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Tangible ways towards climate protection in the European Union

(EU Long-term scenarios 2050)

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Executive Summary

Scope of the study: This study investigates concrete and realizable ways towards a European electricity sector in line with the goal of keeping global warming below 2°C. It analyzes the development of the electricity sector in the EU 27, Norway and Switzerland up to the year 2050. The study is carried out by the Fraunhofer Institute for Systems and Innovation Research ISI for the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.

Focus: The study focuses on two major aspects. First of all, it provides a detailed picture of possible developments in the electricity sector with low carbon emissions and high diffusion of renewable electricity generation. The analysis is carried out on an hourly basis for three year-round meteorological datasets in order to ensure the reliability of the system. Secondly, the study analyzes the impacts of increased efficiency in electricity consumption on the required infrastructure, the structure of the electricity supply and the cost of the system. Therefore, two scenarios are developed. Scenario A "High efficiency" presumes a very ambitious reduction of electricity demand, based on the ADAM study (Jochem & Schade 2009). The second Scenario B "Moderate efficiency" is based on the electricity demand of the TRANS-CSP study (DLR 2006), projecting higher electricity consumption than in Scenario A. In both scenarios, a cap of 75 Mt is applied to the average annual CO_2 emissions in 2050, relating to a 95% reduction compared to 1990 levels. Both scenarios do not rely on additional nuclear capacity and CCS in the electricity sector, since both options are connected with substantial political, economic and technical uncertainties. In both scenarios the given CO_2 target is achieved without relying on these technologies.

Main findings: The study shows in detail that an ambitious greenhouse gas reduction can be achieved solely by high diffusion levels of renewable electricity generation of more than 90%.

A cost-efficient solution for the given task requires considerable increases in the transmission capacity of the electricity grid.

The demand for additional storage capacity is limited if the electricity grid is strong enough and renewable electricity generation is adequate for the given emission cap.

A balanced regional distribution of renewable generation leads to lower total system costs than a distribution which is based on minimization of RES-E generation costs.

Increased efforts to reach a high efficiency in electricity demand can be valuable, since lower demand reduces the cost of electricity supply considerably. This also includes less need for sometimes contested infrastructures such as power lines and electricity storage facilities.

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Glossary

(AA)-CAES	(Advanced adiabatic) compressed air energy storage
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CSP	Concentrating solar power
GIS	geographic information system
GT	Gas turbine
H2	Hydrogen
HVDC	High voltage direct current
NREAP	National Renewable Energy Action Plan
NTC	Net transfer capacity
O&M	Operation and maintenance
PHES	Pumped hydro electric storages

1 Introduction

The reduction of greenhouse gas emissions is one of the central challenges for the energy supply in Europe. The electricity sector plays an important role, since it accounts for most of the European CO_2 emissions. This study investigates concrete and realizable ways towards a European electricity sector in line with the goal of keeping global warming below 2°C. It analyzes the development of the electricity sector in the EU 27, Norway and Switzerland (EU27+2) up to the year 2050. Thereby the study focuses on a high diffusion of renewable electricity generation in order to achieve ambitious greenhouse gas reduction targets. Given this focus, the study analyzes the impacts of increased efficiency in electricity consumption on the required infrastructure, the structure of the electricity supply and the cost of the system. The study is carried out by the Fraunhofer Institute for Systems and Innovation Research (ISI) for the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.

1.1 Approach

Analysing the electricity sector in Europe as a whole is a complex task. It requires data on important parameters such as fuel prices, CO_2 prices, stock of power plants, electricity demand, renewable electricity generation and grid infrastructure. Since the balance between electricity supply and demand has to be maintained at all times, a detailed analysis of the electricity sector requires a high temporal resolution. The central task of this project is to set up an analytical framework which is suitable for the given task.

A first step to keep the analysis manageable is to set up scenarios defined by external parameters which are not modelled endogenously. Among these are electricity demand, fuel prices, CO_2 prices and the emission reduction path. Since the goal of this study is to show how ambitious reductions in greenhouse gas emissions can be achieved with high penetration of renewable electricity generation (RES-E), two scenarios are defined which achieve a reduction in CO_2 emissions to 5% of the 1990 emission levels. This setting is in line with recent publications of the European Commission, in which the electricity sector decreases its emissions to 1 to 7 % of the 1990 level (European Commission 2011b). Since both scenarios assumme ambitious climate policies which require a decarbonisation of the electricity sector, fuel prices and CO_2 prices are equal in both scenarios. As the second goal of this study is to show the impact of increased efforts on the structure of the electricity supply and the cost of the system, the main difference between the scenario parameters is the development of electricity demand which is approximately 530 TWh higher in Scenario B "Moderate efficiency" than in Scenario A "High efficiency". The development of electricity demand in both scenarios is based on existing studies. A more detailed description of the selected input parameters is given in chapter 2.

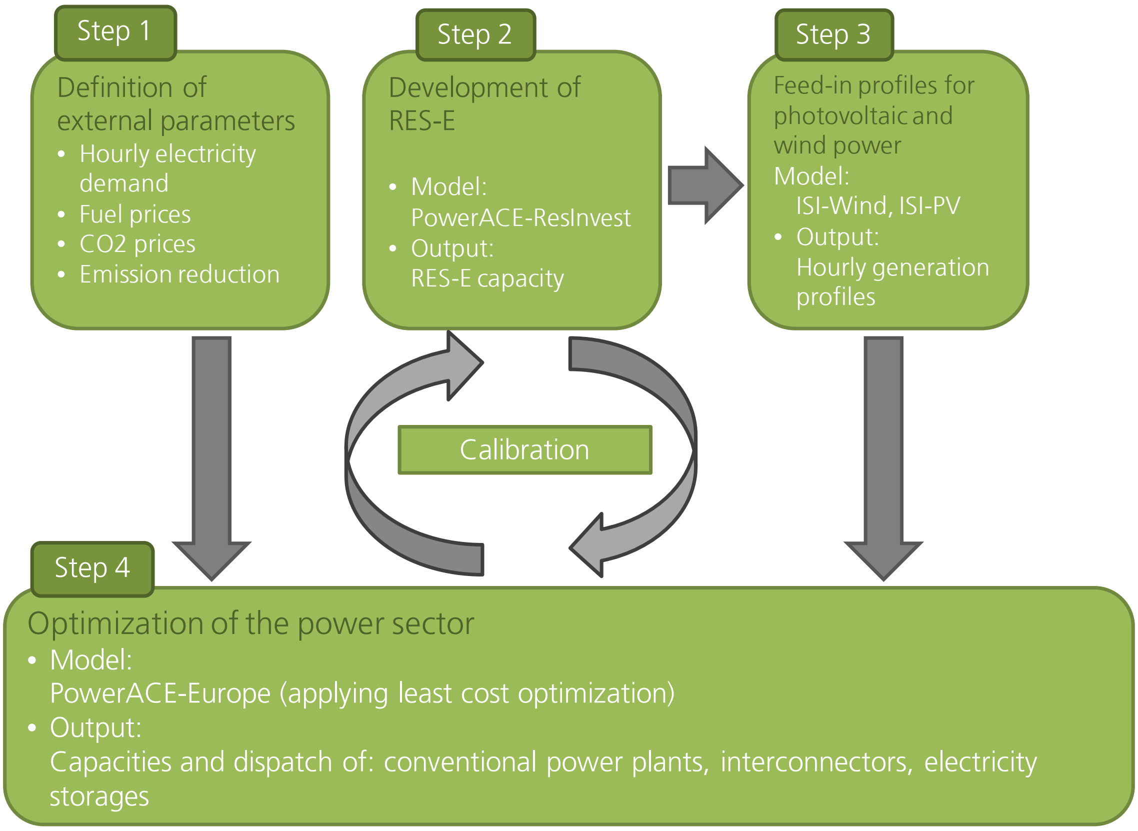
The second step in the analysis framework is to define the development of renewable electricity generation. Until 2020, the developments in terms of installed capacity and generation are based on the National Renewable Energy Action Plans (NREAPs) as published by the European Commission (European Commission 2011a). After 2020, the development is simulated by the agent-based model PowerACE-ResInvest[1]. The model calculates investments into RES-E technologies based on cost-potential curves and support polices. The model forecasts installed capacity, generation and costs for RES-E technologies until 2050. A detailed description of the model and the calibration procedure is given in chapter 3.

In order to use the model results in terms of installed capacity and renewable electricity generation the data needs to be transferred into hourly generation profiles. This step is carried out by own models for wind and PV electricity generation. In order to account for different weather conditions, three meteorological datasets are used. More details are described in chapter 4. In a last step, the optimization of the power sector takes place. Based on the described input data, the required capacity and utilization of conventional generation capacity, storage and interconnection lines is calculated. The description is given in chapter 5. The described steps of the modelling approach are depicted in Figure 1.

Chapter 6 presents the aggregate results of the modelling approach. An in-depth analysis of the matching of supply and demand in the scenarios is given in chapter 7. Chapter 8 discusses the important sensitivities of the results with regard to the underlying assumptions. The study concludes with a summary of the main findings and an outlook in chapter 9. Supplementary tables and figures on data and results can be found in the appendix.

1 For a detailed description of the model ResInvest, please refer to Held (2010).

Figure 1: Step-wise approach of the scenario modelling in this study



Source: own visualization.

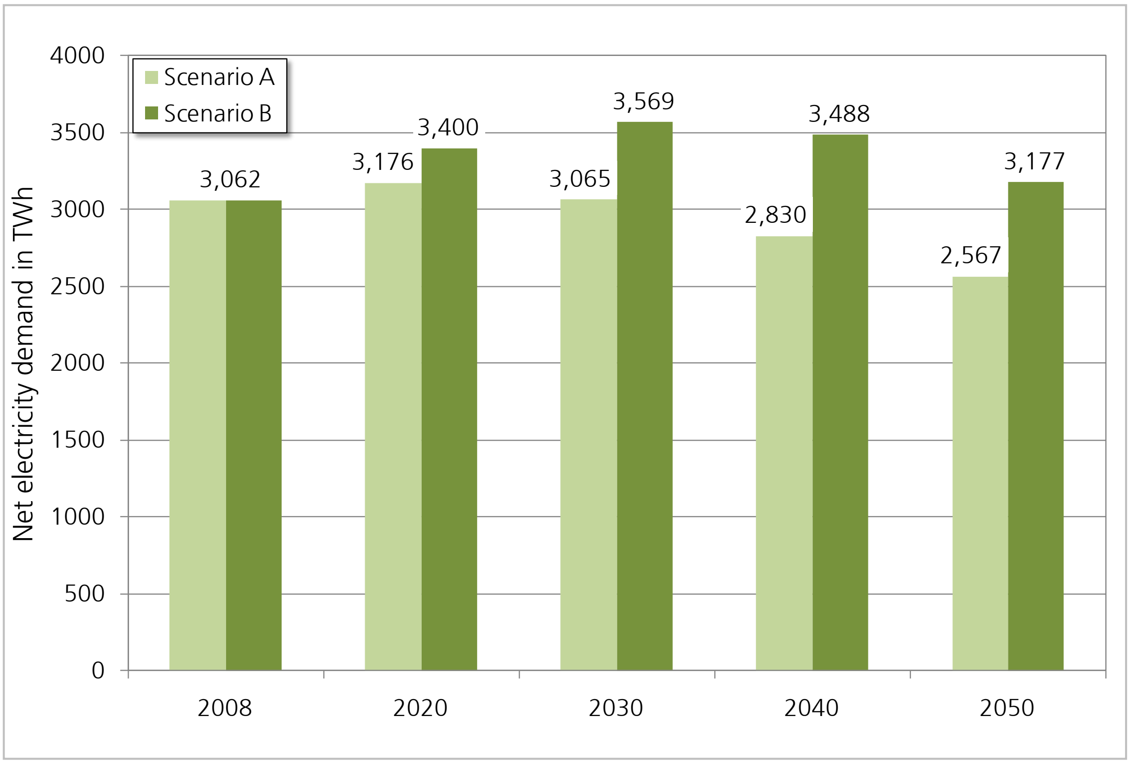
2 Definition of exogenous input parameters

This chapter defines the main input parameters applied in the scenario analysis. Among these are electricity demand, fuel prices, CO_2 prices and the CO_2 emissions levels.

2.1 Electricity demand

One central focus of this study is to show the impact of increased efficiency in electricity consumption on the cost and infrastructure of electricity supply. However, the focus of this study is not to analyze the development of electricity demand itself. Therefore, the development of electricity demand is based on existing studies. The scenarios are selected in order to represent one development with very ambitious reductions in electricity demand and one development with a moderate development of electricity demand. Scenario A "High efficiency" is based on scenario results of the project ADAM (Jochem & Schade 2009). The second Scenario B "Moderate efficiency" is based on the electricity demand of the TRANS-CSP study[2] which projects a higher development of electricity consumption. The development of aggregate electricity consumption is provided in the following figure.

Figure 2: Development of net electricity demand in the scenarios



Source: own illustration based on data from Jochem & Schade (2009) and DLR (2006).

In Scenario A continued efforts to increase efficiency lead to a reduction in electricity demand. In this scenario, the electricity demand increases slightly until 2020 and decreases continuously afterwards, reaching a level of 2,567 TWh in 2050. In Scenario B, electricity demand of the region EU27+2 continues to increase to 3,569 TWh in 2030. Thereafter electricity demand decreases to 3,117 TWh in 2050.

An important aspect for the analysis of the results in this study is the difference between both scenarios, as it is a major cause for deviations between the scenarios in other key aspects. The difference in electricity demand increases until 2040, reaching a peak of 642 TWh. Thereafter a slight decrease of the difference to 550 TWh takes place in 2050. A

2 See: DLR (2006).

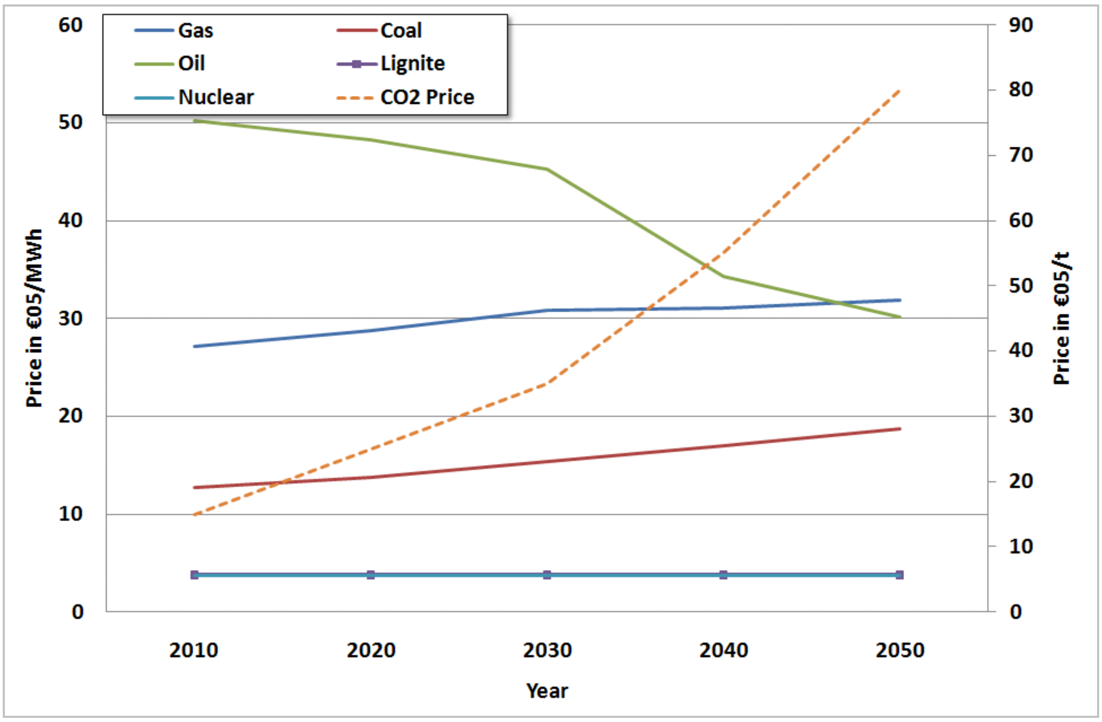
detailed table of the development of electricity demand in different countries is given in the Appendix.

Net electricity demand by itself is not sufficient to determine the required net electricity generation of the electricity sector. Since interconnector losses and storage losses are calculated endogenously within the PowerACE-Europe model, only the losses in the national grid have to be added to net electricity demand in order to provide an adequate model input. An estimation of the grid losses can be found in the literature. Targosz (2008) estimated the grid losses for EU-25 at 7.3%. Based on this estimate, grid losses for the region EU27+2 are set at 7.5% in this study.

2.2 Fuel prices and CO_2 prices

Another important input for the analysis is the development of fuel prices and CO_2 prices. In order to provide a sound dataset, the development of fuel prices and CO_2 prices is also based on the ADAM study. The development over time is shown in Figure 3. The fuel price scenario corresponds to the same scenario in the ADAM project that also provides the development of electricity demand of Scenario A. Furthermore, it is assumed that there is no major change in the prices of lignite and nuclear fuel. The moderate development of coal and gas prices and the decline in oil prices is surprising at first sight. This development can be explained by the underlying assumption in the ADAM scenario that worldwide efforts towards a strong reduction of greenhouse gas emission will take place, which has a negative impact on the demand for fossil fuels. Nevertheless, the sensitivity of the results towards changes in the assumed price developments is discussed in section 8.

Figure 3: Development of fuel prices and CO2 prices in both scenarios[3]



Source: own illustration based on Jochem & Schade (2009).

2.3 CO_2 cap

Like in the case of electricity demand and prices for fuels and emission permits, the maximum amount of carbon that can be emitted from the European power sector depends on global developments. Several organizations, most prominently the Intergovernmental Panel on Climate Change, have performed research on the impact of greenhouse gases on global temperature levels. The studies in most cases associate a certain level of greenhouse gas concentration in the atmosphere with a probability distribution for the average rise in temperature. Although the estimations are subject to uncertainty, higher levels of greenhouse gas concentrations are linked with a decreasing probability that the average rise in global temperatures stays below 2 degrees (IPCC 2007).

As this project focuses on the European electricity sector only, the question is to what extent emissions consistent with the 2° scenario may incur in the electricity sector. This

3 Please note that in the given scenarios the oil price itself is not significant for investments in new plants.

question is influenced not only by the technical potential of all sectors to decrease greenhouse gas emissions, but also strongly depends on the costs associated with the reduction. In reality, many of the reductions could be triggered by the price of emission permits. As all emitters will pay the same price, it is reasonable to assume that the marginal emittent will set the price. Consequently, the question of which degree of decarbonisation of the power sector is economical is thus linked to the developments of other sectors both in Europe and the rest of the world.

An indication is given by studies that implicitly or explicitly dealt with this issue. In the ADAM project, the electricity sector decreased its CO_2 emissions by 80 to 100% (Jochem & Schade 2009) between 2010 and 2050, depending on the applied model. The European Commission recently published a study in which the electricity sector decreases its emissions by 93 to 99 % compared to the 1990 level (European Commission 2011b). Other recent studies, for example by the German Advisory Council on the Environment (SRU) suggested that to reach the climate targets a full or almost full decarbonisation of the electricity sector is feasible and is economically reasonable. (SRU 2010). This is based on the fact that in other sectors, such as freight transport or aviation, reducing emissions to very low levels is projected to be more costly than in the electricity sector.

Due to the range of the necessary emission reductions covered by the studies, a reduction of 95% compared to the emission level in 1990 is chosen as emission cap for 2050 for this study. In line with the development of renewable electricity generation and the first results of the optimization of the power sector, the following caps are set for the emissions levels from 2020 to 2050.

Table 1: CO_2 caps for the EU 27+2 power sector applied in this study

Year	CO_2 emissions	Reduction
2020	900 Mt	-40%
2030	750 Mt	-50%
2040	300 Mt	-80%
2050	75 Mt	-95%

Source: own calculations.

3 Development of renewable electricity generation

The development of renewable electricity generation capacity until 2020 is based on the National Renewable Energy Action Plans (NREAPs) as published by the European Commission (European Commission 2011a). The development in the period 2020-2050 needs to be calculated in this study. From a methodological perspective two approaches are possible: A least cost approach and a simulation approach. The first option is to include learning rates and RES-generatio potential data into a least cost optimization of the power sector. This option has two major disadvantages. First of all it can be questioned whether such a pure least cost approach leads to a realitstic development of RES-E generation in terms of regional distribution and development of the RES-E industry. Secondly, the required computational resources are beyond the resources that are available for this project. Therefore, a simulation approach or the development of RES-generation is applied.

After 2020, the development is simulated by the model PowerACE-ResInvest (see also Held, 2010) which contains detailed data on specific investments, learning rates and generation potential for renewable technologies in Europe. It includes 14 generation technologies and more than 5,000 generation potential classes. The development of generation capacity is based on a simulation of support schemes and maximum penetration levels for wind and photovoltaic. The model also includes technological learning and a simulation of the construction capacities for the different technologies. It has to be pointed out that the simulated investments in renewable energy technologies differs from a pure least cost approach for RES-E investments. The result is a rather distributed allocation of RES-E plants over Europe.

3.1 Calibration and iteration procedure

A central task in this project is to provide an adequate diffusion scenario for renewable electricity generation for the scenarios. The model PowerACE-ResInvest is used to provide a consistent development of renewable electricity generation. In a first step, the model calculates a RES-E diffusion, that is sufficient to reach the required emission reduction in 2050. The electricity generation calculated by PowerACE-ResInvest is used as input for the electricity market model which is described in chapter 5. Basically, the model finds a least cost mix of conventional generation, electricity storage and grid to a given scenario of electricity demand and renewable generation under CO_2 emission constraints. Based on the results of both models the total cost of the electricity system are calculated. Thereafter the calibration parameters of PowerACE-ResInvest are varied and a new dataset for the renewable electricicty generation is calculated and fed into the electricity market model. The total costs of the electricity system are calcuted and compared to the previous results. After several iterations the PowerACE-ResInvest scenario is chosen that leads to the lowest total system cost.

An adequate scenario for the development of RES-E generation needs to fulfil the following criteria in order to ensure cost efficiency of the entire electricity system.

1. The total amount of RES-E generation needs to be set adequately for the given CO_2 cap.
2. The RES-E generation mix in terms of technologies and regional distribution needs to be set adequately.

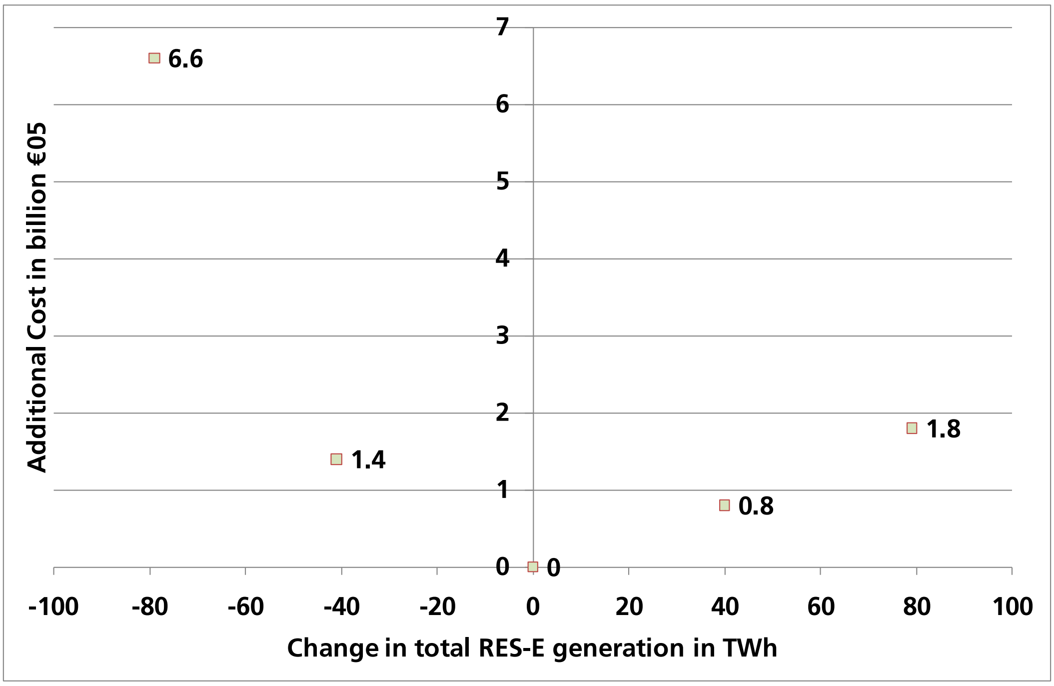
The appropriateness of the selected RES-generation scenarios with regard to the adequate amount of renewable electricity generation in 2050 is tested in the following way. The total renewable generation potential available in the power sector model in 2050 is scaled in steps of 40 (Scenario A) or 50 TWh generation potential (Scenario B) and the resulting total costs of the power sector are calculated. The change in renewable electricity generation affects the cost of the remaining electricity system. The costs for additional renewable generation[4] are estimated[5] and added to the total cost of the system. Figure 3 and Figure 4 show the results of this analysis. It can be seen that neither an increase in renewable generation nor a decrease in renewable generation leads to lower system costs. In both cases the total system cost increase if the RES-E volume deviates from the selected scenario value.

This result is caused by two competing effects. On the one hand, higher renewable electricity generation reduces the cost of the remaining supply infrastructures in a scenario with fixed CO_2 cap, since less conventional generation and interconnectors are required to meet demand within the given CO_2 cap. On the other hand, higher renewable generation is accompanied by higher costs and the additional generation capacity needs to be curtailed more often, when RES-E generation exceeds demand. This leads to situations in which the share of the additional renewable generation that is actually utilized decreases with growing installed capacity. A more detailed description of the discussed effects can be found in chapter 8. In summary this sensitivity analysis shows that the amount of RES-E generation is chosen adequately in the scenarios.

4 The renewable generation refers to the generation potential of the installed capacity and not the actual consumption, which differs due to curtailment and meteorological conditions.

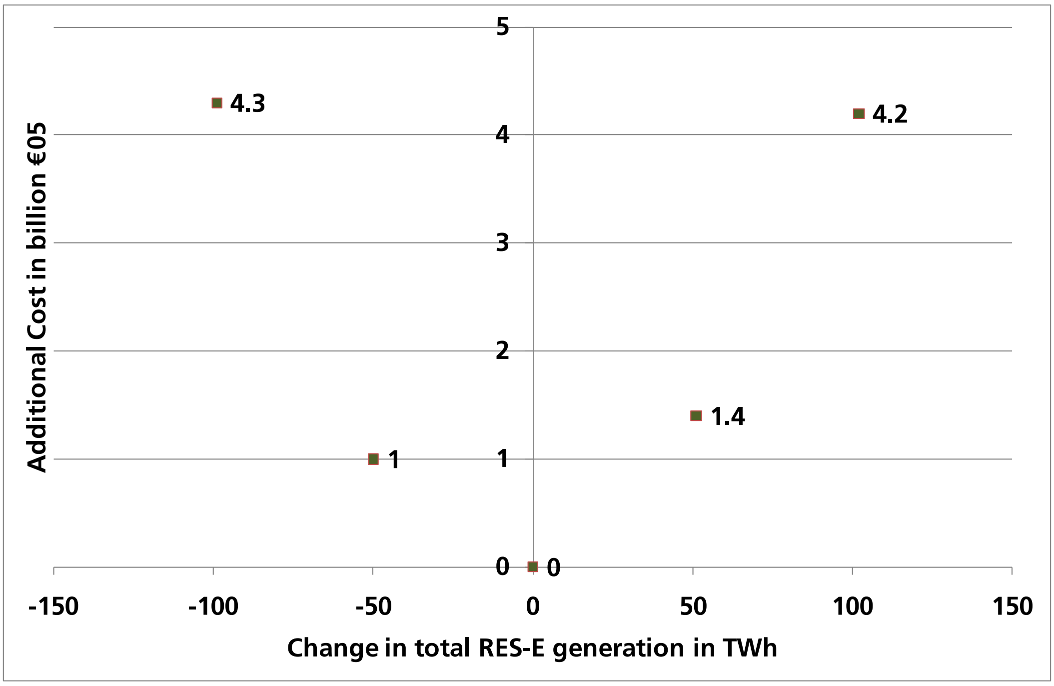
5 Estimation is based on the marginal cost and slope of the underlying renewable cost potential curves.

Figure 4: Impact of RES-E volume on total system cost (Scenario A)



Source: own calculations.

Figure 5: Impact of RES-E volume on total system cost (Scenario B)



Source: own calculations.

Besides the amount of renewable electricity generation, actual distribution of RES-E generation among technologies and regions influences the results strongly. In order to provide better assessment of the question whether the obtained renewable electricity generation is cost efficient, benchmark scenarios are calculated, applying different mixes of renewable electricity generation. Starting from the renewable generation projected by the NREAPs in 2020, a renewable electricity generation mix in 2050 is developed which is based on pure cost optimization of additional renewable generation. Such a scenario could be the result of a harmonized international quota scheme without technological differentiation, in which only the cheapest options for power generation from renewables are exploited, without considering the consequential costs in the rest of the system. These renewable generation portfolios are created for Scenarios A and B. Thereafter the total cost of the electricity system is calculated. While the costs of renewable power generation are lower in these scenarios, total system costs are higher. This is mainly caused by the regional concentration of the low-cost renewable generation potentials. Among the cheapest generation technologies is wind energy in northern Europe. Still, the regional concentration of renewable generation requires extensive infrastructure, in terms of interconnectors and storage facilities. The more balanced approach in the results of PowerACE-ResInvest also requires strong grid infrastructure for interconnectors to important regions such as the UK and the Iberian Peninsula. Nevertheless, increasing RES-E concentration leads to increasing infrastructure costs which outweigh the savings in the cost of renewable electricity generation in the tested scenarios. This is an interesting result for the debate on the harmonization of renewable support schemes.

Having tested the adequacy of the amount and mix of RES-E generation it can be concluded that the applied RES-E generation is sufficient in providing a low cost solution n the given scenario setting. In addition, it provides a sound development of renewable investments which is crucial for the stable development of the renewable energy industry.

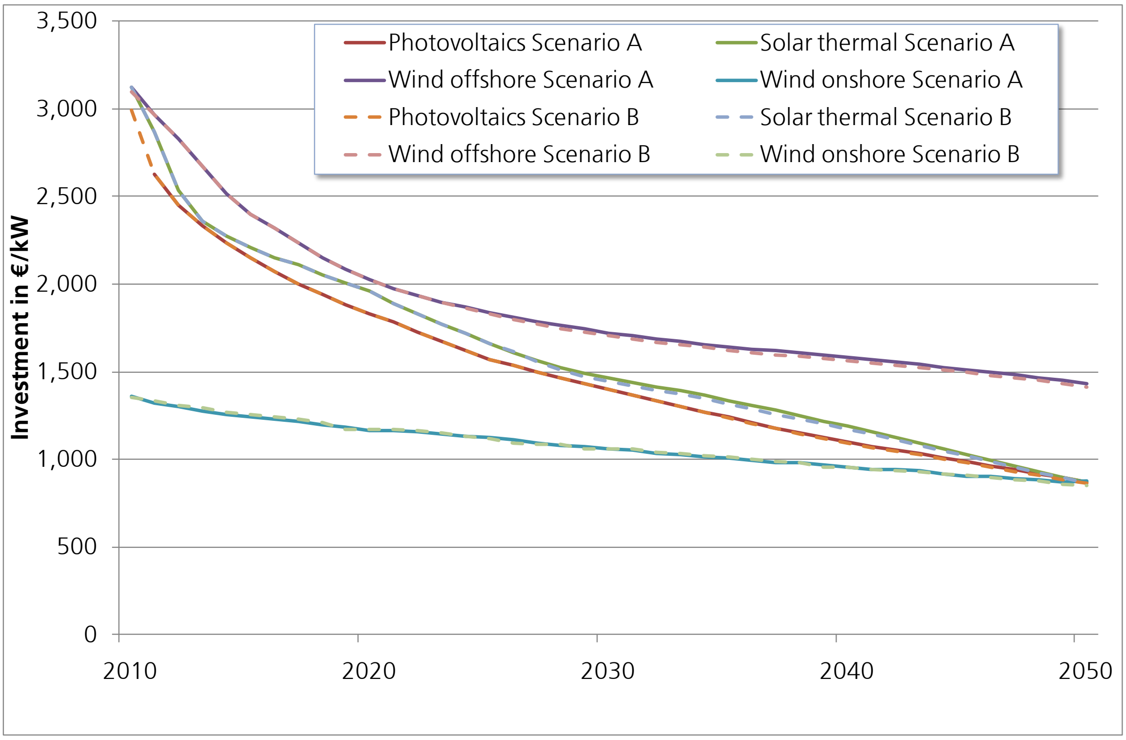
3.2 Development of specific investment costs

The technology learning algorithm leads to a reduction in the investment cost of renewable generation technologies. It depends on the overall capacity development. A comparison of the development of investment cost for the most important technologies is given in

Figure 6. All technologies show a decline in the specific investment, resulting in specific investments of less than 900 €/kW for wind onshore, photovoltaic and solar thermal in 2050. The specific investment for wind offshore decreases to below 1,500€/kW. Since both scenarios show a strong expansion of renewable energy technologies, technological learning reduces specific investments in both scenarios in a very similar way. However,

slight differences occur for wind offshore, where the stronger growth in Scenario B leads to a slightly faster decrease in generation cost.

Figure 6: Development of specific investments for important RES-E Technologies



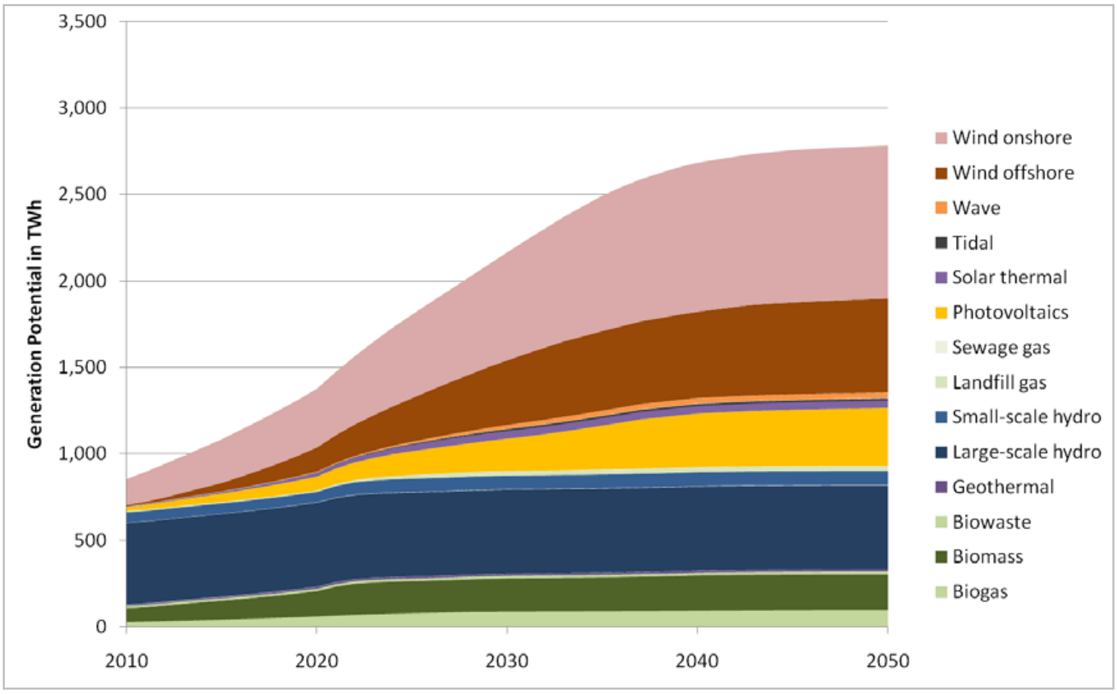
Source: own calculations.

3.3 Development of utilized renewable generation potential

The development of the utilized renewable electricity generation potential which is defined as the possible output of the installed RES-E capacity, without taking curtailment into account. The development in both scenarios is shown in Figure 7 and Figure 8. It is important to note that these figures to not show actual utilization of renewable electricity generation which can deviate because of changing meteorological datasets and curtailment of renewable generation.

In both scenarios, wind energy and photovoltaic show a strong increase in generation potential. The total generation potential of renewables grows to 2,781 TWh in Scenario A und 3,432 TWh in Scenario B.

Figure 7: Generation potential of renewables in Scenario A

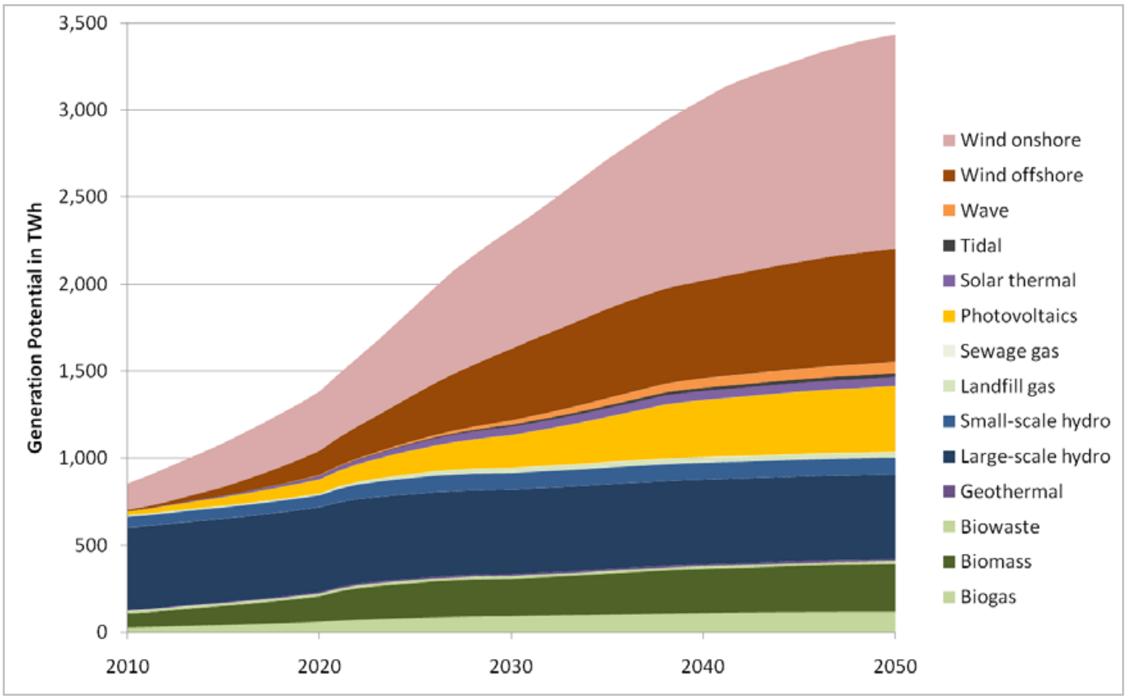


Source: own calculations.

In both scenarios, the strongest expansion in terms of additional generation potential can be observed for wind power, both onshore and offshore, increasing in Scenario A to 882 TWh and 545 TWh, respectively. Consequently, wind accounts for approximately 51% of the total generation potential in 2050. Besides wind power, PV shows the second strongest expansion with the generation potential growing by 9.1% per year on average between 2008 and 2050, thus totalling 333 TWh in 2050. Biomass and biogas increase only moderately after 2020, as the major share of the domestic potential is already used by 2020. In sum, the two technologies can produce 306 TWh per year in 2050. A similar development can be seen for hydropower. The largest part of the potential for large-scale hydro is already exploited by 2020, whereas small-scale hydropower plants below 10 MW capacity are installed moderately after 2020, especially in eastern Europe. Large-scale and small-scale hydropower reach a generation potential of 487 and 81 TWh, respectively. The generation potential of other renewable energy technologies grows steadily but rather slowly, totalling 146 TWh in 2050. Power plants using biowaste and landfill or sewage gas are mostly refurbished after 2020, but few new plants are installed. Concentrated solar power (CSP) plays a certain role in some countries in southern Europe, especially in Spain, whereas wave and tide power plants are installed in northern countries. Enhanced geothermal technologies such as “hot dry rock” are not included in the model and the generation potential of conventional geothermal technologies is limited mostly to the Alpine region. Therefore, the generation potential increases only to 12 TWh by 2050.

It should be noted that fluctuating generation from wind and photovoltaic power accounts for 63% of the total generation potential in this scenario. As it will be explained in section 5, most of the other technologies are assumed to produce a constant and inflexible output, whereas hydro, biogas and biomass are partially dispatchable.

Figure 8: Generation potential of renewables in Scenario B



Source: own calculations.

In Scenario B, the general trends are similar to the ones in Scenario A. Until 2020 the developments are identical, as in both scenarios it is assumed that the predictions in the NREAPs will be fulfilled. The scenarios differ only insignificantly for hydropower, geothermal energy, biowaste, landfill and sewage gas. Although power generation potential from wave and tide almost doubles compared to Scenario A, their role is still relatively small. The generation potentials of onshore and offshore wind power are 39% and 19% higher than in Scenario A, reaching 1,228 and 649 TWh in 2050, respectively. Wind power reaches a total generation potential of 1,876 TWh. The generation potential of photovoltaics increases moderately by 13% compared to Scenario A, whereas biogas and biomass generation increases by 20 and 33%, respectively. In sum, the share of fluctuating generation increases to 66% in Scenario B.

Although CSP, geothermal energy and wave and tide technologies play only a minor role in the scenarios, it is important to note that this study does not neglect their potential to play a larger role in the future electricity system. All of these technologies have a generation potential much larger than the one utilized in the scenarios presented here. Nonetheless, without technical breakthroughs, and at current learning rates, the technologies are in many cases not competitive with other forms of renewable energies technologies. As these breakthroughs cannot be anticipated by the model, increasing the shares of the technologies would lead to higher costs of the scenarios.

3.4 Regional distribution of renewable electricity generation

The regional distribution of the installed capacity and generation is an important result of the investment model and a central input for the modelling of the power system. As mentioned before, the renewable energy investment model uses cost-potential curves, technical parameters and restrictions and projected adaptations to the support systems to simulate the investments in renewable energy technologies.

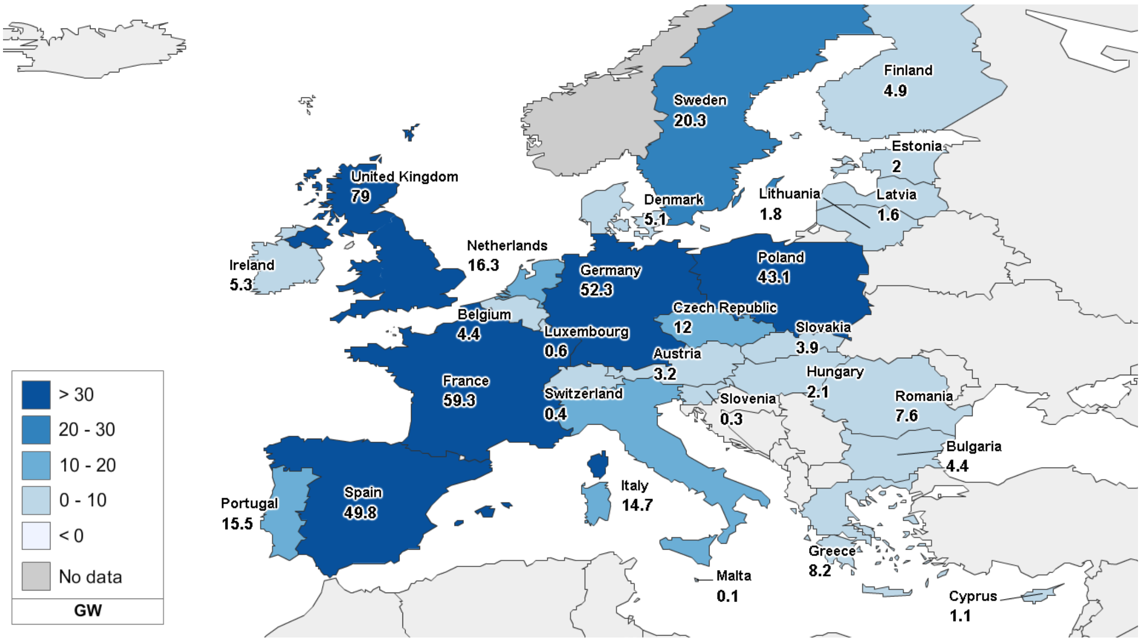
As an example, the resulting capacities installed in 2050 for wind onshore and offshore as calculated by the model are depicted in Figure 9 and Figure 10, whereas Figure 11 shows the installed PV capacities. Wind power and PV are chosen as examples, since their important role in electricity generation and their fluctuating nature act as a trigger for several developments in the scenarios discussed later on. The maps for the other technologies and for Scenario B can be found in the Appendix. Several conclusions can be drawn from the figures.

First of all, the countries adjacent to the North- and Baltic Sea as well as Spain and Portugal have high wind power capacities in absolute numbers. This is caused by favourable wind regimes, in combination with attractive support schemes. In eastern and southern Europe fewer wind parks are built by the model. Still, wind power is distributed all over Europe and although it is utilized in some countries more than in others, it plays in important role in the electricity generation of all countries.

In the case of PV, the countries surrounding the Mediterranean Sea have a strong increase in capacities. Furthermore, Germany shows a high figure in terms of installed capacity because the potential of many other technologies is already exploited to a large degree by 2050 in the scenarios. Another reason is that the model assumes that Germany continues to offer economically attractive feed-in tariffs for PV. It can been seen that the distribution of PV over Europe is less homogeneous than in the case of wind, with several northern countries having installed capacities below 500 MW.

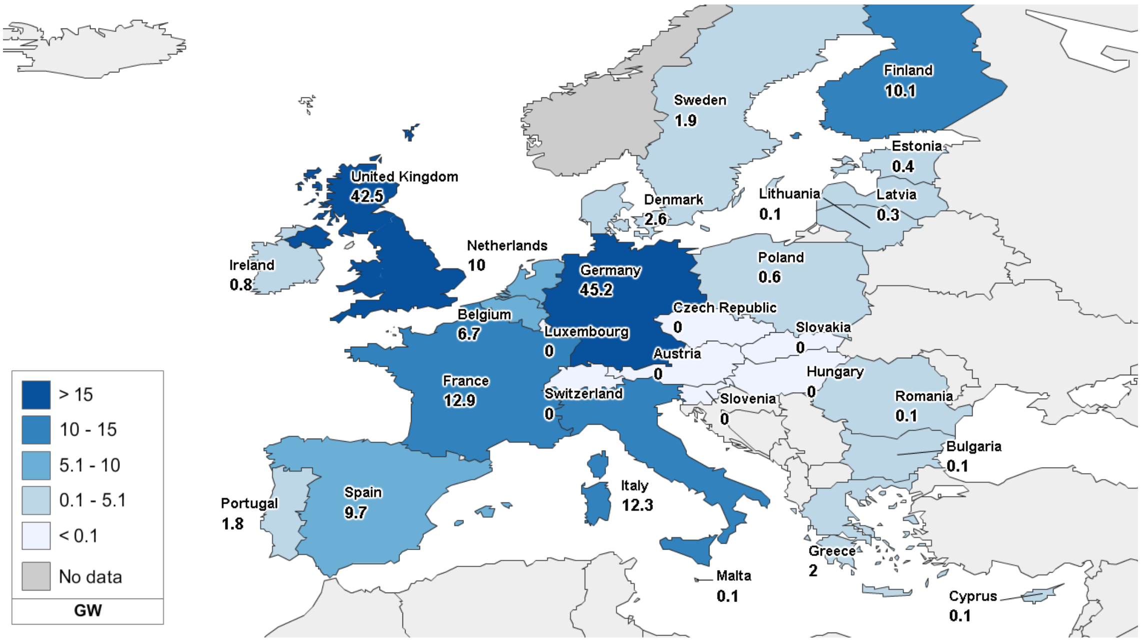
Especially for wind power, it is also important to compare the installed capacity to the maximum load occurring over the year. Several countries have an installed capacity that exceeds their highest demand in any hour. In the Czech Republic, Estonia, Latvia, the Netherlands, Poland, Portugal, Spain and the United Kingdom, the installed capacity of wind power tops the highest demand by at least 50%. This means that even without taking other forms of generation into consideration, these countries will produce excess electricity in a certain number of hours. This is can become problematic for countries like the UK and Spain that are relatively remote in a geographic sense, meaning that they have only few neighbouring countries to exchange electricity with. How these issues are handled in the model and the implications for the scenarios will be explained in section 5 and 7.

Figure 9: Regional distribution of wind onshore capacity installed in 2050 in Scenario A (in GW)



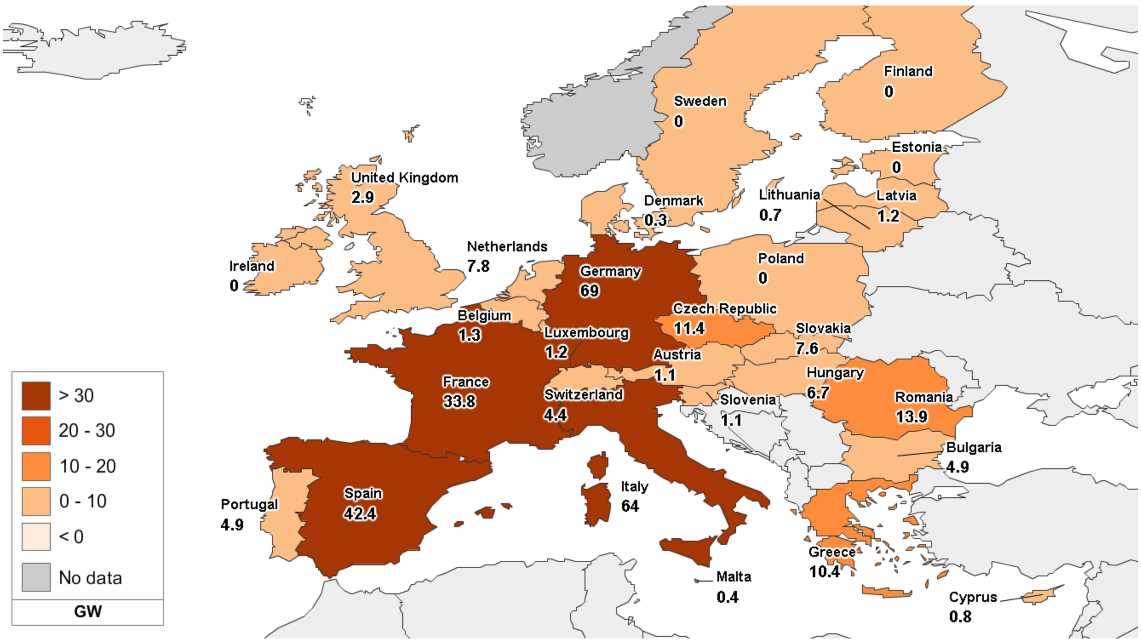
Source: own calculations, map visualization with StatPlanet.

Figure 10: Regional distribution of wind offshore capacity installed in 2050 in Scenario A (in GW)



Source: own calculations, map visualization with StatPlanet.

Figure 11: Regional distribution of PV capacity installed in 2050 in Scenario A (in GW)



Source: own calculations, map visualization with StatPlanet.

4 Feed-in profiles for photovoltaic and wind power

The previous section describes how the model ResInvest is used to generate scenarios of the development of renewables generation. The model provides annual timelines of installed capacities and generation for each technology and country. In order to utilize this data in the electricity market model PowerACE-Europe, the annual data has to be transformed into hourly feed-in profiles. For most technologies a constant production throughout the year is assumed. Geothermal, wave, tide, landfill and sewage gas, as well as concentrating solar power (CSP) plants are assumed to produce a constant output throughout the year. The impact of this simplification on the power system is rather small, as these technologies play only a minor role in the scenarios and their aggregated output is in reality relatively constant. The production from run-of-river hydropower is modelled on the basis of monthly profiles where the data is available, which is the case for most countries in the scenarios.

For the highly weather-dependent RES technologies wind and photovoltaic power, a more detailed approach has to be chosen as the generation from these technologies fluctuates strongly. For this study, real weather data of three years, 2006, 2007 and 2008 is used to transform the annual data delivered by ResInvest into hourly profiles. The main advantage of using actual weather data is that the correlation between the weather conditions in different locations is included in the data.

The profiles for photovoltaic are based on processed satellite irradiation data of SoDa Services[6]. The data points for this study are distributed with a distance of 0.5 times 0.5 degrees of longitude and latitude. In total, the data grid consists of 3,071 stations. To calculate the profiles for PV, the irradiation data is fed into a model calculating the output of PV modules. The photovoltaic conversion process is modelled on the basis of technical parameters of the modules, including module and installation type, orientation and temperature. As a simplification, it is assumed that the PV modules are distributed evenly across locations in the respective country.

The wind profiles are based on data of 3,097 weather measurement stations both on- and offshore. The data was provided by Meteomedia AG and contains data on wind speed, temperature and air pressure. The feed-in profiles are generated by modelling the output of hypothetical wind farms at the measurement site by using the meteorological data, roughness of the surrounding terrain and detailed information on the technical parame-

6 For information on the available data, please refer to: https://www.soda-is.com.

ters of the wind turbines. The wind turbine sites in use today are attributed to the nearest measurement station and their aggregated production forms the feed-in profiles. Different profiles are generated for onshore and offshore sites.

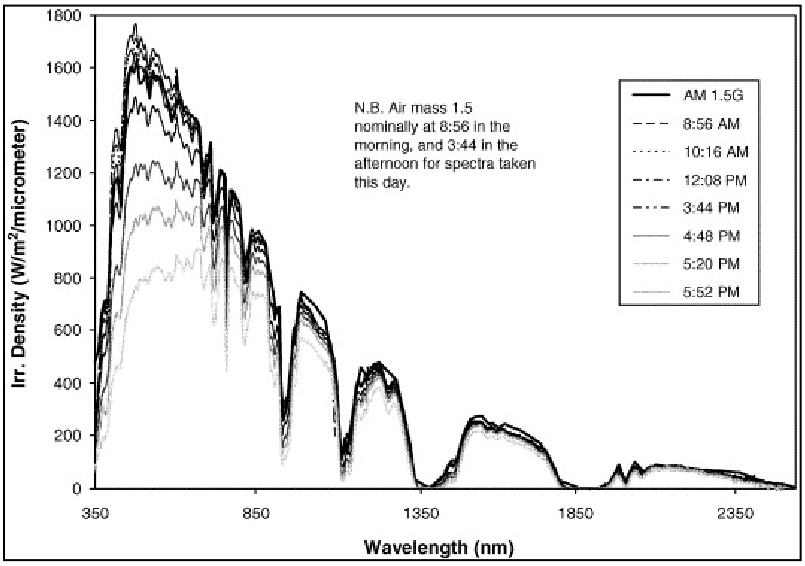
In the following section, the assumptions and methods applied in the process of generating the hourly profiles is described in greater detail, as it is a central task of the project and the overall results of the scenario simulation depend very much on the premises used in the modelling approach. It should be noted though that the description is rather specific and not mandatory for understanding the chapters thereafter.

4.1 Profiles for photovoltaic

Photovoltaic (PV) systems transform solar light into electric energy. The amount of electricity fed into the grid by a single module, a park or a country is determined by several variables, which are briefly introduced in the following.

Irradiance is the primary factor defining the generation of the module. The irradiance reaching the solar panel depends primarily on the position of sun, clouds and the orientation of the module. Furthermore, soil reflectance (albedo) and shading of the module by surrounding objects (like buildings and trees) play a role, although companies installing PV modules try to minimize the effects of the latter by appropriately siting the modules. The spectral distribution of sunlight is variable, as the wavelengths absorbed by the atmosphere depend on the position of the sun and the resulting optical path length through the atmosphere described by air mass. As shown in Figure 12 especially short wavelengths are blocked in times of high air mass and low position of the sun.

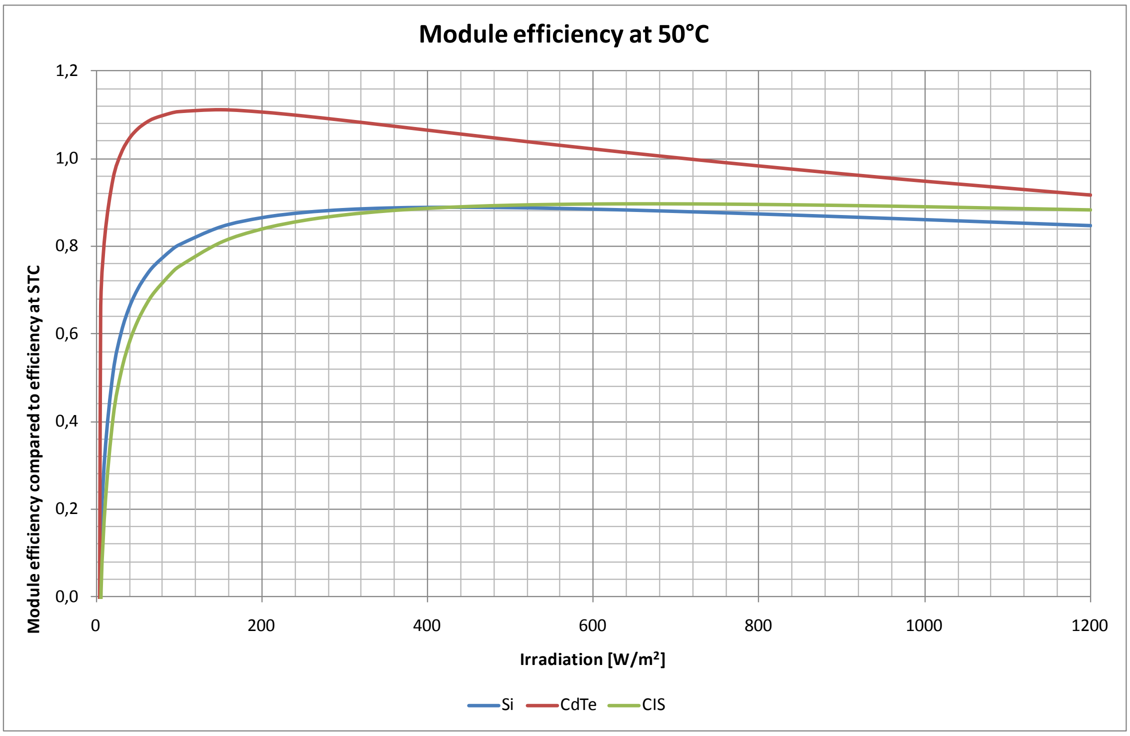
Figure 12: Spectral distribution depending on the position of the sun on a clear day



Source: Kenny et al. (2006).

The conversion efficiency of a PV module is furthermore influenced by its spectral sensitivity and tends to decrease with its age. The efficiency also strongly depends on the temperature of the module, decreasing with higher temperatures. As an example, the conversion efficiency at 50°C is depicted in Figure 13. The temperature of the module is determined by irradiation, ambient temperature, wind speed, module type and type of mounting.

Figure 13: Relative conversion efficiency of modules at 50°C compared to the same modules at standard testing conditions (25°C)



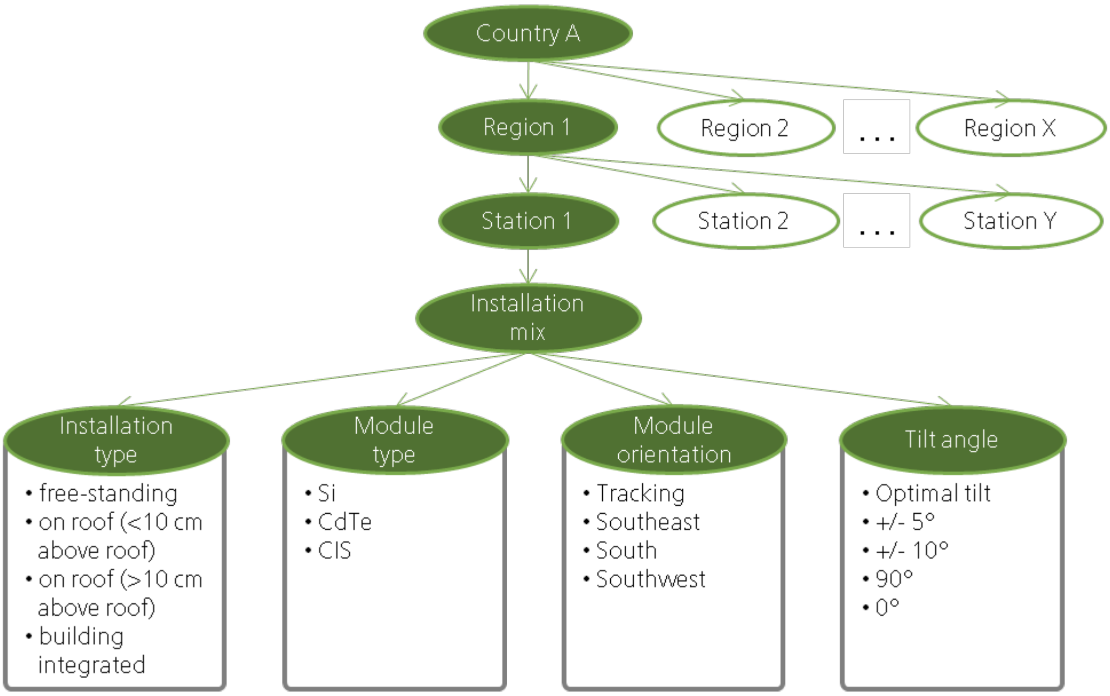
Source: own illustration based on Huld et al. (2010).

Another influential factor is the inverter loss. If a maximum power point tracker is applied, which is the case for most inverters, the efficiency is between 70% and 98%. The efficiency of the inverter is lower on cloudy days with fluctuating irradiance, when the module produces below its rated power.

4.1.1 Approach of the model ISI-PV-Europe

In order to generate the feed-in profiles of PV for the European countries, a large number of calculations have to be performed. This is done in a step-by-step approach, depicted in Figure 14

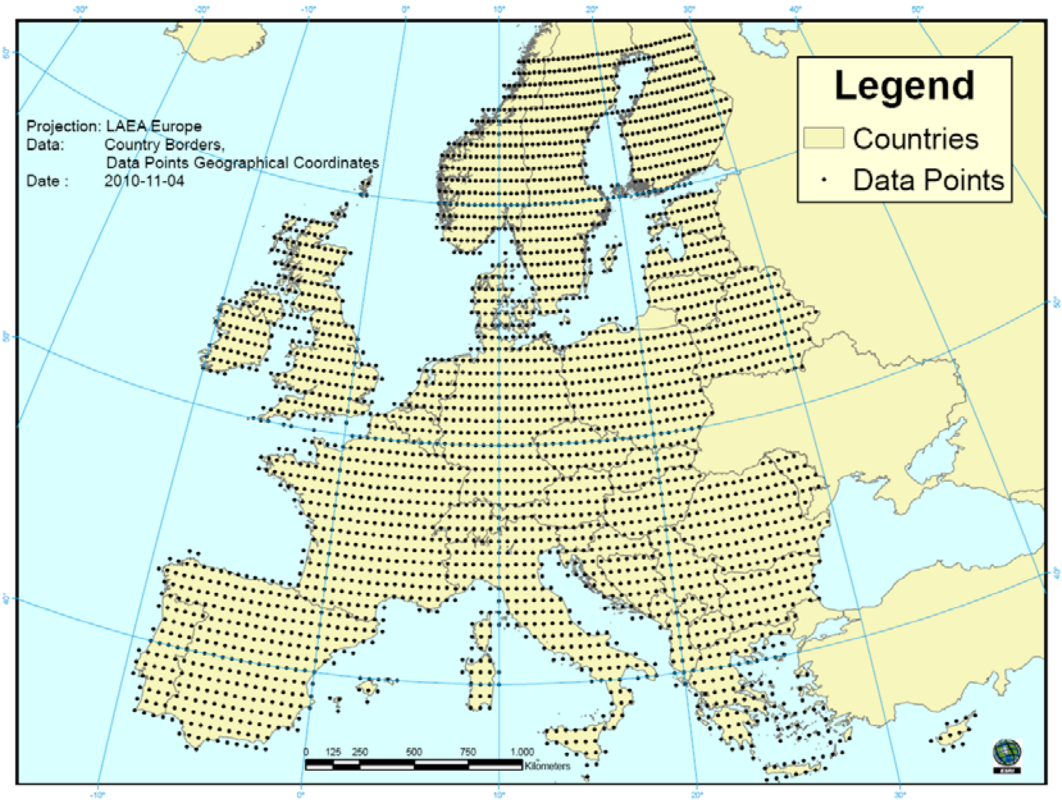
Figure 14: Simplified representation of the approach used in ISI-PV-Europe



Source: own illustration.

In the developed model ISI-PV-Europe, the countries are subdivided into regions, which consist of one or more virtual stations. Figure 15 shows the distribution of the stations in Europe. The stations are distributed with a distance of 0.5 times 0.5 degrees of longitude and latitude. This implies that one station represents an area of less than 2,500 km². A higher resolution would be possible, but would not significantly increase the accuracy of the results at country level.

Figure 15: Distribution of data points used as PV stations in ISI-PV-Europe



Source: own illustration.

The next step is to define a representative mix of solar plants for the respective region. Currently, the data basis for a realistic representation of the existing PV installation portfolios is rather weak. Only for very few countries and regions is reliable data available on which module types are utilized and how the modules are installed, e.g. on a roof or in an empty field. No data is available on actual tilt angles and module orientation (i.e. azimuth). In consequence, one representative set-up was defined for this project and used for all stations until better data becomes available. The set-up chosen and shown in Table 4 is based on existing literature. The configuration is constant in the scenarios over the years.

Table 2: Initial shares of the main variables for the installation mix of 2008

Parameter	Configuration	Share
Installation type	Open Area	6%
	On Roof >10cm	25%
	On Roof <10cm	64%
	Roof Integrated	5%
Module type	Si	94%
	CIS	2%
	CdTe	4%
Module orientation	Tracking	0%
	Southeast	20%
	South	60%
	Soutwest	20%
Tilt angle	Tracking	0%
	-10°	5%
	-5°	20%
	Opt. Angle	50%
	+5°	20%
	+10°	5%
	0°	0%
	90°	0%

Source: own illustration.

Irradiance is the central input data for the model for calculating the feed-in profiles. The data is collected by the geostationary weather satellite METEOSAT and computed with the Heliosat-2 model (see also Rigollier et al. 2004). The data is commercially available from SoDa Service. The resulting timelines are good estimates for the irradiance of the stations, but are not perfect; especially in cloudy times in winter, Heliosat-2 tends to underestimate the actual irradiance. This has to be taken into account in the model evaluation, as the required electricity production that has to be covered by other sources is overestimated, which can lead to a slight overestimation of the total cost of the system.

The sunlight reaching the module is calculated in the model on the basis of the global irradiance described above and the orientation and tilt angle of the module. In the next step, the conversion efficiency of the module is calculated as a function of the type of module and the module temperature, the calculation of the latter being based on Drews et al (2007). The module temperature itself depends on the ambient temperature (provided by the same weather stations also used in the wind model), wind speeds and the type of mounting, as a module directly on the roof tends to have higher temperatures than one on a higher mounting structure).

As shown in formula 1, the weighted average of the system power, defined by the module configuration, equals the power output of the station at a given hour.

The process described above is performed for all stations, thus forming the regional and national profiles. In the next section, the evaluation of the resulting profiles is explained.

Formula 1: Initial setup of the main variables for the installation mix of 2008

$$P_{Station}(h) = \sum_{i=1}^{i=2} \sum_{t=1}^{t=3} \sum_{s=1}^{s=4} \sum_{\gamma_E=1}^{\gamma_E=6} \sum_{\alpha_E=1}^{\alpha_E=4} x_i \cdot x_t \cdot x_s \cdot x_{\gamma_E} \cdot x_{\alpha_E} \cdot P_{System}(h, i, t, s, \gamma_E, \alpha_E, G_{Mod})$$

Legend:

$P_{Station}(h)$	Station capacity	x_s	Share of mounting type
h	Hour of the year	G_{Mod}	Irradiation on the module
i	Inverter type	γ_E	Tilt angle
x_i	Share of inverter type i	$x_{\gamma E}$	Share of tilt angle γ_E
t	Module type	α_E	Module orientation
x_t	Share of module type t	$x_{\alpha E}$	Module orientation α_E
s	Mounting type	$P_{System}(h,i,t,s,\gamma_E,\alpha_E)$	System power of the configuration

4.1.2 Model evaluation

The objective of this work package is to generate realistic feed-in profiles for the modelling work in the next work packages of the project. Therefore, the evaluation has to consider the following questions:

1. Do the model-generated profiles show the same fluctuations as real plants do?

2. Does the modelled behaviour result in the same full-load hours for the plants?

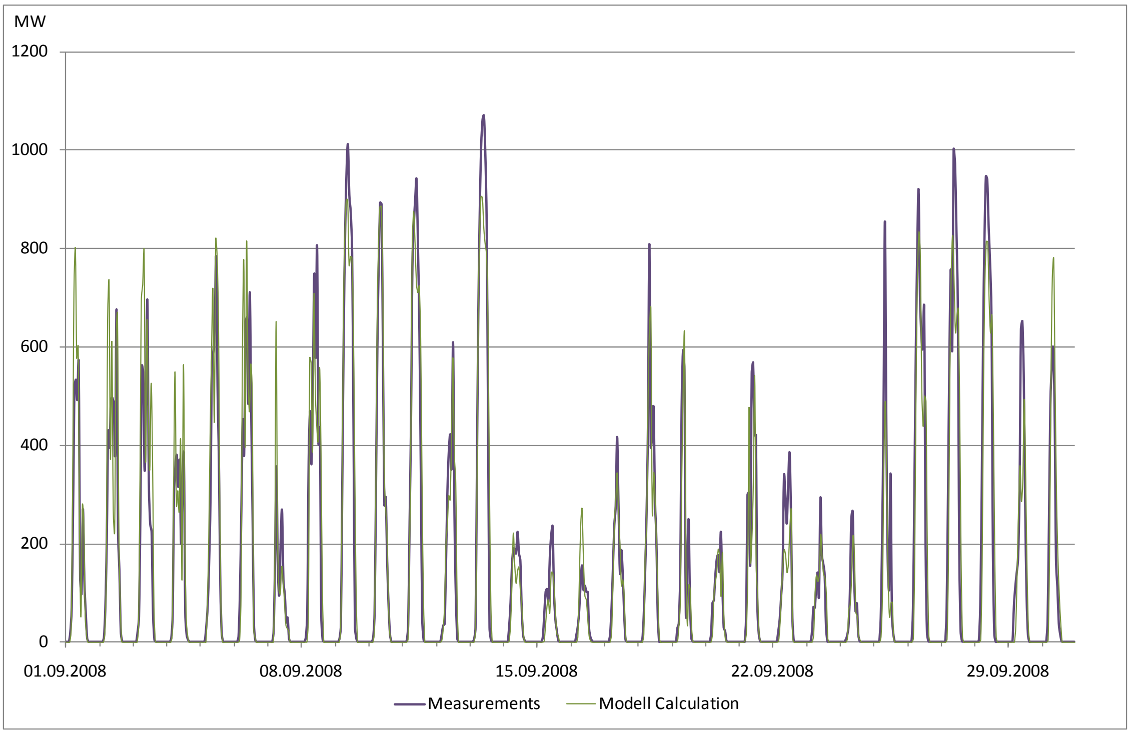
3. Is the aggregated feed-in profile compatible with data published at national level?

This means that the model has to be evaluated using time series of PV plants for benchmarking. Unfortunately, no data has been published on the aggregated behaviour of all PV plants within a country for the years 2006-2008. For Germany, the cumulated hourly feed-in profile is available, starting in July 2010. The data currently covers a time span too short to be used for evaluation purposes.

For this reason, two PV plants in Dresden, Germany were used as benchmarks. The plants consist of 6 polycrystalline modules of 220 W each and are installed in a field in a fixed angle of 35%. Surrounding trees cast shadows on the field in some months, especially in the early and late hours of the day. Data on the plants generation exist for February to November 2008. The differences between the electricity generation of both plants are insignificant.

Figure 16 shows a comparison of the measured power of one of the plants and the profile calculated with *ISI-PV-Europe* for the same location. In general, the model calculates a very accurate representation of the field, on some days missing the peak production slightly.

Figure 16: Measured and calculated generation for a 1.32 MW_p plant in Dresden in September 2008



Source: own calculation.

Table 3 shows statistical indicators for one of the fields and the model results. The differences between average power, full-load hours and cumulated power are within the range that is to be expected due to the shading of the fields, which is not incorporated in the simulation. In combination with the other observations, the very similar standard deviation shows that the fluctuations of the PV modules power are met satisfactorily. The high value of the coefficient of determination, an indicator used to measure the goodness of fit of a model, shows that ISI-PV-Europe is able to calculate the feed-in profile of single PV plants with appropriate accuracy.

Table 3: Comparison between actual results of an existing PV plant of 1.32 MW capacity in Dresden and results of ISI-PV-Europe for the same site and plant size

Indicator	Field Dresden	Model results for Dresden
Average power (kW)	150.7	161.1
Full-load hours	(~812.2)[7]	868.4
Standard deviation	264.5	279.4
Maximum power	1,118.5	1,029.0
Sum Feb - Nov 2008 (MWh)	1,160.0	1,240.3
Coefficient of determination (R^2)	-	0.866

The next part of the evaluation is to compare data at country level. The only information available for this purpose is the data on generation from solar plants published by Eurostat (Eurostat 2011). In the years 2006-2008, only Spain and Germany had enough PV capacity installed to make the data relevant for comparison. Additionally, in many other countries it seems that due to the low relevance of PV in these years the countries submitted rather rough estimates to Eurostat. The comparison for the respective years is shown in Table 4.

7 Generation data for the plant is only available for the month February – November. The full-load hours have to be estimated, the given figure represents the lower estimate.

Table 4: Comparison of data published by Eurostat and results of ISI-PV-Europe for the years 2006-2008

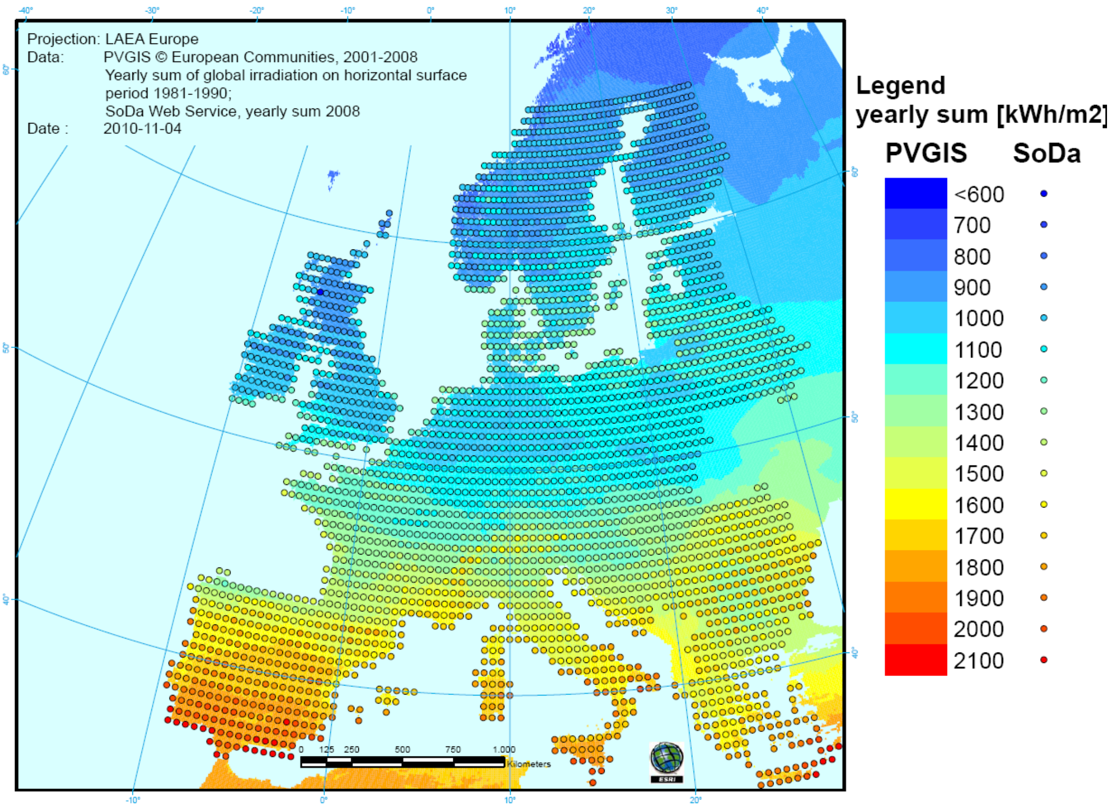
Country	Data source	Generation [MWh]			Full-load hours			Misestimation of the model [%]		
		2006	2007	2008	2006	2007	2008	2006	2007	2008
Germany	Eurostat	2220	3075	4420	1023	926	967	-	-	-
	Model results	1885	2916	3921	869	878	858	-17.8%	-5.5%	-12.7%
Spain	Eurostat	119	501	2562	1123	1102	1280	-	-	-
	Model results	129	560	2403	1215	1231	1200	+7.6%	+10.5%	-6.6%

Source: Eurostat (2010) and own calculations.

In the case of Germany, the model underestimates the published generation by 5.5% - 17.8%. The results for Spain are ambiguous, overestimating by 10.5% in 2007 and underestimating by 6.6% in the following year. One factor which could influence this comparison is the growth of generation capacity within the year. In this comparison a linear growth of capacity throughout the year is assumed. If the actual growth differs from this assumption, the results can be influenced considerably. In addition, it has to be pointed out that the origin of the data published by Eurostat could not be clarified. Since the majority of PV modules are connected to the distribution grid, distribution system operators (DSOs) are the only ones that could provide actual data on the generation. As already mentioned, DSOs have just recently started to publish this information. Therefore, the quality of the data published by Eurostat is uncertain. Further research is necessary as soon as longer time series are provided by the DSOs and a detailed calibration of the model is made possible.

Furthermore, it has to be noted that the profiles generated in this work package can only represent the generation in the respective years. Naturally, weather conditions in each year are different and differ from the perennial average. This means that generation in some regions is higher or lower than in an average year. As an example, Figure 17 illustrates that 2008 was an above-average year in terms of sunshine, especially in southern Europe.

Figure 17: Comparison of the yearly sums of global irradiation: In the background the average of the years 1981-1990, the dots show the values of 2008 provided by SoDa



Source: own illustration, based on data from PVGIS and Soda

In summary, ISI-PV-Europe shows solid results. The feed-in profiles generated by the model show the desired characteristics and are able to depict the generation satisfactorily, although it seems that some issues exist in modelling PV plants' peak behaviour. The feed-in profiles will be applied in the electricity market model PowerACE-Europe to model generation from PV plants.

4.2 Profiles for wind power

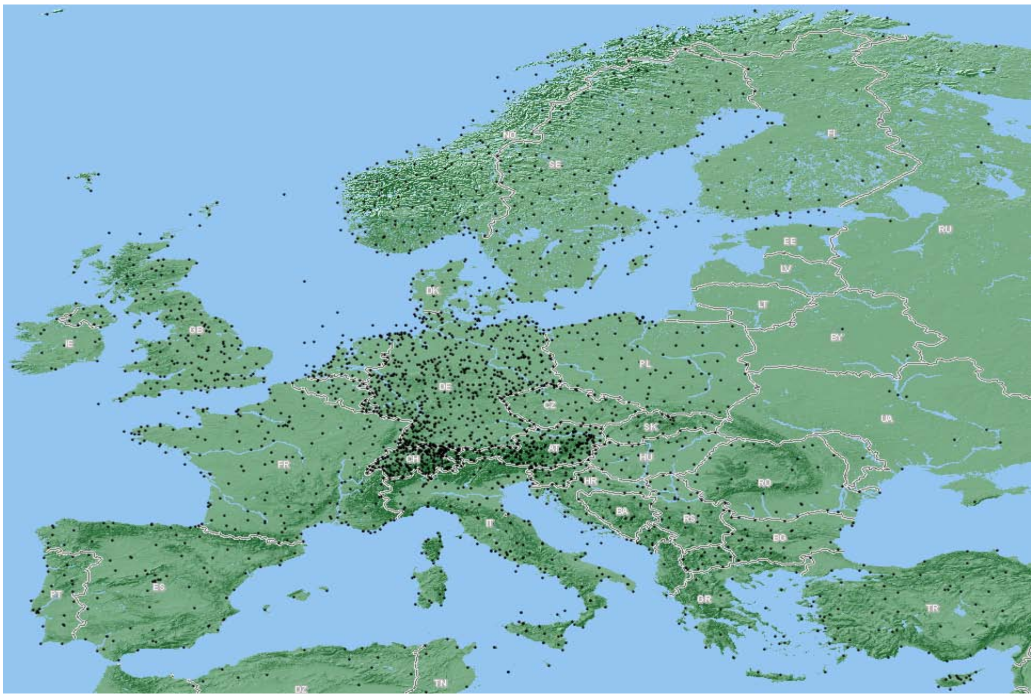
Wind power is today already a very important and influential component of the European electricity system. According to the European Wind Energy Association, 74,767 MW of wind power were installed in the EU27 at the end of 2009, producing 163 TWh of electricity in a normal wind year. This meets approximately 4.8% of total EU power demand (EWEA 2010). All scenario studies published in recent years agree that wind power will grow strongly in the next decades. Therefore, in order to build realistic scenarios for the future European electricity system, it is of great importance to regard the fluctuating nature of the generation from wind turbines. Consequently, one central objective of this project is to generate accurate hourly wind power profiles for the EU27+2.

The model ISI-Wind-Europe developed in this project was used to transform weather data into country wind power feed-in profiles. The approach of the model will be described in the following.

4.2.1 Approach of the model ISI-Wind-Europe

The crucial issue for modelling the electricity generation of wind energy is to provide an appropriate dataset. In this project, data provided by Meteomedia AG is utilized which includes information collected at 3,097 weather stations (shown in Figure 18). Central parameters are information on wind speed, temperature and atmospheric pressure.

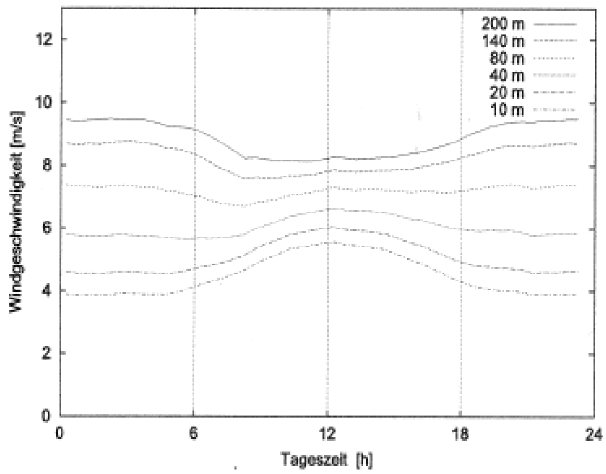
Figure 18: Positions of the weather stations that provided input data for ISI-Wind-Europe



Source: own visualisation based on Meteomedia data.

The data is processed by ISI-Wind-Europe to fill gaps that occur due to technical difficulties and outages of the stations. In the next step, wind speeds at hub height of the wind turbines are calculated. The weather stations typically collect the wind data at 10 m above ground. The wind profile is influenced by the atmospheric stratification. Figure 19 shows an average development over the day. The figure illustrates that, during the night, wind speeds increase more strongly with increasing height.

Figure 19: Average development of the wind speed at different heights at a measuring station in Cabouw, the Netherlands. The y-axis shows the wind speed, the x-axis the hour of the day



Source: Focken (2003).

Wind speed at hub heights are calculated through exponential height correction based on Focken (2006). The model derives the stratification on the basis of daytime, wind speed and roughness of the surrounding. The roughness is calculated using a geographic information system (GIS) analysis of the location of the measurement station. Furthermore, temperature has to be included in the calculation because air density decreases with increasing temperature, influencing energy density of the wind. Temperature data was also provided by the measurement stations of Meteomedia. The weather input data used by ISI-Wind-Europe is shown in Table 5.

Table 5: Weather input data for ISI-Wind-Europe

Weather data	Influence on profiles	Data preciseness	Used in the model
Wind speeds 10 m above ground	Very high	$1\,kn \cong 0{,}5144\,\frac{m}{s}$	Yes
Atmospheric stratification	High	Estimation based on VDI-Directive 3782 (VDI 2009) and "TA Luft" (BMU 2002)	Yes
Roughness length at measuring station	Medium	Estimation on land use based on CLC (ETC/LUSI 2009) and GLC (ETC/LUSI 2006)	Yes
Temperature	Low	$1\,K$	Yes
Air pressure	Low	$0{,}1\,hPa$	Yes
Air humidity	Very low	-	No
Turbulence	Low	-	No

The next step is to include the characteristics of the wind turbines in the model. The model contains central turbine characteristics, shown in Table 10, for 8 different turbine models of different turbine manufacturers. Wind speed is calculated at hub height of the respective turbine. The model then uses the published power curves of the turbine to calculate its power output at the given wind speed. A representative mix of turbine types, based on the installed capacity in Germany in 2008, is applied to all stations. The mix changes in the scenarios, as the average hub height typically increases with new installation. Consequently, the resulting feed-in curve is the result of a combination of the characteristics of different turbine types.

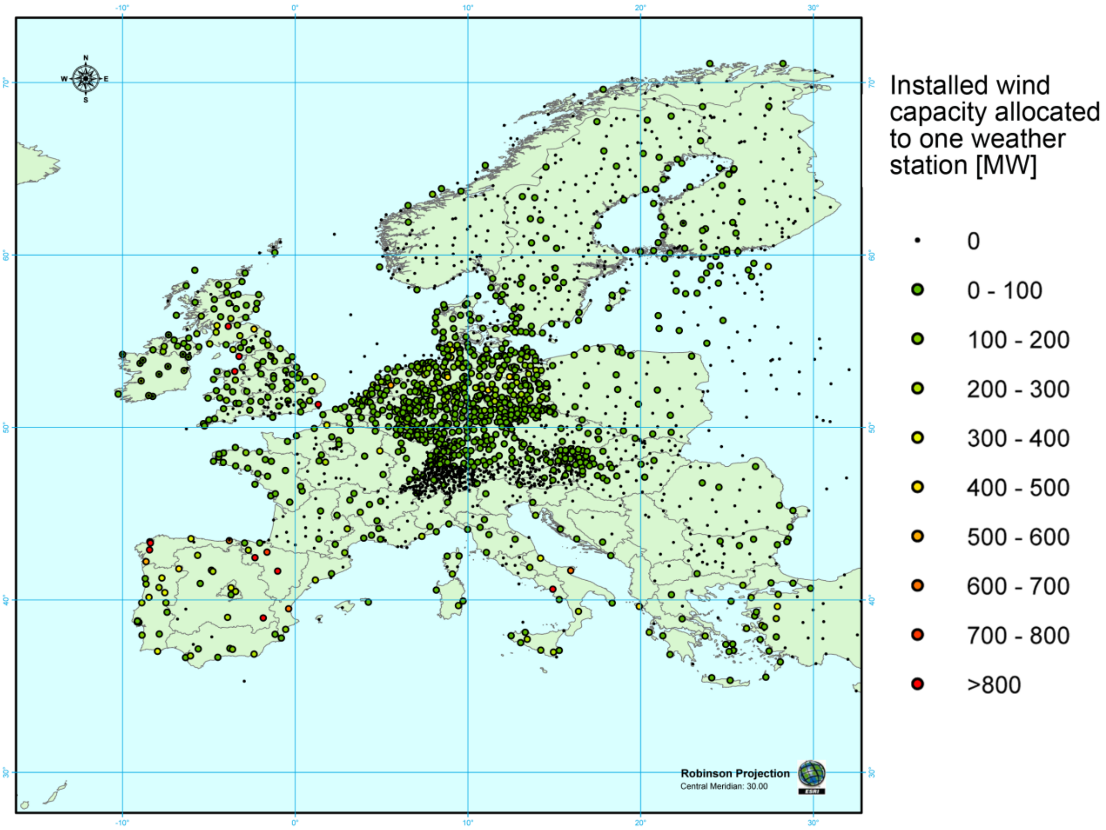
Table 6: Key characteristics of the wind turbines

Characteristics	Data preciseness	Used in the model
Power curve	$1 \frac{m}{s}$	Yes
Hun height	Characteristic hub height of the reference turbines	Yes
Distribution of the turbines	Option 1: Allocate to closest measuring points Option 2: Allocate based on the maximum possible generation at the measuring point	Yes
Availability	Estimation	Yes
Wind park layout	No enough data available	No
Local wind regimes	No enough data available	No

The position and peak capacity of almost all wind parks are available in map from La Tene Maps[8]. The data was entered into the GIS model and the capacity of each wind farm is allocated to the closest measurement station. The result of the allocation is shown in Figure 36.

8 For more information please refer to www.latene.com.

Figure 20: Allocation of the installed capacity to the measurement stations



Source: own illustration.

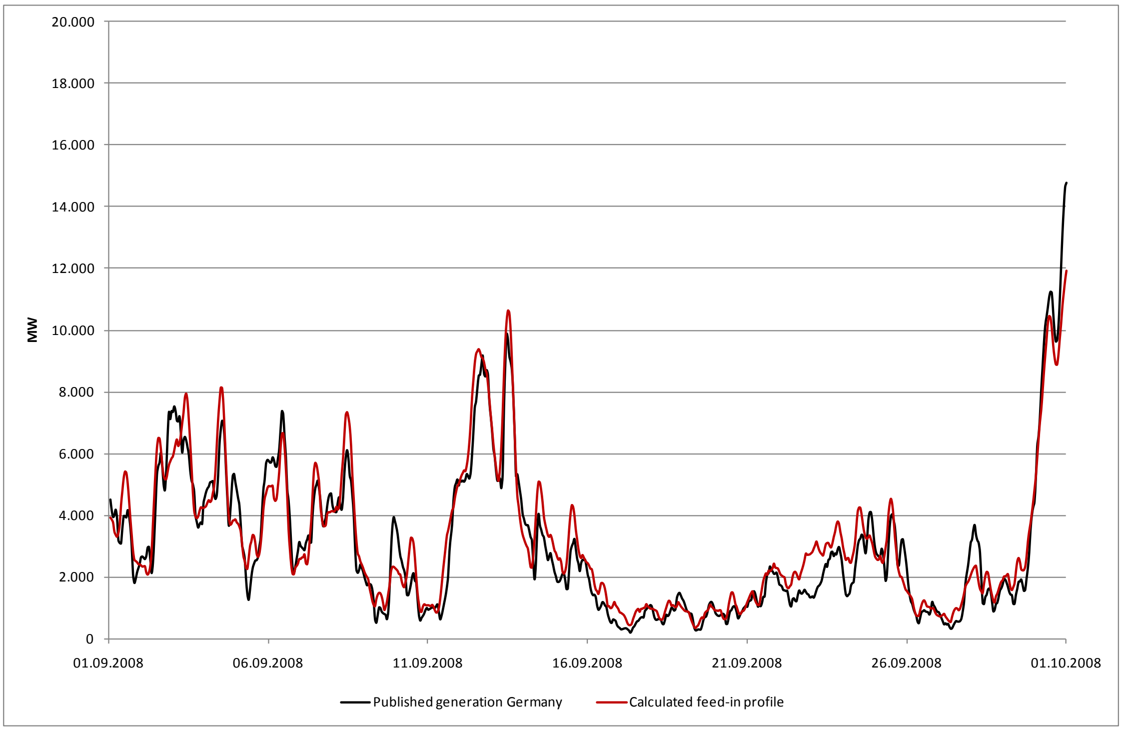
4.2.2 Model evaluation and calibration

ISI-Wind-Europe calculates feed-in profiles for all European countries. The evaluation process is different to the one applied for ISI-PV-Europe, as more data is available for comparison that also allows for a model calibration. Several transmission system operators or power exchanges publish hourly data on the wind power fed into the grid. This data is not available for all countries and the entire period 2006 - 2008. Namely, cumulated feed-in profiles for these years are available for Germany, Spain, Ireland and Denmark. The data is used for evaluation and calibration purposes.

In the calibration process, the parameters of the model are fine-tuned to meet the published full-load hours of the wind parks of the respective countries. Consequently, the calculated generation equals the published data on generation

The trend and fluctuations are met quite well, although the modelled time series is a bit more volatile, which is likely to lead to an slight overestimation of the cost of the electricity system. By contrast, in Spain, where the density of measurement stations is lower, the modelled results are significantly more volatile. Two different approaches for temporal smoothing are tested in order to address a better reproduction of fluctuations. The first approach is based on Nørgård and Holttinen (2004) and the second approach is based on a detailed analysis of calculated and measured hourly profiles for Germany, Spain, Denmark and Ireland. The second approach shows better results and is used in this project. Figure 21 shows a comparison of the published and modelled wind feed in profile for Germany, September 2008.

Figure 21: Comparison of published and modelled generation profile for Germany, September 2008



Source: own calculations and data of the European Energy Exchange.

Analogous to the comparison in the previous chapter, central statistical indicators of the published and modelled time series are shown in Table 7, using Germany as an example. Naturally, as the model is calibrated using published full-load hours, average power of the cumulated generation over the year and full-load hours are met by definition. Standard deviation is slightly higher for the modelled profile, but in the same order of magnitude. The maximum generation is met very well and the coefficient of determination R^2 shows a very high goodness of fit. In the case of Denmark, the comparison shows similar results. For Spain and Ireland, R^2 is significantly lower (around 0.72), due to the lower number of measurement stations.

Table 7: Comparison of data published by Eurostat and results of ISI-Wind-Europe for 2008

Indicator	Published generation Germany	Model results Germany
Average power (MW)	4,603.0	4,607.9
Full-load hours	1,756.0	1,757.9
Maximum generation	19,040.0	17,878.5
Generation 2008 [GWh]	40,433.1	40,510.4
R^2	-	0.951

Source: own calculations and data of Eurostat.

Summing up the evaluation, ISI-Wind-Europe performs satisfyingly in generating feed-in profiles for wind power and the calculated profiles will be used in the following.

5 Optimization of the power sector

The steps described in the previous section add up to an aggregated description of the power generation from renewable energies, including installed capacities, generation and hourly load profiles. In the next step, the remaining parts of the power sector are optimized in a least cost approach. The overarching question is, what technologies have to be installed to secure that electricity demand is met at all hours of the analyzed years? To account for the variability of generation from weather-dependent RES technologies, the optimization is performed for the meteorological years 2006, 2007 and 2008.

In general, three types of technological options are incorporated in the optimization process: conventional electricity generation technologies, interconnector lines between the countries and electricity storage facilities. As already mentioned, these technologies will be referred to as complementary technologies in the following, as their role is mainly to balance the fluctuating generation from renewable energies. In PowerACE-Europe, the optimal mix of complementary technologies to a given renewable generation is calculated using linear optimization. The problem to be solved and the applied constraints are explained in the following.

5.1 Optimization problem

The objective of the optimizer is to minimize the costs for meeting demand in all three meteorological years. The costs taken into account are capital and operating expenditures of all complementary technologies, including capital costs for investments, operation and maintenance, fuels and the costs of carbon credits to be acquired for emissions. Consequently, the cost function consists of two components: fixed costs occurring if the optimizer decides to “build” one MW of capacity of a certain technology and a variable part, depending on the utilization of the technology. The capital costs are calculated as annuity in order to express the costs attributed to one year, as the model finds the least costs option for each year detached from other years.

The costs for transmission capacities are calculated based on the distance between the weighted centres of demand for each country. The price of carbon credits is incorporated as part of the variable costs of power plants. The costs assumptions for conventional power generation are depicted in section 5.2.

The optimization is subject to several restrictions, the most important ones are explained in the following.

1. Demand has to be met at all hours for each country, i.e. supply and consumption have to be equal More precisely, this means that the sum of the power generation from both

renewable and conventional plants, the output of storage facilities and electricity imported from neighbouring countries, less the electricity consumed in the loading process of storage facilities, electricity exported to other countries and the curtailment of renewable energy has to equal demand at every hour in every country. In this restriction both demand and generation of most renewable technologies are fixed for each hour. The generation from other technologies, such as conventional plants can be adjusted in the search for a least cost option.

2. In a rather trivial restriction, the output of each power plant cannot be larger than its installed capacity and each connector cannot transport power more than its transmission capacity.

3. Storage plants can only operate within their technical limits. The filling level of the reservoir or compressed air tank has to be between zero and its maximum. Pumping water into the reservoirs, compressing air in compressed air energy storage facilities (CAES) and electricity production from these facilities are restricted by the installed capacities.

4. Furthermore, the partially flexible generation of electricity from biomass, biogas and hydro plants equipped with storage has to be taken into account. In the scenarios, 75% of the power generation from biomass and biogas is assumed to be flexible. The FLH of 4,500 to 6,000 has to be met though, meaning that the flexibility is restricted. This also applies to storage hydro plants, for which capacity and generation data is included in the model for countries where these plants play a major role. The installed capacity and generation of these plants is kept at values for 2008 throughout the scenarios.

5. The total amount of $C0_2$ emissions is limited at a certain level for each year, decreasing over time and reaching a 95% reduction compared to 1990 levels in the year 2050.

6. The availability of power plants is set at 95%.

Besides these main restrictions, several other aspects have to be incorporated, such as losses occurring in power transmission or storage facilities and the integration of already existing power plants and transmission capacities.

The resulting linear problem is solved for all scenario years and for all weather years using a commercial solver programme. The results are stored in databases allowing access to the information in aggregated or very detailed form.

In a first step, the optimal mix of complementary technologies is calculated for each year without the influence of previous or following years. Afterwards a reasonable mix between renewable energies and complementary technologies is calculated, through multiple model iterations of both ResInvest and PowerACE-Europe described in chapter 3. The resulting scenario is the basis for a final iteration, in which the results in terms of installed capacities (conventional plants, storages, interconnectors) from previous years are taken into account in the following years. The result is a consistent scenario robust for all three weather years in 2020, 2030, 2040 and 2050.

In the following the technical assumptions applied in the scenarios are presented.

5.2 Technological assumptions

As already mentioned before, the model uses conventional power plants, storage facilities and grid expansions as complementary technologies to integrate renewable energies and match demand and supply. The assumptions used in both scenarios will be explained in the following.

5.2.1 Conventional power plants

The existing power plant park as of 2008 is included in the model in high detail, using Platts' World Electric Power Plant (WEPP) as data source[9]. The individual plants have to be aggregated into groups to some extent to keep calculation time low. For the plants to be installed in the future, only hard coal power plants and gas power plants, both as regular gas turbines (GT) and combined cycle gas turbines (CCGT) are taken into consideration. The technical assumptions are shown in Table 8.

9 For details on the database, please refer to: http://www.platts.com/Products/worldelectricpowerplantsdatabase

Table 8: Assumptions on the characteristics of conventional power plants in PowerACE-Europe

Technology	Year	Investment	O&M	Lifetime	Efficiency	CO_2-emissions
Unit		[€/kW]	[€/(kW*a)]	[years]	[%]	[kg/MWh]
Coal	2020	1,500	20,000	40(18)	50%	672
	2030	1,800	20,000	40(8)	50%	667
	2040	1,300	20,000	40	51%	663
	2050	1,200	20,000	40	51%	659
Gas turbines	2020	350	15,000	35	38%	528
	2030	333	14,000	35	39%	510
	2040	317	13,000	35	41%	493
	2050	300	12,000	35	42%	477
Combined cycle gas turbines	2020	750	30,000	35	60%	334
	2030	717	28,700	35	61%	331
	2040	683	27,300	35	61%	327
	2050	650	26,000	35	62%	323

Source: own database constructed from various input sources.

The least cost mix of complementary options calculated by the model implicitly depends on the possible full-load hours (FLH) of the technologies in the scenarios: If high FLH are possible, for example, because many existing plants of a country have reached the end of their economic lifetime, this creates high demand for new generation capacities. If additionally the share of fluctuating renewables is still low, coal is the most cost-efficient technology for power generation. For lower FLH, CCGT plants are most economic, while regular gas turbines are applied only for covering peak demand with very low FLH.

In the applied CO_2 price scenarios, building new coal power plants stops being attractive between 2030 and 2040, even for highest FLH. Furthermore, the decreasing attractiveness of coal plants due to decreasing FLH in the later years has to be incorporated indirectly, as the model calculates each analyzed year individually; the significantly lower FLH for coal plants are not foreseeable for the solver in the year 2020. Therefore, the depreciation period of coal was decreased to 18 years, resulting in coal being only attractive if the plants can run at very high FLH in the period between 2020 and 2030.

Both scenarios do not rely on additional nuclear capacity and CCS in the electricity sector since both options are connected with political, economic and technical uncertainties. In both scenarios the given CO_2 target is achieved without relying on these technologies.

Ramp rates are currently not considered in the model, since incorporating them leads to immensely increased calculating times for each model run. As the majority of the new power plants are very flexible gas power plants, the influence of ramp rates is rather small, at least in hourly resolution.

5.2.2 Grid expansions

As previously mentioned, grid expansions are modelled on the basis of the distance between load centres of each country. Onshore grid expansions are assumed to have specific investments of 1,000 €/km*MW, based on ECF (2010). As in the case of pumped storage plants, this figure is an approximation as the costs depend very much on terrain and other circumstances. Undersea cables are assumed to have specific investments of 1,667 €/km*MW, based on published data for the undersea cable NorGer[10]. Losses of the lines are assumed to be 0.01% per km for onshore transmission; the losses in undersea cables are calculated separately, due to the additional losses in the HVDC-converter and -inverter-stations.

Table 9: Assumptions on the characteristics of net transfer capacities in PowerACE-Europe

Technology	Investment	O&M	Lifetime	Losses
Unit	[€/(kW*km)]	[€/(kW*a)]	[years]	[1/km]
Onshore interconnector	1,000	-	40	0.01%
Undersea cable	1,667	-	40	Calculated individually

5.2.3 Storage facilities

Dealing with electricity storage in a power system model is challenging for several reasons: the data on existing pumped storage hydro plants is fragmented for many countries. Especially the reservoir size is uncertain in many cases and has to be estimated. Furthermore, the integration of storage facilities into the model leads to growing calculation times because the values for reservoir levels and generation depend on the values in many other hours.

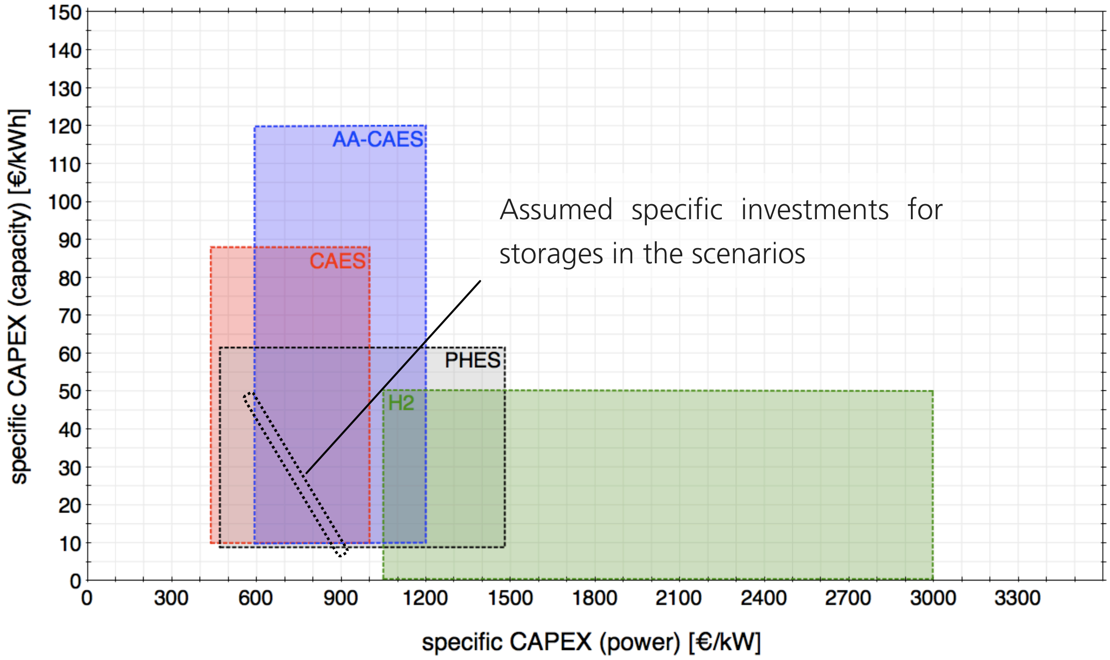
10 For details, please refer to: http://www.norger.biz/

For the storage plants, the characteristics are chosen to fit both small pumped storage hydro plants and larger advanced adiabatic compressed air energy storages (AA-CAES). For both systems, a storage allowing eight hours of electricity conversion at peak capacity is assumed.[11] The costs of the technologies can only be estimated roughly, since the specific investments for hydro power vary from one location to another and costs for future large CAES can only be projected. The specific investments for storage are composed of two components, investments occurring for the capacity and for the power to be stored, i.e. the size of the storage unit. Possible ranges of these are depicted in Figure 22.

For this study, total specific investments of 1,000 €/kW are assumed, allowing a range of combinations of the two components indicated in Figure 22 as well. O&M costs of approximately 1% of the investment are to be added.

11 In sensitivity analysis larger storage volumes have been tested, but the impact is relatively small.

Figure 22: Possible specific investment ranges for 8 hours of storage for pumped hydro electric storage (PHES), (advanced adiabatic compressed air energy storage [(AA-)CAES] and hydrogen storages (H2)



Source: Fraunhofer ISI based on specific projects for each technology. CAPEX is an abbreviation for capital expenditures.

The resulting information on storage facilities is summarized in Table 10.

Table 10: Assumptions on the characteristics of electricity storage facilities in PowerACE-Europe

Technology	Year	Investment	O&M	Lifetime	Efficiency	CO_2-emissions
-	-	[€/kW]	[€/(kW*a)]	[years]	[%]	[kg/MWh]
Storage	2020	1000	10	40	80%	0
	2030	1000	10	40	80%	0
	2040	1000	10	40	80%	0
	2050	1000	10	40	80%	0

Source: own calculations.

6 Results

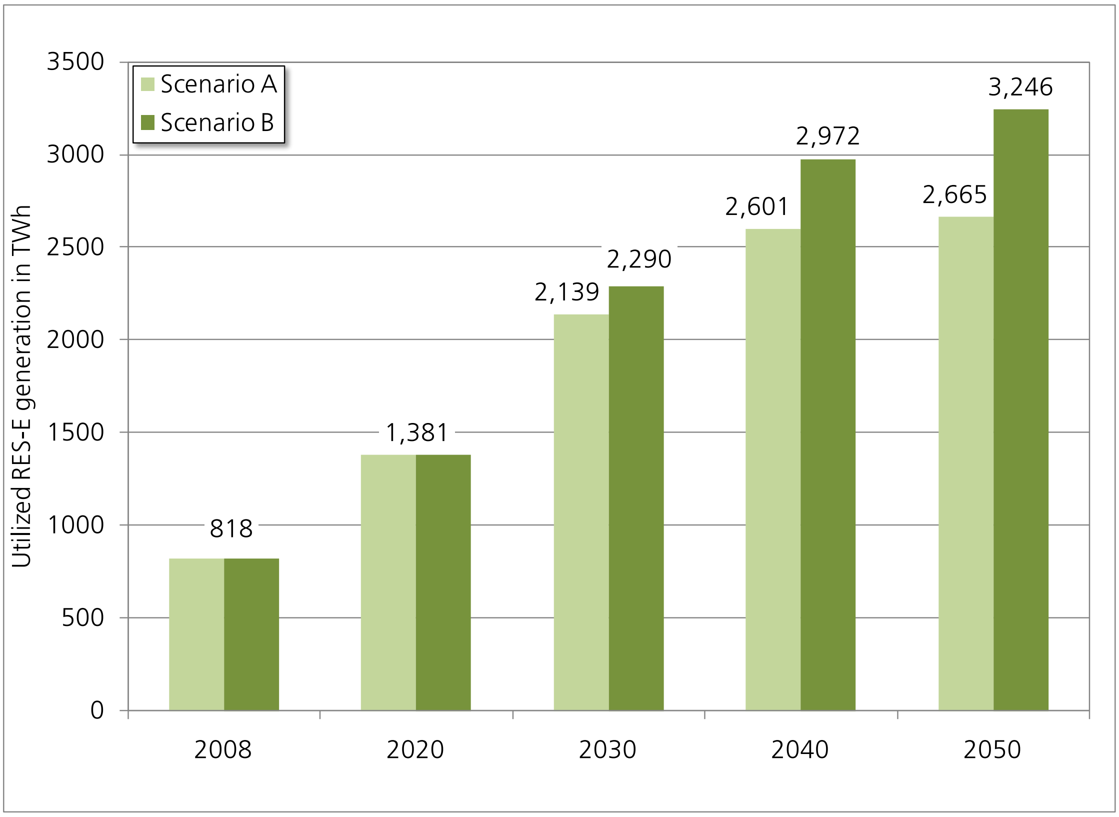
The following section summarizes the main results of the model PowerACE for both scenarios: conventional power plants to be installed, necessary grid expansions, the need for storage systems and the resulting carbon emissions.

6.1 Renewable electricity utilization

A central aspect in both scenarios is the development of renewable electricity and utilization, i.e. the total renewable generation minus RES-E curtailment. The development is given in Figure 23 for both scenarios. Up to 2020, the absolute RES-E generation is at the same level in both scenarios due to the underlying assumption of the continued development according to the National Renewable Energy Action Plans. However, due the different development in electricity demand and differences in the conventional power plants park, the actual share of RES-E generation in total net electricity generation varies. While Scenario A reaches a RES-E share of 40%, Scenario B reaches a level of 37%. In 2050 both scenarios reach comparable RES-E shares of 93% (A) and 94% (B). Although the share is comparable, total renewable generation is different. While Scenario A requires approximately 2,665 TWh of RES-E generation, total generation in Scenario B is approximately 580 TWh higher.

Another factor which has to be taken into account in scenarios with very high diffusion of renewable energy is RES-E curtailment. Curtailment takes places if excess electricity production cannot be utilized because of insufficient demand in the producing countries and its neighbours, or if the interconnection lines are congested. Until 2030 RES-E curtailment is below 1% in both scenarios. Thereafter, curtailment increases to 3.7% in 2050 in Scenario A and 4.9% in Scenario B. Curtailment differs significantly for the individual countries. To evaluate this result, it has to be taken into account that the difference in average curtailment of 1.2% between the scenarios translates into an even higher difference in curtailment of the marginal RES-generation in some countries. This means, that when additional power wind farms are installed in a country with a curtailment of, for example, 5%, of the additional generation much less then 95% can be utilized.

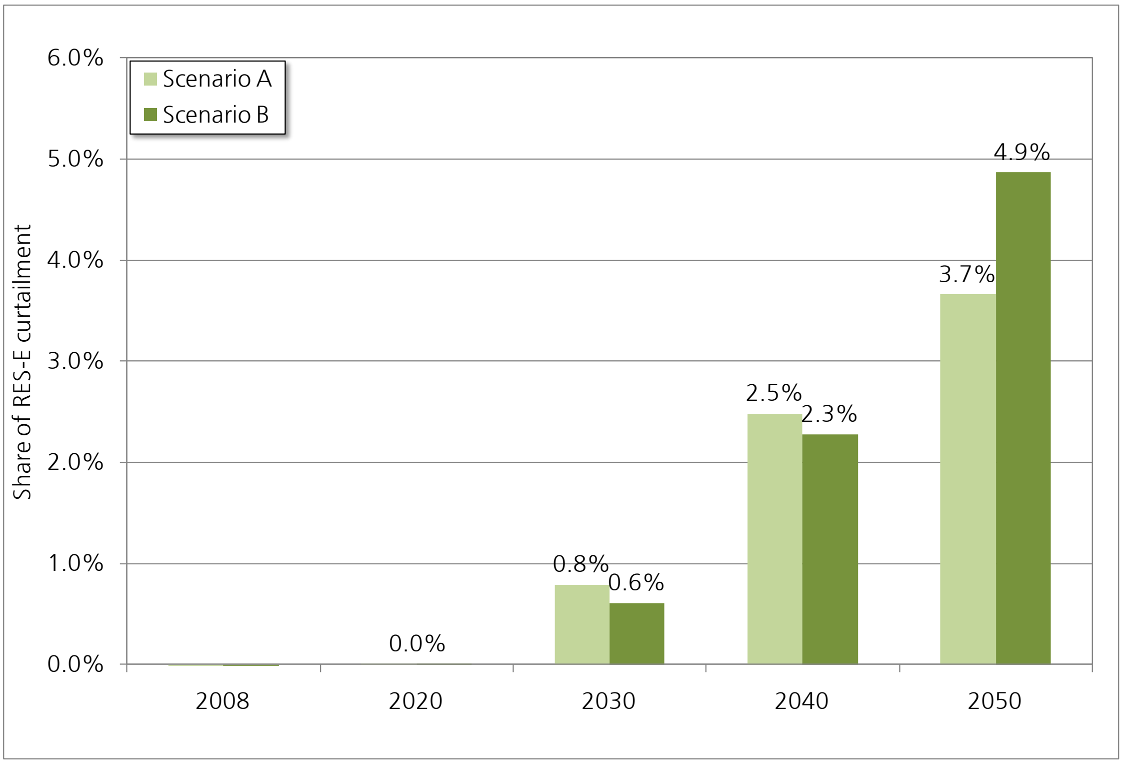
Figure 23: Development of utilized RES-E generation



Source: own calculations.

A comparison of RES curtailment in both scenarios is shown in Figure 24. It can be seen that the slightly higher RES-share of Scenario B is associated with significantly higher curtailment of generated electricity.

Figure 24: Development of RES-E curtailment

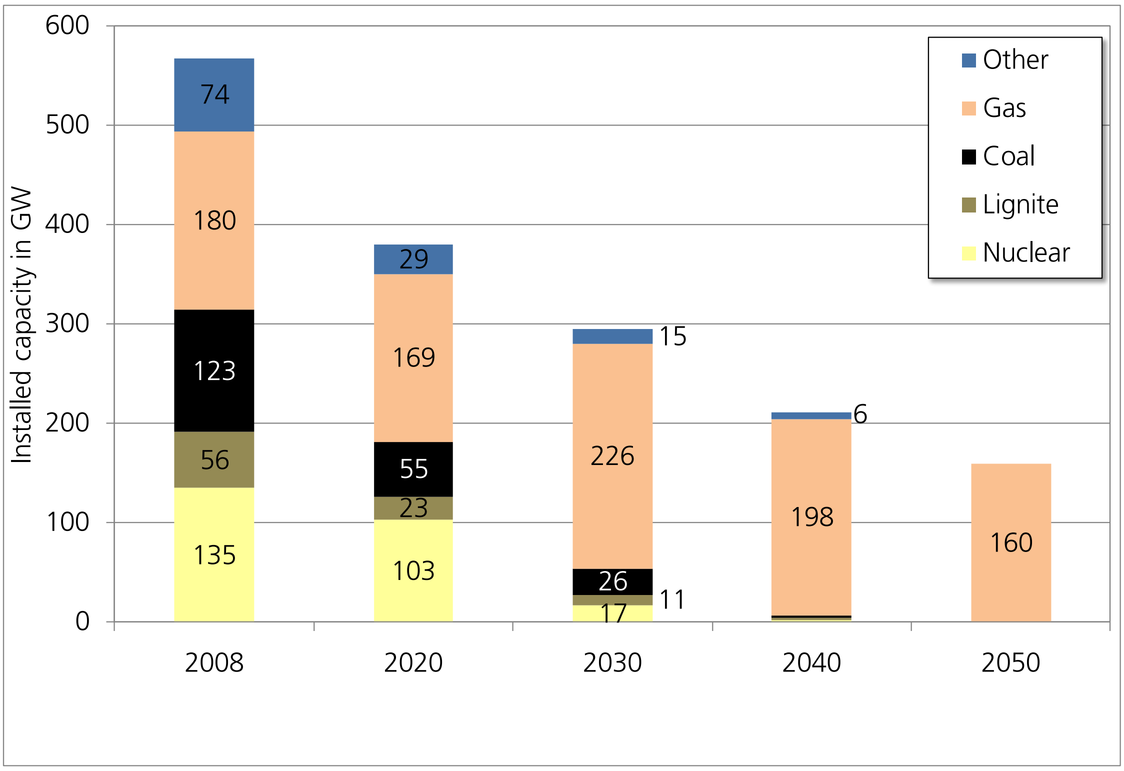


Source: own calculations.

6.2 Conventional power plants

As mentioned before, the technological options for conventional power plants are limited to hard coal power plants, combined gas turbines and regular gas turbines. The calculated development of installed capacity of conventional power plants is given in Figure 25: and Figure 26:. In Scenario A the installed capacity of nuclear, lignite and coal is declining sharply. The decline in installed capacity of these technologies is partially compensated by newly installed gas power plants, thereby increasing the installed gas capacity to 226 GW in 2030. Thereafter, the installed gas capacity declines as well, as more old power plants reach the end of their lifetime than new ones are built. By 2050 gas power plants are the only conventional power plants in the system, with 160 GW of installed capacity. The total capacity of the European conventional power plant portfolio decreases by 72% until 2050 in the “High efficiency” scenario.

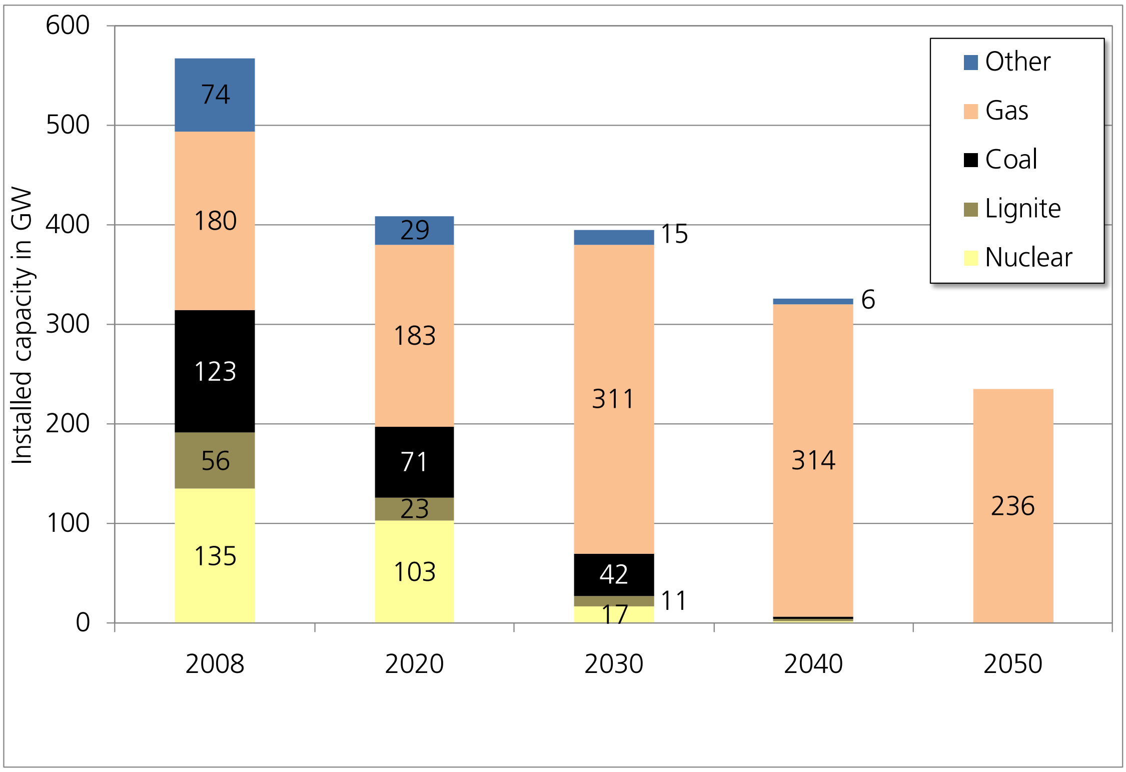
Figure 25: Development of installed conventional capacity in Scenario A



Source: own calculations.

The development in Scenario B shows the same characteristics. Since electricity demand is higher in this scenario, the installed gas capacity reaches its peak at 314 GW in 2040. Thereafter, the installed capacity decreases to 236 GW in 2050. The decommissioning of nuclear and lignite follows the same path as Scenario A. The installed capacity of coal-fired power plants is 16 GW higher in 2020 and 2030 than in Scenario A as the model builds 26 GW of new coal capacity in 2020 which is only utilized for approximately 18 years, while in Scenario A only 10.7 GW of new coal capacity are built in 2020. A comparison of the construction of new plants in both scenarios is given in Table 11. The high share of fluctuating renewable energy leads to gas turbines reaching the highest market share in the construction of new capacities. In the "Moderate efficiency" scenario, the conventional power plant park decreases only by 59% until 2050. The lower decrease in conventional capacity is caused mainly by the significantly higher demand in Scenario A, but also by the slightly higher share of fluctuating renewables.

Figure 26: Development of installed conventional capacity in Scenario B



Source: own calculations.

Table 11: New conventional generation capacity built in the scenarios

Year	Coal		CCGT		GT		Unit
	Scenario A	Scenario B	Scenario A	Scenario B	Scenario A	Scenario B	
2008 - 2020	10.7	26.3	2.0	6.1	13.9	23.7	GW
2021 - 2030	0.0	0.0	24.1	44.0	46.9	97.8	GW
2031 - 2040	0.0	0.0	13.0	24.6	19.4	38.9	GW
2041 - 2050	0.0	0.0	0.0	0.0	0.0	0.0	GW

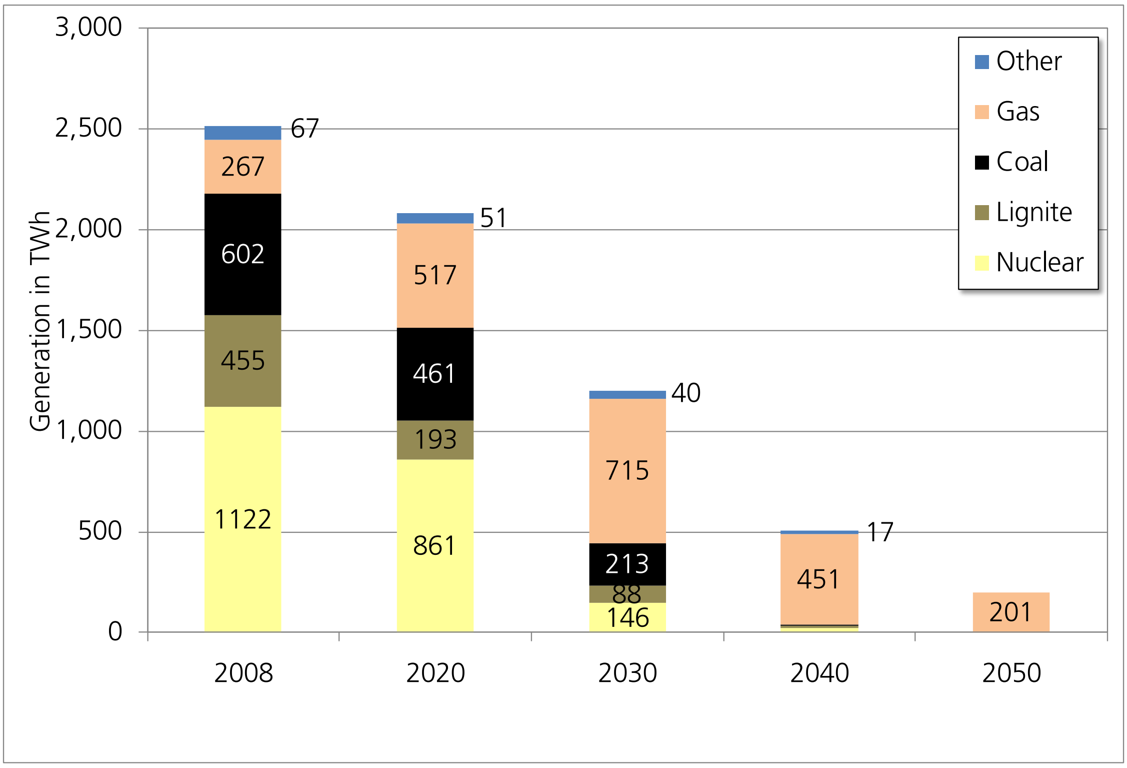
Source: own calculations.

The previously discussed installed capacity is a central indicator for the development of the power plant portfolio. Another important factor is the development of electricity generation and utilization of power plants. Figure 27 and Figure 28 show the development of electricity generation from conventional sources in both scenarios.

The electricity generation of nuclear and lignite power plants declines in line with the development of the installed capacity. The existing plants are heavily utilized up to 2030. During this period, utilization is above 8,000 full-load hours. In the case of coal-fired plants, utilization is also above 7,700 full-load hours in 2030 for both scenarios. Thereafter, the utilization of the remaining hard coal-fired plants drops to levels below 3,000 full-load hours. This effect is caused by the CO_2 cap and the high penetration of renewables. Average utilization of gas-fired power plants is below 3,400 full-load hours throughout the entire time period. It has to be taken into account that this result is mainly caused by the low utilization of the large number of gas turbines necessary to cover peak demand.

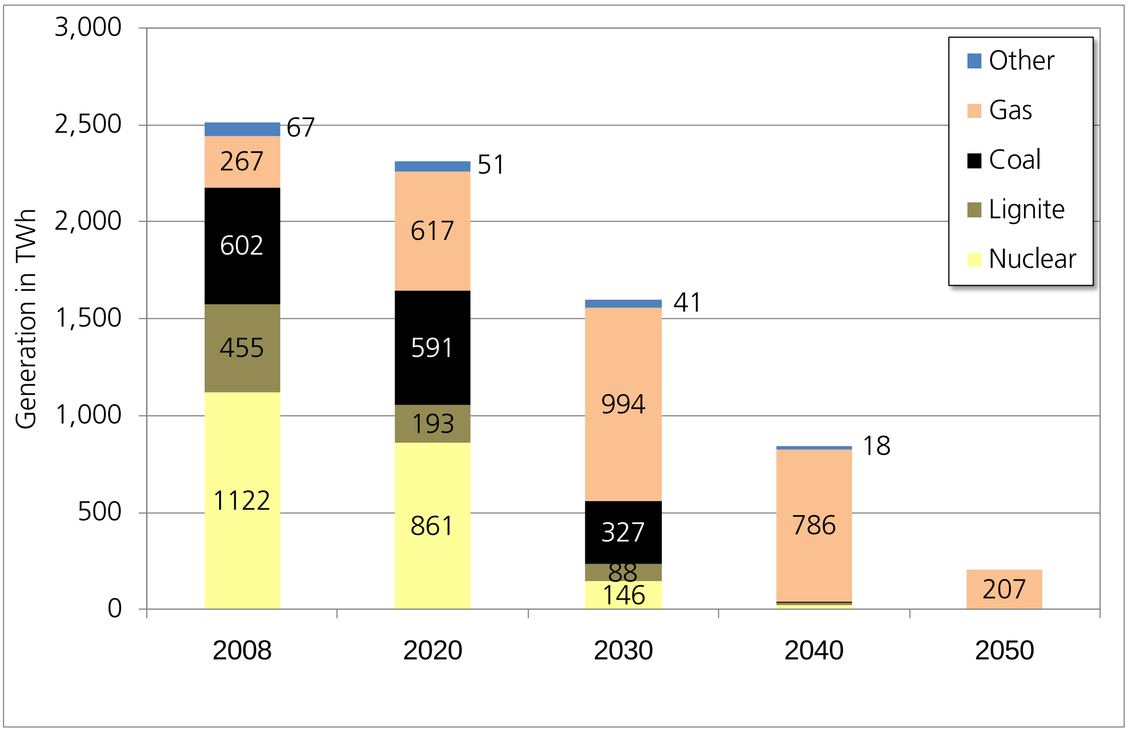
The low utilization also results in a shift of cost structure for power plants. As of today, fuel and other variable cost forms are responsible for a large share of the total costs. The distribution of costs changes until 2050. In both scenarios the share of the power that is generated in conventional power plants decreases by 92 – 93%, whereas the installed capacity only decreases by 59 – 72%. Consequently, the costs of conventional plants are caused to a high degree by the necessity of providing peak capacity, rather than producing power.

Figure 27: Development of conventional generation in Scenario A



Source: own calculations.

Figure 28: Development of conventional generation in Scenario B



Source: own calculations.

Figure 29: Average utilization of power plants in Scenario A and B

Year	Nuclear		Lignite		Coal		Gas		Other	
	A	B	A	B	A	B	A	B	A	B
2008	8,303	8,303	8,085	8,085	4,886	4,886	1,483	1,483	907	907
2020	8,322	8,322	8,322	8,322	8,322	8,322	3,063	3,375	1,749	1,748
2030	8,322	8,322	8,322	8,322	8,036	7,772	3,165	3,201	2,681	2,709
2040	8,248	8,322	6,264	6,754	1,297	2,272	2,279	2,505	2,800	2,861
2050	-	-	-	-	2,736	3,519	1,257	877	-	-

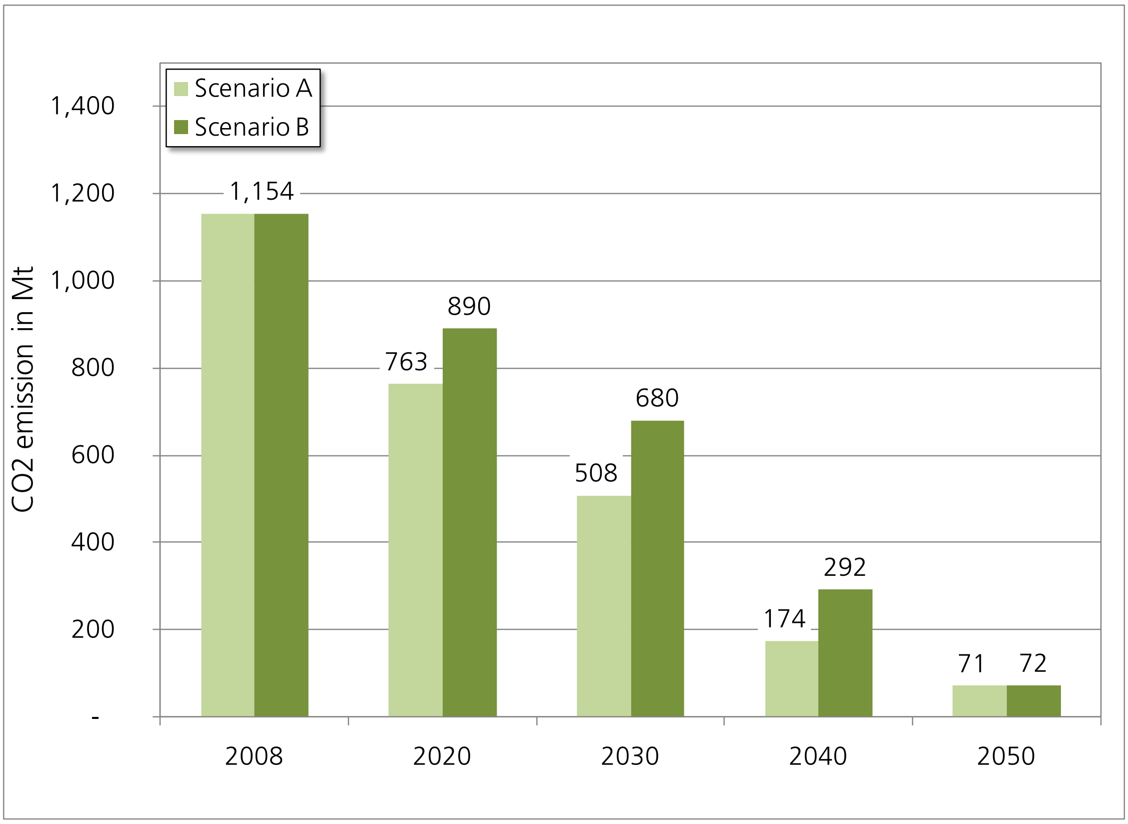
Source: own calculations.

6.3 CO_2 emissions

The development of RES-E generation in both scenarios is based on the NREAPS until 2020. In combination with different developments in electricity demand, this leads to different CO_2 emissions in 2020. While the annual average CO_2 emissions in 2020 reach approximately 742 Mt in Scenario A, the corresponding emission value of Scenario A is 127 Mt higher. The development of CO_2 emissions in both scenarios is shown in Figure 30.

Due to the underlying development of electricity demand, the reduction of CO_2 emission is faster in Scenario A.

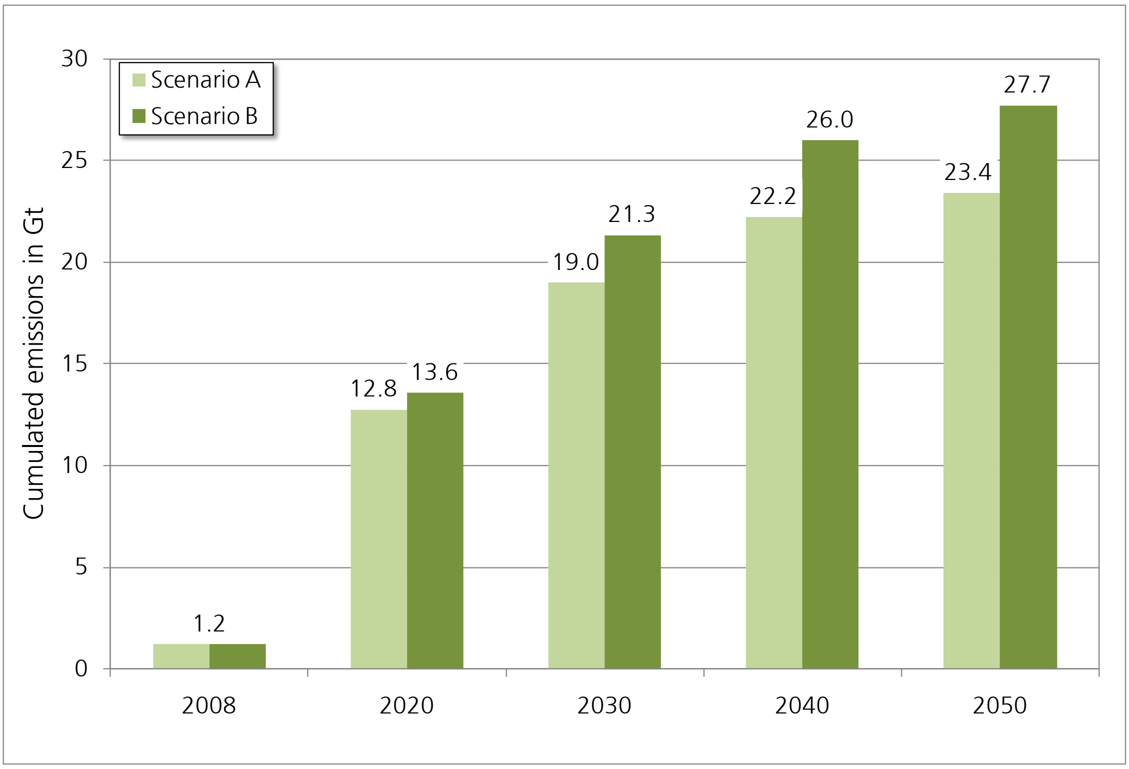
Figure 30: Average annual CO_2 emissions



Source: own calculations.

Although both scenarios achieve a reduction of CO_2 emissions to approximately 95% of 1990 emission levels, the development of cumulated emissions in both scenarios, depicted in Figure 31 differs considerably as a result of the effects described above. The total difference between cumulated CO_2 emissions reaches approximately 4.3 Gt in 2050.

Figure 31: Development of cumulated CO_2 emissions



Source: own calculations

6.4 Interconnector capacity

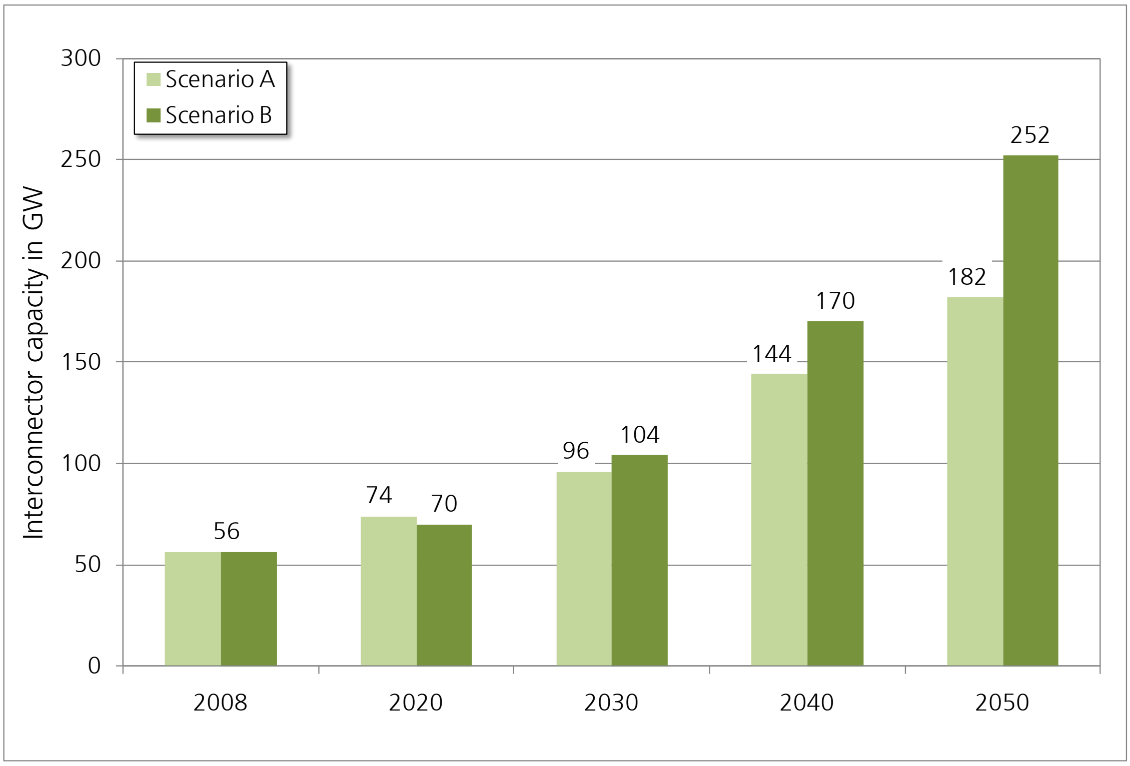
Higher electricity demand in Scenario B and the resulting necessity to install more wind and PV power plants also lead to a higher demand for interconnector capacity. The development of the aggregated interconnector capacity in both scenarios is shown in Figure 32. The resulting figures express the demand for net transfer capacity (NTC)[12]. In Figure 33 and Figure 34 the resulting need for interconnectors is depicted for scenarios A and B at regional level, the results for other years can be found in the Appendix. In 2008, the available transfer capacity of the interconnectors in the analyzed region equals approximately 56 GW.[13] Starting at this value, the cumulated interconnector capacity grows to

12 NTC is the maximum transfer capacity that is still compatible with security standards. For more information on the definition of transfer capacities, please refer to www.entsoe.eu/fileadmin/user_upload/_library/ntc/entsoe_transferCapacityDefinitions.pdf.

13 The value is not fixed and is determined and published by the transmission system operators on a regular basis.

182 Mt in 2050 in Scenario A. In Scenario B the cumulated interconnector capacity in 2050 needs to be higher and reaches ca. 252 GW in 2050, which equals an increase by factor 4.5 from today's levels. Only in 2020 is the interconnector capacity in Scenario A 4 GW higher, since the RES-E-share in net electricity generation is higher.

Figure 32: Development of interconnector capacity in both scenarios



Source: own calculations.

One of the central results of the model is the importance of new interconnection transmission capacities between the countries. Although the applied model PowerACE-Europe can be adjusted to regional arrangements other than countries, a differentiation by countries was chosen because many important datasets of the required quality are only available at the national level.

The greatest need for new power lines is caused by the necessity to connect Britain to continental Europe. In both scenarios the vast wind potential of Britain is exploited, leading to a very high share of fluctuating generation. The lines are utilized to export the excess production that cannot be stored and conversely, to import power in times of calm winds. A similar result can be observed for the Iberian Peninsula. The region has a high share of fluctuating renewable generation from both wind and PV, but only has France as a direct neighbour. Therefore, the interconnectors between Spain and France have to be strengthened considerably. Due to its closeness to the critical regions, France becomes an important hub for renewable electricity. The great need for grid investments in western Europe, with power being transported over large distances, suggests that realizing at least parts of the grid in the form of HVDC connectors could be most efficient. The concept and implications of a "Supergrid" approach will not be discussed here in detail, as it is beyond the scope of this study.

In eastern and south-eastern Europe the grid expansions calculated by PowerACE-Europe are significantly lower than in western Europe. This is due mainly to the lower share of fluctuating renewables: The higher share of generation technologies with adjustable generation such as hydropower, biomass and gas power plants in the eastern part of Europe reduces the necessity for power ex- or imports.[14]

Another interesting point is the rather modest connection to Scandinavia, especially Norway. In the past years, the possible role of Scandinavia as a provider of electricity storage has been discussed due to the region's potential for pumped storage plants. The question arises, why the model does not include this option in the solution. First of all, the prices for storage facilities are not differentiated between countries. Therefore, the model tends to build storage facilities closest to the area in which the challenges arise, meaning additional storage facilities are built only in the UK and Spain. The interconnection to Norway calculated by the model is used to utilize the already existing hydro storage plants, which are very valuable to the system even without the ability to pump water into the reservoirs. Hydropower not needed to meet national demand can be exported. Other countries can in turn export their excess generation to Scandinavia, thus allowing the reservoirs to fill and use the stored power later. Therefore, the combination of Scandinavian demand and the flexible hydro power plant park works as energy storage, even without additional pumped storage hydropower plants.[15] Nevertheless, it should be noted that it is possible that some additional storage capacities needed in the UK could be realized at lower cost in Scandinavia for some projects. For these single cases, additional undersea cables between the UK and Norway could be part of the least cost solution.

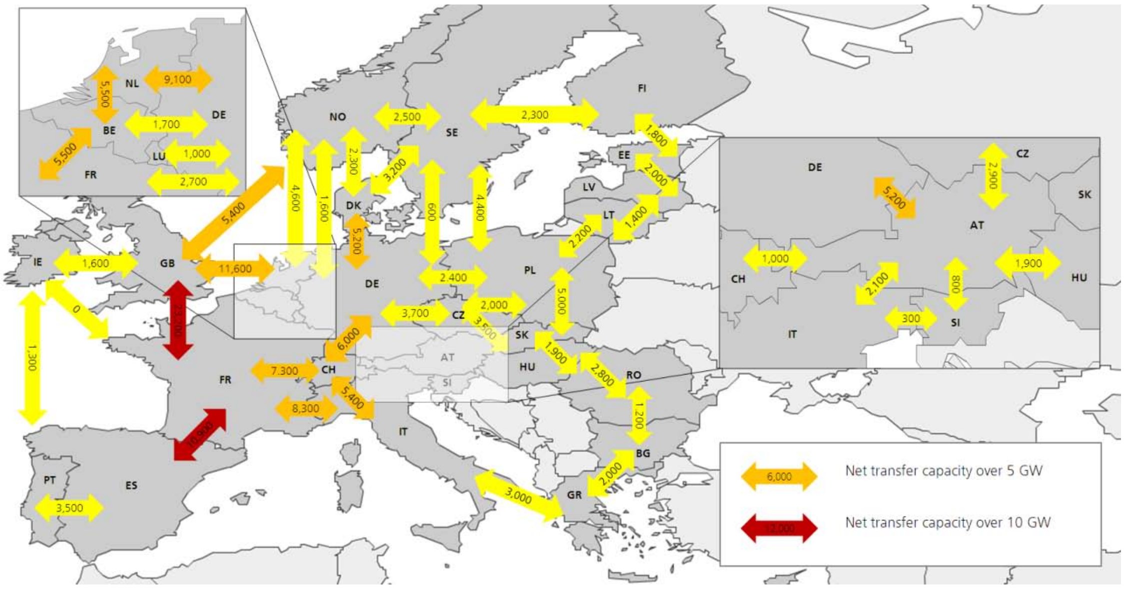
In summary, both scenarios result in considerable new interconnection capacities. Still, the order of magnitude of the expansion seems to be very challenging, but not unattainable.

14 As already metioned this result is partly based on the fact that the need for intra-country transmission capacity is not explicitely considered. The implications will be explained in the next section.

15 The role of Scandinavia is explained in more detail in section 6, using Norway as an example.

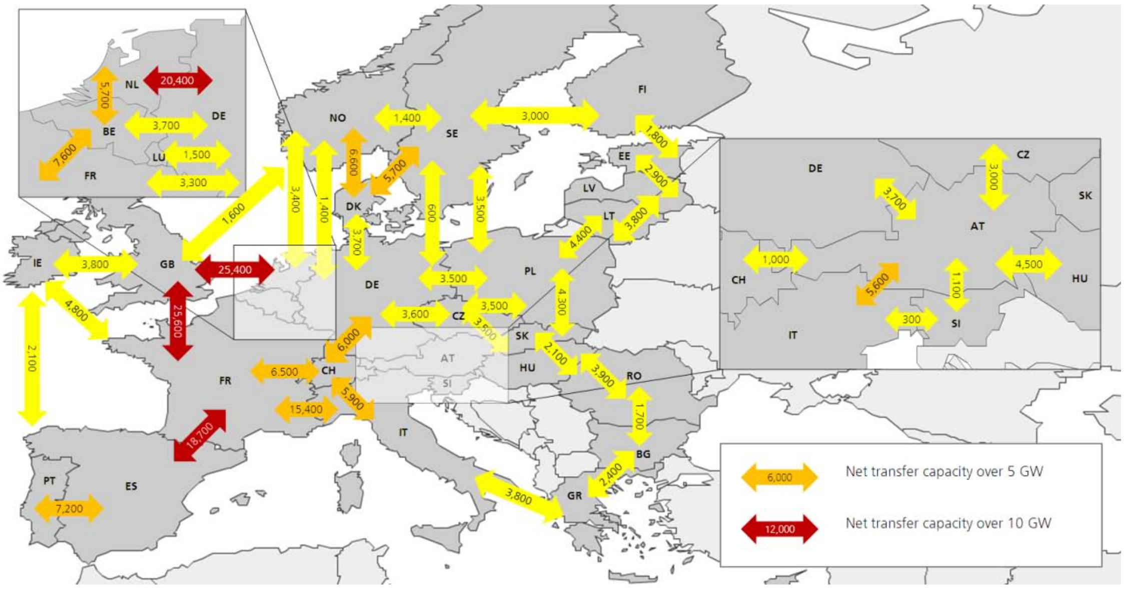
A recent study carried out by SRU projects a considerably stronger growth of interconnector capacity in a scenario with high electricity demand of 5,400 TWh for the EUNA region and 100% RES-E share (SRU 2010). As an example, the interconnector capacity to Norway grows to more than 200 GW in this case.

Figure 33: Additional interconnector capacities installed in 2050 in Scenario A expressed in MW (rounded to hundreds)



Source: own calculations, map by StatPlanet.

Figure 34: Additional interconnector capacities installed in 2050 in Scenario B expressed in MW (rounded to hundreds)



Source: own calculations, map by StatPlanet.

6.4.1 Implications for national transport grids and electricity distribution grids

The results presented above only cover the net transfer capacity between countries, i.e. the power lines and cables used to exchange power between countries, while other components of the grid are not included. This simplification implies that the countries do not have transmission bottlenecks within their borders. This means that the transport and distribution grids do not restrict the flow of electricity at any time. Electricity generated at any location in the respective country can either be consumed at any location in the country or be exported to any country. The occurring losses are taken into account in the model, either implicitly for losses within the country of origin, or explicitly for exports. In the model, situations in which the transport or distribution within countries are congested are not taken into account.

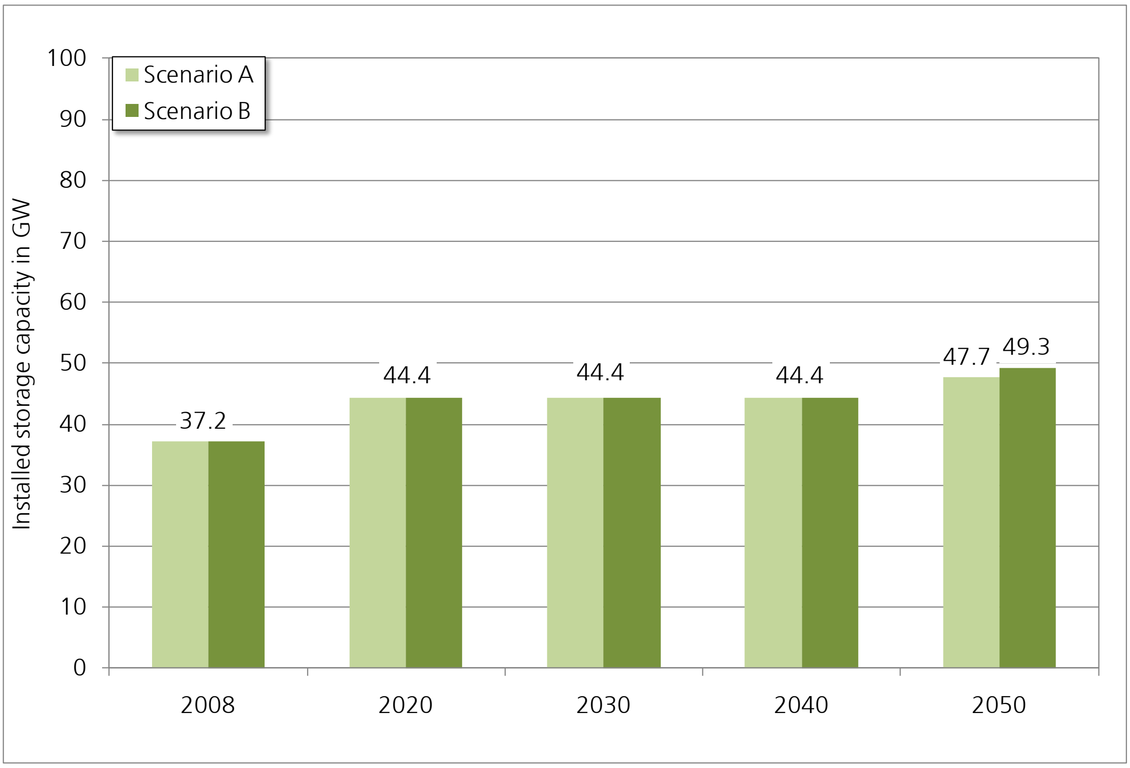
Consequently, the modelling approach used in this study covers a significant share of the European grid, but assumes that the remaining parts are developed adequately. If this is not the case, for some hours more RES-E generation would have to be curtailed than estimated by the model. This restriction is not as challenging as it might seem, for two reasons. First of all, the interconnection lines presented above are calculated between weighted centres of demand. This means that they act as strong backbones connecting major demand centres that are also available for transport within the countries. Secondly, the transport lines within the countries are mostly congested during very windy hours. At these times, curtailment is already taking place in the model anyway, since the interconnecting lines are not designed to transport all the power produced at any time. This means that although congestion might occur on the transport lines within the countries, this is most likely superposed by the curtailment induced by the congested interconnectors in windy hours.

Modelling the remaining transport grid individually requires explicit modelling of each power line and a very detailed knowledge about the location of both load centres and generation capacities. Although this is possible, the immensely increased calculating time would require simplifications in other aspects of the model. Modelling the lower voltage levels of the distribution grid is even more challenging and not possible for a model covering Europe as a whole. It is clear that the changes in the structure of electricity generation towards decentralized generation require new grid concepts. Especially the high growth rates of PV will become a challenge in this context. Nevertheless, a detailed modelling of the remaining transport and distribution grid is beyond the scope and possibilities of this study. Improving this aspect will be a task for future studies.

6.5 Storage capacity

Another important result of the scenario calculations is the development of storage capacity. The development of cumulated storage capacities is given in Figure 35. The figure shows two steps in the development of storage capacities. The first step takes place between 2008 and 2020. The available storage capacity increases by ca. 7 GW. This increase is based on projects that are already planned or are under construction. Thereafter storage capacity remains constant in both scenarios. The next step takes place in 2050 when the effective RES-E share increases to more than 90%. In Scenario A, 3.3 GW additional storage capacity is built. In Scenario B approximately 5 GW of additional storage capacity is built. The very low demand for additional storage capacity is a remarkable result.

Figure 35: Development of storage capacity



Source: own calculations.

The question arises, why the advantages of storage are not utilized at an earlier stage in the timeline and why the total need for storages is very moderate. The function of storage capacities in the model has to be explained in order to answer these questions.

The main benefit of additional storage systems in the model under the given assumptions would be to utilize renewable electricity generation that would otherwise be curtailed because national demand is already being met and the interconnectors are congested. In the case of excess production in a country, the model implicitly has three options:

1. Curtail the generation from renewable power plants. This means wasting electricity that is produced at virtually no variable costs.

2. Increase the net transfer capacity of the interconnectors. This only makes sense if the new power lines can be used often enough to justify the costs, which means that there has to be enough demand in neighbouring countries during the overproduction times.

3. Build new storage systems. In this case, most of the produced electricity can be used later, thus saving fossil fuels or even decreasing the need for peak power plants.

The economic feasibility of these options depends on the number of hours when they can be utilized. Curtailing the highest peaks of RES-E production can be reasonable to offset only few hours of excess production, because utilizing the energy requires building infrastructure that is rarely used. For this reason, curtailment takes place in all countries with significant RES-E shares at a certain number of hours.

If the number of hours of excess production is higher and there is demand in a country not too far away, it is economical to build additional lines and transport the power to meet the demand, thus utilizing the electricity.

The last option of building storage facilities makes economic sense only if two conditions are met: there are many hours of excess production and additional grid connections are not feasible because countries with remaining electricity demand in these hours are too far away. In these cases, which can be observed in both scenarios A and B in 2050 for Spain and the UK, building storage capacity is a useful and economic option.

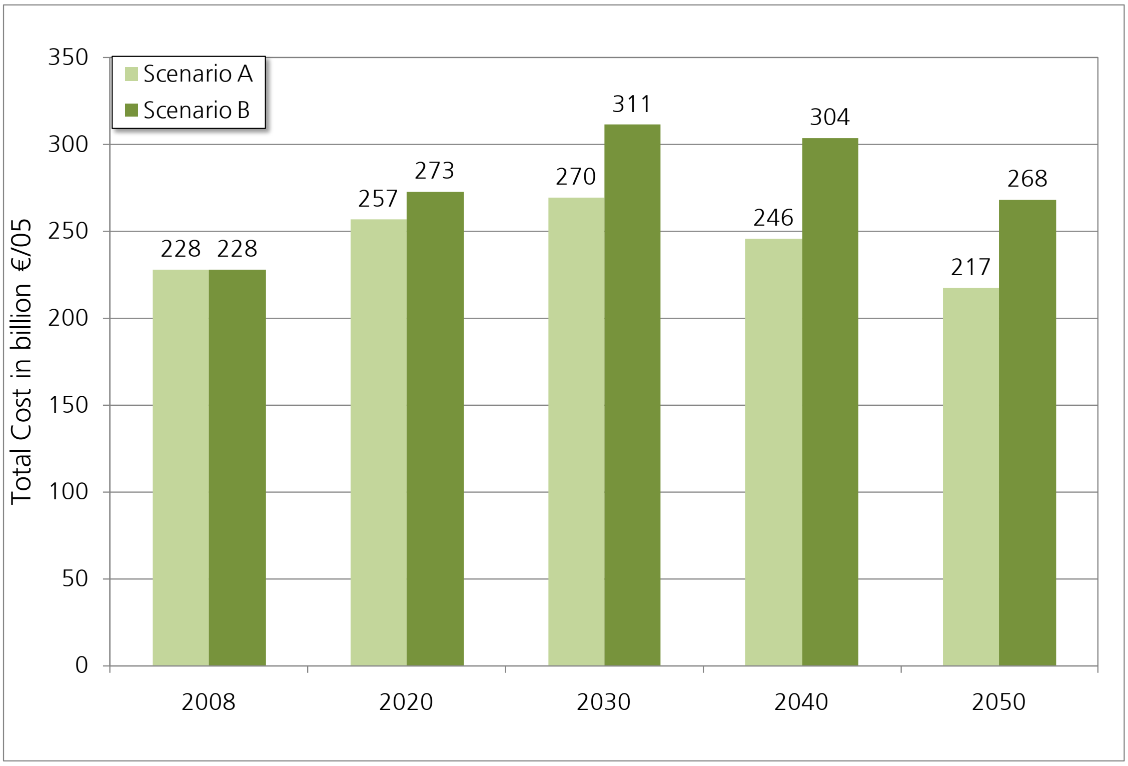
The second area of application is in systems with a total RES-share very close to 100% or for decreasing emissions very close to zero. If the electricity system comes close to the CO_2 cap, curtailing electricity and compensating the wasted power with thermal plants is no longer an option. Still, even in the scenarios of this study with very high RES-shares, the need for storage systems remains manageable. In sensitivity analysis it became clear that if further increases of the effective RES-E share or a more ambitious CO_2 cap are to be achieved, the need for storage systems increases considerably. Due to the high costs of storage systems, this is accompanied by increasing CO_2 abatement costs based on the given technology options.

6.6 Costs

A key result of the scenario is the cost development in both scenarios. When interpreting the results, it has to be taken into account that the calculations do not cover the cost of the entire electricity system: the costs for most parts of the transmission grid and the entire distribution grid are not included. The reasons for and implication of this necessary simplification are explained in section 6.4.1. However, in order to provide a basis for comparison, the entire cost analysis is also applied for the year 2008. The cost of the existing infrastructure is estimated by applying cost annuities. Since the actual cost of most installations is unknown, they are estimated with aggregate values applied for the future scenario analysis. Therefore the calculated values are subject to considerable uncertainty. Nevertheless, they provide a basis for the comparison. Figure 36 shows the development of total costs in both scenarios. Both scenarios start with total cost of ca. € 228 billion in 2008. Thereafter, the higher electricity demand in Scenario B leads to higher cost. While

Scenario A reaches its maximum in 2030 with annual cost of ca. € 270 billion, the cost of Scenario B reaches a value of € 311 billion in the same year. Due to lower demand, total costs in both scenarios decrease between 2040 and 2050 to a level of € 217 billion for Scenario A and € 268 billion in Scenario B. In relative terms, the total cost in 2050 are ca. 5% lower than in 2008 for Scenario A and ca. 18% higher in Scenario B.

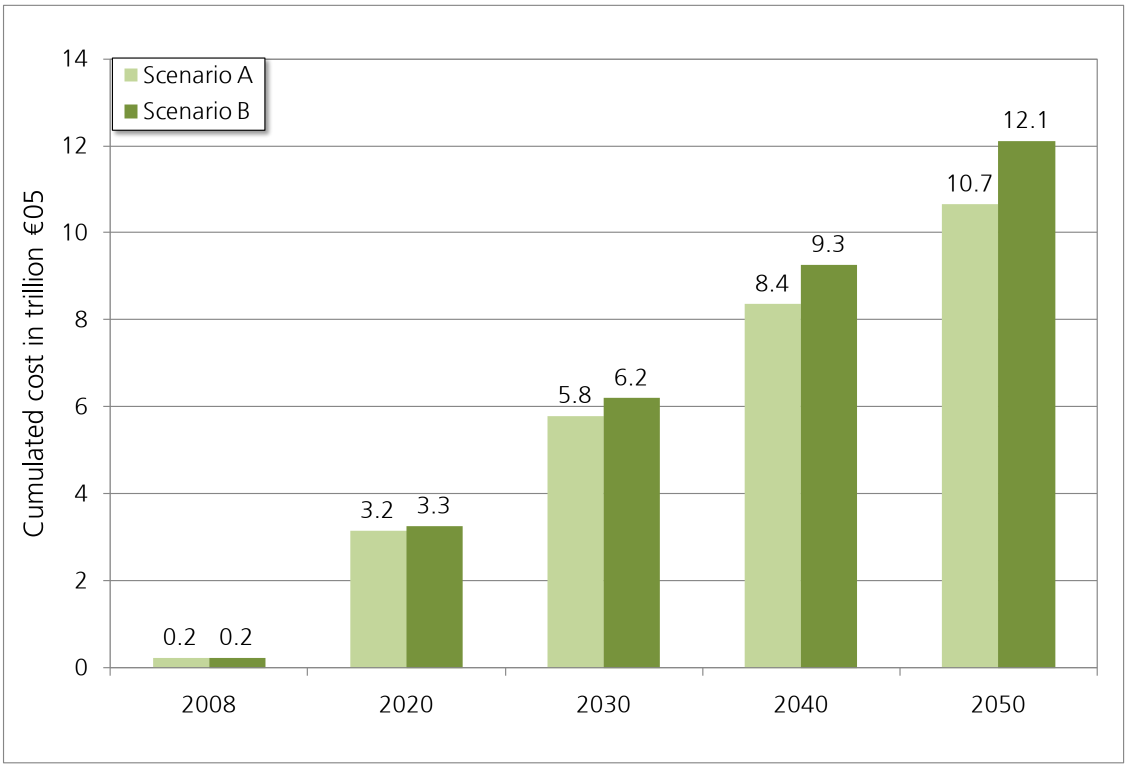
Figure 36: Development of total costs per year



Source: own calculations.

A comparison of the cumulated cost throughout the entire time period can be estimated by linear interpolation of the calculated values shown above. In cumulated terms, the total cost until 2050 reach ca. € 10.7 trillion in 2050 in Scenario A. In total, the costs of Scenario B are 14.2% higher, amounting to € 12.1 trillion. The development of cumulated costs is shown in Figure 37.

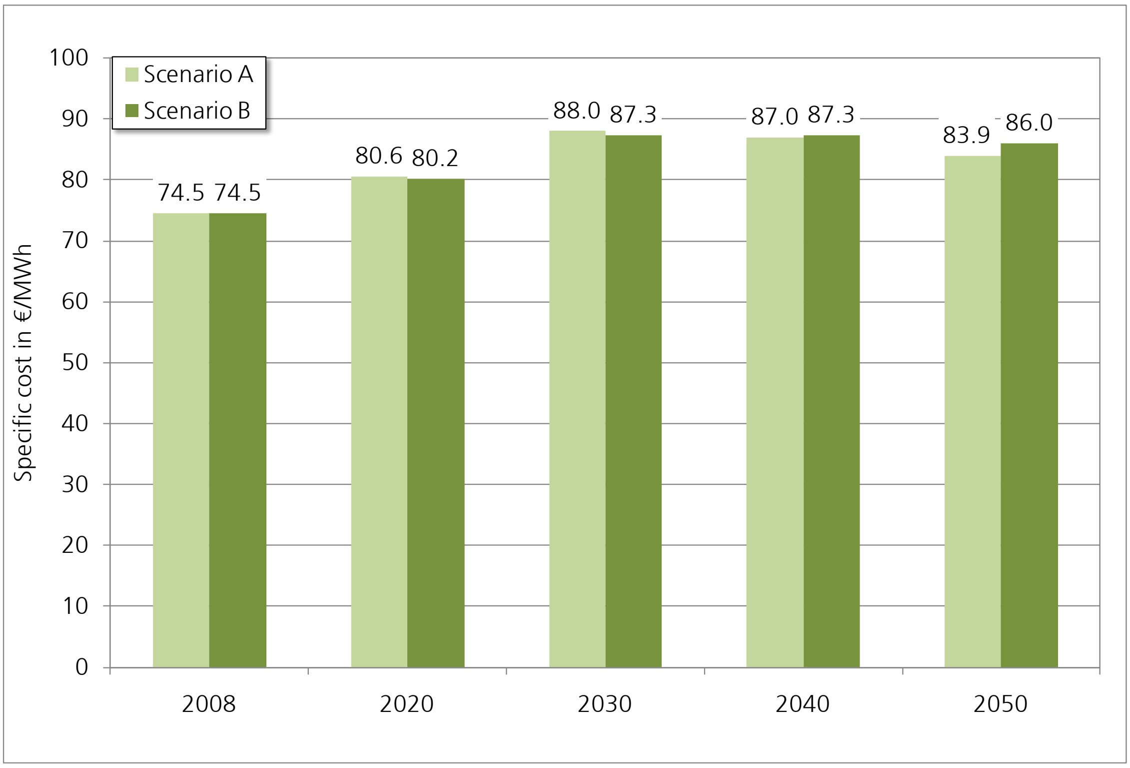
Figure 37: Development of cumulated costs



Source: own calculations.

Another important perspective in analysing the development of the cost of the electricity system is the development of specific cost per MWh. The development of specific cost is given in Figure 38. Both scenarios start with specific costs of 74.5 €/MWh. In both scenarios specific costs increase over the next decades. While Scenario A reaches its peak in specific costs with ca. 88.0 €/MWh in 2030, the total cost of Scenario A reaches a slightly lower value of 87.3 €/MWh. The comparison of both scenarios shows that specific costs in both scenarios reach a similar level in the period 2020-2040. However, in 2050 the specific cost of Scenario A is 2.1 €/MWh or ca. 2.4 % lower. Despite the ambitious reduction of CO_2 emissions, the specific costs in 2050 are only 13% (Scenario A) and 15.4% (Scenario B) higher than in 2008. As the analysis does not include most parts of the grid costs, the increase of the entire cost of electricity supply is likely to be higher, since the increase in RES-E generation and interconnector capacity is also likely to require strengthening national grid infrastructures.

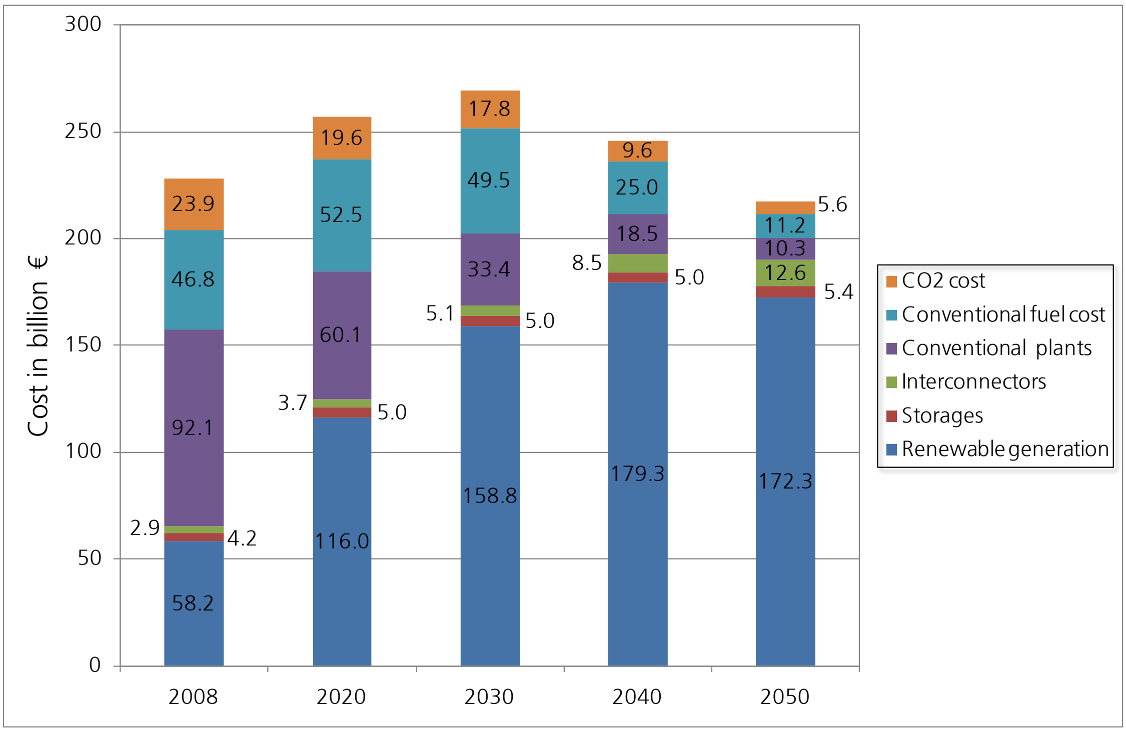
Figure 38: Development of specific cost



Source: own calculations.

A more detailed analysis of the cost development can be derived from the breakdown of the different cost factors. Figure 39 and Figure 40 show the development of the different cost components over time. Both scenarios are characterized by strong shift of cost from conventional power generation including fuel cost, CO_2 cost, operation cost and capital cost to renewable electricity generation. In line with this development, the cost for infrastructure such as storage facilities and interconnectors increases as well, but at a lower level. While the cost for renewable electricity generation in Scenario A increases from ca. € 58 billion in 2008 to ca. € 172 billion in 2050, the cost for interconnectors increases from € 2.9 billion to € 12.6 billion. The cost for storage plants increases from € 4.2 billion to € 5.4 billion in the same time period.

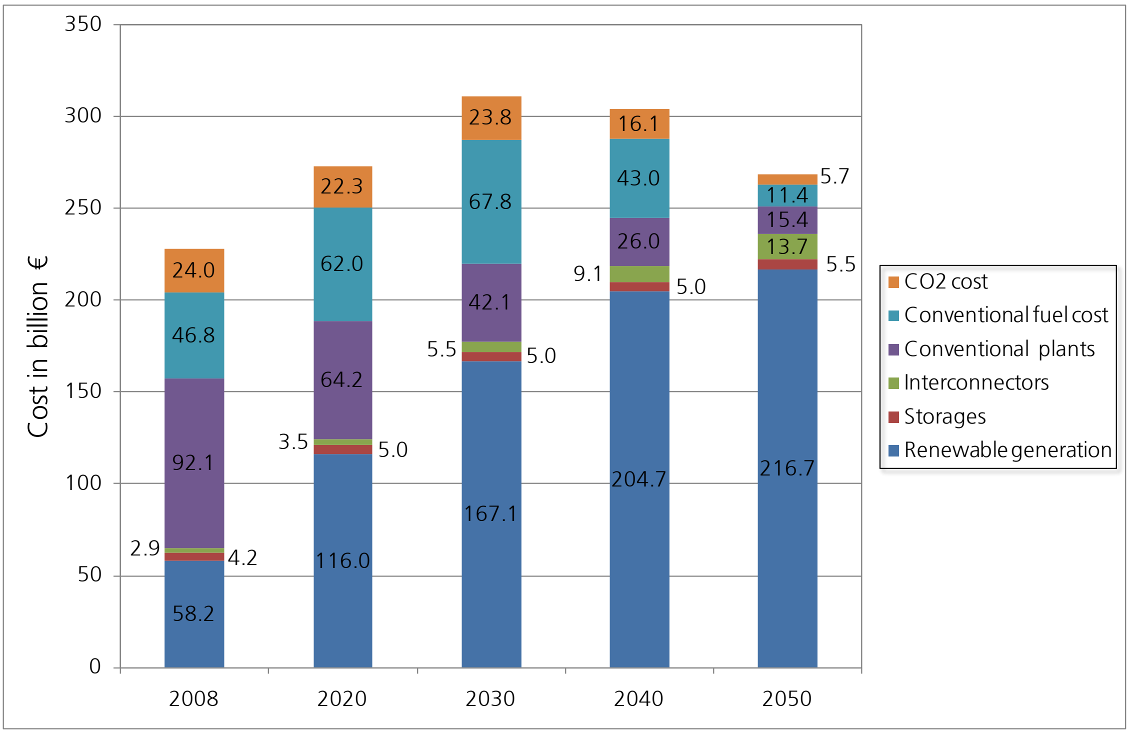
Figure 39: Development of costs in Scenario A



Source: own calculations

A similar development takes places in Scenario A. The cost for renewable electricity generation increases to ca. € 217 billion in 2050. The cost for interconnectors and storage plants increases to € 13.7 billion (interconnectors) and € 5.5 billion (storage) in 2050. Since renewable electricity generation accounts for most of the cost, it is crucial that the support schemes for RES-E generation keep the support close to the actual generation cost.

Figure 40: Development of cost in Scenario B

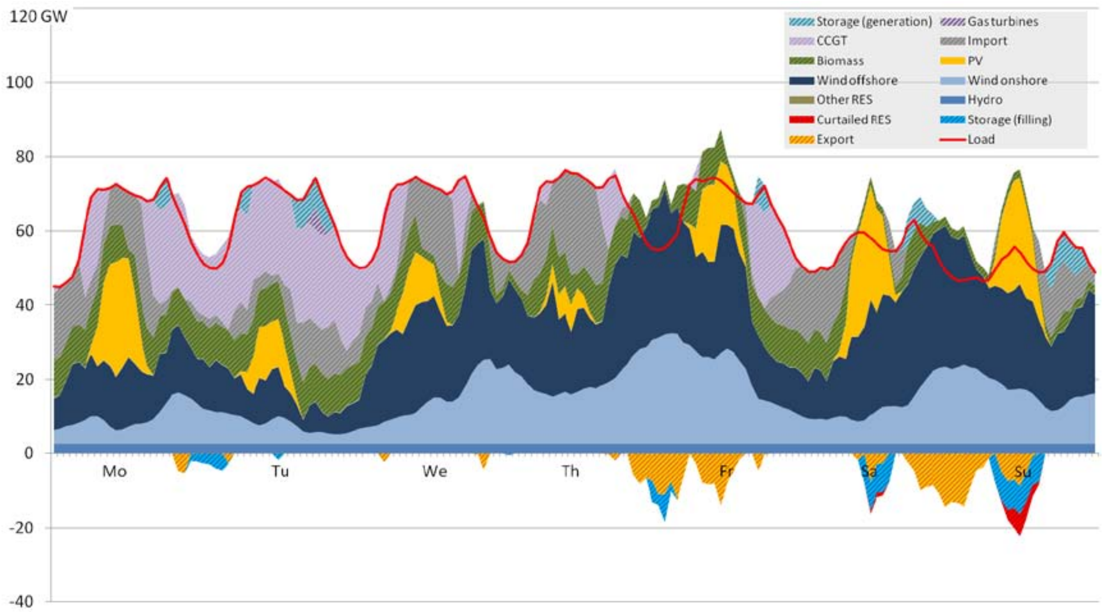


Source: own calculations.

7 Matching supply and demand in every hour

The previous sections showed that the functioning of an electricity system that is to a large extent based on renewable energy sources requires a well-balanced set of complementary components. The following section seeks to demonstrate how the components are utilized, using concrete examples of results for different countries. The goal is to show why the proposed scenarios are technically feasible, despite the fact that CCS, nuclear or imports of RES-E form northern Africa are not used in the scenarios. All examples are taken from results of Scenario B with the meteorological dataset of 2008 in order to ensure comparability.

Figure 41: Example of the hourly matching between supply and demand for Germany calendar week 42 in 2050, with weather settings of 2008



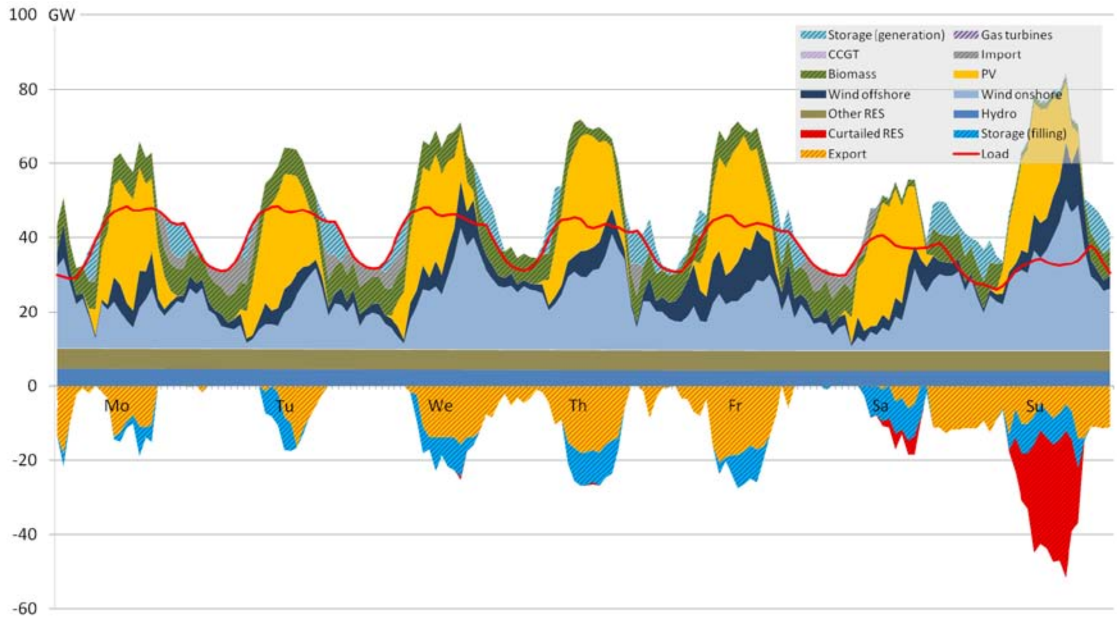
Source: own illustration

Figure 41 shows the results for Germany in a September week in Scenario B in 2050. The underlying weather data contains data from 2008. Above the x-axis the total load and the supply are depicted. Below the x-axis all system components are depicted that utilize excess generation in a given hour. Flexible components are shown striped, although it has to be kept in mind that biomass generation is only partially flexible in the model, whereas hydro is partially flexible in countries with many storage hydropower plants.

In this example, from Monday to Thursday there is only moderate generation from wind and photovoltaics. The grey dashed part indicates that Germany imports electricity, in some hours of low demand at night, almost half of the supply comes from neighbouring countries. The installed gas power plants supply significantly more than their daily average over the year, with conventional gas turbines only being used to cover peak demand on Tuesday. Pumped storage hydro plants are mostly filled in the night when demand is low.

As soon as supply exceeds demand, the excess electricity has to be handled: It can be exported, stored or curtailed; all of these procedures are shown below the x-axis. Export is in many cases the best option, as the losses are often below the losses that occur when storing electricity. Curtailment of generation only takes place if the other options are not possible. In this example, on Sunday the pumps of the pumped storage hydro plants are already operating at their maximum, biomass generation can not be decreased further due to heat led CHP plants and there is not enough demand to export all electricity.

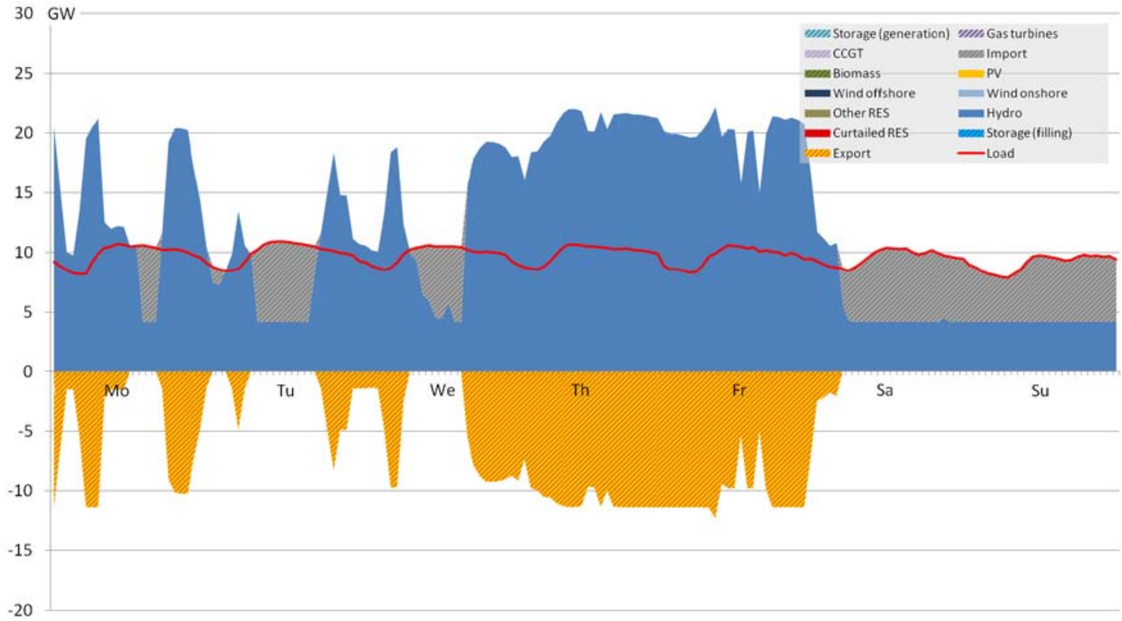
Figure 42: Example of the hourly matching between supply and demand for Spain in calendar week 27 in 2050, with weather settings of 2008



Source: own illustration.

The next example in Figure 42 shows a summer week in Spain. In both scenarios the country has a high share of both wind and solar. Supply exceeds demand for many hours of the year. In order to utilize the excess production, the transfer capacity to France is strengthened to almost 18 GW. As the example shows, the connection is used regularly during midday, often close to its full capacity. France often acts as a hub and forwards power to its neighbouring countries. Unlike in Germany, the Spanish storage systems are filled mostly around noon. The stored energy is mainly used to fill the generation gap during morning and evening hours. The high share of fluctuating generation can lead to extreme situations in hours in which a high share of the generation has to be curtailed. In this example on a Sunday, over 50% of the RES-E generation is not utilized. Nevertheless, it would be too costly to build additional storage facilities or power lines as these situations do not occur often enough.

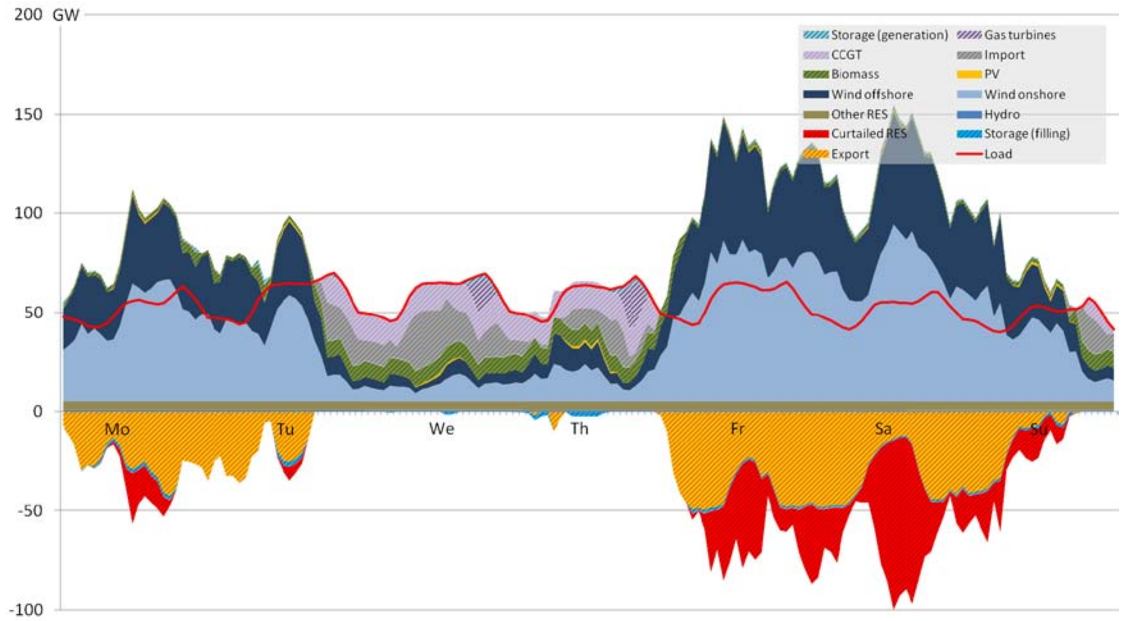
Figure 43: Example of the hourly matching between supply and demand for Norway in calendar week 29 in 2050, with weather settings of 2008



Source: own illustration.

The next example shows a typical situation of a summer week in Norway. As already mentioned, the diffusion of RES-E technologies is not modelled explicitly for Norway, as the renewable investment model covers only EU member states. Therefore, the only generation capacities are the hydropower plants installed today. The constant part of the hydro generation is produced by the country's run-of-river plants, while the flexible part is generated by over 21 GW of capacity in reservoir hydropower plants. These are not only used to cover Norwegian demand, but to a large extent are exported to neighbouring countries, including the United Kingdom. The country acts as an electricity storage system, as it imports power when other countries can provide excess energy by holding back its own production, while at other hours it produces at full capacity to cover gaps in the generation of its neighbours.

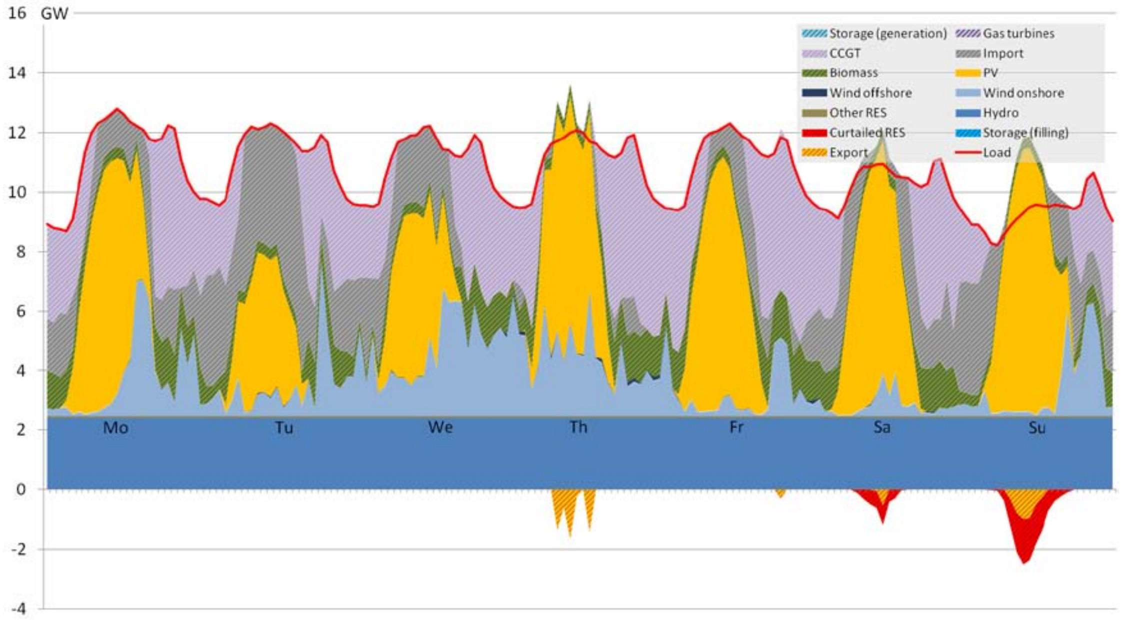
Figure 44: Example of the hourly matching between supply and demand for the United Kingdom in calendar week 29 in 2050, with weather settings of 2008



Source: own illustration.

The example depicted in Figure 44 shows the situation for the United Kingdom in the same week. In Scenario B, the United Kingdom is the greatest exporter of RES-E as the capacity of the wind turbines exceeds the country's maximum demand by far. In windy times, the country utilizes its strong connection transfer capacities of over 55 GW with its neighbouring countries for export. In very windy times in northern Europe, a significant share of the power has to be curtailed because the demand for power is low in the neighbouring countries as well. In the example this can be observed on Friday and Saturday around midday, when the existing export capacities cannot be used to their full capacity.

Figure 45: Example of the hourly matching between supply and demand for Romania in calendar week 29 in 2050, with weather settings of 2008



Source: own illustration.

Again using calendar week 29 as an example, Figure 45 shows a typical situation of the Romanian power sector in Scenario B. The country has a relative high share of hydropower plants, which are assumed to be entirely run-of-river. As can be seen, the installed PV capacity leads to very low residual load around noon on sunny summer days. During morning and evening, gas power plants and imports are used to meet demand. This is a rather typical situation for many east European countries in the scenarios, as the RES share of these countries is in most cases lower than in western and northern Europe. The lower RES share also leads to smaller demand for additional transfer capacities.

These examples above show that although the majority of the generation is weather-dependent and fluctuating, it is still possible to meet the electricity demand for every hour. The fluctuating generation is compensated by the flexibility provided by controllable RES-E generators, interconnectors, pumped storage plants and conventional power plants. Only the combination of these components allows the system to function robustly.

The examples also indicate that in order to analyze large electricity systems with very high shares of renewable energies, detailed hourly feed-in profiles of the fluctuating RES technologies over several years are necessary. Only in doing so complex weather phenomena such as long calm or cloudy periods and the interdependencies between different weather zones can be accounted for in the model.

8 Sensitivity analysis

This chapter discusses the possible impacts of changes in assumptions and input parameters to the scenarios described above. Some important aspects such as the meteorological dataset and the impact of the volume of RES-E generation are assessed in a quantitative way. In addition to the goal of assessing the robustness of the results, this chapter also seeks to deepen the understanding of underlying mechanisms in the scenarios.

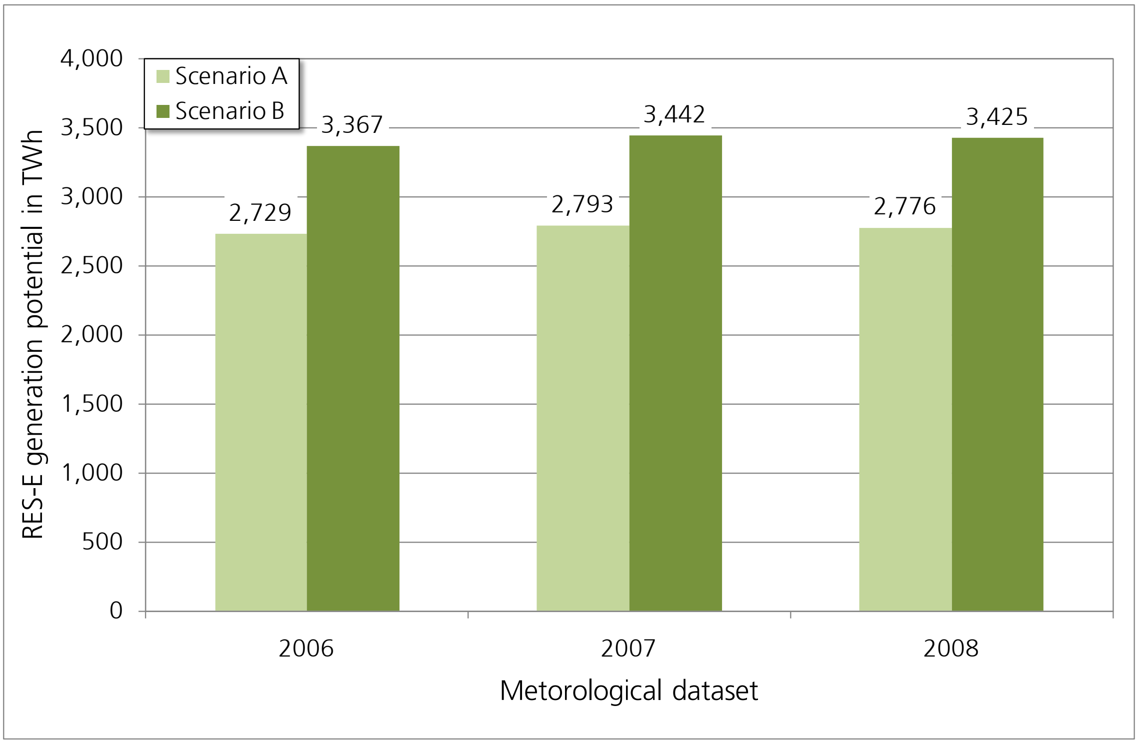
8.1 Meteorological dataset

Scenarios with renewable electricity generation are likely to be sensitive to the weather conditions in a given year, therefore this study applies three meteorological datasets. Most results presented before are averages of the three meteorological datasets. In the following sections, the differences between the results for the meteorological datasets will be analyzed in more detail.

8.1.1 Renewable electricity generation

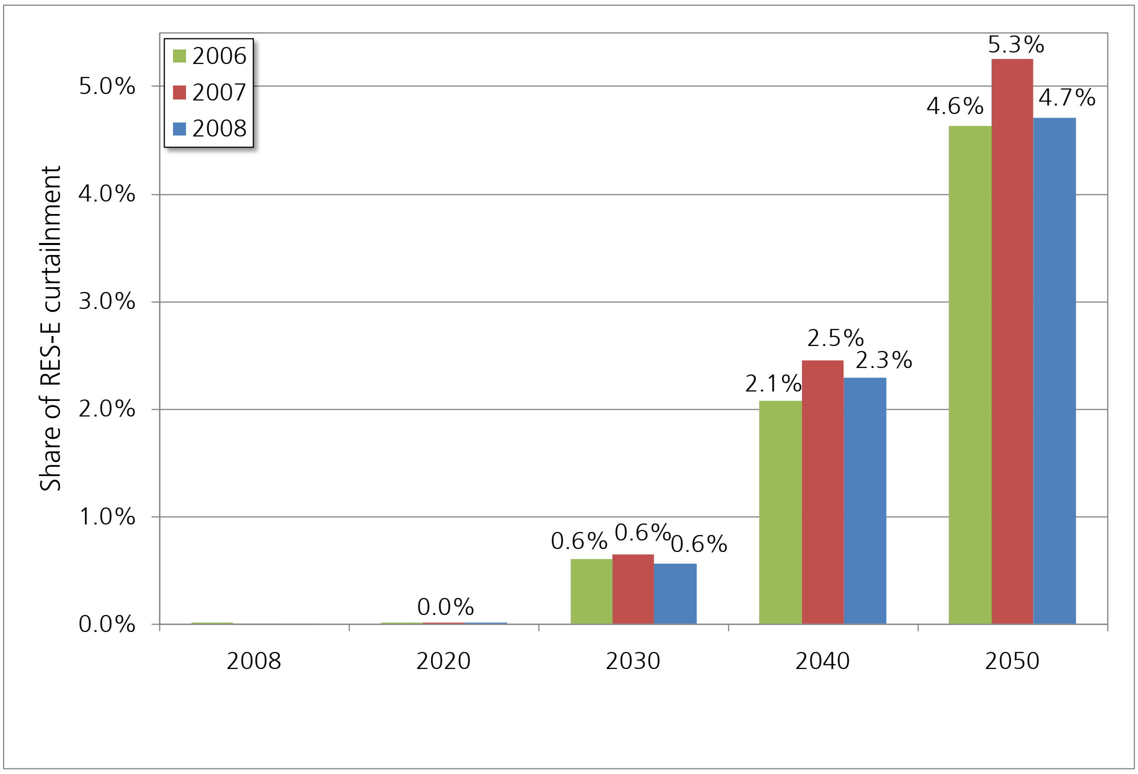
The most obvious effect of different weather conditions on the results is the impact on the amount of renewable electricity generation. Figure 46 shows the RES-E generation potential in 2050 for both scenarios and the meteorological datasets. Thereby electricity generation potential is defined as electricity that can be produced by the installed RES-E capacity if no curtailment takes place. The figure shows that the impact of weather conditions is considerable. The lowest renewable electricity generation potential is reached in the weather year 2006. With the capacity installed in 2050 in Scenario A it is 64 TWh lower than the value for the weather year 2007. In Scenario B the difference reaches 75 TWh. Taken for itself, the generation potential does not provide a complete picture of the impact of weather conditions. Another important factor is curtailment. Figure 47 shows the impact of weather conditions on curtailment in Scenario A. It can be seen that the impact of weather conditions on curtailment increases over time. In 2050, the curtailment of RES-E generation varies between 4.6 % and 5.3%. This effect reduces the differences in the actually utilized renewable electricity generation, as in a very windy or sunny year more renewable energy plants have to be curtailed.

Figure 46: Impact of meteorological dataset on RES-E generation potential in 2050



Source: own calculations.

Figure 47: Impact of meteorological dataset on RES-E curtailment in Scenario B

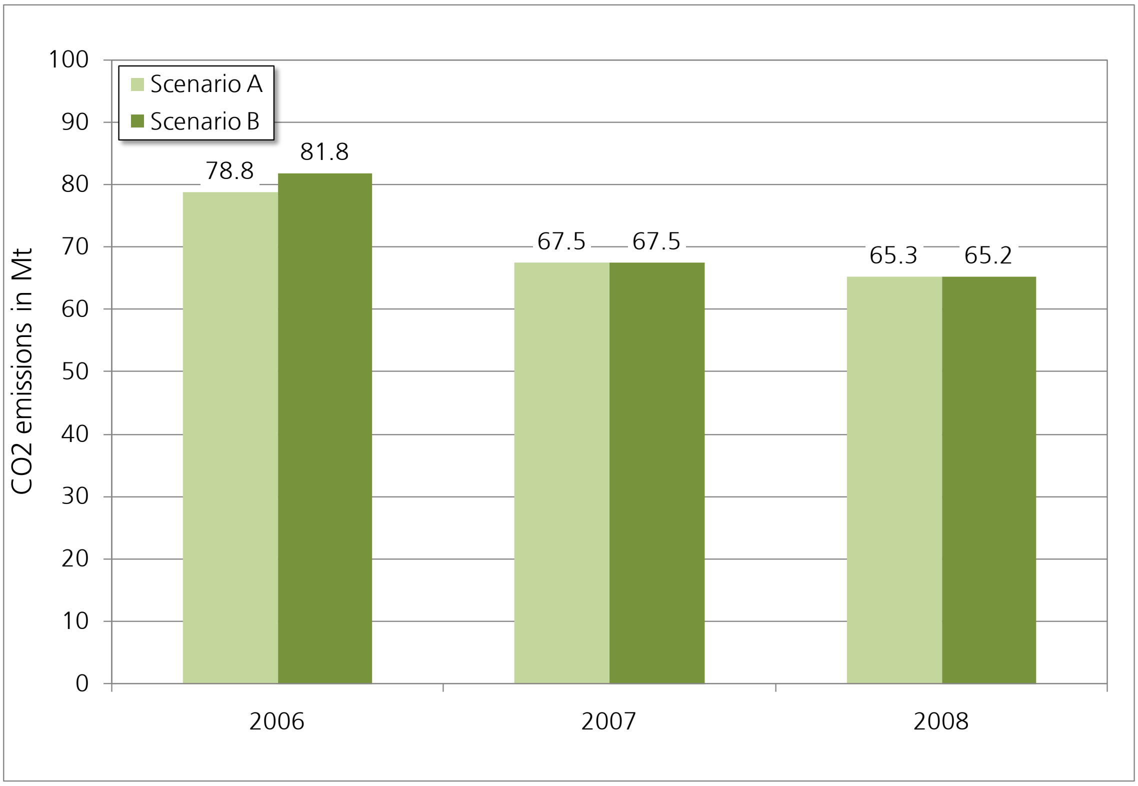


Source: own calculations.

8.1.2 CO_2 Emissions

The differences in renewable electricity generation between the meteorological datasets directly relates to CO_2 emissions in the scenarios. A comparison of the CO_2 emissions in 2050 is given in Figure 48. Generally, CO_2 emissions are lowest in 2008. In Scenario B the difference between 2008 and 2006 reaches 14.4 Mt, which relates to more than 25%. This figure indicates the importance of utilizing different meteorological datasets in a scenario analysis.

Figure 48: Impact of meteorological dataset on CO_2 emissions in 2050



Source: own calculations.

8.1.3 Infrastructure

Other important aspects which are influenced by the meteorological dataset are the required infrastructures, such as conventional power plants, interconnectors and storage capacity. The experience of the analysis carried out in this study shows that not only the total RES-E generation potential is important to the results, but also its timely distribution and correlation with electricity demand. In the analysis conducted, the biggest additions to the interconnector capacity are necessary for the meteorological dataset of the year 2008. In the case of Scenario A, the differences in the total interconnector capacity required for the different meteorological dataset is between 3% and 15% for the analyzed time period 2020 to 2050. In Scenario A the relation is comparable. A detailed comparison of the required interconnector capacity for the different meteorological datasets is given in Table 12.

Table 12: Impact of the meteorological dataset on the required interconnector capacity

Year	2006		2007		2008	
	Scen. A	Scen. B	Scen. A	Scen. B	Scen. A	Scen. B
2020	71.6	68.5	73.9	69.6	73.9	69.6
2030	91.6	91.2	95.2	101.2	96.2	103.9
2040	131.3	151.7	141.1	167.0	143.9	170.4
2050	157.7	217.6	171.4	243.8	181.6	251.5

Source: own calculations.

8.2 Renewable energy technology parameters

The utilization of renewable generation is based on available technologies. If technology learning is faster than assumed, or technologies with higher energy yield such as wind turbines with increased hub height are available, the cost of renewable generation will be lower than forecasted in the scenarios. This will also lead to lower total system costs. The application of very conservative assumptions of the energy yield per capacity, especially for wind energy, is intended to create robust results, as this approach is likely to overestimate the cost. Lower renewable generation cost could also lead the situation that a slightly higher RES-E share in 2050 represents a more cost-efficient solution. In the case of slower technology learning and lower energy yield, the effects will be reversed.

8.3 Renewable energy imports (e.g. Desertec)

This study shows that high diffusion of renewables and low carbon intensity of the electricity sector can be reached without RES-E imports, if efforts to increase efficiency in electricity consumption are successful. If additional RES-E imports, for example from northern Africa as proposed in the Desertec concept, were made available to the modelling system, it is possible that overall cost would be lower. However, it is uncertain whether the flexibility or possibility of cheaper generation cost will outweigh the additional cost in grid infrastructure necessary for utilizing the imports. An assessment of the potential costs and benefits should take into account that the required growth of interconnector capacity between the Mediterranean area and central Europe already reaches high levels in the developed scenarios. If electricity demand increases to high levels in 2050, the utilization of RES-E imports could be inevitable in order to reach high RES-E targets. This discussion shows that an analysis addressing these issues could provide interesting insights but is beyond the scope of this study.

8.4 Availability of CCS and nuclear power

In technical terms, CCS and nuclear electricity generation are potential options for reducing CO_2 emissions in the electricity sector. However, high construction costs, political uncertainties and the unsolved problems regarding long-term nuclear waste management render both options a risky investment. In the given scenario, both technologies are not likely to attain adequate utilization in the case of the high penetration rates of renewables in 2050. Depending on the actual construction costs, some CCS or nuclear capacity could be profitable up to 2040. However, a detailed analysis with varying renewable penetration rates and construction costs of these plant types could provide additional insights which cannot be generated within the scope of this study.

8.5 Fuel prices

In most scenarios for the development of the electricity sector, fuel prices play a central role in calculating the results. However, in the given scenario framework the impact of conventional fuel prices on the results is limited. The main driver in the scenario is the CO_2 cap and the development of renewable electricity generation. However, higher conventional fuel prices could move the results towards a slightly higher renewable penetration, slightly higher interconnector capacity, storage systems and vice versa. A change in the relation between coal and gas prices could also have a slight impact on the results for the years 2020-2030. Cheaper coal could lead to a limited increase of coal capacity in 2020 at the cost of gas-fired units. However, the effect is likely to be limited, as coal depreciation times are low due to the low utilization after 2030. Higher gas prices on their own could lead to a limited shift from gas turbines to the more efficient combined cycle plants.

8.6 CO_2 prices

Similar to the fuel prices, the impact of CO_2 prices on the overall results is limited. It is outweighed by the general CO_2 cap for 2050. Again, the CO_2 price is applied as an exogenous paramter in this study. In reality, these parameters are linked strongly. In the given scenarios, higher CO_2 prices would slightly increase the profitability of additional RES-E generation or infrastructure in terms of interconnectors or storage systems. In the conventional generation portfolio, higher CO_2 prices shift the profitability of CO_2-intensive technologies towards less CO_2 intensive technologies and vice versa. In this scenario set-up, more electricity generation would be shifted from coal to CCGT in 2020 and 2030. In 2050 gas-fired generation would be shifted from GT to CCGT.

8.7 CO_2 cap

The CO_2 cap in 2050 has an important impact on the results. Lowering the CO_2 cap increases the cost of the system. The modelling system reacts to a lower CO_2 cap by higher renewable electricity generation and more infrastructures in terms of interconnector capacity and storages. Experimental model runs show that lowering the CO_2 cap while keeping RES-E generation constant leads to an enormous increase in demand for storage capacity. In the case of a slightly higher CO_2 cap, the costs of the system are reduced, but the impact on the general infrastructure is moderate.

8.8 Volume of RES-E generation

The relation of RES-E generation to the CO_2 cap is crucial to the results of the scenarios. Since an integrated optimization of the power system and renewable investment is not possible with the given resources, the adequate RES-E generation is determined by an iterative procedure. The main procedures and results concerning the total cost of the electricity system are already described in chapter 3.1. In this section, the underlying mechanisms driving the cost will be indentified. Table 13 shows the impact of a variation of the renewable electricity generation and fixed CO_2 cap on major indicators, such as storage capacity, cost of interconnectors and RES-E curtailment. If renewable generation capacity is reduced, the model has to reduce RES-E curtailment in order to meet the CO_2 target. In the case of ca. 40 TWh less renewable generation potential, ca. 6 GW additional storage capacity is required. The required increase of interconnectors leads to additional costs of € 2.4 billion per year. If renewable generation is further reduced, additional storage capacity jumps to ca. 38 GW which shows that the model is close to infeasibility.

If renewable electricity generation is increased above the selected level in the scenario, storage capacity is also slightly increased as the possibilities for using storage capacity increase. However, more than 50 % of the additional renewable generation needs to be curtailed. These mechanisms lead to the situation that less renewable capacity leads to higher system costs as the costs for infrastructure grows faster than the saved costs for renewable capacity. On the other side, the costs of additional renewable generation outweigh the savings in infrastructure.

Table 13: Impact of RES-E generation on the electricity system in 2050 (Scenario A)

RES-E generation	Storage capacity	Cost of interconnectors	RES-E curtailment
TWh	GW	billion €	TWh
-78.9	37.8	4.8	-79.5
-39.4	5.9	2.4	-35.7
0.0	0.0	0.0	0.0
39.5	0.4	0.1	27.1
78.9	0.8	0.6	42.5

Source: own calculations.

8.9 Demand-side management

Due to the fact that the demand for additional storage plants is rather low in both scenarios, demand-side management is not taken into account in the analysis. If additional flexibility in electricity demand could be activated, it is likely that demand for storage capacity is reduced further. Demand-side management could also reduce the demand for conventional and interconnector capacity. As a consequence, demand-side management would reduce the cost of the scenario. From another point of view, it can be stated that the non-use of demand-side management in the created scenario shows their robustness. If necessary, additional flexibility could be activated in the described electricity system by demand-side management.

9 Conclusions and outlook

This study investigates concrete and realizable ways towards a European electricity sector in line with the goal of keeping global warming at a minimum level. It shows that an ambitious reduction of greenhouse gas emissions to 5% of 1990 levels based on a high penetration of renewable electricity generation is possible. The system is stable for three meteorological datasets (26,304 hours). In the transition towards a low carbon power sector, only technologies that are available as of today are utilized. The analysis does not rely on new renewable generation technologies or options that are subject to substantial technical, economical or political uncertainties, such as new nuclear power plants or CCS. A similar argumentation applies to imports from non-European countries. They are not utilized in order to prove that a stable system can be established even without this option. Absolute and specific costs of the system remain at a level comparable to current cost of the system. Since the analysis framework does not include national grid infrastructures, additional costs are likely to occur, but are difficult to estimate.

A key result of both scenarios is that it is very important to strengthen the grid connections between the countries. Total interconnector capacity grows from ca. 56 GW in 2008 to 182 GW (Scenario A) and 252 GW (Scenario B), respectively. Important routes in this context are the connections between Britain and the continent, connections to the Alpine region, connections to Scandinavia and transit routes in western Europe.

A striking result is that the demand for additional storage capacity is rather low. The total storage capacity grows only by 3 - 5 GW above the expected level in 2020. However, the sensitivity analysis shows that this result is based on a good balance of RES-E shares and emission reductions, otherwise demand for storage can be higher.

Another central finding of the scenario comparison is that increased efforts to strengthen the efficiency in electricity consumption can lower demand for infrastructures like interconnector capacity considerably. In Scenario A "High efficiency" the need for new interconnection capacity is 70 GW below the requirements in Scenario B "Moderate efficiency". This is one of the reasons for the total cost in 2050 being € 51 billion lower in Scenario A. However, the specific cost per MWh is on a comparable level in both scenarios. Despite the ambitious reduction of CO_2 emissions, the specific costs in 2050 are only 13% (Scenario A) and 15.4% (Scenario B) higher than in 2008.

An interesting side effect of the analysis that an adequate distribution of renewable generation leads to lower system costs than a system which is based on pure optimization of RES-E costs which could be be reached by a simplified least cost resource allocation without consideration of infrastructure costs and constraints.

From the methodological perspective, it can be stated that the analytical framework developed can provide valuable insights for the further development of the electricity sector in Europe. The use of different meteorological datasets increased the reliability of the results and provides additional information on the impact of different weather conditions. It could be valuable to apply the analytical framework developed for additional scenarios, including higher electricity demand or RES-E imports from northern Africa. In methodological terms, the task for future analysis is to provide a more detailed representation of the electricity grid.

10 Appendix

Table 14: Data Sheet; Region: EU27 +2M; year: 2050

Category	Scenario A	Scenario B	Unit
Net electricity generation	2,866	3,452	TWh
Grid losses	257	317	TWh
Storage losses	42	19	TWh
Net electricity demand	2,567	3,117	TWh
Effective RES-E generation	2,665	3,246	TWh
Effective RES-E share	93%	94.0%	-
Conventional generation	201	207	TWh
CO_2 emissions	71	72	Mt
Interconnector capacity	182	252	GW
Storage capacity	47.7	49.3	GW
Installed conv. capacity	160	236	GW
Wind onshore capacity	419	599	GW
Wind offshore capacity	160	191	GW
PV capacity	289	325	GW
Renewable generation	172.3	216.7	Billion €05
Specific RES-E cost	64.64	66.75	€05/MWh
Storages	5.4	5.5	Billion €05
Interconnectors*	12.6	13.7	Billion €05
Conv Plants	10.28	15.44	Billion €05
Fuel cost	11.2	11.4	Billion €05
CO_2 cost	5.6	5.7	Billion €05
Sum	217.3	268.4	Billion €05
Specific cost of demand	84.67	86.12	€/MWh

Source: own calculations

Table 15: Development of electricity demand in Scenario A

Year	2008[16]	2020	2030	2040	2050	Unit
AT	68	57	54	50	46	TWh
BE	90	77	76	75	73	TWh
BG	34	29	28	28	29	TWh
CH	64	79	75	69	63	TWh
CY	5	7	6	6	5	TWh
CZ	65	66	59	56	55	TWh
DE	556	538	512	463	416	TWh
DK	36	40	40	38	36	TWh
EE	8	8	8	7	7	TWh
ES	270	297	283	263	236	TWh
FI	87	84	79	71	65	TWh
FR	493	499	485	428	380	TWh
GR	56	66	62	56	51	TWh
HU	41	42	39	35	33	TWh
IE	29	30	30	29	29	TWh
IT	339	352	348	324	294	TWh
LT	12	10	10	9	9	TWh
LU	7	6	6	6	6	TWh
LV	8	8	7	7	7	TWh
MT	2	3	3	2	2	TWh
NL	120	126	123	114	105	TWh
NO	129	109	99	88	79	TWh
PL	142	153	152	148	140	TWh
PT	52	66	71	67	61	TWh
RO	55	74	75	82	83	TWh
SE	144	129	120	109	99	TWh
SI	13	14	13	12	11	TWh
SK	28	50	48	43	38	TWh
UK	366	417	406	378	348	TWh
Sum	3,318	3,436	3,316	3,062	2805	TWh

Important note: Electricity demand includes national grid losses, but excludes storage losses and interconnector losses. Scaling of national values in the period 2020-2050 is based on the ADAM study (Jochem & Schade 2009).

16 Data for 2008 is based on ENTSOE and Eurostat (Final electricity consumption +7.5% grid losses) Link:

Eurostat: http://epp.eurostat.ec.europa.eu/tgm/table.do?tab=table&init=1&plugin=1&language=en&pcode=ten00097

ENTSOE: https://www.entsoe.eu/resources/data-portal/consumption/

Table 16: Development of electricity demand in Scenario B

Year	2008[17]	2020	2030	2040	2050	Unit
AT	68	66	66	60	49	TWh
BE	90	93	91	82	67	TWh
BG	34	28	29	29	27	TWh
CH	64	64	61	52	39	TWh
CY	5	5	5	5	5	TWh
CZ	65	60	61	59	52	TWh
DE	556	639	654	624	549	TWh
DK	36	49	52	53	51	TWh
EE	8	8	9	10	9	TWh
ES	270	298	335	345	320	TWh
FI	87	84	85	82	76	TWh
FR	493	541	550	512	426	TWh
GR	56	62	68	68	62	TWh
HU	41	40	45	47	44	TWh
IE	29	35	38	38	34	TWh
IT	339	372	383	362	311	TWh
LT	12	10	11	12	12	TWh
LU	7	10	11	11	11	TWh
LV	8	7	8	9	9	TWh
MT	2	3	3	3	2	TWh
NL	120	131	137	132	116	TWh
NO	129	132	131	124	112	TWh
PL	142	153	178	196	191	TWh
PT	52	54	61	64	62	TWh
RO	55	58	75	91	96	TWh
SE	144	160	164	161	154	TWh
SI	13	12	12	11	9	TWh
SK	28	28	30	31	29	TWh
UK	366	476	507	500	451	TWh
Sum	**3,318**	**3,677**	**3,861**	**3,774**	**3,376**	**TWh**

Important note: Electricity demand includes national grid losses, but excludes storage losses and interconnector losses. Scaling of national values is based on the TRANS-CSP study(DLR 2006).

17 Data for 2008 is based on ENTSOE and Eurostat (Final electricity consumption +7.5% grid losses) Link:

Eurostat: http://epp.eurostat.ec.europa.eu/tgm/table.do?tab=table&init=1&plugin=1&language=en&pcode=ten00097

ENTSOE: https://www.entsoe.eu/resources/data-portal/consumption/

Table 17: Input prices for fuels and emission permits

Year	Gas	Coal	Oil	Lignite	Nuclear	CO_2 Price
	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€ /t
2008	27.11	12.73	50.23	3.80	3.68	15.0
2020	28.74	13.74	48.31	3.80	3.68	25.0
2030	30.84	15.39	45.22	3.80	3.68	35.0
2040	31.07	17.03	34.31	3.80	3.68	55.0
2050	31.82	18.67	30.15	3.80	3.68	80.0

Source: Schade & Jochem (2009) and own calculations.

Table 18: Installed development of RES-E capacity (Scenario A)

Technology	2008	2020	2030	2040	2050	Unit
Biogas	2	11	56	17	18	GW
Solid biomass	13	32	43	42	42	GW
Biowaste	3	3	5	3	3	GW
Geothermal	1	2	159	2	2	GW
Hydro	183	166	171	172	172	GW
Landfill gas	2	2	5	5	5	GW
Sewage gas	1	-	0	1	1	GW
Photovoltaics	10	85	170	268	289	GW
Solar thermal	0	7	15	15	15	GW
Tide	0	1	3	3	3	GW
Wave	-	1	7	11	11	GW
Windoffshore	1	43	107	144	160	GW
Windonshore	63	170	292	404	419	GW
Total	**278**	**523**	**831**	**1,088**	**1,141**	**GW**

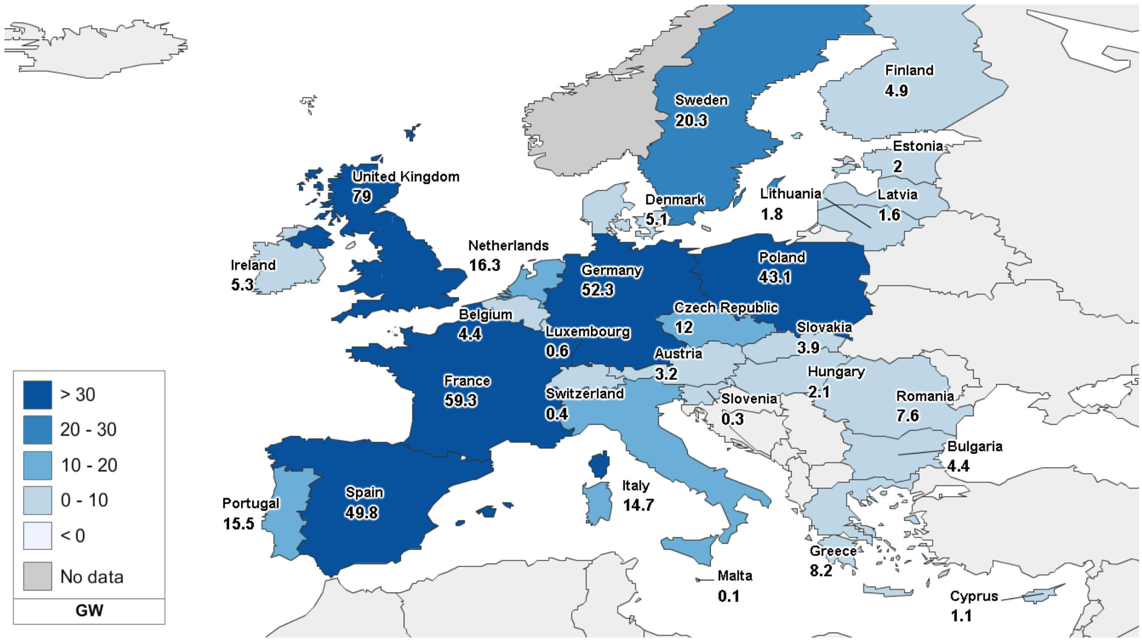
Source: own calculations based on the model PowerACE-ResInvest.

Table 19: Development of RES-E capacity (Scenario B)

Technology	2008	2020	2030	2040	2050	Unit
Biogas	2	11	17	21	22	GW
Solid biomass	13	32	43	50	54	GW
Biowaste	3	3	3	3	3	GW
Geothermal	1	2	2	2	2	GW
Hydro	46	18	28	29	29	GW
Landfill gas	2	2	5	5	5	GW
Sewage gas	1	-	0	1	1	GW
Photovoltaics	10	85	171	282	325	GW
Solar thermal	0	7	16	18	18	GW
Tide	0	1	3	6	6	GW
Wave	-	1	8	18	20	GW
Windoffshore	1	43	117	161	191	GW
Windonshore	63	170	313	484	599	GW
Total	**278**	**530**	**880**	**1,232**	**1,428**	**GW**

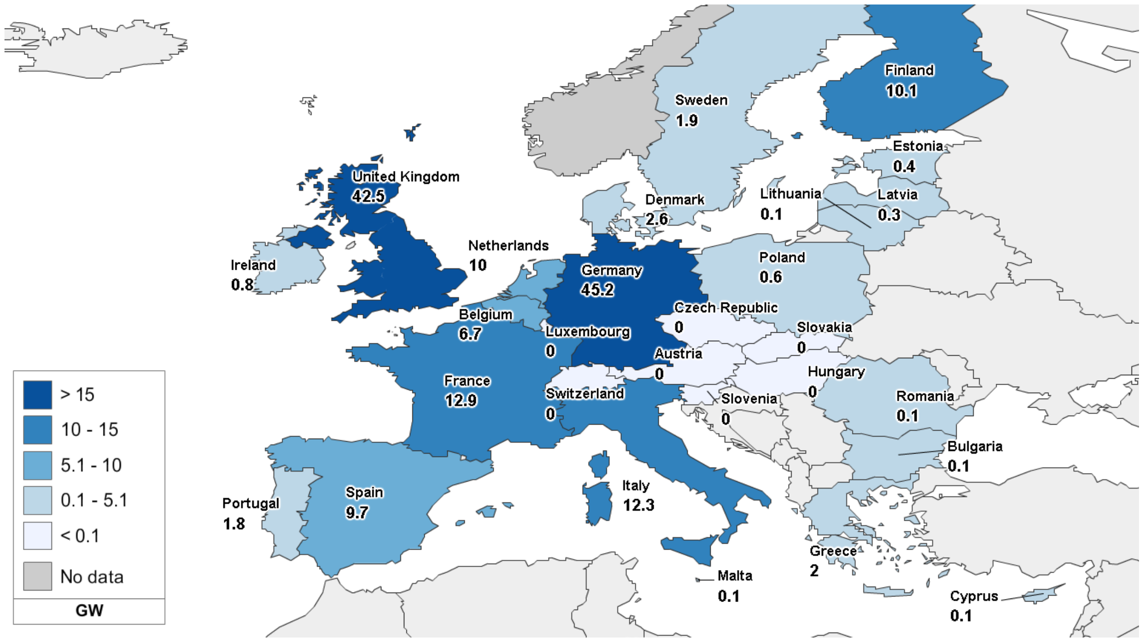
Source: own calculations based on PowerACE-ResInvest

Figure 49: Installed wind onshore capacity in 2050 (Scenario A)



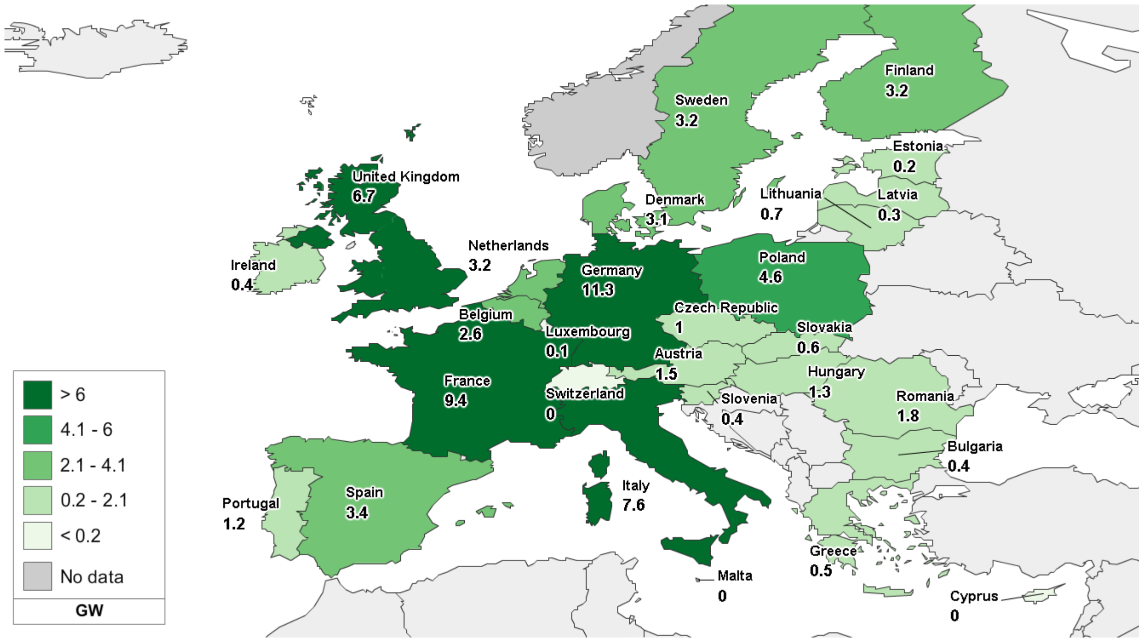
Source: own calcualtions, map visualization with StatPlanet.

Figure 50: Installed wind offshore capacity in 2050 (Scenario A)



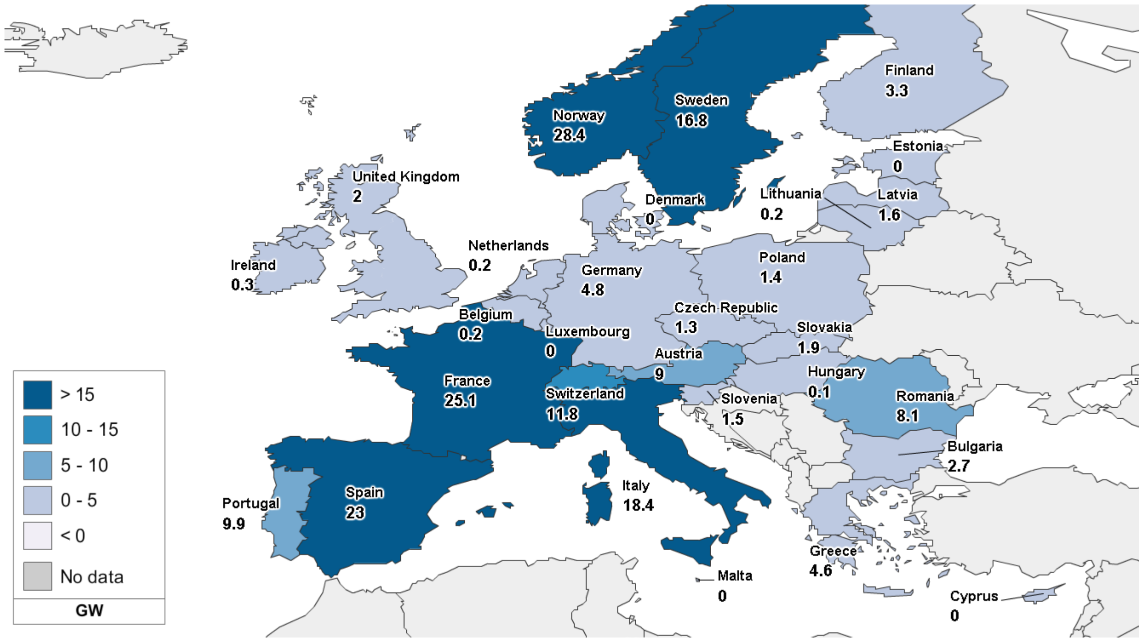
Source: own calcualtions, map visualization with StatPlanet.

Figure 51: Installed biommass and biogas capacity in 2050 (Scenario A)



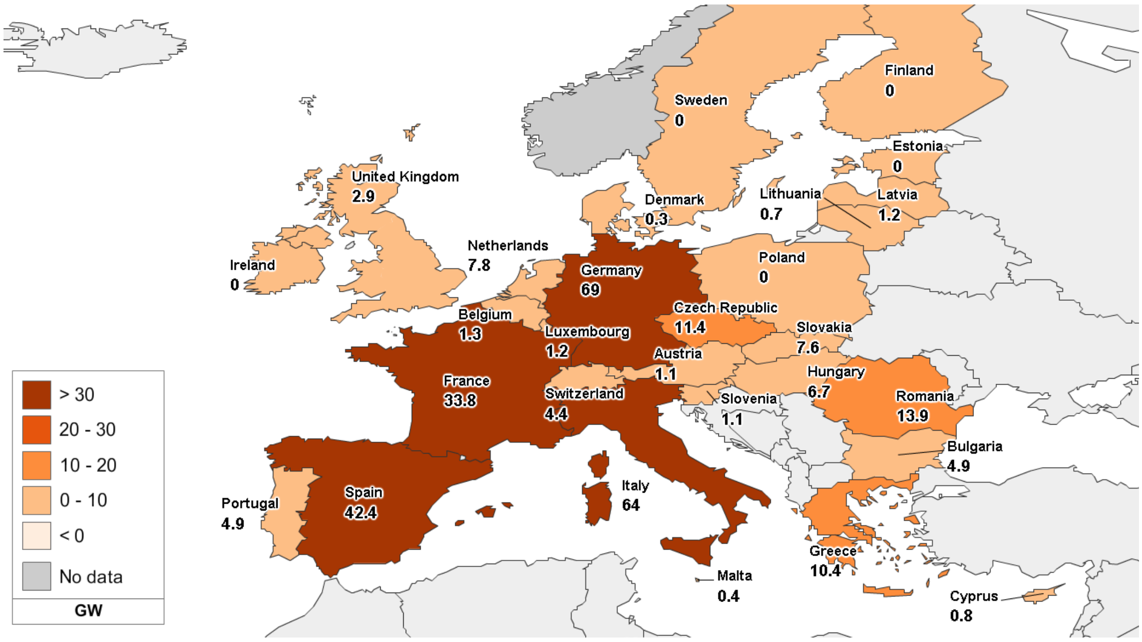
Source: own calcualtions, map visualization with StatPlanet.

Figure 52: Installed hydropower capacity in 2050 (Scenario A)



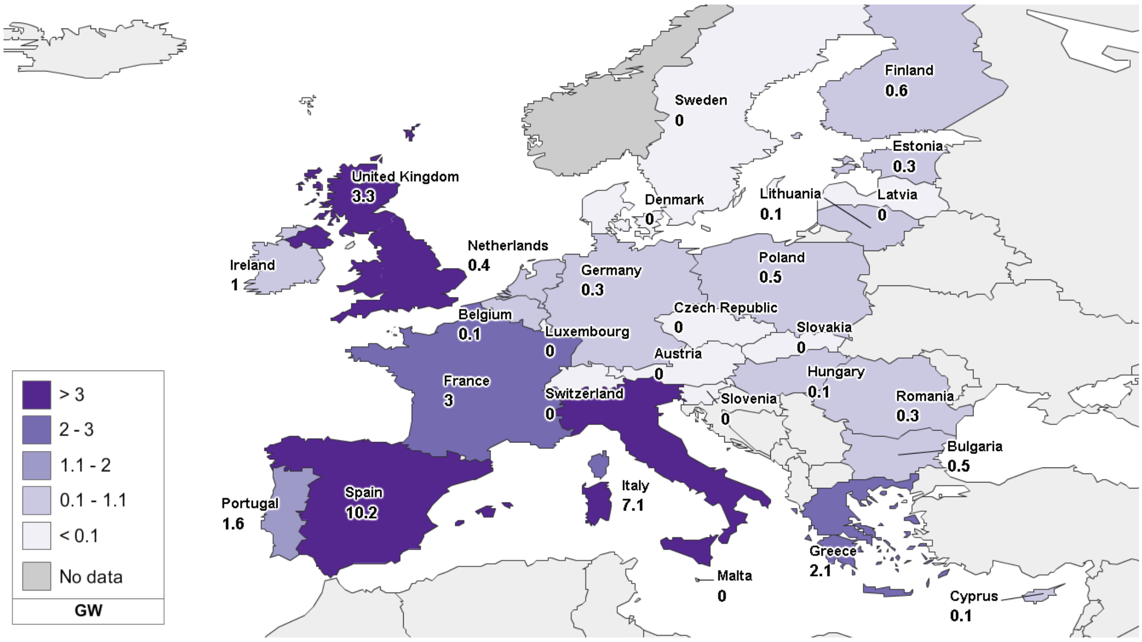
Source: own calcualtions, map visualization with StatPlanet.

Figure 53: Installed photovolatics capacity in 2050 (Scenario A)



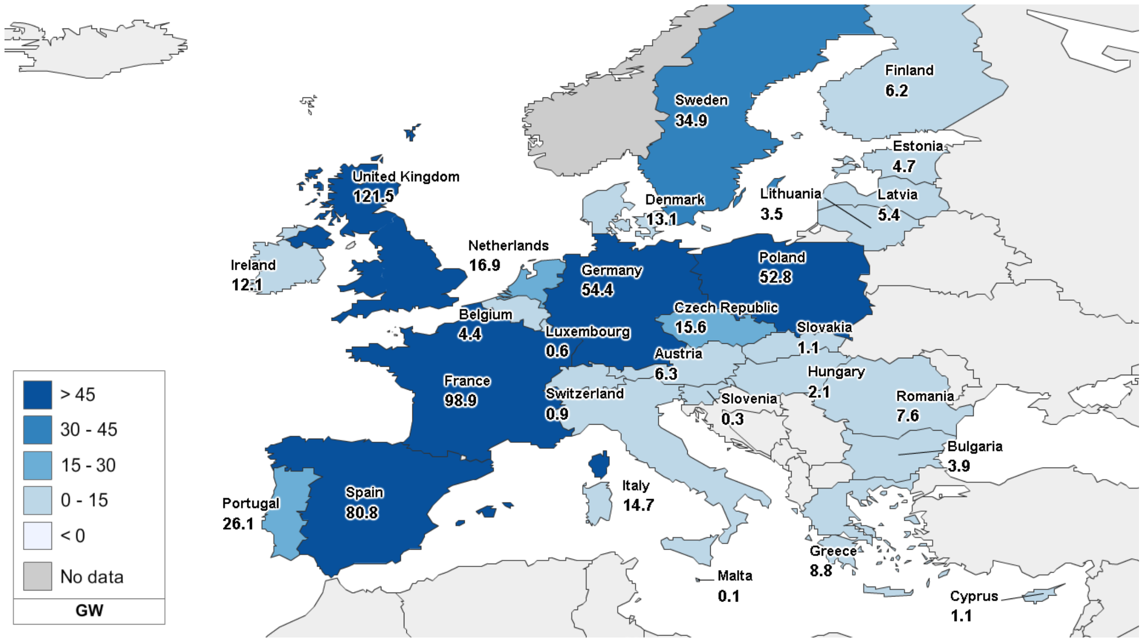
Source: own calcualtions, map visualization with StatPlanet.

Figure 54: Installed capacity of other technologies (biowaste, sewage and landfill gas, wave, tidal, geothermal and solar thermal) in 2050 (Scenario A)



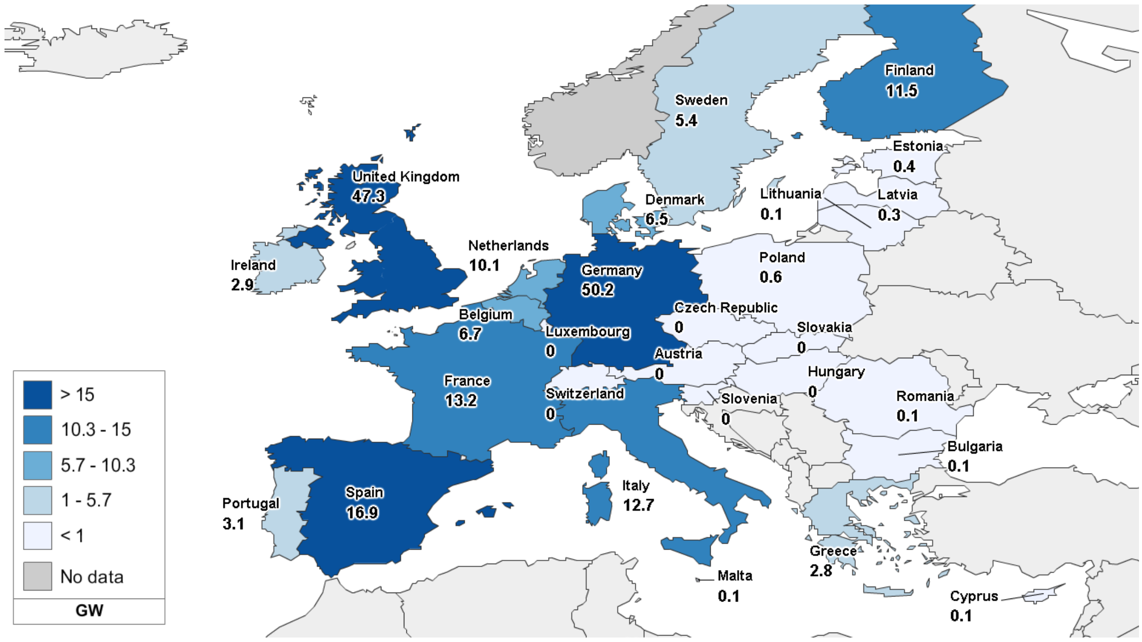
Source: own calcualtions, map visualization with StatPlanet.

Figure 55: Installed wind onshore capacity in 2050 (Scenario B)



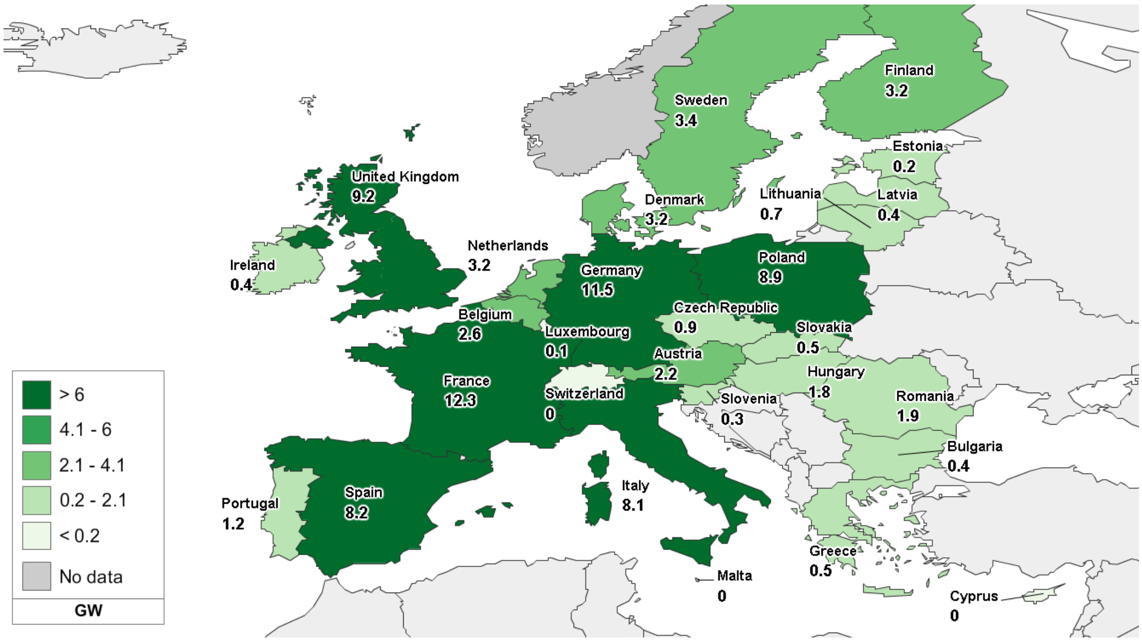
Source: own calcualtions, map visualization with StatPlanet.

Figure 56: Installed wind offshore capacity in 2050 (Scenario B)



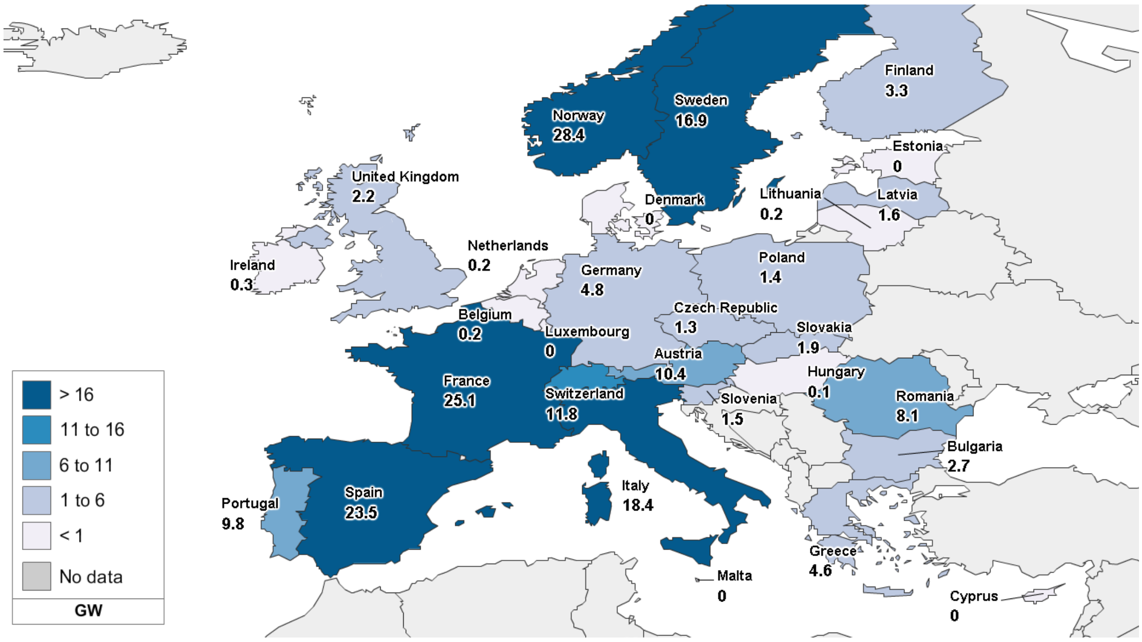
Source: own calcualtions, map visualization with StatPlanet.

Figure 57: Installed biomass and biogas capacity in 2050 (Scenario B)



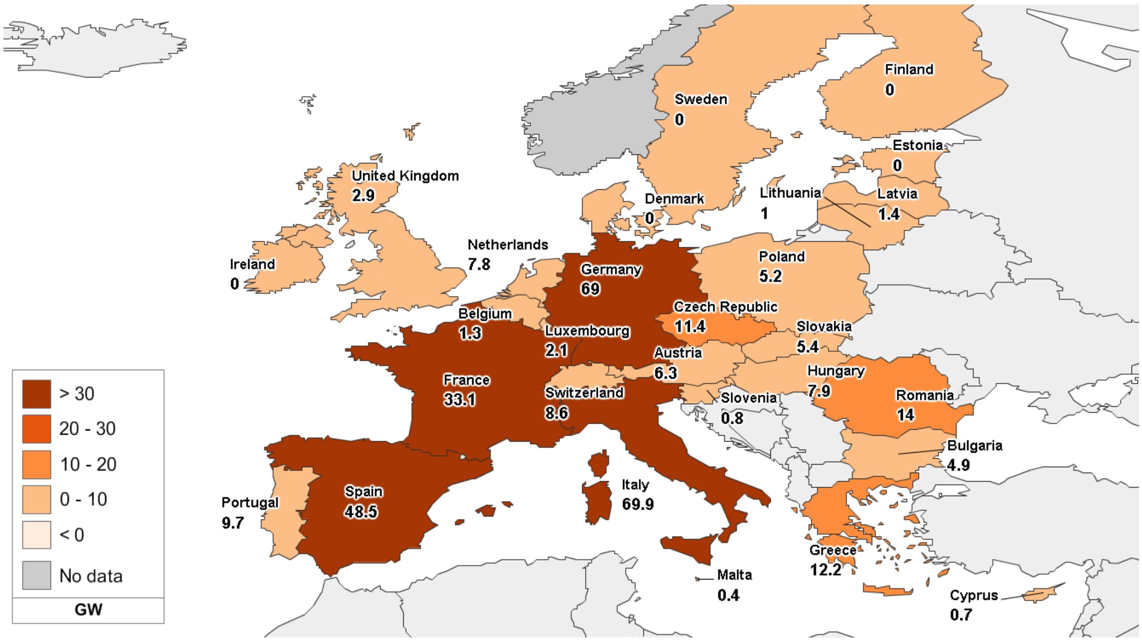
Source: own calcualtions, map visualization with StatPlanet.

Figure 58: Installed hydropower capacity in 2050 (Scenario B)



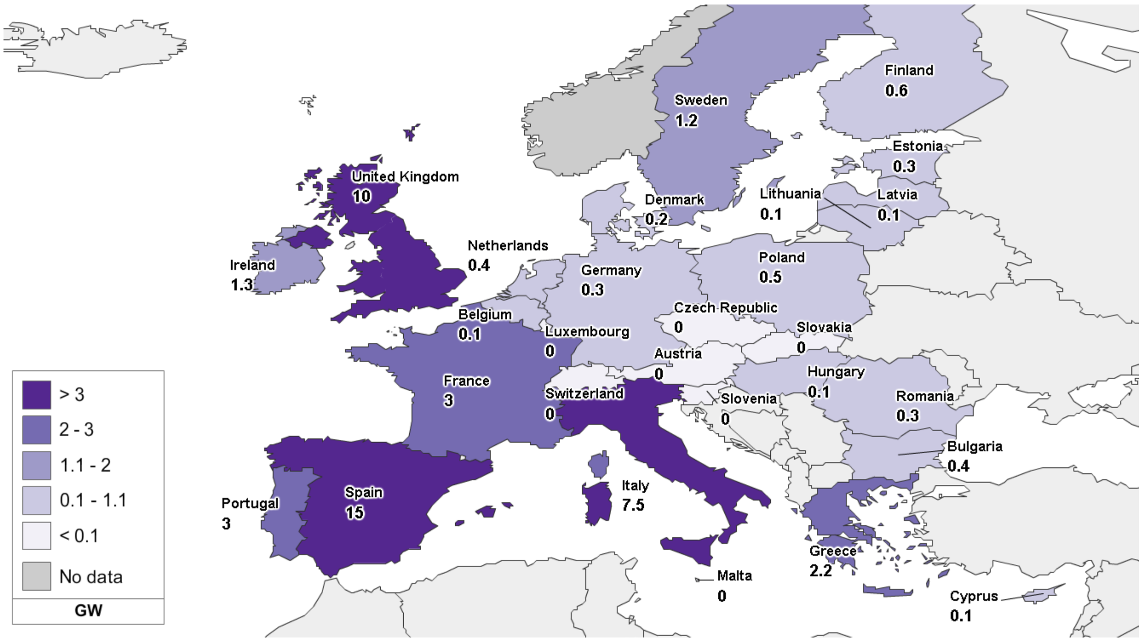
Source: own calcualtions, map visualization with StatPlanet.

Figure 59: Installed photovolatics capacity in 2050 (Scenario B)



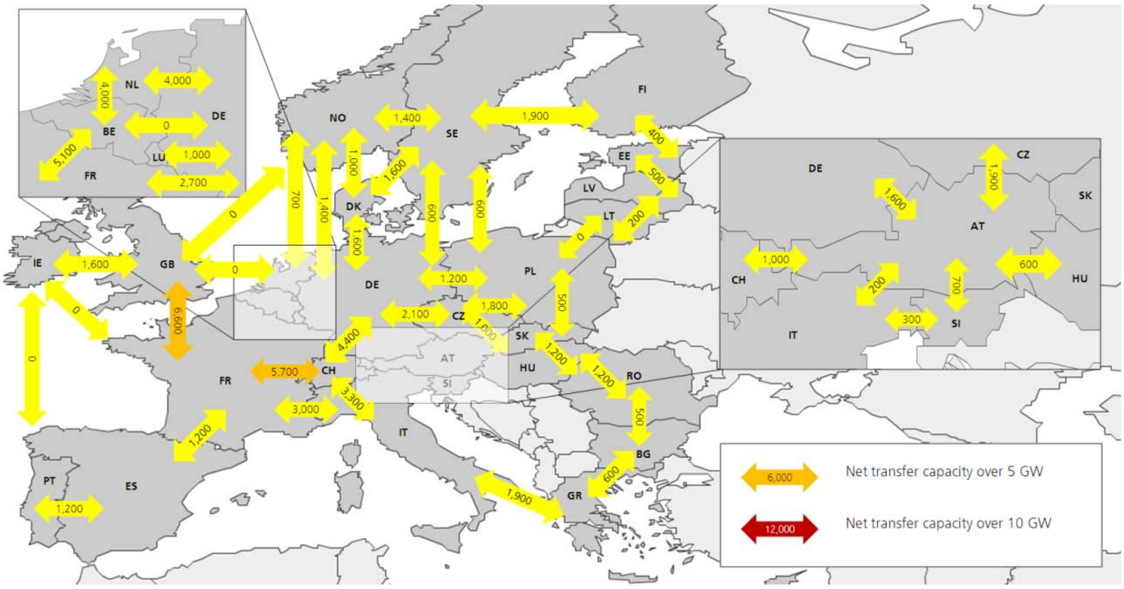
Source: own calcualtions, map visualization with StatPlanet.

Figure 60: Installed capacity of other technologies (biowaste, sewage and landfill gas, wave, tidal, geothermal and solar thermal) in 2050 (Scenario B)



Source: own calcualtions, map visualization with StatPlanet.

Figure 61: Installed net transfer capacities between countries in 2020 (Scenario A)



Source: onw calculations, map by StatPlanet.

Figure 62: Installed net transfer capacities between countries in 2030 (Scenario A)

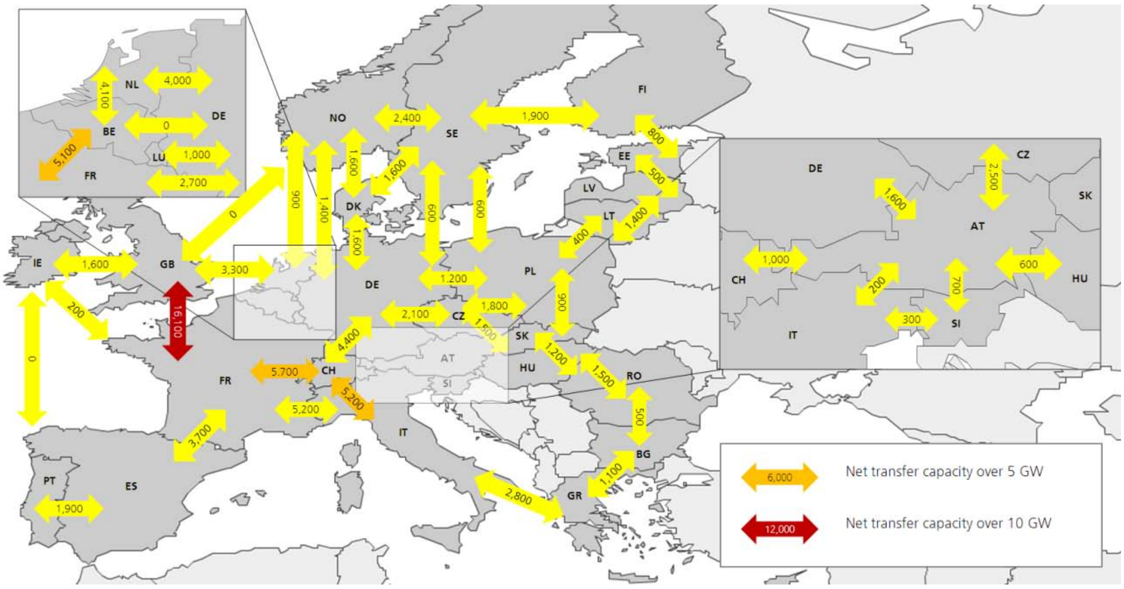
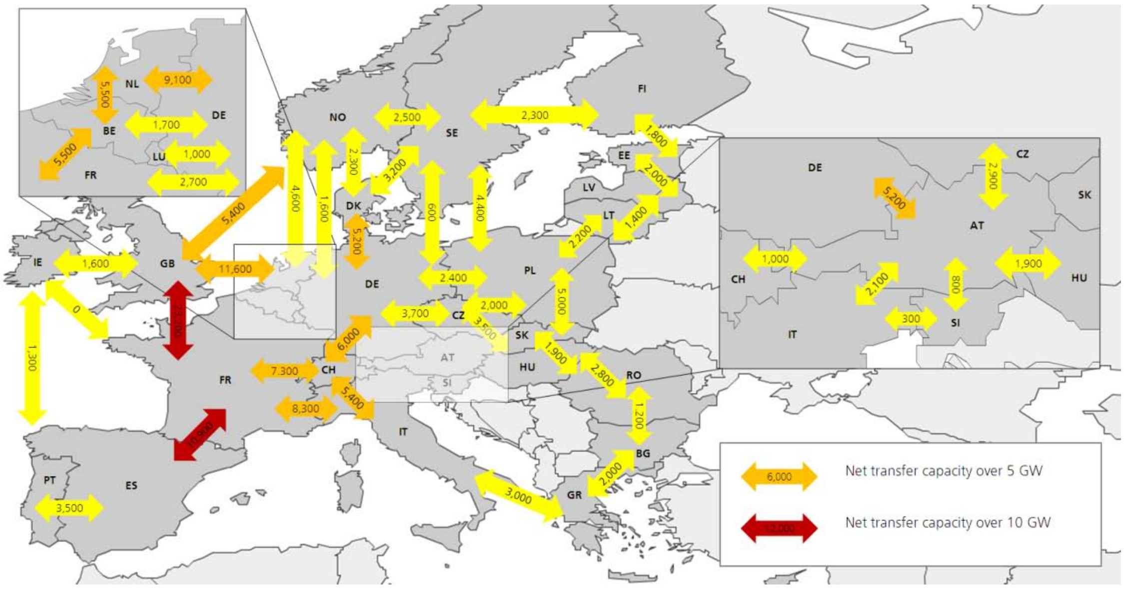
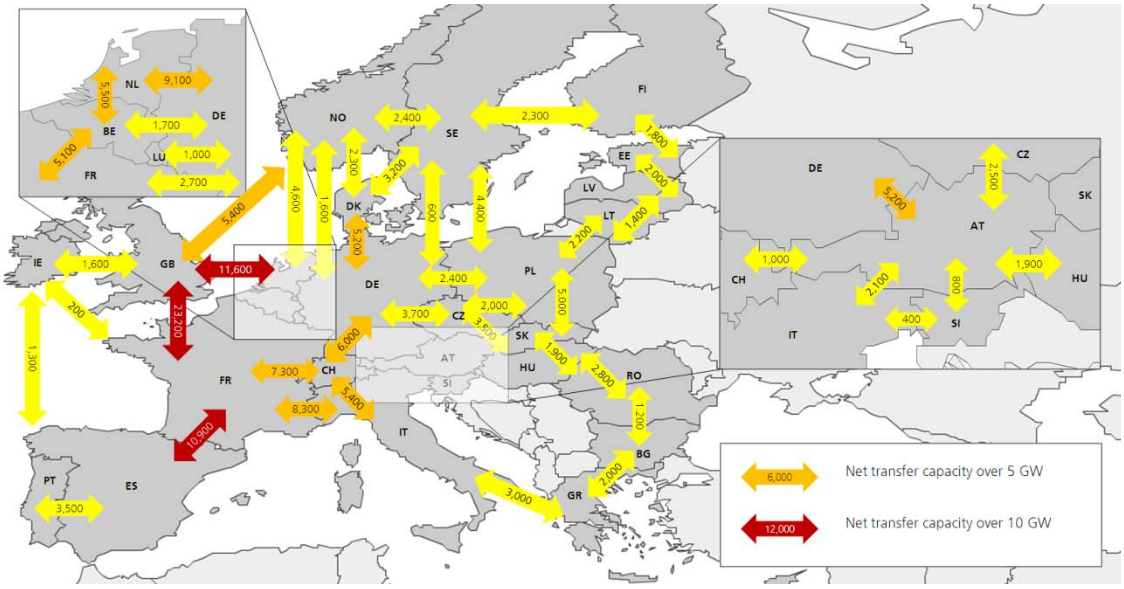


Figure 63: Installed net transfer capacities between countries in 2040 (Scenario A)



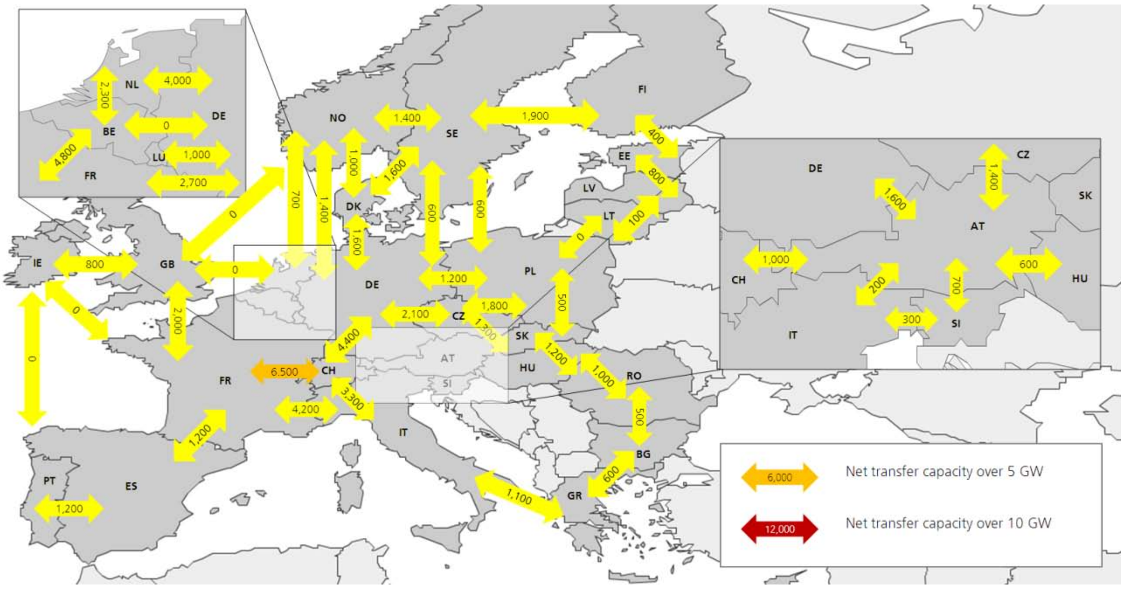
Source: onw calculations, map by StatPlanet.

Figure 64: Installed net transfer capacities between countries in 2050 (Scenario A)



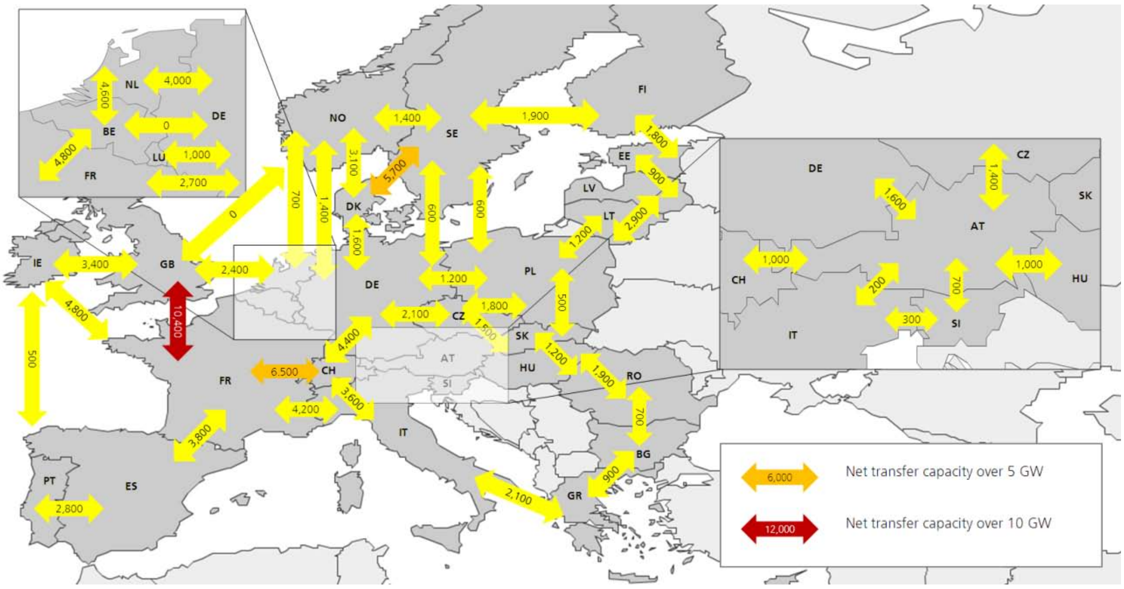
Source: onw calculations, map by StatPlanet.

Figure 65: Installed net transfer capacities between countries in 2020 (Scenario B)



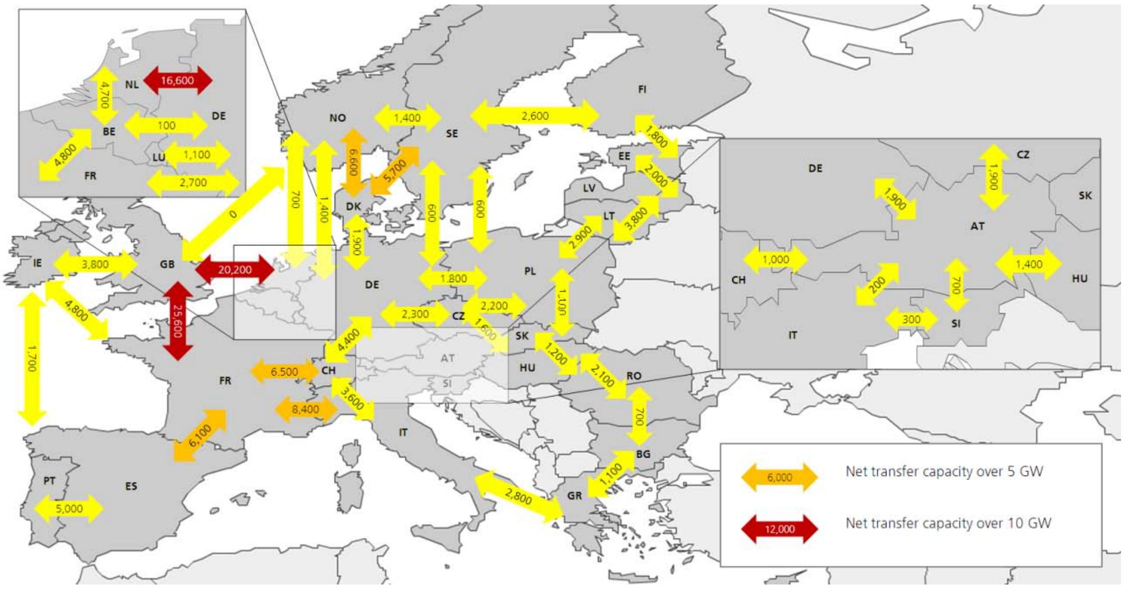
Source: onw calculations, map by StatPlanet.

Figure 66: Installed net transfer capacities between countries in 2030 (Scenario B)



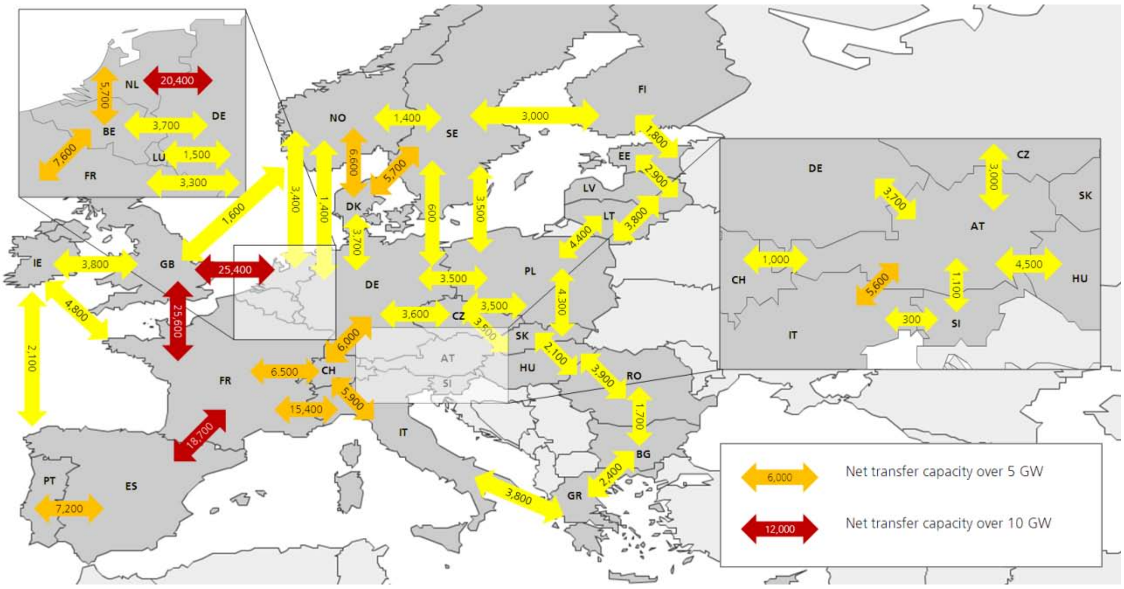
Source: onw calculations, map by StatPlanet.

Figure 67: Installed net transfer capacities between countries in 2040 (Scenario B)



Source: onw calculations, map by StatPlanet.

Figure 68: Installed net transfer capacities between countries in 2050 (Scenario B)



Source: onw calculations, map by StatPlanet.

Table 20: Quick fact sheet Scenario A

	2008	2020	2030	2040	2050	Unit
Net electricity generation	3,330	3,455	3,341	3,107	2,866	TWh
Grid losses	267	275	270	266	257	TWh
Storage losses	2	4	5	10	42	TWh
Net electricity demand	3,062	3,176	3,065	2,830	2,567	TWh
Effective RES-E generation	818	1,373	2,139	2,601	2,665	TWh
Effective RES-E share	25%	40%	64%	84%	93%	-
Conventional generation	2512	2082	1201	506	201	TWh
CO2 emissions	1154	763	508	174	71	Mt
Interconnector capacity	57	74	96	144	182	GW
Storage capacity	37.2	44.4	44.4	44.4	47.7	GW
Installed conv. capacity	568	380	295	211	160	GW
Wind onshore capacity	63	170	292	404	419	GW
Wind offshore capacity	1	43	107	144	160	GW
PV capacity	10	85	170	268	289	GW
Total RES-E generation cost	58.2	116.0	158.8	179.3	172.3	Billion €05
Specific RES-E cost	71.12	84.51	74.21	68.96	64.64	€05/MWh
Storage facilitiy cost	4.2	5.0	5.0	5.0	5.4	Billion €05
Interconnector cost	2.9	3.7	5.1	8.5	12.6	Billion €05
Conventional plants[a] cost	92.11	60.10	33.44	18.51	10.28	Billion €05
Conventional fuel cost	46.8	52.5	49.5	25.0	11.2	Billion €05
CO_2 cost	23.9	19.6	17.8	9.6	5.6	Billion €05
Total costs	**228.1**	**256.9**	**269.5**	**245.9**	**217.3**	**Billion €05**
Specific cost of demand	74.49	80.89	87.93	86.89	84.67	€/MWh

a. Including capital and operational expenditures without fuel costs.

Table 21: Quick fact sheet Scenario B

	2008	2020	2030	2040	2050	Unit
Net electricity generation	3,330	3,693	3,886	3,817	3,452	TWh
Grid losses	267	289	311	319	317	TWh
Storage losses	2	5	5	10	19	TWh
Net electricity demand	3,062	3,400	3,569	3,488	3,117	TWh
Effective RES-E generation	818	1,381	2,290	2,972	3,246	TWh
Effective RES-E share	25%	37%	59%	78%	94.0%	-
Conventional generation	2512	2312	1596	845	207	TWh
CO2 emissions	1154	890	680	292	72	Mt
Interconnector capacity	57	70	104	170	252	GW
Storage capacity	37.2	44.4	44.4	44.4	49.3	GW
Installed conv. capacity	568	410	396	327	236	GW
Wind onshore capacity	63	170	313	484	599	GW
Wind offshore capacity	1	43	117	161	191	GW
PV capacity	10	85	171	282	325	GW
Total RES-E generation cost	58.2	116.0	167.1	204.7	216.7	Billion €05
Specific RES-E cost	71.12	84.05	72.96	68.87	66.75	€05/MWh
Storage facilitiy cost	4.2	5.0	5.0	5.0	5.5	Billion €05
Interconnector cost	2.9	3.5	5.5	9.1	13.7	Billion €05
Conventional plants[a] cost	92.11	64.23	42.09	26.01	15.44	Billion €05
Conventional fuel cost	46.8	62.0	67.8	43.0	11.4	Billion €05
CO_2 cost	24.0	22.3	23.8	16.1	5.7	Billion €05
Total costs	**228.1**	**272.9**	**311.3**	**303.9**	**268.4**	**Billion €05**
Specific cost of demand	74.50	80.29	87.21	87.13	86.12	€/MWh

a. Including capital and operational expenditures without fuel costs.

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