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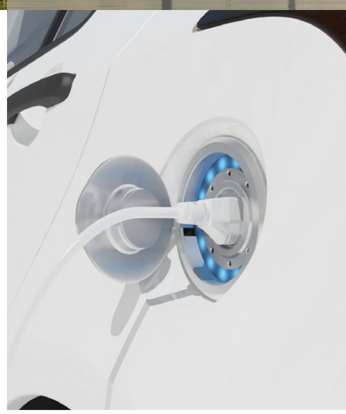

Managing wind power variability and uncertainty through increased power system flexibility

Juha Kiviluoma

VTT SCIENCE 35

Managing wind power variability and uncertainty through increased power system flexibility

Juha Kiviluoma

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Managing wind power variability and uncertainty through increased power system flexibility

Tuulivoimatuotannon vaihteluiden ja epävarmuuden hallinta parantamalla sähköjärjestelmän joustavuutta. **Kiviluoma, Juha.** Espoo 2013. VTT Science 35. 77 p. + app. 88 p.

Abstract

Variability and uncertainty of wind power generation increase the cost of maintaining the short-term energy balance in power systems. As the share of wind power grows, this cost becomes increasingly important. This thesis examines different options to mitigate such cost increases. More detailed analysis is performed on three of these: flexibility of conventional power plants, smart charging of electric vehicles (EVs), and flexibility in heat generation and use. The analysis has been performed with a stochastic unit commitment model (WILMAR) and a generation planning model (Balmorel).

Electric boilers can absorb excess power generation and enable shutdown of combined heat and power (CHP) units during periods of high wind generation and low electricity demand. Heat storages can advance or postpone heat generation and hence affect the operation of electric boilers and CHP units. The availability of heat measures increased the cost optimal share of wind power from 35% to 47% in one of the analysed scenarios.

The analysis of EVs revealed that smart charging would be a more important source of flexibility than vehicle-to-grid (V2G), which contributed 23% to the 227 €/vehicle/year cost savings when smart charging with V2G was compared with immediate charging. Another result was that electric vehicles may actually reduce the overall CO_2 emissions when they enable a higher share of wind power generation.

Most studies about wind power integration have not included heat loads or EVs as means to decrease costs induced by wind power variability and uncertainty. While the impact will vary between power systems, the thesis demonstrates that they may bring substantial benefits. In one case, the cost optimal share of wind-generated electricity increased from 35% to 49% when both of these measures were included.

Keywords wind power, unit commitment, economic dispatch, generation planning, energy balance, electric boiler, heat storage, heat pump, electric vehicle, hydro power, flexibility, variability, uncertainty

Tuulivoimatuotannon vaihteluiden ja epävarmuuden hallinta sähköjärjestelmän joustavuutta parantamalla

Managing wind power variability and uncertainty through increased power system flexibility. **Kiviluoma, Juha.** Espoo 2013. VTT Science 35. 77 s. + liitt. 88 s.

Tiivistelmä

Tuulivoimatuotannon vaihtelevuus ja ennusvirheet lisäävät energiatasapainon ylläpitämisen kustannuksia sähköjärjestelmissä. Tuulivoiman osuuden kasvaessa näiden kustannusten suhteellinen merkitys kasvaa. Tämä väitöskirja tutkii eri tapoja lieventää kustannusten nousua lisäämällä järjestelmän joustavuutta. Tarkempi analyysi on tehty kolmelle eri menetelmälle: perinteisten voimalaitosten joustavuuden lisääminen, sähköautojen älykäs lataaminen sekä lämmön tuotannon ja kulutuksen mahdollisuudet joustavuuden lisäämisessä. Analyysit on tehty stokastisella ajojärjestysmallilla (WILMAR) sekä investointimallilla (Balmorel).

Sähkökattilat voivat hyödyntää liiallista sähköntuotantoa ja samalla mahdollistaa sähkön ja lämmön yhteistuotantolaitosten alasajon ajanjaksoina, jolloin tuulivoimatuotanto on suurta ja kulutus vähäistä. Lämpövarastot voivat siirtää lämmöntuotannon ajoitusta ja sitä kautta lisätä sähkökattiloiden sekä sähkön ja lämmön yhteistuotantolaitosten joustavia käyttömahdollisuuksia. Tulokset indikoivat merkittävää potentiaalia suhteellisen pienillä kustannuksilla.

Analyysin mukaan sähköautojen älykäs lataaminen tarjoaa enemmän joustavuutta kuin sähkön syöttö verkkoihin sähköautoista tarvittaessa. Sähkönsyötön osuus älykkään lataamisen kokonaissäästöistä (227 €/auto/vuosi) oli 23 %. Toinen tulos oli, että sähköautot näyttäisivät vähentävän sähköntuotannon päästöjä, koska niiden tuoma joustavuus johtaa entistä suurempaan tuulivoiman osuuteen sähköjärjestelmässä.

Suurin osa tuulivoiman vaihtelevuuden ja ennusvirheiden kustannuksia arvioineista tutkimuksista ei ole huomioinut sähköautojen tai lämmön tuotannon ja kulutuksen mahdollistamaa lisäjoustavuutta. Vaikutukset vaihtelevat järjestelmästä toiseen, mutta väitöskirja osoittaa, että näistä voidaan saada merkittäviä hyötyjä. Yhdessä tutkitussa tapauksessa tuulivoiman kustannustehokas osuus kasvoi 35 %:sta 49 %:iin, kun sekä lämmön kulutuksen että sähköautojen joustavuus huomioitiin.

Avainsanat wind power, unit commitment, economic dispatch, generation planning, energy balance, electric boiler, heat storage, heat pump, electric vehicle, hydro power, flexibility, variability, uncertainty

Preface

This doctor's thesis was carried out at the VTT Technical Research Centre of Finland, presently in the Wind Integration team at the Energy Systems Knowledge Centre. The main source of financing for the thesis was Fortumin Säätiö (Fortum Foundation). Part of the work received financing from Tekes through national IEA Wind collaboration projects and the SGEM research programme. The EU has financed the work through the FP5 project Wind Integration in Liberalised electricity MARkets WILMAR. A year-long research fellowship at the Kennedy School of Government at Harvard University was made possible by a joint grant from the ASLA-Fulbright and Helsinki University of Technology.

I am deeply grateful for the support and joint research efforts of my instructors Dr. Hannele Holttinen and Dr. Peter Meibom. My supervisor, Prof. Peter Lund, has been encouraging and helpful through my PhD studies and has provided valuable comments on the thesis. I have also received comments from Prof. Liisa Haarla and Dr. Ritva Hirvonen, for which the reader should be grateful as they have greatly improved the readability of the thesis. I would like to thank my co-authors for their contributions and for the valuable lessons on how to write journal articles. I am also indebted to my colleagues with whom I had the privilege to work during the course of the thesis. Special thanks to the WILMAR project participants, my colleagues at IEA Wind Task 25, and my friends from the YSSP 2006 at IIASA as well as the Kennedy School during 2007–2008. I am extremely grateful for the opportunity to work with my colleagues at VTT from whom I have learned much during these years.

During the course of the dissertation, two new family members emerged and changed my life. Thanks to Heimo and Lenni for being. My wife Katri is due dual thanks. First, she contributed to my research and this thesis through her immense abilities for critical thinking. Second, thanks for being with me.

Helsinki, June 2013
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List of publications

This thesis is based on the following original publications, which are referred to in the text as I–VIII. The publications are reproduced with kind permission from the publishers.

I Lu Xi, McElroy MB and Kiviluoma J, Global potential for wind-generated electricity. Proc. Nat. Acad. Sci., Vol. 106, No. 27, pp. 10933–10938, 2009.

II Kiviluoma J, Meibom P, Tuohy A, Troy N, Milligan M, Lange B, Gibescu M and O'Malley M, Short Term Energy Balancing With Increasing Levels of Wind Energy. IEEE Trans. Sustain. Energy, Vol. 3, No. 4, pp. 769–776, 2012.

III Meibom P, Kiviluoma J, Barth R, Brand H, Weber C and Larsen HV, Value of electric heat boilers and heat pumps for wind power integration. Wind Energy, Vol. 10, pp. 321–337, 2007.

IV Kiviluoma J and Meibom P, Influence of wind power, plug-in electric vehicles, and heat storages on power system investments. Energy, Vol. 35, No. 3, pp. 1244–1255, 2010.

V Kiviluoma J and Meibom P, Flexibility from district heating to decrease wind power integration costs. In: Proc. of the 12th International Symposium on District Heating and Cooling, pp. 193–198, Tallinn, Estonia, 5–7 Sep. 2010.

VI Kiviluoma J and Meibom P, Coping with wind power variability: how plug-in electric vehicles could help. In: Proc. of the 8th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Farms, pp. 336–340, Bremen, Germany, 14–15 Oct. 2009.

VII Kiviluoma J and Meibom P, Methodology for modelling plug-in electric vehicles in the power system and cost estimates for a system with either *smart* or *dumb* electric vehicles, Energy, Vol. 36, No. 3, pp. 1758–1767, 2011.

VIII Kiviluoma J and Meibom P, Decrease of wind power balancing costs due to smart charging of electric vehicles. In: Proc. of the 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Farms, pp. 501–506, Aarhus, Denmark, 25–26 Oct. 2011.

Author's contributions

In Publication I, the author contributed to the understanding of wind energy resources, and participated in the data analysis and writing of the paper. In Publication II, the author was the main writer of the paper and participated in its design. In Publication III, the author participated in the writing and design of the paper and performed most of the analysis of the results. In Publications IV, V, VI, VII and VIII, the author was the main writer and performed most of the data analysis. The design was done together with the co-author, and the co-author performed the Balmorel model runs, while the author performed the WILMAR model runs.

The author has also contributed to the development of the WILMAR planning tool including the module on electric vehicles (Publication VII), the databases containing the input and output data (Kiviluoma and Meibom 2006) and the joint market model of WILMAR (Meibom *et al.* 2006, p. 4). The author has not participated in the writing of the journal or conference publications that document the WILMAR core model.

Contents

List of abbreviations

AA-CAES	Advanced adiabatic compressed air energy storage
AC	Alternative current
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
COP	Co-efficient of performance
DC	Direct current
DR	Demand response
DSM	Demand side management
EV	Electric vehicle
EWIS	European wind integration study
EWITS	Eastern Wind Integration and Transmission Study
FLH	Full load hours
GAMS	General Algebraic Modeling System
GHG	Greenhouse gas
GW	Gigawatt
HVDC	High voltage direct current
JMM	Joint market model
LP	Linear programming
LTM	Long term model
MIP	Mixed integer programming
NTC	Net transfer capacity
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
OTC	Over-the-counter
PHEV	Plug-in hybrid electric vehicle
TCL	Temperature-controlled load
V2G	Vehicle-to-grid
WILMAR	Wind power integration in liberalised electricity markets
WWSIS	Western Wind and Solar Integration Study

1. Introduction

Power generation from wind is variable – even if aggregated generation in a large power system is considered. It is also uncertain, because it is not possible to fully predict wind generation. When the share of wind power in a power system is small, these qualities only have a minor impact on the short-term energy balance of the power system. If the share of wind power grows, the associated variation and uncertainty will start to overshadow the existing variation in and uncertainty of electricity demand and power plant availability (Holttinen *et al.* 2011b). At the same time, maintaining the short-term energy balance in the power system will become more expensive. The research for this thesis focuses on how such cost increases could be mitigated. The analysis concentrates on three options: flexibility from conventional power plants, smart charging electric vehicles, and flexibility from heat generation and heat use.

The research problem is becoming increasingly important because wind power is already an important source of new power generation. The global wind power capacity grew by 38.3 GW in 2010 (GWEC 2011), which corresponds to approximately 80 TWh annually. In comparison, the average annual increase in global electricity generation has been 473 TWh a year from 1990 to 2010 (BP 2011). Meanwhile, the annual installed wind capacity has doubled on average every 3 years between 1991 and 2009 (BTM 2009, GWEC 2011). The growth stagnated in 2010 and fell in 2011–2012, but if wind power manages to get back on the growth track after the current economic turmoil, it could become the largest source of new electricity generation globally. The technical potential for wind-generated electricity is many times greater than the global electricity demand (Jacobson and Archer 2012).

While the market share of wind power is growing, it takes time for power systems to change. Wind power has reached a sizable share of the total electricity generation in only a few balancing areas or synchronous systems, while many others are planning large increases. As part of the planning for a large increase in wind power generation, studies have been conducted to analyse the costs of the variability and prediction errors of wind power as well as the benefits of reduced fuel use due to wind power generation. These studies usually analyse the costs to integrate wind power penetration levels of 5–25% in terms of produced electricity (review in Holttinen *et al.* 2011a, IPCC 2011 Section 8.2.1).

A more flexible power system can integrate variability and uncertainty at lower cost (Chandler 2011). Flexibility is influenced by the types and numbers of power plants in the system, the availability of reservoir hydro power or pumped storage, transmission lines to other power systems, transmission constraints within the system, and availability of demand response including electricity use in transport and heat generation. This thesis attempts to estimate the economic limits for wind power penetration when taking into account relevant options to increase the capabilities of the power system to cope with the increased variation and uncertainty

The important research task of finding cost-effective ways to increase power system flexibility for the short-term energy balance is highly justified. This thesis examines the options mentioned in the above paragraph more closely. Increased flexibility of a power system will not only help wind generation but also enable other forms of power generation to operate more efficiently. The aim of the analysis is therefore operational system costs rather than wind integration costs, which are difficult to isolate from the simultaneous benefits (Milligan *et al.* 2011).

The focus of the analysis is on a future Nordic power system characterised by large-scale reservoir hydro power and district heating systems with combined heat and power generation. Publication III covers the whole Nordic power system as well as Germany. Publications IV–VIII are based on data from Finland only. The latter articles have used a generation planning model to replace retired generating units and to meet the demand increase. Therefore, the resulting power system is not that of Finland but rather a result of the cost assumptions made for the articles together with some data from Finland. The results may apply to other systems as well, but they are then subject to interpretation.

Wind power is not the only new variable form of power generation. Much of the analysis also has relevance to solar power and other variable sources of power (e.g. run-of-river hydro, tidal and wave power). These are not explicitly modelled, as wind has been the dominant new source of variable power.

The models used for the analysis minimise the total system costs. They do not try to maximise the profits of the market participants as assumedly happens in real life. However, the end result should be the same if the markets were perfectly competitive and all the market actors had the same information. However, this is not the case in real life. Therefore, the results can either be interpreted as approximations of what would happen in power markets or they can be seen from the perspective of a central planner who optimises the social surplus.

Some aspects of power system operation have been excluded from the study. For the analysis, the power grid has been simplified into net transfer capacities (NTC) between different regions. This approach ignores real power flows, which will often force restrictions in the actual dispatch of power plants. The inclusion of power flows in the analysis of this study would reveal additional costs, especially at high wind power penetration levels and hence decrease the cost-optimal share of wind power in the system. However, the analysis that compares different ways to integrate wind power is less affected by the omission of power flows.

There are also other grid issues not dealt with in this dissertation, including system stability in case of faults, adequacy of system inertia, small signal stability, dynamic transients and voltage stability. While these are necessary aspects to secure reliable operation of the system, their effect on the first-order economic optimisation of the system is usually limited.

The flexibility of charging and discharging electric vehicles will be dependent on the possible bottlenecks in distribution grids, but it was not possible to include this aspect as distribution grids were not modelled.

Another limitation concerns the costs of future technologies. It was necessary to make a large number of assumptions concerning future costs. A guiding principle behind the assumptions was to try out cost scenarios in which wind power covered a high share of electricity consumption. The assumptions are not predictions of what is going to happen but should be seen as ‘what if’ scenarios.

A further issue is whether the current market designs provide incentives to ensure sufficient investment in flexibility and capacity adequacy (e.g. Milligan *et al.* 2012). However, this is beyond the scope of the thesis.

The structure of the thesis is the following. Chapter 2 outlines the research issues and the research task more closely and is partially based on Publication II. The literature review in Chapter 3 surveys different possibilities for flexibility. The main tools for the analysis are presented in Chapter 4. These include the generation planning model Balmorel and the unit commitment model WILMAR. These have been used to optimise and analyse the economic operation of power systems with a high penetration of wind power. A closer analysis is performed on some of the flexibility options: the use of conventional power plants, electric vehicles, and heat generation and heat storages (Chapter 5). Chapter 6 discusses the results and Chapter 7 concludes the thesis.

2. Research issues

This chapter provides a background to the main characteristics of wind power that alter the functioning of the power system: variability (Section 2.1) and uncertainty (Section 2.2). Increased variability and forecast errors will impact the mechanisms used to maintain the short-term energy balance (Section 2.3) in an energy system. Wind power will also change investments in other generation (Section 2.4). Lastly, the chapter provides rationale for studying high wind power penetration levels (Section 2.5).

2.1 Variability of wind power generation

The variability in generation from a single wind turbine can be great, but the variability will smooth out considerably as the level of aggregation increases (Holttinen *et al.* 2011b). Wind power generation from a single turbine has quite high variation and includes many hours of zero and full outputs. However, this is not important from the perspective of a power system, as the output from one wind turbine is miniscule in comparison with the average power system size. Under normal operation, the output from a wind power plant with multiple turbines is more stable than the output from a single turbine, as wind gusts are smoothed out over many wind turbines. Furthermore, wind shade from other turbines and non-operational turbines decrease the time with full output. The smoothing continues as the level of aggregation increases. Aggregated wind power generation within a market zone will be smoothed considerably compared with a single wind power plant. The smoothing will be influenced by the number of separate wind power plants, how well the capacity is dispersed between the wind power plants, and how distant the wind power plants are from each other. When multiple market zones are combined, the smoothing will continue as displayed in Figure 1.

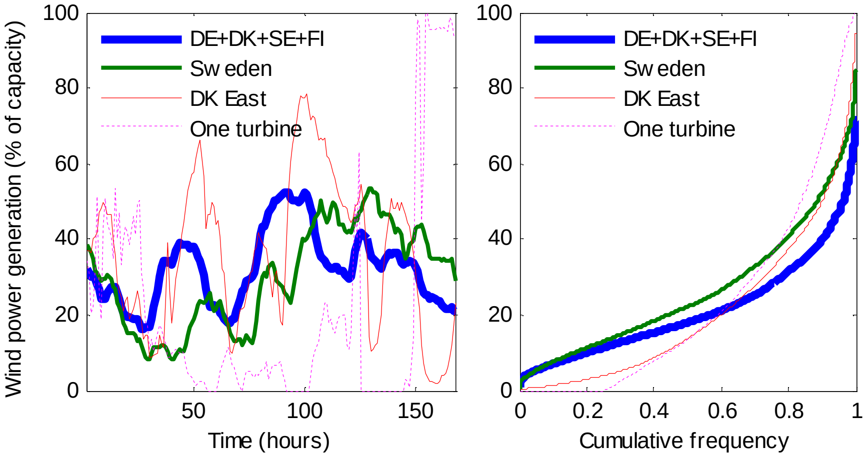

Figure 1. Typical variation in wind power generation on different geographical scales. The left figure displays one week of data from 2010. The right figure shows two years (2010 and 2011) of hourly data sorted by generation level. The aggregated generation for the four countries has been created by calculating a weighted average of the capacity factor for each hour. Germany had a weight of three, and other countries had a weight of one. (Finnish Energy Industries/VTT, Amprion, 50hertz, TenneT, TransnetBW, Energinet.dk, Svenska Kraftnät).

A change in aggregated wind power output can be faster and bigger than a change in demand. It can increase or decrease the rate of change in residual demand (demand net of wind generation), which needs to be met by conventional power plants or by demand-side measures. However, unlike the output from a single wind farm, wind power from a control area does not usually ever generate at full power. If the area is small, there can be weather events when all turbines are facing sustained winds inside the full output range of 12–25 m/s wind speeds, but these are rare. Even during these events, some turbines will not be functional due to repairs or maintenance and thus the output will not be full. Swings in output as well as the maximum output decrease as the area becomes larger, although what really matters is the distance between different wind power sites and how the weather patterns may lie across the area. Wind power variability in different power systems has been described in Holttinen *et al.* (2011b).

Variation in wind power creates costs for the power system. At first, when wind power is a small component of the total electricity generation, the variation creates very small costs. At this point, the variation in demand is much greater. Nearly half of the time, wind power reduces the overall variation and hence the impact remains low (Holttinen *et al.* 2011b).

As the share of wind power of the total generation grows, the variability has three mechanisms that increase power system costs. These are general principles; the actual costs will also depend on the operational practices.

1) When wind power increases the variation in the system, it can cause situations that would not have taken place otherwise. For example, during a low demand event with high wind power generation, it is more likely that a baseload unit has to operate at part load instead of full load. The baseload unit makes room for the wind generation if there is nothing else to back down. In part-load operation, most generation units use more fuel per generated unit of electricity, and part-load operation may increase the need for maintenance. This cost could be avoided if less costly flexibility were available. Meanwhile, the generated wind power decreases the overall cost of operating the system as, despite the decreased efficiency, fuel use is reduced in relation to wind generation. The exception to this is when wind power replaces other non-fuel generation that cannot be used later, such as run-of-river hydro power.

2) The portion of the time that wind power will increase the rate of change in residual demand, which will affect the ramping of conventional power plants. If ramp rates are fast, power plants with faster ramping capability may have to be used in addition to the most economic ones[1]. For example, in a situation in which demand is going up and wind generation is going down, low marginal cost units with a slow ramp up rate are slowly ramping up, but they have to be helped by faster ramping units. These can be ramped back down once the slower units have been fully ramped up, but an extra cost will have been incurred.

3) In the power system planning timescale, more variable residual demand will increase the attractiveness of more flexible power plants over less flexible plants. More flexible plants will have higher investment costs or higher operational costs than less flexible power plants. The former happens if a power plant is made more flexible by increasing start-up and ramping capabilities. The latter takes place if efficiency is reduced in order to gain flexibility (e.g. choosing an engine power plant instead of a combined cycle power plant).

Figure 2 and Figure 3 give an indication of the effect of wind power variability on the power system. The demand curve shows the variability present in the Nordic system in 2011. When large-scale wind power generation is subtracted from the demand, the remaining residual demand shows the new variability in the system. Without wind, the system has variation from winter to summer as well as some daily variation. Wind generation will decrease the average difference between summer and winter, but the variation in the daily timescale will be of a different magnitude.

[1] An energy-only market does not appreciate the full extent of the ramping capability. It only pays for energy during those periods when ramping is required. There is discussion on whether there should be a separate ramping product in order to assign value to the ramping capability (e.g. Milligan *et al.* 2012).

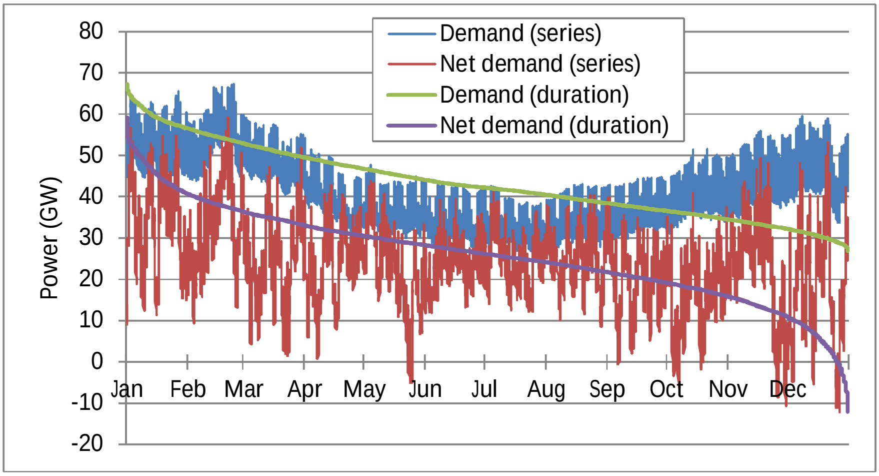

Figure 2. One year of time series for demand (blue) and residual demand (red) for the Nordic countries. The green and purple lines have been sorted in descending order (duration curves). Wind power has been scaled up to cover 40% of the electricity consumption in each country. The data are from 2011. (Finnish energy industries/VTT, Svenska Kraftnät, Energinet.dk, for Norway wind speeds from Rienecker *et al.* 2011 converted to wind generation by the author).

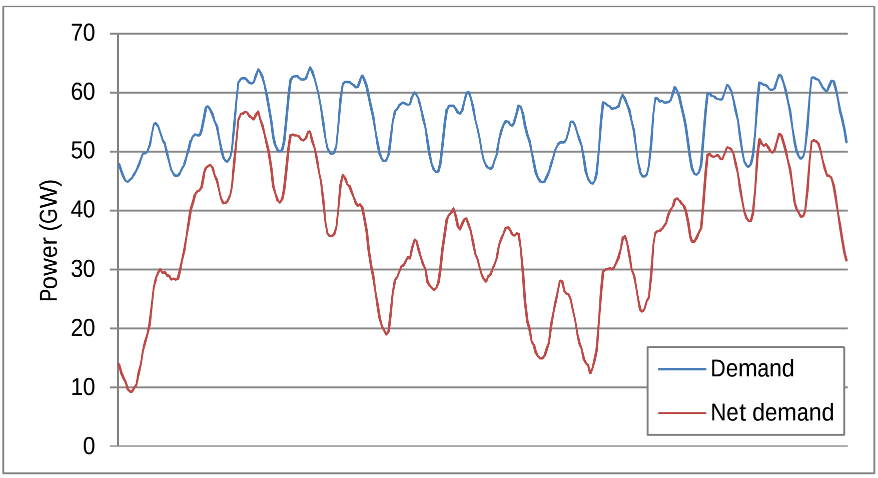

Figure 3. Two weeks of hourly demand (blue) and residual demand (red) for the Nordic countries. Wind power has been scaled up to cover 40% of electricity consumption in each country. The data are from January 2011. (Finnish energy industries/VTT, Svenska Kraftnät, Energinet.dk, for Norway wind speeds from Rienecker *et al.* 2011 converted to wind generation by the author).

The increased variability will increase the benefits of flexibility in new investments. The thesis explores this, especially in Publication IV. On the other hand, variability does not necessarily require many changes to the current practice in the upkeep of the short-term energy balance. The market rules and grid codes can accommodate variability as long as there are power plants and demand-side resources available that can change their behaviour in relation to wind and demand variability. Uncertainty, on the other hand, could have a much bigger impact on market rules and grid codes, as will be explored in the next two sections.

2.2 Uncertainty due to forecast errors

Just like errors in demand forecast, errors in wind power forecasts after the clearing of the day-ahead market have to be corrected with the help of the intra-day market and the balancing market[2]. The markets pool together balancing resources and should therefore find the least cost solutions to correct the sum of all upward and downward errors. However, individual power producers have an incentive to reduce forecast errors as fewer errors mean lower costs over time. In addition to demand and wind power forecast errors, unexpected power plant failures, run-of-river hydro power, solar power, and wave power create forecast errors.

When the wind power forecast error is in the same direction as the demand forecast error, the need for balancing power will increase. Likewise, when the wind power forecast error is in the opposite direction to the demand forecast error, the need for balancing power will decrease – unless the wind power forecast error is greater than the demand forecast error. In this case, the wind power forecast error first changes the sign of the overall system error and then starts to increase the error in the new direction.

Similarly to variation, as wind power penetration increases, the need for correcting forecast errors increases. At the very high levels of penetration, wind power will dominate the intra-day and the regulation power market because demand is more predictable than wind. The accuracy of the wind forecast is quite dependant on the length of the forecast (Figure 4).

[2] The balancing market is called the joint Nordic regulation market in the Nordic power system.

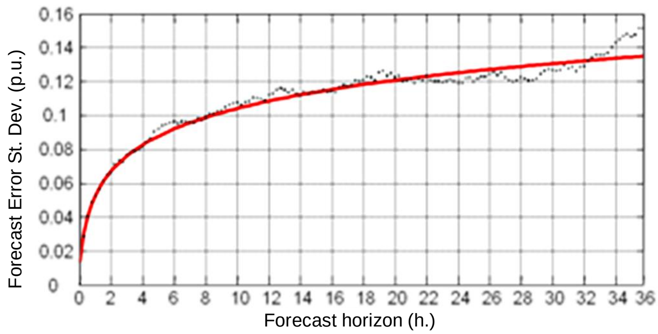

Figure 4. Normalised standard deviation of a wind power forecast error for 12 GW installed capacity versus a forecast horizon (Gibescu *et al.* 2009).

Forecast errors for single wind farms can be quite big. Aggregation of many wind farms over a dispersed area reduces the forecast error, since the correlation of forecast errors typically decreases with distance. The aggregated forecast error of all the wind farms in a power system spanning hundreds of kilometres is therefore much smaller than the forecast errors for individual wind farms (e.g. the st.dev of the forecast error is about half when the region diameter is about 700 km in Giebel 2011). However, the forecast error distributions have thick tails – there are rare occasions when the forecast error is very big (Giebel 2011). These can be challenging for power system operation.

2.3 Power markets and power system operation

In a power system there has to be a balance between demand and generation at all times. The demand for electricity changes according to the needs of the electricity consumers. The balance is maintained mainly by adjusting generation, although some forms of demand can also be adjusted. There are also generation forms that use by-passing energy flows (wind power, run-of-river hydro power and PV). It is usually not worthwhile to adjust these, since it would mean the loss of practically free electricity. An increase in wind power makes it more difficult to maintain the balance, especially if no modifications are made to the way the power system is operated. This thesis explores ways to maintain the balance in a cost-effective manner considering mainly timescales of one hour and higher.

In market-based power systems, the short-term energy balance is achieved through a combination of markets and reserves. As the cases analysed in this thesis are from the Nordic power system, it is used as an example power system in the next paragraphs; other market-based power systems often have similar conventions. The models used in the dissertation try to approximate the Nordic market structure. The operational model (WILMAR) minimises the operational costs of the system, which should lead to the same end result as markets, if the markets are perfectly competitive and all market players have the same information.

The long-term capacity adequacy is maintained through investments in generation capacity while interties, load shedding and demand response may also contribute. The Nordic power market is an energy-only market and hence there are no direct payments for capacity. In an energy-only market, the revenue to justify investments in peak load power plants should come from energy and ancillary service markets through scarcity pricing (Hogan 2005). The generation planning model (Balmorel) used in the thesis minimises the total system costs. The resulting generation portfolio is likely to differ from a portfolio developed by market actors. Investors will consider risks and expected profits.

Starting from investments, Figure 5 shows the timeline of decisions in power system planning and operations, which will be explained below.

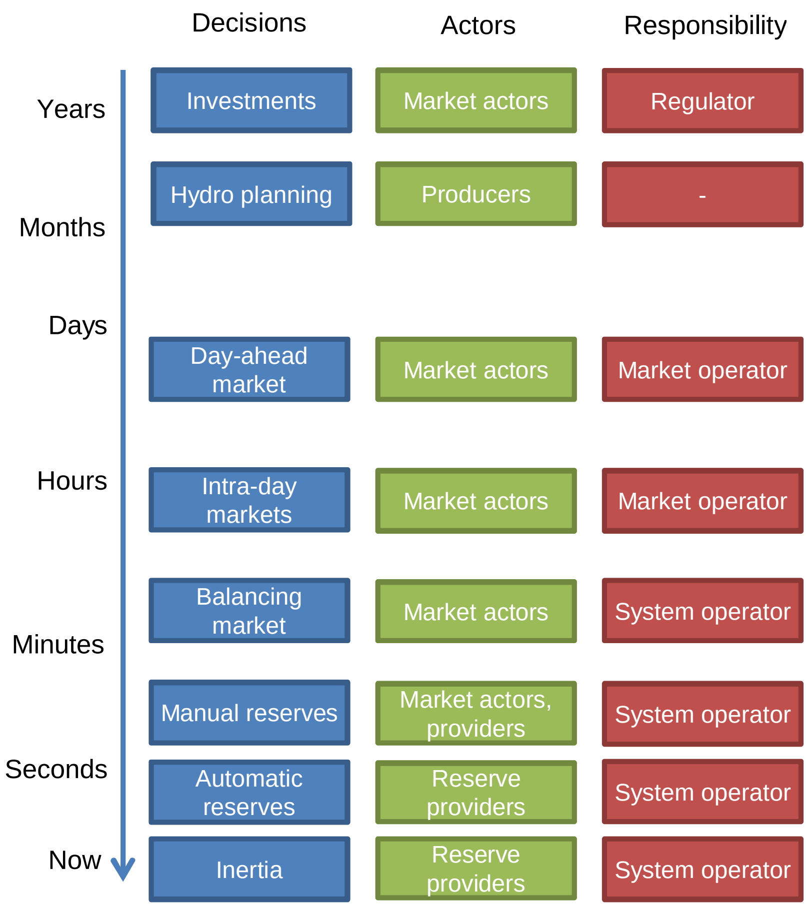

Figure 5. A timeline of decisions affecting generation in power system planning and operations.

The use of reservoir hydro power and other resource-constrained generation forms needs to be planned with a longer term view (from days to years). The value of water in hydro reservoirs is related to the expected revenue from future sales in the hydro plants downstream of the reservoir. The expected sales price depends on the operational costs of generation that hydro generation is likely to replace. The WILMAR model includes a separate model to estimate the water value. In some of the model runs, WILMAR was forced to stay close to the historical water levels because the water value model led to excessive hydro spillage. Balmorel was optimised with a whole year at a time while the end level for the reservoir content was forced.

At the hourly level, the balance between generation and demand was found by using bids made to electricity markets. Hourly electricity markets consist of day-ahead market (ElSpot in Nord Pool ASA), intra-day market (ElBas) as well as over-the-counter (OTC) trades. ElSpot takes place 12–36 hours before the hour of delivery. ElBas closes one hour before delivery, which allows market participants to react to changes that have taken place after ElSpot has closed. The trading volumes in ElBas are small in comparison with ElSpot and hence there is less liquidity. The WILMAR model simulates the ElSpot market solution and approximates the ElBas market together with the Nordic regulation market, as explained in the next paragraph.

During the hour of operation, the electricity demand is not exactly the same as that predicted by the markets before they closed. A further complication is that the demand varies within the hour. Power plants can also fail to generate what they bid due to unavailability of the plant or forecast errors in the energy resource such as wind. The resulting deviation between generation and demand are eliminated by a system consisting of a joint Nordic regulation market, manual reserves and automatic reserves. The Nordic regulation market is the primary source for balancing. The power plant owners make bids to the regulation market before the hour of operation. The Nordic regulation market should not be confused with automatic regulation used in some other power systems.

Frequency deviations within the normal operating range (49.9–50.1 Hz) are first corrected by governor action in power plants in which power plant speed governors sense the frequency and automatically adjust the power output to increase or decrease the frequency. In the Nordic system, this automatic reserve is called the frequency-controlled normal operation reserve, and the responsibility is divided between the different subsystems (Nordel 2007).

If deviations stack up in one direction, the automatic capacity could run out. To avoid this, the system responsible calls power plants from the joint Nordic regulation market to relieve the automatic units. The balancing units have to deliver in 15 minutes.

In addition to the operational reserves, upward disturbance reserves are maintained to ensure a secure system during faults. A frequency-controlled disturbance reserve is automatically activated if the frequency drops below 49.9 Hz and it should be completely activated if the frequency goes down to 49.5 Hz. It consists of power plants and load shedding. In contrast, fast active disturbance reserves are activated manually. They are used to restore the frequency-controlled disturbance reserves. The reserve consists of the transmission system operator's own power plants, contracted power plants, load shedding, the Russian DC link and voluntary bids from the regulation market. The distinction between operational and disturbance reserves is a matter of convention and does not exist in all power systems. Only the capacity procurement for the reserves was included in the WILMAR and Balmorel models.

In the upkeep of the balance as well as the procurement of the reserves it is necessary to take transfer restrictions in the power grid into account. Any foreseeable change in demand or generation cannot be allowed to overload any part of the transmission system. This has to be taken into account by enforcing constraints on the market-based unit dispatch or by using power plants out of the merit order during the operational phase. Only net transfer capacities were used in the model runs for the thesis articles.

2.4 Impact of wind power on generation investments

Thermal power plants, especially intermediate power plants, will have fewer full load hours per year when wind generation replaces thermal generation. At higher wind power penetration levels (tens of per cent of annual energy; depending on the specific power system), the generation from baseload power plants will also be replaced. If the increasing share of wind power is predicted well before it happens, the power generation fleet should change to contain more flexible intermediate and peak load thermal power plants. This is a response to the change in the residual demand duration curve (Figure 2 green and purple lines) as well as increased variability (Figure 2 blue and red lines) and uncertainty. In terms of power plant flexibility, the turn-down ratio is especially important as units that can operate at a low minimum load factor can avoid extra starts and stops (Shortt *et al.* 2013). As peak power plants replace more expensive capacity, the total investment costs in power plants, excluding wind power investments, are reduced.

However, the rise of wind power has been fast and for the most part underpredicted. The result has been more intermediate and/or baseload capacity than would be necessary – at least in the short term (for current capacity adequacy in Europe see ENTSO-E 2012). These stranded investments are a cost factor from the system perspective but have not been analysed in this thesis.

There is also on-going discussion on whether there is sufficient incentive to build enough peak load capacity in the future, partially due to the increasing revenue uncertainty caused by the growing share of variable renewables (Milligan *et al.* 2012). This work assumes that enough capacity is built.

2.5 Rationale for high penetration levels of wind power

The costs of variability and prediction errors per produced wind power MWh rise as the penetration of wind power increases. It therefore becomes more and more relevant to find ways to reduce these costs as the penetration increases. Whereas most studies have analysed penetration levels that could be possible in the short term, some of the studies in this dissertation look at penetration levels up to 60–70% of the produced electricity. There are a couple of reasons for looking at such high penetrations.

First, the competitiveness of wind power relative to conventional power generation could continue to improve and hence very high wind penetration levels are feasible. Although the wind power cost development experienced an upward bump due to high commodity prices and a seller's market for turbines during 2005–2008 (Milborrow 2009), the turbine prices have returned to lower levels. At the same time new turbine models have increased the yield per invested euro. More importantly for the long term, much development is going on and new technologies are being tried out in the turbines. More cost-effective solutions are likely to be found, although it is impossible to predict how much more (a stochastic approach has been taken in Cohen *et al.* 2008). Meanwhile, competing technologies have seen cost increases due to commodity and fuel price rises. The impact of carbon pricing will further increase the cost for some of the competitors.

It is possible that wind or some other form of variable power will emerge as the lowest cost option for generating electricity in a large part of the world. If this is reached, two wind power cost components will determine the optimal wind penetration in the system. First, as more wind power is built, inferior sites will have to be used for power generation. Second, the costs of integrating variable and partly predictable generation increase with penetration. In many regions of the world, wind resources are more than adequate to provide all the energy at a reasonable cost, as demonstrated by the global wind resource assessment made in Publication I. The competitiveness of wind power and the vastness of the resource can lead to very high penetration levels in the future. At these levels, the integration costs become increasingly important.

Second, there have not been many studies looking at higher levels of penetration and there is a need to understand how the costs and benefits will change. There are indications that levels above 50% energy penetration are possible (Burges *et al.* 2008). While each power system is different, in the Irish case it appears that at approximately 40% penetration, the grid would have required a redesign instead of reinforcements (Nedic *et al.* 2008, p. 13). The estimate of the total societal costs for an Irish scenario with 42% of electricity made with renewables was 7% higher than the costs for the base case, which had 16% renewable electricity (Burges *et al.* 2008, p. 74).

Third, the benefits of increased power system flexibility will only be more visible if the penetration is high. Studying low penetration levels would not yield information that was as useful. However, not all scenarios in the dissertation have high penetration. The lower penetration cases improve understanding and often serve as benchmarks for comparisons.

Fourth, climate change mitigation will require radical reductions of greenhouse gases from energy production. Energy efficiency improvements alone will not be enough, especially since global energy consumption is expected to increase (IEA/OECD 2012). The reductions can be achieved either by relying heavily on renewables, nuclear power, carbon capture and storage (CCS), or on a combination of these. CCS will increase the cost of fossil fuel-based electricity considerably, which will make wind power more competitive. Furthermore, CCS technology will only reduce CO_2 emissions of coal- or natural gas-based electricity by 80–90% (IPCC 2005), which may not be enough if GHG emissions need to be reduced by 50–80% by 2050 (compared with 2000) to reach an estimated global average temperature rise of 2.0–2.4 ºC (IPCC AR4 WG1 2007). High reliance on nuclear power will also require flexibility from the system as it is expensive to underutilise high capital cost nuclear power plants. Furthermore, the current nuclear fuel cycle would threaten the known and expected uranium resources (IEA/OECD 2008), if nuclear power is one of the main components of low-carbon energy generation in a world with much greater electricity consumption. Other fuel cycles are still economically unproven. Due to uncertainties in all of the options, it is reasonable to try out ways to cover large portions of electricity and energy demand with variable renewables. Solar energy has by far the largest potential (Vries *et al.* 2007, Trieb *et al.* 2009), but the resource potential of wind power is also several times higher than current consumption (Publication I).

2.6 Summary of the research gaps and dissertation contribution

There is not very much literature on the analysis of the flexibility potential of thermal power plants (Section 3.1). This is a clear research gap, since thermal power plants are the prime source of flexibility for most existing power systems. In section 5.1, the dissertation synthesis therefore extracts results concerning thermal power plant flexibility from the analyses made for the dissertation.

The flexibility off reservoir hydro power is also understudied compared with its potential (Section 3.2). While work was carried out for a better understanding of hydro power flexibility during the dissertation, it also became clear that it is a very complex issue and therefore requires a more concentrated effort to yield robust economic results. Those analyses were therefore left out of the dissertation.

Electricity storage could in theory solve all the problems related to variability and forecast errors of wind power. However, as will be demonstrated in Section 3.3, the economics are quite challenging. Pumped hydro and CAES at some locations could be feasible even today, but site-independent solutions will require considerable technological progress. This area was therefore not analysed further in the dissertation.

Demand response has considerable potential (Section 3.4) to level out fluctuations from large-scale wind power schemes. There is some literature on this topic as will be shown in Section 3.4, but comprehensive approaches to DR and wind power are still missing. Incorporating DR into large-scale energy models is highly challenging, since it can come in so many forms and have various constraints. In the dissertation, electric vehicles, which are a well defined subset of DR, were analysed in detail. The existing research when starting the thesis work had not captured all of the most important economic factors of charging and discharging electric vehicles with a consistent approach (Section 3.5). Deficiencies included assumptions of static market prices, a lack of a cost benefit analysis and missing the impact of electric vehicles on the generation investments. The dissertation developed and used an approach in which a generation planning model was combined with a unit commitment and dispatch model to include these aspects in a single analysis.

There was negligible literature on exploiting heat production and heat use to increase power system flexibility (Section 3.6). The existing literature published before the analysis of the dissertation had not used a power system perspective in estimating the benefits and did not in most cases consider the increased variability of wind power. This was a clear gap and the dissertation has made an early contribution to filling this gap.

Super grids can smooth wind power variability by combining wind generation from a geographically larger area. A few attempts to tackle this question were found, but with some limitations: the lack of a cost analysis, data issues, no transmission constraints, small system size and limitations on available generation options (Section 3.7). A first order estimate was therefore made for this dissertation to take these into account (Kiviluoma and Lu 2010). However, the methodology used was rough and therefore not included in this thesis. A robust methodology would require a huge effort as in the recent work by the NREL (2012) for North America.

The literature on wind power integration from the methodological perspective is surveyed in Section 3.8. It can be concluded from the review that the methodologies developed and used in this study are advanced compared with the literature.

3. Review of power system flexibility

Energy systems have been studied extensively at different levels. Since variability of wind power is a key issue in the analysis of cost-effective ways to increase power system flexibility, this review will focus on articles that have used methodologies that deal with variability. Several energy system models do not have a chronological representation of demand and generation patterns and consequently cannot treat variable generation in a realistic manner (Shortt *et al.* 2013). Studies that have not considered uncertainty can still be relevant to the analysis of flexibility as long as they have considered the chronology of demand and wind power.

As a result of the expected large share of wind power in several power systems, many studies have been made to analyse the effects of high wind power penetrations (reviews in Holttinen *et al.* 2012, IPCC 2011 Section 8.2.1). This review focuses on studies that assess energy penetration greater than 20%, as the dissertation focuses on higher penetrations. Some studies do not reveal the penetration level or are methodologically important to review, and these are hence included.

As the costs due to variability and prediction errors grow, it becomes more economical to use different methods to increase power system flexibility to decrease these costs. This makes the analysis of very large wind power penetrations difficult for two reasons. First, there is no good understanding of the relative merits of different flexibility options. Second, there is a lack of tools to conduct the analysis. These issues stand out in the existing literature.

Some of the options to reduce the costs of wind power variability and prediction errors have received much attention and some very little. Since one dissertation cannot cover all the options in detail, the literature review is used to select options that seem promising and have received little attention.

3.1 Thermal power plants

It is often assumed that large-scale variable electricity generation will require technology that currently does not exist before it can be accommodated in the power system (discussed in Milligan *et al.* 2009). However, most thermal power plants have always adjusted their operations to changes in demand. With wind power in the system they need to adjust operation to changes in the residual demand. Due to the greater variability in the residual demand, conventional power plants will experience more shut-downs, part-load operation and steeper ramps, but it is not clear that new, currently non-existent, technologies are required even at high wind power penetrations. To study this, a power system with thermal power plants as a benchmark can be used with which new flexibility-providing technologies are compared in order to see whether they benefit the system.

The analysis of flexibility from thermal power plants is usually implicitly assumed in wind power integration studies (see Section 3.8). Hence there are few studies that specifically address this issue. This section reviews studies in which the flexibility of thermal power plants is assessed, as they provide more details on the issues of start-ups, part-load operation and steeper ramps.

Troy *et al.* (2010) demonstrate that the impact of wind variability and uncertainty on thermal power plants is dependent on the characteristics of thermal power plants. Part-load efficiencies, in particular, but also minimum down times, start-up costs, and the capability to provide primary reserves mean that inflexible coal units are preferred over combined cycle gas turbines (CCGTs) at high wind penetration levels. However, Troy and O'Malley (2012) show that adding an open cycle gas turbine (OCGT) mode capability to a CCGT plant changes this behaviour and reduces the use of coal units in the Irish power system. In Troy *et al.* (2010) the effect of electricity storage was also evaluated and, similarly, it had a remarkable effect on the utilisation of different plant types. The results indicate that the relations between wind power and thermal power plant types are complex and sensitive to power plant characteristics. They also mean that the development of new kinds of thermal power plants for high wind power penetration systems could yield considerable operational savings as well as reductions in CO_2 emissions.

Corbus *et al.* (2010) studied wind integration in the power system of the Hawaiian Islands from both perspectives: the unit commitment and dispatch as well as dynamic stability. While the system is small and has characteristics not present in larger systems, the study provided an interesting insight. The flexibility of existing conventional generators was put to the test and an upgrade programme was performed. Initial results indicated enhancements in the ramp rates and the possibility of a reduced minimum load factor.

3.2 Reservoir hydro power

There appear to be very few studies that analyse the capabilities of reservoir hydro power for large-scale wind power integration, despite the apparent cost-effectiveness of the technology. Several studies have co-optimised the operation of one wind power plant and one hydro power plant, but this is only interesting if they are behind the same grid connection bottleneck and in some specific market designs (e.g. Zima-Bočkarjova *et al.* 2010). These are not included in this review as the perspective is on optimising the whole power system. One reason for the lack of studies is probably the distinctiveness of hydro power systems.

Even if the actual characteristics differ, there are common features shared by the hydro power plants: reservoir size, plant capacity, design flow and head height. On the contrary, the inflow patterns can have a large variance between hydro power systems. The variance in efficiency is much lower as most hydro power plants reach very high efficiencies. Reservoir hydro power plants are often part of a larger river system with upstream and downstream reservoirs and hydro power plants. The interaction of these creates specific complexities, including time of use constraints and optimal utilisation of reservoir level changes, which are affected by inflows from upstream. Most hydro power systems have constraints regarding minimum and maximum flows that are based on environmental concerns.

While the differences limit the applicability of specific results, it is still interesting to ask how reservoir hydro power affects the economics of integrating variable power generation. While it is certainly an important question for the owners of hydro power assets, the literature only had a few answers to the question. Millham (1985) evaluated the capability of the Columbia-Snake river hydro power system to smooth monthly variations in wind generation during a critical period of low flows. The results suggested that the wind power capacity that could be firmed was clearly lower than the available hydro power capacity. Løvseth (1995) suggests that Norwegian hydro power would be a good match to balance variations in Norwegian wind power, but the analysis is on monthly scale.

Kiviluoma *et al.* (2006) estimated the energy balancing potential of Nordic hydro power based on river system data. The share of run-of-river hydro power was small, less than 10% of the total generation. Most Nordic hydro power capacity has upstream reservoirs and, on average, the reservoirs are large. In Norway, the average reservoir can hold water for nearly a year's worth of generation and is a short distance from the hydro power station. Swedish reservoirs are smaller and the average time lag from the reservoir to the hydro power station is longer. The results imply that there is a large amount of untapped flexibility potential in the Nordic hydro systems, but their value was not quantified in economic terms. However, the constructed data were used to increase the accuracy of the Nordic hydro power modelling in WILMAR.

Kiviluoma and Holttinen (2006) presented results on the energy balancing of large-scale wind power in the Nordic power system with Germany included in the model. The results were somewhat obscured since the modelling of hydro power was too flexible compared with reality. Given this, there were no energy balancing problems even when wind power served 30% of the annual electricity consumption. The modelling approach does not cover all timescales and it does not include security-constrained power flows, so the conclusion is hypothetical. Market prices were strongly affected since the system had very little thermal generation other than nuclear power.

In a more recent development, the tools to analyse hydro and wind power in large systems have received attention. Dennis *et al.* (2011) presented two methods to simplify the modelling of large-scale hydro power in a production cost model PROMOD used in the Western Interconnect of USA. Rinne (2011) has improved the estimation of water value in WILMAR.

3.3 Electricity storage

Electricity storage options to mitigate wind variability have received considerable attention. As there are many different options, it is prudent first to understand their possible benefits and drawbacks for large-scale wind power integration. When the variation in electricity demand is combined with the variation in very large-scale wind power, the resulting residual demand exhibits cycles that have a time range from one to several days. The weather patterns that create the variations in large-scale wind power generation usually take days to pass over a region. This means that electricity storage acting in such an environment could expect roughly 50–250 full cycles per year. The relatively low number of full cycles promotes forms of storage that can achieve a low MWh cost.

The large range (50–250 full cycles) is partly dependent on the cycling efficiency of the storage. Low round-trip efficiency means that only big differences in electricity costs will be worth smoothing. High cost differences occur more seldom than low cost differences. Low-efficiency storage will therefore receive considerably fewer full cycles than high-efficiency storage. Variable operation and maintenance (O&M) costs will also reduce the possible full cycles per year, as variable O&M costs will increase the arbitrage range further.

The cost per MW is another factor, but for most storage types it is not binding. Large-scale energy storage often leads to large power capacity by default. However, notable exceptions include CAES (Compressed Air Energy Storage) and pumped hydro, for which the investment in MW is separate from the investment in MWh. For these technologies, the cost per MW dominates the cost calculation. It is problematic to compare technologies over such distinctions.

The prime electricity storage option is pumped hydro plants. However, their economics are very site dependent and the resource is limited to locations where upper and lower reservoirs are available. The relatively high penetration of variable renewables in the Iberian and Irish power systems has already prompted pumped hydro investments and investment plans.

Denholm *et al.* (2010) articulated further arguments why reliable cost comparisons between storage technologies are not available. Efficiency calculations are often based on different principles. Additionally, most storage technologies are not yet in mass production, and changes in market prices from year to year are high, which makes the comparison even more difficult.

Albeit that the actual investment costs are uncertain, it is still possible to assess the upper limits that the investment costs of different technologies should undercut to be viable. This is done by first calculating the nominal value of the annual sales profit from a set of optimistic assumptions:

$$\left(\mathrm{p_{sale}} - \frac{\mathrm{p_{purchase}}}{\eta}\right) \times \mathrm{c} \times \mathrm{t}, \text{ where} \qquad (1)$$

$\mathrm{p_{sale}}$ is the average selling price (80 €/MWh)

$p_{purchase}$ is the average purchase price (30 €/MWh)
η is the cycle efficiency
c is the number of full cycles per year (250)
t is the length of full discharge in hours (8 h).

The present value of sales is calculated from the nominal values, assuming the lifetime from Table 1 and an 8% interest rate. The present value of sales should be at least the same as the investment cost for storage to be profitable. For pumped hydro and CAES, the target investment cost is expressed in €/kW because that is their main cost component. However, they have an additional cost based on €/kWh of storage (see Table 1). For battery technologies, the target investment cost is in €/kWh of storage, and it is assumed that there is no separate cost to obtain enough charge/discharge capacity. The resulting target costs are presented in Table 1.

Table 1. A target cost below which different storage technologies may become feasible using optimistic assumptions. For pumped hydro and CAES, the target cost (in bold) is in €/kW and for the others it is in €/kWh.

	Target cost				depth of
	€/kW	€/kWh	eff.	lifetime	disch.
Pumped hydro	**1024**	10	0.8	100	1
CAES	**750**	50	0.85	60	1
Flow battery	0	**104**	0.85	40	0.75
Metal-air	0	**9**	0.5	2	1
Regenerative fuel cell	0	**102**	0.75	20	1
Lead acid	0	**53**	0.85	8	0.8
NaS	0	**81**	0.89	10	1
Lithium Ion	0	**78**	0.99	12	0.8

When the target costs are compared with the cost estimates in the literature (Ibrahim *et al.* 2008, Schoenung 2011, Divya and Ostergaard 2009 for batteries, Deane *et al.* 2010 for pumped hydro power), only pumped hydro and CAES appear to be economically feasible. These are scrutinised in the literature review. For other options, technological progress and mass production may reduce costs to a profitable level, but with the current data that would be speculative, and the effort is targeted at pumped hydro and CAES. It should also be noted that further income could be gained from reserve or capacity markets, but in case there is a large-scale implementation of storage, these markets would probably be saturated by electricity storages with low variable costs and the prices would collapse (Publication IV).

A large portion of the electrical storage studies analyse situations in which storage would be connected to the operation of a single wind power plant and their operation co-optimised in relation to the electricity price (c.f. Garcia-Gonzalez *et* *al.* 2008, review of hydro storage in Matevosyan 2008, Costa *et al.* 2008, Faias *et al.* 2008, Bakos 2002, Castronuovo & Lopes 2004, Korpås & Holen 2006; Greenblatt *et al.* 2007, Denholm 2006). This can smoothen the output of single wind power plants, but it is not a cost-effective approach unless there are immediate transmission restrictions and, even then, it is not certain (Denholm and Sioshansi 2009). The outputs of multiple wind power plants at different locations smoothen each other and only the aggregate output of all the wind power in a given region is of concern to the economic operation of the rest of the power system.

If the wind power plant and the electricity storage are in the same grid and there are no transmission constraints, the respective investment decisions are two separate decisions. Even if the two plants have the same ownership, the optimisation of each should be done in relation to the rest of the system and not each other. Only transaction costs in the market place can make it worthwhile in some, usually rare, situations to change the operational strategy due to common ownership. More importantly, there is no rationale, except to save transaction costs, to link the investments of two different plants. The results by Greiner *et al.* (2008) demonstrate this from the operational perspective.

To investigate properly the benefit of storage, a system-wide model is required in which geographically dispersed wind power generation influences the system operation and market prices. This literature review therefore concentrates on studies that have a system perspective.

Black *et al.* (2005) calculated the value of storage in a high wind power penetration system. They found that the value was very dependent on the existing flexibility of the system. The results indicate that only in low flexibility systems might investment in storage be feasible.

Swider (2007) includes endogenous investments in the model and finds that CAES takes a portion of the newly invested capacity by replacing part of the new gas turbine capacity. The applied assumptions lead to investment in CAES even without large wind power penetration. In the highest wind power scenario with just over 20% from wind, wind power increases CAES investments. However, other options than CAES and conventional power plants were not available to increase system flexibility.

Benitez *et al.* (2008) have analysed the benefit of pumped hydro power in Alberta with medium and high wind scenarios. They assume that wind power will replace existing baseload coal condensing generation units of similar energy output. However, it is very unlikely that it would be cost optimal to replace only coal condensing (Publication IV, Swider 2007). The study has assumed that wind power has investment costs while the coal condensing that the wind power replaces does not have any investment costs. In other words, it is assumed that the baseload coal condensing units disappear when wind power is connected to the system and, at the same time, new peak capacity has to be built. In effect, the investment costs of stranded units have been included in the wind power integration cost.

Ummels *et al.* (2008) have made a cost-benefit comparison of CCGT, pumped hydro, underground pumped hydro, CAES and natural gas heat boilers as means to reduce the operational costs of the system at different levels of wind power penetration. Natural gas heat boilers would increase power system flexibility since they would be built in locations with existing inflexible CHP generation. Heat boilers would enable a reduction in CHP electricity generation at times of low residual demand. Their approach suffers from the assumption that pumped hydro or CAES would avoid investments in CCGT only. This decision should be subjected to cost optimisation. Their largest wind power scenario would cover about 27% of the electricity demand. The most profitable flexibility at that wind penetration level comes from natural gas heat boilers. CAES would also have been cost-effective at higher wind penetration levels – at least if heat boilers were not an option. The results also show that electricity storage can increase CO_2 emissions, as it increases the use of baseload units, which often use coal as a fuel.

Lund and Salgi (2009) estimated the operational benefits of CAES in the Danish system with 59% of demand covered by wind power, and they found that in energy arbitrage, CAES would not even be close to profitable. The results from an undocumented analysis showed that electric heaters and electric heat pumps in district heating systems were a much better investment to increase system flexibility.

Thermal electricity storage has also been proposed either as an extension of CAES (AA-CAES) or as a stand-alone concept (Desrues *et al.* 2010). The analysis builds a technical model and does not assess economic aspects.

Göransson and Johnsson (2011) evaluate the possibilities of reducing thermal power plant cycling with storage. While the storage is able to reduce power plant emissions due to cycling, it does not appear to be economical even at a relatively high wind power penetration level.

3.4 Demand response and demand-side management

Demand-side management (DSM) refers to attempts to modify electricity usage patterns through utility programmes. Demand response (DR) is the fast response of dedicated demands if the value of electricity becomes too high. From the perspective of wind power integration and increasing system flexibility, DR offers the most interesting prospects. DR can usually be very fast to react, which means that it can be used for a wide variety of system services starting from spinning reserves all the way to long-term capacity adequacy. Kazerooni and Mutale (2010) have even assessed the value of DR for avoiding transmission investments due to wind power.

Faruqui and Sergici (2010) have surveyed 15 DR experiments in which household electricity customers have received some form of compensation for reducing demand (including time-of-use pricing and critical-peak pricing). The average reduction in loads during peak demand periods varied considerably. Time-of-use pricing resulted in modest reductions of 3–6% while critical-peak pricing had a much higher effect of 13–20%. Enabling technologies, such as programmable, communicating thermostats and always-on gateway systems that controlled multiple end-uses remotely, increased the reductions considerably for both compensation schemes (raising the reduction to 21–36% and 27–44% respectively). Empirical results from on-going DR programmes in the U.S. have achieved levels of 3–

9% of potential reduction in peak demand (Cappers *et al.* 2010). This includes industrial DR as well as household DR. While these results cannot be directly applied to the residual demand variations with large-scale wind power, it is apparent that DR offers considerable potential for increased flexibility. Widergren (2009) also points out that aggregating DR from households will include significant uncertainties in terms of actual delivery. These have to be understood and addressed.

Klobasa (2010) has evaluated that the DR potential in Germany could be more than 30 GW, although a major portion (20 GW) would not be available outside the heating season. The article also explored that the DR would enable the system to cost-effectively balance 48 GW of wind power in the system. The wind power balancing costs were estimated to be about 1 €/MWh lower with DR, which was translated to allow 10–20 €/kW/year activation cost for DR.

Stadler (2008) has analysed possibilities for DSM in the household sector. The analysis concentrates on ventilation systems, refrigeration and water heating. Stadler concludes that storing heat in different applications offers a large potential for integrating variable renewables. However, the results lack an economic component.

Paulus and Borggrefe (2011) analyse the technical and economic potential of DR from energy-intensive industries in Germany. Variable costs from these resources are high, which means that they cannot be used very often for energy balancing. However, they can supplant a considerable amount of investment in peak generation capacity, which will reduce the integration costs of variable generation.

Finn *et al.* (2010) have analysed how domestic hot water heating cylinders could offer DR for price changes anticipated in the electricity market. This was inspected in relation to the anticipated significant wind power penetration in Ireland. While the example demonstrated increased flexibility, especially with well-insulated hot water cylinders, the possible impact of large-scale use of DR was not studied.

Moura and Almeida (2010) analyse how DSM and DR could decrease the peak demand in Portugal. Peak demand situations are especially relevant for wind power in Portugal as wind power generation is usually low at those times. However, the DSM loads in the article were not price sensitive and therefore of limited applicability to wind power integration.

Hamidi *et al.* (2008) present a case using the IEEE standard 30-bus test system. Two wind farms are connected to the system and the effects of multi-tariff rates and DR are investigated. DR is assumed to respond to variations in wind power output. DR appears to offer significant savings in the system operation and increase the value of wind power. However, it is unclear whether wind power forecast errors have been considered or what system services the wind farms are capable of providing.

Short *et al.* (2007) demonstrate the effects of the response by millions of household refrigerators and freezers to frequency signals. These are able to keep the system frequency more stable than a conventional spinning reserve. The effect is especially pronounced with higher shares of wind generation. However, the minute-to-minute variations in wind power generation that they have applied (max change -5.8%) are unrealistically high in comparison with empirical data (c.f. Wan 2005, where max is -2.7%).

Troncoso and Newborough (2010) suggest the use of hydrogen electrolysers to create flexible demand. They use an example of an isolated system for which they aim is to smooth the output from wind so that a thermal power plant can operate almost continually. However, the approach tries to maximise the use of electrolysers and minimise the carbon intensity of electricity generation instead of minimising the system costs.

Understandably, DSM and DR include a very diverse set of possible actions, which further vary between countries. From the system perspective, a specific DSM and DR action should be invested in only when it creates more benefits than costs. As the costs are application specific, it is far easier to analyse the possible benefits of different types of DSM or DR. For example, it would be interesting to calculate the benefit of increasing the amount of DR for several wind power penetration levels. In literature, such analysis seems to be lacking. While such analysis would have matched the intentions of this dissertation well, it was left to future work except for the analysis of electric vehicles.

3.5 Electric vehicles

Electric vehicles can increase the power system flexibility in two ways. First, with smart charging, the charging would occur during hours with low electricity prices, if possible. Second, vehicle-to-grid (V2G) would enable discharging of the batteries to the grid during hours of high prices. An analysis of electric vehicle impacts should consider a charging pattern based on driving profiles, and the effect of electric vehicles on market prices and system costs as well as on CO_2 emissions, and preferably the impact of electric vehicles on generation investments.

There have been several publications about the possible benefits of the participation of electric vehicles in the electricity markets. Kempton and Letendre (1997), Kempton and Tomic (2005), Tomic and Kempton (2007), and Williams (2007) represent calculations of the possible benefits of using electric vehicles and fuel cell vehicles as a new power source in which the authors use power market prices as a reference. Several vehicle setups and electricity markets are analysed. Blumsack *et al.* (2008) assume simple night time charging and use marginal CO_2 emissions based on the current merit order for three regions in the U.S. This static approach does not take into account the pressure to reduce emissions in the future and the possibilities of smart charging to enable further emission reductions. Similarly, Camus *et al.* (2009) assume that off-peak baseload electricity will mainly be used to charge plug-in hybrid electric vehicles (PHEVs).

Hadley (2006) and Hadley and Tsvetkova (2007) use a dispatch model to estimate the cost of charging PHEVs. The generation portfolio is taken from an external estimate and is not influenced by the introduction of flexible demand from PHEVs. The PHEVs are dispatched according to a pre-set schedule, and no vehicle-to-grid (V2G) is considered.

Shortt and O'Malley (2009) consider the effect of electric vehicles on future generation portfolios and use a simplified model to dispatch electric vehicles on top of the demand profile. V2G, or the use of electric vehicles as reserves, was not considered. Short and Denholm (2006) estimated the effect of PHEVs on future generation portfolios, and Denholm and Short (2006) analysed how dispatch might be affected. Costs and benefits were not analysed. Juul and Meibom (2011) are the only ones so far who include endogenous investments in the transport sector as well as in power generation. Investments in PHEVs trigger investments in wind power that more than offset the electricity consumption of PHEVs.

Sioshansi and Denholm (2010) applied a unit commitment model to analyse the impacts of electric vehicles. The method uses measured driving profiles and includes a piecewise approximation of depth of discharge costs. The article indicates the saturation of a spinning reserve market with an increasing share of electric vehicles. The results are in line with the dissertation articles.

Peterson *et al.* (2010b) calculate the costs and benefits of peak shaving with the vehicle batteries. The analysis is based on historical market prices. McCarthy and Yang (2010) simulated the effect of the electricity demand due to electric vehicles on CO_2 emissions. The results were based on the assumption that the emissions of the marginal power plants would be allocated to electric vehicles. Marano and Rizzoni (2008) analyse the effects of PHEVs on the household electricity bill based on end-user rates in combination with household-scale wind power or solar PV generation and thus do not have a systems perspective.

Lund and Kempton (2008) analysed the effect of smart electric vehicles on integrating variable wind power. While the article has results on CO_2 emissions, it does not include costs and benefits. The EnergyPLAN simulation tool included a simplified presentation of electric vehicles.

3.6 Heat storage

Literature on the use of heat storage to mitigate wind variability and prediction errors is sparse. This is surprising as heat storage is one of the least expensive methods to increase power system flexibility. It is clearly a good area for further research and has been one of the main areas in the dissertation.

Early work on heat storage includes Margen's (1986) analysis for both short-term and seasonal thermal energy storage. The analysis concludes that short-term storage is attractive for extending the use of heat boilers intended for base or intermediate heat loads. It can also work economically with a back-pressure CHP unit to increase electricity generation during high prices and decrease it during lower prices. Seasonal use of heat storage was much more sensitive to the fuel price assumptions. While the benefits of increasing power system flexibility were not specifically addressed, the results can be inferred to indicate that heat storage could be useful for integrating large amounts of variable power generation.

Hughes (2010) has analysed the operation of heat storage in residential homes when used in conjunction with resistance heaters powered by wind electricity. While the results are interesting, as they show the dynamics of electric heating with storage in a single household, the study does not have a power system perspective.

Callaway (2009) considers the use of temperature-controlled loads (TCL) for regulation, automatic generation control and load following. The analysis changes the temperature set points of large group of TCLs. Changes can be small and still yield large aggregate changes in short-term demand. The approach takes into account the probabilities in the actual response to set point changes, as not all loads will change behaviour due to a small set-point change. The method is tested to smooth short timescale fluctuations of a single wind farm. While this application is not interesting from the system perspective, the methodology for controlling TLCs appears solid. Callaway also refers to other literature on TCL, but this does not specifically analyse the use of TCL in wind integration.

Warmer *et al.* (2006) have studied the balancing of a market participant with wind power in the portfolio using heat pumps and tap water resistance heaters as flexible demand. The setup was able to reduce the balancing error of the market participant, but the monetary benefits were not reported.

Kennedy *et al.* (2009) analyse the use of the residential building thermal mass for storing heat from a heat pump. They implement a price-dependent temperature control that lets the indoor temperature vary between 18 and 22 ºC while minimising the heating costs. A heating cost reduction of 10% is achieved and the correlation with wind power generation is increased.

Pöyry Energy (2010) includes an analysis of flexibility from heat by treating space heating with electricity as movable demand. The report concludes that heat loads can be an important source of flexibility.

3.7 Super grids and variability

Wind power variation decreases as the area increases (Wan 2005, Ernst *et al.* 1999), since wind power generation is mainly caused by weather patterns that have a limited size. There are currently severe restrictions on the possibility of using the smoothing effect, since power flows over continental-scale power grids are limited due to transmission bottlenecks and administrative barriers. Some studies have therefore been conducted to investigate the reductions in the variability of wind power generation if these barriers were to be transcended.

Giebel (2000) investigated Central European-wide wind power generation on an hourly level. Considerable smoothing was demonstrated as well as an estimate for wind power capacity credit. The main limitation of the study is that the model did not include transmission bottlenecks, which is one of the main issues for large-scale integration of wind power (van Hulle 2009). The wind data were based on 28 meteorological sites from Denmark, the UK, Portugal, Spain, the Netherlands, Germany, France, Italy and Greece only. Czisch and Giebel (2000) and Czisch and Ernst (2001) extended the analysed region with ERA-15 data to cover the whole of Europe as well as neighbouring areas.

Czisch and Giebel (2007) presented a paper with cost optimisation for creating an entirely renewable energy system for Europe. Their analysis indicated that it would be cheaper to build a large transmission system to reduce the variability of wind power than to deal with the variability more locally. Their base case with existing technology found a cost-optimal solution with 70% of the electricity coming from wind power and backup from available hydro resources and biomass. Transmission played a big role in smoothing the wind output. When new building of transmission was restricted, the cost of the additional biomass backup required to cope with the increased variation was found to be greater than the cost of transmission. However, only renewable sources of energy were allowed to deal with the variability.

Osborn (2010) presents point-to-point overlays of high voltage direct current (HVDC) lines collecting mainly wind generation from the U.S. Midwest and distributing it to the consumption centres on the East Coast. It is estimated that the overlays would be more economic than reinforcing the AC system.

Rebours *et al.* (2010) stated that the costs of variable generation (presumably additional cost due to variation) were reduced significantly in the scenario with more new transmission lines than in the scenario with fewer new transmission lines. The area under study contained ten western European countries.

Kempton *et al.* (2010) demonstrate the reduction in variability and periods of low-output generation when connecting wind farms along the U.S. East Coast with an HVDC cable.

Kiviluoma and Lu (2010) argue that it is likely to be more economical to tap into good wind resources with a long-distance transmission network than to use poorer wind resource sites closer to consumption. If the cost of high voltage transmission is near the assumed level (600 $/MW/km and 255,000 $/MW for a substation in the scenario with higher transmission costs), the lower cost of wind energy provides enough justification by itself. In addition, there are benefits due to decreased variability, smoother duration curves and less steep system ramp rates.

3.8 System studies with high wind power penetrations

This section takes a look at the existing studies that have analysed high wind power penetration levels (above 20% of electricity). The focus of the review is to analyse what means of flexibility have been taken into account in these studies. The actual results vary between power systems due to differences in the systems and hence are not necessarily comparable with the results in the dissertation.

Purvins *et al.* (2011) review options to manage variability of wind power generation. The article contains examples from literature about the spatial distribution of wind power plants, electricity storage, wind power-induced reserve requirements and the benefit of additional interconnections.

Jonghe *et al.* (2011) present a chronological generation planning model for studying the impacts of variable generation on generation investments. The model is linear and does not include start-up costs. The impact of ramp rate limitations in baseload power plants and pumped hydro on the optimal generation portfolio is examined.

DeCarolis and Keith (2006) analysed the use of five possible wind sites situated very far from a single point of electricity consumption. Wind power generation time series were based on a single up-scaled wind speed ground level measurement, which yields an unrealistically large variation in wind power generation (see Figure 1 of DeCarolis and Keith 2006). The benefits of CAES and hydrogen storage were analysed, but the assumptions reduce the reliability of the results.

The EnergyPLAN model has been used in several high wind power penetration analyses. The model simulates hourly power system operation with aggregated power plants. It uses analytical formulations to simulate the behaviour of power plants, storages and demand-side response (Lund 2011). These can be fast to calculate, but it is unclear how close to optimised solutions the algorithms can get, especially when there are multiple interacting flexibility mechanisms. In Connolly *et al.* (2010), EnergyPLAN is used to estimate a technically optimum wind power penetration level for Ireland, but there are no monetary results. The technical optimum in the article is a theoretical construct, which is not comparable with the more thorough and applied analysis in, e.g., the All Island Grid Study. In Lund and Mathiesen (2009), very large wind penetrations are achieved with power system flexibility from hydrogen generation and biomass CHP plants. However, the results do not reveal the efficiency of these options specifically for integrating variable generation. In another article (Mathiesen & Lund 2009), the same authors compare different ways of facilitating the integration of fluctuating power sources. Their analysis demonstrates that heat storages can have an important impact on power system flexibility. They also show that the use of electrolysers to produce hydrogen for fuel cell vehicles or combined heat and power plants does not appear to be cost competitive with the flexibility mechanisms provided by heat measures and battery electric vehicles.

The All Island Grid Study together with later assignments is the most in-depth analysis of large-scale integration of wind power so far. It includes a search for representative scenarios for power plant portfolios (Doherty 2008, Doherty *et al.* 2006). The approach contains simplified costs for variable generation management and grid expansion as well as a declining capacity factor and capacity value for wind power. The results are based on a large number of optimised power plant portfolios with variations in fuel prices and power plant options. The weakness of the approach is the lack of chronology in the optimisation model. However, it was only used to create portfolios for the later studies that were chronological and included, e.g., start-up costs and power flow constraints.

Meibom *et al.* (2007) analysed the scenarios from Doherty (2008) in the unit commitment model WILMAR. The model has been used in this dissertation and is described later. At the same time, a grid study (Nedic *et al.* 2008) was made in order to analyse the feasibility of challenging situations based on Meibom *et al.* (2007). The scenario with the highest wind power penetration was not feasible due to the extreme situations in which the demand and reserve requirements could not be met (Nedic *et al.* 2008). A system redesign would have been required. The

WILMAR results indicated reasonable operational costs even with high wind power penetrations. This was the case even though sources of flexibility were limited to conventional power plants. Tuohy *et al.* (2009) continued the analysis by looking at the benefits of stochastic unit commitment optimisation as enabled by WILMAR as well as the benefits of more frequent commitments. The inclusion of uncertainty led to more optimal results and better performing schedules. The article also contains a good description of equations used in the WILMAR model.

A study using Balmorel by Karlsson and Meibom (2008) demonstrated that it could be economically optimal to provide a major share of electricity, district heating and transport sector energy requirements from renewable energy if hydrogen were assumed to be the main fuel in the transport sector. The result is naturally dependent on the assumptions about the investment and operational costs for different technologies. Hydrogen acted as a buffer to incorporate fluctuations, especially in wind generation.

The dissertation of Ummels (2009) analysed wind integration with two models: a unit commitment and dispatch model as well as a model for frequency stability. The models were applied for short-term balancing of the Dutch system in the presence of large-scale wind power generation. The analysed periods were worst case situations in the residual demand.

Ummels *et al.* (2008) and Ummels *et al.* (2009) have analysed different options to increase flexibility in the Netherlands with a deterministic unit commitment and economic dispatch model. The results demonstrated a decrease in coal and natural gas. When wind power penetration increased, a particularly cost-effective way to decrease operational costs was the installation of fuel-based heat boilers in CHP units. On the other hand, a new interconnection to Norway resulted in the highest operational cost saving, but it was much more expensive to build than the heat boilers. Other considered options included pumped hydro and compressed air energy storage.

A report by Pöyry Energy (2010) analyses different options to create a low carbon energy system for the UK. It concludes that electrification, especially of space heating, may provide the necessary flexibility to incorporate large amounts of variable power generation. A demand-side response and bulk storage are good for shifting demand within the day, but they are less effective for longer periods. For longer timescales than a couple of days, most of the flexibility is expected to come from generation. The model behind the analysis, Zephyr, is a chronological mixed integer (MIP) model without uncertainty. The portfolios for the scenarios were developed with Zephyr runs using the internal rate of return for each plant to provide information on investment decisions.

There have also been several studies with a big footprint. These have mainly looked at the operational impacts of large-scale wind (and solar) power, the need for additional interconnections, established the contribution of wind energy to resource adequacy and/or analysed the benefits of new market designs. European studies include GreenNet (Kröger-Vodde *et al.* 2009), Tradewind (van Hulle 2009) and EWIS (Winter 2010) while studies in the U.S. include EWITS (NREL and EnerNex 2010) and WWSIS (NREL and GE 2010). The main conclusion related to this dissertation is that long-distance transmission can contribute substantially to the economic integration of wind power and that variability and uncertainty can be greatly reduced when wind generation is collected from a large footprint. WILMAR was applied in GreenNet, Tradewind and EWITS.

4. Methods and models of the thesis

This chapter presents selected methods and models that were used in the dissertation. The exact mathematical formulations and modeling approaches used in the tools employed in this study can be found in the articles and reports shown in the references. Both WILMAR and Balmorel models are freely available, and can be found in internet (http://www.wilmar.risoe.dk and http://www.balmorel.dk). For these reasons, the models are not described in detail here. The main tool was the WILMAR planning tool and it is hence presented in more detail. The author has participated in the development of the WILMAR planning tool (Meibom *et al.* 2006, Kiviluoma and Meibom 2006). Part of the dissertation was the development of an electric vehicle model for WILMAR that includes the necessary data on electric vehicle behaviour. A couple of additional methods were developed to explore different ways to integrate wind power. One developed methodology is for creating synthetic wind power forecast errors. At the time, real stochastic forecasts were not available. The developed method was used but not documented. It is not presented here either, since real forecasts are starting to become available and the Scenario Tree Tool in WILMAR can also create satisfactory forecast scenarios. The data manipulation that led to the time series for electric vehicle behaviour was rather complex and is documented in Publication VII.

4.1 WILMAR model

The WILMAR model is a power system modelling tool that optimises unit commitment and economic dispatch for the next 36 hours. It incorporates stochastic time series for wind power and demand. As a consequence, the forecasts for wind and demand include uncertainty in the form of multiple paths for their evolution during the next 36 hours. This stochasticity is taken into account in the unit commitment optimisation. After the initial unit commitment for the next day, the model takes three-hour steps and recalculates with new forecasts. Only some power plants can be rescheduled, which emulates the functioning of the intra-day and regulation markets. At noon it makes a new unit commitment for the next day and continues solving the intra-day market every three hours.

The model can be solved in deterministic mode in which there is only one prediction for residual demand. The deterministic mode makes the model solve faster, which can be useful as multiple model runs can be time-consuming. The deterministic mode can also be solved with perfect foresight in wind power and demand forecasts. This helps to evaluate the value of such forecasts and the costs associated with forecast errors.

The model can be solved with linear programming (LP) or a MIP solver. The LP version is documented in Barth *et al.* (2006a) and the MIP version in Tuohy *et al.* (2009) as well as Meibom *et al.* (2011). The advantage of MIP is its capability to perform 'lumpy' unit commitment decisions in a more realistic manner. However, this requires unit level power plant data and can be very time-consuming in a big system, especially if run in conjunction with the stochastic forecast data. The LP mode approximates unit commitment decisions by aggregating similar units together and applies an additional variable to keep track of the capacity online. There is still a cost to bring capacity online, but the binary value for the online status of individual units is not present.

WILMAR consists of the Scenario Tree Tool (Barth *et al.* 2006b), Input Database (Kiviluoma and Meibom 2006), Joint Market Model (JMM, Tuohy *et al.* 2009), Long Term Model (LTM, Ravn 2006) and Output Database (Kiviluoma and Meibom 2006). The Scenario Tree Tool creates stochastic scenarios for the wind generation and electricity demand based on Monte-Carlo simulations. For most of the work in this dissertation, the Scenario Tree Tool has been replaced by a forecast replication tool that introduces uncertainty bands around the average forecast based on forecast statistics. The input and output databases are Access databases and contain code and queries to ease the upkeep of assumptions and analysis of results. JMM contains the actual equations for the unit commitment and is written in GAMS. GAMS calls an external solver to solve the LP or MIP problem. IBM ILOG CPLEX has been used as the solver. Figure 6 shows the most important data requirements and the data flow in the WILMAR model.

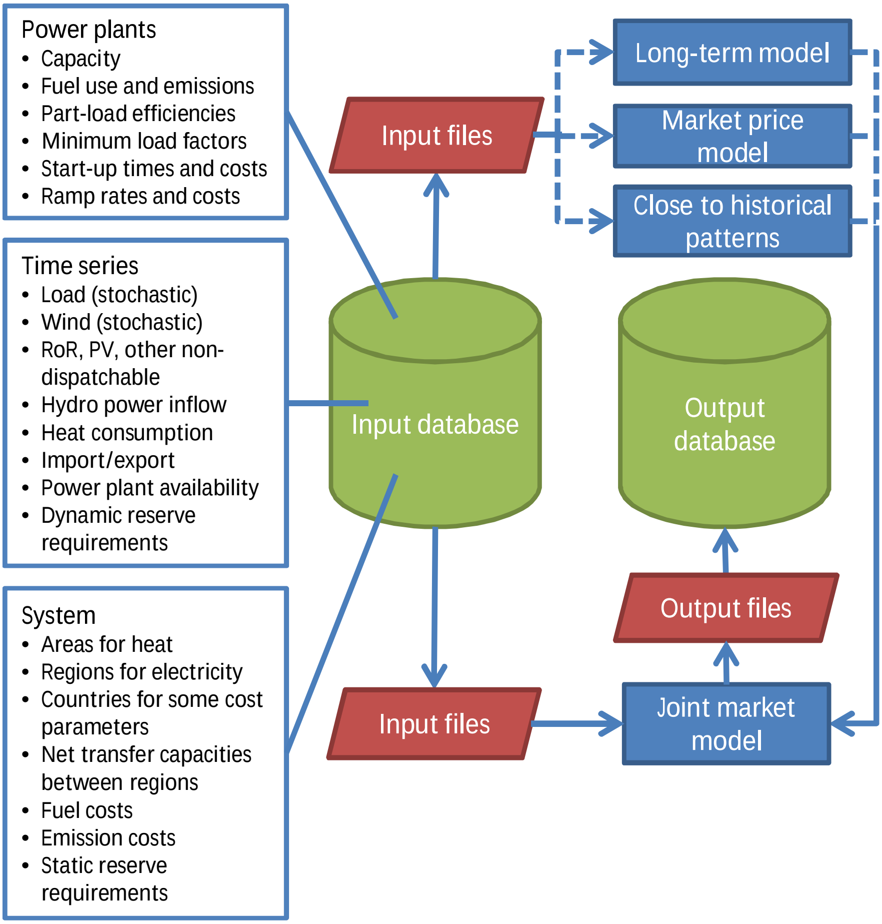

Figure 6. Flow chart for WILMAR.

LTM solves the water value for reservoir hydro power, which is based on the generation reservoir hydro power can expect to replace in the longer term. LTM receives a simplified set of assumptions so that the model can solve a much longer time horizon than JMM. The water value table is transferred from LTM to JMM once a week. LTM did not always perform satisfactorily and in some of the articles it was replaced by a very simple code that penalised the objective function if the reservoir levels deviated too much from the annual historical patterns. Later work replaced JMM with a market price model (Rinne 2011).

WILMAR minimises the following operational costs of the power system: *Fuel use + O&M + start-up + fuel consumption during start-ups + emission costs.*

There are several restrictions on the problem. Heat generation has to equal heat demand separately in each district heating network. The positive spinning reserve from power plants and storage has to be larger than the demand for spinning reserve and the same applies to negative spinning reserve. A non-spinning reserve, which can also be provided if power plants are currently offline but capable of starting up fast enough, has to be larger than the demand for this reserve. This reserve is procured dynamically: if there is a chance that the residual demand may increase considerably, more spinning reserve will be required.

For each unit, down regulation minus up regulation plus negative spinning reserve has to be smaller than the generation bid to the day-ahead market. Wind power can shed generation or act as a downward reserve, restricted to the predicted output.

The fuel consumption of power plants increases linearly with power output, and for most power plants there is also some fuel consumption not dependant on the output. This creates a difference in the efficiencies for partial and full load. Extraction-type combined heat and power plants (CHP) have more equations, as described in Barth *et al.* (2006a).

The model was originally made for the Nordic power system and Germany. At the time unit aggregation was used, as the number of power plants would have made the model impossible to solve. For part of studies in this dissertation, power plant data have been updated to unit level for Finland.

WILMAR was originally developed in an EU project in 2002–2006 and it has been applied to several studies since, where it has also been developed further. A recent study was conducted for the Irish power system in which the model was verified against a Plexos model, and this showed high consistency for the Irish system (Meibom *et al.* 2007, p. 26). In this dissertation, WILMAR has been applied to a portfolio based on Balmorel results as well as to the Nordic power system together with the German power system.

4.2 Model for plug-in electric vehicles

In the dissertation, WILMAR was upgraded to include a model for electric vehicles. The electric vehicle model treats the electric vehicles as electricity storage that is not always connected to the power grid and, while gone, spend some of their stored electricity. Each vehicle type has its own general electricity storage pool in each model region. It would be more correct to have separate storage for each vehicle, but the problem would not be possible to solve with thousands of vehicles, and some simplification had to be made. The model is documented in Publication VII.

The model includes a relation between the vehicle departure and arrival times. Figure 7 shows an example pattern of electric vehicles that arrive at 7 pm in the network. Some of them had left in the morning and some during the afternoon. This influenced the calculated consumption of electricity during the trip, since the distribution of trip lengths varies throughout the day. Furthermore, there can be system benefits if the batteries do not need to be completely full on departure.

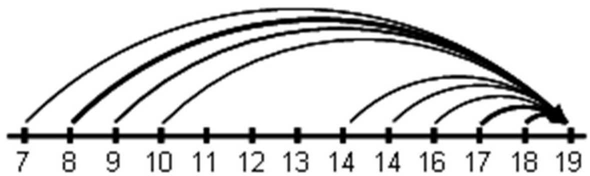

Figure 7. Electric vehicles arriving at 7pm have multiple departure times from the grid (Publication VII).

4.3 Balmorel model

The Balmorel model is a linear optimisation model of a power system, including district heating systems. It calculates investments in storage, production and transmission capacity and the operation of the units in the system while satisfying the demand for power and district heating in every time period. Investments and operation will be optimal under the input data assumptions covering, e.g., fuel prices, CO_2 emission permit prices, electricity and district heating demand, technology costs and technical characteristics. The original model was developed by Balmorel Project (2001) led by H. Ravn and has been extended in several projects, e.g. Jensen and Meibom (2008), Karlsson and Meibom (2008), and Publication VII. Balmorel has a very similar structure to WILMAR in Figure 6.

The optimisation period in the model is one year divided into time periods. The yearly optimisation period implies that an investment is carried out if it reduces system costs, including the annualised investment cost of the unit.

The geographical resolution is countries divided into regions that are in turn subdivided into areas. Each country is divided into several regions to represent its main transmission grid constraints. Each region has time series of electricity demand and wind power production. The transmission grid within a region is only represented as an average transmission and distribution loss. Areas are used to represent district heating grids, with each area having a time series of heat demand. There is no exchange of heat between areas.

The hourly heat demand has to be fulfilled with the heat generation units, including heat storages. The loading of heat storages adds to the heat demand. Loss during the heat storage process is not considered. The dynamic aspects of district heating networks are not taken into account. The district heating network is a small storage unit in itself with complicated properties, and the buildings are another.

5. Results

This chapter presents the main findings of the different analyses made. The focus is on those results that help in understanding the benefits of increasing power system flexibility for the integration of variable power generation. First, the results on conventional power plants and reservoir hydro power are presented. The next flexibility option is different heat measures in Section 5.2. The results on electric vehicles are presented in Section 5.3.

5.1 Conventional power plants and hydro power

The main tool to compensate for wind power variability and prediction errors in the power system is conventional power plants including reservoir hydro power. This is not likely to change even if other options become available in the future. It is therefore important to understand the limitations of the operational properties of the power plants. For thermal power plants, minimum load factors, efficiencies in part load operation, and the wear and tear costs of cycling are especially important. Cold, warm and hot starts are also likely to increase and these have complicated cost structures. These properties are important in the current power plant fleet as well as for new investments.

The combined output of spatially distributed wind power plants changes rather slowly in comparison with possible ramp rates that can be managed by the conventional power plant fleet. However, the magnitude of the ramp rate increases with wind power penetration (Holttinen *et al.* 2011b). If wind power generates half of the load, the absolute ramp rates of wind power on an hourly timescale are higher than the ramp rates in the demand. In the Nordic system, the largest one hour demand change in 2011 was 5.7 GW upwards and 3.5 GW downwards. The largest change in the residual demand, which combines the demand and upscaled wind power generation with 60% energy penetration, has a ramp of 7.7 GW upwards and 6.2 GW downwards. The downward ramp in the residual demand is easier to deal with since wind power generation can be limited if necessary.

A 7.7 GW change in the Nordic power system requires approximately 10–11% of the total capacity (> 70 GW, ENTSO-E 2011) to participate in the ramp up during the hour. This ramp would require about 130 MW per minute. Only large hydro power plants or gas turbines could come close to managing that, but this is not necessary since multiple units can ramp up simultaneously. Almost all units can ramp from minimum generation to maximum generation during one hour if they are warm (Kumar *et al.* 2012), expect nuclear units, which may have more severe technical or regulatory restrictions (NEA 2012). In practice this kind of ramp up would see some units ramping up more slowly than others. Managing the ramping up event requires co-ordination that can be achieved through market mechanisms. However, day-ahead and intraday markets with hourly resolution will not be accurate enough for this purpose (Ela and O'Malley 2012). Hence, the coordination would benefit from markets with a higher time resolution, e.g. 5, 10 or 15 minutes.

5.1.1 Use of conventional power plants

Power plants have quite different properties when it comes to minimum load factors, efficiency at part-load operation, wear and tear of cycling, and the expense of starting up and shutting down. Since wind power variability and prediction errors will increase cycling of conventional power plants, these matters become more important in systems with a large amount of wind power. The results here are derived from Publication IV, in which the generation planning model (Balmorel) was applied to a future system based on the hourly load and wind time series from Finland.

Figure 8 demonstrates the effect of increasing wind penetration on the cycling of conventional units (the wind power investment cost was varied between 900, 800 and 700 €/kW[3]). The cycling is calculated by summing absolute changes in the power plant output over the year and divided by the installed capacity and by two (whole cycle includes up and down ramps). Interestingly, the increase in the cycling occurs mostly in mid-merit and baseload power plants. However, the results are from the Balmorel model runs (Publication IV), which did not include start-up costs or part-load efficiencies.

[3] The investment cost is low from the current perspective. At the time of the analysis, it was assumed that wind power investment costs would continue to decrease towards the study year of 2035. However, it now appears that progress in wind turbine manufacturing in the last few years has improved the yield rather than lowered the investment costs.

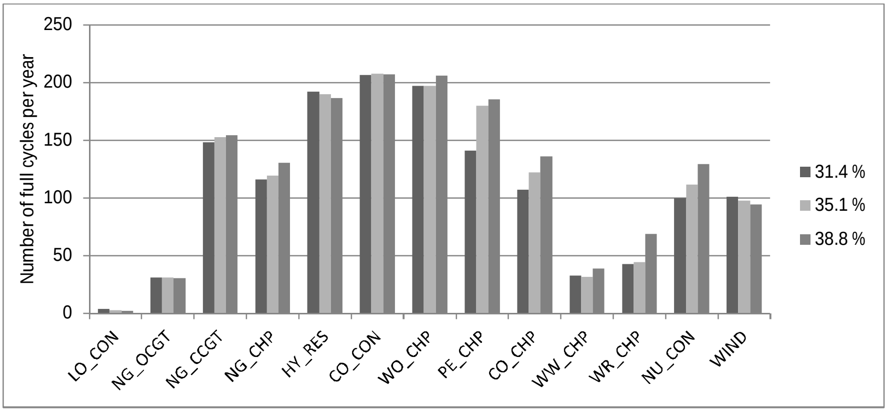

Figure 8. Cycling of conventional units with increasing wind power penetration (from 31.4% to 38.8% of annual consumption). LO = Light Oil, NG = Natural Gas, HY = Hydro, CO = Coal, WO = Wood, PE = Peat, WW = Industrial Wood Waste, WR = Forest Residues, NU = Nuclear, CON = Condensing, OCGT= Open Cycle Gas Turbine, CCGT = Combined Cycle Gas Turbine, CHP = Combined Heat and Power.

Increasing wind power generation will decrease the operating hours of fuel-based conventional power plants (Figure 9), which leads to lower profitability of the base- and intermediate load power plants. These will find it more difficult to recuperate capital costs and in the long term change the power plant structure towards plants with lower capital costs and higher fuel costs. This can be seen in Figure 9, in which the capacity of natural gas-based plants increases and the capacity of the mid-merit and baseload plants decreases with increasing wind power penetration. The decrease was especially pronounced for coal-based generation. Nuclear and reservoir hydro generation were not open for new investments. Forest residue and wood waste-based CHP were resource limited. Peat-based CHP generation was based on existing units.

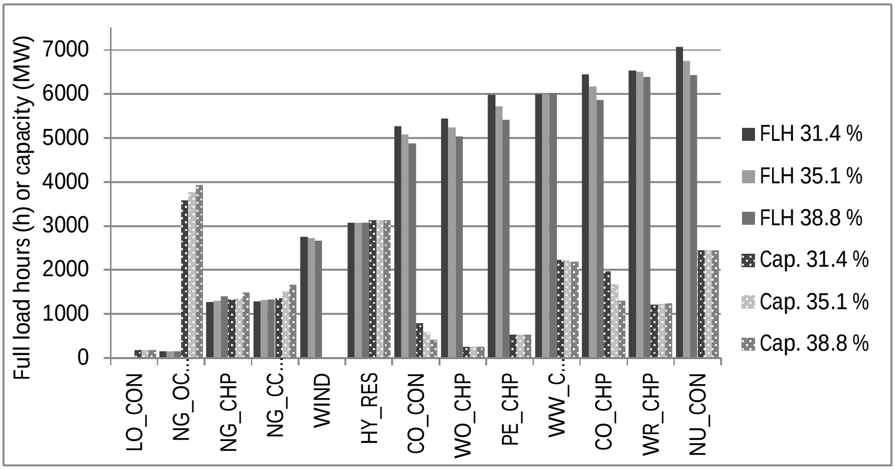

Figure 9. Full load hours (FLH) and installed capacities (Cap.) of conventional units with increasing wind power penetration (from 31.4% to 38.8% of annual consumption). The capacity for wind power was removed as it did not fit in the figure (12.9–16.5 GW). LO = Light Oil, NG = Natural Gas, HY = Hydro, CO = Coal, WO = Wood, PE = Peat, WW = Industrial Wood Waste, WR = Forest Residues, NU = Nuclear, CON = Condensing, OCGT= Open Cycle Gas Turbine, CCGT = Combined Cycle Gas Turbine, CHP = Combined Heat and Power.

In the scenarios in which new nuclear power was allowed (not shown in the figures above), reduced wind power costs led to decreased investments in nuclear capacity. However, nuclear power had already replaced all coal-based generation, so coal could not be reduced further with decreasing wind power cost. Investments in wind power correlated positively with investments in gas turbines, but their use remained low in all scenarios. They were only used during periods of high demand and low wind power generation. The results are highly dependent on the chosen parameters and would have exhibited different behaviour if, for instance, lower natural gas prices had been assumed.

Publication IV also explores a larger set of scenarios, which include different flexibility measures in addition to the wind power investment cost. Figure 10 demonstrates that the availability of different flexibility measures can increase the competitiveness of wind power more than the investment cost of wind power at higher penetration levels. Furthermore, it shows that heat measures were more important than electric vehicles. It is also apparent that the availability of relatively low cost nuclear power (2.625 M€/MW) as an investment option would replace a large portion of wind power generation. Other electricity sources were not as competitive, but this is naturally sensitive to the parameters assumed.

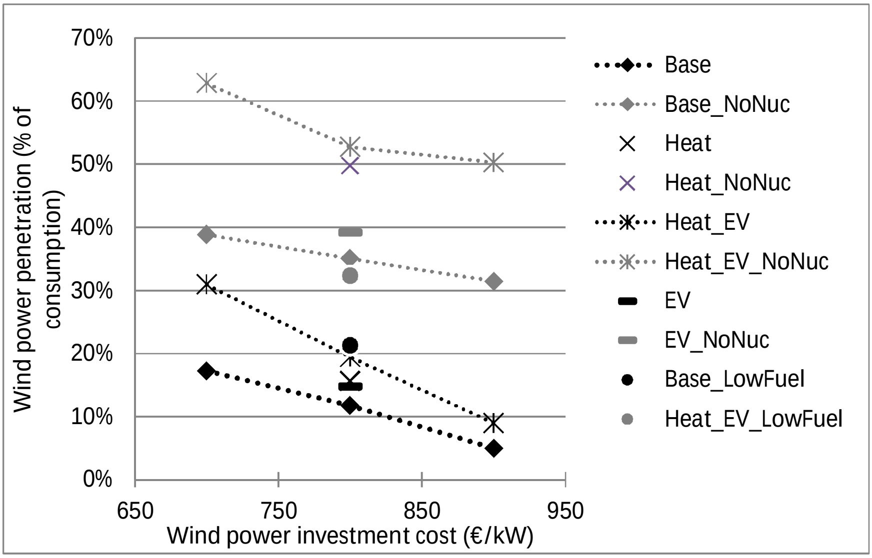

Figure 10. Resulting wind power penetration from the Balmorel generation planning model with different assumptions about wind power investment costs in 2035 (x-axis) and the availability of electric vehicles (EV), heat measures (Heat) and nuclear power (NoNuc) as well as two scenarios with lower fuel prices (LowFuel) for gas and coal.

In the scenarios of Figure 10, the cost of electricity varied between 33 and 43 €/MWh (old power plants were assumed to have been fully amortised and the value of heat was 10 € per produced MWh). The cost refers to the average cost for produced electricity including annualised investment costs. The cheapest scenarios were those with low fuel costs and low wind power costs and the most expensive were those in which the construction of new nuclear plants was not allowed, in addition, flexibility was not available and wind power costs were higher.

Figure 10 also demonstrates that flexibility from heat measures had a greater impact on the cost optimal share of wind power than electric vehicles, especially in the scenarios without new nuclear power plants. It was assumed that about half of the personal vehicles in Finland used electricity as fuel, while heat pumps and electric boiler investments were applicable to below 30% of the district heating loads and heat storage investments were available for all district heating loads (Publication V).

5.1.2 Capabilities of reservoir hydro power

Limitations on the regulation of hydro power with reservoirs originate from the degree of automation and from the reservoir and river system properties (Kiviluoma *et al.* 2006). Reservoirs that are enlargements of the existing river bed can usually produce only a couple of hours at full capacity before the reservoir is at its minimum. This is often good enough to provide daily peak demand power, but periods of low wind power generation can last longer. For hydro power plants with large reservoirs, this is clearly not a problem, since they can easily provide full power through the low wind power generation periods. New units in these locations would increase capacity and hence they could offer rather cheap additional flexibility for integrating wind power, but this can be restricted by flow limitations in the rivers. Another option at locations with two reservoirs at different heights would be to include pumping capability.

Kiviluoma *et al.* (2006) estimated the energy balancing potential of Nordic hydro power based on river system data. The share of run-of-river hydro power was small, less than 10% of the total generation. Most Nordic hydro power capacity has upstream reservoirs and, on average, the reservoirs are large. In Norway, the average reservoir can hold water for about 0.7 years' worth of generation and is a short distance from the hydro power station (estimate for the time lag was close to zero in central and northern Norway and about 2 hours in southern Norway). Swedish reservoirs are smaller (on average 0.45 years' worth of generation) and the average time lag from the reservoir to the hydro power station is longer (estimated as 2–3 hours). The results imply that there is a high amount of untapped flexibility potential in the Nordic hydro systems, but their value was not quantified in economic terms. However, the constructed data were used to increase the accuracy of the Nordic hydro power modelling in WILMAR throughout this dissertation.

5.2 Heat storages with heat pumps or electric boilers

Storage of electricity on a large scale is still not economically feasible nor always technically practical, except for pumped hydro in some locations. On the other hand, converting electrical energy into other energy forms that can be stored and used for other purposes than electricity can be relatively cheap. This section examines the possibility of converting electricity into heat or cold and using heat storages as a buffer between periods of cheap electricity and demand for heat.

Electricity can be converted to heat directly in resistance coils, which warm up water. The efficiency is close to 100%. Electricity can also be converted into heat with heat pumps, which use the high exergy of electricity to prime heat from an ambient source to a higher temperature. Depending on the required temperature lift, the co-efficient of performance (COP) of a heat pump may typically vary between 2 and 5. When the heat use is space heating and the heat source is outside air, the COP will decrease to one at cold temperature. When the heat source is ground water or sea water, the temperature lift remains reasonable throughout the year. This was assumed in the dissertation, which analysed only large-scale district heating systems in which sea water can be an economic option for the heat source.

The dissertation includes three articles that contain analyses on heat measures. The first article (Publication III) analysed the operational benefits of electric boilers and heat pumps in three district heating areas with the WILMAR model. The value of wind power was increased with the heat measures, since the additional electricity consumption increased power prices (2.0% wind power value increase due to electric boilers and 2.6% increase due to heat pumps). This took place, especially, during low power prices, which were the result of high wind power generation. Fuel use in heat boilers and CHP plants was reduced and caused overall system benefits especially in those district heating systems that used fuel oil for heating. The analysis in the article covered 25 days in February and the results are therefore tentative.

The second article (Publication IV) used the generation planning model Balmorel. The model was used to analyse a future power system in 2035 based on Finnish data for time series and the remaining power plants. Scenarios with heat measures were compared with scenarios in which heat measures were not allowed as investments. The impact of heat measures was significant for the integration of wind generation. The main results from Publication IV are presented next.

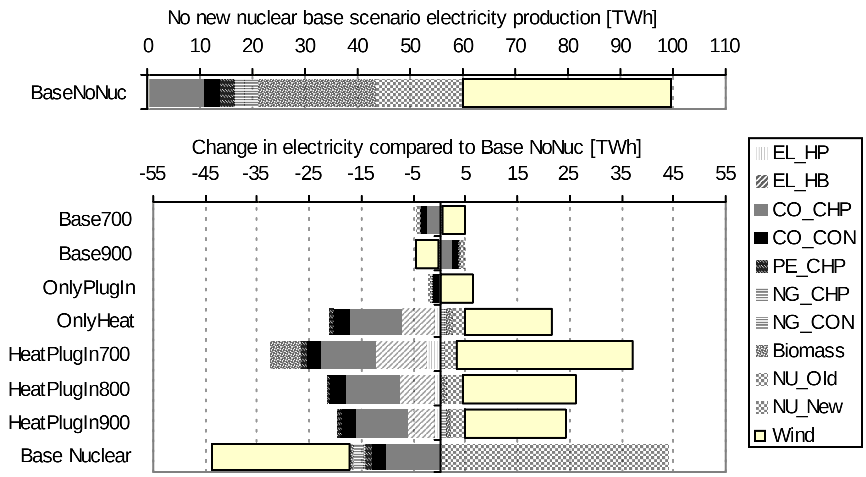

Figure 11. Electricity generation in the scenarios without new nuclear power. The upper figure shows the generation mix in the base scenario without new nuclear power. Changes in the generation mix are then shown in the lower figure. Heat pumps (EL_HP) and electric boilers (EL_HB) will increase electricity consumption and are therefore negative changes in the graphs. Hydropower is not shown, as electricity generation from hydro power does not change between scenarios. CO = Coal, PE = Peat, NG = Natural gas, NU = Nuclear, CHP = Combined heat and power, CON = Condensing.

In the scenarios in which new nuclear power was not allowed (Figure 11), heat measures increased the cost optimal share of wind generation from 35% to 47%. In the scenarios in which new nuclear power was allowed, there was an increase in wind generation from 12% to 15%. It was more difficult to replace relatively inexpensive nuclear generation (2.625 M€/MW) than coal generation, which was already replaced by the nuclear generation. The results are highly sensitive to the assumed cost parameters for heat measures, wind, nuclear and other generation units (assumed costs in Table 3 of Publication IV). As a comparison, the reduction of wind power investment cost from 800 €/kW to 700 €/kW increased the wind power share from the base of 35% to 39% in the no nuclear scenarios and from 12% to 17% in the nuclear scenarios.

In operational terms, electric boilers were especially important to cope with the high wind-low demand situations (Figure 12). Heat pumps were not nearly as important, since they require a high number of full load hours in order to be profitable and do not match the variable wind power generation as well. However, during low wind-high demand situations, heat pumps reduced electricity consumption, which brought useful flexibility to the power system.

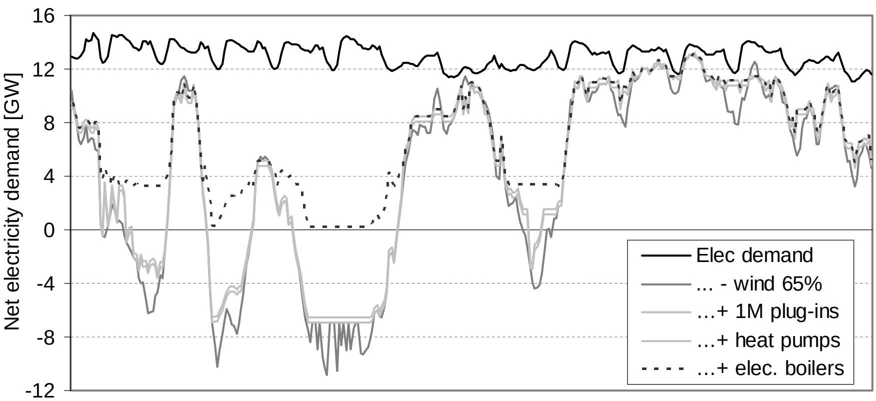

Figure 12. Changes in net electricity demand when flexibility mechanisms are overlaid on top of each other (Publication VII). The x-axis holds two weeks in March from the ‘HeatPlug NoNuc 700’ scenario. This scenario (heat measures available, no new nuclear power allowed and wind power at 700 €/kW) had the greatest wind power penetration, and the selected weeks included both a very high and a very low wind power generation event.

The heat measures included heat storages as an investment option. The impact of this was examined more closely in a third paper (Publication V). The results imply that if the share of variable generation becomes large, heat storages will become very beneficial for district heating networks. Heat storages create operational benefits, which justify the investments in heat storages, by moving demand from more expensive sources of heat to less expensive ones by shifting demand in time. The heat storages create additional flexibility by allowing CHP units to shut down during events with relatively low residual demand and hence remove must-run electricity generation (Figure 13). Heat storages also helped heat pumps to displace generation from CHP units because it allowed the shut-down of heat pumps during high residual demand situations and hence decreased electricity consumption.

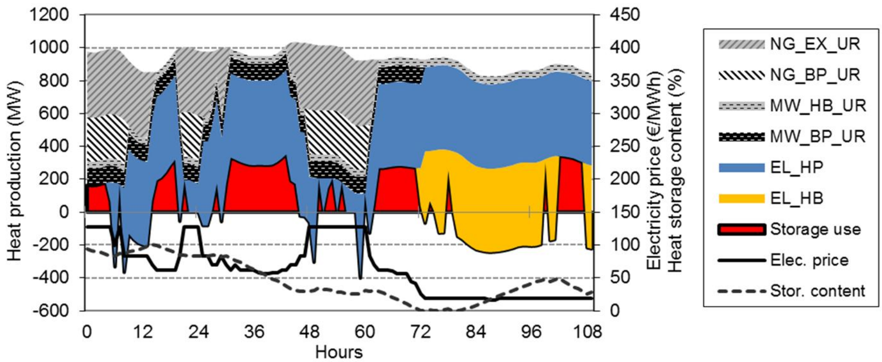

Figure 13. Example of 4.5 days of heat generation in January for the 'Urban' district heating system (Publication V). The negative heat generation values are due to the loading of the heat storage. The electricity price (solid line) and heat storage content (dashed line) are on the right y-axis. NG_EX_UR is natural gas extraction CHP, NG_BP_UR is natural gas backpressure CHP, MW_HB_UR is a municipal waste heat boiler, EL_HP is a sea water heat pump, EL_HB is an electric resistance boiler, and storage refers to the heat storage in the district heating system.

In the winter, the charging of heat storages was mostly based on the use of electric boilers. They create large amounts of heat in a relatively short time during periods of low power prices. In summer, heat storages were charged by turning on wood waste and forest residue CHP units or heat pumps. During spring and autumn, CHP units operate more often, since the heat load is greater, but the heat storage still helps to shut them down for periods of a few hours.

5.3 Electric vehicles

Personal vehicles are idle most of the time (WSP LP Consultants 2006). For electric vehicles, this means that there can be a considerable time window for charging their batteries. Typical daily driving distances (52 km in Publication VII) at 0.2 kWh/km imply a charging need of three hours on a 220 V/16 A one-phase household plug. The possible flexibility in electricity demand could benefit the integration of variable generation. Vehicle-to-grid could offer additional flexibility during hours of high power prices or by relieving more expensive forms of rarely used reserves.

The dissertation includes four articles that address electric vehicles. In the first article (Publication IV), Balmorel is used to analyse the power generation investment impacts of electric vehicles and heat measures for the year 2035 using time series from Finland. The Balmorel version in use had a model for charging and discharging the batteries in electric vehicles but it did not include investments in the transport sector. It was therefore assumed that approximately 25% of the personal vehicle fleet was based on full electric vehicles and 25% on PHEVs.

The impact of electric vehicles on generation investments was interesting. The assumed one million electric vehicles (half of the vehicle fleet) increased electricity consumption by 4.0 TWh. In the scenarios in which no new nuclear power was allowed, wind power generation increased by 6.2 TWh (from 35% to 39% of the annual energy). The smart charging electric vehicles enabled wind power to displace mainly coal condensing generation due to the increased flexibility of the system. In the scenarios in which new nuclear power was allowed, wind increased by 4.0 TWh (from 12% to 15% of the annual energy) while existing nuclear power increased by 2.0 TWh to reach 19.7 TWh. At the same time, new nuclear generation was reduced by 1.5 TWh down to 41.1 TWh. These results mean that electric vehicles may actually reduce overall CO_2 emissions (2–3 Mt CO_2 in the analysed scenarios for one million electric vehicles compared with 90 gCO_2/km gasoline vehicles).

The Balmorel runs also provided power plant portfolios for the WILMAR runs in Publication VII. This was the first time when a generation planning model was combined with an operational model in order to analyse the benefits of smart charging electric vehicles more comprehensively. The article presents a robust methodology for analysing the impact of electric vehicles in a unit commitment time frame. According to the results, smart charging electric vehicles reduced power system costs by 227 €/vehicle/year. Part of the benefits come from less expensive operations and part comes from smaller investments and fixed costs. The scenario setup indicated that the benefit was divided between spinning reserve procurement (17%), capability to change output after day-ahead unit commitment (47%), and day-ahead planning of charging and discharging (36%). V2G was enabled with a round-trip efficiency of 85% and 10 €/MWh wear and tear costs. In a scenario in which V2G was not allowed, the system benefit was reduced by 53 €/vehicle/year. When V2G was available in half of the one million electric vehicles, the system benefit was only reduced by 6.7 €/vehicle/year.

The third article on electric vehicles (Publication VI) gave an estimate of how the size of the electric vehicle fleet influences the system benefits of smart charging electric vehicles compared with electric vehicles that start charging immediately after plugging in. The more smart charging electric vehicles there are, the smaller the system benefits per vehicle. However, it should be considered that increasing the penetration of variable and uncertain generation will increase the need for flexibility and therefore better maintain the benefits of smart charging. The article remained inconclusive about this hypothesis. The use of a generation planning model to set up the power plant portfolios would have improved the results.

Lastly, Publication VIII analysed the impact of electric vehicles on wind power, focusing on balancing cost reductions due to electric vehicles. The average wind power balancing cost decreased from 2.4 €/MWh ('No EVs' scenario) and from 2.7 €/MWh ('Dumb' electric vehicles scenario) down to 1.6 €/MWh in the 'Smart' electric vehicles scenario. In the 'Dumb' scenario, charging started immediately as the vehicles were plugged in. In the 'Smart' scenario, charging was optimised when the operational costs for the power system were minimised. However, the revenue for wind power from other power markets decreased at the same time and the net result was almost zero. In the 'Smart' scenario, electric vehicles were allowed to discharge to the grid when the benefit exceeded the discharging costs. When this V2G was disabled, the balancing costs increased back to 2.2 €/MWh. When half of the electric vehicles had V2G disabled, the balancing cost was 1.8 €/MWh. Interestingly, the introduction of electric vehicles increased the overall balancing activity, since conventional power plants changed their schedules with the help of electric vehicles in order to increase average efficiency and reduce start-up costs.

6. Discussion

This dissertation investigates wind power integration through the exploration of the economic possibilities of increasing power system flexibility with conventional power plants, electric vehicles and heat loads.

Analysing flexibility from heat loads is difficult due to the complexities in the systems that use heat. The results presented in the thesis are based on a simplified description of heat loads, heat pumps, electric boilers and heat storage. The reliability of the results may be improved by comparing them against real systems. The results concerning the heat load are mainly valid for district heating systems, with their main applicability to northern latitudes. Local heating and cooling systems are more common. Local systems will have higher investment costs before their flexibility can be increased (Estanqueiro *et al.* 2012). Nonetheless, they can be operated along similar principles and may thus offer substantial flexibility even without district heating networks.

The dissertation includes the development of comprehensive methodology for analysing the impact of electric vehicles on the power system economics. The driving patterns were based on real data from the Finnish National Road Administration. The stochastic unit commitment model was able to optimise the charging and discharging of electric vehicles within the driving pattern constraints. A power generation planning model was combined with an operational model. Even so, not all possible revenue streams were covered: distribution grid benefits were not included and revenues from reserves only partially. To further improve the model, the literature review indicates that inclusion of depth-of-charging-based variable costs would be important at least for some battery chemistries (Peterson *et al.* 2010a) as well as more realistic behaviour of battery storage pools. Instead of one storage pool for each vehicle type, there should be a separate pool for each hour of leaving vehicles, as also suggested in the discussion in Publication VII.

Some of the assumptions used in the beginning of the dissertation may have been too optimistic. The cost of wear and tear of the battery due to V2G use was assumed at 10 €/MWh. The latest research indicates an estimate of up to 50 €/MWh based on data from Peterson *et al.* (2010a) and Millner (2010). The estimated benefits of V2G (53 €/vehicle/year) would be lowered by the higher wear and tear costs. Clear improvements in battery cost and/or cycling durability are necessary to achieve the assumptions used in this study.

The investment costs of wind power, which ranged between 700 and 900 €/kW in the analysis, have not yet been achieved. The investment costs are currently around 1500 €/kW (Milborrow 2012), but at the same time the average yield and capacity factor have increased. As a consequence, the wind power production costs (€/MWh) have decreased. As the target of the analysis is 20 years ahead, the cost assumptions, and in particular the wind production cost, may still be realistic. Higher capacity factors of wind power in the future may change the variability of wind power generation and more research would be needed to quantify these impacts.

Reservoir hydro power consisting of several reservoirs and power plants within a river system is highly complex to optimise. A model such as WILMAR aggregates river systems, which yields generation from the hydro assets that is too flexible. Work is on-going to improve the river system representation in the WILMAR model. More restrictive use of hydro power is likely to increase the value of other forms of flexibility.

A simplified modelling approach to the power grid was used here due to the necessity to reduce the research task and the size of the optimisation problem. The preclusion of grid issues is a limitation, as high levels of wind power generation could considerably increase the costs to mitigate the problems that arise. This should be evaluated separately.

The power system is characterized through a range of factors such as the power plant mix, plant flexibility and ramping capabilities, capacity and strength of the electric network, and in particular the high voltage grid, interconnections between power systems, operational rules and regulations, shape and profile of the electricity demand, wind power generation patterns, etc. (Chandler 2011, p. 37–39). Understandably, the number of combinations to characterize the power system is so vast that a uniform and generalized picture on wind power integration is difficult to accomplish, if not impossible. Hence, this thesis has been restricted by a geographical scope of Finland and the Nordic countries. Thus, while the results and conclusions should have relevance to wind integration in many regions, they are not necessarily universally applicable. The following paragraphs consider the impact of power system flexibility on the applicability of the results.

The Nordic power system as a whole is very flexible, due to the high share of reservoir hydro power with large water reservoirs, in particular in Norway and Sweden. The Finnish power system per se, though the share of hydropower of all electricity varies from 11 to 19% (Official Statistics of Finland 2012), is not that flexible due to the dominance of backpressure-type CHP with fixed ratios between heat and power and nuclear power with regulatory and technical restrictions on ramping (NEA 2012). From a wind power integration point of view, a flexible power system would inherently allow more variable generation capacity than a rigid one.

Chandler (2011) has calculated rough estimates for the potential of variable generation in present power systems. While the Nordic countries scored 48% in this index, on the lower end of the scale Japan obtained just 19%, where the percentage describes how much variable generation of total could be possibly integrated into the present power system. Flexibility is subject to diminishing returns and thus flexibility is more valuable in a power system with less of it (Holttinen et al. 2012). Therefore, the value of the flexibility options estimated in the dissertation is likely to be higher in more rigid power systems. However, the relative importance of different flexibility options will tend to vary between power systems subject to different conditions and having different configurations.

7. Conclusions

The main finding of this dissertation is that high levels of wind power generation (30–60% of the annual energy) are possible without dedicated electricity storage through other flexibility-increasing methods. The analysed scenarios assume continued fossil fuel scarcity, costs from CO_2 emissions and decreasing wind power costs. The results demonstrate the relative impact of wind power investment costs and available flexibility measures on the cost optimal share of wind power. Reducing the wind power investment cost from 900 €/kW to 700 €/kW increased wind power penetration by 7–12 percentage points when flexibility from the heating sector and electric vehicles were not available. When these flexibility measures were available, the penetration increased by 9–21 percentage points when the investment cost was reduced from 900 €/kW to 700 €/kW. As a simplified transmission system description was used, the results may underestimate the true power system costs of wind power.

Many past studies have not optimised the power plant portfolio to match the new situation created by the increasing share of variable generation. Instead, wind generation is just added to an existing power system or it is assumed to support increasing electricity demand, which is often depicted by a flat block. The dissertation highlights the importance of the generation planning approach for the studies on future systems with tens of per cent of annual energy from wind power. The resulting power plant portfolio can be surprising, for example, the availability of the flexibility measures enabled portfolios in which wind and nuclear power together generated up to 77% of the annual energy.

The results indicate a large and economic flexibility potential from the heat measures – e.g. in one of the analysed settings they increased the cost optimal share of wind power from 35% to 47%. The mechanisms that increase flexibility include electric boilers, heat storages and heat pumps. Electric boilers can convert excess power generation into heat and therefore enable the shutdown of CHP units during periods of high wind generation and low electricity demand. The economic consequences for CHP were not assessed. Heat storages can advance or postpone heat generation and hence affect the operation of electric boilers and CHP units. The interactions can be complex, for example, during periods of relatively high wind power generation heat storages were not usually charged with heat from electric boilers. Instead heat storages were discharged in order to shut down combined heat and power plants.

Electric vehicles have received much more attention as means to increase power system flexibility than the heating sector. The results in the dissertation indicate that electric vehicles will not be as important as the heating sector – the availability of electric vehicles increased the share of wind power from 35% to 39% in a comparable scenario. Furthermore, the electric vehicle batteries are dimensioned for road trips while heat storages in district heating systems are relatively low cost and therefore additional investments can be justified by power system benefits alone – as demonstrated by the analysed scenarios.

Electric vehicles can still constitute an important source of flexibility if they charge and discharge smartly, e.g. smart charging electric vehicles constituting half of the personal vehicles if Finland were able to increase the cost optimal share of wind power by 3–4 percentage points in the analysed scenarios. The results also indicate that smart charging is more important than V2G, which contributed 23% to the 227 €/vehicle/year cost savings when smart charging with V2G was compared with immediate charging. Another result was that electric vehicles may actually reduce the overall CO_2 emissions when they enable a higher share of wind power generation (a reduction of 2–3 Mt CO_2 in the analysed scenarios for one million electric vehicles compared with 90 gCO_2/km petrol vehicles).

In wind power integration studies, conventional power plants are often assumed to take care of the increased flexibility needs. Power plants do this by cycling more and operating more at part-loads. For lower wind penetration levels, this is possibly the only form of flexibility that is economic in addition to non-technical means (e.g. changes in rules and regulations).

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Title	**Managing wind power variability and uncertainty through increased power system flexibility**
Author(s)	Juha Kiviluoma
Abstract	Variability and uncertainty of wind power generation increase the cost of maintaining the short-term energy balance in power systems. As the share of wind power grows, this cost becomes increasingly important. This thesis examines different options to mitigate such cost increases. More detailed analysis is performed on three of these: flexibility of conventional power plants, smart charging of electric vehicles (EVs), and flexibility in heat generation and use. The analysis has been performed with a stochastic unit commitment model (WILMAR) and a generation planning model (Balmorel). Electric boilers can absorb excess power generation and enable shutdown of combined heat and power (CHP) units during periods of high wind generation and low electricity demand. Heat storages can advance or postpone heat generation and hence affect the operation of electric boilers and CHP units. The availability of heat measures increased the cost optimal share of wind power from 35% to 47% in one of the analysed scenarios. The analysis of EVs revealed that smart charging would be a more important source of flexibility than vehicle-to-grid (V2G), which contributed 23% to the 227 €/vehicle/year cost savings when smart charging with V2G was compared with immediate charging. Another result was that electric vehicles may actually reduce the overall CO_2 emissions when they enable a higher share of wind power generation. Most studies about wind power integration have not included heat loads or EVs as means to decrease costs induced by wind power variability and uncertainty. While the impact will vary between power systems, the thesis demonstrates that they may bring substantial benefits. In one case, the cost optimal share of wind-generated electricity increased from 35% to 49% when both of these measures were included.
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Nimeke	**Tuulivoimatuotannon vaihteluiden ja epävarmuuden hallinta sähköjärjestelmän joustavuutta parantamalla**
Tekijä(t)	Juha Kiviluoma
Tiivistelmä	Tuulivoimatuotannon vaihtelevuus ja ennusvirheet lisäävät energiatasapainon ylläpitämisen kustannuksia sähköjärjestelmissä. Tuulivoiman osuuden kasvaessa näiden kustannusten suhteellinen merkitys kasvaa. Tämä väitöskirja tutkii eri tapoja lieventää kustannusten nousua lisäämällä järjestelmän joustavuutta. Tarkempi analyysi on tehty kolmelle eri menetelmälle: perinteisten voimalaitosten joustavuuden lisääminen, sähköautojen älykäs lataaminen sekä lämmön tuotannon ja kulutuksen mahdollisuudet joustavuuden lisäämisessä. Analyysit on tehty stokastisella ajojärjestysmallilla (WILMAR) sekä investointimallilla (Balmorel). Sähkökattilat voivat hyödyntää liiallista sähköntuotantoa ja samalla mahdollistaa sähkön ja lämmön yhteistuotantolaitosten alasajon ajanjaksoina, jolloin tuulivoimatuotanto on suurta ja kulutus vähäistä. Lämpövarastot voivat siirtää lämmöntuotannon ajoitusta ja sitä kautta lisätä sähkökattiloiden sekä sähkön ja lämmön yhteistuotantolaitosten joustavia käyttömahdollisuuksia. Tulokset indikoivat merkittävää potentiaalia suhteellisen pienillä kustannuksilla. Analyysin mukaan sähköautojen älykäs lataaminen tarjoaa enemmän joustavuutta kuin sähkön syöttö verkkoihin sähköautoista tarvittaessa. Sähkönsyötön osuus älykkään lataamisen kokonaissäästöistä (227 €/auto/vuosi) oli 23 %. Toinen tulos oli, että sähköautot näyttäisivät vähentävän sähköntuotannon päästöjä, koska niiden tuoma joustavuus johtaa entistä suurempaan tuulivoiman osuuteen sähköjärjestelmässä. Suurin osa tuulivoiman vaihtelevuuden ja ennusvirheiden kustannuksia arvioineista tutkimuksista ei ole huomioinut sähköautojen tai lämmön tuotannon ja kulutuksen mahdollistamaa lisäjoustavuutta. Vaikutukset vaihtelevat järjestelmästä toiseen, mutta väitöskirja osoittaa, että näistä voidaan saada merkittäviä hyötyjä. Yhdessä tutkitussa tapauksessa tuulivoiman kustannustehokas osuus kasvoi 35 %:sta 49 %:iin, kun sekä lämmön kulutuksen että sähköautojen joustavuus huomioitiin.
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Managing wind power variability and uncertainty through increased power system flexibility

Wind power generation can replace fuel-based power generation, but it is inherently variable and only partially predictable. As the share of wind power increases, these characteristics will impact the cost-effective upkeep of the balance between power generation and load. This dissertation explores methods to mitigate these impacts.

The approach taken in the dissertation is based on cost optimisation models for two time scales. The generation planning model for the investment time scale matches selected periods of hourly electricity load with generation from existing and new power plants. Several scenarios with high levels of wind power were explored. The unit commitment and dispatch model for the operational time scale included forecasts of wind power and load for the electricity spot market time horizon of 36 hours. In some cases, stochastic forecasts were used to increase the accuracy of the cost optimisation.

The results highlight that even without any additional measures, conventional generation can go a long way towards mitigating the variability and forecasting errors at a low cost. The cost can be further cut with additional measures. Flexibility from heat use in district heating systems proved to be especially useful. Periods with surplus generation were mitigated by electric boilers and heat pumps. Heat storage introduced additional flexibility to keep combined heat and power units running even though there is increased variation in the system. Large numbers of electric vehicles can also be helpful, but their contribution is limited by the relatively small amounts of electricity they consume. Discharging their batteries was of limited use.

The results improve the understanding of how energy futures with high amounts of variable power generation can function in a cost-effective manner. This may be useful for decision-making in different realms: politics, policy, energy regulation, power grid operation and planning, and energy business. There is also considerable public discussion on the feasibility of high amounts of variable power generation. The dissertation provides research-based evidence for that discussion.

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