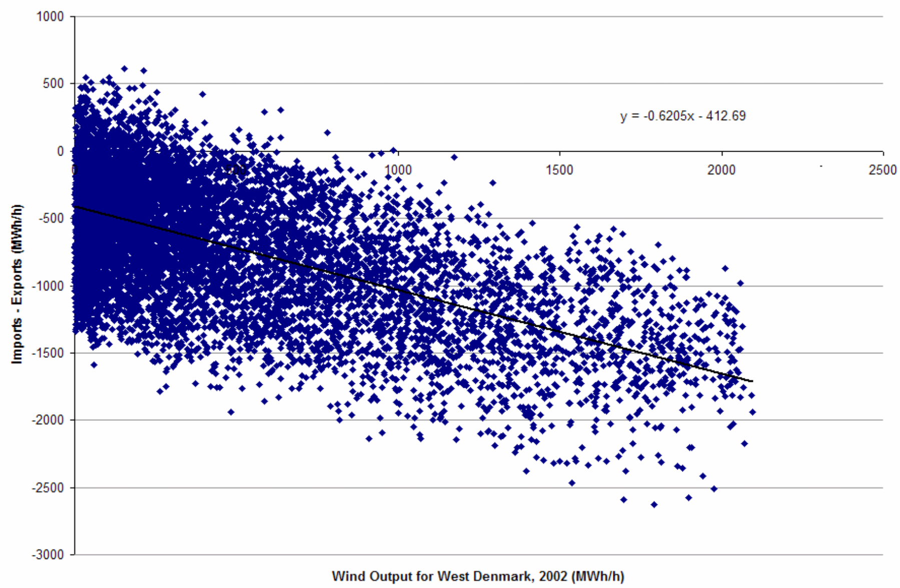


Fig. 7. Danish Electricity Exports and Wind Production

Rooijmans (2004) examined a proposed 9 GW (9000 km^2) wind farm off the Dutch coast. Model results indicate that wake-effect losses that occur for the bulk of the turbines located in the wind farm interior can reduce the average electricity production by up to 50%. Furthermore, cloud formation and precipitation patterns were affected dramatically by the presence of the wind farm.

Baidya Roy et al (2004) were motivated by the fact that wind farms would extract energy from the atmosphere at a rate of ~ 1W/m^2, a rate comparable to other terms in the atmospheric energy balance equation. Even though the energy extracted from the atmosphere is small compared to the absolute values of kinetic and potential energy stored in the atmosphere, the rate of energy extraction is comparable to other atmospheric energy conversion processes such as frictional dissipation. Thus wind farms have the potential to influence atmospheric and surface processes. This study modeled a 10,000km^2 square wind farm (10 GW) in the Great

Plains. The significant reduction of wind speed at the turbine hum height of 100m can lead to a downward momentum flux whose vertical footprint extended beyond 1km in altitude. Observed modeling impacts include enhanced surface drying and moisture content increasing with altitude echoing the previous work's observation of precipitation pattern changing.

Keith et al (2004) tried to estimate the global warming potential (GWP) of wind power due to the induced momentum transfer and dissipative effects introduce by large-scale wind farms and compared it to the effective reduction in GWP due to the displacement of CO_2 producing electricity production. To the authors' surprise the numbers are comparable.

At this point, caution should be exercised before drawing significant conclusions based on these three studies. First, they are all preliminary attempts employing suite of sophisticated modeling tools that do not always resolve the physics of the underlying processes, and the authors present their results as 'first order'. This is due in part to the uncertainty of some of the key atmospheric energy transfer coefficients. For example, the higher resolution Baidya Roy et al (2004) work suggests that Keith et al (2004) may have underestimated the climate impacts of wind turbines.

Nevertheless, the main point is the extraction of energy using large-scale deployments of wind farms may have a discernable impact on the local meteorological patterns. This should not be too surprising as any large-scale industrial activity has impacts of some form. This pioneering preliminary work suggest it is important to pursue these impact questions more rigorously in order to better understand the potential implication of deploying wind power on the scales envisioned by some jurisdictions.

CONCLUSIONS

Presently there are no isolated systems with multi-TWh demand that have wind penetration levels above a few percent. Thus operational impacts experienced to date are likely to be small. Due to the expanding deployment of wind power motivated by CO_2 mitigation desires, it is an opportune time to conduct a rigorous assessment of this form of power production. We believe this assessment has only just begun.

A review of available literature along with some additional results presented here leads us to conclude that:

1) The ancillary costs for wind are non-zero for small wind penetrations and escalate for increasing penetration ratios, although the amounts are not onerous but they are not insignificant either.
2) The effective capacity credit for wind is difficult to generalize, as it is a highly site-specific quantity determined by the correlation between wind resource and load. Values range from 26 % to 0% of rated capacity.
3) Observed capacity factors for existing, predominantly on-shore wind plants are in the range of 20% – 25 % rather than the optimistic range of 30% - 35%. This suggests that more capital investment will be required to achieve production targets from wind power.
4) A distinctive feature of wind power is the signature of diminishing returns with increasing wind penetration, whether from the viewpoint of capacity displacement (amount of conventional plant retired by wind), CO_2 displacement as a result of fuel displacement by wind, or estimates of payments to wind farms.

5) A serious effort to estimate the costs of integrating wind into a predominantly gas fired thermal system suggest the true costs are very high, mainly due to impacts on the thermal plant fuel consumption and the fact that there are fewer MWhs for the non-wind plant to recover costs.
6) The resulting CO_2 mitigation costs are also high.
7) Large-scale wind farms may have discernable effects on local weather patterns and possibly climate behavior. We should not be too surprised that large-scale resource extraction would have impacts on natural systems as our experience with industrial scale forestry, fisheries and energy attest.

We feel these conclusions are, at best, a preliminary assessment of the impacts of wind power. Much more work is required to test their robustness. However, due to the incentive from policy tools such as Renewable Portfolio Standards and direct subsidies favouring wind power development, we consider that research into all facets of wind power's impact to be of high importance.

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