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IEEE POWER ENGINEERING SOCIETY
ENERGY DEVELOPMENT AND POWER GENERATION COMMITTEE

Towards Successful Integration of Wind Power into European Electricity Grids: Challenges, Methods and Results

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Working Group European Electricity Infrastructure[1]

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Sponsored by: International Practices for Energy Development and Power Generation

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Track: New Technologies

INTRODUCTION

On behalf of the Energy Development and Power Generation Committee, welcome to this Panel Session on Successful Integration of Wind Power into European Electricity Grids focused on challenges, methods and results.

Reliability of supply, environmental protection and economic service delivery has been for decades forming the "golden triangle" of energy policy in Europe and beyond. But with evidence on Global Warming becoming stronger and at the same time Europe's own resources of fossil fuels decreasing substantially, interest into renewable energy resources and especially electricity generation from renewable sources has increased substantially during the last decade. Most outstanding among the renewable electricity generating technologies by its growth rates and achieved market penetration is wind energy. At the same time it poses new challenges to power systems.

The integration of substantial amounts of wind power in a liberalized electricity system will impact both the technical operation of the electricity system and the electricity market. In order to cope with the fluctuations and the partial unpredictability in the wind power production, other units in the power system have to be operated more flexibly to maintain the stability of the power system. Technically this means that larger amounts of wind power will require increased capacities of spinning and non-spinning power reserves and an increased use of these reserves. Moreover, if wind power is concentrated in certain regions, increased wind power generation may lead to bottlenecks in the transmission networks. Economically, these changes in system operation have certainly cost and consequently price implications. Moreover they may also impact the functioning and the efficiency of certain market designs. Even if the wind power production is not bid into the spot market, the

[1] Document prepared and edited by T J Hammons

feed-in of the wind power will affect the spot market prices, since it influences the balance of demand and supply.

As substantial amounts of wind power will require increased reserves, the prices on the regulating power markets are furthermore expected to increase. Yet this is not primarily due to the fluctuations of wind power itself but rather due to the partial unpredictability of wind power. If wind power were fluctuating but perfectly predictable, the conventional power plants would have to operate also in a more variable way, but this operation could be scheduled on a day-ahead basis and settled on conventional day-ahead spot markets. It is the unpredictability of wind power that requires an increased use of reserves with corresponding price implications.

In this situation the operation and management of power systems with high shares of wind power require extended analyses. This panel fits very well with the objectives of IEA annex 25 on Design and Operation of Power Systems with Large Amounts of Wind Power.

Some of the key persons of the research and industry in Europe will participate with technical presentations.

The Panelists and Titles of their Presentations are:

1. Frans van Hulle, European Wind Energy Association (EWEA), Belgium and Achim Woyte, 3^E NV, Brussels, Belgium. Integration of Wind Energy in Europe's Power Systems: Transmission Infrastructure and Market Design Requirements. (Invited Discusser)
2. Daniel Waniek, Ulf Häger, Christian Rehtanz and Edmund Handschin, Dortmund University, Germany. Influences of Wind Energy on the Operation of Transmission Systems (Invited Panel Presentation Summary 08GM0449)
3. Krzysztof Rudion, Zbigniew A. Styczynski, University Magdeburg, Germany, Antje Orths, Energinet.dk, TSO, Denmark, Olaf Ruhle, Siemens AG, Germany. MaWind--Tool for the Aggregation of Wind Farm Models (Invited Panel Presentation Summary 08GM0602)
4. Christoph Weber, University Duisburg-Essen, Germany. Valuation of Variability and Unpredictability for Electricity Generation (Invited Panel Presentation Summary 08GM0653)
5. Matthias Lange and Ulrich Focken, Energy and Meteo Systems GmbH, Oldenburg, Germany. New Developments in Wind Energy Forecasting (Invited Panel Presentation Summary 08GM0386)
6. Wojciech Wiechowski, Peter Børre Eriksen, Energinet.dk, TSO, Denmark. Selected Studies on Offshore Wind Farm Cable Connections - Challenges and Experience of the Danish TSO (Invited Panel Presentation Summary 08GM0369)
7. W. L. Kling, TSO, Delft University, The Netherlands; and Madeline Gibescu, Bart Ummels, and Ralph Hendriks, Delft University, The Netherlands. Implementation of Wind Power in the Dutch Power System (Invited Panel Presentation Summary 08GM0480)
8. Olivier. Chatillon and Dietmar Graeber, EnBW Grid TSO, Karlsruhe, Germany. Efficient Management of Wind Energy In-feed at a Large German TSO (Invited Panel Presentation Summary 08GM0802)
9. Invited Discussers

Each Panelist will speak for approximately 30 minutes. Each presentation will be discussed immediately following the respective presentation. There will be a further opportunity for discussion of the presentations following the final presentation.

The Session has been organized by Tom Hammons (Chair of International Practices for Energy Development and Power Generation IEEE, University of Glasgow, UK), Antje Orths (Energinet.dk, Fredericia, Denmark), and Christoph Weber (Chair for Management Sciences and Energy Economics, University of Duisburg-Essen, Germany)

Tom Hammons, Antje Orths and Christoph Weber will moderate the Panel Session.

The first presentation is an Invited Discussion that has been prepared by Frans van Hulle, European Wind Energy Association (EWEA), Belgium and Achim Woyte, 3^E NV, Brussels, Belgium. It is entitled: *Integration of Wind Energy in Europe's Power Systems: Transmission Infrastructure and Market Design Requirements*

Frans Van Hulle holds a M.Sc. degree in Metallurgical Engineering from KU Leuven, Belgium (1974). Today he is senior technical advisor of the European Wind Energy Association EWEA.

From 1981 to 2002 he was project leader at the Energy Research Center of the Netherlands (ECN) in wind turbine design and certification. He was actively involved in the development of IEC standards in wind energy as WG Convener and TC88 member. From 2002 to 2005 he has been coordinating wind farm due diligence projects with the renewable energy consulting engineers 3E in Brussels. In his present position at EWEA he is leading the dossiers on grid integration of wind energy in Europe and coordinating the European integration project Trade-Wind.

Achim Woyte obtained the Electrical Engineering degree at the University of Hannover (Germany) in 1997 and the PhD degree in Engineering at the Katholieke Universiteit Leuven (Belgium) in 2003. At the beginning of 2004, Achim Woyte joined the Energy Strategy unit of the technical consultancy company 3E in Brussels (Belgium). As a senior reference expert for renewable energy in power systems he coordinates policy-related European, national and regional projects in renewable energy technology, grid integration and energy markets. His current work covers applied research, product and service development and consultancy for public and private institutions. Within the TradeWind project he is leading the work package on wind energy in power markets.

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The second presentation has been prepared by Daniel Waniek, Ulf Häger, Christian Rehtanz and Edmund Handschin, Dortmund University of Technology, Germany. Daniel Waniek will give it. It is entitled*: Influences of Wind Energy on the Operation of Transmission Systems*

Daniel Waniek received his diploma of economic engineering in the field of European energy management in 2006 from the Dortmund University of Technology, Germany. He is working at the Dortmund University of Technology, Institute for Power Systems and Power Economics, on his doctoral degree in the field of market-oriented planning and operation of dispersed generation in a future energy supply system.

Ulf Häger received his diploma degree in Electrical Engineering in 2006 from the Dortmund University of Technology. He is working at the Dortmund University of Technology, Institute for Power Systems and Power Economics, on his doctoral degree in the field of congestion management by use of dynamic power flow controllers.

Christian Rehtanz received his diploma degree in Electrical Engineering in 1994 and his Ph.D. in 1997 at the Univ. of Dortmund, Germany. From 2000 he was with ABB Corporate Research, Switzerland and from 2003 Head of Technology for the global ABB business area Power Systems. From 2005 he was Director of ABB Corporate Research in China. From 2007 he is professor and head of the Institute for Power Systems and Power Economics at the Dortmund University of Technology. His research activities include technologies for network enhancement and congestion relief like stability assessment, wide-area monitoring, protection, and coordinated FACTS- and HVDC-control.

Edmund Handschin received his diploma in Electrical Engineering in 1965 from the Swiss Federal Institute of Technology, Zurich, Switzerland and his Ph.D. in 1968 from the Imperial College London, United Kingdom. From 1969 until 1974 he was a staff member of the Brown Boveri

Research Center in Baden, Switzerland. From 1974 until 2007 he has been Professor of the Institute for Power Systems and Power Economics at the Dortmund University of Technology, Germany.

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The third presentation is by Krzystof Rudion, Zbigniew Styczynski, Germany, Antje Orths, Denmark, and Olaf Ruhle, Germany. It is entitled: *Tool for the Aggregation of Wind Farm Models.*

Krzysztof Rudion studied electrical engineering at Wroclaw University of Technology, Poland and Rostock University of Technology, Germany. He graduated in 2003 from Wroclaw University of Technology with a Dipl.-Ing. degree. He then joined the Department of Electric Power Networks and Renewable Energy Sources at Otto-von-Guericke University, Magdeburg, Germany as a research engineer. His primary field of interest is dispersed generation with a focus on wind energy.

Zbigniew Antoni Styczynski became in 1999 the Head and the Chair of Electric Power Networks and Renewable Energy Sources, Faculty of Electrical Engineering and Information Technology, Otto-von-Guericke University, Magdeburg, Germany. Since 2006 he has been also President of the Center of the Renewable Energy Saxonia Anhalt. His special field of interest includes electric power networks and systems, expert systems and optimization problems. He is senior member of IEEE, PES, member of CIGRE SC C6, VDE ETG und IBN and fellow of the Conrad Adenauer Foundation.

Antje Orths (M'01) joined the Planning Department (Analysis and Methods) of Energinet.dk, the Danish TSO for Electricity and Gas in 2005. Before, she was researcher at the OvG-University Magdeburg, Germany, where she finished her PhD in electrical engineering. She was head of the group Critical Infrastructures at the Fraunhofer Institute "IFF" in Magdeburg. Her special fields of interests include electric power networks and systems, modeling of dispersed energy resources, distribution network planning and optimization problems. She is member of the IEEE-PES, VDE-ETG and CRIS.

Olaf Ruhle received his Dipl.-Ing. and Ph.D. degrees in electrical engineering from the Technical University of Berlin in 1990 and 1994, respectively. Since 1993 he is a member of Power Transmission and Distribution Group and the System Planning Department at Siemens, Erlangen, Germany. He is working as a Senior Consultant/Senior Product Manager on power system stability, dynamics of multi-machine systems, control, optimization, and identification problems in electrical power systems. He is responsible for the program System PSS™NETOMAC Support, sale and training worldwide. He is visiting professor at several universities.

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The fourth presentation has been prepared by Christoph Weber, University of Duisburg-Essen, Germany. It is entitled***:** Valuation of Variability and Unpredictability for Electricity Generation.*

Christoph Weber holds a Diploma degree in mechanical engineering from the University of Stuttgart, Germany and a Ph.D. in economics from the University of Hohenheim, Germany. Currently he is full professor for management sciences and energy economics at the University of Duisburg-Essen, Germany. His research interest is on the application of mathematical models to describe liberalized energy markets.

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The next presentation has been prepared by Matthias Lange and Ulrich Focken from Energy & Meteo Systems, Oldenburg, Germany. It is entitled***:*** *New Developments in Wind Energy Forecasting.* Matthias Lange will present it.

Matthias Lange and Ulrich Focken are co-founder of Energy & Meteo Systems, a German SME specialized on meteorological services for use in the Power Industry. Energy and Meteo Systems offers innovative services and developments to all points concerning the integration of renewable energy sources into the power supply. The main area of business specifically centers on energy meteorology, i.e. the refinement of meteorological information for the energy community. The two are also authors of the 2005 book published by Springer: “Physical Approach to Short-Term Wind Power Prediction”

Matthias Lange studied physics in Oldenburg (Germany), Warwick (UK) and Marburg. A scholarship recipient of the “German Foundation for the Environment” (Deutsche Bundesstiftung Umwelt - DBU) he was awarded a doctorate in 2003 by the Carl von Ossietzky Universität Oldenburg on the subject of the uncertainties of wind power prediction.

Before co-founding Energy & Meteo Systems in 2004, he was project leader for the grid integration and prediction of wind energy at the ForWind center for wind energy research. Prior to that he conducted on-location surveys for wind power facilities. Furthermore, Matthias Lange one of the co-developers of the wind power prediction system Previento and as such works for its transfer into operational service.

Ulrich Focken studied physics at the Carl von Ossietzky Universität Oldenburg. He began setting the focal point of his studies in physical-meteorological exploitation of renewable energies at an early stage. His diploma thesis and dissertation were on the determination of wind potential in complex terrain and wind power predictions.

Before founding the company in 2004, he was project leader for grid integration and prediction of wind energy at the Oldenburg Center for Wind Energy Research ForWind. He also worked several years as a surveyor of international wind park projects, among others, for the German Wind Energy Institute (DEWI). Ulrich Focken was significantly involved in development of the wind power prediction system Previento as well as its conversion into operational service.

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The sixth presentation is entitled *Selected Studies on Offshore Wind Farm Cable Connections - Challenges and Experience of the Danish TSO.* It has been prepared by Wojciech Wiechowski, and Peter Børre Eriksen from Energinet.dk, Denmark.

Wojciech Wiechowski joined the Planning Department (Analysis and Methods) of Energinet.dk, the Danish TSO for Electricity and Gas in 2006. Before he was an Assistant Professor at Aalborg University,Denmark, where he received a PhD degree. From 2001 to 2002 he worked for HVDC SwePol Link as a Technical Specialist. His current responsibilities include various harmonic, transient and dynamic studies related to integration of wind farms and incorporation of long AC cable links into the Danish transmission network.

Peter Børre Eriksen is head of Analysis and Methods, Planning Department, Energinet.dk, the Danish Transmission System Operator for Electricity and Gas. After a career in system planning with the Danish utility ELSAM he joined Eltra, the former Western Danish TSO in 1998, where he was leading the Development Department from 2000 until 2005. Peter Børre Eriksen is author of numerous technical papers on system modeling.

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The penultimate presentation is made by Wil Kling from the Dutch TSO TenneT, The Netherlands.

It is co-authored by W. L. Kling, TSO, Delft University, The Netherlands; M. Gibesco, B. C. Ummels and R. L. Hendriks, TenneT, TSO, The Netherlands, Madeline Gibescu, Bart Ummels, and Ralph Hendriks, Delft, University, The Netherlands. It is entitled: *Implementation of Large-Scale Wind Power in the Dutch Power System*.

Wil L. Kling received his M.Sc. degree in electrical engineering from the Technical University of Eindhoven The Netherlands, in 1978. Since 1993 he has been a (part time) professor in the Department of Electrical Engineering at Delft University of Technology in the field of Power Systems Engineering. In addition, he is with the Transmission Operations Department of TennetT, the Dutch TSO. Since 2000, he has also been a part-time professor at the Technical University of Eindhoven. His area of interest is related to planning and operations of power systems. Prof. Kling is involved in scientific organizations such as CIGRE and the IEEE. As Netherland's representative, he is a member of CIGRE Study Committee C6 Distribution Systems and Dispersed Generation, and the Administrative Council of CIGRE.

Madeleine Gibescu received her Dipl.Eng. in Power Engineering from the University of Politehnica, Bucharest in 1993 and her MSEE and Ph.D. degrees from the University of Washington in 1995 and 2003, respectively. She has worked as a Research Engineer for Clear-sight Systems of Kirkland, Washington and as a Power Systems Engineer for the AREVA T&D Corp. of Bellevue, Washington, U.S. She is currently an Assistant Professor with the Electrical Power Systems Group of Delft University of Technology, Netherlands. She is a member of IEEE. Her research interests include power system economics, system security under open access and operations planning for systems with significant wind power.

Bart C. Ummels received the M.Sc. degree in Systems Engineering, Policy, and Management in 2004 from Delft University of Technology, Netherlands, where he is currently working towards his Ph.D. degree. He has done internships at Eltra, TSO, Western-Denmark (now Energinet.dk) and KEMA T&D Consulting, Netherlands. He is engaged in wind power integration studies with the Dutch Transmission System Operator, TenneT. His current research interests include long-term power system stability, wind power/power system interactions and power system operation in deregulated environments. He is a member of the IEEE.

Ralph Hendriks has worked as a research assistant at Delft University of Technology, The Netherlands since 2005, where he is currently completing his Ph.D. He is involved in a research project on the combination of cross-border inter-connectors and offshore wind farms, based on high-voltage direct-current technology. He is also a consultant with the network consulting group of Siemens Power Transmission and Distribution, Erlangen, Germany, where he is working on grid integration of renewable energy sources.

The final presentation has been prepared by Olivier Chatillion and Dietmar Graeber, EnBW Transportnetze AG, Stuttgart, Germany. It is entitled: *Efficient Management of Wind Energy Infeed at a Large German TSO*

Olivier Chatillon is head of the department 'market processes' with EnBW Transportnetze AG, the TSO of Baden Württemberg, Germany. He is in charge of the risk management and procurement of ancilliary services such as network losses and balancing power, so as congestion management and wind management. He formerly worked for the french TSO RTE and the french utility EDF, has an

MBA from HEC (France) and an engineer degree from the Ecole Centrale Paris (France) and the University of Stuttgart (Germany).

Dietmar Graeber is an Analyst in the department 'market processes' with EnBW Transportnetze AG, the TSO of Baden Württemberg, Germany. He has been working on the management of fluctuating energy input from renewable sources. He studied economics and business administration at the University of Hohenheim, Stuttgart and Kyushu University, Japan.
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BIOGRAPHIES

Thomas James Hammons (F'96) received the degree of ACGI from City and Guilds College, London, U.K. and the B.Sc. degree in Engineering (1st Class Honors), and the DIC, and Ph.D. degrees from Imperial College, London University.

He is a member of the teaching faculty of the Faculty of Engineering, University of Glasgow, Scotland, U.K. Prior to this he was employed as an Engineer in the Systems Engineering Department of Associated Electrical Industries, Manchester, UK. He was Professor of Electrical and Computer Engineering at McMaster University, Hamilton, Ontario, Canada in 1978-1979. He was a Visiting Professor at the Silesian Polytechnic University, Poland in 1978, a Visiting Professor at the Czechoslovakian Academy of Sciences, Prague in 1982, 1985 and 1988, and a Visiting Professor at the Polytechnic University of Grenoble, France in 1984. He is the author/co-author of over 350 scientific articles and papers on electrical power engineering. He has lectured extensively in North America, Africa, Asia, and both in Eastern and Western Europe.

Dr Hammons is Chair of International Practices for Energy Development and Power Generation of IEEE, and Past Chair of United Kingdom and Republic of Ireland (UKRI) Section IEEE. He received the IEEE Power Engineering Society 2003 Outstanding Large Chapter Award as Chair of the United Kingdom and Republic of Ireland Section Power Engineering Chapter (1994~2003) in 2004; and the IEEE Power Engineering Society Energy Development and Power Generation Award in Recognition of Distinguished Service to the Committee in 1996. He also received two higher honorary Doctorates in Engineering. He is a Founder Member of the International Universities Power Engineering Conference (UPEC) (Convener 1967). He is currently Permanent Secretary of UPEC. He is a registered European Engineer in the Federation of National Engineering Associations in Europe.

Antje Orths joined the Planning Department (Analysis and Methods) of Energinet.dk, the Danish TSO for Electricity and Gas in 2005. Before, she was a researcher at the OvG-University Magdeburg, Germany, where she finished her PhD in Electrical Engineering She was head of the group Critical Infrastructures at the Fraunhofer Institute "IFF" in Magdeburg.

Her special fields of interests include electric power networks and systems, modeling of dispersed energy resources, distribution network planning and optimization problems. She is member of the IEEE-PES, VDE-ETG and CRIS.

Christoph Weber (M' 07) holds a Diploma degree in mechanical engineering from the University of Stuttgart, Germany and a Ph.D. in economics from the University of Hohenheim, Germany.

Currently he is full professor for management sciences and energy economics at the University of Duisburg-Essen, Germany. Prior to this he worked as researcher and research group leader at the Institute for Energy Economics and Rational Use of Energy in Stuttgart, Germany. He has been involved and directed himself research projects with European and national government support in a broad field of energy economics including energy demand, energy efficiency policy, climate change and liberalized electricity markets. He also does many studies in cooperation with energy companies in Germany and abroad. Currently he is among others directing the project “SUPWIND - Decision Support for Large Scale Integration of Wind Power”, funded by the European Union under the Sixth Framework Program, aiming at developing methods and tools to support grid operators and other stakeholders to cope with large amounts of fluctuating wind power. His principal overall research interest is on the application of Operations Research Methods to analyze energy systems and energy markets.

Christoph Weber is author/co-author of more than 150 scientific papers and member of IEEE-PES as well as of other engineering and economic associations including IAEE, VDI, VfS, VHB and GOR. He currently is on the board of the GEE, the German branch of IAEE.

1. INTEGRATION OF WIND ENERGY IN EUROPE'S POWER SYSTEMS: TRANSMISSION INFRASTRUCTURE AND MARKET DESIGN REQUIREMENTS (INVITED DISCUSSION)

Frans van Hulle, European Wind Energy Association (EWEA), Belgium and Achim Woyte, 3E NV, Brussels, Belgium.

(Discussion Pending—Should be available April 20 2008)

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2. Influences of Wind Energy on the Operation of Transmission Systems

Daniel Waniek, Ulf Häger, Christian Rehtanz and Edmund Handschin, University Dortmund, Germany

***Abstract*--**In this work the impact of wind energy on the power flow is analyzed. After the development of a reduced sample network, possible network congestions are identified and the costs for the required redispatch of the generation are evaluated. To avoid or reduce the probability of congestions, different network upgrades can be installed. The efficiency of additional lines and power flow controlling devices is discussed on the basis of power flow calculations and dynamic simulations.

***Index Terms*—**Power flow analysis, power flow control, power generation dispatch, power system economics, wide area networks, wind energy

1. INTRODUCTION

THE increasing installed wind capacity leads to new challenges for the operation of transmission systems. Especially the generated electricity of large offshore wind parks has to be transported on long distances to the load centers. In addition to the regional mismatch of generation and load the time mismatch due to the fluctuations of the actual feed-in from wind energy converters has to be regarded. As shown in [1], the integration of wind energy leads to high costs for the system operators. Trading transactions based on different forecasts are necessary and also the dimensioning of operating reserves is influenced by the uncertainties of the wind feed-in.

Besides this integration process, the wind feed-in influences the operation of the transmission system. The connecting lines between the offshore areas and the load centers are not designed for high transits. These high loadings might lead to congestions in the system. To solve possible bottlenecks, short-, middle- and long-term measures are available. On a short-run the system operator is able to redispatch the generation. The installation of power flow controlling devices (PFCs) can lead to a reduction of the bottleneck and has the advantage of a relatively fast implementation. To avoid permanent congestions it is necessary to develop new lines. Due to approval procedures, the project duration might reach more than ten years. The three mentioned measures will be presented in detail and their benefits will be estimated.

2. FEATURES OF THE REDUCED SAMPLE NETWORK

The analysis in this work is performed with a reduced sample network that represents typical situations of the German transmission system. In this chapter, the development of this network and the required data are described. Besides the network topology also the cost functions of the generators are important for the presented model.

2.1 Estimation of the required network data

The power flow analysis in this work is carried out with a reduced sample network. This network was developed to reproduce realistic situations of the present German transmission system in a simplified form. Later on in this work, different network upgrades are respected. As detailed network data is not publicly available, it is necessary to approximate the 220- and 380-kV-system with public information. In this work, especially the north south connections to transport the future offshore wind energy from the North and Baltic Sea are relevant to analyze the influence of the fluctuating wind feed-in. Furthermore, also the connections between the Rhine and Ruhr Area (increased power generation with lignite and hard coal in the future) and the load centers in the south are regarded. In this context, the abandoning nuclear energy in Germany is important as it leads to a considerable change of the allocation of power generation.

For the development of the reduced sample network, the real nodes are locally merged, e.g. the concentrated generation at the Rhine and Ruhr Area is represented by one node. The resulting line lengths are estimated on the basis of network maps (fig. 1) to provide a representative image of the German transmission system. The resistance per length of a 380-kV-system is assumed with R’ = 0.025 Ω/km, the reactance with X’ = 0.25 Ω/km and the shunt admittance with B’ = 4.3 µS. The maximum line current is 2600 A corresponding to an apparent power of about 1700 MVA. In addition to that, selected 220-kV-systems are modeled to evaluate the replacement of such a system with a 380-kV-system. The parameters are not constant in this case because the system is simulated in general with 380 kV. Therefore, a 220-kV-connection is modeled with the line itself and transformers at the beginning and the end of the line. These connections have high impedances so that the loadings are comparatively low.

Fig. 1. German transmission system (source: UCTE)

The allocation of the loads is carried out according to data of the entire UCTE area in [2]. This approach evaluates the regional allocation with an assumed proportionality between population and electric load. The transits to the neighboring countries are modeled as positive or negative network supplies. The utilization of the UCTE dataset has the advantage that for a given load scenario the resulting imports and exports are known.

In spite of the reduction to 28 nodes, fig. 2 shows that the relevant connections can be identified. Hence, the impact of the wind feed-in and the affectivity of network upgrades can be analyzed. The wind feed-in is applied in nodes 1, 3, 4, 5 and 6 as the existing wind energy converters in the southern regions will have a comparatively low relevance in the future. These converters also contribute to the supply of the local loads and therefore have a negligible impact on the regarded power flows. The largest generation capacity is located in node 10, representing the power plants at the Rhine and Ruhr Area. This node is defined as the slack node for the power flow calculations.

Besides the network topology and the load and transit scenario, the feed-in from conventional power plants and its future development is essential for the analysis of possible congestions. For the present situation a detailed dataset of the power plants is available. The included units can be differentiated between installed capacity, fuel type and age. With the help of geographical material, these units are assigned to the nodes of the sample network.

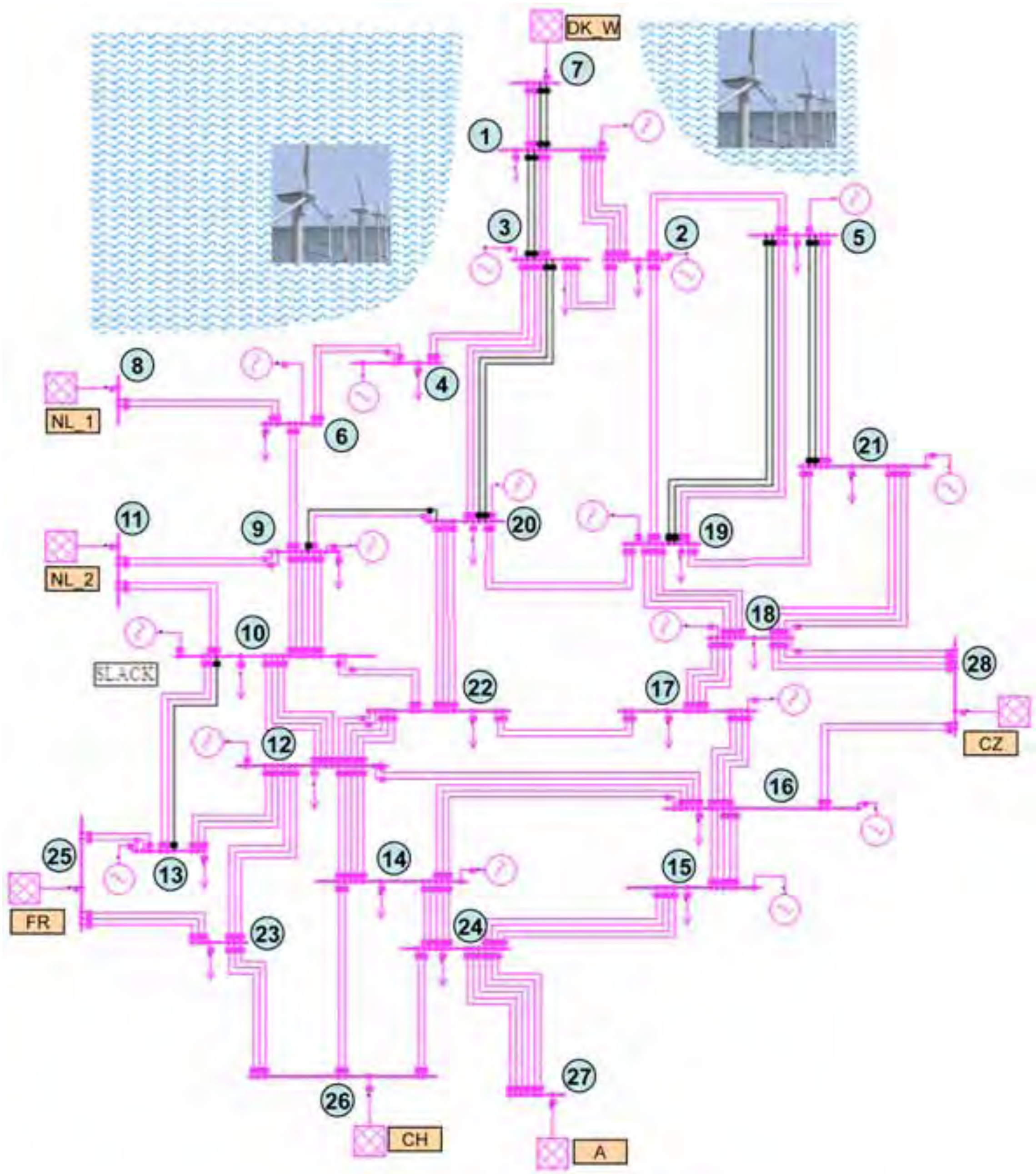

Fig. 2. 28-node sample network

For the future development of the power plant mix no overall and exact prognoses of every single station are known. Therefore, the allocation is carried out according to global data given in table I [3], planned investments and own appraisals.

TABLE I

DEVELOPMENT OF THE POWER PLANT MIX IN GERMANY (IN GW)

		2005	2010	2015	2020
Nuclear	Inst. capacity	21.5	17.4	14.1	7.1
	Removal		-4.1	-3.3	-7.0
	Change		-19.1%	-34.4%	-67.0%
Lignite	Inst. capacity	22.0	21.2	16.1	15.3
	Installation		2.7	1.1	0.0
	Removal		-3.5	-6.2	-0.8
	Change		-3.6%	-26.8%	-30.5%
Hard coal	Inst. capacity	29.4	30.8	33.9	30.1
	Installation		10.4	4.6	0
	Removal		-9.0	-1.5	-3.8
	Change		4.8%	15.3%	2.4%
Natural gas	Inst. capacity	23.3	29.7	36.3	47.6
	Installation		13.4	9.3	12.1
	Removal		-7.0	-2.7	-0.8
	Change		27.5%	55.8%	104.3%
Wind energy	Inst. capacity	18.4	24.4	28.4	32.7
	Installation		6.0	4.0	4.3
	Change		32.6%	54.3%	77.7%
Total	Inst. capacity	114.6	123.5	128.8	132.8
	Change		7.8%	12.4%	15.9%

The net generating capacity in Germany grows from 2005 to 2020 by over 15 %. The reliably available capacity is almost constant as the fluctuating wind energy is not always available.

2.2 Assumptions for the cost functions of the generators

For every analyzed load scenario and for a given wind feed-in, a merit order of the conventional power plant is set up on the basis of marginal costs. With this, the actual feed-in of every generator and the resulting feed-in at the nodes is calculated. The feed-in of the last power plant type in the merit order is prorated to the appropriate nodes. This approach provides that the load less the wind feed-in and the transit balance is met exactly. To avoid that the slack generator exclusively covers the network losses, an estimated value of the losses is added to the load. The assumed efficiency factors η and the marginal costs of the regarded power plants are listed in table II. The fuel specific CO_2-emissions thereby are rated with a constant price of 20 €/t.

TABLE II

MARGINAL COSTS OF THE REGARDED POWER PLANTS

	Fuel price €/MWh	η %	Fuel costs €/MWh	CO_2-em. t/MWh	CO_2-costs €/MWh	Marg. costs €/MWh
Nuclear	3.00	33	9.09	0.00	0.00	9.09
Lignite (new)	3.00	44	6.82	0.92	18.48	25.30
Lignite (old)	3.00	37	8.11	1.10	21.97	30.08
Hard coal (new)	9.50	46	20.65	0.73	14.54	35.20
Hard coal (old)	9.50	37	25.68	0.90	18.08	43.76
Gas-steam (new)	23.10	58	39.83	0.35	6.94	46.77
Gas-steam (old)	23.10	45	51.33	0.45	8.95	60.28
Gas turbine (new)	24.30	35	69.43	0.58	11.51	80.94
Gas turbine (old)	24.30	28	86.79	0.72	14.39	101.17

To estimate the costs for increasing and decreasing the output power in case of a redispatch, different cases have to be considered. If an additional generator is started, the fuel and start-up costs less the saved fuel costs in the decreased generator have to be calculated. Thereby, the lowered efficiency of the generators in partial load is also relevant. If a generator is already in partial load before the redispatch to provide a reserve, the lost revenues in this situation have to be priced. This illustration shows that the actual re-dispatch costs depend on various factors that cannot be estimated if only independent scenarios and no continuous time period are simulated. Therefore, the costs for increase and decrease, respectively, are assumed with ±10 % of the marginal costs. Different tests show that this value is a rather conservative estimation and the actual price the system operator has to pay to the operator of a generator depends on the closed contract.

With these assumptions the free capacity in every node can be interpreted as an offer to increase the output power with the appropriate specific costs. The actual capacity in use is accordingly an offer to reduce the output power. This results in the strictly monotonic increasing function shown in fig. 3 at the right. The different offers produce an hourly, nodal cost function due to the changing output power [4].

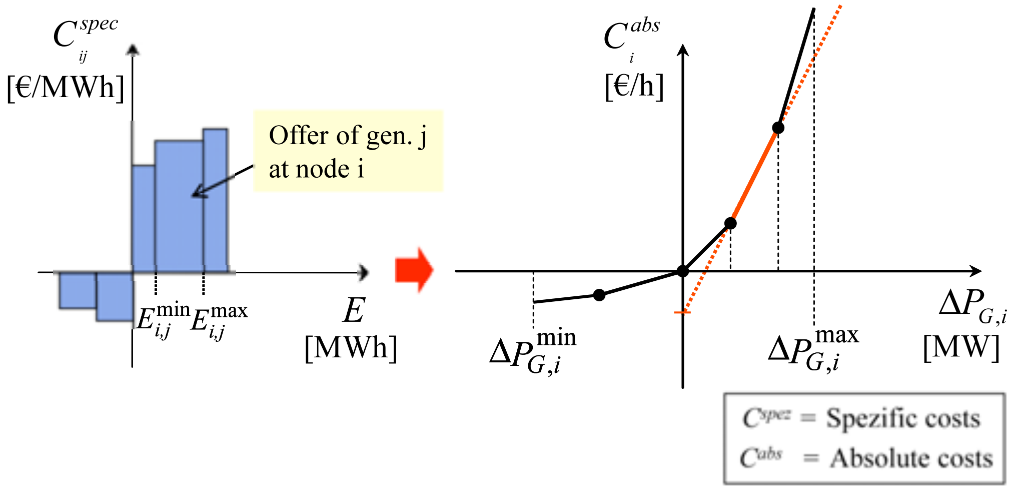

Fig. 3. Derivation of the nodal redispatch costs

Network congestions are defined as situations in which the transmission system does not comply with the (n-1)-criterion. This might be the case for high wind feed-in in the northern nodes so that the surplus of power in this region cannot be transported to the south. Thereby, a single failure of every north south connection is simulated and the remaining lines are checked for overloads. If at least one line is overloaded, the output power of the conventional power plants in the north has to be reduced and increased in the south, respectively, until the (n-1)-security is ensured again. According to the notation in fig. 3, the following optimization problem results for the redispatch:

$$f(\Delta P_{G,i}) = \sum_{i=1}^{n} C_i^{abs}(\Delta P_{G,i}) \overset{!}{=} \min \qquad (1)$$

The required change of output power in the nodes has to be provided with minimum total costs to comply with the (n-1)-criterion of the transmission system.

3. ESTIMATION OF THE ANNUAL REDISPATCH COSTS

In this chapter the frequency of possible network congestions based on development scenarios of the power plant fleet in Germany is estimated. The main influencing factor on the congestions is the feed-in from wind energy converters. It changes the entire merit order and is therefore used to specify the frequency of the congestions. In a first step, the maximum feed-in to barely guarantee the (n-1)-security is identified. For a higher feed-in the resulting costs of the required re-dispatch are calculated in a second step. Based on a reference case, the effects of different network upgrades on the congestion costs are evaluated.

3.1 Weighting of the calculated situations

For the estimation of the average annual redispatch costs on the basis of hourly costs, an appropriate weighting of the calculations is required. A first subdivision is done with three regarded load scenarios:

- Winter peak (15 % → 1314 h/a)
- Winter off-peak (35 % → 3066 h/a)
- Summer (50 % → 4380 h/a)

For each of these scenarios the maximum wind feed to comply with the (n-1)-criterion is identified. Followed by that, two situations with higher feed-ins are simulated and the resulting costs for the redispatch are calculated. The weighting of these three situations results from the frequency distribution of the wind feed-in according to fig. 4. The maximum feed-in in this example is 46 % related to the installed wind capacity. This value corresponds to a probability of 95.8 % that no congestion and therefore no redispatch costs occur. Under the assumption that the probability of a feed-in above 70 % of the installed capacity is negligible, the frequency distribution is liberalized in two sections between the identified value (46 %) and the possible maximum (70 %). In this example, two situations with 52 % and 64 % feed-in, respectively, are simulated (‘Red 1’ and ‘Red 2’) leading to a weighting of ‘Red 1’ with 2.8 % and ‘Red 2’ with 1.4 %.

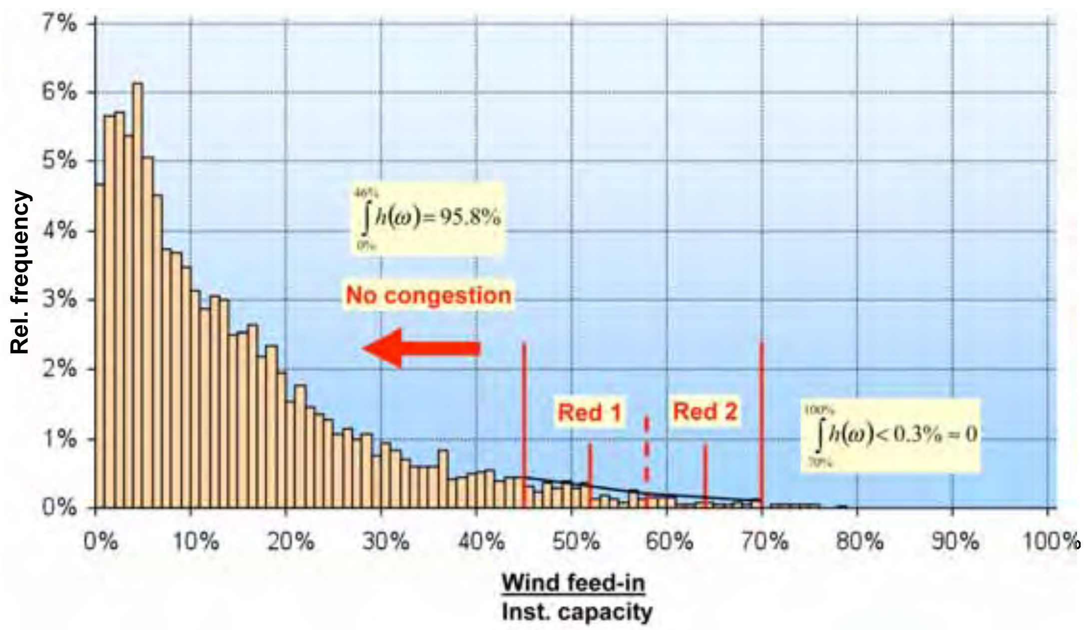

Fig. 4. Weighting of the calculations based on the frequency distribution of the wind feed-in

3.2 Redispatch costs in the reference case

As demonstrated in the prior chapter, the annual redispatch costs consist of two situations with a required redispatch for each of the three load scenarios. The frequency of congestion on the north south connections and the resulting average annual costs for the re-dispatch are summed up in fig. 5.

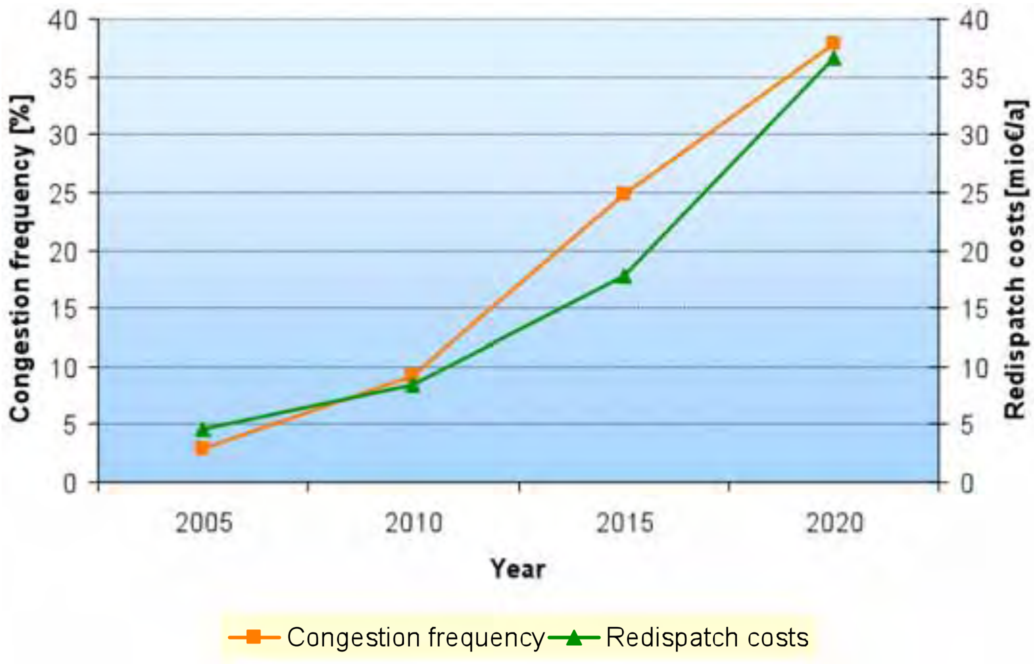

Fig. 5. Congestion frequency and redispatch costs in the reference case

In this reference case no upgrades of the network are regarded, so that also in 2020 the network is the same as shown in fig. 2. This methodology is used to quantify the effect of network upgrades at different dates, although it is obvious that the transmission system will change during the regarded 20 years. This fact also explains the considerable increase of frequency and costs in 2015 and 2020 due to the high installed wind capacity in northern Germany and the further changes of the power plant mix. From chapter IV on, the calculations are based on a network scenario representing the year 2015 to estimate the benefit of the installation of PFCs.

In addition to the analyzed congestions on the north south connections, the future loading of the lines from the Rhine and Ruhr Area towards southeast is estimated. Currently there are no congestions but for the future a considerably higher loading is expected. This results from the replacement of nuclear power plants mainly located in the south by coal-fired power plants in the Rhine and Ruhr Area. The power flow calculations depend on the wind feed-in but the main influencing factor is the transit situation towards France and the Netherlands. For this purpose, the transits are varied according to [5] to represent situations with a high export from Germany as well as a high import to Germany. The assumed values are listed in table III.

TABLE III
VARIATION OF THE TRANSIT SITUATION (IN MW)

	Transit 1 (high export)		
	Winter peak	Winter off-peak	Summer
Transit_F	-666	-991	86
Transit_NL1	-1648	-1280	-792
Transit_NL2	-3297	-2559	-1583
	Transit 2 (high import)		
	Winter peak	Winter off-peak	Summer
Transit_F	2964	2794	3620
Transit_NL1	-634	-610	-377
Transit_NL2	-1269	-1220	-754

The power flow calculations show that the regarded lines are not overloaded in any situation. In 2020, the connection between nodes 10 and 22 has a maximum loading of about 91 % in case of an outage of the second system. This loading refers to a situation with high load (winter peak), low wind and high import. With a high wind feed-in, the loading decreases to 89 %. In case of high export the maximum values are between 88 and 85 %. The loadings decrease considerably for lower load situations.

3.3 Redispatch costs after network upgrades

Based on the calculations for the reference case, the effects of two network upgrades on the congestion frequency and the redispatch costs are analyzed. These upgrades are the replacement of a 220-kV-doublesystem with a 380-kV-doublesystem and the development of a new 380-kV-doublesystem. Both upgrades represent measures to strengthen the north south connections as only these connections show congestions. The upgrades have the following features:

- Upgrade 1: Replacement of 220 kV with 380 kV on a length of 120 km between nodes 3 and 20, leading to investment costs of about 36 mio€ and annual operating costs of about 0.36 mio€/a;
- Upgrade 2: Development of a new 380-kV-doublesystem on a length of 60 km between nodes 4 and 20, leading to investment costs of about 42 mio€ and annual operating costs of about 0.42 mio€/a.

The investment and operating costs are based on values given in [6]. For the analysis only one of the measures is installed at a time. The results are shown in fig. 6, analogue to the diagram of the reference case. Both network upgrades considerably decrease the congestion frequency and the resulting costs with a little advantage for the development of a new connection. The frequency with the upgrades is about one third of the frequency in the reference case and the costs are less than one fourth. From 2015 on, the system operator saves more than 10 mio€ of redispatch costs per year. Compared to the investment and operating costs, a payoff of these upgrades can be reached in several years.

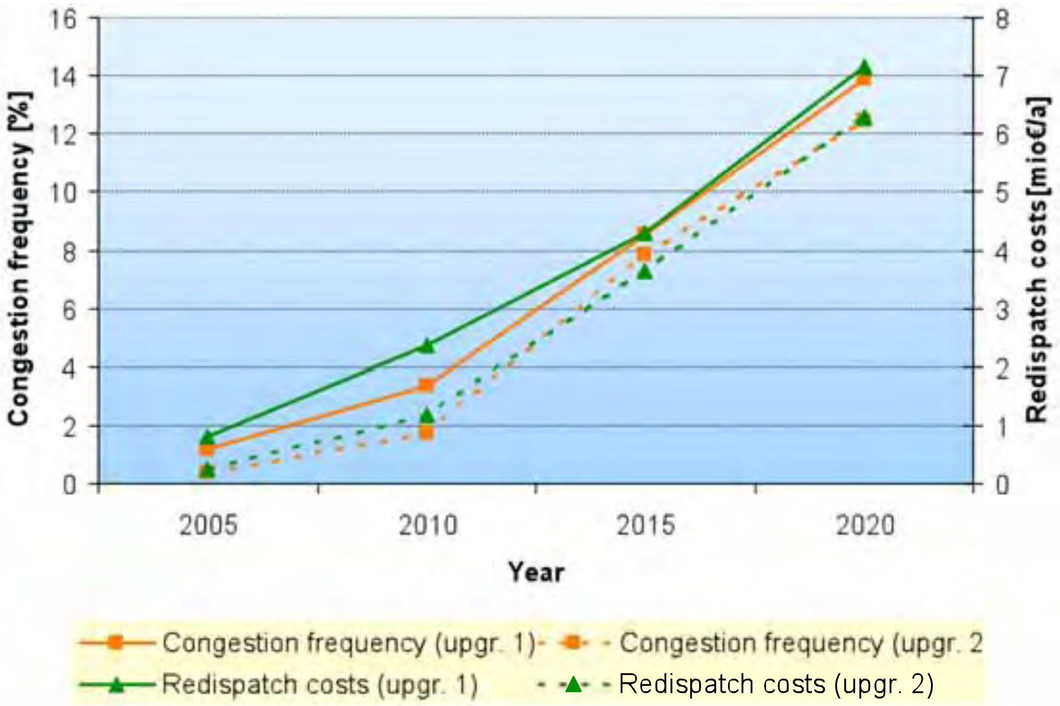

Fig. 6. Congestion frequency and redispatch costs with network upgrades

The cash flow for the system operator and the possible payoff of the analyzed network upgrades strongly depend on the regulatory conditions and therefore vary in different countries. Even in Germany the accounting and acceptance of the cash flow changes is not defined precisely and purpose of various expertises at present.

4. COORDINATION OF POWER FLOW CONTROLLING DEVICES

To reduce the frequency of congestion new investments into the transmission system are needed. The prior presented measures are linked with the establishment of new or with the upgrade of existing transmission lines. The approval procedure for a new trace is very difficult and takes many years. Even the replacement of a 220-kV-line with a 380-kV-line is a very time consuming project. To bridge the time gap until extensions of the transmission system are fulfilled, an installation of PFCs can help to reduce the bottleneck. These PFCs can be used to shift the power flow from a highly loaded transmission line to a parallel path with free capacity to get a higher utilization of the existing lines [7]. If the installation of several PFCs with a mutual influence of adjacent units is planned, also the implementation of a coordination procedure is needed to get the highest possible rise of transfer capability [8].

In the following chapters, the presented sample network is provided with fast PFCs. Dynamic simulations are performed to assign the possible decrease of the congestion frequency by this measure. As coordination method for the PFCs, the so-called autonomous wide area control, presented in [9], is used. Its basic idea is to generate a set of generic rules for every PFC device. For the implementation of this method, a sensitivity analysis has to be performed to determine the lines that can be influenced by every PFC. The loading measurements of these lines are then the input values for the control of the PFC. The influence able lines can be classified into lines that either belong to the control path or lines that belong to a parallel path of the PFC, according to fig. 7. The control path is a transmission path in which a PFC is installed and which only has junctions at its end-nodes. A parallel path is a transmission path between the same end-nodes as the control path and in which no PFC is installed.

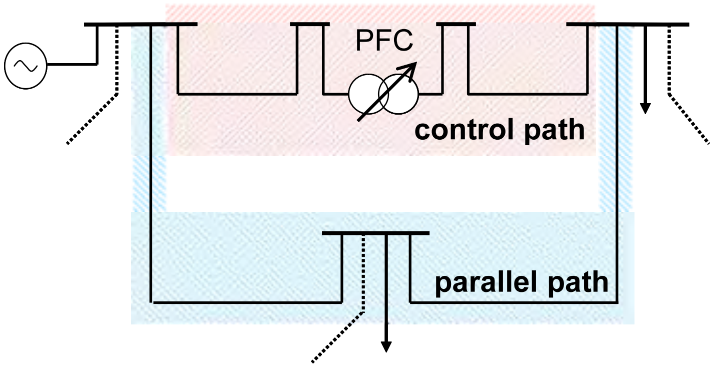

Fig. 7. Example for the control and parallel path of a PFC

Feeding the PFC with the following three coordinating rules performs the control:

1. IF a device on the control path or on a parallel path of a PFC is overloaded, THEN modify the set point-values of the PFC;
2. IF there is a failure of a device on a parallel path AND no further parallel path exists for a PFC THEN deactivate the PFC;
3. IF a short circuit happens on a control path or on a parallel path of a PFC, THEN slow down the operating point control of the PFC.

The control circuit for the autonomous wide area control is illustrated in fig. 8. Its target is to control the input value of the PFC to regulate the active power transmission over a line to its highest possible value without violating its maximum current carrying capacity. To implement this behavior, the reference value for the active power transmission is determined in the block “set point calculation” by clearing the measured reactive power with the maximum apparent power of the line according to (2) and (3).

$$S_{\max} = \sqrt{3} \cdot I_{\max} \cdot U_n \quad (2)$$

$$P_{ref} = \sqrt{S_{\max}^2 - Q_{act}^2} \quad (3)$$

The control deviation between actual and reference value is then passed to the input of the PFC and the resulting power flow situation is looped back inside the control circuit by the measurement of the active and reactive loading of the controlled line. The choice of the controlled line is performed by the coordinating rules of the autonomous wide area control.

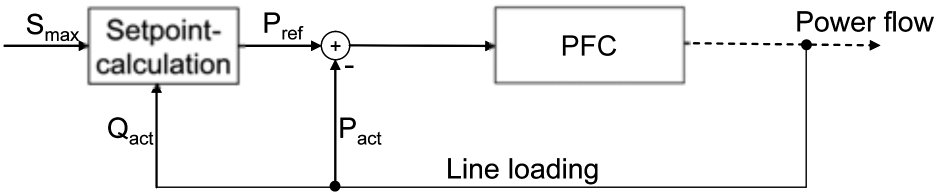

Fig. 8. Control circuit for the autonomous wide area control

5. ALLOCATION OF THE POWER FLOW CONTROLLING DEVICES IN THE NETWORK

The simulations with PFCs are based on the German network situation as it is expected to be in the year 2015, according to [10]. This approach is chosen because different network upgrades are already decided and no comparison between time points is necessary. The most important upgrades for the congestion corridor are:

- Development of a new 380-kV-doublesystem on a length of 60 km between nodes 4 and 20;
- Development of a new 380-kV-doublesystem on a length of 200 km between nodes 6 and 10;
- Development of one additional 380-kV-doublesystem between nodes 20 and 22;
- Development of one additional 380-kV-doublesystem between nodes 1 and 3;
- Installation of PFCs between nodes 4 and 6.

Fig. 9 shows the northern part of the sample network including the network upgrades for the 2015 scenario. The illustrated percentile line loadings are the results of a power flow calculation with a wind feed-in of 70 % related to the installed wind capacity. This situation indicates the highly stressed lines that have to be controlled by the PFCs. Besides the already planned PFCs between nodes 4 and 6, three additional pairs of PFCs are suggested. All PFCs are placed on the lines in west-eastern direction, interconnecting the highly stressed lines. A sensitivity analysis shows that the devices placed in this position have a higher influence on the neighboring lines as if they are placed directly on the stressed lines in north-southern direction. In this way a better flexibility in the operation of the devices can be reached.

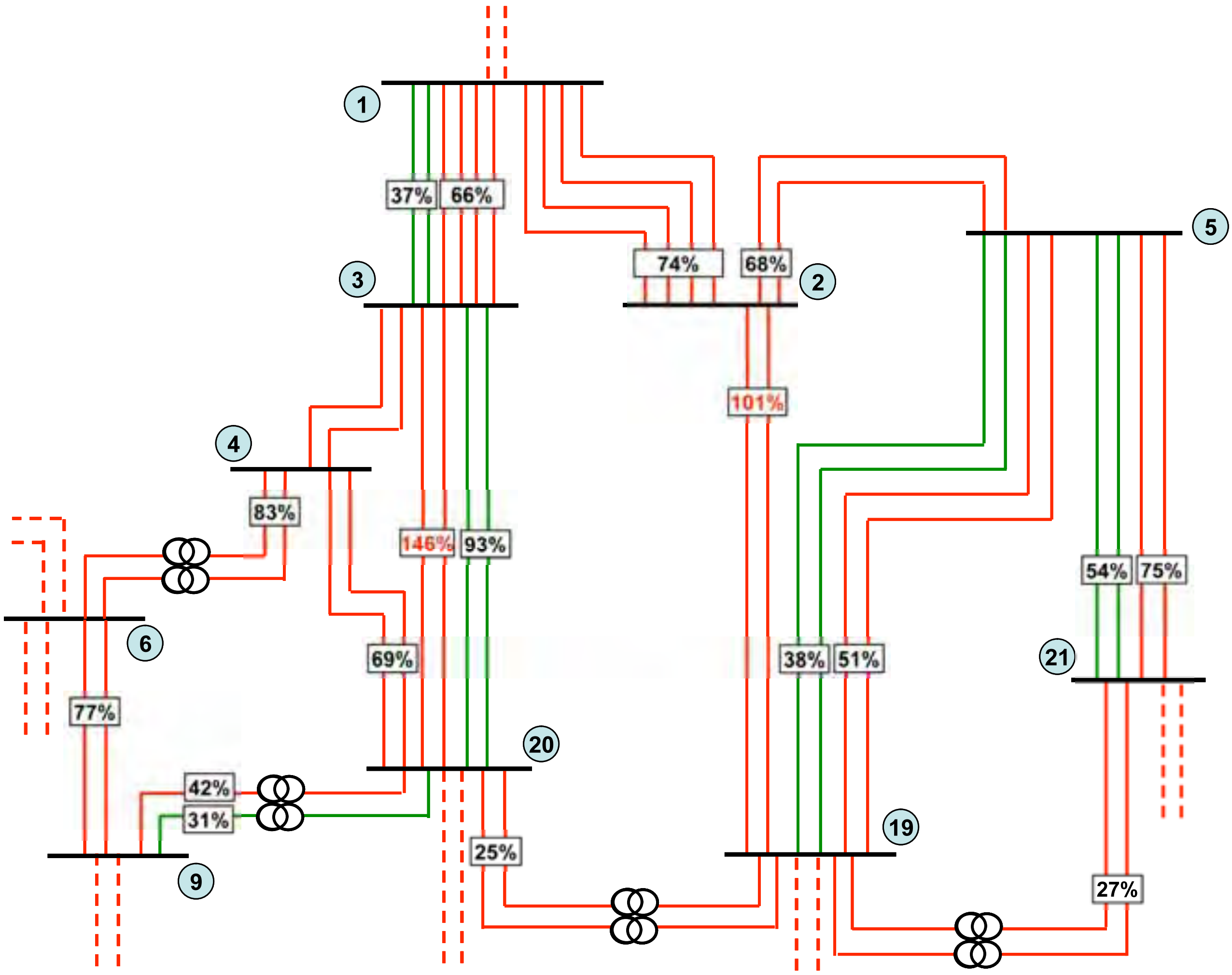

Fig. 9. Northern part of the sample network including the network upgrades for the 2015 scenario and the positions of all suggested PFCs

6. DYNAMIC SIMULATIONS

To determine the value of different combinations of the suggested PFCs, simulations are performed with a wind feed-in rising continuously from 0 % to 100 % related to the installed wind capacity. At first, the progression of the line loadings of some important lines (the four lines with PFCs and the two most stressed lines) are shown in fig. 10 for the reference case without the use of any power flow controlling device. This progression is strongly nonlinear because of the given merit order model. By executing similar simulation for all (n-1)-cases, the resulting maximum wind feed-in is 16 % related to the installed wind capacity. The limiting (n-1)-case is the outage of one 380-kV-system connecting the nodes 3 and 20.

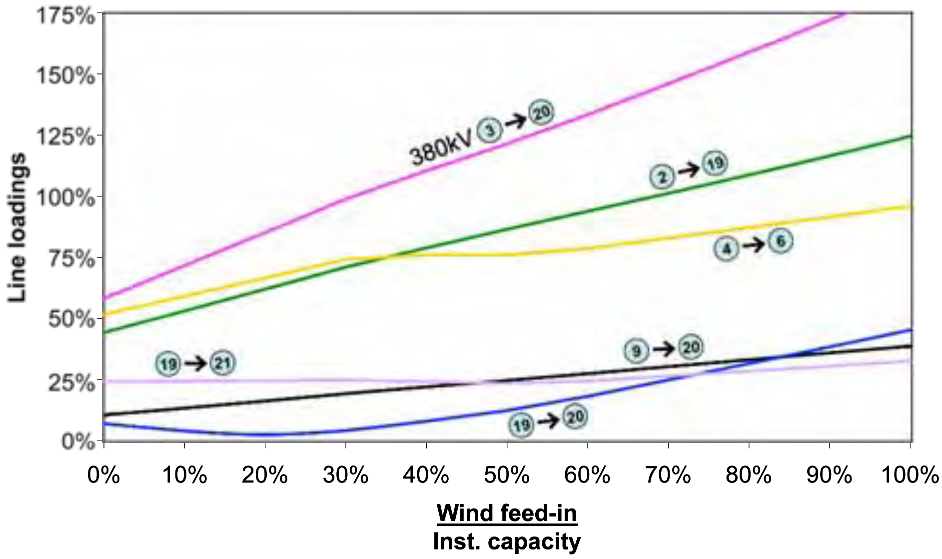

Fig. 10. Progression of the line loadings over the amount of wind feed-in without PFCs

To illustrate the behavior of the coordination procedure, fig. 11 and fig. 12 show the rising wind feed-in simulation for a coordinated operation of all suggested PFCs. Fig. 11 presents the progression of the percentile line loadings while fig. 12 shows the progression of the control values of the PFCs. These figures are separated into five sections. In the first section all PFCs are in initial state because none of the transmission lines is overloaded. When the 380-kV-lines between nodes 3 and 20 reach their maximum loading at the border between section one and two, all PFCs except the devices between nodes 19 and 21 begin to regulate the power flow to provide a constant loading on these lines in the second section. In the third section also the loading of the lines connecting nodes 4 and 6 reach their limits and the PFCs connected to these lines change the regulation direction to decrease the loading on their control path. When also the capacity of the lines between nodes 2 and 19 is exploited in section four, the last PFCs begin to regulate. In the beginning of section five the PFCs between nodes 9 and 20 as well as 19 and 21 have reached their control limit and the control path of the PFC between nodes 19 and 20 has reached its maximum loading. Thus, the power flow over the highly stressed lines cannot be controlled any more and a further increase of wind feed-in leads to an overloading of these lines.

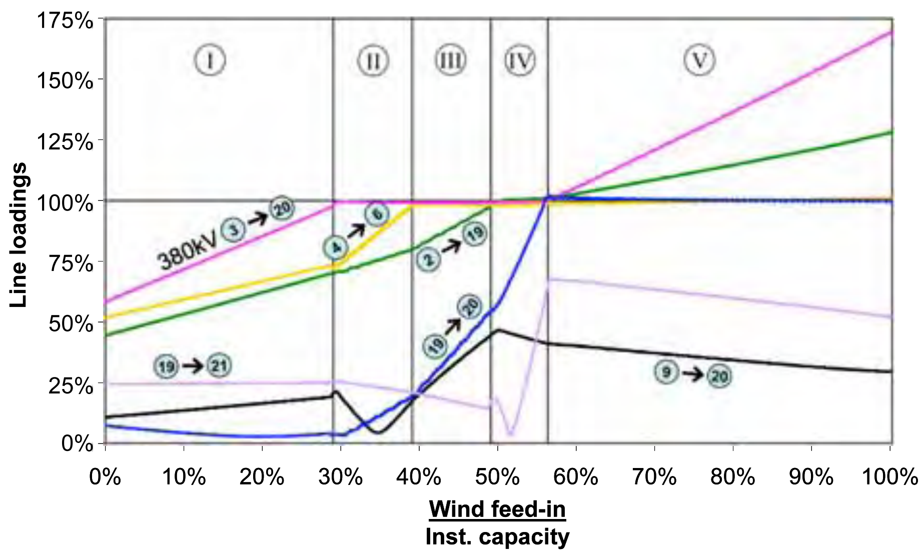

Fig. 11. Progression of the line loadings over the amount of wind feed-in with PFCs

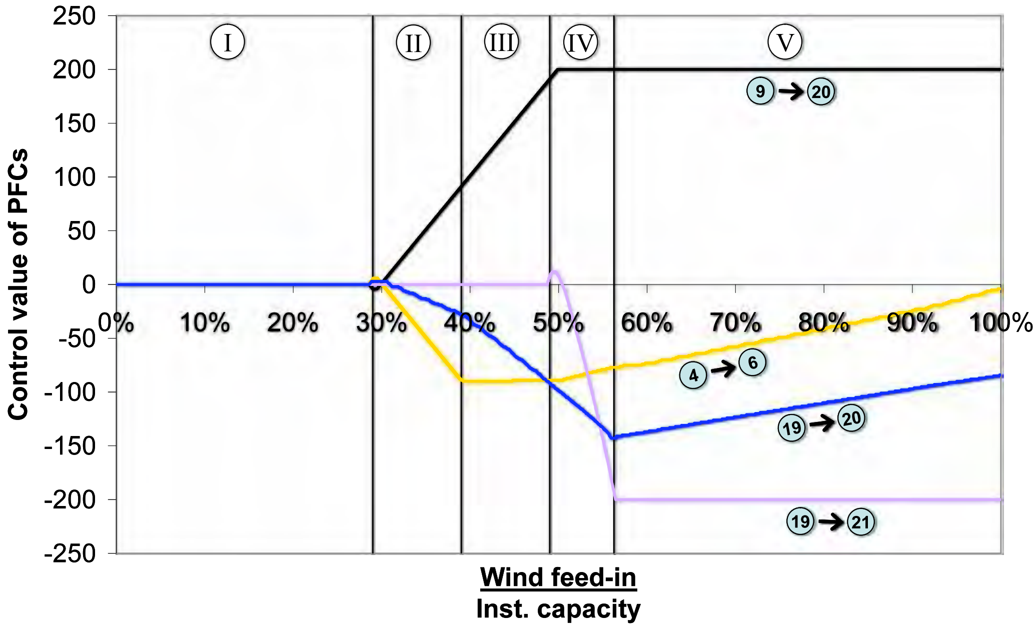

Fig. 12. Progression of the control values of the PFCs over the amount of wind feed-in

By performing the rising wind feed-in simulation for several combinations of PFC installations, the maximum wind feed-in is calculated with respect to (n-1)-security. The results are presented in table IV. For all PFC combinations the outage of one 380-kV-system connecting the nodes 3 and 20 is the limiting case. Adding the PFCs between the nodes 4 and 6, as it is already planned by the TSOs, a first rise of transmission capability can be reached in comparison to the case without PFCs. In the next step only the installation of the PFCs between nodes 19 and 20 is beneficial for limiting the congestion. It is obvious that the devices between nodes 19 and 21 do not have any influence on the limiting line between the nodes 3 and 20. As third stage of expansion these PFCs lead to a further increase of transmission capability. Adding the PFCs between the nodes 9 and 20 is not sufficient for this congestion corridor because they have similar control features like the already installed PFCs between nodes 4 and 6.

With the installation of PFCs between the nodes 19 and 20 as well as 19 and 21 in addition to the already planned PFCs, a raise of the maximum relative wind feed-in from 16 % to 39 % can be reached leading to a considerable decrease of congestion probability.

TABLE IV

TRANSMISSION CAPABILITY OF THE SAMPLE NETWORK FOR DIFFERENT COMBINATIONS OF PFC INSTALLATIONS

PFC installations				Max. wind
04→06	09→20	19→20	19→21	feed-in
				16%
x				21%
x	x			21%
x		x		35%
x			x	21%
x		x	x	39%
x	x	x	x	39%

7. CONCLUSIONS

The analysis shows that several bottlenecks can be expected in the future in the German transmission system. The main influencing factor is the rising installed wind capacity in the northern part of Germany, especially caused by large offshore wind parks. The present network is not dimensioned for these challenges. One the one hand, this leads to high redispatch costs for the system operator and on the other hand, different network upgrades are required. The reduced redispatch costs can cover the investment costs for the development of new lines but due to the time consuming approval procedure temporary measures are required. In this time period the installation of PFCs can increase the transmission capacity.

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BIOGRAPHIES

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Edmund Handschin received his diploma in electrical engineering in 1965 from the Swiss Federal Institute of Technology, Zurich, Switzerland and his Ph.D. in 1968 from the Imperial College London, United Kingdom. From 1969 until 1974 he was a staff member of the Brown Boveri Research Center in Baden, Switzerland. From 1974 until 2007 he has been Professor of the Institute for Power Systems and Power Economics at the Dortmund University of Technology, Germany.

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3. MaWind--Tool for the Aggregation of Wind Farm Models

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Abstract— The existing software for the simulation of power system operation was mainly developed and optimized for the analysis of conventional systems that are characterized by a low number of large, central synchronous generators. New forms of power generation, like wind turbines, that are characterized by a high number of small units cannot be analyzed effectively with this software. In this paper a new software tool, MaWind, for the aggregation of wind farm models for dynamic system analysis is described. The MaWind tool uses a new mathematical approach to represent wind generation in system analysis. The background of this method, the method itself and some representative results of the calculation with MaWind are presented in the paper. MaWind allows for significant reduction of the model complexity while retaining a good approximation of dynamic farm behavior at the same time.

Index Terms – Power system, wind farm, model aggregation, dynamic simulation**.**

1. INTRODUCTION

The planning and secure operation of the power system became a complex challenge for system operators when the number of installed wind turbines and their capacity reached a significant level in some European countries, like Germany, Denmark and Spain. Currently, the number of installed wind turbines in Germany alone has reached a level of over 19000 units with total capacity of over 21 GW [1] whereas the peak load equals about 84 GW. In Denmark, for example, there are already situations where the power produced by wind turbines exceeds the power demand [2]. According to the European Wind Energy Association there are now about 50 GW of wind generation in Europe and there will be an additional 70 GW from offshore wind farms (WF) by the year 2020 [3].

Compared to the large conventional power plants, which are characterized by a high rated power of installed generators and a relatively low number of units spread over a defined area, e.g. over a country, the wind turbines have a low rated power of individual units but their number is very high. Moreover, the power produced by wind turbines has, in general, a non-controllable stochastic character since it depends on the weather conditions, while the output power of the conventional generation units can be controlled according to the existing demand. Since in the power system there must be a continuous balance between power demand and generation the additional amount of positive and negative reserve power has to be available in the conventional power plants in order to compensate the immediate changes in wind generation. Besides influencing the balance of the power system, the wind turbines influence also its dynamic behavior during fault conditions in a significant manner. Therefore, it is essential to investigate the operation of the power system by means of numerical simulations considering its new components.

The existing tools for simulation and analysis of the power system operation are currently optimized to cope with the conventional power systems where generation is centralized and the number of power

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system components is not very high. Consideration of the additional large number of wind turbines in the power system model would lead to long simulation times and, in some cases, to problems with the numerical stability of the simulation. Therefore, a new tool – MaWind that allows aggregated representation of large wind farms has been developed and is discussed in this paper. The main challenges for the aggregation tool are:

- minimization of simulation duration,
- complexity reduction of wind farm model,
- accurate representation of dynamic behavior,
- consideration of changing weather conditions.

Moreover, the aggregation tool has to be integrated as an extension to the power system simulator, which allows an automatic operation for the different simulation cases. A lower number of equivalent generators and an equivalent grid structure represent the resulting aggregated model of the considered wind farm. The method used in this paper for the aggregation of wind farm models is based on the coherency analysis of individual wind turbines within a farm and includes the influence of the wake effect on the farm operation as well.

2. BACKGROUND OF THE AGGREGATION ISSUE

2.1 Conventional Power Systems

The investigations that have been done on the field of model aggregation and complexity reduction so far are devoted to the conventional power systems that consist only of large synchronous generators. Such systems are characterized by direct dependency between angular speed of the generators and the grid frequency, since the synchronous generators are directly connected to the grid. This means that changes of frequency in an interconnected system result from changes of the angular speed of generators, which in turn, result from unbalance between the mechanical and electromagnetic torque in the event of fault, for example. This fact has been used in some reduction approaches that rely on the analysis of swing behavior of individual synchronous generators initialized by the change of grid voltage – as in the case of fault [4]. Due to the spatial distribution of generators within the grid they can show different swing behavior that is characterized by a different magnitude, frequency and phase. Thus, in order to obtain an appropriate aggregated model only the group of generators that has similar swing behavior can be replaced by an equivalent unit. The first step in the aggregation process is the identification of units with similar dynamic behavior; which means units that are coherent. Next, the parameters of equivalent generators have to be determined and then the structure of the passive grid has to be reduced. The aggregated model obtained in this way has to guarantee the same values of the load flows at the coupling points to the other parts of the considered system model, and in case of dynamic analysis, like fault simulation, it has to deliver similar dynamic behavior. Typical for the discussed aggregation approach is that the whole system has to be modeled first and then its behavior has to be analyzed in order to create the aggregated model. This method can be followed only if the conventional power system, like UCTE without wind generation, is considered. The exemplary model of this system consists of 610 generators, 4400 nodes, 12000 grid branches and 1050 controllers [5]. The detailed consideration of wind generation in Germany alone would require additional implementation of over 20000 WT into the model. Therefore, the optimal solution would be the possibility for the creation of an equivalent farm model without detailed modeling of the whole farm in advance.

2.2 Wind Farms

Most of the wind turbines installed in the last few years are units that operate at variable angular speed [6]. These turbines are usually equipped with doubly fed induction generators (DFIG) or converter driven synchronous generators (SG). In order to allow operation with variable speed the generators are decupled from the grid, which operates at constant frequency in normal state. Therefore, both WT concepts use the power electronic frequency conversion systems with DC-link as a grid interface. Since the frequency converter for the WT with SG has to be dimensioned for the full generator power, the rated power of the frequency converter for the WT with DFIG is only a fraction of the rated generator power, which makes this concept more profitable regarding the network interface.
Due to the different characteristic of WT and conventional power plants the aggregation methods developed for the latter become less meaningful in the new applications including wind generation [7]. The issue of wind farm aggregation has been already investigated in some publications, e.g. [7] - [9]. However, these approaches are usually either not comprehensive, e.g. there is no information about the equivalence of the internal farm grid, or they lead to an equivalent “black-box” model, which does not correspond to the physical structure of the considered farm and is difficult to implement into the professional power system simulator systems.

3. AGGREGATION APPROACH

3.1 General Information

The dynamic behavior of a wind farm depends strongly on the current point of operation of each wind turbine. This point is defined by the electrical and mechanical parameters of WTs, like angular speed, active and reactive power level, and pitch angle. The value of these parameters is directly influenced by the speed of the incoming wind. In the wind farm the wind speeds at the individual wind turbines can have different values since there are strong interactions between WTs that are evoked by the wake effect. This can lead to a situation where some of the wind turbines within a farm are still in partial load operation while the others are already in full load operation. Such turbines have different behavior during a system fault since in the partial load operation the controllers of each WT track the optimal point of operation regarding the produced power, while in the full load operation the main goal for the control system is to keep the produced power and angular speed within the acceptable range. Due to the fact that the operating point of each wind turbine results from the present wind speed value, this variable can be used in order to identify the coherent units. As coherent units, one understands those units that have the same or similar input wind speed and therefore, as already discussed, have the same operating points. Thus, to find the points of operation of an individual WT the wake effect has to be considered. The wake effect describes the mutual interactions between wind turbines within a wind farm. Because of these interactions the wind speed incoming to the wind farm is disturbed when passing through the rotor plane of the WTs. Therefore, the input wind speed of the individual wind turbines that are located in front of the wind farm, with respect to the direction of the incoming wind speed, is higher than the input wind speed of the wind turbines in the middle and in the back of the wind farm, because the units located in the front induce the “wind shadow” for the following units. This shadow is cone-shaped and its parameters are dependent on the wind turbine type as well the type of natural surrounding. In general, the wake effect has a three dimensional character, but such representation is too complex to be included in the power system analysis. Therefore, a simplified representation of the wake effect, e.g. according to the Jensen model [10], that can be considered within the one-dimensional profile of wind speed has to be used, as discussed in [11].

3.2 Coherency Matrix Based Aggregation Approach

In this paper the introduced coherency approach is based on the search for units with similar behavior on the basis of the wind profile. The turbines with a similar wind profile are coherent and belong to one group that is replaced with an equivalent unit. Due to the wake effects within the wind farm the input wind speeds for individual wind turbines are not equal. These wind profiles depend on the direction of the incoming wind to the farm and also on the structure of the farm. In Fig. 1 the groups of turbines obtaining the same input wind speed for two different wind directions are marked. It can be seen that for the first direction (from the left) the turbines belonging to the same column of the farm obtain similar wind profile as input. Analogously, for the second wind direction (from the bottom) the turbines belonging to each row of the farm have similar wind profiles. Hence, for these two cases the groups of the coherent wind turbines can easily be found and correspond to each row, or respectively to each column of the wind farm, as stated in [12]. More complicated situations occur if the wind has a direction different than the basic one (N, S, W, E) – as presented in Fig. 1 or if the farm structure is not symmetric. In this case the turbines located in the middle of the farm can experience the influence of more than one wake, and therefore the detailed analysis of shadowing effects is necessary in order to find the groups of coherent wind turbines. In the example presented in Fig. 1 the different points of operation are marked with OP1 and OP2, respectively. Assuming that the incoming wind speed is lower than the rated one the power produced by the considered wind turbines results from the power curve given in Fig. 2. Additionally, the angular speed of both units can vary according to the curve given in Fig. 3. This results from the fact that the angular speed of the aerodynamic turbine is adjusted by the MPPT – controller in the partial load operation in order to optimize the produced power.

In order to find groups of coherent wind turbines for a given wind farm an appropriate identification algorithm has been introduced and discussed in [11]. The method uses the wake model for calculating the input wind speeds of the individual wind turbines within the farm. Because of the large amount of information obtained from this calculation, a new structure – the coherency matrix - has been introduced in order to manage this information. This matrix is a 3D-object that is filled with the coherency indexes that are assigned to each WT for each considered wind speed and wind direction.

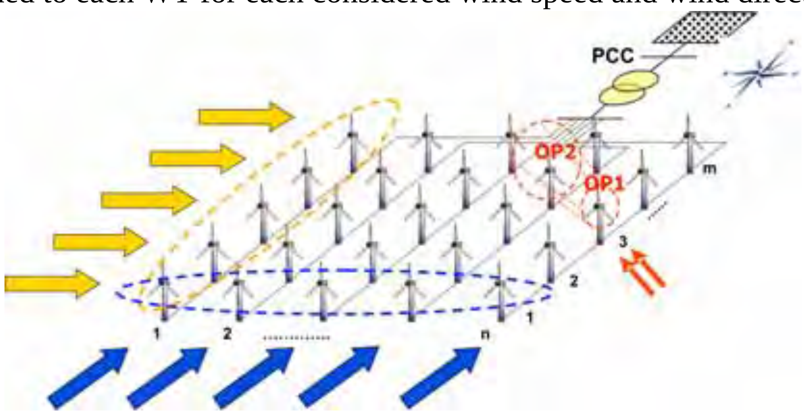

Fig. 1. Influence of wind direction on coherency of WT

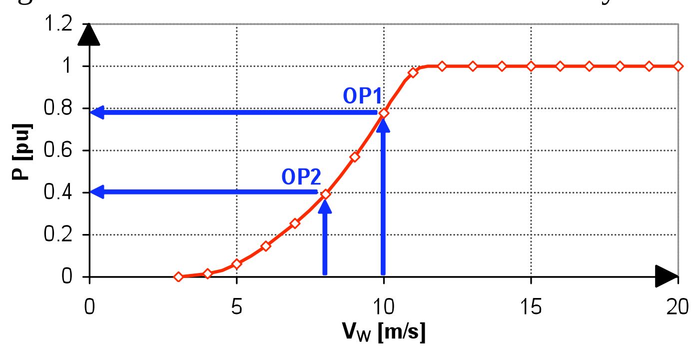

Fig. 2. Power curve of pitch controlled wind turbine

These indexes carry the information about the structure of the aggregated farm. It means that a single equivalent unit in the aggregated farm model can replace each group of WTs that have the same coherency indexes. Moreover, the value of the index can be used to find the resulting wind speed profile for each equivalent wind turbine [11].

The algorithm of the coherency matrix calculation and required input data are shown in Fig. 4. At the beginning, the structure of the farm has to be given and the coordinates of all units and their parameters, like rotor radius and hub height, have to be defined. Additionally, an appropriate profile of the incoming wind has to be characterized. Since the wake characteristics in the farm depend on wind direction and wind speed the whole possible spectrum for the operation range has to be considered.

For wind direction the operation range is between 0° and 360°, and for wind speed this range is assumed to be between 4 – 25 m/s. The lower limit is defined by the cut-in wind speed of the wind turbine and the upper by the cut-off wind speed. Thus, as input for the wake model the wind profile is defined as a step function, which alters within the chosen range with a defined step. For each step of the wind speed the direction is also changed from 0° to 360° with the defined step. As a result of this calculation the characteristic of the wind farm in the whole operation range regarding the input wind speed of individual units is obtained. Then, based on these wind speeds the groups of coherent units can be evaluated.

If the coherency matrix for the considered wind farm is known the structure of the aggregated model can be directly established for a given wind speed and wind direction. This structure is not equal for all parameters of the incoming wind profile and, therefore, always has to be established if the wind profile has new parameters.

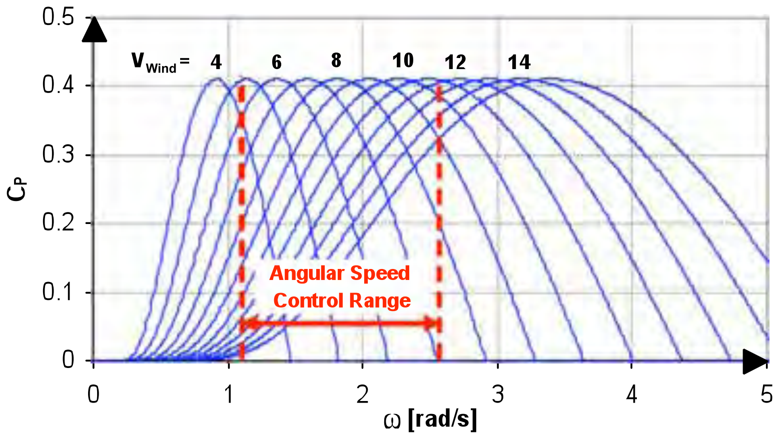

Fig. 3. Power coefficient vs. angular speed for different wind speeds

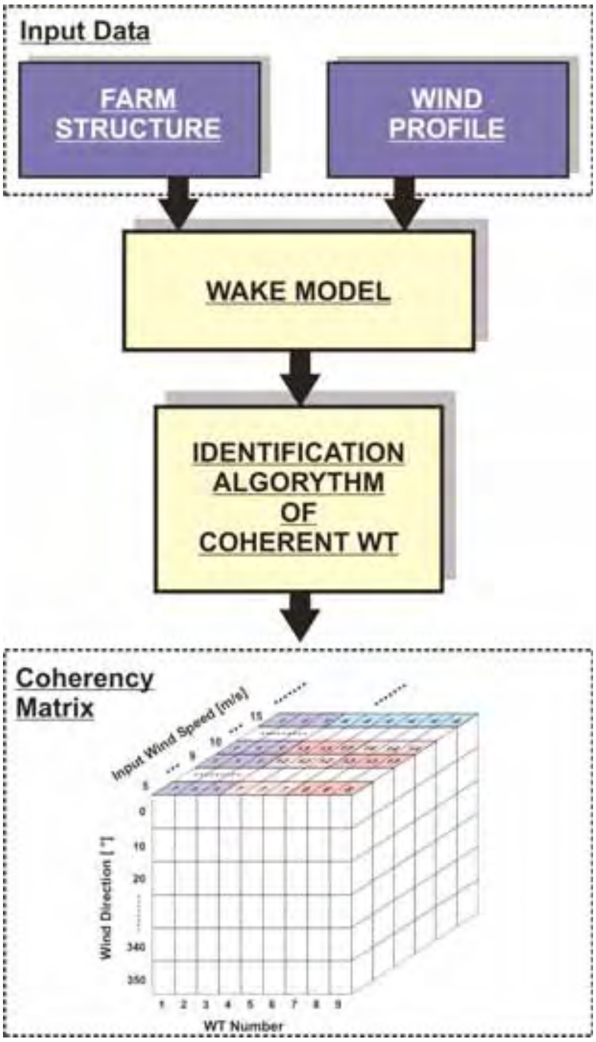

Fig. 4. Calculation algorithm of the coherency matrix

4. DEVELOPMENT OF THE AGGREGATION TOOL - MAWIND

4.1 Aggregation Tool Structure

In order to create the aggregated models of several wind farms that have to be considered in the power system analysis, a new tool – MaWind has been proposed. The general structure of this tool as well as the information flow is presented in Fig. 5. As input to the tool the information about the forecasted wind profiles for the chosen sites is used. This information is provided by the weather services, which employ specific local models with an appropriately high spatial resolution for the weather forecasting. The wind speed and the wind direction can be forecasted for a chosen time point in the future; however, the shorter the time horizon of the forecast, the lower the resulting deviation. The weather services provide the forecasted weather parameters in the form of csv-files that can be then processed in the developed aggregation tool. The forecasted wind profile for each site is assigned by the data manager to the corresponding coherency matrixes which are stored in the data base – the so called coherency matrix set. This matrix set is the main part of the MaWind aggregation tool and it delivers information about the structure of the resulting aggregated model for chosen incoming wind profile. However, this information includes only the number of equivalent wind turbines in each farm, the number of individual units replaced by each equivalent wind turbine as well as the corresponding wind profiles. But, it does not include any information that is needed to represent the equivalent farms in the power system simulator, like the parameters of the equivalent generators, turbines, and controllers as well as the parameters of the equivalent farm grid. In order to specify these parameters the dynamic model generator is used. The input for this dynamic model generator is the information obtained from the coherency matrix set about the structure of the equivalent farm models and the information about the structure of the original grid of each farm as well as about the interconnection point to the main grid. The latter information is included in an additional database. The approach for parameter calculation of the equivalent wind turbines, generators and controllers as well as of the equivalent farm grid is discussed in [13]. In order to allow the use of the MaWind aggregation tool with different power system simulators an additional coupling interface is needed. This interface creates the model of the equivalent wind farm using the power system simulator's specific programming language, such as BOSL in the case of PSS^{TM}NETOMAC [14] or DPL in the case of Power Factory [15].

4.2 Implementation of the MaWind Aggregation Tool

The introduced aggregation tool has been implemented using MATLAB graphic interface builder [16]. The main window of the developed application is presented in Fig. 6. The current version of the tool allows for simultaneous processing of the WTs in the single wind farm and, it is coupled to the program PSS^{TM}NETOMAC.

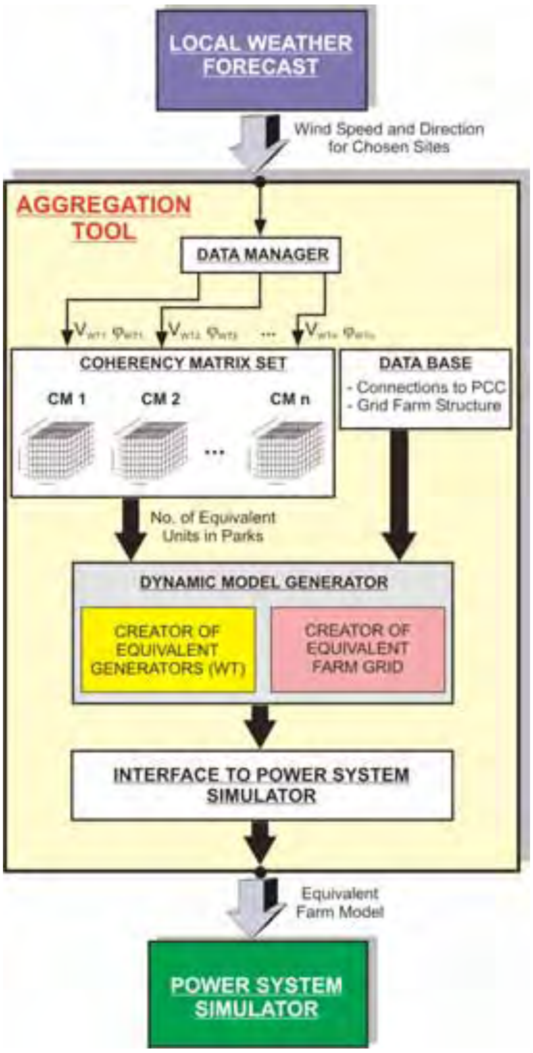

Fig. 5. Structure of the wind farm aggregation tool - MaWind

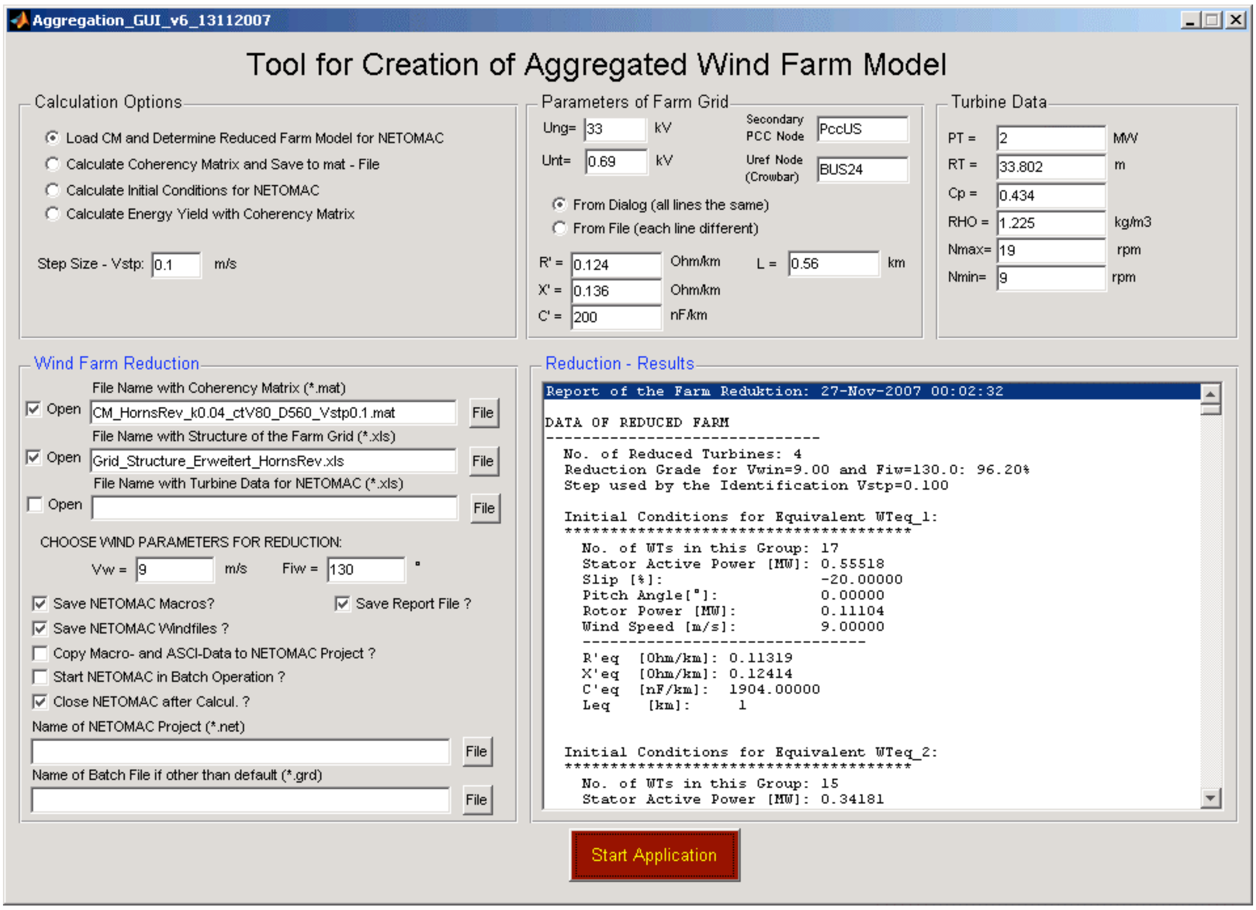

Fig. 6. Main window of the MaWind aggregation tool

The graphic user interface is used to specify parameters of the considered farm on the one hand, and to communicate the parameters of the resulting aggregated farm model in form of a report, on the other hand. The user can choose one of the following calculation options:

- load coherency matrix from file and determine aggregated farm model,
- calculate coherency matrix and save to file,
- calculate initial conditions for power system simulator,
- calculate energy yield using coherency matrix.

The first option is used to create an aggregated farm model for given wind speed and wind direction if the coherency matrix is already known. For this purpose the file containing the coherency matrix has to be specified. As a result of the aggregation process the following actions are available:

- save the report file with general information about the aggregated farm model,
- save the aggregated farm model for use in the power system simulator,
- execute the power system simulator in batch modus.

If a new farm has to be processed and the coherency matrix does not exist yet, the available option can be employed to create it and to store it in a file for future utilization.
Moreover, the tool provides some additional functions, like calculation of the initial conditions for a given wind speed in order to avoid the transients at the beginning of the dynamic simulation and, additionally, it is able calculate the energy yield for a given wind profile considering the wake effects within a farm.

5. TEST SYSTEM AND EXEMPLARY SIMULATIONS

5.1 Test System Used

In order to show the operation of the MaWind aggregation tool an exemplary wind farm has been analyzed. The structure of the chosen test wind farm corresponds, in general, to the Horns Rev offshore farm that is operated in Denmark in the North Sea [17]. It consists of 80 variable speed wind turbines with doubly fed induction generators with a rated power of 2 MW each. The general layout of this farm is shown in Fig. 7. The wind turbines are located in 10 columns and 8 rows at a distance of 560 m to each other. Moreover, the location of single units is not symmetrical within a farm, which has the form of a parallelogram. Each WT – column is twisted at 6 ° counter-clockwise in respect to the vertical axis of the farm (i.e. North – South axis).

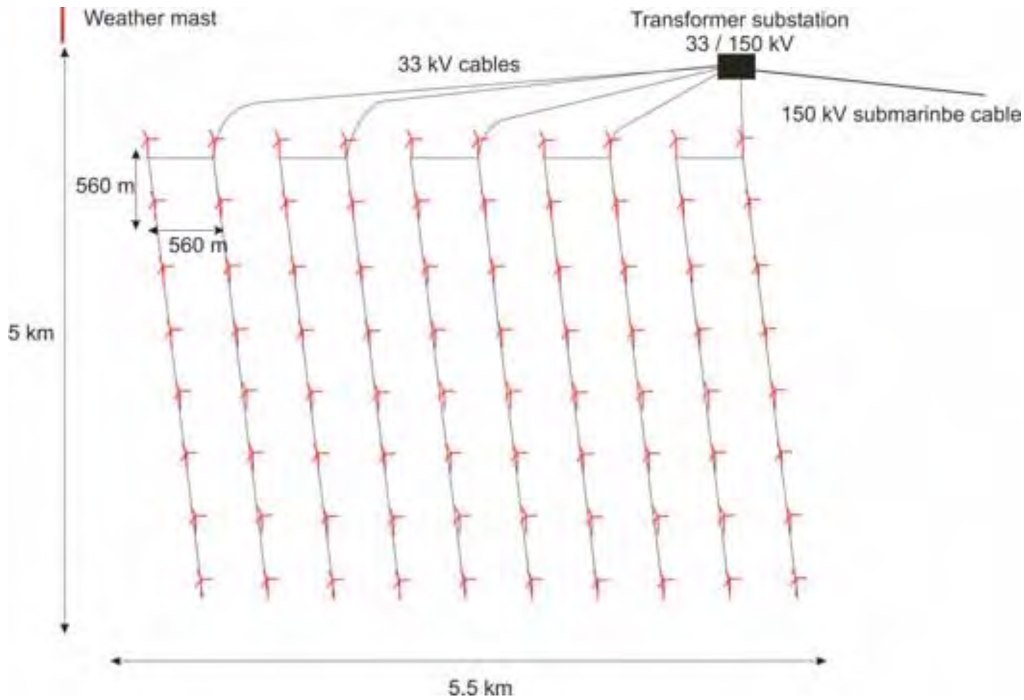

Fig. 7. Layout of the exemplary wind farm (Horns Rev)

TABLE 1
PARAMETERS OF CABLES IN THE TEST WIND FARM

U_{rat}	Cross Section	R’	L’	C’	Length	I_{rat}
[kV]	[mm^2]	[Ω/km]	[mH/km]	[nF/km]	[km]	[kA]
33	150	0.124	0.36	200	0.56	315
150	400	0.047	0.6	150	35	595

The wind turbines are interconnected using a 33 kV cable to the offshore transformer station that steps up the voltage level to 150 kV. The farm is then connected with a 150 kV cable to the transformer station on the shore, which then couples the whole farm to the main power system. In this study, the New England Test System was used as the main power system [18]. The considered wind farm was coupled by a 150/345 kV transformer to bus 24 of this test system. The specific parameters of the used cables correspond to that given in [19] and are summarized in

Table 1. The length of each 33 kV cable was assumed to be the same and equal to 0.56 km. The length of the 150 kV cable was assumed to be 35 km.

5.2 Aggregation of the Farm Model

In the first step of the aggregation process the coherency matrix for the test wind farm was determined according to the algorithm given in Fig. 4. For this purpose the thrust characteristic of the Vestas V80 wind turbine, which is shown in Fig. 8, was used. The obtained matrix was then used as input for the developed aggregation tool. Different wind speeds and different wind directions were used to check the performance of this tool. The results are summarized in

TABLE 2. It can be seen that for the chosen wind speeds and wind directions the whole farm is represented by between 2 and 5 equivalent wind turbines. The resulting number of equivalent wind turbines is not constant in the whole wind direction spectrum, which results from the fact that the intensity of the shadowing effects influencing individual wind turbines changes when the wind direction varies. Moreover, the intensity of the wake effect depends on the wind speed since the employed wake model uses the non-linear thrust characteristic of the wind turbine as a parameter, see Fig. 8.

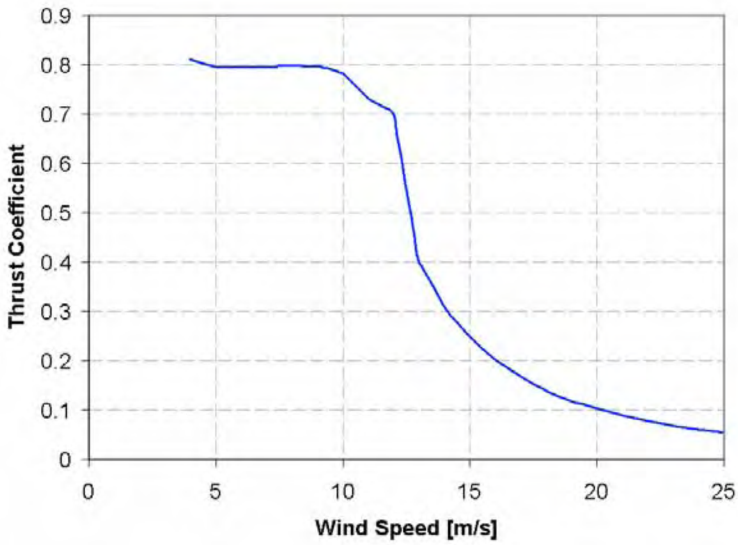

Fig. 8. Thrust characteristic of Vestas V80 wind turbine [20]

TABLE 2
RESULTING NUMBER OF EQUIVALENT WT FOR DIFFERENT WIND SPEED AND DIRECTION

Wind Direction	**V_W= 5**	**V_W= 9**	**V_W= 15**	**V_W= 20**
[°]	**[m/s]**	**[m/s]**	**[m/s]**	**[m/s]**
0	3	2	2	2
30	2	4	2	2
60	3	3	2	2
90	4	5	4	3
120	4	4	4	2
150	2	3	3	3
180	3	2	2	2
210	2	4	2	2
240	3	3	2	2
270	4	5	4	3
300	4	4	4	2
330	2	3	3	3

5.3 Dynamic Simulation

The introduced exemplary wind farm and the New England Test System are used to perform the analysis of the dynamic behavior in the event of a fault. For this purpose a three-phase short circuit is simulated in node 16. The residual voltage during the fault at the point of common coupling of the wind farm is equal to ca. 0.15 pu. The duration of the short circuit is set to 200 ms. The simulation results are presented in Fig. 9 for the point of common coupling of the farm to the main grid at 345 kV voltage level. For the analysis three different models of the farm are used. The first simulation is performed using a detailed farm model that consists of 80 individual wind turbines. The resulting curves obtained with this model are used as reference for evaluation of aggregated farm models and are marked by the suffix – “det”. The second simulation is carried out using a single unit equivalent model of the wind farm. In this model the whole wind farm is represented as one single equivalent unit and the wake effects are not considered in the calculation. In Fig. 9 the curves representing this simulation case are marked by the suffix – “sgu”. The single unit representation of the whole wind farm is a traditional approach used by system analysis. The last simulation is performed using the aggregated farm model obtained from the developed aggregation tool. In this case the number of equivalent wind turbines representing the whole farm depends on the wind direction and wind speed defined as input to the farm. The corresponding curves are marked by the suffix – “agg”. The dynamic analysis has been made for wind speed equal to 11m/s and wind direction equal to 90°. The resulting charts of voltage, current, active and reactive power in PCC show that the single unit equivalent model of the farm introduces significant deviations compared to the detailed model, while the model obtained with the MaWind tool shows very good agreement with the detailed model. The aggregated model consists of five equivalent units for the chosen wind profile. The strong deviations in the single unit equivalent are present because the wake effects are not considered and thus, information about operating points is lost.

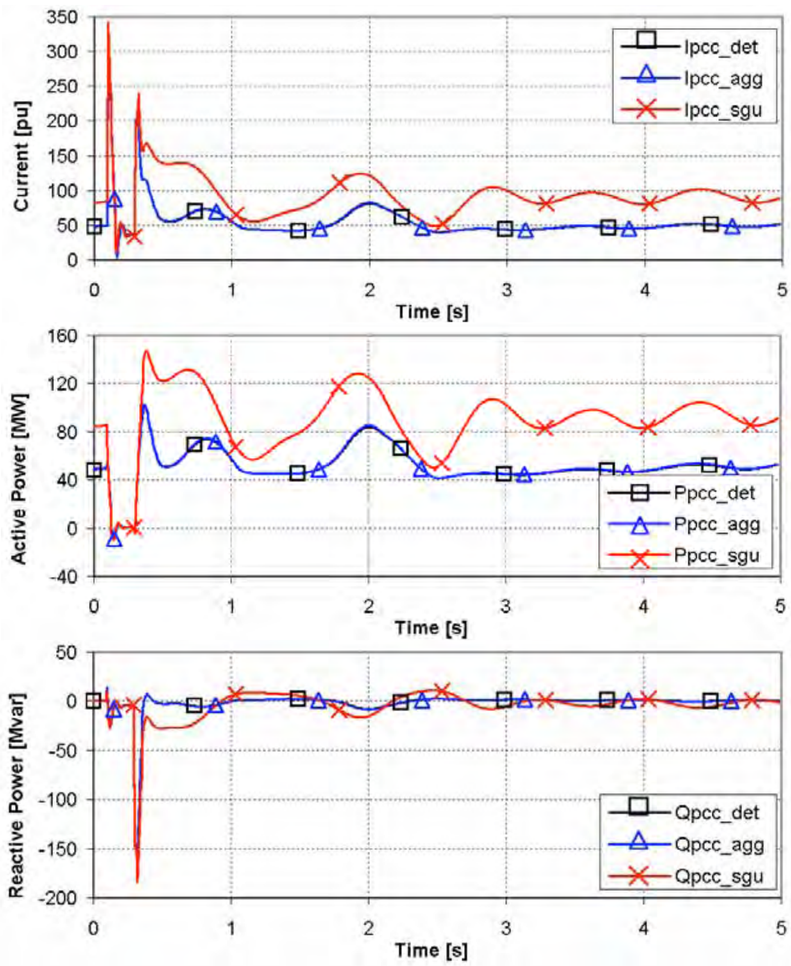

Fig. 9. Simulation results for the point of common coupling of wind farm in the event of a three-phase fault at node 16 (t_{fault} =200ms)

6. CONCLUSIONS

In this paper a novel tool for the aggregation of wind farm models - MaWind - was introduced. This tool uses the coherency approach to aggregate wind farm models. It allows for automated reduction of the farm model complexity for given wind speed and wind direction. The implemented reduction algorithms first establish the structure of the equivalent farm and then determine the parameters of the equivalent turbines, generators and controllers as well as the parameters of equivalent farm grid. Moreover, the MaWind tool is coupled with the power system simulator in order to analyze power system behavior taking into account wind farms. The exemplary simulation results show that the aggregated model obtained with the MaWind tool represents the dynamic behavior of the farm with a high degree of accuracy in the case of fault analysis. However, the proposed tool can only be applied to wind farms that consist of one type of wind turbine. It has been tested using wind farms containing variable speed turbines with doubly fed induction generators.

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8. BIOGRAPHIES

Krzysztof Rudion studied electrical engineering at the Wroclaw University of Technology, Poland and the Rostock University of Technology. He graduated in 2003 at the Wroclaw University of Technology with a Dip.-Ing. Degree. He then joined the Chair of Electric Power Networks and Renewable Energy Sources at the Otto-von-Guericke-University Magdeburg, Germany as a research engineer. His primary field of interest is wind energy.

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Antje G. Orths (M’2001) joined the Planning Department (Analysis and Methods) of Energinet.dk, the Danish TSO for Electricity and Gas in 2005. Before this, she was a researcher at the OvG-University Magdeburg, Germany, where she finished her PhD in electrical engineering. She was also head of the group Critical Infrastructures at the Fraunhofer Institute "IFF" in Magdeburg. Her special fields of interests are electric power networks and systems including the implementation of wind energy, modeling of dispersed energy resources, distribution network planning and optimization problems. She is member of the IEEE-PES, VDE-ETG and CRIS.

Olaf Ruhle received his Dipl.-Ing. and his Ph. D. degree in electrical engineering from the Technical University of Berlin in 1990 and 1994, respectively. Since 1993 he has been a member of the Power Transmission and Distribution Group and the system-planning department at Siemens in Erlangen, Germany. He works as a Senior Consultant / Senior Product Manager on power system stability, dynamics of multi-machine systems, control, optimization and identification problems in electrical power systems. He is responsible for the program system PSS™NETOMAC support, sale and training worldwide. He is also visiting professor at several universities.

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4. Valuation of Variability and Unpredictability for Electricity Generation

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Abstract—In this paper the costs of integrating fluctuating sources like wind or solar into an existing electricity system are quantified using a systematic, theoretically well-founded approach. The paper notably stresses that this requires measuring integration costs against some reference technology and it highlights the link between integration costs and changes in system costs. The costs related to wind and solar integration is furthermore decomposed into several components, including notably the costs of variability and the cost of unpredictability. It is then discussed, how a rough assessment of these cost components may be obtained using peak-load pricing concepts. But it is then highlighted that a detailed assessment requires stochastic optimization approaches.

Index Terms: wind energy, electricity markets, renewable energy sources, stochastic optimization

Nomenclature:

C	total cost in (Mio.) €
c	specific cost per kW or kWh
C^*	optimal system cost
C_{Int}	integration cost
K_{PL}	installed capacity
t	time
y	production output

Indices:

Add	additional
Inv	investment
Op	operation
u	unit
t	time

1. INTRODUCTION

With wind and solar energy getting increasingly popular as ecological, emission free energy sources, the question is gaining importance, whether the inherent fluctuations in their production don't make them very poor substitutes of conventional, controllable electricity production from coal, gas and other power plants. In other terms, one might ask whether the installation of wind and solar, being costly by itself, does not induce further costs necessary for ensuring that these fluctuating sources adequately contribute to the overall power supply system. These costs are often summarized under the general term of "integration costs".

In Europe, a first detailed discussion and quantitative estimates of the additional costs induced by the installation of fluctuating renewables was provided in [1]. Results on the costs of increased part-load operation, start-ups and backup costs for wind energy are given by [2] and [3], without much detail however on the calculation methodology. [4] discusses the additional costs related to the integration of large amounts of renewables in the British electricity system, following closely the approach developed by [1]. Different approaches to the quantification of integration costs and also corresponding numerical values may also be found in [5]. The relevant cost components are reviewed in [6], which also discusses numerical estimates taken from various European studies.

More model-oriented, the value of wind energy is derived in [7] from an electricity system model, which includes explicitly the stochasticity of wind as well of hydro sources. [8] uses a stochastic system operation model to compute two different values for the integration costs – including the impacts of more frequent part-load operation, increased number of start-ups and higher reserves.

In these various contributions, both a broad variety of numerical results may be found as well as a challenging diversity of methods used. Key differences between approaches and their implications are notably discussed in [9]. A systematic framework for dealing with integration costs is derived in [10]. The present contribution aims in this context at highlighting how integration costs may be quantified on the one hand by using aggregate modeling approaches which have been popular in electricity market economics ever since the nineteen-sixties and on the other hand how these results may be extended and improved by using stochastic optimization models.

The structure of the present paper is as follows: subsequently, a unifying framework for analyzing integration costs is briefly outlined. Integration costs for renewables are thereby decomposed according to their underlying causalities. The remainder of the paper then focuses on the analysis of the costs of variability and the costs of (partial) unpredictability. In Section 3 the costs of variability are then quantified in a long-term perspective using a consistent peak-load-pricing approach. Section 4 then contrasts these results with the outcomes of a stochastic optimization approach.

2. THE CONCEPT OF INTEGRATION COST

The concept of integration costs is intended to measure the additional costs arising when “something new” is integrated into a preexisting system. A key question then is, what is the new and different thing about the new alternative. In order to be able to identify this, a reference technology *Alt* is needed for comparison purposes. Then integration costs may be defined in general terms as:

$$C_{Int} = C^{*}_{Add,\mathrm{Re}n} - C^{*}_{Add,Alt} \qquad (1)$$

Thus the integration costs are equal to the difference between the additional system costs when imposing renewables *Ren* and the additional system costs when using the alternative technology *Alt*.

In the case of wind or other fluctuating energy sources, one might consider of the following three reference technologies as alternatives:

- *T1:* a technology with same cost characteristics and generation capacity, but fully controllable output;
- *T2:* again with same cost characteristics, but same annual electricity production delivered at a constant hourly rate;
- *T3:* also same cost characteristics, but with similar electricity supply profile than wind, yet without uncertainty on future supply.

Obviously *T1* is a very optimistic technology alternative, “too nice to be true”. Therefore the comparison should focus on *T2* and *T3*. Additionally, the different geographical dispersion of conventional and renewable generation should be considered.

In a rather broad way, integration cost are defined hereafter as the following cost difference:

$$C_{Int} = C^{*}_{Add,\mathrm{Re}n} - C^{*}_{Add,T2c} \qquad (2)$$

That is, the integration costs are determined as the difference between the additional costs for renewables minus the additional costs for the hypothetical technology T_2 with identical output, investment and variable costs and geographically distributed as conventional power plants (therefore subscript *c*). This definition seems most in line with what is usually denominated integration costs.

It lends to the following decomposition, which allows looking closer at the causes for integration cost:

$$C_{Int} = C_{Grid,con} + C_{Grid,ext} + C_{Unpred} + C_{Variab} \tag{3}$$

Thereby we define as components of the integration costs:

Grid connection costs:

$$C_{Grid,con} = \left(C^*_{Add,Ren} - C^*_{Add,Ren,r}\right) \tag{4}$$

They correspond to the increase (or decrease) in cost due to the fact that the renewables are distributed, dispersed generation technologies. They are determined by comparing the additional costs to those of a hypothetical system, where the renewable technologies would have the same distribution over regions (therefore the index *r*), but are concentrated within the regions at the location of conventional power plants.

Grid extension costs:

$$C_{Grid,ext} = \left(C^*_{Add,Ren,r} - C^*_{Add,Ren,c}\right) \tag{5}$$

Those reflect the uneven distribution of some renewable sources (like wind in the German case) over the regions. This uneven distribution causes costs for additional grid investments, as emphasized in Germany by the so-called *dena*-study [11]. Here they are computed by comparing the costs of the aforementioned system with regionally concentrated renewables (index *r*) to those of a system with renewables distributed like the existing conventional plants (index *c*), both within and between regions.

Costs of unpredictability:

$$C_{Unpred} = C^*_{Add,Ren,c} - C^*_{Add,T3,c} \tag{6}$$

These are the additional costs occurring when comparing the system with renewables to one with the hypothetical technology *T*3 having same, time-varying output but perfect predictability. This cost, taken with the opposite sign, corresponds to the *value of perfect information*, commonly referred to in the stochastic programming literature (e.g. [12]).

Costs of variability

$$C_{Variab} = C^*_{Add,T3,c} - C^*_{Add,T2,c} \tag{7}$$

This finally describes the cost gap between using the aforementioned technology *T3* and using the technology *T2*, which provides the same energy output as constant flow. This cost difference may get negative, if the variations in renewable output correspond by-and-large to the variations in electricity demand. For wind, these costs will be positive in almost every real-world case– when applying photovoltaics in some hot arid climate with demand peaking strongly linked to solar irradiation (due to cooling requirements), this might be different.

Subsequently, the focus will be on the latter two parts of integration costs. Grid connection and grid extension costs are discussed notably in [6] and [11].

3. LONG-TERM COSTS OF VARIABILITY

The long term is characterized in economics by the fact that all production factors are flexible; i. e. the existing capital stock does not restrict the system operation. In this (always) hypothetical situation the planners may choose the optimal system components.

The corresponding optimization problem (corresponding to a market equilibrium under perfect competition) may be characterized by the following four equations:

$$\min_{y_{u,t},K_u} C \tag{8}$$

$$C = \sum_u C_u = \sum_u \left(c_{Inv,u} K_{PL,u} + \sum_t c_{Op,u} y_{u,t} \right) \tag{9}$$

$$\sum_u y_{u,t} \geq D_t \tag{10}$$

$$y_{u,t} - K_{PL,u} \leq 0 \tag{11}$$

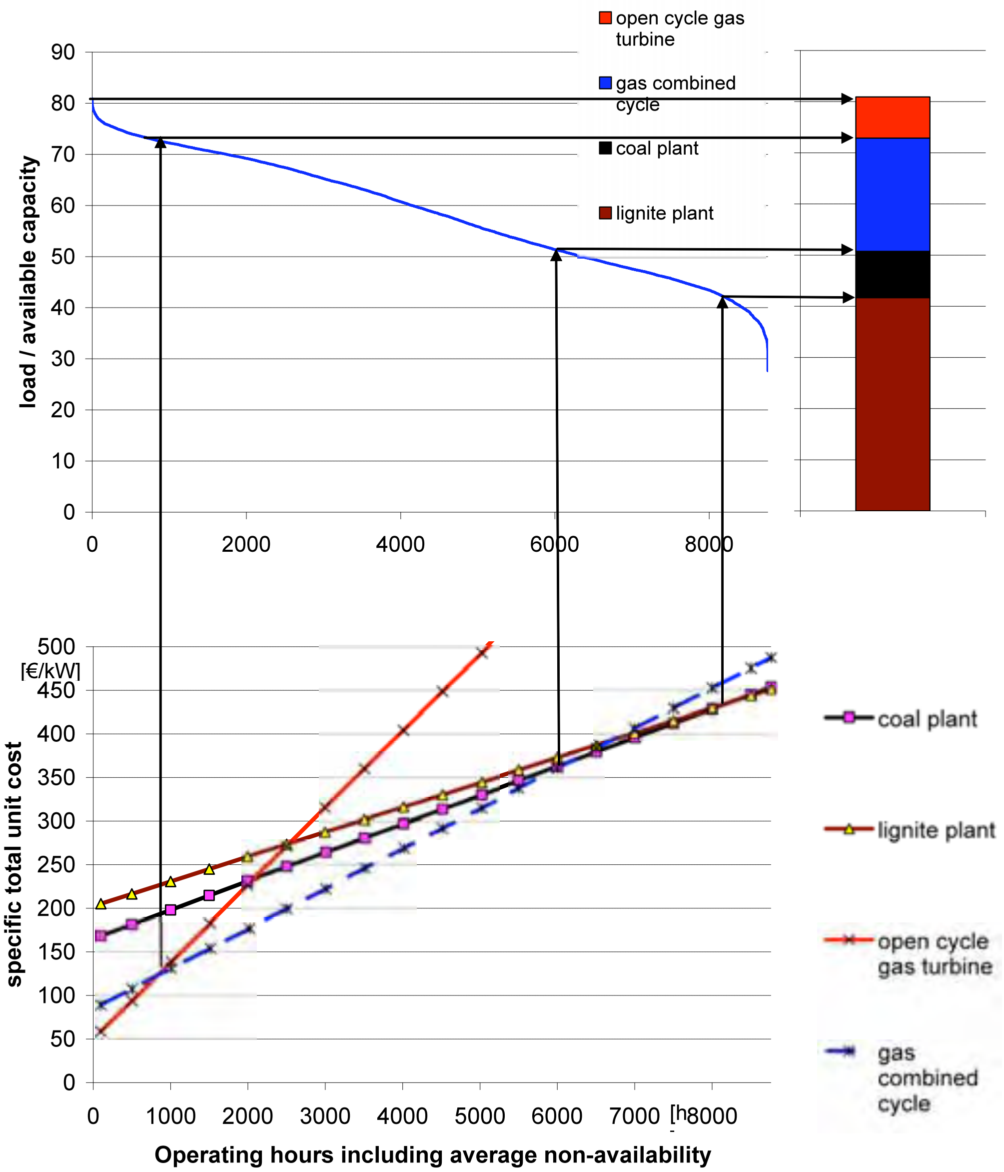


Fig. 1. Graphical solution to the peak-load pricing problem

It has been shown (cf. e.g. Oren 2000 for a short summary) that the optimal solution to the technology choice problems can be obtained graphically as shown in Figure 9-2. In the lower part, the total (annualized) costs per MW $c_u = C_u / K_u$ are plotted as a function of total annual operation hours tOp,u:

$$t_{Op,u} = \left(\sum_t y_{u,t} \right) \Big/ K_{PL,u} \qquad (12)$$

From Eq. (9), the linear form of the graphs may readily be derived:

$$c_u = C_u / K_u = c_{Inv,u} + c_{Op,u} \cdot t_{Op,u} \qquad (13)$$

In the example depicted in Fig. 1., clearly the open cycle gas turbine is the cheapest for operation duration between 0 and about 800 h, combined cycle units are cheapest between 800 h and 6200 h, followed by hard-coal-fired plants and lignite plants being only effective from 8200 h operating hours onwards. Since in the upper part, the load in all time segments *t* has been ordered by decreasing values, this may be directly used to determine the optimal installed capacity for each technology. Starting with the highest load duration, the optimal capacity for lignite plants (the base load plants) is determined as the load level that is exceeded in at least t_2 hours per year. In statistical terms, the (1 – t_2/8760)-quartile of the load duration curve is chosen as optimal capacity $K_{PL,2}$. By similar reasoning, the optimal capacity for technology 2 is determined as the difference between the (1 – t_1/8760)- and the (1 – t_2/8760)-quartile of the load duration curve… And finally the peak load technology has to have an equilibrium capacity equal to the difference between the maximum load x_{max} and the (1 – t_1/8760)-quartile.

In order to assess the impact of wind or other fluctuating renewables at zero variable cost in this model, the easiest way is to determine the load duration curve for the residual load, i.e. the load remaining after the wind supply has been subtracted. From this residual load curve then the optimal capacities may be deduced as before. Given that the lower part of the graphical peak-load-pricing solution is not touched, we focus on changes in the upper part. The load duration curves without wind, with wind and with the reference technology *T2*, as derived from the German transmission operators' data, are given in Fig. 2. Obviously technology *T2*, with its constant output rate corresponds to a downward shift of the duration curve, whereas the wind production contributes less to peak load reduction – this is the phenomenon of reduced capacity effect of wind power. In the middle part of Fig. 2, the two curves are almost identical, yet on the right side; the residual load with wind is again considerably lower than the reference alternative *T2*.

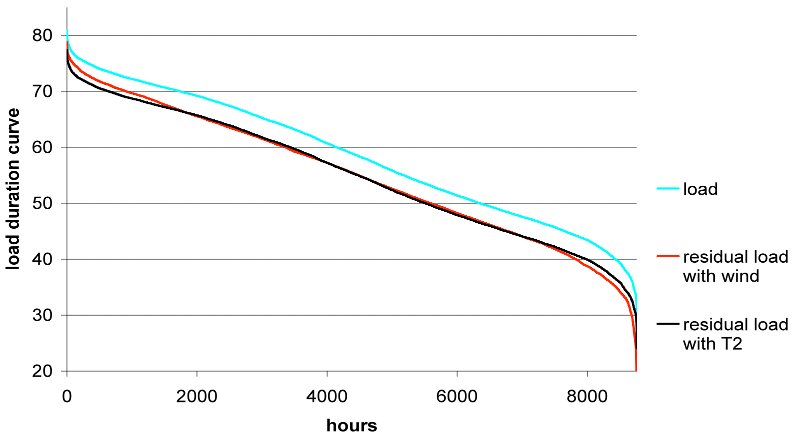


Fig. 2. Load duration curves for different scenarios

The impact on the optimal capacities is depicted in Fig. 3. Obviously the base load quantities are reduced by approximately 5 GW compared to the situation without wind and by 1.4 GW compared to the reference case with T2. These data have been derived using 2006 load and wind data for Germany, i.e. with 31 TWh of wind energy production compared to a total demand (at transmission grid level) of 513 TWh, so that wind energy accounts for 6 % of all production. The shifts in conventional generation capacities correspondingly remain limited, with an increase in shoulder capacities by 1.7 GW for hard coal and 0.8 GW for gas-fired combined cycle plants. The true peaking capacities are only slightly increased by 0.3 GW, given that under the assumptions used (cf. Table 1) the open cycle gas turbines are run a maximum of 800 h per year. The difference in overall peaking capacities – understood as capacities with less than 2000 h - operation time is with 1.6 GW considerably larger.

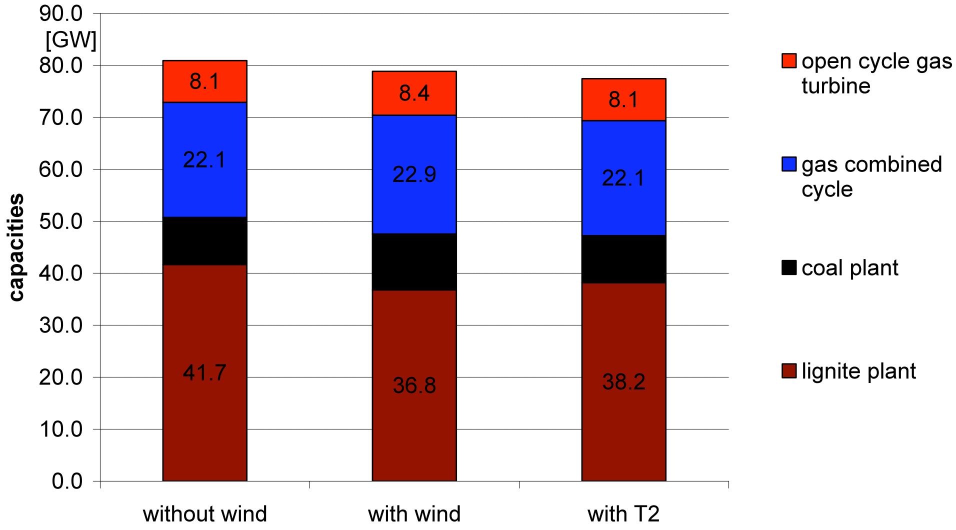


Fig. 3. Graphical solution to the peak-load pricing problem

When comparing the total costs between the alternatives *with wind* and *with T2* a cost difference of 208 Mio. €. Per MWh of wind energy produced this corresponds to 6.67 €/MWh.

TABLE I
KEY DATA USED FOR THE PEAK-LOAD-PRICING MODEL

		coal plant	lignite plant	open cycle gas turbine	gas combined cycle
Net output capacity	MW	800	1050	146	800
Overall efficiency	%	46	43	33	58
Planning and construction period	a	5	5	1.5	3
Economic lifetime	a	40	40	35	35
Specific total investment cost	€/kW	1100	1400	270	570
Specific removal cost	€/kW	33	36	7	13
Specific other fix costs	€/kW	30.9	32.6	18.4	18.4
Other variable costs	€/MWh	1.0	1.0	0.7	0.7
Scheduled non-availability		9.0%	9.0%	10.0%	10.0%
Unplanned outages		4.5%	4.5%	3.5%	3.5%
Fuel costs	ct/kWh	0.80	0.38	2.50	2.20
Operational costs	€/MWh	32.95	28.42	88.68	45.97
Emission factors	kg/kWh	0.3348	0.3996	0.2016	0.2016
Emission price	€/t CO2	20			
Interest rate	%	8.0			

Obviously this calculation approach not only neglects grid dependent costs but also rather focuses exclusively on the costs of variability. In fact, the approach does not allow accounting for the imperfect predictions of wind energy and the corresponding costs for increased reserves, more part load operation etc. In order to quantify this part of the integration costs, a stochastic model is needed. Moreover the peak-load-pricing model neglects all existing capacities and therefore will be not adequate for real systems

4. LONG-TERM COSTS OF VARIABILITY AND (PARTIAL) UNPREDICTABILITY

In order to quantify the costs of fluctuations for an existing system, one has first to consider which elements in the system will be allowed to adapt to the fluctuations. If it is only operation, integration costs will tend to be higher than if also flexibility on new investments allows adapting gradually to increasing wind. Hence an optimizing modeling approach with endogenous investment clearly is preferable. On the other hand the stochastic of wind has to be represented, and given that this occurs at a rather short time scale, the time resolution of the model should be rather high.

One way to overcome these conflicting interests is to use a model with typical days. This is the approach chosen in E2M2s, an electricity market model specifically designed to cope with wind integration issues [3].

This is a fundamental model using an LP approach given that large-scale systems with hundreds of plants, such as the continental European market are to be modeled. In this framework an approximation for the start-up and part-load costs is implemented, going back to [15]. The increased requirements for reserves are determined by using a convolution method. The fluctuations of wind are represented by a recombining stochastic tree such as represented in Fig. 3.

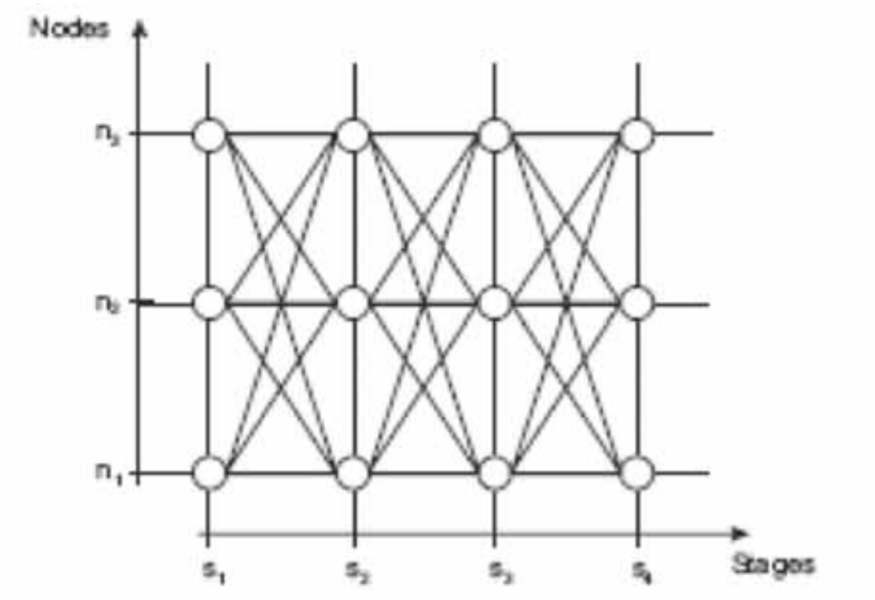


Fig. 4. Stochastic representation of wind fluctuations by a recombining tree

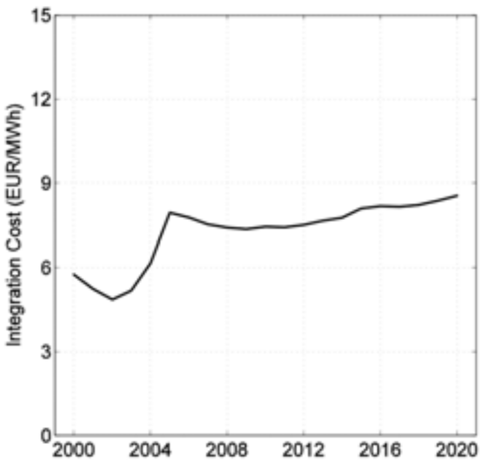
This allows incorporating the uncertainty at each moment in time on future evolution of wind power yet at the same time avoids the curse of dimensionality proper to ordinary stochastic programs.

When applying the approach to Germany, two scenarios for CO_2-prices are considered:

- Low prices: 10 €/t CO_2 constantly from 2005 to 2020
- High prices: linear increase from 20 €/t CO_2 in 2005 to 40 €/t in 2020

Fig. 5 gives the yearly integration costs of a base wind generation scenario that includes a linear increase in wind power, leading to a fraction of 15 % of wind serving demand in 2020. It can be seen that the integration costs increase over the considered time horizon due to the increasing wind energy deployment. In fact the integration costs greatly depend on the ability of the considered system to dynamically adapt to an increased share of wind generation. ^

Fig. 5. Yearly development of integration cost: High CO_2 price path (left); Low CO_2 price path (right) [15]



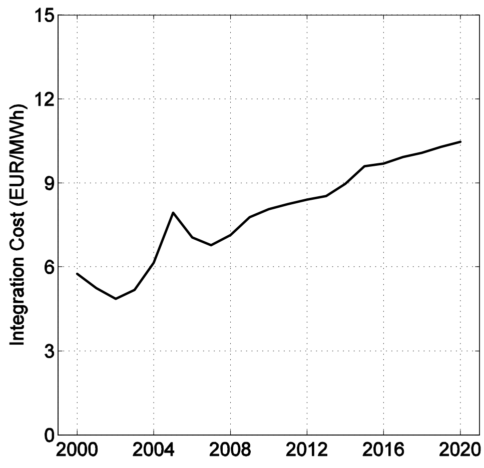


Fig.5. Yearly integration costs of a base wind generation scenario

When comparing the high and low CO_2 allowance price path one finds that the estimated integration costs are lower in case of the assumed high CO_2 allowance prices, cf. Figure 5 (left), compared to the low CO_2 allowance prices, cf. Figure 5 (right). This is a consequence of different investments. Under the high CO_2 allowance prices, the variable costs (including the respective fuel and CO_2 allowance prices) for coal- and lignite-fired plants increase faster than the variable costs of gas-fired plants. Hence, the investments are dominated by gas-fired combined-cycle plants leading to a higher flexibility of the system; even if wind could be considered to be perfectly predictable.

Fig. 6 shows that the integration costs are obviously depending on the share of wind installed, yet that this dependency is non-linear and dependent on other parameters

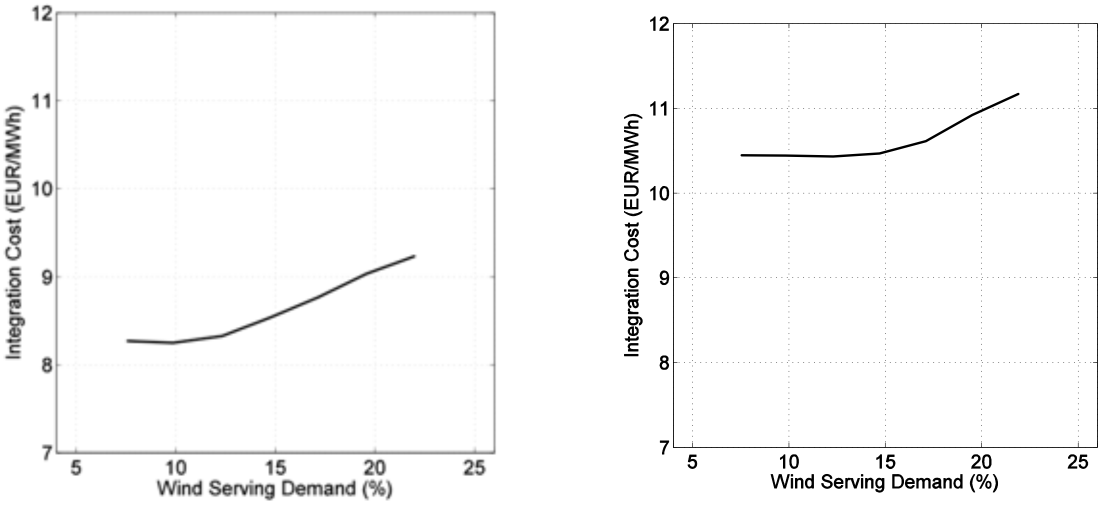


Fig. 6. Integration cost as a function of wind serving demand: High CO_2 price path (left); Low CO_2 price path (right)

5. FINAL REMARKS

The analysis has shown that the valuation of fluctuations in wind or similar power production needs to be done carefully. In particular one should state the used approach in detail, indicating especially which reference technology is chosen for comparison. Another key parameter is the share of wind energy production. An evaluation of wind integration costs has to be done using stochastic optimization models, especially if the costs of (partial) unpredictability are to be determined. The numerical results indicate that integration costs are in the range of 5 to 10 €/MWh, which is roughly around 10 % of the wind energy generation costs. So it is a non-negligible quantity, but its impact on overall generation cost is so far limited. Yet this proportion might increase with additional wind turbines being installed.

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BIOGRAPHY

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5. New Developments in Wind Energy Forecasting

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***Abstract*--**An overview of new and current developments in wind power forecasting is given where the focus lies upon practical implementations and experiences concerning the operational systems in Europe.

In general, modern short-term wind power prediction systems use either statistical or physical approaches to determine the anticipated wind power based on numerical weather forecasts. As an example the physical system Previento is described in detail. The typical accuracy of the forecasts for single wind farms as well as the aggregated production is shown.

One focus of this paper is the intelligent use of multiple inputs from numerical weather models to improve the accuracy of the power forecast. The two main approaches that are applied operationally are ensemble predictions from one weather model and the combination of different numerical weather models. A weather-dependent combination tool that exploits the capabilities of numerical models of different weather services is described in detail.

In the future, wind power predictions will be embedded deeper in the processes of grid operators and traders. An example shown here are highly localized predictions for specific grid points which can directly be used as input for power flow calculations, grid management or day-ahead congestion forecasts (DACF). In addition, the market integration of wind energy is pushed in a number of countries such that trading platforms that convert fluctuating wind power production into electricity products become more important.

***Index Terms*--**Wind energy, Wind power generation, Forecasting, Meteorology, Weather forecasting, Research and development.

1. INTRODUCTION

Wind power prediction systems provide the information how much wind power can be expected at which point of time in the next few days. In countries having a high penetration of wind energy in the electrical grid, in particular Denmark, Spain and Germany, wind power prediction tools turned out to be indispensable for the energy industry.

The forecasts are mainly used for the day-ahead scheduling of conventional power plants and trading of electricity on the spot market. Therefore, the time horizon of the forecast comprises at least 36 hours as the deadline to place bids on the market is typically at noon for the complete following day.

In addition, precise wind power predictions play an important role in the allocation of balancing power for the next few hours to come. This intraday application requires reliable updates of the predictions in order to have increasingly better forecasts for decreasing look ahead times.

In Germany the installed wind power has grown tremendously in recent years and reached more than 20 GW. On stormy days the electricity production has already exceeded 18 GW. Thus, the contribution of wind energy to the total electricity production fluctuates substantially such that wind power predictions play an important role in the daily planning procedures at utilities.

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2. STATE-OF-THE-ART

Modern wind power prediction systems provide forecasts for a time horizon of up to ten days in advance and are typically based on numerical weather predictions (NWP). Hence, all the information about the future evolution of the wind field is provided by the NWP. The national weather services but also private weather data providers offer a broad range of different NWP data that are suitable for wind power predictions.

The key issue in wind power forecasting is to transform the given numerical weather data into the power output of a wind turbine. For this purpose two fundamentally different approaches, the statistical approach on the one hand and the physical approach on the other hand have been developed in recent years. Both of them led to prediction systems that are scientifically as well as commercially successful. Recent overviews can be found in [1] and [2].

2.1 Statistical Systems

The statistical approach is based on training with measurement data. The idea is to derive a statistical relation between the given input from the weather prediction and the measured power output of wind farms. Hence, these systems completely rely on data analysis ignoring the meteorological details.

Several different methods to determine the relation between forecast and power output have been developed. One very prominent example is the system WPPT by the Danish Technical University [3], [4] which has been working operationally at the Danish TSO Eltra for many years. This system uses autoregressive statistical methods to determine the predictions. Under this approach the power production is described as a nonlinear and time-varying (and, hence, non stationary) stochastic process.

Another example is the system developed by ISET in Germany [5] that provides forecasts for a number of German TSOs. The system works on artificial neural networks (ANN) that are trained with either historical wind farm data or measurements from transformer stations where a number of wind farms is connected. In addition, the system provides an online estimation of the wind power that is currently fed into the electrical grid based on extrapolating measurements at representative wind farms.

The advantage of statistical systems is clearly that the predictions are inherently adapted to the location of the wind farm such that systematical errors are automatically reduced. The disadvantage lies in the need for long-term measurement data and an additional effort for the training. Moreover, it is difficult for these systems to correctly predict rare atmospheric conditions if they appear too seldom during the training period. Unfortunately, a correct prediction of these rare situations is rather important and can otherwise lead to large forecast errors.

2.2 Physical Systems

Physical systems use parameterizations based on a detailed physical description of the lower atmosphere. The basic problem to be solved is the transformation of the wind speed given by the weather service on a coarse numerical grid to the on-site conditions at the location of the wind farm. This involves two important steps: the horizontal interpolation from the grid points to the co-ordinate of the turbine and the transformation of the wind speed from the height provided by the NWP, e.g. 10 m or 100 m, to the hub height as illustrated in Fig. 1. For this purpose methods from boundary layer meteorology are applied to calculate the vertical wind profile for individual forecast situations. The corrected wind speed is then plugged into the corresponding power curve of the wind turbine to determine the power output. More details can be found in a recently published book on this subject [6].

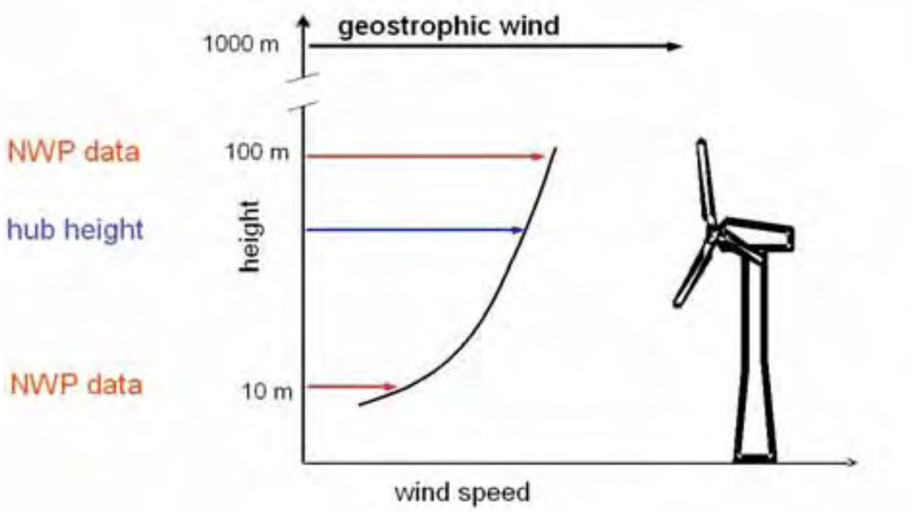


Fig. 1. A physical prediction system uses methods from boundary layer meteorology to extrapolate the wind speed at hub height from the given numerical weather prediction.

A number of physical systems have been introduced in recent years. One of the first systems was Prediktor [7] developed by Risoe in Denmark. In Germany two physical systems are in operational use for the major TSOs: The system SOWIE by Eurowind GmbH and Previento by energy & meteo systems GmbH that was developed by the University of Oldenburg [8], [9].

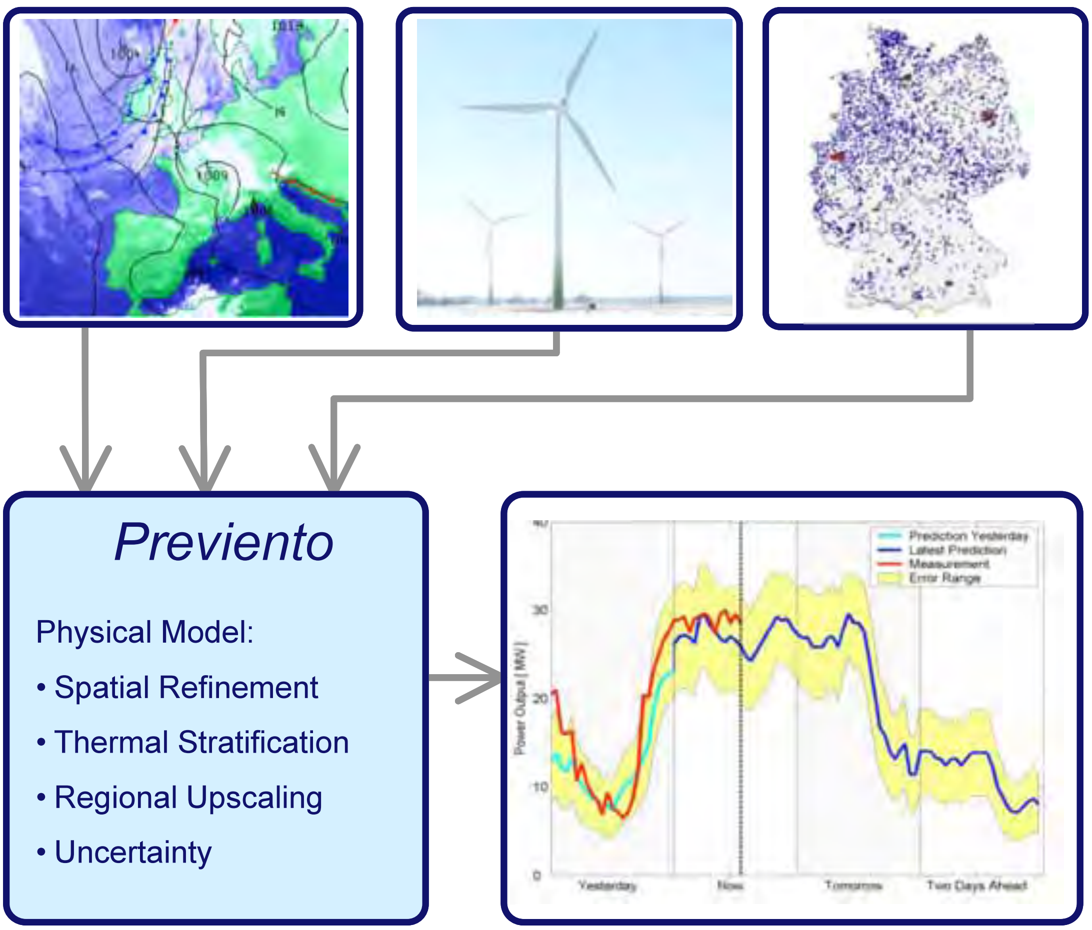


Fig. 2: Basic scheme of the physical prediction system Previento which uses different weather models to calculate predictions for single wind farms or regionally aggregated predictions.

As an example the physical prediction system Previento is discussed: Fig. 2 shows the basic scheme of Previento. To calculate the wind speed at hub height the thermal stratification of the atmosphere is modeled in detail [10]. Then the wind speed is transferred to power output by the power curve where either the certified curve or a site-specific curve that has been determined at the location can be used. In a wind farm the shadowing effects among the wind turbines can lead to reductions in power output up to 20% such that these farm effects are also considered. As a result Previento provides the predicted power output of a single wind farm.

In addition to the prediction values Previento calculates the individual uncertainty for each forecast time depending on the wind speed and the prevailing weather situation [11], [12]. Thus, the end-user is supplied with an estimation regarding the risk of trusting in the prediction.

In practical use energy traders and TSOs require the combined power output of many spatially dispersed wind farms in a region instead of that of a single wind farm. Consequently, Previento contains an advanced up-scaling algorithm that determines the expected power output of all wind farms in a certain area based on a number of representative sites selected in an appropriate manner such that spatial smoothing effects are properly taken into account [13].

If measurement data from the wind farms are available a statistical correction of systematic forecast errors is applied using linear regression techniques.

3. ACCURACY

The accuracy is an important topic as forecast errors are directly related to the use of balancing power and, thus, additional costs. A forecast error of the magnitude of 1 GW over several hours could produce costs of the order of one million Euros.

The accuracy of the wind power predictions is constantly evaluated by the TSO in Germany. The most popular error measure to assess the quality of the forecast is the root mean square error (rmse) based on the deviation between prediction and measurement normalized to the installed wind power. It has turned out that the rmse reflects the corresponding cost function as it emphasizes large forecast errors that are disproportionately expensive.

An evaluation by the German EnBW Trading of predictions of the aggregated power production of all German wind farms from several providers in Germany revealed a significant improvement over the last years [14]. The results of this evaluation for the Previento prediction are shown in Fig. 3. The investigated period comprises November 2004 to July 2006, i.e. several months including the stormy periods in winter and spring. The accuracy is expressed in terms of the rmse normalized to the installed capacity. The rmse increases from 3.1% intraday (0 - 23 h), to 4.4% day-ahead (24 - 47 h) up to 5.8% 2 days ahead (48 – 71h).

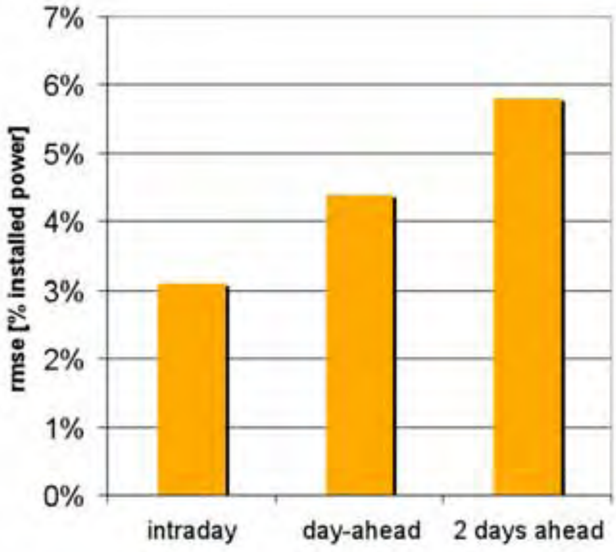


Fig. 3: Accuracy of prediction of aggregated production of all German wind farms. The Previento system has been evaluated from November 2004 to July 2006.

The monthly evaluation of the German wide Previento prediction is illustrated in Fig. 4. Typically, forecast errors are higher in winter, which is due to the generally higher level of wind speeds on the one hand, and the larger uncertainty in the prediction of the stormy weather situations, in particular low-pressure systems and their frontal zones. During summer effects of thermal stratification mainly dominate the forecast errors. Especially, in high-pressure situations the wind speed at large hub heights strongly increases after sunset that is difficult to predict.

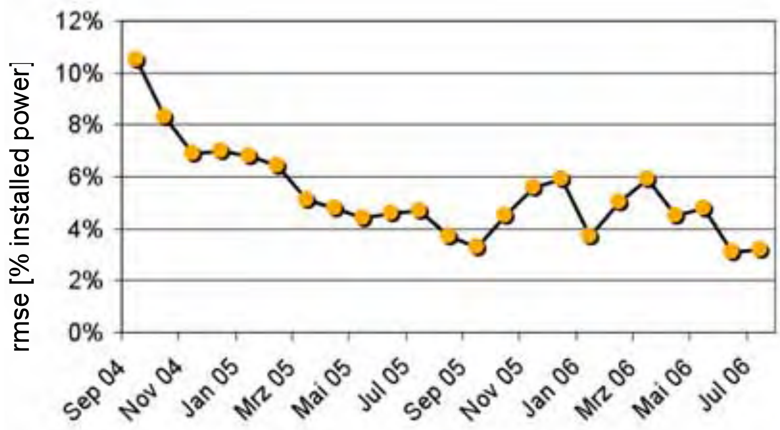


Fig. 4: Monthly evaluation of day-ahead prediction of Previento for Germany showing the overall improvement from Sep 2004 to July 2006 and the seasonal variation of the prediction accuracy.

The German wide prediction has a comparatively low forecast error because it can take full advantage of spatial smoothing effects [13], i.e. errors at one location cancel out partly with other distant locations. For a single wind farm the power prediction is, therefore, associated on average with a relatively higher forecast error. In Fig. 5 the results of the Previento prediction for a wind farm with 17 MW installed capacity is shown. This site is typical for the locations in flat terrain in the North of Germany.

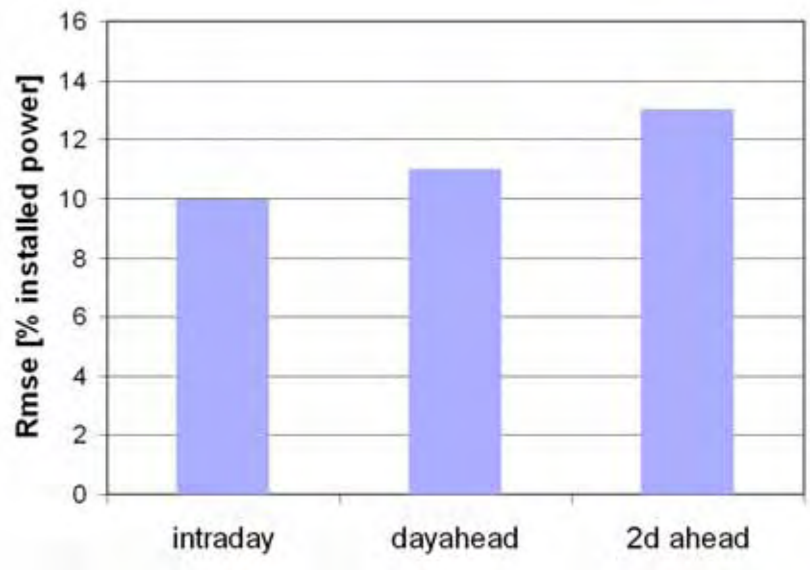


Fig. 5: Accuracy of single wind farm with 17 MW installed power located in flat terrain in Northern Germany.

4. MULTIPLE METEOROLOGICAL INPUT DATA

The majority of the existing wind power forecasting systems is based on numerical weather prediction models (NWP) that do not provide perfect predictions due to the fact that the atmosphere is a highly non-linear chaotic system [15]. It was shown in several investigations, e.g., that the accuracy of the NWP input has a major impact on the accuracy of the power prediction. The reason for this is quite clear: if, for example, the NWP predicts a storm front with a time delay of two hours, the wind power prediction system cannot compensate for this type of error.

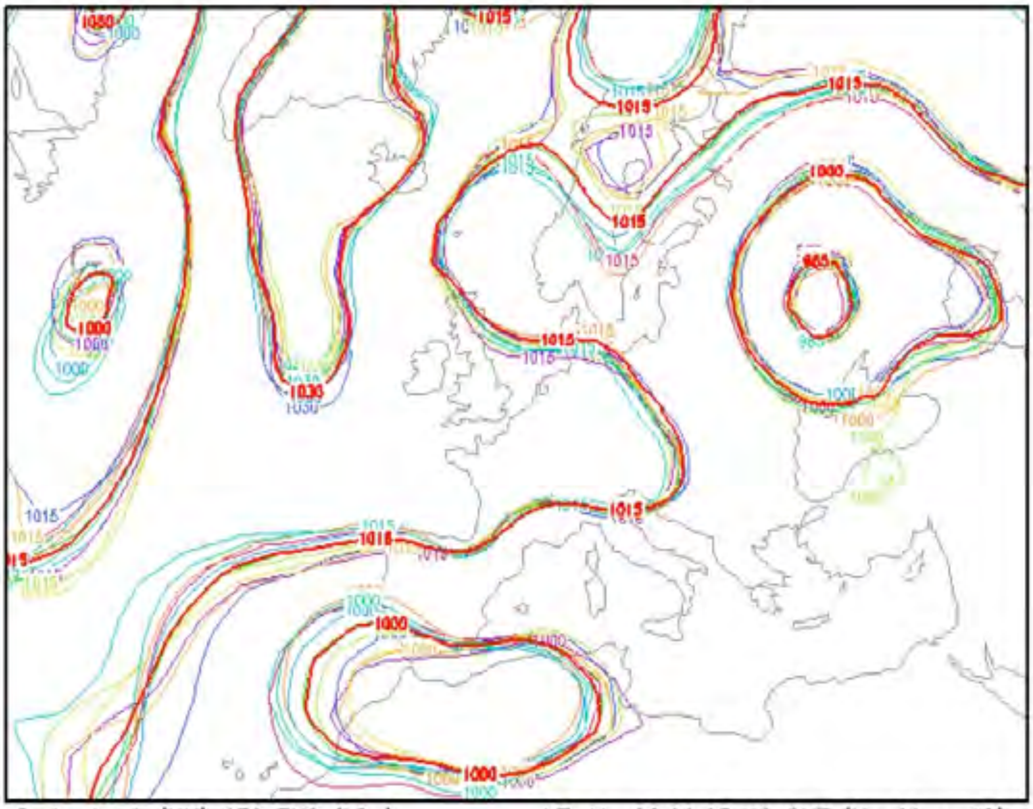
Hence, meanwhile several operational systems, physical as well as statistical, use more than one single NWP output to produce the wind power forecast and somehow combine the results. The major advantage of using multiple inputs is that the different forecasts have different capabilities such that the errors cancel out partly.

Two main approaches in this context are:

- Ensemble predictions where one numerical model calculates a number of different predictions by using slightly different initial conditions.
- Combination of NWP models where the output of several different NWP models with different physical and numerical implementations is used.

4.1 Ensemble Predictions

In this approach the inherent non-linear properties of one NWP model are reflected. For example Fig. 6 shows ensembles of the American NWP GFS. Due to the chaotic behavior of the equations of motion a slight perturbation of the initial conditions for the numerical calculations leads to increasingly divergent weather situations within 96 hours.



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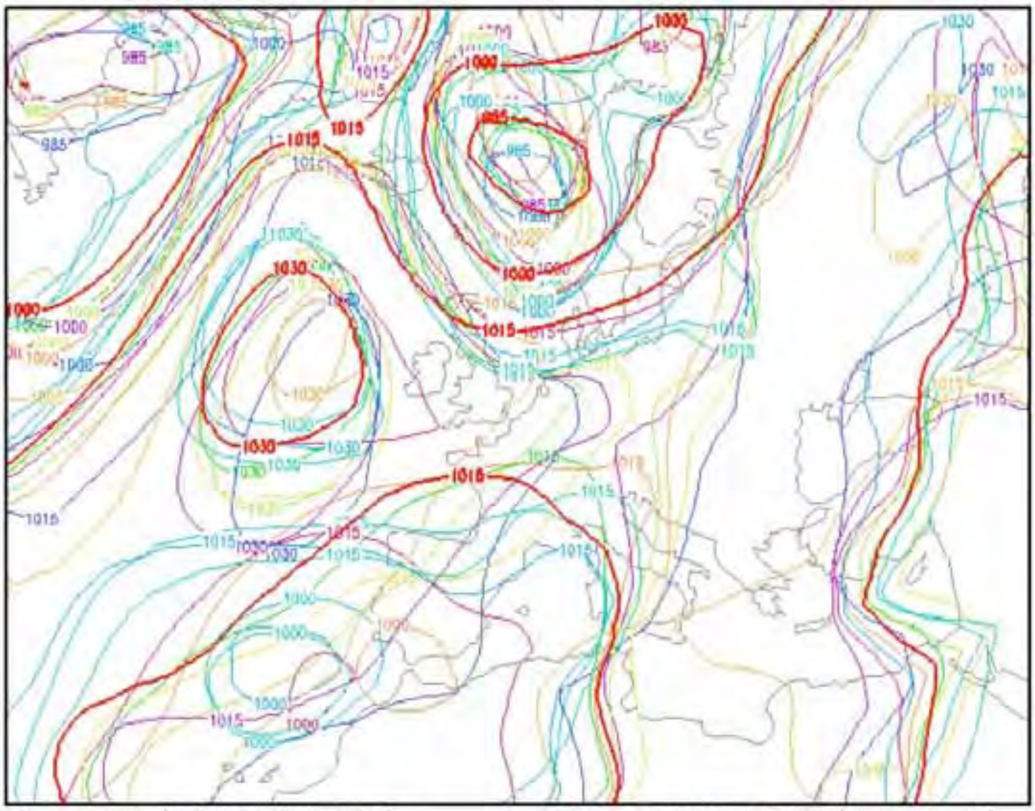

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Fig. 6: Ensemble prediction (spaghetti plot) of the American weather model GFS. Top: 12 hours after initialization the different ensembles are still close together. Bottom: After 96 hours the ensemble members fall apart into different weather situations.

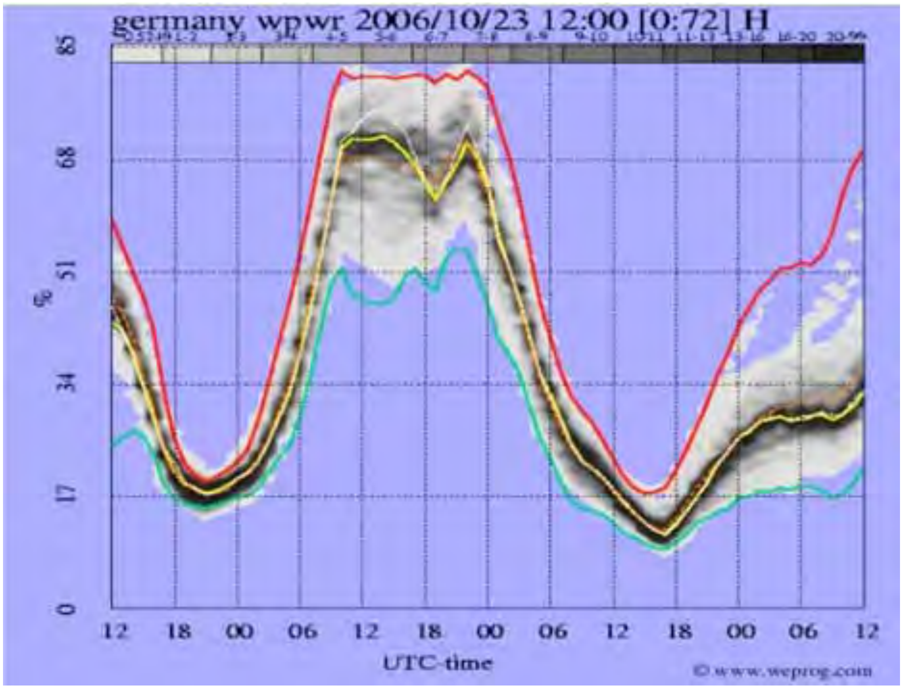

Fig. 7: Probability forecast based on 75 ensemble predictions (75 ensembles) by WEPROG.

The European weather service ECMWF also supplies ensemble predictions based on 51 different ensembles [16], [17]. For wind power prediction purposes the ensembles have been investigated by Giebel et al. [18] and it was shown that averaging could lead to a significant improvement. The Danish company WEPROG uses an ensemble with 75 members to generate wind power predictions (Fig. 7). The output is a probability distribution, which provides the mean as predicted value, and an uncertainty based on the spread of the ensemble members for the specific weather situation [19].

4.2 Combination of Weather Models

The combination of different NWP models takes advantage of the fact that different forecast models have different strengths and weaknesses in different weather situations. This is due to the broad variety of physical and numerical implementations of the dynamics of the atmosphere inside the models.

In a recently finished project energy & meteo systems together with the German TSO RWE and the German Weather Service DWD (funded by the German Ministry for the Environment, Nature Conservation and Nuclear Safety) used the NWP models of the major European weather services to find the optimal combination of the models for typical weather situations [20]. Fig. 8 shows an overview of the weather services providing numerical data.

Fig. 8: The combination of multiple input data from different international weather services is used to improve wind power predictions.

The different capabilities of the NWP models are exploited by applying optimal weighting factors to the predictions that depend on the prevailing weather conditions (like fronts, various configurations of high pressure / low pressure systems over Europe). For this purpose an objective weather classification algorithm based on methods from synoptic climatology was developed [11], [12]. A schematic overview of the combination approach is shown in Fig. 9. The algorithms are meanwhile implemented as a software tool running operationally at the German TSO RWE.

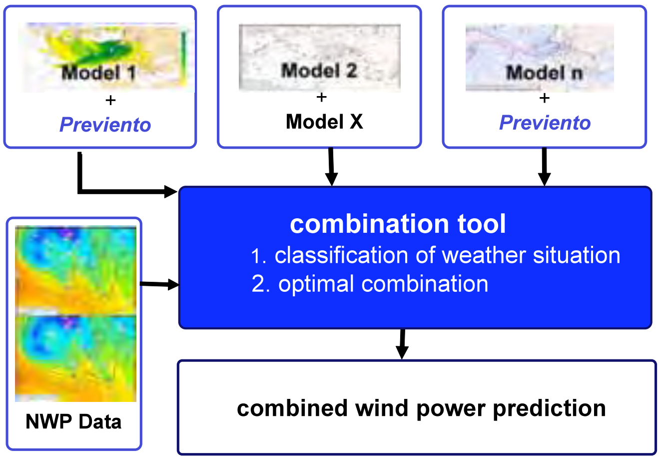

Fig. 9: The combination tool uses multiple weather data input to automatically determine the optimal combination of different weather models for individual weather situations based on methods from synoptic climatology.

One advantage of combining the models is, of course, a reduced prediction error. The optimal combination significantly outperforms predictions based on weather data from one single NWP model even if the single models are already very well optimized (Fig. 10).

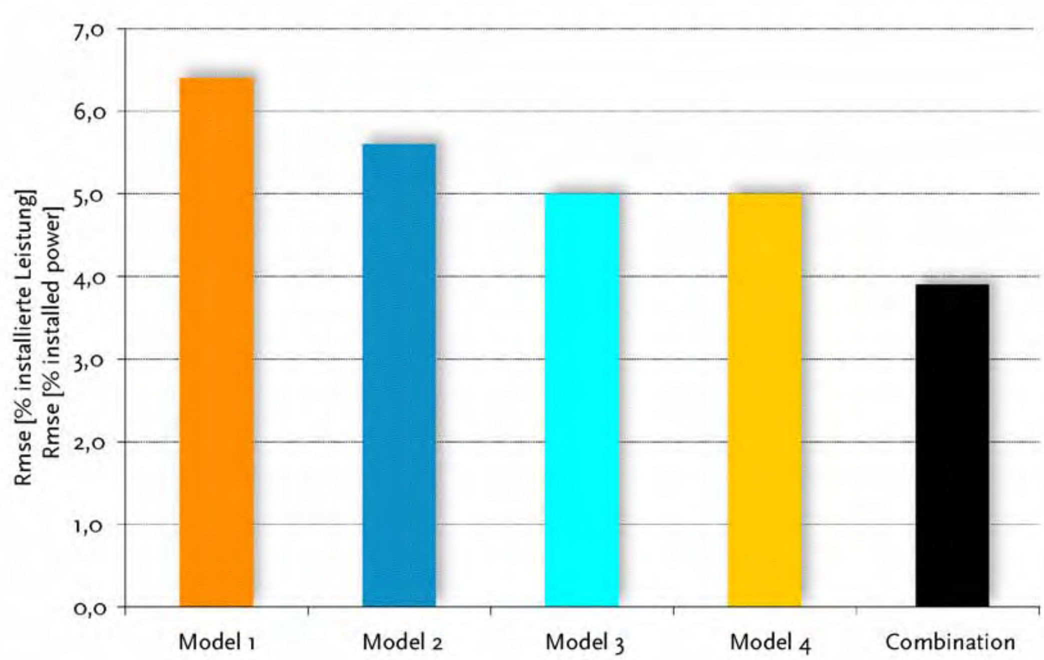

Fig. 10: The weather-dependent combination outperforms even well tuned models (Model 1 – 4) that are based on a single NWP model. The results refer to the prediction of the total of all German wind farms. As before Rmse normalized to installed power is used as error measure.

An additional advantage of the combination is an error reduction in extreme events. This is very important in every-day use because the prediction models can show very large deviations in extreme situations like storms (Fig. 11). In these cases the combination typically captures the situation better.

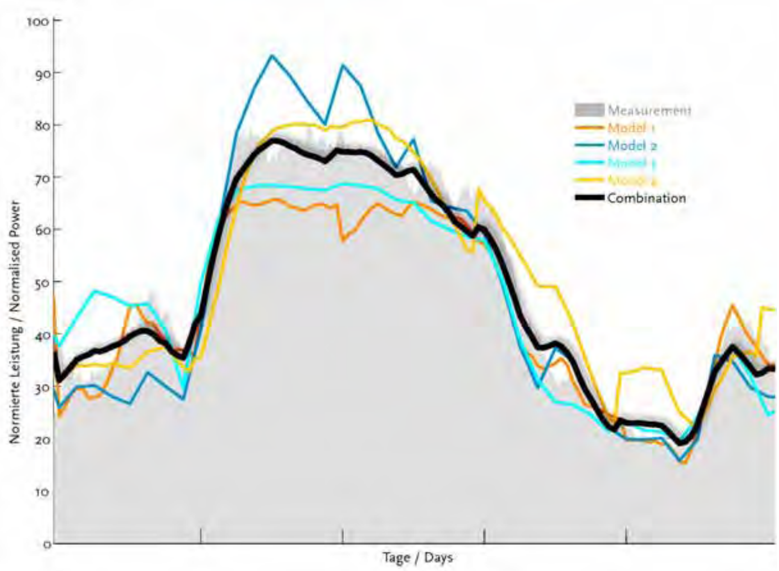

Fig. 11: Combining forecasts from different models reduces the danger of extremely large forecast errors. In this example the single predictions (thin lines) deviate strongly on a high level of wind power production. The combined forecast (thick line) captures the real power in-feed (gray area) quite well.

5. RESEARCH AND DEVELOPMENT

The ongoing research and development (R&D) activities related to wind power prediction follow two main approaches: First, the improvement of the wind power prediction systems by enhanced statistical or physical methods. Second, a number of R&D projects are devoted to a better integration of fluctuating wind energy into the electricity supply system where wind power prediction plays, of course, an important role. Hence, these activities are concentrated on the question how to use the information generated by a wind power prediction system in the downstream decision processes.

5.1 Improved wind power prediction systems

In order to improve wind power prediction systems, i.e. to obtain better results from a given input by a NWP, the research concentrates on the major challenges faced by wind energy utilization:

- **Offshore**
  The wind conditions over the ocean are only partly known. In particular, the vertical wind profile is different from onshore due to the large heat capacity of the ocean and the variable roughness of the water surface, e.g. [21], [22].
- **Complex terrain**
  For hilly and mountainous terrain, especially in connection with high solar irradiation like on the Iberian Peninsula, advanced numerical flow models are required to refine the weather data to the site-specific conditions. The wind fields have to be calculated in detail by so-called meso-scale models, e.g. [23].
- **Prediction Uncertainty**
  The uncertainty quantifies the range of possible deviations from the given forecast value in individual forecast situations. This additional information allows users to assess the risk of trusting in the prediction, e.g. [24].

These topics were, for example, investigated in the framework of the European research project ANEMOS [25].

5.2 Integration into Decision Support Tools

Wind power forecasts are helpful on all levels where the fluctuating production of wind farms needs to be taken into consideration, in particular, this comprises:

- Grid management
- Day ahead congestion forecasting (DACF)
- Storage management for wind energy
- Trading wind energy on wholesale markets

These topics are briefly highlighted in the following.

Grid Management: A highly localized wind power forecast allows predicting possible bottlenecks in local grids (Fig. 12). With forecasts for specific grid points a detailed picture of the anticipated load of the grid can be obtained. The predictions and the uncertainty of the predictions can be used as input for power flow calculations. The aim is to achieve an active grid management that reduces or avoids the danger of grid congestions due to wind power production. In addition, the wind power forecasting is to be used to integrate wind energy into the day ahead congestion forecast (DACF) of the European grid UCTE.

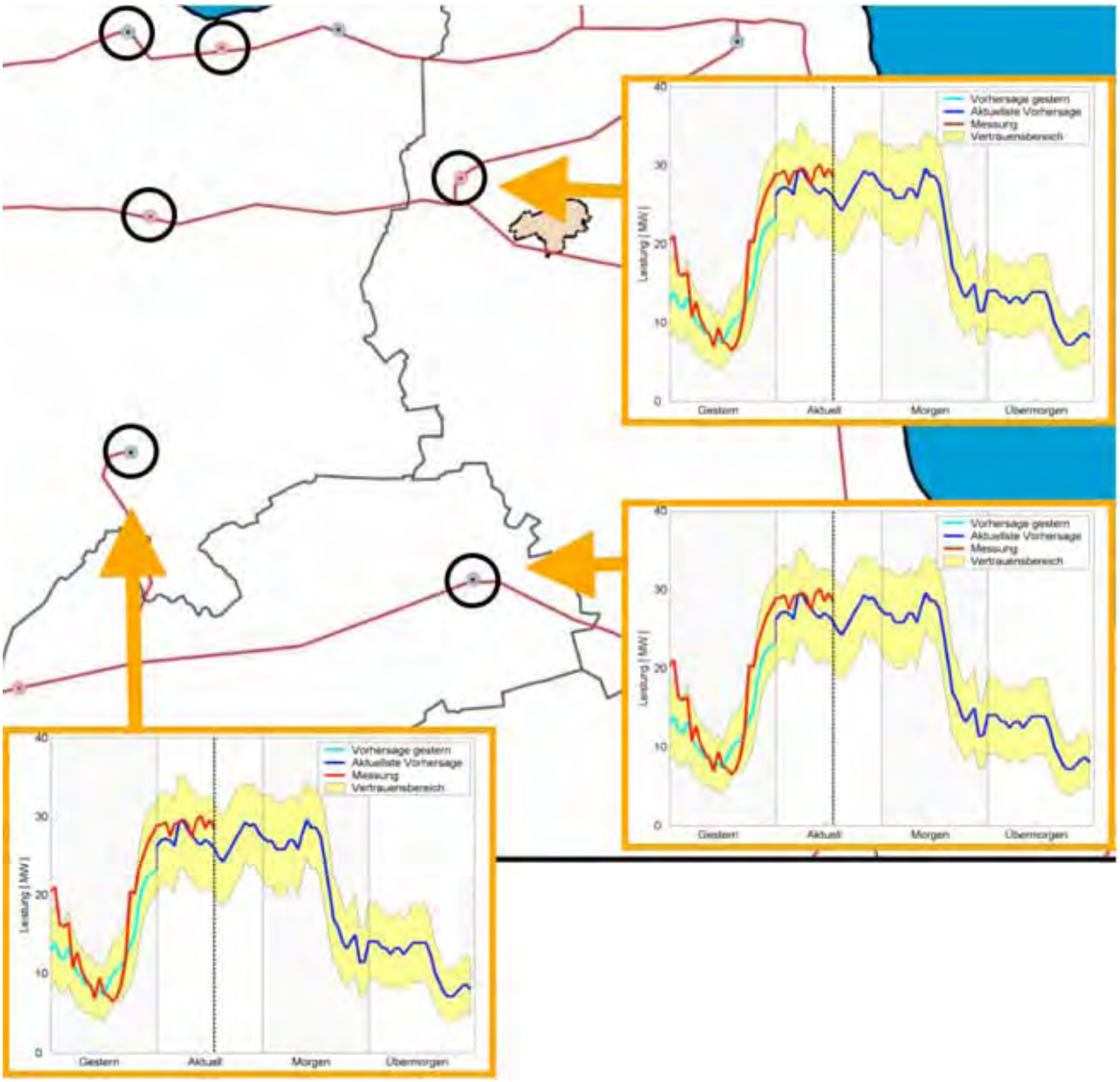

Fig. 12: Highly localized wind power predictions are used to predict the production at specific grid points. This provides the input for e.g. power flow calculation in local grids.

Storage management: Storage is regarded as very helpful to compensate for fluctuations of wind energy. Several techniques are already on the agenda for different applications, e.g. pumped water storage, compressed air, or hydrogen. Here, wind power predictions enable strategies to anticipatory operate the storage, e.g. to empty the storage shortly before a storm.

Trading wind energy: Wind power is currently traded on wholesale markets in several countries in Europe (Spain, The Netherlands) whereas in countries like Germany the transition from a purely fixed tariff system to a system which offers the opportunity for market participation is heavily discussed.

In order to directly trade wind power on the energy market, e.g. on intraday or day ahead markets, the amount of wind power that can be offered can only be known with a reliable prediction. The prediction is the key to create standard electricity products based on the weather-dependent energy production (Fig. 11). The important point is to estimate the volume risk associated with the offered wind energy by using the uncertainty of the wind power prediction

[26]. Meanwhile, trading platforms to manage the complete process from calculating wind power predictions for a large number of wind farms, pooling the wind farms, assessing the risk and producing bids for the energy markets in scheduling format have been developed [27].

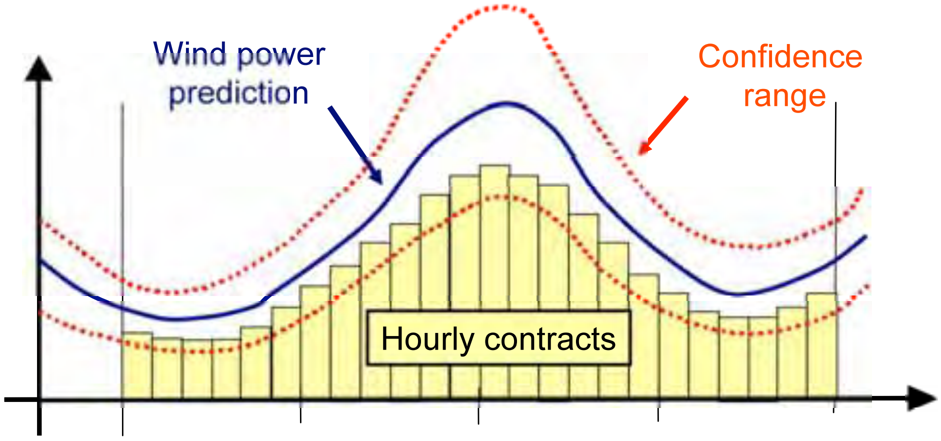

Fig. 11: With wind power predictions the fluctuating output of wind farms becomes a product on wholesale electricity markets.

Several development projects are dealing with the integration of wind power forecasts into decision processes of grid operators and energy traders. One of them is the European project ANEMOS.plus [28] starting in January 2008 where new intelligent management tools for addressing the variability of wind power are developed to demonstrate the applicability of such tools at an operational level both for managing wind penetration and for trading wind generation in electricity markets.

6. CONCLUSION

Wind power predictions are established as valuable tools to integrate wind energy into the electricity supply. The predictions of the power output of wind farms are mainly used for grid operation, power plant scheduling and trading. The important time horizons are intraday (0-23 hours), day-ahead (24-47 hours), and from Friday to Monday (72-96 hours).

Several providers offer wind power predictions on a commercial basis. The accuracy of the predictions has significantly improved over the last years.

This is also due to the intelligent use of several numerical weather predictions as input to wind power prediction systems opens further possibilities to reduce the forecast error. On-going projects in this direction focus on ensemble predictions and combinations of different weather models.

In order to further improve wind power forecasts intense research and development efforts are already on track. In a close co-operation between scientific community and energy industry the important topics of future wind energy utilization are treated. This comprises in particular offshore, complex terrain, up scaling of representative sites to regions, and assessment of the forecast uncertainty.

In the very near future, wind power predictions will be further embedded into the downstream processes of grid operators and traders. One example are highly localized predictions for specific grid points which can directly be used as input for power flow calculations, grid management or day-ahead congestion forecasts (DACF).

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Matthias Lange studied physics in Oldenburg, Warwick (UK) and Marburg (Germany). A scholarship recipient of the “German Foundation for the Environment” (Deutsche Bundes-stiftung Umwelt - DBU) he was awarded a doctorate in 2003 by the Carl von Ossietzky Universität Oldenburg on the subject of the uncertainties of wind power prediction. Before co-founding Energy & Meteo Systems in 2004, he was project leader for the grid integration and prediction of wind energy at the ForWind center for wind energy research. Prior to that he conducted on-location surveys for wind power facilities. Furthermore, Matthias Lange one of the co-developers of the wind power prediction system Previento and as such works for its transfer into operational service.

Ulrich Focken studied physics at the Carl von Ossietzky Universität Oldenburg (Germany). He began setting the focal point of his studies in physical-meteorological exploit-tation of renewable energies at an early stage. His diploma thesis and dissertation were on the determination of wind potential in complex terrain and wind power predictions. Before founding the company in 2004, he was project leader for grid integration and prediction of wind energy at the Oldenburg Center for Wind Energy Research ForWind. He also worked several years as a surveyor of international wind park projects, among others, for the German Wind Energy Institute (DEWI). Ulrich Focken was significantly involved in development of the wind power prediction system Previento as well as its conversion into operational service.

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6. Selected Studies on Offshore Wind Farm Cable Connections: Challenges and Experience of the Danish TSO

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Abstract**--**The Danish power system is characterized by a high share of wind power production. Most of the wind power has so far been distributed onshore and connected to the lower voltage levels. The recent tendency is to group it in large offshore wind farms. The wind farms are often connected directly to the high voltage network via long AC cable lines compensated by shunt reactors. These cable connections impose some additional challenges that should be considered in the planning stage. This paper presents the recent experience of the Danish TSO with long cable connections of wind farms and shows the results of selected simulation studies made of the planned Horns Rev B wind farm connection.

Index *Terms*--Harmonic analysis, Impedance, Inductors, Power cables, Power system transients, Voltage control, Wind power generation.

1. INTRODUCTION

So far two large offshore wind farms have been built in Denmark, the 160 MW Horns Rev A wind farm and the 165 MW Rødsand 1/Nysted wind farm. Both wind farms are connected directly to the high voltage network via long AC cable lines. The planned 210 MW offshore wind farms Horns Rev B and Rødsand 2 will also be connected to the transmission network by long HVAC cable lines. The cable connection of Horns Rev B will be the longest such connection built in Denmark; its nominal voltage will be 150 kV, and its total length will be slightly over 100 km. 42 km of this connection will be a sea cable and the remaining part will be a land cable. For the reactive power compensation of the cable, a shunt reactor will be installed close to the connection point between the sea cable and the land cable. Such a system of large shunt capacitance and reactor inductance may result in problems not normally encountered in networks based on overhead lines. This paper demonstrates the results of selected studies of the AC cable connection of Horns Rev B wind farm. The studies concern steady-state reactive power compensation issues, effects of cable/reactor systems on the harmonic impedances of the network and issues concerning transient over voltages appearing directly after the wind farm enters into isolated operation.

2. SYSTEM DESCRIPTION

Horns Rev B offshore wind farm will be located off the west coast of the Jutland Peninsula in Denmark, next to the existing Horns Rev A wind farm, as shown in Fig. 1. The farm will be composed of wind turbines of 2.3 MW rated power (in total approx. 210 MW). The wind turbines will be equipped with induction generators connected to the grid through full-scale frequency converters. The concept of such a wind turbine configuration is shown in Fig. 2. The power generated by these wind turbines will be transmitted via an internal MV network (split actually into two parts, part A and part B) from the farm to a three-winding transformer (220 MVA, 165/35/35 kV) installed on an offshore platform. The connection from the offshore transformer to the transmission network at a 150 kV substation, Endrup, will be achieved by an AC cable line of a length of some 100 km. Approximately 42 km of the cable line will be a sea cable and the remaining 58 km section will be placed onshore. A schematic diagram of the cable connection of

Horns Rev B wind farm is shown in Fig. 3. A 75 MVar compensating reactor will be installed in the middle section of the wind farm cable connection. The entire 150 kV wind farm connection, including offshore transformer, sea cable, compensating reactor, land cable, onshore connection point and 167.5/410 kV autotransformer belong to the Danish Transmission System Operator, Energinet.dk.

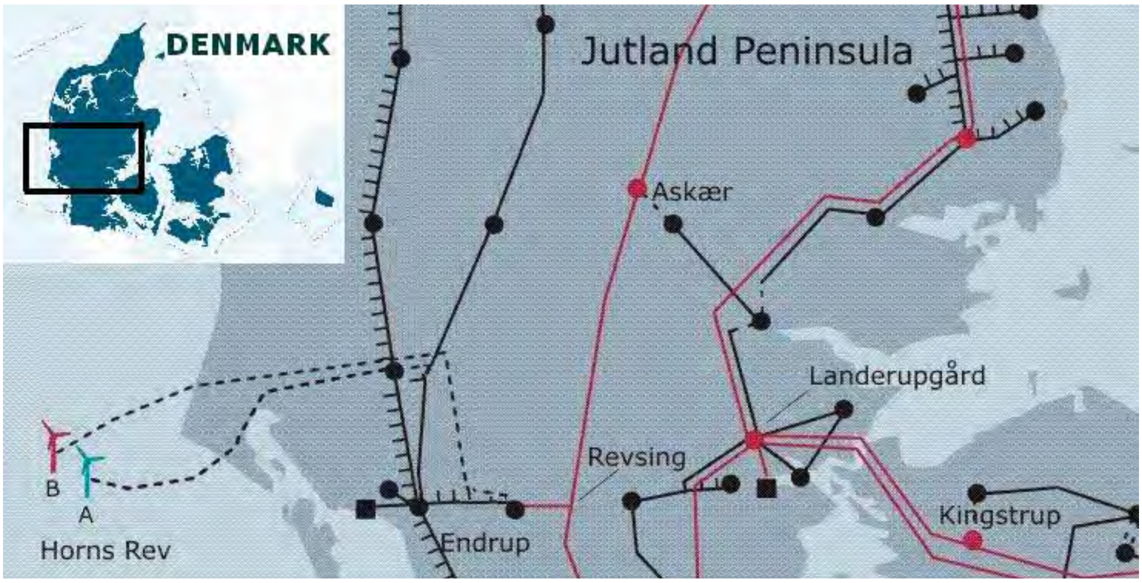


Fig. 1. Connection of offshore wind farms Horn Rev A (existing) and Horns Rev B (planned) to the transmission grid of Energinet.dk, Denmark.

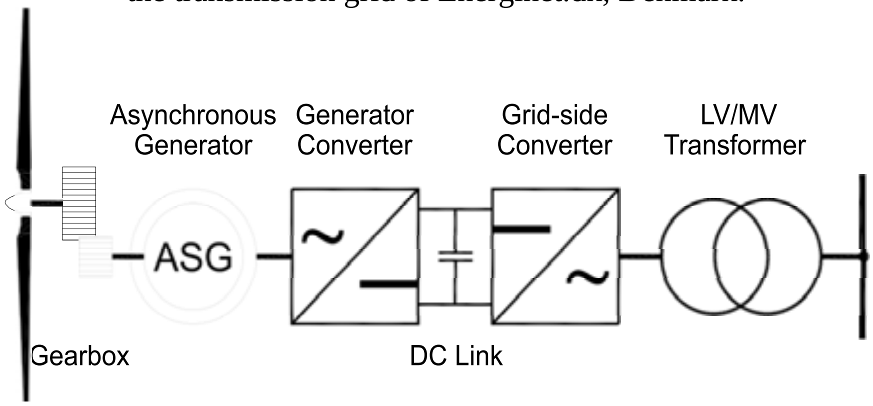


Fig. 2. The configuration of a wind turbine with induction generator and full-scale frequency converter [1].

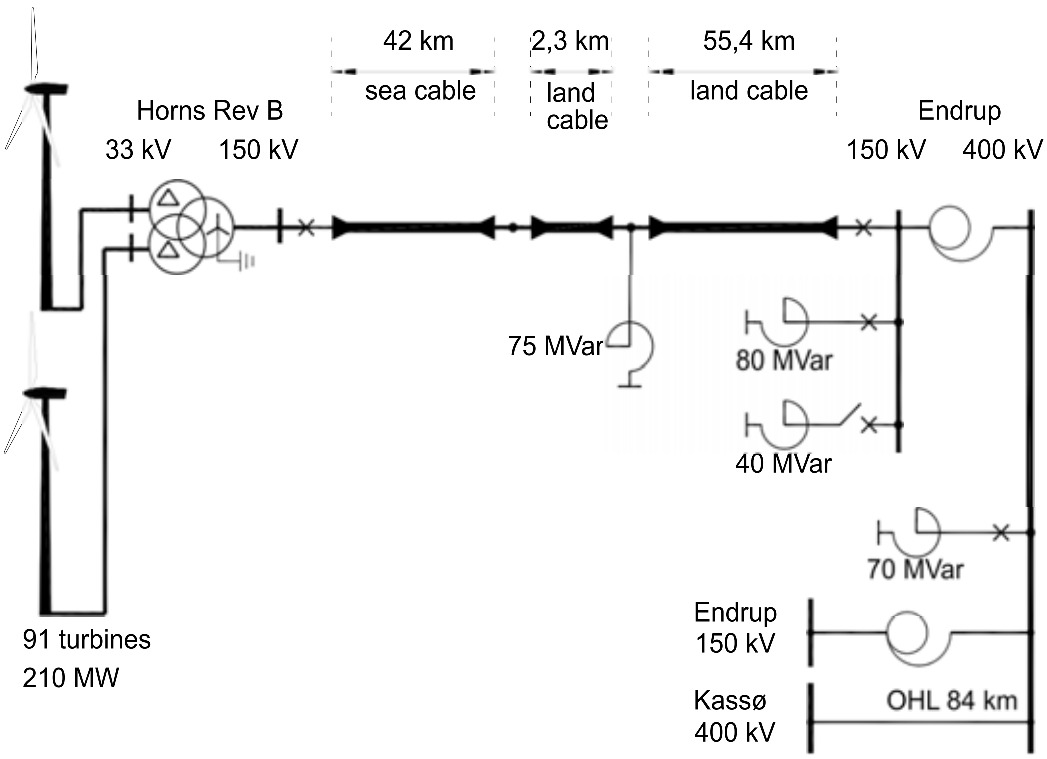


Fig. 3. **Schematic** diagram of the AC cable connection of the planned Horns Rev B wind farm.

The main components installed directly at Endrup 150 kV and 400 kV substations are also illustrated.

3. THE NETWORK MODEL

Energinet.dk carries out various technical analyses and simulations using, among other tools, the DIgSILENT PowerFactory simulation software. A model of the entire electrical power network is available with exact representation of all 400 kV, 150 kV and 132 kV power lines. The aggregated 60 kV distribution network models, main power plants, aggregated onshore wind power generation; CHP plants and loads are connected to the 60 kV buses of the corresponding models of HV/MV transformers.

The studies presented in this document of the Horns Rev B wind farm cable connection concerning steady-state reactive power compensation and harmonic network impedance were made using this full network model. The transient investigations presented in section 0were also made using the PowerFactory software (EMT module), but the entire network model was not necessary. Only the essential components were therefore included in the EMT model.

4. REACTIVE POWER COMPENSATION

AC cable lines are characterized by many times as large shunt capacitance compared to overhead lines. The resulting charging current will limit the remaining cable ampacity for active power transfer, increase the active power losses and increase the voltage along the line due to the Ferranti effect.

In order to reduce these negative effects in long HVAC cable lines, reactive power compensation may need to be installed not only at the ends of the line but also along the line.

4.1 Cable ampacity and reactive power flow

The loading of an open-end cable line due to charging current for various distributions of the reactive power compensation along the line is illustrated in Fig. 4. Basically, the worst case would be if the compensation were installed at one end only. It is better to install it in the middle because the reactive current would flow towards the reactor from both sides, so only half of the charging current would be flowing at the most loaded points. The same effect would be reached if the compensation were distributed equally at both ends of the line. If more compensating stations are located along the line in order to obtain an optimal loading of the line, the compensation located at both ends should be half the compensation located along the cable line.

In the actual case of the Horns Rev B cable connection it was decided to install reactive power compensation approx. 2 km from the shore. The size of the reactor is 75 MVar and as can be seen in Fig. 5 a) and Fig. 5 b) it entirely compensates the capacitance of the sea cable (0.3 kA). Behind the reactor location (closer to the shore) the reactive current is zero but increases again up to 0.4 kA at the onshore connection point. It can also be seen that in case the reactor is out of service, the charging current of an open-ended cable will exceed 0.7 kA at the connection point, and in case the wind farm generates full power, the current at the connection point will be 0.86 kA - higher than the cable ampacity, whereas with the reactor in service and full wind farm production it will be within limits - 0.73 kA. Fig. 5 b) shows that the reactive power generation of an open-end cable is 210 MVar and, if loaded with active power, the overall reactive power is reduced (due to the series reactance) by 60 MVar.

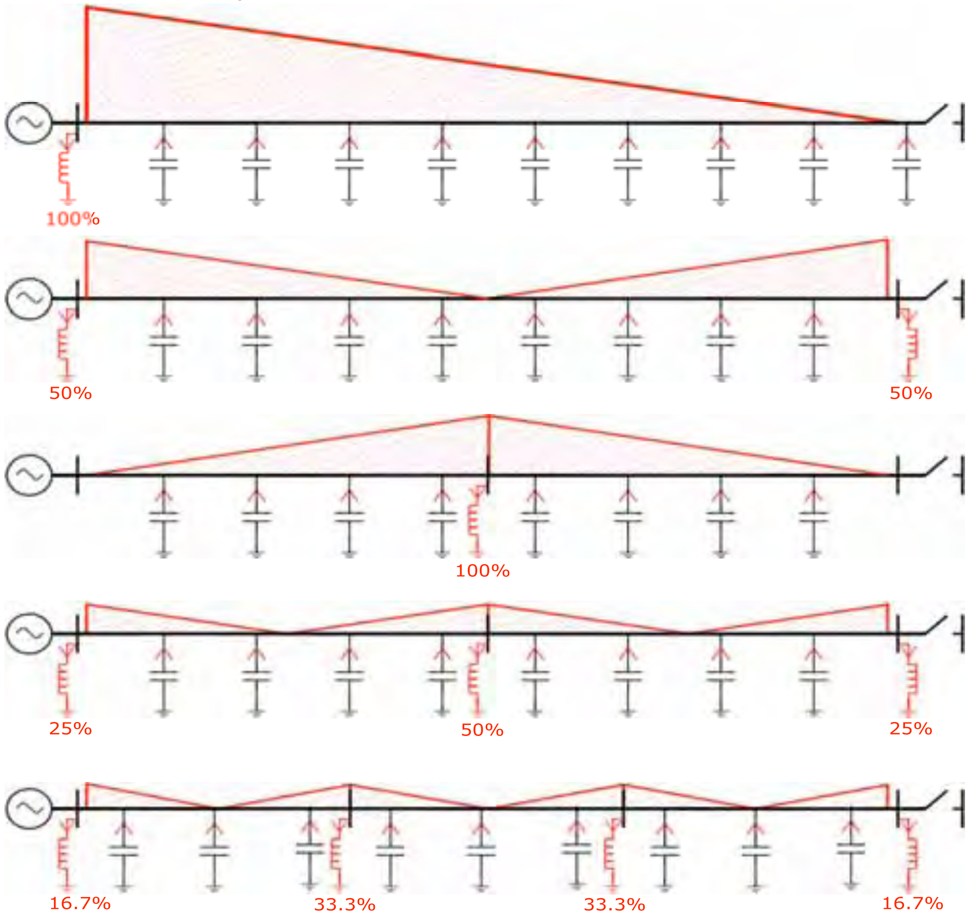
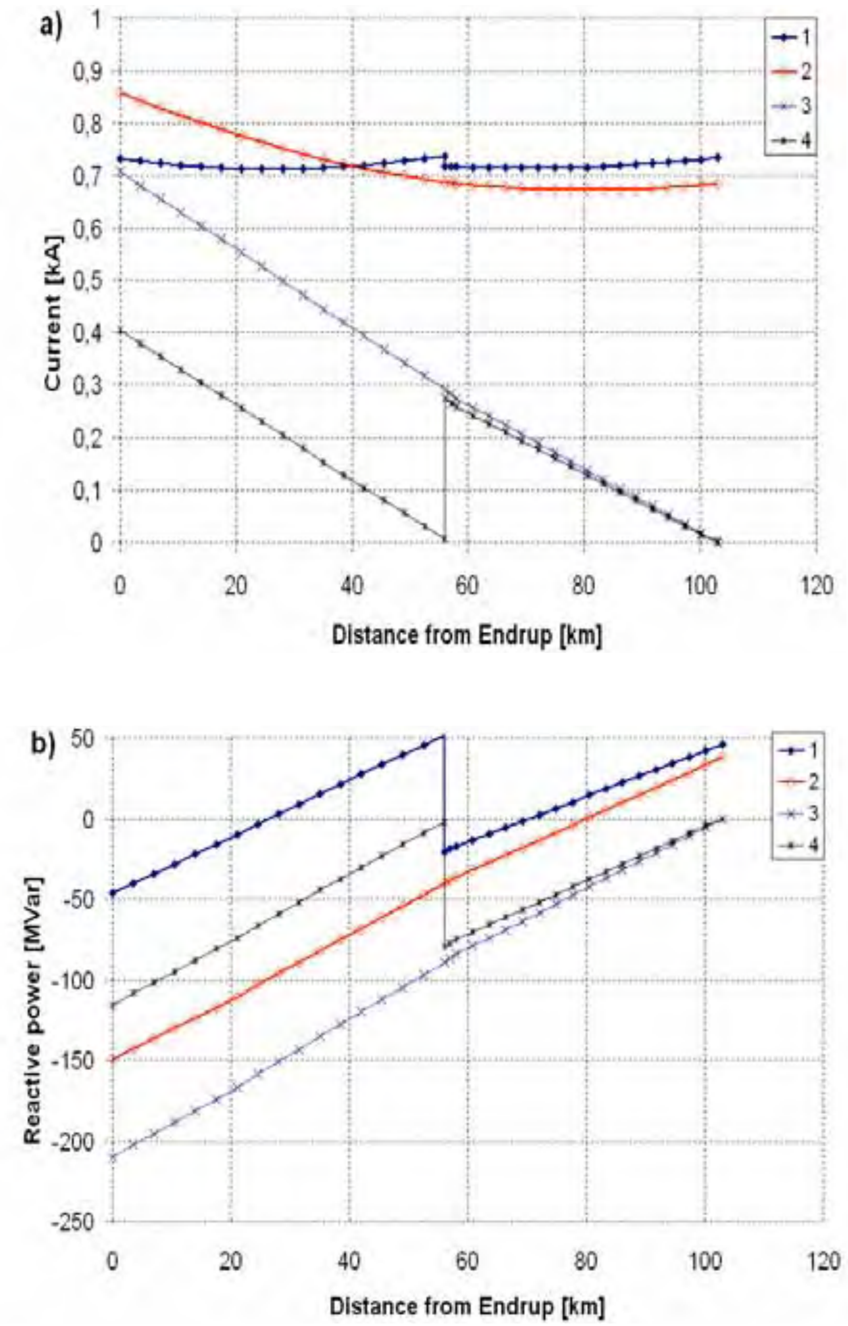


Fig. 4. Loading of an open-end cable line due to the capacitive charging current for different schemes of reactive power compensation.



1 Full power generation, shunt reactor in service;
2 Full power generation, shunt reactor out of service;
3. Wind farm disconnected at the three-winding transformer, shunt reactor out of service;
4. Wind farm disconnected at the three-winding transformer, shunt reactor in service

Fig. 5. a) - RMS current value, and b) - reactive power at different locations along the HVAC cable connection of Horns Rev B wind farm in various situations:

In such a case nearly 40 MVar is consumed by the series reactance of the offshore transformer. This 40 MVar is delivered by the cable capacitance, and as can be seen, a 20 km section of the cable balances it (at the distance of approx. 20 km from the offshore transformer, 80 km from Endrup the reactive power is zero). Closer to the shore the reactive power produced by the cable increases and flows towards the gird.

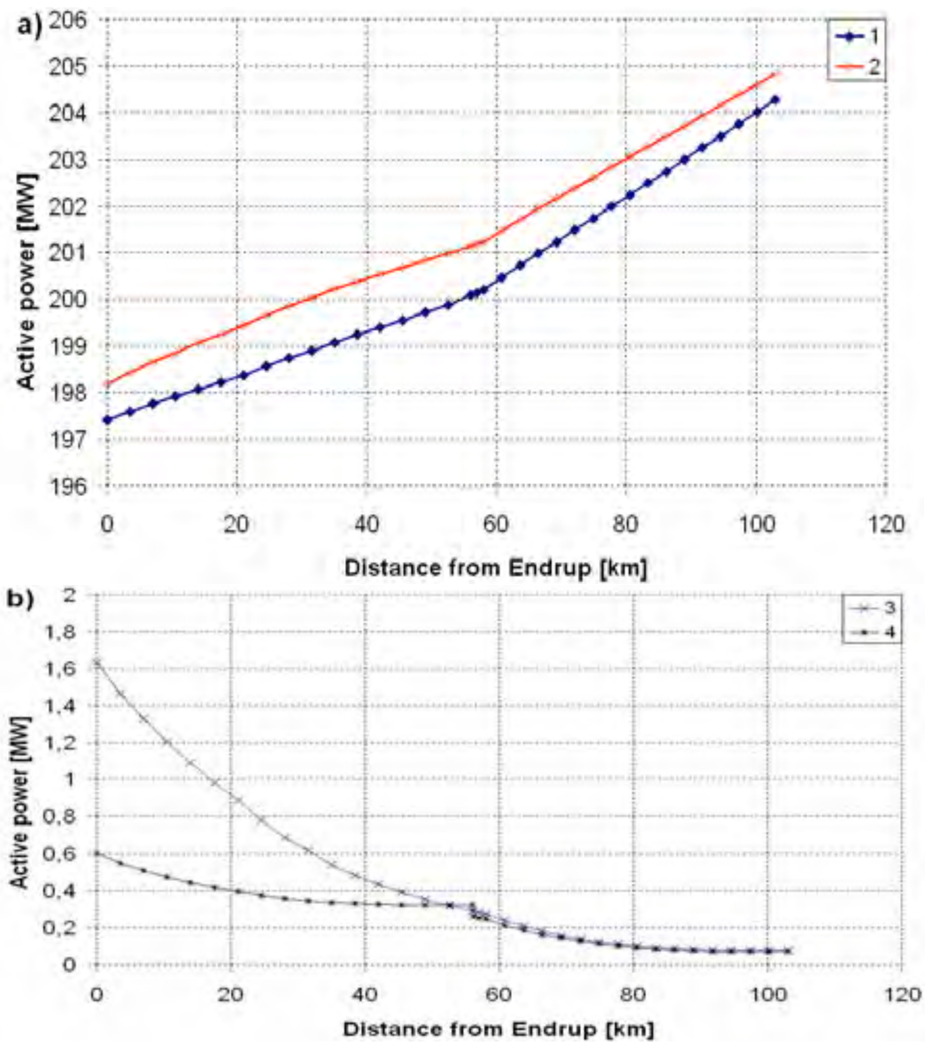
If the shunt reactor is in service, the voltage in the system becomes lower, the current flowing through the offshore transformer becomes larger, and the reactive power consumption becomes higher due to its series inductance.

4.2 Effect of the shunt reactor on active power losses

Fig. 6 shows the active power flow in the cable line under various conditions. In general, without the shunt reactor in service, the power loss in the line has increased, both at full generation and at no load conditions, because the reactive power is provided locally and does not have to flow longer distances through the system resistances.

The output of a wind farm is obviously a function of the wind, and the level of losses in the AC connection of the farm is a function of the output of the wind farm. Therefore, the wind farm's realistic levels of generation have to be known to assess the total yearly energy loss in the cable connection with and without the shunt reactor in operation.

The planned wind farm Horns Rev B will be located close to the existing offshore wind farm Horns Rev A. The amount of active power generated by both wind farms can therefore be expected to be strongly related to each other.



1 - Full power generation, shunt reactor in service;
2 - Full power generation, shunt reactor out of service;
3- Wind farm disconnected at the three-winding transformer, shunt reactor out of service;
4 - Wind farm disconnected at the three-winding transformer, shunt reactor in service.

Fig. 6. Active power flow in the HVAC cable connection of Horns Rev B wind farm in various situations a) - full power generation, b) - open end at the offshore transformer.

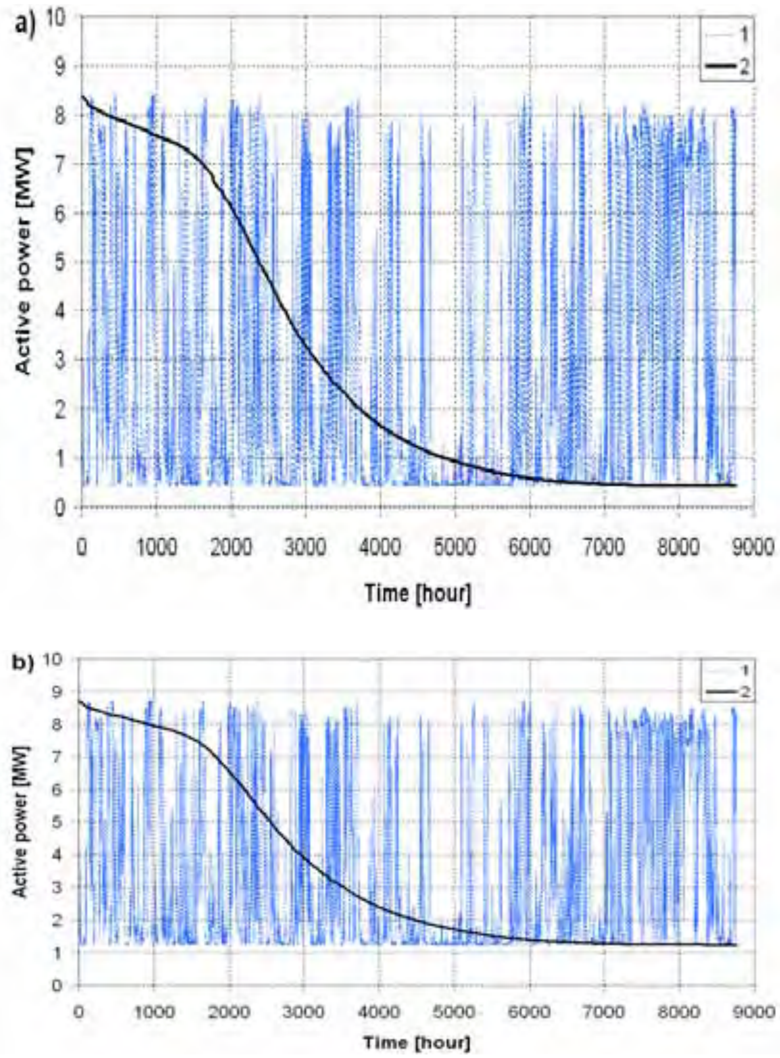
This fact can be used to estimate the losses in the AC cable connection of Horns Rev B wind farm. The power generated by Horns Rev A wind farm has been continuously monitored. A different value is available for every hour of for instance year 2006 (8760 hours). Such values after rescaling (to match the larger size of Horns Rev B) have been used, and 8760 load-flow calculations have been run with and without the shunt reactor in service. The total active power losses (including the losses in both transformers) have been calculated and the results are shown in Fig. 7.

From these calculations, the total yearly energy loss in the cables and the transformers up to the 400 kV substation Endrup (but without the MV internal wind-farm network) is estimated at 25.26 GWh with the shunt reactor in service and 31.08 GWh without the reactor. This means that the presence of the compensating reactor has reduced the energy loss by some 23%.

4.3 Effect on the voltage profile

Energinet.dk's guideline for operation of the 150 kV network states that the voltage should be kept in the 160-167 kV range, and that the maximum operating voltage cannot exceed 170 kV.

Fig. 8 shows the phase-to-phase voltage amplitude at different points along the cable line under various conditions. The entire network model used in the study was the same in each case; the only changes were the switching in/out of the shunt reactor along the cable line, and having either full power generation from the wind farm or having the wind farm disconnected at the offshore transformer.



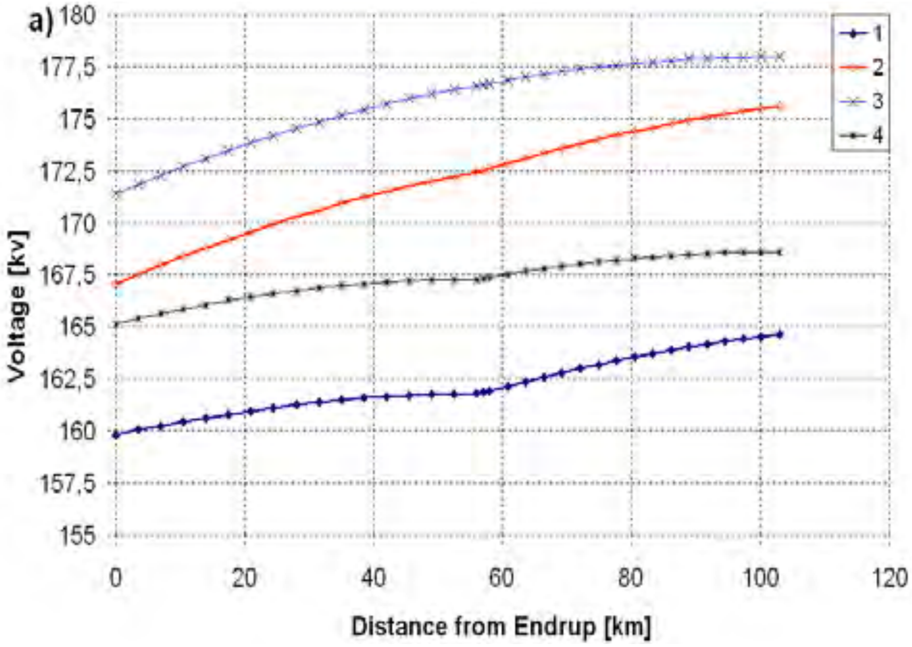
1 - Power loss calculated every hour,
2 - Duration curve.

Fig. 7. Anticipated active power losses in the Horns Rev B AC cable connection including the offshore transformer and the autotransformer, calculated for every hour using the wind conditions prevailing in the area in 2006. a) - with shunt reactor in service, b) - without shunt reactor.

At full power generation and with the reactor in service, the voltage at Endrup 150 kV substation is 160 kV, and it rises to nearly 165 kV at the offshore transformer. When the wind farm is disconnected, the voltage at Endrup substation is 165 kV and 168.5 kV at the offshore transformer.

If the shunt reactor is disconnected and the wind farm generates full power, the voltage at Endrup is 167.5 kV and it rises at the offshore transformer to 176 kV. When the wind farm is disconnected at the offshore transformer, the voltage is 171.5 kV at Endrup and reaches 178 kV at the offshore transformer.

As can be seen, the voltage is within required limits in both cases with the shunt reactor in service, whereas the allowed maximum voltage level is exceeded in both cases when the reactor is out of service.



1 - Full power generation, shunt reactor in service;
2 - Full power production, shunt reactor out of service;
3.- Wind farm disconnected at the three-winding transformer, shunt reactor out of service;
4.- Wind farm disconnected at the three-winding transformer, shunt reactor in service.

Fig. 8. Voltage amplitude along the HVAC cable connection of Horns Rev B wind farm in various situations:

5. HARMONIC IMPEDANCE OF THE NETWORK

Wind turbines with full-size frequency converters produce some level of harmonic currents.

In general, the grid-side converters have clock frequencies in the range of 2-3 kHz and mainly produce interharmonic frequencies [1]. In order to assess the level of voltage distortion caused by a wind farm, the network harmonic impedance seen from the wind farm terminals must be known.

The harmonic impedance of the network at Horns Rev B wind farm has been determined by calculating the frequency sweep with the DIgSILENT PowerFactory simulation software [5] and the full network model.

5.1 Modification to the computer network model

The computer model of the network had to be adjusted in order to correctly represent the higher frequency behavior of the physical network. State-of-the-art adjustments have been made [2], and the most important ones are listed briefly below:

1) Transmission lines

DIgSILENT PowerFactory software calculates line constants from the tower geometries. All the data of the conductors was included as well as the distributed parameter nature of the lines, skin and non-ideal earth return path effects, etc. [2].

2) Transformers

Frequency-dependent series resistance of transformers is increasing with the square root of harmonic order [3], [4]. The series inductance is constant.

3} Synchronous machines

The resistance of synchronous machines increases with the square root of harmonic order. The reactance is the average value of sub transient reactance [3].

4) Asynchronous machines

The locked rotor resistance increases with the square root of harmonic order [3]. The reactance is the sum of stator and rotor reactance [3].

5) The Horns Rev B cable connection

The electrical constants of the cables have been taken from the manufacturer catalogues. From these values the software creates an equivalent pi circuit of the lines (to achieve the effect of distributed parameters [3]). Unfortunately the skin effect on the series reactance could not be calculated automatically. Therefore, a frequency characteristic was assigned to the series resistance *R(f)*, according to the method of Electricité de France (EDF) for power cables at voltage levels below 225 kV and harmonic order above the second harmonic [3] (1):

$$R(f) = R_1 \cdot \left(0{,}187 + 0{,}532 \cdot \sqrt{h}\right) \qquad (1)$$

where R_1 is the 50 Hz positive sequence resistance value and h is the harmonic order.
The frequency sweep was performed from 10 Hz up to 3 kHz, as shown in Fig. 9.

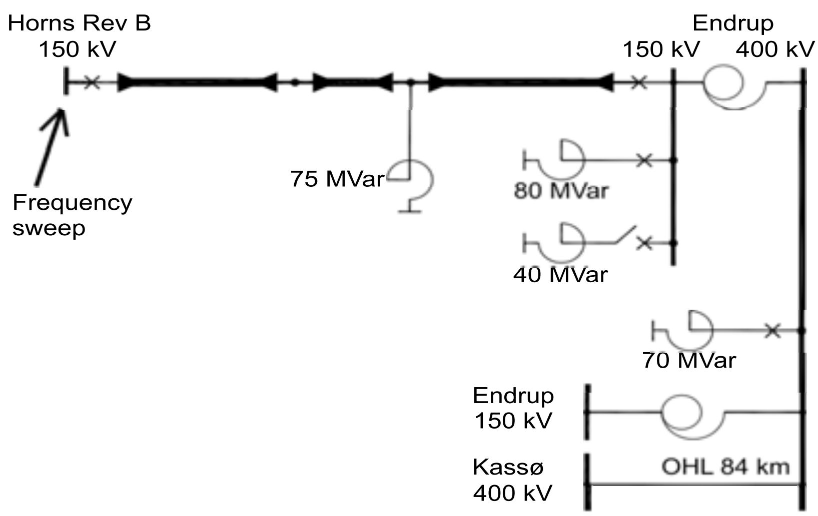


Fig. 9. Determination of the network harmonic impedance at Horns Rev B.

Two cases were inspected at first, with and without the 75 MVar shunt reactor in operation. The obtained harmonic impedance amplitude, phase angle, and the impedance locus are shown in Fig. 10.

Fig. 10 a) and b) show that the first parallel resonance is at the frequency of approx. 140 Hz. Such a low frequency of the first resonance is due to the high capacitance of the cable line. The equal distribution of the resonances along the frequency axis suggests that the harmonic impedance is dominated by the impedance of long cable line.

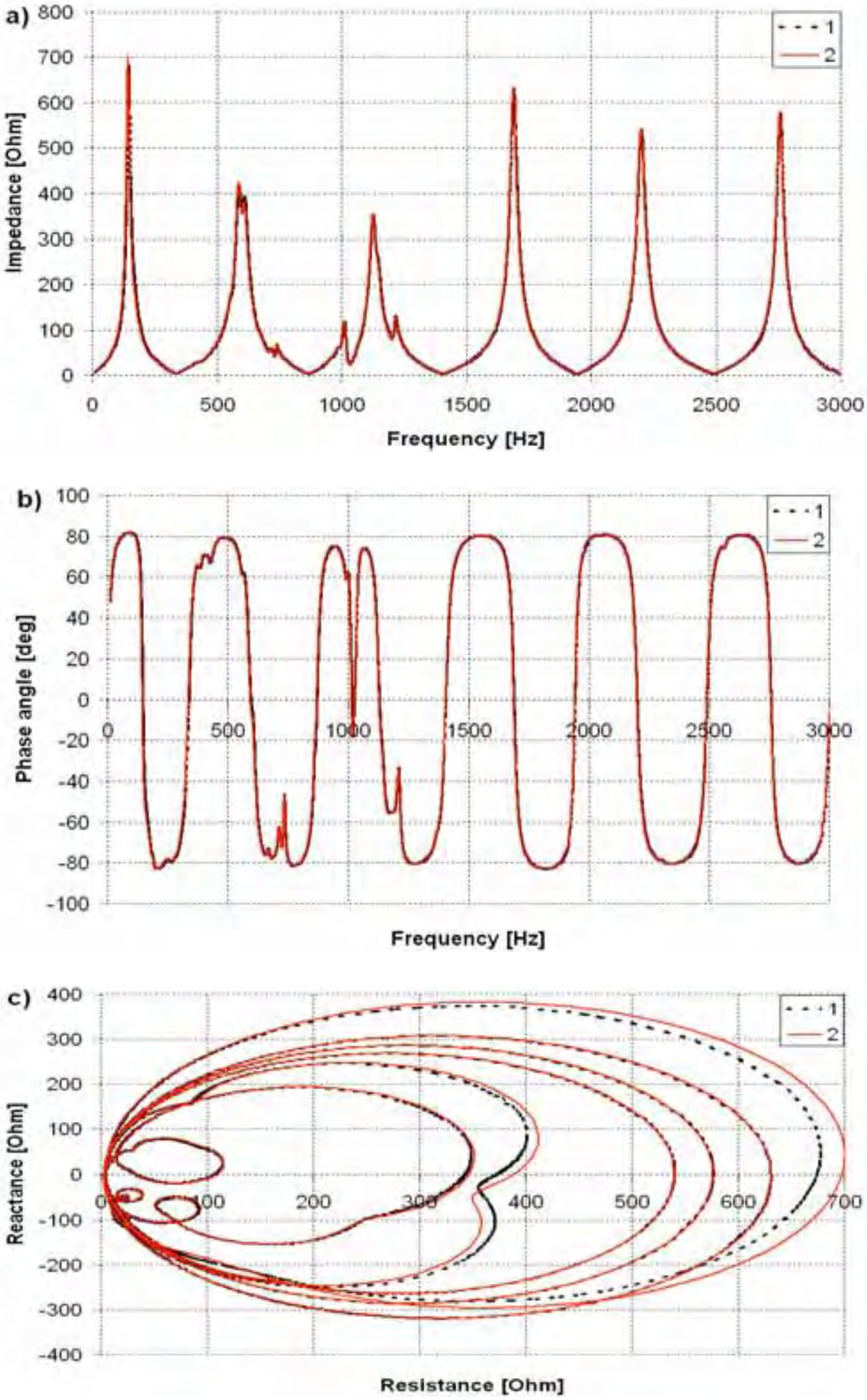


Fig. 10. Positive sequence network harmonic impedance determined at the HV side of the offshore transformer Horns Rev B. The transformer is disconnected. a) - magnitude, b) - phase angle, and c) - harmonic impedance locus. 1 - base case, 2 - shunt reactor disconnected.

Only up to the 1.5 kHz are there some additional resonances, which should be attributed to the effects of other components present in the system.

Disconnection of the shunt reactor does not change the impedance to any significant degree; the impedance magnitude of the first resonance is a little higher due to a higher quality resonant circuit. This is difficult to notice both in the magnitude and the phase angle plots of Fig. 10, and on this occasion, the advantage of using the impedance locus plot - Fig. 10 c) - manifests itself. There are six parallel harmonic resonances in the frequency range in question; it indicates that the switching frequency of the grid-side converters should be matched to the system impedance in order to avoid any excessive harmonic voltages.

5.2 Extent of transmission network model required for correct determination of harmonic impedance

In this study the entire transmission network model was used to calculate harmonic impedance. However, it would be beneficial if it could be proved that a reduced model would suffice. This would be favorable both because the computational burden would be smaller and the required amount of data would be reduced. In order to inspect whether a reduced size model would suffice, an equivalent model was built, see Fig. 11, with the X_{eq} as the equivalent system reactance ωL_{eq}, with L_{eq} constant, and with R_{eq} as the frequency-dependent equivalent system resistance, increased by the factor of $\sqrt{h}$, where h is the harmonic order. The comparison of the harmonic impedances determined using the full model and the simplified model is shown in Fig. 12. As can be seen, the agreement is good - especially at higher frequencies. The magnitude at the lower frequency resonances is higher than the one obtained using the full model. Some resonances are not represented around frequencies 400 Hz up to 1400 Hz (most likely due to lack of capacitances of the 400 kV overhead lines connected directly to Endrup 400 kV substation), but the differences are still small. It can be stated that such a simplified model is satisfactory for general studies, and a more detailed network model may only be necessary if the switching frequency of wind turbine converters is very close to a frequency of a parallel resonance. That is moreover true because the actual wind farm is installed on the MV side of the offshore transformer, so the series transformer impedance would make the differences between the results obtained from the full model and the simplified model even less significant.

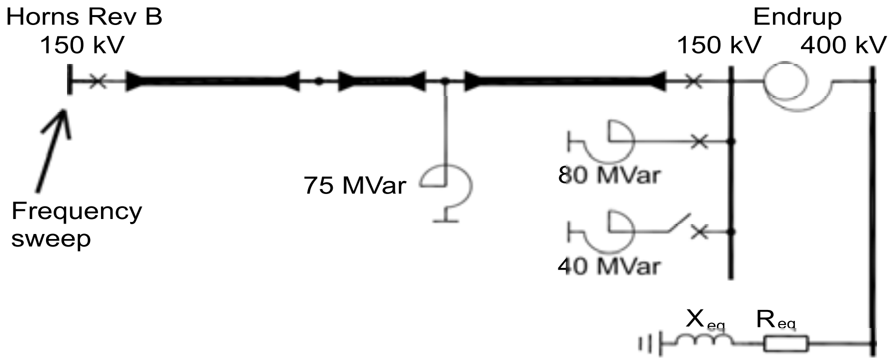
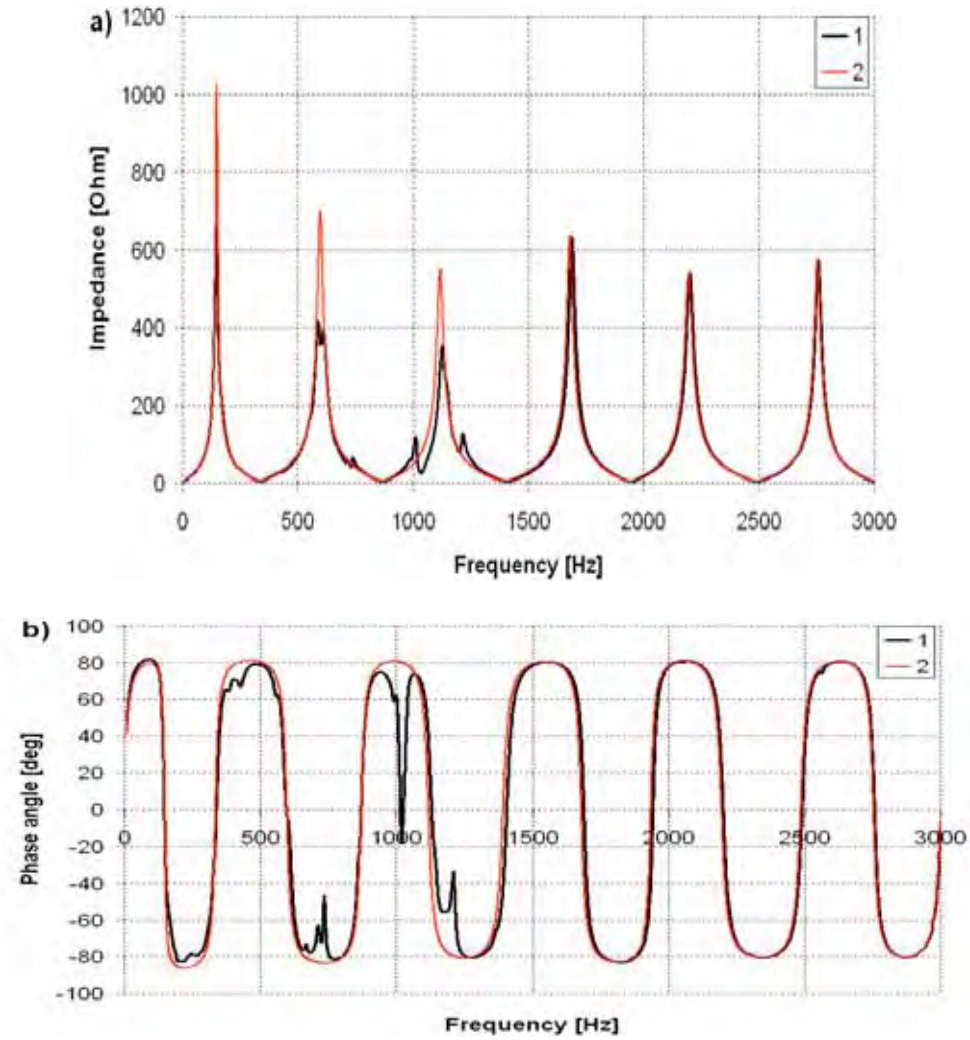


Fig. 11. Schematic diagram of the AC cable connection of the planned Horns Rev B wind farm with the impedance of the remaining power system represented as equivalent elements R_{eq} and X_{eq}.



1 - Harmonic impedance obtained using the full model,
2 - Harmonic impedance obtained using the simplified network model.

Fig. 12. Positive sequence network harmonic impedance determined at the HV side of the offshore transformer Horns Rev B. The transformer is disconnected. a) - magnitude, b) - phase angle

The harmonic impedance seen on the MV side of the offshore transformer will have a different value than the one seen on the HV side due to the transformer impedance (besides the transformer ratio), see Fig. 13. As can be seen especially in Fig. 13 b), the series transformer reactance causes the total harmonic impedance to be predominantly inductive.

The harmonic impedance in Fig. 13 is in fact not the final harmonic impedance seen by Horns Rev B wind farm, although it is close to reality. The reason for that is that it was determined at one MV terminal of the offshore transformer and the other part of the wind farm connected to the other MV winding of the offshore transformer was not present during the simulation.

The AC cable connection, offshore transformer, MV wind farm networks, and the power system can be represented as an equivalent circuit as shown in Fig. 14. At higher frequencies, the wind turbines, together with the internal MV networks of Horns Rev A and B can be represented as equivalent current sources I_{ah} and I_{bh} and some value of impedances Z_{Ah} and Z_{Bh}. The network harmonic impedance shown in Fig. 10 is the impedance Z_{eqh}, and the harmonic impedance from Fig. 13 is a sum of the impedances:

$$Z_{TA} + Z_{THV} + Z_{eqh}, \qquad (2)$$

where Z_{TA} is the series harmonic impedance of the corresponding MV winding, and Z_{THV} is the series harmonic impedance of the HV winding.

However, during normal operation of both wind farms, the harmonic currents I_{Bh} generated by Horns Rev B would in reality see the harmonic impedance of the system, altered by the harmonic impedance of Horns Rev A:

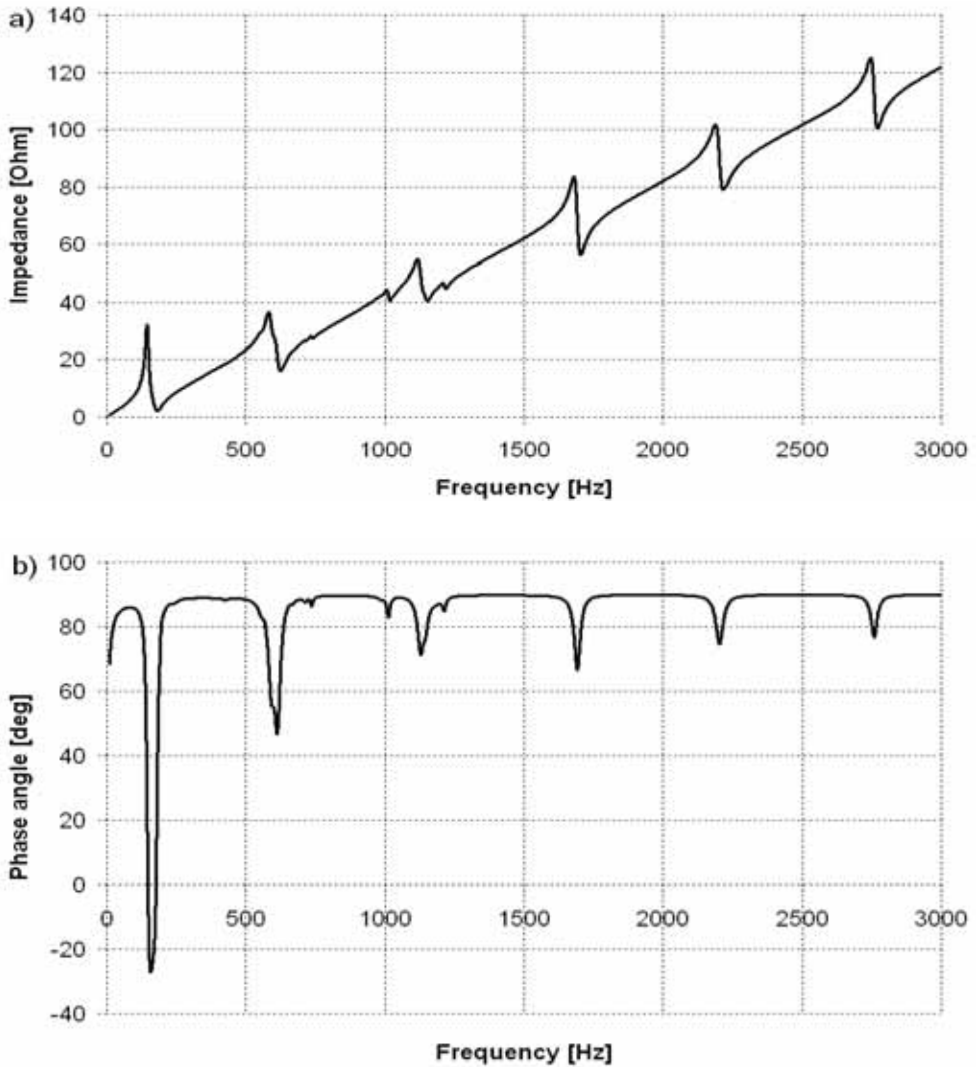


Fig. 13. Positive sequence network harmonic impedance determined at the MV side of the offshore transformer Horns Rev B, "seen" from only one side of the wind farm. The other part of the farm, connected to the other MV winding is disconnected. a) - Impedance magnitude, b) - Impedance phase angle.

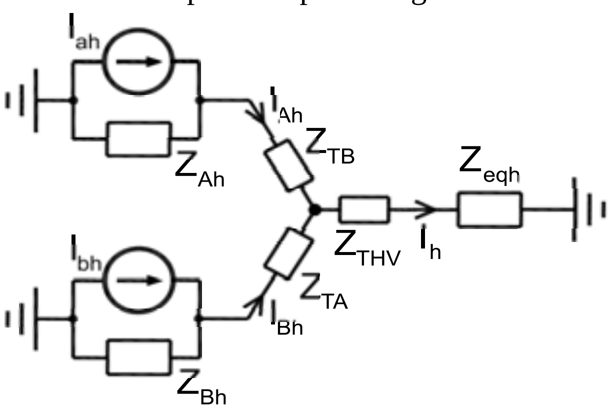


Fig. 14. Equivalent circuit of wind farms A and B, the offshore transformer, and the rest of the power system with the long AC cable line.

$$Z_{TA} + \frac{(Z_{THV} + Z_{eqh}) \cdot (Z_{TB} + Z_{Ah})}{Z_{THV} + Z_{eqh} + Z_{TB} + Z_{Ah}}, \qquad (3)$$

where Z_{TB} is the series harmonic impedance of the corresponding MV winding.

Since the wind turbines are equipped with full-size converters, their harmonic impedance seen by other harmonic sources can be represented as an open circuit [3]. Therefore, the harmonic impedance of a wind farm Z_{Ah}, seen from the outside will be composed of the cable capacitances C_L, resistances R_L, inductances L_L, impedances of MV windings of the turbine transformers R_{MV}, X_{MV} and their magnetizing impedances R_m and X_m, as shown in Fig. 15.

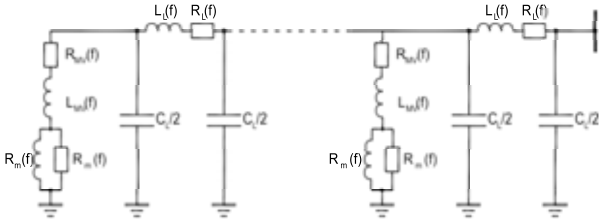


Fig. 15. The equivalent circuit of wind farms A and B, seen from the MV bus of the offshore transformer, is dominated by the cable impedances and capacitances. The impedances of the MV windings and the magnetizing impedances of the turbine transformers may be included for better accuracy.

6. TRANSIENT OVERVOLTAGES DUE TO THE WIND FARM DISCONNECTION

There is a risk of significant over voltages in the long AC cable/shunt reactor system of Horns Rev B wind farm. An issue of special concern is the temporary over voltage that can occur immediately after the main circuit breaker at the on-land connection point disconnects the cable from the rest of the transmission network and the wind farm together with the cable goes into isolated operation.

Energinet.dk has experienced such over voltages in Horns Rev A offshore wind farm. The over voltage reached 2.3 p.u. before the protective systems of particular wind turbines disconnected them from the internal MV network of the wind farm. In the first moments the turbines still injected active current into the separated network, charging its capacitance. After they had been disconnected, the energy stored in the long AC cable capacitance and the shunt reactor inductance oscillated with low frequency, leading to high over voltages lasting for seconds. The measurement results, consequent analyses and conclusions obtained by Energinet.dk based on the experience from Horns Rev A wind farm are described in [6]. Also some preliminary studies concerning Horns Rev B wind farm have been shown. However, at that time limited information was available on the particular solutions that will be applied in relation to Horns Rev B wind farm.

This paper presents a follow-up study of the transient over voltage issues at Horns Rev B wind farm.

Fig. 16 shows the Horns Rev B wind farm cable connection that was modeled in the EMT simulation module of the DIgSILENT PowerFactory software. A generic model of wind turbines has been used with the frequency converter modeled as a controlled voltage source placed behind the turbine transformer. Some realistic values of impedances and capacitances were used to represent the influence of the internal MV network of the wind farm.

Under normal operating conditions, a fast communication channel links the two circuit breakers CB1 and CB2. Both circuit breakers therefore open at the same time during operation. However in case of a failure of the main communication channel, the communication is redirected to a reserve channel. In such a case, the delay between the operation of circuit breakers CB_1 and CB_2 can reach 15 ms.

The actual level of worst-case over voltages needs to be assessed in order to design appropriate over voltage protection capable of absorbing the excessive energy.

Two basic cases have been inspected: when both circuit breakers operate simultaneously, and when there is a 15 ms delay between the operation of CB_1 and CB_2. Since the over voltage values depend on the point of wave switching, point of wave switching studies have been made, see Fig. 17. In order to inspect all possibilities, the time of switching circuit breaker was changed to cover the entire waveform period, from 0 ms up to 20 ms in steps of 1 ms.

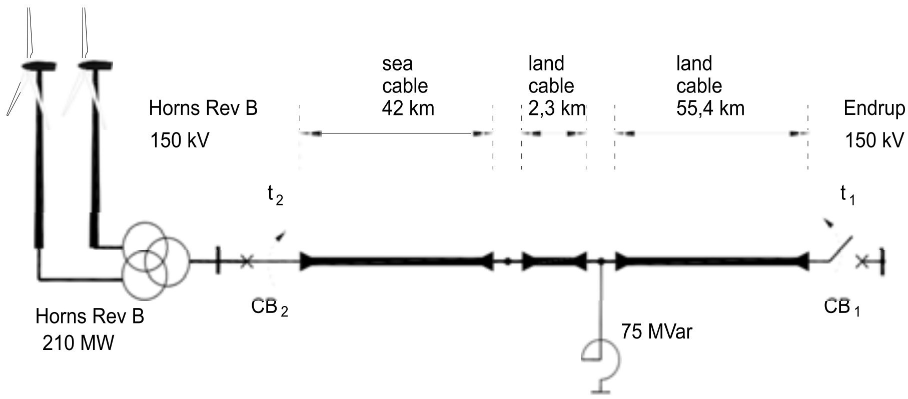


Fig. 16. Extent of the Horns Rev B wind farm connection modeled in the EMT simulation module of the DIgSILENT PowerFactory software.

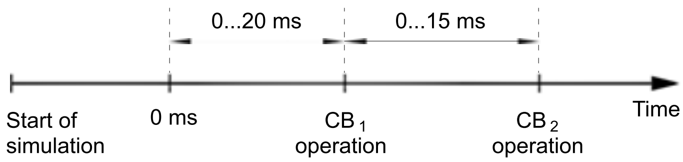


Fig. 17. The time of point of wave switching studies.

Simultaneously the time of switching the second circuit breaker after the first one was increased from zero (for simultaneous operation) up to the maximum delay of 15 ms, which means that 300 simulation runs were performed. Fig. 18 shows the 3-phase voltage at the EDR150 substation in case of simultaneous tripping of both circuit breakers, and Fig. 19 shows the worst case over voltage on the cable/reactor system after it has become separated from the system and the offshore transformer. As can be seen in the case of simultaneous tripping of both circuit breakers the over voltage is approx. 1.35 p.u., and it is the first peak value that reaches such a value. Where CB_2 trips 14 ms after CB_1, the over voltage reaches the level of 2.2 p.u. and it decays very slowly due to the energy oscillating between the shunt reactor and the capacitance of the cables. In the first moments after circuit breaker CB_1 opens, the wind turbines still generate

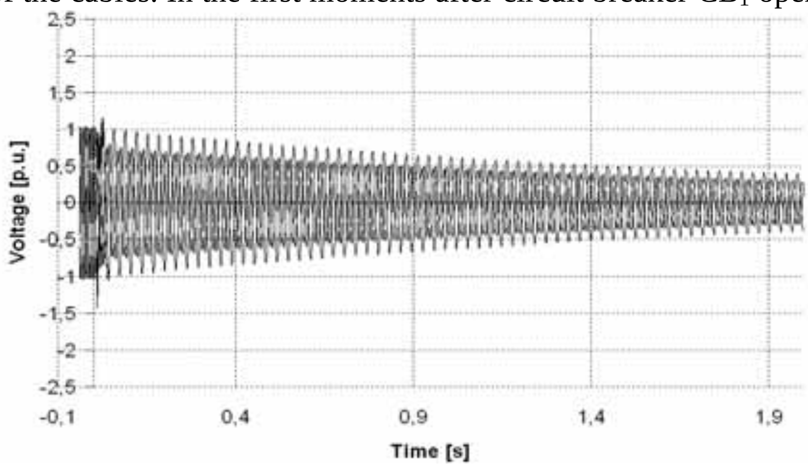


Fig. 18. 3-phase voltage at the EDR150 substation in case of simultaneous tripping of both circuit breakers CB_1 and CB_2.

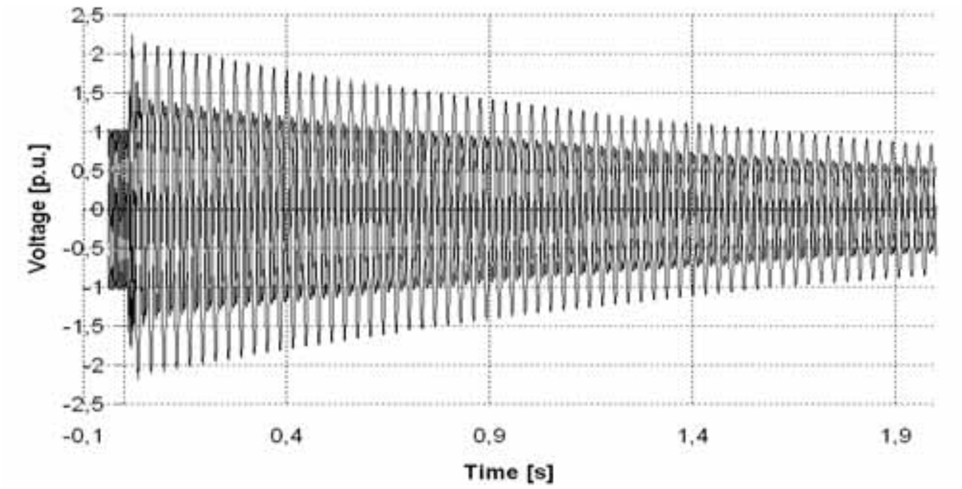


Fig. 19. 3-phase voltage at the EDR150 substation in case of 14 ms delayed tripping of circuit breaker CB_2 after the tripping of circuit breaker CB_1.

power. The injected current charges the large capacitance of the internal MV network and the long AC cable connection resulting in an increase in the AC voltage. As a consequence, also the wind turbine converter DC link voltage increases. When the DC link voltage exceeds a certain value, the protection of the wind turbine reacts, and the converter of the wind turbine is blocked. The time from the disconnection of the wind farm by circuit breaker CB_1 until the converters block is a function of the setting of the DC voltage level leading to the tripping, transfer function of the grid-side converter and the time constant of the increase in the AC voltage. Therefore, in order to model most exactly the behavior of the wind turbine, the above-mentioned parameters should be known.

7 CONCLUSION

i. Thanks to the reactive power compensation placed in the middle of the cable line, the loading of the cable is reduced and it is not necessary to use cables with larger cross-section.
ii. In the investigated case, the installation of a shunt reactor reduced the yearly energy loss by 23%.
iii. It would not be possible to keep the voltage below the maximum allowable limit of 170 kV without the additional reactive power compensation. However, this objective could also be reached by installing an additional shunt reactor at Endrup 150 kV substation - installation in the middle of the cable line could be avoided if necessary.
iv. The installation of a shunt reactor does not affect the harmonic impedance to any significant degree seen from the wind farm if the cable is connected to a larger network or if it were directly grounded at one end (theoretical case). The parallel resonance between the reactor and the cable capacitance would be seen if harmonic impedance of an open-end cable with the reactor was to be determined.
v. For the investigated case, a significantly reduced size model would have sufficed to determine the harmonic impedance of the network seen from the wind farm side. This is also the case for any general-purpose study except cases where the magnitude of harmonic impedance at the resonant frequencies is important. The higher the frequency, the better the agreement between the harmonic impedance determined using the full network model and the reduced size model, which also indicates that the higher the frequency of interest, the smaller the required network model is needed for correct determination of harmonic impedance.
vi. In case the circuit breaker at the onshore connection point opens first, and there is a time delay before the circuit breaker at the offshore transformer opens, the wind turbines will

inject current for a short while, charging the cable capacitances. The result is transient over voltages reaching 2.2 p.u. of the frequency equal to the resonant frequency between the shunt reactor and the cable capacitance. These over voltages will decay slowly.

vii. Over voltage protection with sufficient ability to remove the energy from the cable/reactor system has to be applied.

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9. BIOGRAPHIES

Wojciech Wiechowski joined the Planning Department (Analysis and Methods) of Energinet.dk, the Danish TSO for electricity and gas in 2006. Before that he was an assistant professor at Aalborg University in Denmark, where he received a PhD degree. From 2001 to 2002 he worked for HVDC SwePol Link as a technical specialist. His current responsibilities include various harmonic, transient and dynamic studies related to the integration of wind farms and incorporation of long AC cable links into the Danish transmission grid.

Peter Børre Eriksen is Head of Analysis and Methods of Energinet.dk, the Danish Transmission System Operator (TSO) for electricity and natural gas, which was founded in January 2005. After a career in system planning for the Danish utility ELSAM he joined Eltra, the former West Danish TSO in 1998, where he headed the Research and Development Department from 2000 until 2005. His main interests include the modeling and analysis of power and natural gas systems. Peter Børre Eriksen is the author of numerous technical papers on system modeling.

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7 Implementation of Wind Power in the Dutch Power System

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Abstract: We present the current status of wind power in the Netherlands and its future prospects, in particular for the development of offshore wind. An overview is given of the performance of the wind power on land. We briefly discuss the experience with OWEZ, the first offshore wind park commissioned April 2007, and the expectations for Q7, to be completed March 2008. The organization of the energy and imbalance markets in the Netherlands is described. Balancing requirements due to variability and limited predictability of wind energy are estimated, at system and market participant level. Next, we present the results of a wind power integration study performed in order to estimate the amount of wind curtailment due to the technical limitations of the conventional units in the Netherlands. It is found that due to must-run constraints on the combined heat and power units, which constitute over 50% of the Dutch production park, sufficient reserve is available to cover wind fluctuations and prediction errors for up to 8000 MW installed wind power. The only limiting factor is the minimum output of the conventional units, which may result in increasing curtailed wind starting around 4000 MW installed capacity. Changes in system operating costs, curtailed wind and total emissions due to the application of various large-scale storage technologies are described in the final section of the paper.

1. INTRODUCTION

The share of wind power in the European electricity supply has increased significantly in the past decade. With the recently set ambitious European targets for future increase in energy produced from renewable sources, the growth of wind power can be foreseen to continue. The development of wind power towards an energy source of significance will have substantial impacts on the operation of power systems. The variability and limited predictability of wind can cause power fluctuations in the system that are more difficult to manage than load variations or load forecasting errors. In particular, wind power influences the need for regulating power and calls for reserves in the minute to hour time frames [1]. These services are often provided by conventional (coal and gas-fired) generating units. Therefore, wind power must be taken into account in the commitment and dispatch of the other units in the system and, consequently, will have an influence on the technical and economical aspects related to the operation of these generators.

It is suggested that wind power and energy storage form a natural combination, for example in [2], [3], [4]. Wind power is used to fill up storage reservoirs during high wind periods and the stored energy may be used for electricity generation during calms. However, large-scale wind power will become part of the existing power system and its associated market structure. Therefore, the technical capabilities of the existing system will determine the constraints for integrating wind power. The technical and economic benefits of energy storage facilities for wind power should be considered for the whole system where both wind power and energy storage are integrated into. A system approach furthermore opens up a wider range of possible solutions for wind power integration.

In case a significant part of generation capacity is heat-demand constrained, such as the case in the Danish [5] and Dutch [6] power systems, due to a large percentage of combined heat and power (CHP) units, wind power may have to be curtailed at moments of low load and high wind. The flexibility of CHP-dominated systems to integrate wind power could be significantly increased by a more price-based operation philosophy for these units, according to [5]. A system-oriented approach is applied in [7] to investigate the net benefits of wind power under different generation portfolios. Reference [8] assesses the benefits of compressed air energy storage (CAES) in a case study for Germany using a stochastic electricity market model. It is found that the benefits of CAES are partly, but not solely, driven by the installed wind power.

In the Netherlands, 1.75 GW of wind power has been installed up to date (Jan. 2008), including 127 MW offshore wind. Governmental targets for the moment are 3.5–4.0 GW onshore and 700 MW offshore capacity installed in 2011 and possibly 6–10 GW offshore by 2020. No large-scale energy storage facilities are currently available in the Netherlands, mainly due to the absence of geographically favorable locations in this flat country. The large share of heat-driven CHP units developed in the last decades, in addition to increasing distributed generation (DG) unavailable for dispatch challenge the integration of wind power [6].

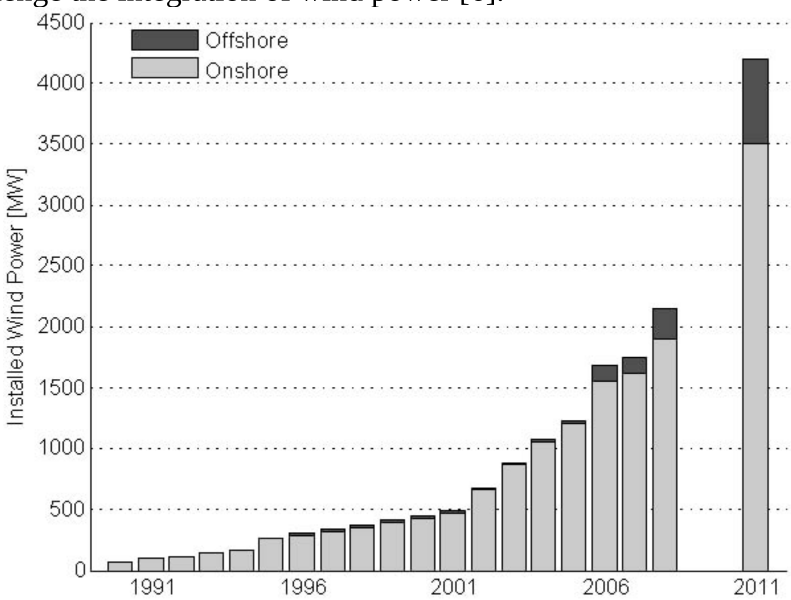

Figure 1. Installed and targeted wind power in the Netherlands.

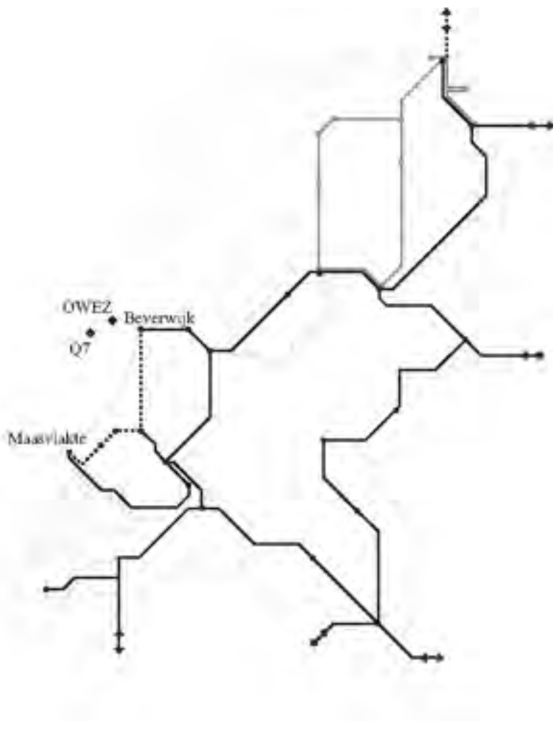

Figure 2. Offshore wind farms and EHV (380 and 220 kV) grid in the Netherlands, including

planned reinforcements in the West.

This paper is organized as follows. First, an overview of the current implementation status of wind power in the Netherlands is given (Section II). Next, the structure of the Dutch liberalized electricity markets is presented in section III. Balancing requirements due to the variability and limited predictability of wind at the central and market participant level are estimated in the next section. Then, results of integration studies performed by Delft University of Technology in cooperation with the Dutch TSO are presented in sections V and VI. Overall conclusions are presented in Section VII.

2. CURRENT STATUS OF WIND POWER IN THE NETHERLANDS

Originally, the government target for onshore wind power was 1000 MW installed by 2000. This capacity was reached in 2004, as can be seen in Fig.1. A subsequent national target of a minimum 1500 MW onshore by 2010 was already reached by the end of 2006. As per end of 2007, installed capacity equals 1620 MW onshore and 127 MW offshore.

Following the ratification of the Kyoto protocol and the embracing of European Union targets for electricity production from renewable sources, national targets for 2011 currently include 3500–4000 MW onshore and 700 MW offshore wind power installed. The past few years were characterized by drastic changes in governmental policy and accompanying subsidy schemes. Especially the target for offshore wind in 2020 was a subject of political discussion. Nevertheless this period witnessed an upsurge of activities such as requests for environmental permits from developers to realize between 10 to 13 GW installed offshore wind power, equivalent to 27-32% of the present electricity consumption in the Netherlands. In addition, several studies on the issue of integration of large amounts of wind power in the Dutch electrical power system were commissioned.

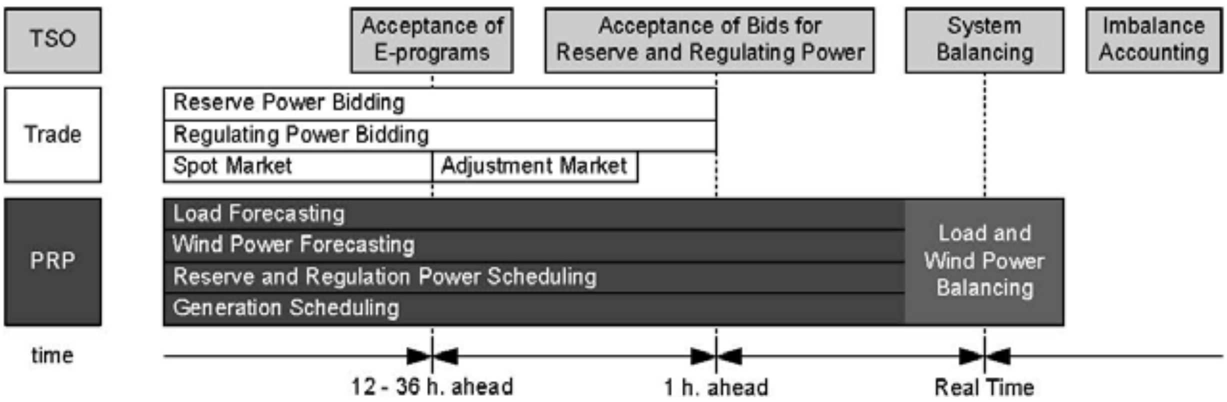

Figure 3. Activities and participants in the Dutch markets.

The first offshore wind farm at Egmond aan Zee (OWEZ) was brought in operation in December 2006. This is a government-sponsored demonstration project, hence allowed within the Dutch offshore 12-mile zone. It is owned and operated by a joint venture of Shell Renewables and NUON, one of the major energy producers in the Netherlands. The installed power is 108 MW, consisting of 36 Vestas V-90 turbines of 3 MW each, placed at a distance 8–12 km from the coast. Due to its “near-shore” location, a submarine cable of medium voltage was deemed to be the most efficient solution, with a coastal substation that steps up the voltage to 150 kV.

Next, wind farm Q7 – expected completion date March 2008 – is the first truly commercial offshore wind park, developed through a tailor-made non-recourse financing scheme. The project was initially developed by E-Connection and later taken over by a group of companies including Econcern, ENECO and Energy Investment Holdings. The farm has an installed capacity of 120 MW, consisting of 60 Vestas V-80 turbines of 2 MW each – a more conservative choice of proven technology compared to OWEZ. Due to its location about 23 km from the coast, an offshore transformer substation has been built to step the voltage from the 22 kV offshore medium-voltage grids up to a transmission level of 150 kV. The farm will be connected through a submarine 150 kV cable to land, and then – through the same corridor as the OWEZ – to the 150 kV grid close to the 380 kV Beverwijk substation (see Fig. 2). An overview of the main characteristics of the OWEZ and Q7 wind farms is presented in Table I.

Table I OVERVIEW OF DUTCH OFFSHORE WIND FARM CHARACTERISTICS

	OWEZ	Q7
Distance from Shore (km)	10	23
No. Turbines	36	60
Turbine Power (MW)	3	2
Hub Height (m)	70	59
Capacity (MW)	108	120
Capacity Factor	0.37	0.42
Yearly Energy (GWh)	350	435
Equivalent No. Households	100000	125000

The 2007 onshore wind energy production from the 1620 MW installed was approximately 3500 GWh, or about 3% of the Dutch electricity demand, resulting in a capacity factor of 25%, understandably lower than the capacity factors quoted for the two offshore wind parks. The average onshore turbine size is now at 885 kW. However, the average installed capacity per turbine for *ne*w projects is somewhere between 2 and 3 MW, with the major players being Vestas and Enercon.

3. STRUCTURE OF DUTCH MARKETS

In the Netherlands, wind power is treated on an equal footing with conventional generation and is thus fully integrated in the day-ahead and imbalance market structures. The Dutch TSO TenneT is not responsible for operating wind power, nor for performing system-aggregated wind power forecasts, as is the case e.g. for system operators in the Danish or German control areas. Instead, wind producers sell their output to an energy company, or more likely enter into the various markets together with a mixed portfolio participant, that operates both conventional and renewable resources. These participants, recognized as Program Responsible Parties (PRP), submit to the TSO balanced schedules for energy delivered to and absorbed from the system during a 15-minute interval, or Program Time Unit (PTU). This arrangement provides some protection from the full exposure to imbalance charges for the wind producer, as conventional units in the PRP's portfolio may act to correct energy program deviations due to wind variability and unpredictability.

A wholesale day-ahead market is operated by the Amsterdam Power Exchange (APX), and is cleared over hourly intervals. In addition, an intra-day, hour-ahead energy market has been operated by APX since Sept. 2006. The imbalance market, closing one hour before real-time, is operated by the TSO, which acts as a single buyer. This market is cleared over quarter-hourly intervals, and the settlement rules make it a dual-imbalance pricing system, with payments based on the price of the marginal balancing bid called upon by the TSO during that PTU. A summary of the time-line and actors involved in the various markets in the Netherlands is shown in Fig. 3.

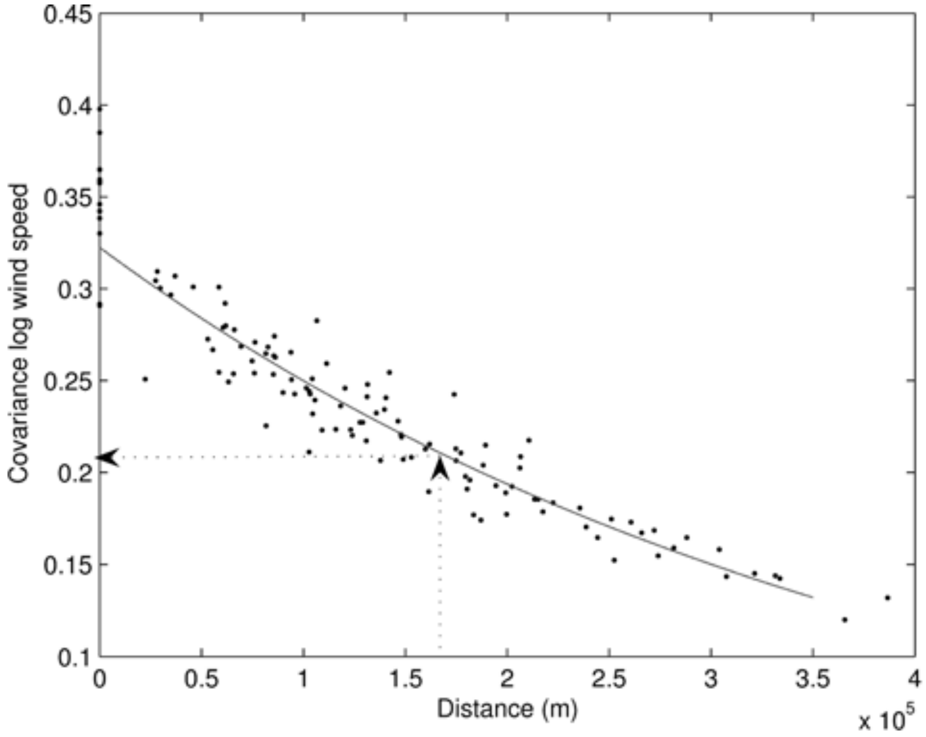

Figure 4. Wind speed covariance versus distance.

Under the *ME*P support mechanism (translated from Dutch as ”Environmental Quality of Electricity Production”), in effect since 2003, renewable electricity generators in the Netherlands receive subsidies that depend on the difference in costs (including investment, operation and maintenance cost) between their facilities and conventional generation units. The maximum level of the subsidy is set at the difference between the production cost of offshore wind power and the average selling price of fossil-fuelled power. However, the subsidy does not apply to projects started after Aug. 2006, due to government concerns for over-reaching the target for electricity supply from renewable sources by 2010.A new support scheme is under discussion.

4. ESTIMATION OF BALANCING REQUIREMENTS

In order to estimate the need for balancing power, both forecast errors and the variability of wind power production have to be investigated. In this work, the measured data originates from actually measured wind speeds at weather stations across the Netherlands and the North Sea, and the forecast data originates from real wind speed forecasts performed by the Energy Research Center of the Netherlands (ECN) using the High Resolution Limited Area Model (HIRLAM). The data consists of one-year time series of 15-minute averages for measured and forecasted wind speeds. The imbalance due to wind forecasting errors is conservatively estimated based on day-ahead predictions only, which means that the potential for more accurate hour-ahead predictions as applicable to intra-day markets is not considered.

An interpolation method that takes into account the spatial and temporal correlations among multiple sites, based on an exponential decay model for the covariance versus distance [9], is employed to derive time series of wind speeds and forecasts at the locations where wind farms are planned. The covariance data and the exponential decay fits are shown in Figs. 4 and 5, for wind speed measurements and wind speed forecast errors, respectively. Note that in Fig. 5 the data for wind speed forecast errors has been grouped by prediction lag, to account for the fact that forecasts at multiple sites become more highly correlated as the prediction horizon increases. A model similar to that in Fig. 4 has been constructed for the lag-1 (auto) covariance as well. We assume that the wind speed time series have the Markov property. This means that, given the measurements at time *t*, and the measured and interpolated values at time t-1, the interpolated values at time t are independent of values at previous time steps t-*k*, for *k*> 1.

It was found that wind variability across consecutive 15-minute time intervals typically does not exceed plus/minus 12% of the system-wide installed wind capacity, while imbalances due to wind forecast errors could be as high as 50% (assuming a 24-36 hours prediction lag). Aggregating at the market participant level introduces slight inefficiencies, with a 2-3% increase in balancing energy requirements. This calculation was done assuming wind production is divided among 7 PRPs, with installed wind capacities in line with what we expect from the market players currently active in the Netherlands.

5. INTEGRATION STUDY USING UC-ED

This section presents some results of a wind integration study performed by TSO TenneT in collaboration with Delft University of Technology, during 2006-2007, and published in [6] and [10]. Up to 8000 MW installed wind was simulated using a central unit commitment and economic dispatch (UC-ED) model. Wind capacity was divided up into 2000 MW installed onshore and 6000 MW offshore. The year 2012 was taken as a study case, with a foreseen composition of the conventional generation park as shown in Table II.

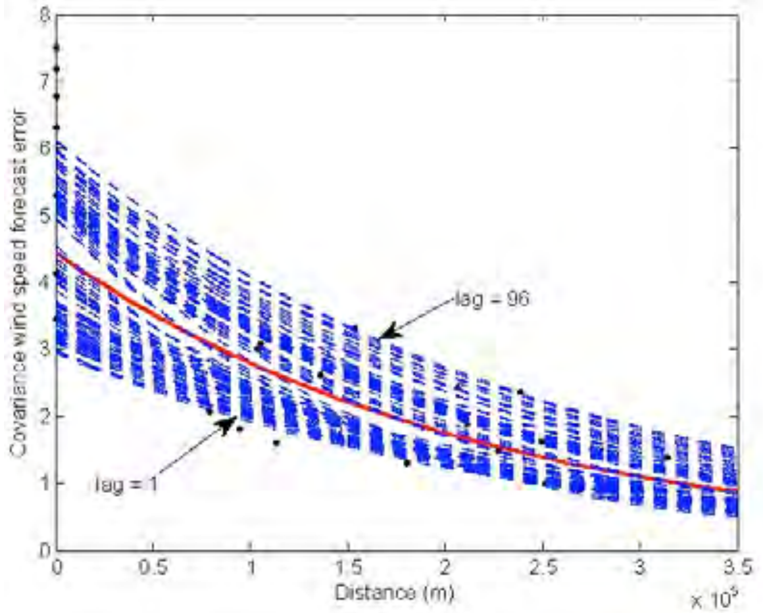

Figure 5. Wind speed forecast error covariance versus distance.

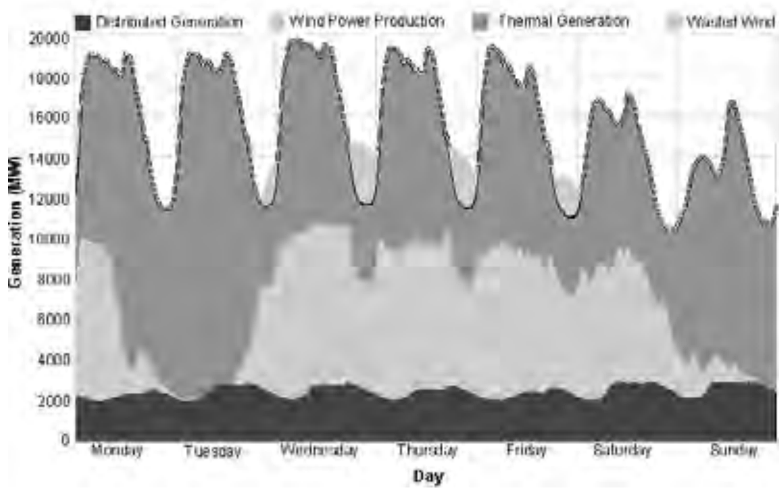

Figure 6. Weekly unit commitment and dispatch, 8 GW wind.

It was assumed that wind power does not replace conventional generation capacity. Wind power is curtailed as a last resort in case of constraint infeasibilities, such as conventional unit minimum output. Results are found to be sensitive to assumptions on the scheduling of imports, boiler capacities at CHP units, and unit flexibility (such as minimum up-and down-times). An example unit dispatch profile for a given week is shown in Fig. 6.

Available versus wasted wind energy over the simulated one year of operation is shown in Fig. 7, for various levels of installed wind power. System interchange was assumed to be zero to assess the technical capabilities of the Dutch conventional generation park itself. Obviously, flexible import schedules would provide additional technical space for integrating wind power. The output of distributed generation units was assumed to be 50% constant and 50% variable with system load, and entirely independent of the central dispatch. Wind power forecasts were updated hourly and used as an input into the UC-ED calculations. Minimum load problems appear around 4 GW installed wind power, as can be explained by the large percentage of heat-driven CHP units and non-dispatch able distributed generation (see Table II). In addition, it is found that due to the presence of must-run CHP units, large amounts of reserves are typically present in the Dutch system, providing sufficient regulating power to simultaneously balance the load and wind power variations.

Table II FORESEEN DUTCH INSTALLED GENERATION BY 2012

Generation Type	GW	%
Gas-Fired	12.1	53
Coal-Fired	4.1	18
Nuclear	0.4	2
Other	1.3	4
Distributed Gen.	5.2	23
Total	22.9	100
of which CHP		55

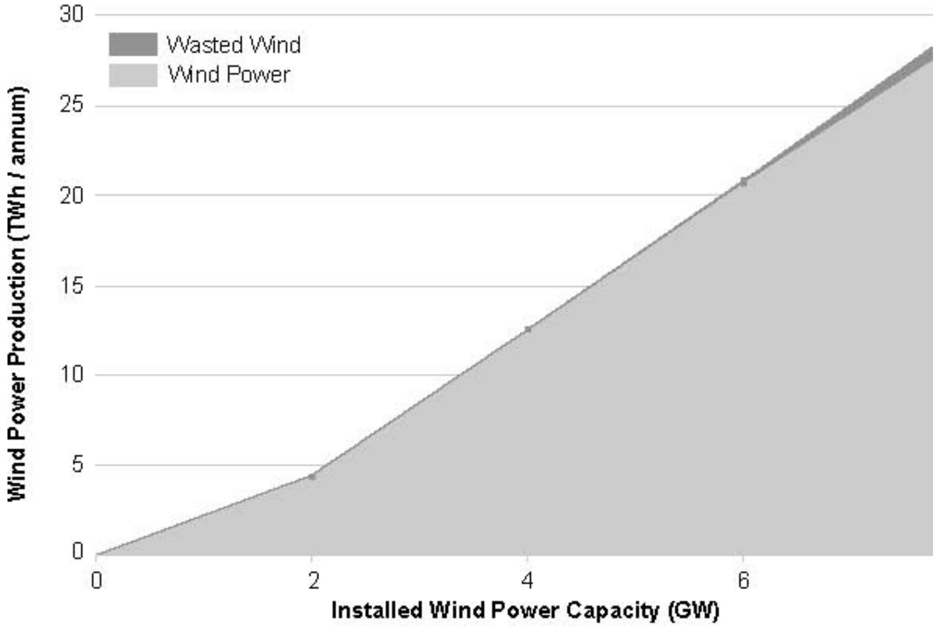

Figure 7. Available and wasted annual wind energy production.

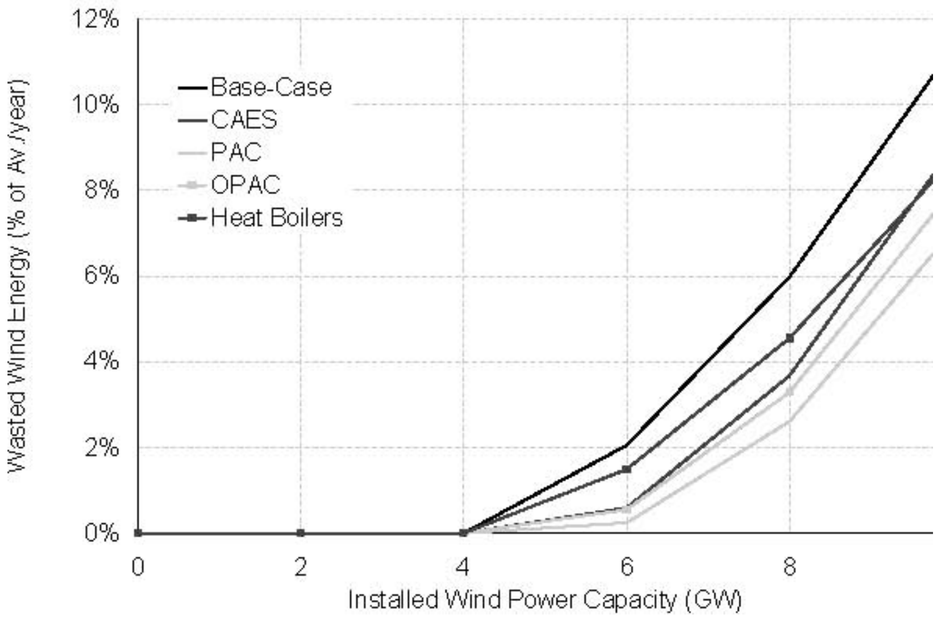

Figure 8. Curtailed wind due to minimum load problems.

6. STORAGE

The study presented in the previous section was extended with models for three large-scale energy storage technologies: pumped hydro accumulation storage (PAC), underground PAC (UPAC) and compressed air energy storage (CAES) – with a capacity of 1500 MW. Furthermore, an alternative solution was investigated, comprising the installation of heat boilers at selected combined heat and power locations (CHP) in order to increase operational flexibility of these units. For increasing installed wind power scenarios, results are shown for the base-case and for each storage solution, in terms of: wasted wind, cost savings and emissions in Figs. 8, 9 and 10 respectively.

As can be seen from Fig. 8, all options considered here indeed reduce the amount of wind wasted, i.e. that has to be curtailed, due to minimum-load problems. Energy storage and heat boilers all increase the flexibility of the Dutch system and thereby enable larger amounts of wind energy to be integrated, with PAC as the option with the highest potential for this. For the higher wind penetration levels, however, none of the options can separately prevent wasting wind energy altogether.

With the use of large-scale wind power, total system operating costs decrease – as shown in Fig. 9 and reported in [6] – due to the low operational costs of wind power. At the same time, wind power reduces the Dutch system's emission levels. Fig. 10 shows the emission levels of CO2 compared to the base-case without energy storage or heat boilers. Interestingly, the simulation results show that the application of energy storage in the Dutch system increases overall CO2 emissions.

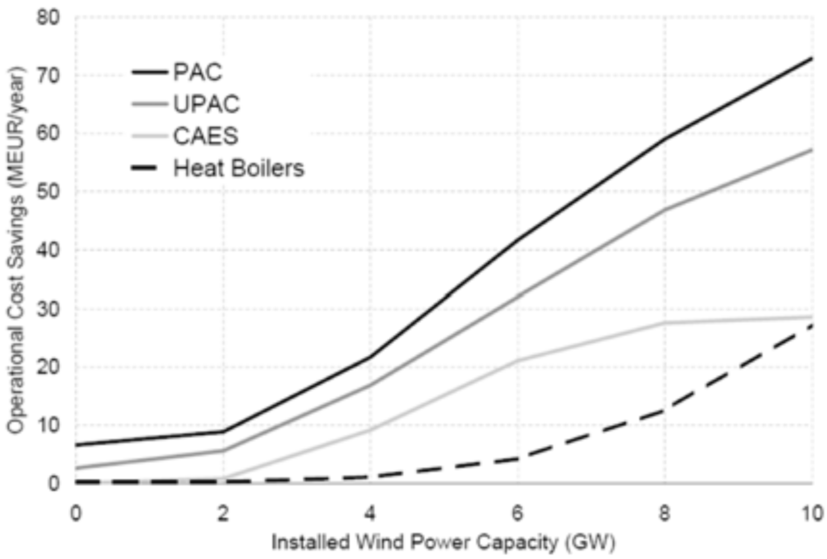

Figure 9. Operational cost savings compared to the base-case.

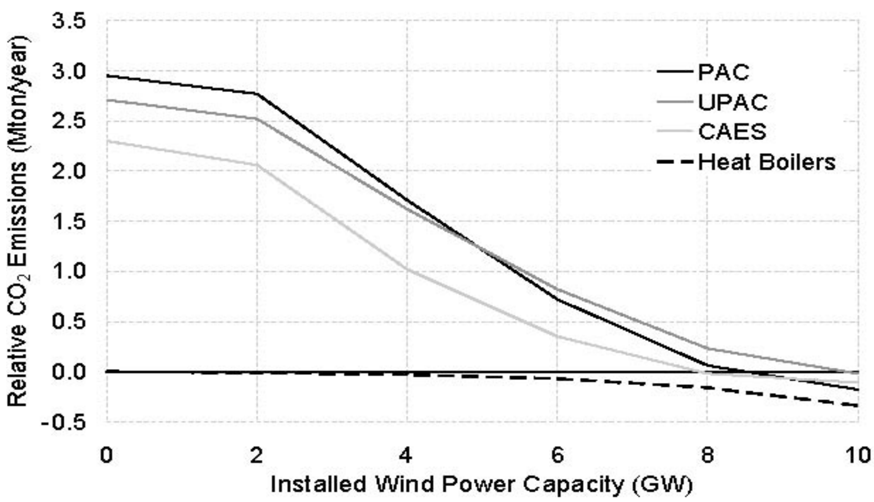

Figure 10. Relative CO_2 emissions for various storage alternatives compared to the base-case.

The additional emission of CO2 can be explained by two factors. For cost optimization, the storage reservoirs will be filled when prices are low, and emptied for generating electricity when prices are high. In the Dutch system, energy storage in fact substitutes peak-load gas-fired production by base-load coal-fired production. Since coal units emit more CO2 on an MWh basis than gas units, the net coal-for-gas substitution by energy storage increases the overall amount of CO2 emitted within the Dutch system. Secondly, energy storage brings about conversion losses that must be compensated by additional generation from thermal units, which again increases CO2 emissions. From this, it follows that from a CO2 emission perspective, energy storage is an option only for very high wind penetration levels, when energy storage prevents substantial amounts of wasted wind.

A cost-benefit analysis for the various storage options shows that the operation cost savings from energy storage increase with the amount of wind power installed. Taking into account the large investment costs, energy storage units are however unlikely to result in a profitable exploitation when the focus lies on optimizing the use of wind power. The installation of heat boilers at CHP-locations is found to be more efficient and a promising solution for the integration of large-scale wind power in the Netherlands [10].

7. CONCLUSIONS

This paper presented an overview of the current status of implementation of onshore and offshore wind power in the Netherlands. After a description of the organization of the Dutch day-ahead, intra-day and imbalance markets, results of some system integration studies were summarized. High amounts of wind power may lead to constraint infeasibilities in the system starting around 4000 MW installed capacity. The paper showed the opportunities for energy storage and heat boilers to facilitate better integration of wind power in the Dutch system. However, from both an economic and an emissions perspective, it is unlikely that storage systems are the best solution. Adding more flexibility in the system and using (international) market mechanisms are more appropriate solutions as long as the share of wind power is moderate.

8 ACKNOWLEDGEMENTS

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BIOGRAPHIES

Wil L. Kling received his M.Sc. degree in Electrical Engineering from the Technical University of Eindhoven in 1978. Since 1993 he has been a part-time Professor at the Delft University of Technology, in the field of Electrical Power Systems. In addition, he is with the Asset Management Department of the Dutch Transmission System Operator TenneT. Since 2000, he has also been a part-time Professor at the Technical University of Eindhoven. His area of interest is related to planning and operations of power systems. Prof. Kling is involved in scientific organizations such as CIGRE and the IEEE. As Netherlands’ representative, he is a member of CIGRE Study Committee C6, Distribution Systems and Dispersed Generation, and the Administrative Council of CIGRE.

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8. Efficient Management of Wind Energy In-feed at a Large German TSO

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***Abstract*—**In Germany, the four transmission system operators (TSO) are in charge of integrating the fluctuating electricity production of wind power plants into the grid. Due to the framework of the Renewable Energy Sources Act (EEG) the EnBW Transportnetze AG is responsible for about 14 % of the wind energy production in Germany although the EnBW grid has only about 2% of the installed capacity.

This paper describes the integration of wind power in Germany especially within EnBW Transportnetze AG. The EEG and the immediate exchange of wind power between the four German grid control areas will be explained shortly. The different activities for transformation and balancing wind energy are described in more detail. These activities can be divided into two parts: Transformation of the fluctuating wind generation into a base load power supply by using the wholesale (day ahead and earlier) and activities for balancing the remaining differences between predicted and actual wind power generation. The focus of the paper is on reporting practical experiences.

***Index Terms*—**wind power, regulating power, forecasting systems, energy market

1. INTRODUCTION

The framework of the Renewable Energy Sources Act (EEG) provides regulation for payment and in-feed of energy produced with renewable resources. Within this system producers are granted a fixed payment for energy for a defined period. The amount of payment varies depending on the type of renewable energy. It is, for example, higher for photovoltaics (about 450 €/MWh) and lower for hydropower (about 70 €/MWh). The payment for wind energy in-feed is about 86 €/MWh on average. Another important point within the EEG is the priority of in-feed for electricity from renewable energy sources (RES-E).

In the last decade the EEG led to a strong rise of installed RES-E capacity. Wind power in particular became popular. Fig. 1 shows the installed wind capacity in Germany over time. In November 2007 the wind capacity alone exceeds 21 GW. This is already about 20% of total German installed capacity.

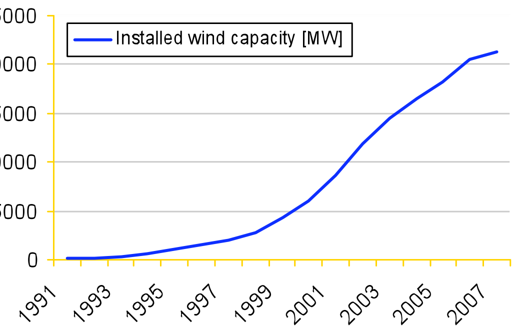

Fig. 1: Development of installed wind capacity in Germany since 1991. Source: ISET

Fig. 2 shows the system of balancing and distributing renewable energies in Germany. In Germany the four transmission system operators (TSO) are responsible for balancing and distributing wind energy that is fed in the transmission grid either directly at high voltage or via the medium-voltage grid. The TSO transform the fluctuating in-feed into a constant base load power supply. This base load is delivered to the end consumers who pay the granted payments via the energy suppliers.

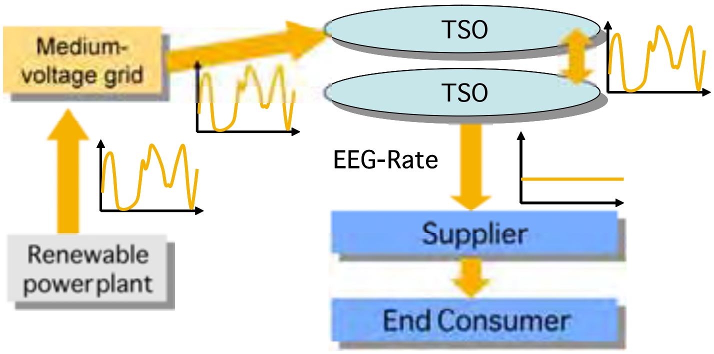

Fig. 2: The system of balancing and distributing renewable energies based on the latest amendment of Renewable Energy Sources Act. The TSO play a central role in the system.

The amount of base load is defined by the TSO in the previous month. It is always constant for one month and based mainly on historical data. The four TSO grant the exact delivery of the base load. Therefore this delivery commitment provides a basis for the scheduling of energy traders and suppliers.

As shown in fig. 3 the volatility of wind energy in-feed due to meteorological conditions is high. This poses a real challenge to transform the production of 21 GW installed wind power into base load and affects all important sectors of the electricity system: grid operation, power plant scheduling and energy trading. As the cost of transformation and balancing is high it has to be allocated fairly among grid operators. Therefore a horizontal exchange of wind power has been installed between the four German TSO.

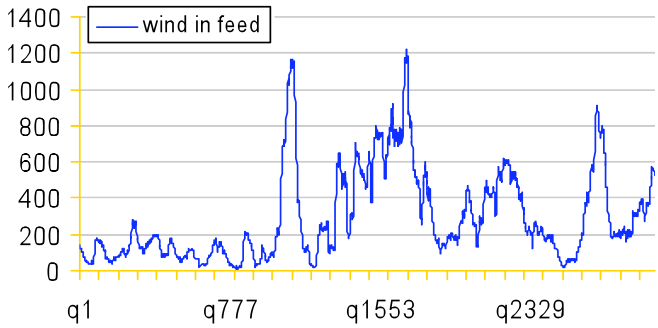

Fig. 3: Wind energy in-feed within the responsibility of EnBW Transportnetze in October 2007 (Values per quarter hour). The chart shows a strong fluctuation with steep gradients. Within 24 hours there is a possible fluctuation of more then 1000 MW.

2. HORIZONTAL EXCHANGE OF WIND POWER

With the amendment of the German Renewable Energy Sources Act (EEG) in September 2004 a new mechanism was introduced which induces the TSO to exchange fluctuating wind power between each other in proportion to the electricity consumption in their control area (Fig. 4 and 5) immediately.

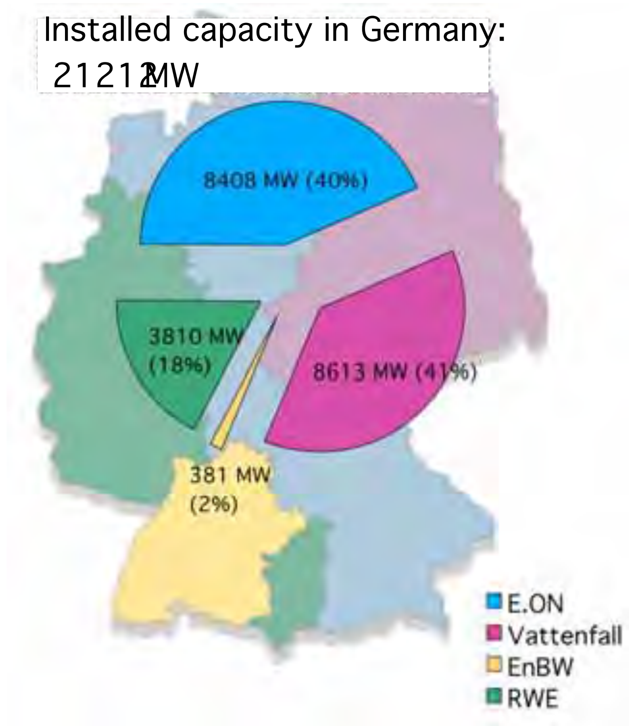

Fig. 4. The distribution of installed wind capacity is not homogenous. Especially grids with coastal areas have a high number of wind power plants.

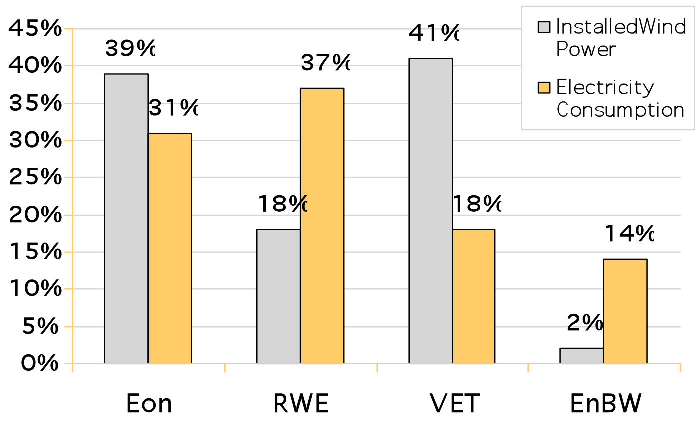

Fig. 5: The distribution basis for the fluctuating wind power in-feed is the electricity consumption within the grid area. With a relatively high number of installed plants E.ON and VET are net exporter whereas EnBW and RWE are net importer of fluctuating wind energy.

This horizontal wind exchange distributes wind power including the fluctuations among the TSO in near real-time leading to a comparable situation for all TSO regarding the allocation of balancing power and associated costs. The immediate exchange of wind power is based on measurements of the current production at representative wind farms in each control area. The exchange is regarded as temporarily until the accounting data from all wind farms is available for final validation and correction schedules.

3. TRANSFORMATION OF WIND ENERGY IN-FEED

The transformation of the wind energy in-feed to base load is done with the use of the energy markets. Predictions of wind energy in-feed occupy a central position in this process. Based on the time horizon the process can be divided into three different parts: The first part takes place on the derivates markets in the previous month, the second part day ahead on the day ahead markets and the third part on the derivates markets in the following month.

3.1 Activities in the Previous Month

Typically the value of the base load delivery for a given month is announced around the 15th of the previous month. Right after the announcement the first market activities of EnBW Transportnetze AG start.

The announced value of base load is not necessarily an equivalent of the latest predictions of wind energy in-feed. If the delivery commitment is significantly higher than the predictions a specific percentage of base load can already be bought in the previous month at the derivates market. Fig. 6 illustrates the purchase of energy in the previous month. Another reason may be the appraisal that there will be an energy scarcity in the next month due to extremely cold or hot weather and station blackouts. In those cases it is reasonable to buy physical contracts to reduce volume risk.

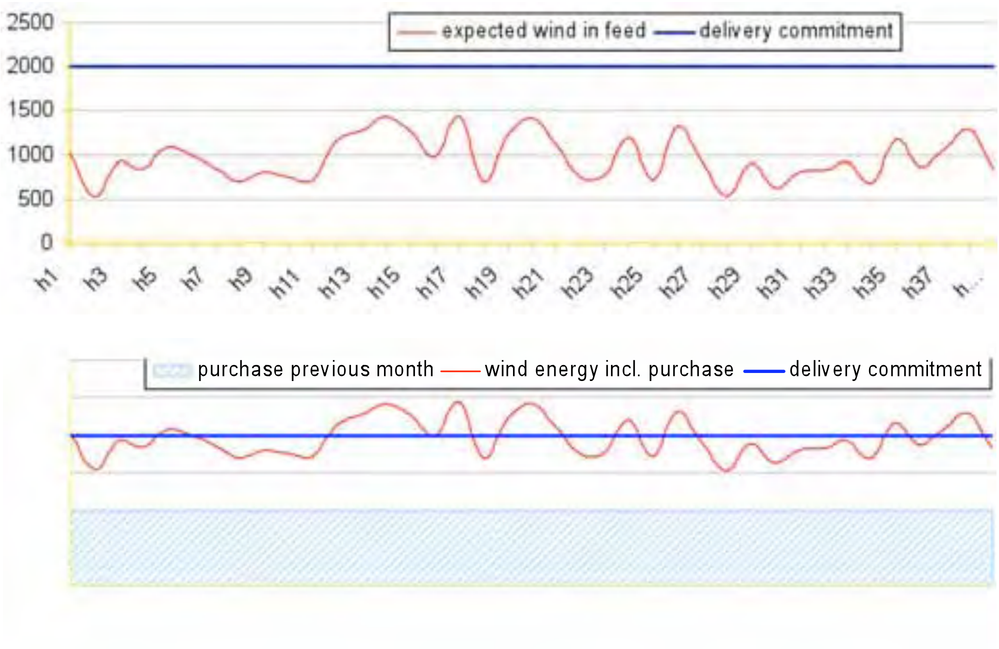

Fig. 6: The first figure shows a predicted wind energy in-feed that is less than the base load delivery. The second figure shows the possibility of buying the missing energy on the derivates markets.

In both cases there could be relatively high and low wind energy in-feeds within the same month. That is why it is not always expedient to buy a whole monthly base load product, as in the time of high wind energy in-feed this energy has to be sold again - to low prices. Therefore EnBW TSO is working on long term forecasts that will allow to identify weeks with high and low wind energy in-feed and to buy adequate weekly or daily contracts.

3.2 Activities Day Ahead

EnBW Transportnetze AG does a day ahead prediction of wind energy in-feed. Based on this prediction the market activities are done. This basically means that if the prediction shows a higher wind energy input than the delivery commitment, the surplus energy has to be sold at wholesale. Vice versa is true if the predicted energy in-feed is too low, the missing energy has to be bought (see fig. 7). Those market activities are carried out at the European Energy Exchange (EEX) in Leipzig.

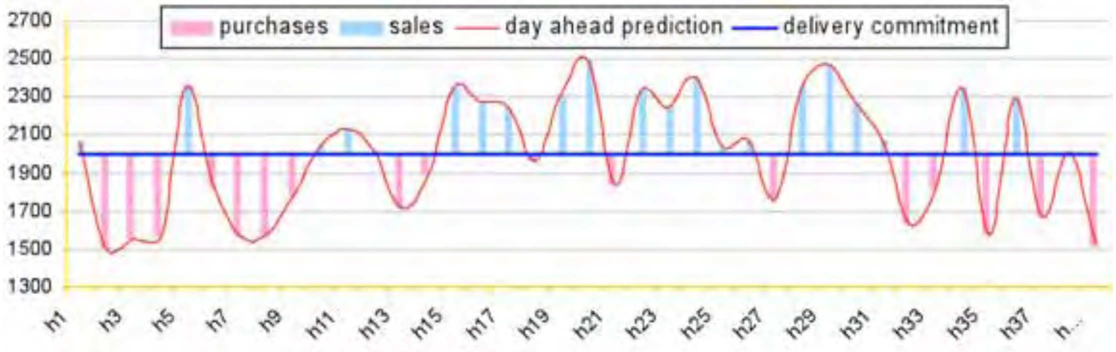

Fig. 7: Based on a day ahead prediction EnBW transforms the fluctuating in-feed into base load. In times of high in-feed EnBW acts as a net seller of energy and in times of low in-feed as a net buyer.

The marginal production costs of one MWh wind power are almost zero. Expecting that wind power plants substitute conventional power plants, in times of high wind energy production, less conventional power plants are used. Due to the merit order effect, the market prices are going down in this case. This effect can be explained with a shift in the supply curve as shown in fig. 8:

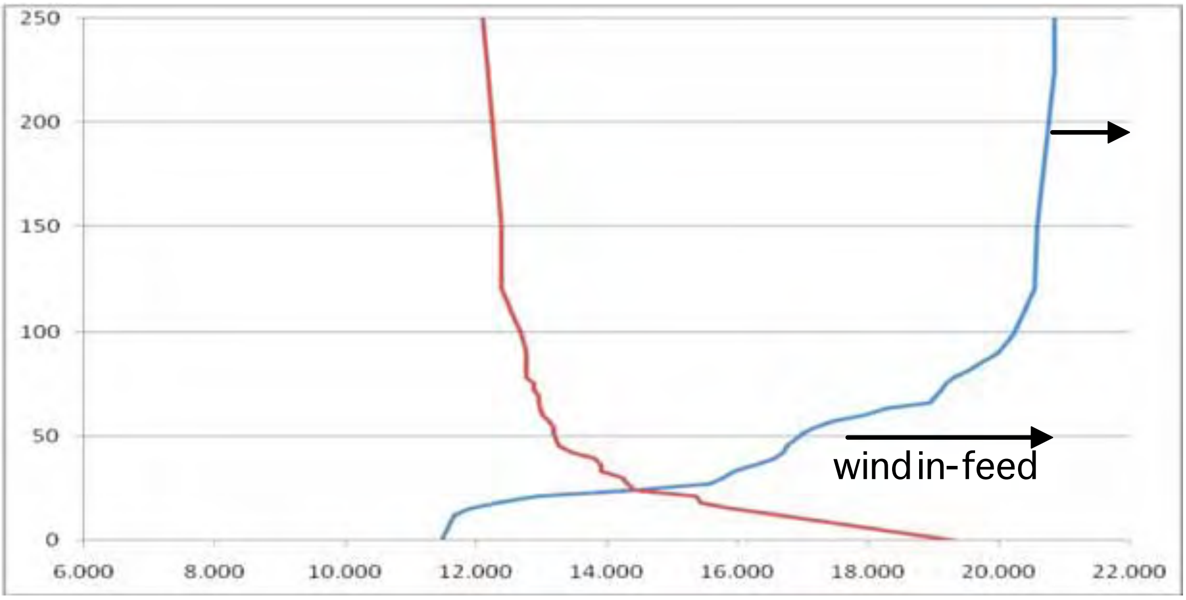

Fig. 8: The figure shows a supply curve (blue) and demand curve (red). An increased (decreased) wind power in-feed leads to a right (left) shift of the supply curve. The price decreases (increases).

Basically the TSO sell wind energy when the in-feed is relatively high and the prices are low and they buy energy when the prices are high. Altogether this leads to the fact that one MWh of wind energy is less valuable than one MWh of base load energy.

A possibility to calculate the difference in prices between wind power and base load power within a month is the following: The price for one MWh of baselaod power is just the average of all hourly EEX prices. The wind power price is the sum of wind energy production of each hour multiplied with the hourly EEX Price divided by the whole wind energy production. Fig. 9 shows the difference between the two prices since Oct 2006. The price difference is equivalent to the cost of transformation per MWh of wind energy [1].

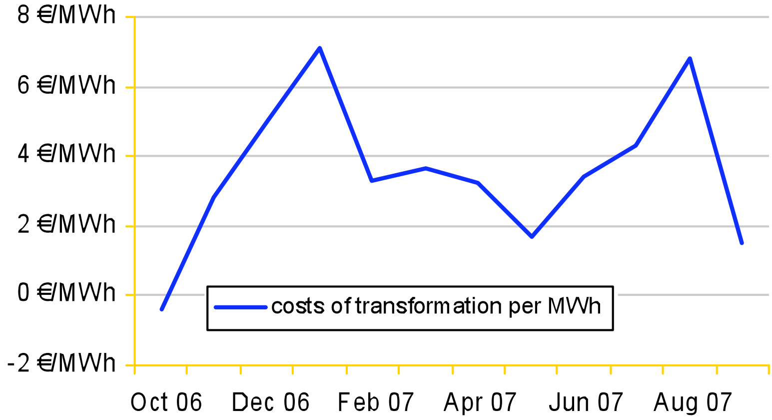

Fig. 9: The cost of transformation is different each month. It depends on market situation, amount of wind energy in-feed and other factors.

Actually on Sunday, Saturday and public holidays the EEX is closed. To avoid inaccuracies days with no day ahead spot-market activities are left out in this analysis.

3.3 Activities in the Following Month

Self-evident the real in-feed of wind energy does not correspond exactly to the prediction in the previous month. Assuming that the total wind energy production in a month is lower than predicted the TSO are net buyers of energy. The base load delivered to the energy suppliers is higher than the wind energy production. This surplus of energy has to be returned to the TSO later. Typically the return takes place within the same legal year. This compensation is only cost neutral for all parties concerned when the energy prices are the same in the period of delivery and return. In fact in the last years this compensation was not cost neutral for the TSO in Germany. The reason for this is that in months of relatively low wind energy in-feed the TSO are net buyers of energy to high prices and get the compensation to average prices. With high in-feeds they are sellers to low prices and transfer the compensation to average prices.

It is a possibility to hedge the corresponding positions immediately at the derivates markets. This leads to a minimum of financial risks. As the prediction of the previous month could be both, too high and too low (leading to long and short positions) there is often a possibility of netting within a period of time. Therefore the EnBW Transportnetze AG follows a strategy with a trade of between transaction costs and financial risk. Positions are only hedged when they exceed a distinct risk level.

3.4 Other Renewable Resources

Besides wind energy other renewable resources are getting more and more popular. Some of them have a negative correlation with wind energy. Photovoltaics for example show a high production on hot summer days with no wind and typically a relatively low production when it is rainy and windy. Therefore an integrated handling of all types of renewable energies makes sense. The EnBW Transportnetze AG is already working on such an approach. One important point in that case is the availability of forecasts for other renewable energies in the same quality than for wind energy.

4. MONITORING AND FORECASTING WIND POWER

Currently wind power production is assessed separately in each TSO area using a standardized procedure that is based on online-measurement of representative wind farms. A set of approximately 110 sites is adequately scaled up to give an estimation of all 19,000-wind turbines in Germany. This online-estimation is automatically updated every 15 minutes and works fully automatic. The estimation is considered as the “real” wind power production and therefore a reference for the quality of predictions. Not only the TSO require predictions. Independent of the implemented balancing concept grid operators, energy traders and power plant schedulers require day-ahead information of the anticipated production of wind energy. Thus, wind power predictions with a time horizon of at least 72 hours have become indispensable instruments for the energy market.

Several providers offer operational wind power predictions for the German market and deliver to the large TSO on a daily basis. The forecast quality of the prediction is an important issue that is constantly evaluated within EnBW Transportnetze AG. One measurement for the accuracy of wind-energy predictions is the root mean square error (RMSE). For the aggregated power output of all German wind farms the accuracy is currently between 4 – 6% for intraday and between 5 – 8 % for day-ahead in normal wind years. The error is measured as root mean square error normalized to installed capacity. Figure 10 shows the performance of different prediction models that are operationally used by EnBW since Sep 04 up to two days ahead.

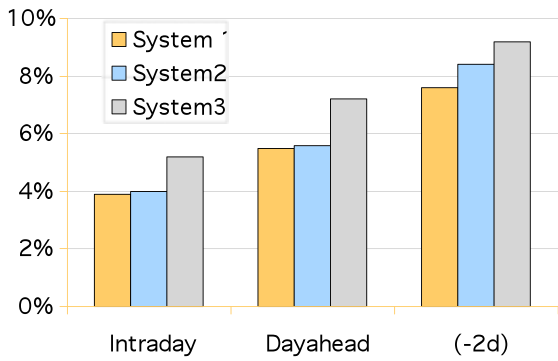

Fig. 10: Evaluation of prediction accuracy for three wind power predictions that are used by EnBW.

The use of different commercial wind power predictions allows getting slightly better results than the exclusive use of the best single prediction. This small enhancement of prediction quality is achieved by a weighted combination of different commercial forecasts. In this context the evaluation of prediction quality is important. Based on the performance of the last days the weights for each single prediction are defined. In addition this process helps to improve the stability of forecasting against failures of single commercial predictions.

The prediction error varies significantly over the year being naturally larger in times with high winds and smaller during calmer periods. Figure 11 shows the changing prediction error of the three commercial systems and the EnBW prediction since Jan 2005.

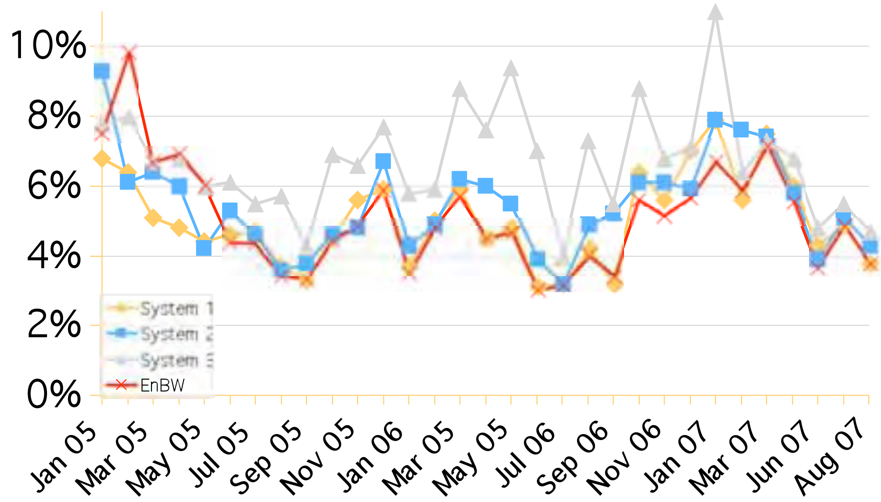

Fig. 11: The prediction accuracy varies from month to month. This mainly due to the fact that during stormy periods the chance to produce a large forecast error is higher.

However, in certain cases where the meteorological situation does not evolve as predicted, the forecast errors can be substantial. These phenomena are mainly due to the highly non-linear processes in the atmosphere that are difficult to rule out completely. Hence, the further improvement of wind power predictions is an important issue [2].

5. BALANCING OF WIND ENERGY IN-FEED

In cases of forecast errors the expected wind in-feed is different to the real wind energy production. With the immediate horizontal exchange of fluctuating wind power generation, EnBW Transportnetze AG is responsible for balancing those deviations. There are several concepts for performing this task. One basic distinction is whether the balancing is performed separately from the classical grid regulation or integrated with it.

If the balancing is carried out separately, specific reserve capacities allocated to wind balancing have to be provided. The required quality can differ from traditional products on the reserve market like secondary and tertiary reserve due to limited gradients and good short-term predictability of wind power generation. Besides contracted reserves the grid operator could partly use the intra-day market to perform the balancing.

The integrated approach combines the balancing of wind power forecast errors with traditional balancing tasks for load fluctuations, load forecasts errors, power plant outages and scheduling errors, for which secondary and tertiary reserves are used. As all of these deviations are almost uncorrelated the required additional reserve capacities due to wind power are lower then in the separate balancing approach [3].

Considering the period between Jul 05 and Jun 06 studies at EnBW show that load- and wind-forecasting errors exhibit an empirical correlation coefficient of -0.01. Consequently the sum of the RMSE of the wind energy prediction and the RMSE of the load prediction is less than the RMSE of the deviation induced by the aggregate time series of load and wind (Figure 12). Thus combined balancing is advantageous in practice.

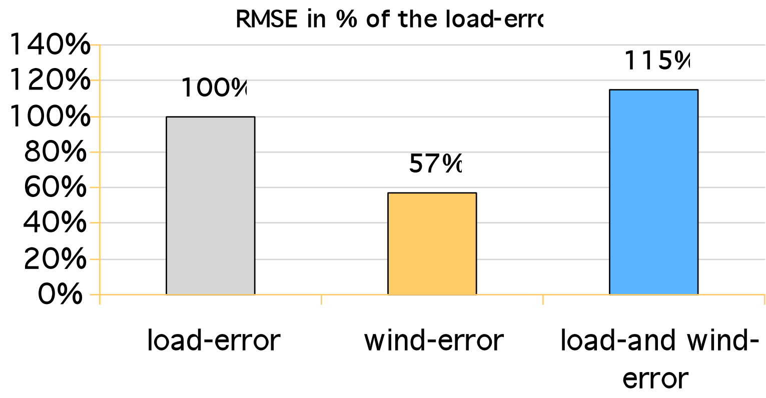

Fig. 12: Combined balancing of wind errors together with conventional load errors is adventurous as the two errors are uncorrelated.

The required reserve energy for balancing can be provided with defined reserve qualities, especially secondary and tertiary reserves which are dispatched by the grid operator e.g. on a 15 min or 1 h basis. Alternatively, the balancing is performed within a large power plant system with the most suitable plants at any time.

7. ACKNOWLEDGMENT

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8. BIOGRAPHIES

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