Institut für Solare Energieversorgungstechnik
Verein an der Universität Kassel e.V.

Institut für Elektrische Energietechnik
Rationelle Energiewandlung

Erneuerbare Energien und Energieeffizienz

Renewable Energies and Energy Efficiency

Band 1 / Vol. 1

Herausgegeben von / Edited by
Prof. Dr.-Ing. Jürgen Schmid, Universität Kassel

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The Influence of Modelling Accuracy on the Determination of Wind Power Capacity Effects and Balancing Needs

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This work has been accepted by the faculty of electrical engineering / computer science of the University of Kassel as a thesis for acquiring the academic degree of Doktor der Ingenieurwissenschaften (Dr.-Ing.).

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Defense day 19th July 2006

Bibliographic information published by Deutsche Nationalbibliothek
Die Deutsche Nationalbibliothek lists this publication in the Deutsche Nationalbibliografie;
detailed bibliographic data is available in the Internet at http://dnb.ddb.de

Zugl.: Kassel, Univ., Diss. 2006
ISBN-10: 3-89958-248-9
ISBN-13: 978-3-89958-248-2
URN: urn:nbn:de:0002-2480

www.upress.uni-kassel.de

Cover layout: Grafik Design Jörg Batschi, Kassel
Printed by: Unidruckerei, University of Kassel
Printed in Germany

Vorwort

Die vorliegende Arbeit entstand im Rahmen meiner Tätigkeit als Leiter „Energieversorgungsstrukturen“ am Institut für Solare Energieversorgungstechnik (ISET) in Kassel.

Als die in Deutschland installierte Windleistung zur Mitte der 90er Jahre den Gigawattbereich erreichte, wurden für Netzbetreiber Fragen zum Leistungsdargebot der Windenergie drängender. Seit dieser Zeit beschäftigte ich mich – zunächst nur auf nationaler Ebene - mit Auswertungen zur Statistik großräumiger Windstromeinspeisung.

Arbeiten für die Europäische Kommission im Rahmen von Projekten des 5. und 6. Forschungsrahmenprogramms, die sich mit Fragen der Integration dezentraler Energietechnologien in die Elektrizitätsversorgung befassten, ergaben einen engen Kontakt mit Europäischen Netzbetreibern. Aus Studien für den „European Grid Report“ erwuchs schließlich die Notwendigkeit, die Methodik europäischer Windintegrationsstudien genauer zu beleuchten, ihre Modellgenauigkeit zu hinterfragen und zu verbessern.

Damit ist das vorrangige Ziel der vorliegenden Arbeit, die Qualität zukünftiger Wind-Integrationsstudien im Bereich der „System Adequacy Studies“ zu verbessern.

Ich danke Herrn Prof. Jürgen Schmid für die Übernahme der Betreuung als Erster Gutachter. Er hat in den vergangenen Jahren im Bereich der Integration dezentraler Energietechnologien wegweisende Projekte angebahnt und geleitet, die auch Ausgangspunkt der vorliegenden Arbeit waren und sie zu einer ausgesprochen Europäischen Studie gemacht haben.

Die Kollegeninnen und Kollegen am ISET haben mich nach Kräften unterstützt. Nennen möchte ich hier insbesondere Alexander Badelin für die gemeinsamen Arbeiten bei der Erstellung des European Grid Report und Yves-Marie Saint-Drenan für seine Ratschläge im Bereich der Wahrscheinlichkeitsrechnung. Dr. Kurt Rohrig hat die Verwendung und Anpassung des Programm SepCaMo im Rahmen dieser Arbeit – als wesentliches Hilfsmittel der Parameterstudien und Sensitivitätsanalysen - ermöglicht.

Schließlich möchte ich Prof. Hatziargyriou als international renommiertem ‚Power Systems’-Experten für die Übernahme der Betreuung als Zweiter Gutachter danken.

Meine Frau Ulrike hat in den vergangenen Monaten durch persönliches *Load Management* manchen *Blackout* im System verhindert. Ich freue mich, dass ich nun wieder mit *Guaranteed Capacity* im privaten Bereich präsent sein kann.

Kassel, im April 2006 Cornel Ensslin

Preface

The present work is a result of my work as Head of Energy Supply Structures at the Institut für Solare Energieversorgungstechnik (ISET) in Kassel.

Since the beginning of the 90s I have been working – initially on the national level in the WMEP Programme - on the evaluation of statistics of large-scale wind energy supply. After the wind installations in Germany had reached the gigawatt region, network operators were faced more urgently with questions of integration of wind energy.

Fundamental questions about the integration of decentralized energy technologies in electricity supply continued to occupy me in the form of work for the European Commission. Projects in the 5th and 6th Framework Programmes resulted in close contacts with European system operators.

Studies on the European Grid Report revealed the need to describe the methodology of European wind integration studies as well as to fundamentally elucidate and improve the modelling accuracy.

Thus, it is the principal objective of the present work to improve the quality of future wind integration studies with respect to system adequacy considerations.

I wish to thank Prof. Jürgen Schmid for being the first evaluator. He initiated and lead strategic Europesan research projects in the field of distributed generation and renewable energy technologies, the particatin in which provided an essential basis for this thesis and helped to make a markedly European Study.

I am also grateful to my colleagues in ISET's Division Information and Energy Economy for their support and the opportunity to discuss the subject with them. I am grateful to Alexander Badelin for his collaboration on the European Grid Report, Yves-Marie Saint-Drenan for his suggestions in the area of probability calculation. Dr. Kurt Rohrig was kind enough to make his program SepCaMo available and enabled me to use and adjust the program in detail so that I could make the parameter studies of this work.

Finally, my thanks are due to Prof. Hatziargyriou as an internationally renowned power systems expert for being the second evaluator of the thesis.

My wife Ulrike's personal *load management* prevented a fair number of system *blackouts* in the past months. I am glad to have resumed my private life with *guaranteed capacity*.

Kassel, April 2006 Cornel Ensslin

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1 Wind Power in Europe: Success Story and Integration Challenge

Europe will face a fundamental change in its energy supply in the next two decades. Of more than 650 GW total conventional generation capacity within EU 25 [EURPROG 2004], more than half will be phased out and replaced by new power stations in the next 20 years. Now is the time for the planning of this ambitious process, as the power systems will be changed and wind power has all the prerequisites to substantially contribute to this modernisation.

Wind power is the world's fastest growing energy technology and the wind power targets set by the European Commission during the last decade have all been exceeded. By the year 2020, 230 GW of wind turbine capacity is expected to be online [EWEA2004].

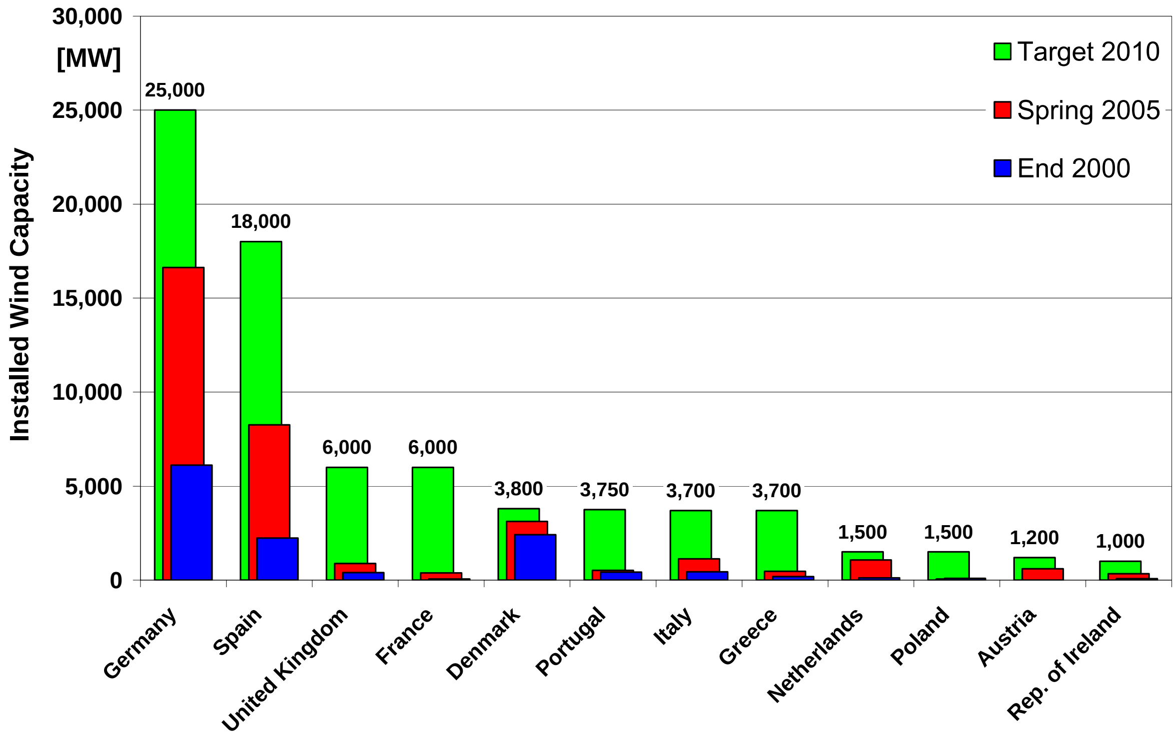

Figure 1-1: Growth of installed wind capacity in twelve European Member States [1]

From the year 2000 to 2005, the rise of the total wind power capacity in Europe was more than 20% per year. This development calls for a closer view on individual characteristics. Figure 1-1 depicts the wind capacity development in twelve European countries, showing the status at the end of the year 2000, in spring 2005 and the expectation for 2010 according to governmental plans.

[1] The official target value for 2010 in the case of Gemany is 25 GW. This value is often mistaken for the scenario value of 29.8 GW applied in the dena study [DENA2005].

For a detailed analysis of integration efforts, the capacity and number of installations has to be seen in relation to the size and technical ability of the respective electricity system, in order to valuate the success and enable the electricity supply system to cope with the arising integration tasks.

An essential issue of wind integration studies is "Which wind penetration level can be accepted without endangering system reliability, i.e. system adequacy and security[2]?". This in turn leads to three more detailed questions:

1. What is the expected availability of wind power at peak demand[3]? How large is the sensitivity of calculated results to different input parameters?
2. To what extent does wind power increase the demand for reserves and balance energy[4]? How does this depend on the different balancing market mechanisms in Europe?
3. How critical will the situation 'High wind / low demand' be in the future in different national power systems? Which options will have to be developed?

A number of national studies have dealt with the subject of large-scale wind power integration, namely: "The impacts of increased levels of wind penetration on the electricity systems of the Republic of Ireland and Northern Ireland" by CER/OFREG NI [GH2003], "Survey of the integration of 6,000 MW offshore wind power in the electrical grid of The Netherlands" [NOVEM2003], "Energy planning of network integration of wind energy in Germany inland and offshore till 2020" by the German energy agency dena [DENA2005].

All existing and all future studies require a best-possible characterisation of cumulative wind power generation on a national level. They all need to synthesise time series of cumulative wind power feed-in. This is due to the fact that large-scale, cumulative wind power feed-in data are not available, either because these data are restricted or because installations have not yet been made.

Usually the studies try to cope with the lack of aggregated wind power feed-in data with help of the following approaches:

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[2] Power system reliability consists of system security and adequacy. The system adequacy describes the amount of production and transmission capacity in varying load situations. The security of the power system is maintained by planning and operating the system in a way that minimises disturbances caused by faults.

[3] In this work both terms ‚peak load' and 'peak demand' are used. The UCTE glossary of terms states „*LOAD means an end-use device or customer that receives power from the electric system. LOAD should not be confused with DEMAND, which is the measure of power that a load receives or requires. LOAD is often wrongly used as a synonym for DEMAND.*" Nevertheless, the term 'peak load' is used in the majority of publications.

[4] The term 'balancing energy' refers to the energy in MWh which is actually used for balancing, while 'reserves' stands for the capacity in MW, being available for balancing tasks.

- Upscaling of *wind power* feed-in data from selected reference wind farms to the total scenario of all wind farms installed or planned, or
- use of *wind speed* data observed by meteorological services, which have to be extrapolated to wind turbine hub height, followed by the application of wind turbine power curves in order to determine the wind power output;
- Transfer of results from other countries or regions. Especially data from Denmark and Germany have been used up to now. Unfortunately, study results have been treated as generally applicable, while being valid only for specific input data and boundary conditions.

The following chapter of this work provides an insight into definition and methodology of calculating the capacity credit and clarify which input data are requested and which of them are critical with respect to accuracy.

Chapter 3 describes the individual mathematical steps of probabilistic approaches, as applied for instance in the dena study. Based upon these explanations, analytical descriptions and graphical interpretations of parameter sensitivity have been looked for.

This is followed in chapter 4 by the introduction of the newly developed simulation tool *Sim.WIN*, which allows synthesising cumulative wind power feed-in under a variety of boundary conditions and different kinds of input data. Using this software, the influence of parameter variations on wind power capacity credit and thus on the modelling accuracy are then looked at. In an empirical investigation described in this work, the sensitivity to the different model parameters were tested using 'Germany-2000' values as reference. The retrospective view on the real situation in Germany in the year 2000 has been chosen as reference case for sim.WIN, due to the large quantity of data available.

Chapter 5 of this work is dedicated to the ways of calculating the balancing needs induced by wind power. It intends to show that market conditions and regulatory issues strongly influence the results of these calculations.

Chapter 6 deals with a third part of capacity investigations: the 'high wind – low demand' situation.

Finally, the situation in twelve European states, which were selected according to their expected expansion of wind power, is analysed with respect to the influence on the power system, and on power market aspects being relevant for wind power integration.

2 Approaches to Assessing Wind Power Capacity Effects

Security of supply criteria for power systems request that any peak electricity demand can be covered in a reliable way. The determination of necessary generation capacities is generally done on a statistical basis.

In this work, the 'capacity credit' of wind power is defined as the amount of conventional power plant capacity that can be replaced with wind power, without decreasing the level of the security of supply for the power system.[5]

2.1 System adequacy considerations

The UCTE System Adequacy Forecast 2006 – 2015 [UCTE2005] states with respect to this issue: "*UCTE approach is based on a comparison between the load and the generating capacity considered as "reliably available" for power plant operators (generating capacity after the deduction of various sources of unavailability - non-usable capacity, scheduled and unscheduled outages - and reserves required by TSOs for system services). …In addition the difference between these reference loads and peak load is estimated.*

Developments have been performed by UCTE in order to estimate the level of remaining capacity (RC) necessary to provide a required level of security of supply taking into account the characteristics of every subsystem. A probabilistic approach has been used which allowed to define the statistical characteristics of the RC as the results of the probabilistic characteristics of each component: load and unavailability of generation."

In different national specifications, security of supply levels are found ranging from a 99 % level (see 'dena study' [DENA2005] for Germany) down to a 91 % level (see 'SCAR report' [UMIST2002] for UK).

The inverse 'risk level' refers to a probability of the power system under investigation not to be able to cover its peak demand without electricity import. The condition "not without import into the system" needs to be highlighted. It means that the criteria not being met do not automatically lead to a blackout in the system. Instead, cross border transit capacities have to be used – a fact that links adequacy to market and regulatory aspects.

Looking again at the technical features - how can the generation capacity available in the power system at a given moment be calculated? The decisive underlying

[5] For a comprehensive collection of the variety of capacity credit definitions see [Giebel2005].

assumption in such calculations is that long-term statistics for power plant availability can be used as expectation values of availability in one specific moment: the moment of peak demand.

Figure 2-1 shows the components of the national power balance in the moment of peak demand. In this kind of graphical representation, the majority of installed wind capacity is assigned to the so-called “non usable capacity”!

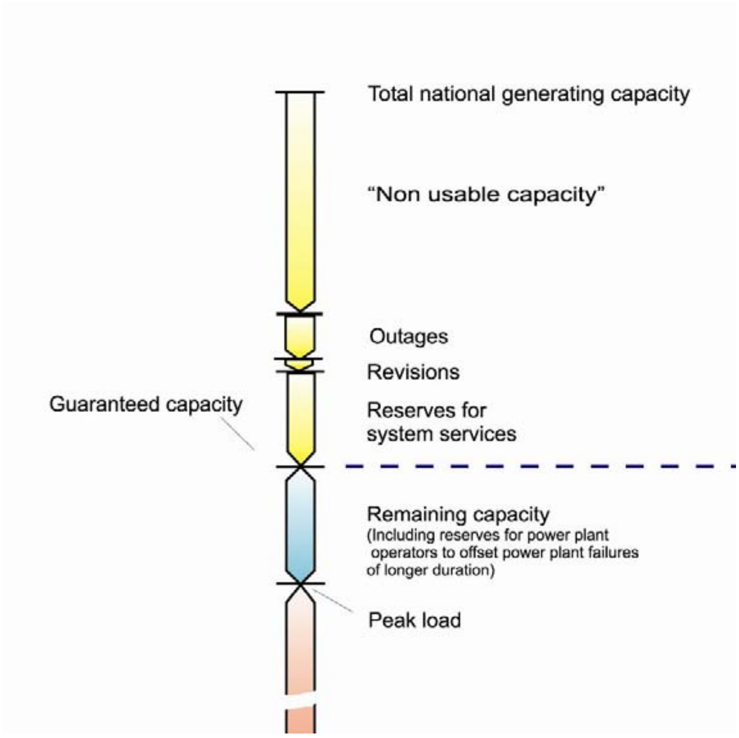


Figure 2-1: Power balance in the moment of peak demand (adopted from VDN2005)

The guaranteed conventional generation capacity is calculated by the combination of all individual power plants’ probability of availability. This needs to be based on the assumption that outages of individual generation units are independent.

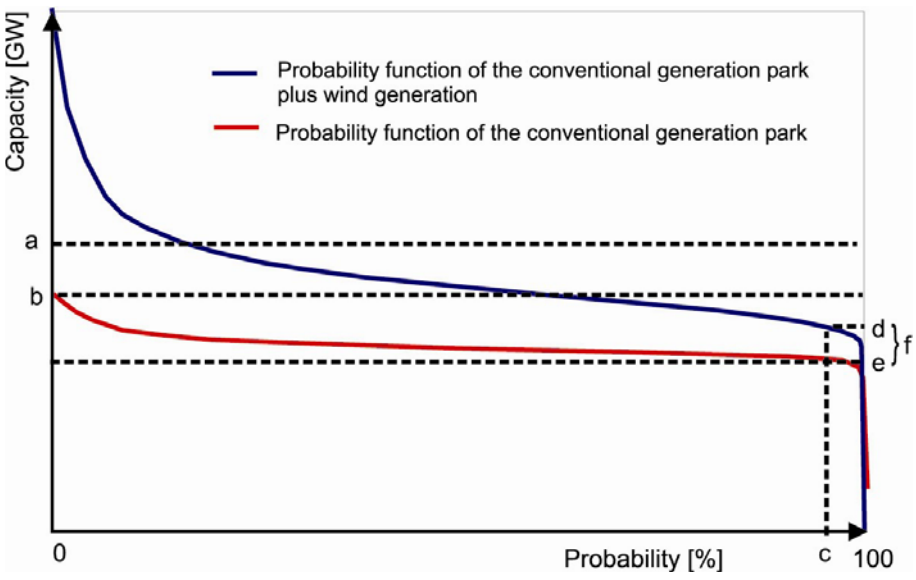
The probability of generation unit outages due to planned maintenance / repair or unplanned events, vary for individual generation units between 1% and 8% of the time, depending upon technology, age and size of the plant (Statistics from operation in Germany see Table 2-1).

Figure 2-2 shows how the conventional (thermal and large hydro) generation capacity varies with the respective level of probability of its technical availability for power generation. Thus, the graph provides the so-called ‘guaranteed’ generation capacity. If wind turbines are added to the system, the ‘guaranteed’ generation capacity is increased to the upper (blue) line in Figure 2-2.

Power plant technology	Unplanned, non disposable periods of non-availability
Nuclear power stations	3.0 %
Lignite-fired power stations	3.2 %
Hardcoal-fired power stations	3.8 %
Natural gas-fired combined-cycle power stations	1.8 %
Natural gas-fired condensation power stations	1.8 %
Gas turbines	3.0 %
Oil-fired condensation power stations	1.8 %
Reservoir power stations	0.0 %
Pumped-storage power stations	0.0 %

Table 2-1: Conventional power plant non-availablity statistics, Germany [DENA2005]

The assumption of non-correlation is not generally applicable in the case of wind power generation. The dena report [DENA2005] and the study "Quantifying the System Costs of Additional Renewables in 2020" (SCAR report) [UMIST2002] have therefore defined all installed wind power as one wind power 'unit'.



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

Figure 2-2: Dependency of wind power capacity credit on the probability of 'guaranteed capacity' (based on dena study figure [DENA2005])

In order to determine the power probability function of this aggregated ‘wind power block’, it is again assumed that long-term statistics on wind power availability deliver its probability to be available in the moment of peak demand.

In the case of wind power, this is a problematic assumption, as statistics gathered in specific periods do not necessarily represent the day of peak demand. On the other hand: the more specific the wind power data are selected (e.g. only from winter days, only from 20 coldest days of the year, etc.), the smaller the statistical data source gets. As an extreme, only wind statistics at the day of peak demand would be used, providing extremely limited statistics. This will be discussed in detail in chapter 3.

In any case, the guaranteed capacity of the system including wind is determined by statistically combining the wind power probability density function with conventional power plant probabilities.

In a final step, the capacity credit is calculated as difference between the two guaranteed capacities: the power system without and with wind energy.

2.2 Chronological and Probabilistic Models

Capacity credit is a statistical value, which has to be derived from system observation in the time domain: from load time series, from time series of conventional generation and time series of wind power feed-in. The different ways of transition from the chronological values to frequency distributions provide an essential distinction between approaches for the calculation of capacity credits.

Figure 2-3 shows the relevant magnitudes on different aggregation levels in both time domain and statistical system observation: the load, the conventional generation, and wind power. In this ‘map’ the main model paths to the desired result – the capacity credit - can be found. It is best explained in a deductive way:

The uppermost row in Figure 2-3 deals with system adequacy magnitudes: The *load coverage* includes the *capacity credit* as measure applied with respect to the moment of peak load. At the same time, the *maximum reserve demand*, arising from the maximum balancing power needed throughout the year, is as well a statistical value collected from the time series.

The *load* is covered by conventional generation and wind. Hence the row describing load magnitudes includes *annual peak load* as the statistical maximum value. In addition, the dena study has introduced seasonal peak load. The respective time domain magnitudes are *load time series*, both *predicted load time series* and *observed*.

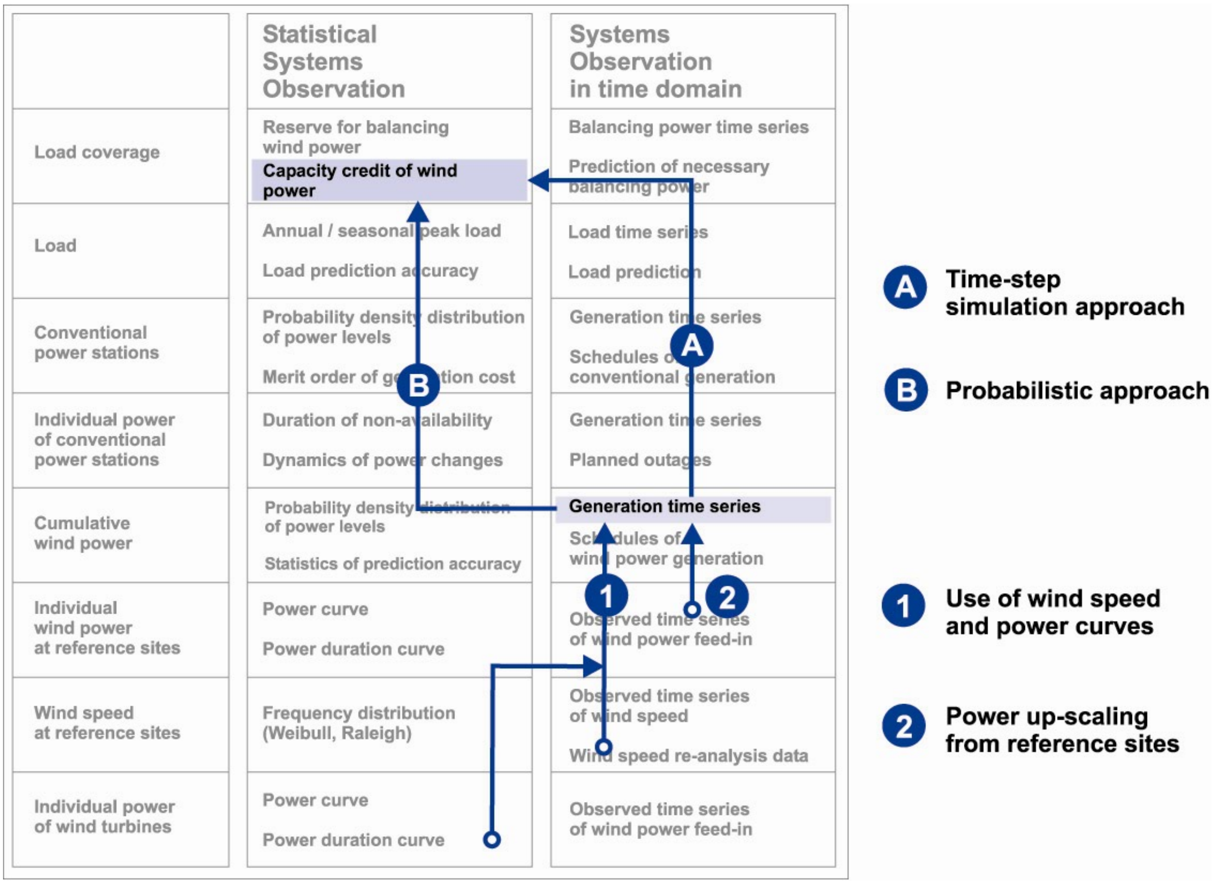


Figure 2-3: Model paths for the calculation of wind power capacity credit

The row describing the contribution of the conventional generation park contains the *probability density of power levels* (statistics), and *generation time series* in the time domain.

Those magnitudes are derived from *individual power of conventional power stations*: the magnitudes are *duration of non-availability* (statistics), and in the time domain the power stations' *generation time series* as well as *planned outages*.

The cumulative wind power contribution to load coverage is described by *probability density of power levels* (statistics), and *generation time series* in the time domain.

As not every individual wind turbine is observed, the cumulative wind power generation needs to be derived, either from individual wind farms at reference sites, or from wind speed at reference sites.

The *individual wind power* at reference sites is described by the *power curve* (statistics) and *observed time series of wind power feed-in* (in time domain).

The wind speed at reference sites is statistically described by the *probability density function* (Weibull, Raleigh), in the time domain by the *observed time series of wind* *speed* or – in cases where measured values are not available – by *time series of wind speed re-analysis data*.

With respect to *individual power of wind turbines*, usually only the statistical value of their *power curves* is available, while the *observed time series of all individual wind turbine power* feed-in is listed here for reasons of completeness. It cannot be expected to be available for national wind integration studies.

Path A and Path B, both starting from the time series of cumulative wind power, guide the way towards capacity credit: Path A as a chronological simulation approach, while Path B uses an early transition to statistics and probabilities.

2.2.1 Time-step simulation approach

In the time-step or chronological simulation approach (Path A in Figure 2-3) the hourly or 15min values of the total wind power production are subtracted from hourly or 15min load data and the residual power is assigned to the available conventional generation units by a scheduling model, e.g. the 'National Grid model' [GIEBEL2000].

For each time step, the unused conventional generation units are identified. At the final stage, the capacity credit, defined as the conventional generation capacity unused throughout the period observed due to wind power feed-in, is determined.

According to this description, the approach requires:

1. correct[6] load time series for the period of investigation,
2. unbiased wind power time-series,
3. a complete inventory of conventional generation units,
4. power generation cost per unit or per type of power station, in order to determine the merit order of power stations for dispatch.
5. required level of security of supply.

2.2.2 Probabilistic approach

While the chronological approach turns only in the last step to statistics, the probabilistic approach (Path B) immediately converts wind power time series into

[6] The terms "correct", "unbiased", "complete" in the list of requirements describe target values, which can only be reached to a certain extent. It is a key issue of this work to describe the accuracy of fulfilling the requirements and to describe consequences.

probability density of power levels, to be combined with the probabilities of conventional power stations' availabilities.

A main reason to apply this approach can be the lack of appropriate chronological data. Especially national *load time series* have up to now not been disclosed by system operators.

The probabilistic approach requires instead:

1. a complete inventory of installed capacity of conventional generation plant,
2. each unit's statistical values of time share of non-operation,
3. correct probabilities of power levels of wind power feed-in.
4. required level of security of supply.

Time series of aggregated, cumulative, wind power feed-in are needed in any case, as they are the intercept point of path A and path B. Therefore, a bias in those wind power time series has always a strong influence on the resulting capacity credit.

Again, the 'map' in Figure 2-3 shows us two different ways to determine the aggregated, cumulative wind power in power systems, being described in the following two chapters.

2.2.3 Use of wind speed and power curves

In cases where only a limited number of wind farm power output data is available, wind power feed-in can be computed from measured wind *speed* values, using wind turbine power curves after extrapolation of wind speed values to the known or assumed wind turbine hub height (path 1 in Figure 2-3).

From the individual wind measurement sites, the power has to be extrapolated to the whole number of wind farms existing or planned.

The approach requires:

1. the best-possible scenario of wind farms to be installed, including their correct geographical distribution;
2. correct wind turbine data: power curve, hub height;
3. best-possible site description, correct roughness length.

In general, wind integration studies will need to make assumptions on values for the magnitudes mentioned above: the hub height of wind turbines and the roughness length of sites. The assumed values naturally differ from the true values. We search for an analytical description of wind speed deviations arising from deviations of roughness length and hub height from true/reference values. The equation describing the wind speed u_2 in height h_2 above ground depending on wind speed u_1 in height h_1 by the logarithmic profile[7] with roughness length z_0 is given by

$$u_2 = \frac{\ln\left(\frac{h_2}{z_0}\right)}{\ln\left(\frac{h_1}{z_0}\right)} \cdot u_1 \tag{2.1}$$

The specific interest in this work refers to the sensitivity of the relationship (2.1) to deviations. The relative deviation of u_2 depending on deviations of z_0 and h_2 is

$$\frac{\Delta u_2}{u_2} = \left| \frac{1}{\ln\left(\frac{h_2}{z_0}\right) * h_2} \right| * \frac{\Delta h_2}{h_2} + \left| \frac{\ln\left(\frac{h_2}{h_1}\right)}{\ln\left(\frac{h_1}{z_0}\right) * \ln\left(\frac{h_2}{z_0}\right)} \right| * \frac{\Delta z_0}{z_0} \tag{2.2}$$

The empirical investigations in chapter 4.4 will show how the relative deviations of the wind speed $\Delta u_2 / u_2$ are converted into capacity credit deviations.

2.2.4 Power upscaling from reference sites

As soon as sufficient wind farm power data are available, a second way for determination of the aggregated wind power is given by upscaling the power feed-in of reference wind farms. The measured power output is extrapolated to the total number of installed wind farms (Path 2 in Figure 2-3). This approach needs a spatial extrapolation model to scenario sites, and a vertical upscaling to the correct hub heights of scenario turbines.

The approach therefore requires:

1. the best-possible scenario of wind farms to be installed, including their correct geographical distribution;
2. correct wind turbine hub height;
3. best-possible site description, correct roughness length.

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[7] The relationship is valid for stable atmospheric conditions only. Increased wind turbine hub heights require refined atmospheric modelling.

In his dissertation "Rechenmodelle und Informationssysteme zur Integration großer Windleistungen in die elektrische Energieversorgung" [ROHRIG2003], Rohrig introduced an upscaling algorithm, which calculates the wind power produced in an geographical area (represented by a grid square i) by

$$P_i = k_i \sum_j s_j \cdot A_{ij} P_j \qquad \textbf{(2.3)}$$

with the magnitudes

P_j : measured wind power feed-in of reference site j, scaled to rated power

s_j : status of measurement equipment (0 := in error; 1 := ok).

The parameters A_{ij} are calculated by

$$A_{ii} = a_{ij} * P_{NPFi} * R_{ji} \qquad \textbf{(2.4)}$$

with

a_{ij} : weighting factor, depending on distance

P_{NPFi}: installed wind capacity of grid square i

R_{ji}: roughness parameter.

The correction factor k_i is chosen in such a way that the total of all weights amounts to one. Downtime or errors of measurement equipment is considered by multiplication with the status indicator s_j. In case of erroneous measurements s_j is set to zero and other measurement sites receive higher scaling factors.

The procedure depicted in Figure 2-4 is repeated for each grid square in the area investigated.

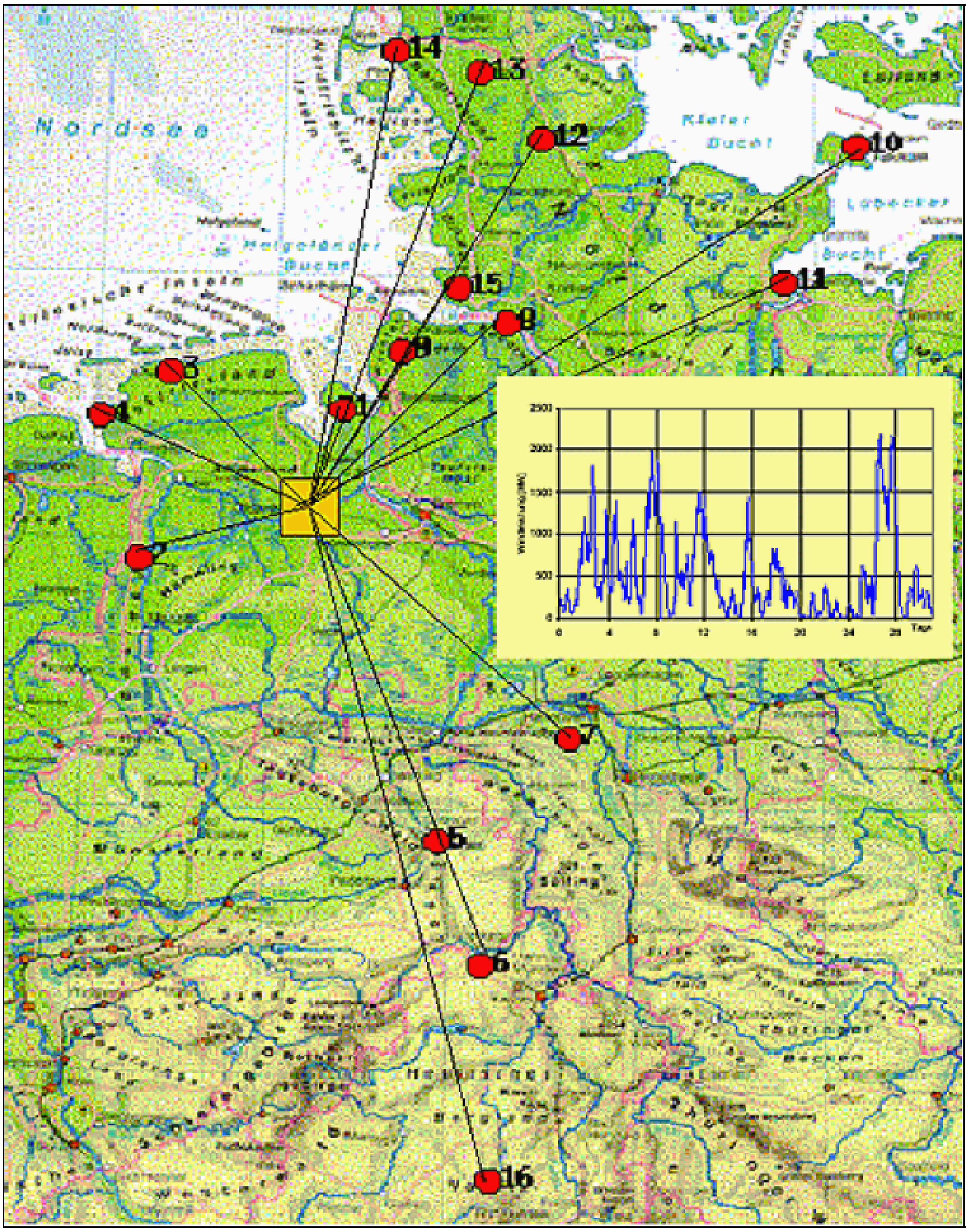

Figure 2-4: Power upscaling from reference sites to geographical grid squares [ROHRIG2003]

2.3 Approaches and parameters of selected prominent studies

Having now the background of different ways to the capacity credit, we will investigate which concrete methods and input values were chosen in four studies, the capacity credit results of which are often quoted: Giebel's calculation of a European wind capacity credit [GIEBEL2000], a study of ADEME and Armines on the wind integration into the French power system [BALEA2004], the German 'dena-study' [DENA2005], and the 'SCAR report' on the cost of large wind power integration into the UK power system [UMIST2002].

2.3.1 Power curves and time-step approaches

In his dissertation 'On the Benefits of Distributed Generation of Wind Energy in Europe', Giebel followed the model-paths 1 and A by the following steps (see Figure 2-5).

A European average wind turbine power curve was used to calculate the total European wind power generation.

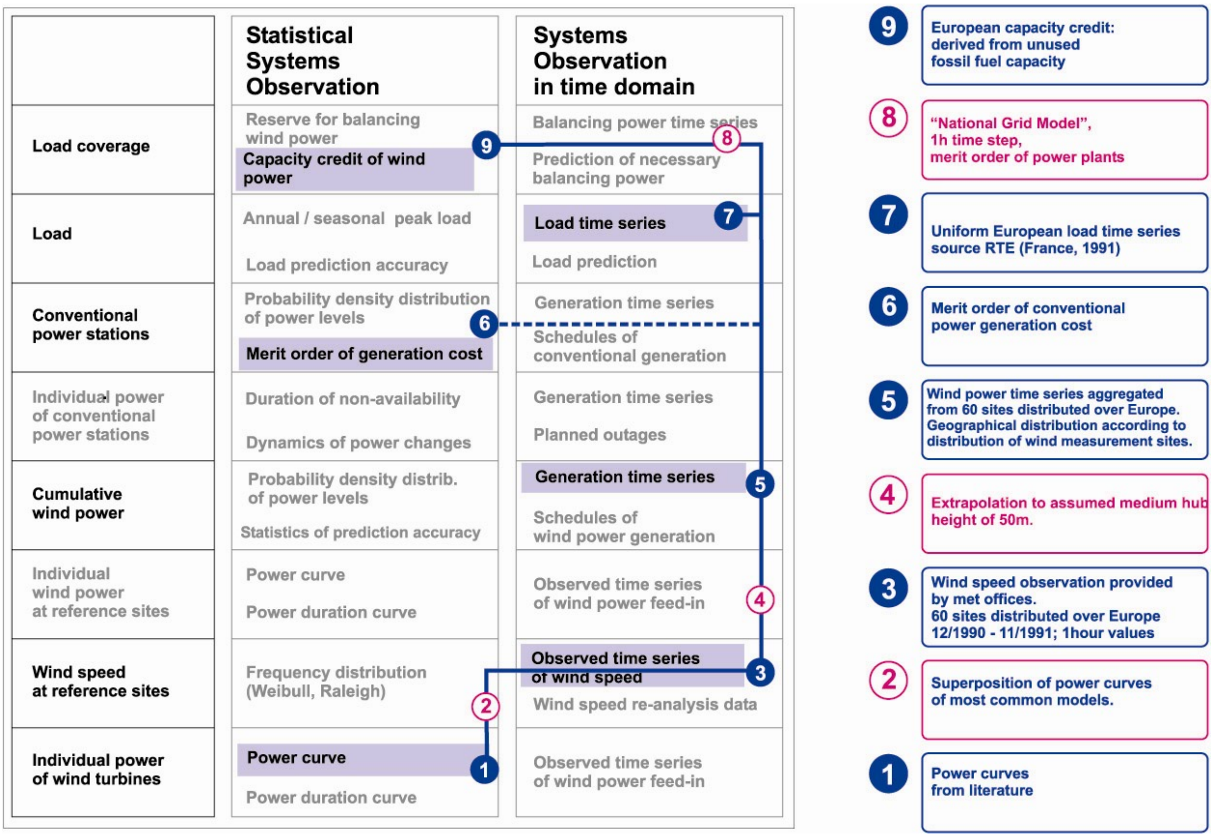

Figure 2-5: Methodology for assessing a European wind power capacity credit

The European wind data came from 60 meteorological stations in the selected European countries and were taken for the period from December 1990 to December 1991.

The time series have a three-hour time resolution, and since hourly time series were needed for the scheduling model, the wind speed was linearly interpolated at every station before applying the power curve.

The wind speed was scaled to a height of 50m above ground level, using the sector dependent roughness from WA^{s}P analysis in the logarithmic wind profile.

The load time series were available from France, England/Wales and Portugal. They were scaled in order to fit the overall European load 1991.

All power plants are listed in a merit order, which means that the operators choose the plant at the lowest production cost per kWh first, and then work their way through the list up to the number of plants which are able to cover the predicted load.

For the assessment of a capacity credit, the replacement of conventional power plant by wind power was investigated. The National Grid Model shows how many fossil fuel plants were not used during the run: the 'unused fossil fuel capacity'.

"If we assume that with the high number of conventional plants in the grid, the outages of single plants are averaging each other out, then we can use the unused fossil fuel capacity as at least some measure of the capacity credit." [GIEBEL2000]

It is important to note that this approach could not include refined wind farm installation scenarios. Instead, the 60 wind speed measurement sites are representing large areas around them.

A second example of the chronological approach is given by the study presented by ADEME and ARMINES [BALEA2004], which especially takes the question of installation scenarios into account: "*The geographical dispersion is a problematic issue because of many uncertainties and externalities*". Therefore, nine different installation scenarios were applied to France 2010.

In order to investigate the sensitivity of capacity credit to the geographic dispersion of wind farms, we dedicated a series of sim.WIN simulation runs to this issue (see chapter 4.4).

The availablity of load time series is a bottleneck of power system descriptions in several countries. In those cases, either the chronological approach needs to transfer load time series from other systems or probabilistic approaches have to be applied.

2.3.2 Upscaling of reference wind farm power

The dena study [DENA2005] followed Path 1 (upscaling of power feed-in) and path B (convolution of probabilities) in its calculation of wind power capacity credit for the years 2003, 2007, 2010 and 2015, with the following individual steps:

Wind farm power data were taken from more than 70 reference wind farm sites in Germany, with wind power and wind speed observations over 10 years: 1993 to 2002, in 15min time steps.

The so-called ‘online model’ of ISET [ROHRIG2003] was applied to the upscaling from the reference sites to the total amount of wind farm sites according to the real German wind farm distribution in the year 2003, and to scenarios of distributions in 2007, 2010 and 2015.

The probability density of the aggregated German wind power feed was calculated as an average of different data set selections from 1994 to 2003: days of peak demand only / winter months / 20 coldest days of the year.

The inventory of conventional power stations in Germany includes the technology and age of the units, in addition the probabilities of (non-)availability per plant technology.

The view on the magnitude “electrical load” provides an important reason for the choice of the probabilistic approach in the case of the dena study: Continuous load time series for Germany were non-disclosed and therefore not available for the study.

By means of the probabilistic combination of wind power and conventional power station availabilities, the capacity credit was calculated for Germany in 2003, 2007, 2015, at a required security of supply level of 99 % for a combination of all four German control zones.

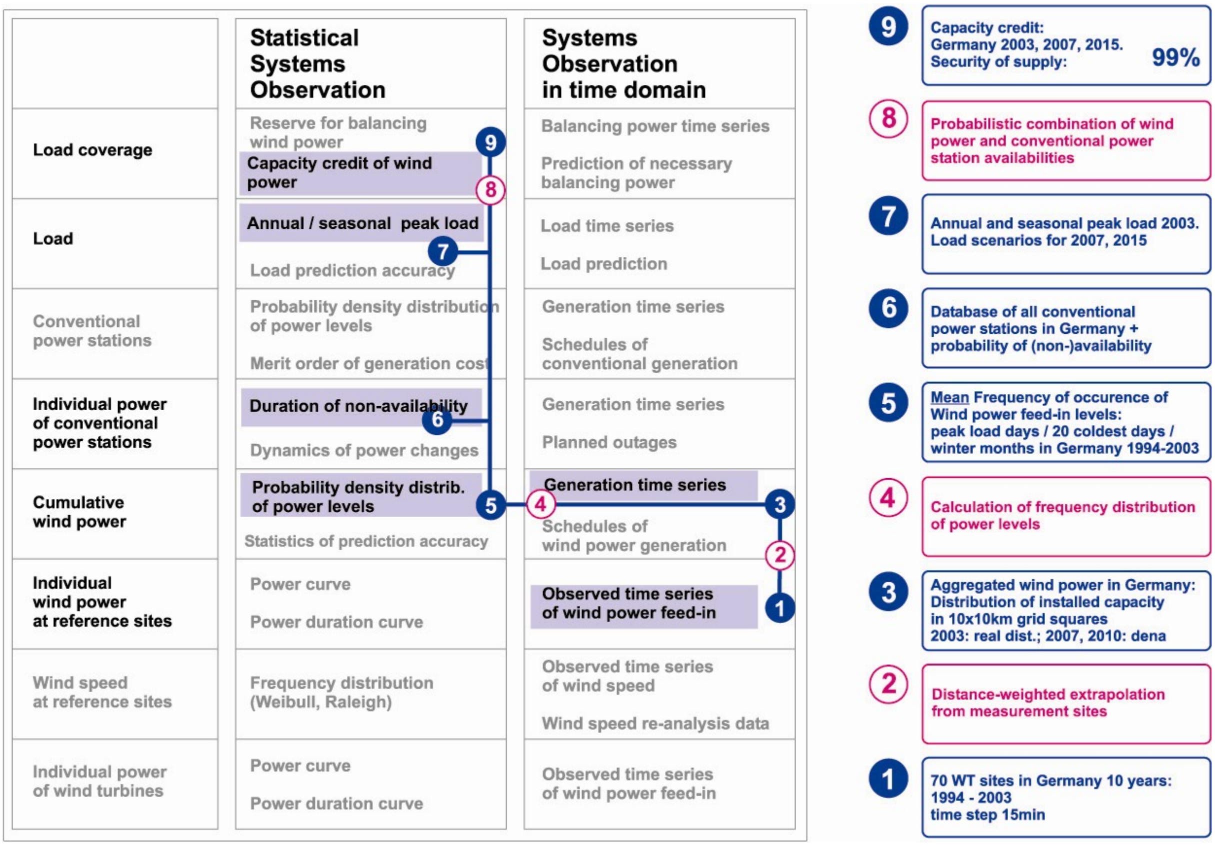

Figure 2-6: Probabilistic methodology for capacity credit calculation (here: dena study)

Ilex and UMIST have presented a study for the UK [UMIST2002], following a comparable model path. Yet, important characteristics have to be noted:

- Power feed-in data were available from one wind farm in the UK only, with a time span of 1 year and a resolution of 1 hour;
- Capacity credit for the UK in 2006, security of supply: 91%.

A set of sim.WIN simulation runs were therefore dedicated to variations in input wind regime, and to the influence of the required ‘security of supply level’ on the resulting wind power capacity credit, see chapter 4.4.

3 Statistical and Probabilistic methods

This chapter will guide us in the mathematical way to get from input wind power samples via their probability density distribution to the wind power capacity credit. Two different sources of deviations in the input data set (insufficient samples and the choice of representative data sets) will be investigated and the influence of these input data deviation described in a mathematical form.

The first source of misinterpretations in the context of probabilistic investigations and their graphical depictions can be found in assigning abscissa and ordinate. In power systems-related depictions and wind integration studies, generally the y-axis shows ‘power’, while the x-axis shows ‘probability’. A typical example of a ‘power system depiction’ is the upper part of Figure 3-1, orginally adopted from the dena study [DENA2005]. The lower part depicts the identical information, now with ‘probability’ as y-axis and ‘power’ as x-axis. This way of representation allows a better represention of probabilistic approaches and is therefore applied in the following sections.

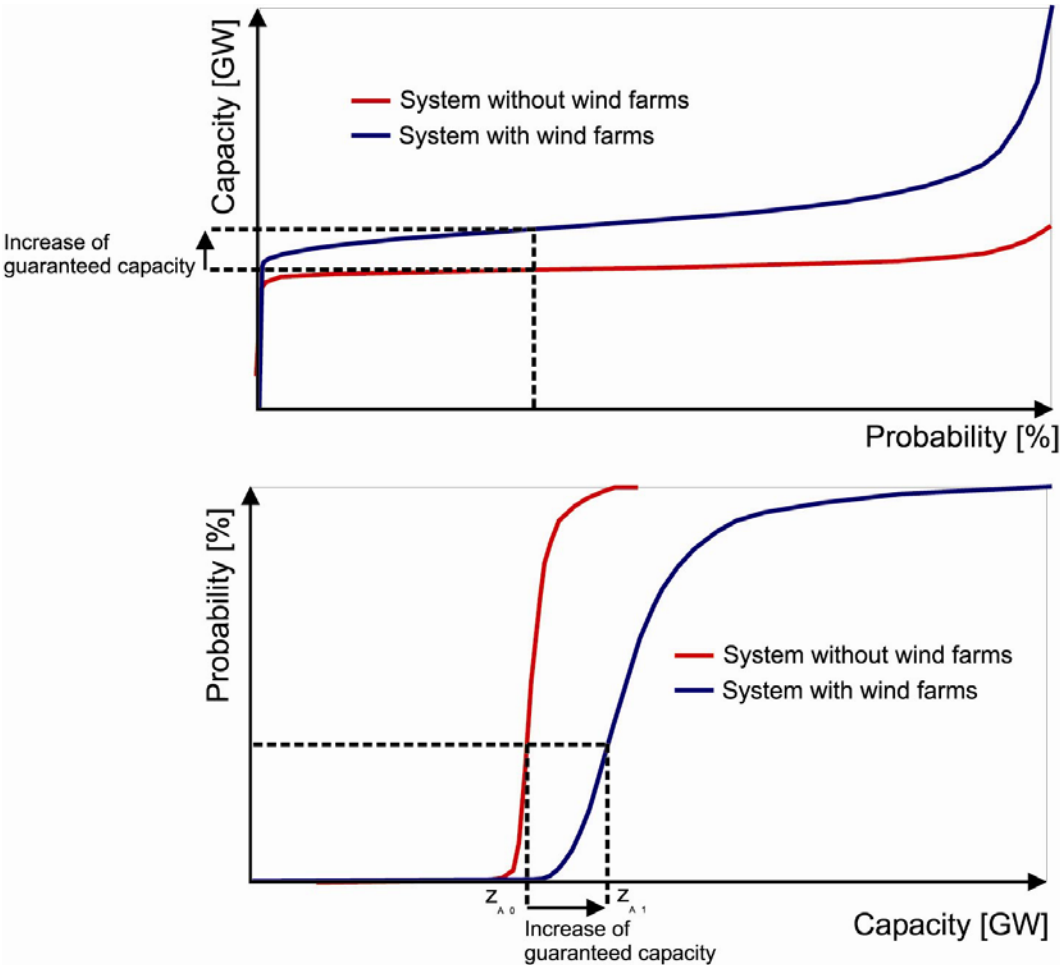

Figure 3-1: Two ways of capacity credit depiction with identical information: (a) from the power system perspective and (b) for probabilistic approaches

3.1 Probabilistic combination by means of the convolution product

The mathematical approach to determine the statistical characteristics of a power generation system including wind power consists of statistical combination of the probability density distributions of (1) the conventional power plants and (2) of the wind farms under investigation. Let P_{wind} be the probability density of the aggregated wind power under investigation:

$$P_{wind} : x_i \mapsto a_i \tag{3.1}$$

The probability that the wind power feed-in is x_i (in GW[8]) is a_i (in %), the condition for probability density is that the total of all individual probabilities amounts to 1:

$$\sum_i a_i = 1$$

The probability density of all conventional generation units is P_{conv}:

$$P_{conv} : y_i \mapsto b_i \tag{3.2}$$

The probability that the power feed-in of all conventional generation units is y_i (in GW) is b_i (in %). The condition for the probability density is that the total of all individual probabilities amounts to 1:

$$\sum_i b_i = 1$$

The power levels (x_i) and (y_i) need to have the same scale and resolution to allow using the convolution product. The probability density of the system including the conventional generation units plus wind farms is P_{syst} .

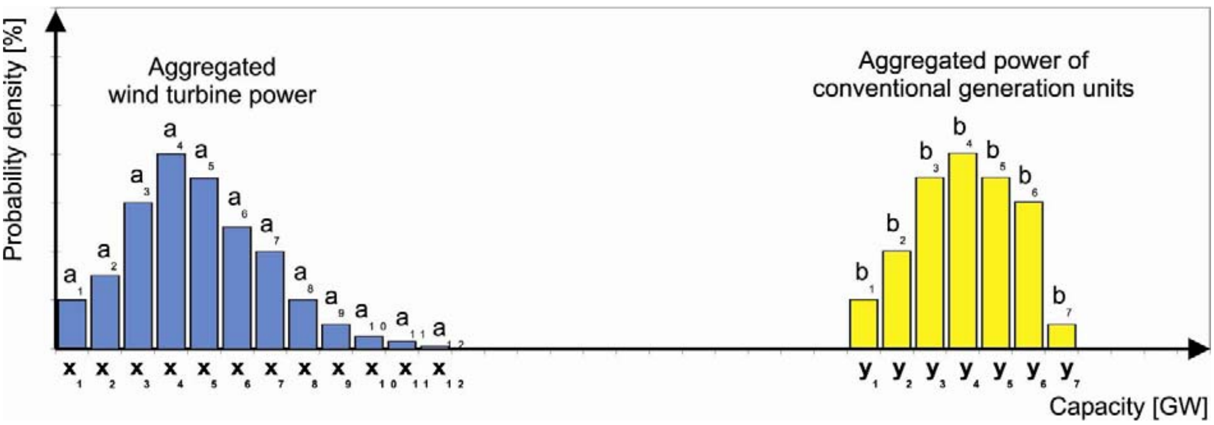

Figure 3-2: Probability density distributions of aggregated wind power and conventional generation units

[8] The unit Gigawatt (GW) is used for the wind power block, to underline the necessity to depict power levels in the same scale and resolution for all generation units to be statistically combined.

The probability that the system output is z_i (in GW) is c_i (in %):

$$P_{Syst} : z_i \mapsto c_i \tag{3.3}$$

The probability that the power feed-in of all conventional generation units is y_i (in GW) is b_i (in %), the condition for probability density is that the total of all individual probabilities amounts to 1:

$$\sum_i c_i = 1$$

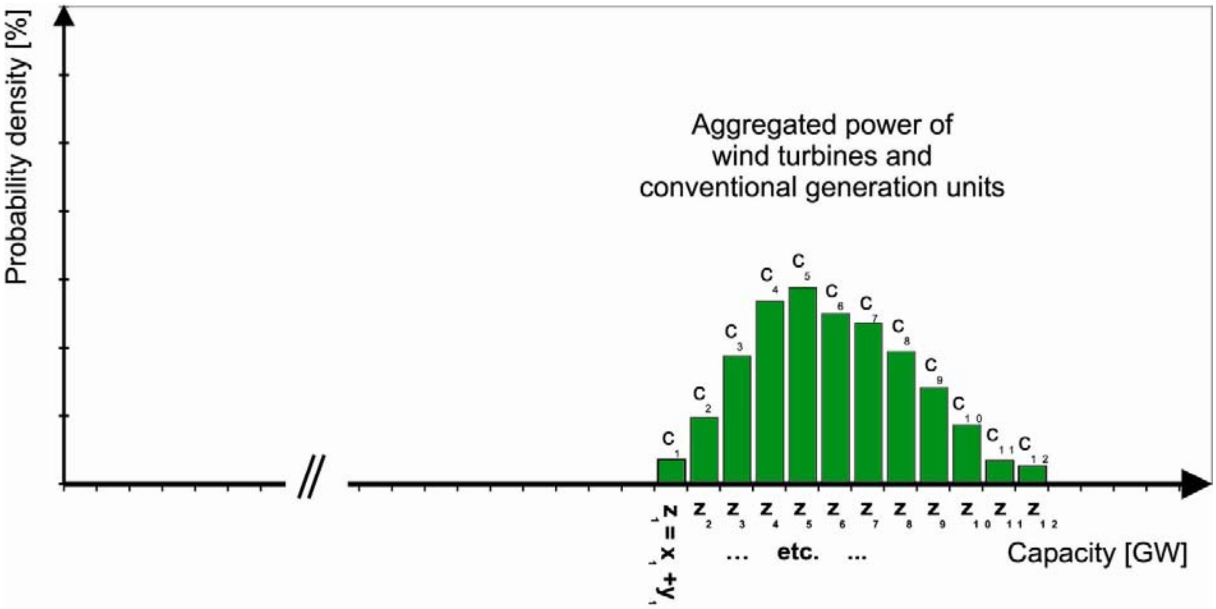

Figure 3-3: Probability density of wind power feed-in and conventional generation combined

The correlation between the conventional generation unit availabilities and wind power feed-in is generally assumed negligible. With this precondition fulfilled, we can treat P_{wind} and P_{conv} as independent random variables and compute the computation of P_{syst} by means of the convolution product:

$$P_{Syst} = P_{wind} \otimes P_{conv} \tag{3.4}$$

and determine the parameters c_i by

$$c_i = \sum_x a_x b_{i-x}$$

The resulting probability density distribution of the combined generation park is shown in Figure 3-3.

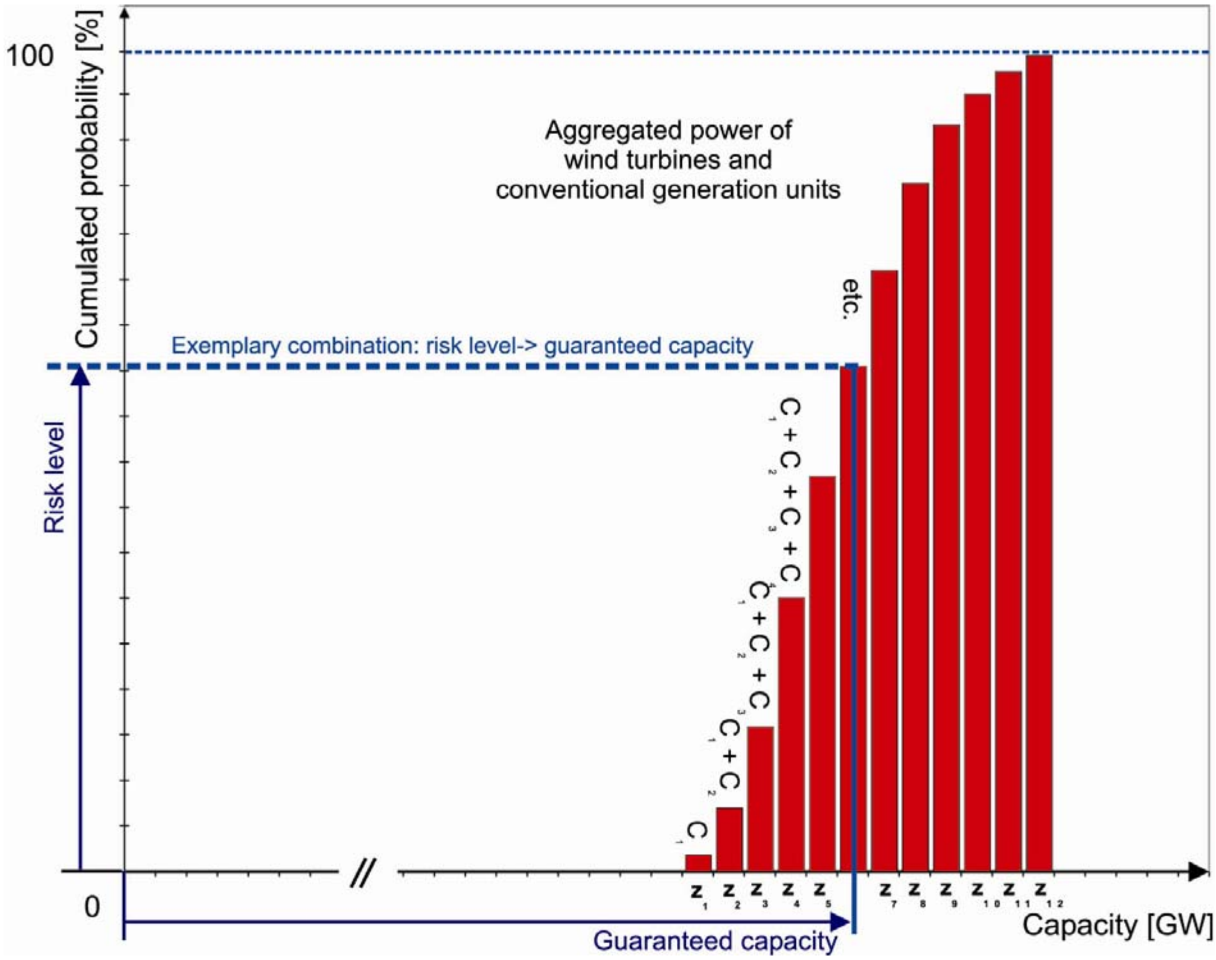

Figure 3-4: Cumulative probability of total power system feed-in

In a final step, the probability densities are added up for each power level to the cumulative probability. Figure 3-4 shows the probability that the total of conventional and wind generation are below a certain power level.

The wind power capacity credit is now determined by the comparison of the cumulated probabilities at the identical risk level for the power system including wind farms and without wind farms (Figure 3-5).

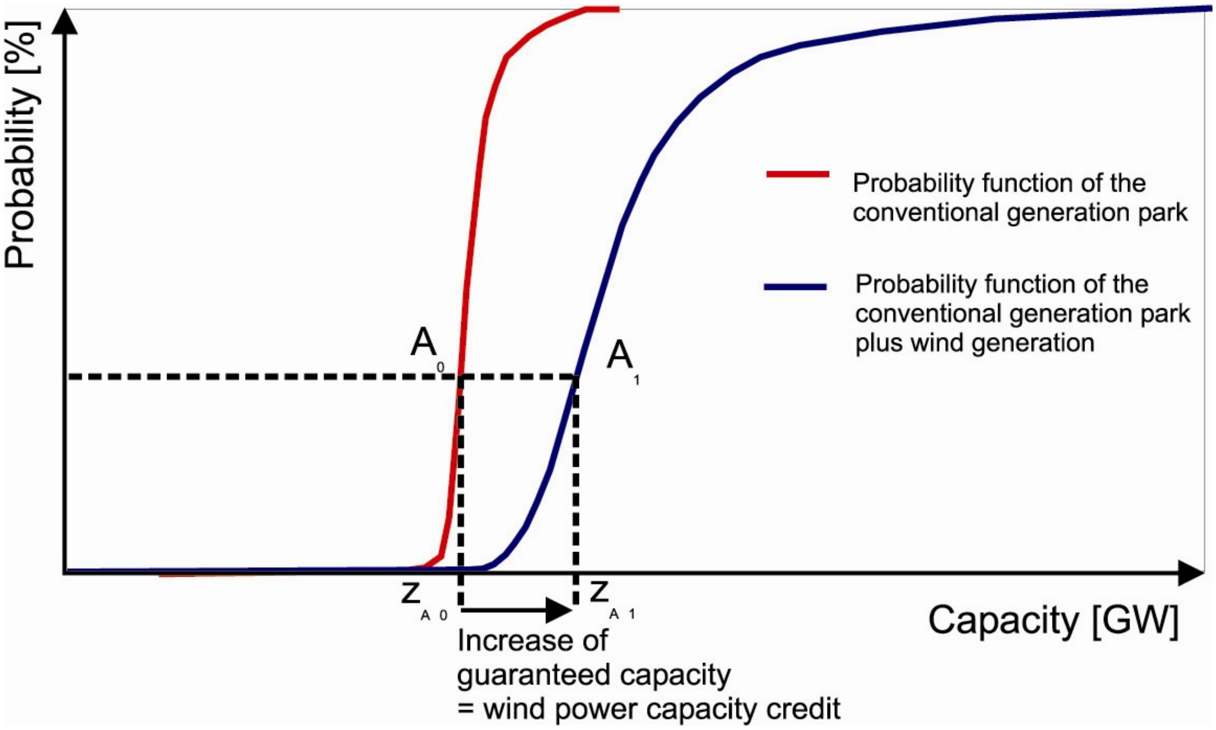

Figure 3-5 – Wind power capacity credit defined as increase in guaranteed capacity

As can be seen in Figure 3-5, the introduction of wind power in the power system results in changes of the power cumulated probability distribution, characterised by:

a) A general shift to the right to higher capacities;
b) A change in the slope of the curve, related to the probability density distribution of the wind power output.

These two parameters will change the place of the point A, whose coordinate are the "guaranteed capacity" and the "security level" or "1 minus risk level", from A_0 to A_1. The inclusion of wind farms in the power system will increase the guaranteed capacity by (z_{A1}-z_{A0}) in GW.

$$\Delta P_{guaranteed} = (z_{A1} - z_{A0}) \tag{3.6}$$

This amount is equal the wind power capacity credit as defined earlier in this work.

3.2 Assessment of statistical uncertainty

The probabilistic approach treated in the previous chapter requests knowledge of the statistical behaviour of the conventional generation park on the one hand and the aggregated wind power feed-in on the other hand. The question arises: How reliable are these statistics?

With respect to the conventional generation units, it is generally assumed that individual outages of generation units are not correlated.

The operation of wind turbines instead is depending on meteorological situation and to much higher extent correlated. It is therefore treated as one generation unit with the full power range from zero (large-scale wind calm) to full rated power.

The samples of wind power data to be used for the determination of expectation values for the moment of peak demand need to be examined in detail.

3.2.1 Biased wind power input data

We can identify two different kinds of sources for deviations in wind power statistics: data with insufficient statistical basis and biased[9] estimators.

A first potential deviation simply arises from too few input data, such as wind power feed-in data only from the day of annual peak load or even the hour of peak load. Wind integration studies have intended to enlarge this statistical basis. Scottish power for instance has used all wind power feed-in data from times with 90-100% of peak load to get a higher number of samples. Naturally, this procedure is only possible, if the respective load time series are available.

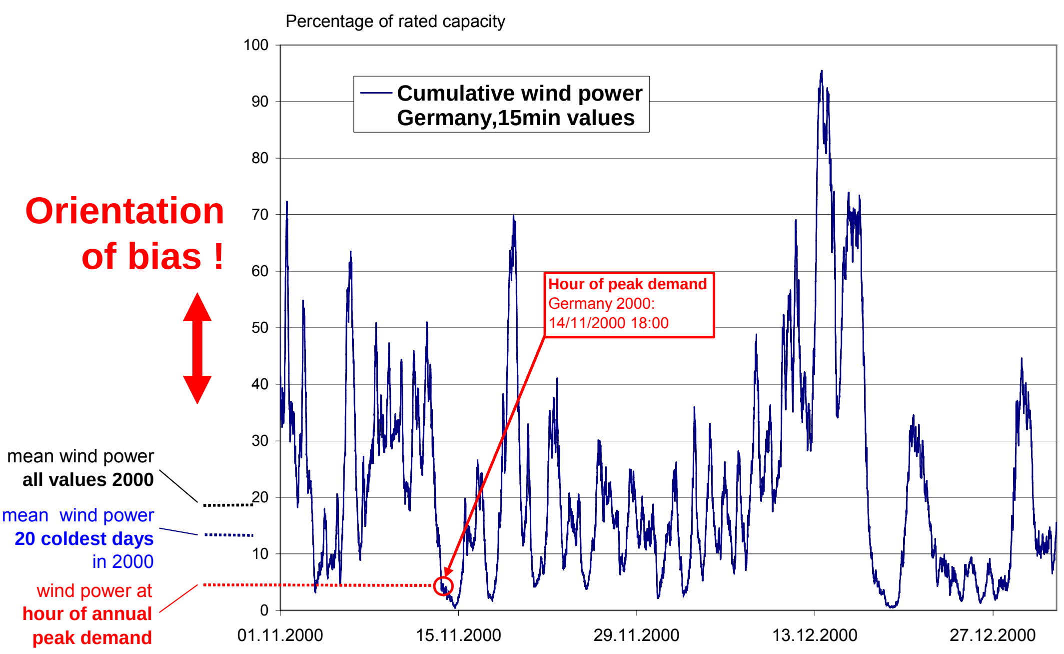

Figure 3-6: Biased samples in time series of total wind power feed-in, Germany 2000

[9] The term ‚bias' is used in a statistical way to denominate deviations and not necessarily meant pejorative.

3.2.2 Biased estimator

Another kind of bias in statistics involves the use of a data sets whose average value differs from the value of the quantity being estimated. A systematic deviation shows for instance the "wind power at coldest days of the year" criteria for trying to estimate wind power when searching for a statistically sound data sample representing the moment of peak demand. The problem has been described in the expertise document [SCHMID2005] with respect to the dena study:

"For the computation of probability distributions of the wind energy feed-in at the time of the peak load fundamental aspects have to be considered. The following options were discussed for the dena study:

a) All days of all years under consideration,

b) each year's single day of annual peak load,

c) the 20 coldest days of each year

d) all winter months of all years

With respect to option c), a direct correlation with the peak load days could be assumed at first glance. Such a correlation could however not be found. Investigations of the daily mean temperatures of the years 1994 to 2003 showed only two cases where the day of annual peak load belonged to the set of 20 coldest days of the year. Instead a clear correlation of the coldest days to low wind speeds emerged. Relating the wind power capacity credit to the coldest days of the year is therefore a misleading approach. Since option b) delivers only a minimum data sample, option d) is also taken into account. Finally, the average value of the options b) to d) was used."

The effect of biased wind power time series on their respective probability time series can be observed in Figure 3-7, which depicts values from different wind years.

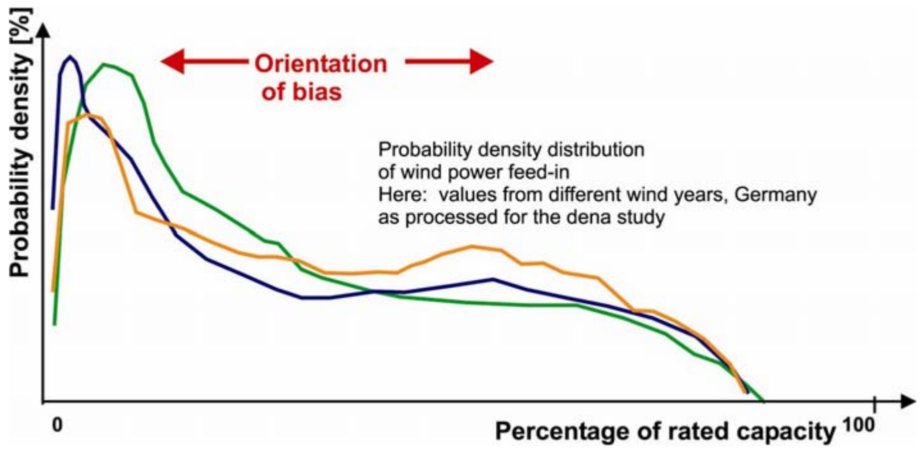

Figure 3-7: Influence of bias on probability density distributions

3.2.3 Convolution product uncertainty

In order to describe the impact of biased wind power time series on the estimated wind power capacity credit, we consider a deviated wind power output probability density distribution $\tilde{P}_{Wind}$ as the sum of the unbiased wind power probability density distribution P_{wind} and the probability density deviation ΔP_{wind}, as stated in relation (3.7) and (3.8).

$$\tilde{P}_{wind} = P_{wind} + \Delta P_{wind} \tag{3.7}$$

$$\tilde{P}_{wind} = x_i \mapsto a_i + \Delta a_i \tag{3.8}$$

The biased probability of the wind power feed-in level x_i, is the total of the original probability a_i plus the probability deviation Δa_i, illustrated in Figure 3-8.

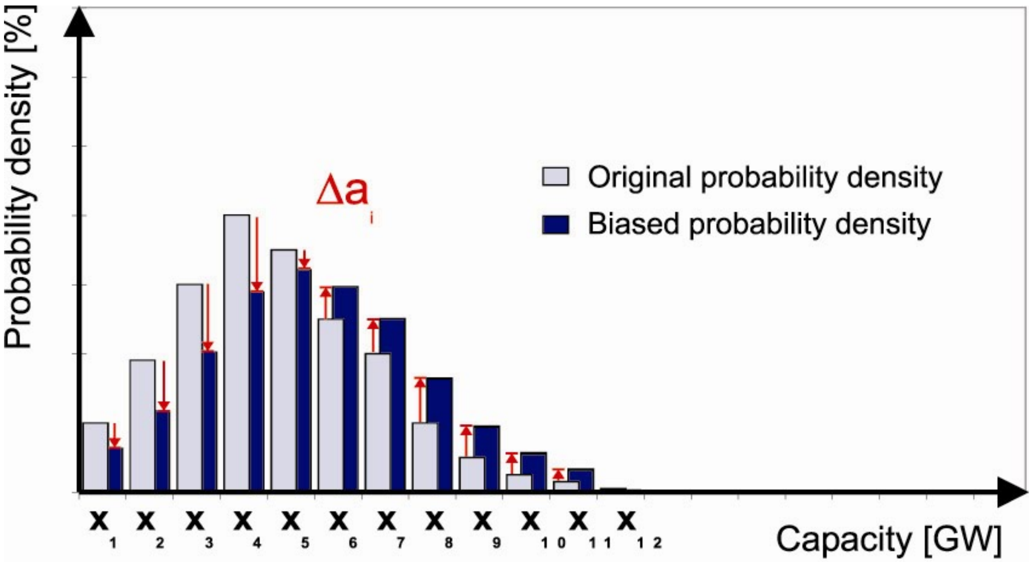

Figure 3-8: Probability density deviations due to biased wind power time series

The overall power system probability density distribution $\tilde{P}_{Syst}$, can be deduced from the following relation:

$$\tilde{P}_{Syst} = P_{conv} \otimes \tilde{P}_{wind} \tag{3.9}$$

where P_{conv} is the probability density distribution of the conventional power plant availability and $\tilde{P}_{wind}$. The relation (3.9) can be expressed as follow:

$$\tilde{P}_{Syst} : z_i \mapsto \tilde{c}_i \tag{3.10}$$

with

$$\sum_i \tilde{c}_i = 1$$

Relation (3.10) shows: the probability (being influenced by a bias in wind power) that the total power system available power z_i is $\tilde{c}_i$. Referring to the definition of the convolution product, the probability $\tilde{c}_i$ is defined by:

$$\tilde{c}_i = \sum_x \tilde{a}_x \, b_{i-x} \tag{3.11}$$

where $(\tilde{a}_j)_{j\in N}$ and $(b_j)_{j\in N}$ are the probability of $\tilde{P}_{wind}$ and P_{Syst} respectively, as defined in the previous sections. If we consider $\tilde{c}_i$ as the sum of the wind power output probability and of a probability deviation, the relation (3.11) becomes:

$$\tilde{c}_i = \sum_x (a_x + \Delta a_x) b_{i-x} \tag{3.12}$$

$$\tilde{c}_i = \sum_x a_x \, b_{i-x} + \sum_x \Delta \, a_x \, b_{i-x} \tag{3.13}$$

$$\tilde{c}_i = c_i + \sum_x \Delta \, a_x \, b_{i-x} \tag{3.14}$$

$$\tilde{c}_i = c_i + \Delta \, c_i \text{ with } \Delta c_i = \sum_x \Delta \, a_x \, b_{i-x} \tag{3.15}$$

It can be observed from relation (3.15) that the resulting power system deviation depends both on the deviation of the wind power probability density distribution and on the conventional power plant characteristics (see the yellow area in Figure 3-9).

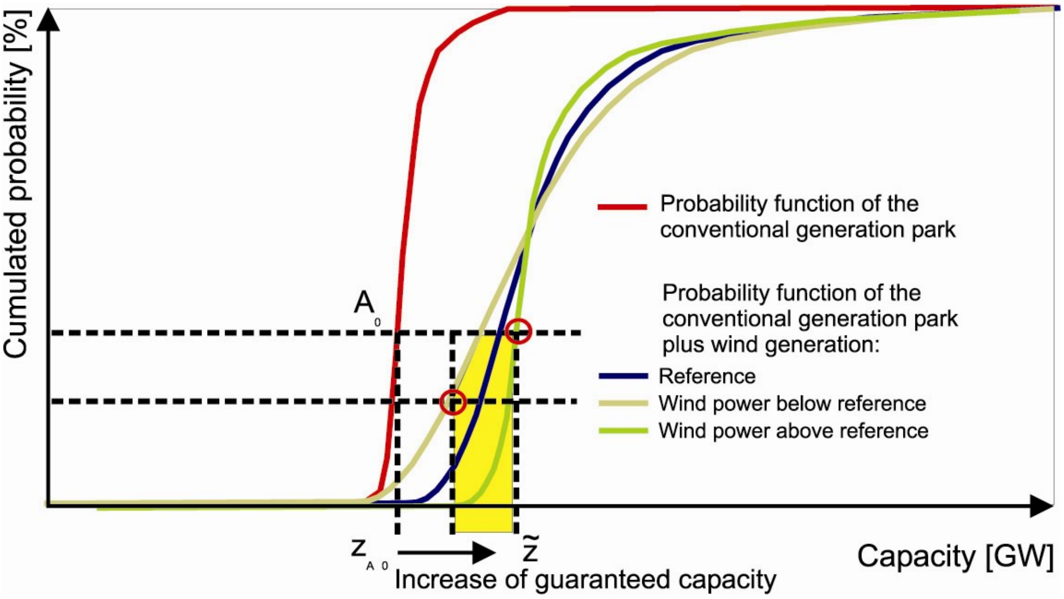

Figure 3-9: Influence of wind power probability density deviations on wind power capacity credit

We can express the impact of biased wind power probability density distributions on the wind power capacity credit as follows:

$$\Delta P_{guaranteed} = \left\{ \tilde{z}_k - z_k, k \in N \middle| \sum_{i=1}^{k} \tilde{c}_i = Security\_Level \right\} \quad \textbf{(3.16)}$$

where $\tilde{z}_k$ arises from the biased wind power data, z_k refers to the orginal un-biased values.

Relation 3.16 expresses that deviations of the guaranteed capacity are determined by the shift of the point A right- or leftwards, whose coordinate are z = guaranteed capacity and y = security level (fixed by the national regulations). A mis-estimation of the wind power time series will shift the statistical distribution of the power system guaranteed capacity to the left (under-estimation) or to the right (over-estimation). This bias will finally result in a biased estimation of the guaranteed capacity at the expected security level (represented by the point A), which will also result in a variation of the wind power capacity credit.

4 Sensitivity Analysis of Capacity Credit Calculations

The previous probabilistic accuracy considerations shall now be extended by a case study based on known power system and wind power data.

The simulation software *Sim.WIN* has been developed to enlarge the capabilities for parameter variations when calculating aggregated wind power time series and capacity credit. It is based on the Spatial Extrapolation Model SepCaMo developed by [ROHRIG2003], enabling a free choice of parameters such as roughness length, hub height, and reference wind farm sites. This makes the tool suitable as a 'test stand' for comparing results produced with a range of different parameters, and for new European studies which have to deal with varying input parameters.

4.1 The Sim.WIN Programme

The *Sim.WIN* module developed in this work for calculating cumulative wind power time series is linked with

- a data base of wind farm sites, including data geographical co-ordinates, roughness length z_0, site category, which is part of the WMEP data collection.
- a data base of wind turbine model data;
- a data base of wind turbine power characteristics, which are power curves acquired under field conditions within the WMEP program [ISET2001].

The module allows parameter variations for a number of reference sites, time step of calculations, roughness lengths, hub heights, power curves, geographical distribution of sites. The *sim.WIN* module for calculating capacity credit values applies the convolution of probabilities densities of wind power and conventional power plant.

It is linked with a database of thermal power stations, including rated power, technology and statistics of availability.

Figure 4-1 shows the layout of *Sim.WIN* with reference to the data bases mentioned above. The graph shows which parameters were varied in the course of this work.

The layout of the graphic is reflecting the fact that the probabilistic calculation path (denominated 'Path 2' in Figure 2-3) was used for all simulations.

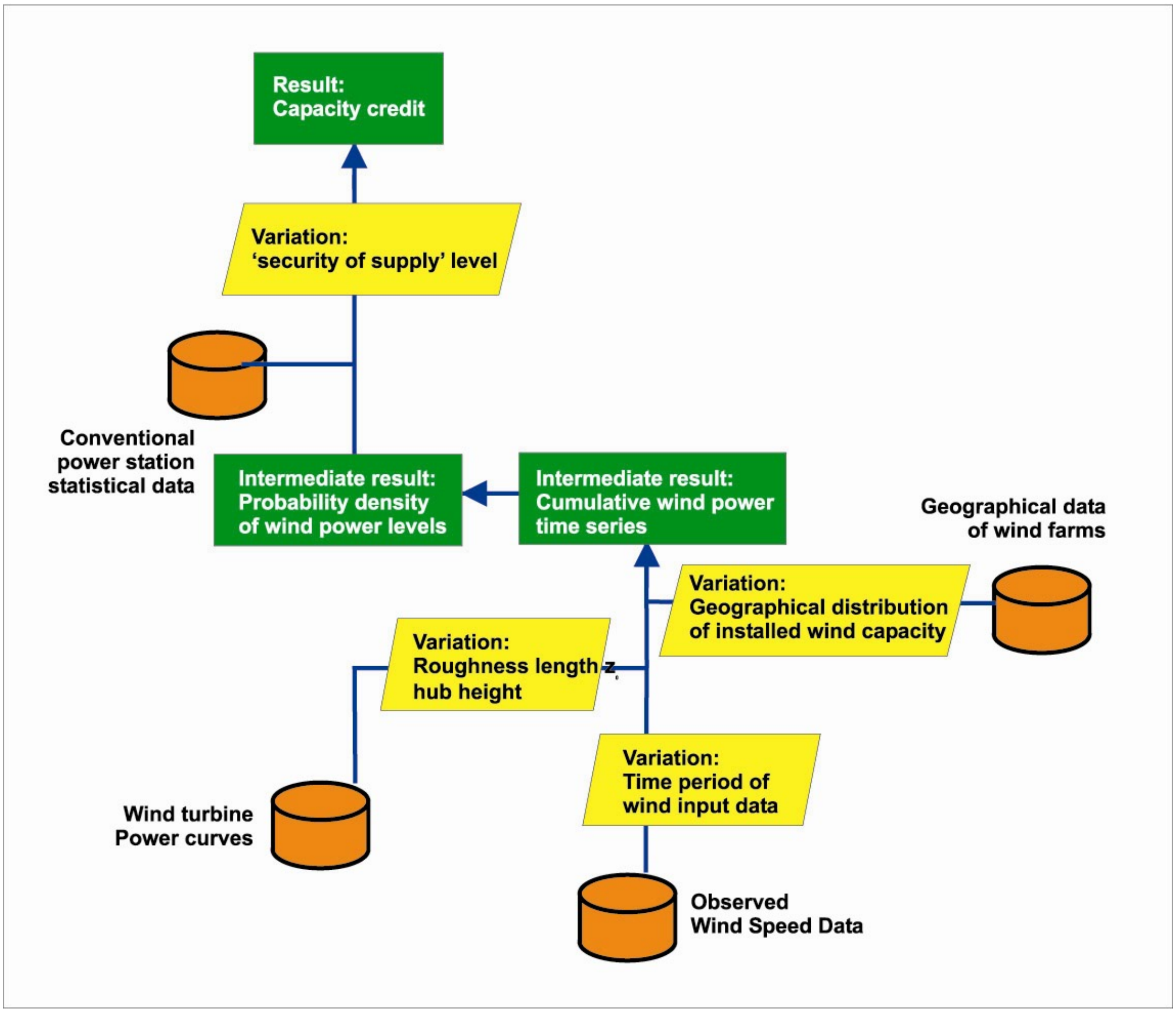

Figure 4-1: Sim.WIN programme structure: data bases, parameter variation, results

4.2 Reference case 'Germany 2000'

The retrospective view on the real situation in Germany in the year 2000 has been chosen as reference case for sim.WIN simulation runs, due to the large number of data available: the characteristics of the wind year itself, the aggregated wind power and the characteristics of the conventional power plant were available as input data.

4.2.1 Wind turbines installed

The “Wind Energy Report” for Germany 2000 [ISET2001] states the following details for installations within the year 2000 and the resulting figures at the end of the year.

	Installed in 2000	**Status at end of year 2000**
Number of wind turbines	1,500	9,300
Total rated capacity	1,650 MW	6,051 MW
Average rated power	1,100 kW	650 kW
Average hub height	70 m	54 m
Stall control Pitch control	37 % 63 %	43 % 57 %
Induction generator Doubly-fed induction generator Synchronous generator	46 % 25 % 29 %	59 % 10 % 31 %
Constant speed Variable speed	43 % 57 %	57 % 43 %

Table 4-1: Reference case “Germany 2000”: Characteristics of wind turbines installed

We see that in the case of Germany, where the rise of wind installation has started in the beginning of the 90ties, a clear distinction has to be made between the characteristics of new installations in the year 2000 and the overall picture of all wind farms installed.

4.2.2 Geographical distribution and site characteristics of wind farms

The roughness length at sites with wind measurements (for the distribution of sites see [ISET2001) was determined by the SepCaMo model from measured turbulence intensity. Table 4-2 shows a mean value of 6 cm.

Roughness length	Value
z_0 max	0.4 m
z_0 mean	0.06 m
z_0 min	0.008 m

Table 4-2: Reference case “Germany 2000”: Statistics on roughness lengths of wind farm sites

In addition to the mean value, Rohrig has assessed the statistical distribution of the roughness length values at wind farm sites in Germany [ROHRIG2003].

The geographical distribution of installed wind capacity in Germany at the end of 2000 is shown in Figure 4-2.

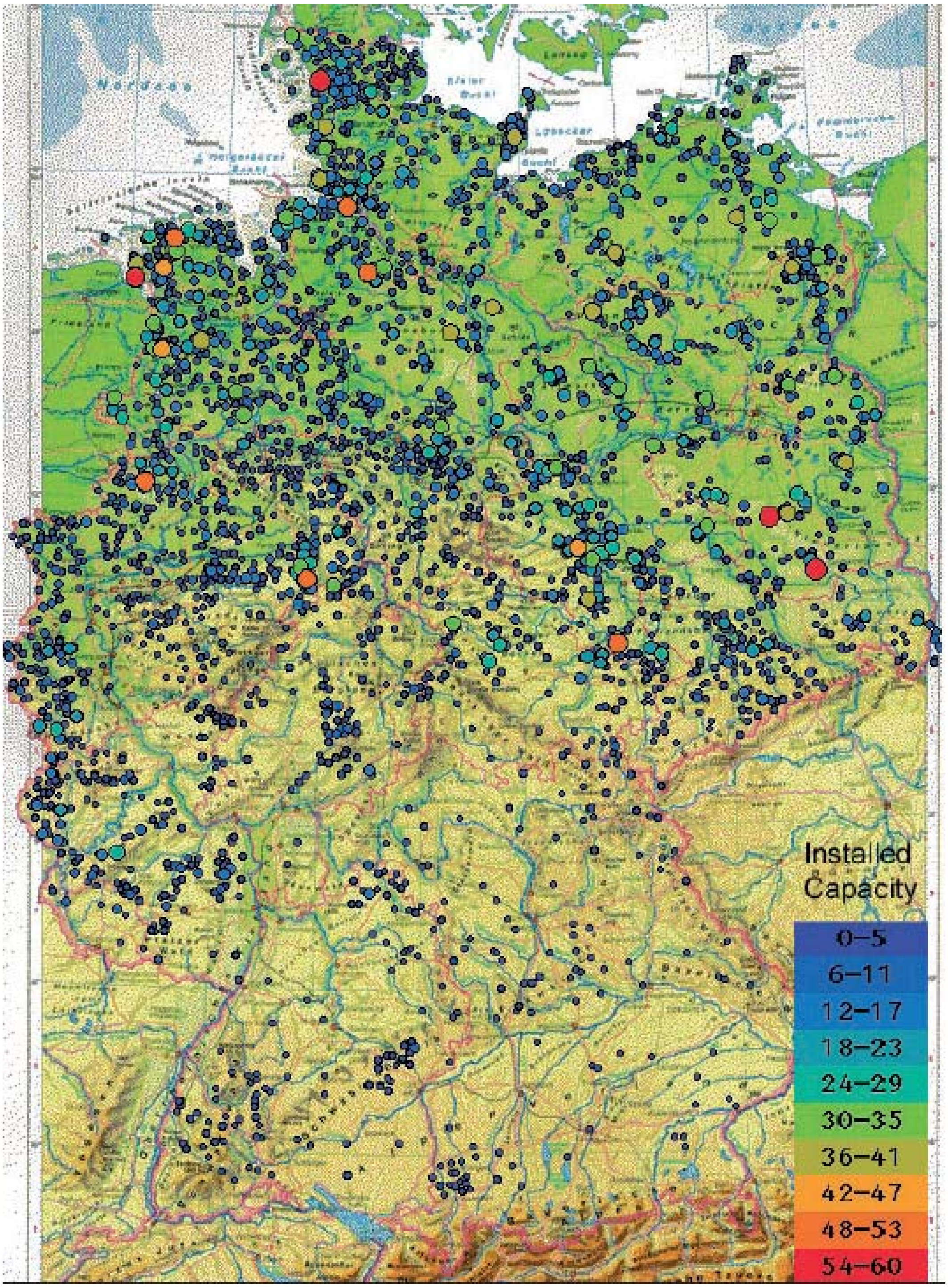

Figure 4-2: Reference case "Germany 2000": Geographic distribution of installed capacity

4.2.3 Conventional generation units

For the conventional power plants in the German power system, the system adequacy report for 2000 [VDN2001] states for the installed thermal and large hydro generation capacity the numbers in Table 4-3:

Total installed capacity of conventional power plants	100.5 GW
Available conventional power plant capacity when taking into consideration planned maintenance	91.2 GW
Capacity guaranteed by the conventional power plants	84.8 GW

Table 4-3: Reference case "Germany 2000": Conventional power plant data

The security of supply level is taken from the dena study [DENA2005], where 99 % value has been assigned to the combination of all four German control zones, the required level for the individual TSO control zones being 97 %.

4.3 Wind power characteristics observed in reference case 'Germany 2000'

The values for wind farm operation in the year 2000 in Germany are calculated by the upscaling algorithm description in chapter 2.2.4.

This upscaling for 15min time step values is provided by ISET's SepCaMo model, based on remote wind speed and wind turbine power measurements distributed over Germany. Since 1991, this national measurement network (see [ISET2001], [ISET2005]) acquires 10Hz measurement values, being stored as 5-minute mean values and further processed to probability density statistics.

4.3.1 Cumulative wind power time series

Cumulative wind power time series are extrapolated from wind power feed-in data observed at selected representative sites. The model is based on a parameterised algorithm [ROHRIG2003]. The parameterised algorithm takes into account technical data of wind turbines, their spatial distribution and roughness length of the sites.The control area considered is divided into several grid squares with an approximate size of 10 x 10 km. With the help of a geographical information system, each wind turbine is assigned to a certain grid square. Thus each grid square has it own unique parameters, such as location, installed wind turbine capacity, number of wind turbines, type of power output control (stall or pitch), mean roughness length of the site, etc. .

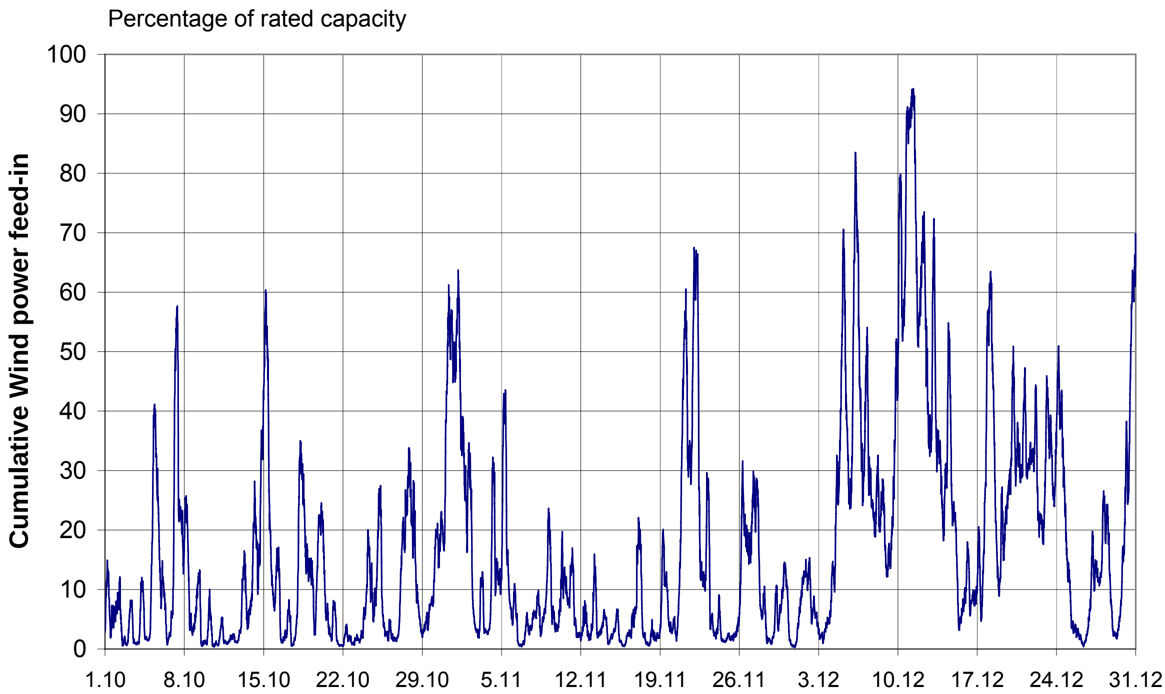

Figure 4-3: Time series of cumulative wind power in Germany 2000 (here: Oct.-Dec. 2000)

In the process of probabilistic capacity credit calculations, the time series has been analysed with respect to its probability density distribution of power levels.

4.3.2 Wind power duration curve and power probability density

The power duration curve of total cumulative wind power feed-in in Germany (roughly 1000 km extension as shown in Figure 4-2) shows the maximum power to be in this specific year 2000 of 97% of the installed wind turbine capacity (Figure 4-4). During 3000 hours in the year 2000, wind power exceeded the level of 20 % of its installed capacity. The total duration of wind calms in Germany was roughly 690 hours. This number is based on the ‘wind calm’ criteria of wind power feed-in being below 2 % of total installed wind capacity.

When converted into the probability density function of wind power feed-in, the graph depicts for each power level bin the percentage of time the power is reached.

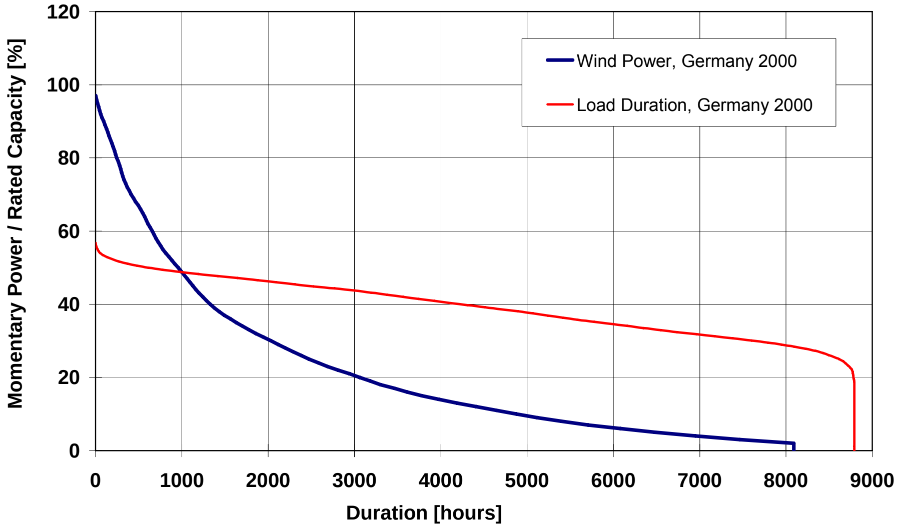

Figure 4-4: Power duration curve of total wind power feed-in (Germany, year 2000)

The probability density of power levels is accordingly calculated, see Figure 4-5.

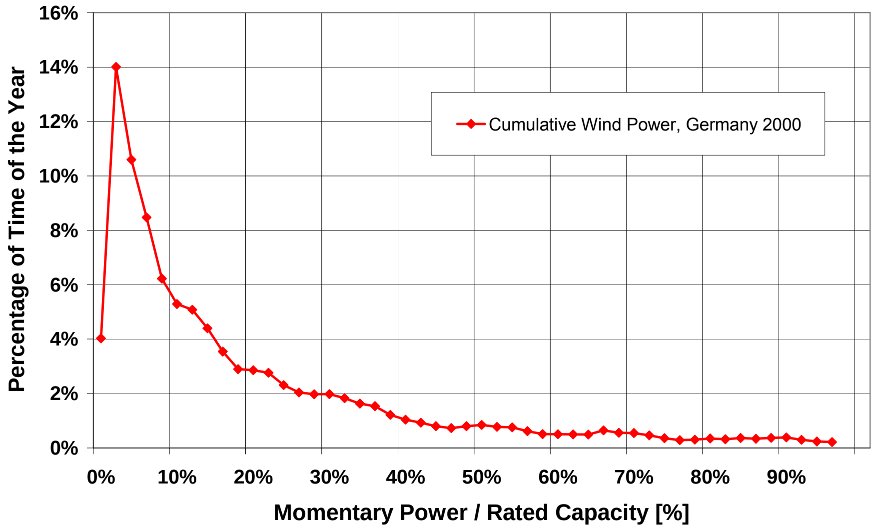

Figure 4-5: Probability density of wind power feed-in (Germany, year 2000)

4.3.3 Wind power capacity effects

For the reference case ‘Germany 2000’ under investigation, the capacity guaranteed by the conventional generation units alone, at the required security level of 99 %, has been determined being 84.8 GW.

The probability density of the conventional power plants and the probability density of all German wind farms being combined by the convolution product, results in an increase of the guaranteed capacity to 85.38 GW for the system including wind power, equal to a capacity credit of 578 MW (or 9.6 %) for the 6.0 GW installed wind power in Germany (year 2000).

This capacity credit value was used as reference value in the sensitivity analyses described in the following sections. This means that the focus has been laid on the relative deviations from this reference – not on the numerical value itself.[10]

[10] The value can not be directly compared to the capacity credit values published for instance in the dena study, due to the different input values used. It was not the intention of this work to use identical values. So differences are fully coherent with the messages of this work with respect to influences of parameter variations.

4.4 Capacity credit sensitivity to parameter variations

The sensitivity to the different parameters as listed for the approaches in chapter 2, has been investigated by simulation runs of sim.WIN, having the 'Germany 2000' values being described in chapter 4.3 as reference.

The following parameters were varied:

- Input wind regime (wind years);
- Roughness length z_0: instead of the site-specific 'true' values uniform values for all sites have been applied;
- Wind turbine hub height: instead of the 'true' values for the individual turbines, uniform values for all turbines have been applied;
- Regional distribution of wind farms;
- 'Security of supply' level of the power system.

4.4.1 Input wind years

In general, wind integration studies need to apply historic data (wind speed data or wind power feed-in data) to future installation scenarios. Up to now, many studies have applied data from only one single wind year. Figure 4-6 shows the bandwith of annual wind potential values observed between 1993 and 2004.

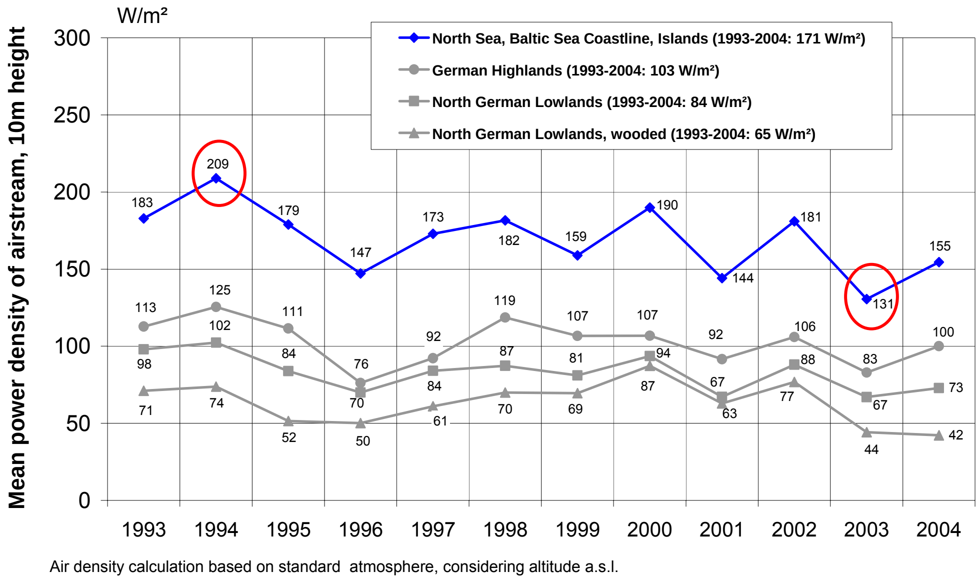

Figure 4-6: Variation of wind potential [W/m²] in different years; German coastal regions highlighted [ISET2005]

We simulated the effect of using specific input wind years by upscaling the complete wind power time series in Germany from the 1994, 1996, 1998, 2002 and 2003 to the ‘true’ capacity installed in 2000 and compared the resulting capacity credit values with the reference value.

Table 4-4 shows the resulting deviations due to different input wind years.

	1994	**1996**	**1998**	**2000 (ref)**	**2002**	**2003**
Capacity credit	687 MW	520 MW	581 MW	579 MW	565 MW	535 MW
Deviation from reference value [%]	+18.6	- 10.2	+ 0.4	-	-2.4	-7.6

Table 4-4: Capacity credit sensitivity to variation of input wind regime

The variation in wind resource of different wind years itself is already known. The sim.WIN tool has now provided us a ‘translation’ into capacity credit values: the range of deviation from reference from minus 7.6 % to plus 18.6 % impressively demonstrates the need to take more than one year into account.

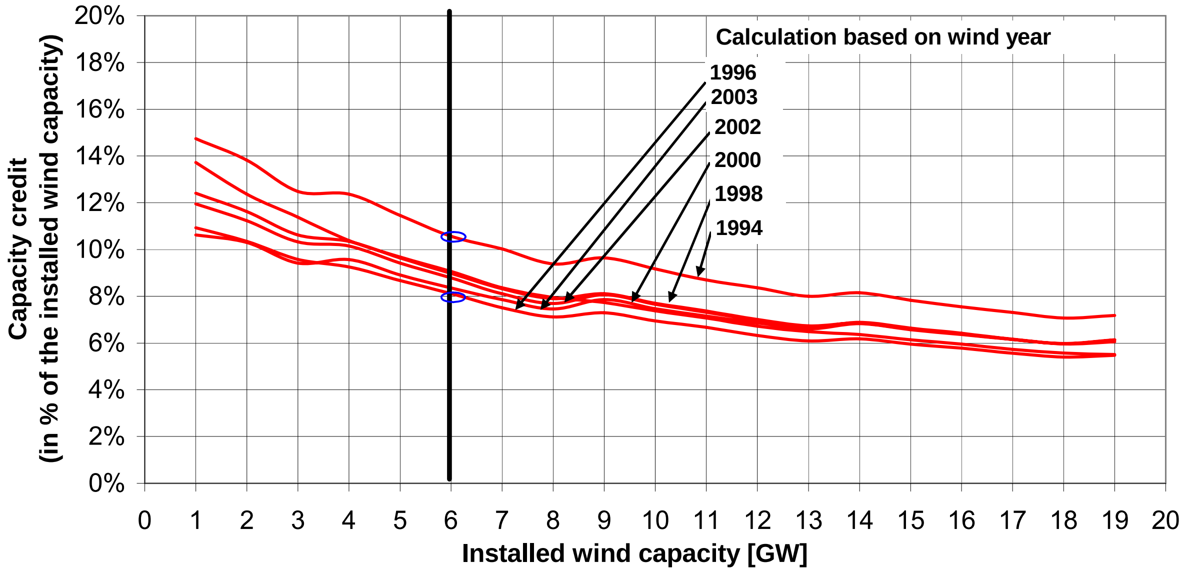

Figure 4-7: Capacity credit sensitivity to different input wind years

Figure 4-7 additionally introduces a full range of scenarios for installed wind capacity: from 1 GW to 19 GW. All other parameters of the ‘Germany 2000’ case were left identical. We see the well-known behavior of capacity credit decrease with rising wind capacity, as described in literature ([GIEBEL2000], [DENA2005], [UMIST2002]).

In addition, the graph clearly illustrates the need to take the variation of wind power probability densities with different wind years into account.

The choice of values for the parameters

- roughness length of sites,
- geographic distribution of wind farms, and
- hub height

provides an additional source of bias when calculating the cumulative wind power time series. We will see how such bias is translated into capacity credit deviations.

4.4.2 Geographical distribution of wind farms

An additional source for biased time series of wind power is given by scenario assumptions regarding the location of future wind farms. Assigning too high capacities to regions with lower wind speeds naturally leads to decreased capacity credit values and vice versa.

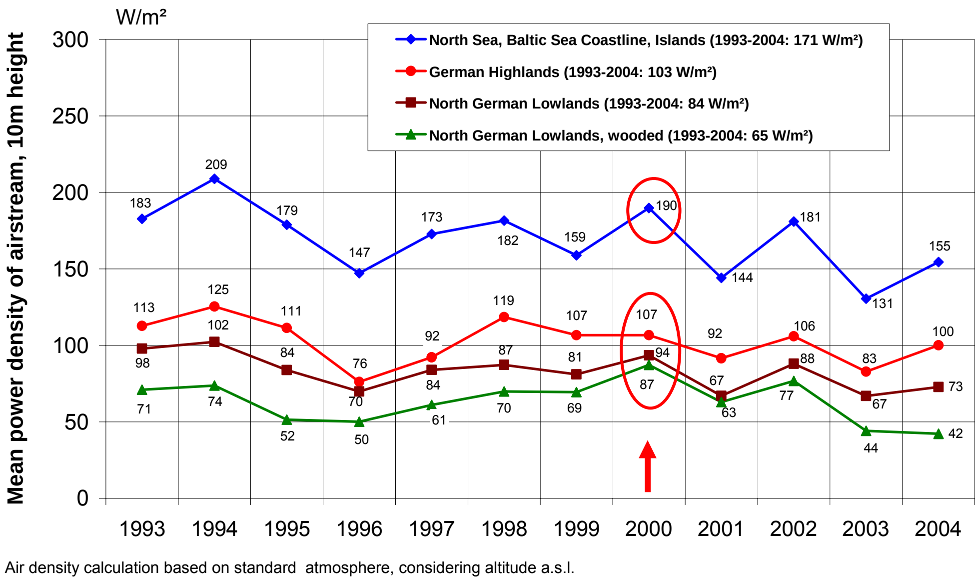

Figure 4-8: Variation of wind potential [W/m^2] in 2000, in different German regions [ISET2005]

The correlation between regional distribution and capacity credit is unique for each case study and can hardly be generalized. Nevertheless, we changed the true regional distribution of 6000 MW installed capacity (Figure 4-2) for the following sim.WIN simulation runs:

- 6000 MW capacity being equally distributed in all grid squares,
- 6000 MW capacity being distributed inversely, i.e. regions with originally maximum wind capacity have now minimum and vice versa, to simulate the maximum deviation.

Table 4-5 depicts in this case the maximum deviation to be minus 15.8 %.

Regional distribution	Reference: Correct distribution	All wind capacity equally distributed	Maximum deviation (inversely distributed sites)
Capacity credit deviation from reference value [%]	0 %	- 7.5 %	- 15.8 %

Table 4-5: Sensitivity to variation of geographical distribution of wind farm sites

4.4.3 Roughness lengths of wind farm sites

When lacking more specific information on the individual wind farm sites, a uniform value of roughness length z_0 equal to 0.12 m is regularly proposed for the logarithmic wind profile (Figure 4-9). In reality, we have seen a mean value of 0.06 m in our case study, naturally with a bandwidth of values for all individual sites. Table 4-6 shows the results of sim.WIN runs, where four different roughness length values were applied.

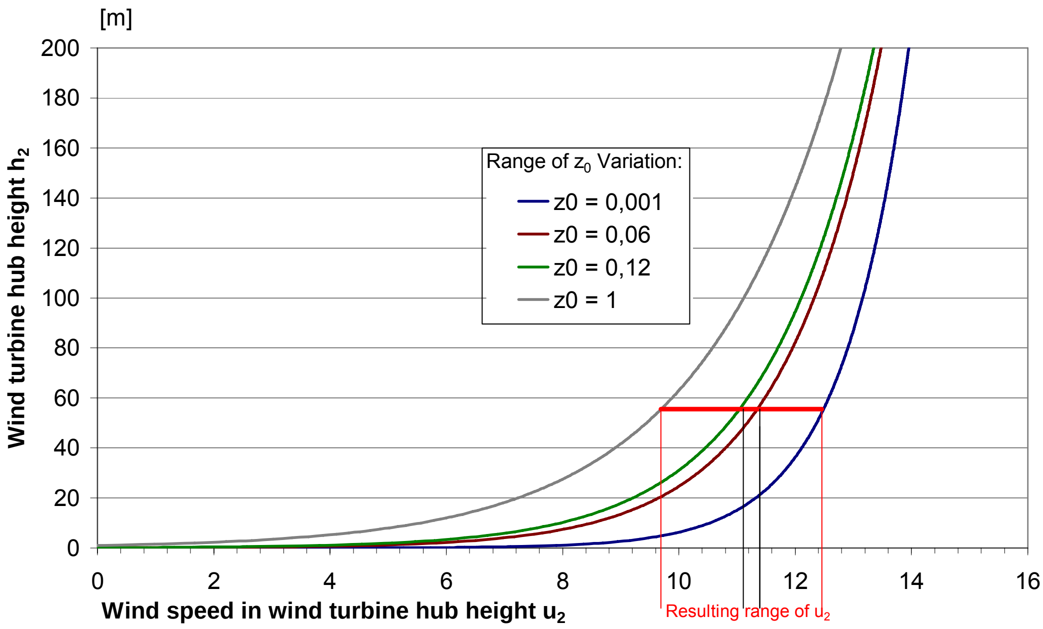

Figure 4-9: Effect of roughness length variation on wind speed in hub height

Z_0	**0.001 m**	**0.06 m (reference)**	**0.12 m**	**1 m**
Capacity credit deviation from reference value [%]	+12.2 %	-	-6.2 %	-21.3 %

Table 4-6: Sensitivity to roughness length variation

We see in Table 4-6 deviations ranging from plus 12.2 % to minus 21.3 % from the reference capacity credit – knowing well that nobody would seriously apply the uniform value of 1 m. Nevertheless, the deviation of minus 6.2 % for z_0=12 cm has to be underlined.

4.4.4 Hub height of wind turbines

Another value, which has either to be known from an inventory of installed wind turbines, or to be chosen as scenario value, is the hub height of wind turbines. What happens if we apply one uniform value for all wind farms in the scenario investigated?

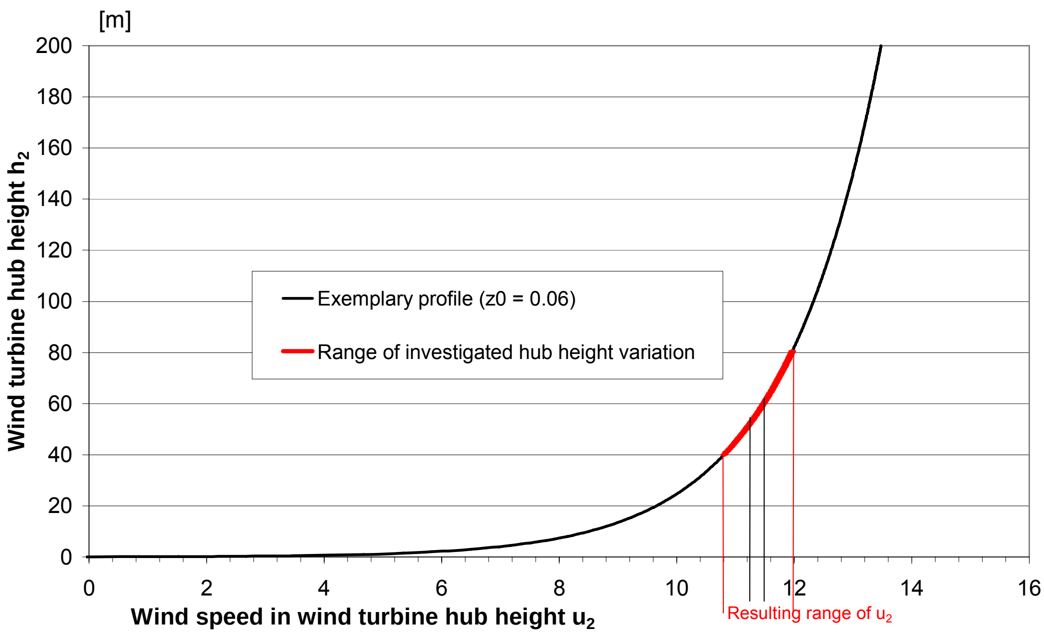

Figure 4-10: Effect of hub height variation on wind speed in hub height

Table 4-7 shows a relatively benign behavior, if a 'good guess' of hub height has been made, such as 50 m instead of the true mean value of 54 m: a deviation of minus 1.4 % for the capacity credit is the result.

Hub height	40m	50m	54m (ref)	60m	80m
Capacity credit deviation from reference value [%]	-6.3 %	-1.4 %	-	+2.2 %	+7.9%

Table 4-7: Sensitivity to hub height variation

4.4.5 'System security of supply' levels

We have seen earlier in chapter 0 that the guaranteed generation capacity in a power system depends on probabilities of power plant availability. For the reference case 'Germany 2000', Figure 4-11 depicts a value of 618 MW capacity credit related to 91 % supply security, compared to 578 MW related to the reference value 99 %. This is equal to a deviation of 6.9 % produced by parameter often overlooked when comparing results of wind power integration studies.

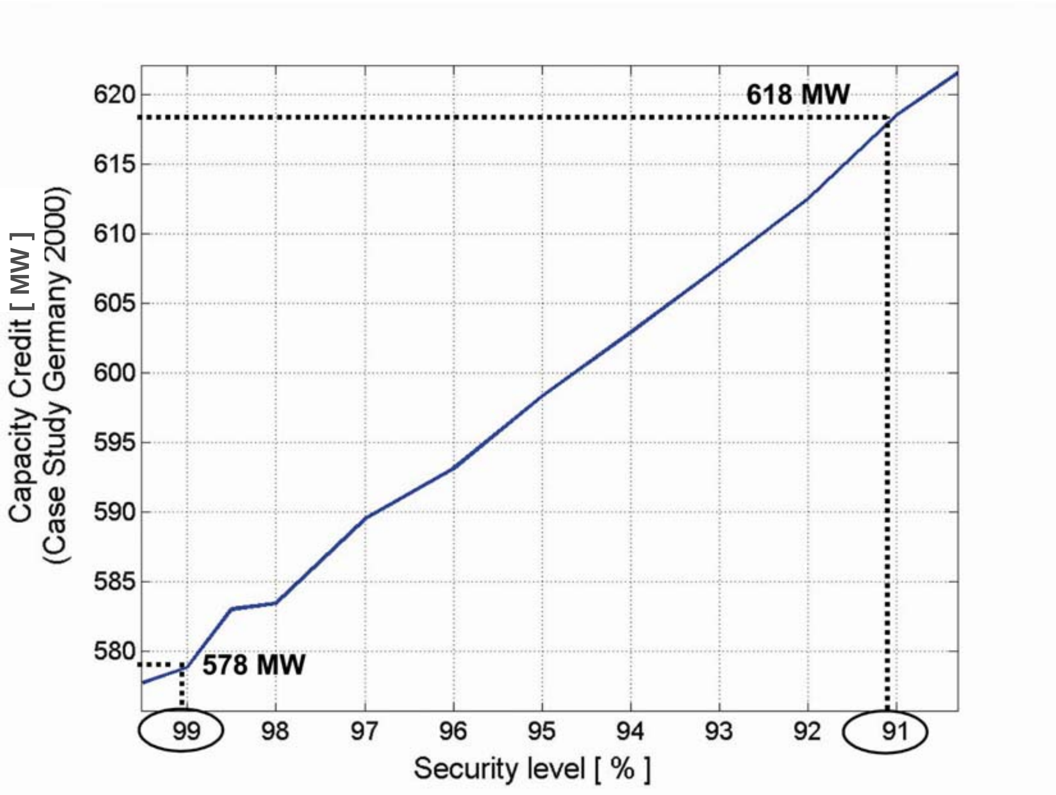

Figure 4-11 Capacity credit sensitivity to variation of 'security of supply" level

4.4.6 Summary: Sensitivity of capacity credit to parameter variations

The assessment of wind power capacity effects cannot be done by a simple transfer of values from one national power system to another. The results are only valid for specific combinations of conventional power system characteristics, together with the wind regime, the regional distribution of wind farms and security of supply level.

When capacity credit calculations are based on a limited number of reference wind data and assumptions on site characteristics and wind turbine characteristics, severe bias in wind regime can lead to large deviations in capacity credit values.

The sensitivity analysis described in this work for the case study ‘Germany 2000’ showed capacity credit deviations for the factors of influence:

- wind regime: -7.6% (2003) … +18.6 % (1994);
- roughness length: ~- 6% (12cm);
- hub height: ~+-3% / 10m deviation;
- distribution of sites: -15.8% (maximum capacity shifted to inland);
- Level of security of supply: +6.9% (91% instead of 99%).

Results of capacity credit calculations are more accurate, if the following requirements are respected:

- The best-possible sample of wind data is used;
- The variation in probability densities of wind power in different wind years is covered by a sufficient number of data;
- Offshore installation scenarios are treated with extra care in order to take the special boundary layer conditions into account;
- Sufficient number and distribution of reference sites for spatial extrapolation;
- Best possible scenario assumptions for regional distribution of wind farm sites are applied.

5 Balancing wind power variability

The following chapter leaves the field of statistical and probabilistic considerations. Instead it points out, which specific market conditions and regulatory issues strongly influence the results of these calculations.

In order to maintain a secure and stable operation of the electricity system, demand and generation must be continually balanced. System frequency is the direct measure of the balance between generation and system demand at any one instant and must be maintained continuously within narrow statutory limits around 50Hz. Frequency falls when demand is greater than generation and rises when generation is greater demand.

In order to manage frequency effectively, system operators utilise a range of balancing services that operate over different time horizons.

The variability of wind power feed-in into the system provokes the question “To what extent does wind power increase the load for reserves and balance energy?”

In the course of this work the following issues were examined:

Who is in charge of balancing, i.e. who is the ‘balance responsible party’ and will bear the cost of the balance services?

What is defined as target values of ‘balancing wind power’? We will see two fundamentally different concepts here:

(1) balancing ‘wind fluctuations’, which means balancing deviations from mean values of wind power and

(2) balancing deviations from previously scheduled values.

Do we have to balance wind power-induced imbalances separately or does ‘balance’ refer to the total amount of deviations in the power system?

5.1 Balancing markets

To understand the differentiation into physical delivery of electricity and the commodity ‘electricity’ we use a graph provided by ECN’s Policy Studies unit [Dispower2005a).

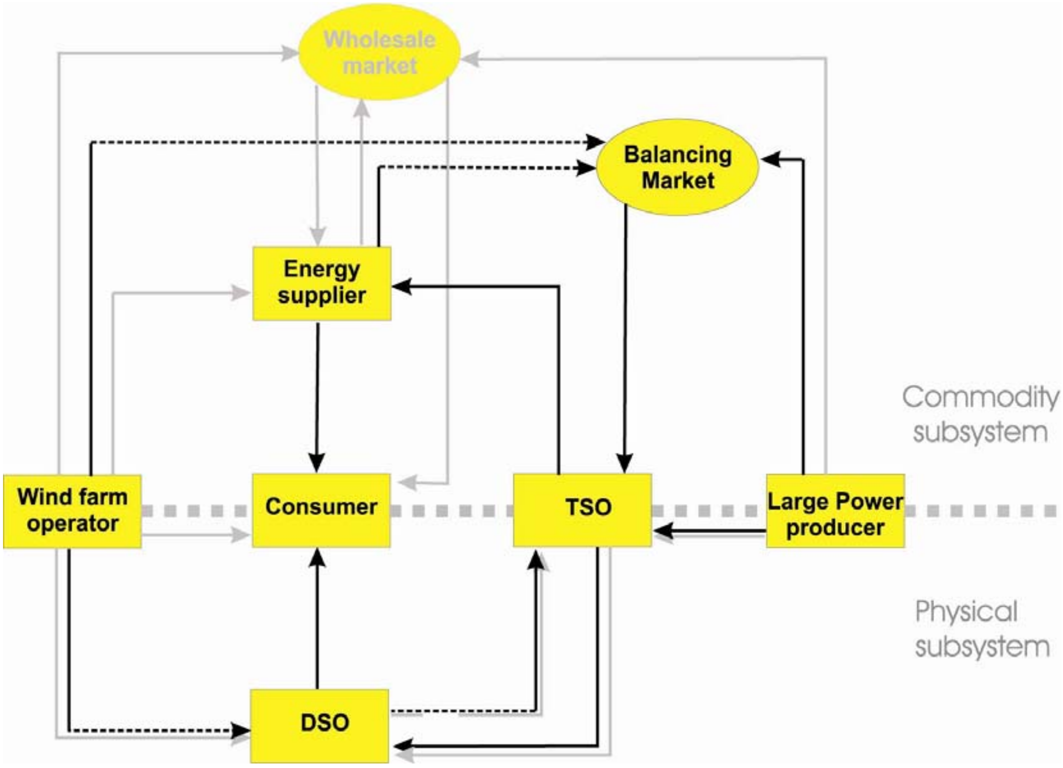

Figure 5-1: Overview of transactions within the electricity market (adopted from [Dispower2005a])

In Figure 5-1, the physical power streams have been separated from the commodity trade. Scheepers et. al. stated in [Dispower 2005a]: The electricity system is divided into a physical subsystem, centered around the production, transmission, and distribution of electricity, and a commodity subsystem, in which the commodity is traded. Both subsystems are constrained by regulations, such as safety limits, construction permits, operating licenses and emission permits for the physical sub-system, and competition law and market rules, such as the time of 'gate closure', for the commodity subsystem.

System operators and contractors have to estimate demand in order to make sure that sufficient supply is available on short (seconds and minutes), medium (hours), and long timescales (days). Because the electricity system is liberalised, the market itself is responsible for matching supply and demand on the long term.

Deviations between electricity demand and production on the actual moment of execution of the energy programs become visible to the Transmission System Operator (TSO) as an exchange of electrical power with neighbouring control areas, different from the agreed international exchange programs. In this way the TSO has insight in the actual balance of the total system.

5.2 Physical balancing services

The scope of reserves available to TSOs is varied and wide. It is possible to group services by timescale.

Some countries have services that are delivered quickly (<5 mins). This stems from specific system needs in those countries e.g. low inertia, high rates of change of demand. All countries have reserves that can act in approximately 15 minutes (although the specific requirements and terminology is varied). A few countries have slow to deliver reserves. These are not generally needed in the Nordic region because of the abundance of fast acting hydro plant. [ETSO2003].

The so-called Secondary Control only applies to countries in UCTE, and the TSO responsible for managing a control block co-ordinates the control area TSOs in that block. The terminology of reserve power types and markets that are present in Germany and the Nordic countries is summarised in the following table provided by [Meibom2006]:

Reserves, by activation	Germany	Nordic
Frequency	Primary *Public auction, 6 months before covering 6 months ahead*	Primary Momentary disturbance *Capacity reserved using agreements between TSOs and certain producers, different arrangements for different countries*
Automatic load flow	Secondary *Public auction, 6 months before covering 6 months ahead*	
Manual, 15 min	Minute reserves (also called Tertiary) Day-ahead market: Capacity price (if selected) + Energy price (if activated)	Fast reserves (also called: Regulating power, Secondary) *Regulating power market: TSOs buy regulation, Capacity reserved for making bids at this market months ahead (reserve capacity market)*
Manual, hours	Existing as OTC-market; responsibility with Gencos, not with TSOs	Tertiary
Energy markets, by (approximate) time to delivery:		
Day-ahead	EEX Day-ahead, often called Spot market	Nordpool Elspot, often called Spot market
Balancing market	almost non-existing *(only OTC)*	*Nordpool Elbas (only S + F), Hour-ahead market*

Table 5-1: Terminology of reserve power types and markets that are present in Germany and the Nordic countries [Meibom 2006]

5.3 Balance responsible parties

In a general terminology, the 'balance responsible party' is the entity responsible for the imbalance generated by deviations from predicted schedules (energy programs). In the case of wind power, it can - according to the national regulatory framework - be either a wind power operator or the TSO himself.

The description of the electricity market situation with respect to wind power balancing in Great Britain, The Netherlands and Germany give valuable insights into the range of national market specifications:

Great Britain[11]: Under the electricity trading arrangement BETTA, electricity is traded through bilateral contracts between generators, electricity suppliers and customers across a series of markets operating on a rolling half-hourly basis.

Both electricity suppliers and generators need to provide forecasts of their planned demand and generation respectively by 'gate closure time' (1.5 hours ahead of real time). Up to and in real time, the TSO buys balancing services from generators and load customers in order to balance demand and supply.

Generators and suppliers are penalized for forecast errors. Any deviations from schedules are traded at balancing market prices. Small wind generators (less than 50 MW) are exposed to these costs through their power purchase agreements with suppliers/ retailers which are of lower value compared to other dispatchable generators. Larger wind generators (more that 100 MW) must operate within the bilateral market and pay penalties for non perfect forecasts (1 hour ahead).

The Netherlands: In the Dutch liberalized electricity market, balancing is the responsibility of so-called Programme Responsible Parties (PRPs). Every generator and load in the Netherlands is assigned to a PRP who are responsible towards the TSO TenneT to maintain the scheduled quarter-hourly energy exchange with the Dutch system of all generators and load in their portfolio. Deviations from the schedule are penalized by the TSO (imbalance-pricing). A PRP with a high share of wind power in its portfolio will have a higher risk of imbalance than PRPs without and consequently will make arrangements by minimizing its imbalance costs. On that background short-term wind power forecasting will become crucial for optimising the level of reserves within the portfolio. The schedule for programme submission is day

[11] Electricity market specifications refer to the island of Great Britain, not to UK. National Grid Company (NGC) is the System Operator (SO) of the electricity transmission system on the island of Great Britain (GB): England, Wales and Scotland. In April 2005 the Scottish system has come under NGC control.
The synchronous zone of (Island of) Ireland is operated by two TSOs: ESB and SONI.

ahead (i.e. 12 – 36 hours before delivery). Trading after closure of the spot-market is limited.

Germany: The four TSOs take care of the balancing in their control areas, they are 'balance group co-ordinators'. In the case of wind power feed-in, they are at the same time 'balance group responsibles' (BGR), as by law the German TSOs are BGR for the 'balance group EEG[12]', which includes wind power feed-in. Thus the TSOs take care of balancing tasks related to wind power. Since the German TSOs have to handle unequal shares of wind power an online-equalisation scheme distributes the costs of wind power production among them according to their electricity supply volume. All TSOs apply short-term predictions of the aggregated wind power generation in their control areas. The production has to be scheduled day-ahead (i.e. 9.5 – 33.5 hours before delivery).

The ETSO reports "Current State of Balance Management in Europe" [ETSO2003] and "Current State of Trading Tertiary Reserves Across Borders in Europe" [ETSO2005] give a comprehensive overview of the variety of market characteristics. Supplementary wind power-specific information can be found in the country profiles in the Annex, see also [HULLE2005].

5.4 Target values for wind power balancing

The comparison of wind integration studies reveals two fundamentally different concepts regarding the definition of '*wind power imbalance*'.

In [UMIST2002] for instance, the calculation of additional reserve requirements due to wind power refers to *wind fluctuation around their mean value,* mathematically described by wind power standard deviations.

[DENA2005] calculates additional reserve requirements due to wind power by assessing wind power deviations from *previously scheduled programs.* When these two concepts are applied to identical time series of electrical load and wind generation, the calculation results show significant differences. Figure 5-2 depicts an exemplary load time series of the E.ON control zone.

The part of the load being covered by wind power feed-in[13] is depicted in the right-hand graph of Figure 5-2.

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[12] EEG: German feed-in law covering renewable energies including wind power

[13] The wind power feed-in values have been calculated by ISET's SEpCaMo extrapolation model from reference sites and – for reasons of graphical representation in Figure 5.2 and

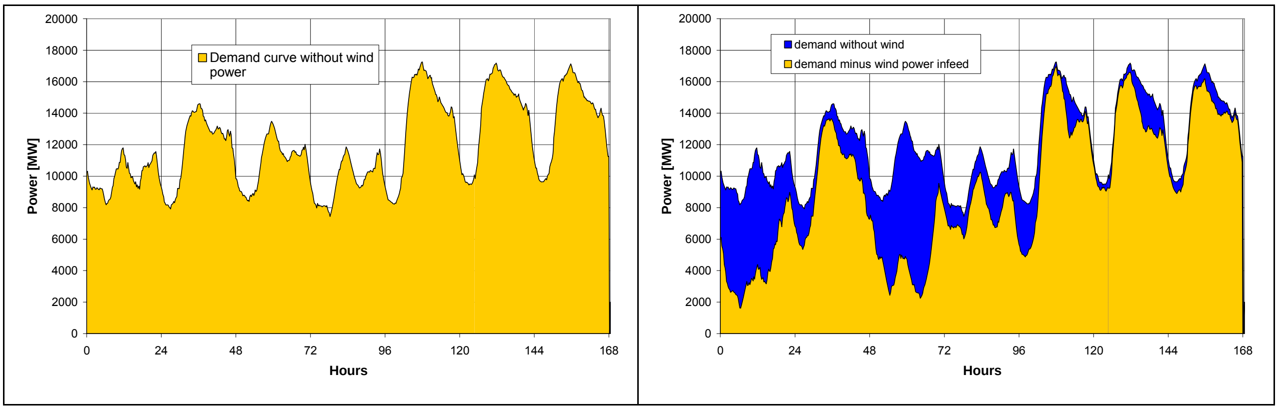

Figure 5-2: Weekly load profile without wind power (left), including wind power feed-in (right)

The Figure 5-3 shows on the left-hand side the wind power-induced balancing needs when the balance target is 'mean wind power' and thus the wind power deviation around its longer term average value has to be balanced.

With respect to load following, this concept intends to have the load to be followed only changed by the constant offset of mean wind power production.

The more sophisticated concept defines deviations of wind power in-feed from previously predicted wind power schedules as imbalance. Only the deviation from this program have to be balanced and the necessary reserves depends on the wind power prediction error (right-hand side of Figure 5-3).

For the specific values in this exemplary one-week time series with 22.3% wind energy penetration the following values were derived:

Balancing target 'mean wind': 35.5 % of wind energy production was above the mean value of wind power feed-in (green areas), 35.5 % of wind energy production was below the mean value of wind power feed-in (red areas).

Balancing target 'predicted wind': 12.7 % of wind energy production was above the mean value of wind power feed-in (green areas), 18.2 %[14] of wind energy production was below the mean value of wind power feed-in (red areas).

The concept of using predicted wind power schedules as balance target can only be applied if wind power prediction services are actually available.

Figure 5.3 been doubled. The comparison of balancing concepts is based on relative magnitudes. The graphical oversizing does therefore not alter the results of the comparison.

[14] Wind power prediction parameters usually will be set in a way that the resulting negative reserve power demand is higher than the resulting positive reserve power demand. The decisive information provided by this example is the reduction related to ‚mean wind'.

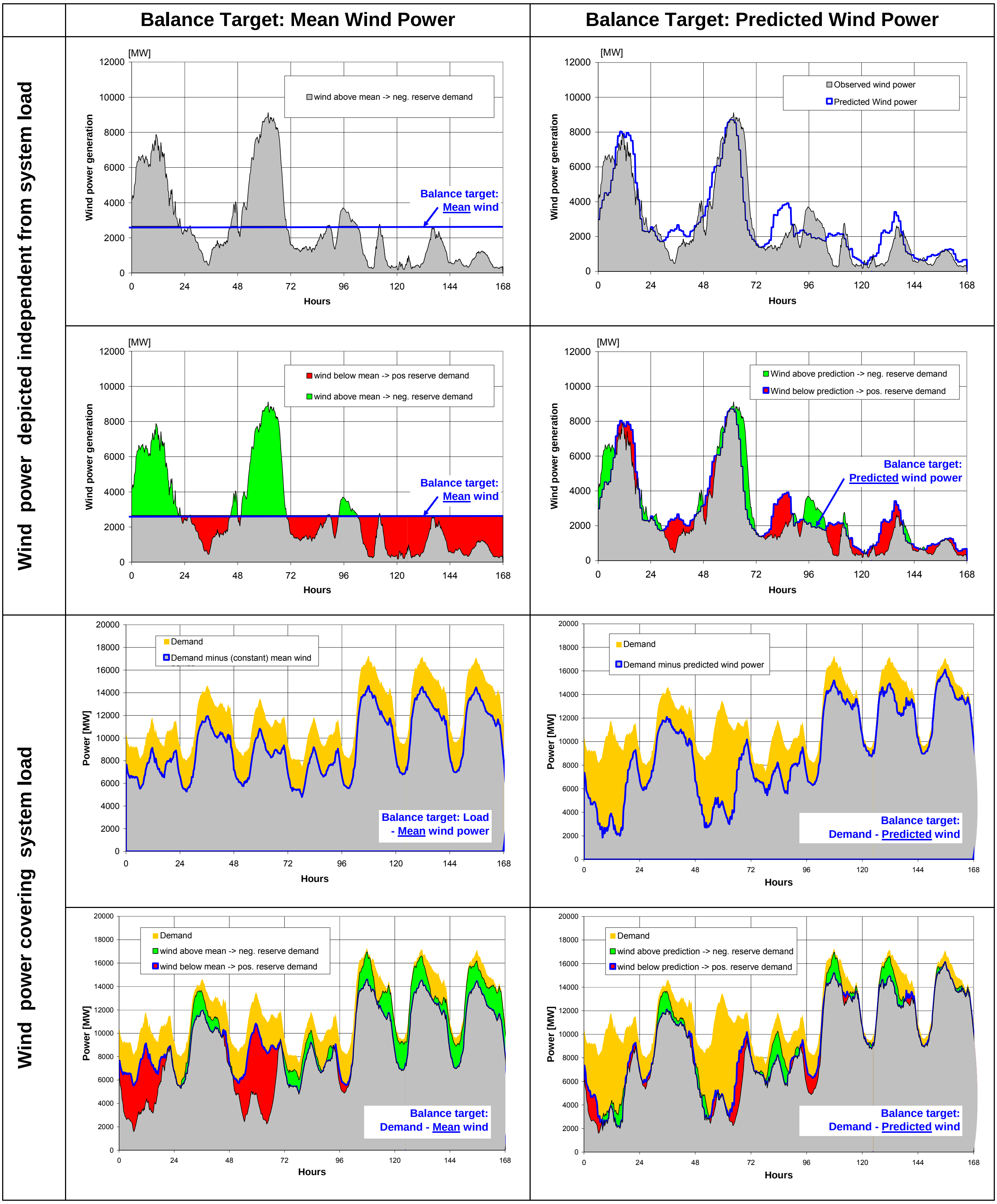

Figure 5-3: Distinction of balance target values: ‘mean wind power’ vs. ‘predicted wind power’

The dena study determined the amount of balance capacity necessary for balancing wind power in a similar – probabilistic - way as it was done for the capacity credit of the wind power.

The combination of individual probability functions of generation plant delivers the combined probability function for capacity deficits or surpluses. In contrast to the determination of the guaranteed capacity of the generation system in the hour of peak demand, all unplanned outages of conventional generation units in periods longer than the lead time for dispatch are left out. These longer persisting outages do not have to be balanced by balance energy, since they can be considered in normal dispatch of generation units.

For the comparison of the generation system without wind power generation and including wind plant, in a first step, the balancing demand without consideration of the prediction errors of the wind turbine feed-in is determined with given deficit levels for the balance deviation.

This level specifies the probability of sufficient balance capacity being available for adjusting imbalances. Since the load prediction error as well as the wind prediction error can have positive and negative values, a deficit probability for both power deficits and for power surpluses must be assumed.

This so-called ‘deficit probability’ of capacity deficits specifies the probability of the following situations: either an under-supply cannot be covered by the available incremental balance power, or an over-supply cannot sufficiently be balanced by decremental control power.

The prediction errors of the wind turbine power output for a rising installed wind capacity are included and the need for incremental and decremental control power is determined.

The dena study uses the following input data for the model:

- the distribution of the load prediction errors;
- the distribution of the wind prediction errors ("day ahead' prediction);
- the probabilities of unplanned outages of generation units.

Similar to the statements made with respect to security level / risk level in the case of capacity credit calculations, also the results of reserve power calculations always need information about the applied security level (risk level). For instance, the dena study applied a security level of 0.1%[15] , while the SCAR report applied 1%.

5.5 Responsibility of individual balance groups for reserve energy demand

This chapter intends to answer the question: “Does the TSO have to balance wind power-induced imbalances separately or the total amount of deviations in the power system?

The Figure 5-1 in its original form shows ‘energy suppliers’, ‘consumers’ and ‘DSO’ as distinct market actors. In Figure 5-4 we extended this figure and introduced balance groups[16] and a graphical separation of individual balance groups into group 1 to n and a balance group ‘wind power’. This depiction shows at given time the physical imbalances produced by individual balance groups.

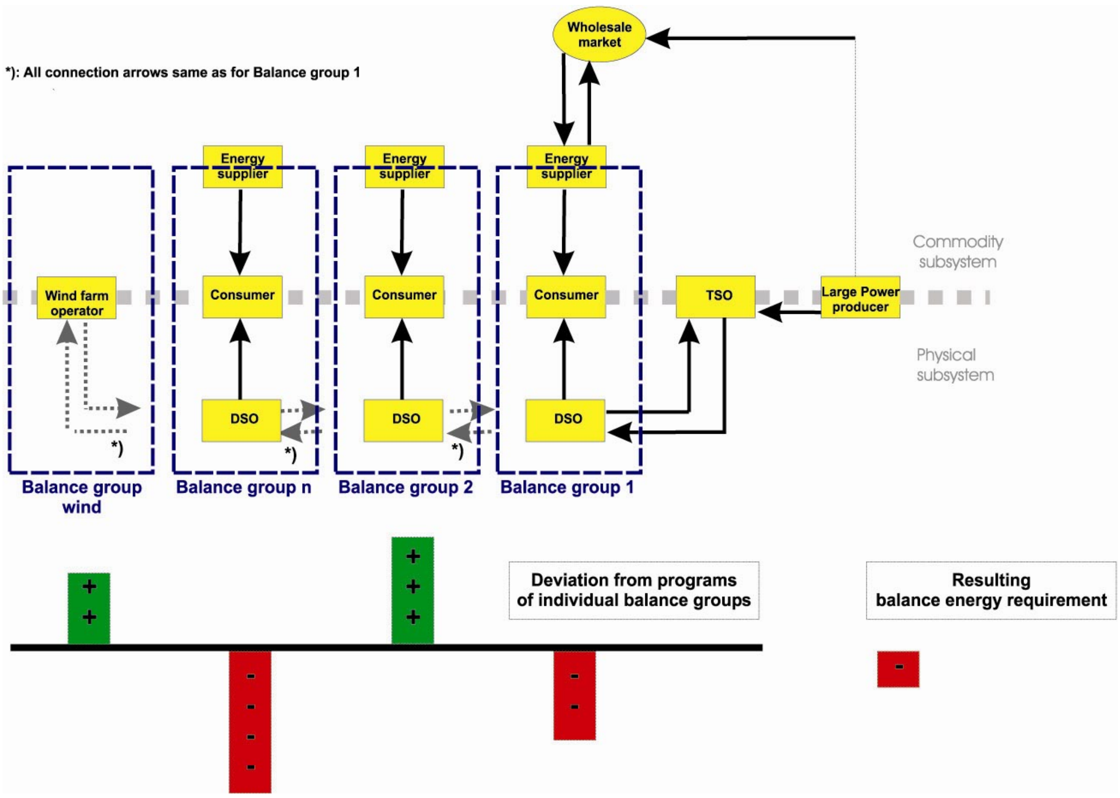

Figure 5-4: Reduced reserve requirements due to un-correlated deviations of individual balance groups

[15] This amount of capacity committed to support the regulation will contain 99.9 % of the possible mismatches between demand and supply in the characteristic time horizons.

[16] The combination of suppliers and customers into a virtual group within which a balance between the electric energy procured (purchase schedules, feed-in) and supply (supply schedules, feed-out) of electric energy is carried out.

We see that TSOs have to balance only the total net amount of the deviations of all balancing groups by dispatching balance energy from contracted power producers. As Figure 5-4 shows, not every single deviation of a given balancing group defines the necessary amount of activated reserve. In fact, the actually activated reserve is much smaller than the energy assigned to the individual balance groups.

The SCAR report confirmed this statement: "It is important to stress that reserve requirements are not necessarily assigned to back up a particular plant type (wind), but to deal with the overall uncertainty in the balance between demand and generation. The uncertainty to be managed is driven by the combined effect of the fluctuations in demand and conventional and renewable generation. These individual fluctuations are generally not correlated, which has an overall smoothing effect with a consequent beneficial impact" [UMIST2002].

5.6 Wind power prediction accuracy and gate closure

A number of different arrangements exist for *gate closure*, when schedules have to be delivered and expected physical notifications become firm.

In some countries this is day ahead, some are fixed windows in the operational day and some are based upon a rolling settlement period basis. There are a range of times between gate closure and real time in use including 1 hour, 3 hours and day ahead.

The *accuracy* of wind power prediction largely depends on the *lead time* of prediction. An explicit comparison of wind power prediction accuracy has been done in the Dispower project with reference to six wind farms in UK [Dispower2005b].

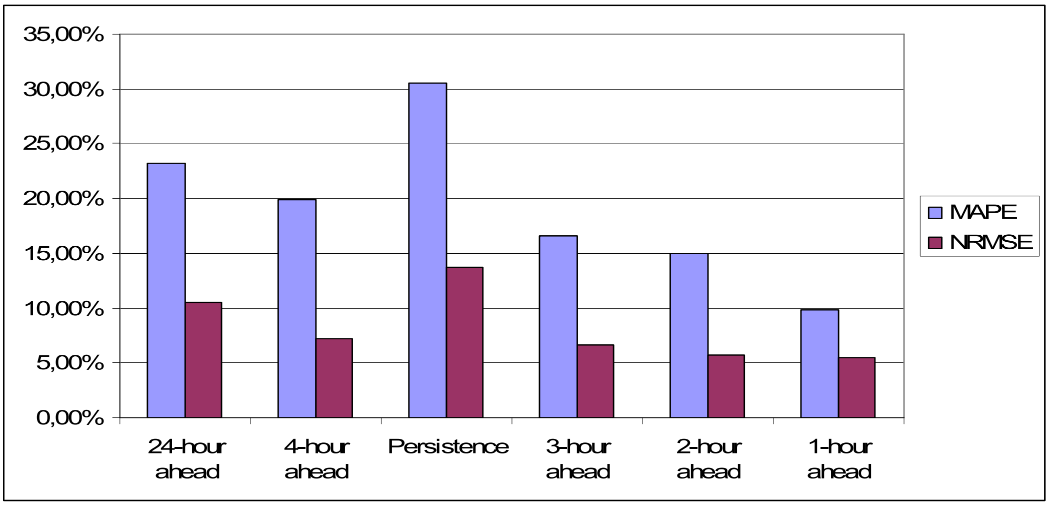

Figure 5-5: Dependence of prediction errors (MAPE and NRMSE) on the prediction horizon (here 6 UK wind farms [Dispower2005b)

The predictions compared in the Dispower project (24-hour, 4-hour ,3-hour ,2-hour and 1-hour ahead) show a steady increase of the prediction accuracy to a NRMSE[17] 5.52 % and a MAPE[18] of 9.89 % in the case of the 1-hour ahead prediction.

Gate closure is defining the lead time of prediction. Current values for the German control zones are: gate closure for day-ahead schedule: 14:00, leading to 10:00 being the time when wind power prediction has to be submitted).

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[17] NRMSE: Normalised root mean square error.
[18] MAPE: Mean absolute percentage error.

6 Effects of High Wind Power Penetration

After having discussed the wind capacity being available at the power system's peak demand (the 'low wind – high demand' case), we will now examine the opposite case: 'high wind – low demand'.

For assessing effects of high wind penetration, it is important to know which concept is meant by 'wind power penetration'. Several options exist and can be found in literature. The *installed wind capacity* can be referred to

1. total installed conventional (thermal and large hydro) capacity;
2. annual peak electricity demand;
3. annual minimum electricity demand;
4. the total of annual minimum electricity demand and cross-border transit capacities.

All options have their specific applications. In our case 'high wind – low demand', options 3 and 4 shall be used.

6.1 National wind power penetration and cross-border transit capacities

What happens in the case of high winds and low demand? The extreme case is wind power feed-in of 100 % installed capacity in the moment of minimum demand.

For reasons of load-frequency control one or several measures can be necessary:

1. re-dispatch of generation capacity;
2. use of cross-border transit capacities (as far as available),
3. application of demand-side measures (demand response, demand-side management, see chapter 6.2);
4. use of wind generation-specific measures (wind generation curtailment, wind cluster management).

The country-specific ratio of installed wind capacity and minimum demand gives an impression of the dimension of this issue and to which extent the measures 1 to 4 are necessary.

We have investigated the installed wind capacity (end 2004 and plans for 2010), the generation mix, the transit capacities (winter 2004) for twelve EU member states.

In Table 6-1 we see the penetration values defined by the ration of installed wind capacity and minimum demand. We compared the wind capacity 2004 / load 2004 and also the wind capacity 2010 / load 2004 ratio.

In the year 2004, the ranking of wind power penetration was lead by Denmark, Spain and Germany. If the foreseen increase of wind capacity is realised and the NTC values were not changed, the ranking in 2010 would be lead by Denmark, Portugal and Greece.

Country	Denmark	Portugal	Greece	Spain	Ireland	Germany
Conventional generation capacity	9.5	12.6	12.2	58.4	5.5	106.0
Installed wind capacity, end 2004	3.2	0.5	0.5	8.3	0.3	16.6
Installed wind capacity, 2010	3.8	3.8	3.7	18.0	1.0	25.0
Minimum load	2.0	3.0	3.0	20.0	1.5	38.0
Wind power penetration, end 2004	**160%**	**17%**	**17%**	**42%**	**20%**	**44%**
Wind power penetration, 2010	**190%**	**125%**	**123%**	**90%**	**67%**	**66%**

	Nether-lands	Austria	United Kingdom	France	Italy	Poland
Conventional generation capacity	20.1	17.8	81.0	110.9	82.0	31.7
Installed wind capacity, end 2004	1.1	0.6	0.9	0.4	1.1	0.1
Installed wind capacity, 2010	1.5	1.2	6.0	6.0	3.7	1.5
Minimum load	5.0	4.0	21.5	30.4	22.0	14.0
Wind power penetration, end 2004	**22%**	**15%**	**4%**	**1%**	**5%**	**1%**
Wind power penetration, 2010	**30%**	**30%**	**28%**	**20%**	**17%**	**11%**

Table 6-1: Wind power penetration 2005 and 2010, reference: minimum load (Capacity values in GW)

It is worth noting that the following effects will alter these indicative values:

- Increased values of minimum demand in 2010,
- Increasing Net Transfer Capacity values in 2010.

Figure 6-1 shows the geographical situation in 2010. All cases where countries with high export demands due to wind power are neighbouring (e.g. Denmark and

Germany) need special attention. It can also be seen that for instance France will still be in a moderate situation.

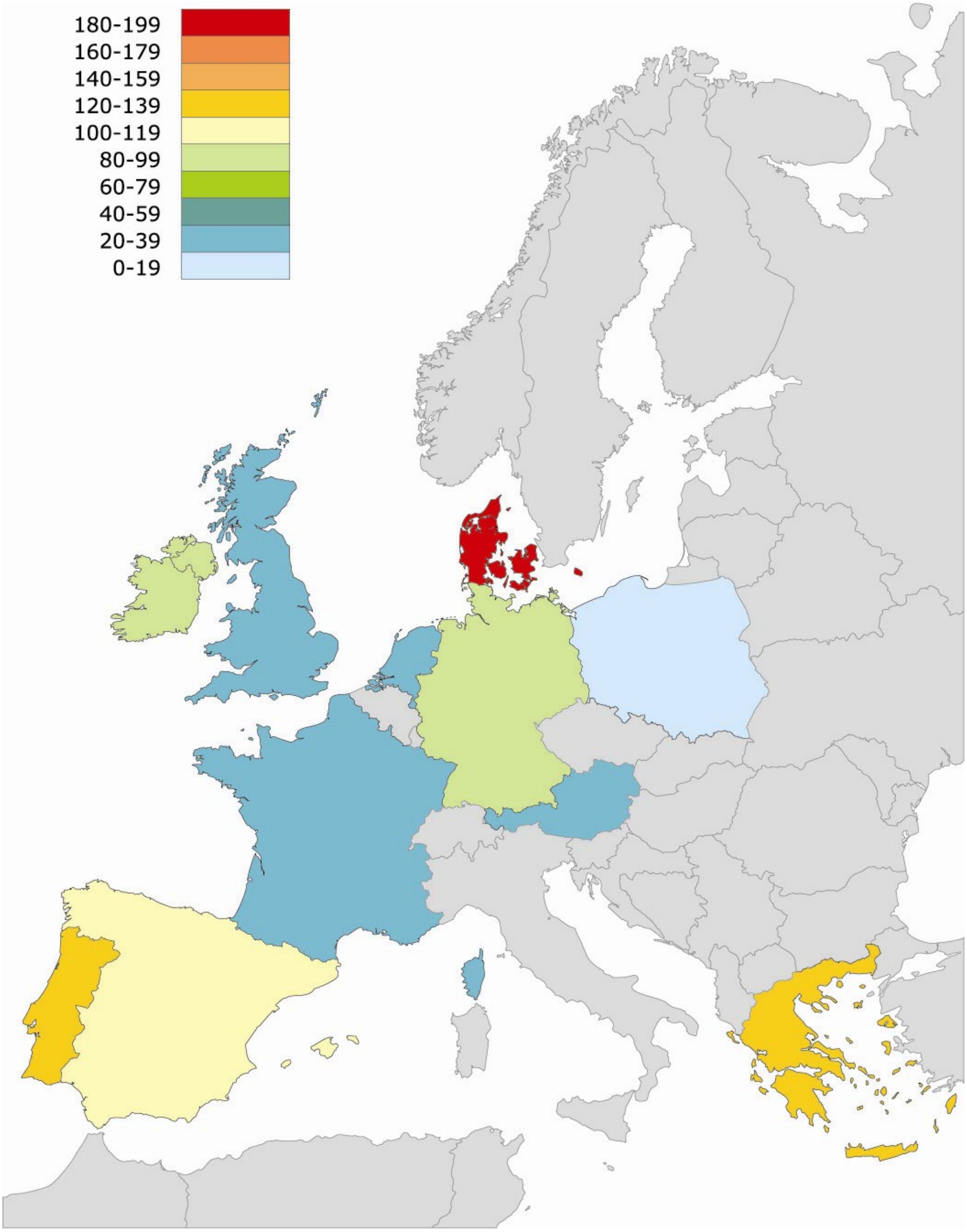


Figure 6-1: Wind power penetration level 2010 (wind capacity related to minimum demand) of twelve EU states with strong wind power development

In a second step we investigated the possible 'relief' that export can give to the 'high wind – low demand' situation. We investigated the effect of adding the total of all export NTC values (values provided by ETSO) to the mimimum load values. In reality these values will not be obtained, as they refer to a situation where all NTC would be available for wind export alone. Nevertheless they give us an indication of the maximum 'relief', knowing that the true values lie somewhere between the values listed in Table 6-1 and those listed in Table 6-2.

Country	**Portugal**	**Greece**	**Spain**	**Ireland**	**Denmark**	**Germany**
Conventional generation capacity	12.6	12.2	58.4	5.5	9.5	106.0
Installed wind capacity, end 2004	0.5	0.5	8.3	0.3	3.2	16.6
Installed wind capacity, 2010	3.8	3.7	18.0	1.0	3.8	25.0
Minimum load	3.0	3.0	20.0	1.5	2.0	38.0
NTC out	0.9	1.1	2.4	0.0	4.9	18.1
Wind power penetration, end 2004	**13%**	**12%**	**37%**	**20%**	**46%**	**30%**
Wind power penetration, 2010	**97%**	**90%**	**80%**	**67%**	**55%**	**45%**

Country	United Kingdom	Italy	Austria	Nether-lands	France	Poland
Conventional generation capacity	81	82	17.8	20.1	110.9	31.7
Installed wind capacity, end 2004	0.9	1.1	0.6	1.1	0.4	0.1
Installed wind capacity, 2010	6	3.7	1.2	1.5	6	1.5
Minimum load	21.5	22	4	5	30.4	14
NTC out	2.33	0.98	4.12	5.4	14.05	2.85
Wind power penetration, end 2004	**4%**	**5%**	**7%**	**11%**	**1%**	**1%**
Wind power penetration, 2010	**25%**	**16%**	**15%**	**14%**	**13%**	**9%**

Table 6-2: Wind power penetration level 2004, 2010 for EU states with strong wind power development (Reference: minimum load plus NTC) Capacity values in GW

We can see in Table 6-2 and accordingly in the map in Figure 6-2 the known fact that Denmark can profit from cross-border transits to neighbouring countries. Mainly for

Portugal and Greece stronger cross-border transmission has to be developed if the 2010 target values come true.

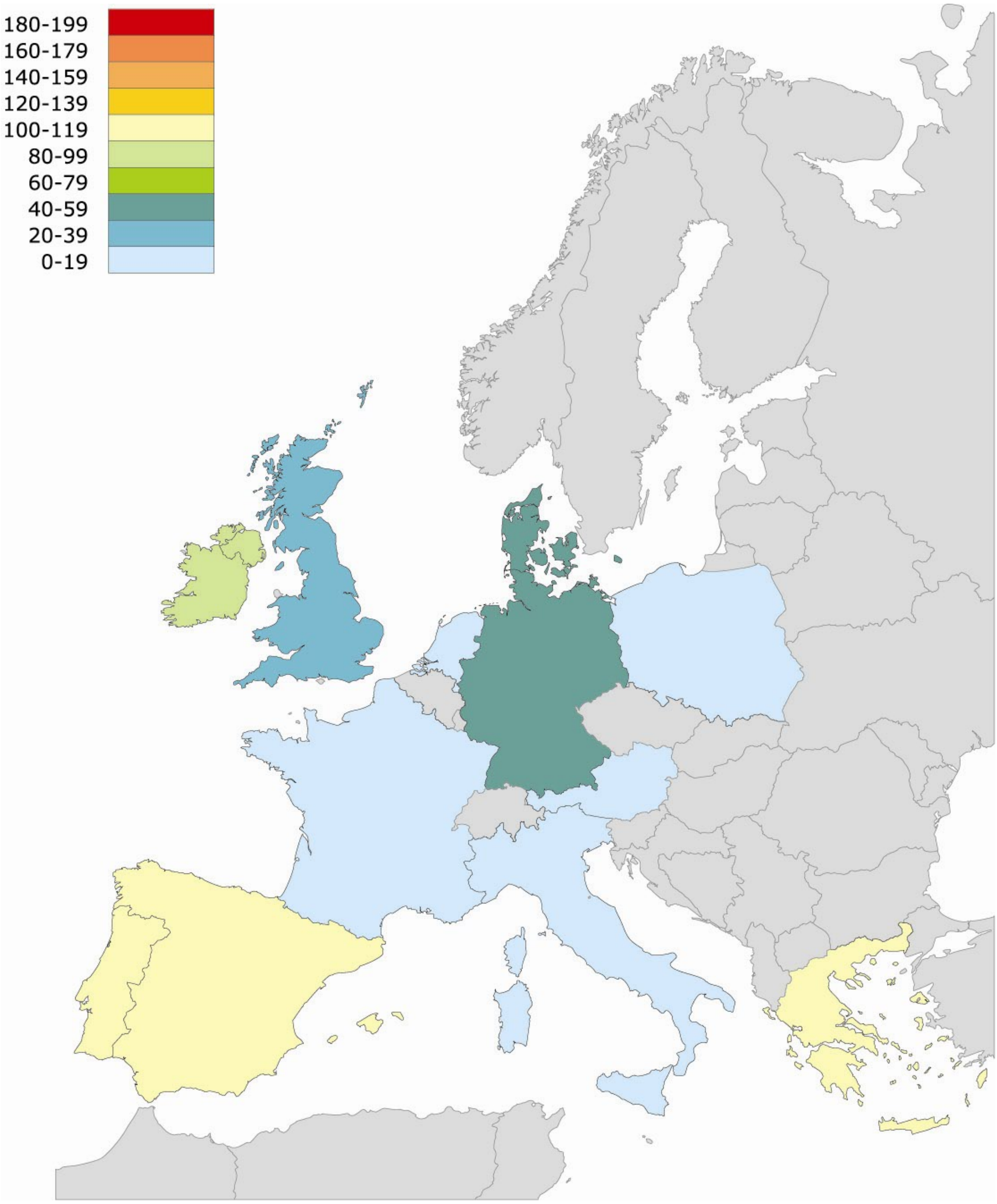


Figure 6-2: Wind power penetration level 2010 (wind capacity related to minimum demand plus NTC) of twelve EU states with strong wind power development

It is obvious that this kind of capacity-related investigation requests a detailed view on national generation system characteristics and the electricy markets. One important factor of influence is the generation mix of the national system (hydro, steam thermal, nuclear, etc.), which determines the effects of high wind power penetration. This country-specific information is provided in the Annex ‘Country Profiles”.

In the following two chapters we will discuss two options: demand-side measures and increase of exportable capacity.

6.2 Demand-side management

It is increasingly understood that time shifting of demand has various beneficial effects. According to IEA Demand-side Management working group, the term “demand response” refers to a set of strategies which can be used in competitive electricity markets to increase the participation of the demand side in setting prices and clearing the market (see Table 6-3). When customers are exposed in some way to real-time prices, they may respond by

a) shifting the time of day at which they demand power to an off-peak period, and/or

b) reducing their total or peak demand through energy efficiency measures or self generation.

The net effect of the demand response is to ease system constraints and to generate security and economic benefits for the market as a whole.

DR program	Definition
Direct load control and curtailment	*Direct control programs are implemented by system operators and are triggered in response to volatility in wholesale pricing, or system and network constraints. This approach necessitates pre-agreed programs with consumers, which establish commercial terms for participation.*
Emergency Demand Response Program	*Emergency Demand Response Programs are portfolio of measures designed to deal with declared emergencies, during which the continued controlled operation is at risk and brownouts and/or blackouts are likely.*
Demand Side Bidding	*Demand Side Bidding (is a term which refers to the opportunity offered by some electricity trading markets for consumers to choose when and how to participate in real-time and day ahead spot markets. The process allows the consumer to be paid a market price for withdrawing load, when required by the market operator, in a similar way that generators are paid to supply.*

Time of Use Pricing	*Under Time of Use Pricing, the retail price varies in a preset way within certain blocks of time. It is typically divided into three different price categories for three different parts of the day:* • *<u>On peak</u>. Demand for electricity is highest,* • *<u>Mid-peak</u>. Demand for electricity is between on-peak and off-peak.* • *<u>Off-peak</u>. Demand for electricity is the lowest.*
Real Time Pricing (RTP)	*Under real time pricing tariffs, electricity consumers are charged prices that vary over short time intervals, typically hourly, and are quoted one day or less in advance to reflect contemporaneous marginal supply costs.*

Table 6-3: Definitions provided by IEA Demand-side Management working group [IEA2003]

Auer et al. have investigated the options of using demand-side measures in case of high wind power penetration ('Demand Response supporting Wind Integration').

Potentials for demand response are determined for different consumption sectors and technical as well as economical aspects of using power demands to provide reserves are investigated. Potentials for demand response are primarily determined by the aggregated consumption of flexible appliances and are therefore depending on daytime and season. The technical potential is furthermore reduced by the aggregated availability that is in the range of 80 %. Technical constraints (like e.g. temperature limits of cooling appliances) limit the potential of demand response as the duration of the activation increases. The comparison of technical potentials off flexible loads in households with current and future requirements for minute reserves in Austria show, that the consumption is able to contribute to system balancing to a high extent.

Sector	Appliance	Categorie		
		Storage	Flexible	Discetionary
Housholds	Cooling/Freezing	X		
	Washing		X	
	Drying		X	
	Dish washing		X	
	Lightning			X
Commercial sector	Cooling	X		
	Ventilation		X	
Public sector	Cooling	X		
	Ventilation		X	
Industry	Cooling	X		
	Ventilation		X	

Table 6-4: Overview on responsive loads in different sectors [Auer2006]

In the expertise [SCHMID2005] on the dena-study, Schmid has provided values for responsive loads in different sectors in Germany.

6.3 European efforts to increase transit capacities

Wind power utilisation supports the necessary process of adaptation of the European electricity infrastructure. It is important that this process is not limited to local or short-term solutions, but becomes instead a strategic development. A strong co-ordination is required on the European level to identify, monitor, interface and support essential infrastructural developments.

In the Trans-European Energy Networks programme the first necessary steps towards this objective have been made. In 2001, the European Commission issued a proposal to amend the guidelines for funding the TENs. Two new policy priorities have been introduced, one concerned with market bottlenecks, the second with 'connecting renewable energy production to the interconnected network'. This new emphasis on renewable energy is carried throughout the proposed new guidelines, and reflected in a number of proposed new 'projects of common interest'. For instance, there are proposals for connections in the north-east and west of Spain 'in particular to connect to the network wind power generation capacities', and to allocate funds to 'adapting the methods of forecasting and of operating electricity networks required by the functioning of the internal market and the use of a high percentage of renewable energy sources'.

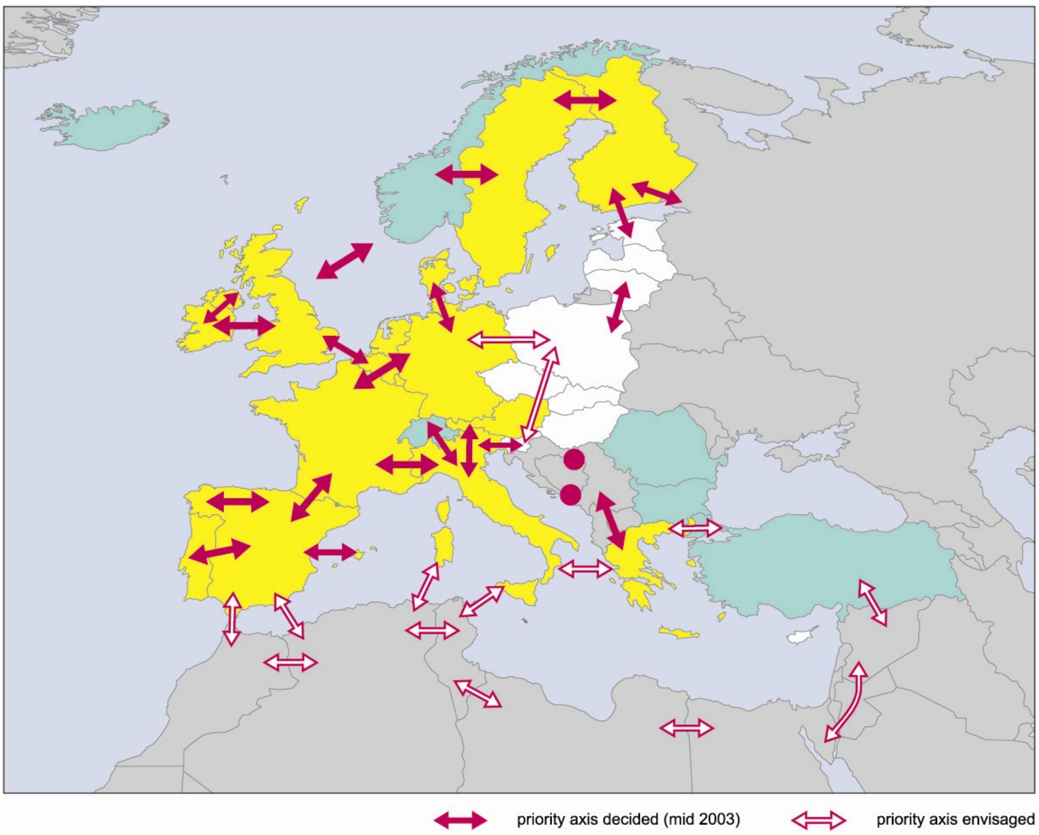


Figure 6-3: Electric priority axes of the Transeuropean Networks (adopted from DG TREN, TEN-E initiative [EC2003])

European Commission's DG Transport and Energy states [EC2003): *The opening of the internal energy market, with the associated benefits of increased competitiveness for European consumers, requires a major increase in interconnections between national networks. The trans-European energy networks programme identifies the missing links and the bottlenecks on the network and we have identified priority routes that are in need of upgrading. European infrastructure development is driven not by wind power development alone, but is a required step towards more reliable, sustainable and cost-effective electric power supply. Wind power development is fully in line with the global processes of the power supply systems in Europe - creation of the internal European electricity market, expansion of the UCTE networks, and the development of TENs.*

7 National characteristics of wind power, grids and market

Country specific parameters such as generation structure, level of internal and external interconnections, regulations and market rules influence the contribution of wind power to a secure and reliable operation of power supply systems.

7.1 Data collection

In the course of this work a questionnaire was developed which contributed to [Hulle2005].

Generation mix

1. Is the power system thermal- or hydro based? What are the shares of national electricity production?
2. What is the conventional generation capacity?
3. What is the peak and minimum demand of the system?
4. How much is current wind power capacity?
5. What is the expected wind power development? In which regions will it take place?
6. Are short-term wind power prediction tools applied by TSOs?

Electricity grids

7. Who are transmission system operators of the country?
8. In which synchronous zone power system is operated?
9. Are there guidelines for wind farms interconnection to HV networks?
10. Which infrastructure investments are planned (especially for compliance with wind power development goals)?
11. Are there congestions in the transmission network? Are there any congestion induced by wind?

Power market aspects

12. How can wind power be sold? Is a network operator obliged to purchase electricity from wind farms?
13. Must a wind power operator submit production schedule to TSO? How many hours ahead?
14. Is there an intra-day trading in the country? How often does it take place per day? Is it possible for wind farm operators to adjust their schedules?
15. Balancing market: How are deviations from schedules are charged for wind farm operators?

Figure 7-1: Questionnaire for country-specific profiles on wind power development

7.2 Graphical representation

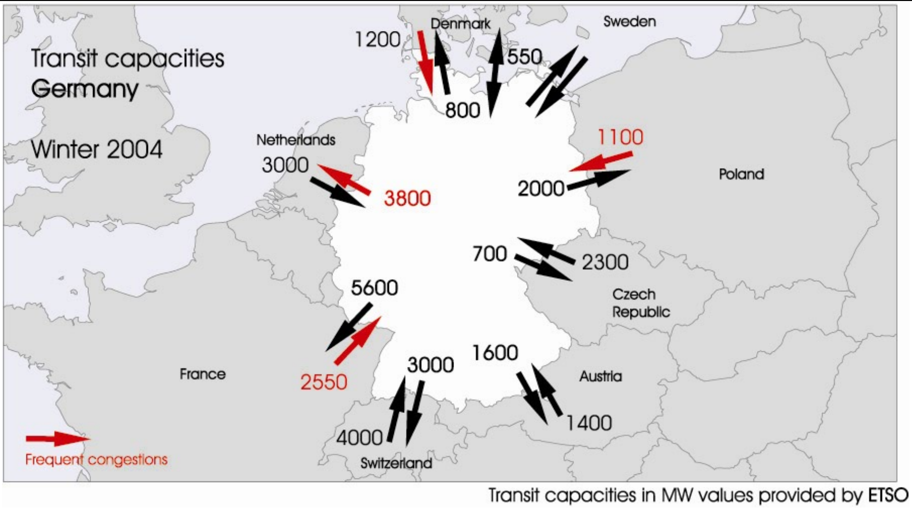
In order to show essential details for system adequacy consideration with increasing wind power, we developed a national ‘wind penetration fingerprint’ depiction consisting of three maps including information on:

- Geographical information on the planned national wind power development and the distance to load centers;
- Cross-border transit capacities to neigboring systems;
- Generation and load balance, including information on the national generation mix.

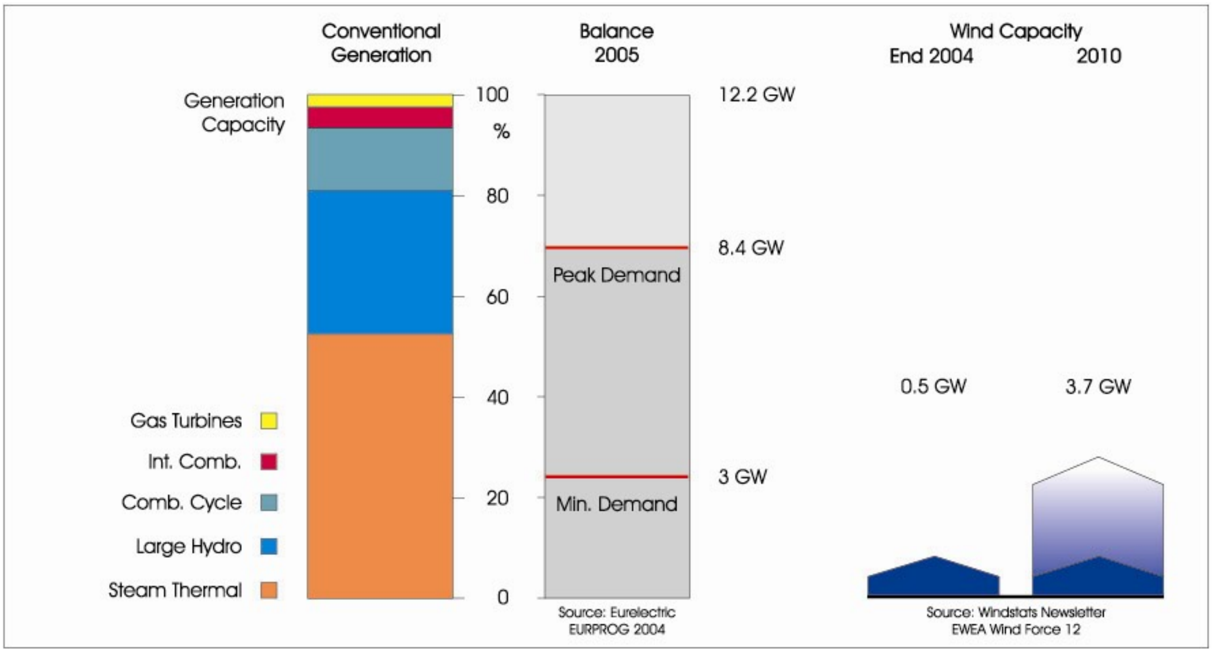
The explanation of the following three figures (containing exemplarily selected maps) applies to the twelve ‘wind penetration fingerprint’ depictions in the Annex “Country Profiles”.

Use of background map by kind permission of UCTE

UCTE’s network map is used as background layer for an indication of regions in which most wind farm installations are foreseen in the coming years until 2010. The distance between the regions of major wind power generation and centres of consumption are shown. The centres of consumption are approximated.



The European TSO association ETSO publishes twice a year NTC values. These indicative values are computed by extrapolation from standard situations, in order to evaluate the transfer capacity through a single interface at the same time. **Thus these figures should be considered separately and are not cumulative**. When the evaluation of a transfer limit requires to use a set of assumption which are too far from usual or foreseeable situation (leading to high inaccuracies), the NTC figure has been replaced by « no realistic limit ». [ETSO2006]



The capacity balance is based on data from Eurelectric (generation capacities, generation mix). The peak demand and minimum demand are annual maximum and minimum values which are determined differently in different countries. The 100 percent value of the balance is conventional generation capacity, being thermal and large hydro power generation.

The wind power penetration level as defined in chapter 6 (wind capacity related to minimum demand) can be directly derived.

8 Summary of Results

The principal objective of this work has been to improve the understanding of wind integration studies and increase the accuracy of their system adequacy considerations. It has therefore focussed on system capacity issues arising from increasing values of national wind power penetration.

The main outcome of this work includes:

- A sensitivity analysis of capacity credit computation, covering the currently applied approaches (probabilistic / chronological) and calculation parameters (input wind profile, site parameters, power system information);
- The simulation software sim.WIN, available as “test stand” for capacity credit parameter studies;
- Decision criteria for selecting appropriate approaches for calculating wind power-induced system reserve demand, covering the variety of regulatory and market situations.
- Outlook on the wind power pentration levels to be expected in Europe with a special focus on the situation ‘maximum wind / minimum demand’;
- National ‘wind penetration fingerprint’ depictions showing the relevant geographical information on the planned national wind power development and the distance to load centers, the cross-border transit capacities and the generation / load balance, including information on the national generation mix.

In detail, this work achieved the following results:

As far as the sensitivity of capacity credit calculations to different input parameters is concerned, this work did not search for any one and only ‘true value’ of wind power capacity credit. Instead, it investigated the relevant calculation parameters, some of them being frequently overlooked when quoting study results. One prominent example for this is the ‘security of supply’ level.

The principal idea was to make use of the full range of information available from a retrospective view on the wind power capacity in Germany in the year 2000. Especially the data provided by the German national wind power reseach program WMEP (see [ISET2001], [ISET2005]) were used for calculation of a reference wind power capacity credit. This reference value was applied to a “*What … if*” analysis.

"*What* would be the capacity credit, *if* only one specific wind power input year had been used?", "*What* would be the capacity credit, *if* a uniform roughness length of 12 cm" had been used for wind farm site description?", etc.

We intended to cover the full range of assumptions to be found in existing wind integration studies. Selected outcome of this case study exercise for the specific situation 'Germany 2000' consisted in the information:

- If only one specific wind year of the sample 1994 to 2003 were used, maximum deviations of -7.6% to +18.6% from the reference capacity credit would result.
- If typical uniform values for roughness length and wind turbine hub height were used, deviations in the range of plus/minus 10% would arise.
- The assumed geographical distribution of wind farm sites can also lead to severe deviation. The case study investigations lead to minus 15.8% of the capacity credit value, when capacity was shifted between the existing coastal and inland sites.
- The level of security of supply applied for the national power system under investigation should always be taken into account. Applying 91% instead of 99% leads to an overestimation of the capacity credit of 6.9%.

The specific values listed are valid for the specific case study situation described in this work.

No matter which modelling approach (deterministic or probabilistic models) is chosen, wind integration study will always need time series of aggregated, cumulative, wind power feed-in. Therefore, an over- or underestimation of the wind power in-feed is the main source of deviations in capacity credit results.

The use of chronological models could solve the problem of statistically insufficient number of samples (to which several wind integration studies have been exposed to), e.g. by using all time series values corresponding to 90-100 percent of maximum demand. The reason for not using chronological models has up to now been the non-disclosure of national electrical load data. Therefore, for future wind integration studies it is strongly recommended to make more load data available.

The section on 'balancing wind power variability' left the field of statistical and probabilistic considerations. Instead it points out which specific market conditions and regulatory issues strongly influence the results of these calculations.

A prominent example of market conditions is the so-called ‘gate closure’, the time when schedules have to be delivered and physical notifications become firm.

In some countries this is day ahead, some are fixed windows in the operational day and some are based upon a rolling settlement period basis. There are a range of times between gate closure and real time in use including 1 hour, 3 hours and day ahead. The accuracy of wind power prediction largely depends on the lead time of prediction. We could show in this work to what extent prediction accuracy can be increased by changing the time of ‘gate closure’.

Another important factor of influence within wind integration studies refers to the *target value* of calculating reserve demand. Two concepts exist:

The first concept of the calculation of additional reserve requirements due to wind power refers to *wind fluctuation around their mean value,* mathematically described by wind power standard deviations.

The alternative concept calculates additional reserve requirements by assessing the wind power deviations from *previously scheduled programs.*

We strongly recommend that the latter concept is used. It can easily be demonstrated that the results can be strongly improved. The case study presented in this work halved the necessary demand.

It is important to stress that reserve requirements are not necessarily assigned to back up a particular plant type (wind), but to deal with the overall uncertainty in the balance between demand and generation.

A third part of system adequacy investigations in this work dealt with the ‘high wind – low demand’ situation. Impressive values were shown when we ranked the national systems according to wind power penetration defined as installed wind capacity related to annual minimum load.

In the year 2004 the wind power penetration ranking had been led by Denmark, Spain and Germany. If the foreseen increase of wind capacity is realised the ranking in 2010 would be led by Denmark, Portugal and Greece with values of 190%, 125%, 123% respectively.

Up to now, the penetration levels could be successfully handled because (1) the *absolute* capacity values were relatively small (e.g. in the case of Denmark) and (2) by the possibility of exporting wind power via cross-border transits. Denmark has the advantage of strong connections with neighbouring countries. In the cases of

Portugal and Greece, additional efforts will be necessary to incease the exportable capacity.

We investigated the possible ‘relief’ that wind power export could give to the ‘high wind – low demand’ situation. We investigated the effect of adding the total of all export NTC values (values provided by ETSO) to the mimimum load values. In reality these values will not be obtained, as they refer to a situation where all NTC would be available for wind export alone. Nevertheless they give us an indication of the maximum ‘relief’.

Investigations related to power system adequacy request a detailed view on national generation system characteristics and electricity markets. The generation mix of the national system (hydro, steam thermal, nuclear, etc.) clearly determines the effects of high wind power penetration. This has been the motivation for the analysis of the situation in twelve European states, which were selected according to the expected wind power expansion, with respect to the influence on the power system, and on power market aspects relevant for wind power integration. We developed a graphical ‘penetration fingerprint’ for Austria, Denmark, France, Germany, Greece, Ireland, Italy, Netherlands, Poland, Portugal, Spain and the United Kingdom containing indications on the planned national wind power development and the distance to load centers, the cross-border transit capacities to neigboring systems and generation and load balance, including information on the national generation mix.

What lies ahead?

It is the very nature of *focussing* on specific issues which leads to others being blinded out.

We focussed in this work on *system adequacy* issues. This means that much work lies ahead in the area of *system reliability* issues and their sensitivity to wind-power related assumptions.

9 ANNEX – Country Profiles on Wind Energy Development

Origin of graphics and texts

The twelve ‘graphical fingerprint’ depictions for Austria, Denmark, France, Germany, Greece, Ireland (Republic of Ireland and Northern Ireland), Italy, Netherlands, Poland, Portugal, Spain and United Kingdom were developed and processed by the author.

The text descriptions for the twelve above mentioned countries were originally delivered by the author to EWEA.

They were used in the document “Large Scale Integration of Wind Energy in the European Power Supply: Analysis, Issues and Recommendations” [HULLE2005] after being extended and comprehensively revised by Frans van Hulle (EWEA). The country profile texts quoted in the following annex are extracts from this EWEA document in its final version and are therefore fully assigned to the reference [HULLE2005].

AUSTRIA

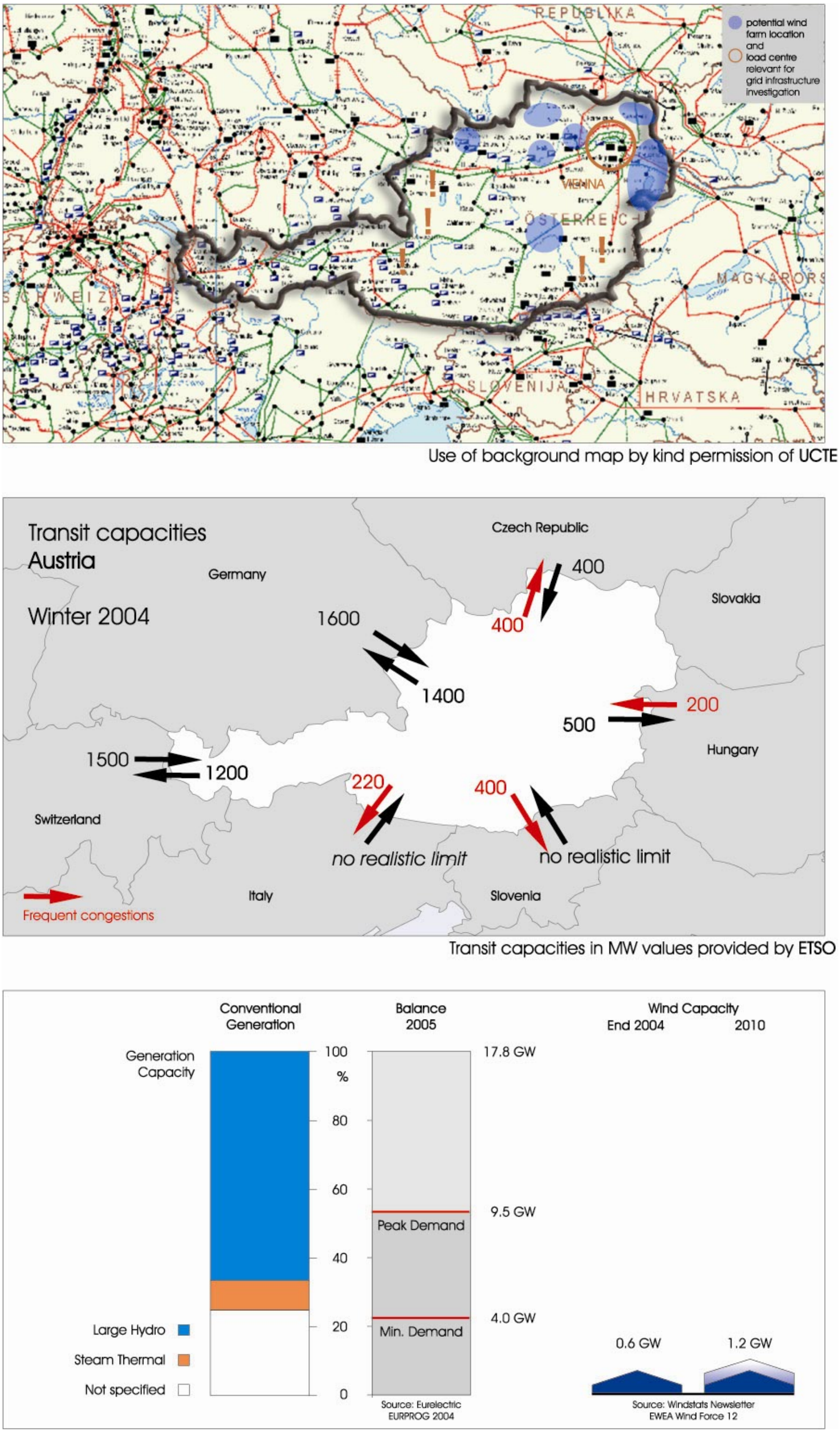


Figure 9-1: National characteristics of generation capacity, grids and power markets: Austria

AUSTRIA

Wind power status and prospects

At the end of 2004 the installed wind power in Austria was 606 MW. This is 3.3% of the net generation capacity in the country. A total wind power capacity of more than 1,000 MW is currently planned for the North-East. Wind power prediction tools are presently not applied.

Electricity grids

Synchronous zone: UCTE, Central Block.

Transmission system operators: Tiroler Regelzone AG, Verbund - Austrian Power Grid, VKW-Übertragungsnetz AG

Because the majority of the new wind power plants will be installed in North-East, the already existing North-South bottleneck in the Austrian transmission grid will be further increased. For this purpose, 380 kV lines in Styria and Salzburg would be required. As the 380 kV ring within Austria still contains gaps, the 220 kV lines have already repeatedly been subject to extreme loading.

Electricity generation and demand

The maximum net generating capacity in 2005 was 17.8 GW. The peak load was 9.5 GW, the minimum load around 4 GW.

The net electricity generation was 61.7 TWh and the consumption 60.7 TWh.

The Austrian electricity supply is mainly hydro-based. The fraction of conventional thermal generation is mainly based on natural gas and hard coal.

Power market aspects

Starting on 1 January 2003 the Eco-Electricity Act (Ökostromgesetz) introduced three “green balance groups” responsibles for the purchase of the green energy and distribution to electricity retailers at an internal price of 4.5 cent/kWh, which is intended to support the development of green energy. The green plant operators now have the right to obtain certificates of origin which subsequently can be traded over the Austrian Energy Exchange.

DENMARK

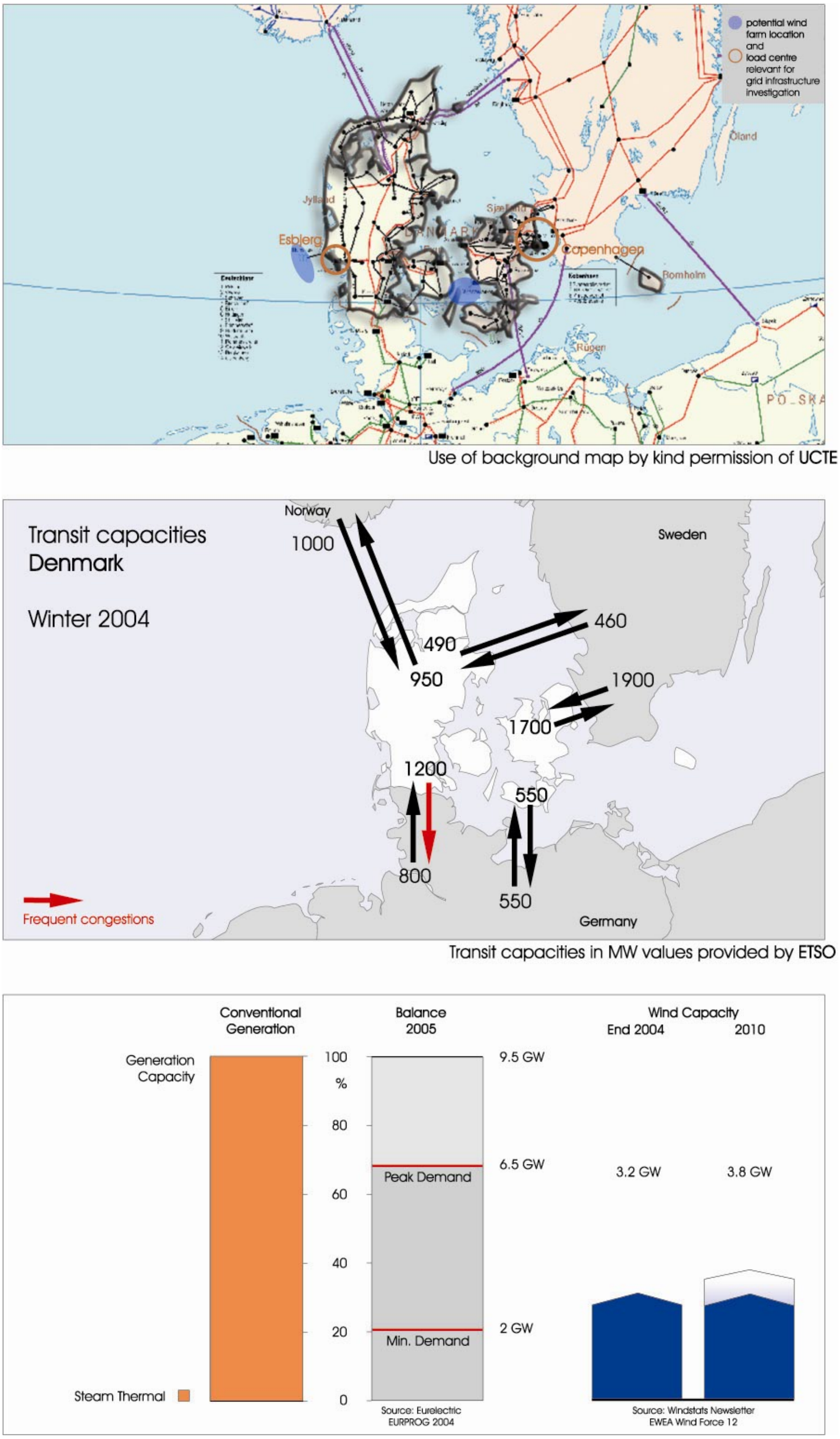


Figure 9-2: National characteristics of generation capacity, grids and power markets: Denmark

DENMARK

Wind power status and prospects

At the end of 2004 the installed wind power in Denmark was 3117 MW. This is 23.4% of the net generation capacity in the country. Denmark already satisfies 21% of its national electricity needs from wind power, and the target is to increase this to 25% by 2010. Wind energy installed capacity in Denmark can expand from 3,1 GW today to 5 GW in 2025. Offshore wind power is becoming significant in Denmark: 427 MW are presently in operation, including the large offshore wind farms of Horns Rev in the North Sea and Rødsand in the Baltic Sea.

Electricity grids

The Danish power system is split into two sections, which make part of different synchronous areas. The transmission system in Western Denmark operated by the TSO Eltra, covering the Jutland peninsula and the Islands west of the Great Belt is part of the UCTE (Main Block) synchronous zone with two AC connections to Germany. The transmission system in the eastern part of Denmark covers the islands east of the Great Belt including the largest island Zealand. It is part of the Nordel synchronous zone with several AC connections over the Øresund to Sweden. The TSO in Eastern Denmark is Elkraft. In 2005 Eltra and Elkraft have merged together with the Danish gas TSO into a state-owned company Energinet. Despite this merger, the two synchronous areas keep on being operated separately and are not synchronously connected with each other.

The Eltra system contains 400 kV and 150 kV lines. It is linked by HVDC links to Sweden and Norway. The Elkraft system contains 400 kV and 132 kV lines. It is linked by HVDC to Germany. A HVDC link between Eastern and Western Denmark is under consideration.

Interconnection aspects

Denmark is situated between the hydro power dominated systems in the Nordel zone and the fossil-fuel dominated UCTE zone. In the European internal electricity market, it therefore functions as a bridge for extensive power exchanges between these two zones. Therefore, existing transmission bottlenecks in the Danish system are generally subject to competition between commercial exchange power and balancing power flows related to variations in wind farm output.

Electricity generation and demand

The maximum net generating capacity in 2005 was 9.5 GW. The peak load in West Denmark (former Eltra area) in 2005 was 6.5 GW, the minimum load was approximately 1.7 GW. The peak load in Eastern Denmark (former Elkraft area) was 2.68 GW and the minimum load was 0.83 MW.

The net electricity generation was 43.8 TWh and the final consumption 32.4 TWh.

The Danish electricity supply is mainly based on hard coal and gas; however, wind power makes almost one quarter of the total generation capacity.

Beside wind power, Western Denmark also has a high amount of distributed generation by means of small combined heat and power (CHP) systems.

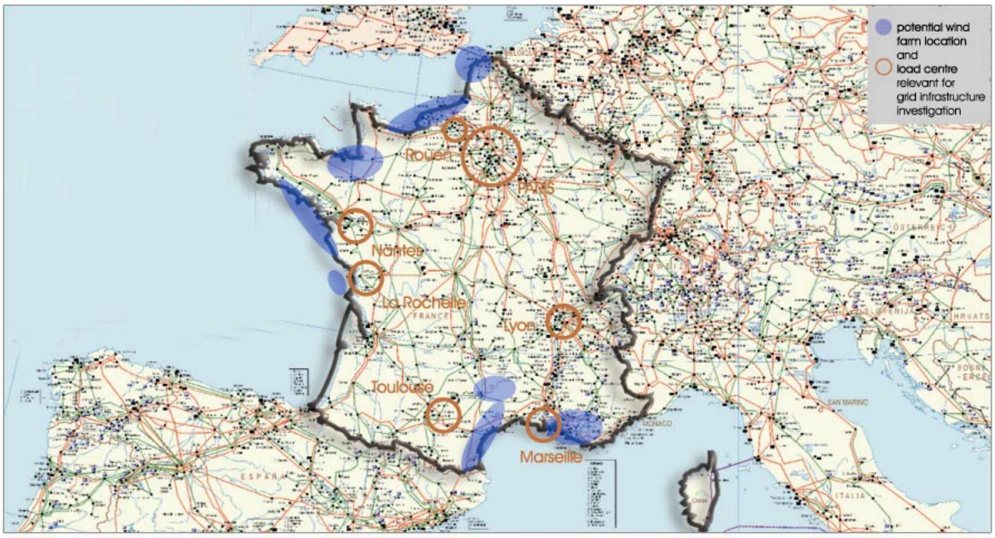
Power market aspects

In the Nordic liberalized electricity market, balancing is the responsibility of so-called Balance Responsible Players (BRPs). Every generator and load in the Nordel system is assigned to a BRP. BRPs are responsible towards the national TSOs to maintain the scheduled hourly energy exchange. Deviations from the schedule are penalized by the TSO (imbalance-pricing). Balancing the wind power in Denmark lies in the responsibility of the two TSOs who have to buy balancing power locally or from the regulating power market operated by the Nordel TSOs.

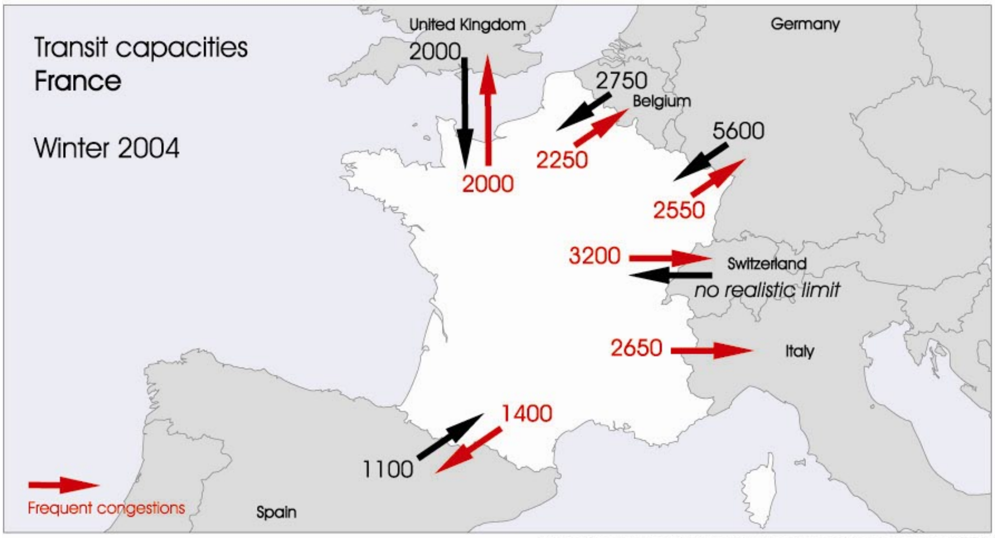
TSOs generate monthly forecasts of wind power production three months ahead and are responsible for deviations from these values, which are traded on the Nord Pool day ahead market, on the base of shorter-time and more accurate forecasts.

Any departures from the expected wind production will be settled at regulating power market prices of the Nordic TSOs, or at German balance markets.

FRANCE



Use of background map by kind permission of UCTE



Transit capacities in MW values provided by ETSO

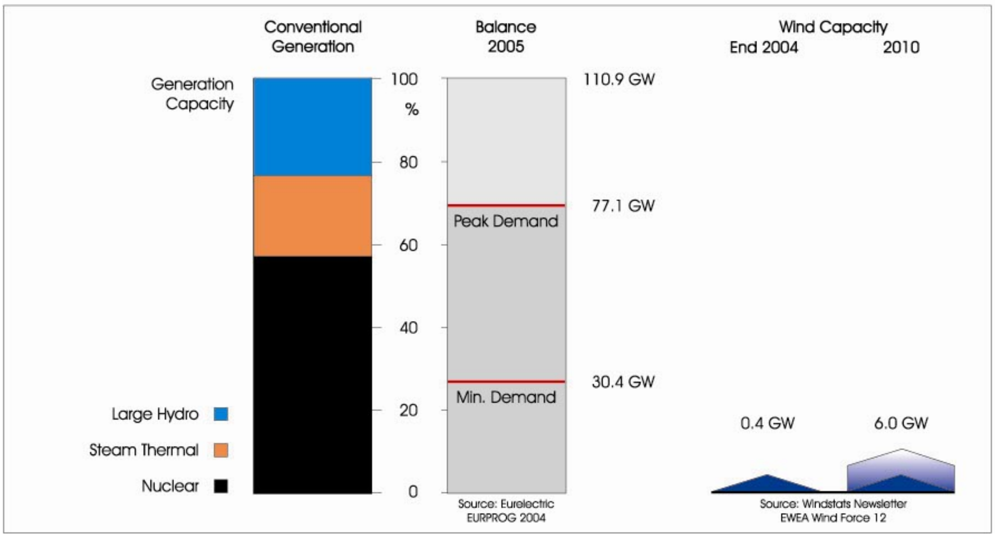


Figure 9-3: National characteristics of generation capacity, grids and power markets: France

FRANCE

Wind power status and prospects

During 2004 the installed wind power in France has increased to 386 MW. This is 0.3% of the net generation capacity in the country. According to estimations by ADEME, based on resource evaluation, present developments, policy targets for renewables, the projected wind power capacity for 2010 ranges between 7.7 and 11.4 GW and for the year 2020 between 27 GW and 40 GW. A study commissioned by the French SER (Syndicat des Energies Renouvelables) in 2004 indicates that if constraints on building permits and projects authorizations are not softened, even a target of 6 GW in 2010 would be difficult to reach.

Electricity grids

RTE Gestionnaire du Réseau de Transport d'Electricité is the national TSO. France is part of the synchronous zone UCTE, Main Block. The distribution system operator (EDF) is in charge of grid connection up to 20 kV. RTE is in charge of grid connection beyond this limit. Studies by the TSO indicate that the French national transmission and distribution grid could cope with 6 GW of wind power with only minor reinforcement work and that 10 GW of wind power in operation in 2010 could avoid building 2.5 GW of conventional power.

Interconnection aspects

Interconnection capacities from France to neighbouring countries are large: for example in 2003 gross exports of electricity (in TWh/year) were 5.3 to UK, 9.4 to Belgium, 20.2 to Germany, 11.7 to Switzerland, 18 to Italy and 6.4 to Spain. Due to the limited wind energy production (0.6 TWh in 2004) and due to the power purchase agreements with EDF, there are almost no exports of wind power from France.

Electricity generation and demand

The maximum net generating capacity in 2005 was 110.9 GW. The peak load was 77.1 GW, the minimum load was 30.4 GW. The net electricity generation was 542 TWh and the final consumption 408 TWh.

The French electricity supply is mainly nuclear-based. The fraction of conventional thermal generation is mainly based on natural gas and hard coal.

Power market aspects

EDF and non state-owned electric distribution utilities are obliged to buy wind power. For energy from wind farms of less than 12 MW they must pay an official tariff defined from Decree of June 8th 2001. Larger wind farms are issued by the government via calls for tenders. Wind power operators under 12 MW are not obliged to submit production schedules to the TSO. For projects from the Government calls for tenders, selected operators will have to submit production schedule to TSO for the following day.

GERMANY

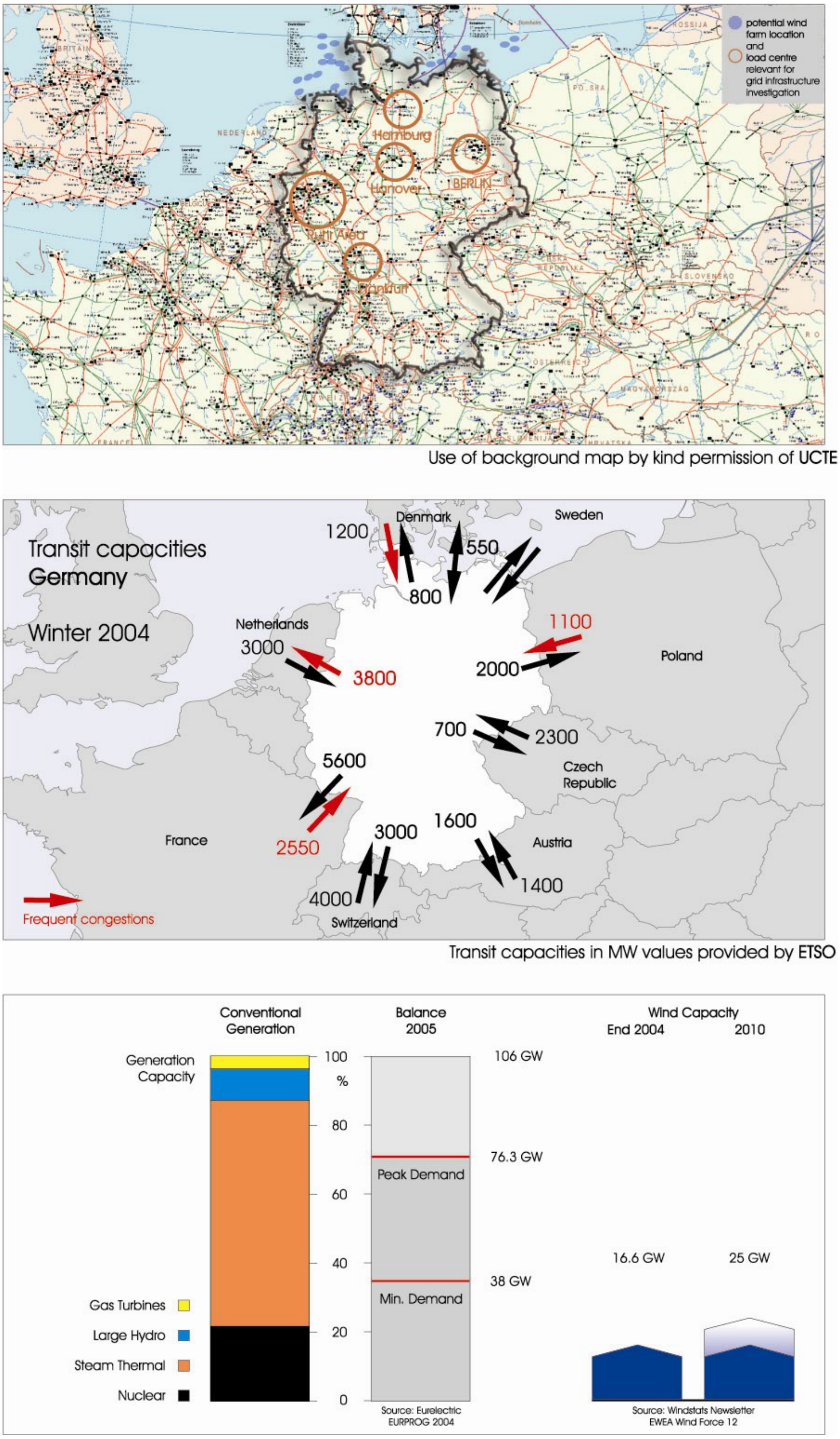


Figure 9-4: National characteristics of generation capacity, grids and power markets: Germany

GERMANY

Wind power status and prospects

During 2004 the installed wind power in Germany has grown by 13.7% from 14.6 GW to 16.6 GW. This is 13.3% of the net generation capacity in the country.

By 2010 the estimated installed wind power amounts to 25.0 GW. The onshore developments are concentrated in the states Lower Saxony, Schleswig-Holstein, North Rhine-Westphalia, Brandenburg-Berlin and Saxony-Anhalt. Offshore wind farms will be constructed in the North Sea: (Borkum, Helgoland, Sylt regions and open sea) and the Baltic Sea (Rostock and Rügen regions). The expected developments have been analysed in detail in the Dena study. A distribution of the installed wind power (end 2004) over the four TSO areas is given in Table below.

Electricity grids

The transmission system is part of the UCTE synchronous zone and is operated by four independent operators: EnBW Transportnetze AG, E.ON Netz GmbH, RWE Transport-Netze GmbH, Vattenfall Europe Transmission GmbH.

General guidelines for the connection of wind farms to the transmission system have been published by VDN, the association of power system operators in Germany [VDN 05]. Moreover the transmission code is applicable (see par. 5.3.5 of main report).

The rather concentrated wind power production in the North is often leading to overloading in the interconnectors to the Netherlands, France, Poland and Western Denmark. Increasing share of wind power can lead in the future to congestions in the transmission grid and already restricts wind power supply on the 110 kV distribution level in the regions with high installed capacity of wind power.

Interconnection issues

Power transit from Scandinavia already today leads to congestion in the north of Germany. Wind power imported from Denmark could add up to the power injection from offshore wind in the German exclusive economic zone (EEZ). In specific situations (high wind – low load) German TSOs are using cross-border connection (for example via Netherlands and Belgium) to redirect the power flows.

Electricity generation and demand

The maximum net generating capacity in 2005 was 106 GW. The peak load was approximately 79.1 GW and the minimum load 35 GW.

The net electricity generation was 565 TWh and the final consumption 509 TWh.

The German electricity supply is mainly thermal-based (hard coal, lignite and nuclear). Nuclear power will be phased out and decreased to 9% in 2020, thus raising the share of other energy sources. The contribution of electricity from natural gas will increase to 20% in 2020.

Power market aspects

In Germany renewables have priority access to the grid. The connection charges for renewables are shallow. TSOs are obliged according to the Renewable Energy Act to buy power from wind farms and make it possible to connect them without compromising security of supply.

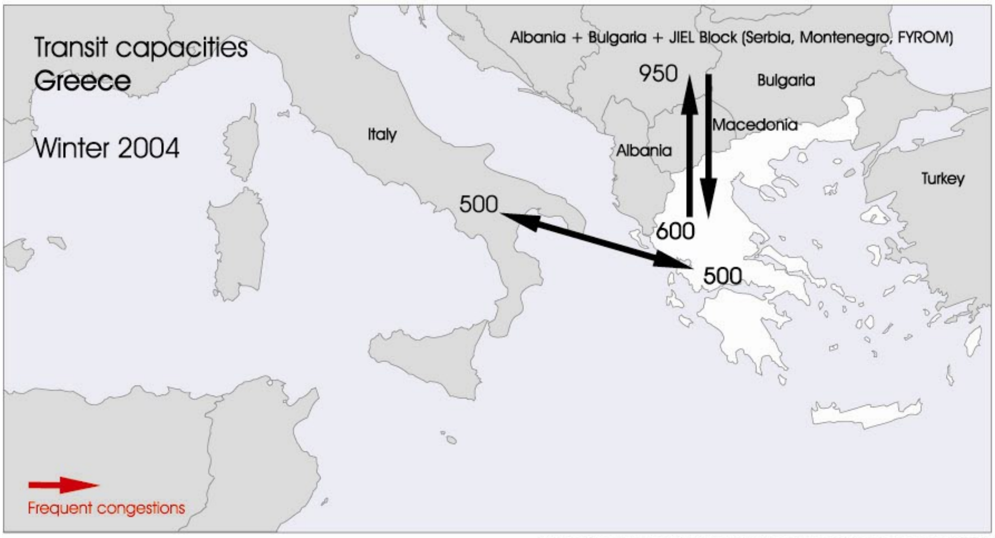
TSOs take care of the balancing in their control areas. Since the four German TSOs have to handle unequal shares of wind power, their market position is affected and in order to cope with this situation, an online-equalisation scheme distributes the costs of wind power production among them according to their electricity supply volume.

All TSOs apply short-term predictions of the aggregated wind power generation in their control areas.

The production has to be scheduled day-ahead (i.e. 9.5 – 33.5 hours before delivery). There is a limited possibility for intra-day trading: schedules can be updated 3 times a day but the option is restricted.

GREECE

Use of background map by kind permission of UCTE



Transit capacities in MW values provided by ETSO

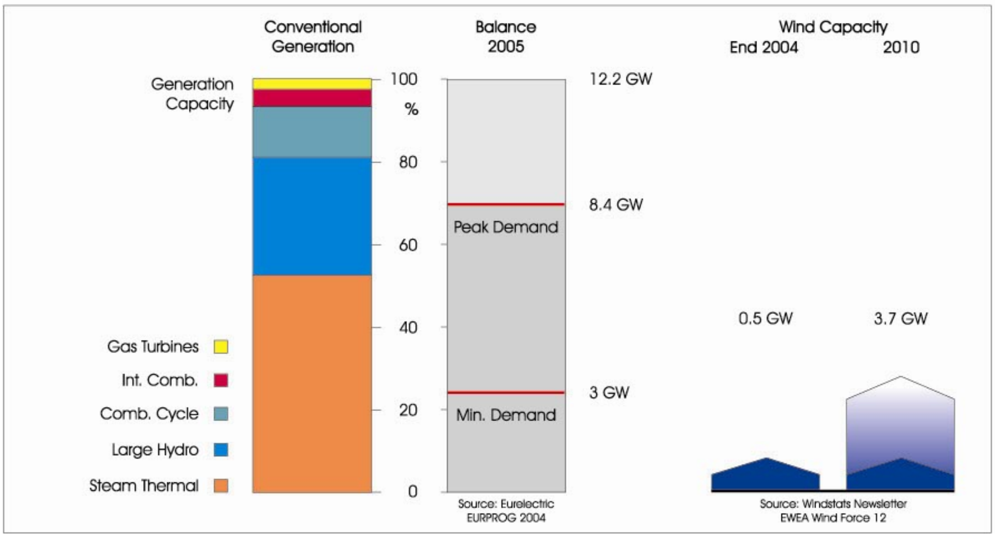


Figure 9-5: National characteristics of generation capacity, grids and power markets: Greece

GREECE

Wind power status and prospects

During 2004 the installed wind power in Greece has grown by 24% from 375 MW to 465 MW. This is 3.9% of the net generation capacity in the country. The expected capacity in 2010 is approximately 3.7 GW.

Wind power is expected to develop mainly on the Aegean islands, the west part of the island of Crete, Thrace and the eastern coast of continental Greece including the Evia island, Lakonia and Troizinia in Peloponnesus.

Electricity grids

The transmission grid is operated by the Hellenic TSO DESMIE. The mainland grid makes part of the synchronous zone of UCTE. Crete and most islands are independent island grids.

The optimum expansion plan foresees connection of future wind farms to the 150 kV grid of the Metropolitan area of Athens, through two submarine cables, and reinforcement of the 150 kV connecting grid, between Evia and continental Greece.

Electricity generation and demand

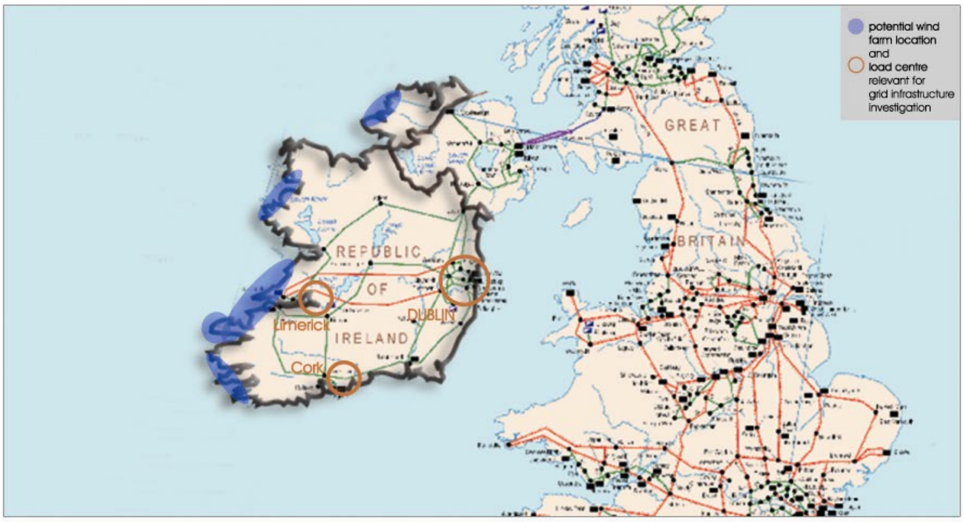
The maximum net generating capacity in 2005 was 12.2 GW. The estimated peak load in 2004 is 8.7 GW. The peak load was 11.2 GW, the minimum load is estimated at around 3 GW. The net electricity generation was 54.3 TWh and the final consumption 48.6 TWh.

The Greek electricity supply is mainly based on thermal generation from lignite.

Power market aspects

Greece's Public Power Corporation (PPC) is a majority state-owned monopoly that controls electric production, transmission, and distribution in the country. The company owns and operates 33 power plants on the mainland and numerous smaller plants on the country's many isolated islands. Both EU and OECD have urged Greece to break up PPC. Although EU member countries were required to open their electricity markets by February 1999, Greece was granted a two-year waiver in recognition of its unique situation: it borders no other member state, and much of its territory is comprised of islands that are difficult to link into the national grid. PPC presently estimates that it still produces 97% of all electricity in Greece. Greece is not realistically expected to maintain a liberalized free market until 2006-2007.

IRELAND



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Transit capacities in MW values provided by ETSO

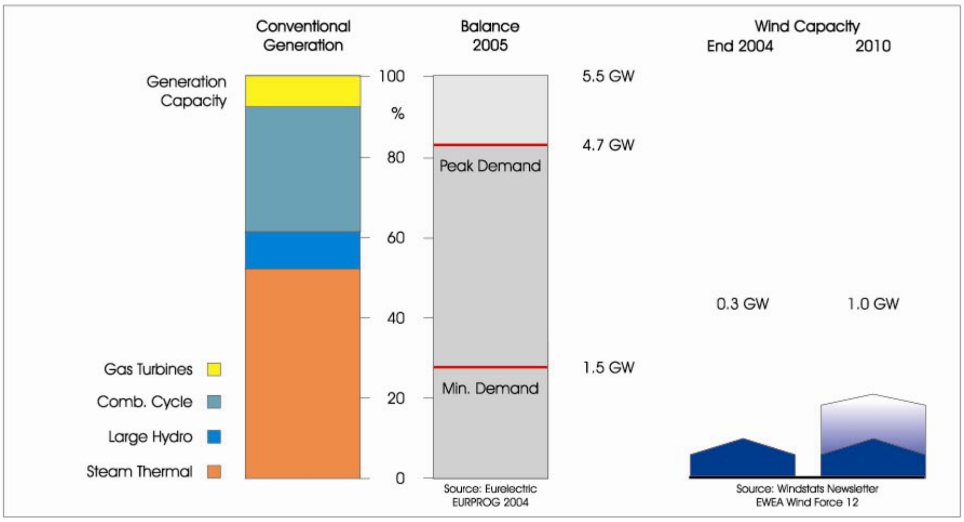


Figure 9-6. National characteristics of generation capacity, grids and power markets: Republic of Ireland

REPUBLIC of IRELAND

Wind power status and prospects

During 2004 the installed wind power in the Republic of Ireland has grown by 77.5% from 191 MW to 339 MW. This is 6.2% of the net generation capacity in the country. The target for 2010 is 1.0 GW. Wind development will be concentrated along the Atlantic side of the Island.

Electricity grids

The transmission system operator is the Electricity Supply Board - National Grid (ESB NG). The synchronous zone is the Island of Ireland.

The generating capacity in the Irish synchronous zone (7.6 GW) and the interconnection with GB are rather limited. Therefore, amongst others, the TSO requires wind power plants to participate in frequency control.

Dynamic system stability with a high share of wind power and balancing of the transmission system are generally considered as more technically challenging. Accordingly, short-term predictions of wind farm output are already today required by the Wind Grid Code of ESB National Grid.

Electricity generation and demand

The maximum net generating capacity in 2005 was 5.5 GW. The peak load was 4.634 GW, the minimum load around 1.509 GW. The net electricity generation was 24.1 TWh and the final consumption 23.0 TWh. The electricity supply in the Republic of Ireland is mainly thermal based. The fraction of conventional thermal generation is mainly based on natural gas and hard coal.

Power market aspects

In Ireland balancing is taken care of by the TSO via the “top-up” and “spill” imbalance market that all other operators use. Plans for a Republic of Ireland electricity market have been suspended in order to develop an all Ireland market. The market is a day-ahead bilateral market, but balancing can be done “ex-poste” for up to 7 days after the trading period.

In addition, the Wind Grid Code obliges operators of wind farms of more than 30 MW to provide short-term power forecasts. Moreover, the available wind power output has to be declared whenever changes in available power occur.

ITALY

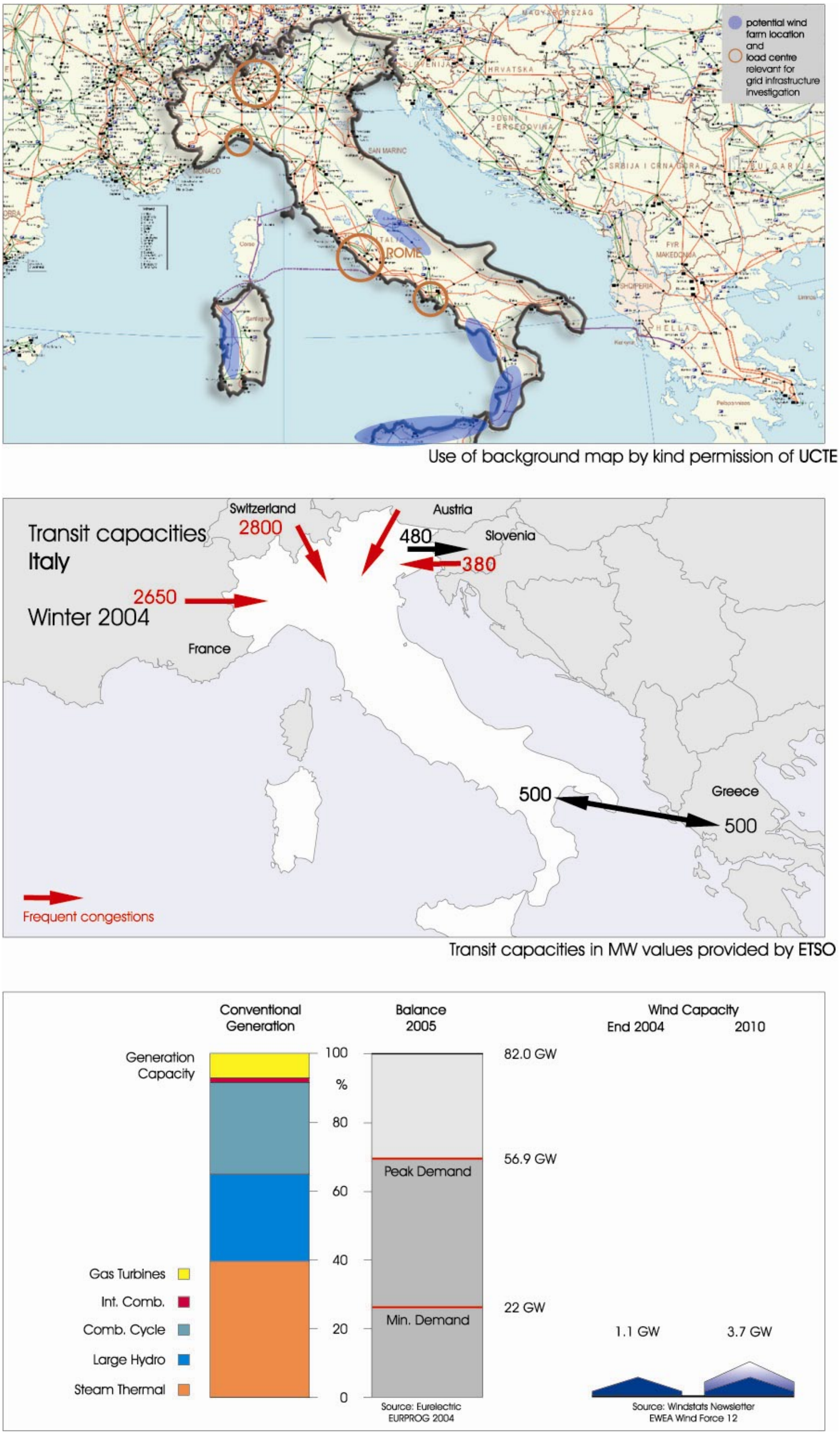


Figure 9-7: National characteristics of generation capacity, grids and power markets: Italy

ITALY

Wind power status and prospects

At the end of 2004 the installed wind power in Italy was 1125 MW. This is 1.4% of the net generation capacity in the country.

The “White Book”projected wind power capacity for 2010 is 2.5 – 3.0 GW and in 2020 approximately 9.5 GW, whereas updated studies by the Ministry of Industry and Ministry of Environment give projections of 7 – 10 GW of wind power capacity for 2010. Future and existing wind power plants are located mostly in the Southern part of Italy (Campania, Apulia, Basilicata, Molise and Abruzzo Regions) and in the major Islands (Sicily and Sardinia).

Electricity grids

Gestore della Rete di Trasmissione Nazionale (GRTN) is the national transmission operator. The Italian grid is part of the synchronous zone UCTE.

Until now, there have not been grid impact problems with existing wind farms due to their relatively low capacity. In view of further deployment, Enel and GRTN have undertaken the construction of wind-dedicated power collection systems in the most densely developed areas (Campania and Apulia). Dedicated substations will receive power from local wind farms and feed it through 150 kV lines into two 380/150 kV stations of the national 380 kV transmission system, thus avoiding affecting any longer the local 150 kV systems which are rather weak.

Electricity generation and demand

The maximum net generating capacity in 2005 was 82 GW. The peak load was 56.9 GW, the minimum load is estimated at around 20 GW. The net electricity generation was 280.8 TWh and the final consumption 291.0 TWh. The Italian electricity supply is mainly based on thermal generation from natural gas and oil. Another significant fraction originates from hydro power.

The net thermal production (gas, fuel-oil and coal power plants) reached 233.8 TWh in 2004 (+1.6% on 2003), whilst hydro production amounted to 49.3 TWh, up by 12.9% from the previous year.

Power market aspects

Older wind farms benefit from a fixed feed-in tariff granted by CIP provision No. 6/92 over their first 8 years of life. Most operating wind plants currently benefit from this system. In the meantime, another system based on a renewable quota obligation (2.35% in 2004) put on electricity producers and tradable green certificates has come into force. Thus, more recent wind farms have to rely upon the sale of electricity on the regular market plus the sale of green certificates to obliged producers (allowed over the first 8 years of plant lifetime)

According to Decree No. 387 (as of 29 December 2003), wind is assigned to non-dispatchable sources. Plants above 10 MW can sell energy on the national market through the Power Exchange. Smaller plants can sell their energy to the local distribution company or to GRTN (and therefore to the Acquirente Unico, the trader that provides electricity to the residential market ‘Mercato Vincolato’).

NETHERLANDS

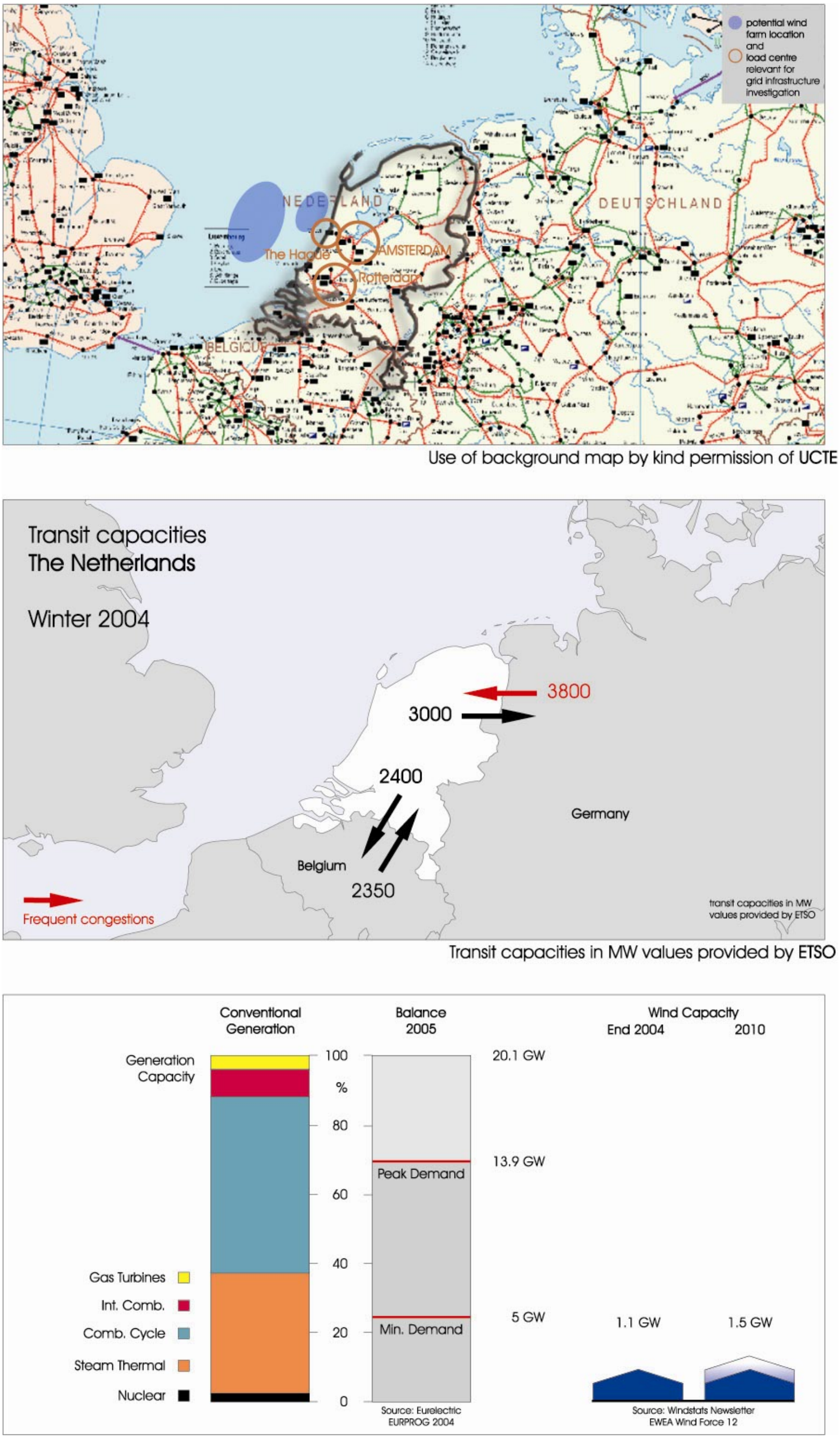


Figure 9-8: National characteristics of generation capacity, grids and power markets: Netherlands

NETHERLANDS

Wind power status and prospects

At the end of 2004 the installed wind power in the Netherlands was 1080 MW. This is 5.2% of the net generation capacity in the country. The targets are approx. 1.5 GW for 2010 and 6 GW by 2020 although the latter has not been formalised in the latest Energy Report.

Large-scale offshore development in the North Sea is foreseen to be fed in the substations Beverwijk, Maasvlakte and Eemshaven. One 108 MW offshore project is under construction near Egmond aan Zee. Another offshore project (120 MW) is in the .nal planning stage.

Electricity grids

TenneT BV is the national TSO. The applicable synchronous zone is UCTE, Central Block.

HV transmission capacity has not yet been a bottleneck, but in future will be a major limiting factor for the large-scale deployment of offshore wind energy in the Netherlands. Currently, 2000 MW of offshore wind power could be accommodated.

Interconnection issues

Early 2008, a 700 MW HVDC inter-connector to Norway (NorNed) will be in operation. Furthermore, investigations are made for a 1320 MW connector to UK.

Electricity generation and demand

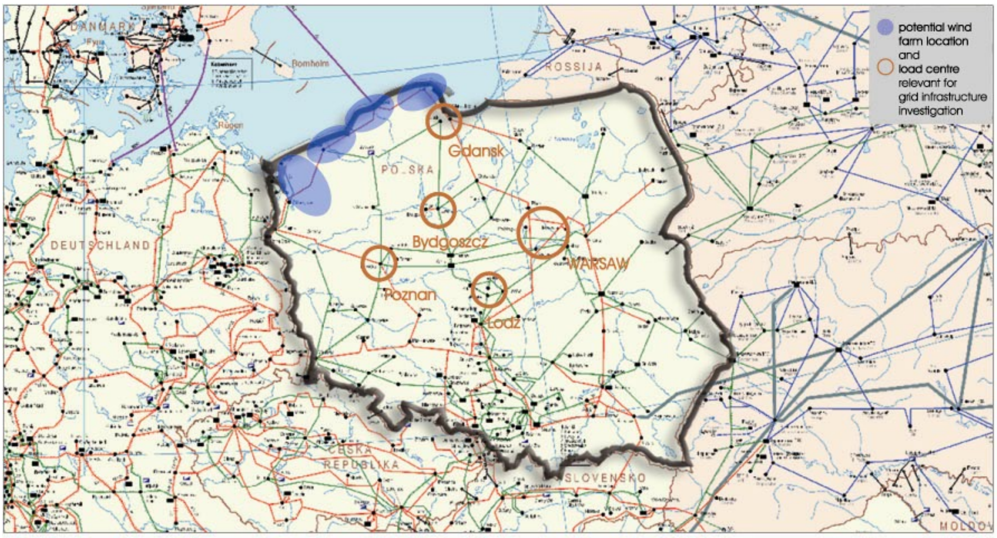
The maximum net generating capacity in 2005 was 20.1 GW. The peak load was 17.1 GW, the minimum load around 5 GW.

The net electricity generation was 92.9 TWh and the .final consumption 100.4 TWh. The Dutch electricity supply is mainly thermal based from natural gas and, to a lesser extent, from hard coal.

Power market aspects

In the Dutch liberalized electricity market, balancing is the responsibility of so-called Programme Responsible Parties (PRPs). Every generator and load in the Netherlands is assigned to a PRP who are responsible towards the TSO TenneT to maintain the scheduled quarter-hourly energy exchange with the Dutch system of all generators and load in their portfolio. Deviations from the schedule are penalized by the TSO (imbalance-pricing). A PRP with a high share of wind power in its portfolio will have a higher risk of imbalance than PRPs without and consequently will make arrangements by minimizing its imbalance costs. On that background short-term wind power forecasting will become crucial for optimising the level of reserves within the portfolio. The schedule for programme submission is day ahead (i.e. 12 – 36 hours before delivery). Trading after closure of the spot-market is limited.

POLAND



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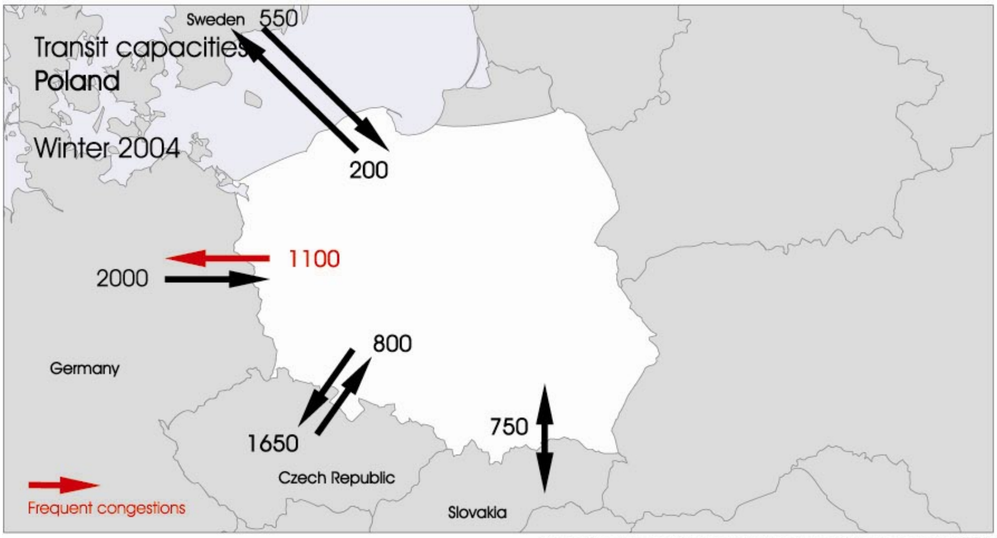


Transit capacities in MW values provided by ETSO

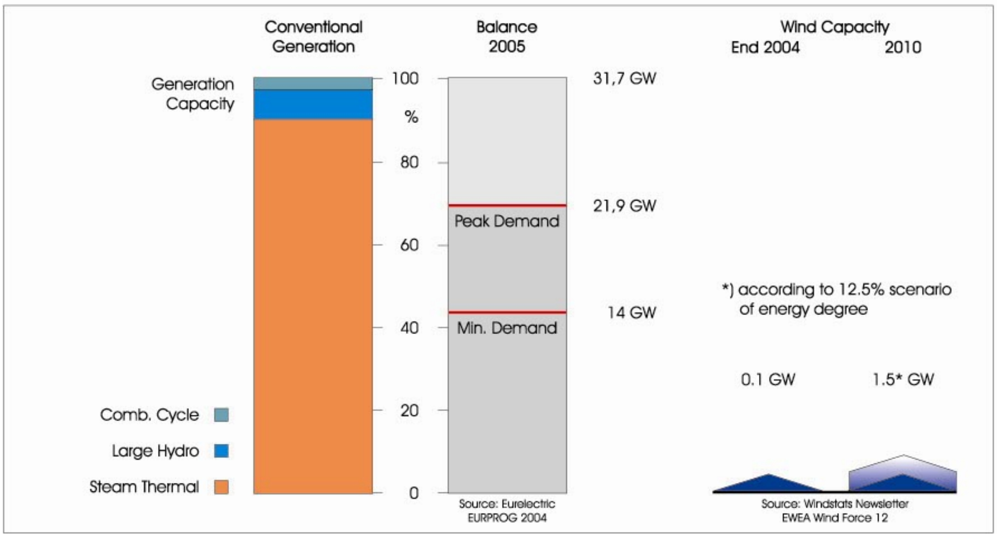


Figure 9-9: National characteristics of generation capacity, grids and power markets: Poland

POLAND

Wind power status and prospects

At the end of 2004 the installed wind power in was 63 MW. This is 0.2% of the net generation capacity in the country.

Most of the future planned offshore projects are concentrated on the central part of the coast and two farms with more than 100 MW are planned east of the Gulf of Gdansk. Realistically, 150 MW of offshore wind farms could be commissioned by 2010. The total of .led applications and other projects under consideration, offshore and onshore, amounts to about 1500 MW.

Electricity grids

The Polish transmission system is operated by PSE-Operator SA. It contains lines of 750 kV, 400 kV and 220kV. PSE-Operator also operates the 110 kV distribution system. The Polish transmission system is part of the UCTE synchronous zone.

The TSO has prepared a study about the grid connection of wind farms focused at onshore wind power developments. For up to 2500 MW of wind power only reinforcements in the distribution grids are necessary. Increasing of wind penetration above 3000 MW would demand installation of new EHV/110 kV transformers. At such level of wind penetration wind farms need to comply with advanced grid codes to cope with reactive power and fault ride through capability. In a later stage possibility of overloadings in the transmission grid and occurrence of large loop flows involving the German network would occur at wind penetration about 4000 - 5000 MW. HVDC link Sweden-Poland (600 MW), pumped storage power stations (900 MW) located in the northern Poland as well as application of wind power curtailment schemes can solve the problem. Further growth of wind generation will need substantial investments in the Polish 400 kV transmission network.

Electricity generation and demand

The maximum net generating capacity in 2005 was 31.7 GW. The peak load was 21.9 GW, the minimum load around 14.66 GW.

The net electricity generation was 138.4 TWh and the final consumption 98.3 TWh.

The Polish electricity supply is mainly based on thermal generation from hard coal and lignite.

Power market aspects

Renewable energy producers in Poland have priority access to the grid. However, there is no minimum price for renewables. The coming Energy Law envisages minimum prices for electricity from renewable sources as a market average price of electricity from the previous year. This minimum price will be announced every year by the regulator.

Balancing in Poland is the responsibility of the TSO. Operators of large wind farms (from >50 MW wind farms) have to submit short-term predictions of their generation day-ahead and are penalized for deviations. A number of aspects with regard to pricing, grid access and balancing are not yet clarified in Poland. They will be integrated into an amendment of the Energy Law that will come into force soon.

PORTUGAL

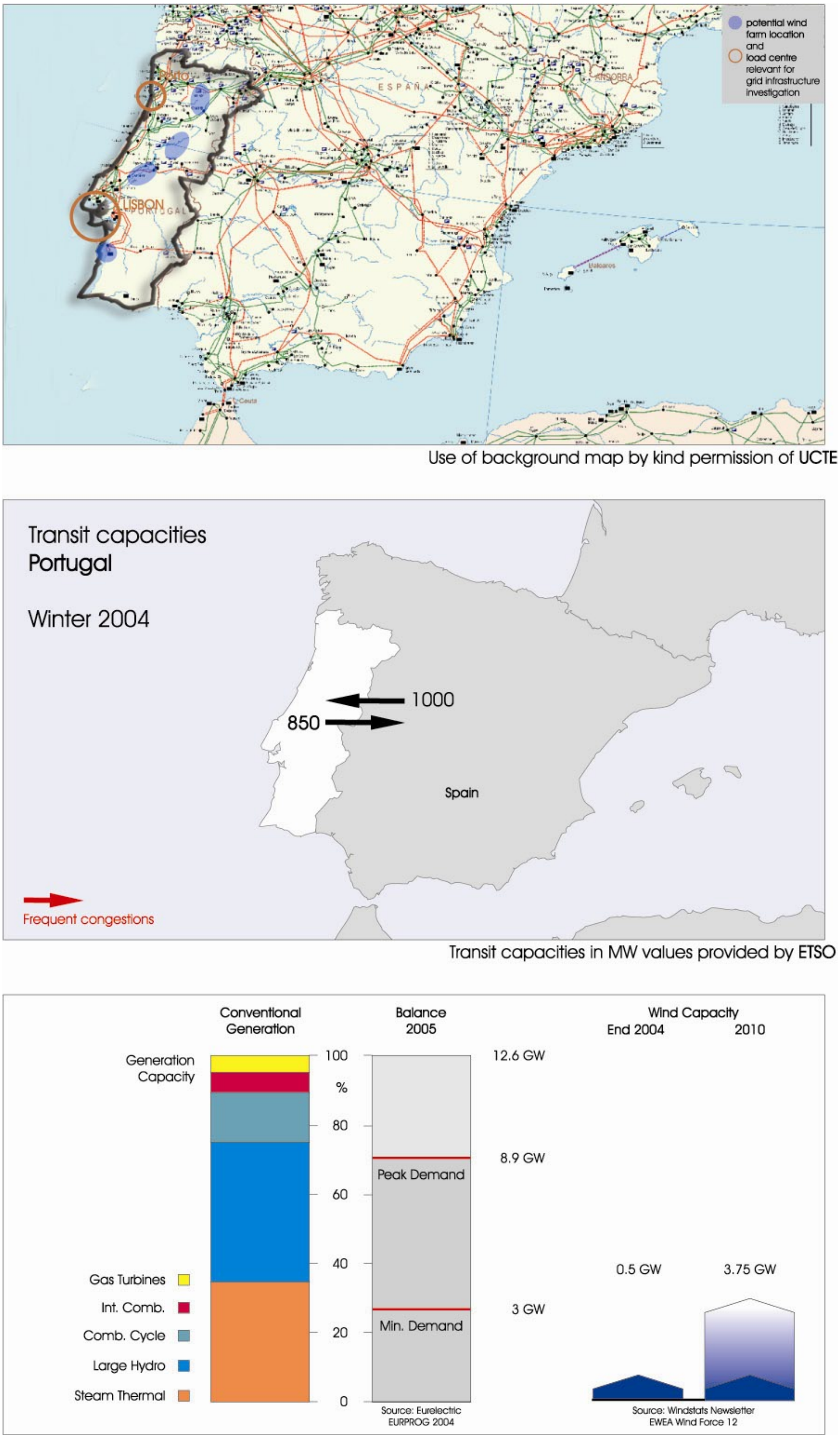


Figure 9-10: National characteristics of generation capacity, grids and power markets: Portugal

PORTUGAL

Wind power status and prospects

At the end of 2004 the installed wind power in Portugal was 522 MW. This is 4.5% of the net generation capacity in the country.

In 2010 the expected capacity will be approx. 3.75 GW of which 1710 MW in the North, 1820 MW in the Centre and 220 MW in the South. With this installed amount of wind power capacity, Portugal will be able to cover 12-15% of its electricity demand.

Electricity grids

The Portuguese transmission system is operated by the TSO Rede Eléctrica Nacional, S.A. It is part of the UCTE synchronous zone Spain & Portugal Block.

Infrastructure investments are planned to comply with the wind power and other power sources expansion plans.

Electricity generation and demand

The maximum net generating capacity in 2005 was 12.6 GW. The peak load was 8.7 GW, the minimum load around 2.95 GW. The net electricity generation was 45.4 TWh and the final consumption 43.2 TWh.

The Portuguese electricity supply is mainly thermal-based from hard coal, oil and natural gas. Portugal also generates a significant fraction from hydro power.

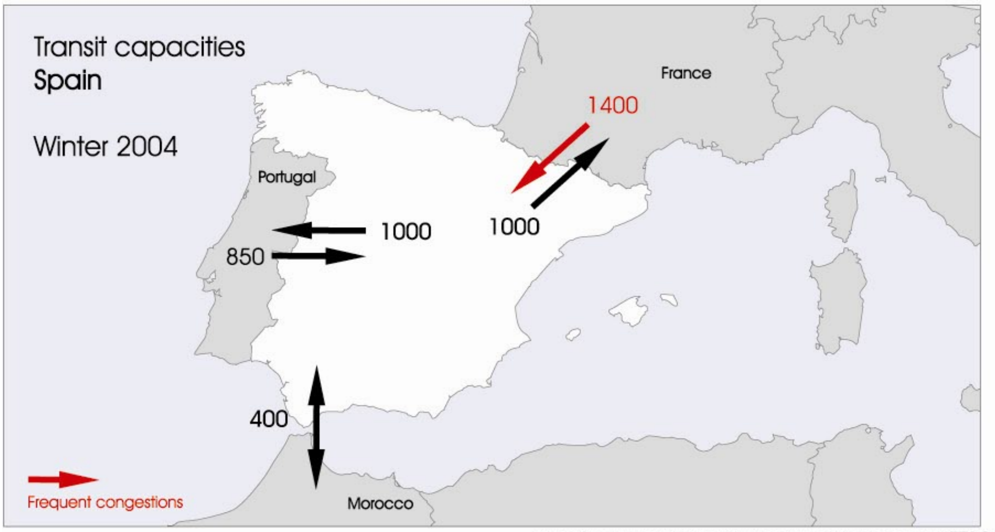
The Portuguese electricity grid is connected with Spain’s, the interconnection capacity is approximately 10 % of the demand. The annual amount of hydropower is .fluctuating and so is the balance between generation and demand. The relative amount of thermal generation has been increasing strongly in the past years7 (DOE).

Power market aspects

Network operators are obliged to purchase all electricity generated from wind farms. No payments for deviations from schedules are charged.

There are two electricity systems in Portugal, the Public and the Independent. The Public Electricity System (PES) is regulated to ensure a guaranteed power supply under long term contracts between power generators and transmission system operator Rede Eléctrica Nacional (REN) (the state 70% and EdP 30%). The Independent Electricity System (IES) includes a Non-binding Electricity System (NES) and the so-called Special Regime (SR). In NES, generation and distribution services are unrestricted and allow eligible consumers to choose their suppliers. In SR, power producers are small, generating power from mini-hydro (less than 10 MW), cogeneration, and other renewables. Erse, Portugal’s energy market regulator, oversees the these systems to ensure that operators abide with the PES and IES rules, as well as sets power tariffs (www.eia.doe.gov)

SPAIN



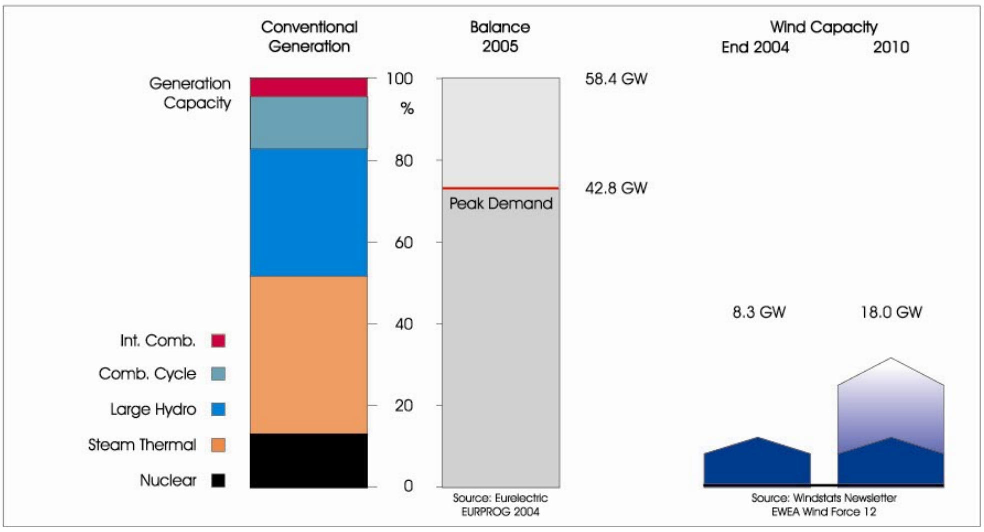


Figure 9-11: National characteristics of generation capacity, grids and power markets: Spain

SPAIN

Wind power status and prospects

At the end of 2004 the installed wind power in Spain was 8.26 GW. This is 12.0% of the net generation capacity in the country. The recently revised target for 2011 is now set at 20 GW.

Electricity grids

The national TSO in Spain is the company REE (Red Eléctrica de España S.A.). The grid is part of the synchronous zone UCTE, Spain & Portugal Block.

From January 2006 all wind farms are required to forecast their hourly supply for a 24-hour period, 30 hours in advance of the start of each day.

There are frequent congestions on imports from France, but no internal congestions on 400 kV level. However, 220 kV and distributions networks have to be reinforced to take up new generation and rapidly growing electricity demand.

In the regions with major wind power development reinforcement measures are planned involving approx. 250 km of new 230 kV lines, and over 1600 km of 400 kV lines.

Electricity generation and demand

The maximum net generating capacity in 2005 was 58.4 GW. The peak load was 42.8 GW. The net electricity generation was 252 TWh and the final consumption 220 TWh.

The Spanish electricity supply is mainly thermal-based (hard coal, oil and nuclear). Another significant fraction originates from hydro power.

Power market aspects

Network operators are forced to purchase electricity available from wind turbines as a priority. Wind farm operators have three options to sell wind power – a market option, a fixed tariff option and a transition one. In any option, they have to submit generation schedules based on short term forecasts. Producers have to schedule submission to the market operator at 10:00 day ahead (i.e. 14 – 38 hours before power delivery). Furthermore there are 6 intraday trading periods, which are followed by deviation markets

Imbalances from wind power schedules are charged at €7/MWh for producers who chose fixed tariff option, and €3.1/MWh for those with market option. The penalty is not being charged for the deviations up to 20% from the forecasted value.

Interconnection

Spain has in total 16 interconnectors with the neighbouring countries. The yearly volumes of import and export are quite variable, depending on the available hydro-power in winter. In the last years Spain was a net importer of electricity mainly from France, whereas it exports to Portugal, Morocco and Andorra. In 2004 however, the export to Portugal was that important that the total export exceeded the total imports.

UNITED KINGDOM

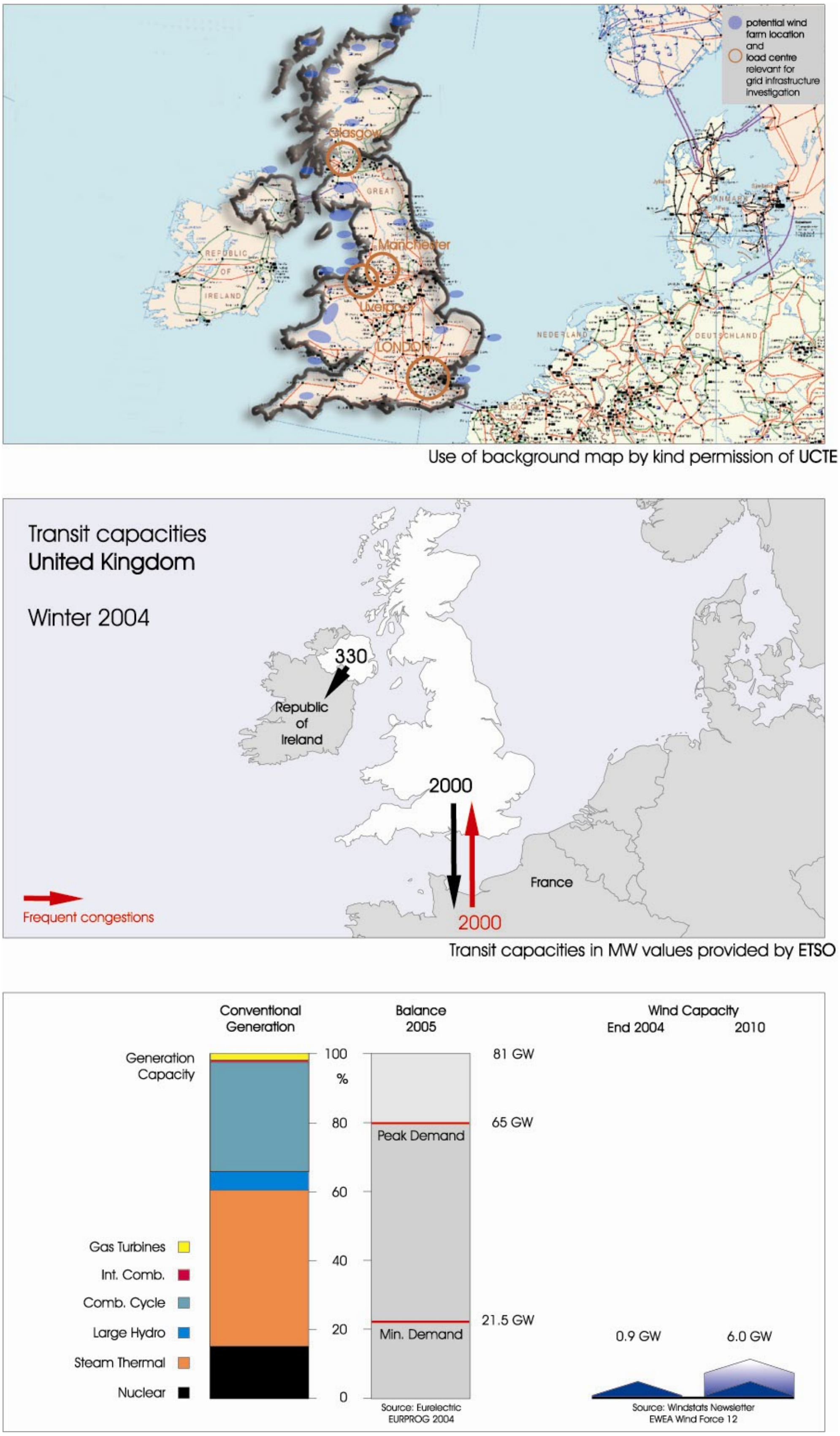


Figure 9-12: National characteristics of generation capacity, grids and power markets: UK

UNITED KINGDOM

Wind power status and prospects

At the end of 2004 the installed wind power in the UK was 888 MW. This is 1.1% of the net generation capacity in the country. It is likely to increase to 6-8 GW in 2010 and 15-26 GW in 2020.

Onshore developments are likely to occur almost anywhere within the UK, but are expected to be predominantly in Wales, south-western and northern England, and all of Scotland. Offshore developments are expected to be concentrated in three identified areas – in the east (Greater Wash, Thames estuary) and North-West (Irish Sea).

Electricity grids

From April 2005, the power system in GB is operated by National Grid Transco (NGT). NGT also own the system in England and Wales. The transmission networks in Scotland remain under the ownership of the Scottish Transmission companies (Scottish Power limited and Scottish Hydro Electric Transmission Ltd). The transmission system in Northern Ireland belongs to the Ireland synchronous zone and is operated by SONI.

The power system of England, Wales and Scotland (Great Britain or GB) is a separate synchronous system: the GB system. It is synchronously connected to the island of Ireland by a DC link (effectively 450 MW) and to the UCTE system (France) by a 2 GW DC link. The current interconnection capacity is 4% of maximum national demand. A third DC link of 1.32 GW is planned for 2009 to Holland from the south east, which will extend the capacity to 5.6 %.

Reinforcements are needed in Scotland, to the Scottish-English interconnector and in the North of England to accommodate the wind power potential. A critical transmission reinforcement in Scotland is the Beauly to Denny upgrade from 132 kV to 400 kV, over 200 km, without which the amount of generation that could be added in the north-west of Scotland (an area with high wind resource) is limited.

Electricity generation and demand

The maximum net generating capacity in the UK in 2005 was 81 GW. The peak load in the Great Britain power system (NGC area: Great Britain) was 70.1 GW, the minimum load 26 GW. The peak load in Northern Ireland (SONI area) was approximately 1.6 GW. The net electricity generation in the whole UK was 380 TWh and the final consumption 337 TWh.

The UK electricity supply is mainly thermal-based with generation from hard coal, natural gas and nuclear power.

Power market aspects

The British market is a fully-traded system administered through the British Electricity Trading and Transmission Arrangement (BETTA) which came into operation in 2005 to cover the whole GB electricity grid; replacing the New Electricity Trading Arrangements (NETA). Under BETTA, electricity is traded through bilateral contracts between generators, electricity suppliers and customers across a series of markets operating on a rolling half-hourly basis.

Both electricity suppliers and generators need to provide forecasts of their planned demand and generation respectively by ’gate closure time’ (1.5 hours ahead of real time). Up to and in real time, the TSO buys balancing services from generators and load customers in order to balance demand and supply.

Generators and suppliers are penalized for forecast errors. Any deviations from schedules are traded at balancing market prices. Small wind generators (less than 50 MW) are exposed to these costs through their power purchase agreements with suppliers/ retailers which are of lower value compared to other dispatchable generators. Larger wind generators (more that 100 MW) must operate within the bilateral market and pay penalties for non perfect forecasts (1 hour ahead).

Electricity is traded on a long-term, medium-term and short-term basis. The short term wholesale balancing market is administered by Elexon. Electricity is traded at half hourly intervals with a closure of trading one hour before the electricity is due to be delivered. Due to the high cost of trading most companies usually trade several hour blocks. For instance, NPower’s typical approach is to trade at three hourly intervals. The idea of this trading mechanism is to be able to balance the system by making up any shortfalls in predicted generation.

For the medium term and long term market electricity is traded as part of the UK power exchange. This is administered by the United Kingdom Power Exchange (UKPx). Trading can take place on spot, prompt and forwards market. The majority of electricity is traded in this manner.

- Spot market - This is effectively a day ahead market.
- Prompt - This is trades based on one week to one month
- Forwards - Trading based on six month to ten seasons market.

Most wind generation is traded as part of a mixed portfolio on reasonably long-term contracts. However for large wind farms in excess of 100MW electricity will have to be traded separately. This will be the case for some of the largest onshore wind farms and a number of the offshore wind farms. This will mean that accurate prediction will become extremely important in the future. Currently electricity from an intermittent source does incur a penalty of around 5% compared to guaranteed base-load figures for long term markets.

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Abbreviations

ADEME	L'agence de l'environnement et de la maîtrise de l'énergie (FrANCE9
BETTA	British Electricity Trading and Transmission Arrangement (UK)
BRP	Balance Responsible Party
BMU	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit / Federal Ministry for the Environment, Nature Conversation and Nuclear Safety (Germany)
Dena	Deutsche Energie-Agentur GmbH (German Energy Agency)
DSM	Demand-side management
DR	Demand response
EDF	Electricité de France
ESB	Electricity Supply Board (Republic. of Ireland)
ETSO	European Transmission System Operators
EWEA	European Wind Energy Association
GRTN	Gestore della Rete di Trasmissione Nazionale
HVDC	high-voltage, direct current electric power transmission systems
IEA	International Energy Agency
IES	Independent Electricity System
MAPE	Mean absolute percent prediction error
NES	Non-binding Electricity System
NETA	New Electricity Trading Arrangements (UK)
NGT	National Grid Transco (Great Britain)
NTC	Net Transfer Capacity
NORDEL	association for electricity co-operation in the Nordic countries
NRMSE	Normalized root mean square error
OECD	Organisation for Economic Cooperation and Development
REE	Red Eléctrica de España S.A.
PPC	Greece’s Public Power Corporation
PRPs	Programme Responsible Parties

RTE	Réseau de Transport d'Electricité (France)
SepCaMo	Spatial Extrapolation Calculation Model (Rohrig, ISET)
SR	Special Regime (Spain)
UCTE	Union for the Co-ordination of Transmission of Electricity
UKPx	United Kingdom Power Exchange
UMIST	University of Manchester Institute of Science and Technology
WMEP	Wissenschaftliches Mess- und Evaluierungsprogramm (Scientific Measurement and Evaluation Program), Germany 1989 - 2006

Table of symbols

u_1	wind speed in height h1
u_2	wind speed in height h2
z_0	roughness length
P_i	wind power in grid square i
Pj	measured wind power infeed of reference site j, scaled to rated power
k_i	correction factor
s_j	status of measurement equipment (0 := in error; 1 := ok)
a_{ij}	weighting factor, depending on distance
P_{NPFi}	installed wind capacity of grid square i
R_{ji}	roughness parameter
P_{wind}	wind power generation
x_i	power level (wind turbine capacity)
a_i	probability density (wind turbine capacity)
y_i	power level (conventional generation capacity)
b_i	probability density (conventional generation capacity)
P_{conv}	conventional power generation
P_{Syst}	conventional power generation plus wind farms
z_i	power level (conventional generation capacity plus wind turbine capacity)
c_i	probability density (conventional generation capacity plus wind turbine capacity)

$\tilde{P}_{Wind}$	Biased wind power generation values
$\tilde{P}_{Syst}$	Biased values of conventional power generation plus wind farms
$\tilde{c}_i$	Biased power level (conventional generation capacity plus wind turbine capacity)
$\tilde{z}_i$	Biased probability density (conventional generation capacity plus wind turbine capacity)

Glossary of Terms

Adequacy (CIGRE definition) : a measure of the ability of the power system to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking into account planned and unplanned outages of system components. Adequacy measures the capability of the power system to supply the load in all the steady states in which the power system may exist considering standards conditions [HULLE2005]

Balance energy: The difference between the amount agreed in the schedule and the actual purchase or supply of electric energy by a balance group per defined metering period, whereby the electric energy per metering period can be actually metered or calculated. [APCS2006]

Balance group The combination of suppliers and customers into a virtual group within which a balance between the electric energy procured (purchase schedules, feed-in) and supply (supply schedules, feed-out) of electric energy is carried out. [APCS2006]

Balance group coordinator: A natural or legal entity, who operates the “clearing and settlement center”, which organises and settles balance energy supply within a control zone on the basis of an official concession. [APCS2006]

Balance group member: Suppliers or customers who are included within a balance group with the purpose of achieving balance between the procurement and supply of electric energy.

Balance group responsible: An entity representing the balance group in dealings with market participants and the balance group coordinator. [APCS2006]

Capacity is the rated continuous load-carrying ability of generation, transmission, or other electrical equipment, expressed in megawatts (MW) for ACTIVE POWER or megavolt-amperes (MVA) for APPARENT POWER. [UCTE2004]

Capacity Factor (load factor) is the ratio between the average generated power in a given period and the installed (rated) power. [HULLE2005]

Clearing, financial: Settling of financial balances for each "clearing period" and "balance group" concerning balance energy effected by the clearing and settlement center, as well as the settling of balances over the whole settlement period per balance group and the issuing of statements for the individual "balance group responsibles". [APCS2006]

Clearing, technical: Balancing of the technical accounts for each balance group established in the clearing and settlement center. In this process, the time series allocated by the network operators to the respective balance group for each supplier or producer and any schedule values (commercial schedules) that have been exchanged between balance groups are taken into account. [APCS2006]

Gate Closure: The point in time when generation and demand schedules are notified to the system operator. [HULLE2005]

Load means an end-use device or customer that receives power from the electric system. LOAD should not be confused with DEMAND, which is the measure of power that a load receives or requires. LOAD is often wrongly used as a synonym for DEMAND. [UCTE2004]

Net Transfer Capacity: Maximum value of generation that can be wheeled through the interface between the two systems, which does not lead to network constraints in either system, respecting technical uncertainties on future network conditions [HULLE2005]

Schedule: Document that specifies what volume of electric power is fed in and withdrawn as a projected mean value within a constant time framework (metering periods) at particular network points. [APCS2006]