Tobias Aigner

System Impacts from Large Scale Wind Power

Thesis for the degree of Philosophiae Doctor

Trondheim, July 2013

Norwegian University of Science and Technology
Faculty of Information Technology,
Mathematics and Electrical Engineering
Department of Electric Power Engineering

NTNU – Trondheim
Norwegian University of
Science and Technology

NTNU
Norwegian University of Science and Technology

Thesis for the degree of Philosophiae Doctor

Faculty of Information Technology,
Mathematics and Electrical Engineering
Department of Electric Power Engineering

ISBN 978-82-471-4508-1 [printed ver.]
ISBN 978-82-471-4510-4 [electronic ver.]
ISSN 1503-8181

Doctoral theses at NTNU, 2013:198

Printed by NTNU-trykk

Preface

The research work was carried out at the Department of Electric Power Engineering in the Power Systems group at the Norwegian University of Science and Technology (NTNU). My supervisors have been Prof. Olav Bjarte Fosso, Department of Electric Power Engineering (NTNU), and Dr. Terje Gjengedal, Sogn og Fjordane Energi (SFE).

The project was financed by the Norwegian Research Council.

Acknowledgements

First and foremost I would like to thank my supervisors Dr. Terje Gjengedal from Sogn og Fjordana Energi and Prof. Olav Bjarte Fosso from the NTNU for providing me with the opportunity for my doctoral studies and for their guidance through the last years. Their valuable comments, their support, their encouragement and their positive attitude were greatly acknowledged.

Furthermore, I would like to thank Prof. Thomas Hamacher from the Technical University Munich for giving me the opportunity for an research exchange at the Department for Energy Economy and Application Technology. My specials thanks go to Katrin Schaber from the Technical University Munich for the valuable discussions and the successful co-operation.

I want to thank my friends and colleagues from the NTNU and SINTEF Energy Research for their support during the last couple of years. I owe a debt of gratitude to Dr. Hossein Farahmand for his continuous support during my doctoral studies. Without him this thesis would not have been possible. I would also like to thank Dr. Vijay Venu Vadlamudi for his valuable comments and his time spent correcting my thesis. A special thanks goes to Dr. Daniel Huertas Hernando, John Olav Tande, Dr. Bjørn Bakken, Dr. Magnus Korpås and Dr. Leif Warland from SINTEF Energy Research for the valuable discussions and their support. Furthermore, I would like to thank Dr. Steve Völler and Ida Fuchs for the pleasant working climate - all the best for the little family. My special thanks go to Håkon Kile for some fishing tales and for reminding me about beer o' clock. Finally, I would like to thank Dr. Stefan Jaehnert for his knowledge, his comments, his support and for being a friend.

Last but not least I would like to thank my family and friends for their encouragement and their patience during than last couple of years.

Summary

The objective of the European Union to increase the share of renewable energy sources and Wind Power Production in particular, will be a severe challenge for the power system. Unscheduled production changes and remaining forecast deviations will require more control actions and a tighter interconnection between areas. To benefit from distributed generation and geographical smoothing, grid reinforcements and the commissioning of new cross-border interconnections will be necessary. Furthermore, a regulatory framework to exchange energy across country borders has to be established. This thesis studies the impacts of Wind Power Production on the European power system and proposes measures for its efficient and secure integration. These measures include a cost-optimal grid expansion in the European transmission system and the integration of intra-day and regulating power markets in Northern Europe and the Nordic area.

The thesis is divided into two parts.

Part I includes a detailed description of the developed and the applied models. The research includes the development of a detailed model simulating onshore and offshore wind power production on a European level. The production time series data is used as an input to a mathematical model simulating an integrated Northern European intra-day and regulating power market, developed in the course of the thesis. Furthermore, a joint model was established simulating a cost-optimal grid expansion under the the influence of large scale wind power and its effects on a common European day-ahead market.

Part II includes a set of analyses carried out on the aforementioned models. The investigated cases analyse the influence of wind power production on the power system and the power markets, including scenarios for the years 2010, 2020 and 2030. For these scenarios the wind power production is simulated, analysing wind power production variability and the affects on net-load variations in the European system. Cost-optimal grid expansion scenarios for inter-area and cross-border connections are evaluated. Their affect on day-ahead market prices, price volatility and the inter-area load flow is investigated. Taking into account changes in the production portfolio and including the variability of wind power production, the possibility of an integrated regulating power market in Northern Europe is analysed for the years 2010 and 2020. Finally, the possibility of an integrated intra-day market is investigated. It is shown that the integration of national intra-day and regulating power markets can significantly reduce system imbalances and hence costs in the respective market areas.

The main findings of the research are:

- Despite the increasing geographical distribution of wind power facilities in 2020 and 2030, the Wind Power Production on a European scale remains highly variable. The production varies between 2.2% to 62.2% of the installed capacity. Due to the clustering of offshore facilities in the North and Baltic Seas, the annual offshore production in 2020 and 2030 becomes almost intermittent, varying between 0.6% and 92% of the installed capacity.

- For future scenarios, the hour-to-hour variability of WPP will drastically increase up to 19 GW/h in Europe and 11 GW/h in the North Sea and the Baltic Sea. Even though offshore installations only correspond to about 20% to 25% of the total installed capacity in Europe, they are responsible for 40% to 60% of the overall hourly production fluctuations.

- Despite high WPP production variations, the influence on hourly net load ramps in Europe remains rather little. In 2030, the magnitude of hourly net load ramps will exceed the regular load variations only by about 3 GW/h. In the Northern European area, including a large amount of offshore installations, the influence on net load variations is more distinct. In 2030, the maximum net load ramps will increase by about 7 GW/h.

- The volatility of day-ahead market prices largely increases under the influence of WPP. Cost-optimal grid expansion can reduce price fluctuations by enabling the exchange of energy over country-borders. The proposed grid expansion reduces the annual European mean electricity price by around 5%. The price volatility between areas reduces by about 40% to 60%.

- The cost-optimal grid expansion requires investment costs to the tune of 34.1 bn€ in 2020 and 37.1 bn€ in 2030, respectively. On the other hand, the European production costs decrease by about 16 bn€ p.a. and 19 bn€ p.a. in 2020 and 2030.

- The rising wind power penetration level will increase the demand for regulating reserves and balancing power in the system. The WPP forecast length and the possibility to readjust day-ahead market bids largely influences the necessary amount of regulating reserves and balancing power in the system.

- Utilising wind forecasts with a lead time of 3 hours, the simulation results show that without integrated regulating power markets the total balancing costs increases from 2010 to 2020 by about 230 M€. In the same period of time, the integration of regulating markets lead to savings of 170 M€.

- Based on revised wind power production forecasts an integrated intra-day market in Northern Europe can reduce the activation of balancing reserves by about 60% in 2010 and about 70% in 2020. Thus, the balancing costs decrease by 145 M€ and 341 M€ in 2010 and and 2020, respectively.

Contents

Abbreviations

ATC	Available Transfer Capacity
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
COSMO	Consortium for Small Scale Modelling
DMI	Danish Meteorological Institute
DSO	Distribution System Operator
DWD	Deutscher Wetterdienst (German Meteorological Institute)
EMPS	EFI's Multi-area Power-market Simulator
ENTSO-E	European Network of Transmission System Operators for Electricity
ELBAS	Electricity Balance Adjustment System
EWEA	European Wind Energy Agency
FRR	Frequency Restoration Reserves
GHG	Green House Gas
GT	Gas Turbine
HV	High Voltage
IRiE	Integrated Regulating power market in Europe
MAE	Mean Absolute Error
MBI	Market Based Instruments
Met	Meteorological
NMRSE	Normalized Root Mean Square Error
NTC	Net Transfer Capacity
NTC	Net Transfer Capacity

NWP	Numerical Weather Prediction
OMEL	Operador del Mercado Ibérico de Energia, Polo Español
OMIP	Operador do Mercado Ibéico, Polo Portugal
OTC	Over the counter
PSST	Power System Simulation Tool
PV	Photovoltaic
TGC	Tradable Green House Certificates
TSO	Transmission System Operator
RR	Replacement Reserves
UCTE	Union for the Co-ordination of Transmission of Electricity
URBS	Urban Research Toolbox: Energy Systems
WVs	Water Values
WPP	Wind Power Production

Nomenclature

Wind power model

Indices	
g	Geographical coordinates
$[]$	Rotated coordinates
N	Pole rotated coordinates
Parameters	
X, Y, Z	Cartesian coordinates
$\widetilde{X}, \widetilde{Y}, \widetilde{Z}$	Rotated coordinates
H_f	Scaling factor
h_{ref}	Reference hub height
z_0	Surface roughness length
h_{meas}	Measurement height
V_H	Wind speed velocity at hub height
V_M	Measured wind velocity
λ, λ_g^N	Longitude in the rotated and the geographical system, respectively
φ, φ_g^N	Latitude in the rotated and the geographical system, respectively
P_N	Pole coordinates
u, u_g	Zonal wind speed in the rotated and the geographical system, respectively
v, v_g	Meridonal wind speed in the rotated and the geographical system, respectively

δ	Deviation angle

URBS-EU

Sets and Indices	
$i \in I$	Process type (generation and transmission)
$x \in X$	Model areas
$t \in T$	Time steps
Parameters	
κ_i^l	Annuity of investment costs
κ_i^F	Maintenance costs
Variables	
$C_i(x)$	Power plant and storage in- and output capacity
$E_i^{out}(x,t)$	Electricity production in area x at time step t
$E_{Transmission}^{in}$	Electricity imports
$E_i^{in}(x,t)$	Stored Energy, sum of exports in area x at time step t
$CN_i(x)$	Capacity additions in area x
κ_i^{Var}	Variable costs

Power System Simulation Tool (PSST)

Superscript	
D	Day-ahead dispatch
I	Intra-day dispatch
R	Real-time dispatch
$\uparrow/\downarrow$	Upward/ Downward
$^{-}/_{-}$	Maximum/ Minimum
rat	Rationing
hyd	Hydro units
h	Hydro generators
g	Thermal units
th	Thermal units

win	Wind facilities
l	Transmission lines
Sets and Indices	
$\tau \in T$	Hour in simulation period
$a, b \in BR$	Balancing regions
$a', b' \in BA$	Balancing areas
$g \in G$	Thermal generators
$lf \in LF$	Load following units
$gr \in GR$	Regulating resources
$h \in H$	Hydro generators
$w \in W$	Wind facilities
$hvdc \in HVDC$	HVDC connections
$l \in Line$	AC transmission lines
$i, j \in Bus$	Buses in the system with Bus_a and Bus_b being subsets of buses situated in region a or b respectively
Functions	
$F_\tau^D(\cdot), F_\tau^I(\cdot), F_\tau^R(\cdot)$	Cost functions of day-ahead, intra-day and real time market, respectively
Parameters	
$\overline{P}_h^{hyd}, \underline{P}_h^{hyd}$	Maximum and minimum hydro power production capacity of hydro unit h, respectively [MW]
$C_h^{hyd,D}, C_h^{hyd,I}$	Marginal cost of hydro unit h in day-ahead and intra-day dispatch [EUR/MWh], respectively
$\uparrow C_{h,\tau}^{hyd,R}, \downarrow C_{h,\tau}^{hyd,R}$	Marginal cost of hydro unit h for up- and downward regulation in real-time dispatch at time step τ, respectively [EUR/MWh]
$Q_{h,\tau}^{hyd,D}, Q_{h,\tau}^{hyd,I}$	Hydro reservoir inflow in day-ahead and intra-day dispatch of hydro unit h at time step τ, respectively [MWh]
$Rl_{h,\tau}^{hyd,D}, Rl_{h,\tau}^{hyd,I}$	Day-ahead and intra-day reservoir level of hydro unit h at time step τ, respectively [MWh]
$\overline{P}_g^{th}, \underline{P}_g^{th}$	Maximum and minimum available thermal power production capacity of thermal unit g, respectively [MW]
$\overline{P}_{gr}^{th}, \underline{P}_{gr}^{th}$	Maximum and minimum available balancing power production capacity of thermal unit g, respectively [MW]

$C^{th,D}_{g,\tau}, C^{th,I}_{g,\tau}$	Marginal cost of thermal unit g in day-ahead and intra-day dispatch at time step τ, respectively [EUR/MWh]
$\uparrow C^{th,R}_{g,\tau}$,$\downarrow C^{th,R}_{h,\tau}$	Marginal cost of thermal unit g for up- and downward regulation in real-time dispatch at time step τ, respectively [EUR/MWh]
$Cs^{th}_{g,\tau}$	Start-up cost of thermal unit g [EUR]
$\uparrow T^{th}_{g}, \downarrow T^{th}_{g}$	Minimum up- and down time of thermal unit g, respectively [h]
$\overline{P}^{hvdc}_{ij}$	Maximum HVDC cable transmission capacity from bus i to bus j [MW]
$\overline{P}^{l}_{ij}$	Maximum AC transmission capacity from bus i to bus j [MW]
$B_{i,j}$	Susceptance between bus i and bus j
$NTC_{a'b'}$	Net Transfer Capacity between balancing areas a' and b' [MW]
$\uparrow Re_{a'}, \downarrow Re_{a'}$	Up- and downward reserve requirements for balancing area a' [MW]
$\uparrow Re_{a}, \downarrow Re_{a}$	Up- and downward reserve requirements for balancing region a [MW]
$\widetilde{P}^{dev,R}_{i,\tau}$	Real-time imbalance at bus i at time step τ [MW]
C^{rat}	Rationing cost
L_{τ}	Length of time step [h]

Variables

$\Delta\uparrow P^{hyd,R}_{h,\tau}, \Delta\downarrow P^{hyd,R}_{h,\tau}$	Hydro power up- and downward regulation of hydro unit h at time step τ in real-time dispatch, respectively [MW]
$\Delta\uparrow P^{hyd,R}_{i,\tau}, \Delta\downarrow P^{hyd,R}_{gr,\tau}$	Hydro power up- and downward regulation at bus i at time step τ in real-time dispatch, respectively [MW]
$P^{hyd,D}_{h,\tau}, P^{hyd,I}_{h,\tau}$	Hydro power production of unit h at time step τ in day ahead and intra-day dispatch, respectively [MW]
$P^{hyd,D}_{h,i}, P^{hyd,I}_{h,i}$	Hydro power production of unit h at bus i in day-ahead and intra-day dispatch, respectively [MW]
$\Delta\uparrow P^{th,R}_{gr,\tau}, \Delta\downarrow P^{th,R}_{gr,\tau}$	Thermal up- and downward regulation for thermal unit gr at time step τ in real-time dispatch, respectively [MW]

$\Delta{\uparrow}P^{th,R}_{i,\tau}, \Delta{\downarrow}P^{th,R}_{i,\tau}$	Thermal up- and downward regulation at bus i at time step τ in real-time dispatch, respectively [MW]
$P^{th,D}_{g,\tau}, P^{th,I}_{g,\tau}$	Thermal power production of unit g at time τ in day ahead and intra-day dispatch, respectively [MW]
$P^{th,D}_{g,i}, P^{th,I}_{g,i}$	Thermal power production of unit g at bus i in day-ahead and intra-day dispatch, respectively [MW]
$Str^{th,D}_{g,\tau}, Str^{th,I}_{g,\tau}$	Approximate relative start-up cost of thermal unit g at time step τ in day-ahead and intra-day dispatch, respectively [0,1]
${\uparrow}T^{th,D}_{g,\tau}, {\downarrow}\, T^{th,D}_{g,\tau}$	Actual up- and down time of thermal unit g at time τ, respectively [h]
$up^{th,D}_{g,\tau}, do^{th,D}_{g,\tau}$	Binary variables for thermal unit g at time τ, respectively [0,1]
$X^{th,D}_{1,g,\tau}$	Per unit production between 0 and minimum production of thermal unit g in day ahead dispatch, $\in$ [0,1]
$X^{th,D}_{2,g,\tau}$	Per unit production between minimum and maximum production of thermal units in day-ahead dispatch $\in$ [0,1]
$X^{th,D}_{3,g,\tau}$	Spinning reserve capacity of thermal unit g in day-ahead dispatch
$P^{win,D}_{w,\tau}, P^{win,I}_{w,\tau}$	Wind power production of unit w at time τ in day-ahead and intra-day dispatch, respectively [MW]
$\Delta P^{win,I}_{w,\tau}, \Delta P^{win,R}_{w,\tau}$	Wind power forecast deviation of unit w at time τ in intra-day and real-time dispatch, respectively [MW]
$ATC_{a'b',\tau}$	Available Transfer Capacity between balancing areas a' and b' at time step τ [MW]
$\delta^{D}_{i,\tau}, \delta^{I}_{i,\tau}\delta^{R}_{i,\tau}$	Voltage angles at bus i for day-ahead, intra-day and real-time dispatch, respectively [radians]
${\uparrow}imp^{D}_{a'b',\tau}, {\downarrow}imp^{D}_{a'b',\tau}$	Implicit allocated transmission capacity in day-ahead dispatch for up- and downward regulating reserve exchange from balancing area a' to b' [MW]
$P^{hvdc,D}_{ij,\tau}, P^{hvdc,I}_{ij,\tau}$	HVDC exchange on interconnection between buses i and j in day-ahead and intra-day dispatch, respectively [MW]
$P^{l,D}_{ij,\tau}, P^{l,I}_{ij,\tau}, P^{l,R}_{ij,\tau}$	AC power exchange on transmission lines between bus i and bus j in day-ahead, intra-day and real-time dispatch, respectively [MW]

$P_{i,\tau}^{rat}$	Load rationing at bus i [MW]
$P_{i,\tau}^{L,D}, P_{i,\tau}^{L,I}$	Load demand [MW]

Chapter 1

Introduction

This thesis deals with the integration of large scale wind power production in the European power system. The motivation for this thesis is explained in Section 1.1. Section 1.2 briefly explains the scope of the research. While Section 1.3 outlines the scientific contributions, Section 1.4 lists the publications on which this thesis is based. Section 1.5 explains the thesis structure and gives a brief overview of the content in each chapter.

1.1 Research motivation

Within the last two decades the increasing public awareness and the knowledge about green house gases and their effect on global warming enforced the political willingness to reduce CO_2 emissions, to promote energy production from renewable energy sources, and to enhance the energy efficiency. With the release of the climate and energy package *(EU directive 2009/29/EC)*, the EU commission set binding targets to ensure that the EU member states would meet the ambitious climate and energy targets for 2020 [1, 2]. These targets, also known as *"20-20-20"*, set three key objectives for the EU member states:

- A 20% reduction in EU greenhouse gas emissions from their corresponding levels in 1990.
- Raising the share of EU energy consumption produced from renewable resources to 20%.
- A 20% improvement in the EU's energy efficiency.

The commitment of the EU member states to establish an environmental friendly and sustainable energy production was underpinned by the release of the *Energy Roadmap 2050 (EU directive 2009/29/EC)*, aiming to reduce CO_2 emissions by at least 50% below their 1990-levels [3]. To achieve these ambitious objectives, the EU member states introduced a set of incentives to promote Renewable Energy Sources (RES) in the European power system. Besides other RES such as solar power, biomass and hydro, wind power is considered as a key technology for sustainable energy production in Europe.

Based on various installation forecasts, the total capacity in Europe will continuously increase over the next years, and is assumed to reach a total capacity of about 270 GW in 2020 [4].

Even though the increasing geographical distribution of wind power production facilities will lead to a more stable overall production, wind power, like other RES, remains inherent to production variations. Especially, future offshore installations bundled in small geographical areas in the North and Baltic Seas will contribute to the overall wind power production variability. Besides the production variability, the predictability of wind power production is of great concern. Even though the accuracy of numerical weather prediction models has considerably improved, the predictability of wind power production remains limited. Forecast errors cause unscheduled production changes, inducing a high degree of production uncertainty in the power system.

Since electricity cannot be stored easily in large scale, production fluctuations and unscheduled changes in wind power production have to be balanced by conventional power plants in order to maintain the supply and demand equilibrium.

The system impacts of wind power production are evident in areas with a high share of RES. In countries like Denmark, where the penetration level is around 26% (2011), temporarily production exceeds the corresponding area demand [5]. This imposes severe challenges for system operation including an increased demand for regulating reserves along with improved production flexibility of thermal power plants. Besides, backup capacity is required to replace wind power production during times with low production [6]. Denmark constitutes only a small part of the European system, and since it is highly interconnected with its neighbouring areas, potential operational challenges can be solved with external support.

The example of Denmark illustrates that the rising share of wind power production requires a revision of the operational strategy in the European power system and a better interconnection between the European countries and the grid zones. Instead of a local or a national approach, a multinational cooperation is required to assure a secure and efficient integration of RES in the European power system.

Especially in areas along the North and Baltic Seas, already having a high share of wind power production, a further increase in the penetration level will evoke severe problems. To utilize the possibilities of the European power system with respect to production flexibility and the exchange of power production, a sufficient amount of transmission capacity has to be available. Bottlenecks on cross-border and inter-area transmission lines limit the power exchange between neighbouring areas. This decreases the power system's efficiency due to cycling losses, a non-optimal use of conventional generators, an unnecessarily high amount of balancing sources and the curtailment of wind power production. Since a sufficient amount of transmission capacities has to be available not only to utilise the possibilities of distributed wind power production generation and reduce its affect on the power system, but also for the bulk transport of energy from the coastal areas around the North and Baltic Seas to the load centres further south.

Besides transmission grid expansion, a multinational regulatory framework is required defining common rules for trade and transmission. This includes the implementation and the integration of day-ahead, intra-day and balancing markets. The possibility to trade electricity over country borders not only enhances the security level in the power system but also increases the efficiency by giving market participants the possibility to procure power from the least cost generation sources. Due to the limited predictability of wind power production, the development of integrated Northern European intra-day and balancing markets will be necessary to enable wind power producers to adjust their day-ahead market bids and balance their production portfolio in a cost efficient manner.

1.2 Scope of the thesis

The scope of this thesis is to simulate wind power production and assess variations in on a short term basis, including gradients and smoothing effects, depending on the geographical distribution of the wind farms and how these variations may affect system operation. This includes the power system as well as the power markets. The objective is to develop and suggest solutions for a cost efficient and secure integration of wind power production in the power system, based on a scientific foundation.

This thesis addresses:

- The modelling of wind power production on a European level

- The possibilities of a cost optimal grid expansion of inter-area transmission connections to remove bottlenecks and to enable a further integration of wind power production in the power system

- The integration of day-ahead, intra-day and real-time power markets in Northern Europe

1.3 Scientific contributions

The scientific contributions of the thesis are:

- The development of a detailed model simulating wind power production on a European level. The model is based on a high resolution numerical weather prediction model along with an extensive data set of European on- and offshore wind power facilities, including production scenarios for 2010, 2020 and 2030.

- The development of an enhanced model simulating a common European day-ahead market. The model is based on the Power System Simulation TOOL (PSST) developed by SINTEF Energy Research. The original model has been extended by implementing the technical constraints of thermal generators, e.g. minimum up- and down times, in order to simulate the unit-commitment problem in a more realistic way.

- The development of a mathematical model to simulate an integrated Northern European intra-day market, which is based on the outcome of the common day-ahead spot market. The intra-day market is simulated based on a continuous revision of wind power forecasts. It is used to assess the integration of national intra-day markets.

Based on the above models listed above, a set of case studies is executed, which analyse:

- The variability and the predictability of wind power production on a full European level, including on- and offshore scenarios for 2010, 2020 and 2030. Hourly and annual production variations and their influence on net load ramps in the European system are investigated.

- The impacts of a cost optimal macroscopic grid expansion on the European power system and its effects on day-ahead market prices and load flow. The grid expansion costs and the socio-economic benefit are evaluated.

- The possibilities of balancing market integration in Northern Europe under the influence of large scale wind power production. The simulations are based on wind power production forecast with different lead times, illustrating the influence of forecast deviations on tha balancing market operation.

- The possibilities of an integrated Northern European intra-day market to reduce effects of forecast deviations on the procurement of balancing reserves. Various market layouts are applied and evaluated based on their efficiency with respect to system costs and remaining deviations.

1.4 List of publications

The main research contributions are presented in the following publications.

Publication A T. Aigner and T. Gjengedal. Modelling wind power production based on numerical weather prediction models and wind speed measurements. In *Proc. 17th Power Systems Computation Conferences (PSCC), Stockholm*, 2011

Publication B S. Jaehnert, T. Aigner, G. Doorman and T. Gjengedal. Impact of large scale wind integration on power system balancing. In *Proc. IEEE PowerTech Conference, Trondheim*, 2011

Publication C T. Aigner and T. Gjengedal. Modelling the northern European electricity market. In *Proc. of IEEE PES General Meeting, San Diego*, 2012

Publication D T. Aigner, K. Schaber, T. Hamacher and T. Gjengedal. Integrating wind - Influence of transmission grid extension on European electricity market prices. In *Proc. of IEEE PES Innovative Smart Grid Technologies (ISGT), Berlin*, 2012

Publication E T. Aigner, S. Jaehnert, G. Doorman and T. Gjengedal. The Effect of Large-Scale Wind Power on System Balancing in Northern Europe. In *IEEE Transactions on Sustainable Energy*, 2012

Publication F T. Aigner, T. Gjengedal and O.B. Fosso. Assessing wind power production variability and net load variations on a European level. Submitted to *Wiley & Sons Wind Energy Journal*, 2013.

Publication G T. Aigner, T. Gjengedal and O.B. Fosso. Large scale wind power production in Northern Europe: Possibilities of an integrated intraday market in Northern Europe. Submitted to *Elsevier Applied Energy*, 2013

The research included following additional publications, which are offshorts of this thesis.

Publication H T. Aigner and T. Gjengedal. Detailed wind power production in Northern Europe. In *Proc. Renewable Energy Conference 2010, Yokohama*, 2010

Publication I H. Holttinen, J. Kiviluoma, A. Estanqueiro, E. Gómes-Lázaro, B. Rawn, J. Dobschinski, P. Meibom, E. Lannoye, T. Aigner, Y. Huei

Wan and M. Milligan. Variability of load and net load in case of large scale distributed wind power. In *Proc.10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Farms, Aarhus*, 2011

Publication J H. Farahmand, T. Aigner, G. Doorman, M. Korpås and D. Huertas-Hernando. Balancing Market Integration in the Northern European Continent: A 2030 Case Study. In *IEEE Transactions on Sustainable Energy*, 2012

1.5 Thesis outline

The thesis is prepared on the basis of the previously listed publications. The publications are partly revised and updated with recent results. Chapters 3 to 10 include parts of these publications. A summary of the content and the publication number is given at the beginning of each chapter. The main body of the thesis is split into two parts. Part I includes a description of the applied models. Part II focuses on case studies and simulation results.

The thesis is structured as follows:

Chapter 2 compiles the background for the research.

PART I

Chapter 3 describes the wind power production model used to simulate the European wind power production. The model is capable of simulating actual and future on- and offshore scenarios. The simulation results are used for a theoretical discussion of wind power production in Chapter 7 as well as an input to the subsequent models. The chapter is based on **Publications A** and **F**.

Chapter 4 includes a description of the day-ahead spot market model EMPS and the regulating power market model IRiE, used for the simulations in **Publications B** and **E**

Chapter 5 describes the transmission grid expansion model URBS-EU. The chapter includes an extended model description of **Publication D**.

Chapter 6 presents a full mathematical description of the day-ahead, intra-day and real-time market models using the Power System Simulation model (PSST). The chapter is based on **Publication C**

PART II

Chapter 7 is based on **Publications A** and **F**, which investigates the variability and the predictability of wind power production on a European level. Furthermore, the influence on net load variations in the European power system is investigated.

Chapter 8 discusses the impact of transmission grid expansion under the influence of large-scale wind power production. The influence on market prices and load flow, before and after the evaluated grid expansion scenarios, are analysed. The costs and benefits of the proposed grid expansion are evaluated. The chapter is based on **Publications C** and **D**.

Chapter 9 discusses the impacts from large scale integration of wind power production on the regulating power market outcome. The first stage of the analysis is presented in **Publication B**. The chapter is extended by the findings included in **Publication E**

Chapter 10 investigates the possibilities of an integrated northern European intra-day market. The evaluated cases along with the respective results are taken from **Publication G**.

Chapter 11 finalises the thesis. It includes a summary of the the thesis and gives recommendations for further research topics.

Chapter 2

Background

This chapter compiles a background of the Wind Power Production (WPP) in Europe, the European power system and the liberalised European electricity markets. Section 2.1 describes the actual status of WPP in the European system and gives an overview of the legislative framework (Subsection 2.1.1), the Renewable Energy Sources (RES) support schemes (Subsection 2.1.2), the installation scenarios (Subsection 2.1.3) and the challenges for the power system (Subsection 2.1.4). While Section 2.2 includes a description of the European power system, Section 2.3 deals with the contemporaneous process of market integration.

2.1 Wind power production in Europe

2.1.1 Legislative Framework

In 1997, the introduction of the Kyoto protocol was the first milestone in a great many of agreements to reduce GHG emissions. The Kyoto Protocol is an international agreement linked to the United Nations Framework Convention on Climate Change [7]. The major feature of the Kyoto Protocol is that it sets binding targets for 37 industrialized countries and the European community. The binding targets of the protocol are defined in Article 3, stating that: *"The Parties included in Annex I shall, individually or jointly, ensure that their aggregate anthropogenic carbon dioxide equivalent emissions of the greenhouse gases listed in Annex A do not exceed their assigned amounts, calculated pursuant to their quantified emission limitation and reduction commitments inscribed in Annex B and in accordance with the provisions of this Article, with a view to reducing their overall emissions of such gases by at least 5 per cent below 1990* *levels in the commitment period 2008 to 2012"* [7, p.3].

Since the 5% goal of the Kyoto Protocol is rather conservative, the European Commission initiated the white paper 'Energy for the Future: Renewable Sources of Energy' in the same year [8]. The EU member states were encouraged to develop the legislative and regulatory framework for the expansion of renewable sources in the power system with the goal to achieve a 12% penetration of RES by 2010 [8].

In 2001, the subsequent directive 2001/77/EG on the promotion of electricity from RES in the internal electricity market was introduced. Even though the directive did not include binding targets, the purpose was to *"...promote an increase in the contribution of renewable energy sources to electricity production in the internal market for electricity and to create a basis for a future Community framework thereof."* [9, p.3].

Already in 2007 it was obvious that the ambitious 2010 targets could not be met by all EU member states. Nevertheless, the willingness of the European Commission to cut CO_2 emissions was underpinned by the introduction of the energy road map *"Renewable energies in the 21st century"* and the subsequent EU proposal *"An Energy Policy for Europe"*, aiming to define a longer term energy policy for Europe [10, 11].

Directive 2009/28/EC finally translated the previous decelerations of intent into binding targets [1]. The newly introduced targets for the year 2020 aim to:

- Reduce CO_2 emissions by 20% compared to to the existing levels in 2005
- Cover 20% of the gross final energy consumption from RES
- Increase energy efficiency by 20%

The last step to reduce CO_2 emission in the European union was made with the implementation of EU directive 2009/29/EC. The directive defines a long term goal for 2050, aiming to reduce the global Green House Gas (GHG) emission by 50% below their 1990 levels [12].

2.1.2 Support schemes in Europe

Even though the political framework was established by the implementation of the above mentioned EU directives, support schemes had to be introduced to achieve the energy policy goals of sustainability, security of supply and competitiveness. Directive 2001/77/EG plays a key role in the implementation of national support schemes, aiming to promote an increase in the contribution of renewable energy sources to electricity production.

The relatively high costs for installation and maintenance in combination with the production uncertainty, leave an economical disadvantage of WPP, compared with conventional production sources. To promote the installation and to increase the attractiveness for power producers to invest in RES, the EU members states established a variety of support schemes. The incentives can mainly be divided into two Market Based Instruments (MBIs) [13, 14]:

- Quantity-based market instruments
- Price-based market instruments

While most of the EU member states have implemented price-based MBIs, only seven member states use quantity-based MBIs or a mix of various support schemes respectively(see Figure 2.1). The most important MBIs and their effectiveness are explained in the following Subsections.

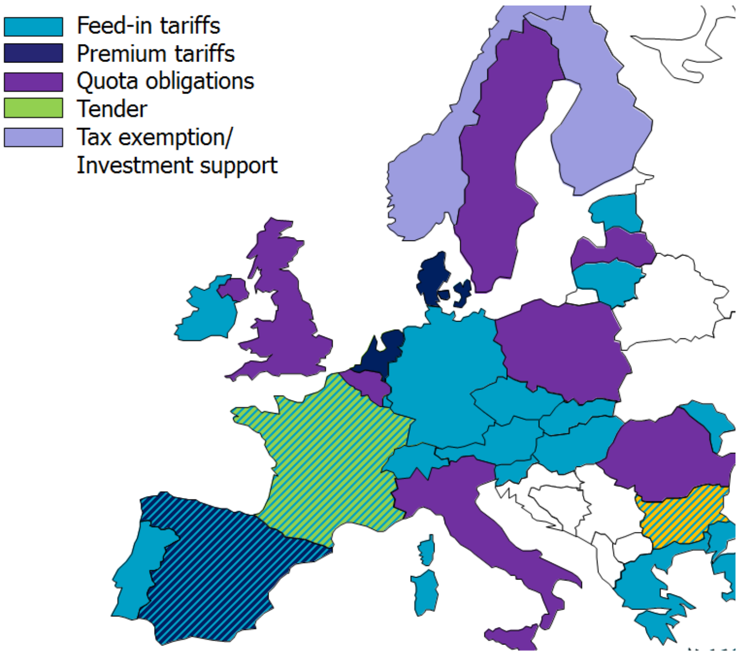


Figure 2.1: Support schemes in Europe in 2012

2.1.2.1 Quantity-based market instruments

i) *Quota obligations*
Quota obligations are used by governments to enforce consumers, suppliers

and producers to procure a certain percentage of their power consumption from RES. This obligation is usually implemented by the issuing of Tradable Green House Certificates (TGCs). Power producers can sell electricity from RES at the power market price, or provide green certificates to market participants. Suppliers and consumers can prove the fulfilment of the quota obligations using the issued TGCs. If suppliers cannot prove that they have fulfilled the obligations, they have to pay a penalty to the government.

ii) *Tendering*
In the tendering process, a tender is announced for a certain amount of electricity from a specific RES (e.g., solar, wind). The bidding process ensures that the cheapest offer is accepted.

2.1.2.2 Price-based market instruments

i) *Feed-in tariffs and premiums*
Feed-in tariffs are the preferred MBIs among the European countries. Feed-in tariffs are granted to both industrial and private electricity producers for the electricity from RES which is fed into the electrical grid. Therefore, producers are reimbursed for the produced energy instead of RES capacity in their production portfolio. The tariffs are regulated by governmental orders, taking the respective RES technology and the installed capacity of the production unit into account.

Both support schemes are usually guaranteed for a period of ten to twenty years. The regulatory framework can be used to promote specific RES by granting higher feed-in tariffs or/ and advanced premium payment.

While regular feed-in tariffs are purely based on government orders, premiums are fixed extra payments added on top of the regular market price. The advantage from the perspective of a sustainable energy producer is that the premium price model causes a high financial turnover. On the other hand, the variable price structure of premiums leaves a planning uncertainty for new investments since there is no exactly definable basis for revenue calculations.

ii) *Fiscal incentives*
Fiscal incentives mainly include tax reductions or exceptions, and are mainly used as supplementary instruments to promote RES. Power producers of renewable energy are exempted from certain taxes, mainly carbon taxes, as a compensation for the competitive disadvantages of RES. The success of tax incentives is mainly based on the tax level in the respective country. Especially in the Nordic countries, where there is a high

energy tax level, these incentives can be used to promote and stimulate the construction of new RES facilities in the system.

The effectiveness of each support scheme, and thus the ability to deliver an increasing amount of electricity produced by RES, largely depends on the country-specific regulatory and legislative framework. Nevertheless, a comparison of the main support schemes suggests that feed-in tariffs achieve the highest level of penetration from RES in the electrical system [14].

2.1.3 Wind power installations in Europe

The previously described support schemes have drastically increased the share of RES in the European power system. The transition from a mainly thermal dominated power system to a system widely affected by RES and WPP in particular will further continue. The latest available data on a European level displays that a share of 12.5% of the EU-27 gross energy consumption was reached in 2010, out of which 7.7% was produced by wind power [15]. Therefore, wind energy is the third largest source of renewable energy in Europe after biomass and hydro power[15].

It is assumed that the share of wind power will further increase in the future. Especially in Northern Europe, where Photovoltaics (PV) cannot provide the required efficiency, wind power will be one of the key technologies to reach the 2020 targets. Depending on the source, the predicted installed WPP capacity in 2020 will rise up to 200 GW and can reach up to 300 GW in 2030 (see Figure 2.2). Other installation forecasts predict an even higher installed capacity of up to 255 GW in 2020 [16].

The share of offshore installations in the North Sea and the Baltic Sea is especially expected to increase extraordinarily. The higher offshore wind speeds, together with an assumed decrease in investment costs for turbines and cables, will further increase its attractiveness to investors [18]. Furthermore, the public acceptance for offshore wind farms is high, especially in coastal areas with a high density of already existing onshore installations.

2.1.4 Challenges of WPP

Even though the advantages of WPP with respect to GHG emissions and sustainability are obvious, its integration into the power system is a challenge. Holttinen [19] states that WPP affects the electrical system on all time-scales. On a shorter time-scale, the system will mainly be affected by voltage variations, increasing demand for operating reserves, transmission and distribution losses, the replacement of conventional energy production, and the curtailment

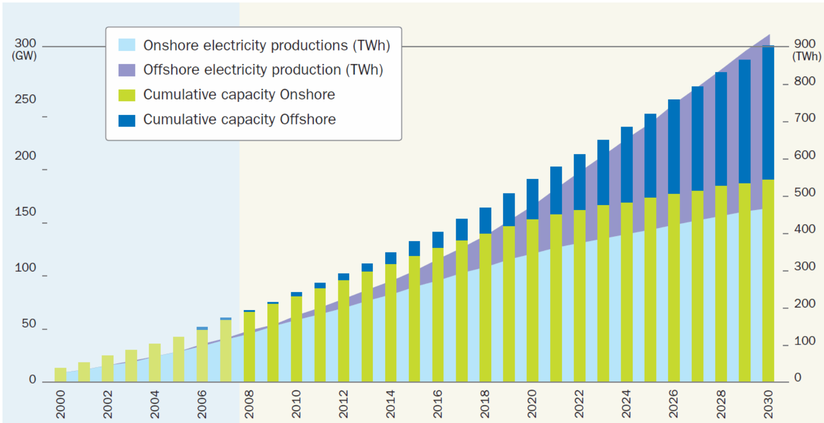


Figure 2.2: Installation scenario the WPP in Europe [17]

of WPP. These negative repercussions will further increase in the future with an increasing penetration level of WPP in the power system.

The main challenge of WPP is its varying production pattern. Unlike thermal power plants having a scheduled production pattern, wind power is subject to continuous production changes. This requires a system providing sufficient production flexibility in order to balance the fluctuations accompanied by wind power production. Even though the geographical distribution of generation facilities and the resulting smoothing effects will reduce the overall production variability, WPP remains inherent to variations and production ramps.

Furthermore, the predictability of wind power is of great concern. Within the last couple of years newly introduced numerical weather prediction models have highly increased the accuracy of wind speed forecasts. Nevertheless, the remaining forecast deviations lead to uncertainties in the production scheduling and the unit-commitment of conventional power plants [20].

Besides, a certain amount of backup capacity is required in the power system to replace wind power during times of low production. Especially in islanded or areas with weak interconnections to neighbouring areas the power system has to provide a sufficient amount of production reserves has to be available [6].

2.2 The European power system

2.2.1 System design

In the beginning of the 1990s, the transformation and reorganization of the European electricity sector was launched by the Electricity Act in Wales and England, followed by the Energy Act in Norway and the European Electricity Market directive 1996/92/EC [21]. The objective of restructuring was to transform the vertically integrated utilities, operating as franchised monopolies, into competitive electricity markets, facilitating an efficient production, transmission and retail of electricity [22]. Besides an increased efficiency in a competitive market environment, the objective of the European energy policy was to provide a secure, sustainable and competitive energy supply for Europe.

To reach these goals, the unbundling of generation, transmission and distribution was the focus of EU directive 2003/54/EC [23]. Furthermore, the directive defined common rules for an internal electricity market and a non-discriminatory access to the network, based on the third-party access rights.

In 2009, the Third EU Energy Package was launched by the introduction of EU directive 2009/72/EC [24], repealing directive 2003/54/EC. A revised directive was necessary since the EU commission came to the following conclusion: *"In the light of the dysfunction in the internal market in electricity, the European Commission considered it necessary to redefine the rules and measures applying to that market in order to guarantee fair competition and appropriate consumer protection"* [25].

Article 9 therefore directly addresses the unbundling of vertically integrated utilities based on an effective separation of supply and generation activities from network operations:

"Member States shall ensure that from 3 March 2012:

a) *each undertaking which owns a transmission system acts as a transmission system operator;*

b) *the same person or persons are entitled neither:*

    i) *directly or indirectly to exercise control over an undertaking performing any of the functions of generation or supply, and directly or indirectly to exercise control or exercise any right over a transmission system operator or over a transmission system; nor*

    ii) *directly or indirectly to exercise control over a transmission system operator or over a transmission system, and directly or indirectly to exercise control or exercise any right over an undertaking performing any of the functions of generation or supply."*

Furthermore, the Directive addresses and encourages the member states and regulating authorities to:

"...cooperate with each other for the purpose of integrating their national markets at one or more regional levels, as a first step towards the creation of a fully liberalised internal market. In particular, the regulatory authorities where Member States have so provided or Member States shall promote and facilitate the cooperation of transmission system operators at a regional level,including on cross-border issues, with the aim of creating a competitive internal market in electricity, foster the consistency of their legal, regulatory and technical framework and facilitate integration of the isolated systems forming electricity islands that persist in the Community."

By now, the European power system is split into five synchronous areas (see Figure 2.3), mutually interconnected by DC transmission corridors. The independent TSOs, organized in the European Network of Transmission System Operators for Electricity (ENTSO-E), now coordinate the various European synchronous power systems under one body. This will lead to a further standardization of technical regulations and a gradual convergence of system operation.

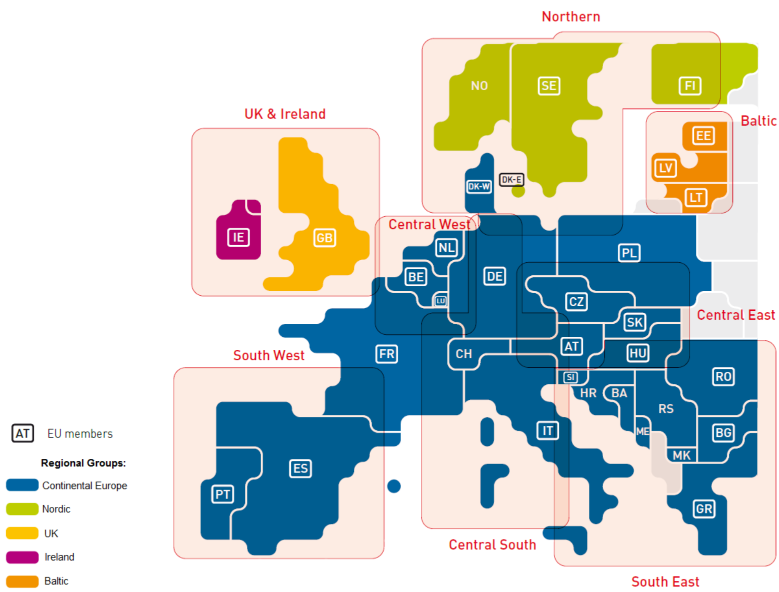


Figure 2.3: Synchronous regions and coordination areas in Europe [26]

2.2.2 System operation

The restructuring of the electrical system and the unbundling of hierarchical structures has led to a division between the physical flow of electricity, including power generation, transmission and consumption, and the financial flow of money, connecting producers, grid owners and consumers via the power markets (see Figure 2.4).

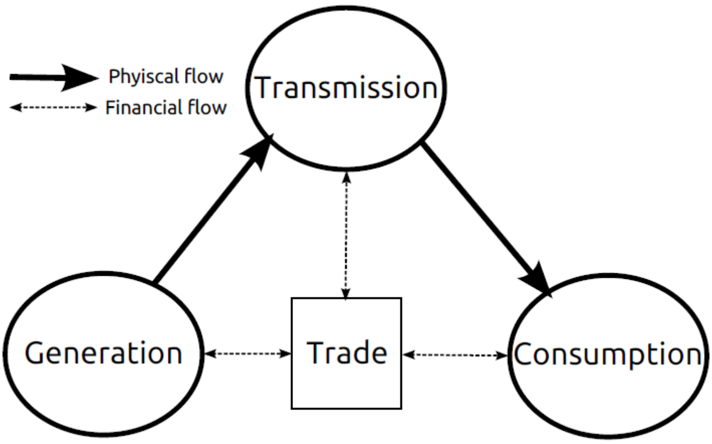


Figure 2.4: Layout of an unbundled electricity system [5]

2.2.2.1 Generation

Power generation in Europe is largely dependent on the energy sources in the respective area. While the Nordic area is a hydro-thermal system, the continental European region as well as the UK, Ireland and Baltic area are largely dominated by thermal production facilities. Besides nuclear power, fossil fuels such as coal and gas represent the main share in the respective area production portfolio. Due to the political willingness to cut CO_2 emissions and the implementation of binding requirements, e.g., the 20-20-20 targets, defined in directive 2009/28/EC [1], the system will successively transform from a thermal system into a system widely affected by RES. Not only WPP will be of a rising concern in the electrical system, but also PV and Biomass will play a key role in the future power production. Due to the unique features of electricity, e.g., instant balance of generation and consumption and a lack of large scale storing possibilities, along with the variable nature of most RES, a revision of the power plant portfolio will be necessary.

Since the generator portfolio of most power producers includes several power plants and various types of production sources, the production schedule has to be optimized in order to minimise production losses. The optimization, called unit commitment and dispatch, takes the expected demand, the respective marginal production costs and the technical generator constraints into account.

The variability of WPP along with the production uncertainty will largely affect the unit-commitment and subsequent generator dispatch of conventional generators. Especially, the technical constraints of thermal generators, e.g., minimum up- and down times, limit the unit-commitment of power plants. Therefore, a large share of fast starting generators, e.g., gas turbines or hydro power plants, providing the required production flexibility will be necessary for a secure integration of large scale wind power.

2.2.2.2 Transmission

The purpose of the transmission system is to connect the power producers with the consumers of electricity. The transmission system is vertically divided into a transmission and a distribution grid, distinguished by the associated voltage levels. While the transmission grid is owned and operated by the Transmission System Operator (TSO), the distribution grid is operated by the Distribution System Operator (DSO). The role of the respective system operators is to co-ordinate and guarantee equilibrium between supply and demand, and to manage the security of the power system in real time in a manner that avoids fluctuations in frequency or interruptions of supply.

In addition to their roles of managing real-time dispatch and system security, the system operators are also responsible for grid maintenance and future grid expansion planning, facilitating the commissioning of new generators.

2.2.2.3 Consumption

Electricity consumption is the main driver in the power system. The generation pattern as well as the transmission is scheduled based on stochastic demand forecasts predicting daily and annual demand variations. Each country or area in the European power system shows specific demand patterns which have to be considered in the system scheduling.

2.2.2.4 Trading

In the traditional organisation of the electricity sector, consumers were forced to buy electricity at a set price from the franchised monopolies in the respective areas. However, the restructuring of the electricity sector, competitive power markets were established, connecting consumers and producers, based on the principle of economic supply and demand. The balance is created by price, which consumers and producers observe and adapt [27]. The electricity markets enable the market participants to trade electricity bilaterally or on a spot market basis. With the restructuring, various market layouts have been established in the in the European power system.

The following description focuses on the NordPool market design used in the Nordic area. The wholesale electricity market mechanism is typically divided into a set of consecutive steps including the forward or futures market, the day-ahead, intra-day and balancing market. Figure 2.5 displays the market layout in the Nordic area.

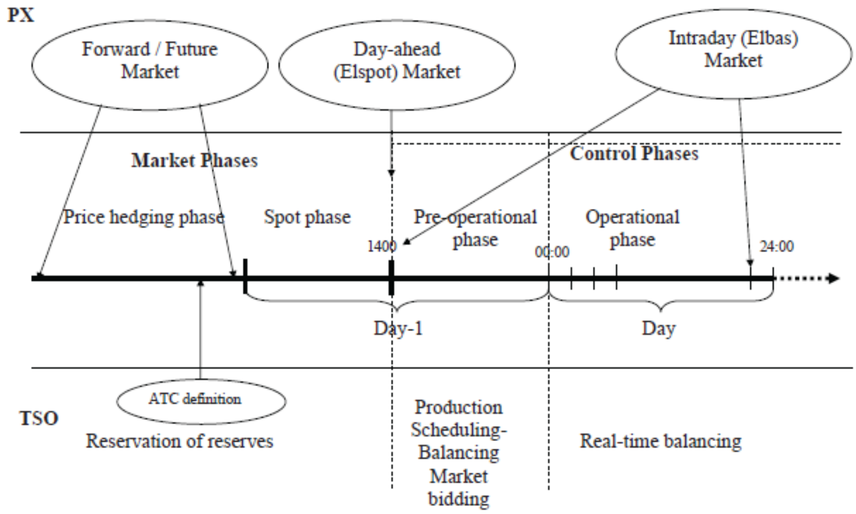


Figure 2.5: Overview of the Nordic electricity market [28]

2.2.2.5 Forward/Future market

The forward market is divided into a bilateral Over-The-Counter(OTC) market and the Eltermin market for financial trading run by NordPool. The Eltermin market is used for trading forwards and futures which are purely financial contracts, for trading and risk management, e.g., hedging against future price uncertainties. While futures have a trading horizon of eight to nine weeks, forward contracts can be traded for a time span of up to four years [29]. Furthermore, Contracts for Differences (CfDs) are available to overcome possible price differences between system price and the actual area price.

In contrary to the specified financial products traded in the Eltermin market, OTCs are bilateral contracts with a certain flexibility in the load profile (load factor contracts) [29]. In bilateral contracts, two parties agree on a specified amount of electricity within a certain time period. These contracts may include the physical delivery of electricity.

2.2.2.6 Day-ahead market (NordPool Spot)

With real-time approaching, the day-ahead market settles the physical delivery of electricity based on hourly contracts, block contracts and flexible hourly contracts, covering all 24 hours of the next day [30]. Market participants are able to participate in the market by placing offers for electricity supply and demand. The intersection point between supply and demand biding curve sets the market price of electricity for each hour of the bidding period.

2.2.2.7 Intra-day market

After day-ahead market closure until delivery, the market participants need market access in the intervening hours to improve and adjust their physical electricity balance. Therefore, the intra-day market offers the possibility to readjust the scheduled day-ahead market bids, based on a continuous trading from day-ahead market closure until one hour before delivery, as in the Nordic ELBAS system, or based on consecutive spot trading sessions, as in the Iberian OMEL market [30, 31]. Due to the integration of RES and the related issues with respect to variability and predictability, the intra-day market will be of prime concern in the future.

2.2.2.8 Balancing market

After intra-day market closure, the responsibility to assure system balance is handed over to the TSO. The regulating or balancing market therefore may be regarded as the market where the TSOs acts as intermediary or facilitator to assure the supply and demand equilibrium [32]. The TSO therefore transfers part of its balancing obligation to market participants, called Balancing Responsible Parties (BRP), by making them responsible for keeping their own portfolio balanced via the imbalance settlement. The basic structure of the regulating power market is shown in Figure 2.6.

Since the liberalisation and the reorganisation of the electricity sector the TSO no longer holds generation resources in direct ownership. Therefore, the TSO has to contract balancing services, namely *reserve capacity* and *balancing energy*, from market participants called Balancing Service Providers (BSP).

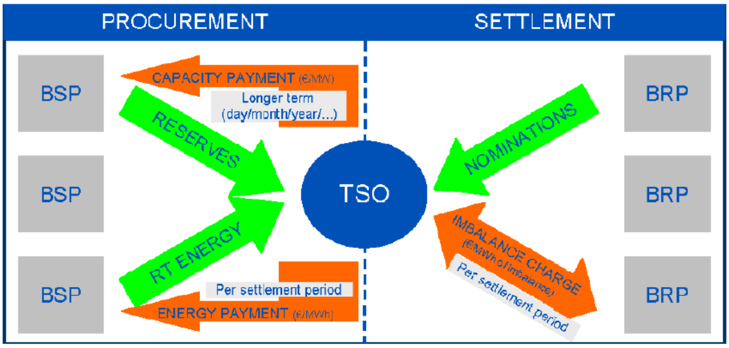


Figure 2.6: Regulating power market structure [33]

Reserve capacity refers to the procurement of regulating reserves, where the TSO commissions BSPs for the availability of regulating reserves which can be activated in real-time. For the provision of reserve capacity, BSPs receive capacity payments from the TSO. Depending on the actual market arrangement, the TSO is able to procure these reserves through mandatory impositions, bilateral contracts or via an auctions market [28].

Balancing energy is provided in case of disturbances in the system. The TSO takes the necessary actions to re-establish system balance by activating regulating reserves in real-time. The BRP causing the imbalance in the system has to pay an imbalance charge (€/MWh) to the TSO, which is then paid to the corresponding BSP as an energy payment.

Market participants, whose actual production or consumption deviates from their day-ahead or intra-day market bids, have to pay their share to re-establish balance in the system.

2.3 European power market integration

The restructuring and liberalisation of the European electricity system was the first step towards competitive power markets on a national basis. As early as 1996, the EU commission released directive 1996/92/EC aiming for a gradual establishment of an internal power market in Europe [21]. The market integration on a European level was emphasised by the EU member states by introducing following directives 2003/54/EC and 2009/72/EC [23, 24]. Regulation 1228/2003 and directive 2009/72/EC directly addressed cross-border issues by aiming to establish fair rules for cross-border exchanges and to enhance the competition within the internal electricity market [24, 34].

Regional incentives were initiated by the European regulators in a 'European body of independent regulators acting as an advisory group to the Commission' called ERGEG [35]. On the way to a common European electricity market, the European regulators introduced an initiative to establish seven regional markets, integrating neighbouring countries (see Figure 2.3).

The overall aim of market integration and coupling is to maximise the surplus of all participants and increase the social welfare [36]. Furthermore, the coupling of different market areas increases the security of supply, since the dependency on one particular country, fuel type or trading partner is reduced. With respect to WPP, an internal European power market offers the possibility to fully utilize the effects of geographical smoothing, therefore reducing the impacts of WPP on the system under the premise that a sufficient amount of cross-border transmission capacity is available.

The actual status of market integration for Europe is described in the following Sections.

2.3.1 Day-ahead sport market coupling

A first achievement in Europe was the introduction of the integrated common day-ahead market, NordPool, in the Nordic area. The NordPool market started in Norway and was gradually extended to Sweden (1996), Finland (1998), Denmark (2000) and Estonia (2010). Germany partly joined in 2005. By now, NordPool includes day-ahead spot market and intra-day trading.

In 2006, the Trilateral Market Coupling (TLC) between France, Belgium and the Netherlands was introduced. Despite a market integration as in the NordPool area, a price-coupling mechanism was introduced to optimize the utilization of cross-border transmission corridors while retaining the national power markets. In 2010, the TLC was replaced by the Central Western European (CWE) region, now including the TLC members plus Germany, Luxembourg and Austria.

Due to the success of NordPool and the TLC, the Interim Tight Volume Coupling (ITVC) between Denmark and Germany was introduced in 2009, now connecting the Nordic and the CWE area.

Besides the day-ahead spot market coupling in Northern Europe, the Iberian electricity market 'Mercado Ibérico de Electricidad (MIBEL)' was launched in 2007. It constitutes a joint initiative by the Portuguese and the Spanish government to establish a regional electricity market. While the day-ahead spot market is operated by the Spanish market operator 'Operador del Mercado Ibérico de Energia, Polo Español (OMEL)', the derivatives market is run by its Portuguese counterpart the 'Operador do Mercado Ibérico, Polo Portugal (OMIP)'.

2.3.2 Intra-day market

Along with the day-ahead market coupling, the planning of cross-border intra-day market is the focus of TSOs and regulators. Two of the most established systems are the Electricity Balance Adjustment System (ELBAS) in the Nordic area and the Spanish OMEL intra-day market. [37]

2.3.2.1 ELBAS

In the Nordic Area, the ELBAS market was introduced as part of NordPool. Presently (2012) Norway, Denmark, Finland, Germany and Estonia have joined the trading platform [38]. The ELBAS market allows a continuous trading from day-ahead market closure until one or two hours before real time. Both, hourly bids and block bids are accepted. Prices are set based on a first-come first-served principle. The available transmission capacity between areas is automatically controlled and updated after each trading session. In 2010, a joint venture consisting of the market operators APX-ENDEX, Belpex and NordPool have agreed to establish an integrated cross border intra-day market based on the ELBAS system [39]. The market will first be implemented in Belgium and the Netherlands, coupled to NordPool through the NorNed cable between Norway and the Netherlands and the transmission corridors connecting Germany and Denmark [35, 40].

2.3.2.2 OMEL

Based on Article 15 of Royal Decree 2019/1997, the Iberian intra-day market was established as part of the OMEL electricity market [31]. Contrary to the ELBAS system offering continuous trading possibilities, the Spanish intra-day market is split into six consecutive trading sessions, starting 28 hours before real time. Agents who have participated in the corresponding day-ahead market or who have executed a bilateral contract are allowed to sell or purchase bids in the intra-day market corresponding to those daily market sessions they have participated in.

2.3.3 Balancing markets

Despite the progress in the harmonization and integration of day-ahead spot and intra-day markets, the achievements in establishing an integrated balancing market are limited. Different proposals for the cross-border exchange of balancing energy and the integration of balancing markets have been made, which can generally be divided into two approaches [33, 41, 42]:

TSO-BSP

This approach enables TSOs with the possibility to contract balancing services from BSPs in a neighbouring area. BSPs therefore have the possibility to identify the best possible offer for their services either by selling in their own control area or to TSOs elsewhere.

TSO-TSO

This approach enables a TSO to procure real-time energy from its neighbouring TSOs. The TSO providing balancing services is reimbursed through energy payments. Exchanges can either be limited to services in excess of those needed to maintain the balance in the TSO's own control area, or can include all services via the use of a common merit order [33].

The possibilities and benefits of an integrated Northern European balancing market, especially the possibilities of using Norwegian hydro power as a buffer or swing bus, are discussed in [5, 28].

Part I

Modelling

Chapter 3

Modelling wind power production

Publications A and F

The chapter summarizes Publication A and is extended by updated simulation results from Publication F. The chapter provides the modelling methodology for simulating wind power production time series based on numeric wind prediction models, wind speed measurements and mixed data sets. This chapter tries to answer the following questions: What is the best wind speed data source for modelling distributed large scale wind power production on a European level? How accurate are the models? What are the advantages and disadvantages of each data set? The chapter begins with Section 3.1 including background information and an overview over previous models. Section 3.2 gives a description of the model parameters and the various wind speed data sets. Section 3.3 describes the methodology of the proposed models followed by a validation of the simulation results in Section 3.4. The chapter ends with Section 3.5 including a discussion of the various models.

3.1 Background

The increasing share of RES in the Europe has brought the modelling of WPP into the focus of power system simulations. In order to simulate the effects of distributed WPP on the system stability, the reserve requirements and other the affects related to WPP, a high temporal and geographical resolution of the model is needed.

Previous wind power production models were mainly based on two approaches:

- Up-scaling the WPP time series from a limited number of wind power facilities to match the installed area capacity [43, 44].
- Utilization of wind speed re-analysis wind speed data [45].

Both approaches exhibit several limitations.

The up-scaling of WPP using a limited number of wind power production sites disregards the effects of geographical smoothing. The resulting scaling error leads to overestimation of hourly production variations, ramping gradients and misinterpretation of wind power variability [46]. Furthermore, the procurement of real wind power production data on a European level is problematic due to the secrecy of power producers.

Simulations based on re-analysis data mainly suffer from accuracy problems. Since the wind speed data is only available with a six-hourly time resolution, short term variations of WPP and the corresponding effects on the power system cannot be simulated with the desired accuracy. Furthermore, the distance between wind speed data points of 2.5 degrees in longitude and latitude requires an interpolation over long distances. The topographical characteristics between the data points, e.g., the hilliness of the terrain, influencing the wind speed and therefore the WPP, cannot be captured by the data set.

The intention of the presented model is to increase the precision of WPP simulations and to identify the most reliable data set. The evaluated wind speed data sources include:

i) Real wind speed measurements

ii) Numerical Weather Prediction (NWP) models provided by the Consortium for Small Scale Modelling (COSMO)

   - COSMO EU - Regional model covering Europe
   - COSMO DE - Local model covering Germany

iii) Re-analysis data

While the Danish simulation results are based on wind speed data from 2004, the German results are based on a 2008 data set. Different years had to be chosen due to the limited availability of wind speed and TSO data.

3.2 Model Parameters

3.2.1 Simulation area

The simulation area includes Denmark and Germany. Since the aim of the model is to simulate WPP on a European level, the opportunity to provide accurate simulation results for a complex terrain is necessary. Due to topographical dissimilarities between Germany and Denmark, and also variations in the installed capacity and the size of the simulation area, a representative portrayal of Europe is outlined.

3.2.2 Wind speed measurement grid

Most European meteorological offices provide wind speed measurement data sets for academic research. Wind speed measurements for Germany and Denmark were provided by the meteorological institutes namely the 'Deutscher Wetter Dienst (DWD)' and the 'Danmarks Meteorlogiske Institut (DMI)', respectively [47, 48]. The data set includes 56 and 88 measuring stations for Denmark and Germany, respectively (see Figure 3.1). This corresponds to the maximum amount of available measuring stations, providing a time resolution of one hour or less. In fact, all chosen stations deliver measurements with a time resolution of ten minutes. This enables the simulation of intra-hourly WPP variations. The wind speeds were mainly measured at a height of ten meters to reduce the influence of ground effects.

3.2.3 The COSMO model

The numerical weather prediction model COSMO was developed by the Consortium for Small Scale Modelling [49]. The consortium formed in 1998, is a joint venture of seven meteorological offices from Switzerland, Germany, Italy, Greece, Poland, Romania and Russia. *"It's general goal is to develop, improve and maintain a non-hydrostatic limited-area atmospheric model, to be used both for operational and for research applications by the members of the consortium"* [49].

The model is based on thermal-hydrodynamical equations describing the compressible flow in a moist atmosphere [49]. A detailed documentation including the basic model design, dynamics, physical parametrizations and the data assimilation is provided in the technical reports on the COSMO website [50]. The actual wind speed data is available with a time resolution of one hour.

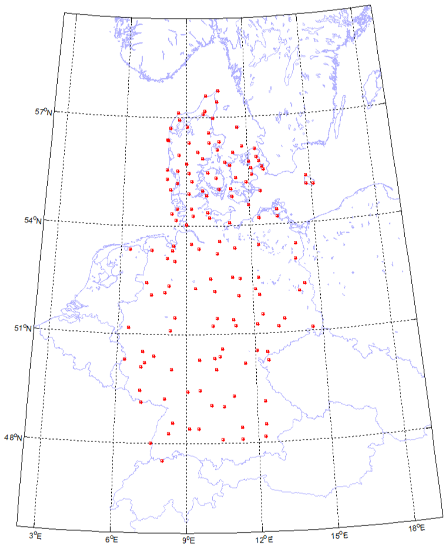


Figure 3.1: Wind speed measuring stations in Germany and Denmark

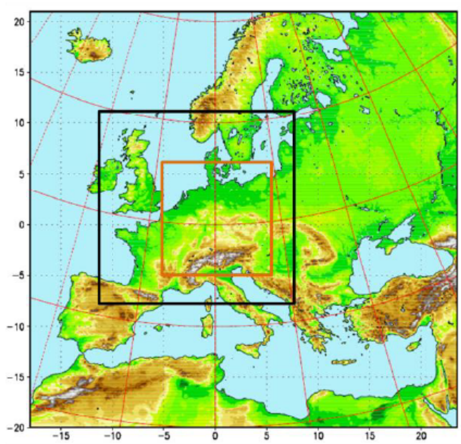


Figure 3.2: Model domain COSMO EU(whole picture), COSMO LM (black box) and COSMO DE (red box) [51, 52]

3.2.3.1 Regional NWP Model COSMO EU

In 2005, the latest version of the regional NWP model called COSMO EU covering the whole European continent, was launched, replacing the previous COSMO-LM model [51]. The highly sophisticated modelling routine simulates a meshed data grid with a point to point resolution of 7 km x 7 km. The resulting 665 x 657 data nodes include the meridional and zonal wind components, offering the possibility to simulate the absolute wind speed in line with the respective wind direction.

Like all COSMO NWP models, the topography and the ruggedness of terrain is included in the wind speed data assimilation. The surface roughness length z_0 of each wind speed data point is available via the PAMORE web interface of the DWD [53].

3.2.3.2 Local NWP Model COSMO DE

The COSMO DE model is the latest step in the development of the COSMO models and represents the possible future of NWP models. With a spatial resolution of 2.8 km x 2.8 km, which corresponds to 421 x 461 data grid points, COSMO DE was developed to simulate local weather phenomena and atmospheric convection [1]. Due to its high resolution, the main purpose of COSMO DE is the forecasting of thunderstorms and subregional weather events [52].

Even though the COSMO DE model is only available for Germany, it offers the opportunity to display the possibilities of improved NWP models with an increasing point to point resolution. A numerical prediction model covering the COMSO EU area with the COMSO DE resolution is likely to be introduced within the next few years [47].

3.3 Modelling approach

3.3.1 Simulation parameters

The input data, including power curves, roughness length and wind power facilities, build the basis for the simulations and are applied to all methodologies.

3.3.1.1 Wind turbine production curve

The wind speed to power conversion is based on two different turbine power curves. While facilities with an installed capacity of less than 10 MW are de-

[1]Convection generally means the lifting of a portion of air which is warmer compared to its environment [47]

scribed by a single turbine curve, larger facilities are modelled by an aggregated curve (see Figure 3.3).

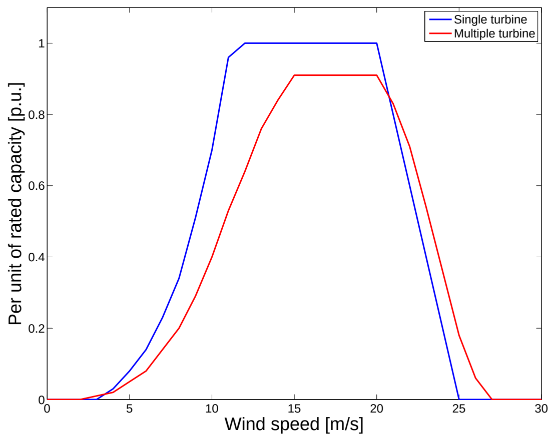


Figure 3.3: Single and aggregated wind turbine curve

The aggregated turbine curve is derived from the multi-turbine power curve approach described in [44], using a one-year historical production data of a Norwegian wind farm. Wind farm wake effects are neglected in the simulations since the modelling requires an extensive data set including the farm layout and the relative wind direction for each turbine. The aggregated power curve therefore represents a best estimate reflecting the mutual blocking and outages of turbines within a wind farm.

3.3.1.2 Installation scenarios

The European onshore wind power facilities, except for Germany, are based on the data provided in [54]. The numbers given in the data set largely correspond to the installation scenarios published by the European Wind Energy Association (EWEA) [55]. For Germany the renewable energy act (′Erneuerbare Energien Gesetz (§§45 - §§52)′) stipulates the German TSOs to publish the RES energy production in line with the wind power production facilities connected to the grid [56, 57]. The open source data base contains all registered wind power facilities in Germany, including the installed capacity and the respective geographical coordinates.

For Germany, the data set includes around 16000 wind power facilities while the Danish area is represented by 1229 wind units, ranging from single turbines up to multi-megawatt wind farms. In order to illustrate the correlation of wind speeds over a certain distance and to incorporate regional as well as supra-regional weather phenomena, each production facility is modelled individually.

The data distinguishes wind power facilities by their inauguration year. Therefore, the data base is a snapshot of Denmark in 2004 and Germany 2008 respectively. Figure 3.4 shows the Danish wind power facilities in 2004 with an installed capacity of more than 10 MW.

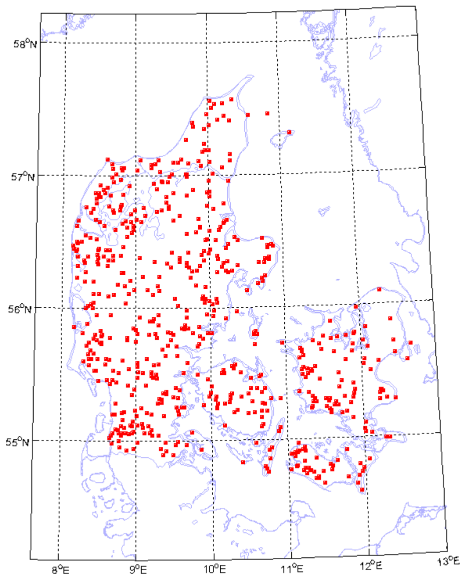


Figure 3.4: Danish wind power facilities with an installed capacity of more than 10 MW

Since there might be minor deviations between the applied data sets and the commonly accepted EWEA reference data, a correction factor is introduced to compensate these deviations (see Table 3.1) [55].

Table 3.1: Installation scenarios Germany and Denmark

Area	EWEA	Data base	Correction Factor
Germany	23897	21589	1.10
Denmark	3123	3165	0.98

3.3.1.3 Scaling wind speeds

Since the delivered wind speed data from both sources - wind speed measurements and COSMO data, is measured in a height of 10 m, a logarithmic scaling is necessary to obtain the wind speed at wind turbine hub height, according to Equation (3.1). The surface roughness length , describing the roughness characteristic of the terrain, is considered in the scaling process of each wind speed data point.

$$H_f = log_{10}(h_{ref}/z_0)/log_{10}(h_{mes}/z_0) \tag{3.1}$$

where:

H_f:	Scaling factor
h_{ref}:	Reference hub height
z_0:	Surface roughness length
h_{mes}:	Measurement height

According to Equation 3.2 the wind speed velocity at hub height V_H, called meso wind, is the product of the scaling factor H_f and the measured wind speed velocity V_M [58].

$$V_H = H_f \cdot V_M \tag{3.2}$$

3.3.2 Simulation procedure based on measurements

The modelling procedure based on wind speed measurements is divided into several consecutive steps. In the first step, a two dimensional coordinate system including the geographical coordinates of measuring stations and WPP facilities is established. In the second step, the wind speed for every hour in the wind speed data time series, for each measuring station, is plotted along the z - axis. The corresponding wind speeds for each measuring station are scaled up to hub height according to Equations 3.1 and 3.2. The resulting meso wind is less affected from external influences like surface roughness variations or obstacles [58][2].

The meso wind data points are meshed via a triangulation in order to get a three dimensional hull, representing the interpolated wind speed in the geographical area. The perpendicular intersection between wind farm coordinates and the wind speed hull defines the respective wind speed for each WPP facility in the coordinate system (see Figure 3.5).

[2] Higher up in the surface layer, the wind flow will be less disturbed, except for minor streamline displacements [58]

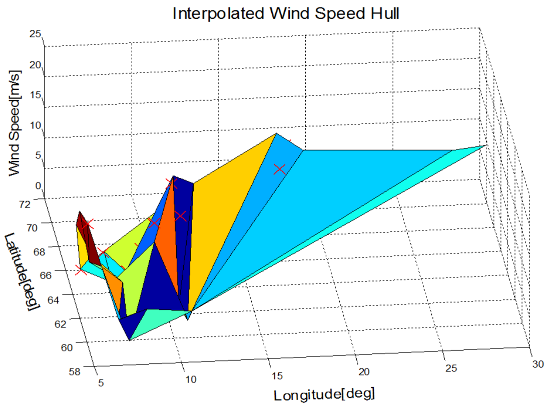


Figure 3.5: Wind speed triangulation using the example of Norway

3.3.3 Simulation procedure based on numerical models

The simulations for both NWP models - COSMO DE and COSMO EU, follow the same data conversion and modelling guidelines.

The COSMO data provided by the German meteorological office [47] is stored in a rotated coordinate system. Therefore, a data conversion is necessary to obtain the wind speeds in a spherical system, which can be further processed during the wind power simulations. Pole rotation is a consequence of numerical convergence problems of the meridians resulting in pole singularities in the spherical coordinate system. Therefore, the pole is tilted and transferred so that the equator runs through the center of the model domain (see Figure 3.6)[50]. This allows a minimization of convergence problems for any model domain.

Two consecutive coordinate transformations are used to obtain appropriate dynamic equations.

In the first step, the Cartesian coordinate system (X, Y, Z) located at the earth's center and the Z-axis oriented along the axis of the earth's rotation pointing to the North Pole, is transferred into a new system $(\tilde{X}, \tilde{Y}, \tilde{Z})$.

The origin of the new system is also the center of the earth.In the new coordinate system, the $\tilde{Z}$- axis points from the centre towards a point $P_N = (\lambda_g^N, \varphi_g^N)$ in which λ_g^N is the geographical longitude and φ_g^N is the geographical latitude [50]. P_N defines the new North Pole of the rotated system. In COSMO EU and COSMO DE, the pole coordinates are set to $\lambda_g^N = 170°\ W$ and $\varphi_g^N = 40°\ N$.

As the first step is only a rotation of the Cartesian coordinate system, the second step is needed to transfer the spherical longitude λ and latitude φ into

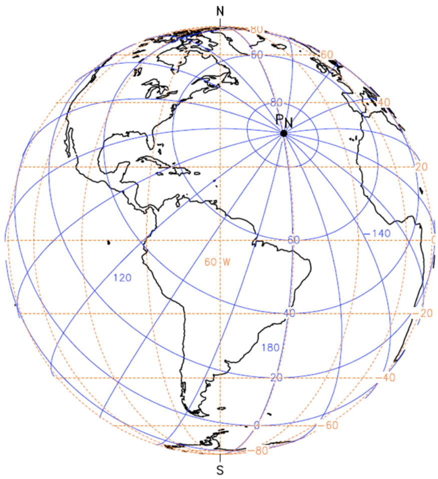


Figure 3.6: Full lines display the rotated spherical coordinate system with the North Pole shifted to point P_N with geographical Coordinates $\lambda = 40^\circ\ W$ and $\varphi = 30^\circ\ N$. Broken lines indicate the natural geographic coordinate system [51]

the geographical longitude λ_g and latitude φ_g [51]. Using Equations 3.3 and 3.4, each point of the rotated coordinate system is transferred into the equivalent geographical position.

$$\lambda_g = \arctan\left\{\frac{-\cos\rho\sin\lambda}{-cos\varphi\sin\varphi_g^N\cos\lambda + \sin\varphi\cos\varphi_g^N}\right\} + \lambda_g^N \tag{3.3}$$

$$\varphi_g = \arcsin\left\{\sin\varphi\sin\varphi_g^N + \cos\varphi\cos\lambda\cos\varphi_g^N\right\} \tag{3.4}$$

where:

- φ: Latitude
- λ: Longitude

Labelling:

- g: geographical coordinates
- N: pole coordinates

After the rotation of the coordinate system, the zonal u_g and meridional v_g wind components can be calculated as follows:

$$u_g = u \cos\delta - v \sin\delta \tag{3.5}$$

$$v_g = -u \sin\delta + v \cos\delta \tag{3.6}$$

Where δ is the angle between the meridians of the geographical and rotated system defined according to:

$$\delta = \arctan \left\{ \frac{\cos\varphi_g^N \sin(\lambda_g^N - \lambda_g)}{\cos\varphi_g \sin_g^N - \sin\varphi_g \cos\varphi_g^N \cos(\lambda_g^N - \lambda_g)} \right\} \tag{3.7}$$

Since the rotated pole is set to 170° W, δ becomes zero for all grid data points along 10° E. Therefore, the meridional and zonal wind speeds in the rotated (u,v) and the geographical (u_g,v_g) system are equal. With an increasing distance from 10° E, δ and the differences between wind speeds in the rotate and geographical system become larger. To compensate the angular offset and to determine the correct wind speed for each data point in the geographical system, the data conversion according to Equations 3.5 and 3.6 is necessary.

After the conversion, each single data grid point is scaled up to hub height according to Equations 3.1 and 3.2, taking the respective surface roughness z_0 into account. The geographical wind farm coordinates can now be implemented into the converted COSMO data grid. The wind speeds for each wind facility are interpolated from the surrounding wind speed data points.

3.4 Simulation results

The legal framework in Germany and Denmark forces the local TSOs, namely energinet.dk, 50Hertz, TenneT, Amprion and Transnet, to publish historical WPP time series data of the respective areas [59, 60, 61, 62]. The modelling results are validated using the TSO production data of both countries as reference values.

3.4.1 WPP in Denmark

The simulation results for Denmark 2004 are displayed in Table 3.2 and Figure 3.7. While the statistical errors in Table 3.2 are based on annual simulation results, the results in Figure 3.7 display a three week simulation period.

The results in Table 3.2 illustrate that the best model results in Denmark can be achieved by simulations based on wind speed measurements. With an annual Mean Absolute Error (MAE) of 145 MW and Normalised Root Mean

Square Error (NRMSE)[3] of 0.030, the simulation results are slightly better than the results achieved by COSMO EU wind speed data. The results based on the COSMO data set reach a a MAE of 186 MW and a NRMSE of 0.031. The results of both wind speed data sources largely correspond to the TSO data, reflected by a correlation coefficient r of 0.97 and 0.94, respectively.

On the other hand, the simulation results based on re-analysis data largely deviate from the TSO reference data. With an MAE of 331 MW and an NRMSE of 0.15, the simulation results are beyond acceptable limits. Due to the six-hourly time increment, wind power production can only be simulated with rudimentary accuracy.

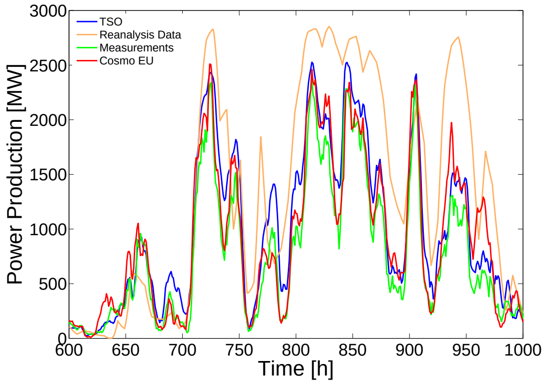


Figure 3.7: Simulation results WPP Denmark, January, 2004

Table 3.2: Simulation results WPP Denmark

	MAE [MW]	NRMSE	r
Measurements	145	0.030	0.97
COSMO EU	186	0.031	0.94
Reanalysis	331	0.156	0.85

3.4.2 WPP in Germany

The simulation results for Germany 2008 are displayed in Figure 3.8 and Table 3.3. As in the case of the simulations for Denmark, the statistical errors in

[3]Normalised by the installed area capacity

Table 3.3 are based on annual simulation results, while the results in Figure 3.8 display a snapshot from January 2008.

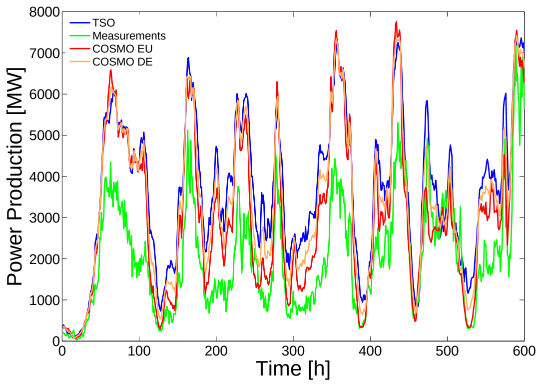


Figure 3.8: Simulation results WPP Germany, January, 2008

The simulation results for Germany are in contradiction to the Danish results. The numbers in Table 3.3 as well as the plots in Figure 3.8 illustrate that the grid of wind speed measuring stations does not provide the required density for an accurate simulation of WPP in Germany. With an MAE of 1 016 MW and an NRMSE of 0.068, the simulations results are beyond acceptable limits.

Table 3.3: Simulation results WPP in Germany

	MAE [MW]	NRMSE	r
Measurements	1016	0.068	0.89
COSMO EU	531	0.035	0.96
COSMO DE	265	0.015	0.98

The accuracy of the modelling results based on COSMO EU data on the other hand, largely match the Danish simulation results. With an MAE of 531 MW and an NRMSE of 0.035 the real wind power production is simulated with high accuracy.

Even better results can be achieved with the COSMO DE data set. The MAE is further reduced to 265 MW and the NRMSE to 0.015 respectively. The increased resolution of the COSMO DE wind speed data grid reduces the simulation error by about 50%.

3.5 Conclusion

The Danish results show that with measurements based on a dense wind speed measuring grid most promising results can be achieved. For countries similar to Denmark, in station density but also in topography, wind speed measurements are the most accurate source for WPP simulations. Furthermore, most meteorological offices provide measurements with a time resolution of ten minutes, offering the possibility to simulate sub-hourly variations.

For a widely meshed grid of measuring stations or rough areas, the accuracy of the results is beyond acceptable limits. The limited number of measuring stations in Germany is in no proportion to the size of the country. In combination with the varying landscape, the ruggedness of the terrain and the disregarding of obstacles in the triangulation process, an accurate simulation of wind power production based on measurements is not possible. The major disadvantage of simulations based on measurements is the inability to simulate offshore WPP. Furthermore, TSO data is required to verify the simulation results since it is problematic to predict if the measurement grid is dense enough. Another drawback is the computation time of the triangulation.

Based on the highly sophisticated COSMO data set, very accurate results are achieved. The simulations prove that even in areas with a varying topographic terrain, the model delivers simulation results with almost equal accuracy. The constant accuracy of modelling results is one of the major advantages of WPP simulations based on NWP models. The main advantage of NWPs is the possibility to simulate on- as well as offshore facilities. This is of high importance especially when simulating future scenarios including a high share of wind installations in the North Sea and the Baltic Sea.

Chapter 4

EFI's Multi-area Power-market Simulator (EMPS)

Publications B and E

The chapter includes a summary of the EMPS model (EFI's Multi-area Power-market Simulator) used in Publications B and E. The EMPS model is developed by SINTEF Energy to simulate hydrothermal power systems including a considerable share of hydro power [63]. The model was considerably extended by Jaehnert [5] and is now capable of simulating the northern European regulating market. Section 4.1 includes a description of the parameters considered in the model. Section 4.2 explains the modelling steps including the day-ahead-market, the reserve procurement phase and the real-time system balancing. A complete mathematical description of the model can be found in [64][65].

The EMPS market model was developed to simulate and optimize the Nordic power system, including Norway, Sweden and Finland, while explicitly taking the hydrological conditions and other properties unique to a hydro power system into account. The model is based on a detailed description of the Nordic hydro power system including generator capacities, size of hydro reservoirs, water course description and numerous inflow scenarios [66]. Within the model, the power system is split into various interconnected areas, as shown in Figure 4.1. The area boundaries are defined based on the hydrological conditions and other properties of the hydro system, bottlenecks in the transmission system as well as country borders [65, 66].

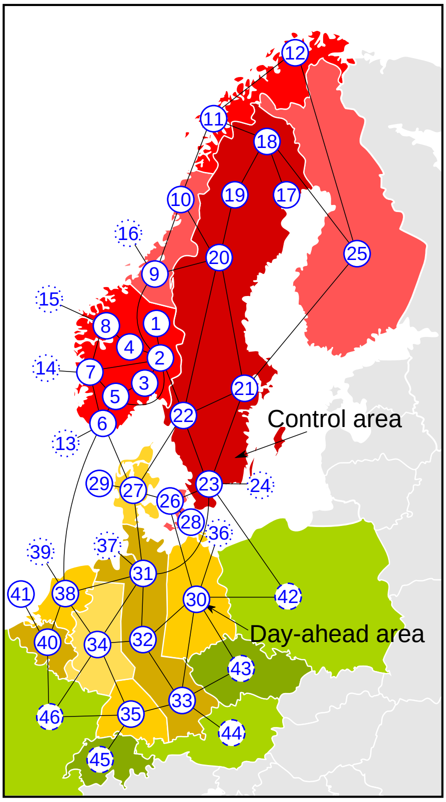


Figure 4.1: Geographic overview of day-ahead and regulating power market model [5]

4.1 Model parameters

The simulation of the power market is based on the following assumptions and parameters.

Hydro power

In EMPS, a detailed description of the Nordic hydro power system is implemented. Each hydro power module in the model is simulated based on a set of parameters including reservoir data, inflow, installed generator capacity, water discharge, spillage and bypass paths connecting the hydro system (see Figure 4.2).

The possible production of each hydro power plant is largely dependent on the capacity of the corresponding reservoir and the equivalent stored energy. The inflow is divided into storable inflow into the reservoirs, and non-storable inflow which is instantaneously used for power production. For the Nordic area, the model includes inflow scenarios for more than 75 years. The reservoirs can be discharged through the connected power plants, spillage of water or through bypasses in the system. The power production for each plant is represented by the respective energy conversion factor $[kWh/m^3]$. The power plant output is defined by a piecewise linear function, describing the dependency between water discharge and power production [5].

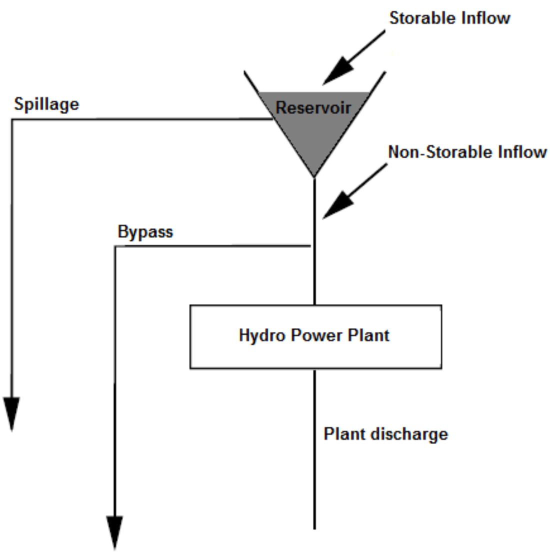


Figure 4.2: Hydro power model

Thermal power

Thermal power plants are defined by their installed generation capacity, marginal costs and availability during the year. Furthermore, power plants used for district heating are subjected to a minimum production level, depending on the corresponding month. The start-up state as well as the start-up costs of thermal generators is considered by a linear approximation according to [67].

Wind power

In the EMPS model, WPP is simulated as a fixed energy input based on an aggregated area production. The time series data with an hourly resolution is based on the WPP model described in Chapter 3.

Transmission

The inter-area and cross-border transmission corridors are simulated by their respective NTCs. The energy transmission is simulated as a transport problem. Therefore, the actual load flow is not considered in the simulation. No explicit distinction between AC and DC transmission lines is made.

Demand

The electricity consumption in EMPS is divided into firm and flexible demand. While the firm demand is represented by a weekly or annual load pattern, the flexible demand is price dependent, reflecting the influence of spot market prices on the electricity consumption. Furthermore, the temperature dependency of load is included in the model portraying the influence of electrical heating in the Nordic area and its influence on the overall demand.

Reserve capacity

Reserve requirements can be included in the EMPS model. The model only considers upward regulating reserves, which can be provided by hydro power facilities or thermal power plants.

4.2 Market model

The system balancing analysis in **Publication E** is based on the joint market model depicted in Figure 4.3. It simulates an integrated Northern European regulating power market, which is based on a common day-ahead market, including the Nordic and the northern continental European countries (see Figure 4.1). The consecutive modelling steps include the day-ahead market, the reserve procurement and finally the real-time system balancing.

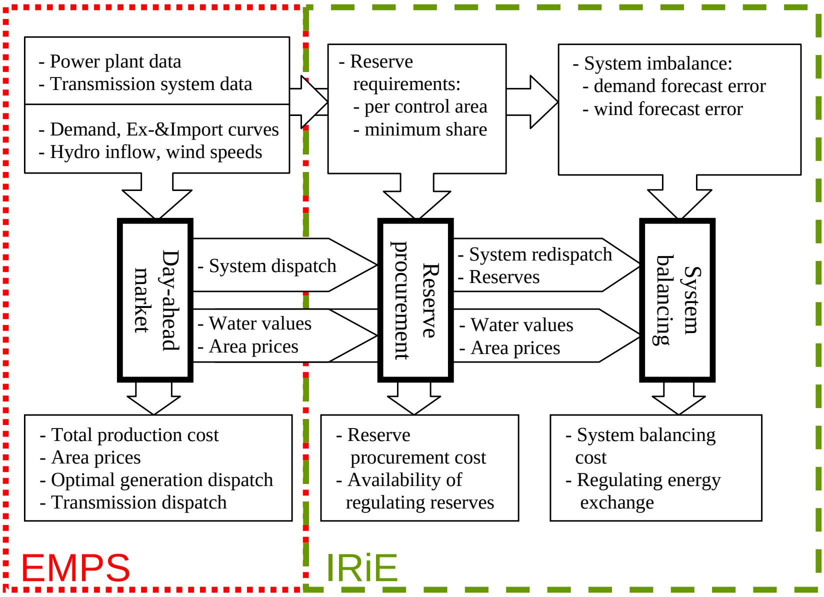


Figure 4.3: Model structure and workflow [64]

4.2.1 Day-ahead market

The **common day-ahead market** is modelled with EMPS [65]. It determines the socio-economic optimal dispatch of electricity production and transmission on a weekly basis split into several periods, with a time horizon of several years. In this stage, Water Values (WVs) for hydro reservoirs are calculated, serving as production costs.

The simulation of the day-ahead market is based on a two-step approach. In the strategy phase, an aggregated strategy for the utilization of hydro reservoirs (calculation of the WVs) is determined, followed by a detailed system simulation using the results from the strategy phase as an input. The strategy phase is based on a on a stochastic dynamic programming. The natural variations in climatic variables such as temperature and inflow scenarios to hydro reservoirs is stochastic, while the time-dependent coupling of hydro reservoirs is dynamic.

4.2.1.1 Strategy phase

Since water itself has no marginal cost, the price for hydro power production is defined by the so-called WVs. The WVs largely depends on the inflow to reservoirs, power production and a possible spillage of water (see Figure 4.2).

To represent the stochasticity of inflow, the data of more than 75 years is implemented in the model.

Since the availability of water in the future is influenced by the actual hydro power production, the current production has to be balanced against the possibility to produce in the future. Therefore, a mid or long term optimization based on different inflow scenarios is necessary to derive an optimal strategy taking into account the generation, the reservoir levels and the water release. The final result of the strategy determination phase is a WV table for each area, showing the expected marginal value of passing more water to different weeks for different reservoir levels [65]. To reduce the computational effort, all hydro power stations are aggregated to one equivalent power station with a joint reservoir.

4.2.1.2 Detailed simulation

In the second simulation step, the aggregated power production is allocated to the actual hydro power plants in the simulated area. A detailed reservoir draw-down model gives the distribution of each subsystem's aggregated hydro generation among available plants in each week [27]. Furthermore, varying efficiency of generators and the coupling of water courses is considered. Using the incremental WVs calculated in the strategy phase as marginal costs, in the detailed simulation is carried out to minimize the operational costs of the hydro-thermal system.

4.2.2 Regulating power market

During the **reserve procurement**, the Integrated Regulating power market in Europe (IRiE) model is used to adjust the optimal day-ahead generation dispatch in order to fulfil given reserve requirements. In the integrated regulating power market, regulating reserves can not only be procured in the respective countries, but also across the borders. In order to procure reserves externally, the remaining transmission capacity after day-ahead market clearing is utilized. The procurement is done for each hour in a socio-economic optimal way, based on marginal production costs of the thermal units and WVs for hydro power plants, taking into account the start-up state of thermal units.

System balancing, by means of activating the least-cost regulating reserves, compensates for system imbalances including the wind forecast error. The remaining transmission capacity is likewise taken into account. Throughout the simulation period the system balancing is done for every 15 minutes. The costs for system balancing are estimates for up- and downward regulation based on the marginal production costs of thermal and the WV for hydro units [64].

4.3 Concluding remarks

The described modelling routine is used to simulate the Nordic and the Northern European day-ahead and regulating power markets. A case study along with the evaluated results is shown in Chapter 9.

Chapter 5

Grid expansion model URBS-EU

Publication D

The chapter summarizes the modelling methodology of the grid expansion model 'Urban Research Toolbox: Energy Systems (UBRS)' used in Publication D. The model methodology URBS-EU applied in Publication D is an extension of the German system model URSB-D developed by Heitmann and Haase [68, 69]. A complete mathematical description of the European model can be found in [70, 71].

5.1 Model description

URBS-EU is a power system model using a linear optimization approach to simulate the total system costs on a European level while minimizing the socio-economic costs according to Equation 5.1.

$$COST = \sum_{(x,i)} \kappa_i^l CN_i(x) + \kappa_i^F C_i(x) + \sum_t \kappa_i^{Var} E_i^{out}(x,t) \tag{5.1}$$

In the modelling process the total system costs are minimized on an hourly basis while taking into account the annuity of investment costs κ_i^l, the fixed capacity-dependent operation and the maintenance costs κ_i^F as well as the variable costs κ_i^{Var} for power plant, storage and transmission technologies. The related costs depend on the respective generator technology including bio-energy, coal (hard and lignite), gas (Gas Turbines (GT) and Combined Cycle Gas Turbines (CCGT)), geothermal, oil, nuclear, hydro (run off and storage) [70].

While $C_i(x)$ represents the total generation capacity, $CN_i(x)$ includes the capacity addition per technology i within the respective region x. The regional power production for each technology and time-step t is described by $E_i^{out}(x,t)$. The minimization of the total system costs is based on an optimisation of the hourly power plant dispatch per region and technology. Storage opportunities and their possible activation as well as the power flow between areas are taken into account.

The optimization of the system costs is subject to the equilibrium of supply $E_i^{out}(x,t)$ and demand d in each area, considering the area imports and exports $E_{Transmission}^{in}$ and the energy dispatch or feed-in to storage facilities $E_{Storage}^{in}$(see Equation 5.2).

$$\sum_i E_i^{out}(x,t) - E_{Transmission}^{in} - E_{Storage}^{in} = d(x,t) \tag{5.2}$$

Within the model, the European power system is divided into 83 regions, 50 of which correspond to the major TSO regions in the ENTSO-E grid while 33 are defined as specific offshore regions (see Fig. 5.1).

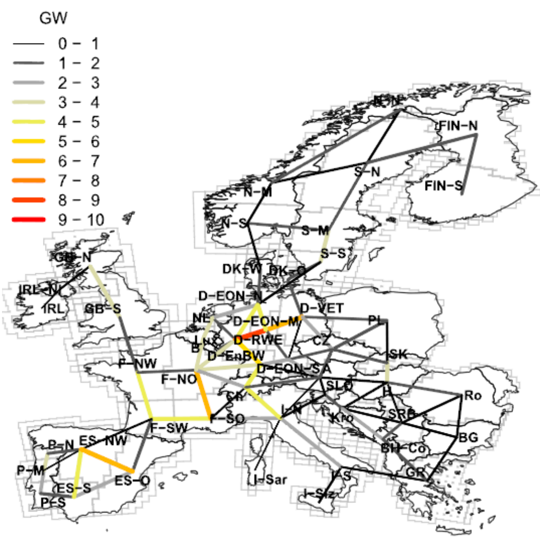


Figure 5.1: European model regions with aggregated ENTSO-E transmission grid

The inter-area power flow is modelled as a linear transport problem based on a simplified grid representation of the ENTSO-E system. The capacities of inter-area transmission lines are aggregated based on the available data in [72].

On demand, the model also computes cost-optimal extensions of power plant, storage and transmission infrastructure, based on the annuity of investment costs. This is achieved by using $CN_i(x)$ as control variable, in addition to $E_i^{out}(x,t)$.

5.2 Concluding remarks

The described modelling routine is used to simulate a cost-optimal grid expansion under the influence of large scale wind power production. The modelling results and the connection to other models developed in the context of this work is described in Chapter 8.

Chapter 6

Power System Simulation Tool PSST

Publication C

This chapter is based on Publication C. The chapter contains a description of the modelling methodology of the Power Market Simulation Tool PSST. Furthermore, the connection between wind power model (see Chapter 3) and PSST is explained. The market model simulates the European day-ahead, intra-day and real-time power markets. The modelling process is divided into three consecutive steps. First, the day ahead market is modelled as a common European market including a simultaneous reserve procurement for northern Europe. Second, the intra-day market is simulated for the Nordic area and the northern European area using the day-ahead market results as basis for the simulations. The scheduled day-ahead dispatch is successively adjusted based on a continuous revision of wind power forecasts. Finally, the balancing market is modelled as a real time power dispatch on the basis of intra-day market results. The Chapter is structured as follows. Section 6.1 explains the possibilities and advantages of the flow based model approach. Section 6.2 gives an overview of the basic simulation structure in PSST. The model for the day-ahead, the intra-day and the real-time market models, including a complete mathematical description is given in Section 6.3

The Power System Simulation Tool (PSST) is a flow based market model developed in the EU TradeWind project [73]. The model aims to facilitate the dismantling of barriers for the large-scale integration of wind energy in European power systems, on transnational and European levels, and to formulate recommendations for policy development, market rules and inter-connector allocation methods to support wind power integration [73]. The high voltage network topology, generation and transfer capacities, wind power production and hydro power characteristics, as well as fuel price scenarios are incorporated in the model. Based on a DC optimal power flow the model minimizes the total generation costs on a hourly basis throughout the year [74].

6.1 Flow based approach

The coupling of power markets enables market participants to buy or sell electricity over national borders with the premise that sufficient cross-border transmission capacity is available. As a consequence of market activity and bilateral cross-border trading, the allocation of transmission capacity is mainly based on a commercial exchange, using scheduled exchange programs from one market to another [75]. By now, the commercial allocation of transmission capacity is mainly based on explicit or implicit auctions.

In **explicit auctions**, the transmission capacity on an inter-connector is auctioned to the market, independently from the electricity markets [76]. The capacity allocation is solely determined based on the auctioning results, taking the NTCs of cross-border transmission corridors into account. The time frame for explicit auctions includes a period of up to several months.

In **implicit auctions**, the power and the transfer capacity are coordinated as one single activity. Contrary to the explicit auctioning process, the implicit allocation of transmission capacities takes place within or after the day-ahead market closure. The remaining cross border transmission capacity after the explicit auctioning and the day-ahead market clearing are available. The remaining ATC between bidding areas is made available to the spot price mechanism, in addition to bids and offers per area. Thus, the resulting prices per area reflect both the cost of energy in each internal price area and the cost of congestion [76].

The disadvantage of both auctioning approaches is the disregarding of the physical flow of electricity in the settlement process. Therefore, the auction results rather represent a flow of money than the physical flow of electricity [77]. Especially in a highly meshed transmission system, the electric power does not follow the cross-border transmission results settled in ATC or NTC auctions, but flows from source to sink. The flow pattern within the power system is a result of all the generation sources, consumption at all the sinks and the network topology, utilizing all available transmission lines in accordance with Kirchhoff's and Ohm's laws.

In the **flow-based** model, the network topology and the impacts of cross-border exchanges are taken into account simultaneously with the power market clearing. The flow based approach offers the possibility for a better utilization of transmission capacities while optimizing the social welfare [78]. Furthermore, transmission congestion and its influence on electricity market prices is identifiable. Following the recommendations of [75] and [78], a flow based market coupling approach will be implemented in the CWE area in 2013 [79].

Uhlen et al. [77] present a flow based market model using an optimal power flow approach to simulate congestion between market areas. The model includes a flow based market coupling method which can be applied to the European power system. PSST is based on the same methodology using a DC power flow (P-δ power flow) based on the following simplifications [77]:

- All line resistances are neglected: $z_{ij} = jx_{ij}$
- All voltage angles are assumed to be small: $sin(\delta) \approx \delta$
- All voltages are assumed constant and equal to 1.0 pu

In terms of pricing, PSST basically uses a nodal approach. In consideration of all transmission and production constraints, the optimal prices for all nodes are based on the optimal system dispatch. However, PSST calculates the area prices based on the weighted average of the nodal prices within each area. The prices are weighted by the respective demand in each node [28].

6.2 Basic simulation structure

The PSST model is based on a perfect market assumption minimizing the total generation costs in the system for each hour of the simulation period. The basic PSST simulation structure is displayed in Figure 6.1.

The inputs to the market simulation are split into constant and time dependent parameters. The electrical grid, generator capacities, the respective marginal generator costs and the reservoir volume of hydro generators define the constant prevailing conditions for the whole simulation period. WPP and load time series, water inflow into hydro reservoirs, reservoir levels and the subsequent water values are updated for each hour throughout the year.

6.2.1 Constant parameters

6.2.1.1 Power flow description and grid model

The grid model used in PSST is a combination of three single grid representations covering the Nordel, the ENTSO-E and the UK/Ireland areas. The Nordel

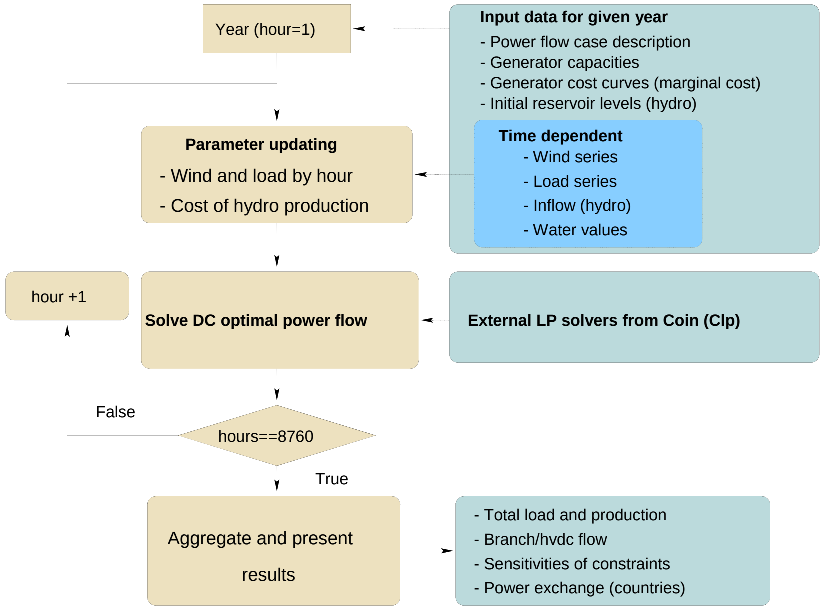


Figure 6.1: PSST simulation structure [80]

area is simulated as a 23 generator model, developed by SINTEF Energy Research [81, 82]. Even though the model is a simplification of the Nordel grid, the power flow corresponds to a full scale model and reflects the real production and bottlenecks within the northern European grid. HVDC connections to Denmark and the ENTSO-E area, e.g., the NorNed cable, are included in the grid model (see Figure 6.2). The ENTSO-E (former UCTE) region is modelled based on the approximated UCTE network created by Bialek and Zhou [83, 84]. The grid model for the UK and Northern Ireland is an approximate model based on data from National Grid, provided in the *"Seven Year Statement"* [85].

Furthermore, an intermediate level of detail is introduced by splitting larger countries into several grid zones representing different market areas (e.g., Norway), TSO areas (e.g., Germany) or areas with important grid constraints and bottlenecks in between (e.g., Sweden) [80]. The subdivision of the electrical grid into various grid zones offers the possibility to study the main power flow within one country, to simulate the area-wise effects of WPP, and to identify internal bottlenecks in connection with the integration of large scale WPP. Overall, the PSST grid model contains 2756 nodes, 4925 branches and 56 HVDC lines (see Figure 6.2).

The cross-border power flow on transmission corridors, connecting the various countries, are defined by the respective NTCs. The NTCs are in accordance with the ENTSO-E specifications [86]. Even though a flow based approach is used, the ENTSO-E NTC values are used as constraints limiting the cross-border transmission between countries and grid areas. Due to a lack of of available information, most of the inter-area transmission lines are modelled with infinite capacity. Exceptions are the Norwegian system and a limited number of lines in Germany.

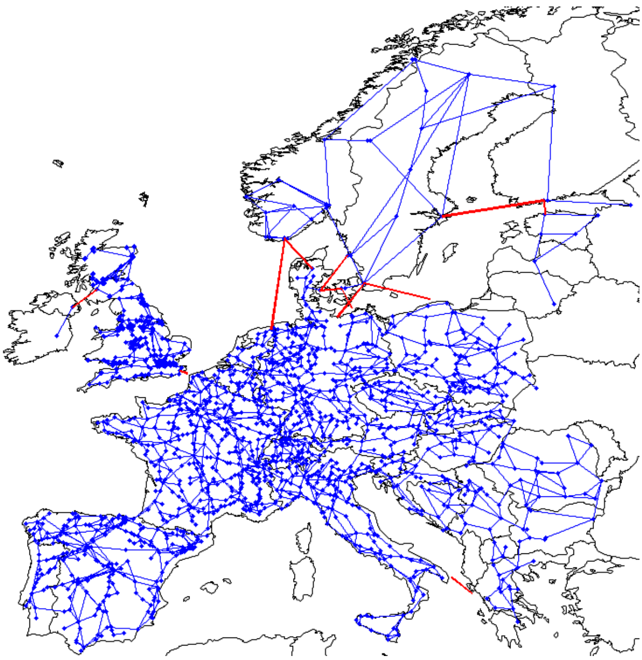


Figure 6.2: Simplified grid representation (blue: AC connections, red: DC connections)

6.2.1.2 Generator capacities and marginal costs

In total, the PSST model includes 1148 conventional generators,not including the WPP facilities. The model distinguishes the power plants by the respective type of fuel- hydro power, nuclear, lignite and hard coal, gas and oil/gas. Furthermore, renewable sources other than wind and hydro power, e.g., photovoltaic and biomass facilities are included in the data set. The actual as well as the predicted future installed generator capacities have been aggregated based on the UCTE system adequacy forecast and the data from Europrog [80, 86, 87].

The accuracy of the hydro power plant data set differs significantly for the respective areas. While a high resolution data set for hydro power units in the Nordic area, including the installed capacity, location and reservoir volume is available, data for the ENTSO-E (UCTE) area is based on the UCTE system adequacy forecast and the Europrog statistics [87, 88]. Since the data from [87, 88] does not distinguish between run-off-river, conventional and pumped hydro power plants, the UCTE hydro data set is largely based on approximations using the information available in [89, 90].

The respective marginal costs for each fuel type of thermal generators are derived from [91]. The marginal costs are split in average variable and average fixed costs, taking the fuel prices, O&M costs, generator efficiencies and taxes, in terms of greenhouse emissions taxes, into account. Increasing fuel prices for future scenarios are considered in the simulations based on the assumptions made in the TradeWind report [80]. In the model, the marginal costs are simulated by a piecewise linear cost function.

6.2.1.3 Initial reservoir levels (hydro)

In the Nordic area, the initial reservoir levels at the beginning of the simulation period are based on the long-term statistics and inflow scenarios specified in the EMPS model (see Chapter 4). Based on a lack of information, the initial reservoir level for hydro power facilities in the UCTE area is assumed to be 70% of the total reservoir capacity [80].

6.2.2 Time dependent parameters

6.2.2.1 Wind series

The detailed description of the wind power model can be found in Chapter 3. The installed wind power capacity for each country is divided into different regions and areas according to [16]. Within each area, the wind power facilities are connected to the geographically nearest bus in the grid model (see Figure 6.3). Therefore, the influence of WPP on each and every node can be determined in the modelling process. Furthermore, the geographical smoothing, the interaction between WPP and transmission bottlenecks, the influence of WPP on power market prices and the power production of conventional generators can be evaluated with high accuracy.

When modelling future wind power scenarios, the installed capacity of onshore facilities is scaled up to the assumptions made by the wind energy associations of the respective model areas. Planned and already commissioned offshore wind farms are based on the data available in [92].

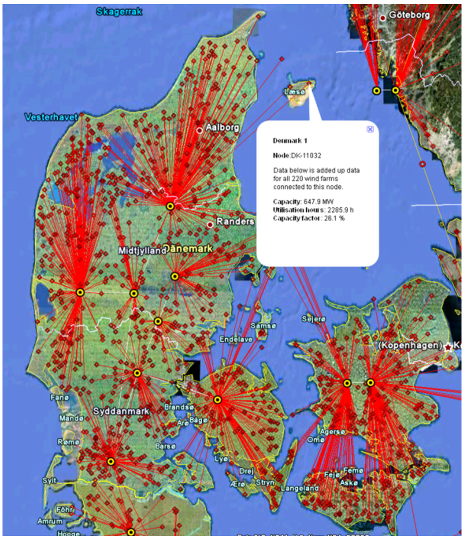


Figure 6.3: Aggregated WPP facilities in Denmark

6.2.2.2 Load series

The load profiles used in the simulations are based on the numbers from the TradeWind project [80] provided by Nordpool, National Grid, Eirgrid and UCTE [88, 93, 94, 95]. The load patterns for future scenarios are evaluated based on the 2006 load profiles, assuming a relative increase/decrease of the annual load demand in the respective area.

6.2.2.3 Inflow and water values

The inflow scenarios in PSST are based on the same long term statistics as in the EMPS model (See Chapter 4). The inflow pattern for countries outside the Nordic area has been aggregated based on the hydrological study 'FRIEND' (Flow Regimes from International Experimental and Network Data) [96] and the data in [97]. As with the inflow scenarios, the water values have been constructed by the EMPS model. The resulting water value matrix used in PSST is a function of reservoir level and the time of the year (see Figure 6.4).

Since no information about water values outside the Nordic region was available, the Norwegian values for the first two weeks in January have been used for all hydro power plants located in the UCTE area, for all weeks throughout the year. The main reason for choosing the same water value function for all weeks of the year is that power production in the UCTE area is not dominated

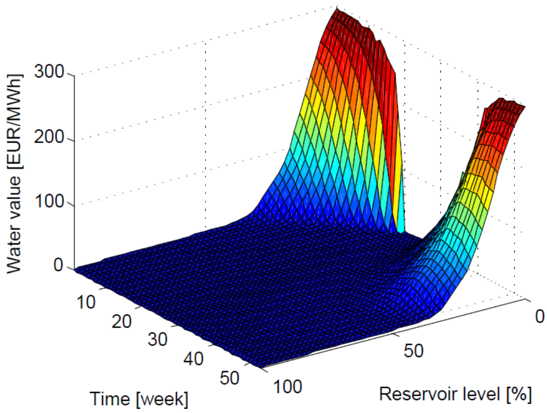


Figure 6.4: Water value matrix for Western Norway [5]

by hydro power plants with large reservoirs. Therefore, special cases such as low water values during summer may be invalid. [80].

6.3 Market model

The market model simulates the three distinct electricity markets namely day-ahead, intra-day and regulating power markets. While the day-ahead market is solely based on the respective case description including, e.g., generator, grid and load portfolios, the intra-day and real-time markets take the modelling results of antecedent simulation step into account. The schematic model procedure is displayed in Figure (6.5).

6.3.1 Mathematical description of the day-ahead market model

The day-ahead market is modelled as a common market for the whole European continent, including a simultaneous reserve procurement for Northern Europe. The day-ahead optimization is based on a DC optimal power flow aiming to minimize the total system costs. The objective function of the day-ahead dispatch is given by in Equation(6.1).

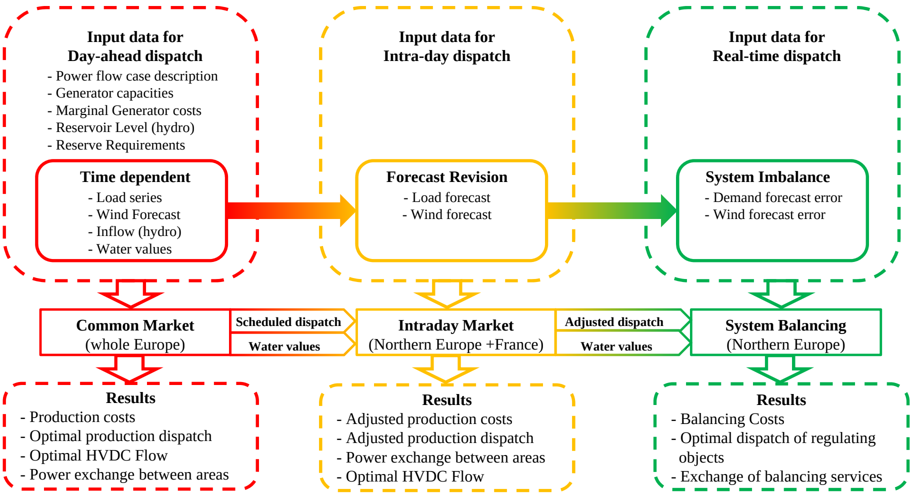


Figure 6.5: Schematic market model

$$
\begin{aligned}
F_\tau^D(\cdot) = min \Bigg\{ \sum_{\tau \in T} \Bigg[& \sum_{g \in G} (Cs_g^{th,D} \cdot Str_{g,\tau}^{th,D} + C_g^{th,D} \cdot P_{g,\tau}^{th,D}) \\
& + \sum_{h \in H} (C_{h,t}^{hyd,D} \cdot P_{h,\tau}^{hyd,D}) + \sum_{i \in Bus} (C^{rat} \cdot P_{i,\tau}^{rat,D}) \Bigg] \Bigg\}
\end{aligned}
\tag{6.1}
$$

The piecewise linear incremental cost function considers the start-up costs $Cs_g^{th,D}$ for thermal plants, the associated approximate relative start-up costs $Str_{g,\tau}^{th,D}$ and the production costs for each thermal plant, taking the particular marginal costs $C_g^{th,D}$ and the power production $P_{g,\tau}^{th,D}$ into account. The costs for hydro power production are considered by the respective water values $C_g^{hyd,D}$ along with the respective production $P_{h,\tau}^{hyd,D}$. In case of load shedding, the corresponding rationing costs are estimated by the amount of unserved load $P_{i,\tau}^{rat,D}$ and the associated rationing cost C^{rat}. The day-ahead market is successively simulated in steps of 24 hours throughout the simulation period.

6.3.1.1 Hydro generation

Despite the constant marginal costs of thermal generators, the water values depend on the reservoir level $Rl_{h,\tau}^{hyd,D}$ and therefore on the amount of water that can be utilized for energy production. According to Equations (6.2) and (6.3) the available hydro power production at time step τ is therefore not only constrained by the maximum and minimum production capacity ($\overline{P}_h^{hyd}$, $\underline{P}_h^{hyd}$), but also by the reservoir level, the inflow $Q_{h,\tau}^{hyd,D}$, which is evenly divided among the hours within a week, and the interaction between power production and reservoir level.

$\forall h \in H, \tau \in T$:

$$\underline{P}_h^{hyd} \leq P_{h,\tau}^{hyd,D} \leq min\left(\overline{P}_h^{hyd}, \frac{Rl_{h,\tau}^{hyd,D}}{L_\tau}\right) \tag{6.2}$$

$$Rl_{h,\tau}^{hyd,D} = Rl_{h,\tau-1}^{hyd,D} + Q_{h,\tau}^{hyd,D} - P_{h,\tau-1}^{hyd,D} \cdot L_{\tau-1}^{D} \tag{6.3}$$

6.3.1.2 Thermal generation

Within the model, thermal generators are divided into base-load (non-regulating) and regulating power plants (see Table 6.1). Power plants providing base load, e.g., nuclear or lignite, operate with low marginal costs and zero start-up costs when operating with at least minimum production larger than zero. On the other hand, regulating power plants providing the production flexibility and the ability to provide spinning reserves are re-dispatched in the real-time model to compensate for imbalances.

Table 6.1: Generator types

Non-regulating generators	Regulating generators
Nuclear	Gas
Lignite coal	Oil
Hard coal	Oil & Gas
Wind	Hydro
Renewable other than wind	Pump storage

Even though the start-stop decision of thermal generators is mainly based on economical aspects, minimum up- and down times limit the commitment of thermal power plants. The necessary flexibility for integrating large amounts of wind power into the system is therefore largely restricted by the technical constraints of load following and regulating power plants. While the minimum down time is modelled as a 'stiff' constraint which has to be adhered to, the minimum up time is represented as a 'soft' constraint which can be neglected in case of a better economical utilization in the system. The respective up- and downtimes used in the simulation are displayed in Table 6.2.

Table 6.2: Technical constraints of thermal plants

Type	Min. uptime [h]	Min. downtime [h]	
	warm	cold	warm
Hard coal	5	14	6
Oil	4	8	4
Oil-gas	6	8	5
Gas	1	-	1

Therefore, the production of thermal generators is not only limited by the respective upper and lower production limits ($\overline{P}^{th}_{g,\tau}$, $\underline{P}^{th}_{g,\tau}$) but also by the corresponding technical generator constraints for minimum up- and downtimes $\uparrow T^{th}_{g}$ and $\downarrow T^{th}_{g}$ which are represented by the binary variables $up^{th,D}_{g,\tau}$ and $do^{th,D}_{g,\tau}$ (see Equation 6.4).

$\forall g \in G, \tau \in T$:

$$up^{th}_{g,\tau} \cdot \underline{P}^{th}_{g} \leq P^{th,D}_{g,\tau} \leq \overline{P}^{th}_{g} \cdot do^{th}_{g,\tau} \tag{6.4}$$

According to Equations (6.5) and (6.6), the binary variable $do^{th,D}_{g,\tau}$ and therefore the maximum thermal production $\overline{P}^{th}_{g}$ are set to zero if the minimum down-time criteria $\downarrow T^{th}_{g}$ is not satisfied by the actual down time $\downarrow T^{th,D}_{g,\tau}$ at τ. Based on the binary variable $up^{th,D}_{g,\tau}$, a generator has to produce at least with its minimum production $\underline{P}^{th}_{g,\tau}$ if the minimum up-time $\uparrow T^{th}_{g}$ has not been reached at τ.

$\forall g \in G, \tau \in T$:

$$do^{th,D}_{g,\tau} = \begin{cases} 0, & \text{if } \downarrow T^{th,D}_{g,\tau} < \downarrow T^{th}_{g} \\ 1, & \text{if } \downarrow T^{th,D}_{g,\tau} \geq \downarrow T^{th}_{g} \end{cases} \tag{6.5}$$

$$up^{th,D}_{g,\tau} = \begin{cases} 0, & \text{if } \uparrow T^{th,D}_{g,\tau} < \uparrow T^{th}_{g} \\ 1, & \text{if } \uparrow T^{th,D}_{g,\tau} \geq \uparrow T^{th}_{g} \end{cases} \tag{6.6}$$

The generation dispatch of thermal generators for each time step is handed over to the consecutive period, connecting and predefining the binary variables and therefore the portfolio of available production units which can be utilized in the optimisation.

Equations (6.7) - (6.10) describe a linear approach to simulate start-up costs of thermal power plants. Each thermal generator is represented by three variables ranging from 0 to 1.

$\forall g \in G, \tau \in T$:

$$P_{g,\tau}^{th,D} = X_{1,g,\tau}^{th,D} \cdot \underline{P}_g^{th} + X_{2,g,\tau}^{th,D} \cdot (\overline{P}_g^{th} - \underline{P}_g^{th}) \tag{6.7}$$

$$X_{1,g,\tau}^{th,D} \geq X_{2,g,\tau}^{th,D} + X_{3,g,\tau}^{th,D} \tag{6.8}$$

$$X_{2,g,\tau}^{th,D} + X_{3,g,\tau}^{th,D} \leq 1 \tag{6.9}$$

$$X_{1,g,\tau}^{th,D} - X_{1,g,\tau-1}^{th,D} \leq Str_{g,\tau}^{th,D} \tag{6.10}$$

In Equation(6.7), the relation between the actual production and the synthetic variables $X_{1,g,\tau}^{th,D}$, $X_{2,g,\tau}^{th,D}$ is displayed. While Equation (6.8) assures that a power plant has to be in operation before it produces power, Equation (6.9) limits the maximum production. The production in Equation (6.9) consists of two variables simulating the actual production $X_{2,g,\tau}^{th,D}$ and the spinning reserve $X_{3,g,\tau}^{th,D}$. Equation (6.10) ensures that the approximate relative start-up cost $Str_{g,\tau}^{th,D}$ is at least equal to the value of the difference between $X_{1,g,\tau}^{th,D}$ and $X_{1,g,\tau-1}^{th,D}$.

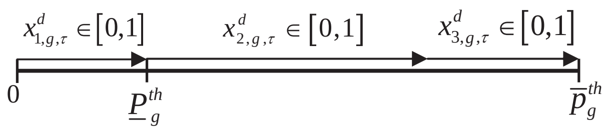


Figure 6.6: Thermal plant representation [98]

6.3.1.3 Transmission and grid

The underlying electrical grid, the transmission and the energy balance for each bus and the corresponding constraints are represented by Equations (6.11) - (6.14).

$\forall ij \in Line, \tau \in T$:

$$P^{l,I}_{ij,\tau} = B_{ij}(\delta^D_{i,\tau} - \delta^D_{j,\tau}) \tag{6.11}$$

$\forall i \in Bus, \tau \in T$:

$$\begin{aligned} P^{L,D}_{i,\tau} =& P^{th,D}_{i,\tau} + P^{hyd,D}_{i,\tau} + P^{win,D}_{w,\tau} + \\ & \sum_{j \in Bus} (P^{hvdc,D}_{ij,\tau} - P^{hvdc,D}_{ji,\tau}) - \sum_{j \in Bus} P^{l,D}_{ij,\tau} + P^{rat,D}_{i,\tau} \end{aligned} \tag{6.12}$$

$\forall ij \in Line, \tau \in T$:

$$-\overline{P}^l_{ij} \leq P^{l,D}_{ij,\tau} \leq \overline{P}^l_{ij} \tag{6.13}$$

$\forall a', b' \in BA, \tau \in T$:

$$-NTC_{b'a'} \leq \sum_{i \in Bus_{a'}} \sum_{j \in Bus_{b'}} P^{l,D}_{ij,\tau} \leq NTC_{a'b'} \tag{6.14}$$

$\forall ij \in HVDC, \tau \in T$:

$$-\overline{P}^{hvdc}_{ij} \leq P^{hvdc,D}_{ij,\tau} \leq \overline{P}^{hvdc}_{ij} \tag{6.15}$$

The energy exchange between buses i and j is given in Equation in (6.11). Equation (6.12) assures the energy balance between the load $P^L_{i,\tau}$ and the production from thermal, hydro and WPP facilities at each bus. The WPP data $P^{win,D}_{w,\tau}$ is based on wind power forecasts ranging from one hour to 24 hours ahead. Furthermore, the transmission from and to each bus, along with a possible load rationing, is taken into consideration.

According to the regulations and definitions from the European Transmission System Operator (ETSO), the synchronous systems are divided into balancing areas BA and balancing regions BR [99]. Therefore, the maximum and minimum number of AC transmission lines is not only constrained by the respective maximum and minimum transmission capacities according to Equation (6.13) but also by the respective net transfer capacities $NTC_{b'a'}$ described by Equation (6.14). The HVDC transmission is limited by the transmission capacity according to Equation (6.15).

To exchange balancing power between areas or regions, a sufficient amount of transmission capacity has to be available upon request. In the model, the reserve procurement is done simultaneously within the day-ahead dispatch, based on an implicit allocation of transmission capacity.

Equations (6.16) - (6.18) determine the use of intra-area transmission capacity for balancing purposes.

$\forall a', b' \in BA, \tau \in T, h \in H, gr \in GR$

$$\uparrow imp^{D}_{a'b',\tau} \leq NTC_{b'a'} + \sum_{i \in Bus_{a'}} \sum_{j \in Bus_{b'}} P^{l,D}_{ij,\tau} \tag{6.16}$$

$$\begin{aligned} \uparrow Re_{a'} \leq & \sum_{b' \in BA} \uparrow imp^{D}_{a'b',\tau} + \sum_{h \in Bus_{a'}} (\overline{P}^{hyd}_{h} - P^{hyd,D}_{h,\tau}) \\ & + \sum_{gr \in Bus_{a'}} (X^{th,D}_{3,gr,\tau} \cdot (\overline{P}^{th}_{gr} - \underline{P}^{th}_{gr})) \end{aligned} \tag{6.17}$$

In Equation (6.16) the implicit reservation for the exchange of upward regulating energy between areas is defined. Equation (6.17) states that the area reserve requirements for upward regulation must be fulfilled by regulating entities within an area, and by the available transmission capacity for importing balancing power from other areas. Correspondingly, the implicit reservation for the allocation of downward regulating energy exchange and the corresponding values for downward regulating reserve requirements are defined by Equations (6.18) and (6.19).

$\forall a', b' \in BA, \tau \in T, h \in H, gr \in GR$

$$\downarrow imp^{D}_{a'b',\tau} \leq NTC_{a'b'} - \sum_{i \in Bus_{a'}} \sum_{j \in Bus_{b'}} P^{l,D}_{ij,\tau} \tag{6.18}$$

$$\begin{aligned} \downarrow Re_{a'} \leq & \sum_{b' \in BA} \downarrow imp^{D}_{a',b',\tau} + \sum_{h \in Bus_{a'}} max[(P^{hyd,D}_{h,\tau} - \underline{P}^{hyd}_{h}), 0] + \\ & \sum_{gr \in Bus_{a'}} (X^{th,D}_{2,gr,\tau} \cdot (\overline{P}^{th}_{gr} - \underline{P}^{th}_{gr})) \end{aligned} \tag{6.19}$$

In the present state of market integration, the exchange of balancing power is limited by the UCTE regulations. Based on Equations (6.20) and (6.21) the up- and downward reserve requirements for each area are defined. In case of market integration, these can be relaxed.

$\forall a \in BR, \tau \in T, gr \in GR$

$$\begin{aligned}\uparrow Re_a \leq & \sum_{h \in Bus_a} (\overline{P}_h^{hyd} - P_{h,\tau}^{hyd,D}) + \\ & \sum_{gr \in Bus_a} (X_{3,gr,\tau}^{th,D} \cdot (\overline{P}_{gr}^{th} - \underline{P}_{gr}^{th}))\end{aligned} \tag{6.20}$$

$$\begin{aligned}\downarrow Re_a \leq & \sum_{h \in Bus_a} max[(P_{h,\tau}^{hyd,D} - P_h^{hyd}), 0] + \\ & \sum_{gr \in Bus_a} (X_{2,gr,\tau}^{th,D} \cdot (\overline{P}_{gr}^{th} - \underline{P}_{gr}^{th}))\end{aligned} \tag{6.21}$$

6.3.2 Intra-day dispatch

The relevance of intra-day markets will increase with the rising share of RES in the power system. Since the forecast error increases with the lead time (see Figure 10.1), the market participants and the system operators must be able to adjust the day-ahead market results and the scheduled system operation based on revised WPP forecasts (see Figure 6.22).

To reflect the actual situation in Northern Europe, the simulation area of the intra-day market is reduced to the Central Western European Area (CWE) and the Nordic area (Nordel).

The intra-day objective function is given in Equation (6.22).

$$\begin{aligned}F_\tau^I(\cdot) = min \Bigg\{ \sum_{\tau \in T} \Bigg[& \sum_{g \in G} (Cs_g^{th,I} \cdot Str_{g,\tau}^{th,I} + C_g^{th,I} \cdot \Delta P_{g,\tau}^{th,I}) \\ & + \sum_{h \in H} (C_{h,\tau}^{hyd,I} \cdot \Delta P_{h,\tau}^{hyd,I}) + \sum_{i \in Bus} (C^{rat} \cdot P_{i,\tau}^{rat,I}) \Bigg] \Bigg\}\end{aligned} \tag{6.22}$$

Intra-day generation

For the time after day-ahead market closure until one hour before real time, the intra-day dispatch is simulated on an hourly basis. As mentioned previously, the day-ahead dispatch is based on WPP forecasts ranging from one hour up to 24 hours ahead. Within the intra-day market, the forecast length and therefore the forecast accuracy increases over a decreasing lead time. The forecast deviation between day-ahead and intra-day forecasts is defined according to Equation (6.23).

$\forall i \in Bus, \tau \in T$:

$$\Delta P_{i,\tau}^{win,I} = P_{i,\tau}^{win,I} - P_{i,\tau}^{win,D} \tag{6.23}$$

To ensure equilibrium between load and production at each bus (see Equation (6.24)), the wind forecast deviation $\Delta P_{i,\tau}^{win,I}$ has to be compensated by adjusting the thermal and hydro production by $\Delta P_{g,\tau}^{th,I}$ and $\Delta P_{h,\tau}^{hyd,I}$ according to Equations (6.25) and (6.26).

$\forall i \in Bus, \tau \in T$:

$$\begin{aligned} P_{i,\tau}^{L} =& (P_{i,\tau}^{th,D} + \Delta P_{i,\tau}^{th,I}) + (P_{i,\tau}^{hyd,D} + \Delta P_{i,\tau}^{hyd,I}) + (P_{i,\tau}^{win,D} + \Delta P_{i,\tau}^{win,I}) + \\ & \sum_{j \in Bus} (P_{ij,\tau}^{hvdc,I} - P_{ji,\tau}^{hvdc,I}) - \sum_{j \in Bus} P_{ij,\tau}^{l,I} + P_{i,\tau}^{rat,I} \end{aligned} \tag{6.24}$$

where:

$\forall i \in Bus, \tau \in T$:

$$\Delta P_{i,\tau}^{th,I} = P_{i,\tau}^{th,I} - P_{i,\tau}^{th,D} \tag{6.25}$$

$$\Delta P_{i,\tau}^{hyd,I} = P_{i,\tau}^{hyd,I} - P_{i,\tau}^{hyd,D} \tag{6.26}$$

Corresponding to the day-ahead dispatch, the intra-day adjustment of thermal generators is limited by the respective technical constraints, defining the minimum up- and downtimes, therefore limiting the production adjustment $\Delta P_{i,\tau}^{th,I}$. Start-up costs are considered in the intra-day dispatch according to Equations (6.7) - (6.10).

$\forall g \in G, \tau \in T$:

$$up_{g,\tau}^{th} \cdot \underline{P}_{g}^{th} \leq \Delta P_{i,\tau}^{th,I} \leq \overline{P}_{g}^{th} \cdot do_{g,\tau}^{th} \tag{6.27}$$

Similar assumptions are made for the generation adjustment of hydro generators according to Equation (6.28).

$\forall h \in H, \tau \in T$

$$0 \leq \Delta P_{h,\tau}^{hyd,I} \leq \left(min \left(\overline{P}_h^{hyd}, \frac{Rl_{h,\tau}^{hyd,I}}{L_\tau} \right) \right) \tag{6.28}$$

6.3.2.1 Intra-day transmission

The transmission system in the intra-day dispatch is limited by the following constraints. The power exchange between buses in the intra-day market is described by Equation (6.29).

$\forall ij \in Line, \tau \in T$:

$$P_{ij,\tau}^{l,I} = B_{i,j}(\delta_{i,\tau}^I - \delta_{j,\tau}^I) \tag{6.29}$$

The implicit allocation of inter-area transmission capacities takes takes into account the reserved transmission capacity for the exchange of up- and downward regulating power settled in the day-ahead market. The remaining ATC available in the intra-day dispatch, is based on Equations (6.30) - (6.32).

$\forall a', b' \in BA, \tau \in T$:

$$ATC_{b'a',\tau} = NTC_{b'a'} - {\uparrow}imp_{b'a',\tau}^D \tag{6.30}$$

$$ATC_{a'b',\tau} = NTC_{a'b'} - {\downarrow}imp_{a'b',\tau}^D \tag{6.31}$$

$$-ATC_{b'a',\tau} \leq \sum_{i \in Bus_{a'}} \sum_{j \in Bus_{b'}} P_{ij,\tau}^{l,I} \leq ATC_{a'b',\tau} \tag{6.32}$$

The HVDC intra-day transmission is limited according to Equation (6.33). Therefore, only the remaining transmission capacity after the day-ahead dispatch can be utilized in the intra-day market.

$\forall ij \in HVDC, \tau \in T$:

$$-\overline{P}_{ij}^{hvdc} - P_{ij,\tau}^{hvdc,D} \leq P_{ij,\tau}^{hvdc,I} \leq \overline{P}_{ij}^{hvdc} - P_{ij,\tau}^{hvdc,D} \tag{6.33}$$

6.3.3 Real-time dispatch

The aim of the real-time dispatch is to compensate for remaining imbalances from the intra-day market while minimising the respective balancing costs. The objective of the balancing market is therefore not to do an optimal re-dispatch, but to relieve remaining imbalances.

The corrective control objective represented by Equation (6.34) is used to minimize the deviation costs from the initial operating point [98, 100]. The balancing costs therefore result from the production change of a regulating generator ΔP_i and the associated marginal costs C_i.

$$F(\cdot) = \sum C_i \, |\Delta P_i| \tag{6.34}$$

$|\Delta P_i|$ is represented as two hypothetical generators $\Delta \uparrow P_i$ and $\Delta \downarrow P_i$, corresponding to up- and downward regulation with an associated incremental cost $\uparrow C_i$ and $\downarrow C_i$ respectively. The cost function of the real-time dispatch is displayed in Equation (6.35).

$$\begin{aligned} F^R_\tau(\cdot) =& min \left\{ \sum_{gr \in GR} (\uparrow C^{th,R}_{gr,\tau} \cdot \Delta \uparrow P^{th,R}_{gr,\tau} + \downarrow C^{th,R}_{gr,\tau} \cdot \Delta \downarrow P^{th,R}_{gr,\tau}) \right. \\ & + \sum_{h \in H} (\uparrow C^{hyd,R}_{h,\tau} \cdot \Delta \uparrow P^{hyd,R}_{h,\tau} + \downarrow C^{hyd,R}_{h,\tau} \cdot \Delta \downarrow P^{hyd,R}_{h,\tau}) \\ & \left. + \sum_{i \in Bus} (C^{rat} \cdot P^{rat,R}_{i,\tau}) \right\} \end{aligned} \tag{6.35}$$

In addition the constraints displayed in Equations (6.40)-(6.41) have to be satisfied. While Equation (6.36) displays the real-time power exchange between bus i and bus j, Equation (6.37) assures the real-time balance between production and consumption at each bus, taking imbalances into account.

$\forall ij \in Line, \tau \in T$:

$$P^{l,R}_{ij,\tau} = B_{i,j}(\delta^R_{i,\tau} - \delta^R_{j,\tau}) \tag{6.36}$$

$\forall i, j \in Bus, \tau \in T$

$$\begin{aligned} \widetilde{P}^{dev}_{i,\tau} =& (\Delta \uparrow P^{th,R}_{i,\tau} - \Delta \downarrow P^{th,R}_{i,\tau}) + (\Delta \uparrow P^{hyd,R}_{h\tau} - \Delta \downarrow P^{hyd,R}_{h,\tau}) \\ & + \sum_{j \in Bus} (P^{hvdc,R}_{ji,\tau} - P^{hvdc,R}_{ij,\tau}) \\ & - \sum_{j \in Bus} P^{l,R}_{ij,\tau} - P^L_{i,\tau} + P^{rat,R}_{i,\tau} \end{aligned} \tag{6.37}$$

The production capacity of regulating generators providing up- and downward regulation are limited according to Equations (6.38) and (6.39), respectively.

$\forall gr \in GR, \tau \in T$

$$P^{th,D}_{gr,\tau} \leq \Delta \uparrow P^{th,R}_{gr,\tau} \leq \overline{P}^{th}_{gr,\tau} \tag{6.38}$$

$$\underline{P}^{th}_{gr,\tau} \leq \Delta \downarrow P^{th,R}_{g,\tau} \leq P^{th,D}_{gr,\tau} \tag{6.39}$$

Hydro generators providing regulating energy are constrained by Equations (6.40) and (6.41), taking the intra-day reservoir level and the production limits into account.

$\forall h \in H, \tau in T$

$$0 \leq \Delta \uparrow P^{hyd,R}_{h,\tau} \leq \left(min \left(\overline{P}^{hyd}_{h}, \frac{Rl^{hyd,I}_{h,\tau}}{L_\tau} \right) - Rl^{hyd,I}_{h,\tau} \right) \tag{6.40}$$

$$0 \leq \Delta \downarrow P^{hyd,R}_{h,\tau} \leq (P^{hyd,I}_{h,\tau} - \underline{P}^{hyd,I}_{h}) \tag{6.41}$$

6.4 Concluding remarks

The described modelling routine is used to simulate the European day-ahead market and the intra-day and the real-time markets in Northern Europe and the Nordic area. A case study along with the evaluated results is shown in Chapter 10.

Part II

Case Studies

Chapter 7

Wind power production on a European level

Publications A and F

The chapter summarizes Publications A and F. The chapter examines WPP on a European level. Based on an extensive data set of European on- and offshore wind power facilities, the variability and the predictability of wind power production on the full European level is modelled. Various scenarios, including the current state and future scenarios for 2020 and 2030, are applied to illustrate the hourly and annual production variations and their influence on net load ramps in the European system. A special focus is set on offshore wind power production in the North and Baltic Seas. Furthermore, the predictability of wind power generation on a European level is evaluated. The chapter is divided into four sections. Section 7.1 and Section 7.2 describe the applied wind speed data and the wind power installation scenarios. In Section 7.3, the variability of wind power production on an annual and an hourly basis is displayed. Furthermore, the net load variations for Europe and the neighbouring countries of the North Sea are evaluated. The section concludes with an illustration of WPP predictability. This chapter concludes with a discussion in Section 7.5.

7.1 Wind speed data set

To establish a reliable data set covering the fluctuations of European WPP, a long term recording of wind speed data is desirable. The data set, including the years from 2006 to 2012, was provided by the German meteorological office [47].

The actual wind speed data is provided with a time resolution of one hour.

Even though most system simulations focus on short term WPP variations and the subsequent influences on voltage stability, the procurement of primary and secondary reserves, cycling losses and annual distinctions have to be considered for assessing the system adequacy. *"System adequacy of a power system is a measure of the ability of a power system to supply the load in all the steady states in which the power system may exist considering standards conditions. System adequacy is analysed through generation adequacy and transmission adequacy"* [86, p.20].

Figure 7.1 displays a map of the annual average wind speeds in Europe from 2006 to 2012. The data set illustrates significant differences between the annual wind speed recordings. While the wind speed in 2010 was about 10% below the long term wind speed average in Europe, the 2011 wind speed was about 10% above it. [101]. Consequently these years have been chosen for the further simulations since they present the limiting values.

The highest average wind speeds in both years can be observed in the Scottish Sea, north-west of Scotland while the highest variations occur in the North Sea along the Norwegian coast, Ireland and Wales. They can also be observed in the area between Germany and Denmark. Furthermore, the coastal and onshore areas in Germany, Denmark and the UK are largely affected by annual variations. These deviations illustrate the necessity to consider long term recordings for system simulations, since the regions most affected by annual variations include the main construction sites for future offshore wind farms.

7.2 Installation scenarios

The installed wind power capacity for each year is based on the 'high' scenario estimated in the TradeWind project [16]. The high scenario was chosen since it corresponds the most with the annual gain of newly installed wind power facilities during the past years.

In the TradeWind project, each regional wind power organisation has been questioned about the assumptions regarding future WPP installations within their respective countries. Furthermore, larger countries, e.g., Germany and Spain, have been split up into separate areas. Each area is defined by an individual installation scenario taking the local potential for a further wind integration into account. The predicted capacity gain for each country is displayed in Table 7.1.

The numbers in Table 7.1 show a triplication of the current installed wind power capacity til 2020 and almost a fivefold increase til 2030. Especially, the capacity expansion of offshore installations in the North and Baltic sea will contribute to the overall capacity.

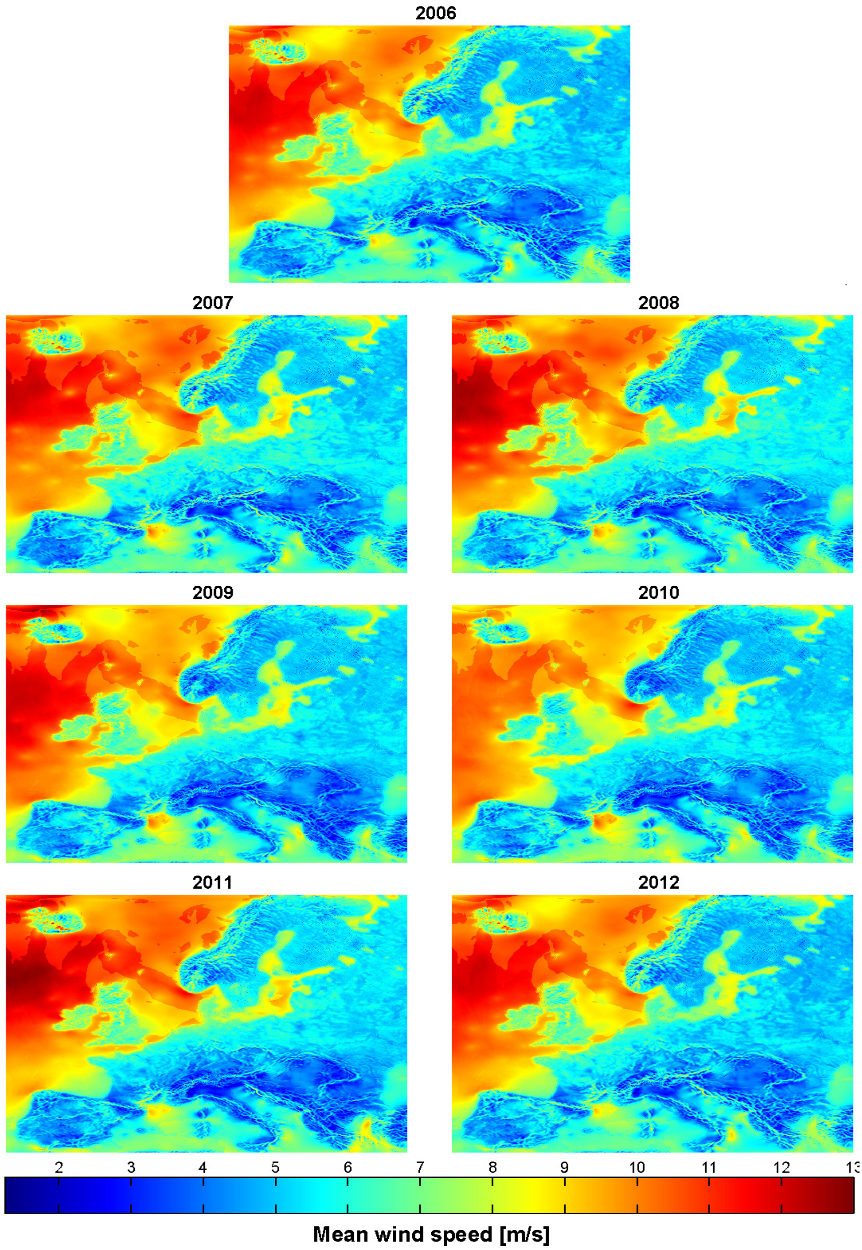


Figure 7.1: Mean annual wind speed in Europe for 2010 and 2011

Table 7.1: Wind power installation scenarios [MW]

	2010		2020		2030	
Country	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Austria	1221	-	5160	-	8320	-
Belgium	1022	165	2951	2156	6057	3956
Bulgaria	182	-	1167	-	3471	-
Croatia	53	-	648	-	1642	-
Czech Republic	578	-	2404	-	3419	-
Denmark	3677	612	3815	2811	4653	4611
Finland	351	-	3020	846	6120	3605
France	5528	-	40012	3935	55024	5650
Germany	25277	60	32383	8805	33883	24063
Greece	1482	-	6052	-	9789	-
Hungary	325	-	902	-	1604	-
Ireland	2794	25	5500	2119	6029	3219
Italy	6988	-	18721	-	22635	-
Luxenbourg	65	-	131	-	205	-
Netherlands	2597	228	4259	5298	3922	12794
Norway	725	2	4913	415	4367	3213
Poland	1243	-	7246	0	14502	300
Portugal	3858	-	7913	-	9836	-
Romania	301	-	1907	-	2310	-
Slovakia	25	-	86	-	112	-
Slovenia	130	-	560	-	860	-
Spain	19419	-	39163	-	52973	-
Sweden	1233	110	4731	3079	6268	6865
Switzerland	43	-	304	-	565	-
United Kingdom	9673	1341	31640	16311	33536	36201
Sum	88800	2441	225738	45775	292602	104479
Overall	91 241		271 513		397 081	

The applied offshore data set is based on the assumptions in the 'Global Offshore Wind Farms Database' provided by 4Coffshore [92]. The data set includes 180 Offshore Wind Farms (OWF) in 2020 and about 320 in 2030. The highest density of OWF is assumed to be in the border area between Germany and Denmark, between the UK and the Netherlands, and also within the Doggers Bank area along the English east coast (see Figure 7.2).

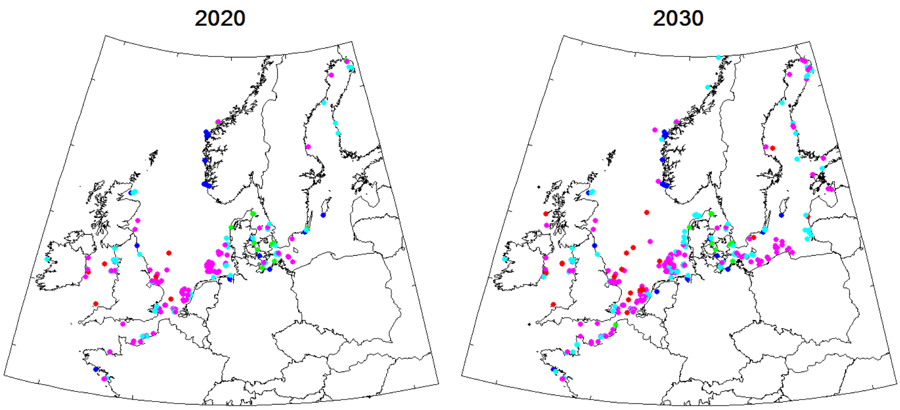


Figure 7.2: Wind farms in the North and Baltic Sea in 2020 and 2030; Colorcode installed capacity: blue<10MW, green 10MW<80MW, cyan 80MW<200MW, magenta 200MW<800MW, red>800MW

The European onshore wind power facilities, except for Germany, are based on the data provided by [54]. The numbers given in the data set largely correspond to the 2010 installation scenario published by the EWEA [102].

For Germany, the 'Erneuerbare Energien Gesetz (§§45 - §§52)' stipulates the German TSOs to publish their RES energy production in line with the wind power production facilities connected to the grid [56][57]. The open source data base contains all registered wind power facilities in Germany, including the installed capacity and the corresponding geographical coordinates.

The overall data set includes more than 24000 wind power facilities (see Figure 7.3). The annual gain in installed capacity is not considered in the simulations due to a lack of available data. The base case data set therefore corresponds to the installed capacity at the end of 2010.

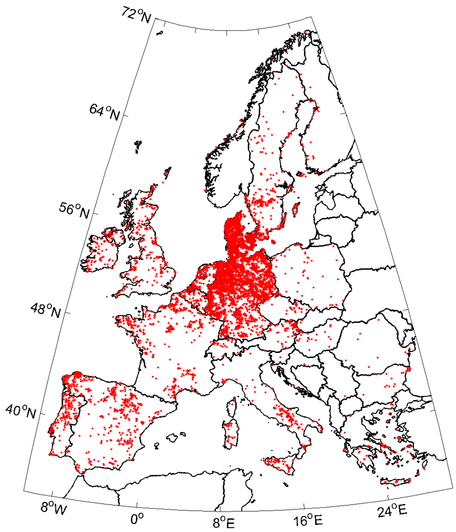


Figure 7.3: European onshore wind installations

7.3 Simulation results

7.3.1 Annual wind power production

The annual wind speed variations displayed in Figure 7.1 directly affect the European wind power production, leading to a production offset of 12.7 TWh between 2010 and 2011 (see Figure 7.4). This corresponds to about 9.04 % of the annual production. Both wind speed scenarios will be used in the following scenarios. For each simulation it is clearly stated which wind speed time series was used as an input.

The duration curves in Figure 7.5 display the annual wind power production for whole Europe and the offshore areas in the North Sea. To illustrate the future offshore WPP, the simulated output of OWFs in the North and Baltic sea are displayed separately.

Besides the large gain in WPP for future scenarios, the duration curves illustrate the high variability throughout the year. While the average European production is rather stable and between 17% to 20% of the installed European capacity for about 6000 h of an year, the tails of the duration curves display extreme events with almost no production or a very high production.

The key numbers representing the duration curves are depicted in Table 7.2.

While the upper part of Table 7.2 displays the whole European minimum, mean and maximum WPP, the lower part focuses on offshore facilities in the

Table 7.2: Annual wind power production

Europe						
	2010		2020		2030	
	[MW]	[%] of Inst. capacity	[MW]	[%] of Inst. capacity	[MW]	[%] of Inst. capacity
Min	1470 (2239)	1.6 (2.4)	6138 (7117)	2.2 (2.6)	9855 (12100)	2.5 (3.0)
Mean	15151 (16 521)	16.6 (18.1)	46647 (52069)	17.2 (19.1)	74152 (82882)	18.6 (20.1)
Max	51291 (54543)	56.2 (59.7)	157611 (165053)	58.0 (60.8)	238704 (246951)	60.1 (62.2)
Offshore facilities in the North & Baltic Sea						
Min	10.8 (15.7)	0.4 (0.6)	655 (767)	1.4 (1.7)	1889 (1589)	1.5 (1.8)
Mean	431 (533)	17.6 (21.8)	11770 (13862)	25.7 (30.3)	29910 (35002)	28.6 (33.5)
Max	1885 (1979)	77.2 (81.1)	38024 (39701)	83.1 (86.7)	90682 (96221)	86.8 (92.1)

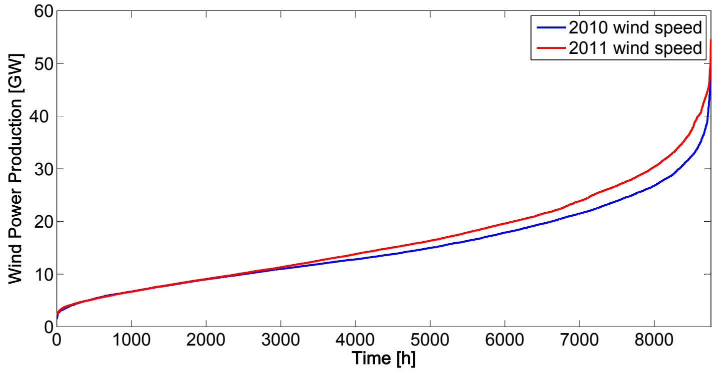


Figure 7.4: Duration curves of annual European wind power production based on 2010 and 2011 wind speeds

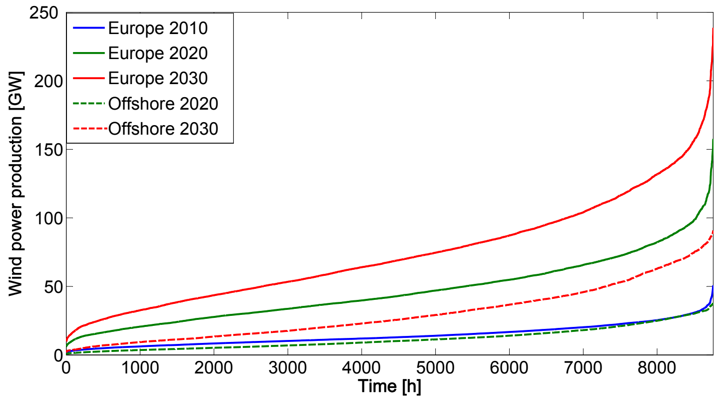


Figure 7.5: Duration curves of annual European and offshore WPP in 2010, 2020 and 2030

North and Baltic Seas. Besides the actual production numbers in MW, the respective percentage of the installed capacity is shown. The data is based on the 2010 and 2011 wind speed data set (2011 data in brackets).

7.3.1.1 Offshore WPP

Although the average wind speed in offshore areas is higher than that of onshore areas, the annual production variations are tremendous. Considering the two future offshore scenarios for 2020 and 2030, the minimum production based on the 2010 wind speed data is as little as 655 MW and 1 889 MW at an installed capacity of about 45 GW and 104 GW respectively. This corresponds to 1.4% in 2020 and 1.5% in 2030. Using the high wind speed data set from 2011 a slight increase to 1.7% and 1.8% can be noticed for 2020 and 2030, respectively. The maximum production on the other hand rises up to around 38 GW to 90.6 GW for the 2010 wind speed data and around 39.7 GW to 96 GW for the 2011 wind speed data. This corresponds to around 90% of the overall installed capacity. The extremely high variations of offshore wind power production is the direct consequence of installed production capacities clustered in areas with low geographical separation.

7.3.1.2 European WPP

From the current 2010 installation scenario, the mean annual production in Europe will rise from approximately 15 GW up to 52 GW in 2020 and 82 GW in 2030. Especially the offshore facilities, representing around 17% in 2020 and 25% in 2030 of the installed capacity, will contribute to the overall production. Due to high wind speeds, the mean offshore wind production is between 30% and 33% of the installed offshore capacity.

Although the actual European wind power facilities are already highly separated and geographically distributed, the minimum European production in 2010 is only around 1470 MW for the 2010 wind speed data and 2239 MW for the 2011 wind speed data. This corresponds to 1.6% and 2.4% of the installed capacity, respectively. These numbers seem surprisingly low, but a comparison with the German TSO production data from 2010 reveals that the minimum production was as little as 122 MW at an installed capacity of 25 GW. The German system provides far less geographical dispersion than the European system, nevertheless it can be used as a benchmark illustrating the annual WPP in a large area.

Even though there will be further geographical spreading and a large share of offshore facilities built in areas with high average wind speeds, the annual production variations in future scenarios remain considerably high. The numbers in Table 7.2 indicate that the minimum production for the future European scenarios only corresponds to about 2.2% to 3.0% of the installed capacity, while the maximum production reaches its limit between 56% and about 60% of the installed capacity. In fact the WPP in all cases is below 10% of the installed capacity for about 1000 hours and above 50% for about 600 hours during a year.

The numbers display that WPP will largely contribute to the European energy production with about 456 TWh in 2020 and 649 TWh in 2030. Nevertheless, WPP on a European level is not able to deliver a substantial amount of energy at any time throughout a year. In fact, the numbers in Table 7.2 indicate that the minimum production is very little. Furthermore, low WPP around 5% of the installed capacity or even below is not limited to just one hour but stretch over a certain period of time. An evaluation of the modelling results shows that for a duration of 48 hours, before and after the minimum WPP, the European wind power production was below 5% of the installed capacity. Even though the geographical distribution of wind power facilities will further increase and offshore sites will be put into operation, there are days without wind, even on a European level.

7.3.2 Hourly variations

The hour-to-hour variability of wind power production is one of the major topics in system simulations. Voltage variations, the procurement of primary and secondary reserves and cycling losses of thermal power plants are largely affected by the unscheduled production pattern of large scale WPP. Figure 7.6 displays the hourly variations for whole Europe and for the offshore facilities in the North and Baltic Seas. The simulations are based on wind speeds from 2010 and 2011.

The hourly variations displayed in Figure 7.6 and Table 7.3 are based on wind speeds from 2010 and 2011.

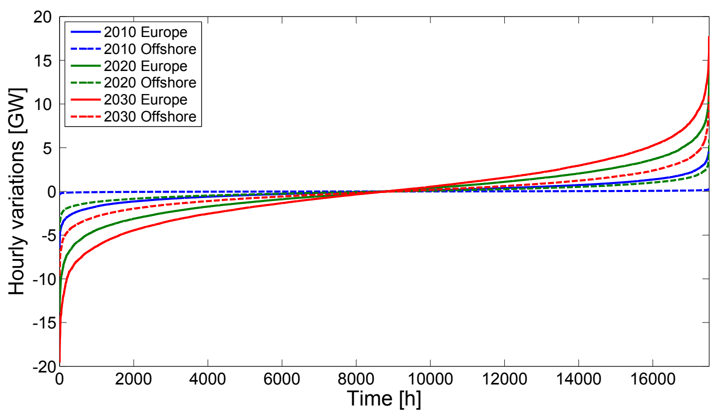


Figure 7.6: Hourly production variations in Europe and for offshore facilities in the North and Baltic sea

Figure 7.6 illustrates a rapid increase in WPP variability for future scenarios. While the hourly variations in 2010 are still modest, with a maximum hourly production change of -6525 MW and 4824 MW on a European level, they will be doubled in 2020 and more than tripled in 2030. The hourly downward ramping of about -13.7 GW in 2020 and -19.6 GW in 2030, as well as the upward variations of 15 GW and 17.7 GW, are largely influenced by the offshore production facilities. In fact, according to Table 7.3 up to 40% of the overall fluctuations in 2020 and up to 60% of the overall fluctuations in 2030 directly result from offshore facilities. This is remarkable since OWF only represent around 20% and 25% of the installed capacity in the future scenarios.

Table 7.3: Hourly wind power variations

Europe			
	2010 [MW]	2020 [MW]	2030 [MW]
Max. Downward	-6525	-14936	-19601
Max. Upward	4824	13755	17741
Offshore facilities in the North & Baltic Sea			
Max. Downward	-414	-4526	-9628
Max. Upward	355	5954	11122

An inconsistency of up- and downward ramps between the European level and the offshore facilities is ascertainable. While on a European level the absolute value of hourly changes is larger for downward variations, an opposite behaviour is detectable for future offshore installations. This results from the clustering of offshore production sites in relatively small areas.

While the European wind power production is well distributed and therefore not sensitive to local weather phenomena, the clustering of OWFs results in a reduction of the geographical smoothing. Regional and local weather phenomena have therefore a much higher impact on the future wind power production.

Taking the wind speeds from storm front ‘Carmen’ along with the 2030 offshore installation scenario as an example (see Figure 7.7), the reason for the inconsistent up- and downward variations becomes more obvious. While the wind power production in the North and Baltic Seas before the storm front is on a rather modest level with about 20 GW, which corresponds to about 25% of the installed capacity. At around hour 8380 (see Figure 7.7) the storm front hits the wind power facilities in the North Sea almost simultaneously. The resulting change in offshore power generation resulted in an upward ramp of 11 GW per hour. Even though the increase in power production occurred almost simultaneously, the wind speed abatement after the storm is less distinctive and delayed for the different production sites in the North Sea.

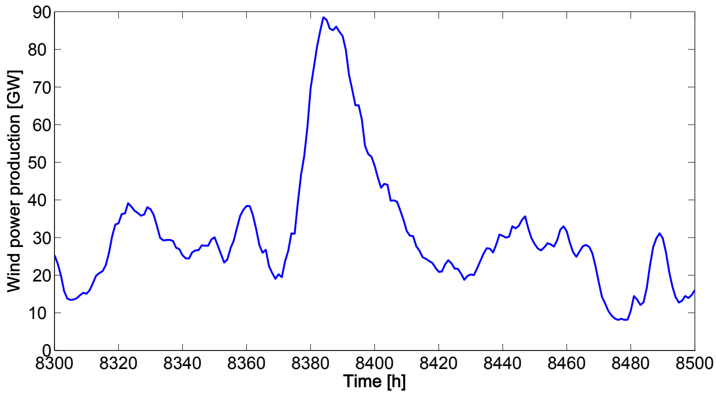


Figure 7.7: Simulated 2030 offshore wind power production during storm front 'Carmen'

7.3.3 Net load variations

The previously described wind power production variations directly affect system operation due to resulting net load variations induced in the system. The net or residual load corresponds to the remaining demand in the power system which is not covered by wind power or any other power production from RES. The net load is therefore a measure of how much production flexibility is required in the system due to a rising share of wind power.

In a system without the variability of renewable energy sources, changes in power production are solely based on the diurnal and annual load variations. While the production scheduling is based on well-developed and proven diurnal load pattern, wind power production does not follow a diurnal production pattern but is more or less randomly distributed and less predictable. In case of an opposite course of load and wind power production, e.g., during times of increasing load and a decreasing wind power production, conventional power plants are forced not only to cover the load gradients but also to replace the missing wind power production.

For thermal systems that are based on slow responding base load power plants, e.g., lignite and nuclear, the integration of WPP will require an adoption of the power plant portfolio. Even today, with a rather modest share of WPP, some areas e.g. Northern Germany cannot provide the required production flexibility to compensate wind power fluctuations [103].

The net load and the corresponding ramping gradients largely depend on the penetration level of wind power in the system. The assumed installation scenarios for 2020 and 2030 will lead to an annual WPP of about 456 TWh and

649 TWh on a European level, respectively. This corresponds to a penetration level of about 13% and 16% of the annual electricity consumption, respectively. For the countries bordering the North Sea, the penetration level in 2020 and 2030 will be even higher with a share of 20% and 30%, respectively.

The predicted annual load in each country used for the simulations is shown in Table 7.4. The scenarios have been developed within the TradeWind project [104] in cooperation with [87]. Since there are specific diurnal and annual production changes in each country, the demand for each country is modelled independently to reflect the differences in the national load patterns.

The maximum hourly load and net load variations for Europe and Northern Europe are displayed in Figures 7.8 and 7.9, respectively. The figures depict the maximum hourly ramp rates subdivided into hours and months to display the diurnal and annual variations.

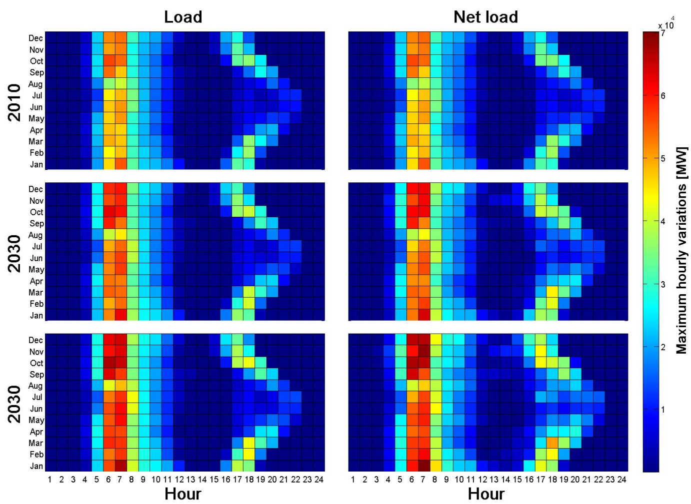


Figure 7.8: Maximum European Load and Net Load variations based on 2011 wind speed data

The load pattern on the left side clearly illustrates the diurnal and annual changes in the European consumption. The highest ramp rates throughout the year occur during the morning hours between 5 am and 8 am. The afternoon or evening peak is not clearly distributed over the year. During the winter months, a high demand change is detectable around 5 pm. This mainly results from electrical heating. For the rest of the year, the afternoon peak is far less distinctive. The increasing European electricity consumption will result in rising maximum hourly load variations from 60 GW currently up to 67 GW in 2030.

Table 7.4: Predicted annual electricity consumption [TWh]

	2010	2020	2030
Austria	63	70	83
Belgium	97	109	109
Bosnia	12	15	18
Bulgaria	36	51	62
Croatia	19	23	28
Czech Republic	68	77	83
Denmark	38	41	45
Finland	96	107	117
Germany	572	575	572
Greece	67	84	101
Hungary	45	53	58
Ireland	34	43	43
Italy	366	450	550
Luxenbourg	6	7	618
Macedonia	8	8	8
Netherlands	129	157	191
Norway	133	143	153
Poland	136	160	181
Portugal	59	76	97
Romania	59	78	105
Serbia	48	58	58
Slovakia	31	35	39
Slovenia	16	18	20
Spain	317	390	463
Sweden	150	154	156
Switzerland	65	80	98
United Kingdom	458	512	523

The net load column on the right side illustrates that the actual influence of wind power production in 2010 is still rather small. In fact, almost no influence of wind power production on the hourly ramping can be detected. With the rising share of wind power in 2020 and 2030, the hourly variations become more obvious. While in 2020 only minor changes during the morning peak are noticeable, the change during the day is more obvious. The WPP leads to higher variations after 12 am and prolongation of the afternoon peak. In 2030, the influence of WPP is unquestionable. The number and the magnitude of hourly ramps increase during the morning peak and reach their maximum at about 70 GW per hour, which is about 3 GW more than in the load scenario. The boundaries between morning and afternoon are less distinctive and minor load variations occur during the day. Nevertheless, the influence of WPP on a European level is rather small. The diurnal and annual load variations remain the main drivers behind hourly ramping. This is evident since there are no net load changes detectable during the night time. Even though the number of hours with higher net load ramping increase, the additional flexibility required is rather little.

Figure 7.9 illustrates the maximum hourly load and net load variations of the North Sea neighbouring states including the Scandinavian countries, Germany, the Netherlands, Belgium, the UK and Ireland.

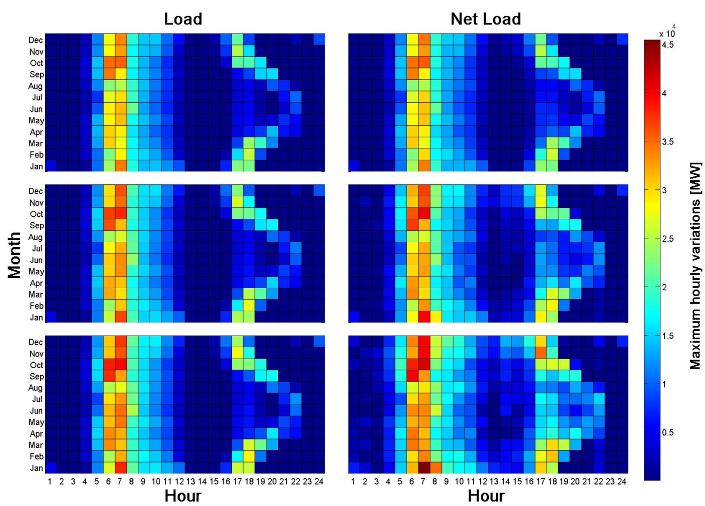


Figure 7.9: Load and Net Load variations in the North and Baltic Sea based on 2011 wind speed data

Unlike on the European level, a slight increase of net load variations is already detectable in 2010 for the afternoon hours after 2 pm. An increase in variations during the morning hours is not detectable.

For both future scenarios, the difference between load and net load variations in Northern Europe are much more distinct than on an European level. Not only the number of maximum ramping gradients will increase during the morning hours, but also the intra day variations. In 2020 the maximum hourly variations will increase from about 38 GW to 42 GW, while in 2030 a further increase from 38 GW to 45 GW can be detected. For both scenarios, the boundary between morning and afternoon peaks is almost non existent any more. Instead, the variations continue throughout the day. Even during night time, a relatively high number of ramping gradients can be detected. The large influence of WPP on the Northern European countries is mainly based on the production variations of offshore facilities situated in the North Sea.

When comparing both scenarios, it appears that even with a high penetration of WPP, its influence on net load variations in the European system is rather small. In fact, the European system provides almost enough flexibility to compensate wind power and the resulting net load variations. Therefore, the integration of wind power is not limited by a lack of production flexibility in the European system but by a lack of transmission capacity between different countries and areas.

7.4 WPP Forecasting

The previous sections illustrated that WPP varies on all time scales and therefore effects the system operation and the production scheduling of conventional power plants. Figures 7.8 and 7.9 display that the magnitude of hourly net load variations on a European level is only slightly higher than that of the hourly load variations without RES. The additional demand for flexible generation facilities therefore results from a lack of forecasting accuracy and the subsequent unscheduled production changes of WPP. Since base load and mid merit power plants cannot provide the required production reserves to compensate for forecast deviations, a higher amount of fast acting production sources such as gas power plants is necessary to assure operational security in the system.

The forecasting of WPP is one of the most important topics for a safe and cost efficient integration of WPP in the power system, and has therefore been one of the main research subjects in the past years [105][73].

Figure 7.10 displays the annual normalized root mean square error (normalized by the installed capacity) for the day-ahead production forecasts, based on the 2010 installation scenario.

The influence of geographical smoothing is clearly ascertainable. While forecasts including all European production facilities show a very small production

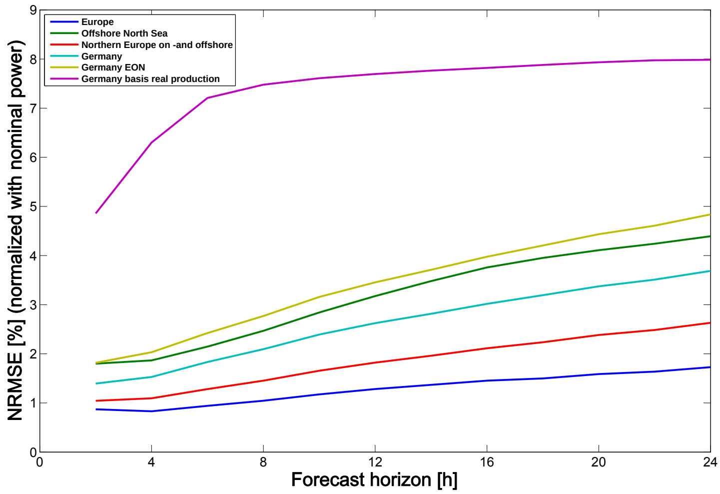


Figure 7.10: Normalized root mean square error of WPP forecasts

error, ranging from a NRMSE of 1% for a one hour prediction up to about 1.8% 24 hours ahead, the forecasts for smaller areas such as Germany EON is more than doubled. This is a consequence of geographical smoothing or netting of wind power production forecasts, meaning that an underestimated WPP in one area is compensated by an overestimation in another area.

An important aspect for the estimation of forecast accuracy is the source of real time production. A comparison between the curves for Germany shows the difference between taking the real TSO production as a basis and the simulated real time production as a basis for the calculations. While the production forecasts based on COSMO data provide an accuracy ranging from 1.5% up to 3.8%, the forecast accuracy based on TSO data is about 5% for the one hour prediction and rises up to around 8% for the day ahead forecast. This difference has to be considered when discussing the forecast deviations for Europe and other parts of Europe where no real production data is available.

Figures 7.11 through 7.13 illustrate the hourly forecast deviations for Europe, Germany and the offshore facilities in the North Sea for the 2010, 2020 and 2030 scenarios, respectively.

Despite the rather low average NRMSE, Figures 7.11 through 7.13 illustrate that the range of hourly forecast deviations is much higher. The maximum, minimum and mean forecast error in MW for Germany, the North Sea and Europe for all scenarios is shown in Table 7.5.

Event though there is a drastic reduction of the forecast error from 24 to

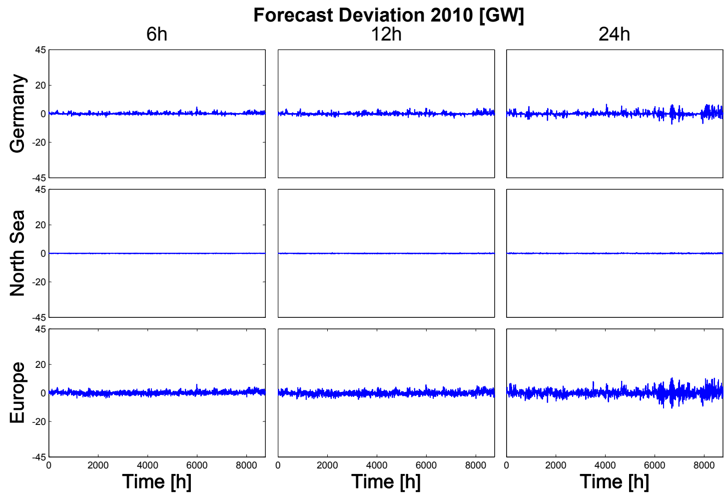


Figure 7.11: 2010 Forecast deviation for Germany, offshore facilities in the North sea and whole Europe [GW]

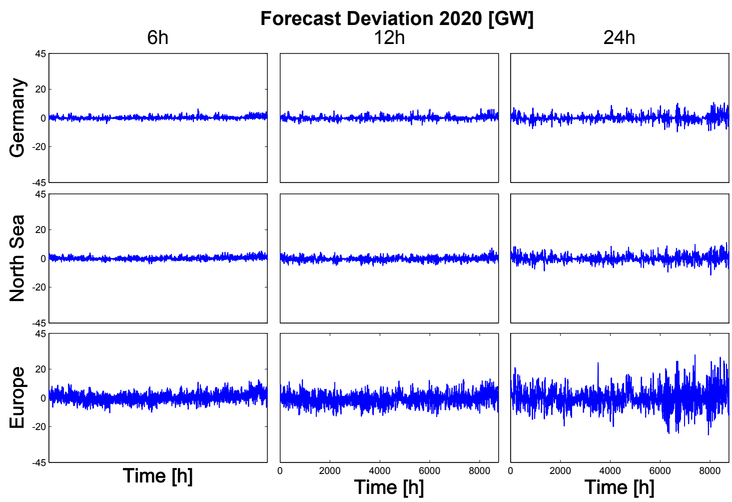


Figure 7.12: 2020 Forecast deviation for Germany, offshore facilities in the North sea and whole Europe [GW]

Table 7.5: Forecast Error [MW]

		6h			12h			24h		
	Year	2010	2020	2030	2010	2020	2030	2010	2020	2030
DE	min	-2432	-4011	-5867	-3146	-5033	-8769	-7408	-9701	-19407
	mean	357	597	999	437	795	1381	736	1324	2261
	max	3800	6392	8852	4025	6550	14546	6732	10906	18486
North Sea	min	-261	-3845	-7391	-383	-5415	-11577	-566	-11619	-23457
	mean	37	674	1640	53	955	2211	82	1567	3709
	max	293	5524	13079	505	7351	19031	496	11130	27600
EU	min	-3671	-10476	-14583	-4886	-13090	-20603	-10822	-25885	-41178
	mean	689	2025	3145	882	2757	4193	1493	4524	6926
	max	6088	12671	20753	5768	13276	25132	10676	29968	43319

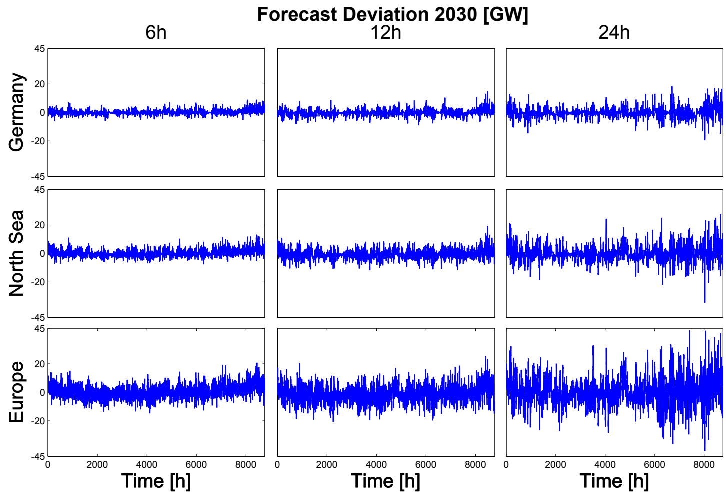


Figure 7.13: 2030 Forecast deviation for Germany, offshore facilities in the North sea and whole Europe [GW]

6 hours ahead, the maximum and minimum errors remain considerably high. Even in the current state, the mean 6 h forecast error in Germany is around 357 MW while the maximum error reaches a value of around 3.8 GW. Til 2030, these numbers will rise up to 1 GW and 8.8 GW, respectively.

The forecast error for offshore facilities will be even higher. In 2010, the maximum 6 hour error is still rather small due to small installed capacity, but will rise up to 5.5 GW in 2020 and to around 13 GW in 2030. The mean forecast error will increase from 37 MW up to 1640 MW in 2030.

As in the case of the NRMSE in Figure 7.10, the forecast error on a European level is rather low with a maximum deviation of 20 GW. The netting of forecast deviations leads to a rather low mean error ranging from 689 MW in 2010 to about 3145 MW in 2030.

When comparing the 6 hour deviations with the respective 12 and 24 hour forecasts, the necessity for a continuous rescheduling of conventional power production is obvious.

7.5 Discussion

7.5.1 Model methodology

The simulation results in this chapter are based on a wind speed to power conversion using the results of a high resolution numerical weather prediction model along with a highly detailed wind facility data base as an input. The scenarios of future wind power installation are based on the expert knowledge of national wind energy associations.

The scaling procedure to match future onshore scenarios is inevitably accompanied by scaling errors. Therefore, the effects of geographical smoothing and netting of wind power production might be reflected inaccurately. Nevertheless, an estimation of the exact location of future wind turbines is almost impossible.

For the simulation of offshore wind farms, an aggregate power curve is derived based on a multi turbine power curve estimation, using the production data of an existing wind farm. This approach attempts to incorporate wake effects and the unavailability of single turbines within a wind farm. A reliable simulation of wake effects would require an independent simulation of each wind farm, taking wind direction and farm layout into account. Since most future offshore facilities are not even commissioned, a ground-plan is not available. Furthermore, the simulation of wake effects including all wind farms in the North and Baltic Seas would exceed the scope of this research. Even though the data set for offshore wind facilities represents the state of the art knowledge, uncertainties with respect to installed capacity and geographical coordinates remain.

In Section 7.4, the importance of the respective data basis used for calculating the forecast error is illustrated. Since no production data is available for any other countries than Germany and Denmark, a statement regarding the predictability of WPP, on a European level or for Northern Europe, is not possible.

7.5.2 WPP in the power system

The simulation results in Table 7.2 show large WPP variations throughout the year. The minimum production of only 2.5% illustrates of the installed capacity that only a very limited amount of conventional generation capacity can be substituted by WPP. Since periods with very low wind power production can stretch from hours to several days, a persistent generation capacity providing backup power is required. Batteries or comparable storage technologies, which are only capable of supporting the system for a short period of time, are therefore not suited to provide the required backup capacity needed for the large scale integration of WPP. Instead, a large number of power plants acting as cold reserves will be necessary to provide the required backup capacity.

The net load variations display the need for a sufficient amount of production flexibility in the power system to compensate for the WPP variations. While the hourly net load variations in Northern Europe increase significantly by 7 GW/h, the additional net load ramps of 3 GW/h on a European level are rather small. Thus, it can be concluded that the European power system provides sufficient production flexibility to integrate large scale WPP. However, the system suffers from a lack of transmission capacity. By transmitting WPP from the centres of production along the North Sea to other European areas, the additional demand in production flexibility could be drastically reduced. Besides the technical constraints, the regulatory framework for the exchange of WPP over country borders has to be established. Especially the construction of an offshore super-grid in the North Sea will require further steps towards an integrated electricity market. Furthermore, a supra regional TSO will be necessary to coordinate the European wide distribution of WPP. The future integration of large scale WPP is therefore not a topic restricted to some areas but requires a solution on a European basis.

Even though the accuracy of numerical weather prediction models is expected to further increase, a certain prediction error will remain. Besides the possibility of rescheduling the production portfolio based on updated WPP forecasts, an increasing amount of reserve capacity will be necessary to compensate the remaining forecast deviations. The necessary amount of reserve capacities and the way to define them, based on stiff requirements or WPP forecasts, is still under discussion [106][107]. Furthermore, the integration of balancing markets and the possibility to procure balancing power over country boarders will play a key role for a safe and cost efficient integration in the European system.

7.6 Conclusion

To reach the CO_2 emission targets proposed by the European Commission, the share of renewable energy sources in the European system will further increase. Wind power production, especially in offshore regions in the North and the Baltic Seas, is considered as one of the key measures to achieve these goals.

In this chapter, the European wind power production is simulated based on a high resolution numerical weather prediction model in line with an extensive data set including on- and offshore wind power facilities. The modelling includes various scenarios for 2010, 2020 and 2030, simulating the European wind power production with respect to the annual and hourly variability, the net load variations in the power system and the predictability of wind power production. A special focus is on offshore WPP in the North and the Baltic Seas.

Despite the high geographical separation of wind power facilities on a European level, the modelling results illustrate high annual variations in wind power production ranging from 1.6% up to 62.2% of the installed capacity. Due to the clustering of offshore facilities in the North and Baltic Seas the annual production in 2020 and 2030 becomes almost intermittent, varying between 0.6% and 92% of the installed capacity. While the average production in Europe is rather low with about 19% of the installed capacity, offshore facilities can benefit from higher wind speeds in the North and the Baltic Sea, resulting in a mean production of about 30% of the installed capacity.

For future scenarios, the hour-to-hour variability of WPP will drastically increase up to 19 GW/h in Europe and 11 GW/h in the North and the Baltic Seas. Even though offshore installations only correspond to about 20% to 25% of the total installed capacity in Europe, they are responsible for 40% to 60% of the overall fluctuations.

Despite high production variations of WPP, the influences on hourly net load ramps in Europe are rather little. Only in 2030, the magnitude of hourly net load ramps will exceed the regular load variations by about 3 GW/h leading to a maximum ramp rate of 70 GW/h. In the northern European area, including a large amount of offshore installations along with a high wind power penetration level, the influence on net load variations is more distinct. In 2030, the maximum net load ramps will increase by about 7 GW/h.

Wind power forecasting is largely dependent on the size of the simulation area due to the netting of regional errors. Even though the annual normalized root mean square error of WPP forecasts is rather small, the hourly values illustrate high maximum deviations even for short forecast horizons.

Chapter 8

Grid expansion

Publications C and D

The chapter summarizes Publications C and D. Based on a combination of the previously described models (WPP, URBS-EU and PSST), the effects of wind power production and grid expansion on the European power system and the electricity market prices are evaluated. Using the WPP model, the actual and the forecasted wind power production is simulated for the years 2010, 2020 and 2030. These scenarios are taken as an input to the regional power system model URBS-EU, modelling a cost optimal macroscopic grid expansion. Finally, the European power system is simulated, using the flow based market model PSST. The influences of the proposed cost optimal grid expansion scenarios on power production, load flows and day-ahead market prices are evaluated - with and without grid expansion. Furthermore, the grid investment costs and social economic benefit are estimated. The chapter is divided into five sections. While Section 8.1 includes a introduction, Section 8.2 explains the model parameters and the simulation procedure. In Section 8.3 the simulation results are shown. While Section 8.4 includes a discussion of the evaluated results, the chapter is finalises with a conclusion in Section 8.5

8.1 Introduction

Transmission grid expansion is a crucial topic for the integration of wind power due to several reasons. First, to remove internal transmission bottlenecks being able to transmit electricity from coastal or offshore areas to inland urban regions and industrial consumers. Second, to fully utilize the potential of geographic smoothing of wind power production by exchanging electricity over country and electricity market borders. Third, to reduce the effects of WPP on other generation sources.

In this chapter, the influence of wind power production on power plant dispatch and the European electricity market prices is evaluated, taking a cost-optimal macroscopic transmission grid expansion into account. Based on this analysis, the payback period of the grid expansion and its social-economic benefit are quantified.

Power plant operation and electricity market prices with and without transmission grid extensions are simulated for the years 2010, 2020 and 2030. In previous works, the systematic advantage of grid expansions for the integration of wind energy has been shown [71, 108, 109]. Neuhoff et al. (2010) and Schaber et al. (2012) showed the beneficial effects of grid extensions for power plant owner [70, 71], while Farahmand et al. (2011) quantified the total benefit of an offshore grid in the North Sea [110]. In this study, the value of a cost-optimal macroscopic grid is quantified from both, consumer side and the total production cost side, filling the gap between the existing studies mentioned above.

8.2 Model Parameters

The inputs to the grid expansion model URBS-EU and the power system simulation tool PSST have been matched. Therefore, the simulations are based on the same input data sets including WPP time series, generator portfolio and transmission constraints.

8.2.1 Modelling input

8.2.1.1 Wind power installations

The assumed onshore wind power capacities in the 2020 and 2030 scenarios are based on the expert knowledge of the particular regional wind energy associations pooled within the TradeWind EU project [16]. The implemented scenarios are in accordance with the **high** scenario in the TradeWind report, predicting a tripling of the currently installed WPP capacity in 2020 and a quadrupling in 2030. The selected scenario closely corresponds to the WPP development in the past years. For future scenarios, the 2010 data set is extended by commissioned and projected offshore wind facilities. Future offshore installations are based on the data from [92]. Onshore facilities have been scaled up to match the supposed installed capacity in 2020 and 2030. The assumed installed WPP generation capacity for Europe is displayed in Table 8.1.

Table 8.1: Installed Wind Power Generation Capacity in Europe [MW]

Year	2010	2020	2030
Total installed capacity [MW]	89 069	274 942	386 624

8.2.1.2 Generator portfolio

In the simulations, the change in the production portfolio from a mainly thermal dominated system to a system widely affected by RES is considered within the respective generation scenarios (see Figure 8.1). Changes in the thermal and the hydro power production portfolios, e.g., the dicomissioning of nuclear power plants in Germany and a higher share of gas turbines, as well as a growing share of renewable technologies other than wind, are taken into account in the simulations. Furthermore, the marginal costs are adapted to account for the increasing fuel prices in future scenarios. Production portfolios as well as fuel price assumptions are based on the numbers from the TradeWind project [80].

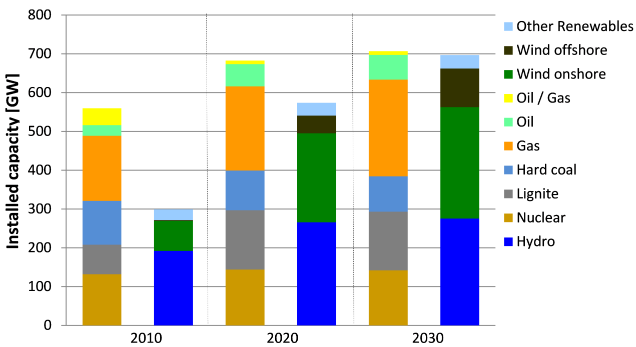


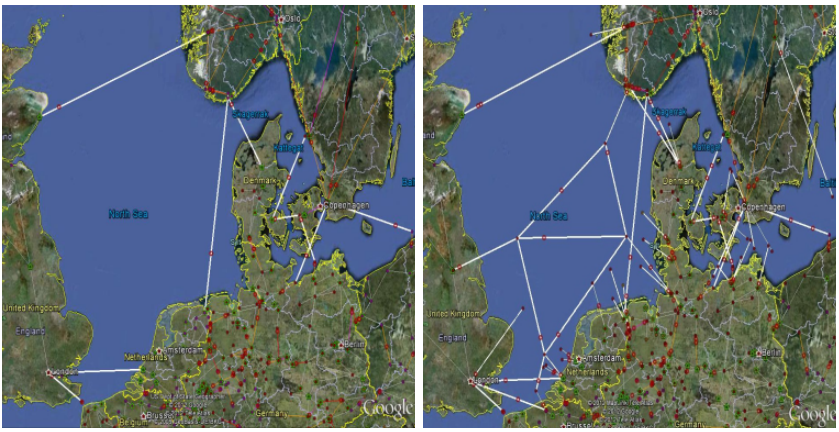
Figure 8.1: European generation capacity scenarios

8.2.1.3 Grid scenarios

The grid model used in PSST is a combination of three single grid representations covering the Nordic, Continental and the UK/Ireland areas. The Nordic area is simulated as a 23 generator model developed by SINTEF Energy Research [104]. The Continental area is modelled based on the approximated UCTE network [72], including 1410 nodes, 2212 branches, 56 HVDC lines and 1540 Generators [111]. The UK and Ireland grid model consists of about 350 generators and more than 2000 transmission lines, based on the *"National Elec-*

tricity Transmission System Seven year statement" [112]. HVDC connections from Scandinavia to Denmark and the Continental area, e.g., the NorNed cable are included in the grid model.

As described in Chapter 5, the load flow in the URBS-EU is simulated as a linear transport problem. The underlying transfer capacities between the different areas are aggregated, based on the data available in [72]. In both simulation tools, the PSST and the URBS-EU models, the future base case scenarios for 2020 and 2030, without cost optimal grid expansion, have been extended by the commissioned HVDC connections, e.g., the HVDC link between Norway and the UK (see Figure 8.4). Furthermore, the offshore super grid layout as recommended by the EWEA (see Figure 8.2b) is included in the 2030 scenario, based on the data available in [113].



(a) 2020 (b) 2030

Figure 8.2: Offshore grid configuration in 2020 (a) and 2030 (b) recommended by the EWEA [114]

While cross-border transmission capacities are defined by NTCs, the aggregated inter-area connections are defined by the corresponding thermal transmission line capacities. The existing grid infrastructure is obtained from publicly available data on the European high voltage (220 kV and 380 kV) electricity grid [72, 115].

8.2.2 Model coupling

The modelling process is split into three consecutive steps. In the first step, WPP model is used to simulate the actual and expected European wind power production [116]. The aggregated production for each area is used as input to the linear optimization model URBS-EU [70]. Using the WPP time series, and the generation and transmission portfolio as input, the URBS-EU model minimizes the total system costs and determines and economic optimal transmission grid expansion.

Finally, the flow based market model PSST simulates the electricity prices assuming a perfect market with grid representation, aggregated capacities and marginal costs for each generator within specified grid zones [104, 111]. Based on a DC optimal power flow, the model minimizes the total generation costs on an hourly basis throughout the year. Technical constraints of thermal generators as well as changing generator portfolios for future scenarios are considered in the simulations.

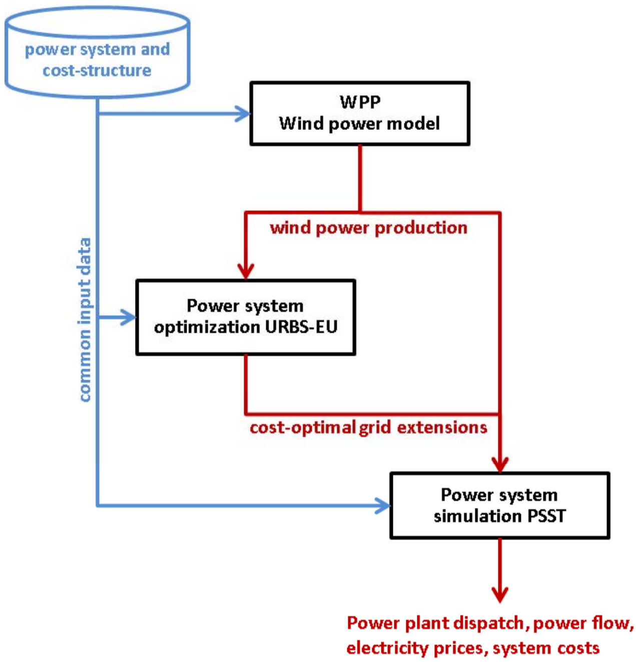


Figure 8.3: Schematic description of model coupling

A detailed description of the applied models can be found in Chapter 3, Chapter 5 and Chapter 6.

8.3 RESULTS

8.3.1 Cost-optimal grid extension scenarios

The cost-optimal macroscopic grid expansion results for 2020 and 2030 are shown in Figure 8.4 and Figure 8.5, respectively.

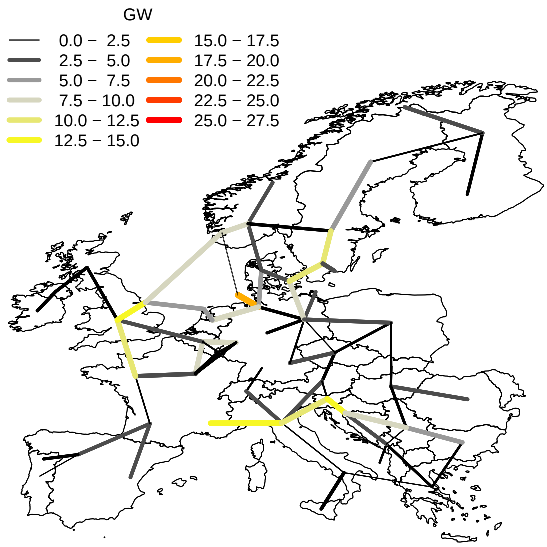


Figure 8.4: Cost optimal grid extension 2020

Figure 8.4 shows that in 2020 the main transmission corridors linking Continental Europe with the UK and the Nordic area require a substantial transmission capacity expansion. Especially the connections between Germany and East Denmark (KONTEK), France and the UK, as well as the HVDC link connecting the UK and Norway require reinforcements of the transmission capacity. Besides, Italy having rather weak interconnections with its neighbouring countries requires massive reinforcements of the connections to France and Slovenia. This also applies for the well-known bottleneck between France and the Spanish peninsula. Furthermore, the inter-area lines connecting the Swedish areas are subjected to extensive capacity expansions.

The URSB-EU 2030 grid expansion results are displayed in Figure 8.5. As in the 2020 case, the connections between the Continental Europe, the UK and the Nordic area require an enhancement of transmission capacity in addition to

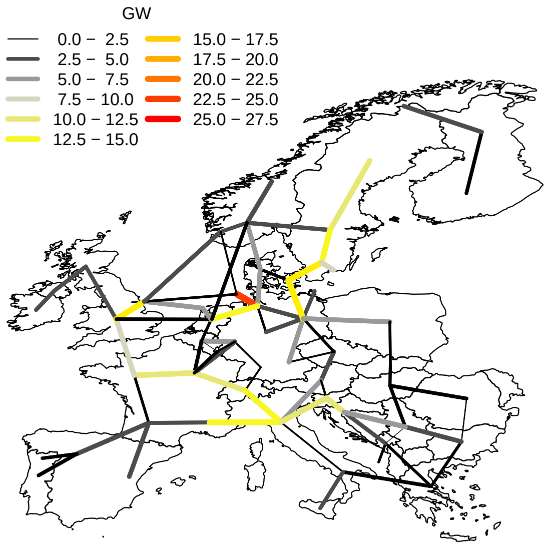


Figure 8.5: Cost optimal grid extension 2030

the proposed North Sea offshore super grid. This allows a cost optimal exchange of wind power production between the countries bordering the North Sea. To utilize the advantages of a hydro based power system, a strong grid, which connects the hydro power plants in Northern Sweden and Norway with the centres of wind power production in the North and the Baltic Seas, is needed. Therefore, the Swedish north-south connections require substantial grid reinforcements. Germany, France and the BeNeLux countries act as transit countries, requiring substantial amount of transmission capacities, in order to be able to transmit the northern European wind power production further south and to link the Continental Europe with the Nordic area. Therefore, France and Germany have to strengthen not only the cross-border transmission capacities to their neighbouring countries, but also their internal grid, to be able to fully utilize the WPP installed in the coastal and the offshore areas. In Southern Europe, a vast amount of transmission capacity is required linking France, Switzerland and Italy with the Balkans.

8.3.2 Load flow

The day-ahead market model simulates a flow based common integrated market. Therefore, market participants are able to procure energy from the least cost production units over country borders. The exchange between areas or countries therefore largely depends on the physical system constraints and the marginal costs of generators. Figure 8.6 displays the energy exchange on the main transmission corridors connecting the Continental Europe with the Nordic area and the UK.

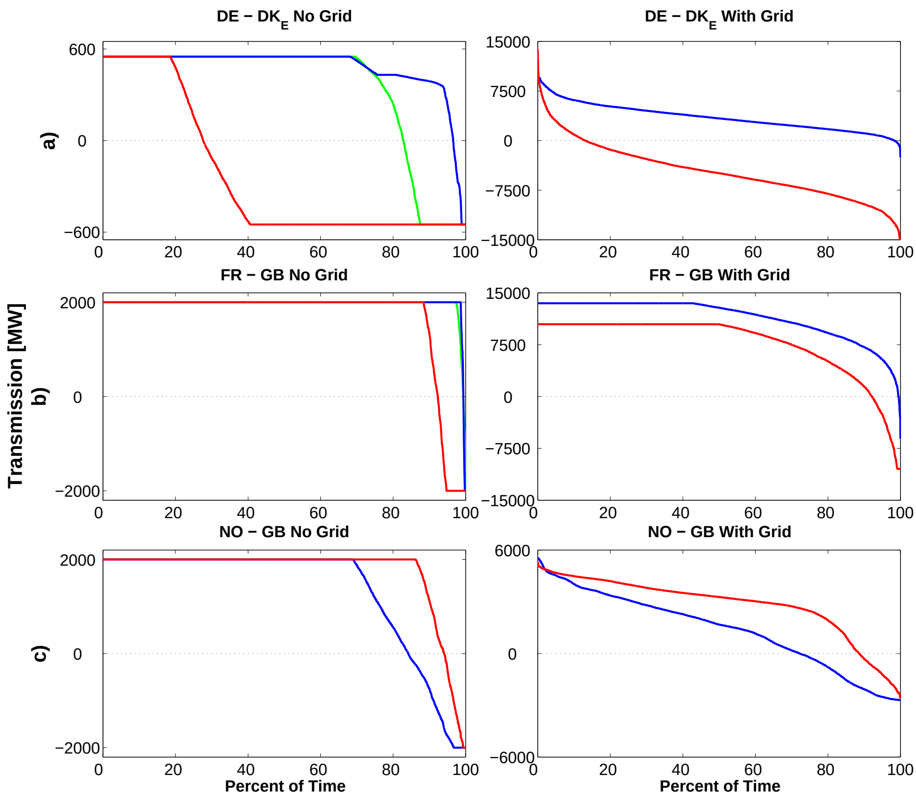


Figure 8.6: Load flow results at the most exploited corridors with and without grid extension. For each connection A-B, positive values mean flow from A to B (A→B) while negative values represent the flow from B to A (A←B) (Green line: 2010; Blue line: 2020; Red line: 2030)

It is seen from Figure 8.6 a) that the load flow between Denmark and Germany is largely constrained by the available transmission capacity. The proposed capacity expansion leads to a vast increase in energy exchange between the Continental Europe and the Nordic area. For the 2010 base case and the 2020 scenario, Germany acts as an exporter for up to 95% of the time, while becoming a net importer in 2030. The change in direction is largely dependent on modifications in the production portfolio, largely influenced by the decommissioning of nuclear power plants in Germany. Due to the substantial enhancement of transmission capacities between the Scandinavian countries Denmark, Norway and Sweden, along with the extended inter-area transfer corridors, there is a possibility to export electricity based on hydro power production to the Continental Europe. Thus, Denmark will act as a transit country between Germany and the Nordic area.

Figure 8.6 b) illustrates the exchange between France and the UK. Even though the main share of future offshore wind power installations will be connected to the UK, it will remain an energy importer. Without grid expansion, the cross-channel connection is congested for around 98% of the time. Even with a capacity expansion, the inter-connector is fully utilized for up to 50% of the time, transmitting energy from France to the UK. Only during peak WPP, the British system will act as an exporter.

The same transmission pattern can be noticed for the connection between Norway and the UK, illustrated in Figure 8.6 c). The Norwegian hydro power will largely support the electrical system in the UK during at least 80% of the time. As in the case of the connection with the Continental Europe, exports to Norway mainly occur during times with high wind power production in the North Sea, which cannot be solely absorbed by the British system.

8.3.3 WPP curtailment

The cumulative installed wind power capacity in Europe will rise up to 274 GW in 2020 and 386 GW in 2030 (see Table 8.2). This corresponds to a respective share of 30% and 42% of the overall installed generation capacity, assuming that 904 GW in 2020 and 931 GW in 2030 of thermal generation is in operation (see Figure 8.1).

Depending on the power system parameters, i.e. production flexibility of generators and availability of transmission capacities, a high penetration level of WPP might lead to a substantial curtailment of wind energy. The results in [108, 117] display that at a WPP level of about 20% of the gross demand, the amount of discarded energy may rise up to 10% of the total production. When comparing the potential WPP with the actual production, these numbers can be confirmed (see Table 8.2).

In the 2010 base case scenario, the discarded European WPP sums up to about 32.7 TWh on a European level, which corresponds to about 15% of the potential European WPP (see Table 8.2). This is even higher than in the 2020 case without grid expansion, where the curtailment of energy is reduced to about 15.7 TWh or 3.1%. The increasing ability to absorb WPP in the system results from the assumed grid reinforcements and the change in the generator portfolio. Based on the proposed grid expansion, the loss of WPP can be further reduced to about 4.2%.

In the 2030 **No Grid** scenario the loss of WPP production will increase up to 75.3 TWh. This corresponds to about 6.5% of the overall production. Especially, offshore facilities that are not directly connected to shore but to the proposed HVDC super grid, are forced to reduce their production during times with peak production since the proposed super-grid transmission capacity is not sufficient to fully transmit the energy to shore . Figure 8.7 shows the potential 2030 offshore WPP in the North sea along with the actual production for the cases with and without grid expansion.

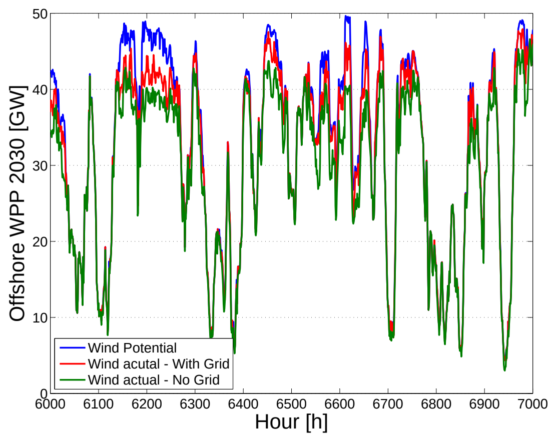


Figure 8.7: Potential and actual offshore WPP in the North Sea - 2030 with and without grid extension

Even though the proposed cost optimal grid expansion cannot fully avoid the curtailment of WPP, the amount of discarded energy can be reduced by about 50%-75%.

8.3.4 Influence of WPP and grid expansion on conventional generation

The high share of wind power production in the electrical system will largely affect the production pattern of thermal generators. As wind power production

Table 8.2: Potential and actual European wind power production [TWh]

		No Grid			With Grid		
	Potential	Actual	Lost	[%]	Actual	Lost	[%]
2010	213.1	180.4	32.7	15.3	-	-	
2020	498.3	482.6	15.7	3.1	494.5	4.2	0.8
2030	1 148.4	1 073.1	75.3	6.6	1 118.3	30.1	2.6

with its low marginal cost replaces conventional production, the full load hours of thermal generators will be drastically reduced.

In Figure 8.8, the PSST results for the northern German electricity production are displayed for the 2030 scenario with and without grid expansion.

Figure 8.8 a) displays the 2010 **Base Case** scenario, which is the actual system. Even though the wind power penetration level is still rather modest, the system can neither provide the required production flexibility nor the transmission capacities to fully integrate the local WPP. This leads to a substantial amount of discarded WPP in this area. The electricity prices on the right side of Figure 8.8 a) illustrate that the influence of WPP is still rather modest. Instead, the diurnal load pattern is strongly reflected in the day-ahead market prices.

Figure 8.8 b) and Figure 8.8 c) illustrate the 2020 scenarios without and with grid expansion, respectively. Even though the increasing share of wind power production leads to a high production volatility, almost no WPP curtailment can be detected. This reflects the increased production flexibility, especially due to the rising production capacity of fast acting gas turbines, and the increased transmission capacities to neighbouring areas. The production volatility is also reflected in the day-ahead market prices, where the low marginal costs of WPP largely influence the price setting. Even though the WPP reduces the average price level, price spikes occur during times with low WPP and high demand, since the missing wind has to be substituted by expensive gas turbines. Figure 8.8 c) illustrates the power production with the proposed grid expansion. The production volatility of conventional power plants is largely reduced. The production pattern of base load power plants, e.g., lignite is not affected by WPP fluctuations. Instead, WPP fluctuations can solely be balanced by gas turbines and the import and export possibilities to neighbouring areas. The decreased production volatility is reflected in the area prices. The influence of WPP on electricity prices is largely reduced.

In Figure 8.8 d) and Figure 8.8 e), the 2030 scenarios without and with grid

[1] *'Renew' in Figure 8.8 includes all other renewable energy sources not specified by hydro and wind e.g. PV, biomass*

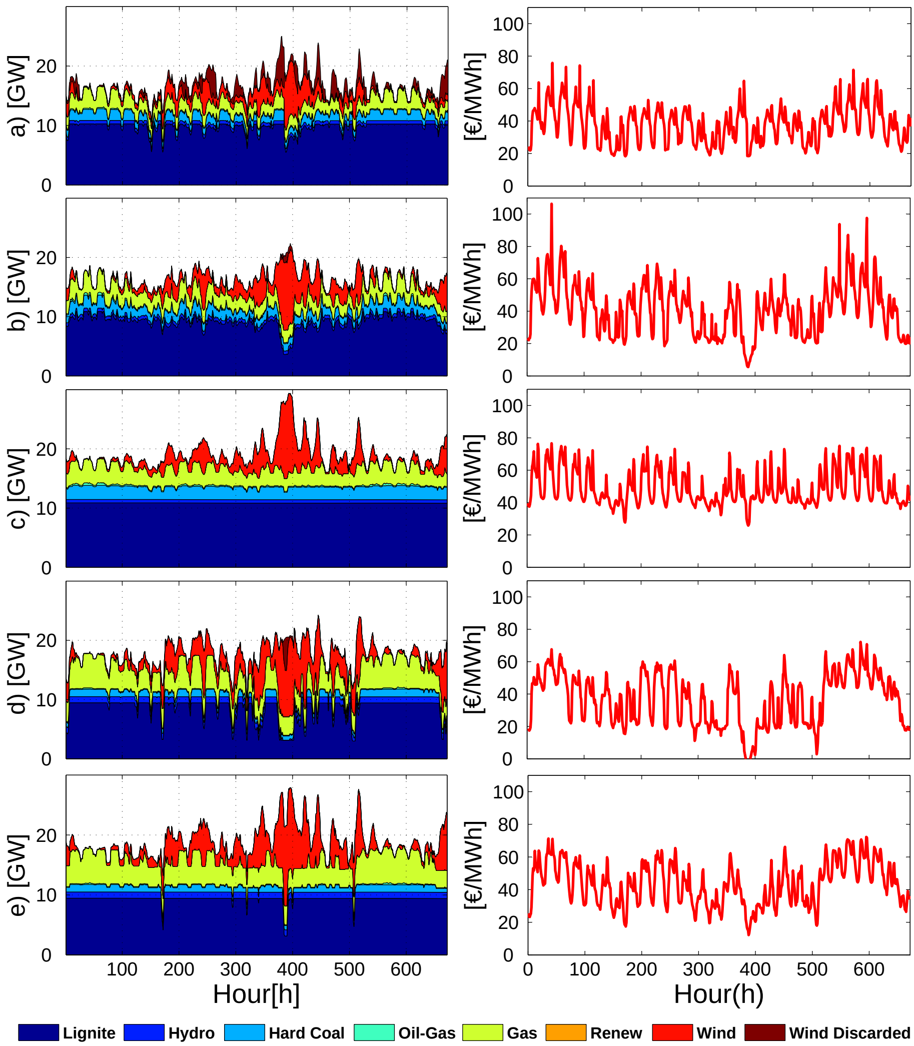


Figure 8.8: Power production and area prices Germany NE (a) 2010 - Base case b) 2020 - No grid c) 2020 - With grid d) 2030 - No grid e) 2030 - With grid[1]

expansion, respectively, are shown. Like in the 2020 case without grid expansion the production pattern of thermal plants in Figure 8.8 d) reflects the WPP variability in this area. During times with high WPP, the market prices are reduced to zero. Even though the electricity demand in these hours can solely be covered by WPP or even has to be curtailed, a certain share of conventional power plants is still in operation. This results from district heating obligations assumed within the model. Figure 8.8 e) displays that the production as well as the price volatility is largely reduced. The increased transmission capacity allows taking advantage of the smoothing effects resulting from distributed wind power generation. While excessive electricity from wind power can be exported to areas with low wind power production or high electricity prices, it can be imported during periods with low WPP production.

8.3.5 European electricity prices

The European electricity prices are largely affected by wind power production, transmission capacity expansion and changing production portfolios. Figure 8.9 illustrates the area prices for the 2010 base case along with the 2020 and 2030 scenarios with and without grid expansion. In Figure 8.9 the cases without grid expansion are labelled with **No Grid** while the cases with grid expansion are labelled with **With Grid**

The price variance among the areas displays the lack of transmission capacity for the exchange of energy. Especially the BeNeLux countries, the islanded UK system and the southern German areas have to cope with unnecessarily high prices. The expansion of transmission capacities results in decreasing system costs and a declining variance of area prices (see Table 8.3).

Table 8.3: Mean European electricity price and price variance with and without grid expansion

	2010	2020		2030	
	Base Case	No Grid	With Grid	No Grid	With Grid
Mean price [MW]	36.8	39.6	37.8	33.5	32.2
Price variance	214.1	233.9	144.9	204.7	99.0

Although there is a rising share of renewable energy sources in Europe, only areas directly connected to or containing a large number of wind power facilities can benefit from the low marginal prices of renewable energy sources. Taking Germany as an example, a very distinctive area price splitting for the cases without grid expansion is noticeable. While the average electricity price in the

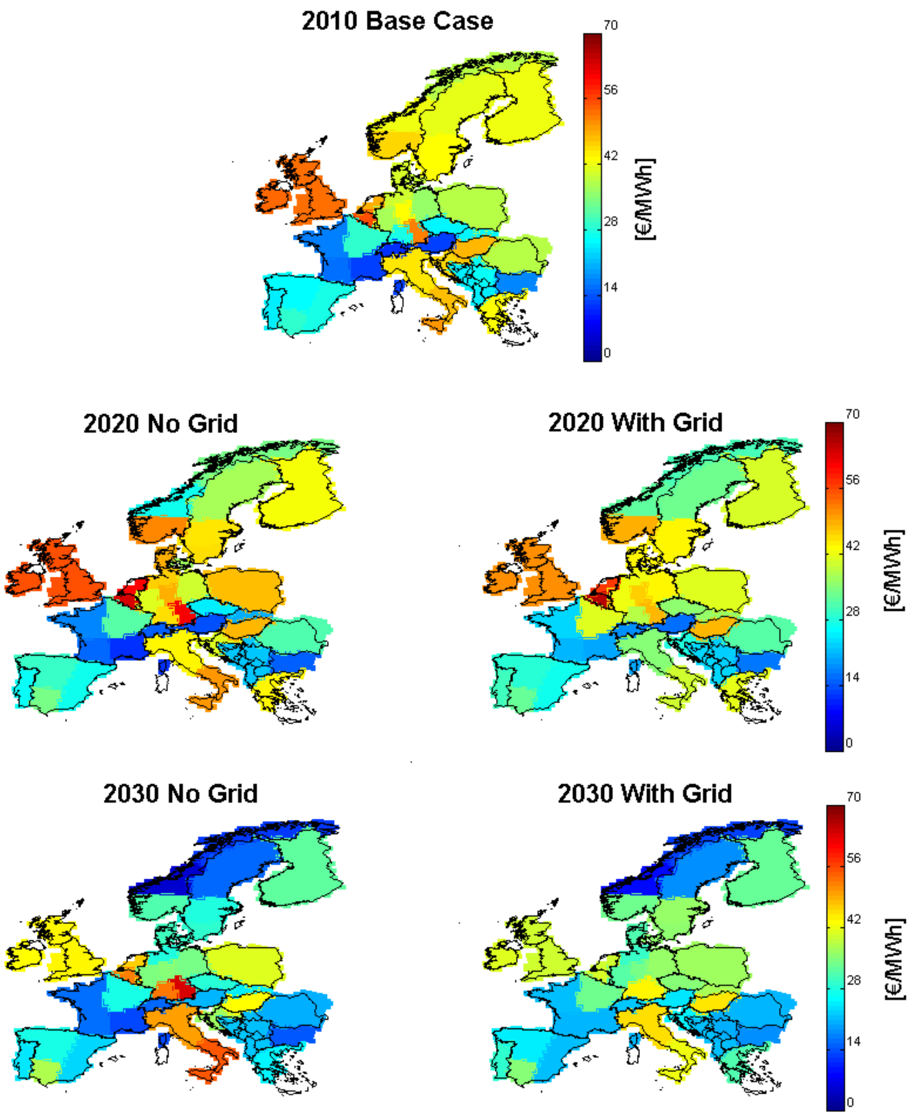


Figure 8.9: Average annual electricity prices [€/MWh]

north-eastern part is around 40 €/MWh in the 2020 **No Grid** scenario, the price in the highly industrialized areas in the south reach an average level of up to 61 €/MWh. Due to increased wind power installations and energy imports from Denmark (see Figure 8.6 a)), a further price reduction in the north-eastern German region down to 34 €/MWh can be identified, while having a price increase to 64 €/MWh in the Southern Germany in 2030.

The proposed grid expansion leads to a harmonization of area prices. In 2020, the area prices in Northern Germany increase up to 43 €/MWh, while a significant decrease of 14% down to 48 €/MWh takes place in the Southern part. The extensive grid expansions in line with new wind power installations and imports from Denmark result in an overall price reduction in Germany of 4% and 35%, respectively. In Europe, the grid expansion leads to a minor reduction of the overall price level while reducing the price variance significantly. While some areas such as southern Germany or Italy largely benefit from a better interconnection with their neighbouring areas, Austria, Switzerland or North-east Germany will be confronted with rising costs.

8.3.6 Investment costs

The enhancement of existing transmission lines and the installation of new lines is a time consuming and cost intensive task. Especially, the laying of offshore cables requires substantial monetary expenditures. The cost calculation including total expenses and annual benefits, for both transmission expansion scenarios, is displayed in Table 8.4. The calculation assumes investment costs of 400 €/MWkm for HV lines and 2500 €/MWkm for HV cables respectively. For the computation of the annuity of investment, a weighted average cost of capital (WACC) of 7% is assumed, with the depreciation period being 40 years.

Table 8.4: Costs and Benefits [bn €]

	2020	2030
Costs of grid extension		
Grid investment costs	34.1	37.1
Additional annual fix costs for new grid	0.37	0.46
Macro-economic benefits		
Annual savings due to lower electricity production costs	15.9	19.2
Payback time of grid investment [2]	6.3 years	5.17 years
Social economic benefits		
Annual savings due to lower prices on the consumer side	15.8	23.7

The results illustrate that substantial costs reductions of 16 bn € p.a. and 19 bn € p.a. can be achieved in 2020 and 2030, respectively, by the implementation of the proposed cost optimal grid extension. Comparing this annual benefit to the total investment costs for grid extension, a comparatively short payback period of around 6 years results for both scenarios. The additional costs to realize forty-year investment with 7% WACC, i.e. the cost of capital, are taken into account here.

As discussed above, the grid expansions lead to a lower average price level. This entails important social-economic benefits for the electricity consumers to the time of 15.8 bn € and 23.7 bn € for the 2020 and 2030 scenarios, respectively, with grid expansion.

8.4 Discussion

For the analysis in this chapter three high resolution models were combined in order to simulate cost the optimal grid expansion scenarios and to identify their influence on load flows, wholesale market prices, the resulting socio economic costs of electricity and the overall production costs.

The system parameters, e.g., the marginal costs of production, the power plant portfolio, the WPP time series and the system load are adjusted to the 2020 and 2030 scenarios. It is attempted to include the supposed system expansion scenarios for the base cases as realistically as possible. The assumed wind power production is modelled with high accuracy and corresponds to the latest available scenarios. The input data was harmonized for all the three models.

While PSST is a flow based market model, the electricity transmission in URBS-EU is modelled as a transport problem, neglecting the effects of load flows in the system. The combination of two different model approaches includes the risk of inconsistencies. The proposed transmission capacity between Germany and Denmark as an example (see Figure 8.6 a)), is never fully utilized in the flow based market model. Therefore, the proposed transmission capacity expansion of URBS-EU is beyond the actual needs of the flow based approach. However, analysing the cross-border energy exchange is a good indicator for the transmission capacities needed in a system containing a high share of wind power.

Furthermore, the influence of selected input parameters becomes obvious when comparing the simulated grid expansion scenarios with the results from a previous work [5]. While in this previous work, the main grid extension in 2020 was proposed for the connection between France and the Spanish peninsula,

[2] For the computation of the payback time, the WACC is taken into account leading to a triplication of necessary initial capital

the focus in the actual scenarios is on the corridors between continental Europe with Scandinavia and the UK.

8.5 Conclusion

The integration of renewable energy into the power system will be a challenge for power producers and electricity markets. The analysis done in this paper is based on three highly sophisticated models simulating wind power production, grid extension scenarios and their influence on day-ahead market prices. The modelling includes various scenarios for 2010, 2020 and 2030, and the effect of transmission grid expansion in the context of a rising share of wind power in Europe is simulated.

The results show that the variability of wind power largely affects the production pattern of conventional thermal power plants. Furthermore, the increasing share of WPP has significant impacts on electricity markets and their participants. Transmission grid extension can help in stabilising base load power production and market prices by exchanging excessive energy across area and country borders by utilizing the effects of geographical smoothing. Therefore, grid extension in line with a high level of market integration, providing the regulatory framework to procure energy throughout the system, will reduce the need for new power plant installations backing up wind power production.

Using the possibility to exchange energy between countries, the curtailment of wind power production can be reduced. Even though the investment costs for the installation of new transmission lines and cables are substantial, the investments will be compensated by cost reductions in the power system.

Chapter 9

Integration of regulating power markets

Publications B and E

The chapter summarizes Publications B and E. Based on the previously described wind power model, the actual and the forecasted wind power production is simulated for the years 2010 and 2020. These scenarios are taken as an input to a northern European regulating power market model, analysing the procurement of reserve capacity and their activation. Further on, the potential benefit of integrating northern European regulating power markets, handling the varying wind power production, is investigated. Due to remaining wind forecast errors, more reserve capacity is required in the power system. The simulations of the regulating power market focus on WPP forecasts with a three hour forecast horizon, assuming that WPP forecast deviations would have been handled in the intraday market. The simulations include Frequency Restoration Reserves (FRR) and Replacement Reserves (RR). It is shown, that the Nordic countries can be a provider of such reserves, assumed there is an integrated regulating power market. Furthermore an overall cost increase is recognized, displaying significant saving possibilities by cross- border procurement of reserves and the exchange of regulating energy. The chapter is divided into seven sections. Section 9.1 includes a introduction to the model and the evaluated cases. While Section 9.2 explains the model parameters for WPP, Section 9.3 explains the assumptions made in the power market simulations. In Section 9.4 the evaluated cases are described. Section 9.5 contains the evaluated results. While Section 9.6 includes a discussion, the chapter ends with a conclusion in Section 9.7.

9.1 Introduction

Integrating large scale wind power production in the power system is a major challenge due to its variations and prediction errors. The already existing load uncertainties and unplanned outages in combination with the intermittent WPP require not only more regulating resources but also a higher flexibility in order to keep production and consumption in balance at any instance. The differences between the annual load and the net load (load minus WPP) duration curves, depicted in Figure 9.1, illustrate the additional demand for flexibility due to hourly production changes under the influence of WPP [106]. In liberalised power markets, the scheduled load and production together with the forecasted WPP are handled by market participants within the day-ahead and intra-day markets. However, remaining WPP forecast errors with their resulting production deviations, outages of regular power plants as well as short term load variations have to be compensated by the activation of regulating reserves available in the power system.

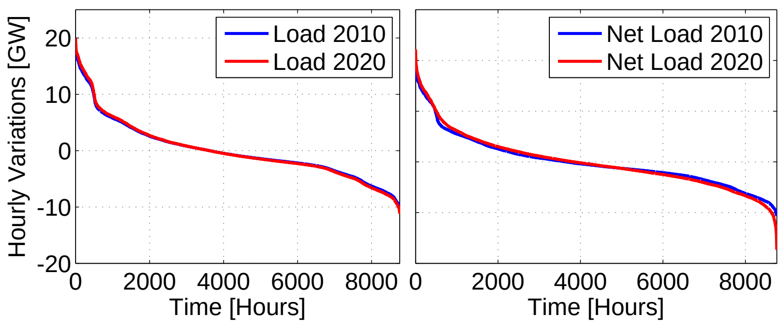


Figure 9.1: Duration curves of annual load and net load variability

The procurement and the possible real-time activation of these regulating reserves is done within regulating power markets. In order to study the effects of WPP on regulating reserve procurement and system balancing, the Northern European area is simulated and the corresponding costs are estimated. Simulations are done for national regulating power markets as well as for an integrated northern European market, estimating possible benefits of exchanging regulating reserves as well as energy.

9.2 Wind Power Production

9.2.1 WPP Simulation

The assumed wind power capacity for the simulations is displayed in Table 9.1. The modelling routine of the WPP model was described in Chapter 3. The assumed 2020 wind power capacity is based on the expert knowledge of the associated regional wind energy associations polled within the TradeWind EU project [16]. Theemployed 2020 scenario is in accordance with the 2020 high scenario in the TradeWind report, containing nearly a triplication of the currently installed WPP capacity.

Table 9.1: Installed WPP capacity [MW] 2010 & 2020

Areas	2010	2020
Norway	545	6600
Sweden	1250	10 000
Finland	350	3000
Denmark	3700	6000
Germany	24 900	57 300
Netherlands	1000	2950
Belgium	2800	10 400
Sum	34245	96 250

9.2.2 Forecast Error

In a system with a high penetration of WPP, production forecasts are necessary to schedule the production of conventional production units in order to assure a stable operation at all times.

Table 9.2 displays the MAE and NMAE for the 2010 and 2020 scenarios including different forecast horizons. Due to the highly sophisticated NWP models, the system-wide 24 hour NMAE only amounts up to about 3.7% for the 2020 scenario. Correspondingly, a further increase in accuracy is noticeable for the 3 hour forecast, reducing the NMAE to about 0.7%. Even though the values for MAE and NMAE provide a rather optimistic view on the wind forecast error and the required regulating resources in the system, Figure 9.2 displays that there are considerably high wind forecast errors, which especially occur before and after storm fronts.

Table 9.2: Forecast error

	2010	2020
MAE 3 h [MW]	218	883
NMAE 3 h [%]	0.6	0.9
MAE 24 h [MW]	915	3596
NMAE 24 h [%]	2.6	3.7

Figure 9.2 displays the hourly forecast errors for 3 and 24 hours ahead, indicating the improved forecast over a descending time period and thus the significantly reduced need for balancing WPP. The largest deviations in the 2020 high wind scenario reach an absolute value of about 40 GW. This illustrates the challenges the system is confronted with upon the addition of large amounts of intermittent wind power. Even though, the 3 hour forecast MAE is relatively small, the hour to hour variations may rise up to 10 GW (see Figure 9.2 and Figure 9.3).

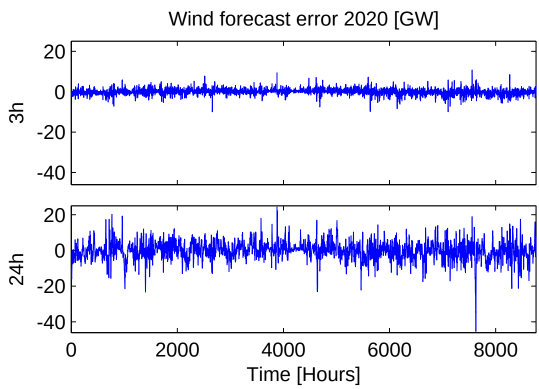


Figure 9.2: Forecast error of WPP in GW - 3 and 24 hours ahead

Figure 9.3 shows the WPP 3 and 24 hour forecast error duration curves for the 2010 and 2020 scenarios. It shows the overall increase of the forecast error as well as a significant increase in the maximum forecast error, as seen at both ends of the curves.

Based on WPP forecasts, producers are able to identify their approximate wind power production and reschedule the preliminary production portfolio considering the technical constraints of thermal power plants. Nevertheless, this requires a functioning intra-day market which gives power producers the possi-

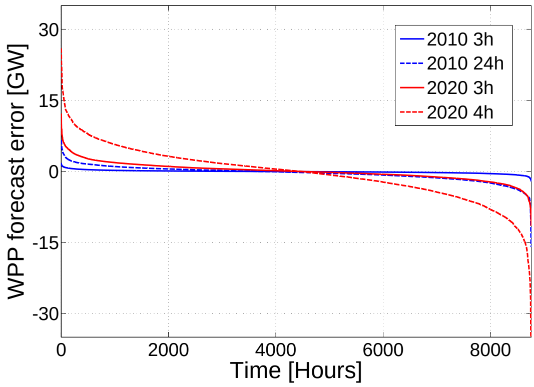


Figure 9.3: WPP forecast error duration curve for the simulated area

bility to balance their production portfolio based on updated WPP forecasts.

The simulations using the 24 hour WPP forecasts therefore represent a scenario without an intra-day market, while in the simulations using the three hour forecasts it is assumed that wind power producers are able to balance their production portfolio either by re-dispatch or in the intra-day market up to 3 hours before real-time. This reduction of the forecast horizon assumes higher flexibility of the system and will lead to more trading in the intra-day market.

9.3 Market Model

The applied EMPS market model has beend described in Chapter 4.

9.3.1 Market data

For the 2020 scenarios, all the system parameters such as the power plant portfolio, the inter-area transmission capacity and the WPP are updated to incorporate the supposed system expansion in the upcoming years.

Due to reinforcements and the commissioning of new connections between the Nordic area and Continental Europe, particularly the extension of the Skagerrak cable, the Nordlink and as well as the NorNed connection, the estimated transmission capacity will be expanded from the existing 3700 MW up to 6800 MW [118].

Furthermore, the expected increase in hydro production capacity, especially in southern Norway, provides additional balancing resources. The increase of production capacity is done for single power plants and sums up to about 6 GW in total.

Due to the variability of WPP, it is necessary to adapt the reserve requirements to the increased WPP system penetration to be able to provide sufficient balancing power. The adjustment of the reserve requirements done in this chapter is based on the 3 sigma approach as discussed in [106] and [119]. The estimation of the reserve requirements is based on the 3 hour WPP forecast error.

Table 9.3: Reserve Requirements [MW] 2010 & 2020

	2010		2020	
Areas	pos.	neg.	pos.	neg.
Norway	1200	1200	1485	1485
Sweden	1220	1220	1950	1950
Denmark	1200	1200	1510	1510
Germany	3010	2045	6720	5755
Netherlands	300	300	1330	1330
Belgium	150	150	465	465
Sum	7080	6115	13460	12495

For the 2010 scenario, the reserve requirements for the countries modelled are based on the current requirements set [64]. These are adjusted based on the previously mentioned 3 sigma approach for the 2020 scenario. The overall reserve requirements used in the analysis are shown in Table 9.3. The total requirements are nearly doubled in 2020. The main increase takes place in Germany and the Netherlands, which is primarily due to high increase in offshore WPP.

9.4 Case Studies

The influence of WPP on system operation is studied based on four scenarios. First, 2010 is simulated using the actual installed wind power capacity and the corresponding imbalances as a reference. Secondly, two cases for the 2020 scenario are simulated. Two different cases for the reserve procurement as well as the system balancing are defined. These cases are **no market integration** and **full market integration**.

The case **no market integration** represents the current state. Regulating reserves have to be procured in the respective countries. In countries split into different control areas, e.g., Norway and Germany (see Figure 4.1), reserve requirements are defined by control area; however, the procurement can be done country-wide with the consideration of available transfer capacities. Exchange of balancing power with neighbouring countries is not possible.

Full market integration describes a future state in which regulating power markets in Northern Europe are fully integrated. Besides the procurement of reserves in their respective countries, reserves now can also be procured in the whole simulated area. However, as suggested by ENSTO-E [120], 50% of the required reserves must be procured in the respective country.

Given the available transmission capacity, exchange of regulating energy is enabled in the fully integrated market. This exchange results in the activation of the system-wide most economical reserves.

9.5 Results

9.5.1 Transmission dispatch and day-ahead market results

The EMPS model is run with different hydrological years, to reflect the hydro inflow stochasticity. Solving the model results in the day-ahead market dispatch. One of the main results of the dispatch is the available capacity after the day-ahead market clearing. Figure 9.4 and Figure 9.5 depict the cumulative transmission of the HVDC lines connecting the Nordic area with Continental Europe. The dotted black lines indicate the transmission limits. The graphs display the percentiles of the transmission dispatch duration curve, considering different inflow years. Instead of analysing single transmission lines, the evaluation of transmission corridors (here Nordic to Continental Europe), results in smoother duration curves and disposable transmission capacity most of the time. It evinces, that only in wet years, during about 200 hours, all the transmission lines are congested in the same direction at the same time in the 2010 scenario (Figure 9.4).

This value increases up to about 1500 hours in 2020 (Figure 9.5), when there is full export on all the transmission lines from Northern to Continental Europe. The remaining free transmission capacity can be used for cross-border reserve procurement and the exchange of regulating energy. However, also during congested hours a one directional exchange is viable (downward regulating reserves in this case).

Another important result is the day-ahead market prices (see Figure 9.6), indicating the marginal production cost during a certain hour in the system. In a well-functioning regulating power market, the regulating power prices lie in the vicinity of the day-ahead market prices, i.e., the day-ahead market price also gives a rough indication of the marginal production cost of the available regulating reserves. Comparing day-ahead market prices for the 2010 and 2020

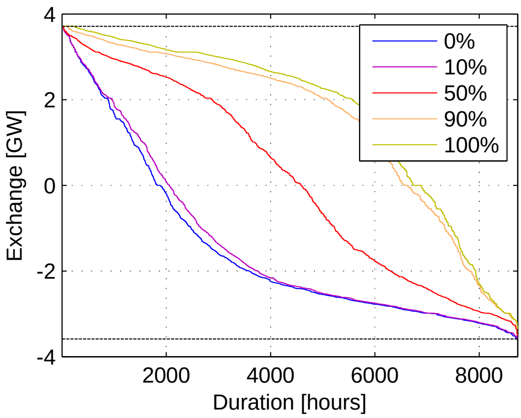


Figure 9.4: Transmission dispatch 2010

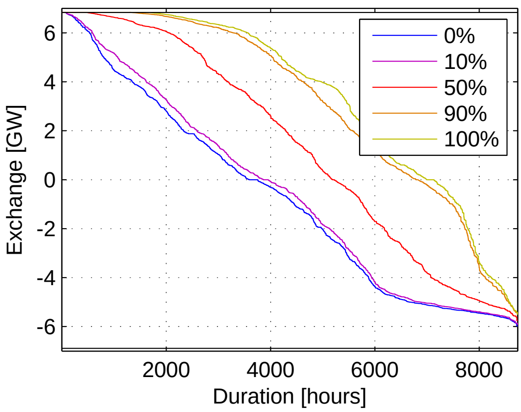


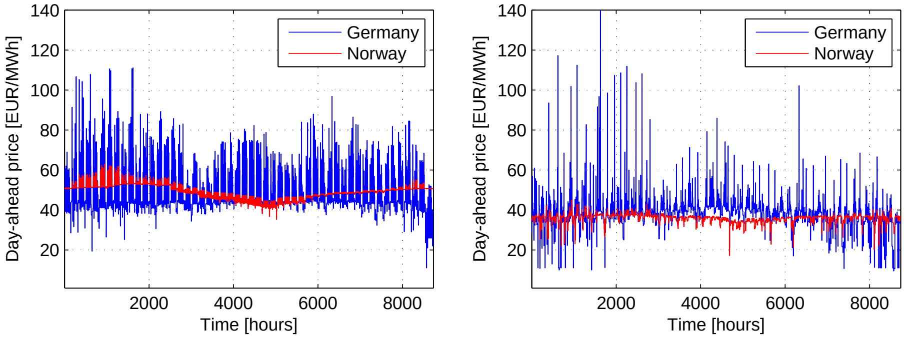
Figure 9.5: Transmission dispatch 2020

scenarios, it can be seen that volatility increases in Germany, but decreases in Norway. However, the average day-ahead market price is lower in both countries, thus indicating cheaper regulating reserves in 2020 than in 2010.

9.5.2 Regulating power market results

Table 9.4 and Table 9.5 give an overview on the results of the regulating power market simulations for the defined scenarios and cases.

Table 9.4 presents results of the current market situation, without an in-



(a) 2010

(b) 2020

Figure 9.6: Day-ahead market prices Norway, Germany in 2010 and 2020

tegration of the Nordic and continental European regulating power markets. Due to the increased reserve requirements, the reserve procurement costs are more than doubled in 2020. The additional WPP in 2020 increase the system imbalances by about 90%. Hence, the gross reserve activation rises by about 80%. The fact that reserve activation increases less than system imbalances, is caused by the netting of imbalances within the Nordic system and in Germany. As new WPP mainly will be built in continental Europe, there only is a minor increase of imbalances and therefore reserve activation in the Nordic area. The balancing costs are estimated to increase only by about 25%, far less than the increase in reserve activation. The reason for that is the overall decrease of day-ahead prices in the 2020 scenario and the expected availability of more reserve capacity than in 2010.

Table 9.4: Regulating Power Market Outcome - No Market Integration

	2010	2020
Total reserve requirements [MW]	7080	13460
Procurement costs [M€]	146.5	343.6
Gross imbalance [GWh]	13637	24622
Gross reserve activation [GWh]	8945	14670
Gross reserve activation in the Nordic area [GWh]	3597	4209
Balancing costs [M€]	126.8	154.6

Table 9.5 contains results for the full market integration case, i.e. the possibility of cross-border procurement of regulating reserves and the exchange of regulating energy is given. Again the 2010 scenario and two cases for 2020 scenario - with and without transmission reservation for the regulating power market - are analysed. In 2010 the average cross-border procurement is about 10% of the total reserve requirement (nearly only upward regulating reserves), resulting in a possible cost reduction of 40%. Fig. 9.7 depicts the annual average distribution and procurement of upward regulating reserves for this case. It can be seen that there is an export of reserves from Sweden and Norway to Denmark and Germany. The Danish import covers nearly 50% of the required reserves, which equals the limit set for the cross-border procurement of reserves. Surprisingly there also is an export of reserves from the Netherlands, which can be explained by its rather low reserve requirements.

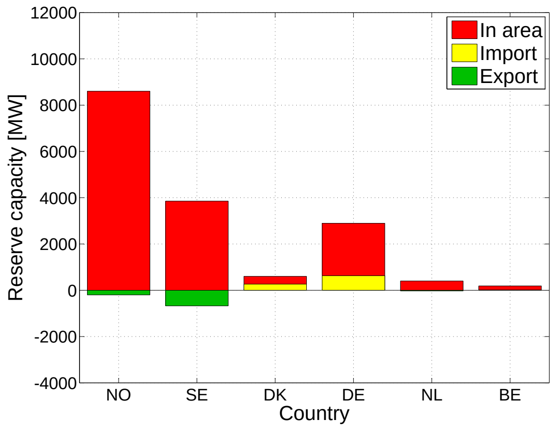


Figure 9.7: Reserve procurement 2010 full integration

As described previously it is assumed that there will be an increase in reserve requirements in 2020. With the additional transmission capacity, the cross-border procurement of reserves is more than doubled. Unlike 2010 there is a notable cross-border procurement of downward regulating reserves, of about 16% of the total cross-border procurement. Fig. 9.8 depicts the annual average procurement of upward regulating reserves in 2020. Compared to 2010 it can be noticed, that due to the additionally installed hydro capacity in southern Norway, significantly more reserves are available in the system.

Fig. 9.8 show that the main additional export of regulating reserves is from Norway to Germany. When comparing the 2020 reserve procurement costs in Table 9.5 with the numbers of the no market integration scenario in Table 9.4, a cost reduction of about 30% is detectable.

Table 9.5: Regulating Power Market Outcome - Full Market Integration

	2010	2020
Total reserve requirements [MW]	7080	13460
Mean cross-border procurement [MW]	765	1854
Procurement costs [M€]	88.3	248.3
Gross imbalance [GWh]	13637	24622
Gross reserve activation [GWh]	6761	10464
Gross reserve activation in the Nordic area [GWh]	4664	7824
Regulating energy exchange [GWh]	3190	6340
Balancing costs [M€]	91.8	85.5

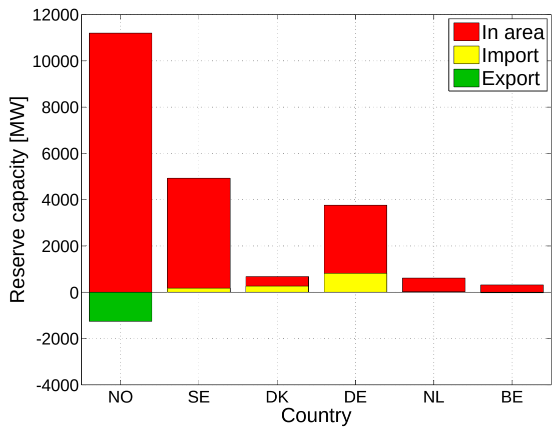


Figure 9.8: Reserve procurement 2020 full integration no reservation

Fig. 9.9 shows the cross-border procurement of upward as well as downward regulating reserves for 2020 with no transmission reservation. It displays that in most instances there is an export from Nordic to Continental Europe, but with exceptions during a minority of hours, in which the exchange characteristics are turned around. Furthermore, the maximum cross-border procurement of reserves is about 4.6 GW, which corresponds to 50% of the reserve requirements in the continental countries.

In the lower part of Table 9.5 results for the system balancing in the case of full market integration can be found. As stated above, imbalances nearly double in 2020 compared to 2010. However, the activation of reserves only amounts

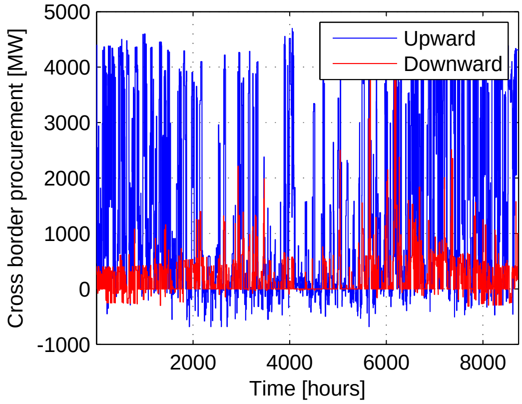


Figure 9.9: Hourly cross-border procurement of regulating reserves from Nordic to continental Europe in 2020 - no reservation

up to about 40%-50% of the total imbalances, which is a drastic reduction, compared with the case of no market integration, where it is about 60%-70%. The reduction is achieved by cross-border netting of imbalances of the different countries. In the case of WPP, the netting can also be interpreted as the geographical smoothing of WPP. There is no significant further increase in imbalance netting in the case of transmission reservation, as the reserve activation only decreases by about 2%. Considering the reserve activation in the Nordic system solely, it can be seen, that its share of the overall activated reserves increases dramatically from 40% to 70% in 2010 and from 30% to 80% in 2020, when integrating markets. The share increases not only due to the decreased overall activation, but also due to an ascending activation in the Nordic area. Fig. 9.10 depicts the reserve activation duration curve in 2020 for the no and full market integration case. The characteristics discussed above, the overall decrease and Nordic increase of reserve activation, are clearly illustrated. Furthermore it can be seen, that there are about 5000 hours with no activation of reserves in the continental area, in case of full market integration.

Fig. 9.11 shows the country wise activation of regulating reserves for the no and full market integration case in 2010 and 2020. It is obvious that market integration drastically reduces the activation of reserves in Denmark, Germany and Netherlands. As Belgium has no direct connection to the Nordic area, only a minor reduction in reserve activation is noticed. Due to its hydro resources, Norway is the main provider of regulating reserves.

As can be seen in Table 9.4 and Table 9.5, the reserve activation in the Nordic system, assuming a fully integrated market, increases by about 1100

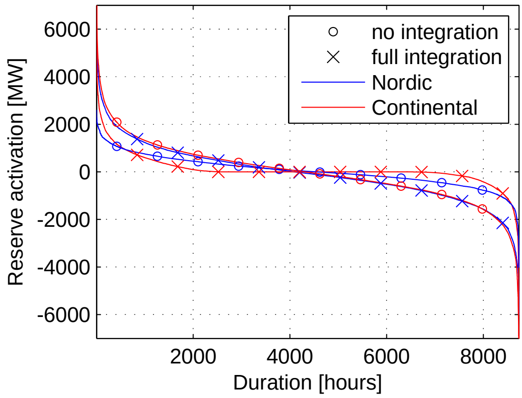
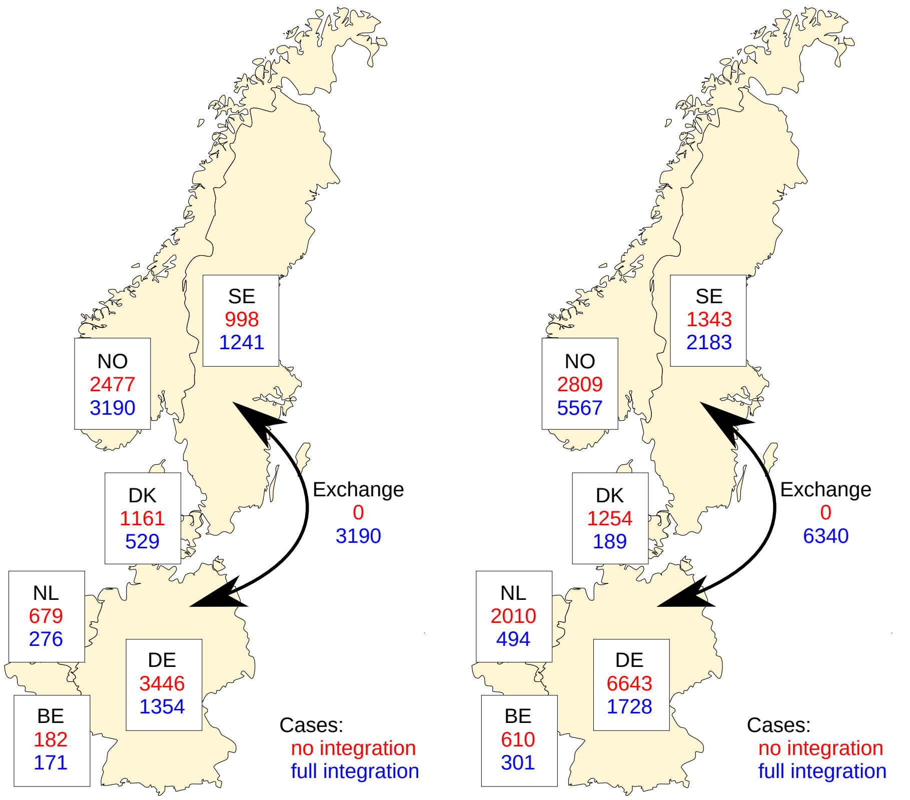


Figure 9.10: Nordic and continental regulating reserve activation in 2020 - no reservation

GWh when being compared to the no market integration scenario in 2010. The exchange of regulating energy would be about 3200 GWh between the Nordic and the continental European system in 2010. The difference between these values result from the netting of imbalances between those systems. The same accounts for the 2020 scenario.

The hourly exchange of regulating energy in Fig. 9.12 is quite even distributed during the whole year. The maximum and minimum exchange is about 6 GW, which roughly equals the installed transmission capacity, between Nordic and continental Europe. However, this amount of transferred energy in combination with the quarter hourly changes comprises enormous challenges to the operation of the HVDC connections.

Finally, analysing the balancing costs shows that there can be high savings by integrating regulating power markets, amounting up to about 30% in 2010 and around 50% in 2020. With no market integration, the increasing system imbalances from 2010 to 2020 are accompanied by rising balancing costs. In case of integrated markets the system balancing costs decrease over the examined time period, which is in contradiction to expected results. A reason for that are additional possibilities of exchanging regulating energy with the Nordic system, due to transmission expansion and the increasing hydro capacity in the Nordic system, providing cheap regulating reserves. Another reason can be, as previously mentioned, the overall decreased day-ahead prices, also leading to lower costs for system balancing. While balancing costs decrease there is a significant increase in the costs for reserve procurement, leading to an overall increase in costs.



(a) 2010 (b) 2020

Figure 9.11: Country wise annual regulating reserve activation [GWh]

9.6 Discussion

The models used for the analyses, are based on a perfect market assumption. Furthermore a sequence is chosen in which reserve procurement takes place after the day-ahead market clearing, resulting in a re-dispatch.

In reality, several different market designs are in use. Thus, comparing the simulated economic outcome with real market data is difficult. However, analysing the possible cross-border procurement of reserves and the exchange of regulating energy is a good indicator.

System parameters i.e. the power plant portfolio of thermal plants, inter-area transmission capacities, reserve requirements and WPP capacities are updated

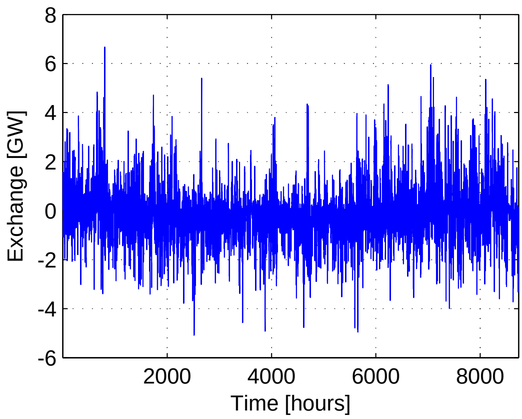


Figure 9.12: Hourly regulating energy exchange from Nordic to continental Europe 2020 no reservation

for the 2020 scenarios. It is attempted to incorporate the supposed system expansion in the upcoming years as realistically as possible. The influence and necessity of these modifications become obvious, when comparing the simulated market outcomes with results from a previous work [121]. In this previous work, the estimated balancing costs of about 1.6 billion € in 2020, are multiple higher than the 74.5 million € mentioned in this paper. The main drivers for this amazingly high gap are the additional available transfer capacities and the forecast length of WPP. The forecast length was reduced from 24h to 3h as it is assumed that the interim fluctuations are taken care of in the intra-day market, reducing the gross imbalance by about 40%. Trading on the intra-day markets implies shifting balancing responsibility from TSOs to wind power producers. Thus costs for TSOs, which are analysed in this paper, will be reduced. In contrast costs for wind power producers will increase, which are not taken into account here. The increase of transfer capacities between Nordic and continental Europe inaugurate new possibilities of gaining balancing power from the least cost regulating reserves in an integrated market. This causes a further significant reduction of balancing costs.

9.7 Conclusion

The installation and integration of large amounts of WPP capacity into the power system comprises exceptional challenges. Amongst those, system balancing and the procurement of regulating reserves are of outstanding importance.

The analyses done in this paper includes four scenarios for two market models simulating a non- and a fully integrated northern European regulating power market.

The regulating power market outcome without integration shows that gross system imbalances and gross activation of regulating reserves are almost doubled in the 2020 scenario.

With an overall amount of 343 M€ the reserve procurement costs are more than twice as high as the 2010 results. The system balancing costs increase by about 28 M€.

Using the possibilities of a fully integrated market with its system-wide reserve procurement and exchange possibilities, the 2010 procurement costs can be cut down by 40% while in the 2020 scenarios the costs are reduced by about 30%. Almost the same conclusion can be drawn for the balancing costs, being reduced by 50% to about billion 74 M€ in the 2020 scenario with transfer reservation. As most of the cheap balancing resources are situated in the Nordic area, the exchange of regulating reserves will ascend and become more and more important in future scenarios, while the activation of reserves in continental Europe will decrease by about 300%.

The investigated scenarios in this paper confirm that WPP results in an enormous increase of activating regulating reserves, especially in a split market environment. However, regulating power market integration would significantly reduce the activation and hence the cost for reserve procurement as well as for system balancing.

Chapter 10

Intra-day market

Publication G

This chapter summarizes Publication G. Based on the previously described wind power model, the actual and the predicted WPP is simulated for the years 2010 and 2020. These WPP scenarios are taken as an input to the flow based market model PSST simulating the day-ahead, the intra-day and the real-time market in Continental Europe plus the Nordic area. In a first step the day-ahead market is modelled based on WPP forecasts for the next 24 hours including a simultaneous reserve procurement within Continental Europe and the Nordic area. Secondly, the intra-day market is simulated using the day ahead market results as an input. In the intra-day market the scheduled day-ahead production is successively adapted based on revised wind power forecasts up to one hour before real time. Finally, remaining forecast deviations are balanced in the real time. The chapter is divided into six sections. Section 10.1 includes a introduction to the chapter. Section 10.2 states the model parameters for WPP, Section 10.3 explains the market model and the assumptions made. Section 10.4 contains the evaluated results. Finally, Section 10.5 includes a discussion and the chapter ends with a conclusion in Section 10.6.

10.1 Introduction

The integration of WPP is a challenge for the European power system due to several reasons. In contrary to conventional generators the production pattern of WPP is delicate to variations on all time scales. These will add to already existing load and production variations, therefore demanding a higher flexibility from the remaining system. Besides, in liberalised power markets the scheduled load and production are handled within the day-ahead and intra-day markets. Thus, wind power producers and TSOs have to rely on production forecasts based on NWP models to place bids in the power markets, to schedule power production and to assure the balance between production and consumption at any time. Even though, the forecast accuracy has largely increased over the past couple of years the remaining day-ahead forecast error standard deviation in Northern Europe sums up to almost 10 GW in the 2020 scenario (see Figure 10.1). With real-time approaching the forecast error standard deviation reduces to about 1200 MW one hour ahead.

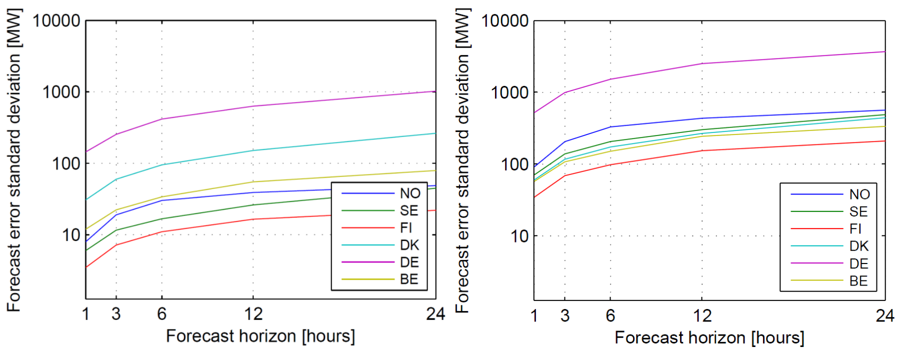


Figure 10.1: Forecast error 2010 and 2020 in Northern Europe

To avoid the procurement and the possible activation of an unnecessary high amount of regulating reserves and to assure system stability, power producers should be able to adjust their day-ahead market bids based on revised WPP forecasts. To study the effects of intra-day production adjustments on the activation of regulating reserves various cases with and without an integrated intra-day market in Northern Europe are simulated for the years 2010 and 2020.

10.2 Wind Power Production

The modelling methodology corresponds to the approach described in Chapter 3. Like in previous chapters the assumed future onshore installation scenario for 2020 is based on the expert knowledge of the associated regional wind energy associations collected in the TradeWind project, while the offshore installations are based on the data from 4coffshore [16, 92]. The assumed overall capacity in Northern Europe and France for the years 2010 and 2020 is displayed in Table 10.1. The differences in the installation scenarios between Table 10.1 and the numbers used in Chapter 9 result from an updated wind data base build up in the course of the thesis. Especially the data base for offshore facilities was largely extended and revised based on the numbers from [92].

Table 10.1: Wind power installation scenarios in 2010 & 2020 [MW]

	2010		2020	
Country	Onshore	Offshore	Onshore	Offshore
Belgium	1022	165	2951	2156
Denmark	3677	612	3815	2811
Finland	351	-	3020	846
Germany	25277	60	32383	8805
Netherlands	2597	228	4259	5298
Norway	725	2	4913	415
Sweden	1233	110	4731	3079
France	5528	-	40012	3935
Sum	46991	1287	140827	10508

Figure 10.2 shows the 2020 forecast errors for Northern Europe one hour and 24 hours ahead.

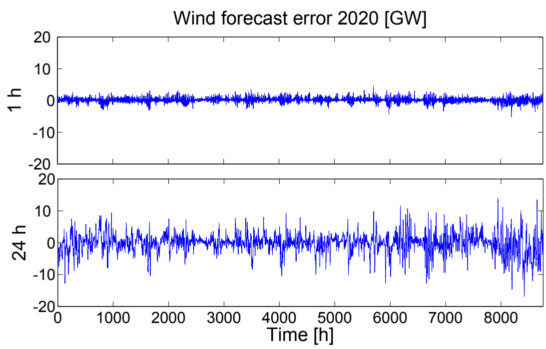


Figure 10.2: 2020 forecast error in Northern Europe - 1 and 24 hours ahead

The simulated WPP is based on wind speed data from 2011. The differences between the one hour and the 24 hour forecasts are evident. While the maximum absolute forecast error for the one hour ahead is around 5100 MW, the 24 hour forecasts error reaches values of up to 17 GW (see Figure 10.2). These numbers illustrate the necessity of a functioning intra-day market being able to re-schedule the WPP forecasts after day-ahead market closure.

10.3 Market model

A detailed description of the flow based market model PSST and its mathematical framework can be found in Chapter 6. The model simulates a common European day-ahead market including a simultaneous reserve procurement together with the day-ahead market clearing. Based on the day-ahead market results the intra-day market is simulated including the intra-day and the balancing market area (see Figure 10.3). The balancing area is restricted to the Nordic area plus the Northern European countries including Germany, DK-West and the Netherlands.

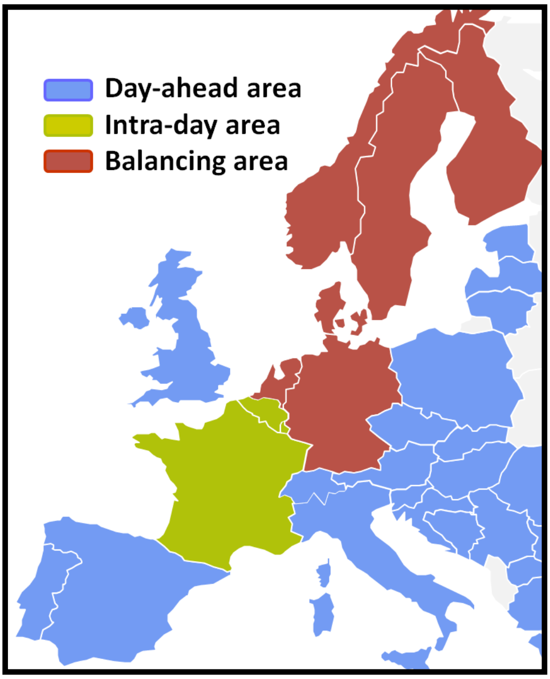


Figure 10.3: Geographical overview of the simulated market areas in PSST

In the common **day-ahead market** a socio-economic optimal dispatch of electricity production for Europe is determined, taking transfer capacities, generator constraints, start-up costs and power production from RES into account. The day-ahead market is simulated on an hourly basis. WPP is included based on production forecasts ranging from one to 24 hours ahead. To fulfil the reserve requirements in Northern Europe regulating reserves are procured simultaneously to the day-ahead market clearing. The selection of regulating reserves is done in a socio-economic optimal way based on the marginal production costs of thermal power plants and the water values for hydro power plants, respectively.

The simulation of the **intra-day market** is based on the day-ahead market results, taking the optimal generation dispatch, the transmission to other areas outside the intra-day market area and the scheduled HVDC transmission into account. In the intra-day market only the remaining HVDC transmission capacity available after the day-ahead dispatch can be utilised. The intra-day market is simulated on an hourly basis. For every simulation step, revised wind power forecasts are used as an input to the market model. Accordingly, the generation dispatch of conventional generators is adapted taking the updated wind production forecasts into account. The dispatch of thermal generators is limited by the according constraints including minimum up- and down times. Generation capacity procured for balancing purposes is excluded from the intra-day market dispatch. A complete mathematical description of the intra-day market can be found in Chapter 6.

In the integrated **regulating power market** remaining imbalances after day-ahead market or intra-day market closure are settled. While wind forecasts errors are based on simulation results, load forecasts errors and plant outages are modelled by recorded imbalances from the year 2010 [122, 123]. System balancing is done in an cost-optimal way, meaning that the least-cost reserves are activated.

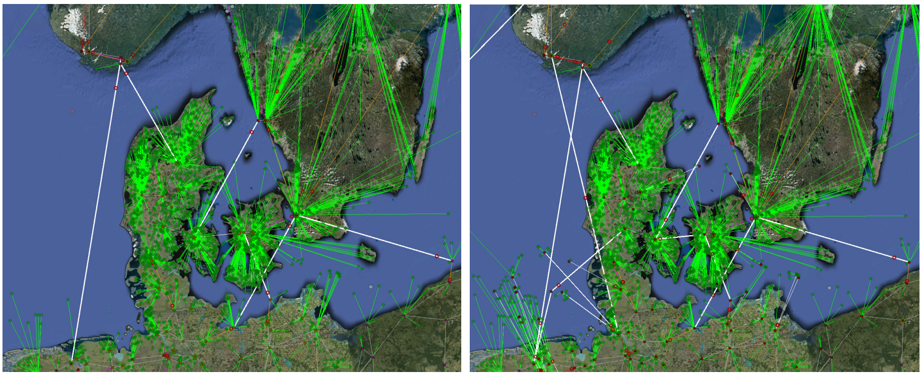
10.3.1 System data

10.3.1.1 Transmission system

The transmission system in PSST is simulated based on the aggregated grid described in Chapter 6. While transmission lines within one area are assumed to have an infinite capacity, inter-area and cross-border lines are constrained by the according NTCs. The applied NTCs are based on the available data from ENTSO-E for the year 2011 [115].

The HVDC transmission system for 2010 is based on the ENTSO-E data available at [72]. Due to reinforcements and the commissioning of new lines the HVDC capacity will largely increase until 2020, especially in the North and the Baltic Seas. Future interconnections, including the construction of new cables between Norway and the UK, Norway and Germany (NorGer) and the Cobra cable, connecting the Netherlands with Denmark, are considered in the model. Furthermore, the capacity extensions of the Skagarak cable, the SwePol cable and the NorNed cable are included in the simulations. The actual transmission capacity between the Nordic and the Continental area therefore increases from around 3700 MW in 2010 up to 6345 MW in 2020.

The bold white lines in Figure 10.4 indicate the HVDC connections between Continental Europe and the Nordic area for 2010 and 2020. The aggregated on- and offshore wind power facilities are shown as green dots. Offshore wind farms are either directly connected via AC cable connections (green lines) or are connected to offshore hubs equipped with a HVDC connection to shore (narrow white lines).



(a) 2010 (b) 2020

Figure 10.4: Offshore grid configuration between Continental Europe and the Nordic area in 2010 (a) and 2020 (b)

10.3.1.2 Generators

As described in Chapter 6, generators are divided into regulating and non-regulating power plants providing base load power. While base load power plants are assumed to produce at maximum capacity throughout the year due to their low marginal costs, regulating and load following power plants are used to compensate for diurnal load changes and WPP variations. In case the WPP exceeds the downward regulation possibilities of regulating and load following power plants, the production of base load power plants is reduced accordingly. The commitment of regulating and load following power plants is limited by the associated minimum upward and downward time constraints shown in Table 6.2.

For 2020 the generator portfolio is adapted based on the predictions and forecasts made in [87, 88]. This includes the successive decommissioning of nuclear power plants in Germany and the construction of new hydro power and pump storage capacity in Southern Norway. Besides, a rising share of fast reacting power plants e.g. gas turbines has been assumed. Increasing marginal costs resulting from rising fuel prices are included in the future scenarios.

10.3.1.3 Reserve requirements

The production variability and the forecast uncertainty of wind power will increase the reserve requirements in the power system. For 2010, the assumed reserve capacity corresponds to the actual values in the Northern European system. For 2020 the reserve capacity is adjusted based on the 3- σ approach also used in Chapter 9. The estimation of the reserve requirements is based on the 24 h forecast error. This leads to an significant increase of the reserve requirements, especially in Germany and the Netherlands (see Table 10.2). Even though the results in [124] indicate that the amount of balancing reserves in the system can be reduced according to the forecast length of WPP, the 24 h WPP forecasts were applied to make the results with and without intra-day market directly comparable.

Table 10.2: Reserve Requirements [MW] 2010 & 2020

	2010		2020	
Areas	pos.	neg.	pos.	neg.
Norway	1200	1200	2800	2800
Sweden	1220	1220	2600	2600
Denmark	1200	1200	1900	1900
Germany	3010	2045	13300	12350
Netherlands	300	300	3900	3900
Finland	865	865	1700	1700
Sum	7795	6830	26200	25250

10.3.2 Case Studies

Using the actual and the predicted installation scenarios for 2010 and 2020 the influence of WPP on system operation is studied based on four cases. Firstly, an integrated regulating power market in Northern Europe is simulated **Without Intra-day** market. Secondly, the possibilities of production adjustments and revised wind power forecasts are simulated in a case **With Intra-day** market.

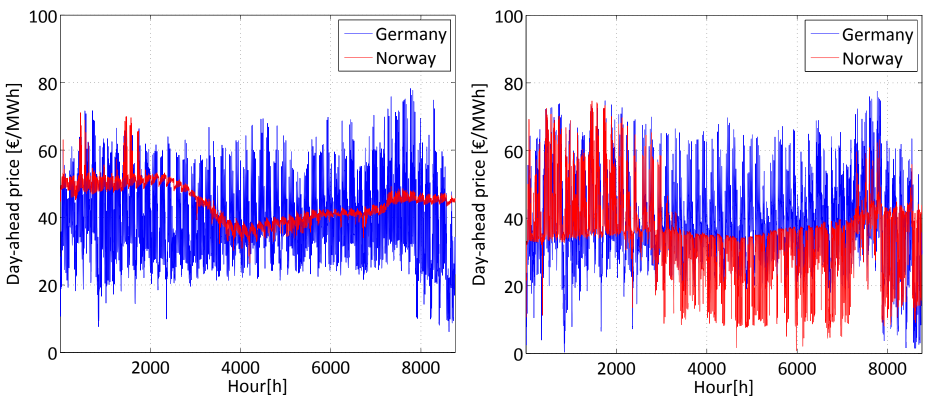
The case **Without Intra-day** largely corresponds to the **Full market integration** case described in Chapter 9. This case describes a future state in which regulating reserves cannot only be procured within the respective countries but in the whole Northern European area. Despite a forecast length of three hours like in the 'full market integration' case described in the preceding Chapter, wind speed forecasts ranging from one to 24 hours are utilised in the day-ahead market. The day-ahead market results are taken as an input to the regulating power market where imbalances are settled.

In the case **With Intra-day** market production adjustments of conventional generators are possible, taking revised WPP forecasts after the day-ahead market clearing into account. While the intra-day market includes Northern Europe, France and the BeNeLux countries, the regulating power markets focuses on the Northern European area. The intra-day market includes the time span from day-ahead market closure until one hour before real-time.

10.4 Results

10.4.1 Day-ahead market results and transmission dispatch

The PSST day-ahead market model is run for a 'dry' year representing a low inflow scenario in the Nordic area. The simulated day-ahead market prices for Norway and Germany in 2010 and 2020 are shown in Figure 10.5. The system prices indicate the marginal production costs in the system. For Norway a typical annual price pattern can be determined reflecting the water-values and the varying inflow to the hydro reservoirs throughout the year.



(a) 2010 (b) 2020

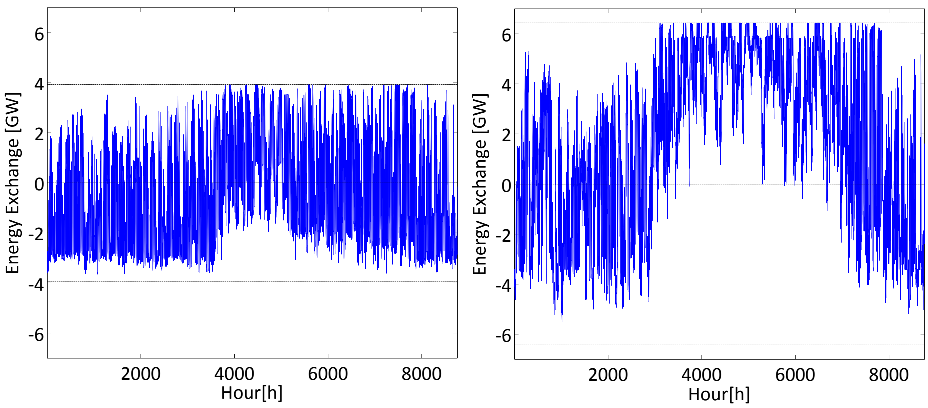
Figure 10.5: Day-ahead market prices in Germany and Norway in 2010 (a) and 2020 (b)

While the 2010 day-ahead prices are hardly influenced by WPP a clear influence of WPP is ascertainable in the 2020 scenario. The increasing share of WPP in the system leads to a higher price variability and to a reduction of the mean annual prices in both areas. The according numbers for the mean annual price and the price variance for Germany and Norway in 2010 and 2020 are shown in Table 10.3.

Table 10.3: Mean annual price and price variance in Germany and Norway

	2010		2020	
	DE	NO	DE	NO
Mean annual price [EUR/MWh]	39.5	44.6	36.9	34.7
Price variance [-]	125.2	28.5	169.2	129.7

Another important indicator for the influence of WPP in the system is the energy exchange between areas. Figure 10.6 illustrates the cumulative HVDC transmission dispatch between the Nordic and the Continental areas- including the connections to Sweden and Denmark. The dotted black lines indicate the maximum transmission capacity.



(a) 2010

(b) 2020

Figure 10.6: Day-ahead transmission dispatch from Nordic to Continental Europe in 2010 (a) and 2020 (b)

Like for the day-ahead market prices the energy exchange in 2010 shows a seasonal pattern. While the hydro based system in the Nordic area mainly imports electricity during winter time it becomes an exporter of energy during the summer months. Besides, the transmission dispatch is largely dependent on diurnal price differences in the respective areas.

The simulation results for 2020 show a strong seasonal transmission pattern. While an almost equable energy exchange between the areas can be noticed during winter time, the Nordic area becomes a main exporter of energy during the summer months. This results from a energy surplus, increased hydro capacity and the decommissioning of Nuclear power plants in Germany.

10.4.2 Intra-day market results and production adjustments

Table 10.4 illustrates the gross imbalances between the day-ahead wind power forecasts and the revised wind power forecasts from the intra-day market. Besides, the subsequent production adjustments of conventional generators along with the associated adjustment costs are shown.

The numbers illustrate large deviations between the forecasted WPP from the day-ahead market and the revised forecasts applied in the intra-day market. Overall, gross imbalances of about 9.5 TWh can be notified in 2010. This number increases to about 33.5 TWh in 2020.

The updated wind power forecasts result in major production adjustments of conventional power plants during the intra-day period. In 2010 the gross production adjustment in the intra-day area sum up to about 9.5 TWh. The discrepancy between production adjustments and wind production imbalances result from netting effects in the simulation area. In 2020 the the production adjustments are more than tripled and correspond to about 33 TWh. This is slightly lower than the gross imbalances from WPP. Netting effects like in the 2010 scenario are largely reduced due to future offshore installations clustered in small geographical areas and due to congestion between areas in Continental Europe resulting in major intra-day production adjustments particularly in Northern Germany.

This results in production adjustment costs of 23.6 M€ in 2010 and around 163.4 M€ in 2020.

Even though the installed wind power capacity in the Nordic area is still rather modest, a substantial amount of the production adjustments are delivered from Norway and Sweden. With real time approaching a large share of the thermal power plants in Continental Europe cannot provide the required production flexibility due to the associated production constraints. About one third of the adjustments corresponding to about 3 TWh in 2010 and about 12 TWh in 2020 is dispatched from the Nordic area. The increased HVDC transmission capacity between Continental Europe and the Nordic area enables the

Table 10.4: Intra-day market adjustments

	2010	2020
Gross imbalance [GWh]	10013	34050
Gross production adjustment [GWh]	9452	33454
Gross production adjustment in the Nordic area [GWh]	2930	12160
Adjustment costs [M€]	23.6	163.4

activation of the system-wide most economical production sources providing the required production flexibility. The intra-day transmission adjustments between the Nordic area and Continental Europe are displayed in Figure 10.7.

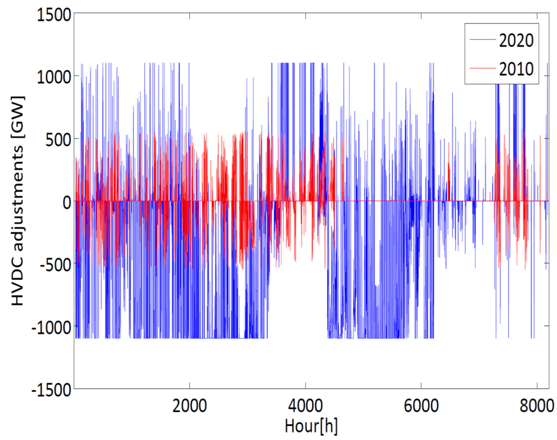


Figure 10.7: Intra-day transmission adjustments between the Nordic area and Continental Europe

10.4.3 Regulating power market results

Table 10.5 and Table 10.6 give an overview over the regulating market results for the defined scenarios and cases.

The regulating market results **Without Intra-day** market including the gross reserve activation in the simulation area and the Nordic area, the regulating energy exchange and the balancing costs are shown in Table 10.5.

The wind forecast error together with the load forecast error result in the activation of about 8500 GWh of the available regulating reserves in 2010. The additional WPP increases this value by about 90% in the 2020 scenario. A main share of the activated reserves is in the Nordic area, corresponding to about 65% and 72% of the total activated reserves in 2010 and 2020, respectively. Accordingly, the regulating energy exchange between the Nordic area and Continental Europe rises from approximately 16 TWh in 2010 to around 24 TWh in 2020. Even though the gross reserve activation increases by about 90% from 2010 to 2020, the respective balancing costs only increase by about 73%, rising from 279.5 M€ to 484.1 M€. The main reason for the discrepancy are the lower overall prices in 2020 along with a higher share of fast acting power plants in Continental Europe and the better interconnection with the Nordic area.

Table 10.5: Regulating Power Market Outcome - Without Intra-day market

	2010	2020
Total reserve requirements [MW]	7080	25650
Gross reserve activation [GWh]	8478	15825
Gross reserve activation in the Nordic area [GWh]	5529	11422
Regulating energy exchange [GWh]	16026	23760
Balancing costs [M€]	279.5	484.1

Table 10.6 shows the regulating power market results for the case **With Intra-day** market, i.e. the possibility of production adjustments after day-ahead market closure based on revised wind power forecasts. In comparison to the previous results in Table 10.5 a clear reduction in activated reserves can be noticed- both in the whole Northern Europe as well as in the Nordic area.

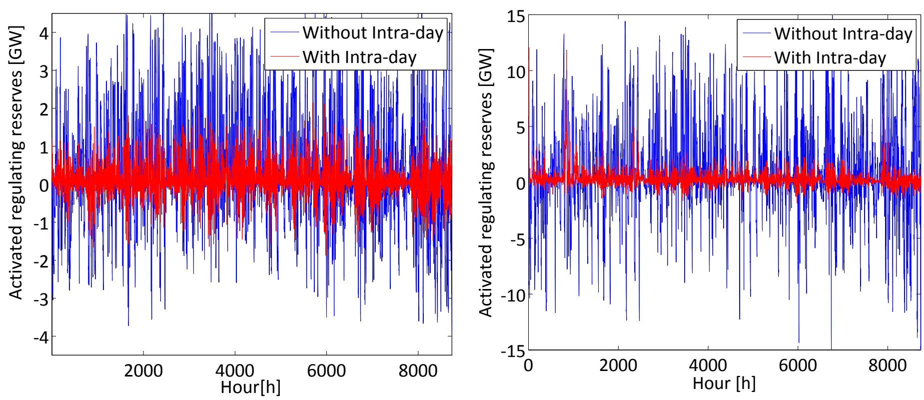
In 2010 only 3260 GWh of regulating reserves are activated in the whole simulation area. This corresponds to a reduction of about 60% compared to the case without intra-day market. For the 2020 scenario an even higher reduction of about 70% is noticeable, corresponding to about 4400 GWh. The results for the Nordic area show the same behaviour. The reserve activation is reduced by about 60% in 2010 and about 70% in 2020, respectively. Consequently the balancing costs reduce to about 133 M€ in 2010 and about 143.4 M€ in 2020.

Figure 10.8 shows the activation of regulating reserves in the whole simulation area for 2010 and 2020. The figure emphasises the results from Table 10.5 and Table 10.6. The reduction of activated reserves in the case with intra-day market is clearly detectable for the actual and the future scenario. While in the case without intra-day market the reserves are activated up to the maximum available capacity their activation is rather modest in case of an integrated intra-day market. Furthermore, the modelling outcome shows that without intra-day market the procured reserves are occasionally not sufficient to balance the re-

Table 10.6: Regulating Power Market Outcome - With Intra-day market

	2010	2020
Total reserve requirements [MW]	7080	25650
Procurement costs [M€]	155.2	554.5
Gross reserve activation [GWh]	3260	4373
Gross reserve activation in the Nordic area [GWh]	2275	3320
Regulating energy exchange [GWh]	10881	16298
Balancing costs [M€]	113.6	143.4

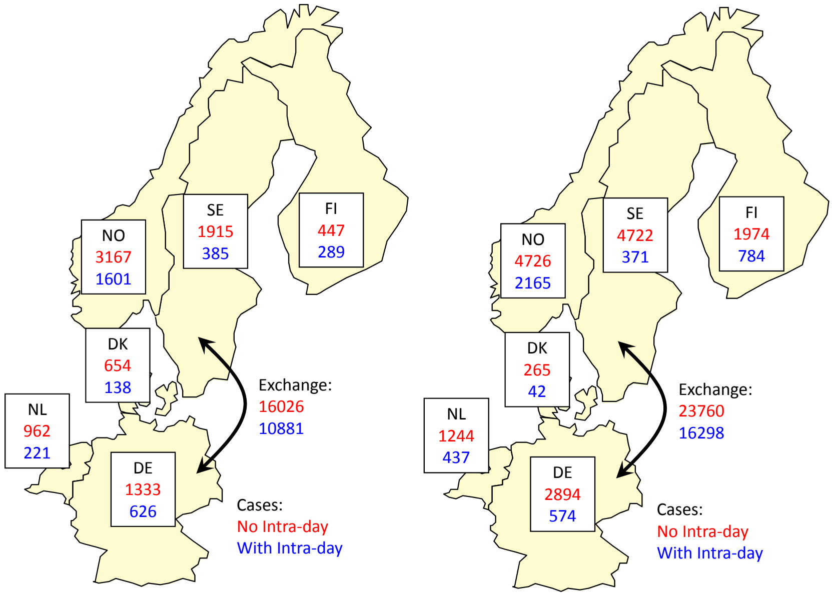
maining forecast deviations. Especially the EON area in north-western Germany, having a large amount of offshore wind power, is not able to provide a sufficient amount of up- and downward regulating reserves in the 2020 scenario. This results in the curtailment of WPP or load shedding in around 120 hours of the year.



(a) 2010 (b) 2020

Figure 10.8: Reserve activation in Northern Europe in 2010 (a) and 2020 (b)

Finally, the country wise annual reserve activation is illustrated in Figure 10.9. For all scenarios and cases it can be noticed that the main share of regulating reserves is provided through production facilities in the Nordic area - particularly in Norway and Sweden. A comparison of the two cases illustrate that the amount of activated reserves in all countries reduces drastically in all countries for the 2010 as well as for the 2020 scenario.



(a) 2010 (b) 2020

Figure 10.9: Country wise annual reserve activation 2010 (a) and 2020 (b)

10.5 Discussion

The used models and the applied data sets for the transmission system, the generation capacity and the marginal costs are based on the latest available specifications. This includes the adjustment of the according number for the 2020 scenario.

However, a comparison with the modelling results from Chapter 9 or real market data is complicated. Even though the results from the EMPS model applied in the preceding chapter indicate the same tendency for an integrated regulating power market, a direct comparison of the evaluated results is not possible due to different modelling approaches. Besides, the evaluated results give a lower boundary compared to reality since a perfect market is assumed.

The simulation results indicate that the activation of regulating reserves can be largely reduced for the case with an integrated intra-day market. However, this requires that the intra-day markets are equipped with a sufficient amount of liquidity.

10.6 Conclusion

In this Chapter the influences of wind power production on the three distinct power markets, namely the day-ahead, the intra-day and the regulating power market, are simulated. The possibilities of an integrate intra-day market in Northern Europe with respect to production adjustments after day-ahead market closure and the regulating power market outcome are shown. Two scenarios including the years 2010 and 2020 are simulated for two cases with and without intra-day market.

The results indicate that production adjustments in the intra-day market based on revised wind power forecasts can substantially reduce the activation of regulating reserves in the regulating power market. For 2010 the reserve activation can be reduced by about 60% while a further reduction of about 70% can be reached for 2020. This results in annual savings of about 145 M€ in 2010 and about 341 M€in 2020.

However, the necessary production adjustments in the intra-day market result in adjustments costs of about 23.6 M€and 163.4 M€in 2010 and 2020, respectively.

Chapter 11

Conclusion and future research

This Chapter finalises the thesis. Section 11.1 includes an overall summary and concluding remarks for the evaluated results included in PART II of the thesis. Section 11.2 proposes future research topics related to wind power integration in Europe which are not covered within this thesis

11.1 Conclusion

The European power system currently develops from a mainly thermal dominated towards as system largely affected by renewable energy sources. Besides hydro power, solar power and biomass, wind power is considered as a key technology to achieve the CO_2 targets set by the European Union. However, the production variability of wind power along with the limited predictability induce a high level of uncertainty in the power system. Thus, a higher degree of production flexibility from conventional generators and a larger amount of regulating reserves is expected to be required.

To attenuate the impacts of wind power production on system operation a multi-national rather than a national approach is required. Besides the physical expansion of inter-area and cross-border transmission capacity a regulatory framework towards an internal European power market has to be created. This not only includes the day-ahead market but also the establishment of integrated intra-day and regulating power market.

The research documented in this thesis evaluates the system impacts of large scale wind power and proposes measures for a cost efficient and secure integration in the power system. Thereby, the focus was on the development of a high resolution wind power production model, a joint grid expansion model and the development of markets models to simulate an integrated intra-day and regulating power market in Northern Europe. These models are utilised to simulate the actual and the future effects of wind power production on the power system and the power markets.

An overview of the determined results is given in the following Sections.

11.1.1 Wind power production on a European level

The simulations include scenarios for the years 2010, 2020 and 2030. The installed capacity is assumed to increase from an actual value of 97 GW to 270 GW in 2020 and 397 GW in 2030. The share of offshore installations in the North and Baltic Seas will account for 16% (45 GW) in 2020 and 25% (100 GW) in 2030, respectively. Even though the geographical separation of production facilities will further increase in future scenarios the overall production pattern remains highly variable. The European WPP varies between 2.2% and 61% in 2020 and between 2.5% and 62% in 2030. Considering only offshore installations in the North and Baltic Seas, the production variability becomes almost intermittent, ranging from 1.4% to 86.7% and 1.5% to 92.1% for 2020 and 2030, respectively. The increased variability results from clustering offshore facilities in small areas thereby reducing the effect of geographical smoothing. Until 2030 the hour-to-hour variations will drastically increase up to 19 GW/h in Europe and 11 GW/h in the North and the Baltic Seas. Even though offshore installations only correspond to about 20% to 25% of the total installed capacity in Europe, they are responsible for 40% to 60% of the overall hourly fluctuations. Although, the hourly WPP variability will largely increase, its effects on the European net-load variability remains limited. While in 2020 almost no increase in net-load variations can be detected on a European level the variability will only increase by about 3 GW/h in 2030. This appears to be rather modest when assuming maximum hourly load variations of up to 70 GW/h on a European level.

11.1.2 Cost-optimal grid expansion

The URBS-EU model simulates cost-optimal grid expansion scenarios for the European cross-border and inter-area transmission capacity for the years 2020 and 2030. In the simulations the WPP time series data as well as changing generator portfolios are taken into account. For both scenarios, the modelling results propose a large capacity expansion along the coastline of the North Sea, establishing a east-west connection between Germany, the Netherlands, Germany and Denmark. Further on, reinforcements in the HVDC transmission capacity connecting Germany with Eastern Denmark and Sweden are proposed. For a cost efficient exchange of energy a vast expansion of the offshore supergrid capacity is proposed. Furthermore, the need for massive reinforcements of the cross-border connections between France, Italy and Slovenia has been determined. This especially applies for the 2030 scenario. The results display that besides the cross-border connections, the inter-area connections within the countries itself have to be strengthened. Especially the north-south connections in France and Germany require large scale reinforcements for being able to transmit the WPP from the coastal areas to the load centres in land. Also Sweden requires large internal grid expansions for a better interconnection between the Southern areas and the hydro reservoirs in northern Sweden.

Taking these results as an input the load flow, the production pattern and the day-ahead market prices were simulated using the simulation tool PSST. The load flow results display that even with the proposed grid expansion scenarios the respective transmission capacity is utilised to a large extent. Furthermore, the results display that the removal of inter-area and cross-border transmission bottlenecks leads to a stabilised production pattern of conventional generators. For both future scenarios, the grid expansion leads to an overall price reduction of about 5% on a European level. Price reductions are largely dependent on the respective area and can decrease by 40% in comparison with the case without grid expansion. Other areas, e.g., Austria will be confronted with increasing prices as a result from a better interconnection with the neighbouring countries. The price variance between areas largely reduces by about 40% to 60% in 2020 and 2030, respectively.

The cost-optimal grid expansion requires investment costs to the tune of 34.1 bn € in 2020 and 37.1 bn € in 2030, respectively. On the other hand, the European production costs decrease by about 16 bn € p.a. and 19 bn € p.a. in 2020 and 2030, respectively. This results in a relatively short payback period of around 6 years.

11.1.3 Integration of regulating power markets

The simulations of an integrated Northern European regulating market, based on the day-ahead market results, is executed with the modelling tool EMPS. The simulations take a change in the generator portfolio and the transmission grid into account. The regulating market outcome is simulated for two scenarios including the years 2010 and 2020. For both years the regulating market is simulated for the actual state *"without market integration"* and for a scenario *"with market integration"*. The regulating power market outcome without integration shows that gross system imbalances and gross activation of regulating reserves are almost doubled in the 2020 scenario. With an overall amount of 343 M€ the reserve procurement costs are more than twice as high as the 2010 results. The system balancing costs increase by about 28 M€. Using the possibilities of a fully integrated market with its system-wide reserve procurement and exchange possibilities, the 2010 procurement costs can be cut down by 40% while in the 2020 scenarios the costs are reduced by about 30%. Almost the same conclusion can be drawn for the balancing costs, being reduced by 50% to about billion 74 M€ in the 2020 scenario with transfer reservation. As most of the cheap balancing resources are situated in the Nordic area, the exchange of regulating reserves will ascend and become more and more important in future scenarios, while the activation of reserves in continental Europe will decrease by about 300%.

11.1.4 Intra-day markets in Northern Europe

The day-ahead, the intra-day and the regulating power market are modelled with the Power System Simulation Tool PSST. The three distinctive power markets are simulated for two scenarios including the years 2010 and 2020. For each scenario two cases are simulated- with and without and integrated intra-day market in Northern Europe.

The simulation results indicate that an integrated intra-day market can substantially reduce the activation of regulating reserves. While in 2010 the reserve activation can be reduced by about 60% a further reduction of about 70% is detectable in 2020. This results in annual savings in the regulating market of about 145 M€ in 2010 and about 341 M€in 2020. The production adjustments in the intra-day market sum up to about 23.6 M€and 163.4 M€in 2010 and 2020, respectively. Therefore, an integrated intra-day market in Northern Europe is able to decrease the overall system costs while increasing system security.

11.2 Future research

The focus of this thesis was on the simulation of WPP and its affects on the European power system as well as on the power markets. Several measures including a cost-optimal grid expansion and the integration of intra-day and regulating power markets have been addressed.

The evaluated results indicate that the future integration of WPP in the European system will require a multinational instead of a national approach. Therefore, a topic for future research might include the expansion of the applied models to other European areas. Especially the increasing interconnection with the UK should be considered in future models. A further expansion of the intra-day and regulating power market towards an integrated model covering the whole European system would be desirable.

Besides, the establishment of a grid expansion tool within PSST, considering the load flow along with the power markets, would be relevant for future research. Since load flow and grid constraints play a key role for the further integration of future wind power facilities, both parameters should be directly considered within the optimisation process.

"Des is wia bei jeda Wissenschaft, am Schluss stellt sich dann heraus, dass alles ganz anders war"

Karl Valentin
1882 - 1948

Bibliography

[1] European Commission. *Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the Promotion of the Use of Energy from Renewable Sources and Amending and Subsequently Repealing Directives 2001/77/EC and 2003/30/EC*. 2009. URL `http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=Oj:L:2009:140:0016:0062:en:PDF`.

[2] European Commission, 2012. URL `http://ec.europa.eu/clima/policies/package/index_en.htm`.

[3] European Commission. *Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community*. 2009. URL `http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0063:0087:en:PDF`.

[4] J. McLean and Gerard Hassan and Partners Ltd. TradeWind, WP 2: Wind Power Scenarios, WP2.6: Equivivalent Wind Power curves. Technical report, European Wind Energy Association (EWEA), 2008. URL `http://www.trade-wind.eu/index.php?id=27`.

[5] S. Jaehnert. *Integration of Regulating Power Markets in Northern Europe*. PhD thesis, Norwegian University of Science and Technology, 2012.

[6] EURELECTRIC. RES Integration and Market Design: Are Capacity Remuneration Mechanisms Needed to ensure generation adequacy? Technical report, Union of the Electricity Industry – EURELECTRIC, 2011.

[7] United Nations Framework Convention on Climate Change. Kyoto Protocol - Refenrence Manual. Technical report, UN, 1997. URL `http://unfccc.int/resource/docs/publications/08_unfccc_kp_ref_manual.pdf`.

[8] European Commission. Energy for the Future: Renewable Sources of Energy. White Paper for a Community Strategy and Action Plan. Technical report, 1997. URL `http://europa.eu/documents/comm/white_papers/pdf/com97_599_en.pdf`.

[9] European Commission. *Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the Promotion of Electricity from Renewable Energy Sources in the Internal Electricity Market.* 2001. URL http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2001:283:0033:0033:EN:PDF.

[10] European Commission. *Communication from the Commission to the European Parliament and the Council: Renewable Energy Roadmap: Renewable Energies in the 21st century- building a sustainable future.* 2007. URL http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2006:0848:FIN:EN:PDF.

[11] European Commission. *Communication from the Commission to the European Council and the European Parliament: An Energy Policy for Europe.* 2007. URL http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2007:0001:FIN:EN:PDF.

[12] Commission of the European Communities. DIRECTIVE 2009/29/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community. Technical report, EU, 2009. URL http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0063:0087:en:PDF.

[13] M. Scoccimarro D. Collins. Market-based instruments decision support tool. Technical report, BDA Group, 2008. URL http://www.marketbasedinstruments.gov.au/Portals/0/docs/DST_%20final_web.pdf.

[14] R. Stavins. Environmental policy instruments for market and mixed-market economies. Technical report, Environmental policy instruments for market and mixed-market economies, 2001. URL http://www.rff.org/rff/documents/rff-dp-01-58.pdf.

[15] Eurostat. *Electricity generated from renewable sources - % of gross electricity consumption.* 2012. URL http://epp.eurostat.ec.europa.eu/tgm/table.do?tab=table&init=1&language=en&pcode=tsien050&plugin=1.

[16] G. van der Toornan and Gerard Hassan and Partners Ltd. Tradewind, Work Package 2: Wind Power Scenarios, WP2.1- Wind Power Capacity Data Collection. Technical report, European Wind Energy Association (EWEA), 2007. URL http://www.trade-wind.eu/index.php?id=27.

[17] European Wind Energy Association (EWEA). Pure Power - Wind Energy Scenarios up to 2030. Technical report, European Wind Energy Association (EWEA), 2008. URL http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/purepower.pdf.

[18] European Wind Energy Association (EWEA). Wind in our Sails - The coming of Europe's offshore wind energy industry. Technical report, European Wind Energy Association (EWEA), 2011. URL http:

//www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/23420_Offshore_report_web.pdf.

[19] H. Holttinen. *The impact of large scale wind power production on the Nordic electricity system.* PhD thesis, Helsinky University of Technology, 2004.

[20] T. Aigner and S. Jaehnert. The effect of large scale wind power on system balancing in Northern Europe. *IEEE Transactions Special Issue on sustainable Energy*, to be published, 2012.

[21] European Commission. *Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity.* 1996. URL www.ems.rs/eng/stranice/regulativa/direktive/dir96-92.pdf.

[22] M. Pollitt T. Jamasb. Electricity Market Reform in the European Union: Review of Progress towards Liberalisation and Integration. Technical report, University of Cambridge - Department of Applied Economics, 2005. URL www.econ.cam.ac.uk/electricity/publications/wp/ep66.pdf.

[23] European Commission. *Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.* 2003. URL http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2003:176:0037:0055:EN:PDF.

[24] European Commission. *Directive 2009/72/EC of the European Parliament and of the Council of 23 April 2009 on the Promotion of the Use of Energy from Renewable Sources and Amending and Subsequently Repealing Directive 2003/54/EC.* 2009. URL http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF.

[25] European Commission, 2012. URL http://europa.eu/legislation_summaries/energy/internal_energy_market/en0016_en.htm.

[26] Union for the Co-ordination of Transmission of Electricity (UCTE). UCTE Transmission Development Plan - Edition 2008. Technical report, UCTE, 2008. URL www.energiestrategie.at/images/stories/pdf/33_ucte_08_transmdevelplan.pdf.

[27] I. Wangensteen. *Power System Economics - the Nordic Electricity Market.* tapir academic press, ISBN 978-82-519-22005, 2006.

[28] H. Farahmand. *Integrated Power System Salancing in Northern Europe - Models and Case Studies.* PhD thesis, Norwegian University of Science and Technology, 2012.

[29] T. Kristiansen. Pricing of Contracts for Difference in the Nordic Market. *Energy Policy*, 32:1075–1085, 2004.

[30] Nord Pool ASA. Trade at the Nordic Spot Market. Technical report, Nord Pool, 2004. URL http://www.ieee.hr/_download/repository/Nord%20Pool%20Spot%20Market.pdf.

[31] V. Meneu D. Furió, J. Lucia. The Spanish electricity intraday market: prices and liquidity risk. Technical report, Departamento de Economía Financiera y Actuarial, Facultad de Economía (Universidad de Valencia), 2009. URL http://www.aeee.es/archivos/documentosCientificos/CONGRESOS%20AEEE/2008%20-%20III%20CONGRESO%20AEEE%20-%20BILBAO/14%20M%AA%20Dolores%20Furio.pdf.

[32] L. Nielsen C. Weber K. Sander D. Swider H. Ravn P.Meibom, P. Morthorst. Power System Models - A Description of Power Markets and Outline of Market Modelling in Wilmar. Technical report, Risø National Laboratory, 2003.

[33] Tractebel Suez Engineering, Katholieke Universiteit Leuven. Study of the interactions and dependencies of Balancing Markets, Intraday Trade and Automatically Activated Reserves. Technical report, 2009.

[34] European Commission. *Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity.* 2003. URL http://ec.europa.eu/energy/electricity/package_2007/doc/2003_1228_regulation_amending_en.pdf.

[35] European Market Coupling Company (EMCC), 2012. URL http://www.marketcoupling.com/.

[36] TenneT. Marktintegration- Kopplung der europäischen Strommärkte. Technical report, TenneT, http://www.tennet.de, 2010. URL http://www.tennettso.de/site/binaries/content/assets/press/information/de/broschuere_marktintegration.pdf.

[37] Amprion, RTE, EnBW TNG. Successful launch of the new Franco-German Intraday solution- EPEX Spot realizes integrated Franco-German Intraday market place, 2010. URL http://www.enbw.com/content/en/press/press_releases/2010/12/PM_20101214_ID-Plattform_cu_ys_01/20101214_ID-Plattform_ENG.pdf.

[38] APX-ENDEX, Belpex, Nord Pool Spot. APX-ENDEX, Belpex and Nord Pool Spot to Launch the First Step of the Cross-Border Intraday Market. 2011. URL http://www.belpex.be/uploads/media/PR_XBID_2011-02-17_02.pdf.

[39] APX-ENDEX, 2011. URL http://test.apxendex.com/index.php?id=24&tx_ttnews[tt_news]=394&tx_ttnews[backPid]=94&cHash=2701138266.

[40] REKK Energiapiaci Tanácsadó Kft., and REKK Energiapiaci Tanácsadó Kft. Target Model and European Market Integration in the Electricity Sector. Technical report, http://www.eh.gov.h, 2011.

[41] NordREG. Harmonising the balancing market- Issues to be considered. Technical report, 2010.

[42] European Regulators Group for Electricity and Gas (EREG). ERGEG Guidelines of Good Practice for Electricity Balancing Markets Integration. Technical report, EREG, 2006. URL http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2006/E05-ESO-06-08_GGP-EBMI_2006-12-06.pdf.

[43] P. Sø rensen G. Giebel and H. Holttinen. TradeWind Project, D2.2 Forecast error of aggregated wind power. Technical report, European Wind Energy Association (EWEA), 2007. URL http://www.tradewind.eu/fileadmin/documents/publications/D2.2_Estimates_of_forecast_error_for_aggregated_wind_power_Final.pdf.

[44] P. Nørgaard and H. Holttinen. A Multi-Turbine Power Curve Appoach. In *Nordic Wind Power Conference*, pages 1–5, 2004.

[45] E. Kalnay. The NCEP/NCAR 40-year reanalysis project. *Bulletin of the American Meteorological Society*, 77:437–470, 1996. URL http://journals.ametsoc.org/doi/abs/10.1175/1520-0477%281996%29077%3C0437%3ATNYRP%3E2.0.CO%3B2.

[46] H. Holttinen. Hourly wind power variations in the Nordic countries. *Wind Energy*, 8:173–195, 2005.

[47] Deutscher Wetterdienst (DWD), January 2010. URL www.dwd.de.

[48] Danish Meteorological Institute (DMI), January 2010. URL www.dmi.dk.

[49] Consortium for Small-scale Modelling (COSMO), November 2010. URL www.cosmo-model.org.

[50] G. Doms and U. Schättler. A Description of the Nonhydrostatic Regional Model LM, Part I: Dynamics and Numerics. Technical report, Consortium for Small-Scale Modelling, 2002. URL http://www.cosmo-model.org/content/model/documentation/core/cosmoPhysParamtr.pdf.

[51] J. Schulz and U. Schättler. Kurze Beschreibung des Lokal - Modells Europa COSMO-EU (LME) und seiner Datenbanken auf dem Datenserver des DWD. Technical report, Deutscher wetterdienst (DWD), 2010. URL http://www.dwd.de/bvbw/generator/DWDWWW/Content/Forschung/FE1/Veroeffentlichungen/Download/LME__DBeschr__Rungek__1005,templateId=raw,property=publicationFile.pdf/LME_DBeschr_Rungek_1005.pdf.

[52] S. Klink T. Reinhradt C. Schraff A. Seifert M. Baldauf, J. Förster and K. Stephan. Kurze Beschreibung des Lokal- Modells Kürzestfrist COSMO-DE(LMK) und seiner Datenbanken auf dem Datenserver des

DWD. Technical report, Deutscher Wetterdienst (DWD), 2010. URL http://www.dwd.de/bvbw/generator/DWDWWW/Content/Forschung/FE1/Veroeffentlichungen/Download/LMK__DBbeschr__1104__en,templateId=raw,property=publicationFile.pdf.

[53] Deutscher Wetterdienst (DWD). PAMORE Web-Interface, 2011. URL http://www.dwd.de/bvbw/appmanager/bvbw/dwdwwwDesktop?_nfpb=true&_pageLabel=dwdwww_menu2_kontakt&_state=maximized&_windowLabel=T34203040811665340375 44.

[54] TheWindPower, January 2010. URL www.thewindpower.net/.

[55] European Wind Energy Agency (EWEA). Wind energy development in the EU 1998 to 2009, 2010. URL http://www.ewea.org/fileadmin/ewea_documents/documents/statistics/cumulative_wind_per_ms_1998_2009_ws.xls.

[56] EnergyMap. EEG-Anlagenregister, 2011. URL http://www.energymap.info/.

[57] Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit. *Gesetz für den Vorrang Erneuerbarer Energien.* 2009. URL http://www.bmu.de/erneuerbare_energien/downloads/doc/40508.php.

[58] A. Smits J.W. Verkaik. Interpretation and estimation of the local wind climate. In *Proceeding of the 3rd European and African Conference on Wind Engineering, 2–6 July 2001, Eindhoven, the Netherlands*, pages 43–56, 2001.

[59] Energinet.dk, July 2010. URL http://www.energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx.

[60] Amprion. *http://www.amprion.net/.* 2012.

[61] TransnetBW. *http://www.transnetbw.de/.* 2012.

[62] 50Hertz. *http://www.50hertz.com.* 2012.

[63] SINTEF Energy Research. URL http://www.sintef.no/home/SINTEF-Energy-Research/Project-work/Hydro-thermal-operation-and-expansion-planning/EMPS/.

[64] S. Jaehnert and G. Doorman. Modelling an integrated northern European regulating power market based on a common day-ahead market. In *Proc. of IAEE International Conference, Rio de Janeiro*, 2010.

[65] B. Mo A. Gjelsvik I. Wangensteen O. Wolfgang, A. Haugstad and G. Doorman. Hydro reservoir handling before and after deregulation. *Energy*, 34:1642–1651, 2009.

[66] SINTEF Energy Research. Samkjøringsmodellen Brukermanual (EMPS User Manual). 1999.

[67] E.S. Huse G. Warland, A. Haugstad. Including thermal unit start-up costs in a long-term hydro-thermal scheduling model. In *16th Power Systems Computation Conference, Glasgow*, 2008.

[68] N. Heitmann. Solution of energy problems with the help of linear programming. Master's thesis, Naturwissenschaftliche Fakultät der Universität Augsburg, 2005.

[69] T. Haase. *Anforderungen an eine durch Erneuerbare Energien geprägte Energieversorgung - Untersuchung des Regelverhaltens von Kraftwerken und Verbundnetzen (Requirement for Power Supply with Major Shares of Renewables - Analysis of the Power Plant and Network Control)*. PhD thesis, Fakultät für Informatik und Eletroktechnik der Universität Rostock, 2006.

[70] K. Schaber, F. Steinke and T. Hamacher. Transmission grid extension for the integration of variable renewable energies in Europe: Who benefits where? *Energy Policy*, 43:123–135, 2012.

[71] K. Schaber, F. Steinke, T. Hamacher and P. Mühlich. Parametric study of variable renewable energy integration in Europe: Advantages and costs of transmission grid extensions. *Energy Policy*, 42:498–508, 2012.

[72] European Network of Transmission System Operators for Electricity (ENTSO-e). ENTSO-E Grid map, 2011. URL `https://www.entsoe.eu/resources/grid-map/`.

[73] European Wind Energy Association (EWEA). Integrating Wind- Developing Europe's power market for the large-scale integration of wind power. Technical report, European Wind Energy Association (EWEA), 2009. URL `http://www.trade-wind.eu/`.

[74] G. Doorman H. Farahmand and O. B. Fosso. Modelling of balancing market integration in the Northern European Continent. In *Proc. 17th Power Systems Computation Conference (PSCC'11)*, pages 1–9, 2011.

[75] European Network of Transmission System Operators for Electricity (ENTSO-e) and Association of european Power Exchanges (EuroPex). Flow-based Market Coupling - A Joint ETSO-EuroPEX Proposal for Cross-Border Congestion Management and Integration of Electricity Markets in Europe. Technical report, 2004. URL `http://www.google.com/url?sa=t&rct=j&q=enstone%20flow%20based%20market%20coupling&source=web&cd=2&ved=0CCgQFjAB&url=https%3A%2F%2Fwww.entsoe.eu%2Ffileadmin%2Fuser_upload%2F_library%2Fpublications%2Fetso%2FCongestion_Management%2FETSO-EuroPEX_Interimreport_Sept-2004-.pdf&ei=QNlVUIDjMuTc4QTgyoCYBg&usg=AFQjCNG_Si_50abDFk3wS3hMH-JeGNxGqA&cad=rja`.

[76] TenneT. Market integration - Coupling of the European electricity markets. Technical report, TenneT, 2010. URL `http://www.tennet.org/images/100478%20TEN%20Broch.%20marktkoppeling-internet_tcm41-19590.pdf`.

[77] K. Uhlen, L. Warland, and O. S. Grande. Model for area price determination and congestion management in joint power markets. In *Proc. Int. CIGRE/IEEE PES Symp*, pages 100–109, 2005.

[78] TenneT. CWE Enhanced Flow-Based MC feasibility report. Technical report, TenneT, 2011. URL `http://www.tennet.org/english/images/CWE_FB-MC_feasibility_report_2.0_19102011_tcm43-20387.pdf`.

[79] TenneT. Questions and Answers. Technical report, TenneT, 2001. URL `http://www.tennet.org/english/images/FAQ%20-%20update%2013%2012%202011_tcm43-20249.pdf`.

[80] J. Tande M. Korpås, L. Warland and K. Uhlen. TradeWind, D3.2 Grid modelling and power system data. Technical report, SINTEF Energi, 2007. URL `http://www.trade-wind.eu/index.php?id=27`.

[81] GreenNet EU/27. Guiding a least cost grid integration of RES-electricity in an extended Europe. Deliverable D8: Case Studies on System Stability with Increased RES-E Grid Integration. Technical report, Green-Net Europe, http://www.greennet-europe.org/, 2006.

[82] B.H. Bakken. *Technical and economic aspects of operation of thermal and hydro power system*. PhD thesis, Norwegian University of Science and Technology, 1997.

[83] Qiong Zhou and J. W. Bialek. Approximate model of European interconnected system as a benchmark system to study effects of cross-border trades. *IEEE Transactions on Power Systems*, 20(2):782–788, 2005.

[84] Q. Zhou and J. W. Bialek. Correction to 'Approximate model of European interconnected system as a benchmark system to study effects of cross-border trades'. *IEEE Transactions on Power Systems*, 20(3), 2005.

[85] National Grid. GB Seven Year Statement 2010. Technical report, National Grid, 2010. URL `http://www.nationalgrid.com/uk/Electricity/SYS/archive/sys10`.

[86] Union for the Co-ordination of Transmission of Electricity (UCTE). UCTE System adequacy forecast 2008-2020. Technical report, European Network of Transmission System Operators for Electricity (entsoe), 2008. URL `https://www.entsoe.eu/index.php?id=58`.

[87] EURPROG Network of Experts. Statistics and prospects for the European electricity sector. Technical report, 2006.

[88] UCTE. Ucte system adequacy forecast 2008-2020. Technical report, UCTE, 2008.

[89] S. Vassoloa B. Lehner, G. Czisch. The impact of global change on the hydropower potential of Europe: a model-based analysis. *Energy Policy*, 33:839–855, 2005.

[90] NORDEL. URL www.nordel.org.

[91] V. Papandreou N. Tasios P. Capros, L. Mantzos. European Energy and Transport, Trends to 2030 - Update 2007. Technical report, ICCS-NTUA for European Commission, 2008. URL http://ec.europa.eu/dgs/energy_transport/figures/trends_2030_update_2007/energy_transport_trends_2030_update_2007_en.pdf.

[92] 4coffshore, 2011. URL http://www.4coffshore.com/offshorewind/.

[93] National Grid, 2006. URL www.nationalgrid.com.

[94] Eirgrid, 2006. URL www.eirgrid.ie/.

[95] Norwegian Water Resources and Energy Directorate, 2006. URL www.nve.no.

[96] Institute of Hydrology (UK). Flow Regimes from International Experimental and Network Data, Vol. I, Hydrological studies (FRIEND). Technical report, 1993.

[97] N.W. Arnell. A simple water balance model for the simulation of streamflow over a large geographical domain. *Hydrology*, 217:314–335, 1999.

[98] H. Farahmand. Modelling of balancing market integration in the Northern European continent. In *Power System Computational Conference 2011, Stockholm*, 2011.

[99] European Network of Transmission System Operators for Electricity (ENTSO-e). Balance management harmonisation and integration. Technical report, 2007. URL http://www.marketcoupling.com/document/1000/ETSO%20-%20Report%20on%20Balance%20Management%20Harmonisation%20and%20Integration.pdf.

[100] Xing Wang, Yong-Hua Song, and Qiang Lu. A coordinated real-time optimal dispatch method for unbundled electricity markets. *IEEE Trans. Power Systems*, 17(2):482–490, 2002.

[101] MET office UK. Wind Review: Where were the windiest loacations in Europe? Technical report, 2011.

[102] European Wind Energy Association (EWEA). Wind in power - 2010 European statistics. Technical report, European Wind Energy Association (EWEA), 2011. URL http://www.ewea.org/index.php?id=180.

[103] Deutsche Energie Agentur. DENA Netzstudie II- Integration erneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015 – 2020 mit Ausblick 2025. Technical report, DENA, 2010. URL http://www.dena.de/fileadmin/user_upload/Publikationen/Erneuerbare/Dokumente/Endbericht_dena-Netzstudie_II.PDF.

[104] J. O. G. Tande M. Korpås, L. Warland and K. Uhlen. TradeWind, WP 3: - D3.2 Grid modeling and power system data. Technical report, SINTEF Energy, Trondheim, 2007. URL http://www.trade-wind.eu/fileadmin/documents/publications/D3.2_grid_modelling_and_power_system_data.pdf.

[105] R. Mackensen, B. Lange, and F. Schlögl. Integrating wind energy into public power supply systems- German state of the art. *International Journal of Distributed Energy Resources*, 3(4):259–271, 2007.

[106] B. Kirby T. Acker V. Neimane H. Holttinen, M. Milligan and T. Molinski. Using standard deviation as a measure of increased operational reserve requirement for wind power. *Wind Engineering*, 32:355–378, 2008.

[107] M. Milligan, P. Donohoo, D. Lew, E. Ela, and Brendan Kirby. Operating Reserves and Wind Power Integration: An International Comparison. Technical report, National Renewable Energy Laboratory, 2010. URL www.nrel.gov/docs/fy11osti/49019.pdf.

[108] G. Giebel. On the benefits of distributed generation of wind energy in Europe. *VDI Reihe*, 444:116ff, 2001.

[109] G. Czisch. *Scenarios for a future power supply. Cost-optimal scenarios for renewables in Europe and its neighbors.* PhD thesis, University of Kassel, 2005.

[110] H. Farahmand, D. Huertas-Hernando, L. Warland, M. Korpas and H. Svendsen. Impact of system losses on the value of an offshore grid for North Sea offshore wind. In *IEEE Power Tech, Trondheim, Norway*, 2011.

[111] H. Farahmand and T. Aigner. Balancing Market Integration in the Northern European Continent: A 2030 Case Study. *IEEE Trans. Special issue on sustainable energy*, 2012.

[112] National Grid. 2011 National Electricity Transmission System (NETS) Seven Year Statement. Technical report, National Grid, 2011.

[113] 3E, dena, EWEA, ForWind, IEO, NTUA, Senergy and SINTEF. Offshoregrid: Offshore electricity infrastructure in europe. Technical report, 2011.

[114] F. van Hulle N. Fichaux, J. Wilkes and A. Cronin. Oceans of Opportunity. Technical report, European Wind Energy Association (EWEA), http://www.ewea.org/, 2009.

[115] European Network of Transmission System Operators for Electricity (ENTSO-e). ENTSO-E NTC map. 2011. URL https://www.entsoe.eu/resources/ntc-values/ntc-map/.

[116] T. Aigner and T. Gjengedal. Modelling wind power production based on numerical prediction models and wind speed measurements. In *Power System Computational Conference 2011, Stockholm*, pages 1–7, 2011.

[117] Gerard Hassan Consulting. Impacts of increased levels of wind penetration on the electricity system of the republic of Ireland and Northern Ireland: Final Report. Technical report, 2003.

[118] European Network of Transmission System Operators for Electricity (ENTSO-e). Ten year network development plan. Technical report, 2011. URL `https://www.entsoe.eu/index.php?id=232`.

[119] M. Milligan. Wind power plants and system operation in the hourly time domain. In *Proc. of Windpower 2003 Conference, Austin, Texas*, 2003. URL `http://www.nrel.gov/publications/`.

[120] Union for the Co-ordination of Transmission of Electricity (UCTE). Operational Handbook, P1 - Policy 1. Technical report, 2009. URL `http://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/oh/%Policy1_final.pdf`.

[121] G. Doorman S. Jaehnert, T. Aigner and T. Gjengedal. Impact of large scale wind integration on power system balancing. In *Proc. IEEE PowerTech Conference, Trondheim*, 2011.

[122] TenneT. System operation agreement. URL `http://www.tennet.org/english/operationalmanage-ment/exportdata.aspx`.

[123] NordPool. URL `http://www.nordpoolspot.com/Market-data1/Maps/Elspot-Market-Overview/Elspot-Prices/`.

[124] S. Jaehnert. European regulating power market operation: The impact of wind forecasts and reserve requirements. In *In 9th International conference on the European Energy Market, Florence*, 2012.