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A COST-EFFICIENT EXPANSION OF RENEWABLE ENERGY SOURCES IN THE EUROPEAN ELECTRICITY SYSTEM – AN INTEGRATED MODELLING APPROACH WITH A PARTICULAR EMPHASIS ON DIURNAL AND SEASONAL PATTERNS

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ABSTRACT

This thesis determines a cost-efficient expansion of electricity generated by renewable energy sources (RES-E) in the European power generation system. It is an integrated modelling approach with a particular emphasis on diurnal and seasonal patterns of renewable energy sources (RES). An integrated modelling approach optimizes the overall European electricity system while comprising fossil, nuclear, and renewable generation as well as storage. This also corresponds to a situation in which renewable technologies are subject to the competition of electricity markets. However, current support policies for RES-E in Europe frequently exempt renewable technologies from the competition of electricity markets and from electricity price signals. Renewable technologies are granted priority feed-in rights before conventional technologies. In sensitivity scenarios, the inefficiencies associated with a priority feed-in and a decoupling from electricity price signals for renewable technologies are quantified and analysed. Such a situation is modelled by a sequential model approach. Here, the conventional power plant fleet has to adapt to the conditions of the RES-E which have been determined ex-ante. Finally, the role of different flexibility options, which can be provided by storage capacities and grid expansion are scrutinized.

The methodology of the thesis consists of two parts. First, it develops an integrative model approach by extending an existing bottom-up, linear and deterministic optimization model which until now comprises only conventional power generating technologies. The development of the integrative model essentially entails the programming of a new renewable module and the inclusion, definition, and processing of additional data concerning renewable technologies. The renewable technologies considered are intermittent RES, such as wind and solar power as well as continuous available RES, such as power from biomass and geothermal energy. The sequential model part for RES-E is deducted from the renewable module. Second, an appropriate representation of intermittent RES for electricity market models is established by the determination of

corresponding typedays. The appropriate representation of intermittent RES is a prerequisite for electricity market models that include renewable technologies. The typeday modelling takes the spatial correlation of RES and the correlation between wind and solar power into account. Moreover, the typeday modelling captures average dispatch-relevant, diurnal and seasonal RES characteristics such as the level, the variance, and the gradient.

In the scenario analysis it will be shown that separate developments of renewable and conventional technologies imply several inefficiencies. These increase with higher RES-E penetration. The inefficiencies relate to an increased regional and technological concentration of RES capacities. As a consequence e.g. huge amounts of wind power curtailment become necessary. Moreover, discontinuous changes in the RES-E development cause an augmented capital turnover and a higher cumulative installed power generating capacity. By contrast, in a coordinated development the integration capability of regions and the opportunity to smooth RES outputs are taken into account. More flexibility on the electricity supply side, such as storage capacities and grid expansion, decreases the demand for regional and technological diversification of RES and the necessity to curtail wind power.

Keywords: Linear optimization, renewable energy sources, integration into electricity markets, Europe, promotion policies, diurnal and seasonal feed-in characteristics, smoothening of RES output, regional and technological diversification, wind power curtailment, storage plants, grid expansion

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D	set of typedays; d = {summer-high-wind, summer-low-wind, winter-high-wind, winter-low-wind}
H	hours of the day; $h = \{1, \ldots, 24\}$
$OP \subset h$	set of off-peak-load hours; $OP = \{1, \ldots, 7; 20, \ldots, 24\}$
$P \subset h$	set of peak-load hours; $P = \{8, \ldots, 19\}$
$quota\_tech \subset tech$	set of renewable technologies that are counted towards meeting the renewable quota
r	model region (wind region or country)
$resf\_tech \subset tech$	set of renewable technologies based on fluctuating RES
$resd\_tech \subset tech$	set of renewable technologies base on continuously available RES
s	Season; s = {winter, summer}
$tech$	set of all technologies included in the respective model
WS	wind state; WS = {high, low}
y	Investment period; y= $\{2010, 2020, 2030, 2040, 2050\}$

List of Parameters

A_{PV}	Area of a solar power plant [m²]
$availability_{y,d,h,tech,r}$	Availability of respective technologies [%]
$avail\_res\_fluc_{resf\_tech,r,d,h}$	Availability of renewable technologies based on fluctuating RES
$avail\_res\_dis_{resd\_tech,d}$	Availability of renewable technologies based on continuously available RES
$\overline{D}_{h}^{r,s,WS}$	Empirical average hourly wind speed [m/s]
$\overline{D}^{r,s,WS}$	Empirical average daily wind speeds [m/s]
$demand_{y,d,h,r}$	Hourly electricity demand [MW]
η_{PV}	Efficiency of a solar power plant [%]
$exo\_supply\_res_{y,d,h,res\_tech,r}$	Hourly exogenous RES-E supply [MW]
$exo\_instcap\_res_{y,d,h,res\_tech,r}$	Exogenous cumulative installed RES capacity [MW]
$\mathrm{GD}_{\mathrm{h}}^{\mathrm{r,s,WS}}$	Empirical difference of wind speeds between two successive hours [m/s]
$\overline{\mathrm{GD}}^{\mathrm{r,s,WS}}$	Empirical average difference of wind speeds between two successive hours [m/s]
h	High level of wind speed
I_{solar}	Global solar irradiation [W/m²]

l	Low level of wind speed
N	Number of days in the type day sample
res_quota_y	Renewable quota [Two]
$residual\_load_{y,d,h,r}$	Hourly residual load [MW]
$peak\_demand_{y,d,h,r}$	Peak demand [MW]
v_r	Representative wind speed [m/s]
$Y_{optimal}$	Optimal power yield of a solar power plant
z	Hub height [m]
z_0	Surface roughness

List of Variables

$EXPORTS_{y,d,h,r2,r}$	Hourly electricity exports from country r to country $r2$ [MW]
$\mathrm{GT}_{\mathrm{h}}^{\mathrm{r,s,WS}}$	Difference of optimized wind speeds between two successive hours at respective type day [m/s]
$\overline{GT}^{r,s,WS}$	Average difference of optimized wind speeds between two successive hours at respective type day [m/s]
$IMPORTS_{y,d,h,r,r2}$	Hourly electricity imports from country $r2$ to country r [MW]
$INSTCAP_{y,tech,r}$	Cumulative installed capacity [MW]
$REDUC\_RES_{y,d,h,res\_tech,r}$	Hourly RES-E curtailment [MW]
$SUPPLY_{y,d,h,tech,r}$	Hourly electricity generation by technology [MW]
$\mathrm{T}_{\mathrm{h}}^{\mathrm{r,s,WS}}$	Hourly optimized wind speed at respective type day [m/s]
$\bar{T}^{r,s,WS}$	Daily Average of optimized wind speed at the respective type day [m/s]

List of Abbreviations

AA-CAES	Advanced Adiabatic and Diabetic Compressed Air Energy Storage
AC	Alternating-Current
CAES	Compressed Air Energy Storage
CHP	Combined Heat Production
COM	Commission of the European Communities
CONOPT	Non-linear GAMS solver
CSP	Central Solar Power
DC	Direct Current
DIME	A simulation model for European electricity markets
DIMENSION	Follow-up model of DIME with only conventional technologies included
DOE	Department of Energy
EC	European Commission
EIA	Energy Information Administration
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	European Trading Scheme
EU	European Union

EU-27-plus	EU-27 plus Norway and Switzerland
EUSUSTEL	European Sustainable Electricity
€/MHz	Euro per Megawatt-hours
EWI	Energiewirtschaftliches Institut
EXRES	Model based on renewable module of INTRES including only renewable technologies
GAMS	General Algebraic Modelling System
GO	Guarantee of Origin
GW	Gigawatt
h/a	Hours per year
HQS	Harmonized Quota System
INTRES	Model based on DIMENSION including renewable and conventional technologies
$kWh/m^2/a$	Kilowatt-hour per square meter per year
$kWh/m^3/a$	Kilowatt-hour per cubic meter per year
LOEE	Loss-of-energy expectation
LOLE	Loss-of-load expectation
LOLP	Loss-of-load probability
LORELEI	Linear Optimisation Model for

	Renewable Electricity Integration in Europe
m/s	Meter per seconds
MINLP	Mixed Integer Nonlinear Programming
MWh	Megawatt-hours
NTC	Net Transfer Capacity
O&M	Operating and Maintenance
OCGT	Gas fired power stations
PV	Photovoltaics
R&D	Research and Development
RE	Renewable Energy
RES	Renewable Energy Sources
RES-E	Electricity generated by RES
RMSE	Root-Mean-Squared-Error
TSO	Transmission System Operator
TWh	Terawatt-hours
TWh/a	Terawatt-hours per year
UCTE	The Union for the Co-ordination of Transmission of Electricity
USD	United States dollar

USD/€	US dollar per Euro
W/m²	Watt per square meter
WILMAR	Wind Power Integration in a Liberalised Electricity Market

1 SUMMARY

This work examines a cost-efficient expansion of electricity generated by renewable energy sources (RES-E) in Europe. It is an integrated modelling approach with a particular emphasis on diurnal and seasonal patterns of renewable energy sources (RES). An integrated modelling approach optimizes the overall European electricity system development while comprising fossil, nuclear, and renewable generation as well as storage. It corresponds to a situation in which renewable generation is subject to electricity price signals. Moreover, the inefficiencies associated with a priority feed-in and a decoupling from electricity price signals for renewable technologies are quantified and analysed. The thesis constitutes a continuation of research published by Fürsch et al. (2010) considerably improving on and extending the methodology used in this earlier work.

1.1 Status Quo

A new European Union (EU) directive on the promotion of RES, agreed on in December 2008, obliges the Member States to increase their share of RES. By the year 2020, 20 per cent of the European energy consumption should be provided by RES. Longer-term targets for RES are also suggested, with proposals of 50 per cent and more by 2040/50. The expansion of RES-E is to be achieved with the help of the diverse promotion systems implemented in the EU Member Countries (COM (2008) 19 final).

Current support policies for RES-E in Europe frequently exempt renewable technologies from competition of electricity markets and the electricity price signals. Renewable technologies are granted priority feed-in rights before conventional technologies. As a result, renewable technologies are dispatched irrespective of the state of the electricity markets. Moreover, investment incentives take place on the basis of investment costs, site-specific utilization rates, and the level of reimbursements. All else being equal, sites with favourable conditions are generally preferred to sites with adverse conditions, sometimes leading to increased concentrations of RES-E, and affecting in turn the operation and investments within the conventional power plant fleet. Consequently, the exclusion of renewable technologies from the competition of the electricity markets entails inefficiencies, with respect to the total power generation system as a whole.

Thus, the following question is examined: **"What is the optimal allocation and expansion of RES-E in Europe if renewable technologies compete along with conventional technologies in electricity markets?"**

In addition, in sensitivity scenarios **the inefficiencies associated with a priority feed-in and a decoupling from electricity price signals for renewable technologies are quantified and analysed**.

Finally, in further sensitivity scenarios, the **role of different flexibility options** of the electricity supply side (storage capacities and grid expansion) will be scrutinized.

Recent literature has focused on either the determination of additional costs due to the inclusion of RES-E, given a certain RES-E allocation, or the determination of an optimal allocation of RES-E, without considering the influences on the conventional power generation system and its feedback effects on the RES allocation. Fürsch et al. (2010) takes into account some interaction between the European RES-E allocation and the impacts on the conventional power market. However, the link is quite weak, as the study assumes a priority feed-in for renewable energy technologies, so that the conventional power plant fleet is made to adapt to the RES-E quantities. These have been determined by another model ex-ante.

There are models which optimize renewable and conventional power generating capacities simultaneously (integrative models), so that RES-E is allocated in a way that is optimal for the whole power generation system. However, these approaches are very limited in their geographical and technological scope. Among other things, this dissertation develops an integrative approach, including the associated data input for the scope of

EU-27, plus Norway and Switzerland (EU-27-plus) and for diverse renewable technologies. The renewable technologies considered are intermittent RES, such as wind and solar power as well as continuous available RES, such as power from biomass and geothermal energy.

1.2 Development of Typedays for European Electricity Market Models Including RES-E

Due to the high geographical and technological scope of the model and computational constraints, it is necessary to reduce the intra-annual time resolution of the model and therewith of the data input. Until now, there is not a methodology to represent intermittent RES in multi-technological and multi-regional investment and dispatch electricity market models comprising several investment periods. The usage of “typedays” is a commonly applied measure to reduce the intra-annual temporal resolution of such models. Thus, in this work typedays for intermittent RES are developed in order to represent the intra-annual availability of RES in a representative way. The appropriate representation of intermittent RES is a prerequisite for electricity market models that include renewable technologies.

The reduction of the temporal resolution with respect to intermittent RES-E is particularly challenging as the characteristics of intermittency and non-regular availability unfold better in a high time resolution. Although, as a consequence some characteristics of intermittent RES are cut off, it is important that other characteristics are sustained. Chapter 4 analyses the characteristics of wind and solar power, whereby the focus is set on wind power as it is still more economic and expected to have a higher contribution to renewable targets fulfilments in the future. Chapter 4 isolates the following characteristics of wind power that should be represented in the data input:

- The quality of a wind site should be represented by its empirical annual yields.
- The seasonality of the wind speeds in the respective regions should be considered.
- Different possible weather conditions (low and high wind periods) should be represented for all modelled seasons and regions.
- These should correspond to their empirical frequencies of occurrence.
- Both, steep as well as flat wind speed gradients, should be taken into account.
- Smoothing effects of wind speeds between regions should be considered.

The last point excludes an isolated typeday modelling of wind for single regions. Hence, wind conditions of one region have to be considered under the aspect of simultaneity in relation to the wind conditions of other regions. In general, the typeday modelling intends to reduce the data complexity and to reveal a structure within the data. The data consists of simultaneous, hourly wind speed and solar irradiation data for a four year horizon. In the end, the modelled typedays should represent the maximum available wind power at one point in time.

The methodology of the typeday modelling for wind is subdivided into three iterative and intertwined components. First, reducing the data complexity requires reducing the original amount of wind regions to be examined. This is facilitated by a so called regional cluster analysis, which is a common technique for statistical data analysis in order to identify patterns in big data sets. Cluster analysis assigns a set of observation into subsets (called clusters), so that the objects in one subset are similar in terms of one or more criteria. Hence, here the objective is to cluster regions with a similar wind speed structure into “wind supra regions”.

As demanded by long-term adequacy studies, in a second step, the different levels of wind speeds, along with their frequencies of occurrence, are identified for each wind supra region. The levels of wind speeds considered are two wind states - “high wind” and “low wind” - differentiated by season. Thereby, the same wind state applies to all regions within one wind supra region, thus assuming perfect correlation of wind conditions between all belonging regions. Due to the high complexity, smoothing effects in terms of time lags of wind conditions between single regions within a wind supra region are not considered. Moreover, since wind conditions of one region have to be considered under the aspect of simultaneity in relation to the wind conditions of other regions, the identified low- and high wind periods of one wind supra region are put in relation to the low- and high wind periods of the other wind supra regions. Based on that, different wind states for the whole geographical area (here: EU-27-plus) can be identified, with their corresponding frequencies of occurrence.

In a third step, synthetic daily wind structures are calculated for all single wind states, regions, and seasons. Here, it is not aimed at representing a “typical” daily structure for wind as wind does not follow a regular daily pattern, but rather to incorporate the average fluctuations and gradients of wind, which affect the dispatch decisions of conventional power plants. In doing so, it is ensured that the synthetic daily wind structure does not exhibit an atypical behaviour in relation to the electricity demand. The synthetic wind structure is calculated by a nonlinear optimization, subject to several constraints. For instance, the empirical average variance has to be met by the synthetic daily wind structure for each typeday.

Since the focus in this work is on wind speed modelling, the variations of solar irradiation are not captured in the data input, as this would raise the number of typedays to a higher power. For solar power, the availability will be represented by the hourly average irradiation per season and wind state. This implies that variations in the irradiation levels are averaged out. Concerning Southern European countries, in which solar power is more relevant, this assumption is valid, as solar power is relatively stable there. Nevertheless, the negative correlation between wind speed and solar irradiation values are accounted for.

1.3 Development of European Electricity Market Models Including Renewable Technologies

In order to answer the problem statement at hand, alongside with conventional technologies, the electricity market model needs to include renewable technologies (integrative model approach). On the basis of an existing investment and dispatch model for conventional technologies for the European electricity market, in this dissertation an integrative European electricity market model is developed that also includes, for the first time, renewable technologies (INTRES). In specific, a new renewable module is developed that fits into the existing model structure.

Investment relevant parameters of renewable technologies, such as costs, renewable quotas, and realistic potential limits as well as dispatch relevant parameters, such as the intra-annual availability of intermittent RES, which has been developed in chapter 4, are incorporated. Since the typeday modelling for intermittent RES accounts for the spatial correlation of wind speeds between wind supra regions with their associated empirical frequencies of occurrence, endogenous balancing effects between wind outputs at different sites are incorporated. Wind output can be further balanced by solar power, which is slightly negatively correlated to wind power, and by output from biomass and geothermal plants. Regional or technological diversification can either reduce the need to curtail RES-E or the need for backup capacity. Thus, smoothing RES output is not an aim in itself, but the advantages of a less fluctuating or less extreme output structure, in terms of e.g. less RES-E curtailment or less ramping-up and -down operations, are traded off against the disadvantage, in terms of increased total generation costs for RES-E. In the integrative model approach, smoothening of RES-E takes place if it is beneficial from the perspective of the whole power generation system. The model extends existing modelling approaches, by calculating endogenously the RES-E curtailment from technologies based on fluctuating RES and the dispatch of biomass power plants. Thus, although a maximum annual yield is implied by the typeday structures for RES and the associated frequencies of occurrence, necessary RES-E curtailment or dispatch reductions directly affect the profitability of investments in renewable capacities.

Moreover, the optimized synthetic daily wind structures entail different ramp-rates and fluctuations of wind power that comply with empirical data. Thus, increasing ramping costs and flexibility needs on the conventional supply side, as a result of including large-scale RES-E, are accounted for. In addition, the amount of capacity which is necessary to backup capacities based on fluctuating RES is determined endogenously by the intra-annual availability of RES implied by the typeday modelling. Furthermore, transmission restrictions between different regions are considered, which limit the possibilities of balancing RES output and of sharing backup capacities between regions. The integrative capability of regions is accounted for.

Hence, the developed integrative model trades off the options to reallocate RES-E at less favourable sites or to switch to more expensive renewable technologies, against the option of an increased integration burden for concentrated RES-E at favourable sites. The model approach and the data input cover the EU-27-plus.

In order to comprehend the effects of an integrative optimization compared to a situation in which RES-E has priority feed-in rights and is decoupled from electricity price signals, in addition to an integrative model approach, a sequential model approach is needed. A sequential model approach refers to the optimization of renewable and conventional technologies respectively in two separate models that are coupled in a row.

First, the model EXRES simulates the development of RES-E, by minimizing the discounted total costs of reaching certain renewable quotas. The model EXRES is developed on the basis of the renewable module of the integrative model approach. The relevant modelling equations, the time resolution as well as the data input, e.g. the intra-annual availability of the different RES in certain hours at different typedays, correspond to the ones used in the integrative model approach. This facilitates the comparability of the different model approaches.

The resulting RES-E quantities are then incorporated into the existing electricity market model as must-run generation, by deducting the hourly RES-E from the hourly electricity demand. Afterwards, the second model calculates the development of the residual electricity market, which adapts to the development of RES-E. The existing electricity market model has been extended in a way that it allows for RES-E curtailment and the determination of backup capacities, given the intra-annual availability of RES calculated by the model EXRES.

1.4 Scenario Analysis of an Optimal RES-E Allocation in Europe

In chapter 6, the two developed model approaches as well as the developed typedays for intermittent RES are applied. Due to reasons of calculation time and the related cut backs in the time resolution, the scenario analysis focuses on Western Europe. With such a geographical coverage, a two hourly time resolution for all typedays can be facilitated. In total simulations are reported until the year 2050, with investment periods of 2020, 2030, 2040 and 2050. The data of the parameters in 2010 is included as status quo.

In total, there are two base scenarios with different renewable target requirements for Western Europe, presuming competition for all technologies, and two associated sensitivity scenarios supposing priority feed-in and a decoupling from electricity market conditions for renewable technologies (S1). Moreover, two further sensitivity scenarios concerning the temporal (S2) and regional flexibility (S3) are calculated. In order to isolate effects, the technique of comparing two scenarios which differ only with respect to one aspect is deployed. In all scenarios, a coordinated RES-E policy approach for Western Europe is presumed. This means that an overall renewable quota has to be satisfied by the aggregated RES-E quantities of all countries in Western Europe.

With the help of the developed integrative model INTRES and the developed data input, two different base scenarios are calculated. These differ alone with respect to the RES-E penetrations. In the **"RES MOD"** scenario, relatively moderate shares of RES-E of the total electricity demand are assumed, whereas the "**RES HIGH"** scenario supposes relatively high renewable quotas. These scenarios can be interpreted as a competitive market setting for conventional as well as for renewable technologies. All technologies have to bid into the electricity markets. This implies that endogenous RES-E curtailment and dispatch of biomass plants are calculated, as well as that the model regions' integration capability of large-scale RES-E feeds back to the RES allocation and expansion. Besides of flexibilities on the conventional supply side, regional and technological diversification of RES-E can increase the RES-E integration capability of regions and reduce the need for backup capacity. Thus, balancing effects between different sites and technologies are considered in the data input, facilitated by the typeday modelling of intermittent RES. Furthermore, the capacity that is necessary to back up fluctuating energy sources is minimized endogenously. The two base scenarios with different renewable requirements are compared in order to demonstrate the impact of different RES-E penetrations on modelling results, in specific, in terms of the necessity to diversify RES-E regionally and technologically as well as in terms of the impacts of RES-E on the conventional supply side.

Moreover, each base scenario is compared to the associated sensitivity scenario **"PRIO RES"**, each having equal aggregated RES-E requirements for Western Europe as in the respective base scenario. In these scenarios, RES-E has a priority feed-in guarantee whenever the source is available, irrespective of the state of the electricity markets. If RES-E curtailment becomes necessary due to grid stability reasons, then renewable generators are fully compensated for the foregone output. The reimbursement of RES-E is completely decoupled from electricity price signals. The incentives induce dispatches and investments of renewable technologies, irrespective of electricity market conditions. These scenarios require the deployment of the sequential model approach. First, RES-E is optimized only in terms of its levelized costs, so that the most economic renewable technologies in terms of levelized costs are built first until the potential limit is reached. Subsequently, the residual power plant fleet has to adapt to the development of RES-E. This comparison is supposed to reveal the inefficiencies related to the use of priority feed-in and a decoupling from the electricity market signals for RES-E, compared to a competitive market setting for all technologies with respect to different RES-E penetrations. Until now, this analysis has not been carried out by existing literature.

The sensitivity scenarios **“NO CAES”** (S2) primarily analyse the differences in the optimal expansion of RES-E in a competitive market setting when the temporal flexibility is restricted. The temporal flexibility is restricted in terms of limitations on the use of storage capacities. Finally, another sensitivity scenario (S3) concerns the assumptions made for all previous scenarios with respect to the transmission capacity between countries. These are assumed to amount to the existing net transfer capacities (NTCs). They are enlarged in this sensitivity scenario **“UNLIM NTC”**, in order to reveal the advantages of more integrated European electricity markets e.g. in terms of the ability to utilize RES at favourable sites.

TABLE 1-1: OVERVIEW OVER SCENARIO SETUP AND ASSUMPTIONS

		High RES-E share	Mod. RES-E share	Priority Access	High Temporal Flexibility	High Geographical Flexibility
Basis Scenarios	RES HIGH	√			√	
	RES MOD		√		√	
S1: Priority access	PRIO RES HIGH	√		√	√	
	PRIO RES MOD		√	√	√	
S2: Temporal flexibility	NO CAES (RES HIGH)	√				
	NO CAES (PRIO RES HIGH)	√		√		
S3: Geographical flexibility	UNLIMNTC (RES HIGH)	√			√	√

Source: own assumptions

1.5 Scenario Results

The scenario results indicate that separate developments of renewable and conventional technologies entail several inefficiencies. The inefficiencies increase with higher RES-E penetrations. In a situation of aggregated RES-E quotas coupled to a priority feed-in and a decoupling from electricity price signals for renewable energy technologies, the technological and regional concentration is augmented, compared to a competitive market system.

The high regional concentration of wind capacities in countries with favourable wind conditions (i.e. Nordic countries, Ireland, and Great Britain) makes huge amounts of wind power curtailment necessary. In the PRIO RES scenario with high RES-E quotas, the intensified regional concentration of wind power increases aggregated wind power curtailment to about 50 per cent of possible wind output, or 1200 terawatt-hours per year (TWh/a) respectively, in 2050. This is apparently not economic for the power generation system as a whole. Under certain conditions, it is rather more valuable for the power generation system, to diversify wind sites in order to smooth total wind output than to only make use of the most favourable wind sites concentrated at one location. The conditions relate e.g. to the generation costs of alternative production sites.

The installation of additional renewable capacity based on fluctuating RES at favourable sites is valuable only up to a certain threshold, until the integration capability of a region is reached. The integration capability is determined by the market size, the interconnectedness and other flexibility options. Thus, the integration capability of regions is an important influencing factor for the optimal RES-E expansion.

Similar to the demand for regional diversification of RES sites, the demand for technological diversification between different renewable technologies increases with higher renewable quotas. Although in an optimal RES-E expansion wind power is the dominating technology, it is beneficial to complement distributed wind power capacities by dispatchable biomass plants. In 2050, in the RES MOD scenario, 83 per cent of the total optimized renewable output is provided by wind power. The wind share drops to 74 per cent in the RES HIGH scenario. In return, the shares of biomass and photovoltaics (PV) increase with high renewable quotas. While wind and biomass capacities are installed in several countries, photovoltaic roof top devices are rather built in Southern Europe from 2040 on, due to the decrease in investment costs.

The regional and technological diversification of RES-E in both base scenarios can keep the level of wind power curtailment at very low levels. Overall, in the scenarios RES MOD and RES HIGH only 1.9 TWh/a and 18.8 TWh/a respectively of RES-E are curtailed in 2050.

However, the inefficiencies owing to a priority feed-in and a decoupling from electricity price signals for renewable technologies are not limited to renewable technologies. The abrupt and sometimes delayed RES-E development in certain countries (e.g. in the Netherlands or Germany) in the PRIO RES scenario, relative to the base scenario, induce high investments in base- and mid-load capacities in early investment periods (2020 to 2030). With the inclusion of large-scale RES-E in later investment periods (2040 to 2050), the utilization of the base- and mid-load capacities is greatly reduced. Moreover, discontinuous changes in the RES-E development in the PRIO RES scenario, cause increased capital turnovers because of necessary adaptations on the conventional supply side. Thus, the timing of the large-scale inclusion of RES-E in a country decisively determines the development of the power plant mix.

As in the PRIO RES scenario, with moderate renewable quotas the inefficiencies are largely limited to the Nordic countries, Ireland, and Great Britain, overall differences are small. This implies an increase of total discounted costs by 38 billion $€_{2010}$, or 3 per cent respectively, compared to the base scenario. Due to the increase in mentioned inefficiencies with high renewable quotas, also the discounted differential costs between the PRIO RES and the base scenario are augmented. The discounted total costs in the PRIO RES scenario exceed the ones in the RES High scenario by 127 billion $€_{2010}$, or respectively by about 10 per cent.

If less temporal flexibility is available than assumed in the base scenarios, the demand for regional and technological diversification increases in an integrative modelling approach. Furthermore, the need to curtail RES-E increases only to a limited extent. Compared to the RES HIGH scenario, RES-E curtailment is increased by approximately 35 per cent, or 6.5 TWh/a respectively, in 2050. Given the significant increase of gas and CO_2 prices over time, the large-scale deployment of Advanced Adiabatic and Diabatic Compressed Air Energy Storage (AA-CAES) capacities saves 14 billion $€_{2010}$ discounted to 2010, accumulated in the whole period 2010 to 2050.

Although in an optimal RES-E expansion, a higher geographical flexibility supports a distribution of wind power at relatively favourable sites (e.g. in countries surrounding the North-Sea), an extreme regional concentration of wind capacity is also not found beneficial. This is because wind power fluctuations in the respective countries are positively correlated, and it further demands to remove massive amounts of wind output to other countries. In that case, e.g. Germany acts as an absorber or transit country for Nordic countries. In the UNLIM NTC scenario, RES-E balancing takes place rather between different countries than within countries. The increased scope for balancing RES-E between countries reduces the amount of total RES-E curtailment to 1.5 TWh/a in 2050. Still, it is beneficial for the whole power generation system to complement wind power with some other RES, such as solar power in Southern Europe and RES-E from biomass. On the conventional supply side, an increased geographical flexibility in the first place implies the possibility of countries to share capacities.

1.6 Implications for Policy Makers

The results show that, in particular with ambitious renewable targets, the use of a priority feed-in and a decoupling from electricity price signals for renewable technologies produce high inefficiencies. The inefficiencies do not take place only on an international, but also on a national level. For instance, in the case of Germany, a high concentration of wind power plants in the North has been the consequence. If renewable generators are not subject to electricity market conditions, they do not have an incentive to smooth output, by investing in distributed sites or to produce or curtail electricity when needed.

Policy makers of countries, which have adopted RES-E support schemes, designed with a priority feed-in guarantee and a decoupling from electricity price signals for RES-E, such as e.g. frequently feed-in tariffs, should rather progressively introduce renewable technologies into the competition of electricity markets. In the case of a technology-neutral RES-E support system, the results still indicate that a certain technological diversification would take place, though not necessarily in the early investment periods. The advantage of a European-wide harmonized support system exposing renewable technologies to electricity price signals without guaranteeing them a priority feed-in, compared to a national approach, remains: The market determines the cost-efficient allocation and expansion of RES-E on a European scale, weighting the option to reallocate RES-E at less favourable sites against the option of an increased integration burden for concentrated RES-E at favourable sites. Thereby, existing geographical and temporal inflexibilities are accounted for.

2 INTRODUCTION

2.1 Background

In times when climate change is believed to threaten societies' future welfare growth and simultaneously European countries are becoming increasingly dependent on energy imports, a radical change of the energy system is more and more envisaged in the European legislation. A part of this change consists in the implementation of a sustainable energy production. Alongside with power savings and higher energy efficiencies, renewable energy sources (RES) are seen as an integral part of a sustainable energy system.

A new European Union (EU) directive on the promotion of RES, agreed on in December 2008, obliges the Member States to increase their share of RES. By the year 2020, 20 per cent of the European energy consumption should be provided by RES, compared to 7.8 per cent in 2007 (Eurostat, 2010). Longer-term targets for renewable energy are also suggested with proposals of 50 per cent and more by 2040/50 (COM (2008) 19 final). In the electricity sector, shares will be even higher as here the possibilities of using RES are technically already available and are more economical (COM (2006) 848 final). The ultimate goal of current renewable energy support is their ability to compete with fossil fuel technologies on the market. However, in many instances, they are not yet economical.

Given the ambitious targets for RES, the change of the energy system will involve substantial financial investments. In order to keep the transformation still affordable, it is vital that the investments in RES will be efficient specifically concerning the technology and place invested in. The importance of the question is reflected in the current debate on the optimal allocation of RES in Europe and the optimal technology choice in order to achieve a given renewable target. However, it does not need to be necessarily the allocation in the most economic renewable technologies at the most favourable sites. This is because certain RES are not always available when needed. As a consequence, they bring along additional costs. These costs are associated with preserving the reliability of the power system when including the RES in the energy mix. But the additional costs are not constant and cannot be ascribed to one generation unit by RES. Among others, they are influenced by the configuration of the power system or the available transmission capacities that balance areas with power surplus and deficits.

Recent literature has focused on either the determination of additional costs, given a certain RES-E allocation, or the determination of an optimal allocation of RES-E, without considering the influences on the conventional power generation system and its feedback effects on the RES allocation. Fürsch et al. (2010) takes into account some interaction between the European RES-E allocation and the impacts on the conventional power market. However, the link is quite weak, as the study assumes a priority feed-in for renewable energy technologies, so that the conventional power plant fleet is largely made to adapt to the RES-E quantities, which have been determined by another model ex-ante.

In Europe current support policies for electricity generated by RES (RES-E) frequently exempt renewable technologies from competition. Renewable technologies are granted priority feed-in rights before other conventional technologies. As a result, renewable technologies are dispatched, irrespective of the state of the electricity markets. Lately there occurred more and more situations of excess wind power in-feed. Especially at times of high wind generation and low load, integrating wind power into the power system becomes problematic. As recent studies suggest, the combination of high wind power feed in and low load can lead to negative stock market prices (Andor et al., 2010; Nicolosi, 2010). Negative electricity prices at the European Energy Exchange (EEX) occurred for the first time at the end of 2009. For instance, at 4th October in 2009 the day-ahead price in the German/Austrian market zone between 2 a.m. and 3 a.m. fell to -500.02 €/MWh (Euro per megawatt-hour) (EEX, 2011).

Current RES-E support schemes commonly set incentives in a way that investment decisions take place on the basis of investment costs, site specific utilizations rates, and the level of reimbursements. The state of the electricity markets are not accounted for. All else being equal, sites with favourable conditions are generally preferred to sites with adverse conditions, leading partially to increased concentration of RES-E. Consequently, the exclusion of renewable technologies from the competition of the electricity markets entails inefficiencies, considering the total power generation system as a whole. The inefficiencies are expected to rise with increasing RES-E penetration in Europe.

2.2 Problem Statement and Scope of Work

Thus, in this work the question "**What is the optimal allocation and expansion of RES in Europe if renewable technologies compete in electricity markets along with conventional technologies?"** will be analysed for differing RES-E quantities.

In addition, in sensitivity scenarios **the inefficiencies associated with a priority feed-in and a decoupling from electricity price signals for renewable technologies are quantified and analysed**.

Finally, in further sensitivity scenarios, the **role of different flexibility options** of the electricity supply side (storage capacities and grid expansion) will be scrutinized

The study at hand constitutes a continuation of research published by Fürsch et al. (2010). In this study, a database concerning RES potentials and costs in Europe has been developed. Moreover, in an iterative model approach the development of the renewable and the conventional power market are optimized. The answer to the problem statement, however, requires that the allocation of RES-E in Europe is optimized in an integrative modelling approach, in which feedbacks between the RES allocation and the conventional power generation system, including transmission constraints, are directly accounted for.

In the integrative model, investment options on the conventional supply side that can ease the integration of electricity generated by RES (RES-E) - such as flexible gas units or storage capacities – will be weighed against reallocation options of RES at less favourable sites or in more expensive renewable technologies. Technological and regional diversification may lead to lower costs for the power generation system as a whole. Although the focus is on long-term investments by the power generation supply system, dispatch decisions have to be modelled also endogenously. They have a high influence on investment decisions. This holds especially for RES that are not always available when needed and in certain hours require additional controllable capacity to back them up. On the other hand, there are hours – typically in low electricity demand situations - in which feed-in by fluctuating RES exceeds the electricity demand and the transmission capacity to transport the surplus to bordering regions. In these situations, it will be necessary to cut off some RES-E. This translates into a decrease in the profitability of investments in the respective renewable technologies.

There are already models which optimize renewable and conventional power generating capacities simultaneously (integrative models), so that RES-E are allocated in a way that it is optimal for the whole power generation system. However, these approaches are very limited in their geographical and technological scope. Among others, this dissertation develops an integrative approach, including the associated data input for the scope of the EU-27, plus Norway and Switzerland (EU-27-plus) and for diverse renewable technologies. The renewable technologies considered are intermittent RES, such as wind and solar power as well as continuous available RES, such as power from biomass and geothermal energy. The development of an integrative model approach rests on the extension of an existing bottom-up, linear and deterministic optimization model having a central planer perspective. The extension essentially entails the programming of a new renewable module and the inclusion, definition, and processing of additional data. The new renewable module fits into the existing model structure and can be optionally activated or deactivated. Moreover, additional adaptations to existing model equations are necessary in order to consider the peculiarities of the RES typeday modelling.

Due to the high geographical and technological scope of the model and given computational constraints, it is necessary reducing the intra-annual time resolution of the model and the data input. Until now, there does not exist a methodology to represent intermittent RES in multi-technological, multi-regional investment and dispatch electricity market models comprising several investment periods. The usage of “typedays” is a commonly applied measure to reduce the intra-annual temporal resolution of such models. Typedays represent certain “typical” days with certain characteristics. Thus, in this work typedays for intermittent RES in Europe are developed in order to represent the intra-annual availability of RES in a representative way. Thereby, the typedays for intermittent RES contain information about variances, gradients, the correlation with other RES, and the spatial correlation. The appropriate representation of intermittent RES is a prerequisite for electricity market models that include renewable technologies.

Since the characteristics of fluctuating RES are critical for investment and dispatch decisions of the conventional supply side, they will be analysed in depth in chapter 4. The analysis is based on high resolution, simultaneous data covering a four year time horizon. Thereby, a European geographical scope[1] is taken because due to resource differences between countries' investment decisions and reallocation effects of RES unfold better on an international than on a national level. Since ambitious European RES targets will require the contribution from more than one sort of RES, not

[1] In specific all EU-27 in addition Norway and Switzerland are included.

only the characteristics of wind power are examined, but also of solar power and their dependence on each other. In the analysis, diverse RES characteristics are identified, including their diurnal and seasonal patterns, different production levels and variances as well as the spatial correlations. Due to the latter, it is important that the availability of RES is considered under the aspect of simultaneity.

In view of the fact that the representation of fluctuating RES in Europe for the purpose of European electricity market models is lacking, a modelling approach of the same will be developed in chapter 4. The focus in this work is set on wind power. This is a valid because wind power is expected to be more important in the future as it is comparatively economical. The methodology of the typeday modelling for wind is subdivided into three iterative and intertwined components. Thereby, each component aims at reducing the data complexity, without losing too much information and still retaining the major wind characteristics. In a first modelling step, the original amount of wind regions is reduced by a regional cluster analysis. Secondly, different European wind events along with their frequencies of occurrence are identified, whereby wind conditions of one region are considered under the aspect of simultaneity in relation to the wind conditions of other regions. This allows the representation of balancing effects of wind power between regions. Finally, synthetic daily wind structures are optimized for each predefined typeday and each region. The typeday modelling of solar power accounts for the correlation between solar and wind power.

In chapter 5, an existing investment and dispatch model for the European electricity market is extended. Besides conventional technologies, renewable technologies will be included in the model set-up (integrative model approach). Investment relevant parameters of renewable technologies, such as costs and potential limits as well as dispatch relevant parameters, such as the availability of fluctuating RES, as developed in chapter 4, will be incorporated. The model extends the existing model by calculating endogenously the optimal RES-E curtailment from technologies based on fluctuating RES and the dispatch of biomass power plants. In addition, the amount of capacity necessary to backup capacities based on fluctuating RES is determined endogenously taking into account transport restrictions. The integrative capability of regions directly feeds back to the investment decisions for RES. The integrative capability is influenced by the market size, the prevailing geographical-, temporal-, and technological flexibility as well as by the resulting consequences for renewable technologies in terms of e.g. RES-E curtailment. Finally, endogenous balancing effects between renewable output at different sites and from different technologies are accounted for. This is facilitated by the typeday modelling of chapter 4. The model approach and the data input have a European coverage.

Chapter 6 applies the European investment and dispatch model, including an appropriate representation of fluctuating RES. In two base scenarios the integrative model approach will be applied. This means that renewable energy technologies have to bid in the electricity market as conventional technologies do and are not treated prior ranking. The two base scenarios differ in terms of the renewable quotas. Both base scenarios will be compared to two associated scenarios, in which RES-E enjoys priority feed-in whenever the source is available, irrespectively of the situation on the electricity market. Two further sensitivity scenarios, establish the sensitivity of results with respect to the temporal and geographical flexibility. Remaining limitations of the approach will be discussed.

Finally, chapter 7 draws important conclusions for policy makers. Recommendations for further research are given.

3 RENEWABLE POWER IN POWER SYSTEMS

3.1 A Definition of Renewable Energy Sources

Commonly renewable energy sources (RES) are defined in relation to their difference to fossil energy sources. The characteristics of RES are defined among others by Farret and Simões (2006).

"*A renewable energy source cannot run out and causes so little damage to the environment that its use does not need to be restricted.[…] A renewable energy source is replenished continuously.*" (Farret and Simões, 2006, p. 4)

Thus, RES can be distinguished from mineral resources, such as fossil fuels and uranium, with regard to two aspects. First, in contrast to mineral resources, RES describe energy sources that replenish themselves near-term, or whose usage does not contribute to the depletion of the source in timeframes relevant for human mankind. A second attribute of renewable energy sources is that they can be harnessed to produce e.g. electricity or process heat with less adverse impacts on the environment, either in terms of emissions or long-lasting waste products.

The legal definition of RES for the European Union is given by the Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources of the European Commission (EC). According to the directive, RES refer to renewable non-fossil energy sources such as wind, solar, geothermal, wave, tidal, hydro power as well as to the energetic potential of biomass, landfill gas, sewage treatment plant gas, and biogases (COM (2001) 2001/77/EC).

In this dissertation, the following RES will be considered: wind, solar and geothermal power as well as biomass[2].

Concerning wind onshore, two plants with different nominal capacities will be incorporated. Wind offshore power plants are represented by a plant size of 5 MW nominal capacity. Solar power will be converted to electricity by small photovoltaic devices only. As the available land for large-scale photovoltaic power plants and central solar power (CSP) in Europe is scarce (Fürsch et al., 2010), they will not be accounted for. Moreover, except of lower costs due to economies of scale, large-scale photovoltaic power plants are not qualitatively different from smaller photovoltaic devices. Therefore, they are not expected to offer interesting new insights. By contrast, the direct storage possibility of CSP plants gives this technology a competitive advantage compared to technologies based on fluctuating RES. However, since the CSP potential is limited in Europe, CSP deployment in Northern Africa and an associated physical transport of electricity to Europe is more relevant (Desertec, 2011). Yet, the analysis of how electricity generated by CSP in Northern Africa affects the optimal allocation of RES-E in Europe is beyond the scope of this work.

Three different power plants fired by biomass will be included. They differ with respect to costs and technical properties. Concerning geothermal power, two sorts, based on the type of reservoir, are considered. Currently, the world wide geothermal power generation is dominated by the utilization of high enthalpy reservoirs, which are located in areas with volcanic activities. High enthalpy reservoirs consist of fluids with temperatures of several hundred degrees Celsius. In the EU-27, high enthalpy reservoirs can be found only in Italy. Geothermal power

[2] Although burning biomass does produce CO2 emissions, this is part of the so-called short CO2 cycle. Plants and trees absorb CO2 emissions from the atmosphere in their growth process. This is released again when burned; thus building a closed-loop system with no extra production of CO2 (Tietenberg, 2000). However, secondary adverse environmental aspects of the use of biomass, such as forest clearance, are not considered.

generation based on high enthalpy reservoirs is relatively competitive and can be described as being a mature technology. By contrast, in other European countries geothermal power generation is only possible by drilling deeper, to around 5000 meter below the earth surface. Methods to extract geothermal energy from the deep underground are subsumed under the term enhanced geothermal or petrothermal power generation. They are characterized by very high investment costs, whereby the costs for the drilling constitute the biggest part (Wissen, 2012; Fürsch et al., 2010).

Moreover, the focus lies on the electricity produced by RES (RES-E) only. Other sectors in which RES can be utilized, such as in the transport or the heating sector, are not considered. Furthermore, the geographical scope of the analysis contains the EU-27, in addition to Switzerland and Norway (in the following termed EU-27-plus). Given the geographical focus, the next paragraph will concentrate on the development of RES-E in the EU-27-plus. Thereby, special attention is put on the policies that promote the use of RES-E.

3.2 RES-E Development and Regulation in Europe

In general, RES-E in absolute terms has increased over time, while the RES-E share at the total electricity demand has remained relatively constant. The latter is due to the simultaneous increase in electricity demand. According to a study of Eurelectric (2009), RES-E has increased steadily since 2000 (see Figure 3-1). Especially “new” RES-E provided by biomass and wind power has augmented considerably. Still, the lion’s share is provided by large hydro power which is dependent upon the amount of precipitation. However, the development potential of large hydro power in Europe is limited, due to environmental and geographical aspects (Gatzen, 2008). Thus, the biggest contribution to increase RES-E in the future has to be provided by RES other than hydropower. This is also reflected in the predicted RES-E development for 2020 and 2030 by

Eurelectric (2009). Accordingly, wind power and biomass are projected to increase the most in Europe until 2030.

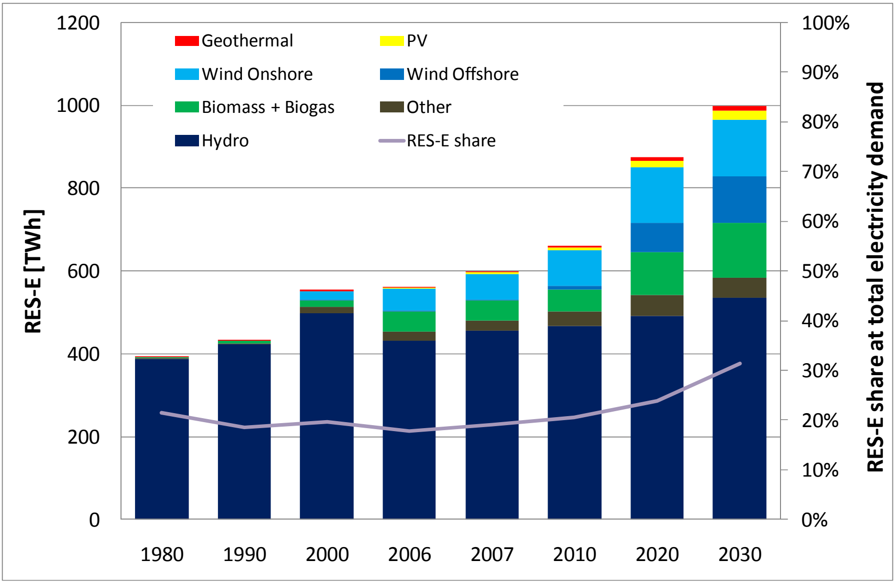

FIGURE 3-1: DEVELOPMENT AND PROJECTED DEVELOPMENT OF RES-E IN EU-27-PLUS

Source: Author based on Eurelectric (2009)

RES-E development has been triggered by national and European support policies for the promotion of RES-E. Based on climate protection and security of supply considerations, the European Member States have committed themselves to promote the development of RES-E. Since, in the electricity sector, renewable energy technologies are in many cases not yet competitive compared to conventional power producing technologies based on fossil fuels, they require financial support, if their expansion is intended (COM (2006) 848 final).

Within the framework of the EU climate package from December 2008, the European Member States obliged themselves for the first time to mandatory renewable energy targets for 2020 (COM (2008) 19 final). By contrast, renewable targets for the year 2010, as defined in the Directive EC/77/2001, were not binding (COM (2001) 2001/77/EC). Obligatory RES targets for 2020 have been motivated by the Renewable Energy Progress Report, which revealed that the voluntary renewable targets for the year 2010 were not able to be met (COM (2009) 192 final).

Within the framework of the EU climate package from December 2008, the European RES target for the year 2020 is defined as a percentage of final energy consumption. According to the prevailing EC-Directive for the promotion of RES, in 2020, 20 per cent of final energy consumption in the EU-27 should stem from RES (COM (2008) 19 final), compared to 7.8 per cent in 2007 (Eurostat, 2010).

Since the EU Member States have different RES potentials, as well as different economic preconditions, they will contribute differently to the achievement of the 2020 RES targets. However, every Member State is required to increase its share of RES by 5.5 per cent until 2020 compared to their respective 2005 levels. The other part of the RES increase is calculated on the basis of the Member States' gross domestic product per capita.

Besides a specific 10 per cent biofuel target in the transporting sector, the overall RES target is broken down to the individual sectors (electricity, heat, traffic). The breakdown between the sectors is specified within the National Allocation Plans that had to be submitted by the national governments to the European authorities in June 2010. According to the Roadmap of the EC, within the European electricity sector an approximate RES-E share of 34 per cent is aimed at (COM (2006) 848 final).

The expansion of RES-E shall be achieved with the help of the diverse promotion systems which are implemented in the EU Member Countries (COM (2008) 19 final). Currently, eighteen countries have chosen a price-based support, such as feed-in tariffs or premium systems. Six countries use quantity-based support, i.e. quota systems. Three countries have implemented other systems. Moreover, some countries have hybrid systems that allow the RES-E producers to choose between a feed-in tariff system and a premium support scheme.

Countries with quota systems oblige the market participants (producer, supplier, or consumers of electricity) to cover a certain share of the produced, supplied or consumed electricity by RES-E. Herein, tradable certificates are usually a substantial component of the system. On a separate market, the market participants can trade the certificates, independent of the physical power. Thereby, one certificate corresponds to one specific unit of RES-E generated, typically one megawatt-hour (MWh). In certain intervals, the obliged parties prove the fulfilment of the prescribed quota by delivering the certificates. If they cannot prove compliance, penalty payments are due. Moreover, usually suppliers receive revenues on the electricity market (Drillisch, 2001) as in practice quota systems are usually coupled to a direct marketing of RES-E on electricity markets. On the electricity market, they are subject to the same conditions as other technologies and compete accordingly. This means that RES-E is exposed to electricity price signals and have not priority feed-in guarantee. Except for Great Britain, which lately introduced different technology bands (Ofgem, 2011), quota systems are usually designed technology-neutral, so that more competitive renewable technologies benefit (Fürsch et al., 2010).

Priced-based instruments fix a premium price or a price mark-up for the supply of RES-E in order to stimulate growth in RES-E. Premium prices should ensure the profitability of the otherwise non-competitive technologies. The quantity of RES-E hence depends on the price that has been established in the political process. As opposed to quota systems, price-based instruments imply an inherent uncertainty about the produced quantity of RES-E. In some countries, such as Germany, tariff degression dependent on the time of commissioning are implemented. Moreover, there are a variety of tariff differentiations with respect to site and production conditions. Usually, defined tariffs and tariff degressions are not effective over a long period, as regularly new tariff regulations are enacted (Sijm, 2002). Though, theoretically, price-based instruments can also be designed technology-neutral, in practice, tariffs are distinguished for renewable technologies (Fürsch et al., 2010).

Frequently, price-based instruments, such as feed-in tariffs, are associated to a priority feed-in for RES-E into the grid. Moreover, feed-in tariffs completely exempt renewable technologies from the competition of the electricity markets. The reimbursement for RES-E is completely decoupled from electricity price signals. Advocates of feed-in tariffs (e.g. Mitchell et al., 2006; Ragwitz et al., 2007) argue that the minimization of the market risk of feed-in tariffs is the major reason of their effectiveness. Nonetheless, the argument is somewhat flawed since although the exposure to market risk would imply higher risk premiums, if properly designed, a quantity- based support system would by definition ensure that a certain amount of RES-E is actually produced.

By contrast, feed-in premium systems stipulate to sell RES-E directly on the electricity markets in combination with a premium payment. This is received in addition to the electricity price. The options to use premium systems are available in Spain and Germany (Klessmann et al., 2008). While the Spanish premium option is widely in application, the German direct marketing option is hardly used. This is a direct consequence of the height of the premium payment (Peters, 2009).

The exemption of RES-E from electricity market conditions by a priority feed-in guarantee imply that e.g. with increasing RES-E penetrations, situations of excess RES-E feed-in become more frequent. Although network operators are allowed to curtail excess feeding-in of RES-E, if it is not compatible with grid reliability and security (COM (2008) 19 final), the incentives in place distort investment and dispatch decisions of renewable generators, not to respond to electricity market conditions.

Moreover, as a consequence of the different national RES-E support policies, RES deployment in Europe does not primarily take place on the basis of resource quality, but is mainly influenced by the height of the national support compared to the local generation costs. This is reflected in Figure 3-2 and 3-3, which show the discrepancy of the RES site quality, measured by the levelized electricity generation costs (LEC)[3] (Stoft, 2002), and the respective RES deployment, measured by the installed generation capacity for onshore wind power and photovoltaics (PV) in Europe in 2007. Here, the colour coding represents the differences in regional levelized generation costs, whereby blue stands for a relatively competitive resource quality, compared to red, which denotes relatively unfavourable sites in terms of costs. While in the case of wind power the most favourable sites in terms of annual power yields are located at coastal sites, deployment mainly took place in Germany, Spain, and Denmark. Photovoltaic devices are most favourable in Southern Europe due to the high annual solar irradiation, but have been essentially adopted in Germany. Thus, it can be concluded that until now RES-E deployment in Europe did not coincide with resource quality, but is rather induced by the attractiveness of the respective support system (Golling and Lindenberger, 2009).

[3] Levelized energy cost denote the cost of generating electricity including initial capital, return on investment, as well as the costs of continuous operation, fuel, and maintenance measured per unit of electricity. It is the price at which electricity must be generated from a specific source to break even.

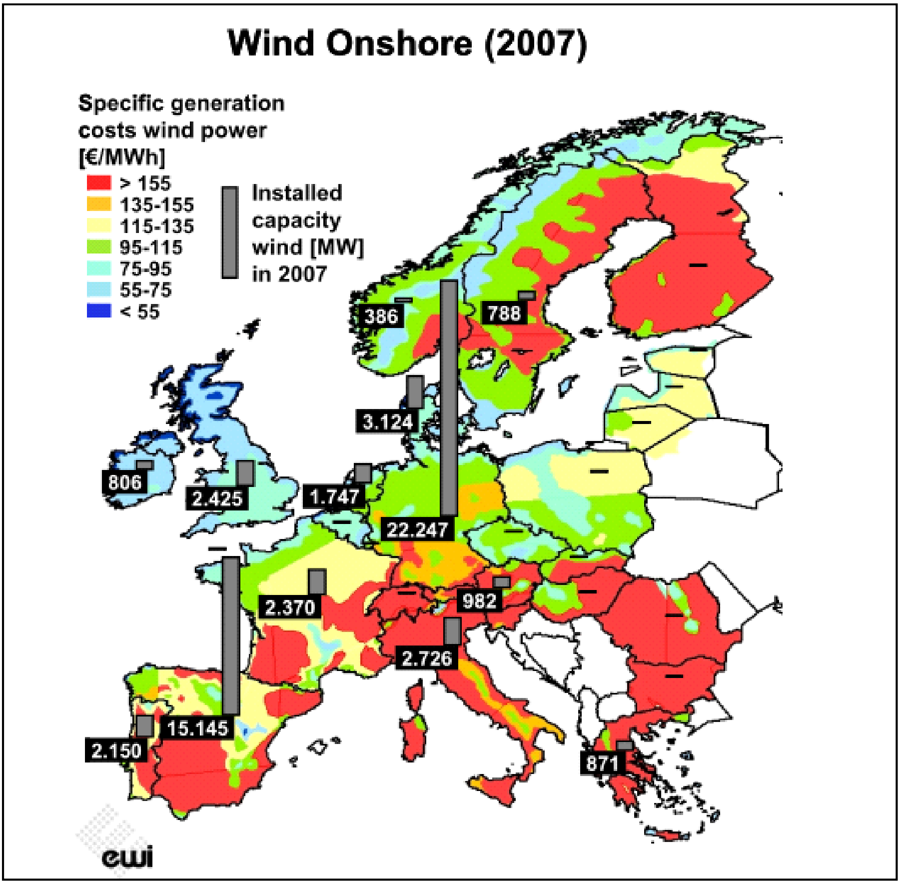

FIGURE 3-2: INSTALLED CAPACITY OF WIND ONSHORE COMPARED TO SPECIFIC GENERATION COSTS

Source: Golling and Lindenberger (2009)

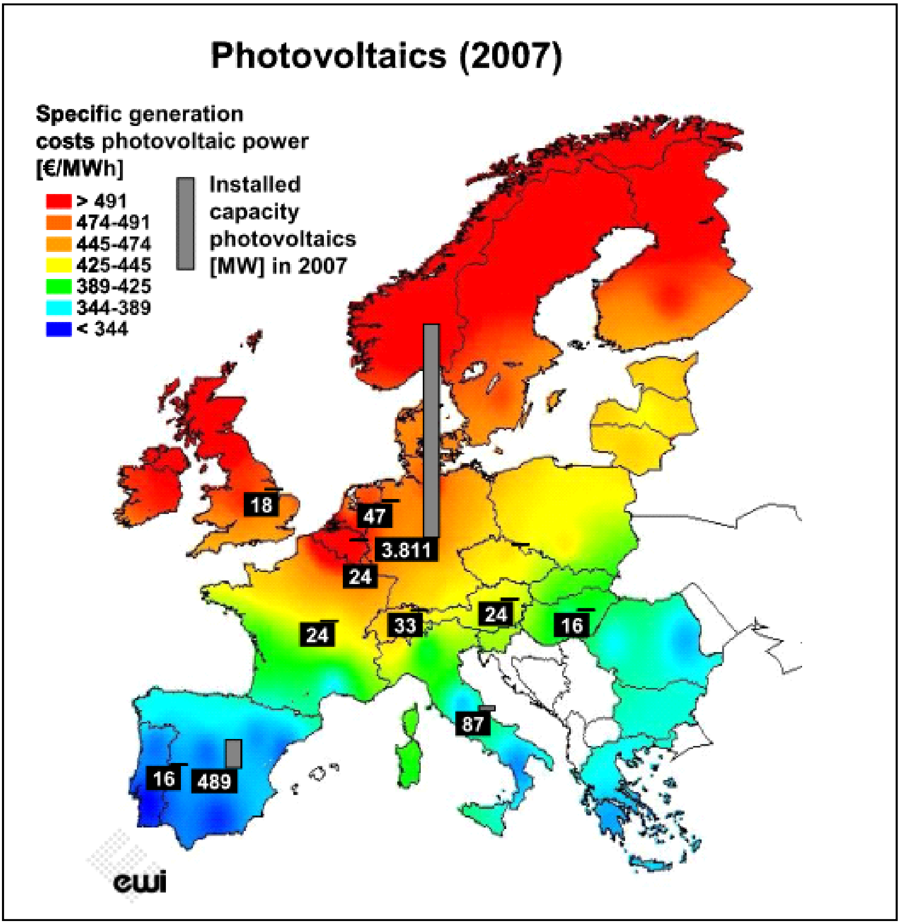

FIGURE 3-3: INSTALLED CAPACITY OF PHOTOVOLTAICS COMPARED TO SPECIFIC GENERATION COSTS

Source: Golling and Lindenberger (2009)

Alternatively to the existing national support mechanisms, a EU-wide system has been discussed. This allows for an EU-wide trade of Guarantees of Origin (GOs). GOs are issued electronically for a certain unit of electricity generation (usually per MWh). They are traded and redeemed by suppliers as evidence of the quality of the delivered electricity. Thereby, one of the most used attributes to certify quality is the proof of generation from RES.

Although such a system would exist alongside the national schemes, in essence, it would work similar to a harmonized quota scheme in which RES-E are supported by a uniform price. Thus, moving from a national and, in most instances, technology-specific support to a technology-neutral EU-wide support implies that apart from electricity price differences, RES-E deployment would take place, where resources are best, and in technologies, which are relatively competitive. This means that high investments would be made rather in renewable technologies that are comparatively cheap (e.g. wind power in Great Britain). On the other hand, countries that do not have relatively favourable RES resources would not contribute on their own to the EU target fulfilment, but would have to buy additional GOs on the international market. However, a system of open GO trading between all market participants was rejected in favour of a system in which one EU Member State can only statistically transfer GOs to another Member State, provided it has reached its interim RES target. In essence, this means that the national RES-E support schemes remain effective alone. Only if a surplus of RES-E is produced, excited by the national support schemes, the surplus quantities can be transferred statistically towards the quota counting of another country. The investment incentives remain unchanged from a national approach. The decision has been motivated by the concern of some parties, fearing that such an open trading system would undermine national support schemes (Golling et al., 2008).

The harmonization gains that could be reaped by a European harmonized RES-E support system, in comparison to a national approach, are evaluated in Fürsch et al. (2010). However, the study assumes that renewable technologies have priority feed-in and are not dispatched according to electricity market conditions. As a result of largely neglecting electricity market conditions, the concentration of wind power plants at favourable sites is excessive, thereby increasing the integration costs for the power system as a whole. Thus, the study concludes that the benefits of harmonization have to be weighed against the resulting increase in integration costs. These include higher wind curtailment, more backup capacities consisting of flexible gas units, base- and mid-load power plants that are operated with lower utilization, as well as a higher cumulative installed storage capacity.

The impacts of incorporating large-scale intermittent RES-E into the power system are discussed in the next chapter.

3.3 Effects of Intermittent Renewable Generation on the Power System

In this dissertation, a distinction within renewable technologies will be made in regard to the feasibility to control their dispatch. Due to their dependency on weather conditions, intermittent RES, such as wind and solar power, are not continuously available. By contrast, biomass, biogas, and geothermal power plants can be dispatched as needed to meet the demand of a power system. Thus, the latter do not influence the power system decisively as they can be operated equivalent to conventional technologies.

The effects and costs of intermittent generators on the power system depend both on the characteristics of the intermittent energy source and on the characteristics of the system which they are integrated in. For instance, the size and the flexibility of the power system, as well as the penetration rate and the quality of the RES, influence the costs of integration. The effects of intermittent generation on power systems are closely related to the attempt of sustaining the “reliability” of the system, when integrating new energy sources. Although reliability is a quite general term, signifying the capability of the power generation system to supply as much electricity as desired to all customers within acceptable standards (UCTE, 2004; Eurelectric, 2004), it can be addressed by considering two aspects of the electric system, namely adequacy and (operational) security (Luickx et al., 2008). Figure 3-4 gives a clear overview, of how the different elements of reliability are related to one another.

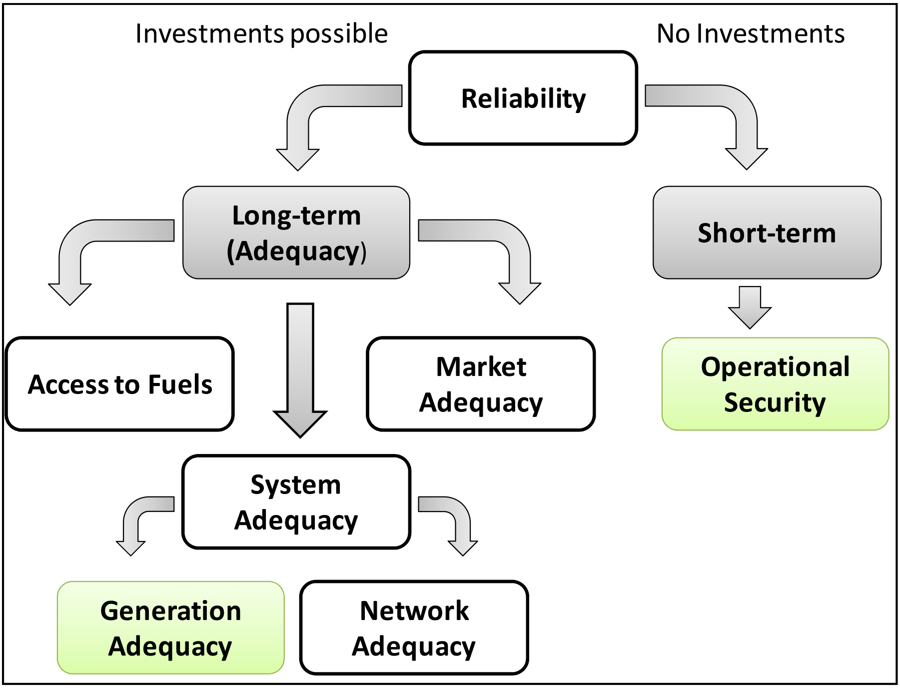

FIGURE 3-4: THE DIFFERENT COMPONENTS OF RELIABILITY OF POWER GENERATION SYSTEMS

Source: Author based on Luickx et al. (2008)

According to Luickx et al. (2008), security refers to the capability of the power system to cope with sudden disturbances in the operational time frame, such as electric short circuits, unanticipated outages of system components, unforeseeable changes in load conditions or RES feed-in that require immediate action.

Whereas the security of electricity generation systems has to be considered in the short run, adequacy is related to the long run attributes of the system. Adequacy is about the power generation system's capability to provide the aggregate electric power and the energy demands of the customers with a very low probability of failure. Adequacy consists of three elements: the system adequacy, the market adequacy and the access to fuels (Eurelectric, 2004). In order to scrutinize the effects of integrating large-scale intermittent generation on power systems, it will be focused on generation adequacy and operational security.

In that line of reasoning, as can be seen in the figure above, the effects of intermittent generation on power systems can be broadly classified into short- and long-term effects. While, in the short-term, only output can be optimized, given the available capital stock, in the long term also investments can be reallocated. Thus, short-term effects relate to the operational time scale, whereas the long-term effect deals with the ability of the system capacity to provide enough power during periods of peak load. The effects will be discussed in more detail in the following sections. Although the terminology might be different from one author to the other, the described effects of intermittent generation and, more particular, of wind power[4] on the power system are consistent with literature, such as (Ackermann, 2005; Gross et al., 2007; Holttinen et al., 2007; Luickx et al., 2008; Renewables Advisory Board, 2006).

3.3.1 Short-Term Effects

The variable production pattern of certain RES can lead to mismatches of demand and supply. In order to compensate this, adaptations on the

[4] Since today wind power makes up the biggest part of intermittent RES-E, current literature dealing with the effects of intermittent RES-E on power systems concentrates on wind power. Principally, the effects may be conveyed also to other intermittent RES, though in certain respects adaptations might be necessary.

operational time scale of other parts of the energy sector are necessary. These changes refer to the production schedule of conventional power plants and the utilization of transmission capacity. The following paragraphs will explain the costs and risks associated with this adaption.

In a situation with only conventional power plants in a competitive market setting, the production schedule and the respective dispatch commonly follows least-cost criteria. In general, a portfolio of power plants, which vary in their degree of flexibility and cost structure, is employed to meet varying segments of daily and yearly demand. Flexible plants are able to respond to rapid swings and demand as they have lower start-up times and higher ramp-rates. Flexible plants, such as open gas cycle turbines, are characterised by low fixed costs and high variable costs. By contrast, base load power plants have higher start-up times and higher fixed costs, but in general are cheaper to operate.

With the introduction of large amounts of intermittent generation, the consequential increased total supply fluctuations then lead to increased ramp-up and –down, or part-load operations. Compared to the original situation with only conventional power plants, the needed modifications in the production schedule, then, result in a lower efficiency in power plant operation and higher costs.

Alongside the costs associated to short-term effects, a risk factor has to be taken into account. In specific, a part of the output fluctuations by RES is not predictable and hence cannot be fully compensated by an alteration of the production plan beforehand. The prediction error of wind power is usually measured by the Root-Mean-Squared-Error (RMSE) of nominal capacity. It is influenced by the time frame, the size of the region considered, and the forecasting models used. According to Peters (2009), RMSE values for forecasting horizons of a few hours are 4 to 8 per cent of the installed capacity of single wind parks. For 36 hours ahead, they increase to 10 to 15 per cent and to 15 to 25 per cent for 48 hours ahead. Hence the forecast improves with a decreasing forecast horizon. From the point of view of regional integration, the level of prediction accuracy increases for larger areas due to smoothing effects. For instance, by aggregating single wind plants to predictions for a whole control area, the prediction error can be decreased to below 10 per cent for a prediction horizon of one day ahead. Although the error values seem quite low, it has to be emphasized that frequently prediction errors are measured as a share of nominal capacity and not as a share of average power output. According to Holttinen et al. (2007), a 6.2 per cent prediction error measured as a percentage of nominal capacity in West Denmark, translates to a prediction error of 28 per cent of yearly energy output. Finally, another possibility to reduce the prediction error is the combination of different forecasting models (Lei, 2008).

At the operational level, a distinction can be made between balancing services and non-balancing issues (Luickx et al., 2008). First, the distinction can be motivated by established market regulation. While current market regulation is quite heterogeneous on the European level,[5] generally, balancing takes place after gate closure. Gate closure denotes the point in time at which the power schedules by the market participants have to be defined and reported to a central settlement system. Between gate closure and real time, it is the transmission system operator (TSO) who is responsible for matching demand and supply. Reserve and response services can be contracted by the TSO from different market participants. In the very short time frame of seconds to several minutes (frequency), response services are triggered automatically. Reserve services need to be ready to operate on the TSO's request within a few minutes. Positive reserve services may be provided e.g. by power plants that run in part-load, by gas turbines with low start-up restrictions, by pump storage plants or even by demand reduction. Though there are several categories of reserve services, contingent on the speed of delivery and on other characteristics, these are not considered here further. More details

[5] An overview of balancing rules in Europe can be found on www.etso-net.org.

about the different categories of reserve services can be found in Wawer (2007) and Schulz (2007).

In general, system balancing services are needed to deal with unexpected or respectively unpredictable short-term fluctuations, which are caused e.g. by unplanned plant outages, demand and intermittent output prediction errors (Gross et al., 2007). In the context of intermittent generation in the power system, balancing requirements depend on the size of the control area and the concentration of intermittent generation capacity as well as on the accuracy of demand and output prediction (Holttinen et al., 2007). Emerging intraday markets potentially decrease the amount of required reserve capacities due to predictions that are closer to real time (Weber, 2010). The non-balancing part, by contrast, occurs before gate closure, at which the power plant units have to commit themselves to provide a certain power output, e.g. one day after. Thereby, the unit commitment will largely be based on the knowledge available at this point in time.

Despite of efficiency losses in conventional generation, large-scale intermittent generation can lead to increased transmission between regions, depending on the location of intermittent generation capacity relative to the load, and the correlation between intermittent production and load consumption. As a consequence, transmission losses or, in case transmission capacity is insufficient, bottlenecks in transmission are boosted (Ackermann T. , 2005).

Furthermore, large amounts of intermittent generation may simply exceed the amount that can be absorbed by the system (Golling C. , 2010). In these instances, it may be necessary to curtail a part of the intermittent generation. According to Fink et al. (2009), curtailment of intermittent generation can be ascribed to two reasons: First, the lack of sufficient transmission capacity and second, high wind generation, especially at times of low load. For instance, a study by Sinclair Knight Merz (2008), which analyses growth scenarios for RES-E in Great Britain, estimates that e.g. at an installed wind capacity of 66 Gigawatt (GW) in Great Britain around 9 per cent of associated wind output has to be curtailed. Moreover, beyond a certain threshold of installed wind capacity – established by the study at 40 GW for the case of Great Britain - the level of curtailment grows rapidly. The need to curtail is aggravated, if there is a lot of other must-run generation, such as combined heat production (CHP) in the system, as in Denmark or if conventional thermal plants are continued to be run in part-load, due to operational strategies.

As stated earlier, when quantifying the impacts and costs of intermittent generation, it is important to take into account the characteristics of the system of which it forms part. The integration costs into a rigid system are a lot higher than integrating intermittent generation into a more flexible system (DeCarolis and Keith, 2006). There exist a wide range of technology options that enhance the flexibility of the power system.

Examples for existing flexibility options in the electricity sector are (Ackermann T. , 2005; Gatzen, 2008):

- Flexible generation units e.g. gas units and flexible CHP units: **operational flexibility on the supply side**
- Short-term flexibility by renewable technologies by curtailing RES-E output, if required: **operational flexibility on the supply side**
- Increased interconnector capacities between regions: **geographical flexibility**
- Electricity storage options such as pump hydro storage, advanced adiabatic and diabatic compressed air energy storage (CAES and AA-CAES): **temporal flexibility**
- Demand-side-management and demand-side-bidding: **operational flexibility on the demand side**

Though flexibilities at the demand side are viable options in order to absorb more variable energy sources, these will not be considered further. More information on the possibilities and costs to integrate large-scale RES-E into the German power system can be found in DENA II (2010).

3.3.2 Long-Term Effects

In order to ensure an adequate electricity supply in the long run, there has to be enough capacity in the markets to satisfy annual peak demand. Due to possible plant outages, wrong demand predictions or other unforeseen occurrences a so called “system margin” of maximum possible capacity over annual peak demand is considered necessary. In contrast to system balancing reserves and with regard to the long lead-times for capacity expansion, the concept of system margin is to be seen as a long-term planning issue.

The closer to real time, the smaller the system margin becomes, due to e.g. the realization of outages. Weather patterns have an effect on intermittent output, on the level and timing of peak demand. The capacity termed as system margin exceeds the capacity dedicated for balancing services. In contrast to capacities for balancing services the system margin capacities are not explicitly contracted for. In a liberalized market setting, the current practice by the TSO is simply to scrutinize and inform on this margin. In case of a perceived lack the of system margin, the market signals in terms of scarcity rents should at least in theory be sufficient to trigger new capacity investments (Stoft, 2002).

The aim of generation adequacy is to ensure that a specific measure of reliability is maintained, with only a small risk of demand being unfulfilled. The measure most often used when assessing the impact of generation adequacy on customers, is related to the Loss-of-load probability (LOLP). LOLP expresses the likelihood that loads will need to be shed because of insufficient supply (Gross et al., 2007). The Union for the Co-ordination of Transmission of Electricity (UCTE) specifies a LOLP guideline value of 1 per cent that should be aimed at within a power system (UCTE, 2009, p. 12). Other measures to evaluate the generation adequacy are the Loss-of-load expectation (LOLE) and the Loss-of-energy expectation (LOEE) (Luickx et al., 2008). Generation adequacy is typically determined in terms of the amounts of planning and operable power plants in the system (Gross et al., 2007).

All else being equal, intermittent generation increases the required system margin. Due to a higher variability in output, it is less likely that it can be produced at nominal capacity at times of peak demand. Nevertheless, intermittent generators can contribute to system reliability, given there is some probability of output during peak periods. They may balance conventional plants' output, if these experiences forced outages. Moreover, intermittent output may be independent or even positively correlated to fluctuations in energy demand. The capacity credit is a widely applied measure of the contribution that intermittent generation can make to generation adequacy. It is usually expressed as a percentage of the intermittent generator's installed capacity. Although the system margin required to achieve a given level of reliability depends on many complex factors, it can be approximated by statistical calculations or simplified models (Holttinen et al., 2007). Literature review concerning the quantification of capacity credits will be provided in chapter 3.4.2.

Among other things the following chapter will introduce some models used in the literature that attempt to quantify some of the effects mentioned above.

3.4 RES-E and Power System Models in the Literature

In energy economic system analysis, different model approaches are used for analyzing RES-E in power systems. Thereby, the different approaches focus on different aspects of the subject matter. While some try to optimize renewable energy sources independently of the electricity market, others analyze integration problems or costs that are caused by RES-E in the conventional power market, given a certain allocation of RES-E. Then there are models that use two models – one for the conventional and one for renewable technologies – iteratively. Finally, other approaches model conventional and RES in conjunction. Thus, the prevailing modelling approaches can be grouped according to whether they represent the electricity market explicitly, only the renewable energy market or both. Consequently four categories are distinguished:

1) Renewable power models without explicit electricity market representation
2) Explicit power market modelling with exogenous renewable power
3) Iterative modelling of the conventional and renewable power markets
4) Integrative modelling of the conventional and renewable power markets

In general, energy system models can be classified into bottom-up and top-down models. Top-down approaches represent the energy system from a macroeconomic perspective. Technical production conditions are represented on an aggregated level and substitutions of processes or energy sources are resolved on the basis of elasticities (Groschke et al., 2009). Top-down approaches are therefore not suited for the analysis carried out in this thesis, due to the lack of technical detail.

Bottom-up models, by contrast, describe the energy system from a detailed technological perspective. Within the class of bottom-up models, there are optimization models and simulation models. Since simulation models are not built on closed equilibrium frameworks, but, instead, their solution is based on a set of rules that define the development of certain variables and processes, they will not be considered further. By contrast, partial equilibrium optimization models optimize the electricity system subject to certain conditions and have a closed solution. Therefore, they are also called normative models. Since individual technology options are represented explicitly, technological developments induced by exogenous influences, such as higher fuel prices or certain policy measures, can be shown with a high level of detail. When the demand is assumed to be inelastic, the problem reduces to a cost minimization problem for a central planner of the energy system. Dynamic optimization models capture inter-temporal effects, by incorporating a perfect foresight perspective for all included time periods or a quasi-dynamic or a myopic perspective, by optimizing the time periods sequentially (Sensfuß, 2007). As optimization models are well suited for optimizing capacity expansion planning of the electricity sector, in the following they will be focused on.

In addition to the distinction between bottom-up and top-down models, modelling approaches can be classified according to other specific attributes, such as time-, and regional scope, and whether or not and in which way uncertainty and transmission constraints are modelled (Ventosa et al., 2005). For example, concerning the time scope, it can be differentiated between long-term planning and short-term scheduling studies. In the long run, capacity-investment decisions have to be included as decision variables, while unit-commitment decisions are usually neglected. In contrast, in the short run, start-up and shut-down decisions become more important, while the capacity is often taken as given. According to the way in which uncertainty is represented, models can be classified into probabilistic and deterministic models. Probabilistic models model the uncertain nature of random variables by using probabilistic distributions, while deterministic models only consider the expected value of variables. Transmission constraints for electricity transports between model regions are also an important influencing factor of results.

The following section will provide a literature review on existing models of the electricity sector. In addition, other approaches that attempt to optimize the allocation of RES-E by applying mean variance theory and statistical approaches that determine additional capacity requirements due to RES-E are touched. According to the classification of models given in the preceding paragraphs, the models differ in several accounts. Primarily, the prevailing model approaches will be classified according to the four categories specified in the beginning of this subsection. Thus, the approaches are classified according to whether they represent the electricity market explicitly, only the renewable energy market or both. The literature review given here makes no claim to be complete. The focus will be on the most recent literature.

3.4.1 Renewable Power Optimization without Explicit Electricity Market Representation

Modelling approaches, which optimize RES-E without explicitly modelling the electricity market, are models that focus on optimizing the RES-E distribution subject to different problem specifications. Although some approaches take some elements from the electricity market into account, they refrain from modelling it explicitly, i.e. the dispatch characteristics of conventional plants or transmission constraints.

The projects GreenX, GreenNet, and ADMIRE REBUS simulate RES generation capacity by calculating competitive market equilibriums. Thereby, different policy options are evaluated. While GreenX aims at deriving optimal promotion strategies in the EU-15 countries, GreenNet expands the focus to an optimal integration of RES-E into the European electricity grid by adding exogenous system integration costs to the RES capacity costs. Moreover, GreenNet includes all EU-27 states. ADMIRE REBUS focuses on the European RES-E market only (Uyterlinde et al., 2003). Its objective is to project the future RES-E growth and analyse shortfalls of the promotion systems. Its basic modelling approach corresponds to the GREEN X model, except that the modelling is reduced to the RES-E market.

The GreenX model determines the equilibrium level of supply and demand within each market segment – e.g. tradable green certificate market, electricity power market, tradable emissions permit market – on a yearly basis. Supply is derived from dynamic cost-resource curves which are composed of technology potential and corresponding cost combinations. It is important to note, that the dispatch of capacities is not modelled explicitly, but the technologies' annual full load hours are set exogenously (Ragwitz et al., 2004).

As mentioned earlier, the GreenNet model additionally includes system integration costs into the calculations, whereby integration costs consist of grid connection costs, grid reinforcement costs, additional system capacity costs and balancing costs. The costs are based on empirical studies and separate modelling and are given exogenous to the model. In effect, additional costs shift the dynamic cost-resource curves for intermittent RES-E technologies upward. While grid connection and reinforcement costs add to the long term investment costs, system capacity and balancing costs are modelled as being short term by adding them to the existing generation marginal costs (Auer et al., 2006).

The advantage of these models is the reduced calculation time needed and the possibility of modelling markets with a big geographical scope with low computational effort. But the models cannot capture the aspect of intermittency of the RES-E technologies. In the GreenNet project, these effects are captured trough exogenous costs, which are based on empirical studies and separate modelling approaches. However, explicit modelling indicates that the costs induced by intermittent RES-E technologies are strongly varying, dependent on the generation system they are incorporated in. An approach which does not explicitly include the power generation system, therefore, does not seem appropriate to analyse interactions of RES-E technologies and the conventional electricity generation system.

As opposed to this, there are approaches that optimise renewable portfolios across different regions and or technologies, by taking either the correlations between the outputs of different technologies into account or the correlation of the output of one technology located in different areas. There are several papers that apply Mean-Variance Portfolio theory to identify portfolios that minimize the total variance of wind power portfolios output for a given level of production. For instance, Drake and Hubacek (2007) identify the optimal weights for a given target capacity of 2.7 GW at four different wind sites in the UK. They use hourly wind values and compare the optimal portfolio with a more concentrated allocation of wind power capacity at one wind site, which is characterised by favourable wind conditions. Although they find that wind power variability can be reduced by 36 per cent with a more distributed wind power capacity, they show that in return the average wind power generation decreases due to lower average power generation at the other wind sites.

Roques et al. (2010) establish optimal wind portfolios for five European countries for two different scenarios. In the first scenario, they maximize the wind capacity factor and, at the same time, minimize the variance of hourly wind production values, whereas, in the second scenario, the variance is minimized only during peak hours. The second scenario is interpreted as an assessment of the contribution of wind power to the system adequacy. Additionally, a constrained portfolio is calculated for both scenarios. Two types of constraints are considered: wind resource potential and network limitation constraints. As they are expressed as percentages of total installed capacity for certain years, in effect, they are limiting the weights of the different portfolio elements. As expected, it is shown that constrained portfolios are less efficient than unconstrained ones.

Grothe and Schnieders (Forthcoming) deviate from the Mean-Variance Portfolio Theory, as they state that variance as such is not what matters for the power system, but that wind energy should instead provide a stable baseload. Thus, instead, they maximize the lower quantiles or the Value-at-Risk of the daily means of wind power production at 36 wind sites in Germany. Since the multivariate data are not normally distributed, they apply nonlinear time series models and copula methods.[6] Some weights have been limited for certain wind sites (e.g. the Zugspitze), due to unfavourable geographical characteristics.

Muñoz et al. (2009) use Mean-Variance Portfolio Theory on different energies, which are wind, photovoltaic, mini hydro and thermo electrical in Spain. However, since the paper takes on the investor's perspective here, not the daily or hourly variations of the different energies are the matter of interest, but the variations in the energies' internal rate of return, which are calculated on a yearly basis. The bases of the internal rates of return

[6] Copula functions describe the dependency structure of random variables.

calculation are different annual cash flows that materialize due to different scenario settings. Scenarios are differentiated by the annual electricity price development and the mode of financing (external versus internal or bonus versus regulated price). The fraction of annual production that has to be complemented by reactive energy is fixed at 8 per cent for non-controllable energies like wind.

Heide et al. (2010) determine the seasonal optimal mix of solar and wind in Europe by minimizing the mismatch energy of a 100 per cent renewable portfolio – consisting of solar and wind power – net of European load. Thus, this paper introduces a new energy economic aspect compared to the other portfolio approaches, namely that it is not only the variability of fluctuating energy sources that matters, but the level of power production by renewable energy sources compared to the load pattern. Although the solar and wind shares are resolved endogenously, the distribution of solar and wind capacities across the countries of Europe is done “empirically” (Heide et al., 2010, p. 6). Moreover, Europe is modelled as a copperplate. While the possibility of a less than 100 per cent renewable portfolio is considered later, by incorporating fossil-nuclear power generation, its dispatch is not modelled, nor is it commented on its possible balancing effect.

Thus, even though the simplicity of portfolio approaches in the sense that only renewable energies are taken into account, allow a high time resolution and, thereby, a detailed treatment of the variances, co-variances, or distributions of the renewable power output, several important economic and energy economic aspects are omitted. For example, it is not discussed, what the value of reducing the variability of the portfolio is, which in economic terms may show in a reduced requirement for flexibility in the power system. Furthermore, constraints such as transmission or renewable resource potential constraints are often not accounted for. If they are, only the weights are restrained, but not in terms of absolute values, thus offering only a snap-shop, instead of a dynamic analysis for different levels of renewable penetration or transmission between regions. Moreover, on the basis of the literature reviewed, one can say that no simultaneous multi-technological and multi-regional portfolio approach exists, i.e. either the approaches are multi-dimensional on the technology side or on the regional side. Finally, the opportunity costs of reallocating renewable capacities or changing the fractions of different technologies in the portfolio are not accounted for.

3.4.2 Explicit Power Market Modelling with Exogenous Renewable Power

Next to the studies mentioned above, there is a rich variety of studies that analyze the impact of renewable generation, in most cases of wind generation, on the power system. While here the conventional power system is modelled in detail – sometimes in conjunction with Direct Current (DC) load flow models[7] – wind generation or other renewable generation is included exogenously through scenarios. According to Holttinen et al. (2007), the studies can be sub-divided into three main research fields that focus on different aspects: grid reinforcement and efficiency, balancing and efficiency of production and finally power system adequacy and capacity credit of wind power. Due to different areas of interest, in which different time scales are important, different kinds of models are required. In figure 3-5 the different research fields are depicted.

[7] Neglecting actual load flows can lead to suboptimal power plant allocation, which due to transmission bottlenecks or due to grid stability reasons are not possible. Direct Current (DC) models are one approach to model the physical load flows. By contrast to Alternating-Current (AC) approaches, DC-models can be used in complex applications, though by doing so there have to be made assumption for linearization (Groschke et al., 2009).

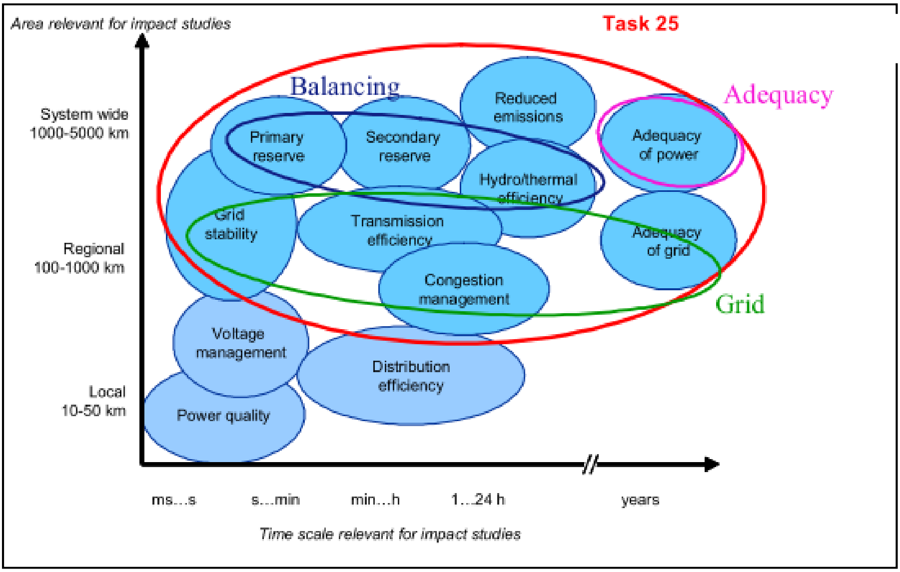

FIGURE 3-5: IMPACTS OF WIND POWER ON POWER SYSTEMS

Source: Holttinen et al. (2007)

Despite of pure electric engineering types of questions, such as voltage stability or voltage control, questions related to the required transmission reinforcement and efficiency tackle rather the economic impacts on the grid that wind power causes. The impact of wind power on the power transmission depends on the regional allocation of wind power plants relative to load and on the correlation across time between wind power production and load consumption. As a consequence of increasing wind power generation, bottlenecks in transmission can arise.

One study that exclusively relies on DC load flow modelling in answering, how much transmission reinforcement is required, is a study by Ackermann et al. (2009). Ex ante a distribution of renewable and conventional power plants is specified. The study stipulates that 90 per cent of Europe's electricity demand is being supplied by renewable power generation. RES-

E is mandated to be mostly located near the North Sea in the case of wind power or in Southern Europe with respect to solar energy. Bottleneck situations are then identified by the DC load flow model for single extreme weather situations that have occurred in Europe over the past twenty-five years. Based on that, recommendations are given on how much transmission capacity is needed and where grid reinforcement should be located.

On the basis of the Dena grid study I (DENA I, 2005), the Dena grid study II (DENA II, 2010) develops a long term strategy for the integration of large-scale offshore in Northern Germany, in addition to a high level of onshore wind energy into the German grid. The study's approach is to evaluate the costs of different integration options, such as regional grid extensions, demand-side measures or new storage technologies such as CAES for a given amount of wind power production. However, the study neglects the possibility of wind curtailment within the system optimization, although abandoning relatively low amounts of wind energy may save significant integration costs in the system as a whole.

Hulled van et al. (2009) emphasizes the benefits of higher interconnector capacity between countries, so that the smoothening effect of a diversified wind portfolio can be exploited and backup and balancing capacities be shared. Moreover, the study highlights the importance of establishing intra-day markets for cross-border trade. Cross-border power flows in the European transmission system are simulated for different points in time up to 2030, given future wind power capacity scenarios, present and future network configurations, and different market rules. In the study, different models are used: one simplified DC flow based market model and two market models, which focus on the marginal operation costs of the power system. One of the market models employed is the WILMAR planning tool explained subsequently.

WILMAR stands for Wind Power Integration in a Liberalised Electricity Market and is a stochastic, linear, multi-stage electricity model focusing on short-run decision variables. The model optimizes the dispatch in the power system on an hourly basis, with power trade being possible at different markets. An approximation of minimum operation times and minimum shut down times is included in a linear way. Amongst others, a day-ahead market and an intra-day market are represented. Whereas the first is responsible for the physical power trade, in the latter deviations between expected production and consumption agreed upon in the day-ahead market and their realized values are balanced. In specific, the demand for regulating power is attributed to the forecast errors of wind power production. The forecast errors of wind production are considered, using a scenario tree approach. Each tree represents a wind forecast, which assigns discrete probabilities to hourly wind outcomes with different time horizons corresponding to each hour of the planning period. Moreover, due to "rolling planning", reconsideration of decisions on the basis of new information is taken into account. The dispatch is modelled in separate daily planning loops, which are connected trough the shadow values of plants in operation at the end of each loop (Meibom et al., 2006a).

There are several applications (Auer et al., 2006; Meibom et al., 2006b) that use the WILMAR model to calculate the costs of integrating intermittent wind power generation into the electricity system in Europe or single countries. The focus is put on the effects of unpredictability of wind generation and its impacts on power system balancing. In general, the wind power impacts on power system balancing depends on the size of the balancing region, load variations, the degree of concentration or distribution of wind power plants, and the forecast horizon (Holttinen et al., 2007). The studies mentioned, in addition to Strbac (2002), analyze the effects of wind power on power system operation, by modelling the electricity system bottom-up. Intermittent renewable power generation is added to the system and integration costs are determined by the difference of the system costs with and without wind. However, the studies mentioned neglect the dynamics of the electricity system or at least assume the future plant power plant mix exogenously. The electricity system is not allowed to adapt endogenously to the changed requirements, due to a higher share of renewable energies in the system, i.e. by becoming more flexible.

By contrast, Swider and Weber (2007) discuss the integration costs of wind, due to changed system operation and investments in Germany. Changed system operation, due to increased variability by wind power generation, is determined by conventional power plants' reduced efficiencies in terms of increased part load modes of operation and increased start-up costs. Here, the unpredictability of wind is not modelled explicitly in terms of the forecast error, but the uncertainty related with wind output is captured by a stochastic recombining tree.[8] At each stage of the tree - corresponding to one specific time segment – there are three nodes for three different wind output scenarios: low, medium, and high wind output. Between the stages the nodes are connected with transition probabilities. Additional capacity to maintain system adequacy on the same level is determined endogenously by sequentially calculating the convolutions of the probability distributions of all power plants and the probability distribution of the wind power plants - the latter being represented by the nodes. Integration costs are then computed by the differential costs of the stochastic and the deterministic model version. In the deterministic case, a hypothetical alternative technology is included, which share the properties of wind power, such as zero variable cost, but by contrast, is predictable and constant. Wind power production, as in the other studies, is assumed to be exogenous to the model.

Although Swider and Weber (2007) calculate the additional capacity requirements and costs arising from the inclusion of intermittent generation into the power system endogenously, mostly the renewable capacity credit is determined ex-ante. Gross et al. (2006) review twenty-nine studies that

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[8] A recombining tree is a measure to decompose multistage stochastic programs, in order to retain computational convenience. Here, the state of the power system at each stage is computed as the weighted average of the prior stages scenarios. Thus, the decisions at each stage are independent of the realization of the decision at the previous stage.

estimate capacity credits quantitatively. All studies apply statistical or simulation approaches based upon a measure of reliability, such as LOLP. In Figure 3-6, it can be observed that the range of capacity values is very wide. The figure shows the results of studies where capacity credits are expressed as a percentage of installed intermittent generation capacity at given levels of penetration. Penetration levels are defined as a percentage of the total power production of the system. It can be seen that capacity credits as a percentage of installed intermittent capacity declines, as the share of electricity supplied by intermittent sources increases. The shaded area covers only studies for the Great Britain power system.

Increasing the wind capacity in the power system amplifies the additional variability of the system, which decreases the capacity credit. Due to the stochastic independence of the system components (power plant availability, wind power availability and electricity demand) with small wind penetrations, wind generation has a high balancing effect on the system and equals approximately the wind capacity factor. However, with higher wind penetrations, the smoothening effect of wind power decreases as wind power within a certain geographical radius is positively correlated. Nonetheless, it has to be noted that the decreasing trend pops up only when the capacity credit is expressed as a percentage of wind capacity installed. In absolute terms, the capacity credit rises, even though at a diminishing rate (Giebel, 2000). However, until now there are no studies that examine the capacity credit of wind power for extreme wind penetrations.

According to Gross et al. (2006), the wide range of capacity credit values reveals the sensitivity of the capacity credit to different factors. First, the value of the capacity credit is dependent on the resource availability. For instance, relatively weak wind resources have a negative impact on the capacity credit value. Second, a high degree of positive correlation between resource availability and periods of high demand affect the capacity value favourably. However, there is evidence that wind output and demand are largely uncorrelated. Of cause, the choice of the wind years to be selected for calculation is important for the results. Moreover, results are sensitive with respect to the distribution of wind farms, which is given exogenous to the calculation and to the level of reliability. Furthermore, the configuration of the power system influences the outcome as a system composed of few large power plants attributes a higher capacity credit to wind than one composed of many small units. Mentioned influencing factors are in line with e.g. (Haslett and Diesendorf, 1981). As the concept of the capacity credit is a pure national approach, in which transmission and transmission restriction are ignored, it neglects the possibility of wind output balancing between countries.

In Holttinen et al. (2007) and Gross et al. (2006), an extensive literature review of relevant studies on assessing integration costs of wind energy can be found.

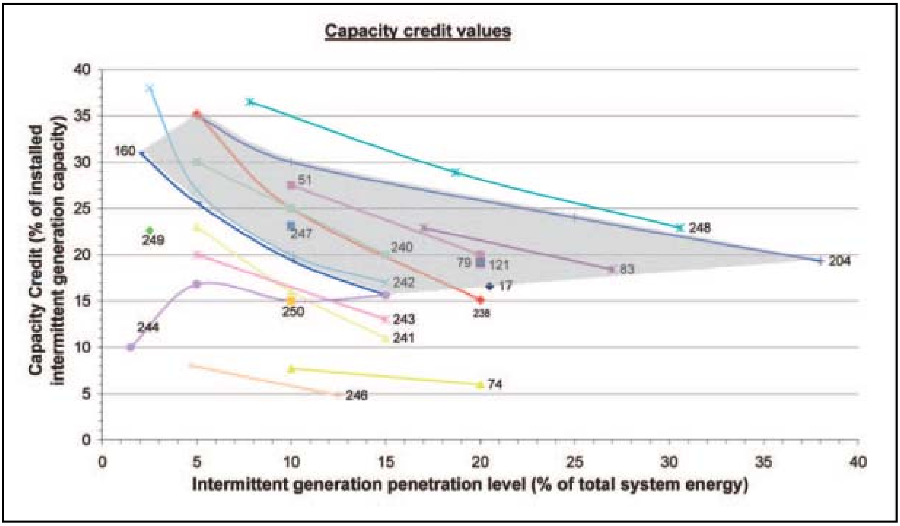

FIGURE 3-6: RANGE OFF FINDINGS ON CAPACITY CREDIT OF INTERMITTENT GENERATION

Source: Gross et al. (2006)

To summarize, there are various models that attempt to quantify the impact of intermittent RES-E on the power system. There are short-term electricity market models that mimic the uncertainty related to intermittent RES-E by including forecast error for wind power generation. However, static models, such as DC load flow models, short-term electricity system models, and statistic approaches to calculate the additional capacity requirement, do not account for the dynamic development of the power system, as they take the configuration of the power plant fleet and the allocation of RES-E as given. Although, in Swider and Weber (2007), investments in conventional capacities are allowed, a myopic approach is opted for. Moreover, dispatch decisions are taken, dependent on the average state of the system at the previous modelling state. Therefore, no dynamic optimal solution is calculated and the analysis of the stochastic effects is reduced. In general, stochastic modelling increases the calculation times greatly, because decision variables have to be calculated for every scenario path. Though stochastic modelling is desirable in order to capture the uncertainty inherent in RES-E, stochastic modelling is strongly constrained in the decision variables through the feasibility of calculations. Endogenous investments in intermittent generation would increase the complexity drastically. Thus, although the studies in this section analyze the impact of intermittent RES-E on the power system on a high level of detail, the possibility to reallocate RES-E renewable energies in order to reduce the integration burden is ignored.

3.4.3 Iterative Modelling of the Conventional and Renewable Power Markets (RES-E Study)

One study that takes the interaction between the European RES-E allocation and the impacts on the conventional power market into account is the European RES-E Policy Analysis by Fürsch et al. (2010). The modelling approach adheres to the approach described by Golling and Lindenberger (2009). In order to check the ability to integrate a high share of fluctuating generation, two models, one for the electricity market (DIME) and one for the renewable energy market (LORELEI),[9] are coupled iteratively. The regional coverage of both models contains EU-27, plus Norway and Switzerland.[10] First, LORELEI calculates the development of electricity generation and capacity from RES. In case of quantity-based support systems (quota systems), the RES-E expansion is computed on the basis of cost minimization of the RES-Es' levelized costs, modelling competition within the RES-E market segment and requiring fulfilment of a specific quota.[11] The installation of renewable capacities is limited by site specific resource potentials and maximum expansion rates of production capacities.

The LORELEI output – the RES-E quantities – serves as input for the DIME model to determine the development of the conventional power plant fleet. The RES-E quantities are deducted from total electricity demand as must-run generation, in order to arrive at the residual load which has to be met by the conventional power plants. Thus, the model approach implicitly assumes a priority feed-in for RES-E. Moreover, it has to be emphasized that the annual generation quantities by RES-E, as retrieved from the LORELEI output, have to be translated into a higher time resolution that fits into a so called typeday structure of the DIME model.[12] The data

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[9] In the renewable market, demand for RES-E is induced by different support schemes, such as feed-in tariffs or quotas. The supply of RES-E depends on the cost and resource potential of the renewable technologies. Equilibrium is determined by the equation of inelastic demand and supply.

[10] The LORELEI model has a higher regional resolution than the DIME model, as it contains 57 wind onshore regions, in contrast to the by-country-resolution of the DIME model.

[11] Although RES-E expansion may be computed on priced-based support systems as well, a least-cost approach appears to be more relevant in the long-run.

[12] The usage of "typedays" is often employed in bottom-up dispatch and investment models for computational convenience. Different "typical" daily structures on an hourly or multi-hourly basis are used, standing for idealized cases (e.g. working day and weekend load patterns), in order to reduce the intra-annual time resolution of the model. They will be described in chapter 4 in more detail.

transformation, however, has not been verified empirically. Moreover, exogenous capacity credits for fluctuating RES-E are implemented, which require reserving additional controllable capacity to ensure that increasing amounts of RES-E capacity is backed by conventional capacity. In order to facilitate the integration of large amounts of must-run and, in most cases fluctuating RES-E generation, the following flexibility options are incorporated into the DIME model. These include fixed current and planned interconnector capacities between regions and a “backstop-technology”, which acts as a black-box concerning additional flexibility measures, such as demand side management, the reduction of other RES-E or storage options (i.e. adiabatic CAES). Furthermore, the possibility to disconnect wind plants in individual hours, in which load is exceptionally low and wind feed-in is high, is included. The amount of wind reduction serves as one indication for the severity of integrating wind power into the conventional power market. The resulting regional electricity prices from the DIME model are in turn incorporated as input into the LORELEI-model to account for their influence on RES-E expansion. All else equal, a higher RES-E generation causes a lower residual load to be served by conventional technologies, thus partially leading to lower annual electricity prices.

One main finding of the study is that increasing renewable generation requires an increasing amount of backup capacities[13], while, at the same time, the utilization of conventional capacities is reduced. Thus, the function of conventional generation units shifts from merely power generation towards a function of providing capacity. Here, gas fired power stations constitute one viable and cost-efficient backup solution. Moreover, high wind power generation in hours with low demand challenge the power

[13] The use of large-scale intermittent RES-E requires additional controllable generation capacity investments to produce electricity at moments of low RES production. According to EUSUSTEL (2007), the provision of backup capacity can be brought down to two options, namely the construction of new power plants with low fixed costs or the retention of older plants that would otherwise have been decommissioned.

system. Especially in regions with favourable wind resources, notable shares of wind generation have to be discarded, if interconnector capacities are insufficient to remove the excess power supply.

Integration challenges are aggravated in a scenario that optimizes the RES-E allocation solely according to RES-E levelized costs (Harmonized Quota System or HQS scenario). In the HQS scenario, the promotion for RES-E is designed European-wide and technology-neutral, with a priority feed-in for RES-E. In this scenario, the most economic technologies at the most favourable sites are built first. Thus, due to its favourable levelized costs, wind power is the dominating technology in this scenario. Since wind power plants are built first in regions with favourable wind conditions, albeit limited by certain constraints, the concentration of wind power in certain regions is amplified in this scenario setting. Although moving from a national to a European-wide RES-E support bears discounted “harmonisation gains” of 118 billion $€_{2007}$, accumulated from the period 2008 to 2020, the study objects that the harmonization gains are counteracted by increased integration costs that arise due to a higher concentration of RES-E in certain regions.

However, the study does not account sufficiently for the systemic repercussions of integration challenges. Although a feedback loop is implemented between the DIME and the LORELEI model in terms of annual electricity prices, the influence is quite weak. This is because the dispatch of renewable technologies is not modelled endogenously. Instead the annual yields of RES are fixed exogenously. Thus, wind power quantities that have to be curtailed do not affect the allocation of RES-E. Other integration costs, such as increased backup capacities, also do not influence the allocation of RES-E. Moreover, the convergence of annual electricity prices, implying the end of the iteration loop, could not be assured anytime. Hence, due to the study’s implicit assumption of priority feed-in for RES-E, the residual power plant fleet largely has to adapt to the previous determined RES-E quantities.

One repercussion effect is discussed in Golling (2010). More specifically, the paper examines the effect of wind curtailment as a response to excess wind output on the profitability of selected wind sites. The model approach is similar to Golling and Lindenberger (2009), except that the reduced full load hours due to the necessary wind power curtailment are additionally incorporated into the LORELEI model. Thereby, it is accounted for the consequences of decreased wind utilization rates at specific sites on their relative profitability.

In the paper, a negative re-allocation effect on installed wind capacity due to wind power curtailment can be demonstrated for Ireland, the Netherlands, and Great Britain, all countries with exceptionally favourable wind conditions. Moreover, it is shown that when installed wind capacity exceeds a certain threshold, the level of curtailment grows rapidly. Higher international interconnection capacities are one remedy to alleviate the required level of curtailment. Nevertheless, though it has been shown that accounting for RES-E integration issues, such as wind curtailment, does have a noticeable effect on the allocation of RES-E, the optimal allocation of RES-E with respect to the whole power system could not be determined. By contrast, this can be done with the help of models that optimize conventional and renewable technologies simultaneously, as discussed in the proceeding subsection.

3.4.4 Integrative Modelling of the Conventional and Renewable Power Markets

One project that optimizes conventional and renewable technologies simultaneously is, for instance, the European Sustainable Electricity (EUSUSTEL) project (EUSUSTEL, 2007). The EUSUSTEL project aims at analysing the development of the electricity generation system under different policy assumptions, such as different CO_2 emission reduction targets in the EU-25. This is analysed with the help of the TIMES model, which may be applied to the analysis of the whole energy sector, but in this application is restricted to the electricity sector. It is a partial-equilibrium, bottom-up model, assuming perfect foresight, and perfect competitive and complete markets. The objective function minimizes the discounted system costs to meet electricity demand. Thereby, investment and dispatch are optimized simultaneously. The optimal dispatch is calculated for controllable power plants. Besides conventional electricity generating technologies, renewable technologies can be built endogenously. Provided that renewable energy capacity is not competitive compared to other technologies, the expansion can be either effectuated by constraints or subsidies that reduce their effective costs. Generation of intermittent renewable technologies is included as deterministic generation values in terms of capacity factors. For example, for wind power, three different capacity factors for three different locations in Europe are mentioned, which are offshore, coastal and inland regions. However, generation by renewable energies is not limited by regional potential constraints. Thus, in this study the focus is clearly on the average competitiveness of renewable energy sources, compared to conventional technologies in a European context, but not on the different regional resource potentials or on the intermittent character of certain RES. In order to account for the limited ability of intermittent renewable generation to provide secured capacity, a constant capacity credit is assigned.

The U.S. Energy Information Administration (EIA) and the Department of Energy (DOE) also uses a least-cost, linear, bottom-up model in order to determine future investments and dispatches of conventional electricity generating units and those based on RES (DOE/EIA, 2009a; DOE/EIA, 2009b). One application is e.g. their Annual Energy Outlook 2010 (DOE/EIA, 2010). However, dispatch decisions are effectuated on the basis of annual load duration curves, split into nine different time segments per annum. Renewable generation is represented by fixed capacity factors corresponding to the average generation in the respective time interval. As dispatch decisions are calculated for each year separately, here a myopic approach is taken. Prior to each model run / iteration, the capacity credits for each intermittent technology[14] and the amount of wind output that exceeds operational limits[15] are calculated stochastically.

DeCarolis and Keith (2006) examine the cost competitiveness of large-scale wind power, when carbon emissions are constrained. Thereby, they take two increasing cost factors arising from the inclusion of wind power – the spatial distribution and the intermittency – into account. The first factor refers to costs due to long distance electricity transmission, being one mean to offset the imbalance in the regional distribution of wind power generation and electricity demand. The second factor, in contrast, arises due to backup capacities or storage systems that offset the mismatch in the temporal distribution of supply and demand. The optimization is based on an idealized greenfield model, which includes five dispersed wind sites in the U.S., a storage system restricted to one site, and two gas technologies (gas turbines and gas turbines combined cycle) located at the demand centre. Despite of the installed capacities of the different technologies (wind, storage, and gas power plants), the transmission capacities between the defined production sites are decision variables of the model. Due to the regional simplicity of the model, the authors are able to implement a high temporal resolution. Since wind time series are included explicitly on an hourly basis for a five year horizon, the necessity to capture the effects of intermittency implicitly, i.e. by a capacity credit, is circumvented. One interesting result of the study is that, although the dispersion of wind power reduces carbon emissions and the hours with very low output, there are still some hours in which backup capacities have to be utilized to satisfy

[14] Since in the calculation the other intermittent technologies are included in the conventional power plant fleet, given the availability or the capacity credit respectively of the previous model iteration, balancing effects between different technologies are not accounted for.

[15] The excess of operational limits is defined as the amount of wind output that can be absorbed by a specific region, so that power generation by coal or nuclear can be still run in base load.

demand. Moreover, they find that CAES is not cost-competitive, compared to other flexibility options.

The approach of Neuhoff et al. (2008) is similar to the approach of DeCarolis and Keith (2006). In contrast to them, however, they do not use a greenfield methodology, but focus on system evolution. As in DeCarolis and Keith (2006), a least-cost, bottom-up dispatch and investment model is employed in order to meet the present and future electricity demand in the UK. Ramping and start-up constraints are not considered. As investment is allowed in gas and wind technologies at seven onshore sites, the UK is further split into seven sub-regions. Between the sub-regions, power transmission is constrained by specified interconnector capacities. The author intends to reflect the spatial and temporal variation in wind output and to calculate endogenously the benefits of diversifying wind output, while accounting for load pattern and transmission constraints. Therefore, the time resolution has to be adequate. However, since computational constraints prohibit an hourly time resolution, the year is split into 52 weeks. From each week one day is chosen arbitrarily from which the respective wind output serves as representative wind output for the other days of the week. After that, the hours of the week are aggregated into 20 demand slots with different duration. The wind output in the respective periods is averaged in order to match to the selected demand slots. As a result, wind output is smoothed. One result of the paper is that when transmission constraints are imposed, the distribution of wind power significantly changes, compared to an unconstrained setting. Although resource potential constraints are discussed, they are set rather in an approximate way.

To conclude, an integrative bottom-up modelling approach that optimizes renewable and conventional power generating capacities in conjunction is appropriate for answering the problem statement of this work. Integrative modelling approaches are able to allocate RES-E in a way that is optimal for the whole power generation system. Within the optimization, the negative effects of the inclusion of large-scale RES-E are weighted against the positive effects, e.g. in terms of low levelized costs at favourable sites. In order to facilitate an appropriate trade-off between positive and negative effects of large-scale intermittent RES-E however, it is a prerequisite that the intermittent characteristics of certain RES (such as wind and solar power) are sustained. The usage of very few, fixed capacity factors clearly does not fulfil this objective.

Neuhoff et al. (2008) and DeCarolis and Keith (2006), by contrast, achieve to model the intermittency of wind power in a suitable way. Moreover, both approaches accomplish to quantify the balancing effects of a distributed RES-E allocation. Whereas, due to the simplicity of the model set up in the latter case, there has been no need to reduce the temporal resolution, the more realistic modelling of the power system in terms of a higher regional resolution and more detailed technological representation in Neuhoff et al. (2008) requires data reduction in the temporal dimension. However, also this analysis is limited in the geographical and regional scope as it concentrates on wind power in the UK only.

It will be discussed in chapter 4 how the characteristics of RES intermittency can still be sustained given a higher geographical and regional scope. Before that, the aspects which have to be accounted for, in order to answer the problem statement are highlighted in the next subsection.

3.4.5 Aspects to be accounted for in an Integrative Investment and Dispatch Model with a European Coverage

As elaborated before, the problem statement requires a least-cost, bottom-up dispatch and investment model, in which conventional and renewable capacities are optimized simultaneously, in order to meet the present and future electricity demand in Europe. Moreover, the model should be built on today’s electricity generating capacities and also show the trajectory to a power system with a high share of RES-E. The electricity sector is characterized by long investment cycles and is not built from scratch. This also brings along that a myopic perspective should not be taken, but the evolution of the system should be optimized dynamically, as investments in the energy sector are ideally be made with respect to long term policy objectives.

Although representing the uncertainty of RES-E is desirable, endogenous investments in several renewable technologies in several countries would increase the complexity of a stochastic model approach tremendously. Therefore, it is refrained from including the reserve market in the analysis. Without the inclusion of uncertainty or the forecast error of RES-E, the inclusion of a reserve market does not provide an added value. Thus, it is assumed that the RES output is known with certainty. This assumption comes close to the representation of intraday electricity markets, in which the RES output can be predicted with greater precision. Close to real time, the dispatch of other parts of the supply side and also of renewable technologies can be adapted to the availability of RES and the situation on the electricity markets.

Moreover, the impacts of large-scale intermittent RES-E on the power system should be modelled as realistic as possible. According to Gross et al. (2006), the impacts depend on several factors, whereby some can be assigned to the configuration of the power system and others to the RES-E characteristics. All else being equal, the more flexible the power system is, the lower are the impacts of including large quantities of RES-E. As the current power system does not exclusively consist of flexible gas units, but also on less flexible coal, lignite or nuclear power stations, the development of the power mix has to be seen endogenous to the problem statement. Thus, also less flexible power stations that run rather base-load have to be included in the model. Their lower flexibility has to be accounted for by ramping, start-up and minimum load constraints. As mentioned before, another measure to increase the flexibility of the power system is to increase the (interconnector) capacities to transfer power between countries. Thus, also transmission constraints should be explicitly accounted for.

With respect to the characteristics of intermittent RES, the impacts on the power system are dependent on the quality and strength of the renewable resource and the degree to which it fluctuates. Related to the degree of fluctuations is the extent to which intermittent generators are geographically dispersed or are located in a particular area. If wind generators are located close together, their output will tend to fluctuate up and down at the same time, increasing variability of the total output and increasing the costs of integration (Gross et al., 2006). Thus, the spatial and temporal variation, as well as the quality of the intermittent RES-E output, should be considered in the model. Moreover, the interaction between the availability by intermittent RES and load has to be taken into account.

In contrast to Neuhoff et al. (2008), this work does not take a national, but a European-wide geographical scope. This is, because especially in the context of ambitious European RES-E targets, the optimal allocation of RES-E becomes a European wide question. Neither does every country have the same possibility to contribute to the RES-E target fulfilment, which is due to renewable potential limits, nor would it be efficient that every country contributes the same. As it is essential that the transformation of the energy system remains affordable and acceptable in economic terms, the least cost variant has to be figured out. Moreover, balancing effects of fluctuating RES-E will be even higher between all countries of Europe than only within a country. Furthermore, in contrast to Neuhoff et al. (2008), it won’t be included only wind power, but also other RES, such as solar power, biomass, and geothermal power. This allows the examination of balancing effects between different renewable technologies. In order to facilitate a realistic modelling of the RES expansion, the RES expansion should be constrained by realistic potential limits.

Due to a higher regional and a higher technological scope of the model, the approach taken by Neuhoff et al. (2008) to represent the intermittency of RES, is not suitable here. First of all, due to given calculation limits, the temporal resolution of 1,040 time slots per investment period is certainly too high. Secondly, choosing arbitrarily 52 days in one random year in order to represent the intermittent RES-E output is not representative. In a national context the randomness can be defended, as wind output is relatively highly correlated within a country. However, in a European-wide context in a certain year, some regions experience a good wind year compared to their long run average, while others do not. In the next year, the situation might be completely reversed. Since it is important for RES investment decisions that the quality of a renewable resource is modelled correctly, a more representative approach has to be developed. As mentioned earlier, in doing so, it is a prerequisite that the intermittent character of certain RES has to be sustained. Thus, in the next chapter, a methodology is developed to represent intermittent RES-E in a reduced temporal resolution. The methodology accounts for the intermittency of RES-E, smoothening effects between regions and different RES as well as the quality of RES in a specific region.

4 DEVELOPMENT OF TYPEDAYS FOR EUROPEAN ELECTRICITY MARKET MODELS INCLUDING RES-E

The data input used for the calculation is just as important as the model structure. The bulk of literature reviewed in chapter 3, is devoted to model structure. In the majority of cases, the data used for representing intermittent RES-E in the model calculations are mentioned, if at all, only superficially. Considering limits in calculation power, certain tradeoffs have to be accepted (e.g. temporal resolution versus regional resolution and technological details). Nevertheless, data should suit the respective problem statement.

Some approaches simply use few fixed capacity factors (EUSUSTEL, 2007; DOE/EIA, 2009a; DOE/EIA, 2009b), while others achieve a more appropriate representation of the intermittency of RES-E (Neuhoff et al., 2008; DeCarolis and Keith, 2006). The characteristics of intermittency and non-regular availability unfold better in a higher time resolution. A reduction in time resolution may hence restrict the representation of intermittency to a certain degree. Due to the simplicity of these models, a significant data reduction in the temporal dimension is not necessary. Conversely, considering the modelling complexity in this work, a considerable reduction of the temporal resolution is required.

When reducing the temporal resolution and analyzing the effects of intermittent RES-E on the power system, it should be attempted to sustain the characteristics of intermittency of certain RES, such as wind and solar power. Aspects of intermittency that are cut off and the consequences for modelling results should be made transparent. Moreover, the interaction between the availability by intermittent RES and electricity demand has to be taken into account.

Thus, this chapter first examines the characteristics of wind and solar power, as well as of electricity demand in Europe. Based on that, a methodology is developed to represent wind, solar, and load in a reduced temporal resolution. Wind power is expected to be more important than solar power, at least in the near future. For this reason, the focus is rather set on the representation of wind power, its associated fluctuations and balancing effects between regions.

In case of wind and solar power, the analysis is based on hourly and simultaneous wind speed and solar radiation data for the four year period January 2006 to December 2009. Four years of wind speed and solar radiation data have been considered as a minimum, in order to exclude effects that cannot be ascribed to typical patterns, but occur randomly in one specific year. Wind speeds are measured at 95 meter above ground level in meter per seconds (m/s). Global irradiation data are measured in Watt per square meter (W/m²).

Both data sets refer to average values in the respective modelling regions. 54 wind onshore- and 16 wind offshore regions in EU-27, plus Norway and Switzerland, have been distinguished. Data on solar irradiation have been provided for all 54 wind onshore regions. The data has been supplied by Eurowind (2011).

4.1 Characteristics of Wind Power

In general, wind power is characterized by ample, irregular fluctuations. Thus, it poses a big challenge to capture the essential characteristics of wind that are critical for investment and dispatch decisions in a limited temporal resolution. When analyzing the effects of wind power generation on the European power system, the following aspects are particularly relevant (Ackermann T. , 2005):

- Location of the wind resource
- Average wind speeds and annual yields
- Seasonal patterns
- Daily patterns
- Weather patterns
- Frequencies and magnitudes of fluctuations
- Balancing effects between regions

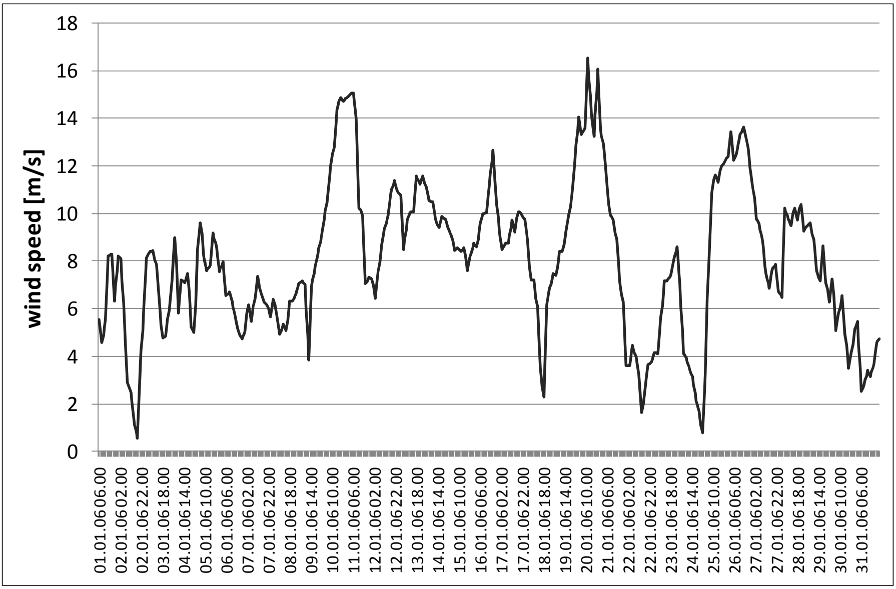

FIGURE 4-1: HOURLY WIND SPEEDS IN THE REGION ENGLAND WALES, JANUARY 2006

Source: Own calculation based on Eurowind (2011)

One determining factor of the wind speed is the location of the wind resource. The location affects the average wind speed, its frequency distribution, as well as its seasonal and daily patterns. All these aspects differ from one location to the next. Figure 4-2 depicts the average wind speeds 100 meter above ground level, based on high resolution data by the HIRLAM model, in the period 2002 to 2007 (Eurowind, 2008). It can be observed that the majority of favourable wind resources in Europe are located near the North Sea, followed by the Atlantic or the Baltic Sea. A first general distinction can be made for onshore and offshore sites. Wind speeds at offshore sites, in general, exceed the wind speeds that can be found at the nearby onshore sites.

Average wind speeds at offshore sites in the North Sea region can reach up to 9.5 m/s. Among the onshore sites, those in regions located at the coast of the North Sea (e.g. in Great Britain, Ireland or Denmark) can exhibit the most favourable results in the analyzed area. Average wind speeds reach as high as up to 8.5 m/s. However, due to limited land availability, the potential for onshore sites located near the coast is limited. Inland onshore sites have significantly lower wind speeds, depending on the location from 3.5 to 7.0 m/s. In addition to location, wind speeds are highly influenced by weather fronts. These vary daily to weekly and may involve also seasonal cycles. While there are low- and high wind periods, both in the summer and in the winter, the frequency and intensity vary by region and season. According to Ackermann (2005), for long-term adequacy studies, it is especially important to examine the variation in levels of wind speeds together with their probability of occurrence.

Dependent on the location, wind speeds are characterized by a pronounced seasonality, which is influenced especially by the large-scale distribution of pressure (Eurowind, 2008). For instance, in Northern Europe as well as in parts of Western and Central Europe, average wind speeds in the winter are considerably higher than in the summer (Ackermann T. , 2005).

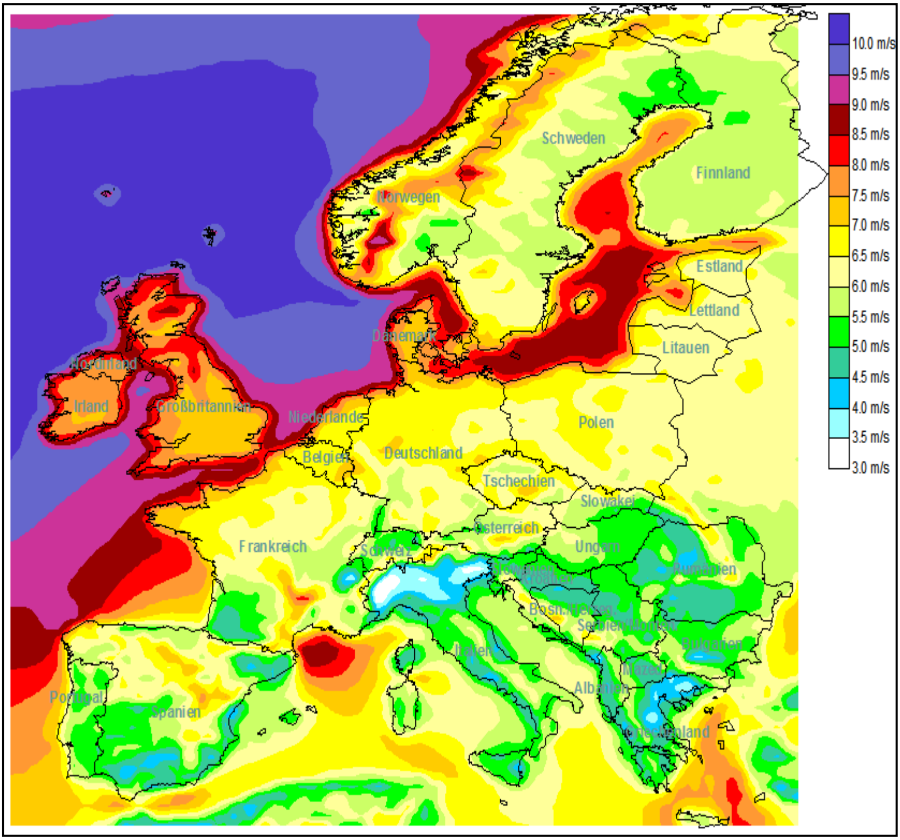

FIGURE 4-2: AVERAGE WIND SPEEDS IN EUROPE BASED ON HIGH RESOLUTION DATA

Source: Eurowind (2008)

This can be observed in Figure 4-3, which shows the average monthly wind speeds and the corresponding standard deviation in the region England and Wales. The average wind speeds in the winter months January to March and October to December (on average: 8.6 m/s) exceed the average wind speeds in the summer months April to September (on average: 6.8 m/s). Other regions, such as South-East Europe, the Mediterranean area or the Iberian Peninsula have different seasonal characteristics, as they join the Northern subtropical High Pressure Zone (Eurowind, 2008). Next to higher average wind speeds in winter months, a higher dispersion of the wind speeds can be detected in Figure 4-3. This is confirmed by Eurowind (2008). For instance, in Wales and England, the standard deviation amounts to 3.6 m/s in the winter, compared to a standard deviation of 2.7 m/s in the summer.

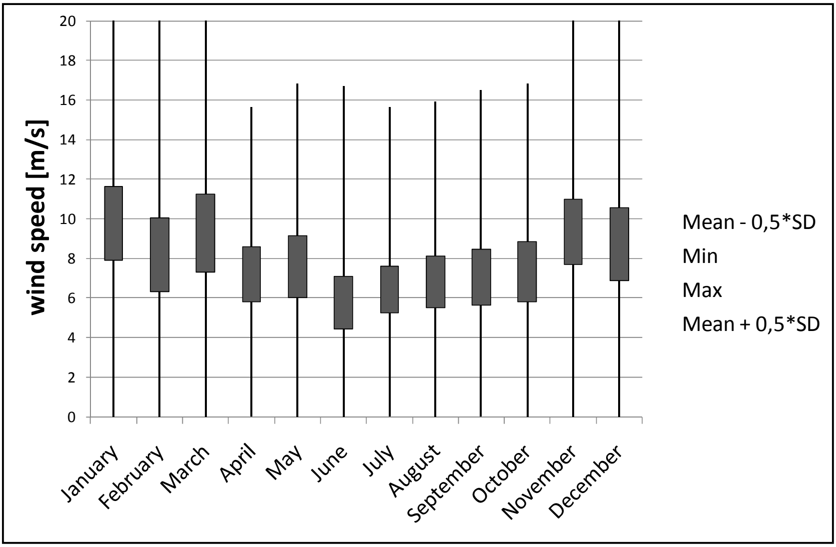

FIGURE 4-3: AVERAGE MONTHLY WIND SPEEDS IN THE REGION WALES, ENGLAND

Source: own calculations

Furthermore, wind speeds may also possess a daily pattern caused by thermal conditions. Depending on the season and region, there may be either a strong (e.g. coast or mountain) or hardly any diurnal pattern of the wind speeds. Due to a higher solar irradiance, the diurnal pattern is stronger in the summer than in the winter. In principle, the diurnal pattern is dominated by seasonal patterns and weather fronts (Eurowind, 2008).

Finally, the spatial correlation of wind speeds has to be taken into consideration. Increasing the geographical dispersion of wind sites smoothes wind fluctuations (Nørgaard and Holttinen, 2004). The larger the distance between regions, the longer is the period of time over which the smoothing effect unfolds. This is, if for instance a synoptic peak[16] occurs in one region, it takes little time for the peak to arrive in a region nearby. By contrast, the time lag for the synoptic peak to appear in a more distant region is larger. Contingent on the distance, it may take from five minutes to twelve hours for a weather front to spread out (Ackermann T. , 2005). However, this applies rather to comparatively uniform areas. With regard to even more distant regions that are exposed to different weather patterns, the smoothing effect will be even stronger (Giebel, 2000). Thus, the curve progression of hourly wind speeds of the neighbouring regions Western Netherlands and Northern Germany is quite similar (see Figure 4-4), exhibiting a correlation coefficient of 0.79. On the contrary, this is not the case for remote regions, such as Northern Germany and Southern Portugal (see Figure 4-5), which have a correlation coefficient of –0.18.[17]

[16] A synoptic wind peak denotes a wind peak that, in contrast to a diurnal peak, is caused by changing weather conditions (Ackermann, 2005).

[17] Smoothening effects within modelling regions are already included in the data as they refer to average wind speeds within a modelling region.

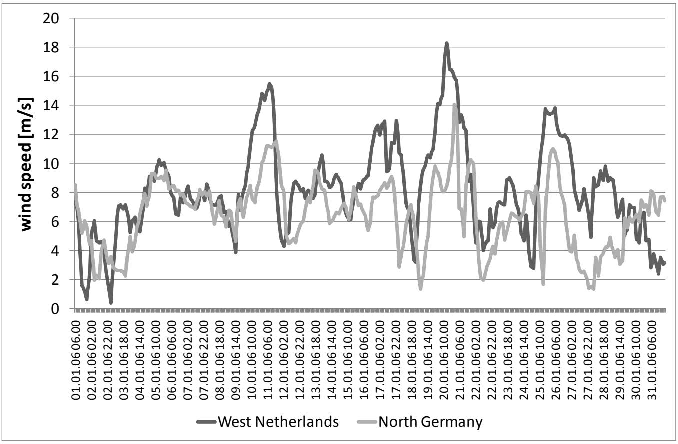

FIGURE 4-4: HOURLY WIND SPEEDS IN THE WESTERN NETHERLANDS AND NORTHERN GERMANY IN JANUARY 2006

Source: own calculations based on Eurowind (2011)

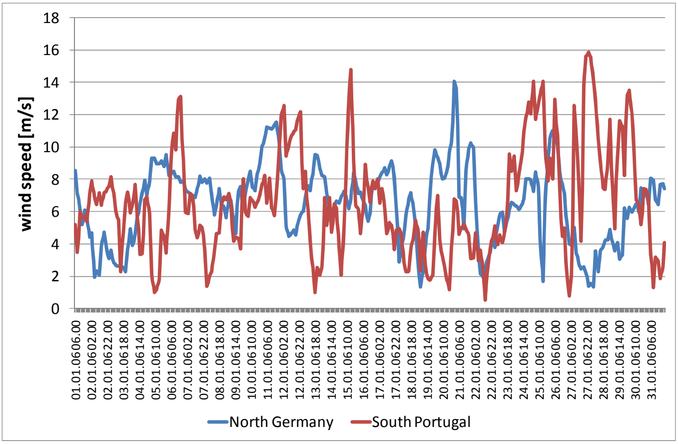

FIGURE 4-5: HOURLY WIND SPEEDS IN SOUTHERN PORTUGAL AND NORTHERN GERMANY IN JANUARY 2006

Source: own calculations based on Eurowind (2011)

As a consequence of smoothening effects between regions, extreme wind power events occur rather seldom when the geographical scope is increased. This can be observed in 4-6, 4-7, and 4-8, which depict the annual frequency of occurrence of different low wind production events for wind generation of less than 1, 3, and 5 per cent of nominal wind capacity that take place at least a certain duration of time (from 1 to 48 hours consecutively). For instance, in the single wind onshore region “Northern Germany”, wind production levels of less than 1 per cent of the installed wind power capacity for at least 6 hours in a row happen about 28 times a year. However, when the average wind production weighted by respective wind potentials of the regions surrounding the North Sea is examined, such low production levels occur only once a year for one single hour. A slightly higher average capacity factor (5 per cent of nominal capacity) for twelve successive hours can be found once in four years in the North Sea regions. For a geographical area as large as Europe, low wind production levels only take place in single hours.

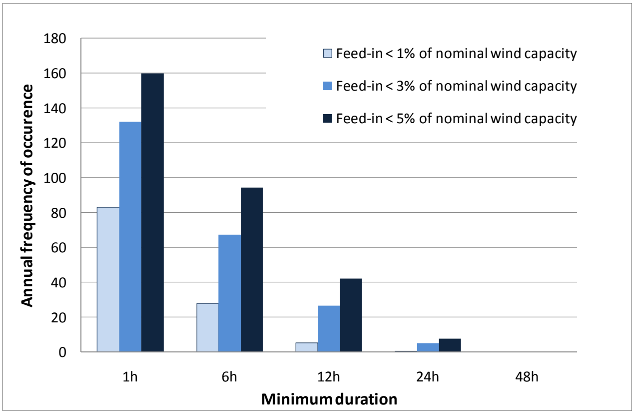

FIGURE 4-6: ANNUAL FREQUENCY OF OCCURRENCE OF LOW WIND PRODUCTION IN NORTHERN GERMANY

Source: own calculations

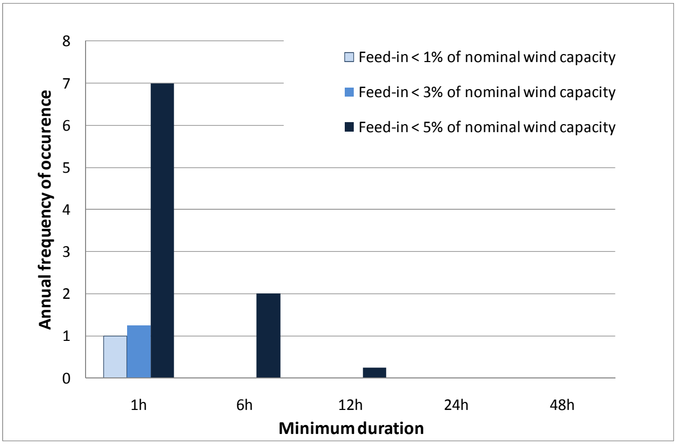

FIGURE 4-7: ANNUAL FREQUENCY OF OCCURRENCE OF LOW AGGREGATED WIND PRODUCTION IN REGIONS SURROUNDING THE NORTH SEA

Source: own calculations

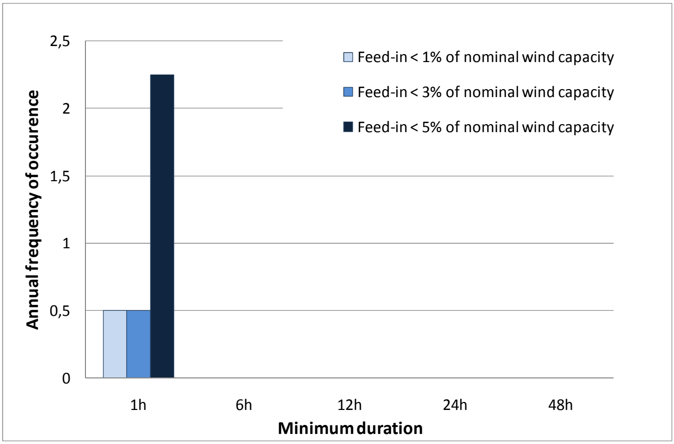

FIGURE 4-8: ANNUAL FREQUENCY OF OCCURRENCE OF LOW AGGREGATED WIND PRODUCTION IN EU-29

Source: own calculations

4.2 Characteristics of Solar Power

The analysis of the solar power characteristics will follow the same structure as the previous chapter. The employed dataset refers to global irradiation data, which are necessary to calculate the yield of solar power. Global irradiation is defined as the total solar radiation that hits the earth's surface on a horizontal area. It is composed by the direct radiation that reaches the earth's surface in a direct way and the diffuse radiation that arrives indirectly, being diffused by clouds or dust particles. The influence of the diffuse radiation on the global radiation, however, is only marginal (Kaltschmitt et al., 2006, p. 50).

Due to a steeper angle of incidence, the yearly sum of the horizontal global irradiation increases when approaching the equator. Thus, in Europe, a North-South divide can be detected, as shown by 4-9. While the blue colouring indicates low yearly yields, the red colouring stands for favourable solar resources. In Germany, the yearly sum of horizontal global irradiation adds up to about 1200 kWh/m²/a, whereas in Spain it is about 2000 kWh/m²/a.

Due to the direct radiation's changing angle of incidence, the global irradiation is stronger at noon than in the morning or in the evening, and in the summer stronger than in the winter. Moreover, changing periods of time, between sunrise and sunset in the course of the year, lead to varying global irradiation, too. Thus, there are highly pronounced seasonal and diurnal patterns, again being dependent on the respective locations.

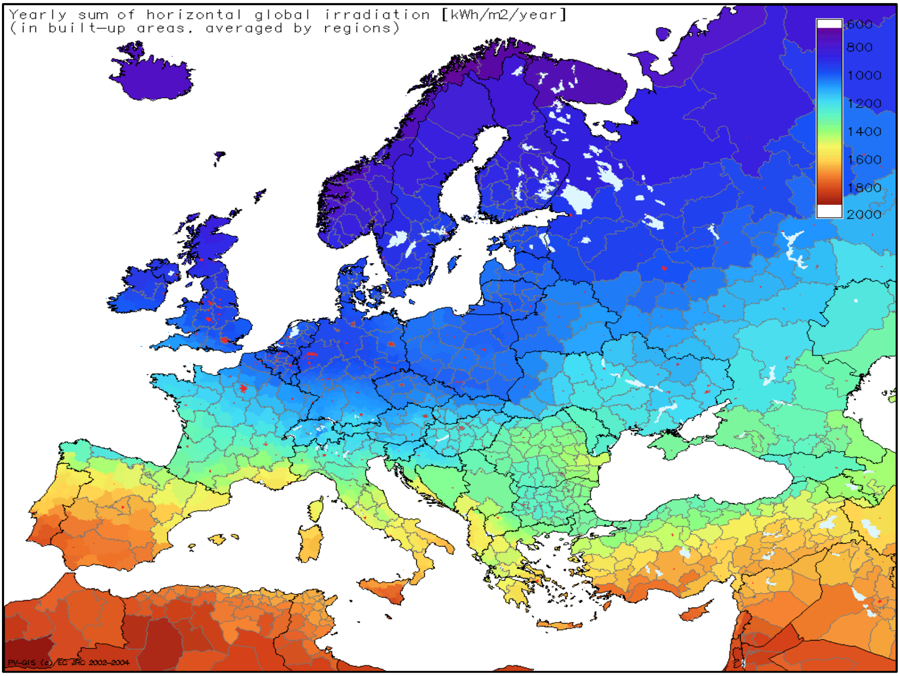

FIGURE 4-9: YEARLY SUM OF HORIZONTAL GLOBAL IRRADIATION [KWH/M²/A]

Source: JRC EC PVGIS (2011)

Figure 4-10 shows the average hourly global irradiation in Northern Germany and Southern Spain in the summer months (April to September) and in the winter months (October to March).

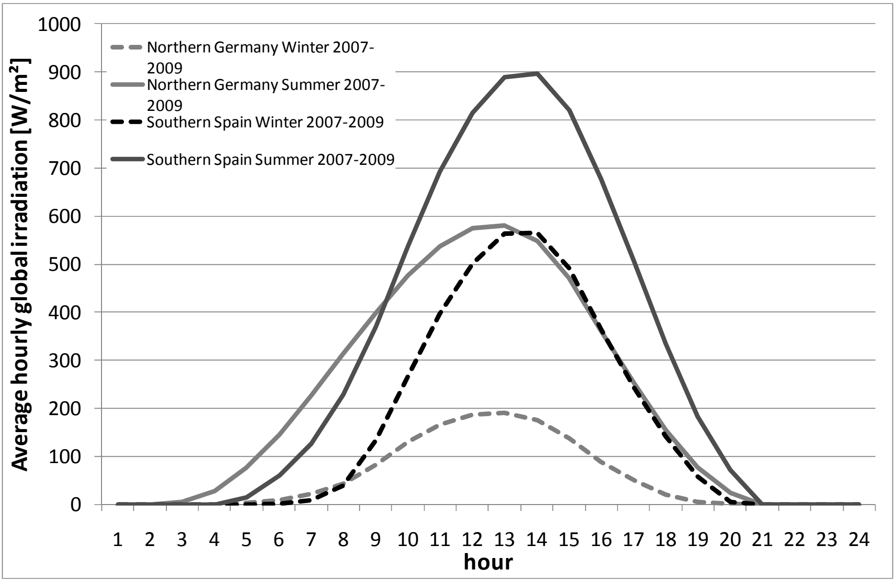

FIGURE 4-10: SEASONAL AVERAGE GLOBAL IRRADIATION IN NORTHERN GERMANY AND SOUTHERN SPAIN, 2007 TO 2009

Source: own calculations based on Eurowind (2011)

Differences between the two regions regarding the level, as well as regarding the relative magnitude of seasonality can be observed. The maximum of the average hourly global irradiation is higher in Southern Spain than in Northern Germany, e.g. in the summer the maximum of the average hourly global irradiation amounts to about 900 W/m² in Southern Spain, while in Northern Germany it lies only at about 400 W/m². Moreover, the difference between the seasonal maxima is lower in Southern Spain than in Northern Germany.

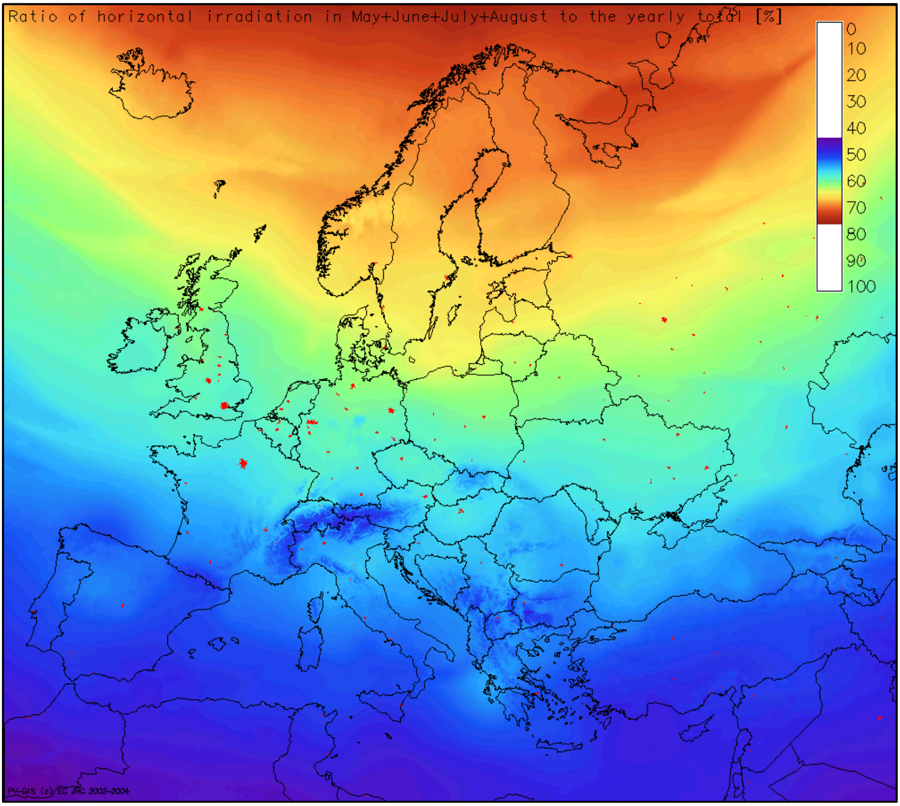

FIGURE 4-11: RATIO OF HORIZONTAL IRRADIATION IN MAY, JUNE, JULY, AND AUGUST TO THE YEARLY TOTAL

Source: JRC EC PVGIS (2011)

Figure 4-11 also reveals that the magnitude of seasonality differs by region. It shows the proportion of global irradiation in the months May to August, compared to the global irradiation of the whole year. Northern regions receive up to 80 per cent of their total yearly irradiation in these months, whereas the proportion lies below 50 per cent in Southern regions.

By nature, the global irradiation also depends on weather conditions and fluctuates accordingly. The instantaneous values of the global irradiation are subject to very high fluctuations, due to cloudiness or atmospheric opacity (Kaltschmitt et al., 2006). On the hourly timescale, however, fluctuations are not that high, but rather regular, as can be seen in Figure 4-12 and 4-13. On the respective time scale, global irradiation is influenced rather by diurnal and seasonal weather conditions and the sun's angle of incidence. Figure 4-12 and Figure 4-13 show the hourly global irradiation in the months January and July 2006, for the regions Northern Germany and Southern Spain.

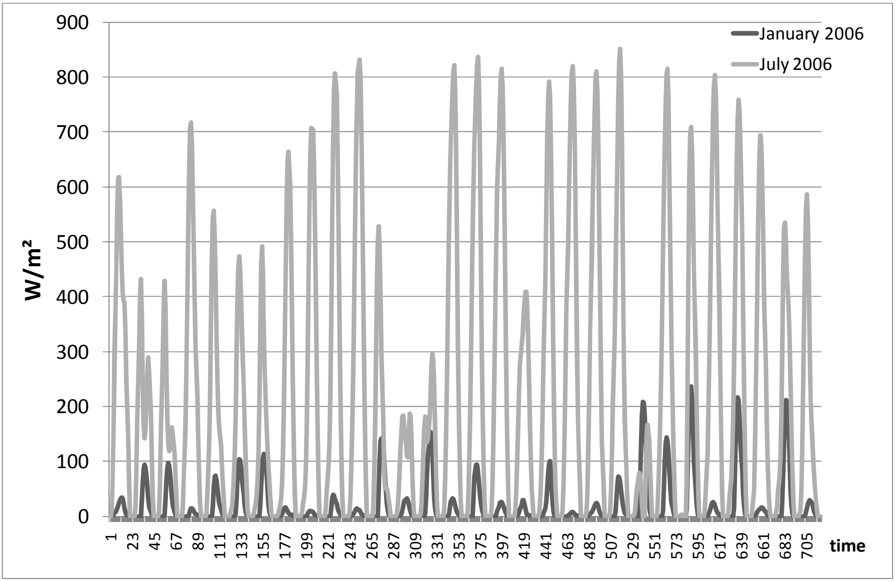

FIGURE 4-12: GLOBAL IRRADIATION IN NORTHERN GERMANY IN THE PERIODS JANUARY AND JULY 2006

Source: own calculations

In contrast to the global irradiation in Germany, the global irradiation in Spain is more constant. Here, with little exceptions, the maximum daily global irradiation stays on a constant level in the respective months. The picture is different in the case of Germany. Here, daily weather and irradiation conditions are more unstable and vary highly from one day to the next.

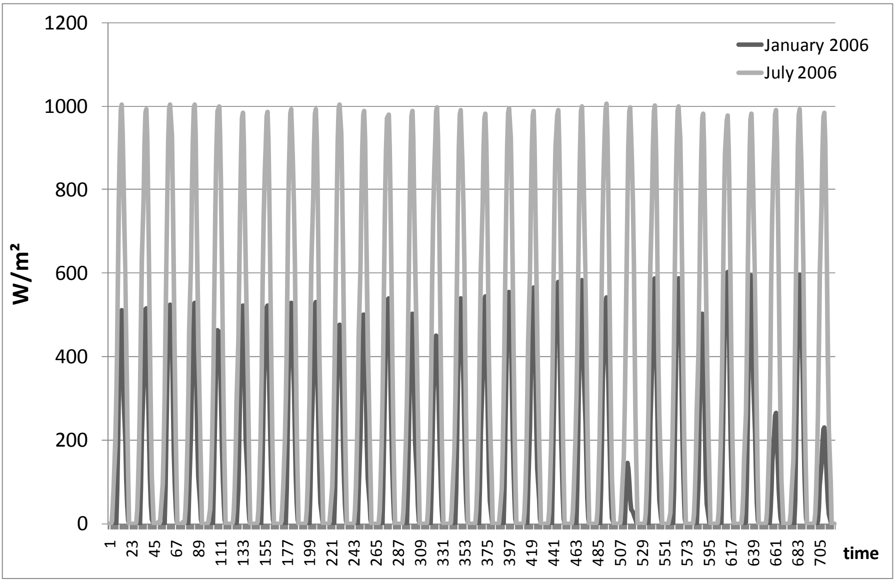

FIGURE 4-13: GLOBAL IRRADIATION IN SOUTHERN SPAIN IN THE PERIODS JANUARY AND JULY 2006

Source: own calculations

In respect to the relationship between wind and solar power, often a negative correlation is mentioned, which corresponds mostly to the seasonal patterns of the resources (Heide et al., 2010). As described above, solar irradiation peaks in the summer months, whereas, on average, wind speeds usually show higher values in the winter period. On the daily basis, the correlation is not that straightforward. However, Hupfer and Kuttler (2006) found that high pressure areas are generally related to low wind speeds and a low cloud cover.

The data by Eurowind (2011) in 2007 to 2009[18] confirm a negative correlation between the two renewable energy sources, apart from the seasonal pattern. In order to quantify the dependence between wind speed and solar irradiation values, the *Pearson correlation* ρ[19] of the daily averages is used. For two random variables (X, Y), it is defined as $\rho_{X,Y} = \frac{Cov_{X,Y}}{\sigma_X * \sigma_Y}$, where $Cov_{X,Y}$ denotes the covariance between the variables and σ the respective standard deviations. Correlation coefficients for every region are calculated for the whole year, as well as for single months, correcting thereby for the seasonality. The monthly and yearly averages of the regional correlation coefficients are shown in Table 4-1.

All in all, the averages of the regional correlation coefficients are strictly negative for the months, as well as across the whole year. Although some regions show positive values for single months, the yearly average correlation is negative for each region. Thereby, the year round correlation coefficient (-0.31) is lower than the average of the monthly correlation (-0.22), relating to the higher prevalent seasonality in the former. The monthly correlation coefficients still show an obvious negative relationship

18 At the point in time of data processing, simultaneous data for wind and solar power have had been available only for a three-year period.

19 Although for multivariate normal distributions canonical measures that represent the complete stochastic dependence of normally distributed variables are the appropriate way to quantify the dependence between the variables (Grothe and Schnieders, Forthcoming), here the Pearson correlation measure is considered sufficient. The purpose here is simply to show the dependence between the variables qualitatively, but not to use the correlation coefficients for modelling purposes.

between the two variables. Furthermore, results point to a more pronounced negative correlation in winter months.

TABLE 4-1: AVERAGE CORRELATION BETWEEN WIND AND SOLAR POWER IN THE EU-27-PLUS

Time horizon / Months	Correlation coefficient
Year	**-0.31**
January	-0.25
February	-0.23
March	-0.26
April	-0.16
May	-0.17
June	-0.16
July	-0.19
August	-0.18
September	-0.24
October	-0.27
November	-0.25
December	-0.28
Monthly Average	**-0.22**

Source: own calculations

4.3 Characteristics of the Electricity Demand[20]

In contrast to wind power, electricity demand follows more regular patterns, though the exact level may not be forecasted with certainty, as it depends

[20] The analysis of electricity demand has been carried out by Christina Elberg.

among others on weather and economic conditions. Nevertheless, electricity demand has a clear seasonal, weekly, and diurnal pattern, as can be seen in Figure 4-14 and 4-15. Every day is characterized by so called peak- and off-peak-load hours, whereby peak-load hours comprise hours in the period from 8 a.m. to 8 p.m. and off-peak the residual hours. Moreover, during the week, electricity load is higher than during the weekend, due to working and industry electricity demand. For instance, the average electricity demand during the week is nearly about 20 per cent higher than on the weekend, in Germany in January 2007. Last but not least, a pronounced seasonality can be detected in the demand data. For instance, in Germany, electricity demand tends to be higher in the winter than in the summer (here about 10 per cent), e.g., due to weather conditions (e.g. lower temperatures, shorter periods of daylight).

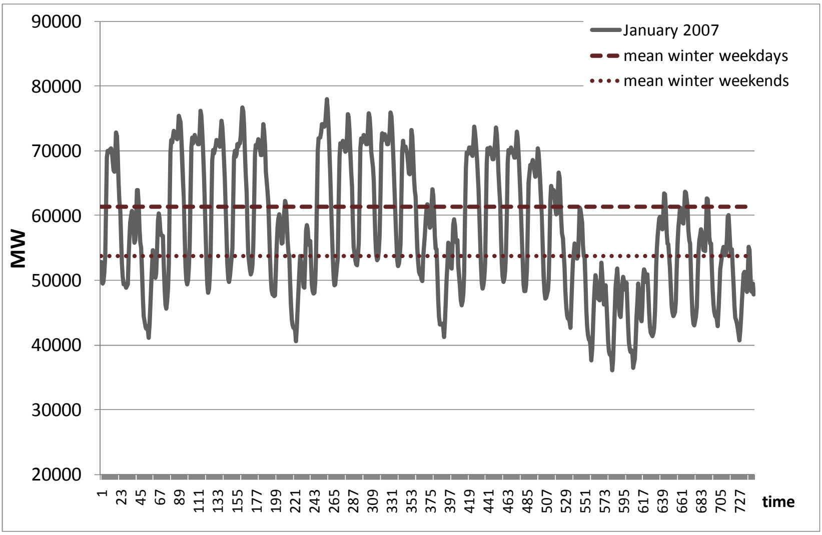

FIGURE 4-14: HOURLY ELECTRICITY DEMAND IN GERMANY IN JANUARY 2007

Source: own calculations based on ENTSO-E (2007)

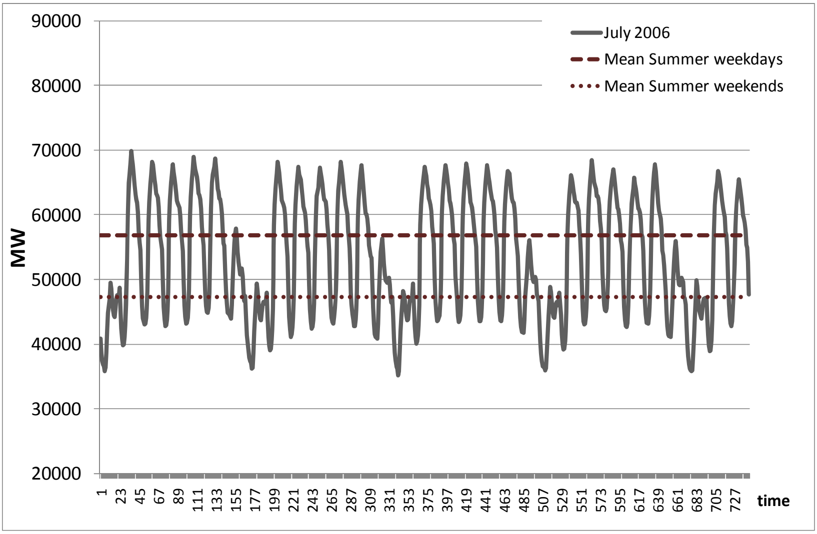

FIGURE 4-15: HOURLY ELECTRICITY DEMAND IN GERMANY IN JULY 2007

Source: own calculations based on ENTSO-E (2007)

4.4 Modelling of Typedays

The usage of "typical days", or in the following called „typedays", is a common applied measure in order to reduce the intra-annual temporal resolution of multi-technology, and multi regional bottom-up models comprising several investment periods. Thereby, the models can be kept solvable with respect to limitations in calculation power. The concept of typedays signifies the representation of certain days with different characteristics. In general, typedays should span a bandwidth of typical occurring events and represent them accordingly. Thereby, one day does not necessarily need to be represented by 24 hours, but may contain more or fewer time slots. However, usually the time horizon of one day is chosen as the diurnal pattern is significant for most of the input data, such as e.g. for electricity demand. Moreover, often typedays are further distinguished seasonally (Bartels, 2009; Fürsch et al., 2010; Swider and Weber, 2007).

In Bartels (2009), the focus has been set on the representation of different electricity demand criteria. An intra-annual temporal resolution of twelve different typedays is used, which again can be sub-divided into 24 hours. Since electricity demand varies seasonally and during the week, a division of four seasons and three weekdays has been opted for. In order to reach the annual quantities, the typedays are multiplied with the corresponding frequencies of occurrence. How intermittent RES-E is represented, is not documented.

Swider and Weber (2007) use weather data from ten different weather stations in Germany in their stochastic model. The spatial distribution of wind power plants in Germany is assumed to remain constant over time. The time series are first distinguished by season. After that, for each six hour period within a season, wind speeds are grouped into three possible wind cases (high, medium, and low), yielding the capacity factor of wind production. For each wind case, the corresponding probabilities of occurrence and transition to another wind state are calculated. However, the three capacity factors are assumed to remain constant over the time horizon. Correlations of wind speeds and associated balancing effects between different wind sites are not accounted for endogenously.

As mentioned before, the approach taken by Neuhoff et al. (2008) is appropriate for a national, but not for a European-wide approach. This is because of its required very high intra-annual time resolution and its incapability of modelling the quality of different RES sites in a representative way.

Thus, in the following a methodology for representing intermittent RES-E in Europe in a dispatch and investment model based on the available empirical data will be developed. Thereby, the focus is set on wind power. In total for every region 30 (2 x 8 + 2 x 7) typedays are established. From these, two typedays are assigned to different daily load patterns (weekend and workday). Eight typedays are assigned to different daily wind patterns in the winter and seven in the summer.

4.4.1 Modelling of Typedays for Wind Power

4.4.1.1 Modelling Requirements

From the characteristics of wind power described above, and keeping the impacts on the investment and dispatch decisions of conventional plants and renewable plants in mind, the following requirements for the modelling of typedays for wind power can be deducted:

- The quality of a wind site should be represented by its actual resulting full load hours.
- The seasonality of the wind speeds in the respective regions should be considered.
- Different possible weather conditions (low and high wind periods) should be represented for all modelled seasons.
- These should correspond to their empirical frequencies of occurrence.
- Both, steep as well as flat wind speed gradients, should be taken into account.
- Smoothing effects between regions should be considered.

The last point excludes an isolated typeday modelling of wind for single regions. Wind conditions of one region have to be considered under the aspect of simultaneity, in relation to the wind conditions of other regions. As mentioned before, another requirement is that, due to computational constraints and the additional representation of multiple technologies and regions, only a limited amount of typedays may be used. Here, a maximum of thirty-two typedays is envisaged. In general, the typeday modelling for wind power intends to reduce the data complexity and to reveal a structure within the data. The methodology of the typeday modelling for wind is subdivided into three iterative components.

First, reducing the data complexity requires reducing the original amount of wind regions (54 onshore- and 16 offshore regions) to be examined. This is facilitated by a so called cluster analysis, which is a common technique for statistical data analysis in order to identify patterns in big data sets. Cluster analysis assigns a set of observation into subsets (called clusters), so that the objects in one subset are similar in terms of one or more criteria. By contrast, objects in different clusters should differ in terms of the criteria defined ex ante. Hence, here the objective is to cluster regions with a similar wind speed structure into “wind supra regions”. Moreover, for every wind supra region one representative region is defined, which in the following serves as representative for all the other regions within the cluster.

As demanded by long-term adequacy studies, in a second step, the representative regions’ different levels of wind speeds along with their frequencies of occurrence are identified. The levels of wind speeds are reduced to two wind states - “high wind” and “low wind” - and differentiated by season. Thereby, the same wind state applies to all regions within one wind supra region, thus assuming perfect correlation of wind conditions between all belonging regions. Due to the high complexity, smoothing effects in terms of time lags between single regions are not considered. Moreover, since wind conditions of one region have to be considered under the aspect of simultaneity in relation to the wind conditions of other regions, subsequently, the identified low- and high wind periods of one representative region will be put in relation to the low- and high wind periods of the other representative regions. Based on that, different wind states for the whole geographical area (here: EU-27-plus) can be identified with their corresponding frequencies of occurrence.[21]

Until now, only the different levels of regional wind speeds have been taken into account. However, wind is not constant, but is characterized by different kinds of fluctuations. Unfortunately, these do not follow a regular daily pattern, but are largely determined by weather conditions and are highly irregular. Since only a limited number of typedays can be included in the model, in this third step, one synthetic daily wind structure is calculated for all single wind states, regions, and seasons. Here, it is not aimed at representing a “typical” daily structure for wind, which does not exist, but rather to incorporate the average fluctuations and gradients of wind, which affect the dispatch decisions of conventional power plants. In doing so, it is vital to ensure that the synthetic daily wind structure does not exhibit atypical behaviour in relation to electricity demand, i.e. there must not be a correlation of the synthetic wind structure and electricity demand, which is not supported by empirical data. The synthetic wind structure is calculated by a nonlinear optimization subject to certain constraints.

4.4.1.2 Regional Cluster Analysis

The aim of the regional cluster analysis is to cluster the wind regions, as defined by Eurowind (2008), with similar wind speed characteristics into the same wind supra region. The characteristics of the wind regions to be examined can be described as points or vectors in a vector space. Areas in which points agglomerate are called clusters. Thus, the objects of a heterogeneous total quantity are merged to homogenous subgroups.

In order to determine quantitatively the dissimilarity or similarity between the objects (in this case wind regions), a distance measure has to be

[21] In further research, a subdivision into general weather conditions may be developed (Gerstengarbe et al., 1999).

selected. For this objective, here the Mahalanobis distance is used. The Mahalanobis distance uses the correlation coefficients between the observations and uses that as a measure to cluster them. Since the objective here is to combine groups of regions with similar wind patterns, the correlation coefficients are based on the correlation of wind speeds at the same points in time between all regions.

In doing so, the correlation coefficients are based on average weekly wind speeds, as the correlation coefficients of daily averages may be distorted. There are time lags for weather front patterns to arrive, even at a highly correlated region nearby. That is, if for instance wind speeds increase in one region, the wind speeds most likely increase in the neighbouring regions, either with a positive or negative time lag. In order to eliminate this effect, while still maintaining a relatively high number of observations, the next higher time horizon is used, the week.[22]

Formally, the Mahalonobis distance of a multivariate vector $x = (x_1, x_2, \dots, x_N)^T$ from a group of values with mean $\mu = (\mu_1, \mu_2, \dots, \mu_N)^T$ and covariance matrix S is defined as:

$$D_M(x) = \sqrt{(x-\mu)^T S^{-1} (x-\mu)} \tag{4-1}$$

If the covariance matrix is the identity matrix, the Mahalanobis distance reduces to the Euclidean distance. Here, the covariance matrix is constructed by the covariance of average weekly wind speeds of one region with all other regions. Hence, it is not only controlled for whether the two regions are correlated, but also whether they exhibit similar or different wind patterns with other regions.

Cluster methods can be subdivided into hierarchical and partitioned cluster analysis. Here, a hierarchical cluster analysis has been applied. By contrast

[22] The basic preparation of cluster analysis as well as the basic idea had been developed together with Cosima Jägemann.

to partitioned methods in hierarchical algorithms, successive clusters are generated, based on previously established clusters. In agglomerative algorithms, the sequence of partitions begins with the smallest arrangement, in which every object forms a separate cluster and merges them into successively larger clusters. In contrast to partitioned cluster analysis, hierarchical algorithms reduce processing time and effort for big datasets, as, once combined, two objects are kept in one group. Moreover, it facilitates graphical analysis, alleviating the choice for an appropriate number of clusters (Handl, 2010, pp. 373 - 431).

Subsequently, the clusters in the Mahalonobis distance matrix with the smallest distances are merged by the „Average-Linkage-method", forming a new cluster. This method is less prone to data distortions than the "Single-Linkage"- or the "Complete-Linkage" method.[23] According to this method, the distance measurement of two classes is accomplished by using the distance of the average Mahalonobis distance between elements of one cluster and the elements of the other. Formally, this can be expressed as $D_{\{u,v\}.\{k\}} = \frac{d_{uk}+d_{vk}}{n}$, whereupon $D_{\{u,v\}.\{k\}}$ is the distance between the clusters $\{u, v\}$ and $\{k\}$, d_{uk} and d_{vk} are the distances between the single elements, while n is the number of possible combinations of all elements of both clusters. This process is repeated as long as the predefined quantity of groups or clusters respectively is reached (Handl, 2010).

[23] The "Single-Linkage" method tends to group the objects "too quickly", since it requires only one object to be close to another one. Therefore, the calculated distances are by trend smaller, and this can lead to a chain formation, since objects are collected by a bigger group successively. However, the „Complete-Linkage" method tends to group objects "too slowly", as objects which are the furthest away from each other are the ones that determine the distance. Thus, the distances tend to be bigger, which results in rather smaller groups. Due to a limited number of possible groups, however, this is problematic.

Based on the correlations of average weekly wind speeds between all 54 onshore and 16 offshore regions, six regional clusters are established. The resulting clustering can be seen in Figure 4-16. However, two outlier regions have had to be excluded: Southern Spain and Eastern Ireland. Since the correlation of the two regions with any other region is very low, they would be allocated in a single cluster. As a consequence, the remaining three clusters would be unacceptably high, thus running contrary to the initial intention. Another adjustment has been that the splitting up of a big geographical group “Central Europe”, plus “France and Spain Atlantic” is treated prior ranking as the splitting up of a smaller geographical group comprising Southern France, the Iberian Peninsula, except Northern Spain, and Italy. Whenever a regional cluster is too big, smoothing effects cannot be quantified sufficiently. The decision is further motivated by the fact that the wind regions in Italy and Southern France have rather low average wind speeds compared to the “France and Spain Atlantic” group, thus being limited in their capability to balance other regions’ wind slacks.

The resulting clustering is in line with Giebel (2000). In general, neighbouring regions are clustered into one group, due to their high correlation of average weekly wind speeds. Here, cluster analysis supports the decision where to separate different wind regimes. Accordingly, onshore regions and offshore regions located in the vicinity of the North Sea, such as Great Britain, the Netherlands, Northern Germany, and Southern Scandinavia, show similar wind speed characteristics. Regions in Southern Scandinavia are correlated more with regions located near the North Sea than with regions in Northern Scandinavia. Another cluster comprises wind onshore- and offshore regions located near the Atlantic, such as France and Northern Spain. Furthermore, regions in the Southern part of Europe (the Iberian Peninsula, South of France, and Italy) have to be seen distinct from that. Regions in Central and Eastern Europe form the fifth cluster. The sixth cluster is composed of regions in South East Europe. Due to mentioned calculation limits, the sixth cluster will not be considered further. One important result from the analysis is that offshore regions are rather grouped into a cluster comprising also onshore regions, but located in their vicinity, as with other offshore regions located further away.

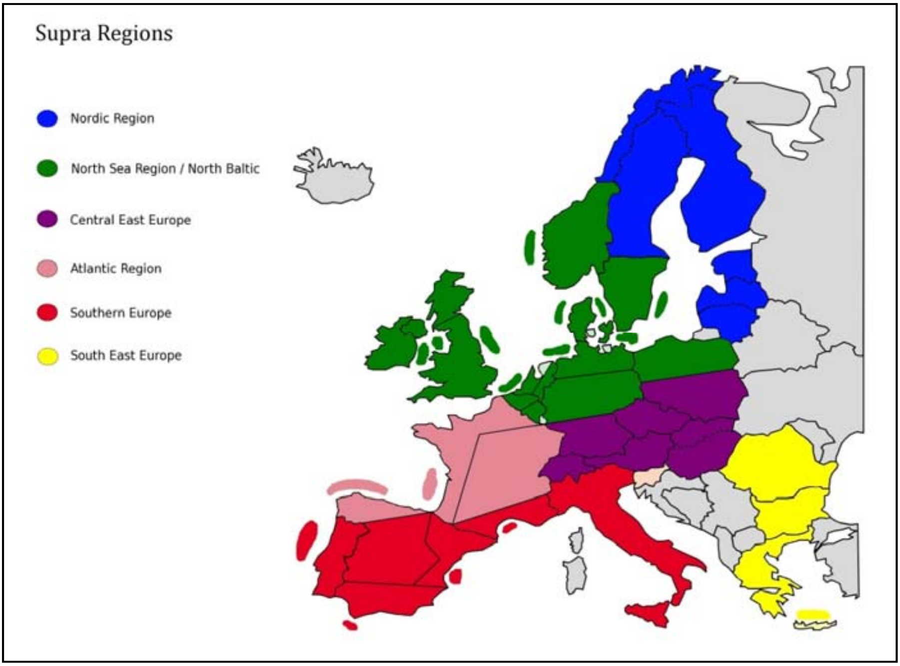

FIGURE 4-16: REGIONAL WIND CLUSTERS IN EUROPE

Source: own calculations

On the basis of the wind supra regions, representative regions are specified. Selection criteria are the following: First the representative region should be located as centrally as possible in the wind supra region. Second, and most importantly, the representative region should maximize the sum over all correlation coefficient with all the other regions in the same wind supra region given by the Mahalonobis distance matrix. Thereby, it should be ensured that the representative region represents the wind supra region as good as possible. Consequently, the following representative regions are identified in Table 4-2.

TABLE 4-2: REPRESENTATIVE REGIONS OF THE WIND SUPRA REGIONS

Supra region	Representative region
North/Baltic Sea region	Western Netherlands
Nordic region	North-East Sweden
Atlantic region	Western France
Southern Europe	South-East Spain
Central East Europe	Southern Czech Republic

Source: own calculations

4.4.1.3 Identification of Different Wind States in Europe

In this modelling step, the representative regions' different levels of wind speeds, along with their frequencies of occurrence, are established. The levels of wind speeds considered here are two wind states: "high" and "low". Due to seasonal peculiarities, they will be further differentiated by season. Once again, the time horizon of a week is considered appropriate in this modelling step, as, when examining correlations or combinations between simultaneous regional wind speeds, shorter time intervals may distort results due to the time lags of weather fronts between regions. The weekly arithmetic means of the representative regions' wind speeds, in comparison to their seasonal medians[24], serve as classification criterion for the regional wind states "low" and "high" in all 208 single weeks in the four year period 2006 to 2009. Thus, by definition both wind states are evenly distributed for every representative region. For illustration an extract of the procedure for the first four weeks is depicted in Table 4-3.

TABLE 4-3: CLASSIFICATION OF WEEKS IN REPRESENTATIVE REGIONS INTO THE WIND STATES "HIGH" AND "LOW"

Week	Subregion: North-East Sweden	Subregion: South-East Spain	Subregion: Western France	Subregion: Western Netherlands	Subregion: Southern Czech Republic
1 2006	Low	High	Low	Low	High
2 2006	High	Low	Low	Low	Low
3 2006	Low	Low	Low	High	High
4 2006	High	High	Low	Low	High

Source: own calculations

Since wind conditions of the different representative regions have to be considered under the aspect of simultaneity, subsequently, the identified low- and high wind periods of one representative region will be put in relation to the low- and high wind periods of the other representative regions. Based on that, different wind events for the whole geographical area (here: EU-27-plus) can be identified, with their corresponding frequencies of occurrence. A European wind event comprises the single regions' wind states at one point in time. For example, in the first week in

[24] The median has been chosen as classification criterion as it is robust against outliers and later alleviates the matching of corresponding frequencies of occurrence. If more than two different wind levels are opted for, the distinction can be made analogous for different quintiles. The use of quintiles is advised as they allow the even distribution of the different wind states for every region compared to one specific value.

2006, on average, low wind levels occurred in the representative regions North-East Sweden, Western France, and Western Netherlands. At the same time South-East Spain and the Southern Czech Republic had, on average, a high wind level. As mentioned before, in this analysis five regional clusters are considered as a maximum, since, with two possible wind states per region ("low" and "high"), 2^n combinations of wind states between the representative regions will have to be considered, whereby here n denotes the number of regions. Five clusters thus produce 2^5 or 32 combinations per season. Due to the computational constraints, unfortunately not all 64 combinations can be included. With two load levels per season (see chapter 4.3) and a target of 32 typedays, overall, that leaves at most eight wind typeday combinations per season that may be selected.

Obviously, the most frequent occurring European wind states should be incorporated. Moreover, it has to be ensured that overall the representative regions' wind states "high" and "low" multiplied with the respective frequencies of occurrence are evenly represented, as demanded by the subdivision criterion – the median. Otherwise, one representative region would possess too many "high" or respectively "low" wind levels, which is not supported by the empirical data. Furthermore, as will become clear in the subsequent chapters, the construction of synthetic daily wind structures and the calibration to annual values would not be possible. As expected, the latter criterion cannot be fulfilled instantaneously for the eight most frequent European wide wind events. Therefore, the eighth event has been left vacant, to be occupied by an alternative event that supports the evenly representation of the wind states in every region. In the season "winter", events with frequencies of occurrence less than six times are discriminated against, while in the season "summer", the line is drawn at events that happen less than five times.

The selection of the eighth event is based on the principle of keeping the degree of adjustments of events low, i.e. levelling their frequencies of occurrence. Necessary adjustments of the frequencies of occurrence can be observed in Table 4-4 in the column "Adjusted Frequency", compared to the original frequencies left aside. As the degree of adjustment has been kept low, in total and for each event, they are not expected to affect results decisively. However, in the season "summer", additionally, it had been indispensable to exclude the sixth event, in order to preserve a minimum of adjustment. The sixth and the seventh event differ from each other only with regards to the region which balances the low wind level of the remaining regions, which in the sixth event is done by South-East Spain, compared to North-East Sweden in the seventh event. To a certain extent, the exclusion is bolstered by the additional event – event number twelve - in which both regions, North-East Sweden and South-East Spain, counterbalance the low wind levels of the other regions.

Moreover, it has been ensured that the additional eighth event or respectively the seventh event in the season "summer" is also taking place relatively often and not just once or twice. Another point of caution has been that the chosen events cover different kinds of events. There are comparatively extreme events in the sense of obtaining high or low wind levels in all over Europe, and there are rather balanced weeks, in which some regions may smooth the other regions' low wind levels. In the winter season, the selected events match quite well the characteristics of total events. The share of extreme events - high and low levels having about the same proportions – and balanced events correspond approximately to the total sample shares. In the summer season, balanced events tend to be modestly underrepresented compared to extreme events with high wind levels. This is most probably due to the fact that the first event characterized by a rather extreme wind situation with high wind levels in four out of five regions comes to pass more often than the other events.

With the help of the heuristics[25] described above, in total, nearly about 50 per cent of the European wind states can be incorporated, as symbolized by the grey coloured fields in Table 4-4 and 4-5.. Of course, leaving some events aside will have consequences for modelling results, especially with respect to the whole spectrum of possible smoothing effects between regions.[26] Nonetheless, the included cases reasonably typify extreme, as well as balanced wind situations in Europe, thereby inducing adequate effects on allocation and diversification decisions of wind plants across Europe (see Chapter 6). In order to check that the concurrence of the same wind state between regions within the same wind supra region is higher than between regions of different wind supra regions, a controlling calculation has been carried out for the region “North Sea”. The examined regions within this wind supra region show a 64 per cent concurrence of the same wind level (either all “low” or all “high”), compared to 10 per cent in case of regions located in different wind supra regions. This result is not surprising, due to the much higher correlations of average weekly wind levels within a wind supra region, compared to correlations between wind supra regions (see Chapter 4.4.1.2).

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[25] Alternatively to a heuristic approach, a nonlinear mixed-integer optimization (MINLP) model may be formulated to maximize the total frequencies of occurrence within at most eight events per season, subject to the constraint that the amount of low wind levels equals the amount of high wind levels within a region. However, “the modelling and solution of these MINLP optimization problems has not yet reached the stage of maturity and reliability” (GAMS Development Corporation, 2011, p. 1). Moreover, as the amount of events is limited and some qualitative constraints cannot be implemented into an optimization model, a heuristic approach most probably provides better results.

[26] The possibility of one region to counterbalance another region’s low wind levels do not only depend on the prevailing wind level in the same region, but also on the possibility to exchange power between the regions, as restricted by the interconnector capacity between regions. The restriction becomes even more limiting, when regions are located more far apart and thus have to transfer power over long distances with increasing probability of bottlenecks for transferring power. This aspect will be examined in more detail in chapter 6.

TABLE 4-4: EUROPEAN WIND EVENTS WITH FREQUENCIES OF OCCURRENCE IN THE WINTER IN THE PERIOD 2006 TO 2010

Winter						
Original Frequency	Adjusted Frequency	**Western Netherlands**	**Southern Czech Republic**	**North-East Sweden**	**Western France**	**South-East Spain**
		Region 1	Region 2	Region 3	Region 4	Region 5
8	6	l	l	h	l	h
7	7	h	h	h	h	l
7	6	h	h	h	l	l
7	7	l	l	l	l	h
6	6	h	h	h	h	h
6	6	l	h	l	l	l
6	6	l	l	l	h	h
5	5	h	h	l	h	l
5	5	l	h	h	h	h
5	5	h	l	h	l	l
4	4	h	h	l	l	l
4	6	h	l	l	h	l
4	4	l	l	l	l	l
3	3	h	h	l	h	h
3	3	l	h	l	h	h
3	3	l	h	l	l	h
3	3	h	l	h	h	l
3	3	l	l	l	h	l
3	3	l	l	h	l	l
2	2	h	h	h	l	h
2	2	h	l	h	h	h
2	2	h	l	l	h	h
2	2	h	l	l	l	h
2	2	l	l	h	h	h
1	1	l	h	h	l	h
1	1	l	l	h	h	l
0	0	h	h	l	l	h
0	0	l	h	h	h	l
0	0	l	h	l	h	l
0	0	l	h	h	l	l
0	0	h	l	h	l	h
0	0	h	l	l	l	l

Source: own calculations

TABLE 4-5: EUROPEAN WIND EVENTS WITH FREQUENCIES OF OCCURRENCE IN THE SUMMER IN THE PERIOD 2006 TO 2010

Summer						
Original Frequency	Adjusted Frequency	**Western Netherlands**	**Southern Czech Republic**	**North-East Sweden**	**Western France**	**South-East Spain**
		Region 1	Region 2	Region 3	Region 4	Region 5
11	12	h	h	l	h	h
8	7	l	l	l	l	l
7	7	h	l	h	l	l
5	5	h	h	l	h	l
5	7	l	h	h	h	h
5	5	l	l	l	l	h
5	5	l	l	h	l	l
4	4	h	h	h	h	h
4	4	h	h	h	l	l
4	4	l	h	l	h	h
4	4	l	h	h	l	l
4	4	h	l	h	h	l
4	4	l	l	h	h	h
3	3	l	h	l	h	l
3	3	h	l	l	l	h
3	3	h	l	l	l	l
3	3	l	l	l	h	h
3	5	l	l	h	l	h
2	2	h	h	h	h	l
2	2	h	h	h	l	h
2	2	h	h	l	l	l
2	2	l	h	h	l	h
2	2	h	l	h	h	h
2	2	l	l	h	h	l
1	1	h	h	l	l	h
1	1	l	h	h	h	l
1	1	l	h	l	l	h
1	1	l	h	l	l	l
1	1	h	l	l	h	h
1	1	h	l	h	l	h
1	1	l	l	l	h	l
0	0	h	l	l	h	l

Source: own calculations

4.4.1.4 Modelling of the Daily Structure

In the previous modelling step, only different levels of regional wind speeds have been considered, whereas, the wind speed development over time and its irregular fluctuations have been neglected. In this third modelling step, the daily typeday structures of the seasonal low- and high wind periods of all single regions are determined. Yet, in contrast to solar power wind speeds do not have a pronounced daily pattern. Wind power is rather dominated by prevailing weather conditions. Since only a limited number of typedays can be included in the model, in this third step, one synthetic daily wind structure is calculated for all single wind states, regions, and seasons. Hence, it is not aimed at representing a "typical" daily structure for wind, which does not exist, but rather to incorporate the average fluctuations and gradients of wind which affect the dispatching of conventional power plants.

The determination of the daily wind structures rests on the wind typedays defined earlier. To recapitulate, there are two wind states per season in each wind region, which are "low" and "high". Afterwards, the wind state of one region has been assigned to the wind states of the other regions, under the condition of simultaneity. For each season and wind state, one wind typeday structure is calculated. Consequently, altogether four different wind structures are separately estimated for each region. Thereby, the peculiarities of the different regions are accounted for. Here, all days[27] within the sample period are differentiated by the wind states "low" and "high". This is done by setting the daily arithmetic means of regional wind speeds in relation to the seasonal medians of regional wind speeds. This

[27] Remember that in the previous modelling step, the classification of the wind states is based on weekly data. As mentioned earlier, this has been necessary when regarding the simultaneity of wind speeds, due to the time lags regarding wind patterns between regions. By contrast, here the intention is to determine daily wind structures. Since it is assumed that regions within a supra region are perfectly correlated, the principle of simultaneity can be relaxed.

means that if the average daily wind speed exceeds the seasonal median, then the day is defined as “high”, otherwise as “low”.

The synthetic wind structures are calculated by a nonlinear optimization, subject to certain constraints.[28] The basis of the non-linear optimization forms the average hourly wind speed $\overline{D}_h^{r,s,WS}$, which has been specified beforehand from the empirical data. Thereby, r denotes the region, WS the wind state, s the season, and h signifies the hours of the day 1 to 24. Taking the arithmetic mean of the empirical wind speeds in the hour h results in a flat daily wind speed curve, in which all fluctuations have been averaged out. To be exact, this wind speed curve is the diurnal wind pattern that exists in the different wind regions, though differentiated by wind state and season. On average, a humble diurnal wind structure could be identified for almost all regions.

In the optimization, advantage is taken of the empirical diurnal wind structure $\overline{D}_h^{r,s,WS}$ by minimizing the deviations between the typeday variables $\mathrm{T}_\mathrm{h}^{\mathrm{r,s,WS}}$ and the empirical diurnal wind structure $\overline{D}_h^{r,s,WS}$. Thereby, it is ensured that the typeday variables, on the one hand, share some properties of the average hourly wind speeds, such as the level and the diurnal pattern. On the other hand, the variables should deviate from others, which will be specified later in the constraints. Moreover, it is important to minimize the absolute value of the deviations, as otherwise positive and negative deviations would cancel out. Since including discontinuous functions, such as the function of the absolute value, is problematic, the minimization of the sum of squared differences between the average hourly wind speeds resulting from the empirical data and the

[28] The criterions for modelling the daily typeday structure have been developed together with Cosima Jägemann and Christina Elberg. The exact mathematical formulation has been done by Christina Elberg.

typeday variables is opted for. The disadvantage of this approach is that big differences are weighed relatively more. Analogous to the empirical average hourly wind speeds $\overline{D}_h^{r,s,WS}$, the hourly typeday variables $\mathrm{T}_\mathrm{h}^{\mathrm{r,s,WS}}$ are differentiated by region, season, and wind state. Minimization has been carried out with the non-linear GAMS solver CONOPT. Thus, the objective function is the following:

$$Minimize \sum_{h=1}^{24} \left(T_h^{r,s,WS} - \overline{D}_h^{r,s,WS}\right)^2. \tag{4-2}$$

In order to account for the average fluctuations and gradients, the average daily variances of wind speeds and the average daily variance of wind speeds from one hour to the next $(h-(h-1))$ are included in the following two constraints. In probability theory and statistics, the variance is used as a measure of how far a set of numbers are spread out from each other. It is one of several descriptors of a probability distribution, describing how far the numbers lie from its expected value. The second part in the first constraint, the empirical average daily variance, has been completely specified before the actual minimization. The constraint prescribes that the daily variance of the typeday variables should equal the empirical average daily variance at the respective typeday. Instead of dividing by 24 for all 24 hours, the denominator 23 has been chosen, as here it is dealt with the sample variance compared to the population variance (Mosler and Schmid, 2006, p. 201). Since the daily expected value of the typeday variables must equal the empirical daily expected value of the wind speeds, it is possible to substitute the expected value of the variable $\overline{T}^{r,s,WS}$ in the first part of the equation by its empirical counterpart, $\overline{\overline{D}^{r,s,WS}}$. $\overline{D}^{r,s,WS}$ must be distinguished from the average hourly wind speeds $\overline{D}_h^{r,s,WS}$.

The average daily variance for each region, season, and wind state has to be met:

$$\frac{1}{23}\sum_{h=1}^{24}\left(T_h^{r,s,WS} - \overline{D}^{r,s,WS}\right)^2 - \frac{1}{|N|}\sum_{D^{r,s,WS}\in N}\frac{1}{23}\sum_{h=1}^{24}\left(\overline{D}_h^{r,s,WS} - \overline{D}^{r,s,WS}\right)^2 = 0, \tag{4-3}$$

whereby N is the number of days in the respective typeday sample.

Since the variance itself does not indicate the nature of the fluctuations - whether fluctuations are small and frequent or whether they are rather large and less frequent - an additional constraint has had to be formulated. The constraint stipulates that the average daily variance of the differences between two successive hours should equal its empirical pendent. Apart from the fact that the average daily variance of the wind speed gradients is calculated, the constraint is similar to the first constraints,.

The average daily variance of the differences between two successive hours has to be met:

$$\frac{1}{22}\sum_{h=2}^{24}\left(\left(GT_h^{r,s,WS}\right) - \left(\overline{GT}^{r,s,WS}\right)\right)^2 - \frac{1}{|N|}\sum_{D^{r,s,WS}\in N}\frac{1}{22}\sum_{h=2}^{24}\left(GD_h^{r,s,WS} - \overline{GD}^{r,s,WS}\right)^2 = 0, \tag{4-4}$$

thereby $\mathrm{GT}_{\mathrm{h}}^{\mathrm{r,s,WS}} = \left(\mathrm{T}_{\mathrm{h}}^{\mathrm{r,s,WS}} - \mathrm{T}_{\mathrm{h-1}}^{\mathrm{r,s,WS}}\right)$, and $\overline{GT}^{r,s,WS}$ denotes the arithmetic mean of the term $\left(\mathrm{T}_{\mathrm{h}}^{\mathrm{r,s,WS}} - \mathrm{T}_{\mathrm{h-1}}^{\mathrm{r,s,WS}}\right)$. Moreover, $\mathrm{GD}_{\mathrm{h}}^{\mathrm{r,s,WS}} = \left(\overline{\mathrm{D}}_{\mathrm{h}}^{\mathrm{r,s,WS}} - \overline{\mathrm{D}}_{\mathrm{h-1}}^{\mathrm{r,s,WS}}\right)$, and $\overline{\mathrm{GD}}^{\mathrm{r,s,WS}}$ stands for the arithmetic mean of the term$\left(\overline{\mathrm{D}}_{\mathrm{h}}^{\mathrm{r,s,WS}} - \overline{\mathrm{D}}_{\mathrm{h-1}}^{\mathrm{r,s,WS}}\right)$.

Due to the diurnal wind speed pattern, the variance conditions (see equations 4-3 and 4-4), combined with the minimization of the sum of squared differences, in most of the cases lead to an underestimation of wind speed levels in off-peak-load hours and to an overestimation of wind speed levels in peak-load hours. In order to avoid that the synthetic daily wind structure exhibit an atypical behaviour in relation to electricity demand, two additional conditions have been specified. Otherwise, a more positive correlation would be suggested than indicated by the empirical data.

The arithmetic mean of the peak load hours (from hour 9 to 20)[29] has to be met by the typeday structure of the respective hours:

$$\frac{1}{12}\sum_{h=9}^{20} T_h^{r,s,WS} - \frac{1}{|P|}\sum_{h\in P} \overline{D}_h^{r,s,WS} = 0 \,, \tag{4-5}$$

P denotes the set of peak-load hours.

Similarly, the arithmetic mean of the off-peak-load hours (from hour 1 to 8 and from hour 21 to 24) has to be met by the typeday structure of the respective hours:

$$\frac{1}{12}\sum_{h\in\{1,\ldots 8,21,\ldots,24\}} T_h^{r,s,WS} - \frac{1}{|OP|}\sum_{h\in PO} \overline{D}_h^{r,s,WS} = 0 \,, \tag{4-6}$$

OP denotes the set of off-peak-load hours.[30]

---

[29] Hour 9 signifies the period of 8 until 9 o'clock, hour 20 means the time period from 19 to 20 o'clock.

[30] Constraints 4a and 4b in conjunction also specify implicitly that, in total, the arithmetic mean of the typeday variables should equal the total empirical arithmetic mean of the wind speeds in the respective wind state, region, and season.

Whenever the empirical average diurnal structure $\overline{D}_t^{r,s,WS}$ does not display a distinctive diurnal structure, but is just a vertical line, the resulting typeday variables are to some extent random, at least the curve progression (whether first increasing and later decreasing or the other way around). As smoothing effects between regions within the same wind supra regions are explicitly not considered, it is vital that all belonging regions do have the same curve progression in each wind state.[31] Thus, extra conditions make sure that all typeday curves' slopes of all belonging regions, within defined time intervals, are of the same sign, i.e. either all negative or all positive. Thereby, the standard of the signs are in accordance with the curve progressions of the majority of the belonging regions. Additionally, the signs have been tested by a supplementary calculating run, specifying further that all regions have the same slopes in the defined time intervals. However, with respect to the final optimization, this condition has been found being too restrictive, as wind speeds of belonging regions may well have different slopes, but still a reasonably similar curve progression.

Exemplary optimized and averaged daily wind typeday structures over a five day time horizon for Northern and Central Germany can be seen in Figure 4-17. Thereby, the optimized wind typeday structures correspond to the hourly typeday variables $\mathrm{T}_{\mathrm{h}}^{\mathrm{r,s,WS}}$and the averaged typeday structures to the average hourly wind speeds $\overline{D}_h^{r,s,WS}$. It can be observed that the curves of the averaged hourly wind speeds are more flat, compared to the optimized daily wind structure in which the average wind fluctuations and gradients have been accounted for. Moreover, the optimized wind typeday structures fluctuate around their empirical counterparts, as by construction both have the same arithmetic mean, thereby accounting for the specific wind levels in the respective regions, seasons and wind states. Furthermore, as smoothing effects between regions within the same wind

[31] This is especially true later when some wind regions are subsumed into one.

supra region are not considered, the optimized typeday structure of the two regions do not display time lags with respect to wind peaks or slacks, but are parallel to each other. Finally, the average daily variances and the average daily variances of the differences between two successive hours is higher for “high” wind states than for “low” wind states. Although the differences between the variances in different wind states is not high for the wind onshore regions in Germany (about 35 per cent), the picture is different for other wind regions, in which average daily variances in “high” wind situation can add up to twice the values that occur in “low” wind situations.

In the following, the optimized wind typeday structures have to be compared to actual wind speeds. As before, the optimized wind typeday structures are depicted for a five-day time horizon. Actual wind speeds are chosen for arbitrary points in time, again for five series-connected days. Nevertheless, it has been paid attention that as a counterexample one wind progression curve is shown, which, with respect to the interval of possible daily variances is situated at the upper end.

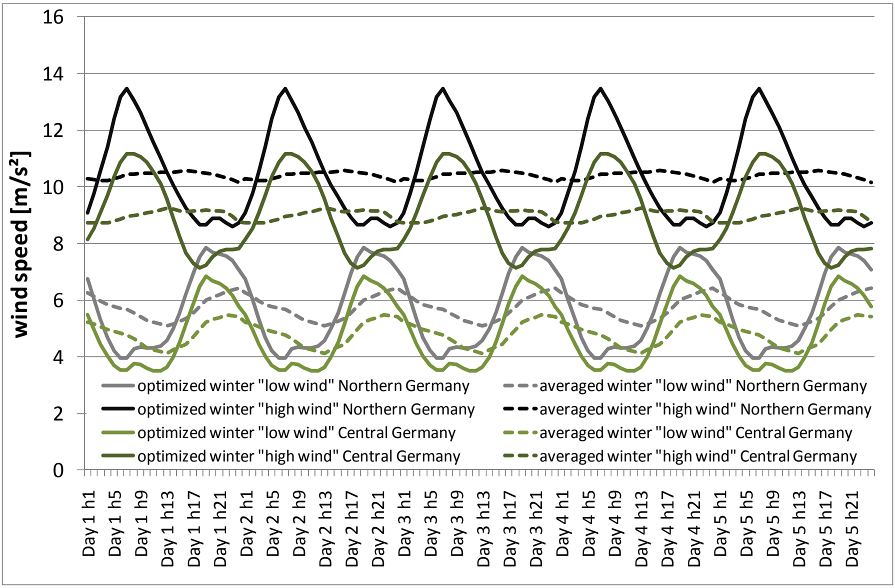

FIGURE 4-17: OPTIMIZED AND AVERAGED DAILY WIND TYPEDAY STRUCTURES IN THE WINTER SEASON IN NORTHERN AND CENTRAL GERMANY

Source: own calculations

For the “low” wind situation in the winter, the extreme example consists of a time period, in which one day has an average wind speed variance of 7.5 (m/s)², compared to the seasonal average of 2.8 (m/s)². For the “high” wind situation in winter, one time period comprising a day with a wind speed variance of just less than 20 (m/s)² is chosen, compared to the seasonal average of 2.88 (m/s)². The other curves relate to days, in which average wind speeds and the average variance of wind speeds correspond approximately to the seasonal averages. In both figures below (figure 4-18 and 4-19), the grey curve relates to the extreme example with a high daily wind speed variance. The thicker black curves coincide with the optimized wind typeday structures for five days in a row. The other curves match up with actual wind speed periods that approximately have the same arithmetic means and variances as the optimized wind typeday structures.

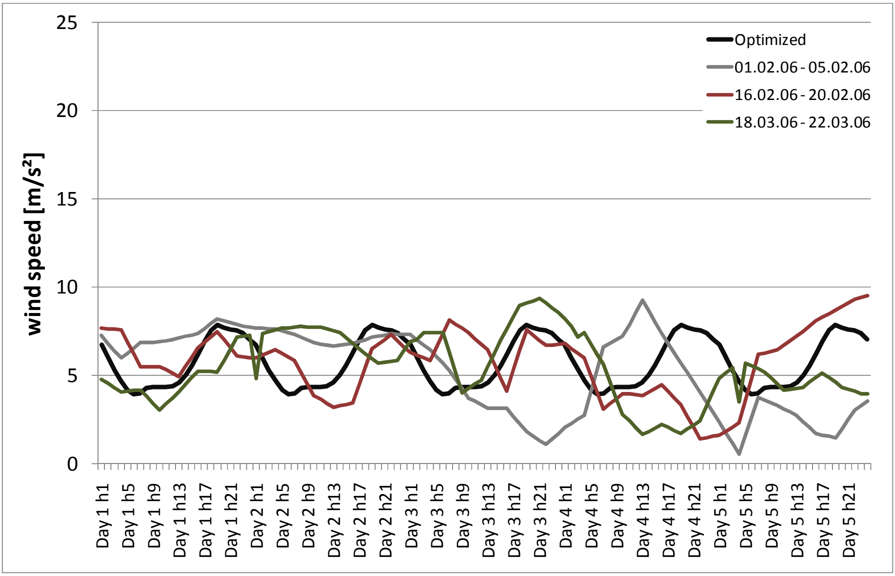

FIGURE 4-18: OPTIMIZED AND ACTUAL WIND SPEEDS IN A 5 DAY HORIZON (WINTER SEASON, "LOW" WIND, NORTHERN GERMANY)

Source: own calculations

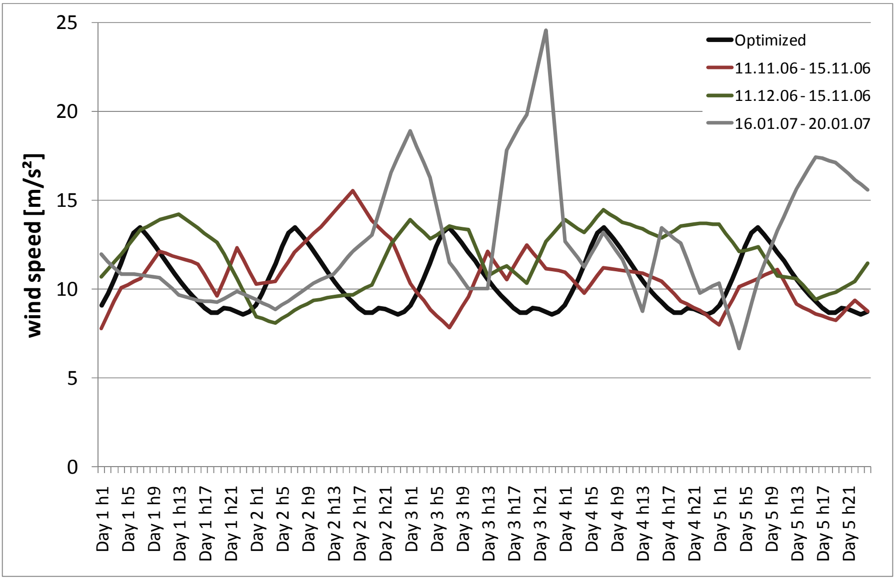

FIGURE 4-19: OPTIMIZED AND ACTUAL WIND SPEEDS IN A 5 DAY HORIZON (WINTER SEASON, "HIGH" WIND, NORTHERN GERMANY)

Source: own calculations

It can be observed, that with the exception of the extreme examples, the optimized typeday structures reflect the major characteristics of actual wind speeds, though on a much more regular level. Accordingly, the daily minimum and maximum wind speed levels as well as the typical ramp rates of average days are roughly met. However, as expected, the optimized wind typeday structures fall short of reproducing extreme wind situations, such as extremely low or high wind in-feeds or extreme ramp rates that occur in single wind regions.

This can be also observed in figure 4-20, in which the annual frequency distribution for the same wind region example is graphically depicted. The optimized wind speed distribution cuts of outstanding low or high winds speeds of the empirical Weibull distribution. Instead it contains more values in the medium range. However, the wind speeds themselves are not relevant as model input parameter but the generated power. Therefore, the annual frequency distribution of the resulting capacity factor of a 5 MW wind power plant (compare chapter 4.4.1.5.) has been established and graphically depicted in figure 4-21.

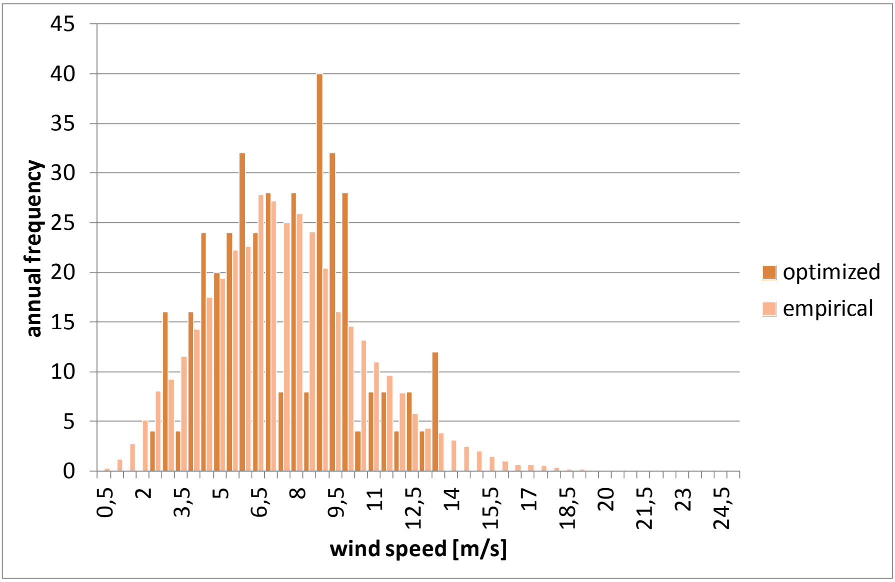

FIGURE 4-20: ANNUAL FREQUENCY DISTRIBUTION OF EMPIRICAL AND OPTIMIZED WIND SPEEDS, NORTHERN GERMANY

Source: own calculations

By contrast, here, the annual frequency distributions of the empirical and optimized capacity factors are much more similar than for the raw data – the wind speeds. Since due to mass inertia wind power plants of that size can produce power only from a wind speed of at least 3 m/s, the omission of extreme low wind speeds does not cause a high imprecision. The same applies for extreme high wind speeds as the power curve flattens for higher wind speeds (compare chapter 4.4.1.5).

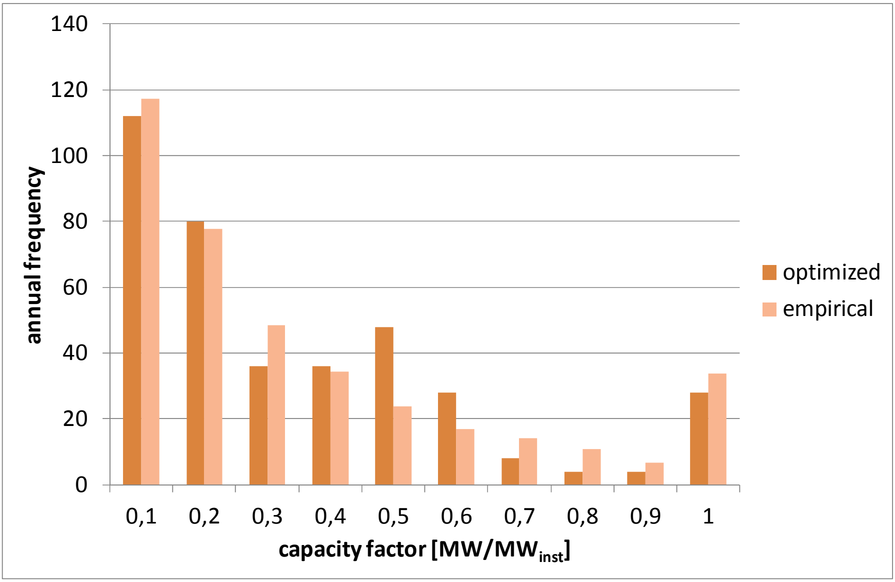

FIGURE 4-21: ANNUAL FREQUENCY DISTRIBUTION OF EMPIRICAL AND OPTIMIZED CAPACITIY FACTORS

Source: own calculations

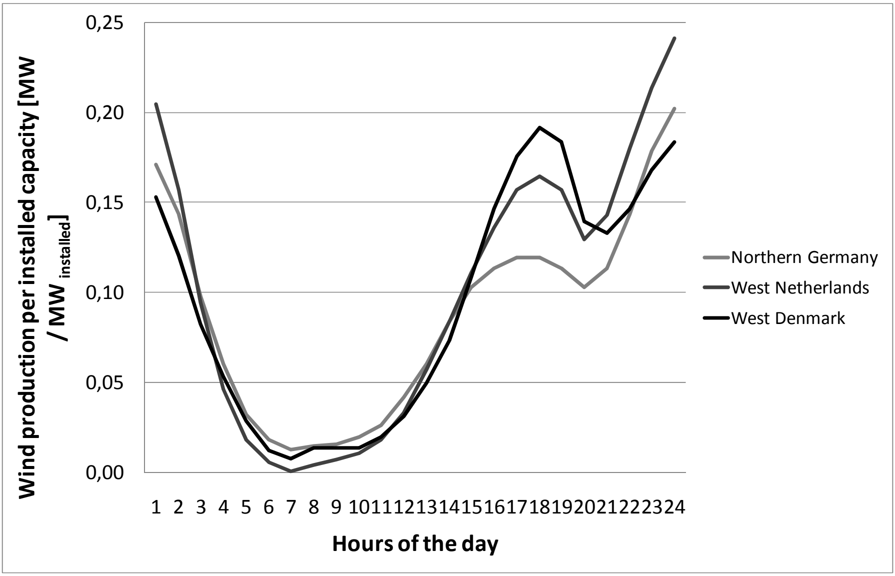

FIGURE4-22: SYNTHETIC DAILY WIND PRODUCTION CURVES FOR "SUMMER LOW WIND" IN THREE REGIONS CLOSE TO THE NORTH-SEA

Source: own calculations

In Figure 4-22, the wind power capacity factors of the typeday "summer low wind" for three exemplary wind regions close to the North-Sea are shown. Although due to favourable wind conditions the average capacity factor is relatively high in all three regions (from 8 to 10 per cent), there are at least five consecutive hours in each exemplary region, in which the wind feed-in per installed MW fall short of 0.1. As balancing effects within a wind supra region are not considered, the hours characterized by extreme low wind production take place at the same time. As a consequence, extreme events will be rather overestimated in the modelling. The modelling of the typeday structure for load follows a similar logic, except that the subscript wind state is substituted by the subscript weekday ("working day" and "weekend").[32] It is obvious that equations 4-4 and 4-5 are needless here. The optimization of the electricity demand structures has been accomplished by Christina Elberg.

4.4.1.5 Calculation of Wind Yields and Calibration to Annual Values

The wind speeds provided by Eurowind (2011) refer to a height of 95 meter above ground level. In order to transfer them to wind speed at hub height, they are inserted into the logarithmic wind profile (Hau, 2003, p. 457):

$$v = v_r \frac{\ln\left(\frac{z}{z_0}\right)}{\ln\left(\frac{z_r}{z_0}\right)} \tag{4-7}$$

From that, the wind speed at hub height (z) can be determined, dependent on the representative wind speed (v_r), the representative height (z_r), and the surface roughness (z_0). The surface roughness is a measure of the obstacles in the terrain. It is defined as the height above ground, at which the wind speed is theoretically zero (Thomas and Goudie, 2000, p. 421). Here, the respective regional values of surface roughness (Eurowind, 2008) are used. With the help of power characteristic curves of different wind power plants, the wind power yields are calculated. Power characteristic curves determine the theoretical wind power production of wind turbines from wind speeds at hub height. The typical shape of a power curve is depicted in figure 4-23, which shows exemplary the power curve of a 5 MW REpower wind power plant.

[32] Due to the limitations in the number of typedays to be included into the model, it is just distinguished between two states of weekdays.

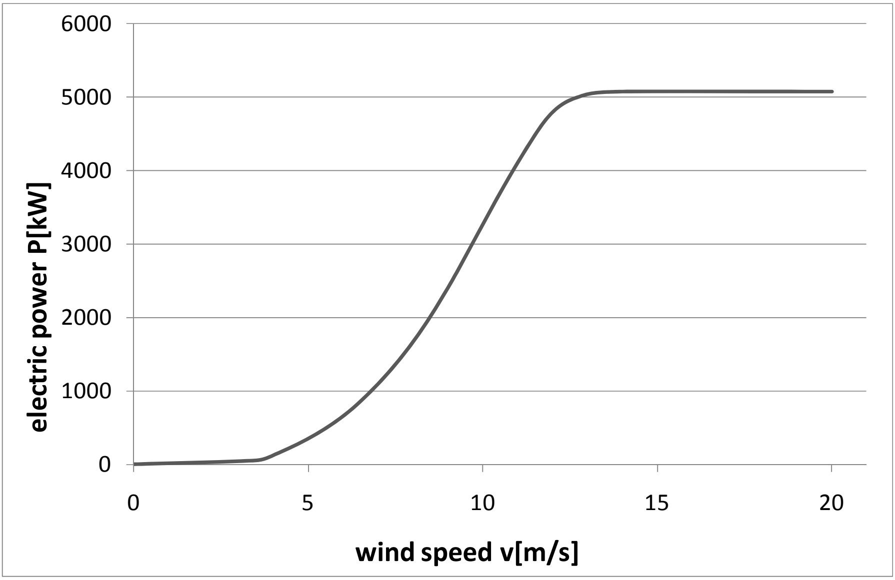

FIGURE 4-23: POWER CURVE OF A 5 MW REPOWER WIND POWER PLANT

Source: Eurowind (2011)

Dependent on wind speeds, the power curve can be distinguished by four different phases. Initially, at wind speeds below 3 to 4 m/s, wind power plants do not produce any electricity, as frictional and inertia forces cannot be overcome. After that, with wind speeds up to 12 to 14 m/s, the power produced increases proportionally to the third power of the wind speeds until the nominal power of the wind power plant is reached. Then the wind power generation remains constant for wind speeds up to 24 to 30 m/s, as with higher wind speeds the turbine is shut down in order to avoid damages (Kaltschmitt et al., 2006, p. 313).

Here, two different wind power plants are considered with rated powers of 3 and 5 MW, and corresponding hub heights of 92 (Wissen, 2012) and 120 meters respectively (Eurowind, 2011). Although there are also other drivers, such as average wind speeds at the respective site, the trend goes towards higher rated wind power plants with higher hub heights. In this regard, the 3 MW plant can be considered an existing plant. By contrast, the bulk of current installed onshore- and offshore wind power plants has a nominal capacity of 5 MW or even 6 MW, thus comprising the latest wind technology. Hence, onshore wind power production is calculated for the wind power plants with nominal powers of 3 and 5 MW. By contrast, offshore wind power production is computed for a 5 MW wind power plant only, as offshore wind power plants below a rated power of 5 MW do not play a significant role. Though depending on the prevailing wind speed level at a site and the relationship between the rotor diameter and the wind turbine, higher rated wind power plants are usually associated with higher full load hours per year (Wissen, 2012). For the 3 MW and the 5 MW wind power plants, this could be verified in the calculations.

By means of the methodology described above, the hourly wind power production is calculated for each wind region at each wind typeday (“winter low wind”, “winter high wind”, “summer low wind”, and “summer high wind”), as well as for each wind region in the whole sample period. As the regional wind qualities should be represented by the annual wind yields, possible deviations between the wind yields of the reduced and the whole sample period have to be corrected for. The annual yields of the wind typedays are estimated by scaling the typedays by their annual frequencies (see chapter 0 and 4.4.1.4). Although, with respect to the wind speeds, the reduced and the whole sample period, by definition, have the same arithmetic mean deviations with respect to wind power production arise due to the non-linear power curve. In general, the annual yields of wind regions with low average wind speeds are underestimated by the typedays and vice versa. This can be explained by the fact that at low quality sites, there still exist some high wind hours, which are not captured by the typedays. If this occurs in the fraction of the power curve, in which wind speeds translate to wind production with the third power, then this makes a big difference. By contrast, high quality sites are situated frequently in the subsequent fraction of the power curve, in which power production approximates the nominal capacity. In this case, lower actual wind speeds not captured by the typeday relatively result in lower annual yields.

Fortunately, the deviations between the annual wind production yields of the reduced (the synthetic wind in-feed structure) and the whole sample are small, lying on average at about 80 full load hours. With respect to the average annual yield of the European wind regions, this signifies a deviation of about 3.6 per cent. In order to correct for the deviations, the total amount of the deviation is scaled down to be uniformly distributed on the hourly wind production values of the typedays. This means a slight upward or downward shift for the whole typeday curve. On average, hourly production is shifted up- or downwards by about 0.01 MW per installed capacity. In terms of wind speeds, this translates into hourly wind speed differences of 0.05 to 0.2 m/s. In doing so, the shape of the wind feeding curve is hardly changed. However, in hours in which initial wind production is zero or one, corrections in the negative or positive direction respectively cannot be carried out.

4.4.2 Modelling of Typedays for Solar Power

In contrast to wind speeds, solar irradiation has a strong pronounced diurnal and seasonal pattern, which can be accurately and easily captured by the seasonal and daily structure of the typeday modelling. However, as the focus in this work is on wind speed modelling and due to the computational constraints, the variations of solar irradiation cannot be captured in the modelling. This would raise the number of typedays to a higher power. For solar power, a “typical” day will be represented by the hourly average irradiation per season and wind state. This of cause implies that variations in the irradiation levels are averaged out. Nevertheless, the negative correlation between wind speed and solar irradiation values will be accounted for. Instead of merely establishing one typical typeday for solar power for each season, the solar power typedays are linked to the wind typeday structure. For each region and seasonal wind state described in chapter 4.4.1, a corresponding solar typeday is identified. These are calculated by the average hourly irradiation in the time span of the respective seasonal wind states (“high” and “low”). Figure 4-24 shows exemplary the diurnal structure of the solar typedays for Germany. The negative correlation (see chapter 4.2) between wind and solar power is represented by the slightly higher irradiation values at days on which wind blows strongly. In the modelling, this results in a smoothing effect between the two renewable energy sources. This means that the combined wind and solar power output is less variable than one resource on its own. As indicated by the correlation analysis in chapter 4.2, the correlation coefficients are less negative in the summer months, signifying a weaker smoothing effect in the summer period.

Based on the regional and hourly global irradiation data, the energy yield of solar plants per region and hour can be determined. In contrast to mechanical energy conversion, the efficiency of solar cells remains approximately constant. Aside from the irradiation intensity, the energy yield of a solar plant depends on the inclination angle, the kind of system-elevation and the performance ratio, which includes a diminution from optimal output caused by e.g. efficiency losses of cables or inverters, contamination or shadowing effects. The performance ratio specifies the relationship between the actual and the optimal output. Values of the performance ratio are between 0.6 and 0.86. Quaschning (1999) identifies a performance ratio of 0.75 for new rooftop power installations. Actually, also efficiency losses due to high temperatures of the solar cells - which may rise to 70 °C – should be considered. The efficiency by the manufacturer is defined under so called standard test conditions, fixing the temperature at 25 °C. Unfortunately, simultaneous data of temperature have not been available for the considered sample period. Hence, the optimal power yield $Y_{optimal}$ of a solar power plant is simply calculated by Quaschning (1999):

$$Y_{optimal} = A_{PV} \cdot \eta_{PV} \cdot I_{solar} \quad (4\text{-}8)$$

Thereby, A_{PV} relates the area of the power plant in m², η_{PV} to the efficiency of the power plant and I_{solar} to the global radiation in W/m². The advantage of this calculation method is the low level of detail, which keeps the amount of data input manageable.

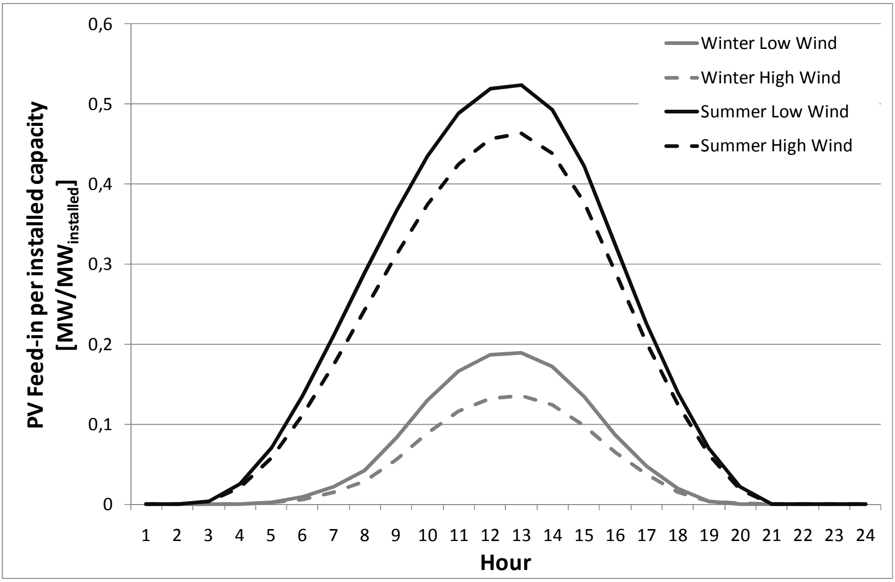

FIGURE 4-24: SYNTHETIC SOLAR STRUCTURE IN NORTHERN GERMANY

Source: own calculations

4.4.3 Combination of Typedays

Finally, the typeday modelling of wind and solar power, as well as of the electricity demand, has to be combined. Whenever a clear relationship between the variables of interest cannot be established[33], every typeday of one variable has to be combined with all typedays of the other variables. In the case of solar and wind power, this has been resolved by including the average hourly solar irradiation within the time span, at which the respective wind states take place. Thus, the typedays of solar power are consistent with the typedays of wind power and consequently in the combination do not have to be considered further. By contrast, the variables, wind power and electricity demand, have to be combined with each other. Given the two typedays of electricity demand and the eight/seven seasonal typedays of wind power, overall, the combination of the typedays results in sixteen typedays in the winter and fourteen typedays in the summer. Thereby, the typeday sequence is arranged in a way that one European wind event takes place for one whole week, including weekdays and the weekend.

On average, the week in the winter season in Europe consists of 4.88 weekdays and 2.12 days at the weekend, including bank holidays. In the summer, the week in Europe has, on average, 4.78 weekdays and 2.22 days at the weekend. The wind events are then distributed over the 26 weeks in each season according to their individual frequencies of occurrence (see chapter 0). In total, the following typedays can be established with the corresponding frequencies (see Table 4-6).

[33] The dependence between electricity demand and wind speeds has not been matter of examination. It has been assumed that both variables are independent.

Table 4-6: Combination of typedays for wind power and electricity demand

Season	Typeday	Frequency	Electricity Demand	Region 1	Region 2	Region 3	Region 4	Region 5
Winter	d1	15.2	Weekdays	low wind	low wind	high wind	low wind	high wind
	d2	6.6	Weekend	low wind	low wind	high wind	low wind	high wind
	d3	17.8	Weekdays	high wind	high wind	high wind	high wind	low wind
	d4	7.7	Weekend	high wind	high wind	high wind	high wind	low wind
	d5	15.2	Weekdays	high wind	high wind	high wind	low wind	low wind
	d6	6.6	Weekend	high wind	high wind	high wind	low wind	low wind
	d7	17.8	Weekdays	low wind	low wind	low wind	low wind	high wind
	d8	7.7	Weekend	low wind	low wind	low wind	low wind	high wind
	d9	15.2	Weekdays	high wind	high wind	high wind	high wind	high wind
	d10	6.6	Weekend	high wind	high wind	high wind	high wind	high wind
	d11	15.2	Weekdays	low wind	high wind	low wind	low wind	low wind
	d12	6.6	Weekend	low wind	high wind	low wind	low wind	low wind
	d13	15.2	Weekdays	low wind	low wind	low wind	high wind	high wind
	d14	6.6	Weekend	low wind	low wind	low wind	high wind	high wind
	d15	15.2	Weekdays	high wind	low wind	low wind	high wind	low wind
	d16	6.6	Weekend	high wind	low wind	low wind	high wind	low wind
Summer	d17	31.1	Weekdays	high wind	high wind	low wind	high wind	high wind
	d18	14.4	Weekend	high wind	high wind	low wind	high wind	high wind
	d19	18.1	Weekdays	low wind	low wind	low wind	low wind	low wind
	d20	8.4	Weekend	low wind	low wind	low wind	low wind	low wind
	d21	18.1	Weekdays	high wind	low wind	high wind	low wind	low wind
	d22	8.4	Weekend	high wind	low wind	high wind	low wind	low wind
	d23	18.1	Weekdays	low wind	high wind	high wind	high wind	high wind
	d24	8.4	Weekend	low wind	high wind	high wind	high wind	high wind
	d25	12.9	Weekdays	low wind	low wind	high wind	low wind	low wind
	d26	6.0	Weekend	low wind	low wind	high wind	low wind	low wind
	d27	12.9	Weekdays	high wind	high wind	low wind	high wind	low wind
	d28	6.0	Weekend	high wind	high wind	low wind	high wind	low wind
	d29	12.9	Weekdays	low wind	low wind	high wind	low wind	high wind
	d30	6.0	Weekend	low wind	low wind	high wind	low wind	high wind
	d31	0.0	Weekdays					
	d32	0.0	Weekend					
Sum		**364.0**						

Source: own calculations

5 DEVELOPMENT OF A EUROPEAN ELECTRICITY MARKET MODEL INCLUDING RES-E

In this chapter, on the basis of an existing investment and dispatch model for the European electricity market, covering only conventional technologies, an integrative model is developed. This model also includes, for the first time, several renewable technologies, which are incorporated in a separate renewable module. First, the basic model set-up of the existing model is described. Afterwards the most important aspects that are needed to include renewable technologies into the existing model within the renewable module are explained. Investment relevant parameters of renewable technologies such as costs and potential limits as well as dispatch relevant parameters, such as the availability of fluctuating RES, developed in chapter 4, are incorporated. Moreover, existing model equations are adjusted to the RES typeday modelling of chapter 4. In order to comprehend the effects of an integrative optimization compared to a situation in which RES-E has priority feed-in rights and is decoupled from electricity price signals, in addition to an integrative model approach, a sequential model approach is needed, comprising two separate models. The first model, including only renewable technologies, is developed based on the renewable module of the integrative approach. The existing electricity market model, including only conventional technologies, is used with additional adaptations as the second model in a row.

5.1 Non-Technical Description of the Model DIMENSION

The model DIMENSION is based on Richter (2011) and is a linear optimization model for the European electricity generating market. Since it is a time-sequenced model instead of a load duration approach, it is able to simulate investment as well as dispatch decisions of the supply side of the electricity sector. DIMENSION uses a technology-based bottom-up approach, thereby allowing for a detailed representation of different technical and economical properties. Simulations can be conducted for representative periods, whereby valid periods are e.g. 2010, 2020, 2030. The model assumes a perfect foresight over the whole time horizon. Especially energy economic parameters, such as the development of fuel prices and the electricity demand, are anticipated by assumption. Uncertainties on real markets or uncertainties with respect to fluctuating RES-E are not considered. In the objective function, total discounted costs are minimized.

Cost components include investment costs, fixed operating and maintenance (O&M) costs, fuel costs, variable O&M costs, and start-up costs. Investment costs are annualized according to predefined depreciation times and an interest rate. Fixed O&M costs encompass costs for maintenance and personnel. Fixed O&M costs are defined on an annual basis and do not depend on production decisions. By contrast, production decisions are influenced by the variable cost components (fuel-, variable O&M-, and start-up costs). Fuel costs are affected by fuel prices and electrical efficiencies, as well as by prices for carbon emissions and the carbon intensity of production. Start-up costs depend on specific costs for additional attrition from warm start. Investment decisions are made on the basis of all cost components. In addition, the future capacity utilization is taken into account. Apart from reaching the technical life time, power generating installations are decommissioned if their fixed O&M costs cannot be covered by sales revenues.

DIMENSION provides for different kinds of technologies for electricity generation, comprising fossil-fuelled, nuclear, hydro storage, pumped storage plants, and CAES plants. In order to account for different properties of the technologies, such as electrical efficiencies, for each kind of technology a further distinction is made into representative vintage classes. The vintage classes encompass information on the total amount of installed capacity and the projected decommission path. Information on installed capacities and on the decommission path are obtained from EWI's power plant database (EWI database, 2011). The decommission path is dependent on the age structure in each class and region. In addition to age-based commissioning, installations can be retired for economical reasons before their technical lifetime expires. Decommissioned, aged plants are substituted by new installations that are built on a least-cost ratio for the whole power system (or alternatively from the perspective of a central planner). Constraints of new installations and constraints in fuel consumption can be given either by overall or annual limits. For instance, lignite power stations are bound to local deposits and local mining limits, or the operation of nuclear power plants is subject to political restrictions.

In principle, the model can be applied to any geographical scope, whereby a typical application is e.g. EU-27 plus Norway and Switzerland (EU-27-plus). The model regions (here: countries) are represented as copperplates or single nodes, in which electricity can be transported without limits. Between the model regions, however, electricity transport is constrained by exogenous specified net transfer capacities (NTCs). At each time step (e.g. one hour), generation has to meet the demand for electricity. Electricity generation in one region can be provided by the power plant capacities in the respective region, contingent on their availability, or by electricity imports of neighbouring regions. Thereby, efficiency losses due to large-distance electricity transports are accounted for. Moreover, dispatch is constrained linearly by the capacity that is ready to operate and the ramp-up time needed by the different technologies from warm-start. While there is an inter-temporal interconnection between the variables concerning the capacity that is ready to operate during one typeday, there is no inter-temporal interconnection between the different typedays. Therefore, the flexibility of the power plants will be overestimated. By contrast, storage technologies are linked inter-temporally on the hourly, daily, and yearly timescale. For more detailed information, please refer to Richter (2011).

Model outputs are, for instance, the installed capacities, the commissioning and decommissioning of capacities, the power generation by technology, region and time period, and the power transports between regions.

5.2 Inclusion of Renewable Technologies in the Model

In the developed integrative modelling approach renewable technologies will be included alongside conventional technologies. This means that renewable energy technologies have to bid in the electricity market as conventional technologies do and are not treated prior ranking. The development of the integrative model essentially entails the programming of a new renewable module and the inclusion, definition, and processing of additional data. The new renewable module fits into the existing model structure and can be optionally activated or deactivated. Moreover, additional adaptations to existing model equations are necessary in order to consider the peculiarities of the RES typeday modelling. The integrative model is termed INTRES standing for the integrative treating of renewable technologies in electricity markets. The model in- and outputs can be seen in the figure below. The lower box on the left constitutes the renewable module that is integrated into the existing electricity market model. The in- and outputs of the model are described in greater detail in chapter 5.2.1 to 5.2.3.

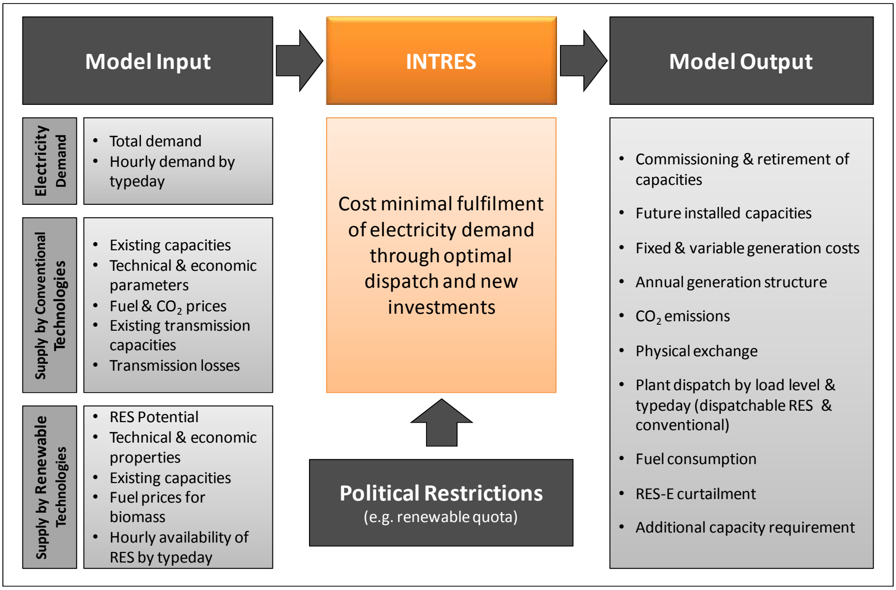

FIGURE 5-1: MODEL INPUTS AND OUTPUTS IN THE MODEL INTRES (INTEGRATIVE MODEL APPROACH)

Source: own presentation

Since the typeday modelling for intermittent RES accounts for the spatial correlation of wind speeds between wind supra regions, including their associated empirical frequencies of occurrence, endogenous balancing effects between wind outputs at different sites are incorporated. Wind output can be further balanced by solar power, which is negatively correlated to wind power, and by output from biomass and geothermal plants. Regional or technological diversification can either reduce the need to curtail RES-E or the need for backup capacity. Thus, smoothing RES output is not an aim in itself, but the advantages of a less fluctuating or less extreme output structure. The advantages relate to e.g. less RES-E curtailment or less ramping-up and –down operations. The advantages are traded off against the disadvantage in terms of the increased total generation costs for RES-E. In the integrative model approach, smoothening of RES-E takes place if it is beneficial from the perspective of the whole power generation system. The model extends existing modelling approaches by calculating endogenously the RES-E curtailment from technologies based on fluctuating RES and the dispatch of biomass power plants. Thus, although a maximum annual yield is implied by the typeday structures for RES and the associated frequencies of occurrence, necessary RES-E curtailment or dispatch reductions directly influence the profitability of investments in renewable capacities.

Moreover, the optimized synthetic daily wind structure entails different ramp-rates and fluctuations of wind power that comply with empirical data. Thus, increasing ramping costs and flexibility needs on the conventional supply side as a result of including large-scale RES-E are accounted for. In addition, the amount of capacity necessary to backup capacities based on fluctuating RES is determined endogenously by the availability of RES implied by the typeday modelling. Furthermore, transmission restrictions between different regions are considered, which limit the possibilities of balancing RES output and of sharing backup capacities between regions. The integrative capability of regions, which is influenced e.g. by their market size and transmission capacities as well as the associated consequences for renewable technologies in terms of e.g. RES-E curtailment, directly feeds back to the investment decisions for RES. In addition to the flexibilities in the electricity market, such as existing interconnector capacities and the expansion of more flexible electricity generating units, the integrative capability of regions may be increased by diversifying renewable technologies and sites. Furthermore, the capacity that is necessary to backup fluctuating energy sources will be minimized.

Hence, the developed integrative model trades off the options to reallocate RES-E at less favourable sites or to switch to more expensive renewable technologies, against the option of an increased integration burden for concentrated RES-E at favourable sites. The model approach and the data input cover the EU-27-plus.

Since the original data regarding renewable technologies - largely retrieved from Fürsch et al. (2010) - corresponds to different model regions than used in the model INTRES, the data has to be transformed. The mapping will be described subsequently. Furthermore, investment relevant parameters of renewable technologies, such as costs, renewable quotas, and realistic potential limits as well as dispatch relevant parameters, such as the availability of intermittent RES, will be described. The data regarding renewable technologies is largely imported, defined, and processed in the renewable module.

5.2.1 Mapping of Modelling Regions and Technologies

In the LORELEI model 57 wind onshore and 18 wind offshore regions are simulated. By contrast, the residual data of the INTRES model (e.g. conventional power plants, transmission capacities) is based on a by country resolution. Increasing the regional resolution of the INTRES model would mean challenging the computing complexity at the expense of other modelling aspects. Hence, it is decided to retain the by-country resolution. However, simulating only one site quality per country for each renewable technology would be too rough as especially wind speeds sometimes differ significantly between different sites within a country. As average annual wind speeds or the resulting full load hours are the most important investment criteria for investors, they need to be represented in the model with a sufficient differentiation. In order to still being able to represent diverse wind site qualities within a country, a trick is applied. Instead of simulating all wind site qualities within a country by a higher regional resolution, regions are classified according to their “technology (performance)”, namely good, medium, and bad.[34] For instance, the LORELEI wind onshore region “Northern Germany” corresponds to a “good” wind technology in the model region “Germany” in the model INTRES. Therewith, it is possible to cover nearly all wind onshore site differentiations that are contained within the RES-E only model LORELEI.[35] However, this does not mean that a wind site in Italy, with a “good technological performance”, has high average wind speeds compared to other countries, such as e.g. Denmark. It only signifies that the respective wind site is relatively “good” in an intra-country comparison. If there are more than three wind onshore site differentiations per country in the LORELEI (e.g. in Spain), some wind sites have to be merged. Moreover, if the difference in wind speeds between sites within a country is small (e.g. in Austria), wind onshore sites are pooled as well. In addition, the INTRES wind technologies, standing among other things for a certain region within a country, are assigned to one wind supra region that has been identified in chapter 4. Since the typeday modelling for intermittent RES accounts for the spatial correlation of wind speeds between wind supra regions with their associated empirical frequencies of occurrence, endogenous balancing effects between wind outputs at different sites are incorporated in data input.

[34] The idea has been developed by Michaela Fürsch and Stephan Nagl.

[35] From the 57 wind onshore regions, only 54 are taken into consideration. Malta, Cyprus, Aragon and Galicia in Spain are neglected.

TABLE 5-1: WIND ONSHORE INPUT DATA IN THE MODELS LORELEI AND INTRES

Country	Wind Onshore Model Regions - LORELEI	Wind Onshore Model Technologies - DIMENSION	Wind Supra Region
Germany	CENTRAL	MEDIUM	SR 1
	NORTH	GOOD	SR 1
	SOUTH	BAD	SR 2
France	CENTRAL	BAD	SR 5
	NORTH	GOOD	SR 4
	SOUTH	BAD	SR 5
	WEST	MEDIUM	SR 4
Spain	CENTRAL	BAD	SR 5
	NORTH	GOOD	SR 4
	SOUTH	MEDIUM	SR 5
	SOUTH/EAST	BAD	SR 5
Belgium	EAST	MEDIUM	SR 1
	WEST	GOOD	SR 1
Netherlands	EAST	MEDIUM	SR 1
	WEST	GOOD	SR 1
Switzerland		MEDIUM	SR 2
Austria	EAST	MEDIUM	SR 2
	WEST	MEDIUM	SR 2
Italy	CENTRAL	GOOD	SR 5
	NORTH	MEDIUM	SR 5
	SOUTH	MEDIUM	SR 5
Czech Republic	NORTH	MEDIUM	SR 2
	SOUTH	MEDIUM	SR 2
Poland	NORTH	GOOD	SR 1
	SOUTH	MEDIUM	SR 2
Denmark	EAST	MEDIUM	SR 1
Great Britain	NORTH	GOOD	SR 1
	SOUTH	MEDIUM	SR 1
Portugal	NORTH	MEDIUM	SR 5
	SOUTH	GOOD	SR 5
Bulgaria		MEDIUM	SR 6
Greece	NORTH	MEDIUM	SR 6
	SOUTH	GOOD	SR 6
Hungary		MEDIUM	SR 5
Slovenia		MEDIUM	SR 5
Slovakia		MEDIUM	SR 2
Romania	EAST	MEDIUM	SR 6
	WEST	MEDIUM	SR 6
Denmark	WEST	MEDIUM	SR 1
Norwegen	NORTH	MEDIUM	SR 3
	SOUTH	GOOD	SR 1
Sweden	NORTH/EAST	MEDIUM	SR 3
	NORTH/WEST	MEDIUM	SR 3
	SOUTH	GOOD	SR 1
Finland	NORTH	MEDIUM	SR 3
	SOUTH	GOOD	SR 3
Latvia		MEDIUM	SR 3
Lithuania		MEDIUM	SR 3
Ireland	EAST	MEDIUM	SR 1
	WEST	GOOD	SR 1
	NORTH	GOOD	SR 1
Luxembourg		MEDIUM	SR 1
Estonia		MEDIUM	SR 3

Source: own presentation

Concerning wind offshore and solar power, the approach is similar. Diverse solar site qualities are incorporated in the model INTRES by inserting different solar power technologies. The original LORELEI modelling regions for solar power correspond to the modelling regions for wind onshore, as with them the North-South-divide can be captured well. To recapitulate, the synthetic solar power typedays are dependent on the specific wind state of the region they are situated in. The fact that solar and wind onshore regions correspond, facilitates the assignment of the wind supra regions to the INTRES solar technologies.

Since the LORELEI wind offshore regions are located quite near to each other (e.g. Southern German Bight and German Bight) and average offshore wind speeds in a height of around 100 meter above sea level do not differ a lot (Eurowind, 2011), many wind offshore sites can be merged without losing too much information. Wind offshore sites will be rather differentiated by their distance to the shore and/or water depth. Both factors are important cost factors for wind offshore installations (EEA, 2009). Remote wind offshore sites within the same country that do not resemble similar average wind speeds (e.g. “France Atlantic” and “Bay of Lion”) still need to be distinguished. Nevertheless, most wind offshore regions are located in the North and Baltic Sea, and at the Atlantic Ocean. Analogous to wind onshore and solar power, the different wind offshore technologies are assigned to a wind supra region.

Concerning biomass and geothermal power, the data of LORELEI is consistent with the requirements of INTRES.

TABLE 5-2: SOLAR POWER INPUT DATA IN THE MODELS LORELEI AND INTRES

Country	Solar Power Model Regions - LORELEI	Solar Power Model Technologies - DIMENSION	Wind Supra Region
Germany	CENTRAL	MEDIUM	SR 1
	NORTH	MEDIUM	SR 1
	SOUTH	GOOD	SR 2
France	CENTRAL	GOOD	SR 5
	NORTH	BAD	SR 4
	SOUTH	GOOD	SR 5
	WEST	MEDIUM	SR 4
Spain	CENTRAL	MEDIUM	SR 5
	NORTH	BAD	SR 4
	SOUTH	GOOD	SR 5
	SOUTH/EAST	MEDIUM	SR 5
Belgium	EAST	MEDIUM	SR 1
	WEST	MEDIUM	SR 1
Netherlands	EAST	MEDIUM	SR 1
	WEST	MEDIUM	SR 1
Switzerland		MEDIUM	SR 2
Austria	EAST	MEDIUM	SR 2
	WEST	MEDIUM	SR 2
Italy	CENTRAL	MEDIUM	SR 5
	NORTH	BAD	SR 5
	SOUTH	GOOD	SR 5
Czech Republic	NORTH	MEDIUM	SR 2
	SOUTH	MEDIUM	SR 2
Poland	NORTH	MEDIUM	SR 1
	SOUTH	MEDIUM	SR 2
Denmark	EAST	MEDIUM	SR 1
Great Britain	NORTH	MEDIUM	SR 1
	SOUTH	MEDIUM	SR 1
Portugal	NORTH	MEDIUM	SR 5
	SOUTH	GOOD	SR 5
Bulgaria		MEDIUM	SR 6
Greece	NORTH	MEDIUM	SR 6
	SOUTH	GOOD	SR 6
Hungary		MEDIUM	SR 5
Slovenia		MEDIUM	SR 5
Slovakia		MEDIUM	SR 2
Romania	EAST	MEDIUM	SR 6
	WEST	MEDIUM	SR 6
Denmark	WEST	MEDIUM	SR 1
Norwegen	NORTH	MEDIUM	SR 3
	SOUTH	MEDIUM	SR 1
Sweden	NORTH/EAST	MEDIUM	SR 3
	NORTH/WEST	MEDIUM	SR 3
	SOUTH	MEDIUM	SR 1
Finland	NORTH	MEDIUM	SR 3
	SOUTH	MEDIUM	SR 3
Latvia		MEDIUM	SR 3
Lithuania		MEDIUM	SR 3
Ireland	EAST	MEDIUM	SR 1
	WEST	MEDIUM	SR 1
	NORTH	MEDIUM	SR 1
Luxembourg		MEDIUM	SR 1
Estonia		MEDIUM	SR 3

Source: own presentation

TABLE 5-3: WIND OFFSHORE INPUT DATA IN THE MODELS LORELEI AND INTRES

Country	Wind Offshore Model Regions - LORELEI	Distance to the Coast	Wind Offshore Model Technologies - DIMENSION	Wind Supra Region
Germany	German Bight	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
	Southern German Bight	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
	Baltic Sea	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
France	Atlantic	Big	GOOD (A)	SR 4
		Small	BAD (A)	SR 4
	Bay of Lion	Big	GOOD (B)	SR 5
		Small	MEDIUM (B)	SR 5
Spain	Atlantic	Big	GOOD (A)	SR 4
		Small	BAD (A)	SR 4
	Bay of Valencia	Big	GOOD (B)	SR 5
		Small	MEDIUM (B)	SR 5
Belgium	North Sea	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
Netherlands	North Sea	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
Denmark	EAST	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
Great Britain	Eastern Coast	Small	MEDIUM	SR 1
		Big	GOOD	SR 1
	Western Coast	Small	MEDIUM	SR 1
		Big	GOOD	SR 1
	Irish Sea	Small	MEDIUM	SR 1
		Big	GOOD	SR 1
Portugal	Atlantic	Small	MEDIUM	SR 5
		Big	GOOD	SR 5
Denmark	WEST	Small	MEDIUM	SR 1
		Big		SR 1
Norwegen	North Sea	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
Sweden	Baltic Sea	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
Ireland	not defined	Big	GOOD	SR 1
		Small	MEDIUM	SR 1
Greece	Mediterranean Sea	Big	GOOD	SR 6
		Small	MEDIUM	SR 6

Source: own presentation

As indicated, wind onshore plants, wind offshore plants, photovoltaic devices, different biomass- and gas fired plants as well as geothermal power plants will be included into the model INTRES. Concerning wind onshore, two plants with different nominal capacities will be incorporated, whereby the one with the lower nominal capacity embodies existing wind power plants and the one with the higher nominal capacity rather new installations. Wind offshore power plants are represented by a plant size of 5 MW nominal capacity. Solar power will be converted to electricity by small photovoltaic devices only. Since the potential for solar and wind power will be restricted in terms of available land, the specific land requirements per technology have to be contained as well.

The two bio-solid technologies differ only with respect to fuel costs. While the first can fire cheaper solid biomass sorts, such as used wood and energy crops, the second utilizes more expensive bio-fuels, such as agricultural residues and forestry. Moreover, a biogas fired plant based on manure is included. Concerning geothermal power, two sorts, based on the type of reservoir, are considered.

TABLE 5-4: RENEWABLE TECHNOLOGIES CONSIDERED IN THE MODEL

Renewable Technology	Comment on Technology	Nominal Capacity [MW]	Land requirements [km²/MW]
Wind Onshore1	existing plant	3	0.0740
Wind Onshore2	new plant	5	0.0580
Wind Offshore1	small distance (0 - 30 km)	5	0.1318
Wind Offshore2	big distance(30 - 50 km)	5	0.1318
Photovoltaics	small roof top device	0.004	0.0075
Biosolid1	cheap biomass sorts	20	n.d.
Biosolid2	expensive biomass sorts	20	n.d.
Biogas	-	5	n.d.
Geothermal Power (high enthalpy)	in Italy only	10 to 50	n.d.
Geothermal Power (enhanced)	hydro- or petrothermal systems	10 to 50	n.d.

Source: own assumptions based on Wissen (2012)

5.2.2 Investment Relevant Parameters of Renewable Technologies

The investment relevant parameters of the renewable technologies consist of investment costs, the maximum annual full load hours, RES-E potential limits, a European quota for RES-E, and the additional controllable capacity that is required when integrating fluctuating RES-E.

Investment costs and fixed O&M costs

Data for investment and O&M costs of immature renewable technologies are partly subject to high fluctuations and wide cost estimates.[36] Different cost estimates have been retrieved from Wietschel et al. (2010), IEA (2009), IEA (2010), EWI et al. (2010), and Wissen (2012). Based on conversations with industry spokespersons and expert knowledge, a combination of sources is opted for. Data for biomass, biogas, and geothermal power plants has been retrieved from Wissen (2012). However, future costs developments are available in Wissen (2012) only until 2030. Since especially the future cost developments of immature technologies are important for modelling results, costs of wind and photovoltaic plants are taken from IEA (2010, p. 134). The IEA values for 2010 are in a similar cost range as values in Wissen (2012). IEA (2010), however, lacks detailed data on biomass and biogas plants, and only contains information on high-enthalpy geothermal power plants.

Cost estimates in IEA (2010) are given for the years 2010 and 2050. In between, the cost development is not indicated. In this work, the cost degression rate between 2010 and 2050 is assumed to halve every decade. In this line of reasoning, the cost development is extrapolated for biomass, biogas, and geothermal plants. Although O&M costs are also expected to decrease in the future, the model INTRES does not allow for

[36] Although in principle cost assumptions are scenario dependent they are listed in this chapter as they belong to the data input incorporated in the developed renewable module.

annually dependent O&M costs. Since, due to a higher cost degression in the beginning, the O&M costs in 2020 amount to approximately the average throughout the period, these are selected. With respect to the present wind offshore costs, another source is chosen. Due to upward cost revisions that recently emerged for wind offshore installations (EWI, Prognos, GWS, 2010) the costs given in Wissen (2012) and IEA (2010) are considered too low. In 2010, wind offshore investment costs, as indicated in Schlesinger et al. (2010), are considered more realistic, at least for wind power plants that are installed in a high water depth or respectively at a big distance to the coast. In order to have cost estimates for plants installed in shallow water depth or respectively at a small distance to the coast, a scale factor (1.32) is applied. The scale factor is a function of both, the distance to the coast and the water depth (EEA, 2009, p. 39). O&M costs are adapted accordingly.

Concerning the future cost development, in this work, it is deliberately refrained from applying a learning curve approach, which in its simplest definition describes the relationship between cost decreases over time with every doubling of output. Adler and Clark (1991) find a wide range of learning rates across plants, even where products and scale are similar. Kahouli-Brahmi (2008) also detects a high variability of learning rates in the literature between and among energy technologies. He identifies several issues that are responsible for learning curve variations, which are e.g. the additional consideration of research and development (R&D) expenditures, omitted variables, and spillover effects from other technologies. Due to the high variability in estimated learning rates for renewable technologies, this concept is not considered as being useful for supporting estimates of future cost developments, particularly as these depend additionally on future projections of world output growth.[37]

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[37] Since learning-by-doing in the case of renewable technologies does not take place only European wide but worldwide (Wene, 2000), the inclusion of learning curves in a European-

TABLE 5-5: INVESTMENT COST DEVELOPMENT AND O&M COSTS

Renewable Technology	Investment costs [$€_{2010}$/KW]					O&M costs
	2010	2020	2030	2040	2050	[$€_{2010}$/KW]
Wind Onshore1	1230	1070	1000	960	950	31
Wind Onshore2	1240	1070	1000	960	950	31
Wind Offshore1	2660	1840	1530	1400	1340	55
Wind Offshore2	3500	2420	2020	1840	1760	73
Photovoltaics	3080	1570	1130	950	880	19
Biosolid1	2310	2210	2100	2050	2030	137
Biosolid2	2310	2210	2100	2050	2030	137
Biogas	2840	2670	2510	2440	2400	250
Geothermal (high enthalpy)	2290	2240	2200	2170	2160	192
Geothermal (enhanced)	13900	10790	8380	7440	7030	308

Source: own assumptions based on IEA (2010),[38] Wissen (2012), and Schlesinger et al. (2010)

Annual full load hours of RES

For every renewable technology that is dependent on weather conditions, a maximum annual amount of full load hours is implied by the typeday modelling. As described, they are specified by the respective combination of the synthetic typeday structures, or, respectively, the intra-annual availability of RES (see chapter 5.2.3), times the corresponding frequencies of occurrence (compare chapter 4). Overall annual full load hours correspond to the empirical average of the four year horizon, high resolution data by Eurowind (2011). The annual yields of the different RES are in line with the resource qualities of wind and solar power in Europe. This means that generally annual full load hours of photovoltaic devices are relatively higher in the South than in the North and that annual full load

---

wide model would not be entirely endogenous as not the whole learning system could be represented.

[38] For the conversion of United States dollar (USD) amounts to € amounts a 1.4786 USD/€ exchange rate is used, as retrieved from finanzen.net (2011).

hours of wind power plants are relatively higher at sites near the North Sea, Baltic Sea, or the Atlantic Ocean.

RES-E potentials

In the renewable module, investments in renewable technologies will be limited by potential restrictions. In general, different definitions of renewable potential exist. For instance, Lako and Kets (2005) distinguish several potential definitions for RES (see Figure 5-2). Whereas the theoretical potential of a RES is defined as the total physical energy flow from that energy source, the technical potential additionally accounts for conversion efficiencies of the state-of-the art technologies and evident conflicts in land availability. The realistic potential further considers spatial planning, environmental impacts, and public acceptance. Costs are not taken into account. In this work, the notion of the realistic potential is used.

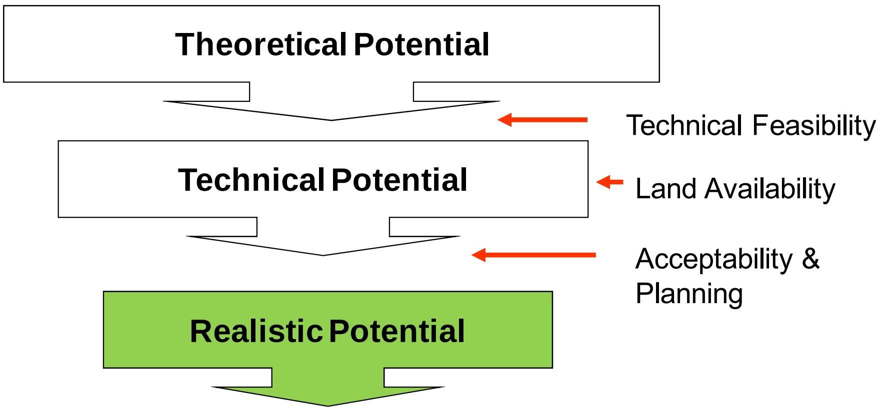

FIGURE 5-2: DEFINITION OF POTENTIAL
Source: own presentation based on Lako and Kets (2005)

Realistic potentials for different RES have been developed in Wissen (2012). For instance, the realistic wind onshore potential is determined by deducting forest areas, rivers, and conservation areas from the available area. Moreover, competitive usages, such as landscape protection and agriculture, have been accounted for. Alternatively, the calculation for the area potential of photovoltaic devices roof top considers architectural suitability (including construction, historical and shading elements) and solar suitability, defined as surfaces with relatively good solar yields. Since, in comparison to other sources, Wissen (2012) specifies very low potential values for offshore wind, EEA (2009) values are used instead. EEA (2009) gives offshore areas for different offshore categories, depending on the distance to the coast. Here, also potential limiting factors, such as shipping routes, military use of offshore areas, oil and gas exploration, tourist zones, and spatial planning considerations are accounted for. Concerning geothermal energy, only high enthalpy resources in Italy have been limited, as determined by Wissen (2012). The determination of the petrothermal potential is a lot more difficult (Wissen, 2012). Thus, within this work the petrothermal potential will not be restricted and will serve in the optimization as expensive renewable technology of last resort. Again, the biomass potential has been determined by Wissen (2012). In figure 5-3, the realistic renewable generation potential in EU-27-plus can be seen. Potential values, which are expressed in the model in terms of different units, are converted into generation values, with respect to the latest technologies. As the biomass potential is expected to increase until 2030, the potential values of 2030 have been taken.

The allocation of the different RES potentials is unevenly distributed across the countries. It can be seen that countries, such as Germany, Great Britain, France, Poland, and Spain, possess a relatively high area potential for the use of onshore wind. On the one hand, this is due to their relatively flat terrain with relatively good wind conditions and on the other hand to their relatively big shares of agriculturally used or idle lied areas. By contrast, countries such as Romania, Bulgaria, Norway, Austria, Slovenia, Greece, Sweden, and Finland can use only a fraction of their land area, due to their relatively high shares of mountainous, forest, or water areas. Since the methodology of the photovoltaic roof top area potential rests on the amount of inhabitant per region, countries with a high number of inhabitants (e.g. Germany, France, and Spain) exhibit the highest photovoltaic area potential. The bulk of the biomass potential is situated in France, Spain and Germany, due to their high area release potential. Other countries, such as Great Britain, Italy, and Portugal, have hardly any biomass potential, due to the low availability of idle land and their deficit self-sufficiency (Wissen, 2012).

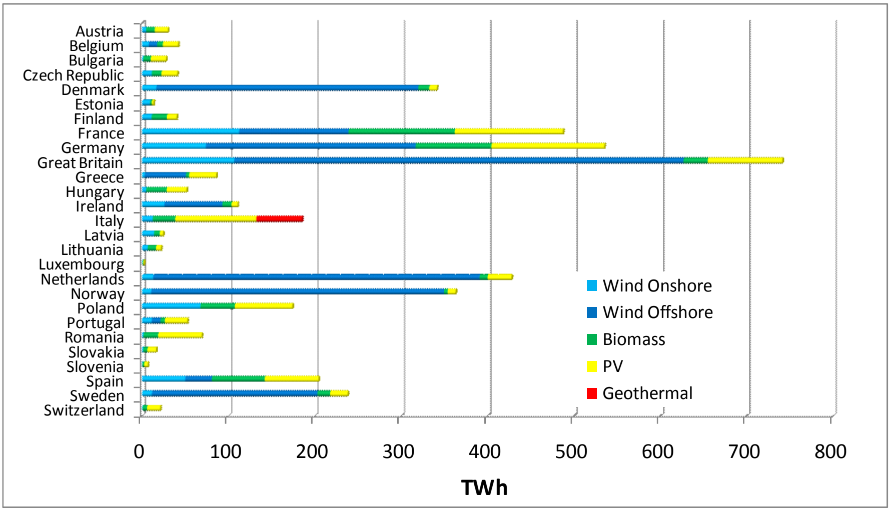

FIGURE 5-3: REALISTIC RENEWABLE POTENTIAL IN EU-27-PLUS

Source: own calculations based on Wissen (2012), EEA (2009)

RES-E quota

As indicated before, most renewable technologies are not competitive, compared to conventional electricity generating technologies. Therefore, in order to initiate a certain renewable power generation or, alternatively, investments in renewable technologies, a renewable quota has to be fixed in the renewable module. Here, the res_quota in a certain year is specified as being the sum of the electricity supply of all eligible renewable technologies, res_quota_tech, over all typedays, hours, and modelling regions. Eligible renewable technologies are all renewable technologies included in the model, except large hydro power. The scale factor scales hourly typeday values to annual values. Hence, the renewable quota equation demands that a certain amount of electricity generation is supplied by RES-E, irrespective of which renewable technology provides the electricity. Due to cost minimization of the power generation system costs (compare chapter 5.1), however, RES-E will be provided by renewable technologies that are most economical for the power system as a whole.

$$res\_quota_y = \sum_d \sum_h \sum_{quota\_tech} \sum_r \left(SUPPLY_{y,d,h,tech,r} * scale\_factor\right), \qquad (5\text{-}1)$$

whereby $quota\_tech \subset technology$. Furthermore d denotes the typeday, h the hour, r is the region, y stands for the year or investment period, and $tech$ is the technology.

Additional capacity requirement due to fluctuating RES-E

As already described in chapter 3.4.2, mostly the determination of additional capacity requirements, arising from the inclusion of intermittent generation into the power system, is based on a separate ex-ante stochastic calculation of the capacity credit of the respective RES. Inputs to the calculation are the distribution and the penetration of the respective RES, the configuration of the residual power system[39], the selected peak demand hours, and the selected year. This signifies that the capacity credit is rather a static concept, which is suitable to determine the capacity reliability requirements to a certain point in time for given scenario settings. Moreover, as mentioned before, the capacity credit does not account for transmission possibilities or restrictions between regions. Although Swider and Weber (2007) accomplish to calculate an endogenous capacity credit for wind, the analysis is limited to Germany and to wind power. Furthermore, investments in renewable technologies and thus the RES-E distribution are exogenous to the model.

By contrast, some studies with endogenous investments in renewable technologies and a sufficient high intra-annual resolution, or, respectively, sufficient RES-E availability cases, model the additional capacity requirement indirectly (e.g. Neuhoff et al., 2008; DeCarolis and Keith, 2006). This means that the additional capacity required to retain system adequacy is not calculated stochastically ex-ante, but endogenously. This is done by equalizing the deterministic hourly load with the deterministic available capacity of the included power generating technologies in the respective hour. Although the downside of this methodology is that it cannot deliver robust estimates for the actual additional capacity that is required by system adequacy, the advantage of its simplicity is that it is dynamic with respect to the distribution of RES-E, the total amount of RES-E, the quality of RES-E, and the sort of RES-E. Moreover, transmission possibilities and restrictions can be accounted for. Thus, for models that aim at demonstrating the effects of a certain RES-E allocation and its

[39] This also implies that other fluctuating RES are subsumed in the conventional power plant fleet.

reallocation possibilities on the power system, an endogenous approach dependent on the availability of the different RES is more appropriate. An endogenous determination of the additional capacity requirement, however, can only be facilitated with an appropriate representation of the availability of RES. This has been made possible by the RES typeday modelling developed in chapter 4.

Specifically, a peak capacity requirement is specified in the model, which demands that the sum of the installed capacity in each region, at each typeday, in each hour and year exceeds the seasonal peak demand of electricity, given the availability of the various technologies (see chapter 5.2.3). In general, the inclusion of a peak capacity requirement in dual competitive models with inelastic electricity demand is necessary. These mimic scarcity rents when capacity is extremely short (Stoft, 2002). In addition, a system margin on the expected peak demand is included for reasons described earlier.

$$
\begin{aligned}
peak\_demand_{y,d,h,r} &< \sum_{tech} availability_{y,d,h,tech,r} * INSTCAP_{y,tech,r} \\
&+ IMPORTS_{y,d,h,r,r2} - EXPORTS_{y,d,h,r2,r}
\end{aligned} \tag{5-2}
$$

Here, r stands for the considered model region and $r2$ for another region.

$$
peak\_demand_{y,d,h,r} = Maximum_s \left(demand_{y,d,h,r}\right) * 1.1 \tag{5-3}
$$

whereby s denotes the season.[40]

Thus, the equation explicitly considers the low availability of certain RES in certain hours. The equation is defined for every single hour and not only for hours when peak demand is actually occurring. For instance, normally peak demand in Germany occurs in the evening hours in the winter (Eurelectric, 2009). The synthetic wind typeday structures, established in chapter 4, account for different wind speed levels with corresponding frequencies of occurrence, variances and variances of the first differences. Moreover, they ensure that, on average, synthetic wind speeds equal actual wind speeds in peak and off-peak periods. However, they are not robust in terms of wind availability in a specific hour. Thus, because a low availability of wind may occur in every hour of a typeday with about the same probability, the peak capacity requirement has to be defined for every single hour.

Concerning wind power, the equation accounts for balancing effects between regions of different wind supra regions and the quality of the resource. This is, when a country is subject to two different wind supra regions (e.g. Germany, Spain, France), a more dispersed distribution of wind power plants (e.g. wind plants distributed in Northern and Southern Germany instead of all wind plants concentrated in one region) can reduce the requirement for additional controllable capacity. In general, the higher the quality of the resource, meaning a higher average output and a low average fluctuation of the output, the lower is the necessity to hold additional capacity available.

Although the implemented additional specific capacity requirement (as a percentage of additional wind capacity installed) also decreases with higher

[40] Before electricity market liberalisation, UK pratice was to ensure that installed capacity should be approximately 20 per cent larger than expected annual peak demand (Gross et al., 2007). Since the plant margin is most probably smaller with liberalised markets, a 10 per cent margin is assumed.

wind penetrations, the reasons differ from stochastic approaches. In stochastic approaches, increasing the wind capacity in the power system amplifies the variability of the system, as a consequence of the higher share of typically positively correlated variability of wind output. Here, the additional specific capacity requirement decreases with higher wind penetrations, due to the decreased capability of electricity imports to cover wind slacks. However, the values indicated by scenario analysis, though not exactly representing the capacity credit, roughly correspond to values found in the literature. In equation 5-2, power generating capacities in other countries or, respectively, electricity imports from other countries, are allowed to contribute to the system adequacy of one specific country.

With respect to the capacity credit of solar power, the assumption made might be quite rough for some countries, as in effect the equation specifies a zero capacity credit for solar power. This is because solar power is not available during the night. Combined with a fixed seasonal peak demand value, being effective for all hours, solar power has to be completely backed up by other capacities. It is not problematic for countries that experience their peak demand in evening hours in the winter, as most of the European countries do. Yet, in countries such as Greece, in which peak demand occurs at noon in the summer (ENTSO-E, 2007; Eurelectric, 2009), solar power may well have a positive contribution to system adequacy. However, the analysis to which extent solar power may contribute to system adequacy in countries with peak demand in the summer is beyond the scope of this work.

5.2.3 Dispatch Relevant Parameters of Renewable Technologies

In the following, parameters of renewable technologies that are important for dispatch decisions will be discussed. To them belong the availability of RES, required ramp-up times and attrition costs with respect to warm starts.

Availability of RES

The availability of a renewable technology or more specifically of the renewable resource, which is defined for each typeday, hour, renewable technology, region, and year, in essence, limit the possible electricity generation, SUPPLY, by the respective technology. The availability for technologies based on fluctuating RES (*resf_tech*) is defined by the synthetic typeday structures of wind onshore and offshore, as well as of solar power, as established in chapter 4. The availability for fluctuating RES (*avail_res_fluc*) is specified in terms of the hourly capacity factor [MW/$MW_{installed}$] for every typeday, technology, and region. Similar to conventional electricity generating technologies, the availability of “dispatchable” renewable technologies (*resd_tech*) is defined only annually or respectively alike for every typeday and is assumed to be 85 per cent annually.

$$SUPPLY_{y,d,h,tech,r} = INSTCAP_{y,tech,r} * availabilty_{y,d,h,tech,r} \tag{5-4}$$

$$availability_{y,d,h,resf\_tech,r} = avail\_res\_fluc_{resf\_tech,r,d,h} \tag{5-5}$$

whereby $resf\_tech \subset tech$.

$$availability_{y,d,h,resd\_tech,r} = avail\_res\_dis_{resd\_tech,d} \tag{5-6}$$

whereby $resd\_tech \subset tech$.

Since the typeday modelling for intermittent RES accounts for the spatial correlation of wind speeds between wind supra regions and for a negative correlation of wind and solar power, endogenous balancing effects between wind output at different sites as well as between wind and solar power are incorporated. RES-E by intermittent RES can be further balanced by output from dispatchable renewable technologies, such as biomass and geothermal plants.

Ramp-up times and attrition costs

In contrast to renewable technologies based on fluctuating RES, generally the dispatch of biomass, biogas, and geothermal power plants can be controlled. Similar to conventional electricity generating technologies, load alternations of the power plants go along with additional attrition costs and often cannot be effectuated instantly. A power plant fired by solid biomass is technologically rather comparable with a power plant fired by coal than by gas. The ramping-up time depends on the combustion of the solid fuel and amounts to about seven to eight hours from cold start, depending on the boiler (Ortwein, 2011). Biogas power plants, by contrast, can be ramped-up from cold-start to nominal capacity within several minutes (Gerhardt, 2009, p. 9). Information concerning attrition costs has been hard to find. Therefore, attrition costs of conventional coal and gas power plants from the EWI database (EWI database, 2011) will be used. New coal and combined cycled gas power plants have attrition costs, due to ramp-up and -down processes of about 4.8 and 9 $€_{2010}$/MW respectively.

Although a geothermal power plant principally could be ramped-up within two hours, it is rather run in base-load. A deployment in peak-load operation would lead to massive attrition of the pump. In the extreme case, the pump would have to be exchanged every month (Ewald, 2010). In that case, attrition costs would exceed 20,000 $€_{2010}$/MW.

Fuel prices and costs of biomass

In addition to the mentioned costs components, also fuel prices have to be considered with regard to power plants fired by biomass or biogas. In general, fuel prices of the different biomass sorts are based on IE Leipzig (2006). Fuel prices are individually calculated for every biomass technology, whereby the specific fuel price is composed by the average of the two biomass sorts weighted by the respective potentials. Here, importance has been attached to the fact that the fuel prices of the biomass sorts are relatively similar. As mentioned before, one biomass technology deploys used wood and energy crops as fuel input, while the other fires agricultural residues and forestry. In figure 5-4, the bandwidth of fuel costs for different biomass potentials in Europe in the period 2010 to 2050 can be observed. The upper part of the bandwidth is made up of fuels such as agricultural residues and forestry. It is also striking that in all countries biomass potentials are available with a fuel price of zero. The biomass potentials free of charge basically consist of biogas made from excrement and litter. The future development of the biomass fuel prices is linked to a projected growth of the European economy and a related increase in purchasing power. Therefore, fuel prices are assumed to increase until 2030 (Wissen, 2012). Fuel prices after 2030 are assumed to be constant. Biomass fuel prices are converted into biomass fuel costs, by taking account of the efficiencies of the different power plants. Efficiencies are in line with Wissen (2012).

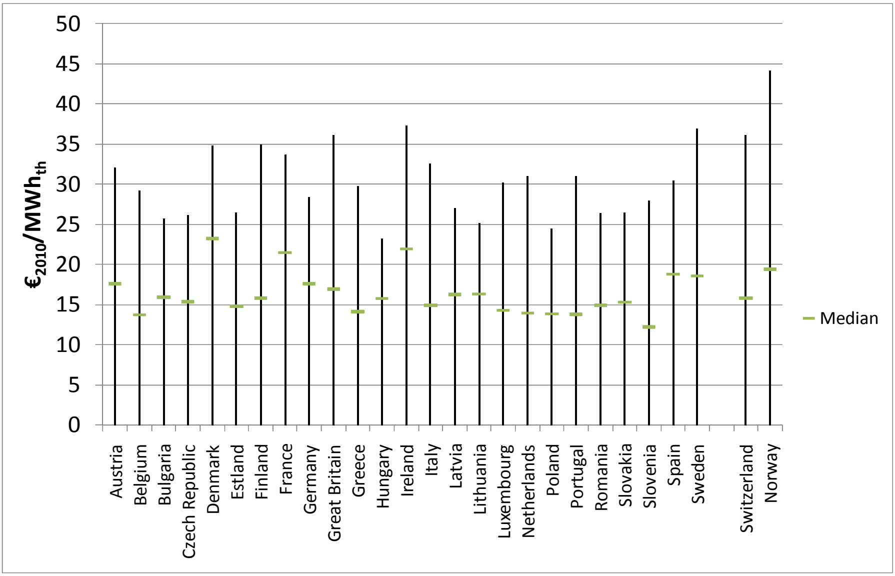

FIGURE 5-4: BIOMASS FUEL PRICES IN EUROPE IN THE PERIOD 2010 TO 2050

Source: own calculation based on IE Leipzig (2006)

5.2.4 Difference in Model Equations when RES-E is Exogenous to the Model

In order to comprehend the effects of an integrative optimization, compared to a situation in which RES-E has priority feed-in rights and does not receive any electricity price signals, in addition to an integrative model approach, a sequential model approach is needed. A sequential model approach refers to the separate optimization of renewable and conventional capacities in two separate models that are coupled in a row. Conceptually, the modelling approach is similar to Golling and Lindenberger (2009).[41]

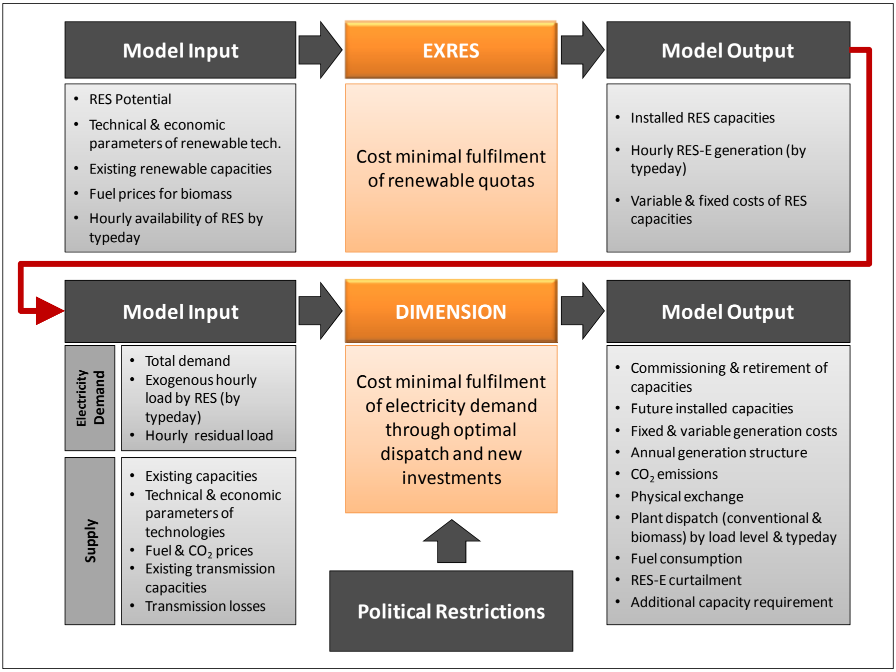

FIGURE 5-5: MODEL INPUTS AND OUTPUTS IN THE MODELS EXRES AND DIMENSION (SEQUENTIAL MODEL APPROACH)

Source: own presentation

First, the model EXRES, including only renewable technologies, simulates the development of RES-E. The resulting RES-E quantities are incorporated into the second model (DIMENSION) as must-run generation,

[41] However, in contrast to the modelling approach by Golling and Lindenberger (2009), in this sequential model approach, not an iteration loop is carried out, but the linkage between the models is restricted to the RES-E quantities.

by deducting the hourly RES-E from the hourly electricity demand. Afterwards, DIMENSION calculates the development of the residual electricity market, which adapts to the development of RES-E. The set-up of both models as well as the interface between them can be seen in the figure above.

The model EXRES is developed on the basis of the renewable module of the integrative model approach INTRES. The relevant model equations, the time resolution as well as the data input, e.g. the availability of the different RES in certain hours at different typedays, correspond to the ones used in the integrative model approach. This facilitates the comparability of the different model approaches. Moreover, instead of using an annual time resolution as in the model LORELEI, here, an hourly time resolution is opted for, taking advantage of the daily structure of the fluctuating RES-E at the different typedays. Although the daily structure does not influence results in the EXRES model, it is beneficial for determining the hourly specific electricity generation of different technologies over time.

EXRES optimizes the expansion of RES-E according to the discounted least cost criterion, subject to the achievement of renewable quotas and RES potential limits. However, by contrast to the model INTRES, RES-E is not optimized in a way that is optimal for the power system as a whole. RES-E is rather optimized solely according to least costs concerning the renewable submarket or according to the levelized costs of RES-E respectively. Electricity price signals do not affect investment and dispatch decisions of renewable technologies. Thus, the most economic RES are built first until its potential is exhausted, then the second and so forth. In contrast to Golling and Lindenberger (2009), in this work no additional constraints, such as medium term production capacity limitations, are implemented, avoiding distortive effects.

The resulting RES-E quantities are then incorporated into the model DIMENSION as must-run generation, by deducting the hourly RES-E from the hourly electricity demand, yielding the hourly residual load. Afterwards, the second model calculates the development of the residual electricity market, which has to adapt to the development of RES-E. In contrast to the integrative model, DIMENSION cannot build renewable technologies to satisfy the residual load, but only conventional electricity generating and storage technologies. Similar to the integrative model approach, DIMENSION determines the development of the conventional power plant fleet, by minimizing total discounted system costs, requiring satisfying the regional electricity demands anytime. The restrictions used in the model DIMENSION are largely analogue to the ones used in the integrative model INTRES. Although for the most part, the model EXRES is similar, it differs from the integrative approach especially in two model equations. The model DIMENSION has been extended in a way that it allows for RES-E curtailment and the endogenous determination of backup capacity, given the availability of RES calculated by the model EXRES.

First, in the model DIMENSION the electricity market equilibrium conditions demand to match the residual load, determined beforehand. As residual load can become negative in hours in which electricity demand is low and RES-E in-feed high, the equation, additionally, offers the opportunity to curtail some RES-E. Curtailment is capped by the exogenous hourly electricity quantities generated by the different RES. These have been determined ex-ante in the model EXRES based on the hourly availability of the respective renewable technologies. The capability to satisfy the residual load by national power generating technologies, $SUPPLY_{y,d,h,tech,r}$, is reduced by power exports and enhanced by imports.

$$\sum_{tech} SUPPLY_{y,d,h,tech,r} - \sum_{r2} EXPORTS_{y,d,h,r2,r} + \sum_{r2} IMPORTS_{y,d,h,r,r2} - \sum_{res\_tech} REDUC\_RES_{y,d,h,res\_tech,r} = residual\_load_{y,d,h,r} \tag{5-7}$$

$$REDUC\_RES_{y,d,h,res\_tech,r} \leq exo\_supply\_res_{y,d,h,res\_tech,r} \tag{5-8}$$

whereby this time $res\_tech \not\subset tech$.

Second, the peak capacity equation in the model DIMENSION has to be specified not only with respect to the endogenous installed capacity (i.e. conventional and storage technologies), $INSTCAP_{y,tech,r}$, but also with respect to the exogenous installed renewable capacity, $exo\_instcap\_res_{y,d,h,res\_tech,r}$.

The peak demand is specified analogue to equation 5-3 of the integrative model version.

$$peak\_demand_{y,d,h,r} < \sum_{tech} availability_{y,d,h,tech,r} * INSTCAP_{y,tech,r} + IMPORTS_{y,d,h,r,r2} - EXPORTS_{y,d,h,r2,r} + exo\_instcap\_res_{y,d,h,res\_tech,r} * availability_{y,d,h,res\_tech,r} \quad (5\text{-}9)$$

In the following chapter both model approaches are applied in the scenario analysis.

6 SCENARIO ANALYSIS OF AN OPTIMAL RES-E ALLOCATION IN EUROPE

In this chapter, the developed model approaches – the integrative model INTRES and the sequential models EXRES and DIMENSION – are applied to different scenarios.[42] First, the underlying assumptions that are valid for almost all scenarios are described. Second, different scenarios are calculated, and the results are discussed.

6.1 Data Assumptions

6.1.1 Development of Fossil Fuel and CO_2 Prices

The assumptions on the development of fuel and CO_2 prices are adopted from the Reference Scenario of the World Energy Outlook by the International Energy Agency (2009). The assumptions can be seen in table 6-1, in which fossil fuel und CO_2 prices are expressed in $€_{2010}$ per unit. The conversion from USD to € is based on an exchange rate of 1.48 USD/€ (finanzen.net, 2011). Average transport costs for the transport from harbour to the power plant of 3 $€_{2010}/MWh_{th}$ are added to the coal import prices. The growth rates of fuel prices, from 2030 onwards, are extrapolated from the previous decade. However, gas prices are supposed to increase only half as much, as the linkage between oil and gas is expected to cease. Nonetheless, it can be observed that the gas-coal spread is still high during the whole period, even including the CO_2 price. Thus, it is to be expected that scenario results will tend to benefit investments and generation by coal power plants.

[42] Scenarios are extrapolations under given sets of assumption. They do not represent most-likely developments.

TABLE 6-1: FOSSIL FUEL AND CO2 PRICE ASSUMPTIONS (EUROS PER UNIT)

	Unit	2010	2020	2030	2040	2050
Real terms (€$_{2010}$ prices)						
IEA crude oil imports	barrel	64.8	70.8	81.4	93.2	106.7
Natural gas imports Europe	Mbtu	7.4	8.6	9.9	10.3	10.7
OECD steam coal imports	tonne	74.9	73.7	77.2	82.7	88.6
CO_2 price under ETS*	tonne	16.4	29.0	37.0	47.2	60.2
Gas-Coal Spread	MWh_{th}	12.9	17.2	21.4	23.3	25.3
Gas-Coal Spread (incl. CO2)	MWh_{th}	10.9	11.8	14.0	13.3	11.9
*European Trading System						

Source: own calculations based on IEA (2009)

As the analysis of CO2 emission reduction within the power sector under the European Trading Scheme (ETS) is not part of the analysis, the CO_2 price will not be modelled endogenously, but fixed exogenously. The decision to fix CO_2 prices exogenously can be further justified by the facts that, first, CO_2 emission targets beyond 2020 have not yet been agreed on and, second, that the models do not incorporate all CO_2 emission abatement options, such as technologies with carbon capture.

Concerning the fossil fuel prices of lignite, it is assumed that until 2030, only one third are actually included in the model as dispatch relevant costs. For the maintenance of the mines a further third is incorporated in the annual fixed O&M costs, which are assumed to fall in the medium term. The costs of exploration are sunk costs (a further third). This is because it is assumed that no further mines have to be explored until 2030. Uranium prices are assumed to remain constant.

6.1.2 Parameter of New Conventional, CHP and Storage Power Plants

The assumptions on economic and technical properties of conventional, CHP and storage power plants are given intable 6-2. It is assumed that technological progress improves electrical efficiency, while real costs basically remain at the same level as in 2010. The assumptions on the economic properties of technologies are largely adopted from EWI et al. (2010). The economic properties of technologies have been retrieved from the EWI database (2011).

TABLE 6-2: ASSUMPTIONS CONCERNING NEW CONVENTIONAL, CHP, AND STORAGE POWER PLANTS

		Invest costs	Annual fixed O&M costs	Reference efficiencies (el)	Duration from cold start	Attrition costs	Technical Lifetime
	unit	€2010/KW	€2010/KW	%	h	€2010/MW	years
Power plant type	Nuclear	3,000	97	33	6	1.7	50
	Lignite	1,950	37	46.5	2.8	3	40
	Lignite (CHP)	4,100	37	37.5	2.8	3	30
	Coal	1,875	24	46 - 50	2.8	4.8	40
	Coal (CHP)	3,600	24	36	2.8	4.8	30
	CCGT	950	20	60	2	10	30
	Gas (CHP)	1,350	20	40	2	10	30
	OCGT	400	9	40	< 1	10	25
	AA-CAES	850	9.2	70	< 1	10	40

Source: own assumptions based on EWI et al. (2010); EWI database (2011)

CHP plants are also included in the modelling in a simplistic way. Instead of requiring a specific heat demand to be met by the plants, it is assumed that approximately the same amount of electricity (in a range of +5 and -5 per cent), which is generated by CHP plants today, is continued to be generated also in the future. This is fulfilled by flexible, bleeding-condensing CHP plants[43].

[43] Today a significant part of CHP-based power generation is contributed by CHP plants that are not primarily orientated at the hourly electricity price, but rather at the heat demand profile. However, in the future with an increasing share of RES-E, flexibility in the power system becomes a severe issue, thus requiring rather flexible CHP plants that are driven by the electricity price. Heat driven plants can be made more flexible by adding heat storage devices or by using heat demand side management (Gatzen, 2008).

Although, in Germany, nuclear power plants are predominantly run in continuous operation, nuclear power plants may be also run in load sequential operation, which is already done in France today (Hundt et al., 2009). Nevertheless, the start-up time is about twice as high as for power plants fired by lignite or coal.

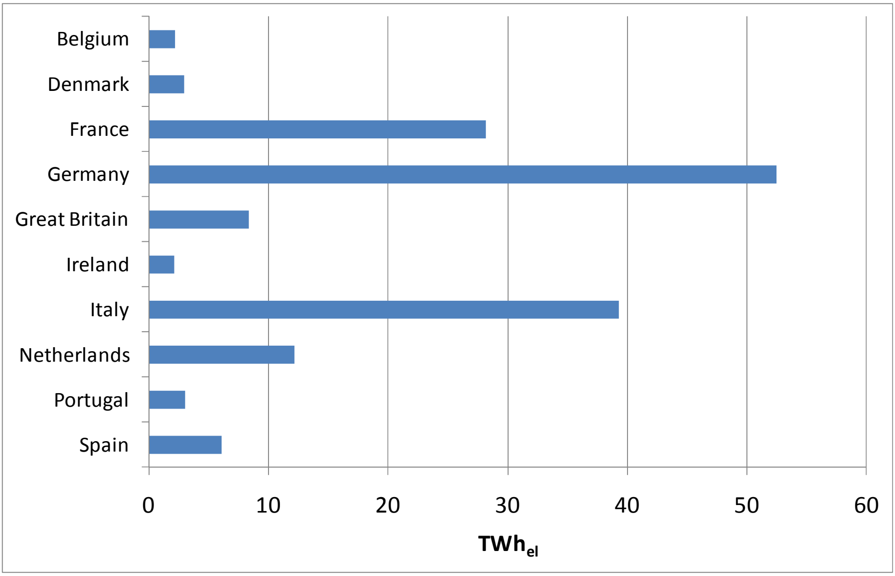

FIGURE 6-1: AA-CAES GENERATION POTENTIAL[44] IN SOME EUROPEAN COUNTRIES

Source: own calculations based on Gillhaus (2007); BP (2011); Dena II (2010)

Concerning installations in new storage capacities, AA-CAES plants are considered, since they have a higher efficiency as diabatic CAES plants. Although worldwide an AA-CAES plant is not yet installed, there exist concrete project development plans. The specific configuration of an AA-

[44] In the model, the countries' AA-CAES potential is restricted in terms of maximum installed capacity, whereby a utilization of AA-CAES plants of at most 2000 h/a is assumed.

CAES power plant, i.e. the relationship between the compressor and the turbine, is fixed at 1:0.8. In general, the specific configuration depends on economic conditions and the application area. However, an optimization of the configuration is beyond the scope of this work. AA-CAES can be installed only at sites with suitable geological conditions (DENA II, 2010). Here, the storage in salt caverns is considered. Salt caverns can be found in several countries in Europe. The specific storage capacity, i.e. the storage volume relative of annual natural gas consumption in cavern storages of European countries is estimated by Gillhaus (2007). Combined with the annual natural gas consumption of the respective countries and an AA-CAES energy density of 2.9 kWh/m³, AA-CAES generation potentials are calculated as depicted in Figure 6-1. Competing usages in terms of e.g. gas storage are not considered.

Future costs are discounted to the year 2010 with a discount rate of 10 per cent. The discount rate reflects the utilities' expected rate of return to cover average investment risks. A discount rate of 10 per cent is also used in DeCarolis and Keith (2006) and Bartels (2009).

6.1.3 Development of the European Gross Electricity Demand

As referred to by Eurelectric (2009), the growth of the European gross electricity demand proceeds approximately linear until 2030, with about 10 to 13 per cent growth per decade. After 2030, gross electricity demand is assumed to stay at the same level.

TABLE 6-3: DEVELOPMENT OF THE EUROPEAN GROSS ELECTRICITY DEMAND

TWh	2010	2020	2030	2040	2050
Austria	68	81	92	92	92
Belgium	97	109	109	109	109
Bulgaria	36	53	67	67	67
Czech Republic	68	78	83	83	83
Denmark	34	38	44	44	44
Estonia	8	12	12	12	12
Finland	86	101	109	109	109
France	494	533	533	533	533
Germany	567	562	553	553	553
Great Britain	366	390	422	422	422
Greece	64	78	78	78	78
Hungary	40	48	56	56	56
Ireland	32	40	49	49	49
Italy	360	450	550	550	550
Latvia	8	11	14	14	14
Lithuania	12	15	18	18	18
Luxembourg	7	8	9	9	9
Netherlands	113	138	168	168	168
Norway	130	143	153	153	153
Poland	146	173	206	206	206
Portugal	53	67	83	83	83
Romania	51	65	81	81	81
Slovakia	31	35	40	40	40
Slovenia	16	18	18	18	18
Spain	317	400	470	470	470
Sweden	138	144	148	148	148
Switzerland	63	67	72	72	72
Sum	**3405**	**3858**	**4236**	**4236**	**4236**

Source: own calculations based on Eurelectric (2009)

6.1.4 Development of Hydro Power Generation in Europe

According to Eurelectric (2009), the power generation by conventional hydro power, including run of river, is not anticipated to increase significantly until 2030. Analogue to the electricity demand, the values after 2030 are assumed to remain at the 2030 levels.

TABLE 6-4: DEVELOPMENT OF CONVENTIONAL HYDRO POWER GENERATION IN EUROPE

TWh	2010	2020	2030	2040	2050
Austria	25	29	31	31	31
Belgium	0	0	0	0	0
Bulgaria	0	0	0	0	0
Czech Republic	0	0	0	0	0
Denmark	0	0	0	0	0
Estonia	0	0	0	0	0
Finland	0	0	0	0	0
France	66	69	91	91	91
Germany	20	22	22	22	22
Great Britain	6	6	6	6	6
Greece	0	0	0	0	0
Hungary	0	0	0	0	0
Ireland	1	1	1	1	1
Italy	46	50	50	50	50
Latvia	0	0	0	0	0
Lithuania	0	0	0	0	0
Luxembourg	0	0	0	0	0
Netherlands	0	0	0	0	0
Norway	120	121	123	123	123
Poland	2	2	3	3	3
Portugal	10	11	12	12	12
Romania	0	0	0	0	0
Slovakia	0	0	0	0	0
Slovenia	0	0	0	0	0
Spain	35	37	39	39	39
Sweden	67	68	70	70	70
Switzerland	17	19	20	20	20
Sum	**414**	**435**	**466**	**466**	**466**

Source: own calculations based on Eurelectric (2009)

6.1.5 Net Transfer Capacities between Regions

Net Transfer Capacities are important indicators for market participants to anticipate and plan their cross-border transactions. "NTC is the maximum exchange program between two areas compatible with security standards applicable in both areas and taking into account the uncertainties on future network conditions" (ENTSO-E, 2001, p. 7).

Transmission capacities are one important way to provide flexibility to power systems. In the base scenarios, existing cross border transmission capacities will be taken into account, corresponding to the indicative values for NTCs of the summer 2010 in Europe, published by the ENTSO-E (2010). Table 6-5 provides an overview of the current cumulated net import and export capacities of European countries. It can be observed that there are countries that are relatively highly meshed with other countries (e.g. Germany, France, Switzerland, and Sweden) and others, which act nearly as island power systems (e.g. Ireland, Great Britain, Portugal, Spain, Denmark). Of cause the amount of NTCs available depends not least on the location of the country. Neither an expansion nor a removal of transmission lines is assumed.[45]

[45] Since later on a sensitivity scenario with high NTC values is calculated, the base scenarios are conservative concerning the electricity exchange possibilities between countries, in order to highlight the differences with respect to geographical flexibility.

TABLE 6-5: OVERVIEW OF COUNTRIES' IMPORT AND EXPORT NET TRANSFER CAPACITIES [MW]

MW	Import	Import
Austria	4670	3870
Belgium	5600	4100
Bulgaria	500	1000
Czech Republic	4300	5400
Denmark (East)	2450	2850
Denmark (West)	2840	3420
Estonia	850	850
Finland	2400	2000
France	8820	14100
Germany	17230	14680
Great Britain	2080	2410
Greece	1100	600
Hungary	1750	1400
Ireland	410	80
Italy	6890	3000
Latvia	1750	1600
Lithuania	1100	1250
Luxembourg	1480	1480
Netherlands	6850	5900
Norway	5350	5195
Poland	2700	3600
Portugal	1200	1200
Romania	1000	900
Slovakai	2800	2650
Slovenia	1020	1230
Spain	3000	2600
Sweden	7865	8590
Switzerland	6410	8760

Source: own calculations based on ENTSO-E (2010)

6.1.6 Nuclear Policies of European Member States

Since decisions concerning the power generation by nuclear is the responsibility of the individual European Member States, the nuclear policies differ between the countries, due to different risk perceptions and ethical considerations. In the scenario analysis, the nuclear policies most recently decided on in the different Member States will be included as additional constraints. Accordingly, a complete ban on the usage of nuclear is incorporated for some Member States (Austria, Denmark, Estonia, Greece, Ireland, Latvia, Luxembourg, and Portugal). Furthermore, there are Member States in which closures of existing plants take place according to agreed schedules (Belgium, Bulgaria, Germany, Lithuania, the Netherlands, and Slovakia). In Sweden, an extension of the lifetime of existing plants is allowed by the insertion of a nuclear retrofit technology, which requires investments of 500 $€_{2010}$/KW, in order to fulfil safety standards (EWI and Prognos, 2007). New nuclear investments are possible in Bulgaria, the Czech Republic, France, Finland, Hungary, Italy, Lithuania, Romania, Slovakia, Slovenia, Spain, and Switzerland (IEA, 2010; Capros et al., 2010).

6.1.7 Geographical Coverage, Time Resolution and Period of Scenario Calculations

Due to reasons of calculation time and the related cutbacks in the time resolution, the scenario analysis will focus on Western Europe. The choice has been made, first, because the green dyed area in figure 6-2 contains all five wind supra regions, so that the area is large enough to demonstrate effects of RES-E reallocations due to smoothening between regions. Moreover, because of renewable energy resource conditions in Europe, it is considered more important to include the whole South-North extension instead of a total West-East coverage of the EU-27-plus. Finally, the data for Eastern countries (e.g. Poland, Latvia, Lithuania, and Estonia) is incomplete (e.g. offshore wind speeds have not been available). With such a geographical coverage, a two-hourly time resolution for all wind typedays can be facilitated. Although the two hourly values correspond to the average of two subsequent single-hourly values, it has been ensured that the structure of the typeday is maintained and only little information is lost (i.e. ramp rates and fluctuations are sustained). Due to calculation time, within this work, a differentiation of the electricity demand typedays "weekday" and "weekend" could not be included in the modelling approaches. Therefore, the two electricity demand typedays have been averaged, weighted by their relative frequencies of occurrence. In total, simulations will be reported until the year 2050, with investment periods of 2020, 2030, 2040 and 2050. The data of the parameters in 2010 is included as status quo.

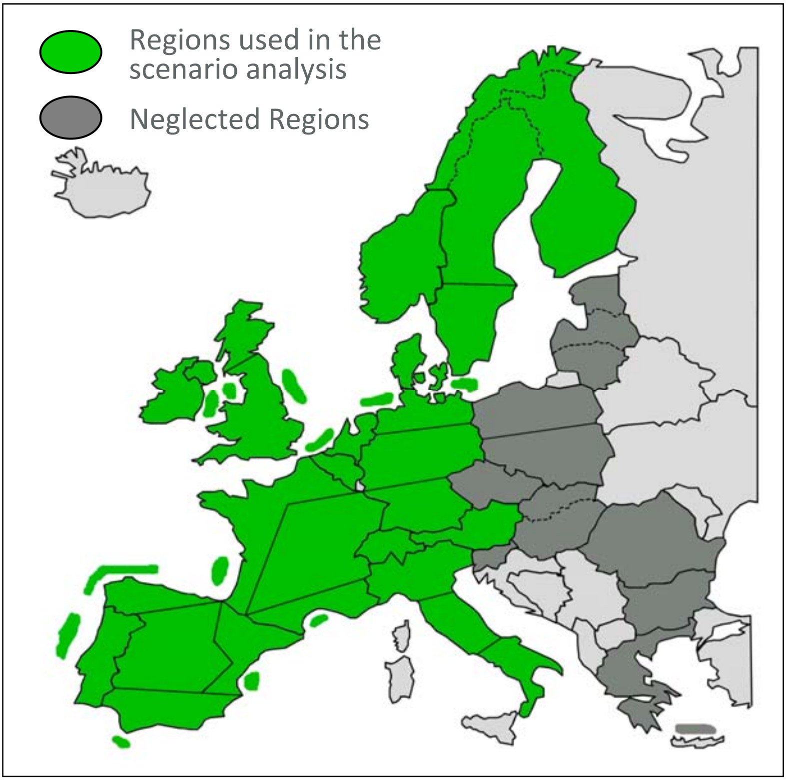

FIGURE 6-2: MODEL REGIONS INCLUDED IN SCENARIO ANALYSIS

Source: own calculations

6.2 Scenario Set-Up

In total, there will be two base scenarios with different renewable target requirements presuming optimal investment and dispatch for all technologies. Moreover, there will be two associated sensitivity scenarios (S1) having equivalent RES-E targets, assuming priority feed-in and a decoupling from electricity price signals for renewable technologies. In addition, two further sensitivity scenarios should reveal the role of temporal (S2) and regional flexibility (S3) in determining results. Here, temporal flexibility is varied by restrictions on storage capacity potentials, while regional flexibility is enhanced by expanding current power transportation capacities.

Whereas the integrative model approach is applied in scenarios that assume optimal dispatches and investments of renewable technologies, the sequential model approach is utilized in scenarios that presume that renewable technologies “must run” as they are prioritized in the electricity market. In both model set- ups an overall European RES-E quota is fixed, thus presuming a European cooperation concerning the achievement of RES-E targets.

Applying the integrative modelling approach means that **renewable energy technologies have to bid in the electricity market** as conventional technologies do and are not treated prior ranking. This implies that endogenous RES-E curtailment and dispatch of biomass plants is calculated, as well as that the model regions’ integration capability of large-scale RES-E feeds back to the RES allocation and expansion. Besides of flexibilities in the electricity market, such as existing interconnector capacities and the commissioning of more flexible electricity generating units (i.e. gas turbines and AA-CAES), the integrative capability of regions may be increased by diversifying renewable technologies and sites. Thus, balancing effects between different sites and technologies are considered in the data input, facilitated by the RES typeday modelling. Furthermore, the capacity that is necessary to back up fluctuating energy sources will be minimized.

In scenarios that assume priority feed-in for RES-E whenever the source is available, RES-E is fed in into the grid irrespectively of the state on the electricity markets. If RES-E curtailment becomes necessary due to grid stability reasons, then renewable generators are fully compensated for the foregone output. Moreover, investment and dispatch decisions for RES-E are completely decoupled from the electricity market. These scenarios require the deployment of the sequential model approach, which has been described in chapter 5.2.4, in which first RES-E is optimized only in terms of its levelized costs. Subsequently, the resulting RES-E quantities are taken as given within the optimization of the conventional power plant fleet. This scenario is similar to the “HQS-scenario” in Fürsch et al. (2010). In the PRIO RES scenarios, the most economic renewable technologies in terms of levelized costs are built first, until the potential limit is reached. Then the next more expensive technology is selected and so on, until the renewable quotas are reached. This means that in these scenarios the potential of the most economic RES will be exploited entirely if no other constraints are set. An interior solution does not exist. Additional constraints (e.g. annual expansion of production capacities) will not be considered, in order to ease the comprehension of the effects.

However, in contrast to Fürsch et al. (2010) annual average power system marginal costs are not included in an iterative process into the first model EXRES in order to account for a weak influence of the power system on RES investments. This is mainly due to two reasons. First, in reality under quota systems RES-E is subject to an annual quota price for RES-E and hourly power prices. Average annual power system marginal costs, which should approximate annual power prices, are not sufficiently accurate in their temporal resolution. Second, in the iteration process a sufficient convergence could not always ensured. Therefore, in this work power price signals are not considered at all in the first calculation step, or in the model EXRES respectively. Dispatch and investment decisions concerning renewable capacities take place completely isolated from conditions on the electricity markets. In the real world this comes close to a fixed price support for RES-E or a quota regulation for RES-E that is completely separated from the electricity market. However, in order to facilitate the comparability of scenarios they must be subject to the same RES-E quantities.

With the help of the developed integrative model INTRES and developed data input for representing intermittent RES in electricity market models, two different base scenarios will be calculated. As stated above, the base scenarios presume optimal investment and dispatch for all technologies. As effects are sensitive to the degree of the renewable resource exploitation, the two scenarios will differ in terms of the renewable quota fixed collectively for the model countries.[46] In the **"RES MOD" scenario**, relatively moderate shares of RES-E at the European gross electricity demand, corresponding to Eurelectric (2009) are included. Until **2050**, the share is assumed to increase to **40 per cent**. By contrast, in the **"RES HIGH" scenario**, the RES-E share at the European gross electricity demand is fixed at 34 per cent in 2020 (COM (2006) 848 final). Until **2050**, the RES-E share increases to **60 per cent**. This can already be considered as quite ambitious as not all available renewable technologies are included in the model. Moreover, in 2050 a significant share of RES-E may be provided by RES-E imports from Northern Africa. The total RES-E amount to be collectively provided by the model countries is reduced by conventional hydro power generation in the respective countries (see table 6-6).

[46] Since not all EU-27 Member Countries (plus Norway and Switzerland) are included in the model calculations, it is assumed implicitly that the included and the excluded part of Europe are subject to the same RES-E quota.

TABLE 6-6: RES-E SHARES IN THE BASE SCENARIOS

	2020	2030	2040	2050
RES MOD	24%	31%	36%	40%
RES HIGH	34%	40%	50%	60%

Source: own assumptions based on Eurelectric (2009); COM (2006) 848 final

In order to isolate effects, the technique of comparing two scenarios, which differ only with respect to one aspect, is deployed. The two base scenarios with different renewable targets will be compared to demonstrate the impact of different RES-E penetrations on modelling results, in specific in terms of the necessity to diversify RES-E regionally and technologically as well as in terms of the impacts of RES-E on the conventional supply side.

Moreover, each base scenario will be compared to the associated sensitivity scenario **"PRIO RES"** in which RES-E enjoys a priority feed-in guarantee and is decoupled from the electricity markets. Each sensitivity scenario is subject to equivalent European renewable quotas as in the base scenarios. This comparison is supposed to reveal the inefficiencies related to the use of a priority feed-in and a decoupling from the electricity markets for RES-E, in comparison to a setting, in which renewable technologies are dispatched optimally. As the respective inefficiencies with respect to different RES-E penetrations can be related to one another, one can further draw conclusions concerning the dependency of the inefficiencies on the RES-E penetrations.

Another sensitivity scenario examines the role of the temporal flexibility in terms of introducing limitations on the use of storage capacities. Thus, the sensitivity scenarios **"NO CAES"** analyse the differences in optimal expansion of RES-E when the **temporal flexibility is restricted**. In the models, temporal flexibility is included by pump storage and AA-CAES technologies, which can balance electricity over time, subject to their respective storage volume. However, the storage of electricity is associated with power losses corresponding to their respective overall efficiencies (see table 6-2). In principle, temporal flexibility might be provided also by other storage possibilities, such as electrical mobility. Since the estimation of the AA-CAES potential does not account for competing usages of salt caverns, such as gas storage, this sensitivity scenario should provide an evaluation of how optimal expansion of RES-E develops when AA-CAES capacities cannot be developed in that extent. The question to be answered is what the consequences on RES-E curtailment and the residual power plant fleet are. Moreover, it should give insights in the role temporal flexibility plays for an optimal RES-E expansion and what investments in AA-CAES capacities trigger. How much are the cost savings for the whole power system due to the availability of temporal flexibility? Since temporal flexibility is more relevant for a scenario with a high RES-E share, the analysis will be restricted to a comparison between the base scenario with high renewable targets, the associated sensitivity scenario with a priority feed-in for RES-E and equivalent renewable targets, and the corresponding sensitivity scenarios with limited temporal flexibility. Results in earlier investment periods give an indication how differences in scenarios with moderate renewable targets would be.

Finally, another sensitivity scenario concerns the assumptions made for all previous scenarios with respect to the transmission capacity between countries according to existing NTCs. These will be enlarged in this sensitivity scenario, in order to reveal the advantages of more integrated European electricity markets in terms of the utilization of renewable resources. In some instances the NTCs between countries put significant limitations on the cross border power flows and the possibility to balance out each other's RES-E. In order to estimate the effects of the NTC restrictions on the optimal RES-E allocation in a competitive market setting, a scenario "**UNLIM NTC**" will be included. In this scenario quasi unlimited NTCs between countries are available. Thus, the **geographical flexibility will be enlarged**, representing a development towards a vision of an integrated European electricity market. Across-the-board NTC values are assumed to increase to 10 GW between all neighbouring countries in 2020. Although, 10 GW might not be considered as "unlimited", it still signifies an increase of existing NTCs by a multiple. A uniform approach is certainly not optimal for the power system as a whole since the usefulness of NTC expansion depends on the respective RES-E allocation. However, here, the results concerning an optimal RES-E allocation should not be biased by allowing different NTC expansion between countries. Nonetheless, countries that possess more bordering regions still have a competitive advantage in terms of their transmission possibilities. For instance, the total transmission capacity available for electricity imports and exports in Germany amounts to 70 GW. By contrast, the total transmission capacity available for Ireland increases only to 10 GW. Still, this signifies a twentyfold increase in the total transmission capacity of Ireland compared to the status quo.

The UNLIM RES scenario aims at analyzing the question, in how far the optimal expansion and allocation of RES-E in a competitive market setting approaches a scenario in which renewable technologies are built solely according to their levelized costs (PRIO RES scenario). Or put differently, it should be examined, in how far the transmission capacities put limitations on the integration capability of countries and determine results in an integrative modelling approach. Thus, the advantages of more integrated electricity markets in Europe should be revealed in a comparison between the scenario UNLIM NTC and RES HIGH, both being characterised by competition among all technologies. Moreover, the scenario UNLIM NTC will be compared to the scenario PRIO RES with high renewable quotas. If the RES-E allocations in the different investment periods of the UNLIM NTC scenario approach the RES-E allocations implied by the PRIO RES scenario, then it could be concluded that it is only the transmission restrictions that limit the use of the most economic RES at the most economic sites. Again, since geographical flexibility is more relevant for high RES-E penetrations the comparison will be restricted to comparisons between scenarios being subject to high renewable quotas. An overview of the scenario setup and the associated assumption is presented in table 6-7.

TABLE 6-7: OVERVIEW OVER SCENARIO SETUP AND ASSUMPTIONS

		High RES-E share	Mod. RES-E share	Priority Access	High Temporal Flexibility	High Geographical Flexibility
Basis Scenarios	RES HIGH	√			√	
	RES MOD		√		√	
S1: Priority access	PRIO RES HIGH	√		√	√	
	PRIO RES MOD		√	√	√	
S2: Temporal flexibility	NO CAES (RES HIGH)	√				
	NO CAES (PRIO RES HIGH)	√		√		
S3: Geographical flexibility	UNLIMNTC (RES HIGH)	√			√	√

Source: own assumptions

6.3 Scenario Results

In the following the scenario results are discussed. Thereby, one scenario is compared with another scenario at a time. Sometimes scenario overlapping comparisons are drawn.

6.3.1 Base scenarios RES MOD[47] and RES HIGH: Moderate and High Renewable Power Generation

What are the consequences of including renewable technologies in competitive electricity markets, with respect to the RES-E allocation and a possible diversification, as well as to the effects on the conventional power plant fleet? How do model results in the base scenarios differ as a result of different renewable quotas?

[47] RES-E even has to be capped in the moderate RES-E penetration scenario. Given the assumptions on investment costs, fuel and CO_2 prices, a RES-E share of 42 per cent of the total electricity demand of the model regions is found to be competitive in 2050. However, in order to facilitate the comparison with the scenario PRIO RES, later on approximately the same amount of RES-E in both scenarios is required. Moreover, a clear distinction between the base scenarios is required.

One of the main results concerning the development of the renewable technologies in both base scenarios is that the expansion of renewable capacities across regions and time is very regular and even. In specific, this means that sudden large-scale expansions in renewable capacities in certain countries do not take place. Since the integrative model approach has an internal solution, the development of RES-E is not only determined by RES potential limits. Though site qualities insert a significant influence on the expansion of RES-E, other factors are also result-determining. These factors can be summarized under the notation of "integration capability" of the model regions. The integration capability of a model region is affected, among others, by the market size, the interconnectedness with other regions, and the possibility to provide flexibility by conventional power and storage plants.

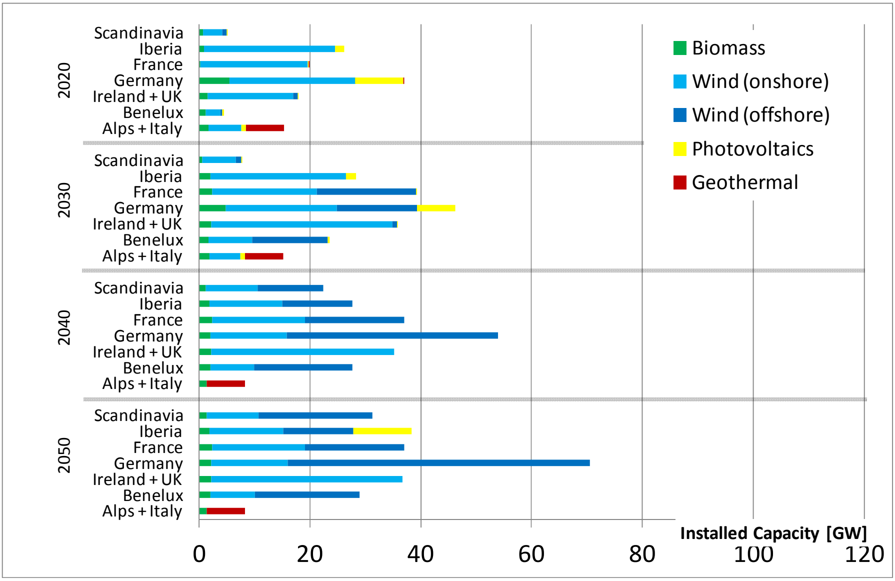

FIGURE 6-3: DEVELOPMENT OF RENEWABLE CAPACITIES IN THE SCENARIO RES MOD

Source: own calculations

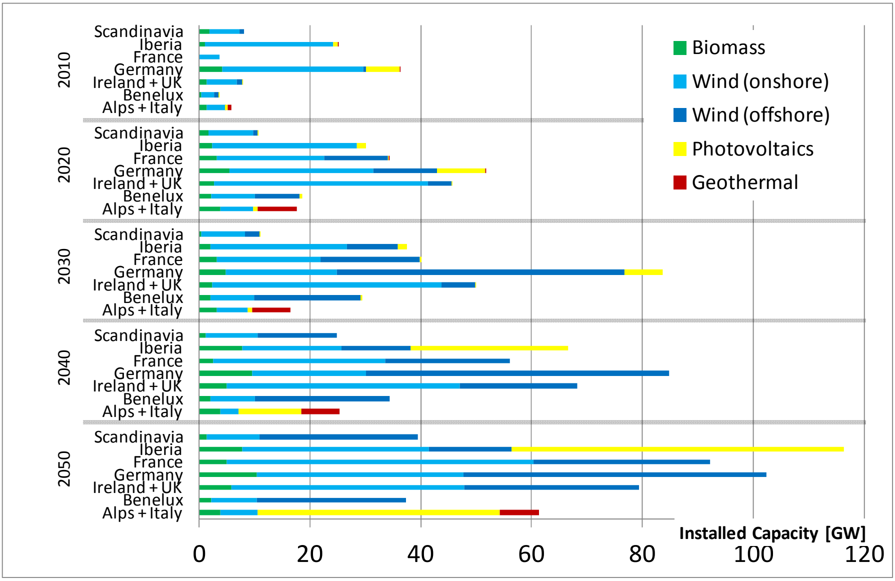

FIGURE 6-4: DEVELOPMENT OF RENEWABLE CAPACITIES IN THE SCENARIO RES HIGH

Source: own calculations

Figures 6-3 and 6-4 show the development of the renewable capacities for different country groups for the base scenarios. It is striking that countries such as Germany and France provide a big share of the RES-E to fulfil the respective quotas, though not possessing the most favourable RES conditions in the country comparison. For instance, rather wind offshore sites are used, which have lower average wind speeds and are located at a higher distance to the coast, in countries with a comparatively high integration capability (e.g. Germany, France, Netherlands, Spain) than wind offshore sites with higher average wind speeds in countries surrounding the North-Sea (e.g. Ireland, Scandinavia, Great Britain), which, however, are characterized by comparatively lower integration capabilities. Of course, the average wind speeds of wind sites still insert a notable influence. For instance, wind sites in countries with low average wind speeds (Italy, Switzerland, and Austria) are not deployed at all, at least in the scenario RES MOD. Moreover, in both scenarios, first favourable48 onshore wind sites are deployed, which are later supplemented with favourable offshore wind sites near the shore. Furthermore, cheap biogas power plants and geothermal energy from the mature high enthalpy geothermal power plant in Italy are built from 2020 on. In almost all scenarios, enhanced geothermal power plants are not competitive. Primarily, this is due to their high investment costs.

In the scenario RES HIGH, integration aspects become even more evident. For instance, in Nordic countries and Ireland, the wind capacity installed in 2050 is approximately at the same level as in the scenario RES MOD, albeit marginally higher (38 GW compared to 30 GW). Yet, this is not due to wind potential limits, but caused by wind integration reasons, i.e. the small market size of the respective countries and poor electricity transport possibilities. In these countries, even dispatchable biomass plants are augmented only marginally. In general, in countries with a limited RES-E integration capability and a high wind offshore potential (Nordic countries, Ireland, Great Britain, the Netherlands), the potential is not completely exploited in the base scenarios.

By contrast, in other countries, onshore and offshore wind capacities increase considerably in the RES HIGH, compared to the RES MOD scenario. As a proportion of total electricity demand, wind generation in the model regions increases from 23 per cent in the RES MOD scenario to 35 per cent in the RES HIGH scenario in 2050. More unfavourable onshore wind sites and progressively more wind offshore sites at higher distances from the shore are utilized in countries with comparatively high integration capabilities. Even relatively unfavourable wind onshore sites in Austria and Italy are utilized in the RES HIGH scenario in 2050. In some countries with reasonably good wind conditions and good integration capabilities and/or

[48] The notation “favourable” in these scenarios does not only mean favourable in the overall country comparison but especially with respect to other wind sites within the countries themselves.

limited wind potential, the total wind potential is completely exploited (Germany, France, Belgium, Spain, and Portugal).

In a competitive market setting for all technologies, regional diversification of renewable capacities, in specific of wind capacities, is not only caused by the exhaustion of the absorption capacity for the RES-E of countries. Another reason for diversifying wind power regionally is the smoothening of wind output[49]. A more stable wind output with fewer extreme high or low wind levels first reduces the need to curtail wind output and second reduces the need to backup wind slacks. In terms of total power system generation costs, it is sometimes more beneficial to diversify wind sites than to make use only of the most favourable wind sites concentrated at one location. This argument at least holds if quality differences between different wind sites are not too high.

In order to ascribe regional diversification of wind capacities solely to reasons of smoothening wind output and not to the exhaustion of absorption capacity of countries for wind power, the effect has to be isolated. This can be done only in an intra-country comparison. Since the countries are all modelled as being a copperplate without transmission bottlenecks, the same market size, the same level of interconnection, and the same transport distance to other nodes apply for all wind sites within a country. Thus, in countries that are subject to at least two wind supra regions regional diversification of wind sites due to reasons of wind output smoothening may be detected. Since in the RES MOD scenario, mostly the most economic wind sites within countries are deployed, the isolation of the effect by an intra-country comparison of wind sites is not possible. By contrast, in the scenario RES HIGH wind smoothening effects between

[49] However, the modelling of the balancing effects is quite rough and might be refined in future research by taking into account more wind supra regions and the time lags of wind speeds between neighbouring regions. Moreover, including more countries in central Europe might also have beneficial effects in terms of smoothening wind output.

wind supra regions can be isolated as in this scenario the development of wind capacities at different wind sites within a country take place.

In the Nordic countries, the wind sites in the North, having lower average wind speeds than sites in the South, are not used at all. In Norway, balancing wind power by diversifying wind sites within the country does not actually make sense, as the country is abundant of hydro power, which is able to balance wind power fluctuations within the country without greater problems.[50] Moreover, Norway and Sweden are characterized by rather small market sizes, which cannot absorb a high amount of RES-E, given the limited interconnector capacities to countries southwards. By contrast, wind smoothening effects in terms of a diversification of wind power plants in different wind supra-regions can be detected in Germany, Spain, and France. For instance, in Germany, wind power plants in the South, with lower average wind speeds, are developed earlier (in 2040) than wind power plants in central Germany (in 2050). In France a similar wind balancing effect can be observed as onshore wind sites within the Southern part of the country are deployed piecewise, dependent on the cumulative wind offshore power plant capacity at the Atlantic coast. The same applies to Spain.

The technological diversification is more pronounced in the scenario with high renewable quotas. In the RES MOD scenario, as a percentage of the total optimized renewable output in 2050, 83 per cent is provided by wind power, 10 per cent by biomass, 5 per cent by geothermal energy, and only 1 per cent by photovoltaics. Conversely, in the RES HIGH scenario, only 74 per cent of the total optimized renewable output in 2050 is provided by wind power, but 15 per cent by biomass, 8 per cent by photovoltaics, and 3 per cent by geothermal energy. One important reason for the higher technological diversification in the RES HIGH scenario is the increased

[50] In public discussion it is even talked about the possibility to balance European wind power by Norwegian hydropower, provided the interconnection capacity is available (Handelsblatt, 2010).

depletion of integration capability of countries with favourable wind resources.

If the power generation by biomass is dispatched dependent on the situation of the electricity market, it can bolster fluctuating renewable output. Successively and in line with higher renewable quotas, power generation by more expensive biofuels increases in all model regions (except the Nordic counties and Ireland). Instead of running in base-load operation, biomass plants are typically run in mid-load in countries with high wind power penetration. Nevertheless, they are not suited for peak-load operation due to their high fixed costs. If they do not obtain further subsidies, they need comparatively high annual full load hours to be profitable. Conversely, geothermal power plants are used rather in base-load operation, due to their high attrition costs, related with ramping-up and –down operations. Since in Italy, the RES-E penetration and thus the demand for flexibility are very low, the base-load operation of the geothermal plants is not constricted.

Concerning photovoltaics, in the RES MOD scenario the model finds it competitive to build 11 GW in the South of the Iberian Peninsula in 2050 given the steep decline in investment costs over time and the comparatively high irradiation values. Higher renewable quotas benefit the development of photovoltaic capacity in Southern European countries (i.e. Italy, Spain, and Portugal) and in countries with moderate solar irradiation, but low RES-E penetration by other renewable technologies (Switzerland) from 2040 on. However, direct balancing effects between solar and wind power, similar to the smoothening effects of wind output by diversifying sites, cannot be revealed. This is because photovoltaic plants in Southern countries are not developed until other RES potentials in the respective countries are already depleted.

The investments in photovoltaic capacity in Southern Europe may be induced only by the decreased availability of absorption capacity for RES-E in other countries. The possible lack of balancing effects of solar power and wind output can be due to several reasons. First and most importantly, balancing effects between solar power in Southern Europe and wind power in Northern Europe cannot materialize when electricity markets are not sufficiently integrated. Second, balancing effects between solar output and wind output in Southern countries may not be beneficial because the seasonality of wind speeds in countries in Southern Europe is not as distinctive as in countries surrounding the North-Sea (see chapter 4.1). Moreover, on the typeday level, only a small negative correlation between wind speeds and solar irradiation could be established. On the other hand, before 2040, the balancing of RES-E by solar output might not be beneficial due to the high investment cost of photovoltaic plants.

As described in chapter 3, the development of the residual power plant fleet is closely linked to and significantly influenced by the development of RES-E. In addition to a comparison of both base scenarios, a benchmark scenario **NO RES** is incorporated in figure 6-5. The scenario NO RES show the development of the conventional power plant fleet without any contribution by RES. Figure 6-5 shows the aggregated capacity development in the base scenarios and the benchmark case without RES-E. In figure 6-5 it can be seen that despite an increase in overall electricity demand, the total amount of capacity shrinks in a scenario without renewable technologies from 2010 to 2020. This is due to the reduction of excess capacity from times before the electricity market liberalization and due to the increasing efficiencies of newly installed capacities. Afterwards, the total amount of capacity rises modestly, as a response of the growing electricity demand. In the scenario NO RES, the development of the power plant mix over time favours nuclear, coal, and lignite power plants. Gas capacities decrease continuously, although a certain amount is retained to satisfy peak-load demand. Due to the relatively low fixed O&M costs and the long technical life time of pump storage plants, the capacity level existing today is approximately retained. Hydro power capacities are exogenously fixed.

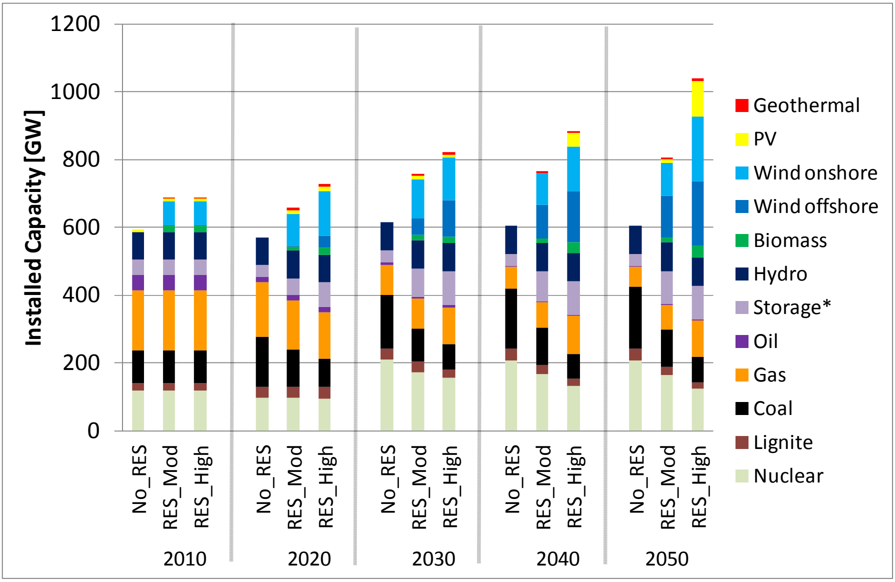

FIGURE 6-5: COMPARISON OF THE AGGREGATED CAPACITY DEVELOPMENT OF THE BASE SCENARIOS

Source: own calculations; 2010 values based on Eurelectric (2009)

When comparing the three scenarios, it is striking that the total amount of power generating capacity is higher, the higher the share of renewable technologies is, especially if based on fluctuating RES. On the one hand, this is due to the lower possible utilization of some renewable technologies, which is restricted by the availability of the RES. On the other hand, this is due to the smaller secured capacity of renewable technologies based on fluctuating RES. In the scenario RES MOD and RES HIGH, 197 GW and 422 GW respectively additional capacity is necessary to satisfy the aggregated electricity demand of the model regions.[51]

[51] Again, it has to be noted that the modelling of the required backup capacity in this work cannot claim to be robust with respect to the exact height but only gives tendencies.

Nevertheless, in both scenarios, conventional capacity can be cut down by the inclusion of renewable technologies based on fluctuating RES-E. As a percentage of total conventional power generating capacity, capacity based on fluctuating RES-E replaces between 9 and 13 per cent of conventional capacity. However, the values do not correspond to the capacity credit as here also other effects are included (Anderson, 2006). The capacity savings are fairly higher in the RES MOD scenario and decrease with higher RES-E penetration. In general, the savings of conventional capacity by renewable capacity depends on the quality of the RES, the integration capability, and the transport possibility.

Moreover, it is noticeable that the higher the RES-E penetration, the smaller is the share of base- and mid-load capacity (nuclear, lignite, and coal power plants) and, conversely, the higher the share of peak-load capacity (gas and storage capacities). A higher share of RES-E requires more flexible power plants, which have to respond to fluctuations of RES output.[52] Despite of ramping constraints, another trigger for more peak-load capacity are the low variable costs of many renewable technologies. As a result, these are situated at the beginning of the merit order, crowding out generation by technologies with higher variable costs. So, with increasing RES-E, the utilization and therewith the profitability of conventional plants with high investment costs is reduced.

This can be also observed in figure 6-6, in which the annual average utilization of conventional power plants of all model regions, in terms of full load hours, is depicted. For reasons of convenience, only the base scenarios are included. The increase in average full load hours from 2010 to 2020 for all technologies is due, amongst others, to the already mentioned diminution of excess capacity. In the scenario RES MOD, the

[52] Yet, the flexibility requirement is underestimated in the modelling as only a two hourly time resolution is implemented. Thus, ramping-up and -down constraints below two hours are not binding. Moreover, the model rests on the assumption of perfect foresight, thus uncertainty with respect to the RES output in terms of forecast errors is not accounted for.

average utilization of base-load capacities (nuclear and lignite power plants) remains relatively constant over time. The average utilization of plants fired by coal is reduced marginally, but stays at a higher level than in 2010. The reduction of the average utilization of gas power plants is more notable to just fewer than 1000 h/a in 2050. Partly, the reduction may be explained by the increasing gas and CO_2 prices. However, since the reduction is more intense than in the benchmark scenario (2600 h/a in 2050), another part of utilization decrease is due to a shift of the function of gas units from merely power generation towards a function of providing capacity. Increasing renewable generation, in specific fluctuating RES-E, requires an increasing amount of backup capacities to retain system stability. Due to their low fixed costs, gas fired power stations (OCGT) constitute one viable and cost-efficient backup solution.

In the RES HIGH scenario the reduction in average full load hours applies for all conventional generating technologies and is more pronounced than in the RES MOD scenario. This is because the higher RES-E penetration increasingly crowds out the conventional generation. Nonetheless, the level of average utilization is still relatively high for all technologies, except gas units. Yet, the presentation of the full load hour development averaged over all model regions conceals country specific developments. These will be presented below in several country case studies.

As mentioned earlier, one important advantage of the model approach is the endogenous calculation of wind and solar power curtailment, in addition to the endogenous determination of biomass plant dispatch, as well as the related feedback on the allocation of RES. Thus, a higher level of RES-E curtailment directly feeds back on the utilization and therewith profitability of all already installed renewable plants.

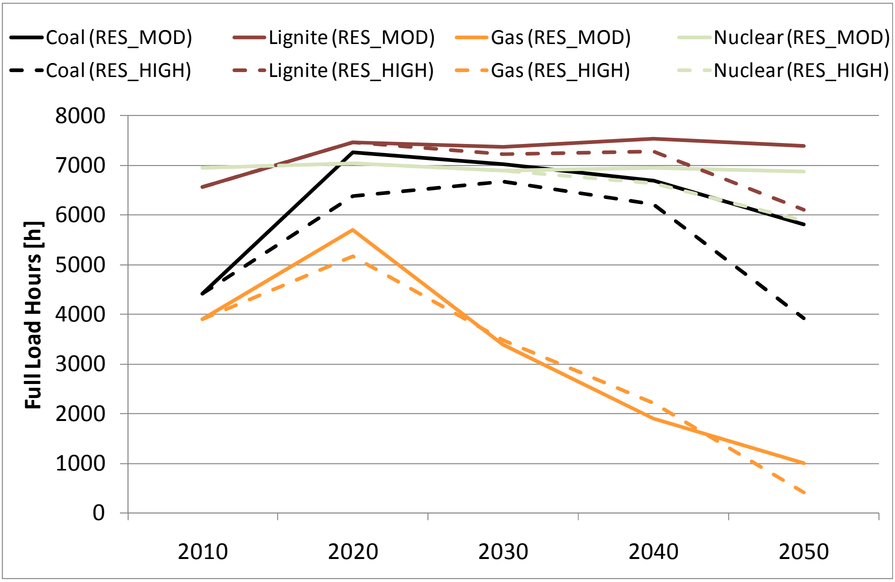

FIGURE 6-6: DEVELOPMENT OF AVERAGE FULL LOAD HOURS OF CONVENTIONAL TECHNOLOGIES IN THE SCENARIOS RES MOD AND RES HIGH

Source: own calculations; 2010 values based on Eurelectric (2009)

It has been anticipated that therefore, the absolute amount of wind power curtailed would be relatively low. However, the markedly low levels of RES-E curtailment have been still surprising. Overall, in the scenario RES MOD, only 1.9 TWh/a of RES-E are curtailed in 2050 and in the scenario RES HIGH, only 18.8 TWh/a in 2050.[53] While in the scenario RES MOD, the

[53] Concerning the determination of RES-E curtailment, it is absolutely essential how the RES-E feed-in structure of a country relates to the RES-E feed-in structure of other countries and to the respective demand structures. This has been established by the typeday modelling in chapter 4. The inclusion of a weighted averaged demand structure tends to underestimate the total amount of RES-E curtailment required, while the omission of balancing effects within wind supra region tends to overestimate RES-E curtailment. Moreover, a higher temporal

bulk of curtailment takes place in Ireland, in the scenario RES HIGH Ireland, Denmark, Great Britain, the Netherlands, Germany, and France are affected. In the RES HIGH scenario, also solar power has to be curtailed with about 0.5 TWh/a in Portugal in 2050. This is due to the low transmission capacity of Portugal to Spain and its relatively small market size. Nonetheless, the low curtailment values permit the conclusion, that generally in terms of total power system generation costs, it is beneficial to allow the installation of additional renewable capacity based on fluctuating RES at favourable sites only up to a certain threshold, until the absorption capacity of a region is reached. Of course, the acceptable level is further determined by the costs of alternatives and by the transmission possibilities of a country. Even so, curtailment of RES-E in single hours eases the integration into the power generation system.

To conclude, in scenarios in which renewable technologies have to bid in the electricity market as other technologies do, the expansion of RES-E across regions and time is regular and even. Despite of renewable technologies' levelized costs, the expansion is influenced by the integration capability of countries. Countries with a sizeable electricity market, good interconnectivity with other countries, and flexible options in the residual power plant fleet are characterized by a high integration capability (e.g. Germany) and vice versa. In addition, regional diversification of wind sites is caused by wind balancing considerations, which can reduce wind power curtailment and the need to backup wind slacks. Thus, contingent on the costs of alternative production sites, it is more beneficial to diversify wind capacities across wind sites than to deploy only the most favourable ones concentrated at one location. Also within countries that are subject to transmission constraints, in some cases regional diversification of wind sites proves beneficial in order to dampen wind output fluctuations. Similar

resolution might also imply different curtailment values .Thus, the total amounts of RES-E curtailment should not be interpreted as being completely robust, concerning the absolute values. Nevertheless, the bottom line remains valid, in the sense that a low amount of RES-E curtailment is beneficial for the power generation system as a whole.

to the regional diversification of RES-E, the technological diversification increases with higher renewable quotas. Besides higher wind power generation, the generation by biomass and photovoltaics increases over-proportionately over time. While wind and biomass capacities are installed in several countries, photovoltaic roof top devices are rather built in Southern Europe. Geothermal energy is only competitive in Italy. A higher amount of RES-E based on fluctuating RES causes an increase in total power generating capacity. The increase in total capacity goes along with an increase in the share of peak-load capacity and a reduction in the utilization in specific of peak-load capacity. In general, the level of wind power curtailment is exceptionally low in both scenarios.

6.3.2 Scenario “PRIO RES MOD”: Comparison of Scenario RES MOD and Associated Scenario PRIO RES

Given moderate renewable quotas, how does the expansion and allocation of RES differ in a scenario in which renewable technologies have to bid in the electricity market compared to a situation in which they enjoy a priority feed-in? What are the differences in the residual power plant mix?

In this paragraph, the differences of model results with and without priority feed-in for RES, given moderate renewable quotas, are analyzed.

Figure 6-7 shows the differences of renewable capacities between the two scenarios. It can be seen that, compared to the base scenario, in the PRIO RES scenario in all investment periods more wind capacities, predominantly wind offshore, are built in countries that have very favourable wind conditions in the country comparison (the Nordic countries, Ireland, and Great Britain). The additional wind capacities in countries surrounding the North-Sea substitute wind capacities in Germany, Benelux, and the Iberian Peninsula. In the PRIO RES scenario, biogas power plants are needed only in 2050. Photovoltaic capacity is not needed at all. The mature geothermal technology in Italy is also economical in the PRIO RES scenario, though the commissioning of the geothermal capacity occurs one decade later than in the base scenario. However, since wind power is also the dominating technology in the RES MOD scenario, the overall wind penetration, as a percentage of total electricity demand, remains approximately constant at about 22 to 23 per cent in 2050. Solely the locations of generation differ. Hence, in the PRIO RES scenario, the regional concentration increases. Conversely, with moderate renewable quotas, the technological concentration amplifies only marginally in some investment periods.

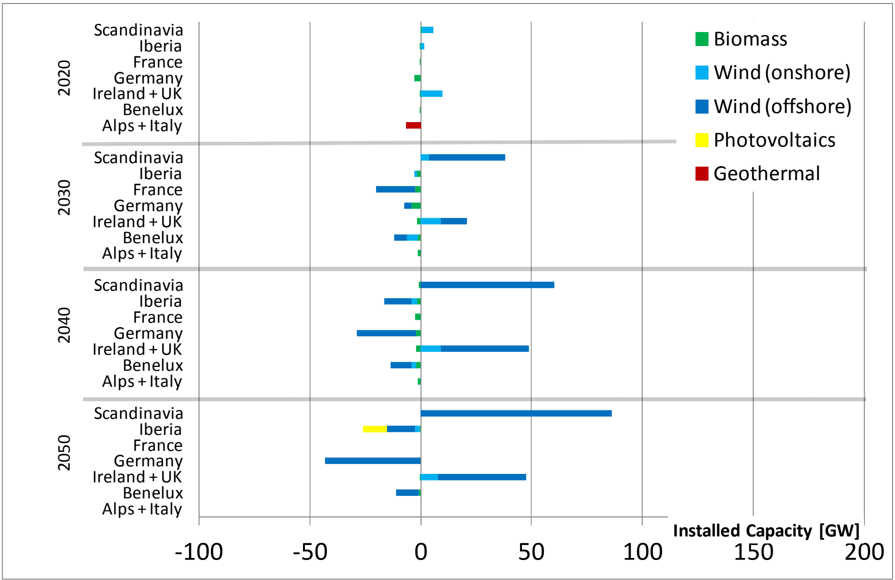

FIGURE 6-7: DIFFERENCE OF INSTALLED RENEWABLE CAPACITIES IN SCENARIO PRIO RES LESS THE CAPACITIES IN THE BASE SCENARIO RES MOD

Source: own calculations

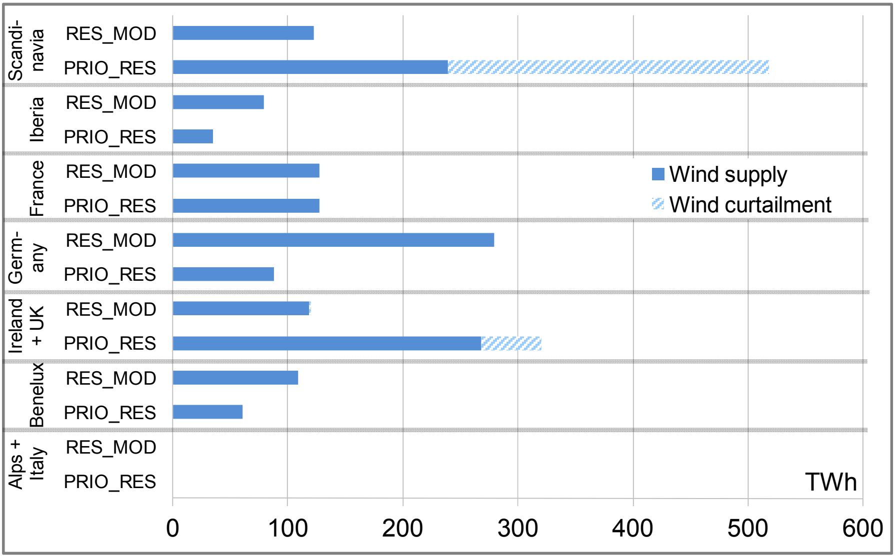

FIGURE6-8: ANNUAL WIND SUPPLY AND CURTAILMENT IN THE SCENARIOS RES MOD AND PRIO RES IN 2050

Source: own calculations

A high amount of wind capacity installed in Nordic countries, Ireland, and Great Britain brings along high amounts of wind curtailment. In the PRIO RES scenario in 2050, overall 28 per cent of the possible generated electricity by wind power plants or 331 TWh/a has to be curtailed.[54] In the Nordic countries and Ireland the proportions of curtailment are even higher

[54] Due to the high amount of curtailments, higher renewable quotas have had to be fixed in the iterative modelling approach. This has been done by trial and error, so that, in total, the original quota is approximately met with maximum 30 TWh degrees of deviation per investment period.

(up to 79 per cent in Norway).[55] The curtailment of RES-E by biomass remains negligible (see appendix).

The effects on the residual power plant mix can be observed in figure 6-9, which shows the development of the aggregated installed capacity in the scenario RES MOD and the associated scenario PRIO RES. Overall, the development of the aggregated power plant mix in the model regions proceeds relatively similar in both scenarios. Small differences between the results can be noticed with respect to the total amount of capacity and the power plant mix. The higher amount of power generating capacity necessary in the scenario PRIO RES, compared to the scenario RES MOD (plus 4 GW in 2050), is caused by two reasons. The first reason is the lower utilization of wind power plants in Nordic countries and Ireland, due to the high levels of curtailment. The second reason refers to increasingly diminished capacity savings in the conventional power plant fleet, due to the inclusion of more fluctuating RES-E.

Though in early investment periods (2020 and 2030), the capacity savings in conventional capacity by renewable capacity tend to be higher, due to the usage of higher quality sites, in later investment periods (2040 and 2050), the average capacity savings in the PRIO RES scenario fall short of the average savings in the RES MOD scenario (4 to 7 per cent compared to 10 to 13 per cent respectively). This is due to the following reasons: First, since all additional wind sites are built within the same wind supra

[55] Certainly, such high amounts of curtailment would not be tolerated by the respective governments or the public. Thus, under a European-wide harmonized quota system with a priority feed-in for RES-E, further legal restrictions might be enacted, which limit the extreme expansion of RES in certain countries. Though apparently not economical and not fully realistic, in this work it is attempted to demonstrate the theoretical difference between both scenarios.

region, they are not benefiting from balancing effects.[56] Second, electricity imports from other countries can dampen wind slacks only to a limited extent.[57] Especially, countries with limited interconnector capacities are affected. In that line of reasoning, Ireland has hardly any savings in the conventional capacity from including excessive wind capacity. Finally, the inclusion of a CHP quota requires that a certain amount of electricity is produced by power plants fired by fossil fuels.[58] Hence, beyond a certain point, a further reduction in conventional capacity is not possible. This, however, also makes sense as always a certain amount of power has to be provided by synchronous generators, in order to retain system frequency (Klessmann et al., 2008).

The aggregated power plant mix is largely the same in both scenarios, except that the aggregated capacity of nuclear is a little lower in the PRIO RES (145 GW in 2050) than in the base scenario RES MOD (164 GW in 2050). This, however, is due to country specific energy policies and the development of RES-E in the respective countries. Since only a limited number of countries in the model regions are assumed to invest in nuclear capacities in the future, one of them Great Britain, the higher amount of wind capacity there in the PRIO RES scenario, compared to the base scenario, crowds out national and thus overall nuclear capacities. The higher aggregate coal capacity in the PRIO RES (135 GW in 2050) compared to the RES MOD scenario (110 GW in 2050) is caused by the

[56] The assumption of perfect correlated wind speeds within a wind supra region underestimates the amount of secured capacity that can be provided by wind capacity within the same wind supra region.

[57] Nonetheless, it has to be examined in more detail in future research, in how far countries can share capacity reserves.

[58] Although in principle the heat could also be obtained from CHP plants fired by biomass, this possibility is not included in the modelling. Furthermore, it is questionable whether the CHP quota could be met by biomass alone.

lower RES-E penetration in countries in central and Southern Europe.[59] The countries, I am referring to, have adopted nuclear phase-out regulations, and, additionally, have limitations with respect to the extraction of lignite.

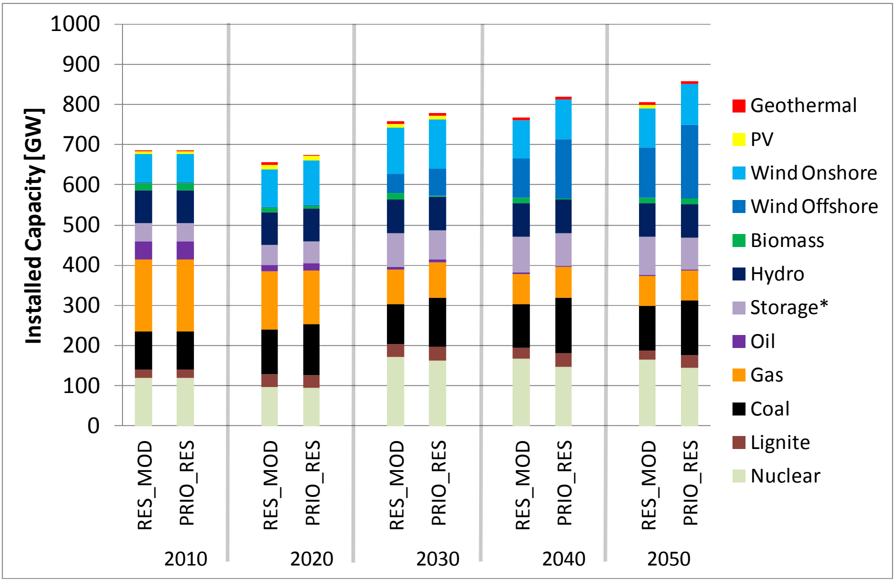

FIGURE 6-9: DEVELOPMENT OF THE AGGREGATED INSTALLED CAPACITY IN THE SCENARIO RES MOD AND THE ASSOCIATED SCENARIO PRIO RES

Source: own calculations; values for 2010 based on Eurelectric (2009)

Furthermore, the aggregated cumulative storage capacity installed is lower in the PRIO RES scenario (81 GW in 2050) than in the RES MOD scenario

[59] The notation „central Europe“ refers to countries in the center of Western Europe, such as Germany and France, whereas the notation „Southern Europe“ refers to countries in the Southern part of Western Europe, such as Spain, Portugal or Spain.

(97 GW in 2050), which once again is largely due to country specifics. Since Germany is relatively abundant in AA-CEAS sites, and the total renewable capacity in Germany is significantly reduced (27 GW in 2050) compared to the base scenario (71 GW), less AA-CAES capacities are necessary over the whole period of consideration.[60] Nonetheless, in the PRIO RES scenario 9 GW of AA-CAES capacity is commissioned in Germany in 2030. It could be objected that, compared to 2010 (26 GW), only a marginally higher cumulative wind capacity is installed in 2030 (31 GW) in Germany. So why is AA-CAES economical in 2030 when it is not in 2010? Does the typeday modelling of only two wind speed levels actually overestimate wind fluctuations and therewith the price spreads? Yet, compared to 2010, in 2030, more than twice as much wind power is generated, as the proportion of offshore wind is higher. Moreover, in 2030 the distribution of wind capacity in Germany is more concentrated than in 2010. Finally, the gas and CO_2 prices increase over time, thus benefiting AA-CAES (see further discussion in chapter 6.3.4).

Except for nuclear power plants, the average utilization of conventional power plants in all model regions is also quite similar in both scenarios, though the average over all regions dominates country specific effects.

[60] Moreover, one could argue that, all else being equal, it is always more profitable to build AA-CAES capacities in an integrative approach (conventional and renewable technologies together) than in an iterative approach (conventional and renewable technologies separately), as also the costs of reallocating RES are taken into account when minimizing total power system costs.

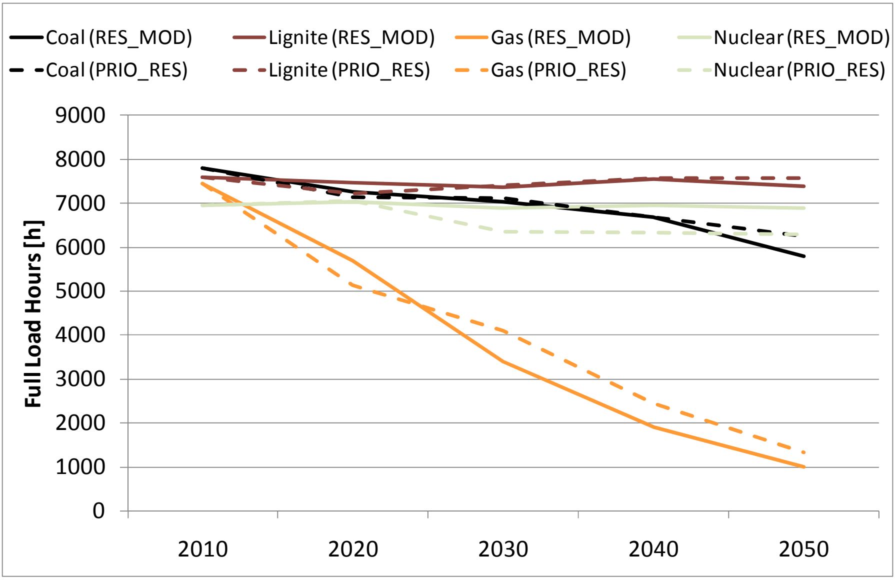

FIGURE 6-10: COMPARISON OF AVERAGE UTILIZATION OF CONVENTIONAL POWER PLANTS IN THE SCENARIO RES MOD AND THE ASSOCIATED SCENARIO PRIO RES

Source: own calculations

Individual country results for Germany, Great Britain, the Netherlands, and Spain, with respect to the development of capacity and generation for the scenario comparison RES MOD and the associated scenario PRIO RES can be found in the appendix. Since the effects are quite straight forward, for convenience reasons they are rather integrated in the appendix. The development of the aggregated gross generation in the scenario RES MOD and the associated scenario PRIO RES can be seen in figure 6-11.

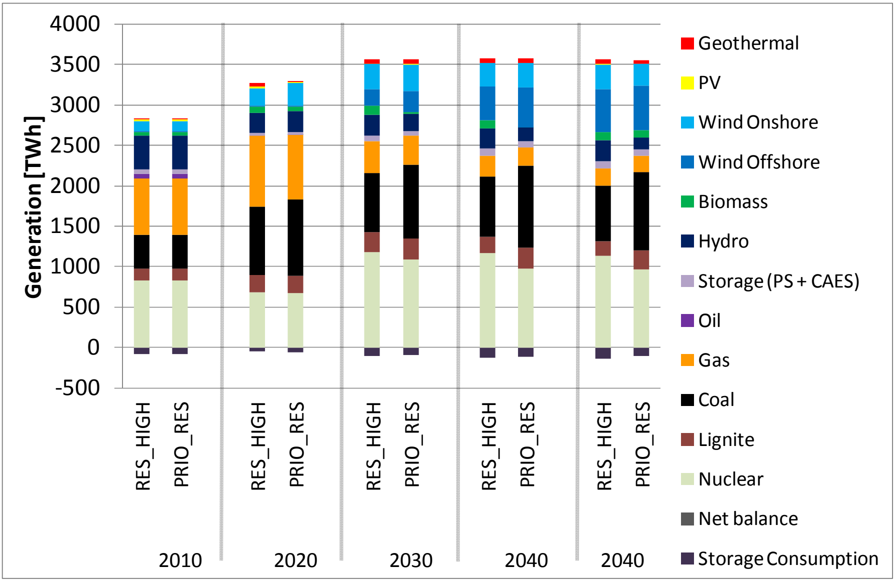

FIGURE 6-11: DEVELOPMENT OF THE AGGREGATED GROSS GENERATION IN THE SCENARIO RES MOD AND THE ASSOCIATED SCENARIO PRIO RES

Source: own calculations

The discounted total power generation system costs in the PRIO RES scenario exceed the ones in the base scenario RES MOD by 38 billion €$_{2010}$ or respectively 3 per cent. Since the inefficiencies are largely limited to the Nordic countries, Ireland, and Great Britain, overall differences in costs are comparatively small. Individual differential cost elements can be seen in figure 6-12. The bulk of the differential costs is made up by the heightened investment costs in the PRIO RES scenario, due to the excessive wind capacity in Nordic countries and the resulting inefficient utilization of wind capacity. The negative differential of the fixed O&M costs can be largely explained by the lower nuclear capacity, being characterized by relatively high fixed O&M costs, and the lower biomass capacity until 2040. Higher variable costs arise in the PRIO RES scenario because more generation has to be supplied by conventional technologies in central and Southern Europe, which are subject to increasing fuel and CO_2 prices.

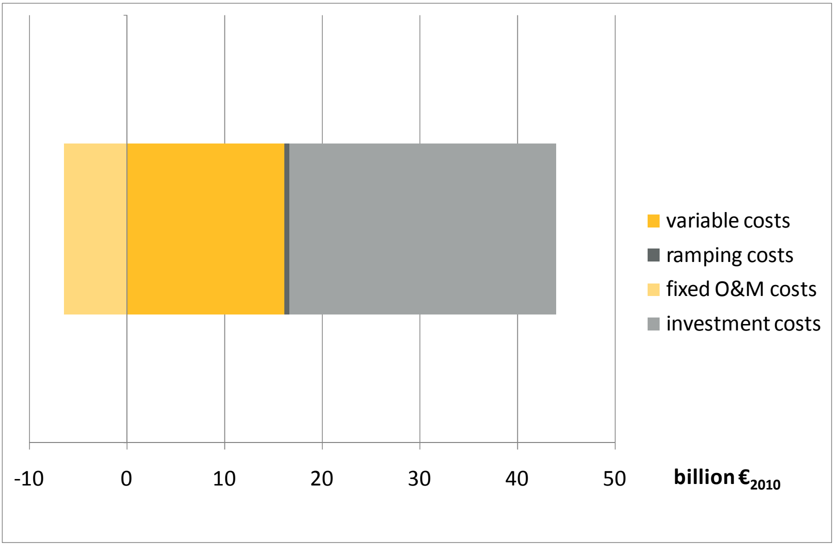

FIGURE 6-12: DISCOUNTED DIFFERENTIAL COSTS BETWEEN SCENARIO PRIO RES LESS THE SCENARIO RES MOD

Source: own calculations

In the modelling, ramping costs constitute only a marginal part of total costs, which can be partly attributed to the simplified linear representation of ramping operations in the model. The increase in ramping costs, due to more extreme modes of operations in countries with vast wind installations (e.g. Great Britain), dominates the decrease in ramping costs, due to less RES-E in countries in central and Southern Europe and the decrease in biomass ramping costs.

To sum up, in a scenario with priority feed-in for RES-E with moderate renewable quotas, the regional concentration of RES-E generating sites, especially wind sites, is augmented, compared to a competitive market setting for all technologies. Due to the moderate renewable quotas, wind power is the dominating RES-E generating technology, with similar proportions in both scenarios. The higher regional concentration of wind capacities in Nordic countries, Ireland, and Great Britain makes a high level of wind power curtailment necessary. In 2050, 28 per cent of the possible generated electricity by wind power plants or 331 TWh/a have to be curtailed. As a consequence of a lower utilization of wind capacities and diminished savings in the conventional power plant fleet, from the inclusion of more concentrated renewable capacity, in the scenario PRIO RES a higher amount of power generating capacity is necessary. Concerning the aggregated power plant mix, in the PRIO RES scenario, nuclear and biomass capacities are largely substituted by coal fired capacities. More coal capacity is caused by lower RES-E penetration in countries in Western and Southern Europe.

6.3.3 Scenario "PRIO RES HIGH": Comparison of Scenario RES HIGH and Associated Scenario PRIO RES

Given high renewable quotas, how does the expansion and allocation of RES differ in a scenario in which renewable technologies have to bid in the electricity market compared to a situation in which they enjoy a priority feed-in? What are the differences in the residual power plant mix? How do the effects differ with respect to different levels of renewable quotas?

In this paragraph the scenario RES HIGH is compared to the associated scenario PRIO RES. In addition to an aggregate analysis for all model regions, country case studies provide further insides into the effects. Figure 6-13 shows the differences of renewable capacities between the two scenarios with high renewable quotas. It can be seen that also with high renewable quotas, wind capacities, predominantly wind offshore at favourable sites, substitutes wind capacities at sites with less favourable wind conditions. However, the regional concentration is enlarged in the PRIO RES scenario with high renewable targets compared to the PRIO RES with moderate renewable targets, now encompassing also Benelux.

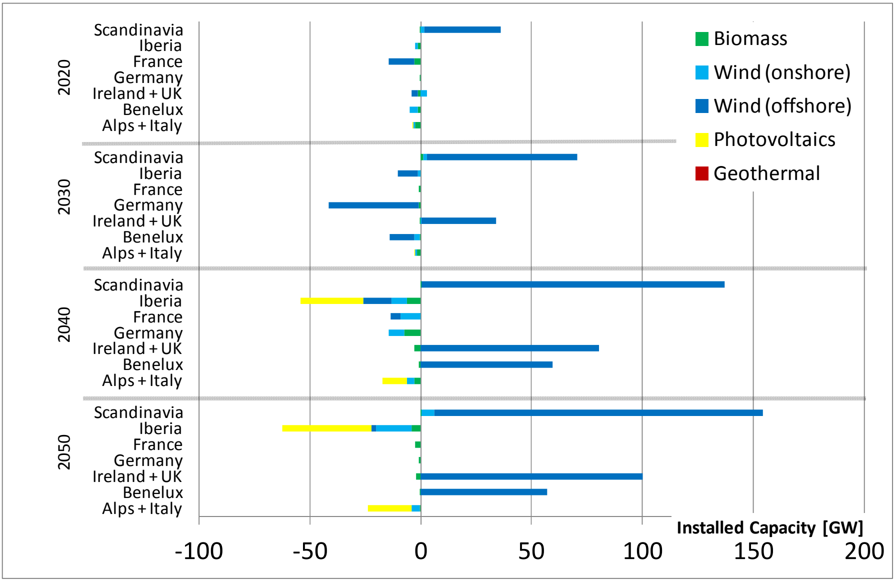

FIGURE 6-13: DIFFERENCE OF INSTALLED RENEWABLE CAPACITIES OF SCENARIO PRIO RES LESS THE CAPACITIES OF THE BASE SCENARIO RES MOD

Source: own calculations

In the Netherlands the growth of wind capacity is only higher after 2030 in the PRIO RES scenario compared to the base scenario RES HIGH. In the decade from 2030 to 2040, suddenly an enormous amount of wind capacity (74 GW) is commissioned in the PRIO RES scenario. Germany and France have the same amount of wind capacity in 2050, in both scenarios – RES HIGH and PRIO RES. Nonetheless, the development of large-scale wind capacity in Germany in the PRIO RES scenario is similarly late (also from 2040 on). This is due to the fact that the entire favourable wind potential in the Nordic countries, Ireland, and Great Britain is exploited first, before less favourable renewable resources in countries southwards are utilized.

In general, the growth of renewable capacities is more irregular und uneven in the PRIO RES than in the RES HIGH scenario. This can be noticed also with respect to the development of plants fired by biomass. Though some cheap power generation by biogas takes place before 2050, a further sudden surge takes place in 2050. As more jump discontinuities, or respectively potential limits, are reached in the PRIO RES scenario with high renewable targets, the abrupt development is more pronounced here than in the PRIO RES scenario with moderate renewable targets.

In 2050, in total there are 10 GW less biomass capacity and 60 GW less photovoltaic capacity in the PRIO RES, compared to the RES HIGH scenario. The total wind capacity in the model regions in the PRIO RES scenario exceeds the aggregated wind capacity in the RES HIGH scenario by about 1370 GW in 2050. Especially from 2040 on, the differences in offshore wind capacities between the two scenarios become tremendous.

Nonetheless, the differences between the two scenarios in terms of wind generation are much less intense, although the differences start to increase from 2040 on, as well. In 2040 and 2050, the differences amount to a surplus of 190 and 170 TWh/a respectively in the PRIO RES scenario, compared to the RES HIGH scenario. From 2040 on, the wind generation share of total electricity demand is approximately 5 percentage points higher in the PRIO RES than in the RES HIGH scenario (33 versus 28 per cent in 2040 and 40 versus 35 per cent in 2050). Before 2040, the wind penetration is comparable in both scenarios.

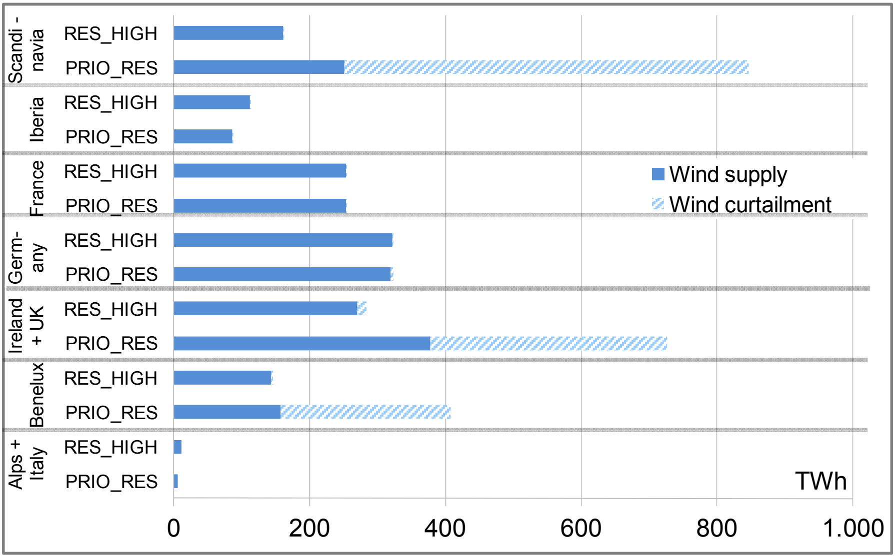

FIGURE 6-14: ANNUAL WIND POWER SUPPLY AND CURTAILMENT IN THE SCENARIOS RES HIGH AND PRIO RES IN 2050

Source: own calculations

Due the vast concentration of wind capacity in Nordic countries, Ireland, Great Britain, and Benelux, 1200 TWh of wind power has to be curtailed in 2050 (see figure 6-14). This constitutes more than 50 per cent of the total possible wind power that could be generated if RES-E integration into the power system is not considered. With high renewable quotas, also biomass has to be curtailed in countries with high wind penetration, if biomass plants are not dispatched according to the situation on electricity markets (see figure 6-15). This is apparently not economical.

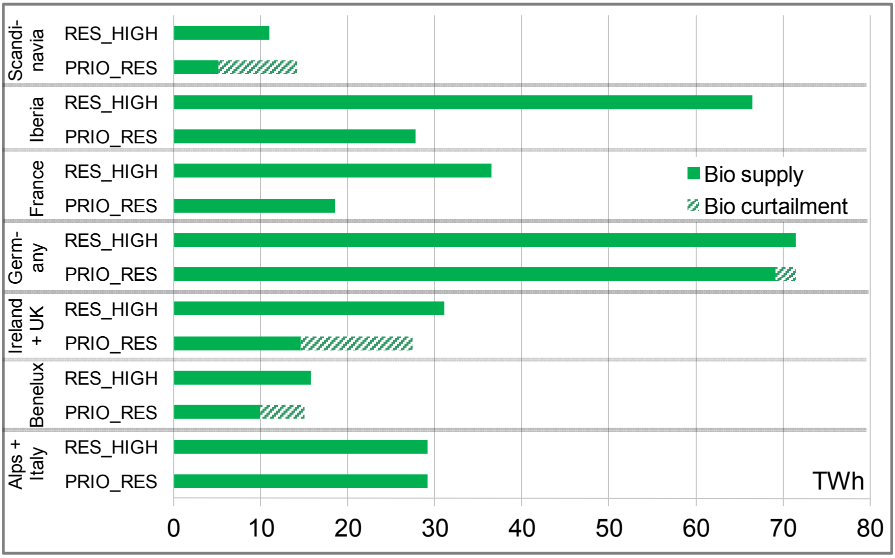

FIGURE 6-15: ANNUAL BIOMASS POWER SUPPLY AND CURTAILMENT IN THE SCENARIOS RES HIGH AND PRIO RES IN 2050

Source: own calculations

Overall, the total amount of aggregated generation capacity is higher in the PRIO RES (1250 GW in 2050) than in the RES HIGH scenario (1025 GW in 2050). This not least can be ascribed to the immense wind power installations in some countries, of which only a fraction of the possible generated electricity can be used. Moreover, compared to the base scenario RES HIGH, the average capacity savings in the conventional power plant fleet from the inclusion of fluctuating RES-E is again lower in the PRIO RES scenario. In the investment period 2020, the capacity savings tend to be higher in the PRIO RES than in the base scenario, due to the usage of higher wind quality sites. However, in later investment periods (2030 to 2050), the average capacity savings in the PRIO RES scenario are smaller (2 to 9 per cent) than the average savings in the RES HIGH scenario (9 to 13 per cent).

Both effects - the less efficient use of wind power capacity and the increased capacity saving loss of conventional capacity by renewable capacity – are higher in a scenario with priority feed-in for RES-E and high renewable quotas than with moderate renewable quotas. With high renewable quotas, 22 per cent more aggregated capacity is necessary in the PRIO RES than in the RES HIGH scenario. With moderate renewable quotas in the PRIO RES scenario, the additional aggregated capacity requirement exceeds the one in the base scenario only by 6 per cent.

Concerning the aggregated power plant mix, in the PRIO RES scenario, nuclear and biomass capacities are largely substituted by coal and lignite fired capacities. Again, the development of nuclear depends largely on the development in Great Britain. Similar to the comparison of scenarios with moderate renewable quotas, more coal capacity is caused by lower RES-E penetration in countries in central and Southern Europe.[61] Furthermore, in the PRIO RES scenario with high renewable quotas, a higher share of coal capacity is further caused by a "delayed" development of RES-E in certain countries (e.g. the Netherlands), compared to the base scenario RES HIGH. Given the current age structure of the power plant fleet and the need to replace existing capacities eventually, in early investment periods with a small RES-E penetration it is invested greatly in coal capacities to meet the electricity demand. Although investment and retirement decisions adapt to the large-scale inclusion of RES-E in later investment periods, it is not economical to retire coal plants that have been built just recently and to shift from coal to gas.

[61] Less RES-E penetration in one country also implies less electricity imports for neighbouring countries.

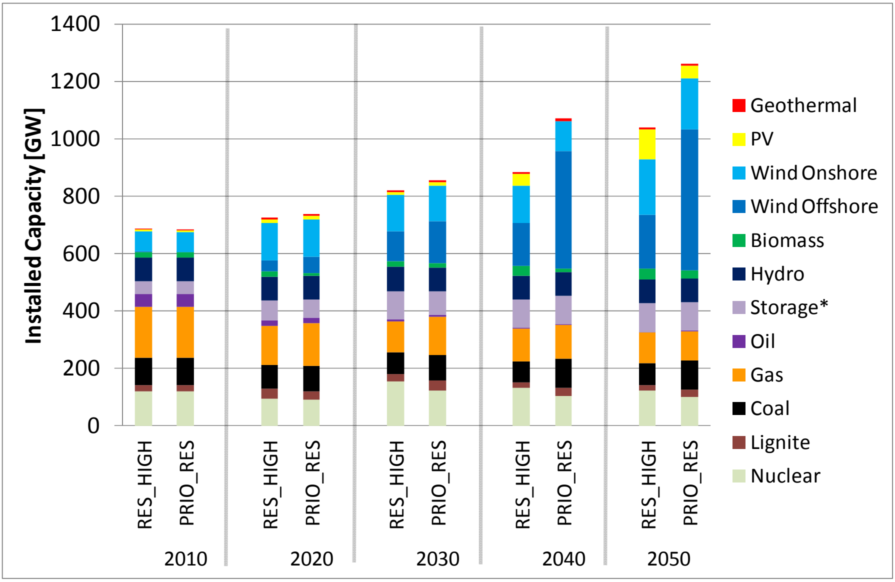

FIGURE 6-16: DEVELOPMENT OF AGGREGATED INSTALLED CAPACITY IN SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

Therefore, also the timing of the large-scale inclusion of RES-E in a country is important for the development of the power plant mix. The aggregated cumulative installed storage capacity is approximately the same in both scenarios (98 and 99 GW) in 2050. Yet, in the PRIO RES scenario the development over time is lagging behind the development in the RES HIGH scenario. This is because wind and solar power capacities in countries with noteworthy AA-CAES potential (Germany and France) are built later in the PRIO RES scenario, after the favourable wind potential in Northern Europe is exploited. On the aggregated level, there are differences concerning the conventional power plant mix between the two scenarios with high renewable quotas. However, it cannot be said that they are more pronounced than the differences between the scenarios with moderate renewable quotas.

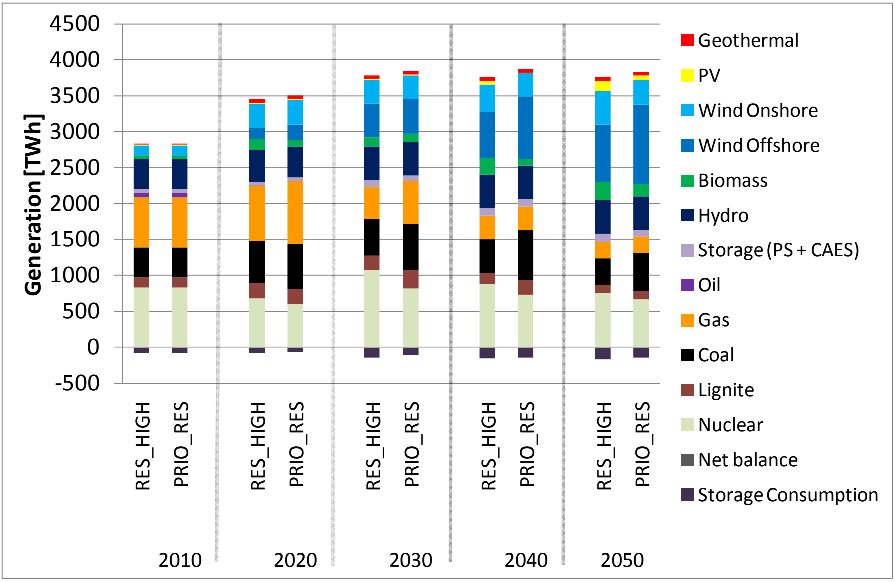

FIGURE 6-17: DEVELOPMENT OF AGGREGATED GROSS GENERATION IN SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

Another important distinction between the two scenarios is the increased capital turnover in the PRIO RES, compared to the RES HIGH scenario. Abrupt changes and a delayed development of RES-E in certain countries in the PRIO RES scenario demand more adjustments in the conventional power plant fleet and thus bring along less optimal investments in terms of total power generation system costs. For instance, until 2040, in Germany and the Netherlands, a delayed development of large-scale RES-E in the PRIO RES compared to the RES HIGH scenario can be noticed. In 2020 and 2030, a lot of conventional capacity that has reached its technical lifetime has to be replaced, which, partly, is not needed anymore in the successive investment periods. As a consequence, also more decommissioning of conventional capacity happens from 2040 on. This however does not change the fact that the remaining base- and mid-load units have to assume more and more the function of backup capacities, by providing capacity instead of power supply (see figure 6-18).

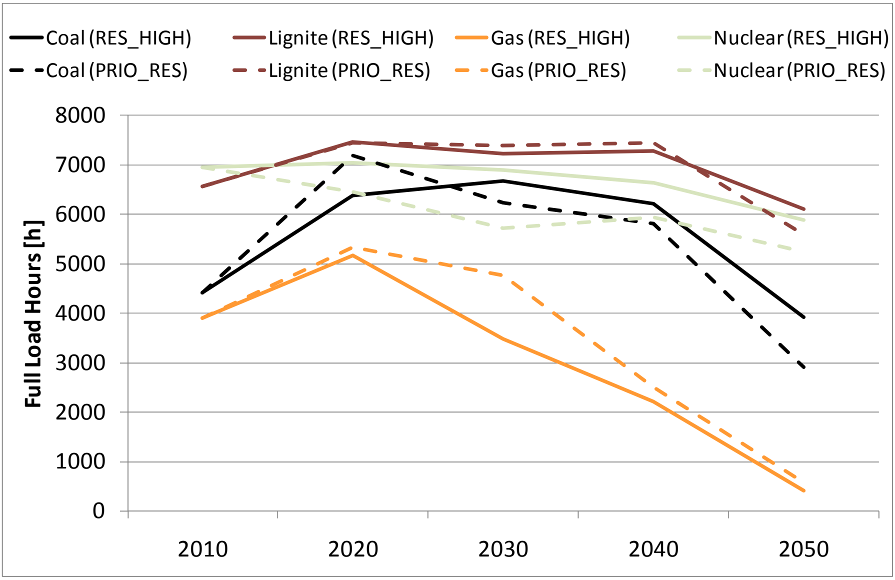

FIGURE 6-18: COMPARISON OF AVERAGE UTILIZATION OF CONVENTIONAL POWER PLANTS IN THE SCENARIO RES HIGH AND THE ASSOCIATED SCENARIO PRIO RES

Source: own calculations

Due to the increase in mentioned inefficiencies with high renewable quotas, also the discounted differential costs between the scenarios with and without priority feed-in for RES-E are augmented. The discounted total power generation system costs in the PRIO RES scenario exceed the ones in the base scenario RES HIGH by 127 billion €$_{2010}$, or respectively by about 10 per cent (see figure 6-19).

The high investment cost differential between the scenarios is, on one hand, caused by the inefficient high wind installations in some countries, and on the other hand, triggered by the delayed RES-E development and the related build-up of a high amount of conventional base- and mid-load capacities in early investment periods. The reinforced inefficiencies in investment decisions with high renewable quotas are also reflected in the now positive fixed O&M cost differential.

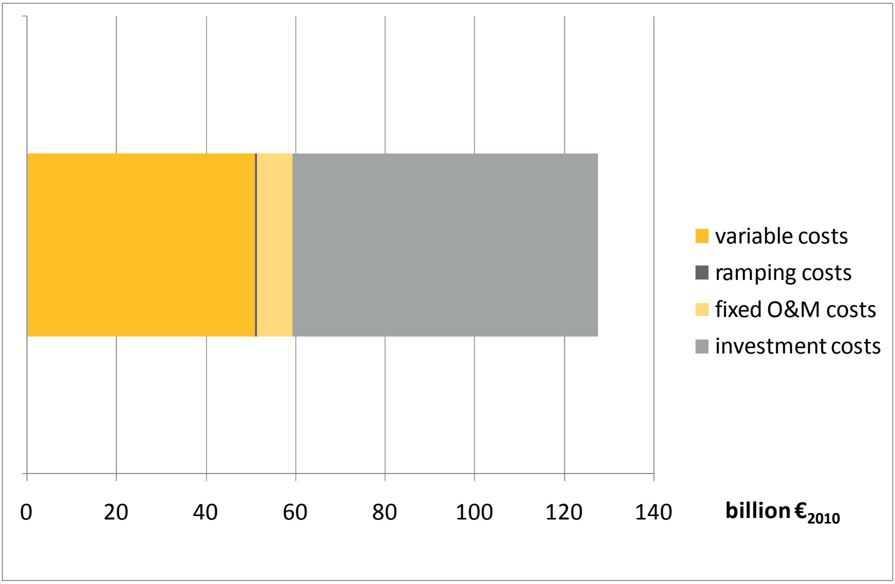

FIGURE 6-19: DISCOUNTED DIFFERENTIAL COSTS BETWEEN SCENARIO PRIO RES LESS THE SCENARIO RES HIGH

Source: own calculations

Similar to the comparison of scenarios with low renewable quotas, here, higher variable costs arise in the PRIO RES scenario because more generation has to be supplied by conventional technologies in central and

Southern Europe, which are subject to increasing fuel and CO_2 prices. In addition, in some countries (e.g. Great Britain) base-load capacity is nearly completely crowded out through the excessive build-up of wind capacity, so that generation by wind plants has to be complemented largely by gas fired generation. The increase in ramping costs, due to more extreme modes of operations in countries with vast wind installations (e.g. Great Britain), dominates the decrease in ramping costs, due to less RES-E in countries in Western and Southern Europe and the decrease in biomass ramping costs.

To summarize, in the PRIO RES scenario with high renewable targets in the early investment periods, the regional concentration of wind power plants increases. From 2040 on, the regional concentration is spread to more countries. Nevertheless, the concentration of wind sites in the Nordic countries and Great Britain amplifies. Furthermore, from 2040 on, the technological concentration increases significantly in favour of wind power, compared to the base scenario RES HIGH. The intensified regional concentration of wind capacities in Nordic countries, Ireland, Great Britain, Benelux increases aggregated wind power curtailment to about 50 per cent of possible wind output in 2050. Even biomass, which, in this scenario, is not dispatched according to the demand/supply situation on the electricity market, has to be curtailed in countries with a high wind penetration. Moreover, the expansion of renewable capacities is more irregular and uneven in a sequential than in an integrative modelling approach and more abrupt than in a scenario with moderate renewable targets. The abrupt and sometimes delayed RES-E development in certain countries, compared to the base scenario, induces high investments in base- and mid-load capacity in early investment periods. With the inclusion of large-scale RES-E in later investment periods, the utilization of base- and mid-load capacities is greatly reduced.

Since the presentation of the aggregated development of certain key data conceals the development of individual countries, in the following four country case studies for high renewable quotas are discussed: Great

Britain, the Netherlands, Germany, and Spain.[62] Comparisons to the scenarios with moderate renewable quotas are drawn when suitable.

6.3.3.1 Country Case: Great Britain

As indicated before, Great Britain has wind sites with favourable wind conditions but currently still has only a minor amount of cumulative wind capacity installed. At the end of 2010, cumulative installed wind capacities amounted to about 5 GW in Great Britain (EurObserv'er, 2011). Thus, there is still a relatively high scope with respect to further installations of onshore wind plants. In all scenarios, it is optimal to first exploit the wind onshore potential, which amounts to about 33 GW. In scenarios with high renewable quotas, the onshore wind potential is already reached in 2020. Due to the more continuous growth paths in the scenarios without priority feed-in for renewable technologies, in 2020, it is also found optimal in the RES HIGH scenario to construct 4 GW of offshore wind capacity.

Because of its geographical location as an island, Great Britain has only limited transmission possibilities available (in total about 2.4 GW NTC-capacity to France and Ireland). Hence, the corresponding power output (117 and 131 TWh/a respectively) from 33 GW and 37 GW wind capacity in the scenario PRIO RES and RES HIGH makes a notable difference with respect to the residual load fluctuations and the resulting price spreads. AA-CAES capacities benefit from more extreme and more frequent price spreads. They feed-in energy in situations of excess supply of RES-E and/or low electricity demand, or, put differently, when electricity prices are low or even negative. Conversely, they release energy in times of tight electricity markets. In Great Britain, it is already economical to exploit the entire AA-CAES potential of 4.7 GW in 2020 in both scenarios. Even with less wind capacity installed in scenarios with moderate renewable quotas, AA-CAES is found economical in Great Britain (see appendix).

[62] The country case studies for moderate renewable quotas can be found in the appendix.

Until 2020, the generation capacity development is relatively similar in all scenarios because of the predetermination of existing power generating capacities,. From 2020 on, results deviate, basically as a function of the amount of RES-E penetration in the market, which is higher in the PRIO RES scenarios. In principle, the higher the RES-E penetration, the higher are the gas and the lower the nuclear shares at the power plant mix in Great Britain. Because nuclear plants need more full load hours to amortize and are less flexible in their operation, gas units benefit from higher RES-E. In all scenarios, coal capacity is replaced either by nuclear or gas capacity, owing to the assumptions on fuel and CO_2 prices and the possibility to build further nuclear capacity in Great Britain. Thus, in the RES HIGH scenario, cumulative installed nuclear capacity increases until 2030 and decreases moderately afterwards. The decrease is caused by the crowding out of conventional generation by progressively higher RES-E. In 2050, the total cumulative installed nuclear capacity in Great Britain in the RES HIGH scenario is still 27 GW. By contrast, in the PRIO RES scenario the cumulative installed nuclear capacity decreases from 2010 on and is only 4 GW in 2030.

The replacement capability of the higher wind capacity in the PRIO RES scenario (150 GW compared to 64 GW in the RES HIGH scenario in 2050) with respect to conventional capacity is decreasing progressively with higher wind power penetration. In 2050, about 4.4 per cent of the additional wind capacity, compared to the RES HIGH scenario, or 4 GW, can be economized in conventional capacity. In 2030, it is still 15 per cent.

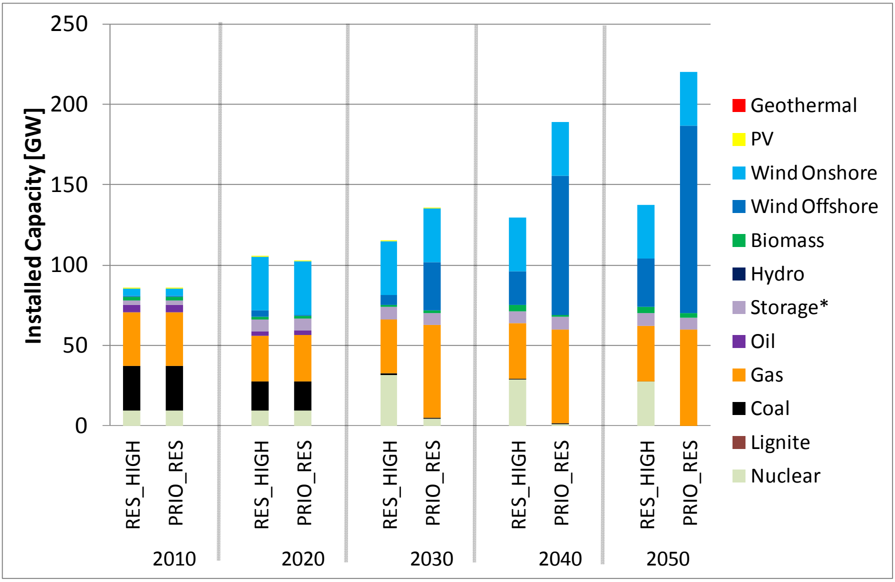

FIGURE 6-20: DEVELOPMENT OF THE INSTALLED CAPACITY IN GREAT BRITAIN IN THE SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

In figure 6-21, the corresponding development of the gross generation in Great Britain in the scenarios with high renewable quotas can be seen. The development of the power generation by nuclear plants is largely consistent with the development of capacity. The utilization of nuclear plants is higher in the RES HIGH relative to the PRIO RES scenario, though the utilization also decreases moderately to about 4700 h/a in later investment periods. Since, in the PRIO RES scenario, base-load capacity is nearly completely crowded out, gas capacities have to entirely adopt the role of power generation on the conventional supply side. Nonetheless, in both scenarios the utilization of gas capacities gets smaller over time as they are in particular suitable for providing backup capacity. The utilization of gas capacities amounts to more than 1000 h/a in the PRIO RES scenario, compared to 470 h/a in the RES HIGH scenario.

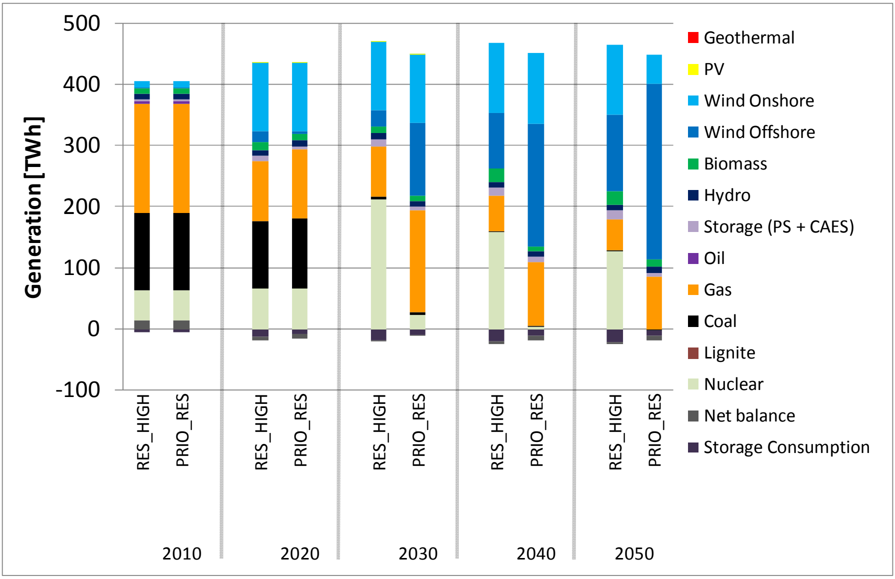

FIGURE 6-21: DEVELOPMENT OF THE GROSS ELECTRICITY GENERATION IN GREAT BRITAIN IN THE SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

Concerning the power generation by AA-CAES plants, it is striking that it is lower in the PRIO RES scenario (7 TWh/a in 2050) with higher wind output than in the RES HIGH scenario (15 TWh/a in 2050) with less wind output. It has been anticipated that storage supply is a positive function of the amount of wind output. This has been also confirmed for Great Britain in the comparison between the PRIO RES and the RES MOD scenario (see appendix). Although price spikes usually tend to increase with higher fluctuating output, in extreme situations, they might even be reduced again. This is the case, if for instance RES-E completely crowds out base- and mid-load generation capacities and the whole conventional power generation portfolio consists exclusively of gas capacities. Then, due to more homogenous generation costs the scope for price fluctuations is diminished.

Due to the high RES-E penetration in Great Britain relative to France, Great Britain has a negative net power balance in all investment periods.[63] Due to a surge in wind capacity in France in 2030, the negative net power balance shrinks in the same investment period. Afterwards, power exports to France rise again. The power transmission with Ireland is extremely restricted.

Since the amount of wind power curtailment is extraordinary high, the inclusion of the same would distort the readability of figure 6-21. In absolute values, the amount of wind power curtailment in the PRIO RES scenario with high renewable quotas amounts to 230 TWh/a compared to a possible wind output of 516 TWh/a in 2050.This signifies that nearly 50 per cent of the possible wind output has to be curtailed. The curtailment of biomass production is about 10 TWh/a in 2050. By contrast, in the RES HIGH scenario, only 4 per cent of the possible wind output, or respectively about 9 TWh/a, has to be curtailed.

6.3.3.2 Country Case: the Netherlands

The capacity development in the Netherlands proceeds very differently in the scenarios. In the moderate renewable quota comparison, throughout the whole period of consideration wind capacities in the PRIO RES scenario are lower than in the RES MOD scenario. Conversely, with high renewable quotas, installed wind capacities in the corresponding PRIO RES scenario triple in 2050, compared to the 30 GW cumulative installed wind capacity in the RES HIGH scenario (see figure 6-22). However, the

[63] A negative power balance signifies that the country's electricity exports exceed the country's imports.

growth of the cumulative installed wind capacity in the PRIO RES scenario is not steady as in the RES HIGH scenario, but characterized by a surge in wind capacities (plus 78 GW) in 2040. Before 2040, in the PRIO RES scenario the contribution of wind power is rather limited. The lacking generation capacity is substituted by coal fired capacity in 2030, which is still in operation in 2050. Capacity investments after 2040 are gas fired.

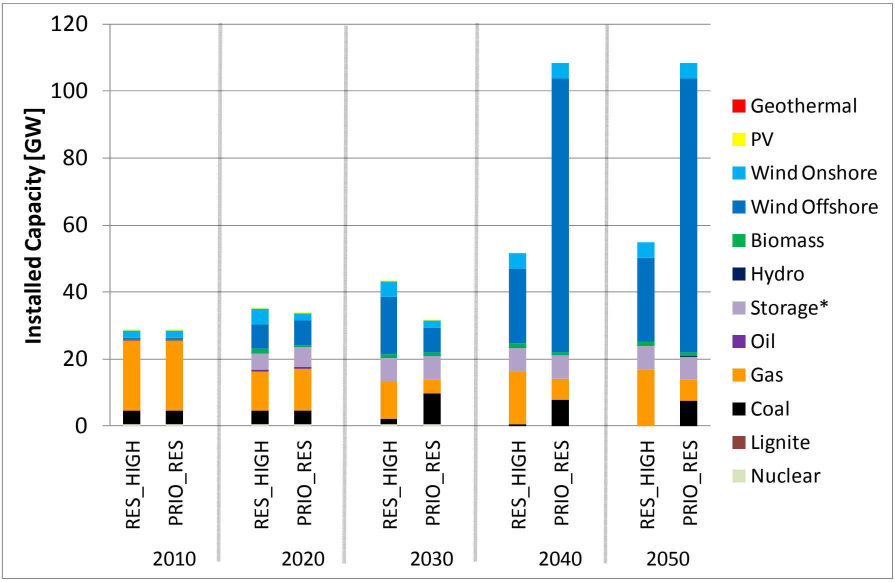

FIGURE 6-22: DEVELOPMENT OF THE INSTALLED CAPACITY IN THE NETHERLANDS IN THE SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

By contrast, the capacity development of renewable as well as of conventional technologies is much more regular and even in the RES HIGH scenario. Already early on, capacity investments are in line with a high RES-E share in the future. In 2050, there is only gas capacity (17 GW) available in the conventional power plant portfolio combined with AA-CAES and pump storage plants.

In general, the AA-CAES potential in the Netherlands is already entirely exploited, with 10 GW cumulative wind power capacity installed and a corresponding 42 TWh/a of wind power generation. However, under consideration of the small national electricity market, this power quantity translates to more than 30 per cent of the national electricity demand. For comparison, in 2010, Germany had a wind power penetration of about 6 per cent of national electricity demand, with a corresponding wind power generation of 36 TWh/a (EurObserv'er, 2011). The points of time of AA-CAES installation correspond to the development of wind power.

The savings in conventional capacity by additional wind power capacity in the PRIO RES, compared to the RES HIGH scenario, is about 5 per cent in 2040 and 2050.

The development of the gross electricity production in the Netherlands replicates the capacity development. While in the RES HIGH scenario, the role of backup capacity is provided rather by gas capacity, in specific flexible gas CHP units, in the PRIO RES scenario also coal capacities have to respond to the increased fluctuations in wind output. The utilization of coal capacities in the PRIO RES scenario decreases to about 1300 h/a in 2040 and 800 h/a in 2050. From 2040 on, power generation of storage units in the PRIO RES scenario exceeds the one in the RES HIGH scenario by about 1 TWh/a at any one time. In this case, a higher RES-E share benefits the electricity supply by storage units because of higher residual demand fluctuations and because of more diverse short-run electricity generation costs in the merit order.

Relative to the market size, the electricity market of the Netherlands is quite well integrated with other electricity markets (Germany, Belgium, and Norway). Consistent with the RES-E development, the electricity exchange develops. In the PRIO RES scenario, the net electricity balance is nearly zero in 2020 and plus 28 TWh in 2030. With the massive wind installations in 2040, the net balance is highly negative in the successive investment periods (less than minus 30 TWh). In the RES HIGH scenario, the net balance is moderately positive in 2020 and 2030 and highly negative afterwards (less than minus 20 TWh).

Wind power curtailment in the PRIO RES scenario amounts to more than 60 per cent of the possible wind output or, respectively, 250 TWh/a in 2050. By contrast, the wind power curtailment in the RES HIGH scenario is only 3 per cent of the possible wind output of 2050, or 3 TWh/a respectively.

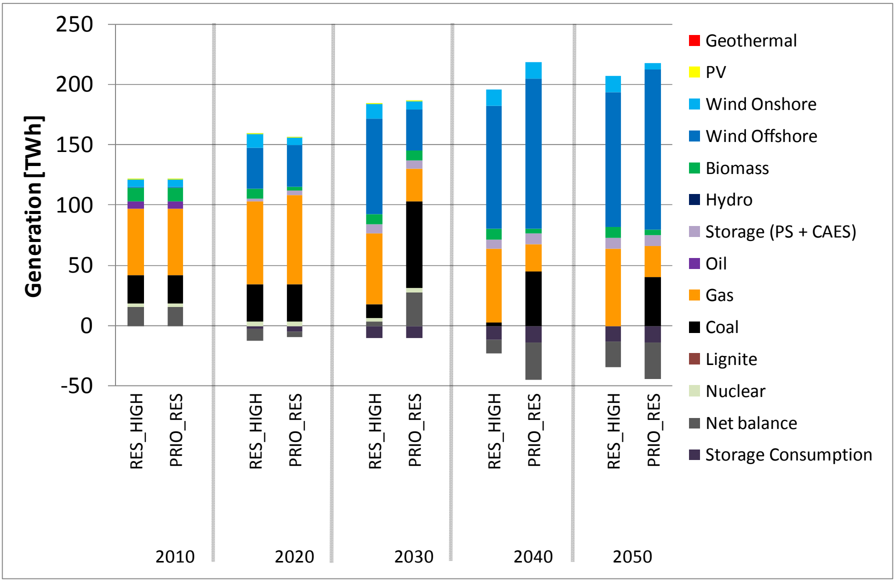

FIGURE 6-23: DEVELOPMENT OF THE GROSS ELECTRICITY GENERATION IN THE NETHERLANDS IN THE SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

6.3.3.3 Country Case: Germany

Similar to the case of the Netherlands, in Germany the RES-E expansion in the PRIO RES scenario is delayed, relative to the RES HIGH scenario. In the PRIO RES scenario, there is no steady expansion of wind capacity. There is even a cutback with respect to the cumulative installed wind capacity in 2030, when a high amount of existing wind power plants in central Germany is decommissioned and not replaced. With the increased exhaustion of the wind potential in countries northwards, a surge of wind power capacity of 46 GW happens in 2040. By contrast, in the RES HIGH scenario, a cumulative wind capacity of 72 GW and associated wind output of 274 TWh/a, is already installed in 2030. This is because Germany is characterized by a high integration capability as it has a sizable market size and is well meshed with other countries. Moreover, its AA-CAES potential is sizeable. In any investment period, photovoltaic capacity is not economical in Germany in both scenarios.

In Germany, the following factors make additional generation capacity necessary in the PRIO RES scenario in 2020: first, the “delayed” development of RES-E in the Netherlands, second, the associated lower electricity exports to Germany, and finally, the nuclear phase-out in Germany. This is provided by new installations in gas, lignite, and AA-CAES plants. A further capacity complement is necessary in 2030 and 2040 because of the “delayed” development of renewable capacity, mostly of wind capacity but also of biomass capacity, in Germany. This is provided especially by lignite plants that are commissioned in 2030 and which remain in operation until 2050. In 2050, there is twice as much lignite capacity in the PRIO RES (14 GW) than in the RES HIGH scenario (7 GW) (see figure 6-24).

Although in 2050 the amount of RES-E as well as the RES-E mix is the same in Germany, there is a higher cumulative capacity installed in the PRIO RES scenario (179 GW) than in the RES HIGH scenario (176 GW). The higher capacity in 2050 in the PRIO RES scenario can be explained by the lower electricity imports from France, by reason of a lower biomass production. During the period of consideration, the commissioning in coal units, mostly CHP, is alike in both scenarios. In both scenarios, gas capacities are eliminated completely until 2050. Flexible backup capacity is provided by about 30 GW of AA-CAES capacity. Thereby, the installation of the AA-CAES plants complies with the RES-E development. Investments in AA-CAES capacity are already economical in 2020, with about 100 TWh/a of wind power output.

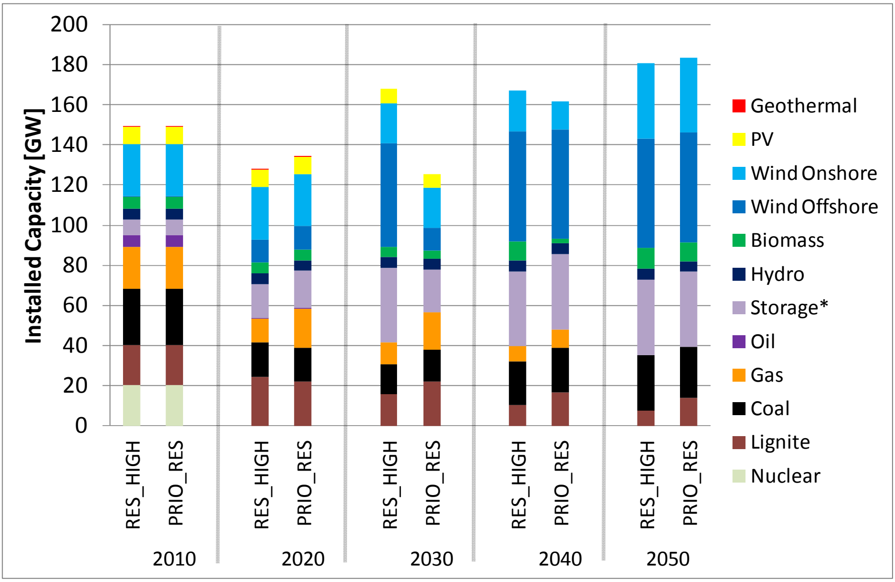

FIGURE 6-24: DEVELOPMENT OF THE INSTALLED CAPACITY IN GERMANY IN THE SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

In the PRIO RES scenario, in 2050, the higher cumulative installed capacity, in specific of lignite plants, is reflected also with respect to the decrease in the utilization of lignite units. The full load hours of lignite plants drop to 3170 h/a in 2050, compared to 4600 h/a in the RES HIGH scenario.

In both scenarios, the utilization of coal plants decreases, in line with the increase in RES-E, to about 1900 h/a in 2050. In the PRIO RES scenario, the utilization of gas plants is outstandingly high in the investment periods of 2020 and 2030. After 2040, with higher RES-E and related higher power supply by storage plants, the competition for gas capacities intensifies. In 2040, the annual full load hours of gas units still exceed 3000 h/a in both scenarios. Conversely, the utilization of storage units is increased over time, due to the diminishing gas capacities, with which they are directly competing. In general, Germany develops towards being a net importer of electricity from the Netherlands, France, Denmark, and Sweden.

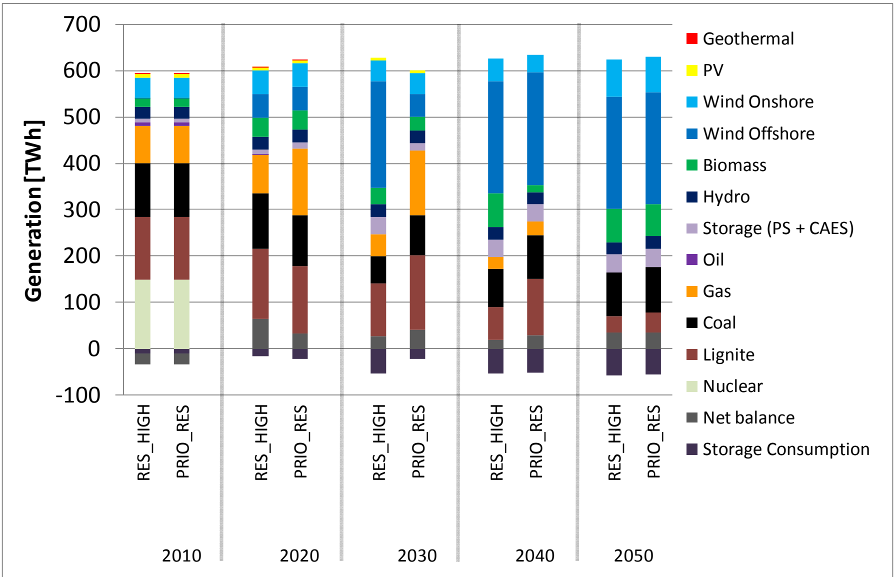

FIGURE 6-25: DEVELOPMENT OF THE GROSS ELECTRICITY GENERATION IN GERMANY IN THE SCENARIO RES HIGH AND THE ASSOCIATED SCENARIO PRIO RES

Source: own calculations

Wind power curtailment is negligible in both scenarios. Nevertheless, it is not exactly alike in 2050, despite of the same amount of cumulative wind capacity installed. In the RES HIGH scenario, it is confined to 0.5 TWh/a, and, in the PRIO RES scenario, it amounts to about 4 TWh/a. This may be explained first by the fact that the surrounding countries have build up more wind capacity in the PRIO RES scenario, thus leaving less scope for balancing wind power between the countries. An alternative explanation in terms of the model logic is that wind power curtailment in the PRIO RES scenario largely comes for free (except of the power that is forgone) while in the RES HIGH scenario the cost of RES allocation is included additionally. This explanation, however, can only hold if ramping costs are the decisive factor.

6.3.3.4 Country Case: Spain

In the case of Spain, in the PRIO RES scenario, the development of biomass and photovoltaic capacities, as well as of wind capacities at more unfavourable wind sites takes place at later investment periods or not at all. Thus, in the PRIO RES scenario, in 2050, the total cumulative installed renewable capacity (34 GW) falls short, compared to the total cumulative installed renewable capacity in the RES HIGH scenario (97 GW). In the RES HIGH scenario, the Spanish market size and the related increased integration capability is an asset which is neglected in the scenario with priority feed-in for RES-E.

The reduction of excess capacity in 2020 is followed by an increase in cumulative installed capacity in 2030. This is a response of higher electricity demand. The phase-out of nuclear capacity and the retirement of existing capacities, as they reach their technical lifetime, are compensated by the commissioning of mostly coal plants and a few gas plants. Thereby, the distribution between the two technologies complies with the development of RES-E in the respective scenarios, i.e. a higher coal share with less RES-E and vice versa.

It is striking that, in Spain, AA-CAES plants are not economical in any scenario. If anything, the RES HIGH scenario would be the scenario, in which investments in storage units were economical. A wind output of 64 TWh/a in 2030, however, does not seem to be sufficient relative to the Spanish market size, to induce sufficiently large price swings. In addition to a wind output of 67 TWh/a in 2040, photovoltaic devices produce 30 TWh/a. In 2050, wind and solar energy output is increased by 23 TWh/a, and 32 TWh/a respectively. Yet, wind output is quite evenly distributed in two wind supra regions. Concerning solar output, variations of solar irradiation are not accounted for in the data. And even then, the solar irradiation in Southern Europe is quite stable. Moreover, an increase in wind and solar output does not necessarily mean that total fluctuations are amplified, as they are somewhat negatively correlated. Furthermore, solar output is positively correlated to electricity demand, thereby decreasing the fluctuations of the residual load, i.e. electricity demand less RES-E.

Another point may be that the inclusion of large-scale RES-E occurs in the last investment period. Although the calculation proceeds until 2060 and investment costs are allocated over different years in the form of an annuity, still it might be the case that technologies with high fixed costs are not profitable in later investment periods. This refers to the so called end time problem. Generally, lignite and coal units can keep a high utilization in all scenarios. The utilization of gas units decreases only in the RES HIGH scenario to about 350 h/a in 2050. This is especially caused by the 100 per cent backup capacity requirement of photovoltaic plants.

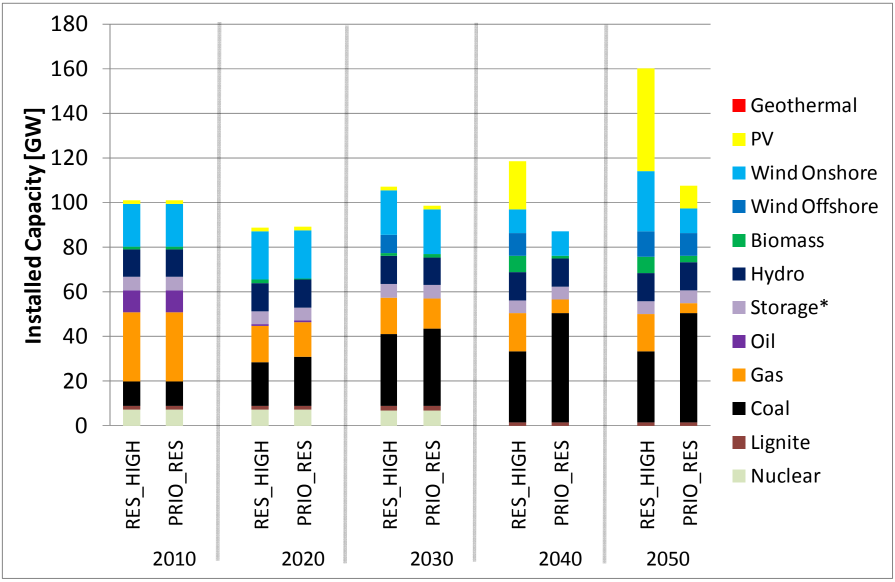

FIGURE 6-26: DEVELOPMENT OF THE INSTALLED CAPACITY IN SPAIN IN THE SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

Since in 2050, the utilization of existing pump storage capacities is very low, even in the RES HIGH scenario, with just about 200 h/a and zero in the PRIO RES scenario, one can a arrive at the conclusion that with the incorporation of large-scale photovoltaics either the fluctuations of residual load are reduced or that fluctuations occur rather at the front end of the merit order. Over time, Spain develops more and more towards a net importing county.

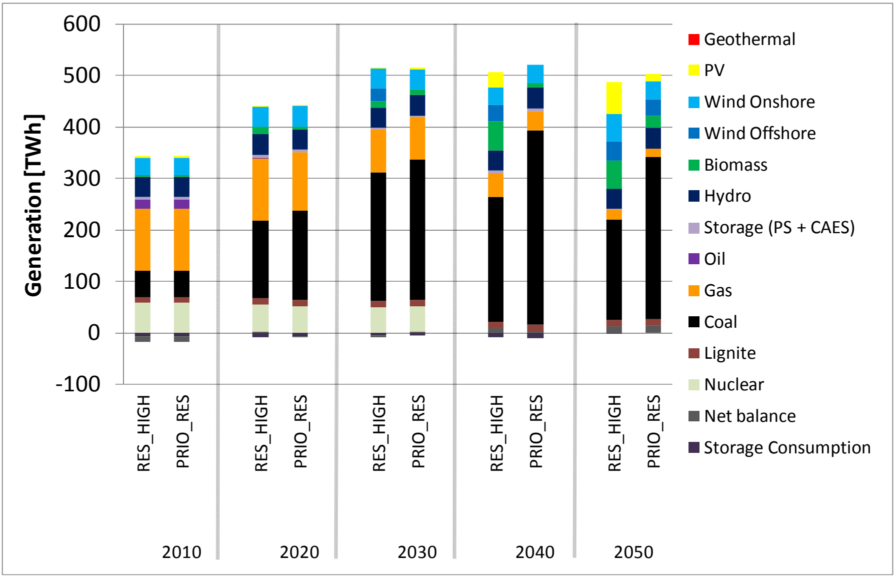

FIGURE 6-27: DEVELOPMENT OF THE GROSS ELECTRICITY GENERATION IN SPAIN IN THE SCENARIO RES HIGH AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

6.3.4 Sensitivity “NO CAES”: AA-CAES Investments are not allowed

If large-scale AA-CAES capacities cannot be built due to e.g. competing usages of salt caverns, what are the consequences for optimal RES-E expansion, RES-E curtailment and the residual power plants fleet? What role does temporal flexibility play in scenarios with high renewable quotas? What triggers investments in AA-CAES capacities?

In this paragraph primarily the two scenarios with a competitive market setting for all technologies, but with different degrees of temporal flexibility available, are compared. In contrast, a comparison between the two scenarios with priority feed-in for RES-E and differing degrees of temporal flexibility are only made occasionally. This is because a limitation on the temporal flexibility does not have consequences for the RES-E expansion in a scenario with priority feed-in for RES-E, as in the optimization of RES-E the conditions of the electricity markets are neglected. When doing so, this is mentioned explicitly. In the rest of the time, the scenario comparison is constricted to the one mentioned at first.

If large-scale investments in AA-CAES capacities are not allowed and temporal flexibility is restricted, especially countries with a significant AA-CAES potential (Germany, the Netherland, and France) see less investments in wind capacities, particularly in later investment periods. In earlier investment periods (2020 and 2030), they are substituted by wind capacities in other countries (Iberia, Ireland, and even Scandinavia). In later investment periods (2040 and 2050), higher installations in biomass plants fired with expensive biofuels, in the same model regions, and photovoltaic plants at comparatively unfavourable sites in Southern European countries complement the RES-E mix. In 2050, even a small amount of enhanced geothermal energy in Belgium becomes competitive. Thus, in a competitive market setting for all technologies, the technological and regional diversification augments if only limited temporal flexibility is available.

Moreover, in a scenario with limited temporal flexibility, the demand for wind output smoothing, by diversifying wind sites, enhances. This can be derived from Germany and France, which both are subject to two wind supra regions and in addition have much lower temporal flexibility available in this sensitivity scenario than in the base scenario RES HIGH. In both countries, investments are rather made at worse wind sites, which are able to balance some output from wind sites with better wind conditions, than to invest in wind power plants concentrated either at the Atlantic or the North-Sea. For example, in Germany, the entire wind offshore potential is nearly exploited in 2030 already in the RES HIGH scenario (230 GW). However, in the NO CAES scenario, only 181 GW wind offshore capacity is installed, in addition to 10 GW wind onshore capacity in the South of Germany. This result is further caused by the presumed transmission restrictions in both scenarios.

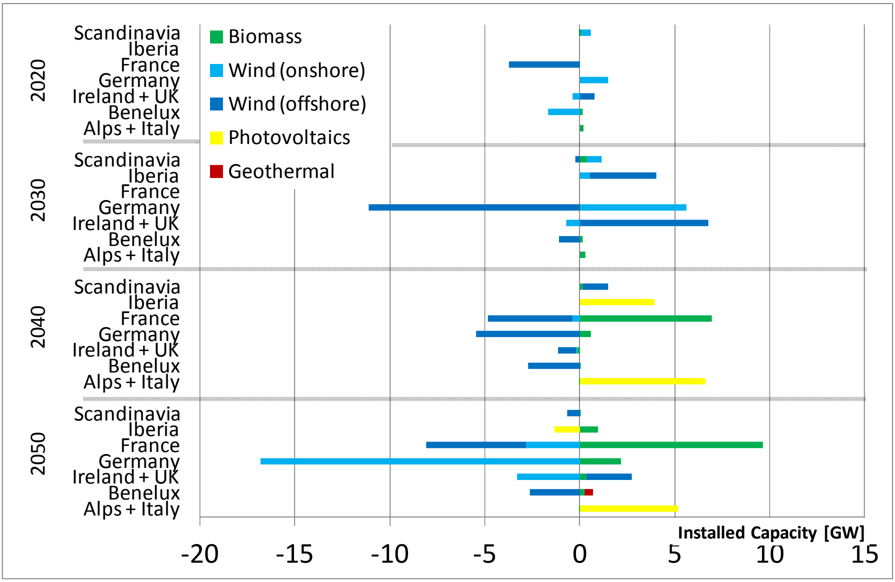

FIGURE 6-28: DIFFERENCE OF RENEWABLE CAPACITIES OF SCENARIO NO CAES LESS RENEWABLE CAPACITIES OF THE SCENARIO RES HIGH

Source: own calculations

Without the large-scale possibility to balance electricity between different points in time, contingent on the aggregated storage volume, the integration capability of a region is reduced. All else being equal, this implies a higher amount of RES-E curtailment in the respective regions. In figure 6-29, the annual wind power supply and curtailment in 2050 for the scenarios RES HIGH and NO CAES can be seen. In the integrative model, the options of "reallocating RES-E" versus "curtailing more RES-E" and their associated costs are weighted against one another. Compared to the

RES HIGH scenario, RES-E curtailment is increased approximately by 35 per cent, or 6.5 TWh/a respectively, in 2050. Since the aggregated level of RES-E curtailment still remains comparatively low (25 TWh/a in 2050), it can be concluded that, although the temporal flexibility is limited, it is possible to integrate large-scale RES-E without significant amounts of foregone power. This can be achieved by increasing the regional and technological diversification of RES-E.

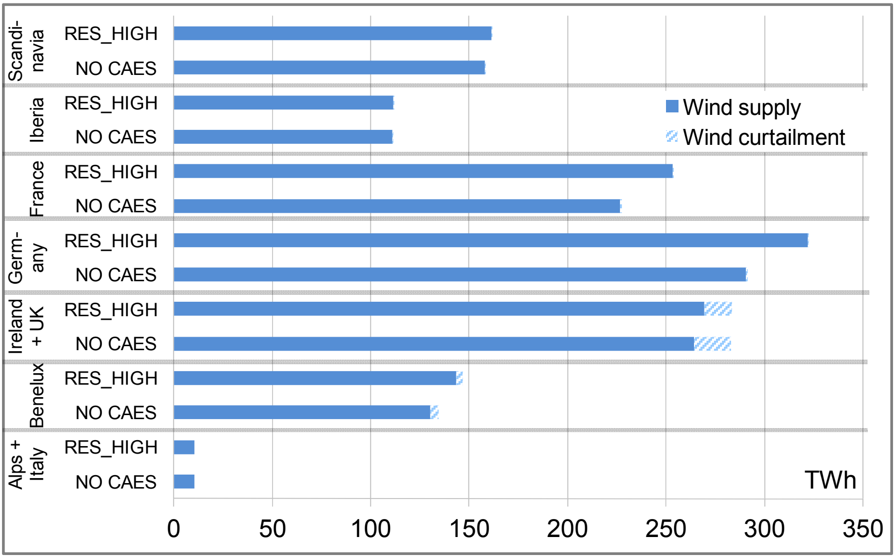

FIGURE 6-29: ANNUAL WIND POWER SUPPLY AND CURTAILMENT IN THE SCENARIOS RES HIGH AND NO CAES IN 2050

Source: own calculations

The limits on the temporal flexibility in the PRIO RES scenario with high renewable quotas do not have a big effect on the levels of wind curtailment, at least relatively. In 2050, about 40 TWh/a of the aggregated wind power has to be curtailed additionally. Compared to the original level of 1230 TWh/a in 2050, this is negligible. This is due to the fact that the highest levels of wind curtailment occur in countries with already limited temporal flexibility. However, in Germany, in 2050, the lower temporal flexibility leads to 20 TWh/a additional wind power curtailment in 2050, from the initial level of 4 TWh/a.

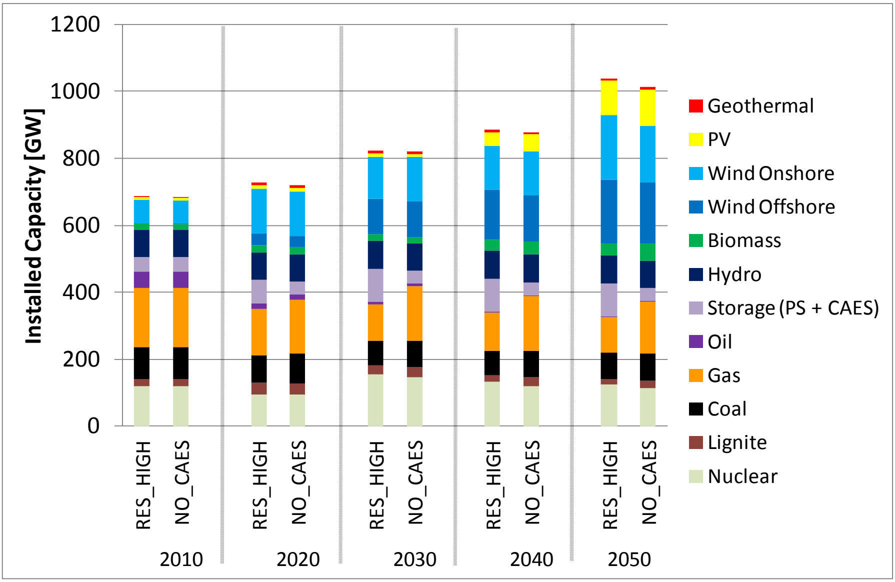

FIGURE 6-30: COMPARISON OF THE AGGREGATED CAPACITY DEVELOPMENT IN THE BASE SCENARIO RES HIGH AND THE CORRESPONDING SCENARIO NO CAES

Source: own calculations

On the aggregated conventional supply side, two major differences between the scenarios can be noticed. First, the total aggregated generation capacity in the sensitivity scenario is 20 GW lower than in the RES HIGH scenario. In the sensitivity scenario compared to the base scenario, capacity input (mostly storage and a bit nuclear) has been traded off against fuel input in the production process. Second, the decrease in storage capacity mainly induces an increase in gas capacity. Thus, storage capacity directly competes with gas capacity in the peak-load interval.

Gas capacities and especially open cycle gas turbines have the advantage of low investment costs. On the other hand, they have high variable costs, mostly consisting of fuel costs, which are highly rising over the period of consideration. The investment costs of AA-CAES plants are about twice as high as the costs of gas capacities. Under the simplified assumption that it is always fed into AA-CAES plants when the system marginal costs are approximately zero, the breakeven full load hours, at which it pays off to invest in AA-CAES instead of OCGT, amount to 275 hours in 2050. In the RES HIGH scenario the utilization of AA-CAES capacities, e.g. in Germany, amounts to more than 700 h/a from 2030 on. As the PRIO RES scenario with moderate renewable quotas represents the lower bound with respect to RES-E quantities in Germany, the AA-CAES utilization in Germany is similar in this scenario. In general, the operation mode of the AA-CAES capacities is to feed-in energy in situations of high electricity supply, being positively correlated with wind output, and/or low electricity demand. Energy is then released in situations of tight electricity markets.

The average utilization of conventional power plants can be increased by the large-scale deployment of AA-CAES capacities as they are able to smooth the residual load to be met by conventional power plants.

The differential costs of the NO CAES scenario in an integrative modelling approach compared to the base scenario RES HIGH amount to a surplus of 14 billion $€_{2010}$. Due to the relatively high fixed costs for AA-CAES units, total discounted fixed costs are lower in the NO CAES scenario. This effect dominates the higher fixed costs from the reallocation of renewable capacities. However, all other cost components increase in the NO CAES compared to the base scenario. The bulk is made up by variable costs from gas units. The differential costs of a NO CAES scenario in a sequential modelling approach, compared to the PRIO RES scenario with high renewable quotas, have a surplus of about 9 billion $€_{2010}$.

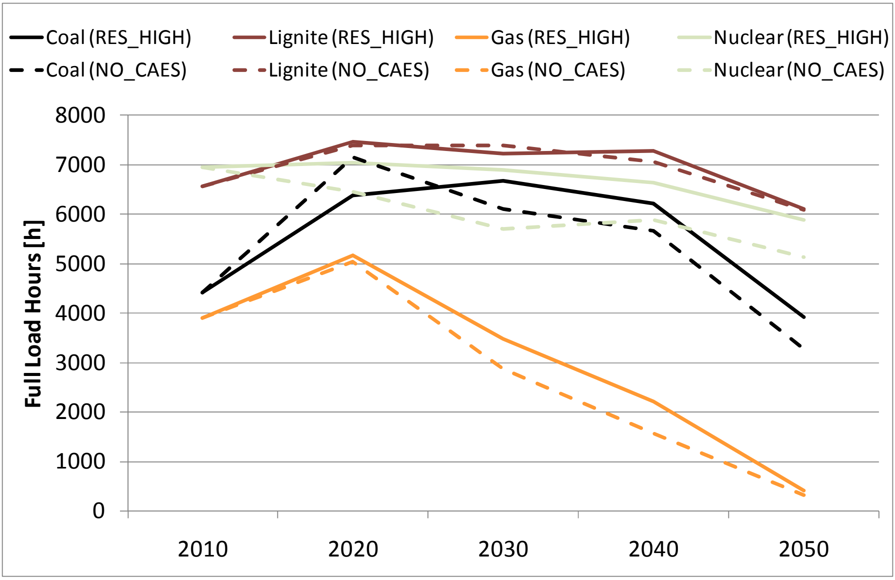

FIGURE 6-31: COMPARISON OF AVERAGE UTILIZATION OF CONVENTIONAL POWER PLANTS IN THE SCENARIOS NO CAES AND RES HIGH

Source: own calculations

To summarize, in a competitive market setting, less temporal flexibility increases the demand for regional and technological diversification. Moreover, the integration capability of a country is reduced. Furthermore, the need to curtail RES-E increases only to a limited extent. In general, in terms of total power generation system costs, the options to reallocate a certain RES or to switch to other renewable technologies are preferred before curtailing excessive RES-E amounts. In a scenario with limited storage capacity available, capacity input is traded off against fuel input. This means, that gas units have to assume the role of backing-up renewable capacity and meeting demand at peak-load situations instead. Given the significant increase of gas and CO_2 prices over time, the deployment of AA-CAES capacities saves 14 billion €$_{2010}$, discounted to

2010, and accumulated over the whole period of consideration from 2010 to 2050.

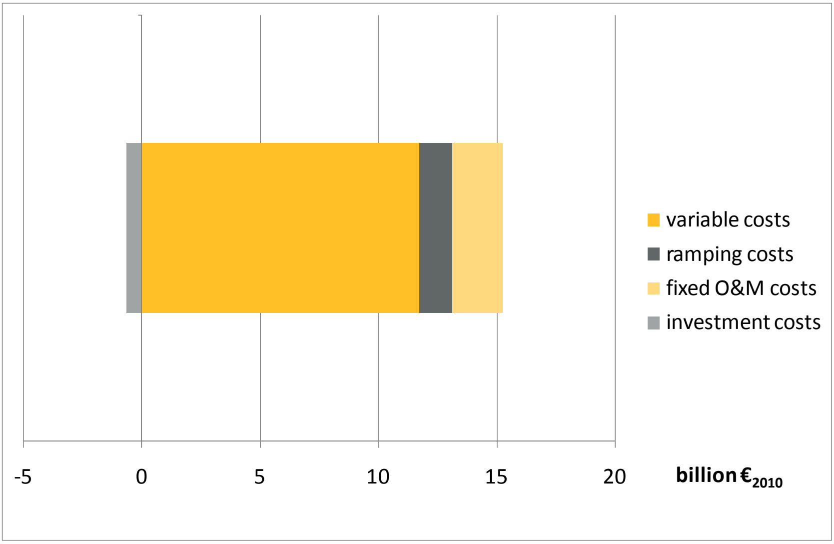

FIGURE 6-32: DISCOUNTED DIFFERENTIAL COSTS BETWEEN SCENARIO NO CAES LESS THE SCENARIO RES HIGH

Source: own calculations

6.3.5 Sensitivity “UNLIM NTC”: More NTC Capacity Available

In how far does the geographical flexibility determine the optimality of RES-E allocation in a competitive market setting? Does a greater geographical flexibility facilitate a RES-E allocation, in which only the most economic renewable technologies at the most favourable sites are used? Or is it rather beneficial to have some technological and regional diversity? Is it beneficial to have solar power in Southern Europe to balance wind output in Northern Europe?

In this paragraph the scenario with higher transmission flexibility, high renewable quotas and a competitive market setting is compared on the one hand to the base scenario RES HIGH and on the other hand to the scenario PRIO RES with high renewable quotas. The comparison between the three scenarios shall reveal whether in the face of higher transmission flexibility a competitive market allows the use of the most economical renewable technologies at the most favourable sites, such as implied by the scenario PRIO RES, or whether also in this case some regional and technological diversification is beneficial for the power generation system as a whole, such as implied by the scenario RES HIGH.

In figure 6-33 and 6-34, one can see the differences in terms of the cumulative installed renewable capacity of the integrative modelled scenario, with higher NTCs between countries and high renewable targets, compared to the base scenario RES HIGH and the PRIO RES scenario respectively. There are differences with respect to both scenarios. However, in terms of absolute quantities, the differences are more distinct compared to the scenario PRIO RES, especially in later investment periods (2040 and 2050). The extreme regional and technological concentration towards wind sites, especially offshore, in countries surrounding the North-Sea in the PRIO RES scenario, is also not found beneficial in a scenario with greater transport flexibility.

On the one hand, all countries surrounding the North-Sea are subject to the same wind supra region. Thus, wind power fluctuations in the respective countries are positively correlated. Huge wind power capacities within one wind supra region imply enormous swings in wind output that have to be somehow balanced.[64] Even in the case of a European copperplate, if there was such a high wind offshore wind capacity installed in the countries surrounding the North-Sea as in the PRIO RES scenario with high renewable targets (445 GW in 2050), about 81 TWh/a would have to be curtailed of wind offshore power alone. Thereby, curtailment happens

[64] Nonetheless, the assumption of perfect correlation within a wind supra region underestimates balancing possibilities that could be effected across countries within the same wind supra region. There are time lags for one wind state to arrive in a country nearby.

primarily during off-peak demand and during the winter, as then the average wind speeds are high in the “North-Sea” wind supra region. Thus, the higher the share of wind power concentrated in one area, the more difficult it becomes to integrate it into the power system without having to curtail significant amounts of wind output, even on a European scale.[65]

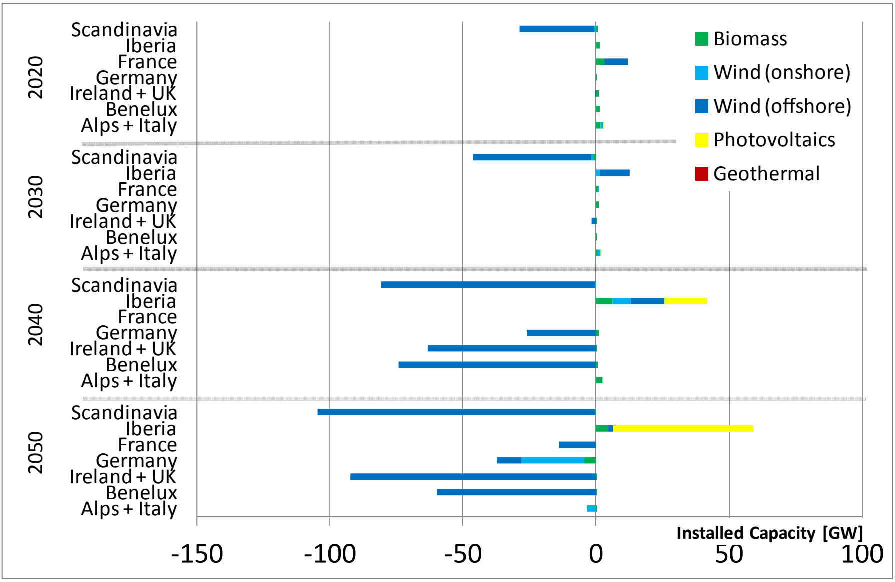

FIGURE 6-33: DIFFERENCE OF RENEWABLE CAPACITIES OF SCENARIO UNLIM NTC LESS RENEWABLE CAPACITIES OF THE SCENARIO PRIO RES

Source: own calculations

On the other hand, an extreme concentration of wind power plants in one area also demands to remove massive amounts of wind output to other countries, sometimes through several other countries. Even with high NTC

[65] A more refined modelling of balancing effects of European wind power may find it possible to integrate even higher shares of wind output, without having to curtail a significant amount.

values, bottlenecks may arise from the transport of massive amounts of wind output, not to speak from bottlenecks within the countries themselves. These are neglected in this work.

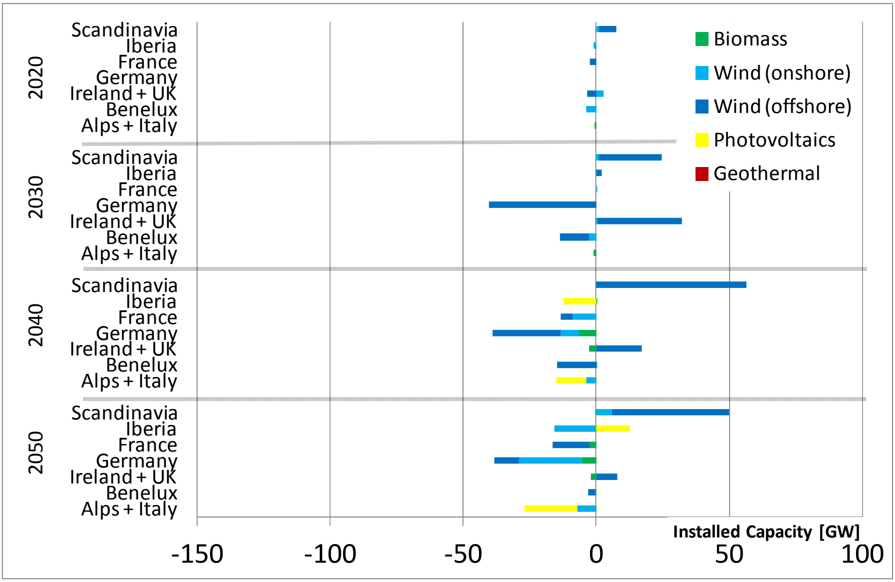

FIGURE 6-34: DIFFERENCE OF RENEWABLE CAPACITIES OF SCENARIO UNLIM NTC LESS RENEWABLE CAPACITIES OF THE SCENARIO RES HIGH

Source: own calculations

From the fact that the total wind capacity in Germany is reduced in the UNLIM NTC scenario, compared to both scenarios, in addition to increased imports from Nordic countries, it can be concluded that in case of high transport capacities, Germany acts as an absorber or transit country for Nordic countries. Although Germany has quite favourable wind sites available, they are adverse, compared to wind sites in Nordic countries, Ireland, and Great Britain. In addition, the offshore wind sides of Germany are subject to the same wind supra region as offshore wind sites in the

Nordic countries, Ireland, and Great Britain. The same applies to offshore wind sites in the Netherlands. Moreover, in the presence of high transport capacities between countries, the integration capability of a specific country ceases to be an asset. Hence, compared to the base scenario RES HIGH, in the UNLIM NTC scenario, a higher overall wind capacity is built in Nordic countries, Ireland, and Great Britain together. For instance, in 2050, a surplus of 57 GW, is built with an associated wind output of 249 TWh/a.

In the UNLIM NTC scenario, regional diversification takes place rather between different countries than within countries. Thus, the diversification within countries that could be observed in the base scenario RES HIGH, e.g. in Germany between more favourable sites in the North and less favourable sites in the South, is not economical any more in the UNLIM NTC scenario. However, there are not any wind power investments in the wind supra region “Central Europe”. This might be different if some more regions of this wind supra region with more favourable wind conditions, such as Southern Poland and the Czech Republic, were included in the analysis. Although, compared to the RES HIGH scenario in 2050, there are less wind power capacities installed in France and the Iberian Peninsula, there is still a considerable amount available in the two different wind supra regions “Atlantic region” and “Southern Europe” – even at less favourable wind sites. Thus, wind power from other wind supra regions than the “North-Sea” balance the wind output from the Nordic countries, Ireland, and Great Britain.

The technological diversity is not markedly reduced in the UNLIM NTC scenario, compared to the RES HIGH scenario, at least in 2050. In 2050, even a higher cumulative photovoltaic capacity is installed on the Iberian Peninsula in the UNLIM NTC (72 GW), compared to the RES HIGH scenario (60 GW). Conversely, the cumulative wind power capacity on the Iberian Peninsula is reduced in the UNLIM NTC (33 GW) compared to the RES HIGH scenario (49 GW). The lower cumulative photovoltaic capacity in Italy in the UNLIM NTC (24 GW in 2050) compared to the RES HIGH (40 GW in 2050) scenario, is largely due to a higher cumulative nuclear capacity in the UNLIM NTC (65 GW in 2050), compared to the RES HIGH scenario (54 GW in 2050). Only in 2040, in the UNLIM NTC scenario, relative to the RES HIGH scenario, some photovoltaic capacity on the Iberian Peninsula and Italy is replaced by more wind capacity in the Nordic countries, Ireland, and Great Britain.

In general, in the data input, there are times at which wind power output is on a high level in several wind supra regions simultaneously. Hence, in a scenario with higher geographical flexibility and high renewable targets, it is beneficial to complement wind power with some other RES, such as solar power and RES-E from biomass. This is even more the case as electricity demand across the countries is also highly positively correlated, thus off-peak electricity demand hours occur more or less simultaneously in all countries of Western Europe. While the advantage of a biomass plant is its capability of dispatching it when desirable, the advantage of solar power lies in the positive correlation with electricity demand during the day.

The amount of total RES-E curtailment in the UNLIM NTC scenario is even lower than in the scenario RES HIGH. In 2050, only about 1.5 TWh/a of wind power in Ireland has to be curtailed. With higher transport flexibility, balancing effects of RES-E output can materialize over country borders.

In general, in the UNLIM NTC scenario a lower renewable capacity is needed in order to reach the renewable quotas (see figure 6-35). This is because a higher cumulative wind capacity can be installed in countries with favourable wind conditions without needing to curtail more wind power. Thus, higher average utilization rates of renewable capacities can be achieved by a higher geographical flexibility.

The increase in geographical flexibility drastically affects the conventional supply side, as can be deducted from figure 6-35. Countries which have not adopted policies of phasing out nuclear electricity generation greatly expand their nuclear capacities, in order to export the electricity to other countries (i.e. France, Great Britain, Sweden, and Italy).

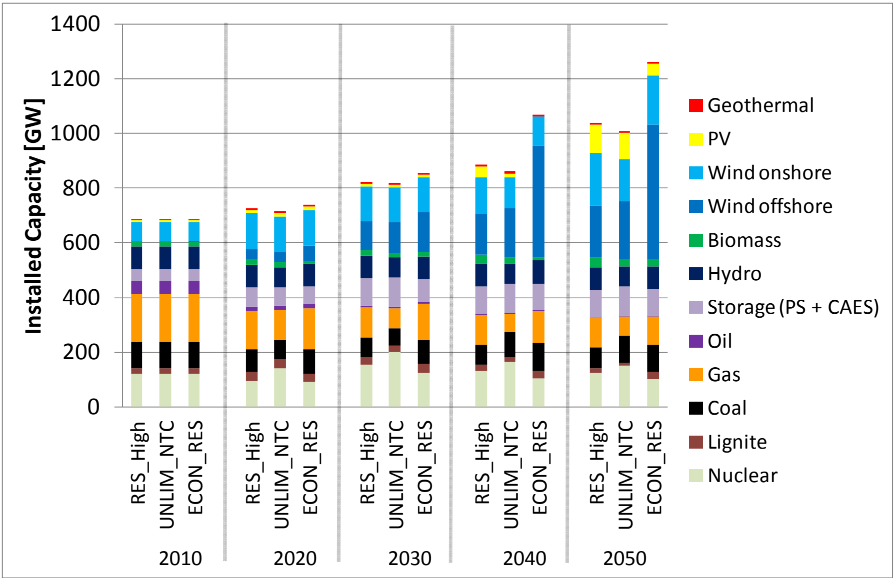

FIGURE 6-35: COMPARISON OF THE AGGREGATED CAPACITY DEVELOPMENT IN THE SCENARIOS RES HIGH, UNLIM NTC, AND PRIO RES

Source: own calculations

This can be also seen in figure 6-36, which shows the annual electricity net balance of country groups. The positive electricity net balance of the country group “Italy and the Alps” is caused by the high imports of Switzerland and Austria. On the other hand, countries, which have decided to abandon the use nuclear power in the future, find themselves with a decreasing total generation capacity over the period of consideration and an augmented positive electricity net balance. Moreover, the gas capacity can be reduced, most probably as a result of countries sharing backup capacities. Furthermore, countries with a high share of fluctuating RES-E are not exposed to output fluctuation primarily by themselves any more, but can export RES-E to other countries. The possibility to transport high amounts of electricity facilitates to store electricity at locations different from the generation of large-scale RES-E. Thus, cumulative storage capacity soars, even in countries with a low RES-E share, which store the electricity from other countries on their behalf.

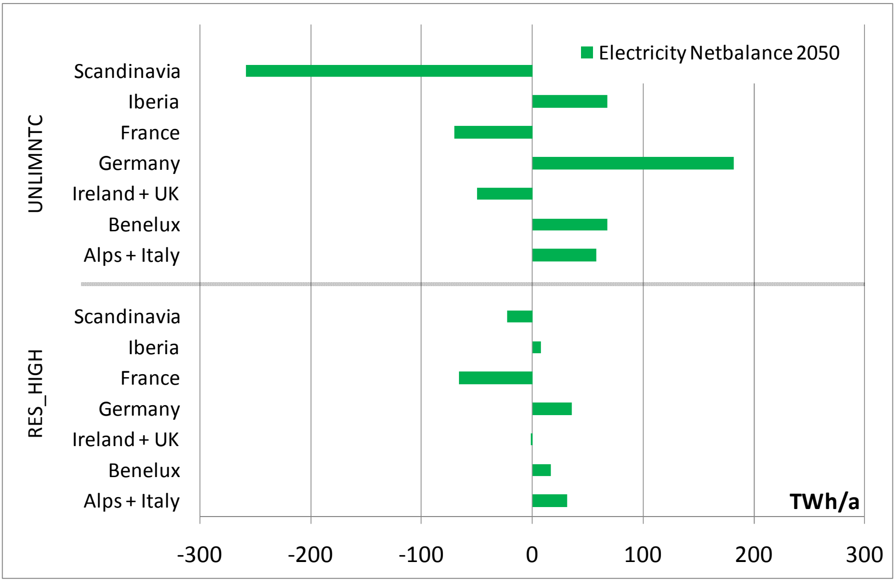

FIGURE 6-36: COMPARISON OF THE ELECTRICITY BALANCES OF THE MODEL REGIONS IN 2050 IN THE SCENARIOS RES HIGH AND UNLIM NTC

Source: own calculations

As an increased geographical flexibility implies the possibility of countries to share capacities, the utilization of especially nuclear power plants can be increased. The development of the utilization of coal and gas capacities is relatively similar in both scenarios. The utilization of lignite power plants decreases due to the higher imports by countries with high nuclear power shares.

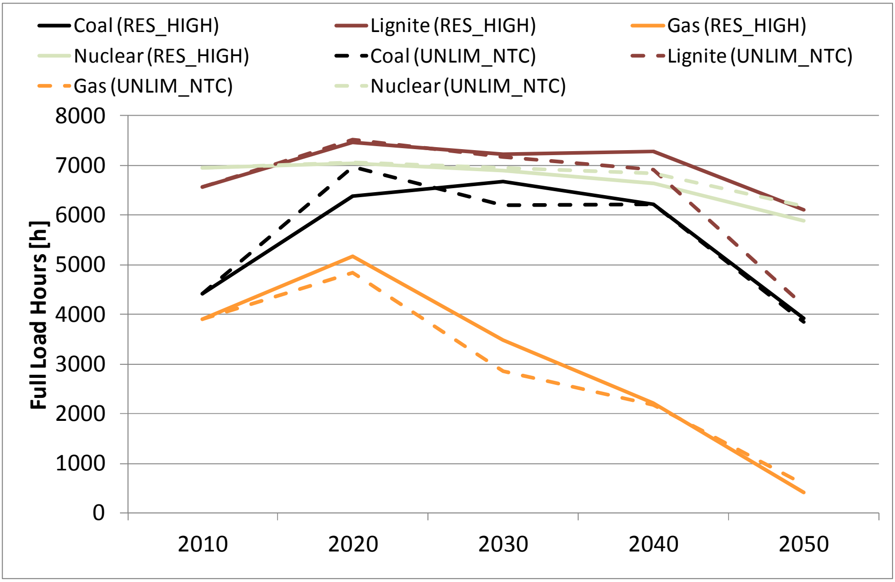

FIGURE 6-37: COMPARISON OF AVERAGE UTILIZATION OF CONVENTIONAL POWER PLANTS IN THE SCENARIOS UNLIM NTC AND RES HIGH

Source: own calculations

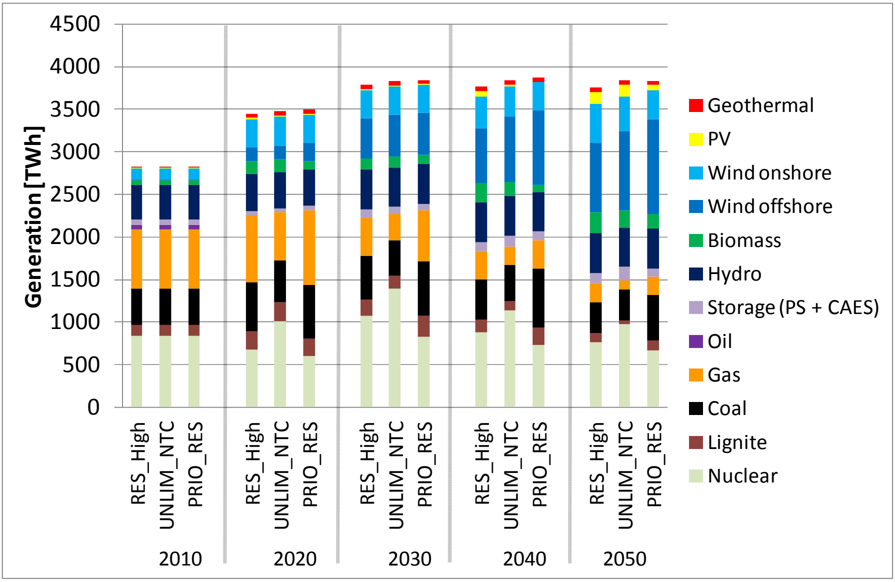

FIGURE 6-38: DEVELOPMENT OF THE AGGREGATED GROSS ELECTRICITY GENERATION SCENARIOS RES HIGH, UNLIM NTC, AND PRIO RES

Source: own calculations

Due to the drastic impacts on the conventional supply side, differential costs between the scenarios cannot be primarily ascribed to differences in renewable capacities and related consequences. Discounted differential costs between the UNLIM NTC and the base scenario RES HIGH amount to less than minus 80 billion $€_{2010}$.

Estimating, in how far this scenario is technically and politically feasible, is beyond the scope of this work. Within a certain radius, a minimum share of generation has to be provided by synchronous generators that establish the system frequency. Then, load flows might follow different ways than implied here. Thus, future research could examine how, in the optimum, NTC expansion relates to the allocation of RES-E and the residual power plant fleet.

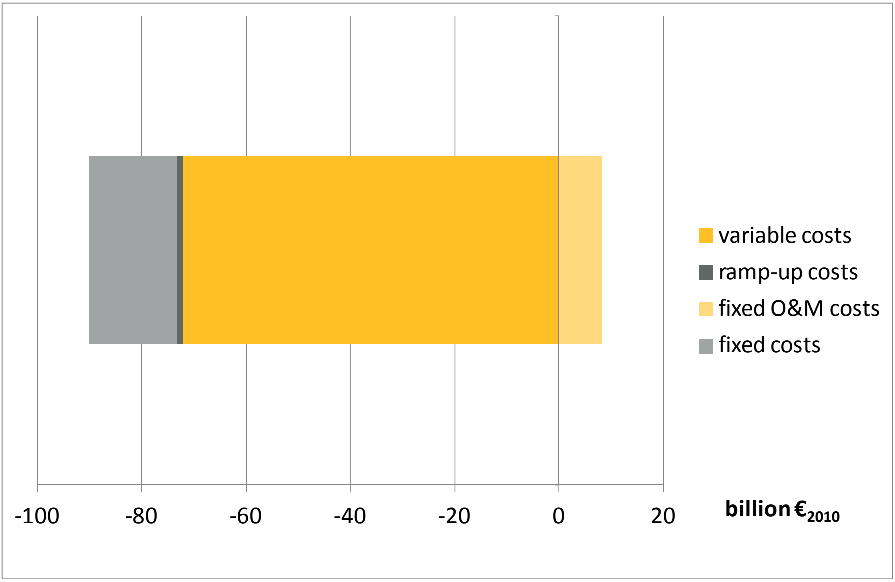

FIGURE 6-39: DIFFERENTIAL COSTS BETWEEN THE SCENARIO UNLIM NTC AND THE BASIS SCENARIO RES HIGH

Source: own calculations

Despite of the technical feasibility, also market design considerations play a role in the realization of a scenario with greater geographical flexibility and the resulting sharing of power generating capacity. Currently, the TSOs are responsible for guaranteeing the operation of the power systems on the national level (UCTE, 2009). Moreover, although a higher geographical flexibility supports the deployment of RES-E at favourable sites, it also bears a high political explosive force for the responsibility of energy politics. In an integrated European electricity market, the responsibilities blur, as e.g. the adoption of nuclear phase-out regulations would have had even more marked effects as already today. As a result, some countries would have an extremely high positive net power balance in the future, thus becoming increasingly dependent on the electricity imports of other countries. This most probably is not desired by the respective governments.

To sum up, in a scenario with greater transport flexibility, an extreme regional and technological concentration towards wind sites, especially offshore, in countries surrounding the North-Sea is also not found beneficial. This is because wind power fluctuations in the respective countries are positively correlated, and it further demands to remove massive amounts of wind output to other countries. Nonetheless, a higher geographical flexibility facilitates a higher overall wind capacity in countries with exceptionally good wind conditions (i.e. Nordic countries, Ireland, and Great Britain) than in the base scenario. In that case, Germany acts as an absorber or transit country for Nordic countries. In the UNLIM NTC scenario, balancing takes place rather between different countries than within countries. Moreover, in a scenario with higher geographical flexibility and high renewable targets, it is still beneficial to complement wind power with some other RES, in specific with solar power, in Southern European countries, but also with electricity from biomass. On the conventional supply side, an increased geographical flexibility in the first place implies the possibility of countries to share capacities. The possibility to transport high amounts of electricity facilitates to store electricity at locations different from the generation of large-scale RES-E. However, it is not claimed that this scenario is realistic with respect to the technical and political feasibility. This has to be explored in more detail in future research.

6.4 Conclusion from Scenario Analysis

In scenarios in which renewable technologies have to bid in the electricity market as other technologies do, the expansion of RES-E across regions and time is very regular and even. Although renewable technologies' levelized costs still insert a notable influence on investment decisions, the

RES expansion is further affected by the integration capability of countries. The integration capability of countries becomes more binding with high renewable quotas. While in countries with good integration capabilities, the wind potential is partly exploited (e.g. Germany, France, Belgium, Spain, and Portugal), the wind potential is left idle in countries with limited integration capability and high offshore potentials (Nordic countries, Ireland, Great Britain, the Netherlands). Moreover, for the power system as a whole, under certain conditions it is more valuable to diversify wind sites in order to smooth total wind output, than to make use only of the most favourable wind sites concentrated at one location. The conditions relate e.g. to the costs of alternative production sites.

Similar to the regional diversification, the technological diversification between different renewable technologies increases with higher renewable quotas. Besides of dampening the wind power output, technological diversification is largely induced by the increased depletion of the integration capability of countries with favourable wind resources. This is aggravated when electricity transports are restricted. Nonetheless, the bulk of RES-E is still provided by wind power. In 2050, in the RES MOD scenario, 83 per cent as a percentage of the total optimized renewable output is provided by wind power. The wind share drops to 74 per cent in the RES HIGH scenario. In return, the shares of biomass and photovoltaics increase with high renewable quotas. The already mature geothermal energy in Italy is competitive in all scenarios. While wind and biomass capacities are installed in several countries, photovoltaic roof top devices are rather built in Southern Europe from 2040 on, due to the decrease in investment costs. Direct balancing effects between solar power and wind power cannot be revealed.

In general, the level of wind power curtailment is exceptionally low in both base scenarios. Overall, in the scenarios RES MOD and RES HIGH, only 1.9 TWh/a and 18.8 TWh/a respectively of RES-E are curtailed in 2050. Thus, the installation of additional renewable capacity based on fluctuating RES at favourable sites is valuable only up to a certain threshold, until the absorption capacity of a region is reached. RES-E curtailment in single hours eases the integration of RES-E.

In a scenario with priority feed-in for RES-E with moderate renewable quotas, the regional concentration of favourable wind sites, especially offshore, is augmented, compared to a competitive market setting that applies equally for all technologies. However, due to the moderate renewable quotas, wind power is the dominating RES-E generating technology in both scenarios. The high regional concentration of wind capacities in Nordic countries, Ireland, and Great Britain, makes a high level of wind power curtailment necessary. In 2050, 28 per cent of the possible generated electricity by wind power plants, or 331 TWh/a respectively, has to be curtailed. Biogas power plants are needed only in 2050. Photovoltaic capacity is not needed at all.

In the PRIO RES scenario with high renewable targets, in the early investment periods, the regional concentration of wind power plants increases similar to the PRIO RES scenario with moderate renewable targets. From 2040 on, the regional concentration is spread to more countries. The concentration of wind sites in the PRIO RES, compared to the base scenario, amplifies in the Nordic countries, Ireland and Great Britain, and the Netherlands. The intensified regional concentration of wind power increases aggregated wind power curtailment to about 50 per cent of possible wind output, or 1,200 TWh respectively, in 2050. Even biomass, which in this scenario is not dispatched according to the demand/supply situation on the electricity market, has to be curtailed in countries with a high wind penetration. This apparently is not economical.

Furthermore, the PRIO RES scenario with high renewable targets exhibits a higher technological concentration in favour of wind power, compared to the base scenario RES HIGH. For instance, in 2050, the aggregated total wind capacity in the PRIO RES scenario exceeds the aggregated wind capacity in the RES HIGH scenario by about 1370 GW. Especially from 2040 on, the differences in the aggregated amount of offshore wind capacities between the two scenarios become tremendous. Conversely, the aggregated level of biomass and photovoltaic capacity is reduced by 10 GW and 60 GW respectively, in 2050, in the PRIO RES, relative to the RES HIGH scenario. Nonetheless, in terms of wind generation, the differences between the two scenarios are much less intense, due to the excessive amounts of wind curtailment. In general, the expansion of renewable capacities in the PRIO RES with high renewable quotas is very irregular and uneven and in some countries is lagging behind the development of the integrative approach.

Generally, a higher amount of RES-E based on fluctuating RES causes an increase in the total cumulative installed power generating capacity. On the one hand, this is due to the lower possible utilization of some renewable technologies. On the other hand, this is due to the smaller secured capacity of renewable technologies based on fluctuating RES. In the base scenarios, between 9 and 13 per cent of the aggregated conventional generation capacity can be replaced by renewable capacity based on fluctuating RES. The capacity savings are fairly higher in the RES MOD scenario. The increase in total cumulative installed capacity goes along with an increase in the share of peak-load capacity and a reduction in the utilization, in specific, of peak-load units. This is because the low variable costs of renewable technologies crowd out conventional generation by power plants with high fixed costs. Moreover, a high RES-E share demands more flexibility and backup power by the conventional power plant fleet, which is mostly supplied by gas and AA-CAES plants.

In scenarios with priority feed-in, despite of a less efficient use of wind power capacity, a diminished saving in the conventional capacity by renewable capacity result. While with moderate renewable quotas, the additional requirement is only 6 per cent compared to the aggregated capacity in the base scenario, it amounts to 22 per cent when high renewable targets are set. Concerning the aggregated power plant mix, in the PRIO RES scenarios, nuclear and biomass capacities are largely substituted by coal and lignite fired capacities. Lower nuclear capacities in the model countries are greatly determined by the excessive increase in cumulative installed wind capacity in Great Britain. A higher amount of coal capacity is caused by lower RES-E penetration in central and Southern European countries. Moreover, the abrupt and sometimes delayed RES-E development in certain countries (e.g. in the Netherlands or Germany) in the PRIO RES scenario with high renewable quotas relative to the base scenario, induce high investments in base- and mid-load capacities in early investment periods (2020 to 2030). With the inclusion of large-scale RES-E in later investment periods (2040 to 2050), the utilization of the base- and mid-load capacities is greatly reduced compared to the base scenario. Moreover, discontinuous changes of the RES-E development in the PRIO RES scenario cause increased capital turnovers due to the necessary adaptations on the conventional supply side. Thus, the timing of the large-scale inclusion of RES-E in a country decisively determines the development of the power plant mix.

As in the PRIO RES scenario with moderate renewable quotas, the inefficiencies are largely limited to the Nordic countries, Ireland, and Great Britain differences in total costs are comparatively small. This implies an increase of total discounted costs by 38 billion €$_{2010}$, or 3 per cent respectively, compared to the base scenario. Due to the increase in mentioned inefficiencies with high renewable quotas, also the discounted differential costs between the PRIO RES and the base scenario are augmented. The discounted total costs in the PRIO RES scenario exceed the ones in the RES High scenario by 127 billion €$_{2010}$, or respectively by about 10 per cent.

If less temporal flexibility is available than assumed in the base scenarios, the demand for regional and technological diversification increases in an integrative modelling approach. Furthermore, the need to curtail RES-E increases only to a limited extent. Compared to the RES HIGH scenario, RES-E curtailment is increased by approximately 35 per cent, or 6.5 TWh/a respectively, in 2050. In general, in the integrative modelling approach, the option to reallocate RES-E with respect to location or technology is mostly preferred in terms of total power generating system costs than to curtail excessive RES-E amounts. The limits on the temporal flexibility in the PRIO RES scenario with high renewable quotas require additionally to curtail about 40 TWh/a of aggregated wind power in 2050.

In a scenario with limited storage capacity available, capacity input is traded off against fuel input in the production process. Moreover, the decrease in storage capacity mainly induces an increase in gas capacity. Thus, storage capacity directly competes with gas capacity in the peak-load interval. The minimum breakeven full load hours, at which it pays off to invest in AA-CAES instead of OCGT units, amount to 275 hours in 2050. Mostly, the utilization of AA-CAES capacities exceeds 700 h/a from 2030 on. AA-CAES capacities benefit from more extreme and more frequent price spreads. Although price spikes usually tend to increase with higher fluctuating output, in extreme situations, they might even be reduced again. This is, for instance if the whole conventional power generation portfolio consists entirely of gas capacities. In that case the scope for price fluctuations is diminished because of more uniform generation costs. Given the significant increase of gas and CO_2 prices over time, the large-scale deployment of AA-CAES capacities saves 14 billion $€_{2010}$ discounted to 2010 and accumulated over the whole period 2010 to 2050.

In a scenario with greater transport flexibility and a competitive market setting for all technologies, an extreme regional and technological concentration towards wind sites, especially offshore, in countries surrounding the North-Sea is also not found beneficial. This is because wind power fluctuations in the respective countries are positively correlated, and it further demands to remove massive amounts of wind output to other countries. Nonetheless, a higher geographical flexibility facilitates a higher overall wind capacity in countries with exceptionally good wind conditions (i.e. Nordic countries, Ireland, and Great Britain) than in the base scenario. In that case, e.g. Germany acts as an absorber or transit country for Nordic countries. In the UNLIM NTC scenario, RES-E balancing takes place rather between different countries than within countries.

Moreover, in a scenario with higher geographical flexibility and high renewable targets, it is still beneficial to complement wind power with some other RES, such as solar power in Southern Europe and RES-E from biomass. With higher transport flexibility, balancing effects of RES-E output can materialize over country borders. Thus, the amount of total RES-E curtailment in the UNLIM NTC scenario is even lower than in the scenario RES HIGH. In 2050, only about 1.5 TWh/a of wind power in Ireland has to be curtailed. On the conventional supply side, an increased geographical flexibility, in the first place implies the possibility of countries to share capacities.

7 CONCLUSION, IMPLICATIONS AND RECOMMENDATIONS FOR FURTHER RESEARCH

7.1 Conclusion

In this dissertation, scenarios for a cost-efficient expansion of large-scale RES-E in Europe with particular emphasis on diurnal and seasonal patterns of RES have been calculated. These scenarios can be interpreted as a competitive market setting for conventional as well as for renewable technologies. All technologies have to bid into the electricity markets. This situation is modelled by an integrated modelling approach. Since uncertainty is not considered, the scenarios further approximate a situation of intra-day markets, in which power trade takes place nearly real-time.

Moreover, the inefficiencies associated with a priority feed-in and a decoupling from electricity price signals for renewable technologies are quantified and analysed. The incentives induce an RES-E expansion, irrespective of electricity market conditions. The residual power plant fleet then has to adapt to the development of RES-E. This situation has been modelled by a sequential model approach.

Certainly, separate developments of renewable and conventional technologies entail several inefficiencies. The inefficiencies increase with higher RES-E penetrations. In a situation of a European harmonized quota system with a priority feed-in and a decoupling from electricity price signals for renewable technologies, the technological and regional concentration of RES is augmented, compared to a competitive market setting.

The high regional concentration of wind capacities in Nordic countries, Ireland, and Great Britain, makes huge amounts of wind power curtailment necessary. However, for the power system as a whole, under certain conditions it is more valuable to diversify wind sites, in order to smooth total wind output than to make use only of the most favourable wind sites concentrated at one location. This applies to inter- and intra-country balancing of RES-E. The latter is more relevant with transmission constraints between countries.

The installation of additional renewable capacity, based on fluctuating RES, is valuable only up to a certain threshold, until the absorption capacity of a region is reached. Thus, the integration capability of countries– determined by the market size, the interconnectedness and other flexibility options in the power systems – is an important influencing factor for the optimal RES-E expansion in Europe.

Although, in an optimal RES-E expansion, wind power with its relatively low levelized costs is the dominating technology, for the power system as a whole it is beneficial to complement distributed wind power capacities by dispatchable biomass plants. RES-E by photovoltaics is not economic until 2040. From 2040 on, a large-scale expansion of photovoltaic roof-top devices in Southern Europe is advantageous for a cost-efficient European renewable target fulfilment.

However, the inefficiencies due to a priority feed-in and a decoupling from electricity price signals for renewable technologies are not limited on the expansion and allocation of renewable technologies. First, there is a requirement to provide additional aggregated capacity. Moreover, the abrupt and sometimes delayed RES-E development in certain countries induces an increase in base- and mid-load capacity in earlier investment periods. With the sudden inclusion of large-scale RES-E in the respective countries in later investment periods, the utilization of these technologies is greatly reduced. The inefficiencies with respect to the discontinuous changes of the RES-E development are further reflected in an increased capital turnover within the conventional power plant fleet.

The accumulated inefficiency over the period 2010 to 2050 for a RES-E share of 60 per cent at the electricity demand in Western Europe, which results from a priority feed-in and a decoupling from electricity price signals for renewable technologies, can be quantified to 127 billion €$_{2010}$. This signifies a 10 per cent increase in total power generation system costs to achieve the defined renewable target.

Regarding the harmonization gains calculated by Fürsch et al. (2010), it cannot be assessed whether these would be increased or decreased as a result of abandoning the priority feed- in for renewable technologies. There are two counteractive effects. On the one hand, it could be concluded that the harmonization effects tend to be increased since a scenario without priority feed-in for RES-E is more cost-efficient than a scenario with priority feed-in. On the other hand, some costs have not been quantified in the study by Fürsch et al. (2010). For instance, the amounts of wind curtailment have not been accounted for in the renewable target fulfilment. Thus, in the study, actually less RES-E is produced in the HQS-scenario, compared to a national approach. Moreover, the results of an optimal RES-E expansion in terms of power generation system costs already point at a more distributed RES-E allocation than implied by the HQS-scenario. Apart from that, the assumptions underlying both studies and the periods of consideration are different. Thus, the costs cannot be directly set in relation to each other.

The advantage of a European-wide harmonized support system exposing renewable technologies to electricity price signals without guaranteeing them a priority feed-in, compared to a national approach, remains: The market determines the cost-efficient allocation and expansion of RES-E on a European scale, weighting the option to reallocate RES-E at less favourable sites against the option of an increased integration burden for concentrated RES-E at favourable sites. Thereby, existing geographical and temporal inflexibilities are accounted for.

As demonstrated in the scenario analysis, geographical and temporal flexibility in the power generation systems decrease the costs of reaching ambitious renewable targets. For instance, the large-scale deployment of AA-CAES capacities saves, accumulated over the period 2010 to 2050, 14 billion €$_{2010}$, discounted to 2010. In contrast to DeCarolis and Keith (2006), the scenario analysis indicated that AA-CAES is cost-competitive, given the assumptions on investment costs, fuel- and CO_2 prices, as well as regarding the renewable quotas. Nevertheless, valuable temporal flexibility might also be provided by other storage options, such as electric mobility or demand-side-management.

In line with Neuhoff et al. (2008), it is found that the distribution of wind power changes, compared to a setting with unconstrained electricity transmission possibilities. Although a higher geographical flexibility supports a distribution of wind power at relatively favourable sites, an extreme regional concentration is, however, not found beneficial. This is because wind power fluctuations in the respective countries are positively correlated and it further demands to remove massive amounts of wind output to other countries. Moreover, even on a European scale with ample transmission possibilities, a certain renewable technological diversification is advantageous. Nonetheless, a greater geographical flexibility does not only mean a more efficient fulfilment of the renewable targets, but also a more efficient supply of electricity by conventional technologies, due to the opportunity to share capacities. A higher interconnectedness between countries saves, accumulated over the period 2010 to 2050, more than 80 billion $€_{2010}$ power generation system costs, discounted to 2010.

7.2 Implications for Policy Makers

For policy makers the results imply that, in particular with ambitious renewable targets, the use of a priority feed-in and a decoupling from electricity price signals for renewable technologies produces high inefficiencies. These do not take place only on an international but also on a national level. For instance, in the case of Germany, a high concentration of wind power plants in the North of the country has been the consequence. If renewable generators are not subject to electricity market conditions, they do not have an incentive to smooth output[66] and to produce or curtail RES-E when needed. The latter can lead to other inefficiencies related to the inflexibility of conventional technologies, which,

[66] The incentive to distribute wind farms would be even higher if renewable generators or generators, in general, are subject to nodal-pricing, in which locational price signals are set.

however, have not been sufficiently accounted for in this analysis. This is, at certain occasions, electricity producers are willing to receive even negative prices for electricity in order to save costs associated with ramping-up and -down operations. If renewable operators do not have an incentive to react to (negative) electricity prices, inefficient dispatching and investment decisions will be made.

Policy makers of countries, which have adopted RES-E support schemes designed with a priority feed-in guarantee and a decoupling from electricity price signals for RES-E, such as e.g. frequent feed-in tariffs, should rather progressively introduce renewable technologies into the competition of electricity markets. RES-E support schemes, such as premium and quota systems, are suitable for this objective.

In the case of a technology-neutral RES-E support system, the results still indicate that a certain technological diversification would take place, though not necessarily in the earlier investment periods. Nonetheless, the technological diversification in most countries is limited on wind power and power from biomass. Leaving the argument of “learning-by-doing” or “experience curves” aside, whose validity is not yet proven, only countries in Southern Europe should produce RES-E by photovoltaics. However, it is not cost-efficient to produce large-scale RES-E from photovoltaic plants instantly, but it is advised to wait until investment costs have decreased sufficiently. Until then, a part of the money saved from the support of RES-E by photovoltaics could be employed for fundamental research.

The progressive introduction of renewable technologies into competitive electricity markets also brings along that market designs will have to change. For instance, intra-day markets give renewable generators a greater certainty about their production schedule, as the prediction of output based on fluctuating RES increases with a smaller forecast horizon. If mainly day-ahead electricity markets are in place, renewable generators have to assume a great market risk concerning deviations from their planned production schedule and thus have to pay high imbalance costs. Furthermore, though not directly conditional on exposing renewable technologies to competition, on the conventional supply side, it might prove progressively necessary to supply backup capacity instead of energy. Whether this can be provided by the incentives in the "energy-only" electricity markets in Europe, has to be examined in further research (see below). Furthermore, new services will emerge, due to the introduction of competition for renewable technologies. For instance, it will be beneficial to use intermediaries that pool a larger number of wind farms and market them on the owners' behalf as forecasts of wind output can be improved by pooling, due to balancing effects. How exactly market design has to change and what kind of new services might need to evolve in order to ease the exposure of renewable technologies to market risk, will have to be examined in further research (see below). However, in the face of ambitious renewable targets, it is progressively necessary to set incentives for an efficient integration of RES-E.

Besides of introducing renewable technologies into the competition of electricity markets it will be necessary to move from a national to an international, European-wide support scheme in order to increase cost-efficiency in reaching defined European renewable targets.

7.3 Recommendations for Further Research

Concerning the modelling of the typedays for wind and solar power, some aspects have not been accounted for. First, the spatial correlation of wind speeds within wind supra regions has been neglected. Thus, when accounting for the spatial correlation within supra regions, it is interesting, how much additional wind capacity can be integrated into the countries surrounding the North-Sea, without sacrificing excessive amounts of wind output. Furthermore, variations of solar power have not been considered. Hence, it is of interest, how results change when variations of solar power are incorporated into the analysis and what contribution solar power can make to the provision of secured capacity in Southern European countries. Moreover, the analysis can be extended to all countries of the EU-27-plus. Furthermore, the endogenous determination of the additional capacity requirement from the inclusion of fluctuating RES in a multi-regional, -

technological, and -period electricity market model could be refined. Regarding the consideration of additional technologies or flexibility options, CSP plants, endogenous pump-storage investments, and demand-side-management flexibility options may be included in future analysis. Then, instead of using a deterministic model approach, a stochastic model approach considers explicitly the uncertainty associated with the availability of RES at the point of time of decision making.

In the previous paragraphs, several fields of potentially interesting fields of future research have been touched already. First, how do the designs of the electricity and balancing markets need to change, in order to ease the introduction of RES-E into the competition of electricity markets? Second, are the prevailing investment incentives sufficient to provide to trigger enough backup capacity which is required with increasing RES-E penetrations? Are the incentives for future investment cost reductions of photovoltaic or other immature renewable technologies sufficient in a learning-by-research approach? If they are not, how do the results of this work change with endogenous experience curves?

Then, the study of Fürsch et al. (2010) could be extended, in order to establish harmonization gains due to the introduction of a European-wide harmonized quota system without a priority feed-in for RES-E. Finally, how does optimal grid expansion, accounting for investment and dispatch characteristics of renewable and conventional technologies, look like? What are the consequences for market designs if the geographical flexibility is enhanced (e.g. international trade of reserve services)?

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APPENDIX

In figure A-1, the annual biomass supply and curtailment in 2050 for can be seen. Moreover, Figure A-2 to A-9 show individual country results for Germany, Great Britain, the Netherlands, and Spain with respect to the development of capacity and generation for the scenario comparison MOD and the associated scenario PRIO RES.

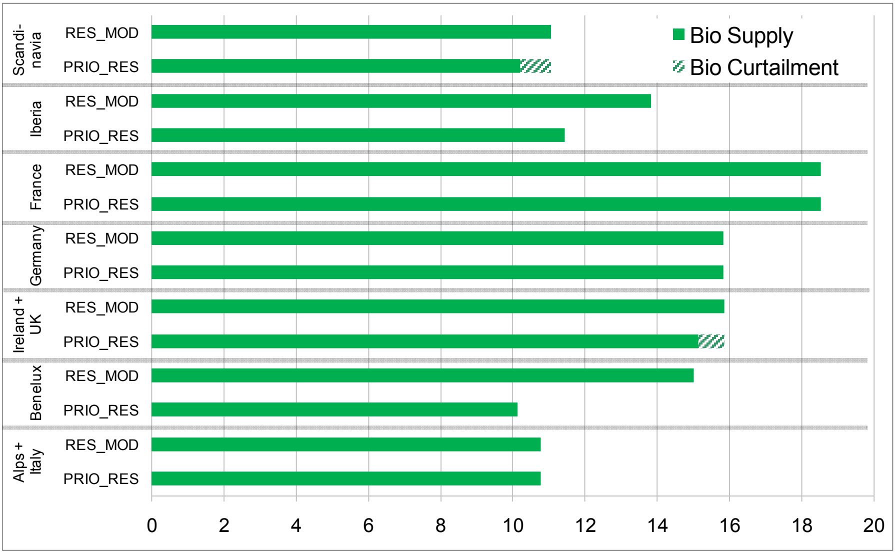

FIGURE A 1: ANNUAL BIOMASS POWER SUPPLY AND CURTAILMENT IN THE SCENARIOS RES MOD AND PRIO RES IN 2050

Source: own calculations

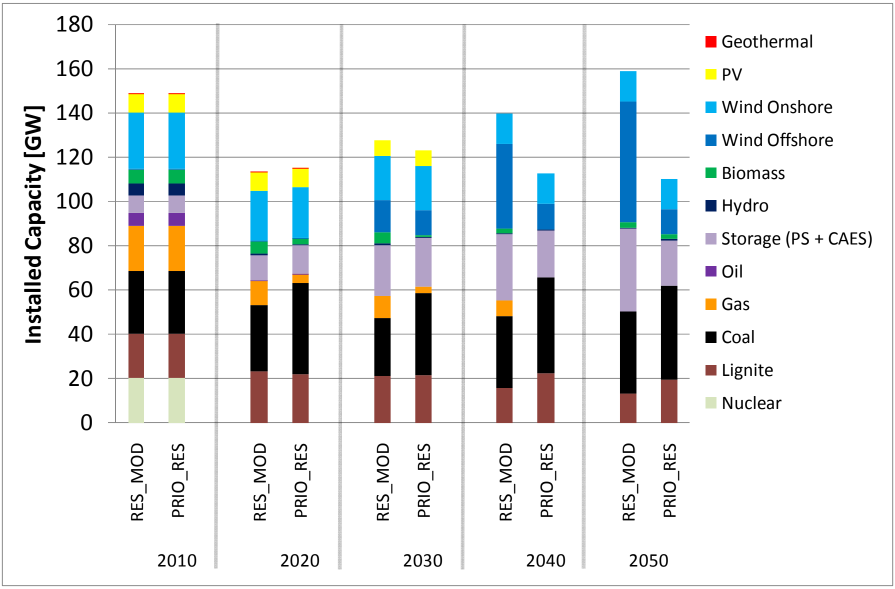

FIGURE A 2: DEVELOPMENT OF THE INSTALLED CAPACITY IN GERMANY IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

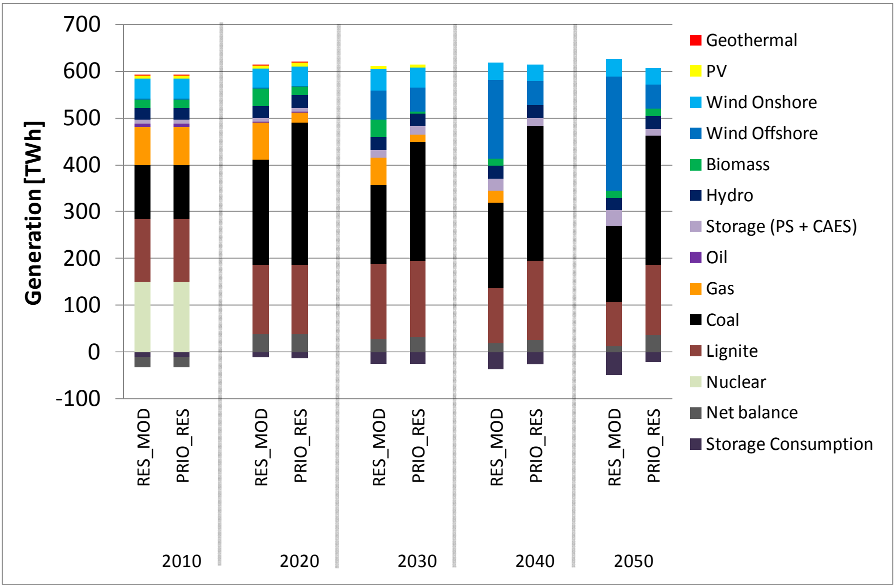

FIGURE A 3: DEVELOPMENT OF THE GROSS ELECTRICITY GENERATION IN GERMANY IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

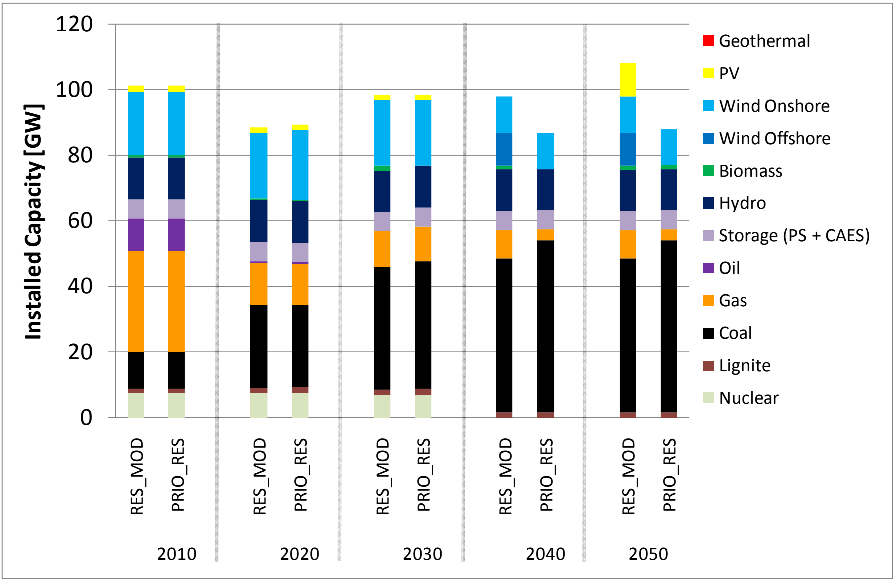

FIGURE A 4: DEVELOPMENT OF THE INSTALLED CAPACITY IN SPAIN IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

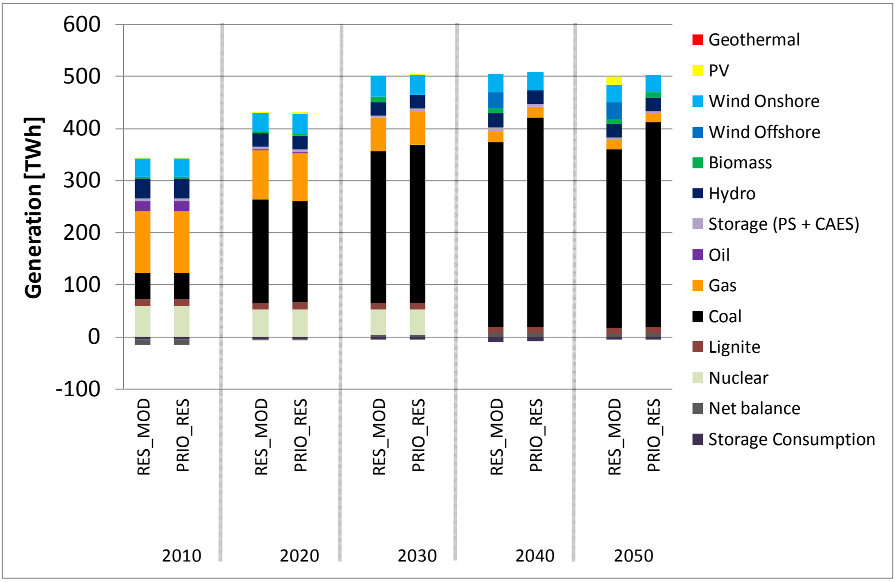

FIGURE A 5: DEVELOPMENT OF THE GROSS ELCTRICITY GENERATION IN SPAIN IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

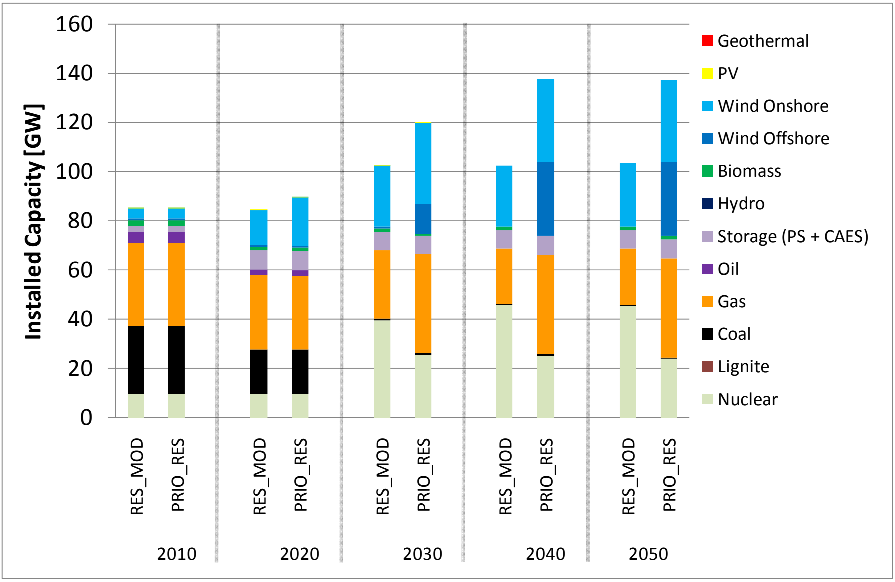

FIGURE A 6: DEVELOPMENT OF THE INSTALLED CAPACITY IN GREAT BRITAIN IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

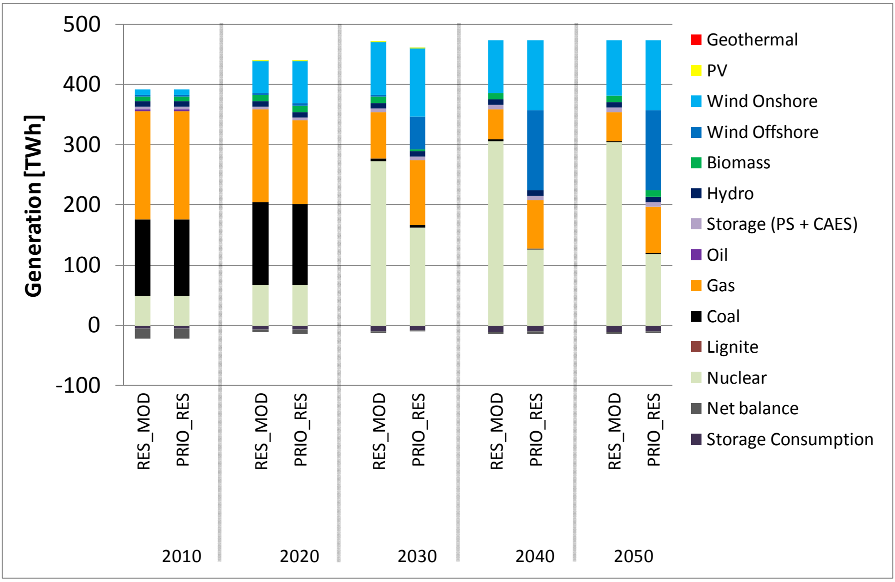

FIGURE A 7: DEVELOPMENT OF THE GROSS ELECTRICITY GENERATION IN GREAT BRITAIN IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

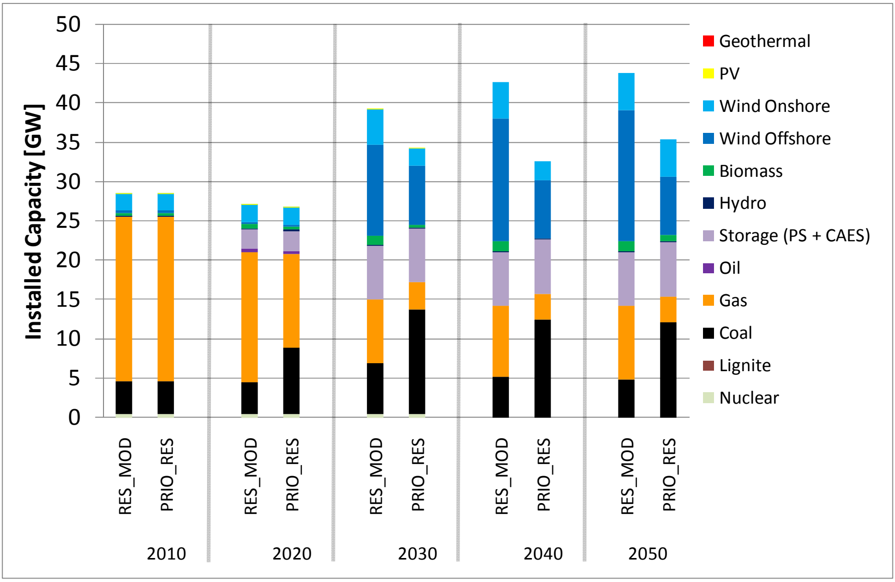

FIGURE A 8: DEVELOPMENT OF THE INSTALLED CAPACITY IN THE NETHERLANDS IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculations

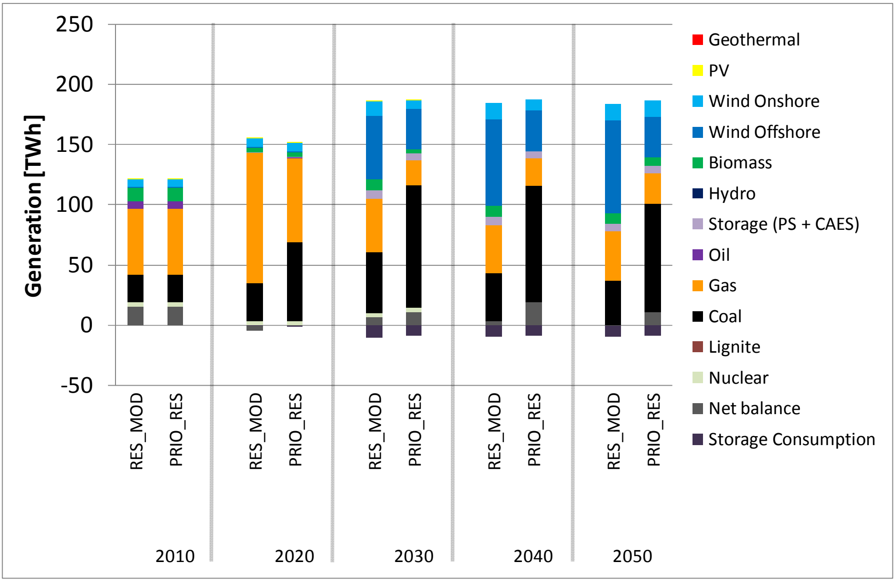

FIGURE A 9: DEVELOPMENT OF THE GROSS ELECTRICITY GENERATION IN THE NETHERLANDS IN THE SCENARIO RES MOD AND ASSOCIATED SCENARIO PRIO RES

Source: own calculation

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