The impact of large scale wind power production on the Nordic electricity system

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Abstract

This thesis studies the impact of large amounts of wind power on the Nordic electricity system. The impact on both the technical operation of the power system and the electricity market are investigated.

The variability of wind power is reduced when looking at a large interconnected system with geographically dispersed wind power production. In the Nordic countries, the aggregated wind power production will stay between 1–90 % of the installed capacity and the hourly step changes will be within ±5 % of the installed capacity for most of the time. The reserve requirement for the system, due to wind power, is determined by combining the variations with varying electricity consumption. The increase in reserve requirement is mostly seen on the 15 minutes to 1 hour time scale. The operating reserves in the Nordic countries should be increased by an amount corresponding to about 2 % of wind power capacity when wind power produces 10 % of yearly gross demand. The increased cost of regulation is of the order of 1 €/MWh at 10 % penetration and 2 €/MWh at 20 % penetration. This cost is halved if the investment costs for new reserve capacity are omitted and only the increased use of reserves is taken into account. In addition, prediction errors in wind power day ahead will appear in the regulating power market to an extent which depends on how much they affect the system net balance and how much the balance responsible players will correct the deviations before the actual operating hour.

Simulations of increasing wind power in the Nordic electricity system show that wind power would mainly replace coal fired production and increase transmission between the areas within the Nordic countries and from Nordic countries to Central Europe. The CO_2 emissions decrease from an initial 700 gCO_2/kWh to 620 gCO_2/kWh at 12 % penetration. High penetrations of wind power will lower the Nordpool spot market prices by about 2 €/MWh per 10 TWh/a added wind production (10 TWh/a is 3 % of gross demand).

Preface

This doctor's thesis has been carried out at the Technical Research Centre of Finland VTT[1]. The work was mainly financed by the Nordic Energy Research Programme and Fortum Säätiö (Fortum Foundation), with co-funding from the Finnish Energy Industries Federation Finergy. Part of this work has been co-financed through the EU project "Wind power Integration in Liberalised electricity markets WILMAR" and the national Tekes ClimTech programme research project "The possibilities of wind power for limiting climate change".

First of all I want to thank the wind power producers and power companies for providing data without which a large part of this thesis would not have been possible. The use of energy system models EMPS in SINTEF, Norway, and SIVAEL in Eltra, Denmark is acknowledged.

My supervisor professor Peter Lund and my instructor docent Ritva Hirvonen[2] have given me valuable comments related to the work, for which I am grateful. This work is the fruit of Nordic co-operation – visiting research institutes and power companies in Denmark, Norway and Sweden has given me the opportunity to use different models and obtain data for this thesis as well as interesting discussions on the Nordic power system. I wish to extend special thanks to the following persons for both organising and contributing to my successful visits: Klaus-Ole Vogstad, Audun Botterud, Birger Mo in NTNU/SINTEF Energy Research; Gregor Giebel, Erik Lundtang Petersen, Poul-Erik Morthorst in Risø National Laboratories; Hans Ravn and Claus Nielsen in Elkraft System; Jens Pedersen and Peter Børre Eriksen in Eltra; Torben Nielsen and Henrik Madsen at IMM/DTU; Lars Tallhaug in Kjeller Vindteknikk and Lennart Söder in KTH. In Finland, the wind power team as well as the energy systems group at VTT have provided a good working environment, special thanks for discussions go to Esa Peltola, Bettina Lemström and Göran Koreneff.

Last but not least, my family has given me the hugs and kisses needed to keep me going. Special thanks for the patience of my daughters Sara and Meri, not getting angry when the mother had eaten the last chocolate biscuits. And to my dear husband Esa, for his love and impatience.

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[1] VTT Processes, Energy production research area, Distributed energy group
[2] currently working at Energy Market Authority EMA

List of publications

The thesis consists of the following publications:

A. Holttinen, H., Hirvonen, R. 2005. Power system requirements for wind power. Chapter 8 in Wind Power in Power Systems. Ed. by Ackermann, T. John Wiley & Sons Ltd. Pp. 144–167. ISBN 0-470-85508-8 (HB). (In print.)

B. Holttinen, H. 2005. Hourly wind power variations in the Nordic countries. Wind Energy. (In print.)

C. Holttinen, H. 2005. Impact of hourly wind power variations on the system operation in the Nordic countries. Wind Energy. (In print.)

D. Nørgård, P., Holttinen, H. 2004. A Multi-Turbine Power Curve. In: Proceedings of Nordic Wind Power Conference NWPC'04, 1.–2.3.2004. Gothenburg, Sweden. 5 p. Submitted to Wind Energy.

E. Holttinen, H., Pedersen, J. 2003. The effect of large-scale wind power on a thermal system operation. In: Proceedings of the 4th International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms. 20.–22. Oct. 2003, Billund, Denmark. KTH, Stockholm, Sweden, Denmark. 7 p.

F. Holttinen, H., Vogstad, K.-O., Botterud, A., Hirvonen, R. 2001. Effects of large scale wind production on the Nordic electricity market. Proceedings of European Wind Energy Conference, Wind Energy for the New Millenium, EWEC'2001, July 2–6th, 2001, Copenhagen, Denmark. 4 p.

G. Holttinen, H., Tuhkanen, S. 2004. The effect of wind power on CO_2 abatement in the Nordic Countries. Energy Policy, Vol. 32/14, pp. 1639–1652.

H. Holttinen, H. 2005. Optimal electricity market for wind power. Energy Policy. (In print.)

Publication A is a summary of the impact wind power has on power systems, presenting the knowledge so far of the extent of the impact.

Publications B and C study the operating reserve requirements of wind power, based on hourly wind power production data. In publication B, large scale wind power production is studied, looking at statistical parameters defining the smoothing effect of the production time series from geographically dispersed production. In C, the data is used together with synchronous load data to reveal the incremental effect of wind power fluctuations on the variability of load that the power system will experience. The method developed in publication D is used in publication B when working with wind speed time series. The method aims to make a single point measurement represent wind farm production of a larger area.

In publications E and F, the operation of the power system is studied via simulations with increasing amounts of wind power. In E, the focus is on the thermal system operation with hourly level simulations of the West Denmark power system. In F, the focus is on the effects on the hydro power system and the Nordic electricity market.

In Publication G, the role of wind energy in reducing CO_2 emissions is studied. Energy system simulation models are used to find out what production forms and fuels wind energy would replace in the Nordic and Finnish energy systems.

Publication H studies wind energy in the electricity markets. The short term prediction of wind power production and the challenge of wind power production in a day-ahead market are described. A case study based on realised data for year 2001 is presented, where the benefits of more flexible market mechanisms are illustrated from a wind power producers' point of view.

Own contribution

The author has been the main person responsible for writing the publications, making the analyses and drawing the conclusions, except for publication D. In publication A, the co-author wrote section 2. In publication G, the co-author wrote chapter 3, carried out the corresponding simulations and participated in the analysis of the results. For publications E and F, the co-authors were involved in forming the input files, and helping to run the model and interpret the results. However, the simulation set-up and scope of the work was by the author. For publication D, the main author is responsible for the writing and formulating the multi-turbine power curve approach and my contribution as a co-author has been to join the discussions and provide the examples of how the method works.

Contents

Appendices

Publications A–H

List of symbols

a	annuity factor
c_p	capacity factor of wind power (production divided by time of operation and nominal capacity)
CHP	combined heat and power
CO_2	carbon dioxide
EFOM	Energy Flow Optimisation Model
EMPS	EFI's Multi-Area Power market Simulator model
GHG	green-house gas(es)
LOLP	loss-of-load-probability
n	number of data sets / wind farms
NGCC	natural gas combined-cycle (power plant)
SIVAEL	planning model for heat and power production
TEP	tradable emission permits
TGC	tradable green certificates
TSO	transmission system operator
σ	standard deviation
σ_L	standard deviation of load
σ_{NL}	standard deviation of net load

1. Introduction: wind power status and future trends

Wind energy is a renewable electricity production form converting the kinetic energy of moving air masses into electricity. Wind power is characterised as distributed generation with the exception of large offshore wind farms which are power plants more than 100 MW in size.

Wind power has experienced a rapid global growth since the 1990's. At the beginning of 2004, there were 40 GW installed worldwide increasing by 8 GW per year. The annual growth rate is expected to reach 15 GW/a in 2010 (BTMConsult, 2004). The major market area for wind power is the European Union with nearly 30 GW installed capacity. In the Nordic countries, the installed wind power capacity at the end of year 2003 was 3076 MW in Denmark, 428 MW in Sweden, 101 MW in Norway and 53 MW in Finland (BTMConsult, 2004).

The high growth rate of wind power capacity is explained by the cost reductions in the 1980's and 1990's as well as by public subsidies in many countries, linked to efforts to increase renewable power production and to reduce CO_2 emissions. Further cost reduction is anticipated (Dale et al., 2004). The production cost of wind power now ranges between 30–70 €/MWh[3].

Wind power production is highly dependent on the wind resources at the site. Therefore the average production, the distribution of the production, as well as the seasonal and diurnal variations may look very different in different areas of the world as well as at different sites within an area. For most sites on land, the average power as the percentage of the nominal capacity (capacity factor c_p), is between 20 and 40 %. This can be expressed as full load hours of 1800–3500 h/a. Full load hours are the annual production divided by the nominal capacity. Offshore wind power production, or some extremely good sites on land, can reach up to 4000–5000 full load hours (c_p = 45–60 %).

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[3] Without subsidies, 20 years and 5 % interest rate for the investment. Assumptions: the range of investment costs 800–1200 €/kW, the range of production 1800 h/a–3000 h/a, operation and maintenance costs 8–12 €/MWh.

We can compare the above figures to other forms of power generation. Combined heat and power production (CHP) has full load hours in the range of 4000–5000 h/a, nuclear power 7000–8000 h/a, and coal fired power plants 5000–6000 h/a. However, full load hours are only used to compare different power plants. They do not tell us how many hours the power plant is actually in operation. Wind turbines, which operate most of the time at less than half of the nominal capacity, will typically produce power during 6000–8000 h/a (70–90% of the time).

In 2003, wind energy produced about 2 % of the electricity consumption in the EU, the largest shares being 16 % in Denmark (21 % in West Denmark), 4 % in Germany (about 30 % in Schleswig Holstein) and 5 % in Spain (about 50 % in Navarra) (Eltra, 2004; Elkraft, 2004; Ender, 2004; ISET, 2004; EWEA, 2004). The projection for year 2010 is 75 GW in EU (EWEA, 2004). With increasing penetration[4], the integration of wind power and the extra costs of absorbing an intermittent energy source in the power system become highly relevant.

The expected developments of wind power technology will affect the extent of the impact that wind power has on the power system. Very large wind farms (hundreds of MW) is one trend that can pose serious challenges to the integration of wind power. They concentrate the capacity to a few sites and the smoothing effect of variations by geographical spreading can be partly lost. However, large wind farms will also pave the way for other technologies that will help with integration. Increasingly sophisticated power electronics and computerised controls in wind farms, as well as an improved accuracy of wind forecasts, will lead to improvements in the predictability and controllability of wind power. Large wind energy power plants will mean that there are new requirements regarding the integration of wind power into the power system. Increasingly, wind farms will be required to remain connected to the grid when there are faults in the system, providing power production and reactive power support during the fault.

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[4] **Penetration:** in this study the concept energy penetration is used. Wind energy penetration is the yearly wind power production as percentage of the yearly total electricity consumption (gross demand). Capacity penetration is another concept, where the wind power capacity relative to the total installed generation capacity of an area is used.

2. Setting the scene: previous work and the scope of this thesis

The drawbacks of wind power, from the power system point of view, are its variability and unpredictability. However, these problems are greatly reduced when wind power is connected to larger power systems, which can take advantage of the natural diversity in variable sources. Large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output.

2.1 Previous work on power system impacts of wind power

(Publication A)

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. Even though the average annual wind power penetration in some island systems (e.g. Crete in Greece) or countries (e.g. Denmark) is already high, on average wind power generation represents only 1–2 % of the total power generation in the Nordic power system (Nordel) or the Central European system (UCTE). The penetration levels in the USA (regional systems) are even lower.

The need for more flexibility to meet larger fluctuations in the system depends on the portion of consumption covered by wind power production. It is relevant to know how the wind power is geographically dispersed, to account for the smoothing of variations, as well as the general patterns in the wind power production of the area (the amount of diurnal variation and its coincidence with load patterns). Also, power systems are different in how much inherent variability in the system (the load) there is and in how loaded and well meshed the system is (available transmission). The amount of flexibility already there in the system, as well as the amount that can be cost effectively increased is important. The treatment of imbalances in the power systems differs internationally.

The system impacts of wind energy are presented schematically in Figure 1. These impacts are divided into two parts: short term, balancing the system during the operational time scale (minutes to hours), and long term, providing enough power and energy in peak load situations.
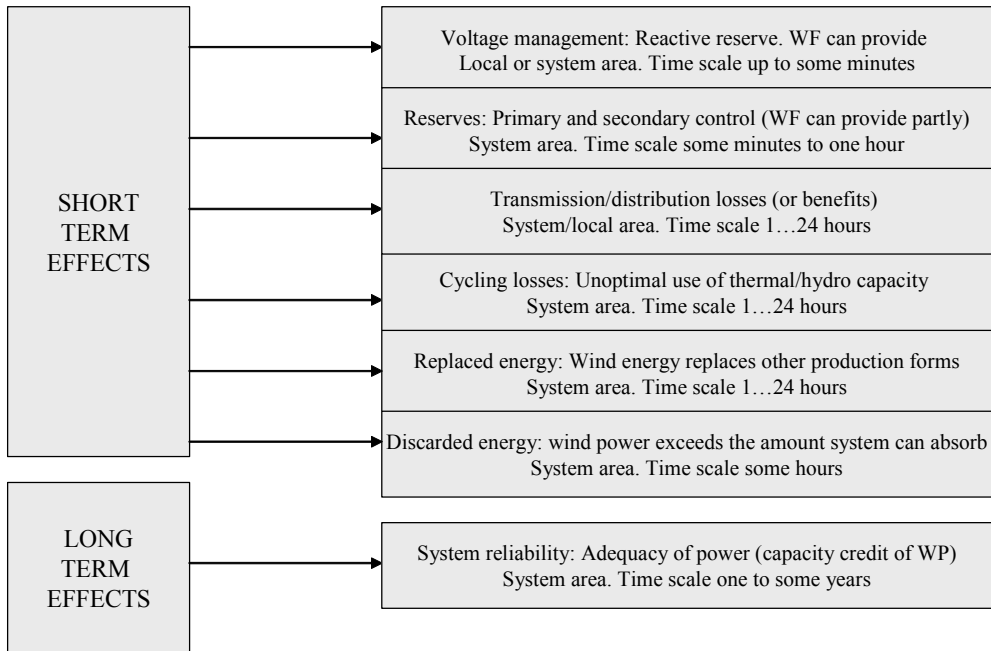
Figure 1. System impacts of wind power (WP) and wind farms (WF), causing integration costs. Part of the impacts can be beneficial for the system, and wind power can have a value, not only costs.

Voltage management is a more local issue, where measures should be taken when wind farms are installed. There is already technology which allows wind farms to benefit power system operation: modern wind farms can be equipped with power electronics providing voltage management, reactive reserve and some primary control (Kristoffersen et al., 2002).

Wind power can either decrease or increase the **transmission and distribution losses** depending on where it is situated in relation to the load. An example from a study made for the UK shows that concentrating the wind power generation in the North would double the estimated extra transmission costs to 2 and 3 €/MWh

at a wind power penetration level of 20–30 %. This would not be the case if production was more geographically dispersed. According to the study, at more modest penetration levels transmission costs would decrease (ILEX, 2003). First experiences from West Denmark and the northern coast of Germany have shown that when significant amounts of electrical demand are covered with wind power, it is first seen as increased transmission with neighbouring countries or areas (Eriksen et al., 2002; Lund & Münster, 2003). Increased transmission between regions can lead to an increase in bottlenecks of transmission (Matevosyan, 2004).

Discarded energy occurs only at substantial penetration and it depends strongly on the operational strategy of the power system. The maximum production of wind power is many times larger than the average power produced. This means that at a wind power penetration of about 20 % of the gross demand, wind power production may equal the demand during some hours (a 100 % instant penetration). When wind power production exceeds the amount that can be safely absorbed while maintaining adequate reserve and dynamic control of the system, a part of the wind energy produced may have to be curtailed. This is especially pronounced in island systems not having the possibility of transmission between areas to fully account for the smoothing effects of large scale wind power. Studies on thermal systems show that about 10 % (energy) penetration is the starting point where a curtailing of wind power may become necessary. When wind power production is about 20 % of yearly consumption, the amount of discarded energy will become substantial and about 10 % of the total wind power produced will be lost. (GarradHassan, 2003; Giebel, 2001). In West Denmark, few occasions of curtailment have occurred since the year 2001 when wind power exceeded 16 % penetration on a yearly basis.

For the short term effects of wind power on reserves and cyclic losses, the main cause is the fluctuation of wind power production. The extent of wind power variability has been the subject of several studies. Many studies have been based on wind speed data from several geographically dispersed measurement masts, converting wind speeds first to higher altitude (hub height of wind turbines) and then to the production of a single wind turbine using a power curve. There are possible caveats; first of all in up-scaling the wind to higher altitudes, as the wind profile is dependent on atmospheric conditions (vanWijk, 1990), and secondly, in using a single point measurement to represent a wind farm

stretching several kilometres in dimensions. Simulated wind power production tends to exaggerate the fluctuations. Studies based on actual wind power production are rare, due to the fact that large scale wind power production has only started to emerge in the past few years (Ernst, 1999; Wan, 2001). A study of the smoothing effect and its saturation has been made for the northern part of Germany (Focken et al., 2001). As concluded in several studies in the USA (Smith et al., 2004), it has become clear that to estimate the impacts of wind power on the power system, the wind induced imbalances have to be treated together with aggregated system imbalances. The results from estimating the **increased reserve requirements** show a very small impact on primary reserve (regulation time scale) (Ernst, 1999; Smith et al., 2004; Kirby et al., 2003; Dany, 2001). For secondary reserve (load following time scale), there is an increasing impact with increasing penetration (Milborrow, 2001; Milligan, 2003; ILEX, 2003). The first estimates regarding the increase in secondary (load following) reserves in the UK and US thermal systems suggest 2–3 €/MWh for a penetration of 10 % and 3–4 €/MWh for higher penetration levels (Smith et al., 2004; Milborrow, 2001; ILEX, 2003; Dale et al., 2004)[5]. It is difficult to compare the results from the studies made so far. The different results for the cost estimates are due to different system characteristics, penetration levels and study methods. The studies made so far often use simulated wind power output data that exaggerates the variations in wind power production, and make conservative assumptions unfavourable to wind power. A caveat in some of the studies is a modelling approach not taking into account the flexibility in the system, such as hydro power (Dragoon & Milligan, 2003). Also, the division of integration costs to different time scales of reserves varies, and the cost of increased reserve requirements is not always documented (Dale et al., 2004). For the Nordic countries, the impact of wind power on balancing the system on an hourly time scale has not been studied before this study.

In the time scale of unit commitment (4–24 h), wind power can cause extra costs for the system, if the operation of the power plants is made more inefficient due to varying wind power production and prediction errors. The positive effects of wind power, reduced fuel use and emissions are also issues relevant in this time scale. Day-ahead predictions are required in order to schedule conventional units

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[5] Currency exchange rate from the end of 2003 used: 1 € = 1.263 $; 1 € = 0.705 £

(Giebel et al., 2003). Simulations of system operation with different levels of wind power prediction errors show that minimising prediction error increases the benefits of the wind plant measured as fuel savings from the conventional units. However, both the system in question (production mix and load variations) and the properties of wind power production (correlation with load) have a strong effect on the results of how much benefit the improved predictions bring about (Milligan et al., 1995). For a thermal system, the effects depend on the strategy of operation, over or under committing the plants due to wind power (Persaud et al., 2003). Ramping rates have not proved to be a problem (Persaud et al., 2003; Dany, 2001). The decrease of efficiency in the hydro power system of Sweden due to the forecast errors of wind power production would be equivalent to 1 % of the wind power production at a wind power penetration of 4 % of the yearly gross demand (Söder, 1994).

Power system studies are often carried out considering the system as it was operating before the liberalisation of electricity markets. Balancing the forecast errors between the bids and the delivery is the responsibility of the power producer (Wibroe et al., 2003; KEMA, 2002). Theoretical studies on how wind power would come to the markets have shown that market design has a crucial effect on wind power producers in how the regulating costs are allocated (Hutting & Clejne, 1999; Nielsen et al., 1999). In West Denmark, with a wind penetration of about 20 %, it is the responsibility of the transmission system operator (TSO) to balance the so-called prioritised production. The cost for compensating forecast errors in the day-ahead market at the regulating market has amounted to almost 3 €/MWh (Eriksen et al., 2002). Market rules can also change the bidding strategy from simply minimising the error in forecasted energy (Bathurst et al., 2002; Nielsen & Ravn, 2003). In the USA, due to the new set up in which generators have to self-supply or purchase ancillary services, the regulation burden of one single project has been evaluated by several studies, showing a cost of 1–3 €/MWh (Hirst, 2002; Smith et al., 2004). However, for Europe or the Nordic countries this is not relevant, as ancillary services are defined for large interconnected systems where any considerable amount of wind power would mean thousands of turbines in tens or hundreds of sites.

The long term effects concerning the adequacy of supply involve the estimation of capacity value for wind power. The ability of wind power to offset conventional capacity, capacity credit, has been widely studied. The results of

several studies of wind power capacity credit (Milligan, 2000; Giebel, 2001; Peltola & Petäjä, 1990; Kirby et al., 2003) show that at low wind power penetration the capacity credit is close to the average production of wind power during times of high loads. When wind power penetration is increased, the capacity credit will decrease. For example, for the UK, it has been estimated that at low penetration, the capacity credit is 35 % of installed wind power capacity, decreasing to 20 % of installed capacity at 20 % penetration (ILEX, 2003; Dale et al., 2004). In the liberalised electricity markets, the capacity credit is no longer routinely used for comparing the production forms. However, the adequacy of power systems also has to be maintained in the long term, and knowledge to what extent wind power can be relied upon is required.

2.2 Objectives and approach of the thesis

Increasing penetration levels of a new, variable production form raise concern for the system operators regarding system reliability. Knowledge about the extent of variations and production patterns, and analyses together with system variables are needed to ensure system adequacy and security with increasing penetration levels of wind power. Integration costs, or system costs, are the costs incurred to incorporate the electricity from a generation source into a real-time electricity supply, ensuring system security. The power system works for the consumers, and they also pay the system cost in their tariffs, as they pay for the production, distribution and taxes. It is not usually necessary to allocate these system costs to a certain producer or consumer. However, when setting the policy to subsidise renewable production, there is a need to quantify the system costs of wind power; environmental goals need to consider economic efficiency as well as security of supply. Estimating the real potential of wind power in reducing CO_2 emissions involves estimating all of the costs involved.

This thesis aims to produce an overall picture of the impacts of wind power on the power system in the Nordic countries. The focus is on estimating the order of magnitude for the extra costs due to integration of wind power at penetration levels of 10–20 % of the gross demand.

What this thesis is about. The work concentrates on the impact of large scale wind power on the power system operation in the Nordic countries, on a time

scale from some minutes to some days. The emphasis is on short term effects – impacts on operating reserves and operation of thermal/hydro plants as well as replaced energy, replaced fossil fuels and reduced CO_2 emissions. Wind power in the Nordic electricity market is discussed in detail.

In this thesis, the main focus is on short term effects, mainly reserves (Figure 1). Cyclic losses, discarded energy and increased transmission between the areas in the Nordic power system are also touched upon. The long term effects are already well covered in the literature, but some analyses made during this thesis gave insight into system adequacy as well.

What this thesis is NOT about. The thesis excludes such areas as the investments and incentives needed for large scale wind power, including possible grid reinforcements (ILEX, 2003; KEMA, 2002). The local issues of power system reliability related to voltage management, system stability or power quality are also beyond of the scope of this thesis. The starting point for this thesis is that large scale wind power is already in the power system and is connected to the network according to grid codes specified to maintain power quality and system stability.

To study the impact of wind power on a large interconnected power system, two basic approaches can be used: simulating the system operation or using analytical methods based on available data. Both methods have been used in this thesis. First, existing energy system models were sought and simulations with increasing amounts of wind power were run to see the effects of wind power production on the rest of the power system. The emphasis was on models in the Nordic area simulating the operation of the power system. Secondly, realised data for wind power production, the varying load and electricity market prices, were analysed to study the variability of wind power together with the varying load, as well as the market operation of wind power. This approach took advantage of the situation in West Denmark, where large scale wind power has been a reality since the 90's and the wind power penetration has exceeded 15 % of gross demand since the year 2000. The data contains the properties of large scale wind power with the smoothing effect of thousands of turbines. Several years of data contain different low and high wind and load situations as well as the situations of low and high load and wind variations. The data implicitly includes the effect of wind power on the market price.

2.3 The geographical area of the study: the Nordic countries

The common liberalised Nordic electricity market covers Norway, Sweden, Finland and Denmark. East Denmark is part of the Nordel system, and West Denmark is part of the Central Europe UCTE system. West and East Denmark are not connected by a transmission line, but are both connected to Sweden and Germany, and West Denmark also to Norway. Sweden, Norway and Finland are well interconnected: the transmission capacity exceeds 2000 MW between Norway and Sweden and 1000 MW between Finland and Sweden. In addition, Sweden and Denmark have interconnections to Central Europe (in total 2000 MW) and Finland to Russia.

The production mix is shown in Figure 2. A large share of hydro power is characteristic for the Nordic countries: Norway covers almost 100 %, Sweden almost 50 % and Finland almost 20 % of the electricity consumption by hydro power.
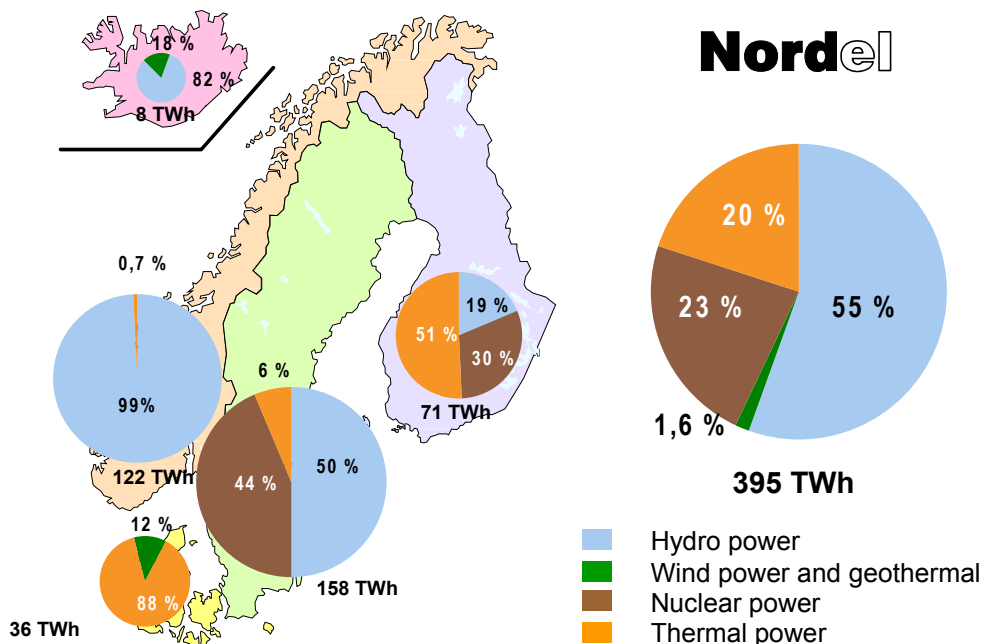

Figure 2. Electricity production in the Nordic countries in 2001. Installed power plant capacity is about 90 GW. (Source: Nordel/Finergy.)

3. Description of the models and data used in the thesis

Three energy system models were used in this thesis. To study the impact of wind power on a thermal power system, the planning tool SIVAEL for West Denmark was used (Pedersen, 1990). This tool optimises the hourly dispatch during one operating year. To study the impact of wind power on the Nordic electricity market as well as on the hydro power system the EMPS model was used (SINTEF, 2004). This model optimises the operation of the system for one year with weekly time steps. For future CO_2 reduction estimates, the EFOM model for Finland was used, optimising the investment and use of production capacity. At the end of this chapter the data used in this thesis is described, also covering the wind power inputs to the models.

3.1 SIVAEL model

SIVAEL is a simulation model developed in Denmark for electricity and heat production planning purposes (Pedersen, 1990). It is an hourly dispatch/unit commitment model, scheduling the starts and stops as well as unit production rates of power and heat. The scheduling is based on minimising the total variable costs including operational, maintenance, and start-up costs of both electricity and heat production. Operational constraints in the optimisation consist of fulfilling the electricity and heat demands while taking care of the reserve requirements given as input. Unit commitment involves dynamic programming. The model has an iteration loop to fulfil both the local heat demands and the electricity demand for the whole area. Reserve requirement (spinning reserves, secondary reserves and load following) is taken into account as a given percentage of hourly load. Reserves are allocated as part load operation of thermal plants: making sure that the required amount will be available as reserve means not allowing all the plants to reach full power or minimum power. Wind power production is modelled as an hourly profile (8760 hours). The latest version of SIVAEL also includes the forecast errors of wind power. The model uses simulated predictions for unit commitment and dispatch. The regulation requirement due to wind power is calculated as the difference between predicted and actual wind power production and it is allocated to either thermal plants or

exchange to neighbouring countries (Pedersen & Eriksen, 2003). The input and scenarios run are described in more detail in publication E.

The SIVAEL model is used for the electricity system planning in a single region. The strength is detailed simulation of the thermal units on hourly basis, with realistic large scale wind power input, capturing the variability of wind power. The weakness is that it is for one region only, so it is not able to take into account the transmission possibilities in a realistic way.

3.2 EMPS model

The power market model EMPS is a commercial tool developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting (Flatabø et al. 1998; SINTEF 2004). EMPS simulates the whole of the Nordic market area. The market is divided into areas with transmission capacities between the areas. Central Europe is modelled as one big area (Germany and the Netherlands) and treated like a large buffer with which the Nordic system has transmission possibilities. The main substance of the model is the detailed optimisation of the hydro system. The hydro power producers try to save the water in the reservoirs for the critical times of high consumption during the winter, when they get the best price for their production and also when the system needs all the power available to cover the load. To determine the way that the limited amount of water in the reservoirs can be used most cost-effectively, the value for stored water is calculated. These so called water values vary both by the time of year and by the current reservoir content and anticipated water inflow to the reservoirs. Water values are calculated by a stochastic dynamic programming algorithm, maximising the value of hydro production (Flatabø et al., 1998). The model simulates the operation of the Nordic day-ahead market, described in more detail in chapter 4 (Figure 4). The water values are used as the marginal cost for hydro power production. For the thermal capacity, the operating costs for the production are used, from input data. The simulation in this thesis is made for one year, with weekly time steps. The model simulates the market price, production and export/import for each area. The input data and scenarios run are described in more detail in publications F and G.

The EMPS model is designed to simulate the electricity market price, taking into account the large hydro power share in the market, and scheduling the hydro power production from the large reservoirs in an optimal way. The strength in EMPS is that it can simulate the different production units in a large, interconnected area. Therefore, it is able to look in detail to what forms of energy wind power will replace in a hydro-thermal system during a large number of different high and low load situations with 30 years of inflow and wind power data. Wind power is modelled as a run-of-river plant and the uncertainty will be included in the simulations. The weakness of EMPS is that wind power simulation is with weekly steps, losing thus information on the variability of wind.

3.3 EFOM model

In EFOM, the whole system is represented as a network of energy or material chains. The network of the described energy system starts from the primary energy supply and ends in the consumption sectors. EFOM is a bottom-up model and it is driven by an exogenous demand for useful or final energy in the consumption sectors. The Finnish EFOM model includes descriptions of other activities that emit greenhouse gases (e.g. waste management and agriculture) and, due to national characteristics, detailed subsystems for e.g. domestic fuel supply, pulp and paper industry, and combined heat and power production. The system is optimised by linear programming, using the total present value costs of the entire system over the whole study period as the objective function which is to be minimised. The whole study period is divided into sub-periods, which can be of different length. In this thesis, the period is 2000–2025 and the time step is 5 years. The year is divided into winter and summer seasons and therefore the seasonal changes e.g. in wind and hydro power production can be taken into account. In EFOM, the GHG emissions from the energy system are calculated directly by multiplying the annual fuel use with the corresponding emission factor. The input data and scenarios run are described in more detail in publication G.

The EFOM model is mainly used for long-term energy and environmental policy support studies at the national level. All calculations are carried out on an annual basis and only seasonal changes can be taken into account. Consequently, factors such as variation of power production, consumption and cross-border trading are

clearly beyond the scope of the model. On the other hand, EFOM enables estimation of the cost of different kind of greenhouse gas abatement measures. Due to the nature of the model, both capacity extension and replacement of present capacity are results of optimisation.

3.4 Hourly wind power production data

Hourly data was collected from example years 2000–2002 to study the variations and reserve requirements of wind power (Figure 3).
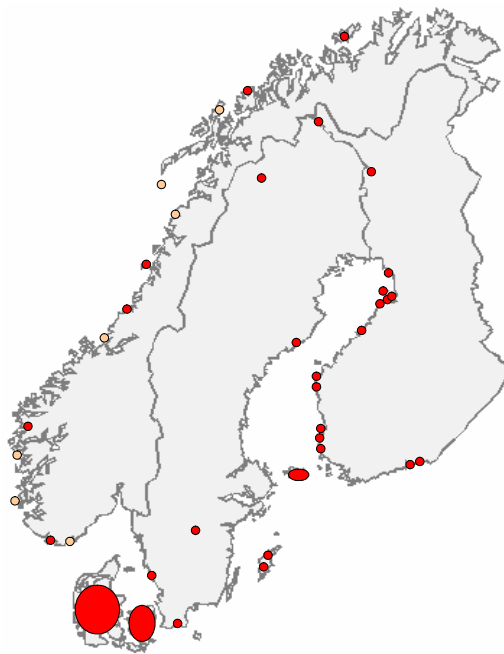
Figure 3. Data for hourly wind power production was available from 21 sites in Finland, 6 sites in Sweden, 6–12 sites in Norway and the aggregated total production of hundreds of sites in Denmark West and East. From the lighter coloured sites data was available for different lengths of time during the study period 2000–2002.

The time period used, 2000–2002, gives a wind power production that is somewhat less than average: 90 % of the average production in Denmark, 87 % in Finland and 96 % in Sweden. The data handling principles and the

representativeness of the data were studied in detail in Publication B. The hourly variations were judged representative for Denmark, Finland and a total Nordic time series.

3.5 Wind power data for the models

For the models used in this thesis, representative input data for wind power is crucial for the credibility of the results.

For SIVAEL simulations for the West Denmark region, one year of hourly onshore and offshore wind power production time series were used, based on real hourly production and offshore wind speed data from the region scaled to represent an average wind year. Realised hourly data for 2001 was used as an alternative input together with price data from the same year.

For EMPS simulations, weekly wind power production profiles over 30 years 1961–1990 were used, derived from wind speed measurements (historical wind measurements were used from 3 sites in Norway and Sweden, 1 site in Denmark and Finland respectively). The weekly average was found to be quite representative for the wind power production profile, even if few data series were used. This data will slightly exaggerate the weekly variations, compared with weekly averages calculated from hourly dispersed wind power production.

For EFOM simulations, the Finnish wind power production was described by yearly average wind power production. Onshore and offshore wind power production were split into summer and winter seasons.

3.6 Other data used

Hourly data for the load in the Nordic countries, and CHP production in Denmark and Finland for 2000–2002 were used (publication C).

For 2001, half hourly data for wind power predictions made in West Denmark, and electricity market data for Elspot, Elbas and the Danish regulation market was used (publication H).

4. Production as a part of the power system: Nordic electricity market

(Publications A and C)

Electric power systems include power plants, consumers of electric energy and transmission and distribution networks connecting the production and consumption sites. The operation of the power system involves providing a total amount of electricity, at each instant, corresponding to a varying load from the electricity consumption. The power system, which is operated synchronously, has the same frequency. With the nominal frequency, 50 Hz, the production and consumption (including losses in transmission and distribution) are in balance. When the frequency is below 50 Hz, the consumption of electric energy is higher than the production. If the frequency is above 50 Hz, the consumption of electric energy is lower than the production. This constantly fluctuating interconnected system should maintain the balance so that faults and disturbances are cleared with the smallest disadvantage in the delivery of electricity.

4.1 Merit order of electricity production

Power systems comprise a wide variety of generating plant types, which have a range of capital and operating costs. To produce power cost effectively, the power plants running at low operational costs will be kept running almost all the time (base load demand), and the power plants with higher costs will be run only when the load is high. When ignoring second order costs (such as start-up, shutdown and reserves) plants can be stacked in merit order, where production with low marginal costs run first. Wind power plants as well as other variable sources like solar and tidal have very low marginal costs, usually assumed as 0, so they come to the top of the merit order, i.e., their power is used whenever available (Grubb, 1991).

The electricity markets operate in a similar way, at least theoretically. The price the producers bid to the market is slightly higher than their variable cost, because it is cost effective for the producers to operate as long as they get a price

higher than their direct costs. When the market is cleared, the power plants operating at lowest bids come first. The market price at each hour is determined by the market cross as the intersection of supply and demand curves, which can be drawn from the bids for supply and demand (Figure 4).
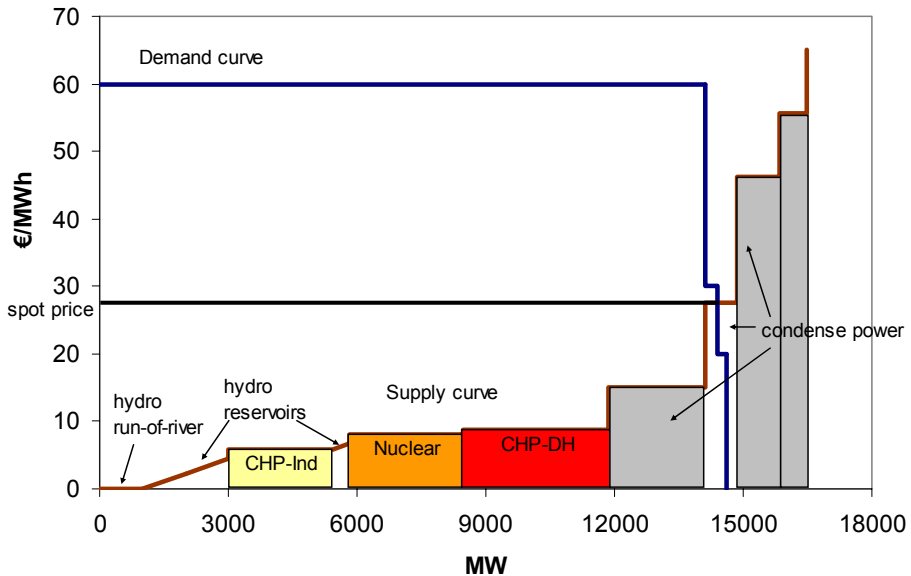
Figure 4. Market cross: spot price formation in the electricity market. Wind power will appear in the supply curve, like the run-of-river hydro plants. The amounts and prices are not based on real data.

In the Nordic countries, hourly production can be traded at the Nordpool spot market. The market is cleared at noon, for the bids for the 24 hours the following day, 12–36 hours ahead. There also exists an after-sales market Elbas[6], with continuous trade which closes one hour before delivery.

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[6] It seems probable that this market will be operational in all the Nordic countries in the future, currently it is operating in Finland, Sweden and East Denmark.

4.2 Reserves

Failure to keep the electricity system running has serious and costly consequences, thus the reliability of the system has to be kept at a very high level. Security of supply needs to be maintained in both the short and the long term. This means maintaining both the flexibility and reserves necessary to keep the power system operating under a range of conditions, including peak load situations. These conditions include credible plant outages (disturbance reserves) as well as predictable and uncertain variations in load and in primary generation resources, including wind (operational reserves).

Load following is performed partly beforehand as scheduling and dispatch of power plants according to the load forecast and partly by operational reserves to balance the load forecast errors. Scheduling includes planning the start-ups and shut downs of slower power plants, called unit commitment, in the time scale of 3–12 hours. Optimising the use of the water stored in hydro power reservoirs, the hydro power plants take into account an even longer scheduling horizon. The scheduling can be based on electricity market operation, where bids for production and bids for consumption based on forecasts are made. Figure 5 shows an example of the actual load in the power system over 3 hours compared to hourly forecasted load, denoting forecast errors and short-term load deviations in the system.
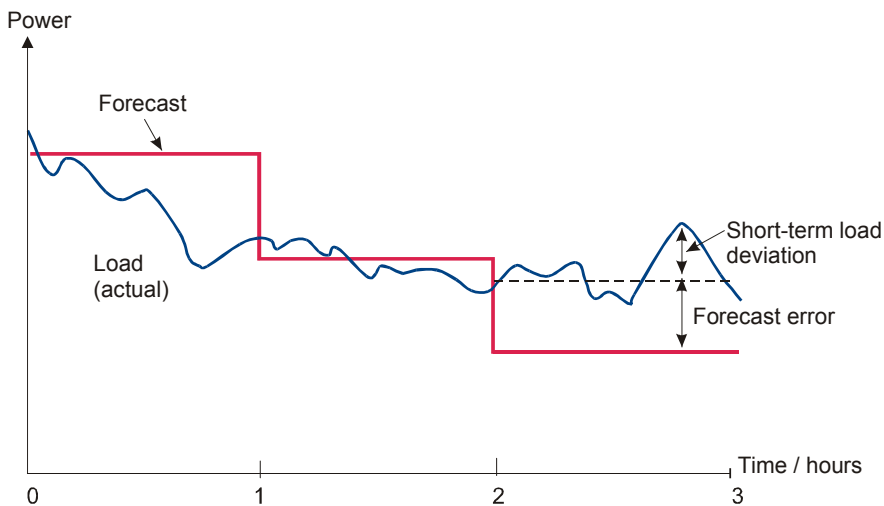
Figure 5. Example of actual load in the system over 3 hours compared to forecasted load.

Both the operational and disturbance reserves are divided into different categories according to the time scale within which they are operating. An example of how the reserves operate is illustrated in Figure 6. It shows the frequency of the system and activation of reserves as a function of time when a large power plant is disconnected from the power system. Activation of reserves divides the reserves into primary reserve (also called instantaneous or automatic reserve), secondary reserve (also called fast reserve) and long-term reserve (also called slow or tertiary reserve). Primary reserve is activated automatically by frequency fluctuations. Secondary reserve is active or reactive power activated manually or automatically in 10 to 15 minutes after the occurrence of frequency deviation from nominal frequency. It replaces the primary reserve and it will be in operation until long-term reserves substitute it as seen from Figure 6. The secondary reserve consists of spinning reserve (hydro or thermal plants in part load operation) and standing reserve (rapidly starting gas turbine power plants and load shedding).
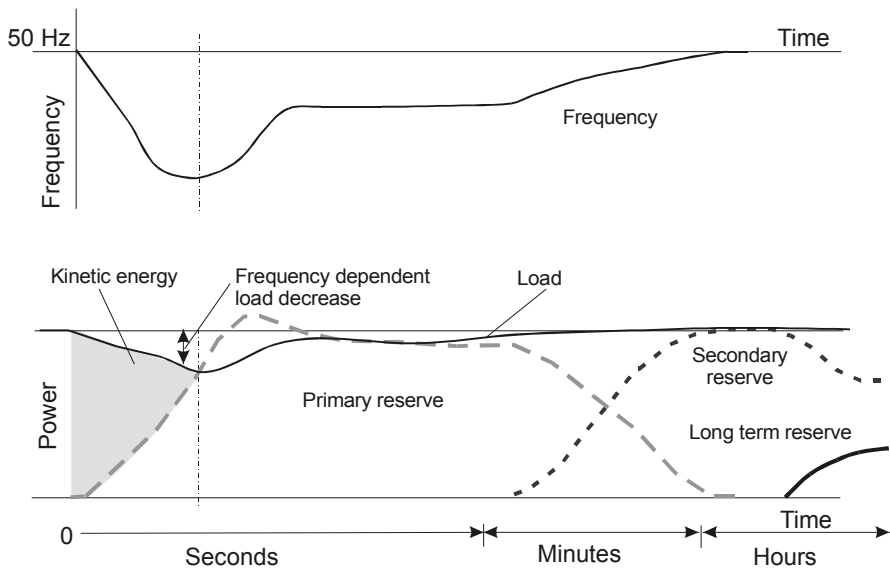
Figure 6. Activation of power reserves and frequency of power system as a function of time when a large power plant is disconnected from the power system (Hirvonen, 2000).

In addition to frequency control, the voltage level is managed to prevent under- and over-voltages in the power system and to minimise grid losses. Frequency is a wide area quantity. Measures can be taken anywhere in the system to maintain the balance, as long as transmission capacity is available. Voltage is a local quantity, and voltage management should be taken care of in the vicinity of imbalances. In order to manage the voltage level during disturbances, reactive reserves in power plants are allocated to the system. These reserves are mainly used as primary reserves in order to guarantee that the voltage level of the power system remains stable during disturbances. Power plants and special equipment, e.g. capacitors and reactors, control the reactive power. The voltage ratio of different voltage levels can be adjusted by tap-changers in power transformers. This requires a reactive power flow between different voltage levels.

The operation of the power system also has to be guaranteed in the liberalised electricity markets. In the Nordic electricity market, there is an independent Transmission System Operator (TSO) in every country[7] as a system responsible grid company securing system operation. The amount of disturbance reserve is planned according to dimensioning fault. In the Nordel system, the requirement of disturbance reserve in each country is specified in relation to the largest power unit (Nordel, 2004)[8]. The operational primary reserve is also planned for in the Nordel system, and divided in relation to yearly consumed energy in each country. A common regulating power market is used within the operating hour for balancing (operational secondary reserve).

The frequency control of the synchronous part of Nordel is based on the frequency deviations due to total net imbalances in production and consumption. The TSOs in Sweden and Norway coordinate the task of maintaining the frequency of the whole synchronously operated area during operation. All the TSOs are responsible for activating secondary reserve in their own areas and for ensuring that the physical constraints of the transmission grid are observed (Wibroe et al., 2003).

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[7] The two TSOs in Denmark will merge as of 1.1.2005.
[8] The total amount of disturbance reserve is according to the largest unit in the Nordic countries. This is divided between the countries in relation to the largest unit in each country.

Nordel relies on decentralised production management, so all the producers are either balance responsible players or have a contract with one (or are lower in the hierarchy but always a balance responsible can be tracked). The balance responsible players submit their schedules to TSOs the day before, and can update them up until the hour of operation. The TSOs take over the regulation of the balance during the hour of operation. First, the balance is secured by means of primary reserve (automatic frequency reserve and the instantaneous automatic active disturbance reserve). In the event of major frequency deviation, the TSOs adjust the production or the consumption manually, using secondary reserve through a common regulating power market, where the players submit their bids for upward and downward regulation of production or consumption. Contracts between some producers (and consumers) and system operators can also be made to allocate the primary and secondary reserves.

After the operating hour, the imbalances of the individual players are calculated and these players will be charged or compensated for at regulating power prices realised at the market. The Nordic system is still in the process of moving towards common procedures and the common regulating power market is one step. However, there are still different measures taken in all countries when it comes to balance settlement. In the one-price model used in Norway, the ones having the imbalance in the opposite direction to the system net imbalance gain extra. In a two-price model, the ones whose imbalance is in the opposite direction to the net system imbalance will be paid according the spot market price. This will create an incentive for keeping the balance, and also contribute to the cost of balance settlement. In Denmark and Sweden, the balance is settled separately for production, consumption and trade, whereas in Norway and Finland the balance settlement is for the total balance of the players.

5. Large scale wind power production

The main issues in wind power production from the power system point of view are presented in this chapter: the production patterns (seasonal/diurnal) and the variability, the predictability and correlation with other variable sources of electricity and the varying load. The smoothing effect and representativity of wind power data for power system studies has been dealt with in detail in publication B and the main findings are presented here.

5.1 Production patterns of wind power

(Publication B)

The results of 3 years of hourly wind power production data analyses from publication B are summarised as follows:

- Average yearly wind power production during the example years 2000–2002 is 22–24 % of installed capacity in Denmark, Sweden and Finland and 31–34 % of capacity in Norway.

- Seasonal variation of wind power is clearly present in the Nordic countries, i.e. more production in winter than in summer: 110–140 % of the average in the winter months, 60–80 % of the average in the summer months.

- Wind power production in Denmark and Sweden shows a diurnal variation, more pronounced in summer. In Norway and Finland diurnal variation is present mostly in summertime (Figure 7). The sites in the northern part of Finland, Sweden and Norway do not experience any detectable diurnal variation.

- From the combined production in the Nordic countries, it can be seen that as wind power production comes from geographically distributed wind farms, the total production never reaches the total installed capacity. The minimum production is above 0 as it is never totally calm in all of the Nordic area (Figure 8). Production above 50 % of rated capacity is rare in summer and production above 75 % is rare in winter.

The lowest hourly production was 1.2 % of capacity. The production was below 5 % of capacity about 2 % of the time.
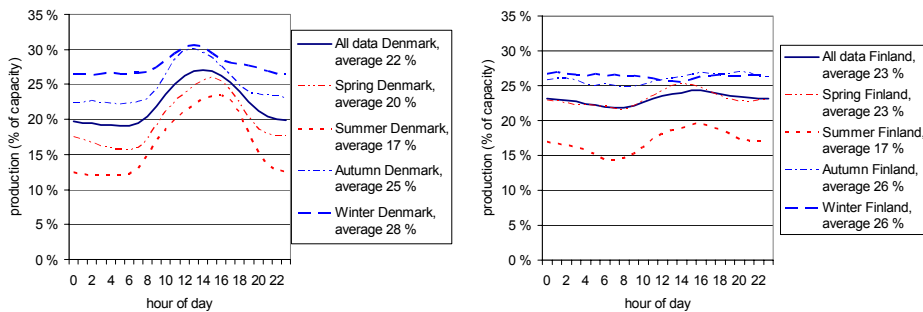
Figure 7. For the Nordic countries, diurnal variation of wind power production is more pronounced in summer time and in the South.
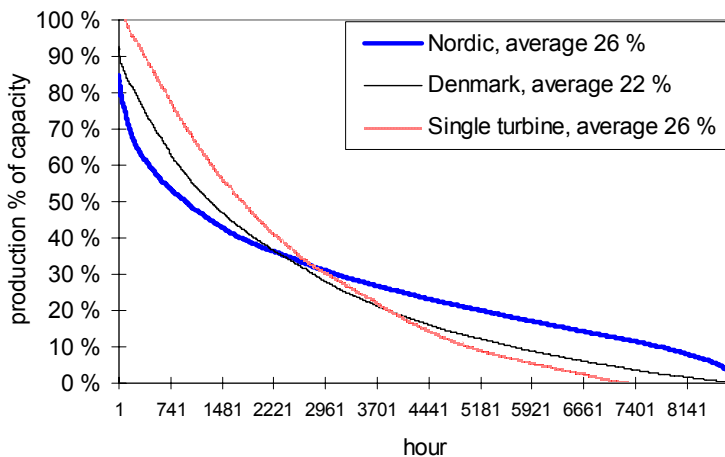
Figure 8. The effect of geographical spreading is to flatten the duration curve of wind power production. Wind energy distributed to all 4 Nordic countries is compared with one of the wind farms and one of the countries (Denmark). Average production for the curves is denoted in the legend text (year 2000 data).

Even for large-scale geographically dispersed wind power production, the production range will still be large compared with other production forms. The maximum production will be three or even four times the average production, depending on the area.

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5.2 Variations of wind power production

(Publication B)

For the operation of power systems, the variations from day to day, hour to hour and minute to minute are of interest. For system planning, extreme variations of large-scale wind power production are of importance, together with the probability of the variations.

The in-hour variations are less in magnitude than the hourly variations (Ernst, 1999). The inertia of the large rotating blades of a wind turbine will smooth out the very fast gusts of wind. For a wind farm, the same gusts will not occur simultaneously at all turbines, situated several hundred metres apart. The extreme step changes recorded from one 103 MW wind farm (10 x 14 km^2) are 4–7 % of capacity in a second, 10–14 % of capacity in a minute and 50–60 % of capacity in an hour (Parsons et al., 2001). The ramping rates are not as large as the extreme step changes: maximum 10 s ramping rate (from 1 s data) was 3 % of capacity per second and maximum 10 min ramping rate (from 1 min data) was 6 % of capacity per minute (Wan, 2001). For two large wind farms situated 200 km apart, the extreme step changes are ±1 % of capacity for one second data, ±3 % of capacity for one minute data and ±30 % of capacity for hourly data (Wan, 2001). These examples are from a limited area compared with the system operation. For a larger area of geographically dispersed wind farms, the second and minute variations will be less significant.

There are means to reduce the fast variations of wind power production. Staggered starts and stops from full power as well as reduced (positive) ramp rates could reduce the most extreme fluctuations, in magnitude and frequency, over short time scales (Kristoffersen et al., 2002). This will happen at the expense of production losses, so any frequent use of these options should be weighed against other measures (in other production units) in cost effectiveness.

The results from publication B, for the hourly wind power production time series from the Nordic countries, are summarised as follows:

- Correlation for hourly wind power production is strong (more than 0.7) for distances of less than 100 km and becomes weak (below 0.5) with distances

above 200–500 km. The large scale wind power production of the countries is correlated between Denmark and Sweden, and weakly correlated between the other Nordic countries. There is no correlation between the hourly variations in wind power production for the Nordic countries.

- The maximum hourly step changes are inside ± 20 % of installed capacity for one country, somewhat more for Denmark. The hourly step changes in one country are 91–94 % of time between ± 5 % of installed capacity and 99 % of time between ± 10 % of capacity. For the total Nordic time series the hourly step changes are about 98 % of time between ± 5 % of installed capacity (Figure 9). Taking only the time periods when the initial production level is more than the average production, the larger variations occur relatively twice as often.

- The maximum 4-hour-variations are about ± 50 % of installed capacity for one country (for Denmark ± 60 % and for Finland ± 40 %). For the Nordic area it is ± 35 % of installed capacity according to the 3-year data set. This has also been reported for a longer following period from Germany (ISET, 2002). The maximum 12-hour-variation for the Nordic area is ± 50 % of installed capacity (for Denmark ± 80 % and for Finland ± 70 %).

The largest hourly variations are about ± 30 % of installed capacity when the area is in the order of 200 x 200 km^2 (e.g. West/East Denmark), about ± 20 % of capacity when the area is in the order of 400 x 400 km^2 (e.g. Germany; Denmark; Finland; Iowa, US), and about ± 10 % in larger areas covering several countries, e.g. the Nordic countries (ISET, 2002; Milligan & Factor, 2000). For longer time scales, 4–12 h variations, short term prediction tools for wind power give valuable information on the foreseeable production levels and expected variations in wind power production.

For large scale wind power, it is the wind variability that leads to the largest production variations. The stops and starts of the individual power plants during normal operation do not coincide and thus do not impose large variations for large scale wind power when a single turbine is a small part of total capacity (for example, a 2 MW turbine in a country with 1000 MW wind power). The extreme case is a storm when all the turbines are shut down from full power to protect the components. In the case of very large, concentrated offshore

installations the chosen cut-out speed for wind turbines as well as control strategies should be applied to avoid situations with large wind power capacity shutting down in an hour (KEMA, 2002). However, large scale wind power is unlikely to materialise in a very concentrated way in the Nordic countries. Based on three years data from Denmark, storms do not seem to hit wind farms in a larger area simultaneously. The wind speeds have not exceeded the cut-off wind speeds for turbines at all sites, as the maximum hourly step change downwards from realised data for West Denmark has been 26 % of installed capacity.
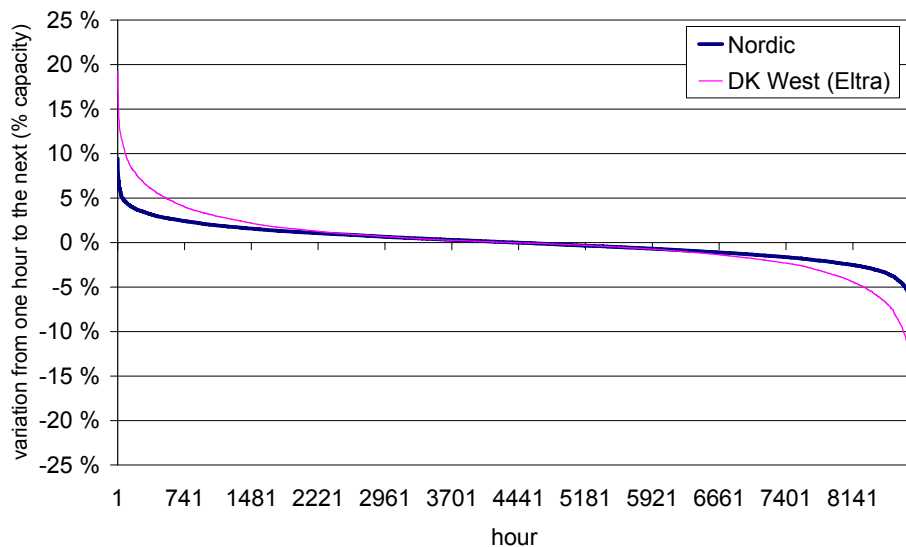
Figure 9. Duration curve for hourly variations of wind power production in West Denmark and in the 4 Nordic countries, assuming an equal amount of wind power in each country.

5.3 Representativity of the variations and smoothing effect

(Publication B)

To be able to up-scale limited wind power production data to large scale production data, the smoothing effect should be incorporated into the time series. When enough turbines from a large enough area are combined, the smoothing

effect reaches saturation, and the time series can be up-scaled with representative hourly variations. Guidelines for the statistical properties of large scale wind power were made in publication B:

- To be representative for large-scale wind power production, an hourly time series should have a standard deviation of the production series less than the average power, maximum hourly production less than 100 % of installed capacity (85–95 % depending on how large the area in question is), duration of calms limited or non existent, standard deviation of the hourly variation series less than 3 % of installed capacity and the hourly variations within ±20 % of installed capacity, or even less if the area is larger than the size of Denmark (300 x 300 km^2).

- The clearest indicator of reduced variability in the time series was found to be the standard deviation of the time series for hourly variations. The relative standard deviation for uncorrelated time series will decrease as $1/\sqrt{n}$ (= n$^{-0.5}$) where n is number of data sets. In the case of wind power some correlation exists, however, demonstrated by the results in chapter 5.2. Increasing the radius of the sample size, the standard deviation would follow the relation ~x$^{-0.244}$ where x is the diameter of the sample area (Figure 10). The standard deviation of the variations is reduced to less than 3 % of installed capacity from a single site value of 10 % of capacity.

- The hourly data collected from about 6 sites in Norway and Sweden represent the range and duration of large scale wind power production. However, when looking at the hourly variations and the decreasing trend of standard deviation with increasing number of wind farms in a larger area (Figure 10), 6 sites is too small a sample to catch the hourly variations, even if the sites are well dispersed over the countries. There will be a slight overestimation of variability for Finnish data (20 sites) when up-scaling the data to large scale wind power production. Combining the data sets of the 4 countries to form a Nordic data set shows a continuing smoothing and has been considered representative for the study of large scale wind power.

Standard deviation of hourly variations

Legend:
- Denmark
- Finland
- Norway
- Sweden
- Nordic
- y=0.11x-0.244

y-axis: stdev (% of capacity)

x-axis: Average diameter of area (km)
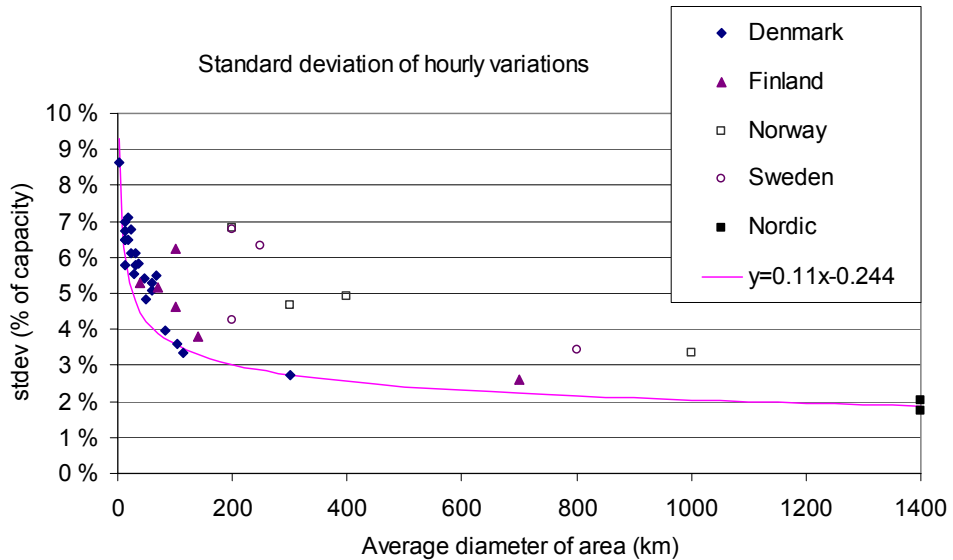
Figure 10. Reduction in variability of wind power production: reduction in standard deviation of hourly variations taken from different areas, 2001 data.

A representative data set for the variations of large-scale wind power could be accomplished simply by collecting time series from different sites until reaching saturation of smoothing effect. After this, the data could be safely up-scaled. In practice, enough data may not be available. In this case, taking sliding averages or weighted sliding averages of wind farm data is one way to smooth it (ILEX, 2003; Persaud et al., 2003). The methodology presented in publication D includes sliding averages of the wind speed time series and the use of a multi-turbine power curve.

The wind power data should also represent the future geographical distribution when simulating the impact of large-scale wind power on the power system. This is taken into account to some extent in this thesis. For example, it is assumed that in Finland 80 % of capacity will be along the West coast and in Sweden 80 % of capacity will be south of Stockholm. In Denmark, there will be fewer turbines and sites but better production from MW-scale turbines with higher towers in the future, especially in offshore wind farms. When a substantial share of wind energy comes from large offshore wind farms this will introduce a less dispersed and thus more variable production, but with higher duration, as there are fewer calms than on shore (Pryor & Barthelmie, 2001).

5.4 Predictability of production

Wind power prediction plays an important part in the system integration of large-scale wind power. Predictability is stressed at times of high wind power production and for a time horizon of up to 6 hours ahead, giving time to react to varying wind power production. An estimate of the uncertainty, especially the worst-case error, is important information.

Wind power production on an hourly level for 1–2 days ahead is more difficult to predict than other production forms, or the load. The overall shape of the wind power production curve can be predicted using weather forecasts and time series analysis. Predictions of the wind power production 4–8 hours ahead, or longer, rely almost entirely on meteorological forecasts for local wind speeds. In northern Europe, the variations of wind power production correspond to weather systems passing the area causing high winds which then calm down again. The wind speed forecasts of the Numerical Weather Prediction models contribute the largest error component to the wind power predictions. So far, an accuracy of ± 2–3 m/s (so called level error) and ± 3–4 hours (so called phase or time-lag error) has been sufficient for wind speed forecasts. However, the power system requires a more precise knowledge of the wind power production.

Forecast tools for wind power production are still under development and they will improve (Giebel et al., 2003). However, it will probably not be possible to get to the same level of accuracy with wind power predictions as with predictions of the electricity consumption, the load. The load forecasts are made with long experience, and the load has more predictable diurnal and seasonal patterns. When looking at larger areas, the average errors in load forecasts are in the order of about 1.5–3 % of peak load. This corresponds to an error of about 3–5 % of total energy when forecasting one day ahead (Fingrid, 2002).

In publication H, prediction errors for different prediction horizons were studied based on one year of operational data from West Denmark. The predictions are made up to 39 hours ahead and updated half hourly. The results for the prediction errors of 1900 MW wind power are:

- When forecasting 6 hours ahead, the error was within ±100 MW for 61 % of the time. Large errors (> 500 MW) occurred nearly 1 % of the time. When forecasting 36 hours ahead, the errors were within ±100 MW 37 % of the time and large errors (outside ±500 MW) occurred 7 % of the time.

- The proportion of produced energy that will be known x hours beforehand can be seen from Figure 11. Assuming the same level of wind power production ahead as presently (persistence), 90 % of wind power production will be known 1 hour beforehand. From the prediction model, 70 % of the wind power production will be known 9 hours before, 60 % 24 hours before and only 50 % 36 hours before.
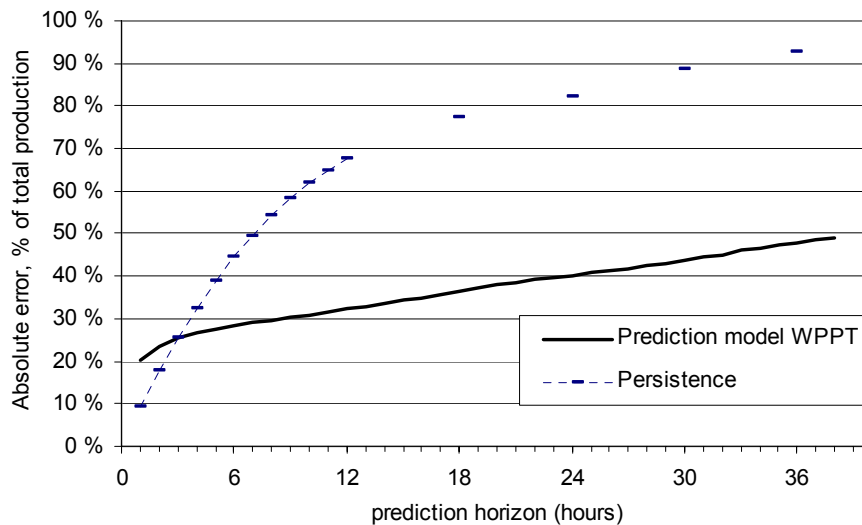
Figure 11. The sum of absolute prediction error for wind power predictions in 2001 for different prediction horizons, as a percentage of the total realised wind power production. Predictions from the model Wind Power Prediction Tool (WPPT) are from on-line runs during the year.

- For the Nordpool electricity market (prediction horizon 13–37 hours ahead), the mean absolute error (MAE) of wind power prediction is 8–9 % of installed capacity. However, for market operation it is relevant to know the error in the amount of energy produced, and this is 38 % of the yearly wind power production.

- The decrease in prediction errors for larger areas was analysed from one year data for Denmark. Including East Denmark adds 100 km or 50 % to West Denmark's area, in the direction in which most weather systems pass (West–East). For about a third of the time production is overpredicted in the West and underpredicted in the East, or vice versa, resulting in errors canceling each other out to some extent. The total prediction error is reduced by 9 %. If East Denmark would have the same amount of wind power capacity as West Denmark, the reduction in prediction error would be 14 %, according to 2001 data.

It has to be noted, improvements in wind power prediction are expected in the future and the results reported here are not from the latest state-of-the-art prediction models, as explained in more detail in Publication H.

5.5 Correlation of load, wind power and other variable energy sources

(Publication C)

The correlation between wind power production and electrical load is of importance when considering the power system effects of a variable production form such as wind power.

The electrical load is characterised by a daily and hourly pattern which is higher on weekdays than weekends (Figure 12). In addition to daily cycles, strong temperature dependence can be seen in the Nordic countries. In Denmark, also wind strength is taken into account in forecasting the heat demand. In the Nordic data, there is a slight positive correlation between wind power production and load (Denmark 0.21; Finland 0.16; Norway 0.37; Sweden 0.24; Nordic 0.31). However, when looking at the winter months only, the correlation is near zero. The positive correlation comes from the diurnal pattern of wind power mostly present in summertime.

Even simple statistical independence makes different variable sources more valuable than just more of the same. When variable sources are directly complimentary, e.g. wind and solar in the same location, there may be large

benefits. Also, combining variable sources with energy limited plants can be beneficial. For the Nordic countries, an interesting example is hydro power. Even if dry years are not likely to be high wind years, as the correlation between the yearly wind power production and hydro inflow is zero or positive in the Nordic countries, the monthly and weekly distribution over the year is quite beneficial. Hydro inflow has a peak in May/June in the Nordic countries, whereas wind power production is dominant in wintertime (October–February). Studies in Sweden and Norway show that wind power production combined with hydro power brings benefits for the system (Söder, 1999; Tande & Vogstad, 1999).
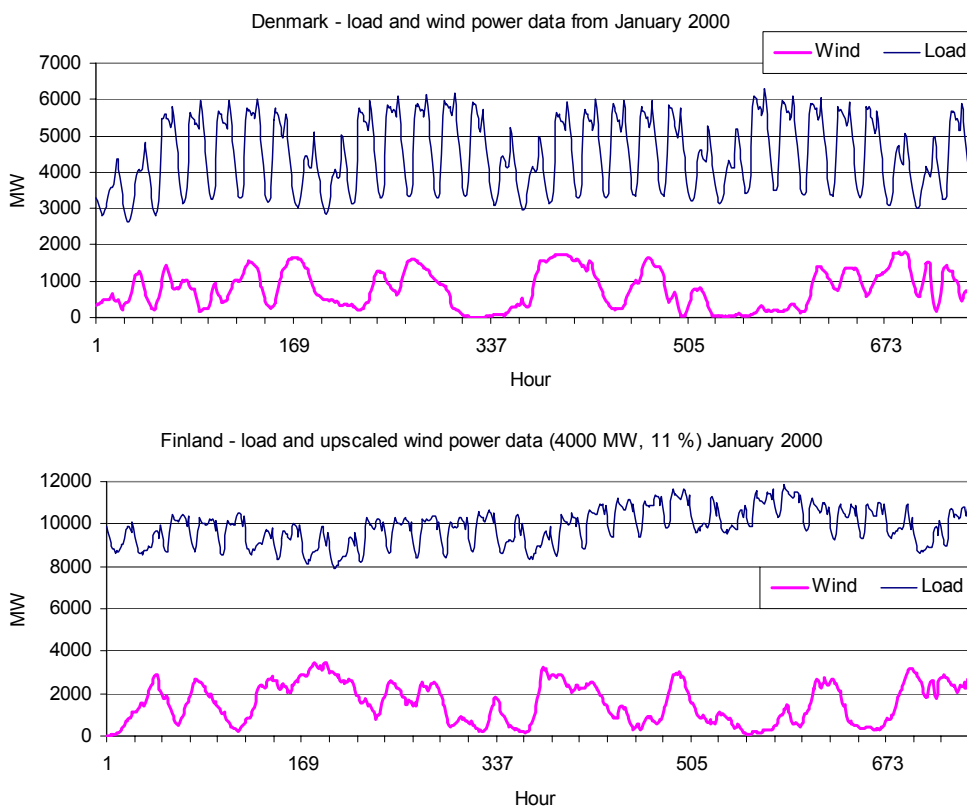
Figure 12. Electricity consumption (load) and wind power production in January 2000. Denmark is real data (12 % wind power). Finland data comes from scaling up wind farm data to a wind power penetration of about 11 % of yearly gross demand.

Correlation between wind power production and the temperature dependent district heating CHP production is only slightly positive for Denmark (0.14–0.24) and Finland (0.17–0.27). For wintertime, again the correlation is nearly zero.

6. Short term effects of wind power on the power system

In this chapter, the impact of wind power on the power system on a minutes-to-hours time scale are discussed. The impacts are divided into two parts: the operating reserves and the production/transmission. This division reflects the working of the power system: even if the reserves are mostly provided by the production units, the operation as reserve, moving the production up and down as required for the total balance, is different from the energy production function of power plants.

First, the reserve needs due to wind power are discussed, and the estimate in publication C is extended to include a cost estimate. The effects on the production of the rest of the production capacity – cyclic losses, increased transmission between the areas, replaced production and reduced emissions are described, in the light of simulations made in Publications E, F and G. The chapter ends with a discussion about the modelling of wind power with the existing dispatch/simulation models.

6.1 Operating reserve requirements for wind power

Dimensioning of the disturbance reserve in each Nordic country is based on the largest production unit tripping off instantaneously. In addition operational reserve is also needed in power systems. Wind power has no influence on the disturbance reserve as long as wind farms are less than the largest production unit in the system (1200 MW in 2004)[8].

The impacts of wind power on requirements and costs of balancing the system on the operational time scale (from several minutes to several hours) are primarily due to the fluctuations in power output generated from wind. In the Elbas market, the players can trade up to one hour before delivery. For Finland and Sweden, bilateral trading can take place up to 20 minutes before the delivery hour. In Norway, generation plans can be changed within a balance area up till the time of delivery if this is accepted by the TSO. Operation and balancing of the system is left to the TSOs during the operating hour. This is what the operational reserves and the regulating power market are used for.

To estimate the impact of wind power on power system operating reserves, it has to be studied on a control area basis. Every change in wind output does not need to be matched one-for-one by a change in another generating unit moving in the opposite direction. It is the total system aggregation, from all production units and consumption, that has to be balanced. A producer with flexible production could in principle counteract changes in wind power levels also during the operational hour. Self regulation is discouraged, however, as it is more cost effective for both the system and the individual players to bid all regulating power to a joint pool for the TSO to use the cheapest options first.

6.1.1 Primary reserve

Primary control is performed on a time scale of seconds/minutes. On this time scale, variations are already smoothed by different gusts for the individual turbines, inertia of the large rotors as well as variable speed turbines absorbing the variations, and there is no correlation between the variations of geographically dispersed wind farms (Ernst, 1999). The effect of wind power on the system operation in the primary control time scale is very small even at considerable penetration (Ernst, 1999; Kirby et al., 2003; Dany, 2001).

A rough estimate of the effects of large-scale wind power on the primary reserve assumes that increase in wind power and its variations requires the same addition to reserves as the increase in electricity demand and its variations (Holttinen & Hirvonen, 2000). The primary reserve has been 600 MW for 360 TWh/a demand in the synchronously operated Nordic area (Nordel, 2004). Assuming an increase relative to how much variable consumption there is, producing 10 % of the demand with wind power (36 TWh/a; 18 GW wind power) would increase the primary reserve by 10 %. This means an increase of 60 MW or about 0.3 % of the wind power capacity installed. This estimation gives order of magnitude only, based on earlier experience on the amount of primary reserve needed in the system. Actually the same 600 MW has been the amount of primary reserves for more than 10 years, with gross demand below 300 TWh/a. The primary reserve requirement is based on second/minute values of power, not the (yearly) energy.

6.1.2 Secondary reserve

(Publication C)

For operational reserves, the unforeseen variations induced from wind power are relevant on the time scale of 10 min – 1 hour. In the Nordic system, there is no operational secondary reserve defined any more, after the regulating power market was started. Norway and Sweden have agreed to coordinate the frequency control and activation of reserves from the regulating power market according to net balance in the Nordic synchronous area.

In publication C, wind power variations are studied combined with the load variations: the net load is the load minus the wind power production for each hour. In Figure 13, the extent of hourly variations are depicted, without wind (the hourly variations of the load) and with wind (the hourly variations of net load). The difference in the maximum value indicates the amount that the operating reserve capacity has to be increased. The difference in the duration curves indicates the amount that the existing reserve capacity is operating more when wind power is added.
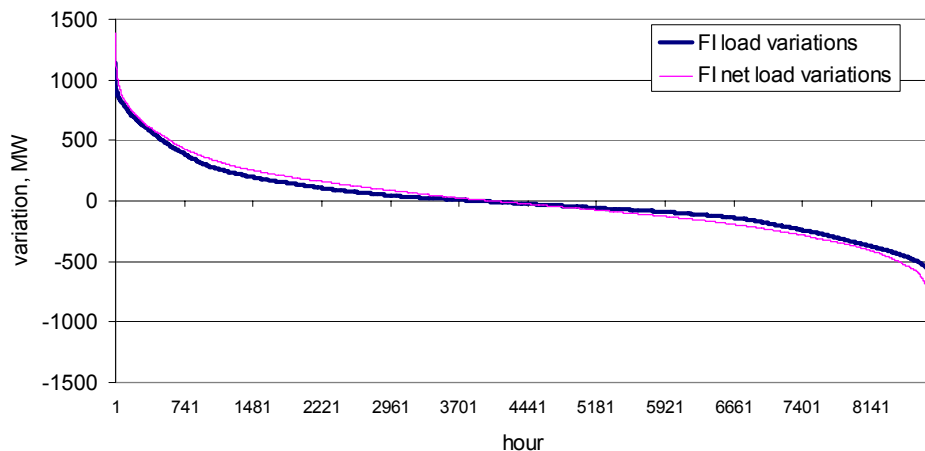

Figure 13. Duration curves of load variations without wind power and net load variations with wind power. The case is for Finland in the year 2000 with hypothetical 6000 MW wind (17 % of gross demand).

The increase in reserve requirement due to wind power was estimated using a statistical approach. Planning and operating a power system is based on probabilities and risk. Reserves in the power system are determined so that variations within a certain probability are covered, for example 99.99 % of the variations. Standard deviation σ indicates the variability of the hourly time series: for a normally distributed probability distribution a range of ±3σ will cover 99 % and ±4σ will cover 99.99 % of all variations. In this work, 4σ is used as a confidence level to determine the amount of reserves that need to be allocated in the power system. The increase in the variations due to wind power is $4(\sigma_{NL} - \sigma_L)$, where σ_{NL} is the standard deviation for the net load and σ_L for the load, respectively.

Calculating the increase in variability this way assumes that wind power only contributes to the reserve requirement by the increase due to its addition to the system. This means that wind power can make use of the benefits of the existing power system. In the USA, different allocation methods for joining two varying elements have been elaborated (Kirby & Hirst, 2000) where the benefit is divided by the two. In this case, the system would benefit a part of the addition of wind power and the impact of wind power would be more than the simple increase in variations calculated here. Both methods are numerically correct. The difference in these approaches is in the fairness or design of regulation payments. In the Nordic countries, different loads and production units do not pay different tariffs for the regulation burden they pose to the system. Thus it is justified to calculate only the simple addition to reserve requirements for wind power.

To account for the better predictability of load (Milligan, 2003), a case study for Finland was performed for year 2001 load data with load forecasts. The standard deviation of the forecast error was 123 MW (1 % of peak load), in comparison with 268 MW for the load hourly variations. This indicates that about half of the variability in load can be predicted. Comparing the load forecast error with wind power variations resulted in a 100 % increase in net load variations. The results of Publication C are summarised in Table 1 and Figure 14. As Denmark consists in practice of two separate areas, the West Denmark results are also of interest. They are roughly the same as the results presented here for Denmark.

The estimation is based on hourly wind power data from a 3-year-period in which the wind resource was less than average. This may underestimate the true

variations. For the Danish data, the error was estimated to be of the order of 5 %, and it has been added to the results in Figure 14 in the last section of Table 1.

The results show that when the penetration of wind power in the system increases, an increasing amount needs to be allocated for operating reserve. For a single country the increase in reserve requirements can range 2.5–4 % of the installed wind power capacity at 10 % penetration. The effect of wind power is nearly double in Finland compared to that for Denmark. This is mainly due to the low initial load variations in Finland. When the Nordic system works without bottlenecks of transmission the impact of wind power becomes significant at 10 % penetration level, when the increase in reserve requirement due to wind power is about 2 % of installed wind power capacity or 310–420 MW. At a high wind power penetration of 20 %, the increase is already about 4 % of wind power capacity or 1200–1600 MW. The range is for a less or more concentrated wind power capacity in the Nordic countries.
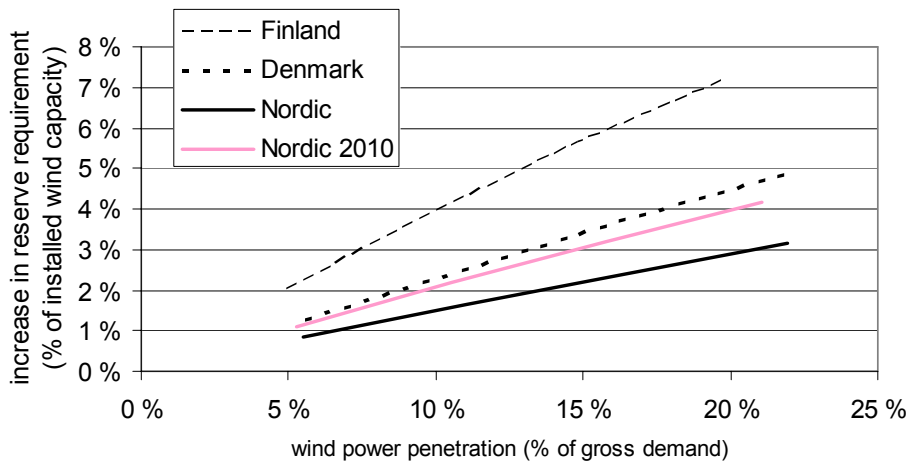
Figure 14. Increase in hourly load following requirement for wind power, calculated from the standard deviation values of load and wind power production from years 2000–2002. Increase is relative to installed wind power capacity.

These estimates present a theoretical approach for estimating the order of magnitude of the effects of wind power variability on the system operation. As the total Nordic balance is handled at a common regulating market, the true estimate would require data for the total load and production schedules for the whole Nordic area. The variations in wind power production are probably still

somewhat conservative for Finland and the total Nordic area, as the smoothing effect of thousands of wind turbines at hundreds of wind farm sites is underestimated by the data sets used. It has been assumed that the hourly variations give an estimate of the secondary reserve operated on a 10–15 minutes scale. As the wind power varies less within an hour than on an hourly basis, using hourly data would not underestimate the effects. The results from a study for Northern Ireland suggest that, at a 10 % penetration, the increase in hourly variations in the net load is less than 2 % of wind power capacity, whereas the half hourly data gives an increase of less than 1 % of wind power capacity (Persaud et al., 2000).

Table 1. The increase in reserve requirement due to wind power with different penetration levels. Statistical analysis of hourly data for wind power and load in the Nordic countries for 2000–2002. The range in Nordic figures assumes that the installed wind power capacity is more or less concentrated.

	Finland		Denmark		Nordic	
	MW	% of peak load or capacity	MW	% of peak load or capacity	MW	% of peak load or capacity
Range of hourly variations*:						
- Load	-985–1144	-7.2–8.4	-862–1141	-13.7–18.1	-5138–6698	-7.6–9.9
- Wind		-15.7–16.2		-23.1–20.1		-10.7–11.7
Stdev of hourly variations:						
- Load	268	2.0 %	273	4.3 %	1438	2.1 %
- Wind		2.6 %		2.9 %		1.8 %
Increase in variations (4σ), 2000–2002 data:						
- 5 % penetration	20	1.0 %	6	0.6 %	40–55	0.4–0.6 %
- 10 % penetration	80	2.0 %	24	1.2 %	155–210	0.8–1.1 %
- 20 % penetration	285	3.6 %	94	2.4 %	600–800	1.6–2.1 %
Increase in reserve requirements:						
- 5 % penetration	40	2.0 %	13	1.3 %	80–110	0.8–1.2 %
- 10 % penetration	160	3.9 %	50	2.5 %	310–420	1.6–2.2 %
- 20 % penetration	570	7.2 %	200	4.9 %	1200–1400	3.1–4.2 %

*The hourly load variations are 99 % of the time between -7.2–16 % of peak load in Denmark, -4–6.6 % of peak load in Finland and -4.4–7.4 % of peak load in the total Nordic time series. The hourly variations of large scale wind power production are 99 % of the time between ± 10 % of installed capacity for Finland and Denmark and about 98 % of the time between ± 5 % of installed capacity for the total Nordic time series.

The prediction errors of wind power day-ahead may also be seen at the system net imbalance and thus require extra balancing at the regulating power market. The increased balancing requirements would be seen either as changes of schedules at the balance responsible players responsible for wind power production, or as individual imbalances that might affect the system net imbalance. This is further discussed in chapter 8.

6.1.3 Cost of increase in reserve requirement

Both the allocation and the actual use of reserves cause extra costs. The same reserve capacity can in principle be used for both up and down regulation. Either up or down variations can determine the need for increase in the reserves. In most cases, the increase in reserve requirements at a low wind power penetration could be handled by the existing capacity. This means that only the increased use of dedicated reserves or increased part-load plant requirement will cause extra costs. Beyond a threshold, the capacity cost of reserves also has to be included. In the Nordic countries this threshold depends on whether there is still capacity available to bid to regulating power market.

Regulation power costs more than the bulk power available on the market. The reason is that it is used during short intervals only and that it has to be kept on stand-by. Therefore, any power continuously produced by this capacity cannot be sold to the electricity spot market. The cost of reserves depends on the type of production. Hydro power is the cheapest option and gas turbines are a more expensive one.

In the following, the cost of increased reserve requirement due to wind power is estimated. The cost of increased regulation in the hydro power system is difficult to obtain. Thus, the cost is estimated in two ways: based on thermal capacity costs and on existing regulating power market prices. The cost estimates for thermal capacity include the price for new reserve capacity and assume a price for the use of the reserve.

Primary reserve is not assumed to cause extra costs for wind power penetration levels below 10 %. The cost of an extra 60 MW in the Nordic synchronous area, for 36 TWh/a wind power production producing 10 % of the gross demand, is

the price for reimbursing the power plants for using automatic frequency control. This is paid irrespective of the use, for all the hours the reserve is allocated. Using the payments in place in Finland (3.3 €/MWh and a fixed payment of 7500 € per MW; Fingrid, 2004), the primary reserve cost for 10 % wind power penetration would be less than 0.1 €/MWh of wind power produced. An increase of 60 MW in reserve requirement is conservative, as the total 600 MW has been in use in the Nordic countries for years, irrespective of the load increase. It seems that there is not a linear relationship between the reserve allocation and the amount of total consumption in the system, as the same 600 MW requirement has been in place for more than 10 years.

The estimate made in publication C for the increase in reserve requirement due to wind power is the need for new capacity with a 4σ confidence level. In the case of the Nordic countries, this amounts to 310–420 MW at a 10 % wind power penetration and 1200–1400 MW at 20 % penetration (Table 1), depending on how concentrated the installed wind capacity will be. The corresponding costs can be estimated by increasing flexible natural gas combined cycle (NGCC) gas turbines in the power system (investment cost 505 €/kW). Dividing the annualised costs of NGCC (a=13 %) to the wind power production results in a cost of 0.5–0.7 €/MWh at 10 % penetration and 1.0–1.3 €/MWh at 20 % penetration level.

In addition to the increase in allocated regulation capacity, there is the actual use of the capacity causing reserve power costs. The amount of increased use as MWh can be seen from the duration curves of load and net load variations (example in Figure 13). For the Nordic countries, this amounts to 0.33 TWh/a and 1.15 TWh/a, respectively. To account for the better predictability of load variations, these amounts have been doubled. For Finland, load forecast time series was available, and the increase in variations was 0.28 TWh/a at 10 % penetration and 0.81 TWh/a for 20 % penetration.

The relevant reserve cost for wind power is determined by the Nordic regulating power market. The extra paid for regulation is the difference between the spot price and the regulating market price. This has been on average 4–5 €/MWh for up regulation and 5–9 €/MWh for down regulation in Finland, and 6–8 €/MWh up and 10–15 €/MWh down in West Denmark in 2001–2003. The increased cost of thermal capacity for operating at secondary reserve has been assumed as 8 €/MWh (Milborrow, 2001), so the market prices are in line with the actual costs.

Assuming a price range of 5–15 €/MWh for the extra reserve used, the cost of increase regulation need in Finland is 0.2–0.5 €/MWh wind power produced at a 10 % wind penetration level and 0.3–0.8 €/MWh at 20 % penetration For the Nordic dataset, the cost is 0.1–0.2 €/MWh for 10 % penetration and 0.2–0.5 €/MWh for 20 % penetration, respectively.

Since the opening of a common regulating power market, most of the reserve power activated has been from Norway and Sweden, with the lowest bids from the large regulated hydro plants. There seems to be ample capacity bidding to the regulating power market (Lehikoinen, 2003). It is thus unlikely that an increase in wind power would result in new reserve capacity being built. However, it is quite likely that a major increase in wind power would result in an increase in the regulating market price. In a situation where the cheapest regulation bids have already been used and more expensive regulation has to be allocated, the costs of regulation may rise substantially and suddenly. This is why the historical prices can be used to estimate the costs only as long as the regulation amounts needed are such that the regulating capacity bidding to the market has a similar price. In West Denmark with 16–20 % wind power penetration, the down regulation costs have increased 50 % but no other changes have been observed. With the cost range presented here, the higher estimate of 15 €/MWh accounts for doubled regulation market prices due to wind power.

In conclusion, the cost of increased operating reserves in the Nordic power system will be 0.7 €/MWh for the allocation of capacity and 0.2 €/MWh for the use of the reserves, or a total of nearly 1 €/MWh for a 10 % penetration. For a 20 % penetration we have 1.3 €/MWh plus 0.5 €/MWh respectively, or a total of nearly 2 €/MWh for 20 % penetration. These costs would be halved if the conservative estimate for allocating investment costs for new reserve capacity to the wind power production is replaced by the increased use of reserves only.

To integrate wind power into the power system in an optimal way requires use of the characteristics and flexibility of all production units, so that a total system optimum is reached. In addition there are already existing technologies that could be used to absorb more variable energy sources such as Demand-Side-Management (DSM), increased transmission between the areas and electrical or thermal storages in the power system. Also wind farms can provide down regulation to a certain extent.

6.2 The impact of wind power on electricity production and transmission

6.2.1 Replaced energy and reduced emissions

(Publications E, F and G)

The electricity supplied by wind power is CO_2 free. Taking into account the materials and construction of wind farms, the CO_2 emissions are of the order of 10 gCO_2/kWh (Lenzen and Munksgaard, 2002).

The amount of CO_2 that will be abated depends on what production type and fuel is replaced when wind power is produced. Both in regulated and deregulated electricity systems, the use of the production form with highest marginal cost will be lowered by wind energy. Wind energy often replaces electricity from old coal fired plants, resulting in a CO_2 abatement of about 800–900 gCO_2/kWh. This is true for most systems with some coal fired production plants, when wind energy provides a minor amount of the total electricity consumption. This is a good estimate for the CO_2 reduction when introducing wind power in a country. This is also valid for large amounts of wind, for the countries where electricity production is based on coal. For other conditions, wind energy may replace gas fired production (400–600 gCO_2/kWh), or even CO_2 free production forms such as hydro, biomass or nuclear power. Even if the hydro production is reduced by wind energy, the hydro power stored in the reservoirs may be used later, possibly reducing fossil fuel fired production. Interconnected systems can also respond in such a way that wind power is partly replacing coal fired production in a neighbouring country.

The simulations made in this thesis reveal the replaced energy and fossil fuel savings due to wind energy. The results indicate that in the Nordic countries, wind power will replace production in condensing power plants, mostly in coal fired plants, resulting in CO_2 abatement of 620–700 gCO_2/kWh wind power produced. The exact result depends on the amount of wind power in the power system, and on the amount and costs of coal and gas fired production in the system.

If the use of coal-condensing power were to be prohibited in Finland, new wind power capacity would mainly replace other condensing power capacity, most likely natural gas combined-cycle (NGCC) capacity. In this case, the average CO_2 reduction would be about 300 gCO_2/kWh, due to the high efficiency of NGCC and other small changes in the energy system. It should be noticed that in this scenario part of the wind power potential would be used already in the basic cost-optimal case, against which the wind cases are compared, and so this is the result of an extra increase in wind production to the system. This case reflects the situation in the future, when there is possibly no more coal to be replaced.

The results for the Nordic electricity system and the Finnish energy system are based on assumptions that the wind energy is already in the system, and there are no extra costs due to in-week variability of wind. The more detailed simulation for the West Denmark energy system includes the extra operational costs of thermal power. If all wind energy is used within West Denmark, it will decrease mostly coal and gas power, but at high penetrations effects on other renewables can also be seen. The first 10 % share of wind power shows a 450 g CO_2/kWh reduction. Going from a 30 to a 40 % penetration level would result in a lower abatement, or 350 gCO_2/kWh. When the possibility for electricity transmission outside West Denmark is included, and the reduction in fuel use is calculated in West Denmark only, the emission reduction is 50–200 g/kWh, mainly due to the added exports of electricity.

The cost of wind power as a CO_2 reducing technology could be calculated from the Finnish energy system simulations. In the scenario where wind energy would be 1 TWh/a in 2010, the average emission reduction cost during 2010–2025 was about 20 €/t CO_2 (wind power penetration 1–6 % of gross demand). When the wind power capacity is further increased, the average cost will rise gradually to about 35 €/t CO_2. This is quite an obvious result because at first wind power replaces the most expensive condensing power capacity and after that the replacement is aimed at less expensive capacity.

According to simulations reported in publication G, wind power production in Norway and Sweden would mostly reduce emissions elsewhere in the interconnected market area. This also means that the CO_2 emission benefits of wind power would partly materialise in a country other than where the wind power is installed. The interactions of the electricity market with Tradable

Emission Permits (TEP) and Tradable Green Certificate (TGC) markets have been ambiguous for the energy policy makers – it is not a straightforward relationship between the quotas and prices set by policy makers and the resulting emission savings (Jensen and Skytte, 2002; Nese, 2002). There might be problems, especially with international trade of TGCs: as the CO_2 benefit is not tied into TGC, the country where it is most cost effective to build the renewable production will benefit from the CO_2 reductions, paid for by other countries (Jensen and Skytte, 2002; Nese, 2002).

6.2.2 The impact of wind power on thermal power scheduling

(Publication E)

Optimised unit commitment, i.e. planning the starts and shutdowns of slow-start units, is more complicated when the intermittent output from wind power is included. Large variations in wind power output can result in operating conventional power plants less efficiently. If wind power production exceeds the amount that can be absorbed while maintaining adequate reserve and dynamic control of the system, a part of the wind energy produced may need to be cut off.

The effect of wind power on existing thermal units can be estimated by simulating the system on an hourly basis. In publication E, the West Denmark power system was simulated with SIVAEL model, increasing wind power using different transmission possibilities (no/low/high) and market prices (low/high).

The main findings of SIVAEL simulations for West Denmark are summarised as follows:

- Increased exchange between West Denmark and the neighbouring countries was 50–90 % of the wind energy produced in the region in most cases.

- Increase in the starts and stops of the thermal plants could only be seen in the simulation results when looking at the system without transmission possibilities. Allocating the extra start/stop costs to wind power added 0.6 €/MWh for the first 10 % of wind power and 0.5 €/MWh for the first 20 % of wind power, respectively. Having more than 20 % of wind power in the

system resulted in increased part load operation of thermal plants, and thus the starts and stops were reduced.

- The increased penetration of wind power resulted in an increase in the cost of power produced by the system of 4 €/MWh at a 40 % penetration (allocating the cost to wind power production). This is the result for the power system operating without exchange, and it was derived from the value of wind energy as reducing fuel costs in the power system (19 €/MWh at a 10 % penetration, and 15 €/MWh at a 40 % penetration).

- If no electricity transmission was allowed from the region, surplus power (discarded energy) occurred from a 20 % wind power penetration onwards. When high transmission of electricity was allowed, the surplus problem first arose at a 50 % wind power penetration.

- The regulation burden due to the prediction errors of wind power was simulated separately, not aggregating with total power system balance. When simulating the West Denmark area without exchange, the extra regulation requirement due to wind power will result in increased discarded (surplus) energy. In the case of a 10 % share of wind energy, 20 % of the down-regulation needs result in a surplus of energy and 10 % of the up-regulation needs would result in a deficit of energy, showing an increasing trend with increasing penetration. With electricity exchange possibilities, the thermal power plants in West Denmark would be used for about half of the up-regulation needs but only about 10 % of the down-regulation needs, and the rest would come from the electricity exchange. Increasing the wind power penetration level would mean using more exchange for up-regulation and less for down-regulation.

6.2.3 The impact of wind power on hydro power scheduling

(Publication F)

The results from the EMPS simulations on the changes in hydro power production from increased wind power production are summarised:

- Wind power may influence the reservoir contents and reservoir management. Figure 15 demonstrates the average content of the reservoirs in Northern Sweden, as well as minimum and maximum during each week, over 30 years. When the wind production is large compared to the reservoir size in the area, such as in Finland, there is a clear effect on reservoir management (Figure 16). The largest changes in reservoir management were seen in Finland and North Norway (Finnmark), where wind power production was increased to more than the total reservoir content of the area.

- Wind power may also influence the losses of hydro power production. For example, a large wind power production in the spring flood time can result in the loss of some hydro production. In the Nordic power system with 46 TWh/a wind production (12 % penetration), the losses due to increased floods were 0.5–0.6 TWh/a, which is about 1 % of the wind power production.
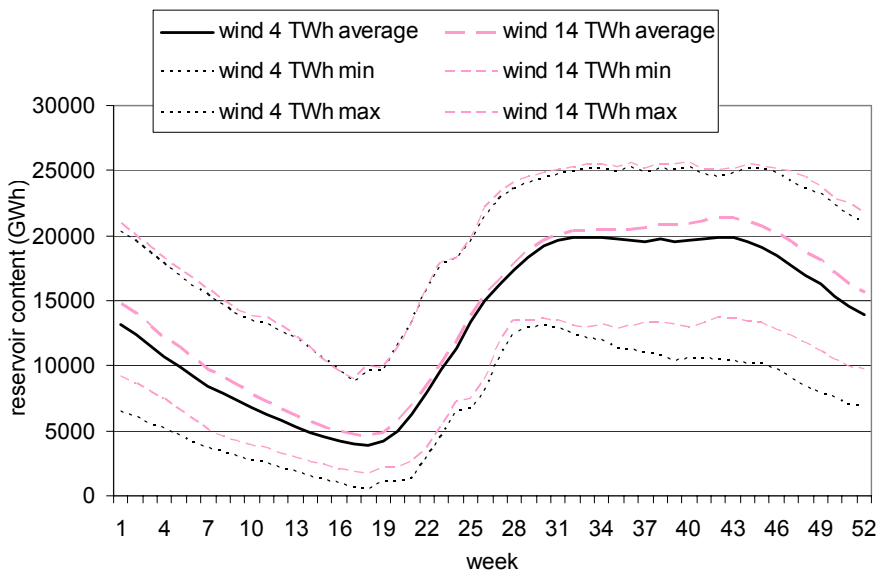

Figure 15. Simulated contents of the hydro power reservoirs in North Sweden when the amount of wind energy in Sweden is increased from 4 to 14 TWh/a and in the Nordic countries from 16 to 46 TWh/a (average, minimum and maximum content over 30 years).
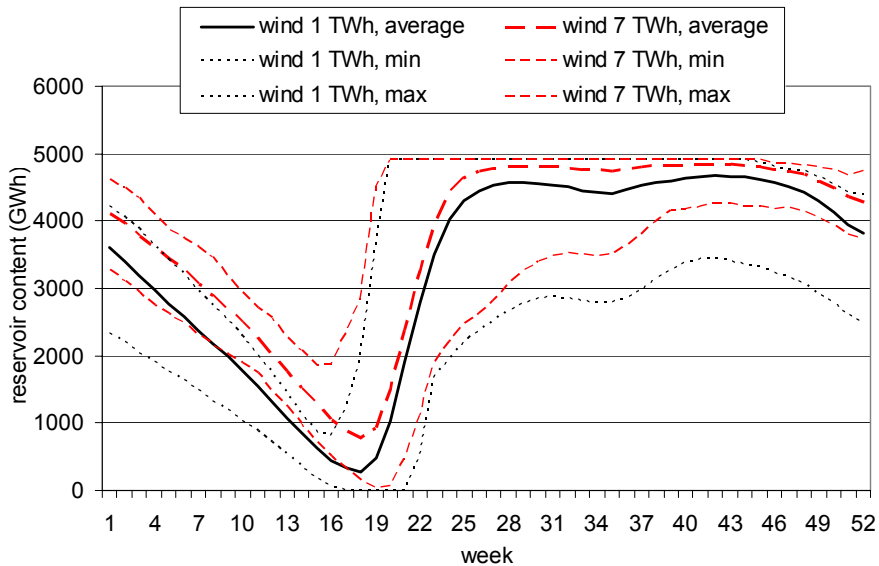
Figure 16. Simulated contents of the hydro power reservoirs in Finland when the amount of wind energy in Sweden is increased from 1 to 7 TWh/a and in the Nordic countries from 16 to 46 TWh/a (average, minimum and maximum content over 30 years).

The impact on the value of hydro power produced will depend on how wind power will affect the market prices discussed more in chapter 8. Hydro power is also providing regulating power for which the demand will grow with higher penetration of wind power.

The simulations made here cannot assess the impacts that the wind power may have on the short-term operation of hydro power where unit commitment is an important issue and where the scheduling horizon must cover 10–14 days ahead in well regulated hydro reservoir systems.

6.2.4 The impact of wind power on the transmission between the areas

(Publications E and G)

The simulations made for the whole Nordic area and West Denmark showed that an increase in wind power in the power system resulted in an increase of electricity transmission between the countries and regions.

The SIVAEL simulations indicate that 50–90 % of the wind energy in West Denmark is exported in different cases for price levels and electricity exchange possibilities. At the border of two regional power systems a huge transit of power is observed in certain situations. When transmission to Germany is available, this will increase both the imports and exports, as there will be transit of electricity through Denmark from the hydro power dominated Nordic countries to the thermal power system in Germany and vice versa. The exception is the case of a high price level and transmission availability to Nordic countries only. If a dry year in Norway and Sweden occurred this would result in an increased price level and export of thermal power from West Denmark, even if wind power was increased in West Denmark. In this case most of the wind power would reside in West Denmark.

The EMPS simulations for the Nordic area show that about half of the wind power production in the Nordic countries would be exported to Central Europe. For a 8–12 % penetration of wind power, indications of bottlenecks in transmission in all lines to Central Europe were seen, especially from West Denmark to Germany. Between Norway and Denmark, Norway and Sweden, and within Norway, wind production would ease dry year conditions but strengthen some bottlenecks during wet years. High wind production in northern Norway would create a bottleneck in the weak transmission line between northern Norway and Finland. Between Sweden and Finland and inside Sweden even large-scale wind production may not substantially increase the use of transmission lines compared to the reference situations.

The results presented here are theoretical cases, assuming that the remaining electricity system is static while increasing the share of wind power. The general conclusion can be drawn that using the models with a large buffer with

transmission capacity (Germany in the Nordic models), simulations end with increased transmission instead of dealing with the variability in the area where wind power is installed. This supports the observation that in many cases the most effective way of integrating wind power is to increase transmission capacity, or deal with the bottleneck situations (Matevosyan, 2004). The results may overestimate the effect of increased exports, however. To see how much the exports were due to overcapacity due to increased wind power, simulations with EMPS were performed, reducing conventional condense capacity while increasing wind power. This showed lower net exports to Central Europe, about 10 % of the wind power produced.

6.2.5 Discussion on the modelling of wind power

The models used here are not specifically designed for dealing with high shares of wind power. Some remarks on their restrictions have been made in chapter 3.

For wind power impact on the operating of power systems, modelling on an hourly level would be needed to catch the variability of wind. From weekly simulations, the assumption that the hydro system can handle the in-week variations of wind power can be feasible for Norway and perhaps also for Sweden. It leaves, however, doubts regarding the effects of wind variability on the system.

The effects of wind power on a power system are spread over the total control area (synchronously operated area) or electricity market, with constraints on transmission capacities between the areas. Effects of wind power are first seen as an increase in exchange of electricity between the areas. The results will, however, show only increase in transmission unless boundary conditions are set, to be able to see the limits to the transfer of wind power variability to the neighbouring areas. Contingencies, due to dynamic phenomena, cannot be modelled with an hourly time scale model. Due to this, the low transmission possibility scenario is often used, and this can underestimate the exchange possibilities during most of the time.

Modelling the effect of prediction errors is complicated by the uncertainties to different time scales of unit commitment (starting and shutting down slow

thermal units) and dispatch (production levels of thermal units). Problems can also emerge from the simulation logic in itself: optimisation of the system can be fundamentally different if taking into account the different nature of wind power production. Also, regulation requirements are often not modelled directly, but based on years of operating experience, so the effect of wind power cannot be modelled either (Dragoon & Milligan, 2003). Electricity market interactions and price levels should also be looked at when simulating wind power in the system.

7. Long term effects of wind power on the power system

The power system has to serve electricity consumption with a low probability of failure. The economic costs of failing to provide adequate capacity to meet electricity demand are so high that power companies have traditionally been reluctant to rely on intermittent resources for capacity. The 3–4 years of hourly wind power and load data collected for this thesis has been analysed to investigate wind power production during high electricity demand situations (Holttinen, 2003).

7.1 Temperature dependence of wind power

In Northern Europe, the electricity demand is strongly correlated to the ambient temperature. The correlation between wind power production and temperature has an effect on the adequacy of power production when determining the capacity value of wind power.
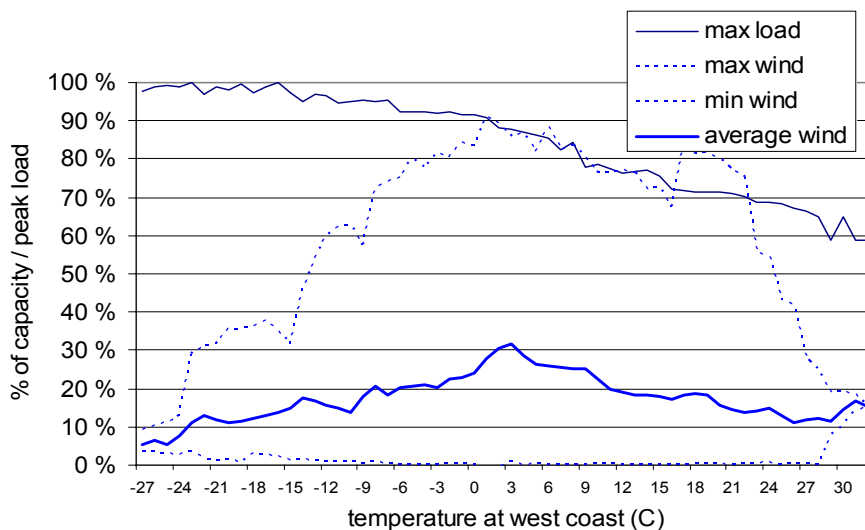

Figure 17. Temperature dependence of wind power production and load in Finland (1999–2002). The average wind power production was 22 % of capacity. There were 549 hours (1.6 % of time) below –14ºC.

The average wind power production at low temperatures of below –15°C is somewhat lower than the yearly average wind power production in Finland, and these are the incidents of highest load (Figure 17). Similar behaviour can be seen in Denmark (Figure 18). The average wind power production in the total Nordic wind power time series does not show this kind of reduction (Figure 19).
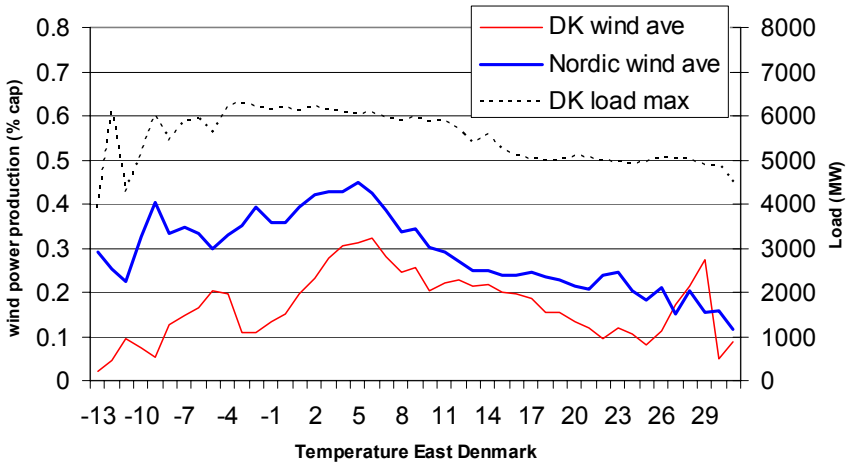

Figure 18. Temperature dependence of wind power production and load in Denmark (2000–2001).
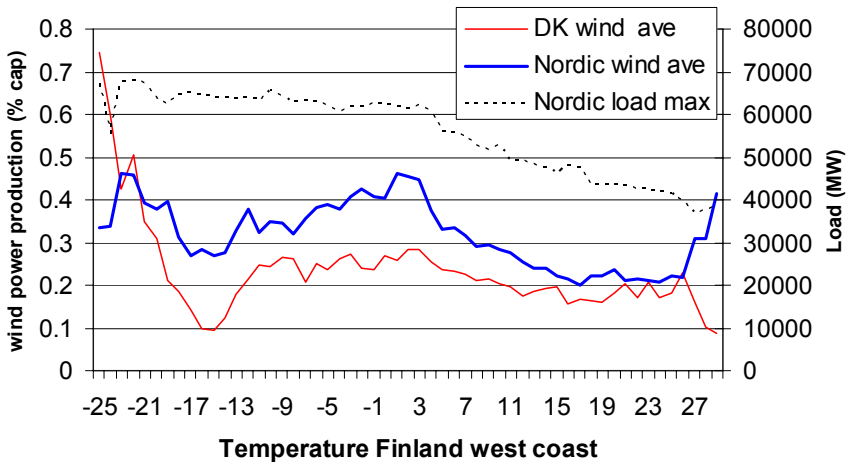

Figure 19. Wind power production and load in Nordic countries as a function of temperatures in Finland (2000–2001).

7.2 Capacity credit for wind power

Dimensioning the power system for system adequacy usually involves estimation of the Loss-of-load-probability LOLP index. As wind power production from one area can be zero during wintertime, it is often assumed that wind power does not contribute to the adequacy of the power production system and the capacity credit of wind power is neglected. Nevertheless, variable sources can save thermal capacity. Since no generating plant is completely reliable, there is always a finite risk of not having enough capacity available. Variable sources may be available at the critical moment when demand is high and other units fail. Fuel source diversity can also reduce risk.

Several studies show that at low system penetration the capacity value of wind power is close to that of a completely reliable plant generating the same average power at times when the system could be at risk (Giebel, 2001). As the penetration increases, wind power becomes progressively less valuable for saving thermal capacity (ILEX, 2003). The dispersion of wind power and a positive correlation between wind power and demand increase the value of wind power to the system. For very high penetration levels (more than 50 % of gross demand), the capacity credit tends towards a constant value, i.e. there is no increase in the capacity credit when increasing wind power capacity (Giebel, 2001). For hydro dominated systems, where the system is energy restricted instead of capacity restricted, wind power can have a significant energy delivery value. As wind energy correlates only weakly with hydro power production, wind energy added to the system can have a considerably higher energy delivery value than adding more hydro (Söder, 1999).

It has been shown that the capacity factor of wind power (i.e., production as % of installed capacity) during the peak load hours give a good indication of the capacity credit (Milligan & Parsons, 1997). Wind power production during the 10, 50 and 100 highest peak load hours, using data from this study, is shown in Table 2 for the different years and countries. Wind power production during the 10 highest peak load hours each year ranges between 7–60 % of installed capacity.

Results from a previous Finnish study indicate that the capacity credit for wind power in Finland is initially 23 %, but decreases to 18 % of installed capacity at a 6 % penetration (Peltola & Petäjä, 1993). This is a conservative estimate,

assuming that large scale wind power would have a 7 % probability of not producing during wintertime. Two Danish studies estimated the capacity credit for 5, 10 and 15 % wind power penetration levels giving a capacity credit of 23–30 %, 16–25 % and 11–20 % of installed wind power capacity, respectively (Giebel, 2001). In Norway, the probability of wind power production is similar during high loads to the average (Alm & Tallhaug, 1993). The 3–4 year data in Table 2 give as the average capacity factor during high load situations 24–25 % in Denmark, 18–20 % in Finland, 23–26 % in Sweden, 46–54 % in Norway and 28–32 % in the 4 countries as a whole. This corresponds quite well with the above estimates for capacity credits of wind power.

Table 2. Wind power production, as % of installed capacity, during highest peak load hours.

| | The whole year | During 10 peaks | During 50 peaks | During 100 peaks |
	Average (min–max)	Average (min–max)	Average (min–max)	Average (min–max)
Denmark 2000	24 % (0–93 %)	24 % (1–70 %)	31 % (1–87 %)	31 % (0–87 %)
Denmark 2001	20 % (0–90 %)	37 % (0–74 %)	30 % (0–87 %)	28 % (0–87 %)
Denmark 2002	22 % (0–91 %)	11 % (3–23 %)	14 % (2–53 %)	17 % (1–89 %)
Finland 1999	22 % (0–86 %)	7 % (5–10 %)	7 % (3–37 %)	9 % (2–46 %)
Finland 2000	24 % (0–91 %)	36 % (4–72 %)	32 % (3–75 %)	29 % (3–75 %)
Finland 2001	22 % (0–86 %)	19 % (3–38 %)	19 % (3–38 %)	17 % (3–38 %)
Finland 2002	20 % (0–84 %)	17 % (7–32 %)	17 % (6–54 %)	18 % (2–70 %)
Sweden 1999	25 % (0–100%)	23 % (16–29 %)	20 % (2–63 %)	20 % (1–66 %)
Sweden 2000	24 % (0–95 %)	16 % (7–49 %)	16 % (1–55 %)	16 % (0–63 %)
Sweden 2001	23 % (0–95 %)	47 % (40–51 %)	33 % (3–55 %)	29 % (3–63 %)
Sweden 2002	24 % (0–91 %)	16 % (3–36 %)	24 % (2–80 %)	25 % (2–80 %)
Norway 1999	32 % (0–100%)	55 % (17–86 %)	51 % (0–100%)	53 % (0–100%)
Norway 2000	34 % (0–93 %)	36 % (9–74 %)	35 % (9–74 %)	35 % (9–79 %)
Norway 2001	31 % (0–93 %)	61 % (39–84 %)	54 % (26–84 %)	46 % (15–84 %)
Norway 2002	32 % (0–86 %)	63 % (46–84 %)	58 % (22–84 %)	51 % (13–84 %)
Nordic 2000	27 % (1–81 %)	16 % (4–40 %)	21 % (4–56 %)	24 % (4–66 %)
Nordic 2001	24 % (1–84 %)	48 % (43–50 %)	37 % (9–56 %)	30 % (7–56 %)
Nordic 2002	25 % (1–73 %)	33 % (16–54 %)	33 % (11–61 %)	30 % (10–69 %)

8. Electricity markets and wind power

There have been changes in power system operation due to liberalised electricity markets. For example, even if the physical system is operated according to similar principles, the markets influence how the operating reserves are used. In chapter 6, the main emphasis was on the technical operation aspects of power systems. In this chapter, wind power in the electricity market is discussed. First, the market operation is described from the wind power producer's point of view. Then the effect of large scale production on market prices is discussed.

Wind power production has been marginal in the electricity markets so far. The bulk of wind power capacity is in countries with feed-in tariffs, where the TSO takes over the responsibility of balancing. In Denmark, the TSOs are trading a part of the wind energy produced in order to ease the scheduling of the conventional power plants. As the feed-in tariffs are for a specified time only (eg. 10 years), there will be an increasing amount of wind power coming to the markets during the next 5 to 10 years.

8.1 Market operation of a wind power producer

(Publication H)

In the Nordic countries, all bulk electricity production must be through a balance responsible player. For a wind power producer there are three options available. One option is to become a balance responsible player. Secondly, one could trade wind power and have a contract with a balance responsible player for balancing any mismatches. Thirdly, one could sell all wind power to a balance responsible player. It would be easier for the balance responsible player if there was flexibility in the production or consumption portfolio, and if there were several wind power projects geographically spread around to reduce the forecast error.

Producers with wind power bidding on the electricity market need to forecast their wind power production. Through forecast, the wind power available can be estimated when making a bid, selling all possible production. Forecast errors

will result in an imbalance with the bid, which will be penalised and lead to reduced net income for the producer.

The income from the wind power produced is determined by the spot market (Figure 4). The cost of imbalances will be deducted from this income. For part of the time, the imbalance due to wind power may be opposite to the overall system imbalance, and for those hours there will be no cost. Depending on whether a one-price or a two-price model for the balance settlement is used, the above mentioned hours will either result in extra income (one-price-model) or will be reimbursed according to the spot price (two-price-model). The producers can trade outside the spot market for up to one hour before the delivery hour to reduce any larger imbalances.

It could be advantageous for the wind power producer to make a contract with a larger balance responsible player who owns regulating capacity. This is because the amount of imbalance cost is based on the net imbalance of the balance responsible player. The balance responsible player can also change the production schedule up to the delivery hour to reduce any larger imbalances.

8.1.1 Spot market income to a wind power producer

(Publication F)

The historical electricity spot market price level during wet and average hydro years[9] has not been enough to initiate investments in wind power without subsidies.

The price paid for wind power in the spot market will depend on how much wind energy is available in times of high price hours. The simulations for the Nordic market (EMPS model) over 30 years give about 2 % higher average value for wind power production than the average electricity spot price. With large scale wind production (12 % penetration) this price difference would

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[9] Average yearly spot price was 12–26 €/MWh in 2000–2002 and 37 €/MWh in 2003 (Nordpool, 2004).

reduce to about 1 %. In Denmark, with higher wind power penetration than in the other Nordic countries, wind power production would be priced 1–2 % lower than the average spot price.

The income for a wind power producer at spot market prices was calculated for the hourly wind power data collected for this study, assuming perfect prediction for wind power and geographically dispersed production. For Finland and Sweden in 2001 and 2002, the average income for wind power would have been 98–102 % of the average area spot price. In West Denmark with realised wind power production and system price the average income would have been 99–103 % of the average spot price. For the area price of West Denmark, the average income relative to average spot price decreased from 96 % to 86 % from 2001 to 2003 due to a larger share of wind power in the power system.

8.1.2 Regulation market cost for a wind power producer

(Publication C)

In publication C, a case study based on one year of wind power and market price data from Denmark was made to quantify the benefits of operating on a shorter forecast horizon. This study assumed that wind power producers of a larger area (West Denmark) formed a balance responsible player and had to take responsibility for all imbalances due to prediction errors. In year 2001 with 3.35 TWh of wind power or 16 % of the total electricity consumption:

- The prediction error for the year totals 39 % of the wind energy produced for the Nordpool 12–36 h market. With the two-price regulating power market, 31 % of the production incurred a regulating cost. For a 6–12 h market, 30 % of the total yearly energy would have been predicted wrongly, and 21 % of the production would have to be balanced at the regulation market. For a constantly operating hourly market, 18 % of the energy would be mispredicted and 10 % of the production would have to be balanced at the regulation market.

- The regulation cost for the 12–36 hour market would be 2.3 €/MWh when allocated for the wind power produced during 2001. The

regulation cost would be reduced by 30 % and the net income increased by 4 % for a 6–12 hour market, compared with the 12–36 hour market. An hourly operation would reduce the regulation costs by nearly 70 % and increase the net income by 8 %.

- Trading at the after sales market Elbas, where the trade closes one hour before delivery, enables the wind power producer to trade the over- or under-predicted amount when the production is more accurately known. From 2001 data, the net income could increase by 7 % if trading at Elbas compared to trading at the Nordpool 12–36 h market only.

The results are not based on a state-of-the-art version of the prediction model, so the prediction errors of wind power are somewhat overestimated. It is assumed that the price level of the after sales market Elbas would stay near the day-ahead spot market prices most of the time. This means that wind power is not influencing the after sales market price more than the lowest-price-for-selling and highest-price-for-buying assumed here. On the other hand, acting at flexible markets could also bring about extra trading costs.

For a producer selling wind power production on the electricity market, there is a clear benefit in trading as close to the delivery hour as possible, since this reduces the prediction error and thus the extra cost from regulating. Also, a larger geographical area improves the forecasts.

The electricity market design will have a crucial effect on the balancing costs for wind power producers. The Dutch system of rewarding overproduction with 16 €/MWh and penalising undelivered power with 120 €/MWh would result in a drop in the net income of a wind power producer by over 50 %, if 25 % of the production were wrongly predicted (Hutting & Clejne, 1999). In a Danish study (Nielsen et al., 1999), the mispredictions of wind power production would impose a 1.3–2.7 €/MWh extra cost from settling the deviations at the balancing market. This is in line with the cost calculated here for year 2001 (2.3 €/MWh). These studies estimate the cost by relying on predictions that try to minimise the forecast error in energy. Market design can also change the bidding strategy from simply minimising the error in energy (Bathurst et al., 2002; Nielsen & Ravn, 2003).

Only the net imbalance in a power system needs to be balanced. In a large system this results in considerable benefit when imbalances from individual production units and consumption counteract one another. This could also be reflected by the balance settlement. The two-price model only penalises those having their imbalance on the same side as the system (net) imbalance. However, it does not recognise that only part of this imbalance, i.e. the net imbalance, needs to be corrected. In the one-price model, the ones having their imbalance in the opposite direction to the system will gain, as they are paid a price higher than the spot price. As the imbalance for wind power is about the same in both directions this results in almost no extra regulation costs for wind power in Norway (Gustafsson, 2002). In California, the imbalance for wind power is calculated as the average over a month, which also results in almost zero imbalance costs for wind power (Caldwell, 2002). In Denmark and Germany, allocating the balancing costs has been a part of the policy for increasing renewable power production, so any increase in imbalance costs is distributed evenly to all consumers.

The rules for balance services are based on producers that can influence their production amounts for most of the time. Market mechanism should not be a barrier for renewable production forms and mechanisms for intermittent sources such as wind power should be considered.

8.2 The impact of large amounts of wind power on spot market

(Publication F)

Due to its negligible variable costs, wind energy would always be taken up by the electricity market. This means that the supply curve will be shifted to the right with the amount of wind power bid to the market at that hour. The market cross will be formed either to the same price as without wind (when the amount of wind power is less than the amount of the production form on the margin) or a price lower to that without wind (Figure 4).

The results from the EMPS simulations for the Nordic electricity market give an average spot price of about 23 €/MWh for the year 2000 system in an average

inflow situation. The average spot price rises to 35 €/MWh for the 2010 scenario, due to a CO_2 tax and reduced power surplus (more consumption than production capacity added). According to the simulations of these two different cases, adding a significant amount of wind energy to the Nordic system would decrease the average spot price by 2 €/MWh for each 10 TWh/a wind energy added. A decrease in spot market price is connected with adding wind power in the market as an extra production. Results of simulations when thermal capacity was decreased while adding wind, show only a moderate price decrease (about 2 €/MWh for each 40 TWh/a added wind production).

In West Denmark, with more than 15 % of gross demand from wind power, the area price was reduced to 0 during some hours in 2002 and 2003. This was due to too much production in the area, resulting partly from the local prioritised CHP production as well. The wind power production during those hours has been above average.

The implications of the lowering of spot market price are twofold. The consumers will gain from a price reduction, and when wind power is replacing fossil thermal production, the power system will be operating with less fuel consumption and emissions. For the producers of fossil fuel operated power plants this can be a crucial drop in income. If the capacity is removed even if it would be needed in extreme dry years, it could affect adequacy of supply. Wind power should replace fossil fuels, to make the CO_2 and other emission savings required. However, the way this is done, in practice and from a power system point of view maintaining the reliability can become an issue. Overcapacity in the Nordic countries when the electricity markets were started resulted in some of the capacity being mothballed, and it was taken back to operation during the dry period 2002–2003. This could also be the way the system security is maintained with large amounts of wind power if the time scale of dry and low wind periods allow for it.

8.3 The impact of wind power on the regulating power market

Regulating power is nearly always more expensive than bulk power on the electricity market. This is because it is used for short intervals only, and has to

be kept on stand-by. Paying more for regulation power is also one incentive for the market players to maintain their power balance.

Since 2003, there has been a common regulating power market in the Nordic system. The decentralised balancing by the balance responsible players means that they will pay the costs of balancing through balance service, and move the costs associated forward to either the wind power producer or the consumers. Here the balancing means the deviations from the schedules submitted to TSOs before the operating hour[10]. There is the possibility of trading larger deviations in the Elbas market, closing 1 hour before. Self regulation is discouraged, however, as it is more cost effective for both the system and the individual players to bid all regulating power to a joint pool for the TSO to use the cheapest options first.

In California, a study of the existing wind power showed that even doubling the wind power in the area will not influence the regulating power market (less than 5 % penetration level) (Kirby et al., 2003). Large amounts of wind power will influence the regulating power market. In West Denmark, wind power penetration is large enough to influence the market price in the area. However, the common regulating power market in Nordel is not influenced by the Danish wind power as the wind power produced is less than 2 % of the gross demand of Nordel.

The historical electricity market prices are not valid with a high penetration level of wind power. On a 10–20 years time horizon, which may be relevant to a potential investor, it is difficult to predict the cost of balancing as well as the market value of wind power.

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[10] Sweden and Denmark: separately for production and consumption schedules.

9. Conclusions

The integration of large amounts of wind power is a challenge to power systems. In this work, the impact of large-scale wind power on the operation of the Nordic power system, on the electricity market operation and on market prices was studied.

The variability of wind power is reduced when considering a large inter-connected system with geographically dispersed wind power production. In the Nordic countries, the aggregated wind power production will stay within 1–90 % of the installed wind power capacity, and production levels of above 75 % or below 5 % of the installed wind power capacity are rare. The hourly changes of the production are most of the time within ±10 % of installed capacity in one country and inside ±5 % of capacity in the whole Nordic area.

The increased reserve requirement for the power system is determined by combining the wind power variations with varying electricity consumption. Combined with the varying load, wind power will not impose major extra variations on the system until a substantial penetration is reached.

The increased reserve requirement is seen on a 15 minutes – 1 hour time scale. In the Nordic countries, wind power would increase the reserve requirements by 1 %, 2 and 4 % of wind power capacity at 5, 10 and 20 % wind power penetration of gross demand, respectively. The increased reserve cost is of the order of 1 €/MWh at a 10 % penetration and 2 €/MWh at 20 % penetration of wind power. This is halved if the conservative estimate for allocating investment costs for new reserve capacity to the wind power production is omitted and only increased use of reserves is taken into account. In addition, the prediction errors of wind power day-ahead may affect the system net imbalance and thus will reflect on the regulating power market, depending on how much the balance responsible players will correct the deviations before the operating hour.

The simulations of the Nordic power system show that wind power will mostly replace coal or gas condense power, partly in different countries to those with the installed wind power if the system is interconnected. The variability of wind power will first reflect in the increase in exchange between the countries before

thermal power plants in the area of installed wind power will be affected. The reduction of CO_2 emissions in the Nordic countries is 700 gCO_2/kWh at low penetration of wind power, reducing to 620 gCO_2/kWh at higher than 10 % penetration. At penetration levels greater than 10 %, there would be increased losses in hydro power production of the order of 1 % of the produced wind energy. Based on the simulations confirmed by experience in West Denmark, discarded energy becomes relevant for the Nordic electricity system when wind power produces more than 20 % of the gross demand, or in some cases earlier if there are bottleneck situations in the interconnected Nordic network.

The analyses from 3 years of realised hourly data confirm the results from earlier studies that the capacity credit for wind power is close to average power produced. Wind power production in Finland and Denmark is lower than average at low ambient temperatures, but the Nordic wind power production does not show a similar trend.

The operation of wind power producers in the electricity market requires forecasting of the wind power production. The forecast errors are substantial when forecasting one day ahead: about 90 % of wind power production will be known 1 hour beforehand, 70 % 9 hours before, and only 50 % 36 hours before, respectively. The prediction errors will lead to balance deviations that will be charged according to regulating power market prices after the operating hour. The producer acting at the market can use after sales tools and bilateral trade to correct most of the error, as the production will be known more accurately some hours before delivery. This would increase the net income of a wind power producer by nearly 10 %, according to 2001 data. The market rules will have a crucial effect on the costs for intermittent production like wind power. The balancing costs for the wind power producers should reflect the real costs for the power system, from balancing the system net imbalance.

High penetrations of wind power will affect the market price – lower the spot market prices and raise the regulating power prices. High penetration of wind power will lower the Nordpool spot market prices by about 2 €/MWh for each 10 TWh/a added wind production (10 TWh/a is 3 % of gross demand). This applies if the wind power production is added to the system without replacing any production capacity.

The results from this work clearly show the benefits of large interconnected systems in absorbing variable production like wind energy. The results of wind power variability and increased reserve requirements give new insight for the Nordic countries in particular and other power systems in general. Important future issues would be the effects of wind power on the regulating market prices and hourly energy system modelling, including wind power integration in a large interconnected system. When the penetration of wind power becomes greater, data on a minute or even second level would be beneficial to carry out transient studies on the variations of wind power and load.

Large-scale wind power utilisation still lies in the future for many countries. There are long-term trends that can influence the impact of wind power on the power system. A greater system interconnection is highly beneficial: wind power spread all over Europe would be a more reliable source. The use of electricity for vehicles may open up new possibilities for variable and intermittent power production. Producing fuel for vehicles that are only used for about 1000 hours per year will ease the flexibility needs in power systems.

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Title
The impact of large scale wind power production on the Nordic electricity system

Abstract
This thesis studies the impact of large amounts of wind power on the Nordic electricity system. The impact on both the technical operation of the power system and the electricity market are investigated.

The variability of wind power is reduced when looking at a large interconnected system with geographically dispersed wind power production. In the Nordic countries, the aggregated wind power production will stay between 1–90 % of the installed capacity and the hourly step changes will be within ±5 % of the installed capacity for most of the time. The reserve requirement for the system, due to wind power, is determined by combining the variations with varying electricity consumption. The increase in reserve requirement is mostly seen on the 15 minutes to 1 hour time scale. The operating reserves in the Nordic countries should be increased by an amount corresponding to about 2 % of wind power capacity when wind power produces 10 % of yearly gross demand. The increased cost of regulation is of the order of 1 €/MWh at 10 % penetration and 2 €/MWh at 20 % penetration. This cost is halved if the investment costs for new reserve capacity are omitted and only the increased use of reserves is taken into account. In addition, prediction errors in wind power day ahead will appear in the regulating power market to an extent which depends on how much they affect the system net balance and how much the balance responsible players will correct the deviations before the actual operating hour.

Simulations of increasing wind power in the Nordic electricity system show that wind power would mainly replace coal fired production and increase transmission between the areas within the Nordic countries and from Nordic countries to Central Europe. The CO_2 emissions decrease from an initial 700 gCO_2/kWh to 620 gCO_2/kWh at 12 % penetration. High penetrations of wind power will lower the Nordpool spot market prices by about 2 €/MWh per 10 TWh/a added wind production (10 TWh/a is 3 % of gross demand).