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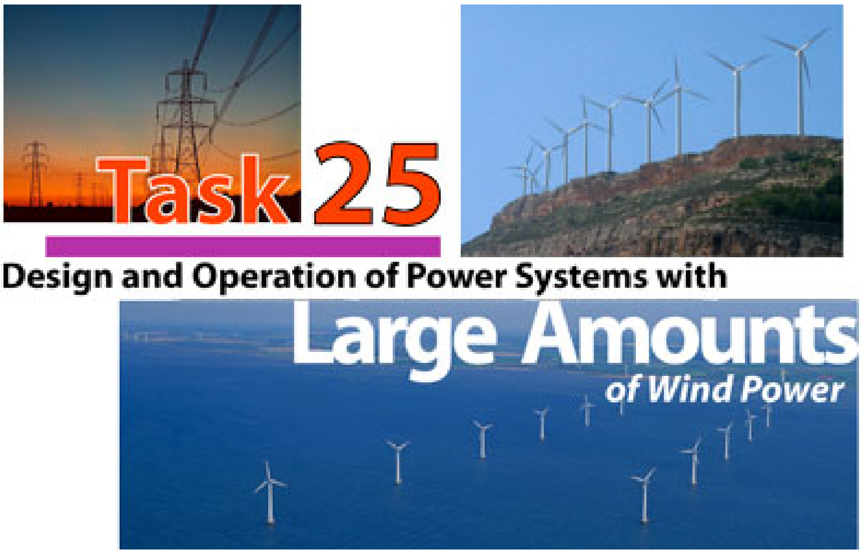

Design and operation of power systems with large amounts of wind power

State-of-the-art report

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Title

Design and operation of power systems with large amounts of wind power

State-of-the-art report

Abstract

High penetration of wind power has impacts that have to be managed through proper plant interconnection, integration, transmission planning, and system and market operations. This report is a summary of case studies addressing concerns about the impact of wind power's variability and uncertainty on power system reliability and costs. The case studies summarized in this report are not easy to compare due to different methodology and data used, as well as different assumptions on the interconnection capacity available. Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels.

Several issues that impact on the amount of wind power that can be integrated have been identified. Large balancing areas and aggregation benefits of large areas help in reducing the variability and forecast errors of wind power as well as help in pooling more cost effective balancing resources. System operation and working electricity markets at less than day-ahead time scales help reduce forecast errors of wind power. Transmission is the key to aggregation benefits, electricity markets and larger balancing areas.

From the investigated studies it follows that at wind penetrations of up to 20% of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to about 1–4 €/MWh. This is 10% or less of the wholesale value of the wind energy.

With current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, and participating in system operation with output and ramp rate control. The cost of grid reinforcements due to wind power is very dependent on where the wind power plants are located relative to load and grid infrastructure. The grid reinforcement costs from studies in this report vary from 50 €/kW to 160 €/kW. The costs are not continuous; there can be single very high cost reinforcements, and there can also be differences in how the costs are allocated to wind power.

Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution can be up to 40% of installed capacity if wind power production at times of high load is high, and down to 5% in higher penetrations and if local wind characteristics correlate negatively with the system load profile. Aggregating larger areas benefits the capacity credit of wind power.

State-of-the-art best practices so far include (i) capturing the smoothed out variability of wind power production time series for the geographic diversity assumed and utilising wind forecasting best practice for the uncertainty of wind power production (ii) examining wind variation in combination with load variations, coupled with actual historic utility load and load forecasts (iii) capturing system characteristics and response through operational simulations and modelling and (iv) examining actual costs independent of tariff design structure.

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Preface

A R&D Task titled "Design and Operation of Power Systems with Large Amounts of Wind Power" has been formed within the "IEA Implementing Agreement on the Co-operation in the Research, Development and Deployment of Wind Turbine Systems" (www.ieawind.org) as Task 25. This R&D task will collect and share information on the experience gained and the studies made on power system impacts of wind power, and review methodologies, tools and data used.

The following countries and institutes have been involved in the collaboration (TSO is Transmission System Operator):

- Denmark: Risö National Laboratories; TSO Energinet.dk
- EWEA (European Wind Energy Association)
- Finland: VTT Technical Research Centre of Finland (Operating Agent)
- Germany: ISET; TSOs RWE and E.ON Netz
- Ireland: SEI; UCD; TSO Eirgrid
- Norway: SINTEF; Statkraft
- Netherlands: ECN
- Portugal: INETI; TSO REN
- Spain: University Castilla La Mancha
- Sweden: KTH
- UK: Centre for Distributed Generation & Sustainable Electrical Energy
- USA: NREL; UWIG.

The Task has started with producing this state-of-the-art report on the knowledge and results so far. In this report a summary of only selected, recently finished studies is presented. In the final report, due end of 2008, there will be more studies included from the participating countries. The Task will end with developing guidelines on the recommended methodologies when estimating the system impacts and the costs of wind power integration. Also best practice recommendations may be formulated on system operation practices and planning methodologies for high wind penetration.

Portugal: The studies mentioned in sections 5.5.1 and 5.5.2 were performed by the "Centro de Energia Eléctrica" of the Departament of Electrothecnic and Computer Engineering of the "Instituto Superior Técnico" (IST) (Technical University of Lisbon), under contract with the Portuguese TSO, REN SA. The work referred in section 5.5.1 was coordinated by Professor Rui de Castro and the research and technical staff was constituted by Fernando Batista (IST) with the participation of J. Medeiros Pinto, António Pitarma and Tiago Rodrigues (REN, SA). The study of section 5.5.2 was coordinated by Professor J.P. Sucena Paiva (IST) and João Ricardo (REN, SA) and the research and technical staff was constituted by the Professors J. Ferreira de Jesus, Rui G. Castro, Pedro A. Flores Correia and the students Luís G. Vaz de Carvalho and Rui M. de Matos Pires (IST) and, from REN, SA, Reis Rodrigues, João Moreira and Bruno Nunes. The study mentioned in section 5.5.3, held by Red Eléctrica de España, SA (the Spanish TSO) with the participation of REN, SA, was performed by Luis Ímaz Monforte, Juan Manuel R. Garcia, Fernando Soto Martos, Francisco J. Rodríguez-Bobada, Sergio M. Villanueva (REE, SA) and, for the contribution of REN, SA, João Ricardo, Reis Rodrigues, João Moreira and Bruno Nunes. The data that enabled to construct Figures 2-b and the Portuguese contribution to Figure 6, was kindly made available by the Portuguese renewable utility, ENERSIS, S.A.. The Portuguese Advisory Group to IEA Wind Task 25 would like to thank Prof. António Sá da Costa, Mr. Mattos Parreira and Mr. Rui Maia to give the conditions for that Portuguese contribution.

Spain: Study (REE/REN 2006) was performed by a working group involving Red Eléctrica de España –REE– (Spain), Rede Eléctrica Nacional –REN– (Portugal), Comisión Nacional de la Energía (Spain) the Spanish Wind Energy Association (Spain). Among others, it was carried out by REE –Luis Ímaz Monforte, Juan Manuel R. Garcia, Fernando Soto Martos, Francisco J. Rodríguez-Bobada and Sergio M. Villanueva– and REN –João Ricardo, Reis Rodrigues, João Moreira and Bruno Nunes–. Comments and assistance provided by Luis Coronado –REE–, Alberto Ceña and Ángeles Mora –Spanish Wind Energy Association– and Venancio Rubio –Iberdrola S.A.–are also gratefully acknowledged.

Contents

List of symbols/acronyms

AGC	Automatic Generation Control
ELCC	Effective Load Carrying Capability
FACTS	Flexible AC Transmission System
FRT	Fault-Ride-Through
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LVRT	low-voltage ride-through
MAE	Mean Average Error, measure for prediction errors
NRMS	Normalised Root-Mean-Square error, measure for prediction errors
RMS	Root-Mean-Square error, measure for prediction errors
SCADA	Supervision Control And Data Acquisition
Statcom	Static Compensator
SVC	Static Var Compensator
TSO	Transmission System Operator
WT	Wind Turbine

1. Introduction

The existing targets for wind power anticipate a quite high penetration of wind power in many countries. It is technically possible to integrate very large amounts of wind capacity in power systems, the limits arising from how much can be integrated at socially and economically acceptable costs. So far the integration of wind power into regional power systems has mainly been studied on a theoretical basis, as wind power penetration is still rather limited in most countries and power systems. However, already some regions (e.g. West Denmark, North of Germany and Galicia in Spain) show a high penetration and have provided the first practical experience from wind integration.

Wind power production introduces more additional variability and uncertainty into the operation of the power system. To meet this challenge, there will be need for more flexibility in the power system. How much extra flexibility is required depends on the one hand on how much wind power is embedded in the system, and on the other hand on how much flexibility already exists in the power system.

In recent years, numerous reports have been published in many countries investigating the power system impacts of wind generation. However, the results on the technical constraints and costs of wind integration differ and comparisons are difficult to make due to different methodologies, data and tools used, as well as terminology and metrics in representing the results. Estimating the cost of impacts can be too conservative for example due to lack of sufficient data. Some efforts on compiling the results have been made in (DeMeo et al., 2005; Axelsson et al., 2005; UKERC, 2006). The conclusion has, however, been that due to lack of detailed information on the methodologies used, a direct comparison can only be made with a few results. An in-depth review of the studies is needed to draw conclusions on the range of integration costs for wind power. This requires international collaboration. As system impact studies are often the first steps taken towards defining feasible wind penetration targets within each country or power system control area, it is important that commonly accepted standard methodologies related to these issues are applied.

The circumstances in each country, state or power system are unique with regard to wind integration. However, with careful analysis pointing out the differences, some general remarks can be made, at least when classifying the different case studies with relation to wind penetration and power system characteristics.

This state-of-the-art report is the first approach to collect and share information on the experience gained and the studies made, with analyses and guidelines on methodologies. The national case studies address different impacts: balancing the power system on different short term time-scales; grid congestion, reinforcement and stability as well as power adequacy. Further case studies will also be made during the 3 years of this R&D Task. A summary of on-going research is given in Appendix 1.

For the case studies reviewed in this report, the emphasis is on more recent studies and especially on those that have tried to quantify the power system impacts of wind power. A state-of-the art review process will search for reasons behind the wide range of results for costs of wind integration – definitions for wind penetration, reserves and costs; different power system and load characteristics and operational rules; underlying assumptions on variability of wind, generation mix and fuel costs, size of balancing area, etc.

This report starts with a description of wind power variability and forecastability as well as introducing power system impacts of wind power in Chapter 2. The case study results and description of methodology are divided in three sections: Chapter 3 for balancing, Chapter 4 for grid and Chapter 5 for power adequacy. The emphasis has been on studies that have tried to quantify the power system impacts of wind power, as well as on the more recent studies. In Chapter 6, experience from high penetration regions so far is summarised, and in Chapter 7 the results from the case studies are summarised. Chapter 8 lists the current best practices in integration studies so far. Chapter 9 contains conclusions and discussion.

2. Power system impacts of wind power

Wind power brings more variability and uncertainty to power systems. This has potential impacts on power system reliability and efficiency. These impacts can in principle be either positive or negative; however, large amounts of wind power usually turn even positive impacts to negative at some stage of penetration level with regards to the cost of integration. This section summarises the results of wind variability and uncertainty and lists the possible power system impacts of wind power.

2.1 Wind power characteristics

For power system operation the following characteristics are relevant: the knowledge of wind power variability and forecastability; the knowledge of wind turbine capabilities in providing ancillary services and the knowledge of future wind power installations to help system planning.

2.1.1 Variability of wind power production

It is very important to take the variability of wind into account in a right way in power system studies. The variability will smooth out to some extent if there is geospread wind power, and part of the variability can be forecast. Because of spatial variations of wind from turbine to turbine in a wind power plant – and to a greater degree from wind power plant to wind power plant – a sudden loss of all wind power on a system simultaneously due to a loss of wind is not a credible event. Sudden loss of large amounts of wind power due to voltage dips in the grid can be prevented by requiring fault-ride-through from the turbines.

The variability of wind has been widely studied. Recently also measured large scale wind power production data has become available to give insight on the variability that is relevant for power system operation (Figure 1). In-depth information about the variability can be found in (Lipman et al., 1980; Beyer et al., 1993; Ernst, 1999; Focken et al., 2001; Holttinen, 2004; Wan, 2005; Giebel, 2007).

Generally, the variability of wind decreases as there are more turbines and wind power plants distributed over the area. Larger areas also decrease the number of hours of zero output – one wind power plant can have zero output for more than 1000 hours during a year, whereas the output of aggregated wind power in a very large area is always above 0. The variability also decreases as the time scale decreases – the second and minute variability of large scale wind power is generally small, whereas the variability over several hours can be large even for distributed wind power. For time scales from several hours to day-ahead, forecasting of wind power production is crucial.

Even if some general conclusions can be drawn from the variability of large-scale wind power, however, it should be noted that the size of the area and the way wind power plants are distributed is crucial. Also the landscape can have influence. Offshore, the wind resource has been found to be more coherent, thus increasing the variability compared to similarly distributed wind power onshore.

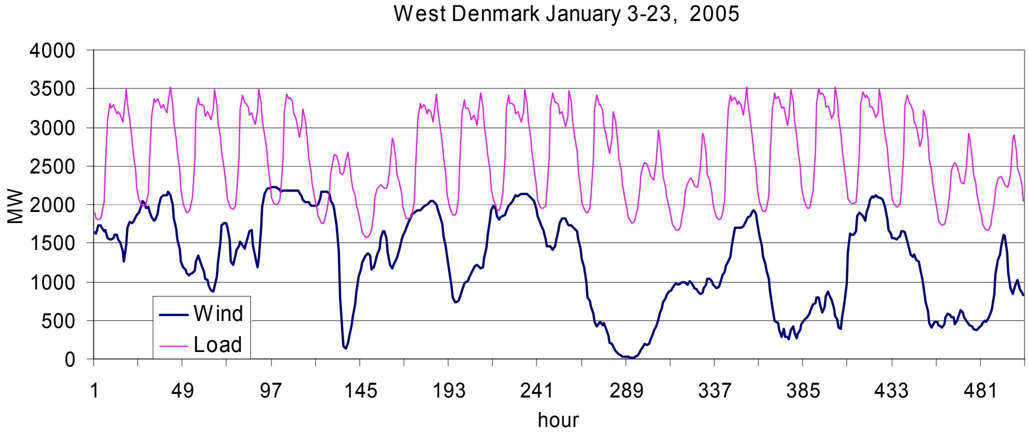


Figure 1. Wind power production (2400 MW wind power) and load in Western Denmark. The storm event of 8th January can be seen in hours 128–139. (Data source: www.energinet.dk)

General findings on large-scale variability can be summarised as:

- Very fast variations of distributed wind power are low (second-minute level). This is illustrated with data for a single wind power plant in Table 1, where the standard deviation of 1 sec variations is only 0,1% for a large wind power plant. Smoothing can be seen also in the 1 minute step changes where the standard deviation decreases from 2,1% to 0,6% of nominal capacity moving from 14 turbines to 250 turbines. There is increase in variability from the 10 minute to the hourly time scale. The hourly variations do not smooth out very much inside one wind power plant.

- The largest hourly step changes recorded from regional distributed wind power are summarised in Table 2 and range from ± 10% to ± 35% depending on region size and how dispersed the wind power plants are. These are extreme values. Most of the time the hourly variations will be within ± 5% of installed capacity (Figure 3, Figure 4, Figure 5). The German example illustrates this: wind power changes are inside ±1% of the installed power 84% of time for 15 minute intervals and 70% of the time for 1 hour time intervals (Figure 4).

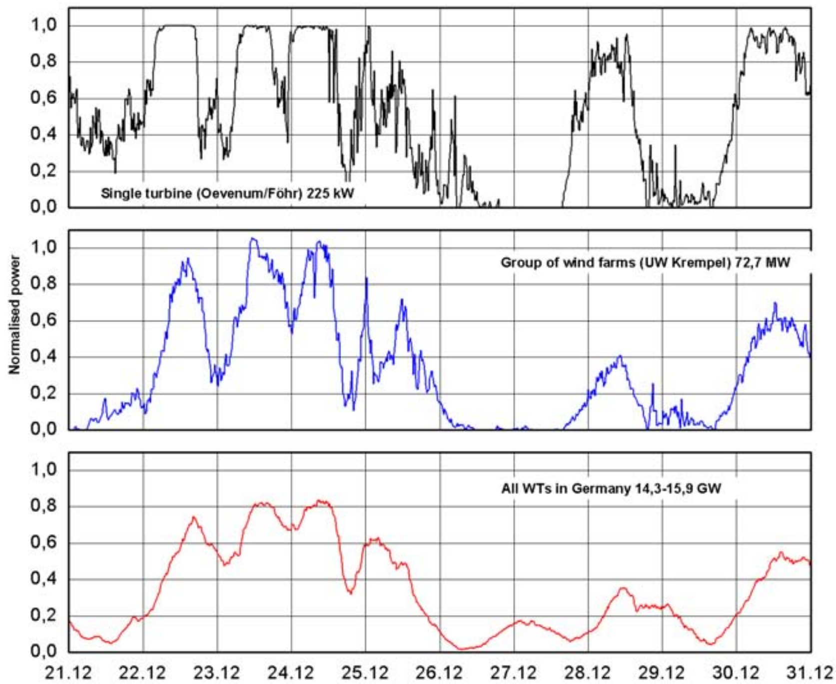


Figure 2. Example of time series of normalised power output from a single WT, a group of Wind power plants and all WTs in Germany (21.–31.12.2004).

- Wind power production can vary a lot in longer time scales, like 4–12 hours. For this time scale, forecasting the production can help. In extreme storm situations turbines stop from full power. Storm fronts take 4–6 hours to pass over an area of several hundreds of kilometres. Extreme ramp rates recorded during storms:
  - Denmark: 2000 MW (83% of capacity) decrease in 6 hours or 12 MW (0.5% of capacity) in a minute on 8th January, 2005 (Eriksen et al., 2005).
  - North Germany: over 4000 MW (58% of capacity) decrease within 10 hours, extreme negative ramp rate of 16 MW/min (0,2% of capacity) on 24th December, 2004 (Figure 2).
  - Ireland: 63 MW in 15 mins (approx 12% of capacity at the time), 144 MW in 1 hour (approx 29% of capacity) and 338 MW in 12 hours (approx 68% of capacity) (from TSO Eirgrid data)
  - Portugal: 700 MW (60% of capacity) decrease in 8 hours on 1st June, 2006
  - Spain: Large ramp rates recorded for about 11 GW of wind power: 800 MW (7%) increase in 45 minutes (ramp rate of 1067 MW/h, 9% of capacity), and 1000 MW (9%) decrease in 1 hour and 45 minutes (ramp rate -570 MW/h, 5% of capacity) (from TSO REE). Generated wind power between 25 MW and 8375 MW have occurred (0,2%–72% of capacity).
  - Texas, US: loss of 1550 MW of wind capacity at the rate of approximately 600 MW/hr over a 2½ hour period on February 24, 2007 (ERCOT, 2007).

For large offshore wind power plants ramp rates can be more dramatic and this should be taken into account if most of the wind power capacity in the region is concentrated on one offshore site.

Table 1. Wind power step change average magnitude and standard deviation (Std) values as a function of an increasing number of aggregated wind turbines in a large wind plant in the Midwest of the US (Wan, 2005).

		14 turbines		**61 turbines**		**138 turbines**		**250+ turbines**	
		(kW)	(%)	(kW)	(%)	(kW)	(%)	(kW)	(%)
1-second	Average	41	0,4	172	0,2	148	0,1	189	0,1
1-second	Std	56	0,5	203	0,3	203	0,2	257	0,1
1-minute	Average	130	1,2	612	0,8	494	0,5	730	0,3
1-minute	Std	225	2,1	1 038	1,3	849	0,8	1 486	0,6
10-minute	Average	329	3,1	1 658	2,1	2 243	2,2	3 713	1,5
10-minute	Std	548	5,2	2 750	3,5	3 810	3,7	6 418	2,7
1-hour	Average	736	7,0	3 732	4,7	6 582	6,4	12 755	5,3
1-hour	Std	1 124	10,7	5 932	7,5	10 032	9,7	19 213	7,9

Table 2. Extreme variations of large scale regional wind power, as% of installed capacity. The distribution of variations can be seen in next page Figs. (Denmark, data 2000–2002 from www.energinet.dk. Ireland, Eirgrid data, 2004–2005. Germany, ISET, 2005. *Finland, VTT years 2005–2006. Sweden, simulated data for 56 wind sites 1992–2001 (Axelsson et al, 2005). US, NREL years 2003–2005. Portugal, INETI.*

			10–15 minutes		**1 hour**		**4 hours**		**12 hours**	
Region	Region size	Number of sites	max decrease	max increase	max decrease	max increase	max decrease	max increase	max decrease	max increase
Denmark	300x300 km^2	>100			-23%	+20%	-62%	+53%	-74%	+79%
-West Denmark	200x200 km^2	>100			-26%	+20%	-70%	+57%	-74%	+84%
-East Denmark	200x200 km^2	>100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280x480 km^2	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300x800 km^2				-16%	+13%	-34%	+23%	-52%	+43%
Germany	400x400 km^2	>100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400x900 km^2	30			-15%	+16%	-41%	+40%	-66%	+59%
Sweden	400x900 km^2	56			-17%	+19%	-40%	+40%		
US Midwest	200x200 km^2	3	-34%	+30%	-39%	+35%	-58%	+60%	-78%	+81%
US Texas	490x490 km^2	3	-39%	+39%	-38%	+36%	-59%	+55%	-74%	+76%
US Midwest+OK	1200x1200km^2	4	-26%	+27%	-31%	+28%	-48%	+52%	-73%	+75%

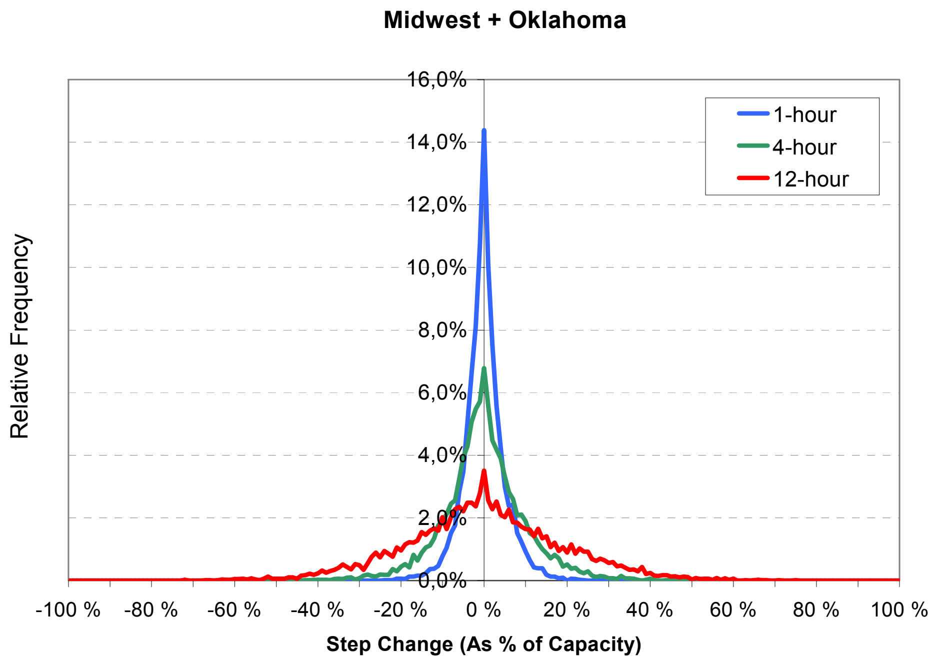


Figure 3. Distribution of hourly, 4-hourly and 12-hourly step changes from aggregation of large wind power plants in the U.S. Midwest and Oklahoma. (Wan, 2005).

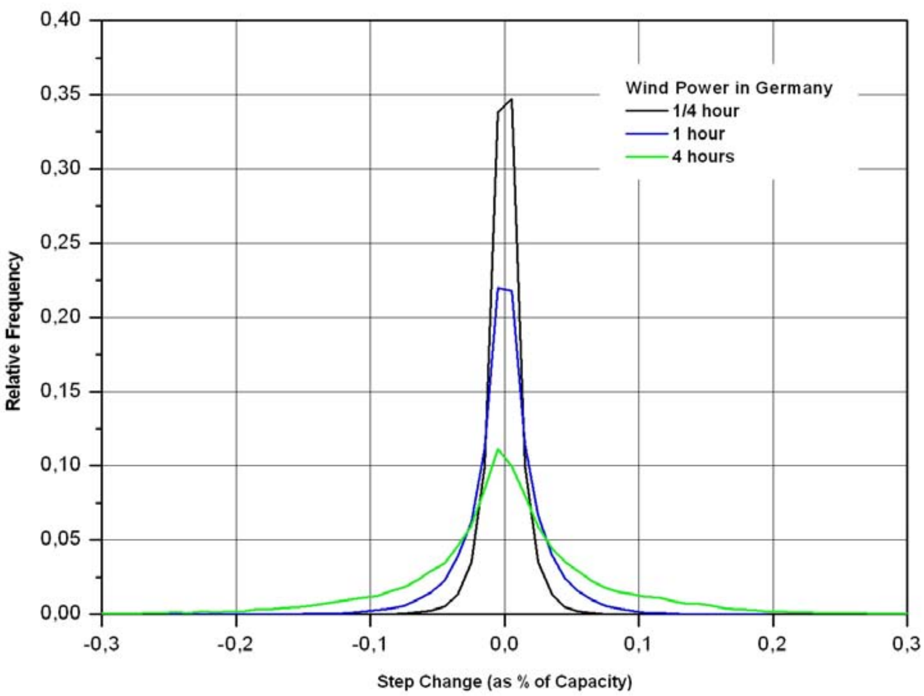


Figure 4. Frequency of relative power changes in ¼, 1 and 4 hour intervals, Germany, 01/01–31/12/2004 (ISET, 2005). A positive value reflects an increase in power and a negative value a decrease.

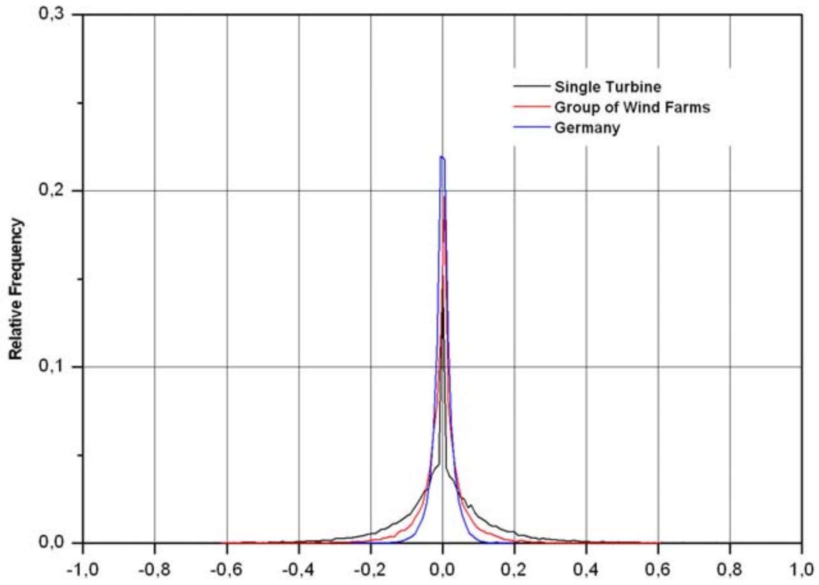


Figure 5. Frequency of relative power changes in 1 hour intervals (15 min mean values) from a single WT, a group of wind power plants and all WTs in Germany, 01/01–31/12/2004 (ISET, 2005). A positive value reflects an increase in power and a negative value a decrease.

The smoothing effect of wind power production from larger areas is due to low correlation of production from different sites. This is especially pronounced for the variations of production (Figure 6).

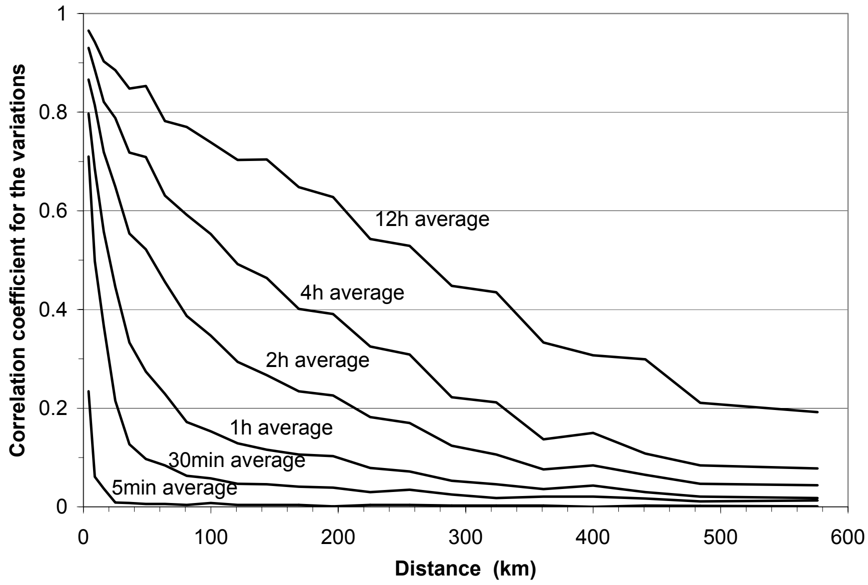


Figure 6. Variations of wind power production will smooth out faster when the time scale is small. Correlation of variations for different time scales, example from Germany (Ernst, 1999).

Wind power variability and the smoothing effect due to geospread wind power plants can be quantified for example by looking at the standard deviation of the time series for variations (Figure 7). There are differences in how the variations smooth out in different regions, as can be seen from Figure 7. Part of the differences can be due to fewer wind power plant sites in the data – the data from US and Ireland, as well as the white dots for Norway and Sweden consist of less than 20 sites. The data from Denmark and Germany represent a well dispersed wind power production. However, in some power systems the wind power plants will not be built as dispersed but in more concentrated large wind power plants. The data from 3 years in Denmark and US suggests that one year gives rather good estimate for the variability – the difference in the stdev values for different years are smaller than the variations in wind resource.

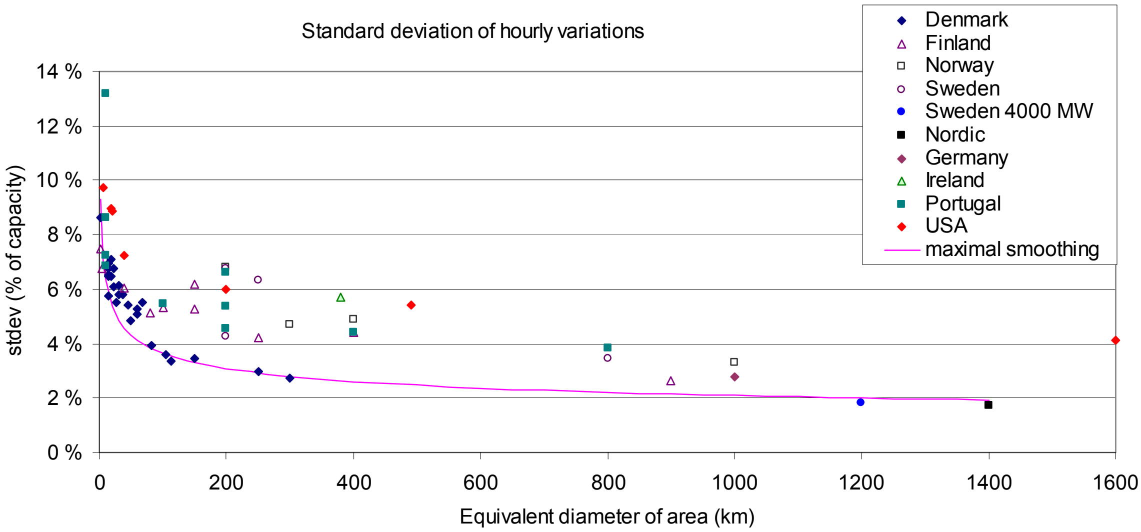


Figure 7. Reduction in variability of wind power production: reduction in standard deviation of hourly variations taken from wind power production data (except Sweden 4000 MW data from simulations for 56 sites) for different areas (Holttinen, 2004; ISET, 2006; Estanquiero, 2006; Wan, 2005; Axelsson et al., 2005; Ilex et al., 2004). The line is an estimate for the maximum smoothing effect for the size of the area.

2.1.2 Forecastability of wind power production

The short-term forecasting of wind power production is still a recent power system tool when compared to load forecasting. For wind power, the level of accuracy will not be as high as for load. The experience so far shows that the overall shape of the production can be predicted most of the time. However, large deviations can occur both in the level and in the timing of the winds (Giebel et al., 2003; Kariniotakis et al., 2006). For power system operation, the uncertainty of the forecast is as important as the level of accuracy.

Level of accuracy improves when combining predictions for larger areas (Figure 8). For a single wind power plant the mean error for day-ahead forecasts is between 10% to 20% (as RMSE% of nominal capacity). For a single control area this error will be below 10% (Table 3). The latest results from West Denmark day-ahead forecasts show an average (absolute) prediction error of 6,2% of installed capacity. In these numbers the relative forecast errors are to nominal capacity of wind power. When looking at the relative errors to average power (which give errors in terms of energy) the 6,2% for West Denmark corresponds to an error of 28% of yearly energy. Further reductions can be expected from combining different forecasting models: The first results from Germany show the best model performing at 5,1% RMSE, a “simple” combination 4,2% and “intelligent” combination 3,9% (Focken, 2007).

The level of accuracy also improves when the forecast horizon decreases (Figure 9, Table 3).

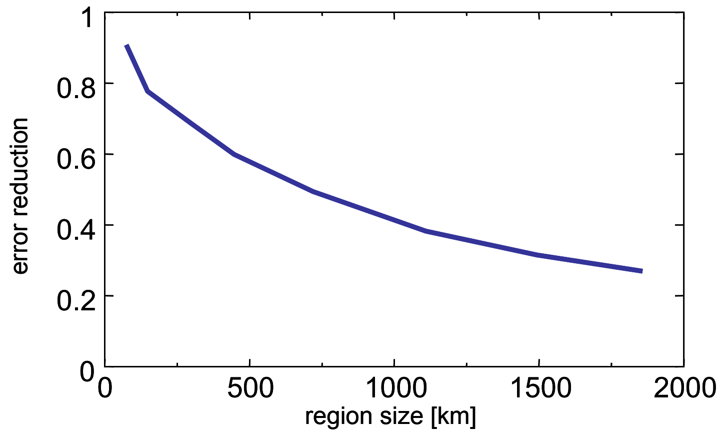


Figure 8. Decrease of forecast error of prediction for aggregated wind power production due to spatial smoothing effects. Error reduction = ratio between rmse (root-mean-square-error) of regional prediction and rmse of single site, based on results of measured power production of 40 wind farms in Germany. Source: energy & meteo systems.

Table 3. Level of accuracy of wind power predictions will increase when predicting to larger areas and for shorter time scales. Example from Germany (NRMSE = normalized root mean square error,% of installed wind capacity). Source: Rohrig, 2005.

NRMSE [%]	**Germany (all 4 control zones) ~1000 km**	**1 control zone ~ 350 km**
day-ahead	5,7	6,8
4h ahead	3,6	4,7
2h ahead	2,6	3,5

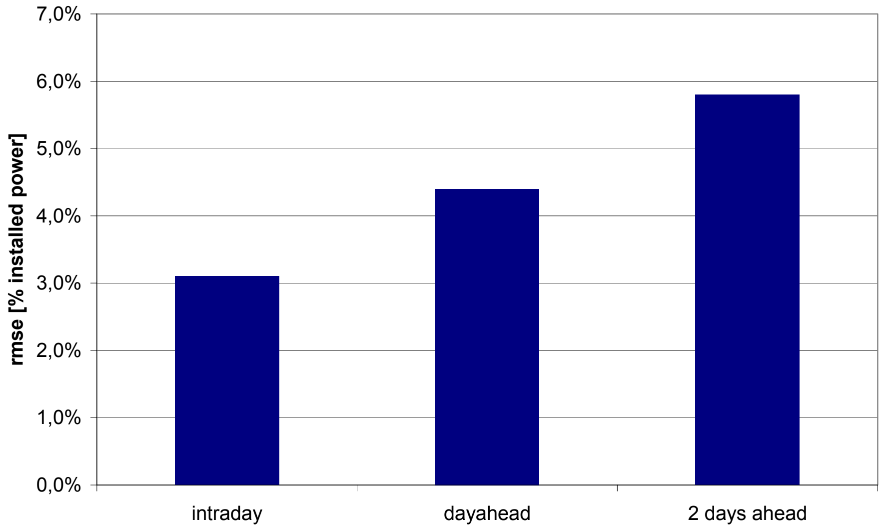


Figure 9. Increasing forecast error as forecast time horizon increases. Results from regional wind power production from Germanuy (Krauss et al., 2006).

2.1.3 Wind turbine capabilities

Wind turbine capabilities are covered in (for example, Cardinal and Miller 2006, Gjengedal 2004, Burges et al., 2003). The modern wind turbines are still developing and have possibilities for both tolerance and management of voltage and frequency variations.

Wind power plants can actively take part in grid operation by centrally controlled active and reactive power managed by the wind power plant SCADA. Active power can be regulated to bear a fixed relationship to the available power, such as maintaining some percentage or some delta value, or set at some fixed value less than the available output. Turbine ramp rate controls can control the rate of increase of active power output, and provide for a smooth plant shutdown. Governor droop characteristics can also be programmed into the power electronic controller, as illustrated in Figure 10. Turbine reactive power controls can be used to regulate either the voltage or power factor to a user defined reference.

Based on the results of several studies and on the experience with existing wind projects, modification of the existing Grid Codes for connection and operation of wind power plants in the high voltage grid have proved necessary, for instance in view of fault-ride-through and grid voltage maintenance. Countries planning very high wind penetration in the near future (e.g. Germany, Portugal and Spain) are already requiring these capacities for new wind park projects. The implementation of the new measures will improve and stabilize wind turbine behaviour and will result in decreasing loss of wind power following disturbances (Erlich et al., 2006; Gómez et al., 2006; Gómez et al., 2007a,b).

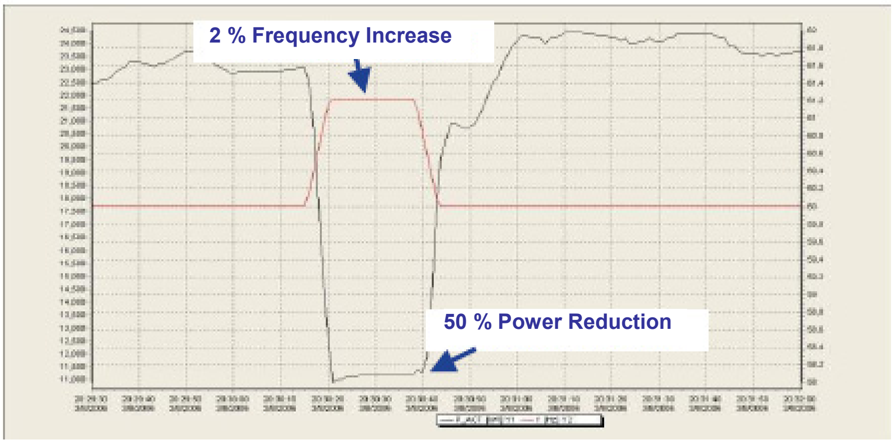


Figure 10. Power response of wind power plant to underfrequency condition (Cardinal and Miller, 2006).

One example of requirements imposed on wind power plants connected to the grid at the transmission system level is the Danish technical requirement (Energinet, 2004) specified by the Danish TSO, Energinet.dk, and implemented e.g. at the Horns Rev offshore wind power plant. The technical requirements specify six types of active power regulation available to the TSO:

- absolute limit of the output of the wind power plant to a specific value set by the operator,
- balance regulation where the wind power plant is ordered to reduce the output with a certain amount,
- delta control where the output of the wind power plant with a delta amount so this amount can be used as spinning reserve,
- rate limitation where the output of the wind power plant is not allowed to increase more than a specified amount per minute,
- droop control and
- system protection by output reduction.

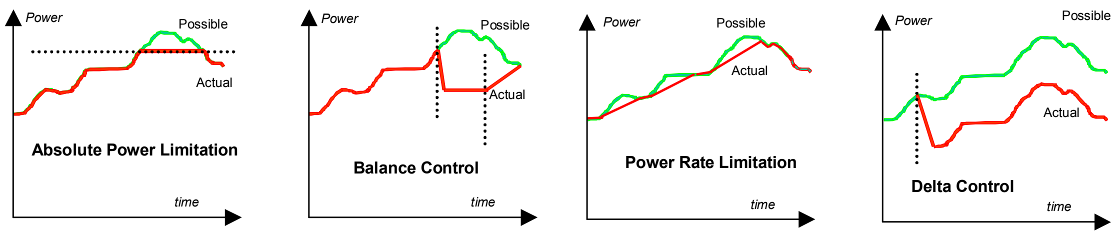


Figure 11. Outline of the active power control functions. The plots show the possible power and the actual achieved power with the different control functions active.

The four first types of regulation are illustrated in Figure 11. Results from the Horns Rev wind power plant executing several types of regulation commanded are shown in Figure 12 (Kristoffersen, 2005). It shows that the wind power plant is quite capable of performing fast regulation of the output.

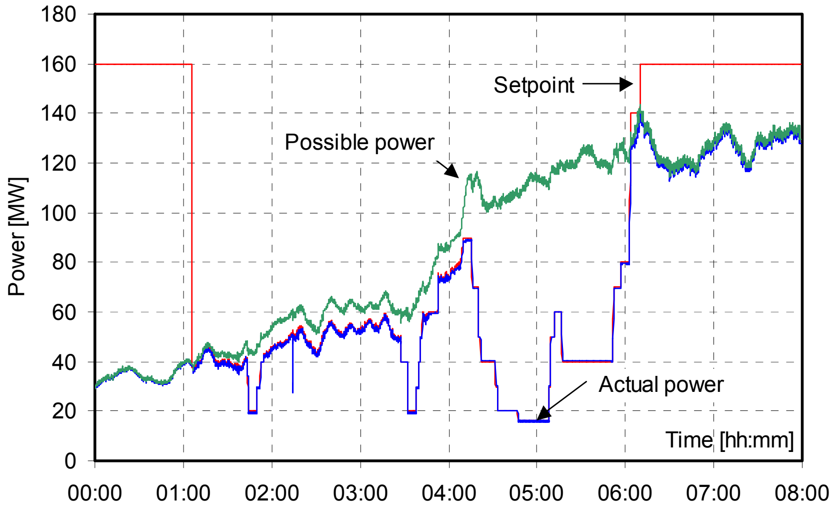


Figure 12. Measured output of Horns Rev wind power plant operating with balance control and reservation for frequency control at the same time (Kristoffersen, 2005).

Other solutions for improving stability of already existing wind power plants are SVC (Static VAr compensator) or STATCOM (Static synchronous compensator) at wind power plants.

The possibilities for providing support for power system control come at a cost of either increased investment cost or production losses. This makes the issue more complex and it is mainly being considered at very high wind penetrations (e.g. above 15%) and isolated and/or weak grids.

2.1.4 Grid code requirements for wind power plants

Grid codes determine what is required of power plants when connecting to the network. The new grid code requirements for wind power plants in many countries (Figure 13) include a requirement for low-voltage ride-through (LVRT, also called FRT fault-ride-through) in the event of system faults. The generator must stay online during three phase and single line to ground faults and in a range of grid frequencies. The fault clearing times as well as the voltage dip requirements and the requirements for providing voltage support during the fault, vary in the codes implemented so far (Figure 13). The grid code can also include a requirement for reactive power control (f.ex. of 0,95 at the point of interconnection), and the need to supply SCADA data as agreed with the TSO. Additional requirements that are being met when requested include voltage control, active power and frequency control (for example ramp rate control). Verified plant models can also be required to be supplied for simulation purposes (Smith et al., 2007).

The grid code requirements are being met by commercial wind plants entering service today, either through the inherent capability of the wind turbine technology being deployed or through the addition of suitable terminal equipment, such as some combination of static and dynamic shunt compensation.

Increased demands will be placed on wind plant performance in the future. Future requirements are likely to include post-fault machine-response characteristics more similar to those of conventional generators (e.g., inertial response and governor response).

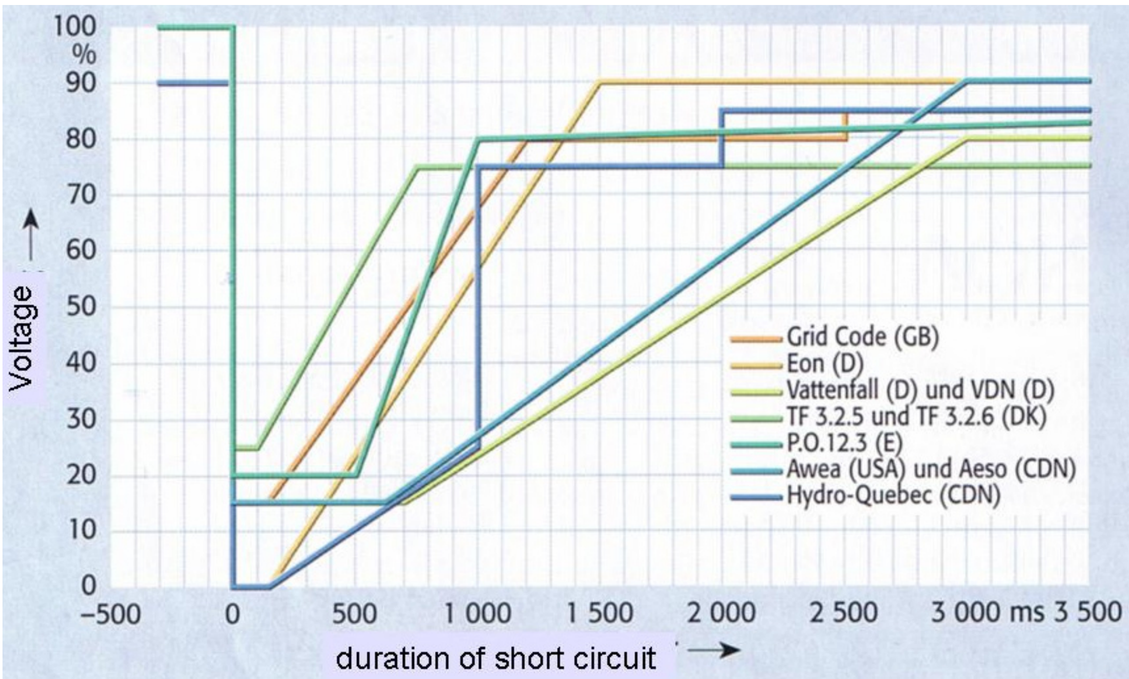


Figure 13. Comparison of fault ride through requirements. Source: Elektrizitätsz-wirtschaft, 2006.

2.1.5 Foreseeing the building of wind power capacity

Wind power has a short construction lead time compared with building transmission. In most cases there is not enough information available on the future wind power sites in time for power system planning purposes. The national and global trends and reasons behind the capacity increase of wind power are the need for emission free electricity, especially decreasing greenhouse gas emissions, as well as efforts to reduce fossil fuel dependence due to scarcity and price volatility (covered in f.ex. GWEC, 2005; Bird et al., 2003). The way in which these needs are implemented in policy frameworks for renewable energy strongly determines the local (national) growth rate of the installed wind power capacity (ex. Germany, Spain).

In many cases wind capacity development is depending on network extension or reinforcement. As network planning / permitting / implementation starts only if the project is able to apply formally (permits acquired, financing assured) this can create a barrier for smooth implementation.

Wind resource studies are needed in order to get knowledge on the geographic areas where the resource exists and the total MW possible to be implemented, also depending on the environmental sensitivity of the areas. The study results can also be used to assess some basic statistical characteristics of the wind in each of these areas and between these areas (see section 2.1.1) (f.ex. INEGI, 2002).

2.2 Possible power system impacts of wind power

If the electricity system fails, the consequences are far-reaching and costly. Therefore, power system reliability has to be kept at a very high level. Wind power has impacts on power system reliability and efficiency (Figure 14). These impacts can be either positive or negative.

Different time scales usually mean different models (and data) must be used in impact assessment studies. The case studies for the system wide impacts can thus fall into the following focus areas:

Regulation and load following: (time-scale seconds…half an hour). This is about how the variability and uncertainty introduced by wind power will affect the allocation and use of reserves in the system. Prediction errors of large area wind power should be combined with any other prediction errors the power system experiences, like prediction errors in load. General conclusions on the increase in balancing requirements will depend on region size relevant for balancing, initial load variations and how concentrated or well distributed wind power is sited, as well as the type of terrain orography and local wind structure and typical behaviour. The costs will depend on the marginal costs for providing balancing services or mitigation methods used in the power system for dealing with increased variability and uncertainty. Market rules will also have an impact, as technical costs can be different from market costs.

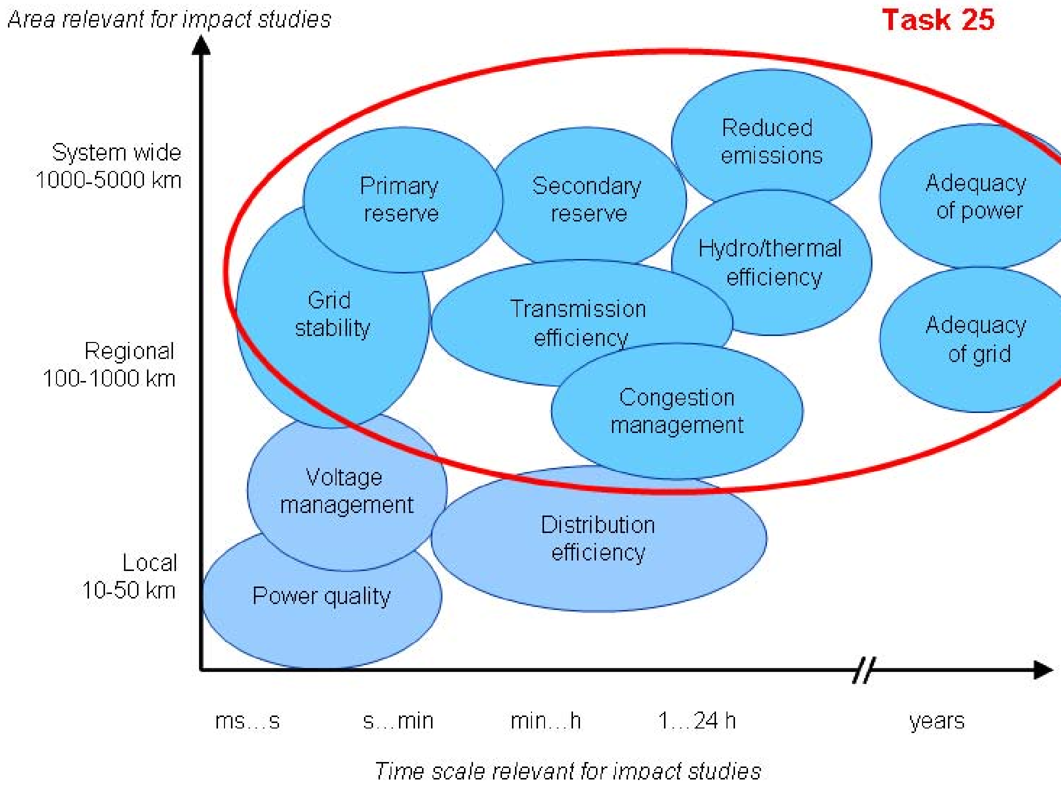


Figure 14. Impacts of wind power on power systems, divided in different time scales and width of area relevant for the studies. In this report (Task 25), more system related issues are addressed, as opposed to local issues of grid connection like power quality. Primary reserve is here denoted for reserves activated in seconds (frequency activated reserve; regulation) and Secondary reserve for reserves activated in 5–15 minutes (minute reserve; load following reserve).

Efficiency and unit commitment: This impact is due to production variability and prediction errors of wind power (time scale: hours…days). Here the interest is on how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment: both the time of operation and the way the units are operated (ramp rates, partial operation, starts/stops). Analysing and developing methods of incorporating wind power into existing planning tools is important, to take into account wind power uncertainties and existing flexibilities in the system correctly. The simulation results give insight into the technical impacts of wind power, and also the (technical) costs involved. In electricity markets, prediction errors of wind energy can result in high imbalance costs. Analyses on how current market mechanisms affect wind power producers are also important.

Adequacy of power generation: This is about total supply available during peak load situations (time scale: several years). System adequacy is associated with static conditions of the system. The estimation of the required generation capacity needs includes the system load demand and the maintenance needs of production units (reliability data). The criteria that are used for the adequacy evaluation include the loss of load expectation (LOLE), the loss of load probability (LOLP) and the loss of energy expectation (LOEE), for instance. The issue is the proper assessment of wind power's aggregate capacity credit in the relevant peak load situations – taking into account the effect of geographical dispersion and interconnection. Local storage systems with high energy capacity are also starting to be used in some power systems and may have a strong impact of adequacy of power, when cost competitive.

Transmission adequacy and efficiency: (time scale hours to years). The impacts of wind power on transmission depend on the location of wind power plants relative to the load, and the correlation between wind power production and load consumption. Wind power affects the power flow in the network. It may change the power flow direction, reduce or increase power losses and bottleneck situations. There are a variety of means to maximise the use of existing transmission lines like use of online information (temperature, loads), FACTS and wind power plant output control. However, grid reinforcement may be necessary to maintain transmission adequacy. When determining the reinforcement needs of the grid, both steady-state load flow and dynamic system stability analysis are needed.

System stability: (time scale seconds to minutes). Different wind turbine types have different control characteristics and consequently also different possibilities to support the system in normal and system fault situations. More specifically this is related to voltage and power control and to fault ride through capability. The siting of wind power plants relative to load centres will have some influence on this issue as well. For system stability reasons, operation and control properties similar to central power plants are required for wind plants at some stage depending on penetration and power system robustness. System stability studies with different wind turbine technologies are needed in order to test and develop advanced control strategies and possible use of new components (e.g. FACTS) at wind plants or nearby busbars.

2.3 Wind penetration levels in the case studies

The power systems studied in following chapters are summarised in Table 4. Determining what is "high" penetration of wind power is not straightforward. Often either energy or capacity metrics are used: wind power production as% of gross demand (energy) and wind power as% of peak load (capacity). To determine high penetration for a power system also interconnecting capacity needs to be looked at. This is because critical moments of high wind and low load can be relieved by using interconnector capacity. This is why also wind power installed capacity as% of min load + interconnector capacity has been calculated in Table 4.

Table 4. Power system size and wind power penetration studied in national cases.

	Load			**Inter-connect. capacity**	**Wind power**					
					2006	Highest studied		Highest penetration level		
Region / case study	Peak MW	Min MW	TWh/a	MW	MW	MW	TWh /a	% of peak load	% of gross demand	% of (min load + interconn)
West Denmark	3700	1400	26	2570*	2350		26		100%	
Nordic 2004	67 000	24 000	385	3000*	4108	18 000	46	27%	12%	67%
Nordic+Germany / Greennet	155 500	65 600	977	6600	24730	57 500	115	37%	12%	80%
Finland 2004	14000	3600	90	1850*	86	4000	8	29%	9%	73%
Germany 2015 / dena	77 955	41 000	552,3	10000*	20622	36 000	77.2	46%	14%	71%
Ireland / ESBNG	5000	1800	29	0	754	2000	4,6	40%	16%	111%
Ireland / ESBNG	6500	2500	38,5	0	754	3500	10,5	54%	27%	140%
Ireland / SEI	6127	2192	35,5	500	754	1950	5,1	32%	14%	72%
Ireland / SEI	6900	2455	39,7	900	754	1950	5,1	28%	13%	58%
Netherlands	15 500		100	12 930*	1560	6000	20	39%	20%	46%
Mid Norway / Sintef	3780		21			1062	3,2	28%	15%	
Portugal	8800	4560	49,2	1000	1697	5100	12,8	58%	26%	92%
Spain 2011	53 400	21 500	246,2	2400*	11 615	17 500		33%	19%	73%
Sweden	26 000	13 000	140	9730*	572	8000	20	31%	14%	35%
UK	76 000	24 000	427	2000*	1963	38 000	115	50%	27%	146%
US Minnesota 2004	9933	3400	48,1	1500*	895	1500	5,8	15%	12%	31%
US Minnesota 2006	20 000	8800	85	5000	895	5700	21	30%	25%	41%
US New York	33 000	12 000	170	7000	430	3300	9,9	10%	6%	17%
US Colorado	7000		36,3			1400	3,6	20%	10%	

** The use of interconnection capacity is not taken into account in these studies. In Nordic 2004 study the interconnection capacity between the Nordic countries is taken into account.*

3. Balancing and efficiency of production

Wind power impacts on power system balancing can be seen in several time scales, from minutes to hours, up to the day-ahead time scale. General conclusions on increase in balancing requirement will depend on region size relevant for balancing, initial load variations and how concentrated/distributed wind power is sited. Here also the operational routines of the power system are relevant – how often the forecasts of load and wind are updated, for example. If a re-dispatch based on forecast update is done in 4–6 hours, this would lower the costs of integrating wind compared with scheduling based on only day-ahead forecasts. Emerging intra-day markets reflect this, giving the opportunity for hourly updates. The costs will depend on the marginal costs for providing regulation or mitigation methods used in the power system as well as on the market rules. The way the power system is operated regarding the time lapse between forecast schedules and delivery will impact the degree of uncertainty wind power will bring about.

For efficiency of production, the interest is on how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment: both the time of operation and the way the units are operated (ramp rates, partial operation, starts/stops). Developing methods of incorporating wind power uncertainties into existing planning tools and models is important (Dragoon & Milligan, 2003). The simulation results give insight into the technical impacts that wind power has, and also the (technical) costs involved. Analyses on how current market mechanisms affect wind power producers is also important.

3.1 Approaches to assessing balancing requirements and efficiency of production

Effects of wind power on power system operation are in most cases analysed by making simulations of system operation. Reserve requirements, on a time scale of minutes, are often estimated based on statistical methods. In simulation models the reserve requirement can also be calculated based on a statistical approach, and then this reserve requirement can be allocated to generation in the simulation.

The statistical approach for estimating the increase in reserve requirements is based on looking at the variability as a probability density. Combining the variability of wind with load variations, and looking at the increase in the net load variations is often referred to as the "3σ method" (Milligan, 2003). This means that 3 times the standard deviation can be taken as a confidence level for how much of the variations should be covered by reserves (values of 2–7 have been used instead of 3). Also forced outages can be included when estimating the increase in reserve requirements, which means combining the uncertainty of load, wind and other production. Because of spatial variations of wind from turbine to turbine in a wind plant – and to a greater degree from plant to plant – a sudden loss of all wind power on a system simultaneously due to a loss of wind is not a credible event. This is an important consideration for first contingency evaluation (disturbance/contingency reserves).

In energy system simulations, wind is added to the system and any effects are analysed comparing the production and costs of the system with and without wind. For assessing the cost of variability of wind, the comparison can be made by adding wind as a flat production block over 24 hours, or with a foreseeable diurnal pattern.

3.2 Terminology for reserves

The terminology for reserves varies in every country. In Table 1 of Appendix 3, the terminology in several European countries is presented according to division of the time scales of operating the reserves (Söder et al., 2006). In this report, the reserves are referred to according to these time scales: below 5–10 minutes; 10–15 minutes and more than 15 minutes. In the US the terms regulation, load following and unit commitment are generally used to describe the operation time periods in the studies. When necessary, the division between disturbance (contingency) reserves and operating reserves will be made.

3.3 Check-list for review

A list of relevant issues to be taken into account when assessing the impacts of wind power on the power system is presented here. The important issues are:

- **What is the main set-up** for the assessment or simulation: is wind power replacing other production or capacity and to what extent is the power system operation optimised when wind power production is added. What is the level of detail of the simulation model, time resolution, pricing?
- **What is the wind input used** – how well does the wind data represent the geospread of the power system, how is wind power simulated, what time scale effects on variability and predictability have been taken into account.
- How is the **uncertainty in the wind plant output forecast** handled with respect to the load forecast uncertainty. Are both recognized? Are they combined in the proper statistical fashion?

- What is the level of detail in the simulation of conventional generation and transmission? What has been taken into account when modelling **thermal and hydro units and transmission possibilities**.

The matrix developed in (Söder & Holttinen, 2007) has been further processed to form a check-list for the national studies that have used simulations (Table 5). The main idea is to present tables from simulations regarding balancing requirements. When going through this check-list, the idea is to find out whether the approach has been conservative or whether some important aspects have been omitted, producing either high or low estimates for the impacts.

Table 5. Modelling the integration costs of wind power. Methodology and input data to be considered.

<table>
<tr><td colspan="7">Study conducted by + year when made:</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied:</td></tr>
<tr><td colspan="7">Power system characteristics:</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Interconnection</td><td colspan="2">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td>MW</td><td>TWh/a</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="7">Power system details: thermal-hydro-mixed (MW hydro MW thermal: MW gas MW coal MW nuclear)</td></tr>
<tr><td colspan="7">Interconnection details: MW DC MW AC links, how flexible or bulk contracted the interconnection is, assumptions on how much of this available for regulation/reserves</td></tr>
<tr><td colspan="7">Wind power details: geographical distribution: how wide and how well distributed, offshore-onshore MW amounts; how much transmission / distribution network connected</td></tr>
<tr><td colspan="7">Characteristics of system planning:</td></tr>
<tr><td colspan="7">Description of market:</td></tr>
<tr><td colspan="7">Integration time frames of importance:</td></tr>
<tr><td colspan="7">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="4">1 what happens with x GWh (or y GW) wind
2 how much wind is possible
3 other:</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="4">1 add wind energy
2 wind also replaces capacity
3 load is increased same amount of GWh as wind
4 optimal system design
5 other:
For capacity credit also: a – chronological, using wind power and load profiles b–probabilistic</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="4">1 deterministic simulation, one case
2 deterministic simulation several cases
3 deterministic planning with stochastic wind forecast errors
4 Stochastic simulation several cases
5 other:</td></tr>
<tr><td colspan="7">Simulation detail</td></tr>
<tr><td>R</td><td colspan="2">Resolution of time</td><td colspan="4">1 day/week
2 hour
3 minute/second
DURATION of simulation period:</td></tr>
</table>

P	**Pricing method**	1 costs of fuels etc. 2 prices for trading with neighbours, historical market prices 3 perfect market simulation (each actor maximizes its benefit according to some definition considering the physical and legal constraints) 4 market dynamics included (different actors on the market make investments or change their behaviour depending on the market prices) 5 other:
D	**Design of remaining system**	1 constant remaining system 2 optimized remaining production capacity 3 optimized remaining transmission 4 changed operation due to wind power 5 perfect trading rules 6 other:
Uncertainty and balancing		
I	**Imbalance calculation**	1 only wind cause imbalances 2 wind+load forecast errors cause imbalance 3 wind+load +production outages cause imbalances 4 other:
B	**Balancing location**	1 dedicated source 2 from the same region 3 also outside region 4 other:
U	**Uncertainty treatment**	1 transmission margins: 2 hydro inflow uncertainty: 3 wind forecasts: (a assume no knowledge and large margins for wind 0…full capacity b assume perfect forecast for wind, c persistence forecasts for wind d best available forecasts, specify what level of forecast error assumed) 5 load forecasts considered: 6 thermal power outages considered: 7 other: TIME HORIZON for forecasts assumed in the simulation (1–2 hours…day-ahead)
Power system details		
G	**Grid limit on transmission**	1 no limits 2 constant MW limits 3 consider voltage 4 N-1 criteria 5 dynamic simulation 6 other MULTI-AREA SIMULATIONS: limits inside the whole area and limits outside the simulated area separately
H	**Hydro power modelling**	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered 6 limited, deterministic run-of-river 7 interaction with hydro resources not significant 8 other:
T	**Thermal power modelling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered 4 heat production considered 5 other:
W	**Wind power modelling**	1 time series: a – measured wind speed + power curve (how many sites) b – wind power from wind power plants (how many sites) c – re-analysis wind speed + power curve (how many sites) d – time series smoothing considered (how) 2 wind power profiles (a – climatic, e.g. lowest / highest temperature, b – hour of day, c – season, e.g. only winter, d – load percentile) 3 synchronous wind data with load or not 4 installation scenarios for future wind power distribution (put together scenarios by association, government plans; according to projected regional capacity factors…); specify geographical distribution of wind 5 other:

3.4 Finland / Nordic

3.4.1 Nordic reserve requirements

Estimate for the operating reserve requirement due to wind power in the Nordic countries is reported in (Holttinen, 2005 and Holttinen, 2004).

Results are presented in Table 6.

- The increase in reserve requirements corresponds to about 2% of installed wind power capacity at 10% penetration and 4% at 20% penetration respectively. For a single country this could be twice as much as for the Nordic region, due to better smoothing of wind power variations at the regional level. If new natural gas capacity was built for this purpose, and the investment costs would be allocated to wind power production, this would increase the cost of wind power by 0,7 €/MWh at 10% penetration and 1,3 €/MWh at 20% penetration.

- The increase in use of reserves would be about 0,33 TWh/a at 10% penetration and 1,15 TWh/a at 20% penetration The cost of increased use of reserves, at a price 5–15 €/MWh would be 0,1–0,2 €/MWh at 10% penetration and 0,2–0,5 €/MWh at 20% penetration.

Table 6. The increase in reserve requirement due to wind power with different penetration levels, as% of gross demand. The increase in reserve requirement takes into account the better predictability of load variations. The range in Nordic figures assumes that the installed wind power capacity is more or less concentrated.

	Increased use of reserves		Increased amount of reserves		
	TWh/a	€/MWh	%	MW	€/MWh
– Nordic 10% penetration	0,33	0,1–0,2	1,6–2,2	310–420	0,5–0,7
– Nordic 20% penetration	1,15	0,2–0,5	3,1–4,2	1200–1400	1,0–1,3
– Finland 10% penetration	0,28	0,2–0,5	3,9	160	
– Finland 20% penetration	0,81	0,3–0,8	7,2	570	

Input data, wind power modelling: synchronous, hourly data for wind power production and load for years 2000–2002. Many wind power time series, smoothing considered, but assumed to be fully incorporated in the data for 5% penetration level up (no more smoothing effect with larger penetration levels). Danish data is real large scale wind power production data (time series of the sum of wind power production in the East and West DK). The increase in installed capacity has been taken into account when converting the data to unit “% of capacity” for up-scaling. Finnish data is mostly wind power production data from 21 sites. Swedish data is mostly wind power production data from 6 sites only (too few to represent Sweden). Norwegian data is mostly wind speed data from 6–12 sites only (too few to represent Norway). Stdev for time series of hourly variations was about 2% (less for more dispersed and more for concentrated scenario).

Methodology: time series analysis of load forecast errors and wind power variations. Increase in hourly variations from load to net load, 4sigma used as confidence level. Load forecast dropping the load hourly variability to half. Existing reserves for disturbances have not been considered, impact only estimated on operating reserves used for load following, no remaining generation system simulation.

Assumptions: Hourly data is assumed representative for 10–15 minute variations that determine the use of the secondary reserve (regulating power market) in the Nordel power system. 10–15 minute variations are less than hourly variations, so this is a conservative assumption. Prediction errors of wind power day-ahead have not been taken into account, imbalance calculation is for the operating hour only. This will underestimate the need for reserves, even if it is possible in the Nordel system that the producers or Balance responsible players correct their schedules up to the operating hour. No bottleneck situations limit the availability of reserves. Existing reserves for disturbances have been assumed not available for wind power, the impact is calculated on operating reserves only. The primary reserve requirement (seconds…minute) has been assumed to be very small.

Limitations: the result applies for the operating hour only. The prediction errors known 1–2 hours before operating hour are assumed to be balanced by the producers or balance responsible players as more accurate information on wind power production appears.

3.4.2 Nordic / efficiency of hydro thermal system

Simulations adding wind power to the Nordic power system are reported in (Holttinen et al., 2001 and Holttinen, 2004).

Results: In the Nordic power system with 46 TWh/a wind production (12% penetration of gross demand), the losses due to increased bypass of water through the hydro power plants were 0,5–0,6 TWh/a, which is about 1% of the wind power production.

Input wind data: wind speed measurement time series years 1961–1990: hourly time series (1) for Denmark. Daily time series (3) for Norway. Twice a day measurements (3) for Sweden. Weekly time series (1) for Finland. Wind speed was converted to power production by a wind turbine power curve (2 MW). Weibull distribution was used for data with daily/weekly averages.

Methodology: simulation with EMPS tool, Nordic countries. Review matrix is in Appendix 2 (Table 2.3).

Assumptions: hydro power will handle the in-week variations of wind power. Marginal prices of thermal power plants estimated to produce near real life Nordel system operation. Coal assumed in the margin, not gas.

Limitations: Weekly time scale does not take into account the variability of wind power. Static transmission limits do not take into account possible dynamic bottlenecks.

3.5 Denmark

3.5.1 Nordic + Germany

A stochastic, linear optimisation model specifically aimed at taking wind power forecast errors into account when optimising unit commitment and dispatch of the power plants was developed in the WILMAR project (www.wilmar.risoe.dk). A study with the Wilmar Planning tool done in the EU project Greennet-EU27 (Meibom et al., 2006) estimated increases in system operation costs as a result of increased shares of wind power for a 2010 power system case covering Denmark, Finland, Germany, Norway and Sweden combined with three wind cases. The base case has a "most likely" forecast of wind power capacities in 2010 for all countries. For Finland, Norway and Sweden wind power capacities equal to cover 10% and 20% of the annual electricity demand are used in respectively the 10% and 20% case. For Denmark and Germany forecasted wind power capacities for 2015 (equal to cover approximately 29% and 11% of the annual electricity demand, respectively) are used in both the 10% and 20% cases. Due to calculation time restrictions each wind case is run for 5 weeks selected as the best representative weeks of a year. These five weeks are chosen using a scenario reduction technique with the hourly wind power production, electricity demand and heat demand taken as input parameters, because these input parameters are judged as the most important for the variation in wind power integration costs between weeks. The integration costs of wind is calculated as the difference between the system operation costs in a model run with stochastic wind power forecasts and the system operation costs in a model run where the wind power production is converted into an equivalent predictable, constant wind power production during the week. If the realised wind power production in one week has a positive correlation with the load variations, it can happen that in fact in this week the integration costs are negative. This is most likely to happen for low amounts of wind power, and did in fact occur in the Base case. Figure 15 shows the results distributed on countries.

Results:

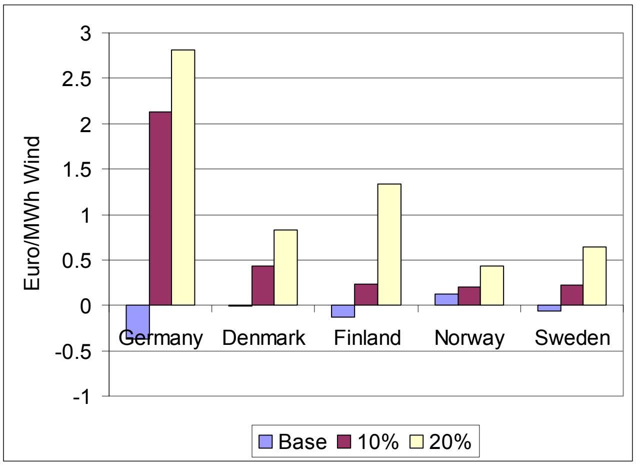


Figure 15. Increase in system operation costs per MWh wind power production for three wind cases (base, 10%, 20%) and divided on countries.

The following conclusions could be drawn from the study:

- The wind power integration costs are lower in hydro dominated countries (especially Norway) compared to thermal production dominated countries (Germany, Denmark). The reason is that hydropower production has very low costs connected to part-load operation and start-up and that hydro-dominated systems are generally not constrained in regulating capacity.
- The wind power integration costs increase when a neighbouring country gets more wind power. Germany and Denmark have the same amount of installed wind power capacity in wind case 10% and 20%, but because the export possibilities become less attractive, due to the increased amounts of wind power capacity in Finland, Norway and Sweden, the integration costs of Germany and Denmark increase from wind case 10% to 20%.
- Germany has the highest integration costs because the wind power capacity in Germany is very unevenly distributed with North-western Germany having a high share of wind power relatively to the electricity demand and the export possibilities out of the region.
- Denmark has the highest share of wind power among the countries, but also excellent transmission possibilities to neighbouring countries compared with e.g. Finland. Therefore the wind power integration costs of Denmark are lower than those of Finland in wind case 20%.

Input data, wind power modelling: Historical hourly wind speed and wind power production time series for 2000–2002 aggregated and converted into hourly wind power production time series for each region in the model. Denmark: Historical hourly, total wind power production data for East and West Denmark. Finland: Historical hourly wind power production time series for 21 sites. Germany: Historical hourly wind speed time series for 10 sites. Norway: Historical hourly wind speed time series for 6–12 sites. Sweden: Historical hourly wind power production time series for 6 sites.

Methodology: WILMAR model for the Nordic/Germany area. Review matrix is in Appendix 2 (Table 2.4).

Assumptions: Perfect market assumption i.e. power producers will produce when prices become higher than short-term marginal production costs (mainly fuel costs), and there will be no exercise of market power. Usage of transmission capacity between model regions co-optimised with usage of production capacities, i.e. no possibilities for reservation of transmission capacity by specific market actors before the daily operation takes place. All production capacity is available for the balancing of wind power production except the capacity restricted by start-up times or other technical constraints. This corresponds to assuming a very liquid regulating power market. Linear approximation of unit commitment allowing that any amount of additional capacity can be brought online, as long as the amount is smaller than the available capacity, thereby avoiding the usage of integer variables. The linear approximation is not as problematic as it sounds in a model where individual power plants anyhow are aggregated into unit groups, such as for the large model area analysed in this study.

Limitations: Load uncertainties and stochastic outages of power plants were not included in the model at the time of the study.

3.5.2 Energinet.dk 100% wind study

A study made by Energinet.dk (Pedersen et al., 2006) investigates the effect of further implementation of wind energy into a fictitious isolated Western Danish power system, where CHP units and international interconnections are disregarded.

Results: The results show that the system can absorb about 30% wind power without any problems concerning selling this energy: there is no surplus electricity. The surplus grows substantially when the share of wind energy exceeds a share of about 50% of electricity consumption. This surplus has to be served by new products of new market players, for example heat pumps, electric boilers, or other electricity-consuming devices that are not depending on the time of their usage.

Demand-side study (Nordel, 2005) identifies demand response as both an alternative and a prerequisite for investments into new production capacity and recommends that all Nordic TSOs prepare action plans for developing demand response. Thermal generation is provided to balance the system during deficit conditions. The extra cost curve is a result of increased specific cost per thermal unit due to smaller utilisation time (amortisation) and also increase of specific fuel consumption (less efficiency).

Input data, wind power modelling: The share of wind power is gradually increased onshore as well as offshore (6 TWh + 20 TWh) from 0% to 100% coverage of the annual electricity consumption (26 TWh) using measurement-based time series.

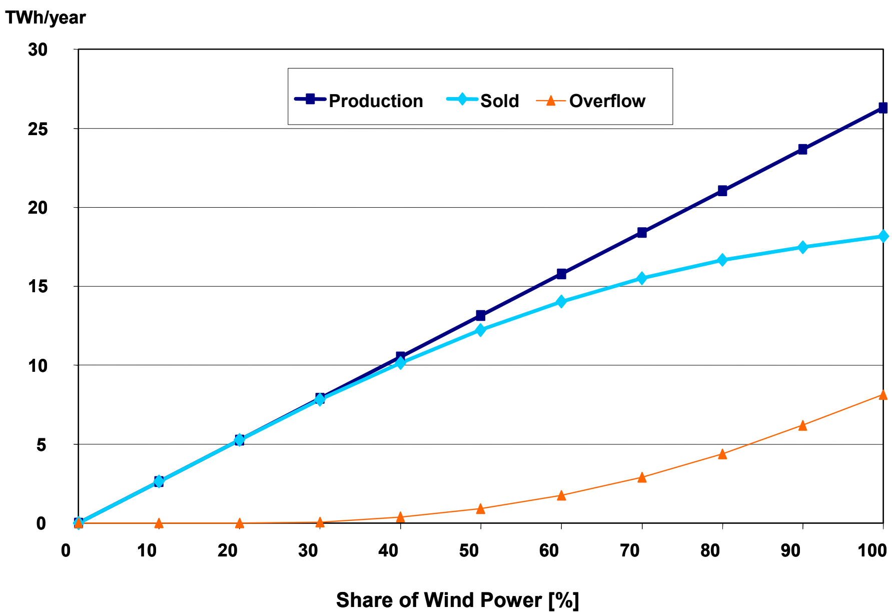


Figure 16. Demand side of residual market.

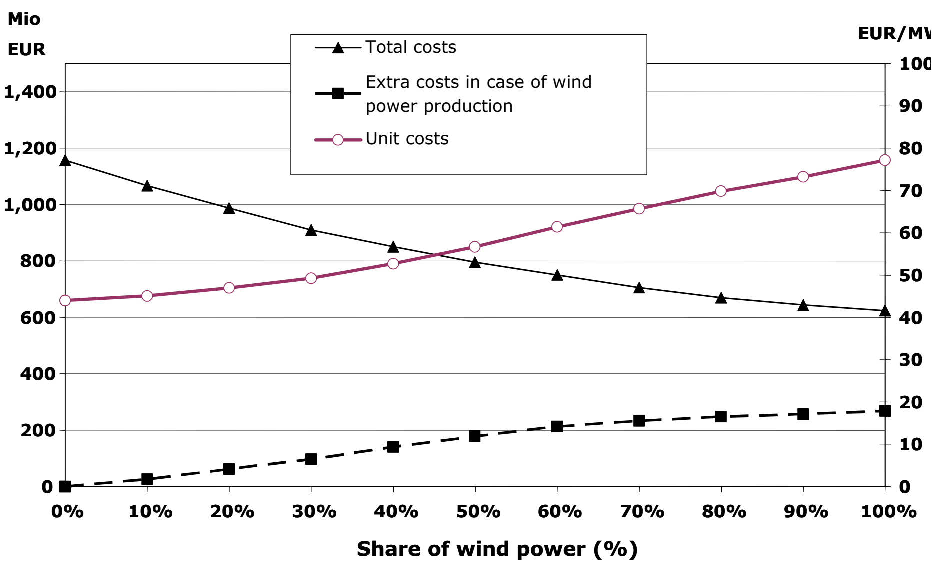


Figure 17. Costs related to residual production.

Methodology: The used simulation tool "SIVAEL – simulation of district heating and electricity" solves the week-scheduling problem on an hourly basis and finds the optimum load dispatch minimising variable costs with regard to start-stop, planned overhauls and forced outages. The simulations result – depending on the share of wind power – in different number of conventional units, their different distribution on generation type and different utilisation time per unit taking two generation types into account (coal- and natural gas-fired for base resp. peak load).

The results do not show the balancing costs but the total costs for the fictitious system taking into account the stranded costs of thermal plants operating less within a wind power based system.

Review matrix is in Appendix 2.

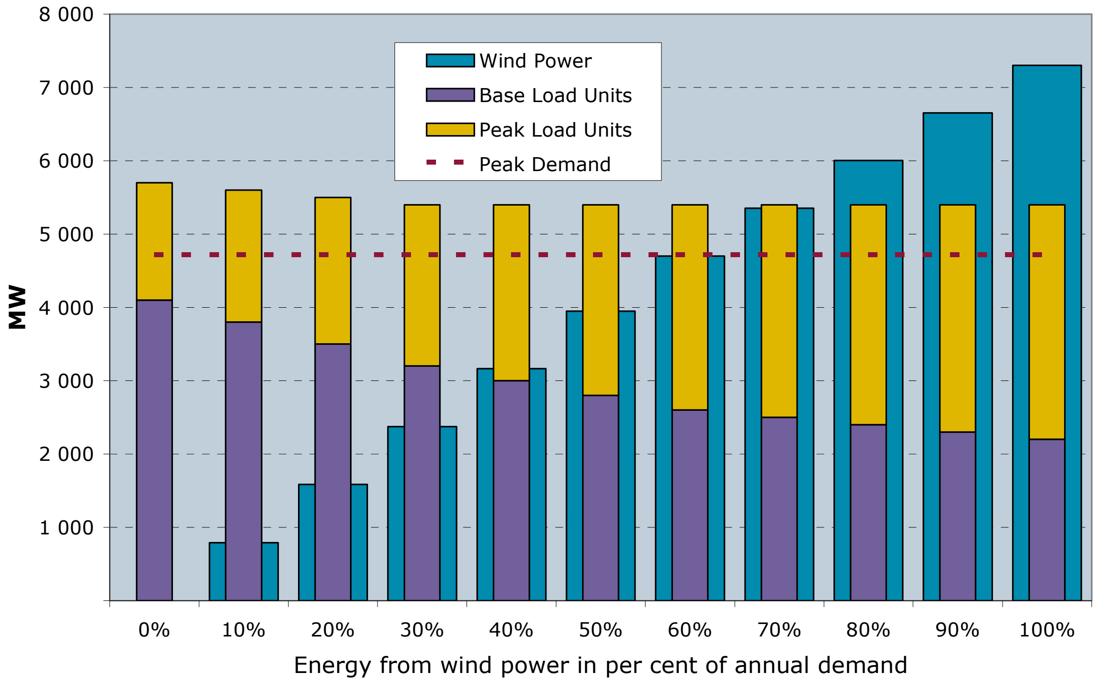


Figure 18. Production mix at different levels of wind power.

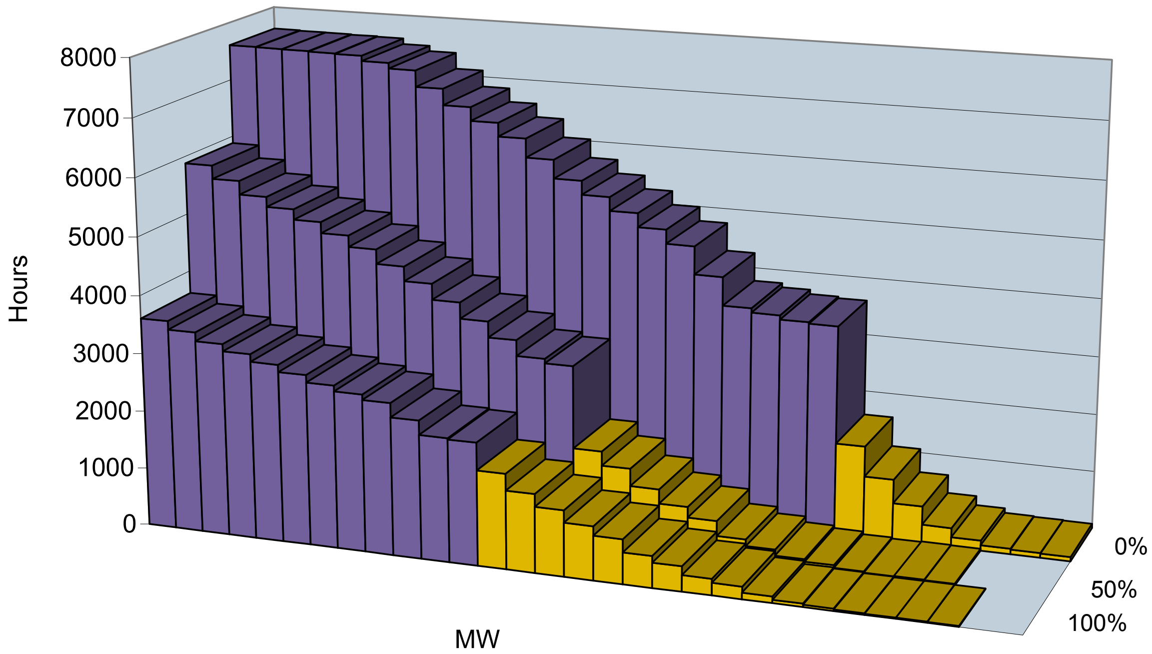


Figure 19. Utilization Time for Base Load and Peak Load Units.

Assumptions: International connections and CHP units have been disregarded in the simulations to maintain simplicity and generality.

Limitations: The simulations refer to a fictitious Western Danish power system using rough simplifications – no interconnection possibilities are taken into account even if the real system has an import capacity of about 70% of its peak load and an export capacity of 40% of total production capacity. The CHP-units that have a share of around 30% of the electricity consumption have also been disregarded. Aspects of network operation have not been investigated in this study, but play of course an important role.

3.5.3 Denmark: increasing flexibility

(Lund & Münster, 2006) evaluate the ability of heat pumps and electric boilers to increase the flexibility of a power system with a high share of CHP and wind power production. The model they use, EnergyPLAN, is a deterministic simulation input/output model of Western Denmark with the rest of the Nordic power system treated as a price interface to Western Denmark. They find high feasibility of investments in flexibility especially for wind power production inputs above 20% of the electricity consumption.

3.6 Sweden

3.6.1 Reserve requirements

Report: 4000 MW wind in Sweden (Axelsson et al., 2005).

Results: The results are in Table 7. The report neither estimates whether this increase in reserve requirements could be met with existing capacity, nor estimates the cost of increased use of reserves. To estimate how much potential bottleneck situations could affect the results, the same calculation has been made for different regions in Sweden.

Table 7. Results of increased reserve requirements in Sweden for different wind power penetrations and different time scale reserves.

Installed wind power MW	Penetration level %	1 hour stand. dev. MW (%)	4 hours stand. dev. MW (%)	Day-ahead Max. positive MW (%)	Day-ahead Max. negative MW (%)
4000	6.6	20 (0.5)	195 (5.0)	690 (17.2)	590 (14.8)
6000	9.9	45 (0.75)	-	1350 (22.5)	1030 (17.2)
8000	13.2	80 (1.0)	-	1570 (19.6)	1220 (15.2)

Input data, wind power modelling: The wind power production input is from a synthetic time series for years 1996–2001, coinciding with the load data. Load forecasts were available for 2002–2004 indicating forecast error of 1,5% of peak load one hour ahead. Wind power forecasts were assumed reducing the variability to 80% of persistence for one hour ahead (from 1,8% to 1,4% of installed capacity). For 4 hours ahead, the same level of forecast errors as in Germany were used (2,5% of installed capacity). For day-ahead, German data was scaled for Sweden.

Methodology: The methodology for 1 and 4 hour calculations is the same as in section 3.4.1 (Holttinen, 2004), except that also wind power forecastability has been taken into account. For day-ahead, the methodology of 3.7.1 (DENA, 2005) has been used, by scaling the German results to Sweden assuming similar forecastability of wind power. It is a rough estimate and can be considered as an upper limit, and only applies for days with high wind power production (Axelsson et al., 2005).

3.6.2 Increase in the use of reserves

Report: Future trading with regulating power, Magnus Brandberg and Niclas Broman, Master's Thesis, Uppsala Universitet, performed at Vattenfall Utveckling AB.

The purpose has been to investigate how the Nordic regulating power market will react to integration of 4000 MW of wind power in Sweden.

Methodology: The method used for investigating the impact on the regulating market prices is by studying the impact of wind power forecast errors. The forecast errors for wind power production have been added to historical regulating quantities and the new prices have been estimated according to the new regulating power quantity levels. Wind power production forecast errors have been estimated in two different ways:

1. Data from 2003 for the West Danish power system with an installed wind power capacity of 2400 MW have been used. The data consists of 24-hour and 4-hour forecasts and actual production of wind power. The forecasts errors have been calculated and scaled up to reflect an installed capacity of 4000 MW of wind power. The 24-hour forecast errors have been used to estimate the increase of adjustment power on the Elbas market, and the 4-hour forecast for increase of regulating power.
2. Calculation of forecast errors by setting the forecast errors to the change in production between the hour prior to the hour of operation and the hour of operation. This forecast error has also been calculated for the Danish data and scaled up to 4000 MW.

Results: Results from this study by using the two different methods are presented in the Table 8.

Table 8. Impacts of wind power prediction errors in Sweden on the regulating power market and intraday market volumes.

	No wind power	**4000 MW Method 1**	**4000 MW Method 2**
Regulating power [GWh]	2279	3566	2680
Turnover on Elbas [GWh]	2490	4010	-

3.6.3 Efficiency of hydro power

Integration study of small amounts of wind power in the power system (Söder, 1994)**.**

Results:

- Swedish wind power installations of about 2–2,5 TWh/year do not affect the efficiency of the Swedish hydro system.
- At wind power levels of about 4–5 TWh/year the installed amount of wind power has to be increased by about 1% to compensate for the decreased efficiency in the hydro system.
- At wind power levels of about 6,5–7,5 TWh/year the needed compensation is probably about 1,2%, but this figure has to be verified with more extended simulations.

Input data, wind power modelling: Many generated power series based on stochastically generated wind speed forecast errors.

Methodology: Wind power balancing was performed in one river and the result was upscaled to Sweden. Deterministic planning but evaluation based on stochastic forecast errors. The "integration cost" was calculated as needed extra energy (MWh) to compensate for lost hydro energy. The weekly load was increased in order to compensate for mean wind energy increase. Load and wind uncertainty were treated. Wind power was increased until evaluation strategy did not work. Review Table is in Appendix 2.

Assumptions: Best available wind speed forecasts (in 1994) assumed available. Rescheduling of hydro plants assumed every hour to consider new improved wind speed forecasts. Full access to a grid assumed, i.e., no limitations and 100% reliable.

Limitations: All Swedish wind power assumed to be balanced only with Swedish hydro power. Trading with neighboring systems and thermal power operation assumed unchanged. Results origin from study of a smaller part of the Swedish system and scaled up to be representative. Changes in electrical grid losses not considered.

3.7 Germany

The German Energy Agency (dena) commissioned the study "Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020" (dena Grid study). The goal of this study was to enable fundamental and longterm energy-economy planning, supported by associations and firms in the sectors of wind energy, grid and conventional power plants.

Scenarios for the increased use of renewable energy sources for the years 2007, 2010, 2015 and 2020 were geographically differentiated for wind power development onshore and offshore, with the assignment of wind power feed-in to particular network nodes. Based upon these scenarios, the effects of wind power feed-in on the transmission network and on the conventional generation plants were investigated.

The results of the study show, that the planned share of at least 20 percent of renewable energy in power generation in Germany with high amount of wind energy is achievable. However, the precondition for this is the implementation of the measures shown in the study in regard to the development of the transmission system. This wind power is in line with the target of a 20 per cent share of all renewable energy in the German electricity supply that the Federal Government wants to achieve by 2020 at the latest. Within the given framework conditions of the study it would only be possible to draft technical solutions for the integration of renewable energy sources into the existing power system up to a share of approx. 20% in electric power generation (5% offshore-wind, 7,5% onshore-wind, and 7,5% other renewable sources). A further major increase in geographically concentrated offshore wind power plants in Northern Germany, as it is planned after 2015, would require a more extensive investigation to develop viable technical solutions.

The results on the increase in balancing needs are presented in this chapter and the results on grid and adequacy in following chapters.

3.7.1 Dena study / reserves

Results: The forecast errors for wind energy give rise to an additional requirement for regulating and reserve power capacity to guarantee the balance between infeeds and loads at all times. Despite an assumed improvement in the predictability for wind energy, the required regulating and reserve power capacity increases disproportionately as the installed wind capacity increases. Due to the dependency of the wind-related regulating and reserve power capacity requirement on the level of the predicted wind infeed, the regulating and reserve power capacity required for the following day can be determined in dependency on the forecasted wind infeed level, taking into account optimisation aspects. This provides an average "day ahead" regulating and reserve power capacity. The additionally required regulating energy could be provided by the existing conventional power stations. However, the power stations must be collectively configured in order to provide the required maximum regulating and reserve power capacity at all times. For 2015:

– additional maximum 7064 MW of positive regulating and reserve power capacity is needed, of which on average 3227 MW has to be contracted "day ahead" (9% of wind power capacity). In 2003, the corresponding values were 2077 MW maximum and 1178 MW on average.
– additional maximum 5480 MW of negative regulating and reserve power capacity is needed, of which on average 2822 MW has to be contracted "day ahead" (8% of wind power capacity. In 2003, the corresponding values were 1871 MW maximum and 753 MW on average.

Input data, wind power modelling: many wind power time series, from reference sites to 10–10 km areas covering Germany Data of wind speed and wind direction from up to 220 measuring points in Germany for the years 1992 to 2003 with sampling rate of 10 Hz in 10 m 30 m and 50m hight were used to calculate wind power generation time series with 5 minute invervals for 7 years.

Methodology: in the calculation of the control/reserve requirements the probability distribution of the forecast errors of the wind power infeeds as well as those of the forecast errors of the load demand were considered. Together with the probability distribution of the power deficit caused by stochastic power plant outages a probability distribution of the power system power deficit/surplus was derived. This probability distribution was the input parameter for the calculation of the necessary control/resreve power provision (calculation was carried out for one year).

Assumptions: day-ahead forecasts for wind power, no updates closer to the operating hour considered**.** Assumed development of hub high in the year 2010: 90 m onshore, 100 m offshore and in the year 2015: 100 m onshore, 110 m offshore.

Key figures for the distributions of the day ahead and 4 h forecast errors are shown for the years 2003, 2007, 2010 and 2015 in the following table.

Table 9. Key figures for the forecast quality of the day ahead and 4h WT forecast in percentage (%) of installed capacity, 2003–2015 (DENA, 2005).

	Day ahead wind forecast				**4-hour wind forecast**			
	Average	Standard deviation	Min.	Max.	Average	Standard deviation	Min.	Max.
2003	-0,28%	7,29%	-27,5%	41,5%	1,26%	4,92%	-17,0%	33,0%
2015	-0,32%	5,91%	-23,5%	29,5%	0,97%	3,89%	-14,0%	24,3%

Values of 0,1% deficit probability for positive and negative regulation and reserve capacity for individual contractual zones (approx 8,76 hours per annum) were assumed. Sensitivity analyses were carried out with 0,01% (approximately 52 minutes per annum) and 0,0025% (approximately 13 minutes per annum) deficit probabilities. The influence of the deficit level on the additional, wind-related regulation and reserve power demand was marginal compared to the influence of the development of installed wind turbine capacity between 2003 and 2015.

3.8 UK

In the United Kingdom, government policies aim to meet 15% of the country's electricity needs from renewable sources (mainly wind power) by the year 2015. With the rapid growth of wind power in the UK the extent and cost of the provision of these additional operating reserves may become significant. In the last few years some studies have been carried out in the UK to comprehend the magnitude and cost of these additional system balancing requirements. Those studies considered more relevant to this report are described in this section: (Ilex/Strbac, 2002) and (Strbac et al., 2007).

3.8.1 ILEX/Strbac, 2002

The scope of this study conducted for the UK Department of Trade and Industry, was to quantify the additional system costs that are likely to be incurred if the volumes of renewables in Great Britain are to increase to 20% or 30% of demand by 2020. The study used scenario analysis to estimate the costs under various combinations of demand, renewable technology mix and volumes of renewable (predominantly wind) generation. The wind did not make the same portion of the renewables penetration in the study, although in many cases wind was most (about 95%) of the renewables.

Results: Balancing costs in this study comprise:

- Response and Synchronised reserve costs; related to the balancing of generation and demand over seconds and minutes.
- Standing reserve costs; related to the balancing of generation and demand over hours.
- Start-up costs;
- Wind curtailment costs; incurred usually during periods of low demand and high wind output, when wind generation needs to be constrained-off the system to avoid over-generation relative to demand.

The total balancing costs, prior to netting off the baselines, are illustrated in Figure 20. It can be observed that although response costs are the greatest component of total costs in the baselines, they are a far less significant element of the additional costs. In contrast, reserve costs are most substantial of the additional balancing costs.

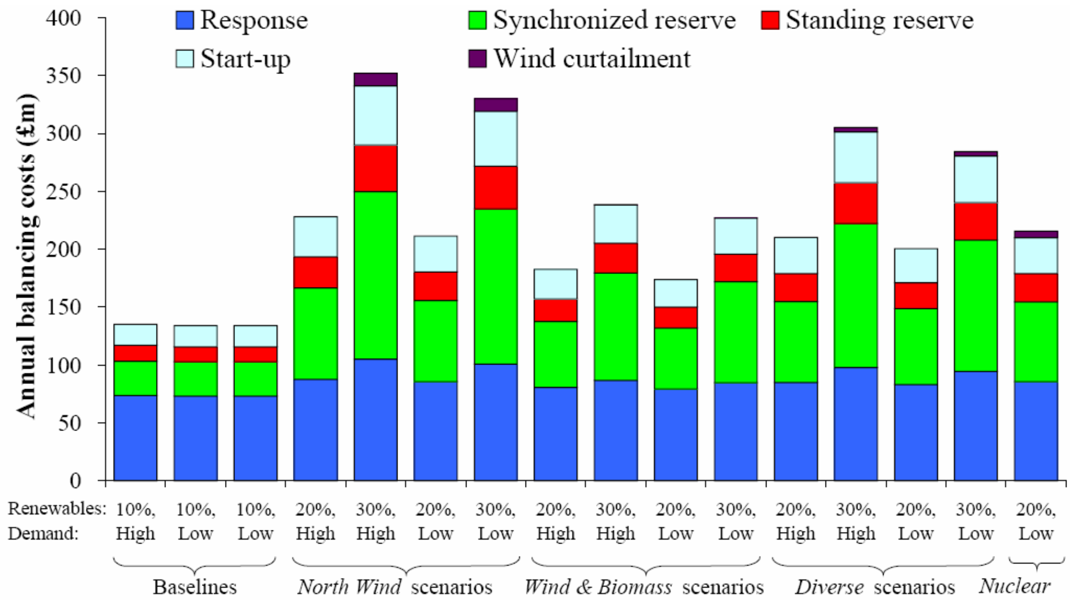


Figure 20. Total annual balancing cost by component. Wind represented most of the renewables in most of the cases.

Estimates of extra short term balancing or reserve costs were not explicitly made in the report. Taking the original values and dividing by produced wind energy resulted in £2,38 per MWh of wind produced for 10% wind, rising to £2,65/MWh at 15% and £2,85/MWh at 20%. The costs were presented as additional, so on top of 10% renewables case.

Input data, wind power modelling: Wind generation data used was gathered from 39 wind projects across UK with an averaging period of a half-hour over a consistent one year period. To build profiles of high wind penetration, representative of the diversity of the large scale wind generation, diversity was created by time-slipping proportions of aggregate half hourly wind profiles, to build up new profiles. Time-slipping involves scaling-up the observed generation data by overlaying annual half-hourly aggregate generation profiles for the 39 projects, but slipping each tranche of data by half-an-hour more than the last tranche. The sum of these profiles becomes representative of substantially large wind systems. The degree of diversity introduced was an arbitrary assumption, with our target level of diversity being a middle point between the observed diversity exhibited by the wind projects for which data was available and a theoretical maximum diversity if output across a much larger number of projects was totally uncorrelated.

Frequency distributions of the level of wind power variation in half-hr (relevant for determining response requirements and four-hour (relevant for determining reserve requirements) are shown in Figure 21.

Figure 21

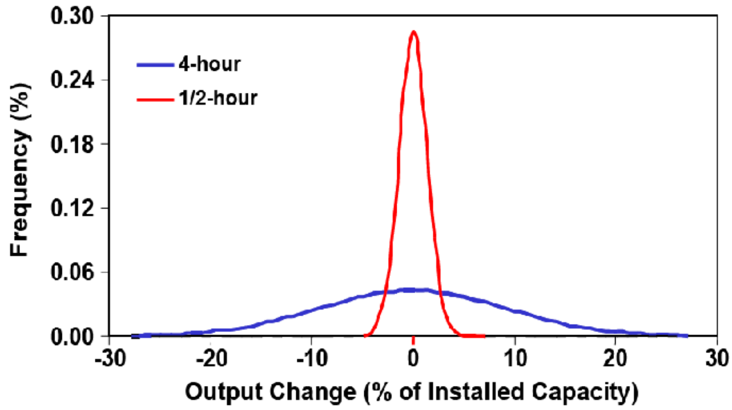


Figure 21. Frequency distribution of changes in wind generation over half-hour and four hour time horizons.

Methodology: In order to assess the additional resources to manage the balance between generation (both conventional and wind) and demand the standard deviations of fluctuations in renewable generation were statistically combined with the variations in demand and conventional generation to determine the amount of operating reserve (response and reserve) that would cover about 99% of the mismatches between demand and supply in the characteristic time horizon.

Two approaches, simulation and analytical, were applied to assess the additional cost of system balancing that includes de-loading, holding, start-up, running and the cost of wind energy curtailment.

In the simulation approach, system operation is modelled by stepping through time series data and taking into account a number of dynamic constraints such as start-ups, minimum on and off times, ramp rates, minimum stable generation etc. A combined energy, response and reserve scheduling programme was applied for this purpose. The cost of balancing was estimated by performing a number of simulation studies on six characteristic days covering business and non-business days in all seasons. Annual costs were estimated by scaling up the sample days on a time weighted basis to represent a year. The analytical approach uses statistical analysis methods. A range of studies performed confirmed that both methods were giving acceptably consistent results. The analytical approach, being less complex and computationally less intensive was mainly applied with the simulation approach to calibrate the analytical model in order to run the sensitivity and cost assessments.

Assumptions: All generators operating in the system were assumed to contribute to system inertia. The amount of dynamic response that a conventional generator provides was considered to be at least 10% of its installed capacity. Efficiency losses were considered to be between 10% and 20%.

Synchronised reserve was provided by part-loaded coal and CCGT plant while standing reserve was provided by OCGTs and pump storage plant. The allocation of reserve between Synchronised reserve and Standing plant was determined by a trade-off between efficiency losses of part-loaded synchronised plant (plant with relatively low marginal cost) and the cost of running standing plant with high marginal cost.

Limitations: The techniques applied for determining the need for operating reserve and associated costs does not comprehensively capture various impacts raised by variable and uncertain wind generation on power system operation such as the few analysed in the second study (Strbac et al) described in this report.

3.8.2 Strbac et al., 2007

Impact of wind generation on the operation and development of the UK electricity systems (Strbac et al., 2007).

Results: When analysing the need for additional continuous response and reserve requirements time horizons of 0,5-h and of 4-h, respectively, were considered. Extra plant may be needed if the existing capacity is insufficient, but the amounts involved are very modest – around 5% of the wind plant capacity, at the 20% penetration level (% of gross demand).

Table 10. Additional requirements for continuous frequency response and reserve for increasing wind power penetration in UK. Expected minimum and maximum of MW reflect the dispersion of wind power plants. Expected minimum and maximum of costs reflect also the reserve holding cost range 2–4 £/MWh. Cost converted from consumer costs in (Strbac et al., 2007) to €/MWh wind energy assuming 1 £ = 1,3 €.

Installed wind capacity GW	**Additional frequency response requirements MW**		**Range of additional cost of frequency response €/MWh**		**Additional reserve requirements MW**		**Range of additional cost of reserve €/MWh**		**Total additional cost of reserve €/MWh**	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
5	34	54	0,1	0,3	340	526	0,7	1,7	0,8	2,0
10	126	192	0,3	0,6	1172	1716	1,4	2,5	1,6	3,1
15	257	382	0,4	0,8	2241	3163	1,7	3,1	2,1	3,8
20	413	596	0,5	0,9	3414	4706	1,9	3,5	2,3	4,4
25	585	827	0,5	1,0	4640	6300	2,0	3,7	2,6	4,7

In Table 10 the estimated amounts of additional reserve required to accommodate changes in wind output for various levels of penetration are based on a 4-hour time horizon. For the evaluation of the cost of reserve two scenarios are investigated, with fuel cost of £10/MWh and £20/MWh. The increase in demand for continuous frequency regulation was found to be relatively small for modest increases in wind power connected. However, at the level of 25GW of wind, the requirement for additional continuous frequency regulation is likely to double. The expected minimum figures correspond to a highly diversified wind output. If there will be large concentrations of wind power plants now expected in The Wash, Thames Estuary, North West England or Scotland, the need for continuous frequency response is likely to be closer to the expected maximum.

This study has also quantified the value of storage in providing standing reserve by evaluating the difference in the performance of the system, fuel costs (and CO2), when intermittency is managed via synchronized reserve only, against the performance of the system with storage facilities used to provide standing reserve. Considering different flexibility levels of generating capacity in the system, the capitalized value of the reduced fuel cost due to storage is as high as 970 £/kW for systems with low flexibility, and 252 £/kW for systems with high flexibility.

Input data, wind power modelling: This study used an updated wind input time series data from the previous (Ilex, 2002) study.

Methodology: The additional response and reserve requirement was estimated using 3 sigma of the distribution of load and wind+load variations. The reserve requirements are driven by the assumption that time horizons larger than 4 h will be managed by starting up additional units, which should be within the dynamic capabilities of gas fired technologies. Over that time horizon, the maximum change in wind output could be about 25% to 30% of the installed wind capacity. Consequently corresponding amounts of reserve will need to be made available to accommodate these changes. At high wind penetrations the reserve levels equivalent to 25% of wind installed capacity will cover even the extreme variations in wind output. However, the corresponding response requirement will be about twice the existing levels.

Assumptions: The cost is obtained by assuming that all wind power output can be absorbed by the system. For relatively high penetration of wind power (above 20%) in systems with the conventional generation dominated by plant of low flexibility (such as nuclear), it may not be possible to absorb all wind power generated. However, in such a system, reserve provided by standing plant (OCGT or storage) will increase the capability of the system to incorporate wind power.

Limitations: It is important to mention that demand currently makes a significant contribution to providing non-dynamic response in UK and the role of demand could increase which would reduce the cost of both reserve and response. However, this was not included in this study.

3.9 Ireland

Investigations into the effects of integrating wind power into the Irish electricity system and the limits to wind energy penetration date from 1990. Many of the earlier studies on wind energy in the Irish power system looked solely at transmission network issues rather than effects upon the generating system. The (ESBNG, 2004) study found out that a high wind energy penetration greatly increased the number of start ups and ramping for gas turbine generation in the system and that the cost of using wind power for CO2 abatement in the Irish electricity system is €120/Tonne. It is described in more detail in section 5.

3.9.1 Ireland /SEI

Sustainable Energy Ireland published a report "Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System" (Ilex et al., 2004).

Results: The study findings were that fuel cost and CO2 savings up to a 1500 MW wind power penetration in the ROI system were directly proportional to the wind energy penetration. It was found that over longer time horizons (1 to 4 hours), there is an increasing requirement for additional operating reserve as wind penetration increases, as shown in Table 11 below. It found that while wind did reduce overall system operation costs it could lead to a small increase in operating reserve costs 0,2 €/MWh for 1300 MW wind and 0,5 €/MWh for 1950 MW of wind.

Table 11. Additional reserve requirement for different levels of installed wind power.

Wind Power Installed (MW)	% Gross Demand	1 hour Reserve Requirement (MW)	4 hour Reserve Requirement (MW)
845	6,1	15	30
1300	9,5	25	60
1950	14,3	50	150

Input data, wind power modelling: time series generated from statistical manipulation of historic wind power plant data. 10% of wind power is offshore, 50% is onshore connected to transmission network, and 40% is onshore connected to distribution network.

Methodology: The system assessment methodology was generating system simulation using a proprietary system dynamic model. The costs used for this were derived from a dispatch model. Review matrix is in Appendix 2.

Assumptions: It is assumed that it is possible to curtail wind production if necessary.

Limitations: Study looked at impact on operating reserve only, did not take into account transmission network. Limited quantity of high quality wind generation data. Study did not explicitly look at capacity issue.

3.10 USA

3.10.1 Minnesota 2004

The Minnesota Dept. of Commerce/Enernex Study was completed in 2004 (EnerNex/WindLogics, 2004). It estimated the impact of wind in a 2010 scenario of 1500 MW of wind in a 10 GW peak load system.

Results: Hourly to daily wind variation and forecasting error impacts are the largest cost items. Incremental regulation due to wind was found to be 8 MW (at 3σ confidence level). Incremental intra-hour load following burden increased 1–2 MW/min. (negligible cost).A total integration cost of $4,60/MWh was found, with $0,23/MWh representing increased regulation costs, and $4,37 due to increased costs in the unit commitment time frame. Balancing energy was self-provided by reserves carried by the control area operator.

Input data, wind power modelling: Three year data sets of 10-minute power profiles from atmospheric modelling were used to capture geographic diversity. Wind plant output forecasting was incorporated into the next day schedule for unit commitment. Extensive time-synchronized historic utility load and generator data was available.

Methodology: Review matrix is in Appendix 2 (Table 2.5)

Assumptions: A monopoly market structure, with no operating practice modification or change in conventional generation expansion plan, was assumed.

Limitations: No control area consolidation or market operation was assumed in this study.

3.10.2 Minnesota 2006

An update to the MN Dept of Commerce study was completed in 2006 by the same EnerNex/WindLogics team performing the 2004 study. This study looked at the integration cost associated with providing 25% energy from wind to the load in the state of Minnesota, assuming a well-developed market operating in the territory of MISO, the Midwest Independent System Operator.

Results: The study results show that the addition of wind generation to supply 25% of Minnesota load can be reliably accommodated by the power system, if adequate transmission is provided to support it. The highest wind integration cost was found to be $4,40/MWh of delivered wind energy, including the cost of additional reserves. The control area consolidation in Minnesota, and the size of the MISO market made a significant difference in the results, compared to the 2004 study. Balancing energy within the hour is provided by resources within the Minnesota balancing area at marginal cost. Hourly variations are managed at the MISO market level.

Input data, wind power modelling: Three year data sets of 5-minute wind plant output power profiles from atmospheric modelling were used across a region consisting of a square approximately 750 km on a side to model 6000 MW of wind capacity, achieving a good geographic diversity. Wind plant output forecasting was incorporated into the next day schedule for unit commitment, and into next hour scheduling for real-time operation. Extensive time-synchronized historic utility load and generator data was available.

Methodology: Review matrix is in Appendix 2.

Assumptions: A well-functioning market region, consisting of day-ahead, hour-ahead, and ancillary service markets, has evolved in MISO, virtual control area consolidation has occurred for the state of Minnesota, and transmission congestion has been eliminated for all practical purposes.

Limitations: The MISO territory covers parts of 14 states, with a current market load of 116 GW. The next round of studies should examine the extension of the RPS to additional parts of MISO outside of the assumed Minnesota load of 21 GW.

3.10.3 New York

The study for the New York ISO (GE Energy, 2005) estimated the impact of wind in a 2008 scenario of 3300 MW of wind in 33-GW peak load system. Wind power profiles from atmospheric modelling were used to capture statewide diversity. The study used the competitive market structure of the NYISO for ancillary services, which allows determination of generator and consumer payment impacts. For transmission, only limited delivery issues were found. Post-fault grid stability improved with modern turbines using doubly-fed induction generators with vector controls. Incremental regulation due to wind was found to be 36 MW. No additional spinning reserve was needed. Incremental intra-hour load following burden increased 1–2 MW/ 5 min. Hourly ramp increased from 858 MW to 910 MW. All increased needs can be met by existing NY resources and market processes. Capacity credit was 10% average onshore and 36% offshore. Significant system cost savings of $335–$455 million for assumed 2008 natural gas prices of $6,50–$6,80/MMBTU were found. The results for improved forecasting were also studied. Day-ahead unit-commitment forecast error σ increased from 700–800 MW to 859–950 MW. Total system variable cost savings increases from $335 million to $430 million when state of the art forecasting is considered in unit commitment ($10,70/MWh of wind). Perfect forecasting increases savings an additional $25 million.

3.10.4 Colorado

The Xcel Colorado/Enernex Study (2006) (Zavadil, 2006) examined 10% and 15% penetration cases (wind nominal to peak load) in detail for ~7 GW peak load system. (The results for 20% penetration case where not available in time of printing of this report.) Regulation impact was $0,20/MWh and hourly analysis gave a cost range of $2,20–$3,30/MWh. This study also examined the impact of variability and uncertainty on the dispatch of the gas system, which supplies fuel to more than 50% of the system capacity. Additional costs of $1,25–$1,45/MWh were found for the 10% and 15% cases, bring the total integration costs to the $3,70–$5,00/MWh range for the 10% and 15% penetration cases.

3.10.5 California

The CA RPS Integration Cost Project examined impacts of existing installed renewables (wind 4% on a capacity basis). Regulation cost for wind was $0,46/MWh. Load following had minimal impact (Shiu et al., 2006).

Results for new study on 33% renewables will be available in a final report by the end of 2007 (http://www.energy.ca.gov/pier/final_project_reports/).

3.10.6 PacifiCorp

PacifiCorp is a regulated electricity company operating in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California, serving a peak load of 9000 MW in 2004. As a vertically integrated electric utility, PacifiCorp owns or controls fuel sources such as coal and natural gas. Along with sources of wind, geothermal and hydroelectric resources, as well as energy from the wholesale market, PacifiCorp serves its customers throughout its six-state region.

An Integrated Resource Plan (IRP) is developed by PacifiCorp every two or three years. The IRP provides an analytical framework for PacifiCorp to investigate the costs and risks associated with a range of future possibilities to serve the load in its six state region. This framework provides a useful basis for discussion of the least cost plan with the regulatory bodies which oversee its operation. It provides a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp's existing generation and transmission assets. The hourly dispatch model used for the analysis includes consideration of market trading hubs, and transmission paths and constraints, to provide a detailed examination of the economic and operational performance of resource alternatives.

PacifiCorp first introduced wind into its IRP in 2003. At a penetration level of 1000 MW, the cost of incremental operating reserves in the 2003 IRP for a wind site with a capacity factor of 30% was $2,72/MWh. Combined with the $3,00/MWh estimate for imbalance, the total integration cost for 1000 MW was approximately $5,50/MWh. Since this analysis was first completed, the assumption for imbalance costs have remained unchanged at $3,00/MWh in 2002 dollars but the cost of incremental reserves has been updated for new market prices. The same methodology was used in the update, only the cost of reserves was adjusted. Currently for 1000 MW of wind capacity in the system, the 20 year levelized cost of integration in 2004 dollars is estimated to be $4,64/MWh (Pacificorp, 2006).

4. Grid reinforcement and efficiency

Requirements for new generation connecting to the network (Grid codes) assure that reliability of the grid will be maintained at a high level. Wind power affects grid adequacy and efficiency in several ways and time-scales. Some impact is negative, e.g. costly or challenging from a technical point of view, but increasing wind power also brings along clear benefits and opportunities for the grid and the operation of it.

Large scale integration of wind power sets requirements for the power system, but also the wind power technology must be developed to meet system needs. The development of IEC 61400-21 (IEC, 2001) specifying procedures for characterizing the power quality of wind turbines and the various grid codes setting system requirements for wind power plants are examples of such development.

The different aspects of grid impact that wind power causes or contributes to are described below:

A. Voltage control – reactive power compensation

A main challenge related to voltage control is to maintain acceptable steady-state voltage levels and voltage profiles in all operating conditions, ranging from minimum load and maximum wind power production to maximum load and zero wind power. Modern wind turbines are equipped with power electronics which control reactive power output and terminal voltage within some range. After the generators themselves, capacitor banks and transformer tap changers represent the most common means to control voltage profiles. Static Var Compensators (SVC) and STATCOMs placed in the grid or at wind power plants open up possibilities to serve both the grid and wind power plants to the benefit of both. Another challenge in this context is related to the control (or limitation) of the exchange of reactive power between the main transmission grid and the regional distribution grid.

B. Voltage Stability

Due to disturbances in the grid reactive power shortage at the wind power plant may occur. If the power system cannot supply reactive power, a voltage instability or collapse may occur. Sufficient and fast control of reactive compensation is required to relax possible voltage stability constraints. This can be provided through the use of wind turbines with active voltage control, or by using external compensators (SVCs and STATCOMs).

C. Transient and dynamic stability

Before, the protection systems of wind turbines were designed to disconnect and stop the units whenever a grid fault (temporary or permanent) is detected. System requirements implying that wind turbines must be able to “ride through” temporary faults, and contribute to the provision of important system services, such as momentary reserves and short circuit capacity, become more common with increasing wind power. This puts emphasis on transient stability performance, power oscillations and system damping. Also, the inertia of the power system is decreased when the share of wind power is increased. This is due to less synchronous generators being directly coupled to the grid. Consequently a power plant trip-off causes a larger and more rapid frequency drop.

Modern wind turbines can control both active and reactive power, in some cases more quickly than conventional power plants. Therefore the ability of wind turbines to actively support the power system during grid disturbances is now explored. Some simulation results indicate that with new equipment designs and proper plant engineering, system stability in response to a major plant or line outage can actually be improved by the addition of wind generation (GE Energy, 2005).

D. Transmission capacity and efficiency

The impact of wind power on the power transmission depends on the location of wind power plants relative to the load, and the correlation between wind power production and load consumption. Wind power, like any load or generation, affects the power flow in the network and may even change the power flow direction in parts of the network. The changes in use of the power lines can bring about power losses or benefits. Increasing wind power production can affect bottleneck situations. Depending on its location wind power may at its best reduce bottlenecks, but at another location result in more frequent bottlenecks.

Transmission capacity problems associated with wind power integration may typically be of concern for only a small fraction of the total operating time. Network investments can be avoided or postponed by several means. Applying control systems that limit the wind power generation during critical hours is one possible solution. Alternatively, if other controllable power plants are available within the congested area, coordinated automatic generation control (AGC) may be applied. Demand side management that is controlled according to the wind and transmission situation is another option. The latter two may be more beneficial than limitation of wind power as energy dissipation is avoided. Despite application of wind generation controllability and DSM, grid expansion and/or capacity reinforcement may become necessary not only in cases of very high wind penetration but also when it is necessary to extend the grid to areas to collect important and proved wind resources.

E. Adverse impact from interaction of power electronic converters

Modern wind turbines utilizing power electronic converters provide enhanced performance and controllability compared to traditional fixed speed solutions. With increasing use of power electronics, however, there may be uncertainties with respect to possible adverse control interactions within the wind power plant itself. Converter modulation principles and filter design are important issues that must be addressed and analyzed as part of the wind power plant design and installation.

4.1 Germany

The results of the dena grid study show that the Federal Government's planned goal of a share of at least 20 percent of renewable energy in power generation in Germany between 2015 and 2020 is achievable. However, the precondition for this is the implementation of the measures shown in the study in regard to the onward development of the power supply system.

Impact on grid reinforcement: In windy periods, network bottlenecks can be expected already for the 2007 time horizon unless new lines are constructed. These bottlenecks will require intervention in the market in order to maintain system security. In total up to the time horizon 2015, there will be a need for approximately 850 km of 380-kV-transmission routes in order to transport wind power to the load centres. This corresponds to a share of 5% of the currently existing extra high voltage line tracks. Reinforcement of 390 km of existing power lines will also be needed. In addition, numerous 380-kV-installations will need to be fitted with new components for active power flow control (e. g. Quadrature Regulators) and reactive power compensation (approximately 7350 Mvar till 2015). The total costs for the transmission system extension necessary up to the time horizon 2015 are approximately 1,1 billion €.

Table 12. Grid reinforcement to integrate 3r6 GW wind power by 2015 (DENA, 2005).

Total wind power capacity	36 000 MW
Construction of new 380 kV lines	850 km
System reinforcement of existing lines	400 km
Qadrature regulators (1400 MW in each case)	3
Reactive power compensation	7350 Mvar

An increase in the use of renewable energies to generate electricity and developments due to the liberalisation of the energy markets result in alterations in the way electricity generation is structured, which in turn affect the dynamic stability of the electricity grid (performance of the grid at times of fault-based fluctuations in voltage or frequency). The dena Grid Study examined these effects, identifying critical situations and suggesting solutions.

Dynamic grid analyses have shown that certain faults can lead to large-scale voltage drops and critical grid situations. If, for example, a regional voltage drop of more than 20% were to occur as a result of the three-pole short-circuit of a busbar, those wind turbines which were taken into operation before 2004 would have to disconnect from the grid in accordance with the Grid Codes in force at that time. These additional disconnections would worsen the critical grid situation and could lead to a total short-term drop in voltage of over 3000 MW. This value exceeds the primary control reserve level maintained by UCTE (Union for the Coordination of Transmission of Electricity) to compensate for short-term power station failure and could thus put the reliability of supply in the German and European interconnected network at risk. To prevent this, the regulations were altered for power stations joining the grid from 2004. According to the new terms, wind power plants need not disconnect from the grid until the voltage drops by more than 80%.

Wind turbines installed before 2004 are, however, still ruled by the old grid regulations, thereby increasing the supply risk and as such endangering dynamic grid stability. In principle, technical instruments are available for the adaptation of the interconnected network and power stations, but their implementation still needs to be examined in detail and agreed between network and wind power plant operators. The measures include:

- technical adaptation of old wind turbines built before 2004 to the standards of the new Grid Codes
- installation of voltage-supporting devices such as static var compensators
- accelerated repowering and
- further enhancement of the Grid Codes.

Based on the results of the dena-study and other studies and on the experience with existing wind projects, modification of the existing Grid Code for connection and operation of wind power plants in the high voltage grid will be necessary, for instance in view of fault-ride-through and maintaining grid voltage relative to voltage control. E.ON Netz has adapted its Grid Code for the high and extra-high voltage system in April 2006 (http://www.eon-netz.com) on the one side, for a better adaptation of grid requirements to wind turbine capabilities and, on the other side, for the introduction of more specific control and protection rules. The implementation of the new and extended measures will e.g. improve and stabilize wind turbines behaviour and result in decreasing loss of wind power following disturbances (Erlich et al., 2006).

Input data, wind power modelling: Data on the regional development of wind energy for the years 2007, 2010 and 2015 (see following table). To describe the regional effects, the German extra high voltage grid is divided into six grid regions: East, Northwest, Central, Southeast, West, Southwest.

Table 13. Resulting feed-in wind turbine capacity per time horizon and grid region [in MW] (taking into account the coincidence factor of 0,9) (DENA, 2005).

	2003	2007	2010	2015
East	4950	7970	8843	9410*)
Northwest	4240	4980	5250	5600**)
Central	1590	2020	2160	2178
Southeast	70	200	280	298
West	1620	4052	4946	5647
Southwest	193	368	436	450
Total	12 663	19 590	21 915	23 583

*) additional offshore 2015: 1540 MW
**) additional offshore 2015: 7281 MW

For the static investigations the following variants are examined respectively for each examined time horizon:

- Peak load without wind
- Peak load with wind
- Low load without wind
- Low load with wind.

A comparison of generation, grid load, losses, storage and power exchange in Germany in 2015 for peak load with wind / without wind and low load with wind / without wind is shown in the following figure. During times of low load and high wind up to 60% of load is generated by wind energy only.

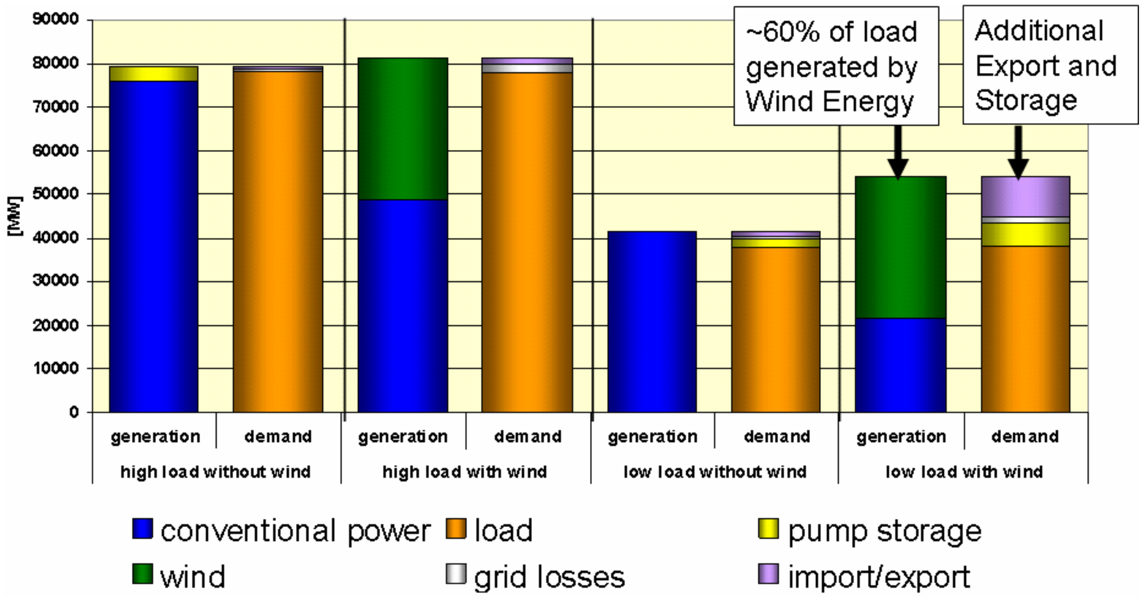


Figure 22. Comparisons of Generation, Grid Load, Losses, Storage and Power Exchange in Germany in 2015 (DENA Grid Study, 2005).

Methodology: The grid calculation software INTEGRAL developed by the research institute Forschungsgemeinschaft für Elektrische Anlagen und Stromwirtschaft e.V. (FGH e.V.) is used for quasi-static calculations. The dynamic calculations and simulations carried out as a part of this study are carried out with the software NETOMAC.

Assumptions: For the calculations in the strong wind scenarios it is assumed that 90% at most of the installed capacity from wind turbines are simultaneously fed into the grid throughout Germany.

Limitations: Analysis covers only the grid extension and effects in the 380 kV transmission grid.

4.2 UK

The location of wind generation, like conventional generation, can have a significant effect on transmission. Historically, transmission costs in the UK have been driven by a north-south flow from thermal generators located predominantly in the north, to demand in the south. With significant wind resources in Scotland and off the North West and North East of England and North Wales coasts, it is possible to envisage scenarios where this pattern of flows endures, despite the retirement of many of the existing conventional stations, thereby increasing the requirement for transmission reinforcement and the level of transmission losses.

Alternatively, if onshore wind generation were developed across Great Britain and included the offshore wind resources around the England and Wales coast, then transmission reinforcement costs could be significantly smaller. Furthermore, the location of new conventional generation and of decommissioned plant will also have a considerable impact on the future needs for transmission capacity.

The effects of connecting wind power plants at various locations across the country on the transmission reinforcement cost was considered (Strbac et al., 2007). This included the impact of the locations of new conventional plant and decommissioning of existing generation. The range of cost was found to be between £65/kW to £125/kW of wind generation capacity for 26 GW of wind power and £35/kW–£77/kW for 8 GW of wind. Lower values correspond to scenarios with dispersed wind generation connections, with significant proportions of offshore wind around the England and Wales coast, while the higher values correspond to the scenarios with considerable amount of wind being installed in Scotland and North of England. Still higher costs could be obtained if all existing conventional generation is assumed to remain in service in Scotland and northern areas. A value of £100/kW is used as a representative value for transmission infrastructure costs. For 26 GW of wind, this implies capital investment requirements of £2,6b, but given the range of costs in (ILEX & Strbac, 2002), the investment, depending on its location, will be between £1,7b and £3,3b.

The cost of connecting dispersed wind generators in remote areas to the main transmission network may be significant. For example, the cost of connecting renewable resource from the Western Isles in Scotland or connecting offshore wind power plants to the transmission system may be considerable. Average wind connection costs are assumed to be in the range of £40/kW to £70/kW reflecting a variety of siting and different scope for economies of scale. £50/kW is used as a representative value. Assuming 60% of wind is directly connected to the transmission system gives a connection capital investment requirement between £0,6b and £1b.

4.2.1 Impact on system stability

Much speculation exists concerning the influence of wind power plants on system operation and stability. Wind power plants based on Fixed Speed Induction Generators (FSIGs) have poor transient stability characteristics, but they add significantly to the damping of the system. The operating characteristic of a synchronous generator is such that power output changes are most directly linked to changes in rotor angle. Since, damping is governed by torque (or power) variations in phase with speed variations, the natural response of a generator connected to a power network is oscillatory. The operating characteristic of an induction machine is such that torque changes are related directly to speed changes. With an induction generator, therefore, under oscillatory system conditions the torque variations produced are predominantly in phase with speed variations. Consequently, under oscillatory conditions the power variation imposed on the synchronous generators is predominantly damping power so that the introduction of an FSIG on a system improves the system damping. Although damping contribution of a doubly fed induction generator (DFIG) tends to be less than that of a FSIG, the results indicate that significant improvement in the system damping and dynamic stability margin is provided.

4.2.2 Value of fault ride through capability for wind power plants

UK Centre for DG&SEE has conducted a study with the objective to estimate the order of magnitude of additional system cost that would need to be incurred in order to accommodate wind generation of varying degree of the capability to withstand faults (www.sedg.ac.uk). The cost associated with accommodating wind generation that is not fully capable to ride through faults were assumed to be composed of: (i) additional response cost, mainly fuel cost due to running the conventional plant at lower efficiency and (ii) additional fuel cost due to the substitution of conventional generation for wind generation curtailment, that occasionally may be necessary to maintain the feasibility of system operation. Furthermore, operating an increased number of generators part loaded and having to curtail some of wind generation increases CO_2 emissions that were also estimated. Overall, the work carried out demonstrated that, if a significant amount of wind generation with relatively low robustness is to be installed this would lead to a very considerable increase in system costs in the case of the UK. These additional costs would be significantly higher than the expected cost of engineering necessary to provide fault ride through capability. The results of the studies performed suggest that requiring sufficient fault ride through capability for large wind power plants would be economically efficient.

4.3 Netherlands

4.3.1 Grid reinforcement, Connect 6000 MW I

In 2003 the Ministry of Economic Affairs of The Netherlands initiated a study on the effects of 6000 MW offshore wind on the Dutch grid. The peak load of the high voltage grid is 15,2 GW (2005). The best locations for 6000 MW wind power were determined based on cost analysis and the options to transport the power to the on-shore substation were investigated.

In the second part of the study, the consequences for the 150/380 kV grid of The Netherlands have been determined by a load flow study (Jansen & de Groot, 2003).

Results: Figure 23 shows the bottlenecks caused by the additional wind power. New and/or upgraded HV connections are suggested to mitigate the problems. Secondly, voltage control equipment is required. Investment costs were estimated at about 310 ME. If 30% of the new or upgraded connections have to be cables instead of overhead lines the total costs rise to about 970 ME.

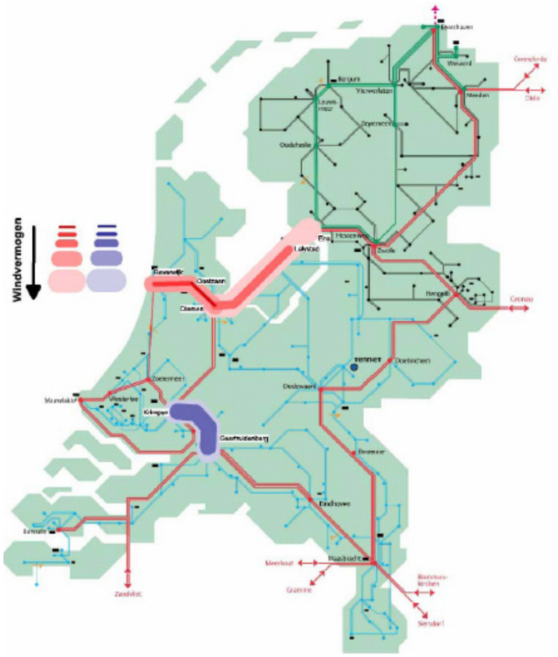


Figure 23. Offshore wind power induced bottlenecks in the transmission grid of the Netherlands.

Input data, wind power modelling: There is no wind model used. Amount of wind power changes up to nominal power.

Methodology: The consequences of 6000 MW offshore wind power on the 150/380 kV grid have been determined by a load flow study. The feed-in locations are Beverwijk and Maasvlakte.

4.3.2 Electrical infrastructure at sea, Connect 6000 MW-II

In 2005 the Ministry of Economic Affairs contracted a second study, Connect II. This study consists of scenarios for the implementation of wind power, pre-design and costs for the grid at sea as well as environmental, legal and political aspects. Here the part Electrical infrastructure at sea is summarized (Eleveld et al., 2005).

Methodology: The study comprises a further development of three of the options in the Connect 6000 study: 150 kV-AC, 380 kV-AC and HVDC Classic. For the 150 kV-AC a different case is studied than previously, viz. individual connection of wind power plants. For the 380 kV option two cases are studied: radial and ring structure. The HVDC option is also ring shaped. The main technical features of the options are determined, including aspects related to the sea-shore crossing. The investment costs of the options were determined and different economic scenarios were compared.

Results: Table 14 gives the net present value (Billion Euro) of the investments for a discount rate of 7% and four development scenarios. The scenarios differ in the time to fully complete the total installed capacity.

Table 14. Net present value (billion Euro) of the investments for a discount rate of 7%. In scenario 1 the total capacity 6000 MW is reached in 2020 whereas in scenario 2 in 2030.

	Scenario 1	**Scenario 2**
150 kV AC	0,96	0,77
380 kV AC star	1,01	0,80
380 kV AC ring	1,55	1,19
HVDC Classic	1,80	1,43

4.4 Portugal

4.4.1 Transmission grid development studies

Grid development due to high wind penetration goals was needed for two main reasons: need for the grid to be extended to collect wind power in areas of high wind potential and because wind power will increase the excess generation of several inner areas of the country. The 'Transmission Grid Development Plan for Renewables – 2010' was carried out in 2001, and its results incorporated in the grid planning decisions included in the Transmission Grid Plans that the TSO REN must present to the Regulator each two years. The original plan of 2001 was done by 'Centro de Energia Eléctrica', Department of Electrotechnical and Computer Engineering of the Instituto Superior Técnico (IST), Lisbon Technical University, and REN, SA.

Results: It will be necessary to build new transmission grid 400, 220 and 150 kV lines and substations, to uprate a considerable number of existing 220 and 150 kV lines, to increase the grid reactive compensation and to introduce phase shifter autotransformers in two substations. As for transmission grid integration costs, and for a level of 4000 MW, for the overall period 2005–2010, the investment directly attributable to renewables, mostly for wind parks, will total 200 Million €. That number:

- Is the sum of the proportion of the cost of each individual grid item (line, substation, etc.) directly attributable to the creation of grid capacity for renewables. We must take into consideration that most of the grid elements of this plan also will serve other grid objectives. Should we add simply the cost of all the grid items involved, the total cost would be around double (400 M€).

- Does not consider the investment of the wind park main substation nor the direct line to the TN connection point, which are built and paid by the developer.

Methodology: Usual AC steady-state simulation of the grid with PSS/E model of Siemens/PTI, the same used in 'classic' grid development studies.

Assumptions: Wind generation was set in three levels: 80%, 30% (average situation, used also to calculate expected losses in the grid) and 10%. As for the other generation components, the usual planned scenarios were considered: 'Crossing' among the relevant: 1 – High hydro (less thermal) and dry situations (more thermal) 2 – Balanced and high interchange situations 3 – Extreme import or export values 4 – Loads are simulated in peak, valley and some intermediate load situations. It was also assumed that it is possible to uprate the ratings of some existing lines and that it is possible to consider the contribution of FACTS such as phase shifter autotransformers.

Limitations: When the first study was done neither the detailed location of the future wind power plants nor the pace of building was known. The TSO REN had to rely on the previous studies of location of wind potential. REN had to introduce some flexibility items in the planning solutions to cope with possible different outcomes in those two fronts.

4.4.2 Power system transient stability of the Portuguese grid

REN investigated, in 2004, the impact of the expected wind by 2010 on the transient stability of the Portuguese transmission grid, also in cooperation with IST – Instituto Superior Técnico – Centro de Energia Eléctrica, and examined the need to specify new requirements for wind turbine generators (WTGs) to withstand voltage dips produced by short-circuits in the grid without disconnection.

Results: For some faults in a few specific busbars of the grid loss of synchronism may occur in some parts of the Iberian Peninsula grid, should the current practice of undervoltage protection to operate instantaneously in WTGs remain in the future. The implementation, in a significant percentage of the installed wind generation, of control equipment to ensure fault ride through capability – FRTC, results in a significant reduction in the disconnection of wind power.

It is relevant to note that the loss of wind power in Portugal has an impact on the Spain-France interconnection, which is normally operated with commercial exchanges from France to Spain.

Input data, modelling: Usual PSS/E dynamic simulation data with detailed Iberian Peninsula and French system equivalent. Special care has been taken in the simulation of each WTG technology.

Methodology: Usual transient simulation studies with the following assumptions:

Assumptions: Three-phase faults cleared in time of the circuit-breaker failure protection and of 2nd step of distance protection (teleprotection failure), as well as the usual three-phase faults with 'normal' clearing times.

Limitations: WTG's models acceptable but not state-of-the-art. Wind penetration (2600 MW) smaller than later set national objectives.

4.5 Power system stability of the Iberian transmission grid

A study by Red Eléctrica de España, SA (Spanish TSO), 'Producción Eólica Tecnicamente Admissible en el Sistema Eléctrico Peninsular Ibérico – Horizonte 2011' with the participation of REN – Rede Eléctrica Nacional, SA, the Portuguese TSO, was concluded in 2006 and covered the transient simulation of the Iberian network in order to identify limits for wind penetration under the stability point of view.

Results: It showed that 20 GW of wind power in Spain and 5 GW of wind power in Portugal are possible if fault ride through capability (FRTC) is reached for 75% of the installed wind turbines. It also showed that there are no limits, due to transient stability reasons, should 100% FRTC be possible.

Input data, modelling: Usual PSS/E dynamic simulation data with detailed Iberian Peninsula and French grids + 'Remaining UCTE system equivalent'. Special care has been taken in wind turbines modelling, getting models from manufacturers, in most of the cases under non-disclosure agreements.

Methodology: Transient simulations of the Iberian power system submitted to three-phase faults located in bus bars of the transmission network. Simulations of these faults are based in the operation of protective relays (REE, 1995) in the Spanish case. The simulation time is 20 s since the fault is applied. A peak demand scenario in winter and a valley demand one in summer are considered.

Assumptions: Three phase faults cleared in time of the circuit breaker failure protection and of 2nd step of distance protection (teleprotection failure) as well as the usual three faults with 'normal' clearing times. The clereance of three-phase faults are 250 ms in Spain and 250/300 ms in Portugal. The study is focused in 11 nodes (400 kV). All the wind farms operating in Spain are considered, distinguishing technology (induction generator –squirrel cage and wounded rotor– synchronous generator –full power converter– and doubly fed induction generator) and adding future wind farms. Future wind farms are modeled with wind turbines supporting voltage dips and complying the Spanish Grid Code. In simulated scenarios, a new 400 kV line between France and Spain has been considered which will increase the interconnection capacity between France and Spain from the current maximum of 1,5 to 4 GW.

Limitations: This new France – Spain interconnection reinforcement has not yet the environmental and administrative licences. The results assume that it will be possible to enhance a part of the existing wind turbines to FRTC. This will not be easy considering that in the Iberian Peninsula, more than 12 GW are already installed, many of which with 'old' technologies.

4.6 Spain

The Spain's installed power capacity was 11 615 MW (14% of the total power capacity) at the end of 2006, with a generated energy of 23 063 GWh (9% of the total annual demand). Moreover, Canary Islands, currently with installed wind power of 129,49 MW, have fixed a final target of 1025 MW for 2015. The generated energy of this target will exceed the forecasted electricity demand for this year in valley hours.

4.6.1 Power system transient stability and grid reinforcement

Different studies, (REE/REN 2005, Rodríguez-Bobada et al., 2006), were carried out by Spanish and Portuguese TSOs REE and REN to determine the maximum wind power capacity that the Iberian grid could handle (see previous section).

The importance of future 400 kV D/C interconnection line with France was highlighted. In the Spanish case, wind power development has imposed new connecting and operating rules, being the connection and reinforcement costs paid by wind power plants (from the wind power plant to the electrical substation). On the other hand, this has provoked an updating in connecting requirements, protection equipment, remote metering and control, resolution of constraints or wind power plant clustering.

Obviously, transmission network must be updated as well; the investment 2200 Million €, not only attributable to renewable, has been estimated by REE for the overall period 2006–2010. In terms of investments due to wind energy, it is difficult to obtain the figures for the Spanish case, since grid reinforcements and new lines are needed for wind power plants and other clients (electrical demand growing rates have been high in the last years).

4.6.2 Low Voltage Ride Through capability for wind power plants

REE grid code, recently approved, specifies that the wind farm must support voltage dips, at the point of interconnection with the transmission network, without tripping. In (Gómez-Lázaro et al., 2007) REE grid code is commented in detailed, justifying the different values imposed by the Spanish Grid code (Operational Procedure 12.3).

The procedure for measuring and assessing the response of wind farms submitted to voltage dips – specified in the electrical system Operational Procedure 12.3 – will be established in the "Procedure for measuring and assessing the response of wind farms in the event of voltage dips".

This procedure can be accomplished with a general verification process or using a particular verification process. The general verification process consists on verifying that the wind farm does not disconnect and the execution of the requirements settled down in the OP 12.3, by means of the realization of the following actions:

- Wind turbine and/or FACTS tests in field, measuring their response during a voltage dip
- Wind turbine and/or FACTS simulation and validation. Simulated results are compared with the measurements.
- Wind farm simulation. Wind farm model must include certified wind turbine models, together with the wind farm electrical installation – cables and transformers –, being the rest of the electrical system outside of the wind farm modeled as an ideal programmable voltage source. The source must provide two different Rms voltage profiles – three-phase and phase-to-phase voltage dips –. Assessment and certification of compliance of wind farm model is obtained when none of the wind turbines in the wind farm is tripped together with the fulfillment of active and reactive power requirements imposed by the Spanish grid code.

Clearly, wind turbine and wind farm models have an important role to play in the whole process. According to the requirements imposed by this procedure, complete wind turbine and wind farm models must be developed (Gómez et al. 2007a,b).

4.7 Norway

Report: (Korpås et al., 2006)

When planning wind power in areas with limited power transfer capacity, conservative assumptions may lead to unnecessary strict limitations on the possible wind installation. By introducing Automatic Generation Control (AGC) and coordinated power system operation, a large increase in installed wind power is viable. When assessing the impact of wind power on the power system operation it is necessary to take into account the stochastic and dispersed nature of wind power. This study and previous studies have shown that in the Nordic region, the periods with highest wind generation typically appear in the winter season when the consumption also is high, which has a positive impact on the utilisation of the existing transmission capacity. Moreover, this study shows that the power smoothing effect of geographically dispersed wind power plants gives a significant reduction of discarded wind energy in constrained networks, compared to a single up-scaled wind power plant site.

The specific case study presented consists of a regional power system with assumed 420 MW power transfer capacity. With existing hydro power installation of 380 MW and 75 MW minimum local, the most conservative approach limits the total wind power installation to 115 MW.

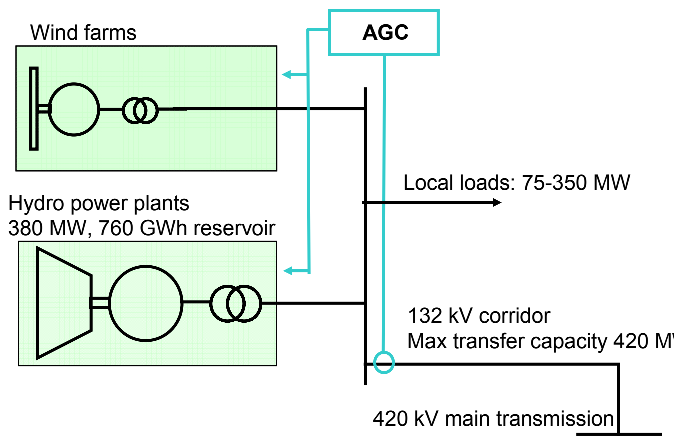


Figure 24. Overview of the case study power system. The regional grid is connected to the 420 kV national grid via a corridor of several 132 kV lines. Automatic Generation Control (AGC) is regarded for keeping the power transmission below the maximum export capacity of 420 MW.

Method: A simulation model of the regional power system has been implemented in MATLAB. To run the simulations of the regional power system, 30-year time-series with hourly resolution has been constructed for the following time-varying parameters:

- Normalised wind power output (non-congested) from three wind power plants
- Electricity consumption
- Storable inflow
- Non-storable inflow
- Scheduled hydro generation
- Electricity market price.

For the construction of wind power time-series for each wind power plant site, a common 30-year wind speed series with weekly resolution has been combined with the 1-year wind speed series with hourly resolution. The weekly wind speed series is scaled to give a 30-year average of 10,5 m/s. The 1-year time-series is normalised and multiplied with the weekly wind speed averages to give an 8760 hour x 30 year matrix of wind speed which is converted to power by using a typical wind turbine power curve. The sum hourly wind generation is simply calculated as the sum of power generation from the three wind power plants.

The other time-series listed above have been constructed by using the EMPS-model (Multi-Area Power Market Simulator), a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting. This is a complex stochastic optimisation model that simulates the optimal operation of the hydro power resources in a region with a stochastic representation of inflow to the hydro power stations and a number of physical constraints taken into account. The electricity consumption has been modelled as temperature-dependent, causing some yearly variations. Long-term increase in consumption has not been considered. An EMPS-simulation of the Nordic power system has been run without wind power in the area of interest, to provide a basis for the hydro power scheduling as well as the electricity market price.

It is possible to use EMPS to simulate the Nordic power system with geographically dispersed wind power, especially to assess the value of wind power in the electricity market and to determine the effects of large-scale wind power integration on optimum long-term hydro scheduling. In this case, on the other hand, EMPS is less suitable mainly because of the low time resolution of the EMPS-model (one week) and the limited flexibility of defining control strategies for wind-hydro coordination in an area with considerable transmission constraints.

Since the time resolution of the output from EMPS is one week, the hour-to-hour variations of consumption, inflow, hydro generation and price has to be synthetically generated. The hourly values of the consumption and hydro generation have been constructed as products of the weekly average values and typical diurnal variations observed in the Nordic power system. The hourly values of the other parameters (storable inflow, non-storable inflow and price) are simply constructed by interpolating the weekly values.

Result: The study shows that for the specific system studied up to 600 MW wind power is possible without noticeable reduction in income from energy sales compared to an ideal non-congested case, by applying coordinated operation of the wind and hydro power plants. It is emphasized that this is achieved for a hydro power system with relatively small reservoir and a high share of non-storable water inflow (37% of the total storable + non-storable inflow). Even if the local hydro power plant follows the generation schedule unaffected by wind power, the reduction in income due to discarded wind energy is as low as 1–5%, depending on the annual wind speed and water inflow.

It is concluded that power system coordination allows for surprisingly large amounts of wind power. It is essential to take account for the power system flexibility and the stochastic and dispersed nature of wind power. The presented methodology facilitates this and represents a rational approach for power system integration of wind power plants in areas with limited transfer capacity.

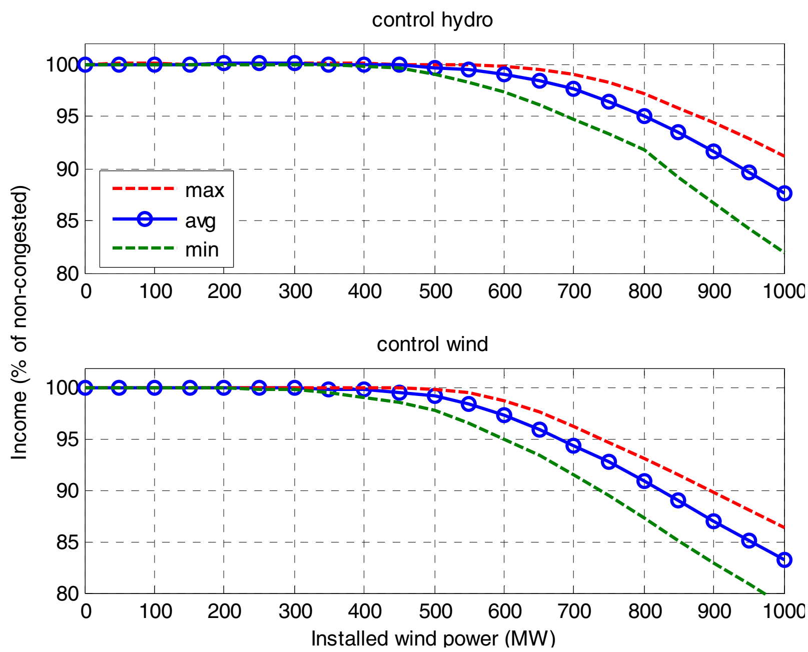


Figure 25. Annual income (wind+hydro) from energy sales to electricity market relative to the non-congested case.

4.8 Sweden

PhD study by Julija Matevosyan "Wind power integration in power system with transmission bottlenecks", 2006. Study: Economical evaluation of the value of transmission expansion to limit wind power spillage.

Results: With no grid extension the spillage resulting of different wind power installations in northern Sweden are presented in Table 15.

Table 15. Estimated wind energy spillage in North Sweden without grid investments, calculated with two methods.

Installed wind power [MW]	Transm. limit exceeded [h]	Spill, % (discrete probabilistic method)	Spill, % (direct method)
1000	94	1.9	0.8
2000	453	5	3.4
3000	750	10.1	7.4
4000	1019	16.7	12.4

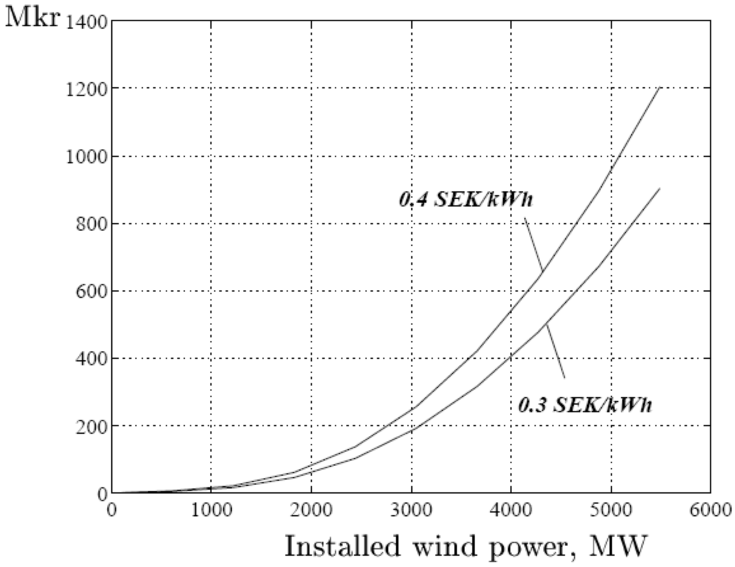


Figure 26. The cost for the spillage as a function of installed amount of wind power for two price levels of the spillage.

4000 MW of wind power will lead to 15,4% of wind energy being curtailed with cost of approximately 540 MSEK/year with the curtailment cost of 0,4 SEK/kWh. For 3200 MW it is 300 MSEK/year. Consequently, a new 800 MW transmission line decreases costs for energy spillage to 540–300 MSEK/year. The cost for the needed 800 MW transmission line is for this case 400 MSEK/year. For this case it is therefore not motivated to build a new line just to motivate lower wind energy spillage.

Input data, modelling: Line cost data, current use of actual transmission corridor, interest rate for transmission line investment, duration curve of possible wind power production. Cost of wind energy spillage.

Methodology: Simplified calculations based on duration curves and available time series.

Assumptions: No use of local hydro power storage (or any other kind of local use of wind power) in Northern Sweden to store excess wind power. If this is considered (which is done in the thesis) then the value of increased transmission will decrease even more.

Limitations: A specific study for this certain region, where an extension of a large corridor with 7000 MW capacity is considered.

4.9 USA

The US grid code for issues dealing with the interconnection of wind turbines in projects greater than 20 MW is addressed in FERC Order 661-A, issued in December of 2005. The major provisions of the order address requirements for low-voltage-ride-through LVRT, reactive power, and SCADA. For LVRT, the generator is required to stay on line during a 3 phase fault for normal fault clearing time up to 9 cycles and single line-to-ground faults with delayed clearing during a voltage dip as low as .15 pu at the high side of the generator step-up transformer for units in service before 2008. The voltage dip requirement extends to 0,0 pu in 2008. For reactive power requirements, the wind plant must provide power factor of +/- .95, including dynamic voltage support, if needed for safety and reliability. For SCADA, the wind plant must provide the necessary information, as agreed upon with the transmission provider. This information may include some combination of electrical parameters and weather data.

The impact of wind generation on system dynamic performance is illustrated in Figure 27 (GE Energy, 2005). The simulation is for a normally cleared three phase fault on a critical 345 kV bus in New York State. The simulation assumed a 10% wind penetration (3300 MW on a 33 000 MW system) of doubly fed induction machines with vector controls. As can be seen from the simulation results using the GE PSLF program, the post-fault voltage recovers more rapidly and is more highly damped with the wind plants than without, and the line flow has less over-shoot and is more highly damped.

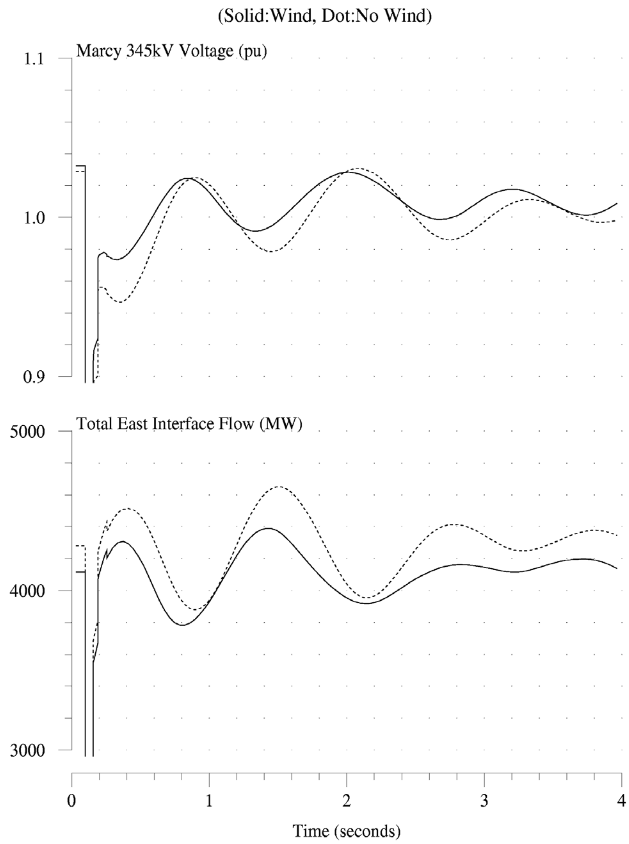


Figure 27. Impact of Wind Generation on System Dynamic Performance.

4.10 European Wind Integration Study EWIS: Phase one, 2006

European Transmission System Operators launched a European wide grid study on the integration of wind power in 2006. The scope of work covers the technical, operational and market aspects related to the smooth integration of large scale wind power all over Europe. The study focus is on measures needed to be taken by legislators, regulators, grid operators and grid users, to enable establishing a harmonised set of rules for the integration of wind power, which is vital for secure and reliable operation of the electricity networks in the presence of variable generation. Phase one of the project has analysed cases for year 2008. Phase two will investigate the time horizon up to 2015. The study will obtain the necessary information for the technical and operational measures for risk mitigation and the secure operation of the European electricity grid, identified by the steady-state and dynamic investigations on electricity grid models (EWIS, 2007).

Results: First results show that expansion of wind power generation has significant effects on the European electricity system. Wind power is concentrated in Europe: 70% of the installed wind power is concentrated in only 3 countries. This is producing a high surplus of power generation in regions like northern Europe resulting in large North-South power flows through the transmission system of Germany and neighbouring countries e.g. the Netherlands, Belgium, Poland and Czech Republic. Serious bottlenecks on internal and cross border lines in northern Europe are detected already today, becoming more structural for the time horizon of 2008. Internal overloads are observed in Germany, Czech Republic, Poland, Belgium and the Netherlands for single circuit outages in case of high wind power production in northern Europe.

Investigated measures for the time horizon of 2008 to prevent these overloads are described in the EWIS interim report (EWIS, 2007).

Input data, wind power modelling: Using existing time-series (15-minutes-values) of the wind power production, a point in time with the highest simultaneous wind power production in the northern UCTE countries was identified for UCTE Scenario North. For UCTE Scenario South the highest simultaneous wind power production in southern UCTE countries was identified.

For each country an individual level of wind power generation was then determined. In order to extrapolate the data into the year 2008, the expected wind power installed in each country in 2008 was used. Synchronous time series were available from Germany, Spain, Portugal, Denmark, Austria and Belgium. In circumstances where no time-series of wind power production data was available, the wind power production was estimated from wind speed measurements of numerous weather stations in the countries.

Methodology:

Assumptions: Year 2008 wind scenario: The study comprises two wind situations with major impact on the operation and security of the European transmission network:

- Wind Situation UCTE North: Maximum wind power production of northern UCTE countries (Austria, Belgium, Czech Republic, Denmark, North-France, Germany, Hungary, Netherlands, and Poland)
- Wind Situation UCTE South: Maximum wind power production in southern UCTE countries (South-France, Greece, Italy, Portugal and Spain).

Limitations: The precise impact of phase-shifters on cross-border bottlenecks will be further analysed in later studies. Without the use of phase-shifters, overloads of tie-lines are observed between Germany and the Netherlands, and Germany and Poland. By adjusting the settings of the phase-shifters in the Netherlands, Germany and Belgium to limit cross-border flows, the overloads of the tie-lines between the Netherlands and Germany can be reduced in 2008. Overloads near the Dutch-Belgian border can also be reduced with the use of phase-shifters in Belgium. Considering the already planned network expansion inside Germany, overloads of the interconnection between Poland and Germany do not occur any more. Until the realisation of the new 380 kV double overhead line between Neuenhagen and Bertikow, which is planned for 2009, a set of temporary operational measures can be taken in order to ensure operational security.

Internal bottlenecks: High wind power generation combined with high power production of conventional power plants with comparatively low marginal costs in the North of Germany and additional large import from NORDEL results in large North-South power flow in Germany. This causes several internal overloads during N-1 conditions. Internal overloads are also observed in Czech Republic, Poland, Belgium and the Netherlands for N-1 conditions in UCTE Scenario North. Investigated measures to eliminate these overloads are described in the detailed analysis.

5. Power system adequacy and capacity credit of wind power

Power system reliability consists of system security and adequacy. A power system is adequate if there is a sufficient installed power supply to meet customer needs. A system is secure if it can withstand a loss (or potentially multiple losses) of key power supply components such as generators or transmission links. This chapter focuses on the impact that wind generation has on generation adequacy. Transmission adequacy is the issue in chapter 4.

The analyses for system adequacy are made several months or years ahead and associated with static conditions of the system. This can be studied by a chronological generation-load model that can include transmission and distribution or by probabilistic methods. The estimation of the required production needs includes the system demand and the availability data of production units.

Capacity credit (sometimes called capacity value) is the contribution that a given generator makes to overall system adequacy. Even the availability of conventional generation is not assured at all times because there is always a non-zero risk of mechanical or electrical failure. Because reliability is expensive it is common to adopt a reliability target for the system. The capacity value of any generator is the amount of additional load that can be served at the target reliability level with the addition of the generator in question.

The next section of this chapter discusses methods that are used to assess wind capacity value. The following sections provide a brief summary of results from countries that have performed capacity valuation of wind generation.

5.1 Approaches to assessing wind power capacity effects

Although there are several methods used to calculate wind capacity value, most methods are based on power system reliability analysis methods.

The criteria that are used for the adequacy evaluation include the loss of load expectation (LOLE), the loss of load probability (LOLP) and the loss of energy expectation (LOEE), for instance. LOLP is the probability that the load will exceed the available generation at a given time. This criterion gives an idea of the possibility of system malfunction but it lacks information on the importance and duration of the outage. LOLE is the number of hours, usually per year, during which the load will not be met over a defined time period. One key capacity value metric is effective load carrying capability (ELCC). This metric is calculated by calculating a suitable reliability measure such as loss of load probability or loss of load expectation for the year.

During the course of system operation through the year, generating units can be in one of several states. Units are scheduled for maintenance at regular intervals, and this is typically scheduled during non-critical system periods. However, it is always possible that any generator could fail unexpectedly at any time of the year. The unexpected nature of these forced outages is the primary concern and focus of reliability analysis. Contingency reserves (sometimes called disturbance reserves) are provided to ensure against system collapse in the event of a forced outage. System adequacy assessments must take planned outages and forced outages into account, although the different types of outages are treated very differently in the reliability model. Additional consideration includes hydro system operation, both run of river and reservoir hydro power (and pumped storage, if available). Other system services may also be quantified in the reliability model. Thus generating capacity, after the deduction of various sources of unavailability – non-usable capacity, scheduled and unscheduled outages – and reserves required by TSOs for system services (UCTE, 2005) are all considered in the reliability calculation. The level of remaining capacity (RC) necessary to provide a required level of supply adequacy must be estimated taking into account the characteristics of the power system. Figure 28 shows the components of the national power balance at the moment of peak demand. In general, this kind of graphical representation assigns the installed wind capacity partially to the so-called "non usable capacity" and partially to "guaranteed capacity[1]". The proportion reflects the capacity credit assigned to wind power. Unfortunately, several prominent system adequacy reports (UCTE, VDN) still fully allocate wind power to "non usable capacity"[2] . System risk as measured by various reliability metrics is reduced for each additional MW of generating capacity that is online, whether scheduled or not. We therefore recommend that a reliability-based metric should be used to address wind capacity value.

[1] Because no capacity can be absolutely guaranteed, we use this term to denote the capacity that is available with a given probabilistic target. This target is commonly measured as loss of load expectation (LOLE). A common reliability target for a system is 1 day in 10 years LOLE. The capacity that can provide this target, or other suitable target, is what we call 'guaranteed capacity.'

[2] UCTE definition of non-usable capacity: "Non-usable capacity is the part of generating capacity which cannot be scheduled, for different reasons: a temporary shortage of primary energy sources (hydroelectric plants, wind farms) …." (http://www.ucte.org/statistics/terms_power_balance/e_default_definitions.asp)

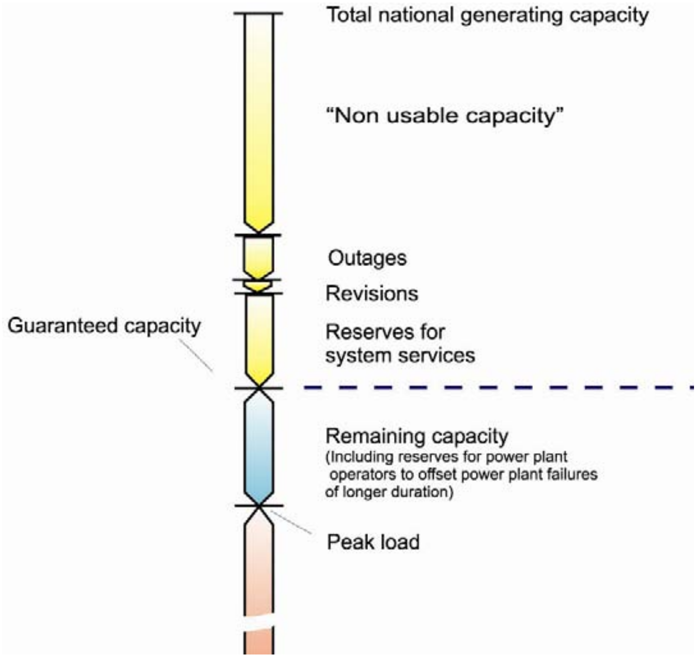


Figure 28. Power balance in the moment of peak demand (adopted from VDN2005).

To determine system adequacy, a desired level of achievable reliability is chosen (Ensslin, 2006). A commonly used reliability target is 1 day per 10 years outage rate, known as the loss of load expectation. In different national specifications, reliability levels are found ranging from a 99% level (see dena, 2005, for Germany) to a 91% level (Ilex & Strbac, 2002, UK). The 'risk level' refers to a probability of the power system under investigation not to be able to cover its peak demand without electricity import. Here "without import into the system" needs to be highlighted. It means that the criteria not being met do not automatically lead to a blackout in the system. Instead, cross border transit capacities have to be used – a fact that links adequacy to market and regulatory aspects.

The 'guaranteed' or reliable conventional generation capacity is calculated by the combination of all individual power plants' probability of availability which can be calculated using the forced outage rate. This is based on the assumption that outages of individual generation units are statistically independent. The probability of generation unit forced outages vary for individual generation units between 1% and 10% of the time, depending upon technology, age and size of the plant (see for example statistics from operation in Germany, (Dena, 2005 for Germany).

For wind power, the capacity value indicates the increase in load that could be served by wind, holding the reliability level constant. In effect this measures the capacity value of wind relative to a perfectly-reliable generating unit. One variation on this method measures capacity value relative to a benchmark unit.

5.1.1 Chronological Reliability Models

Capacity credit is a probabilistic value that is derived from system observation in the time domain using several time series that include load, wind, and conventional capability. The different ways of transition from the chronological values to frequency distributions provide an essential distinction between approaches for the calculation of capacity credit.

In the time-step or chronological simulation approach the hourly or 15 min values of the total wind power production are subtracted from hourly or 15 min load data and the residual power is assigned to the available conventional generation units by a scheduling or reliability model, e.g. the 'National Grid model' (Giebel, 2000). The chronological approach requires:

1. correct load time series for the period of investigation,
2. unbiased wind power time-series for the same period as the loads,
3. a complete inventory of conventional generation units' capacity and forced outage rates,
4. target reliability level.

To calculate the capacity value of wind, three reliability model runs are required. Each run may require several iterations to achieve the various reliability targets. First, the model is run to ensure that the reliability target can be attained. If the system does not achieve this reliability level, generation must be added or load decreased (or both changed) to achieve the target. Second, the wind generation is added to the modelled system. The new higher reliability value (lower LOLP) is recorded, and the wind is then removed from the model. Third, either a benchmark unit is added to the system or the load is increased so that the reliability level matches the one from the second step. The increase in load (or benchmark generation) from this step is the capacity value of wind.

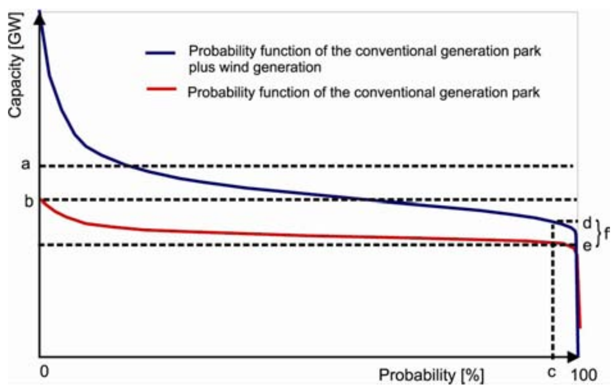
Capacity value, as measured by a reliability metric such as ELCC, is quite sensitive to the timing of wind energy delivery relative to peak load periods. Recent work in the U.S. has utlized high-quality wind data that is from the same time period as the load. This provides the most realistic assessment of wind's contribution to system adequacy if these time-sychronized data series are used as inputs to a chronological reliability model. Wind and load vary from year to year, so it is important to perform a multi-year analysis using time-synchronized wind and load data if possible. Otherwise, sequential Monte Carlo can be used as long as the Monte Carlo method can retain the diurnal and seasonal characteristics of the wind generation through time.

5.1.2 Probabilistic Reliability Methods

While hourly load and wind generation profiles for at least one year are essential prerequisites for wind power capacity credit calculations, a number of studies – such as the dena study – have been exposed to a lack of load profiles for the power system investigated. As an alternative, several of those studies used a probabilistic representation of wind generation for the capacity credit calculation (also called load duration curve method).

The reliable capacity of the system including wind is determined by convolving the wind power probability density function with conventional power plant probabilities. In the studies, (DENA, 2005; Ilex & Strbac, 2002), all installed wind power has been defined as one wind power 'unit'. In order to determine the power probability function of this aggregated 'wind power block', it is again assumed that long-term statistics on wind power availability deliver its probability to be available during hours of significant system risk (high LOLP or equivalent). Reliability models look for periods of time with significant risk. To ensure that no human bias is involved, it is recommended that specific hours or days should not be pre-screened to use for the analysis.

The capacity credit is calculated as the difference between the two reliability curves at the target risk level: the power system without and with wind energy. Figure 29 shows how the conventional (thermal and large hydro) generation capacity varies with the target risk level, when taking into account the probabilities arising from technical availability for power generation. In the figure, *c* denotes the reliability target, the red line is the reliability curve without wind, and the blue line is the reliability curve with wind. The distance between points *d* and *e* is the ELCC capacity value of the wind generation.



a: installed conventional generation capacity
b: available conventional generation capacity
c: level of supply security
d: guaranteed capacity of combined wind and conventional generation according to level of supply security
e: guaranteed capacity of conventional generation according to level of supply security
f: guaranteed capacity of wind power = 'capacity credit'

Figure 29. Dependency of wind power capacity credit on the probability of 'guaranteed capacity' (based on dena study figure (DENA, 2005)).

Weather influences both electricity consumption and wind power generation. Although it may be difficult to directly calculate the statistical correlation between them, there are certainly complex interrelationships between wind and load. Even in cases with wind separated from load centres by relatively large distances, the weather correlation may consist of a complex lag structure that varies based on time and weather conditions. Because of this, it is critically important to use wind and load profiles that result from a common weather driver to calculate wind capacity value. In a practical sense this means that at least one year of hourly wind generation and load must be obtained from the same calendar year. Because wind generation profiles and energy capture can vary from year to year, it is preferable to assess wind capacity value on multiple years of time-synchronized wind and load data.

The probabilistic approach immediately converts wind power time series into probability density of power levels, to be combined with the probabilities of conventional power stations' availabilities. A main reason to apply this approach can be the lack of appropriate chronological data. However, the probabilistic approach will not be informed by variability of wind generation and is not as accurate as the chronological approach. The probabilistic approach requires:

1. correct load time series for the period of investigation,
2. wind power probability density, varying by month or season that can accurately represent the same period as the loads,
3. a complete inventory of conventional generation units' capacity and forced outage rates,
4. target reliability level.

If a probabilistic representation of wind generation is used it should be consistent with the load year(s) used in the analysis. An analysis that uses wind and load data from different years will yield invalid results. Many reliability models have the capability to perform Monte Carlo analysis, in which random states of the conventional generation are sampled repeatedly. Even though this is computationally expensive, it can be valuable to more accurately assess the risk of alternative system states. However, the intrinsic Monte Carlo ability that is provided by most, if not all, reliability models is inadequate for wind because of the more complex probabilistic structure of wind power generation.

5.1.3 Alternative Methods

Because of the relatively intense calculation and data requirements for a reliability assessment of wind capacity value, some approximation methods have been developed. Although reliability-based approaches (including new methods recently developed, and new ones that may appear) appear to be the most robust methods of assessing wind capacity value, there has been considerable interest in developing simpler methods that can be applied on abbreviated data sets. This appears to be more prevalent in the United States. Simplified methods are generally based on wind capacity factor that is calculated over a suitably-defined peak period. The advantage of this approach is that the metric is transparent, and is easy to understand and to relate to system conditions. The disadvantage of these methods is that they are not capable of assessing and finding times that the system may be at risk even though loads are not especially high. If a significant fraction of the generating capacity is on maintenance during the shoulder seasons, this can cause a potentially large increase in LOLP and can result in potentially much higher risk than peak periods.

There is also emerging interest in reliability-based approaches that differ from LOLP-based methods. Rather than look at LOLP, it may be useful to examine state transition probabilities, focusing on the likelihood that the system will evolve into a state that requires additional balancing or other operator action that arises because of wind (Doherty & O'Malley 2005). More work is anticipated in this area, and as the experience with wind grows around the world, international collaboration will move the state of the art forward.

5.2 Germany

Capacity credit: The increase in (statistically) guaranteed capacity provided by wind power – the capacity in the conventional power plant system which can be completely given up without restricting supply reliability – is between 6 and 8% in the case of an installed wind power capacity of around 14,5 GW (in 2003) and between 5 and 6% in the case of an installed wind power capacity of around 36 GW (in 2015), at a level of supply reliability of 99%.

The selection of the period for the derivation of the probability function of wind turbine feed-in is an important factor. Optimally, the times at which the annual peak load actually occurred should be used for the derivation of the probability function of wind turbine feed-in. From 1994 to 2002 the annual peak load occured in the late hours of the afternoon on days in November or December. To ensure the accuracy of the results, sensitivity calculations were carried out for all winter days (November, December, January and February). The maximum positive or negative deviations of the individual sensitivity calculations from the mean value are approximately +1% or -1,5% for 2003 and drop to under +0,5% or -0,7% for 2015. These differences can be regarded as marginal and have no major bearing on subsequent calculations.

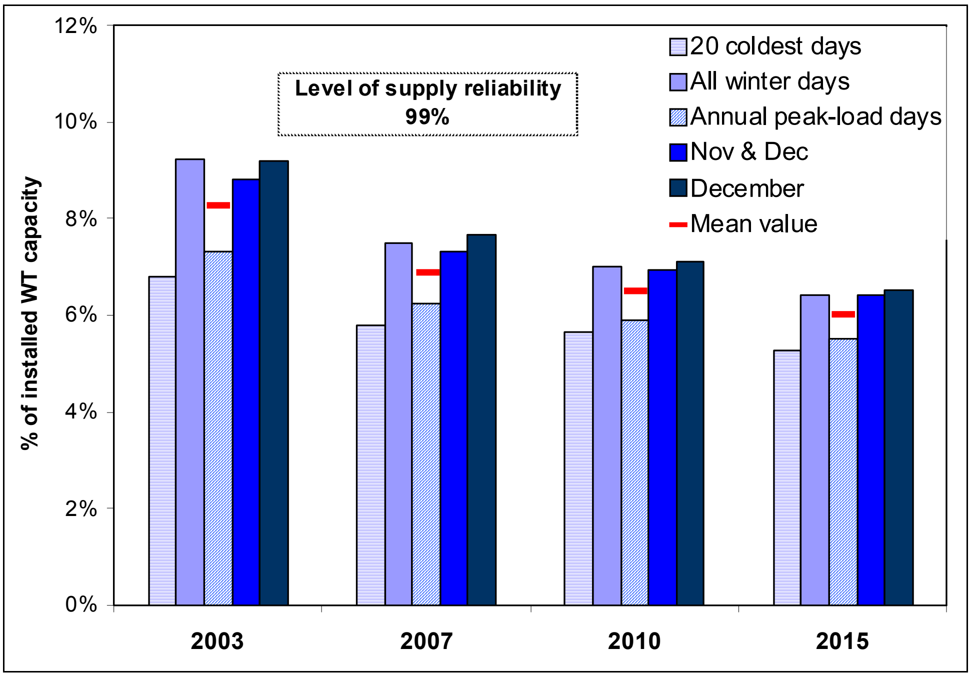


Figure 30. Average gain in secured capacity of the wind turbines in% of the installed WT capacity at the time of the annual peak load (DENA, 2005).

The additionally secured capacity which can be assigned to the installed wind turbines depends on the level of supply reliability. To analyse the influence of this factor, sensitivity calculations were conducted with a level of supply reliability of 97%, 98% and 99%. The selected level of supply reliability influences the values for the specific secured capacity of wind turbines at the time of the annual peak load only slightly (see following figure).

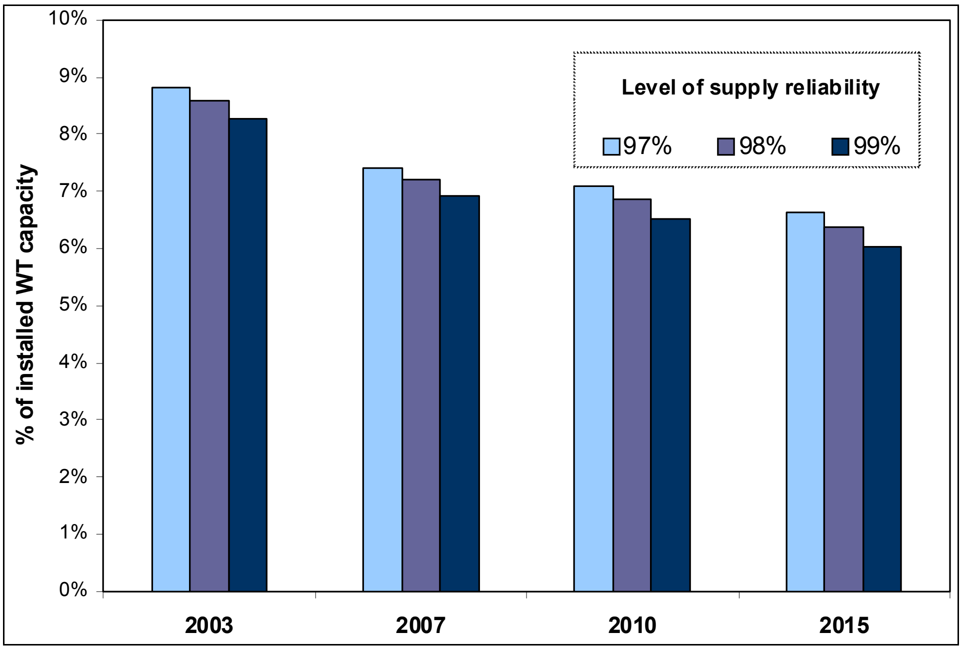


Figure 31. Sensitivities to rises in secured capacity of wind turbines at the time of the annual peak load in relation to the level of supply reliability (DENA, 2005).

The level of the secured capacity of the wind turbines varies seasonally. It is the highest in spring and winter, and in summer it is distinctly below these values (see following table).

Table 16. Seasonal rise in secured capacity of wind turbines (DENA, 2005).

	2003	**2007**	**2010**	**2015**
	% of installed wind turbine capacity			
Winter	8,3%	6,9%	6,5%	6,0%
Spring	8,6%	7,2%	6,9%	6,4%
Summer	6,1%	5,3%	5,4%	5,1%
Autumn	7,2%	6,1%	5,9%	5,5%
	in MW			
Winter	1199	1542	1941	2163
Spring	1245	1605	2057	2289
Summer	889	1187	1599	1824
Autumn	1040	1352	1750	1970

Methodology: The secured capacity of the entire generation system is determined by using a model in several steps. In the first step the secured capacity of the thermal generation system is determined; in the second step the secured capacity of the entire generation system including the conventional generation system and the dispersed wind power generation system is determined. Dispersed wind power generation includes all wind turbines installed onshore and offshore taking into account their spatial distribution.

The probability and level of outage of thermal generating capacity is determined by an analytical derivation based on the outage probabilities of the single generating units using the recursive convolution method known from probability calculus.

Assumptions: The probability function of the seasonal feed-in of the dispersed wind power generation system is based on quarter-hour feed-in values for the forecast years 2003, 2007, 2010 und 2015. For winter not only the probability function for the entire period (November to February) is determined, but also probability functions for other periods – days when historically annual peak loads were reached, 20 coldest days, days in November and December as well as days in December – are determined.

Assumptions about unplanned outages are differentiated according to the technology involved. They range from 1,8 to 4% (see following table). An unplanned outage of 0% is assumed for storage head installations and pumped storage power stations.

Heat controlled combined heat and power plants, run-of-river power stations as well as other electricity options based on renewable energy sources (except wind) are not included endogenously in the model because they are given a secured capacity according to the average feed-in during peak load hours.

A level of supply reliability of 99% is assumed for further calculations. Levels of supply reliability between 97% and 99% are used for sensitivity calculations.

It is assumed that the peak-load case occurs in the winter and without significant wind power feed-in. The peak-load is assumed to be constant over the long term. Depending on the grid region, the peak load can occur up to 800 hours a year.

Table 17. Outage rates for power plants (DENA, 2005).

Power plant technologies	Unplanned, non-disposable outages
Nuclear power stations	3,0%
Lignite fired power stations	3,2%
Hard coal fired power stations	3,8%
Natural gas and steam fired power plants	1,8%
Gas fired steam turbine	1,8%
Gas turbines	3,0%
Oil fired power station	1,8%
Storage power station	0,0%
Pumped storage hydro power stations	0,0%

Limitations: No additional measures to raise the level of the secured capacity of wind turbines like storage systems or extended power exchange over large areas with different weather conditions were assumed in this study.

5.3 Ireland /ESBNG

The transmission system operator of the Republic of Ireland, ESB National Grid (now EirGrid), published a report in 2004 (ESBNG, 2004). The objective of this study was to analyse and quantify the impact of increasing levels of Wind Power on operation of conventional plant in the Republic of Ireland, and calculate the capacity credit of wind power on the system.

Results: The study found that a high wind energy penetration greatly increased the number of start ups and ramping for gas turbine generation in the system and that the cost of using wind power for CO_2 abatement in the Irish electricity system is €120/Tonne. The capacity credit for different levels of wind is shown in Figure 32.

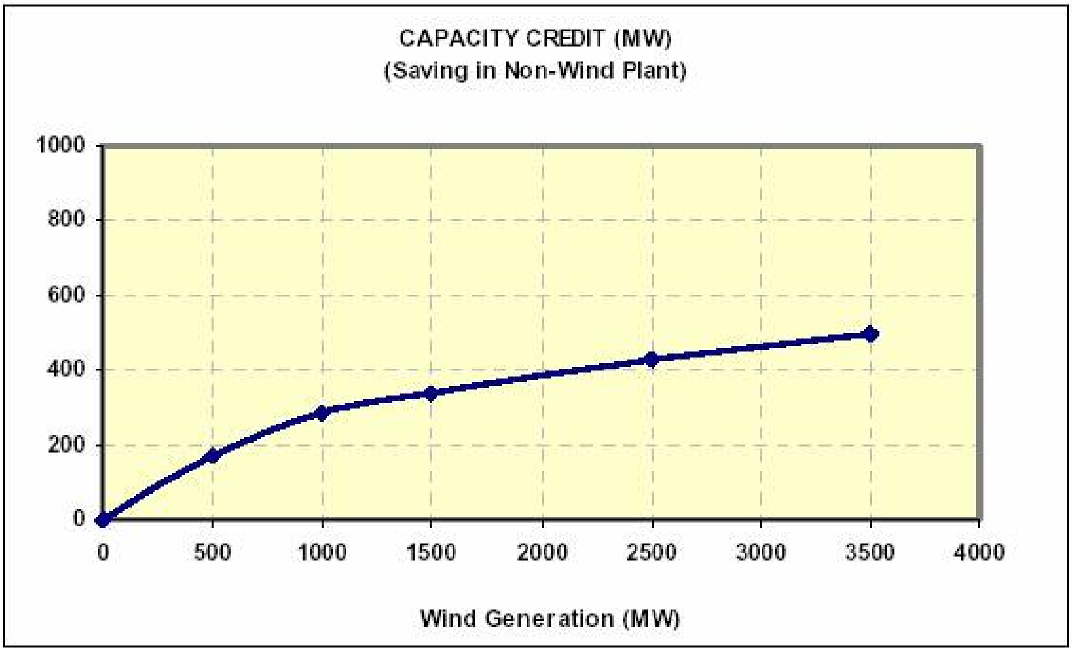


Figure 32. Results for capacity credit of wind power for Ireland (ESBNG, 2004).

Input data, wind power modelling: The wind input assessment methodology used was direct scaling of output data from existing wind power production combined with some planned site wind data to create a power time series.

Methodology: Capacity credit was calculated by assessing the amount of conventional thermal plant that may be removed to maintain the adequacy at the desired level. The system assessment methodology was generating system simulation using a unit commitment and dispatch simulator. Two scenarios were examined – one with a peak load of 5000 MW and one with a peak load of 6500 MW. For each scenario, 4 different levels of installed wind power were examined. Review matrix is in Appendix 2.

Assumptions: Diverse wind power plant locations were assumed, including an assumption that 33% of wind power capacity is offshore. It was assumed wind power can be forecast with a high degree of accuracy.

5.4 Norway

The impact of wind power on system adequacy for one region in Norway was reported in (Tande and Korpås, 2006). The impact is assessed using data from a real life regional hydro-based power system with a predicted need for new generation and/or reinforcement of interconnections to meet future demand.

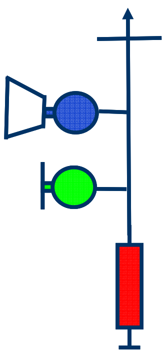


Figure 33. Assumed case study system specifications.

Methodology: The loss of load probability LOLP = Pr (Pm < 0) is calculated by using standard statistical methods as briefly described below. Here, the generating capacity margin Pm is the difference between the available conventional capacity Pc and the net load Pn.

The generating capacity margin distribution is calculated as the convolution of the available conventional capacity distribution and the net load distribution, i.e. no correlation between the available conventional generating capacity and the net load in the peak hour is assumed.

The net load distribution is calculated as the convolution of the wind power distribution and the consumers load distribution, i.e. no correlation between the wind power variations and the consumers load within the peak hour is assumed.

The wind power distribution from each group is calculated by a two-step procedure. First the wind power distribution from one 100% available wind turbine is calculated from time-series of the hour-to-hour wind speed variations and a typical wind turbine power curve. This approach makes it convenient to take into account the smoothing effect of geographically distributed wind power. Then the wind power distribution from the number of wind turbines is calculated as the convolution of the wind power distribution of the "ideal" wind turbine and the binomial distribution of the available wind turbines.

Results: Wind power will have a positive effect on system adequacy. Wind power contributes to reducing the LOLP and to improving the energy balance. Adding 3 TWh of wind or 3 TWh of gas generation are found to contribute equally to the energy balance, both on a weekly and annual basis. Both wind and gas improves the power balance. The capacity value of gas is found to be about 95% of rated, and the capacity value of wind about 30% at low wind energy penetration and about 14% at 15% penetration. The smoothing effect due to geographical distribution of wind power has a significant impact on the wind capacity value at high penetration.

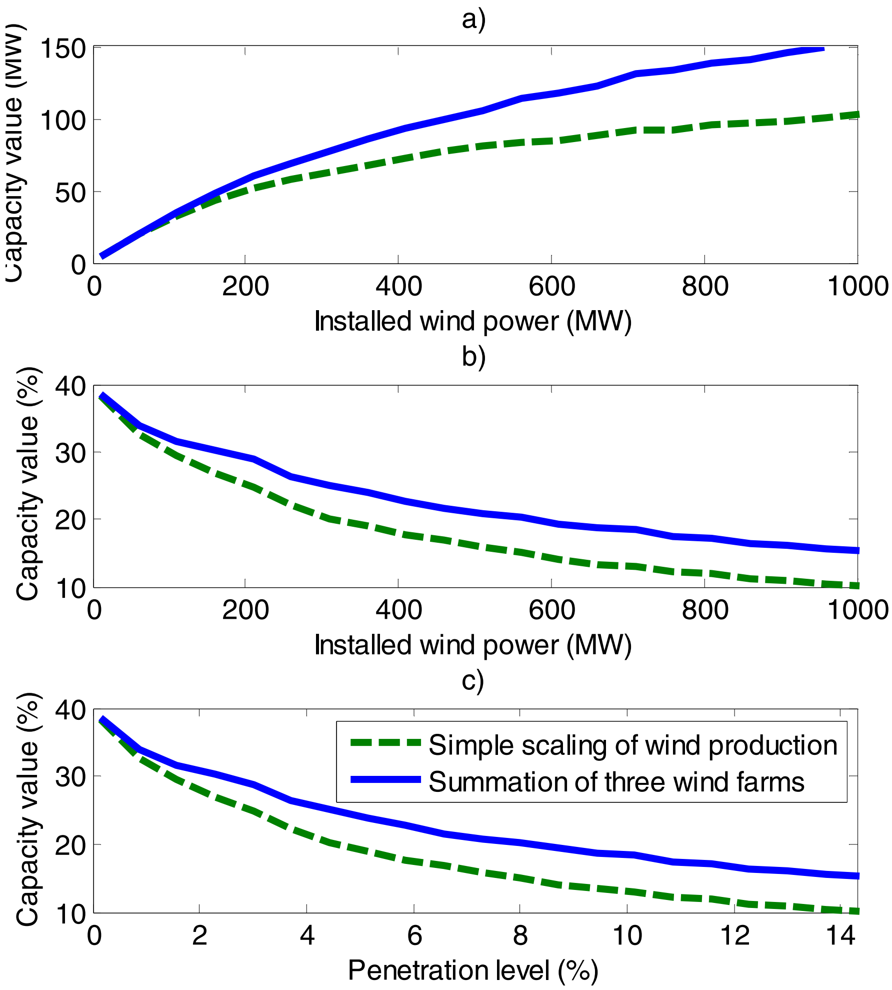


Figure 34. Capacity value of wind power with and without geographical smoothing effect. a) Capacity value in MW. b) Capacity value in percentage of installed wind power. c) Capacity value as a function of wind penetration level.

5.5 UK

5.5.1 Ilex/Strbac, 2002

The current electricity market does not contain a statutory or formal generation security standard that would define the required capacity margin for a particular mix of generation types. To make an explicit calculation, the last security standard employed in the UK was taken as indicative of the security of supply that would be acceptable. Assuming no increase in loss of supply risk (chance of needing to interrupt supplies not being more that nine winters in one hundred, i.e. a 9% risk), the amount of conventional generation that can be displaced by wind generation was evaluated.

Results: For a small level of wind penetration the capacity value of wind is roughly equal to its load factor, approximately 35%. But as the capacity of wind generation increases, the marginal contribution declines. For the level of wind penetration of 20 GW, about 4GW of conventional capacity could be displaced, giving a capacity credit of about 20%.

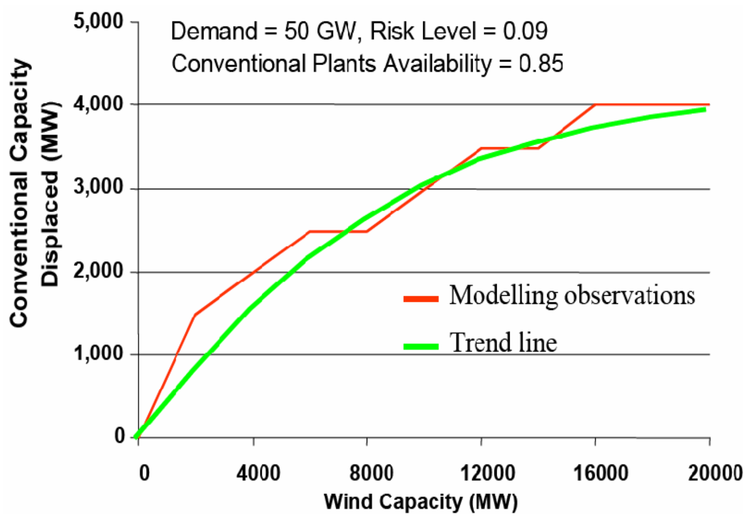


Figure 35. Capacity of conventional plant that can be displaced by wind generation.

Input data, wind power modelling: Annual half-hourly profiles of wind output based on historic wind generation data were developed. These one-year time series for various levels of wind penetration in the system depicted different levels of wind diversity. For the purposes of assessing capacity credit, the typical distribution of wind output seen in the various time series available is also expected to occur during high demand conditions.

Limitations: As this study was based on a one-year time series of wind generation data (for which a consistent set of data was available), extreme conditions of the coincidence of very high demand and little or no wind may not be captured. The reliability criterion

LOLP applied in establishing the capacity contribution of wind in this study, only provides a simplified comparison of the reliability of prospective generation systems as it does not provide any indication of the frequency, duration and the severity of potential shortages. Impact of extreme weather conditions, widespread anticyclones and storms (taking into consideration effects of clustering) were also not analysed. These factors have been identified as an imperative area of further work relevant to future electric system development in the UK. Furthermore, the impacts of supply interruptions on electricity consumers are an important factor in the determination of acceptable and economically justifiable service reliability levels and on the investments required to attain and sustain these levels. The information about frequency, duration and severity of supply interruptions is vital for assessing the opportunities for alternatives such as; demand side and bulk storage systems, in providing cost effective solutions to integration of wind power.

Also the approach used in this study to quantify additional system capacity costs attributed to wind generation were relatively simple and more advanced methodologies are being developed.

5.5.2 Strbac et al., 2007

This study has also applied one of the conventional techniques, that quantifies the probability that peak demand will exceed available generation, to determine the capacity credit of wind power. However, these approaches neither give any indication of the frequency of the occurrences of insufficient capacity conditions, nor the duration for which they are likely to exist. Furthermore, the severity of shortages, in terms of power and energy is not quantified (only the probability of a single shortage occurring). The information about the frequency, duration and magnitudes of various potential deficits is necessary to establish if bulk energy storage facilities or demand side management options are to be considered as an alternative to conventional plants as backup for wind generation. In order to determine the risk of supply interruptions at various levels of wind penetration, the frequency and duration method (FDM) was applied in this study.

Results: For the calculation of the capacity value of wind generation in UK, profiles with two different diversity levels were created. Figure 36 shows the results of analysis carried out for a range of wind penetrations to examine the generating capacity of conventional plant that can be displaced by wind while maintaining the risk of loss of supply at the historical level of 9%, for a 70 GW peak load and a 400 TWh energy demand, and a 35% load factor of wind.

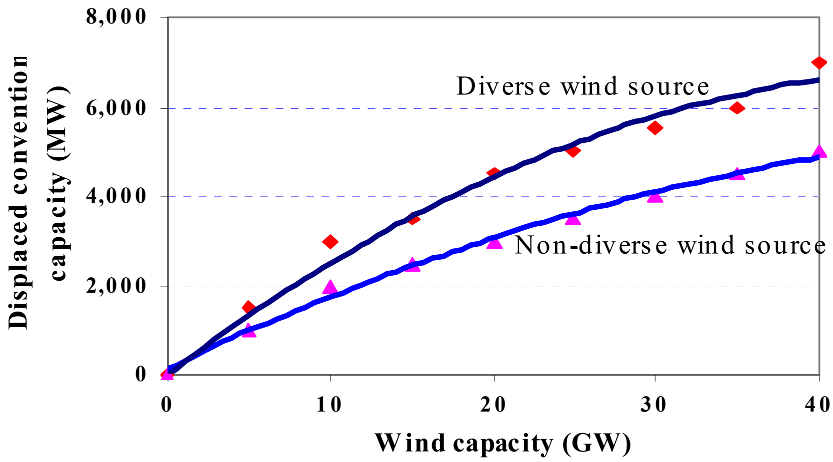


Figure 36. Conventional capacity displacement by diverse and non-diverse wind resource.

By applying the frequency and duration FDM approach it was investigated how various extents of wind penetration affect the frequency and duration of potential capacity deficits. A comparison of this is made with a system having no variable source. The results are presented in Figure 37.

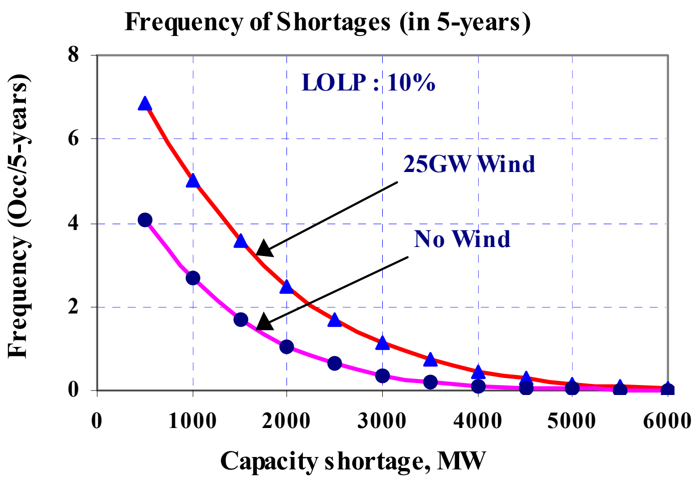


Figure 37. Frequency of interruptions at various magnitudes of shortages in systems with and without wind.

Methodology: The reliability index called loss of load probability (LOLP) was used to measure the adequacy of the generation system and determine the amount of plant necessary to meet the demand at an adequate level of security. This index quantifies the probability of peak load exceeding available generation (i.e. probability of a shortage). The conventional units are characterised by their long-term behaviour in terms of their average failure and repair cycles and this defines their average availabilities. The total wind capacity is represented in the system as a multistate unit.

In order to determine the risk of supply interruptions using the frequency and duration method FDM the generation system model (conventional as well as wind) was based upon a Markov chain model. The generation capacity states are combined with the load statistics to compute data on the probability and frequency of occurrence of various reserve margin states. A negative margin state indicates that the system load exceeds available capacity and depicts a loss of supply situation.

5.6 USA

There is no uniformly accepted method for calculating the capacity value of wind plants in the US. Probabilistic reliability planning programs are generally accepted as the "gold standard" for determining capacity value of wind plant. The Effective Load Carrying Capacity ELCC of wind generation can vary significantly, and depends primarily on the timing of the wind energy delivery relative to times of high system risk (defined as loss of load probability or similar metric). The capacity value of wind plants has been shown to range from approximately 5%–40% of the wind plant rated capacity. Table 18 (Ref.) shows the variety of methods being used in different regions of the US, and some of the results obtained. In some cases, simplified methods are used to approximate the rigorous reliability analysis.

The Minnesota Dept. of Commerce/Enernex Study described in 3.10.1 estimated the impact of wind in a 2010 scenario of 1500 MW of wind in a 10 GW peak load system. A capacity credit of 26%–34% was found with a range of assumptions using the ELCC method. Updated study was made for wind penetration of 25% energy from wind to the load in the whole state of Minnesota, assuming a well-developed market operating in the territory of MISO, the Midwest Independent System Operator (see also section 3.10.2). The capacity value of the wind generation was subject to substantial inter-annual variability, ranging from a low of 5% of installed capacity to over 20%.

Simplified methods based on wind capacity factor over peak period have been used in several studies. PJM, a Regional Transmission Operator (RTO) in the northeastern section of the US, considers the peak period to be in the hours ending 3:00–7:00 PM during June, July, and August. The wind capacity value is therefore calculated as the capacity factor achieved by wind in this time period. To help account for interannual variations, PJM prescribes the use of a 3-year rolling average that is based on the most recent 3-year period during the peak period. Studies done in New York and California found that similar approaches did a reasonably good job of approximating the ELCC, based on the regional definitions of peak periods. The Mid-Continent Area Power Pool (MAPP) uses a similar method, but instead of calculating the capacity factor, MAPP prescribes the use of the median wind generation value in a 4-hour window that includes the monthly system peak. Up to ten years of data can be used if available. The

Southwest Area Power Pool (SPP) uses a similar approach, but uses the 85 percentile of wind generation instead of the 50% percentile (median) that is used by MAPP. The SPP approach is shown to be extremely conservative by Milligan & Porter (2005).

For California, a wind capacity credit of 23%–25% of a benchmark gas unit was found.

PacifiCorp determined the capacity value for wind resources on its system by using a probabilistic reliability assessment technique in the 2005 IRP. The wind power plant average contribution to capacity value was 21%. Due to the results of this study with its conservative performance assumptions, PacifiCorp adopted a 20% capacity contribution toward the planning reserve margin for wind resources, which was a change from the 0% capacity contribution assumption used in the 2003 IRP.

Table 18. Wind Capacity Value in the U.S (Milligan & Porter, 2005).

Region/Utility	**Method**	**Note**
CA/CEC	ELCC	Rank bid evaluations for RPS (mid 20s)
PJM	Peak Period	Jun-Aug HE 3 p.m. – 7 p.m., capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor, 4 p.m. – 6 p.m., Jul (2,8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26–34%)
GE/NYSERDA	ELCC	Offshore/onshore (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (30%), Full ELCC study using 10-year data has begun; Xcel using MAPP approach (10%) in internal work
RMATS	Rule of thumb	20% all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%). New Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
PGE	Not stated	33%
Idaho Power	Peak Period	4 p.m. – 8 p.m. capacity factor during July (5%)
PSE and Avista	Peak Period	PSE will revisit the issue (lesser of 20% or 2/3 Jan C.F.)
SPP	Peak Period	Top 10% loads/month; 85th percentile

CA/CEC: California/California Energy Commission
RPS: Renewable Portfolio Standard
ELCC: Effective load-carrying capability – capacity value based on reliability metric
PJM: Pennsylvania-Jersey-Maryland, an RTO (regional transmission organization) in the US
HE: Hours ending
ERCOT: Electric Reliability Council of Texas
MN/DOC: Minnesota Department of Commerce, the sponsor of the Xcel Wind Integration Study
GE/NYSERDA: General Electric Energy Consulting, New York State Energy Research Development Authority
CO PUC: Colorado Public Utilities Commission
MAPP: Mid-Continent Area Power Pool
RMATS: Rocky Mountain Area Transmission Study
PGE: Portland General Electric
PSE: Puget Sound Energy
CF: Capacity factor
SPP: Southwest Area Power Pool

6. Experience from operating power systems with large amounts of wind power

Even if wind power penetration is still rather limited in most countries and power systems, already some regions show a high penetration and have first practical experience from wind integration. Here experience from regions where wind power production is more than 20% of gross demand is reported: West Denmark (24%), North of Germany (33%), certain Spanish regions (Navarra 47%, Aragón 30%, Castilla-La Mancha 30%, Galicia 29% and Castilla y León 24%) and Gotland in Sweden (20%).

Table 19. Regions with high penetration level of wind power.

Region	Load			Inter-connection	Wind power		Wind power penetration	
	Peak MW	Min MW	TWh/a	MW	MW	TWh/a	% of gross demand	Max wind / (Min load + interconn.)
West Denmark	3700	1400	21	2570/3070	2 350	5	24%	59%
North- Germany	2000	750	12,6	5200	2 275	4,2	33%	38%
Ireland	5000	1800	29	500	745	1,6	6%	32%
Spain	38 200	15 300	230	1800–2800	11 615	23,4	10%	68%
Gotland, Sweden	160	45	0.93	180	90	0,18	19%	40%

6.1 West Denmark

- Most of the variability of wind can be balanced by using strong HVDC-interconnections especially to Norway and Sweden. The expected wind power production is traded at the Nordpool spot market (day-ahead forecasts) and forecast errors paid by Nordic regulating power market prices (regulating power used according to system net imbalances in Nordel). Estimated costs due to forecast errors day-ahead are between 1,2 and 2,6 €/MWh.
- Difficulties when large forecast errors occur that are not foreseen even from updated forecasts. An example has been the storm in January 2005 when 1600 MW were lost within 6 hours, 66% of the installed wind power capacity. These situations do not occur very often, but the system should be prepared anyhow.
- Surplus production requiring curtailing of wind power has seldomly occurred since 2003. This has partly been due to large amount of distributed local combined heat and power plants that have operated according to fixed tariffs. After enhanced flexibility in CHP production, wind curtailment has not occurred so often. Interconnection capacity to Germany cannot be utilised during high wind periods because surplus wind production in Northern Germany occurs simultaneously.

- No increase in amount of reserve capacity, but increase in use of operating reserves (regulating power 10–15 min). Wind power has contributed to the increase of Automatic Generation Control (AGC), which amounts to 140 MW of regulation capacity from conventional power plants to be able to manage the fast fluctuations (time scale seconds).
- No experience of turbines tripping off in large quantities due to grid faults.

6.2 North-Germany

- The variability of wind is dealt with by the TSOs, sharing the amount of regulation power needed. TSOs tender and purchase adequate control power on the basis of the day-ahead wind power prognosis. The large variations of wind power production especially in storm events pose a major challenge to grid operators. On occasions with large amounts of wind during low load, the interconnections to neighbouring countries (the Netherlands and Poland) are used so much that the neighbouring power systems are significantly affected.
- Surplus production requiring curtailing of wind power has occurred since mid 2003 in Schleswig-Holstein and since 2005 in Lower Saxony. This is due to grid bottlenecks during windy periods. In order to be in a position to connect further renewable energy generators before the grid expansion is completed, E.ON Netz has developed the so-called generation management as a transitional solution. Generation management involves the intermittent reduction of the power fed in by the renewable energy generators, in order to protect grid equipment such as overhead lines or transformers from feed-in-related overloads, thereby avoiding supply failures.
- No increase in amount of reserve capacity, but increase in use of operating reserves (regulating power 10–15 min) (Eriksen et al., 2005).
- Faults in the extra-high voltage grid can result in a sudden failing of a large number of wind power plants in the affected region. If 3000 MW were to fail, grid stability would be put at risk. E.ON Netz published new grid interconnection regulations on 1st April 2006 (www.eon-netz.com) requiring fault-ride-through to deal with this problem.

6.3 Ireland

EirGrid has successfully integrated almost 800 MW of wind to date. With 1200 MW of installed wind capacity, expected in 2008, Ireland would have a penetration level comparable to that of West Denmark where Maximum Wind Power / (Lowest

Consumption + Export Capacity) would equal 57% and bring Ireland amongst the systems with the greatest wind penetration levels.

Successfully integrating 800 MW of wind capacity has involved addressing issues such as:

- Producing new Grid/Distribution Code rules for Wind Farms;
- Processing connections including the development and implementation of the Group Processing Approach for the processing of large numbers of grid-connection applications;
- Constructing connections to the network and associated deep reinforcements;
- Development of operational procedures;
- Wind power forecasting;
- Introduction of wind farm SCADA;
- Assessment of the impact of wind on system economics;
- Assessment of likely levels of curtailment and/or constraint of wind generation;
- System stability assessment including involvement in model development.

These technical activities have been paralleled by significant stakeholder involvement by management and staff. However, despite these achievements the continuing rapid growth of renewable generation in line with Government targets will require even greater efforts to address the ever-more complex technical, commercial, regulatory and stakeholder issues that will arise.

6.4 Spain: Galicia/Navarra

- No increase in amount of reserve capacity, but increase in use of operating reserves (regulating power 10–15 min). (Eriksen et al., 2005).
- Curtailing of wind power has occurred due to concern of power system transient stability since 2004 (Eriksen et al., 2005)
- Faults in the extra-high voltage grid can result in a sudden failing of a large number of wind power plants in the affected region, thereby putting the grid stability at risk. As an example, several successive wind power decreases directly provoked by voltage dips occurred at 19 March 2007 during about 6 hours (500 MW, 400 MW and 1000 MW). Before, Spanish requirements established that wind turbines had to disconnect when they were submitted to voltage dips, avoiding so disturbances caused by the operation of the wind turbine under these conditions. New grid codes require fault-ride-through to avoid this problem.

6.5 Sweden: Gotland

- All balancing in the island is done with the HVDC cable to the mainland. When wind power penetration (of gross demand) exceeded 10% there were occasional curtailments when wind power production was close to the local load and the cable was run near 0 MW. To overcome this problem, control of the cable was enhanced to enable switching to export and import near 0 MW. After this there has not been any need to curtail wind power. From mainland side point of view Gotland wind power production is comparatively small (Söder et al., 2006).

7. Summary and review of the results

Integration cost can be divided into different components arising from the increase in the operational balancing cost and grid expansion cost. The value of the capacity credit of wind power can also be stated.

Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. In most case studies a comparison to other alternatives to wind has not been studied.

When estimating the costs, allocation of new grid or reserve capacity to wind power can differ. For increased balancing it is important to note whether a market cost has been estimated or whether the results refer to technical cost for the power system. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels. The trade-off between curtailing wind output in critical times and providing new transmission or production capacity would be needed in some cases. In this report only the cost component has been analysed.

The case studies summarized are not easy to compare due to different methodology and data used, as well as different assumptions on the interconnection capacity available.

Different metrics for the results have been used in the studies: Results as monetary value per MWh of wind or per MWh of total consumption (reflecting the increase in consumer price). There are also results as% of more wind power production needed to cover extra losses.

Determining what is “high” penetration of wind power is not straightforward. Often either energy or capacity metrics are used: wind power production as% of gross demand (energy) and wind power as% of peak load (capacity). To determine high penetration for a power system also interconnecting capacity needs to be looked at. This is because critical moments of high wind and low load can be relieved by using interconnector capacity.

The power systems and highest wind penetrations presented in the case studies of previous chapters are summarised in Table 4 of Section 2. The on-going studies that have not been taken in this state-of-the-art report are listed in Appendix 1.

7.1 Summary of balancing requirement results

Summaries for the quantified results for balancing requirements presented in section 3 are presented in Figure 38 and Figure 39.

The increase in reserve requirement is most often estimated by statistical methods combining the variability of wind power with that of load. In some studies also the sudden outages of production are combined with reserve requirements (disturbance or contingency reserve). For the impact on operation of power systems, model runs are made and most results are based on comparing costs of system operation without wind and adding different amounts of wind. The costs of variability are also addressed by comparing simulations with flat wind energy to varying wind energy (for example in US Minnesota and Greennet Nordic + Germany).

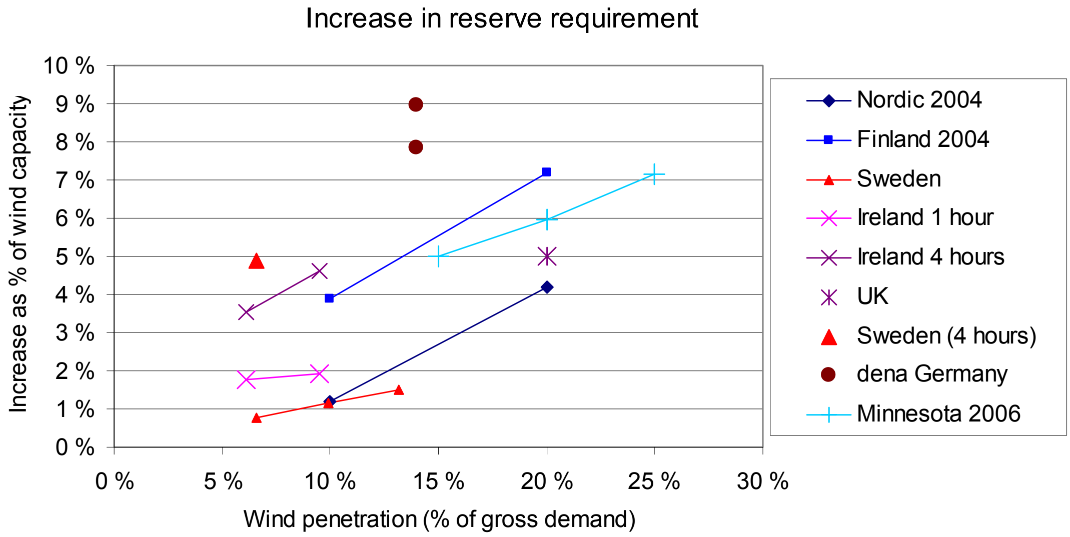


Figure 38. Results for the increase in reserve requirement due to wind power. German dena estimates are taking into account the day-ahead uncertainty (for up and down reserves separately) and UK the uncertainty 4 hours ahead. In Minnesota, day ahead uncertainty has been included in the forecast. For the others the effect of variations during the operating hour is considered For Ireland and Sweden the 4 hour-ahead uncertainty has been evaluated separately.

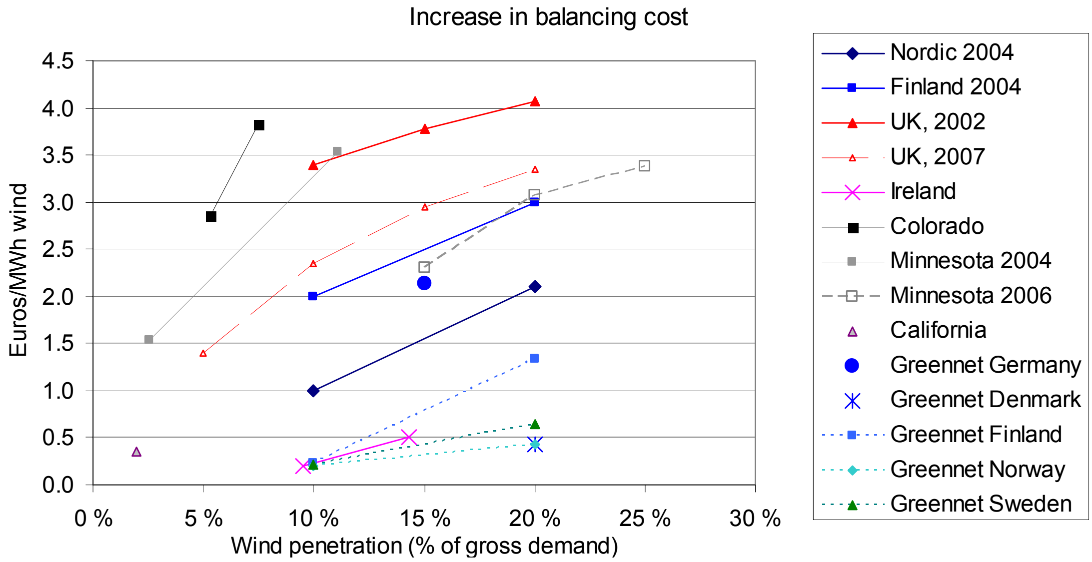


Figure 39. Results from estimates for the increase in balancing and operating costs due to wind power. The currency conversion used here is 1 € = 0,7 £ and 1 € = 1,3 US$. For UK, 2007 study the average cost is presented here, the range in the last point for 20% penetration level is from 2,6 to 4,7 €/MWh.

At wind penetrations of up to 20% of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to about 1–4 €/MWh. This is 10% or less of the wholesale value of the wind energy. It can be seen that there is considerable scatter in results for different countries and regions. The following differences have been remarked:

- Different time scales used for estimating – For UK, the increased variability to 4 hours ahead has been taken into account. For US studies also the unit commitment impact for day-ahead scheduling is incorporated. For the Nordic countries and Ireland only the increased variability during the operating hour has been estimated. For the Greennet study, the unit commitment and reserve allocation are done according to wind forecasts but the system makes use of updated forecasts 3 hours before delivery for adjusting the production levels.
- Costs for new reserve capacity investment – For the Greennet, UK and SEI Ireland studies only incremental increase in operating costs has been estimated whereas also investments for new reserves are included in some results (Nordic 2004)
- Larger balancing areas – The Greennet, Minnesota 2006 and Nordic 2004 studies incorporate the possibilities for reducing operation costs through power exchange to neighbouring countries/markets, whereas Colorado, California, German dena study, Sweden, UK and Ireland studies analyse the country/market in question without taking transmission possibilities (giving balancing potential

from neighbouring regions) into account. The two studies for Minnesota show the benefit of larger markets in providing balancing. The same can be seen from the Greennet study results and the Nordic 2004 results compared with results calculated for Finland alone. Larger power systems make it possible for smoothing of the wind variability.

As shown in Table 4 the interconnection capacity to neighbouring systems is often significant. For the balancing costs, it is then essential to note in the study setup whether the interconnection capacity can be used for balancing purposes or not. A general conclusion is that if interconnection capacity is allowed to be used also for balancing purposes, then the balancing costs are lower compared to the case where they are not allowed to be used. From the first review of methodology, the other important factors identified as reducing integration costs were aggregating wind plant output over large geographical regions, and operating the power system closer to the delivery hour.

7.2 Summary of simulation model review tables

A summary of tables in Appendix 2 is presented in Table 20. The main idea has been to present tables from simulations regarding balancing requirements. Most studies are based on comparing results and costs of system operation without wind and adding different amounts of wind. The costs of variability are also addressed by comparing simulations with flat wind energy to varying wind energy (US Minnesota and Nordic + Germany).

The table can be used to look for explanations for different results: what has been taken into account in the estimates. In (Söder & Holttinen, 2007) the best possible methodology for simulations means taking all possible market and grid dynamic aspects into account, which is impossible in practice due to the small time step (less than second) and long simulation time (years). Assumptions need to be made when simulating the system operation.

The most general finding comparing the study set-ups is the use of interconnection capacity – this is crucial when estimating the impacts of wind power.

Table 20. Summary of review tables in Appendix 2 that are describing energy system modelling with and without wind to assess wind integration impacts on balancing.

Set up		SE Söder 1994	Nordic Holttinen 2001	Nordic+GER Meibom 2005	US Minnesota Enernex 2004	US Minnesota Enernex 2006	IR ESBNG 2004	IR SEI 2004
A	Aim of study	1 what happens with x GWh wind[1]	1 what happens with x GWh wind	1 what happens with x GWh wind	1 what happens with x GWh wind	1 what happens with x GWh wind	1 what happens with x GWh wind[2]	1 what happens with x GW wind[3]
M	Method	1 add wind energy (4a)	1 add wind energy	1 add wind energy (4b)	1 add wind energy(6)	1 add wind energy(6)	2 wind repl. capacity(5,6)	1 add wind energy
S	Simulation model of operation	3 determ. planning with stoch. wind forecast err[8]	2 determ. simulation, 30 hydro inflow cases	4 Stochastic simulation several cases	2 determ. simulation several cases	2 determ. simulation several cases	2 determ. simulation, unit commitm. and dispatch	2 determ. simulation
Simulation detail								
R	Resolution of time	hour;	week (9); for 30 years	hour, for 5 weeks (year)	hour; for 3 x year	hour; for 3 x year	hour; for1 year	half hourly
P	Pricing method	5 other: (10a)	1 costs of fuels 3 perfect market	1 costs of fuels/start-up 3 perfect market	1 costs of fuels	1 costs of fuels	1 costs of fuels 5 other: (10b)	1 costs of fuels
D	Design of remaining system	1 constant 6 load increased correspond. to wind increase	1 constant 4 changed operation due to wind power	1 constant 4 changed operation due to wind power 5 perfect trading rules	1 constant	4 changed operation due to wind power 5 perfect trading rules 6 plant and transm. added	1 existing plant reduced when wind added (11a).	1 constant, (11b) with new CCGTs and OCGTs added to replace retired plant
Uncertainty and balancing								
I	Imbalance calculation	2 wind+load	no imbalance calculation	1 only wind 4 wind + production for reserve allocation	3 wind+load +production	3 wind+load +production	4 other: wind + production.	3: wind + load + production
B	Balancing location	1 dedicated source 4 other (12)	no imbalance calculation	3 also outside region	2 from the same region	3 also outside region	2 from the same region	2 from the same region
U	Un-certainty treatment	3d: wind forecasts (1–2 hours… day-ahead) 5 load forecasts	2 hydro inflow uncertainty: 3 no wind forecasts [13a] 6 thermal outages	2 hydro inflow uncertainty: 3d wind forecasts 3–36 h ahead (13b)	3d wind forecasts day-ahead [13d] 5 load forecasts 6 thermal outages	3d wind forecasts 1h& day-ahead[13d] 5 load forecasts 6 thermal outages	3 wind forecasts: average wind (13e) 6 thermal outages	3d wind forecasts 1 and 4 h (13f) 5 load forecasts [13g] 6 thermal outages
Power system details								
G	Grid limit on transm.	1 no limits	2 constant MW limits	2 constant MW limits	1 no limits	2 constant MW limits	1 no limits	1 no limits
H	Hydro power modelling	1 head height 2 hydrological coupling 3 hydrological restrictions 4 availability of water 5 optimization	1 head height 2 hydrological coupling 3 hydrological restrictions 4 availability of water 5 optimization	3 hydrological restrictions 4 availability of water 5 optimization	6 limited, deterministic run-of-river 7 interaction with hydro not significant	6 limited, deterministic run-of-river 7 interaction with hydro not significant	8 other: hydro plant operating in accordance with historical production profiles	8 other: hydro plant operating in accordance with historic profiles
T	Thermal power modelling	no thermal power in the system	only availability	2 start/stop 3 efficiency 4 heat prod.	1 ramp rates 2 start/stop 3 efficiency	1 ramp rates 2 start/stop 3 efficiency	1 ramp rates 2 start/stop	1 ramp rate 2 start/stop 3 efficiency
W	Wind power modelling	1a wind speed + power curve (8 sites) Stochastic forecast errors	1a few wind speed time series (weekly), 30 years of data	1a and b wind speed and power time series. 1d smoothing 3 synchr. wind data with load 4 future wind distribution	1c time series: re-analysis wind (50 sites) 2b wind profiles 3 synchr. wind / load 4 future wind distribution	1c time series: re-analysis wind 2b wind profiles 3 synchr. wind / load 4 future wind distribution	1b wind power time series 19 sites 2b wind profiles 4 future wind distribution	1 time series: 10 sites 2b wind profiles 4 scenarios for future wind power distribution

(1) how much wind is possible (wind power increased until evaluation strategy did not work (2) impact of Wind Power on operation of conventional plant (3) impact of wind on operating reserve (4a) load is increased same amount of GWh as wind (4b) comparison between stochastic, variable wind production and equivalent predictable, constant wind production (5) while maintaining system adequacy (6) For capacity credit: a – chronological, using wind power and load profiles (7) capacity credit calculated using wind power and load profiles. (8) Deterministic planning but evaluation based on rescheduling every hour based on stochastic forecast errors (9) 4 load profiles, hydro inflow and wind assumed constant during the week (10a) "integration cost" was calculated as needed extra wind energy (MWh) to compensate for lost hydro (10b) additional reserve capital costs attributable to wind energy calculated (11a) 5000 MW peak case: existing plant reduced when wind added. 6500 MW peak case: mixture of (CC) and (CT) units (11b) constant, with new CCGTs and OCGTs added to replace retired plant (12) Wind power balancing was performed in one river and the result was upscaled to Sweden (13a) some wind uncertainty through weekly uncertainty in water value calculations (13b) std 15–18% of installed capacity 8–36 h ahead (13c) load forecasts: 2,5% mean forecast error (13d) 20% MAE day-ahead (13e) average 24 h wind was used as the forecasted value for commitment algorithm, with variations above or below this used for dispatch algorithm (13f) MAE 14–18% (13g) load forecast errors: 1 hour – 40 MW, 4 hours – 60 MW.

7.3 Summary of grid reinforcement and efficiency results

With current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, participating in system operation with output and ramp rate control, and providing SCADA information. In areas with limited penetration, system stability studies have shown that modern wind plants equipped with power electronic controls and dynamic voltage support capability can improve system performance by damping power swings and supporting post-fault voltage recovery. The results of studies performed in UK suggest that at higher penetration levels, requiring sufficient fault ride through capability for large wind power plants is economically efficient compared with modifying the power system operation for ensuring power system security in case wind farms are not having fault ride through capability.

Grid reinforcement may be needed for handling larger power flows and maintaining stable voltage, and is commonly needed if new generation is installed in weak grids far from load centers. The issue is generally the same be it modern wind power plants or any other power plants. The cost of grid reinforcement due to wind power is therefore very dependent on where the wind power plants are located relative to load and grid infrastructure, and one must expect numbers to vary from country to country.

For the grid reinforcement, the reported results in the national case studies are:

- UK: £65–125 / kW (85–162 €/kW) for 26 GW wind (20% energy penetration) and £35/kW–£77/kW for 8 GW of wind
- Netherlands: 60–110 €/kW for 6000 MW offshore wind
- Portugal: from 53 €/kW (only summing the proportion related to the wind program of total cost of each grid development or reinforcement) to around 100 €/kW (adding total costs of all grid development items) for 5100 MW of wind
- German dena study results are about 100 €/kW for 36 000 MW wind.

The costs of grid reinforcement needs due to wind power cannot be directly compared, as they will vary from country to country depending greatly on location of the wind power plants relative to load centers. The grid reinforcement costs are not continuous; there can be single very high cost reinforcements. There can be differences in how the costs are allocated to wind power. It is also important to note that grid reinforcements in general should be held up against the option of curtailing wind or altering operation of other generation, and these latter options may in some cases prove to be very cost efficient.

7.4 Summary of power adequacy/capacity credit results

The capacity credit of wind power answers questions like: Can wind substitute for other generation in the system and to what extent? Is the system capable of meeting a higher (peak) demand if wind power is added to the system? This is related to the long-term reserve or planning reserve that power systems carry.

Wind generation will provide some additional load carrying capability to meet projected increases in system demand. This contribution can be up to 40% of installed wind power capacity (in situations with low wind penetration and high capacity factor at times of peak load), and down to 5% in higher wind penetrations, low capacity factor at times of peak load or if regional wind power output profiles correlate negatively with the system load profile (Figure 40). The aggregation benefits apply to capacity credit calculations – for larger geographical areas the capacity credit will be higher.

The wind capacity credit in percent of installed wind capacity is reduced at higher wind penetration, but depends also much on the geographical smoothing. This is demonstrated comparing the cases of Mid Norway with 1 and 3 wind power plants. In essence, it means that the wind capacity credit of all installed wind in Europe or the US is likely to be higher than those of the individual countries or regions, even if the total penetration level is as in the individual countries or regions. Indeed, this is true only when assuming that the grid is not limiting the use of the wind capacity, i.e. just as available grid capacity is a precondition for allocating capacity credit to other generation.

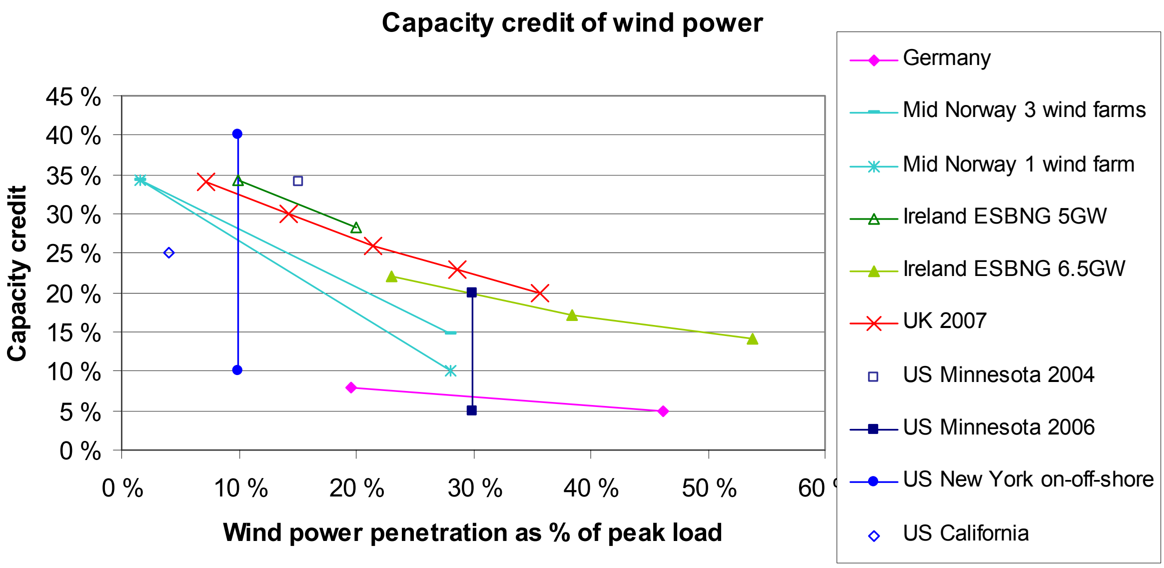


Figure 40. Capacity credit of wind power, results from eight studies.

Results for the capacity credit of wind power in Figure 40 show a considerable spread. One reason for different resulting levels arises from the wind regime at the wind power plant sites and the dimensioning of wind turbines. This is one explanation for low German capacity credit results shown in Figure 40. For near zero penetration level, all capacity credit values are in the range of the capacity factor of the evaluated wind power plant installations. The correlation of wind and load is very beneficial, as can be seen in the case of US New York offshore capacity credit being 40%.

8. Current practice and insights

Challenges for estimating the impacts of wind power include developing representative wind power production time series across the area of study, taking into account the (smoothed out) variability and uncertainty (prediction errors) and then modelling the resultant power system operation. The state-of-the-art best practice so far includes:

- Capturing the smoothed out variability of wind power production time series for the geographic diversity assumed. Use actual data from several wind power plants and met towers, or synchronized weather simulation. Utilize wind forecasting best practice for estimating the uncertainty of wind power production.
- Examine wind variation in combination with load variations, couple with actual historic utility load and load forecasts
- Capture system characteristics and response through simulations and modelling of system operation
- Examine actual technical costs independent of tariff design structure.

For high penetration levels of wind power, the optimisation of the integrated system should be explored. Modifications to system configuration and operation practices to accommodate high wind penetration may be required. Not all current system operation techniques are designed to correctly incorporate the characteristics of wind generation and surely were not developed with that objective in mind. For high penetrations also the surplus wind power needs to be dealt with, e.g. by transmission to neighbouring areas, storage (e.g. pumping hydro or thermal) or even demand side management (avoiding wind power curtailment). There is a need to assess wind power integration at the international level, for example to identify the needs and benefits of interconnection of national power systems.

Power systems are different in how much flexibility exists and how flexibility can be increased in a cost effective manner when high amounts of wind power are integrated. A number of insights related to the integration of increasing amounts of wind power in power systems gained from the work to date include:

- ***Larger balancing area size and wind aggregation:*** both load and generation benefit from the statistics of large numbers as they are aggregated over larger geographical areas. Larger balancing areas make wind plant aggregation possible. The forecasting accuracy improves as the geographic scope of the forecast increases; due to the decrease in correlation of wind plant output with distance, the variability of the output decreases as more plants are aggregated. On a shorter time scale, this translates into a reduction in reserve requirements; on a longer time scale, it produces some smoothing effect on the capacity value. Larger balancing areas also give access to more balancing units.

- ***Available transmission capacity:*** Transmission helps to achieve benefits of aggregating large scale wind power development and provides improved system balancing services. This is achieved by making better use of physically available transmission capacity and upgrading and expanding transmission systems. High wind penetrations may also require improvements in grid internal transmission capacity.
- ***System operation:*** Integrating wind generation information in system operation both real-time and with updated forecasts up to day-ahead will help manage the variability and forecast errors of wind power. Shortening the gate closure time in market operation practices will help integration but may require improvements in the operating tools. Well-functioning hour-ahead and day-ahead markets can help in providing the balancing energy required by the variable-output wind plants more cost-effectively.
- ***Enhancing wind power plant capabilities:*** Improvements in wind-plant operating characteristics will enhance reliable operation of the system through the ability to provide voltage control at a weak point in the system, the ability to provide an inertial response in a stability constrained system, the ability to participate in providing ancillary services, and the ability to ride through faults (voltage and frequency deviations) without disconnection.
- ***System expansion:*** Sufficient flexibility in new generation additions as well as increased demand-side-management will help to accommodate increased variability expected due to the increased wind plant production.

9. Conclusions and discussion

High penetration of wind power has impacts that have to be managed through proper plant interconnection, integration, transmission planning, and system and market operations. Several issues that impact on the amount of wind power that can be integrated have been identified. Large balancing areas and aggregation benefits of large areas help in reducing the variability and forecast errors of wind power as well as help in pooling more cost effective balancing resources. System operation and working electricity markets at less than day-ahead time scales help reduce forecast errors of wind power. Transmission is the key to aggregation benefits, electricity markets and larger balancing areas.

Integration cost can be divided into different components arising from the increase in the operational balancing cost and grid expansion cost. The value of the capacity credit of wind power can also be stated. Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. It is important to note whether a market cost has been estimated or whether the results refer to technical cost for the power system. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels. In this report only the cost component has been analysed. The case studies summarized are not easy to compare due to different methodology and data used, as well as different assumptions on the interconnection capacity available.

Wind generation may require system operators to carry additional operating reserves. Wind's variability cannot be treated in isolation from the load variability inherent in the system. From the investigated studies it follows that at wind penetrations of up to 20% of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to about 1–4 €/MWh. This is 10% or less of the wholesale value of the wind energy. The actual impact of adding wind generation in different balancing areas can vary depending on local factors. From a first review of methodology some important factors were identified to reduce integration costs, such as aggregating wind plant output over large geographical regions, larger balancing areas, and operating the power system closer to the delivery hour.

With current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, and participating in SCADA system operation with output and ramp rate control. Grid reinforcement may be needed for handling larger power flows and maintaining a stable voltage, and is commonly needed if new generation is installed in weak grids far from load centers. The cost of grid reinforcements due to wind power is therefore very dependent on where the wind power plants are located relative to load and grid infrastructure, and one must expect numbers to vary from country to country. The grid reinforcement costs from studies in this report vary from 50 €/kW to 160 €/kW. The costs are not continuous; there can be single very high cost reinforcements, and there can also be differences in how the costs are allocated to wind power. It is also important to note that grid reinforcements in general should be held up against the option of curtailing wind or altering operation of other generation.

Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution can be up to 40% of installed capacity if wind power production at times of high load is high, and down to 5% in higher penetrations or if local wind characteristics correlate negatively with the system load profile. Aggregating larger areas benefits the capacity credit of wind power.

State-of-the-art best practices so far include (i) capturing the smoothed out variability of wind power production time series for the geographic diversity assumed and utilising wind forecasting best practice for the uncertainty of wind power production (ii) examining wind variation in combination with load variations, coupled with actual historic utility load and load forecasts (iii) capturing system characteristics and response through operational simulations and modelling and (iv) examining actual costs independent of tariff design structure.

For high penetration levels of wind power, the optimisation of the integrated system should be explored. Modifications to system configuration and operation practices to accommodate high wind penetration may be required. Not all current system operation techniques are designed to correctly incorporate the characteristics of wind generation and surely were not developed with that objective in mind. Increasing system flexibility through such means as transmission to neighbouring areas, demand side management and optimal use of storage (e.g. pumping hydro or thermal) will impact the amount of wind that can be integrated cost effectively. There is growing recognition of the need to assess wind power integration at the international level to identify the needs and benefits of interconnection of national power systems in achieving stated policy goals of accommodating higher levels of renewable energy penetration.

This state-of-the-art report presents a summary of only selected, recently finished studies. In the final report, due end of 2008, there will be more studies included from the participating countries. Classifying power systems and giving rough estimates for wind integration impact remains the task for the final report of IEA WIND Task 25. Wind integration has been studied to wind penetration levels of 10–20% of gross demand (up to 50% of peak load). What happens in larger penetration levels, where wind becomes dominating part of power system, is still unclear – the future power systems may also provide different options for flexibility in demand side that do not exist today. Furthermore, if solar power takes off like wind power has, it will need to be incorporated into integration studies in similar manner and in many regions this will help smoothing the variability of individual technologies.

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Appendix 1: National activities on wind integration in participating countries

A wide range of case studies from different power systems have already been made and case studies will also be made during the 3 years. The national case studies address different impacts: balancing; grid congestions, reinforcement and stability; power adequacy; impact of wind farm technology and control to stability; increased flexibility and value of DSM/storage; forecast model experience; wind and hydro interaction; generation mix and operation methodologies to support a high penetration of wind power. Here a short overview of the on-going work is given.

Denmark

Risø is one of the core developers and users of the Wilmar Planning tool enabling detailed analysis of the planning of the unit commitment and dispatch of power plants on the day-ahead market subject to stochastic wind power forecast errors and the corresponding replanning on the subsequent intra-day and regulating power markets. The work will continue in SUPWIND EU project 2006–2008.

There is ongoing national research for increased flexibility in the power system (demand side and/or storage), for example Vanadium batteries in the power system. Focus in these projects is not only on balancing issues but also on system stability and grid issues. Risø is also involved in EU projects Anemos (Prediction tools) and Nightwind (storage).

Finland

There is ongoing work on case studies simulating the effects of large wind power in the North of Norway and Finland on the Finnish North-South bottleneck situations and simulating the effect of wind power prediction errors to one energy producer with limited amount of hydro power. Ongoing studies include a PhD work comparing methods to decrease wind integration costs and analysing effects that large scale wind power can have on long-term power plant investments. The national research includes also activities related to load flow analysis of different siting options of 4000 MW wind power in Finland and neighbouring areas. Also the impact of different wind power technologies on system stability will be made, together with VTT and Technical University of Helsinki.

Germany

ISET (Institut für Solare Energieversorgungstechnik) works on several projects regarding the integration of renewable energies into electrical power supply: sequentially further-developed software tools for the determination of the current wind power feed (online-model) and short term prediction for the German TSOs E.ON Netz (ENE), RWE Transportnetz Strom (RWE) and Vattenfall Europe Transmission (VE-T). The combination of the on-line and prediction model forms the basis for the immediate horizontal exchange of the wind energy fed between the German TSOs. ISET is also coordinating German national network "Energy and Communication" and participating in the following European projects related to wind energy: Upwind (Integrated Project), POWWOW (Coordinated Action), Reliance (Coordinated Action) and Wind on the grid (Specific Targeted Research Project).

A national project "Integration of large offshore wind farms into electricity grids" is a co-operation with the Transmission Grid Operators ENE and VE-T, the wind turbine manufacturer Enercon, the German weather forecast service Deutsche Wetterdienst, and the Kassel University. Measures optimising the economy and the safety of grid operation are studied. Objectives of this project are to develop and test concepts for the control of large wind farms ashore and offshore as well as management systems for the grid operation and the power plant dispatching.

A national research project on power systems operation with high penetration of renewable energy is coordinated by Ecofys. One aspect of the project is a simulation study covering the High and Extra High Voltage network of Germany, where major network congestions are identified and combined with an estimate of their respective probabilities taking into account near term growth of wind power.

There will be a continuation for the German Energy Agency's (dena) study "Planning of the integration of wind energy into the German grids ashore and offshore regarding the economy of energy supply".

Ireland

The Irish (Republic of Ireland and Northern Ireland) power system presents specific challenges for integrating high levels of wind energy because of its relatively small size and low level of interconnection with other systems. The system characteristics which present challenges are low system inertia, large frequency excursions, tight capacity margins, a high ratio of average generating plant size to overall system size and regional network constraints.

In 2005 an All-Island Grid Study was requested by the Governments of the Republic of Ireland and Northern Ireland to inform renewable energy policy to 2020. As wind power will be the dominant renewable electricity generation technology in Ireland up until 2020 the study has a primary focus on the system effects of a high wind penetration.

To identify and manage the issues relating to increased levels of wind generation on the Irish system, TSO EirGrid has established a dedicated group with the specific objective of ensuring a co-ordinated and best-in-class approach to renewables integration. This group has developed recommendations for immediate implementation in a number of areas including the following:

- Complete the development of operational rules to cater for high levels of variable generation. These rules will address areas such as dealing with high wind output at low load, minimum conventional plant requirements, reserve requirements, implementation of curtailment emergency procedures, use of forecasts etc.;
- Develop jointly with the Distribution System Operator voltage/reactive power regulation schemes for distribution-connected wind farms;
- Ensure that existing and future generation plant complies with Grid Code performance requirements (min output, ramp rate, frequency response etc.);
- Develop a number of approaches to move the current batch of “under-test” wind farms to full Operational Certification status;
- Scope wind data storage, access and analysis requirements;
- Develop a communications strategy to ensure that all staff and all external stakeholders are fully aware of EirGrid’s role, current initiatives and future plans in this field;
- Ensure that EirGrid’s service providers can meet the design, construction, commissioning, telecommunications, SCADA and other requirements for the connection and integration of the envisaged levels of renewable generation.

Netherlands

Two research programmes currently exist in The Netherlands: the we@sea research program and the EOS-program. The we@sea consortium, a collaboration of research institutes and industry, specifically investigates large-scale wind power generation offshore with the objective of innovative and sustainable business research. The EOS (Energy Research Subsidy) program includes a research theme dedicated to future grid design in combination with a substantial increase in renewable generation capacity, large-scale as well as decentralised.

Within we@sea, research line 3 is dedicated to the power system integration of offshore wind power. The Ph.D. project 'Grid Stability' (TUD) focuses on the development of solutions for power balancing the variability and partial unpredictability of wind power, taking into account the liberalized environment. Investigated solutions include the use of existing capacity in the system for balancing wind power, improved market designs, increased interconnection capacity and energy storage. A second Ph.D. project 'HVDC-interconnectors and Offshore Wind Parks' (TUD) explores the synergies between cross-border interconnector cables and offshore wind farms. Combination of both in a single infrastructure facilitates additional possibilities for the interconnection of offshore wind power and international trade whle significantly reducing overall costs for the electrical infrastructure offshore. A third Ph.D. project 'Wind Park and Grid Integration' (TUD) focuses on the technical aspects of the grid integration of different wind farm configurations. Parallel to the Ph.D.-research projects, industry research projects within line 3 focus on the system integration of wind power, balance control and imbalance market designs for large-scale offshore wind power (TenneT, Ecofys, Kema, ECN, TUD).

Norway

Recent and ongoing studies include development of numerical wind farm models for use in power system simulation tools (operating agent for IEA Wind R&D Task 21, Tande et al, 2004), power system stability studies in conjunction with planning of large wind farms at various sites in Norway, and also more generic type of studies (Hagstrøm et al., 2005; DiMarzio et al., 2005; Palsson et al., 2002 and 2003). Studies on wind/hydro integration have focused on planning and operation of large wind farms in areas with limited power transfer capacity, (Tande & Uhlen, 2004; Korpås et al., 2006). It is shown that surprisingly large amounts of wind power can be integrated without costly grid reinforcements, but utilizing the control possibilities of modern wind farms.

A new study is being planned for assessing the impact of large scale wind power on system adequacy in a regional hydro-based power system with weak interconnections. Other relevant themes of study are a) calculation of required national regulation capacity depending of wind energy share, b) market solutions for cost effective integration of wind power and c) using Nordic hydro for balancing Northern-European wind power.

Portugal

The Portuguese TSO, REN SA, is currently involved in several major activities concerning the integration of wind.

The construction program of grid reinforcements for renewables resulting from the grid planning studies referred in 5.5 including new lines and substations is continued and involving also uprating and upgrading of existing lines is under way. Support is given to wind park developers to help them designing, promoting and constructing their main substations and connection 150 or 220 kV lines.

Field measurements are continued also carried out at some of the largest wind parks with WTG's of different technologies to assess waveform quality of service parameters such as harmonics, flicker and inverse component. These measurements are made not only in normal grid configuration but also in low short circuit situations (such as connection to far substations, temporarily disconnecting existing lines) to evaluate consequences.

A new version of key regulations such as the Transmission Grid Regulation has been proposed to the National Directorate for Geology and Energy (Ministry of Economy and Innovation) in November 2006. The new Transmission Grid Regulation will have new specifications for wind parks. A more detailed Grid Code will be written in the near future with the contributions of the TSO and DSO and other national stakeholders in wind power.

Ongoing activities also include power system stability studies involving development of fast dynamic security assessment tools, use of FACTS and special control mechanisms for wind generators and impact on small signal stability from large scale integration of wind generation and identification of solutions for damping large oscillations.

Evaluation of the adequacy of reserve amounts and types of the Iberian system and ancillary services delivery through wind generation is going on. Correlation of wind and hydro resources and production and the impact of added storage as well as grid integration of small wind parks (DGS operation) focusing on the rise of the voltage quality of weak radial rural distributions grids are also topics.

Also, the main developers of wind parks are involved in the design and implementation of detailed wind forecast models, with the participation of Universities, State and Associated Laboratories.

Spain

In Spain, Universities, Research Institutes, Utilities and System Operators have performed Wind Integration studies (Rodrigues-Bobada et al., 2006). A substantial body of the work focuses on power systems stability and wind power prediction tools to improve forecasting for electricity production.

Ongoing work on wind integration includes grid congestions management, grid reinforcement, power system stability analysis, forecast model improvement, wind farm control and wind power data analysis.

With increasing wind farm penetration in the power system, national grid code is demanding additional requirements to integrate wind power plants with the other conventional types of generation. Specifically, national grid code is requiring uninterrupted generation throughout power system disturbances supporting the network voltage and frequency, and therefore, extending characteristics such as low voltage ride through, or reactive and active power capabilities. Low voltage ride through is particularly important to maintain voltage stability, especially in areas with high concentration of wind power generation, such is the case of Spain.

The Spanish Wind Energy Association has developed a proposal about the verification of requirements imposed by the Spanish grid code. It is focused on:

- Procedure of test of wind turbines and FACTS
- Procedure for model validation
- Procedure for wind power plant simulation.

The certification process includes the following verifications of specified requirements:

- Verification that the wind power plants do not disconnect as a consequence of voltage dips in the grid connection point associated with correctly cleared short circuits according to the voltage time curve indicated in the grid code.
- Verification that the power and energy consumption (active and reactive) in the grid connection point, for balanced and unbalanced faults, are less than or equal to the levels marked in the grid code.

Canary Islands case is being currently studied by the Spanish TSO REE (Red Eléctrica de España), taking into account the forecasted installed wind power. Canary Islands, currently with installed wind power of 129,49 MW, have fixed a final target of 1025 MW for 2015. The generated energy of this target will exceed the forecasted electricity demand for this year in valley hours. In the case of more populated island, and therefore, the biggest power systems, Gran Canaria and Tenerife, the installed wind power will indeed be around 115% share of the valley-hours power load, whereas in the smaller systems, the ratio will largely exceed this value. Additionally, during daylight hours, wind generation will be added to the forecasted photovoltaic generation output to be installed in these systems. Obviously, this forecasted scenario, with isolated and small sized power systems, with the commented proportion of non-manageable renewable energy generation, imposes the establishment of new technical requirements in wind turbines to be able to keep the safety & reliability of supply levels. In this study, several key aspects will be analyzed, such as fault ride-through requirements (voltage dips), frequency control, voltage control, short-circuit power, oscillation damping, and service restoration.

Sweden

There have been several studies on the wind integration with hydro power (Söder, 1994). The on-going PhD work at KTH are related to wind power in areas with limited export capabilities, Hydropower bidding under significant uncertainty and Frequency control in a system with large amounts of wind power.

UK

UK has been very active in the following relevant topics:

- Adequacy of network: transmission network planning and operation standards for systems with large contribution of wind generation and development of methodologies for their update
- Evaluation of contribution of wind power to generation security (Milborrow, 2005)
- Role and value of storage and demand side in managing variability (Strbac & Black, 2004)
- Role and value of wind forecasting
- Impact of wind turbine technology and control on network stability (Strbac & Bopp, 2004; DTI Centre for DG and SEE, 2005).

USA

An increasing number of traditional utilities and system operators are performing operational impact studies. A summary of these can be found for example in (DeMeo et al., 2005).

Studies for Public Service of New Mexico and Sacramento Municipal Utility District have started, using the AREVA dispatch simulator used for training utility operators, which allows for simulation of the power system response to the variable wind energy generation and extreme events. Issues of accuracy of wind forecasting will be addressed. NREL is investigating modifications to GE MARS (Multi-Area Reliability Simulator) to address improvements in ELCC calculations for wind plants.

Ongoing work includes several systems with significant amounts of multi-constrained hydro in the Northwest US and Western Area Power Administration (WAPA) system, including Bonneville Power Administration, Grant County Public Utility District on the mid-river section of the Columbia, Avista located in North Idaho and eastern Washington state, Idaho Power on the Snake River and WAPA on the Missouri River (Dakotas). UWIG is participating in a project with Xcel Energy to investigate the incorporation of a range of wind plant output forecasts into utility operations planning tools.

Work for high penetration has just started in US, driven by RPS mandates and consideration of higher mandate levels. A major study of California is has just been completed. The California Energy Commission CAISO study, performed by a consortium of companies including GE, studied up to 33% energy penetration from renewables, including wind, and again found no significant barriers to achieving this level of penetration, again assuming sufficient flexibility continued to be provided in the system (report published in 2007). A new high penetration study of the southwestern part of the US in the Western Electricity Coordinating Council (WECC) is getting underway in late 2007.

Other studies

The participants of this task do not cover all countries, and studies on wind integration are made also by organisations, like the recent publications of EWEA Grid Report (EWEA, 2005) and IEA Natural Variability report (IEA, 2005).

There is an ongoing activity at CIGRE under Study Committee SC C6 on distributed generation called Integration of large share of fluctuating generation, and SC 1.3 has completed a report on Power System Planning with the Uncertainty of Wind Generation.

The study by European TSOs, started in 2006, is in the second phase. The objective of the European Wind Integration Study (EWIS) is to seek proposals for a generic and harmonized European wide approach towards wind energy issues addressing operational and technical aspects including grid connection codes, market organizational arrangements, regulatory and market-related requirements, common public interest issues and even some political aspects impacting the integration of wind energy.

The European wind energy industry through EWEA launched a study in 2006 to look at interconnection and market measures needed to accommodate very high wind power penetration levels in Europe (Tradewind). Various scenarios with gradually increasing wind power penetration, up to the year 2030 are investigated. Power flows at interconnectors and selected transmission corridors are calculated, combining aggregated output of conventional power plants and wind power plants. For the purpose of the study an equivalent grid representation is constructed concentrating on the physical interconnectors between the member states. Future topologies, for example transnational offshore grids are included in the investigation as well. The simultaneous wind data used to calculate the time series of injected wind power in the model nodes are based on a 11 years Reanalysis data set, which is believed to capture a sufficient amount of meteorological situations. The investigated area covers the synchronous zones of UCTE, Nordel, GB and Ireland. The first simulation results will be available in the end of 2007.

Appendix 2: Detailed review of simulations for case studies

In this Appendix, the review tables from simulations regarding balancing requirements are presented.

Table 2.1. West Denmark.

Pedersen, J; Eriksen, P.B.: "System and Market Changes in a Scenario of increased Wind Power Production"						
Geographic area of study + year(s) studied: Western Denmark, 2005						
Power system characteristics:						
Load			**Installed (non-wind) generation**	**Interconnection**	**Wind power**	
Peak (MW)	**Min (MW)**	**TWh/a**	**Capacity (MW)**	**Capacity (MW)**	**MW**	**TWh/a**
		26.3	**ca. (5700-x) with x= simulation result**	**0**	**0…ca 7200**	**0 …26.3**
Power system details: thermal-wind-mixed (5700-x) MW thermal: ca. (1500 +y) MW gas; ca. (4000-z) MW coal 0 MW nuclear) (x, y and z are simulation results)						
Interconnection details: 0 MW						
Wind power details: geographical distribution: existing plants up to production of 6 TWh onshore, 20 TWh offshore.						
Set up						
A	**Aim of study**	1 what happens with 26,3 TWh wind (= 100% of consumption)				
M	**Method to perform study**	1 add wind energy 2 wind also replaces capacity For capacity credit also: a – chronological, using wind power and load profiles				
S	**Simulation model of operation**	2 deterministic simulation several cases				
Simulation detail						
R	**Resolution of time**	2 hour; DURATION of simulation period: one year				
P	**Pricing method**	1 costs of fuels etc 3 perfect market simulation				
D	**Design of remaining system**	2 optimized remaining production capacity 4 changed operation due to wind power				
Uncertainty and balancing						
I	**Imbalance calculation**	3 wind+load +production outages cause imbalances				

B	**Balancing location**	2 from the same region
U	**Uncertainty treatment**	1 transmission margins: 3 wind forecasts: b assume perfect forecast for wind, 5 load forecasts considered: 6 thermal power outages considered: TIME HORIZON for forecasts assumed in the simulation: day-ahead
Power system details		
G	**Grid limit on transmission**	2 constant MW limits
H	**Hydro power modelling**	8 other: no hydro power
T	**Thermal power modelling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered 4 heat production considered
W	**Wind power modelling**	1 time series: b – wind power from wind farms (onshore and offshore) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution (put together scenarios by association, of wind: whole region

Table 2.2. Sweden / hydro power efficiency.

Study conducted by + year when made: Lennart Söder, 1994						
Geographic area of study + year(s) studied: Sweden (one river system, results upscaled to Sweden)						
Power system characteristics:						
Load			**Installed (non-wind) generation**	**Interconnection**	**Wind power**	
Peak (MW)	**Min (MW)**	**TWh/a**	**Capacity (MW)**	**Capacity (MW)**	**MW**	**TWh/a**
Power system details: hydro						
Interconnection details: no						
Wind power details:						
Characteristics of system planning:						
Description of market: 0–90 MW of wind power in a 478 MW hydro system consisting of seven linked stations was considered and the results were scaled up to be representative for a hydro system with an installed capacity of 16 400 MW. Perfect information and perfect economic operation was assumed.						

Integration time frames of importance:		
Set up		
A	**Aim of study**	1 what happens with x GWh (or y GW) wind 2 how much wind is possible (wind power increased until evaluation strategy did not work)
M	**Method to perform study**	1 add wind energy 3 load is increased same amount of GWh as wind
S	**Simulation model of operation**	3 deterministic planning with stochastic wind forecast errors Deterministic planning but evaluation based on rescheduling every hour based on stochastic forecast errors
Simulation detail		
R	**Resolution of time**	2 hour. Several representative days were simulated
P	**Pricing method**	5 other: The "integration cost" was calculated as needed extra wind energy (MWh) to compensate for lost hydro energy
D	**Design of remaining system**	1 constant remaining system 6 other: load was increased corresponding to wind increase
Uncertainty and balancing		
I	**Imbalance calculation**	2 wind+load forecast errors cause imbalance
B	**Balancing location**	1 dedicated source 4 other: Wind power balancing was performed in one river and the result was upscaled to Sweden
U	**Uncertainty treatment**	3 wind forecasts: d best available forecasts, forecast error 2 h … 30 h ahead (RMSE) 1,56 …3,21 m/s in winter and 1,56 …2,70 m/s in summer. 5 load forecasts considered: RMSE 1 h ahead 1% and 24 h ahead 2% of peak load For each day 1–24 hour forecasts are used for both wind and load uncertainty.
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modelling**	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered
T	**Thermal power modelling**	5 other: no thermal power in the system

W	**Wind power modelling**	1 time series: a – measured wind speed + power curve (8 sites) many generated power series based on stochastically generated windspeed forecast errors including generalized dependency

Table 2.3. Nordic hydro efficiency.

<table>
<tr><td colspan="8">Study conducted by + year when made: (Holttinen et al, 2001)</td></tr>
<tr><td colspan="8">Geographic area of study + year(s) studied: Nordic countries 2000 and 2010</td></tr>
<tr><td colspan="8">Power system characteristics:</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Interconnection</td><td colspan="2">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td>MW</td><td>TWh/a</td></tr>
<tr><td>67 000</td><td>24 000</td><td>385</td><td>90 000</td><td>3000</td><td>18 000</td><td>46</td></tr>
<tr><td colspan="8">Power system details: thermal-hydro-mixed: hydro 191 TWh/a, nuclear 92 (2010: 89) TWh/a; CHP 60 (2010: 88) TWh/a; thermal condensing 5500 (2010: 7700) MW</td></tr>
<tr><td colspan="8">Interconnection details: Nordic area is well interconnected within the four countries. Total 1800 MW DC and 1200 MW AC links to Central Europe, flexible.</td></tr>
<tr><td colspan="8">Wind power details: distributed over the 4 Nordic countries (11 TWh/a West Denmark, 5 TWh/a East Denmark, 9 TWh/a Norway, 14 TWh/a Sweden (South), 7 TWh/a Finland); no distinction between offshore/onshore nor transmission / distribution network connected in the model</td></tr>
<tr><td colspan="8">Characteristics of system planning: weekly optimization according to water values of hydro power, using 4 load steps during the week</td></tr>
<tr><td colspan="8">Description of market: common Nordic market with possibilities to import/export from/to Central Europe</td></tr>
<tr><td colspan="8">Integration time frames of importance: weekly</td></tr>
<tr><td colspan="8">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="5">1 what happens with x GWh wind, increased wind power with remaining system kept the same</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="5">1 add wind energy</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="5">2 deterministic simulation, 30 different hydro inflow cases</td></tr>
<tr><td colspan="8">Simulation detail</td></tr>
<tr><td>R</td><td colspan="2">Resolution of time</td><td colspan="5">1 week (with 4 load profiles, hydro inflow and wind assumed constant during the week), duration of simulation period: 30 years</td></tr>
<tr><td>P</td><td colspan="2">Pricing method</td><td colspan="5">1 costs of fuels etc. Pricing from market simulation (demand and supply curves)</td></tr>
<tr><td>D</td><td colspan="2">Design of remaining system</td><td colspan="5">1 constant remaining system
4 changed operation due to wind power</td></tr>
</table>

Uncertainty and balancing		
I	**Imbalance calculation**	no imbalance calculation, weekly resolution
B	**Balancing location**	no imbalance calculation, weekly resolution
U	**Uncertainty treatment**	2 hydro inflow uncertainty: 3 no wind forecasts (assume persistence), some wind uncertainty taken into account through weekly uncertainty in water value calculations 6 thermal power outages considered:
Power system details		
G	**Grid limit on transmission**	2 constant MW limits both inside the whole area and outside the simulated area
H	**Hydro power modelling**	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered
T	**Thermal power modelling**	only availability considered, no detailed modelling (weekly)
W	**Wind power modelling**	1 few wind speed time series (weekly), 30 years of weekly wind data derived from wind speed measurements, 1–2 wind series per country

Table 2.4. Nordic/Germany.

Study conducted by + year when made: Risoe National Laboratory, 2006

Geographic area of study + year(s) studied: Power system consisting of Denmark, Finland, Germany, Norway and Sweden, divided into 12 regions, 2010 power system scenario, 3 wind power cases

Power system characteristics:

Load			Installed (non-wind) generation	Interconnection To outside model area	Wind power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
155 500	**65 00**	**977**	**196 000**	**6600**	**Case dep**	**Case**

Power system details: mixed (57 500 MW hydro including pumped hydro storage, 138 500 MW thermal: 31 000 MW gas 36 000 MW coal 32 000 MW nuclear)

Interconnection details: Transmission capacity between model regions: 3120 MW DC, 28 000 MW AC links, the usage of transmission capacity is co-optimised with the usage of production capacity in the study, i.e. very flexible usage of transmission, model decides on the distribution of transmission capacity used for reserves and used for the day-ahead market. Usage of transmission more flexible than in the real power system.

Wind power details: geographical distribution: distributed into 12 model regions with wind power production time series reflecting geographical smoothing, Base wind case: 5500 MW offshore, 30 000 MW on-shore, 10% wind case: 11 500 MW offshore, 46 000 MW onshore, 20% wind case: 11 500 MW offshore, 64 000 MW onshore. Distribution network not treated in the study i.e. no difference between connection to transmission network or distribution network		
Characteristics of system planning: Transmission capacity planning done by TSOs. Investments in power plants decided by power producers. Day-to-day operation of power plants planned by power producers that trade on power pools, sell heat to district heating networks, and sell system services to TSOs.		
Description of market: Day-ahead spot market (Nord Pool in the Nordic countries, EEX in Germany), also a lot of bilateral power trade. Reserve power markets organized by TSOs.		
Integration time frames of importance: activation of regulating power (10–15 minutes), unit commitment (hours)		
Set up		
A	**Aim of study**	1 what happens with x GWh (or y GW) wind
M	**Method to perform study**	1 add wind energy – comparison between stochastic, variable wind production and equivalent predictable, constant wind production
S	**Simulation model of operation**	4 Stochastic simulation several cases
Simulation detail		
R	**Resolution of time**	2 hour. DURATION of simulation period: 5 weeks, selected to represent one year.
P	**Pricing method**	1 cost of fuels, including star-up costs 3 perfect market simulation (each actor maximizes its benefit according to some definition considering the physical and legal constraints)
D	**Design of remaining system**	1 constant remaining system 4 changed operation due to wind power 5 perfect trading rules
Uncertainty and balancing		
I	**Imbalance calculation**	1 only wind cause imbalances – for reserve power allocation wind forecast errors and production outages are combined
B	**Balancing location**	3 also outside region
U	**Uncertainty treatment**	2 hydro inflow uncertainty: 3 wind forecasts: d best available forecasts, standard deviation of wind power production forecast error equal to 15–18% of installed wind power capacity for forecast horizons 8–36 hours ahead, lower for shorter forecast horizons. TIME HORIZON for forecasts 3–36 hours ahead

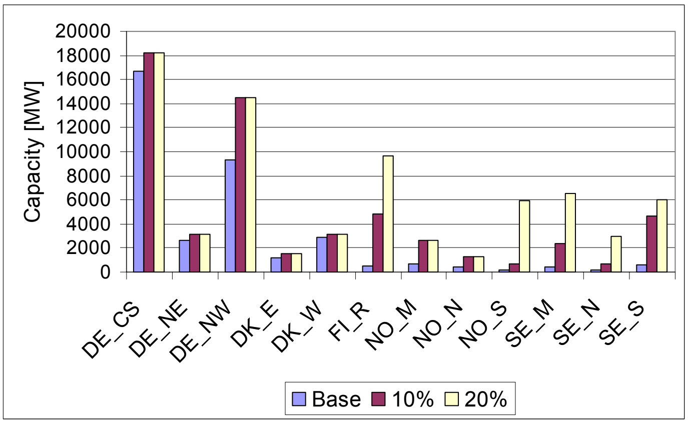
Power system details		
G	**Grid limit on transmission**	2 constant MW limits, limits inside the whole area: 31 000 MW, limits outside the simulated area: 66 00 MW
H	**Hydro power modelling**	3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered
T	**Thermal power modelling**	2 start/stop costs considered (linear approximation) 3 efficiency variation considered (linear approximation) 4 heat production considered
W	**Wind power modelling**	 *Figure: Geographical distribution of installed wind power capacity.* Denmark: Historical hourly, total wind power production data for East and West Denmark. Finland: Historical hourly wind power production time series for 21 sites. Germany: Historical hourly wind speed time series for 10 sites. Norway: Historical hourly wind speed time series for 6–12 sites. Sweden: Historical hourly wind power production time series for 6 sites. d – time series smoothing considered (aggregation of time series from different sites into one time series for each model region) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution (put government plans combined with expert judgement and wind power projects applying for planning permits)

Table 2.5. USA Minnesota 2004.

Study conducted by + year when made:EnerNex/WindLogics, 2004
Geographic area of study + year(s) studied:Minnesota, 2010
Power system characteristics:

Load			Installed (non-wind) generation	Interconnection	Wind power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
9933	**3400**	**48,1**	**11 426**	**1500**	**1500**	**5,8**

Power system details: thermal-hydro-mixed (App. 2% hydro; 28% gas; 25% coal; 12% nuclear; 4% oil, 21% short and long term purchases; 8% other, including wood, biomass, wind at 13,5% capacity factor)
Interconnection details: Transmission not explicitly modeled; no DC ties, some purchases via transmission ties, self provides regulation/reserves
Wind power details: wind plants well distributed over a 1000 km square, all on-shore, all assumed transmission connected.
Characteristics of system planning: Assumed vertically integrated utility environment for thermal system, with wind plants built in response to an RPS
Description of market: Bilateral trading
Integration time frames of importance: Regulation, load following, unit commitment

Set up		
A	**Aim of study**	1 what happens with x GWh (or y GW) wind
M	**Method to perform study**	1 add wind energy For capacity credit: a – chronological, using wind power and load profiles
S	**Simulation model of operation**	2 deterministic simulation several cases
Simulation detail		
R	**Resolution of time**	1 day/week 2 hour DURATION of simulation period: 3 one-year periods
P	**Pricing method**	1 costs of fuels etc
D	**Design of remaining system**	1 constant remaining system
Uncertainty and balancing		
I	**Imbalance calculation**	3 wind+load +production outages cause imbalances
B	**Balancing location**	2 from the same region
U	**Uncertainty treatment**	1 transmission margins: not considered 2 hydro inflow uncertainty: deterministic 3 wind forecasts: (d best available forecasts, app. 20% MAE) 5 load forecasts considered: yes

		6 thermal power outages considered: yes 7 other: TIME HORIZON for forecasts assumed in the simulation (day-ahead)
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modelling**	6 limited, deterministic run-of-river 7 interaction with hydro resources not significant
T	**Thermal power modelling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered
W	**Wind power modelling**	1 time series: c – re-analysis wind speed + power curve (50 sites) 2 wind power profiles (b – hour of day) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution based on knowledge of local developments with assistance of wind association in 1000 km square region

Table 2.6. USA Minnesota 2006.

Study conducted by + year when made: EnerNex/WindLogics, 2006						
Geographic area of study + year(s) studied: Minnesota, 2020						
Power system characteristics: (Area of Minnesota included in study)						
Load			**Installed (non-wind) generation**	**Interconnection**	**Wind power**	
Peak (MW)	**Min (MW)**	**TWh/a**	**Capacity (MW)**	**Capacity (MW)**	**MW**	**TWh/a**
21 000	**8800**	**85**	**23 500**	**5000**	**5700**	**21**
Power system details: thermal-hydro-mixed, MISO percentages (3,5% hydro, 6% renewables, 90,5% thermal: 23,5% gas, 5% oil, 55% coal, 7% nuclear)						
Interconnection details: The Minnesota system is part of the MISO market and the NERC Midwest Reliability Organization (MRO), which is a part of the larger Eastern Interconnection. Minnesota is estimated to have approximately 5000 MW of interconnection capacity in place by 2020. Part of Minnesota load is regularly supplied by generation from out of state.						
Wind power details: The 5700 MW of wind capacity in 2020 is onshore, spread in four regions of a 3 state area with good regional diversity, in a square of approximately 750 km per side, all transmission connected, with minimal transmission congestion.						
Characteristics of system planning: Assumed vertically integrated utility environment for thermal system capacity planning purposes, operating in a market environment for dispatch purposes, with wind plants built in response to an RPS.						

Description of market: The Minnesota load is served from the MISO market, made up of parts of 14 states in the Upper Midwest region of the US. MISO operates a day-ahead market, hour-ahead market, and is in the process of implementing an ancillary services market. The market currently consists of 116 GW of load, and 133 GW of generation, which is assumed to grow to approximately 170 GW of generation by 2020.		
Integration time frames of importance: regulation, load following, unit commitment		
Set up		
A	**Aim of study**	1 what happens with x GWh of wind
M	**Method to perform study**	1 add wind energy For capacity credit also: a – chronological, using wind power and load profiles
S	**Simulation model of operation**	2 deterministic simulation several cases
Simulation detail		
R	**Resolution of time**	1 day/week 2 hour DURATION of simulation period: 3 periods of 1 year each
P	**Pricing method**	1 costs of fuels etc
D	**Design of remaining system**	4 changed operation due to wind power 5 perfect trading rules 6 other: added additional generation and transmission capacity in accord with current plans, as expressed most clearly in CapX 2020
Uncertainty and balancing		
I	**Imbalance calculation**	3 wind+load +production outages cause imbalances
B	**Balancing location**	2 from the same region 3 also outside region
U	**Uncertainty treatment**	1 transmission margins: honor constraints 2 hydro inflow uncertainty: deterministic 3 wind forecasts: (d. best available forecasts, 20% MAE of rated capacity day ahead) 5 load forecasts considered: yes 6 thermal power outages considered: yes TIME HORIZON for forecasts assumed in the simulation (hour ahead and day-ahead)
Power system details		
G	**Grid limit on transmission**	2 constant MW limits
H	**Hydro power modelling**	6 limited, deterministic run-of-river 7 interaction with hydro resources not significant
T	**Thermal power modelling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered

W	**Wind power modelling**	1 time series: c – re-analysis wind speed + power curve 2 wind power profiles (b – hour of day) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution (based on detailed wind resource maps and knowledge of local developments, with assistance of stakeholders); specify geographical distribution of wind covers square of 750 km per side.

Table 2.7. Ireland ESBNG.

Study conducted by + year when made: ESB National Grid (now EirGrid), 2004

Geographic area of study + year(s) studied: Republic of Ireland

Power system characteristics: Republic of Ireland electricity system, 2 different peak loads analysed – 5000 MW and 6500 MW

Load			Installed (non-wind) generation	Inter-connection	Wind power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
5000/6500		29/38,5	5732/7354	not considered	0/500/1000/ 1500/2500/ 3500	5,2/10,5/ 15,7/19,6/ 27,4

Power system details: thermal-hydro-mixed (5000 MW peak system: 544 MW hydro 4935 MW thermal: 3769 MW gas 855 MW coal 344 MW peat; 6500 MW peak system: 544 MW Hydro, 6650 MW Thermal: 5153 MW gas 855 MW coal 344 MW peat)

Interconnection details: Interconnection not considered for this study

Wind power details: Distributed over the whole country, based on 67% onshore and 33% offshore.

Characteristics of system planning: Grid System is centrally planned

Description of market: None specified – cost based study

Integration time frames of importance: Unit Commitment time frame

Set up

A	**Aim of study**	1 what happens with x GWh (or y GW) wind 3 other: impact of Wind Power on operation of conventional plant
M	**Method to perform study**	2 wind replaces existing capacity, while maintaining system adequacy For capacity credit also: a – chronological, using wind power and load profiles
S	**Simulation model of operation**	2 deterministic simulation, with unit commitment and dispatch, for 2 scenarios, each with four different amounts of wind on the system

Simulation detail

R	**Resolution of time**	1 hourly, for duration of 1 year

P	**Pricing method**	1 costs of fuels 5 other: additional reserve capital costs attributable to wind energy calculated
D	**Design of remaining system**	1 for 5000 MW peak load scenario, existing plant with plant dropped as various levels of wind added For 6500 MW system peak load scenario, most older plant is assumed to have been replaced and augmented by a mixture of Combined Cycle (CC) and Combustion Turbine (CT) units
Uncertainty and balancing		
I	**Imbalance calculation**	4 other: wind + production outages cause imbalances.
B	**Balancing location**	2 from the same region
U	**Uncertainty treatment**	3 wind forecasts: average value of wind over the 24 hour period was used as the forecasted value for commitment algorithm, with variations above or below this used for dispatch algorithm 6 thermal power outages considered: both scheduled and forced outages considered
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modelling**	8 other: hydro plant operating in accordance with historical production profiles
T	**Thermal power modelling**	1 ramp rates considered 2 start/stop costs considered
W	**Wind power modelling**	1 time series: b – Wind Power Profiles. On-shore time series based on 18 existing wind farms, mainly in the south-west and north-west of the country. Offshore time series based on power output of proposed off-shore site in the East of the country 2 wind power profiles b – hour of day 3 wind data not synchronous with load 4 installation scenarios for future wind power distribution according to projected regional capacity factors; on-shore mainly sited in south-west and north-west of country

Table 2.8. Ireland SEI.

<table>
<tr><td colspan="7">Study conducted by + year when made: ILEX, UMIST, UCD, QUB, 2004</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied: Ireland, 2006 and 2010</td></tr>
<tr><td colspan="7">Power system characteristics: Irish electricity system, consisting of Republic of Ireland and Northern Ireland</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Inter-connection</td><td colspan="2">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td>MW</td><td>TWh/a</td></tr>
<tr><td>6127/6900</td><td>2192/2455</td><td>35,5/39,7</td><td>8110/8900</td><td>500/900</td><td>845/1300 /1950</td><td>2,2/3,4/5,1</td></tr>
<tr><td colspan="7">Power system details: Mixed(217,5 MW Hydro, 292 MW pumped hydro storage, 7488 MW thermal (4932 MW gas, 345,6 MW peat, 1215 MW coal, 995,4 MW oil)</td></tr>
<tr><td colspan="7">Interconnection details: 500 MW HVDC interconnection to Scotland; Planned 400 MW Interconnector to England used for 2010 scenarios</td></tr>
<tr><td colspan="7">Wind power details: Wind power distributed over the whole island, 10% off shore, remainder onshore, 50% transmission network connected, 40% distribution</td></tr>
<tr><td colspan="7">Characteristics of system planning: Grid System is centrally planned</td></tr>
<tr><td colspan="7">Description of market: None specified – cost based study</td></tr>
<tr><td colspan="7">Integration time frames of importance: Seconds to 4 hours</td></tr>
<tr><td colspan="7">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="4">1 what happens with x GW wind?
3 other: impact of wind on operating reserve</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="4">1 add wind energy
capacity credit calculated using wind power and load profiles</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="4">2 deterministic simulation, for three different cases: winter peak day, summer valley day and shoulder business day</td></tr>
<tr><td colspan="7">Simulation detail</td></tr>
<tr><td>R</td><td colspan="2">Resolution of time</td><td colspan="4">half hourly data
Duration: 1 day</td></tr>
<tr><td>P</td><td colspan="2">Pricing method</td><td colspan="4">1 costs of fuels</td></tr>
<tr><td>D</td><td colspan="2">Design of remaining system</td><td colspan="4">1 constant remaining system, with new CCGTs and OCGTs added to replace retired plant</td></tr>
<tr><td colspan="7">Uncertainty and balancing</td></tr>
<tr><td>I</td><td colspan="2">Imbalance calculation</td><td colspan="4">3: wind + load + production outages cause imbalances</td></tr>
<tr><td>B</td><td colspan="2">Balancing location</td><td colspan="4">2 from the same region – all reserve is provided on the island</td></tr>
</table>

U	**Uncertainty treatment**	3 wind forecasts: d best available forecasts for wind assumed, standard deviation of error increases as forecast horizon increases (14%–18% for 1–8 hours ahead) 5 load forecasts considered: Defined for different timeframes – 1 hour – 40 MW, 4 hours – 60 MW 6 thermal power outages considered: both scheduled and forced outages considered 7 wind and load forecast errors are combined for different time horizons TIME HORIZON for forecasts assumed in simulation: 1 and 4 hours
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modelling**	8 other: hydro plant operating in accordance with historic profiles
T	**Thermal power modelling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered
W	**Wind power modelling**	1 time series: b – wind energy time series for future years was produced based on historical data from 10 wind farms, and scaled appropriately 2 wind power profiles b – hour of day 3 wind data not synchronous with load 4 installation scenarios for future wind power distribution according to projected regional capacity factor, distributed across the country

Appendix 3: Reserve terminology in Europe

Table 1. Terminology for short term operational reserves in Europe (Söder et al, 2006)

OVERALL	DETAIL	UNIT	SUPRANATIONAL ASSOCIATIONS			NATIONAL					
			UCTE	NORDEL	DC Baltija	Belgium	France	Germany	Great Britain	Netherlands	Poland
LOAD-FREQUENCY AND RESERVES CONTROL	**Primary (Spinning)**		**Primary Control**			**Primary Control**	**Primary Control**	**Primary Control**	**Contingency & Operating Reserves, Primary Response**	**Primary Reserve**	
	Reference		OH: Policy 1 & Appendix 1: Load-Frequency Control and Performance, A. Primary Control	NGC-Appendix 2 of System Operation Agreement	GC, Sec. 2.1.2	Titre IV Chapter XIII, Art 236 to 242	INDI0301719A: Chapter III, Art 11,Primary reserve must be >/= 2.5% of capacity for generating plant > 40MW. Référentiel Technique: Chapitre 4.1.	TC Section 2.3.6, section 2.3.7 and Appendix D 3.1.	Grid Code: CC.A.3.2, BC 1.5.4 and BPS	NetCode 5.1.1.1.a.1 and System Code 2	
	Definition		Stabilises frequency, although the level may differ from the set point and border power exchanges may be altered.	Stabilises frequency, although the level may differ from the set point and border power exchanges may be altered.	The definition of primary control reserves on page 12 is "- a second reserve of active power used for frequency control."		INDI0301719A: Chapter III, Art 11,Primary reserve response such that for frequency drop of >/= 200mHz, restoration of primary reserve in < 30s and half this in < 15s.	Generating units > 100MW must be capable of delivery of primary response as per TC Figs 2.1 & 2.2	Operating Reserve comprises Reserve for Response and Short-Term Reserve	System Code 2.1.13 and Appendix 3 presents the voltage/ frequency U/f charts, power output levels and durations	
	Governor Mode		Governor control of all generators subject to primary control	Governor control of all generators subject to primary control. Load shedding allowed for f=49.5-49.9 Hz	Governor control of all generators subject to primary control	Art 236 requires automatic control of primary reserve		Governor control of all generators subject to primary control, =/- 2% of rated output	Some generation in Frequency Sensitive Mode, other in Limited Frequency Sensitive Mode	SystemCode 2.2.20 and Imple-mentation Regulations 1.3.4	
	Speed of response		Primary Control Power to increase linearly up to 3000MW over 30s	Primary Control Power to increase linearly up to 3000MW over 30s	Ramp rate no less than 2.5% of the rated power in 5 sec. and 5% in 30 sec.; hydrogenerators and turbogenerators must be able to maintain the varied power at frequency deviation for at least 15 min.; primary control power must be available repeatedly after 10 min. of the previous attempt;	Art 242 requires 50% of primary reserve to be provided within 15s of the start of the frequency deviation with the remainder following between 15s and 30s of the start.		TC 2.3.7.1, up to 30s	Primary Response ramps from 0 to 10s, effective for another 20s	System Code 2.1.6 and Appendix 2 , up to 30s @ 7% per minute	
	Maximum load loss		Up to 3000MW load loss without load shedding; maximum permissible dynamic frequency deviation 800mHz	Up to 600 MW load loss without load shedding; maximum permissible dynamic frequency deviation 100mHz	Loss of generator transformer block up to 750 MW, bus as well as busbar of total generating power under 600 MW; loss of loas up to 250 MW; frequency should not deviate by more than 0.5 Hz				For 300 to 1000MW power loss, frequency should not deviate by > 0.5Hz	Tennet: Imple-mentation Regulation 1.3 describes regulating, reserve and emergency power categories.	
	Self regulation		Self regulation of load (MW/Hz) taken into account	Self regulation of load (MW/Hz) taken into account. Load decrease of 200 MW at 49.5 Hz assumed	Not considered in grid code. It can here be noted that DC Baltija is strongly and synchronously connected to Russia and Belorus, so all items concerning frequency control is not a responsibility of DC Baltija				Response requirement (MW) calculated by NGC every half-hour and determined according to load conditions	Self regulation of load (MW/Hz) taken into account	
	Contribution		Primary control shared between Control Areas according to contribution coefficients	Primary control shared between four countries according to yearly consumption and dimensioning faults	Primary control shared between Control Areas and is set up to 5% depending on max load of the Control Area in the previous period				Reserve standard is LOLE of 1 event per annum, a 1 in 365 expectation.	Tennet: Estimated primary reserve contribution for 2005 is 109MW i.e. 3.6% of UCTE total.	

OVERALL	DETAIL	UNIT	SUPRANATIONAL ASSOCIATIONS			NATIONAL					
			UCTE	NORDEL	DC Baltija	Belgium	France	Germany	Great Britain	Netherlands	Poland
	Secondary (spinning and non-spinning)		**Secondary Control**		Secondary control	**Secondary Control**	**Secondary Control**	**Secondary Control**	**Contingency & Operating Reserves, Secondary Response**	**Secondary Regulation**	
	Reference		OH: Policy 1 & Appendix 1: Load-Frequency Control and Performance, B. Secondary Control	NGC-Appendix 2 of System Operation Agreement	Section 2.1.3	Titre IV Chapter XIII, Art 243 to 247	INDI0301719A: Chapter III, Art 12 Référentiel Technique: Chapitre 4.1.	TC Section 2.3.7 and Appendix D 3.2	GC: CC.A.3, BC 1.5.4 and BPS	Tennet: Summary of current operating principles of UCTE, sections 3 & 5.	
	Control mechanism		Automatic Generator Control, to restore power exchanges to set point value	No Automatic Generator Controll Bids from regulating market called when needed	Automatic Generator Control, to restore power exchanges to the preset value	Art 246 The system operator determines the amount of secondary reserve that each generator is to put at the disposal of the system operator.	INDI0301719A: Chapter III, Art 12, any generating group > 120MW must have a half-band of secondary reserve > 4.5% of rating.	TC Appendix D 3.2.1 and 3.2.2.6 - automatic control by Regulating Zone using central secondary automatic controller	Short Term Reserve comprises Standing Reserve and Regulating Reserve (latter includes Fast Reserve)		
			Controls Area Control Error (ACE) to zero	Cheapest bids in the whole area accepted as long as transmission limits are not violated	Area Control Error not considered in Grid Code	Art 248 The system operator is to determine the unbalance with the foreign regulating zones		Load frequency controller for German control unit is located in Brauweiler near Cologne and is operated by RWE	Operations under instruction		
	Response		30s to 15 mins	Available in 10 mins. Disturbance reserves available within 15 minutes	30s to 15 mins			TC Appendix D 3.2.1 - entire contracted secondary response to be available in 5 minutes	30s to 30 minutes		
			Amount of reserve quantified by formula according to demand, by Control Area	No formal requirements of total reserves, but the TSO:s have extra reserves for disturbance situations	Requirements for secondary reserves for Control Areas (each country = 1 TSO = one CA) and the control Block are set according to methodology approved by the Operators and control block operator.				Response requirement (MW) calculated by NGC every half-hour and determined according to load conditions		
	Capacity		Each Control Area to have sufficient control of generation or load control to control ACE to zero.	Cheapest bids in the whole area accepted as long as transmission limits are not violated	No requirements of specific amount of control in each area. At least not in the grid code.			TC Appendix D 3.2.2.- each generating unit providing secondary response must be able to provide +/- 30 MW.			
	Tertiary		**Tertiary Control**		**Tetriary control**	**Tertiary Reserve**	**Tertiary Control**	**Minute Reserve**		**Emergency Power**	
	Reference		OH: Policy 1 & Appendix 1: Load-Frequency Control and Performance, C. Tertiary Control	NGC-Appendix 2 of System Operation Agreement	Section 2.1.4	Titre IV Chapter XIII, Art 249 to 256		TC Appendix D 3.3		Dte: SystemCode 2.2.5b and Tennet: Operations - Managing Concept 5.8	
	Control mechanism		Activated manually by TSOs	Included in secondary control	Few details concerning treatment of tertiary control	Procured through competitive bidding		Contract with ÜNB			
	Purpose		Frees up Secondary Reserves		Frees up Secondary Reserves			Frees up Secondary Reserves			
	Response		15 minute reserve		Is carried out in every control area			15 minute reserve		To be available in 30 mins	

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