Assessing the Optimized Spatial Allocation of Wind Turbines in the German Electricity System

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Doctoral Thesis

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Flensburg, August 2016

For Lisa. In loving memory.

The sands of time were eroded by the river of constant change.
Genesis, Firth of Fifth

Executive Summary

Scope

In energy models a usual approach to simulate the electricity generation from wind power is to relate wind power capacity to measured wind speed time series and a power curve of wind turbine generators (WTGs). In recent work, emphasis has been increasingly put on the spatial distribution of wind power capacity in order to improve modeling results.

In this thesis a new approach to model the allocation of WTGs and their power output in future power systems is presented. A new model with a high spatial and temporal resolution has been developed in which the area potentially available for WTGs, space requirements of WTGs and development trajectories of the installed capacity are incorporated in an integrated approach. In the new model, wind power capacity is allocated to the next best locations available, on an annual basis, under consideration of the size development of WTGs and temporal interdependencies of the installed capacity. The approach can be regarded as a vintage model of the WTG stock. For the year of analysis the spatially distributed capacity is then used to model the electricity generation from wind power in a high temporal and spatial resolution.

In the context of this work the question was what is the impact of pre-defined area restrictions for wind power installations – given as percentages of the total federal state areas and of the district areas, respectively – on the allocation of the capacity, on its corresponding power production, on its levelized cost of electricity (LCOE) and on the residual load in a specific year of analysis.

With the newly developed model, possible development trajectories, i.e. scenarios, were calculated for the showcase of Germany. Although the focus was put on wind power, other variable renewable energies (VRE), namely photovoltaics and run-of-the-river hydro power, were also included in the considerations and it was analyzed how much of Germany's future electricity demand can be covered by power generation from those sources.

The scenarios were modeled in several variants. They did not only differ in the total capacity to be allocated but also in area restrictions defined for the allocation of wind power capacity and in the capacity allocation mode applied. Model calculations were conducted for the national and sub-national level – i.e. districts, federal states and transmission grid regions – in order to detect potential regional differences in power production, in the residual load and in transmission requirements. The modeling approach can be applied as an input to other research activities and the scenarios and scenario

variants modeled show how renewable energy sources can contribute to Germany's future power supply.

Methodology

In this thesis the newly developed model is presented. It consists of two main parts (cf. figure 0.1) that are run sequentially: the capacity allocation part and the electricity generation part. In the model, technical data (WTG size development, power curves), economical data (capital expenditures (CAPEX), operation expenditures (OPEX)), meteorological data (long-term mean wind speeds, wind speed time series), geographical data (areas potentially excluded from wind power use) and scenario data (installed capacity over time) are utilized as fixed inputs. Additionally, variable inputs such as the spacing of WTGs and additional area restrictions for wind power installations in the federal states and in the districts need to be defined.

In the model the area potentially available for wind power installations can be further restricted by additional variable model inputs that set a limit of the usable area at the federal state and at the district level. This model feature represents potential limitations set by political decision and it can substantially reduce the area potentially available for wind power installations. Intermediate model results are available for the district level and at the end of each model run results are aggregated for defined transmission grid regions and nationally.

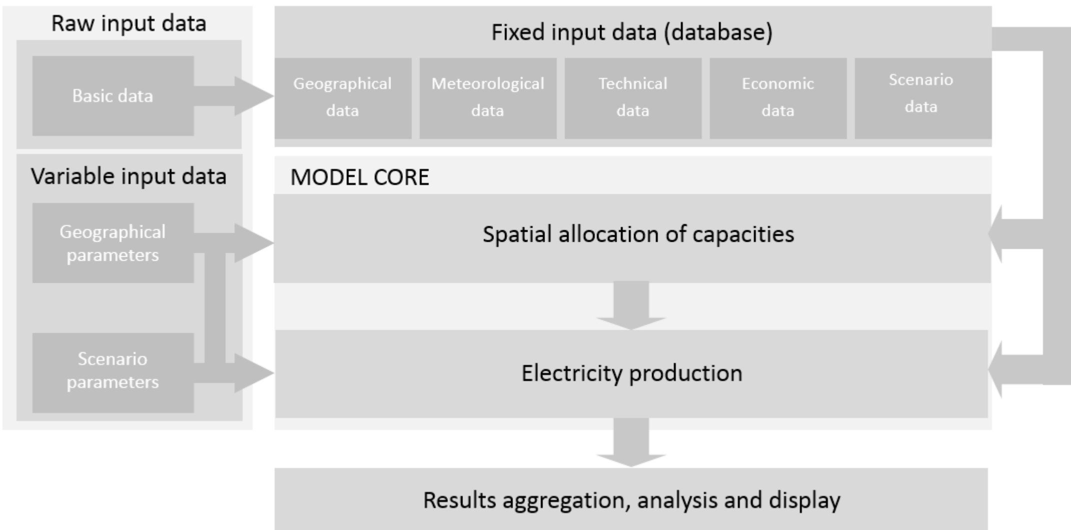


Figure 0.1: Basic flow chart of the new model

The model includes three important new features of wind power modeling. First, future wind power installations as defined in scenarios are allocated to the expectedly next best locations available, year by year in a sequential order until 2050. This approach generates an age structure of WTGs in all scenario years, i.e. also in the year of analysis. Second, in the model development trajectories of onshore wind power are considered not only at the national level but also at a sub-national level, i.e. in the showcase of Germany for the federal states. This again allows to detect potential differences between two capacity allocation modes incorporated in the model, meaning an allocation of wind power capacity envisaged at the sub-national level ("state-by-state allocation") and an allocation of the same total capacity amount installed without such sub-national installation targets ("nationwide allocation"). Third, in the model potential additional area restrictions for onshore WTGs can be taken into account, i.e. percentages of the federal state areas and of the district areas to be available for wind power installations at maximum. In the new model, these issues are simultaneously taken into account in an integrated approach.

In the first core part of the model the potentially available area in every federal state and district is either limited to the remaining areas as found in the geographical analysis or, if resulting in a lower value, to the maximum area percentages as defined as additional model inputs. The pre-defined wind power capacity from a selected scenario is allocated year by year, i.e. additional new capacity plus repowered capacity, on a square kilometer basis to available areas. Those locations with the highest expected EFLH (onshore) and lowest cost (offshore), respectively, are utilized first and marked as unavailable for the following twenty years. More capacity to be installed is then allocated to the next best locations and so on. Based on an assumed limited service life of WTGs, after twenty years a location is regarded to be available for new installations again.

The so-derived allocated capacity acts as the key input to the second core part of the model. In that model part, the capacity newly installed in the years prior to and in the year of analysis year is related to wind speed time series recorded at measuring stations that represent the wind speed conditions in the respective districts and combined with a multi-turbine power curve of a WTG and the respective hub height in the year of installation. The so-derived electricity production time series in all districts can also be spatially and temporally aggregated.

Besides wind power, the model includes a simplified simulation module of solar PV and run-of-the-river hydro power, based on historical and future installation figures and historical power production patterns, and the electricity load.

Table 0.1: Benchmark data of the scenarios modeled

Scenario no.	Scenario name	Target year	Capacity* onshore wind [GW]	Capacity* offshore wind [GW]	Capacity* PV [GW_p]	Capacity allocation mode
1	*Offshore wind leads*	2050	39.50	73.20	59.54	nationwide
2	*PV leads*	2050	54.27	35.50	79.03	nationwide
3	*The anticipated*	2035	82.40	17.52	60.70	nationwide
3	*The anticipated*	2035	82.40	17.52	60.70	state-by-state
4	*Beyond the anticipated*	2050	115.70	73.20	79.03	nationwide
4	*Beyond the anticipated*	2050	115.70	73.20	79.03	state-by-state

*) in the respective year of analysis

Results

With the new model the technical potential of onshore wind power without further area limitations was detected to range between 401 GW and 702 GW in Germany, depending on the assumed spacing of WTGs. For offshore wind power the technical potential was detected to range between 60 GW and 104 GW.

A restriction of the available area for wind power installations substantially reduced the technical potential. A narrow spacing of WTG assumed, an area restriction of 2 % of both the federal state areas and the district areas resulted in a potential of approx. 75 GW whereas a wider restriction of 5 % resulted in a potential of approx. 181 GW. The producible power was accordingly found in a broad range.

Four scenarios were calculated with the model, based on scenarios presented in relevant studies on Germany's future power system. Each scenario was modeled in several variants in which the area potentially available for wind power installations was altered. All scenarios were calculated assuming the capacity to be allocated to the expectedly next most preferable locations available throughout Germany. Additionally, in the scenarios 3 and 4 sub-national installation targets of the individual federal states were taken into account. In all scenarios an extreme case with no additional area restrictions for wind power installations was calculated first. Those variants resulted in the highest possible power production all the other scenario variants could be compared with. All scenarios covered the period until 2050, except for scenario 3 reaching until 2035.

The scenarios differed in the amount of installed capacity of onshore wind power, offshore wind power and PV (cf. table 0.1). Run-of-the-river hydro power was expected to reach 4.45 GW and remain constant until 2050. The capacity of onshore wind power ranged between 39.5 GW and 115.7 GW in 2050 in the scenarios modeled.

In summary the model results show the impact a restriction of the available area in the federal states and in the districts can have on the allocation of WTGs and therefore on their power output. The comparison with the respective scenario variant without additional area restrictions revealed the deviation from this optimum, caused by the additional area restrictions. The impact however was also dependent on the scenario, i.e. the total amount of capacity to be installed until the year of analysis, and on the capacity allocation mode.

Key results of the scenario calculations are:

- In all the scenarios modeled a range of produced electricity from onshore wind power was found, depending on the area restrictions set:
  - scenario 1: 67.5 – 82.5 TWh/a (2050)
  - scenario 2: 89.1 – 120.0 TWh/a (2050)
  - scenario 3 (nationwide allocation): 119.8 – 171.4 TWh/a (2035)
  - scenario 3 (state-by-state allocation): 105.6 – 147.1 TWh/a (2035)
  - scenario 4 (nationwide allocation): 187.9 – 233.4 TWh/a (2050)
  - scenario 4 (state-by-state allocation): 163.6 – 207.0 TWh/a (2050)
- The higher the area limitations were set, the fewer districts were affected by wind power installations and vice versa. An increase in potentially available area in every district and in every federal state resulted in a higher concentration of wind power capacity, i.e. the wind power capacity was allocated to fewer districts with a higher capacity density, in particular to locations mainly along the coastline in the North of Germany. Depending on the scenario and scenario variant, substantial regional differences were found. Not in all the scenario variants modeled, however, the full capacity could be allocated if area restrictions were set tight.
- In all cases, an increase in the potentially available area also resulted in an increase in power output because more favourable locations were available and utilized. This aspect however interacted with the amount of wind power capacity to be installed in the scenarios and the space requirements of the installed WTGs.
- The comparison of the results of the scenarios 1, 2 and 3 in which the onshore wind power capacity was allocated in the nationwide allocation mode shows that

the more capacity was installed, the stronger was the impact of the area restriction. With the same area restrictions, a larger deviation from the techno-economic optimum was found, the more onshore wind power capacity was installed.
Compared to that, the scenario variants of the scenarios 3 and 4 in which the allocation was conducted with the state-by-state allocation mode showed smaller deviations from their respective techno-economic optimum. These deviations, again, became even smaller the more area was potentially available for wind power installations.

- In all cases the deviation from the techno-economic optimum was reduced if the area limitation was increased because more locations with more favourable wind speed conditions became available.

- The wider the area limitations were set, the smaller the difference between the allocation modes was.

- The comparison of both allocation modes revealed that the state-specific installation targets partly substantially diverted from what a nationwide optimized allocation of the same total amount of capacity would suggest. In all variants of the scenarios 3 and 4, the installed capacity in the federal states of Bavaria, Saarland and Saxony was smaller in the case of a state-by-state allocation than in the case of a nationwide allocation, meaning that in those federal states the envisaged capacity was clearly below what an optimized nationwide allocation of the same total capacity amount would suggest. On the other hand, in the federal states of Brandenburg, Saxony-Anhalt (Sachsen-Anhalt) and Schleswig-Holstein the envisaged installed capacity in all scenario variants was larger than an optimized nationwide allocation of the same total capacity would suggest.
This aspect can also be found in the levelized cost of electricity (LCOE) that were increased by setting federal state-specific installation targets.

- The lowest LCOE of wind power was found in the scenario variant with the smallest installed wind power capacity (scenario 1), making use of the most favourable locations available.

- In the scenarios analyzed in which an additional restriction of the area available for wind power installations was taken into account, LCOE of onshore wind power in 2050 was found to range between 5.90 Ct./kWh and 7.51 Ct./kWh, depending on the installed capacity, the allocation mode and the restrictions defined.

- By tendency, an increase in the area availability for onshore wind power installations resulted in an increase in annual national gross electricity surpluses. The maximum gross power shortage, on the other hand, was practically unaffected by the area availability for onshore wind power installations while the annual gross shortage energy amount was marginally reduced the more area was available for wind power installations.

- In scenario 3, even under the assumption that the transmission capacity to neighbouring regions including the expected transmission grid extension according to the national planning would be available in 2035, it would not be sufficient for transmission grid region 1 (congruent with the area of Schleswig-Holstein) at all moments during the year under the assumptions made. This is mainly caused by the vast amounts of offshore wind power landed in that region in that scenario causing high power surpluses.
  A similar result was found in scenario 4. If the full amount of surplus power was to be transmitted from region 1 to neighbouring regions, a further expansion or enhancement of the transmission grid by more than 5 GW or other flexibility options in that region would be required unless power production was curtailed.

- Even though not the full amount of onshore wind power capacity could be allocated in all variants of scenario 4, the annual gross power production by VRE still exceeded the annual power demand, i.e. the net demand coverage was larger than 100 %.

At least 47.8 % of Germany's annual power demand in the scenarios modeled could be covered by production from VRE (scenario 3, 2035, nationwide allocation, area limitation of 2 %). In 2050 at least 58 % of the annual power demand could be covered by production from VRE (scenario 2, area limitation of 2 %). In all the other scenarios and scenario variants modeled focusing on 2050 higher VRE shares were detected. As onshore wind power was only part of the VRE mix in the respective years of analysis, the effect of an alteration of the area availability for onshore wind power installations was only partly found in the resulting figures of the power production from all VRE.

The relation of the produced electricity and the resulting LCOE of onshore wind power is illustrated in figure 0.2. The diagram shows the resulting electricity production and LCOE of onshore wind power in the different scenario variants modeled. In all cases a larger area availability resulted in an increased power production, thus lower specific cost. The results of the different allocation modes applied in scenario 3 and 4 converged, the more area was potentially available for wind power installations.

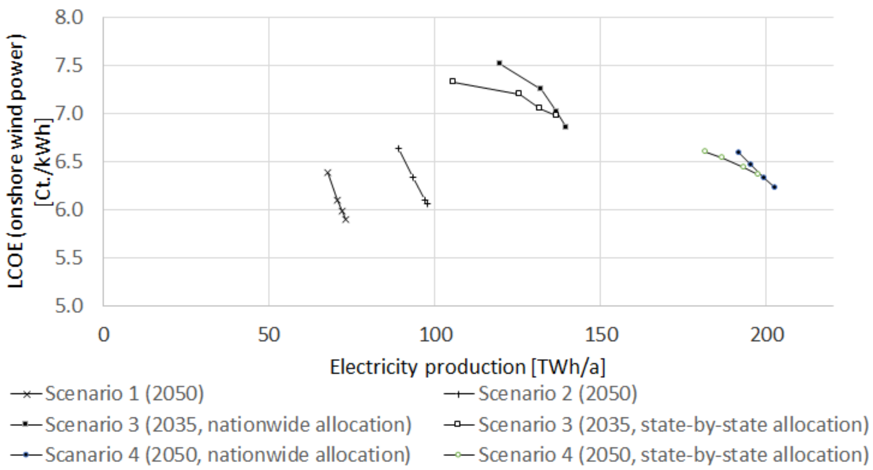


Figure 0.2: LCOE of onshore wind power as a function of the electricity production from onshore wind power in Germany (respective target years)

Conclusions

The model has been successfully tested and it has proven itself as a flexible, powerful and reasonable tool that allows to generate inputs to other energy system models as well as to conduct stand-alone analyses. Continuous model improvement as well as a calibration and adjustment have ensured to generate sound results. The model allows key input parameters such as national or sub-national installation targets, area limitations and space requirements of WTGs to be varied. The model might also be used for a comparison and, where applicable, improvement of other models or model modules.

The results of the scenarios modeled have shown that an economically optimized allocation of WTGs as defined in individual federal state targets deviates from a nationwide economically optimized allocation of the same total capacity. It was also found that area limitations at the federal state and the district level for potential wind power use can have a strong impact on the power production and on LCOE of wind power. That impact, however, also depends on the level of the wind power penetration in the system. It is therefore useful to incorporate such area restrictions also in other modeling activities.

It can be concluded that in order to achieve the envisaged long-term climate protection goals it will be useful to further increase the installed capacity of wind power in Germany. As shown in scenario 4, with the installed capacity in that scenario a full VRE supply could be reached in 2050 on condition that the demand level is low. In turn this means that framing conditions must ensure that such an envisaged development can be achieved. This can be the case, for instance, with a continued development of the legal framework and with political decision not only on appropriate installation targets but also on the flexibility options required in such a system.

As shown, the model can be applied for calculations on the German power system but also for other countries. This requires, however, modifications of the model scripts and input data that need to be country-specific and of the correct resolution and format.

Even with additional area restrictions taken into account, the potential of wind power in Germany is sufficient to install substantial amounts of capacity, however this means a substantial area requirement for wind power installations. The higher the level of public acceptance towards wind power installations is, the bigger the probability is to account for sufficiently large enough space for high numbers of WTGs. This is not only helpful to achieve a power supply fully based on RES in Germany but also keep LCOE of wind power and of all VRE low.

The scenarios calculated show that VRE can substantially contribute to Germany's electricity supply. Their share depends in particular on the installed VRE capacity, on their shares in the total installed capacity and on the demand level in the year of analysis. The scenarios modeled illustrate the capability of wind power in Germany's future energy system. The installed capacity of onshore and offshore wind power, PV and run-of-the-river hydro power presented in scenario 4 is capable to generate approx. 100 % of Germany's power demand in 2050 if a comparably low demand level can be reached.

Contents

List of Figures

List of Tables

Acronyms

ATC	Available transfer capacity
B	Berlin
BB	Brandenburg
BGBl.	Federal Law Gazette (Bundesgesetzblatt)
BMU	Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit)
BMUB	Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety (Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit)
BMVI	Federal Ministry of Transport and Digital Infrastructure (Bundesministerium für Verkehr und digitale Infrastruktur)
BMWi	Federal Ministry for Economic Affairs and Energy (Bundesministerium für Wirtschaft und Energie)
BNetzA	Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (Bundesnetzagentur)
BS	Baltic Sea
BSH	Federal Maritime and Hydrographic Agency of Germany (Bundesamt für Seeschifffahrt und Hydrographie)
BW	Baden-Württemberg
BY	Bavaria (Bayern)
BWE	German Wind Energy Association (Bundesverband WindEnergie e.V.)
CAES	Compressed air energy storage
CAPEX	Capital expenditures
CCS	Carbon capture and storage

CF	Capacity factor
COP21	21st Conference of the Parties to the United Nations Framework Convention on Climate Change
COSMO-CLM	COnsortium for Small-scale MOdelling in CLimate
CPU	Central processing unit
CRF	Capital recovery factor
Ct.	Euro cent
dena	German Energy Agency (Deutsche Energie-Agentur GmbH)
DEWI	Deutsches Windenergie-Institut (DEWI UL International GmbH)
DLR	German Aerospace Center (Deutsches Zentrum für Luft- und Raumfahrt e.V.)
DWD	Germany's National Meteorological Service (Deutscher Wetterdienst)
EEG	Renewable Energy Sources Act (Gesetz zum Vorrang der Einspeisung aus erneuerbaren Energien, Erneuerbare-Energien-Gesetz)
EEX	European Energy Exchange AG
EEZ	Exclusive Economic Zone
EFLH	Equivalent full load hours
EnLAG	Energy Line Extension Act (Gesetz zum Ausbau von Energieleitungen, Energieleitungsausbaugesetz)
EnWG	Energy Law (Gesetz über die Energie- und Gasversorgung, Energiewirtschaftsgesetz)
ESRI	Environmental Systems Research Institute, Inc.
EU	European Union
EUF	Europa-Universität Flensburg

FfE	Forschungsstelle für Energiewirtschaft e.V.
FFH	Habitat for flora and fauna
FINO	Research platforms in the North Sea and Baltic Sea (Forschungsplattformen in Nord- und Ostsee)
Fraunhofer ISE	Fraunhofer Institute for Solar Energy Systems (Fraunhofer-Institut für Solare Energiesysteme)
Fraunhofer ISI	Fraunhofer Institute for Systems and Innovation Research (Fraunhofer-Institut für System- und Innovationsforschung)
Fraunhofer IWES	Fraunhofer Institute for Wind Energy and Energy System Technology (Fraunhofer-Institut für Windenergie und Energiesystemtechnik)
FStrG	Federal Highways Act (Bundesfernstraßengesetz)
GHG	Greenhouse gas
GIS	Geographic Information System
GL	Germanischer Lloyd WindEnergie GmbH
HB	Bremen
HE	Hesse (Hessen)
HEI	Dithmarschen
HH	Hamburg
HVAC	High voltage alternating current
HVDC	High voltage direct current
IBA	Important Bird and Biodiversity Area
IPCC	Intergovernmental Panel on Climate Change
K	Thousand
LFC	Levelized fixed cost
LCOE	Levelized cost of electricity

LVC	Levelized variable cost
M	Million
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, Version 2
MRO	Maintenance, repair and operations
MVP	Mecklenburg West-Pomerania (Mecklenburg-Vorpommern)
NASA	National Aeronautics and Space Administration
NDS	Lower Saxony (Niedersachsen)
NEP	Grid Development Plan (Netzentwicklungsplan)
NF	North Frisia (Nordfriesland)
No.	Number
NS	North Sea
NRW	Northrhine-Westphalia (Nordrhein-Westfalen)
NTC	Net transfer capacity
O&M	Operation and maintenance
OPEX	Operation expenditures
PHP	Hypertext preprocessor
ppm	Parts per million
PR	Performance ratio
PV	Photovoltaics
REMix	Sustainable Energy Mix for Europe
REMod–D	Regenerative Energien Modell – Deutschland
renpass	Renewable Energy Pathways Simulation System
RES	Renewable energy sources

ROV	Spatial Planning Act (Verordnung über die Raumordnung)
RP	Rhineland-Palatinate (Rheinland-Pfalz)
SeeAufgG	Federal Maritime Responsibilities Act (Gesetz über die Aufgaben des Bundes auf dem Gebiet der Seeschifffahrt, Seeaufgabengesetz)
SH	Schleswig-Holstein
SL	Saarland
SN	Saxony (Sachsen)
SQL	Structured Query Language
SRU	German Advisory Council on the Environment (Sachverständigenrat für Umweltfragen)
ST	Saxony-Anhalt (Sachsen-Anhalt)
STCs	Standard test conditions
TH	Thuringia (Thüringen)
TSO	Transmission system operator
UBA	Federal Environment Agency (Umweltbundesamt)
VRE	Variable renewable energies
WEsER	Wind Energy substitutes conventional Electricity Resources
WiSTl	Wind-Szenario-Tool
WS	Weather station
WTG	Wind turbine generator

1 Introduction and research scope

The latest Assessment Reports of the Intergovernmental Panel on Climate Change (IPCC) have clearly shown the anthropogenic impact on the global climate. Since the beginning of the industrialization in the late 18th century, the CO_2 concentration in the Earth's atmosphere has substantially increased from approx. 280 to 390 ppm (Intergovernmental Panel on Climate Change (IPCC), 2013, pp. 166–167). The combustion of fossil fuels – coal, lignite, oil and natural gas – has been responsible for additional CO_2 emissions to the atmosphere exceeding the natural carbon cycle, which has led to an increase in the atmospheric CO_2 concentration (ibid., pp. 474–475). CO_2 is in the centre of the scientific and political discussion due to its high greenhouse potential (ibid., p. 661) and the strong increase in its atmospheric concentration.

The increase in the atmospheric CO_2 concentration has led to an increase in the global average temperature by 1.2° in the 20th century alone (cf. Intergovernmental Panel on Climate Change (IPCC), 2013, pp. 187–201). A global temperature rise has already had and will increasingly have tremendous effects on nature and on human society (cf. Intergovernmental Panel on Climate Change (IPCC), 2014a). Negative impacts in the global perspective are, for instance, irreversible damages (e.g. the melting of the Greenland ice shield), damages from an increasing number of extreme weather situations (e.g. floods and dry seasons), effects on biodiversity (e.g. disappearance of species, invasive species, parasites), and social and financial impacts (e.g. people starving and dying from hunger, conflicts due to water scarcity, refugees) (ibid., pp. 21). Moreover, the adaptation to climate change will cause direct cost (e.g. for building deichs for flood protection) and induced or indirect cost (e.g. due to downtimes of production facilities caused by weather extremes, additional or higher insurance premiums or reparation cost due to storm damages) (ibid., pp. 559 and 962).

Projections have shown that a future increase in the global temperature can be limited if far less CO_2 is emitted in the next years and decades (Intergovernmental Panel on Climate Change (IPCC) (2013, pp. 1106)). This does not necessarily mean an instant stop of emitting CO_2 in the global perspective but the aim is to specify emissions reduction targets for specific years in the future as a mitigation measure in order to avoid the most severe consequences from climate change. The so-called "2-degree target" can be regarded as the best known and accepted long-term goal. Until 2050, the global CO_2 emissions are to be reduced by 50 % relative to the 1990 level in order to limit the global temperature increase to 2° above the average temperature prior to industrialization. At the 21st Conference of the Parties to the United Nations

Framework Convention on Climate Change (COP21) in Paris in December 2015 it was agreed to pursue "efforts to limit the temperature increase to 1.5 °C above pre-industrial levels" (United Nations Framework Convention on Climate Change (UNFCCC), 2016, "Paris Agreement", Article 2, p. 22). For most industrialized countries a limit of the temperature increase to 2° or even 1.5° translates into a necessary reduction by $80 - 95$ % (Intergovernmental Panel on Climate Change (IPCC), 2007, p. 776) until 2050 (principle of "common but differentiated responsibility", cf. Intergovernmental Panel on Climate Change (IPCC) (2014b, p. 102)).

Long-term targets of the reduction of greenhouse gas (GHG) emissions have been scientifically recommended and aimed at on the multinational level (cf. Intergovernmental Panel on Climate Change (IPCC), 2014a), on the European level (cf. European Commission (EC), 2011) and on the national level (e.g. for Germany: cf. §1 EEG, Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (BMUB) (2015b, pp. 17)).

Additionally, intermediate emissions reduction targets have been defined for the decades until 2050. Usually emissions reduction targets are accompanied by targets aiming at the improvement of energy efficiency and targets for an increased use of renewable energy sources (RES) (cf. Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (BMUB), 2015b, p. 18).

Some sectors and industries will not be capable to substantially reduce their GHG emissions (cf. Sachverständigenrat für Umweltfragen (SRU), 2011, p. 329). For instance, in the concrete and in the carbon steel industry, CO_2 emissions origin directly from production and conversion processes (cf. Gandy (2007), European Commission (EC) (2016)) and cannot be avoided unless production would be fundamentally reduced. Other sectors, on the other hand, will be capable to reduce their GHG emissions even further than by the targeted 95 %. Such sectors therefore will have to compensate for others that cannot reach their emissions reduction targets, i.e. their CO_2 emissions will have to fall virtually to zero or even below zero (cf. Sachverständigenrat für Umweltfragen (SRU), 2011, p. 329). One of these sectors is the power sector (ibid.).

Nuclear power is no option to reduce the power sector's emissions. Even though there are no CO_2 emissions during power production in nuclear power plants, during the life cycle of a nuclear power plant GHGs however are induced (cf. Sovacool (2008)). Moreover, the question on the disposal of nuclear waste has not yet been answered and the risk of accidents is high (cf. Sachverständigenrat für Umweltfragen (SRU), 2011, pp. 51).

The technical option of capturing carbon from the atmosphere or directly from flue gas emissions of coal-fired power plants and store it below ground (carbon capture and storage (CCS)) currently is in the testing phase. CCS's role in future power systems is subject of discussion, however so are its sustainability criteria (cf. Sachverständigenrat für Umweltfragen (SRU), 2011, pp. 50). The SRU concluded that CCS for coal-fired power plants should be waived (ibid.).

The only way to substantially reduce CO_2 emissions from the power sector is a transition towards a system fully based on RES. The Intergovernmental Panel on Climate Change (IPCC) (2011, p. 164) described renewable energies as "any form of energy from solar, geophysical or biological sources that is replenished by natural processes at a rate that equals or exceeds its rate of use".

On the European level, the European Union (EU) agreed on increasing the share of RES in the power sector, the heating sector and the transportation sector until 2030 to at least 27 %. Until 2030, the EU's CO_2 emissions are to be reduced by 40 % compared to 1990 (cf. European Commission (EC), 2011). On the national level, the German federal goverment is striving to reduce GHG emissions by at least 40 % until 2020 and by 80 – 95 % until 2050 (cf. §1 EEG, Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (BMUB) (2015b, pp. 17)). In Germany, the power sector is responsible for about one third of the national CO_2 emissions (Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (BMUB), 2015a) due to the combustion of fossil fuels. The Renewable Energy Sources Act (Gesetz zum Vorrang der Einspeisung aus erneuerbaren Energien, Erneuerbare-Energien-Gesetz) (EEG), introduced in 2001, has established a successful framework that has built sound economic conditions for the installation of RES capacity in Germany.

The transition towards a power supply based on RES raises several questions. In this thesis, one aspect of the complex system transition is analyzed in further detail. The first section includes the author's motivation to work on the topic, a short description of Germany's power system, an overview over energy models and studies on the German power system and, deduced from that, the research questions to be answered in this thesis.

1.1 Outline of the thesis

The thesis has four main parts. First, the problem is introduced, the research questions are presented and the contribution of the thesis is described (section 1.2). Second, the applied methodology is presented, in particular the newly developed model is introduced (section 2). Third, the analysis of different scenarios with the model developed is presented and the research questions are answered (section 3). And fourth, conclusions are drawn (section 4).

1.2 Motivation and problem statement

A high penetration of power generation from RES in the German energy system will have great multidimensional impacts, for instance technically, ecologically, economically and socially. Within the framework of the development of the Renewable Energy Pathways Simulation System (renpass) model (cf. Wiese (2014), Wiese (2015), Bökenkamp (2015)) at the Europa-Universität Flensburg (EUF) the aim was to develop a computer-based model that could generate highly temporally and spatially resolved future production time series from wind power installations in Germany. The newly developed model is central part of this thesis.

In early model versions wind power was incorporated in the renpass model in a simplified approach. Exogenously defined installed wind power capacity was allocated to the regions in the model based on educated guesses, at further stages of the model a wind power capacity allocation was based on allocation algorithms (cf. Christ et al. (2015)). In combination with a wind turbine generator's power curve and representing wind speed time series, the electricity production from wind power could be modeled. An optimized allocation of wind power capacity over time has not yet been incorporated in the model.

Such an approach would have an impact on the utilization of the available area as well as on the power production because sizes of wind turbine generators (WTGs), i.e. their hub heights, can be expected to further increase in the future. The aim now was to develop a more detailed model of an optimized allocation of WTGs in order to improve model results.

The newly developed model can deliver inputs to the renpass model, for instance, but it also can be run independently from the renpass model or other models. It was developed to compute long-term installation pathways of variable renewable energy (VRE) capacity in Germany simultaneously in consideration of a high spatial and temporal resolution. The long-term timeframe was defined to range until 2050, the temporal resolution of modeled production data was defined to be 15 minutes in the year of analysis. The main focus was set on wind power but other supply-dependent, intermittent renewables (photovoltaics (PV) and run-of-the-river hydro power) – i.e. VRE – have been included in the model, too. Additionally, further aspects such as a limitation of area potentially available for wind power installations and its impact on model outputs were to be analyzed. As a result, with the new model levelized cost of electricity (LCOE) and the residual load in different scenario settings and scenario variants can be calculated, analyzed and compared.

For several reasons Germany was selected as a showcase for the calculation of scenario results with the new model. With its history in the use of wind power already for decades, wind power does not only already play an important role in Germany's electrical power generation but it is also faced with new challenges. For instance, minimum distances between WTGs and settlements has been regular subject of discussion. With its current and future installation, large areas are and will be used for WTGs, thus the visibility of wind power installations potentially will be increasing, being one reason for potential resistance against further wind power installations. On the other hand wind power plays a key role in Germany's transition towards an energy supply fully based on RES. Nuclear power will be phasing out by 2022 (cf. section 1.3) and the increase in the share of RES in the German electricity mix has already caused conventional power plants to operate increasingly less economic (cf. Bontrup & Marquardt (2015)) and can be expected to do so in the future. Wind power as well as PV will be key substitutes for conventional power generation. Therefore a balance needs to be found in particular for wind power installations between the necessity to be built for climate protection reasons on the one side and potential public resistance by people potentially affected by such installations on the other side. If this can be presented for a major economy such as Germany, the showcase can act as a role model for other countries, too.

1.3 Germany's electricity system

Before the modeling approach and modeling results are presented, Germany's electricity system is briefly introduced in order to classify the model approach, its inputs and its outputs.

In 2014, the annual gross electricity production in Germany was 627 TWh/a (cf. AG Energiebilanzen e.V. (AGEB) (2016)), ranging between around 40 GW and 90 GW during the year (cf. European Network of Transmission System Operators for Electricity (ENTSO-E) (2013a)). Renewable energy sources (onshore and offshore wind power, PV, run-of-the-river hydro power, liquid and gaseous biomass and geothermal energy) contributed 25.9 % (163 TWh/a) to that value. Although the share of RES has steadily increased in the past decades, conventional power production based on fossil and nuclear fuels were still dominating Germany's power production, accounting for nearly 70 % of Germany's power production in 2014 (lignite: 24.8 %, hard coal: 18.9 %, nuclear power: 15.5 %, natural gas: 9.7 % (all figures: AG Energiebilanzen e.V. (AGEB) (2016)).

In Germany's power system, a total production capacity of 188 GW was installed (Bundesministerium für Wirtschaft und Energie (BMWi) (2014)). The amount of RES capacity has substantially increased since the early 1990's, mainly supported by the EEG law. At the end of 2014, 93 GW of RES capacity were installed in Germany (onshore wind power: 38 GW, offshore wind power: 2 GW, PV: 38 GW_p, biomass: 9 GW, hydro power: 6 GW, and geothermal energy: 24 MW), i.e. approx. half of the total installed capacity.

A lifetime of conventional power plants of 30 to 45 years assumed, several of these will reach the end of their expected service life within the decades to come (cf. (Sachverständigenrat für Umweltfragen (SRU), 2011, p. 133ff)). Moreover, until 2022 all German nuclear power plants will be decommissioned on the basis of the so-called phasing out nuclear energy (Atomausstieg) as defined in §7 of the German Atomic Energy Act (Gesetz über die friedliche Verwendung der Kernenergie und den Schutz gegen ihre Gefahren, Atomgesetz). Due to existing overcapacity in the German power system, a decommissioning of production units does not necessarily mean a reduction of the security of supply.

In the long run, however, it will be necessary to further promote other technical options of power generation such as additional RES capacity that also needs to be supplemented by an appropriate transmission grid, storage options, dispatchable generation and dynamic load response.

Germany has set specific targets for its expansion of RES. In 2025, 40 – 45 % of its electricity demand are to be produced by RES, in 2035 a share of 55 – 60 % is aimed at and for 2050 at least 80 % (cf. §1 EEG and Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (BMUB) (2015b, p. 18)). As presented, in order to reach an 80 – 95 % reduction of GHG emissions compared to the level of 1990, it might be necessary to fully convert Germany's power generation towards RES until 2050. Research has shown that this is technically possible and economically feasible (cf. Sachverständigenrat für Umweltfragen (SRU) (2011)).

Driven by the increase in power production from renewable energy sources and the expected decommissioning of conventional power generation units, Germany's power transmission grid will undergo several changes within the next years and decades, too. The Grid Development Plan (Netzentwicklungsplan) (NEP) (50 Hertz Transmission GmbH et al. (2014a)), developed on the basis §12b of the Energy Law (Gesetz über die Energie- und Gasversorgung, Energiewirtschaftsgesetz) (EnWG), has provided a framework of approved and planned transmission lines, taking the anticipated future development of RES expansion into account. It has included vertical and horizontal enhancements of existing grid connections, additional power lines (AC as well as HVDC links) and additional interconnectors to neighbouring countries.

1.4 Energy models and studies

In the complex transition towards the goal of achieving a power supply fully based on RES, several issues need to be addressed, for instance on future support schemes, market mechanisms, infrastructural matters (e.g. power transmission and energy storage), and technical challenges (e.g. system services). Computer-based optimization and simulation models help find answers to such questions. A great number of energy models is available and such models have been applied for a number of research projects and studies.

Energy models – in other sources and in the following also referred to as energy "tools" – depict the electric power system or the entire energy system. In the latter case, other sectors than only the power sector are included in the models, for instance the heat sector or the transportation sector. Due to the complexity of the topic a multitude of energy system models exists. A meta-study published by Connolly et al. (2010) (updated in Connolly (2012)), for instance, listed 68 energy tools. In the study, energy tools were categorized into 7 classes: simulation tools, scenario tools, equilibrium tools, top-down tools, bottom-up tools, operation optimization tools, and investment optimization tools. Sometimes energy models have been categorized slightly differently (cf. Mai et al. (2013, pp. 20) and Pfenninger et al. (2014)).

Besides and depending on the methodological approach, energy models differ in terms of

- the system examined
  (ranging from individual power plants to the global perspective),
- the energy sectors examined
  (e.g. the power sector only, RES only, or the entire energy system including the heat and transportation sectors),
- the timeframe
  (ranging from seconds to several decades),
- temporal resolution
  (i.e. time-steps, ranging from milliseconds to years and decades),
- the spatial resolution
  (ranging from square kilometers to entire countries and continents), and

- the specific research scope and objective
  (e.g. analysis of power plant operation, transmission grid requirements or a full power supply by RES).

An overview over selected energy models and their main characteristics is shown in the table in figure 1.1. Huge differences in the model approach, the region covered, the model resolution and other parameters could be found. Also depending on the individual model approach and scope, the models differed in their level of detail and in their underlying data. Moreover, several of the models used for energy system analyses were proprietary, i.e. their procedures or input data are not transparent or publicly available.

In energy tools that can model the future electricity system, wind power usually is incorporated (cf. Intergovernmental Panel on Climate Change (IPCC) (2011, p. 562)). Depending on the modeling objective and the model approach, again, wind power is modeled with different levels of detail. In models with a high temporal resolution a common approach is to relate figures of an installed wind power capacity to meteorological data (i.e. wind speed time series) in order to generate electricity production time series for a specific year of analysis.

Several models have been developed by German research institutes and applied for studies on Germany's future energy system. A selection of most relevant models of the German power sector and of their main characteristics is presented in the following list:

- Renewable Energy Pathways Simulation System (renpass) and its derivatives by Europa-Universität Flensburg (EUF)
  - model approach: RES simulation, optimization of dispatchable units
  - allocation of wind power capacity: by educated guess and in its latest application in consideration of socio-demographic factors at district level
  - temporal resolution: variable (e.g. 15 minutes)
  - time horizon: variable (e.g. 2050)
  - spatial resolution: districts, transmission grid regions, national
  - documented/applied e.g. in Wiese (2014), Wiese (2015), Bökenkamp (2015), Christ et al. (2015)
- Sustainable Energy Mix for Europe (REMix) by German Aerospace Center (Deutsches Zentrum für Luft- und Raumfahrt e.V.) (DLR)
  - model approach: full-cost optimization

Tool	Geographical area	Scenario timeframe	Time-step
			1. National energy-system tools
			1.1. Time-step simulation tools
Mesap PlaNet	National/state/regional	No limit	Any
TRNSYS16	Local/community	Multiple years	Seconds
HOMER	Local/community	1 year[a]	Minutes
SimREN	National/state/regional	No limit	Minutes
EnergyPLAN	National/state/regional	1 year[a]	Hourly
SIVAEL	National/state/regional	1 year[a]	Hourly
STREAM	National/state/regional	1 year[a]	Hourly
WILMAR Planning Tool	International	1 year[a]	Hourly
RAMSES	International	30 years	Hourly
BALMOREL	International	Max 50 years	Hourly
GTMax	National/state/regional	No limit	Hourly
H2RES	Island	No limit	Hourly
MARKAL/TIMES	National/state/regional	Max 50 years	Hourly, daily, monthly using user-defined time slices
			1.2. Sample periods within a year
PERSEUS	International	Max 50 years	Based on typical days with 36–72 slots for 1 year
UniSyD3.0	National/state/regional	Max 50 years	Bi-weekly
RETScreen	User-defined	Max 50 years	monthly
			1.3. Scenario tools
E4cast	National/state/regional	Max 50 years	Yearly
EMINENT	National/state/regional	1 year[a]	None/yearly
IKARUS	National/state/regional	Max 50 years	Yearly
PRIMES	National/state/regional	Max 50 years	Years
INFORSE	National/state/regional	50+ years	Yearly
ENPEP-BALANCE	National/state/regional	75 years	Yearly
LEAP	National/state/regional	No limit	Yearly
MESSAGE	Global	50+ years	5 years
MiniCAM	Global and regional	50+ years	15 years
			2. Tools with a specific focus
			2.1. Time-step simulation tools
AEOLIUS	National/state/regional	1 year[a]	Minutes
HYDROGEMS	Single-project investigation	1 year[a]	Minutes
energyPRO	Single-project investigation	Max 40 years	Minutes
BCHP Screening Tool	Single-project investigation	1 year[a]	Hourly
ORCED	National/state/regional	1 year[a]	Hourly
EMCAS	National/state/regional	No limit	Hourly
ProdRisk	National/state/regional	Multiple years	Hourly
COMPOSE	Single-project investigation	No limit	Hourly
			2.2. Sample periods within a year
EMPS	International	25 years	Weekly (with a load duration curve representing fluctuations within the week)
WASP	National/state/regional	Max 50 years	12 load duration curves for a year
			2.3. Scenario tools
Invert	National/state/regional	Max 50 years	Yearly
NEMS	National/state/regional	Max 50 years	Yearly

[a] Tools can only simulate 1 year at a time, but these can be combined to create a scenario of multiple years.

Figure 1.1: Selected energy models and their main characteristics

Excerpt from Connolly et al. (2010, p. 1064)

  - allocation of wind power capacity: according to least-cost in the year of analysis (in the following also referred to as the "target year"), wind power part of the optimized capacity mix in the target year
  - temporal resolution: 1 h
  - time horizon: variable (e.g. 2050)
  - spatial resolution: 7 km · 7 km cells. Results: national
  - documented/applied e.g. in Scholz (2010), Sachverständigenrat für Umweltfragen (SRU) (2011)

- SimEE by Fraunhofer Institute for Wind Energy and Energy System Technology (Fraunhofer-Institut für Windenergie und Energiesystemtechnik) (Fraunhofer IWES)
  - model approach: RES simulation, optimization of dispatchable units
  - allocation of wind power capacity: educated guess
  - temporal resolution: 15 minutes
  - time horizon: 2050
  - spatial resolution: 14 km · 14 km cells. Results: national
  - documented/applied in Saint-Drenan et al. (2009), Bundesverband Erneuerbare Energien e.V. (BEE) & Agentur für Erneuerbare Energien e.V. (AEE) (2009), Klaus et al. (2010)

- Plattform Virtuelles Stromversorgungssystem by Fraunhofer Institute for Wind Energy and Energy System Technology (Fraunhofer-Institut für Windenergie und Energiesystemtechnik) (Fraunhofer IWES)
  - model approach: cost-optimized plant deployment
  - allocation of wind power: not specified
  - temporal resolution: 1 h
  - time horizon: 2050 and beyond
  - spatial resolution: 10 km · 10 km cells. Results: national
  - documented/applied e.g. in Nitsch et al. (2012)

- Regenerative Energien Modell – Deutschland (REMod–D) by Fraunhofer Institute for Solar Energy Systems (Fraunhofer-Institut für Solare Energiesysteme) (Fraunhofer ISE)

  - model approach: full cost optimization
  - allocation of wind power: not specified. Wind power part of the optimized capacity mix in the target year.
  - temporal resolution: 1 h
  - time horizon: 2050
  - spatial resolution: Germany
  - documented/applied e.g. in Henning & Palzer (2013), Henning (2014)

- E25 Invest by Fraunhofer Institute for Solar Energy Systems (Fraunhofer-Institut für Solare Energiesysteme) (Fraunhofer ISE)
  - model approach: explorative investment decision model
  - allocation of wind power: based on economic, political and technical framing conditions.
  - temporal resolution: years
  - time horizon: 2050
  - spatial resolution: districts
  - documented/applied e.g. in Kost et al. (2013)

- ISI-Wind and PowerACE by Fraunhofer Institute for Systems and Innovation Research (Fraunhofer-Institut für System- und Innovationsforschung) (Fraunhofer ISI)
  - model approach: system simulation and optimization. Wind power (physical model) one out of several input parameters.
  - allocation of wind power: not specified
  - temporal resolution: 1 h
  - time horizon: 2050
  - spatial resolution: national, wind power: based on approx. 180 measuring stations
  - documented/applied e.g. in Sensfuß et al. (2003), Klobasa & Erge (2009), Klobasa & Sensfuß (2013)

- WEsER by Universität Oldenburg
  - model approach: simulation

  - allocation of wind power: based on present installations
  - temporal resolution: 1 h
  - time horizon: 2020
  - spatial resolution: 28 regions in northern Germany
  - documented/applied e.g. in Krämer (2002)
- Wind-Szenario-Tool (WiSTl) by Forschungsstelle für Energiewirtschaft e.V. (FfE)
  - model approach: simulation
  - allocation of wind power: based on existing plants and stochastic capacity expansion
  - temporal resolution: 1 h
  - time horizon: 2025
  - spatial resolution: 200 m · 200 m
  - documented/applied e.g. in Mauch (2015)

Due to the multitude of available energy models and ongoing model development the list cannot be complete. It shows, however, most renowned and discussed models mainly focusing on the German power system. Other research activity such as described in Hoffschmidt et al. (2009), Grothe & Schnieders (2011) or Biank (2013) focused on specific aspects of Germany's future power system. They applied simplifications for the allocation of wind power capacity or had a rather medium-term time horizon (e.g. 2033). Further models have been presented in Hennings et al. (2014), for instance.

Moreover, energy models have been utilized for the following relevant studies:

- German Energy Agency (Deutsche Energie-Agentur GmbH) (dena) Grid Study II (Deutsche Energie-Agentur GmbH (dena) (2010a)):
  The study was developed by the German Energy Agency (Deutsche Energie-Agentur GmbH) (dena) in cooperation with federal ministries, associations and leading businesses from the German power sector. Its objective was to "investigate suitable system solutions for the German power supply system (up to 2020 with an outlook to 2025), to fully integrate 39 % renewable energy in the power supply into the German power grid while guaranteeing the security of supply and taking the effects of the liberalised European energy market into account" (Deutsche Energie-Agentur GmbH (dena), 2010b, p. 2). The study focused on questions concerning the transmission grid, for instance grid extension requirements. The modeling for

the study was driven by the power production from wind power and PV. Different capacity expansion scenarios were explored. The electricity production from wind power was modeled by DEWI for 1332 grid nodes, based on data from existing wind farms. In the modeling, wind power capacity was assigned to those grid nodes by the application of estimated regional "expansion factors" ("Ausbaufaktor", Deutsche Energie-Agentur GmbH (dena) (2010a, p. 93)). The electricity production from wind power was calculated with the help of capacity-weighed average hub heights for 2020.

- Grid Development Plan (Netzentwicklungsplan) (NEP) (50 Hertz Transmission GmbH et al. (2014a)):
  The NEP was developed by the German transmission system operators (TSOs). It included medium-term installation scenarios of renewable capacity in the federal states in Germany. Its central aim was the identification of grid expansion requirements, based on the future installation of RES. In its 2014 issue, the NEP included four scenarios: three targeting at 2025 and one targeting at 2035. The scenarios were based on the announcements and estimates of future wind power and PV installation of the federal states. In the 2015 issue of the NEP (50 Hertz Transmission GmbH et al. (2016)) the same approach was used, however with updated scenarios utilized for calculations.
  In the NEP, wind power was modeled in two steps: in the first step, calculated by FfE, wind power capacity was allocated according to the installation scenarios, taking present and future installation, an exploitation probability as well as geographical and meteorological parameters into account (cf. Stark (2015)). In the second step, built upon the first, the electricity production was generated taking wind speed data and a reference WTG into account.

- Consentec GmbH & Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES) (2013b) and Consentec GmbH & Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES) (2013a):
  In the study, published by Agora Energiewende, a German think tank on energy issues, a cost-optimized capacity allocation was compared to a situation with capacity installed closer to the centres of demand. The time frame of the scenarios analyzed was 2023 and 2033. The modeling was conducted by Fraunhofer IWES. In the model, wind power capacity in the year of analysis was allocated taking present installations, restrictions on area use in every grid cell (7 km · 7 km) and the natural resource into account. The study's aim was to reach the same amount

of electricity produced in both scenarios, i.e. the scenarios were so-called target scenarios (cf. Sachverständigenrat für Umweltfragen (SRU) (2011, p. 59)), resulting in different amounts of installed wind power capacity in the scenario variants.

Besides energy studies as categorized and presented, several studies focused solely on the potential of wind power in Germany. Those studies usually were based on detailed geographical analyses and assumptions for instance on the utilization of specific land use types. Analyses on the national wind power potential could be found, for instance, in

- Lütkehus et al. (2013) for the Federal Environment Agency (Umweltbundesamt) (UBA), calculated by Fraunhofer IWES and accomplished by Salecker & Lütkehus (2014), and in
- potential studies for Germany and for the federal states, respectively, published by Bundesverband WindEnergie e.V. (BWE) (2012a).

Further detailed potential analyses could be found for the federal state level. In Landesamt für Natur, Umwelt und Verbraucherschutz Nordrhein-Westfalen (LANUV) (2012), for instance, the wind power potential in the federal state of Northrhine-Westphalia was estimated based on a high spatial resolution and detailed assumptions of the utilization of areas, supplemented by data of a reference WTG. In such potential studies, however, neither a scenario on the expansion or allocation of wind power capacity nor power production from WTGs in a high temporal resolution was further explored.

Summing up, in existing models the focus has been either been set on wind power, or wind power has been incorporated as one out of several inputs to the model calculations, usually integrated as a standardized module of the models. The models differed with regard to the allocation of wind power capacity and their general research scope.

If at all, with the existing simulation models the spatial allocation of wind power capacity has been conducted by

- scaling and weighting of the present installed capacity (e.g. 50 Hertz Transmission GmbH et al. (2014a), Deutsche Energie-Agentur GmbH (dena) (2010a), Krämer (2002)), i.e. the present installed wind power capacity was used as a basis for assumptions of the allocation of future wind power capacity or it partly built the basis to that, i.e. this approach did not or does not fully follow an economic optimization, or by
- optimization with or without further area constraints.

In those models and studies in which wind power capacity was allocated in Germany in an optimized way, this was conducted either

- under the assumption that all potential area would be available for wind power installations (e.g. 50 Hertz Transmission GmbH et al. (2014b)), i.e. no further area restrictions were assumed, or
- under consideration of further area restrictions. In the studies in which this was the case, the area limitation was kept constant and either referred to specific land use types (cf. Scholz (2010), Stark (2015)) or to the public perception towards wind power or other parameters at district level (cf. Christ et al. (2015)). In potential analyses such as conducted by Bundesverband WindEnergie e.V. (BWE) (2012a), an area limitation was not linked to an analysis of installation scenarios.

An area limitation for wind power installations set at the federal state level and at the district level for the analysis of scenarios has not been subject of research activity. Moreover, if an optimized allocation of wind power capacity was conducted with the existing models, this usually was the case for a specific year of analysis. In the models, relevant input parameters such as WTG sizes were assumed to be a constant factor even though they can be expected to develop over time. The allocation of wind power capacity was conducted, for instance, using scaling factors that took the present installed capacity, the installed future capacity in the year of analysis, expected equivalent full load hours (EFLH) and land use parameters into account (cf. e.g. Christ et al. (2015)). A common approach found in the models was to assume a particular WTG type with specific technical characteristics and space requirements of WTGs for the year of analysis. The technical characteristics refer to WTG hub heights, the nominal power and the specific space requirement of a WTG – given as MW/km^2 or ha/WTG – that were assumed for the year of analysis. A development of technical and economic parameters in the period until the year of analysis has not been reflected in such approaches even though those can be expected not to be constant factors over time. The models analyzed did not incorporate that WTGs operating in the year of analysis would have been commissioned in different years, except for Deutsche Energie-Agentur GmbH (dena) (2010a) applying an average-weighed hub height for the year of analysis.

This aspect, however, would have an effect on the allocation of wind power capacity as the specific space requirement of a WTG might change over time and also on power production as hub heights of WTGs can be expected to experience a growth in size over time. It would therefore affect the power output of the installed wind power capacity in the year of analysis and the resulting LCOE of wind power.

A model that allows to allocate WTGs in a high spatial resolution and in an economically optimized way, year by year, taking specific additional area restrictions at both the federal state level and the district level into account, was not detected. The consideration of such parameters, however, would be helpful to consider the evolution of WTG sizes as well as the impact potential area limitations would have on the allocation of wind power capacity, electricity production and LCOE.

1.5 Research objective and research questions

The analysis of existing energy models and studies showed that there was no model available that combined the following aspects:

- an economically optimized allocation of wind power capacity (in Germany)
- over time (i.e. for all years until 2050, year by year)
- under consideration of area restrictions in the federal states as well as in the districts
- under consideration of specific space requirements of WTGs
- for scenarios of the installed capacity of VRE in Germany as a whole on the one hand and in its federal states on the other,
- generating national and region-specific results.

Current modeling and research activities focused on one or the other facet mentioned above but did not follow an integrated approach that covered all these issues simultaneously. These aspects, however, affect one another: An economically optimized allocation of WTGs at a high spatial resolution is affected by the area available, i.e. also by possible restrictions of the area potential, and by WTGs' specific space requirements which also develop over time. The allocation of additional wind power capacity in subsequent years is then affected by the wind power capacity that has already been installed in the years before, i.e. areas that have already been occupied by WTGs. This temporal interaction of parameters results in an age structure of WTGs in every administrative district and in every scenario year. It is necessary to gain information about this age structure, again, as it can be read as a size structure of WTGs in a district in a specific year which directly affects their power output.

Moreover, the impact of area availability and area restrictions (in the following also referred to as area "limitations") on the allocation of wind power capacity and on the power production from WTGs has only been subject to studies in that sense that an area restriction was conducted with regard to specific land use types or the public acceptance of or resistance against WTGs, for instance at district level. A potentially politically defined maximum share of the federal state and district areas available for wind power installations has not yet been utilized for the analysis of installation scenarios. In the political, scientific and public discussion, however, area availability and space requirements of WTGs play a relevant role.

In the public discussion and in political decisions areas potentially available for wind power installations often are related to the total area. For instance, in the German federal state of Schleswig-Holstein 1.7 % of the area were accounted for suitable sites for wind power installations in 2015 (cf. Bundesverband WindEnergie e.V. (BWE) (2015a). The regional plans that included priority areas for wind power use in Schleswig-Holstein were however reworked (cf. Staatskanzlei Schleswig-Holstein, der Ministerpräsident (2015)). Another example is the potential study of Landesamt für Natur, Umwelt und Verbraucherschutz Nordrhein-Westfalen (LANUV) (2012) in which a share of 2.2 % of the total area of the federal state of Northrhine-Westphalia detected to be potentially available for wind power installations was further analyzed. In EUtech Energie & Management GmbH (2008, p. 40), a share of 1 % of the total area of Northrhine-Westphalia was assumed to be area indicated for wind power use. In the potential study of Bundesverband WindEnergie e.V. (BWE) (2012a), Germany's terrestrial area was limited to 2 % to be available for wind power installations.

In the context of this thesis the question therefore was what is the impact of predefined area restrictions – given as a percentage of the total federal state areas and the district areas, respectively – on an economically optimized allocation of wind power capacity, on power production and on LCOE in a specific year of analysis. Therefore a new simulation model was developed that would simultaneously incorporate all these issues raised. As within a federal state the area potentially available for wind power installations might be further restricted, not only the state area could be restricted in the newly developed model but also the area in the administrative districts within the federal states (cf. section 2.3.6.2).

In the newly developed model, a part of the power sector was modeled. Model outputs can be utilized as inputs to other energy system models or grid node models, for instance. It is possible, however, to run the model on its own and to analyze the impact of a parameter variation on the allocation of wind power capacity, its corresponding power production, and on LCOE as presented in section 3 of this thesis.

The overarching question of how parts of Germany's future power system would appear under specific conditions included further aspects to be analyzed, for instance on the spatial allocation of wind power capacity and its power production, questions on regional differences between scenarios and scenario variants, potential grid bottlenecks and LCOE. A central aspect to be analyzed was the question which effect a variation of area availability and limitation, respectively, would have on the power output and on LCOE of onshore wind power.

Of special interest was the question where future wind power capacity would be allocated in a cost-optimized manner, especially with regard to large amounts of wind power. It is necessary to know about future capacity amounts and production patterns in a high spatial resolution in order to evaluate potential impacts on the operation and requirements of conventional power plants and on storage and transmission capacity. Other allocation algorithms that could be based on the present installation, on acceptance factors, on educated guesses or a combination of such factors, for instance, might be a suitable basis for an analysis but they however depict a possible future setting that also incorporates uncertainties. Another option, as presented in this thesis, is an economically optimized allocation of capacity, within specific framing conditions. This approach would result in a least-cost state of wind power installations, i.e. ceteris paribus any other capacity allocation method would result in higher LCOE of wind power. Such an optimized system thus does not necessarily depict the most foreseeable future setting but it merely represents an extreme case that reveals upper and lower system boundaries. With the new model, additional wind power capacity was allocated in the showcase of Germany, WTG by WTG, on a square kilometer scale and for every year of an installation scenario exogenously defined. The so-allocated capacity was then aggregated at the district level.

Derived from the allocated wind power capacity – and also depending on the scenario selected and its variants – the power output was calculated as generation time series in the year of consideration for all districts and, as aggregates of that, for transmission grid regions in a temporal resolution of fifteen minutes. This allowed to compare scenarios and their variants in terms of the spatial allocation of wind power capacity, the distribution of power generation, generation patterns, the pattern of the residual load, shares of RES, and LCOE.

The focus was set on wind power as it already has played an important role in Germany's power system and could be expected to be one of the central elements of Germany's future power system. Moreover, wind power and its multi-dimensional implications was expected to be subject of further political discussion. Together with PV, wind power could be expected to account for the largest share in Germany's future electricity mix in all long-term scenarios available. In the following, "wind power" is understood as commercial utility-scale WTGs and it does not include small WTGs for microgeneration.

The new model combined aspects of bottom-up and top-down model approaches. Several input parameters were taken into account in detail as in bottom-up models, for instance meteorological, technical and geographical data. Other input parameters rather had a top-down perspective such as the exogenously defined installation and demand scenarios to be modeled. Besides wind power, other volatile RES – PV and run-of-the-river hydro power – were incorporated in the model.

With the help of the model the following research questions were analyzed and answered.

Before analyzing different expansion pathways of the installed capacity it was necessary to identify existing limitations:

1. What is the geographical potential and the technical potential for wind power in Germany?

   The allocation of wind power capacity in all the scenarios modeled would be restricted by the available area, i.e. the available area constituted a central input parameter and framing condition to the model. For all further analyses and calculations it was therefore helpful to know about the area available at maximum (given as km^2), translated into installable wind power capacity (given as MW) and producable electricity (given as TWh/a).

   Besides the identification of the overall potential it was relevant to detect the technical potential taking further area restrictions into account:

   - What is the impact of an area limitation in the federal states and in the districts on the technical potential of onshore wind power?

   In practice, not all potentially available areas were expected to be utilized for wind power installations due to possible limits set by political decision and a potentially limited public acceptance of WTGs. A variation of area limitations would highlight its potential impact on the allocation of wind power capacity and consequently on power production, on the residual load and on LCOE.

A second set of research questions refers to the modeling of installation scenarios until 2050 and the consideration of limitations of the federal state areas and of the district areas.

2. Where would wind power installations in Germany be located and what electricity amounts would they produce if an economically optimized allocation was conducted?

   For exogenously determined scenarios on a high penetration of installed wind power capacity, an economically optimized spatial allocation was to be modeled and analyzed for specific target years. Additionally, the effect of area limitations was analyzed:

   - What is the impact of an area restriction in the federal states and in the districts on the spatial allocation of wind power capacity?

   Variations of area limitations would alter the geographical potential, thus the technical potential for wind power installations. This would affect the number of districts with wind power installations as well as the capacity density in the districts affected.

   Depending on the allocated capacity, questions on the power production from WTGs in specific years were analyzed:

   - What electricity amounts will be produced by WTGs in the years of analysis?

   Based on the capacity allocated in the scenarios and scenario variants and on the allocation parameters, variations in power production could be expected, depending on the defined area restrictions and scenario settings, for instance in terms of the total national power production and also in terms of the power production in the individual transmission grid regions. This led to another sub-question:

   - In which regions can what amounts of electricity be expected to be produced by wind power in the future?

A third group of research questions focused on the impact the power production of all VRE aggregated (onshore and offshore wind power, PV, and run-of-the-river hydro power) in combination with the electricity demand:

3. How do other VRE complement with wind power?

   Besides wind power, the electricity production from PV and run-of-the-river hydro power was taken into account in the new model, however in a simplified approach. The analyzed scenarios covered a wide range of potential future VRE combinations. The integration with other VRE and the electricity demand in Germany and in its transmission grid regions were expected to show regions with higher and lower renewable energy penetration. This again led to additional sub-questions:

- How much of the electricity demand can be matched by wind energy, PV and run-of-the-river hydro power in Germany and in its transmission grid regions in the future?

Depending on the capacity allocated in the different scenarios and scenario variants, electricity production from wind power was expected to differ in the transmission grid regions.

- What impact does the allocation of WTGs have on the residual load?

Accompanied by the power production from PV and run-of-the-river hydro power, the variation in the settings of the allocation of wind power capacity allowed to analyze their impact on the residual load. This was expected to give answers concerning potential power shortfalls or power surpluses in terms of energy amounts as well as the minimum and maximum capacity that would need to be handled.

This set of sub-questions refers to both the national production and the production in the transmission grid regions.

- Can regions be identified that show a high surplus production or underproduction from VRE?

Depending on the previous questions and on the scenario parameters, transmission grid regions were expected to differ from each other.

- To which extent is the residual load in the transmission grid regions affected by the allocation of WTGs?

This led to further sub-questions on regional differences:

- Does the transmission capacity of grid connections to neighbouring regions and cross-border basically suffice potential electricity shortfalls and surpluses?

Transmission grid regions in which the residual load would exceed the transmission capacity to neighbouring regions and cross-border were to be detected. This question also refers to the installed capacity as well as the energy amounts. To answer the question, the transmission capacity between grid regions was incorporated in the model and a number of scenarios was analyzed. It was decided, however, to set the system boundary at this point, i.e. a full grid flow simulation and analysis was not conducted with the new model.

Besides the technical questions on capacity and energy amounts, economic questions were to be answered:

4. What levelized cost of electricity (LCOE) of wind power can be expected in the future?

   Depending on the scenario selected, the year of analysis and the allocation parameters, LCOE was expected to vary. The impact of the input parameters on LCOE were analyzed. This, again, led to further sub-questions:

   - How does the LCOE of wind power differ in the transmission grid regions?

   The scenarios and scenario variants of an economically optimized allocation of WTGs were expected to result in differences of the power production in the transmission grid regions, thus LCOE of wind power was expected to differ between the scenarios and scenario variants. The impact of the modeling inputs on LCOE in the transmission grid regions and in Germany as a whole were therefore to be analyzed.

   Additionally it was tested whether a capacity allocation with pre-defined installation targets of the federal states would differ from a nationwide allocation of the same total capacity without such targets:

   - Will there be differences between a nationwide optimized capacity allocation and the installation targets of the individual federal states?

The answers to these research questions were expected to show whether the wind power simulation of existing models should incorporate further aspects of the allocation of wind power capacity and area restrictions.

1.6 Contribution

This thesis, the modeling approach and the modeling results will contribute to scientific research and the discussion on future energy systems by the following aspects:

- the modeling approach and the model developed,
- the scenarios and scenario variants investigated focusing on wind power, and
- the scenario analysis in the context of the integration with other VRE.

With the new model, installation scenarios over time with an economically optimized allocation of WTGs in Germany were calculated, taking further area restrictions for onshore WTGs into account. As presented, these aspects affect each other and thus needed to be modeled in an integrated approach. The model can contribute to existing energy models, for instance the renpass model developed at EUF.

As presented, the modeling of an optimized spatial allocation of wind power capacity over time would result in a specific age structure of the WTGs operating in the year of analysis. The age structure, again, would translate into a mix of WTGs of different sizes in that target year, which would directly affect their power production.

A limitation of area potentially available for wind power installations – in the model defined as maximum shares of the federal state areas and of the district areas – reflected that there can be other than geographical, technical and economic parameters that affect the allocation of WTGs. A variation of the area availability and limitation, respectively, allowed to analyze its impact on electricity production and on LCOE.

The model allowed to generate figures of the power production and LCOE of wind power and all VRE combined for the year of analysis. The modeling of different scenarios and scenario variants resulted in regionalized figures of wind power capacity, electricity production and LCOE. It was expected to help identify the impact of specific input parameters – for instance a pre-defined amount of capacity to be installed in the system or area limitations set – in the modeling as well as differences between the scenarios and scenario variants.

A high spatial resolution can improve decision-making on the siting of new WTGs in the federal states and in the planning of the transmission grid. A regionalized visualisation of the installed capacity, production, LCOE and other resulting parameters can help to detect the impact of varying specific scenario parameters.

With the model developed and the scenarios analyzed, energy policy can obtain a valuable input for the further development of energy models, the regulatory framework and land-use planning. The new model and its outputs can be applied for further research on the future energy system, for instance questions on the future operation of power plants or on the utilization or enhancements of the transmission grid.

2 Description of the simulation model

In order to analyze and discuss the research questions, a simulation model was developed that allowed to allocate wind power capacity in Germany in an economically optimized way, year by year, and that generated power production time series from wind power and other VRE in a specific year of analysis. The model incorporated all relevant technical and economic input parameters and allowed a region-specific results analysis. It included both bottom-up and top-down approaches, for instance a highly spatially resolved capacity allocation on the one hand and the development of the power demand on the other.

In this section, the model developed is presented, including its concept, its input parameters, its procedures and its outputs. First, the central parts of the model are introduced. After the presentation of all the model inputs, the model functions are presented in more detail.

2.1 Basic model structure

With the simulation model developed, the future electricity production from VRE in Germany was simulated in a temporal resolution of fifteen minutes and a high geospatial resolution for a specific year of analysis. The main focus was set on wind power but PV and run-of-the-river hydro power were modeled, too. Scenarios on the installation of VRE capacity – i.e. the capacity expansion of VRE over time – were incorporated in the model. The resulting electricity production was modeled for specific target years. Model outputs were national and regional figures on the allocated capacity, power produced and LCOE. In combination with the electricity demand in the year of analysis it was possible to detect the shares of wind power and of all VRE combined in the total power demand. Several flexibility options were incorporated in the model that allowed the simulation, analysis and comparison of different scenarios and scenario variants.

With the model, an economically optimized allocation of wind power capacity was calculated for all scenario years. Based on that, power production from WTGs was simulated for a specific year within the scenario time frame which was decided to be 2050 at maximum. In the scientific and political discussion, 2050 is key as the most relevant climate protection targets have been defined and discussed for 2050 (cf. section 1).

The basic flow chart of the model is depicted in figure 2.1. The model consisted of two central parts ("model core"): the capacity allocation part and the electricity generation part. The latter depended on the outcomes of the first and therefore these model parts were run sequentially. Two sorts of data inputs were fed into the two core

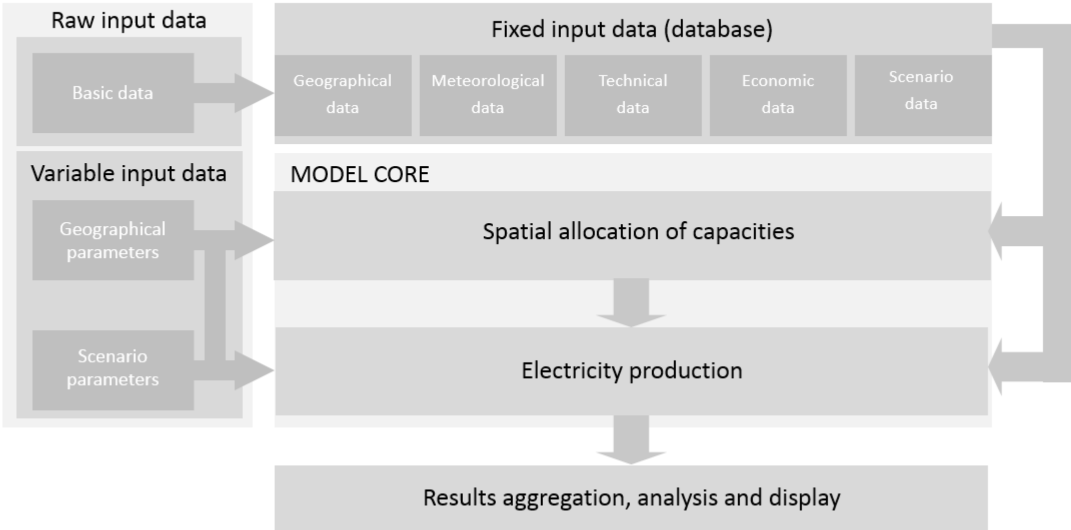


Figure 2.1: Basic flow chart of the new model

model parts: pre-processed fixed input data stored in the model database and variable input data that needed to be additionally defined. At the end of each model run, results were aggregated, displayed and analyzed.

In the first core part of the model, wind power capacity, i.e. WTGs, were allocated in the showcase in Germany and its waters in the North Sea and Baltic Sea in an economically optimized way, i.e. to those locations first where the expected LCOE were the lowest. The capacity allocation was conducted for all years between 1990 and the target year defined, year by year in succession.

The allocation of onshore wind power capacity took place considering the expected wind power performance in every square kilometer potentially available. This means, in a specific year of the scenario timeframe, available locations where wind speed conditions were expected to be most favourable would be utilized first for new wind power installations. WTGs were then allocated to those locations that subsequently would be not available for twenty years which represented the assumed service life of WTGs. For a specific year within the scenario timeframe this could mean that the most favourable locations might have already been occupied by WTGs installed in former years. If so, the next favourable locations were then utilized for additional WTGs that also, again, would not be available for twenty years.

This approach can be considered as a vintage model of the WTG stock in the country and year of analysis. The results of this procedure, conducted successively for every year of the full scenario timeframe, were aggregated in a matrix of newly installed capacity in the districts, for every scenario year until the target year, and stored in the model database.

The second core part of the model built upon the first. The allocated capacity from the first core model part represented a mix of older and younger WTGs in the system in the target year. Besides the consideration of capacity allocated in the first core part of the model, the electricity production in the target year was modeled taking sets of historical wind speed time series, wind shear coefficients and technical data of WTG into account.

In each of the model parts, data input was available from the model database and additional input through the model's front-end was required. For instance, meteorological, technical and economic data were regarded to be fixed inputs, i.e. unaltered in all the scenarios, yet developing over time. They were stored in the model database whereas further parameters such as the space requirement of WTGs and further area restrictions needed to be additionally defined.

The underlying wind speed time series and model results had a temporal resolution of fifteen minutes and represented the time series in the year of analysis. The geographical system boundary of the model was defined to be Germany as a showcase, consisting of Germany's terrestrial (onshore) area and offshore areas in the North Sea and in the Baltic Sea, mainly found in the German EEZ. Germany was chosen as a showcase and the model basically allowed to be applied for other countries or regions.

The highest spatial resolution in the capacity allocation part of the model was square kilometers. Intermediate results from that model part were aggregated at the district level which, again, was also used for the electricity generation part of the model. For the results analysis, modeled data from the district level were further aggregated at the level of the transmission grid regions and nationally.

2.2 Software applied

The model developed consisted of coded scripts that were related to a database. For data storage, a MySQL database was used. MySQL is an open source software and MySQL databases allow an easy and clear structuring of model data, i.e. inputs, intermediate results and model outputs. For the model developed, complex tables (e.g. containing geographical data) were normalized if possible and useful, i.e. their complexity was reduced by splitting them into several smaller tables related to each other through unique keys. Tables with input data, intermediate results and output data were stored separately from each other in the model database in order to make them easily distinguishable and accessible through the back-end of the model.

The model scripts were written in hypertext preprocessor (PHP) and in R. PHP is a script language widely used for web applications that can easily be connected to the model database using Structured Query Language (SQL). The model's front-end scripts, written in PHP, included the model procedures and needed to be launched in a web browser and allowed a straightforward input and selection of variable scenario parameters as well as the display of intermediate and final results and diagrams. Screenshots of the model's front-end (excerpts of the input and output pages) are shown in figures A1 and A2 in the appendix. The script bundle phpMyAdmin was used as the back-end of the model.

R is a programming language originally developed for statistical analyses. It allows efficient calculations, the inclusion of SQL queries by using the RMySQL package, and the display of diagrams.

Additionally, a Geographic Information System (GIS) was utilized for the analysis of the geographical potential for wind power installations as inputs to the model. A GIS allows to create, process and analyze geographical data such as specific locations (points), point-to-point connections (lines) and regions (polygons), based on coordinate data in the digital format of ESRI vector shapefiles, for instance. For all geographical considerations and inputs to the model the freely available QGIS software was applied (versions Quantum GIS 1.5.0-Tethys and QGIS 2.0 Dufour).

2.3 Input data on wind power

Input data to the model could be divided into two categories:

- fixed data and
- variable data.

The variable data needed to be defined as additional inputs in the model front-end before the model was run. The fixed data were pre-processed and stored in the model database. They were kept constant when the model was run. During the model procedures, the fixed data in the model database were accessed by the model scripts and utilized as calculation inputs. The fixed data, again, could be categorized as follows:

- geographical data,
- meteorological data,
- technical data,

- economic data and
- scenario data.

Although scenario data were considered as fixed inputs, they also could be altered in the model database, as all the other model inputs, too. The selection of the scenario to be modeled, however, was a variable parameter.

In the following, all the input data to the model are presented.

2.3.1 Geographical data

In both core parts of the model, highly resolved geographical data were essential inputs. In the capacity allocation part of the model, areas potentially available were taken into account for the allocation of WTGs at a square kilometer scale. In the electricity generation part of the model, wind measuring stations were related to administrative districts. The recorded wind speeds at their locations were then related to the installed capacity in the corresponding districts in order to generate electricity production time series from wind power. Moreover, geographical information was essential in the results aggregation part of the model when results from smaller area units, i.e. districts, were aggregated, for instance at the level of the transmission grid regions.

In the data pre-processing, areas in the onshore and the offshore regions were identified that were not and foreseeably will not be available for wind power use due to specific criteria of disqualification. Those areas were excluded from all further considerations. In turn, areas that were not excluded at the end of this data pre-processing step were regarded to be basically potentially available for wind power installations. These remaining areas represented the geographical potential that could then be translated into the technical potential of wind power.

For the capacity allocation part of the model, square kilometers were chosen as the highest geographical resolution for onshore wind power. This spatial resolution was regarded to be detailed enough to consider highly spatially resolved area exclusion criteria, specific space requirements of WTGs in the capacity allocation part of the model and location-specific differences in the wind power potential.

In the electricity generation part of the model, meteorological stations and their recorded wind speed data were related to nearby districts in order to model highly spatially resolved electricity production time series. In that part of the model, the district level was chosen as spatial resolution. This was useful due to the number of available wind measuring stations. Moreover, the number of districts in Germany, thus the number of resulting wind speed data sets, also allowed to keep computation times at a reasonable level.

In the results aggregation part of the model, data from the district level – electricity production time series, capacity values and other – were further aggregated and combined, resulting in electricity production time series for all the transmission grid regions and for Germany as a whole.

2.3.1.1 Onshore areas

Germany has a terrestrial area of 353 399 km^2 and it consists of sixteen federal states (Bundesländer). The largest federal state is Bavaria with 70 550 km^2, the smallest is the city state of Bremen with 325 km^2 (all figures: Statistisches Bundesamt (Destatis) (2011)). Every federal state consists of administrative districts, whereas the cities of Hamburg and Berlin are both a federal state and a district concurrently. The administrative districts are either rural districts (Kreise, Landkreise) or urban districts (Kreisfreie Städte, Stadtkreise, Stadtverbände).

By 2009, Germany consisted of 412 districts (Statistisches Bundesamt (Destatis) (2011)) with an average size of 867 km^2. A full list of the German federal states and districts can be found in table B2 in the appendix. The German districts, complemented by the offshore areas in the German EEZ, are illustrated in figure 2.2. In the figure the areas marked with a white border show the districts and the federal states are marked with a black border. Additionally the German EEZ in the North Sea and in the Baltic Sea is depicted as the light gray areas.

In the model, information on both the federal state areas and on the district areas was taken into account. It was utilized in the capacity allocation part of the model when a restriction of both the federal state areas and the district areas potentially available for wind power installations (cf. section 2.3.6.2) was to be defined. In that model part, wind power capacity was allocated to individual square kilometers that were again assigned to their corresponding district. Allocated capacity was summed up at the district level to be an input to the electricity generation part of the model.

At the end of both core model parts, results were stored as district-specific data in the model database, i.e. the wind power capacity newly installed in every scenario year as well as the electricity production time series in the year of analysis. For all model procedures, a unique key (official municipality key, Amtlicher Gemeindeschlüssel, cf. Statistisches Bundesamt (Destatis) (2011)) of every federal state and district was utilized.

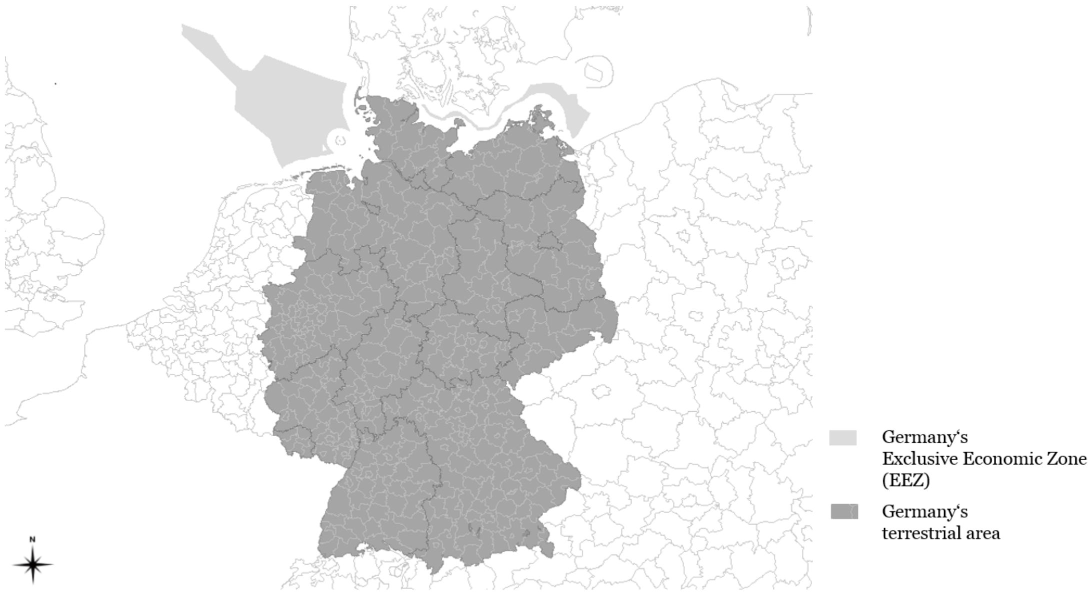


Figure 2.2: Germany's federal states, districts and Exclusive Economic Zone (EEZ)
Own illustration based on Geofabrik GmbH (2012), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009g) and Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2012b)

The capacity as provided in the installation scenarios however was not allocated to the full area of Germany and its EEZ. Areas with specific characteristics were regarded to be not available for wind power use. Those excluded – i.e. disqualified – areas were subtracted from the full area, resulting in remaining areas that were regarded to be potentially available for wind power installations. The area exclusion was conducted as a pre-process to the model.

Areas regarded to be not available for wind power use were

- buildings,
- inland waters,
- forests (their utilization for wind power installations has been discussed, however the potential would be severely limited (cf. Bundesamt für Naturschutz (BfN) (2011b)), and
- protected areas

plus additional buffers around some of those land use categories.

For the pre-processing, geographical data from Geofabrik GmbH (2012) and from the European Environmental Agency (EEA) (2011) were processed. Those data were available as GIS processible files, for instance ESRI shapefiles, and they were highly spatially resolved. Geofabrik GmbH (2012) provided geographical data on land use types from the crowd-sourced openstreetmap.org map service, categorized by area characteristics, for example forests or buildings. The European Environmental Agency (EEA) (2011) provided official geographical information on all protected sites under the Natura 2000 regime in the EU.

Areas within a specific circumcircle around buildings and protected areas were regarded to be not available for WTG installations. Those buffering areas reflected the fact that statutory minimum distances exist that could not be complied with for the allocation of WTGs. Such minimum distances have been defined in order to keep noise and visual impairment low, for instance. In Germany, those minimum distances differ between the federal states and they also depend on land use categories.

In a publication by the Federal Ministry for Economic Affairs and Energy (Bundesministerium für Wirtschaft und Energie (BMWi)) (2013) a summary of recommendations on minimum distances between WTGs and settlements and protected areas, respectively, in the German federal states has been provided. Another detailed overview over minimum distances between different land use categories and WTGs in Southern Germany could also be found in Bons (2014, pp. 23). According to the BMWi, the minimum distances to residential areas ranged between 500 m and 1000 m. In most of the federal states, 1000 m have been applied (cf. also Bundesverband WindEnergie e.V. (BWE) (2012b, p. 16)). Exemplarily, in the state of Hesse (Hessen) the regional development plan (Landesentwicklungsplan) did not allow any WTG being built closer than 1000 m to settlements (Hessische Landesregierung, 2013, 3.2 Z3b). In the BMWi list, 7 categories of settlements were presented. For industrial and business parks, for instance, the minimum distances recommended were smaller than for residential areas, however not available in all federal states.

Additionally, in the states of Bavaria, Mecklenburg West-Pomerania and Brandenburg a minimum distance of ten rotor diameters of WTGs has been discussed to be the minimum distance to settlements (Bundesministerium für Wirtschaft und Energie (BMWi) (2015a), Bayerische Staatsministerien des Inneren, für Wissenschaft, Forschung und Kunst, der Finanzen, für Wirtschaft, Infrastruktur, Verkehr und Technologie, für Umwelt und Gesundheit sowie für Ernährung, Landwirtschaft und Forsten (2011)) which translates into approx. 600 – 1000 m, actual WTG rotor diameters assumed. Moreover, for the identification of areas potentially usable for wind power installations local conditions needed to be taken into consideration, for instance in Saxony (Sachsen) (cf. Bundesverband WindEnergie e.V. (BWE) Landesverband Sachsen (2012, p. 11), Sächsisches Staatsministerium des Innern (2013, pp. 146)). Expert judgement from the German wind industry qualified a buffer of 750 m around settlements as the "absolute minimum value" (Ehlers (2011)) and, respectively, a buffer of 1000 m around settlements as to be a "conservative" assumption (Schorer (2011)). The German Wind Energy Association (Bundesverband WindEnergie e.V.) mentioned a buffer of 1000 m around settlements and protected areas (Bundesverband WindEnergie e.V. (BWE) (2012a, p. 17)).

For protected areas, a broad range of recommended or obligatory minimum distances to WTGs was valid, depending on the type of protection, e.g. FFH areas or breeding grounds (Bundesministerium für Wirtschaft und Energie (BMWi) (2013)).

For the model, a distance of 1000 m around buildings and protected areas was selected as a representative buffer. Protected areas refer to areas protected as FFH and Natura 2000 areas according to the FFH law. That European protection regime was established in order to protect endangered plant and animal species in their natural habitats in a European ecological network of protected areas (European Environmental Agency (EEA) (2011)). National parks (cf. Bundesamt für Naturschutz (BfN) (2011c)) and areas identified as Important Bird and Biodiversity Areas (IBAs) are part of the Natura 2000 regime (cf. BirdLife International (2016)). In Germany, Natura 2000 areas account for more than 15 % (more than 55 000 km^2) of the terrestrial area (cf. European Commission (EC) (2010)). These areas cannot be used for wind power installations.

For the model, further land use categories such as the main traffic routes and 250 m buffers around them were additionally subtracted from the remaining areas at the end of the data pre-processing. Such buffers are however greater than defined in the current legislation: The Federal Highways Act (Bundesfernstraßengesetz) (FStrG) (§9) does not allow any high-rise building constructions in less than 40 m around the motorways and special approvals are required for buildings in 100 m distance.

As some of the excluded areas fulfilled several of the exclusion criteria (e.g. forests within protected areas), overlaps between excluded areas were merged. The procedure of the area exclusion is exemplarily illustrated in figure 2.3. Image a shows the full area of a district and its individual square kilometers. They are marked in different shades of gray, representing their expected EFLH (cf. section 2.3.3.3), ranging from light gray (low expected EFLH) to black (high expected EFLH). Although buildings and other excluded areas are not explicitly depicted in the example, disqualified areas are hatched in image b. They represent area categories as presented that are regarded as to be not available for the allocation of WTGs, thus subtracted from the total area. Image c shows the remaining area after that subtraction. The so-derived remaining square kilometers of each district were stored in the model database.

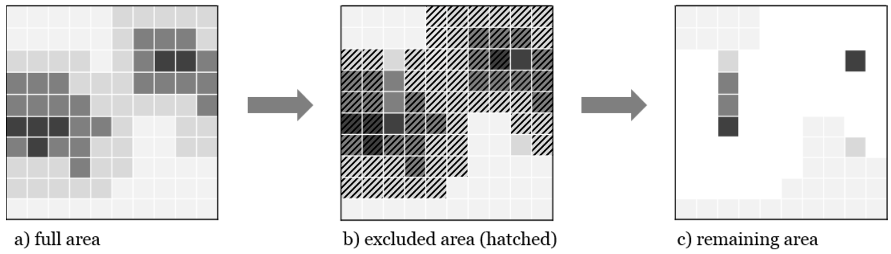


Figure 2.3: Methodology of area exclusion (onshore)

The remaining areas after the geographical analysis were not necessarily square-shaped as in the example. In the model, all remaining areas however were taken into account. When a WTG was allocated – based on the expected EFLH at the measuring points located within the remaining areas –, its individual space requirement was subtracted from the overall area and simultaneously the respective measuring point representing the square kilometer in which the WTG was allocated was marked as occupied in the model database. All square kilometers were stored with their coordinates in the model database.

In the geographical analysis, other criteria for the exclusion of areas from potential wind power use such as visual axes, areas of air traffic control and radar, transmission lines, areas affected by monumental preservation (cf. Niedersberg (2009)), areas with a specific slope in the surface (cf. 50 Hertz Transmission GmbH et al. (2014b, p. 65)) or complex terrain as well as potential planning restrictions, rights of use or site-specific questions of a wind farm's configuration (micrositing) were not taken into account. The geographical potential applied in the model therefore tends to include overestimations. This impreciseness however was not quantified as this would have required site-specific data and parameters that either were not available or would have substantially increased processing times. Results therefore need to be considered in this context. A consideration of such additional disqualification criteria would have further reduced the area potential.

Moreover, the existing spatial planning, e.g. potential priority areas for wind power, was left out of consideration in the model. Instead, it was assumed that all non-restricted areas would be potentially available for wind power use.

The excluded and the remaining areas in Germany are illustrated in figure 2.4. Excluded areas are coloured gray whereas remaining areas are shown as the white spots on the map. Based on the assumptions presented, an overall onshore area potential of 60 921 km^2 could be identified (353 399 km^2 of total area less 292 477 km^2 of excluded

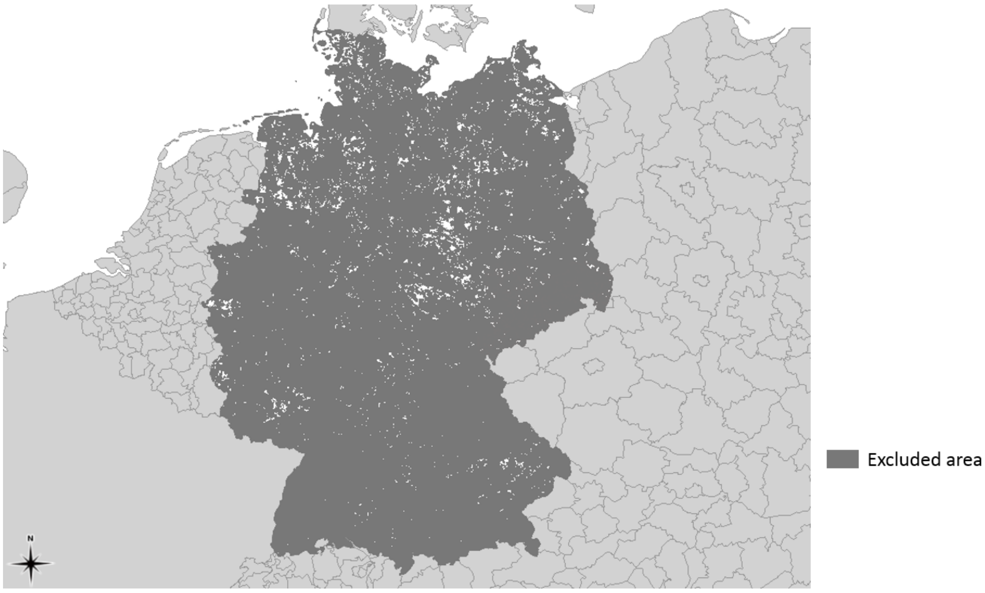


Figure 2.4: Onshore areas excluded from wind power use and remaining areas
Own illustration based on Geofabrik GmbH (2012), European Environmental Agency (EEA) (2011) and own estimates

area), i.e. approx. 17 % of the total German terrestrial area. The percentage varied between the federal states, ranging from 0 % in the city state of Berlin (and 0.2 % in the city states of Hamburg and Bremen) to 34 % in the state of Saxony-Anhalt (Sachsen-Anhalt). An overview over the area potential in the federal states is given in figure 2.5. In the diagram, the black bars represent the excluded areas whereas the gray bars on top represent the remaining areas of the individual federal states. A full list of the district and federal state areas can be found in table B2 in the appendix.

2.3.1.2 Offshore areas

Besides onshore wind power installations, WTGs have been and will additionally be installed in the German waters, i.e. offshore. Although the North Sea and the Baltic Sea do not belong to the German state territory, Germany has special rights in parts of them. Besides the territorial waters (12–mile zone, i.e. up to 12 nautical miles from the shore), laying under the United Nations Convention on the Law of the Sea, the German Exclusive Economic Zone (EEZ), theoretically up to 200 nautical miles from the shore, in the North Sea and in the Baltic Sea fall into Germany's responsibility. All planning in the German EEZ lies in the responsibility of the Federal Maritime and Hydrographic Agency of Germany (Bundesamt für Seeschifffahrt und Hydrographie) (BSH) within the remit

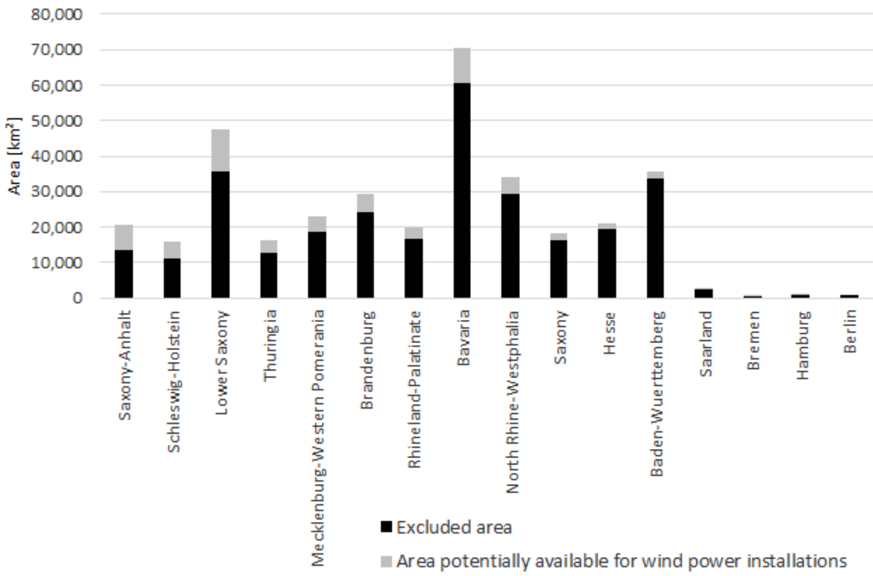


Figure 2.5: Geographical potential for wind power installations by federal states
Own calculations based on Geofabrik GmbH (2012), European Environmental Agency (EEA) (2011) and own assumptions

of the Federal Ministry of Transport and Digital Infrastructure (Bundesministerium für Verkehr und digitale Infrastruktur) (BMVI) (cf. §5 Federal Maritime Responsibilities Act (Gesetz über die Aufgaben des Bundes auf dem Gebiet der Seeschifffahrt, Seeaufgabengesetz) (SeeAufgG)). The German EEZ area in the Baltic Sea (4452 km^2) is much smaller than the German EEZ area in the North Sea (28 539 km^2) (cf. Bundesamt für Naturschutz (BfN) (2011a)). Water depths in the German EEZ range from approx. 15 m to 45 m (cf. Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES) (2010)).

The spatial planning in the German waters in the North Sea and in the Baltic Sea is organized according to the regional planning program which is, again, part of the Spatial Planning Act (Verordnung über die Raumordnung) (ROV) for the North Sea (Verordnung über die Raumordnung in der deutschen ausschließlichen Wirtschaftszone in der Nordsee vom 21. September 2009 (Federal Law Gazette (Bundesgesetzblatt) (BGBl.) pt. I, pp. 3107) ("AWZ Nordsee-ROV")) and for the Baltic Sea (Verordnung über die Raumordnung in der deutschen ausschließlichen Wirtschaftszone in der Ostsee vom 10. Dezember 2009 (BGBl. pt. I, pp. 3861) ("AWZ Ostsee-ROV")). In the ROVs, guidelines for the spatial development in the German EEZ have been defined, including predefinitions of areas for different purposes and uses, i.e. the exploitation of the sea ground and the sea surface, and protected areas have been included, too (cf. Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2014)). The ROVs for both the North Sea and the Baltic Sea include the spatial planning for

- shipping,
- production of raw materials (sediment extraction),
- pipelines and submarine cables,
- scientific research on the ocean (platforms),
- energy generation (particularly wind power),
- military training,
- fishing and sea farming (mariculture), and
- the marine environment.

The different area uses in the German EEZ in the North Sea and in the Baltic Sea as defined in the ROVs are illustrated in figure A3 in the appendix. For the modelling, some of the defined area characteristics were considered to be criteria for the disqualification of areas from potential wind power use.

As of 2015, five FFH or Natura 2000 areas existed in the German EEZ in the North Sea and five in the Baltic Sea, which also contained IBAs. It was assumed that there would be no wind power installation in these areas, except for the already approved wind farm Butendiek west from the island of Sylt in the North Sea.

Additionally to such protected areas, the main shipping routes as defined in the ROVs were excluded from potential wind power use in the model. Similar to the onshore case, excluded areas were subtracted from the full offshore area, resulting in remaining offshore areas for potential wind power use.

In order to be able to process offshore areas similarly to the onshore districts in the model and to derive areas of a similar size as in the onshore case, the remaining offshore areas were segretaged into smaller units (in the following referred to as "offshore sub-regions"). For the model, the segregation was conducted mainly along the shipping routes, based on the maps and coordinates provided in Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009a, pp. 28) and Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009b, pp. 26). A further seggregation was carried out according to the water depth which played a key role for the allocation of offshore wind power capacity as it would directly translate into foundation cost, thus cost of offshore wind power. For this purpose, the offshore sub-regions were additionally subdivided based on 10 m steps of water depth (cf. Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009g) and Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009a)).

As few already approved offshore wind farms have been or will be located outside the EEZ but in the 12-mile zone (e.g. the offshore wind farms Nordergründe in the North Sea and Baltic One 1 in the Baltic Sea), their according areas were also taken into account in the model. A full list of approved wind farms can be found in table B4 in the appendix.

As a result, the German offshore waters were partitioned into 56 offshore sub-regions in the North Sea and 9 offshore sub-regions in the Baltic Sea. A full list of the offshore sub-regions can be found in table B3 in the appendix.

A map of the areas potentially available for wind power installations in the German sea waters is shown in figure 2.6. In the figure, such areas are marked dark grey. All offshore area marked light gray was regarded to be disqualified from wind power use.

A summarizing overview over the full EEZ areas, the excluded and the remaining areas is presented in table 2.1. In the North Sea, 70 % of the total area were excluded from potential wind power use. Considering additional areas due to approved offshore planning outside the remaining areas, the area potentially available for wind power was detected to account for 8518 km^2. In the Baltic Sea, 89 % (3967 km^2) of the total area was excluded for wind power installations. Including the areas of an approved offshore wind farm outside the remaining areas, the area potentially available for wind power accounted for 524 km^2. In total, 9042 km^2 were identified to be potentially available for wind power use in the German parts of the North Sea and the Baltic Sea.

For all the offshore sub-regions, further calculations on distances to service ports and grid connection points were conducted (cf. section 2.3.1.5). They were central inputs to the calculation of CAPEX and OPEX as presented in section 2.3.4.

2.3.1.3 Critical assessment of the geospatial analysis

The analysis of the geographical input data to the model revealed a large geographical potential for onshore and offshore wind power in Germany. The underlying data however implied inaccuracies and uncertainties concerning data quality and their future development. For instance, potential future settlements – and accordingly the expected buffering areas around them – could not be considered in the onshore geographical analysis. Additionally, minimum distances between specific landuse categories and new WTGs might be subject to change in the future.

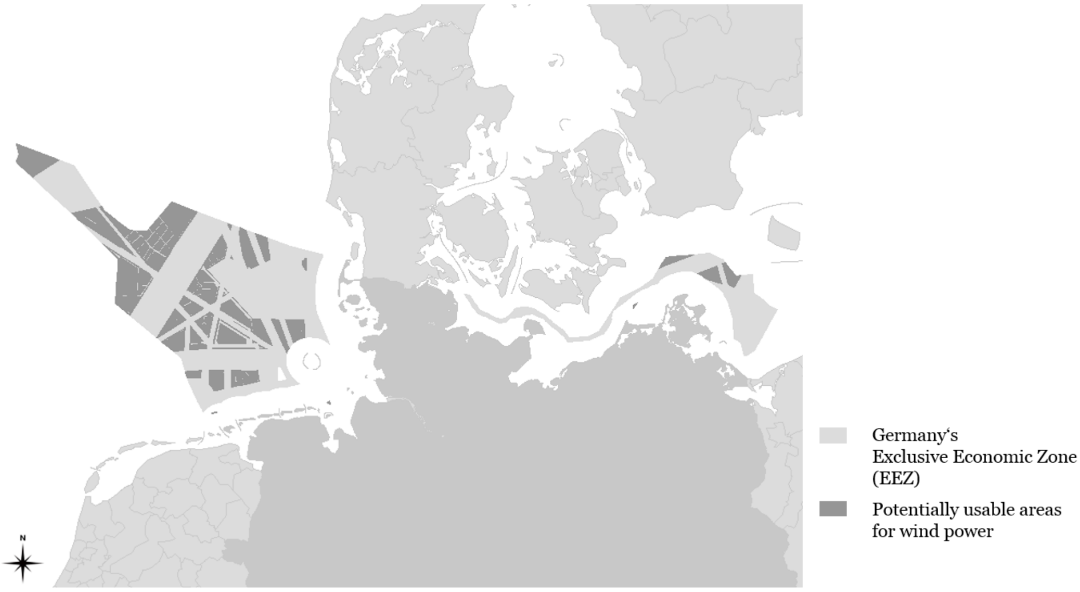


Figure 2.6: Areas potentially available for wind power use in the North Sea and in the Baltic Sea
Own illustration based on Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2014) and offshore wind farm approvals (list in table B4 in the appendix)

In some available models and studies that opted for a high spatial resolution (cf. section 1.4), a similar approach for the analysis of the geographical potential was used. Differences in the approaches and in the underlying data, however, occurred. For instance, Bundesverband WindEnergie e.V. (BWE) (2012a) confined its analysis to locations with a specific expected minimum energy yield from WTGs and a specific minimum mean wind speed, respectively. Additionally, the assumption of buffering areas around specific land use categories differed in the study. This resulted in an area potential that was comparable only to a limited extent to the geographical analysis conducted for the new model.

The potential analysis of Lütkehus et al. (2013) for the Federal Environment Agency (Umweltbundesamt) (UBA) resulted in a total onshore area potential of 49 400 km^2 in Germany, i.e. less than detected in this thesis. Again, it needs to be considered that different approaches and different underlying data and assumptions have been applied. A sensitivity analysis of that potential study conducted by Salecker & Lütkehus (2014) shows, for instance, the impact of different assumed buffers around settlements on the geographical potential, thus technical potential for wind power installations.

Table 2.1: German offshore areas

	Area in NS [km^2]	Area in BS [km^2]	Total area [km^2]
Exclusive Economic Zone (EEZ)	28 525	4484	33 009
Area excluded from use	20 035	3967	24 002
Remaining area in the EEZ	8490	517	9007
Additional areas in the EEZ (approved wind farms)	9	0	9
Available area in the EEZ	8499	517	9016
Additional areas outside the EEZ (approved wind farms)	19	7	26
Total area potentially available for wind power use	8518	524	9042

NS: North Sea, BS: Baltic Sea
Based on Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2014), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009b) and offshore wind farm approvals (list in table B4 in the appendix)

Summing up, the area potential and its analysis heavily depend on the underlying assumptions of input data and on the level of detail. All modeling results thus must be viewed against this background.

2.3.1.4 Transmission grid regions

With the model, district-specific data of the electricity production from wind power, PV and run-of-the river hydro power were generated for the year of analysis. Additionally in the model the spatial level of transmission grid regions was incorporated. At the end of each model run, district-specific model results were aggregated according to the transmission grid regions the districts were located in. Moreover, the transfer capacity between the transmission grid regions and cross-border transmission capacity was another additional input to the region-specific results analysis.

While the distribution grid (in Germany: 110 kV) builds the link between power generation and power consumers, the overlaying transmission grid (220 kV and 380 kV) connects grid regions with each other. Additionally, high voltage direct current (HVDC) links have been planned, approved or being built. Besides the power lines between transmission grid regions there are also interconnections to neighbouring countries. Both internal (national) transmission lines between transmission grid regions and cross-border interconnections were taken into account in the model.

For the model, the transmission grid regions were adopted from Deutsche Energie-Agentur GmbH (dena) (2010a, p. 12). Following that approach, Germany was split into

18 onshore transmission grid regions as listed in table 2.2 and illustrated in figure 2.7. Every onshore transmission grid region covered the area of one or several districts.

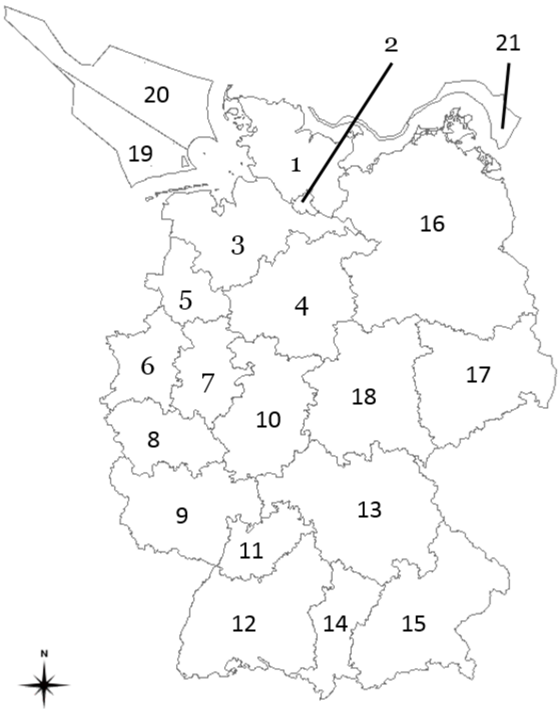


Figure 2.7: Transmission grid regions incorporated in the model
Own illustration, based on Deutsche Energie-Agentur GmbH (dena) (2010a) and own assumptions

In the model, the offshore areas of the German EEZ were regarded as additional transmission grid regions. Based on the existing and planned grid connections to onshore grid connection points and additional assumptions, three offshore grid areas were defined: one in the Baltic Sea and two in the North Sea. The offshore sub-regions in the North Sea therefore were combined to two larger regions, one located northeast and one located southwest from the shipping route that stretches from North-West to South-East.

The transmission grid regions did not fully correspond to the areas of the federal states (cf. section 2.3.1.1). Technically this means that in the model database every district was related to a grid region as well as to a federal state. The assignment of districts and federal states was relevant in the capacity allocation part of the model when installation targets of individual federal states were considered. The assignment of districts and transmission grid regions was relevant for the aggregation of results at the level of the transmission grid regions. Besides the assignment of districts and transmission grid regions, the transmission capacity between the grid regions was incorporated in the model which was relevant for the results analysis.

The transmission capacity of a power line can be calculated according to equation 1 (cf. Deutsche Energie-Agentur GmbH (dena) (2010a, p. 271), also applied in Hohmeyer et al. (2011, p. 14)) by multiplying the voltage and the current of the transmission circuits and the number of electrical circuits. As a safety margin, the product is reduced by 30 %.

$$P = 0.7 \cdot k \cdot \sqrt{3} \cdot U \cdot I \tag{1}$$

with

- P: transmission capacity [MW]
- k: number of circuits
- U: voltage of circuit [V]
- I: current of circuit [A]

As presented in Deutsche Energie-Agentur GmbH (dena) (2010a, p. 271), a circuit of existing power lines at 380 kV can carry a current of $I = 2720$ A, resulting in a transmission capacity of $P = 1253$ MW. According to 50 Hertz Transmission GmbH et al. (2014a, p. 292), the transmission capacity of such a power line is 1660 MW. If lines are reconductored, a transfer capacity of 1900 MW can be reached. Equation 1 hence can be regarded as being a conservative approximation.

Figures calculated according to equation 1 are maximum values of potentially available transfer capacity and can be read as net transfer capacity (NTC). NTC is the "capacity available for commercial transactions" (Elia System Operator NV (2016)), taking into account the capacity of the interconnectors, the $N-1$ criterion and a reliability margin (cf. PSE S.A. (2016), Augstsprieguma tikls – Latvian Transmission System Operator (AST) (2012)).

Due to the concurrency of demand (load) and supply (power production), the transmission capacity however is a variable that depends on the situation of supply and demand in the different grid regions at a specific moment. In meshed network systems, "NTC values between pairs of control areas" (European Network of Transmission System Operators for Electricity (ENTSO-E), 2001a, p 11) are interdependent. Such interdependencies have not been reflected in the transfer capacity values applied in the model.

Table 2.2: Germany's transmission grid regions incorporated in the model

No.	Description (Federal states in transmission grid region)
1	Schleswig-Holstein
2	Hamburg
3	Lower Saxony (*Niedersachsen*) (North), Bremen
4	Lower Saxony (*Niedersachsen*) (South-East), Northrhine-Westphalia (*Nordrhein-Westfalen*) (North-East)
5	Lower Saxony (*Niedersachsen*) (South-West), Northrhine-Westphalia (*Nordrhein-Westfalen*) (North-West)
6	Northrhine-Westphalia (*Nordrhein-Westfalen*) (West)
7	Northrhine-Westphalia (*Nordrhein-Westfalen*) (Centre)
8	Northrhine-Westphalia (*Nordrhein-Westfalen*) (South), Rhineland-Palatinate (*Rheinland-Pfalz*) (North)
9	Rhineland-Palatinate (*Rheinland-Pfalz*) (South), Saarland, Hesse (*Hessen*) (South) ["South-West"]
10	Northrhine-Westphalia (*Nordrhein-Westfalen*) (South-East), Lower Saxony (*Niedersachsen*) (South), Hesse (*Hessen*) (North) ["Central Germany"]
11	Baden-Württemberg (North)
12	Baden-Württemberg (South)
13	Bavaria (*Bayern*) (North)
14	Bavaria (*Bayern*) (South-West)
15	Bavaria (*Bayern*) (South-East)
16	Mecklenburg West-Pomerania (*Mecklenburg-Vorpommern*), Saxony-Anhalt (*Sachsen-Anhalt*) (North), Brandenburg (North), Berlin ["North-East"]
17	Saxony-Anhalt (*Sachsen-Anhalt*) (South-East), Brandenburg (South), Thuringia (*Thüringen*) (East), Saxony (*Sachsen*) (East) ["East"]
18	Saxony-Anhalt (*Sachsen-Anhalt*) (South-West), Thuringia (*Thüringen*) (West), Saxony (*Sachsen*) (West) ["Centre-East"]
19	Areas* in the North Sea (South-West)
20	Areas* in the North Sea (North-East)
21	Areas* in the Baltic Sea

*) mainly EEZ

The exact available transfer capacity (ATC) which can be significantly below the NTC would need to be studied in a separate load flow simulation (cf. European Network of Transmission System Operators for Electricity (ENTSO-E) (2001b) which is not part of this thesis. The figures calculated and considered in the model therefore can only be reached under specific conditions. However they can provide information whether existing or planned transmission capacity basically suffices transmission requirements or not.

In the model, the transmission capacity between grid regions with each other and cross-frontier transmission capacity at the 220 kV and 380 kV voltage level was based on available data on grid connections (Verlag Glückauf GmbH (VGE) (2006b), Verlag Glückauf GmbH (VGE) (2006a), European Network of Transmission System Operators for Electricity (ENTSO-E) (2013b, p. 9)) and information about cross-border transmission lines provided by TSOs (Amprion GmbH (2012), 50 Hertz Transmission GmbH (2012), TenneT TSO GmbH (2012), TransnetBW GmbH (2012) and Energie-Control GmbH (E-Control Austria) (2010)).

Besides the status quo of the transmission capacity between all the grid regions with each other and with other countries, grid extension and enhancement projects as defined in the Energy Line Extension Act (Gesetz zum Ausbau von Energieleitungen, Energieleitungsausbaugesetz) (EnLAG) and planned transmission capacity – grid extension through additional circuits, reconductoring or new power lines – as presented in the NEP (50 Hertz Transmission GmbH et al., 2014a, pp. 138) (cf. section 1.3) were taken into account in the model. In the NEP, future projects of additional horizontal (power lines) and vertical (substations) transmission capacity have been specified. In the model, all projects until 2035 presented in the NEP were assumed to be realized as projected. This includes additional power lines and additional circuits in existing power lines at the 220 kV and the 380 kV high voltage alternating current (HVAC) level as well as HVDC transmission lines. Out of more than 180 grid expansion and enhancement projects presented in 50 Hertz Transmission GmbH et al. (2014a) those projects were identified to be relevant for the model that would increase the transmission capacity between defined transmission grid regions and to neighbouring countries. Other projects presented in the NEP laid within transmission grid regions and were not taken into account in the model.

In figure 2.8 the current and the expected transfer capacity between the transmission grid regions and other regions (transmission grid regions or neighbouring countries) are depicted. The NTC values were stored in the model database as matrices representing the transfer capacity between all the grid regions and also between the grid regions and neighbouring countries.

2.3.1.5 Offshore ports and harbours and offshore grid connection

Besides the analysis of onshore areas potentially available for wind power use and the classification of transmission grid regions, further geographical analyses were conducted for the remaining offshore areas. For all the offshore sub-regions as presented in section 2.3.1.2, the following geographical parameters were analyzed with the GIS:

- distances to grid connection points and
- distances to service ports and harbours.

Both parameters directly affect the capital expenditures (CAPEX) and operation expenditures (OPEX) of offshore WTGs, thus their expected levelized cost of electricity (LCOE) (cf. section 2.3.4). As LCOE was assumed to be crucial for the allocation of offshore wind power capacity, the distances between the offshore sub-regions and both their corresponding grid connection points and service ports were taken into account in the model. In the model, every offshore sub-region therefore was related to one grid connection point and one service port.

In the model database, the shortest distance between the centre of an offshore sub-region and its corresponding grid connection point was stored unless the grid connection of an approved or existing wind farm had already been pre-defined (cf. 50 Hertz Offshore GmbH (2014), 50 Hertz Offshore GmbH (2011a), 50 Hertz Offshore GmbH (2011b), 50 Hertz Offshore GmbH (2011b)). Therefore six grid connection points and their distances to the offshore sub-regions were considered in the model: Emden-Borßum, Diele, Büttel, Bentwisch, Lüdershagen, and Lubmin. Diele was decided to also represent the grid connection point of Dörpen as both substations are located close to each other.

Besides the grid connection, for all the remaining offshore sub-regions in the German sea waters an analysis of potential service ports and harbours for offshore wind farms was conducted. They play an important role for the installation of offshore WTGs, e.g. for the shipping of components (also called "heavy duty ports", cf. Netzwerkagentur Windenergie WindCommunity Schleswig-Holstein (2010, pp. 14)) and during their operation (for maintenance, repair and operations (MRO)) and affect both the investment cost and OPEX. From 27 potential ports and harbours, a smaller number was detected to be crucial for offshore wind power in the North Sea and in the Baltic Sea due to the extent of services they offered and due to their size (cf. Bundesministerium für Wirtschaft und Energie (BMWi) (2016)). For the North Sea areas, those were the five

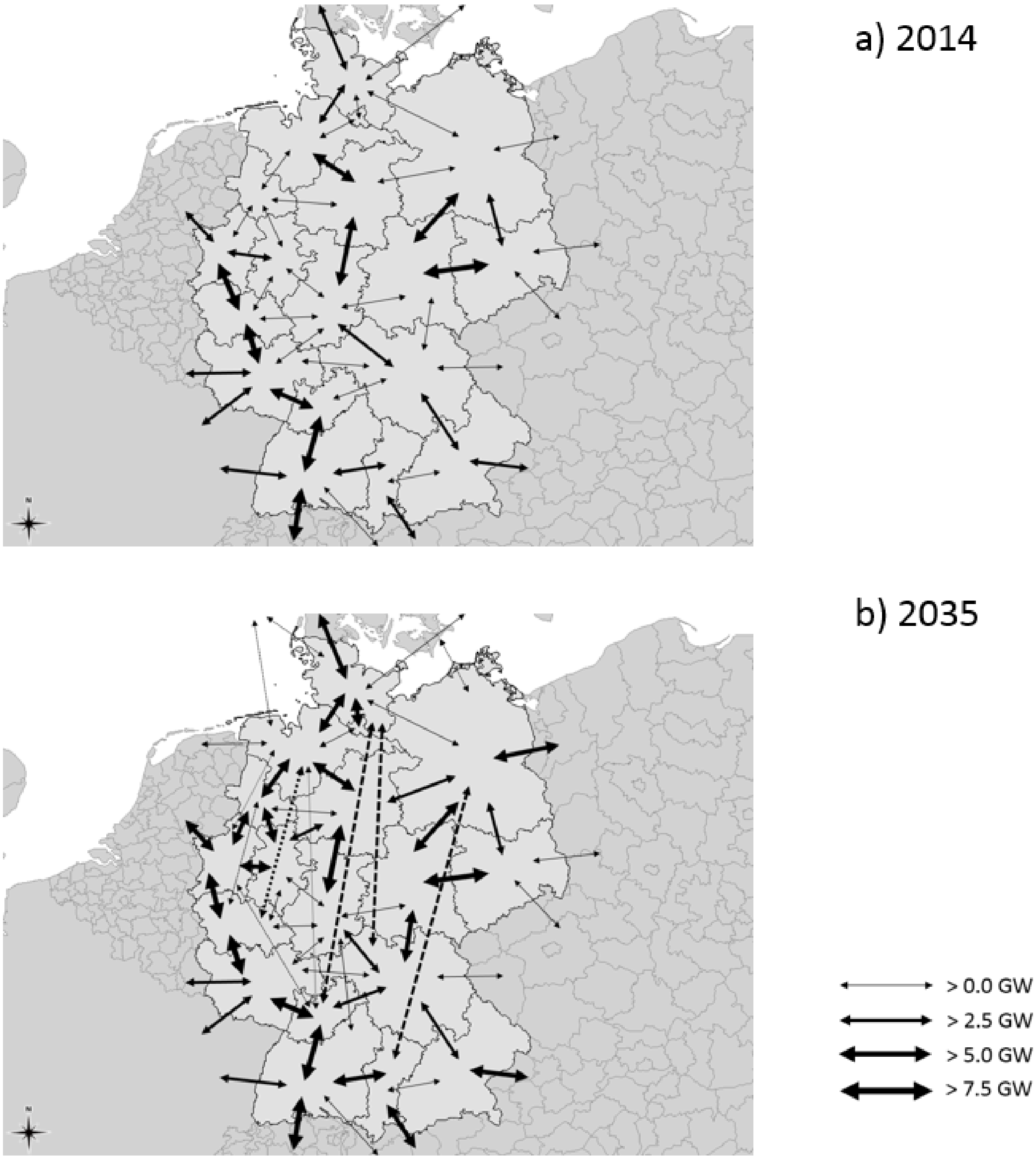


Figure 2.8: Transfer capacity between the transmission grid regions including coupling to neighbouring countries
Dashed: Planned HVDC links
Own illustration, based on Verlag Glückauf GmbH (VGE) (2006a), Verlag Glückauf GmbH (VGE) (2006b), Deutsche Energie-Agentur GmbH (dena) (2010a), 50 Hertz Transmission GmbH et al. (2014a), TransnetBW GmbH (2012), TenneT TSO GmbH (2012), 50 Hertz Transmission GmbH (2012), Amprion GmbH (2012), Energie-Control GmbH (E-Control Austria) (2010), European Network of Transmission System Operators for Electricity (ENTSO-E) (2013b), (50 Hertz Transmission GmbH et al., 2014a, pp. 138), Energy Line Extension Act (*Gesetz zum Ausbau von Energieleitungen, Energieleitungsausbaugesetz*) (EnLAG), Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen (BNetzA) (2013), Amprion GmbH (2012), 50 Hertz Transmission GmbH (2012), TenneT TSO GmbH (2012) and TransnetBW GmbH (2012)

German ports and harbours of Bremerhaven, Cuxhaven, Wilhelmshaven, Helgoland and Husum. From those five, the harbour on the island of Helgoland was detected to be the closest to all the offshore sub-regions in the North Sea. Due to the proximity of the Danish port of Esbjerg (cf. Colliers International Danmark A/S (2014, pp. 4)) to some of the offshore sub-regions in the North Sea, Esbjerg was also included in the analysis. In the Baltic Sea, two ports and harbours were eligible: Sassnitz-Mukran and Rostock.

A map of the potential grid connection points and service ports and harbours considered in the model is shown in figure 2.9. As presented, in the model only few of them actually were utilized and related to the offshore sub-regions due to their proximity to harbours, ports and grid connection points. A full list of offshore sub-regions, their assigned service ports, harbours and grid connection points and the corresponding distances can be found in table B3 in the appendix. The distances between the offshore sub-regions and their corresponding service ports and harbours and grid connection points were stored in the model database to be accessed during the capacity allocation procedure as presented in more detail in section 2.6.1.

2.3.2 Meteorological data

In order to model the electricity production from WTGs as realistic as possible, observed wind speed data from meteorological services were utilized in the model. Two sets of wind speed data were applied:

- long-term mean wind speed data and
- time series of wind speeds.

Those two types of data sets were used at two different stages of the model and must not be confused with each other. The measured long-term figures played a crucial role in the capacity allocation part of the model whereas the time series data were relevant in the electricity generation part.

2.3.2.1 Long-term mean wind speeds

For the allocation of onshore WTGs, locations with the lowest expected LCOE of wind power, thus highest expected equivalent full load hours (EFLH) were utilized in the model first. The expected EFLH in the potentially available areas thus were the central criterion for ranking the available individual square kilometers. The capacity allocation in the model was conducted according to this ranking. For the calculation of EFLH (cf. section 2.3.3.3), long-term recorded wind speed data played an important role.

Figure 2.9: Grid connection points and service ports and harbours for offshore wind farms
Own illustration based on Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2014), 50 Hertz Offshore GmbH (2014), 50 Hertz Offshore GmbH (2011a), 50 Hertz Offshore GmbH (2011b), 50 Hertz Offshore GmbH (2011b), Bundesministerium für Wirtschaft und Energie (BMWi) (2016) and offshore wind farm approvals (list in table B4 in the appendix)

For a large number of meteorological stations and micrometeorological towers, long-term measurements of wind speeds have been documented. For an appropriate assessment of the potential power output from a WTG, information about the probability distribution of wind speeds at the location of consideration is key because the power output of a WTG is no linear function of the wind speed (cf. The European Wind Energy Association (EWEA) (2004, p. 50)). The probability distribution of wind speeds can be expressed by equation 2, the so-called "Weibull distribution" (cf. da Rosa (2013, pp. 734), Deutscher Wetterdienst (DWD) (2011a), Ro & Hunt (2007), Manwell et al. (2009, p. 59) and Bhattacharjee (2010)).

$$p(v) = \frac{k}{c} \cdot (\frac{v}{c})^{k-1} \cdot e^{-(\frac{v}{c})^k} \tag{2}$$

where

- v: wind speed [m/s]

- $p(v)$: probability of windspeed v
- k: shape parameter
- c: scale parameter
- e: Euler-Mascheroni constant ($\approx$ 2.718)

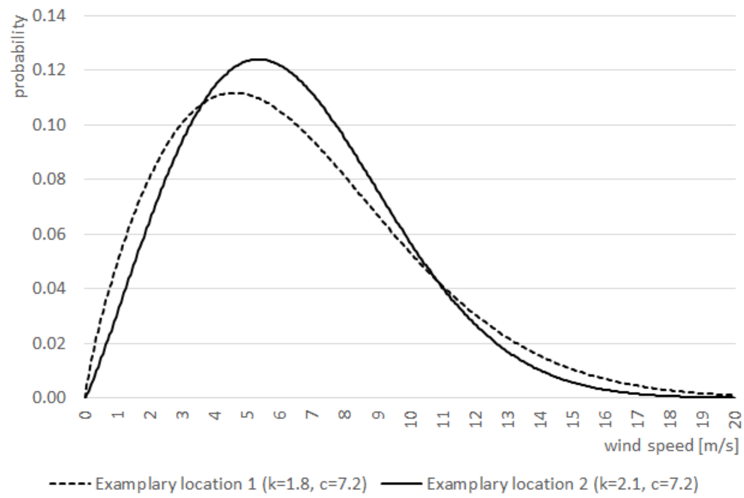


Figure 2.10: Exemplary Weibull probability distribution of wind speeds
Own illustration. Different shape parameters k exemplarily selected.

Equation 2 incorporates two parameters – the Weibull parameters k and c – that characterize the probability distribution of wind speeds at a specific location. Figure 2.10 illustrates exemplarily the effect different Weibull parameters have on the probability distribution of wind speeds. The figure shows the wind speed distribution in two locations according to their exemplary Weibull parameters. Even though the two exemplary locations have the same mean wind speed, it becomes obvious that the distribution of windspeeds at the locations differs, resulting in differences in the power output of WTGs, thus differences in the expected EFLH at the two locations (illustrated in figure 2.11).

The Weibull parameters were available in a square kilometer resolution (Deutscher Wetterdienst (DWD) (2011a)). They were calculated by Germany's National Meteorological Service (Deutscher Wetterdienst) (DWD) in a non-linear multiple regression approach, based on recorded wind speeds of more than 200 measuring stations, orography and landuse parameters (cf. Adam et al. (2004, pp. 8)). In the pre-processing of the model, the expected EFLH were calculated with the help of a normalized single-turbine power curve (cf. section 2.3.3.1) and under consideration of the Weibull parameters k

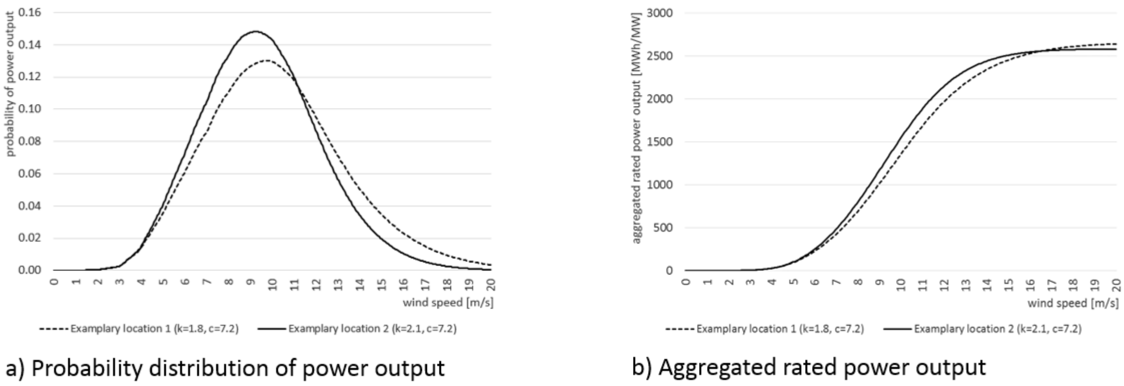


Figure 2.11: Exemplary annual power output probability distribution and integral

Own illustration. Different shape parameters k and a normalized single-turbine power curve utilized in the example.

and c for a height of 80 m above the ground for every square kilometer of the remaining terrestrial area after the geographical analysis. The resulting EFLH were stored in the model database and acted as a central input in the capacity allocation part of the model.

2.3.2.2 Wind speed time series

The long-term mean wind speed data as presented in section 2.3.2.1 provided sound information for the calculation of the expected power output from WTGs in a square kilometer resolution for Germany. Those mean figures, however, did not include information about the exact wind speed at a specific point in time which was relevant in the second main core part of the model in which the power production was modeled in a high temporal resolution. The long-term mean values thus could not act as an input parameter to that model part. That is why in the second core model part measured time series of wind speeds were taken into consideration for this purpose. In the model, the recorded wind speeds – i.e. time series – at a measuring station or measuring point represented the wind speeds in the district the measuring station was located in and partly in nearby districts.

Annual wind speed data series from Deutscher Wetterdienst (DWD) (2013) for onshore areas and from Geyer & Rockel (2013) for offshore areas were utilized. The latter were based on satellite observation of wave activity. The wind speed time series from DWD were recorded data from meteorological stations in Germany.

In the following the wind speed time series of a specific year is referred to as "wind year". In light of other research conducted at the Europa-Universität Flensburg (development of the renpass model, cf. Wiese (2015) and Bökenkamp (2015)) it was decided that the model should be able to handle several wind years to be selected for the calculations. The new model was designed in that way, for this thesis however only historical wind speed data from 2010 for all basic calculations and wind speed data from 2003 for a sensitivity analysis (cf. section 3.4) were applied in the model because they showed sound qualitative and quantitative characteristics.

The wind year 2010 is regarded as a year of rather low wind speeds compared to the years before (cf. also Internationales Wirtschaftsforum Regenerative Energien (IWR), 2011). All modeling results therefore need to be regarded in view of this fact.

The aim was to establish a $1 : n$ relation between measuring stations and districts, i.e. one measuring station representing the wind speeds of n districts. Although wind speed data from the 193 onshore measuring stations operated by DWD were available, only a reduced number was utilized in the model. Not all the measuring stations provided sufficiently enough wind speed data of a full year due to sensor failure, measuring errors, and station downtimes due to maintenance. If more than 10 % of the annual measurements were missing, the station was excluded from further consideration. If applicable, minor gaps in the wind speed time series were linearly interpolated. Moreover, measuring stations at locations that appeared not to be representative for a district or several districts – such as measuring stations located on exposed locations, for instance on hilltops – were also excluded. That reduced the number of measuring stations to be utilized in the model to 165.

As some of the districts incorporated several of the measuring stations and others none at all, further measuring stations were excluded. For those districts with more than one measuring station, only one of these was selected to be applied in the model. In most cases the measuring station located closest to the district's geographical centre was selected. For those districts not containing any measuring station, the closest measuring station nearby, i.e. located in a neighbouring district, was selected.

At the end of this pre-processing step, 149 measuring stations were utilized in the model and every district was related to one measuring station. This implied a relation of 2.8 districts or approx. 2400 km^2 represented by one measuring station. The measuring stations considered in the model are displayed in figure 2.12. In the figure, meteorological stations available and applied in the model are depicted. A full list of the measuring stations utilized in the model can be found in table B5 in the appendix.

For the offshore areas, wind speed time series derived from satellite-monitored waval measurements from the COSMO-CLM model by Helmholz-Zentrum Geesthacht were utilized in the model (Geyer & Rockel (2013)). From that source, hourly wind speed

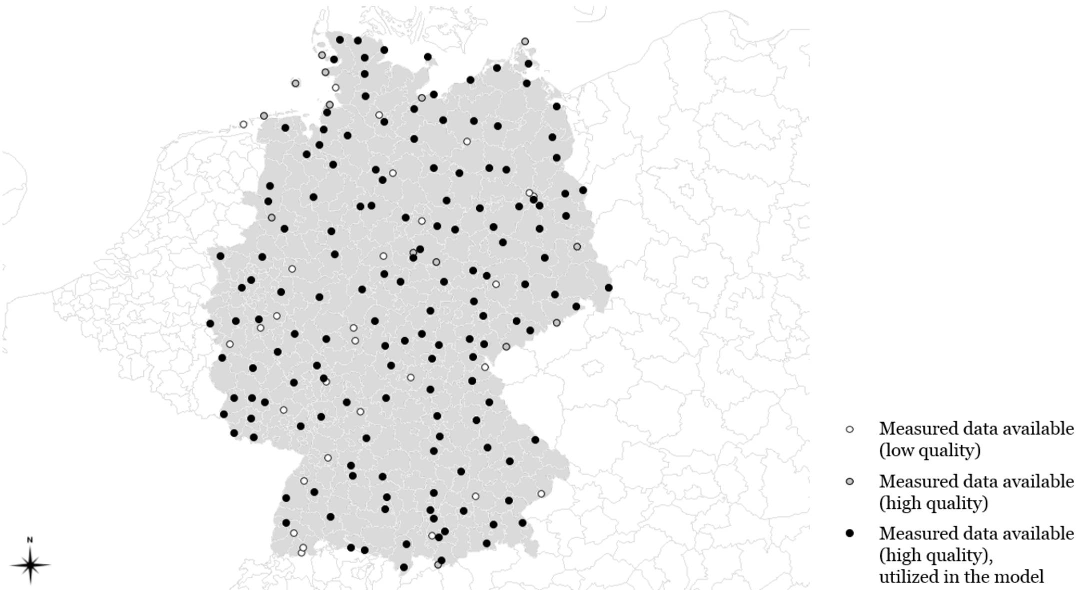


Figure 2.12: Meteorological stations considered in the model
Own illustration based on Deutscher Wetterdienst (DWD) (2012)

data of measuring points in a resolution of approx. 1.3° (longitude) and 0.7° (latitude), respectively, for a height of 10 m above the sea level were available. For the model, measuring points from that data source located in or close to the German EEZ were selected. Two of the locations selected for the model were located outside the German EEZ but close to potential areas for wind power use (cf. section 2.3.1.2). Similar to the case of the onshore areas, a $1 : n$ relation between the offshore sub-regions and the measuring points was created. This resulted in a number of 15 measuring points to be applied in the model. The offshore measuring points considered in the model are illustrated in figure 2.13.

In the model, these measuring points and their respective wind speed time series were handled in the same way as the onshore measuring stations and their respective wind speed time series as presented above, i.e. they were pre-processed and stored in the model database. In the electricity production part of the model, measured wind speeds were related to the installed wind power capacity in the districts or offshore sub-regions they represented and WTG hub heights in order to derive power production time series.

2.3.2.3 Wind shear coefficients

Wind speeds at a specific location do not only fluctuate over time but they also depend on the measuring height above the ground and the ground characteristics, i.e. orographic

Figure 2.13: Offshore wind speed measuring points incorporated in the model
Own illustration based on Geyer & Rockel (2013)

conditions. In principle wind speeds increase with an increasing height above the ground (cf. Bundesverband WindEnergie e.V. (BWE) (2012b, p. 14)).

In the electricity production part of the model, recorded wind speed time series from the measuring stations were converted into wind speed time series at the hub heights of WTGs in the years of consideration. With the help of a WTG power curve, these wind speed time series at hub height were then transformed into power production time series.

Two model approaches for the conversion of wind speeds from one height to another are commonly used: the log law and the power law (cf. Kubrik et al. (2011)). In the model developed, the power law as presented in equation 3 was applied. Kubrik et al. (2011, p. 4080) described it to be more conservative than the log law.

$$\left(\frac{v_1}{v_2}\right) = \left(\frac{h_1}{h_2}\right)^{\alpha} \tag{3}$$

where

- α: wind shear coefficient (exponent)

- h_1: height 1 [m]
- h_2: height 2 [m]
- v_1: windspeed at height 1 [m/s]
- v_2: windspeed at height 2 [m/s]

Equation 3 shows the relation between different wind speeds at different heights. The location-dependent wind shear coefficient α acts as the exponent in the equation. With the wind shear coefficient, barriers in the terrain are taken into account in the vertical extrapolation of wind speeds. Fewer and smaller barriers (e.g. seas or lowlands) result in a high wind shear coefficient whereas a low wind shear coefficient can be found in locations with many or larger barriers (e.g. forests, buildings, mountains).

The equation can be resolved into the wind shear coefficient α as a function of wind speeds and heights above the ground (equation 4). For all locations of the meteorological stations utilized in the model, the wind shear coefficient was calculated from the long-term mean wind speeds at their closest data point as found in Deutscher Wetterdienst (DWD) (2011b) for two measuring heights (10 m and 80 m above the ground).

$$\alpha = \log_{(\frac{h_1}{h_2})}(\frac{v_1}{v_2}) \tag{4}$$

A similar approach was followed for the offshore sub-regions in the model. The wind shear coefficients at the offshore measuring points were calculated from recorded wind speed data at the FINO research platforms in the North Sea and Baltic Sea (Forschungsplattformen in Nord- und Ostsee). The three FINO platforms – FINO 1 and FINO 3 located in the North Sea, FINO 2 located in the Baltic Sea – have been operated by Germanischer Lloyd WindEnergie GmbH for the Federal Ministry for Economic Affairs and Energy (Bundesministerium für Wirtschaft und Energie) (BMWi), the BMVI, and the Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety (Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit) (BMUB). Wind speed data from those measuring stations were available for different measuring heights (Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2015a)) and wind shear coefficients were calculated applying equation 4 to be used as representative wind shear coefficients in all the offshore sub-regions (southern part of the EEZ in the NS, i.e. southwest of the main naval passage: wind shear coefficient from FINO 1; northern part of the EEZ in the NS, i.e. northeast of the main naval passage: wind shear coefficient from FINO 3; EEZ in the BS: wind shear coefficient from FINO 2).

The wind shear coefficients at all measuring stations and measuring points, respectively, were stored in the model database and related to their respective measuring location. Through the relation in the model between measuring stations and districts, every wind shear coefficient at a measuring station was concurrently related to the districts or offshore sub-region represented by that measuring station. Additionally, besides the wind shear coefficient, the measuring height at the measuring stations and measuring points, respectively, was also stored in the model database, relevant for the scaling of wind speeds to the hub heights in the power production part of the model. The application of a multi-turbine power curve in the electricity production part of the model ensured to take potential topological differences within the districts into account.

2.3.3 Technical data

Technical characteristics of WTGs played an important role in both core parts of the model, i.e. for the spatial allocation of wind power capacity and for the electricity production. Four main types of technical parameters were utilized in the model, each subdivided into data relevant for onshore and offshore WTGs:

- power curves,
- rated power,
- hub height and
- rotor diameter.

The technical parameters applied in the model represented a diversity of available WTGs. Except for the power curve, the data were stored as time series in the model database, i.e. as annual figures until 2050. The three parameters nominal power, hub height and rotor diameter represented the size of WTGs that would be newly installed in a particular scenario year. It must be emphasized that all scenario data in the model have been based on best technical estimates. Potential deviations from the assumed development however might occur in the future.

2.3.3.1 Power curves

The power curve of a WTG describes its power output as a function of the wind speed at hub height. In the model, power curves were relevant for the conversion of wind speed time series into power production time series. They were applied at two stages of the model: as an input to the pre-processing of model data (calculation of EFLH, cf. section 2.3.3.3) and in the electricity generation part.

Two types of WTG power curves were applied in the model:

- single-turbine power curves and
- multi-turbine power curves.

Depending on the wind speed at hub height, a WTG's performance can range from zero – i.e. no power output – to its rated power. Power generation starts at the so-called cut-in wind speed. The upper limit is the shutdown or cut-out wind speed under which the WTG is taken out of operation for protection reasons, for instance during heavy storms. For the model it was assumed that a WTG would stop its production instantly if its shutdown wind speed was reached, i.e. a sloping power production as found with some WTGs available on the market was disregarded in the model.

In the model database, a normalized single-turbine power curve was stored for onshore WTGs and one for offshore WTGs. They were derived from power curves of commercially available onshore and offshore WTGs in a three step approach as illustrated in figure 2.14.

In the first step, representative power curves of 29 onshore and 3 offshore WTGs were analyzed (image a). A full list of the WTGs incorporated in the model can be found in table B1 in the appendix.

It was assumed that the WTGs would fully stop producing electricity at a cut-out wind speed of 25 m/s, resulting in a sharp ascend of the curve. The power curves were stored as data sets in bins of 0.5 m/s, which approximated well the relation between the power output P and the wind speed v (cf. Milan (2008, p. 2)).

In order to make the different power curves comparable and processible in the model, they were normalized in a second step (image b), i.e. their power output at the different wind speeds was divided by their rated power. In a third step, the arithmetic mean of the normalized power curves was derived (image c), to be used as the single-turbine power curves in the model.

The onshore single-turbine power curve was utilized for the calculation of expected EFLH (cf. section 2.3.3.3) in the data pre-processing part of the model. As presented, EFLH were derived for every onshore square kilometer potentially available for wind power installations, relevant in the capacity allocation part of the model.

It was however necessary to also apply a multi-turbine power curve in the electricity generation part of the model. As presented, in the model a set of temporally highly

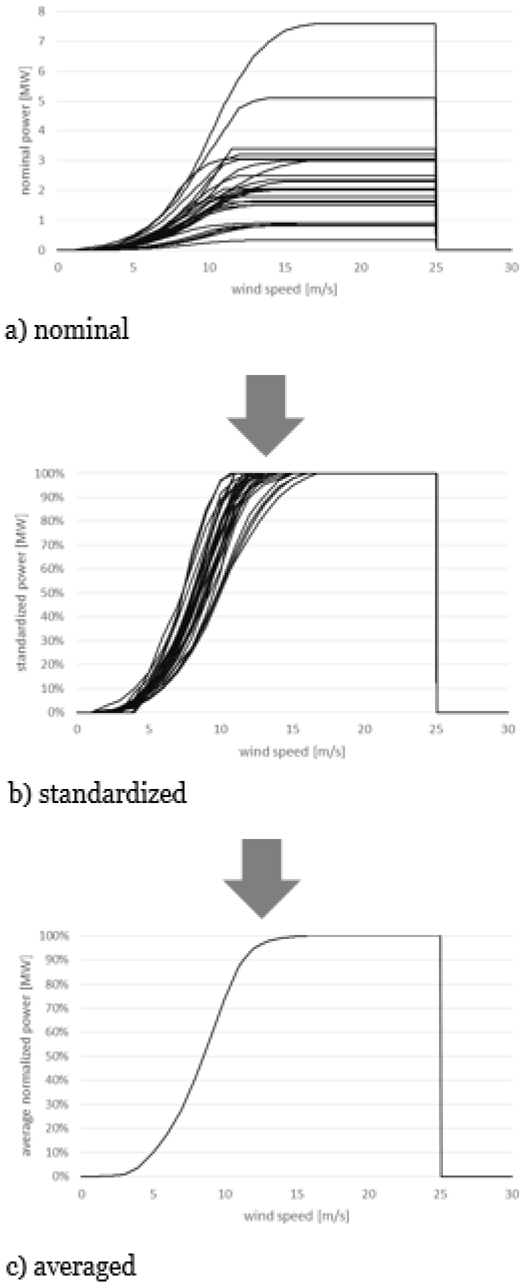


Figure 2.14: WTG power curves: nominal, normalized and averaged
Example: onshore wind turbine generators. Based on the power curves of 29 onshore WTGs (list in table B1 in the appendix)

resolved wind speed data represented the wind speeds in one or several districts and offshore sub-regions, respectively. Within the area represented by a measuring station, however, wind speeds might deviate from these measured data (cf. Manwell et al. (2009, pp. 429)). With a specific probability, wind speeds at locations near the measuring station can be lower or higher than directly at the measuring station.

As the distribution of wind speeds affects the power output of WTGs in the region, a smoothed multi-turbine power curve as described by Nørgaard & Holttinen (2004) and also applied in Deutsche Energie-Agentur GmbH (dena) (2010a, pp. 68) was taken into account in the electricity production part of the model. A specific wind speed observed at a measuring point – thus the corresponding power output of a WTG – can be found with a probability distribution in a region represented by that measuring point. The combination of the probability distribution of wind speeds and the single-turbine power curve results in a multi-turbine power curve as presented in figure 2.15. In equation 5 the calculation of the discrete elements of the multi-turbine power curve is expressed.

$$Pm_j = \sum_i Ps_j(i) \cdot ps(i) \tag{5}$$

where

- Pm: Power (multi-turbine power curve)
- Ps: Power (single-turbine power curve)
- ps: Probability of the spatial distribution
- i: index of wind speeds
- j: index of discrete elements of the power curves

Each discrete element of the multi-turbine power curve (Pm_j) is calculated by summing the products of the j^{th} element of the single-turbine power curve – describing the power output Ps at a specific wind speed v – and the respective probability ps of all wind speeds i around v.

The multi-turbine power curve thus represents the normalized power output of a WTG under consideration of a probability distribution of wind speeds in the region of consideration. At low wind speeds, the multi-turbine power curve has a similar shape as the single-turbine power curve. At higher wind speeds its shape is different: while the single-turbine power curve falls steeply at shutdown wind speed, the multi-turbine

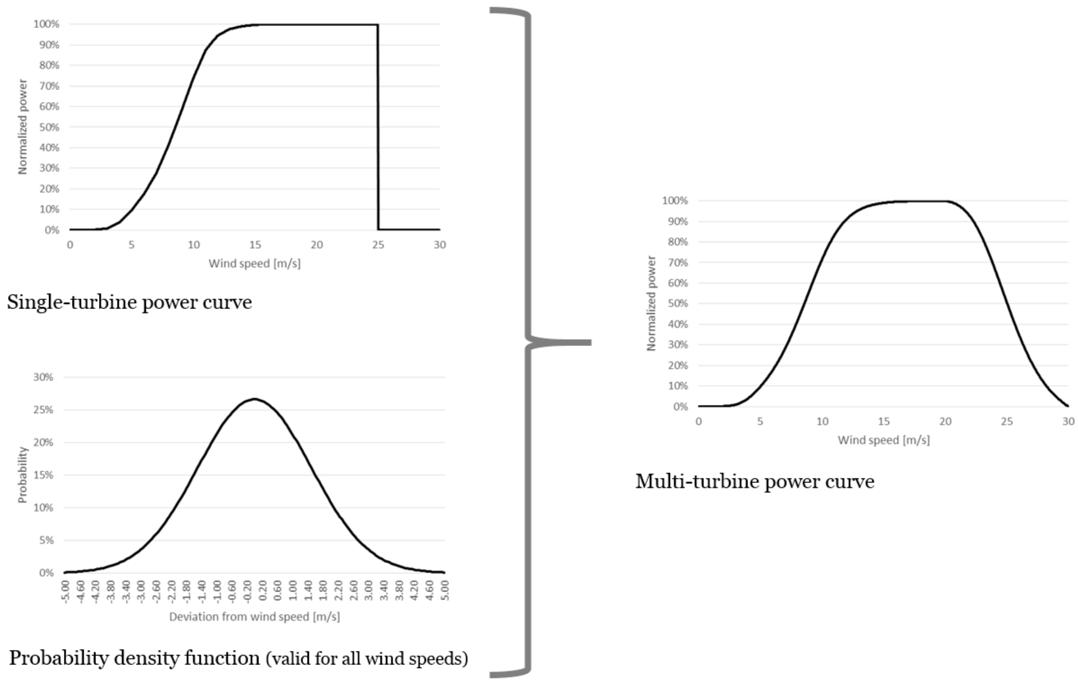


Figure 2.15: Principle of deriving a multi-turbine power curve
The probability density function was determined to be valid for all windspeeds.

power curve falls more smoothly, reaching a production of zero at a higher wind speed than the single-turbine power curve.

By utilizing the multi-turbine power curve, wind speed differences within the regions the measuring station represented were taken into account. By its application in the electricity generation part of the model, the wind speed time series from the measuring stations could remain unchanged in the model database.

For the model, both the single-turbine curves and the multi-turbine power curves were generated for onshore and for offshore wind power. As presented, the multi-turbine power curves were utilized in the pre-processing step of the calculation of expected EFLH whereas the multi-turbine power curves were applied in the electricity production step of the model. For a sensitivity analysis, the applied multi-turbine power curve was altered (cf. section 3.4).

2.3.3.2 Wind turbine generator sizes

Besides a WTG's performance under specific wind speed conditions, its size and its size evolution were taken into account in the model. This was relevant in both the capacity allocation part and the electricity production part of the model.

Table 2.4: Size development of wind turbine generators

Category	unit	1990	2000	2010	2020	2030	2040	2050
Onshore								
Rated power	MW	0.16	1.09	2.00	3.40	4.40	5.00	5.50
Hub height	m	30	70	98	122	127	131	132
Rotor diameter	m	22	57	79	102	116	124	130
Offshore								
Rated power	MW			5.00	6.00	10.00	15.00	18.00
Hub height	m			90	102	128	153	165
Rotor diameter	m			126	136	175	215	235

Based on Landwirtschaftskammer Schleswig-Holstein (2003), Landwirtschaftskammer Schleswig-Holstein (2004), Landwirtschaftskammer Schleswig-Holstein (2005), Landwirtschaftskammer Schleswig-Holstein (2006), Landwirtschaftskammer Schleswig-Holstein (2007), Scholz (2010), Deutsche Offshore-Testfeld und Infrastruktur GmbH & Co. KG (DOTI) (2012), Bundesverband WindEnergie e.V. (BWE) (2015b) and own calculations

A WTG's size can be expressed by its nominal power, its hub height and its rotor diameter. In the past, WTGs have increased in size due to technical improvements of compoments, cost reductions due to improvements in the production processes and due to scale effects.

The past and the future development of the average nominal power, the hub height and the rotor diameter of newly installed WTGs as applied in the model is listed in table 2.4 and illustrated in figure 2.16. As new onshore and offshore WTGs on average have had different sizes in the past and will expectedly have in the future, datasets for both onshore and offshore were developed independently from each other for the model. Even though the projections for the model presented in this thesis were based on expert estimates and judgment, the assumed future development bears uncertainties that cannot be quantified. All model results need to be viewed in this light.

Size figures from the past were derived from installation registers (Landwirtschaftskammer Schleswig-Holstein (2003), Landwirtschaftskammer Schleswig-Holstein (2004), Landwirtschaftskammer Schleswig-Holstein (2005), Landwirtschaftskammer Schleswig-Holstein (2006), Landwirtschaftskammer Schleswig-Holstein (2007)), Deutsche Offshore-Testfeld und Infrastruktur GmbH & Co. KG (DOTI) (2012), Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES) (2012, p. 28) and Bundesverband Wind-

Energie e.V. (BWE) (2015b), expected future sizes were utilized according to Scholz (2010). Missing data were linearly interpolated.

The nominal power is the rated power a WTG can deliver at maximum. In the model database, the nominal power of newly installed WTGs was stored as annual values for every year between 1990 and 2050 (illustrated in image a in figure 2.16), ranging from 200 kW to 5.5 MW for onshore WTGs and from 5.0 MW (2010) to 18.0 MW (2050, cf. Scholz (2010, p. 52)) for offshore WTGs, also taking WTG sizes from Germany's first commercial offshore wind farm Alpha Ventus in the North Sea into account (cf. Deutsche Offshore-Testfeld und Infrastruktur GmbH & Co. KG (DOTI) (2012, p. 2)).

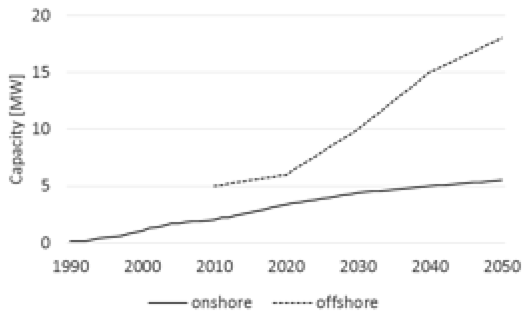
In the electricity generation part of the model, measured wind speeds were scaled to the hub heights of new WTGs in every scenario year. As in the case of the rated power, the evolution of the hub heights of new WTGs was considered in the model for onshore and offshore separately for every year from 1990 to 2050. The hub heights ranged from 30 m (1990) to 132 m (2050) for onshore WTGs and from 90 m (2010) to 165 m (2050) for offshore WTGs (image b in figure 2.16).

In the capacity allocation part of the model, rotor diameters of newly installed WTGs were utilized as a central input to the calculation of the specific space requirement of new WTGs, defined by multiples of rotor diameters between WTGs, i.e. the spacing of WTGs. The exact method applied is presented in section 2.3.6.1.

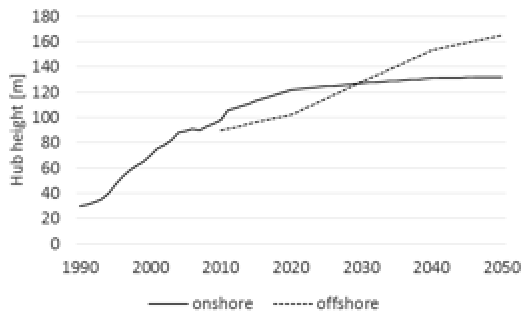
As rotor diameters have grown in dimension and can be expected to do so in the future, size evolution of WTGs strongly influences the allocation of wind power capacity as it translates into a specific space requirement of a WTG. This, again, would affect the electricity production in the scenarios modeled. As in the case of the nominal power and the hub height, the evolution of the rotor diameters was stored as annual time series in the model database, for onshore and offshore separately. Similar to the rated power and the hub height, the rotor diameter of WTGs was expected to become larger until 2050, ranging from 22 m (1990) to 130 m (2050) for onshore WTGs and 126 m (2015) to 235 m (2050) for offshore WTGs (image c in figure 2.16).

2.3.3.3 Equivalent full load hours (EFLH)

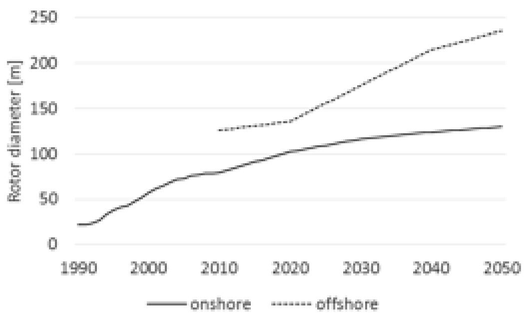
The aim of the capacity allocation part of the model was to allocate wind power capacity to those locations first where the LCOE of wind power were expected to be the lowest, i.e. in an economically optimized way, year by year. For the allocation of WTGs, in the model it was therefore crucial to rank available areas, i.e. square kilometers, and to let the capacity allocation, i.e. the usage of areas, take place according to this order. For onshore wind power, a central input to the calculation of the expected levelized cost of



a) Rated power



b) Hub height



c) Rotor diameter

Figure 2.16: Size evolution of wind turbine generators
Based on Landwirtschaftskammer Schleswig-Holstein (2007), Landwirtschaftskammer Schleswig-Holstein (2006), Landwirtschaftskammer Schleswig-Holstein (2005), Landwirtschaftskammer Schleswig-Holstein (2004), Landwirtschaftskammer Schleswig-Holstein (2003), Scholz (2010), Bundesverband WindEnergie e.V. (BWE) (2015b) and own calculations

electricity (LCOE) – thus the central criterion for ranking the square kilometers – were the EFLH of every square kilometer potentially available (cf. section 2.3.4) .

EFLH are a measure of a power plant's degree of use and in some sources they are also called "equivalent full load operating hours" (cf. Jacobsen (2013, p. 5–6)). They express the duration (given as hours) a plant (here: a WTG) theoretically operates at its rated power during one year. EFLH thus are indicated in hours per year, however EFLH are repeatedly indicated dimensionless in the following. They are calculated by dividing the amount of electricity produced in one year (given as kWh/a) by the rated capacity producing this amount of electricity (given as MW) (cf. Quaschning (2015). Divided by 8760 h/a, the EFLH can be transformed into the electrical load factor (cf. Laughton (2007, p. 23)).

In the pre-processing for the model, the expected EFLH of onshore wind power were calculated for every square kilometer potentially available for wind power installations in Germany. At the end of each model run, actual EFLH were calculated again, based on the electricity production that again was based on recorded wind speed time series. In equation 6 the calculation of EFLH is expressed.

$$EFLH = \frac{Q}{P_{inst}} \tag{6}$$

where

- $EFLH$: equivalent full load hours (EFLH) [h/a]
- Q: (expected) electricity produced per year [MWh/a or kWh/a]
- P_{inst}: installed capacity [MW or kW]

In the equation, the amount of produced electricity is related to the installed capacity. In the pre-processing step for the ranking of available square kilometers in the model, the expected EFLH however were calculated according to equation 7 that corresponds to equation 6 calculated with a normalized power curve (similar to Gantenbein (2011, p. 92)). As presented, the calculation was based on long-term wind speed measurements from Deutscher Wetterdienst (DWD) (2011a), i.e. the Weibull parameters as presented in section 2.3.2.1 and the normalized single-turbine power curve as presented in section 2.3.3.

$$EFLH = \sum_{v} (p(v) \cdot Ps(v) \cdot 8760\,) \tag{7}$$

where

- $EFLH$: equivalent full load hours (EFLH) [h/a]
- v: wind speed [m/s]
- $p(v)$: occurrence probability of wind speed v [%] (cf. equation 2)
- $Ps(v)$: normalized power output of a WTG at wind speed v [%]
- 8760: hours per year [h/a]

The utilization of the dimensionless normalized power output of a WTG allowed to reduce the fraction in equation 6 and disregard the installed capacity. In the calculation, the occurrence probability p of wind speed v according to the Weibull parameters (cf. equation 2) for a measuring height of 80 m above the ground was multiplied with the normalized power output of a WTG ($Ps(v)$) (cf. section 2.3.3.1). By doing so, the probability of the power output at wind speed v was calculated. This figure multiplied with 8760 hours of one year resulted in the electricity amount produced at wind speed v during one year. Summed for all v in 0.5 m/s bins, the total produced electricity of a normalized WTG was calculated, hence EFLH. This calculation was conducted for every square kilometer of the onshore area that was detected to be potentially available for wind power installations according to the geographical analysis (cf. section 2.3.1.1).

In table 2.5 the resulting expected EFLH in the remaining areas (cf. section 2.3.1.1) in the federal states in Germany are listed. Besides the mean EFLH of every federal state, the minimum and maximum EFLH found in the federal states are listed in the table, indicating differences within and between the federal states. Under the assumptions made, the highest expected EFLH were found in Schleswig-Holstein (significantly greater than 2700 on average), the lowest were found in Bavaria and Saxony-Anhalt (below 1700 on average).

In the model, every square kilometer onshore and its corresponding EFLH value was assigned to the district it was located in and stored in the model database. In the model procedure in which the onshore wind power capacity was allocated, the square kilometers were sorted according to their EFLH and the individual square kilometers as well as the total and remaining area available in the districts and in the federal states were taken into acount.

2.3.4 Economic data

In the model, the central criterion for the spatial allocation of WTGs were the expected levelized cost of electricity (LCOE). Available locations with the least expected LCOE

Table 2.5: Expected EFLH of onshore wind power by federal states in Germany

Federal state	Min.	Max.	Mean
Baden-Württemberg	931	3308	1763
Bavaria (*Bayern*)	654	5144	1566
Berlin	n.a.	n.a.	n.a.
Brandenburg	1089	2678	1754
Bremen	2061	2427	2280
Hamburg	2013	2296	2124
Hesse (*Hessen*)	1021	4083	1920
Lower Saxony (*Niedersachsen*)	960	4276	2133
Mecklenburg West-Pomerania (*Mecklenburg-Vorpommern*)	1362	3644	2181
Northrhine-Westphalia (*Nordrhein-Westfalen*)	1082	3665	2203
Rhineland-Palatinate (*Rheinland-Pfalz*)	1053	3586	2110
Saxony (*Sachsen*)	1050	3442	1798
Saxony-Anhalt (*Sachsen-Anhalt*)	757	2748	1582
Saarland	1399	3097	1967
Schleswig-Holstein	1470	5464	2775
Thuringia (*Thüringen*)	1038	3308	1803
Germany	654	5464	1949

Calculations based on Deutscher Wetterdienst (DWD) (2011a), Deutscher Wetterdienst (DWD) (2011b), WTG power curves (list in table B1 in the appendix) and own assumptions.
Calculated for the remaining areas according to the geographical analysis for a height of 80 m above the ground.

were utilized for the allocation first. For onshore wind power this refers to all the individual square kilometers that were found to be potentially available, for offshore this refers to all the offshore sub-regions after the exclusion of unusable areas. The square kilometers and offshore sub-regions, respectively, were sorted in descending order according to their expected wind power performance. In principle, when a WTG was to be allocated in the model in a specific year, available areas from the top of the lists were utilized. Furthermore, the calculation of LCOE was again conducted at the end of each model run for every transmission grid region and for Germany as a whole, for wind power and for all VRE.

In LCOE, production cost and annual electricity production are related to each other (cf. Klessmann (2012, p. 8) and Hartmann et al. (2013, p. 36)). LCOE comprise "five primary factors: annual energy production, investment cost, O&M cost, financing cost and the assumed economic life of the plant" (Intergovernmental Panel on Climate Change (IPCC) (2011, p. 583). In equation 8 (based on National Renewable Energy Laboratory (NREL) (2016b)) the calculation of LCOE is expressed. In the equation, the full production cost over the technology's lifetime are related to its electricity production in the same period. Other non-priced cost such as external cost (cf. Berck & Helfand (2011, pp. 222) and Tietenberg & Lewis (2009, pp. 72)) due to climate change or ambient air pollution or their avoidance have not been included in the calculations of the model.

$$LCOE = \frac{\sum_{n=0}^{N} \frac{C_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+r)^n}} = \frac{\sum_{n=0}^{N} \frac{I_n+M_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+r)^n}} \tag{8}$$

where

- n: index of years
- $LCOE$: levelized cost of electricity [Ct./kWh]
- C_n: annual total levelized cost [€] ($= I_n + M_n$)
- I_n: annual levelized fixed cost (LFC) [€]
- M_n: annual levelized variable cost (LVC) [€]
- Q_n: annual energy [kWh/a]
- N: project lifetime [number of years]

- r: discount rate [%]

As shown in equation 8, for the calculation of LCOE the cost and the amount of electricity produced during a plant's lifetime are related to each other. The total annual cost is the sum of the total annual levelized fixed cost (LFC) and the total annual levelized variable cost (LVC) (cf. The Pennsylvania State University (PennState) (2016)).

Derived from equation 8 and also based on National Renewable Energy Laboratory (NREL) (2016a), a simplified equation expresses LCOE in which the annual cost and the annual electricity production in the year of analysis are related to each other (equation 9, cf. Jacquemin et al. (2011, p. 8)):

$$LCOE_t = \frac{C_t}{Q_t} = \frac{I_t + M_t}{Q_t} \tag{9}$$

where

- t: year of analysis = target year
- C_t: annual total levelized cost in year t [€]
- I_t: annual levelized fixed cost (LFC) in year t [€]
- M_t: annual levelized variable cost (LVC) in year t [€]
- Q_t: annual energy in year t [kWh/a]

The fixed cost I in the year of analysis t is calculated as shown in equation 10:

$$I_t = \sum_{n=t-19}^{t} I_n = \sum_{n=t-19}^{t} c_{inv,n} \cdot P_n \cdot CRF \tag{10}$$

where

- n: index of years
- t: year of analysis = target year
- I_t: levelized fixed cost (LFC) in year t [€]
- I_n: levelized fixed cost (LFC) of installations from year n [€]
- $c_{inv,n}$: specific capital expenditures (CAPEX) in year n [€/MW]
- P_n: newly installed capacity in year n [MW]

- CRF: capital recovery factor = annuity factor

The fixed cost I in the year of analysis t is composed of the sum of the annuitized capital expenditures (CAPEX) I of all installations that have been installed in different years n, i.e. in the period between $y-19$ and y. CAPEX are non-recurring expenses for the investment in a WTG. They include mainly technical components, including the WTG's tower, its nacelle, its generator, and its rotor as well as the foundation and the grid connection.

In the model, the CAPEX occurring in the different years of installation were calculated as the product of the respective year's specific CAPEX read from the model database and the newly installed capacity P_n in that particular year as found in the previous core part of the model, multiplied with the capital recovery factor (CRF) (cf. Gantenbein (2011, p. 39)), sometimes also called "annuity factor" (cf. Hoogwijk (2004, p. 134)). With the CRF the annual consumption of expenditure of an installation was taken into account as presented in equation 11 (National Renewable Energy Laboratory (NREL) (2016a)), i.e. the initial investment was discounted.

$$CRF = \frac{i \cdot (1+i)^N}{(1+i)^N - 1} \tag{11}$$

where

- CRF: capital recovery factor = annuity factor
- i: real interest rate [%]
- N: discount period = project lifetime [number of years]

For the calculations a discount period of 20 years for wind power installations and an interest rate of 6 % were utilized. For a sensitivity analysis (section 3.4), calculations were also conducted using other discount rates and CAPEX, respectively.

Not only the discounted investment cost but also variable OPEX play an important role in the calculation of LCOE. OPEX are regularly cost occurring annually once a WTG is in operation. OPEX include expenses for rents, maintenance and servicing (or maintenance contract fees), technical and yield monitoring, repairs (including spare parts), operational management (including communication), and insurance fees. The annual variable cost M in the year of analysis t is calculated as a function of the installed capacity in the year of analysis $P_{inst,t}$ as presented in equation 12.

$$M_t = P_{inst,t} \cdot c_{varop,t} \tag{12}$$

where

- t: year of analysis = target year
- M_t: levelized variable cost (LVC) in year t [€]
- $P_{inst,t}$: total installed capacity in year t [MW]
- $c_{varop,t}$: specific variable operation expenditures (OPEX) in year t [€/MW]

The total installed capacity in the target year $P_{inst,t}$ is the sum of the capacity $P_{inst,n}$ newly installed in all nineteen years prior to the target year and in the target year (equation 13).

$$P_{inst,t} = \sum_{n=t-19}^{t} P_{inst,n} \tag{13}$$

where

- t: year of analysis = target year
- n: index of years
- $P_{inst,t}$: installed capacity in year t
- $P_{inst,n}$: capacity newly installed in year n

The amount of electricity Q produced in the year of analysis t is shown in equation 14. It is the sum of electricity produced by capacity installed in the nineteen years prior to the target year and in the target year. The electricity produced in a quarter of an hour q is the product of the installed capacity and the normalized power output of a multi-turbine power curve, depending on the wind speed in that moment. The factor $1/4$ in the equation is considered due to the quarters of an hour and in order to receive an energy amount given as TWh/a at the end.

$$Q_t = \sum_{n=t-19}^{t} Q_n = \sum_{n=t-19}^{t} \sum_{q} Pm_q \cdot P_{inst,n} \cdot 1/4 \tag{14}$$

where

- t: year of analysis = target year
- n: index of years

- q: index of time steps [quarters of an hour of one year]
- Q_t: electricity produced in year t [TWh/a]
- Q_n: electricity produced by capacity installed in year n [TWh/a]
- Pm_q: rated power output (multi-turbine power curve) im time step q
- $P_{inst,n}$: capacity newly installed in year n

In the model, the amount of produced electricity was calculated for every district in dependency of the wind speed conditions and installed capacity (cf. equation 16), i.e. equation 14 was further transformed.

Summing up, at the end of each model run LCOE were calculated as expressed in equation 15.

$$LCOE_t = \frac{\left(\sum_{n=t-19}^{t} c_{inv,n} \cdot P_{inst,n} \cdot \frac{i\cdot(1+i)^N}{(1+i)^N-1}\right) + \sum_{n=t-19}^{t} P_{inst,n} \cdot c_{varop,t}}{Q} \tag{15}$$

Due to an increasing market diffusion and the global market development, wind power cost has decreased in the past and can be expected to further decrease in the future due to "more efficient material usage, increased reliability and energy capture, reduced operation and maintenance costs and longer component lifetimes" (Intergovernmental Panel on Climate Change (IPCC) (2011, p. 540)). Both CAPEX and OPEX thus were assumed to undergo a development over time in the model.

Equation 15 was valid for both onshore and offshore wind power but it was utilized differently for onshore and offshore in the capacity allocation part of the model. LCOE of onshore wind power were regarded to be mainly driven by the expected electricity yield. For offshore installations, the ranking of locations for the allocation of wind power capacity was primarily based on differences in CAPEX and OPEX.

For the allocation of onshore WTGs, in the model the CAPEX and the OPEX were assumed to be equal throughout Germany. This was a simplification that disregarded potential different plant configurations and other cost-influencing parameters that might occur region-specifically or site-specifically, for instance area rents, the grid connection and other site-specific parameters such as foundation requirements. With this approach however the ranking of locations in the model could be conducted using the denominator of equation 15 only, thus the calculation of the expected electricity production Q for every square kilometer which again could be expressed by the expected EFLH because the nominator of the equation would have returned the same result for all locations.

At the end of each model run, LCOE were calculated again applying equation 15. Data on onshore CAPEX and OPEX therefore were stored in the model database. The specific investment cost for onshore wind power were expected to decrease from € 1150 K per MW in 2010 to € 850 K per MW in 2050, based on Deutsches CleanTech Institut GmbH (DCTI) (2010, p. 38) and Scholz (2010, p. 52). The OPEX of onshore wind power were assumed to be a function of the installed capacity. Being 4 % of the investment, annual onshore OPEX was expected to develop from € 46 K per MW (2010) to € 34 K per MW (2050).

For the allocation of offshore wind power capacity, the numerator in equation 15 was utilized in the model for ranking the offshore sub-regions according to the expected least LCOE, assuming equal wind speed conditions in all the offshore sub-regions as a first approximation. An analysis of the wind speed time series applied in the model for the offshore sub-regions showed that they did not substantially differ from each other and neither would do the expected energy yield. In relation to substantial differences in expected cost driven by different distances to grid connection points and service harbours (cf. section 2.3.1.2) it was decided to assume potential local deviations in wind speeds as comparably small. The ranking thus took place according to the least cost (expressed as €/MW) in the offshore sub-regions.

The CAPEX of offshore installations were determined to be mainly driven by two technical aspects: the water depth at the location of installation and the distance between the location and the according grid connection point on shore. Water depth directly translates into technical requirements, thus cost, for the foundations whereas the distance between the location and the grid connection point directly translates into the cabling length for the assumed HVDC links, thus cabling cost. Other CAPEX components that are not location-specific such as the generator, the electrical system (in-park cabling, relay station offshore, transformer station onshore) were also taken into account as a function of the capacity to be installed.

The OPEX of offshore wind power installations depend on the distance between the wind power installation and the service port or harbour for maintenance, repair and operations (MRO) and the overall capacity to be maintained. Depending on the distance between the WTG and the respective service port or harbour, ships or helicopters are used for MRO, resulting in distanct-specific OPEX.

As presented in section 2.3.1.5, water depths and the distances between the offshore sub-regions and their corresponding grid connection point and service harbour were analyzed in a pre-processing step of the model. They were stored in the model database to be accessed in the capacity allocation part of the model.

Table 2.6: Cost components of offshore wind power in the model

	Cost component	Cost 2010	Cost 2050	Unit
CAPEX	Rotor, tower, generator	1.85	0.89	M€/MW
CAPEX	Foundation	0.04	0.01	M€/MW per m of water depth
CAPEX	HVDC Cable	1.00	0.48	K€/MW per km of distance to grid connection point
CAPEX	Electrical system	0.51	0.24	M€/MW
OPEX	Maintenance ($\leq$ 20 km)	54.26	12.90	K€/MW per annum
OPEX	Maintenance ($\geq$ 20 , $\leq$ 50 km)	54.26	12.90	K€/MW per annum
		+ 0.06	+ 0.01	K€/MW per any further km of distance from service port per annum
OPEX	Maintenance ($>$ 50 km, $<$ 150 km)	55.98	13.30	K€/MW per annum
		+ 0.09	+ 0.02	K€/MW per any further km of distance from service port per annum
OPEX	Maintenance ($\geq$ 150 km)	67.34	16.00	K€/MW per annum

Based on Baldock & Jacquemin (2009), Scholz (2010), Jacquemin et al. (2011), Greenacre (2012) and own calculations

The cost of offshore wind power components applied in the model are presented in table 2.6. The figures were based on Baldock & Jacquemin (2009), Scholz (2010), Jacquemin et al. (2011) and Greenacre (2012). For each of the cost positions, a future development was deduced according to Greenacre (2012), Intergovernmental Panel on Climate Change (IPCC) (2011), Scholz (2010) and Jacquemin et al. (2011, p. 50), also taking learning curves of the technologies into account. It must be pointed out that the future figures need to be treated with caution because they incorporate uncertainties.

As presented in the table, the investment cost of a WTG and its initial installation cost were assumed not to be location-dependent but to be a function on the amount of capacity to be installed. In the model, the foundation cost (monopile design assumed, cf. Jacquemin et al. (2011, p. 13)) was considered as a function of water depth. Cost of the electrical system was taken into account as capacity-specific figures (in-park cabling, offshore relay station, onshore transformer station) whereas the HVDC link between the respective offshore sub-region and the shore was assumed to be a function of the capacity and the cable length. OPEX were calculated as a function of the water depth and the detected distances, respectively.

In the model, the specific cost (€/MW) for every offshore sub-region was calculated for every scenario year. For this calculation, all the CAPEX and OPEX parameters as well as the distances to the corresponding service ports and harbours and the grid connection points were taken into account. The offshore sub-regions were sorted in descending order of these calculated specific cost. The available least-cost offshore sub-region areas were utilized for the allocation of offshore wind power capacity first.

In the results aggregation part of the model, i.e. in the post-processing, the LCOE of both onshore and offshore wind power was calculated again according to equation 15 and taking the electricity produced in the target year as well as CAPEX and OPEX and their development over time into account.

In the post-processing part of the model, the LCOE of PV and run-of-the-river hydro power was also calculated applying the equation presented. Their CAPEX and OPEX that was also expected to develop over time are presented in their corresponding sections in this work. At the end of each model run, the LCOE of all VRE combined was calculated on the basis of the LCOE and energy amounts produced by the individual technologies.

2.3.5 Scenario data

The central driver of the model was the development of the installed VRE capacity over time. This development was defined in scenarios, i.e. the development of a set of installed capacity over time consisting of onshore and offshore wind power, PV and run-of-the-river hydro power, supplemented by figures on the future development of the power demand and the available transmission capacity between grid regions and cross-border. Besides the development in the future, the historical development of the installed capacity was also incorporated in the model.

In more detail, scenario data included the following categories:

- installed total capacity until the target year (onshore and offshore wind power, PV, run-of-the-river hydro power) by federal states and offshore regions, respectively,
- capacity already installed (onshore and offshore wind power) or approved (offshore wind power),
- annual electricity demand (load) and
- transmission capacity between the transmission grid regions and between Germany and its neighbouring countries.

At the beginning of a model run, a pre-defined scenario as stored in the model database needed to be selected in the model's front-end. The scenario categories are introduced in this section. The scenario data that were applied in the modeling are presented in section 3.2.

2.3.5.1 Development of the installed capacity

A central input to the model and subject of the analyses was the installed capacity of

- onshore wind power,
- offshore wind power,
- PV and
- run-of-the-river hydro power.

They were stored as time series from 1990 until the target year (with 2050 at maximum) in the model database, i.e. as annual capacity figures (given as MW). The scenario figures of onshore wind power were stored as federal state-specific installation expansion pathways that summed up to a national installation expansion pathway. This allowed to model pre-defined national scenarios (e.g. an installation pathway reaching X GW in 2050) as well as scenarios with federal state-specific installation targets of the same total capacity (e.g. an installation pathway reaching X GW in Germany in 2050 with a pre-defined split into Y GW in federal state A and Z GW in federal state B etc.).

In the capacity allocation part of the model, the figures of the installed capacity of onshore and offshore wind power were read from the model database. They acted as the basis for the calculation of the capacity to be additionally installed in every scenario year, supplemented by capacity that went into operation twenty years earlier and thus were regarded to be repowered capacity-wise.

As presented in this section, the spatially resolved figures of the installed PV capacity were used to scale the present district-specific installation to a district-specific installed PV capacity in the year of analysis whereas due to its limited expansion potential (cf. section 2.4.2), the installed capacity of run-of-the-river hydro power was pre-processed once and stored in the model database.

2.3.5.2 Installed wind power capacity

In the model developed, already installed onshore wind power capacity was taken into account. On the basis of §64e of the EEG law, the German TSOs have been obliged to provide information on all RES plants that fall below the EEG scheme which most wind power and PV plants in Germany did. The publicly available RES plant registers (Anlagenregister) (cf. Amprion GmbH (2013), TenneT TSO GmbH (2013), TransnetBW GmbH (2013), 50 Hertz Transmission GmbH (2013)) therefore provided information on nearly all wind power and PV plants in Germany, including information on the plant type, the installed capacity, the location and other aspects. Data on onshore wind power from those registers were GIS-processed and stored in the model database, i.e. the historic installed capacity related to the respective districts.

At the end of 2012, 30 996 MW of onshore wind power were installed in Germany (Bundesministerium für Wirtschaft und Energie (BMWi) (2015b, p. 7)). Most of the capacity was installed in the federal states in the North and in the East (cf. Agentur für Erneuerbare Energien (2015b)). Figure 2.17 illustrates the specific installed capacity in MW/km^2 in the German districts as of December 2012. The highest capacity density (darkest areas) was found in the districts of Emden in the federal state of Lower Saxony with 1.9 MW/km^2, and Bremerhaven in the city state of Bremen, Dithmarschen in Schleswig-Holstein and Greifswald in Mecklenburg-Western Pomerania with 0.7 MW/km^2 each. All coastal districts along the North Sea shore showed a high capacity density. So did a few districts in the inland, too. Those districts coloured white in figure 2.17 had no installed capacity by the end of 2012. Those were either densely populated regions such as the city of Berlin, the Ruhr area or the Frankfurt area or several districts in the Southern federal states of Baden-Württemberg and Bavaria.

In the capacity allocation part of the model, the existing district-specific installed capacity acted as a stop criterion for the allocation of onshore wind power capacity until 2012 (cf. section 2.6.1).

2.3.5.3 Approved offshore planning

Similar to the historic onshore wind power installation, existing and foreseeably realized offshore wind power installations were also taken into account in the model. As of 2015, nine offshore wind farms were in operation in German waters. By May 2015, 32 offshore wind farms were approved in Germany's EEZ in the North Sea and three in the Baltic Sea (Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2015b)). A full list of the approved offshore wind farms, their sizes (capacity) and their expected years of commissioning can be found in table B4 in the appendix. Although several further projects have been planned and applied for, the approved wind farms and thus the approved capacity could be regarded as to be the maximum that would be installed until 2020. Further projects that have not yet been approved were expected not to be

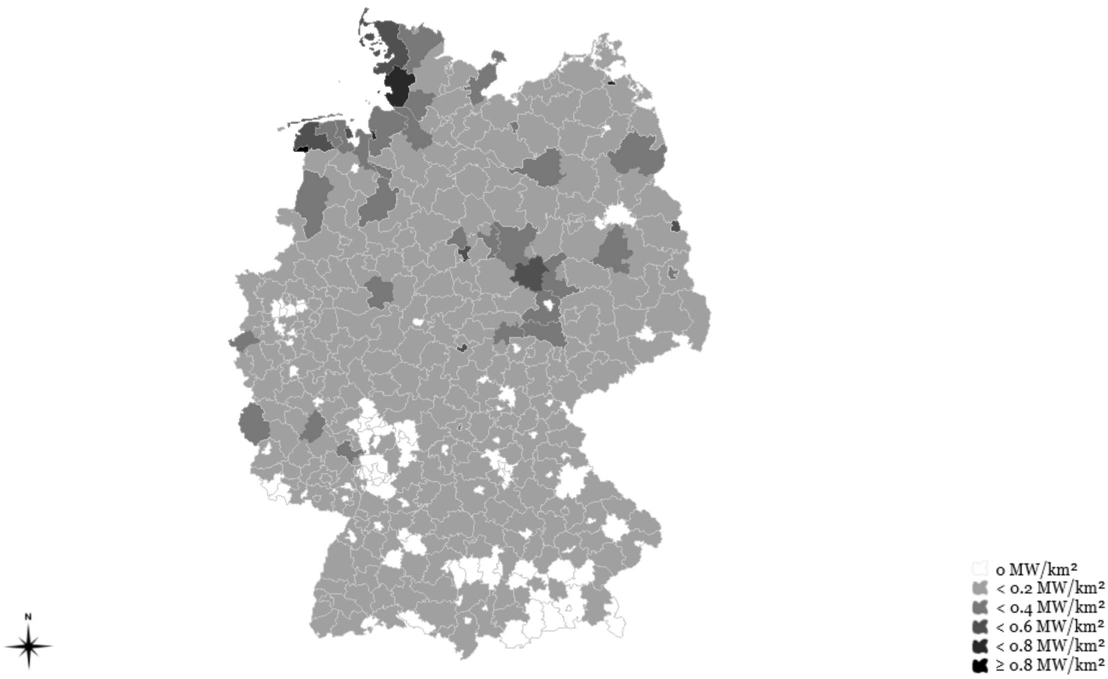


Figure 2.17: Capacity density of wind power in Germany by districts (2012)
Own illustration based on Amprion GmbH (2013), TenneT TSO GmbH (2013), TransnetBW GmbH (2013), 50 Hertz Transmission GmbH (2013) and Statistisches Bundesamt (Destatis) (2011)

installed prior to 2020. Figure 2.18 displays the offshore wind farms that already existed, that were being built or that have been approved.

Additionally, besides the approved wind farms in the EEZ there were a few wind farms with special approvals, located in the twelve mile zone, i.e. closer to the shore. As presented, their areas were considered in the model, too (cf. section 2.3.1.2).

The consideration of approved offshore wind farms and their relation to their respective offshore sub-regions in the model ensured that the foreseeable development was taken into account appropriately. The modeling mechanism for the allocation of offshore WTGs was similar to the allocation of onshore WTGs: in the capacity allocation part of the model, the approved installed capacity in the offshore sub-regions was not allowed and could not be exceeded before 2020.

2.3.5.4 Repowering

As any technology, WTGs reach the end of their service life at some point in time. For WTGs, technical reasons such as mechanical attrition of the rotor blades and of the

Figure 2.18: Approved offshore wind farms in the German waters in the North Sea and in the Baltic Sea
Own illustration based on Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2014) and offshore wind farm approvals (list in table B4 in the appendix)

gear are decisive factors for dismantling. Economic aspects such as a higher efficiency of newer WTGs or the period a feed-in tariff is guaranteed also play an important role for the dismantling of old wind power installations and their replacement by new ones.

A WTG thus can be expected to be dismantled or replaced at the end of its service life (cf. Bundesverband WindEnergie e.V. (BWE) (2012b)). In the model, a service life of twenty years was assumed for onshore as well as offshore WTGs. This also corresponds to the duration the feed-in tariff according to the EEG law was guaranteed.

In the model, the aspect of repowering was taken into account capacity-wise. The capacity of WTGs that were assumed to be decommissioned after their service life would be reinstalled in the subsequent year. The reinstallation thus did not necessarily take place at the same locations but at available locations with the expectedly highest EFLH. After the assumed lifetime of twenty years, area that had been occupied by a WTG during its service life was assumed to be available again for new installations. With this approach additional space requirements of new, i.e. larger WTGs were taken into account, which also was accompanied with a potential disqualification of sites that were in use by the end of 2012 but that did not suffice the space requirements of future WTGs or that showed comparably low expected EFLH.

2.3.6 Variable parameters

Besides the fixed parameters presented in section 2.3.3, further input to the model's capacity allocation part needed to be specified before the model was run. Those additional parameters could be regarded as variable as they were not stored in the model database but needed to be defined as additional inputs in the front-end of the model.

Two sets of parameters needed to be additionally defined in that sense, both dealing with the available area and the space required for wind power installations in the scenarios tested:

- spacing of WTGs (multiple rotor diameters in two directions as the criterion for a WTG's space requirement) and
- maximum shares of the federal state areas and the district areas as another limitation of the area availability.

Both parameter sets played a crucial role for the allocation of WTGs. The latter was relevant for onshore WTGs only and represented a new modeling approach.

2.3.6.1 Spacing of wind turbine generators

WTGs require specific minimum distances between each other in order to keep wake losses (cf. Sanderse (2009)) low, yet their power output high. A WTG thus occupies an area that cannot be utilized for other wind power installations. In the capacity allocation part of the model the specific space requirement of a newly installed WTG in any scenario year therefore was taken into account. In that part of the model, in every scenario year available areas were reduced by the space requirements of a newly allocated WTG, reducing the area potential for further wind power installations of the same year and of successive years.

Other than in current models, not a fixed ratio of wind power capacity and surface area (defined as MW/km^2) was utilized in the model. Instead, the space requirement of WTGs were defined as the spacing, i.e. the minimum distances between individual WTGs (in the following also referred to as "distance factors"). These minimum distances, again, needed to be defined as multiples of WTG rotor diameters in two perpendicular directions, representing the main wind speed direction and its perpendicular direction.

This approach reflected a fact relevant for the micro-siting of a wind farm: in the main wind speed direction usually a greater minimum distance between WTGs is required than in the perpendicular direction (cf. Kaltschmitt et al. (2007, pp. 332)).

The product of the rotor diameter in a particular year and the distance factors additionally defined resulted in the specific space requirement of an individual WTG that was newly built in a specific year (given as km^2/WTG and translated into km^2/MW in the model). In the multiplication, the rotor diameter of a new WTG in the actual scenario year as stored in the model database (cf. section 2.3.3.2) was taken into account. The model input on the spacing of WTGs could be differentiated between onshore and offshore, and onshore and offshore WTG rotor diameters were utilized in the calculation.

As minimum distances to excluded areas had already been taken into account in the geographical analysis (cf. section 2.3.1) it was assumed that WTGs would be allocated at the edges of the available area, resulting in a slightly increased capacity density the smaller the available area was. The specific space requirement of a WTG was therefore slightly reduced in the model, depending on area availability in the district the WTG was allocated.

2.3.6.2 Further restrictions of onshore areas

The geographical analysis as presented in section 2.3.1 resulted in remaining onshore areas that were potentially available for the allocation of wind power installations. In practice, however, further restrictions might apply. As the federal states in Germany are responsible for the planning and approval of RES projects, which again builds the basis for state-specific targets and state energy policies, further area restrictions might be set (cf. Agentur für Erneuerbare Energien (2015a, pp. 21)), for example in order to keep visual and other impacts at a low level (cf. Intergovernmental Panel on Climate Change (IPCC) (2011, pp. 576).

As presented in this section, a central feature of the model developed therefore was the option to define such federal state-specific and district-specific (cf. Jansen (2012, p. 10)) shares of the respective total area to be potentially available at maximum for wind power installations. In the following, the terms area "limitation" and area "restriction" are used synonymously.

As an example, the actual space requirement of WTGs in the districts of North Frisia (Nordfriesland) (NF) and Dithmarschen (HEI) – two rural districts in the federal state of Schleswig-Holstein in the North of Germany in which a high wind power installation was found – was analyzed. Based on the respective installed capacity in these districts (cf. Netzwerkagentur windcomm schleswig-holstein (2015)) and on assumptions of the specific space requirement of WTGs being multiples of rotor diameters, an average rotor diameter of 50 m and a specific capacity of 1.77 MW per WTG, a total space requirement of wind power installations of 3.1 – 5.4 % (NF) and 4.0 – 6.9 % (HEI) of the total district areas was recalculated, depending on the WTG spacing assumed. Those calculated values did not significantly differ from the shares the priority areas for wind power in those districts had (3.3 % and 3.6 %, respectively) (cf. Staatskanzlei Schleswig-Holstein, Landesplanung (2012)).

The installed wind power capacity in those districts related to the total district areas resulted in a specific installed capacity of 0.91 MW/km^2 and 0.75 MW/km^2, respectively. Those figures could be regarded as comparably high, meaning that potential area limitations in the scenarios modeled might by tendency be set lower for the district level.

In the model it was possible to limit the maximum area available for WTGs in every federal state and in every district, respectively, by defining a maximum share of their according total area – percentages of the full state areas and of the full district areas – potentially available before the start of the allocation procedure of wind power capacity. These additional inputs defined the number of square kilometers that were regarded to be potentially available at maximum for the capacity allocation. For instance, setting the limitation to 2 % of the district areas, 98 % of the total district areas were excluded from use and 2 % of the district areas were potentially available for the allocation of WTGs unless the geographical analysis had already set a tighter cap. In the latest version of the model, the maximum percentages defined as variable inputs were applied for all the districts and the federal states, respectively, equally, i.e. in the model the limitation defined for the federal states was valid for all federal states and the limitation defined for the districts was valid for all districts. A regional differentiation, for instance, was not conducted. The application of the area limitations in the model and their potential interaction are introduced in this section and described in further detail in section 2.6.1.

The maximum shares of the federal state areas and of the district areas did not necessarily have to be defined equally high in the model. For instance, the area limitation at the district level might have been set higher than at the federal state level. This option allowed to allocate WTGs within districts until the district-specitific area limitation was reached, within the limitation of the federal states. For instance, the area limitation of the federal states could be set to 3 % while concurrently the area limitation of the districts could be set to 5 %. In the capacity allocation procedure of the model both area limitations were taken into account. As presented in the following, they could interact with each other and also with the area detected in the geographical analysis.

In the model, the limitation of the district areas to be potentially available for the allocation of WTGs could have the following effects on the area potentially available in the districts for the installation of WTGs:

- If the remaining district area as deduced in the geographical analysis was smaller than the maximum district area defined by the limitation percentage defined, the district area potentially available for the allocation of WTGs was limited to the area as deduced in the geographical analysis – i.e. the additional area limitation neither had an effect on the area availability, nor on the capacity allocation.

  Illustrative example:
  The district area was 1000 km^2, the remaining area after the geographical analysis was 25 km^2 in that district. If the area limitation was set to 3 % of the district area (= 30 km^2), 25 km^2 were utilized for the allocation of WTGs.

- If the district area defined by the area limitation was smaller than the remaining district area as deduced in the geographical analysis, the district area potentially available for the allocation of WTGs was defined by the area limitation set.

  Illustrative example:
  The district area was 1000 km^2, the remaining area after the geographical analysis was 25 km^2 in that district. If the area limitation was set to 2 % of the district area (= 20 km^2), 20 km^2 were utilized for the allocation of WTGs.

As in the model the federal state areas potentially available for wind power installations could also be limited by defining a maximum percentage of the federal state areas, the area restriction of the districts and of the federal states could interact with each other. Both inputs therefore were considered concurrently in the model.

- If the limitation of the federal state areas was defined to be greater than or as high as the limitation of the district areas, the calculation of the potentially available district area took place according to the previous list. In such a case the restriction of the federal state areas had no effect on further calculations because the aggregated restricted district areas could never exceed the restricted federal state area.

  Illustrative example:
  The limitation of the federal state areas was set to 5 %, the limitation of the district areas was set to 3 %. The district areas potentially available could sum up to 3 % of the federal state area at maximum, i.e. the 5 % limitation of the federal state areas could be neglected.

- If the limitation of the federal state areas was smaller than the limitation of the district areas, both interacted with each other. In that case those square kilometers with the highest expected EFLH in a federal state were regarded to be potentially available for the allocation of WTGs until
  - a district's remaining area according to the geographical analysis was fully occupied,
  - a district's area according to the area limitation of the districts was fully occupied, or
  - the federal state's area according to the area limitation of the federal states was fully occupied.

  Illustrative example:
  The federal state area was 10 000 km^2, consisting of two districts. District A's area was 1000 km^2 with 25 km^2 potentially available for wind power installations according to the geographical analysis. District B's area was 9000 km^2 with 1000 km^2 potentially available for wind power installations according to the geographical analysis. The limitation of the federal state areas was set to 3 % and the limitation of the district areas was set to 5 %. The area potentially available thus was 300 km^2 at maximum in the federal state (= 3 % $\cdot$ 10 000 km^2) whereas only 25 km^2 would be available at maximum in district A (the area potentially available according to the geographical analysis – 25 km^2 – being smaller than a 5 % limitation of the district area which would have been 5 % $\cdot$ 1000 km^2 = 50 km^2) and 450 km^2 at maximum in district B (= 5 % $\cdot$ 9000 km^2), i.e. 475 km^2 in sum based on the area limitations valid for the districts. From those 475 km^2 theoretically available in the districts not more than 300 km^2 were utilized for the allocation of WTGs then. How many square kilometers from which district were utilized depended on the wind speed conditions of the individual square kilometers, i.e. the expected EFLH.

In the model one of these options was automatically detected for every district, and the areas potentially available at maximum were adjusted accordingly. The interaction of areas potentially available and utilized for the allocation of WTGs is presented in section 2.6.1 in further detail.

2.4 Other fluctuating variable renewable energies

Besides wind power, photovoltaics (PV) and run-of-the-river hydro power are RES operated without fuel inputs. Once their capacity has been installed, their marginal operating cost is close to zero and they can be regarded as conditionally controllable units. They are characterized by a fluctuating production and they can be considered as the central drivers of the supply side in the future power system. Other energy sources that can be controlled – such as biogas plants, storage options or, if necessary or helpful, conventional power plants – and the transmission capacity to neighbouring countries will have to ensure the dispatch in such a system.

For the scenario analysis, the three VRE wind power, PV and run-of-the-river hydro power were incorporated in the newly developed model. As in the case of wind power, installation scenarios and highly temporally resolved power generation were taken into account for PV and run-of-the-river hydro power, too.

2.4.1 Photovoltaics

Photovoltaics (PV) is the direct conversion of sunlight energy into electrical energy. The capacity of PV modules and full PV systems, i.e. PV plants, usually is given as "Watts peak" (W_p), describing the maximum capacity producible under standard test conditions (STCs).

The installed PV capacity in Germany has shown a significant growth in the past two decades, strongly supported by the legal framework of the EEG law and its predecessors. As of the end of 2014, a capacity of more than 38 GW_p was installed in Germany that generated approx. 35 TWh/a (Bundesministerium für Wirtschaft und Energie (BMWi), 2015b).

Power production from PV installations is influenced by several factors. Meteorological and weather parameters on the one side comprise the angle of incidence of the sunlight depending on the day of the year and the moment during the day of consideration as well as weather conditions. Technical parameters such as the tilt and azimuth angles of the PV modules and the performance ratio (PR) of the PV system also play an important role for its power production.

In the new model, a simplified approach for the generation of time series of the power production from PV plants was incorporated. Temporally highly resolved PV electricity generation data for Germany based on Scholz (2010) were pre-processed and a normalized electricity production curve in a 15 minutes temporal resolution of one year was stored in the model database. Those data represented the production pattern of a PV plant mix with the capacity of 1 MW_p in Germany (cf. figure 2.19).

During the modeling, this normalized production curve was multiplied with the installed PV capacity in the year of analysis. The capacity, again, was part of the scenarios defined. In the model the capacity was allocated to the districts according

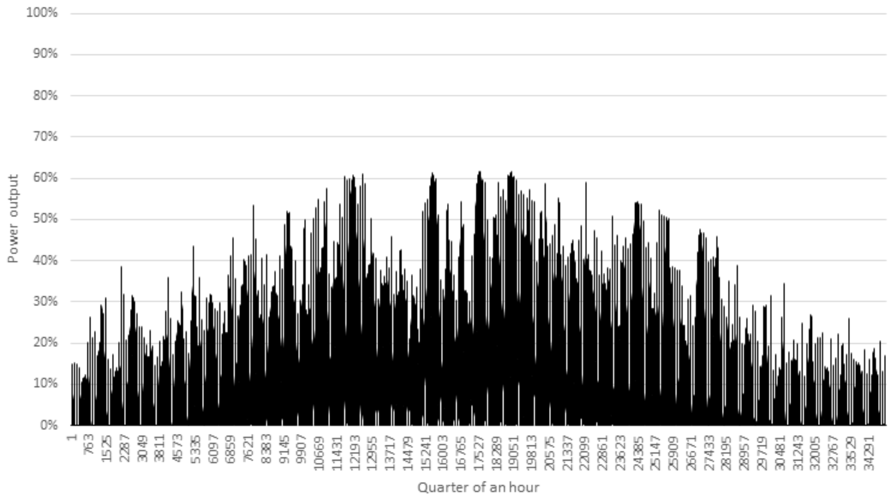


Figure 2.19: Normalized electricity production from photovoltaics (PV) power plants in Germany

Based on Scholz (2010)

to their shares in the total installation in 2014, based on the EEG plant registers from the German TSOs (TenneT TSO GmbH (2013), TransnetBW GmbH (2013), Amprion GmbH (2013), 50 Hertz Transmission GmbH (2013)). In the electricity generation part of the model, the district-wise allocated PV capacity was aggregated to the level of the transmission grid regions and multiplied with the normalized production time series.

For the calculation of LCOE of PV, economic parameters (CAPEX and OPEX) and their developent over time were taken into account in the model, too. Based on Scholz (2010)), the specific CAPEX ranged from € 2795 K per MW_p (2010) to € 840 K per MW_p (2050) (cf. table 2.7) and the specific annual OPEX were assumed to be 5 % of the specific CAPEX. For PV plants a lifetime of twenty years was assumed.

2.4.2 Run-of-the-river hydro power

Run-of-the-river hydro power is a renewable energy source that has been used for electricity production in Germany for more than a hundred years. In 2015, a run-of-the-river hydro power capacity of 4.1 GW was in operation. The annual production ranged between 20 and 29 GWh, which translates into 4800 – 7000 EFLH (cf. Bundesverband Deutscher Wasserkraftwerke (BDW) e.V. (2015)).

Most of the run-of-the-river hydro power capacity in Germany (80 %) has been installed in the federal states located in the South, i.e. in Bavaria and Baden-Württemberg (cf. Agentur für Erneuerbare Energien (2015b)). Major rivers – the Rhine and the Danube – and their tributaries are located there. In combination with a high water head, a large hydro power potential exists in these regions. In Northern Germany such water heads are not available, resulting in a comparably low run-of-the-river hydro power potential.

Power production from run-of-the-river hydro power does not fluctuate as fast as the other VRE. It depends on water availability and tends to vary particularly between the seasons but to a lesser extent on an hourly or daily basis.

As in the case of PV, in the new model a simplified approach for the power production from run-of-the-river hydro power plants was followed. Temporally highly resolved run-of-the-river hydro power electricity generation data for Germany from Scholz (2010) were adjusted for that purpose to the model's requirements.

After a pre-processing, a normalized electricity production curve in a 15 minutes resolution of one year was stored in the model database. That data set represented the normalized production pattern of a run-of-the-river hydro power plant mix in Germany (figure 2.20).

Figure 2.20: Normalized electricity production from run-of-the-river hydro power plants in Germany

Based on Scholz (2010)

In the model, the normalized production curve was multiplied with the installed run-of-the-river hydro power capacity in the year of analysis. The capacity was part of the scenarios and it was allocated to the transmission grid regions according to their shares in the total run-of-the-river hydro power installation in 2014, based on the run-of-the-river hydro power plants that operated under the EEG regime (cf. TenneT TSO

Table 2.7: Cost development of PV and run-of-the-river hydro power (CAPEX)

Category	unit	2010	2020	2030	2040	2050
PV	€/kW	2795	1382	1018	878	840
Run-of-the-river hydro power	€/kW	3386	3981	4492	4756	4890

Own calculations based on Scholz (2010)

GmbH (2013), TransnetBW GmbH (2013), Amprion GmbH (2013), 50 Hertz Transmission GmbH (2013)) and additional installation data from Agentur für Erneuerbare Energien (2015b).

Run-of-the-river hydro power has already reached a relatively mature stage in Europe (Eurelectric, 2011, p. 9). The potential of additional run-of-the-river hydro power capacity in Germany thus is limited. This aspect was reflected in the scenarios modeled.

In the post-processing step of the model, the LCOE of run-of-the-river hydro power and of all VRE was calculated for the year of analysis. Economic parameters of run-of-the-river hydro power and their development over time therefore were taken into account in the model. Based on Scholz (2010), the specific CAPEX were calculated to range from € 3386 K per MW (2010) to € 4890 K per MW (2050) (cf. table 2.7), the specific annual OPEX ranged from € 0.247 K per MW (2010) to € 0.253 K per MW (2050). For run-of-the-river hydro power a lifetime of 40 years was assumed.

2.5 Electricity demand

Besides the modeling of the electricity supply from wind power, PV and run-of-the-river hydro power, the demand side was also incorporated in the new model. The annual sum of the expected future electricity demand (measured as TWh/a) was part of the scenarios analyzed (cf. section 2.3.5). In the model, the demand level and the load curve (measured as GW in a 15 minutes temporal resolution) were utilized for the results analysis.

The German load curve in the model was derived from the European Network of Transmission System Operators for Electricity (ENTSO-E) (2013a) as illustrated in figure 2.21. For the application in the model it was normalized and temporally interpolated in order to derive a 15 minutes temporal resolution. From the national load curve, load curves of the individual transmission grid regions as presented in section 2.3.1.4 were derived by segregating the national figures according to the maximum load in the transmission grid regions as described in Deutsche Energie-Agentur GmbH (dena) (2010a, pp. 262).

The load curves of the transmission grid regions were stored in the model database in order to be accessed in the results analysis part of the model in which they were scaled with the total annual electricity demand of the year of analysis.

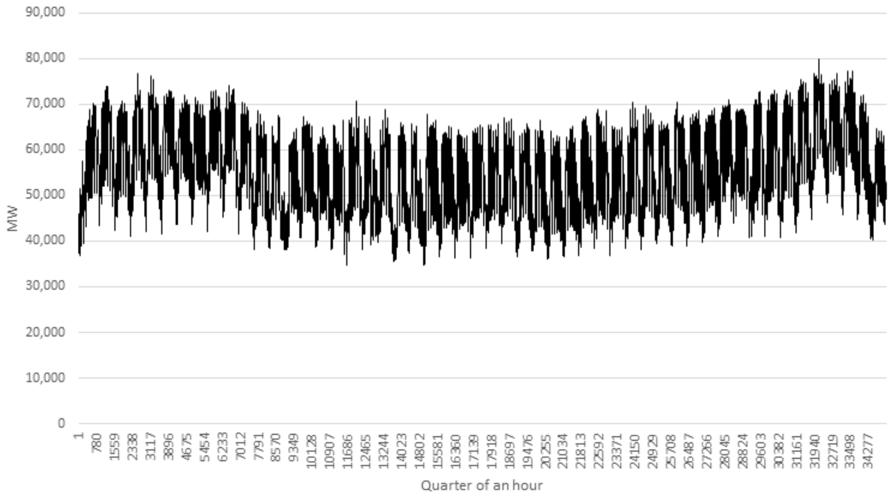


Figure 2.21: Germany's load profile
2010 figures.
Source: European Network of Transmission System Operators for Electricity (ENTSO-E) (2013a)

2.6 Detailed concept of the model

As presented in section 2.1, the model developed consisted of several parts that were run sequentially. Figure 2.22 shows the model's basic flow chart with the main modeling steps and all the input parameters to the model. In the centre of the figure, the model routines are illustrated in the rectangular boxes. Pre- and post-processing procedures are framed gray. On the left the fixed input parameters are depicted, on the right the variable input parameters are shown.

At the beginning, pre-processed data and further inputs were utilized for the spatial allocation of WTGs (first core part of the model). Based on that allocated capacity, on other pre-processed data and on further inputs, the electricity production from wind power and other VRE was modeled (second core part of the model). A successive model part incorporated results post-processing and display. As presented, the model mainly focused on wind power but PV and run-of-the-river hydro power and the load were also taken into account in the model.

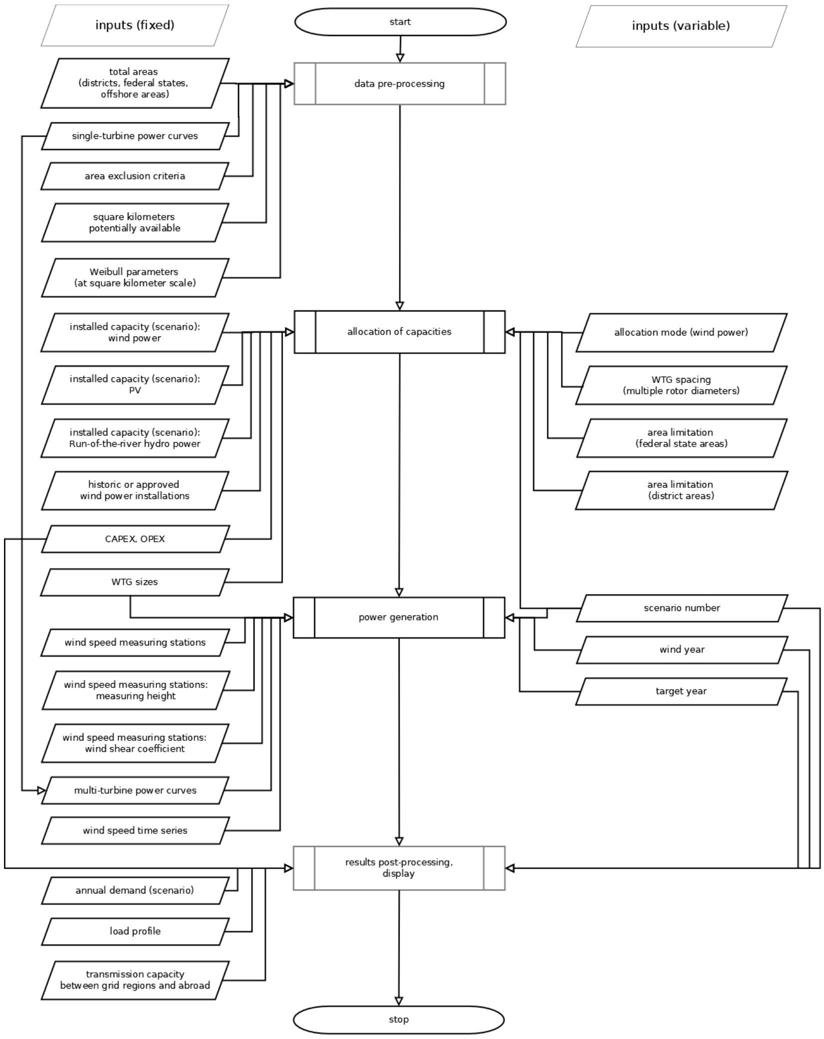


Figure 2.22: Flow chart of the model

2.6.1 Capacity allocation setup

The central aim of the first core part of the model was the allocation of onshore and offshore wind power capacity as defined in scenarios. In the showcase calculations, the allocation took place in the terrestrial area of Germany and its waters in the North Sea and in the Baltic Sea, taking defined area limitations in the federal states and in the districts into account. In order to do so, specific criteria for this allocation were incorporated in the model. In principle, locations with the expectedly most favourable conditions for wind power use were utilized first, i.e. WTGs were allocated first to locations – i.e. square kilometers – with the least expected LCOE of wind power, within the area limitations set. Subsequently, further wind power capacity that was to be installed in the same year or in subsequent years was allocated to locations with the next least expected LCOE and so on. This part of the model resulted in figures of newly installed capacity in all of the districts and offshore sub-regions, for every scenario year. Besides wind power, PV and run-of-the-river hydro power capacity was also allocated to the districts, however in a simplified way.

At the beginning of the wind power capacity allocation part of the model, an installation scenario and the variable parameters as presented in section 2.3.6 (spacing of WTG, area percentage of districts and federal states potentially available at maximum) needed to be defined through the model's front-end. These input parameters remained constant over the entire modeling period.

Additionally, the allocation mode needed to be defined for onshore wind power. This means it was necessary to indicate whether the capacity allocation was to take place within the individual federal states independently from each other and state by state (in the following referred to as "state-by-state allocation") or across the entire potentially available terrestrial area of Germany as one (in the following referred to as "nationwide allocation").

In the case of a state-by-state allocation, the allocation of WTGs was conducted for each federal state individually and independently. This allowed to consider installation targets and scenarios of the individual federal states in the context of an overall national scenario. In order to do so, federal state-specific wind power installation expansion pathways defined in the scenarios analyzed were read from the model database and the allocation procedure was conducted for all the federal states separately and sequentially. Within each federal state, wind power capacity was then allocated to the most favourable locations, for every scenario year and within the area limitations set.

In the case of a nationwide allocation, the total available area of Germany was utilized for the allocation procedure, within the limitations of the federal state areas and the district areas defined as additional inputs to the model. The wind power capacity as specified in an installation scenario for Germany was allocated to locations with the most favourable wind speed conditions in Germany, neglecting federal state-specific installation targets. In order to do so, state-specific installation expansion pathways of the selected scenario were aggregated in the model to an overall national installation scenario, for every scenario year.

In both cases, i.e. in both allocation modes of the same scenario, the overall national sum of the installed capacity thus was the same in every scenario year. In the case of a state-by-state allocation, however, an additional regional split-up of the overall wind power capacity was incorporated in the model, pre-defined within the overall national installation expansion pathway. This allowed to compare federal state-specific installation targets and the according allocation of capacity with a nationwide economically optimized capacity allocation. It depended on the research subject which one of the allocation modes would be to be applied.

In both capacity allocation modes, the capacity allocation part of the model consisted of two main steps that were conducted sequentially:

1. identification of available areas and
2. allocation of capacity.

The first step was conducted for onshore areas only. For offshore, the remaining areas as detected in the geographical analysis were directly utilized for the allocation of wind power capacity, i.e. no further area restrictions were considered.

The identification of available areas and the corresponding table preparation in the model database is illustrated in further detail in the flowchart in figure A4 in the appendix. In the model, this procedure was conducted for all the districts and the federal states successively. It consisted of two steps:

i) First, the shares of the federal state areas and the district areas to be potentially available at maximum as defined as a variable model input (cf. section 2.3.6, "area limitation") were multiplied with the total federal state areas and district areas, respectively. For each federal state and district, these calculated values were then compared with the remaining areas as detected in the geographical analysis (cf. section 2.3.1). In any case the smaller of the two values was stored in the model database to be utilized in the subsequent capacity allocation procedure of the model. This means that at maximum the remaining areas in the federal states and in the districts as detected in the geographical analysis were potentially available for the allocation of wind power capacity. The additional area limitation might have set a narrower frame, i.e. the district areas or the federal state areas might have been further reduced due to the area restrictions additionally defined.

ii) The area sizes calculated this way represented the total area potentially available for wind power use in every federal state and in every district. In the onshore case, the actual allocation of wind power capacity took place however on a square kilometer scale, WTG by WTG. That is why in the database table of potentially available square kilometers in each federal state the most favourable square kilometers – according to their expected EFLH of wind power – were then marked as being potentially available for the allocation of WTGs until the aggregated number of these marked square kilometers equaled the areas potentially available in the federal states and in the districts as detected in step i. All the remaining square kilometers in the federal states were marked as unavailable. They were not further considered in the model.

The procedure of this further area exclusion is illustrated in figure 2.23. In image a, the remaining square kilometers potentially available for wind power installations in an exemplary district after the geographical analysis are depicted. As described, all available square kilometers were stored with their respective coordinates in the model database, i.e. the coordinates acted as a compound key in the model database to identify every square kilometer. Again, in the figure the square kilometers are coloured according to their expected EFLH in different shades of gray (black: high expected EFLH, pale gray: low expected EFLH). All white areas in the images had already been excluded in the geographical analysis. If an additional limitation of the district area was now defined as a variable input to the model, only a limited number of square kilometers in the district was considered to be potentially available for the allocation of WTGs, i.e. those square kilometers with the highest expected EFLH. In turn this means that further areas, i.e. square kilometers, in the district might have got excluded from potential wind power use, i.e. those with the lowest expected EFLH. This is exemplarily illustrated in image b where some of the square kilometers are hatched, others are not. The hatched areas represent the square kilometers excluded due to the additionally defined area limitation. In the example, some of the square kilometers that would have been potentially available for wind power use according to the geographical analysis are also hatched, i.e. further excluded. Those square kilometers that are not hatched represent the area potentially available, defined by both the geographical analysis and the additional area limitation, i.e. by the percentage defined for the district area. In the model, their sum corresponds to the area potentially available as detected in the previous model step. Image c shows the remaining square kilometers after the additional area limitation has been conducted in the model. These remaining square kilometers were potentially available for the allocation of WTGs.

At the end of this pre-processing procedure and before any wind power capacity would be allocated, the resulting model database tables could be read as listing all square kilometers potentially available for onshore wind power installations, in all scenario years.

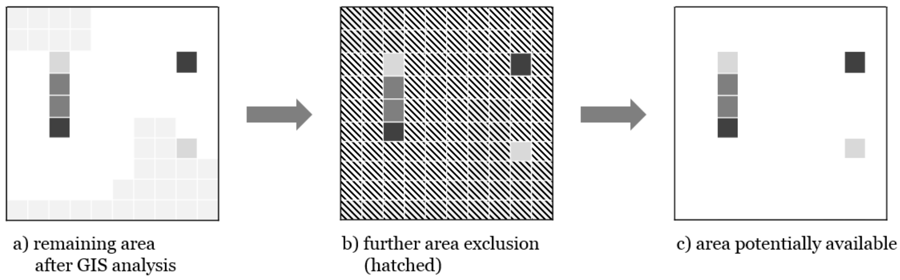


Figure 2.23: Example of the application of further onshore area restrictions in the model

Having completed these preparatory calculations, the subsequent procedure of the capacity allocation was conducted for all scenario years sequentially until the selected target year. The procedure for onshore wind power is illustrated in more detail in figure A5 in the appendix.

For every scenario year, the additional onshore and offshore wind power capacity in the system was calculated on the basis of the installed capacity as defined in the selected scenario, consisting of additional new capacity and repowered capacity from earlier years. The total installed capacity was read from the model database and the annually newly installed capacity was calculated by subtraction of the installed capacity of two successive years. Capacity that went into operation twenty years earlier was assumed to be repowered capacity-wise and it was therefore added to the capacity to be newly installed in a particular year.

The capacity to be newly installed was then translated into the number of new WTGs to be allocated in a specific year, conducted by dividing the additional wind power capacity in that year by a new WTG's nominal power of the same year. Potential remainders were considered in the successive year. The number of WTGs to be installed was multiplied with the specific space requirement of a WTG which was calculated on the basis of the WTG spacing defined as multiple WTG rotor diameters in a specific year (cf. section 2.3.6.1). That multiplication resulted in the total space requirement of all new WTGs in that particular year. This procedure made sure that both the additional wind power installation and the evolution of WTG sizes (in this model step: nominal power and rotor diameter) were taken into account in the capacity allocation procedure.

The allocation of onshore wind power capacity now took place to those square kilometers with the highest expected EFLH that had been marked as available in the square kilometer matrices in the model database. All square kilometers WTGs were allocated to were then marked as unavailable for further wind power installations for the following twenty years. After twenty years, these square kilometers were potentially available for wind power installations again.

The procedure is exemplarily illustrated in figure 2.24 for two successive years. In image a the potentially available square kilometers in a district are depicted as presented in the previous example. In image b the allocation of wind power capacity to the most favourable square kilometers available in year 1 is exemplarily illustrated. In the model these square kilometers were then marked as unavailable for twenty years as they now were occupied (exemplarily shown for the subsequent year in image c). Further WTGs to be installed in the subsequent year therefore were allocated to the next most favourable square kilometers (image d) that were, again, deleted from the list of potentially available square kilometers for twenty years (image e) and so on until the final year of the scenario timeframe (2050) was reached.

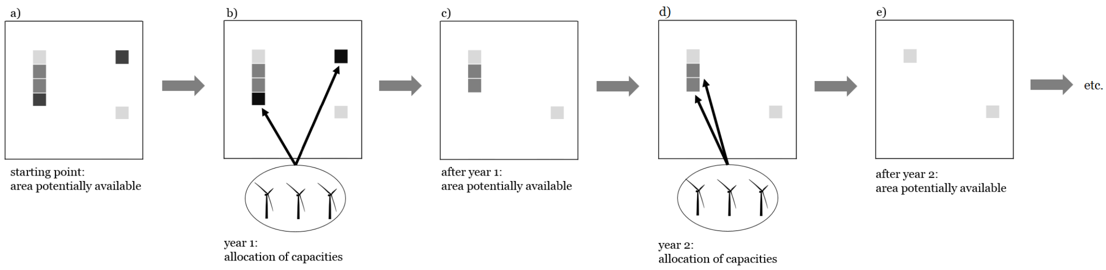


Figure 2.24: Example of the allocation procedure of onshore wind power capacity in the model

Offshore wind power capacity was allocated in a similar way. The WTGs were, however, directly allocated to offshore sub-regions and not to individual square kilometers. The allocation was conducted according to the least expected LCOE of wind power in the offshore sub-regions, i.e. the offshore sub-regions were sorted in descending order of their expected mean LCOE of wind power in the model database, based on CAPEX and OPEX in dependency on the respective distances to service ports and harbours and grid connection points, also evolving over time. Offshore wind power capacity was allocated to the available least-cost offshore sub-region until the area potentially available would be full in use. The occupied area was subtracted from the area potentially available in that offshore sub-region for a period of twenty years in the list of offshore sub-regions in the model database, i.e. an offshore sub-region's area was reduced by the amount of square kilometers occupied by WTGs allocated to it.

With the model, the spatial wind power capacity allocation in Germany and in the federal states, respectively, and the offshore areas was conducted year by year, sequentially. In every single year, the allocation of wind power capacity automatically stopped if specific conditions prevailed. Such criteria are also referred to as "stop criteria" in the following. If that happened, depending on the stop criterion, the model either proceeded to allocate capacity to other square kilometers in other districts in the same year or it moved forward to the following year, starting a new capacity allocation process.

For both onshore and offshore wind power two main criteria stopped the allocation of capacity in a particular year:

- the overall capacity that was to be newly installed had been fully allocated to available areas, or
- all area potentially available for the allocation of WTGs had been fully occupied by wind power installations, i.e. there was no further area available for additional WTGs.

In both cases no further wind power capacity needed to be or could be allocated in the particular year. If the additional capacity in a specific year had been fully allocated, the model moved forward to the subsequent year and started another allocation procedure of additional wind power capacity in that year. If the available area had been fully occupied by WTGs that had been allocated in prior years or even in the same year, further additional capacity simply could not be allocated. This means that even if further capacity was supposed to be allocated as defined in the selected scenario, it would not. This additional capacity could not be allocated in that year, i.e. the sum of the allocated capacity deviated from the capacity as defined in the scenario.

Besides these general stop criteria, further stop criteria ended the allocation process:

- Historic installed capacity (onshore and offshore) or approved capacity (offshore) were reached.

  By starting the capacity allocation procedure in the scenario year 1990, historical wind power installation was taken into account in the model. For all the years between 1990 and 2013, district-specific installation figures as processed from the TSOs' plant registers (TenneT TSO GmbH (2013), TransnetBW GmbH (2013), Amprion GmbH (2013), 50 Hertz Transmission GmbH (2013)) (cf. section 2.3.5) therefore were not allowed to and could not be exceeded in the capacity allocation process. This stop criterion made sure that capacity allocated to the districts during that period matched the historic capacity installed in every district.

  A similar approach was followed for the allocation of offshore WTGs. Besides the historical development, the foreseeable future – i.e. approved wind farms and their expected year of commissioning – was also taken into account in the model (cf. section 2.3.5). Until 2020, offshore wind power capacity was therefore allocated only to those offshore sub-regions where it would be installed in reality.

- There was no further area available in a specific district or offshore sub-region
  In case the area potentially available for wind power installations in a district or offshore sub-region was fully occupied, no further capacity could be allocated to that district or offshore sub-region. The allocation then proceeded to other districts or offshore sub-regions.

Onshore WTGs to be newly installed were allocated to available square kilometers that were then marked in the database as to be not available for a specific period. The corresponding capacity of the installed WTGs was aggregated districtwise. Once one of the stop criteria was reached, the allocation of capacity stopped in that particular district or federal state. The aggregated wind power capacity installed by then represented the capacity that was newly allocated to that district in a specific year.

This resulting capacity allocated to the districts and offshore sub-regions was stored district-wise in the model database. The results matrices could be read as newly installed capacity in district X (rows) in year A (columns).

In this model step, the capacity of PV and run-of-the-river hydro power was also allocated to the districts. Their historically installed capacity in the districts, based on TenneT TSO GmbH (2013), TransnetBW GmbH (2013), Amprion GmbH (2013) and 50 Hertz Transmission GmbH (2013), was scaled with the installed capacity as defined in the scenario, for all scenario years.

Once all the capacity of onshore and offshore wind power, PV and run-of-the-river hydro power as defined in the selected scenario was allocated to the districts, the respective electricity generation in a specific target year was modeled.

2.6.2 Intermediate results

A comparison of modeled and recorded capacity figures of the year 2012 showed that the capacity allocated in the districts by the model approximated well the wind power capacity installed in reality. Minor deviations, however, were caused by deviations between the WTG sizes utilized in the model and those in reality. Moreover, in few districts the geographical analysis (cf. section 2.3.1.1) had resulted in an area potential of zero square kilometers although in reality WTGs were installed there – for instance, WTGs that were installed before specific minimum distances to nearby buildings were obligatory. This deviation, however, related to only few districts and low capacity amounts and was negligible.

2.6.3 Power generation

In the second part of the model core, the electricity production from wind power installations in the target year was calculated, accompanied by the calculation of the electricity production from PV and run-of-the-river hydro power. The results taken from the first core part of the model, i.e. the spatially allocated wind power capacity, were a central input to these calculations. The model generated fifteen-minutes time series and annual data of the power production for any year until 2050.

Besides the allocated wind power capacity from the first core part of the model, further data on wind power and WTGs were incorporated in the second core model part. This included temporally highly resolved wind speed time series recorded at measuring stations and points (cf. section 2.3.2.2), wind shear coefficients (cf. section 2.3.2.3) and the evolution of WTG hub heights (cf. section 2.3.3.2). The outcomes of this modeling part were time series of power produced in every district and offshore sub-region, respectively, in a temporal resolution of 15 minutes, for the year of analysis.

Before running the electricity generation part of the model, the year of analysis needed to be defined in the front-end of the model. The electricity production from wind power in the target year was composed of the electricity production of all the WTGs that were newly installed in the target year and in the nineteen years before the target year, based on an assumed lifetime of a WTG of 20 years (cf. section 2.3.5.4).

In turn this means that a mixture of WTGs from different years of commissioning, thus with different hub heights, was in operation in the target year. It was therefore necessary to model the power output of WTGs from the different years of commissioning separately and have their power production aggregated. By doing so, the age structure – thus the size structure of WTGs – was taken into account in the aggregated electricity production time series of the target year.

The calculation of the electricity production from wind power hence started in the year "target year minus nineteen years" and was conducted for all the following years until and including the target year. For all those years, the following calculation steps were conducted for every district and offshore sub-region:

1. scaling of wind speeds time series of the selected wind year to the hub height of a newly installed WTG in the particular year,

2. conversion of wind speed time series at hub height into the power output from WTGs (normalized multi-turbine power curve), and

3. multiplication of the so-generated normalized electricity production time series with the newly installed capacity in the particular year.

The first step of the calculations was conducted for the wind speed values of all 35 040 quarters of an hour of the selected wind year, to represent the wind speeds in the year of analysis. The measured wind speeds of the representative measuring station of a district as presented in section 2.3.2.2 was scaled to the hub height of a new WTG in the particular year applying the power law (cf. section 3, solved for the wind speed v_2 at height h_2). In the calculations, the measuring height at the measuring station and the hub height of a new WTG in the year of examination were utilized, accompanied by the corresponding wind shear coefficient at the respective meteorological station. This scaling was conducted for all wind speed time series of all the meteorological stations that were related to the districts in the model, for all the twenty years between "nineteen years before the target year" $t-19$ and the target year t.

In the second step, the so-generated wind speeds at hub height were related to the multi-turbine power curve of onshore and offshore WTGs, respectively, as presented in section 2.3.3.1. At this stage, twenty matrices, i.e. data arrays, in the model now included intermediate results: the specific electricity production from wind power in every district and in every quarter of an hour.

As the so derived figures represented the normalized electricity production, in the third step they were multiplied with the according capacity $P_{inst}(n)$ that was newly installed in the respective districts and offshore sub-regions in the respective year n (cf. equation 16). Subsequently, these aggregated values were additionally adjusted as presented in section 2.7.

$$Q_{q_t,d} = \sum_{n=t-19}^{t} Pm(v_{d,q,h_{2_n}}) \cdot P_{inst,d,n} \cdot 1/4 \tag{16}$$

for all districts d
where

- d: index of the districts
- t: year of analysis = target year
- n: index of years

- q: index of time steps [quarters of an hour in year t]
- Q_q: power output in district d in the quarter of an hour q
- $P_{inst,d,n}$ capacity newly installed in district d in year n [MW]
- h_{2_n}: hub height of a WTG newly installed in year n
- v_{d,q,h_2}: wind speed in district d in the quarter of an hour q at hub height
- $Pm(v_{d,q,h_{2_n}})$: rated power output of a WTG (multi-turbine power curve) as a function of the wind speed v in district d in the quarter of an hour q at hub height h_{2_n} [MW]

The electricity production from PV and run-of-the-river hydro power was calculated by multiplying the normalized production time series of one year (cf. section 2.4) and the installed capacity in the transmission grid regions according to the respective scenario and the target year.

2.7 Calibration and adjustment of the model

All the input parameters into the model were selected, analyzed and processed in detail and the model functions underwent several quality assurance measures and testing. Model outputs, however, still could only be an approximation to reality. When compared, modeled data and recorded production data did not necessarily fully match, for several reasons. For instance, in practice the allocation of wind power capacity had not necessarily been conducted solely according to the least expected LCOE, the WTG sizes utlized in the model were mean values and in the model WTG downtimes were not considered while in practice the power generated by WTGs might get disrupted due to technical failure or other reasons. The modeled data before the calibration were expected to be greater than recorded data because in the model perfect operation conditions were assumed. In reality, WTGs are faced with losses, i.e. their electrical output is reduced for several reasons (internal consumption in the WTG, shading losses, downtimes due to failure, maintenance, shutdown and other) that had not been directly taken into account in the model.

In order to keep such deviations between modeled and recorded data at an acceptable level, model outputs were post-processed again. For this post-processing, two procedures were relevant:

1. calibration and

2. adjustment.

The calibration is the ex-post evaluation, i.e. the identification and quantification, of differences between recorded figures and modeled results whereas the adjustment is the modification of model outputs with the objective to reduce such deviations. For the calibration and adjustment of the model, recorded power production figures and modeled data of the year 2010 were processed and compared. The year 2010 was selected because the model incorporated wind speed time series of that year (cf. section 2.3.2.2) and moreover production figures from wind power and the load curve from 2010 were available from the European Energy Exchange AG (EEX) Transparency Platform (European Energy Exhange AG (EEX) (2013)).

Deviations from historical figures arose, for instance, because in the model additional capacity was assumed to be allocated instantly at the beginning of a scenario year. Modeled production of the year 2010 was based on the full 2010 capacity although in reality this capacity amount was not fully installed before the end of that year. The model approach therefore necessarily led to an overestimation of the electricity production modeled. For the calibration of the model, an artificial electricity production curve from wind power for the year 2010 was therefore generated, based on the installed capacity of 2009 and 2010. The production curve was then compared to the recorded electrictiy production from wind power in 2010.

The comparison of 2010 data showed a slightly lower installed capacity and a slightly higher annual production in the modeled data than found in the recorded data. In the adjustment step, a subtraction of 13 % from modeled wind power production was identified to approximate the modeled data to the recorded production figures.

The calibration and adjustment procedure was conducted for different variants of the capacity allocation in which the area availability and a WTG's space requirements were varied. As a result, the necessary adjustment percentage identified slightly varied, depending on the input data sets. The calibration value of 13 % to be subtracted, however, represented an appropriate mean. This is smaller than the deviation between modeled and recorded data analyzed by Gallet et al. (2014, pp. 30) but higher than calculated in Deutsche Energie-Agentur GmbH (dena) (2010a, pp. 48).

The duration curves of historical and modeled data after the calibration and adjustment are illustrated in figure 2.25. The diagram shows that the calibrated modeled electricity production was a sound approximation to the recorded data.

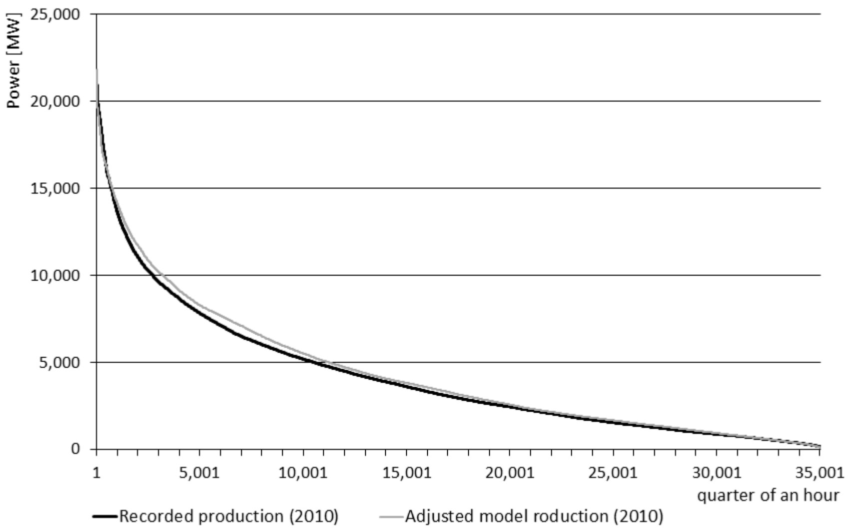


Figure 2.25: Duration curves of recorded and modeled wind power production
Based on European Network of Transmission System Operators for Electricity (ENTSO-E) (2013a), Bundesministerium für Wirtschaft und Energie (BMWi) (2015b) and own calculations

In all the scenarios modeled, the adjustment percentage detected was subtracted from the modeled data of electricity production, i.e. every production value in every quarter of an hour in the year of analysis was reduced accordingly.

2.8 Data post-processing and outputs from the model

In the two core parts of the model, data on the installed capacity and the electricity produced by wind power, PV and run-of-the-river hydro power could be generated, for different installation scenarios, different allocation modes for onshore wind power and for different target years. At the end of each model run, all results would be stored in the model database to be post-processed and analyzed.

The data post-processing included four main categories:

- adjustment (cf. section 2.7),
- spatial aggregation and calculation of district-specific results (capacity, power production time series, LCOE) at the level of the transmission grid regions and national,
- temporal aggregation of results with a 15 minutes resolution to annual figures, and

- calculation of further results (EFLH, LCOE, residual load, minima and maxima of production and residual load, shares in total demand)

With the model, the following outputs were generated for the target year. They were displayed on the output page in the model front-end (excerpt cf. image A2 in the appendix) and stored in the results table of the model database.

- installed capacity of onshore and offshore wind power, PV, run-of-the-river hydro power, and of all VRE combined (given as GW) (cf. equation 13),
- power production time series of onshore and offshore wind power, PV, run-of-the-river hydro power and of all VRE combined (given as GW in a 15 minutes resolution) (cf. equation 16),
- annual sums of power produced by onshore and offshore wind power, PV, run-of-the-river hydro power and by all VRE combined (given as TWh/a) (cf. equation 14),
- minimum and maximum power production of onshore and offshore wind power, PV, run-of-the-river hydro power and of all VRE combined (given as GW),
- annual sums of electricity demand at two demand levels (given as TWh/a),
- minimum and maximum electricity demand at two demand levels (given as GW),
- EFLH and capacity factor (CF) of onshore and offshore wind power, PV, run-of-the-river hydro power and of all VRE combined (cf. equation 6),
- residual load time series at two demand levels (given as GW in a 15 minutes resolution),
- annual sums of positive and negative residual load at two demand levels (given as TWh/a),
- annual sums of residual load at two demand levels (given as TWh/a),
- minimum and maximum residual load at two demand levels (given as GW),
- specific cost of wind power, PV, run-of-the-river hydro power and of all VRE (specific investment cost, specific MRO cost, LCOE) (given as Ct./kWh) (cf. equation 15), and
- share of VRE in final power demand at two demand levels (given as percent values).

All model outputs were available for different spatial levels. For the levels above the districts level, all capacity and energy amounts were aggregated to nodes representing larger areas consisting of one or several districts. The model outputs therefore were available for:

- districts,
- transmission grid regions (aggregated from district data, cf. section 2.3.1.4),
- onshore and offshore (aggregated from district data), and
- Germany as a whole (aggregated from district data, sum of onshore and offshore).

Besides those parameters, the model automatically generated diagrams for some of these categories. The diagrams incorporated the patterns of the electricity production and the residual load over time, as duration curves, as heat maps and as cost-potential-curves. At the end of each scenario calculation, results were written into a conflating database table and the generated diagrams were saved automatically.

3 Application of the model and scenario results

The model presented was developed for the calculation and analysis of different scenarios and scenario variants. While a prognosis provides information about a probable future development, a scenario describes a possible future under specific framing conditions (cf. Sachverständigenrat für Umweltfragen (SRU) (2010, p. 8)).

For the model, a scenario was defined as consisting of a set of future capacity expansion pathways of onshore and offshore wind power, PV and run-of-the-river hydro power, accompanied by the future development of the electricity demand and the transmission grid. All installation data were available for every scenario year until the year of analysis.

Further technical and economic parameters representing a future development such as the development of WTG sizes and cost were also regarded as parts of the scenarios analyzed. Their development over time, however, was not altered in the scenarios modeled.

Outputs from the new model can act as inputs to other energy models. For the scenarios modeled they were however also analyzed independently from further modeling, as presented in the following section.

In this section, results generated with the new model for different installation scenarios and scenario variants are presented and analyzed. The section is divided into three parts:

- technical potential of wind power in Germany,
- scenarios and their variants, and
- central outcomes from model results and their analysis.

3.1 Technical potential of wind power in Germany

In a first step, the maximum amount of installable wind power capacity (given as MW) in Germany and its corresponding electricity production (given as TWh/a) was modeled. They can be understood as the technical potential (cf. Hoogwijk (2004) and Held et al. (2009)).

The technical potential mainly depends on the following variables:

- potentially available area, i.e. the geographical potential
  defined by the area excluded from potential wind power use and remaining areas, respectively (cf. section 2.3.1), and limitations of the potentially available area (cf. section 2.3.6.2), and
- technical parameters of WTGs (cf. section 2.3.3).
- Moreover, the technical potential is affected by the specific space requirements of WTGs, i.e. rotor diameters and spacing parameters (cf. section 2.3.6.1) and
- the underlying wind speed conditions (cf. section 2.3.2.2).

The potential of wind power capacity installable at maximum is correlated to the geographical potential whereas the potential of producible electricity from wind power is a function of the installable capacity – thus area availability –, the wind speed conditions and the technical characteristics of WTGs.

For the potential analysis, the model was run with a virtually infinite amount of capacity to be allocated in the area of Germany and its waters in the North Sea and in the Baltic Sea in the year 2050. The capacity allocation procedure stopped when all potentially available areas were full in use. The accumulated capacity of the allocated WTGs represented the technical potential of installable capacity. The according potential of producible electricity was calculated based on that. The modeling was conducted in several variants, altering the area restrictions set, hence the area availability for wind power installations in the federal states.

The potential analysis was conducted with 2050 figures only, i.e. an age structure of WTGs was not taken into account in this process step. The technical potential analyzed thus refers to installations newly installed in 2050. The utilization of concrete scenarios, i.e. a temporal course of the installation of new capacity, or a target year different from 2050 therefore might lead to minor deviations in the resulting potential due to the development of WTG sizes and the interdependence of area availability between successive years.

The calculation of the technical potential was conducted for two variants of the specific space requirement of WTGs, defined by the spacing between WTGs (cf. section 2.3.6.1). In the case with a comparably low specific space requirement, a spacing of

7 rotor diameters · 4 rotor diameters = 28 square rotor diameters

was utilized (in the following referred to as "narrow spacing"). In the other case a higher specific space requirement of

7 rotor diameters · 7 rotor diameters = 49 square rotor diameters

was assumed (in the following referred to as "wide spacing").

Applying 2050 WTG size figures (cf. section 2.3.3.2), the range of the specific space requirement of a WTG corresponds to 6.6 – 11.6 MW/km^2. This can also be expressed as 47.4 – 82.9 ha/WTG or 8.6 – 15.0 ha/MW.

The comparison with other sources shows that this range could be regarded as realistic. Recommendations by Deutsches Windenergie-Institut (DEWI UL International GmbH) (DEWI) (Seifert et al. (2003)) and Ministerium für Bauen und Verkehr, Ministerium für Umwelt und Verbraucherschutz, Ministerium für Wirtschaft, Mittelstand und Energie (2005), for instance, were in the same range of minimum distances between WTGs. A meta-study comparing global potential analyses as presented in Intergovernmental Panel on Climate Change (IPCC) (2011, pp. 545) summarized a range of 6 – 16 MW/km^2 ($\equiv$ 6.3 – 16.7 ha/MW) for wind power installations utilized in other research studies. In Lütkehus et al. (2013, p. 15) a specific space requirement of 6 ha/MW ($\equiv$ 16.7 MW/km^2) was utlized. In Deutsche Energie-Agentur GmbH (dena) (2010a), 7 ha/MW ($\equiv$ 14.3 MW/km^2) were assumed, the same figure could be found in Neddermann (2006, p. 22). Kunz & Kirrmann (2015) calculated with 6 ha/MW ($\equiv$ 16.7 MW/km^2), too, whereas Christ et al. (2015) calculated with 13 MW/km^2 ($\equiv$ 7.7 ha/MW).

3.1.1 Full technical potential

First, the technical potential of wind power in Germany was analyzed without further area limitations assumed. That means the remaining area as detected in the geographical analysis (cf. section 2.3.1) was regarded to be fully available for the allocation of WTGs. The technical potential derived under this assumption was the maximum possible with 2050 installations. Any area limitation would reduce the technical potential.

The technical potential of onshore wind power without further area limitations was detected to be in the range between 401 GW (wide WTG spacing) and 702 GW (narrow

WTG spacing). For offshore wind power the technical potential was detected to be in the range of 60 GW (wide WTG spacing) and 104 GW (narrow WTG spacing).

This capacity produced 653 – 1143 TWh/a (onshore) and 188 – 331 TWh/a (offshore), respectively, depending on the assumed WTG spacing and based on wind speeds of the year 2010. This translates into 1628 EFLH (onshore mean) and 3183 EFLH (offshore mean).

Due to regional differences in the availability of remaining areas in the federal states and districts the technical potential was distributed unevenly and ranged from 0 GW (producing 0.01 TWh/a) in transmission grid region 2 (Hamburg) to 141 GW (producing 226 TWh/a) in transmission grid region 16 (North-East).

As they depend on the capacity that can be allocated and the electricity that can be produced (cf. section 2.3.4), the resulting LCOE also describes regional differences of the potential. The relation of LCOE and the amount of producible electricity is shown in the cost potential curves in figure 3.1. In the diagram, the sorted mean LCOE in the transmission grid regions in 2050 is depicted as a function of the amounts of the corresponding producible electricity. The thick black curve is the cost potential curve with a narrow WTG spacing, resulting in a comparably large potential (1143 TWh/a). The dottet curve is the cost potential curve derived with an assumed wide WTG spacing (in total 653 TWh/a). Both curves have essentially the same shape but differ in their steepness.

It becomes obvious that a wide range of the potential could theoretically be produced at comparably low cost, illustrated with the flat part of the curves, which made up approximately two thirds of the full potential detected. Differences between the curves were caused by the different assumptions of the spacing of WTGs.

As shown, the potential heavily depended on the input parameters to the modeling. Moreover, in practice the technical potential would be further reduced, for several reasons.

First, in practice the available area might be smaller than detected in the geographical analysis (cf. section 2.3.1.1). As presented, the geographical analysis was based on available geographical data and assumptions on buffering areas on the one hand. On the other hand, location-specific area restrictions could not be considered in full detail. Any further area exclusion would have necessarily resulted in a smaller geographical potential, thus a smaller technical potential.

Second, even the consideration of all kinds of technical area restrictions might still overestimate the upper limits of installable capacity. Public acceptance and political decision might set narrower upper limits that cannot be exceeded. The level of pub-

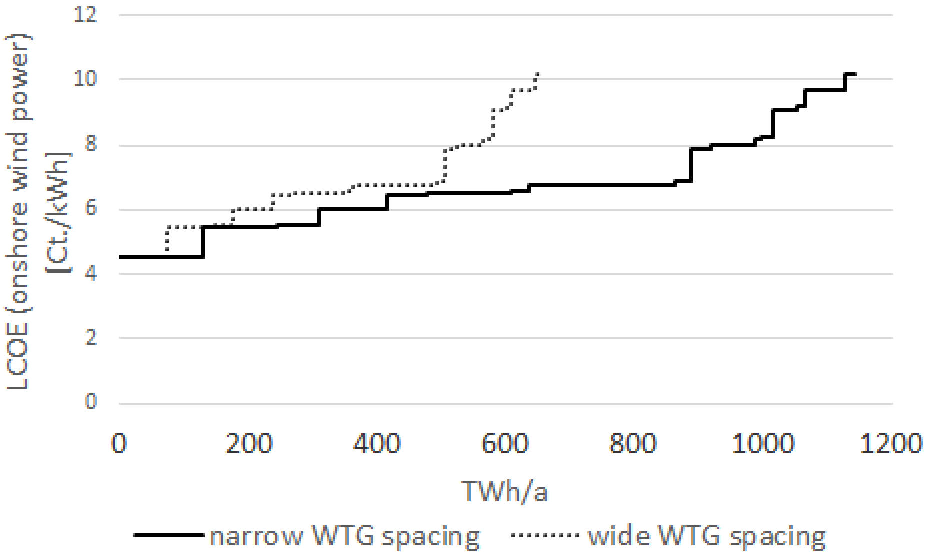


Figure 3.1: Cost potential curves of onshore wind power in Germany

lic acceptance towards RES technologies and especially wind power is region-specific but many concrete project plans have faced resistance of local stakeholders potentially affected or concerned (cf. Betzholz (2013), Seng (2015) and other). A representative survey in the federal state of Schleswig-Holstein, conducted by Europa-Universität Flensburg in scope of the INTERREG research project "Large Scale Bioenergy Lab" in early 2014 revealed and quantified that the level of acceptance decreases if a WTG is audible instead of just visible (cf. Hohmeyer et al. (2015)). Moreover it was shown that the average acceptance towards an energy technology decreases, the closer a technology would be installed to an individual's home.

3.1.2 Technical potential (restricted area availability)

Even though buffers around buildings and protected areas were already considered in the exclusion of areas from potential wind power use in the geographical analysis (cf. section 2.3.1.1) – representing minimum distances to avoid audible and noise impairment – it made sense not to exceed additional area limitations (cf. section 2.3.6.2) in order to keep the acceptance of wind power installations on a high level. In a second step, the onshore area potentially available for wind power installations was therefore limited to specific maximum shares of the federal state and district areas in order to identify the restricted technical potential of onshore wind power under such area limitations. As presented, the maximum area share could be defined as a further input to the model (cf. section 2.3.6).

For the calculations of the restricted potential, the maximum area potentially available for wind power installations in the federal states and in the districts was altered between 2 % and 5 %, again conducted for two variants of WTG spacing. Compared to the full technical potential, the additional limitation of the potentially available area substantially reduced the technical potential of onshore wind power.

In table 3.1 the technical potential identified under consideration of further area restrictions is shown. The table consists of four parts: two including the installable capacity under consideration of two variants of WTG spacing, and two showing the according power production. In each table part, the resulting potential under specific restrictions of the federal state areas and of the district areas are presented.

The figures reveal that the variation of the area availability had a strong impact on the resulting technical potential. As anticipated, a tighter area restriction reduced the technical potential. If both the limitations of the federal state areas and of the district areas were identical, the capacity-wise technical potential nearly was a direct function of the area availability, i.e. a doubling of the potentially available area resulted in a doubling of the installable capacity.

If the area limitations in the federal states and in the districts were not set equally high, variations in the technical potential could be detected. If, for instance, with a narrow WTG spacing the restriction of the federal state areas and of the district areas were set to 2 %, the technical potential was 75.0 GW. If the area limitation of the districts was increased to 5 % and the area limitation of the federal states was kept constant at 2 %, the technical potential increased to 82.2 GW. This difference of the potential can be explained by the interaction between the area potentially available according to the GIS-based exclusion of areas and the logic of the model to allocate wind power capacity. In the example case, the tight restriction of the district areas set a narrow frame for the allocation of wind power capacity: districts either were short of areas for wind power installations anyway (for instance due to a high population density that caused large areas to be excluded in the geographical analysis) or, if more area was potentially available, the additional area limitation set the upper limit for wind power installations. Under such conditions, the sum of the potentially available area in all the districts in a federal state might have been smaller than the area computationally available in the federal state – even if the area limitations were set equally. If now the area limitation of the districts was increased, further areas were available at the district level – thus the technical potential increased –, within the unaltered area limitation at the federal state

Table 3.1: Technical potential of onshore wind power in Germany

Narrow WTG spacing:

Capacity [GW]

		restriction of the federal state areas			
		2 %	3 %	4 %	5 %
restriction of the district areas	2 %	75.02			
	3 %		111.58		
	4 %			146.85	
	5 %	82.23	123.82	161.25	181.10

Electricity production [TWh/a]

		restriction of the federal state areas			
		2 %	3 %	4 %	5 %
restriction of the district areas	2 %	119.95			
	3 %		178.70		
	4 %			235.06	
	5 %	132.03	201.50	256.90	289.39

Wide WTG spacing:

Capacity [GW]

		restriction of the federal state areas			
		2 %	3 %	4 %	5 %
restriction of the district areas	2 %	42.50			
	3 %		63.36		
	4 %			83.52	
	5 %	46.75	70.47	91.80	103.13

Electricity production [TWh/a]

		restriction of the federal state areas			
		2 %	3 %	4 %	5 %
restriction of the district areas	2 %	67.97			
	3 %		101.50		
	4 %			133.69	
	5 %	75.07	114.75	146.20	164.80

level. This effect could be found accordingly in the power generation figures. It became smaller, the higher the area limitation at district level was set.

Depending on the area limitations defined, the restricted technical potential of onshore wind ranged between 75.0 GW (with a 2 % limitation of both the federal state areas and the district areas) and 181.1 GW (with a 5 % area limitation of both the federal state areas and the district areas) at narrow WTG spacing and 42.5 GW and 103.1 GW at wide WTG spacing. Those capacity amounts produced 120.0 – 289.4 TWh/a (narrow spacing) and 68.0 – 164.8 TWh/a (wide spacing), respectively, with wind speeds as of the year 2010 assumed. In all variants, the technical potential translates into average EFLH around 1600.

Compared to the full technical potential, a restriction of the potentially available area also increased the resulting EFLH. Following the logic of the model, the more area was available the more locations with less favourable wind speed conditions (expressed as expected EFLH) were utilized in the calculations, which reduced the overall number of EFLH. In turn, as only the most favourable locations were utilized if an area limitation was set, higher average EFLH resulted. Accordingly LCOE also decreased if an area limitation was applied.

The identified potential is comparable to figures presented in other sources only to a limited degree due to differences in the underlying data, the assumptions made and the methodology applied. For instance, Lütkehus et al. (2013, p. 39) identified a total technical potential of 1188 GW of installable onshore wind capacity with a potential electricity yield of 2898 TWh/a in Germany, without further area limitations assumed. Klaus et al. (2010, p. 10) detected a restricted potential of 60 GW of onshore wind power. Scholz (2010, p. 79) detected a technical potential of 39.5 GW of onshore wind power, resulting in a maximum power production of 90.6 TWh/a. This potential, however, was strongly affected by technical and economic restrictions set, e.g. restrictive assumptions on the usage of agricultural areas. The figures from Scholz (2010) also showed a significantly larger number of EFLH (2294) than detected with the new model due to different underlying assumptions and input parameters. In a study compiled by Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES) (2012, pp. 53) for the German Wind Energy Association (Bundesverband WindEnergie e.V.) (BWE) the total technical potential in Germany was quantified with 1500 GW. A restriction to utilize not more than 2 % of the federal state areas at maximum resulted in a technical potential of 198 GW, however assuming a considerably narrow WTG spacing ($4 \cdot 4$ square rotor diameters) and partly utilizing forest areas, too (cf. also Bundesverband WindEnergie e.V. (BWE) (2012a)). In Henning & Palzer (2013), a technical potential of 150 −180 GW of installable onshore wind power capacity was described which approximately corresponds to the restricted potential at 5 % of both the federal state areas and the district areas with a narrow WTG spacing detected with the new model.

In the light of this comparison, the potential figures calculated with the new model can be considered as to be rather conservative.

3.2 Scenarios

The detected technical potential set the frame and the limitations for all further considerations. From a multitude of available scenarios on Germany's future energy system (cf. e.g. Kronenberg et al. (2012)), four were selected to be simulated and analyzed with the model developed:

- Scenario 1 ("Offshore wind leads")
  based on scenario "2.1.a" from Sachverständigenrat für Umweltfragen (SRU) (2010) and Sachverständigenrat für Umweltfragen (SRU) (2011),
- Scenario 2 ("PV leads")
  based on scenario "2011 B" from Nitsch et al. (2012) and
- Scenario 3 ("The anticipated")
  based on scenario "B" from 50 Hertz Transmission GmbH et al. (2014a).

They were complemented by a self-developed scenario:

- Scenario 4 ("Beyond the anticipated")
  based on scenarios 1 – 3 and own assumptions.

Except for scenario 4, most of the scenario data on the installed capacity were obtained from the underlying scenarios in the original sources. Some data, however, were slightly adjusted to the actual development. The development of the installed capacity of onshore wind power in the scenarios modeled is illustrated in figure 3.2 and described in more detail in the following sections.

The scenarios were fed into the newly developed model in order to detect where wind power capacity was located if the allocation took place in an economically optimized way, with and without further restrictions of area potentially available in the federal states and in the districts. In all the scenarios the capacity allocation part of the model was run for the overall national sum of the installed capacity until the scenario's target

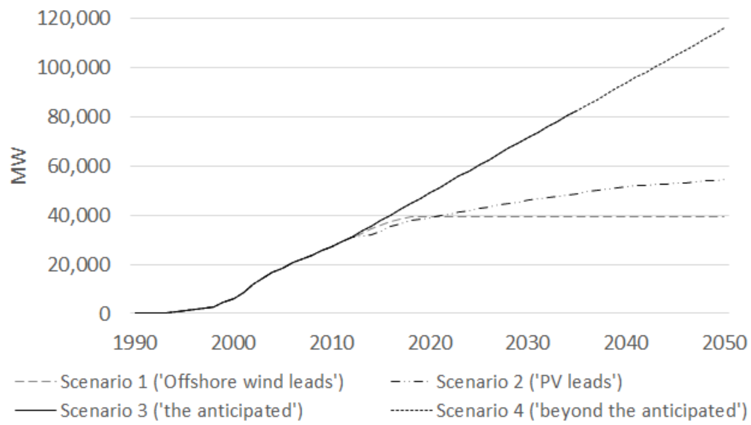


Figure 3.2: Installed onshore wind power capacity in the scenarios analyzed
Based on Scholz (2010), Nitsch et al. (2012), 50 Hertz Transmission GmbH et al. (2014a) and own calculations

year. Additionally, scenarios 3 and 4 were also modeled taking installation targets of the individual federal states into account.

The scenarios were selected for two reasons. First, the studies they originated from were of great importance in the political discussion in Germany. And second, the amounts of the installed capacity of onshore and offshore wind power and of PV in the scenarios selected represented a wide range of Germany's possible future VRE installation.

For all the scenarios modeled and analyzed, two levels of the future electricity demand were taken into account. On the lower end of the range, an annual demand of 500 TWh in Germany in 2050 was assumed. On the upper end of the range, an annual demand of 700 TWh/a was assumed. These assumptions were based on an in-depth analysis of Germany's future electricity demand conducted for the SRU and presented in Sachverständigenrat für Umweltfragen (SRU) (2011, pp. 83). The range can be regarded as to cover the probable development in consideration of efficiency gains on the one side and a potentially increasing demand on the other, for instance due to an increased use of electric mobility. Annual demand figures for the years between 2012 and 2050 were linearly interpolated and the load curve for the year of analysis was scaled accordingly. For instance, in scenario 3 focusing on 2035 the annual demand was expected to range between 508 TWh/a and 631 TWh/a.

In all the scenarios modeled and analyzed, the maximum shares of the potentially available area for wind power installations in the federal states and in the districts was altered gradually. In the scenarios, the other input parameters – evolution of WTG sizes, cost assumptions and others – remained unchanged. The allocation of WTGs was conducted for a space requirement of $7 \cdot 4 = 28$ square rotor diameters, i.e. a narrow WTG spacing was assumed (cf. section 2.3.6.1). A variation with $7 \cdot 7$ square rotor diameters was utilized for a sensitivity analysis (cf. section 3.4).

The modeling of each of the scenarios was split into two parts: First, it was assumed that the full remaining area according to the geographical analysis would be potentially available for the allocation of WTGs. Second, the federal state areas and the district areas were limited to specific maximum shares. This approach allowed to detect the impact an area restriction had in comparison with the respective scenario variant without further area constraints.

3.2.1 Scenario 1 ("Offshore wind leads")

The first scenario analyzed with the model was based on a scenario presented in Sachverständigenrat für Umweltfragen (SRU) (2011). The special report by the SRU showed how a fully renewable electricity supply for Germany in and until 2050 could be achieved. The study contained scenarios of a technically and economically optimized RES capacity mix and it also covered political and legal issues.

In the study, eight scenarios of an electricity supply for Germany in 2050 that would be fully based on RES were presented. They were modeled by DLR applying their REMix optimization model (cf. section 1.4). The scenarios differed in the region covered (Germany isolated, Germany as part of a country group with Denmark and Norway, and Germany as part of a larger region covering Europe and parts of North Africa), the level of the national electrical self-sufficiency (100 % and 85 %, respectively) and the demand level (509 TWh/a and 700 TWh/a in 2050, respectively).

From the eight scenarios in the study, scenario "2.1.a" was selected for further analysis in this thesis. Its target year was 2050 and it was characterized by a comparably low electricity demand in 2050 (509 TWh/a) that was fully self-supplied from German RES. Scenario "2.1.a" was the only scenario in the study that was modeled over time, i.e. for the period from 2010 until 2050.

The scenario was characterized by a comparably little onshore wind power installation and a huge offshore wind power installation in 2050. Reaching a maximum of 39.5 GW of onshore wind power by 2020 and subsequently no further capacity expansion assumed virtually meant a stop of the expansion of onshore wind power installations with regard to the capacity that already had been installed in Germany. Reaching 73.2 GW of offshore wind power in 2050 with a continuous expansion was within the range of the detected technical potential (cf. section 2.7). In terms of wind power, the scenario thus could be regarded as an extreme case in which onshore wind was not promoted any further but offshore wind a fortiori. The development of the PV installation over time from the original scenario was scaled up because the historic development already exceeded the original scenario data. The adjusted PV installation reached 59.5 GW_p in 2050 which corresponds to an increase by approx. one third with regard to the current status (cf. section 1.3). Run-of-the-river hydro power reached an upper limit of 4.45 GW by 2020 and remained constant until 2050 (cf. section 2.4.2).

The scenario was called "Offshore wind leads" in this thesis as the installed offshore wind power capacity made up 41.4 % of the total VRE capacity in 2050. The installed capacity of all VRE technologies in the scenario until 2050 is presented in table 3.2.

Table 3.2: Installed capacity in scenario 1 ("Offshore leads")

	Unit	2020	2030	2040	2050
Onshore wind power	GW	39.50	39.50	39.50	39.50
Offshore wind power	GW	11.02	49.00	58.10	73.20
PV	GW_p	48.64	58.64	59.54	59.54
Run-of-the-river hydro power	GW	4.45	4.45	4.45	4.45

Based on Scholz (2010) and own calculations

3.2.1.1 Scenario 1: Results (unrestricted area availability)

A first set of results of scenario 1 was generated under the assumption that all the remaining onshore areas according to the geographical analysis would be potentially available for the allocation of WTGs.

This assumption was of a purely academic nature. Without any further area constraints, the resulting allocation of wind power capacity would result in the largest electricity production possible and lowest LCOE of onshore wind power because the most favourable locations would be available and utilized. All the scenario variants could not reach larger production figures and lower LCOE because in those cases less favourable locations would be utilized for the allocation of wind power capacity. The resulting figures thus could act as an extreme example the scenario variants could be compared with.

The modeling results (cf. table 3.3) show that the full capacity of 39.5 GW of onshore wind power was allocated in the available area. This could be expected as the technical potential detected was much larger (cf. section 3.1).

Although in the scenario approximately 40 GW of wind power were installed until 2050, the maximum power available during the year was 32.2 GW which is 82 % of the installed onshore wind power capacity. On the one hand this maximum value reflects the fact that the calibration percentage (cf. section 2.7) had been taken into account. On the other hand it also shows that there was no moment during the target year when all WTGs produced at full power as the maximum value was even smaller than the full installed capacity minus the adjustment percentage. Moreover, there were no moments during the target year without any onshore wind power production. As the capacity was allocated in several regions and wind speeds were never 0 m/s in all the districts at the same time, the lowest onshore production was 0.16 GW which corresponds to 0.4 % of the installed capacity.

Without any further area limitations, the wind power capacity would be allocated to only few districts with a high concentration of installed capacity. Those districts were

Table 3.3: Modeling results for scenario 1 (unrestricted area availability, 2050)

Onshore wind power	capacity	GW	39.50
	produced electricity	TWh/a	82.50
	EFLH		2088.54
	capacity factor		0.24
	minimum production	GW (%)	0.16 (0.41)
	maximum production	GW (%)	32.28 (81.72)
	LCOE	Ct./kWh	5.23
	specific investment cost	Ct./kWh	3.60
	specific MRO cost	Ct./kWh	1.63
Offshore wind power	produced electricity	TWh/a	217.71
PV	produced electricity	TWh/a	60.93
Run-of-the-river hydro power	produced electricity	TWh/a	27.42
All VRE	produced electricity	TWh/a	388.56
	share in demand (low demand level)	%	77.71
	share in demand (high demand level)	%	55.50
	LCOE	Ct./kWh	5.81

found mainly in the federal state of Schleswig-Holstein, along the coastlines and in the mountain ranges in central and southern Germany.

The distribution of the installed onshore wind power capacity in 2050 is illustrated in figure 3.3. In the image, the installed capacity in the districts is related to the respective area (given as MW/km^2) in order to have comparable figures. The darker an area in the map, the higher is the specific value of the installed capacity (in the following also referred to as "capacity density"). In districts coloured white there would be no wind power installation in 2050 under the assumptions made.

In comparison to the present distribution of the wind power capacity (cf. figure 2.17), an economically optimized allocation of the onshore wind power capacity as defined in the scenario without further area limitations shows a substantially higher capacity density in fewer districts and a large number of districts without any wind power installation. This can be explained by the logic of the model. In the model, all present wind power installation was replaced capacity-wise until the target year. As the replacement was conducted according to the allocation methodology, i.e. in an economically optimized way, the present capacity was moved away from current locations to available locations with expectedly more favourable wind speed conditions.

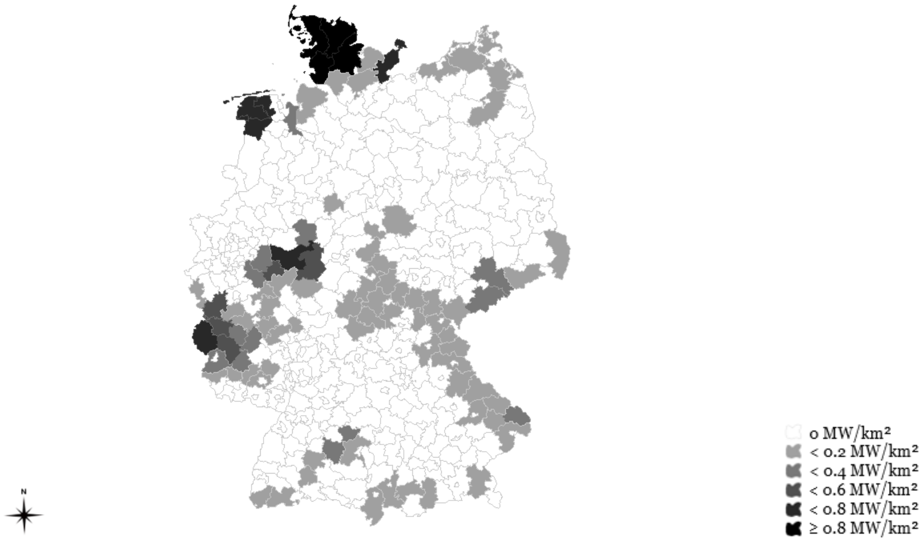


Figure 3.3: Scenario 1: Capacity density of wind power by districts (unrestricted area availability, 2050)

The allocated onshore wind power capacity generated 82.5 TWh in 2050. Due to the absence of further area limitations, not only the wind power capacity was allocated to few districts but also the power production accordingly was concentrated. The largest production was found especially in the North of Germany whereas production would be low in the South. This is also reflected in the resulting EFLH in the transmission grid regions: As the national average, 2016 EFLH were reached. The wind power production in the transmission grid regions ranged from 813 EFLH (region 14, South-West Bavaria) to 2356 EFLH (region 1, Schleswig-Holstein). The offshore wind power capacity was allocated to 54 offshore sub-regions, i.e. nearly all offshore sub-regions were affected by wind power installations. It generated 218 TWh/a, which translates into 2974 EFLH.

In the scenario, the PV capacity of approx. 60 GW_p in 2050 produced 61 TWh/a. Run-of-the-river hydro power (4.45 GW) produced 27 TWh/a. In sum, wind power, PV and run-of-the-river hydro power generated 389 TWh/a. Related to the German electricity demand in 2050 and no additional losses assumed, the share of the power production from VRE in the total national electricity demand in 2050 ranged between 55.5 % at a high demand level and 77.7 % at a low demand level. The annual demand coverage in the transmission grid regions ranged between 0.7 % (region 1, Hamburg) and 468.4 % (region 1, Schleswig-Holstein) at a low demand level and between 0.5 % (region 2) and 334.6 % (region 1) at a high demand level. In any case the power production in region 1 was at least more than three times as high as the annual electricity demand in that region. On the other end of the scale, only a small share of region 2's electricity demand could be covered by power production from VRE located in that region. This is not surprising as region 2 covered the area of a city state (Hamburg) with a comparably high demand and a comparably low VRE potential whereas region 1 covered the area of a territorial state (Schleswig-Holstein) with a comparably low power demand and a comparably high VRE potential.

The national mean LCOE in 2050 was 5.23 Ct./kWh (onshore wind power) and 5.11 Ct./kWh (offshore wind power), respectively. The lowest LCOE was found in region 1 with 4.64 Ct./kWh, the highest LCOE was found in region 10 (South-West Bavaria) with 13.54 Ct./kWh.

The mean LCOE of all VRE combined was 5.81 Ct./kWh. It was higher than the LCOE of wind power alone, driven by comparably high LCOE of PV and a comparably low share of cheap onshore wind power in that scenario.

As said, without further area restrictions, the assumptions and results of that scenario variant represented an extreme case that revealed potential system boundaries.

3.2.1.2 Scenario 1: Results (restricted area availability)

In a second step the maximum area potentially available for the allocation of WTGs was reduced in every federal state and in every district. As in the potential analysis, the areas of the federal states and of the districts were limited to 2 % to 5 % of their total area. In a further scenario variant, the area potentially available for wind power installations in the federal states was limited to 3 % while concurrently the area in the districts was limited to 5 %, within the area limitation of the federal states (in the following referred to as "3 %/5 % variant"). The offshore area was not affected by this additional area limitation, thus the model results for offshore wind power were not affected either.

The results of scenario 1 with further area limitations are presented in table 3.4. The installed capacity and produced electricity in the transmission grid regions is listed in table B6 in the appendix. Starting with a limitation of 2 % of the federal state areas and of the district areas, it was increased stepwise to 5 %. The last column of the table includes the modeling results of the 3 %/5 % variant. The results show that the full amount of 39.5 GW of onshore wind power capacity could be allocated until 2050 even with the tightest area limitation (2 %).

The installed onshore wind power capacity in the scenario variants is illustrated in figure 3.4 (larger version in figure A6 in the appendix). From left to right the maps illustrate the capacity density in the districts with an area limitation ranging from 2 % to 5 % of the federal state areas and the district areas, accompanied by the results of the

Table 3.4: Results of scenario 1 with further area limitations (restricted area availability, 2050)

	Unit	Maximum share of federal states and district areas				
		2 %	3 %	4 %	5 %	3 %/5 %*
Onshore wind power						
capacity	GW	39.50	39.50	39.50	39.50	39.50
produced electricity	TWh/a	67.53	70.67	72.12	73.13	72.95
EFLH		1709.70	1789.06	1825.82	1851.47	1846.79
capacity factor		0.20	0.20	0.21	0.21	0.21
minimum production	GW	0.35	0.30	0.27	0.21	0.24
		(0.89 %)	(0.76 %)	(0.68 %)	(0.54 %)	(0.60) %
maximum production	GW	31.33	31.68	31.49	31.43	31.27
		(79.32 %)	(80.20 %)	(79.72 %)	(79.56 %)	(79.17 %)
LCOE	Ct./kWh	6.39	6.10	5.98	5.90	5.91
specific investment cost	Ct./kWh	4.40	4.20	4.12	4.06	4.07
specific MRO cost	Ct./kWh	1.99	1.90	1.86	1.84	1.84
All VRE						
produced electricity	TWh/a	373.60	376.73	378.18	379.20	379.01
share in demand (low demand level)	%	74.71	75.34	75.63	75.83	75.80
share in demand (high demand level)	%	53.37	53.81	54.02	54.17	54.14
LCOE	Ct./kWh	6.04	5.99	5.97	5.95	5.95

*) 3 %: limitation of federal states areas; 5 %: limitation of districts areas

3 %/5 % variant on the right hand side. The capacity density (given as MW per square kilometer) is coloured in different shades of gray, ranging from white (0 MW/km^2, i.e. no installation) to black (more than 0.8 MW/km^2).

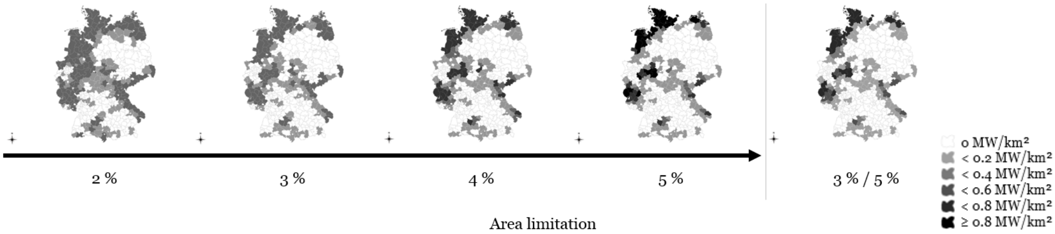


Figure 3.4: Scenario 1: Installed wind power capacity by districts (restricted area availability, 2050)
Percentages: restriction of federal state areas and district areas. 3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

The results show that in the case of an economically optimized allocation of wind power capacity with a limitation of 2 % of the federal state areas and the district areas the wind power capacity was allocated to 199 out of the 412 districts. At maximum, 0.26 MW/km^2 would be installed in 2050. An increase in the area limitation to 5 % of the federal state areas and the district areas resulted in an increasing concentration of capacity, i.e. the capacity was allocated to fewer (133) districts with a higher capacity density (0.64 MW/km^2). The wider the area limitation was set, the fewer districts were affected by wind power installations, illustrated as fewer and darker districts on the maps, and moreover the more similar the capacity allocation became in comparison to the capacity allocated without any area limitations. The 3 %/5 % variant showed an even stronger capacity concentration than the variant of a 5 % limitation of the federal state areas and the district areas.

In turn this means that the tighter the area limitation was set, the more distributed the allocated capacity was. A decrease in the area potentially available in every district and in every federal state resulted in a lower concentration of capacity, i.e. the capacity was allocated to more districts.

Under the assumptions made, just small amounts of wind power capacity were allocated to districts in the East and in the South of Germany. As in the scenario variant without area restrictions, the allocation of onshore wind power capacity clearly differed from the distribution of the present wind power installation (cf. figure 2.17).

This effect also becomes obvious in the aggregated results at the federal state level. In figure 3.5 the total installed capacity in the federal states in 2050 is illustrated, depending on the area restrictions defined for wind power installations. The gray bars illustrate

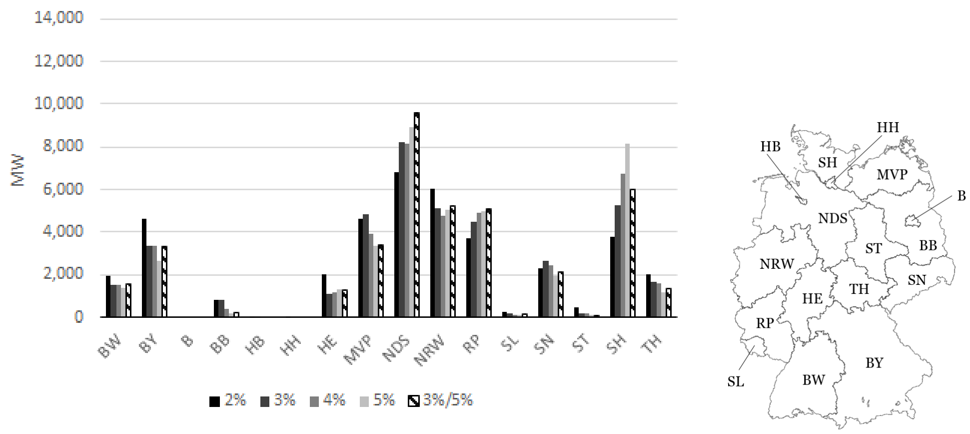


Figure 3.5: Scenario 1: Wind power capacity installed in the federal states (restricted area availability, 2050)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Germany's federal states.

the scenario variants in which the limitations of both the federal state areas and the district areas were equally high, the hatched bars illustrate the results of the 3 %/5 % variant. The more area was available for wind power installations the more capacity was installed in the federal states especially in the North (Schleswig-Holstein and Lower Saxony) in scenario 1. The effect differed between the federal states and moreover the capacity allocated in different federal states conditioned each other. In Schleswig-Holstein, for instance, a doubling of the potentially available area resulted in a strong increase in the allocated capacity (3.8 GW installed with an area limitation of 2 %, 6.8 GW with an area limitation of 4 %) whereas the decrease in installed capacity with an increasing area availability in other federal states was comparably low. Under the assumptions made, in any case most of the capacity was installed in the federal state of Lower Saxony, ranging from 9.4 GW to 12.4 GW. In the states of Bavaria, Mecklenburg-Western Pomerania, Northrhine-Westphalia, Rhineland-Palatinate and Schleswig-Holstein more than 3 GW were installed each, with more than 8 GW in Schleswig-Holstein in the case of a high area availability. In all the other federal states, 2.6 GW of wind power capacity at maximum was installed in 2050, in several of the federal states however substantially less.

The resulting national electricity production by onshore wind power accordingly showed variations depending on the area limitations set, ranging from 67.5 TWh/a (area limitation of 2 %) to 73.1 TWh/a (area limitation of 5 %). An increase in the potentially available area, resulting in a higher concentration of wind power capacity to more favourable locations, thus increased the power output. As illustrated in figure 3.6, in three transmission grid regions that effect could be found: region 1 (Schleswig-Holstein), region 3 (North Lower Saxony), and region 9 (South-East Northrhine-Westphalia). Due to the increased capacity concentration, the effect in region 1 was the biggest: increasing the restriction of the federal state areas and the district areas from 2 % to 5 % more than doubled the power output in that region. On the other hand, altering the area availability had a comparably small effect on the power output in the other transmission grid regions. Some showed a minor decrease in production, others a minor increase. If a larger area was potentially available, the shift of wind power installations to more favourable locations thus strongly increased the power production in the most favourable locations whereas the power output in comparably less favourable regions was only slightly reduced. This result can also be found in the figures of the 3 %/5 % variant in which power production was approx. 2.3 TWh/a larger than in the variant with an area limitation of 3 % of the federal state areas and the district areas.

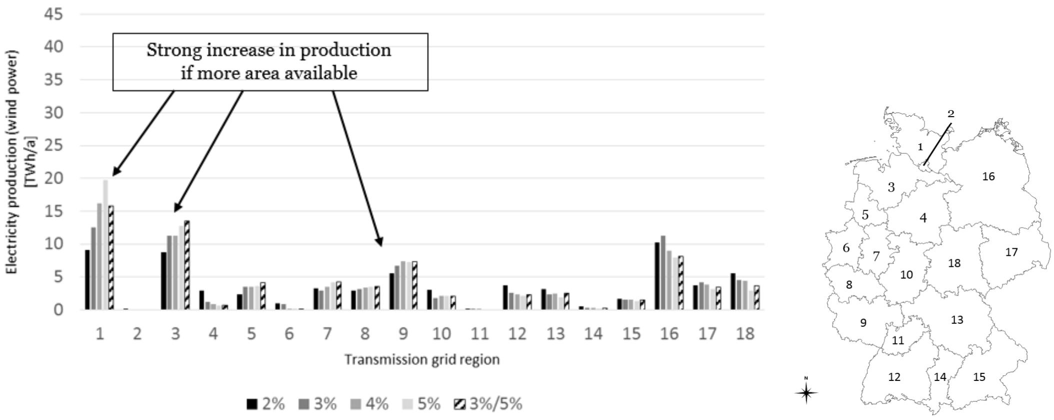


Figure 3.6: Scenario 1: Electricity production from onshore wind power by transmission grid regions (restricted area availability, 2050)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

Related to the installed capacity, the production figures translate into 1709 – 1851 EFLH, depending on the area limitations set. Those figures are the national averages that, again, lay within a range of the resulting EFLH in the individual transmission grid regions.

The marginal change of power production and also of LCOE of onshore wind power decreased with an increasing area availability. This means the effect an additional potentially available area had on the electricity production from wind power decreased the more area actually was potentially available. The scenario results show that an increasing area limitation from 2 % to 3 % of the federal state areas and the district areas resulted in an additional power output of 3.1 TWh/a in total. Increasing the area limitation from 3 % to 4 %, i.e. by the same percentage, however, meant an additional power output by only 1.4 TWh/a. The reason to this lies in the fact that with a larger area availability only few more favourable locations for the allocation of WTGs were potentially available and utilized. In comparison with the variant with no further area limitations, power production was 9.4 TWh/a (5 % area limitation) to 15.0 TWh/a (2 % area limitation) lower, i.e. 11 – 18 % below the maximum power production technically achievable.

Including the power production of PV (60.9 TWh/a) and run-of-the-river hydro power (27.4 TWh/a), the production of all VRE summed up to 373.6 – 379.2 TWh/a. This translates into a share of 74.7 – 75.8 % in total power demand at a low demand level and 53.8 – 54.2 % at a high demand level, respectively. This means that even at a low demand level in 2050 and despite a high share of offshore wind power as in the scenario, that VRE capacity could not fully supply Germany's electricity demand, which however was not surprising as the calculations without further area limitations already indicated that the installed VRE capacity could not fully cover the demand. The annual net demand coverage with the additional area limitation lay approx. 1.7 – 3.3 percentage points below the results of the variant without these area limitations, depending on the area limitations set.

In figure 3.7 (larger version in figure A12 in the appendix) the production pattern of all VRE is exemplarily depicted for the scenario variant with a 2 % limitation of the federal state areas and of the district areas. In order to demonstrate the relation, the load at a low demand level, i.e. 500 TWh/a, is also depicted. In that scenario variant the load fluctuated between 35 and 82 GW whereas the power production from VRE fluctuated between 4 and 117 GW. The VRE production exceeding the demand during the year resulted in gross electricity surpluses of 39 TWh/a, illustrated as negative values in the diagram. At maximum, a power surplus of 58.2 GW would be needed to be handled by flexibility options such as cross-border transmission lines, storage options or other unless power production was curtailed.

As the residual load fluctuated during the target year, a net balance of 126 TWh/a could not be covered by the power generated by the VRE installations in the scenario

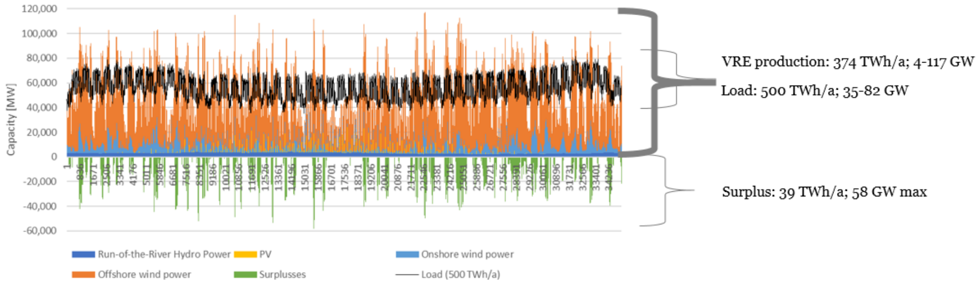


Figure 3.7: Scenario 1: Electricity production from VRE
(2050, restricted area availability: 2 %)

variant with an area limitation of 2 %, thus it would be required from other sources. A high demand level assumed (700 TWh/a), the net balance substantially increased to 326 TWh/a of electricity shortages.

In figure 3.8 the resulting duration curves of the residual load are depicted assuming a low demand level in Germany in the scenario variants modeled for 2050. In such curves the sorted hourly load during the year is depicted ranging from the highest load on the left to the lowest load on the right (cf. Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES) (2009)). The area between the curves and above the abscissa represents the positive residual load, i.e. electricity shortages. The area below the abscissa and above the curves represents the amount of electricity surpluses that would be needed to be stored or transmitted abroad unless power production was curtailed. Differences in the curves are hardly detectable, meaning that the residual load was just slightly affected by a variation of the area availability for onshore wind power installations. In case of an area limitation of 2 %, the demand could be directly covered from VRE during 2524 h of the year. A larger area availability for onshore wind power resulted in a higher number of hours in which demand could be fully covered by powr production from VRE (e.g. 5 % area limitation: 2630 h/a).

At a low demand level, a maximum power surplus of 58.2 GW was reached whereas the maximum power shortage was 70.3 GW. A high demand level in 2050 assumed, the range of the minimum and maximum residual load was shifted upwards: In that case the maximum power surplus was lower (36.7 GW) and the maximum power shortage was substantially higher (101.1 GW). This means that at a high demand level more than 100 GW would be needed to be dispatched by other production, e.g. conventional power plants, biogas power plants, storage, and cross-border transmission lines. Taking all the grid extension projects until 2035 as presented in the NEP into account (cf. 2.3.1.4), Germany's projected transmission capacity to neighbouring countries summed up to

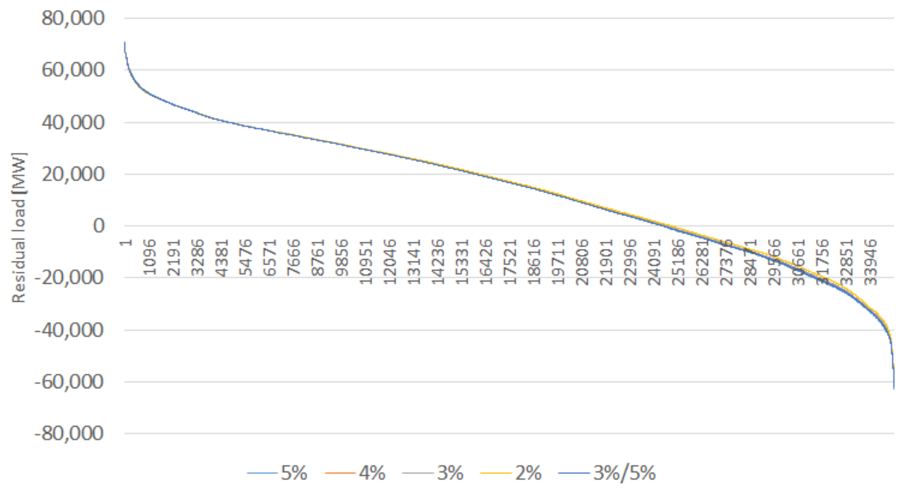


Figure 3.8: Scenario 1: Duration curves of the residual load
(2050, low demand level)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

approx. 74.4 GW. Electricity surpluses thus basically could be transmitted in any case but during times of low wind power and PV production the cross-border transmission capacity would not suffice to fully cover the national load.

Increasing the area availability for wind power installations to 5 % resulted in a larger amount of gross electricity surpluses (43.0 TWh/a, i.e. + 4.0 TWh/a $\widehat{=}$ + 10.4 %) and maximum power surplus (63.0 GW, i.e. + 4.8 GW $\widehat{=}$ + 8.2 %). The maximum power shortage was practically unaffected by the area availability (70.9 GW) but the shortage energy was slightly reduced (163.7 TWh/a).

The region-specific residual load at a low demand level is illustrated in figure 3.9. The 3 %/5 % variant has not been included in the diagrams. In the images, resulting figures from the three offshore grid regions were incorporated in the figures of their respective closest onshore region, i.e. the transmission grid region where the offshore production would be landed. Those regions were

- region 19 (Southern part of the North Sea) combined with region 3 (North-West Lower Saxony),
- region 20 (Northern part of the North Sea) combined with region 1 (Schleswig-Holstein), and
- region 21 (Baltic Sea) combined with region 16 (North-East Germany).

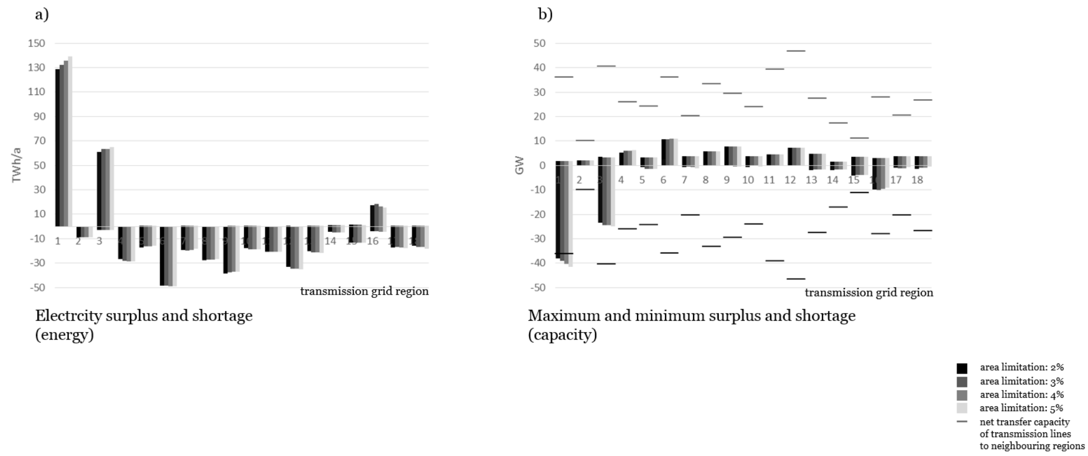


Figure 3.9: Scenario 1: Residual load by transmission grid regions
(2050, low demand level)

In image a the total electricity net balance (balance of annual sums of electricity surpluses and shortages, given as TWh/a) is depicted, for all transmission grid regions, with the area limitations presented. Except for regions 1, 3 and 16, i.e. the regions where offshore wind power was landed, in all the regions a net electricity shortage existed in 2050 in the scenario. In all the scenario variants, the largest shortage was found in region 6 (West Northrhine-Westphalia).

In image b the maximum values of the power surplus and the power deficit in the transmission grid regions during the target year (given as GW) are depicted. Additionally the transmission capacity (NTC) of power lines to neighbouring grid regions and to neighbouring countries are marked as black lines in the diagram, taking all grid expansion projects presented in the NEP into account. It becomes obvious that the transmission lines basically sufficed potential transmission requirements of all the transmission grid regions except one: In region 1 and its assigned offshore grid region 20 combined there were moments during the year when the maximum power surplus – mainly driven by the offshore production – exceeded the net transfer capacity to neighbouring regions and abroad. An increasing share of area availability for wind power, thus an increasing concentration of wind power capacity, exacerbated that situation, i.e. the transmission requirement further increased. The lowest value was found with a narrow limitation of the district areas (2 %): In region 1, 37.2 GW of power surplus were faced with a net transfer capacity of 36.1 GW, i.e. in all the scenario variants modeled a transmission capacity of at least approx. 1 GW was missing. Further research activity should analyze potential transmission requirements in more detail.

A high demand level assumed, the situation did not fundamentally change. An elevated load however reduced the residual load. In region 1 the maximum power surplus still exceeded the transmission capacity to neighbouring regions.

In the scenario variants modeled, the LCOE of onshore wind power ranged between 5.95 and 6.04 Ct./kWh as national means in 2050. There were, again, regional differences: LCOE of onshore wind power ranged between 4.56 Ct./kWh (area limitation of 5 %, region 1) and 13.90 Ct./kWh (area limitation of 2 %, region 6 (West Northrhine-Westphalia)). In figure 3.10 the LCOE of onshore wind power in the transmission grid regions is shown.

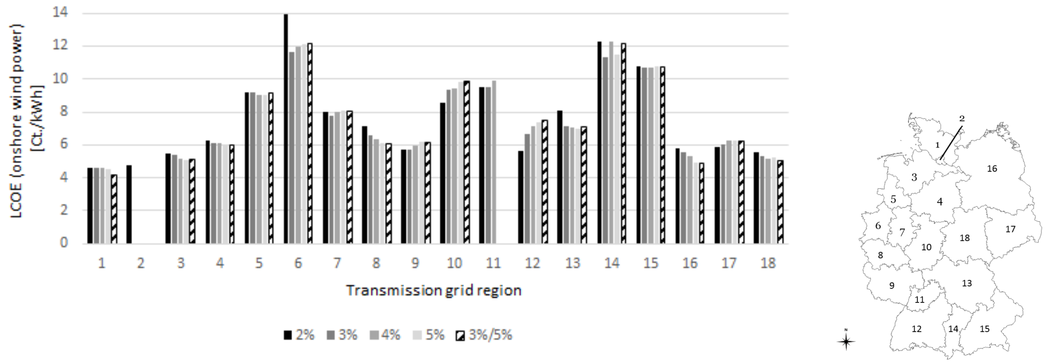


Figure 3.10: Scenario 1: LCOE of onshore wind power by transmission grid region (2050)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

The impact of the area availability for onshore WTGs on the total LCOE of all VRE was small because the share of onshore wind power was only 22 % of the total VRE capacity in 2050 in the scenario. Irrespective of that, the modeling results show that an increase in the area potentially available for onshore wind power installations from 2 % to 5 % of the district area (i.e. by 3 percentage points) resulted in a higher power production (increased by 8.2 %). This also translates in a reduction of LCOE of onshore wind power by the same magnitude.

The result figures show deviations from the results presented in the original source of the scenario (cf. Sachverständigenrat für Umweltfragen (SRU) (2011)). In the original study, onshore wind power production was 90.6 TWh/a in 2050. Compared to the new findings, the difference was in a range of 17 to 23 TWh/a, depending on the area limitations defined, i.e. the production values of SRU were up to 25 % higher than the figures generated with the new model. This deviation was also found in the number of EFLH and in the LCOE: in the original source, 2294 EFLH of onshore wind power in 2050 were detected with LCOE of 4.7 Ct./kWh.

The deviation between the original source and newly modeled data can be explained with differences of technical and economic inputs to the models. The optimization calculation of the REMix model by DLR was conducted for the year 2050 solely, i.e. only technical and economic data for the year 2050 had been taken into account. In turn this means that neither lower hub heights of WTGs installed in prior years, nor higher investment cost in years before 2050 were taken into account. This determined an overestimation of the power production and an underestimation of LCOE in the original source. Moreover, the underlying geographical, meteorological and technical data and assumptions differed. Especially the utilization of 2010 wind speed data as in this thesis tends to be a rather conservative assumption.

3.2.2 Scenario 2 ("PV leads")

In a second scenario a situation with a higher onshore wind power penetration and a different mix of the installed VRE capacity was modeled and analyzed. Scenario 2 was based on a scenario from Nitsch et al. (2012). The so-called "master study" ("Leitstudie") was developed by the German Aerospace Center (Deutsches Zentrum für Luft- und Raumfahrt e.V.) (DLR), Fraunhofer Institute for Wind Energy and Energy System Technology (Fraunhofer-Institut für Windenergie und Energiesystemtechnik) (Fraunhofer IWES) and others for the Federal Ministry for Economic Affairs and Energy (Bundesministerium für Wirtschaft und Energie) (BMWi). It built upon previous work by DLR and others for the Federal Environment Agency (Umweltbundesamt) (UBA) and the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit) (BMU), namely master studies from prior years (Nitsch (2008), Nitsch & Wenzel (2009) and Nitsch et al. (2010)). In the centre of the study, consistent scenarios on the expansion of the RES capacity in Germany until 2050 were developed.

In the study four scenarios for 2050 were presented, oriented towards the goal of reducing GHG emissions by at least 80 % until 2050 ("target scenarios" ("Ziel–Szenarien"), cf. Sachverständigenrat für Umweltfragen (SRU) (2011, p. 59)). The targets were reached by a capacity expansion of RES and energy efficiency improvements. The main scenarios in Nitsch et al. (2012) differed in their assumptions on the future power demand and supply structure, resulting in different supply mixes for 2050.

In scenario "2011 A" a moderate growth of RES capacity was assumed. Scenario "2011 B" was based on the same demand structure as scenario "2011 A" but differed from it by the inclusion of hydrogen production from RES electricity. In scenario "2011 C" the demand structure was altered and the electricity supply also fully covered electrical transportation. Additionally, further scenario variants with higher energy efficiency and more ambitious GHG emissions reduction targets were presented in the study. From the scenarios, scenario "2011 B" was selected for calculations with the new model.

Central data of the installed VRE capacity in the scenario are presented in table 3.5. The scenario was characterized by an installation of 54.3 GW of onshore wind power and 34.5 GW of offshore wind power by 2050. The PV installation reached 79.0 GW_p in 2050. Run-of-the-river hydro power reached an upper limit of 4.45 GW by 2020 and remained subsequently constant due to the potential fully tapped.

The scenario was called "PV leads" in this thesis as PV had the highest share (44.9 %) in the installed VRE capacity in 2050. The onshore wind power capacity ex-

Table 3.5: Installed capacity in scenario 2 ("PV leads")

	Unit	2020	2030	2035	2040	2050
Onshore wind power	GW	39.00	46.57	48.75	51.47	54.27
Offshore wind power	GW	11.02	24.66	27.25	30.50	34.50
PV	GW_p	55.44	66.27	69.77	73.27	79.03
Run-of-the-river hydro power	GW	4.45	4.45	4.45	4.45	4.45

Based on Nitsch et al. (2012) and own calculations

pansion was larger than in scenario 1. Reaching approx. 15 GW more than in scenario 1 in 2050, this development represented an average increase in the installed capacity of approx. 0.5 GW per annum. This was still a low growth rate compared to the development in the past but it can be read as an assumed change in the framing conditions, for instance a lower feed-in tariff guaranteed by the EEG law or a different structure of the support scheme. The offshore wind power installation in 2050 accounted for approx. half of the installed offshore wind power capacity of scenario 1.

As in scenario 1, in a first step of the analysis it was assumed that all the remaining areas according to the geographical analysis would be fully available for wind power use. In a second step, the area was further restricted. In the model calculations a comparably narrow WTG spacing was assumed.

3.2.2.1 Scenario 2: Results (unrestricted area availability)

As in scenario 1, the theoretical case of an area availability for onshore wind power without further area limitations was modeled first. It would result in the highest power generation possible, thus the lowest LCOE of onshore wind power. All scenario variants would result in a lower power production.

The modeling results as presented in table 3.6 show that the full onshore wind power capacity of 54.3 GW was allocated in the available area. The maximum power available during the year was 44.6 GW which is 82.1 % of the installed capacity. The lowest onshore production was 0.3 GW which is 0.4 % of the installed capacity. Both minimum and maximum ratios were nearly in compliance with the results from the corresponding variant of scenario 1 without further area limitations.

The installed capacity of onshore wind power is illustrated in figure 3.11. Without any further area limitations, the capacity was allocated to only few districts (gray areas). Similar to scenario 1 without further area limitations, they were concentrated mainly to the coastal and mountain regions, with a high capacity density in those districts.

Table 3.6: Results of scenario 2 (unrestricted area availability, 2050)

Onshore wind power	capacity	GW	54.27
	produced electricity	TWh/a	119.99
	EFLH		2211.03
	capacity factor		0.25
	minimum production	GW (%)	0.21 (0.38)
	maximum production	GW (%)	44.56 (82.11)
	LCOE	Ct./kWh	4.93
	specific investment cost	Ct./kWh	3.40
	specific MRO cost	Ct./kWh	1.54
Offshore wind power	produced electricity	TWh/a	95.29
PV	produced electricity	TWh/a	80.87
Run-of-the-river hydro power	produced electricity	TWh/a	27.42
All VRE	produced electricity	TWh/a	323.57
	share in demand (low demand level)	%	64.71
	share in demand (high demand level)	%	46.22
	LCOE	Ct./kWh	6.09

The allocated onshore wind power capacity generated 120.0 TWh in 2050. Similar to scenario 1, again, a high concentration of capacity, thus power production, in only few districts could be found, especially in the federal states in the North of Germany (Schleswig-Holstein and Lower Saxony).

The national mean EFLH of onshore wind power were 2211. The EFLH in the transmission grid regions ranged between 820 (Region 14, South-West Bavaria) and 2498 (region 1, Schleswig-Holstein).

In comparison with the results of scenario 1, the national mean EFLH in scenario 2 were higher. This was surprising because in scenario 2 a larger amount of capacity was allocated to more locations with presumably less favourable wind speed conditions, expected to result in a lower specific power output and lower mean EFLH. The deviation from this expectation, however, can be explained by differences between long-term average wind speeds – being a central input parameter in the economically optimized allocation of WTGs – and the wind speed time series of the year 2010 being a central input parameter for the modeling of the electricity generation.

The offshore WTGs were allocated to 22 offshore sub-regions. This is a lower value than in scenario 1, which was expected because the overall offshore wind power capacity

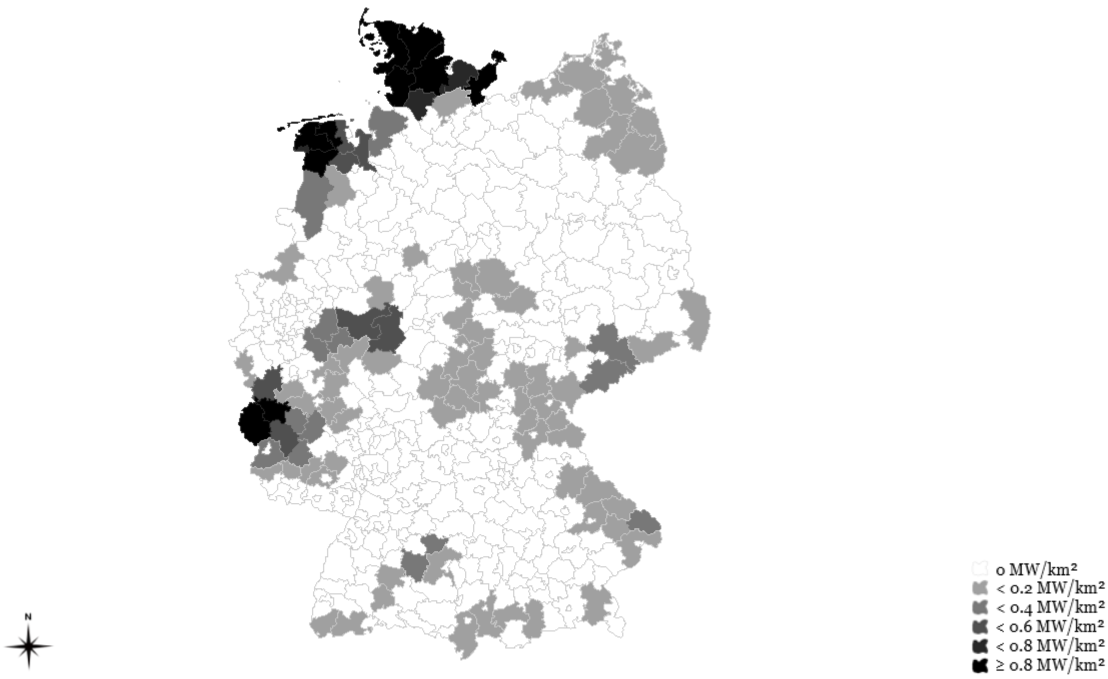


Figure 3.11: Scenario 2: Capacity density of wind power by districts (unrestricted area availability, 2050)

was substantially lower in scenario 2. Not surprisingly, the offshore wind power capacity of 34.5 GW was fully allocated, resulting in an electricity production of 95 TWh/a.

The installed capacity of PV (79.3 GW_p) produced 80.9 TWh/a, run-of-the-river hydro power produced 27.4 TWh/a in 2050. In sum all VRE combined reached a production of 323.6 TWh/a. This translates into a share in the total electricity demand in the target year ranging between 46.2 % at a high demand level and 64.7 % at a low demand level. The theoretical annual net demand coverage in the transmission grid regions ranged between 0.9 % (region 2, Hamburg) and 660.9 % (region 1, Schleswig-Holstein) at a low demand level and between 0.6 % (region 2) and 472.1 % (region 1) at a high demand level.

The German mean LCOE in 2050 was 4.93 Ct./kWh (onshore wind power) and 5.22 Ct./kWh (offshore wind power), respectively. The LCOE ranged between 4.57 Ct./kWh (region 1, area limitation of 2 %) and 12.32 Ct./kWh (region 14, South-West Bavaria). The capacity mix in the scenario resulted in LCOE of all VRE combined of 6.54 – 6.73 Ct./kWh and thus was higher than the LCOE of wind power alone.

Table 3.7: Results of scenario 2 (restricted area availability, 2050)

	Unit	Maximum share of federal states and district areas				
		2%	3%	4%	5%	3 %/5 %*
Onshore wind power						
capacity	GW	54.27	54.27	54.27	54.27	54.27
produced electricity	TWh/a	89.12	93.46	97.02	97.70	96.59
EFLH		1642.19	1722.21	1787.69	1800.26	1779.82
capacity factor		0.19	0.20	0.20	0.21	0.20
minimum production	GW	0.46 (0.84%)	0.43 (0.79%)	0.39 (0.72%)	0.35 (0.64%)	0.36 (0.66 %)
maximum production	GW	43.32 (79.83%)	43.28 (79.75%)	43.73 (80.58%)	43.74 (80.59%)	43.55 (80.25 %)
LCOE	Ct./kWh	6.64	6.33	6.10	6.06	6.13
specific investment cost	Ct./kWh	4.57	4.36	4.20	4.17	4.22
specific MRO cost	Ct./kWh	2.07	1.97	1.90	1.89	1.91
All VRE						
produced electricity	TWh/a	292.70	297.05	300.60	301.28	300.17
share in demand (low demand level)	%	58.54	59.40	60.12	60.25	60.03
share in demand (high demand level)	%	41.81	42.43	42.94	43.04	42.88
LCOE	Ct./kWh	6.73	6.63	6.56	6.54	6.56

*) 3 %: limitation of federal states areas; 5 %: limitation of districts areas

3.2.2.2 Scenario 2: Results (restricted area availability)

In a second step the area potentially available for onshore wind power installations was limited to 2 % to 5 % of the federal state areas and the district areas, accomplished by a variant with limitations of 3 % of the federal state areas and 5 % of the district areas concurrently. The result figures of the simulation can be found in table 3.7. The installed capacity and electricity produced in the transmission grid regions is presented in table B7 in the appendix.

In all scenario variants the onshore wind power capacity of 54.3 GW until 2050 could be fully allocated. From left to right figure 3.12 (larger version in figure A7 in the appendix) depicts the spatial allocation (given as MW/km^2) under area limitations ranging from 2 % to 5 % maximum of total state and district area, supplemented by the 3 %/5 % variant. Again, the capacity density is illustrated in different shades of gray (ranging from white: 0 MW/km^2 to black: more than 0.8 MW/km^2).

The results show that in the case of the tightest area restriction (2 %), 244 out of the 412 districts would be affected by wind power installations, with 0.25 MW/km^2 installed at maximum, implying an extensively spread wind power capacity and a comparably low capacity density. An increase in the area availability to 5 % led to an increasing concentration of wind power capacity: 154 districts were affected in that case, reaching a higher maximum capacity density (0.64 MW/km^2). This means an increase in the area limitation from 2 % to 5 % translated into more than a doubling of the maximum capacity density. In total, the specific capacity was in the same range as in scenario 1 but more districts were affected.

Figure 3.12: Scenario 2: Installed wind power capacity by districts (restricted area availability, 2050)
Percentages: restriction of federal state areas and district areas. 3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

The effect could also be detected at the federal state level (figure 3.13). As in scenario 1, the figure illustrates the total installed capacity in the federal states in 2050, depending on the area restrictions set for wind power installations. The gray bars illustrate the scenario variants in which the area limitation of both the federal state areas and the district areas was equally high whereas the hatched bars illustrate the results of the 3 %/5 % variant. The more area was potentially available, the more wind power capacity was installed in the federal states especially in the North (Schleswig-Holstein and Lower Saxony).

Again, in any case most of the wind power capacity was installed in the federal state of Lower Saxony, ranging from 9.4 GW to 12.4 GW. In the federal states of Bavaria, Mecklenburg-Western Pomerania, Northrhine-Westphalia, Rhineland-Palatinate and Schleswig-Holstein more than 4 GW were installed each, ranging up to more than 8 GW in Schleswig-Holstein and Northrhine-Westphalia. In all the other federal states, a maximum of 4.0 GW of wind power capacity was not exceeded. In some of the federal states the installed wind power capacity was substantially smaller.

In the scenario, the allocated onshore wind power capacity generated 89 – 98 TWh/a, depending on the area limitations set. Compared to the scenario variant without further area limitations, an additional area restriction thus materialized in an electricity production by onshore wind power that is 22.3 – 30.9 % lower, depending on the area

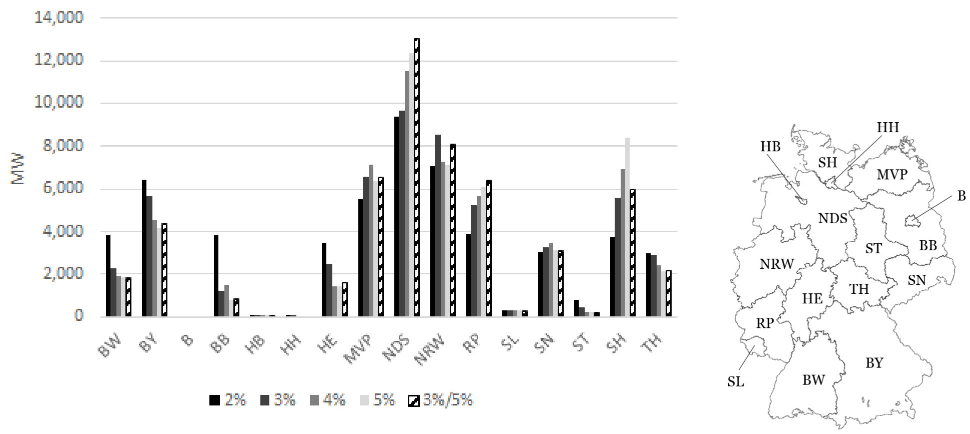


Figure 3.13: Scenario 2: Wind power capacity installed in the federal states (restricted area availability, 2050)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Germany's federal states.

limitations set. This difference was substantially larger than in scenario 1 and can be explained by the larger total capacity amount to be installed, i.e. more wind power capacity was shifted to less favourable locations due to the area limitations set.

Related to the installed capacity of 54.3 GW the production translates into 1642 – 1800 EFLH as the national mean. Both the electricity production and the EFLH were lower than in the comparable variants of scenario 1. That could be expected because with a larger amount of installed capacity, more locations with less favourable wind speed conditions would be utilized.

The alteration of the maximum area availability shows three categories of transmission grid regions, characterized as presented in the following list

- Category a:
  An increase in area availability for wind power resulted in a larger electricity production (transmission grid regions 1 (Schleswig-Holstein), 3 (North Lower Saxony), 5 (South-West Lower Saxony), 9 (central Germany))

- Category b:
  An increase in area availability for wind power resulted in a smaller electricity production (regions 4 (South-East Lower Saxony), 6 (West Northrhine-Westphalia), 8 (South Northrhine-Westphalia), 10 (South-East Northrhine-Westphalia), 12 (South Baden-Württemberg), 13 (North Bavaria)

- Category c:
  An increase in area availability for wind power had hardly any effect on the electricity production (all other regions).

The increase or decrease of power produced in a transmission grid region conditioned the power produced in another: With the same total amount of capacity, wind power capacity was shifted to more favourable locations if the area limitation was increased, resulting in a higher power production there and a lower power production in regions the capacity was moved away from.

Figure 3.14 shows the absolute production from onshore wind power in the transmission grid regions, depending on the area restrictions set.

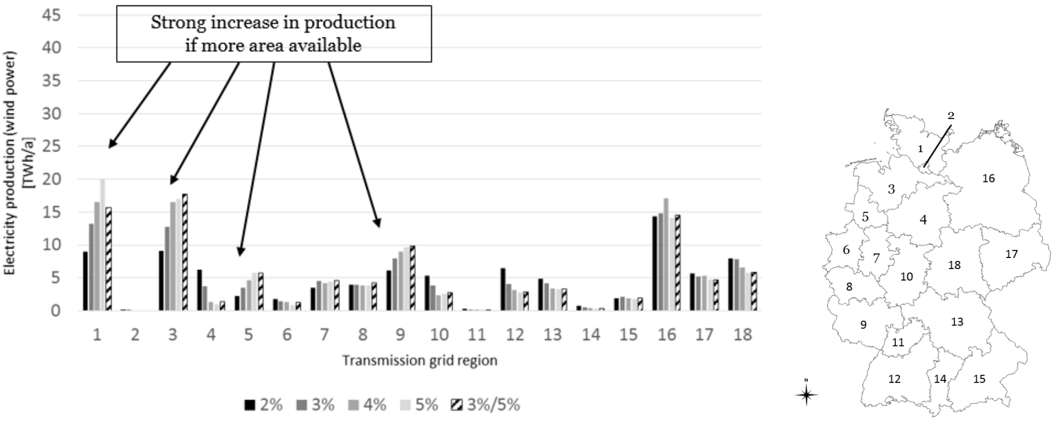


Figure 3.14: Scenario 2: Electricity production from onshore wind power by transmission grid regions (restricted area availability, 2050)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

All VRE combined produced 292.7 – 301.3 TWh/a which translates into 58.5 – 60.3 % of the total national annual demand at a low demand level. A high demand level assumed, the share was 41.8 – 43.0 %. This means that in any case this capacity could not cover the national load in 2050 in every hour of the year and a full load coverage would require power production from other sources.

In figure A13 (larger version in figure A13 in the appendix) the production pattern of all VRE is shown exemplarily for the case of a 2 % limitation of the federal state areas and of the district areas. Again the load curve at a low demand level, i.e. 500 TWh/a, is also depicted. It fluctuated between 35 and 82 GW whereas the power production from VRE fluctuated between 4 and 102 GW. That was lower than in scenario 1, mainly because in scenario 2 there was less offshore wind power capacity installed. VRE production exceeding the demand resulted in gross electricity surpluses of 11 TWh/a. At maximum, a power surplus of 40.4 GW was detected. Both the electricity surpluses and the maximum power surplus were lower than in scenario 1.

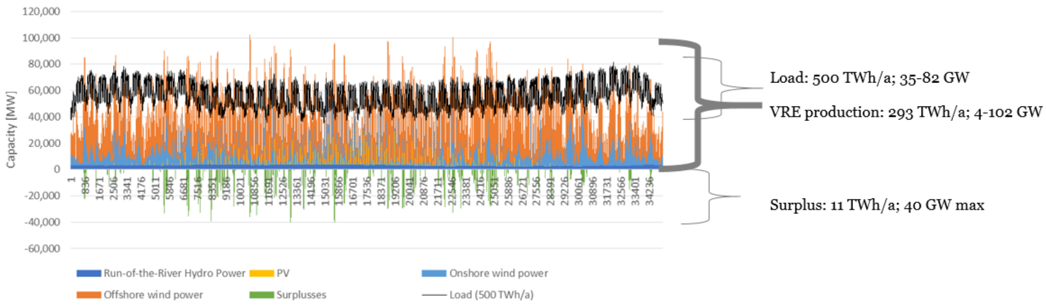


Figure 3.15: Scenario 2: Electricity production from VRE (2050, restricted area availability: 2 %)

A net balance of 217 TWh/a could not be covered by the power generation from the VRE installations in that scenario variant. A high demand level assumed, the net balance substantially increased to 417 TWh/a, i.e. there was an annual energy shortage of this amount.

An increase in the area availability to 5 % resulted in a higher amount of gross electricity surpluses (13.7 TWh/a, i.e. + 2.6 TWh/a $\widehat{=}$ + 22.9 %) and of the maximum power surplus (46.8 GW, i.e. + 6.4 GW $\widehat{=}$ + 15.7 %). The maximum power shortage was practically unaffected by the area availability (70.2 GW) but the shortage energy amount was reduced (212.3 TWh/a).

Figure 3.16 shows the duration curves of the residual load at a low demand level for Germany in 2050 in the scenario variants. Compared with scenario 1, the area below the curves and above the abscissa – i.e. the positive residual load – is larger and the area below the abscissa and above the curves is smaller. This means that the level of the annual demand coverage was lower than in scenario 1. Again, the curves of the different scenario variants slightly differ, meaning that the residual load was slightly affected by the area limitations set for onshore wind power. In the case of a limitation of 2 % of the district areas, the load could be directly covered by VRE production during 1087 h of the year. Increasing the area limitation to 5 % increased that value to 1594 h/a.

At a low demand level, a maximum power surplus of 40.4 GW was detected whereas the maximum power shortage was 69.4 GW. In comparison with scenario 1 this means that the power surplus was lower while the maximum power shortage was nearly at the same level. A high power demand in 2050 assumed, the residual load curve was shifted

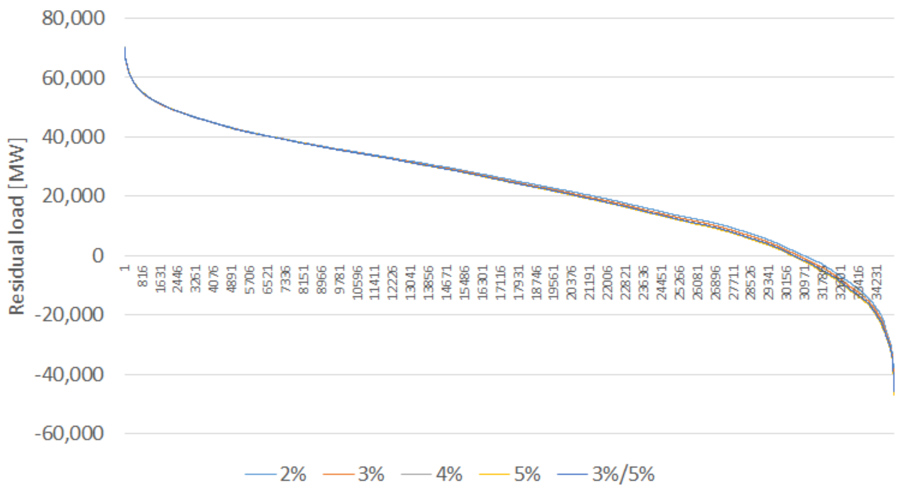


Figure 3.16: Scenario 2: Duration curves of the residual load (2050, low demand level)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

upwards and so was the range of the minimum and the maximum residual load: The maximum value of the power surplus was lower (20.8 GW) and the maximum power shortage was substantially larger (100.1 GW). Again, in comparison with scenario 1 the power surplus was reduced while the maximum power shortage was nearly unaffected. This means that at any demand level approx. 100 GW would be required to be dispatched from other sources.

In figure 3.17 the residual load in the transmission grid regions at a low demand level is illustrated. Again, production from offshore wind power was aggregated with the corresponding closest onshore regions. In image a the impact of an increase in the area potentially available for wind power installations is shown.

With regard to the demand coverage, the transmission grid regions could be grouped into regions with an annual VRE share in the total regional demand of approximately 100 % or higher (regions 1 (Schleswig-Holstein), 3 (North Lower Saxony) and 16 (North-East)) and regions with net electricity shortages (all other regions).

The three regions with net electricity surpluses can be clearly detected in figure 3.17. An increase in the area availability further increased their power generation whereas the districts with a net power shortage were affected just marginally. In some regions, even no difference between the scenario variants could be detected, which means that the shift of capacity to more favourable locations did not affect all the transmission grid regions in the same way. At a high demand level, the big picture did not change but the scaling, i.e. the absolute figures.

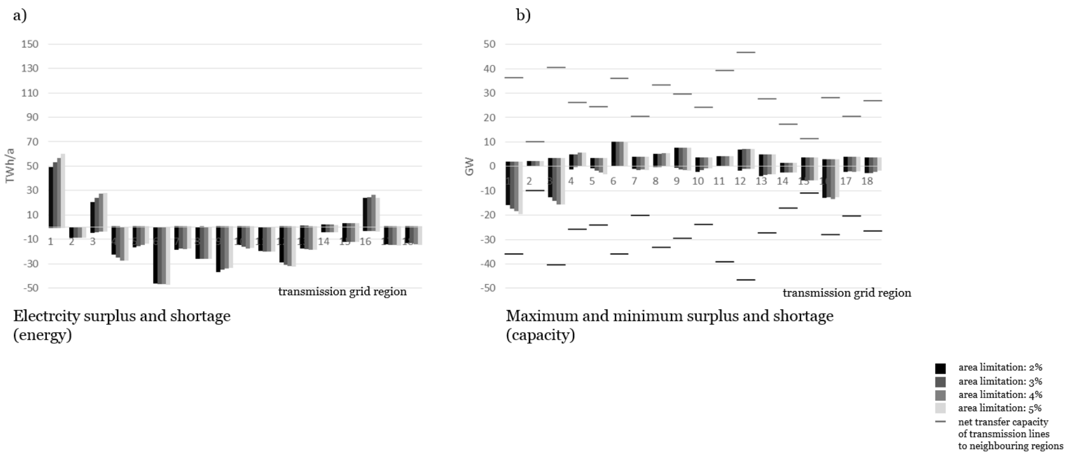


Figure 3.17: Scenario 2: Residual load by transmission grid regions
(2050, low demand level)

In image b the minimum and maximum transmission requirement in the transmission grid regions is depicted. The transmission capacity to neighbouring regions in principle sufficed potential transmission requirements as it was clearly above the maximum transmission requirement in all transmission grid regions.

The resulting LCOE of onshore wind power ranged between 6.06 and 6.64 Ct./kWh, depending on the area limitations set. An increase from 2 % to 5 % of the district areas available for wind power installations therefore implied a reduction by approx. 10 % of the LCOE of onshore wind power.

In figure 3.18 the LCOE of wind power in the different regions and in the scenario variants analyzed is shown. Three categories of grid regions could be detected with regard to LCOE of onshore wind power:

- Category A:
  regions with low LCOE of onshore wind power, i.e. region 1 (Schleswig-Holstein) and 2 (Hamburg) (below 5 Ct./kWh),

- Category B:
  regions with LCOE of onshore wind power also below the national average, e.g. re-

gions 3 (North Lower Saxony), 4 (South Lower Saxony), 9 (South-West), 17 (South-East) and 18 (Thuringia), and

- Category C:
  regions with LCOE of onshore wind power above the national average (all the other regions). In any case, the transmission grid regions 10 (South-East Bavaria), 12 (West Northrhine-Westphalia) and 16 (South-West Bavaria) implied LCOE of more than 10 Ct./kWh.

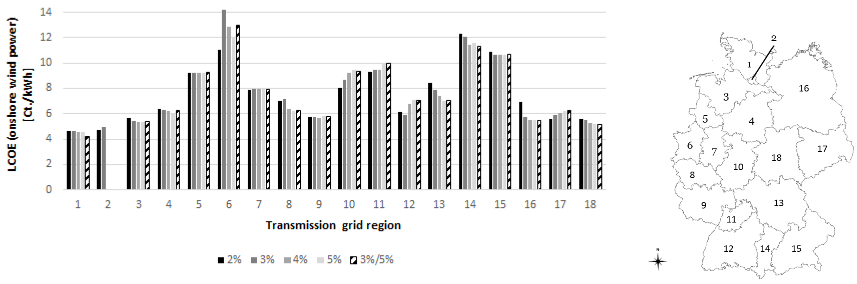


Figure 3.18: Scenario 2: LCOE of onshore wind power by transmission grid region (2050)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

In comparison with scenario 1, a larger onshore wind power capacity was incorporated in scenario 2, resulting in a lower specific energy yield, thus lower EFLH (cf. tables 3.4 and 3.7). LCOE of onshore wind power was slightly higher in scenario 2 than in scenario 1 (+ 0.12 – 0.25 Ct./kWh, i.e. 2.0 – 3.9 %) in the corresponding scenario variants, depending on the area limitations set. LCOE of all VRE aggregated ranged between 6.54 and 6.73 Ct./kWh in scenario 2. This is higher than the LCOE of wind power alone, driven by the comparably high share of PV.

In the original source (Nitsch et al. (2012)) an electricity production of 141.1 TWh/a (onshore wind power) and 138.0 TWh/a (offshore wind power) in 2050 was presented. Both figures were higher than the results generated with the newly developed model. The results from the original source translate into 2600 and 4000 EFLH, respectively, for onshore and offshore wind power. These figures can be regarded as comparably high as a German national average (cf. table 2.5). Moreover, such round figures might indicate that they rather had been applied as calculation inputs and might not have been results from the modeling. Accordingly the RES shares in total production in Nitsch et al. (2012) were comparably high.

3.2.3 Scenario 3 ("The anticipated")

Besides the scenarios covering a period until 2050, one scenario and variants of it was modeled with a time horizon of 2035. It was based on the Grid Development Plan (Netzentwicklungsplan) (NEP) by the German TSOs (cf. 50 Hertz Transmission GmbH et al. (2014a) and section 1.4). The 2014 issue of the NEP was the third of its kind to describe Germany's future transmission grid and transmission requirements. The study was based on the scenario framework approved by the Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (Bundesnetzagentur) (BNetzA) on the basis of §12a Energy Law (Gesetz über die Energie- und Gasversorgung, Energiewirtschaftsgesetz) (EnWG). After public consultation and further revision, the NEP acts as a basis for the federal requirement plan ("Bundesbedarfsplan") that determines the urgent necessity and obligation of grid extension projects.

In the 2014 issue of the NEP, the German TSOs analyzed scenarios on the future RES installation in Germany in order to detect potential bottlenecks in the transmission grid and the impact of additional transmission lines. Official expansion targets for RES installations in the federal states were therefore taken into account.

In the publication, four scenarios of a future RES capacity expansion were presented. Three of the scenarios focused on 2025, one of these was additionally extended until 2035. The NEP scenarios varied as follows. In scenario "A", specific energy and climate policy goals of the federal government were assumed to be implemented until 2025. Scenario "B" ("Basisszenario") was based on scenario "A" but incorporated higher installation figures of RES. It was presented for two timeframes: 2025 and 2035. In scenario "C" an even higher share of RES in 2025 was reached.

In the scenarios the total onshore wind power capacity installed in Germany in 2025 ranged from 53.6 GW (scenario "A") to 63.5 GW (scenario "C") whereas offshore wind power reached 8.9 GW (scenario "A") to 10.8 GW (scenario "C"). In scenario "B", 82.4 GW of onshore wind power capacity were reached until 2035. In comparison with the scenarios 1 and 2 this is a substantially higher value. It is even higher than the 2050 figures from the other scenarios.

Scenario "B" with the timeframe until 2035 was utilized as the third scenario to be analyzed with the new model. The scenario was characterized as presented in table 3.8. In the scenario, the aggregated national wind power installation was based on the federal states' anticipated development of the installed capacity. The federal state-specific installation targets are listed in table 3.9.

In a later version of the NEP (50 Hertz Transmission GmbH et al. (2016)), the expected installed wind power capacity changed, e.g. the total sum in scenario

Table 3.8: Installed capacity in scenario 3 ("The anticipated")

	Unit	2020	2030	2035
Onshore wind power	GW	48.98	71.30	82.40
Offshore wind power	GW	11.02	17.52	17.52
PV	GW_p	46.83	58.20	60.70
Run-of-the-river hydro power	GW	4.45	4.45	4.45

Based on 50 Hertz Transmission GmbH et al. (2014b)

Table 3.9: Scenario 3: Installed wind power capacity in the federal states (2035)

Federal state	Capacity [GW]
Baden-Württemberg	5.20
Bavaria (*Bayern*)	5.00
Berlin	0.00
Brandenburg	9.10
Bremen	0.20
Hamburg	0.10
Hesse (*Hessen*)	3.30
Mecklenburg West-Pomerania (*Mecklenburg-Vorpommern*)	8.90
Lower Saxony (*Niedersachsen*)	14.50
Northrhine-Westphalia (*Nordrhein-Westfalen*)	10.30
Rhineland-Palatinate (*Rheinland-Pfalz*)	5.30
Saarland	0.30
Saxony (*Sachsen*)	1.40
Saxony-Anhalt (*Sachsen-Anhalt*)	4.90
Schleswig-Holstein	10.50
Thuringia (*Thüringen*)	3.40
total	82.40

Source: 50 Hertz Transmission GmbH et al. (2014b, p. 73)

B1 2035/B2 2035 in that issue reached 88.8 GW in 2035 (ibid., p. 48)). Such updated values however were not taken into account in this thesis.

For the analysis presented in this study, the installation targets of PV in the federal states as presented in the source were summed up to compute national figures, too, reaching 60.7 GW_p in 2035. As presented, the full scenario was supplemented with a development trajectory of the run-of-the-river hydro power installation and figures of the annual power demand in Germany until 2035. Linearly interpolated between historic figures and 2050's annual electricity demand of 500 TWh and 700 TWh, respectively, it was calculated to range between 508 TWh/a and 631 TWh/a in 2035.

With the new model, two sets of scenario variants were simulated, differing in the mode of the allocation of onshore wind power capacity:

- allocation of WTGs according to the individual federal state targets ("state-by-state allocation") and
- allocation of WTGs according to the sum of all the individual federal states' targets as an assumed overall national target ("nationwide allocation").

In the case of the state-by-state allocation, the optimized allocation of onshore wind power capacity took place within the federal states independently from each other, i.e. considering the individual federal state expansion targets until 2035. In the case of the nationwide allocation, the same total amount of wind power capacity was allocated across the available areas throughout Germany, however without taking installations targets of the individual federal states into account but within additional area limitations set. As target values of the installed capacity were defined in the NEP for the individual federal states for 2035, it was possible to compare a capacity allocation considering these federal state targets with an allocation of the same capacity amount conducted for the full area of Germany, i.e. a scenario variant without considering individual federal state targets. This comparison allowed conclusions about the impact the individual state targets had with regard to the capacity allocation, the producible energy amounts and LCOE.

3.2.3.1 Scenario 3: Results (unrestricted area availability)

The least-cost result would be achieved if the onshore wind power capacity as defined in the scenario was allocated in an economically optimized way without additional area limitations. This assumption, again, was of academic nature and it was helpful to show a the difference between a nationally optimized allocation and an allocation with predefined area limitations as presented later on. The results figures of both allocation modes without further area constraints can be found in table 3.10 and table 3.11.

Table 3.10: Results of scenario 3 (unrestricted area availability, 2035, nationwide allocation)

Onshore wind power	capacity	GW	82.40
	produced electricity	TWh/a	171.35
	EFLH		2079.47
	capacity factor		0.24
	minimum production	GW (%)	0.32 (0.39)
	maximum production	GW (%)	67.23 (81.60)
	LCOE	Ct./kWh	5.59
	specific investment cost	Ct./kWh	3.87
	specific MRO cost	Ct./kWh	1.72
Offshore wind power	produced electricity	TWh/a	47.77
PV	produced electricity	TWh/a	62.12
Run-of-the-river hydro power	produced electricity	TWh/a	27.42
All VRE	produced electricity	TWh/a	308.65
	share in demand (low demand level)	%	60.74
	share in demand (high demand level)	%	48.89
	LCOE	Ct./kWh	6.76

3.2.3.1.1 Nationwide allocation

In the case of a nationwide economically optimized allocation of WTGs without further area restrictions, the modeling results as presented in table 3.10 show that the full onshore wind power capacity of 82.4 GW was allocated in the available area. This could be expected as the detected technical potential was substantially larger.

The maximum power available during the target year 2035 was 67.2 GW which corresponds to 81.6 % of the installed onshore wind power capacity. During the year there were no moments without onshore production: The lowest onshore production was 0.3 GW which corresponds to 0.4 % of the installed capacity. Those minimum and maximum percentages are comparable to the range detected in the scenarios 1 and 2. Without any further area constraints, the capacity would be allocated to only few districts (cf. figure 3.19).

The allocated onshore wind power capacity generated 171.3 TWh/a in 2035, again concentrated in few regions especially in the North of Germany whereas in the South power production would be low. The energy amount generated with the installed capacity translates into 2079 EFLH as the national mean. In the transmission grid regions, EFLH ranged between 905 in region 6 (West Northrhine-Westphalia) and 2395 in region 1 (Schleswig-Holstein).

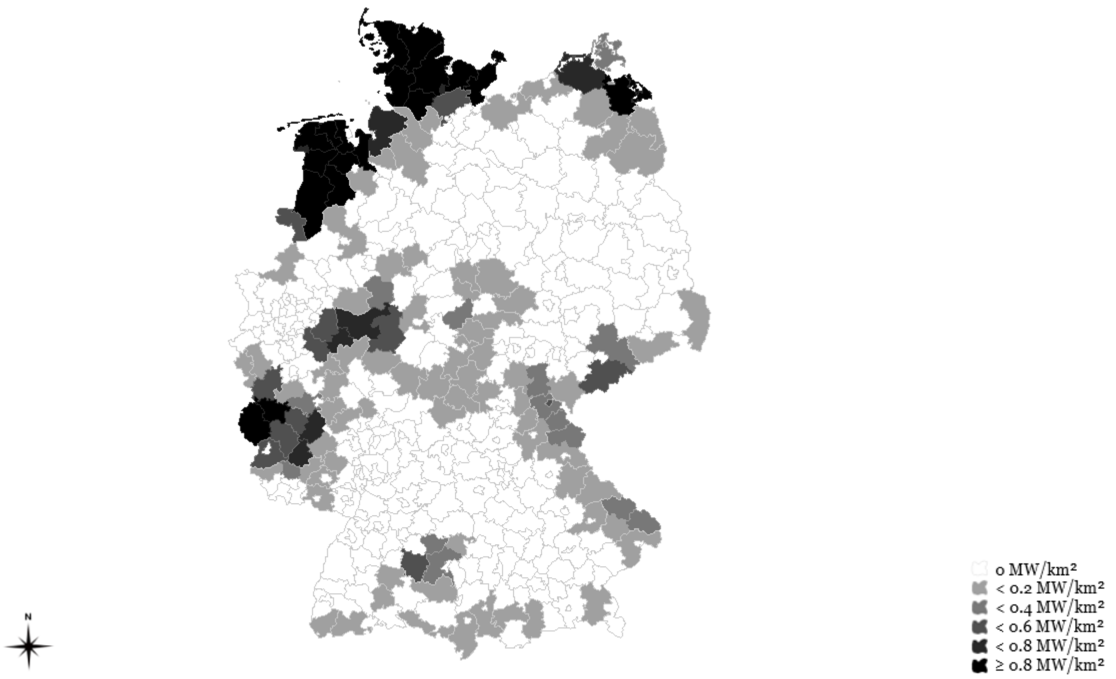


Figure 3.19: Scenario 3: Capacity density of wind power by districts (unrestricted area availability, 2035, nationwide allocation)

Not surprisingly, the offshore wind power capacity of 17.5 GW was also fully allocated, producing 47.8 TWh/a in 27 offshore sub-regions. This translates into 2728 EFLH.

In combination with the electricity production from PV (62.1 TWh/a) and run-of-the-river hydro power (27.4 TWh/a), total power production of all VRE was found to be 308.7 TWh/a in 2035. The share in the total annual electricity demand thus ranged between 48.9 % at a high demand level and 60.7 % at a low demand level. This means approximately half of the annual electricity demand or even more could be covered by VRE production. This is a ratio of the same magnitude as reached in scenario 2 in the year 2050. The range in the transmission grid regions was between 0.7 % in region 2 (Hamburg) and 719.3 % in region 1 (Schleswig-Holstein) at a low demand level and between 0.6 % (region 2) and 579.0 % (region 1) at a high demand level.

The German mean LCOE of wind power in 2035 was detected to be 5.59 Ct./kWh (onshore) and 7.16 Ct./kWh (offshore), respectively. The regional range was between 4.90 Ct./kWh (region 1) and 12.84 Ct./kWh (region 6, West Northrhine-Westphalia). The figures are not directly comparable with the results from the scenarios 1 and 2 as they refer to a different target year. The LCOE of all VRE combined was 6.76 Ct./kWh.

Table 3.11: Results of scenario 3 (unrestricted area availability, 2035, state-by-state allocation)

Onshore wind power	capacity	GW	82.12
	produced electricity	TWh/a	147.10
	EFLH		1791.21
	capacity factor		0.20
	minimum production	GW (%)	0.43 (0.52)
	maximum production	GW (%)	65.98 (80.35)
	LCOE	Ct./kWh	6.49
	specific investment cost	Ct./kWh	4.49
	specific MRO cost	Ct./kWh	2.00
Offshore wind power	produced electricity	TWh/a	47.77
PV	produced electricity	TWh/a	62.12
Run-of-the-river hydro power	produced electricity	TWh/a	27.42
All variable renewable energies	produced electricity	TWh/a	284.41
	share in demand (low demand level)	%	55.96
	share in demand (high demand level)	%	45.05
	LCOE	Ct./kWh	7.33

As said, this scenario variant was an extreme case assuming a nationwide wind power capacity allocation and no further area limitations that scenario variants considering additional area restrictions could be compared with. Any scenario variant would result in a lower power production and higher LCOE.

3.2.3.1.2 State-by-state allocation

In case the same total capacity was installed in Germany but the installation expectations and targets of the individual federal states as presented in the NEP were taken into account, modeling results looked different from the results of a nationwide allocation (cf. table 3.11). Again, this variant was a rather extreme case, however now also taking a federal state-specific split-up of the installed capacity into account.

A state-by-state allocation of wind power capacity and no further area restrictions assumed, the full onshore wind power capacity as defined in the scenario could be allocated. A minor deviation from the corresponding nationwide allocation of the same total capacity amount was however found due to the split-up into federal state installation targets.

The maximum power available during the year was 66.0 GW which corresponds to 80.3 % of the installed capacity. This was lower than in the case of a nationwide optimized capacity allocation. On the other hand, the lowest onshore production was 0.4 GW which corresponds to 0.5 % of the installed capacity. This is slightly higher than in the case of the nationwide allocation.

Again, without any further area limitations, the wind power capacity was allocated to only few districts (cf. figure 3.20), which is comparable to the scenarios 1 and 2. In contrast to the other scenarios, more and other districts were however affected due to the individual federal state installation targets considered.

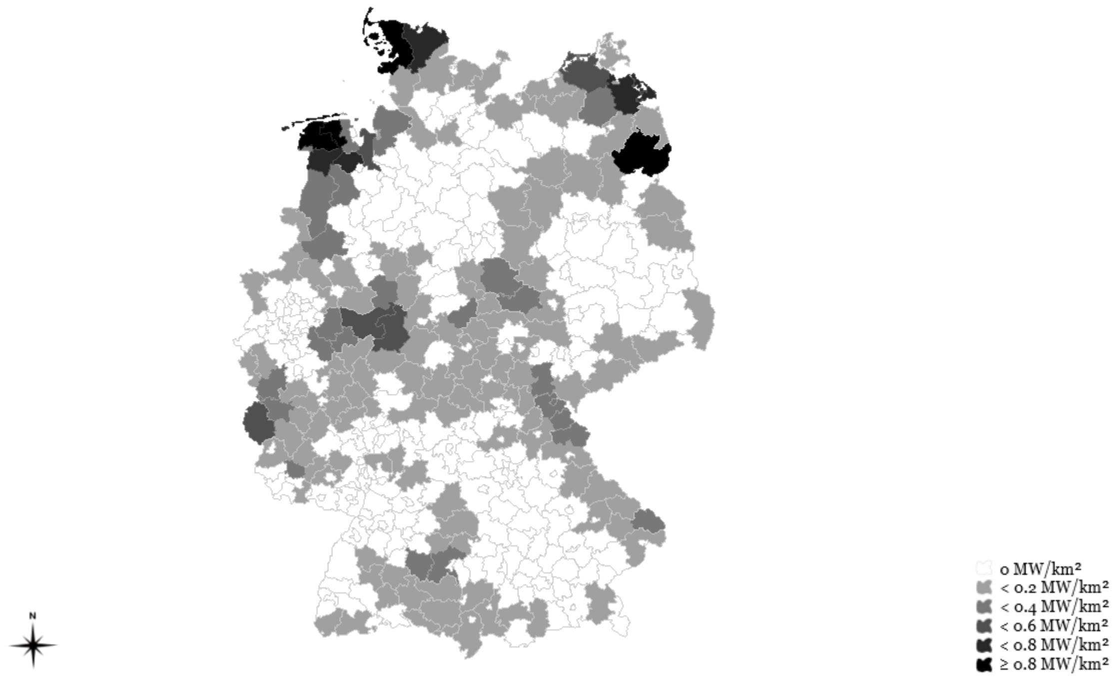


Figure 3.20: Scenario 3: Capacity density of wind power by districts (unrestricted area availability, 2035, state-by-state allocation)

The allocated onshore capacity was detected to generate 147 TWh/a in 2035. This was approx. 25 TWh/a (15 %) less than in the case of a nationwide economically optimized allocation of the same total amount of capacity. This difference highlighted that the individual federal state targets did not fully correspond to a nationwide optimized capacity allocation.

Accordingly the EFLH of onshore wind power were 1791, thus lower than in the case of a nationwide optimized capacity allocation. The EFLH in the transmission grid regions ranged between 908 (Region 6 (West Northrhine-Westphalia)) and 2380 (region 1 (Schleswig-Holstein)). That range is comparable to the one detected in the nationwide allocation.

Keeping the power production of offshore wind power, PV and run-of-the-river hydro power unaltered as compared to the nationwide capacity allocation, the power production from all VRE combined summed up to 284.4 TWh/a. This translates into a share in the total annual electricity demand between 45.1 % and 56.0 %, depending on the demand level. The share thus was found to be slightly lower than in the case of the nationwide optimized allocation. The range in the transmission grid regions was between 0.9 % in region 2 (Hamburg) and 209.6 % in region 1 (Schleswig-Holstein) at a low demand level and between 0.7 % in region 2 and 168.8 % in region 1 at a high demand level.

The mean LCOE of onshore wind power in 2035 was 6.49 Ct./kWh (offshore wind power: 7.16 Ct./kWh). This is higher in the case of a state-by-state allocation than in the case of a nationwide allocation due to the lower power production. The regional range was between 4.88 Ct./kWh in region 1 (Schleswig-Holstein) and 11.78 Ct./kWh in region 6 (West Northrhine-Westphalia). The LCOE of all the VRE combined was 7.33 Ct./kWh.

As outlined, this extreme scenario variant without additional area restrictions was modeled as a baseline other scenario variants could be compared with.

3.2.3.2 Scenario 3: Results (restricted area availability)

As the allocation of WTGs would change if the federal state areas and the district areas availale for wind power installations were restricted, the limitations of both the federal state areas and the district areas were altered in further scenario variants between 2 % and 5 %, accompanied by a 3 %/5 % variant. Under the assumptions made, the full amount of 82.4 GW could be installed only if more than 2 % of all state areas and district areas were potentially available. A tighter area limitation set resulted in a total available area that did not allow to fully allocate all the wind power capacity under the given assumptions.

3.2.3.2.1 Nationwide allocation

Assuming the same amount of wind power capacity allocated in an economically optimized way as in the unrestricted scenario variants and disregarding the individual federal state targets for 2035, model results as presented in table 3.12 were generated. The application of the nationwide allocation mode and the assumption of additional area restrictions necessarily resulted in a larger power production than in the state-by-state allocation with the same area restrictions but also in a lower power production than in the case without any further area restrictions. The installed capacity and produced electricity in the transmission grid regions is listed in table B8 in the appendix.

Table 3.12: Results of scenario 3 (restricted area availability, 2035, nationwide allocation)

	Unit	Maximum share of state and district available				
		2%	3%	4%	5%	3 %/5 %*
Onshore wind power						
capacity	GW	77.18	82.40	82.40	82.40	82.40
produced electricity	TWh/a	119.75	132.22	136.78	139.90	138.63
EFLH		1551.54	1604.64	1659.89	1697.77	1682.35
capacity factor		0.18	0.18	0.19	0.19	0.19
minimum production	GW	0.56	0.65	0.63	0.55	0.63
		(0.72%)	(0.78%)	(0.76%)	(0.67%)	(0.76 %)
maximum production	GW	61.02	65.93	65.94	66.25	65.53
		(79.06%)	(80.02%)	(80.02%)	(80.39%)	(79.53 %)
LCOE	Ct./kWh	7.51	7.25	7.01	6.85	6.91
specific investment cost	Ct./kWh	5.21	5.02	4.85	4.74	4.78
specific MRO cost	Ct./kWh	2.31	2.23	2.16	2.11	2.13
All VRE						
produced electricity	TWh/a	257.05	269.53	274.08	277.20	275.93
share in demand (low demand level)	%	50.58	53.04	53.93	54.55	54.30
share in demand (high demand level)	%	40.72	42.70	43.42	43.11	43.71
LCOE	Ct./kWh	7.89	7.74	7.61	7.53	7.56

*) 3 %: limitation of federal states areas; 5 %: limitation of districts areas

In the scenarios, 3 % or more of both the federal state areas and the district areas were required to fully allocate the 82.4 GW targeted in 2035. As noted above, in the case of a nationwide capacity allocation an area limitation of 2 % did not allow to allocate the full amount of onshore wind power capacity as defined in the scenario. It was found that the installed capacity in that scenario variant was slightly larger than the technical potential detected for 2050 installations with the same area restrictions as presented in section 3.1. This deviation can be explained with the age structure of WTGs taken into account in the scenario modeling whereas the potential calculation was based on WTGs and their respective sizes that would be installed exclusively in the year 2050.

The allocated onshore wind power capacity in 2035 in the scenario variants is depicted in figure 3.21 (larger version in figure A8 in the appendix). From left to right the illustration shows the capacity density considering area limitations ranging from 2 % to 5 % of the federal state and district areas. On the right, the 3 %/5 % variant is illustrated. Again, the capacity density is marked in different shades of gray, ranging from white (no installation) to black (more than 0.8 MW/km^2).

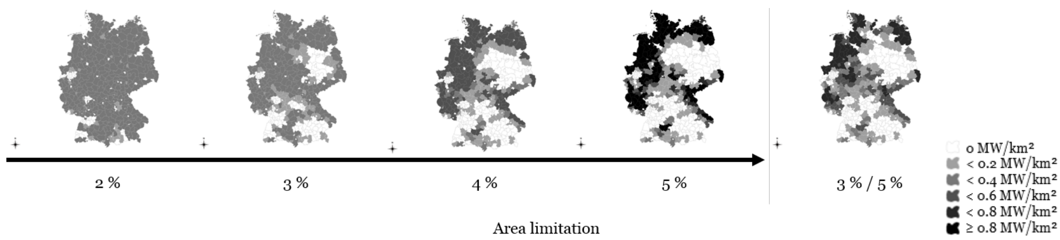
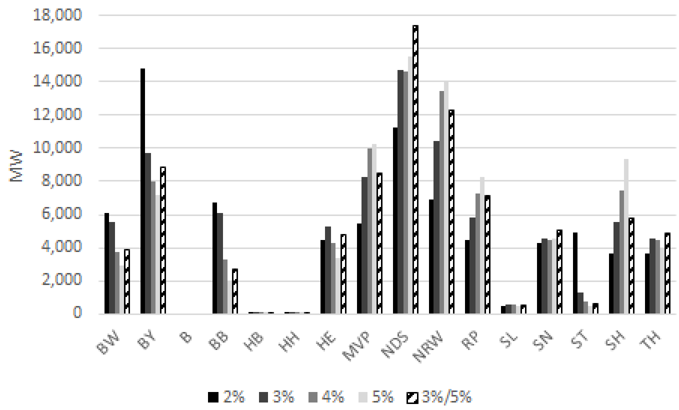


Figure 3.21: Scenario 3: Installed wind power capacity by districts (restricted area availability, 2035, nationwide allocation)

The results show that in the variant of an area limitation of 2 %, wind power installations were allocated to 332 out of the 412 districts. At maximum, 0.248 MW/km^2 were installed. As mentioned earlier, in that variant not the full wind power capacity as defined in the scenario could be allocated.

An increase in the area limitation to 5 % led to an increasing concentration of capacity. With a low WTG spacing, 205 districts were affected then. At maximum, 0.617 MW/km^2 were installed.

The aggregated installed wind power capacity in the federal states show an according picture (figure 3.22). The application of the nationwide allocation mode meant that the more area was potentially available, the more the installed capacity in 2035 substantially increased in the federal states of Mecklenburg-Western Pomerania, Lower Saxony, Northrhine-Westphalia and Schleswig-Holstein. In the federal states of Bavaria, Saxony-Anhalt and Brandenburg the installed capacity substantially decreased with an increasing area availability. In the smaller federal states (cities of Bremen and Hamburg, federal state of Saarland) hardly any effect was detectable.



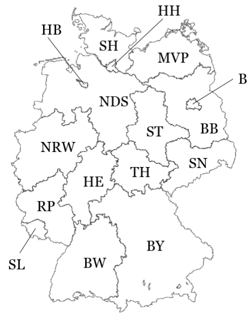


Figure 3.22: Scenario 3: Wind power capacity installed in the federal states (restricted area availability, 2035, nationwide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Germany's federal states.

The onshore wind power capacity of 82.4 GW could be fully allocated with area restrictions between 3 % and 5 % and they produced 132.2 – 139.9 TWh/a, depending on the area restrictions set. This translates into 1605 – 1698 EFLH. Increasing the area limitations from 3 % to 5 % increased the power production and EFLH by 5.8 %.

Compared to the scenario variant without further area limitations, an additional area restriction materialized in an amount of electricity produced from onshore wind power that was 18.4 – 30.1 % lower, depending on the area limitations set.

In figure 3.23 the absolute values of the generated electricity is presented in dependency on the area restrictions set. Again, the results of the 3 %/5 % variant have been hatched. The figure shows that an increase in the area potentially available for wind power installations substantially increased the power production in several of the transmission grid regions whereas in some others power production was reduced. This can be explained by the shift of capacity to more favourable locations in other transmission grid regions the more area was available.

With regard to the power production, the alteration of the area availability by tendency showed three categories of transmission grid regions:

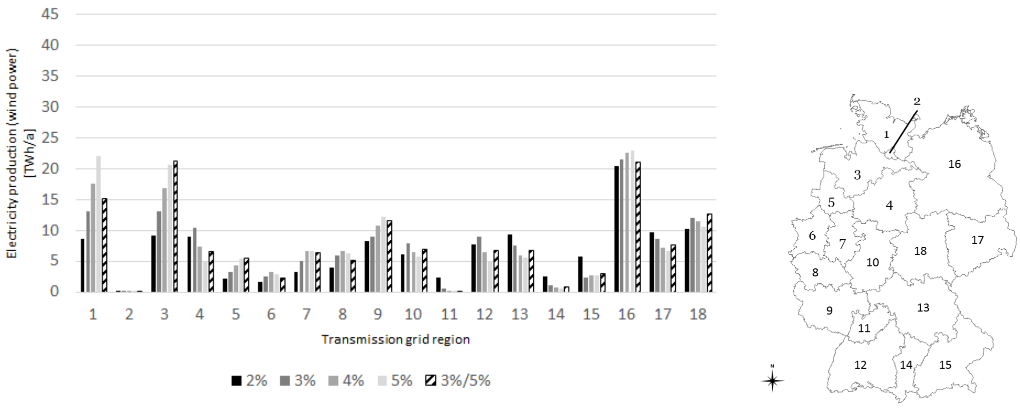


Figure 3.23: Scenario 3: Electricity production from onshore wind power by transmission grid regions (restricted area availability, 2035, nationwide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

- Category a:
  An increase in area availability for wind power installations resulted in a higher electricity generation
  (regions 1 (Schleswig-Holstein), 3 (North Lower Saxony), 5 (South-West Lower Saxony), 7 (central Northrhine-Westphalia), 8 (South Northrhine-Westphalia, North Rhineland-Palatinate), 9 (South Rhineland-Palatinate) and 16 (North-East)).

- Category b:
  An increase in area availability for wind power installations resulted in a lower electricity generation
  (regions 4 (South-East Lower Saxony), 10 (central Germany), 11 (North Baden-Württemberg), 12 (South Baden-Württemberg), 13 (North Bavaria), 14 (South-West Bavaria), 15 (South-East Bavaria), 17 (centre-East)).

- Category c:
  An increase in area availability for wind power installations had hardly any effect on electricity production
  (all other regions).

In all variants of scenario 3, transmission grid region 1 was found to be the one with the highest specific electricity production, ranging from 0.55 GWh/km^2 to 1.39 GWh/km^2. In transmission grid region 2 the lowest specific production was found, ranging from 0.04 GWh/km^2 to 0.05 GWh/km^2. The extreme values thus were found in the same transmission grid regions as in the scenarios 1 and 2.

In combination with offshore wind power (47.8 TWh/a), PV (62.12 TWh/a) and run-of-the-river hydro power (27.4 TWh/a), all VRE produced 257.1 – 277.2 TWh/a. This translates into a share in the total annual national power demand of 50.6 – 54.6 % at a low demand level and 40.7 – 43.1 % at a high demand level. This means that half of the national power demand – as the net balance – could be covered by VRE production if the demand level was low.

In figure 3.24 (larger version in figure A14 in the appendix) the production pattern of all VRE and the load at a low demand level is exemplarily illustrated for the scenario variant with a 3 % limitation of both the federal state areas and of the district areas. The load fluctuated between 36 and 83 GW whereas the power production from VRE fluctuated between 4 and 97 GW. That is slightly lower than in scenario 2, however the target year was 2035 in scenario 3. VRE production exceeding the demand resulted in gross electricity surpluses of 8 TWh/a. At maximum a power surplus of 37 GW was detected that would need to be dealt with by flexibility options. If the available area was increased (e.g. to 5 %), the gross electricity surpluses increased to more than 9 TWh/a with a power surplus of 41 GW at maximum. In any case this was lower than the total transmission capacity to neighbouring countries if all the projects presented in the NEP were completed.

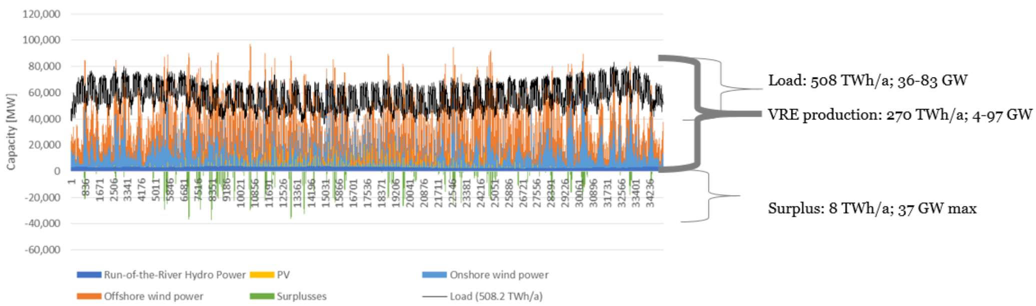


Figure 3.24: Scenario 3: Electricity production from VRE
(2035, nationwide allocation, restricted area availability: 3 %)

In figure 3.25 the duration curves of the residual load at a low demand level in the scenario variants are shown. During most of the year the VRE production could not cover the power demand, i.e. additional power production would be required. On the right side of the diagram where the curves fall below the abscissa, power surpluses are depicted. In the case of a limitation of 2 % of the district areas and a low demand level assumed, power surpluses occurred during 588 hours of the year. An increase in the area availability, resulting in a higher concentration of capacity, increased the number of hours with power surpluses to 849 h/a.

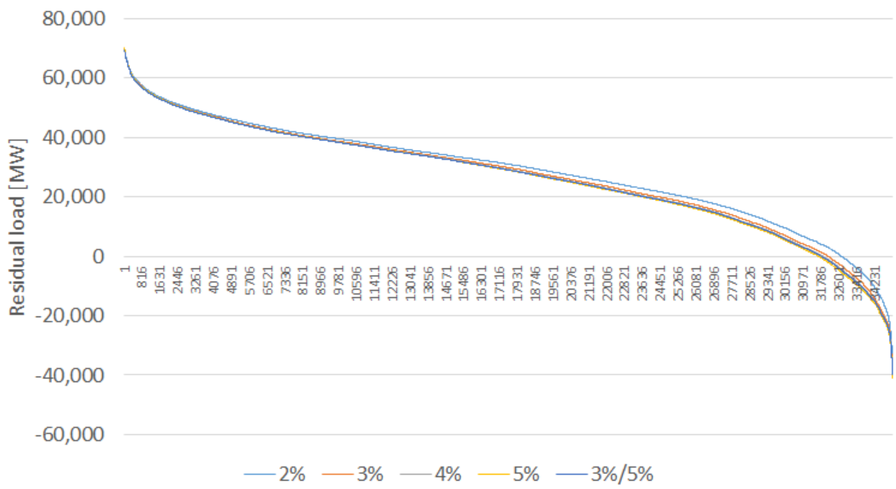


Figure 3.25: Scenario 3: Duration curves of the residual load (2035, low demand level, nationwide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

As in the scenarios 1 and 2, the residual load in the transmission grid regions varied considerably (cf. figure 3.26). Image a shows the annual electricity surpluses and shortages (given as TWh/a), image b shows the maximum and minimum values of the residual load in the transmission grid regions in 2035. Image a reveals that there were three regions where the annual electricity surpluses were larger than the annual electricity shortages, resulting in net electricity surpluses. Those were the regions in the North where offshore wind power production was landed. All the other transmission grid regions show a negative net balance, i.e. their annual power consumption was larger than their annual power production from VRE. Image b illustrates that the maximum and minimum residual load in all the transmission grid regions was substantially below the transmission capacity to neighbouring regions (black lines in the diagram). This means that the transmission lines would basically suffice the transmission requirements under the assumptions made.

The national LCOE of onshore wind power ranged from 6.85 Ct./kWh to 7.51 Ct./kWh, depending on the area limitations set. In the 3 %/5 % variant, the LCOE was substantially lower than in the 3 % variant. Again, regional differences in LCOE could be detected. The lowest LCOE of onshore wind power was found in re-

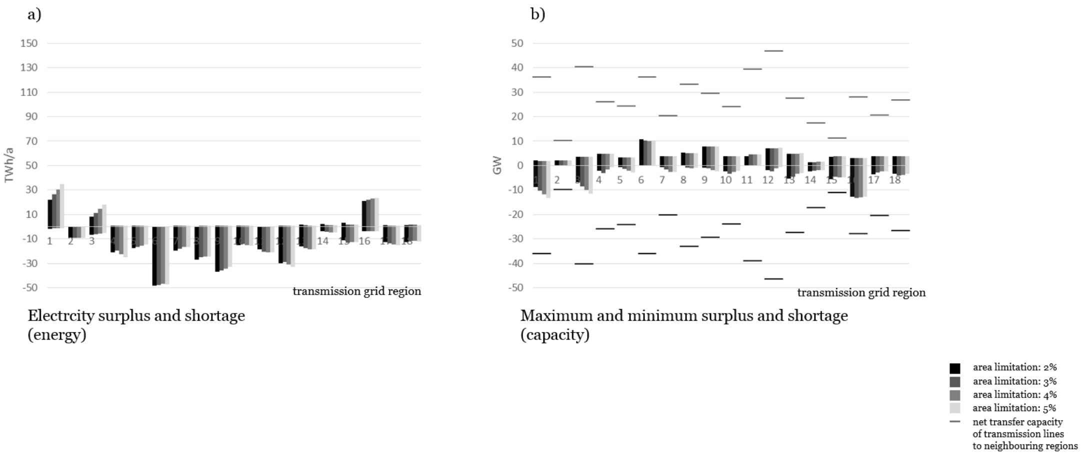


Figure 3.26: Scenario 3: Residual load by transmission grid regions (2035, low demand level, nationwide allocation)

gion 1 (Schleswig-Holstein, ranging from 4.95 Ct./kWh to 5.00 Ct./kWh). The highest LCOE was found in the regions 5 (South-West Lower Saxony), 6 (West Northrhine-Westphalia), 11 (North Baden-Württemberg) and 14 (South-West Bavaria) with more than 10 Ct./kWh (highest value: 13.81 Ct./kWh in region 6). In figure 3.27 the LCOE of onshore wind power in the transmission grid regions in dependency on the area limitation set are illustrated .

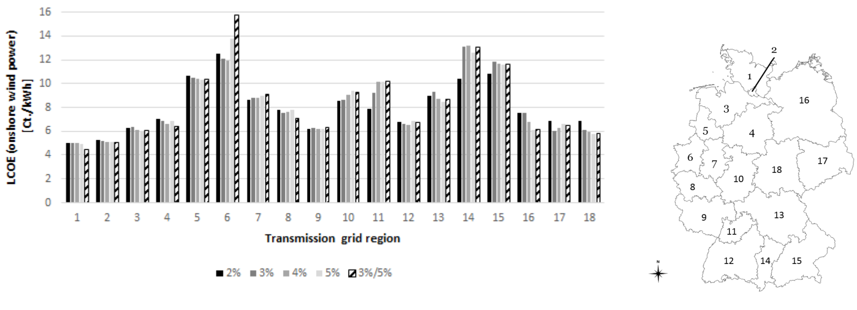


Figure 3.27: Scenario 3: LCOE of onshore wind power by transmission grid region (2035, nationwide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

Table 3.13: Results of scenario 3 (restricted area availability, 2035, state-by-state allocation)

	Unit	Maximum share of state and district available				
		2%	3%	4%	5%	3 %/5 %*
Onshore wind power						
capacity	GW	66.17	77.74	79.90	82.00	78.03
produced electricity	TWh/a	105.60	125.79	131.94	136.72	129.03
EFLH		1595.92	1618.09	1651.40	1667.43	1653.69
capacity factor		0.18	0.18	0.19	0.19	0.19
minimum production	GW	0.55 (0.83%)	0.57 (0.74%)	0.53 (0.66%)	0.49 (0.60%)	0.49 (0.62 %)
maximum production	GW	53.17 (80.35%)	62.55 (80.45%)	64.05 (80.17%)	65.68 (80.10%)	62.32 (79.88 %)
LCOE	Ct./kWh	7.32	7.20	7.05	6.97	7.04
specific investment cost	Ct./kWh	5.08	4.98	4.88	4.83	4.88
specific MRO cost	Ct./kWh	2.24	2.21	2.17	2.15	2.16
All VRE						
produced electricity	TWh/a	242.90	263.10	269.25	274.03	266.34
share in demand (low demand level)	%	47.80	51.77	52.98	53.92	52.41
share in demand (high demand level)	%	38.48	41.77	42.65	43.41	42.19
LCOE	Ct./kWh	7.83	7.73	7.65	7.60	7.65

*) 3 %: limitation of federal states areas; 5 %: limitation of districts areas

The LCOE of all VRE combined ranged between 7.53 and 7.89 Ct./kWh, i.e. the effect of an increased or decreased onshore wind power production was only partly found in the overall LCOE.

3.2.3.2.2 State-by-state allocation

In another group of scenario variants the case of a state-by-state allocation of the same total amount of wind power capacity was calculated, thus the expansion targets of the federal states until 2035 were taken into account. The resulting figures can be found in table 3.13. The installed capacity and electricity produced in the transmission grid regions is listed in table B9 in the appendix.

The results show that the full amount of capacity could only be allocated if the limitation of both the federal state areas and the district areas was set high (as far as 5 % in the scenario variants tested). Even in the scenario variant with a 3 % limitation of the federal state areas and a 5 % limitation of the district areas the full capacity could not be allocated under the given assumptions. This however was caused by the logic of the model: The limitations defined were valid for all the federal states and the districts, respectively, i.e. they were not differentiated between the federal states.

The analysis of the installed capacity in the federal states shows that in most of the scenario variants analyzed the full state-specific capacity as defined in the installation scenarios could be installed. In some of the federal states a narrow limitation of the available area (2 % of the federal state areas and the district areas) would suffice the space requirements of the onshore wind power capacity to be installed. This however did not apply in the federal states of Brandenburg, Hesse, Mecklenburg-Western Pomerania, Lower Saxony and Northrhine-Westphalia where an area limitation of at least 3 % would allow to allocate the full capacity. Again there was another exception: an even wider area limitation in Schleswig-Holstein did not suffice to install the anticipated capacity of more than 10 GW until 2035 under the assumptions made. This would only be possible with an area limitation of 5 % or higher unless other parameters such as area buffers of the spacing of WTGs were changed.

The comparison with the case of a nationwide allocation of the same amount of capacity revealed that the state-by-state allocation, i.e. the state-specific installation targets, partly substantially diverted from a nationwide economically optimized capacity allocation.

The installed wind power capacity in 2035 in the federal states is illustrated in figure 3.28 (larger version in figure A9 in the appendix) and in figure 3.29. As in the other scenarios presented, the installed capacity with area limitations ranging from 2 % to 5 % of the total federal state areas and of the district areas is displayed, accompanied by the 3 %/5 % variant.

Figure 3.28: Scenario 3: Installed wind power capacity by districts (restricted area availability, 2035, state-by-state allocation)
Percentages: restriction of federal state areas and district areas. 3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

The results show that in the variant of an area limitation of 2 %, 261 districts were affected by onshore installations. At maximum, a capacity density of 0.321 MW/km^2 was found. As already mentioned, this however would not allow to fully allocate all

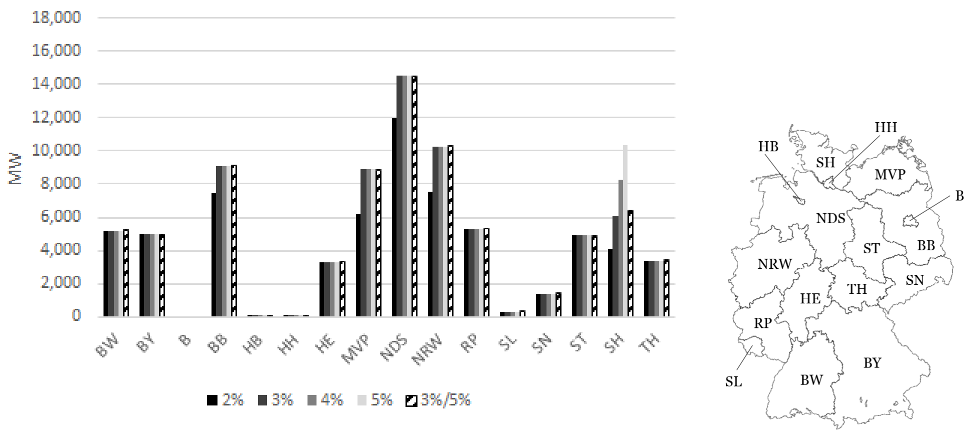


Figure 3.29: Scenario 3: Wind power capacity installed in the federal states (restricted area availability, 2035, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Germany's federal states.

the onshore wind power capacity as defined in the scenario. An increase in the area limitation to 5 % led to an increasing concentration of capacity in which 187 districts were affected. At maximum, 0.756 MW/km^2 were installed.

The comparison with the nationwide allocation of the same total capacity indicates major differences in the federal states, depending on the area limitations set. They can be described as follows:

- Baden-Württemberg:
  If the area limitation was narrow, the installed capacity was larger in the case of a nationwide optimized capacity allocation than in case of a state-by-state allocation. A wide area limitation resulted in the opposite.

- Northrhine-Westphalia, Rhineland-Palatinate:
  If the area limitation was narrow, the installed capacity was smaller in the case of a nationwide optimized capacity allocation than in the case of a state-by-state allocation. A wide area limitation resulted in the opposite.

- Brandenburg, Saxony-Anhalt, Schleswig-Holstein:
  In all scenario variants of a nationwide optimized capacity allocation the installed capacity was smaller than defined as the federal state target for 2035.

- Bavaria, Hesse, Saarland, Saxony:
  In all scenario variants of a nationwide optimized capacity allocation the installed capacity was larger than defined as the federal state target for 2035.

- Mecklenburg-Western Pomerania, Lower Saxony, Thuringia:
  The nationwide and state-by-state allocation were in a similar range.

In the case of a limitation of 3 % of the federal state areas and the district areas – in which all capacity could be fully allocated except for Schleswig-Holstein – 77.7 TWh/a were produced by onshore wind power. Assuming an area limitation of 5 % – in which all capacity could be fully allocated – 136.7 TWh/a were produced by onshore wind power. This was less than in a nationwide optimized allocation with the same area limitations. The difference, however, was 3.2 TWh/a (2.3 %), thus comparably small. Related to the installed capacity, the power produced translates into 1667 EFLH.

Compared to the scenario variant without further area limitations, an additional area restriction materialized in an amount of electricity produced by onshore wind power that was 6.1 – 24.2 % lower, depending on the area limitations set. The biggest difference, however, was also caused by the fact that not the same amount of capacity could be allocated.

The absolute amounts of electricity produced by wind power in the transmission grid regions are illustrated in figure 3.30. Besides the variants of an area limitation between 2 % and 5 %, the 3 %/5 % variant is also depicted. The alteration of the maximum area availability shows three categories of transmission grid regions, characterized as follows:

- Category a:
  An increase in area availability for wind power installations resulted in a larger electricity production (regions 1 (Schleswig-Holstein), 3 (North Lower Saxony) and 16 (North-East), i.e. the regions where offshore wind power production was landed).

- Category b:
  An increase in area availability for wind power installations resulted in a smaller electricity production (regions 4 (West Lower Saxony), 9 (South Rhineland-Palatinate)).

- Category c:
  An increase in area availability for wind power installations had hardly any effect on the electricity production (all the other regions).

As in the case of the nationwide optimized capacity allocation, the highest specific power production was found in transmission grid region 1, ranging from 0.60 GWh/km^2 to 1.54 GWh/km^2). The lowest specific power production was found in region 2 (Hamburg, 0.03 GWh/km^2).

Keeping the production from offshore wind power, PV and run-of-the-river hydro power unchanged compared to the nationwide optimized allocation of onshore wind power, all VRE aggregated produced 242.9 – 274.0 TWh/a, depending on the area restrictions set for onshore wind power. This corresponds to 47.8 – 53.9 % of the annual demand at a low demand level and 38.5 – 43.4 % at a high demand level.

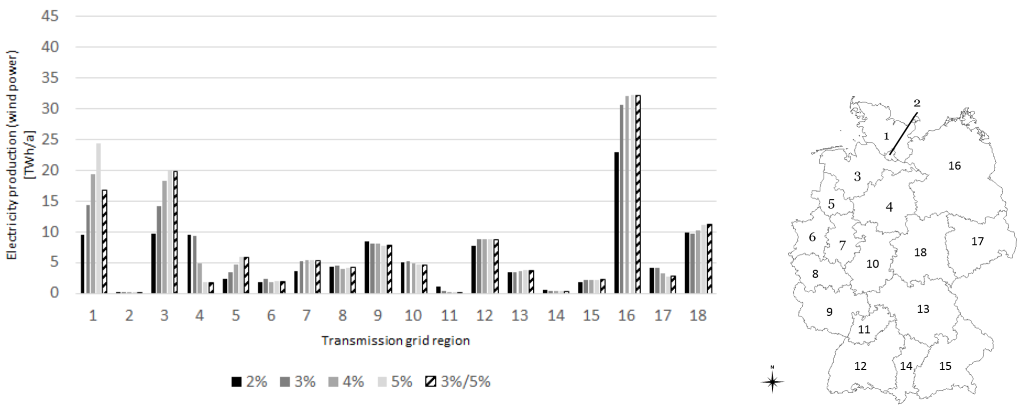


Figure 3.30: Scenario 3: Electricity production from onshore wind power by transmission grid regions (2035, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

In figure 3.31 (larger version in figure A15 in the appendix) the production pattern of all VRE in scenario 3 (state-by-state allocation) and the load curve at a low demand level are exemplarily shown for the case of a 3 % limitation of the federal state areas and of the district areas in which the full capacity was allocated except in the federal state of Schleswig-Holstein. The load fluctuated between 36 and 83 GW whereas the power production from VRE fluctuated between 4 and 96 GW. These maximum figures were in the same range as in the respective scenario variant of a nationwide economically optimized wind power capacity allocation. The VRE production exceeding the demand resulted in gross electricity surpluses of 7 TWh/a. At maximum, a power surplus of 35 GW was found. Both the electricity surpluses as well as the maximum power surplus thus were lower than in the case of a nationwide optimized capacity allocation. As already shown for the case of a nationwide allocation, an increase in area availability for onshore wind power increased electricity surpluses in the state-by-state allocation, too, thus by tendency the necessity of power transmission to neighbouring countries or storage (e.g. scenario variant with a 5 % area limitation: gross electricity surpluses of 9 TWh/a with 38 GW maximum).

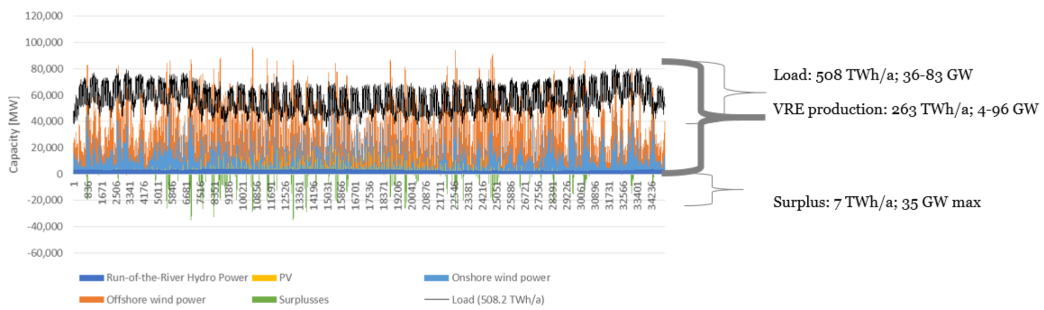


Figure 3.31: Scenario 3: Electricity production from VRE
(2035, state-by-state allocation, restricted area availability: 3 %)

The duration curves of the residual load at a low demand level in the scenario variants are shown in figure 3.32. As explained, not in all the scenario variants the same amount of onshore wind power capacity was installed. As in the case of a nationwide capacity allocation, during most of the year VRE production could not cover the power demand, i.e. other sources would be required to fully cover the demand. The integral above the abscissa however was detected to be larger and the integral below the abscissa smaller, meaning that in the case of a state-by-state allocation less gross electricity surpluses were generated whereas more additional power production from other sources would be required. In the case of an area limitation of 2 % for wind power installations, the demand could be covered by VRE during 428 hours of the year. A higher area availability resulted in a substantially longer duration of load coverage by VRE (841 h/a in the 5 % scenario variant).

The region-specific residual load in the case of the state-by-state capacity allocation was similar to the respective case of a nationwide allocation as depicted in image a of figure 3.33. In the regions 1, 3 and 16 – the regions where offshore wind power was landed – the annual net balance was positive, i.e. there were electricity surpluses whereas in all the other regions there were net electricity shortages. With regard to the maximum residual load in 2035 (image b), again, it could be detected that those values were found to be substantially lower than the transmission capacity available to neighbouring regions.

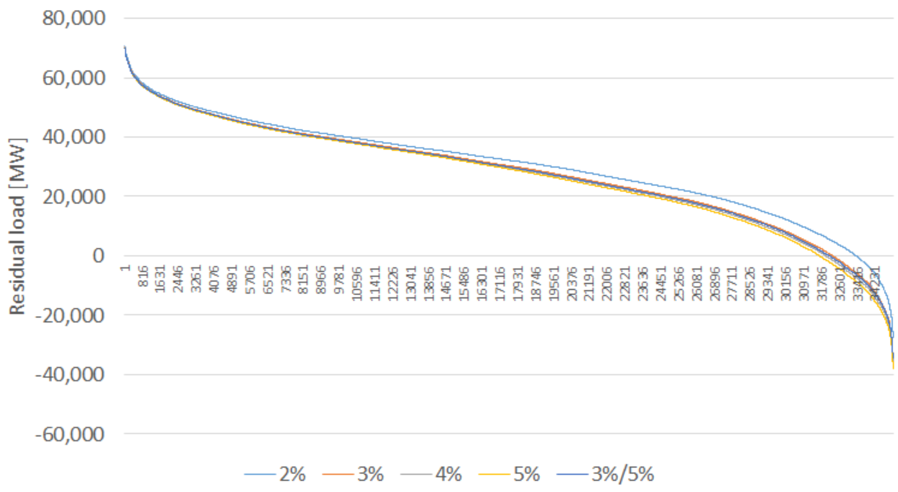


Figure 3.32: Scenario 3: Duration curves of the residual load (2035, low demand level, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

If all the onshore wind power capacity could be allocated, i.e. in the scenario variant with a limitation of 5 % of the federal state areas and the district areas for wind power use, the national mean LCOE of onshore wind power was 6.97 Ct./kWh. This is slightly higher than in the case of a nationwide allocation. The lowest LCOE were found in region 1 (Schleswig-Holstein, 4.95 Ct./kWh), the highest in region 6 (West Northrhine-Westphalia, 13.93 Ct./kWh). The LCOE of wind power in the transmission grid regions is illustrated in figure 3.34. Again, all scenario variants modeled are depicted but only in the case of an area limitation of 5 % the full onshore wind capacity could be allocated.

The national mean LCOE of all VRE combined ranged between 7.60 Ct./kWh and 7.83 Ct./kWh in the scenario variants, i.e. they were higher than the LCOE of onshore wind power alone. This can be explained with the high share of comparably expensive PV.

In the original source, the electricity amount produced by wind power in 2035 was given as 147.6 TWh/a (50 Hertz Transmission GmbH et al. (2014a, p. 49)). This is a larger figure than calculated with the new model, however not substantially larger. Key drivers of the deviation were differences in the assumed WTG sizes – in the NEP a reference WTG of 3 MW capacity was utilized – and in the underlying wind year (NEP: 2011). The comparison of the federal state-specific power production from onshore wind power presented in the NEP and the one calculated with the new model indicates

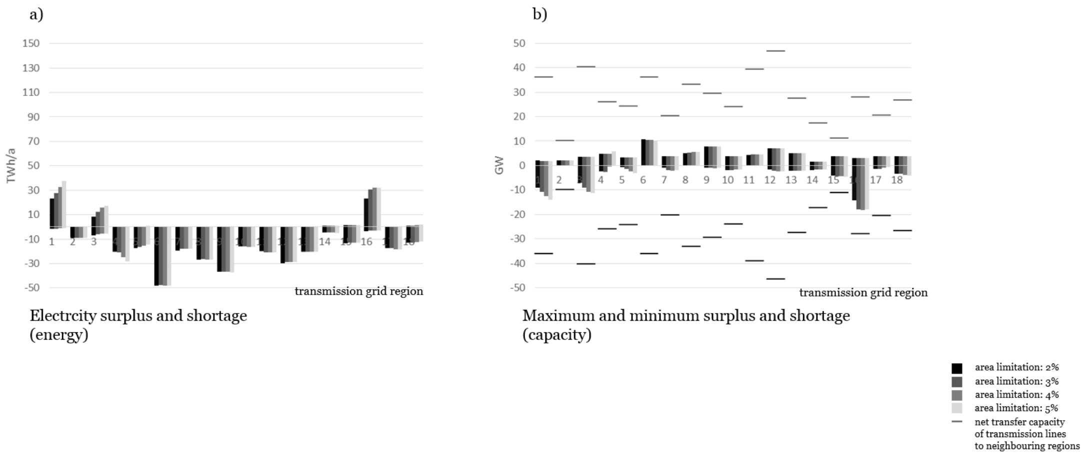


Figure 3.33: Scenario 3: Residual load by transmission grid regions (2035, low demand level, state-by-state allocation)

comparably small differences, for instance a production of 23.6 TWh/a in the NEP and 24.4 TWh/a in the new model (variant with an area limitation of 5 %) in the federal state of Schleswig-Holstein.

In addition to the scenario variants presented, a further scenario variant with lower space requirements of WTGs was tested. Instead of $7 \cdot 4$ square rotor diameters as shown, $4 \cdot 4$ squre rotor diameters were utilized. The capacity of scenario 3 was then allocated in the state-by-state allocation mode and the corresponding electricity generation was modeled. It went to show that a narrower spacing of WTGs, thus a higher density of WTGs, would allow to install the full amount of capacity even if area restrictions were tight. In the case of a 3 % limitation of the federal state areas and of the districts areas, the full capacity amount was allocated, generating 138.9 TWh/a (i.e. 1691 EFLH). In turn this means that even in the federal state of Schleswig-Holstein the full capacity could be allocated if the spacing between WTGs was small.

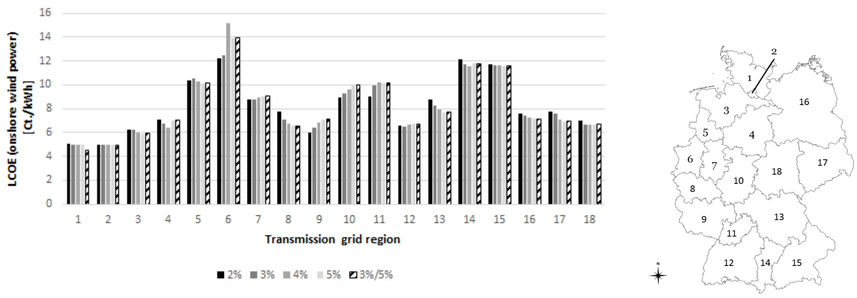


Figure 3.34: Scenario 3: LCOE of onshore wind power by transmission grid region (2035, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

3.2.4 Scenario 4 ("Beyond the anticipated")

The fourth scenario and its variants analyzed were developed by the author. As in the scenarios 1 and 2 the timeframe was 2050 in scenario 4. The installed capacity of wind power and PV were assumed to reach the respective maximum figures as presented in or based on the previous three scenarios:

- The installed capacity of onshore wind power was extrapolated from 2035 until 2050 from the NEP figures presented in scenario 3 (at the federal state level).
- The installed capacity of offshore wind power was the same as in scenario 1.
- The installed capacity of PV was the same as in scenario 2.
- The installed capacity of run-of-the-river hydro power was the same as in the other scenarios and remained constant due to the limited potential.

Scenario data of the installed capacity are presented in table 3.14. In 2050, the installed onshore wind power capacity would be 115.7 GW. Offshore wind power was assumed to reach 73.2 GW in 2050, PV 79.0 GW_p. The scenario can be regarded as ambitious, yet reasonable.

The installed wind power capacity in the federal states in 2050 was based on the NEP as presented in scenario 3. For the period between 2035 and 2050 the installed capacity in the federal states was extrapolated applying the same annual growth rate in the individual federal states as in the period 2025 – 2035. The installed capacity in the federal states in 2050 is listed in table 3.15.

Table 3.14: Installed capacity in scenario 4 ("Beyond the anticipated")

	Unit	2020	2030	2040	2050
Onshore wind power	GW	48.98	71.30	93.50	115.70
Offshore wind power	GW	11.02	49.00	58.10	73.20
PV	GW_p	55.44	66.27	73.27	79.03
Run-of-the-river hydro power	GW	4.45	4.45	4.45	4.45

Based on 50 Hertz Transmission GmbH et al. (2014b) and own calculations.

Similar to scenario 3, scenario 4 was modeled under consideration of state-specific installation development trajectories of onshore wind power ("state-by-state allocation") and also neglecting such targets ("nationwide allocation"). Each of these scenario variants was modeled with and without further area limitations for wind power installations.

3.2.4.1 Scenario 4: Results (unrestricted area availability)

For a first set of results of scenario 4 it was assumed that no further area limitation would restrict the area potentially available for the allocation of onshore WTGs. Running the scenario without such area limitations necessarily led to the least-cost scenario variant in the nationwide allocation mode as well as in the state-by-state allocation mode because all most favourable locations were potentially available for wind power installations. This is, as mentioned, an assumed extreme case that allowed to detect system boundaries and the comparison with scenario variants in which area limitations were taken into account.

3.2.4.1.1 Nationwide allocation

First, the scenario was modeled without further area limitations in the nationwide capacity allocation mode, i.e. the federal state-specific installation targets of onshore wind power were aggregated on the national level and the total capacity was then allocated throughout the available area in Germany.

Central results of scenario 4 without further area limitations can be found in table 3.16. They show that the full onshore capacity of 115.7 GW could be allocated. In 2050, the maximum onshore wind power output during the year was 94.7 GW which corresponds to 81.8 % of the installed capacity. The minimum onshore wind power during the year was 0.4 GW which corresponds to 0.4 % of the installed capacity. This is approximately in the same range as in the other scenarios modeled.

Without further area limitations the wind power capacity would be allocated to only few districts: 147 out of the 412 districts would be affected with a maximum capacity density of 4.50 MW/km^2. As already detected in the other scenarios analyzed, the most

Table 3.15: Scenario 4: Installed wind power capacity in the federal states (2050)

Federal state	Capacity [GW]
Baden-Württemberg	9.10
Bavaria (*Bayern*)	8.00
Berlin	0.00
Brandenburg	11.20
Bremen	0.20
Hamburg	0.10
Hesse (*Hessen*)	5.10
Mecklenburg West-Pomerania (*Mecklenburg-Vorpommern*)	14.30
Lower Saxony (*Niedersachsen*)	18.85
Northrhine-Westphalia (*Nordrhein-Westfalen*)	15.25
Rhineland-Palatinate (*Rheinland-Pfalz*)	6.35
Saarland	0.30
Saxony (*Sachsen*)	1.40
Saxony-Anhalt (*Sachsen-Anhalt*)	4.90
Schleswig-Holstein	15.60
Thuringia (*Thüringen*)	5.05
total	115.70

Own calculations, partly based on 50 Hertz Transmission GmbH et al. (2014b, p. 73)

Table 3.16: Results of scenario 4 (unrestricted area availability, 2050, nationwide allocation)

Onshore wind power	capacity	GW	115.70
	produced electricity	TWh/a	233.44
	EFLH		2017.65
	capacity factor		0.23
	minimum production	GW (%)	0.45 (0.39)
	maximum production	GW (%)	94.66 (81.82)
	LCOE	Ct./kWh	5.41
	specific investment cost	Ct./kWh	3.72
	specific MRO cost	Ct./kWh	1.69
Offshore wind power	produced electricity	TWh/a	217.71
PV	produced electricity	TWh/a	80.87
Run-of-the-river hydro power	produced electricity	TWh/a	27.42
All VRE	produced electricity	TWh/a	559.45
	share in demand (low demand level)	%	111.88
	share in demand (high demand level)	%	79.91
	LCOE	Ct./kWh	5.82

favourable locations and districts were fully occupied. In comparison with scenario 3 which was targeting at 2035, more districts were affected in scenario 4 because the total installed capacity was larger. The installed wind power capacity in the districts is illustrated in figure 3.35.

Under the assumptions made, 233.4 TWh/a were found to be produced by onshore wind power in 2050. Similar to the other scenarios presented, the capacity was concentrated to few locations and so was the production from onshore wind power. This would therefore result in a high electricity production from wind power especially in the North of Germany whereas in the South power production would be comparably low.

Related to the installed capacity, an average of 2018 EFLH was detected. This is lower than in the according scenario variant of scenario 3, which was expected because more less favourable locations were utilized. The EFLH in the transmission grid regions ranged between 927 (Region 6, West Northrhine-Westphalia) and 2399 (region 1, Schleswig-Holstein).

As presented, in scenario 4 the electricity production from offshore wind power was the same as in scenario 1 (217.7 TWh/a) in 2050 and the production from PV was the same as in scenario 2 (80.9 TWh/a). Run-of-the-river hydro power was not altered, producing 27.4 TWh/a. All VRE combined produced 559.5 TWh/a. This translates

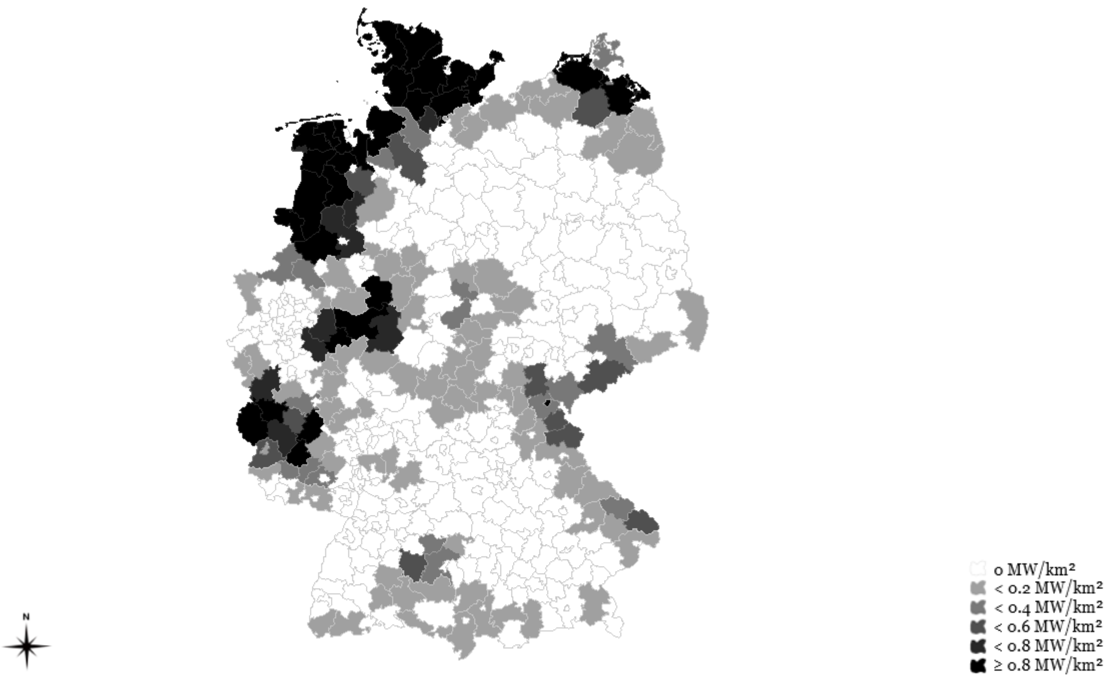


Figure 3.35: Scenario 4: Capacity density of wind power by districts (unrestricted area availability, 2050, nationwide allocation)

into a share of 79.9 % of the annual demand at a high demand level and 111.9 % at a low demand level, respectively. This means that if the demand level in 2050 was low, the installed VRE capacity in the scenario was able to fully cover the electricity demand with regard to the annual balance and no further losses assumed. If the demand level was high, this would not be possible.

The VRE shares varied in the transmission grid regions. They ranged between 0.9 % in region 2 (Hamburg) and 868.4 % in region 1 (Schleswig-Holstein) at a low demand level and between 0.6 % (region 2) and 620.3 % (region 1) at a high demand level.

The German mean LCOE of onshore wind power in 2050 was 5.41 Ct./kWh. It ranged between 4.55 Ct./kWh in region 1 (Schleswig-Holstein) and 12.11 Ct./kWh in region 14 (South-West Bavaria). The LCOE of all VRE combined was 5.82 Ct./kWh.

3.2.4.1.2 State-by-state allocation

In a second step scenario 4 was modeled under consideration of development pathways of onshore wind power in the federal states, i.e. the wind power capacity was allocated in an economically optimized way in each federal state separately, taking expansion targets of the individual states into account. In sum the same amount of capacity as in

Table 3.17: Results of scenario 4 (unrestricted area availability, 2050, state-by-state allocation)

Onshore wind power	capacity	GW	115.42
	produced electricity	TWh/a	206.97
	EFLH		1793.17
	capacity factor		0.20
	minimum production	GW (%)	0.67 (0.58)
	maximum production	GW (%)	92.62 (80.25)
	LCOE	Ct./kWh	6.08
	specific investment cost	Ct./kWh	4.19
	specific MRO cost	Ct./kWh	1.90
Offshore wind power	produced electricity	TWh/a	217.71
PV	produced electricity	TWh/a	80.87
Run-of-the-river hydro power	produced electricity	TWh/a	27.42
All VRE	produced electricity	TWh/a	532.97
	share in demand (low demand level)	%	106.59
	share in demand (high demand level)	%	76.13
	LCOE	Ct./kWh	6.10

the nationwide allocation was used. Capacity and production figures of offshore wind power, PV and run-of-the-river hydro power were not affected by this altered allocation approach.

As in the case of the nationwide allocation mode, the full capacity amount could be allocated (cf. table 3.17). The maximum power available during the year was 92.6 GW which corresponds to 80.3 % of the installed capacity, i.e. it was slightly lower than in the case of a nationwide optimized allocation. The lowest onshore production was 0.7 GW which corresponds to 0.6 % of the installed capacity. This is slightly higher than in the case of a nationwide optimized allocation mode.

As figure 3.36 shows, the wind power capacity allocated with the state-by-state allocation mode was clearly more distributed across the nation than with the nationwide capacity allocation mode. Instead of a concentration in the most favourable locations of the total area of Germany, now a concentration in the most favourable locations within each federal state can be detected. The number of districts affected by wind power installations was higher than in the case in which the nationwide allocation mode was applied (177, i.e. + 30), with a maximum capacity density of 4.14 MW/km^2.

The allocated capacity generated 207.0 TWh/a in 2050. This is 26.5 TWh/a (11.3 %) lower than in the case of a nationwide optimized allocation, indicating that the expansion

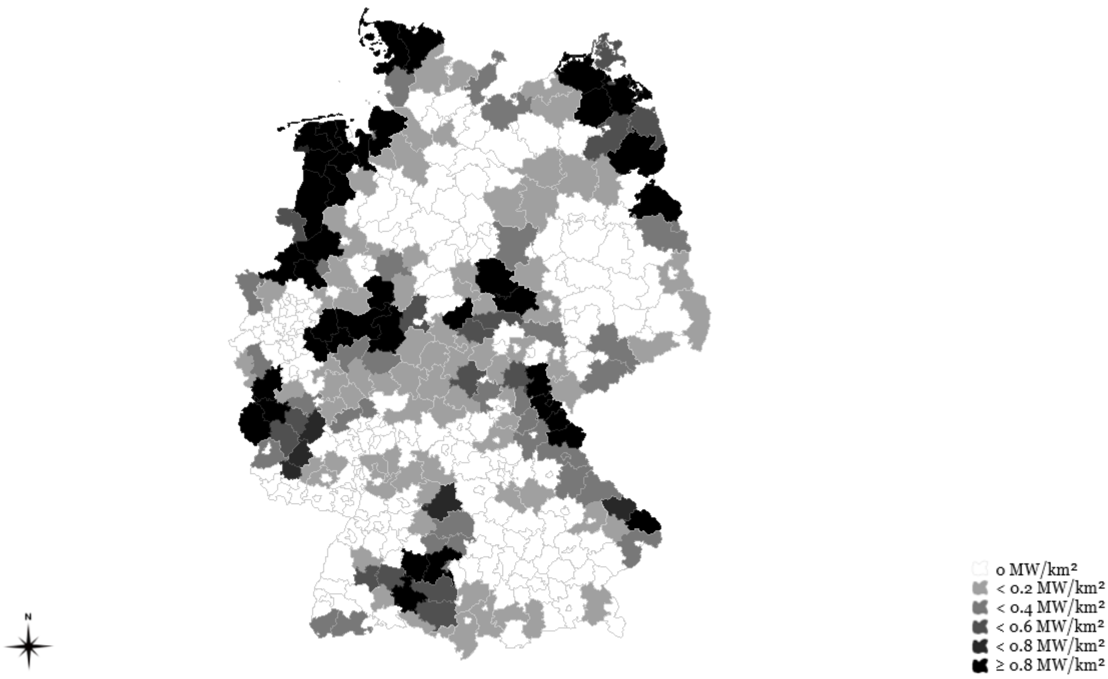


Figure 3.36: Scenario 4: Capacity density of wind power by districts (unrestricted area availability, 2050, state-by-state allocation)

targets of the individual federal states did not fully match a nationwide economically optimized allocation of wind power capacity.

The national mean EFLH of onshore wind power was 1793 and accordingly lower than in the case of a nationwide allocation. The EFLH in the transmission grid regions ranged between 884 in region 6 (West Northrhine-Westphalia) and 2405 in region 1 (Schleswig-Holstein), which is similar to the nationwide allocation case.

In this scenario variant onshore wind power produced less electricity than detected in the nationwide allocation mode and power production from all aggregated VRE was reduced by the same amount, reaching 533.0 TWh/a in total. As the German mean, the share of VRE in total demand in 2050 ranged between 76.1 % at a high demand level and 106.6 % a low demand level. Again, at both demand levels this was lower than in the case of a nationwide allocation. However this also means that even with state-specific installation targets as definded in the scenario, a full net coverage of the annual power demand would be possible if the demand level was low. The range in the transmission grid regions was between 1.1 % in region 2 (Hamburg) and 315.6 % in region 1 (Schleswig-Holstein) at a low demand level and between 0.8 % (region 2) and 225.4 % (region 1) at a high demand level. On both ends of the scale the ratio thus was reduced in comparison to the case of a nationwide optimized capacity allocation. The share of VRE in the total consumption in transmission grid region 1 (Schleswig-Holstein), for instance, was considerably smaller in the case of a state-by-state allocation than in the case of a nationwide allocation but still substantially larger than 100 %.

The German mean LCOE of onshore wind power in 2050 was 6.08 Ct./kWh, i.e. 11 % higher than in the case of a nationwide optimized allocation. The lower production due to the consideration of individual federal state targets thus directly translated into an increase in LCOE of the same ratio. The LCOE of onshore wind power ranged between 4.54 Ct./kWh in region 1 and 12.30 Ct./kWh in region 6 (West Northrhine-Westphalia). The LCOE of all VRE combined was 6.10 Ct./kWh. In comparison to the case of a nationwide allocation without further area limitations this corresponds to additional cost of 0.37 Ct./kWh, i.e. an increase of 4.6 %.

3.2.4.2 Scenario 4: Results (restricted area availability)

As in the other scenarios analyzed, variants of scenario 4 were modeled in which additional area limitations for onshore wind power installations were taken into account. In contrast to the other scenarios, the limitation now was altered between 5 % and 8 % of both the federal state areas and the district areas, i.e. the maximum percentage applied in the other scenarios (5 %) was now utilized as the minimum percentage in scenario 4. Additionally, another 3 %/5 % variant was modeled. That range was selected on the basis of the results from scenario 3 in which even a tighter area limitation partly did not allow to allocate the full onshore wind power capacity. It must be emphasized that such area limitations can be regarded as comparably high. In comparison to the historic wind power installation such area limitations would be in the order of the shares of or larger than priority areas for wind power installations in districts with a large wind power installation, for instance in the districts of Dithmarschen and North Frisia in the federal state of Schleswig-Holstein (cf. section 2.3.6.2).

Again, a nationwide and a state-by-state capacity allocation was conducted and analyzed in the scenario variants. The nationwide allocation variants acted as cases the state-by-state allocation variants could be compared with.

3.2.4.2.1 Nationwide allocation

Central results of a nationwide capacity allocation in scenario 4 with area limitations can be found in table 3.18. In those scenario variants all onshore wind power capacity could be allocated even with the tightest area limitation set (3 %/5 % variant). The

Table 3.18: Results of scenario 4 (restricted area availability, 2050, nationwide allocation)

	Unit	Maximum share of state and district available				
		5%	6%	7%	8%	3 %/5 %*
Onshore wind power						
capacity	GW	115.70	115.70	115.70	115.70	115.70
produced electricity	TWh/a	191.72	195.36	199.39	202.70	187.93
EFLH		1656.99	1688.50	1723.30	1751.89	1624.30
capacity factor		0.19	0.19	0.20	0.20	0.19
minimum production	GW	0.87 (0.75%)	0.79 (0.68%)	0.75 (0.65%)	0.71 (0.61%)	0.95 (0.82 %)
maximum production	GW	93.00 (80.38%)	93.12 (80.49%)	93.43 (80.75%)	93.64 (80.94%)	92.21 (79.69 %)
LCOE	Ct./kWh	6.58	6.46	6.33	6.23	6.71
specific investment cost	Ct./kWh	4.53	4.45	4.36	4.28	4.62
specific MRO cost	Ct./kWh	2.05	2.01	1.97	1.94	2.09
All VRE						
produced electricity	TWh/a	517.72	521.37	525.39	528.70	513.94
share in demand (low demand level)	%	103.54	104.26	105.07	105.73	102.78
share in demand (high demand level)	%	73.95	74.47	75.05	75.52	73.41
LCOE	Ct./kWh	6.29	6.24	6.19	6.16	6.33

*) 3 %: limitation of federal states areas; 5 %: limitation of districts areas

installed capacity and produced electricity in the transmission grid regions is presented in table B10 in the appendix.

The distributed capacity of onshore wind power in 2050 (nationwide allocation, restricted area availability) is illustrated in figure 3.37 (larger version in figure A10 in the appendix). From left to right the illustration shows the capacity density under area limitations ranging from 5 % to 8 % of the state areas and district areas, supplemented by the 3 %/5 % variant on the right. Analogous to the other scenarios, the maps indicate that the tighter the area limitation was, the less concentration of installation was found and the more districts were affected. Districts without any installation, marked in white colour on the maps, could be found especially in the South-West where the area potentially available according to the geographical analysis was limited anyway and in the South-East where wind speeds are comparably low. In the case of an area limitation of 5 %, 244 out of the 412 districts were affected by onshore wind power installations. At maximum, a capacity density of 0.616 MW/km^2 was found in the districts. This is comparable to the results of scenario 3. An increase in the area limitation to 8 % led to an increasing concentration of capacity: 207 districts were affected with a maximum capacity density of 0.983 MW/km^2.

As the total amount of onshore wind power capacity in scenario 4 in 2050 was larger than in all the other scenarios, more districts were affected in all the variants of scenario 4 than in the other scenarios. All districts that were utilized for onshore wind power installations in the case of a 8 % area limitation were also in use in the scenario variants with a more restrictive area limitation.

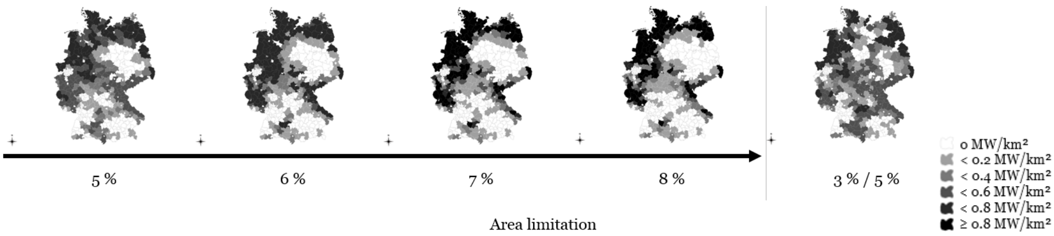


Figure 3.37: Scenario 4: Installed wind power capacity by districts (restricted area availability, 2050, nationwide allocation)
Percentages: restriction of federal state areas and district areas. 3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

The absolute figures of the aggregated wind power capacity in the federal states show a corresponding picture (figure 3.38), similar to the corresponding variant of scenario 3. The more area was available for wind power installations, the more capacity was allocated in 2050 to the federal states of Mecklenburg-Western Pomerania, Lower Saxony, Northrhine-Westphalia, Rhineland-Palatinate and Schleswig-Holstein. In the federal states of Baden-Württemberg, Bavaria, Hesse, Saxony-Anhalt and Brandenburg the installed capacity substantially decreased, the wider the area limitation was set. In the smaller federal states (cities of Bremen and Hamburg, federal state of Saarland) hardly any effect was detectable.

The installed onshore wind power capacity produced 191.7 – 202.7 TWh in 2050, depending on the area limitations set. This translates into 1657 – 1752 EFLH which is lower than in scenario 3. The comparison of the scenario variants with an area limitation of 5 % and of 8 % shows that a higher concentration of wind power capacity resulted in an increase in power production by 5.7 %.

The power production in the transmission grid regions, again, differed a lot. As shown in figure 3.39, the highest production could be found in the regions where offshore wind was landed (region 1 (Schleswig-Holstein), region 3 (North Lower Saxony) and region 16 (North-East)). An increase in the potentially available area substantially increased the power production in the regions 1 and 3 and in the regions 5 (West Lower

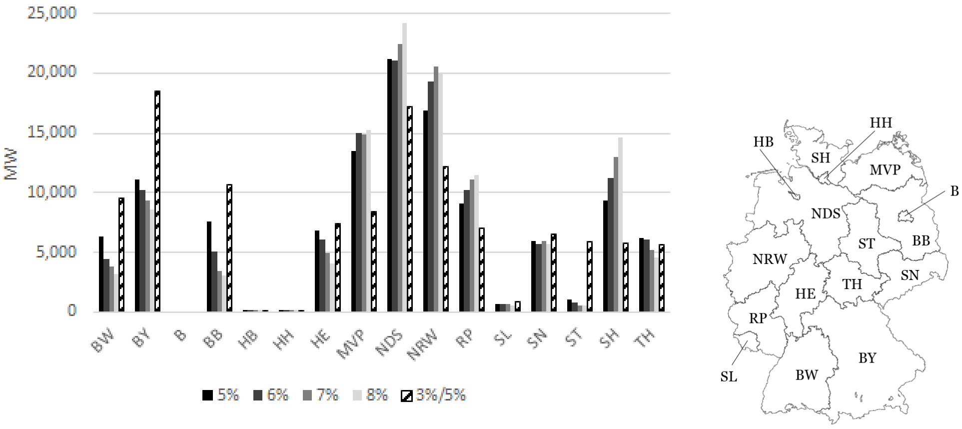


Figure 3.38: Scenario 4: Wind power capacity installed in the federal states (restricted area availability, 2050, nationwide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Germany's federal states.

Saxony) and 9 (South-West Germany), too. In all the other transmission grid regions power production from wind power decreased the more area was available for wind power installations. This is due to the fact that wind power capacity was moved away from these regions towards regions with more favourable wind speed conditions, for instance to districts along the coastlines.

Accordingly the largest specific power production could be found in the transmission grid regions 1 ($1.40 - 2.20$ GWh/km^2) and 3 ($1.07 - 1.61$ GWh/km^2). The lowest specific power production was found in transmission grid region 2 (Hamburg, 0.05 GWh/km^2).

In combination with offshore wind power (217.7 TWh/a), PV (80.9 TWh/a) and run-of-the-river hydro power (27.4 TWh/a), total power production from VRE ranged between 517.7 TWh/a and 528.7 TWh/a in 2050 in the variants of scenario 4 (nationwide allocation, restricted area availability).

In figure 3.40 (larger version in figure A16 in the appendix) the production pattern of all VRE and the load (500 TWh/a in 2050) are exemplarily shown for the scenario variant of a 5 % limitation of both the federal state areas and the district areas. The load fluctuated between 35 GW and 82 GW whereas the power production from VRE fluctuated between 5 GW and 174 GW. That span is substantially larger than in all the other scenarios because the overall installed capacity was substantially larger. VRE production exceeding the demand resulted in gross electricity surpluses of 128 TWh/a that would be needed to be stored or exported unless power production was curtailed.

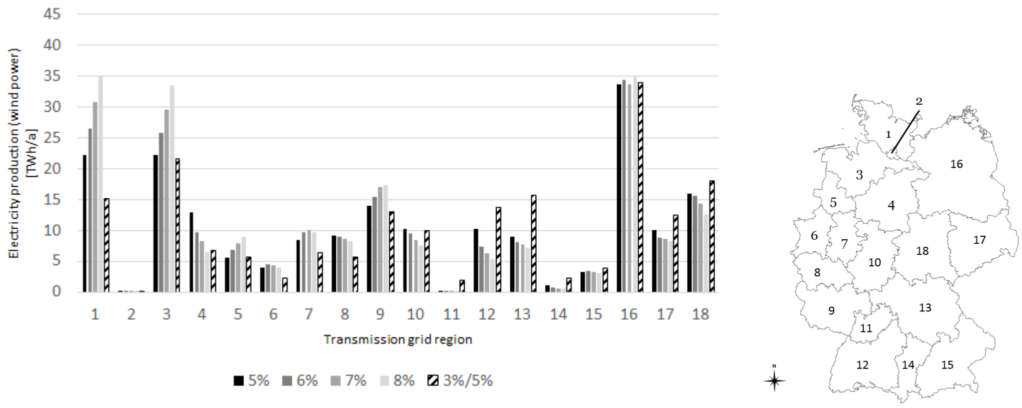


Figure 3.39: Scenario 4: Electricity production from onshore wind power by transmission grid regions (restricted area availability, 2050, nation-wide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

At maximum, a power surplus of 106 GW was reached. Taking the grid enhancement planning as presented in the NEP into account, cross-border transmission capacity added up to 74.4 GW if all the announced projects were completed until 2035 and if all the existing transmission lines remained available, including new links to Norway. The maximum power surplus as detected in the scenario thus could not be fully transmitted to neighbouring countries. At least 30.2 GW could not be exported. Other flexibility options therefore would be necessary, which however was not analyzed in further detail within this thesis and should be subject of to further scientific research.

An increase in area availability resulted in larger gross electricity surpluses (e.g. 8 % variant: 137 TWh/a of gross electricity surpluses with 110 GW at maximum). The situation thus would be exacerbated with an increasing area availability, thus capacity concentration.

In figure 3.41 the duration curves of the residual load at a low demand level in Germany in the scenario variants are depicted. During more than half of the year VRE production could not cover the power demand, i.e. additional power production from other plants, storage facilities or imports would be required to cover the load during such moments. On the right hand side of the diagram it becomes obvious that during the rest of the year power surpluses occurred. Differences in the curves are hardly detectable in the diagram, however an increase in area availability translated into an increase in gross electricity surpluses. In the case of an area limitation of 5 %, during 4158 hours of the

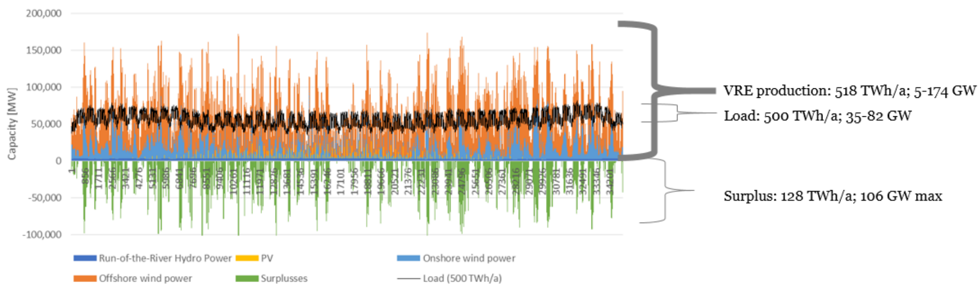


Figure 3.40: Scenario 4: Electricity production from VRE
(2050, nationwide allocation, restricted area availability: 5 %)

year the demand could be directly covered by VRE production which corresponds to nearly half of the year. An increase in the area availability to 8 % increased this figure to 4232 h/a. In sum, gross electricity surpluses exceeded gross electricity shortages in the year of analysis, which also could be detected in the demand coverage ratio.

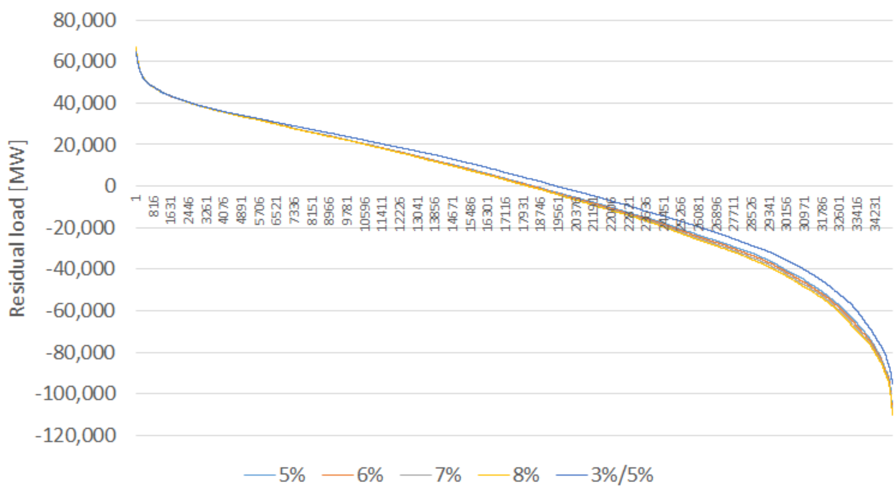


Figure 3.41: Scenario 4: Duration curves of the residual load
(2050, low demand level, nationwide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

The resulting residual load was dependent on the modeling parameters – in particular space requirements of WTGs and area limitations set – and the demand level. A low demand level assumed, the annual VRE production reached 103.5 – 105.7 % of the annual demand. If it was possible to shift gross electricity surpluses to times and locations of power shortages, the power demand therefore could be fully covered by VRE production. At a high demand level, 74.0 – 75.5 % of demand coverage by VRE were reached.

However regional differences occurred, again, depending on the capacity allocation mode, on the consequent electricity production and also on the regional electricity demand. As shown in figure 3.42, the regions where offshore wind power production was landed (regions 1, 3 and 16) showed a substantially positive net balance, i.e. net electricity surpluses, whereas all the other regions show net power shortages (image a). For a full VRE power supply – which, as shown, would be arithmetically possible – power surpluses from those regions would be needed to be transmitted to the other regions. The comparison of the maximum power surplus in those regions in 2050 and the available transmission capacity as illustrated in image b, assuming all grid expansion until 2035 as presented in the NEP were completed, shows that the transmission capacity from region 1 to its neighbouring regions and abroad would not fully suffice to handle the maximum power surplus. If the full amount of surplus power was to be transmitted, a further expansion or enhancement of the transmission grid by more than 5 GW from transmission grid region 1 to neighbouring regions would be required. An increase in the area potentially available for wind power installations would further increase the transmission requirements. A grid flow analysis would however be necessary for a full evaluation of potentially necessary grid enhancements.

Unless further transmission lines were built, other flexibility options could be required. Due to the limited storage potential in transmission grid region 1 – especially compressed air energy storage (CAES) has been discussed in and analyzed for that region (cf. Deutsche Energie-Agentur GmbH (dena) (2010a, pp. 483) and Burges et al. (2014)) – and in order not to have to curtail production from VRE in that region, other options such as power-to-gas or even power-to-heat could play a relevant role in the future.

The national mean LCOE of onshore wind power ranged between 6.23 Ct./kWh and 6.58 Ct./kWh. This was higher than in scenario 1 and most variants of scenario 3 and was expected because with the larger installation, more less favourable locations were utilized. In the transmission grid regions the LCOE of wind power ranged between figures below 5 Ct./kWh in the regions 1 (Schleswig-Holstein) and 2 (Hamburg)) and above 10 Ct./kWh in the regions 6 (West Northrhine-Westphalia), 14 (South-West Bavaria) and 15 (South-East Bavaria).

In figure 3.43 the LCOE of onshore wind power in the transmission grid regions in scenario 4 is illustrated (nationwide allocation, restricted area availability). Only few transmission grid regions were strongly affected by a change in the area availability for

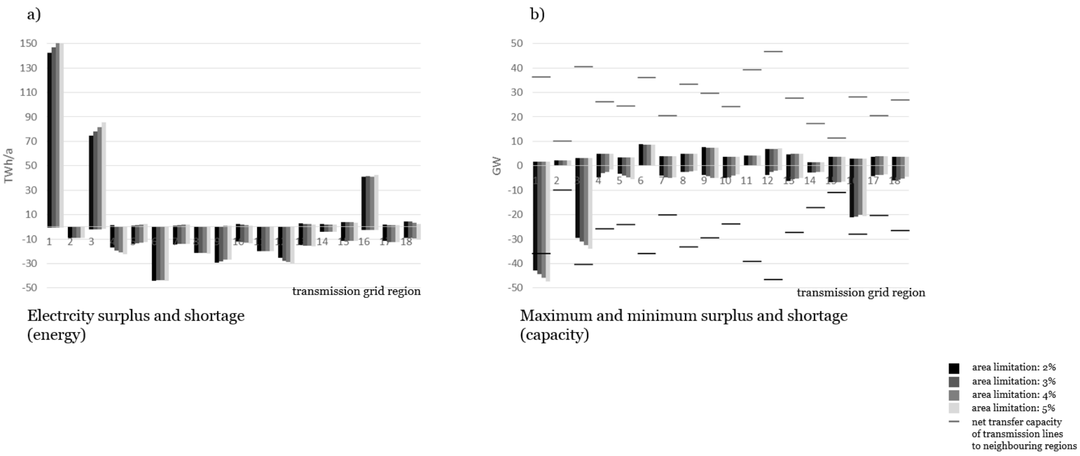


Figure 3.42: Scenario 4: Residual load by transmission grid regions (2050, low demand level, nationwide allocation)

wind power installations: in regions 6 (West Northrhine-Westphalia) and 10 (central Germany) an increase in LCOE of wind power was found, regions 13 (North Bavaria) and 16 (North-East) showed a strong decrease. In all the other regions only minor changes were found when the area limitation was altered.

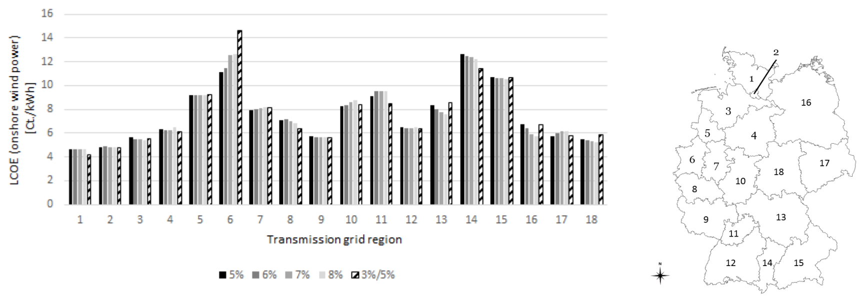


Figure 3.43: Scenario 4: LCOE of onshore wind power by transmission grid regions (2050, nationwide allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

Depending on the area availability for onshore wind power, the national mean LCOE of all aggregated VRE ranged between 6.16 Ct./kWh and 6.29 Ct./kWh. As onshore wind power accounted for 42.5 % of the total installed VRE capacity the effect of altering

Table 3.19: Results of scenario 4 (restricted area availability, 2050, state-by-state allocation)

	Unit	Maximum share of state and district available				
		5%	6%	7%	8%	3 %/5 %*
Onshore wind power						
capacity	GW	110.09	112.15	114.22	115.42	98.99
electricity produced	TWh/a	181.86	186.99	193.46	197.75	163.59
EFLH		1651.93	1667.32	1693.72	1713.34	1652.58
capacity factor		0.19	0.19	0.19	0.20	0.19
minimum production	GW	0.81	0.73	0.71	0.71	0.79
		(0.74%)	(0.65%)	(0.62%)	(0.61%)	(0.80 %)
maximum production	GW	88.31	89.80	91.53	92.37	78.84
		(80.22%)	(80.07%)	(80.14%)	(80.03%)	(79.64 %)
LCOE	Ct./kWh	6.60	6.54	6.44	6.37	6.60
specific investment cost	Ct./kWh	4.54	4.50	4.43	4.38	4.54
specific MRO cost	Ct./kWh	2.06	2.04	2.01	4.38	2.06
All VRE						
electricity produced	TWh/a	507.87	513.00	519.47	523.76	489.59
share in demand (low demand level)	%	101.56	102.59	103.89	104.74	97.91
share in demand (high demand level)	%	72.55	73.28	74.20	74.82	69.94
LCOE	Ct./kWh	6.29	6.27	6.23	6.21	6.28

*) 3 %: limitation of federal states areas; 5 %: limitation of districts areas

the area limitation for onshore wind power accordingly could only be partly found in the overall LCOE of all VRE.

3.2.4.2.2 State-by-state allocation

The state-by-state allocation of wind power capacity in scenario 4 was also conducted taking further area limitations of 5 – 8 % of the federal state areas and district areas into account, complemented by a 3 %/5 % variant.

The results show that the full amount of onshore wind power capacity could be allocated only if the area limitation was set wide, i.e. to 8 % in all the districts. With a tighter area limitation in all the districts, the resulting area would not suffice the space requirements of all the WTGs to be allocated in some of the federal states under the assumptions made. The installed wind power capacity and produced electricity in the transmission grid regions is listed in table B11 in the appendix.

As illustrated in figure 3.44 (larger version in figure A11 in the appendix), the wind power capacity density in the federal states again was concentrated in the variants of scenario 4 in which the state-by-state capacity mode was applied. Unlike the case of a nationwide allocation, the capacity concentration now was found in the most favourable districts within each federal state. A comparably tight limitation of 5 % of the federal state areas and the district areas assumed, more districts (225) than in the respective nationwide allocation would be affected with a higher maximum capacity density (0.753 MW/km^2) but the available area would not suffice to have the full capacity installed. With a wider area limitation, e.g. 8 % of the federal state areas and the district areas, fewer districts (199) would be affected, i.e. the wind power capacity would be more concentrated with a maximum capacity density of 1.196 MW/km and the area would suffice.

Figure 3.44: Scenario 4: Installed wind power capacity by districts (restricted area availability, 2050, state-by-state allocation)
Percentages: restriction of federal state areas and district areas. 3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

In most of the scenario variants in which the state-by-state capacity allocation mode was applied, the full state-specific capacity as defined in the installation scenarios could be installed (cf. figure 3.45). This means that a limitation of 5 % of both the district areas and the federal state areas to would suffice the space requirements of the wind power capacity as defined in the scenario. The only exception was the state of Schleswig-Holstein: Only if the area limitation was increased to 8 %, the targeted more than 15 GW until 2050 could be installed under the assumptions made. This exception caused the deviation between the capacity to be installed nationally in total and the capacity that actually could be allocated in the scenario variants.

The comparison with the same wind power capacity allocated with the nationwide allocation mode illustrates that, depending on the area limitations set, similar differences as in scenario 3 occurred were found in the federal states, however in a different year of analysis. They could be described as follows.

- Hesse, Thuringia:
  The less area was potentially available for wind power installations, i.e. under the

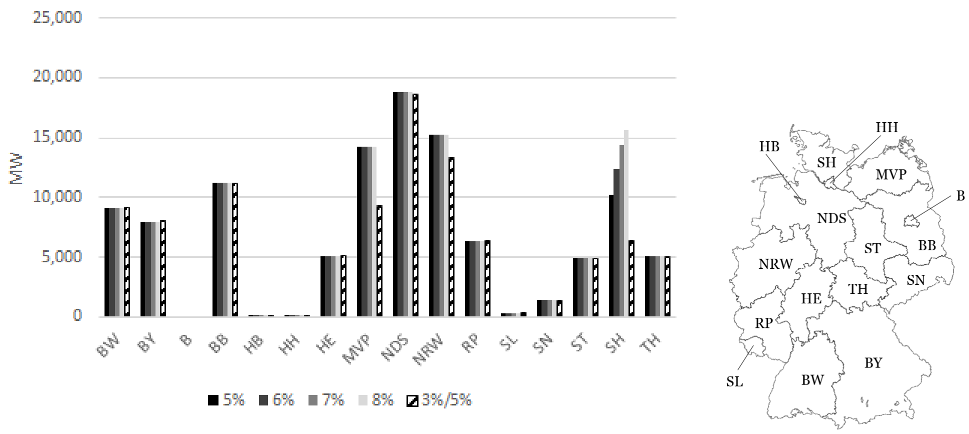


Figure 3.45: Scenario 4: Wind power capacity installed in the federal states (restricted area availability, 2050, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Germany's federal states.

assumption of a tight area limitation, the installed capacity was larger in the case of a nationwide optimized capacity allocation than in the case of a state-by-state allocation. A wide area limitation resulted in the opposite.

- Mecklenburg-Western Pomerania:
  The less area was potentially available for wind power installations, i.e. under the assumption of a tight area limitation, the installed capacity was smaller in the case of a nationwide optimized capacity allocation than in the case of a state-by-state allocation. A wide area limitation resulted in the opposite.

- Baden-Württemberg, Brandenburg, Saxony-Anhalt, Schleswig-Holstein:
  In all scenario variants of a nationwide capacity allocation the installed capacity was smaller than envisaged as the federal state target for 2050 in the scenario.

- Bavaria, Lower Saxony, Northrhine-Westphalia, Rhineland-Palatinate, Saarland, Saxony:
  In all scenario variants of a nationwide capacity allocation the installed capacity was larger than envisaged as the federal state target for 2050 in the scenario.

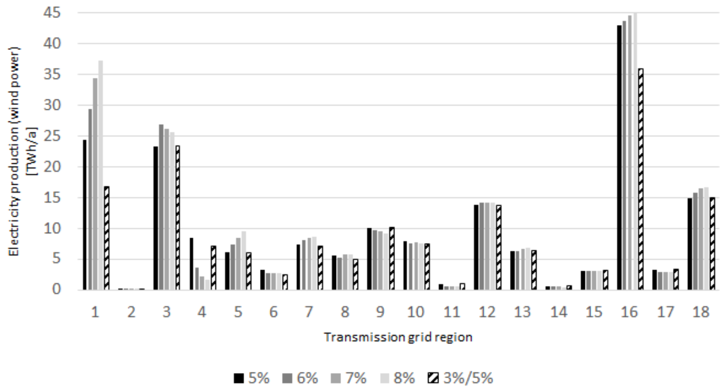
In the case of a nationwide allocation, the allocated wind power capacity in one federal state affected the allocation of capacity in another, depending on area restrictions defined and the specifiedspace requirements of WTGs. Causalities between the area availability and the allocation of the installed capacity deduced from the model results thus need to be taken with care, i.e. they refer to a specific amount of installed capacity as defined in the scenarios.

The installed onshore wind power capacity produced 181.86 – 197.75 TWh/a, depending on the area limitation set. This translates into 1652 – 1713 EFLH. Analogous to the LCOE, such lower values than found in scenario 1 and most variants of scenario 2 were expected due to the higher installation value. Compared to the scenario variant without further area limitations, an additional area restriction materialized in an amount of electricity produced from onshore wind power that is 13.2 –17.9 % lower, depending on the area limitations set.

As in the other scenarios and scenario variants, huge differences in power production in the transmission grid regions were found. In the diagram in figure 3.46 the electricity production with different area restrictions (different shades of gray) is shown for all onshore transmission grid regions (1 – 18). Not surprisingly, in the regions where offshore wind power was landed (regions 1, 3 and 16) the highest power production values were found, which corresponds to the results of scenario 4 with a nationwide allocation of the same amount of wind power capacity. The comparison of the transmission grid regions' production figures is only partially possible because – as presented – not the same amount of wind power capacity was installed in all the scenario variants. By tendency in the regions 1 (Schleswig-Holstein), 5 (West Lower Saxony), 16 (North-East) and 18 (East-South) the power production clearly increased the more area was available. In the regions 4 (South Lower Saxony), 9 (South-West) and 10 (central Germany)) production tended to decrease with an increasing area availability. The largest specific power production could be found in the regions 1 (Schleswig-Holstein, 1.54 – 2.35 GWh/km^2), 3 (North Lower Saxony, 1.12 – 1.29 GWh/km^2) and 5 (South-West Lower Saxony, 0.77 – 1.20 GWh/km^2) whereas the lowest specific power production was found in region 2 (Hamburg, 0.03 GWh/km^2).

Similar to the respective case in which the nationwide allocation mode was applied, in the case of a state-by-state capacity allocation the total VRE production was affected by the area limitations set for onshore wind power. In combination with offshore wind power (217.7 TWh/a), PV (80.9 TWh/a) and run-of-the-river hydro power (27.4 TWh/a), the total VRE production ranged between 507.9 TWh/a and 523.8 TWh/a.

In figure 3.47 (larger version in figure A17 in the appendix) the production pattern of all VRE and the load at a low demand level is illustrated exemplarily for the variant of a 5 % limitation of both the federal state areas and the district areas in 2050.



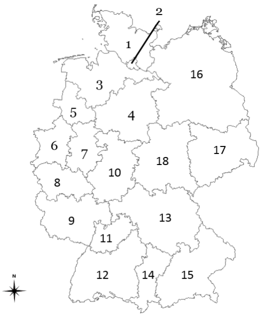


Figure 3.46: Scenario 4: Electricity production from onshore wind power by transmission grid regions (2050, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

The load fluctuated between 36 and 83 GW whereas the power production from VRE fluctuated between 5 and 172 GW. This is 2 GW lower than in the case of a nationwide economically optimized capacity allocation but still substantially higher than in all the other scenarios analyzed. VRE production exceeding the demand resulted in gross electricity surpluses of 121 TWh/a in 2050. This is 7 TWh/a lower than in the case of a nationwide allocation. At maximum, a power surplus of 105 GW was detected. In comparison with the nationwide allocation, the maximum residual load thus was just marginally reduced. Again the comparison of this maximum residual load and the future cross-border transmission capacity (74.4 GW) illustrates that at least approx. 30 GW could not be transmitted.

An increase in the area availability for wind power installations resulted in larger gross electricity surpluses (e.g. variant with an 8 % area limitation: gross electricity surplus of 133 TWh/a with 108 GW at maximum). This is slightly lower than in the case of a nationwide allocation.

In figure 3.48 the duration curves of the residual load at a low demand level in Germany in the scenario variants are depicted. Similar to the case of a nationwide allocation, the curves show that during more than half of the year VRE production could not cover the load. On the right hand side of the diagram, it clearly shows that during the rest of the year power surpluses occurred. Although differences in the curves are hardly detectable, an increase in area availability translated into an increase in gross electricity surpluses due to the higher capacity concentration at locations with more

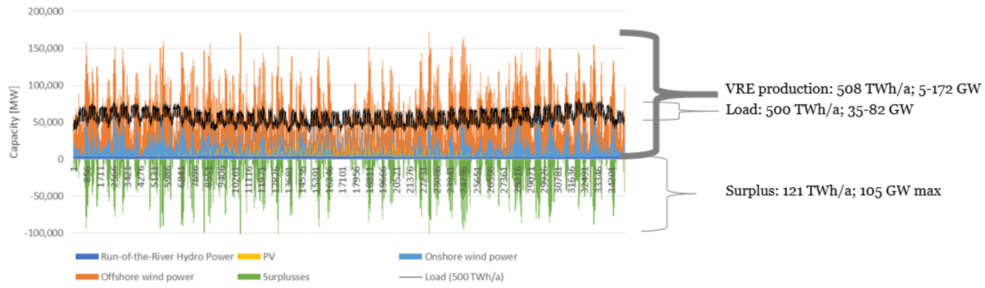


Figure 3.47: Scenario 4: Electricity production from VRE
(2050, state-by-state allocation, restricted area availability: 5 %)

favourable wind speed conditions. In the diagram the area representing the electricity surpluses (negative range between the curves and the abscissa) is larger than the area representing the electricity shortages (positive range between the curves and the x-axis), i.e. surpluses exceeded shortages. If it was possible to transfer power surpluses to times and regions of power shortages, the power demand could be fully covered by VRE production at a low demand level.

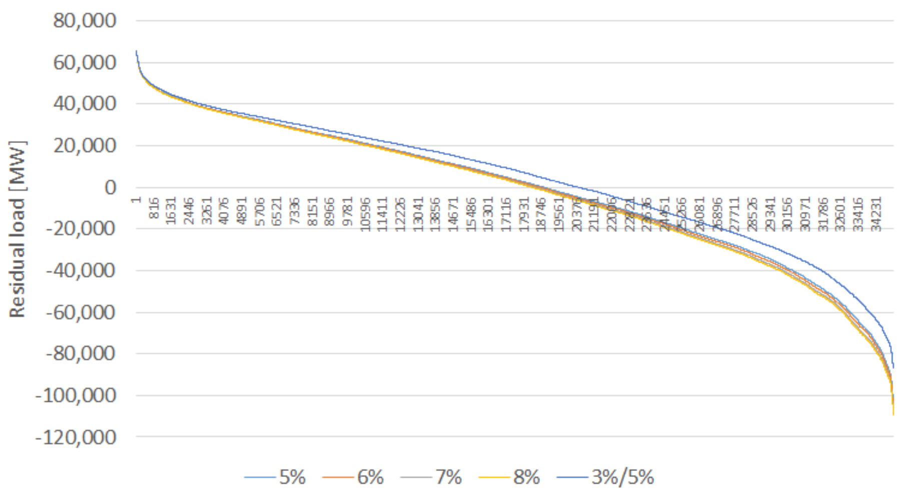


Figure 3.48: Scenario 4: Duration curves of the residual load
(2050, low demand level, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

The resulting residual load depended on the modeling parameters, in particular the space requirements of WTGs and the area limitations defined, and the demand level. A low demand level assumed, the amount of electricity produced by VRE corresponds to a share of 101.6 – 104.7 % in the total annual demand. At a high demand level, it corresponds to a share of 72.5 – 74.8 %. This means that in any case the demand could be covered by power production from VRE under consideration of the individual federal states' installation targets if the demand level was low and if sufficient storage options were available. Moreover the results show that although not the full amount of onshore wind power capacity could be allocated (e.g. in the case of an area limitation of 5 %), the demand coverage still exceeded 100 % in all variants of scenario 4 in which the state-by-state allocation mode was applied.

In figure 3.49 the residual load in the transmission grid regions is illustrated. Again, the regions where offshore wind power was landed clearly show a positive net balance (cf. image a), i.e there were net electricity surpluses, whereas in all the other federal states net power shortages were found. The analysis of the maximum power surplus (cf. image b), however, illustrated again that the transmission lines as planned until 2035 according to the NEP would not suffice the transmission requirements in region 1. An increasing area availability for onshore wind power installations, thus an increasing capacity concentration and power production, further increased the necessity of additional flexibility options in, from or to that region. In comparison to a nationwide optimized allocation, the gross electricity surpluses and shortages and also the maximum figures did not substantially change.

The load could be directly covered by power production from VRE during 4254 hours of the year in the case of a 5 % area limitation. An increase in area availability (e.g. to 8 % of the district areas) reduced the figure to 4141 h/a.

The national mean LCOE of onshore wind power was 6.37 – 6.60 Ct./kWh. This is slightly higher than in the case of a nationwide economically optimized capacity allocation and was expected as power production was lower. LCOE of onshore wind power in the transmission grid regions ranged from 4.57 Ct./kWh in region 1 (Schleswig-Holstein) and 4.88 Ct./kWh in region 2 (Hamburg) to more than 10 Ct./kWh in the regions 14 (South-East Bavaria, 10.66 Ct./kWh), 15 (South-West Bavaria, 11.54 Ct./kWh) and 6 (West Northrhine-Westphalia, 14.33 Ct./kWh). In figure 3.50 the LCOE of onshore wind power in the transmission grid regions is depicted, depending on the area limitations defined.

The national mean LCOE of all VRE in scenario 4 with a state-by-state allocation of onshore wind power was 6.21 – 6.29 Ct./kWh. Again this is higher than in the case of a nationwide economically optimized allocation.

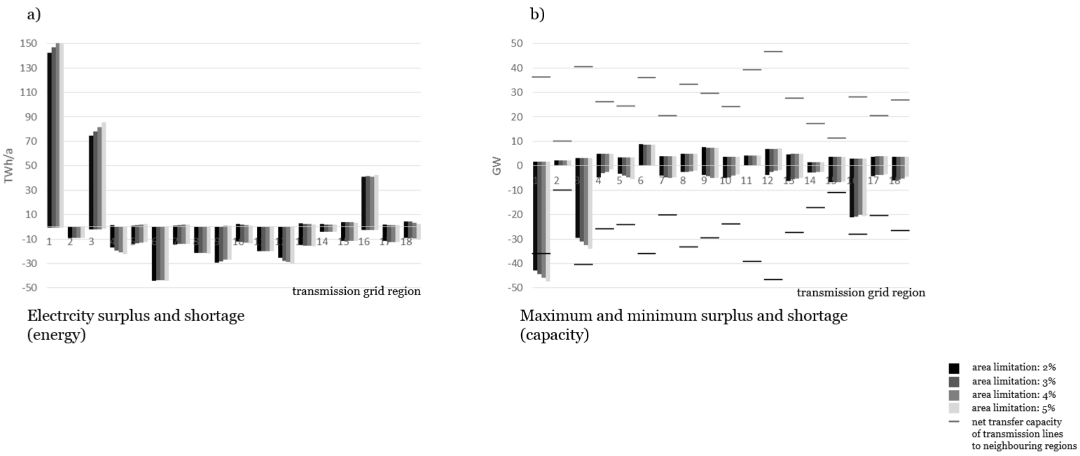


Figure 3.49: Scenario 4: Residual load by transmission grid regions (2050, low demand level, state-by-state allocation)

Table 3.20: Scenarios modeled

Scenario no.	Scenario name	target year	capacity allocation
1	*Offshore wind leads*	2050	nationwide
2	*PV leads*	2050	nationwide
3	*The anticipated*	2035	nationwide
3	*The anticipated*	2035	state-by-state
4	*Beyond the anticipated*	2050	nationwide
4	*Beyond the anticipated*	2050	state-by-state

3.3 Scenario comparison

The comparison of the scenarios analyzed (scenario overview in table 3.20) reveals the impact different variants of development trajectories of VRE installations had on the amounts of produced electricity and on LCOE. With the same amount of wind power capacity, different amounts of electricity could be generated, depending on the area restrictions set.

The comparison of the scenario variants without area restrictions (in the following referred to as the techno-economic "optimum") and the scenario variants in which further area restrictions were considered show the restrictions' impact on modeling results. In figure 3.51 the relative difference from the respective techno-economic optimum in the amounts of generated electricity in the scenario variants is summarized for the respective

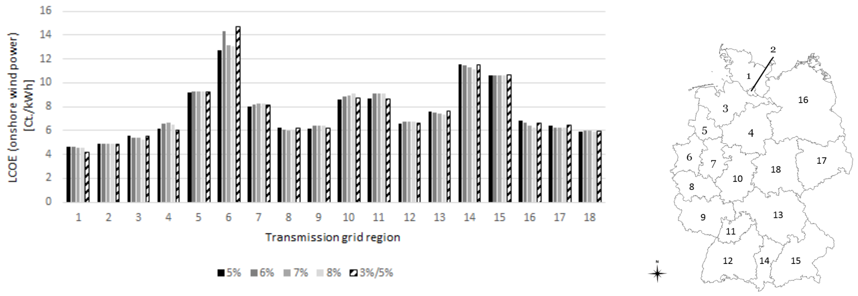


Figure 3.50: Scenario 4: LCOE of onshore wind power by transmission grid region (2050, state-by-state allocation)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.
On the right: Onshore transmission grid regions in the model.

target years. It must be pointed out that the figures of scenario 3 exceptionally refer to the target year 2035 and that the area limitations in scenario 4 ranged between 5 % and 8 %. A comparison of the results illustrated in the diagram is therefore only partly possible.

It becomes obvious that the deviation from the techno-economic optimum tended to be comparably large if the area restriction was tight. The more area was available for wind power installations, the smaller was the deviation from the techno-economic optimum.

For the scenarios and scenario variants modeled it can be concluded:

- Scenario 1 (2050):
  In comparison with the scenario variant with no further area limitations, power production from onshore wind power was 9.4 TWh/a (area limitation of 5 %) to 15.0 TWh/a (area limitation of 2 %) lower if an additional area limitation was set, i.e. 11 – 18 % below the maximum power production technically achievable with the same amount of installed capacity.

- Scenario 2 (2050):
  In comparison with the scenario variant with no further area limitations, power production from onshore wind power was 22.3 TWh/a (area limitation of 5 %) to 30.9 TWh/a (area limitation of 2 %) lower if an additional area limitation was set, i.e. 18.6 – 25.7 % below the maximum power production technically achievable with the same amount of installed capacity.

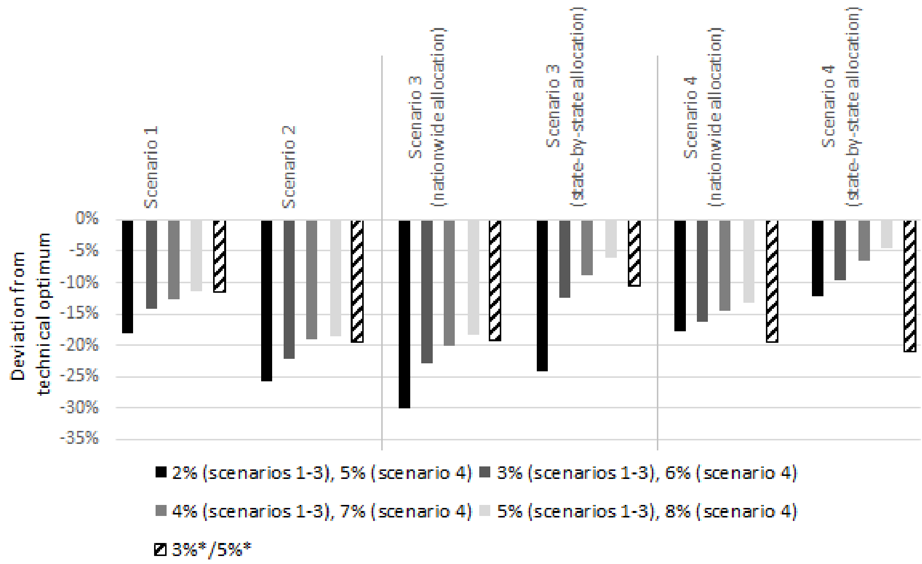


Figure 3.51: Deviation of electricity production of onshore wind power from the optimum case (respective target years)
Percentages: restriction of federal state areas and district areas.
3 %/5 % variant: 3 % limitation of federal state areas, 5 % limitation of district areas.

- Scenario 3 (2035, nationwide allocation):
  In comparison with the scenario variant with no further area limitations, power production from onshore wind power was 31.4 TWh/a (area limitation of 5 %) to 56.1 TWh/a (area limitation of 2 %) lower if an additional area limitation was set, i.e. 18.4 – 30.1 % below the maximum power production technically achievable with the same amount of installed capacity.

- Scenario 3 (2035, state-by-state allocation):
  In comparison with the scenario variant with no further area limitations, power production from onshore wind power was 10.4 TWh/a (area limitation of 5 %) to 41.5 TWh/a (area limitation of 2 %) lower if an additional area limitation was set, i.e. 6.1 – 24.7 % below the maximum power production technically achievable with the same amount of installed capacity.

- Scenario 4 (2050, nationwide allocation):
  As described, the area limitation in scenario 4 was altered between 5 % and 8 %, thus the comparability with the other scenarios was limited. The scenario variants however could be compared with each other. In comparison with the scenario variant with no further area limitations, power production from onshore wind

power was 30.7 TWh/a (area limitation of 8 %) to 41.7 TWh/a (area limitation of 5 %) lower if an additional area limitation was set, i.e. 13.1 – 17.9 % below the maximum power production technically achievable with the same amount of installed capacity.

- Scenario 4 (2050, state-by-state allocation):
  In comparison with the scenario variant with no further area limitations, power production from onshore wind power was 9.2 TWh/a (area limitation of 8 %) to 25.1 TWh/a (area limitation of 5 %) lower if an additional area limitation was set, i.e. 4.5 – 12.1 % below the maximum power production technically achievable with the same amount of installed capacity.

The deviations from the techno-economic optimum however did not solely depend on the area restrictions set. They also depended on the total installed wind power capacity in the scenarios and the mode of the capacity allocation, i.e. whether federal state-specific installation targets had been taken into account or not. The comparison of the scenarios 1, 2 and 3 in which the onshore capacity was allocated in the nationwide allocation mode shows that the more capacity was installed, the bigger was the impact of the area restriction, i.e. with the same area restrictions a larger deviation from the technical optimum was found, the more onshore wind power capacity was installed. Compared to that, the scenario variants of the scenarios 3 and 4 in which the allocation was conducted with the state-by-state allocation mode show smaller deviations from their respective techno-economic optimum. These deviations, again, became even smaller the more area was available for wind power installations. In all cases, the deviation from the techno-economic optimum was reduced if the area limitation was increased because more locations with more favourable wind speed conditions became available.

The results of scenario 4 were however comparable to the other scenarios' results only to a limited degree because the limitations of the federal state areas and the district areas were defined to be 5 % or higher, thus higher than in the other scenarios. In scenario 4 even a comparably wide area restriction resulted in deviations from the technical optimum.

Moreover it can be concluded that

- in the respective nationwide capacity allocation, all the districts affected in scenario 1 were also affected in the scenarios 2, 3 and 4 because the amounts of wind power capacity in these scenarios were bigger than in scenario 1, and

- a capacity allocation considering federal state-specific installation targets was clearly distinguishable from a nationwide economically optimized allocation (scenarios 3 and 4).

The second bullet point reflects the fact that a nationwide allocation and a state-by-state allocation of onshore wind power in the scenarios 3 and 4 clearly differed from each other. This means that the federal state-specific installation targets of onshore wind power – representing a pre-defined split-up of the total installed national wind power capacity until the respective target years – differed from an optimized nationwide allocation of the same capacity amount. In scenario 3, based on the targets defined in the NEP, the federal states thus could be classified into three groups with regard to the installed capacity and the allocation modes:

- Bavaria, Hesse, Saarland, Saxony:
  The wind power capacity as defined in the federal state-specific installation targets for 2035 according to the NEP was smaller than installed in these federal states with a nationwide optimized allocation.
  If the state-by-state allocation was to converge towards the nationwide economically optimized allocation, the installation targets of those federal states would need to be increased.

- Brandenburg, Saxony-Anhalt, Schleswig-Holstein:
  The wind power capacity as defined in the federal state-specific installation targets for 2035 according to the NEP was larger than installed in these federal states with a nationwide optimized allocation.
  If the state-by-state allocation was to converge towards the nationwide economically optimized allocation, the installation targets of those federal states could be reduced.

- All other states:
  The nationwide and the state-by-state allocation of onshore wind power capacity resulted in a similar amount of installed capacity in 2035 or differences between the allocation modes depended on the area restrictions set.
  A clear chain of cause and effect between the allocation mode, area restrictions and the installed capacity could not be detected.

As scenario 4 built upon scenario 3, a similar classification of the federal states as in scenario 3 could be made with regard to the installed capacity and the allocation modes, however for different area limitations:

- Bavaria, Lower Saxony, Northrhine-Westphalia, Rhineland-Palatinate, Saarland, Saxony:
  The wind power capacity as defined in the federal state-specific installation targets for 2050 as defined in the scenario was smaller than installed in these federal states with a nationwide optimized allocation.
  If the state-by-state allocation was to converge towards the nationwide economically optimized allocation, the installation targets of those federal states would need to be increased.

- Baden-Württemberg, Brandenburg, Saxony-Anhalt, Schleswig-Holstein:
  The wind power capacity as defined in the federal state-specific installation targets for 2050 as defined in the scenario was larger than installed in these federal states with a nationwide optimized allocation.
  If the state-by-state allocation was to converge towards the nationwide economically optimized allocation, the installation targets of those federal states could be reduced.

- All the other federal states:
  The nationwide and the state-by-state allocation of onshore wind power capacity resulted in a similar amount of installed capacity in 2050 or the difference between the allocation modes depended on the area restrictions set.
  A clear chain of cause and effect between the allocation mode, area restrictions and the installed capacity could not be detected.

The comparison of the results of the scenarios 3 and 4 show similar differences between a nationwide and a state-by-state allocation in the same federal states. In all scenario variants the installed capacity in Bavaria, Saarland and Saxony was smaller in the case of a state-by-state allocation than in the case of a nationwide allocation, meaning that in those federal states the envisaged capacity was clearly below what an optimized nationwide allocation would suggest. On the other hand, in Brandenburg, Saxony-Anhalt and Schleswig-Holstein the envisaged installed capacity in 2050 in all scenario variants was larger than an optimized nationwide allocation would suggest.

Moreover, the comparison of the two allocation modes applied with scenario 3 revealed:

- Compared to the nationwide allocation, the state-by-state allocation of wind power capacity without further area restrictions resulted in a power production that is

24.2 TWh/a (14.2 %) lower in 2035, thus LCOE of onshore wind power was accordingly higher. This difference also shows that the individual federal state targets did not fully correspond to an optimized nationwide allocation of the same total amount of onshore wind power capacity.

The wider the area limitation was set, the smaller was the difference between the allocation modes: In case the limitation of the federal state areas and the district areas was defined to be 5 %, the difference between the allocation modes was 3.2 TWh/a (2.2 %) and therefore comparably small.

- With the same total amount of installed onshore wind power capacity, the national annual gross electricity surpluses as well as the maximum power surplus in the case of a state-by-state allocation were lower than in the case of a nationwide optimized capacity allocation in 2035.

- The maximum national residual load was hardly affected by the allocation modes, i.e. the same amount of wind power capacity allocated with the nationwide and the state-by-state allocation modes hardly showed a difference in the maximum national residual load. This means that in both allocation modes approximately the same amount of capacity would be required to be provided by flexibility options in order to cover the load in moments with low power generation from VRE.

- If all the onshore wind power capacity could be allocated, i.e. in the case of a limitation of the federal state areas and the district areas of 5 %, the national mean LCOE of onshore wind power was 6.97 Ct./kWh in the state-by-state allocation mode. This was slightly higher than in the case of a nationwide allocation (6.85 Ct./kWh).

For scenario 4 it can be concluded:

- Without further area limitations, the state-by-state allocation resulted in a power production that was 26.5 TWh/a (11.3 %) lower than the production by the same amount of wind power capacity allocated with the nationwide allocation mode due to the individual federal states' capacity development trajectories.

- Even though not the full amount of onshore wind power capacity could be allocated in all scenario variants modeled (e.g. 5 % area limitation, state-by-state allocation), the annual gross power production by VRE still exceeded the annual power demand, i.e. the net demand coverage was higher than 100 % in scenario 4.

- The comparison of the maximum power surplus in the transmission grid regions and their corresponding transfer capacity to neighbouring regions and cross-border – assuming all grid expansion projects and planning until 2035 as presented in the NEP would be realized – shows that the transmission capacity from region 1 to its neighbouring regions and abroad did not fully suffice potential transmission requirements. If the full amount of power was to be transmitted, a further grid expansion or enhancement by more than 5 GW from transmission grid region 1 to its neighbouring regions or other flexibility options in that region would be required unless power production was curtailed.

- The annual gross electricity surpluses and shortages and also the maximum residual load did not substantially vary between a nationwide and a state-by-state allocation of the onshore wind power capacity in scenario 4.

- Similar to scenario 3, in scenario 4 the maximum residual load was hardly affected by the allocation mode, i.e. the nationwide and the state-by-state allocation of the same capacity amount hardly showed a difference in the maximum power shortage. This means that in both allocation modes approximately the same amount of capacity would be required from flexibility options in order to cover the load in times of low electricity production from VRE.

- In scenario 4 the national mean LCOE of onshore wind power was 6.37 – 6.60 Ct./kWh in the case of a state-by-state allocation. This is slightly higher than in the case of a nationwide economically optimized capacity allocation.

  Even though in scenario 4 more capacity was installed than in scenario 3, the resulting LCOE was lower due to the underlying assumed cost reduction until 2050.

Depending on the exogenously defined installed capacity until the target years as defined in the scenarios, the allocation mode selected and the area limitations set for wind power installations, power production from onshore wind power varied a lot between the scenarios and scenario variants. The relation of the produced electricity and resulting LCOE of onshore wind power in the scenarios modeled is illustrated in figure 3.52.

Except for scenario 3, representing 2035 values, the diagram shows 2050 figures. In the diagram the ordinate axis has been shortened. The curves in the figure show the mean national LCOE of onshore wind power in the scenarios analyzed taking different area limitations for wind power installations into account. The diagram illustrates that the larger the installed capacity was (minimum: 39.5 GW in 2050 in scenario 1, maximum:

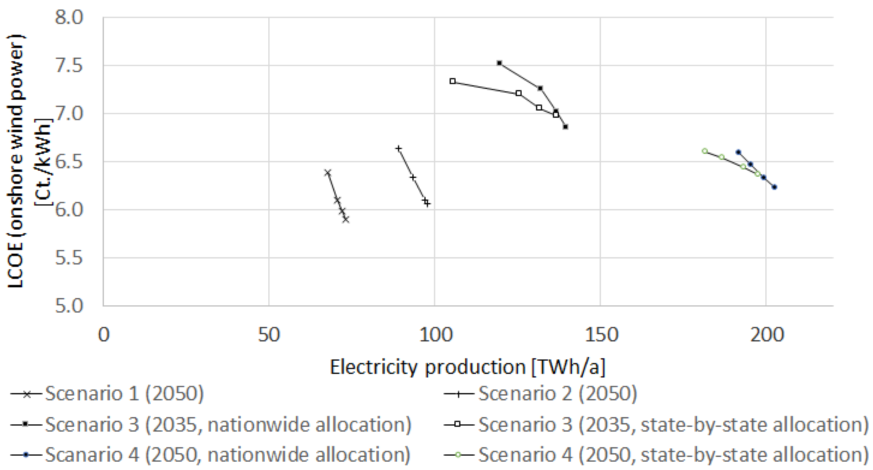


Figure 3.52: LCOE of onshore wind power as a function of the electricity production from onshore wind power in Germany (respective target years)

115.7 GW in scenario 4), the larger was the power output from wind power installations. This also resulted in higher LCOE the more capacity was installed because more less favourable locations needed to be utilized for the allocation of the larger amount of wind power capacity. The tightest area limitation (2 % of the district areas in the scenarios 1 – 3, 5 % in scenario 4) can always be found at the top left of the curves, also representing the highest LCOE and the lowest power production in all the variants of a scenario. The widest area limitation modeled (5 % of the district areas in the scenarios 1–3, 8 % in scenario 4) can always be found in the bottom right of a scenario's curve. This reflects the fact that in every scenario a larger area availability and therefore a heavier capacity concentration resulted in a larger power output and lower LCOE.

In all scenario variants the largest amount of electricity from wind power was produced in those transmission grid regions where offshore wind power was landed, i.e. regions 1 (Schleswig-Holstein), 3 (North Lower Saxony) and 16 (North-East Germany). The largest production was found in region 1 in the scenario variants with the largest amount of installed wind power capacity and the largest area availability. In all scenario variants the lowest specific production was found in region 2 (Hamburg).

An annual net electricity surplus could be generated only in the regions 1, 3 and 16 whereas in all the other transmission grid regions annual net power shortages occurred.

Except for scenario 3, the LCOE of onshore wind power ranged between 5.9 Ct./kWh and 6.6 Ct./kWh, i.e. they differed by up to 0.7 Ct./kWh (10 %) in 2050, depending on the area restrictions set.

As presented, the nationwide and the state-by-state allocation of the same amount of onshore wind power capacity in the scenarios 3 and 4 differed from each other. The wider the area limitations were set, however, the more the allocation of the two allocation modes converged. This is also illustrated in figure 3.52 where the variants of the scenarios 3 and 4 with a high area availability nearly resulted in the same LCOE. In the figure, the respective curves of the different allocations modes of the same scenario thus nearly meet at one point. In turn this means that a tighter area limitation resulted in a bigger difference between allocated capacity in the two allocation modes. The tighter the area limitation was set, the more potentially more favourable locations would be excluded from potential wind power use.

In the diagram in figure 3.52, the resulting curves of scenario 3 were in a higher range of LCOE than the curves of the other scenarios because they refer to 2035 when cost were expected to be higher than in 2050. They are therefore comparable to the result figures of the other scenarios only to a limited degree.

The duration curves in figure 3.53 also illustrate the electricity generation from onshore wind power in the scenarios and their respective target years. The respective curves show the scenario variants with the tightest area limitation in which, as presented, however not in all cases the full capacity as defined in the respective scenario was allocated. Not surprisingly the highest values were reached in scenario 4 in a nationwide optimized allocation mode in which the largest amount of onshore wind power capacity was installed (115.7 GW in 2050, uppermost curve).

In the diagram exemplary results of both allocation modes of the scenarios 3 and 4 are depicted, i.e. a nationwide and a state-by-state allocation of the same total onshore wind power capacity. The results of the respective state-by-state allocation are found slightly below the curves representing the respective scenario variant with a nationwide allocation, which demonstrates the reduced power production due to the pre-defined installation targets of the federal states.

In combination with the scenario-specific power generation from offshore wind power, PV and run-of-the-river hydro power, the amounts of the total power production from VRE also differed between the scenarios and scenario variants in their respective target years. As onshore wind power accounted for only a portion of the total installed VRE capacity, the effect of an increasing power production from wind power due to a larger

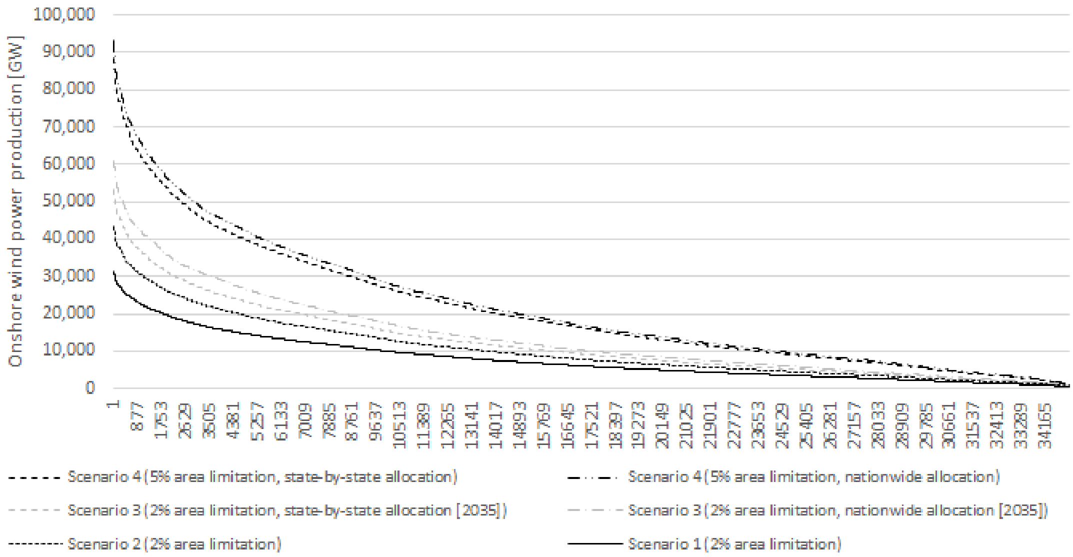


Figure 3.53: Duration curves of onshore wind power in the scenarios modeled (respective target years)

area availability could only partly be found in the total power generation, thus in the LCOE of all VRE.

In figure 3.54 the duration curves of the residual load in the scenarios and scenario variants in the respective target years are shown for an assumed low demand level in the respective years of analysis. Similar to the duration curves of the onshore wind power production but also driven by the production from the other VRE in the scenarios, the duration curves of the residual load of the different scenarios are clearly distinguishable.

The uppermost curve represents the residual load in scenario 3 in which during most of the time in 2035 the power production from VRE could not cover the demand. Scenario 3 however represented a possible system state in 2035 and it was comparable to the other scenarios only to a limited degree. Below the curves of scenario 3, the curves of the scenarios 1 and 2 are found in the diagram, illustrating a higher VRE penetration than in scenario 3. In scenario 1 the share of offshore wind power production was larger than in scenario 3, resulting in a lower duration curve of the residual load which illustrates that the power production from VRE could contribute to cover the demand more often than in scenario 3. The lowest curves represent the residual load in scenario 4 in which the total VRE capacity was larger than in all the other scenarios modeled. The difference between the nationwide allocation and the state-by-state allocation of onshore wind power is detectable in scenario 4, yet comparably small. In total, the annual energy

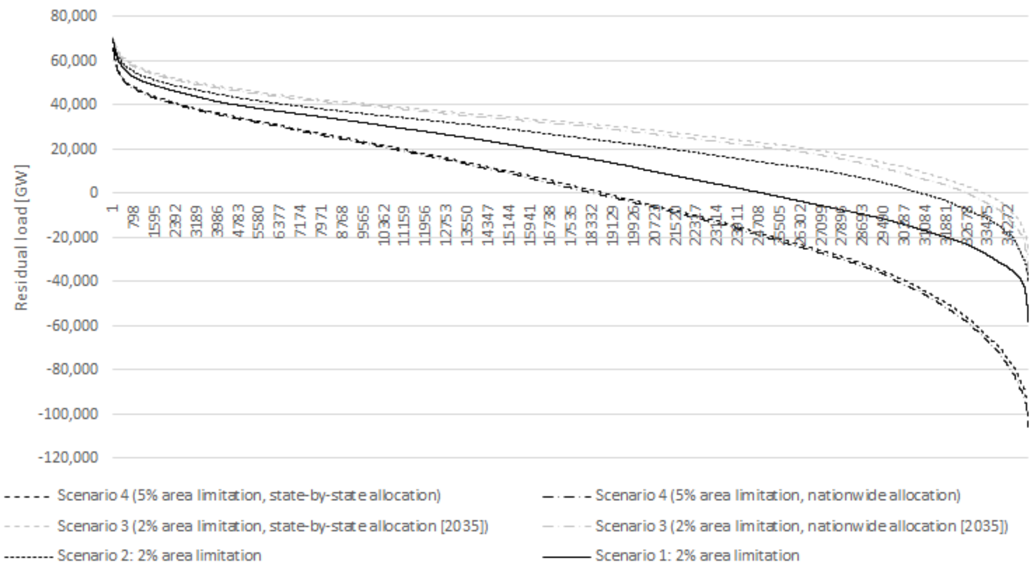


Figure 3.54: Duration curves of the residual load (low demand level) in the scenarios analyzed (respective target years)

balance in scenario 4 in 2050 was positive, a low demand level assumed. This means that the gross electricity surpluses exceeded the gross electricity shortages during the year. A full power supply by VRE thus would be mathematically possible but it would require supporting technical solutions to handle the variability of the power production (cf. section 3.2.4) and the load (cf. section 2.5).

By tendency, an increase in the area availability for onshore wind power installations resulted in a larger amount of annual gross electricity surpluses. At a low demand level power production in scenario 1 was increased by 4.0 TWh/a (10.4 %) if the limitation was increased from 2 % to 5 % of the federal state areas and the district areas. The maximum gross power surplus was increased by 4.8 GW (8.2 %). The maximum gross power shortage, on the other hand, was practically unaffected by the area availability for onshore wind power installations but the annual gross amounts of shortage energy were slightly reduced. In scenario 3 (nationwide allocation) an exemplary increase in the area availability for onshore wind power from 2 % to 5 % resulted in an increase in gross electricity surpluses from 5.4 TWh/a to 9.3 TWh/a with a power surplus of 41 GW at maximum. In any case this was lower than the total cross-border transfer capacity if all the grid expansion projects presented in the NEP were completed.

The ratio between the annual power production from VRE and the total annual electricity consumption at a low demand level is illustrated in figure 3.55 as a function of the installed VRE capacity in the scenario variants in the respective target years. For illustration purposes the axes of the diagram have been shortened. In the diagram the variants of a scenario are marked with an individual symbol and connected with a line.

Differences in the scenario variants resulted from different area restrictions set for the allocation of onshore WTGs. If a curve in the diagram runs vertically, an equally large total amount of VRE capacity was installed in different scenario variants, resulting in different amounts of power produced in dependency of the area availability for wind power installations.

The diagram shows that the VRE shares differed between the scenarios and scenario variants. On the top right the resulting figures of scenario 4 are depicted, with the largest installed capacity, producing approximately 100 % of the annual power demand. On the lower left the results of the scenarios 1–3 are depicted. Scenario 3 represents the lowest installed VRE capacity and the lowest VRE share in total demand, however representing 2035. The curves of the scenarios 3 and 4 show differences between the two allocation modes. The corresponding curves of the different capacity allocation modes, however, converge the wider the area limitations are set.

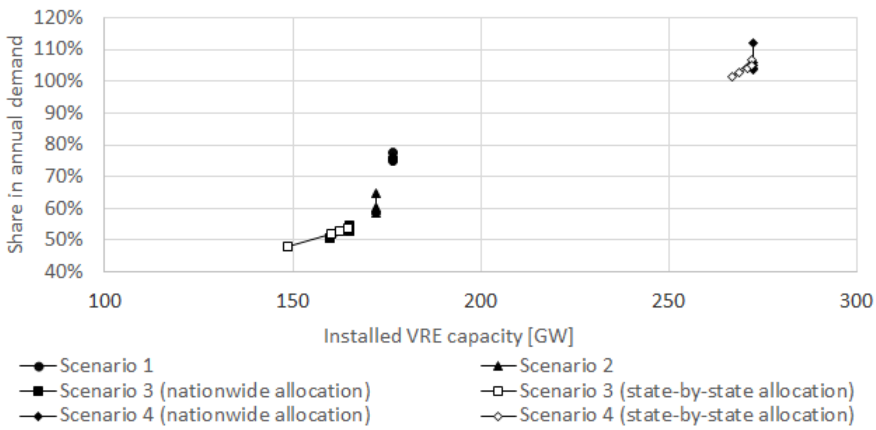


Figure 3.55: VRE shares in annual power demand and installed VRE capacity (respective target years)

At least 47.8 % of the annual power demand in the scenarios modeled could be supplied by VRE production (scenario 3, 2035, nationwide allocation, area limitation of 2 %). In 2050, at least 58 % of the annual power demand could be covered by VRE production (scenario 2, area limitation of 2 %). The results of all the other scenarios and scenario variants modeled were found to be above that figure. The share of power production by VRE in the total annual power demand was affected by the area restrictions set for onshore wind power installations. As onshore wind power was only part of the VRE mix in the respective target years, the effect of altering the area availability for onshore wind power installations was only partly found in the resulting figures of the power production from all VRE.

The frequency distribution of the load coverage during the year is illustrated in figure 3.56. Again the respective curves show the scenario variants with the tightest area limitation. The diagram illustrates how frequent and to what extent the load could be covered by VRE production during the respective target years. The curves are right-skewed: they increase steeply at low levels of load coverage and fall smoothly the higher the level of load coverage gets (cf. also Saint-Drenan et al. (2009, p. 21)). It can be detected that the largest installed capacity as assumed in scenario 4 reached the highest levels of load coverage during 2050 whereas during most of the year 2050 in scenario 2 the load could not be fully covered by VRE production. The comparably steep curves of scenario 3, representing a system state in 2035, illustrate again that in that scenario during most of the year the load could not be covered by VRE production. Differences between the allocation modes of onshore wind power, again, are hardly detectable.

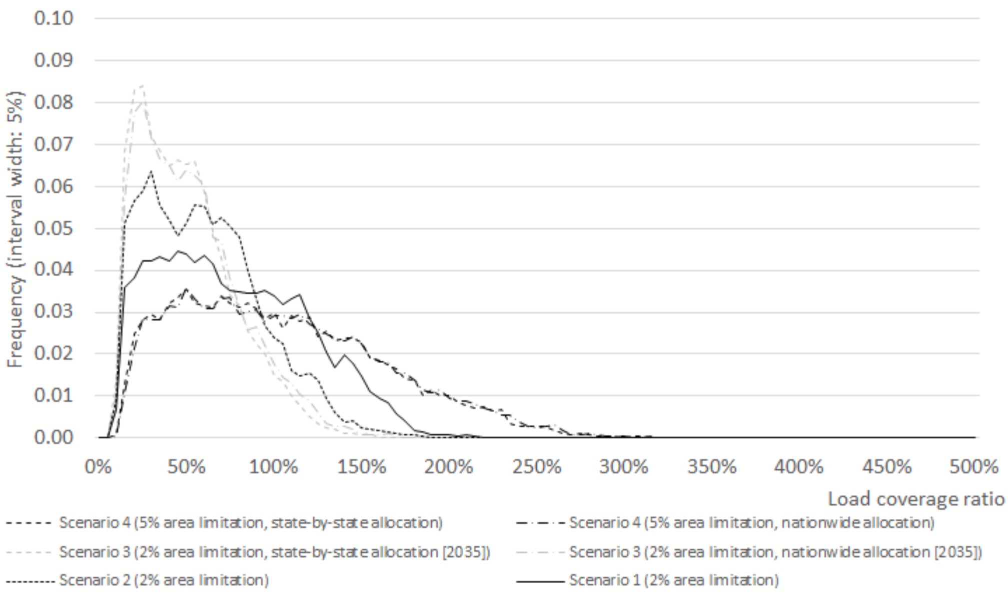


Figure 3.56: Frequency distribution of load coverage in Germany (respective target years)

3.4 Sensitivities

The modeling results need to be regarded against the background of the assumptions made as all input parameters as presented in section 2.3 affected the modeling outcomes. In order to detect their impact, selected input parameters were altered and all scenarios and scenario variants were calculated again. The results of these sensitivity calculations are presented in the following section and in the respective tables in the appendix.

- Geographical data:
  Variation of the area potentially available for wind power installations as detected in the geographical analysis: impact on the allocation of WTGs and eventually on their power output

Although specific land use categories will foreseeably be excluded from wind power use in the future, others might be subject of discussion. For instance, the size of buffering areas around buildings and protected areas might change in the future. If different buffer sizes, i.e. minimum distances around excluded areas, were chosen, the remaining area potentially available for wind power installations would be enlarged or reduced. Different buffer sizes would have a strong impact on the sizes of the remaining areas especially in low-populated regions where buffers tend to overlap less than in other regions where large shares of the total area would already be excluded even with comparably small buffers around buildings.

In addition to the calculations presented in which buffers of 1000 m around buildings and protected areas was assumed, further calculations therefore were conducted using smaller buffers of 750 m around buildings and protected areas. By doing so, the geographical potential for wind power installations in Germany was detected to be approx. 100 000 km^2. A similar increase was also documented in Salecker & Lütkehus (2014) where minimum distances between specific land use categories and WTGs were altered.

The results of the additional modeling calculations applying smaller buffers around buildings and protected areas can be found in table B12 in the appendix. In all scenario variants the power output was increased. That increase was the largest in the scenario variants without further area limitations (at maximum: increase of 8.76 % in scenario 1). This was expected as with a larger area potentially available, more favourable locations would be potentially available, too. In all scenarios and scenario variants modeled with further area constraints, however, the power output increased by 2.43 % at maximum (scenario 4, nationwide allocation, area restriction of 5 %). In most of the scenario variants the increase was below 2 %. Those are comparably small values that can be explained with the interaction of the area potentially available according to the geographical analysis and the available area according to the additional area restrictions set. In most cases the latter set the upper limit of the usable area and a different buffer size therefore only played a minor role. The results thus show that ceteris paribus the power output could be marginally increased with a smaller buffer size. This also resulted in a minor reduction of LCOE.

- Geographical data:
  Variation of further area restrictions

impact on the allocation of wind power capacity and on the corresponding power output (as shown), also depending on the area potentially available for wind power installations as detected in the geographical analysis.

- Geographical and technical data:
  Variation of the spacing of WTGs: impact on all results parameters

As presented, the technical potential of wind power strongly depended on a WTG's space requirement and area restrictions set. If, for instance, a WTG's space requirement was assumed to be larger, less total wind power capacity could be allocated in the available area. With the same amount of installed capacity more area and thus districts would be affected by wind power installations and power production would decrease.

In order to detect the impact of the spacing of WTGs on modeling results, additional calculations were conducted assuming a wide spacing of WTGs ($7 \cdot 7$ square rotor diameters). Results of these calculations can be found in table B15 in the appendix. The modeling with such altered space requirements of WTGs revealed a substantial impact on results: a wider spacing, thus greater space requirement of WTGs, led to a more distributed capacity allocation, lower production and higher LCOE.

In some scenario variants, a wider spacing of WTG did not allow to allocate the full capacity as defined in the scenarios because with the larger space requirement of WTGs, the limited available area was occupied earlier than in the case of a narrower spacing of WTGs. This was the case in the scenarios 3 and 4, in particular in the state-by-state allocation mode. In most of these cases in which the full capacity amount still could be allocated the difference of the power output of the two allocation modes was around 5 %.

The impact a different spacing of WTGs had on the annual power production thus was comparably small if the full amount of capacity could be installed. In several of the scenarios and scenario variants, however, the full wind power capacity could be installed only if the area restriction was set high (e.g. scenario 3, nationwide allocation: the area limitation had to be 4 % or larger while minimum 3 % were found to be sufficient with a narrower spacing of WTGs).

- Meteorological data:
  Variation of the wind year: impact on the power output from WTGs.

A different wind year applied in the modeling would lead to different results, i.e. a different amount of EFLH of wind power, lower or higher LCOE and a different pattern of the residual load. In order to detect the wind year's impact on modeling results, all scenarios and scenario variants were alternatively modeled applying recorded wind speed data from 2003. The results are presented in table B13 in the appendix.

The modeling results indicate that the application of wind speeds as in the year 2003 led to lower electricity production figures than the calculations in which wind speeds as in the year 2010 were utlized. Power production changed by approximately 3.7 – 6.1 % in most of the scenario variants modeled if wind speed time series from 2003 instead from 2010 were utilized. It must be emphasized again that any other wind year would result in differences in the amounts of generated electricity.

- Technical data:
  Variation of power curves: impact on the power output and on LCOE of wind power.

In its latest version, one normalized averaged power curve for onshore WTGs and one for offshore WTGs was utilized in the model. In order to assess the impact of the utilization of different power curves, further calculations were conducted in which a different power curve was utilized. That power curve was based on a selection of the single-turbine power curves as presented in section 2.3.3.1. For the additional calculations only those seven WTGs from the list in table B1 in the appendix were selected that would start their power production at lowest wind speeds, i.e. weakwind turbines. Compared to the original power curve used in the calculations presented, the alternative multi-turbine power curve consequently ramped up at lower wind speeds. Its behaviour at high wind speeds however did not change substantially. The allocated capacity in the scenarios and the WTG size development was not altered. The results of these additional calculations can be found in table B14 in the appendix.

In comparison to the scenario results presented, the utilization of such a power curve for onshore installations resulted in an increase in generated power by 17.3 – 24.0 % in the scenario variants modeled. The impact the power curve had on modeling results thus was substantial.

- Technical data:
  Variation of WTG sizes: impact on the capacity allocation, the power output and LCOE of wind power.

The nominal power, hub heights and rotor diameters of WTGs were inputs to both core model parts and they affected intermediate and final modeling results. Their future development, however, inherited uncertainties even though model data had been based on literature sources. Their impact on modeling outcomes was not further analyzed and could be subject to further research.

- Economic data:
  Variation of CAPEX, OPEX and interest rate: impact on the allocation of WTGs (offshore) and on LCOE.

Although the assumptions on CAPEX and OPEX in the model were based on literature studies they inherited uncertainties. The actual cost development in the future might differ from the assumed development utilized in the calculations, for instance if the pace of cost reductions changes in the future or if shortages of materials or components occur. As a result, LCOE might be lower or higher than calculated.

For a sensitivity calculation of all scenario variants, CAPEX were assumed to increase and decrease, respectively, by 10 % until 2050. All scenario variants were calculated under these assumptions. It was found that such lower CAPEX translated into a reduction of LCOE by 5.33 % in 2050. Higher CAPEX resulted in higher LCOE of the same range. For the variants of scenario 3 targeting at 2035, a smaller increase and decrease in LCOE (by 2.64 %), respectively, was detected because it was assumed that the full cost reduction or increase would be reached not before 2050.

The alteration of the underlying interest rate produced similar results. With an interest rate of 5 % and 7 %, respectively, instead of 6 % as previously presented, the annual cost were also reduced and increased, respectively. An interest rate of 5 % reduced the LCOE of onshore wind power by 5.45 % as the national mean while an interest rate of 7 % increased the LCOE of onshore wind power by 5.69 % as the national mean in the scenarios focusing on 2050. In the 2035 case the difference in LCOE was −5.52 % and 5.72 %, respectively.

- Scenario data:
  Variation of the installed capacity: impact on all results parameters (as shown) and on LCOE.

In summary the sensitivity analysis revealed that the model reacted sensitive towards specific input parameters. It can be concluded that all model results must be viewed against this backdrop and the assumptions made, which also applies to other models that contain similar sensitivities.

4 Conclusion, discussion and outlook

The focus of this study was set on the development of a computer model to simulate the future electricity production from wind power with a high spatial and temporal resolution and on its application for the showcase of Germany. With the model developed, wind power capacity pre-defined in installation scenarios can be allocated in an economically optimized way, year by year, within additionally defined framing conditions.

4.1 Summary of the dissertation

In the newly developed model, relevant and detailed technical, economic, meteorological and geographical data have been taken into account, accompanied by the options to model either national or federal state-specific developent trajectories of the installed wind power capacity. For the allocation of WTGs, individual square kilometers have been taken into consideration in every year of the selected scenario and the resulting power production in the target year can be generated in a high temporal resolution. The resulting calibrated values of the electricity production are reasonably realistic. Taking other variable renewable energies and the load into account allows to analyze consistent scenarios for selected target years.

The model developed has been designed as a tool that is flexible, powerful and reasonable as described in the following list.

- Flexible:
  All input parameters can relatively easily be modified and adjusted to individual research requirements. The variable input parameters can directly be adjusted through the front-end of the model, the fixed input data can be adjusted if necessary in the model database through the model's back-end. This flexibility allows to straightforwardly model different scenarios and scenario variants, for instance with different underlying wind years or different assumptions of the area availability for wind power installations.

- Powerful:
  The utilization of a MySQL database and coded model scripts allows to handle large datasets, which is necessary especially in order to conduct CPU-intensive simulations with a high temporal and high spatial resolution. MySQL and PHP have demonstrated their performance in the showcase calculations and the model can be operated on a cross-platform basis.

- Reasonable:
  Several loops of double-checking and improvements of the model code and the underlying data, accompanied by the calibration and adjustment of the model have guaranteed that model inputs, procedures and outputs can be regarded as sound.

All modeling results, however, must be regarded in the light of the assumptions made, especially with regard to the installed capacity in the scenarios, the detected geographical potential, assumed technical and economic parameters, the utilized wind year and the logic of the model, i.e. the economically optimized allocation of WTGs and its underlying assumptions.

In the model the sub-national level, i.e. the districts, the federal states and the transmission grid regions, are considered in the following ways:

- in the scenarios to be modeled:
  option to consider defined sub-national region-specific installation targets (in the showcase of Germany: installation targets of the federal states) as part of a national installation scenario,
- in additional modeling inputs:
  definition of additional limitations of the federal state areas and of the district areas, i.e. maximum area shares potentially available for wind power installations, and
- in modeling results:
  output and analysis of sub-national region-specific results.

4.2 Main findings

The scenarios analyzed revealed the impact specific variations of model input parameters can have on the allocation of wind power capacity, on its corresponding power production and on other model outputs. For the showcase of Germany different capacity development trajectories were calculated and analyzed and area restrictions for onshore wind power installations were altered, combined with the installed capacity of other variable renewable energies. Key conclusions, also driven by the logic of the model, are:

- Under the assumption of equal area restrictions, a greater capacity amount of allocated onshore wind power capacity resulted in lower mean EFLH of onshore wind power. This followed the logic of the capacity allocation procedure in the model: With a greater amount of allocated capacity more less favourable locations were utilized, hence EFLH were reduced.

- Tighter area restrictions for onshore wind power installations resulted in lower mean EFLH of onshore wind power. Again, this was caused by the logic of the model: If the area availability was comparably low, it was necessary to utilize more less favourable locations for the allocation of a given amount of wind power capacity.

- If the installed wind power capacity was smaller than the technical potential – with defined limitations of the federal state areas and the district areas –, WTGs might not have been allocated with the modeling approach to some of the districts. As detected in the scenarios 1 and 2, even with restrictive area limitations there were districts that were not utilized for the allocation of WTGs because the area in more favourable districts sufficed the space requirements of the WTGs to be allocated.

  This aspect can be taken into account in the spatial planning at federal state level, for instance. Depending on overall installation targets and on area limitations set, there might be no need to define priority areas for wind power installations in specific districts if the available area in other districts is already sufficient to install the envisaged capacity.

  The model can provide information about the total installed capacity in the individual districts in all scenario years as well as information about the exact locations, i.e. square kilometers affected, of WTGs within the districts. This however would require intermediate model results to be further processed.

- In turn this means that specific amounts of wind power capacity could only be allocated if minimum shares of the federal state areas and the district areas were potentially available for wind power installations. Tight area limitations might have prevented to install the full capacity as defined in a scenrio. This, again, depended on the amount of capacity to be installed, on the area limitations defined and on the specific space requirements of WTGs.

  This aspect could also be taken into account in the spatial planning process. If priority areas for wind power installations are to be defined, the total priority area for wind power in a federal state needs to be of a specific minimum size in order to be able to install the full envisaged wind power capacity.

- According to the logic of the model, the more area was potentially available for wind power installations, the more concentrated the installed capacity was allocated to the locations, i.e. districts, with the most favourable wind speed conditions. Vice versa a tight area limitation resulted in a greater dispersion of the installed capacity, i.e. more districts were affected by installations. This aspect could also be found in the resulting power output, i.e. power production from WTGs could be more concentrated or dispersed, depending on the area limitations set.

- Following the logic of the model, limitations of the federal state areas and of the district areas could affect each other and thus could have an effect on modeling results.

  A change of the area availability in the federal states and in the districts tended to result in a shift of the installed capacity to more – or less – favourable locations, thus regional differences in the power output occurred due to different area limitations in the federal states and in the districts. As shown in the scenario variants modeled, a shift of wind power installations to more favourable locations due to a higher area availability strongly raised the power production there, whereas the power output in comparably less favourable regions was just slightly reduced.

- In comparison to the literature sources the scenarios 1 and 2 were based on, the calculations with the new model resulted in a lower power production from wind power and higher LCOE. This mismatch can be explained with differences in the underlying data and in the modeling approach.

From the simulations and modeling results of the scenarios analyzed it can be furthermore concluded:

- The technical potential of onshore wind power in Germany ranges between 401 GW and 701 GW if all non-excluded areas are taken into account, depending on the space requirements of WTGs. A possible area limitation in the federal states and in the districts substantially reduces the technical potential. For instance, the technical potential has been found to range from 43 GW to 181 GW if area limitations were set between 2 % and 5 % of the federal state and district areas and also depending on the spacing of WTGs.

- The upper limit of the expected power production by onshore wind power was detected to be 1143 TWh/a, based on the geographical potential, the specific space requirements of WTGs, the power curve applied and the underlying wind speed conditions as in the year 2010. A restriction of the area potentially available for wind power installations reduces the amount of electricity.

- In the scenarios analyzed and based on wind speed conditions as in the year 2010, 82.5 TWh/a can be produced with a comparably small amount of installed onshore wind power capacity in 2050 (39.5 GW in scenario 1, unrestricted area availability). 233.4 TWh/a can be generated with a comparably large amount of installed capacity (115.7 GW in scenario 4, unrestricted area availability) by onshore wind power in Germany in 2050, no further area restrictions assumed.

- The comparison of the scenario variants modeled without further area restrictions with the variants in which further area restrictions had been considered show a substantial impact of such restrictions on the results. The deviation from the techno-economic optimum depends on the overall installed wind power capacity, on the allocation mode, on the spacing of WTGs and on the area restrictions defined and it ranged between 4.5 % and 30.1 % in the scenarios tested.

- With regard to the installation targets in scenario 3, representing the expected development of the installed wind power capacity as formulated in the NEP, it can be concluded:
  - The federal states' installation targets as described in the NEP do not fully correspond to an economically optimized nationwide allocation of the same total amount of onshore wind power capacity in 2035. In some of the federal states the envisaged installed wind power capacity until 2035 is smaller than a nationwide economically optimized allocation would suggest (Bavaria, Hesse, Saarland, Saxony). On the other hand, in some of the federal states the envisaged installed wind power capacity until 2035 is larger than a nationwide economically optimized allocation of the same overall amount of capacity would result in (Brandenburg, Saxony-Anhalt, Schleswig-Holstein).
  - The state-by-state capacity allocation resulted in a lower national maximum power surplus in 2035 than a nationwide allocation of the same total capacity amount.
  - If installation targets of the individual federal states are taken into account, the power production is lower than in the case of a nationwide allocation of the same total capacity and the LCOE of onshore wind power is also increased.
  - If a spacing of WTGs as presented in the calculations is assumed, the envisaged wind power capacity of more than 10 GW in the federal state of Schleswig-Holstein cannot be fully installed under the assumptions made. In order to be able to install this envisaged wind power capacity in Schleswig-

Holstein until 2035 it will be necessary to increase area limitations, i.e. to account for more priority areas for wind power installations, unless the spacing of WTGs is narrower than assumed in the model calculations or the buffers around excluded areas are narrowed.
If the specific space requirements of WTGs is reduced, the amount of allocatable capacity can be increased. By doing so, installation targets can be reached.

In the respective target years minimum and maximum production from onshore wind power were detected to range between 0.4 % and 81.6 % of the installed capacity in all the scenarios and scenario variants. This shows that there were no moments during the respective target years without power production from onshore wind power installations and no moments in which the full onshore wind power capacity was in operation.

In comparison to a nationwide allocation, a capacity allocation under consideration of federal state-specific installation targets reduced the number of hours in which the demand could be covered by VRE in the transmission grid regions (cf. sections 3.2.4 and 3.3). On the other hand maximum power surpluses and shortages were lower and the LCOE of onshore wind power was higher in the case of a state-by-state capacity allocation than in the case of a nationwide capacity allocation.

The LCOE of onshore wind power and of all VRE combined heavily depends on the scenario analyzed and the area limitations for onshore wind power defined in the scenario variants. For instance, the LCOE of onshore wind power in the case of a state-by-state allocation in scenario 4 (unrestricted area availability) was 11 % higher than in the respective case of a nationwide allocation of the same capacity amount.

The lowest LCOE of wind power in 2050 (5.23 Ct./kWh) was reached in the theoretical case of scenario 1 without further area restrictions for the allocation of WTGs in which a comparably small amount of wind power capacity was allocated to the most farourable locations. By tendency, the more capacity was allocated and the tighter the area restrictions were set, the higher is the LCOE of wind power due to decreasing marginal specific production.

The analysis of the residual load in the respective target years shows that in the scenarios 1 and 2 the transmission capacity to neighbouring transmission grid regions and to neighbouring countries basically sufficed the transmission requirements in order to cope with power surpluses and shortages in the transmission grid regions. In scenario 3, even under the assumption that the transmission capacity to neighbouring regions including the expected transmission grid extension until 2035 according to the NEP planning would be realized, it however would not be sufficient in transmission grid region 1 (Schleswig-Holstein) in all moments during the year. This is mainly caused by the vast amounts of offshore wind power landed in that region in the scenario. An increasing area availability for wind power installations, thus an increasing concentration of wind power capacity was found to exacerbate that situation, i.e. the maximum power surplus would increase. Within the scope of this study, however, necessary flexibility options for such a case (e.g. transmission capacity, storage, thermal power plants, demand side management and other) have not been analyzed in further detail and should be subject of further studies. In Deutsche Umwelthilfe (DUH) (2011, pp. 24), for instance, such options have been analyzed and recommendations have been made.

The more concentrated the onshore wind power capacity was, the greater was the amount of national gross electricity surpluses and of the power surplus during the year. On the other hand the more area was potentially available, the annual amount of shortage electricity was reduced. The maximum shortage power, however, was hardly affected by a variation of the area limitations for onshore wind power installations.

The tighter the area limitations were set, thus the more distributed the onshore wind power capacity was, the lower was the number of hours the national load could be directly covered by power generation from VRE during the year (e.g. scenario 4: load coverage during 4158 h/a with an area limitation of 5 % and during 4232 h/a with an area limitation of 8 %.)

The scenarios show that an expansion of the use of VRE as presented in the scenarios can substantially contribute to supply to the national electricity demand. The share of VRE depends on the installed VRE capacity, the individual shares of the different VRE technologies, i.e. the technology mix, and the demand level in the year of analysis. It was found to range from approx. 50 % in 2035 in scenario 3 to approx. 60 – 100 % in 2050 in the scenarios 1, 2 and 4.

As onshore wind power was only part of the technology mix, the effect the different allocation modes of onshore wind power had on the total power output could only partly be found in the LCOE of all VRE. In principle, large amounts of offshore wind power could reduce the overall LCOE but additional grid enhancements might be required. High shares of PV in the system resulted in comparably high LCOE of all VRE combined (cf. section 3.2.2 and 3.3).

The economically optimized allocation of WTGs is one option to allocate wind power capacity. Other types of an allocation of wind power capacity are thinkable and also applied in other studies, based on educated guesses, present installed capacity and other parameters (cf. section 1.4). The economically optimized case, however, represents the least-cost option from an investor's point of view. Ceteris paribus any other allocation will necessarily result in a lower power production and in higher LCOE of wind power. Other influencing parameters than economic factors only – such as public perception, land use planning, local value added and others that have not been included in the model – might also affect the allocation of WTGs in the future.

4.3 Technology options

As shown, several technical input parameters to the model strongly affect modeling results. With given area restrictions, the spacing of WTGs – in the model defined as a function of their rotor diameters – might lead to the fact that only a part of the full wind power capacity as defined in the scenario can be installed. A narrower spacing of WTGs increases the amount of installable wind power capacity. Installation targets thus could be achievable, yet would need to make sense from a technical and economical point of view as potential performance reductions due to wake effects can result (cf. Sanderse (2009)).

The sensitivity analysis (section 3.4) shows that the underlying power curve of the WTGs in the model plays a crucial role for the power output in the year of analysis. The utilization of a weakwind turbine power curve can substantially increase the total power output of the model, which has already been taken into account in reality. In the latest version of the model, however, the power curve represents an average WTG.

LCOE of wind power could be further reduced if it was possible to further decrease CAPEX and OPEX. Although an expected future cost decrease has been taken into account in the cost figures in the model, uncertainties of the future development exist and future cost might indeed be higher or lower if markets develop differently from the expectations.

In case locations with the expectedly most favourable wind speed conditions are to be prioritized in the expansion of the installed capacity, for instance due to political decision, the transmission grid might require further enhancements and additional transmission capacity between transmission grid regions and cross-border. This aspect, however, is affected by state-specific and national installation targets, area restrictions, the spacing of WTGs and the existing and expected transmission grid infrastructure.

Besides enhancements of the transmission grid, other flexibility options in the system have been and will be potentially and actually available, such as dispatchable power plants, load management measures, storage options (cf. e.g. Grimm (2007)), power-to-gas (cf. Sterner (2009)), power-to-heat and power-to-fuel. Such flexibility options – all having their specific technical potentials, cost and effects on the entire energy system – could allow to cut peaks of power surpluses or shortages that might occur in the transmission grid regions. An integrated modeling approach with such flexibility options, also integrating the heat and the transportation sector, would give answers to their necessity, their mode of operation and their cost.

4.4 Further research direction

The new model has been successfully tested and its approach can act as an input to other energy models. It can also act as a starting point for further research activity which could focus on the following aspects:

- Integration with other models:
  The model can be integrated with other energy models such as the renpass framework at EUF (cf. section 1.4) and provide temporally and spatially highly resolved production data from wind power in order to test research questions e.g. about the transmission grid or the utilization of dispatchable units. In order to do so, underlying data however would need to be adjusted. As renpass has been based on an open data approach, i.e. on data freely available and accessible, the inputs to the new model would need to fulfill this condition as well, which has not been the case so far. For instance, the wind speed data from DWD utilized in the new model are not entirely open source data and would have to be replaced by open data from other sources.
  In its latest version, the new model does not provide information about the substitution of fossil fuels in the energy system by the renewable energy sources installed in the system, nor about its rapidity. This would require additional detailed information about other system components such as coal and gas-fired power plants, their operational behaviour and their lifetime. Such aspects can be found in other energy system models the new model could deliver input to.

- Validity and accuracy of the model:
  Several of the fixed model input parameters could be further specified and improved. The consideration of different wind speed zones in the model, for instance, could improve its validity by also taking different power curves, sizes and cost of WTGs for different wind speed conditions into account. Such a process of further model development has been started but this aspect has not been included in this work.

- Modeling with additional technical and economic parameters:
  As presented, LCOE reveals information about the specific cost of a technology

from an investor's point of view. Due to the increasing variability of the residual load with increasing shares of VRE in the power system, additional cost in the system will however also occur, namely balancing cost and profile cost (cf. Intergovernmental Panel on Climate Change (IPCC) (2011, pp. 568) and Ueckerdt et al. (2013)). Such system cost could be estimated and supplemented to the model. Their implementation, however, would substantially increase the model's complexity.
Moreover, avoided social cost due to climate change or avoided cost of local air pollution could also be taken into account in the model. The consideration of the full picture of cost and avoided cost would improve the quality of model outcomes.

- Modeling of other scenarios and scenario variants:
  As presented, a wide range of potential development trajectories of wind power, i.e. scenarios, has been calculated with the new model. For further calculations and analyses the focus could be set differently. For instance, other pre-defined installation targets in the federal states could be analyzed, e.g. scenario variants with a higher amount of wind power installation in the southern federal states in Germany. This can be helpful for discussions about the necessity of additional transmission links between the North and the South of Germany.

  Moreover, a different development of WTG sizes could be applied in further calculations. As presented in section 2.3.3.2, the underlying future size development in the model bears uncertainties that could be subject of further analyses and studies.

- Application to other regions and countries:
  So far the developed model has been applied for simulations of Germany's future power system only. At the beginning of the development of the model the idea was to develop a flexible tool that can be applied to virtually any country. With the newly developed model, this is possible and it requires country-specific input data as well as slight adjustments in the model scripts and database tables. For instance, the regional split of the country of analysis needs to be considered appropriately and modified in the model, country-specific data in the required resolution and format – for instance wind speed data and the installed capacity – are essential, recorded wind speed time series need to be available and other parameters need to be adjusted.

- Flexibility of the model:
  In its latest version, parts of the model have been flexible and others can be

regarded as to be rather static. For instance, the underlying geographical data needed to be pre-processed and stored in the model database in order to act as a fixed input to the model calculations. In order to increase the model's flexibility, it could be connected to a geographical database such as the PostgreSQL database system instead, which would allow adjustments of geographical data directly in the model. Moreover, the utilization of a different programming language such as Python could decrease computing times.

- Integration with other parameters relevant for the allocation of WTGs:
  Linking further parameters of land use, public perception or nature conservation with the presented approach of an economically optimized capacity allocation and the option to define upper limits of the area potentially available for wind power installations (in the showcase of Germany: in the federal states and in the districts) could improve the significance of model results.

- Other data sources:
  As shown in the sensitivity analysis in section 3.4, several model input parameters and assumptions can substantially affect model outcomes. Besides the parameters already tested, data from other sources could be included in the model in order to analyze their impact on modeling results. For instance, instead of the wind speed data from DWD other data sources such as the MERRA-2 data from the National Aeronautics and Space Administration (NASA) could act as another sound data source. Wind speed data from that source are freely available in a high spatial and hourly resolution for all years since 1980 (cf. National Aeronautics and Space Administration (NASA). Global Modeling and Assimilation Office (2016)).

- Timeframe:
  The model might also be utilized for the calculation and analysis of scenarios that go beyond 2050. In order to do so, model scripts and database tables however need to be adjusted accordingly.

All results need to be regarded as outputs from the model in its latest version. A continuous evaluation and improvement of the model will be necessary to further improve its calculation results.

4.5 Contributions

The modeling approach and the scenarios modeled for the showcase of Germany contribute to scientific and practical work in several dimensions.

4.5.1 Knowledge and practice of modeling

Some of the new model's features allow to model and analyze variations of key settings concerning wind power in future power systems. This includes installation scenarios at the national and sub-national level, area restrictions and the spacing of WTGs.

With the new model it has been shown that and how area limitations for wind power installations as well as the consideration of an age structure of WTGs in a specific target year can be included in modeling projects. The approach to consider sub-national and national installation targets allows to model and analyze their impact on power production, on the residual load, on LCOE and on other output parameters. These aspects can also be taken into account in other research work and models.

The model has shown that specific parameters and assumptions can have a substantial impact on modeling results. For instance, besides the area exclusion due to other land uses and buffering areas the limitation of the available area can affect not only the allocation of WTGs but accordingly the power output from wind power, thus its LCOE. Model results therefore need to be viewed from that perspective, meaning that an assessment of such input parameters should be conducted before evaluating model outputs, which also applies to results from other models.

4.5.2 Germany's energy and electricity policy

Model results have shown that and how an optimized national allocation and a state-by-state allocation of a pre-defined amount of wind power capacity can differ. As presented for the showcase of Germany, the different allocation modes resulted in differences not only in the locations of the installed wind power capacity but also in differences in the corresponding power production, which again had an impact on the residual load in the individual transmission grid regions.

The results have shown that some German federal states have set their wind power installation targets higher than a nationwide allocation of the same total national capacity amount would suggest (cf. sections 3.2.3, 3.2.4 and 3.3). On the other hand some of Germany's federal states showed the opposite, i.e. their installation targets were below what a nationwide optimized allocation of the same total nationwide installed capacity would suggest.

Model results have also shown that state-specific installation targets might not be reached with the assumed spacing of WTGs. It can be concluded that such targets either might be set too high or, in turn, a narrower spacing of WTGs would be required in order to make the targets reachable.

If it was possible to politically agree that each federal state's share in the total national installation would be based on the same conditions of area utilization, however with different wind speed conditions, this would result in a fair share of the installed total capacity in all federal states. Such a scenario would require the same framing conditions in all federal states, for instance the same minimum distances to specific land use types and the same additional area restrictions, and it would allow to be comparably easily communicated to parties potentially negatively affected by the installations. It would however result in a lower power output compared to a system in which the locations with the presumably most favourable wind speed conditions would be prioritized for the installation of WTGs. If a federal state would like to increase or decrease its installation target in such a scenario, i.e. its share in the envisaged total national wind power capacity, this should be conducted against the background of a nationwide optimized allocation and communicated with the other federal states.

Eventually it might be reasonable to make use of more favourable locations in selected federal states in order to achieve a higher national power output and therefore decrease LCOE. Such a prioritization of specific regions would need to be carried out also considering questions of public acceptance which could be ensured or increased by participatory profit-sharing schemes. Moreover, technical questions about the necessity of extensions in the transmission grid infrastructure, which again also raises questions of public perception, need to be taken into account.

A prioritization of regions and locations with the presumably most favourable wind speed conditions, however, might also result in additional power surpluses during moments of the year in such regions that need to be handled with additional flexibility options which again could increase system cost. A system solely based on the expected LCOE of wind power as calculated with the new model would not necessarily be the cheapest option with regard to the full cost. This however was not analyzed in detail in this thesis and should be subject of further research.

A similar conclusion can be drawn for PV which however was not focused on in this work. State-specific installation targets should be aligned or compared with a nationwide optimized capacity allocation in order to detect deviations from it.

With regard to the potential, wind power alone could cover Germany's annual power demand, depending on area restrictions set, the demand level and other parameters. Such a scenario however is a theoretic option as it would require the utilization of vast amounts of area for wind power installations. Moreover, substantial flexibility options would be required in such a system which again would imply high system cost. A power system based on various renewable energy sources could reduce peaks in the residual load and moreover it would be less susceptible to disruption.

With scenario 4 a future system setting has been presented in which approximately 100 % of Germany's power demand in 2050 in the annual balance can be generated, a comparably low demand level assumed. As described, this result has been also dependent on the area available for wind power installations, thus on political decision, and on the spacing of WTGs. Moreover such a system would require a substantial capacity of flexibility options due to the fluctuations of the residual load. Wind power, being a low-cost option of power generation, could deliver a substantial part in the total power production, however also causing high power surpluses and shortages.

All VRE should therefore not be analyzed in isolation but in an integrated approach. Their combined electricity generation directly affects the residual load and the share of renewable energy sources in the total national power production.

Summing up it can be concluded that in order to achieve the long-term goals set (cf. section 1) it will be useful to further increase the installed capacity of wind power in Germany. As shown in scenario 4, it might become difficult to reach a 100 % VRE supply with the capacity installed in that scenario unless a low demand level can be reached. In turn this means that framing conditions must ensure that such a development can be achieved. Ambitious installation targets alone might not be sufficient but political decision, for instance on the continued development of the EEG law and on other framing conditions (e.g. cross-border collaboration as claimed in Smart Energy for Europe Platform (SEFEP) (2013)), needs to support the envisaged development. Moreover such framing conditions could give signal to the wind energy industry to prepare appropriate production facilities and educate technology experts as necessary.

4.5.3 Model application beyond Germany

The model and the scenarios modeled have shown that wind power can substantially contribute to the national power supply of Germany. Even with a tight area limitation for wind power installations huge amounts of energy from WTGs can be produced. In many energy systems aiming at 100 % RES (cf. Hohmeyer & Bohm (2014)) it will be necessary to substantially increase the installed wind power capacity.

In the calculations and analyses presented in this thesis future developments for the showcase of Germany have been taken into account. As presented, the model can be applied for other countries as well. This can be of interest in particular in countries and regions in which the shares of RES still play a minor role or in countries that aim at reaching a 100 % power supply from RES in the future.

In Morocco, for instance, ambitious national targets have been defined with regard to the installed RES capacity in 2030 (cf. Schinke et al. (2016)) but the locations of additional wind power installations, also beyond 2030, have not yet been identified or defined. As in the showcase presented, with the new model the allocation of future wind power capacity in Morocco or also in other countries can be simulated, taking a regional sub-division of the total wind power capacity into account. In the case of Morocco, for instance, it will be crucial to know what it means to include or not include the region of the Western Sahara in considerations about wind power installations in national energy scenarios. That region has a high wind power potential (cf. National Aeronautics and Space Administration (NASA). Global Modeling and Assimilation Office (2016)) but it has also been subject of political and military dispute. The new model can demonstrate the impact different settings of a regionalization of the installed wind power capacity can have on the overall power system, e.g. the impact of substantial amounts of wind power capacity installed in the region of the Western Sahara in the South of the country or, in contrast, substantial amounts of wind power capacity installed in the Atlas Mountains in the North of the country instead. On the other hand, the consideration of additional area restrictions might still result in a substantial potential of wind power. A more evenly distributed wind power capacity might avoid conflicts with parties potentially affected and it could also reduce the necessity of additional flexibility options. Such analyses can provide information about potential transmission requirements, storage requirements and cost.

4.6 Conclusion and Outlook

In this thesis, a powerful model for the allocation of wind power capacity and the consequent electricity production has been developed and presented. The model's main focus was put on the supply side, in particular wind power, but it also incorporates other fluctuating renewable energy sources and the load. As shown, the model has been applied for the showcase of Germany but it is also possible to apply it to any other country. The model can generate inputs to other energy system models and allows key input parameters to be varied, such as national or sub-national installation targets, area limitations and other.

The modeling has shown that area limitations for wind power use at the federal state level and at the district level can have a strong impact on the power production and on LCOE. That impact also depends on the level of wind power penetration in the system. It therefore makes sense to include such area restrictions also in other modeling activities.

The higher the level of public acceptance towards wind power installations is, the higher is the likelihood to account for sufficiently large enough areas for high numbers of WTGs. This is not only helpful to achieve a power supply fully based on renewable energy sources in the future but also to keep LCOE of wind power and of all variable renewable energies low.

The potential of wind power is sufficient to cover large shares of Germany's electricity demand, however this would be accompanied by the occupation of large areas for wind power installations. The installed capacity of onshore and offshore wind power, PV and run-of-the-river hydro power as presented in scenario 4 is capable to generate approx. 100 % of Germany's power demand in 2050 if a comparably low demand level can be reached.

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Appendix

A Figures

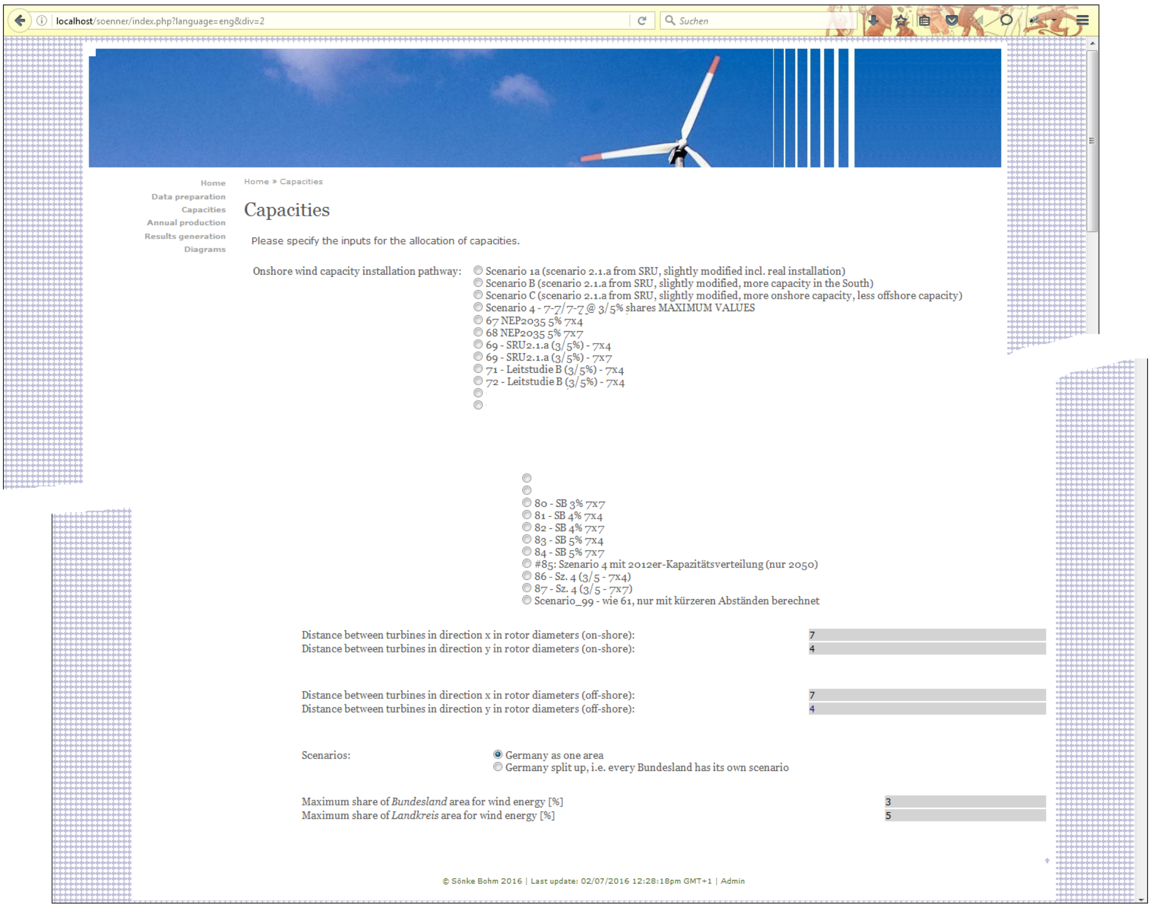

Figure A1: Screenshot of the model's front-end (excerpt from the input page)

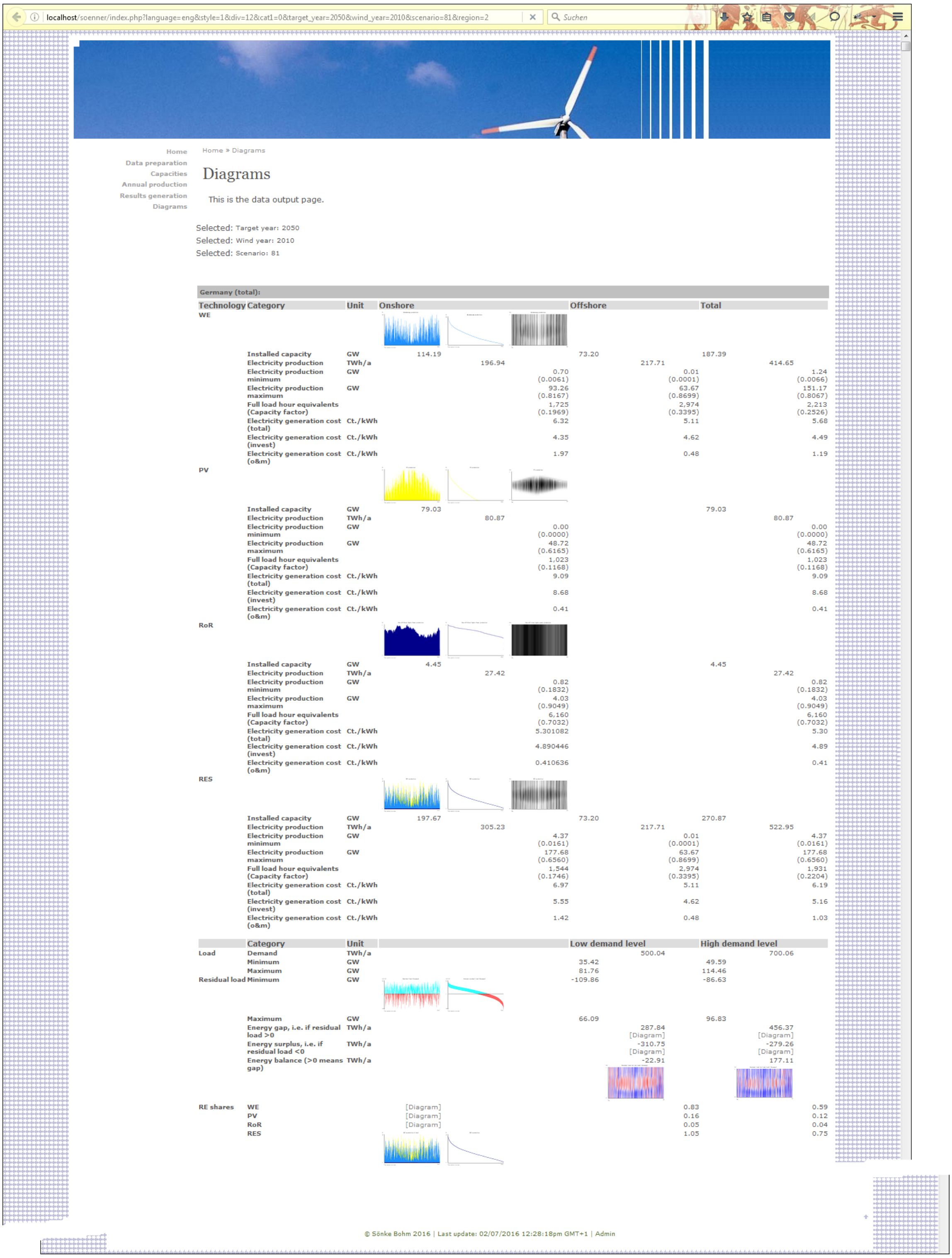

Figure A2: Screenshot of the model's front-end (excerpt from the output page)

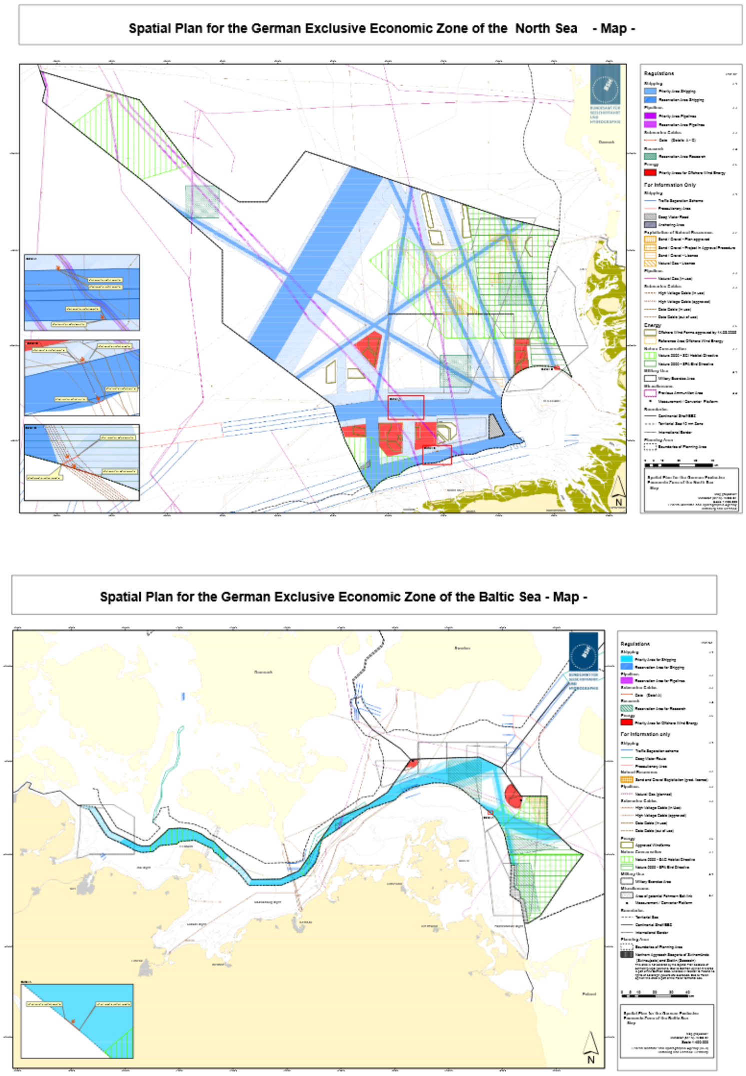

Figure A3: Spatial plans for the German EEZ in the North Sea and in the Baltic Sea

Source: Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2014)

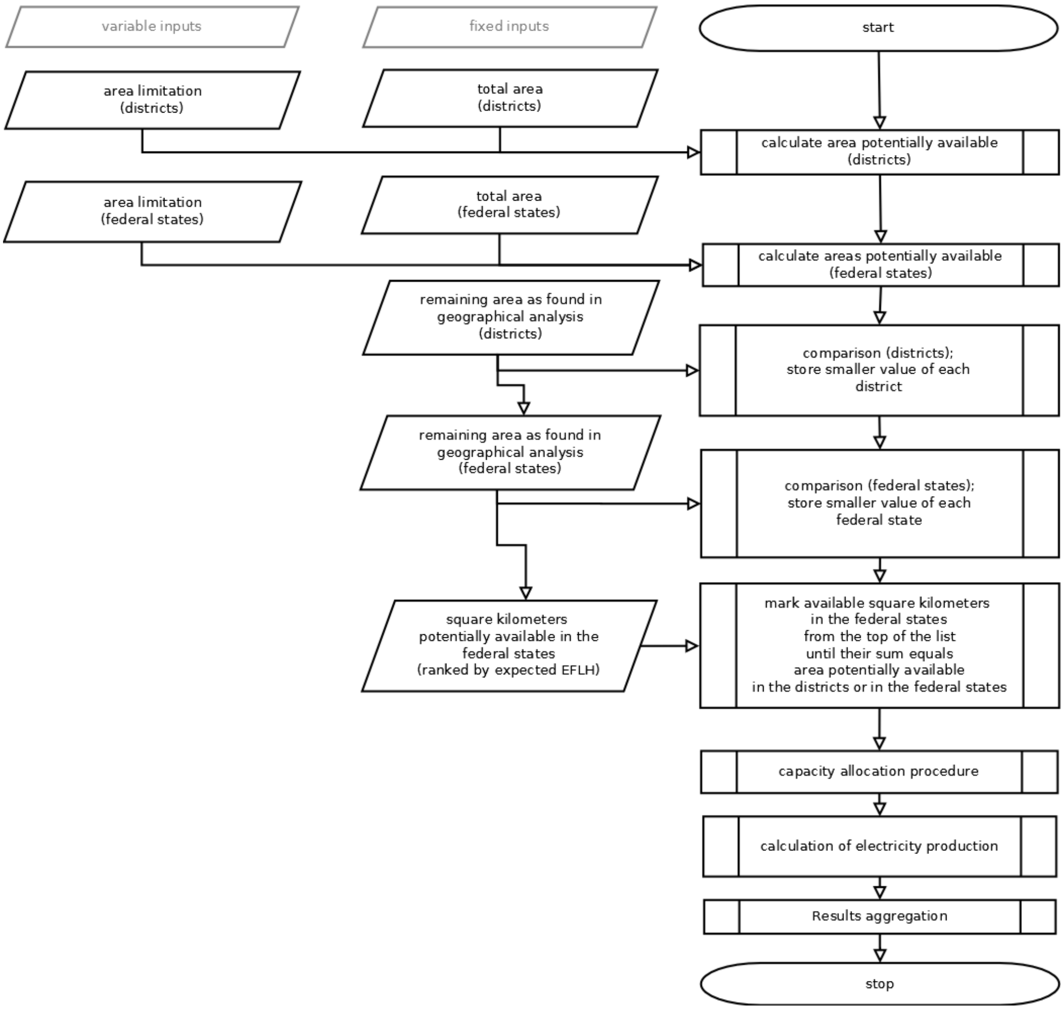

Figure A4: Procedure of capacity allocation (onshore wind power, pt. 1)

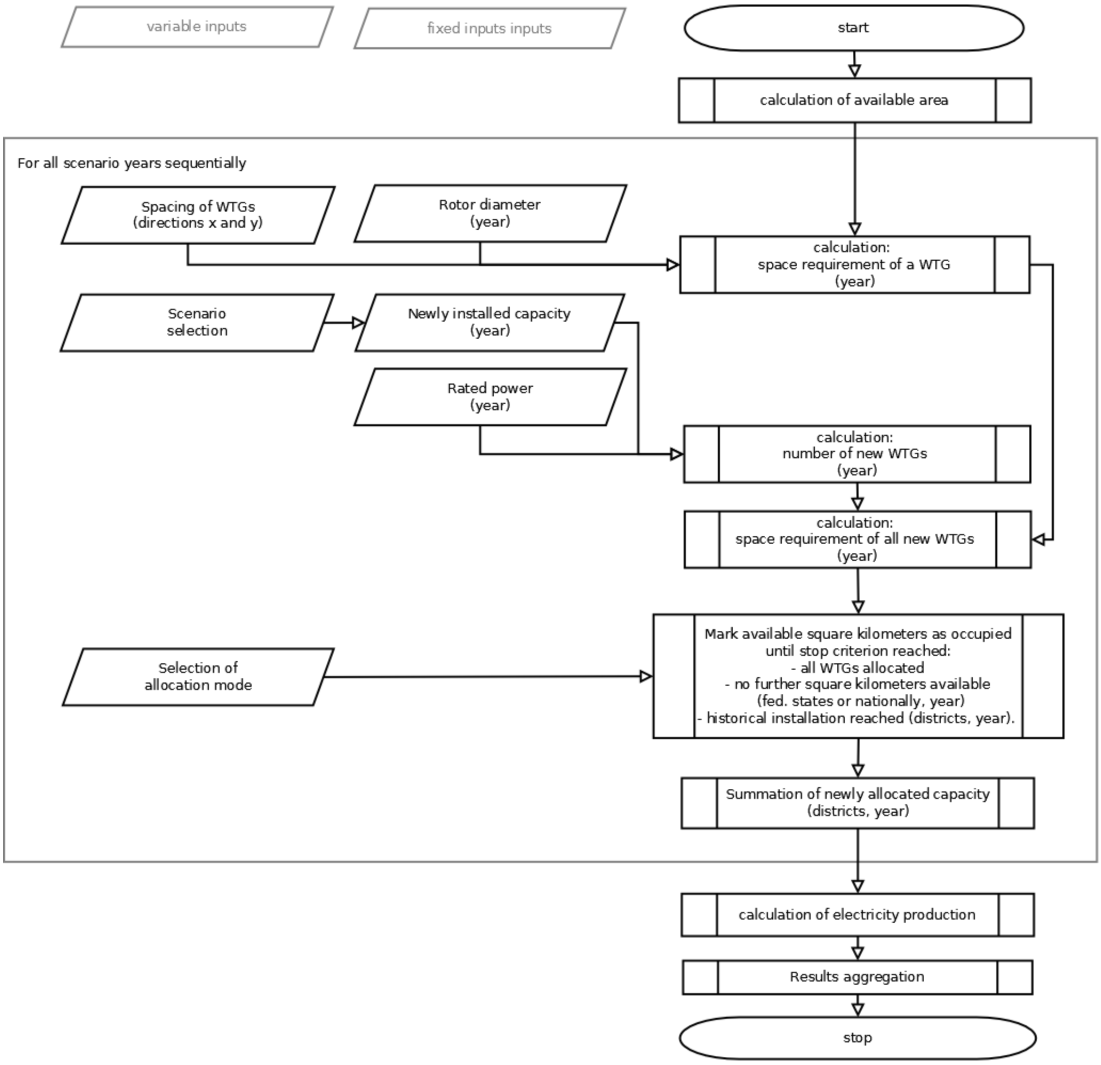

Figure A5: Procedure of capacity allocation (onshore wind power, pt. 2)

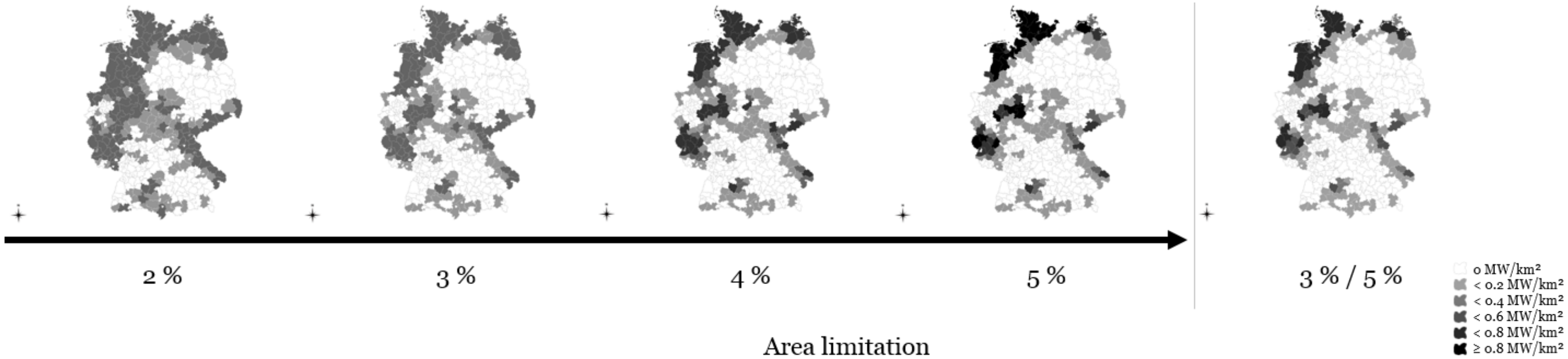

Figure A6: Scenario 1: Installed wind power capacity by districts (restricted area availability, 2050)

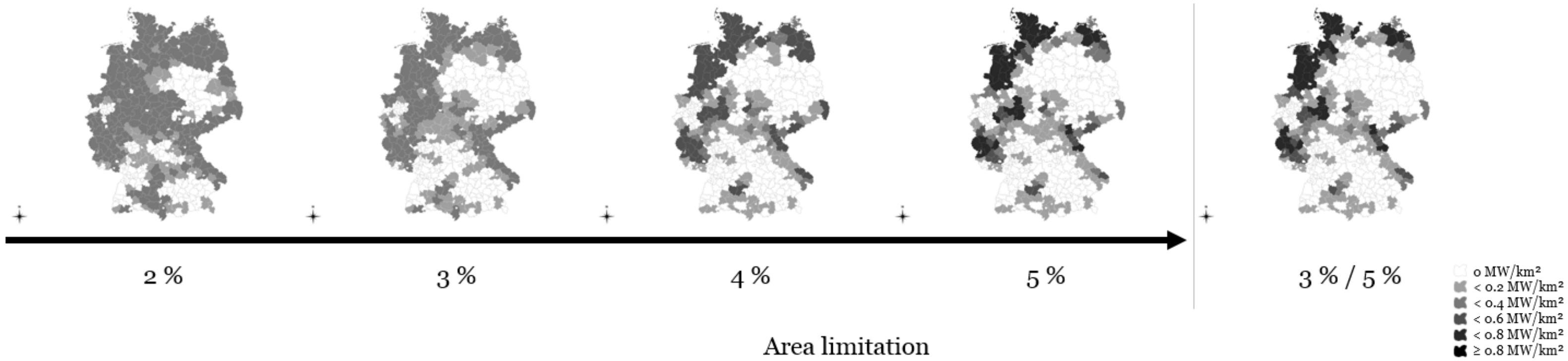

Figure A7: Scenario 2: Installed wind power capacity by districts (restricted area availability, 2050)

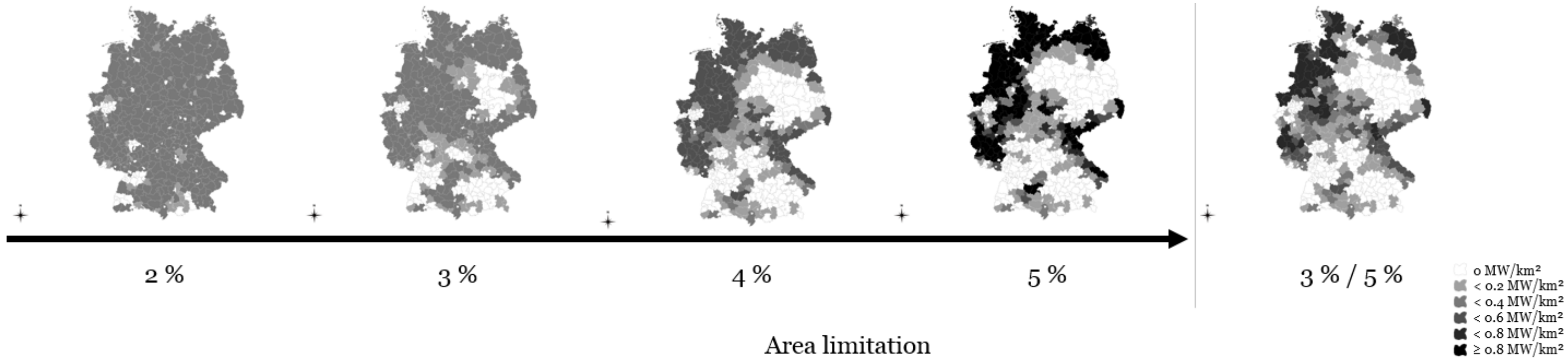

Figure A8: Scenario 3: Installed wind power capacity by districts (restricted area availability, 2035, nationwide allocation)

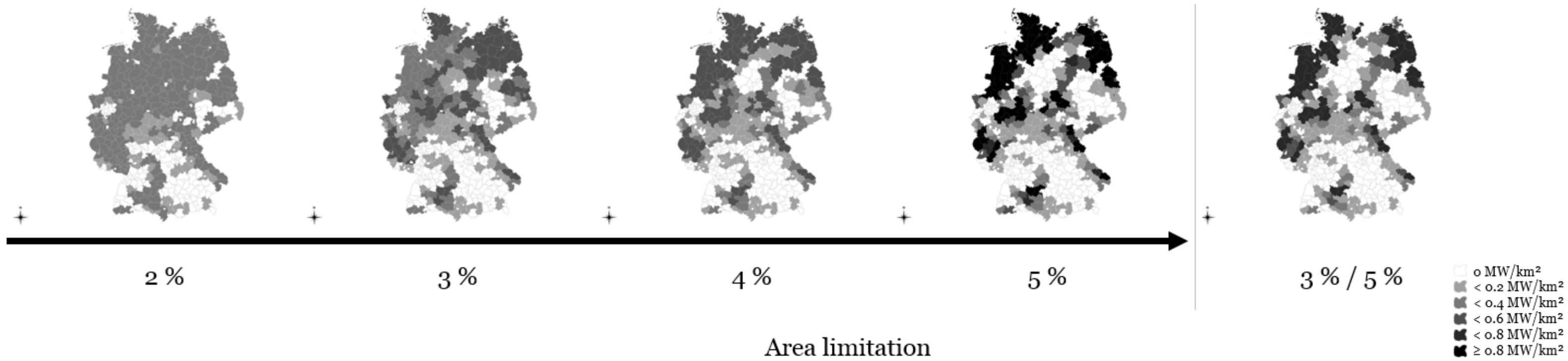

Figure A9: Scenario 3: Installed wind power capacity by districts (restricted area availability, 2035, state-by-state allocation)

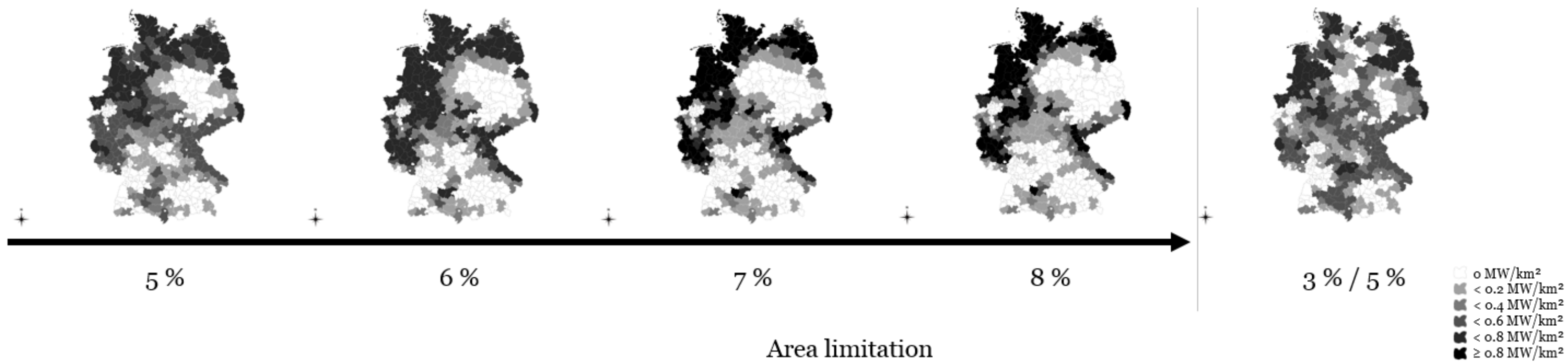

Figure A10: Scenario 4: Installed wind power capacity by districts (restricted area availability, 2050, nationwide allocation)

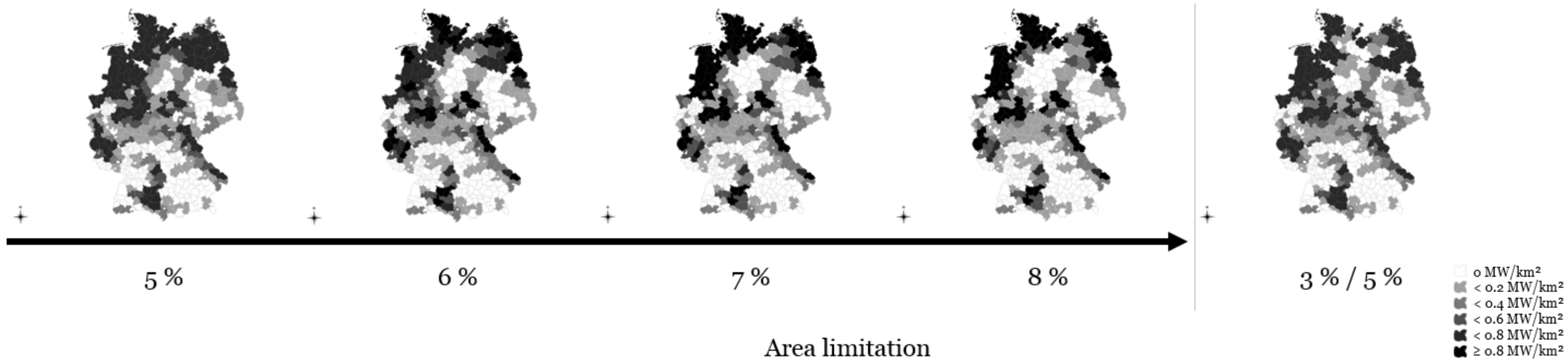

Figure A11: Scenario 4: Installed wind power capacity by districts (restricted area availability, 2050, state-by-state allocation)

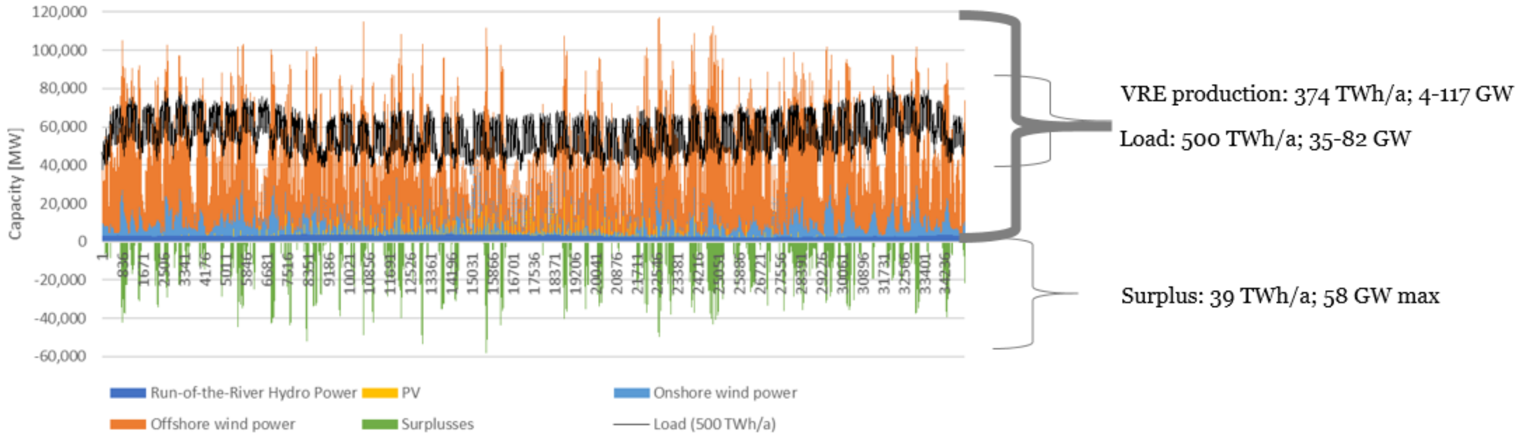

Figure A12: Scenario 1: Electricity production from VRE
(2050, restricted area availability: 2 %)

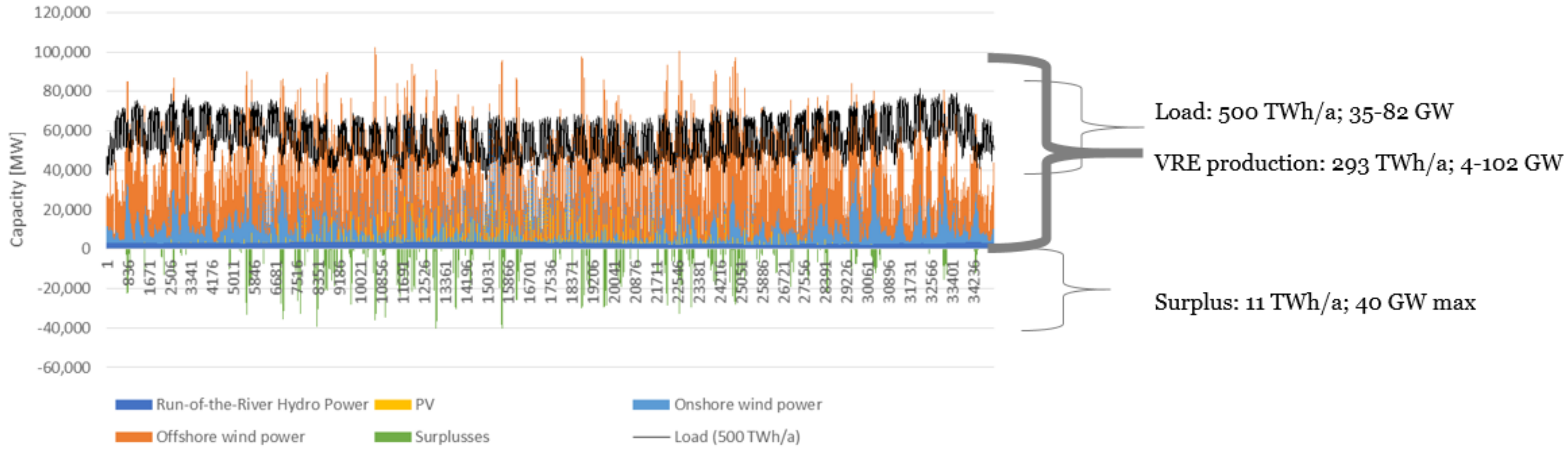

Figure A13: Scenario 2: Electricity production from VRE
(2050, restricted area availability: 2 %)

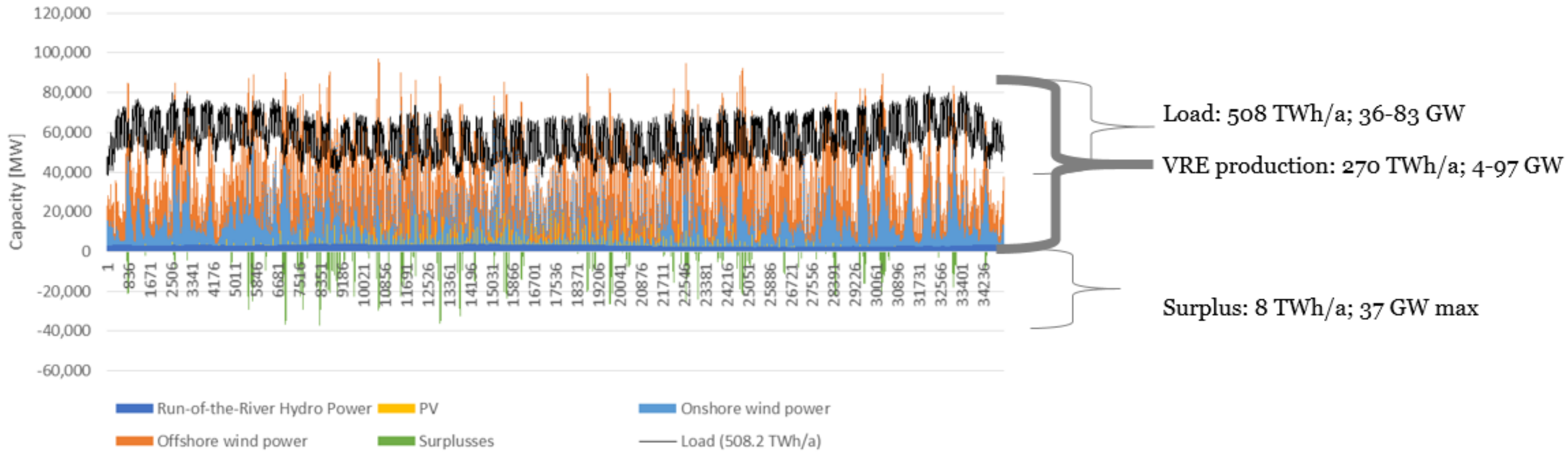

Figure A14: Scenario 3: Electricity production from VRE
(2035, nationwide allocation, restricted area availability: 3 %)

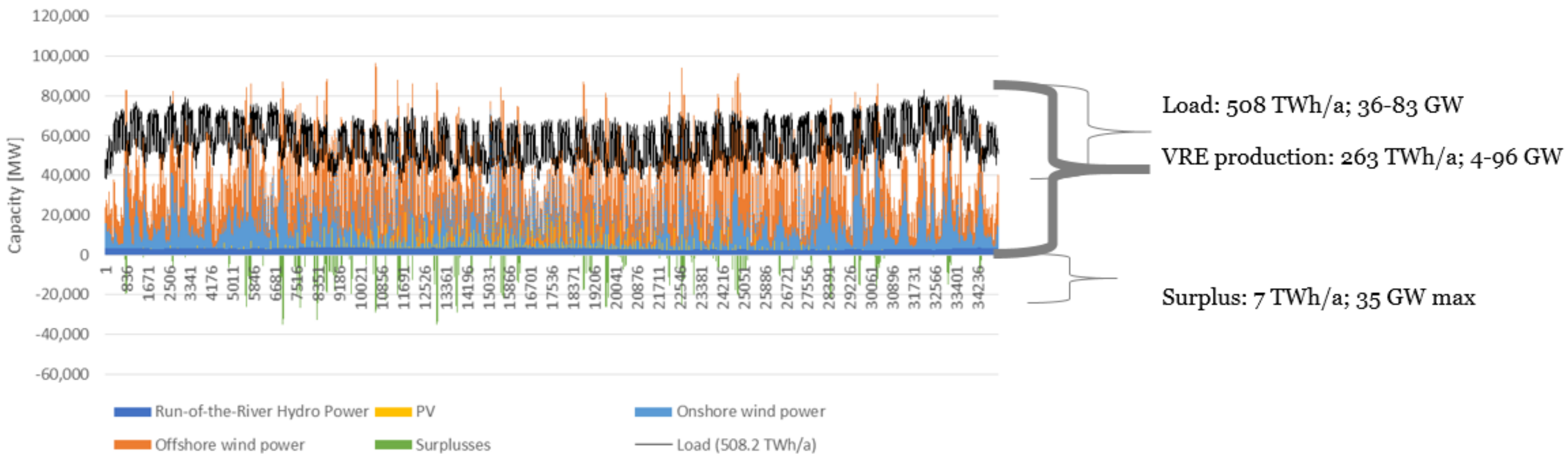

Figure A15: Scenario 3: Electricity production from VRE
(2035, state-by-state allocation, restricted area availability: 3 %)

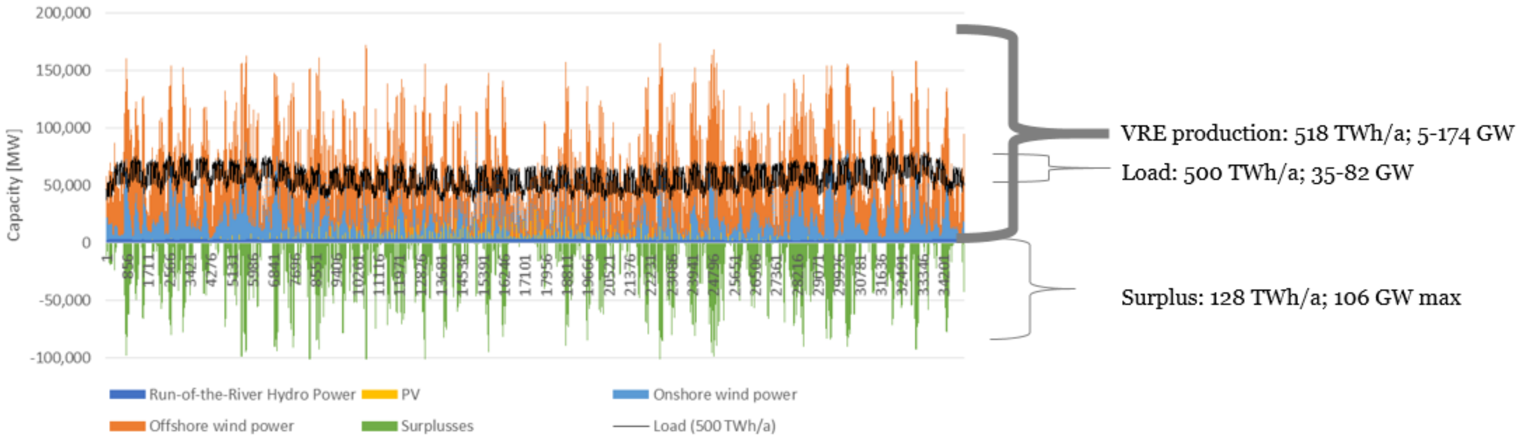

Figure A16: Scenario 4: Electricity production from VRE
(2050, nationwide allocation, restricted area availability: 5 %)

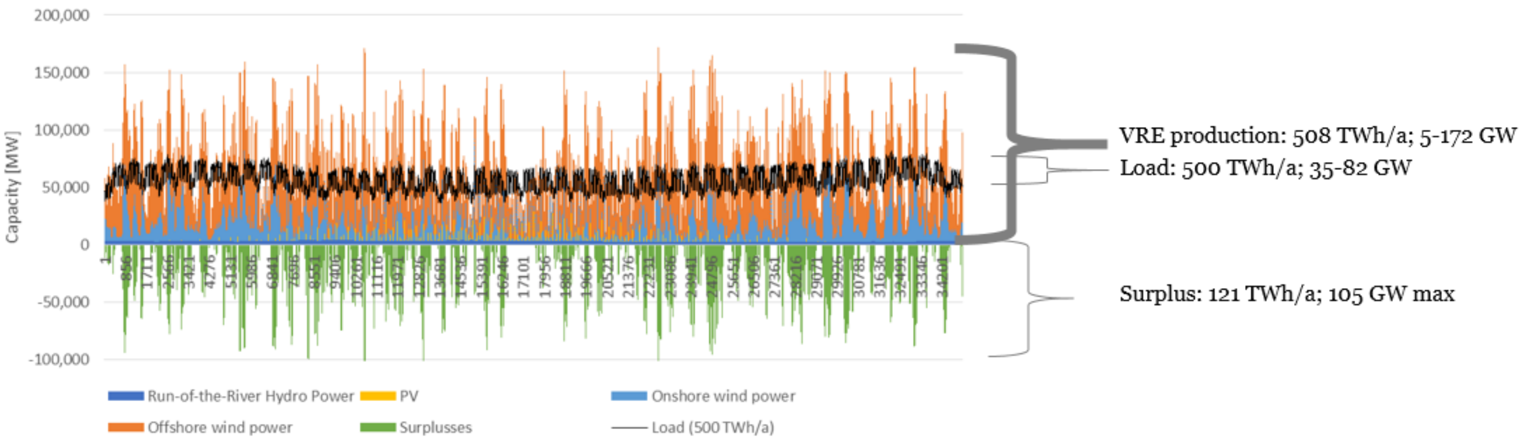

Figure A17: Scenario 4: Electricity production from VRE
(2050, state-by-state allocation, restricted area availability: 5 %)

B Tables

Table B1: Wind turbines incorporated in the model

Type	Rated capacity [MW]
Onshore:	
Enercon E33	0.33
Enercon E44	0.90
Enercon E48	0.80
Enercon E53	0.80
Enercon E70	2.30
Enercon E82	2.00
Enercon E82	2.30
Enercon E82	3.00
Enercon E101	3.00
Enercon E126	7.50
REpower MM82	2.05
REpower MM92	2.05
REpower MM100	1.80
REpower 3.4M104	3.40
REpower 3.2M114	3.20
REpower 5M	5.00
GE 1.6-82.5	1.60
GE 1.5-77	1.50
GE 2.5	2.50
Vestas V52	0.85
Vestas V80-2MW	2.00
Vestas V82-0.9MW	0.90
Vestas V82-1.5MW	1.50
Vestas V82-1.65MW	1.65
Vestas V90-1.8MW	1.80
Vestas V90-2MW	2.00
Vestas V90-3MW	3.00
Vestas V100-1.8MW	1.80
Vestas V112-3MW	3.00
Offshore:	
Areva Wind M5000	5.00
REpower 5M	5.00
Vestas V112-3MW	3.00

Sources: Enercon GmbH (2010), REpower Systems AG (2004), REpower Systems AG (2010b), REpower Systems AG (2010d), REpower Systems AG (2010a), REpower Systems AG (2010c),REpower Systems AG (2004), REpower Systems AG (2007), REpower Systems AG (2012b),REpower Systems AG (2012a), REpower Systems AG (2010e), Vestas Wind Systems A/S (2009a), Vestas Wind Systems A/S (2009b), Vestas Wind Systems A/S (2009c), Vestas Wind Systems A/S (2009d), Vestas Wind Systems A/S (2009e), Vestas Wind Systems A/S (2010a), Vestas Wind Systems A/S (2010b), Vestas Wind Systems A/S (2011), Vestas Wind Systems A/S (2012),GE Power & Water Renewable Energy (2010c), General Electric Company (2012), GE Power & Water Renewable Energy (2010a), GE Power & Water Renewable Energy (2010b), Areva Wind GmbH (2010)

Table B2: Onshore areas, wind speed measuring stations and transmission grid regions incorporated in the model

ID	Type	Name	Transmission grid region no.	Full area [km^2]	Usable area [km^2]	WS no.
	Fed. Republic	Germany		357 117	60 922	
01	Federal state	Schleswig-Holstein (SH)		15 799	4653	
01001	Urban district	Flensburg	1	57	0	61
01002	Urban district	Kiel	1	119	0	158
01003	Urban district	Lübeck	1	214	0	114
01004	Urban district	Neumünster	1	72	9	90
01051	Rural district	Dithmarschen	1	1428	438	165
01053	Rural district	Herzogtum Lauenburg	1	1263	446	114
01054	Rural district	Nordfriesland	1	2083	753	107
01055	Rural district	Ostholsten	1	1392	392	57
01056	Rural district	Pinneberg	1	664	121	2
01057	Rural district	Plön	1	1083	204	1
01058	Rural district	Rendsburg-Eckernförde	1	2186	714	1
01059	Rural district	Schleswig-Flensburg	1	2071	757	156
01060	Rural district	Segeberg	1	1344	420	90
01061	Rural district	Steinburg	1	1056	316	90
01062	Rural district	Stormarn	1	766	92	2
02	City state	Hamburg		755	2	
02000	Urban district	Hamburg		755	2	2
03	Federal state	Lower Saxony (Niedersachsen)		47 635	11 961	
03101	Urban district	Braunschweig	4	192	0	40
03102	Urban district	Salzgitter	4	224	37	40
03103	Urban district	Wolfsburg	4	204	18	168
03151	Rural district	Gifhorn	4	1563	297	40
03152	Rural district	Göttingen	10	1117	110	74
03153	Rural district	Goslar	4	965	96	39
03154	Rural district	Helmstedt	4	674	150	168
03155	Rural district	Northeim	4	1267	339	133
03156	Rural district	Osterode am Harz	4	636	121	39
03157	Rural district	Peine	4	535	181	40
03158	Rural district	Wolfenbüttel	4	723	2289	40
03241	Rural district	Region Hannover	4	2291	480	5

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Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km^2]	Usable area [km^2]	WS no.
03251	Rural district	Diepholz	3	1988	690	52
03252	Rural district	Hameln-Pyrmont	4	796	234	190
03254	Rural district	Hildesheim	4	1206	273	133
03255	Rural district	Holzminden	4	693	77	133
03256	Rural district	Nienburg (Weser)	4	1399	618	190
03257	Rural district	Schaumburg	4	676	228	190
03351	Rural district	Celle	4	1545	260	30
03352	Rural district	Cuxhaven	3	2073	284	132
03353	Rural district	Harburg	3	1245	188	36
03354	Rural district	Lüchow-Dannenberg	4	1221	135	115
03355	Rural district	Lüneburg	3	1323	252	36
03356	Rural district	Osterholz	3	651	79	3
03357	Rural district	Rotenburg (Wümme)	3	2070	793	43
03358	Rural district	Soltau-Fallingbostel	4	1874	490	162
03359	Rural district	Stade	3	1266	200	43
03360	Rural district	Uelzen	4	1454	403	56
03361	Rural district	Verden	3	788	248	41
03401	Urban district	Delmenhorst	3	62	3	41
03402	Urban district	Emden	3	112	6	189
03403	Urban district	Oldenburg (Oldenburg)	3	103	0	137
03404	Urban district	Osnabrück	5	120	3	129
03405	Urban district	Wilhelmshaven	3	107	0	189
03451	Rural district	Ammerland	3	728	289	137
03452	Rural district	Aurich	3	1287	251	189
03453	Rural district	Cloppenburg	3	1418	444	137
03454	Rural district	Emsland	5	2882	1135	124
03455	Rural district	Friesland	3	608	99	189
03456	Rural district	Grafschaft Bentheim	5	981	222	4
03457	Rural district	Leer	3	1086	302	137
03458	Rural district	Oldenburg	3	1063	220	137
03459	Rural district	Osnabrück	5	2122	800	129
03460	Rural district	Vechta	3	820	223	52
03461	Rural district	Wesermarsch	3	822	316	3
03462	Rural district	Wittmund	3	657	136	189
04	City state	Bremen		404	1	

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Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km²]	Usable area [km²]	WS no.
04011	Urban district	Bremen	3	325	1	41
04012	Urban district	Bremerhaven	3	79	1	42
05	Federal state	Northrhine-Westphalia (Nordrhein-Westfalen)		34 088	4595	
05111	Urban district	Düsseldorf	6	217	0	7
05112	Urban district	Duisburg	6	233	0	7
05113	Urban district	Essen	6	210	0	6
05114	Urban district	Krefeld	6	138	0	7
05116	Urban district	Mönchengladbach	6	170	5	7
05117	Urban district	Mülheim an der Ruhr	6	91	0	6
05119	Urban district	Oberhausen	6	77	0	6
05120	Urban district	Remscheid	6	75	0	6
05122	Urban district	Solingen	6	89	0	7
05124	Urban district	Wuppertal	6	168	0	6
05154	Rural district	Kleve	6	1232	126	92
05158	Rural district	Mettmann	6	407	0	7
05162	Rural district	Rhein-Kreis Neuss	6	577	87	7
05166	Rural district	Viersen	6	563	0	7
05170	Rural district	Wesel	6	1042	194	92
05314	Urban district	Bonn	8	141	0	97
05315	Urban district	Köln	8	405	1	97
05316	Urban district	Leverkusen	6	79	0	97
05334	Rural district	Städteregion Aachen	8	79	22	19
05358	Rural district	Düren	8	941	229	134
05362	Rural district	Rhein-Erft-Kreis	8	705	169	134
05366	Rural district	Euskirchen	8	1249	138	93
05370	Rural district	Heinsberg	6	628	294	19
05374	Rural district	Oberbergischer Kreis	7	919	164	97
05378	Rural district	Rheinisch-Bergischer Kreis	6	438	44	97
05382	Rural district	Rhein-Sieg-Kreis	8	1153	51	97
05512	Urban district	Bottrop	6	101	3	6
05512	Urban district	Gelsenkirchen	6	105	1	6
05513	Urban district	Münster	7	105	16	129
05554	Rural district	Borken	6	1419	242	80
05558	Rural district	Coesfeld	6	1110	201	80

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km²]	Usable area [km²]	WS no.
05562	Rural district	Recklinghausen	6	760	13	80
05566	Rural district	Steinfurt	5	1793	600	129
05570	Rural district	Warendorf	7	1318	355	129
05711	Urban district	Bielefeld	4	258	0	153
05754	Rural district	Gütersloh	7	968	70	113
05758	Rural district	Herford	4	450	26	153
05762	Rural district	Höxter	10	1200	229	113
05766	Rural district	Lippe	4	1246	180	153
05770	Rural district	Minden-Lübbecke	4	1152	23	153
05774	Rural district	Paderborn	10	1246	241	113
05911	Urban district	Bochum	6	145	0	6
05913	Urban district	Dortmund	7	280	0	6
05914	Urban district	Hagen	7	160	0	116
05915	Urban district	Hamm	7	226	13	80
05916	Urban district	Herne	6	51	0	6
05954	Rural district	Ennepe-Ruhr-Kreis	6	408	0	116
05958	Rural district	Hochsauerlandkreis	7	1959	216	116
05962	Rural district	Märkischer Kreis	7	1059	140	116
05966	Rural district	Olpe	7	711	129	116
05970	Rural district	Siegen-Wittgenstein	7	1132	67	121
05974	Rural district	Soest	7	1328	68	113
05978	Rural district	Unna	7	543	23	116
06	Federal state	Hesse (Hessen)		21 115	1754	
06411	Urban district	Darmstadt	9	122	0	103
06412	Urban district	Frankfurt am Main	10	248	0	62
06413	Urban district	Offenbach am Main	10	45	0	103
06414	Urban district	Wiesbaden	9	204	3	68
06431	Rural district	Bergstraße	9	720	16	118
06432	Rural district	Darmstadt-Dieburg	9	659	59	103
06433	Rural district	Groß-Gerau	9	453	0	62
06434	Rural district	Hochtaunuskreis	10	482	57	71
06435	Rural district	Main-Kinzig-Kreis	10	1398	45	95
06435	Rural district	Main-Taunus-Kreis	9	222	0	62
06436	Rural district	Odenwaldkreis	9	624	84	125
06438	Rural district	Offenbach	9	356	0	103

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km²]	Usable area [km²]	WS no.
06439	Rural district	Rheingau-Taunus-Kreis	9	811	40	68
06440	Rural district	Wetteraukreis	10	1101	85	71
06531	Rural district	Gießen	10	855	26	71
06432	Rural district	Lahn-Dill-Kreis	10	1067	27	71
06533	Rural district	Limburg-Weilburg	8	738	116	121
06534	Rural district	Marburg-Biedenkopf	10	1263	193	71
06535	Rural district	Vogelsbergkreis	10	1459	70	9
06611	Urban district	Kassel	10	107	0	94
06631	Rural district	Fulda	10	1380	97	84
06632	Rural district	Hersfeld-Rotenburg	10	1097	91	84
06633	Rural district	Kassel	10	1293	178	94
06634	Rural district	Schwalm-Eder-Kreis	10	1538	242	9
06635	Rural district	Waldeck-Frankenberg	10	1849	248	94
06636	Rural district	Werra-Meißner-Kreis	10	1025	75	94
07	Federal state	Rhineland-Palatinate (Rheinland-Pfalz)		19 854	3154	
07111	Urban district	Koblenz	8	105	1	8
07131	Rural district	Ahrweiler	8	787	38	45
07132	Rural district	Altenkirchen (Westerwald)	8	942	90	121
07133	Rural district	Bad Kreuznach	9	864	152	10
07134	Rural district	Birkenfeld	9	777	159	10
07135	Rural district	Cochem-Zell	9	720	56	45
07137	Rural district	Mayen-Koblenz	8	817	96	8
07138	Rural district	Neuwied	8	627	96	8
07140	Rural district	Rhein-Hunsrück-Kreis	9	963	188	8
07141	Rural district	Rhein-Lahn-Kreis	8	782	92	8
07143	Rural district	Westerwaldkreis	8	989	31	121
07211	Urban district	Trier	9	117	1	171
07231	Rural district	Bernkastel-Wittlich	9	1178	142	51
07232	Rural district	Eifelkreis Bitburg-Prüm	9	1626	467	150
07233	Rural district	Vulkaneifel	8	911	148	150
07235	Rural district	Trier-Saarburg	9	1091	163	171
07311	Urban district	Frankenthal (Pfalz)	9	44	7	118
07312	Urban district	Kaiserslautern	9	140	4	182
07313	Urban district	Landau in der Pfalz	9	83	10	182

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km²]	Usable area [km²]	WS no.
07314	Urban district	Ludwigshafen am Rhein	9	78	3	118
07315	Urban district	Mainz	9	98	1	68
07316	Urban district	Neustadt an der Weinstraße	9	117	4	182
07317	Urban district	Pirmasens	9	61	0	152
07318	Urban district	Speyer	9	43	0	182
07319	Urban district	Worms	9	109	30	118
07320	Urban district	Zweibrücken	9	71	3	152
07331	Rural district	Alzey-Worms	9	588	205	68
07332	Rural district	Bad Dürkheim	9	595	39	182
07333	Rural district	Donnersbergkreis	9	645	186	182
07334	Rural district	Germersheim	9	463	15	182
07335	Rural district	Kaiserslautern	9	640	163	182
07336	Rural district	Kusel	9	573	295	10
07337	Rural district	Südliche Weinstraße	9	640	64	182
07338	Rural district	Rhein-Pfalz-Kreis	9	305	24	182
07339	Rural district	Mainz-Bingen	9	606	77	68
07340	Rural district	Südwestpfalz	9	954	105	152
08	Federal state	Baden-Württemberg		35 751	2189	
08111	Urban district	Stuttgart	12	207	0	166
08115	Rural district	Böblingen	12	618	0	1167
08116	Rural district	Esslingen	12	641	1	167
08117	Rural district	Göppingen	12	642	14	163
08118	Rural district	Ludwigsburg	11	687	0	166
08119	Rural district	Rems-Murr-Kreis	12	858	23	166
08121	Urban district	Heilbronn	11	100	0	11
08125	Rural district	Heilbronn	11	1100	75	11
08126	Rural district	Hohenlohekreis	11	777	54	11
08127	Rural district	Schwäbisch Hall	12	1484	305	11
08128	Rural district	Main-Tauber-Kreis	11	1304	243	191
08135	Rural district	Heidenheim	12	627	61	163
08136	Rural district	Ostalbkreis	12	1512	124	163
08211	Urban district	Baden-Baden	12	140	0	101
08212	Urban district	Karlsruhe	11	173	0	182
08215	Rural district	Karlsruhe	11	1085	26	182
08216	Rural district	Rastatt	12	738	0	101

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km^2]	Usable area [km^2]	WS no.
08221	Urban district	Heidelberg	11	109	0	118
08222	Urban district	Mannheim	11	145	2	118
08225	Rural district	Neckar-Odenwald-Kreis	11	1126	158	11
08226	Rural district	Rhein-Neckar-Kreis	11	1062	54	118
08231	Urban district	Pforzheim	11	98	0	166
08235	Rural district	Calw	12	798	0	64
08236	Rural district	Enzkreis	11	574	0	166
08237	Rural district	Freudenstadt	12	871	6	64
08311	Urban district	Freiburg im Breisgau	12	153	0	63
08315	Rural district	Breisgau-Hochschwarzwald	12	1378	0	63
08316	Rural district	Emmendingen	12	680	0	63
08317	Rural district	Ortenaukreis	12	1861	35	101
08325	Rural district	Rottweil	12	769	56	12
08326	Rural district	Schwarzwald-Baar-Kreis	12	1025	0	12
08327	Rural district	Tuttlingen	12	734	23	12
08335	Rural district	Konstanz	12	818	1	98
08336	Rural district	Lörrach	12	807	31	181
08337	Rural district	Waldshut	12	1131	28	181
08415	Rural district	Reutlingen	12	1094	77	167
08416	Rural district	Tübingen	12	519	13	167
08417	Rural district	Zollernalbkreis	12	918	43	12
08421	Urban district	Ulm	12	119	6	173
08425	Rural district	Alb-Donau-Kreis	12	1357	165	173
08426	Rural district	Biberach	12	1410	209	104
08435	Rural district	Bodenseekreis	12	665	26	65
08436	Rural district	Ravensburg	12	1632	138	14
08437	Rural district	Sigmaringen	12	1204	192	12
09	Federal state	Bavaria (Bayern)		70 550	10 029	
09161	Urban district	Ingolstadt	13	133	5	89
09162	Urban district	München	15	310	0	128
09163	Urban district	Rosenheim	15	37	0	175
09171	Rural district	Altötting	15	569	120	15
09172	Rural district	Berchtesgadener Land	15	840	19	176
09173	Rural district	Bad Tölz-Wolfratshausen	15	1111	10	186
09174	Rural district	Dachau	15	579	67	127

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km²]	Usable area [km²]	WS no.
09175	Rural district	Ebersberg	15	549	53	175
09176	Rural district	Eichstätt	13	1214	142	89
09177	Rural district	Erding	15	871	242	127
09178	Rural district	Freising	15	800	64	127
09179	Rural district	Fürstenfeldbruck	15	435	5	106
09180	Rural district	Garmisch-Partenkirchen	15	1012	0	67
09181	Rural district	Landsberg am Lech	15	804	34	102
09182	Rural district	Miesbach	15	863	0	184
09183	Rural district	Mühldorf am Inn	15	805	300	15
09184	Rural district	München	15	67	0	128
09185	Rural district	Neuburg-Schrobenhausen	14	740	161	89
09186	Rural district	Pfaffenhofen an der Ilm	15	761	131	89
09187	Rural district	Rosenheim	15	1440	110	175
09188	Rural district	Starnberg	15	488	7	186
09189	Rural district	Traunstein	15	1534	208	176
09190	Rural district	Weilheim-Schongau	15	966	3	86
09261	Urban district	Landshut	15	66	0	127
09262	Urban district	Passau	15	70	1	164
09263	Urban district	Straubing	15	68	15	164
09271	Rural district	Deggendorf	15	861	213	164
09272	Rural district	Freyung-Grafenau	15	984	70	164
09273	Rural district	Kelheim	15	1066	315	89
09274	Rural district	Landshut	15	1348	365	15
09275	Rural district	Passau	15	1530	508	164
09276	Rural district	Regen	15	975	133	164
09277	Rural district	Rottal-Inn	15	1281	636	15
09278	Rural district	Straubing-Bogen	15	1202	394	164
09279	Rural district	Dingolfing-Landau	15	878	373	164
09361	Urban district	Amberg	13	50	3	99
09362	Urban district	Regensburg	13	81	0	146
09363	Urban district	Weiden in der Oberpfalz	13	71	11	180
09371	Rural district	Amberg-Sulzbach	13	1256	129	99
09372	Rural district	Cham	15	1512	352	164
09373	Rural district	Neumarkt in der Oberpfalz	13	1344	149	149
09374	Rural district	Neustadt an der Waldnaab	13	1428	255	180
09375	Rural district	Regensburg	13	1392	122	146

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km^2]	Usable area [km^2]	WS no.
09376	Rural district	Schwandorf	13	1473	277	99
09377	Rural district	Tirschenreuth	13	1084	251	85
09461	Urban district	Bamberg	13	55	3	26
09462	Urban district	Bayreuth	13	67	0	26
09463	Urban district	Coburg	13	48	1	105
09464	Urban district	Hof	13	58	6	85
09471	Rural district	Bamberg	13	1168	25	26
09472	Rural district	Bayreuth	13	1274	125	26
09473	Rural district	Coburg	13	590	93	105
09474	Rural district	Forchheim	13	643	5	13
09475	Rural district	Hof	13	893	76	85
09476	Rural district	Kronach	13	652	94	105
09477	Rural district	Kulmbach	13	658	155	85
09478	Rural district	Lichtenfels	13	520	56	105
09479	Rural district	Wunsiedel im Fichtelgebirge	13	606	57	85
09561	Urban district	Ansbach	13	100	4	149
09562	Urban district	Erlangen	13	77	0	13
09563	Urban district	Fürth	13	63	0	13
09564	Urban district	Nürnberg	13	186	0	13
09565	Urban district	Schwabach	13	41	0	149
09571	Rural district	Ansbach	13	1972	441	149
09572	Rural district	Erlangen-Höchstadt	13	565	21	13
09573	Rural district	Fürth	13	308	26	13
09574	Rural district	Nürnberger Land	13	800	1	13
09575	Rural district	Neustadt an der Aisch	13	1268	270	13
09576	Rural district	Roth	13	895	91	149
09577	Rural district	Weißenburg-Gunzenhausen	13	971	130	183
09661	Urban district	Aschaffenburg	13	62	0	62
09662	Urban district	Schweinfurt	13	36	0	95
09663	Urban district	Würzburg	13	88	0	191
09671	Rural district	Aschaffenburg	13	699	37	62
09672	Rural district	Bad Kissingen	13	1137	222	95
09673	Rural district	Rhön-Grabfeld	13	1022	174	95
09674	Rural district	Haßberge	13	956	166	95
09675	Rural district	Kitzingen	13	684	91	191
09676	Rural district	Miltenberg	13	716	101	125

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km²]	Usable area [km²]	WS no.
09677	Rural district	Main-Spessart	13	1321	188	191
09678	Rural district	Schweinfurt	13	841	232	95
09679	Rural district	Würzburg	13	968	106	191
09761	Urban district	Augsburg	14	147	0	25
09762	Urban district	Kaufbeuren	14	40	0	102
09763	Urban district	Kempten (Allgäu)	14	60	0	14
09764	Urban district	Memmingen	14	70	9	14
09771	Rural district	Aichach-Friedberg	14	780	6	25
09772	Rural district	Augsburg	14	1071	103	25
09773	Rural district	Dillingen an der Donau	14	792	147	25
09774	Rural district	Günzburg	14	762	73	173
09775	Rural district	Neu-Ulm	14	516	32	173
09776	Rural district	Lindau (Bodensee)	14	323	3	65
09777	Rural district	Ostallgäu	14	1395	24	14
09778	Rural district	Unterallgäu	14	1230	177	14
09779	Rural district	Donau-Ries	14	1275	148	183
09780	Rural district	Oberallgäu	14	1528	55	136
10	Federal state	Saarland		2569	145	
10041	Urban district	Regionalverband Saarbrücken	9	411	0	152
10042	Rural district	Merzig-Wadern	9	555	72	140
10043	Rural district	Neunkirchen	9	249	4	169
10044	Rural district	Saarlouis	9	459	22	35
10045	Rural district	Saarpfalz-Kreis	9	418	7	152
10046	Rural district	St. Wendel	9	476	39	169
11	City state	Berlin		892	0	
11000	Urban district	Berlin	16	892	0	34
12	Federal state	Brandenburg		29 482	5351	
12051	Urban district	Brandenburg an der Havel	16	229	7	69
12052	Urban district	Cottbus	17	164	11	112
12053	Urban district	Frankfurt (Oder)	16	148	5	119
12054	Urban district	Potsdam	16	187	0	143
12060	Rural district	Barnim	16	1472	205	22

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km^2]	Usable area [km^2]	WS no.
12061	Rural district	Dahme-Spreewald	16	2262	263	32
12062	Rural district	Elbe-Elster	17	1889	437	53
12063	Rural district	Havelland	16	1717	233	143
12064	Rural district	Märkisch-Oderland	16	2150	402	126
12065	Rural district	Oberhavel	16	1798	228	16
12066	Rural district	Oberspreewald-Lausitz	17	1217	140	53
12067	Rural district	Oder-Spree	16	2243	388	112
12068	Rural district	Ostprignitz-Ruppin	16	2509	746	16
12069	Rural district	Potsdam-Mittelmark	16	2575	758	187
12070	Rural district	Prignitz	16	2123	754	122
12071	Rural district	Spree-Neiße	17	1648	181	112
12072	Rural district	Teltow-Fläming	16	2092	439	28
12073	Rural district	Uckermark	16	3058	555	77
13	Federal state	Mecklenburg West-Pomerania (Mecklenburg-Vorpommern)		23 189	4373	
13001	Urban district	Greifswald	16	51	3	75
13002	Urban district	Neubrandenburg	16	86	0	178
13003	Urban district	Rostock	16	181	0	148
13004	Urban district	Schwerin	16	131	0	159
13005	Urban district	Stralsund	16	39	0	27
13006	Urban district	Wismar	16	42	3	37
13051	Rural district	Bad Doberan	16	1362	63	148
13052	Rural district	Demmin	16	1922	539	178
13053	Rural district	Güstrow	16	2059	293	72
13054	Rural district	Ludwigslust	16	2518	492	36
13055	Rural district	Mecklenburg-Strelitz	16	2090	384	178
13056	Rural district	Müritz	16	1714	190	178
13057	Rural district	Nordvorpommern	16	2173	410	27
13058	Rural district	Nordwestmecklenburg	16	2076	519	37
13059	Rural district	Ostvorpommern	16	1911	563	75
13060	Rural district	Parchim	16	2233	545	72
13061	Rural district	Rügen	16	978	31	144
13062	Rural district	Uecker-Randow	16	1625	338	172

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km²]	Usable area [km²]	WS no.
14	Federal state	Saxony (Sachsen)		18 420	2153	
14511	Urban district	Chemnitz	17	221	0	48
14521	Rural district	Erzgebirgskreis	17	1828	128	120
14522	Rural district	Mittelsachsen	17	2113	233	48
14523	Rural district	Vogtlandkreis	18	1412	209	142
14524	Rural district	Zwickau	17	949	234	48
14612	Urban district	Dresden	17	328	0	138
14625	Rural district	Bautzen	17	2391	106	138
14626	Rural district	Görlitz	17	2106	374	73
14627	Rural district	Meißen	17	1452	157	138
14628	Rural district	Sächsische Schweiz	17	1654	76	111
14713	Urban district	Leipzig	17	297	21	110
14729	Rural district	Leipzig	17	1647	240	
14730	Rural district	Nordsachsen	17	2020	375	18
15	Federal state	Saxony-Anhalt (Sachsen-Anhalt)		20 449	6975	
15001	Urban district	Dessau-Roßlau	18	245	4	188
15002	Urban district	Halle (Saale)	18	135	0	78
15003	Urban district	Magdeburg	16	201	3	117
15081	Rural district	Altmarkkreis Salzwedel	16	2293	874	66
15082	Rural district	Anhalt-Bitterfeld	18	1453	265	78
15083	Rural district	Börde	16	2367	1091	174
15084	Rural district	Burgenlandkreis	18	1414	584	139
15085	Rural district	Harz	18	2104	646	185
15086	Rural district	Jerichower Land	16	1577	589	69
15087	Rural district	Mansfeld-Südharz	18	1449	467	24
15088	Rural district	Saalekreis	18	1433	583	78
15089	Rural district	Salzlandkreis	18	1426	621	117
15090	Rural district	Stendal	16	2423	862	160
15091	Rural district	Wittenberg	17	1930	385	188
16	Federal state	Thuringia (Thüringen)		16 172	3453	
16051	Urban district	Erfurt	18	269	23	17
16052	Urban district	Gera	18	152	25	70

Continued on next page

Table B2 – continued from previous page

ID	Type	Name	Transmission grid region no.	Full area [km^2]	Usable area [km^2]	WS no.
16053	Urban district	Jena	18	114	0	139
16054	Urban district	Suhl	18	103	0	157
16055	Urban district	Weimar	18	84	0	17
16056	Urban district	Eisenach	18	104	26	84
16061	Rural district	Eichsfeld	18	940	165	108
16062	Rural district	Nordhausen	18	711	202	39
16063	Rural district	Wartburgkreis	18	1305	203	84
16064	Rural district	Unstrut-Hainich-Kreis	18	976	452	108
16065	Rural district	Kyffhäuserkreis	18	1035	320	24
16066	Rural district	Schmalkalden-Meiningen	18	1210	205	123
16067	Rural district	Gotha	18	936	176	17
16068	Rural district	Sömmerda	18	804	302	17
16069	Rural district	Hildburghausen	18	937	159	157
16070	Rural district	Ilm-Kreis	18	843	113	157
16071	Rural district	Weimarer Land	18	803	167	17
16072	Rural district	Sonneberg	18	433	13	105
16073	Rural district	Saalfeld-Rudolstadt	18	1035	90	105
16074	Rural district	Saale-Holzland-Kreis	18	817	143	139
16075	Rural district	Saale-Orla-Kreis	18	1149	234	44
16076	Rural district	Greiz	18	844	289	70
16077	Rural district	Altenburger Land	17	569	149	70

District sizes as of 31.12.2009.
WS: weather station
Based on Statistisches Bundesamt (Destatis) (2011), Geofabrik GmbH (2012) and own calculations.

Table B3: Offshore sub-regions incorporated in the model

ID	Sea	Water depth [m]	Size [km^2]	Grid connection point	Distance to grid connection point [km]	Closest service harbour	Distance to closest service harbour [km]
1001201	NS	>20	14.9	Diele	125.4	Helgoland	110.1
1001202	NS	>20	6.5	Diele	131.4	Helgoland	117.1
1001301	NS	>30	62.6	Diele	126.1	Helgoland	110.7
1002201	NS	>20	139.2	Diele	110.9	Helgoland	90.2
1002301	NS	>30	82.6	Diele	114.6	Helgoland	89.6
1003201	NS	>20	76.5	Diele	100.7	Helgoland	65.8
1003301	NS	>30	203.9	Diele	103.3	Helgoland	64.2
1004101	NS	>10	2.0	Büttel	115.9	Helgoland	38.8
1004201	NS	>20	273.0	Büttel	115.0	Helgoland	34.8
1005101	NS	>10	24.0	Büttel	154.9	Esbjerg	65.2
1005201	NS	>20	9.7	Büttel	230.4	Esbjerg	115.4
1005202	NS	>20	110.7	Büttel	207.1	Esbjerg	104.2
1005203	NS	>20	140.7	Büttel	188.2	Helgoland	114.6
1005301	NS	>30	282.1	Büttel	199.0	Esbjerg	100.1
1006301	NS	>30	223.5	Diele	164.2	Helgoland	129.2
1006401	NS	>40	18.5	Diele	166.9	Helgoland	129.7
1007301	NS	>30	160.4	Diele	154.6	Helgoland	111.9
1007401	NS	>40	18.5	Diele	161.3	Helgoland	115.6
1008301	NS	>30	128.3	Diele	165.9	Helgoland	107.8
1008401	NS	>40	38.0	Diele	166.8	Helgoland	110.0
1009301	NS	>30	0.4	Diele	175.6	Helgoland	148.2
1009401	NS	>40	196.9	Diele	177.8	Helgoland	138.2
1010401	NS	>40	174.2	Diele	185.5	Helgoland	126.7
1011301	NS	>30	95.1	Büttel	207.5	Helgoland	116.8
1011401	NS	>40	219.5	Büttel	209.4	Helgoland	119.1
1011402	NS	>40	0.9	Büttel	204.0	Helgoland	113.1
1012301	NS	>30	26.1	Büttel	218.2	Helgoland	127.8
1012401	NS	>40	144.4	Büttel	219.4	Helgoland	128.9
1013301	NS	>30	24.1	Büttel	221.9	Esbjerg	125.3
1013401	NS	>40	232.4	Büttel	222.4	Esbjerg	128.6
1014301	NS	>30	409.0	Diele	139.3	Helgoland	76.9
1015301	NS	>30	342.2	Büttel	180.7	Helgoland	90.1
1015401	NS	>30	4.3	Büttel	194.4	Helgoland	105.2
1016301	NS	>30	182.1	Büttel	142.1	Helgoland	50.2
1016401	NS	>40	35.7	Büttel	140.6	Helgoland	48.6

Continued on next page

Table B3 – continued from previous page

ID	Sea	Water depth [m]	Size [km^2]	Grid connection point	Distance to grid connection point [km]	Closest service harbour	Distance to closest service harbour [km]
1017201	NS	>20	127.4	Büttel	137.6	Helgoland	50.1
1017301	NS	>30	3.3	Büttel	136.1	Helgoland	48.9
1017302	NS	>30	29.8	Büttel	131.8	Helgoland	42.3
1017401	NS	>40	0.7	Büttel	119.2	Helgoland	26.7
1018301	NS	>30	0.0	Diele	239.5	Helgoland	186.1
1018303	NS	>30	5.8	Diele	254.8	Helgoland	203.8
1018302	NS	>30	3.7	Diele	246.9	Helgoland	202.3
1018401	NS	>40	1040.6	Diele	240.6	Helgoland	194.2
1019301	NS	>30	72.6	Diele	265.1	Helgoland	210.0
1019401	NS	>40	598.7	Diele	275.5	Helgoland	221.2
1020301	NS	>30	34.9	Diele	237.5	Helgoland	177.8
1020301	NS	>30	2.1	Diele	260.7	Helgoland	201.1
1020301	NS	>30	1.7	Diele	268.8	Esbjerg	203.8
1020401	NS	>40	605.8	Diele	251.0	Helgoland	190.7
1021401	NS	>40	1202.2	Diele	267.6	Helgoland	192.3
1021501	NS	>50	39.6	Diele	278.6	Esbjerg	172.0
1022401	NS	>40	288.6	Diele	378.0	Esbjerg	303.5
1022501	NS	>50	353.2	Diele	379.0	Esbjerg	304.5
2001101	BS	>10	4.0	Lüdershagen	92.7	Sassnitz-Mukran	53.6
2001201	BS	>20	134.7	Lüdershagen	89.1	Sassnitz-Mukran	50.1
2001401	BS	>40	48.0	Lüdershagen	91.0	Sassnitz-Mukran	53.5
2002201	BS	>20	37.3	Lüdershagen	75.7	Sassnitz-Mukran	39.3
2002401	BS	>40	161.5	Lüdershagen	75.1	Sassnitz-Mukran	39.5
2003101	BS	>10	5.5	Lüdershagen	79.3	Sassnitz-Mukran	63.4
2003201	BS	>20	43.1	Lüdershagen	76.9	Sassnitz-Mukran	61.3
2003401	BS	>40	82.9	Lüdershagen	76.9	Sassnitz-Mukran	59.5
2004101	BS	>10	7.0	Bentwisch	62.1	Sassnitz-Mukran	61.7

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Table B3 – continued from previous page

ID	Sea	Water depth [m]	Size [km²]	Grid connection point	Distance to grid connection point [km]	Closest service harbour	Distance to closest service harbour [km]
1023051	NS	>5	7.1	Inhausen	29.2	Wilhelmshaven	35.4
1024051	NS	>5	6.0	Emden-Borßum	63.2	Helgoland	102.7
1005204	NS	>20	9.2	Büttel	155.0	Helgoland	95.3

All distances measured from the centres of the respective offshore sub-regions.
NS: North Sea, BS: Baltic Sea
The term "harbours" comprises harbours and ports.
Based on Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2014) and offshore wind farm approvals (list in table B4).

Table B4: Approved offshore wind farms in the German sea waters in the North Sea and the Baltic Sea

Name	Sea	Capacity [MW]	Area [km²]	Start of full operation*
Testfeld "Alpha Ventus"	North Sea	60.0	96.0	2010
Butendiek	North Sea	288.0	33.2	2016
Borkum Riffgrund	North Sea	277.0	34.0	2016
Borkum Riffgrund West	North Sea	400.0	26.7	2018
Amrumbank West	North Sea	400.0	31.9	2016
Nordsee Ost	North Sea	295.2	35.7	2014
Sandbank24	North Sea	288.0	59.8	2018
OWP Delta Nordsee 1	North Sea	240.0	16.8	2019
DanTysk	North Sea	288.0	65.8	2015
Nördlicher Grund	North Sea	400.0	54.7	2018
Global Tech I	North Sea	400.0	4.1	2014
EnBW Hohe See	North Sea	492.0	41.7	2018
Gode Wind 02	North Sea	252.0	29.2	2017
BARD Offshore 1	North Sea	400.0	58.0	2013
Meerwind Ost	North Sea	200.0	22.2	2016
Meerwind Süd	North Sea	200.0	17.9	2016
EnBW He dreiht	North Sea	595.0	42.7	2019
Borkum West II	North Sea	400.0	54.3	2013
Gode Wind 04	North Sea	273.0	29.3	2020
Delta Nordsee 2	North Sea	160.0	9.1	2016
MEG Offshore I	North Sea	400.0	46.0	2018
Veja Mate	North Sea	400.0	52.8	2016
Deutsche Bucht	North Sea	210.0	22.5	2016
Albatros	North Sea	400.0	37.2	2018
Borkum Riffgrund 2	North Sea	485.0	44.1	2018
Nordsee One	North Sea	332.1	31.4	2018
EnBW Windpark Baltic 2	Baltic Sea	288.0	30.3	2015
Arkona-Becken Südost	Baltic Sea	400.0	38.7	2018
Wikinger	Baltic Sea	400.0	33.8	2017
Baltic 1	Baltic Sea	48.3	7.0	2011
Kaikas	North Sea	581.0	60.9	2018
Innogy Nordsee 2	North Sea	295.2	29.0	2018
Innogy Nordsee 3	North Sea	369.0	20.7	2018
Nordergründe	North Sea	110.0	7.1	2015
Riffgat	North Sea	108.0	6.0	2014
total	North Sea	9886.5		
total	Baltic Sea	1136.0		

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Table B4 – continued from previous page

Name	Sea	Capacity [MW]	Area [km^2]	Start of full operation*
total		11 023.0		

*) partially expected.

Based on Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2001), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2002), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2004c), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2004d), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2004a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2004b), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2004e), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2005b), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2005a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2005d), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2005c), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2006b), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2006d), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2006c), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2006a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2007a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2007c), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2007b), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2007d), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2008), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009d), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009c), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009e), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2009f), Deutsche Offshore-Testfeld und Infrastruktur GmbH & Co. KG (DOTI) (2010), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2010), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2011a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2011c), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2011b), Deutsche Offshore-Testfeld und Infrastruktur GmbH & Co. KG (DOTI) (2012), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2013a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2013c), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2013f), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2013b), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2012a), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2013d), Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2013e) and own calculations

Table B5: Onshore wind measuring stations incorporated in the model

Name	No.
Hohn	1
Hamburg-Fuhlsbüttel	2
Brake	3
Lingen	4
Hannover	5
Essen-Bredeney	6
Düsseldorf	7
Alsfeld	9
Idar-Oberstein	10
Öhringen	11
Klippeneck	12
Nürnberg	13
Kempten	14
Mühldorf	15
Neuruppin	16
Erfurt-Weimar	17
Oschatz	18
Aachen	19
Lautertal-Hörgenau	20
Altenstadt	21
Angermünde	22
Arkona	23
Artem	24
Augsburg	25
Bamberg	26
Barth	27
Baruth	28
Bonn-Roleber	29
Bergen	30
Berlin-Alexanderplatz	31
Berlin-Schönefeld	32
Berlin-Tegel	33
Berlin-Tempelhof	34
Berus	35
Boizenburg	36
Boltenhagen	37
Borkum-Süderstraße	38
Braunlage	39
Braunschweig	40
Bremen	41

Continued on next page

Table B5 – continued from previous page

Name	No.
Bremerhaven	42
Bremervörde	43
Brocken	44
Büchel (Flugplatz)	45
Büsum	46
Carlsfeld	47
Chemnitz	48
Cottbus	49
Coxhaven	50
Deuselbach	51
Diepholz	52
Doberlug-Kirchhain	53
Dogern	54
Werl	55
Fassberg	56
Fehmarn	57
Feldberg/Schwarzwald	58
Fichtelberg	59
Fichtelberg/Oberfranken-Hüttenstadl	60
Flensburg	61
Frankfurt, Main	62
Freiburg	63
Freudenstadt	64
Friedrichshafen	65
Gardelegen	66
Garmisch-Partenkirchen	67
Geisenheim	68
Genthin	69
Gera-Leumnitz	70
Gießen	71
Goldberg	72
Görlitz	73
Göttingen	74
Greifswald	75
Großer Arber	76
Grünow	77
Halle-Kröllwitz	78
Hallig Hooge	79
Haltern	80
Harzgerode	81
Hassfurt	82

Continued on next page

Table B5 – continued from previous page

Name	No.
Helgoland	83
Hersfeld, Bad	84
Hof	85
Hohenpreißenberg	86
Hornisgrinde	87
Dörmoschel-Felsberghof	88
Ingolstadt	89
Itzehoe	90
Kahler Asten	91
Kalkar	92
Kall-Sistig	93
Kassel	94
Kissingen, Bad	95
Kleiner Feldberg	96
Köln-Bonn	97
Konstanz	98
Kümmersbruck	99
Kyritz	100
Lahr	101
Landsberg	102
Langen	103
Laupheim	104
Lautertal-Oberlauter	105
Lechfeld	106
Leck	107
Leinefelde	108
Leipzig-Halle	109
Leipzig-Holzhausen	110
Lichtenhain-Mittelndorf	111
Lindenberg	112
Lippspringe, Bad	113
Lübeck-Blankensee	114
Lüchow	115
Lüdenscheid	116
Magdeburg	117
Mannheim	118
Manschnow	119
Marienberg	120
Marienberg, Bad	121
Marnitz	122
Meiningen	123

Continued on next page

Table B5 – continued from previous page

Name	No.
Meppen	124
Michelstadt-Vielbrunn	125
Möncheberg	126
München-Flughafen	127
München-Stadt	128
Münster, Osnabrück	129
Neuhaus am Rennweg	130
Nordeney	131
Nordholz	132
Northeim-Stöckheim	133
Nörvenich	134
Nümbrecht auf dem Lindchen	135
Oberstdorf	136
Oldenburg	137
Dresden-Klotzsche	138
Osterfeld	139
Per-Sinz-Renglischberg	140
Pforzheim-Ispringen	141
Plauen	142
Potsdam	143
Putbus	144
Quickborn	145
Regensburg	146
Rheine-Bentlage	147
Rostock-Warnemünde	148
Roth	149
Roth bei Prüm	150
Rothtalmünster	151
Saarbrücken-Ensheim	152
Salzuflen, Bad	153
Sankt Peter-Ording	154
Schleiz	155
Schleswig	156
Schmücke	157
Schönhagen	158
Schwerin	159
Seehausen	160
Selb, Oberfranken	161
Soltau	162
Stötten	163
Straubing	164

Continued on next page

Table B5 – continued from previous page

Name	No.
Strucklahnungshörn	165
Stuttgart (Schnarrenberg)	166
Stuttgart-Echterdingen	167
Süpplingen	168
Tholey	169
Travemünde	170
Trier-Petrisberg	171
Ueckermünde	172
Ulm	173
Umendorf	174
Vogtareuth	175
Waging am See-Schnäbling	176
Walldürn	177
Waren	178
Wasserkuppe	179
Weiden	180
Weilheim-Bierbronnen	181
Weinbiet	182
Weißenburg	183
Wendelstein	184
Wernigerode	185
Wielenbach	186
Wiesenburg	187
Wittenberg	188
Wittmundhafen	189
Wunstorf	190
Würzburg	191
Zinnwald-Georgenfeld	192
Zugspitze	193

All measuring stations: operated by Germany's National Meteorological Service (Deutscher Wetterdienst) (DWD) as found in Deutscher Wetterdienst (DWD) (2013)

Table B6: Modeling results: wind power in scenario 1 (2050)

	2 %*		3 %*		4 %*		5 %*	
Region	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]
onshore								
1	3.81	9.08	5.26	12.57	6.77	16.24	8.19	19.70
2	0.01	0.02	0.00	0.00	0.00	0.00	0.00	0
3	4.36	8.72	5.55	11.25	5.29	11.24	5.94	12.71
4	1.64	2.87	0.66	1.18	0.50	0.90	0.35	0.63
5	1.96	2.32	2.94	3.47	2.93	3.50	3.00	3.62
6	1.30	1.01	0.88	0.81	0.17	0.15	0.15	0.14
7	2.35	3.23	2.09	2.95	2.58	3.52	3.09	4.14
8	1.89	2.91	1.90	3.17	1.95	3.38	1.96	3.50
9	2.92	5.58	3.51	6.74	3.99	7.38	4.09	7.22
10	2.40	3.07	1.55	1.81	1.81	2.10	1.92	2.15
11	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
12	1.92	3.75	1.54	2.52	1.54	2.36	1.40	2.06
13	2.36	3.18	1.56	2.39	1.56	2.42	1.17	1.82
14	0.59	0.52	0.30	0.29	0.28	0.26	0.18	0.18
15	1.66	1.68	1.53	1.56	1.52	1.55	1.29	1.31
16	5.44	10.21	5.70	11.26	4.34	8.93	3.57	7.90
17	2.01	3.77	2.29	4.16	2.16	3.78	1.78	3.10
18	2.85	5.57	2.22	4.54	2.10	4.43	1.42	2.96
offshore								
19	25.98	69.84	25.98	69.84	25.98	69.84	25.98	69.84
20	40.43	129.32	40.43	129.32	40.43	129.32	40.43	129.32
21	6.79	18.55	6.79	18.55	6.79	18.55	6.79	18.55
onshore	39.50	67.53	39.50	70.67	39.50	72.12	39.50	73.13
offshore	73.20	217.71	73.20	217.71	73.20	217.71	73.20	217.71
total	112.70	285.25	112.70	288.38	112.70	289.83	112.70	290.85

P: installed capacity. Q: electricity production

*) Limitation of federal state areas and district areas

Table B7: Modeling results: wind power in scenario 2 (2050)

Region	2 %*		3 %*		4 %*		5 %*	
	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]
onshore								
1	3.77	8.95	5.57	13.23	6.91	16.50	8.40	20.13
2	0.02	0.04	0.01	0.03	0.00	0.00	0.00	0.00
3	4.70	9.08	6.32	12.73	8.09	16.48	8.29	16.96
4	3.61	6.17	2.10	3.66	0.76	1.33	0.54	0.97
5	1.93	2.27	2.90	3.42	3.89	4.58	4.86	5.73
6	1.75	1.71	1.91	1.47	1.53	1.30	0.89	0.81
7	2.47	3.42	3.28	4.49	3.00	4.13	3.19	4.37
8	2.54	3.98	2.61	3.97	2.22	3.80	2.19	3.85
9	3.23	6.11	4.15	7.94	4.66	8.92	5.16	9.69
10	3.88	5.26	3.07	3.86	1.99	3.11	2.19	2.53
11	0.21	0.25	0.02	0.05	0.01	0.01	0.01	0.01
12	3.60	6.46	2.22	4.09	1.92	3.11	1.82	2.79
13	3.74	4.85	3.02	4.19	2.25	3.33	2.11	3.26
14	0.85	0.75	0.58	0.52	0.40	0.38	0.30	0.28
15	1.83	1.84	2.07	2.12	1.86	1.91	1.73	1.77
16	9.17	14.38	7.76	14.77	8.64	17.06	7.17	14.11
17	2.89	5.66	2.78	5.16	2.96	5.95	2.70	4.73
18	4.09	7.94	3.90	7.78	3.17	6.52	2.71	5.71
offshore								
19	12.95	26.56	12.95	26.56	12.95	26.56	12.95	26.56
20	14.18	48.60	14.18	48.60	14.18	48.60	14.18	48.60
21	7.37	20.12	7.37	20.12	7.37	20.12	7.37	20.12
onshore	54.50	89.12	54.50	93.46	54.50	97.02	54.50	97.70
offshore	34.50	95.29	34.50	95.29	34.50	95.29	34.50	95.29
total	88.77	184.41	88.77	188.75	88.77	192.31	88.77	192.99

P: installed capacity. Q: electricity production

*) Limitation of federal state areas and district areas

Table B8: Modeling results: wind power in scenario 3 (2035, nationwide allocation)

	2 %*		3 %*		4 %*		5 %*	
Region	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]
onshore								
1	3.69	8.65	5.57	13.03	7.47	17.49	9.35	21.96
2	0.02	0.03	0.02	0.04	0.02	0.04	0.01	0.03
3	4.83	9.16	6.94	13.01	8.76	16.87	10.45	20.60
4	5.40	8.91	6.24	10.45	4.20	7.29	10.45	4.87
5	1.92	2.17	2.83	3.21	3.81	4.34	4.76	5.44
6	1.69	1.60	2.53	2.44	3.29	3.17	3.38	2.80
7	2.44	3.28	3.69	4.95	4.96	6.65	5.00	6.58
8	2.56	3.87	3.87	5.94	4.34	6.55	4.16	6.18
9	4.33	8.20	4.85	9.03	5.74	10.80	6.44	12.19
10	4.50	6.14	5.85	7.79	5.05	6.43	4.62	5.67
11	1.55	2.25	0.41	0.50	0.07	0.08	0.03	0.03
12	4.53	7.74	5.14	8.90	3.68	6.53	2.87	4.87
13	7.18	9.26	6.01	7.49	4.47	5.94	4.02	5.53
14	2.27	2.52	1.26	1.11	0.86	0.75	0.57	0.52
15	5.33	5.65	2.44	2.42	2.69	2.68	2.61	2.61
16	13.14	20.37	13.95	21.40	13.28	22.57	12.17	22.94
17	5.74	9.69	4.50	8.60	3.82	7.08	3.76	6.61
18	6.07	10.26	6.32	11.94	5.88	11.51	5.26	10.47
offshore								
19	6.35	12.78	6.35	12.78	6.35	12.78	6.35	12.78
20	6.61	22.44	6.61	22.44	6.61	22.44	6.61	22.44
21	4.55	12.55	4.55	12.55	4.55	12.55	4.55	12.55
onshore	77.18	119.75	82.40	132.22	82.40	136.78	82.40	139.90
offshore	17.51	47.77	17.51	47.77	17.51	47.77	17.51	47.77
total	94.68	167.52	99.91	179.99	99.91	184.55	99.91	187.67

P: installed capacity. E: electricity production

*) Limitation of federal state areas and district areas

Table B9: Modeling results: wind power in scenario 3 (2035, state-by-state allocation)

	2 %*		3 %*		4 %*		5 %*	
Region	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]
onshore								
1	4.08	9.55	6.12	14.35	8.27	19.40	10.37	24.35
2	0.01	0.02	0.01	0.02	0.01	0.02	0.01	0.02
3	5.12	9.72	7.52	14.19	9.42	18.29	10.07	19.84
4	5.76	9.51	5.47	9.31	2.77	4.90	1.07	1.75
5	2.05	2.34	3.04	3.45	4.10	4.69	5.13	5.89
6	1.85	1.78	2.49	2.32	2.26	1.71	2.33	1.90
7	2.66	3.57	3.87	5.17	4.15	5.44	4.08	5.34
8	2.85	4.29	2.76	4.49	2.27	3.89	2.35	4.16
9	4.35	8.46	4.42	8.08	4.74	8.08	4.73	7.75
10	3.87	5.04	4.14	8.08	4.01	4.85	3.96	4.63
11	0.82	1.03	0.26	0.30	0.15	0.16	0.13	0.14
12	4.37	7.75	4.93	8.77	5.05	8.82	5.07	8.72
13	2.61	3.44	2.50	3.49	2.48	3.62	2.48	3.74
14	0.50	0.47	0.42	0.41	0.34	0.34	0.32	0.31
15	1.89	1.87	2.08	2.08	2.18	2.17	2.20	2.20
16	14.78	22.87	19.58	30.54	19.94	32.11	19.75	32.14
17	2.74	4.12	2.63	4.04	1.92	3.16	1.61	2.73
18	5.83	9.77	5.49	9.61	5.84	10.29	6.34	11.12
offshore								
19	6.35	12.78	6.35	12.78	6.35	12.78	6.35	12.78
20	6.61	22.44	6.61	22.44	6.61	22.44	6.61	22.44
21	4.55	12.55	4.55	12.55	4.55	12.55	4.55	12.55
onshore	66.17	105.60	77.74	125.79	79.90	131.94	82.00	136.72
offshore	17.51	47.77	17.51	47.77	17.51	47.77	17.51	47.77
total	83.68	153.37	95.25	173.57	97.41	179.71	99.51	184.50

P: installed capacity. Q: electricity production

*) Limitation of federal state areas and district areas

Table B10: Modeling results: wind power in scenario 4 (2050, nationwide allocation)

	2 %*		3 %*		4 %*		5 %*	
Region	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]
onshore								
1	9.32	22.15	11.18	26.55	12.98	30.84	14.68	34.93
2	0.02	0.04	0.01	0.03	0.01	0.03	0.02	0.03
3	11.45	22.19	13.07	25.83	14.77	29.55	16.60	33.42
4	7.52	12.97	5.51	9.64	4.72	8.19	3.82	6.41
5	4.76	5.61	5.71	6.74	6.67	7.88	7.63	9.01
6	4.08	3.99	4.73	4.50	5.05	4.39	4.67	4.02
7	6.11	8.42	7.00	9.59	7.48	10.11	7.22	9.60
8	5.84	9.04	5.90	8.99	5.52	8.54	5.20	8.32
9	7.32	14.01	8.02	15.47	8.84	17.08	9.08	17.40
10	7.72	10.21	7.34	9.55	6.57	8.35	5.99	7.44
11	0.23	0.27	0.89	0.10	0.05	0.54	0.03	0.04
12	6.03	10.12	4.31	7.36	3.71	6.30	3.20	5.37
13	6.77	8.87	5.94	8.10	5.43	7.66	5.01	7.21
14	1.24	1.07	0.93	0.81	0.71	0.62	0.64	0.57
15	3.13	3.20	3.34	3.43	3.17	3.26	2.93	3.02
16	20.87	33.56	20.10	34.40	18.28	33.71	18.33	35.13
17	5.30	10.08	4.75	8.85	4.81	8.58	4.65	8.23
18	7.99	15.91	7.77	15.60	6.92	14.48	6.01	12.54
offshore								
19	25.98	69.84	25.98	69.84	25.98	69.84	25.98	69.84
20	40.43	129.32	40.43	129.32	40.43	129.32	40.43	129.32
21	6.79	18.55	6.79	18.55	6.79	18.55	6.79	18.55
onshore	115.70	191.72	115.70	195.36	115.70	199.39	115.70	202.70
offshore	73.20	217.71	73.20	217.71	73.20	217.71	73.20	217.71
total	188.90	409.43	188.90	413.07	188.90	417.10	188.90	420.41

P: installed capacity. Q: electricity production

*) Limitation of federal state areas and district areas

Table B11: Modeling results: wind power in scenario 4 (2050, state-by-state allocation)

	2 %*		3 %*		4 %*		5 %*	
Region	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]	P [GW]	Q [TWh/a]
onshore								
1	10.27	24.40	12.33	29.29	14.40	34.28	15.60	37.27
2	0.01	0.02	0.01	0.02	0.01	0.02	0.01	0.02
3	11.79	23.29	13.26	26.86	12.89	26.15	12.34	25.66
4	4.74	8.38	2.18	3.57	1.31	2.14	0.94	1.57
5	5.13	6.05	6.20	7.30	7.21	8.48	8.07	9.51
6	3.68	3.15	3.62	2.75	3.22	2.66	3.25	2.70
7	5.40	7.34	5.99	8.00	6.39	8.42	6.55	8.62
8	3.18	5.58	2.91	5.24	3.09	5.65	3.11	5.71
9	5.69	10.03	5.65	9.60	5.52	9.41	5.39	9.13
10	6.26	7.90	6.07	7.50	6.25	7.63	6.22	7.44
11	0.76	0.95	0.39	0.47	0.39	0.46	0.39	0.46
12	8.34	13.77	8.71	14.15	8.71	14.15	8.71	14.15
13	4.40	6.31	4.40	6.35	4.54	6.64	4.63	6.86
14	0.60	0.57	0.57	0.55	0.51	0.49	0.46	0.45
15	3.00	3.08	3.03	3.11	2.95	3.03	2.91	2.99
16	26.83	42.92	26.57	43.67	26.22	44.62	26.17	45.69
17	1.91	3.23	1.64	2.85	1.60	2.80	1.60	2.80
18	8.10	14.89	8.63	15.71	9.02	16.42	9.07	16.71
offshore								
19	25.98	69.84	25.98	69.84	25.98	69.84	25.98	69.84
20	40.43	129.32	40.43	129.32	40.43	129.32	40.43	129.32
21	6.79	18.55	6.79	18.55	6.79	18.55	6.79	18.55
onshore	110.09	181.86	112.15	186.99	114.22	193.46	115.42	197.75
offshore	73.20	217.71	73.20	217.71	73.20	217.71	73.20	217.71
total	183.28	399.57	185.35	404.71	187.42	411.18	188.62	415.47

P: installed capacity. Q: electricity production

*) Limitation of federal state areas and district areas

Table B12: Results of the scenarios modeled (onshore wind power, sensitivity: area buffers)

Scenario	Allocation mode*	Max. area share**	Capacity [GW]	Produced electricity [TWh/a]	EFLH
1	a	100 %	39.50	89.73	2272
1	a	2 %	39.50	68.38	1731
1	a	3 %	39.50	70.79	1792
1	a	4 %	39.50	72.59	1838
1	a	5 %	39.50	73.24	1854
2	a	100 %	54.27	123.80	2281
2	a	2 %	54.27	90.41	1666
2	a	3 %	54.27	94.84	1748
2	a	4 %	54.27	98.04	1804
2	a	5 %	54.27	98.89	1822
3	a	100 %	82.40	172.00	2087
3	a	2 %	77.01	121.08	1572
3	a	3 %	82.40	133.85	1624
3	a	4 %	82.40	139.36	1691
3	a	5 %	82.40	142.32	1727
3	b	100 %	82.12	151.32	1843
3	b	2 %	66.23	107.25	1619
3	b	3 %	77.80	128.01	1645
3	b	4 %	79.89	134.34	1682
3	b	5 %	82.00	139.78	1705
4	a	100 %	115.70	235.51	2036
4	a	5 %	115.70	196.37	1697
4	a	6 %	115.70	200.03	1729
4	a	7 %	115.70	203.04	1755
4	a	8 %	115.70	206.00	1780
4	b	100 %	115.42	212.13	1838
4	b	5 %	110.09	184.46	1676
4	b	6 %	112.12	191.20	1705
4	b	7 %	114.19	196.94	1725
4	b	8 %	115.42	201.29	1744

All figures: respective target years.
*) Allocation mode: a) nationwide, b) state-by-state
**) Limitation of federal state areas and district areas

Table B13: Results of the scenarios modeled (onshore wind power, sensitivity: wind year)

Scenario	Allocation mode*	Max. area share**	Capacity [GW]	Produced electricity [TWh/a]	EFLH
1	a	100 %	39.50	78.46	1986
1	a	2 %	39.50	64.09	1623
1	a	3 %	39.50	67.33	1704
1	a	4 %	39.50	68.36	1731
1	a	5 %	39.50	69.09	1749
2	a	100 %	54.27	95.29	2099
2	a	2 %	54.27	84.62	1559
2	a	3 %	54.27	90.22	1622
2	a	4 %	54.27	92.49	1704
2	a	5 %	54.27	93.02	1714
3	a	100 %	82.40	160.91	1953
3	a	2 %	77.18	114.07	1478
3	a	3 %	82.40	125.54	1524
3	a	4 %	82.40	129.88	1576
3	a	5 %	82.40	133.10	1615
3	b	100 %	82.12	140.32	1709
3	b	2 %	66.17	102.26	1545
3	b	3 %	77.74	121.36	1561
3	b	4 %	79.90	126.58	1584
3	b	5 %	82.00	130.36	1590
4	a	100 %	115.70	219.29	1895
4	a	5 %	115.70	182.35	1576
4	a	6 %	115.70	185.76	1605
4	a	7 %	115.70	189.85	1641
4	a	8 %	115.70	193.13	1669
4	b	100 %	115.42	199.37	1727
4	b	5 %	110.09	174.38	1584
4	b	6 %	112.15	178.72	1594
4	b	7 %	114.22	184.06	1611
4	b	8 %	115.42	188.36	1632

All figures: respective target years.
*) Allocation mode: a) nationwide, b) state-by-state
**) Limitation of federal state areas and district areas

Table B14: Results of the scenarios modeled (onshore wind power, sensitivity: power curve)

Scenario	Allocation mode*	Max. area share**	Capacity [GW]	Produced electricity [TWh/a]	EFLH
1	a	100 %	39.50	100.13	2535
1	a	2 %	39.50	83.19	2106
1	a	3 %	39.50	86.81	2198
1	a	4 %	39.50	88.41	2238
1	a	5 %	39.50	89.51	2266
2	a	100 %	54.27	146.59	2701
2	a	2 %	54.27	110.18	2030
2	a	3 %	54.27	115.08	2121
2	a	4 %	54.27	119.18	2196
2	a	5 %	54.27	119.96	2211
3	a	100 %	82.40	207.89	2523
3	a	2 %	77.18	148.52	1925
3	a	3 %	82.40	163.86	1989
3	a	4 %	82.40	169.07	2052
3	a	5 %	82.40	172.54	2094
3	b	100 %	82.12	181.30	2208
3	b	2 %	66.17	131.01	1980
3	b	3 %	77.74	155.99	2007
3	b	4 %	79.90	163.25	2043
3	b	5 %	82.00	169.07	2062
4	a	100 %	115.70	283.82	2453
4	a	5 %	115.70	237.06	2049
4	a	6 %	115.70	241.18	2084
4	a	7 %	115.70	245.67	2123
4	a	8 %	115.70	249.44	2156
4	b	100 %	115.42	254.71	2207
4	b	5 %	110.09	224.97	2044
4	b	6 %	112.15	231.02	2060
4	b	7 %	114.22	238.77	2090
4	b	8 %	115.42	243.84	2113

All figures: respective target years.
*) Allocation mode: a) nationwide, b) state-by-state
**) Limitation of federal state areas and district areas

Table B15: Results of the scenarios modeled (onshore wind power, sensitivity: WTG spacing)

Scenario	Allocation mode*	Max. area share**	Capacity [GW]	Produced electricity [TWh/a]	EFLH
1	a	100 %	39.50	79.64	2016
1	a	2 %	39.50	63.85	1616
1	a	3 %	39.50	66.11	1674
1	a	4 %	39.50	68.27	1728
1	a	5 %	39.50	69.82	1767
2	a	100 %	54.27	112.64	2076
2	a	2 %	43.50	69.12	1589
2	a	3 %	54.27	88.37	1628
2	a	4 %	54.27	89.86	1656
2	a	5 %	54.27	92.77	1709
3	a	100 %	82.40	158.70	1926
3	a	2 %	43.50	67.13	1543
3	a	3 %	65.30	101.27	1551
3	a	4 %	82.40	128.90	1564
3	a	5 %	82.40	131.38	1594
3	b	100 %	82.12	141.11	1718
3	b	2 %	43.75	68.74	1571
3	b	3 %	59.99	94.89	1582
3	b	4 %	71.66	113.70	1587
3	b	5 %	77.24	123.70	1602
4	a	100 %	115.70	217.73	1882
4	a	5 %	104.17	165.34	1587
4	a	6 %	115.70	185.69	1605
4	a	7 %	115.70	188.67	1631
4	a	8 %	115.70	189.02	1634
4	b	100 %	115.41	200.92	1741
4	b	5 %	92.00	148.73	1617
4	b	6 %	99.61	161.68	1623
4	b	7 %	104.10	184.06	1629
4	b	8 %	107.98	176.65	1636

All figures: respective target years.

*) Allocation mode: a) nationwide, b) state-by-state

**) Limitation of federal state areas and district areas